Status Report on NOx Controls

for

Gas Turbines
Cement Kilns
Industrial Boilers
Internal Combustion Engines

Technologies & Cost Effectiveness

December 2000

NESCAUM
Northeast States for Coordinated Air Use Management

Members of Northeast States for Coordinated Air Use Management

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Status Report on NOx for Industrial Boilers, Gas Turbines, Internal Combustion Engines and Cement Kilns; Control Technologies and Cost Effectiveness

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A unique feature of this report is a collection of case studies (Chapter IV) of real-world experience with NOx control technologies. The case studies outline recent industrial sector (non-electricity generating sector) experience with control technologies in the United States. This chapter was prepared in cooperation with operators of industrial facilities that are utilizing a number of NOx control technologies for industrial boilers, gas turbines, internal combustion engines, and cement kilns. These companies undertook a substantial level of effort in providing the operating and cost information on control technologies that was the basis for the preliminary version of case studies, prepared by Andover Technology Partners. The preliminary case studies were then reviewed and approved by the industrial operators before inclusion of final versions in this report. Without their assistance, this important aspect of the report would not have been possible.

This report was reviewed by the members of Stationary Source and Permits Committee of NESCAUM, key technical staff from other states in the Ozone Transport Region, and staff from the U.S. Environmental Protection Agency.

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I. Executive Summary

This Northeast States for Coordinated Air Use Management (NESCAUM) report evaluates various control technologies and their cost effectiveness in reducing emissions of oxides of nitrogen (NOx) from four major source categories: industrial boilers, gas turbines, stationary internal combustion engines, and cement kilns. As a group, these sources emit substantial amounts of NOx in the United States, and for this reason, have been identified by the U.S. Environmental Protection Agency (EPA) and many state and local regulatory agencies as potential sources for NOx controls. In the recent past, control of NOx emissions has been required to reduce both the ground-level ozone (NOx and volatile organic compounds are two major precursors to the formation of ground-level ozone) and acid deposition. Additionally, NOx emissions contribute to the air pollution problems of fine particles and regional haze (visibility degradation), and to ecological problems including eutrophication of marine bays and estuaries. Further NOx reductions may be necessary to address these environmental problems in addition to the current focus on ground-level ozone and acid deposition.

A unique feature of this technology assessment report is the detailed description of case studies of actual facilities that are currently using various NOx control technologies for the four source categories. The case studies provide valuable real-world information on applicability, cost, performance, and reliability of technologies used. This information was useful in determining applicability and cost effectiveness of available control technologies to the four source categories. It is important to note that the conclusions drawn in this study regarding technical and economic feasibility of various control technologies are therefore grounded in "real-world data."

A. Report Objectives and Organization

This report identifies and evaluates NOx control technologies that have been commercially applied to the source categories of interest and, based on field experience, assesses the feasibility and cost-effectiveness of applying these technologies to many existing sources that are currently uncontrolled. Case studies were undertaken for actual installations of NOx reduction technologies on many sources, and detailed write-ups were prepared in cooperation with the users of the technologies. The users provided all of the information and approved the written descriptions of the case studies (Chapter IV). Therefore, these case studies represent the user's view of the performance, reliability, and cost of technologies.

In this report, cost effectiveness is measured in dollars per ton of NOx removed ($/ton), and in the case of cement kilns, in terms of dollars per unit of product ($/ton of clinker) as well as in dollars per ton of NOx removed. Cost effectiveness is calculated for both annual and seasonal controls (seasonal controls are for the five-month ozone season from May 1 to September 30). Whenever available and appropriate, case study information was used as the basis for the cost analysis.

This report is organized into four chapters. Following this Executive Summary, Chapter II provides a technical description of control technologies that are commercially available. Chapter II also provides a brief background on those technologies that are rapidly emerging, but are not yet well established. Chapter III deals with the estimates of costs associated with the application of commercially available technologies, including detailed cost effectiveness numbers in $/ton, as a function of fuel use, capacity factors, and size of the units. Finally, Chapter IV presents twenty-eight case studies of field experience (both operating and cost information) with control technologies described in Chapter II. The cost effectiveness calculations of Chapter III incorporate the field experience of case studies where appropriate.

The following section discusses the most significant findings with regard to the technologies and costs for each source category. The concluding section of the Executive Summary (section C) outlines major findings from case studies experience.

B. NOx Control Technologies and Cost Effectiveness

Estimates of cost effectiveness are made for both annual and seasonal NOx control scenarios. In the case of seasonal control, it is assumed that the technology is secured ("turned off"), if feasible, outside of the ozone season to save on the cost of reagents or more expensive fuel. This type of seasonal operation is possible for many secondary control technologies such as Selective Non-Catalytic Reduction (SNCR) or gas reburn. However, most primary control technologies, such as Low-NOx Burners, provide NOx reductions all year. When calculating cost effectiveness on a seasonal control basis, no credit is taken for the NOx reductions outside of the ozone season, since these reductions are not required under current regulations. It should be noted that some states in the Northeast have recently adopted or are seriously considering the adoption of year-round NOx controls to address other environmental problems such as acid deposition and regional haze. Calculations of cost effectiveness for annual controls are based on the assumption that NOx reductions occur on year-round operation.

B.1 Industrial Boilers

For industrial boilers, combustion and post-combustion controls are reviewed. Low-NOx Burners (LNB), overfire air (OFA), Selective Non-Catalytic Reduction (SNCR), Selective Catalytic reduction (SCR), and reburn technology have been used with industrial boilers.

Decisions to use overfire air should be made on a case-by-case basis. Industrial boilers firing pulverized coal that use Low-NOx Burners without overfire air should be capable of meeting NOx levels similar to those of utility boilers using similar equipment. Some industrial boilers are not capable of using overfire air and deep combustion staging, although the case studies discuss four boilers that use overfire air as part of a reburning system. For pulverized coal boilers, annual reductions on the order of 30% can be achieved with Low-NOx Burners at an estimated cost of less than $2,000/ton, even at a capacity factor[i] as low as 45%.

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[i] Capacity factor is a term used frequently in this report to describe the level of operation of the piece of equipment in relation to what the equipment is capable of. Capacity factor is usually expressed as a decimal fraction or a percentage. A capacity factor of 100% (or 1.0) indicates that the equipment is operated at full production capacity for the entire year (8,760 operating hours at full output per year). A capacity factor of 50% (or 0.50) indicates that the equipment is operated at a production level *equivalent to* 50% production capacity for the full year. For example, a 10 MW turbine-generator with a capacity factor of 65% (or 0.65) produces 10 x 8,760 x 0.65 = 56,940 MWhr in one year. While it is

Low-NOx Burners were able to control to a median NOx level of 0.10 lb/MMBTU for industrial boilers firing natural gas, with the substantial majority (over 80%) of these boilers controlling to below 0.15 lb/MMBTU. Boilers equipped with Low-NOx Burners firing number six fuel oil had a median control level of 0.35 lb NOx/MMBTU, with variable performance probably due to the variable nitrogen content of the fuel. Annual NOx reductions with LNBs can be achieved from oil- and gas-fired industrial boilers at an estimated cost effectiveness of about $2,000/ton or less for moderate to high capacity factors (65 to 85%) units.

SNCR appears to be well suited for use with industrial boilers. SNCR is very widely used on industrial boilers, particularly those firing solid fuels, and achieves NOx reductions of over 50% on average. In boilers firing pulverized coal, NOx reductions with SNCR are likely to be similar to those from utility boilers with SNCR – on the order of 35%. NOx reductions from a boiler firing pulverized coal and equipped with SNCR are estimated to cost in the range of $1,300 to $1,800/ton for annual control and from $2,000 to $3,000/ton for seasonal controls.

While SCR has seen limited use in the United States on industrial boilers firing solid fuel, there are no technical reasons to believe that SCR cannot be used in these applications. Substantial NOx reductions up to 90% and greater, as achieved with SCR on electric utility boilers, would be expected for pulverized coal-fired industrial boilers. At moderate to high capacity factors, the reductions from industrial boilers are estimated to cost below $2,000/ton NOx for annual controls. For seasonal controls at moderate to high capacity factors, the range of cost effectiveness varies from $3,000 to $5,000 per ton of NOx. SCR on gas-fired boilers is estimated to provide reductions for $2,000/ton on an annual basis for boilers of about 350 MMBTU/hr size that operate at high capacity factors. Under similar conditions, gas-fired boilers of 100 MMBTU/hr rating can be retrofitted with SCR to provide NOx reductions below $3,400/ton.

Gas and coal reburn technologies are operating on some industrial boilers in the U.S. and are providing NOx reductions on the order of 50% or more. Combinations of gas reburn with SNCR offer the potential for even higher NOx reduction – 60% or more. Both conventional gas reburn and fuel-lean gas reburn are expected to be more applicable to industrial boilers than is coal reburn. Gas reburn technologies are estimated to provide NOx reductions under $2,000/ton, even for seasonal controls in some cases. For example, Amine-Enhanced Fuel-Lean Gas Reburn is expected to provide NOx reductions of about 60% on a seasonal basis for about $2,000/ton or less, assuming an incremental cost of natural gas of up to $1.00/MMBTU over coal and a capacity factor of 65% or more. The cost-effectiveness values of these technologies, as expected, are sensitive to the price of natural gas relative to the price of coal.

Emerging technologies, such as Electro-Catalytic Oxidation and Ozone Injection offer the potential for high NOx reduction, as well as reduction of the emissions of other pollutants. Because there is much less experience with these technologies, available cost information is limited. Therefore, cost analysis was not performed for these technologies.

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acknowledged that equipment production output is usually not at a constant level over the entire year, for the purpose of the calculations in this report this simplifying assumption is made.

B.2 Gas Turbines

There have been some important developments in gas turbine NOx control technology, but well-established technologies continue to play an important role in reduction of NOx. Dry Low NOx (DLN), catalytic combustion, and some new post-combustion methods are making their way into the control technology market, while water or steam injection and SCR continue to be important technologies for reducing NOx from gas turbines.

Many turbine manufacturers can convert or replace conventional combustors on existing turbines with DLN combustors. DLN combustion retrofits have been made possible by recent developments in gas turbine combustor technology. DLN technology offers the potential for substantial reduction of NOx from turbines firing natural gas or other low-nitrogen fuels, as well as improved engine performance when compared to wet controls (water or steam injection). For turbines under about 15 MW in size, NOx emissions of 25 ppm can be guaranteed for new turbines and emissions below 42 ppm can be guaranteed for retrofitted turbines. For large turbines (75 MW and higher in size), controlled NOx emission levels of as low as 9 ppm have been guaranteed, even for retrofits.

DLN capital costs vary with the size of the turbine and the specifics of the particular turbine being retrofitted. Baseline NOx level will significantly affect the estimate of cost per ton of NOx reduced. Using expected baseline NOx emissions levels provided by the turbine manufacturers and retrofit costs expected to be typical of most applications, retrofit of Dry Low NOx on industrial turbines (about 3 to 10 MW) originally equipped with conventional combustion control is estimated to provide NOx reductions under $2,000/ton for annual controls with high capacity factors and at a higher cost for seasonal controls. For larger turbines (~75 MW), cost was estimated to be well below $1,000/ton for nearly all conditions, and only a few hundred dollars per ton of NOx reduced when the turbine was operated at a high capacity factor (~0.85). Calculations show that a DLN retrofit of a large turbine originally equipped with water injection could pay for itself largely from the improved turbine efficiency. If actual baseline turbine emissions are lower than the expected baseline emissions used in these calculations, the cost of reducing NOx (in $/ton) will be higher. DLN typically has lower carbon monoxide (CO) and volatile organic compounds (VOC) emissions than water injection.

Water injection and steam injection are two well-established technologies that can offer controlled NOx emission levels below 42 ppm in many cases. Because water or steam injection technologies frequently have lower capital cost than DLN but higher variable costs, these technologies can be more attractive for peaking turbines or other turbines that operate infrequently. It was estimated that water injection installed on peaking units that operate 200 hours to 400 hours in the summer would reduce NOx at a cost of about $2,500/ton to about $7,000/ton, depending upon the number of operating hours and the fuel used (gas or distillate oil). It is notable that these NOx reductions typically occur on hot summer days when the value of electrical power and the environmental benefit of NOx reductions (to reduce ground-level ozone) are both high.

SCR continues to be the most widely used post-combustion technology for gas turbines. Catalyst technology developments have made SCR viable over a wider temperature range. This makes SCR a viable control option in situations that were difficult in the past, such as simple-cycle turbines that may now benefit from high-temperature SCR and combined-cycle turbines with duct burners that may now benefit from low-temperature SCR.

The cost of NOx reduction with SCR varies considerably according to application, turbine size, and the type of SCR technology that is appropriate for the application. As in the case of the DLN cost estimates, expected baseline NOx emissions levels provided by the turbine manufacturers were used as a basis for cost calculations. Conventional SCR on a large (~75MW) combined-cycle turbine with high capacity factors was estimated to cost about $440/ton for annual controls and $870/ton for seasonal controls, for turbines equipped with conventional combustion technology (baseline NOx emissions of 154 ppm). For turbines with lower baseline NOx emissions (such as those equipped with DLN combustors having baseline NOx emissions of 15 ppm), the cost per ton of additional NOx removed was estimated to be greater, ranging from about $3,700/ton (annual control, high capacity factor) to over $13,000/ton (seasonal controls, low capacity factor). On smaller turbines (~5 MW), the cost of conventional SCR is estimated to be as low as $1,300/ton (with annual control and conventional combustion technology having baseline NOx emissions of 142 ppm). Seasonal controls for smaller turbines are estimated at over $15,000/ton of NOx removed at a low capacity factor (45%) with baseline NOx emissions of 42 ppm.

For installations that may be better suited for high- or low-temperature SCR variants, such as simple-cycle turbines (high-temperature SCR) or combined-cycle turbines with limited space (low-temperature SCR), the cost of SCR is somewhat higher than for conventional SCR on a combined-cycle plant. The analysis of this report found that a 75 MW turbine at a high capacity factor and equipped with conventional combustion technology (baseline NOx emissions of 154 ppm) can be controlled annually with high- or low-temperature SCR for about $550/ton and for about $1,200/ton seasonally. As with conventional SCR, turbines with lower baseline NOx emissions (such as those equipped with DLN combustors) showed a higher cost per ton of NOx reduction. The estimated cost of NOx reduction for a 75 MW turbine with baseline NOx emissions of 15 ppm ranges from $5,170/ton (annual controls, high capacity factor of 85%) to as high as $20,000/ton (seasonal controls, low capacity factor of 45%). On smaller turbines (~5MW), the cost for high- or low-temperature SCR is estimated to be as low as $2,000/ton with annual control and conventional combustion technology (baseline NOx emissions of 142 ppm). Cost is estimated to range from $6,750/ton (annual controls, high capacity factor of 85%) to about $27,000/ton (seasonal controls, low capacity factor of 45%) with baseline NOx emissions of 42 ppm.

Emerging combustion technologies (such as catalytic combustion) and post-combustion technologies (such as SCONOx) offer the potential for very low NOx emission levels. Because there is much less experience with these technologies, available cost information is limited. Therefore, cost analysis was not performed for these technologies.

B.3 Internal Combustion Engines

Several control technologies are available for internal combustion (IC) engines, having a wide range of complexity, cost and performance.

Some in-cylinder methods offer low to moderate NOx reductions at costs well below $1,000/ton. These include injection timing retard, ignition timing retard, and air/fuel ratio adjustment (with or without high-energy ignition). These methods are widely available, and NOx performance will vary from one engine design to another. However, fuel efficiency can suffer as a result of these methods and emissions of products of incomplete combustion can increase.

Spark-ignited engines that can be retrofitted with Low-Emission Combustion (LEC) technology can potentially achieve significant NOx reductions (80 to 90%). LEC technology can be expensive to retrofit on some engines, and it may not be available from all engine manufacturers. For large, low-speed engines, LEC technology is estimated to provide annual NOx reductions of about 80% at under $1,000/ton under most conditions. LEC technology is estimated to be more cost effective on smaller, medium-speed engines (under $500/ton for annual control under most conditions). It is estimated to be somewhat more expensive for dual-fuel engines (annual control at a capacity factor of 65% is estimated to cost under $1,000/ton).

SCR is the only commercially available choice for post-combustion control of diesel and lean-burn spark-ignition engines. Experience in the U.S. with SCR on these engines is growing, especially for diesel engines. SCR has been applied to approximately 30 diesel engines and to an equivalent number of constant-load lean burn IC engines. Experience with SCR on variable-load engines is limited. In analysis using data from case studies, it was estimated that SCR provides annual NOx reductions of as high as 90% at a cost below $1,000/ton in all cases, except for very low capacity factors (~10%), and it provides seasonal reductions at a cost of under $1,000/ton for engines operating at high capacity factors (typically, 65% or greater).

Recent developments from the application of urea-SCR on mobile sources (diesel trucks) offer the possibility of reducing the size and capital cost of SCR systems for stationary IC engines. This new technology, developed from efforts to apply SCR to mobile diesel engines, appears to make it possible to achieve much more cost-effective NOx reduction on stationary IC engines that operate for only a few hundreds of hours a year. NOx reduction of about 75% is estimated to be possible for under $2,000/ton even for seasonal controls of some stationary IC that operate only a few hundred hours each ozone season. Seasonal control at a cost of under $1,000/ton is estimated to be achievable for most applications with capacity factor greater than 45%.

B.4 Cement Kilns

Several methods are utilized to control NOx emissions from cement kilns.

Automated process control has been shown to lower NOx emissions by moderate amounts, through overall efficiency improvements that reduce the firing requirement in the kiln and by reducing kiln variability, which minimizes periodic NOx emission spikes. Estimates of cost effectiveness were not made for automated process control due to the lack of availability of data and wide differences that exist between kilns. However, the use of automated process control is expected to improve overall facility operations and is being adopted at cement kilns for its economic benefits.

Low-NOx Burners have been successfully used in the primary burn zone and especially in the precalciner kilns. Combustion techniques were estimated to provide NOx reduction at a cost-effectiveness value of under $1,000/ton (annual control, high capacity factor).

CemStar^{SM} is a process that involves adding steel slag to the kiln, offering moderate levels of NOx reduction by reducing the required burn zone heat input. CemStar^{SM} is currently being used at several cement plants for its original purpose of increasing production capacity. The technology also reduces total NOx emissions by about 20% or more. Because of the increased production, CemStar^{SM} provides an overall economic benefit while reducing total NOx emissions.

Mid-kiln firing of tires provides moderate reductions of NOx emissions while reducing fuel costs and providing an additional revenue stream from receipt of tire tipping fees. Several cement kilns currently employ this technology because of its economic benefits.

Biosolids injection technology can offer significant reductions on some precalciner kilns. There is one biosolids injection plant in the U.S. Biosolids injection offers the potential for tipping fees, but this technology may not be applicable on a wide variety of kilns. Mainly precalciner kilns with sufficient excess fan capacity may be able to use this technology.

SNCR technology has the potential to offer significant reductions on some precalciner kilns. SNCR has been tested on at least one facility in the U.S. However, SNCR is being used in numerous cement kilns in Europe. In situations where SNCR is technically feasible, NOx reductions are estimated to cost under $1,000/ton, even for seasonal control with capacity factors of about 65% or more.

Many of the control methods discussed in this report for application on cement kilns can be combined. For example, mid-kiln firing and Low-NOx Burners were combined in one case study to provide total NOx reduction of about 50%. It is possible that CemStar^{SM} and process controls could be combined with these technologies for additional reduction and capacity improvement. In some cases it may be feasible to use SNCR in combination with other controls for cement kilns.

C. Case Studies

For all of the case studies, the utilized technologies met the guarantees. In most cases, reliability of control technology to reduce NOx emissions was very good. The few cases where reliability was low (as represented by high lost operating hours) were the result of problems that have since been corrected and are not expected to persist. Therefore, based on the experience of the users in the case studies, future users of the technology are not expected to face reliability problems. For example, some early experience with Dry Low NOx technology on industrial turbines found performance to be unstable during certain transient situations. Some early users experienced frequent tripping of their turbines. Efforts by the turbine manufacturers to improve the Dry Low NOx system controls have overcome the problem, and it should not be a problem for future users.

For industrial boilers, all of the technologies have been demonstrated to have high reliability. A few minor issues were reported, however. There was one instance of tube failure from urea impingement, but the user is correcting the problem with the technology supplier. In another case study plugging of equipment was reported; this is believed to be due to the user's choice of a reagent that does not meet the technology supplier's specifications. Notably, none of the users of SNCR or SCR reported problems normally associated with high ammonia slip, such as ammonium salt deposits on boiler surfaces.

In view of the very limited experience in the U.S. with SCR on IC engines, the high reliability experienced by users in the two case studies is a very positive and promising finding.

For cement kilns, the technologies that were evaluated showed no adverse impact on reliability. In one case study the operator reported that they expect the use of indirect firing to improve kiln reliability. Moreover, cement kiln operators are implementing technologies that both improve facility economics and reduce NOx emissions by moderate amounts.

II. NOx Control Technologies

There are four general source categories addressed in this effort: industrial boilers, gas turbines, internal combustion (IC) engines, and cement kilns. Within these four general categories, there are variations in design based on fuel and application. The different variations in each source category are discussed briefly, as they can influence the applicability of a specific control technology. The control technologies that are commercially available for application are then briefly described for each category. Considering the wide variety of source types addressed in this report, there are potentially a wide variety of NOx reduction technologies available. While this report addresses a number of widely available technology options, technologies that are not currently well established or widely available are only briefly mentioned. Specifically, technologies that have not at least been demonstrated at a commercial scale are not considered in this report.

For those applications and technologies that are addressed in this report, a summary of the important aspects of the application and a brief discussion of the technologies is provided. Readers with an interest in exploring the technical issues in a more comprehensive manner are directed to other sources that are referenced in this report.

A. Industrial Boilers

A wide range of industrial boilers in the United States fire a variety of fuels. The fuels most commonly used in industrial boilers are pulverized coal, crushed coal, oil, natural gas, and biomass (including wood and wood waste). The principal firing types and most common fuels are shown in Table II-1.

Table II-1 Industrial Boiler Firing Configurations and Typical Primary Fuels

Boiler Type	Pulverized Coal	Crushed Coal	Oil	Gas	Biomass
Tangential	✔		✔	✔	
Wall	✔		✔	✔	
Stoker/Grate		✔			✔
Fluid Bed		✔			✔
Cyclone		✔	✔	✔	✔

Tangential- and wall-fired boilers fire pulverized coal, oil or natural gas. Fluidized-bed boilers fire crushed coal and biomass, though they may use oil or gas for initial startup. Cyclone boilers can fire any of the fuels listed except pulverized coal since they generally lack the necessary fuel preparation equipment for firing pulverized coal. Some electric utility cyclone units fire oil or gas, although these boilers were originally built to fire crushed coal. Cyclone boilers in industrial applications, however, most often fire crushed coal and occasionally biomass or other solid fuels.

The NOx control methods available to industrial boiler operators generally fall into two categories: primary control methods and secondary control methods. Primary control methods minimize the generation of NOx itself in the primary combustion zone. Secondary control methods reduce the NOx originally formed in the primary combustion zone.

A.1 Primary Methods of Controlling NOx in Industrial Boilers

These methods include the use of Low-NOx Burners (LNBs), Overfire Air and/or Staged Combustion, and Flue Gas Recirculation. A related method is combustion tempering, in which water is injected into high-temperature regions of the flame.[1] These methods have been explored in detail by others, and Reference [2] provides a good overview of the subject. All of these methods operate on the basic principles of controlling fuel/air stoichiometry and flame temperature to lower NOx generation.

Because of the wide variety of industrial boiler types, firing configurations and fuels, a wide range of controlled NOx levels are achieved in practice. Wall- and tangentially- fired boilers tend to be most amenable to the use of Low-NOx Burners, although other primary methods (overfire air, flue-gas recirculation, gas co-firing, etc.) have been used with success on other furnace types. Because of the smaller size of industrial boilers, permitting less separation, overfire air is rarely used. Some have argued that the operating characteristics of industrial boilers make it more difficult to lower the furnace oxygen levels (known as low excess-air) and apply staged combustion as a means to reduce NOx. [2, 3] Proponents of this argument suggest that industrial boilers have highly variable load characteristics that make combustion controls at low excess-air conditions unworkable. They also note that the size of an industrial boiler makes the length of the Low-NOx Burner flame too long and that there is insufficient room in the boiler for overfire air.

On the other hand, Low-NOx Burners and Overfire Air have been successfully applied to many industrial boilers. Reference 2 lists about 400 Low-NOx Burners installed by one supplier alone, along with their guarantee levels. Chapter IV describes four boilers at Kodak Park (Case Studies BLR-8 and BLR-9) which are using overfire air with reburning, showing that the success achievable in applying primary controls on industrial boilers is determined by the unique characteristics of the facility and the knowledge and skill of the individuals implementing the technology. Despite the differences in facilities, there is a broad selection of primary control methods that may be used at specific units.

For any specific furnace type, the fuel nitrogen, the furnace volumetric heat release rate, and the use of preheated air limit the potential NOx reductions for primary controls. Other furnace constraints may limit the performance of some technologies as well. Fuel nitrogen content is the primary reason that coal produces much higher NOx than oil or gas. Coal typically requires higher excess oxygen levels than oil or gas, providing oxygen for thermal NOx production. The nitrogen content of coal, about 1% to 1.5%, is often double that of residual (No. 6) oil, although nitrogen in residual oil can vary from 0.10% to 0.60%. This range in fuel nitrogen has been a particular problem for boilers firing No. 6 fuel oil, leading to NOx emissions that may vary from 40 ppm to 310 ppm[4] and makes it difficult to get predictable reductions from Low-NOx Burners with this fuel. While manufacturers have successfully found ways to reduce thermal NOx production, reducing fuel-NOx requires deep staging in order to first pyrolize the fuel and then release the fuel-bound nitrogen in a reducing atmosphere. While staged combustion is typically performed with Low-NOx Burners, deep staging requires more furnace volume than most industrial boilers offer.

Furnace volumetric heat release rate, the degree of air preheat, and the excess oxygen level determine, to a large degree, the combustion gas temperature and the thermal NOx generated. In-furnace NOx reduction methods are less effective on high heat release and high preheat furnaces because of the difficulty in overcoming the thermal NOx component. Although undesirable, reducing the boiler load can be used as a means of addressing this issue if primary and secondary methods prove technically or economically less feasible.

Table II-2 shows a statistical summary of the guaranteed performance of one particular manufacturer's Low-NOx Burners as reported in Reference 2. Actual performance is typically better. It is interesting to note the standard deviation for both the gaseous fuel and No. 6 fuel oil. For the gas-fired applications, the variation is due to different burner conditions, such as furnace volumetric heat input, preheat level, and different burner designs. For example, flue gas recirculation may be used in some cases for lower NOx operation. In any event, emissions well below 0.15 lb/MMBTU appear quite achievable with natural gas, probably for well over 80% of gas-fired boilers. In fact, half of the applications reported NOx below 0.10 lb/MMBTU. In the case of No. 6 fuel oil, NOx levels below 0.45 lb/MMBTU appear achievable for about 80% or more of the population and below 0.35 lb/MMBTU for half of the population. However, it appears that some boilers would find it difficult to achieve below this level of NOx control. This is largely because of fuel nitrogen, preheat, and heat release rate. Also, considering that the information summarized in Table II.2 is for burners sold before 1994, performance for more recent applications should be better.

In addition to increasing the temperature of the combustion air, air-preheat increases air velocity at the burner, making a stable flame more difficult to maintain than otherwise. Reference [5] describes the use of low-NOx retrofit technology at industrial boilers firing No. 6 fuel oil with nitrogen content in the range of 0.2-0.4% (by weight). The boilers with preheated air had an initial NOx level at full load in the range of 0.70 to 0.80 lb/MMBTU. In this case, NOx was reduced to about 0.40 to 0.50 lb/MMBTU with the low-NOx boiler retrofit. The other boilers that did not have preheated air had an initial NOx level of 0.35 lb/MMBTU, and the NOx emissions from these boilers were reduced to 0.26-0.27 lb/MMBTU. While there are other differences between these boilers beside air-preheat, the use of air-preheat has a significant effect on achievable NOx emissions. Reference 8 lists an application of the use of deep staging and separated overfire air at a Long Island Lighting power station to achieve NOx levels of 0.14 lb/MMBTU or less with No. 6 fuel oil. However, this form of combustion control is unlikely to be applicable to most industrial boilers since a large furnace and overfire air are needed to implement deep staging. Generally, the range of NOx emissions achievable on industrial boilers firing No. 6 fuel oil can vary substantially.

Table II-2: Statistics Regarding Low-NOx Air Register Burner Performance for Boilers Over ~250 MMBTU/hr[ii,iii]

	Natural Gas/Refinery Gas (lb NOx/MMBTU)	No. 6 Fuel Oil (lb NOx/MMBTU)
Mean Emissions	0.11	0.37
Median Emissions	0.10	0.35
Population Standard Deviation	0.050	0.094
Minimum Emissions	0.05	0.23
Maximum Emissions	0.20	0.55
Analysis based on data from Reference 2 Appendix C.		

Combustion Tempering, also known as Water Injection, is a technique that involves injection of water into the high-temperature and high-oxygen regions of the flame to suppress thermal NOx formation. This approach has been used on electric utility boilers as well as industrial and commercial boilers.[6,7] Its effectiveness will vary from one unit to another and will depend on fuels used; however, low to moderate reductions in the range of 15% to 30% should be expected. This method will, generally, be more effective on gas-fired units than units firing No. 6 fuel oil because this method reduces thermal NOx but not fuel NOx. For cyclone boilers that generate high levels of thermal NOx, reductions of 22% have been demonstrated and higher reductions are possible.[1] In most cases, other combustion techniques are attempted first because this approach adversely affects boiler efficiency. Efficiency losses of up to 1% are possible, but lower efficiency losses are typical.

A.2 Secondary Methods of Controlling NOx in Industrial Boilers

Secondary control methods reduce the NOx already formed in the primary combustion zone. They include Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR) and Reburning. These technologies have been applied on a wide range of utility boilers.[8] Reference 8 contains a comprehensive discussion of these technologies. Summary discussions follow below.

[ii] Notes for tables II-2, II-3a, and II-3b:

- The mean is the arithmetic average of all of the NOx values or reductions reported.
- The median value is calculated such that 50% of the reported values are higher and 50% are lower than the median. When a population is influenced by a small number of unusually high or low values such that the distribution is somewhat skewed (as in Table 2.2), the median is preferable to the mean as a measure for the population.
- The Standard Error of Mean is the measure of the uncertainty in using the sample mean to estimate the mean of a large population. When it is small relative to the mean, the mean is a good measure of the population.
- Population Standard Deviation is a measure of dispersion of a large population.
- Minimum is the minimum value reported.
- Maximum is the maximum value reported.

[iii] The nitrogen content of the No. 6 fuel oil was not available.

Selective Non-Catalytic Reduction (SNCR)

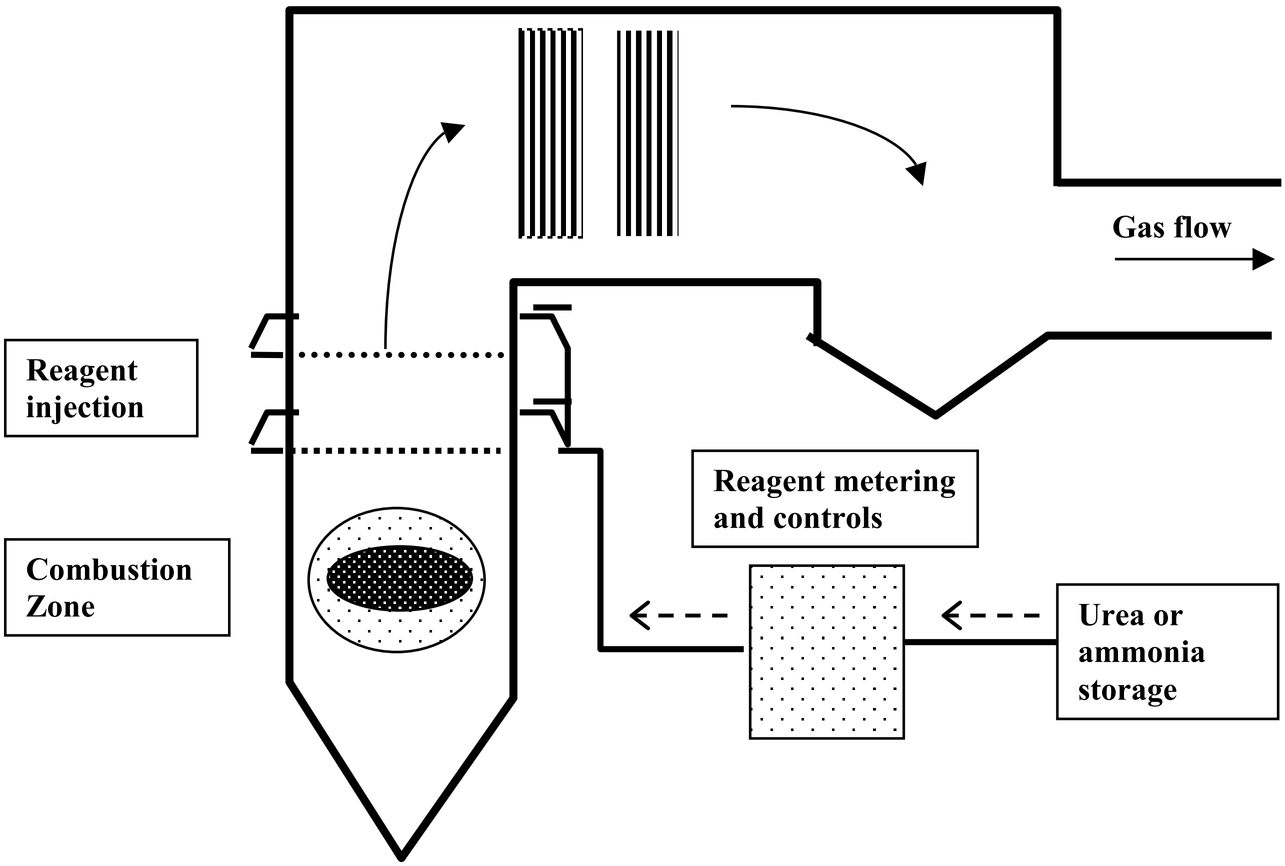
SNCR reduces NOx through a reaction between urea or ammonia and NOx in the furnace region (at temperatures of about 1600ºF to 2200ºF) to produce nitrogen and water. Figure II-1 shows the general scheme for urea SNCR. Aqueous urea, typically 50% by weight, is pumped in a concentrated form through metering pumps or valves to the injection zones in the furnace. Multiple injection zones, each of which may be composed of several injectors, are often needed to address boiler load changes. Dilution water is typically added in order to match the total liquid flow rate to the proper flow rate for the injectors. Ammonia SNCR works similarly, except that the ammonia can be injected in either a gaseous form or as an aqueous solution.

SNCR technology has been used on hundreds of industrial boilers firing a wide range of fuels, including coal, oil, gas, biomass, and municipal waste. The principal determinants of the applicability and achievable performance of SNCR are access for injection of reagent, proper temperature, adequate residence time, and initial NOx level. Because of the wide range of boiler types among the industrial boiler population, the level of reduction possible through application of SNCR varies widely - from under 20% to over 60%. SNCR tends to become less effective at lower baseline levels of uncontrolled NOx. For this reason, many gas-fired units find other approaches such as Low-NOx Burners or SCR more effective. Nevertheless, in some cases SNCR may be effective even on gas-fired units.

The broad applicability of SNCR is illustrated in Tables II.3a and II.3b, which show the types of non-electric utility boilers or process heaters that have been equipped with SNCR and the associated range of NOx reductions. The information in these tables is representative of the performance of SNCR for lowering NOx from industrial units. In addition to showing the average NOx reduction for the facilities, an estimate of the population standard deviation and other statistics were calculated.[iv] An evaluation of the performance of urea SNCR technology on electric utility units firing mostly coal and, in some cases, firing oil, showed average NOx reductions of about 39% with an estimated population standard deviation of 16% using a sample of 22 units.[9] NOx reductions on utility boilers with this technology are, therefore, significantly less than the NOx reductions for any of the industrial units identified above. The data for industrial boilers indicate that 50% or higher (in some cases, much higher) NOx reduction can be achieved on the majority of the industrial boilers. SNCR technology, therefore, seems to be especially well suited for many industrial boilers. It is worth noting that while urea appears to be clearly preferred over ammonia as a reagent for utility SNCR systems (none of the currently operating U.S. utility SNCR systems use ammonia), both urea and ammonia appear to have fairly broad applications in industrial units. Both reagents achieve, on average, over 50% NOx reduction on industrial units. The choice in reagent depends on the specifics of the industrial application.

[iv] The population standard deviation is an indication of the dispersion of performance throughout the entire boiler population. The standard error of the mean is an indication of the potential difference between the sample mean (which is used to estimate the mean of the entire population) and the population mean. Statistically, there is less than a 5% chance that the population mean is more than two times the standard error of the mean from the sample mean. For example, if the sample mean is 50% and the standard error of the mean is 3%, there is a 95% chance that the actual population mean is between 44% and 56%. So, a small standard error of the mean relative to the mean gives confidence in the mean as a measure for the population.

Figure II-1: SNCR Applied to a Boiler



Concerns expressed by users regarding the operation of SNCR technology have been primarily directed at the control of ammonia slip and the potential for adverse side effects. Ammonia "slip" refers to the unreacted ammonia that is present in small quantities in the exhaust gases. Ammonia can react with sulfur compounds to form deposits on heat exchange surfaces. Ammonia may contaminate fly ash, or it may contribute to a white plume formed from reaction of ammonia with chlorine that may be present in the fuel. Although early experience with SNCR showed that ammonia slip could be a problem, extensive experience with hundreds of facilities has shown that properly designed and operated SNCR systems can control ammonia slip very effectively. Difficulties with ammonia slip are extremely rare.[8] A more comprehensive discussion on SNCR and ammonia slip can be found in Reference 8.

Table II-3a: Performance of Industrial Boiler Types Equipped with Urea SNCR [9]

	Independe-nt Power Producers	Pulp/Paper	Refining	Industrial	Steel Industry
Mean NOx Reduction	51%	52%	57%	53%	74%
Standard Error of Mean	1.9%	2.4%	3.6%	2.8%	6.2%
Population Standard Deviation	8.3%	7.9%	14.0%	9.7%	20.5%
Minimum	35%	35%	34%	40%	30%
Maximum	70%	62%	74%	70%	90%
Number of Facilities	19	11	15	12	11
Fuels	Biomass, Wood, Coal	Wood waste, wood, pulp, oil, black liquor	Refined Gas, Petroleum Coke, Natural Gas	Coal, No. 6 Fuel Oil	Coal, Natural Gas

Table II-3b: Performance of Industrial Boiler Types Equipped with Ammonia SNCR [10]

	Stoker	Stoker	Circulating Fluidized Bed or Bubbling Bed	Industrial	Refinery Heaters
Average NOx Reduction	61.7%	57.5%	78.3%	57.7%	58.75%
Standard Error of Mean	2.2 %	3.1%	0.81%	3.5%	3.35%
Population Standard Deviation	7.3%	8.8%	2.1%	11.7%	9.5%
Minimum	57%	46%	76%	30%	43%
Maximum	78%	75%	80%	75%	70%
Number of Facilities	11	8	7	11	8
Fuels	Coal	Biomass	Coal, Biomass	Gas, Oil	Refinery Gas, Natural Gas, Oil

Selective Catalytic Reduction (SCR)

The SCR process (Figure II-2) employs a similar chemical reaction as SNCR, except that the reaction occurs at a much lower temperature (around 650º-700ºF) and requires a catalyst. At these low temperatures, SCR is capable of achieving very high NOx reductions, sometimes in excess of 90%. SCR, however, is more expensive to install than SNCR. Additionally, the catalyst needs to be replaced periodically because of its sensitivity to impurities in the gas stream. In the case of coal-fired boilers, catalysts have been developed that can tolerate coal impurities and provide reasonable catalyst lifetimes (typically, in the range of 14,000-24,000 operating hours before replacing a portion

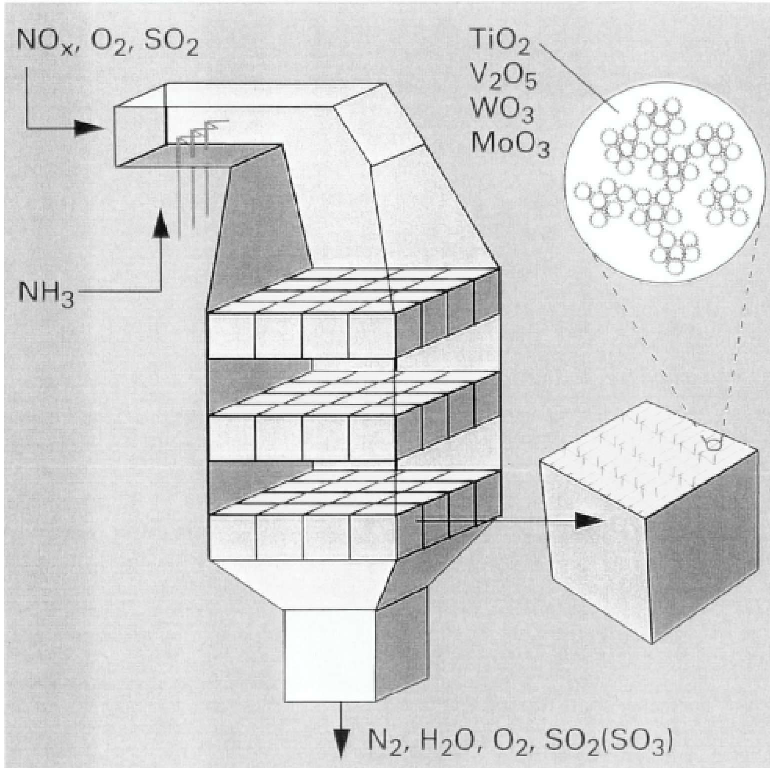
- about 1/4 to 1/3 - of the total catalyst loading). [8] For cleaner fuels such as natural gas, catalysts lose their activity at a much slower rate, permitting longer times between replacement of catalyst. In Germany and Japan there is extensive SCR experience with industrial boilers firing oil, offering evidence of the applicability of the technology on oil applications firing high-vanadium, high-sulfur oil.[8]

SCR catalysts are available in three general temperature-range categories. Conventional SCR Catalysts operate at a temperature range of about 600ºF to 800ºF. They are typically used for boilers and are the focus of this section. High-temperature SCR catalysts operate in the temperature range of 800ºF to 1,000ºF, and are primarily designed for high temperatures associated with the exhaust gases of simple-cycle gas turbines. They are discussed later in Section B.2. Low-temperature SCR catalysts (250ºF to 500ºF) have been designed for use in a variety of applications, including industrial boilers and combined-cycle gas turbines firing relatively clean fuels. These systems offer the advantage of being able to simplify installation by reducing the degree of boiler or system integration necessary to incorporate the SCR catalyst reactor into the facility. The supplier of the technology, KTI, reported fifteen commercial systems installed and two on order at the time of this writing, in addition to the conventional SCR applications listed by Institute of Clean Air Companies (ICAC).[11,12]

SCR has been extensively used to control NOx from hundreds of utility and industrial boilers in Japan and Germany, and several coal and gas-fired utility boilers in the United States. The ICAC reported twelve industrial boilers operating with SCR in the U.S., all firing natural gas or refinery gas (except one boiler firing wood waste).[12] Fifteen refinery process heaters were also identified. SCR is considered technically feasible for nearly all types of industrial boilers.

The principal technical concerns expressed by industry regarding SCR deal primarily with ammonia slip and catalyst deactivation. Ammonia slip from an SCR system is the same as for an SNCR system. However, ammonia slip from an SCR system is much easier to control to low levels than for SNCR. Problems with ammonia slip from SCR systems are extremely rare.[8] Catalyst deactivation occurs as a result of impurities in the gas stream that can produce blinding deposits or poisoning of the catalyst material. Although catalyst deactivation occurs, the rate of catalyst deactivation has not proven to be a problem for coals and certainly not for natural gas. An outstanding issue remains regarding the use of low-sulfur, high-calcium western coals with SCR. These coals are unique to the U.S. and there is no experience with SCR on facilities firing these coals. Catalyst suppliers agree that these coals can produce deposits that deactivate the catalyst, but one supplier states that the rate of catalyst deactivation is expected to be within an acceptable range for commercial use.[13] Commercial experience with these coals on electric utility boilers that have recently commenced operation with SCR will shed more light on this question.

Figure II-2: Selective Catalytic Reduction [14]



Reburning

Reburning operates by creating a fuel-rich reducing region downstream of the primary combustion zone that reduces the NOx formed in the primary combustion zone. Several types of reburning systems can be used with industrial boilers, including conventional reburning, Fuel-Lean Gas Reburning (FLGR), Amine-Enhanced FLGR (AEFLGR), and Methane DeNOx. In the case of conventional reburning, a burn-out zone is necessary downstream of the reburn zone because the entire reburn zone is made fuel rich, requiring completion air to avoid high emissions of products of incomplete combustion (Figure II-3). For Fuel-Lean Gas Reburning (FLGR), a downstream burnout zone is not needed (Figure II-4). Most experience with reburning is on electric utility boilers using natural gas as the reburn fuel, although there are industrial boilers that employ the technology.[8] Coal-fired industrial boilers at Kodak Park in Rochester (New York) are equipped with conventional reburning. Three boilers on the site are equipped with gas reburning and one boiler is equipped with micronized coal reburning. NOx reductions of over 50% have been achieved from the gas reburning systems, and the micronized coal reburning system achieves over 50% reduction at full load and lower reductions at part load (Case Study BLR-9, Chapter IV). Although reburning may not be widely applicable to industrial boilers, it is commercially employed on industrial boilers at Kodak Park and is probably applicable to many other industrial boilers.

Fuel-Lean Gas Reburning (FLGR) has been demonstrated or applied commercially to several electric utility boilers, including roof-fired boilers, wall-fired boilers, tangentially-fired boilers, cyclone boilers, and turbo furnaces. It typically is capable of about 30% to 40% NOx reduction on most facilities and the level of NOx reduction normally becomes limited by increased emissions of

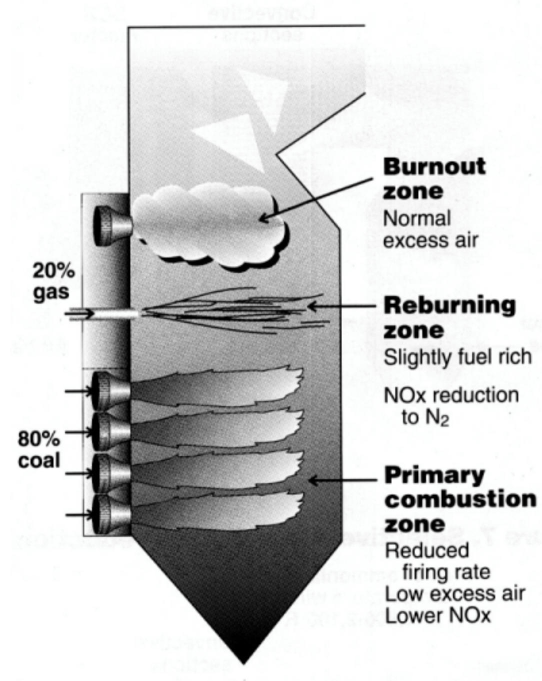
CO. Unlike conventional gas reburning, which typically requires 15% to over 20% of the furnace heat input to be in the reburn zone, FLGR requires typically only 4% to about 7% of the heat input from natural gas. This makes FLGR much less costly to operate. Moreover, FLGR does not require overfire air, which adds expense to a conventional gas reburn system and may also prevent application of conventional reburn to some small boilers. Hence, there may be some industrial boilers that can benefit from FLGR technology but not from conventional reburn.

FLGR and SNCR can be used as separate systems or can be integrated to create an Amine Enhanced (AEFLGR) system. AEFLGR is being used commercially on coal-fired utility boilers to produce NOx reductions of 60% (on average) and up to 70%.[15]

Methane DeNOx is another technology that uses the principals of reburning and is applicable to grate- and stoker-fired boilers. Natural gas and recirculated flue gas are injected above the grate to form a reducing zone while overfire air above the gas ports burns out the combustibles. Methane DeNOx is in operation on four boilers at a Cogentrix facility near Richmond, VA. [16]

Although any fuel can potentially be used for the reburn fuel, natural gas is preferred because it burns more easily than coal or oil and also because it results in zero fuel-NOx emissions. The main disadvantage of natural gas as a reburn fuel is that it is typically more expensive than coal, and it is not available at all locations. Coal has been used in the U.S. as a reburning fuel on one of the Kodak cyclone boilers; however, coal reburn systems tend to require more expensive equipment than gas reburn systems.

Figure II-3: Conventional Gas Reburning



The primary technical concerns expressed by industry regarding these technologies are impacts on boiler tube corrosion, and impacts on unburned carbon (also known as Loss Of Ignition, or LOI) and CO emissions. Experience with numerous long-term demonstration programs and commercial plants indicates that reburning does not accelerate boiler tube corrosion.[8] Increased CO emissions and LOI tend to limit the level of NOx reduction achievable. Commercial reburning systems have been installed and are currently operating on utility and industrial boilers while maintaining CO and LOI within acceptable levels.[8]

Electro-Catalytic Oxidation (ECO)

Electro-Catalytic Oxidation is an emerging technology for reduction of NOx and other pollutants. In the ECO process, NOx and other pollutants (SO_2, mercury, and VOCs) are oxidized in a dielectric barrier discharge reactor located immediately after the electrostatic precipitator (ESP) and prior to a wet ESP. Since NOx is oxidized to nitric acid, it is readily removed from gases by the wet ESP. SO_2 is similarly converted to sulfuric acid and removed. The ECO process is shown schematically in Figure II-5. It is being field tested on a coal fired utility boiler in Ohio.

Low-Temperature Oxidation using Ozone

Low-temperature oxidation using ozone is another emerging technology that operates by oxidizing NOx and SO_2 to acids and then removing the acids out in a wet scrubber. Ozone used in the process is produced on site. The technology has been tested on a coal-fired electric utility boiler and is being tested on a gas-fired industrial boiler. In both cases the technology has been demonstrated to reduce NOx to below 2 ppm.[17]

Figure II-4: Fuel-Lean Gas Reburning

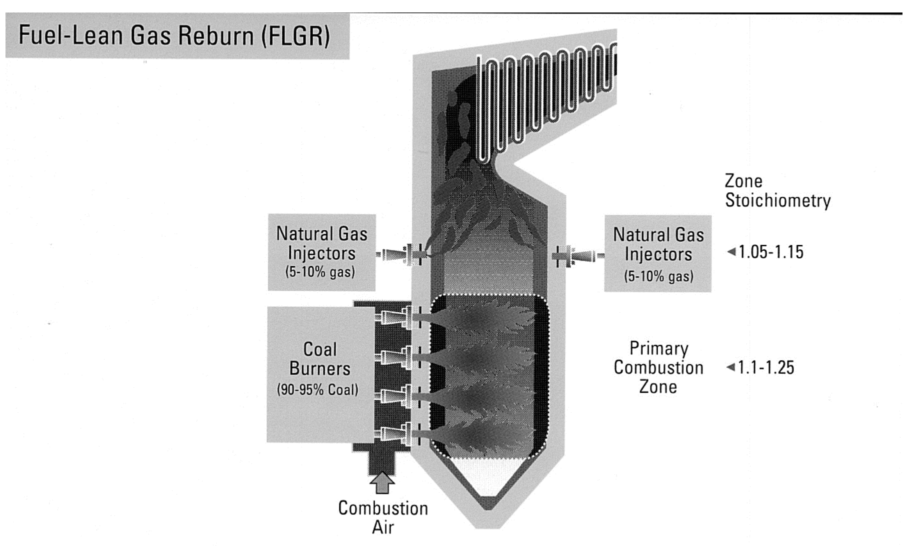
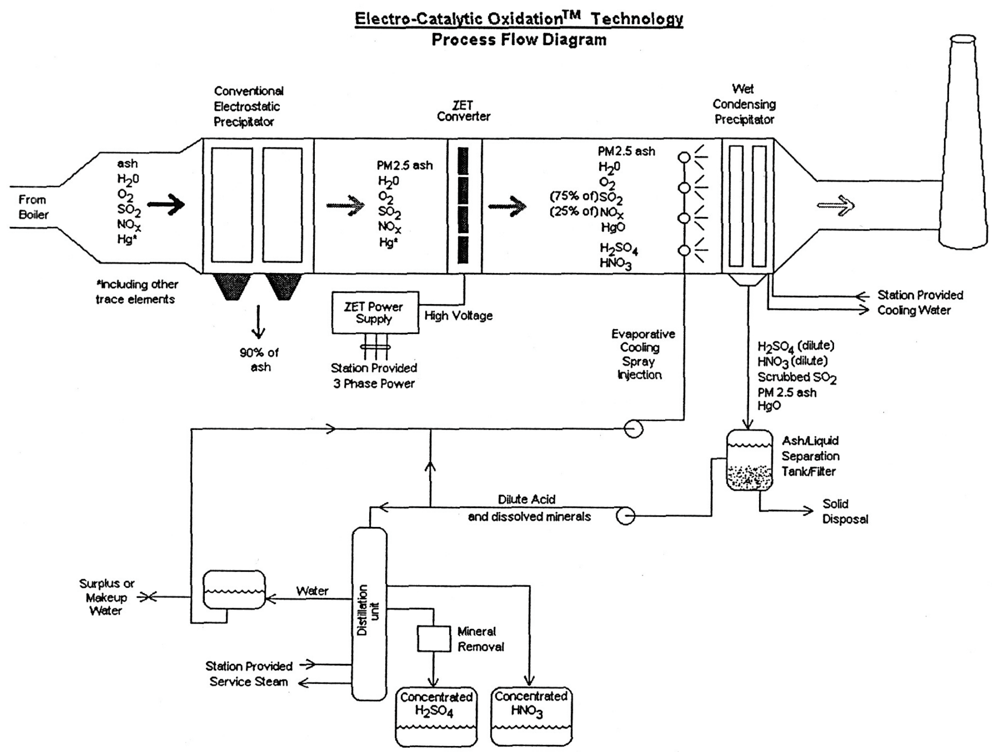


Figure II-5: Electro-Catalytic Oxidation Technology[18]



B. Gas Turbines

Gas turbines fire gaseous fuels (natural gas, waste gas, landfill gas, etc.) and/or distillate oil. Gas turbines use primary (or in-combustor) methods that minimize the production of NOx in the gas turbine combustor and secondary control methods that reduce the NOx that has been formed. Reference [19] provides a comprehensive overview of these technologies. A brief summary follows.

B.1 Primary Methods of Controlling NOx from Gas Turbines

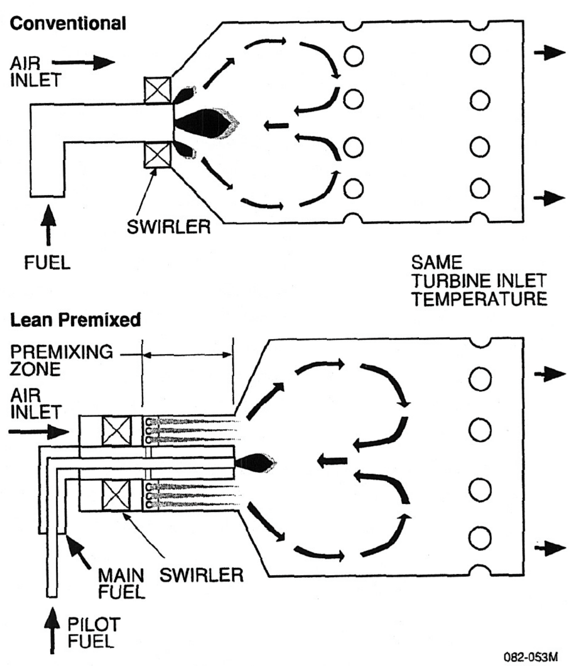
Dry Low NOx (DLN)

DLN is a gas-turbine combustion technology that enables gas-turbine combustors to produce low NOx emission levels without diluents (such as water or steam) or catalysts. Some suppliers offer combustors on new turbines that are capable of NOx emissions under 9 ppmdv (parts per million dry volume basis) at 15% oxygen when firing natural gas.[19, 20] DLN technology utilizes a lean, premixed flame as opposed to a turbulent diffusion flame, therefore typically requiring the use of natural gas. Other fuels that can be premixed might be used, although use of fuels other than gas is rare. Since fuel oil cannot be easily premixed, it is not typically suitable as a DLN fuel. Turbulent diffusion flames are common for boilers and for gas turbines that do not utilize DLN technology. Figure II-6 compares a DLN (lean-premixed) combustor to a conventional gas turbine combustor. As indicated in the figure, in a lean, premixed combustor, the fuel and air are premixed prior to entering the combustion zone. With a lean, premixed flame, the contribution of prompt[v] and thermal NOx can be much lower than for a turbulent diffusion flame. The contribution of fuel NOx is minimized through the use of low-nitrogen fuels, such as natural gas. Achieving low NOx across the full load range requires a sophisticated combustor design, often with variable operating modes in order to maintain flame stability. Not all turbine designs can accommodate a DLN combustor. However, most turbine suppliers have developed the ability to retrofit the existing turbines in the field.

There has been a learning curve in the field implementation of this technology. Because Dry Low NOx combustor technology operates under conditions that are much closer to the flammability limit than the conventional combustor technology, there is a significant risk of flame instability. In fact, some early experience with this technology found that flameouts were frequent under varying weather or load conditions (see case studies in Chapter IV). However, manufacturers have developed improved electronic turbine controls that have addressed this problem. Some early experience also found combustor liners failing after only about 5,000 hours (see case studies), compared to over 20,000 hour lifetime for conventional technology. Again, the turbine manufacturers have addressed this problem by improving the lifetime of the DLN combustor liners to a lifetime similar to, and in some cases longer than, that of conventional combustion technology.

Solar Turbine Company reports that they have retrofitted about 50 turbines with their SoLoNOx™ Dry Low NOx technology, with achieved reductions shown in Table II-4a. Current technology from this manufacturer achieves 25 ppm.[21] Additionally, over 500 new turbines from this manufacturer are operating with DLN technology.

Figure II-6: Comparison of a Lean Premixed Combustor and a Conventional Combustor [21]



[v] There are three types of NOx formation: Fuel NOx, generated by oxidation of fuel nitrogen; Thermal NOx, generated from direct oxidation of nitrogen in the combustion air; and Prompt NOx, generated by oxidation of HCN intermediates formed in the combustion air by nitrogen fixation to hydrocarbon radicals in fuel-rich combustion zones.

Table II-4a: NOx Performance of Solar Industrial Gas Turbines with SoLoNOx™ Dry Low NOx Combustor [22]

Turbine Model	Power (MW)	Pre-Control Emissions (ppm)	Post-Control Emissions (ppm)*	% Reduction
Mars 100	10	240	42	83%
Mars 90	9	178	42	76%
Taurus 60	5.25	143	42	71%
Centaur 50	3.5	105	42	60%
Centaur 40	3	130	42	68%
* These are results from retrofit installations only. Current DLN technology from this manufacturer can achieve 25 ppm on new turbines Other turbine suppliers, such as Allison, also offer DLN technology on their products in this size range				

Solar manufactures gas turbines up to about 16 MW in size. Even lower NOx levels are possible with DLN technology on larger gas turbines available from other suppliers. New and retrofit turbines in the larger, power plant sizes (over 50 MW) have been retrofitted to below 9 ppm of NOx. Table II-4b below lists larger turbines that are available with DLN or can be retrofitted with DLN.

A DLN retrofit, however, is not appropriate for all situations. Figure II-7 shows a turbine comparing a DLN combustor to a standard combustor. The DLN combustor is typically larger than a conventional combustor and may not fit on some older turbines. In some cases it may be economically more attractive to replace the old turbine with a new one due to the extent of the modifications necessary to convert the existing turbine. DLN combustors also can have more limited operating ranges than conventional combustors. Turbines likely to experience frequent and rapid load changes may experience a brief spike in NOx emissions with DLN technology. If these turbines must also comply with hourly average NOx emission requirements, DLN may not be the best approach. Moreover, some turbines require the use of distillate fuel during some periods. The NOx reduction benefit of DLN is achievable with fuels that can be premixed and are low in fuel nitrogen content, such as natural gas. Therefore, turbines that must maintain low NOx levels while operating on fuel oil may find other technologies more appropriate. Nevertheless, despite these considerations that can limit the applicability of DLN technology, DLN retrofit technology is available for the majority of turbine types.

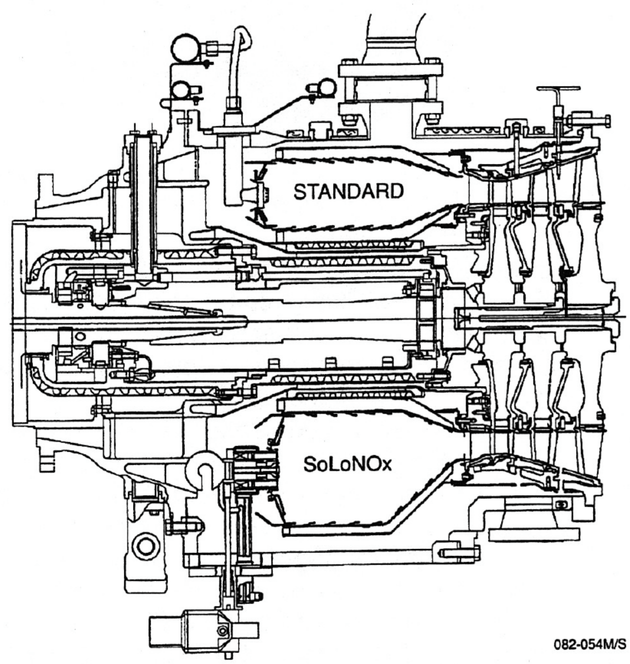
Table II-4b: NOx Performance of Large Gas Turbines with Dry Low NOx [19]

Turbine Model	Manufacturer	Power (MW)	Pre-Control Emissions (ppm)	Post-Control Emissions (ppm)*	% Reduction
MS 6001B	GE	39	148	25/9*	83+
MS7001E	GE	84	154	25/9*	84+
MS7001F	GE	161	210	25	88
MS9001E	GE	125	161	25/9*	84+
MS9001F	GE	229	210	25	88
GT10	ABB	22.6	150	25	84
GT11	ABB	83.3	390	25/9*	94+
V84.2	Siemens	22	212	25/9*	88+
V94.2	Siemens	153	212	9	86
V64.3	Siemens	61.5	380	42	89
V84.3	Siemens	141	380	42	89
V94.3	Siemens	204	380	42	89
* In some cases, 9 ppm limits are offered as retrofit guarantees, in other cases these guarantees may only be available for new turbines.					

Diluent Injection

Injection of water or steam into the combustor has been used to reduce flame temperature and reduce NOx emissions. This is normally achieved with a special fuel injector that permits co-injection of fuel and the diluent. Diluent Injection can be used with any fuel. Steam injection is useful only on applications where a boiler is present, such as Combined Cycle Gas Turbines (CCGT's). Steam injection does not impose as significant a heat rate penalty as water injection, roughly 1% versus 3 to 4%. Diluent may also be injected in the form of a fuel-oil/water emulsion, but this is not a common approach. In general, increased flow rate of diluent will decrease NOx. The amount of diluent that can be injected is limited by permissible carbon monoxide emissions and by impact to turbine wear. Therefore, the level of NOx reduction possible will depend upon the particulars of the turbine. Dilutent injection systems are available from most gas turbine manufacturers.[19] Reference 19 lists various turbines and manufacturer's guarantees for performance. According to Reference 19, for turbines firing natural gas, water/steam -to-fuel ratios range from 0.33 to 2.48 and achieve controlled NOx emission levels ranging from 25 to 75 ppm at 15% oxygen. When firing distillate oil, water/steam-to-fuel ratios range from 0.46 to 2.28 and achieve controlled NOx emission levels ranging from 42 to 110 ppm at 15% oxygen.

Figure II-7: Solar Turbines' SoLoNOx™ DLN and Standard Combustor with Conventional Combustion Technology [21]



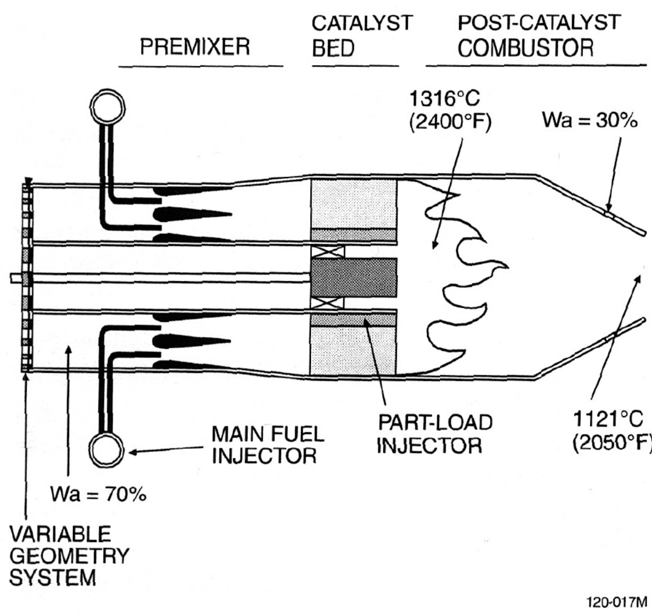
A benefit of diluent injection is an increase in turbine power output that results from the higher mass flow through the turbine. This increase in power is generally of the order of a few percent. Depending upon the capabilities of the generator, compressor, or other device being driven by the turbine and the capability of turbine auxiliaries, this additional power may or may not be useful. Counter to the power benefit, diluent injection adversely impacts the efficiency of the gas turbine and increases wear on the turbine and combustor. Moreover, the consumption of water can be very high for a large turbine, sometimes more than double the fuel flow rate. Such high water usage may pose problems for the local water supply and is an added expense. However, where very low NOx levels are required while firing fuel oil or for peaking turbines, diluent injection may be a technically more appropriate technology choice than DLN. Additionally, due to the lower capital cost of diluent injection, it may be an economically more attractive approach than DLN for turbine applications that only operate for a few hours per year.

Simple-cycle turbines require high-purity water and can therefore be somewhat more expensive to retrofit with this technology than combined-cycle turbines. Combined-cycle power plants generally have water treatment on site to service the boiler but simple cycle facilities do not normally have water treatment on site.

Catalytic Combustion

Catalytic Combustion is an emerging technology that may evolve as a retrofit technology for existing turbines, and is expected to be developed for new turbines in coming years. Catalytic combustion reduces NOx formed from the combustion process by reducing the combustion temperature to reduce thermal NOx. Figure II-8 presents a schematic of a catalytic gas turbine combustor. The technology has been demonstrated on small gas turbines (about 5 MW). According to Catalytica, a developer of catalytic combustion who has business relationships with several turbine manufacturers, this technology has been demonstrated to achieve 3 ppm NOx on a 1.5 MW Kawasaki gas turbine. A NOx level of 3.3 ppm was achieved on a General Electric Frame 9 test stand. [23] These results show that this technology appears to be capable of achieving NOx levels comparable to those achievable when commercially available combustor methods, such as diluent injection or Dry Low NOx, are used in combination with post-combustion methods (such as SCR).

Figure II-8: Schematic of a Catalytic Gas Turbine Combustor [24]



B.2 Secondary Methods of Controlling NOx from Gas Turbines

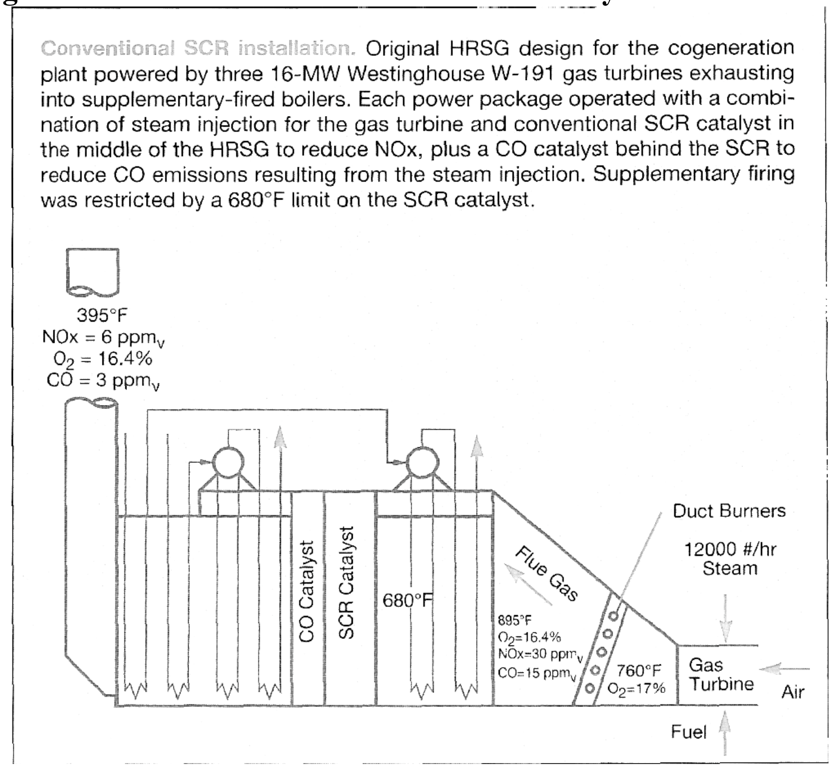
As noted earlier, secondary control methods reduce NOx originally formed in the primary combustion zone. Two methods to accomplish this are described below.

Selective Catalytic Reduction (SCR)

SCR is the exhaust treatment technology most widely used on gas turbines. It is being required on many new gas turbine installations, especially those that are equipped with Heat Recovery Steam Generators (HRSG). SCR operates no differently on gas turbines than on boilers, as was described in Section A.2. Gas turbines equipped with SCR have been guaranteed to 2 ppm NOx.

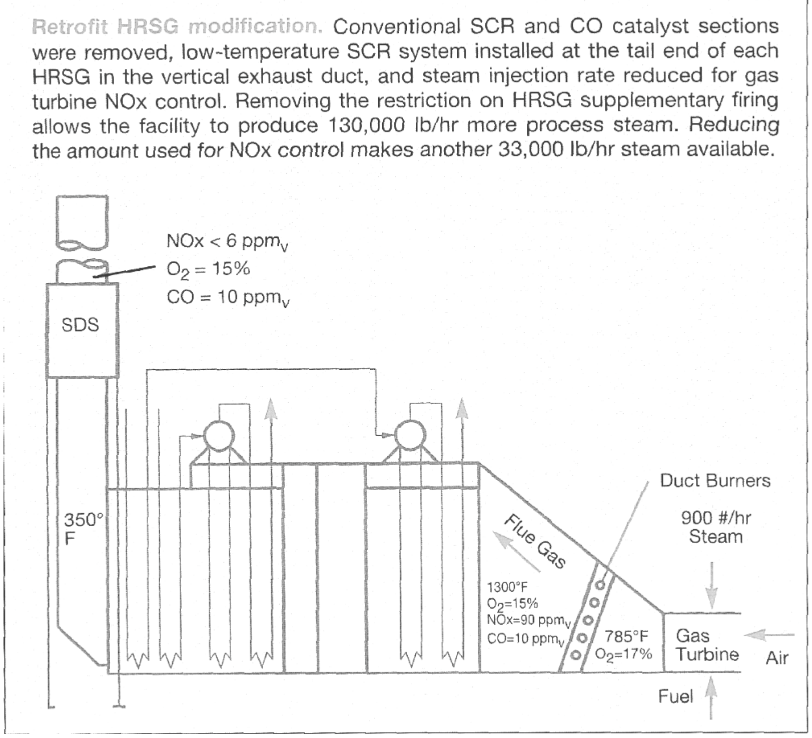
There are over 150 commercial installations of SCR on gas turbines in the United States,[12] nearly all on Combined-Cycle Gas Turbine (CCGT) plants. On combined cycle plants, the catalyst is normally installed in a cavity within the HRSG (Figure II-9), which is designed to provide the proper gas temperature and flow through the catalyst. For simple cycle applications, the SCR is installed at the turbine exhaust. Although standard turbine exhaust temperature is usually higher than most conventional catalysts will permit, some catalyst suppliers have developed catalysts that can perform in the environment of the high-temperature simple-cycle turbine exhaust. These "High-Temperature" SCR applications require expanded, internally insulated ductwork to act as the transition region from the turbine exhaust to the stack.[25] Although the large majority of gas turbine SCR installations are on combined cycle plants, there are a small number of SCR installations on simple cycle plants or upstream of the HRSG. For example, three Solar Centaur Type H simple cycle gas turbines, each rated at 5,500 hp, are equipped with high-temperature SCR at the Southern California Gas Company, Wheeler Ridge Station in Valencia, CA.[26]

Figure II-9: SCR Installation on Combined Cycle Gas Turbine [27]



For many situations, low-temperature SCR offers the potential for a simpler installation than a conventional SCR. Rather than requiring an HRSG with a cavity, the catalyst reactor can be installed at the tail end of the system, as in Figure II-10. Although Figure II-10 shows an HRSG with a cavity for a catalyst, with the low-temperature catalyst, a simpler HRSG design would be possible. This low-temperature catalyst, which was developed by a division of Shell Oil Company, is sometimes referred to as the "Shell DeNOx System," or SDS. In the event that the facility had an existing HRSG without a cavity, the low-temperature SCR could be installed without any need to modify the HRSG. Moreover, there are other benefits with this approach, such as increased distance between the duct burner and the SCR catalyst. This allows improved duct burner firing, permitting higher steam production rates.

Figure II-10: Low-Temperature SCR Installed on a Combined Cycle Gas Turbine (Also known as the "Shell DeNOx System" (or SDS, as it is labeled in the Figure), this SCR was developed by a division of Shell Oil Company.[27])



In principle, SCR can be used downstream of any form of primary control technology to produce extremely low levels of NOx, but some obstacles do exist. Diluent steam or water injection can be used in the combustor to reduce NOx formation, but the moisture can somewhat inhibit the SCR reaction and will increase the gas flow rate. Therefore, when using diluent injection in combination with SCR to achieve low NOx levels, SCR suppliers must account for the effects of the high water content of the exhaust gas. In some situations this may result in higher ammonia slip, shorter catalyst lifetimes, or may require larger catalyst volumes.

A great deal of attention has recently been focused on ammonia slip. Allowable ammonia slip varies by application and also by facility permit requirements, but is rarely more than 10 ppm, and typically much less. Ammonia slip limitations and guarantees are frequently of the order of 2 ppm or less. The catalyst volume, catalyst lifetime, and maximum allowable ammonia slip at the end of the SCR life can be varied based upon the control requirements and economic tradeoffs. In normal operations, ammonia slip from an SCR system is very low - typically well below 1 ppm - for the first several years of SCR operation. Generally, the ammonia slip will begin to approach a guarantee level only after the catalyst activity deteriorates somewhat, usually after several years. For clean fuel applications such as natural gas, many years (often six or more) typically pass before the catalyst activity is diminished to a point where the ammonia slip begins to approach the guarantee level.

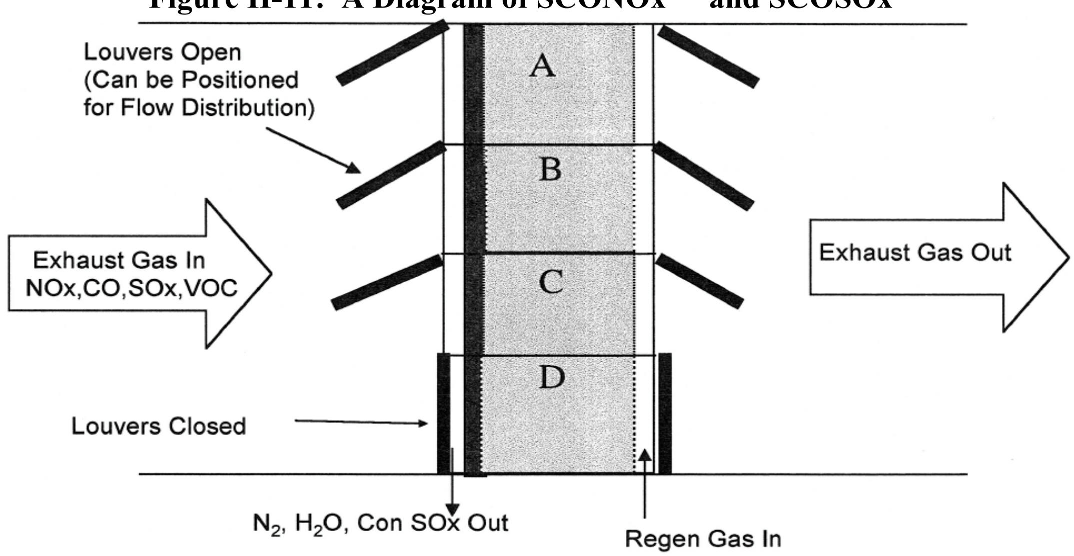
SCONOx™

SCONOx™ is an emerging catalytic sorbent technology that has recently been offered for commercial use. The principal advantage of SCONOx over SCR is that it does not require the use or storage of ammonia. With SCONOx, NOx is oxidized in the presence of a platinum-based catalyst and the resulting NO_2 is adsorbed onto a potassium carbonate sorbent. The sorbent must be regenerated periodically with hydrogen from an on-site hydrogen reformer that consumes steam and natural gas (methane). The sorbent and catalyst also need periodic replacement. SCOSOx (also supplied by the vendor and required to remove SO_2 to avoid poisoning the catalyst used in SCONOx)) removes SO_2 in the same manner as SCONOx (oxidation-adsorption-regeneration) and is normally used upstream of the SCONOx system. This is because even natural gas has small quantities of SO_2 that would poison the downstream SCONOx catalyst. The SCOSOx portion of the system must be regenerated in a similar manner as the SCONOx system. By-products from regenerating the SCONOx and SCOSOx sorbents are ducted downstream of the system. SCONOx also oxidizes carbon monoxide to carbon dioxide.

The system is installed as a bed of sorbent/catalyst (Figure II-11). A system of louvers and piping allows portions of the bed to oxidize and adsorb pollutants and other portions of the bed to undergo regeneration.

SCONOx has two current installations. The demonstration of this technology at a commercial scale was on a gas turbine in Vernon, CA (established as Lowest Achievable Emission Rate (LAER) by EPA Region 9, San Francisco). The developer reported that the technology achieved NOx emissions to below 2 ppm NOx (a reduction of over 90%). The owner of this facility, Sun Law Federal Cogeneration, is also affiliated with the developer of the technology, Goal Line Technologies. The second application of this technology on a commercial scale was on a ~5 MW gas turbine installed in Andover, Massachusetts, and operations commenced in summer of 1999.[28] Because of the limited experience with SCONOX relative to other available technologies, there is only limited information available on actual experience with catalyst or sorbent life, the use of consumables (such as steam and gas) or overall reliability.

Figure II-11: A Diagram of SCONOx™ and SCOSOx™ [28]



Although SCONOx has been applied only to gas turbines, it is expected that the technology will be applicable to other clean-fuel applications such as gas-fired boilers. Products of diesel engine combustion have been shown to deteriorate the catalyst by sulfur masking during tests.[29] Therefore, SCONOx may not be applicable to systems firing fuels other than natural gas or very high-quality distillate fuel oil that is very low in sulfur.

C. Internal Combustion (IC) Engines

Internal Combustion Engines are generally of two types: Compression Ignition (CI, or Diesel) or Spark Ignition (SI). CI engines typically fire fuel oil while SI engines are fueled with gaseous or volatile liquid fuels, such as gasoline. Whereas all CI engines fire in a fuel-lean mode, SI engines can operate under fuel-lean conditions or under stoichiometric to slightly fuel-rich conditions. Most large SI engines (over about 1,000 hp) are of the fuel-lean type and therefore are of greater interest than the smaller SI engines that are generally not major sources of NOx. Rich-burn stationary IC engines are most common at natural gas production facilities.

NOx reduction from IC engines is possible with either in-cylinder methods or exhaust treatment methods. Primary, or in-cylinder methods, minimize the amount of NOx formed itself. Exhaust treatment methods reduce the NOx originally formed in the cylinder.

C.1 Primary Methods of Controlling NOx from IC Engines

Primary methods of controlling NOx involve controlling the combustion process in the cylinder to minimize NOx formation. They involve controlling or modifying the combustion that occurs in the cylinder, and include injection/ignition timing retard, air/fuel ratio changes, and a Low Emission Combustion (LEC) retrofit using a pre chamber.

Injection Timing Retard

For CI engines, retarding the injection timing by about 4 degrees can reduce NOx by 15-30%. With this retard, the fuel ignites entirely during expansion rather than igniting initially during compression and then mostly igniting during expansion. This results in lower combustion temperature and lower thermal NOx, but also in increased fuel consumption. Moreover, some engines may have problems with high CO and soot emissions as a result of these changes. The modification for injection timing retard can be performed with a very low capital cost, and may also require a few hours of a mechanics time. Often some additional hardware or testing is recommended, bringing the total cost to a few thousand dollars. However, this adjustment is not possible on all engines.

Ignition Timing Retard

Ignition timing retard is applicable to SI engines and works on the same principle as injection timing retard. NOx reductions from ignition timing retard are similar to those achieved from injection timing retard, and modifications can be performed with very low capital costs and a few hours of a mechanics time. Again, some additional hardware or testing is recommended, bringing the total cost to a few thousand dollars. SI engines, however, are generally more sensitive to timing retard than CI engines, and they will have more operational problems when it is employed.

Therefore the level of NOx reduction achievable for SI engines can be more limited than for CI engines.

Air/Fuel Ratio Changes

NOx formation from a spark-ignited engine is highest when the mixture is slightly fuel-lean. Richer or leaner mixtures will result in lower NOx. Fuel-lean mixtures are preferred to fuel-rich mixtures because fuel consumption is reduced and hydrocarbon emissions are less likely to be a problem. However, leaner mixtures are more prone to misfire. A richer mixture, on the other hand, will often require the addition of an exhaust treatment technology because of the higher hydrocarbon emissions that are likely to result. Leaning the mixture is normally performed in combination with ignition system improvements, such as high-energy ignition (increasing spark voltage) to avoid misfiring problems. Leaning is also frequently done in combination with Low Emission Combustion Retrofits (described below) to enhance NOx reduction from that technology. An air/fuel ratio change can normally be done at a modest cost because it requires an engine adjustment, and occasionally a limited amount of additional hardware.

Low Emission Combustion (LEC) Retrofit

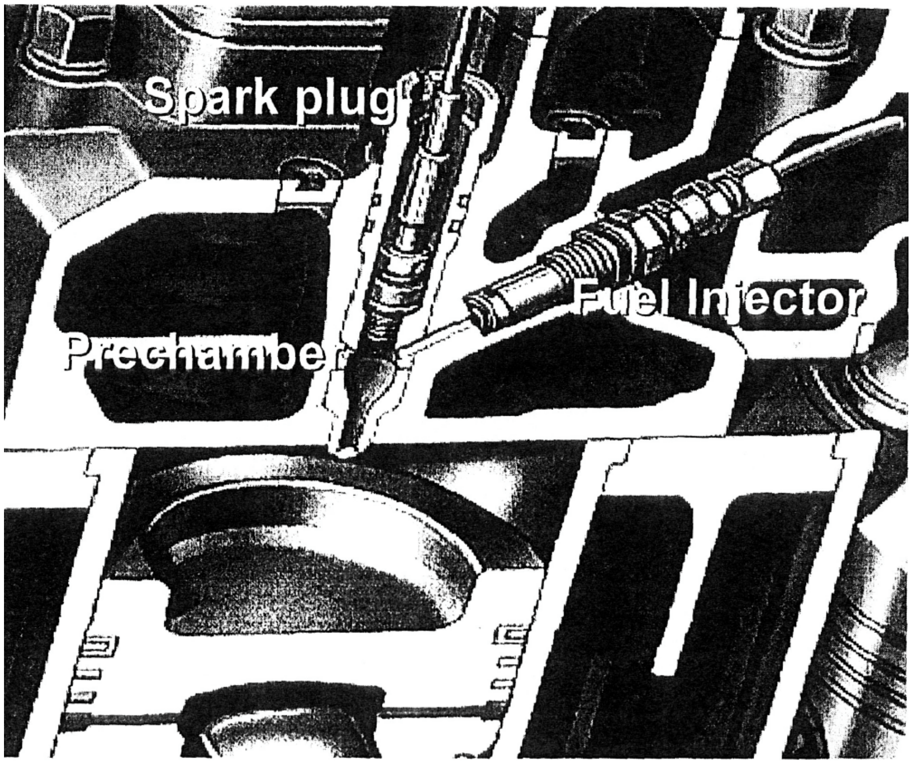
This method can in principle be used on all spark-ignition engines, but some manufacturers may not offer it. LEC enhances the effectiveness of the air/fuel ratio method previously discussed by enabling much deeper leaning without the other adverse effects associated with lean mixtures. On large engines this method is typically employed by relocating the spark plug to a pre chamber where the mixture is somewhat richer than in the cylinder. This early sparking avoids problems associated with ignition and misfiring that can result from leaning the mixture. This method normally requires a significant modification to the engine heads. The extent of the modifications will depend largely on the particular engine and the manufacturer of the LEC Retrofit kit. Figure II-12 shows a LEC retrofit kit from Waukesha Engine Company.

According to Reference [30], large, stationary spark-ignition engines usually achieve 80% NOx reduction through a LEC Retrofit. A NOx emission level of 125 ppm (at 15% oxygen) is an achievable exhaust NOx value, and Reference 30 considers LEC Retrofit a Reasonably Available Control Technology (RACT) for large spark-ignition engines in California.

C.2 Secondary Methods of Controlling NOx from IC Engines

Exhaust treatments from lean-burn IC engines are less common than for gas turbines. This may be because IC engines are usually smaller in total output than turbines. Few IC engines exceed 10,000 HP, with most engines of interest in the range from few hundreds to few thousands of horsepower. Turbines, on the other hand, can have outputs that exceed 100 MW (133,000 HP).

Figure II-12: Pre Chamber Low Emission Combustion Retrofit [30]



Selective Catalytic Reduction (SCR)

SCR is the only commercially proven secondary NOx reduction method for lean-burn gas engines and diesel engines. It has not been used widely, however, because of general preference for in-cylinder methods (in-cylinder methods, however, result in lower level of NOx reductions). Reference 12 lists seven IC (gas or diesel) engine facilities comprising 29 engines equipped with SCR. Some installations (17 engines in all) have been in operation since 1992. NOx reductions on these systems are reported to range from 80 to 95%. Engines with highly variable duty cycles may face challenges with SCR use. Variable duty cycles result in exhaust temperatures that may fall outside the ideal catalyst temperature and result in variable NOx emission that require correspondingly variable ammonia flow rates. Reference [31] argues that applying SCR to lean-burn engines firing natural gas, particularly those used for natural gas transmission, is technically inappropriate. According to Reference 31, in a survey of pipeline engines that use NOx control, only 2 of 599 lean-burn gas-transmission engines surveyed use SCR (both in California). And, according to Reference 31, most of the difficulty in using this technology is associated with the variable operating conditions of these engines, which pose control difficulties for the SCR system and also increases the risk of lube oil residuals masking the catalyst.

Beyond its high level of achievable NOx reduction, SCR offers some advantages over some in-cylinder methods of controlling NOx from IC engines. First, SCR imposes a relatively small efficiency penalty on an engine (on the order of 0.5%) compared to penalties of a few percent and substantially less level of NOx control from in-cylinder methods such as timing retard. Moreover, some of the in-cylinder methods can increase the emissions of other pollutants, such as unburned hydrocarbons, CO, and in the case of diesel engines, soot. Finally, SCR is generally less expensive than LEC Retrofits.

Larger combustion systems such as gas turbines or boilers have primarily used catalysts of ceramic monolith or ceramic-coated steel. Due to their smaller size, IC engines also use metal washcoat catalysts. These catalysts tend to be much more expensive per cubic foot than ceramic monolith catalysts, but have much more catalytic activity per cubic foot, making the net cost about the same as for the other catalyst types. Metal washcoat catalysts are effective with natural gas or diesels using distillate fuel oil, but are unsuitable for dusty abrasive gases, such as those formed from burning coal. Finally, metal washcoat catalysts can withstand engine backfires more effectively than ceramic monolith catalysts

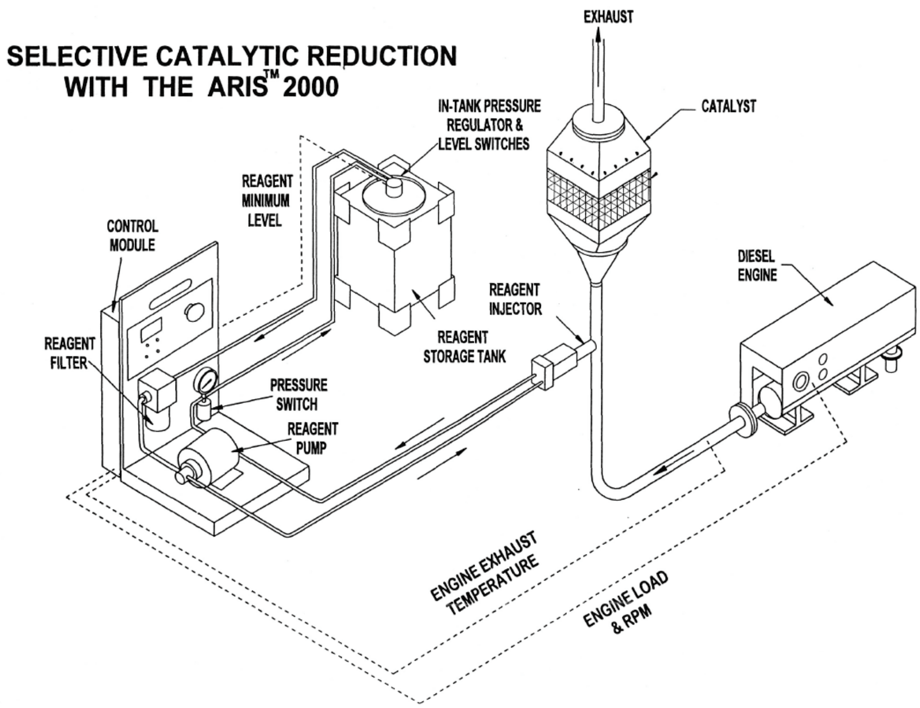
Because SCR technology was, to a large extent, originally developed for facilities such as boilers and gas turbines, SCR technology on IC engines has relied on controls and injection hardware originally developed for these larger applications. This mismatch has resulted in fairly high cost of SCR relative to the system size for IC engines. Recent efforts, however, in SCR development for mobile sources (diesel trucks) have focused on simplifying the control and injection hardware for SCR applications to stationary IC engines, offering the potential for much more cost-effective application of this control technology to stationary IC engines.

Figure II-13 shows a technology developed by Clean Diesel Technologies, Inc. to reduce the cost of applying SCR to IC engines, especially diesel engines. The system takes signals from the engine such as load, exhaust pressure, inlet manifold pressure, etc., and injects an appropriate amount of aqueous urea reagent into the exhaust manifold upstream of the exhaust catalyst. Flow of urea is controlled by pulsing the fuel, which recirculates in a constant pressure recirculation loop. The urea injector has a very similar design to a fuel injector.

NOx emissions are not directly measured by the control system, so it is necessary to first carefully characterize the engine emissions relative to the monitored parameters. The quality of the engine performance map that is needed is dependent upon the level of required NOx reduction. Therefore, in order to retrofit this technology onto an existing engine, it is necessary to perform some testing and data gathering to generate this engine performance map. In cases where the engine performance is not highly reliable or repeatable, such as for an old or poorly maintained engine, lower reductions may be achievable. For example, only a 75% NOx reduction may be achievable from an old engine and a higher 90% reduction from a new engine, depending on the relative quality of the performance map.

The SCR technology shown in Figure II-13 was originally developed for mobile source (diesel trucks) applications, using urea as a reagent. The first commercial application of this technology on a U.S. stationary source was on a lubricant test engine at the development facilities of a major U.S. oil company.[32] In this application, both diesel- and gas-fired engines were equipped with this technology, achieving 82% and 92% reductions, respectively.

Figure II-13: Urea SCR System (ARIS™ 2000) for IC Engines [33]

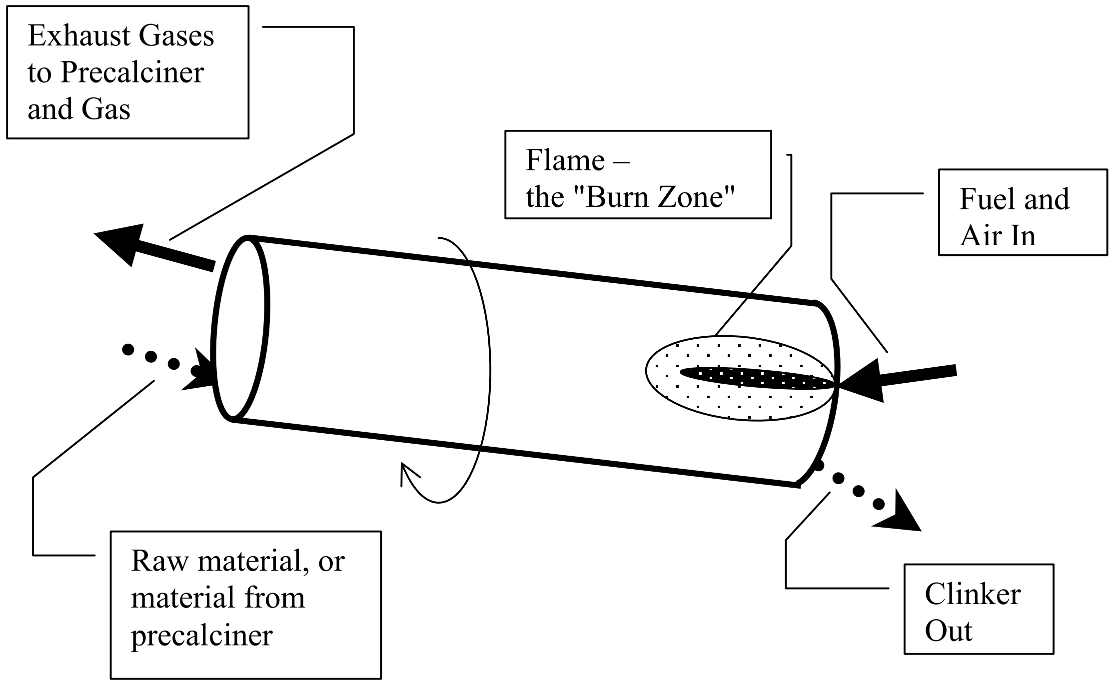


Case study IC-1 (Chapter IV) uses SCR with controls that rely on engine parameters for reducing NOx. The engine parameter controls make continuous measurements of NOx emissions unnecessary. This control system (from another supplier) also requires engine mapping. However, unlike the system shown in Figure II-13, it utilizes conventional ammonia injection technology.

D. Cement Kilns

Concrete is a combination of Portland Cement, sand, and gravel. They key component of Portland Cement is clinker, a material produced by heating limestone to temperatures over 2,650ºF, requiring combustion temperatures of about 3,000ºF. These high temperatures are normally achieved in a rotary kiln, as shown in Figure II-14. Feed material is added at the elevated end of the rotating, refractory-lined, cylindrical kiln and the feed gradually tumbles to the high-temperature end of the kiln and the main combustion zone, sometimes referred to as the "Burn Zone." The tilted design of the cement kiln allows gravity to assist the motion of the clinker material while hot exhaust gases move upward and exit at the elevated end of the kiln.

Figure II-14. Simplified Sketch of a Rotary Kiln



Cement Kilns fall into four general process categories, as identified in Table II-5. Preheater kilns preheat and partially calcine feed material in a series of cyclones or grates prior to admitting the feed to the rotary kiln. This additional heat supplements the heat in the exhaust from the kiln. The calcined feed then enters the rotary kiln at about 1,500ºF to 1,650ºF. Precalciner kilns, on the other hand, utilize a burner in a separate vessel along with a series of cyclones or grates to preheat and calcine the feed. Preheater and precalciner kilns are more energy efficient than long wet or long dry kilns and also typically have greater capacity. Figure II-15 shows a precalciner kiln equipped with five cyclonic preheaters. A preheater kiln is similar, but fuel is not added and there is no burner on the cyclonic preheater portion. Prehearters could also be replaced with suspension preheaters, but these are less common. Long wet and long dry kilns do not have preheaters and have much longer rotary kilns, with wet process kilns being the longest - normally several hundred feet long.

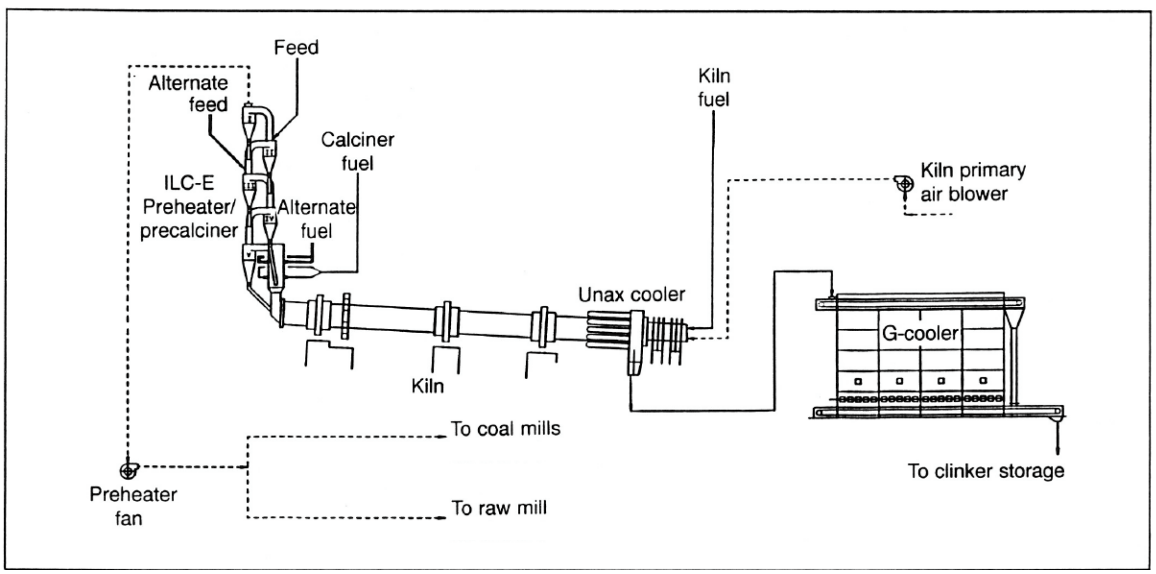
Table II-5: Summary of Cement Kiln Process Types in U.S. [34]

Kiln Type	Number of Kilns	Total Annual US Capacity (1,000 metric tons)	Average Per-Kiln Annual Capacity (1,000 metric tons)
Wet Kilns	70	20,797	297
Long Dry Kilns	66	16,933	256
Preheater Kilns	37	15,148	409
Precalciner Kilns	27	23,774	880
Total	**200**	**77,652**	**388 (avg.)**

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes somewhat to the product. In 1997, 82% of the fuel used in cement kilns was coal, 4% was natural gas, and 14% were other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). Fuel nitrogen therefore contributes a small but significant amount to the total NOx for nearly all cement kiln applications. However, as will be discussed in Section D.1, despite coal's higher nitrogen content, this fuel usually results in lower NOx than natural gas when burned in the primary burn zone despite its higher nitrogen content.

Thermal NOx dominates fuel NOx in cement kilns. At the high temperatures required in the Burn Zone, nitrogen and oxygen in air combine to form NOx, regardless of the source of heat. The thermodynamic equilibrium NOx level at 3,000ºF and 1% oxygen is about 1,500 ppm. The heat input required for cement kilns, however, can vary with the characteristics of the local raw feed. Cement kilns process local limestone deposits, and the mineral's characteristics will vary between locations and may even vary at a particular location. Limestone's mineral properties affect the level of heating necessary to process the material, and thereby affect the level of NOx produced. Changes in residence time and other kiln adjustments can also decrease NOx concentrations, thus, two kilns of similar design may produce different NOx emissions. Finally, NOx emissions vary across kiln types. Long wet kilns tend to have the highest heat input per ton of clinker (typically, about 6 MMBTU per ton), while long dry kilns use somewhat less heat (about 4.5 MMBTU per ton), and preheater and precalciner kilns use even less heat, and these kilns create correspondingly variable levels of thermal NOx (Figure II-16). This variability in NOx emissions from kilns provides a challenge to control NOx emissions from cement kilns. [39]

Figure II-15: A Precalciner Cement Kiln with Five-Stage Cyclonic Preheater/Precalciner [35]



Since 1973, the amount of annual clinker capacity in the U.S. and Canada has remained relatively stable at about 75,000-80,000 tons, with most new capacity coming from kilns of the dry process type. In response to demand for cement, the industry is adding new capacity at this time. Between 1973 and 1997, the average capacity per kiln increased from about 170,000 metric tons per year to 388,000 metric tons per year, corresponding to a reduction of the total number of kilns from nearly 450 small kilns to 200 larger kilns.[36] Many of these larger kilns employ precalciner kilns because they are the newest technology, have the largest capacity, and are more efficient than the older technologies. If past trends continue, many of the existing wet kilns and long dry kilns are expected to be replaced with precalciner kilns.

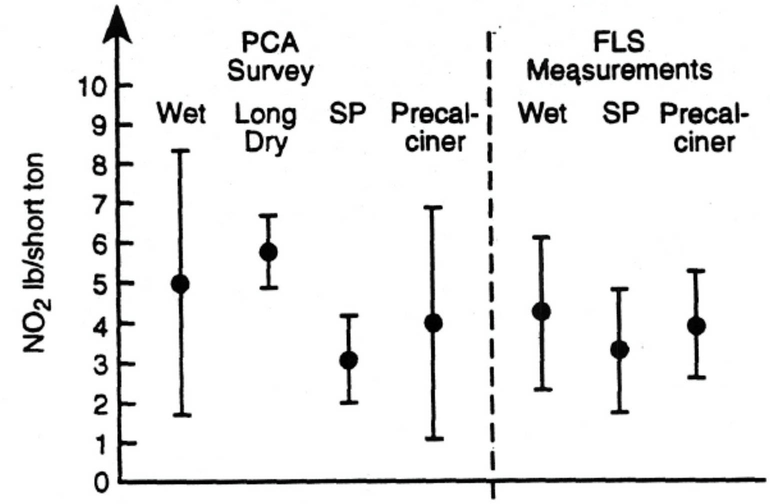
Recent years have seen Portland Cement plant capacity stretched by high demand, making technologies that can increase capacity without increased capital expenditures very attractive. The industry is therefore developing technologies that improve facility's outputs or reduce their operating costs. Conveniently,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

D.1 Primary Methods of Controlling NOx from Cement Kilns

The quality of clinker produced in a kiln varies with characteristics of the combustion; therefore primary controls need to be selected carefully. Dry Low NOx, for example, has seen varied levels of success. The main firing zone of the kiln requires very high temperatures and is not compatible with the lower flame temperature used by DLN to reduce NOx. Low excess air and air staging are problematic control options for kilns because the kilns need an oxidizing environment not provided by those techniques. Despite these problems, indirect firing in combination with a Low-NOx Burner has been successfully used in some facilities, including California Portland Cement (Case Study CK-1 in Chapter IV). Low-NOx combustion methods can be used in the precalciner because high temperatures are not required in that part of the process.

Figure II-16: NOx Emissions for Various Cement Kiln Types[37]

SP is Suspension Preheater kilns



	Wet	Long Dry	SP	Precalciner	Wet	SP	Precalciner
Number of Kilns	8	3	3	10	7	13	7
Average	4.97	5.70	2.98	3.86	4.07	3.13	3.77
Standard Deviation	3.28	0.85	1.05	2.89	1.89	1.57	1.31

Switching to a lower nitrogen fuel may not reduce NOx emissions. In fact, switching from coal to natural gas will rarely help to reduce NOx emissions and will likely cause NOx emissions to increase. The luminous flame of a coal burner is more effective in heating the solid material than a relatively transparent natural gas flame, requiring less total heat when firing coal. The furnace gas temperature, therefore, is lower for a coal flame than for a natural gas flame for the same solid material throughput. Hence, less thermal NOx is generated when firing coal, and the lower nitrogen content of natural gas does not make up for the higher thermal NOx in the natural gas flame. Natural gas fuel may be useful in reducing NOx from precalciner kilns, however, because the temperature in the precalciner is much lower, reducing the impact of thermal NOx.

Lo- NOx Burners (LNBs) with Indirect Firing

Indirect firing is a method that permits use of LNBs in the primary kiln burning zone. When indirect firing is used, pulverized coal is fed to and collected in a particulate matter collection system (a cyclone separator that exhausts gas through a fabric filter). The pulverized coal is then temporarily stored in a bin or hopper, where it is fed to the burner. This method allows less primary air to be used in the burner than with a direct-fired coal mill, resulting in less thermal NOx.

LNBs can be used when indirect firing is employed. When implementing indirect firing with LNBs, other process improvements are often implemented, such as better process controls. Reference 39 mentions that 20%-30% NOx reductions can be achieved from the use of indirect firing with LNBs and associated process modifications. Indirect firing is used in Case Study CK-1 (Chapter IV).

Low-NOx Precalciners

Precalciner kilns can employ LNBs because the temperature in the precalciner is low enough to reduce thermal NOx. Since roughly 60% of the fuel burned in a precalciner kiln is fired in the precalciner, NOx reductions can be substantial. All new precalciner kilns are equipped with Low-NOx Burners in the precalciner. Low-NOx precalciners have been shown to reduce NOx by 30%-40% compared to conventional precalciners .[38] This reduction is from the precalciner-generated NOx, not for the entire kiln.

Mid-Kiln Firing

Mid-kiln firing entails injecting a fuel, usually tires, mid-way through long dry and long wet kilns. This method has been shown to reduce NOx by about 30% with mid-kiln heat input comprising about 20% of the total heat input.[39] Reference [40] provides results of tests of mid-kiln firing on several kilns as summarized in Table II-6. The average NOx reduction for these kilns is about 27%. Mid-kiln firing reduces the heat needed, and therefore the thermal NOx produced, in the primary burn zone. Fuel NOx will also be reduced because tires and other mid-kiln fuels have low nitrogen contents. Nitrogen content in tires is roughly one fifth that of coal on a mass basis, while heating value on a mass basis is similar.[41] Coal can be used as a mid-kiln firing fuel, but tires are preferable because they provide a revenue source when kiln operators are paid a tipping fee for taking whole tires. Other revenue-generating fuels could potentially be used as well.[42]

The mid-kiln combustion process can be sensitive and must be controlled properly. Reference 42 describes the results of a trial burn of a mid-kiln firing system where about 10% reduction in NOx was achieved, but CO emissions increased from about 50% to about 75% over baseline levels. Results have typically been better than this, and the addition of mixing air (discussed below) will address potential increases in CO emissions. Mixing air injected between the tire injection point and the feed inlet (the gas exit) makes it possible to address concerns regarding CO emissions and make further reductions in NOx. This technique is similar to overfire air on boilers, introducing the fuel to reduce NOx further with much less risk of high CO emissions.

Mixing air generally permits better combustion control and more consistent (and, generally lower) NOx emissions. Figures II-17a and II-17b show the effects of mixing air in reducing the variability of NOx, eliminating the highest values and resulting in an overall lower average NOx level.

Table II-6: NOx Reduction at Cement Kilns Using Mid-Kiln Technology [40]

Initial NOx (ppm)	936	1372	1342	1359	565	513
Final NOx (ppm)	790	994	600	883	488	456
% Reduction	16%	28%	55%	35%	14%	11%

Mid-kiln firing can be combined with other approaches, such as indirect firing. Case study CK-1 in Chapter IV discusses the use of mid-kiln firing in combination with indirect firing to achieve combined NOx reductions of nearly 50%. In case study CK-1, it was determined that mid-kiln firing reduced facility production by 10% with a tire addition rate equivalent to a 12% (BTU basis) fuel substitution rate. It is uncertain at this time if the reduced production experienced at the California Portland Cement should be considered typical.

Figure II-17a: Frequency of NOx Values on Cement Kiln with Mid-Kiln Tire Injection (Without Mixing Air) [40]

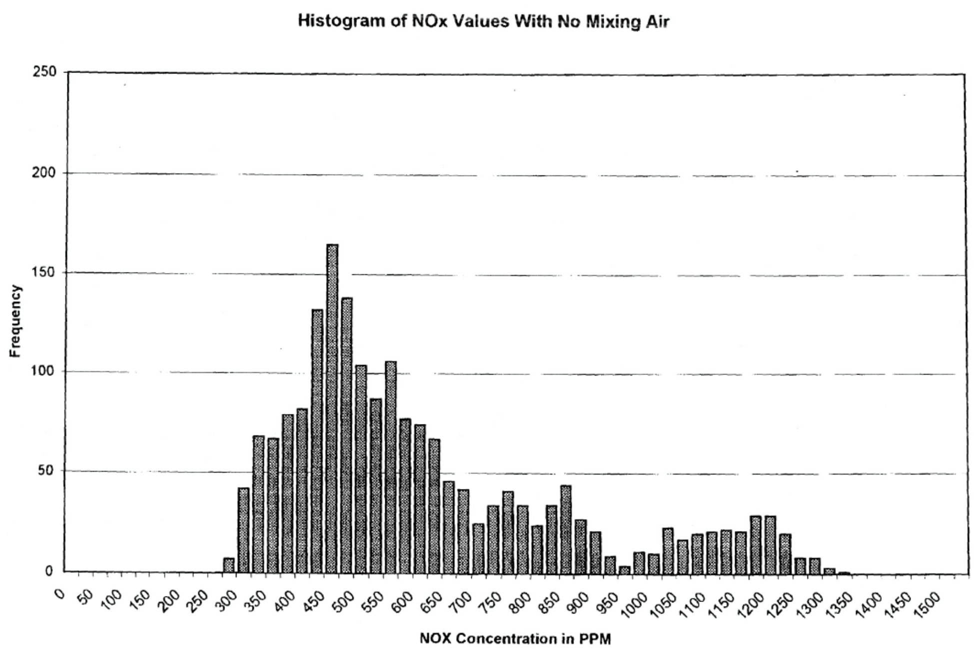
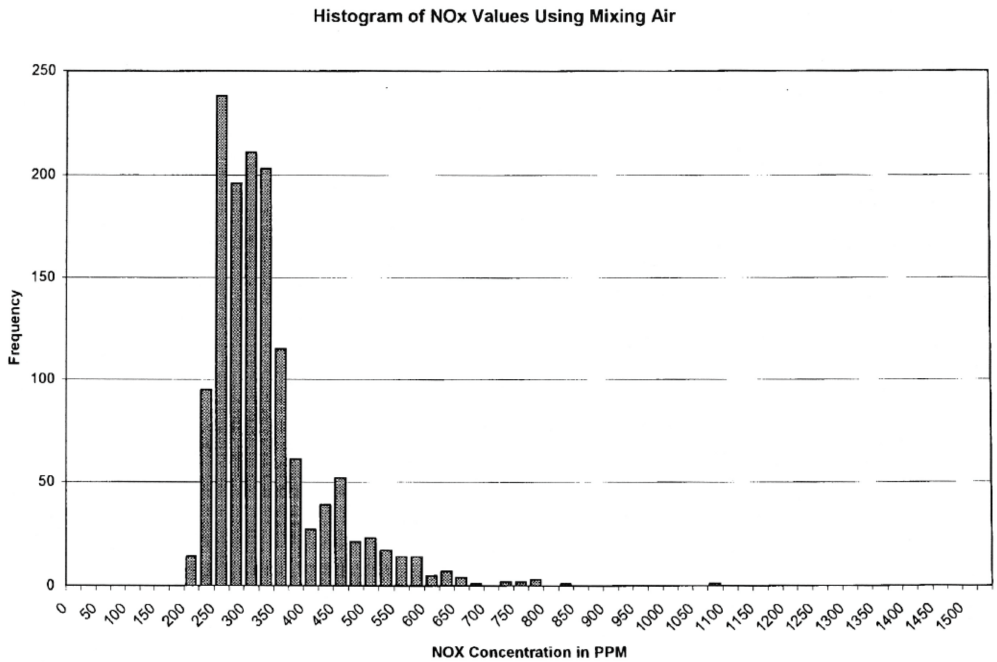


Figure II-17b Frequency of NOx Values for the Cement Kiln with Mid-Kiln Tire Injection in Figure II-17a (With Mixing Air) [40]



CemStar[SM]

Another approach that has been proven effective in reducing NOx is the patented CemStar[SM] process, originally developed and sold as a method to increase production of clinker from existing kilns while minimizing capital expenditures.[43, 44] In the CemStar process, steel or blast furnace slag is introduced as feed material into the kiln. The slag is generally added at the inlet to the rotary kiln (typically after the precalciner or preheater), regardless of kiln type, as shown in Figure II-18. Unlike normal cement materials, which require significant processing to achieve adequate grain size, the slag need only be crushed to 3/4 to 1-1/2 inch pieces. Minimal processing is necessary because the slag has a low melting temperature and its chemical nature is very similar to the desired clinker. Minimal slag processing permits the equipment for the CemStar to be inexpensive and also reduces energy consumption per unit of clinker produced. Moreover, the CemStar process can be implemented on a kiln quickly with minimal impact to facility operations. The equipment needed is mostly material handling equipment as shown on the left in Figure II-18.

Because CemStar provides minerals (such as iron from the steel slag) that are normally provided by other mineral sources such as shale or clay, it is often best to reformulate the kiln feed when implementing CemStar. It may be possible to eliminate the use of mineralizers altogether and reduce the number of raw material components.

The advantages of CemStar approach are many: energy input can be reduced, NOx emissions (both lbs/hr and lbs/ton of clinker) can be reduced, and kiln capacity can be increased. Since the steel slag more closely resembles the desired kiln product than do the normal raw materials, kilns with CemStar require less intense firing and allow for a significant reduction of peak burn-zone temperature. The lower burn zone temperature results in less thermal NOx generation. NOx reduction may be expected to be in the range of 20% or more for most kilns. If initial, uncontrolled NOx is high due to thermal NOx, CemStar is likely to provide reductions on the order of 40%-50%. Figures II-19a and II-19b show the results of testing with baseline conditions and CemStar, respectively. A 20% reduction in NOx resulted from CemStar, corresponding with a reduction in average burn-zone temperature of over 200°F.[45] Kiln capacity is increased because each ton of steel slag added to the kiln results in about a ton of additional production, though the precise amount of additional kiln production is dependent on the mineral characteristics of the local raw material. This capacity increase is the reason that many facility owners may initially choose to use CemStar.

Figure II-18: A Preheater Kiln Adding Steel Slag For CemStar [46]

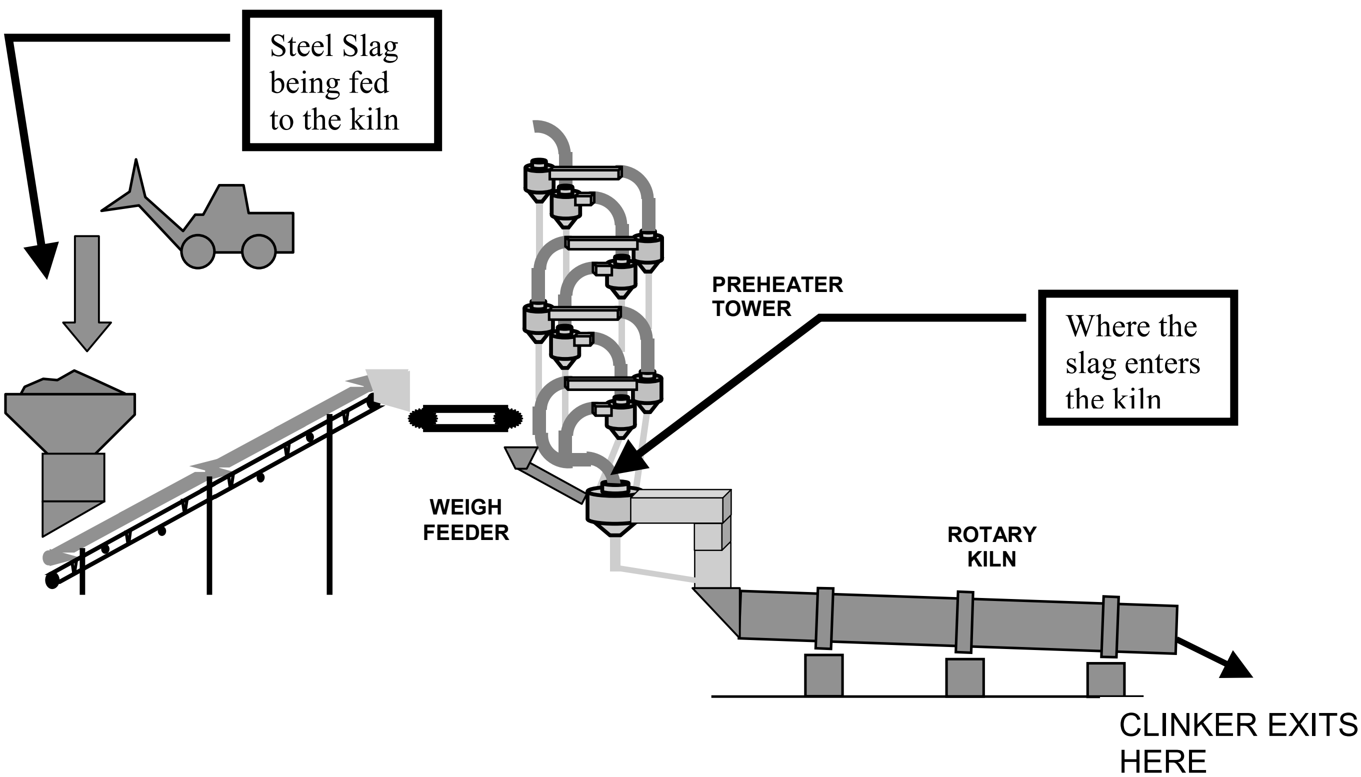


Figure II-19a: Base Case Testing (without CemStar) - NOx versus Burn-Zone Temperature[45]

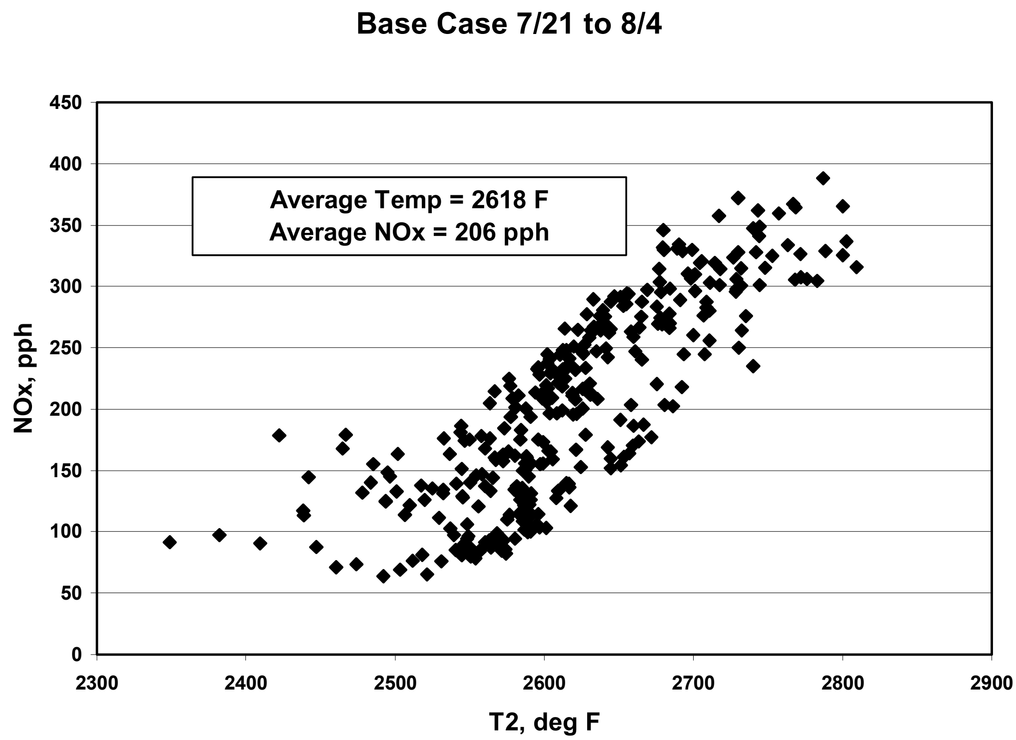
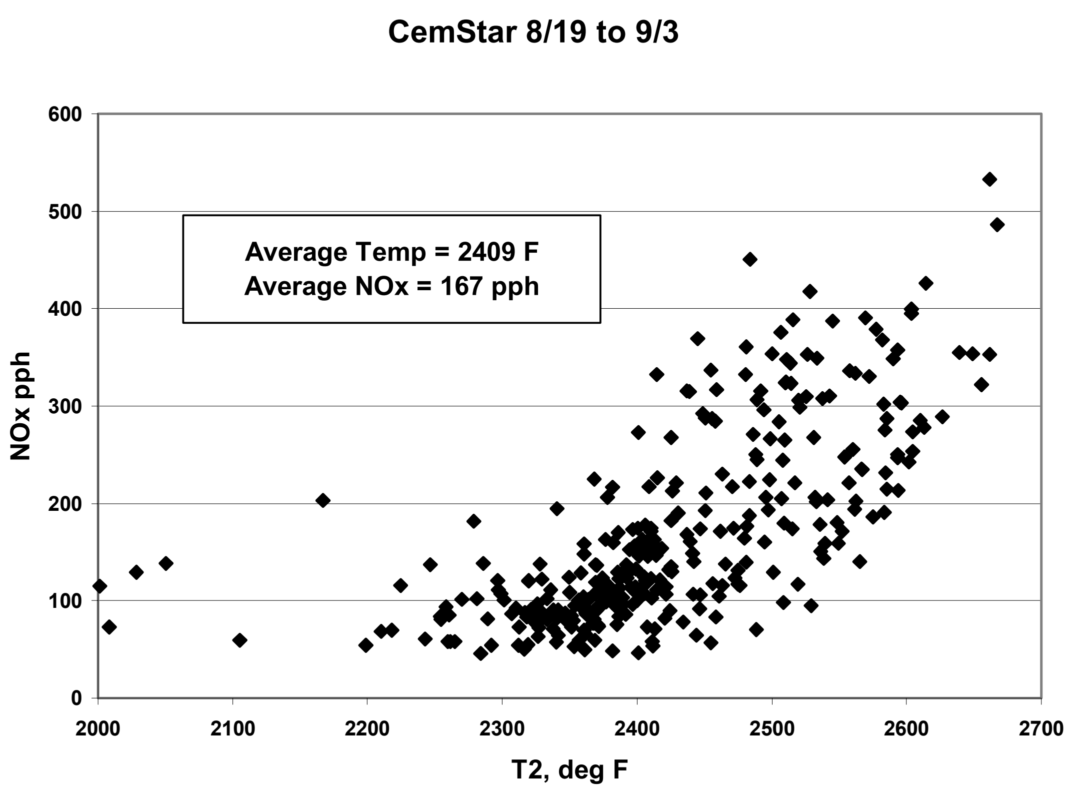


Figure II-19b: CemStar Testing - NOx versus Burn Zone Temperature[45]



A side benefit to CemStar is reduced CO_2 emissions. CemStar reduces the amount of limestone that must be calcined per ton of clinker. For each ton of slag that replaces an equivalent amount of limestone (on a calcium basis), 0.512 tons less CO_2 will be emitted.

TXI, the developer of CemStar, reports that more than 10 plants are equipped with the technology at this writing. Case Study CK-2 (Chapter IV) discusses one application of CemStar on a long-wet process kiln.

Process Optimization

One final method for reducing NOx emissions from cement kilns is process optimization. In principal, any effort that reduces the amount of fuel being fired to produce clinker will result in a reduction in NOx generation. In practice, process optimization often entails the use of advanced computer controls and instrumentation. Many of the primary NOx control technologies described are implemented along with process optimization to take advantage of their combined effects and to improve overall facility operation. NOx reductions reported in the previous sections were generally attributed to the changed combustion process (for example, mid-kiln firing). Combined reductions were achieved in case study CK-4, Ash Grove Cement (Chapter IV). Figures II-20a and II-20b, from case study CK-4, show a 55% reduction in average NOx emissions - from 845 lb/hr to 383 lb/hr - achieved largely by reducing the variability of the process with a computer-automated optimization system. Mid-kiln firing provided additional NOx reduction, for an overall NOx emission reduction of 59% from controls.

D.2 Secondary Methods of Controlling NOx from Cement Kilns

In addition to methods designed to reduce the NOx that is generated by combustion in the kiln, there are methods that can reduce the NOx after it is formed. These methods appear to work best on precalciner kilns. It should also be noted that these secondary control measures can be used in addition to methods used to minimize the NOx generated in the rotary kiln for greater combined NOx reduction.

Selective Non-Catalytic Reduction (SNCR)

SNCR has been tested in the U.S. on precalciner kilns and is planned for commercial use in other countries.[9, 47] Experience is limited to only a few units worldwide, but some tests have reported significant reductions. Table II-7 lists commercial installations of urea SNCR on precalciner kilns and the results of some demonstration programs. Effective operation of SNCR requires availability of a section of kiln with the proper temperature and residence time characteristics for good reduction. The specifics of the installation will determine the level of reduction that is possible. It is unlikely that SNCR can be used effectively on many long kilns (wet or dry) because of the need for access to the proper temperature region for injecting urea or ammonia reagent. However on some precalciner kilns the access to the proper temperature zone is good. In one demonstration of urea SNCR on a precalciner kiln, over 80% NOx reduction was achieved.[35] Commercial systems are expected to deliver 25% to about 50% NOx reduction on some units overseas (see Table II-7). As noted earlier, the specifics of the kiln design determine the level of reduction that may be possible through the use of SNCR.

Figure II-20a: NOx Emissions at Ash Grove Cement After Process Control (from Case Study CK-4)

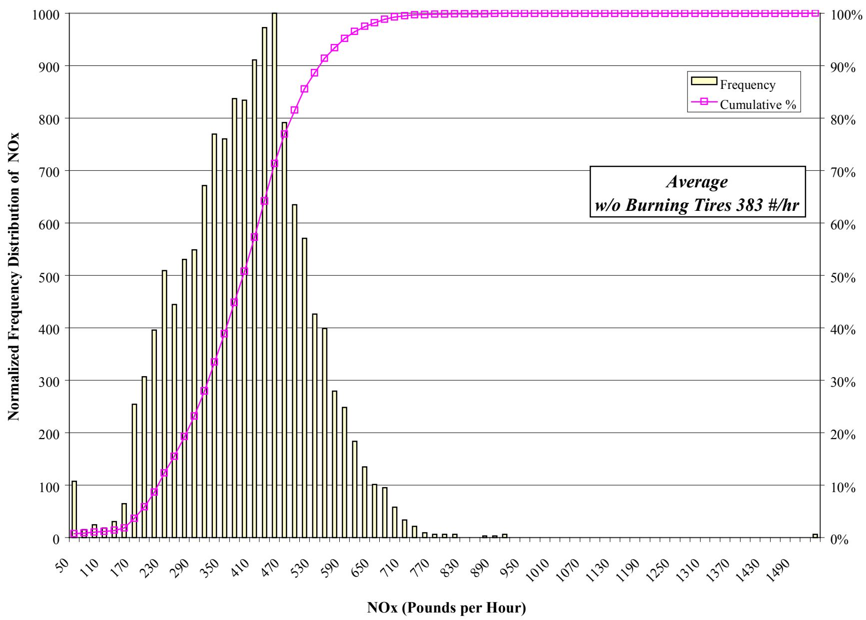
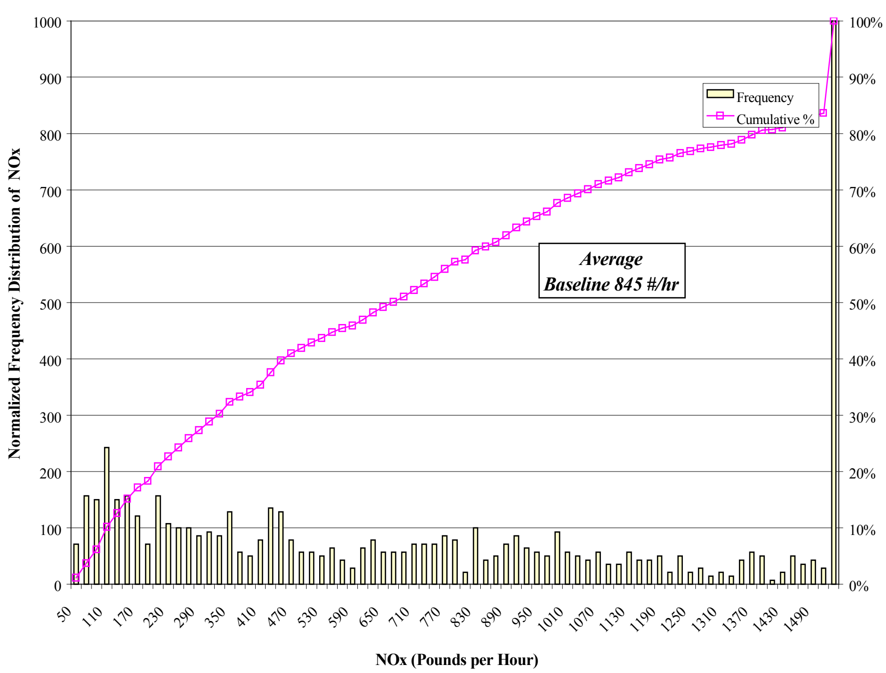


Figure II-20b: NOx Emissions Histogram at Ash Grove Cement Before Process Control (from Case Study CK-4)



Biosolids Injection (BSI)

BSI is a technology that was developed in the 1990's by the cement industry for NOx reduction in precalciner and preheater kilns. BSI adds dewatered sewage sludge to the mixing chamber of the calciner, as shown in Figure II-21. The dewatered biosolids provide a source of ammonia, producing an SNCR reaction to reduce NOx. At a Mitsubishi Cement Kiln in California, BSI provided about 50% reduction in NOx from about 250 ppm (at 12% oxygen) to 120-125 ppm (at 12% oxygen). BSI has the additional benefit of offering a potential revenue stream because many communities are willing to pay a tipping fee for accepting biosolids. BSI technology may require significant capital equipment expenditures, however. The material handling equipment needed and the moisture in the dewatered biosolids is sufficient to strain the capacity of the fans of many existing facilities. It appears that biosolids injection may be an effective approach for NOx reduction, but it will depend on the specifics of the kiln.

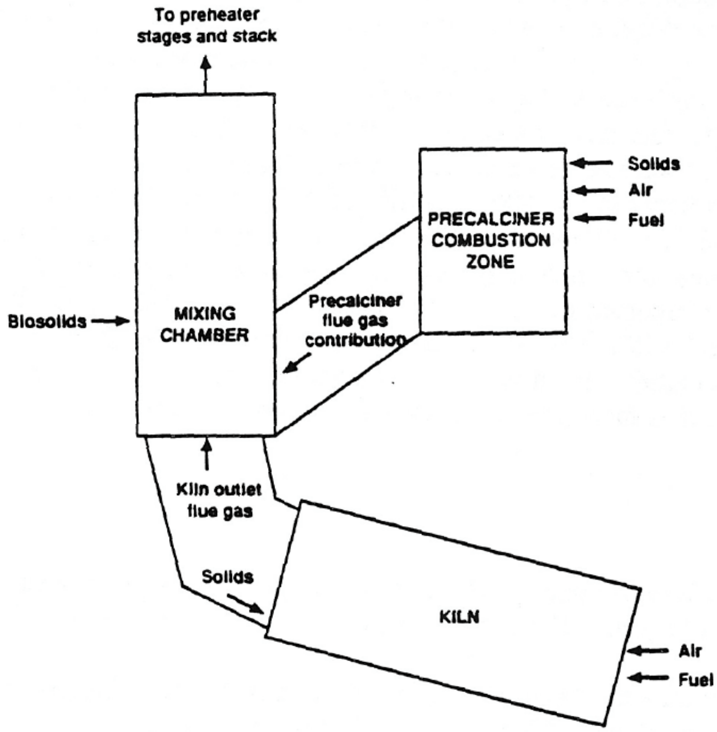
Table II-7: NOx Reduction Performance of Urea SNCR on Precalciner Cement Kilns [9]

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	NOX BASELINE (ppm, lb/MMBtu)	Reduction (%)	AMMONIA SLIP, (ppm)
Ash Grove Cement Seattle, WA (Demo)	Cement Kiln/ Precalciner	160 tons solids/hr	350-600 lb/hr	>80	< 10
Korean Cement Dong Yang Cement, Korea (Demo)	New Suspension Calciner	na	1.27 lb/MMBtu	45	na
Taiwan Cement Units #3, #5, & #6	Cement Kiln/ Pre-calciner	260 697 658	1.29 lb/MMBtu 1.58 lb/MMBtu 0.92 lb/MMBtu	50 45 25	15 15 15
Wulfrath Cement Germany (Demo)	Cement Kiln	140	1000 mg/Nm3 500 ppm	90	na

Selective Catalytic Reduction (SCR)

This technology has not been applied to cement kilns in the U.S. Although, in principal, SCR can be used on cement kilns, the SCR reactor must be installed after gas cleaning devices and will require reheating of the gas to achieve the proper temperature for the reaction. A "high-dust" SCR installation, used for most boilers equipped with SCR, may not be possible because of the high calcium content of the dust in cement kilns, which may contribute to deposits that can rapidly reduce catalyst activity. Therefore, this technology is unlikely to be used in the near future to achieve NOx reduction from existing cement kiln facilities. This technology would more likely be used on new cement kiln facilities rather than existing facilities. In fact, Reference 11 shows low-temperature SCRs on calciner kilns installed in Pittsburgh, CA in 1996. Experience at these calciner kilns may be useful for cement industry applications.

Figure II-21: Biosolids Injection Process Equipment on a Precalciner Kiln [48]



D.3 Combination of Technologies

It is not uncommon to combine combustion technologies with post-combustion technologies for other source types, and this could be done for cement kilns in some cases. It is also possible to combine multiple combustion technologies on cement kilns. For example, California Portland Cement, in Case Study CK-1, combines indirect firing and mid-kiln firing to reduce NOx by a combined amount approaching 50%. It is also reasonable to expect that CemStar might be combined with a combustion technology such as mid-kiln firing to provide combined benefits. The exact amount of reduction will depend upon the regulatory requirements and technical limitations. In some cases the NOx reductions may not be additive.

E. Summary

In this chapter the various commercially available NOx reduction technologies for industrial boilers, gas turbines, IC engines, and cement kilns were explored. In addition, several emerging technologies that have significant near-term commercial potential were discussed. Any of these technologies may play an increasing role in reducing NOx emissions from existing sources. In the next chapter the cost effectiveness of those technologies with significant commercial experience will be evaluated. Finally in Chapter IV, case studies will be presented of actual projects where these technologies have been employed. These case studies are the key feature of this report in that they provide "real world" technical and cost input to the calculations of cost effectiveness in Chapter III.

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III. Technology Costs

The decision to use a particular control technology on a facility is largely an economic one, once the technically feasible approaches and regulatory requirements have been identified. Operators of facilities will always choose the approach that meets their needs for control while minimizing the expected cost of control. Therefore, an understanding of cost effectiveness of different approaches for NOx control is essential to understanding how the technologies might be deployed. This chapter addresses the economics of applying various NOx control technologies to the sources of interest.

This chapter builds upon the information in Chapter II and estimates the costs of applying established NOx reduction technologies on existing facilities. The chapter describes the methods used to estimate lifetime costs of implementing NOx controls, and presents the results of the cost effectiveness analysis for industrial boilers, gas turbines, internal combustion engines, and cement kilns.

A. Costs of Control

The analyses preformed for this report and the results presented are intended to be representative of many situations that are likely to be encountered by potential users of NOx reduction technology, but do not include the entire universe of applications that may be encountered. The situations addressed in this report are *typical*, and though there will be situations that are not addressed in this document, it is expected that these will be only a small fraction of applications. The analyses of this section assume that the technology selected is technically appropriate for its application. Due to the wide range of applications within some source categories, it is possible that, for any particular application, some technologies identified in this report may not be appropriate, or, for a particular actual situation, the technology might be uneconomical due to special circumstances. In order to estimate the cost effectiveness of controlling NOx from a source category with a specific technology, it is necessary to assume that the technology selected is feasible.

Cost analysis was only performed for technologies where commercial installations exist and there was enough data available to estimate cost effectiveness with some reliability. Therefore, technologies that are identified in Chapter II as "emerging" were not analyzed for cost because there is not enough data available to produce reliable estimates for these technologies at this time.

A.1 Cost Data

Industrial users of NOx reduction technology are generally less likely to publish articles or technical papers on their experience with NOx control technology than are electricity generating utilities, leading to much less publicly available data on cost and performance of NOx reduction technology from industrial users than from electric utility boilers. Although actual data from case studies and technology users was relied on heavily, in some cases it was necessary to rely on additional sources. In this respect, the analysis in this report is slightly different than that in Reference [1], which relied almost exclusively on information from case studies and other user-provided information. In this study it was necessary to assemble information from technology suppliers and users, and from documents published by EPA, state, and local regulatory agencies.

Information gathered in case studies was the primary basis for estimating costs, when this data was available. When case study information was not available, cost information from other sources was used. The case study information on capital cost generally corresponded well with the cost information from other sources. Additionally, the case studies provided valuable information about what these users actually budgeted for fixed Operating and Maintenance (O&M) costs.

In contrast to capital cost data, variable operating cost information (reagent costs, incremental fuel cost, etc.) can generally be estimated with good accuracy using existing data and engineering calculations of reagent consumption, catalyst consumption, fuel use, etc. This method was used in this report.

B. General Methodology

In this chapter, two general approaches will be used to estimate cost effectiveness. These two approaches will be shown to be consistent for assessing cost-effectiveness of different control approaches. The results of calculations presented later in the chapter are averages of the approaches. The first method projects a detailed pro forma cash flow over the project life. The second method makes an annualized base-year estimate (with 1999 as the base year). The base-year estimate method is, of course, much simpler to use. Combined use of both methods incorporates the following benefits: 1) the pro forma method is more flexible, it provides a richer amount of information, and can be used to address a much wider range of economic assumptions; 2) the pro-forma method shows the cost of controlling NOx with and without the effect of taxes, which can be a significant factor; and 3) the consistency of the two methods in determining cost-effectiveness of controls on a before-tax basis provides greater confidence in both methods. Costs will be estimated using a "Constant Dollar" approach. The base year for the constant dollar approach was chosen to be 1999.

In order to perform the pro-forma analysis, it is first necessary to make a reasonable estimate of inflation to predict escalation of costs. Inflation is difficult to predict with certainty, but its effects on long-term projects are so significant that it must be considered.[vi] Despite the uncertainty regarding the actual future rate of inflation, it is possible to estimate current or anticipated future inflation. The nominal yield on 3-month treasuries averaged about 2.1% above the rate of inflation from 1976 until 1985, and during this period the yield on 3-month treasuries ranged from 3.33% to 8.11%.[2] At the time of this writing, the yield on 3-month treasuries is about 4.75%.[3] This implies an *expected* near-term rate of inflation of about 2.6%. Although inflation over the life of a project is likely to differ from the current near-term inflation rate, it is impossible to predict how it will differ.

[vi] For example, an average inflation rate of 2.6% will cause prices in ten years to *appear* 30% higher. An annual inflation rate of 5% will cause prices in ten years to appear over 60% higher. The inflation rate will vary over time, which makes estimating inflation difficult. Annual inflation rate averaged 1.3% from 1953 to 1965, averaged 9.2% from 1973 to 1981, and averaged 3.6% from 1982 to 1995.[2] Inflation since 1995 has been extremely low, but it is uncertain if this trend will continue in the coming years.

Moreover, inflation in the early years of the project has the greatest effect on the overall project economics. For the cost estimates in this report, a near-term inflation rate of 2.6% is assumed for the pro-forma analysis.

It is important to note that if costs are estimated for the purpose of capital budgeting for a specific year in the near term (within the next five years, for example), a "Current Dollar" approach would be used to estimate cost and the nominal dollars required in the budget for a particular year.

B.1 Components of Cost

The costs of employing a technology include the capital cost associated with placing the technology in service, lost production due to down time while the technology is installed, and the fixed and variable operating and maintenance costs associated with using the technology.

The capital cost of a project is determined by the cost of the equipment, materials, shipping, labor and other costs associated with placing the system in service. It is often necessary to fund the capital purchase with funds "borrowed" from lenders and shareholders, who each require a fair return on the money they provide. These two considerations determine the financing costs. Moreover, taxes (property and income), insurance, and depreciation all impact the cash-flow effects of employing a piece of equipment. It is not possible to explore every possible mode of financing in this report, but reasonable assumptions can be made (Table III-1). These assumptions were used to determine the Weighted Average Cost of Capital (WACC). For more information about WACC, see Reference [4].

The values in Table III-1 reflect an anticipated average for most U.S. companies likely to install NOx reduction equipment (utilities, large corporations, and medium sized companies). In general, electric utility and other projects financed by large, well-capitalized companies will tend to have lower debt costs, higher proportion financed with debt (lower proportion financed with equity), and longer project economic life than the facilities examined in this report.

Other studies[1,5,6,7,17] have used a simple payment equation for addressing the costs of capital. As shown later in this chapter, this normally provides a sufficiently accurate estimate for cost effectiveness in terms of $/ton of NOx reduced. However, some previous studies have received critical comments regarding this treatment of costs and financing, calling such treatment too simplistic.[1] To address these concerns, the base year approach was combined with the pro forma method. The "base year" approach is consistent with the methods in EPA's Alternative Control Techniques (ACT) documents.[5,6,7,17,] Whether using the simpler approach or the more robust approach, the results in this study were shown to be reasonably close, typically well within 10%, unless the reported values were small. For smaller values, (less than $500/ton of NOx removed), the results of the two analyses sometimes differed by as much as $100/ton, but usually by much less. The results of cost-effectiveness calculations reported in the tables and figures in this chapter are the average of both approaches, unless noted otherwise.

Table III-1: Assumptions for Pro Forma Economic Analysis	
Cost of Debt	7.5%
Fraction of Debt Financing	40%
Cost of Equity	15%
Fraction of Equity Financing	60%
Project Economic Life	15 years
Depreciation for Tax Purposes	MACRS[vii]
MACRS Class	10 year
Property Taxes ($/1,000)	$15[viii][ix]
Insurance	Negligible[viii]
Income Tax Rate	35%
Inflation rate	2.6%

Cost of material and labor used over the life of the program will vary as the costs of those items increase (or sometimes decrease). In most cases they will increase. For the sake of this analysis, it is assumed that all material and labor that make up annual expenditures for operation and maintenance of the system will increase in cost with the general level of inflation. Of course, in reality some items will increase in cost more and some less than the rate of inflation. But, for this analysis the simplifying assumption is that the general rate of inflation will be a reasonable estimate for the increase in cost for all items.

The capital costs for various retrofit projects included in this report were determined from reported costs in published references and as estimated from information in the case studies of Chapter IV. Cost analysis is only performed for those technologies where there is sufficient experience such that reliable data is available to estimate cost. Therefore, there is no cost analysis for emerging technologies in this report.

The operating and maintenance costs of the technology are determined by the cost of additional materials, (fuel, reagent, catalyst, replacement parts, etc.) and labor associated with owning and operating the technology. Published references (cited where appropriate later in this chapter) and case study information are used to determine the value for each of the components of operating and maintenance costs. Table III-2 lists assumed cost of certain consumables that will impact operating cost.

[vii] MACRS is an accelerated method of depreciation accepted by the IRS for tax purposes.

[viii]

[ix] Property taxes are determined by local law and, as discussed in Reference 8, frequently are not applied to capital improvements associated with air pollution reduction. They are included in this analysis for conservatism. In Reference 8, increased insurance costs were shown to be negligible for this type of analysis.

Table III-2: Cost of Operating Consumables	
Coal	$1.50 /MMBTU
Natural Gas	$2.25 /MMBTU
Distillate Fuel Oil	$5.00/MMBTU
Ammonia (aqueous)	$360 /ton (active agent)
Urea (50% by weight aqueous solution)	$0.95/gallon
SCR Catalyst (except metal washcoat)	$10,000-$14,000/m^3
It is recognized that the cost of these operating consumables will vary from time to time and from location to location; however, it is not possible to explore every possible situation in this report. These values are suggested to be representative of a large number of facilities in the U.S.	

B.2 Cost Analysis

The current dollar cash flow impacts of the NOx reduction technology, including operating consumables, maintenance, property taxes and effects of depreciation, are projected in a Microsoft Excel Worksheet. These are adjusted for tax effects because it is assumed that the business has earnings that are subject to income taxes and the company earnings and taxes payable will be impacted by the project. To this is added an annualized capital charge that is determined to be equal to a payment at the company's Weighted Average Cost of Capital (WACC) over the project lifetime. As is normally done in project analysis, the cash flows are estimated as if the hardware and installation was an all-cash acquisition. The cost of financing is captured in the annualized capital charge (the WACC or discount rate). However, in the worksheets (see Appendix A) that were generated the actual cash flows inclusive of financing effects were shown as well, based on the financing assumptions that were made. The financing cash flow projections (specifically, debt interest and principal) are shown for information purposes only, and these numbers do not contribute to the end result of the analysis (the cost-effectiveness in $/ton of NOx removed). The financing cash flows projected in future years do not figure into the cost-effectiveness analysis since, consistent with common project analysis methods, the purchase is treated as an all-cash transaction with financing at the WACC. An annual capital charge, determined by the total capital cost and WACC, is applied each year which does figure into the $/ton cost estimate. Future operating and maintenance cash flows are discounted at the rate of inflation, assumed to be 2.6%/year, to produce constant dollar values.

Because the analyses of References 1, 5, 6, 7, 17 show results on a before tax basis, the Excel worksheet (Appendix A) also shows the results before taxes. *It is notable that the after-tax costs will be less than the before tax costs because for most companies the tax bill will be reduced as a result of reduced before-tax income*. Depreciation, a non-cash expense, has a very large effect on reducing the tax bill. The operating and maintenance expenses are offset somewhat by reduced income taxes. A less significant effect that is incorporated into the analysis is the effect of interest payments in reducing the tax bill. This is why there are two WACC's shown in the spreadsheet. One includes the effect of taxes on effectively reducing debt expense and the resulting annual capital charge, and the other doesn't. The "After Taxes" analysis includes this effect on debt and the "Before Taxes" analysis does not. Because the results of most other studies have been presented on a before-tax basis, the before-tax results of this study should be used for comparison against the results of other studies. All results presented in this chapter and in other parts of the report are on a before-tax basis. After-tax results can be seen on the sample worksheets in Appendix A. The worksheets show that when the effects of taxes are included, the costs can be much less.

Comments Regarding Net Present Value Analysis

For most capital purchases a Net Present Value (NPV) analysis, which discounts all future cash flows, is generally performed by a company. A traditional NPV analysis was not performed in this study because of uncertainty regarding the appropriate discount rate. WACC is typically used as the discount rate for future cash flows in NPV analysis. However, the proper discount rate for an NPV analysis on NOx reduction technology should be somewhat less than the WACC. This is because the costs of reducing NOx can be predicted with much more certainty than customer payments and other cash flows that have a greater impact on business risk than the cost of controlling NOx. So, while the WACC is appropriate for determining the cost of financing the capital cost of a NOx reduction system (providers of debt or equity capital need to be compensated at a fair rate), WACC is not appropriate for discounting the future cash flows associated with the NOx reduction system. *An NPV analysis using WACC as the discount rate would underestimate the true cost of controlling NOx.* Furthermore, many industrial companies (especially utilities) evaluate these projects on a revenue requirement basis (revenue required to cover all costs, including capital recovery), which is similar to the analysis that was performed in this study. Revenue requirement methods apply a Capital Recovery Factor (CRF) to the initial capital cost to determine an annualized capital recovery cost. This is effectively what was done for this analysis. In the analysis performed in this report, future cash flows were discounted at the rate of inflation. It could be argued that the rate of return determined by long-term treasury bonds would be a better choice for discount rate of future operating costs because it would incorporate the cost of money as well as inflation. But, the inflation rate was assumed because of simplicity and conservatism.

Comparison with the Approach in EPA's Alternative Control Technique (ACT) Documents

As noted earlier, a very simple "base year" (1999) analysis using a CRF calculated in the same manner as in the appropriate EPA ACT document (Refs.5, 6, 7, 17) is shown in the worksheet. This is to ensure that the results are comparable to those of the ACT documents. In nearly all cases the results for $/ton of NOx (before-tax basis) are within about 10% of the approach of the ACT document when economic assumptions are similar (project life, etc.). A benefit of performing both analyses (simple, as in the ACT document, and more robust as done in this report) is that the ACT results are shown to be reasonably consistent with the results of the more robust approach. Results were almost always within the greater of 10% or $100/ton of one another and more often much closer.

Cost Effectiveness of Seasonal versus Annual Controls

Ground-level ozone formation is primarily a seasonal concern (May 1 - September 30), and regulations relating to NOx emissions for the purpose of controlling ground-level ozone formation often focus on making reductions over a five-month period when ozone formation is of greatest concern. (It should be noted that a number of states in the Northeast have either adopted or are currently seriously considering year-round controls of NOx emissions for additional benefits towards reductions of acid deposition, improvement in visibility, reductions in fine particle concentrations, and other environmental benefits.) Some technologies can be secured ("turned off") outside of the ozone season if the reductions provided by that technology are not currently required to comply with ozone regulations. This way the operators of the source will incur less cost than if they operated the NOx reduction technology for the entire year.

SNCR and gas reburn are technologies that lend themselves well for operation in this manner because most of the cost of use is associated with reagent consumption or additional fuel cost. On the other hand, some technologies may only be operated such that they provide continuous reductions year round. Generally, they cannot be turned off. Combustion technologies, such as Low-NOx Burners and Dry Low NOx fall into this category. Although the off-season reductions have many environmental benefits noted above, they do not figure into the economic decision of the operator if the operator is not required under current regulations to make those reductions. Therefore, if the operator installs the technology solely for the purpose of obtaining ozone-season reductions, it is reasonable that only ozone season NOx reductions should be used in the calculation of cost effectiveness, as was done in the recent EPA's cost analysis for the "NOx SIP (State Implementation Plan) Call" action. For this reason, in calculations for cost effectiveness in this chapter, values are shown for both annual reductions and ozone-season reductions for all technologies, even if the technology provides NOx reductions year round. In cases where the technology may not be operated outside of the ozone-season, it is assumed that the variable operating costs (costs associated with urea, ammonia, natural gas, etc.) are zero outside of the ozone season. For SCR, it is assumed that the catalyst continues to be degraded in proportion to the annual operation of the facility, not just when ammonia is being injected for the purpose of NOx reduction.

C. Industrial Boilers

C.1Cost Effectiveness of Primary Methods of Controlling NOx from Industrial Boilers

Cost effectiveness of primary control methods is driven primarily by the capital cost of the controls, the effectiveness of the controls in reducing NOx, the uncontrolled NOx level, and the capacity factor of the boiler. Since this study is directed primarily at major sources, small commercial boilers that operate intermittently are of less interest than larger, field-erected units used by large industrial users that operate at higher capacity factors. This study evaluates cost effectiveness of various control technologies at three (low, medium, and high) capacity factors of 45%, 65% and 85%, overlapping the range of 33% to 80% considered in Reference 5.

Unfortunately, few of the case studies described in this report provided additional insight to the cost effectiveness of NOx control for industrial boilers using combustion controls. It is therefore necessary to rely heavily on published data. Reference 5 forms the basis for the costs in this analysis, with other references cited when used. The capital costs of controls are from Reference 5, or from the case studies as available, though it is recognized that performance and cost will vary somewhat from one facility to another. The initial baseline level will vary as well, which will significantly impact the cost effectiveness.

Table III-3a shows cost effectiveness on an annual and seasonal basis for installation of Low-NOx Burners to achieve NOx reduction from 0.60 lb/MMBTU to 0.38 lb/MMBTU (a 60% NOx reduction) on a coal fired boiler as a function of capacity factor. Table III-3b shows the results of similar calculations for identical conditions, with NOx reduced to only 0.45 lb/MMBTU (a 25%

reduction). Experience with electric generating units has shown that NOx levels well below 0.50 lb/MMBTU are typical with LNBs and sometimes NOx levels approaching 0.30 lb/MMBTU are possible on wall- and tangential-fired units, so assuming an approximate control level in the range of 0.40 lb/MMBTU for industrial boilers is reasonable. Application of low NOx combustion technology can adversely impact boiler efficiency, but these effects are difficult to predict and generally have a minor impact on cost. Therefore, these effects are ignored for the purpose of this analysis.

As shown in the tables, NOx reduction is possible on an annual basis for under $2,000/ton of NOx removed for all conditions, and under $1,000/ ton in some cases. For seasonal controls, cost per ton of NOx reduction is higher by a factor of about two.

The analyses for both tables assume a capital cost of about $5,000/MMBTU/hr, which is close to the assumed value in Reference 5. In cases where the cost is higher or lower than $5000/MMBTU/hr, the cost effectiveness is scaled in proportion to the capital cost. For example, if the capital cost is actually $6,000/MMBTU/hr, the cost effectiveness (in $/ton) is increased proportionately by 20%. Similarly, if capital cost is only $2,500/MMBTU/hr, then the cost effectiveness (in $/ton) should be reduced by half.

Table III-3a: Cost Effectiveness for NOx Reduction with LNB on a 350 MMBTU/hr Coal-Fired Boiler with Capital Cost of $5,000/MMBTU/hr (36% NOx Reduction From 0.60 lb/MMBTU)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$3,308	$2,290	$1,751
Annual	$1,378	$954	$730

Table III-3b: Cost Effectiveness for NOx Reduction with LNB on a 350 MMBTU/hr Coal-Fired Boiler with Capital Cost of $5,000/MMBTU/hr (25% NOx Reduction From 0.60 lb/MMBTU)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$4,763	$3,298	$2,522
Annual	$1,985	$1,374	$1,051

Table III-4a shows the cost effectiveness of a gas-fired Low -NOx Burner retrofit capable of 50% reduction from 0.20 lb/MMBTU with a capital cost of ~$5,000/MMBTU/hr for a field-erected facility. Note that for the seasonal analysis, credit is taken only for those reductions during the 5-month ozone season, even though NOx reductions occur year round. In this case annual NOx reductions are possible for under $2,000/ton, while seasonal control is more expensive.

Other, less expensive approaches for reducing NOx may be possible, such as "Burners Out of Service," simple modification of existing hardware, or modification of swirlers, fuel guns, etc. An analysis was performed for modifications that would cost only $300/MMBTU/hr but achieve only a small NOx reduction of 25%. As shown in Table III-4b, modification of existing hardware or otherwise less expensive equipment may reduce NOx, making NOx reductions possible for under $1,000/ton under all circumstances evaluated. Even if NOx reductions were much less (say, only 10%), NOx reductions would still be well below $1,000/ton, annually and under $2,000/ton, seasonally.

As noted in Chapter II Section A.1, fuel nitrogen content of No. 6 fuel oil can vary from 0.1 to 0.6%, which will significantly impact the effectiveness of Low-NOx Burners when firing residual fuel oil. In Case Study BLR-2 (Chapter IV), a NOx reduction of 10% was achieved with a total capital cost of only $30,000 through simple burner modifications. These boilers had a fairly high fuel nitrogen level of 0.46%, limiting the ability to lower NOx with LNBs. Table III-5 shows the results of cost calculations for this application.

Table III-4a: Cost Effectiveness for NOx Reduction with LNB on One Gas-Fired 350 MMBTU/hr Boiler

50% NOx reduction from 0.20 lb/MMBTU and Capital Cost of $5,000/MMBTU/hr

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$7,145	$4,946	$3,783
Annual	$2,977	$2,061	$1,576

Table III-4b: Cost Effectiveness for NOx Reduction Through Minor Modifications on One 350 MMBTU/hr Boiler

25% NOx reduction from 0.20 lb/MMBTU and Capital Cost of $300/MMBTU/hr

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$857	$594	$454
Annual	$357	$247	$189

Table III-5: Cost Effectiveness for Burner Modification on Two Oil-Fired 680 MMBTU/hr Boilers

10% NOx reduction from 0.43 lb/MMBTU and Capital Cost of $30,000, or $22/MMBTU/hr
(Case Study BLR-2)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$72	$50	$38
Annual	$30	$21	$16

C.2Cost Effectiveness of Secondary Methods of Controlling NOx from Industrial Boilers

Selective Non-Catalytic Reduction (SNCR)

The costs of SNCR for an industrial boiler will depend, in part, on boiler type, fuel, reagent, and operating mode. Some boilers, because of their size and higher furnace temperatures, lend themselves better to urea use than to ammonia use. Urea's temperature window is slightly higher and broader than that of ammonia, and urea is easier to distribute in large furnaces. The cost of ammonia systems is sometimes greater due to the more sophisticated injection systems that are required.[1] For the sake of conservatism, the analysis in this program will be for urea-based systems. In some cases this will result in a slightly higher cost per ton of NOx removed than for an ammonia system. However, this analysis does not include the additional cost of safety precautions that may be necessary when using ammonia reagent.

For boilers of about 250 MMBTU/hr or more, capital cost is expected to vary from about \$500,000 to \$1,000,000 for urea SNCR technology. Table III-6 shows the cost of various commercial urea SNCR systems. For ammonia SNCR, the capital cost may be less for fluidized-bed or bubbling-bed boilers. However, this equipment cost advantage may be offset by safety provisions sometimes necessary when using ammonia. Such safety provisions are determined by local government authorities and can vary widely from one location to another.

Minergy Corporation, in Neenah, Wisconsin (Case Study BLR-1, Chapter IV), reported a capital cost of \$500,000 to \$750,000 for its 350 MMBTU/hr facility. Using an average cost of \$625,000 and adding \$150,000 for the cost of installation, a total cost of \$775,000 was used for this analysis. For a 15-year project life, 5-month ozone season control, and a capacity factor of 65%, the cost of NOx reduction over the project life is estimated to be about \$2,450/ton of NOx removed. For annual control the cost effectiveness would be about \$1470/ton of NOx removed. Table III-7 shows the effect of capacity factor on cost effectiveness of NOx reductions

Table III-6: Reported Cost of Urea SNCR for Wood-Fired Power Boilers [8]

Size, MMBTU/hr	Boiler Type	Capital Cost	Estimated Annual Operating Cost	Baseline NOx	NOx Reduction
900	Grate-Fired Biomass	\$1.1 M	\$230 K	235 ppm	50%
475	Combustion Engineering Stoker	\$700K	\$54 K	0.47 lb/MMBTU	60%
300	Riley Stoker	\$600K	\$40K	0.25 lb/MMBTU	30-50%
245	Front-Fired Fiber Waste	\$390K	\$58 K	370 ppm	50%
Capital cost shown includes equipment, engineering, and commissioning, but not installation. Installation typically adds about 20% to 30% to the cost.					

Table III-7: Cost Effectiveness for SNCR NOx Reduction on a 350 MMBTU/hr Boiler 35% NOx reduction from 0.45 lb/MMBTU (Case Study BLR-1)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$3,303	$2,518	$2,101
Annual	$1,814	$1,470	$1,300

Selective Catalytic Reduction (SCR)

There have been relatively few SCR systems installed in the U.S. on industrial boilers or process heaters firing fuels other than natural gas or refinery gas. Since there are currently no coal-fired industrial boilers in the U.S. that have been retrofitted with SCR, it is necessary to estimate costs from what is known about electric generating SCR retrofits on coal-fired boilers. Reference 1 demonstrated that there is a pronounced economy of scale for SCR on coal-fired boilers, which makes SCR more expensive per unit of boiler heat input (or facility output) on a small boiler than a large one. However, on sufficiently small applications, the SCR reactor and controls can be shop fabricated in a modular form. This may reduce the amount of field erection and engineering resulting in lower costs. Operating costs (ammonia and catalyst) can generally be estimated with a high level of certainty once the boiler characteristics are known.

Since SCR application to a coal-fired boiler is most likely to provide cost-effective NOx reductions, an example of a coal-fired application is used to estimate costs. As noted above, since there are no coal-fired industrial boilers in the U.S. that have been retrofitted with SCR, it is necessary to project costs from what is known about electric utility SCR retrofits on coal-fired boilers. Costs are calculated for NOx reduction on a 350 MMBTU/hr boiler at an estimated capital cost range of $10,000/MMBTU/hr to $15,000/MMBTU/hr. This range is reasonable if cost experience with utility boilers is extrapolated to smaller industrial boilers, with $10,000/MMBTU/hr near the high end of the capital cost of a utility boiler of about 100 MW size (1,000 MMBTU/hr). Given the greater economies of scale for utility boilers compared to industrial boilers, we assume that SCR capital cost for an industrial boiler will be higher on a $/MMBTU/hr basis than for a utility boiler.

The SCR applications for an industrial boiler in the U.S. are on relatively clean applications. Even the SCR in Case Study BLR-4 (Chapter IV), a 57 MMBTU/hr wood-fired facility at Sauder Woodworking, is downstream of a hot-side ESP (electrostatic precipitator) that removes most dust in the exhaust stream. In this case study, the cost of the catalyst, catalyst reactor, ammonia flow control, ammonia injection grid, and engineering was about $450,000. Additional costs include installation labor and materials, the anhydrous ammonia storage tank, and startup.[9] Adding 25% for the hardware and labor to install the SCR and to provide an ammonia storage tank yields a cost of under $9,500/MMBTU/hr for this 57 MMBTU/hr application. SCR capital costs tend to exhibit economies of scale and a 350 MMBTU/hr boiler firing relatively clean fuel would likely cost well below $9,500/MMBTU/hr, probably around $5,000-$6,000/MMBTU/hr. This is consistent with utility boiler experience, which found that SCR on clean fuel applications would cost under half the price of SCR on coal applications of similar output. This is also consistent with the cost of reduction as reported by a technology supplier of a urea SCR system of $7,500/MMBTU/hr for a 100 MMBTU/hr gas-fired boiler.[8]

Table III-8a shows the cost effectiveness of SCR on a 350 MMBTU/hr industrial boiler for an 80% NOx reduction from 0.45 lb/MMBTU while assuming a capital cost of $10,000/MMBTU/hr. In this case, SCR can control NOx for under $2,000/ton on an annual basis for most capacity factors of interest. Another analysis is performed for a more expensive SCR, at $15,000/MMBT/hr (Table III-8b). In this case, SCR on higher capacity factor boilers (over 65%) can provide NOx reduction at a cost of under $2,000/ton on an annual basis. In both cases the cost effectiveness in $/ton is over $3,000/ton under most circumstances when control is only on a seasonal basis.

Table III-8a: Cost Effectiveness for SCR NOx Reduction on a 350 MMBTU/hr Coal-Fired Boiler - 80% NOx Reduction from 0.45 lb/MMBTU and Capital Cost of $10,000/MMBTU/hr

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$5,046	$3,677	$2,953
Annual	$2,179	$1,609	$1,307

Table III-8b: Cost Effectiveness for SCR NOx Reduction on a 350 MMBTU/hr Coal-Fired Boiler - 80% NOx Reduction from 0.45 lb/MMBTU and Capital Cost of $15,000/MMBTU/hr

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$7,030	$5,051	$4,004
Annual	$3,006	$2,181	$1,745

SCR on a gas-fired facility will have a lower capital cost due to the lower catalyst volume, but will reduce NOx from a lower baseline NOx. Table III-9a shows the estimated cost effectiveness for an SCR on a 350 MMBTU/hr gas-fired facility with a capital cost of $5,500/MMBTU/hr ($1.925 million) that reduces NOx 80% from 0.15 lb/MMBTU baseline. For annual control, NOx reduction can be achieved at a cost effectiveness approaching $2,000/ton at higher capacity factors. However, for seasonal control, cost of NOx reductions increases by a factor of about two. Since there are numerous gas-fired boilers in the range of 100 MMBTU/hr, analysis was also performed for SCR on a gas-fired boiler of this size (Table III-9b). As indicated, NOx reductions are more costly on a smaller boiler. Except in the case of high capacity factor units that are required to reduce NOx on an annual basis, the cost of NOx reduction will exceed $6,000/ton.

Table III-9a: Cost Effectiveness for SCR NOx Reduction on a 350 MMBTU/hr Gas-Fired Boiler 80% NOx reduction from 0.15 lb/MMBTU and Capital Cost of $5,500/MMBTU/hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$8,519	$6,064	$4,764
Annual	$3,626	$2,603	$2,062

Table III-9b: Cost Effectiveness for SCR NOx Reduction on a 100 MMBTU/hr Gas-Fired Boiler 80% NOx reduction from 0.15 lb/MMBTU and Capital Cost of $7,500/MMBTU/hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$14,479	$10,190	$7,919
Annual	$6,110	$4,322	$3,376

Reburning

Reburning is another technology available for industrial boilers, but most experience has been on utility boiler applications. Conventional Gas reburning is in use at industrial boilers operated by Kodak in Rochester, New York.[1] A version of gas reburning called Methane DeNOx is being commercially used at Cogentrix in Richmond, Virginia. [10]

Another type of gas-reburning, Fuel Lean Gas Reburn (FLGR^{SM}), has been employed on several utility units, but is also applicable to industrial units. For utility units, Conventional Gas Reburn costs about $15/KW (or about $1,500/MMBTU/hr) to deploy and FLGR deployment costs about $7-8/KW (or about $800/MMBTU/hr). For industrial applications, a cost of about $2,000/MMBTU/hr for Conventional Gas Reburn and $1,000/MMBTU/hr for FLGR was assumed. For Amine Enhanced FLGR (AEFLGR^{SM}), which has been deployed on several electric utility units, a cost of $2,500/MMBTU/hr was assumed for this report.

In cost analysis for the three cases of conventional gas reburning, FLGR, and AEFLGR, a 350 MMBTU/hr boiler that fires coal as a primary fuel is assumed to have a baseline NOx level of 0.45 lb/MMBTU with natural gas costs of $0.75/MMBTU higher than coal ("fuel differential") (see Tables III-10a, III-11a and III-12a). Tables III-10b, III-11b and III-12b show results of similar calculations, but at a higher fuel differential of $1.00/MMBTU.

These gas-based technologies provide NOx reduction below $2,000/ton under most conditions when the fuel differential is $0.75/MMBTU. However, these technologies are sensitive to the incremental fuel cost of gas over coal. When the fuel cost differential increases to $1.00/MMBTU, the cost of using conventional gas reburn increases by about $400/ton of NOx reduced. The same fuel differential increases the cost of reducing NOx with FLGR and AEFLGR by about $200/ton and $100/ton, respectively.

Various forms of gas reburning could be used on facilities firing other fuels. For oil-fired facilities, particularly those firing residual oil, similar results might be possible if the furnace could technically accommodate the reburning system. Natural gas facilities could also utilize this technology, but in most cases it is expected that gas-fired facilities will utilize Low-NOx Burner technology rather than reburning because it is likely to be a simpler retrofit and because many gas-fired furnaces may be too small to permit the use of reburning.

Table III-10a: Cost Effectiveness of NOx Reduction by Conventional Gas Reburn, Assuming 55% NOx Reduction from 0.45 lb/MMBTU, 20% Gas Injection, and $0.75/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$2,665	$2,215	$1,975
Annual	$1,810	$1,625	$1,520

Table III-10b: Same as 3.10a, Except $1.00/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$3,097	$2,613	$2,373
Annual	$2,208	$2,019	$1,920

Table III-11a: Cost Effectiveness of NOx Reduction by FLGR, Assuming 35% NOx Reduction from 0.45 lb/MMBTU, 6% Gas Injection, and $0.75/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$2,000	$1,565	$1,330
Annual	$1,170	$985	$890

Table III-11b: Same as 3.11a, Except $1.00/MMBTU Incremental Fuel Cost for Gas.

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$2,220	$1,756	$1,523
Annual	$1,362	$1,179	$1,083

Table III-12a: Cost Effectiveness of NOx Reduction by AEFLGR, Assuming 60% NOx Reduction from 0.45 lb/MMBTU, 6% Gas Injection, NSR=1.2 and $0.75/MMBTU Incremental Fuel Cost for Gas.			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$2,455	$1,965	$1,700
Annual	$1,520	$1,315	$1,210

Table III-12b: Same as III-12a, Except $1.00/MMBTU Incremental Fuel Cost for Gas.			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$2,604	$2,073	$1,812
Annual	$1,631	$1,425	$1,316
NSR is a measure of the urea or ammonia injection rate.			

Coal Reburning is a technology used at Kodak Park (Case Study BLR-8 in Chapter IV). Natural gas was not readily available to Boiler #15 for use as a reburn fuel and a substantial portion of the coal reburning project cost was borne by cofunders who wished to demonstrate the technology. Reference 1 found this to be a costly method for NOx reduction that may be applicable only in specific situations. In most cases it is expected that coal reburning will be too costly to employ in most industrial boilers from a capital cost perspective. Technical challenges will also limit its applicability, and other techniques may be preferred economically and technically. However, there may be special situations where it may be applicable to industrial boilers.

D. Gas Turbines

NOx control methods for gas turbines include methods that reduce NOx that is generated in the combustion process itself (primary controls) and methods that reduce NOx after it is generated in the combustion process in the exhaust gas (secondary controls). In general, primary control methods are less costly and provide a lesser level of control, and secondary methods are more costly but do provide a much higher level of NOx control.

D.1 Cost Effectiveness of Primary Methods of Controlling NOx from Gas Turbines

Primary methods of NOx control minimize the amount of NOx generated in the turbine combustor. The two most widely used methods include Dry Low NOx technology and Diluent Injection technology.

Dry Low NOx (DLN)

Dry Low NOx has been employed on numerous gas turbines in the U.S. Several case studies that use DLN are included in this report. Capital cost was the primary cost associated with implementing Dry Low NOx on the Solar and General Electric (GE) turbines that were evaluated.

Allison offers a DLN retrofit that is fairly low in capital cost, though this retrofit is designed for base-loaded operation under a fairly limited load range.[11] In order to explore a broader range of turbine applications and provide conservative results, Solar turbine retrofits designed for wider load ranges are evaluated in this report.

The cost of NOx reduction by DLN is very sensitive to the capacity factor of the turbine. Analysis of the case study data showed that there could be substantial variation in capital cost measured in terms of dollars/horsepower ($/hp). This is due to different turbine types, variations in turbine designs over the years, and different scopes of supply that often result from turbine differences or simply from additional work the user found convenient at the time of retrofit. For some applications, this additional work can include the addition of sophisticated control retrofits necessary to utilize the DLN technology or equipment overhauls performed at the time of retrofit. In this latter case, when it was known that work was performed that was not essential for the DLN retrofit, its cost was not included for cost analyses in this chapter.

For the analysis in this report, $750,000 was assumed as the total capital cost to retrofit one Solar Centaur turbine (4,700 hp at $160/hp) and $1,950,000 to retrofit one Solar Mars turbine (13,000 hp at $150/hp). These values are similar to the reported cost in the case studies. Also, note that these were the total project costs the owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation. Fixed O&M costs were shown to be about $15,000 per year for each facility, which usually involved more than one turbine. No variable O&M charges were attributed to the DLN retrofit in this analysis. In the case studies, owners reported no adverse change in turbine heat rate. In fact, heat rate was improved when converting a turbine from water or steam injection to DLN.

The economic analysis in this report differs from that shown in the Case Studies GT-1, GT-2, GT-3 and GT-7 that involve Solar Centaurs and Solar Mars turbines (Chapter IV) in several ways. First, the analysis performed in this report averages the estimates from a discounted cash flow approach and a first-year estimate, versus just a first-year estimate for the case studies. The discounted cash flow method of this report uses a fifteen-year project life at a 12% discount rate, and the first- year analysis in this report uses a fifteen-year life and discount rate of 10% (Capital Recovery Factor or CRF = 13.1%). The case study analyses are based on a ten-year life with an 8% discount rate (CRF = 14.9%). These assumptions can have a significant effect on the results. Second, in this study, indirect costs such as property taxes are explicitly stated while the case study analysis makes assumptions regarding other indirect costs (administration, etc.) and applies an annual charge equal to a certain percentage of the capital cost. Results of past studies suggest that using this percentage of total capital invested tends to overestimate the indirect costs, especially on very capital-intensive air pollution technology retrofit projects discussed in this report.[1] Finally, since the installations usually involve multiple turbines rather than a single turbine, the analysis in this report assumes multiple turbine installations. On the other hand, the analyses in the case studies are prepared for single turbine installations. Hence, all of these differences in the analysis approach contribute to differences in results.

Tables III-13 and III-14 show analysis for Solar Centaur and Mars turbines, respectively. These turbines are widely used in industry, as are the Solar Taurus and turbines from Allison and Dresser Rand. As Tables III-13 and III-14 show, retrofit of conventional combustion technology with DLN can cost less than $2,000/ton. DLN retrofits on turbines operated at a high capacity factor

(95%) can reduce NOx emissions in the range of 70% on an annual basis at a cost of about $1,300/ton for a Mars turbine and by about 63% for about $1,900/ton for a Centaur turbine. At lower capacity factors or for seasonal control, the costs are higher. For example this analysis shows that the owner of a Solar Centaur with only 45% capacity factor may find the cost of reducing ozone-season NOx to be over $9,000/ton with DLN. In this case, other approaches such as water injection may be more attractive.

Table III-13. Cost Effectiveness ($/ton) for Two Solar Centaur (7000 hp each) Retrofit with DLN for Reducing NOx from 135 to 50 ppm (63% reduction)

Time Period of Control and NOx Reduction	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal 135 to 50 ppm	$9,483	$6,565	$5,020	$4,492
Annual 135 to 50 ppm	$3,951	$2,736	$2,092	$1,872

If the actual baseline NOx level were lower, as in Case Study GT-7, the cost of control will be higher. New Centaur Turbines equipped with SoloNOx™ technology are guaranteed at 25 ppm.[12]

A 75 MW turbine is evaluated next to represent larger turbines. Case Study GT-4 addresses a Dry Low NOx retrofit of 75 MW GE Frame 7 turbines originally equipped with water injection for NOx reduction. The cost effectiveness of retrofitting turbines with traditional combustion technology and no prior controls is also evaluated. While the case study GT-4 was a retrofit of a turbine that was originally equipped with water injection, for this study it is assumed that the retrofit would have cost about the same if the turbine had conventional combustion technology. This is probably a reasonable assumption for the purposes of this report. It is important to note that in the case study GT-4, the owner reported a significant improvement in the heat rate as a result of the DLN retrofit from water injection. As will be shown below, this improvement in heat rate and reduced water treatment costs help to make a DLN a NOx control retrofit option that can pay for itself.

Table III-14. Cost Effectiveness ($/ton) for Retrofit of Two Solar Mars (2x13,000 hp) Reducing NOx from 167 to 50 ppm (70% reduction)

Time Period of Control and NOx Reduction	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal 167 to 50 ppm	$6,640	$4,597	$3,515	$3,145
Annual 167 to 50 ppm	$2,767	$1,915	$1,465	$1,311

If the actual baseline NOx level were lower, as in Case Study GT-8, cost of control will be higher. New Mars turbines equipped with SoloNOx™ technology are guaranteed at 25 ppm.[12]

Case Study GT-4 showed a capital cost of the retrofit equal to \$49/KW, or about \$36/hp. It is reasonable that for this larger turbine the cost of the retrofit would be less, when measured on a \$/KW or \$/hp basis, than for a smaller turbines, such as Solar Centaur and Solar Mars described earlier. The cost of \$36/hp for the larger 75 MW turbine is about one fourth to one fifth of the amount (in \$/hp) that was used for the cost of DLN retrofits of industrial turbines in the range of 3-10 MW.

As shown in Table III-15, a DLN retrofit of a 75 MW GE Frame 7 equipped with original combustion technology will achieve 90% NOx reduction at a cost effectiveness well below \$1000/ton under almost all of the conditions evaluated.

Table III-15. Cost Effectiveness for 75 MW GE Turbine Retrofit with DLN from Conventional Combustion, Reduction from 154 ppm to 15 ppm (90% reduction)

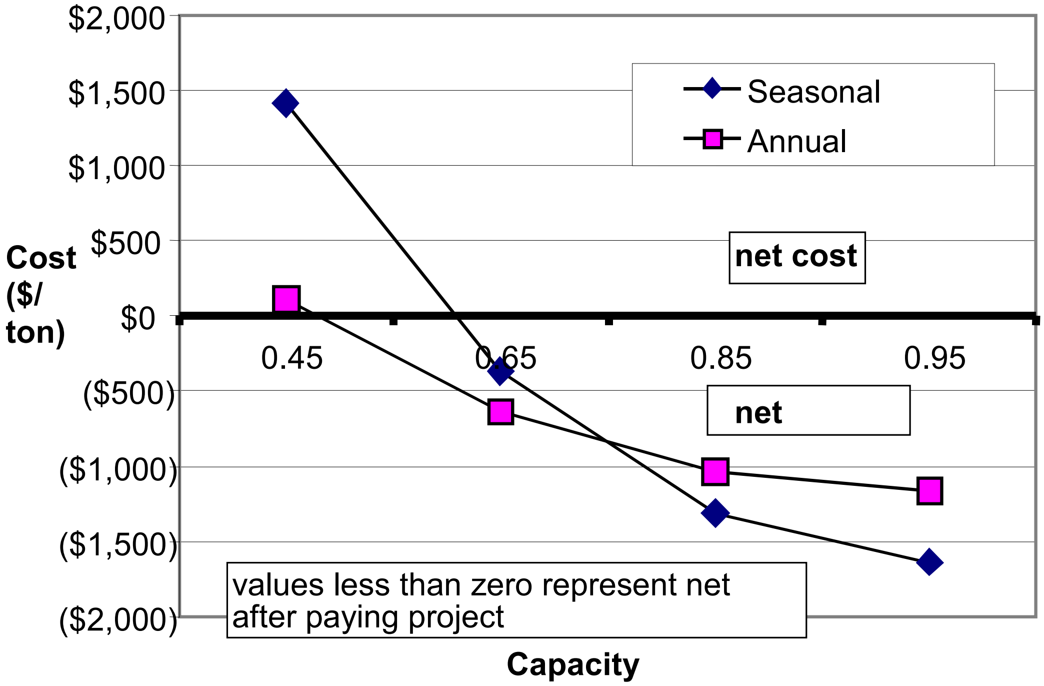
Time Period of Control	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal	\$1,126	\$779	\$596	\$533
Annual	\$469	\$325	\$248	\$222

Table III-16 shows the estimated cost of reducing NOx with a DLN retrofit on a turbine that is originally equipped with water injection. These results are very interesting. For most conditions, reduction of NOx by a DLN retrofit on a turbine originally equipped with water injection will actually pay for itself due to reduced fuel costs and reduced annual costs associated with the operation of the water injection equipment. Of course, this analysis is sensitive to the actual level of efficiency improvement. In case study GT-4, the owner reported a significant improvement in heat rate as a result of the DLN retrofit from water injection, and this efficiency improvement was used in the present analysis. Because the cost savings from reduction in purified water use were not provided in the case study, estimated savings from reduction in purified water consumption were estimated from Table 6-5 of Reference 6 adjusting the water treatment costs to 1999 dollars assuming 2.6% inflation. The results of Table III-16 are plotted in Figure III-1, which show that any project with annual controls and a capacity factor greater than 45% pays for itself.

Table III-16. Cost Effectiveness for 75 MW Turbine Retrofit with DLN from Water Injection, Reduction from 42 ppm to 15 ppm

Time Period of Control	Capacity Factor			
	0.45	0.65	0.85	0.95
Seasonal	\$1,414	(\$369)	(\$1,313)	(\$1,636)
Annual	\$107	(\$636)	(\$1,029)	(\$1,164)

Figure III-1: Cost Effectiveness ($/ton of NOx reduced) of Reducing NOx from a 75 MW Turbine by DLN Retrofit of Turbine Originally Equipped with Water Injection



The cost estimates for seasonal control shown in Table III-16 and Figure III-1 are based on the assumption that the DLN conversion is added to achieve seasonal controlled levels that are lower than what can be achieved by water injection alone. It is also assumed that the baseline condition is the use of water injection on a year-round basis. To compare a DLN retrofit to water injection only during the ozone season, it would be appropriate to compare the results in Table III-16 to the results shown in the section below.

Diluent Injection

DLN retrofit described above offers lower NOx emissions than diluent injection while firing natural gas, and offers several cost and operating advantages, generally making diluent injection a less preferred approach on turbines with higher capacity factors. However, as will be seen, for very low capacity factors that may occur for peaking turbines, diluent injection may be more desirable than DLN. This is because diluent injection has a lower capital cost and because the higher operating cost of diluent injection has little effect on the overall economics due to the very limited operating hours (of the order of 200 to 400 hours a year). Another case where diluent injection may be the only option is any situation where a manufacturer does not offer DLN (for example when turbines fire fuel oil).

The costs for diluent injection include significant operating costs but low capital costs. Operating costs include the costs of purified water or steam, as well as increased fuel costs due to the reduced efficiency that results from water injection. Water and steam injection both have an impact on heat rate (about 2-4% for water injection and about 1% for steam injection). This economic impact is partly offset by an increase in available power output of roughly 3-5% (Ref 6, Table 5.10), but this additional power frequently is not useful due to the limitations of the generator or compressor that is being driven by the turbine. For this reason, the cost analysis of diluent injection did not include a factor for the increase in turbine power. There may be situations, however, where this additional power may be useful and should be included in the analysis.

PSE&G of New Jersey is planning to retrofit 24 peaking turbines at their Edison, NJ facility with high-pressure water injection.[13] Each turbine is about 21 MW in size and will reduce NOx from about 125 ppm to about 50 ppm while firing gas and from about 180 ppm to about 50 ppm when firing oil. The total capital cost is $9 million. Water usage is about 10 gallons per turbine per minute and costs about $0.025/gallon. These turbines only operate a few hundred hours per year (around 200 hours) for summer peak duty and spinning reserve.[13]

Using the cost estimates from PSE&G, an estimate of cost of control for various scenarios can be performed. These estimates are consistent with the general assumptions used in this report and do not reflect PSE&G's analysis, which was not provided for this report. Table III-17 shows estimates of cost effectiveness for diluent injection on turbines with regular use, as well as for peaking duty situations of 200 hours and 400 hours. As shown in Table III-17a, the cost of NOx reduction for peaking duties is about $3,500 to nearly $7,000/ton of NOx removed when firing gas, and the incremental cost of electricity generation ranges from $6.00/MWhr to over $11.00/MWhr. Table III-17b shows the results of similar analysis when firing distillate oil. The incremental cost of generation is high enough that, for many situations, an increase of this size to generation cost may render the unit uneconomical for operation. But because these peaking turbines are operated only when the value of electricity is very high (on hot, summer days), the turbines continue to be economical to operate under these conditions. Recalling that the analysis does not give credit for additional power and assumes that the efficiency penalty will be 4%, actual operating experience may show that the retrofit economics are more favorable than is shown. It should be noted that the analyses of Table III-17a and b are also sensitive to fuel price.

Table III-17a: Estimated Cost Effectiveness for Diluent Injection on Twenty-Four 21-MW Peaking Turbines. Reduction from 125 ppm to 50 ppm (gas firing)

Time Period of Control	Peaking Duty Hours		Capacity Factor		
	200	400	0.45	0.65	0.85
Seasonal ($/ton)	$6,828	$3,684	$1,217	$989	$867
Seasonal ($/MWhr)	$11.38	$6.14	$0.85	$0.69	$0.60
Annual ($/ton)			$784	$688	$638
Annual ($/MWhr)			$1.31	$1.15	$1.06

Table III-17b: Estimated Cost Effectiveness for Diluent Injection on Twenty-Four 21-MW Peaking Turbines. Reduction from 180 ppm to 50 ppm (distillate oil firing)					
Time Period of Control	Peaking Duty Hours		Capacity Factor		
	200	400	0.45	0.65	0.85
Seasonal ($/ton)	$4,212	$2,450	$1,031	$899	$829
Seasonal ($/MWhr)	$12.17	$7.08	$1.24	$1.08	$1.00
Annual ($/ton)			$781	$726	$697
Annual ($/MWhr)			$2.26	$2.10	$2.01

In the analysis for the case where the turbine operates year-round at an average capacity factor, it was assumed that the water injection occurs only when there is a need for control, i.e., only during the summer for seasonal control and year-round for annual controls. It is important to note that, while the cost per ton to reduce NOx is higher with seasonal controls, the impact on the generation cost is reduced. This is because much of the cost of using this technology is associated with increased heat rate and water usage during water injection.

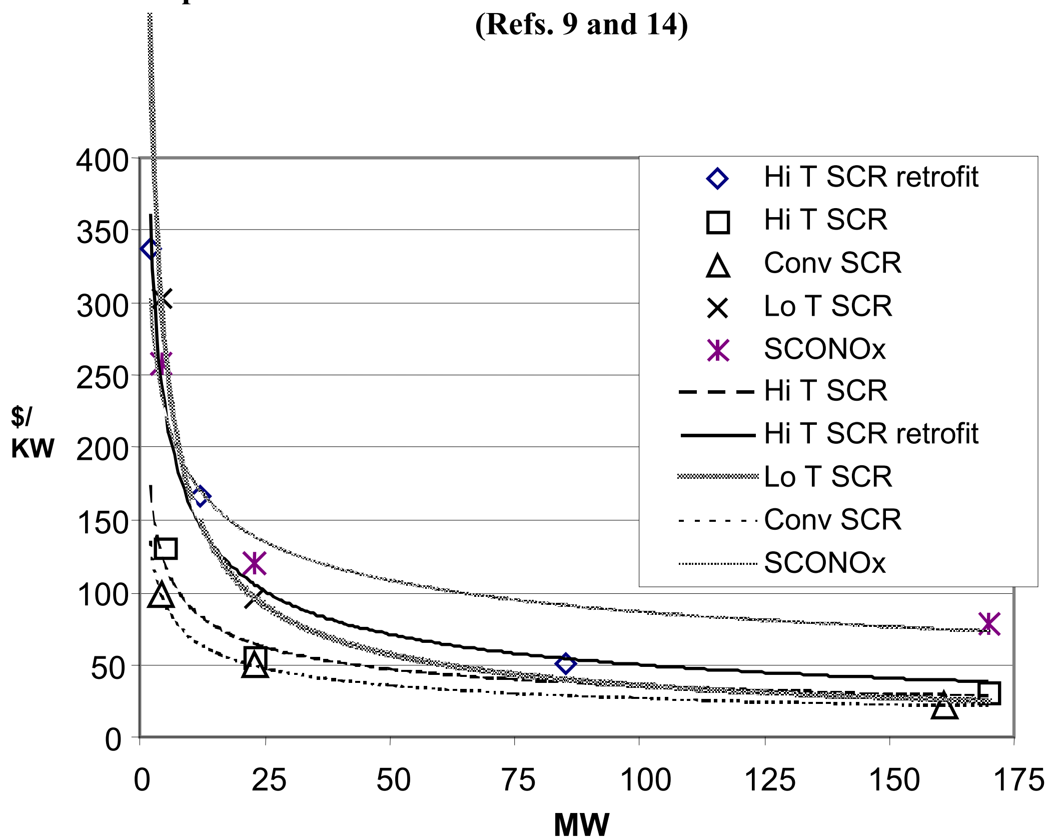
Finally, comparing the results in Table III-17a to those in III-17b, it is observed that, while the cost per ton of NOx removed is higher with gas, the impact on generation cost is lower. This is because the baseline NOx when firing gas is lower than when firing oil; however, the cost of distillate oil is higher than gas, increasing the cost of the heat rate when firing oil.

D.2 Cost Effectiveness of Secondary Methods of Controlling NOx from Gas Turbines

Secondary control methods for exhaust treatment are generally used when primary control methods cannot provide sufficiently low NOx levels to meet regulatory emission limitations. Although secondary methods are more expensive to install and operate, they do provide substantially higher level of NOx reductions compared to primary methods.

Figure III-2 shows the capital cost ($/KW) of various post-combustor technologies. The curves were generated by fitting a power equation of the form $y=ax^{-b}$, where *a* and *b* are constants that are determined in the regression analysis. Reference 15 provided the retrofit cost of a high-temperature SCR system, while Reference 11 provided the incremental cost of the various technologies for a new turbine installation. Additionally, although the cost effectiveness of SCONOx^{TM} is not addressed in detail in this chapter, it is included in the figure because the data was included in Reference 11. Clearly, for all of these technologies there is a very strong scaling effect, especially for turbines well below the 50 MW size.

Figure III-2: Capital Cost of Gas Turbine Exhaust Treatment NOx Reduction Technologies (Refs. 9 and 14)



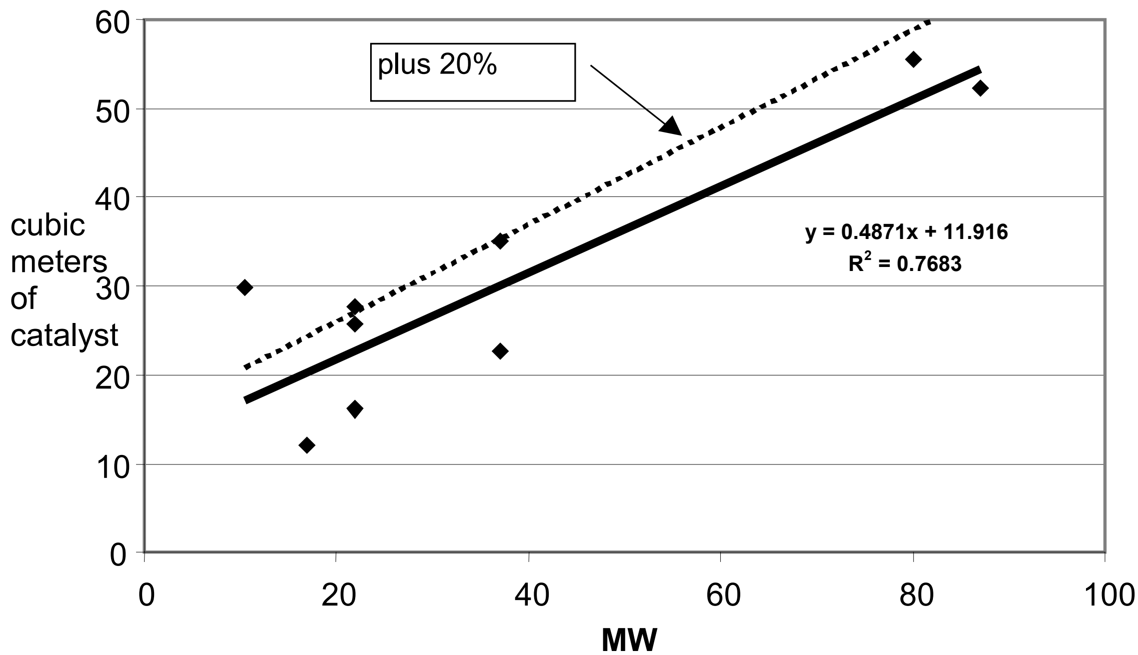
Retrofit of Simple Cycle Turbines with High-Temperature SCR

Retrofit of a simple cycle turbine or placement of an SCR between the turbine and the Heat Recovery Steam Generator (HRSG) on a combined cycle system requires the use of a high-temperature SCR catalyst, which is somewhat more expensive than normal systems (Figure III-2). One supplier mentioned that they typically offer fully-installed SCRs for simple-cycle systems, including the catalyst, reactor, ammonia storage, injection and controls, commissioning, etc., at a price of about $50/KW to $70/KW.[14] This is consistent with a rough cost estimate from another supplier that indicated a price for an 80 MW GE Frame 7 of about $4.1 million ($2.5 million in equipment and $1.6 million in installation for a capital cost of $51/KW), not including balance-of-plant items. Systems with more complex duct modifications will typically cost at the high end of this range. For smaller, industrial turbines, such as in Solar's 2-12 MW product line, the same supplier indicated a cost of about $200,000 to $1.2 million, with installation ranging from $275,000-$800,000. For these smaller, simple-cycle turbines, the cost of high-temperature SCR is in the range of $167/KW to $337/KW.[15] Clearly, there are significant economies of scale for this technology that make the cost in $/KW much lower for larger turbines.

The size of the needed catalyst needs to be estimated to do the cost analysis of the SCR system. Catalysts need to be replaced periodically, and although the catalyst replacement cost is not a large component of the overall expense, it is not insignificant. Therefore, it is necessary to have a good estimate of the catalyst size and its cost. Figure III-3 shows catalyst size plotted as a function of turbine size (in megawatts) for turbine SCR systems addressed in Reference [16]. This plot includes three different types of catalyst types (metal plate, ceramic honeycomb and metal honeycomb), as well as different turbine suppliers, and some different conditions (with or without water injection, and some dual-fuel while others firing only gas), providing enough data for a good linear correlation.

The data in Figure III-3 has some limitations. First, Reference 16 is nearly ten years old and catalyst technology has improved, reducing the necessary catalyst volume. Second, the SCR applications considered in this report are capable of greater NOx reductions, require lower level of ammonia slip guarantees, and include high- and low-temperature catalysts. These factors combine to require slightly more catalyst volume. These factors indicate that an increase of the original regression line by 20% is reasonable. While this adjustment is, at best, approximate, it should be adequate for the purposes of these estimates. As a comparison for this new relationship between catalyst size and plant size, Reference 11 uses an approximation of 30 ft^3/MW for conventional, low-temperature and high-temperature catalysts, which would result in a slightly higher estimate of catalyst volume at the larger size ranges and a slightly lower estimate at the low ranges than using Figure III-3. In this report, Figure III-3 will be used to estimate catalyst volume for all SCR types.

Figure III-3: Cubic Meters of SCR Catalyst for Turbine with HRSG (Ref. 16)



High-temperature SCR is economically attractive for simple cycle turbines because it is well suited for the high-temperature exhaust of a simple-cycle turbine. In many cases, a turbine equipped with an HRSG would not be retrofitted with a high-temperature SCR because of lack of enough space between the turbine and the HRSG. Additionally, most HRSGs built in the last decade are designed to accommodate a conventional SCR catalyst, regardless of whether or not an SCR is initially provided as part of the HRSG. For this reason, combined-cycle turbines are most often retrofitted with a conventional SCR. Therefore this analysis performs all estimates for high-temperature SCR on simple cycle retrofits.

Using the data for the catalyst size in Figure III-3, an assumption of $14,000/$m^3$ of catalyst, and a six-year life (assuming that natural gas is fired nearly all the time), the cost effectiveness of high-temperature SCR on simple cycle turbines was developed (Tables III-18 a through e). The analysis is assumed to apply to either a high-temperature catalyst or to a conventional SCR catalyst with some air-cooling.

Table III-18a: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 154 ppm and Controlled to 15 ppm (90% Control)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$1,853	$1,410	$1,176
Annual	$849	$664	$566

Table III-18b: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 42 ppm and Controlled to 7 ppm (83% Control)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$6,969	$5,210	$4,278
Annual	$2,980	$2,247	$1,859

Table III-18c: Cost Effectiveness for SCR Retrofit on Simple Cycle 75 MW Gas Turbine with Baseline NOx of 15 ppm and Controlled to 3 ppm (80% Control)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$20,075	$14,943	$12,227
Annual	$8,441	$6,303	$5,171

Table III-18d: Cost Effectiveness for SCR retrofit on Simple Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 142 ppm and Controlled to 15 ppm (89% Control)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$7,965	$5,872	$4,763
Annual	$3,395	$2,523	$2,061

Table III-18e: Cost Effectiveness for SCR retrofit on Simple Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 42 ppm and Controlled to 5 ppm (88% Control)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$27,020	$19,835	$16,031
Annual	$11,335	$8,341	$6,756

Retrofit of Combined-Cycle Turbines with Low-Temperature SCR or Conventional SCR

Combined-cycle turbines equipped with an HRSG generally cannot be retrofitted with a high-temperature SCR because there usually is not enough room between the turbine and the HRSG for the catalyst. Moreover, most HRSGs built in the last decade are designed to accommodate a conventional SCR catalyst, regardless of whether or not an SCR was initially provided as part of the HRSG. For these reasons, combined-cycle gas turbines are rarely retrofitted with high-temperature SCR.

If the HRSG design is such that it will readily accommodate a conventional SCR but could possibly accommodate a low-temperature SCR, the user will usually choose a conventional SCR because of its lower cost. However, if the HRSG does not have enough space to accommodate a conventional SCR, or there is inadequate distance for good mixing of the ammonia with the exhaust gas between the ammonia injection grid and the conventional catalyst, a-low temperature SCR system may be the better choice. Turbines that have duct burners and are required to attain high reductions by SCR are more likely to have inadequate mixing distance between the location for the ammonia injection grid and the HRSG catalyst space. In these cases, low-temperature SCR may be an appropriate technology choice.

From Figure III-2, the capital cost of a high-temperature SCR retrofit on a simple cycle turbine is about the same as the incremental cost of low-temperature SCR on a gas turbine with an HRSG. The cost of retrofitting a combined-cycle turbine with a low-temperature SCR will then be roughly the same as the cost of retrofitting the same model turbine in a simple-cycle arrangement with high-temperature SCR. The cost effectiveness values would be expected to be similar as well. Because a principal benefit of low-temperature SCR is the low cost to retrofit, it is assumed that the retrofit cost is roughly equal to the capital cost shown in Figure III-2 for the turbine sizes of interest.

Tables III-19a through III-19e indicate the cost effectiveness of applying conventional SCR on a combined-cycle gas turbine that can readily accommodate the system. As noted earlier in this section, it is expected that the cost-effectiveness of low-temperature SCR on a combined-cycle gas turbine will be very similar to that of high-temperature SCR on similarly sized simple-cycle gas turbines.

Table III-19a: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NOx of 154 ppm and Controlled to 15 ppm

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$1,275	$1,010	$869
Annual	$608	$497	$439

Table III-19b: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NOx of 42 ppm and Controlled to 7 ppm

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$4,673	$3,620	$3,062
Annual	$2,024	$1,585	$1,353

Table III-19c: Cost Effectiveness for Conventional SCR on Combined Cycle 75 MW Gas Turbine with Baseline NOx of 15 ppm and Controlled to 3 ppm

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$13,376	$10,306	$8,680
Annual	$5,650	$4,371	$3,693

Table III-19d: Cost Effectiveness for Conventional SCR on Combined Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 142 ppm and Controlled to 15 ppm

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$4,659	$3,583	$3,013
Annual	$2,018	$1,569	$1,332

Table III-19e: Cost Effectiveness for Conventional SCR on Combined Cycle 7000 hp (~5 MW) Gas Turbine with Baseline NOx of 42 ppm and Controlled to 5 ppm

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$15,672	$11,978	$10,023
Annual	$6,607	$5,068	$4,253

E. Internal Combustion (IC) Engines

E.1 Cost Effectiveness of Primary Methods of Controlling NOx from IC Engines

Primary Control methods reduce NOx that is formed in the engine. These methods are most often performed first, since they provide moderate reductions at moderate costs. The cost and performance of these methods are frequently very specific to the particular engine, particularly for more involved primary methods such as Low-Emission Combustion (LEC). For some engines, such retrofits may not be available. Of course, as in the other analyses in this chapter, it is assumed that each method is technically feasible for the situation being evaluated.

Ignition Timing Retard

The data below is for Tennessee Gas Pipeline in Mercer, PA, which operates six 1100 hp engines using ignition timing retard (Case Study IC-6). Reported costs for this project are shown in Table III-20.

Table III-20: Experience and Costs of Ignition Timing Retard (Case Study IC-6)

Months of Operation (as of Oct '99)	54
Increased Fuel Consumption Cost	\$5,000/year per engine
Project Cost	\$4,000 per engine
Estimated Additional Maintenance	\$1,000/year per engine
Additional Cost of Testing	\$600/yr per engine
Baseline NOx Emissions	10 gm/hp-hr
Controlled NOx Emissions	9 gm/hp-hr
Number of Forced Outages	0
Total Lost Operating Hours	0

The approximate cost of NOx reduction is outlined in Table III-21. It is interesting to note that the cost effectiveness for the 10% NOx reduction does not change very much as capacity factor changes. This is because the largest cost item is increased fuel consumption. Although ignition timing retard will produce NOx reductions year round, the NOx reductions that occur outside of the ozone season are not counted in the seasonal control scenario.

Table III-21: Estimated Cost Effectiveness (\$/ton of NOx removed) for Ignition Timing Retard on six 1,100 HP Engines from 10 gm/hp-hr to 9 gm/hp-hr (10% Reduction)

Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	\$1640	\$1530	\$1,476
Annual	\$685	\$640	\$615

Ignition timing retard tends to be less effective at reducing NOx on spark-ignited engines than injection timing retard on compression-ignition engine (see below). However, both methods provide only small to moderate NOx reductions, making these methods of control of much less interest than other methods.

Injection Timing Retard

Injection timing retard is a very cost effective way to achieve small to moderate NOx reductions of 15% to about 30% on diesel engines. No case study data was available for the costs of injection timing retard, however, information from Reference 16 shows that costs for ignition and injection timing retards are similar and so it will be assumed that the capital cost is about the same as shown in Table III-20. Estimates of cost effectiveness with a 25% NOx reduction are shown in Table III-22.

Table III-22: Estimated Cost Effectiveness ($/ton of NOx removed) for Injection Timing Retard on six 1,100 HP Engines from 10 gm/hp-hr to 7.5 gm/hp-hr (25% Reduction)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$657	$612	$589
Annual	$274	$255	$245

Air/Fuel Ratio Changes and High-Energy Ignition

This method has been used to reduce NOx on several large, two-stroke, reciprocating engines of 2000 hp to 2700 hp with integral gas compressors (Case Studies IC-2, IC-3, IC-4). NOx reductions from baseline levels of 12 to 18 gm/hp-hr to controlled levels of about 5 to 8 gm/hp-hr were achieved in the case study examples - typically a little over 50% NOx reduction. On average, these retrofits cost $22/hp (a range of $12/hp to $28/hp, primarily depending upon engine type). Fixed O&M was about $8,000 for each site, with three to six engines per site. The particular type of engine being considered for air/fuel ratio changes will play a significant role in the cost and effectiveness of employing this method of NOx reduction. To develop a "typical" analysis, it was assumed that an installation of four 2,500-hp engines would achieve a reduction from 15 to 7 gm/hp-hr with a capital cost of $22/hp. The results of this analysis are shown in Table III-23.

Table III-23: Estimated Cost Effectiveness ($/ton of NOx removed) for High Energy Ignition/A-F Ratio Adjustment on four 2,500 HP engines from 15 to 7 gm/hp-hr (53% Reduction)			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$385	$315	$280
Annual	$160	$130	$115

Low-Emission Combustion (LEC)

A low-emission combustion retrofit is being employed on two 3400 hp engines at Tennessee Natural Gas' facility near Syracuse, NY (Case Study IC-7). The capital cost of retrofitting these engines was about $340/hp, close to the value estimated from Reference [17]. The cost effectiveness for this project is shown in Table III-24.

For smaller, medium-speed engines, a lower capital cost would be expected, on the order of $200/hp.[17] According to the California Air Resources Board BACT document on IC Engine controls (Ref. [18], Table D-1), Low-Emission Combustion offered up to a 90% reduction of NOx on natural gas engines and about 60-70% control for landfill gas engines. This difference is probably due to the lower initial NOx from the lower heating-value landfill gas. The cost estimates for a reduction scenario assuming 80% reduction from 15 gm/hp-hr to 3 gm/hp-hr for a natural gas engine, an installation cost of $200/hp, and efficiency penalty of 0.5% for four 2500 hp engines, are shown in Table III-25.

Table III-24: Cost Effectiveness for two 3,400 HP IC Gas Engines (low speed) Equipped with Low-Emission Combustion Technology - 77% NOx reduction from 13 gm/hp-hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$2,296	$1,594	$1,222
Annual	$957	$664	$509

Table III-25: Cost Effectiveness for Four 2,500 HP IC Gas Engines (medium speed) Equipped with Low-Emission Combustion technology - 80% NOx Reduction from 15 gm/hp-hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$1,100	$765	$585
Annual	$460	$320	$245

Dual-fuel engines have much greater capital costs than engines firing a single fuel, which can be approximated by

Capital Cost = $405,000 + ($450 x hp)

for engines larger than 1,000 hp.[17] For a 2,500-hp engine, the capital costs are projected to be about $615/hp. Although NOx reductions occur year round, the seasonal control scenario only takes credit for those NOx reductions made during the ozone season. In this case, the total costs are the same regardless of the need for annual or seasonal control, resulting in the cost effectiveness numbers much greater for seasonal controls, even though the total cost and actual total NOx reduction are the same.

As shown in Table III-26, NOx reductions through Low-Emission Combustion on a dual-fuel engines with high capacity factors can generally be achieved for under $1,000/ton for annual controls, and seasonal reductions can be achieved in the range of $2,000/ton.

Table III-26: Cost Effectiveness for Four 2,500 HP IC Dual-Fuel Engines Equipped with Low-Emission Combustion Technology - 80% NOx Reduction from 15 gm/hp-hr			
Time Period of Control	Capacity Factor		
	0.45	0.65	0.85
Seasonal	$3,388	$2,346	$1,794
Annual	$1,412	$977	$747

E.2 Cost Effectiveness of Secondary Methods of Controlling NOx from IC Engines

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction is used for diesel and lean-burn Spark Ignition (SI) engines. Although two case studies were performed on IC engine SCR applications (case studies IC-1 and IC-5) only one provided information on the capital cost of the system (case study IC-5). It was therefore necessary to rely on other references for additional capital cost values. SCR capital costs for lean-burn engines can be approximated by

Total Capital Cost of Lean Burn IC SCR = $310,000 + ($72.7 x hp),

and the total capital cost of SCR for diesel and dual-fuel engines can be estimated by

Total Capital Cost of Diesel IC = $187,000 + ($98 x hp). [17]

These equations include the cost of a continuous emission monitoring system (CEMS), estimated at $85,000.[17] If a CEMS is not necessary, this cost should be deducted from estimates obtained by the equations above.

Case Study IC-5 included information on capital and fixed operating costs, such as service and testing. The capital cost indicated in Case Study IC-5 was about 35% less than what is suggested by the equation above, even after deducting $85,000 for the CEMS. The large difference in cost is most probably due in large part to the fact that the SCR in Case Study IC-5 was a new installation rather than a retrofit, and may also indicate that SCR technology is becoming less costly. For the analysis in this report, the cost from the equation will be used in keeping with the focus on retrofits.

Case Study IC-1 showed a service cost of $78,000 per year for all three engines ($26,000/engine) plus $9,600 per year for testing. In contrast, Case Study IC-5 showed fixed O&M of only about $2,000/year. One reason for the difference is that the facility at Plymouth Cogeneration (Case Study IC-5) has a CEMS, while the SYCOM system (Case Study IC-1) does not. The emissions testing costs in Case Study IC-5 are probably attributed to its CEMS. On the other hand, the value of the service contract for Case Study IC-1, at $78,000 for three engines, may have to do with the type of duty (pumping versus cogeneration), the specific engine, or the SCR system (larger engines may have higher lube oil leakage that might require more frequent catalyst cleaning or an injection system requiring more frequent service). For this analysis, a middle value between the reported values for the two case studies is assumed for fixed O&M:

$9,600 [for testing] + $14,000x(hp/9130) [for other fixed O&M].

As in most situations, the cost effectiveness of an SCR for IC engines depends to a large extent on the initial NOx level and the capacity factor. In fact, it has been argued that, besides the expense, there are technical reasons for not using SCR on engines with low capacity factors or those with highly variable loads, as addressed in Chapter II. Nevertheless, cost effectiveness values are shown for low capacity factor situations, recognizing that technical issues should be considered for any specific application.

The results of the analysis for SCR on IC engines are shown in Tables III-27a - d for gas and diesel engines. For each fuel type, a single large facility of three 3130 hp engines is considered, as well as a smaller installation of one 1800 hp engine. As shown in the tables, cost effectiveness numbers under $1000/ton are possible for annual control under all situations when the capacity factor is above 45%. Only under conditions where the engine capacity factor is 10% are costs greater than $2,000/ton.

Table III-27a: Cost Effectiveness for Three 3130 HP Diesel Engines Equipped with SCR Technology - 90% NOx Reduction from 10 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	$4,246	$1,044	$763	$614
Annual	$1,838	$503	$386	$324

Table III-27b: Cost Effectiveness for Three 3130 HP Gas-Fired Engines Equipped with SCR Technology - 90% NOx Reduction from 10 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	$3,884	$981	$726	$591
Annual	$1,691	$482	$375	$319

Table III-27c: Cost Effectiveness for One 1800 HP Diesel Engine Equipped with SCR Technology - 90% NOx Reduction from 10 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	$6,866	$1,626	$1,166	$922
Annual	$2,929	$746	$554	$453

Table III-27d: Cost Effectiveness for One 1800 HP Gas-Fired Engine Equipped with SCR Technology - 90% NOx Reduction from 10 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	$8,245	$1,950	$1,397	$1,104
Annual	$3,508	$886	$655	$533

Capacity Factor of 0.10 equates to 876 annual operating hours or 365 hours during the ozone season

As described in Section II.C.2 of this report, manufactures have developed simplified urea-SCR systems that are much less expensive to deploy on IC engines. This new technology stems from efforts to apply SCR to mobile source diesel engine applications. The lower capital cost of the simplified urea technology of Figure II-13 offers the potential for significantly reduced costs for controlling NOx from diesel and lean-burn gas IC engines, particularly at low capacity factors and on smaller horsepower engines. Analysis of a new Caterpillar engine (1971 HP diesel with uncontrolled NOx emissions of 7.62 gm/hp-hr) is shown in Table III-28a. These results showed cost effectiveness numbers below $2000/ton for nearly all situations, including seasonal control. For uncontrolled emission levels more typical of existing engines, around 15 gm/hp-hr, the cost effectiveness is under $1,000/ton for nearly all conditions evaluated (Table III-28b). It is important to note that because this SCR system uses a very simplified injection system that is adapted from diesel fuel injector technology, a lower fixed O&M cost of $2,500/year is assumed.

Table III-28a: Cost Effectiveness for One 1971 HP Diesel Engine Equipped with Mobile-Source Derivative SCR NOx Reduction System Technology - 75% NOx Reduction from 7.62 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	$3,080	$1,043	$864	$769
Annual	$1,491	$643	$568	$528

Table III-28b: Cost Effectiveness for One 1971 HP Diesel Engine Equipped with Mobile-Source Derivative SCR NOx Reduction System Technology - 75% NOx Reduction from 15 gm/hp-hr

Time Period of Control	Capacity Factor			
	0.10	0.45	0.65	0.85
Seasonal	$1,751	$716	$625	$577
Annual	$944	$513	$475	$455
Capacity Factor of 0.10 equates to 876 annual operating hours or 365 hours during the ozone season				

F. Cement Kilns

This section evaluates a number of demonstrated and potential technologies for reducing NOx emissions from cement kilns. Unlike the other three source categories evaluated in this chapter, which burn fuel to produce electric power and/or thermal energy, cement kilns burn fuel to produce a non-energy product – clinker. Clinker is ground to very fine particles to make the Portland Cement, which is an ingredient of concrete. Since Portland Cement is sold into large regional markets from multiple kilns (at the same site), there is some rationale to considering NOx levels in terms of pounds of NOx emitted per ton of clinker produced (lb. NOx/ton clinker). From an air pollution control perspective, it is appropriate to have kilns emit the lowest lbs. of NOx/ton clinker rather than kilns that have higher emission rates. From the perspective of a cement kiln owner, increases in the cost of clinker production resulting from implementation of NOx controls (in $/ton clinker) will affect how they approach complying with NOx reduction requirements. In addition to providing cost data for NOx control in terms of dollars per ton of clinker ($/ton clinker), the analyses in this section also include the more traditional measure of cost effectiveness in dollars per ton of NOx removed. This allows convenient comparison of costs of controlling NOx from cement kilns to costs of NOx reductions from other source categories such as gas turbines, and industrial and utility boilers.

F.1 Cost Effectiveness of Primary Methods of Controlling NOx from Cement Kilns

The primary methods available for controlling NOx depend on the type of kiln. A few kiln types are considered. In many cases, combustion controls result in the improvement of thermal efficiency of kiln, which reduces NOx and reduces operating costs. As will be seen, in some cases these combustion upgrades can actually pay for themselves.

Low-NOx Burners with Indirect Firing and Mid-Kiln Firing of Tires

This analysis uses information from Case Study CK-1 (California Portland Cement, Colton, California). A total NOx reduction of 49% was achieved using both a Low-NOx Burner (with indirect firing) and mid-kiln firing with tires. The capital cost of this program was $7 million. The facility's fixed and operating costs also increased as a result of this approach. It is assumed that this approach is used on a year-round basis, even for ozone-season control scenarios. For seasonal control, only the NOx reduced during the ozone season is considered in the cost-effectiveness calculation. This case study reported that facility production was reduced somewhat by the addition of tires. It is not known if this is a typical effect and because of the complexity it would add to the analysis this was not considered here. Where appropriate, however, this effect should be considered. The analysis also does not include lost revenues due to a four-week outage. This is probably small compared to the overall cost of the program.

The cost effectiveness of this approach is obviously dependent upon the uncontrolled baseline NOx level. If the uncontrolled NOx level is higher, the cost per ton of NOx reduced is likely to be lower than what is shown below. Another important factor in the NOx control costs is the reduced fuel costs resulting from the substitution of tires for the primary fuel (coal). The heating value of whole tires can vary from about 11,500 BTU/lb to nearly 17,000 BTU/lb,[19] and steel-belted tires, though they have low heating value, also contribute valuable minerals (especially iron) to the cement. The tipping fee being paid for whole tires, net of delivery charges, varies between locations from $20/ton to about $200/ton.[20] Assuming an average heating value of about 14,000 BTU/lb, tires can provide cement kiln operators with an estimated revenue source of about $0.71/MMBTU to $7.14/MMBTU of tire fuel used. This effect is incorporated into the cost effectiveness calculations shown in Tables III-29 a through c.

Depending upon the tipping fees and operating conditions, the economic benefit of using tires as fuel for mid-kiln firing may be sufficient to provide a net economic benefit after paying for the cost of equipment (including the indirect firing and Low-NOx Burner equipment) plus the cost of any additional operating expenses, though low tipping fees or low capacity factors may not provide net economic benefits. For this reason, the cement industry has implemented Low-NOx Burners with mid-kiln firing of tires at many facilities, solely for its economic benefits. The combined technology of LNBs and mid-kiln firing, however, has the environmental benefit of moderate reductions in NOx emissions.

Table III-29a: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns No Tipping Fee.[x]			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, $/ton NOx	$4,385	$2,673	$1,766
Seasonal, $/ton clinker	$2.42	$1.48	$0.97
Annual, $/ton NOx	$1,827	$1,114	$736
Annual, $/ton clinker	$2.42	$1.48	$0.97

Table III-29b: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns $20/ton Tipping Fee.			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, $/ton NOx	$3,850	$2,137	$1,231
Seasonal, $/ton clinker	$2.13	$1.18	$0.68
Annual, $/ton NOx	$1,604	$891	$513
Annual, $/ton clinker	$2.13	$1.18	$0.68

Table III-29c: Cost Effectiveness of Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton Clinker on Two 96 Ton/hr. Kilns $75/ton Tipping Fee.			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, $/ton NOx	$2,377	$665	($242)
Seasonal, $/ton clinker	$1.31	$0.37	($0.13)
Annual, $/ton NOx	$991	$277	($101)
Annual, $/ton clinker	$1.31	$0.37	($0.13)

The net economic benefit effect of tire tipping fees is more pronounced on kilns that only use mid-kiln firing and do not install capital-requiring Low-NOx Burner retrofits. NOx reductions from these kilns are quite marginal (about 20%), but the elimination of the LNB significantly reduces capital costs. The prices of mid-kiln firing systems vary by kiln. The cost of a mid-kiln firing system for a 25 or 40 tons per hour (tph) long dry or long wet kiln is $1,600,000, including a 20% charge for contingency.[21] Reference [22] generally listed lower costs, from as little as $387,000 for a single preheater kiln (electrical installation and controls programming not included) to $875,000 for

[x] Notes for Tables III-29 to III-30. Values in parentheses indicate a net economic benefit to the user. It is assumed that the technologies do not significantly impact production. This assumption may not be correct in all cases and the impact on production should be considered when appropriate.

a complete system (all of project costs included), and as high as $1,872,500 for mid-kiln firing on three long dry kilns (with all project costs included except controls programming). Reference 7 lists total capital costs in the range of $391,000 to $707,000 for a mid-kiln firing conversion, generally more consistent with the values of Reference 22 than Reference 21. Finally, case study CK-3 (Blue Circle Cement, Atlanta, Georgia) indicates a total capital cost of $1,495,000 for two 950 tons per day (tpd) or 40 tph kilns, with fixed O&M increasing by $64,000/yr and a decrease of variable O&M costs of over $900,000 through reduced fuel costs. For this analysis, economics similar to those of case study CK-3 are assumed.

It is important to note that this analysis assumes that mid-kiln tire injection will run year-round, even under circumstances where only seasonal controls are needed. This makes sense because the technology has economic benefits when in use and a user would not be motivated to turn it off outside of the ozone season. As in the previous analysis, impact on facility production was not considered. The results of the analysis are shown in Tables III-30a through c, showing that there are potentially significant economic benefits of this technology, in addition to the small environmental benefit of lower NOx emissions. Because the economic benefits of the mid-kiln firing technology are substantial, the cement industry has adopted it even in the absence of any explicit regulatory requirements.

CemStar^{SM}

Case Study CK-2 (Texas Industries, Inc., Midlothian, Texas) reported that the capital cost for retrofitting CemStar^{SM} on each of its four 40 ton/hr wet process kilns was $250,000. In addition to this capital cost is an operating cost (a license fee) equal to about $16/ton of steel slag added to the process. At a plant of similar size to the Midlothian plant, a 3.3 tph slag addition would result in roughly an additional $53/hour for the operating cost of each kiln ($211/hr total for four kilns). Since the reduction in fuel cost expected from using CemStar^{SM} is application-specific, it is not included in this cost analysis. Incremental clinker revenues are valued at an approximate level of $15 to $50 per ton of additional clinker produced.[23] Net clinker value equals about $15-$50 per ton after expenses (production cost, sales cost, transportation, etc.). These amounts will vary from one facility to another and with market conditions.

Table III-30a: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 Ton/hr Kilns

no tipping fee.[x]

Time Period of Control and Units of Cost	*Capacity Factor*		
	0.45	0.65	0.85
Seasonal, $/ton NOx	($2,326)	($3,444)	($4,035)
Seasonal, $/ton clinker	($0.48)	($0.72)	($0.84)
Annual, $/ton NOx	($969)	($1,435)	($1,681)
Annual, $/ton clinker	($0.48)	($0.72)	($0.84)

Table III-30b: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 Ton/hr Kilns $20/ton tipping fee.			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, $/ton NOx	($5,164)	($6,281)	($6,873)
Seasonal, $/ton clinker	($1.08)	($1.31)	($1.43)
Annual, $/ton NOx	($2,151)	($2,617)	($2,864)
Annual, $/ton clinker	($1.08)	($1.31)	($1.43)

Table III-30c: Cost Effectiveness of Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton Clinker on Two 40 TPH Kilns $75/ton tipping fee.			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, $/ton NOx	($12,966)	($14,084)	($14,675)
Seasonal, $/ton clinker	($2.70)	($2.93)	($3.06)
Annual, $/ton NOx	($5,403)	($5,868)	($6,115)
Annual, $/ton clinker	($2.70)	($2.93)	($3.06)

Tables III-31 a, b, and c show the results of cost effectiveness calculations for four wet-process kilns equipped with CemStar for three different net clinker values (in dollars per ton). Three control scenarios are considered for each case: 1) annual NOx control and annual operation (steel slag is added year-round to achieve year-round NOx reductions); 2) seasonal NOx control and annual operation (steel slag is added year round, but only ozone season NOx reduction counts); and 3) seasonal NOx control and seasonal operation (steel slag is added only during the ozone season).

The calculations performed to produce the results in Table III-31a assume that the incremental clinker production is worth slightly less than the incremental license fee, evaluating the situation where NOx reduction is the only reason to use the CemStar technology. This is an unusual case since most facilities will benefit from increased production, even after the cost of the license fee ($16/ton) is considered. Even in this case, cost of controlling NOx is well below $1000/ton. Tables III-31 b and c show cases where the value of the incremental production exceeds the value of the license fee, as should be the case when this technology is applied. In these cases ($30/ton and $50/ton of net clinker, respectively), the CemStar technology produces net economic benefits in addition to the NOx reductions provided. Over twenty kilns in the U.S. have used this technology.

Because of the economic benefits of this technology, the seasonal control and annual operation scenario is more realistic than the seasonal control and seasonal operation scenario.

There is a significant cost trend indicated in the tables. The cost of using CemStar to reduce NOx ($/ton) decreases as usage increases, as would be expected. However, the decrease is slight, reflecting the relatively low capital cost and "pay as you go" nature of this technology. The results shown in Tables III-31b and III-31c show a net economic benefit in using the technology.

F.2 Cost Effectiveness of Secondary Methods of Controlling NOx from Cement Kilns

Selective Non-Catalytic Reduction (SNCR)

There are currently no commercial applications of SNCR on cement kilns in the U.S. However, some information from case studies and from estimates from vendors who have supplied commercial systems overseas provide data to estimate the cost of NOx reduction. In Reference [24], the capital cost of employing urea SNCR on a precalciner kiln is estimated to be $0.08/ton of clinker, estimated on a 15-year life with the plant operating at 85% capacity. This equates to nearly $900,000 for a 100 tph kiln. This would scale to $1.35 million for a 150 tph kiln, but since scaling is probably not linear with size, this is probably a conservative estimate. It is approximately consistent with information in Reference 7 and information from a supplier described in Table III-32.[25]

Using the capital cost of about $1.35 million (including all associated project costs such as installation, site preparation, project management, etc.) for a 150 ton/hr kiln and a 45% NOx reduction from 700 lb/hr to 385 lb/hr, cost effectiveness was calculated (see Table III-33).

Costs in Table III-33 are shown in both $/ton of NOx reduced and $/ton of clinker produced. This is because the kiln operators are interested in the cost impact to the product. Moreover, the kiln operators may choose to apply technology to those kilns where the impact to the cost of product is minimum. Alternatively, operators may choose to preferentially operate those kilns where the impact of the cost of NOx control on the product cost is least.

Table III-31a: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NOx/hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = $15/ton

Time Period of Control and Operation	Capacity Factor		
	0.45	0.65	0.85
Seasonal Control and Operation ($/ton NOx)	$1,120	$822	$664
Seasonal Control and Operation ($/ton clinker)	$0.23	$0.17	$0.14
Seasonal Control/Annual Operation ($/ton NOx)	$1,332	$1,034	$877
Seasonal Control/Annual Operation ($/ton clinker)	$0.28	$0.22	$0.18
Annual Control ($/ton NOx)	$555	$431	$365
Annual Control ($/ton clinker)	$0.28	$0.22	$0.18

Table III-31b: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NOx/hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = $30/ton

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal Control and Operation ($/ton NOx)	($1,156)	($1,454)	($1,611)
Seasonal Control and Operation ($/ton clinker)	($0.24)	($0.30)	($0.34)
Seasonal Control/Annual Operation ($/ton NOx)	($4,129)	($4,427)	($4,585)
Seasonal Control/Annual Operation ($/ton clinker)	($0.86)	($0.92)	($0.96)
Annual Control ($/ton NOx)	($1,721)	($1,845)	($1,910)
Annual Control ($/ton clinker)	($0.86)	($0.92)	($0.96)

Table III-31c: Cost Effectiveness of CemStar - 20% Reduction from 200 lb NOx/hr/kiln (800 pph total) on Four 40-Ton/hr Wet Process Kilns, Net Clinker Value = $50/ton			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal Control and Operation ($/ton NOx)	($4,190)	($4,488)	($4,646)
Seasonal Control and Operation ($/ton clinker)	($0.87)	($0.94)	($0.97)
Seasonal Control/Annual Operation ($/ton NOx)	($11,412)	($11,710)	($11,868)
Seasonal Control/Annual Operation ($/ton clinker)	($2.38)	($2.44)	($2.47)
Annual Control ($/ton NOx)	($4,755)	($4,879)	($4,945)
Annual Control ($/ton clinker)	($2.38)	($2.44)	($2.47)

For those cement kiln applications where SNCR is technically feasible, NOx reductions below $1,000/ton of NOx are achievable. Also, as demonstrated by the results in the table, the impact of SNCR on the cost of the product is reduced under a seasonal scenario.

Table III-32: Reported Approximate Capital Cost for Urea SNCR System on a Precalciner Kiln [25]	
Kiln size NOx Baseline NOx Reduction Heat Input Ratio Temp @ Calciner Injection Point	< 150 ton/hr > 500 ppm @ 10% O2 30 - 50% 40:60 to 50:50 850 deg C or higher
Equipment and Engineering Costs, *excluding installation and area preparation, etc.*	$400,000 - $800,000

Table III-33: Cost Effectiveness of SNCR on 150 Ton/hr Precalciner Kiln, 45% NOx Reduction (from 700 lb/hr to 385 lb/hr)			
Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
Seasonal, $/ton NOx	$1,215	$1,000	$890
Seasonal, $/ton clinker	$0.53	$0.44	$0.39
Annual, $/ton NOx	$810	$725	$675
Annual, $/ton clinker	$0.85	$0.76	$0.71

Biosolids Injection (BSI)

Biosolids injection is being used at the Mitsubishi Cement facility in Lucerne Valley, CA. The facility has a clinker capacity of 221 tons per hour without biosolids injection, but the use of the technology will typically reduce capacity slightly, due to the increased volume of gas from the moisture in the biosolids. At this facility, the capacity is reduced to 185 tph, a 16% reduction. The capital cost of the technology has been published at $371,000 for the Lucerne Valley facility, including all site work, equipment, etc. The operating costs for a facility similar to Mitsubishi's cover a wide range, from a cost of nearly $150,000 to a net *revenue stream* of $1,350,000 per year. This is explained by the potential for a tipping fee for receiving the biosolids, which can be worth up to about $1.5 million. Not included in these operating costs are the costs of increased fan power, incremental fuel cost, cost of lost revenue from reduced clinker production or additional license fees that may be required. Despite reduced clinker production, fuel costs increase because of the additional heat necessary to evaporate the moisture in the biosolids. Without including the value of lost clinker revenues, tipping fees for receiving biosolids, or license fees, Mitsubishi Cement estimated that the cost effectiveness of using biosolids injection in the range of $108/ton to $1,775/ton of NOx reduced for a plant operated at near 90% capacity and NOx reduction year-round.[26]

The economic viability of biosolids injection as a NOx reduction technique is driven largely by the ability to negotiate a contract for receiving the biosolids while being paid a tipping fee. It should be noted that biosolids injection may not be applicable to many kilns. First, kilns must have the proper temperature window for an SNCR reaction, limiting this technology to precalciner kilns. Second, the kiln must have sufficient available fan capacity to support biosolids injection without too much of a decrease in clinker capacity. This is very limiting because most kilns operate near maximum capacity. Under just the right set of circumstances, biosolids injection can be an economically attractive approach for reducing NOx emissions. Because the economics and applicability of this process are so strongly dependent on several variables that could vary widely, additional modeling for cost effectiveness was not performed.

G. Summary

This chapter evaluated a number of technologies for their cost effectiveness that have been commercially applied to reduce NOx emissions under scenarios that are expected to be of interest to existing sources. The costs of these technologies were determined from publicly available data, information provided by technology suppliers, and from information provided by the technology users. An extremely important part of this report is the final chapter (Chapter IV), in which the detailed information related to cost and operating experience from actual technology users is provided in the form of case studies. Incorporating the user-provided operating and cost data from these case studies into the cost analysis just presented provides robust and reliable estimates of cost effectiveness that are strongly anchored in reality.

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[26] Biggs, H.O. "BioSolids Injection Technology: An Innovation in Cement Kiln NOx Control." Thirty-first International Cement Seminar. TP881.I5, 1995.

IV. Case Studies

A. Introduction

The purpose of the case studies is to provide information from the actual technology users on their experience (both operating and cost) with the control technologies addressed in the report. The information was gathered and the case studies were prepared in a manner designed to ensure that the end-user's perspective was maintained.

The case studies were performed in cooperation with the facility owners. In each case the facility owners filled out a questionnaire that was designed for their particular facility type. With the information gathered from the owners, a case study was prepared and then sent to the facility owners for review and comment. After the facility owners had reviewed the case study and revisions were made in accordance with their comments, the facility owners reviewed the revised case study for the final approval. After these steps the final version of the case study was included in this report. Every case study presented in this report went through this procedure.

> ***A note on Cost Effectiveness -*** During this study it became apparent that only a few of the owners of these facilities had performed calculations to estimate cost effectiveness, measured in terms of dollars per ton of NOx removed ($/ton). This may change in the future if market-based approaches, such as "cap and trade" approach, are introduced to meet regulatory requirements for these non-utility sources. Under such an approach, facilities will have an incentive to estimate accurately the cost effectiveness of strategies and technologies under consideration, since they will be able to trade (buy and sell) emission allowances with other sources with different incremental costs for control.
>
> In the gas turbine and IC engine case studies from gas transmission companies (Duke Energy and Tennessee Natural Gas), cost effectiveness calculations were provided by them using a format that the gas transmission industry has devised.
>
> Although cost effectiveness (in $/ton of NOx removed) was estimated by only a few users, all case study participants did provide extremely useful information on capital cost and operating cost- the key pieces of information necessary to estimate cost effectiveness. This information, which for many of these source categories has not been publicly available directly from users until this report, is extremely important for making an accurate assessment of technology costs. These key pieces of information were used where appropriate in Chapter III to provide robust and reliable cost effectiveness estimates that are "anchored in reality."

An effort was made to have a consistent format among case studies in this chapter. However, because each case study represents a unique situation prepared with the user's assistance, formats for case studies vary somewhat to accommodate the type and amount of information provided by the case study participants.

B. Industrial Boiler Case Studies

B.1 Case Study BLR-1, Minergy Corp, Neenah, Wisconsin

Operator Contact - Tom Baudhuin

Background and Technology Selection

Minergy Corporation operates a facility in Neenah, WI. In 1997 Minergy added a boiler for generation of steam for facility use.

General Statistics on Minergy Boiler	
MMBTU/hr	350
Boiler age (yrs)	1.5
Boiler type	Cyclone
Air heater	Tubular
Fuel(s)	Natural Gas and 4000 BTU/lb Paper Sludge
Baseline (uncontrolled) NOx	0.65 lb/MMBTU
Controlled NOx	0.30 lb/MMBTU

As a new source, the facility was subject to New Source Review Regulations and was required to install Best Available Control Technology (BACT). For this type of facility BACT was determined to require addition of Selective Non-Catalytic Reduction (SNCR) technology for control of NOx emissions. Minergy selected urea-based SNCR, or NOxOUT®.

Project Execution

The SNCR system was installed as part of a larger project. Therefore, it is not possible to determine the schedule for the SNCR system alone.

Experience

The operating experience from commissioning through to June 1999 is outlined on the table that follows. Notably, the system met its guaranteed NOx reduction levels and ammonia slip levels. Despite reported ammonia slip of 25 ppm, ammonium bisulfate salt deposition on the air heater has not been a problem. There has not been any noticeable ammonia odor in the fly ash or any disposal problems for ash due to ammonia. The system has been reliable in reducing NOx emissions. On two occasions the boiler required shutdown for repair of tube leaks believed to be due to impingement of urea droplets. Minergy is reviewing this matter with the technology supplier along with their practices for operating and maintaining the urea injectors.

Since the SNCR system was supplied with the boiler, it is uncertain what impact the SNCR system has on boiler efficiency or parasitic loads.

Experience and Performance	
Months in operation (June '99)	18
# Forced outage incidents	2
Lost boiler-operating hrs.	200
Increased parasitic loads	Unknown
Change in boiler efficiency	Unknown
Reagent Consumption	30 gph
Reagent Consumption guarantee met?	Yes
NH_3 slip guarantee, ppm	50
NH_3 slip actual, ppm	25
Air heater washing/deposition?	No
Visible Plume/year	No

Cost Effectiveness

Minergy was unable to provide detailed information regarding the cost of controlling NOx emissions with SNCR at this facility. The approximate cost of the process equipment and associated engineering and startup services was between $500,000 and $750,000. The cost of installation was not separated out since the SNCR system was provided as part of a larger program.

B.2 Case Study BLR-2, International Paper, Jay, Maine

Operator Contact - Peter Lee

Background and Technology Selection

International Paper operates a paper mill in Jay, Maine. At the facility there are two wall-fired boilers that fire No. 6 fuel oil and generate 450 million pounds per hour (pph) of steam. The boilers operate from 25% to 100% of full steam production rates.

General Statistics on International Paper Boilers	
MMBTU/hr	680 each (x 2)
Steam Generation (million pph)	450 each (x 2)
Operating range	25%-100% of full steaming rate
Boiler age (yrs)	34
Boiler type	Wall
Year that NOx reduction system was placed in service	1995
Fuel(s)	No. 6 Fuel Oil
Fuel Nitrogen Content	0.461%
Baseline (uncontrolled) NOx	0.427 lb/MMBTU

In 1995, the facility implemented Low NOx Burner modifications in order to reduce NOx emissions to meet Maine's NOx RACT requirements. The modifications entailed upgrading of existing burner hardware such as swirlers, nozzles, etc., and optimization of the operation of that equipment.

Project Execution

The burner modifications were made with minimal impact to boiler operation.

Experience

The operating experience from commissioning through to September 1999 is outlined on the table that follows. Notably, the program met its guaranteed NOx reduction level of 0.40 lb/MMBTU, and actual NOx emissions are about 0.38 lb/MMBTU. There have not been any increases on opacity or particle matter or CO emissions. The burner modifications have not had any adverse impact on boiler performance or reliability.

Experience and Performance	
Months in operation (Sept '99)	48
# Forced outage incidents	0
Lost boiler-operating hrs.	0
Increased parasitic loads	None
Change in boiler efficiency	None
Adverse changes to CO, PM emissions or opacity?	None
Changes in boiler reliability?	None
NOx Guarantee	0.40 lb/MMBTU
NOx guarantee met?	Yes
Actual NOx	0.38 lb/MMBTU

Cost Effectiveness

International Paper performed this program for a total installed cost of about $30,000. They have not performed a detailed cost estimate of the project.

B.3 Case Study BLR-3, Chevron Process Heater Equipped with SCR, El Segundo, California

Operator Contact - Jim Seebold (510) 242-3313

Background and Technology Selection

Chevron operates a refinery in El Segundo, CA. The facility, which is close to Los Angeles, is subject to the strict air pollution control requirements of the South Coast Air Quality Management District and the California Air Resources Board. In 1991, Chevron was required to reduce NOx emissions from it's fired heaters, including two furnaces that are floor fired and burn refinery fuel gas. The furnaces were originally equipped with combustion NOx controls that maintained NOx at about 40-50 ppm. The combined rated capacity of the two furnaces is 68 MMBTU/hr.

They selected SCR with a low-temperature catalyst due to the lower cost of this technical approach. Aqueous ammonia is used as the reagent for the SCR, and the catalyst is a low-temperature catalyst that is capable of operation at temperatures of 325 F to 650 F. In this case, the operating temperature is about 420 F. The use of a low-temperature catalyst enabled use of SCR with fewer plant modifications and less impact on heater operation than if a conventional SCR catalyst were used. An SCR using conventional SCR catalyst would have entailed a capital cost of roughly 50% more due to the modifications that would have been necessary to fit the catalyst.

General Statistics on Chevron Process Heaters	
MMBTU/hr	34 x 2 (68 total)
Heater Type	Floor Fired
Year that NOx reduction system was placed in service	1991
Fuel(s)	Refinery Fuel Gas
Baseline (uncontrolled) NOx	40-50 ppm
Controlled NOx	<9 ppm

Project Execution

Total system capital cost was \$1.5 million. The project schedule was as follows:

Project Schedule and Cost	
Preparation of Bid Package	4 weeks
Evaluation of Proposals	4 weeks
Award of Contract (AOC) to completion of engineering	8-10 weeks
AOC to delivery of equipment	40-45 weeks
AOC to completion of installation	50 weeks
AOC to completion of system commissioning	52 weeks
Project Cost	\$1.5 million

Experience

The operating experience from commissioning through to September 1999 is outlined on the table that follows. The program met its guaranteed NOx reduction level of 9 ppm, or about 0.01 lb/MMBTU with ammonia slip at undetectable levels. In the eight years of operation of the system, the permitted NOx emissions level has been exceeded four times. The \$35,000 value for levelized catalyst cost includes a provision for disposal of the used catalyst as well as the cost of replacement catalyst. The total variable O&M, which includes the catalyst, ammonia and other minor costs, is \$41,000.

For most boiler applications NO_2 comprises only a small portion of the total NOx. It is notable that due to the high excess air levels and, consequently, the high NO_2 content of the gas stream from this heater, the molar ratio of ammonia to NOx reduced is greater than the expected 1:1 that is common for most boilers. It actually approaches 2:1.

Experience and Performance	
Time in operation (Sept '99)	8 years
# Forced outage incidents	1
Lost heater-operating hrs.	0
# NOx exceedances	4
Increased parasitic loads	75 KW
Change in heater efficiency	None
Adverse changes to CO, PM emissions or opacity?	None
Changes in boiler reliability?	None
NOx Guarantee	9 ppm
NOx guarantee met?	Yes
Actual Controlled NOx	< 9 ppm, or < 0.01 lb/MMBTU
Ammonia slip guarantee	<20 ppm
Measured slip	None detected
Catalyst lifetime guarantee	3 yrs
Catalyst volume	5.1 m3
Levelized catalyst replacement cost	$35,000
Total variable O&M charges for year (includes levelized catalyst, ammonia, etc.)	$41,000
Additional man-hours per week	4

Cost Effectiveness

A detailed, cost effectiveness analysis to determine the $/ton of NOx reduced was not provided. However, using the data above with some assumptions, a determination of cost effectiveness could be made.

B.4 Case Study BLR-4, Sauder Woodworking, Archbold, Ohio

Operator Contact - Thomas Brodbeck (419) 446-3547

Background and Technology Selection

Sauder Woodworking operates a wall-fired, 57 MMBTU/hr boiler that fires wood waste. The facility was installed new in 1994 and was therefore subject to New Source Review (NSR) regulations, which imposes strict controls on new sources of NOx. Sauder was, therefore, required to control NOx to 0.20 lb/MMBTU and install Selective Catalytic Reduction technology.

The uncontrolled baseline NOx level into the SCR was not provided. The controlled NOx, however, is 0.20 lb/MMBTU.

General Statistics on Sauder Boiler	
MMBTU/hr	57
Boiler Type	Wall Fired
Age of Boiler	5 years (since 1994)
Year that NOx reduction system was placed in service	1994
Fuel(s)	Wood
Baseline (uncontrolled) NOx	Not Available
Controlled NOx	0.20 lb/MMBTU

Project Execution

The SCR system was provided as a part of a new boiler facility. Therefore, it was a part of a much larger project. The cost of the SCR catalyst, reactor, controls, ammonia injection grid, and associated engineering to the boiler supplier is reported by the catalyst supplier (Norton) to be $450,000. However, additional costs were incurred in installing the equipment and supply of the ammonia storage tank. So the total cost associated with SCR was greater than $450,000.

Experience

The 72 months of operating experience from commissioning through to September 1999 have demonstrated that the equipment has met its NOx reduction objective of 0.20 lb/MMBTU. This experience is summarized in the table that follows. The catalyst appears to be performing as expected. The system has never caused the facility to lose operating hours. The SCR exit NOx analyzer sampling system has required some periodic attention (four times in the six years). Deposits sometimes form on the sample line, causing erroneous indications.

Cost Effectiveness

A detailed, cost effectiveness analysis to determine the $/ton of NOx reduced was not performed by Sauder Woodworking.

Experience and Performance	
Months in Operation (as of Sept '99)	72 months
# Forced outage incidents	0
Lost operating hrs.	0
# NOx exceedances	0
Increased parasitic loads	Neg.
Change in efficiency	None
Adverse changes to CO, PM emissions or opacity?	None
Changes in boiler reliability?	None
NOx Guarantee	0.20 lb/MMBTU
NOx guarantee met?	Yes
Actual Controlled NOx	<0.20 lb/MMBTU
Ammonia slip guarantee	<20 ppm
Measured slip	None detected
Catalyst lifetime guarantee	2 yrs
Catalyst performing as expected	Yes
Levelized catalyst replacement Cost	$25,000
Additional Man Hours per week	5

B.5 Case Study BLR-5, Michigan State University, TB Simon Power Plant, Unit #4, East Lansing, Michigan

Operator Contact - Bob Ellerhorst

Background and Technology Selection

The Michigan State University in East Lansing, MI, operates a power plant providing energy to the campus. In 1991 it added a new circulating fluidized bed (CFB) boiler that fires coal. The boiler, rated at 380 MMBTU/hr, was required under Michigan New Source Review regulations to install a Selective Non-Catalytic NOx Reduction system using aqueous urea solution as the reagent. The baseline uncontrolled level of NOx was not provided.

General Statistics on Michigan State Boiler	
MMBTU/hr	380
Boiler age (yrs)	8
Boiler type	Circulating Fluidized Bed
Air heater	Tubular
Fuel(s)	Coal
Baseline (uncontrolled) NOx	Not Available
Maximum Controlled NOx	0.16 lb/MMBTU

Project Execution

The SNCR system was installed as a part of a much larger project to install the boiler.

Experience

The operating experience from commissioning through to September 1999 is outlined in the table that follows. Notably, the system met its guaranteed NOx reduction levels and ammonia slip levels. Ammonium bisulfate salt deposition on the air heater has not been a problem. There has not been any noticeable ammonia odor in the fly ash or any disposal problems for ash due to ammonia. The system has met the guarantee level and there have been no occasions when the urea SNCR system has failed to provide the expected performance.

Although the system has been relatively reliable, causing no forced outages or lost operating hours, there have been occasional mechanical problems in the form of injector plugging, metering pump failures, flow meter fouling, and stainless steel pipe leeks. Therefore, periodic maintenance and repair have been needed. There is sufficient redundancy in the system that mechanical failures have never taken the system out of service.

Since the SNCR system was supplied with the boiler, it is uncertain what impact the SNCR system has on boiler efficiency or parasitic loads.

Experience and Performance	
Months in operation (Sept. '99)	84
Guaranteed NOx	0.16 lb/MMBTU
Controlled NOx	0.14 lb/MMBTU
# NOx exceedances attributable to SNCR system failure	0
# Forced outage incidents attributable to SNCR system	0
Lost boiler-operating hrs. attributable to SNCR system	0
Increased parasitic loads	Negligible
Change in boiler efficiency	Negligible
NH_3 slip guarantee, ppm	< 18
NH_3 slip actual, ppm	0.75
Air heater washing/deposition?	No
Visible Plume/year	No
Extra Man-Hours/week for O&M	2

Cost Effectiveness

Michigan State's TB Simon Power Plant was unable to provide detailed information regarding the cost of controlling NOx with SNCR at this facility. The boiler and SNCR system were purchased together. Information identifying the specific cost of the SNCR system versus the boiler is not, therefore, available.

B.6 Case Study BLR-6, Temple Inland Corp. Shippenville, Pennsylvania

Operator Contact - Ted Peters, Temple Inland Corp., (814) 226-8961

Background and Technology Selection

Temple Inland Corporation manufactures medium density fiberboard (MDF) and other wood products. In 1996 they added a 155 MMBTU/hr bubbling bed boiler to provide process heat for the facility. The new boiler is fired with MDF waste and hog fuel (wood waste). Temple Inland is required to control NOx emissions on the boiler to below 0.17 lb/MMBTU. Since the boiler has a baseline emission of 0.40 lb/MMBTU without secondary controls, additional controls were needed. SNCR was chosen as the preferred technical approach and urea was selected as the reagent because urea is used on site for other purposes.

General Statistics on Temple Inland	
MMBTU/hr	155
Boiler age (yrs)	3.5
Year that NOx reduction system was placed in service	1997
Boiler type	Bubbling Bed
Fuel(s)	MDF Waste
Baseline (uncontrolled) NOx	0.40 lb/MMBTU
Controlled NOx	Under 0.17 lb/MMBTU

Project Execution

The SNCR system was installed as part of a much larger project to install the boiler. So, it is not possible to determine precisely the schedule for the SNCR system. However, the following schedule was provided as being approximately the schedule for SNCR. Of course, the entire project schedule was longer since much more equipment was provided.

The total project took 32 weeks after award of contract. Total contract cost was $225,000 for the process equipment, license, controls, etc. Project management, purchasing and other indirect costs were about $8,500, and commissioning and testing costs were $6,500.

Project Schedule (Approximate, SNCR only)	
Task	**Time, weeks**
Preparation of Bid Package	3
Evaluation of Proposals	2
Award of Contract (AOC) to completion of engineering	10
AOC to arrival of equipment on site	26
AOC to completion of installation	30
AOC to completion of system commissioning	32

Project Costs	
Cost for equipment and engineering	$225,000
Commissioning and testing	$6,500
Other indirect costs	$8,500
Total	$240,000

Experience

The operating experience from commissioning through to October 1999 is outlined in the table that follows. Notably, the system met its guaranteed NOx reduction levels and ammonia slip levels. Experience with the reliability of the system has been mixed. Although the pumping and control systems have been highly reliable, the reagent distribution and injection system was initially prone to plugging throughout. The system, therefore, required continual attention to keep it operating. The plugging is believed by Temple Inland to be associated with a chemical reaction between the urea and impurities in the reagent and/or dilution water. For reasons of cost control and availability, Temple Inland does not use the technology supplier's licensed reagent, but a locally-available urea product that is also used on site for other purposes. Temple Inland modified the SNCR system to mitigate the plugging problem, and the modifications were successful at mitigating the plugging to a more manageable level. Labor necessary to service the system is now less than the initial experience.

Experience and Performance	
Months in operation (Oct '99)	41
Guaranteed NOx	0.17 lb/MMBTU
Actual controlled NOx	0.13 lb/MMBTU
Lost boiler-operating hrs. attributable to SNCR system	None
NH_3 slip guarantee, ppm	< 15
NH_3 slip actual, ppm	5
Aqueous Urea Solution Use (30% by wt.)	160 pph
Extra Man-Hours/week for O&M	4-40

Cost Effectiveness

Temple Inland has not performed a detailed analysis of cost effectiveness in terms of dollars per ton of NOx removed.

B.7 Case Study BLR-7, Fort James Corporation, Green Bay, Wisconsin

Environmental Contact - Timothy Mattson, Fort James Corp., (920) 438-2191

Engineering Contact- Kim Dohm, Fort James Corporation, (920) 438-2644

Background and Technology Selection

The Fort James Corporation commissioned a new refractory-lined Bubbling Bed combustor with a waste heat boiler at the end of 1998. The boiler fires paper sludge at a rate of about 250 dry tons per day. Fort James was required to install an SNCR system to reduce NOx to below 100 ppm, or 50% removal, whichever is less stringent. SNCR using aqueous ammonia reagent (19% by wt.) was selected.

General Statistics on Fort James Boiler	
Max. Steam Load	57,000 #/hr @ 180 psig
Boiler age (yrs)	1
Combustor type	Bubbling Bed
Fuel(s)	Paper Sludge and natural gas
Baseline (uncontrolled) NOx	Approx. 250 ppm
Max. controlled NOx	Approx. 75 ppm

Project Execution

The SNCR system was installed as a part of a much larger project to install the boiler. So, it is not possible to determine precisely the schedule for the SNCR system. However, the following schedule was provided by the vendor as being approximately the schedule for a stand-alone SNCR system. Of course, the entire project schedule was longer since much more equipment was provided.

Project Schedule (Approximate, SNCR only)	
Task	**Time, weeks**
Preparation of Bid Package	2
Award of Contract (AOC) to completion of engineering	6-8
AOC to arrival of equipment on site	14-20
AOC to completion of installation	18-24
AOC to completion of system commissioning	20-26

Experience

The operating experience from commissioning through to December 1999 is outlined in the table that follows. Notably, the system met its guaranteed NOx reduction level and ammonia slip level.

Experience and Performance	
Months in operation (December '99)	13
Guaranteed NOx	100 ppm
Controlled NOx	75 ppm
NH_3 slip guarantee, ppm	< 35
NH_3 slip actual, ppm	10
# NOx exceedances attributable to SNCR system failure	0
# Forced outage incidents attributable to SNCR system	0
Lost boiler-operating hrs. attributable to SNCR system	0
Increased parasitic loads	5.56 KW
Extra Man-Hours/week for O&M	1

Cost Effectiveness

Fort James was unable to provide detailed information regarding the cost of controlling NOx with SNCR at this facility. The boiler and SNCR system were purchased together. Information identifying the specific cost of the SNCR system versus the boiler is not available.

B.8 Case Study BLR-8: Eastman Kodak Boiler #15, Micronized Coal Reburn, Rochester, New York

Company Contact: Jim Entwistle (716) 477-3136

Background:

Eastman Kodak's world headquarters at Kodak Park in Rochester, NY has a large facility to provide steam, electricity and other utilities to the site. At the facility, Kodak has several coal-fired cyclone boilers. In an effort to reduce NOx emissions at the site, in 1995 Kodak agreed to reduce NOx emissions from two of the boilers at the site through technology demonstration programs. Based upon the results of these programs, Kodak would implement additional control technology on other boilers at the site. The presumptive emission limit imposed by the State of NY was 0.60 lb/MMBTU, or about a 52% reduction from baseline. Because of the nature of the boilers and the nature of Kodak's business, the options for controlling NOx from the boilers were extremely limited. Data on one of the boilers (boiler #15) is in the table below:

Kodak Park	**Boiler #15**
Total steam flow (K lbs/hr)	400
primary fuel	coal
furnace type	cyclone
MMBTU/hr	478
Approximate Age (yrs)	43
1998 Capacity Factor	90%
1997 Capacity Factor	83%
Projected Capacity Factor	94%
Baseline (uncontrolled) NOx	1.36 lb/MMBTU

Technology Selection:

Kodak could not use SNCR or SCR technology because even small amounts of ammonia on site could potentially have a major, adverse impact on Kodak's manufacturing operations. Boiler #15 does not have gas available to it. The nearest gas line is about 2 miles away. The decision was made to pursue demonstration programs on boiler 15 (micronized coal reburn). Cofunding helped to reduce a significant portion of the capital cost of the program.

Project Execution:

The coal reburn project on Boiler #15 commenced at the end of 1995 and construction activities were completed in March of 1997.

The project for Boiler #15 was executed in accordance with the schedule on the following page. The program, which was partly funded by the Department of Energy to demonstrate micronized coal reburn technology, experienced an extended testing and acceptance program. The program was fast-tracked with an in-house team leading the effort.

Boiler #15 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	37 weeks
In-house team formed to start of construction	32 weeks
In-house team formed to completion of installation	63 weeks
In-house team formed to system acceptance	149 weeks
Total weeks	**149 weeks**

** note: project was fast-tracked with overlapping activities*

Experience:

The micronized-coal reburn system on Boiler #15 operates commercially and has met all expectations with regard to operation. Details are described in the following table. Controlled NOx is a function of boiler load - NOx can be controlled to lower levels at full load than at low loads. Although Kodak reports that unburned carbon in the fly ash did increase significantly with the use of micronized coal reburning, which increased dust accumulation, it has not presented any problems with disposal. Kodak does not reinject fly ash, which is done with some cyclone boilers. Kodak accumulates fly ash in one place prior to disposal.

Boiler #15 Experience		
Controlled NOx (actual)	**Load**	**Controlled NOx Emission**
	400 K lb/hr steam	0.60 lb/MMBTU
	370 K lb/hr steam	0.72 lb/MMBTU
	340 K lb/hr steam	1.00 lb/MMBTU
CO emissions		<200 ppm
LOI (unburned carbon in fly ash)		Increased from 12% to 42%
Load Range of Reburn Operation		70%-100% of full load
Reburn Fuel Heat Input		17%
All guarantees met?		Yes
Months of operation		12
# Of times NOx exceeded limit due to reburn system		0
Outage incidents from NOx control		1
Estimated lost operating hours		90
Estimated additional maintenance needed		$10,000/yr.
Additional man-hours per week		62
Any additional tube wastage due to reburning system?		none
Impact on boiler slagging?		None
Increase in parasitic loads		373 KW
Increased fuel cost		$14/hr
Impact on boiler efficiency		-1.5%

Cost Effectiveness:

Kodak estimates the cost effectiveness to be $1688/ton of NOx reduced. They used a capital recovery factor of 12% and a project lifetime of 15 years.

B.9 Case Study BLR-9: Eastman Kodak Boilers #41, 42, 43. Gas Reburn, Rochester, New York

Company Contact: Jim Entwistle (716) 477-3136

Background:

Eastman Kodak's world headquarters at Kodak Park in Rochester, NY has a large facility to provide steam, electricity and other utilities to the site. At the facility, Kodak has several coal-fired cyclone boilers. In an effort to reduce NOx emissions at the site, in 1995 Kodak agreed to reduce

NOx emissions from two of the boilers at the site, boilers #15 and #43, through technology demonstration programs. Based upon the results of these programs, Kodak would implement additional control technology on other boilers at the site. The presumptive emission limit imposed by the State of NY was 0.60 lb/MMBTU, or about a 52% reduction from baseline. Because of the nature of the boilers and the nature of Kodak's business, the options for controlling NOx from the boilers were extremely limited. Data on three of the boilers are in the table below:

Kodak Park	**Boiler #41**	**Boiler #42**	**Boiler #43**
Primary fuel	Coal	Coal	Coal
Furnace type	Cyclone	Cyclone	Cyclone
MMBTU/hr	500	500	640
Approximate Age (yrs)	35	31	30
1997 Capacity Factor	77%	77%	76%
1998 Capacity Factor	77%	79%	76%
Projected Capacity Factor	79%	78%	77%
Baseline (uncontrolled) NOx, lb/MMBTU	1.20	1.20	1.36

Technology Selection:

Boilers #41, 42, and 43 has gas readily available, while Boiler #15 does not. The decision was made to pursue demonstration programs on boilers 43 (gas reburn) and 15 (micronized coal reburn). After the successful demonstration of gas reburn on Boiler #43, Kodak made the decision to install gas reburning on boilers #41 and 42. Demonstration of the technology on Boiler #43 showed that flue gas recirculation was not necessary for these boilers. Therefore, the design of the Boiler #41 and #42 gas reburn systems differs significantly from the design of the gas reburn system on Boiler #43 in that flue gas recirculation is not used on the two systems for Boilers #41 and #42.

Project Execution:

The project on Boiler #43 was the first to be installed a and was a demonstration program. The projects for Boilers #41, 42 and 43 proceeded according to the following schedules:

Boiler #43 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	46 weeks
In-house team formed to arrival of equipment on site	46 weeks
In-house team formed to completion of installation	58 weeks
In-house team formed to completion of system commissioning	65 weeks
Total weeks (in service in 1996)	**65 weeks**

** note: project was fast-tracked with overlapping activities*

Boiler #41 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	28 weeks
In-house team formed to arrival of equipment on site	35 weeks
In-house team formed to completion of installation	54 weeks
In-house team formed to completion of system commissioning	66 weeks
Total weeks (in service in 1999)	**66 weeks**

** note: project was fast-tracked with overlapping activities*

Boiler #42 Project Schedule	
Preparation of bid package	0* weeks
Evaluation of proposals	0* weeks
In-house team formed to completion of engineering	34 weeks
In-house team formed to arrival of equipment on site	22 weeks
In-house team formed to completion of installation	46 weeks
In-house team formed to completion of system commissioning	58 weeks
Total weeks (in service in 1998)	**58 weeks**

** note: project was fast-tracked with overlapping activities*

Experience:

The reburn systems on Boilers #43, 41,and 42 operate commercially and have met all expectations with regard to operation. Details are described in the table below.

Experience			
	Boiler #41	**Boiler #42**	**Boiler #43**
Year that NOx reduction system was placed in service	1999	1998	1996
Guaranteed NOx, lb/MMBTU	0.60	0.60	0.685
Actual controlled NOx, lb/MMBTU	0.60	0.60	0.60
CO emissions	<200 ppm	<200 ppm	<200 ppm
LOI	8%	10%	12%
Load range of reburn operation, % of full load	70%-100%	70%-100%	70%-100%
Reburn fuel heat input	13%	15.7%	20%
All guarantees met?	Yes	Yes	Yes
Months of operation	8	14	38
# of times NOx exceeded limit	0	0	0
Outage incidents from NOx control	0	0	0
Estimated lost operating hours	0	0	0
Estimated additional labor, man-hr/week	5	5	5
Estimated additional maintenance needed	Negligible	Negligible	Negligible
Increased fuel costs at full load?	$117/hr	$141/hr	$230/hr
Any additional tube wastage?	No	No	No
Impact on slagging?	None	None	None
Increase in parasitic loads	0	0	56 KW
Impact on boiler efficiency	-0.20%	-0.23%	0.50%

As indicated in the table, the gas reburning has operated successfully without any failures for all three boilers.

Cost Effectiveness:

Kodak has estimated the cost effectiveness of the NOx reduction system using a capital recovery factor of 12% and a project economic life of 15 years. Cost effectiveness is estimated as follows:

Estimated Cost Effectiveness ($/ton of NOx removed)		
Boiler 41	Boiler 42	Boiler 43
$1,215	$1,482	$1,246

Actual costs experienced over the life of the facility will be dependent upon gas pricing and availability.

C. Gas Turbine Case Studies

C.1Case Study GT-1, Duke Energy, Cromwell, Connecticut

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Cromwell, CT, are two Solar Centaur turbines that drive compressors. These simple-cycle gas turbines are rated at 4700 hp each.

The turbines were put in place before Connecticut's Reasonably Available Control Technology (RACT) requirements were in place. Therefore, it was necessary to reduce NOx emissions in 1995 when Connecticut RACT requirements took effect.

The units operate as needed to meet gas transmission demands.

The turbines were retrofitted with Dry Low NOx (DLN) Combustor technology was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Cromwell, CT, Gas Turbine	
Turbine Type	Solar Centaur, simple-cycle compressor drive
HP	2 x 4700 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	T1 – 135 ppmvd at 15%O_2 (permit) T2 – 110 ppmvd at 15%O_2 (permit)
Controlled NOx	T1 & T2 - 42 ppmvd at 15%O_2 (permit)

Project Execution

The technology was retrofitted onto the turbines in 1993, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was $1.9 million. This price includes the cost of additional work on the compressors and reflects much more than the cost of the DLN retrofits alone. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1993 with the Dry Low NOx retrofits. During that time, the emissions of the turbines have been maintained under the required level and within the guarantee levels. In the roughly 72 months of operation, the NOx reduction system has resulted in

150 turbine outages and a total of 1,200 lost operating hours for both gas turbines at the facility. The shut downs and lost hours were due to frequent flameouts during weather changes that were not handled well by the first-generation of fuel controls. Duke Energy has since equipped the turbines with more modern electronic fuel controls from the manufacturer that have addressed this problem. Roughly two man-hours per week of additional service is needed to maintain the turbines.

The first generation combustor liner failed after about 5,000 hours. However, a new, third generation combustor liner appears to be operating properly for over 10,000 hours. The cost of replacing a combustor liner is roughly $20,000, including labor and materials.

Experience and Performance	
Months in operation (as of Aug '99)	72
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	$950,000 per turbine (includes significant compressor work not related to DLN retrofit)
Estimated add'l fixed O&M	see Cost Effectiveness Calculations
Add'l man-hours of labor	2 hours/week per turbine
NOx guarantee, ppm	42 ppmvd at 15%O_2
NOx guarantee met?	Yes
Combustor Life prior to DLN	20,000 + hours
Combustor Life after DLN	5,000 to 10,000 hours *
Number of forced outages	150*
Total lost operating hours	1200*
* New fuel controls have addressed the frequent forced outage problem that contributed to high lost operating hours. First-generation combustor liners failed after about 5,000 hours. New, third-generation combustor liner appears to have increased the combustor life to 10,000 hours or more.	

Cost Effectiveness

See attached cost effectiveness spreadsheets provided by Duke Energy.

Cromwell, CT
Solar Centaur (T1)
Dry Low NO_X Combustor Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$950,000	$/turbine	Project Cost
Total Capital Costs		**$950,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		$5,760	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$5,760	$/yr.	OAQPS
Total Maintenance Costs		**$11,520**	**$/yr.**	**Calculation**
Total O&M Costs		**$15,108**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$9,065	$/yr.	OAQPS
Administration	2% of TCI	$19,000	$/yr.	OAQPS
Insurance	1% of TCI	$9,500	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$141,578	$/yr.	OAQPS
Total Indirect Costs		**$179,143**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$194,251**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (135 ppmvd at 15%O_2)	21.30	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (42 ppmv at 15% O_2)	7.76	lb/hr	Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**59.31**	**tpy**	**Calculation**
Cost Effectiveness		**$3,275**	**$/ton**	**Calculation**

Cromwell, CT
Solar Centaur (T2)
Dry Low NO_X Combustor Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$950,000	$/turbine	Project Cost
Total Capital Costs		**$950,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		$5,760	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$5,760	$/yr.	OAQPS
Total Maintenance Costs		**$11,520**	**$/yr.**	**Calculation**
Total O&M Costs		**$15,108**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$9,065	$/yr.	OAQPS
Administration	2% of TCI	$19,000	$/yr.	OAQPS
Insurance	1% of TCI	$9,500	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$141,578	$/yr.	OAQPS
Total Indirect Costs		**$179,143**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$194,251**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (110 ppmvd at 15%O_2)	17.39	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (42 ppmv at 15% O_2)	7.76	lb/hr	Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**42.18**	**tpy**	**Calculation**
Cost Effectiveness		**$4,605**	**$/ton**	**Calculation**

C.2Case Study GT-2, Duke Energy, Southeast, New York

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in the town of Southeast, NY, are two Solar Centaur turbines and one Solar Mars turbine that drive compressors. These simple-cycle gas-turbine engines are rated at 4700 hp each for the Centaurs and 13,000 hp for the Mars.

The turbines were put in place before New York's Reasonably Available Control Technology (RACT) requirements were in place. Therefore, it was necessary to reduce NOx emissions by 1995 when these rules took effect.

The units operate as needed to meet gas transmission demands.

The turbines were retrofitted with Dry Low NOx (DLN) Combustor technology was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Southeast, NY, Gas Turbine	
Turbine Type	Solar Centaurs and Mars simple-cycle compressor drive
HP	2 x 4,700 hp (Centaur) 1 x 13,000 hp (Mars)
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	Centaur - 135 ppmvd at 15%O_2 (permit) Mars - 167 ppmvd at 15%O_2 (permit)
Controlled NOx	50 ppmvd at 15%O_2 (permit)

Project Execution

The technology was retrofitted onto the turbines in 1993, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was $3.5 million. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1993 with the Dry Low NOx retrofit. During that time, the emissions from the turbines have been maintained under the required level and within the guarantee levels. In the roughly 72 months of operation, the NOx reduction system has resulted in 50 turbine outages and a total of 450 lost operating hours for both gas turbines at the facility. The shut downs and lost hours were due to frequent flameouts during weather changes which were not handled well by the first-generation of fuel controls. Duke Energy has since equipped the turbines with more modern electronic fuel controls from the manufacturer that have addressed this problem. The Mars fuel injectors also plugged frequently until a finer upstream filter corrected this problem. Roughly two man-hours per week of additional service is needed to maintain the turbines.

The first generation combustor liner failed after about 5000 hours. However, a new, third generation combustor liner appears to be operating properly for over 10,000 hours. The cost of replacing a combustor liner is roughly $20,000, including labor and materials.

Experience and Performance	
Months in operation (as of Aug '99)	72
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	$3.5 million Centaur - $775,000 per turbine Mars - $1,950,000
Estimated add'l fixed O&M	$15,000/year
Add'l man-hours of labor	see Cost Effectiveness Calculations
NOx guarantee, ppm	42 ppmvd at 15%O_2
NOx guarantee met?	Yes
Combustor Life prior to DLN	20,000 + hrs
Combustor Life after DLN	5,000-10,000 hrs *
Number of forced outages	50 *
Total lost operating hours	450 *
* New fuel controls have addressed the frequent forced outage problem that contributed to high lost operating hours. First-generation combustor liners failed after about 5,000 hours. New, third-generation combustor liner appears to have increased the combustor life to 10,000 hours or more.	

Cost Effectiveness

Ost effectiveness spreadsheets from Duke Energy appear on the following two pages.

Southeast, NY
Solar Centaurs
Dry Low NO_X Combustor Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$775,000	$/turbine	Project Cost
Total Capital Costs		**$775,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		$5,760	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$5,760	$/yr.	OAQPS
Total Maintenance Costs		**$11,520**	**$/yr.**	**Calculation**
Total O&M Costs		**$15,108**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$9,065	$/yr.	OAQPS
Administration	2% of TCI	$15,500	$/yr.	OAQPS
Insurance	1% of TCI	$7,750	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$115,498	$/yr.	OAQPS
Total Indirect Costs		**$147,813**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$162,921**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (135 ppmvd at 15%O_2)	21.60	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (50 ppmv at 15% O_2)	7.59	lb/hr	Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**61.36**	**tpy**	**Calculation**
Cost Effectiveness		**$2,655**	**$/ton**	**Calculation**

Southeast, NY
Solar Mars
Dry Low NO_X Combustor Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$1,950,000	$/turbine	Project Cost
Total Capital Costs		**$1,950,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		$5,760	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$5,760	$/yr.	OAQPS
Total Maintenance Costs		**$11,520**	**$/yr.**	**Calculation**
Total O&M Costs		**$15,108**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$9,065	$/yr.	OAQPS
Administration	2% of TCI	$39,000	$/yr.	OAQPS
Insurance	1% of TCI	$19,500	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$290,608	$/yr.	OAQPS
Total Indirect Costs		**$358,280**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$373,280**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (167 ppmvd at 15%O_2)	75.68	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (42 ppmv at 15% O_2)	7.70	lb/hr	Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**297.75**	**tpy**	**Calculation**
Cost Effectiveness		**$1,254**	**$/ton**	**Calculation**

C.3Case Study GT-3, Duke Energy, Stony Point, New York

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Stony Point, NY are two Solar Centaur turbines and one Solar Mars turbine that drive compressors. These simple-cycle gas-turbine engines are rated at 4700 hp each (Centaur) and 13,000 hp (Mars).

The turbines were put in place before New York's Reasonably Available Control Technology (RACT) requirements were in place. Therefore, it was necessary to reduce NOx emissions by 1995 when these rules took effect.

The units operate as needed to meet gas transmission demands.

The turbines were retrofitted with Dry Low NOx (DLN) Combustor technology was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Stony Point NY, Gas Turbines	
Turbine Type	Solar Centaur and Mars simple-cycle compressor drives
HP	2 x 4700 hp (Centaur) 1 x 13,000 (Mars)
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	Centaur - 135 ppmvd at 15%O_2 (permit) Mars - 167 ppmvd at 15%O_2 (permit)
Controlled NOx	42 ppmvd at 15%O_2 (permit)

Project Execution

The technology was retrofitted onto the turbines in 1993, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was $3.5 million. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1993 with the Dry Low NOx retrofit. During that time, the emissions of the turbines have been maintained under the required level and within the guarantee levels. In the roughly 72 months of operation, the NOx reduction system has resulted in 200 turbine outages and a total of 2,000 lost operating hours for all gas turbines at the facility. The shut downs and lost hours were due to frequent flameouts during weather changes which were not handled well by the first-generation fuel controls. Duke has since equipped the turbines with more modern electronic fuel controls from the manufacturer that have addressed this problem. The Mars fuel injectors also plugged frequently until a finer upstream filter corrected this problem. Roughly two man-hours per week of additional service is needed to maintain the turbines.

The first generation combustor liner failed after about 5000 hours. However, a new, third generation combustor liner appears to be operating properly for over 10,000 hours. The cost of replacing a combustor liner is roughly $20,000, including labor and materials.

Experience and Performance	
Months in operation (as of Aug '99)	72
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	$3.5 million Centaur - $775,000 per turbine Mars - $1,950,000
Estimated add'l fixed O&M	$15,000/year
Add'l man-hours of labor	see Cost Effectiveness Calculations
NOx guarantee, ppm	42 ppmvd at 15%O_2
NOx guarantee met?	Yes
Combustor Life prior to DLN	20,000 + hrs
Combustor Life after DLN	5,000-10,000 hrs
Number of forced outages	200
Total lost operating hours	2,000
New fuel controls have addressed the frequent forced outage problem that contributed to high lost operating hours. First-generation combustor liners failed after about 5,000 hours. New, third-generation combustor liner appears to have increased the combustor life to 10,000 hours or more.	

Cost Effectiveness

Ost effectiveness spreadsheets from Duke Energy appear on the following two pages.

Stony Point, NY
Solar Centaurs
Dry Low NO_X Combustor Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$775,000	$/turbine	Project Cost
Total Capital Costs		**$775,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		$5,760	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$5,760	$/yr.	OAQPS
Total Maintenance Costs		**$11,520**	**$/yr.**	**Calculation**
Total O&M Costs		**$15,108**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$9,065	$/yr.	OAQPS
Administration	2% of TCI	$15,500	$/yr.	OAQPS
Insurance	1% of TCI	$7,750	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$115,498	$/yr.	OAQPS
Total Indirect Costs		**$147,813**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$162,921**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (135 ppmvd at 15%O_2)	27.00	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (42 ppmv at 15% O_2)	7.70	lb/hr	Guarantee/Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**84.53**	**tpy**	**Calculation**
Cost Effectiveness		**$1,927**	**$/ton**	**Calculation**

Stony Point, NY
Solar Mars
Dry Low NO_X Combustor Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$1,950,000	$/turbine	Project Cost
Total Capital Costs		**$1,950,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/turbine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	160 hrs/yr./turbine	160	hrs/yr.	Estimate
Maintenance Labor Cost		$5,760	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$5,760	$/yr.	OAQPS
Total Maintenance Costs		**$11,520**	**$/yr.**	**Calculation**
Total O&M Costs		**$15,108**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$9,065	$/yr.	OAQPS
Administration	2% of TCI	$39,000	$/yr.	OAQPS
Insurance	1% of TCI	$19,500	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$290,608	$/yr.	OAQPS
Total Indirect Costs		**$358,172**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$373,280**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (167 ppmvd at 15%O_2)	85.47	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (42 ppmv at 15% O_2)	7.70	lb/hr	Guarantee/Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**340.63**	**tpy**	**Calculation**
Cost Effectiveness		**$1,096**	**$/ton**	**Calculation**

C.4Case Study GT-4 Kern River and Sycamore Cogeneration Projects, Bakersfield, California

Operator Contact: Daniel Beck (661) 392-2461

Background and Technology Selection

Kern River and Sycamore Cogeneration Companies operate cogeneration and gas compression equipment in Bakersfield, CA. The gas turbines are GE Frame 7's that drive gas compression equipment. Each facility (Kern River and Sycamore) has four turbines each. Each gas turbine is rated at 75 MW, for a facility rating of 300 MW per facility. All four of Sycamore's turbines and two of Kern River's turbines have model EA compressors attached. The other two units at Kern River have model E compressors (not quite as large as the model EA compressors).

Both facilities were originally equipped with water injection for NOx control. Additional reductions were required that were beyond the capability of water injection. Therefore, it was determined that water injection would be removed from the turbines and the turbines would be retrofitted with Dry Low NOx combustors, which were recently made available by the turbine manufacturer, General Electric.

General Statistics on Kern River and Sycamore Cogeneration Projects	
Turbine Type	GE Frame 7
Gas Turbine Output	4 x 75 MW (Kern River) 4 x 75 MW (Sycamore)
Heat Recovery	Yes, HRSG
Fuel(s)	Natural Gas
Capacity Factor	Over 95% both facilities
Previous Controlled NOx (with water injection)	30-40 ppm
Guaranteed Outlet NOx	15 ppm
Controlled NOx (with DLN)	8-12 ppm

The units operate almost continuously, with historical capacity factors of 96.2% and 98.4% at Kern River and Sycamore, respectively.

DLN is capable of 15 ppm of NOx (which approximates to just under 50 lb/hr at full load per turbine). The conventional combustors with water injection that the turbines were previously equipped with, were capable of under 42 ppm.

Project Execution

The first unit was retrofitted in 1995 and the last one was retrofitted in May of 1999. The most recent retrofit took about 24 days to complete, with the work being awarded to the turbine manufacturer - General Electric. It cost about $3.65 million to retrofit each unit.

Experience

Depending on the turbine, operating experience ranges from a few months to four years. During this time there have been a total of 10-20 short-term NOx exceedances, under five forced outages and fewer than 100 lost operating hours. There is no additional labor associated with operating the units with DLN.

Most of the exceedances have been associated with re-ignition problems. In this case, the unit is only in an unstable state for a very short time (i.e., five minutes), but the resulting emissions have sent the units over 1-hr or 3-hr average limits. The facility owners are currently working with the supplier on two outstanding items. They resulted in 4-5 emission exceedances in a short time (i.e., 1-month).

There are a number of advantages DLN has over water injection that are in addition to NOx reduction.

- Since the DLN retrofit, heat rate has improved 4% versus water injection.
- With water injection, combustor life was only 5-6 years. The Kern River and Sycamore operators are hoping for over ten years of combustor life with the DLN combustor.
- Finally, facility consumption of water is reduced from what it would have been with all units running with water injection. This is important especially in dry regions such as Bakersfield, CA.

Experience and Performance	
Months in operation (as of Aug '99)	3 to 48, depending on the turbine
Increased parasitic loads	None
Change in turbine efficiency	4% improvement
Project Cost	$3.65 million/turbine
Estimated add'l fixed O&M	None (actually, O&M was reduced compared to water injection)
Add'l man-hours of labor	None
NOx guarantee, ppm	15 ppm
NOx guarantee met?	Yes
Combustor Life prior to DLN	5-6 yrs
Combustor Life after DLN	Unknown, hoping for over 10 years
Number of NOx exceedances	10-20 *
Number of forced outages	<5
Total lost operating hours	<100
* Exceedances were due to short-term transients (typically under 5-minutes), but were sufficient to cause one-hour or three hour averages to exceed maximum allowed. Facility operators are working with supplier to resolve outstanding items.	

Cost Effectiveness

Sycamore and Kern River did not provide their analysis of cost effectiveness. However, they did evaluate the project on a 10-year life.

C.5Case Study GT-5 PG&E Generating, Manchester Street Station, Providence, Rhode Island

Company Contact: Paula Hamel

Background and Technology Selection

PG&E Generating owns and operates a power plant in Providence, RI. The facility is equipped with three 165 MW Combined Cycle Gas Turbines (CCGT - each CCGT is a 120 MW gas turbine and a 45 MW steam turbine). The turbines primarily fire natural gas and have #2 fuel oil available as a back up. The facility was placed in service in 1995 and was required to meet a NOx emission rate of 9 ppm. The CCGT's were originally equipped with steam injection and SCR in order to meet the emission limit. In 1998 PG&E Generating retrofitted the gas turbine engines with Dry Low NOx (DLN) combustor technology in order to facilitate low NOx emissions in a more cost-effective manner.

General Statistics on Manchester Street Station	
Turbine Type	Siemens
Gas Turbine Output	3 x 120 MW
Heat Recovery	Yes, HRSG
Fuel(s)	Natural Gas #2 Fuel Oil backup
Year turbines in service	1995
Year that DLN NOx reduction system was placed in service	1998
Capacity Factor	~80%
Baseline (uncontrolled) NOx (with steam injection)	<42 ppm
Guaranteed Outlet NOx (with DLN)	9 ppm
Controlled NOx (with DLN)	~7 ppm

The units have operated at about 80% capacity factor. The SCR uses aqueous ammonia as a reagent.

The Dry Low NOx (DLN) technology replaced the steam injection technology for gas operation (steam injection is still used when firing oil), and it has made injection of ammonia for the SCR unnecessary for NOx compliance under most conditions when firing natural gas. When firing #2 fuel oil it is necessary to use the SCR to achieve the required NOx level of under 9 ppm. The retrofit was motivated by the reduced operating costs of DLN, which make it a cost-effective approach to reduce NOx.

Project Execution

The original steam injection system and SCR were installed when the turbines were put in place in 1995. The DLN technology was retrofitted on the facility only a few years later and was in service in 1998.

Experience

Operating experience with the turbines is four years and operating experience with the DLN technology is for one to two years. During this time there have not been any exceedances of the Federal NSPS for NOx emissions from gas turbines (40CFR60 subpart GG). There has been one forced outage per turbine due to pluggage of ammonia injection (for the SCR) and about 24 lost operating hours per turbine. There is no additional labor associated with operating the units with DLN.

Experience and Performance	
Months in operation (as of Oct '99)	47-48, depending on turbine
Months since DLN retrofit	18
Increased parasitic loads	None
Change in turbine efficiency	DLN improved efficiency
NOx guarantee, ppm	9 ppm
NOx guarantee met?	Yes
Number of NOx exceedances	None (Federal NSPS)
Number of forced outages	1 on each turbine from SCR ammonia injector plugging
Total lost operating hours	About 24 on each turbine

Cost Effectiveness

PG&E Generating did not provide capital or operating cost data.

C.6Case Study GT-6 PG&E Generating, Pittsfield Generating Plant, Pittsfield, Massachusetts

Company Contact: Paula Hamel

Background and Technology Selection

PG&E Generating owns and operates a power plant in Pittsfield, MA. The facility is equipped with three Combined Cycle Gas Turbines (CCGTs), each with a 40 MW gas turbine. The facility also provides cogeneration steam. The turbines primarily fire natural gas and have #2 fuel oil available as a back up. The facility was placed in service in 1990 and was required to meet a NOx emission rate of 16.2 pounds per hour. The CCGT's were originally equipped with steam injection and SCR (using aqueous ammonia) in order to meet the emission limit.

General Statistics on Pittsfield Generating Plant	
Gas Turbine Output	3 x 40 MW
Heat Recovery	Yes, HRSG
Fuel(s)	Natural Gas #2 Fuel Oil backup
Year that turbines were placed in service	1990
Capacity Factor	Not available
Controlled NOx	< 16.2 lb/hr

Project Execution

The steam injection system and SCR were installed when the turbines were placed in service in 1990.

Experience

Operating experience is about 113 months (as of September 1999). During this time there have not been any exceedances of the Federal NSPS for NOx emissions from gas turbines (40CFR60 subpart GG). There were two forced outages per turbine due to plugging of ammonia injection (for the SCR) and about 12 total lost operating hours per turbine.

Experience and Performance	
Months in operation (as of September '99)	113 per turbine
NOx without steam injection with SCR	35 ppm
NOx with steam injection and with SCR	7 ppm
CO with steam injection	2-4 ppm
Steam flow : Fuel Flow (mass basis)	1.12 : 1
NOx guarantee, ppm	9 ppm
NOx guarantee met?	Yes
Number of NOx exceedances	None (Federal NSPS)
Number of forced outages	2 on each turbine from SCR ammonia injector plugging
Total lost operating hours	About 12 on each turbine

Cost Effectiveness

PG&E Generating did not provide capital or operating cost data.

C.7Case Study GT-7, Tennessee Gas Pipeline, Lockport, New York

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Lockport, NY, are four Solar Centaur turbine that drive compressors. These simple-cycle gas-turbine engines are rated at 4500 hp. The units were subject to RACT review requirements that took effect due to the units producing greater than 500 hp.

The units operate as needed to meet gas transmission demands.

TGP evaluated several technologies to comply with New York State Department of Environmental Conservation (NYSDEC) presumptive RACT levels of 50 ppm for gas turbines and selected Dry Low NOx Combustor technology to achieve the presumptive NOx RACT. This was the approach required by the State of New York's RACT compliance plans.

General Statistics on Tennessee Gas Pipeline, Lockport, NY	
Turbine Type	Solar Centaur simple-cycle compressor drive
HP	4 x 4500 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NOx	87 ppm (nominal OEM guarantee)
Controlled NOx	50 ppm (guarantee)

Project Execution

The technology was retrofitted onto the turbines in time to satisfy RACT requirements. The cost of this retrofit, including commissioning, was $2.5 million. Three of the turbines cost $600,000 each to retrofit, and the oldest turbine cost $700,000 to retrofit. These project costs include extensive engineering and company overhead costs. Project execution details were not available.

Experience

The facility has been operating since 1995 with the Dry Low NOx retrofit. During that time, the emissions of the turbines have been maintained under the required permit level and within the manufacturer's guaranteed levels.

Experience and Performance	
Months in operation (as of Oct '99)	48
Increased parasitic loads	None
Change in turbine efficiency	None
Project Cost	\$600,000 to \$700,000 per turbine
Estimated add'l fixed O&M	See cost - effectiveness Calculations
Add'l man-hours of labor	5 days/turbine-yr.
NOx guarantee, ppm	50 ppm
NOx guarantee met?	Yes
Combustor Life prior to DLN	Insufficient data
Combustor Life after DLN	Insufficient data
Number of forced outages	0
Total lost operating hours	0

Cost Effectiveness

Cost effectiveness spreadsheets from Tennessee Gas Pipeline appear on the following page.

Lockport, NY
Solar Centaur
DryLoNOx Cost Effectiveness

Cost	*Basis*	*Value*	*Reference*
Total Capital Investment (TCI)	TCI	$700,000	Project Cost

	Basis	*Value*	*Reference*
Operating Labor			
Unit Cost	Hourly rate	$30.00	Industry Average
Labor Required	1 hr/week	52	Estimate
Total Cost ($/yr)		**$1,560**	**Calculation**
Supervisor Labor			
Labor Required	15% Operating Labor	$234	OAQPS
Total Cost ($/yr)		**$234**	**Calculation**
Maintenance			
Unit Cost	Hourly rate	$36.00	Industry Average
Labor Required	80 hrs/year	80	Estimate
Maintenance Cost		$2,880	Calculation
Material Cost	100% of Maintenance Cost	$2,880	Calculation
Total Cost ($/yr)		**$5,760**	**Calculation**
Indirect			
Overhead	60% of O&M Costs	$4,532	OAQPS
Administration	2% of TCI	$14,000	OAQPS
Insurance	1% of TCI	$7,000	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	$104,321	Calculation
Total Indirect Costs ($/yr)		**$129,853**	**Calculation**
Base Case Emission Rate	Uncontrolled @ 87 ppm; lb/hr	16.800	Solar Guarantee
NO_x Emission rate	DryLONOx Guarantee @ 50 ppm; lb/hr	10.200	Permit Limit
Total NO_x Controlled (ton/yr)	Emission Differential; tpy	28.9	Calculation
Total Annual Cost ($/yr)	**Summation**	**$137,407**	**Calculation**
COST EFFECTIVENESS ($/ton)		**$4,753**	

D. Internal Combustion Engine Case Studies

D.1 Case Study IC-1, SYCOM Enterprises, Linden, New Jersey

Operator Contact - Donald Moore

Background and Technology Selection

SYCOM Enterprises is an energy services firm that operates a facility for Buckeye Pipeline's fuel pumping station in Linden, NJ. This pumping facility, which was placed in service in January 1997, is powered by three 3130-hp, gas-fired Waukesha engines. These gas-fired engines were used to replace the existing electrically driven pumps, which are more expensive to operate. As a new internal combustion engine facility, the engines were subject to New Jersey's strict environmental permitting requirements. The requirements of the state of New Jersey made it necessary to install Selective Catalytic Reduction technology for reduction of NOx.

General Statistics on SYCOM Enterprise's Linden, NJ Engine Facility	
Engine Type	Waukesha, reciprocating
HP	3 x 3130 hp
Operating since	January 1997 (2 ½ years)
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	~92%
Baseline (uncontrolled) NOx	Not Available
Controlled NOx	50 ppm

The units operate nearly continuously, with shut downs for periodic maintenance or during changes in pumping operations. Each engine typically operates 18 or more hours per day.

Project Execution

The SCR was installed as a part of a packaged unit with the engine. Each catalyst reactor has two layers of NOx reducing catalyst and a downstream catalyst for removing CO. Aqueous ammonia is used for the SCR reagent. Each of the three engines is served by its own SCR system. There is a common aqueous ammonia storage system for all three SCR's.

Experience

The facility has been operating since January 1997. The system has met its guaranteed NOx emissions level. These engines are not equipped with Continuous Emissions Monitors. Emissions are checked by a monthly emissions test.

The only significant operating difficulties have been: 1) occasional plugging of the ammonia injector by rust flakes from upstream piping, which prevents effective and efficient SCR operation until the problem is corrected; 2) failure of ammonia pumps, that have been since repaired; 3) and the need to clean the catalyst due to deposition of lubricants from the engine during start-up cycles. The increased cost due to the injector plugging is estimated at about $3,000-4,000 per year and the catalyst cleaning has been necessary twice on each of two of the engines and once on the third. Since the catalyst supplier provided for this, the additional cost due to this primarily results from having to own a spare catalyst layer while the other layer is off for cleaning.

Experience and Performance	
Months in operation (as of July '99)	30
Increased parasitic loads	Unknown
Change in engine efficiency	Unknown
Reagent cost per year	$14,000
Cost of service agreement for SCR	$78,000/year (*equal to $2166/month for each engine)*
Cost of additional testing	$9,600/year
NOx guarantee, ppm	50 ppm
NOx guarantee met?	Yes
Catalyst washes	Five total on three engines - *Two for each of two engines* *Once for the third*

Cost Effectiveness

SYCOM Enterprises was unable to provide the capital cost of the SCR system because it was provided as a part of the engine package and was not a separate line item on the contract. Since capital cost is a major determinant of the cost effectiveness, it is not possible to determine this value without more information.

D.2 Case Study IC-2, Duke Energy, Stony Point, New York

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Stony Point, NY are four Clark TLA8 engines. These are two-stroke reciprocating gas engines, 2700 hp each.

The engines are about 40 years old, manufactured well before NOx requirements were in place. As a part of New York's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions to below 5.1 gm/hp-hr of NOx in 1995.

The units operate as needed to meet gas transmission demands.

High-energy ignition was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was the most cost-effective approach.

General Statistics on Duke Energy Stony Point IC Engines	
Engine Type	Clark TLA8, two-stroke, reciprocating
HP	4 x 2700 hp
Facility age	~ 40 years
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	10.08 gm/hp-hr (permit)
Controlled NOx	5.1 gm/hp-hr (permit)

Project Execution

The technology was retrofitted onto the engines in 1994, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was $304,000. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1994 with the high-energy ignition upgrade. During that time, the emissions of the engines have been maintained under the required level. In the roughly 60 months of operation, the NOx reduction system has resulted in six engine outages and a total of 24 lost operating hours. Roughly two man-hours per week of additional service are needed to maintain the engines.

Experience and Performance	
Months in operation (as of Aug '99)	60
Increased parasitic loads	None
Change in engine efficiency	None
Project Cost	$76,000 per engine
Estimated add'l fixed O&M	see Cost Effectiveness Calculations
Add'l man-hours of labor	2 hours/week per engine
Controlled NOx emissions	5.1 gm/hp-hr
Number of forced outages	6
Total lost operating hours	24

Cost Effectiveness

The cost effectiveness spreadsheets from Duke Energy appear on the following page.

Stony Point, NY Clark TLA8 High Energy Ignition System Cost Effectiveness				
Capital Costs	**Basis**	**Value**	**Units**	**Reference**
Total Capital Investment (TCI)	TCI	$76,000	$/engine	Project Cost
Total Capital Costs		**$76,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/engine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	62 hrs/yr./engine	62	hrs/yr.	Estimate
Maintenance Labor Cost		$2,232	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$2,232	$/yr.	OAQPS
Total Maintenance Costs		**$4,464**	**$/yr.**	**Calculation**
Total O&M Costs		**$8,052**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$4,831	$/yr.	OAQPS
Administration	2% of TCI	$1,520	$/yr.	OAQPS
Insurance	1% of TCI	$760	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$11,326	$/yr.	OAQPS
Total Indirect Costs		**$18,437**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$26,489**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (10.08 g/hp-hr)	60.00	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (5.1 g/hp-hr)	30.36	lb/hr	Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**129.84**	**tpy**	**Calculation**
Cost Effectiveness		**$204**	**$/ton**	**Calculation**

D.3 Case Study IC-3, Duke Energy, Burrillville, Rhode Island

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Burrillville, RI are three Clark TLA8 engines. These are two stroke reciprocating gas engines, 2700 hp each.

The engines are about 40 years old, manufactured well before NOx requirements were in place, and previously emitted about 12 gm/hp-hr. As part of Rhode Island's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions to below 1.4 lb/MMBTU, which is equal to 5.1 gm/hp-hr of NOx on these engines, by 1995.

The units operate as needed to meet gas transmission demands.

High-energy ignition was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was the most cost-effective approach.

General Statistics on Duke Energy Burrillville, RI, IC Engines	
Engine Type	Clark TLA8, two-stroke, reciprocating
HP	3 x 2700 hp
Facility age	~ 40 years
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	10.08 gm/hp-hr (test data)
Controlled NOx	1.4 lb/MMBTU (permit) (equivalent to 5.1 gm/hp-hr)

Project Execution

The technology was retrofitted onto the engines in 1994, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was $228,000. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1994 with the high-energy ignition upgrade. During that time, the emissions of the engines have been maintained under the required level. In the roughly 60 months of operation, the NOx reduction system has resulted in six engine outages but no lost operating hours. Roughly two man-hours per week of additional service is needed to maintain the engines.

Experience and Performance	
Months in operation (as of Aug '99)	60
Increased parasitic loads	None
Change in engine efficiency	None
Project Cost	$76,000 per engine
Estimated add'l fixed O&M	see Cost Effectiveness Calculations
Add'l man-hours of labor	2 hours/week per engine
Controlled NOx emission	1.4 lb/MMBTU (equivalent to 5.1 gm/hp-hr)
Number of forced outages	6
Total lost operating hours	0

Cost Effectiveness

The cost effectiveness spreadsheets from Duke Energy appear below.

Burrillville, RI
Clark TLA8
High Energy Ignition System Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$76,000	$/engine	Project Cost
Total Capital Costs		**$76,000**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/engine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	62 hrs/yr./engine	62	hrs/yr.	Estimate
Maintenance Labor Cost		$2,232	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$2,232	$/yr.	OAQPS
Total Maintenance Costs		**$4,464**	**$/yr.**	**Calculation**
Total O&M Costs		**$8,052**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$4,831	$/yr.	OAQPS
Administration	2% of TCI	$1,520	$/yr.	OAQPS
Insurance	1% of TCI	$760	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$11,326	$/yr.	OAQPS
Total Indirect Costs		**$18,437**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$26,489**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (10.08 g/hp-hr)	60.00	lb/hr	Test Data
Controlled NO_X Emissions	Controlled (5.1 g/hp-hr)	30.36	lb/hr	Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**129.84**	**tpy**	**Calculation**
Cost Effectiveness		**$204**	**$/ton**	**Calculation**

D.4 Case Study IC-4, Duke Energy, Cromwell, Connecticut

Operator Contact - Mike Taylor, (617) 560-1456

Background and Technology Selection

Duke Energy owns natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Cromwell, CT are six Cooper GMWA8 engines. These are two stroke reciprocating gas engines, 2000 hp each.

The engines are about 42 years old, manufactured well before NOx requirements were in place, and previously emitted NOx at a rate of 14.53 gm/hp-hr. As part of Connecticut's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions to below 8.72 gm/hp-hr of NOx by 1995.

The units operate as needed to meet gas transmission demands.

High-energy ignition was implemented in order to achieve the necessary NOx reductions. Although other approaches were considered, the primary reason for selection of this technology was that it was evaluated as the most cost-effective approach.

General Statistics on Duke Energy Cromwell, CT, IC Engines	
Engine Type	Cooper GMWA8, two-stroke, reciprocating
HP	6 x 2000 hp
Facility age	~ 42 years
Heat Recovery	None
Fuel(s)	Natural Gas
Capacity Factor	Not Available
Baseline (uncontrolled) NOx	14.53 gm/hp-hr (permit)
Controlled NOx	8.72 gm/hp-hr (permit)

Project Execution

The technology was retrofitted onto the engines in 1994, in time to satisfy RACT requirements. The cost of these retrofits, including commissioning, was $145,000. Personnel that managed the project are no longer with the company, so project execution details are not available.

Experience

The facility has been operating since 1994 with the high-energy ignition upgrade. During that time, the emissions of the engines have been maintained under the required level. In the roughly 60 months of operation, the NOx reduction system has resulted in six engine outages and a total of 12 lost operating hours. Roughly two man-hours per week of additional service is needed to maintain the engines.

Experience and Performance	
Months in operation (as of Aug '99)	60
Increased parasitic loads	None
Change in engine efficiency	None
Project Cost	$24,167 per engine
Estimated add'l fixed O&M	$8,000/year
Add'l man-hours of labor	2/week
Controlled NOx	8.72 gm/hp-hr
Number of forced outages	6
Total lost operating hours	12

Cost Effectiveness

The cost effectiveness spreadsheets from Duke Energy appear on the following page.

Cromwell, CT
Cooper GMWA8
High Energy Ignition System Cost Effectiveness

Capital Costs	Basis	Value	Units	Reference
Total Capital Investment (TCI)	TCI	$24,167	$/engine	Project Cost
Total Capital Costs		**$24,167**	**$**	**Calculation**
Operating Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$30	$/hr	Industry Average
Operating Labor Required	2 hrs/wk/engine	104	hrs/yr.	Experience
Operating Labor Cost		$3,120	$/yr.	Calculation
Supervisor Labor Cost	15% of Operating Labor	$468	$/yr.	OAQPS
Total Operating Costs		**$3,588**	**$/yr.**	**Calculation**
Maintenance Costs	**Basis**	**Value**	**Units**	**Reference**
Unit Cost	Hourly Rate	$36	$/hr	Industry Average
Maintenance Labor Required	62 hrs/yr./engine	62	hrs/yr.	Estimate
Maintenance Labor Cost		$2,232	$/yr.	Calculation
Material Cost	100% of Maintenance Cost	$2,232	$/yr.	OAQPS
Total Maintenance Costs		**$4,464**	**$/yr.**	**Calculation**
Total O&M Costs		**$8,052**	**$/yr.**	**Calculation**
Indirect Costs	**Basis**	**Value**	**Units**	**Reference**
Overhead	60% of O&M Costs	$4,831	$/yr.	OAQPS
Administration	2% of TCI	$483	$/yr.	OAQPS
Insurance	1% of TCI	$242	$/yr.	OAQPS
Cost Recovery Factor (CRF)	10 yrs at 8%	0.149	n.d.	OAQPS
Capital Recovery	TCI x CRF	$3,602	$/yr.	OAQPS
Total Indirect Costs		**$9,158**	**$/yr.**	**Calculation**
Total Annual Costs	**O&M Costs + Indirect Cost**	**$17,210**	**$/yr.**	**Calculation**
NO_X Emission Reduction	**Basis**	**Value**	**Units**	**Reference**
Baseline NO_X Emissions	Uncontrolled (14.53 g/hp-hr)	64.07	lb/hr	Permit Limit
Controlled NO_X Emissions	Controlled (8.72 g/hp-hr)	38.45	lb/hr	Permit Limit
NO_X Emission Reduction	**Emissions Differential**	**112.20**	**tpy**	**Calculation**
Cost Effectiveness		**$153**	**$/ton**	**Calculation**

D.5 Case Study IC-5, NORESCO, Plymouth Cogeneration, Plymouth, New Hampshire

Operator Contact - Jeff Neggers (603) 536-5115

Background and Technology Selection

NORESCO owns and operates a cogeneration facility on the grounds of Plymouth State College in Plymouth, NH. The facility has an 1800 HP, four-stroke diesel engine that runs on No. 2 fuel oil. This engine was put in place in 1994 and was required to comply with Best Available Control Technology (BACT), which was determined to be Selective Catalytic Reduction. The SCR system uses aqueous ammonia and reduces NOx by 90%.

The engine operates nearly continuously, having historical capacity factors well above 90% and projected capacity factors even higher in the future.

General Statistics on NORESCO, Plymouth Cogeneration	
Engine Type	Diesel, 4-stroke
HP	1800 hp
Facility age	~ 5 years
Heat Recovery	Yes
Fuel(s)	No. 2 Fuel Oil
Historical Capacity Factor **1998 Capacity Factor** **Projected Future Cap. Fctr.**	93% 95% 98%
Baseline (uncontrolled) NOx	1200 ppm
Controlled NOx	1 gm/hp-hr (~120 ppm)

Project Execution

As a new engine, the SCR system was provided as part of a larger project. The SCR was placed in service at start up.

Because the original intent was to fire the engine on No. 6 fuel oil, the catalyst is somewhat oversized. The capital cost of the SCR was $180,000.

Experience

The facility has been operating since 1994 with the SCR in operation since startup. In that time there have been no NOx exceedances. The SCR has averaged about 4 forced outages per year totaling about 20 lost operating hours per year. These lost hours and outages are primarily due to the need to periodically clean the catalyst. Engine lubricating oil contributes to the soot and ash that build up over time on the catalyst. Additional labor required for the SCR is roughly 1 hour per week.

With 45,000 operating hours without a need for catalyst replacement, the catalyst is meeting its expected lifetime. The ammonia flow rate has also met its guarantee level at about 2.7 lb/hr.

Instrumentation with brass fittings located at the SCR inlet was found to fail rapidly due to corrosion from ammonia. Downstream equipment was unaffected due to the much lower ammonia concentration.

Experience and Performance	
Months in operation (as of Sept '99)	~ 60
Accumulated Operating Hours	45,000
Change in engine efficiency	Increased back pressure, up to maximum of 12" H2O
Project Cost	$180,000 (SCR only)
Estimated additional fixed O&M	$2,000/year
Estimated additional variable O&M	$21,000/yr
Additional man-hours of labor	1/week
Catalyst Replacement	None yet
Controlled NOx	120 ppm (90% reduction, all loads)
Number of forced outages	~ 4/ yr.
Total lost operating hours	~20/yr

Cost Effectiveness

A detailed cost analysis for cost effectiveness was not done by NORESCO. However, the SCR has facilitated cost savings in other aspects of the overall facility operation. Because this engine is operated almost continuously and controls to a low level, another engine at the facility is not required to install NOx reduction equipment. Moreover, the high capacity factor of the engine permits it's HRSG to provide a significant portion of the university's heating load without any additional fuel being spent. Thus, this cogeneration project has resulted in several benefits, including environmental benefits.

D.6 Case Study IC-6, Tennessee Gas Pipeline, Mercer, Pennsylvania

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Mercer, PA are six Cooper GMV-10 engines. These are two-stroke reciprocating gas engines, site rated at 1100 hp each.

As part of Pennsylvania's Reasonably Available Control Technology (PA RACT) requirements, it was necessary to reduce NOx emissions since the units produced greater than 500 hp.

TGP evaluated several technologies and chose parametric control (retarded ignition timing) as the cost-effective option for these engines in accordance with PA RACT regulations.

General Statistics on Tennessee Gas Pipeline - Mercer PA IC engine	
Engine Type	Cooper GMV-10, two-stroke, reciprocating
HP	6 x 1100 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NOx	10 gm/hp-hr
Controlled NOx	9 gm/hp-hr

The units operate as needed to meet gas transmission demands.

Project Execution

The technology was retrofitted onto the engines in time to satisfy RACT requirements. The cost of this retrofit, including commissioning, was $4000 per engine. The project was implemented quickly, being a relatively minor change.

Experience

The facility has been operating since 1995 with the ignition timing retard. During that time, the emissions from the engines have been maintained at around 9 gm/hp-hr. There is additional maintenance due to increased carbon buildup in the engine with the retarded timing.

Experience and Performance	
Months in operation (as of Oct '99)	54
Increased fuel consumption	See Cost effectiveness calculations
Project Cost	See Cost effectiveness calculations
Estimated add'l maintenance	See Cost effectiveness calculations
Add'l cost of testing	See Cost effectiveness calculations
Controlled NOx emissions	9 gm/hp-hr
Number of forced outages	Insufficient Data
Total lost operating hours	0

Cost Effectiveness

Cost effectiveness spreadsheets from Tennessee Gas appear on the following page.

Mercer, PA
Cooper GMV-10
LEC Cost Effectiveness

Cost	*Basis*	*Value*	*Reference*
Total Capital Investment (TCI)	TCI	$4,000	Project Cost

	Basis	*Value*	*Reference*
Operating Cost			
Unit Cost	Hourly Rate	$30.00	
Labor Required	60 hrs/yr	60	
Total Cost ($/yr)		**$1,800**	**Calculation**
Supervisor Labor			
Labor Required	15% Operating Labor	$270	OAQPS
Total Cost ($/yr)		**$270**	**Calculation**
Maintenance			
Unit Cost	Hourly rate	$36.00	Industry Average
Labor Required	80 hrs/year	80	Estimate
Maintenance Cost		$2,880	Calculation
Material Cost	100% of Maintenance Cost + Added Fuel Cost	$7,880	Calculation
Total Cost ($/yr)		**$10,760**	**Calculation**
Indirect			
Overhead	60% of O&M Costs	$7,698.00	OAQPS
Administration	2% of TCI	$80.00	OAQPS
Insurance	1% of TCI	$40.00	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	$596	Calculation
Total Indirect Costs ($/yr)		**$8,414**	**Calculation**
Base Case Emission Rate	Uncontrolled; lb/hr	35.110	Test Data
NO_x Emission rate	Controlled; lb/hr	31.600	Permit Limit
Total NO_x Controlled (ton/yr)	Emission Differential; tpy	15.4	Calculation
Total Annual Cost ($/yr)	**Summation**	**$21,244**	**Calculation**
COST EFFECTIVENESS ($/ton)		**$1,382**	

D.7 Case Study IC-7, Tennessee Gas Pipeline, Syracuse, New York

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Syracuse, NY are two Clark TLA-10 engines. These are two-stroke reciprocating gas engines, 3400 hp each.

As part of New York's Reasonably Available Control Technology (RACT) requirements, it was necessary to reduce NOx emissions since the units produced greater than 500 hp.

TGP evaluated several technologies to comply with NYSDEC presumptive RACT levels of 3 grams/BHP-hr for reciprocation engines and selected OEM low-emission combustion kits to achieve the presumptive NOx RACT. This was the approach required by the State of New York's RACT compliance plans.

General Statistics on Tennessee Gas Pipeline - Syracuse, NY IC Engines	
Engine Type	Clark TLA-10, two-stroke, reciprocating
HP	2 x 3400 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NOx	13 gm/hp-hr
Controlled NOx	3 gm/hp-hr

The units operate as needed to meet gas transmission demands.

Project Execution

The technology was retrofitted onto the engines in time to satisfy RACT requirements. (With extension granted by state) The cost of this retrofit, including commissioning, was $1,164,000 per engine.

Experience

The facility has been operating since 1995 with the low emission combustion retrofits. During that time, the emissions of the engines have been maintained at 3 gm/hp-hr. There have been some maintenance difficulties associated with check valves to Pre-Combustion Chambers.

Experience and Performance	
Months in operation (as of Oct '99)	54
Project Cost	$1,164,000 per engine
Controlled NOx emissions	3 gm/hp-hr
Number of forced outages	Insufficient Data
Total lost operating hours	Insufficient Data

Cost Effectiveness

Spreadsheet from Tennessee Gas detailing costs follows.

Syracuse, NY
Clark TLA-8
LEC Cost Effectiveness

Cost	*Basis*	*Value*	*Reference*
Total Capital Investment (TCI)	TCI	$1,164,000	Actual Project Cost

	Basis	*Value*	*Reference*
Operating Labor			
Unit Cost	Hourly rate	$30.00	Industry Average
Labor Required	1 hr/shift, 3 shifts/day	1,095	Estimate
Total Cost ($/yr)		**$32,850**	**Calculation**
Supervisor Labor			
Labor Required	15% Operating Labor	$4,928	OAQPS
Total Cost ($/yr)		**$4,928**	**Calculation**
Maintenance			
Unit Cost	Hourly rate	$36.00	Industry Average
Labor Required	20 hrs/month	240	Estimate
Maintenance Cost		$8,640	Calculation
Material Cost	100% of Maintenance Cost	$8,640	Calculation
Total Cost ($/yr)		**$17,280**	**Calculation**
Indirect			
Overhead	60% of O&M Costs	$33,035	OAQPS
Administration	2% of TCI	$23,280	OAQPS
Insurance	1% of TCI	$11,640	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	$173,470	Calculation
Total Indirect Costs ($/yr)		**$241,425**	**Calculation**
Base Case Emission Rate	Uncontrolled; lb/hr	97.440	Test Data
NO_x Emission rate	Controlled; lb/hr	22.500	Permit Limit
Total NO_x Controlled (ton/yr)	Emission Differential; tpy	328.2	Calculation
Total Annual Cost ($/yr)	**Summation**	**$296,482**	**Calculation**
COST EFFECTIVENESS ($/ton)		**$903**	

D.8 Case Study IC-8, Tennessee Gas Pipeline, Coudersport, Pennsylvania

Operator Contact - Sam Clowney (713) 420-3968

Background and Technology Selection

Tennessee Gas Pipeline owns and operates natural gas transmission facilities in the Northeast US. The fleet of engines includes turbines and reciprocating engines with integral compressors. Among the equipment located in Coudersport, PA are ten KVG-412 engines. These are four-stroke reciprocating gas engines, 1,320 hp each.

TGP evaluated several technologies and chose Non Selective Catalytic Reduction (NSCR) with retarded ignition timing as the cost-effective option for these engines in accordance with PA RACT regulations.

General Statistics on Tennessee Gas Pipeline – Coudersport, PA, IC Engine	
Engine Type	KVG-412, four-stroke, reciprocating
HP	10 x 1320 hp
Heat Recovery	None
Fuel(s)	Natural Gas
Baseline (uncontrolled) NOx	20 gm/hp-hr
Controlled NOx	3 gm/hp-hr

The units operate as needed to meet gas transmission demands.

Project Execution

The technology was retrofitted onto the engines in time to satisfy RACT requirements. The cost of this retrofit, including commissioning, was $150,000 per engine.

Experience

The facility has been operating since 1995 with the NSCR. During that time, the emissions of the engines have been maintained at 3 gm/hp-hr. Additional maintenance and testing is required, associated with the catalyst and the fuel/air ratio controls.

Experience and Performance	
Months in operation (as of Oct '99)	54
Project Cost	$183,000 per engine
Estimated add'l maintenance	See cost effectiveness calc.
Add'l cost of testing	See cost effectiveness calc.
NOx emissions	3 gm/hp-hr
Number of forced outages	<20
Total lost operating hours	<1000

Cost Effectiveness

Cost effectiveness spreadsheets from Tennessee Gas follow.

Coudersport, PA
Ingersoll Rand KVG-412
NSCR Cost Effectiveness

Cost	*Basis*	*Value*	*Reference*
Total Capital Investment (TCI)	TCI	$183,000	Actual Project Cost

	Basis	*Value*	*Reference*
Operating Labor			
Unit Cost	Hourly rate	$24.00	Industry Average
Labor Required	1 hr/shift, 3 shifts/day	1,095	Estimate
Total Cost ($/yr)		**$26,280**	**Calculation**
Supervisor Labor			
Labor Required	15% Operating Labor	$3,942	OAQPS
Total Cost ($/yr)		**$3,942**	**Calculation**
Maintenance			
Unit Cost	Hourly rate	$36.00	Industry Average
Labor Required	1hrs/shift, 3 shifts/day	250	Estimate
Maintenance Cost		$9,000	Calculation
Material Cost	100% of Maintenance Cost	$9,000	Calculation
Testing Cost		$600	Average
Total Cost ($/yr)		**$18,600**	**Calculation**
Indirect			
Overhead	60% of O&M Costs	$29,293	OAQPS
Administration	2% of TCI	$3,660	OAQPS
Insurance	1% of TCI	$1,830	OAQPS
Cost Recovery Factor (CRF)	10 Years, 8% Interest	0.149	OAQPS
Capital Recovery	TCI x CRF	$27,272	Calculation
Total Indirect Costs ($/yr)		**$62,056**	**Calculation**
Base Case Emission Rate	Uncontrolled; lb/hr	58.200	Test Data
NO_x Emission rate	Controlled; lb/hr	8.700	Permit Limit
Total NO_x Controlled (ton/yr)	Emission Differential; tpy	216.8	Calculation
Total Annual Cost ($/yr)	**Summation**	**$110,878**	**Calculation**
COST EFFECTIVENESS ($/ton)		**$511**	

E. Cement Kiln Case Studies

E.1 Case Study CK-1, California Portland Cement, Colton, California

Company Contact - John Bennett (626) 852-6261

Background and Technology Selection

California Portland Cement operates two (2) 1150 tons per day, long, dry kilns

General Statistics on California Portland Cement, Colton, California	
Facility Type	Two Long Dry Kilns
Production	2 x 1150 TPD
Original Fuels	Coal/Coke - 97% Natural Gas - 3%
Current Fuels (BTU basis)	Coal/Coke - 88% Tires - 10 % Nat. Gas - 2%
Approx. Facility Age	35 yrs
Year NOx Reduction in Service	1998
Baseline (uncontrolled) NOx	5.4 lb NOx/ton clinker
Controlled NOx	2.73 lb/ton clinker

California Portland Cement was required by the South Coast Air Quality Management District (SCAQMD) to reduce NOx emissions at the facility. The facility previously fired only coal/coke and natural gas. In order to reduce emissions, California Portland Cement decided to convert the kiln to indirect firing and mid-kiln firing with tires. Indirect Firing permits the use of a Low NOx Burner in the kiln. Firing tires mid-kiln enables the firing intensity in the primary combustion zone to be reduced, which helps to reduce NOx.

Project Execution

The technology was retrofitted onto the kiln in 1998. The project took 12 months and required a kiln shutdown of 4 weeks. The entire cost of the project, including equipment, installation and commissioning, was $7 million.

Experience

The facility has been operating since 1998. The modifications have not had any adverse impact on kiln reliability. In fact it is expected that the kiln reliability should be improved with the indirect firing system because problems that may be experienced with the coal mill will not have an immediate impact on the burner operation.

If tires are added at the rate of one tire per rotation (equivalent to a fuel substitution rate on BTU basis of about 12%), the facility clinker production is reduced by about 10% To date, California Portland Cement has not determined a way to regain this lost capacity while operating the tire injection system.

Experience and Performance	
Months in operation (as of Aug '99)	10
Increased parasitic loads	Neg.
Project Capital Cost	$7,000,000
Estimated add'l fixed O&M	$250,000/year
Estimated add'l variable O&M	$100,000
Approximate Baseline (uncontrolled) NOx	5.4 lb/ton clinker
Controlled NOx	2.73 lb/ton clinker
% reduction	~49%
Impact on Kiln reliability	10% reduction in plant production at tire addition rate of one tire per rotation.

Cost Effectiveness

The total capital charges were $7 million and operation and maintenance costs a total of about $350,000/yr ($250,000 fixed and $100,000 variable). The variable O&M cost is primarily associated with replacement of parts associated with the tire feeder and the burner tips.

E.2 Case Study CK-2, Texas Industries, Inc., Midlothian, Texas

Company Contact - Greg Mayes (972) 647 - 7058

Background and Technology Selection

Texas Industries is the largest producer of Portland Cement in Texas. One of their facilities is located just outside of Dallas in Midlothian, TX. The facility has four long-wet kilns with capacities of roughly 40 tons per hour each. The facility normally fires coal, combustible waste, and a small amount of natural gas. The waste is typically about one third of the heat input while the coal is typically 60% of the heat input.

Texas Industries has developed and patented the CemStar^{SM} process, primarily as a method to increase plant capacity (U.S. patents: 5,421,880 and 5,494,515). Although they use CemStar to improve capacity, the Midlothian facility is equipped with Continuous Emissions Monitors and has monitored improvements in NOx emissions while operating with CemStar. Because of the fuel flexibility of the Midlothian plant, there is significant variability in the potential NOx emissions. Recent testing to characterize NOx emissions under well-controlled conditions generated the following results.

General Statistics on Texas Industries, Midlothian Texas, Cement Plant		
Facility Type	Four Long-Wet Kilns	
Production	4 x 40 TPH of clinker	
Typical Fuels (BTU basis)	Coal - ≥50% Natural Gas ≤10 % Waste ~33%	
Approx. Facility Age	39 yrs	
Year that NOx reduction system was placed in service	1995	
NOx Testing	Short Term Tests	Long Term Tests
Fuel Firing Condition	Coal ~ 50% Gas ~ 50% Waste - none	Coal ~100% Waste - none
Baseline (uncontrolled) NOx	813 pph	206 pph

Project Execution

TXI's Midlothian Cement Plant is where CemStar was originally developed. It is located adjacent to TXI's Chaparral Steel Mill, which provides the steel slag. The installation of equipment for CemStar (mostly, standard material handling equipment for the steel slag) required a kiln shutdown of two days. The capital cost of the equipment was $250,000 per kiln.

Although the CemStar process has been used for years at the Midlothian Plant, emphasis so far has mostly been on capacity improvement rather than air pollution emissions improvement. For this reason, TXI recently conducted a series of tests under well-controlled kiln conditions to characterize the level of NOx reduction that CemStar provides.

Experience

The facility has been operating since 1961. The CemStar process has not had any adverse impact on kiln reliability. The results of recent tests to characterize NOx emissions with and without CemStar yielded the results shown below.

Short-term tests were conducted over a period of a few days and the long-term tests were conducted over a period of a few weeks for each condition. The tests were conducted at different conditions. In both cases significant NOx reduction was demonstrated - about 42% from conditions firing coal and gas and about 19% when operating under all-coal conditions.

Experience and Performance		
Months in operation (as of Aug '99)	50	
Increased parasitic loads	Neg.	
Increased Kiln Production Capacity	~10%	
Project Capital Cost	$ 1 million	
Estimated add'l fixed O&M	$20,000 /yr.	
Estimated add'l variable O&M	$10,000/yr	
NOx Testing	Short Term Tests	Long Term Tests
Fuel Firing Condition	Coal ~ 50% Gas ~ 50% Waste - none	Coal ~100% Waste - none
Uncontrolled Baseline NOx	813 pph	206 pph
Controlled NOx	471 pph	167 pph
Percent Reduction	42%	19%
Impact on Kiln reliability	No adverse impact	

Cost Effectiveness

The cost of employing CemStar includes the cost of capital equipment, about $250,000 for each kiln at the Midlothian plant. In addition, there is a running royalty fee that is based upon the usage of steel slag. For the Midlothian plant, this royalty would have added a cost of about $16 per ton of additional clinker produced. Rev 12/15/99

E.3 Case Study CK-3, Blue Circle Cement, Atlanta, Georgia

Company Contact - Tia Bohannon (404) 794-1561

Background and Technology Selection

Blue Circle Cement operates two (2) 950 ton per day (TPD) long, dry kilns

General Statistics on Blue Circle Cement kilns	
Facility Type	Two Long Dry Kilns
Production	2 x 950 TPD
Original Fuels	70% Coal, 30% Coke
Fuels After Retrofit	Coal/Coke 80% Tires - 20%
Approx. Facility Age	38 yrs
Year that NOx reduction system was placed in service	1998
Baseline (uncontrolled) NOx	510 ppm
Controlled NOx	Currently in test phase

Blue Circle Cement decided to implement this technology to reduce NOx emissions and also to take advantage of fuel savings and revenue potential for receiving tires. The economic benefit of receiving the tires in place of purchasing coal is estimated by Blue Circle to be $916,884 per year. Other technologies that Blue Circle considered was tire-derived-fuel (chipped tires) addition to the kiln back end. The facility is equipped with CEMS.

Project Execution

The technology was retrofitted onto the kilns in 1999. The project took 28 weeks and required a kiln shutdown of one week. The entire cost of the project, including equipment, installation and commissioning, was $1,495,000. At this time Blue Circle is still testing the kilns. The process will be officially put in service in the year 2000.

Blue Circle Cement Mid-Kiln Project Schedule	
Award of Contract to Completion of Engineering	4 weeks
Award of Contract to Completion of installation	26 weeks
Award of Contract to system commissioning	28 weeks
Total weeks from Award of Contract	**28 weeks**
Total Required Shutdown Period for Retrofitting of Kiln	**1 week**

Experience

The facility is still being tested. Thus far, the modifications have not had any adverse impact on product quality.

Experience and Expected Performance	
Months in operation (as of Jan 2000)	Still in testing
Project Capital Cost	$1,495,000
Estimated add'l fixed O&M	$64,000/year
Estimated add'l labor m-h's	none
Estimated add'l variable O&M	Economic benefit estimated at $916,884/year
Approx. Starting NOx	510 ppm
Expected Controlled NOx	350 ppm
% reduction	~30%
Impact on product quality	No adverse impact determined thus far

Cost Effectiveness

The total capital charges were $1,495,000 and fixed operation and maintenance costs a total of about $64,000/year with an expected net benefit of $916,884/year due to fuel savings and tipping fee revenue. When Blue Circle cement evaluated this project, they used a 10-year project horizon.

E.4 Case Study CK-4, Ash Grove Cement, Foreman, Arkansas

Company Contact - Steve Bales (913) 451-8900

Background and Technology Selection

Ash Grove Cement operates one 1,300 tpd, wet kiln at this location that is the subject of this case study. Two smaller kilns are also burning tires at this location.

General Statistics on Ash Grove Cement kiln	
Facility Type	One Wet Kiln
Production	1,300 TPD
Original Fuels	73% Coal, 27% Waste
Fuels After Retrofit (BTU basis)	Coal 65%, Waste 27%, Tires - 8%
Approx. Facility Age	42 yr.
Year that NOx reduction system was placed in service	1998
Baseline NOx (with process control)	~383 lb. NOx/hr
Controlled NOx (with process control & tires)	~345 lb. NOx/hr

Ash Grove Cement decided to implement mid-kiln firing primarily to take advantage of fuel savings and revenue potential for receiving and burning tires. There is an immediate fuel replacement of 8% (BTU basis). In addition, Ash Grove receives a tipping fee from the State of Arkansas for the tires. The facility is also equipped with a Linkman process control system that has provided process improvements through reduction of kiln operating variability. The facility is equipped with a CEMS. When using Linkman, a process control strategy that uses NOx as an input, a substitution of 8% of the fossil fuel with tires, reduces the NOx emission rate from 383 lb./hr to 345 lb./hr. This 10% reduction of NOx is obtained by feeding one truck tire every third revolution of the kiln.

Project Execution

The technology was retrofitted onto the kiln in January 1998. The entire cost of the project, for this kiln, including equipment, installation and commissioning, was approximately $500,000.

Experience

The facility has been burning tires for more than 25 months. The experience with the technology is outlined in the table below.

Performance before and after NOx based Process Control

Prior to the installation of the Linkman control method, the baseline for NOx without tires was 845 lb./hr. NOx emissions were reduced to 550 lb./hr through mid-kiln firing of tires - a 35% reduction of NOx. The process control strategies of the Linkman process control system using NOx are primarily for the purpose of maintaining process stability and are not specifically designed to control NOx. Nevertheless, NOx reduction does occur as a result of the improved process control with Linkman. The NOx emission level with Linkman alone without tire addition is 383 lb/hr - a 55% reduction from the uncontrolled NOx emission level of 845 lb./hr. The combined technologies of automated process control (Linkman) with mid-kiln firing of tires achieved a NOx emission level of 345 lb./hr - a 59% reduction from the totally uncontrolled level.

Figure IV-1 compares the frequency histogram of NOx emissions of Linkman process control alone to the frequency histogram of NOx emissions of Linkman process control with mid-kiln firing of tires. As demonstrated, the average NOx emissions for the combination of Linkman with mid-kiln firing of tires is 10% lower than that for kiln operation with Linkman alone.

The benefits of each control strategy are shown in Figure IV-2, A-D. Figure A shows a frequency histogram of NOx emissions for the uncontrolled condition. As shown, NOx is extremely variable. Figure B shows the effect of mid-kiln firing of tires alone. Clearly, the highest NOx values are diminished in frequency, resulting in 35% reduction in average NOx emissions from the conditions of Figure A. Figure C shows the effects of the Linkman process control alone. Again, the highest NOx emissions are avoided and only the lowest NOx emissions result, providing a 55% reduction in average NOx emissions from the conditions of Figure A. Figure D shows that the combined processes provide 59% reduction in NOx emissions from the conditions of Figure A. The arrows show the percent reduction for each condition to provide a combined 59% reduction of NOx emissions.

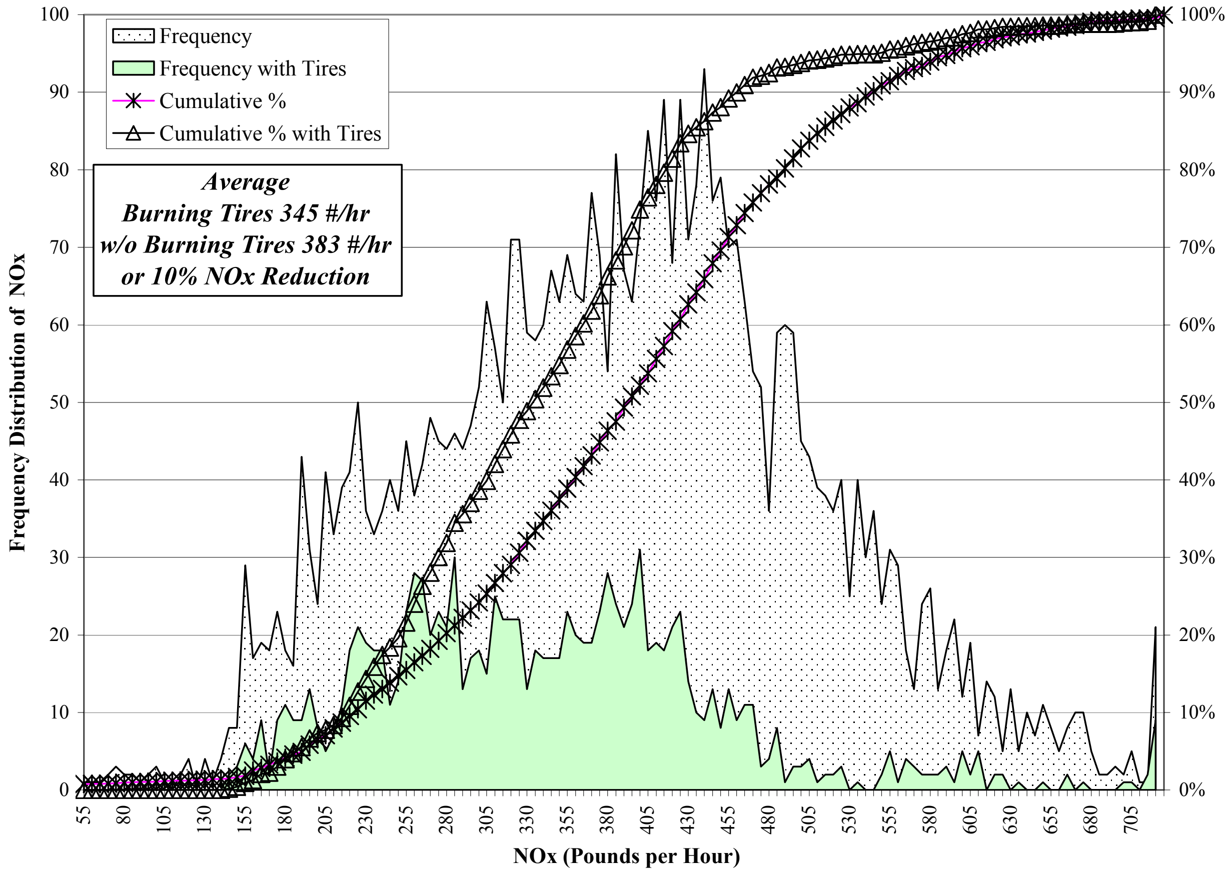
Experience and Expected Performance	
Months in operation (as of Jan 2000)	25
Project Capital Cost	$500,000
Estimated add'l fixed O&M	$15,000/year
Estimated add'l labor man-hours	One man-hour per shift[xi]
Estimated add'l variable O&M	Ash Grove receives a tipping fee from the State
Forced Outages from new equipment	Average 10 outage per year, however the kiln is not stopped to fix the problem until the next kiln outage
Lost operating hours from new equipment	Typically no hour are lost
Impact on product quality	No adverse impact

Cost Effectiveness

The total capital charges were $500,000 for the mid-kiln firing system, and fixed operation and maintenance costs a total of about $15,000/year. In addition, there are fuel savings and tipping fee revenue that justified this project purely from the perspective of return on investment. NOx reduction was not the primary motivation for proceeding with the project, but it was an additional benefit.

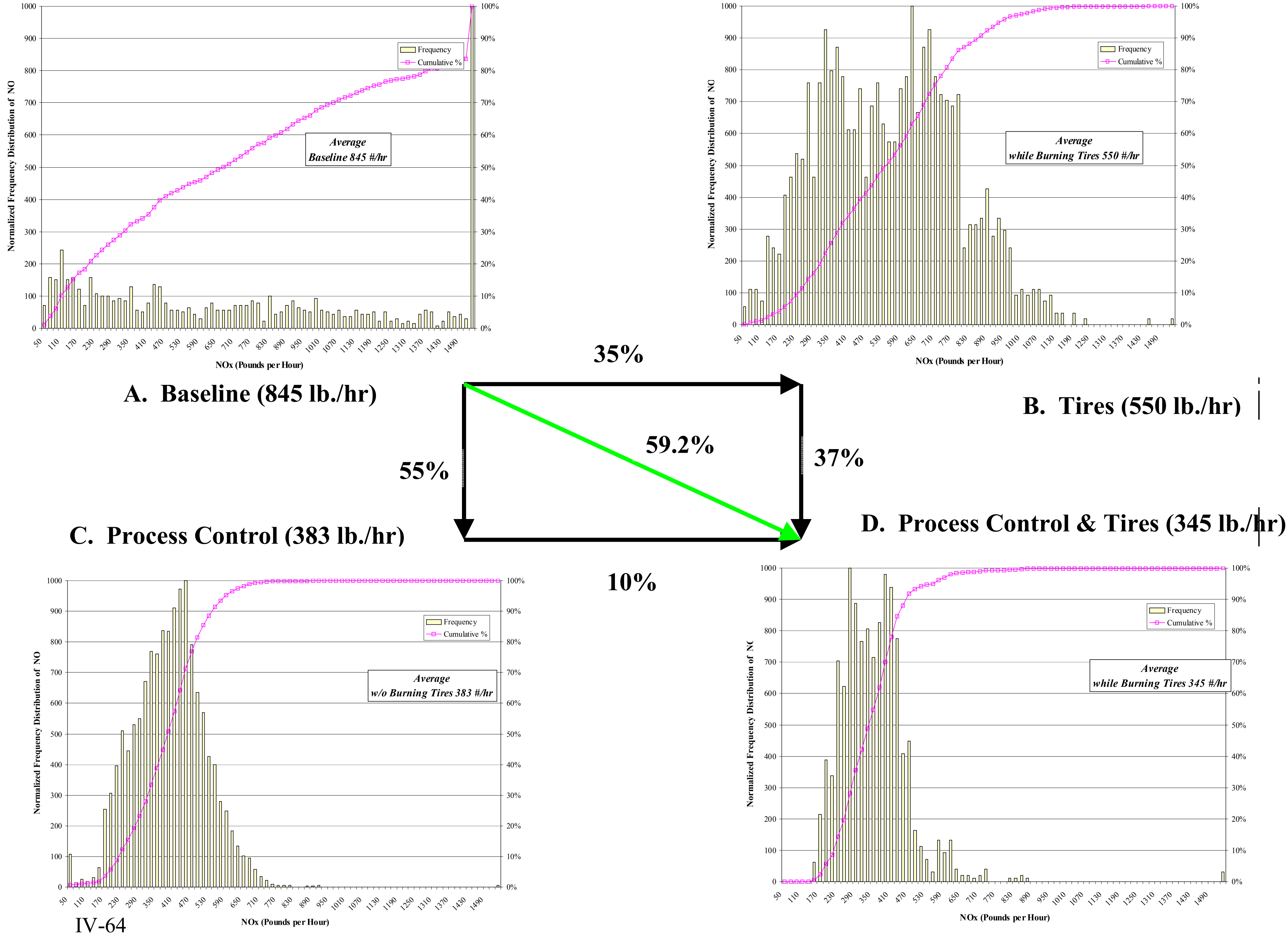
[xi] It usually takes one man-hour to fix hung up tires or to put back tires that have fallen off the conveyer, for all three kilns.

Figure IV-1: Nitrogen Oxide Emission Burning Tires vs. Not-Burning Tires[xii]



[xii] There were 1,158 ½ hour average data points while burning tires and 4,595 ½ hour average data points without tires.

Figure IV-2: Effect of Tires and Process Control on NOx Emissions



Appendixes: Worksheets for Economic Analysis

The following worksheets were prepared to analyze the cost effectiveness of various NOx control approaches. For each condition evaluated, there were three linked worksheets: a project data sheet, a process analysis sheet, and a cash flow analysis sheet. What follows are examples of cost analysis for each source category. These examples do not include every condition analyzed in this report. The analysis shown includes the following:

1. A rigorous analysis of projected cash flows for a 15-year period analyzed on an after-tax basis. Because an after-tax analysis is interested in the net cash flow after taxes, the tax-reducing effects of depreciation and O&M cash expenditures are considered in this analysis. Although financing cash flows (i.e., debt principal and interest payments) are shown over project life, this is really for information purposes and does not figure into the final calculation of cost effectiveness. Capital and financing costs are treated in a manner typical in capital project analysis - applying a capital recovery factor using the WACC to determine an annual capital recovery.
2. A rigorous analysis of projected cash flows for a 15-year period analyzed on a before-tax basis. This is the same as the analysis above, except the tax-reducing effects of some expenses (such as depreciation) are not included.
3. A less rigorous analysis (but, no less valid) that uses a simplified capital recovery approach and assesses cost on a before-tax basis.

It is important to note that the results shown in tables of Chapter III of this report are the average of the results of methods #2 and #3. The reader will notice in the following tables that both of these approaches yielded similar results in all cases, demonstrating that the less rigorous approach is satisfactory for the purpose of this report or other similar efforts.

Although the worksheets in this appendix only show cash flows for the first 3 years, analysis was actually performed for the economic life of the project (15 years).

Boiler Worksheets

NOx Reduction Case Spreadsheet	
Boiler with Selective Non Catalytic Reduction	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 40%)	35%
boiler heat rate (BTU/kWh)	12,000
Outlet NOx Value	0.29
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	65%
Primary Fuel Cost ($/MMBTU)	$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Urea ($/gallon)	$0.95
Cost of Urea ($/ton)	$406.74
Urea Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost ($)	$775,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate ($/$1,000)	$15.00
Pretax Rate of Return (ACT document)	10.0%

Boiler SNCR Process Analysis	
Plant	
MMBTU/hr	350
lb/hr NOx reduced	55
lbmole/hr NOx reduced	1
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$525
Urea Cost ($/gallon)	$0.95
Urea Cost ($/ton)	$406.74
Urea Cost ($/lbmole)	$12.20
Urea Utilization	40%
Urea usage (lbmole/hr)	1.5
Urea usage (gal/hr)	19.25
Urea Cost ($/hr)	$18.28
Heat Rate Increase	0.50%
Uncontrolled NOx	0.45
Controlled NOx	0.29
Capital Cost, includes license ($/kW)	775,000
Fixed O&M ($/yr.)	$25,000
Capacity factor	0.65
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	65

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($1,245,563)	($1,277,947)	($1,311,174)
Controlled Fuel Cost	$0	($1,251,822)	($1,284,369)	($1,317,763)
Urea Cost	$0	($43,365)	($44,493)	($45,650)
Total Variable O&M		($49,624)	($50,915)	($52,238)
Fixed O&M	$0	($25,000)	($25,650)	($26,317)
Total O&M	**$0**	**($74,624)**	**($76,565)**	**($78,555)**
Total Capital Cost	**$775,000**			
Financed with Common Equity	($465,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($310,000)			
Debt payments		($35,119)	($35,119)	($35,119)
Interest portion of payment		($23,250)	($22,360)	($21,403)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($77,500)	($139,500)	($108,500)
EOP Book Value	$775,000	$697,500	$558,000	$449,500
Property Taxes		**($11,625)**	**($10,463)**	**($8,370)**
Adjustment for Income taxes		**$57,312**	**$79,285**	**$68,399**
Net Cash Flow (current $, incl. fin.)	($465,000)	($64,056)	($42,862)	($53,646)
Net Cash Flow (current $, excl fin.)	($775,000)	($28,937)	($7,743)	($18,526)
Capital Expenditure Annuity @ WACC		($107,478)	($107,478)	($107,478)
NCF with annualized capital		**($136,415)**	**($115,221)**	**($126,005)**
Current $ $/ton of NOx reduced		($2,086.12)	($1,762.00)	($1,926.91)
NCF w/ann. cap. Discount by infl rate		**($132,958)**	**($109,455)**	**($116,666)**
Sum of discounted NCF	**($1,823,151)**			
TOTAL Tons NOx reduced Proj. Life	**981**			
$/ton NOx reduced (after taxes)	**($1,859)**			
Before Tax Net Cash Flow		**($193,728)**	**($194,505)**	**($194,404)**
Discounted Before Tax NCF		**($188,818)**	**($184,772)**	**($179,996)**
Sum of discounted Before Tax NCF	**($2,463,127)**			
	981			
$/ton NOx reduced (before tax basis)	**($2,511)**			
Annual Capital Recovery	($85,250)			
Annual O&M	($74,624)			
Total Cost	($159,874)			
Annual NOx reduced (tons)	65			
$/ton (per ACT document)	**($2,445)**			
Average	**($2,478)**			

NOx Reduction Case Spreadsheet	
Boiler Selective Catalytic Reduction	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	**350**
Initial NOx value (lb/MMBTU)	**0.45**
NOx reduction needed (up to 90%)	**80%**
Outlet NOx Value	**0.09**
Project Economic Data	
# of months/year NOx reduction needed	**5**
Capacity Factor	**85%**
Primary Fuel Cost ($/MMBTU)	**$1.50**
Primary Fuel Escalation (%/yr.)	**2.6%**
Cost of Ammonia ($/ton)	**$360.00**
Ammonia Escalation (%/yr.)	**2.6%**
Catalyst Cost ($/m3)	**$10,000**
Op Hrs Between Catalyst Replacement	**20,000**
Estimated Fixed O&M in first year	**$50,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
Capital cost ($/MMBTU/hr)	**$12,500**
Capital Cost ($)	$4,375,000
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT pretax marginal rate of return	**10.0%**

Process Analysis	
Boiler SCR	
Plant	
MMBTU/hr	350
lb/hr NOx reduced	126
lbmole/hr NOx reduced	3
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$525
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	2.7
Ammonia usage (lb/hr)	46.57
Ammonia Cost ($/hr)	$8.38
Approx. Catalyst Loading (m3)	42
Heat Rate Increase	**0.50%**
Uncontrolled NOx	0.45
Controlled NOx	0.09
Capital Cost, includes license ($/KW)	4,375,000
Fixed O&M ($/yr.)	$50,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**195**

	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($3,909,150)	($4,010,788)	($4,115,068)
Controlled Fuel Cost	$0	($3,928,794)	($4,030,943)	($4,135,747)
ammonia cost	$0	($26,004)	($26,680)	($27,374)
annual catalyst addition		($52,122)	($53,477)	($54,868)
Total Variable O&M		($97,770)	($100,312)	($102,920)
Fixed O&M	$0	($50,000)	($51,300)	($52,634)
Total O&M (incl. Dif. Fuel)	**$0**	**($147,770)**	**($151,612)**	**($155,554)**
Total Capital Cost	**$4,375,000**			
Financed with Common Equity	($2,625,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($1,750,000)			
Debt payments		($198,253)	($198,253)	($198,253)
Interest portion of payment		($131,250)	($126,225)	($120,823)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($437,500)	($787,500)	($612,500)
EOP Book Value	$4,375,000	$3,937,500	$3,150,000	$2,537,500
Property Taxes (net of income tax effect)		**($65,625)**	**($59,063)**	**($47,250)**
Adjustment for Income taxes		**$227,813**	**$349,361**	**$285,356**
Net Cash Flow (current $, incl. fin.)	($2,625,000)	($183,835)	($59,566)	($115,700)
Net Cash Flow (current $, excl fin.)	($4,375,000)	$14,418	$138,686	$82,552
Capital Expenditure Annuity @ WACC		($606,732)	($606,732)	($606,732)
NCF with annualized capital		**($592,314)**	**($468,046)**	**($524,180)**
Current $ $/ton of NOx reduced		($3,030.40)	($2,394.62)	($2,681.81)
NCF w/ann. cap. Discount by infl rate		**($577,304)**	**($444,625)**	**($485,331)**
Sum of discounted NCF	**($7,692,965)**			
TOTAL Tons NOx reduced Proj. Life	**2,932**			
$/ton NOx reduced (after taxes)	**($2,624)**			
Before Tax Net Cash Flow		**($820,127)**	**($817,407)**	**($809,536)**
Discounted Before Tax NCF		**($799,344)**	**($776,504)**	**($749,539)**
Sum of discounted Before Tax NCF	**($9,906,260)**			
	2,932			
$/ton NOx reduced (before tax basis)	**($3,379)**			
Annual Capital Recovery	($481,250)			
Annual O&M	($147,770)			
Total Annual Cost	($629,020)			
Annual NOx reduced (tons)	195			
$/ton (per ACT document)	**($3,218.19)**			
	($3,299)		average	

NOx Reduction Case Spreadsheet	
Gas Boiler with SCR	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	**350**
Initial NOx value (lb/MMBTU)	**0.15**
NOx reduction needed (up to 90%)	**80%**
Outlet NOx Value	**0.03**
Project Economic Data	
# of months/year NOx reduction needed	**12**
Capacity Factor	**85%**
Primary Fuel Cost ($/MMBTU)	**$1.50**
Primary Fuel Escalation (%/yr.)	**2.6%**
Cost of Ammonia ($/ton)	**$360.00**
Ammonia Escalation (%/yr.)	**2.6%**
Catalyst Cost ($/m3)	**$10,000**
Op Hrs Between Catalyst Replacement	**20,000**
Estimated Fixed O&M in first year	**$50,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
Capital cost ($/MMBTU/hr)	**$5,500**
Capital Cost ($)	$1,925,000
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT pretax marginal rate of return	**10.0%**

Process Analysis	
Plant	
MMBTU/hr	350
lb/hr NOx reduced	42
lbmole/hr NOx reduced	1
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$525
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	0.9
Ammonia usage (lb/hr)	15.52
Ammonia Cost ($/hr)	$2.79
Approx. Catalyst Loading (m3)	18
Heat Rate Increase	0.50%
Uncontrolled NOx	0.15
Controlled NOx	0.03
Capital Cost, includes license ($/KW)	1,925,000
Fixed O&M ($/yr.)	$50,000
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**156**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
	Year			
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($3,909,150)	($4,010,788)	($4,115,068)
Controlled Fuel Cost	$0	($3,928,794)	($4,030,943)	($4,135,747)
ammonia cost	$0	($20,803)	($21,344)	($21,899)
annual catalyst addition		($10,859)	($11,141)	($11,431)
Total Variable O&M		($51,306)	($52,640)	($54,009)
Fixed O&M	$0	($50,000)	($51,300)	($52,634)
Total O&M (incl. Dif. Fuel)	**$0**	**($101,306)**	**($103,940)**	**($106,643)**
Total Capital Cost	**$1,925,000**			
Financed with Common Equity	($1,155,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($770,000)			
Debt payments		($87,231)	($87,231)	($87,231)
Interest portion of payment		($57,750)	($55,539)	($53,162)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($192,500)	($346,500)	($269,500)
EOP Book Value	$1,925,000	$1,732,500	$1,386,000	$1,116,500
Property Taxes (net of income tax effect)		**($28,875)**	**($25,988)**	**($20,790)**
Adustment for Income taxes		**$112,938**	**$166,750**	**$138,926**
Net Cash Flow (current $, incl fin.)	($1,155,000)	($104,474)	($50,409)	($75,737)
Net Cash Flow (current $, excl fin.)	($1,925,000)	($17,243)	$36,822	$11,494
Capital Expenditure Annuity @ WACC		($266,962)	($266,962)	($266,962)
NCF with annualized capital		**($284,205)**	**($230,140)**	**($255,468)**
Current $ $/ton of NOx reduced		($1,817.56)	($1,471.80)	($1,633.78)
NCF w/ann cap. Discount by infl rate		**($277,003)**	**($218,624)**	**($236,535)**
Sum of discounted NCF	**($3,729,740)**			
TOTAL Tons NOx reduced Proj. Life	**2,345**			
$/ton NOx reduced (after taxes)	**($1,590)**			
Before Tax Net Cash Flow		**($397,143)**	**($396,890)**	**($394,395)**
Discounted Before Tax NCF		**($387,079)**	**($377,029)**	**($365,165)**
Sum of discounted Before Tax NCF	**($4,889,270)**			
	2,345			
$/ton NOx reduced (before tax basis)	**($2,085)**			
Annual Capital Recovery	($211,750)			
Annual O&M	($101,306)			
Total Annual Cost	($313,056)			
Annual NOx reduced (tons)	156			
$/ton (per ACT document)	**($2,002.07)**			
	($2,043)		average	

NOx Case Worksheet	
Conventional Gas Reburn	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 40%)	55%
boiler heat rate (BTU/KWhr)	10,000
Outlet NOx Value	0.20
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost ($/MMBTU)	$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Percent Reburn Fuel, %	20.0%
Cost of Natural Gas ($/MMBTU)	$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost ($)	$700,000
Capital Cost ($/MMBTU/hr)	$2,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	20
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate ($/$1,000)	$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Plant	
MMBTU/hr	350
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$420
Reburn Fuel Cost, $/MMBTU	$2.50
% Fuel Reburn zone	20.0%
Reburn Fuel Cost, $/hr	$175
Uncontrolled NOx	0.45
Controlled NOx	0.20
Capital Cost, $)	700,000
Fixed O&M ($/yr.)	$25,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**134**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($1,628,813)	($1,671,162)	($1,714,612)
Primary Fuel Cost	$0	($1,303,050)	($1,336,929)	($1,371,689)
Reburn Fuel Cost	$0	($542,938)	($557,054)	($571,537)
Tot. Controlled Fuel Cost	$0	($1,845,988)	($1,893,983)	($1,943,227)
Variable O&M		($217,175)	($222,822)	($228,615)
Fixed O&M	$0	($25,000)	($25,650)	($26,317)
Total O&M + dif. Fuel	**$0**	**($242,175)**	**($248,472)**	**($254,932)**
Total Capital Cost	**$700,000**			
Financed with Common Equity	($420,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($280,000)			
Debt payments		($27,466)	($27,466)	($27,466)
Interest portion of payment		($21,000)	($20,515)	($19,994)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($70,000)	($126,000)	($98,000)
EOP Book Value	$700,000	$630,000	$504,000	$406,000
Property Taxes		**($10,500)**	**($9,450)**	**($7,560)**
Adustment for Income taxes		**$112,936**	**$134,373**	**$126,172**
Net Cash Flow (current $, incl fin.)	($420,000)	($167,205)	($151,015)	($163,785)
Net Cash Flow (current $, excl fin.)	($700,000)	($139,739)	($123,549)	($136,320)
Capital Expenditure Annuity @ WACC		($97,077)	($97,077)	($97,077)
NCF with annualized capital		**($236,816)**	**($220,626)**	**($233,397)**
Current $ $/ton of NOx reduced		($1,762.32)	($1,641.84)	($1,736.88)
NCF w/ann cap. Discount by infl rate		**($230,815)**	**($209,586)**	**($216,099)**
Sum of discounted NCF	**($3,307,565)**			
TOTAL Tons NOx reduced Proj. Life	**2,016**			
$/ton NOx reduced (after taxes)	**($1,641)**			
Before Tax Net Cash Flow		**($349,752)**	**($354,999)**	**($359,569)**
Discounted Before Tax NCF		**($340,889)**	**($337,235)**	**($332,920)**
Sum of discounted Before Tax NCF	**($4,779,910)**			
	2,016			
$/ton NOx reduced (before tax basis)	**($2,371)**			
Annual Capital Recovery	($77,000)			
Annual O&M	($242,175)			
Total Cost	($319,175)			
Annual NOx reduced (tons)	134			
$/ton (per ACT document)	**($2,375)**			
	$2,373		**average**	

NOx Case Worksheet	
AE FLGR	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 70%)	60%
boiler heat rate (BTU/KWhr)	10,000
Outlet NOx Value	0.18
Urea NSR	1.2
Project Economic Data	
# of months/year NOx reduction needed	**12**
Capacity Factor	**85%**
Primary Fuel Cost ($/MMBTU)	$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas ($/MMBTU)	$2.50
Natural Gas Escalation (%/yr.)	2.6%
Urea Cost ($/gallon)	$0.95
Urea Cost ($/ton)	$406.74
Urea Escalation	2.6%
Estimated Fixed O&M in first year	$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost ($)	$875,000
Capital Cost ($/MMBTU/hr)	$2,500
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	20
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate ($/$1,000)	$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Plant	
MMBTU/hr	350
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$494
Reburn Fuel Cost, $/MMBTU	$2.50
% Fuel Reburn zone	6.0%
Reburn Fuel Cost, $/hr	$53
Uncontrolled NOx	0.45
Controlled NOx	0.18
Initial NOx (full load), lb/hr	158
Initial NOx (full load), lbmole/hr	3.42
lbmole/hr urea	2.05
lb/hr urea	123
$/hr urea (full load)	$25
Capital Cost, $)	875,000
Fixed O&M ($/yr.)	$25,000
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**352**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($3,909,150)	($4,010,788)	($4,115,068)
Primary Fuel Cost	$0	($3,674,601)	($3,770,141)	($3,868,164)
Reburn Fuel Cost	$0	($390,915)	($401,079)	($411,507)
Tot. Controlled Fuel Cost	$0	($4,065,516)	($4,171,219)	($4,279,671)
Urea Cost		($186,652)	($191,505)	($196,484)
Variable O&M		($343,018)	($351,937)	($361,087)
Fixed O&M	$0	($25,000)	($25,650)	($26,317)
Total O&M + dif. Fuel	**$0**	**($368,018)**	**($377,587)**	**($387,404)**
Total Capital Cost	**$875,000**			
Financed with Common Equity	($525,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($350,000)			
Debt payments		($34,332)	($34,332)	($34,332)
Interest portion of payment		($26,250)	($25,644)	($24,992)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($87,500)	($157,500)	($122,500)
EOP Book Value	$875,000	$787,500	$630,000	$507,500
Property Taxes		**($13,125)**	**($11,813)**	**($9,450)**
Adustment for Income taxes		**$164,025**	**$191,415**	**$181,774**
Net Cash Flow (current $, incl fin.)	($525,000)	($251,450)	($232,317)	($249,412)
Net Cash Flow (current $, excl fin.)	($875,000)	($217,118)	($197,984)	($215,080)
Capital Expenditure Annuity @ WACC		($121,346)	($121,346)	($121,346)
NCF with annualized capital		**($338,464)**	**($319,331)**	**($336,426)**
Current $ $/ton of NOx reduced		($962.03)	($907.64)	($956.24)
NCF w/ann cap. Discount by infl rate		**($329,887)**	**($303,351)**	**($311,493)**
Sum of discounted NCF	**($4,754,991)**			
TOTAL Tons NOx reduced Proj. Life	**5,277**			
$/ton NOx reduced (after taxes)	**($901)**			
Before Tax Net Cash Flow		**($502,489)**	**($510,745)**	**($518,200)**
Discounted Before Tax NCF		**($489,756)**	**($485,188)**	**($479,795)**
Sum of discounted Before Tax NCF	**($6,929,556)**			
	5,277			
$/ton NOx reduced (before tax basis)	**($1,313)**			
Annual Capital Recovery	($96,250)			
Annual O&M	($368,018)			
Total Cost	($464,268)			
Annual NOx reduced (tons)	352			
$/ton (per ACT document)	**($1,320)**			
Average of two methods	**$1,316**		**average**	

NOx Case Worksheet	
Fuel Lean Gas Reburn	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.45
NOx reduction needed (up to 40%)	35%
boiler heat rate (BTU/KWhr)	10,000
Outlet NOx Value	0.29
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost ($/MMBTU)	$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas ($/MMBTU)	$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	$25,000
Labor&Fixed O&M Escalation (%/yr.)	2.6%
Capital Cost ($)	$350,000
Capital Cost ($/MMBTU/hr)	$1,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	20
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate ($/$1,000)	$15.00
ACT pretax marginal rate of return	10.0%

Process Analysis	
Plant	
MMBTU/hr	350
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$493
Reburn Fuel Cost, $/MMBTU	$2.50
% Fuel Reburn zone	6.1%
Reburn Fuel Cost, $/hr	$54
Uncontrolled NOx	0.45
Controlled NOx	0.29
Capital Cost, $)	350,000
Fixed O&M ($/yr.)	$25,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**86**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($1,628,813)	($1,671,162)	($1,714,612)
Primary Fuel Cost	$0	($1,529,048)	($1,568,803)	($1,609,592)
Reburn Fuel Cost	$0	($166,275)	($170,598)	($175,033)
Tot. Controlled Fuel Cost	$0	($1,695,322)	($1,739,401)	($1,784,625)
Variable O&M		($66,510)	($68,239)	($70,013)
Fixed O&M	$0	($25,000)	($25,650)	($26,317)
Total O&M + dif. Fuel	**$0**	**($91,510)**	**($93,889)**	**($96,330)**
Total Capital Cost	**$350,000**			
Financed with Common Equity	($210,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($140,000)			
Debt payments		($13,733)	($13,733)	($13,733)
Interest portion of payment		($10,500)	($10,258)	($9,997)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($35,000)	($63,000)	($49,000)
EOP Book Value	$350,000	$315,000	$252,000	$203,000
Property Taxes		**($5,250)**	**($4,725)**	**($3,780)**
Adustment for Income taxes		**$46,116**	**$56,565**	**$52,189**
Net Cash Flow (current $, incl fin.)	($210,000)	($64,377)	($55,782)	($61,655)
Net Cash Flow (current $, excl fin.)	($350,000)	($50,644)	($42,049)	($47,922)
Capital Expenditure Annuity @ WACC		($48,539)	($48,539)	($48,539)
NCF with annualized capital		**($99,182)**	**($90,588)**	**($96,460)**
Current $ $/ton of NOx reduced		($1,159.86)	($1,059.35)	($1,128.02)
NCF w/ann cap. Discount by infl rate		**($96,669)**	**($86,055)**	**($89,311)**
Sum of discounted NCF	**($1,372,708)**			
TOTAL Tons NOx reduced Proj. Life	**1,283**			
$/ton NOx reduced (after taxes)	**($1,070)**			
Before Tax Net Cash Flow		**($145,298)**	**($147,153)**	**($148,649)**
Discounted Before Tax NCF		**($141,616)**	**($139,789)**	**($137,632)**
Sum of discounted Before Tax NCF	**($1,957,533)**			
	1,283			
$/ton NOx reduced (before tax basis)	**($1,526)**			
Annual Capital Recovery	($38,500)			
Annual O&M	($91,510)			
Total Cost	($130,010)			
Annual NOx reduced (tons)	86			
$/ton (per ACT document)	**($1,520)**			
Average of two methods	**$1,523**		**average**	

NOx Case Worksheet	
Low NOx Burners	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	350
Initial NOx value (lb/MMBTU)	0.6
NOx reduction needed (up to 40%)	25%
boiler heat rate (BTU/KWhr)	10,000
Outlet NOx Value	0.45
Project Economic Data	
# of months/year NOx reduction needed	5
Capacity Factor	85%
Primary Fuel Cost ($/MMBTU)	$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas ($/MMBTU)	$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	$0
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.00%
Capital Cost ($)	$1,750,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate ($/$1,000)	$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate MMBTU/hr	350
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$525
Reburn Fuel Cost, $/MMBTU	$2.50
Uncontrolled NOx	0.60
Controlled NOx	0.45
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**81**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($1,628,813)	($1,671,162)	($1,714,612)
Controlled Fuel Cost	$0	($1,628,813)	($1,671,162)	($1,714,612)
Variable O&M		$0	$0	$0
Fixed O&M		$0	$0	$0
Total O&M + dif. Fuel	**$0**	**$0**	**$0**	**$0**
Total Capital Cost	**$1,750,000**			
Financed with Common Equity	($1,050,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($700,000)			
Debt payments		($79,301)	($79,301)	($79,301)
Interest portion of payment		($52,500)	($50,490)	($48,329)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($175,000)	($315,000)	($245,000)
EOP Book Value	$1,750,000	$1,575,000	$1,260,000	$1,015,000
Property Taxes		**($26,250)**	**($23,625)**	**($18,900)**
Adustment for Income taxes		**$70,438**	**$118,519**	**$92,365**
Net Cash Flow (current $, incl fin.)	($1,050,000)	($35,114)	$15,593	($5,836)
Net Cash Flow (current $, excl fin.)	**($1,750,000)**	**$44,188**	**$94,894**	**$73,465**
Capital Expenditure Annuity @ WACC		($242,693)	($242,693)	($242,693)
NCF with annualized capital		**($198,505)**	**($147,799)**	**($169,228)**
Current $ $/ton of NOx reduced		($2,437.42)	($1,814.81)	($2,077.93)
NCF w/ann cap. Discount by infl rate		**($193,475)**	**($140,403)**	**($156,686)**
Sum of discounted NCF	**($2,515,486)**			
TOTAL Tons NOx reduced Proj. Life	**1,222**			
$/ton NOx reduced (after taxes)	**($2,059)**			
Before Tax Net Cash Flow		**($268,943)**	**($266,318)**	**($261,593)**
Discounted Before Tax NCF		**($262,128)**	**($252,991)**	**($242,205)**
Sum of discounted Before Tax NCF	**($3,098,350)**			
TOTAL Tons NOx reduced Proj. Life	**1,222**			
$/ton NOx reduced (before tax basis)	**($2,536)**			
Annual Capital Recovery	($192,500)			
Annual O&M	$0			
Total Annual Cost	($192,500)			
Annual NOx reduced (tons)	81			
$/ton (per ACT document)	**($2,363.69)**			
Average of both before-tax methods	**$2,450**			

NOx Case Worksheet	
Low NOx Burners - Oil	
Boiler Technical Data	
Target Boiler Size (MMBTU/hr)	1360
Initial NOx value (lb/MMBTU)	0.427
NOx reduction needed (up to 40%)	10%
boiler heat rate (BTU/KWhr)	10,000
Outlet NOx Value	0.38
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	85%
Primary Fuel Cost ($/MMBTU)	$1.50
Primary Fuel Escalation (%/yr.)	2.6%
Cost of Natural Gas ($/MMBTU)	$2.50
Natural Gas Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	$0
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	0.00%
Capital Cost ($)	$30,000
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate ($/$1,000)	$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate MMBTU/hr	1,360
Pri. Fuel Cost, $/MMBTU	$1.50
Pri. Fuel Cost, $/hr	$2,040
Reburn Fuel Cost, $/MMBTU	$2.50
Uncontrolled NOx	0.43
Controlled NOx	0.38
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**216**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($15,189,840)	($15,584,776)	($15,989,980)
Controlled Fuel Cost	$0	($15,189,840)	($15,584,776)	($15,989,980)
Variable O&M		$0	$0	$0
Fixed O&M		$0	$0	$0
Total O&M + dif. Fuel	**$0**	**$0**	**$0**	**$0**
Total Capital Cost	**$30,000**			
Financed with Common Equity	($18,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($12,000)			
Debt payments		($1,359)	($1,359)	($1,359)
Interest portion of payment		($900)	($866)	($828)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($3,000)	($5,400)	($4,200)
EOP Book Value	$30,000	$27,000	$21,600	$17,400
Property Taxes		**($450)**	**($405)**	**($324)**
Adustment for Income taxes		**$1,208**	**$2,032**	**$1,583**
Net Cash Flow (current $, incl fin.)	($18,000)	($602)	$267	($100)
Net Cash Flow (current $, excl fin.)	**($30,000)**	**$758**	**$1,627**	**$1,259**
Capital Expenditure Annuity @ WACC		($4,160)	($4,160)	($4,160)
NCF with annualized capital		**($3,403)**	**($2,534)**	**($2,901)**
Current $ $/ton of NOx reduced		($15.74)	($11.72)	($13.42)
NCF w/ann cap. Discount by infl rate		**($3,317)**	**($2,407)**	**($2,686)**
Sum of discounted NCF	**($43,123)**			
TOTAL Tons NOx reduced Proj. Life	**3,243**			
$/ton NOx reduced (after taxes)	**($13)**			
Before Tax Net Cash Flow		**($4,610)**	**($4,565)**	**($4,484)**
Discounted Before Tax NCF		**($4,494)**	**($4,337)**	**($4,152)**
Sum of discounted Before Tax NCF	**($53,115)**			
TOTAL Tons NOx reduced Proj. Life	**3,243**			
$/ton NOx reduced (before tax basis)	**($16)**			
Annual Capital Recovery	($3,300)			
Annual O&M	$0			
Total Annual Cost	($3,300)			
Annual NOx reduced (tons)	216			
$/ton (per ACT document)	**($15.26)**			
Average of both before-tax methods	**$16**			

Gas Turbine Worksheets

NOx Case Worksheet	
75 MW GT - Dry Low NOx: from Diluent Injection	
Engine Technical Data	
Target Engine Size, (MW)	75
Initial NOx value (ppm)	42
Initial NOx massflow (lb/hr)	139.99
NOx reduction needed (up to 40%)	64%
Engine heat rate (BTU/KWhr)	10,000
Outlet NOx Value (ppm)	15.00
Outlet NOx massflow (lb/hr)	50.00
Project Economic Data	
# of months/year NOx reduction needed	12
Capacity Factor	95%
Primary Fuel Cost ($/MMBTU)	$2.25
Primary Fuel Escalation (%/yr.)	2.6%
Estimated Fixed O&M in first year	$0
Labor&Fixed O&M Escalation (%/yr.)	2.6%
heat rate increase	-4.00%
Capital Cost ($)	$3,650,000
Capital Cost ($/KW)	$49
Cost of Equity Capital (%)	15.0%
Cost of Debt (%)	7.5%
Cost of Preferred Equity (%)	6.0%
% financed with debt (%)	40.0%
Term of debt financing (years)	15
% financed with Common Equity	60.0%
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	35.0%
Projected inflation rate (%)	2.6%
Evaluation period of Project (yrs)	15
Property Tax rate ($/$1,000)	$15.00
ACT Pretax Marginal Rate of Return	10.0%

Process Analysis	
Plant	
Nameplate MW	**75**
Pri. Fuel Cost, $/MMBTU	**$2.25**
Pri. Fuel Cost, $/hr	**$1,688**
Uncontrolled NOx (ppm)	**42.00**
Controlled NOx	**15.00**
Capital Cost	**$3,650,000**
Fixed O&M ($/yr.)	**$0**
Capacity factor	**0.95**
Months NOx reduction in service	**12.00**
Projected Book Life, yrs	**15.00**
Ann. NOx Red'n, tons	**374**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	**1**	**2**	**3**
Operating Costs				
Uncontrolled fuel Cost	$0	($14,043,375)	($14,408,503)	($14,783,124)
Controlled Fuel Cost	$0	($13,481,640)	($13,832,163)	($14,191,799)
Fuel Savings		$561,735	$576,340	$591,325
Water and Water Treatment savings (y or n)	y	$313,500	$321,651	$330,014
Fixed O&M	$0	$0	$0	$0
Total O&M + dif. Fuel	**$0**	**$875,235**	**$897,991**	**$921,339**
Total Capital Cost	**$3,650,000**			
Financed with Common Equity	($2,190,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($1,460,000)			
Debt payments		($165,399)	($165,399)	($165,399)
Interest portion of payment		($109,500)	($105,308)	($100,801)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($365,000)	($657,000)	($511,000)
EOP Book Value	$3,650,000	$3,285,000	$2,628,000	$2,117,000
Property Taxes		**($54,750)**	**($49,275)**	**($39,420)**
Adustment for Income taxes		**($104,370)**	**($10,619)**	**($71,872)**
Net Cash Flow (current $, incl fin.)	($2,190,000)	$495,666	$616,216	$586,698
Net Cash Flow (current $, excl fin.)	**($3,650,000)**	**$661,065**	**$781,615**	**$752,097**
Capital Expenditure Annuity @ WACC		($506,188)	($506,188)	($506,188)
NCF with annualized capital		**$154,877**	**$275,428**	**$245,909**
Current $ $/ton of NOx reduced		$413.61	$735.55	$656.72
NCF w/ann cap. Discount by infl rate		**$150,953**	**$261,645**	**$227,684**
Sum of discounted NCF	**$3,070,707**			
TOTAL Tons NOx reduced Proj. Life	**5,617**			
$/ton NOx reduced (after taxes)	**$547**			
Before Tax Net Cash Flow		**$314,297**	**$342,528**	**$375,731**
Discounted Before Tax NCF		**$306,332**	**$325,388**	**$347,884**
Sum of discounted Before Tax NCF	**$6,333,561**			
	5,617			
$/ton NOx reduced (before tax basis)	**$1,128**			
Annual Capital Recovery	($401,500)			
Annual O&M	$875,235			
Total Annual Cost	$473,735			
Annual NOx reduced (tons)	374			
$/ton (per ACT document)	**$1,265**			
Average ($/ton)-both before-tax methods	**$1,196**			

NOx Case Worksheet	
GT - 75 MW Dry Low NOx from Std. Combustor	
Engine Technical Data	
Target Engine Size, (MW)	**75**
Initial NOx value (ppm)	**154**
Initial NOx massflow (lb/hr)	**513.28**
NOx reduction needed (up to 40%)	**90%**
Engine heat rate (BTU/KWhr)	**10,000**
Outlet NOx Value (ppm)	**15.00**
Outlet NOx massflow (lb/hr)	**50.00**
Project Economic Data	
# of months/year NOx reduction needed	**12**
Capacity Factor	**45%**
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Estimated Fixed O&M in first year	**$0**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
heat rate increase	**0.00%**
Capital Cost ($)	**$3,650,000**
Capital Cost ($/KW)	**$49**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	**11.0%**
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT Pretax Marginal Rate of Return	**10.0%**

Process Analysis	
Plant	
Nameplate MW	**75**
Pri. Fuel Cost, $/MMBTU	**$2.25**
Pri. Fuel Cost, $/hr	**$1,688**
Uncontrolled NOx (ppm)	**154.00**
Controlled NOx	**15.00**
Capital Cost	**$3,650,000**
Fixed O&M ($/yr.)	**$0**
Capacity factor	**0.45**
Months NOx reduction in service	**12.00**
Projected Book Life, yrs	**15.00**
Ann. NOx Red'n, tons	**913**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($6,652,125)	($6,825,080)	($7,002,532)
Controlled Fuel Cost	$0	($6,652,125)	($6,825,080)	($7,002,532)
Fuel Savings		$0	$0	$0
Water and Water Treatment savings (y or n)	n	$0	$0	$0
Fixed O&M	$0	$0	$0	$0
Total O&M + dif. Fuel	**$0**	**$0**	**$0**	**$0**
Total Capital Cost	**$3,650,000**			
Financed with Common Equity	($2,190,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($1,460,000)			
Debt payments		($165,399)	($165,399)	($165,399)
Interest portion of payment		($109,500)	($105,308)	($100,801)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($365,000)	($657,000)	($511,000)
EOP Book Value	$3,650,000	$3,285,000	$2,628,000	$2,117,000
Property Taxes		**($54,750)**	**($49,275)**	**($39,420)**
Adustment for Income taxes		**$146,913**	**$247,196**	**$192,647**
Net Cash Flow (current $, incl fin.)	($2,190,000)	($73,237)	$32,522	($12,172)
Net Cash Flow (current $, excl fin.)	**($3,650,000)**	**$92,163**	**$197,921**	**$153,227**
Capital Expenditure Annuity @ WACC		($506,188)	($506,188)	($506,188)
NCF with annualized capital		**($414,025)**	**($308,267)**	**($352,961)**
Current $ $/ton of NOx reduced		($453.41)	($337.59)	($386.54)
NCF w/ann cap. Discount by infl rate		**($403,534)**	**($292,841)**	**($326,802)**
Sum of discounted NCF	**($5,246,585)**			
TOTAL Tons NOx reduced Proj. Life	**13,697**			
$/ton NOx reduced (after taxes)	**($383)**			
Before Tax Net Cash Flow		**($560,938)**	**($555,463)**	**($545,608)**
Discounted Before Tax NCF		**($546,723)**	**($527,667)**	**($505,171)**
Sum of discounted Before Tax NCF	**($6,462,273)**			
	13,697			
$/ton NOx reduced (before tax basis)	**($472)**			
Annual Capital Recovery	($401,500)			
Annual O&M	$0			
Total Annual Cost	($401,500)			
Annual NOx reduced (tons)	913			
$/ton (per ACT document)	**($440)**			
Average ($/ton)-both before-tax methods	**($456)**			

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction 75 MW turbine with DLN	
Turbine Technical Data	
Engine Size (MW)	**75**
Initial NOx value (ppm)	**15**
Initial NOx massflow (lb/hr)	**50.00**
NOx reduction needed (up to 40%)	**80%**
Engine heat rate (BTU/KWhr)	**10,000**
Outlet NOx Value (ppm)	**3.00**
Outlet NOx massflow (lb/hr)	**10.00**
Project Economic Data	
# of months/year NOx reduction needed	**5**
Capacity Factor	**85%**
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Heat Rate Increase	**0.5%**
Cost of Ammonia ($/ton)	**$360.00**
Ammonia Escalation (%/yr.)	**2.6%**
Catalyst Cost ($/m3)	**$14,000**
Op Hrs Between Catalyst Replacement	**42,000**
Estimated Fixed O&M in first year	**$20,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
Captial cost, ($/KW)	**$60**
Capital Cost ($)	**$4,500,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT pretax marginal rate of return	**10.0%**

Process Analysis	
Gas Turbine SCR	
MW	75.0
lb/hr NOx reduced	40.00
lbmole/hr NOx reduced	0.87
Pri. Fuel Cost, $/MMBTU	$2.25
Pri. Fuel Cost, $/hr @ full load	$1,688
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	0.9
Ammonia usage (lb/hr)	14.78
Ammonia Cost ($/hr)	$2.66
Approx Catalyst Loading (m3)	57
Heat Rate Increase	0.50%
Uncontrolled NOx	15.00
Controlled NOx	3.00
Capital Cost, includes license ($/KW)	4,500,000
Fixed O&M ($/yr.)	$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**62**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($12,565,125)	($12,891,818)	($13,227,006)
Controlled Fuel Cost	$0	($12,628,266)	($12,956,601)	($13,293,473)
ammonia cost	$0	($8,255)	($8,469)	($8,689)
annual catalyst addition		($142,063)	($145,757)	($149,547)
Total Variable O&M		($213,459)	($219,009)	($224,704)
Fixed O&M	$0	($20,000)	($20,520)	($21,054)
Total O&M (incl. Dif. Fuel)	**$0**	**($233,459)**	**($239,529)**	**($245,757)**
Total Capital Cost	**$4,500,000**			
Financed with Common Equity	($2,700,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($1,800,000)			
Debt payments		($203,917)	($203,917)	($203,917)
Interest portion of payment		($135,000)	($129,831)	($124,275)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($450,000)	($810,000)	($630,000)
EOP Book Value	$4,500,000	$4,050,000	$3,240,000	$2,610,000
Property Taxes (net of income tax effect)		**($67,500)**	**($60,750)**	**($48,600)**
Adustment for Income taxes		**$262,836**	**$388,598**	**$323,525**
Net Cash Flow (current $, incl fin.)	($2,700,000)	($242,041)	($115,599)	($174,749)
Net Cash Flow (current $, excl fin.)	($4,500,000)	($38,124)	$88,318	$29,168
Capital Expenditure Annuity @ WACC		($624,067)	($624,067)	($624,067)
NCF with annualized capital		**($662,191)**	**($535,749)**	**($594,899)**
Current $ $/ton of NOx reduced		($10,672.96)	($8,635.01)	($9,588.38)
NCF w/ann cap. Discount by infl rate		**($645,410)**	**($508,940)**	**($550,809)**
Sum of discounted NCF	**($8,686,939)**			
TOTAL Tons NOx reduced Proj. Life	**931**			
$/ton NOx reduced (after taxes)	**($9,334)**			
Before Tax Net Cash Flow		**($925,027)**	**($924,347)**	**($918,424)**
Discounted Before Tax NCF		**($901,585)**	**($878,092)**	**($850,357)**
Sum of discounted Before Tax NCF	**($11,380,334)**			
	931			
$/ton NOx reduced (before tax basis)	**($12,228)**			
Annual Capital Recovery	($495,000)			
Annual O&M	($233,459)			
Total Annual Cost	($728,459)			
Annual NOx reduced (tons)	62			
$/ton (per ACT document)	**($11,741)**			
Average of both before-tax methods	$11,985			

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction - std combustor	
Turbine Technical Data	
Engine Size (MW)	**75**
Initial NOx value (ppm)	**154**
Initial NOx massflow (lb/hr)	**513.28**
NOx reduction needed (up to 40%)	**90%**
Engine heat rate (BTU/KWhr)	**10,000**
Outlet NOx Value (ppm)	**15.00**
Outlet NOx massflow (lb/hr)	**50.00**
Project Economic Data	
# of months/year NOx reduction needed	**5**
Capacity Factor	**85%**
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Heat Rate Increase	**0.5%**
Cost of Ammonia ($/ton)	**$360.00**
Ammonia Escalation (%/yr.)	**2.6%**
Catalyst Cost ($/m3)	**$14,000**
Op Hrs Between Catalyst Replacement	**42,000**
Estimated Fixed O&M in first year	**$20,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
Captial cost, ($/KW)	**$60**
Capital Cost ($)	**$4,500,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT pretax marginal rate of return	**10.0%**

Process Analysis	
Gas Turbine SCR	
MW	75.0
lb/hr NOx reduced	463.29
lbmole/hr NOx reduced	10.07
Pri. Fuel Cost, $/MMBTU	$2.25
Pri. Fuel Cost, $/hr @ full load	$1,688
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	10.1
Ammonia usage (lb/hr)	171.21
Ammonia Cost ($/hr)	$30.82
Approx Catalyst Loading (m3)	57
Heat Rate Increase	0.50%
Uncontrolled NOx	154.00
Controlled NOx	15.00
Capital Cost, includes license ($/KW)	4,500,000
Fixed O&M ($/yr.)	$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**719**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	**1**	**2**	**3**
Operating Costs				
Uncontrolled fuel Cost	$0	($12,565,125)	($12,891,818)	($13,227,006)
Controlled Fuel Cost	$0	($12,628,266)	($12,956,601)	($13,293,473)
ammonia cost	$0	($95,615)	($98,101)	($100,651)
annual catalyst addition		($142,063)	($145,757)	($149,547)
Total Variable O&M		($300,820)	($308,641)	($316,666)
Fixed O&M	$0	($20,000)	($20,520)	($21,054)
Total O&M (incl. Dif. Fuel)	**$0**	**($320,820)**	**($329,161)**	**($337,719)**
Total Capital Cost	**$4,500,000**			
Financed with Common Equity	($2,700,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($1,800,000)			
Debt payments		($203,917)	($203,917)	($203,917)
Interest portion of payment		($135,000)	($129,831)	($124,275)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($450,000)	($810,000)	($630,000)
EOP Book Value	$4,500,000	$4,050,000	$3,240,000	$2,610,000
Property Taxes (net of income tax effect)		**($67,500)**	**($60,750)**	**($48,600)**
Adustment for Income taxes		**$293,412**	**$419,969**	**$355,712**
Net Cash Flow (current $, incl fin.)	($2,700,000)	($298,825)	($173,859)	($234,524)
Net Cash Flow (current $, excl fin.)	($4,500,000)	($94,908)	$30,058	($30,607)
Capital Expenditure Annuity @ WACC		($624,067)	($624,067)	($624,067)
NCF with annualized capital		**($718,975)**	**($594,009)**	**($654,675)**
Current $ $/ton of NOx reduced		($1,000.42)	($826.54)	($910.95)
NCF w/ann cap. Discount by infl rate		**($700,755)**	**($564,285)**	**($606,155)**
Sum of discounted NCF	**($9,517,118)**			
TOTAL Tons NOx reduced Proj. Life	**10,780**			
$/ton NOx reduced (after taxes)	**($883)**			
Before Tax Net Cash Flow		**($1,012,387)**	**($1,013,978)**	**($1,010,386)**
Discounted Before Tax NCF		**($986,732)**	**($963,239)**	**($935,504)**
Sum of discounted Before Tax NCF	**($12,657,532)**			
	10,780			
$/ton NOx reduced (before tax basis)	**($1,174)**			
Annual Capital Recovery	($495,000)			
Annual O&M	($320,820)			
Total Annual Cost	($815,820)			
Annual NOx reduced (tons)	719			
$/ton (per ACT document)	**($1,135)**			
Average of both before tax methods, $/ton	**$1,155**			

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction 75 MW GT with diluent injection	
Turbine Technical Data	
Engine Size (MW)	**75**
Initial NOx value (ppm)	**42**
Initial NOx massflow (lb/hr)	**139.99**
NOx reduction needed (up to 40%)	**83%**
Engine heat rate (BTU/KWhr)	**10,000**
Outlet NOx Value (ppm)	**7.00**
Outlet NOx massflow (lb/hr)	**23.33**
Project Economic Data	
# of months/year NOx reduction needed	**5**
Capacity Factor	**85%**
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Heat Rate Increase	**0.5%**
Cost of Ammonia ($/ton)	**$360.00**
Ammonia Escalation (%/yr.)	**2.6%**
Catalyst Cost ($/m3)	**$14,000**
Op Hrs Between Catalyst Replacement	**42,000**
Estimated Fixed O&M in first year	**$20,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
Captial cost, ($/KW)	**$60**
Capital Cost ($)	**$4,500,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT pretax marginal rate of return	**10.0%**

Process Analysis	
Gas Turbine SCR	
MW	75.0
lb/hr NOx reduced	116.66
lbmole/hr NOx reduced	2.54
Pri. Fuel Cost, $/MMBTU	$2.25
Pri. Fuel Cost, $/hr @ full load	$1,688
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	2.5
Ammonia usage (lb/hr)	43.11
Ammonia Cost ($/hr)	$7.76
Approx Catalyst Loading (m3)	57
Heat Rate Increase	0.50%
Uncontrolled NOx	42.00
Controlled NOx	7.00
Capital Cost, includes license	4,500,000
Fixed O&M ($/yr.)	$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**181**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($12,565,125)	($12,891,818)	($13,227,006)
Controlled Fuel Cost	$0	($12,628,266)	($12,956,601)	($13,293,473)
ammonia cost	$0	($24,076)	($24,702)	($25,344)
annual catalyst addition		($142,063)	($145,757)	($149,547)
Total Variable O&M		($229,280)	($235,242)	($241,358)
Fixed O&M	$0	($20,000)	($20,520)	($21,054)
Total O&M (incl. Dif. Fuel)	**$0**	**($249,280)**	**($255,762)**	**($262,412)**
Total Capital Cost	**$4,500,000**			
Financed with Common Equity	($2,700,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($1,800,000)			
Debt payments		($203,917)	($203,917)	($203,917)
Interest portion of payment		($135,000)	($129,831)	($124,275)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($450,000)	($810,000)	($630,000)
EOP Book Value	$4,500,000	$4,050,000	$3,240,000	$2,610,000
Property Taxes (net of income tax effect)		**($67,500)**	**($60,750)**	**($48,600)**
Adustment for Income taxes		**$268,373**	**$394,279**	**$329,354**
Net Cash Flow (current $, incl fin.)	($2,700,000)	($252,324)	($126,150)	($185,575)
Net Cash Flow (current $, excl fin.)	($4,500,000)	($48,407)	$77,767	$18,342
Capital Expenditure Annuity @ WACC		($624,067)	($624,067)	($624,067)
NCF with annualized capital		**($672,475)**	**($546,300)**	**($605,725)**
Current $ $/ton of NOx reduced		($3,716.13)	($3,018.88)	($3,347.27)
NCF w/ann cap. Discount by infl rate		**($655,433)**	**($518,963)**	**($560,833)**
Sum of discounted NCF	**($8,837,286)**			
TOTAL Tons NOx reduced Proj. Life	**2,714**			
$/ton NOx reduced (after taxes)	**($3,256)**			
Before Tax Net Cash Flow		**($940,848)**	**($940,579)**	**($935,079)**
Discounted Before Tax NCF		**($917,006)**	**($893,512)**	**($865,777)**
Sum of discounted Before Tax NCF	**($11,611,637)**			
	2,714			
$/ton NOx reduced (before tax basis)	**($4,278)**			
Annual Capital Recovery	($495,000)			
Annual O&M	($249,280)			
Total Annual Cost	($744,280)			
Annual NOx reduced (tons)	181			
$/ton (per ACT document)	**($4,113)**			
Average of both before-tax methods, $/ton	$4,195			

NOx Case Worksheet		
GT-Dry Low NOx: Two Solar Centaur		
Engine Technical Data		
Target Engine Size, (hp)	**9,400**	two Centaurs
Initial NOx value (ppm)	**135**	
Initial NOx massflow (lb/hr)	**44**	
NOx reduction needed (up to 40%)	**63%**	
Engine heat rate (BTU/KWhr)	**7,960**	
Outlet NOx Value (ppm)	**50.00**	
Outlet NOx massflow (lb/hr)	**16.11**	
Project Economic Data		
# of months/year NOx reduction needed	**5**	
Capacity Factor	**95%**	
Primary Fuel Cost ($/MMBTU)	**$2.25**	
Primary Fuel Escalation (%/yr.)	**2.6%**	
Estimated Fixed O&M in first year	**$15,000**	
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**	
heat rate increase	**0.00%**	
Capital Cost ($)	**$1,550,000**	
Capital Cost ($/HP)	**$165**	
Cost of Equity Capital (%)	**15.0%**	
Cost of Debt (%)	**7.5%**	
Cost of Preferred Equity (%)	**6.0%**	
% financed with debt (%)	**40.0%**	
Term of debt financing (years)	**15**	
% financed with Common Equity	**60.0%**	
% financed with Preferred Equity	**0.0%**	
WACC, % (after tax)	**11.0%**	
WACC, % (before tax)	**12.0%**	
Income tax rate (%)	**35.0%**	
Projected inflation rate (%)	**2.6%**	
Evaluation period of Project (yrs)	**15**	
Property Tax rate ($/$1,000)	**$15.00**	
ACT Pretax Marginal Rate of Return	**10.0%**	

Process Analysis	
Plant	
Nameplate HP	**9,400**
Pri. Fuel Cost, $/MMBTU	**$2.25**
Pri. Fuel Cost, $/hr	**$126**
Uncontrolled NOx (ppm)	**135.00**
Controlled NOx	**50.00**
Capital Cost	**$1,550,000**
Fixed O&M ($/yr.)	**$15,000**
Capacity factor	**0.95**
Months NOx reduction in service	**5.00**
Projected Book Life, yrs	**15.00**
Ann. NOx Red'n, tons	**47**

		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	$1,045,177	$1,072,352	$1,100,233
Controlled Fuel Cost	$0	$1,045,177	$1,072,352	$1,100,233
Variable O&M		$0	$0	$0
Fixed O&M	$0	($15,000)	($15,390)	($15,790)
Total O&M + dif. Fuel	**$0**	**($15,000)**	**($15,390)**	**($15,790)**
Total Capital Cost	**$1,550,000**			
Financed with Common Equity	($930,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($620,000)			
Debt payments		($70,238)	($70,238)	($70,238)
Interest portion of payment		($46,500)	($44,720)	($42,806)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($155,000)	($279,000)	($217,000)
EOP Book Value	$1,550,000	$1,395,000	$1,116,000	$899,000
Property Taxes		**($23,250)**	**($20,925)**	**($16,740)**
Adj for income tax effect of depn, oper exp, and prop tax		**$67,638**	**$110,360**	**$87,336**
Net Cash Flow (current $, incl fin.)	($930,000)	($40,851)	$3,807	($15,433)
Net Cash Flow (current $, excl fin.)	**($1,550,000)**	**$29,388**	**$74,045**	**$54,805**
Capital Expenditure Annuity @ WACC		($214,956)	($214,956)	($214,956)
Before Tax Capital Expend Annuity		($227,578)	($227,578)	($227,578)
NCF with annualized capital		**($185,569)**	**($140,911)**	**($160,151)**
Current $ $/ton of NOx reduced		($3,907.14)	($2,966.87)	($3,371.97)
NCF w/ann cap. Discount by infl rate		**($180,866)**	**($133,860)**	**($148,282)**
Sum of discounted NCF	**($2,370,546)**			
TOTAL Tons NOx reduced Proj. Life	**712**			
$/ton NOx reduced (after taxes)	**($3,327)**			
Before Tax Net Cash Flow		**($265,828)**	**($263,893)**	**($260,108)**
Discounted Before Tax NCF		**($259,091)**	**($250,687)**	**($240,830)**
Sum of discounted Before Tax NCF	**($3,118,674)**			
	712			
$/ton NOx reduced (before tax basis)	**($4,378)**			
Annual Capital Recovery	($203,784)			
Annual O&M	($15,000)			
Total Annual Cost	($218,784)			
Annual NOx reduced (tons)	47			
$/ton (per ACT document)	**($4,606)**	**Using method of ACT document**		
Average ($/ton)-both methods	**($4,492)**			

NOx Case Worksheet	
GT-Dry Low NOx: Two Solar Mars 13000	
Engine Technical Data	
Target Engine Size, (hp)	**26,000**
Initial NOx value (ppm)	**167**
Initial NOx massflow (lb/hr)	**135**
NOx reduction needed (up to 40%)	**70%**
Engine heat rate (BTU/KWhr)	**7,960**
Final NOx Value (ppm)	**50.00**
Final NOx massflow (lb/hr)	**40.31**
Project Economic Data	
# of months/year NOx reduction needed	**12**
Capacity Factor	***95%***
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Estimated Fixed O&M in first year	**$15,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
heat rate increase	**0.00%**
Capital Cost ($)	**$3,900,000**
Capital Cost ($/HP)	**$150**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	**11.0%**
Before Tax WACC	**12.0%**
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT Pretax Marginal Rate of Return	**10.0%**

Process Analysis	
Plant	
Nameplate HP	**26,000**
Pri. Fuel Cost, $/MMBTU	**$2.25**
Pri. Fuel Cost, $/hr	**$347**
Uncontrolled NOx (ppm)	**167.00**
Controlled NOx	**50.00**
Capital Cost	**$3,900,000**
Fixed O&M ($/yr.)	**$15,000**
Capacity factor	**0.95**
Months NOx reduction in service	**12.00**
Projected Book Life, yrs	**15.00**
Ann. NOx Red'n, tons	**392**

		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($2,890,916)	($2,966,080)	($3,043,198)
Controlled Fuel Cost	$0	($2,890,916)	($2,966,080)	($3,043,198)
Variable O&M		$0	$0	$0
Fixed O&M	$0	($15,000)	($15,390)	($15,790)
Total O&M + dif. Fuel	**$0**	**($15,000)**	**($15,390)**	**($15,790)**
Total Capital Cost	**$3,900,000**			
Financed with Common Equity	($2,340,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($1,560,000)			
Debt payments		($176,728)	($176,728)	($176,728)
Interest portion of payment		($117,000)	($112,520)	($107,705)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($390,000)	($702,000)	($546,000)
EOP Book Value	$3,900,000	$3,510,000	$2,808,000	$2,262,000
Property Taxes		**($58,500)**	**($52,650)**	**($42,120)**
Adj for income tax effect of depn, oper exp, and prop tax		**$162,225**	**$269,514**	**$211,369**
Net Cash Flow (current $, incl fin.)	($2,340,000)	($88,003)	$24,746	($23,270)
Net Cash Flow (current $, excl fin.)	**($3,900,000)**	**$88,725**	**$201,474**	**$153,458**
Capital Expenditure Annuity @ WACC		($540,858)	($540,858)	($540,858)
Before Tax Capital Expend Annuity		($572,615)	($572,615)	($572,615)
NCF with annualized capital		**($452,133)**	**($339,384)**	**($387,400)**
Current $ $/ton of NOx reduced		($1,151.98)	($864.71)	($987.05)
NCF w/ann cap. Discount by infl rate		**($440,676)**	**($322,401)**	**($358,688)**
Sum of discounted NCF	**($5,748,484)**			
TOTAL Tons NOx reduced Proj. Life	**5,887**			
$/ton NOx reduced (after taxes)	**($976)**			
Before Tax Net Cash Flow		**($646,115)**	**($640,655)**	**($630,525)**
Discounted Before Tax NCF		**($629,741)**	**($608,596)**	**($583,795)**
Sum of discounted Before Tax NCF	**($7,514,502)**			
	5,887			
$/ton NOx reduced (before tax basis)	**($1,276)**			
Annual Capital Recovery	($512,748)			
Annual O&M	($15,000)			
Total Annual Cost	($527,748)			
Annual NOx reduced (tons)	392			
$/ton (per ACT document)	**($1,345)**	**Using method of ACT document**		
Average ($/ton)-both methods	**($1,311)**			

NOx Reduction Case Spreadsheet				
Selective Catalytic Reduction				
Turbine Technical Data				
Engine Size (hp)	**7,000**	**HP**	**5.28**	**MW**
Initial NOx value (ppm)	**42**			
Initial NOx massflow (lb/hr)	**9**			
NOx reduction needed (up to 40%)	**88%**			
Engine heat rate (BTU/KWhr)	**11,000**			
Outlet NOx Value (ppm)	**5.00**			
Outlet NOx massflow (lb/hr)	**1.11**			
Project Economic Data				
# of months/year NOx reduction needed	**5**			
Capacity Factor	**85%**			
Primary Fuel Cost ($/MMBTU)	**$2.25**			
Primary Fuel Escalation (%/yr.)	**2.6%**			
Heat Rate Increase	**0.5%**			
Cost of Ammonia ($/ton)	**$360.00**			
Ammonia Escalation (%/yr.)	**2.6%**			
Catalyst Cost ($/m3)	**$14,000**			
Op Hrs Between Catalyst Replacement	**42,000**			
Estimated Fixed O&M in first year	**$20,000**			
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**			
Captial cost, ($/KW)	**$225**			
Capital Cost ($)	**$1,174,950**			
Cost of Equity Capital (%)	**15.0%**			
Cost of Debt (%)	**7.5%**			
Cost of Preferred Equity (%)	**6.0%**			
% financed with debt (%)	**40.0%**			
Term of debt financing (years)	**15**			
% financed with Common Equity	**60.0%**			
% financed with Preferred Equity	**0.0%**			
WACC, %	11.0%			
Before Tax WACC	12.0%			
Income tax rate (%)	**35.0%**			
Projected inflation rate (%)	**2.6%**			
Evaluation period of Project (yrs)	**15**			
Property Tax rate ($/$1,000)	**$15.00**			
ACT pretax marginal rate of return	**10.0%**			

Process Analysis	
Gas Turbine SCR	
MW	7,000.0
lb/hr NOx reduced	8.22
lbmole/hr NOx reduced	0.18
Pri. Fuel Cost, $/MMBTU	$2.25
Pri. Fuel Cost, $/hr @ full load	$129
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	0.2
Ammonia usage (lb/hr)	3.04
Ammonia Cost ($/hr)	$0.55
Approx Catalyst Loading (m3)	16
Heat Rate Increase	0.50%
Uncontrolled NOx	42.00
Controlled NOx	5.00
Capital Cost, includes license ($/KW)	1,174,950
Fixed O&M ($/yr.)	$20,000
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**13**

		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($962,355)	($987,376)	($1,013,048)
Controlled Fuel Cost	$0	($967,190)	($992,337)	($1,018,138)
ammonia cost	$0	($1,696)	($1,740)	($1,786)
annual catalyst addition		($40,835)	($41,896)	($42,986)
Total Variable O&M		($47,367)	($48,598)	($49,862)
Fixed O&M	$0	($20,000)	($20,520)	($21,054)
Total O&M (incl. dif. Fuel)	**$0**	**($67,367)**	**($69,118)**	**($70,915)**
Total Capital Cost	**$1,174,950**			
Financed with Common Equity	($704,970)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($469,980)			
Debt payments		($53,243)	($53,243)	($53,243)
Interest portion of payment		($35,249)	($33,899)	($32,448)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($117,495)	($211,491)	($164,493)
EOP Book Value	$1,174,950	$1,057,455	$845,964	$681,471
Property Taxes (net of income tax effect)		**($17,624)**	**($15,862)**	**($12,689)**
Adj for income tax effect of depn, prop tax, oper exp		**$70,870**	**$103,765**	**$86,834**
Net Cash Flow (current $, incl fin.)	($704,970)	($67,364)	($34,458)	($50,013)
Net Cash Flow (current $, excl fin.)	($1,174,950)	($14,121)	$18,785	$3,229
Capital Expenditure Annuity @ WACC		($162,944)	($162,944)	($162,944)
Before Tax Capital Expenditure Annuity		($172,511)	($172,511)	($172,511)
NCF with annualized capital		**($177,065)**	**($144,159)**	**($159,715)**
Current $ $/ton of NOx reduced		($13,887.26)	($11,306.46)	($12,526.47)
NCF w/ann cap. discount by infl rate		**($172,578)**	**($136,945)**	**($147,878)**
Sum of discounted NCF	**($2,329,079)**			
TOTAL Tons NOx reduced Proj. Life	**191**			
$/ton NOx reduced (after taxes)	**($12,178)**			
Before Tax Net Cash Flow		**($257,502)**	**($257,491)**	**($256,116)**
Discounted Before Tax NCF		**($250,977)**	**($244,606)**	**($237,134)**
Sum of discounted Before Tax NCF	**($3,182,715)**			
	191			
$/ton NOx reduced (before tax basis)	$16,641			
Annual Capital Recovery	($129,245)			
Annual O&M	($67,367)			
Total Annual Cost	($196,611)			
Annual NOx reduced (tons)	13			
$/ton (per ACT document)	**($15,420)**	**Consistent with method of ACT document**		
	$16,031		**Average**	

Reciprocating Internal Combustion Engine Worksheets

NOx Case Worksheet	
Clean Burn-IC - med speed: four 2,500 hp engines	
Engine Technical Data	
Target Engine Size	**10,000**
Initial NOx value (gm/hp-hr)	**15**
NOx reduction needed (up to 40%)	**80%**
Engine heat rate (BTU/KWhr)	**7,500**
Outlet NOx Value	3.00
Project Economic Data	
# of months/year NOx reduction needed	**5**
Capacity Factor	**45%**
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Estimated Fixed O&M in first year	**$8,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
heat rate increase	**-1.00%**
Capital Cost ($)	**$2,000,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT Pretax Marginal Rate of Return	**10.0%**

Process Analysis	
Plant	
Nameplate HP	**10,000**
Pri. Fuel Cost, $/MMBTU	**$2.25**
Pri. Fuel Cost, $/hr	**$126**
Uncontrolled NOx	**15.00**
Controlled NOx	**3.00**
Capital Cost, includes license ($/KW)	**2,000,000**
Fixed O&M ($/yr.)	**$8,000**
Capacity factor	**0.45**
Months NOx reduction in service	**5.00**
Projected Book Life, yrs	**15.00**
Ann. NOx Red'n, tons	**217**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($496,249)	($509,151)	($522,389)
Controlled Fuel Cost	$0	($491,286)	($504,059)	($517,165)
Variable O&M		$4,962	$5,092	$5,224
Fixed O&M	$0	($8,000)	($8,208)	($8,421)
Total O&M + dif. Fuel	**$0**	**($3,038)**	**($3,116)**	**($3,198)**
Total Capital Cost	**$2,000,000**			
Financed with Common Equity	($1,200,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($800,000)			
Debt payments		($90,630)	($90,630)	($90,630)
Interest portion of payment		($60,000)	($57,703)	($55,233)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($200,000)	($360,000)	($280,000)
EOP Book Value	$2,000,000	$1,800,000	$1,440,000	$1,160,000
Property Taxes		**($30,000)**	**($27,000)**	**($21,600)**
Adustment for Income taxes		**$81,563**	**$136,541**	**$106,679**
Net Cash Flow (current $, incl fin.)	($1,200,000)	($42,104)	$15,794	($8,748)
Net Cash Flow (current $, excl fin.)	**($2,000,000)**	**$48,526**	**$106,424**	**$81,882**
Capital Expenditure Annuity @ WACC		($277,363)	($277,363)	($277,363)
NCF with annualized capital		**($228,838)**	**($170,939)**	**($195,482)**
Current $ $/ton of NOx reduced		($1,054.21)	($787.48)	($900.54)
NCF w/ann cap. discount by infl rate		**($223,039)**	**($162,385)**	**($180,994)**
Sum of discounted NCF	**($2,903,706)**			
TOTAL Tons NOx reduced Proj. Life	**3,256**			
$/ton NOx reduced (after taxes)	**($892)**			
Before Tax Net Cash Flow		**($310,401)**	**($307,480)**	**($302,161)**
Discounted Before Tax NCF		**($302,535)**	**($292,093)**	**($279,767)**
Sum of discounted Before Tax NCF	**($3,585,379)**			
	3,256			
$/ton NOx reduced (before tax basis)	**($1,101)**			
Annual Capital Recovery	($220,000)			
Annual O&M	($3,038)			
Total Annual Cost	($223,038)			
Annual NOx reduced (tons)	217			
$/ton (per ACT document)	**($1,027)**			
Average of both before tax methods	**($1,064)**			

NOx Case Worksheet	
Clean Burn-IC, four 2,500 hp dual fuel engines	
Engine Technical Data	
Target Engine Size	**10,000**
Initial NOx value (gm/hp-hr)	**15**
NOx reduction needed (up to 40%)	87%
Engine heat rate (BTU/KWhr)	**7,000**
Outlet NOx Value	**2.00**
Project Economic Data	
# of months/year NOx reduction needed	**12**
Capacity Factor	**45%**
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Estimated Fixed O&M in first year	**$8,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
heat rate increase	**0.00%**
Capital Cost ($)	**$6,200,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT Pretax Marginal Rate of Return	**10.0%**

Process Analysis	
Plant	
Nameplate HP	**10,000**
Pri. Fuel Cost, $/MMBTU	**$2.25**
Pri. Fuel Cost, $/hr	**$117**
Uncontrolled NOx	**15.00**
Controlled NOx	**2.00**
Capital Cost, includes license ($/KW)	**6,200,000**
Fixed O&M ($/yr.)	**$8,000**
Capacity factor	**0.45**
Months NOx reduction in service	**12.00**
Projected Book Life, yrs	**15.00**
Ann. NOx Red'n, tons	**564**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($463,165)	($475,208)	($487,563)
Controlled Fuel Cost	$0	($463,165)	($475,208)	($487,563)
Variable O&M		$0	$0	$0
Fixed O&M	$0	($8,000)	($8,208)	($8,421)
Total O&M + dif. Fuel	**$0**	**($8,000)**	**($8,208)**	**($8,421)**
Total Capital Cost	**$6,200,000**			
Financed with Common Equity	($3,720,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($2,480,000)			
Debt payments		($280,952)	($280,952)	($280,952)
Interest portion of payment		($186,000)	($178,879)	($171,223)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($620,000)	($1,116,000)	($868,000)
EOP Book Value	$6,200,000	$5,580,000	$4,464,000	$3,596,000
Property Taxes		**($93,000)**	**($83,700)**	**($66,960)**
Adustment for Income taxes		**$252,350**	**$422,768**	**$330,183**
Net Cash Flow (current $, incl fin.)	($3,720,000)	($129,602)	$49,907	($26,150)
Net Cash Flow (current $, excl fin.)	**($6,200,000)**	**$151,350**	**$330,860**	**$254,802**
Capital Expenditure Annuity @ WACC		($859,826)	($859,826)	($859,826)
NCF with annualized capital		**($708,476)**	**($528,966)**	**($605,024)**
Current $ $/ton of NOx reduced		($1,255.31)	($937.25)	($1,072.01)
NCF w/ann cap. discount by infl rate		**($690,522)**	**($502,497)**	**($560,184)**
Sum of discounted NCF	**($8,988,031)**			
TOTAL Tons NOx reduced Proj. Life	**8,466**			
$/ton NOx reduced (after taxes)	**($1,062)**			
Before Tax Net Cash Flow		**($960,826)**	**($951,734)**	**($935,207)**
Discounted Before Tax NCF		**($936,478)**	**($904,109)**	**($865,896)**
Sum of discounted Before Tax NCF	**($11,093,970)**			
	8,466			
$/ton NOx reduced (before tax basis)	**($1,310)**			
Annual Capital Recovery	($682,000)			
Annual O&M	($8,000)			
Total Annual Cost	($690,000)			
Annual NOx reduced (tons)	564			
$/ton (per ACT document)	**($1,223)**			
Average of both before tax methods	**($1,267)**			

NOx Case Worksheet	
Clean Burn-IC: two low speed 3400 hp engines	
Engine Technical Data	
Target Engine Size	**6,800**
Initial NOx value (gm/hp-hr)	**13**
NOx reduction needed (up to 40%)	**77%**
Engine heat rate (BTU/KWhr)	**7,500**
Outlet NOx Value (gm/hp-hr)	**2.99**
Project Economic Data	
# of months/year NOx reduction needed	**5**
Capacity Factor	**45%**
Primary Fuel Cost ($/MMBTU)	**$2.25**
Primary Fuel Escalation (%/yr.)	**2.6%**
Estimated Fixed O&M in first year	**$8,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
heat rate increase	**0.50%**
Capital Cost ($)	**$2,328,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT Pretax Marginal Rate of Return	**10.0%**

Process Analysis	
Plant	
Nameplate HP	**6,800**
Pri. Fuel Cost, $/MMBTU	**$2.25**
Pri. Fuel Cost, $/hr	**$86**
Uncontrolled NOx	**13.00**
Controlled NOx	**2.99**
Capital Cost, includes license ($/KW)	**2,328,000**
Fixed O&M ($/yr.)	**$8,000**
Capacity factor	**0.45**
Months NOx reduction in service	**5.00**
Projected Book Life, yrs	**15.00**
Ann. NOx Red'n, tons	**123**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	($337,449)	($346,223)	($355,224)
Controlled Fuel Cost	$0	($339,136)	($347,954)	($357,001)
Variable O&M		($1,687)	($1,731)	($1,776)
Fixed O&M	$0	($8,000)	($8,208)	($8,421)
Total O&M + dif. Fuel	**$0**	**($9,687)**	**($9,939)**	**($10,198)**
Total Capital Cost	**$2,328,000**			
Financed with Common Equity	($1,396,800)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($931,200)			
Debt payments		($105,493)	($105,493)	($105,493)
Interest portion of payment		($69,840)	($67,166)	($64,291)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($232,800)	($419,040)	($325,920)
EOP Book Value	$2,328,000	$2,095,200	$1,676,160	$1,350,240
Property Taxes		**($34,920)**	**($31,428)**	**($25,142)**
Adustment for Income taxes		**$97,093**	**$161,142**	**$126,441**
Net Cash Flow (current $, incl fin.)	($1,396,800)	($53,008)	$14,282	($14,392)
Net Cash Flow (current $, excl fin.)	**($2,328,000)**	**$52,485**	**$119,775**	**$91,101**
Capital Expenditure Annuity @ WACC		($322,851)	($322,851)	($322,851)
NCF with annualized capital		**($270,366)**	**($203,075)**	**($231,750)**
Current $ $/ton of NOx reduced		($2,195.78)	($1,649.28)	($1,882.16)
NCF w/ann cap. discount by infl rate		**($263,514)**	**($192,914)**	**($214,574)**
Sum of discounted NCF	**($3,438,372)**			
TOTAL Tons NOx reduced Proj. Life	**1,847**			
$/ton NOx reduced (after taxes)	**($1,862)**			
Before Tax Net Cash Flow		**($367,458)**	**($364,218)**	**($358,191)**
Discounted Before Tax NCF		**($358,146)**	**($345,992)**	**($331,644)**
Sum of discounted Before Tax NCF	**($4,263,317)**			
	1,847			
$/ton NOx reduced (before tax basis)	**($2,308)**			
Annual Capital Recovery	($256,080)			
Annual O&M	($9,687)			
Total Annual Cost	($265,767)			
Annual NOx reduced (tons)	123			
$/ton (per ACT document)	**($2,158)**			
average of both before tax methods	**($2,233)**			

NOx Reduction Case Spreadsheet		
Selective Catalytic Reduction	**SCR on diesel**	
IC Engine Technical Data		
Engine Size (HP)	**9390**	
Initial NOx value (gm/hp-hr)	**10**	
Initial NOx massflow (lb/hr)	**206.8**	
NOx reduction needed (up to 90%)	**90%**	
Outlet NOx Value (gm/hp-hr)	**1.00**	
Outlet NOx massflow (lb/hr)	**20.7**	
Project Economic Data		
# of months/year NOx reduction needed	**5**	
Capacity Factor	**85%**	
Primary Fuel Cost ($/MMBTU)	**$5.00**	
Primary Fuel Escalation (%/yr.)	**2.6%**	
Heat Rate (BTU/HP-hr)	**5,600**	
Heat Rate Increase	**0.5%**	
Cost of Ammonia ($/ton)	**$360.00**	
Ammonia Escalation (%/yr.)	**2.6%**	
Catalyst Cost ($/m3)	**$14,000**	
Catalyst Volume (ft3)	**84**	
Layers of Cat	**1**	
Op Hrs Between Catalyst Replacement	**24,000**	**between layer change**
Estimated Fixed O&M in first year	**$23,600**	
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**	
Captial cost ($/hp)	**$109**	
Capital Cost ($)	**$1,022,220**	
Cost of Equity Capital (%)	**15.0%**	
Cost of Debt (%)	**7.5%**	
Cost of Preferred Equity (%)	**6.0%**	
% financed with debt (%)	**40.0%**	
Term of debt financing (years)	**15**	
% financed with Common Equity	**60.0%**	
% financed with Preferred Equity	**0.0%**	
WACC, %	11.0%	
Before Tax WACC	12.0%	
Income tax rate (%)	**35.0%**	
Projected inflation rate (%)	**2.6%**	
Evaluation period of Project (yrs)	**15**	
Property Tax rate ($/$1,000)	**$15.00**	
ACT pretax marginal rate of return	**10.0%**	

Process Analysis	
HP	9,390.0
lb/hr NOx reduced	186.15
lbmole/hr NOx reduced	4.05
Pri. Fuel Cost, $/MMBTU	$5.00
Pri. Fuel Cost, $/hr	$263
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	4.0
Ammonia usage (lb/hr)	68.79
Ammonia Cost ($/hr)	$12.38
Approx Catalyst Loading (m3)	2.4
Heat Rate Increase	**0.50%**
Uncontrolled NOx	10.00
Controlled NOx	1.00
Capital Cost, includes license ($/KW)	1,022,220
Fixed O&M ($/yr.)	$23,600
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**289**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	$815,709	$836,918	$858,678
Controlled Fuel Cost	$0	$819,808	$841,123	$862,993
ammonia cost	$0	($38,417)	($39,416)	($40,441)
annual catalyst addition		($3,475)	($3,565)	($3,658)
Total Variable O&M		($37,793)	($38,776)	($39,784)
Fixed O&M	$0	($23,600)	($24,214)	($24,843)
Total O&M (incl. dif. Fuel)	**$0**	**($61,393)**	**($62,989)**	**($64,627)**
Total Capital Cost	**$1,022,220**			
Financed with Common Equity	($613,332)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($408,888)			
Debt payments		($46,322)	($46,322)	($46,322)
Interest portion of payment		($30,667)	($29,492)	($28,230)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($102,222)	($184,000)	($143,111)
EOP Book Value	$1,022,220	$919,998	$735,998	$592,888
Property Taxes (net of income tax effect)		**($15,333)**	**($13,800)**	**($11,040)**
Income tax adj for prop tax, depn, oper exp		**$62,632**	**$91,276**	**$76,572**
Net Cash Flow (current $, incl fin.)	($613,332)	($60,416)	($31,835)	($45,417)
Net Cash Flow (current $, excl fin.)	($1,022,220)	($14,094)	$14,487	$905
Capital Expenditure Annuity @ WACC		($141,763)	($141,763)	($141,763)
Before Tax Capital Exp Ann		($141,763)	($141,763)	($141,763)
NCF with annualized capital		**($155,858)**	**($127,276)**	**($140,858)**
Current $ $/ton of NOx reduced		($539.75)	($440.77)	($487.81)
NCF w/ann cap. discount by infl rate		**($151,908)**	**($120,907)**	**($130,418)**
Sum of discounted NCF	**($2,052,774)**			
TOTAL Tons NOx reduced Proj. Life	**4,331**			
$/ton NOx reduced (after taxes)	**($474)**			
Before Tax Net Cash Flow		**($218,490)**	**($218,552)**	**($217,430)**
Discounted Before Tax NCF		**($212,953)**	**($207,616)**	**($201,316)**
Sum of discounted Before Tax NCF	**($2,707,386)**			
	4,331			
$/ton NOx reduced (before tax basis)	**($625)**			
Annual Capital Recovery	($112,444)			
Annual O&M	($61,393)			
Total Annual Cost	($173,837)			
Annual NOx reduced (tons)	289			
$/ton (per ACT document)	**($602.02)**	**Consistent with method of ACT document**		
	$614			

NOx Reduction Case Spreadsheet		
Selective Catalytic Reduction	**large lean burn engine**	
IC Engine Technical Data		
Engine Size (HP)	**9390**	one engine
Initial NOx value (gm/hp-hr)	**10**	
Initial NOx massflow (lb/hr)	**206.8**	
NOx reduction needed (up to 90%)	**90%**	
Outlet NOx Value (gm/hp-hr)	**1.00**	
Outlet NOx massflow (lb/hr)	**20.7**	
Project Economic Data		
# of months/year NOx reduction needed	**5**	
Capacity Factor	**85%**	
Primary Fuel Cost ($/MMBTU)	**$2.25**	
Primary Fuel Escalation (%/yr.)	**2.6%**	
Heat Rate (BTU/HP-hr)	**5,600**	
Heat Rate Increase	**0.5%**	
Cost of Ammonia ($/ton)	**$360.00**	
Ammonia Escalation (%/yr.)	**2.6%**	
Catalyst Cost ($/m3)	**$14,000**	
Catalyst Volume (ft3)	**63**	
Layers of cat	**1**	
Op Hrs Between Catalyst Replacement	**24,000**	**between layer change**
Estimated Fixed O&M in first year	**$23,600**	
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**	
Captial cost ($/hp)	**$97**	
Capital Cost ($)	**$907,653**	
Cost of Equity Capital (%)	**15.0%**	
Cost of Debt (%)	**7.5%**	
Cost of Preferred Equity (%)	**6.0%**	
% financed with debt (%)	**40.0%**	
Term of debt financing (years)	**15**	
% financed with Common Equity	**60.0%**	
% financed with Preferred Equity	**0.0%**	
WACC, %	11.0%	
Before Tax WACC	12.0%	
Income tax rate (%)	**35.0%**	
Projected inflation rate (%)	**2.6%**	
Evaluation period of Project (yrs)	**15**	
Property Tax rate ($/$1,000)	**$15.00**	
ACT pretax marginal rate of return	**10.0%**	

Process Analysis	
Lean IC SCR	
HP	9,390.0
lb/hr NOx reduced	186.15
lbmole/hr NOx reduced	4.05
Pri. Fuel Cost, $/MMBTU	$2.25
Pri. Fuel Cost, $/hr	$118
Ammonia Cost ($/ton)	$360.00
Ammonia Cost ($/lbmole)	$3.06
Ammonia usage (lbmole/hr)	4.0
Ammonia usage (lb/hr)	68.79
Ammonia Cost ($/hr)	$12.38
Approx Catalyst Loading (m3)	1.8
Heat Rate Increase	**0.50%**
Uncontrolled NOx	10.00
Controlled NOx	1.00
Capital Cost, includes license ($/KW)	907,653
Fixed O&M ($/yr.)	$23,600
Capacity factor	0.85
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**289**

	Year			
	0	**1**	**2**	**3**
Operating Costs				
Uncontrolled fuel Cost	$0	$367,069	$376,613	$386,405
Controlled Fuel Cost	$0	$368,914	$378,506	$388,347
ammonia cost	$0	($38,417)	($39,416)	($40,441)
annual catalyst addition		($7,818)	($8,022)	($8,230)
Total Variable O&M		($44,391)	($45,545)	($46,729)
Fixed O&M	$0	($23,600)	($24,214)	($24,843)
Total O&M (incl. dif. Fuel)	**$0**	**($67,991)**	**($69,759)**	**($71,573)**
Total Capital Cost	**$907,653**			
Financed with Common Equity	($544,592)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($363,061)			
Debt payments		($41,130)	($41,130)	($41,130)
Interest portion of payment		($27,230)	($26,187)	($25,066)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($90,765)	($163,378)	($127,071)
EOP Book Value	$907,653	$816,888	$653,510	$526,439
Property Taxes (net of income tax effect)		**($13,615)**	**($12,253)**	**($9,803)**
Income tax adj for prop tax, depn, oper exp		**$60,330**	**$85,886**	**$72,956**
Net Cash Flow (current $, incl fin.)	($544,592)	($62,406)	($37,256)	($49,549)
Net Cash Flow (current $, excl fin.)	($907,653)	($21,276)	$3,874	($8,419)
Capital Expenditure Annuity @ WACC		($125,875)	($125,875)	($125,875)
Before Tax Capital Exp Ann		($125,875)	($125,875)	($125,875)
NCF with annualized capital		**($147,151)**	**($122,001)**	**($134,294)**
Current $ $/ton of NOx reduced		($509.60)	($422.50)	($465.07)
NCF w/ann cap. discount by infl rate		**($143,422)**	**($115,896)**	**($124,341)**
Sum of discounted NCF	**($1,950,793)**			
TOTAL Tons NOx reduced Proj. Life	**4,331**			
$/ton NOx reduced (after taxes)	**($450)**			
Before Tax Net Cash Flow		**($207,481)**	**($207,887)**	**($207,250)**
Discounted Before Tax NCF		**($202,223)**	**($197,484)**	**($191,890)**
Sum of discounted Before Tax NCF	**($2,601,009)**			
	4,331			
$/ton NOx reduced (before tax basis)	**($601)**			
Annual Capital Recovery	($99,842)			
Annual O&M	($67,991)			
Total Annual Cost	($167,833)			
Annual NOx reduced (tons)	289			
$/ton (per ACT document)	**($581.22)**	**Consistent with method of ACT document**		
	$591			

NOx Reduction Case Spreadsheet	
Selective Catalytic Reduction	**ARIS 2000 on Diesel**
IC Engine Technical Data	
Engine Size (HP)	**1971**
Initial NOx value (gm/hp-hr)	**15**
Initial NOx massflow (lb/hr)	**65.1**
NOx reduction needed (up to 90%)	**75%**
Outlet NOx Value (gm/hp-hr)	**3.75**
Outlet NOx massflow (lb/hr)	**16.3**
Project Economic Data	
# of months/year NOx reduction needed	**12**
Capacity Factor	**10%**
Primary Fuel Cost ($/MMBTU)	**$5.00**
Primary Fuel Escalation (%/yr.)	**2.6%**
Heat Rate (BTU/HP-hr)	**5,600**
Heat Rate Increase	**0.5%**
32.5% Urea Solution Cost ($/gallon)	**$0.86**
Cost of Urea ($/lb)	**$0.29**
Ammonia Escalation (%/yr.)	**2.6%**
Catalyst Cost ($/ft3)	**$1,500**
Catalyst Volume (ft3)	**8.76**
Op Hrs Between Catalyst Replacement	**24,000**
Estimated Fixed O&M in first year	**$2,500**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
Captial cost ($/hp)	**$41**
Capital Cost ($)	**$80,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	**0.0%**
WACC, %	11.0%
Before Tax WACC	12.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
ACT pretax marginal rate of return	**10.0%**

Process Analysis	
Diesel SCR :ARIS 2000	
HP	1,971.0
lb/hr NOx reduced	48.84
lbmole/hr NOx reduced	1.06
Pri. Fuel Cost, $/MMBTU	$5.00
Pri. Fuel Cost, $/hr	$55
Urea Cost ($/lb)	$0.29
Urea Cost ($/lbmole)	$17.64
Urea Usage (lbmole/hr)	0.53
Urea Usage (lb/hr)	31.85
Urea Cost ($/hr)	$9.37
Approx Catalyst Loading (m3)	0.25
Heat Rate Increase	**0.50%**
Uncontrolled NOx	15.00
Controlled NOx	3.75
Capital Cost, includes license ($/KW)	80,000
Fixed O&M ($/yr.)	$2,500
Capacity factor	0.10
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	**21**

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
		Year		
	0	1	2	3
Operating Costs				
Uncontrolled fuel Cost	$0	$48,345	$49,602	$50,891
Controlled Fuel Cost	$0	$48,588	$49,851	$51,147
Urea Cost	$0	($8,204)	($8,417)	($8,636)
annual catalyst addition		($480)	($492)	($505)
Total Variable O&M		($8,441)	($8,660)	($8,885)
Fixed O&M	$0	($2,500)	($2,565)	($2,632)
Total O&M (incl. dif. Fuel)	**$0**	**($10,941)**	**($11,225)**	**($11,517)**
Total Capital Cost	**$80,000**			
Financed with Common Equity	($48,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($32,000)			
Debt payments		($3,625)	($3,625)	($3,625)
Interest portion of payment		($2,400)	($2,308)	($2,209)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($8,000)	($14,400)	($11,200)
EOP Book Value	$80,000	$72,000	$57,600	$46,400
Property Taxes (net of income tax effect)		**($1,200)**	**($1,080)**	**($864)**
Income Tax Adj for prop tax, depn, oper exp		**$7,049**	**$9,347**	**$8,253**
Net Cash Flow (current $, incl fin.)	($48,000)	($8,717)	($6,583)	($7,753)
Net Cash Flow (current $, excl fin.)	($80,000)	($5,091)	($2,958)	($4,128)
Capital Expenditure Annuity @ WACC		($11,095)	($11,095)	($11,095)
Before Tax Cap Exp Ann		($11,746)	($11,746)	($11,746)
NCF with annualized capital		**($16,186)**	**($14,053)**	**($15,222)**
Current $ $/ton of NOx reduced		($756.62)	($656.91)	($711.57)
NCF w/ann cap. discount by infl rate		**($15,776)**	**($13,350)**	**($14,094)**
Sum of discounted NCF	**($218,962)**			
TOTAL Tons NOx reduced Proj. Life	**321**			
$/ton NOx reduced (after taxes)	**($682)**			
Before Tax Net Cash Flow		**($23,887)**	**($24,051)**	**($24,127)**
Discounted Before Tax NCF		**($23,281)**	**($22,848)**	**($22,339)**
Sum of discounted Before Tax NCF	**($309,596)**			
	321			
$/ton NOx reduced (before tax basis)	**($965)**			
Annual Capital Recovery	($8,800)			
Annual O&M	($10,941)			
Total Annual Cost	($19,741)			
Annual NOx reduced (tons)	21			
$/ton (per ACT document)	**($922.79)**	**Consistent with method of ACT document**		
	$944			

Cement Kiln Worksheets

NOx Reduction Case Spreadsheet		
KILN - Combustion CemStar		
Kiln Technical Data		
Target Kiln Size (TPH clinker)	**160**	**four kilns of 40 TPH Each**
Initial NOx value (pph)	**800**	
Initial NOx value (lb/ton clinker)	**5.00**	
NOx reduction needed (up to 40%)	**20%**	
Outlet NOx Value (pph)	**640**	
Outlet NOx Value (lb/ton clinker)	**3.70**	
Project Economic Data		
# of months/year NOx reduction needed	**5**	
Capacity Factor	**45%**	
Net Clinker Value ($/ton)	**$15**	
Heat Input Rate (MMBTU/ton clinker)	**6.00**	
Primary Fuel Cost ($/MMBTU)	**$1.50**	
Primary Fuel Escalation (%/yr.)	**2.6%**	
Secondary Fuel Cost ($/MMBTU)	**$2.25**	
Secondary Fuel Escalation (%/yr.)	**2.6%**	
Fuel cost Change	**-1.0%**	
Slag Fee ($/ton)	**$16.00**	
Slag Feed Rate (ton/hr)	**13**	**for all four kilns**
ton clinker/ton slag	**1.0**	
Estimated Fixed O&M in first year	**$100,000**	
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**	
Capital Cost ($)	**$1,000,000**	
Cost of Equity Capital (%)	**15.0%**	
Cost of Debt (%)	**7.5%**	
Cost of Preferred Equity (%)	**6.0%**	
% financed with debt (%)	**40.0%**	
Term of debt financing (years)	**15**	
% financed with Common Equity	**60.0%**	
% financed with Preferred Equity	**0.0%**	
WACC, %	**11.0%**	
Before Tax WACC	**12.0%**	
Income tax rate (%)	**35.0%**	
Projected inflation rate (%)	**2.6%**	
Evaluation period of Project (yrs)	**15**	
Property Tax rate ($/$1,000)	**$15.00**	
Pretax Rate of Return (ACT document)	**10.0%**	

Process Analysis	KILN - Combustion
Plant	
TPH clinker	160
lb/hr NOx reduced	160
lbmole/hr NOx reduced	3
Heat Input (MMBTU/hr)	960
Fuel Cost (without NOx control)	$9
Fuel Cost (with NOx control)	$9
Fuel Cost Change	**($0)**
Uncontrolled NOx	800.00
Controlled NOx	640.00
Capital Cost, includes license ($/KW)	1,000,000
Fixed O&M ($/yr.)	$25,000
Capacity factor	0.45
Months NOx reduction in service	5.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	131

Cash Flows				
All values shown in current dollars, except where indicated otherwise				
KILN - Combustion Cemstar		Year		
	0	**1**	**2**	**3**
Operating Costs				
Include Fuel Cost Effect (y / n)	**y**			
Misc Var O&M		($20,000)	($20,520)	($20,520)
Change in Fuel Cost		$148	$152	$152
Additional Cost for Slag Addition	$0	($832,550)	($854,197)	($854,197)
Value of additional production		$780,516	$800,809	$800,809
Total Variable O&M		($52,034)	($53,387)	($53,387)
Fixed O&M	$0	($10,000)	($10,260)	($10,527)
Total O&M	**$0**	**($62,034)**	**($63,647)**	**($63,914)**
Total Capital Cost	**$1,000,000**			
Financed with Common Equity	($600,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($400,000)			
Debt payments		($45,315)	($45,315)	($45,315)
Interest portion of payment		($30,000)	($28,851)	($27,617)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($100,000)	($180,000)	($140,000)
EOP Book Value	$1,000,000	$900,000	$720,000	$580,000
Property Taxes		**($15,000)**	**($13,500)**	**($10,800)**
income tax adj for prop tax, depn, oper exp		**$61,962**	**$90,002**	**$75,150**
Net Cash Flow (current $, incl fin.)	($600,000)	($60,387)	($32,461)	($44,879)
Net Cash Flow (current $, excl fin.)	($1,000,000)	($15,072)	$12,854	$436
Capital Expenditure Annuity @ WACC		($138,682)	($138,682)	($138,682)
Before Tax Cap Exp Ann		($146,824)	($146,824)	($146,824)
NCF with annualized capital		**($153,754)**	**($125,827)**	**($138,246)**
Current $ $/ton of NOx reduced		($1,170.12)	($957.59)	($1,052.10)
NCF w/ann cap. discount by infl rate		**($149,858)**	**($119,531)**	**($128,000)**
Sum of discounted NCF	**($1,958,104)**			
TOTAL Tons NOx reduced Proj. Life	**1,971**			
$/ton NOx reduced (after taxes)	**($993)**			
Total Tons Clinker over project life	**9,460,800**			
$/ton clinker	**($0.21)**			
Before Tax Net Cash Flow		**($223,859)**	**($223,972)**	**($221,538)**
Discounted Before Tax NCF		**($218,186)**	**($212,764)**	**($205,119)**
Sum of discounted Before Tax NCF	**($2,671,617)**			
TOTAL Tons NOx reduced Proj. Life	**1,971**			
$/ton NOx reduced (before tax basis)	**($1,355)**			
$/ton clinker	**($0.28)**			
Annual Capital Recovery	($110,000)			
Annual O&M	($62,034)			
Total Cost	($172,034)			
Annual NOx reduced (tons)	131			
$/ton (per ACT document)	**($1,309)**	**Consistent with method of ACT document**		
$/ton clinker	**($0.27)**	average		
	$1,332			
	$0.28			

NOx Reduction Case Spreadsheet			
KILN - Combustion - Mid Kiln Firing			
Kiln Technical Data			
Target Kiln Size (TPH clinker)	**80**	two 40 TPH kilns	
Initial NOx value (pph)	**400**		
Initial NOx value (lb/ton clinker)	5.00		
NOx reduction needed	**20%**		
Outlet NOx Value (pph)	320		
Outlet NOx Value (lb/ton clinker)	4.00		
Project Economic Data			
# of months/year NOx reduction needed	**12**		
Capacity Factor	**85%**		
Tipping Fee, $/ton of tires	**$75**		
Heat Input Rate (MMBTU/ton clinker)	**4.50**	**% normally**	**% with NOx reduction**
Primary Fuel Cost ($/MMBTU)	**$1.50**	**100%**	**80%**
Primary Fuel Escalation (%/yr.)	**2.6%**		
Secondary Fuel Cost ($/MMBTU)	**$2.25**	**0%**	**0%**
Secondary Fuel Escalation (%/yr.)	**2.6%**		
Tires Cost, $/MMBTU	**-$2.68**	**0%**	**20%**
Tires escalation	**2.6%**		
Estimated Fixed O&M in first year	**$64,000**		
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**		
Capital Cost ($)	**$1,495,000**		
Cost of Equity Capital (%)	**15.0%**		
Cost of Debt (%)	**7.5%**		
Cost of Preferred Equity (%)	**6.0%**		
% financed with debt (%)	**40.0%**		
Term of debt financing (years)	**15**		
% financed with Common Equity	**60.0%**		
% financed with Preferred Equity	0.0%		
WACC, %	11.0%		
Before Tax WACC	12.0%		
Income tax rate (%)	**35.0%**		
Projected inflation rate (%)	**2.6%**		
Evaluation period of Project (yrs)	**15**		
Property Tax rate ($/$1,000)	**$15.00**		
Pretax Rate of Return (ACT document)	**10.0%**		

Process Analysis	KILN - Combustion - Mid Kiln Firing
Plant	
TPH clinker	80
lb/hr NOx reduced	80
lbmole/hr NOx reduced	2
Heat Input (MMBTU/hr)	360
Fuel Cost (without NOx control)	$540
Fuel Cost (with NOx control)	$239
Fuel Cost Change	**($301)**
Uncontrolled NOx	400.00
Controlled NOx	320.00
Capital Cost, includes license ($/KW)	1,495,000
Fixed O&M ($/yr.)	$25,000
Capacity factor	0.85
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	298

KILN - Combustion - Mid Kiln Firing		Year		
	0	1	2	3
Operating Costs				
Include Fuel Cost Effect (y / n)	**y**			
Misc Var O&M				
Change in Fuel Cost		$2,240,182		
Variable O&M	$0	$2,240,182	$2,298,427	$2,298,427
Total Variable O&M		$2,240,182	$2,298,427	$2,298,427
Fixed O&M	$0	($64,000)	($65,664)	($67,371)
Total O&M	**$0**	**$2,176,182**	**$2,232,763**	**$2,231,056**
Total Capital Cost	**$1,495,000**			
Financed with Common Equity	($897,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($598,000)			
Debt payments		($67,746)	($67,746)	($67,746)
Interest portion of payment		($44,850)	($43,133)	($41,287)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($149,500)	($269,100)	($209,300)
EOP Book Value	$1,495,000	$1,345,500	$1,076,400	$867,100
Property Taxes		**($22,425)**	**($20,183)**	**($16,146)**
Income tax adj for prop tax, depn, oper exp		**($701,490)**	**($680,218)**	**($701,963)**
Net Cash Flow (current $, incl fin.)	($897,000)	$1,384,521	$1,464,617	$1,445,201
Net Cash Flow (current $, excl fin.)	($1,495,000)	$1,452,267	$1,532,362	$1,512,946
Capital Expenditure Annuity @ WACC		($207,329)	($207,329)	($207,329)
Before Tax Cap Exp Ann		($219,502)	($219,502)	($219,502)
NCF with annualized capital		**$1,244,938**	**$1,325,033**	**$1,305,617**
Current $ $/ton of NOx reduced		$4,179.89	$4,448.81	$4,383.62
NCF w/ann cap. discount by infl rate		**$1,213,390**	**$1,258,729**	**$1,208,854**
Sum of discounted NCF	**$15,568,125**			
TOTAL Tons NOx reduced Proj. Life	**4,468**			
$/ton NOx reduced (after taxes)	**$3,485**			
Total Tons Clinker over project life	**8,935,200**			
$/ton clinker	**$1.74**			
Before Tax Net Cash Flow		**$1,934,255**	**$1,993,078**	**$1,995,408**
Discounted Before Tax NCF		**$1,885,239**	**$1,893,344**	**$1,847,522**
Sum of discounted Before Tax NCF	**$24,460,535**			
TOTAL Tons NOx reduced Proj. Life	**4,468**			
$/ton NOx reduced (before tax basis)	**$5,475**			
$/ton clinker	**$2.74**			
Annual Capital Recovery	($164,450)			
Annual O&M	$2,176,182			
Total Cost	$2,011,732			
Annual NOx reduced (tons)	298			
$/ton (per ACT document)	**$6,754**		**Consistent with method of ACT document**	
$/ton clinker	**$3.38**			
	($6,115)		average	
	($3.06)			

NOx Reduction Case Spreadsheet	
KILN SNCR	
Kiln Technical Data	
Target Kiln Size (TPH clinker)	**150**
Initial NOx value (pph)	**700**
Initial NOx value (lb/ton clinker)	4.67
NOx reduction needed (up to 40%)	**45%**
Outlet NOx Value (pph)	385
Outlet NOx Value (lb/ton clinker)	2.57
Project Economic Data	
# of months/year NOx reduction needed	**12**
Capacity Factor	**45%**
Primary Fuel Cost ($/MMBTU)	**$1.50**
Primary Fuel Escalation (%/yr.)	**2.6%**
Cost of Urea ($/gallon)	**$0.95**
Cost of Urea ($/ton)	$406.74
Urea Escalation (%/yr.)	**2.6%**
Estimated Fixed O&M in first year	**$25,000**
Labor&Fixed O&M Escalation (%/yr.)	**2.6%**
Capital Cost ($)	**$900,000**
Cost of Equity Capital (%)	**15.0%**
Cost of Debt (%)	**7.5%**
Cost of Preferred Equity (%)	**6.0%**
% financed with debt (%)	**40.0%**
Term of debt financing (years)	**15**
% financed with Common Equity	**60.0%**
% financed with Preferred Equity	0.0%
WACC, %	11.0%
Before Tax WACC	12.0%
Income tax rate (%)	**35.0%**
Projected inflation rate (%)	**2.6%**
Evaluation period of Project (yrs)	**15**
Property Tax rate ($/$1,000)	**$15.00**
Pretax Rate of Return (ACT document)	**10.0%**

Process Analysis	KILN SNCR
Plant	
TPH clinker	150
lb/hr NOx reduced	315
lbmole/hr NOx reduced	7
Pri. Fuel Cost, $/MMBTU	$1.50
Urea Cost ($/gallon)	$0.95
Urea Cost ($/ton)	$406.74
Urea Cost ($/lbmole)	$12.20
Urea Utilization	**50%**
Urea usage (lbmole/hr)	6.8
Urea usage (gal/hr)	87.98
Urea Cost ($/hr)	$83.56
Heat Rate Increase	**0.00%**
Uncontrolled NOx	700.00
Controlled NOx	385.00
Capital Cost, includes license ($/KW)	900,000
Fixed O&M ($/yr.)	$25,000
Capacity factor	0.45
Months NOx reduction in service	12.00
Projected Book Life, yrs	15.00
Ann. NOx Red'n, tons	621

KILN SNCR		Year		
	0	1	2	3
Operating Costs				
Urea Cost	$0	($329,386)	($337,950)	($346,737)
Total Variable O&M		($329,386)	($337,950)	($346,737)
Fixed O&M	$0	($25,000)	($25,650)	($26,317)
Total O&M	**$0**	**($354,386)**	**($363,600)**	**($373,054)**
Total Capital Cost	**$900,000**			
Financed with Common Equity	($540,000)			
Financed with Preferred Equity	$0			
Preferred Dividends		$0	$0	$0
Amount financed w/ debt	($360,000)			
Debt payments		($40,783)	($40,783)	($40,783)
Interest portion of payment		($27,000)	($25,966)	($24,855)
MACRS 10 yr.		10%	18%	14%
Depreciation (MACRS)		($90,000)	($162,000)	($126,000)
EOP Book Value	$900,000	$810,000	$648,000	$522,000
Property Taxes		**($13,500)**	**($12,150)**	**($9,720)**
Income tax adj for oper exp, depn, prop tax		**$160,260**	**$188,213**	**$178,071**
Net Cash Flow (current $, incl fin.)	($540,000)	($248,409)	($228,321)	($245,486)
Net Cash Flow (current $, excl fin.)	($900,000)	($207,626)	($187,538)	($204,703)
Capital Expenditure Annuity @ WACC		($124,813)	($124,813)	($124,813)
Before Tax Cap Exp Ann		($132,142)	($132,142)	($132,142)
NCF with annualized capital		**($332,439)**	**($312,351)**	**($329,516)**
Current $ $/ton of NOx reduced		($535.45)	($503.09)	($530.74)
NCF w/ann cap. discount by infl rate		**($324,015)**	**($296,721)**	**($305,095)**
Sum of discounted NCF	**($4,661,382)**			
TOTAL Tons NOx reduced Proj. Life	**9,313**			
$/ton NOx reduced (after taxes)	**($501)**			
Total Tons Clinker over project life	**8,869,500**			
$/ton clinker	**($0.53)**			
Before Tax Net Cash Flow		**($500,028)**	**($507,892)**	**($514,915)**
Discounted Before Tax NCF		**($487,357)**	**($482,477)**	**($476,753)**
Sum of discounted Before Tax NCF	**($6,864,590)**			
TOTAL Tons NOx reduced Proj. Life	**9,313**			
$/ton NOx reduced (before tax basis)	**($737)**			
$/ton clinker	**($0.77)**			
Annual Capital Recovery	($99,000)			
Annual O&M	($354,386)			
Total Cost	($453,386)			
Annual NOx reduced (tons)	621			
$/ton (per ACT document)	**($730.25)**	**Consistent with method of ACT document**		
$/ton clinker	**($0.77)**			
avg $/ton NOx	($734)			
avg $/ton clinker	($0.77)			