TECHNICAL SUPPORT DOCUMENT

for

CONTROL OF NITROGEN OXIDE EMISSIONS

in

ELECTRICAL POWER GENERATION

AQPSTR 00-3

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ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
1021 NORTH GRAND AVENUE EAST
P.O. BOX 19276
SPRINGFIELD, ILLINOIS 62794-9276

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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 of ozone on the public's health. 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). 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 ("SIPs") to reduce the contribution of NOx from sources in the upwind states to ozone problems downwind.

U.S. EPA has defined an EGU as a unit that generates electricity for sale. Typically, electricity is generated by a combustion turbine or by a turbine run by steam produced in a boiler. Those units that produce electricity but do not sell electricity are excluded from this source category.

The Illinois Environmental Protection Agency ("Illinois EPA") has completed its attainment demonstration for the Metro-East St. Louis ozone nonattainment area. This demonstration was completed in cooperation with the State of Missouri and jointly submitted to the U.S. EPA on February 10, 2000 and supplemented on June 29, 2000. The attainment strategy calls for the implementation of all Clean Air Act ("CAA") control measures as they pertain to moderate ozone nonattainment areas, as the St. Louis and Metro-East areas are currently designated. In addition, NOx emissions levels for large electric generating units ("EGUs") that are limited to 0.25 lb/mmBtu in the SIP Call area is sufficient to demonstrate attainment of the 1-hour ozone NAAQS in the Metro-East St. Louis area.

Figure 1-1
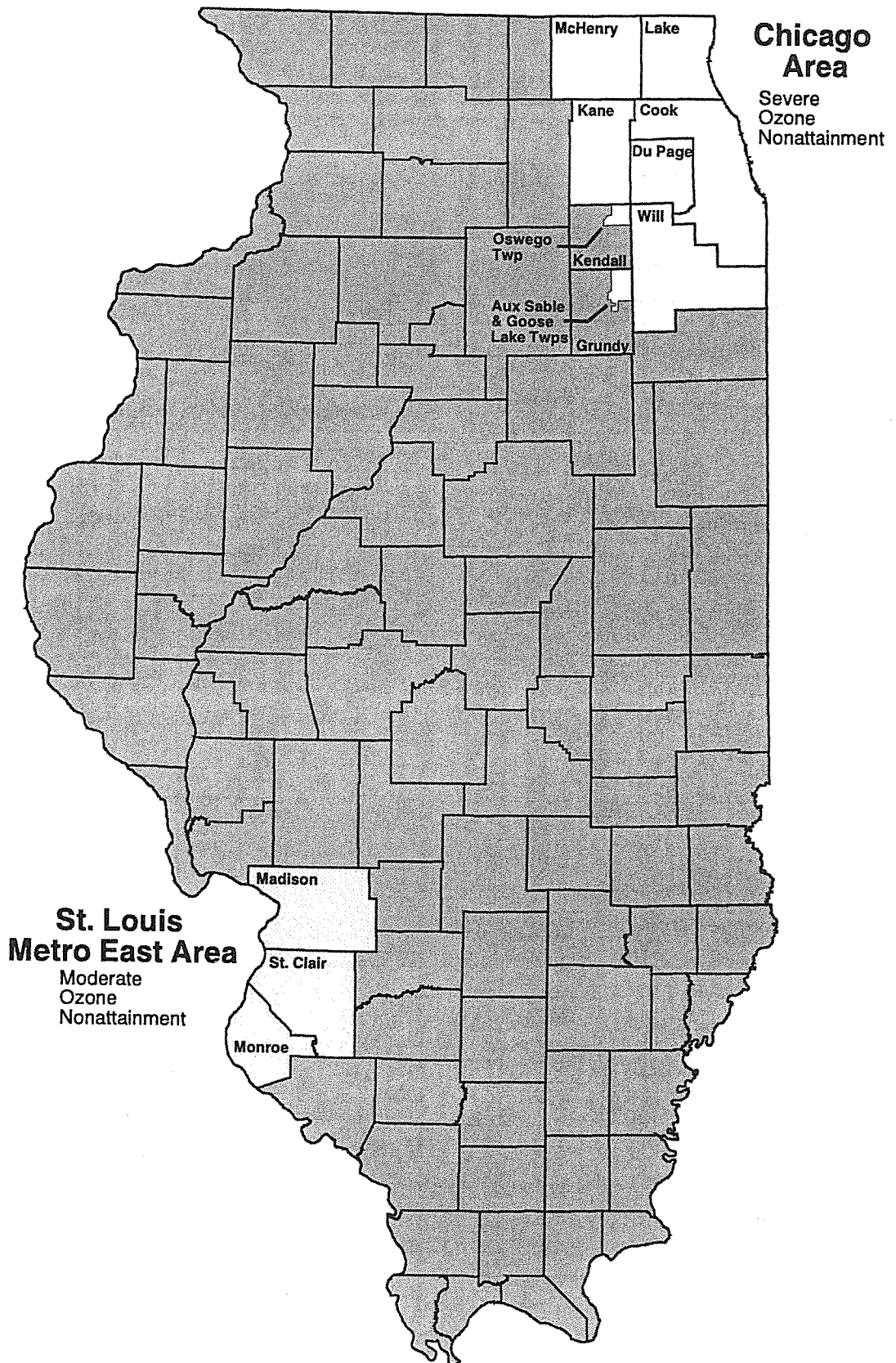
Illinois Ozone Nonattainment Areas

2.0 BACKGROUND

In 1990, Congress amended the CAA to address continued nonattainment of the 1-hour ozone NAAQS. Areas designated as nonattainment were assigned one of five classifications based on observed air quality. Certain counties in the St. Louis Metropolitan Statistical Area ("MSA") were classified as moderate nonattainment, while counties or portions of counties within the Chicago Consolidated Metropolitan Statistical Area ("CMSA") were classified as severe nonattainment. The CAA as amended in 1990 established specific planning requirements for each classification, including the need for Rate-of-Progress ("ROP") reductions in ozone precursor emissions and a demonstration of attainment. The ROP and attainment demonstration SIP submittals for all nonattainment areas were required by November 1994. The attainment of the 1-hour ozone NAAQS was to have been achieved by November 15, 1996, in moderate areas. However, because of its realization of the pervasive extent of ozone transport and its overwhelming impact on nonattainment areas and the in-depth, multi-state study of ozone transport, U.S. EPA established a policy extending the date for submittal of final attainment demonstrations for all areas and the attainment date extension policy particularly for moderate areas for participating states. Final revisions to the attainment demonstrations submitted in 1994, which relied on inter-jurisdictional reductions of ozone transport, were due November 15, 1999, for moderate nonattainment areas and are due December 31, 2000, for serious and worse nonattainment areas. The new attainment deadline for Metro-East is 2003.

The States of Missouri and Illinois have worked cooperatively since 1990 to develop appropriate strategies for attaining the ozone NAAQS in the St. Louis nonattainment area. As part of these planning efforts, the States determined that it will take significant reductions in both local ozone precursor emissions and incoming (transported) ozone and ozone precursor concentrations for the St. Louis nonattainment area to attain the NAAQS.

As indicated above, recognizing the transport problem, U.S. EPA established a two-phase program for states to develop approvable ozone SIPs, due in 1999 and 2000. In a policy memorandum dated March 2, 1995, U.S. EPA outlined the major elements of this program. Phase I required states to complete pre-November 1994 SIP requirements, to submit regulations sufficient to meet the initial ROP requirements, and to submit modeling analyses. Phase II called for a two-year consultative process to assess national/regional strategies to address ozone transport in the eastern United States and subsequent revisions of local control plans, as necessary, based on any new national/regional strategies. To accomplish the Phase II consultative process, the Environmental Council of the States ("ECOS"), in conjunction with U.S. EPA, established the Ozone Transport Assessment Group ("OTAG"). In 1998, U.S. EPA provided an approach for extending the attainment date for moderate areas until regional ozone reductions could be achieved. In 1999, Illinois and Missouri formally requested an extension of the attainment date through this policy.

The States of Missouri and Illinois have worked cooperatively to provide to the U.S. EPA an approvable attainment demonstration for the 1-hour NAAQS for ozone for the St. Louis nonattainment area. The attainment demonstration is addressed in submittals made by the Illinois EPA (dated November 15, 1999, and February 10, 2000), and by the Missouri Department of Natural Resources ("MDNR") (dated November 10, 1999, and January 19, 2000). On april 17, 2000, the U.S. EPA proposed to approve the 1-hour attainment demonstration SIPs for the St. Louis nonattainment area contingent upon the States' preparing revised modeling to incorporate corrections to the 1996 base year emissions inventory (See Reference 2). Both States submitted this revision to U.S. EPA on June 29, 2000.

The model used for the Metro-East/St. Louis attainment demonstration is the Urban Airshed model-Version V ("UAM-V"), which was developed by LADCO and the four Lake Michigan states (including Illinois for application to the Lake Michigan area. This is the same model used by OTAG and by the U.S. EPA in their technical analyses in support of the NOx SIP Call. The modeling domain used for this analysis encompasses most of the Midwest, including the primary, upwind source regions which contribute high levels of ozone and ozone precursors transported into the St. Louis areas. Ozone episodes used in previous modeling conducted by LADCO and U.S. EPA were used in this analysis: July 1991 and July 1995. These episodes were selected because they are representative of typical ozone episodes in the Midwest. The States evaluated the ability of the model to accurately simulate the formation and transport of ozone concentrations in the Midwest. This evaluation has demonstrated that the model's performance meets U.S. EPA acceptance criteria and is appropriate for the control strategy evaluations needed to support the attainment demonstration.

The final attainment strategy for the St. Louis area as contained in the Agency's October 1999 supplement, assumes that the jurisdictions affected by the NOx SIP Call, including the eastern one-third of Missouri, would limit large EGUs to an emission rate not greater than 0.25 lbs NOx/mmBtu by 2003. The EGUs residing in the western two-thirds of Missouri would be limited to an emission rate of 0.35 lbs NOx/mmBtu. The results of the modeling for the final control strategy adequately demonstrates that the 1-hour ozone standard would be met in the St. Louis area by 2003, assuming that the local and regional emission reduction measures incorporated in the modeling are implemented by that time.

Given the need to reduce NOx emissions pursuant to the air quality modeling results described above to demonstrate attainment in the Metro-East area, Illinois EPA is proposing to control large EGUs within the State to a NOx emissions level of 0.25 lb/mmBtu. This level of control is sufficient for attainment in the Metro-East area.

3.0 PROCESS DESCRIPTION AND SOURCES OF NOx EMISSIONS

In the electric utility sector, turbines are used to produce rotary motion for the electric generators. Gas turbines burn fuel, typically natural gas or distillate oils whereas steam from a boiler is used to run steam turbines. Combustion of coal, fuel oils, or natural gas in the boilers and combustion of natural gas or distillate oils in the gas turbines are the sources of NOx emissions in the electric utility sources. Utility boilers and gas turbines are briefly described in this section of the TSD.

3.1 Coal-Fired Boilers

Cyclone furnaces and pulverized coal furnaces are the two types of coal-burning boilers used in Illinois to produce steam to drive turbine generators for electric production. In both of these types of furnaces, suspension firing is the primary combustion mechanism.

In pulverized coal-fired furnaces, coal is pulverized in a mill to a consistency of talcum powder (i.e., at least 70% of the particles will pass through a 200-mesh sieve). The pulverized coal is generally entrained in a primary air stream before being fed through burners to the furnace, where it is fired in suspension. Pulverized coal furnaces are classified as either dry or wet bottom, depending on the ash removal technique. Dry bottom furnaces fire coals with high ash fusion temperatures and use dry ash removal techniques. In Illinois only dry bottom units are currently in operation. Dry bottom units are further classified by the firing position of the burners, i.e., single (front or rear) wall, horizontally opposed, vertical, tangential (or corner-fired) or opposed wall-fired (with burners mounted on two opposite walls). Tangentially-fired boilers have burners mounted in the corners of the furnace. The fuel and air are injected towards the center of the furnace to create a vortex that enhances air and fuel mixing. In Illinois, there are tangentially-fired, and horizontally opposed wall-fired furnaces.

Cyclone furnaces burn low ash fusion temperature coal which has been crushed to below 4-mesh particle size. The coal is fed tangentially in a stream of primary air to a horizontal cylindrical furnace. Within the furnace, small coal particles are burned in suspension while large particles are forced against the outer wall. Because of high temperature developed in the relatively small furnace volume, and because of the low fusion temperature of the coal ash, much of the ash forms a liquid slag on the furnace walls. The slag drains from the walls to the bottom of the furnace where it is removed through a slag tap opening.

Nitrogen oxide ("NOx") emissions from coal combustion in boilers are primarily nitrogen oxide ("NO") with only a few volume percent as nitrogen dioxide ("NO_2"). Nitrous oxide ("N_2O") is also emitted at parts per million ("ppm") levels. Nitrogen oxide formation results from thermal fixation of atmospheric nitrogen (thermal NOx) in the combustion flame and from oxidation of nitrogen bound in coal. Thermal NOx

formation is exponentially dependent on temperature and is proportional to N_2 concentration in the flame, the square root of oxygen ("O_2") concentration in the flame, and the gas residence time. Typically only 20 to 60 percent of the fuel nitrogen is converted to NOx. Bituminous and subbituminous coals usually contain from 0.5 to 2 weight percent nitrogen, mainly present in aromatic ring structures. Fuel nitrogen can account for up to 80 percent of total NOx from coal combustion. Some coals, like those from the Powder River Basin in Wyoming, are low in fuel nitrogen content, and produce lesser amounts of NOx than Illinois coals.

3.2   Fuel-Oil Fired Boilers

Fuel oils fall in two major categories: distillate oils and residual fuel oils. Both types are used in electric utility boilers. Distillate oils are more volatile and less viscous than residual oils, and contain very small amounts of fuel nitrogen. Residual oils being more viscous and less volatile than distillate oils, may need to be heated for ease of handling and to facilitate proper atomization.

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Water-tube boilers are the only ones used in the electric utility industry. In these boilers, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes.

As in the case of coal-fired boilers, NOx formed in the combustion processes is either due to thermal fixation of atmospheric nitrogen (thermal NOx), or to the conversion of chemically bound nitrogen in the fuel (fuel NOx). About 95 percent of emitted NOx is in the form of nitric oxide ("NO"). NOx emissions from residual oil combustion in boilers are predominantly fuel NOx that accounts for 60 to 80 percent of the total NOx formed. Fuel nitrogen conversion is highly dependent on the fuel-to-air ratio in the combustion zone and, in contrast to thermal NOx formation, is relatively insensitive to small changes in combustion zone temperature. In general, increased mixing of fuel and air increases fuel NOx formation. Thus, to reduce fuel NOx formation, the most common technique is to suppress combustion air levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperature, cause volatile fuel nitrogen to convert to N_2 rather than NO.

3.3   Natural Gas-Fired Boilers

Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts. The average gross heating value of natural gas is approximately 1020 Btu/scf. Field-erected watertube boilers are the only ones used for electric generation. These boilers are designed to pass water through the inside of the heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The boilers can further be sub-divided into tangential-fired and wall-fired.

Wall-fired units are characterized by multiple individual burners located on opposite walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

NOx emissions from natural gas combustion in boilers are predominantly thermal NOx, with the remainder consisting of so called "prompt NOx". Most thermal NOx formation occurs in the high temperature flame zone near the burners. Prompt NOx occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOx reactions occur within the flame and are usually negligible when compared to the amount of thermal NOx.

3.4 Stationary Gas Turbines

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines comprise 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 to drive external load units.

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 Rankine cycle (combined cycle or repowering). 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 3-1 describes the uncontrolled NOx emissions from various types of EGUs.

Table 3-1
Uncontrolled NOx Emissions from EGUs

Type of Unit	Uncontrolled NOx Emissions (lb/mmBtu)	
	Range	Typical
Coal fired Tangential Boiler	0.4 – 1.0	0.7
Coal fired Wall, Dry Bottom Boiler	0.6 – 1.2	0.9
Coal fired Wall, Wet Bottom Boiler	0.8 – 1.6	1.2
Coal fired Cell Burner Boiler	0.8 – 1.8	1.0
Coal fired Vertical, Dry Boiler	0.6 – 1.2	0.9
Coal fired Cyclone Boiler	0.8 – 2.0	1.5
Oil fired Tangential Boiler	0.2 –0.4	0.3
Oil fired Wall Boiler	0.2 – 0.8	0.5
Oil fired Vertical Boiler	0.5 – 1.0	0.75
Natural Gas fired Tangential Boiler	0.1 – 0.9	0.3
Natural Gas fired Wall, Single Burner Boiler	0.1 – 1.0	0.5
Natural Gas fired Wall, Opposed Burners Boiler	0.4 – 1.8	0.9
Natural Gas fired Combustion Turbine	0.4 – 1.7	0.44
Distillate Oil fired Combustion Turbine	0.55 – 2.5	0.698

4.0 TECHNICAL FEASIBILITY OF NOx CONTROLS

Control techniques for reducing emissions from new or existing fuel-fired EGUs can be grouped into one of the two fundamentally different methods---combustion controls and post combustion controls (flue gas treatment). Combustion controls reduce NOx formation during the combustion process and include methods such as operational modifications, flue gas recirculation ("FGR"), overfire air ("OFA"), low NOx burners ("LNB"), and reburn. The retrofit feasibility, NOx reduction potential, and cost of combustion control are largely influenced by boiler design and operating characteristics such as firing configuration, furnace size, heat release rate, fuel type, capacity factor, and condition of existing equipment. Flue gas treatment controls reduce NOx after its formation and include selective non-catalytic reduction ("SNCR") and selective catalytic reduction ("SCR"). The term "Selective" means that the technique controls NOx "selectively" rather than controlling many pollutants simultaneously.

4.1 Combustion Control Technologies

Combustion control technologies use modification of combustion conditions, such as flame stoichiometry, or peak flame temperature to prevent the formation of NOx or to destroy NOx formed early in the combustion process. Included among these strategies

are combustion/operational parameter modification such as low excess air, burners out-of-service, low NOx burners, flue gas recirculation and reburn.

4.1.1   Combustion/Operational Parameter Modifications

Operational modifications involve changing certain boiler operational parameters to create conditions that will lower NOx emissions. Burner out of service ("BOOS") consists of removing certain individual burners from service by stopping the fuel flow. The air flow is maintained through the idle burners to create a staged-combustion atmosphere within the furnace. Low excess air ("LEA") involves operating the boiler at the lowest level of excess air possible without jeopardizing good combustion. Biased firing ("BF") involves injecting more fuel to some burners and reducing the amount to others to create a staged-combustion environment. To implement these operational modifications, the boiler must have the flexibility to change combustion conditions and have excess pulverizer capacity (for coal firing). Due to their original design type or fuel characteristics, some boilers may not be amenable to the distortion of fuel/air mixing patterns imposed by BOOS and BF.

Flue gas recirculation ("FGR") is a flame-quenching strategy in which the recirculated flue gas acts as a diluent to reduce combustion temperature and oxygen concentration in the combustion zone. This method is effective for reducing thermal NOx and is used on natural-gas and oil-fired boilers. FGR is not very effective on coal-fired boilers.

Overfire air ("OFA") is another technique for staging the combustion process to reduce the formation of NOx. OFA ports are installed above the top row of burners on wall-fired ("W-fired") boilers, and tangential-fired ("T-fired") boilers. The two types of OFA for T-fired boilers are closed-couple OFA ("CCOFA"), and separated OFA ("SOFA"). The CCOFA ports are incorporated into the main windbox whereas the SOFA ports are installed above the main windbox using separate ducting. The two types of OFA for W-fired boilers are analogous to the T-fired units. Conventional OFA has ports above the burners and utilizes the air from the main windbox. Advanced OFA has separate ductwork above the main windbox and, in some cases, separate fans to provide more penetration of OFA into the furnace.

Low NOx burners ("LNB") are designed to delay and control the mixing of fuel and air in the main combustion zone. Lower combustion temperatures and reducing zones are created by LNB which lower thermal and fuel NOx. Low NOx burners have been applied to both T- and W-fired boilers in retrofit applications. LNB and OFA can be combined in some retrofit applications provided there is sufficient height above the top row of burners.

Reburn is a NOx control technology that involves diverting a portion of the fuel from the burners to a second combustion area (reburn zone) above the main combustion zone. Completion air (or OFA) is then added above the reburn zone to complete fuel burnout. The reburn fuel can be either natural gas, oil, or pulverized coal. Reburn can be applied to most boilers, but is the only known combustion NOx control technique for cyclone boilers.

A similar technology is natural gas co-firing which consists of injecting and combusting natural gas near or concurrently with the main fuel (coal, oil, or natural gas).

4.1.2   Natural-Gas-Based Controls

The environmental benefits of using natural gas instead of coal or residual oil are for the most part obvious ones. Since natural gas is essentially free of sulfur and nitrogen and without inorganic matter typically present in coal and residual oils, SO_2 emissions can be essentially eliminated, NOx emissions can be dramatically reduced, and organic and inorganic particulate and air toxic compounds can be essentially removed from all discharge streams leaving the boiler. With these environmental advantages, it is obvious that natural gas would be viewed as a sound alternative to coal or oil burning in existing powerplants to meet strict emission standards in all categories: SO_2, NOx, particulate, and air toxics.

Because of its ease of transport, ease of burning, and relatively low emissions, natural gas is a premium utility boiler fuel. Its use is often relegated to fuel new advanced, high efficiency, gas turbine-based power generation equipment used in combined cycle or cogeneration applications. Coupled with its normally higher cost (on a Btu basis) compared to coal, its attractiveness is limited to environmental benefits and less obvious benefits such as operational improvements, capacity recovery, life extension, etc.

The principal uses of natural gas as a utility boiler fuel are: cofiring with a primary fuel such as coal or oil, reburning by special application to maximize its NOx reduction properties, boiler fuel conversion when gas is used to replace coal or oil as the principal fuel. Each of these applications has its own advantages and disadvantages when considering overall environmental benefit, cost, operation, retrofit feasibility and other issues. Natural gas use in each of these three applications can also be done on a year-round basis or selectively, i.e., during the peak ozone season when NOx reductions are most needed and when natural gas is more attractively priced. Seasonal use of controls, particularly natural gas-based controls, can be economically attractive because of lower operating costs and, in the case of gas use, more competitive fuel pricing.

Cofiring and boiler fuel conversions have a long history in the power generation industry. Fuel selection for power generation is based on economic consideration

and availability. Various federal regulations and initiatives have also affected utility decisions to burn one fuel over another. In fact, many plants have undergone boiler fuel conversions over the years for a number of reasons other than emissions compliance. Reburning, however, is a more recent technological development commercialized principally in response to the NOx reduction needs under the CAA Amendments of 1990, especially its Title I ozone attainment provisions. Gas reburning aims specifically to maximize the NOx reduction potential with a minimum amount of natural gas. Its development has included demonstrations on LNB-controlled boilers to maximize overall NOx reduction, whereas similar evaluations have not occurred with either cofiring or full-scale gas conversions. Finally, seasonal gas use has attracted some interest because periods of highest gas availability to the utilities coincide with the peak ozone season. NOx reductions during the peak ozone season are deemed beneficial to the goal of ground level ozone attainment in the Northeast States for Coordinated Air Use Management ("NESCAUM") and Mid-Atlantic Regional Air Management Association ("MARAMA") regions.

4.1.2.1   Gas Cofiring

Gas cofiring involves the utilization of natural gas with another primary fuel, e.g. coal or oil, for the purpose of emissions reduction, overcoming load limitations, and for operational improvements such as startups and improved ignition. The gas can be injected into the furnace through existing startup guns, limited capacity igniters, or through gas spuds, nozzles or rings in existing burner ports. Although there are no theoretical limits to the amount of gas cofiring, the technology generally implies natural gas utilization for less than 20 percent of the total heat input. The location of new gas nozzles in existing burner openings is important to the optimization of NOx reduction potential, burner safety, turndown capability, NOx control level, and control of the furnace exit gas temperature etc. Benefits of cofiring include clean startup, improved ESP operation, SO_2 trim for environmental compliance, 25 to 50 percent NOx reduction depending on percent cofire, reduced flame impingement, improved capacity factor, lower CO_2 emissions to alleviate greenhouse gases in the atmosphere, etc.

4.1.2.2   Gas Reburning

In reburning, a fuel is injected above the primary combustion zone to create a reburning zone where stoichiometric ratio is maintained fuel rich at 0.9 or lower for optimum NOx reductions. At these low stoichiometries, various reducing species created from the natural gas fuel react to reduce burner-generated NOx to molecular nitrogen. In commercial natural gas reburning ("NGR") systems, the stoichiometry in the reburn zone can be varied depending on the amount of NOx control desired. Because sufficient fuel is added to bring the overall stoichiometry fuel rich, it is then necessary to add

overfire air above the reburning zone to complete the combustion of the reburning fuel. This final reaction zone is typically referred to as the "burnout zone". Reburning technology has also been referred to as "fuel staging" and in-furnace NOx reduction.

The spacing allotted between the three distinct zones is carefully customized to each boiler taking into consideration furnace design and operating parameters. Efficient mixing of the reburning fuel with the combustion products is also critical to guarantee the maximum NOx reduction possible with the minimum amount of reburning fuel and with minimal adverse impacts in key furnace operating conditions. One fundamental application criterion is that the furnace must have sufficient room above the main combustion zone for reburning and burnout to take place. Most boilers have sufficient volume above the primary zone to achieve NOx reduction levels reported in these NGR demonstrations. However, larger primary combustion zones needed for effective LNB operation can reduce the effectiveness of the NGR process precluding economic application. The amount of fuel needed is dictated by the excess air in the main burner zone and by the NOx reduction required. Reburning fuel is typically in the 15 to 20 percent of the total heat input.

The reburning fuel can be natural gas propane, oil, and micronized coal. Natural gas is often selected because gas it is easier and quicker to burn, requiring smaller furnace volumes above the burnout zone, thus offering greater retrofit potential. In fact, all boiler types, with the possible exception of very small furnaces with high heat release rates, are candidate retrofits irrespective of the primary fuel type and firing configuration, and whether they are equipped with LNB or conventional high turbulence burners. With either coal or oil, instead, the potential for incomplete combustion of reburning fuel is much greater. The installation cost of coal-reburning is also much higher than gas reburning (in most cases) because of the requirements for pulverizers and burner penetration.

The technology of reburning using natural gas is commercial and can be applied to all boiler firing types with approximately equal NOx reduction performance. Boilers that have been retrofitted with LNB can also use gas reburning because the process targets the destruction of NOx generated by the main combustion zone adding to the overall NOx reduction. Utility boiler manufacturers such as Asea Brown Bovery, and Babcock & Wilcox are offering the technology on a commercial basis. Energy and Environmental Research Corporation, the firm that undertook many of the demonstrations on utility boilers, is also offering commercial retrofits for gas reburning. These vendors offer slightly different reburning approaches, but the NOx reduction concept remains the same. Natural gas reburn is presently the most efficient of the gas-based NOx control technologies. With gas reburn, short-term NOx

reductions up to 70 percent are possible on uncontrolled boilers with as little as 15 to 20 percent gas use.

The exact mechanisms that control the gas reburning process are very complex. What is known is that the NO produced in the burner primary zone is reduced by hydrocarbon ("HC") radicals that were generated from the decomposition of the reburn fuel via the following chemical reaction:

$$NO + HC \rightarrow HCN + O$$

The cyanide in turn will decompose to molecular nitrogen or re-form NO in the reburn zone. Additionally, NO can decompose by reaction with hydrogen via the following reaction:

$$NO + H \rightarrow HN + O$$

Most fuels can provide an adequate pool of HC- and H-reducing radicals in the reburning zone. Several fuels have been investigated but none have shown greater NOx reduction efficiencies than natural gas. Higher initial NOx levels from the primary burner zone tend to produce higher reburning NOx reduction efficiencies. The finding reported by some researchers suggests that the effectiveness of reburning decreases when applied to LNB-controlled boilers compared to uncontrolled units.

The stoichiometry of the primary zone plays an important role insofar as the amount of reburning fuel needed to achieve desired reburning stoichiometry is affected. The higher the excess air in the primary reburn zone, the greater the quantity of reburn fuel is needed to achieve desired reburn stoichiometries. From a NOx reduction efficiency viewpoint, its effect is secondary to the reburn stoichiometry.

4.1.2.3   **Gas Conversion**

Gas conversion and cofiring are similar to the extent that conversion implies the ability to reach the design steaming capacity of the boiler with 100 percent gas firing. As with cofiring, the equipment retrofit to implement a complete fuel conversion or create a dual-fuel capability is dependent on the existing burner equipment and control system. For conventional or opposed walls of the furnace, the retrofit of 100 percent gas firing can be accomplished with the addition of gas spuds, canes, or rings on each existing burner. Tangential burners in the corners of the furnace, can also be readily modified to accommodate gas firing without removing the coal or oil-firing capability. Because of the tilting capability of tangential burners, furnace exit gas temperatures and superheat/reheat steam temperatures can more readily be controlled. Steam attemperation is also a common powerplant practice for

superheater and reheater temperature control. Some boiler conversion engineering and architect firms believe that it is easier to convert a coal-fired boiler than an oil-fired boiler to gas firing. This is because the lower waterwall radiation from gas flames is offset by the cleaner waterwalls in the absence of slagging.

From an operations point of view, the burning of 100 percent gas instead of coal or oil brings about one inevitable impact: lower thermal efficiencies. Although some efficiency reduction is likely with cofiring and reburning, the reduction in boiler efficiency is much more evident with full conversion to gas. This reduction is principally the result of increased moisture content in the flue gas, the inevitable effect of higher hydrogen content in the fuel. The ability to burn gas at lower excess air levels will recover a fraction of this thermal efficiency loss. The reported data shows that boiler efficiencies were reduced in a range from about 3 to 4.5 percentage points. Other considerations for gas conversions include boiler operating duty cycle, physical condition of the site, remaining economic life of the unit, etc.

Boilers that operate with variable load can benefit from gas conversions because of the operational flexibility that gas provides especially at reduced loads. The physical condition of the plant and the remaining economic life of the plant will play important roles in the economic justification for the capital investment of converting the boiler to gas fuel and increased operating cost of gas burning.

4.1.2.4   Potential for Retrofit of Gas-based Controls

Natural gas is a clean fuel with wide operational flexibility, documented operational benefits, and proven NOx reduction potential. Among the various applications of natural gas as a utility boiler fuel, reburning remains the most efficient way of using gas for NOx reduction. With this technology, the NOx reduction potential is the highest for a given percent of gas use. Cofire, conversion, and seasonal gas use offer either lower NOx reduction potential or require much higher gas use. Because of the fuel cost differential between gas and coal, the amount of gas needed to reduce NOx from coal-fired boilers is one of the main utility concerns with the application of gas-based technologies.

The realized retrofit potential of gas-based controls for utility boilers hinges on the natural gas availability, access to gas supply, marginal NOx reduction beyond LNB, competitive gas pricing and availability of long-term contracts, reburning performance on large-scale coal boilers, and combustion safety of gas injector designs.

4.1.3 Coal Reburning

There has been limited demonstration of coal reburning to date. It has been tested only on a cyclone boiler burning bituminous coal and a low sulfur western Powder River Basin ("PRB") coal.

The NOx reductions ranged from 36 to 52 percent over the load range for the bituminous coal to NOx levels between 0.39 to 0.44 lb/mmBtu and ranged from 53 to 62 percent for the western coal to NOx levels between 0.28 to 0.30 lb/mmBtu. The NOx reduction performance decreases with load because more burner air is introduced at the reburner zone to maintain flame stability.

The selection of the coal type for reburning is very important to its performance and retrofit feasibility. Ideally, the reburning coal should be most reactive, meaning that it must contain a high percent of volatile matter. Reactive coals will burn faster and hotter thus minimizing the requirements for a large burnout zone and the potential increase in unburned carbon in the flyash.

4.2 Post Combustion NOx Controls

Two commercially available post combustion flue gas treatments include SNCR and 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.

4.2.1 Selective Non-Catalytic Reduction ("SNCR")

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 2100°F. Higher injection temperatures are possible by proper design and operational settings of SNCR systems. Selected vendors of SNCR-based technologies offer proprietary additives aimed at broadening this temperature window and, thus making the efficiency of the process and ammonia slip requirements somewhat less sensitive to flue gas temperature swings.

In a utility boiler operating at full steam load, this temperature window occurs in a zone starting approximately at the furnace exit plane and extending just passed

the first convective superheater and reheater tube banks. The SNCR temperature window shifts towards the burner zone when boiler load is reduced. This nonuniformity of temperature, velocity, and NO concentration coupled with relatively short residence times are major challenges for this technology and often limit the NOx reduction performance of SNCR to maintain ammonia slip below acceptable levels. Alternatively the gases can be treated under controlled temperature conditions in a separate chamber.

Ammonia slip is caused by excessive use of reagent, insufficient mixing of reagent with flue gas, and low flue gas temperatures. When using ammonia-based reagents in a boiler burning sulfur bearing fuels, such as coal or residual oil, the amount of ammonia slip must be particularly controlled to minimize plugging of air heater and cold end corrosion caused by ammonium sulfate and bisulfate compounds formed by the reaction between NH_3 and SO_2/SO_3 in the flue gas. Furthermore, excessive ammonia is also trapped in the flyash often precluding the continued sale of this commodity for cement manufacturing. At least one vendor, however, offers additives to an aqueous urea reagent mix that has proven to minimize NH_3 slip under well-controlled and supervised SNCR operation.

The two principal reagents used in the SNCR process are aqueous ammonia (NH_4OH) and aqueous urea (NH_2CONH_2). Anhydrous ammonia can also be used but it is generally not considered for SNCR applications because of safety and better process operation with aqueous reagents. Urea solution may contain proprietary additives. These additives are used as corrosion inhibitors to facilitate onsite storage, transport, and injection in the furnace, and for performance enhancement. Because flue gas temperatures are not uniform and because SNCR must often perform over some boiler load range, several injection locations are necessary, each capable of distributing the reagent containing droplets over the effective area to ensure maximum reagent utilization. The amount of urea or ammonia injected in the furnace varies with the NOx reduction target. As a minimum, the full conversion of NOx to nitrogen and water will require a stoichiometric amount of NH_3. However, all full-scale tests have shown that more than the stoichiometric quantity is often needed to maximize the performance of the process. This is because of the mass transport limitations imposed by imperfect mixing of reagent with flue gas at optimum reaction temperature. Therefore, most of the excess reagent either reacts to form NO or degrades to nitrogen and carbon dioxide.

NOx reduction performance data has been reported for several cyclone and tangential dry bottom coal-fired utility boilers and oil-/gas-fired utility boilers. Some of these boilers were fitted with combustion control devices such as LNBs, BOOS, OFA, and FGR. The retrofit experience gathered to date on utility boilers would indicate that NOx reduction levels are limited to a range of 25 to 65 percent for coal-fired boilers and from less than 10 to 50 percent for oil-/gas-fired boilers, depending on boiler load and NOx level. Ammonia slip

generally ranged from 5 to 20 ppm. Uncertainties with SNCR performance on larger size boilers, excessive NH_3 slip, load following capability, and the potential for reduced NOx reduction performance when SNCR is implemented on a combustion-controlled boiler may limit the attractiveness of SNCR only controls for post-RACT compliance. Lower performance levels of SNCR might be further aggravated when the controls are applied to large gas-fired utility boilers with variably dispatched loads. Because of the strong dependence on gas temperature and mixing, it is likely that optimum NOx reduction performance for SNCR will come from retrofits on smaller, base-loaded, coal-fired utility boilers with high inlet NOx levels. Currently these candidate boilers include cyclone units and several lower capacity dry bottom coal-fired units.

Reported operational impacts have been small for the most part. This is due principally to the ability of most installations to maintain NH_3 slip at low levels, between 5 to 20 ppm in most cases. Although many of these tests were performed on a short-term basis, long-term operational impacts have also been minimal. Ammonia slip levels below 5 ppm would likely have little effect on the salability of the flyash or air heater pluggage and cold-end corrosion. Other byproducts of the SNCR reaction, especially with urea-based reagents, are N_2O and CO emissions. N_2O is a greenhouse gas that is not currently regulated. Typically N_2O emissions are a function of the reaction temperature and tend to range between 10 to 15 percent of the total NOx reduced. Because of the quantities of water injected into the furnace to provide adequate dispersion of the reagent, a decline in boiler efficiency of 0.5 to 1 percent has been reported.

4.2.2   Selective Catalytic Reduction ("SCR")

Interest in SCR for NOx reductions on a variety of combustion sources has grown substantially in recent years. The technology has been commercially available for gas turbines, and electric utility boilers for several years. SCR technology can reduce NOx emissions in excess of 90 percent. The technology has been used for many years on gas-, oil-, and coal-fired boilers principally in Japan and Germany. There are more than 200 SCR installations on overseas utility coal-fired boilers. Many of these installations are retrofits and have been in place since early to mid-1980s. In the U.S., SCR has been installed on at least 12 gas-fired utility boilers in California in the size range of 230 to 750 MWe. SCR has also been operated or planned on several coal-fired boilers in New Jersey, Florida, New Hampshire, Kentucky, Indiana, and Illinois.

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:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$
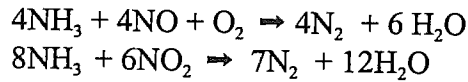
The undesirable reactions that can occur in an SCR system, include oxidation of NH_3 and SO_2 and the formation of sulfate salts. Potential oxidation reactions are:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$$
$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$
$$2NH_3 + 2O_2 \rightarrow N_2O + 3H_2O$$
$$2SO_2 + O_2 \rightarrow 2SO_3$$
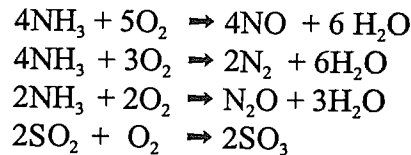
The reaction rates of both desired and undesired reactions increase with increasing temperatures. The optimum temperature depends upon the type of catalyst. Many of the formulations use vanadium pentoxide ("V_2O_5") supported on titanium dioxide ("TiO_2") with an operating window of $570°$ to $750°F$. Zeolites and other rare earth materials are also effective catalysts, but their operating temperatures tend to be higher. Catalysts and substrates are shaped in either parallel or honeycomb modules that are stacked together in a reactor 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 drops sufficiently so that some amount of economizer bypass may be required to maintain the catalyst at the optimum temperature. The bypass inflicts a thermal efficiency loss that is attributed to the operation of the SCR.

Beside temperature, other factors that affect the performance of SCR catalysts include SO_2 content of the flue gas, flyash content in the flue gas, molar feed ratio of ammonia and NO, catalyst space velocity, NH3 distribution, and trace metals in the flyash.

Application of SCR in high sulfur and high dust flue gas represents a particular challenge for SCR catalysts. Some unreacted ammonia is released to the atmosphere as ammonia slip. Some ammonia is also adsorbed by the flyash that may make it unfit for sale.

4.2.2.1   SCR Configurations

Several catalyst configurations have been applied to power plants in Europe and Japan. The most popular arrangements are the following:
· Air preheater catalysts

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- In-duct catalysts
- Combination of air preheater and in-duct catalysts used in tandem
- Full-scale reactor catalysts

In coal-fired applications, full-scale SCR reactors have been most common.

4.2.2.1.1 In-Duct SCR Systems

The in-duct arrangement of SCR catalyst has been primarily used in utility 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. The amount of catalyst is limited, however, not only by access but also by excessive pressure drop. The in-duct arrangement of catalyst modules have been retrofitted on 2-480 MWe and 2-750 MWe gas-fired boilers in California. The target NOx levels with these SCR systems are 0.01 lb/mmBtu with natural gas firing, and 0.03 lb/mmBtu with oil-firing at all loads. Ammonia slip is limited to 10 ppm.

4.2.2.1.2 AH-SCR Systems

The air heater SCR technology was first introduced in Germany by Siemens. The retrofit of this technology will require replacing the existing enamel-coated air heater elements of a rotating Ljungstrom air heater with catalyst-coated ones on the hot end of the rotating elements and installation of NH_3 injection and control system.

Traditionally this technology has been developed for difficult retrofit cases where installation of a full-scale SCR catalyst reactor is made difficult by poor access or insufficient space. The technology has been applied on 2-200 MWe pulverized coal-fired boilers in the Netherlands, and a 25 MWe gas-fired boiler in California. Reported NOx reductions are 30-50 percent in the Netherlands facility, and 50-64 percent in the California facility from a BOOS controlled level of 0.18 lb/mmBtu. Another facility where this technology has been used is a 321 MWe slagging wall -fired boiler burning low sulfur coal. Because of limitations on NOx reduction performance and ammonia slip when used alone, the air heater SCR technology is best applied in tandem with in-duct catalyst SCR and SNCR hybrids with overall NOx reduction performance equalling that of a full-scale SCR reactor.

4.2.2.1.3 Full-Scale SCR Systems

For utility boilers burning sulfur and ash bearing fuels such as residual oil and coal, SCR installations almost exclusively require full-scale SCR

reactors containing layers of catalyst. There are three possible arrangements to place an 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, provided the catalyst can survive in the high dust environment for sufficient time before replacement. The other arrangement requires the installation of a hot side ESP that is not popular in U.S. power plants. In Illinois, Commonwealth Edison's Waukegan Unit 7 is the only one equipped with a hot side ESP. The third arrangement can be placing SCR after the SO_2 scrubbing system.

The full-scale reactors are generally arranged for downward flow to minimize deposition, and made sufficiently large to reduce flue gas velocities as low as 20 ft/sec to minimize erosion from flyash and to provide sufficient space to add active catalyst layers. The catalyst modules are arranged in a minimum of three layers with occasionally a layer of dummy catalyst to take the brunt of erosion from moving flyash. Additional space is also provided in the reactor to add a fresh new layer of catalyst when NOx removal efficiency falls below the required level and/or ammonia slip exceeds design values.

Obviously, the retrofit of a full-scale SCR reactor into an existing power plant will require much more equipment modifications than some of the in-duct systems so successfully retrofitted on gas-fired boilers in California. The catalyst volume of one of these full-scale systems can be as large as $1/10^{th}$ the size of the boiler furnace and the reactor required to house it can require a volume much larger than the active catalyst. Significant engineering must be done to evaluate not only the rearrangement of existing equipment but also to calculate the necessary upgrades in the fan power and air heater to compensate for greater pressure drop and possible increased plugging rates of the air heater. Ammonia slip is of considerable importance not only from an operational point of view but also from an environmental one.

4.3   Combined Technologies

Combining two or more control technologies can be a cost-effective approach to large NOx reductions without major equipment modifications. Recently, several combinations of controls have been proposed, researched, and patented in an effort to attain NOx reduction efficiencies of 80 percent and more without the need for large-scale SCR reactors. In addition to these combined technologies that target NOx reduction only, other gas treatment controls for simultaneous SO_2 and NOx reductions are being demonstrated under the Department of Energy ("DOE's") Clean

Coal Program. These technologies will likely play a significant role in controlling emissions from new coal-fired powerplant installations and may, in the future, offer feasible alternatives to traditionally separate NOx and SO_2 control strategies when both SO_2 and NOx emissions reductions are required.

The following subsections review these technologies and their current commercialization status. Generally, hybrid controls have a much smaller experience base for coal- and oil-fired plants than for gas-fired boilers. However, the recent reported success of the SNCR+SCR+AH-SCR at Mercer Generating Station in New Jersey certainly points to the commercial feasibility of this control approach for coal-fired boilers as well.

4.3.1   Advanced Gas Reburning

The integration of gas reburning with SNCR is referred to as advanced gas reburning ("AGR"). This process is considered by EER Corporation, the patent holder, to be an improvement over gas reburning and SNCR technologies used separately because of synergism between the two technologies. AGR uses reburning with natural gas to enhance the SNCR process, broadening and deepening the SNCR temperature window for greater overall NOx reductions. The reburn zone stoichiometry is adjusted to near stoichiometric conditions, instead of the reburn optimum setting of 0.90. Normally, this would require only 10 percent gas use instead of the 18 percent used in conventional reburning, thus lowering the cost of the technology. Urea or ammonia agents are injected along with the overfire air, reducing the complexity of another separate injection location. Pilot-scale test results showed a peak overall NOx reduction of 90 percent from uncontrolled levels of 890 ppm (about 1.2 lb/mmBtu). The increased CO and OH radicals from the reburn zone produced higher SNCR efficiencies over a broader temperature window than would otherwise be possible with conventional SNCR system. Full-scale utility boiler demonstration of this technology is being planned. Because the process uses a combination of gas reburning and SNCR, reliable operation in large (>200 MWe) boilers and load-following capability as well as gas supply and differential fuel costs remain principal concerns for full-scale retrofits.

4.3.2   SNCR and SCR

The principal objective of combining SNCR and SCR in tandem is to reduce the volume of catalyst needed, thus permitting the installation of SCR with the minimum of modifications to the existing ductwork and heat transfer equipment downstream of the economizer. The synergism between SNCR and SCR also permits more flexibility in the operation of the SNCR. For example, the presence of SCR catalyst downstream of the SNCR allows for greater normalized stoichiometric ratio ("NSR") levels because the catalyst will use the unreacted NH_3 leaving the SNCR temperature window to further reduce NOx. In addition,

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hybrid SNCR is designed for a different temperature window than commercial stand alone SNCR. Stand-alone SNCR is commercially designed for operation at higher temperatures than ideal for NOx reduction in order to keep NH_3 slip at the user guarantee level.

In summary, the combination of higher NSR in the SNCR zone with downstream SCR can permit high NOx reduction efficiencies, in theory approaching the 90 percent level only possible with full-scale SCR, with greater assurances of low NH_3 slip and at lower balance of plant cost.

There are several combinations of SNCR and SCR controls. These are:

- SNCR with full-scale SCR reactor

- SNCR with catalyst air heater (CAT-AH)

- SNCR with in-duct SCR

   - Existing duct
   - Expanded duct

- SNCR with in-duct SCR and CAT-AH in series

The first of these combinations is the least likely and the most costly of retrofits because it does not take advantage of the combination of controls to minimize retrofit capital requirement. To date, retrofit demonstrations have focused on the last three arrangement options using in-duct and AH-SCR catalysts. Nalco Fuel Tech, the major vendor of SNCR systems using urea, has tested the hybrid technology in a pilot-scale program where 85 percent NOx reduction with 6 ppm or lower NH_3 slip was recorded on a short-term basis. The patented process is under the trade mark NOxOUT Cascade®.

As indicated, the in-duct SCR systems can be distinguished between two major applications. Those whose catalyst is made to fit within the existing ductwork, and those whose catalyst volume requires an enlargement of the ductwork. The former truly in-duct systems have appeared only in gas-fired boiler applications in California. For various reasons, including the small NOx reductions, catalyst volumes for dedicated gas-fired boilers have been sufficiently small to fit in existing ductwork with the aide of gas flow control devices. However, these true in-duct systems are considered least likely for coal- or oil-fired boilers because NOx reductions goals are typically larger, excessive gas inlet velocities cannot be tolerated, and maintenance requirements increase.

4.4   Seasonal NOx Controls

This section highlights the feasibility and benefits of NOx controls used on a seasonal basis to achieve the NOx emission reductions required by the proposed regulation. From a practical viewpoint, all control options discussed above can operate either on a year-round basis or during the NOx control season. However, controlling NOx only during the control season reduces overall control cost.

4.4.1   Seasonal Gas Use

The price of natural gas can vary dramatically from season to season and from location to location. In general, natural gas is more expensive during winter than during summer. Seasonal gas use can be implemented via cofiring, reburning, and full gas conversion. Smaller boilers which can not be economically controlled by SCR can be ideal candidates for such controls. Since reburn can produce greater NOx reductions than other controls, this control option should be considered for seasonal use.

4.4.2   Seasonal Flue Gas Treatment

Amongst the three major control options namely SNCR, SCR, and hybrid combination, SCR gives the highest NOx reduction and will be ideal for large EGUs. But in many cases it may not be possible to bypass SCR during the off season because the space and investment necessary to provide additional duct-work. Removal of the catalyst from the gas stream to extend its life may also not prove feasible because reinstallation would require a second boiler outage.

Compared to SCR-only controls, hybrid system such as SNCR with in-duct SCR catalyst may provide greater flexibility to modulate NOx reduction with seasonal needs. In the hybrid controls, the use of reagent in the upstream SNCR can be reduced or eliminated and the downstream catalyst can be operated at lower reduction efficiency with its own supply of reagent.

Table 4-1 and 4-2 describe the NOx reduction potential of various controls for coal-fired, gas-and oil-fired boilers and gas turbines.

Table 4-1
NOx Emission Reduction Potential of Controls for Coal Fired Boilers

Control Technology	Expected Control Level (lb/mBtu)	NOx Reduction Potential (%)
Operational modifications (BOOS, LEA, BF)	Tangential = 0.55 – 0.65 Wall = 0.70 – 0.80	10 – 20
Over Fire Air (OFA)	Tangential = 0.50 – 0.55 Wall = 0.60 – 0.70	20 – 30
Low NOx Burner (LNB)	Tangential = 0.40 – 0.45 Wall = 0.45 – 0.55	Tangential = 35 – 45 Wall = 40 – 50
LNB + Advanced OFA	Tangential = 0.35 – 0.40 Wall = 0.35 – 0.45	Tangential = 40 – 50 Wall = 50 – 60
Reburn	Tangential = 0.30 – 0.35 Wall = 0.35 – 0.45	50 - 60
SNCR	Tangential = 0.30 – 0.50 Wall = 0.35 – 0.65 Cyclone = 0.60 – 1.10	30 – 60
SCR	Tangential = 0.10 – 0.20 Wall = 0.15 – 0.25 Cyclone = 0.25 – 0.40	75 - 85
LNB + SNCR	Tangential = 0.15 – 0.35 Wall = 0.20 – 0.45	50 – 80
LNB + AOFA + SCR	Tangential = 0.05 – 0.10 Wall = 0.05 – 0.10	85 - 95

Table 4-2
NOx Emission Reduction Potential of Controls
for Gas- and Oil-Fired Boilers and Turbines

Control Technology	Expected Control Level (lb/mBtu)	NOx Reduction Potential (%)
Operational modifications (LEA + BF)	Tangential = 0.15 – 0.20 Wall = 0.25 – 0.35	30 – 50
Flue gas recirculation (FGR)	Tangential = 0.15 – 0.20 Wall = 0.25 – 0.30	45 – 55
Over Fire Air (OFA)	Tangential = 0.20 – 0.30 Wall = 0.30 – 0.45	20 – 45
Low NOx Burner (LNB)	Tangential = 0.15 – 0.20 Wall = 0.25 – 0.35	30 – 50
LNB + OFA (or BOOS)	Tangential = 0.15 – 0.20 Wall = 0.25 – 0.30	40 – 50
Reburn	Tangential = 0.10 – 0.20 Wall = 0.20 – 0.25	50 – 60
FGR + OFA (or BOOS); or LNB + FGR + OFA	Tangential = 0.05 – 0.15 Wall = 0.05 – 0.20	60 – 90
SNCR	Tangential = 0.20 – 0.25 Wall = 0.30 – 0.40	25 – 40
SCR	Tangential = 0.03 – 0.10 Wall = 0.05 – 0.10	80 - 90
LNB + SNCR	Tangential = 0.05 – 0.10 Wall = 0.10 – 0.15	70 – 80
LNB + AOFA + SCR	Tangential = 0.02 – 0.10 Wall = 0.03 – 0.10	85 - 95
Water/Steam Injection	Gas/Oil Fired Gas Turbine = 25 – 110 ppmv	70 – 90
Low NOx Combustors	Gas-Fired Gas Turbine = 25 – 42 ppmv	60 – 90
SCR	-	90

4.5   NOx Control for Proposed Rule

There are a number of available control choices for reducing NOx emissions at large
EGUs. U.S. EPA in its final NOx SIP Call (See Reference 1), concluded that liquid
and gas-fired EGUs will most likely be able to rely on pre-combustive control
techniques to meet their required emission rates, and that coal-fired EGUs will
generally need to use post-combustive techniques. Table 4-3 below summarizes
Illinois' large EGUs operating and emissions data, including the average percent
reduction required for each type of EGU to meet the proposed emission rate in this
proposal. From the data contained in Tables 4-1 through 4-3, control scenarios are
available that will provide the needed reductions. The variation in required
reductions for the various categories illustrates the varied or similar nature of the
individual EGUs within each group. In order to provide additional flexibility for
sources to meet the proposed emission rate, the rule allows for inter-system and intra-
system averaging. Appendix F sources may elect to average their emission rates with
other sources so long as the aggregate rate meets the 0.25 lb/mmBtu emission
standard. This allows sources which are more amendable to control to provide the
needed reductions for those sources for which control is more difficult or expensive.

5.0   ECONOMIC REASONABLENESS OF CONTROLS

The U.S. EPA has prepared cost effectiveness estimates for controlling NOx emissions from
EGU sources. Two of the most recent and significant estimates are contained in the federal
Alternative Control Techniques ("ACT") documents for utility boilers, gas turbines and the
"Regulatory Impacts Analysis for the NOx SIP Call, FIP, and Section 126 Petitions" ("RIA")
(See References 3, 4, and 5). The Illinois EPA is relying on these documents to estimate the
cost effectiveness of controlling Illinois NOx sources to the level proposed by this
rulemaking.

5.1   ACT Cost Effectiveness

U.S. EPA's ACT documents review emission sources and evaluate control
technologies that can be used to reduce NOx emissions. These documents provide
technical information for state and local air management agencies to use in
developing and implementing regulatory programs designed to control NOx from
utility boilers and gas turbines. Data presented in the ACTs represent typical plants
operating under various load arrangements and for varying sizes. For example, the
utility boiler ACT selected 30 model plants to represent the population of existing and
projected boilers, covering 6 types of boilers, and applying eight NOx control
alternatives. The results provide a matrix of costs and cost effectiveness values for
the various alternative and boiler types. This information is useful in reviewing the
costs of various controls on specific boiler types. The cost effective data is not based
on a specific emission level or percent control needed to be achieved, but

Table 4-3

Required Reductions for Large EGUs Under Proposed Subpart V

Type of Unit	Number of Units	2003 Base NOx Emissions (Tons/season)	2003 Emissions @ 0.25 lb/mmBtu (TPS)	Average Required Reduction (%)	Reductions @ 0.25
Coal-fired, Cyclone	22	56,579	16,401	71	40,178
Pulverized Coal, Tangential	34	43,047	25,100	42	17,947
Pulverized Coal, Wall	8	9,130	4,933	46	4,197
Gas Turbine	14	2,351	879	63	1,472
#6 Fuel Oil-fired	2	745	621	17	125
#2 Fuel Oil/Nat.Gas -fired	23	1,487	1,857	0	-370
Totals	103	113,340	49,790	56	63,550

rather on typical reduction that would occur from applying the specific control alternative to the model plant. Three cost considerations are presented in the ACT documents - - 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, was calculated for each control technique by dividing the total annual cost by the annual tons of NOx removed.

The ACT documents describe the costs of various NOx controls applicable to the utility boilers and gas turbines. Depending on the type, size, and operating hours of the EGU, the cost effectiveness of each control varies from a few hundred to several thousand dollars per ton of NOx removed. Tables 5-1, 5-2 and 5-3 summarize the range of cost effectiveness of various control options for each type and size of EGU.

Table 5-1
NOx Control Cost Effectiveness for Coal-Fired EGUs (Boilers)

Boiler firing type	NOx control technology	Cost Effectiveness ($/ton)		
		100 MW (Peaking)	300 MW (Cycling)	100 – 600 MW (Baseload)
Tangential	LNB	1,120 – 1,800	280 – 440	100 – 350
	LNB + AOFA	2,060 – 3,300	460 – 730	170 – 630
	Reburn	3,870 – 5,930	1,150 – 3,220	620 – 3,030
	SNCR	2,600 – 2,960	900 – 1,210	600 – 1,160
	SCR	9,470 – 12,200	3,140 – 4,160	1,580 – 2,490
	LNB + SNCR	2,420 – 2,530	660 – 770	340 – 700
	LNB + AOFA + SCR	9,900 – 12,400	3,120 – 4,040	1,500 – 2,490
Wall	LNB	2,000 – 3,200	470 – 750	180 – 620
	LNB + AOFA	3,420 – 5,470	750 – 1,200	270 – 1,050
	Reburn	3,010 – 4,600	900 – 2,500	480 – 2,360
	SNCR	2,160 – 2,470	800 – 1,100	560 – 1,070
	SCR	7,540 – 9,650	2,500 – 3,300	1,270 – 1,990
	LNB + SNCR	2,750 – 2,860	740 – 850	370 – 760
	LNB + AOFA + SCR	9,250 – 11,100	2,760 – 3,480	1,300 – 2,230
Cyclone	Reburn	1,810 – 2,770	540 – 1,510	290 – 1,420
	SNCR	1,460 – 1,780	650 – 960	510 – 940
	SCR	4,670 – 5,940	1,560 – 2,040	810 – 1,260

Table 5-2
NOx Control Cost Effectiveness for Gas- and Oil-Fired EGUs (Boilers)

EGU Type	NOx Control Technology	Cost Effectiveness ($/ton)		
		100 MW (Peaking)	300 MW (Cycling)	100 – 600 MW (Baseload)
Tangential Boiler	LEA + BOOS	230 – 500	90 – 350	70 – 360
	LNB	2,620 – 4,190	640 – 1,020	250 – 810
	LNB + AOFA	4,810 – 7,690	1,060 – 1,700	380 – 1,480
	Reburn	8,480 – 12,800	2,720 – 7,080	1,580 – 6,690
	SNCR	7,090 – 7,450	1,940 – 2,300	1,070 – 2,180
	SCR (Natural Gas)	10,800 – 11,700	3,150 – 3,470	1,530 – 2,470
	SCR (Oil)	12,200 – 14,700	3,690 – 4,600	1,800 – 3,040
	LNB + SNCR	5,830 – 5,990	1,430 – 1,540	640 – 1,370
	LNB + AOFA + SCR (Natural Gas)	13,400 – 14,200	3,640 – 3,930	1,650 – 2,900
	LNB + AOFA + SCR (Oil)	14,700 – 16,900	4,130 – 4,970	1,900 – 3,400
Wall-Fired Boiler	LEA + BOOS	140 – 300	50 – 210	40 – 220
	LNB	3,600 – 5,750	840 – 1,340	310 – 1,110
	LNB + AOFA	6,160 – 9,850	1,350 – 2,160	480 – 1,900
	Reburn	5,080 – 7,690	1,630 – 4,250	946 – 4,010
	SNCR	4,470 – 4,850	1,380 – 1,760	860 – 1,690
	SCR (Natural Gas)	6,700 – 7,200	1,960 – 2,150	970 – 1,550
	SCR (Oil)	7,550 – 8,940	2,280 – 2,830	1,130 – 1,900
	LNB + SNCR	5,200 – 5,310	1,290 – 1,400	590 – 1,250
	LNB + AOFA + SCR (Natural Gas)	10,500 – 11,000	2,740 – 2,910	1,200 – 2,240
	LNB + AOFA + SCR (Oil)	11,300 – 12,700	3,030 – 3,540	1,350 – 2,560

Table 5-3
NOx Control Cost Effectiveness for Gas- and Oil-Fired EGUs (Gas Turbines)

Type of Control	Cost Effectiveness ($/ton)	
	Peaking (25 – 100 MW)	Continuous (25 – 100 MW)
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

5.2   NOx SIP Call Cost Effectiveness

The U.S. EPA has evaluated more specifically the cost and economic impacts of the NOx SIP Call on the groups of sources subject to its requirements, on a control season basis, not on an annual basis. The cost and economic impacts of the NOx SIP Call are discussed in detail by the U.S. EPA in the RIA. Chapter 6 of the document summarizes the potential cost, NOx emission reductions, and economic impacts associated with the NOx SIP Call for EGUs. The results of various regulatory alternatives are presented and compared with each other and with one of two baselines. Section 6.1 introduces the annual cost and emission measures and compares four uniform regulatory alternatives (based on NOx emission rates of 0.25, 0.20, 0.15, and 0.12 lbs/mmBtu) to the Initial Base Case (as well as the Final Base Case). Section 6.2 compares the results under the "0.15 uniform (that is, NOx-SIP-Call-region-wide) alternative" to alternatives that restrict trading to two or three sub-regions, with emission rates that vary by sub-region. Section 6.3 presents the results of an analysis of alternative program designs and sensitivity analyses, in which the results for the "0.15 uniform alternative" are shown under various alternative assumptions regarding electricity demand, equipment life, control measure effectiveness, and the discount rate. Potential direct and indirect economic impacts of the rule are discussed in Sections 6.4 and 6.5 of this chapter, respectively. Finally, Section 6.6 presents administrative costs.

In the U.S. EPA analysis, cost effectiveness is calculated as the total annual costs of the alternative divided by control season emission reductions. The NOx SIP Call defines the summer control season as the period from May 1 to September 30. U.S. EPA considered four alternatives in developing the NOx SIP Call, each one based on a different allowable emissions rate. For example, the 0.15 alternative is based on limiting NOx emissions to 0.15 lb/mmBtu of fuel heat input during the summer control season after allowing for growth in electricity demand to 2007. The "0.15

uniform alternative" provides the point of comparison for sensitivity and other analyses in this chapter. The Integrated Planning Model ("IPM") was used by the U.S. EPA to generate predictions of the technology selection, costs, and emissions for EGUs under the various alternatives.

In this regulatory proposal, Illinois EPA is proposing a uniform regulatory emission rate of 0.25 lb/mmBtu to apply statewide to large EGUs, with no emissions cap and no trading program. In order to estimate the cost effectiveness of the proposal, Illinois EPA is relying on U.S. EPA's cost data presented in the RIA to the NOx SIP Call.

Table 5-4 and Table 5-5 show the various NOx emissions reduction levels and the annual costs and cost effectiveness that the U.S. EPA estimates for the potentially affected part of the electric power industry in the years 2003, 2005, 2007, and 2010. As shown in the Table 5-4, the average costs per control season ton of NOx removed under the "0.25 uniform alternative" with trading for each of the four years differ slightly but for each year is less than $1,200 per ton of NOx removed.

U.S. EPA analyzed the results of cost effectiveness based on the "0.15 uniform alternative" without trading between sources within state boundaries. The cost difference between uniform alternatives with interstate trading and without interstate trading is approximately two percent. If states adopt rate-based approaches, the cost could be expected to be higher.

The RIA document indicated that costs could be as much as 30 percent higher if trading is restricted. Illinois EPA used this information and estimated the cost effectiveness to comply with its proposal of a 0.25 lb/mmBtu rate-based NOx emission standard with no cap and trading program to be $1,465 (1990 dollars) per ton of NOx reduced in a 2003 control period.

Table 5-4
Comparison of Estimated 2007
Incremental Ozone Season NOx Emission Reduction,
Cost, and Cost-Effectiveness for Different Regulatory Alternatives

Year/Alternative	Reductions in Control Season NOx Emissions (1,000 tons)	Annual Cost above Initial Base Case (million 1990$)	Cost per Control Season Ton of NOx Removed (1990$/ton)
2003			
0.25 Trading	523	$589	$1,127
0.20 Trading	711	$894	$1,258
0.15 Trading	899	$1,308	$1,455
0.12 Trading	1,009	$1,766	$1,750
2005			
0.25 Trading	557	$628	$1,128
0.20 Trading	746	$935	$1,254
0.15 Trading	933	$1,354	$1,451
0.12 Trading	1,043	$1,816	$1,741
2007			
0.25 Trading	563	$643	$1,143
0.20 Trading	751	$948	$1,263
0.15 Trading	938	$1,378	$1,468
0.12 Trading	1,049	$1,846	$1,760
2010			
0.25 Trading	572	$632	$1,106
0.20 Trading	760	$932	$1,226
0.15 Trading	948	$1,341	$1,415
0.12 Trading	1,058	$1,757	$1,660

Table 5-5
Comparison of Estimated 2007
Incremental Ozone Season NOx Emission Reduction, Cost; and
for Different Cost-Effectiveness Regulatory Alternatives Without Trading

Year/Alternative	Reductions in Control Season NOx Emissions (1,000 tons)	Adjusted Annual Cost above Initial Base Case (million 1990$)	Cost per Control Season Ton of NOx Removed (1990$/ton)
2003			
0.25	523	$766	$1,465
0.20	711	$1,162	$1,635
0.15	899	$1,700	$1,892
0.12	1,009	$2,296	$2,275
2005			
0.25	557	$816	$1,466
0.20	746	$1,216	$1,630
0.15	933	$1,760	$1,886
0.12	1,043	$2,361	$2,263
2007			
0.25	563	$836	$1,486
0.20	751	$1,232	$1,642
0.15	938	$1,791	$1,908
0.12	1,049	$2,400	$2,288
2010			
0.25	572	$822	$1,438
0.20	760	$1,212	$1,594
0.15	948	$1,743	$1,840
0.12	1,058	$2,284	$2,158

6.0   EXISTING AND PROPOSED ILLINOIS REGULATIONS

6.1   Existing Illinois Regulations

Title 35 Illinois Administrative Code Part 217 contains regulations to control NOx emissions from both existing and new fuel combustion sources. Emission limitations to emit NOx from combustion sources are provided. For new sources with heat input capacities equal to or greater than 250 mmBtu/hr, the emission limits varies 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, sources 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.

6.2   Proposed Regulations

Proposed Part 217, Subpart V applies to all fossil fuel-fired stationary boilers, combustion turbines, or combined cycle systems serving generators with nameplate capacities exceeding 25 Megawatts of electricity and that produce electricity for sale, and to certain smaller generators powered by units with heat input exceeding 250 million Btu per hour. The affected units are known as electrical generating units ("EGUs").

The purpose of Subpart V is to control the emissions of nitrogen oxides ("NOx") during the control period (May 1 through September 30 of each year).

Beginning May 1, 2003, all EGUs are limited to emissions not to exceed 0.25 lb NOx/mmBtu of actual heat input during each control period based on a control period average. EGUs that are listed in Appendix F, consisting of those EGUs commencing operations before 1995, however, can comply with the limitation via averaging in which the weighted average NOx emissions of all units in the averaging plan does not exceed 0.25 lb NOx/mmBtu. EGUs becoming operational in 1995 or later must comply on an individual basis, and all EGUs must comply with any applicable NOx limitation in Part 217, the Illinois Environmental Protection Act, or regulations promulgated pursuant to the federal Clean Air Act.

Compliance with the requirements of Subpart V must be demonstrated by the use of a continuous emissions monitoring system ("CEMS") that meets the requirements of 40 CFR 75. EGUs must submit to the Illinois EPA by November 30 of each year, a report that provides the NOx emission rate of each EGU during that year's control

period. If averaging is used as the method to demonstrate compliance the use of such averaging must be authorized in a federally forceable permit condition.

EGUs must comply with, and keep records of such compliance with, the control period NOx recordkeeping and reporting requirements of 40 CFR Part 75, and each EGU must certify, under penalty of law, that its November 30 report of control period emissions is true, accurate, and complete.

7.0   AFFECTED SOURCES

The following subsections describe who the participating sources are and the NOx emissions reduction estimated from this proposed rulemaking.

7.1   Affected Sources

There are 103 existing Illinois EGUs owned by 9 electric utility companies that meet the definition of a large EGU and are therefore affected by the proposed regulations. Out of 103 units, 14 are gas- and oil-fired combustion turbines, 25 are gas- and/or oil-fired boilers, 64 are coal-fired boilers. Some coal-fired boilers have the capability to burn natural gas, fuel oil or both. Out of 64 coal-fired boilers, 34 are T-fired, 8 are W-fired, and 22 are cyclone-fired boilers. Out of 64 coal-fired boilers, eleven are subject to NOx control under the Acid Rain Phase I regulations, and the remaining 53 are subject to NOx control under the Acid Rain Phase II regulations.

Most of the gas turbines operate on a simple cycle, and are operated primarily during the peak electricity demand periods, and hence capacity factors of most of the gas turbines are very low. Because of higher costs of gas and oil fuels per BTU compared to coal, gas- and oil-fired boilers are expensive to operate, and hence they are only operated primarily during the peak demand periods.

The proposed regulations will potentially impact all 103 existing EGUs. Attachment A identifies the potentially impacted sources.

7.2   Emission Reductions

The proposed regulation is based on a rate-based NOx emission limitation of 0.25 lb/mmBtu for large EGUs. Assuming the electric generation growth rate of 8 percent from 1996 to 2007 projected by U.S. EPA using the IPM and applying this NOx emission level, Illinois EPA estimates that regulated 2003 seasonal emissions to be 49,790 tons of NOx. This represents a reduction of 63,550 tons of NOx emissions or an average reduction of 56 percent from base (unregulated) 2003 NOx emission levels. Attachment A provides the individual emissions data for each of the 103 potentially impacted EGUs.

8.0 SUMMARY

The Illinois EPA has completed its attainment demonstration for the Metro-East St. Louis ozone nonattainment area. This demonstration was completed in cooperation with the State of Missouri and jointly submitted to the U.S. EPA on February 10, 2000 and supplemented on June 29, 2000. The attainment strategy calls for the implementation of all CAA control measures as they pertain to moderate ozone nonattainment areas, as the St. Louis and Metro-East areas are currently designated. The results of Illinois EPA's modeling analysis indicates that an emission rate of 0.25 lb/mmBtu for large EGUs is sufficient to demonstrate attainment of the 1-hour ozone NAAQS in the Metro-East St. Louis area. All of these controls are assumed to be in place by May 1, 2003.

The Illinois EPA has relied on the information contained in the NOx SIP Call and U.S. EPA's guidance documents in developing the proposed Subpart V that requires the NOx emissions from large EGUs greater than 25 MWe nameplate capacities to meet a rate-based NOx emission limit of 0.25 lb/mmBtu. The requirements of the proposed regulations will impact 103 emission units in Illinois and will result in an overall 56 percent reduction in base 2003 NOx emissions or a total of 63,550 tons of NOx reduced per ozone season. A number of control technologies are available to allow sources to meet the required level of control, although it is anticipated that the most likely control will be the use of combustion controls and some SCR or SNCR or some combination of such technologies. The cost effectiveness of NOx controls to meet the reduction requirements of the proposed rule has been determined to be, in 1990 dollars, $1,465 per ton of NOx reduced.

9.0 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. U.S. EPA, "Approval and Promulgation of Implementation Plans; Illinois and Missouri; Ozone. Proposed Rule", 65 FR 20404, April 17, 2000.
3. U.S. EPA, "Alternative Control Techniques Document – NOx Emissions from Utility Boilers", EPA-453/R-94-023, March 1994, U.S. EPA, OAQPS, Research Triangle Park, NC 27711.
4. 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.
5. 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.

ATTACHMENT A

Potentially Impacted Sources and Their Proposed NOx Emissions

PLANT NAME	PLANT ID NUMBER	UNIT DESCRIPTION	1996 HEAT INPUT (mmbtu)	2003 HEAT INPUT (mmbtu)	BASE 2003 NOx EMISSIONS (TONS)	2003 CONTROLLED NOx EMISSIONS (TONS)
AES C/O CILCO	057801AAA	D. Creek	11,285,981	11,860,437	2,728	1,483
AES C/O CILCO	143805AAG	Edwards 1	3,098,948	3,256,684	749	407
AES C/O CILCO	143805AAG	Edwards 2	4,543,024	4,774,264	1,098	597
AES C/O CILCO	143805AAG	Edwards 3	8,082,189	8,493,572	1,954	1,062
Ameren EGC	135803AAA	Coffeen 1	6,913,266	7,265,151	3,124	908
Ameren EGC	135803AAA	Coffeen 2	11,885,094	12,490,045	5,371	1,561
Ameren EGC	077806AAA	G. Tower 3	547,037	574,881	132	72
Ameren EGC	077806AAA	G. Tower 3	691,506	726,704	167	91
Ameren EGC	077806AAA	G. Tower 4	2,501,926	2,629,274	657	329
Ameren EGC	033801AAA	Hutsonville 3	2,020,629	2,123,479	425	265
Ameren EGC	033801AAA	Hutsonville 4	1,627,812	1,710,668	342	214
Ameren EGC	137805AAA	Meredosia 1	413,169	434,199	87	54
Ameren EGC	137805AAA	Meredosia 1	295,519	310,561	62	39
Ameren EGC	137805AAA	Meredosia 2	355,686	373,790	75	47
Ameren EGC	137805AAA	Meredosia 2	289,928	304,685	61	38
Ameren EGC	137805AAA	Meredosia 3	5,431,807	5,708,286	1,284	714
Ameren EGC	137805AAA	Meredosia 4	356,369	374,508	39	47
Ameren EGC	079808AAA	Newton 1	13,850,020	14,554,986	2,911	1,819
Ameren EGC	079808AAA	Newton 2	13,516,168	14,204,141	2,841	1,776
Mid West Generation	063806AAF	Collins 1	3,681,398	3,868,781	387	484
Mid West Generation	063806AAF	Collins 2	3,714,278	3,903,335	390	488
Mid West Generation	063806AAF	Collins 3	5,716,799	6,007,784	601	751
Mid West Generation	063806AAF	Collins 4	3,534,697	3,714,613	557	464
Mid West Generation	063806AAF	Collins 5	1,192,334	1,253,024	188	157
Mid West Generation	031600AIN	Crawford 7	4,454,390	4,681,118	1,053	585
Mid West Generation	031600AIN	Crawford 8	5,652,307	5,940,009	1,337	743
Mid West Generation	031600AMI	Fisk 19	6,381,195	6,705,998	1,509	838
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	031600AMI	GT PEAKERS	659,904	693,493	242	87
Mid West Generation	197809AAO	Joliet 6	1,447,770	1,521,461	654	190
Mid West Generation	197809AAO	Joliet 7	8,645,362	9,085,411	1,817	1,136
Mid West Generation	197809AAO	Joliet 7	5,542,765	5,824,892	1,165	728
Mid West Generation	197809AAO	Joliet 8	6,064,500	6,373,183	1,275	797

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PLANT NAME	PLANT ID NUMBER	UNIT DESCRIPTION	1996 HEAT INPUT (mmbtu)	2003 HEAT INPUT (mmbtu)	BASE 2003 NOx EMISSIONS (TONS)	2003 CONTROLLED NOx EMISSIONS (TONS)
Mid West Generation	197809AAO	Joliet 8	9,122,442	9,586,774	1,917	1,198
Mid West Generation	097190AAC	PEAKING	60,052	63,109	22	8
Mid West Generation	097190AAC	PEAKING	60,052	63,109	22	8
Mid West Generation	097190AAC	PEAKING	60,052	63,109	22	8
Mid West Generation	097190AAC	PEAKING	60,052	63,109	22	8
Mid West Generation	179801AAA	Powerton 5	9,012,328	9,471,055	4,073	1,184
Mid West Generation	179801AAA	Powerton 5	9,012,328	9,471,055	4,073	1,184
Mid West Generation	179801AAA	Powerton 6	9,012,328	9,471,055	4,073	1,184
Mid West Generation	179801AAA	Powerton 6	9,012,328	9,471,055	4,073	1,184
Mid West Generation	097190AAC	Waukegan 6	2,422,753	2,546,071	942	318
Mid West Generation	097190AAC	Waukegan 7	4,579,361	4,812,450	1,083	602
Mid West Generation	097190AAC	Waukegan 8	8,128,724	8,542,476	1,922	1,068
Mid West Generation	197810AAK	Will County 1	4,439,209	4,665,165	2,006	583
Mid West Generation	197810AAK	Will County 2	4,318,786	4,538,612	1,952	567
Mid West Generation	197810AAK	Will County 3	5,472,123	5,750,654	1,294	719
Mid West Generation	197810AAK	Will County 4	9,343,631	9,819,222	2,209	1,227
CWLP	167120AGQ	#2 GAS	1,129,015	1,186,482	312	148
CWLP	167120AAO	Dallman 1	1,744,943	1,833,761	853	229
CWLP	167120AAO	Dallman 2	2,512,923	2,640,831	1,347	330
CWLP	167120AAO	Dalman 3	5,888,782	6,188,521	1,238	774
CWLP	167120AAO	Lakeside 7	581,954	611,575	257	76
CWLP	167120AAO	Lakeside 8	521,936	548,503	230	69
Dom. Enrgy	021814AAB	Kincaid 1	9,778,627	10,276,359	4,419	1,285
Dom. Enrgy	021814AAB	Kincaid 2	10,775,493	11,323,966	4,869	1,415
EEI	127855AAC	Joppa 1	6,147,036	6,459,920	1,453	807
EEI	127855AAC	Joppa 2	6,592,662	6,928,228	1,559	866
EEI	127855AAC	Joppa 3	6,555,679	6,889,363	1,550	861
EEI	127855AAC	Joppa 4	4,912,358	5,162,397	1,162	645
EEI	127855AAC	Joppa 5	5,920,130	6,221,465	1,400	778
EEI	127855AAC	Joppa 6	6,700,654	7,041,717	1,584	880
DMG	157851AAA	Baldwin 1	13,973,608	14,684,865	6,314	1,836
DMG	157851AAA	Baldwin 2	11,488,533	12,073,299	5,192	1,509
DMG	157851AAA	Baldwin 3	16,401,763	17,236,613	3,878	2,155
DMG	125804AAB	Havana 1-5	0	0	0	0
DMG	125804AAB	Havana 1-5	0	0	0	0
DMG	125804AAB	Havana 1-5	0	0	0	0
DMG	125804AAB	Havana 1-5	0	0	0	0
DMG	125804AAB	Havana 1-5	0	0	0	0
DMG	125804AAB	Havana 1-5	0	0	0	0

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Potentially Impacted Sources and Their Proposed NOx Emissions

PLANT NAME	PLANT ID NUMBER	UNIT DESCRIPTION	1996 HEAT INPUT (mmbtu)	2003 HEAT INPUT (mmbtu)	BASE 2003 NOx EMISSIONS (TONS)	2003 CONTROLLED NOx EMISSIONS (TONS)
DMG	125804AAB	Havana 1-5	0	0	0	0
DMG	125804AAB	Havana 1-5	0	0	0	0
DMG	125804AAB	Havana 6	6,806,431	7,152,878	1,645	894
DMG	155010AAA	Hennepin 1	1,854,683	1,949,086	390	244
DMG	155010AAA	Hennepin 2	6,724,666	7,066,951	1,590	883
DMG	183814AAA	Vermilion 1	206,504	217,015	44	27
DMG	183814AAA	Vermilion 2	382,821	402,307	91	50
DMG	119020AAE	Wood River 1	0	0	0	0
DMG	119020AAE	Wood River 2	0	0	0	0
DMG	119020AAE	Wood River 3	0	0	0	0
DMG	119020AAE	Wood River 4	2,708,276	2,846,127	572	356
DMG	119020AAE	Wood River 5	8,891,655	9,344,240	1,869	1,168
SIPCO	199856AAC	Marion 1	151,333	159,036	98	20
SIPCO	199856AAC	Marion 2	103,108	108,356	49	14
SIPCO	199856AAC	Marion 3	321,202	337,551	161	42
SIPCO	199856AAC	Marion 4	5,424,619	5,700,732	2,451	713
U. Elect.	119105AAA	TURBINE	37,297	39,195	14	5
U. Elect.	119105AAA	Venice 1	97,793	102,771	10	13
U. Elect.	119105AAA	Venice 2	121,330	127,506	13	16
U. Elect.	119105AAA	Venice 3	52,068	54,718	5	7
U. Elect.	119105AAA	Venice 4	67,238	70,660	7	9
U. Elect.	119105AAA	Venice 5	138,235	145,271	15	18
U. Elect.	119105AAA	Venice 6	148,385	155,938	16	19
U. Elect.	119105AAA	Venice 7	16,634	17,481	2	2
U. Elect.	119105AAA	Venice 8	19,156	20,131	2	3
Grand Total					113,340	49,790