ONSITE SYCOM
Energy Corporation

FINAL DRAFT

Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines

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PREFACE

This report was prepared by ONSITE SYCOM Energy Corporation as an account of work sponsored by the U.S. Department of Energy. Bill Powers, Principal of Powers Engineering, was the primary investigator for the technical analysis.

The information and results contained in this work are preliminary and should be used for the express purpose of establishing a dialogue among interested parties to examine the environmental impacts and regulatory implications of air-borne emissions from advanced gas turbine systems.

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EXECUTIVE SUMMARY

A new generation of gas turbines and emission control technologies are being developed with the assistance of the U.S. Department of Energy (DOE) under the Advanced Turbine Systems (ATS) program. These gas turbines will exhibit significantly improved environmental and efficiency characteristics over currently available systems. These systems are being developed during a period of electric utility restructuring and proliferation of gas turbines for baseload power. The coming competitive power industry offers opportunities for both small and large gas turbine systems, filling niche markets - distributed generation and IPP/merchant plants, respectively. Although economics may favor development, the former market, distributed generation, is threatened by strict environmental regulations that impose costly post-combustion emission controls.

This study compares costs for the principal technologies being employed or nearing commercialization for control of oxides of nitrogen (NO_x) in stationary gas turbines. NO_x control cost data is compared for gas turbines in the 5 MW, 25 MW and 150 MW size ranges to determine the economic impact based on turbine output. The reference document for this study is the "Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines" EPA–453/R-93-007, ("1993 NO_x ACT document") prepared by the U.S. EPA in 1993. Gas turbine manufacturers and NO_x control technology vendors that participated in the 1993 study were contacted to determine current costs. The NO_x control technologies evaluated in the 1993 NO_x ACT document include water/steam injection, dry low NO_x (DLN) combustion, and selective catalytic reduction (SCR). Cost data is provided for new technologies that were not available in 1993, including low and high temperature SCR, catalytic combustion, and SCONO$_x$™.

Shown in Table S-1, cost data is developed in both "\$/ton NO_x removed" ("\$/ton") and "¢/kWh" formats. The "\$/ton" values indicate a typical estimate of the cost of a technology to remove a given amount of NO_x from the exhaust gas. A "\$/ton" value that is relatively lower means that the technology is more efficient in removing NO_x than the alternatives.

TABLE S-1

Cost Impact Factors for Selected NO_x Control Technologies (1999)

Turbine Output	5 MW Class		25 MW Class		150 MW Class	
Median value	$/ton	¢/kWhr	$/ton	¢/kWhr	$/ton	¢/kWhr
NO_X EMISSION CONTROL TECHNOLOGY						
DLN (25 ppm)	320	0.075	210	0.124	122 *	0.054 *
Catalytic Combustion (3 ppm)	957	0.317	692	0.215	371	0.146
Water/Steam Injection (42 ppm)	1693	0.410	984	0.240	476	0.152
Conventional SCR (9 ppm)	6274	0.469	3541	0.204	1938	0.117
High Temperature SCR (9 ppm)	7148	0.530	3841	0.221	2359	0.134
SCONOx (2 ppm)	16327	0.847	11554	0.462	6938	0.289
Low Temperature SCR (9 ppm)	5894	1.060	3541	0.204		

* 9-25 ppm
"¢/kWhr" based on 8000 hours at full load

The "¢/kWh" value provides an economic indication of the electricity cost impact of a particular NO_x control technology, independent of the NO_x emission reductions achievable with the technology. The "¢/kWh" value indicates the cost impact of NO_x control relative to the amount of electricity generated by the gas turbine. Figures S-1 and S-2 compare the "¢/kWh" values developed in this study and from the 1993 NO_x ACT document, respectively. NO_x control concentrations are indicated below each technology in the figures. Technologies are roughly ordered from highest cost to lowest cost impact.

The "¢/kWh" values for water/steam injection have remained fairly constant between the 1993 NO_x ACT document and the evaluation performed in this study. This is consistent with the fact that water/steam injection was a mature technology in 1993. Considerable innovation has occurred with DLN and SCR and this is reflected in a 50-100% reduction in the "¢/kWh" values for these two technologies between 1993 and 1999.

High temperature SCR is only about 10 percent more costly than conventional SCR. Low temperature SCR and $SCONO_x$™ are typically 2 times more costly than conventional SCR. Each SCR technology fills a unique technical "niche"; cost impact may be of secondary significance. Low temperature SCR is the only SCR technology that can operate effectively below 400 °F. High temperature SCR is the only SCR technology that can operate effectively from 800 to 1,100 °F. $SCONO_x$™ is the only post-combustion NO_x control technology that does not require ammonia injection to achieve NO_x levels less than 5 ppm.

Projected costs for catalytic combustors indicate that the "¢/kWh" cost is 2 to 3 times higher than a DLN combustor alone. The catalytic combustor can achieve NO_x levels of less than 3 ppm, while the most advanced DLN combustor can achieve NO_x levels down to 9 ppm. To reach NO_x levels below 5 ppm, the DLN-equipped turbine requires post-combustion NO_x control device such as SCR or $SCONO_x$™. Although catalytic combustion is not fully commercialized, it is anticipated to have a "¢/kWh" impact comparable to that of existing DLN technology plus conventional SCR.

Figure S-1 indicates that the cost impact is highest when emission control technologies are applied to small industrial turbines (5 MW); a conclusion that was applicable in the 1993 NO_x ACT document as well. This is particularly true for the post-combustion technologies (SCR and $SCONO_x$™) where the cost impact is roughly twice that for larger turbines (25 MW and 150 MW). In ozone non-attainment areas, strict environmental regulations have mandated SCR for gas turbines. These regulations have a disproportionate impact on the construction of small gas turbine systems and that may be too expensive to build. DLN and the development of catalytic combustion are both being funded by the ATS program and promise to significantly reduce the cost impact disparity between small and large gas turbines. It is proposed that regulations mandating post-combustion controls should be re-examined in light of technology improvements through initiatives like the ATS program.

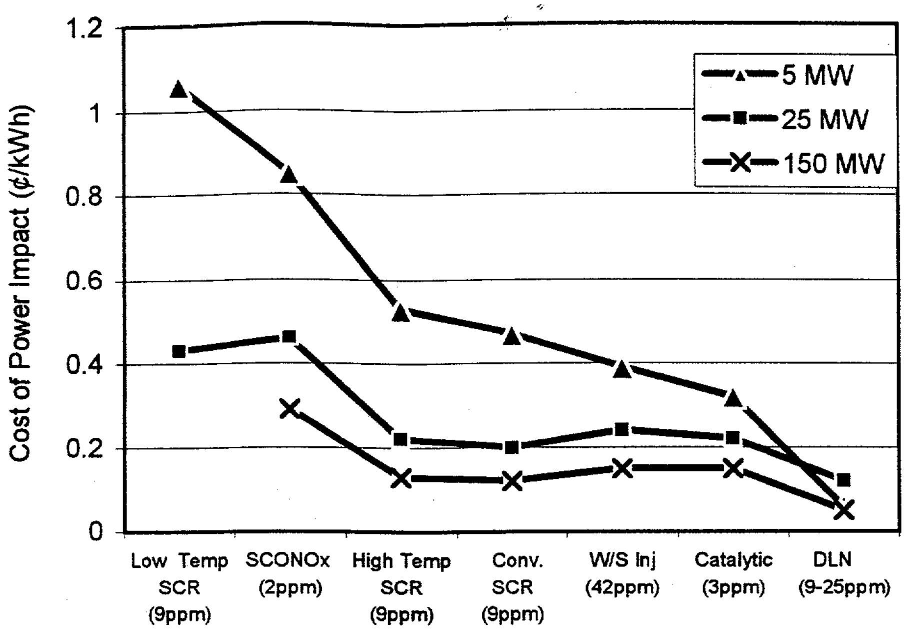

Figure S-1. Comparison of NO_x Control Technologies (1999)

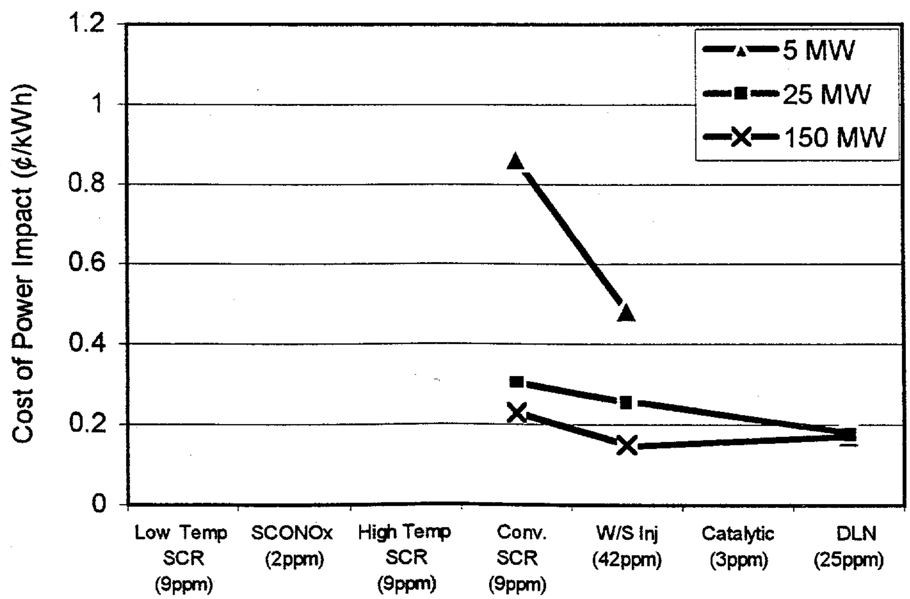

Figure S-2. 1993 EPA Comparison of NO_x Control Technologies

1.0 INTRODUCTION

1.1 Project Objective

The use of stationary gas turbines for power generation has been growing rapidly with continuing trends predicted well into the future. Factors that are contributing to this growth include advances in turbine technology, operating and siting flexibility and low capital cost. Restructuring of the electric utility industry will provide new opportunities for on-site generation. In a competitive market, it may be more cost effective to install small distributed generation units (like gas turbines) within the grid rather than constructing large power plants in remote locations with extensive transmission and distribution systems. For the customer, on-site generation will provide added reliability and leverage over the cost of purchased power.

One of the key issues that is addressed in virtually every gas turbine application is emissions, particularly NO_x emissions. Decades of research and development have significantly reduced the NO_x levels emitted from gas turbines from uncontrolled levels. Emission control technologies are continuing to evolve with older technologies being gradually phased-out while new technologies are being developed and commercialized.

A new generation of small scale power technologies is being developed in response to customer needs for cost effective energy options and more stringent environmental policy. A collaborative effort between industry and the U.S. Department of Energy (DOE) is the Advanced Turbine Systems Program (ATS). This program is tasked with the development and commercialization of the next generation of utility and industrial gas turbines. The benefits of the new technologies include reduced operating costs, improved power quality and reliability, and lower air emissions. General Electric, Siemens-Westinghouse, Solar Turbines, and Allison Engine Company are participating in ATS projects designed to improve turbine efficiency and/or reduce NO_x emissions through improvements in DLN combustor technology or catalytic combustion.

The objective of this study is to determine and compare the cost of NO_x control technologies for three size ranges of stationary gas turbines: 5 MW, 25 MW and 150 MW. The purpose of the comparison is to evaluate the cost effectiveness and impact of each control technology as a function of turbine size. The NO_x control technologies evaluated in this study include:

- Lean premix combustion, also known as "dry low NO_x" (DLN) combustion;
- Catalytic combustion;
- Water/steam injection;
- Selective catalytic reduction (SCR) – low temperature, conventional, high temperature;
- $SCONO_x$™

It has been recognized that certain emission control technologies (e.g. selective catalytic reduction) are cost prohibitive in small gas turbine sizes, however, they have been mandated by stringent regional air quality regulations in many parts of the country. In a coming competitive power market, the opportunities for small turbine installations will grow, however, the economics of these projects will be negatively impacted by such regulations. This study shall update the cost factors ("$/ton" and "¢/kWh") among the various control technologies using as a reference, the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) document, "Alternative Control Techniques (ACT) Document – NO_x Emissions from Stationary Gas Turbines," EPA-453/R-93-007, January 1993 ("1993 NO_x ACT document".)

1.2 Recent NO_x Emission Control Developments

1.2.1 DLN Technology

The 1993 NO_x ACT document was published at the inception of DLN combustor commercialization. In the intervening six years, DLN combustors have largely replaced water injection and steam injection as the primary combustion modification to control NO_x emissions. The gas turbine manufacturers have funded DLN research and development with assistance from the DOE through its ATS program.

Under the ATS program, GE and Siemens-Westinghouse have selected a closed-loop steam cooling system for their utility-class advanced combined cycle turbines. Program objectives are to develop combined cycle units with: 1) 10 percent increase in combined cycle efficiency to approximately 60 percent, 2) NO_x levels of 9 ppm or less, and CO levels less than 20 ppm without post combustion NO_x controls, 3) ability to fire synthetic gas from coal or biomass in the future, and 4) reliability, availability, and maintainability (RAM) at least as good as current gas turbine models.

Solar Turbines, a manufacturer of small industrial gas turbines, has developed a high efficiency turbine in partnership with the ATS program. The 4.2 MW Mercury gas turbine uses a recuperator to achieve greater than 40 percent thermal efficiency in simple cycle operation. The first unit is scheduled for operation in 1999. The Mercury incorporates advanced DLN features to minimize NO_x emissions. These advances include combustor liner modifications and variable geometry injectors. The new combustor can accommodate a catalytic combustion module when that technology is commercialized.

Under the ATS program, Allison Engine Company developed a retrofit DLN silo combustor for its 501K (3-6MW) gas turbine known as the "Green Thumb" combustor. The combustor attained the 9 ppm NO_x target in bench scale laboratory testing, but saw high emissions of CO (> 50 ppm) and unburned hydrocarbons (> 30 ppm). DOE is planning a field test of the Green Thumb combustor for one of the five Allison 501K turbines at Vandenberg AFB (Lompoc, CA).

1.2.2 Catalytic Combustion

Development of catalytic combustion is being funded by the DOE ATS program. Catalytic technology features "flameless" combustion that occurs in a series of catalytic reactions to limit the temperature in the combustor. Catalytic combustors capable of sub- 3 ppm NO_x levels are entering commercialization. Catalytica (Mountain View, CA) has developed an all-metal catalyst substrate that eliminates the potential problems associated with the limitations of high temperature ceramic substrates. Maximum temperature reached in the catalyst is limited to approximately 1,700 °F to avoid damaging the metal substrate. All fuel and air is added upstream of the catalyst.

Approximately 50 percent of the fuel is oxidized in the catalyst limiting the temperature rise to about 1,700 °F. The remaining 50 percent of the fuel is oxidized downstream of the catalyst. Catalytic combustion is one of the most promising new technologies to meet ever stricter emission limits.

Catalytica performed a successful 1,000 hour test of its combustor in a 1.5 MW Kawasaki gas turbine that concluded in mid-November 1997. Another 1.5 MW Kawasaki turbine located at a cogeneration plant in Santa Clara, California has been equipped with a catalytic combustor that began operation in October 1998. A 20 MW Turbo Power FT4 operated by the city of Glendale, CA, will also be retrofitted with a catalytic combustor in 1999. Catalytic combustors have been tested in large GE turbines at the GE test facility in Schenectady, New York. NO_x averaged less than 3 ppm and CO less than 5 ppm (corrected to 15 percent O_2) during a test on a Frame 9E turbine. GE recently announced a Memorandum of Understanding with Catalytica to develop catalytic combustors for all GE turbine models through Frame 7E (78 MW). A second manufacturer of catalytic combustors, Precision Combustion, Inc. (New Haven, CT), has demonstrated the ability to operate on liquid fuel without significant NO_x formation.

1.2.3 Selective Catalytic Reduction

The primary post-combustion NO_x control method is selective catalytic reduction (SCR.) Ammonia is injected into the flue gas and reacts with NO_x in the presence of a catalyst to produce N_2 and H_2O. The operating temperature of conventional SCR systems ranges from 400 – 800 °F. In the past two years, the cost of conventional SCR has dropped significantly. Catalyst innovations have been a principal driver, resulting in a 20 percent reduction in catalyst volume and cost with no change in performance.

Low temperature SCR, operating in the 300 – 400 °F temperature range, was commercialized in 1995 and is currently in operation on approximately twenty gas turbines. Low temperature SCRs have found a niche in retrofit applications downstream of HRSGs.

High temperature SCR installations, operating in the 800–1,100 °F temperature range, have increased significantly from the single installation cited in the 1993 NO_x ACT document. High temperature SCRs are used on simple cycle gas turbines where there is no heat recovery to reduce exhaust temperatures as would be required for a conventional SCR catalyst.

1.2.4 $SCONO_x$

$SCONO_x$™, patented by Goaline Environmental Technologies, is a post-combustion alternative to SCR that has been demonstrated to reduce NO_x emissions to less than 1 ppm and almost 100% removal of CO. $SCONO_x$™ combines catalytic conversion of CO and NO_x with an absorption/regeneration process that eliminates the ammonia reagent found in SCR technology. The $SCONO_x$™ system is generally located downstream of the HRSG since the system operates between 280-700°F. $SCONO_x$™ has been in operation on a General Electric LM2500 in the Los Angeles area since 1996. A second $SCONO_x$™ system is currently being installed on a Solar Centaur turbine located in Massachusetts. $SCONO_x$™ was identified as "Lowest Achievable Emission Rate (LAER)" technology for gas turbine NO_x control by U.S. EPA Region 9 in 1998.

2.0 TECHNICAL DISCUSSION

2.1 Introduction to Gas Turbines

Over the last two decades, the gas turbine has seen tremendous development and market expansion. Whereas gas turbines represented only 20 percent of the power generation market twenty years ago, they now claim approximately 40 percent of new capacity additions. Some forecasts predict that gas turbines may furnish more than 80 percent of all new U.S. generation capacity in coming decades. Gas turbines have been long used by utilities for peaking capacity, however, with changes in the power industry and increased efficiency, the gas turbine is now being relied on for base load power. Much of this growth can be accredited to large (>50 MW) combined cycle plants which exhibit low capital cost (less than $550/kW) and high thermal efficiency. Manufacturers are offering new and larger capacity machines that operate at higher efficiencies.

Gas turbine development accelerated in the 1930's as a means of propulsion for jet aircraft. It was not until the early 1980's that the efficiency and reliability of gas turbines had progressed such that they were widely adopted for stationary power applications. Gas turbines range in size from 30 kW (microturbines) to 250 MW (industrial frames).

2.1.1 Technology Description

The thermodynamic cycle associated with the majority of gas turbines is the Brayton cycle, an open-cycle using atmospheric air as the working fluid. An open cycle means that the air is passed through the turbine only once. The thermodynamic steps of the Brayton cycle includes 1) compression of atmospheric air, 2) introduction and ignition of fuel and 3) expansion of the heated combustion gases through the gas producing and power turbines. A stationary gas turbine consists of a compressor, combustor and a power turbine, as shown in Figure 2-1. The compressor provides pressurized air to the combustor where fuel is burned. Hot combustion gases leave the combustor and enter the turbine section where the gases are expanded across the power turbine blades to rotate one or more shafts. These drive shafts power the compressor and the electric generator or prime mover. The simple cycle thermal efficiency of a gas turbine can range from 25 percent in small units to 40 percent or more in recuperated cycles and large high temperature units. The thermal efficiency of the most advanced combined cycle gas turbine plants is approaching 60 percent. The thermal efficiency of cogeneration applications can approach 80 percent where a major portion of the waste heat in the turbine exhaust is recovered to produce steam.

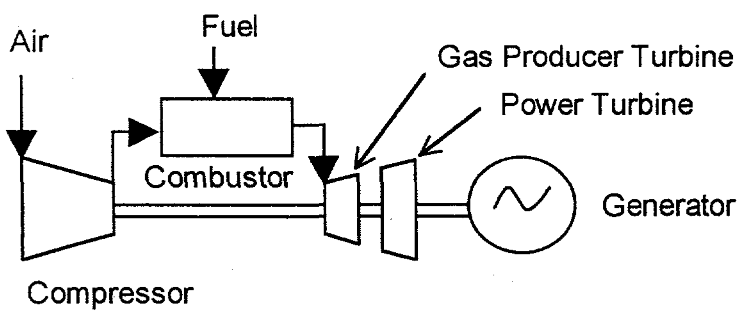

Figure 2-1. Components of a Gas Turbine

2.1.2 Gas Turbine Types

Aeroderivative gas turbines used for stationary power are adapted from their jet engine counterparts. These turbines are light weight and thermally efficient, however, are limited in capacity. The largest aeroderivitives are approximately 40 MW in capacity today. Many aeroderivative gas turbines for stationary use operate with compression ratios of up to 30:1 requiring an external fuel gas compressor. With advanced system developments, aeroderivitives are approaching 45 percent simple cycle efficiencies.

Industrial or frame gas turbines are available between 1 MW to 250 MW. They are more rugged, can operate longer between overhauls, and are more suited for continuous base-load operation, however, they are less efficient and much heavier than the aeroderivative. Industrial gas turbines generally have more modest compression ratios of up to 16:1 and often do not require an external compressor. Industrial gas turbines are approaching simple cycle efficiencies up to approximately 40 percent and in combined cycles can approach 60 percent.

Small industrial gas turbines (1-10 MW) are being successfully used for onsite power generation and as mechanical drivers. Small gas turbines are used to drive compressors along natural gas pipelines to transport product across the country. In the petroleum industry they drive gas compressors to maintain well pressures. In the steel industry they drive air compressors used for blast furnaces. With the coming competitive electricity market, many experts believe that installation of small industrial gas turbines will proliferate as a cost effective alternative to grid power.

2.2 NO_x Formation in Gas Turbines

Virtually all gas turbine NO_x emissions originate as nitrogen oxide (NO) that is further oxidized in the exhaust system or in the atmosphere to form nitrogen dioxide (NO_2) There are two mechanisms by which NO_x is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x).

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form NO_x. The major contributing chemical reactions are known as the Zeldovich mechanism that occur in the high temperature area of the gas turbine combustor. The Zeldovich mechanism postulates that thermal NO_x formation increases exponentially with increases in temperature and linearly with increases in residence time.

Prompt NO_x, a form of thermal NO_x, is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH that are oxidized to form NO_x. Prompt NO_x is formed in both fuel-rich flames zones and dry low NO_x (DLN) combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is a significant percentage of overall thermal NO_x

emissions in DLN combustors. For this reason, prompt NO_x becomes an important consideration for DLN combustor designs, establishing a minimum NO_x level attainable in lean mixtures.

Fuel NO_x is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some kinds of natural gas, does not contribute significantly to fuel NO_x formation. Some low-Btu synthetic fuels contain nitrogen in the form of ammonia (NH_3). Other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x. With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NO_x decreases with increasing nitrogen content, although the absolute magnitude of fuel NO_x increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NO_x, whereas a fuel with a 1.0 percent FBN may have only a 40 percent conversion rate. Natural gas typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not a major contributor to overall NO_x emissions from stationary gas turbines firing natural gas.

2.3 Factors that Affect NO_x Formation in Gas Turbines

The level of NO_x formation in a gas turbine is unique to each gas turbine model and operating mode. The primary factors that determine the amount of NO_x generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine. These factors are discussed below.

2.3.1 Combustor Design

The design of the combustor is the most important factor influencing the formation of NO_x. Control of the air/fuel ratio, extent of pre-combustion mixing, operating load, introduction of cooling air, flame temperature and residence time are design parameters associated with combustor design that affect NO_x formation.

2.3.2 Power Output Level

The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature and the rate of thermal NO_x formation. In conventional combustors (including DLN combustors operating at less than 50 percent load) fuel is injected into the base of the combustor. Air is injected along the length of the combustor to provide both combustion air and "quenching air" to cool the combustor exhaust gas before it reaches the turbine blades. A fuel rich environment is maintained in the immediate vicinity of the fuel injector. As the fuel diffuses into the combustion/cooling air supply, combustion takes place. At low loads, the reaction kinetics are such that combustion proceeds at a relatively fuel rich ratio and combustion products are quenched rapidly. At high load, the flame front reaches its maximum size and length. There is also greater turbulence in the combustor, resulting in a greater percentage of the fuel being combusted in "hot spots" at or near stoichiometric conditions with less air available to quench the products of combustion. As a result, NO_x emissions are greatest at high load conditions.

2.3.3 Type of Fuel

The level of NO_x emissions varies for different fuels. For gaseous fuels, the constituents in the gas can significantly affect NO_x emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (such as ethane, propane and butane) burn at higher flame temperatures, and can increase NO_x emissions greater than 50 percent over NO_x levels for methane. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons.

Conversely, gaseous fuels that contain significant inert gases, such as CO_2, generally produce lower NO_x emissions. These inert gases absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x emissions. Examples include air-blown gasifier fuels and some field gases.

Combustion of hydrogen produces high flame temperatures and gases with significant hydrogen content produce relatively high NO_x emissions. Distillate oil burns at a flame temperature that is approximately 150 °F higher than that of natural gas and produces higher NO_x emissions. Low-Btu fuels such as coal gas burn with lower flame temperatures and produce lower thermal NO_x emissions.

2.3.4 Ambient Conditions

Ambient conditions that affect NO_x emissions are humidity, temperature, and pressure. Humidity has the greatest effect since water vapor quenches combustion temperatures that reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, changes in ambient temperature has a varied effect on NO_x formation. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 50 °F, NO_x emissions decrease with increasing temperature. Higher ambient pressure causes elevated temperature levels in the combustor, promoting NO_x formation.

2.3.5 Operating Cycles

The level of NO_x emissions from identical turbines used in simple cycle, combined cycle, and cogeneration cycles is essentially equivalent and independent of downstream exhaust gas temperature reductions. Duct burners are typically used in combined cycle and cogeneration installations to boost exhaust gas temperature upstream of the HRSG. Duct burner emissions are controlled by post-combustion control systems such as SCR or low NO_x duct burners that guarantee emission levels as low as 0.08 lb NO_x per MMBtu heat input. Duct burner NO_x emission test results included in the 1993 NO_x ACT document indicate that in some cases NO_x emissions are reduced across the duct burner. The reason for this net NO_x reduction is not known, but is believed to be a result of a reburning process in which intermediate combustion products from the duct burner interact with the NO_x already present in the gas turbine exhaust.

2.4 BACT/LAER Determinations

A listing of recent BACT/LAER Clearinghouse entries for gas turbine installations is shown in Table 2-1. A permit limit of 3.0 ppm NO_x at 15 percent O_2 is currently the lowest "demonstrated in practice" NO_x emission rate.

Table 2-1

Summary of Recent Gas Turbine BACT/LAER Determinations

Site	Turbine	Rated Output (MW)	Emission Limits (ppm corrected to 15 percent O_2)						Year Permitted
			NO_x	CO	VOC	PM_{10}	SO_2	NH_3	
California:									
ARCO Carson	GE Frame 6	45	3.5	Not requested					1997
Federal Cogen	GE LM5000	34	3.5	Not requested					1996
Badger Creek	GE Frame 6	48	3.8	11	5.3	NG	NG	20	1994
Goal Line, Escondido	GE LM6000	42	5	25	NG	NG	NG	10	1992
Northern CA Power	GE Frame 6	45	3.0	6.0	0.29 lb/MM Btu	NG	NG	25	1991
Other States:									
Brooklyn Navy Yard, NY	Seimens V84.2	106	3.5 (gas) 10 (oil)	Not requested					1995
K/B Syracuse, NY	Seimens V64.3	63	25	Not requested					1994
Lockport Cogen, NY	GE Frame 6	45	42	Not requested					1993
Tenaska, WA	GE Frame 7FA	164	7.0	Not requested					1992
Sithe, NY	GE Frame 7FA	164	4.5	Not requested					1992

NG: natural gas

2.5 NO_x Emission Control Technologies

The most common NO_x control method for new combined cycle power plants is a DLN combustor combined with SCR to maintain NO_x emission levels at or below 5 ppm. Steam or water injection combined with SCR is also used at a number of existing installations to maintain NO_x emission levels at or below 5 ppm. Often the decision to use water or steam injection over DLN is based on end-user familiarity and the slightly lower first cost of the water/steam injection system. Various gas turbine NO_x emission control technologies are discussed below.

2.5.1 Water/Steam Injection

Water or steam injection is a very mature technology, having been used since the 1970's to control NO_x emissions from gas turbines. Simultaneous mixing of fuel and air and subsequent combustion results in localized fuel-rich zones within the combustor that yield high flame temperatures. Injecting water or steam into the flame area of the combustor provides a heat sink that lowers the flame temperature and reduces thermal NO_x formation. The "water-to-fuel ratio" (WFR) has a direct impact on the controlled NO_x emission rate and is generally controlled by the turbine inlet temperature and ambient temperature. Products of incomplete combustion, carbon monoxide (CO) and unburned hydrocarbons (UHC) increase as more water or steam is added to quench the peak flame temperature. Based on Solar Turbines' experience, WFR's up to 0.6-0.8 generally result in little or no increase in CO and UHC. A WFR above 0.8 generally produces an exponential rise in the CO and UHC emission rates.

Water impingement on the combustor liner limits the maximum practical water injection rate, as direct water impingement results in rapid liner wear. Impingement is not an issue with steam injected turbines meaning significantly higher steam injection rates, on a mass basis, are practical in steam injected turbines.

The high cost of producing large amounts of purified water or steam, water impingement, and control of CO and UHC emissions have slowed the use of water/steam injection systems in favor of DLN combustors over the last five years.

2.5.2 Dry Low NO_x (DLN) Combustors

DLN combustor technology premixes air and a lean fuel mixture that significantly reduces peak flame temperature and thermal NO_x formation. Conventional combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot spots that produce high levels of NO_x. In contrast, DLN combustors generally operate in a premixed mode where air and fuel are mixed before entering the combustor. The underlying principle is to supply the combustion zone with a completely homogenous, lean mixture of fuel and air. DLN combustor technology generally consists of hybrid combustion, combining diffusion flame (for low loads) plus DLN flame combustor technology (for high loads.) Due to the flame instability limitations of the DLN combustor below approximately 50 percent of rated load, the turbine is typically operated in a conventional diffusion flame mode until the load reaches approximately 50 percent. As a result, NO_x levels rise when operating under low load conditions. For a given turbine, the DLN combustor volume is typically twice that of a conventional combustor.

A notable exception to this is the sequential combustion DLN technology developed by ABB for the GT24 (166 MW) and GT26 (241 MW) power generation turbines. Combustion takes place in the primary DLN combustor (EV™) followed by fuel addition in a second (SEV™) combustion chamber located aft of the first row of turbine blades. This DLN technology was commercialized in 1997 and permits DLN operation across the load range of the turbine.

O&M costs for turbines equipped with DLN can be significantly higher than predicted due to a variety of factors including replacement of blades and vanes, redesigned bearings, lift pumps and combustor sensitivity to changes in fuel composition. The high operating temperatures of advanced turbines can cause creep damage in the first stage blades, requiring frequent inspections and blade replacement. Another issue with DLN combustors is "flashback," where fuel upstream of the burner ignites prematurely damaging turbine components. DLN combustors tend to create harmonics in the combustor that result in significant vibration and acoustic noise.

Virtually all DLN combustors in commercial operation are designed for use with gaseous fuels. Some manufacturers are now offering dual fuel (gas and diesel) DLN combustors. DLN operation on liquid fuels has been problematic due to issues involving liquid evaporation and auto-ignition.

DLN combustion is essentially free of carbon formation especially when gaseous fuels are used. The absence of carbon not only eliminates soot emissions but also greatly reduces the amount of heat transferred to the combustor liner walls by radiation and the amount of air needed for liner wall cooling. More air is available for lowering the temperature of the combustion zone and improving the flow pattern in the combustor.

Another important advantage of the DLN combustor is that the amount of NO_x formed does not increase with residence time meaning that DLN systems can achieve low CO and UHC emissions while maintaining low NO_x levels. Long residence times are required to minimize CO and UHC emissions.

GE Power Systems, Siemens-Westinghouse, and ABB, have concentrated their DLN combustor improvement efforts in turbines greater than 50 MW. Given established trends in the industry, it is likely that these DLN improvements will eventually become available in smaller gas turbines. GE has reduced NO_x emissions from 25 ppm to 9-15 ppm in its "can-annular" DLN combustor design for its "Frame" series of turbines. GE has guaranteed 10 ppm NO_x for a limited number of Frame 6 and Frame 7 turbine installations with rated outputs from 70 to 171 MW, respectively. Although hardware costs are approximately constant whether the turbine is guaranteed at 9 or 15 ppm, O&M is increased at the lower emission rate due to more rigorous maintenance requirements.

2.5.3 Catalytic Combustion

The strong dependence of NO_x formation on flame temperature means that NO_x emissions are lowest when the combustor is operating close to the lean flameout limit. One method of extending the lean flameout limit down to lower fuel-air ratios is by incorporating a combustion-enhancing catalyst within the combustor. Catalytic combustion is a flameless process, allowing fuel oxidation to occur at temperatures approximately 1,800 °F lower than those of conventional combustors. Catalytic combustors are being developed to control NO_x emissions down to 3 ppm. A major advantage of the catalytic combustor is low vibration and acoustic noise that are onetenth to one-hundredth the levels measured in the same turbine equipped with DLN combustors, according to preliminary test data.

One problem with catalytic combustors is the potential auto-ignition of the fuel upstream of the catalyst. Although the air-fuel ratios are well below the lean flammability limit and in theory should not be susceptible to auto-ignition, local pockets of rich fuel mixtures can exist near the fuel injector and ignite. Mixing must be achieved quickly to prevent fuel rich pockets from forming. Optimum catalyst performance also requires the inlet air-fuel mixture to be of completely uniform temperature, composition, and velocity profile since this assures effective use of the entire catalyst area and prevents damage to the substrate due to local high gas temperatures.

A major unknown with catalytic combustors is the durability of the catalyst. Research suggests that the catalyst will deteriorate during prolonged operation at high temperature. Thermal degradation results from loss of surface area caused by sintering and volatilization of active metals, such as platinum, which oxidizes at temperatures above 2,010 °F.

2.5.4 Selective Catalytic Reduction (SCR)

The SCR process consists of injecting ammonia upstream of a catalyst bed. NO_x combines with the ammonia and is reduced to molecular nitrogen in the presence of the catalyst. SCR is capable of over 90 percent NO_x reduction, and can be combined with DLN or water/steam injection to achieve NO_x outlet concentrations of 5 ppm or less at 15 percent O_2 when firing on natural gas. Titanium oxide is the SCR catalyst material most commonly used, however, vanadium pentoxide, noble metals, and zeolites are also used. For conventional SCR catalysts, the catalyst reactor is normally mounted on a "spool piece" located within the HRSG at a location where the gas temperature is between 600 to 750 °F.

A certain amount of "ammonia slip" occurs when using SCR. Ammonia slip is usually limited by local regulations to 10-20 ppm at 15 percent O_2. Ammonia passing through the SCR and emitted to atmosphere can combine with nitrate (NO_3) or sulfate (SO_4) in the ambient air to form a secondary particulate, either ammonium nitrate or ammonium bisulfate. The formation of ammonium bisulfate while firing on diesel fuel with a high sulfur content has been responsible for fouling HRSG tubes downstream of the SCR. Operating data indicates that a sulfur limit of 0.05 percent will prevent this kind of HRSG tube fouling .

The Northern California Power (NCP) combined-cycle power plant located in the San Joaquin Valley, CA is a 45 MW facility consisting of a single GE Frame 6 turbine using steam injection and SCR to achieve a permitted NO_x limit of 3.0 ppm. The NCP installation achieves the 3.0 ppm NO_x level through very high rates of ammonia injection, having a ammonia slip limit of 25 ppm. The combined cycle power plant at the Brooklyn Navy Yard in Brooklyn, New York, that became operational in 1996, has the 106 MW Siemens V84.2 water-injected turbines equipped with SCR and achieves the 3.5 ppm NO_x permit limit.

2.5.5 SCONO$_x$™ Catalytic Absorption System

In 1998, the U.S. EPA certified an innovative catalytic NO_x reduction technology, SCONO$_x$™, as a "demonstrated in practice" LAER-level technology for gas turbine NO_x reduction to below 5 ppm. SCONO$_x$™ employs a precious metal catalyst and a NO_x absorption/regeneration process step to convert CO and NO_x to CO_2, H_2O and N_2. NO_x binds to the potassium carbonate absorbent coating the surface of the oxidation catalyst in the SCONO$_x$™ reactor. Each "can" within the reactor becomes saturated with NO_x over time and must be desorbed. Regeneration is accomplished by isolating the can via stainless steel louvers and injecting hydrogen diluted with steam. Hydrogen is generated at the site with a small reformer that uses natural gas and steam as input streams. The hydrogen concentration of the reformed gas is typically 5 percent. The hydrogen reacts with the absorbed NO_x to form N_2 and H_2O, regenerating the potassium carbonate for another absorption cycle. The principal advantages of the SCONO$_x$™ technology over SCR are the elimination of ammonia emissions and the simultaneous reduction of CO, VOCs and NO_x.

A SCOSO$_x$™ catalytic coating can also be added to the oxidation catalyst to effectively remove SO_2 from the exhaust gas. If an SO_2 absorbent is added, the "can" is desorbed in the same manner, resulting in the formation of H_2S. Regeneration gases are then passed through an H_2S scrubber to remove the captured sulfur.

A GE LM5000 (32 MW) turbine located at the Federal Cogeneration facility in the Los Angeles area was retrofitted with a $SCONO_x$™ catalytic NO_x reduction system in 1996. This installation demonstrated compliance with a 3.5 ppm NO_x standard over a six-month period from December 1996 to June 1997. U.S. EPA Region 9 has identified $SCONO_x$™ as a "demonstrated in practice" Lowest Achievable Emission Rate (LAER)-level control technology based on this six-month compliance demonstration. A second $SCONO_x$™ installation will be operational in 1999 on a Solar Centaur turbine located at an industrial facility in Massachusetts.

2.5.6 Rich-Quench-Lean (RQL) Combustors

The RQL concept is under development and uses staged burning to achieve low NO_x emission levels. Combustion is initiated in a fuel-rich primary zone that reduces NO_x formation by lowering both the flame temperature and the available O_2. The hydrocarbon reactions proceed rapidly, causing depletion of O_2 that inhibits NO_x formation. Higher fuel-air ratios is limited by excessive soot and smoke formation.

As the fuel-rich combustion products flow out of the primary zone, jets of air rapidly reduce the gas temperature to a level at which NO_x formation is minimal. Transition from a rich zone to a lean zone must take place rapidly to prevent NO_x formation. The ability to achieve near-instantaneous mixing in this "quick quench" region is the key to the success of the RQL concept. An important design consideration is controlling the temperature of the lean-burn zone. The temperature must be high enough to eliminate any remaining CO and UHCs, however, not too high so as to limit the formation of thermal NO_x.

Most of the research conducted indicates that the RQL concept has potential for ultra-low NO_x combustion. RQL requires only one stage of fuel injection that simplifies fuel metering. Significant improvements in the quench mixer design are necessary before this technology is ready for commercialization. Other inherent problems include high soot formation in the rich primary zone that promotes high flame radiation and exhaust smoke. These problems are exacerbated by long residence times, unstable recirculation patterns, and non-uniform mixing.

3.0 NO_X CONTROL COST ESTIMATES

3.1 1999 NOx Control Cost Estimates

Tables A-1 through A-7 (Appendix A) provide detailed cost estimates and cost factors ("\$/ton" and "¢/kWh") for each NO_x control technology.

The factored cost estimation procedure used in this study is provided in the EPA's Control Cost Manual, 5th Edition (1996). Capital costs are estimated as the sum of the purchased equipment cost, taxes and freight charges, and installation costs. Purchased equipment costs are based on quotes provided by equipment manufacturers. Taxes, freight, and installation costs are estimated as fixed fractions of purchased equipment cost based on OAQPS cost factors. O&M costs are based on manufacturer or operator estimates (when available) or OAQPS cost factors. The OAQPS estimates an accuracy of $\pm$ 30 percent for the factored cost estimation procedure. The annualized capital cost of the installed control equipment is based on a 15-year, 10 percent capital recovery factor as used in the 1993 NO_x ACT document. EPA capital cost factors for modular, prefabricated control equipment have been used except for low temperature SCR which have been installed in retrofit applications and require considerable modifications.

3.2 Uncontrolled NO_x Emission Rate

The uncontrolled NO_x emission rates used in this study are referenced from Tables 6-12 through 6-14 of the 1993 NO_x ACT document. The uncontrolled NO_x emission rates of different turbine models vary considerably from 105 ppm (Solar Centaur) to 430 ppm (ABB GT8). NO_x control cost effectiveness ("\$/ton") will be significantly less for turbines with very high uncontrolled NO_x emissions even though the annualized cost of the NO_x control system may be comparable to other turbines in its output range.

3.3 NO_x Control Technology Cost Estimates

Cost estimates obtained from various manufacturers of gas turbines and NO_x control equipment are discussed in the following subsections.

3.3.1 DLN Cost Estimates

The cost of DLN combustors can vary dramatically for the same size turbine offered by different manufacturers. As an example, the incremental cost of a DLN combustor for a Solar Taurus 60 turbine (5.2 MW) is approximately $180,000. The incremental cost of a DLN combustor for an Allison 501-KB7 turbine (5.1 MW) is $20,000. The cost discrepancy is related to the performance capabilities, design complexity and reliability/maintenance factors.

There have been significant changes in DLN unit cost and manufacturer's NO_x emission guarantees since the 1993 NO_x ACT document was published. Note that the available data used in the 1993 NO_x ACT document may have been limited to a single turbine manufacturer, especially for DLN technology which was just being commercialized at the time. The DLN annual cost for small turbines (5 MW) has dropped by about 50 percent compared to information in the 1993 NO_x ACT document. The current DLN cost for 25 MW turbines appears relatively unchanged. No DLN costs were presented for large turbines (150 MW) in the 1993 NO_x ACT document. DLN cost data is now available for a number of large turbines. The current cost of DLN for the GE Frame 7FA (170 MW) is used in this study.

3.3.2 Solar Turbines Water Injection and DLN Cost Estimate

Solar Turbines provided the incremental cost of water injection and DLN compared to a conventional diffusion combustor for two turbine models as shown in Table 3-1.

Table 3-1

Incremental Water Injection and DLN Costs

Turbine Model	Size (MW)	Fuel	Price Range ($million)	Incremental Cost for Water Injection	Incremental Cost for DLN
Centaur 50	4.3	natural gas	1.5-3.4	$45,000-$96,000	$145,000-$190,000
Taurus 60	5.2	natural gas	1.7-3.6	$45,000-$96,000	$165,000-$190,000

The Solar DLN combustor has been in commercial operation since 1992 and is described in the 1993 NO_x ACT document. The combustor operates in conventional diffusion flame mode over the 0 to 50 percent load range. The DLN injectors operate over the 50 to 100 percent load range. The Solar DLN combustor is designed to operate in harsh unattended environments in electrical generation and mechanical drive applications with no additional O&M costs over conventional combustors. R&D efforts have focused on producing a robust DLN combustor with the reliability and durability of conventional combustors.

Solar indicates there is no incremental cost for routine O&M of the DLN combustors compared to a conventional combustor. The company also indicated that major overhaul of the DLN is more expensive than major overhaul of a conventional combustor. The differential cost between major overhaul of a DLN and conventional combustor is considered proprietary by Solar.

3.3.3 Allison DLN Cost Estimate

The Allison DLN combustor, known as the LE4, entered commercial operation in 1996. The LE4 is a much simpler unit than Solar's DLN combustor since the conventional diffusion injector is used. The LE4 is specifically designed for baseload industrial power applications and has very little turndown capability. The incremental cost of a LE4 combustor for an Allison 501-KB7 turbine (5.1 MW) is $20,000. Incremental annual O&M costs are estimated at $4/fired-hour or approximately $32,000/yr and currently exceed the LE4 capital cost. The principal O&M weaknesses are primarily related to the fuel management system, however, incremental O&M costs are expected to drop to below $1/fired-hour in the near future.

3.3.4 GE LM2500 Water Injection and DLN Cost Estimate

GE Industrial and Marine indicated that the incremental cost of water injection and DLN for the LM2500 turbine (23 MW) are \$100,000 and \$800,000, respectively. The incremental O&M cost for a LM2500 was estimated at \$10-20/fired-hour. This incremental O&M cost includes the cost of periodic major overhaul of the DLN combustor. The LM2500 is an aeroderivative turbine with an annular combustor. Combustor overhaul is more complex in the LM2500 than in a non-aeroderivative industrial turbine equipped with can-annular combustors, such as the General Electric Frame 7FA, since the individual combustor "cans" are modular and can be removed and replaced quickly.

3.3.5 GE Frame 7FA DLN Cost Estimate

GE Power Systems indicated that the cost to replace an existing steam-injected Frame 7FA combustor with a DLN combustor is \$4,500,000 (installed). A definitive O&M cost for the Frame 7FA equipped with DLN has not been determined by GE Power Systems. GE Power Systems indicated that large baseload units such as the Frame 7FA are provided with spare combustors that are typically rotated every 8,000 to 12,000 hours. Combustor rotation eliminates the need for a separate 30,000 to 40,000 hour major combustor overall as is typical with smaller industrial units equipped with annular combustors.

3.3.6 Catalytica Combustor Cost Estimate

Catalytica (Mountain View, CA) provided catalytic combustor cost estimates based on anticipated performance since the technology is not fully commercialized. The cost estimates assume catalyst replacement on an annual basis, however, catalyst life is currently being tested at several gas turbine installations.

3.3.7 MHIA Conventional SCR Cost Estimate

Mitsubishi Heavy Industries America (MHIA) is the principal supplier of conventional SCR to the gas turbine market in the U.S. According to MHIA, advances in SCR technology in the past two years have resulted in a 20 percent reduction in the amount of catalyst required to achieve a given NO_x target level. In addition, experience gained in the design and installation of SCR units has lowered engineering costs. These two factors have substantially reduced the cost of SCR systems since the 1993 NO_x ACT document. Operating costs have been reduced through innovations such as using hot flue gas to pre-heat ammonia injection air which lowers the power requirements of the ammonia injection system.

3.3.8 KTI Low Temperature SCR Cost Estimate

The Kinetics Technology International (KTI) low temperature SCR is designed for retrofit installations with single digit NO_x emission targets. Low temperature SCR systems are installed downstream of an existing HRSG and avoid modification of the HRSG as would be required to accommodate a conventional SCR system.

3.3.9 Engelhard High Temperature SCR Cost Estimate

The high temperature SCR provided by Engelhard uses a zeolite catalyst to permit continuous operation at temperatures up to 1,100 °F. The high temperature resistance of the zeolite catalyst allows for SCR installations on simple cycle gas turbines (no heat recovery.) Simple cycle gas turbines generally have exhaust temperatures ranging from 950 to 1,050 °F at rated load. At part loads, exhaust temperatures can be 100 °F higher than rated conditions that can damage the zeolite catalyst. To prevent damage at sustained part load operation, a tempering air system is included to moderate exhaust temperatures.

3.3.10 $SCONO_x$™ Cost Estimate

The cost of the $SCONO_x$™ system has remained relatively constant since its introduced in 1996. The technology has witnessed several design changes since its inception that have had positive and negative impacts to cost; two examples follow. The original unit was designed with a "space velocity" of 30,000 ft^3 hour exhaust gas per /ft^3 catalyst (ft^3-hour/ft^3). The space velocity has since been reduced to 20,000 ft^3-hour/ft^3 to meet the standard NO_x emission outlet guarantee of

2 ppm. Two actuators instead of one control the isolation louvers for each catalyst module to improve reliability.

Note that the $SCONO_x$ cost estimate used for the 150 MW gas turbine size classification was obtained for an 83 MW turbine and scaled accordingly.

3.4 Results and Conclusions

Table 3-2 summarizes the "cost per ton of NO_x removed" ($/ton) and the "electricity cost impact ("$/kWh") for each NO_x control technology. These cost comparisons assume the gas turbine fires natural gas.

Cost effectiveness ("$/ton") is a useful comparative indicator when the inlet and outlet NO_x concentrations are the same for each group of turbines being evaluated. NO_x can be controlled to within a feasible limit for a particular technology and is largely independent of a gas turbine's uncontrolled NO_x emission rate. Therefore the uncontrolled NO_x exhaust concentrations must be considered when evaluating the "$/ton" cost effectiveness values applied to different makes/models of turbines to obtain a meaningful comparison. For example, SCR is typically used on installations that are also controlled by water/steam injection or DLN. Conventional SCR inlet concentrations typically range from 25 to 42 ppm (corrected to 15 percent O_2). In contrast, all low temperature SCR installations to date have been installed on uncontrolled turbines with NO_x concentrations ranging from 100 to 132 ppm. As a result, the low temperature SCR has a favorable "$/ton" cost effectiveness when compared to the conventional SCR, although the "¢/kWh" cost of the low temperature SCR is significantly higher.

The "¢/kWh" value provides an economic indication of the electricity cost impact of a particular NO_x control technology, independent of the NO_x emission reductions achievable with the technology. A comparison between values is most meaningful for technologies that control NO_x to an equivalent "ppm" concentration.

Table 3-2

Comparison of 1993 and 1999 NO_x Control Costs for Gas Turbines

NO_x Control Technology	Turbine Output (MW)	Emission Reduction (ppm)	1993		1999	
			$/ton	¢/kWh	$/ton	¢/kWh
Water/steam	4-5	unc. → 42	1,750-2,100	0.47-0.50	1,500-1,900	0.39-0.43
DLN	4-5	unc. → 42	820-1,050	0.16-0.19	NA[b]	NA
DLN	4-5	unc. → 25	NA[b]	NA	270-400	0.06-0.09
Catalytic[a]	4-5	unc. → 3	NA	NA	1,000	0.32
Low temp. SCR	4-5	42 → 9	NA	NA	5,900	1.06
Conventional SCR	4-5	42 → 9	9,500-10,900	0.80-0.93	6,300	0.47
High temp. SCR	4-5	42 → 9	9,500-10,900	0.80-0.93	7,100	0.53
$SCONO_x$	4-5	25 → 2	NA	NA	16,300	0.85
Water/steam	20-25	unc. → 42	980-1,100	0.24-0.27	980	0.24
DLN	20-25	unc. → 25	530-1,050	0.16-0.19	210	0.12
Catalytic[a]	20-25	unc. → 3	NA	NA	690	0.22
Low temp. SCR	20-25	42 → 9	NA	NA	2,200	0.43
Conventional SCR	20-25	42 → 9	3,800-10,400	0.30-0.31	3,500	0.20
High temp. SCR	20-25	42 → 9	3,800-10,400	0.30-0.31	3,800	0.22
$SCONO_x$	20-25	25 → 2	NA	NA	11,550[c]	0.46[c]
Water/steam	160	unc. → 42	480	0.15	480[d]	0.15[d]
DLN	170	unc. → 25	NA	NA	124	0.05
DLN	170	unc. → 9	NA	NA	120	0.055
Catalytic[a]	170	unc. → 3	NA	NA	371	0.15
Conventional SCR	170	42 → 9	3,600	0.23	1,940	0.12
High temp. SCR	170	42 → 9	3,600	0.23	2,400	0.13
$SCONO_x$	170	25 → 2	NA	NA	6,900[c]	0.29[c]

Notes:

(a) Catalytic combustor technology is just entering commercial service. Annualized cost estimates provided by the manufacturer are not based on "demonstrated in practice" installations.

(b) "NA" means technology that was not available in 1993, or technology that is obsolete in 1999.

(c) The $SCONO_x$ manufacturer provided a quote for a 83 MW unit. The quote has been scaled to the appropriate unit size.

(d) The one baseload Frame 7F installed in 1990 is the only baseload 7F turbine that is equipped with steam injection. All subsequent 7F and 7FA baseload machines have been equipped with DLN. For this reason, the 1993 figures are assumed to be unchanged for steam injection.

Direct comparisons can be made between 1993 and 1999 costs for water/steam injection, DLN and conventional SCR. Information was not available for low and high temperature SCR, $SCONO_x$™, and catalytic combustion in the 1993 NO_x ACT document.

The "¢/kWh" values for water/steam injection have remained fairly constant between the 1993 NO_x ACT document and the evaluation performed in this study. This is consistent with the fact that water/steam injection was a mature technology in 1993. Considerable innovation has occurred with DLN and SCR, and this is reflected in a 50-100% reduction in the "¢/kWh" values for these two technologies between 1993 and 1999.

High temperature SCR is only about 10 percent more costly than conventional SCR. Low temperature SCR and $SCONO_x$™ are typically 2 times more costly than conventional SCR. Each of these technologies fills a unique technical "niche"; cost impact may be of secondary significance. Low temperature SCR is the only SCR technology that can operate effectively below 400 °F. High temperature SCR is the only SCR technology that can operate effectively from 800 to 1,100 °F. $SCONO_x$™ is the only post-combustion NO_x control technology that does not require ammonia injection to achieve NO_x levels less than 5 ppm.

Projected costs for catalytic combustors indicate that the "¢/kWh" cost is 2 to 3 times higher than a DLN combustor alone. The catalytic combustor can achieve NO_x levels of less than 3 ppm while the most advanced DLN combustor can achieve NO_x levels down to 9 ppm. To reach NO_x levels below 5 ppm, the DLN-equipped turbine requires post-combustion NO_x control device such as SCR or $SCONO_x$™. Although catalytic combustion is not fully commercialized, it is anticipated to have a cost impact comparable to that of existing DLN technology with conventional SCR.

The cost impact is highest when emission control technologies are applied to small industrial turbines (5 MW); a conclusion that was applicable in the 1993 NO_x ACT document as well. This is particularly true for the SCR and $SCONO_x$™ technologies where the cost impact is roughly twice that for larger turbines (25 MW and 150 MW). In ozone non-attainment areas, strict environmental regulations have mandated SCR. These regulations have a disproportionate impact on the construction of small gas turbine systems and may be too expensive to build. DLN and the development of catalytic combustion promise to significantly reduce the cost impact disparity between small and large gas turbines. It is proposed that regulations mandating post-combustion controls should be re-examined in light of technology improvements through initiatives like the ATS program.

APPENDIX A

NO_X CONTROL TECHNOLOGY COST COMPARISON TABLES

TABLE A-1
1999 DLN COST COMPARISON

(Incremental Annual Cost Compared to Conventional Uncontrolled Diffusion Combustor)

		5 MW Class			25 MW Class	150 MW Class	
Turbine Model		Allison 501-KB7	Solar Centaur 50	Solar Taurus 60	GE LM2500	GE Frame 7FA	GE Frame 7FA
Turbine Output		4.9 MW	4.0 MW	5.2 MW	22.7 MW	169.9 MW	169.9 MW
Heat Rate	Btu/kWhr	12,400	12,400	11,240	9,220	9,481	9,481
Heat Content	Btu/lb	20,160	20,610	20,610	20,610	20,610	20,610
Fuel flow	lb/hr	3,014	2,407	2,836	10,155	78,157	78,157
Hours of Operation	hrs	8,000	8,000	8,000	8,000	8,000	8,000
Fuel flow	MMBtu/yr	486,080	396,800	467,584	1,674,352	12,886,575	12,886,575
CAPITAL COST		$20,000	$190,000	$190,000	$800,000	$4,500,000	$4,750,000
ANNUAL COST							
Equipment Life	yrs	15	15	15	15	15	15
Interest Rate	%	10%	10%	10%	10%	10%	10%
Capital Recovery Factor		0.1315	0.1315	0.1315	0.1315	0.1315	0.1315
Capital Recovery		$2,629	$24,980	$24,980	$105,179	$591,632	$624,500
Catalyst Replacement		$0	$0	$0	$0	$0	$0
Other Parts and Repairs		$32,000	proprietary	proprietary	$120,000	$120,000	$120,000
Total Annual Cost		$34,629	$24,980	$24,980	$225,179	$711,632	$744,500
Uncontrolled	ppmv	155	105	114	174	210	210
Uncontrolled	tons/yr	154.4	83.5	106.9	584.1	5,426	5,426
Controlled	ppmv	25	25	25	25	25	9
Controlled	tons/yr	24.9	19.9	23.4	83.9	645.9	232.5
NOx Removed	tons/yr	129.5	63.6	83.4	500.2	4779.9	5193.3
Cost Effectiveness	**$/ton**	**$267**	**$392**	**$299**	**$210**	**$124**	**$120**
Electricity Cost Impact	**¢/kWhr**	**0.088**	**0.078**	**0.060**	**0.124**	**0.052**	**0.055**

Note: O&M cost for LM2500 DLN used for Frame 7FA as default.

TABLE A-2
1999 CATALYTIC COMBUSTION COST COMPARISON

(Incremental Annual Cost Compared to Conventional Uncontrolled Diffusion Combustor)

		5 MW Class	25 MW Class	150 MW Class
Turbine Model		Solar Taurus 60	GE Frame 5	GE Frame 7FA
Turbine Output		5.2 MW	26.3 MW	169.9 MW
Heat Rate	Btu/kWhr	11,240	12,189	9,481
Heat Content	Btu/lb	20,610	20,610	20,610
Fuel flow	lb/hr	2,836	15,554	78,157
Hours of Operation	hrs	8,000	8,000	8,000
Fuel flow	MMBtu/yr	467,584	2,564,626	12,886,575
CAPITAL COST		$217,100	$523,808	$1,443,629
ANNUAL COST				
Equipment Life	yrs	15	15	15
Interest Rate	%	10%	10%	10%
Capital Recovery Factor		0.1315	0.1315	0.1315
Capital Recovery		$28,543	$68,867	$189,799
Catalyst Replacement		$66,100	$253,740	$1,193,676
Other Parts and Repairs		$8,320	$42,080	$271,840
Annual Maintenance Contract		$5,000	$5,000	$5,000
Major Failure Impact		$15,293	$61,052	$265,425
Taxes and Insurance		$8,684	$20,952	$57,745
Total Annual Cost		$131,940	$451,691	$1,983,486
Uncontrolled	ppmv	150	130	210
Uncontrolled	tons/yr	140.6	668.5	5,426
Controlled	ppmv	3	3	3
Controlled	tons/yr	2.8	15.4	77.5
NOx Removed	tons/yr	137.8	653.0	5348.3
Cost Effectiveness	**$/ton**	**$957**	**$692**	**$371**
Electricity Cost Impact	**¢/kWhr**	**0.317**	**0.215**	**0.146**

Note: O&M cost for LM2500 DLN used for Frame 7FA as default.

TABLE A-3
1999 WATER/STEAM INJECTION COST COMPARISON

		5 MW Class		25 MW Class	150 MW Class*
		Water Injection	Water Injection	Water Injection	Steam Injection
Turbine Model		Solar Centaur 50	Allison 501-KB5	GE LM2500	GE MS7001F
Turbine Output		4.2 MW	4.0 MW	22.7 MW	161 MW
Heat Rate	Btu/kWhr	11,700	12,700	9,220	9,500
Heat Content	Btu/lb	20,610	20,610	20,610	20,610
Fuel flow	lb/hr	2,404	2,465	10,155	74,212
Hours of Operation	hrs	8,000	8,000	8,000	8,000
Fuel flow	MMBtu/yr	396,396	406,400	1,674,352	12,236,000
lb water/lb fuel		0.61	0.8	0.73	1.34
Water flow	gpm	2.93	3.95	14.83	198.97
Water Treatment Capacity	gpm	4.92	6.62	24.87	333.67
CAPITAL COST					
Injection Nozzles		$96,000	$0	$107,500	$1,130,000
Injection System		$20,700	$27,800	$104,500	
Total Injection System		$117,000	$27,800	$212,000	$1,130,000
Water Treatment System		$97,400	$113,000	$219,000	$802,000
Total System		$214,400	$140,800	$431,000	$1,932,000
Taxes and Freight		$17,200	$11,300	$34,500	$154,600
Installation - Direct		$50,000	$50,000	$209,475	$938,970
Installation - Indirect		$56,300	$40,400	$227,700	$1,003,400
Contingency		$67,600	$48,500	$180,500	$805,800
Total		$405,500	$291,000	$1,083,175	$4,834,770
ANNUAL QUANTITIES					
Percent Performance Loss		3.50%	3.50%	3.50%	1.00%
Energy Content	Btu/cubic ft	940	940	940	940
Unit Fuel Cost	$/1000 cuft	3.88	3.88	3.88	3.88
Unit Electricity Cost	$/kWhr	0.06	0.06	0.06	0.06
Water Waste		29%	29%	29%	29%
Water Cost	$/1000 gal	0.384	0.384	0.384	0.384
Water Treatment Cost	$/1000 gal	1.97	1.97	1.97	1.97
Labor Cost	$/1000 gal	0.7	0.7	0.7	0.7
Water Disposal Cost	$/1000 gal	3.82	3.82	3.82	3.82
G&A, taxes, insurance	%	4%	4%	4%	4%
Equipment Life	yrs	15	15	15	15
Interest Rate	%	10%	10%	10%	10%
Capital Recovery Factor		0.1315	0.1315	0.1315	0.1315
ANNUAL COSTS					
Fuel Penalty		$35,000	$47,000	$177,000	$677,000
Pumping Electricity		$227	$305	$1,146	$15,376
Added Maintenance		$16,000	$24,000	$28,000	$0
Plant Overhead		$4,800	$7,200	$8,400	$0
Water Cost		$698	$938	$3,527	$47,309
Water Treatment Cost		$3,579	$4,813	$18,093	$242,704
Labor Cost		$1,272	$1,710	$6,429	$43,120
Water Disposal Cost		$1,560	$2,098	$7,887	$105,799
G&A, taxes, insurance		$16,220	$11,640	$43,327	$193,391
Capital Recovery		$53,000	$38,000	$142,000	$636,000
Total Annual Cost		$132,000	$138,000	$436,000	$1,961,000
Uncontrolled	ppmv	130	155	174	210
Uncontrolled	tons/yr	103	126	584	5152
Controlled	ppmv	42	42	42	42
Controlled	tons/yr	33	34	141	1030
NOx Removed	tons/yr	70	92	443	4122
Cost Effectiveness	**$/ton**	**$1,887**	**$1,499**	**$984**	**$476**
Electricity Cost Impact	**¢/kWhr**	**0.390**	**0.431**	**0.240**	**0.152**

* (1993 data) Only the first baseload Frame 7F turbine (operational in 1990) has been sold with steam injection. All subsequent baseload units are equipped with DLN.

TABLE A-4
1999 CONVENTIONAL SCR COST COMPARISON

			5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Centaur 50	GE LM2500	GE Frame 7FA
Turbine Output			4.2 MW	23 MW	161 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		MHIA			
Basic Equipment (A):		MHIA	$240,000	$660,000	$2,100,000
Ammonia injection skid and storage	0.00 x A	MHIA	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$19,015	$52,746	$169,530
PE Total:			$256,704	$712,066	$2,288,649
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$20,536	$56,965	$183,092
Handling and erection:	0.14 x PE	OAQPS	$35,939	$99,689	$320,411
Electrical:	0.04 x PE	OAQPS	$10,268	$28,483	$91,546
Piping:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Insulation:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Painting:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
DI Total:			$77,011	$213,620	$686,595
DC Total:			$333,716	$925,686	$2,975,244
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$25,670	$71,207	$100,000
Construction and field expenses:	0.05 x PE	OAQPS	$12,835	$35,603	$114,432
Contractor fees:	0.10 x PE	OAQPS	$25,670	$71,207	$228,865
Start-up:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Performance testing:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Contingencies:	0.03 x PE	OAQPS	$7,701	$21,362	$68,659
IC Total:			$79,578	$220,741	$580,616
Total Capital Investment (TCI = DC + IC):			$413,294	$1,146,427	$3,555,861
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift: 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost:	OAQPS	$13,125	$13,125	$13,125
Utility Costs:	0% thermal eff 600 (F) operating temp				
Gas usage	0.0 (MMcf/yr) 1,000 (Btu/ft3) heat value				
Gas cost	3,000 ($/MMcf)	variable			
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$405,720
Catalyst replace:	assume 30 ft^3 catalyst per MW, $400/$ft^3$, 7 yr. life	MHIA	$10,352	$56,690	$396,833
Catalyst dispose:	$15/$ft^3$*30 ft^3/MW*MW*.2054 (7 yr amortized)	OAQPS	$388	$2,126	$14,881
Ammonia:	360 ($/ton) [tons NH_3 = tons NO_x * (17/46)]	variable	$3,510	$14,820	$108,257
NH_3 inject skid:	5 (kW) blower 5 kw (NH_3/H_2O pump)	MHIA	$5,040	$7,560	$27,720
Total DAC:			$71,219	$180,500	$994,755
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$8,266	$22,929	$71,117
Insurance:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Property tax:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Capital recovery:	10% interest rate, 15 yrs - period 0.13 x TCI	OAQPS	$52,976	$143,272	$415,329
Total IAC:			$94,314	$213,935	$582,370
Total Annual Cost (DAC + IAC):			$165,533	$394,435	$1,577,125
NO_x Emission Rate (tons/yr) at 42 ppm:			33.4	141.0	1030.0
NO_x Removed (tons/yr) at 9 ppm,	79% removal efficiency		26.4	111.4	813.7
Cost Effectiveness ($/ton):			**$6,274**	**$3,541**	**$1,938**
Electricity Cost Impact (¢/kwh):			**0.469**	**0.204**	**0.117**

*Assume modular SCR is inserted into existing HRSG spool piece

TABLE A-5
1999 HIGH TEMPERATURE SCR COMPARISON

			5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Taurus 60	GE LM2500	GE Frame 7FA
Turbine Output			5.0 MW	23 MW	170 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		Engelhard			
Basic Equipment (A):		Engelhard	$380,000	$730,000	$3,000,000
Ammonia injection skid and storage	0.00 x A	Engelhard	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$30,000	$58,400	$240,000
PE Total:			$405,000	$788,400	$3,240,000
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$32,400	$63,072	$259,200
Handling and erection:	0.14 x PE	OAQPS	$56,700	$110,376	$453,600
Electrical:	0.04 x PE	OAQPS	$16,200	$31,536	$129,600
Piping:	0.02 x PE	OAQPS	$8,100	$15,768	$64,800
Insulation:	0.01 x PE	OAQPS	$4,050	$7,884	$32,400
Painting:	0.01 x PE	OAQPS	$4,050	$7,884	$32,400
DI Total:			$121,500	$236,520	$972,000
DC Total:			$526,500	$1,024,920	$4,212,000
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$40,500	$78,840	$324,000
Construction and field expenses:	0.05 x PE	OAQPS	$20,250	$39,420	$162,000
Contractor fees:	0.10 x PE	OAQPS	$40,500	$78,840	$324,000
Start-up:	0.02 x PE	OAQPS	$8,100	$15,768	$64,800
Performance testing:	0.01 x PE	OAQPS	$4,050	$7,884	$32,400
Contingencies:	0.03 x PE	OAQPS	$12,150	$23,652	$97,200
IC Total:			$125,550	$244,404	$1,004,400
Total Capital Investment (TCI = DC + IC):			$652,050	$1,269,324	$5,216,400
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift: 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost:	OAQPS	$13,125	$13,125	$13,125
Utility Costs:	0% thermal eff 600 (F) operating temp				
Gas usage	0.0 (MMcf/yr) 1,000 (Btu/ft3) heat value				
Gas cost	3,000 ($/MMcf)	variable			
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$12,600	$57,960	$428,400
Catalyst replace:	assume 30 ft^3 catalyst per MW, $400/$ft^3$, 7 yr. life	Engelhard	$25,675	$70,863	$436,475
Catalyst dispose:	$15/$ft^3$*30 ft^3/MW*MW*.2054 (7 yr amortized)	OAQPS	$462	$2,126	$15,713
Ammonia:	360 ($/ton) [tons NH_3 = tons NO_x * (17/46)]	variable	$4,141	$14,820	$108,257
NH_3 inject skid:	** (kW) blower 5 kw (NH_3/H_2O pump)	Engelhard	$5,040	$7,560	$27,720
Total DAC:			$89,262	$194,672	$1,057,909
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$13,041	$25,386	$104,328
Insurance:	0.01 x TCI	OAQPS	$6,521	$12,693	$52,164
Property tax:	0.01 x TCI	OAQPS	$6,521	$12,693	$52,164
Capital recovery:	10% interest rate, 15 yrs - period				
	0.13 x TCI	OAQPS	$82,352	$157,566	$628,435
Total IAC:			$133,240	$233,145	$861,897
Total Annual Cost (DAC + IAC):			$222,502	$427,818	$1,919,806
NO_x Emission Rate (tons/yr) at 42 ppm:			39.4	141.0	1030.0
NO_x Removed (tons/yr) at 9 ppm,	79% removal efficiency		31.1	111.4	813.7
Cost Effectiveness ($/ton):			**$7,148**	**$3,841**	**$2,359**
Electricity Cost Impact (¢/kwh):			**0.530**	**0.221**	**0.134**

*Assume modular SCR is inserted upstream of HRSG or for a simple cycle gas turbine.

** 5, 10, 15 kW blower for 5, 25, 150 MW gas turbine respectively

TABLE A-6
1999 SCONOx COST COMPARISON

			5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Centaur 50	GE LM2500	GE Frame 7FA
Turbine Output			4.2 MW	23 MW	170 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		Goalline			
Basic Equipment (A):		Goalline	$620,000	$1,960,000	$7,700,000
Ammonia injection skid and storage	0.00 x A	Goalline	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$49,760	$157,105	$612,238
PE Total:			$671,760	$2,120,916	$8,265,208
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$53,741	$169,673	$661,217
Handling and erection:	0.14 x PE	OAQPS	$94,046	$296,928	$1,157,129
Electrical:	0.04 x PE	OAQPS	$26,870	$84,837	$330,608
Piping:	0.02 x PE	OAQPS	$13,435	$42,418	$165,304
Insulation:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
Painting:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
DI Total:			$201,528	$636,275	$2,479,562
DC Total:			$873,288	$2,757,191	$10,744,770
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$67,176	$212,092	$826,521
Construction and field expenses:	0.05 x PE	OAQPS	$33,588	$106,046	$413,260
Contractor fees:	0.10 x PE	OAQPS	$67,176	$212,092	$826,521
Start-up:	0.02 x PE	OAQPS	$13,435	$42,418	$165,304
Performance testing:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
Contingencies:	0.03 x PE	OAQPS	$20,153	$63,627	$247,956
IC Total:			$208,246	$657,484	$2,562,214
Total Capital Investment (TCI = DC + IC):			$1,081,534	$3,414,675	$13,306,985
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift: 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost:	OAQPS	$13,125	$13,125	$13,125
Utility Costs:					
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$428,400
Catalyst replace:	** kcfh/MW		$25,880	$106,295	$785,655
Catalyst dispose:	precious metal recovery = 1/3 replace cost	variable	-$8,618	-$35,396	-$261,623
H2 carrier steam	*** lb/hr (93 lb/hr steam/MW @$.006/lb)	variable	$19,686	$107,806	$796,824
H2 reforming	**** CH4 ft3/hr (14ft3/hr/MW @ $.00388/ft3)	variable	$1,916	$10,495	$77,569
H2 skid demand	***** kW (0.6 kW/MW capacity)		$1,270	$6,955	$51,408
Total DAC:			$92,063	$295,458	$1,919,577
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$21,631	$68,293	$266,140
Insurance:	0.01 x TCI	OAQPS	$10,815	$34,147	$133,070
Property tax:	0.01 x TCI	OAQPS	$10,815	$34,147	$133,070
Capital recovery:	10% interest rate, 15 yrs - period				
	0.13 x TCI	OAQPS	$138,791	$434,965	$1,646,226
Total IAC:			$206,858	$596,358	$2,203,312
Total Annual Cost (DAC + IAC):			$298,921	$891,816	$4,122,889
NO_x Emission Rate (tons/yr) at 42 ppm:			19.9	83.9	645.9
NO_x Removed (tons/yr) at 9 ppm,	92% removal efficiency		18.3	77.2	594.2
Cost Effectiveness ($/ton):			**$16,327**	**$11,554**	**$6,938**
Electricity Cost Impact (¢/kwh):			**0.847**	**0.462**	**0.289**

* Assume modular SCONOx unit is inserted downstream of HRSG
** 400, 300, 300 kcfth/MW for 5, 25, 150 MW class respectively (s.v.=20kcfh/ft3, $1,500/ft3 catalyst, 7 yr. life)
*** 391, 2139, 15810 lb/hr for 5, 25, 150 MW class respectively
**** 59, 322, 2380 CH4ft3/hr for 5, 25, 150 MW class respectively
***** 3, 14, 102 kW for 5, 25, 150 MW class respectively

TABLE A-7
1999 LOW TEMPERATURE SCR COMPARISON

				5 MW Class	25 MW Class
Turbine Model				Solar Centaur 50	GE LM2500
Turbine Output				4.0 MW	25 MW
Direct Capital Costs (DC):			Source		
Purchased Equip. Cost (PE):			KTI		
Basic Equipment (A):			KTI	$700,000	$1,714,894
Ammonia injection skid and storage	0.00 x A		KTI	included	included
Instrumentation	0.00 x A		OAQPS	included	included
Taxes and freight:	0.08 A x B		OAQPS	$56,000	$137,192
PE Total:				$756,000	$1,852,085
Direct Installation Costs (DI):*	Allison	Turbo Power			
Foundation & supports:	0.30 x PE	0.08 x PE	OAQPS	$226,800	$148,167
Handling and erection:	0.30 x PE	0.14 x PE	OAQPS	$226,800	$259,292
Electrical:	0.04 x PE	0.04 x PE	OAQPS	$30,240	$74,083
Piping:	0.02 x PE	0.02 x PE	OAQPS	$15,120	$37,042
Insulation:	0.01 x PE	0.01 x PE	OAQPS	$7,560	$18,521
Painting:	0.01 x PE	0.01 x PE	OAQPS	$7,560	$18,521
DI Total:				$514,080	$555,626
DC Total:				$1,270,080	$2,407,711
Indirect Costs (IC):					
Engineering:	0.10 x PE	0.30 x PE	OAQPS	$75,600	$555,626
Construction expenses:	0.05 x PE	0.30 x PE	OAQPS	$37,800	$555,626
Contractor fees:	0.10 x PE	0.10 x PE	OAQPS	$75,600	$185,209
Start-up:	0.02 x PE	0.02 x PE	OAQPS	$15,120	$37,042
Performance testing:	0.01 x PE	0.01 x PE	OAQPS	$7,560	$18,521
Contingencies:	0.03 x PE	0.03 x PE	OAQPS	$22,680	$55,563
IC Total:				$234,360	$1,407,585
Total Capital Investment (TCI = DC + IC):				$1,504,440	$3,815,296
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift:	25 $/hr for operator pay	OAQPS	$13,125	$13,125
Supervisor:	15% of operator		OAQPS	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift	25 $/hr for labor pay	OAQPS	$13,125	$13,125
Material:	100% of labor cost:		OAQPS	$13,125	$13,125
Utility Costs:	0% thermal eff	600 (F) operating temp			
Gas usage	0.0 (MMcf/yr)	1,000 (Btu/ft3) heat value			
Gas cost	3,000 ($/MMcf)		variable	$0	$0
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty		variable	$10,080	$63,000
Catalyst replace:	assume 30 ft^3 catalyst per MW, $400/ft^3, 7 yr. life		MHIA	$9,859	$56,690
Catalyst dispose:	$15/ft^3*30 ft^3/MW*MW*.2054 (7 yr amortized)		OAQPS	$370	$2,126
Ammonia:	360 ($/ton) [tons NH_3 = tons NO_x * (17/46)]		variable	$8,040	$14,820
NH_3 inject skid:	5 (kW) blower	5 kw (NH_3/H_2O pump)	MHIA	$5,040	$7,560
Total DAC:				$74,733	$180,500
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M		OAQPS	$24,806	$24,806
Administrative:	0.02 x TCI		OAQPS	$30,089	$76,306
Insurance:	0.01 x TCI		OAQPS	$15,044	$38,153
Property tax:	0.01 x TCI		OAQPS	$15,044	$38,153
Capital recovery:	10% interest rate,	15 yrs - period			
	0.13 x TCI		OAQPS	$196,498	$493,510
Total IAC:				$281,482	$670,928
Total Annual Cost (DAC + IAC):				$356,215	$901,207
NO_x Emission Rate (tons/yr) at 42 ppm:				76.5	518.0
NO_x Removed (tons/yr) at 9 ppm,		79% removal efficiency		60.4	409.2
Cost Effectiveness ($/ton):				**$5,894**	**$2,202**
Electricity Cost Impact (¢/kwh):				**1.060**	**0.429**

*Assume modular SCR is placed downstream of HRSG

APPENDIX B

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