TECHNICAL SUPPORT DOCUMENT

FOR

CONTROLLING NOx EMISSIONS

FROM

NON-ELECTRICAL GENERATING UNITS

AQPSTR 00-4

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AIR QUALITY PLANNING SECTION
DIVISION OF AIR POLLUTION CONTROL
BUREAU OF AIR
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Table of Contents

List of Figures and Tables

1.0 INTRODUCTION

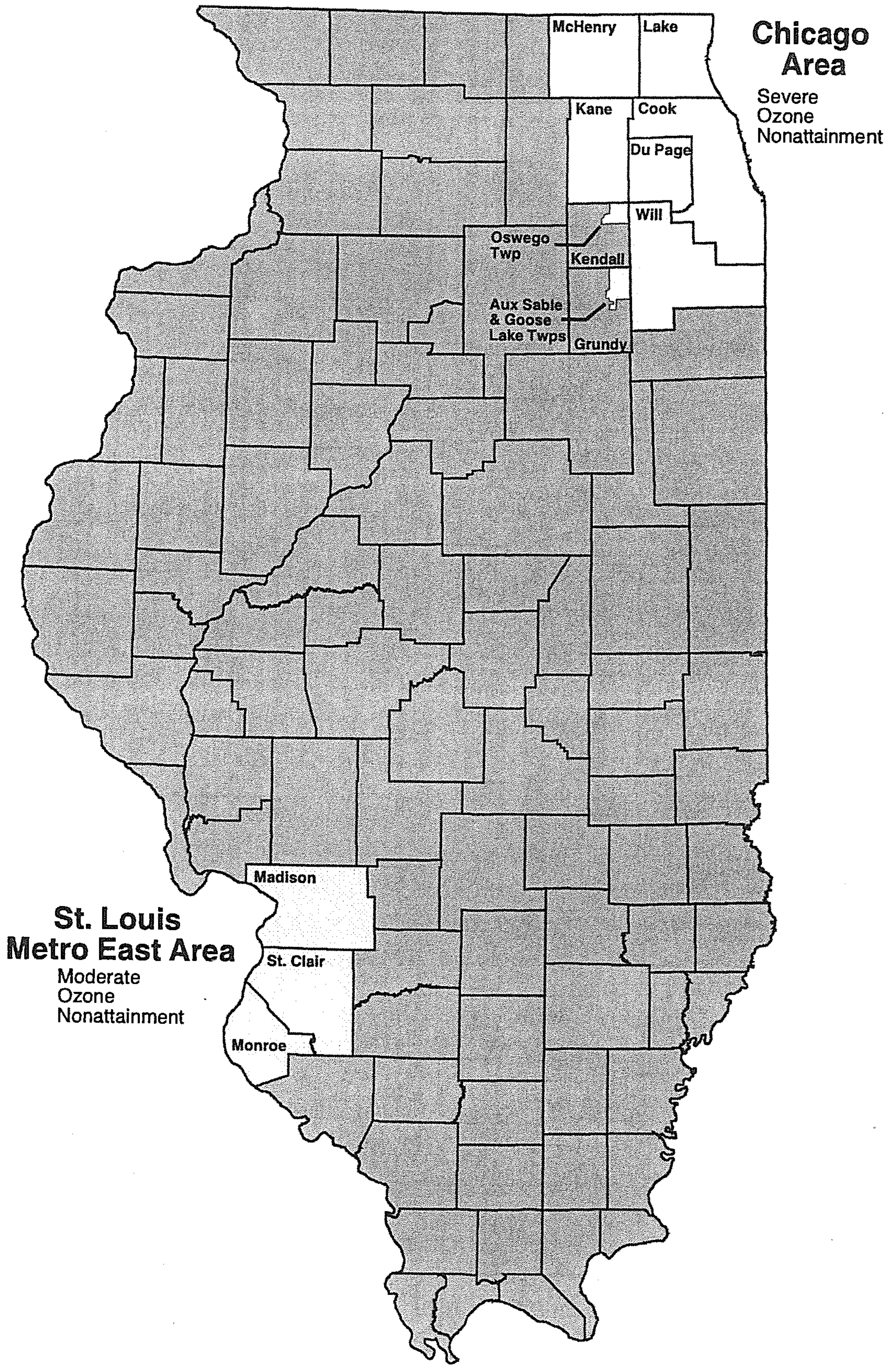
The United States Environmental Protection Agency ("U.S. EPA") has set national ambient air quality standards ("NAAQS") for ozone that are designed to minimize the impact on the public's health from this pollutant. Ground level ozone has been recognized, in both clinical and epidemiological research, as an air pollutant that affects public health.

Ground-level ozone is produced in complex chemical reactions when its precursors, primarily volatile organic material ("VOM") and oxides of nitrogen ("NOx"), react in the presence of sunlight. Past efforts by U.S. EPA and states to reduce ozone concentrations have been aimed at controlling VOM emissions through a variety of regulatory activities within the ozone nonattainment area. Although significant reductions in ozone levels have occurred, many areas still exceed the NAAQS. In Illinois, the Chicago and Metro-East St. Louis areas are still in nonattainment of the ozone standard. (See Figure 1-1). Recently, state and federal efforts have turned to reducing regional NOx emissions to achieve further ozone reductions.

In October 1998, the U.S. EPA determined that sources and emitting activities in each of the 22 States and the District of Columbia (23 jurisdictions) emit NOx in amounts that significantly contribute to nonattainment of the 1-hour ozone NAAQS in one or more downwind States and issued a call for revisions to states' implementation plans, commonly referred to as the "NOx SIP Call" (See Reference 1). The 23 jurisdictions included in the NOx SIP Call are Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. The NOx SIP Call was challenged in court (Michigan v. EPA) (See Reference 2). The court upheld the NOx SIP Call, but determined that U.S. EPA had not justified inclusion of Wisconsin. Inclusion of the entire States of Missouri and Georgia was remanded to U.S. EPA for further justification and subsequent rulemaking.

Based upon extensive air quality analyses conducted over the past five years, the NOx SIP Call requires each of the named upwind jurisdictions to submit revisions to their state implementation plans ("SIP") to reduce the contribution of sources in the upwind states to ozone problems downwind. U.S. EPA then identified measures it determined to be highly cost-effective - - an emissions rate of 0.15 lb/mmBtu from electrical generating units ("EGU") serving generators greater than 25 MWe, a 60 percent reduction of NOx emissions from large industrial boilers and turbines with capacities greater than 250 mmBtu/hour, a 30 percent reduction of NOx emissions from large cement kilns, and a 90 percent reduction of NOx emissions from large stationary internal combustion engines. In the NOx SIP Call legal proceedings, 90% level of NOx reduction for engines was also remanded to U.S. EPA for further justification and rulemaking.

Figure 1-1



Illinois Ozone Nonattainment Areas

On the basis of the reductions that could be obtained through highly cost-effective measures, then, U.S. EPA established jurisdiction or state-wide emission budgets for each of the source sectors in each jurisdiction. States are required to comply with those budgets. At the same time, U.S. EPA established the framework for a federal NOx emissions cap and trade program that it would administer for states that choose to participate. Given the need to meet the NOx SIP Call, the Illinois General Assembly has concluded that participation in the NOx cap and trade program is appropriate (See Reference 3).

Large industrial boilers, turbines, or combined cycle units whose primary purpose is to produce steam or electricity for a source's own use are defined as "non-EGUs". Those units that produce electricity with a primary intent to sell the electricity are defined as "EGUs" and are excluded from the non-EGU source category.

The U.S. EPA has determined that highly cost-effective measures are available to reduce NOx emissions from large non-EGUs. This is based on their finding that large non-EGU boilers and turbines that have rated heat input capacities greater than 250 million British Thermal Units ("mmBtu") per hour can reduce NOx emissions from their uncontrolled level by 60 percent at an average cost of less than $2000 per ton of NOx removed, the level which U.S. EPA has determined to be highly cost-effective. Based on this level of control, U.S. EPA established for Illinois a budget or cap of 4,882 tons of NOx for large non-EGU emissions during the ozone season control period (i.e., May 1 through September 30 of each year beginning in 2003).

To satisfy U.S. EPA's requirements, the Illinois EPA is proposing regulations to cap the NOx emissions from these large non-EGUs, which is consistent with U.S. EPA's NOx SIP Call. These regulations also authorize such large non-EGUs to participate in the Federal NOx Trading Program. This document provides the technical support for adoption of the proposed regulation.

2.0 PROCESS DESCRIPTION AND SOURCES OF EMISSIONS

Non-EGU boilers produce steam or hot water for use in industrial processes or space and process heating and for the generation of mechanical power and electricity. Non-EGU gas turbines are used for driving gas and oil pipeline transmission equipment, the generation of electric power for both standby and continuous needs and the cogeneration of electricity and process steam for industrial use. Non-EGU industrial, commercial and institutional ("ICI") boilers generally have heat input capacities ranging from 0.4 to 1,500 mmBtu/hr. Industrial boilers generally have heat input capacities ranging from 10 to 250 mmBtu/hr. Large industrial boilers with heat input greater than 250 mmBtu/hr are similar to utility boilers in design and operation. ICI boilers with heat input capacities less than 10 mmBtu/hr are generally classified as commercial /institutional units and are used in wide array of applications, such as wholesale and retail trade buildings, office buildings, hotels, restaurants, hospitals, schools, museums, government buildings, airports, primarily providing steam and hot water for space heating.

An important way of classifying boilers is by heat transfer configuration. The four major configurations are watertube, firetube, cast iron, and tubeless. In a watertube boiler, combustion heat is transferred to water through tubes lining the furnace walls and boiler passes. Depending on their size, watertube boilers can be packaged or field erected. In general, most units greater than 200 mmBtu/hr heat input capacity are field erected.

In a firetube boiler, the hot combustion gases flow through tubes immersed in boiler water, transferring heat to the water. Firetube boilers are typically small with heat input capacities limited to less than 50 mmBtu/hr and steam pressures limited to 300 pounds per square inch gauge ("psig").

In a cast iron boiler, combustion gasses 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. They are used primarily in the residential and commercial sectors, and have heat input capacities up to 14 mmBtu/hr.

The tubeless design incorporates nested pressure vessels with water in between the shells. Combustion gasses are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

As the type and sizes of ICI boilers are extremely varied, so are the fuel types and methods of firing. The most commonly used fuels include natural gas, distillate and residual fuel oils, and coal in both crushed and pulverized form. Natural gas and fuel oil are burned in single or multiple burner arrangements. 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 via a nozzle in the center of each burner. Heavy fuel oils must be preheated to decrease viscosity and improve atomization.

Crushed coal is burned in stoker and fluidized bed combustion ("FBC") boilers. Stoker coal is burned mostly on a grate (moving or vibrating) and is fed by various means. Most popular are the spreader and overfeed methods. Crushed coal in FBC boilers burns in suspension in either a stationary bubbling bed of fuel and bed material or in a circulating fashion. The bed material is often a mixture of sand and limestone for capturing SO_2. Higher fluidizing velocities are necessary for circulating beds which have become more popular because of higher combustion and SO_2 sorbent efficiencies. Where environmental emissions are strictly controlled and low grade fuels are economically attractive, FBC boilers have become particularly popular because of characteristically low NOx and SO_2 emissions.

Combustion in pulverized coal ("PC") fired boilers takes place almost entirely while the coal is suspended, unlike in stoker units, in which most, if not all, of the coal burns on a grate. Finely ground coal is typically mixed with primary combustion air and fed to the burner or burners, where upon it is ignited and mixed with secondary combustion air.

Depending upon the location of burners and the direction of coal injection in to the furnace, wall and tangential are the two most common firing configurations in the PC-fired units. Wall-fired boilers can be either single-wall-fired, with burners or only one all of the furnace firing horizontally, or opposed-wall-fired, with burners mounted on two opposing walls. In the tangential firing configuration, the burners are mounted in the concerns of the furnace. The fuel and air are infected toward the center of the furnace to create a vortex that enhances air /fuel mixing.

Although the primary fuel types are fossil based, there are a growing percentage of nonfossil fuels being burned for industrial steam and nonutility power generation. These fuels include municipal and agricultural wastes, and special wastes such as shredded tires, refuse derived fuel ("RDF"), tree bark and saw dust, and black liquor from the production of paper. Solid waste fuels are typically burned in stoker or FBC boilers which provide for mass feed of bulk material with minimal pretreatment and handling of large quantities of ash and other inorganic matter. Some industries also supplement their primary fossil fuels with hazardous organic chemical waste with medium to high heating value. Some of these wastes can contain large concentrations of organically bound nitrogen that can be converted to NOx emissions.

NOx is the high-temperature byproduct of the combustion of fuel and air. When fuel is burned with air, nitric oxide ("NO"), the primary form of NOx, is formed mainly from the high temperature reaction of atmospheric nitrogen and oxygen (thermal NOx) and from the reaction of organically bound nitrogen in the fuel with oxygen (fuel NOx). A third and less important source of NO formation is referred to as "prompt NO," which forms from the rapid reaction of atmospheric nitrogen with hydrocarbon radical to form NOx precursors that are rapidly oxidized to NO at lower temperatures. Prompt NO is generally minor compared to the overall quantity of NO generated from combustion. However, as NOx emissions are reduced to extremely low limits, i.e., with natural gas combustion, the contribution of prompt NO to total NOx emissions becomes more significant.

The mechanisms of NOx formation in combustion are very complex and cannot be predicted with certainty. Thermal NOx is an exponential function of temperature and varies with the square root of oxygen concentration. Most of the NOx formed from combustion of natural gas and high grade fuel oil (e.g., distillate oil or naphtha) is attributable to thermal NOx. Because of the exponential dependence on temperature, the control of thermal NOx is best achieved by reducing peak combustion temperature. Fuel NOx results from the oxidation of fuel-bound nitrogen. Higher concentrations of fuel nitrogen typically lead to higher fuel NOx and overall NOx levels. Therefore, combustion of residual oil with 0.5 percent fuel-bound nitrogen, will likely result in higher NOx levels than natural gas or distillate oil. Similarly, because coal has higher fuel nitrogen content, higher baseline NOx levels are generally measured from coal combustion than either natural gas or oil combustion. This occurs in spite of the fact that the conversion of fuel nitrogen to fuel NOx typically diminishes with increasing nitrogen concentration. Higher heat release rate and preheated combustion air increase the peak temperature of the flame and contribute to higher baseline NOx levels.

A detailed discussion of the description and sources of NOx emissions are contained in the U.S. EPA's Alternative Control Techniques ("ACT") documents which describe how NOx emissions can be reduced from ICI boilers and gas turbines (See References 4 and 5). The ACT for ICI boilers contains information on each type of boiler; however this TSD will only address the types of boilers potentially affected by the proposal.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are comprised of three major components: compressor, combustor, and power turbine. Ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo.

Hot combustion gases are diluted with additional air from the compressor station and directed to the turbine section at temperatures up to 2350°F. Energy from the hot expanding exhaust gases are then recovered in the form of a shaft horsepower, of which 50 percent is needed to drive the internal compressor and the balance of recovered shaft energy is available for useful work.

The heat content of gases exiting the turbine can either be discarded without heat recovery (simple cycle); used with a heat exchanger to preheat combustion air entering the combustor can (regenerative cycle); used with or without supplementary firing, in a heat recovery steam generator to raise process steam temperature (cogeneration); or used with or without supplementary firing to raise steam temperature for a steam turbine. The majority of gas turbines used in large stationary installations are either peaking simple cycle two-shaft or base load combined cycle gas turbines.

The principle type of NOx formed in a turbine firing natural gas or distillate oil is thermal NOx. Most thermal NOx is formed in high temperature stoichiometric flame pockets downstream of fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface. The maximum thermal NOx production occurs at a slightly lean-fuel mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reduction in thermal NOx. The thermal NOx generation also decreases rapidly as the temperature drops below the adiabatic temperature (for a given stoichiometry). Maximum reduction in thermal NOx generation can thus be achieved by control of both the combustion temperature and the stoichiometry.

Table 1 shows a summary of the uncontrolled NOx emissions from various types of non-EGUs.

Table 1
Summary of Non-EGU Baseline NOx Emissions

Fuel	Type of Unit	Uncontrolled NOx range, lb/mmBtu	Average, lb/mmBtu
Pulverized Coal	Wall-fired Boiler	0.46-0.89	0.69
Pulverized Coal	Tangential	0.53-0.68	0.61
Coal	Spreader stoker Boiler	0.35-0.77	0.53
	Bubbling FBC Boiler	0.11-0.81	0.32
	Circulating FBC Boiler	0.14-0.60	0.31
Residual Oil	Watertube Boiler	0.31-0.60	0.38
Distillate Oil	Watertube Boiler	0.18-0.23	0.21
Natural Gas	Watertube Boiler	0.11-0.45	0.26
Natural Gas	Gas Turbine	0.4 – 1.7	.44
Oil	Gas Turbine	0.55 – 2.5	0.698

3.0 TECHNICAL FEASIBILITY OF CONTROLS

The reduction of NOx emissions from ICI boilers can be accomplished with combustion modification and flue gas treatment techniques or a combination of these. The application of a specific technique will depend on the type of boiler, the characteristic of its primary fuel, and method of firing. Some controls have seen limited application, whereas certain boilers have little or no flexibility for modification of combustion conditions because of method of firing, size, or operating practices.

3.1 Combustion NOx Control Technologies

NOx emissions can be controlled by suppressing both thermal NOx and fuel NOx. When natural gas or distillate oil is burned, thermal NOx is the only component that can be practically controlled due to the low levels of fuel nitrogen in the distillate oil. The combustion modification techniques that are most effective in reducing thermal NOx are particularly those that reduce peak temperature of the flame. This is accomplished by quenching the combustion with water injection or steam injection ("WI/SI"), recirculating a portion of the flue gas to the burner zone, or a flue gas recirculation ("FGR"), and reducing air preheat temperature ("RAP") when preheated combustion air is used. The use of WI/SI has thus far been limited to small gas-fired boiler applications in Southern California to meet very stringent NOx standards. Although very effective in reducing thermal NOx, this technique has not been widely applied because of its potential for large reduction in thermal efficiency safety, and burner control problems. FGR, on the other hand, has a wide experience base. The technique is implemented by itself or in combination with low NOx burners ("LNB") retrofits. In fact, many LNB designs for natural gas-fired ICI boilers incorporate FGR. RAP is not a practicable technique because significant losses in boiler efficiency occur when the flue gas bypasses the air preheaters.

Thermal NOx can also be reduced to some extent by minimizing the amount of excess oxygen, delaying the mixing of fuel and air, and reducing the firing capacity of the boiler. The first technique is often referred to as oxygen trim ("OT") or low excess air ("LEA") and can be attained by optimizing the operation of the burner(s) for minimum excess air without excessive increase in 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. OT and LEA are often impractical on packaged watertube and firetube boilers due to increased flame lengths and increase in CO emissions, and can lead to rear wall flame impingement, especially when fuel oil is fired. 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, the most practical 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. The third technique involves reducing the boiler firing rate to lower the peak temperature in the furnace. This approach is not often considered because it involves reducing steam generation capacity that must be replaced elsewhere. Also, with some fuels, gains in reduction of thermal NOx are in part negated by increases in fuel NOx that result by increases in excess air at reduced boiler load.

The reduction of fuel NOx with combustion modifications is most effectively achieved with the staging of combustion air ("SCA"). By suppressing the amount of air below that required for complete combustion (stoichiometric conditions), the conversion of fuel nitrogen to NOx can be minimized. This SCA technique is particularly effective on high nitrogen fuels such as coal and residual oil, which may cause high baseline emissions and would result in high reduction efficiencies. For pulverized coal ("PC)" boilers, BOOS for NOx reduction is not practical. Therefore, SCA is usually accomplished with the retrofit of internally air staged burners or overfire air ports. The installation of low-NOx burners for PC- and residual oil-fired boilers is a particularly effective technique because it involves minimal furnace modifications and retains firing capacity. Staged fuel burners in some packaged watertube boilers without membrane convective side furnace wall(s) may cause an increase in CO emissions at the stack, due to short circuiting of incomplete combustion products to the convective section. The installation of overfire air ("OFA") ports for some boilers is not practicable.

These boilers are principally firetube and watertube packaged designs and most PC-fired units. Large field-erected gas- and low-sulfur oil-fired ICI boilers are the best candidates for the application of OFA because these fuels are least susceptible to the adverse effects of combustion staging, such as furnace corrosion and unburned fuel emissions.

Another combustion modification technique involves the staging of fuel, rather than combustion air. By injecting a portion of the total fuel input downstream of the main combustion zone, hydrocarbon radicals created by the reburning fuel will reduce NOx emission from the primary fuel. This reburning technique is best accomplished when the reburning fuel is natural gas. Natural gas reburning ("NGR") and cofiring have been investigated primarily for utility boilers, especially coal-fired units that are not good candidates for traditional combustion modifications such as LNB. Examples of these boilers are cyclones and stoker fired furnaces. Application of these techniques on ICI boilers has been limited to some municipal solid waste ("MSW") and coal-fired stoker boilers.

3.2 Post Combustion NOx Controls Technologies

Two commercially available post combustion flue gas treatments include selective non-catalytic reduction ("SNCR") and selective catalytic reduction ("SCR"). SNCR involves injecting ammonia ("NH_3") or urea into the flue gas to yield elemental N_2 and water. The ammonia or urea must be injected into the specific high-temperature zones in the upper furnace or convective pass for this method to be effective. By-product emissions of SNCR include N_2O and ammonia slip. In the SCR process, ammonia is injected into the flue gas in the presence of a catalyst and NOx is converted in to N_2 and water.

SNCR is a process that uses ammonia-based reagents to selectively reduce NOx to nitrogen and water without the presence of a catalyst. The principal attractive feature of this technology is that it does not rely on any catalyst surface and, therefore can be implemented at much lower costs compared to catalyst-based technologies. 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 is in the range of 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. Depending on the fuel type, 50 to 80 percent NOx reduction can be achieved with ammonia injection. For urea-based systems, the NOx reduction efficiencies are in the range of 25 to 88 percent.

The SCR process takes advantage of the selectivity of ammonia to reduce NOx to nitrogen and water at lower temperature in the presence of a catalytic surface. The SCR process is based on the selective reduction of NOx by NH_3 over a catalyst in the temperature range of 575° to 800°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. SCR retrofit ICI applications in this country have been limited to a few boilers in California, although the technology is widely used abroad. Nox reduction efficiencies with SCR have been reported in the range between 53 and 90 percent.

3.3 Viable Control Technologies for Affected Sources

The most effective NOx control techniques for PC-fired ICI boilers are LNB, NGR, and LNB+SCA. The federal ACT found that the average reduction achieved with the retrofit of LNB on seven ICI boilers was 55 percent with a controlled NOx emissions rate of 0.35 lb/mmBtu. A combination of LNB plus OFA also achieved an average NOx emissions rate of 0.35 lb/mmBtu on eight ICI boilers. Lower NOx emissions were achieved for tangentially fired-boilers. Evaluation of retrofit combustion controls for coal-fired stokers revealed control efficiencies in the range of 0 to 60 percent. This wide range in control efficiency is attributed to the degree of staging implemented and the method of staging. Typically, existing OFA ports on stokers are not ideal for effective NOx staging. Furthermore, the long term effectiveness of these controls for stokers was not evaluated in these exploratory tests. The average NOx reduction for eight stokers with enhanced air staging was found to be 18 percent with a corresponding controlled NOx emissions rate of 0.38 lb/mmBtu. The gas cofiring in coal-firing stokers, only recently explored, achieves NOx reductions in the 20 to 25 percent range only by being able to operate at lower excess air.

Air staging in coal-fired FBC boilers is very effective in reducing NOx from these units. FBCs are inherently low NOx emitters because low furnace combustion temperatures preclude the formation of thermal NOx. Furthermore, the in-bed chemistry between coal particles, CO, and bed materials (including SO_2 sorbents) maintains fuel nitrogen conversion to NO at a minimum. The control of NOx is further enhanced by operating these boilers with some air staging. In fact, many new FBC designs, including circulating FBCs, come equipped with air staging capability especially for low NOx emissions. Excessive substoichiometric conditions in the dense portion of the fluidized bed can result in premature corrosion of immersed watertubes used in bubbling bed design. Circulating FBC boilers are better suited for deep staging because these units do not use in-bed watertubes.

NOx reductions and controlled levels for residual oil combustion are influenced by the nitrogen content of the oil, the degree of staging implemented, and other fuel oil physical and chemical characteristics. Because of these factors, NOx control performance on this fuel is likely to vary. The data contained in the ACT for LNB technology for residual oil-fired ICI boilers was obtained primarily from foreign applications. The average controlled NOx level reported with LNB for residual oil-fired ICI boilers is 0.19 lb/mmBtu based on 17 Japanese installations and one domestic unit equipped with Babcock and Wilcox (B&W) XCL-FM burner for industrial boilers.

The ACT database for distillate oil- and natural gas-fired boilers is much larger than that for residual oil-fired units. This is because many of the distillate oil- and natural gas-fired applications are in California, where current regulations have imposed NOx reductions from such units. Among the controls more widely used are LNB, FGR, and LNG with FGR. Many LNB designs also incorporate low excess air and FGR, internal to the burner or external in a more conventional application. The average NOx reduction for FGR on natural gas-fired boilers is approximately 60 percent from many industrial boilers, nearly all located in California. The average controlled NOx level for FGR-controlled ICI watertube boilers is 0.05 lb/mmBtu or approximately 40 ppm corrected to 3 percent O_2. For distillate oil, the average FGR-controlled level from watertube boilers is 0.08 lb/mmBtu or approximately 65 ppm corrected to 3 percent O_2. Average NOx emissions controlled with LNB plus FGR are slightly lower than these levels.

Application of flue gas treatment controls in the United States is generally sparse. NOx reduction efficiency of SNCR for PC-fired boilers is based on results from four boilers, one a small utility unit. For these boilers, NOx reductions ranged from 30 to 83 percent and averaged 60 percent, with controlled NOx levels in the range of 0.15 to 0.40 lb/mmBtu. SNCR performance is known to vary with boiler load because of the shifting temperature window. SNCR has been reported to be more effective for FBC and stoker boilers. In a circulating FBC boiler in California, SNCR with either urea or ammonia injection, achieved an average NOx reduction and controlled level of nearly 75 percent and 0.08 lb/mmBtu, respectively. SNCR results for 13 coal-fired stokers ranged from 40 to 74 percent reduction, with controlled NOx levels between 0.14 and 0.28 lb/mmBtu.

Table 2 summarizes the NOx reductions performances of various NOx control technologies applicable to the types of ICI boilers which may be affected by the proposal.

Table 2
Summary of NOx Reduction Performance for ICI Boilers

Boiler Type and Fuel	NOx Control	Range in Performance: Reduction Efficiency %	Range in Performance: Controlled NOx lb/mmBtu	Average Performance: Reduction Efficiency (%)	Average Performance: Controlled NOx lb/mmBtu
PC-fired boilers: All firing types With wall or Corner burners	SCA	15-39	0.33-0.93	27	0.62
	LNB	18-67	0.26-0.50	55	0.35
	Reburn+OFA	30-65	0.23-0.52	52	0.34
	LNB+SCA	42-66	0.24-0.49	60	0.38
	SNCR	30-83	0.15-0.40	45	0.39
Coal-fired stokers	SCA	-1-35	0.22-0.52	18	0.38
	SNCR	40-74	0.14-0.28	58	0.22
Coal-fired FBC	SCA	40-67	0.05-0.45	58	0.18
	FGR+SCA	N/A	0.12-0.16	N/A	0.14
	SNCR	57-88	0.03-0.14	74	0.08
	SCR	53-63	0.10-0.15	60	0.12
Gas-fired single Burner watertube	WI	50-77	0.04-0.056	64	0.05
	FGR	53-74	0.02-0.08	64	0.05
	LNB	46-71	0.03-0.11	58	0.08
	LNB+FGR	55-84	0.018-0.09	76	0.06
	SCR	80-91	0.011-0.06	85	0.024
Gas-fired multi-Burner watertube	SCA (BOOS)	17-46	0.06-0.24	31	0.15
	LNB	39-52	0.10-017	46	0.12
	SCNR	5-72	0.03-0.19	58	0.10
	SCR	N/A	0.024	N/A	0.024
	LNB+SCA	N/A	0.10-0.20	N/A	0.15
Distillate Single Burner watertube	LNB	N/A	0.08-0.33	N/A	0.10
	FGR	20-68	0.04-0.15	44	0.08
	LNB+FGR	N/A	0.03-0.13	N/A	0.07
	SCR	N/A	0.011	N/A	0.011
Residual-oil single Burner watertube	LNB	30-60	0.09-0.23	40	0.19
	FGR	4-30	0.12-0.25	15	0.17
	LNB+FGR	N/A	0.23	N/A	0.23
Residual-oil multi-Burner watertube	SCA	5-40	0.22-0.74	20	0.34
	LNB	30-60	0.09-0.23	40	0.19
	LNB+SCA	N/A	0.22	N/A	0.22
	SCR	58-90	0.025-0.15	85	0.045

The ACT for gas turbines contains information on combustion and post-combustion controls for reducing NOx. Although, the output capacities of the gas turbines are generally described in megawatts ("MW"), they are used in producing electricity and mechanical power to run industrial devices. The control techniques are the same for a gas turbine whether it runs an electric generator or a compressor. Water or steam injection lowers combustion temperatures, which reduces thermal NOx formation. Fuel NOx is not reduced with this technique, however, steam or water injection can achieve emission levels from 25 to 75 parts per million by volume ("ppmv") for natural gas fuel and from 42 to 110 ppmv for distillate oil fuel. Depending upon the uncontrolled level, this technique can achieve NOx emissions reduction from 70 to 90 percent.

Dry low NOx combustion design reduces combustion temperatures, thereby reducing thermal NOx. Lean premixed combustion is commercially available technology that functions by providing a large amount of excess air to the combustion chamber, lowering peak flame temperatures by dilution. Air and fuel are premixed in lean premixed combustors to avoid the creation of local fuel-rich and, therefore, high-temperature regions. Controlled emission levels achievable on gas-fired turbines are in the order of 25 to 42 ppmv which corresponds to NOx emissions reductions of 60 to 90 percent.

Regarding the post-combustion techniques, SCR as described above is available to reduce NOx emissions. Achievable emission reductions using SCR exceed 90 percent, which corresponds to controlled emissions below 10 ppmv.

4.0 COST EFFECTIVENESS OF CONTROLS

The U.S. EPA has prepared a number of cost effectiveness estimates for controlling NOx emissions from ICI boilers and gas turbines. Two of the most recent and significant estimates are contained in the federal ACTs for ICI boilers and gas turbines, and the Regulatory Impacts Analysis ("RIA") for the NOx SIP Call, FIP, and Section 126 Petitions (See References 4, 5, and 6). The Illinois EPA is relying on these documents to estimate the cost effectiveness of controlling NOx emissions from ICS boilers and gas turbines in Illinois affect by the Illinois NOx sources to the level proposed by this rulemaking.

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. 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 ACTs describe the costs of various NOx controls applicable to the non-EGU ICI boilers and gas turbines. Depending on the type and size of the unit, 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, and this regulatory proposal are based on controlling large non-EGUs (i.e., a boiler or turbine greater than 250 mmBtu/hr design capacity), data for that size of unit was extracted from the ACT. Tables 3 and 4 summarize the cost effectiveness of various control options for large non-EGUs, excluding any impact of emissions trading.

Table 3
Cost Effectiveness of Various Control Options for Non-EGU Boilers

Type of Unit	NOx Control Technology	Unit Capacity, (mmBtu/hr)	Cost-effectiveness ($/ton NOx removed)
PC Wall-fired Boiler	LNBurner	250 - 750	980 – 1,760
	SNCR-ammonia	250 - 750	1,270 – 1,450
	SNCR-urea	250 - 750	960 – 1,340
	SCR	250 - 750	3,000 – 4,800
CFBC	SNCR-urea	250 - 750	810 – 1,130
Spreader Stoker	SNCR-urea	250 - 750	1,80 – 1,480
N. Gas-fired Single Burner	WI + OT	250	380 – 430
N. Gas Wall-fired Multiple Burner	LNB	250	240 - 920
	LNB + FGR	250	650 – 1,760
	SCR	250	1,810 – 3,460
	BOOS + OT	250 - 750	150 – 330
	BOOS + WI + OT	250 - 750	300 – 570
	LNB	250 - 750	1,690 – 6,210
Distillate Oil Single Burner	LNB	250	280 – 1,110
	LNB + FGR	250	580 – 1,910
Dist. Oil Wall-fired Multiple Burner	SCR	250	2,170 – 4,150
	LNB	250 - 750	2,530 – 7,450
Residual-Oil-fired Single Burner	LNB	250	150 – 580
Resi. Oil Wall-fired Multiple Burner	LNB + FGR	250	520 – 1,220
	SCR	250	1,140 – 2,190
	LNB	250 - 750	1,330 – 2,680

Table 4
NOx Control Cost Effectiveness for Gas- and Oil-Fired Non-EGU Gas Turbines

Type of Control	Cost Effectiveness ($/ton)	
	Peaking (25 – 100 MWe)	Continuous (25 – 100 MWe)
Water and Steam Injection	Oil-fired = 1,210 – 1,900 Gas-fired = 1,780 – 2,350	Oil-fired = 672 – 1,000 Gas-fired = 375 – 1,130
Dry Low NOx Combustors	Gas-fired = 219 – 560	Gas-fired = 55 – 140
Low NOx Combustors + SCR	Gas-fired = 924 – 2,400	Gas-fired = 348 – 902
Wet Injection + SCR	Oil-fired = 2,260 – 5,563 Gas-fired = 3,340 – 4,080	Oil-fired = 1,070 – 1,410 Gas-fired = 645 – 1,800

4.2 NOx SIP Call Cost Effectiveness

There are two types of costs incurred with the addition of NOx control technologies: a one-time capital cost for new equipment installation, and increased annual operating and maintenance costs. In general, economies of scale exist for pollution control technologies for both capital costs and operating and maintenance costs. Thus, the size of the unit to which controls are applied will determine, in part, the cost of implementing the pollution control(s).

In U.S. EPA's analysis, large industrial boilers and combustion turbines are included in the NOx Trading Program. These sources will be allowed to participate in this interstate emissions trading program if States elect to include these sources in this program. U.S. EPA has modeled the cost effectiveness of the NOx SIP Call and the effect of its cap and trade program on cost effectiveness using its Integrated Planning Model ("IPM"). However, the IPM model does not currently cover the non-EGU sources, so U.S. EPA has conducted a least-cost analysis for them. The least-cost analysis is U.S. EPA's attempt to simulate the outcome of an efficient emissions trading program by assigning control responsibility based on sources with the lowest control costs. The least-cost analysis only reflects the efficient allocation of control responsibility among the group of industrial boilers and turbines, and does not, therefore, take advantage of potentially more efficient outcomes that could occur if these sources were modeled in conjunction with the rest of the utility sources included in the NOx SIP Budget Trading Program.

Table 5 shows the emissions reductions achieved in the least-cost analysis for each regulatory alternative. The table indicates that the alternatives achieve incremental reductions from the 2007 Clean Air Act ("CAA") baseline ranging from 31 percent to 66 percent.

Table 5
2007 Ozone Season NOx Baseline Emissions and Emission Reductions for Large Non-EGUs

Regulatory Alternative	Number of Affected Sources	2007 Baseline NOx Emissions (tons/control period)	2007 Post-Control NOx Emissions (tons/control period)	2007 Emission Reductions (tons/control period)
40% Control	292	194,445	133,630	60,815
50% Control	592	194,445	108,880	85,565
60% Control	803	194,445	90,193	104,252
70% Control	805	194,445	65,611	128,834

In addition to control costs, potentially affected sources could incur administrative costs associated with the collection and reporting of NOx emissions. Estimates are developed of the administrative costs for requirements beyond those that exist in the baseline. The additional requirements include one-time activities and annual activities. The RIA document provides information on the administrative costs associated with trading for EGUs. These same costs apply to industrial boilers and turbines and other stationary sources that participate in the trading program, and these costs are provided in the RIA.

Table 6 shows the annual costs and resulting average cost-effectiveness for each regulatory alternative. The annual control costs range from $49.5 to $249.5 million for all affected sources. Annual monitoring and administrative costs depend on the number of covered sources, and since the number of sources is constant across the alternatives, this cost is also constant at $26.1 million. The accompanying average cost-effectiveness results range from $1,243 to $2,140 per ozone season ton. The 60 percent control level is the most stringent control level that does not exceed U.S. EPA's framework for highly cost-effective ozone season NOx emissions reductions, and is selected as the basis for establishing state level emissions budgets.

Table 6
2007 Cost and Cost-Effectiveness Results for Large Non-EGUs

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
40% Control	$49.5	$26.1	$75.6	$1,243
50% Control	87.6	26.1	113.7	1,329
60% Control	126.8	26.1	152.9	1,467
70% Control	249.5	26.1	275.7	2,140

Based on U.S. EPA's NOx SIP Call analysis, relying on the chosen regulatory alternative of 60 percent control, results in a control period cost-effectiveness for large non-EGUs of $1,467 per ton of NOx reduced in a control period. This does not exceed U.S. EPA's "highly cost effective" criteria of less than or equal to $2,000 per ton of NOx reduced.

5.0 EXISTING AND PROPOSED ILLINOIS REGULATIONS

Title 35 of Illinois Administrative Code, Part 217, contains regulations to control NOx emissions from both existing and new fuel combustion sources. Emission limitations from combustion sources are provided. For new sources with heat input capacities equal to or greater than 250 mmBtu/hr, the emission limits vary from 0.20 to 0.70 lb/mmBtu, depending upon the type of fuel. For existing sources located in the Chicago or St. Louis (Illinois) major metropolitan areas, with heat inputs equal to or greater than 250 mmBtu/hr, the emission limits range from 0.30 to 0.90 lb/mmBtu, depending upon the type of fuel. However, existing fuel combustion sources which are either cyclone- fired boilers burning solid or liquid fuel, or horizontally opposed-fired boilers burning solid fuel, are exempt from the provisions of these NOx emission limits. Additionally, existing coal-fired EGU boilers in Illinois are subjected to the Federal Regulations under the Acid Rain program that provide NOx emission limitations varying from 0.40 to 0.86 lb/mmBtu depending on the size and type of boiler.

5.1 Proposed Illinois Regulations

Proposed Subpart U

Proposed Part 217, Subpart U, applies to all fossil fuel-fired stationary boilers, combustion turbines, or combined cycle systems with nameplate capacities exceeding 250 mmBtu/hr, and not having the primary purpose of producing electricity for sale. The affected units are known as "budget units".

The purpose of Subpart U is to cap the emissions of NOx during the ozone control period from budget units based on reducing baseline 2007 emissions by 60 percent and issue NOx allocations to sources which meet the NOx SIP Call budget.

Beginning in 2004, all budget units are limited to emitting during each control period the tonnage of NOx not exceeding the number of allowances they have been allocated for that control period. Budget units that are listed in Appendix E of Subpart U, consisting of those budget units commencing operations before 1995, are allocated a fixed number of lifetime allowances for each control period, as set forth in this appendix, with subtractions for a "new source set aside", and for any small emitting units that are able to "opt out" of the Trading Program, and with additions for any allowances made available from reductions from other units. Fixed allowances are approximately equivalent to seasonal operations with a 60% reduction in NOx emissions.

The low emitting (less than 25 tons of NOx per control period) units that opt out of the Trading Program do so by burning only natural gas, fuel oil, or only natural gas and fuel oil, for a limited number of hours during the control period, such that they can demonstrate that the period's NOx emissions are truly less than 25 tons.

Subpart U also contains a provision whereby boilers, combustion turbines, combined cycle units, reciprocating engines, and cement kilns can "opt in" to the regulations and receive permanent fixed allowances. Although opt in units would then be required to comply with all the provisions of Subpart U, they might choose to do so because any allowances allocated might exceed actual NOx emissions due to combustion or post-combustion controls, and excess allowances could be sold at a possible profit to other budget units needing extra allowances for demonstrating compliance.

In addition, all budget units with fixed allowances can permanently transfer some or all of those allowances to units required to comply with Part 217, Subpart W, the NOx Trading Program for electrical generating units.

In each year, newer budget units will be able to purchase allowances from the Illinois EPA for the average price at which allowances were traded in the Ozone Transport Region during the previous year, until the number of allowances in the set aside is exhausted. Any additional allowances required for operating the budget unit would have to be obtained from sources or individuals holding allowances in the NOx Trading Program. All newer budget units will become existing units after three years of operation.

Budget units that achieve NOx control period reductions of at least 30 percent from their 2001 control period emissions during the 2002 or 2003 control periods are eligible for "early reduction credits" equal to the difference between the unit's actual control period emissions and those emissions that would occur were the control period emissions rate exactly equal to 30 percent less than the 2001 control period's emissions rate. Early reduction credits may be used for demonstrating compliance in 2004 or any later year allowed by U.S. EPA, subject however to a total number of allowances available to all units, which when exceeded causes the number of available credits to be adjusted pro rata.

Compliance with the requirements of Subpart U must be demonstrated by the use of a continuous emissions monitoring system ("CEMS") that meets the requirements of 40 CFR 75, Subpart B, except for those budget units appearing in Appendix E that have obtained alternative monitoring requirements pursuant to the provisions of 40 CFR 75, Subpart E.

Budget units must obtain a federally enforceable permit that reflects the requirements of Subpart U and must demonstrate to the Illinois EPA and to the U.S. EPA by November 30 of each year, their compliance status and monitoring certifications for any control periods during which they operated during that year.

Proposed Subpart X

Another way by which emission units subject to Subpart U can acquire NOx allowances is from sources that generate such allowances through the voluntary reduction procedures of proposed Subpart X of the Part 217 NOx regulations. Subpart X reductions are NOx emission reductions from fossil fuel-fired units that are not subject to Subpart U or to the requirements of Subparts T (cement kilns), V (the NOx rate-based rule) and W (the NOx trading program), but that did operate and have NOx emissions during the baseline year of 1995.

In other words, Subpart X provides that emission units that are not required to reduce their NOx emissions from the 1995 base year may undertake such reductions and sell, or otherwise make available, those reductions as creditable allowances to Subpart U (or Subpart W) emission units. Eighty percent of the reductions achieved would be actually credited to the recipient source(s) while twenty percent of the emission reductions would be retired for the benefit of improved air quality.

In order for its emission reductions to be creditable, the source generating the reductions must thoroughly describe the specific actions it will be undertaking to reduce emissions during the ozone control period, such as shutting down, switching to a fuel that produces lower NOx emissions, reducing operating rates or hours, or installing and operating NOx combustion or post-combustion controls.

Further, the reductions must be quantifiable, included in a plant-wide NOx emissions cap consisting of all emission units of the same kind as those achieving the reductions, and verifiable via emissions monitoring, generally by using a continuous emissions monitoring system.

Finally, Subpart X emissions reductions must appear in an emissions reduction plan that is approved by the Agency and U.S. EPA and incorporated into a federally enforceable operating permit in order for the emissions reductions to be creditable.

6.0 AFFECTED SOURCES AND EMISSION ALLOCATIONS

U.S. EPA's NOx SIP Call is a cap and trade emissions reduction control program. This type of program establishes a base emissions level for affected sources for a specified base year. The required reduction amount is then applied to that base, to establish the emissions cap needed to carry out the air quality goals of the program. Once established, emissions trading may take place among participating sources, so long as the cap or emissions budget is not exceeded. This is accomplished by assigning or issuing emission allowances to the participating sources such that the sum of all allowances equals the budget. The following subsections describe who the participating sources are and how the non-EGU emissions budget was determined.

6.1 Affected Sources

There are 45 existing Illinois non-EGUs owned by 14 companies that meet the definition of a large non-EGU and are therefore affected by the proposed regulation. Out of 45 units, one is gas turbine, 26 are gas- and/or oil-fired boilers, and 18 are coal-fired boilers. The proposed regulations will potentially impact all 45 existing non-EGUs. Attachment A identifies the potentially impacted sources.

6.2 Emission Allocations

The proposed regulation is based on NOx emission allocations for each non-EGU subject to the regulation for the year 2007. The following describes how these allocations were derived and converted into NOx budget allowances contained in Appendix E of the proposed rule.

To determine the budget for non-EGUs sources, U.S. EPA established a base year 1995 inventory. It should be noted that there were a number of comment periods during which U.S. EPA accepted comments on various aspects of the NOx SIP Call emission inventories. Illinois EPA submitted a number of inventory revisions to the U.S. EPA during these comment periods regarding Illinois' non-EGUs. As a result of the Notice of Proposed Rulemaking ("NPR") and Supplemental Notice of Proposed Rulemaking ("SNPR") public comment periods, U.S. EPA revised the inventories with approved data addressing issues such as emission estimate revisions, missing sources, retired sources, incorrect source sizes, base year control levels, and facility name changes. Details of these comments and their effect on the base inventory can be found in the U.S. EPA response to significant comments document for the NOx SIP Call.

The emissions data relied upon in this TSD reflect the revisions made by U.S. EPA in response to the public comments filed during these comment periods. The final NOx SIP Call budgets are contained in the March 2000 Technical Amendment to the NOx SIP Call (See Reference 7). Illinois EPA has reviewed the final NOx budget for Illinois and determined that Illinois EPA's requested revisions to the non-EGU boilers and turbines have been incorporated. This information provides the basis for the allowances contained in Appendix F of the proposed regulation.

6.2.1 Base Case

The 1995 NOx emissions for each non-EGU were projected to 2007 by multiplying the 1995 emissions with a projected growth factor from 1995 to 2007. The Illinois EPA relied on U.S. EPA's economic growth model ("E-GAS") to provide the growth factors for each emissions unit. The 2007 base case includes all applicable controls required by the CAA. Applicable controls required for non-EGUs include NOx RACT where applicable. The 2007 base case NOx emissions from the 45 large boilers and turbines were calculated to be 9,078 TPS.

6.2.2 2007 Budget Case

The 2007 budget case was developed for each unit by applying E-GAS growth factors and a budget emission reduction rate to the 1995 base year NOx emissions. Budget emissions for large boilers and turbines greater than 250 mmBtu/hr design capacities were calculated based on a 60 percent NOx emissions reduction from the uncontrolled level. For other large non-EGUs, cement kilns and internal combustion engines (NOx emissions greater than one ton per 1995 summer day), budget emissions were calculated by applying 30 percent NOx emissions reduction for cement kilns and a 90 percent emissions reduction for internal combustion engines.

The total 2007 budget case NOx emissions from all non-EGUs including those with heat inputs less than 250 mmBTU/hr. for Illinois is 59,577 TPS. The 2007 budget case emissions for the 45 large non-EGUs subject to the provisions of the proposed rule are 4,882 TPS. Therefore, the proposed regulations will achieve an estimated NOx reduction of 4,196 TPS. This represents an overall reduction of 46 percent from the large non-EGU boilers and turbines.

7.0 SUMMARY

In October 1998, the U.S. EPA determined that sources and emitting activities in each of 22 States, including Illinois and the District of Columbia emit NOx in amounts that significantly contribute to nonattainment of the 1-hour ozone NAAQS in one or more downwind States and issued a call for revisions to states' implementation plans, commonly referred to as the "NOx SIP Call".

In order to comply with the federal NOx SIP Call, which requires affected states to meet statewide NOx emissions budgets, the General Assembly has concluded that participation in the NOx cap and trade program is appropriate. Therefore, Illinois EPA is proposing to control large non-EGU boilers and turbines within the state to comply with an emissions cap, established by U.S. EPA as 4,882 tons of NOx during the ozone season control period, and to allow thee sources to participate in the federal NOx trading program.

The Illinois EPA has relied on the information contained in the NOx SIP Call in developing the proposed Subpart U that requires the NOx emissions from large non-EGUs boilers and turbines greater than 250 mmBtu/hr design capacities to be capped at their 2007 budget emissions. The requirements of the proposed regulations are consistent with the NOx SIP Call requirements and will impact 45 emission units in Illinois. The statewide 2007 base NOx emissions are estimated to be 9,078 from large non-EGUs boilers and turbines. The proposed regulations will achieve a NOx reduction of 4,196 tons per control period or approximately 27 tons per day. A number of control technologies are available to allow sources to meet the required levels of control. It is anticipated that the most likely control will be the use of combustion control techniques, although there are post-combustion control techniques available that will meet the requirements of the proposed rule. Participation in the national NOx trading program will allow sources to make decisions of how to control their emissions to meet their budget, to over-control their sources and trade excess reductions in the market, or to limit control and purchase needed reduction allowances from the market. U.S. EPA has determined the cost effectiveness of NOx controls to meet the reduction requirements of the proposed rule in 1990 dollars to be $1,467 ($1,583 in 1999 $) per ton of NOx reduced.

8.0 REFERENCES

1. U.S. EPA, "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. *Michigan V. EPA*, No. 98-1497, 2000 WL 18065 (D.C. Cir. March 3, 2000).

3. Illinois Public Act 91-631, August 19, 1999, 415 ILCS 5/9.9

4. U.S. EPA, "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional Boilers", EPA-453/R-94-022, March 1994, U.S. EPA, OAQPS, Research Triangle Park, NC 27711.

5. U.S. EPA, "Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines", EPA-453/R-91-007, January 1993, U.S. EPA, OAQPS, Research Triangle Park, NC 27711.

6. U.S. EPA, "Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Volume 1: Costs and Economic Impacts", EPA-452/R-98-003, September 1998, U.S. EPA, Office of Air and Radiation Washington, DC 20460.

7. U.S. EPA, "Technical Amendment to the Finding of Significant Contribution and Rulemaking for Certain States for Purposes of Reducing Regional Transport of Ozone", 65 FR 11222, March 2, 2000.

ATTACHMENT A

NON-ELECTRICAL GENERATING UNITS

UNIT BY UNIT INITIAL ALLOCATIONS

COMPANY ID # / NAME	UNIT DESIGNATION	UNIT DESCRIPTION	BUDGET ALLOCATION	BUDGET ALLOCATION LESS 3% NSSA
1	2	3	4	5
A. E. STALEY MANUFACTURING CO				
115015ABX	85070061299	COAL-FIRED BOILER 1	176	171
115015ABX	85070061299	COAL-FIRED BOILER 2	175	170
115015ABX	73020084129	BOILER #25	125	121
A. E. STALEY MANUFACTURING CO (Total Allocation)			**476**	**462**
ARCHER DANIELS MIDLAND CO EAST PLANT				
115015AAE	85060030081	COAL-FIRED BOILER 1	238	231
115015AAE	85060030081	COAL-FIRED BOILER 2	261	253
115015AAE	85060030081	COAL-FIRED BOILER 3	267	259
115015AAE	85060030082	COAL-FIRED BOILER 4	276	268
115015AAE	85060030082	COAL-FIRED BOILER 5	275	267
115015AAE	85060030082	COAL-FIRED BOILER 6	311	302
115015AAE	85060030083	GAS-FIRED BOILER 7	19	18
115015AAE	85060030083	GAS-FIRED BOILER 8	19	18
ARCHER DANIELS MIDLAND CO EAST PLANT (Total Allocation)			**1,666**	**1,616**
CORN PRODUCTS INTERNATIONAL INC				
031012ABI	91020069160	GAS-FIRED BOILER 6	55	53
031012ABI	73020146041	BOILER # 1 COAL-FIRED	210	204
031012ABI	73020146042	BOILER # 2 COAL-FIRED	210	203
031012ABI	73020146043	GAS FIRED BOILER NO 4	81	79
031012ABI	73020147045	BOILER # 3 COAL-FIRED	211	205
031012ABI	73020147046	GAS FIRED BOILER NO 5-	81	79
CORN PRODUCTS INTERNATIONAL INC (Total Allocation)			**848**	**823**
GREAT LAKES NTC				
097811AAC	78080071011	BOILER # 5	26	25
097811AAC	78080071011	BOILER # 6	26	25
GREAT LAKES NTC (Total Allocation)			**52**	**50**
JEFFERSON SMURFIT CORPORATION				
119010AAL	72120426001	BLR 7-COAL FIRED	39	38
JEFFERSON SMURFIT CORPORATION (Total Allocation)			**39**	**38**

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NON-ELECTRICAL GENERATING UNITS

UNIT BY UNIT INITIAL ALLOCATIONS

COMPANY ID # / NAME	UNIT DESIGNATION	UNIT DESCRIPTION	BUDGET ALLOCATION	BUDGET ALLOCATION LESS 3% NSSA
1	2	3	4	5
MARATHON OIL CO ILLINOIS REFINING DIV				
033808AAB	72111291055	BOILER #3 OIL,REF GAS	53	51
033808AAB	72111291056	BOILER #4 REF GAS,OIL	53	52
MARATHON OIL CO ILLINOIS REFINING DIV (Total Allocation)			**106**	**103**
EXXON MOBIL				
197800AAA	72110567002	AUX BOILER-REFINERY GAS	101	98
197800AAA	86010009043	STATIONARY GAS TURBINE	85	82
EXXON MOBIL (Total Allocation)			**186**	**180**
WILLIAMS				
179060ACR	73020087019	BOILER C - PULVERIZED DRY	377	366
WILLIAMS (Total Allocation)			**377**	**366**
EQUISTAR				
063800AAC	72100016013	BOILER # 1	40	39
063800AAC	72100016013	BOILER # 2	40	39
063800AAC	72100016014	#3 GAS FIRED BOILER	40	39
063800AAC	72100016016	#5 GAS FIRED BOILER	40	39
063800AAC	72100016017	#6 BOILER	40	38
EQUISTAR (Total Allocation)			**200**	**194**
EQUISTAR				
041804AAB	72121207108	BOILER NO 1	121	118
041804AAB	72121207109	BOILER NO 2	121	118
041804AAB	72121207110	BOILER NO 3	121	117
041804AAB	72121207111	BOILER NO 4	120	116
041804AAB	72121207112	BOILER NO 5	0	0
EQUISTAR (Total Allocation)			**483**	**469**
TOSCO				
119090AAA	72110633080	BOILER NO 15	40	38
119090AAA	72110633081	BOILER NO 16	40	39
119090AAA	72110633082	BOILER NO 17	80	78
TOSCO (Total Allocation)			**160**	**155**

ATTACHMENT A

NON-ELECTRICAL GENERATING UNITS
UNIT BY UNIT INITIAL ALLOCATIONS

COMPANY ID # / NAME	UNIT DESIGNATION	UNIT DESCRIPTION	BUDGET ALLOCATION	BUDGET ALLOCATION LESS 3% NSSA
1	2	3	4	5
U S STEEL - SOUTH WORKS				
031600ALZ	82010044013	NO. 6 BOILER,#5 POWER	90	88
031600ALZ	82010044014	NO 1 BLR NG	90	87
U S STEEL - SOUTH WORKS (Total Allocation)			**180**	**175**
UNIV OF ILL - ABBOTT POWER PLANT				
019010ADA	82090027006	BOILER #7	86	83
UNIV OF ILL - ABBOTT POWER PLANT (Total Allocation)			**86**	**83**
CITGO PETROLEUM CORPORATION				
197090AAI	72110253037	BOILER 43-B-1	23	22
CITGO PETROLEUM CORPORATION (Total Allocation)			**23**	**22**
GRAND TOTAL			**4,882**	**4,736**