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Alternative Control Techniques Document -- NOx Emissions from Stationary Gas Turbines

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Alternative Control Techniques Document-- NO_x Emissions from Stationary Gas Turbines

Emission Standards Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993

ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

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TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF FIGURES (continued)

LIST OF FIGURES (continued)

LIST OF FIGURES (continued)

LIST OF TABLES

LIST OF TABLES (continued)

LIST OF TABLES (continued)

1.0 INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Stationary gas turbines have been identified as a category that emits more than 25 tons of nitrogen oxide (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from stationary gas turbines. Additional ACT documents are being developed for other stationary source categories.

Gas turbines are available with power outputs ranging from 1 megawatt (MW) (1,340 horsepower [hp]) to over 200 MW (268,000 hp) and are used in a broad scope of applications. It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable for every gas turbine application. The size and design of the turbine, the operating duty cycle, site conditions, and other site-specific factors must be taken into consideration, and the suitability of an alternative control technique must be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by gas turbine manufacturers, control equipment vendors, gas turbine users, and regulatory agencies. Chapter 2.0 presents a summary of the findings of this study. Chapter 3.0 presents information on gas turbine operation and industry applications. Chapter 4.0 contains a discussion of NO_x formation and uncontrolled NO_x emission factors. Alternative control techniques and achievable controlled emission levels are included in Chapter 5.0. The cost and cost effectiveness of each control technique are presented in Chapter 6.0. Chapter 7.0 describes environmental and energy impacts associated with implementing the NO_x control techniques.

2.0 SUMMARY

This chapter summarizes the more detailed information presented in subsequent chapters of this document. It presents a summary of nitrogen oxide (NO_x) formation mechanisms and uncontrolled NO_x emission factors, available NO_x emission control techniques, achievable controlled NO_x emission levels, the costs and cost effectiveness for these NO_x control techniques applied to combustion gas turbines, and the energy and environmental impacts of these control techniques. The control techniques included in this analysis are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR).

Section 2.1 includes a brief discussion of NO_x formation and a summary of uncontrolled NO_x emission factors. Section 2.2 describes the available control techniques and achievable controlled NO_x emission levels. A summary of the costs and cost-effectiveness for each control technique is presented in Section 2.3. Section 2.4 reviews the range of controlled emission levels, capital costs, and cost effectiveness. Section 2.5 discusses energy and environmental impacts.

2.1 NO_x FORMATION AND UNCONTROLLED NO_x EMISSIONS

The two primary NO_x formation mechanisms in gas turbines are thermal and fuel NO_x. In each case, nitrogen and oxygen present in the combustion process combine to form NO_x. Thermal NO_x is formed by the dissociation of atmospheric nitrogen (N_2) and oxygen (O_2) in the turbine combustor and the subsequent formation of NO_x. When fuels containing nitrogen are combusted, this additional source of nitrogen results in fuel NO_x formation. Because most turbine installations burn natural gas or light distillate oil fuels with little or no nitrogen content, thermal NO_x is the dominant source of NO_x emissions. The formation rate of thermal NO_x increases exponentially with increases in temperature. Because the flame temperature of oil fuel is higher than that of natural gas, NO_x emissions are higher for operations using oil fuel than natural gas.

Uncontrolled NO_x emission levels were provided by gas turbine manufacturers in parts per million, by volume (ppmv). Unless stated otherwise, all emission levels shown in ppmv are corrected to 15 percent O_2. These emission levels were used to calculate uncontrolled NO_x emission factors, in pounds (lb) of NO_x per million British thermal units (Btu) (lb NO_x/MMBtu). Sample calculations are shown in Appendix A. These uncontrolled emission levels and emission factors for both natural gas and oil fuel are presented in Table 2-1. Uncontrolled NO_x emission levels range from 99 to 430 ppmv for natural gas fuel and from 150 to 680 ppmv for distillate oil fuel. Corresponding uncontrolled emission factors range from 0.397 to 1.72 lb NO_x/MMBtu and 0.551 to 2.50 lb NO_x/MMBtu for natural gas and distillate oil fuels, respectively. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with combustor design. There is no discernable correlation between turbine size and NO_x emission levels evident in Table 2-1.

2.2 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

Reductions in NO_x emissions can be achieved using combustion controls or flue gas treatment. Available combustion controls are water or steam injection and dry low-NO_x combustion designs. Selective catalytic reduction is the only available flue gas treatment.

2.2.1 Combustion Controls

Combustion control using water or steam lowers combustion temperatures, which reduces thermal NO_x formation. Fuel NO_x formation is not reduced with this technique. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower

TABLE 2-1. UNCONTROLLED NO_x EMISSION FACTORS FOR GAS TURBINES

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% O_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.
[b]Not available.

flame temperatures. This control technique is available for all new turbine models and can be retrofitted to most existing installations.

Although uncontrolled emission levels vary widely, the range of achievable controlled emission levels using water or steam injection is relatively small. Controlled NO_x emission levels range from 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel. Achievable guaranteed controlled emission levels, as provided by turbine manufacturers, are shown for individual turbine models in Figures 2-1 and 2-2 for natural gas and oil fuels, respectively.

The decision whether to use water versus steam injection for NO_x reduction depends on many factors, including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

A system that allows treated water to be mixed with the fuel prior to injection is also available. Limited testing of water-in-oil emulsions injected into the turbine combustor have achieved NO_x reductions equivalent to direct water injection but at reduced water-to-fuel rates. The vendor reports a similar system is available for natural gas-fired applications.

Dry low-NO_x combustion control techniques reduce NO_x emissions without injecting water or steam. Two designs, lean premixed combustion and rich/quench/lean staged combustion have been developed.

Lean premixed combustion designs reduce combustion temperatures, thereby reducing thermal NO_x. Like wet injection, this technique is not effective in reducing fuel NO_x. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs simultaneously with combustion. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogeneous air/fuel mixture, which minimizes

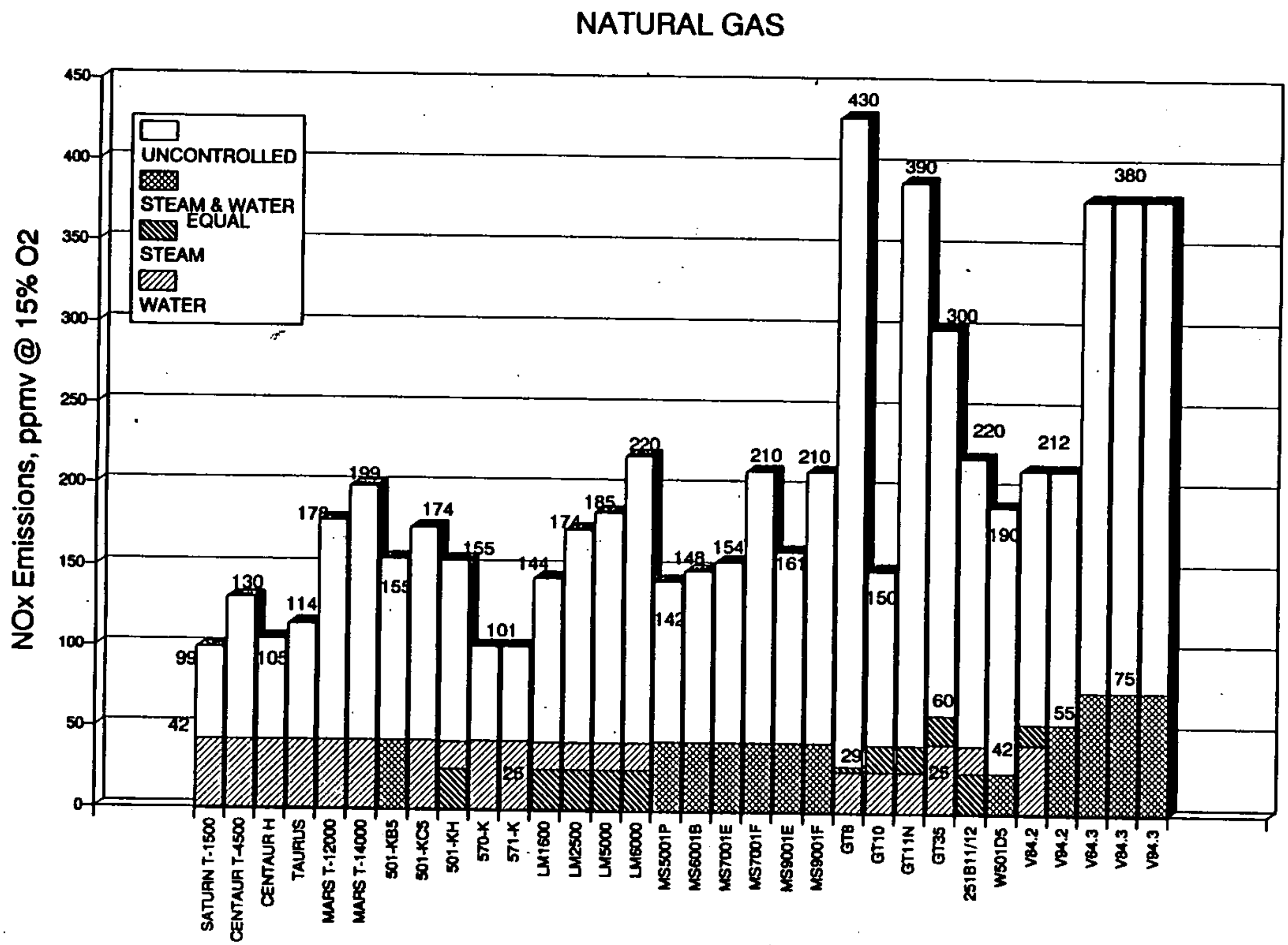


Figure 2-1. Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.

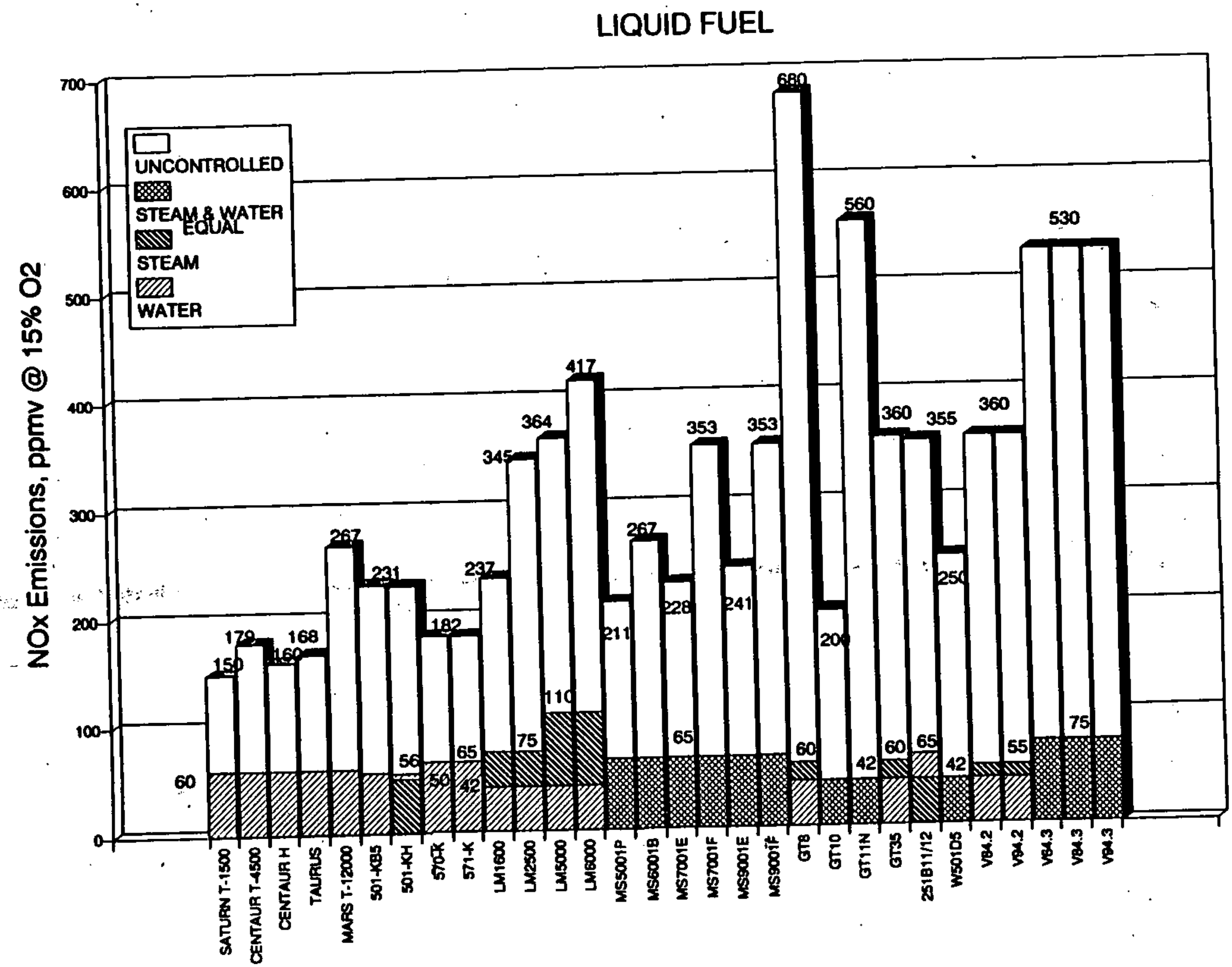


Figure 2-2. Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate oil fuel.

localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air acts as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Lean premixed combustors are currently available from several turbine manufacturers for a limited number of turbine models. Development of this technology is ongoing, and availability should increase in the coming years. All turbine manufacturers state that lean premixed combustors are designed for retrofit to existing installations.

Controlled NO_x emission levels using dry lean premixed combustion range from 9 to 42 ppmv for operation on natural gas fuel. The low end of this range (9 to 25 ppmv) has been limited to turbines above 20 megawatts (MW) (27,000 horsepower [hp]); to date, three manufacturers have guaranteed controlled NO_x emission levels of 9 ppmv at one or more installations for utility-sized turbines. Controlled NO_x emissions from smaller turbines typically range from 25 to 42 ppmv. For operation on distillate oil fuel, water or steam injection is required to achieve controlled NO_x emissions levels of approximately 65 ppmv. Development continues for oil-fueled operation in lean premixed designs, however, and one turbine manufacturer reports having achieved controlled NO_x emission levels below 50 ppmv in limited testing on oil fuel without wet injection.

A second dry low-NO_x combustion design is a rich/quench/lean staged combustor. Air and fuel are partially combusted in a fuel-rich primary stage, the combustion products are then rapidly quenched using water or air, and combustion is completed in a fuel-lean secondary stage. The fuel-rich primary stage inhibits NO_x formation due to low O_2 levels. Combustion temperatures in the fuel-lean secondary stage are below NO_x formation temperatures as a result of the quenching process and the presence of excess air. Both thermal and fuel NO_x are controlled with this design. Limited testing with fuels including natural gas and coal have achieved controlled NO_x emissions of 25 ppmv. Development of this design continues, however, and currently the rich/quench/lean combustor is not available for production turbines.

2.2.2 Selective Catalytic Reduction

This flue gas treatment technique uses an ammonia (NH_3) injection system and a catalytic reactor to reduce NO_x. An injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water (H_2O) in the catalyst reactor. This control technique reduces both thermal NO_x and fuel NO_x.

Ammonia injection systems are available that use either anhydrous or aqueous NH_3. Several catalyst materials are available. To date, most SCR installations use a base-metal catalyst with an operating temperature window ranging from approximately 260° to 400°C (400° to 800°F). The exhaust temperature from the gas turbine is typically above 480°C (900°F), so the catalyst is located within a heat recovery steam generator (HRSG) where temperatures are reduced to a range compatible with the catalyst operating temperature. This operating temperature requirement has, to date, limited SCR to cogeneration or combined-cycle applications with HRSG's to reduce flue gas temperatures. High-temperature zeolite catalysts, however, are now available and have operating temperature windows of up to 600°C (1100°F), which is suitable for installation directly downstream of the turbine. This high-temperature zeolite catalyst offers the potential for SCR applications with simple cycle gas turbines.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x and avoids excessive NH_3 emissions downstream of the catalyst, known as ammonia slip. The selected catalyst formulation must be resistant to potential masking and/or poisoning agents in the flue gas.

To date, most SCR systems in the United States have been installed in gas-fired turbine applications, but improvements in SCR system designs and experience on alternate fuels in Europe and Japan suggest that SCR systems are suitable for firing distillate oil and other sulfur-bearing fuels. These fuels produce sulfur dioxide (SO_2), which may oxidize to sulfite (SO_3) in the catalyst reactor. This SO_3 reacts with NH_3 slip to form ammonium salts in the low-temperature section of the HRSG and exhaust ductwork. The ammonium salts must be periodically cleaned from the affected surfaces to avoid fouling and corrosion as well as increased back-pressure on the turbine. Advances in catalyst formulations include sulfur-resistant catalysts with low SO_2 oxidation rates. By limiting ammonia slip and using these sulfur-resistant catalysts, ammonium salt formation can be minimized.

Catalyst vendors offer NO_x reduction efficiencies of 90 percent with ammonia slip levels of 10 ppmv or less. These emission levels are warranted for 2 to 3 years, and all catalyst vendors contacted accept return of spent catalyst reactors for recycle or disposal.

Controlled NO_x emission levels using SCR are typically 9 ppmv or less for gas-fueled turbine installations. With the exception of one site, all identified installations operate the SCR system in combination with combustion controls that reduce NO_x emission levels into the SCR to a range of 25 to 42 ppmv. Most continuous-duty turbine installations fire natural gas; there is limited distillate oil-fired operating experience in the United States. Several installations with SCR in the northeast United States that use distillate oil as a back-up fuel have controlled NO_x emission limits of 18 ppmv for operation on distillate oil fuel.

2.3 COSTS AND COST EFFECTIVENESS FOR NO_x CONTROL TECHNIQUES

Capital costs and cost effectiveness were developed for the available NO_x control techniques. Capital costs are presented in Section 2.3.1. Cost-effectiveness figures, in $/ton of NO_x

removed, are shown in Section 2.3.2. All costs presented are in 1990 dollars.

2.3.1 Capital Costs

Capital costs are the sum of purchased equipment costs, taxes and freight charges, and installation costs. Purchased equipment costs were estimated based on information provided by equipment manufacturers, vendors, and published sources. Taxes, freight, and installation costs were developed based on factors recommended in the Office of Air Quality and Planning and Standards Control Cost Manual (Fourth Edition). Capital costs for combustion controls and SCR are presented in Sections 2.3.1.1 and 2.3.1.2, respectively.

2.3.1.1 Combustion Controls Capital Costs. Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system consisting of pumps, piping and hardware, metering controls, and injection nozzles. All costs for wet injection are based on the availability of water at the site; no costs have been included for transporting water to the site. These costs apply to new installations; retrofit costs would be similar except that turbine-related injection hardware and metering controls purchased from the turbine manufacturer may be higher for retrofit applications.

The capital costs for wet injection are shown in Figure 2-3, and range from \$388,000 for a 3.3 MW (4,430 hp) turbine to \$4,830,000 for a 161 MW (216,000 hp) turbine. These capital costs include both water and steam injection systems for use with either gas or distillate oil fuel applications. Figure 2-3 shows that the capital costs for steam injection are slightly higher than those for water injection for turbines in the 3 to 25 MW (4,000 to 33,500 hp) range.

The capital costs for dry low-NO_x combustors are the incremental costs for this design over a conventional combustor and apply to new installations. Turbine manufacturers estimate retrofit costs to be approximately 40 to 60 percent higher than new equipment costs. Incremental capital costs for dry low-NO_x

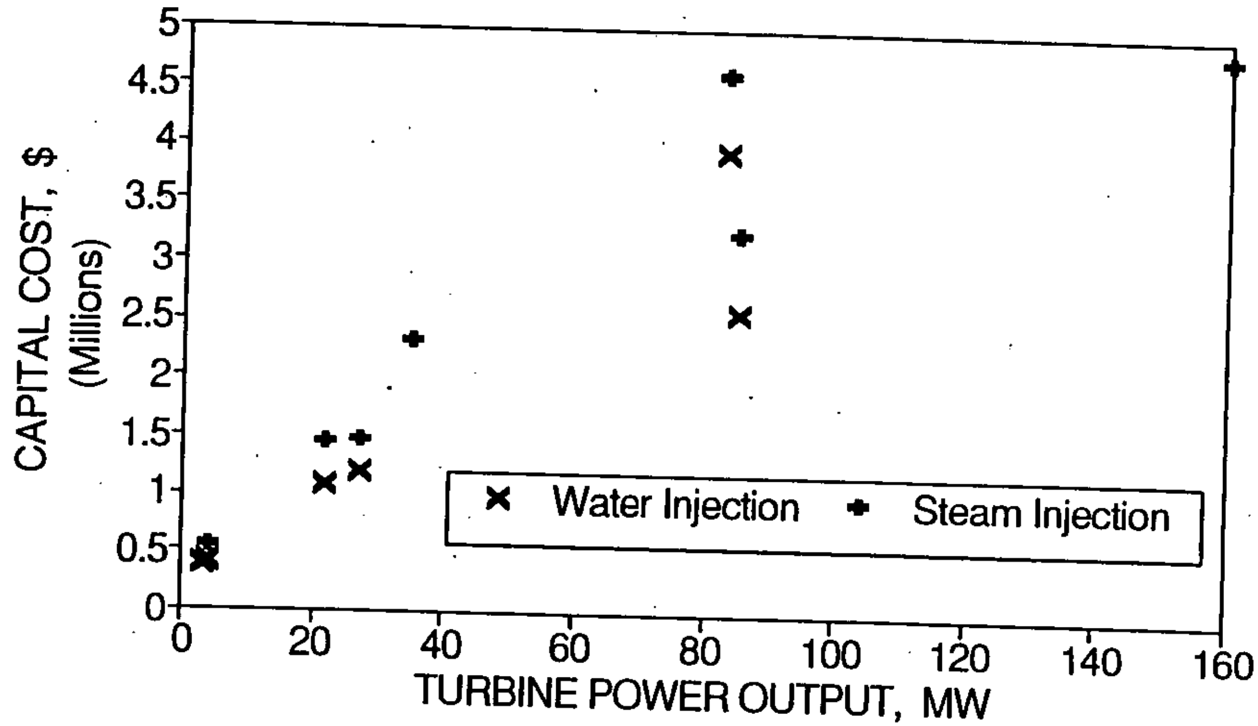


Figure 2-3. Capital costs for water or steam injection.

combustion were provided by turbine manufacturers and are presented in Figure 2-4. The incremental capital costs range from $375,000 for a 3.3 MW (4,430 hp) turbine to $2.2 million for an 85 MW (114,000 hp) machine. Costs were not available for turbines above 85 MW (114,000 hp).

When evaluated on a $/MW ($/hp) basis, the capital costs for wet injection or dry low-NO_x combustion controls are highest for the smallest turbines and decrease exponentially with increasing turbine size. The range of capital costs for combustion controls, in $/MW, and the effect of turbine size on capital costs are shown in Figure 2-5. For wet injection, the capital costs range from a high of $138,000/MW ($103/hp) for a 3.3 MW (4,430 hp) turbine to a low of $29,000/MW ($22/hp) for a 161 MW (216,000 hp) turbine. Corresponding capital cost figures for dry low-NO_x combustion range from $114,000/MW ($85/hp) for a 3.3 MW (4,430 hp) unit to $26,000/MW ($19/hp) for an 85 MW (114,000 hp) machine.

2.3.1.2 SCR Capital Costs. Capital costs for SCR include the catalyst reactor, ammonia storage and injection system, and controls and monitoring equipment. A comparison of available cost estimates for base-metal catalyst systems and high-temperature zeolite catalyst systems indicates that the costs for these systems are similar, so a single range of costs was developed that represents all SCR systems, regardless of catalyst type or turbine cycle (i.e., simple, cogeneration, or combined cycle).

The capital costs for SCR, shown in Figure 2-6, range from $622,000 for a 3.3 MW (4,430 hp) turbine to $8.46 million for a 161 MW (216,000 hp) turbine. Figure 2-7 plots capital costs on a $/MW basis and shows that these costs are highest for the smallest turbine, at $188,000/MW ($140/hp) for a 3.3 MW (4,430 hp) unit, and decrease exponentially with increasing turbine size to $52/MW ($40/hp) for a 161 MW (216,000 hp) machine. These costs apply to new installations firing natural gas as the primary fuel. No SCR sites using oil as the primary fuel were identified, and costs were not available. For this

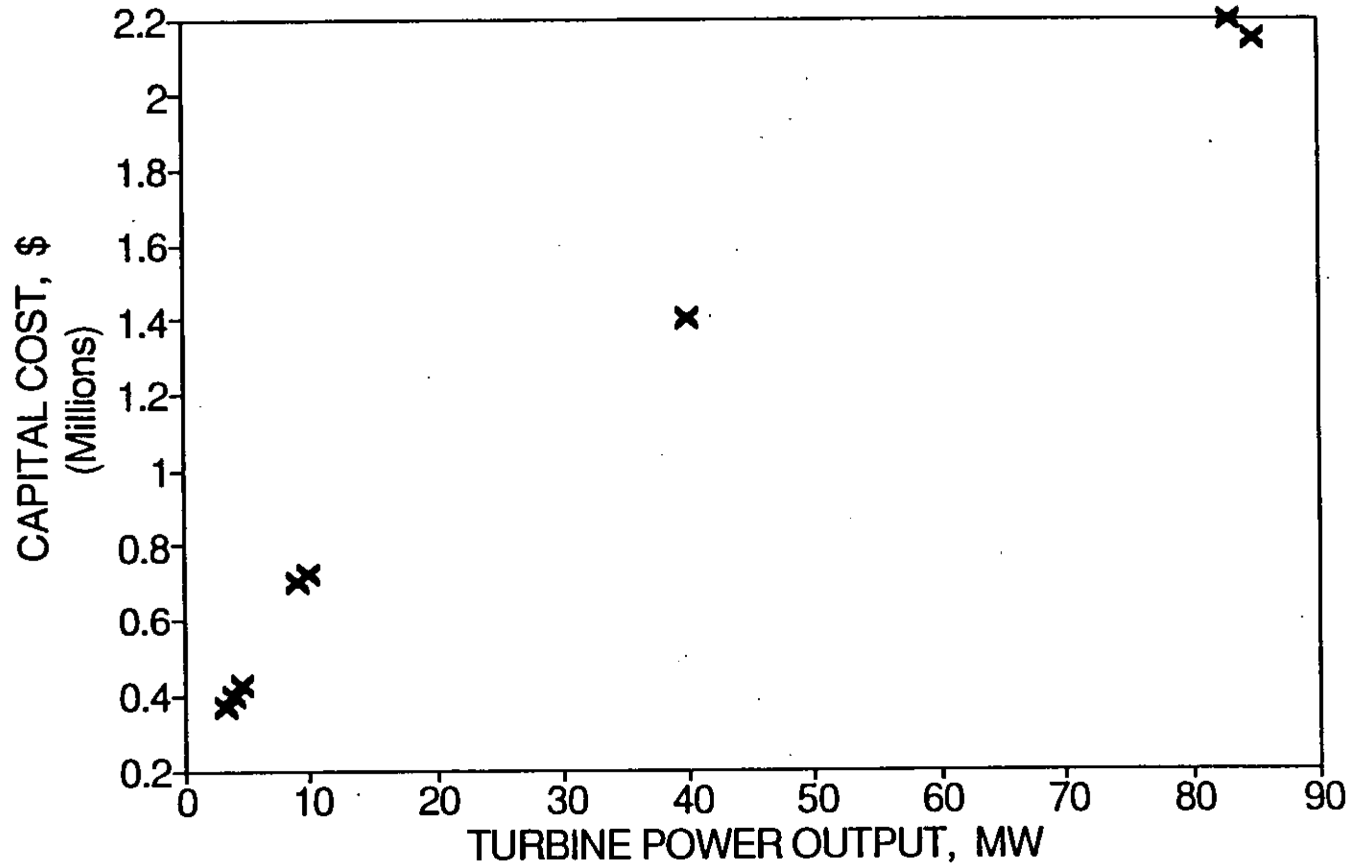


Figure 2-4. Capital costs for dry low-NO_x combustion.

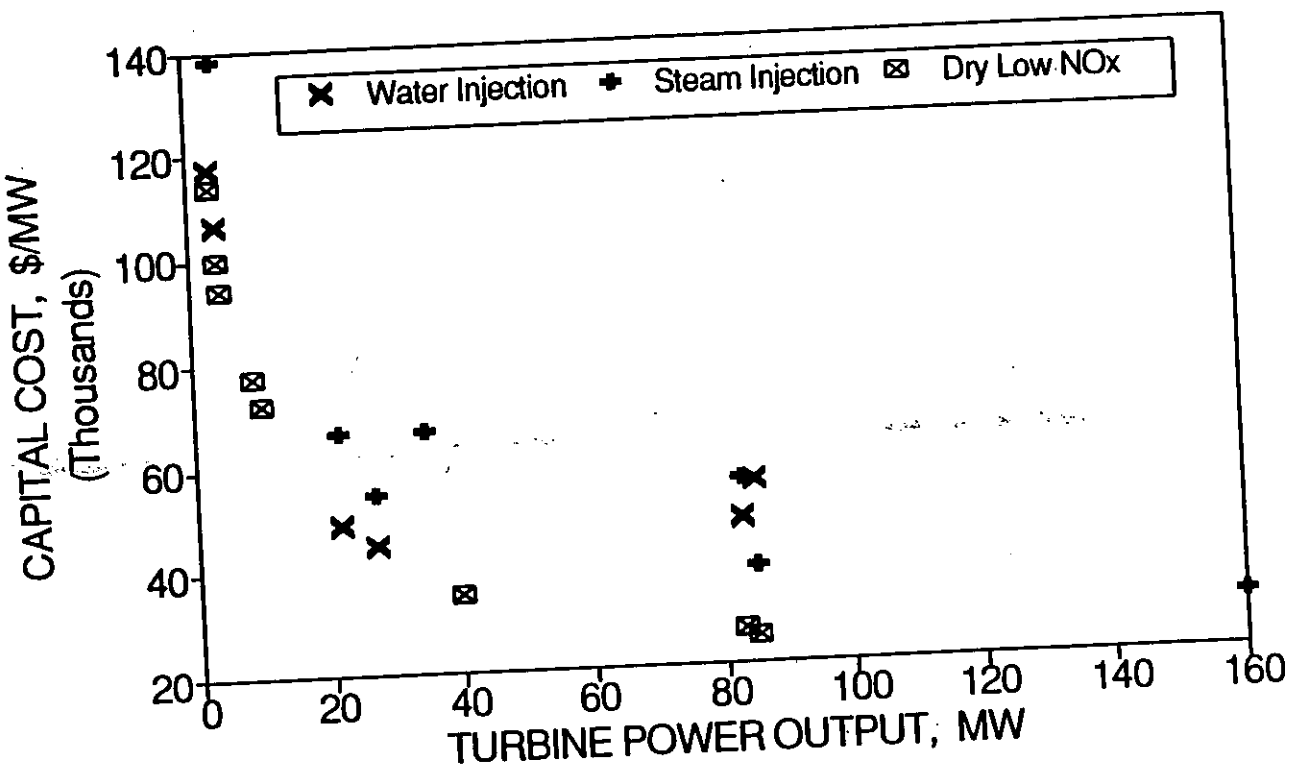


Figure 2-5. Capital costs, in $/MW, for combustion controls.

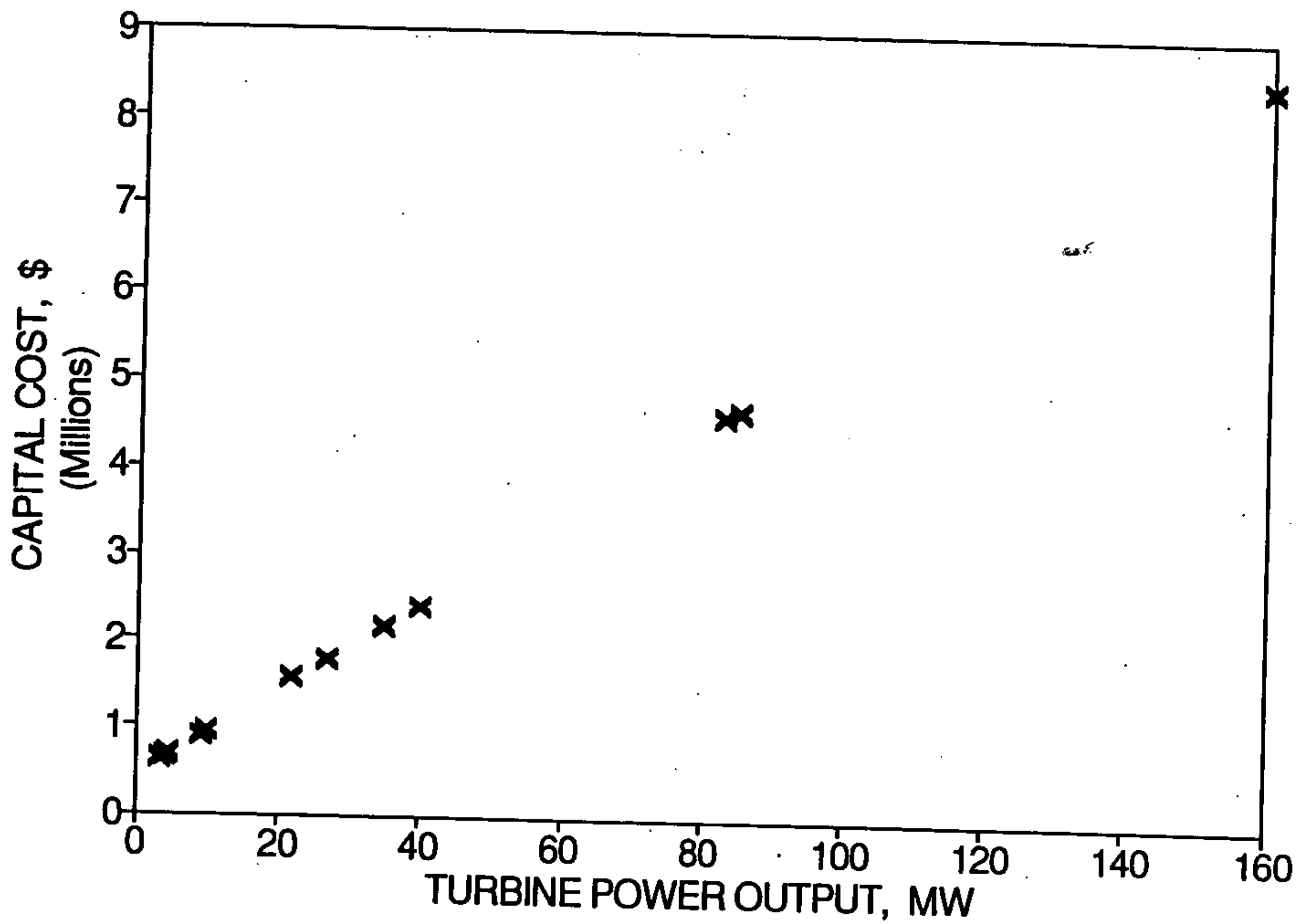


Figure 2-6. Capital costs for selective catalytic reduction.

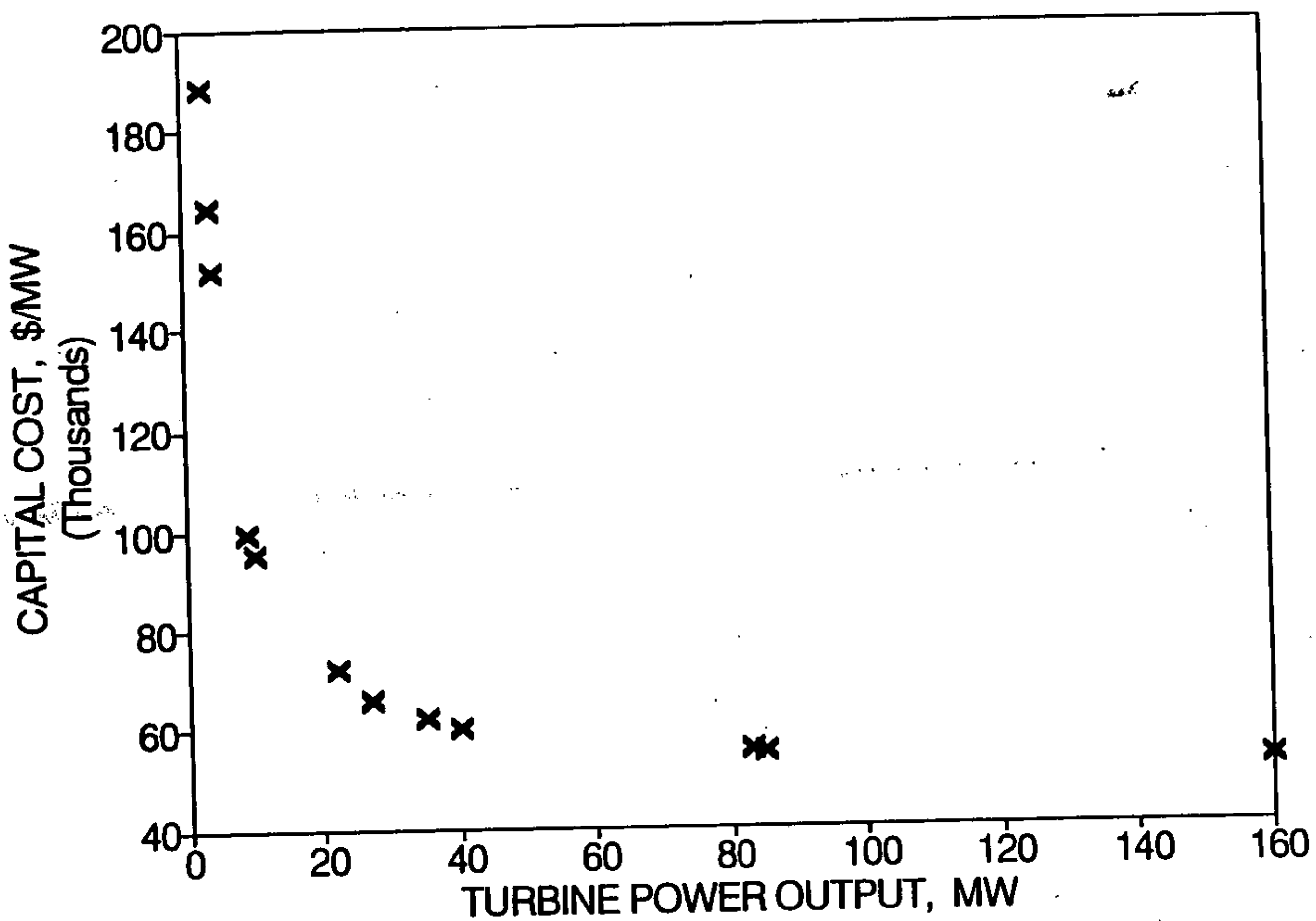


Figure 2-7. Capital costs, in $/MW, for selective catalytic reduction.

reason, the costs for gas-fired applications were also used for oil-fired sites. Retrofit SCR costs could be considerably higher than those shown here for new installations, especially if an existing HRSG and ancillary equipment must be moved or modified to accommodate the SCR system.

2.3.2 Cost Effectiveness

The cost effectiveness, in \$/ton of NO_x removed, was developed for each NO_x control technique. The cost effectiveness for a given control technique is calculated by dividing the total annual cost by the annual NO_x reduction, in tons. The cost effectiveness presented in this section correspond to 8,000 annual operating hours. Total annual costs were calculated as the sum of all annual operating costs and annualized capital costs. Annual operating costs include costs for incremental fuel, utilities, maintenance, applicable performance penalties, operating and supervisory labor, plant overhead, general and administrative, and taxes and insurance. Capital costs were annualized using the capital recovery factor method with an equipment life of 15 years and an annual interest rate of 10 percent. Cost-effectiveness figures for combustion controls and SCR are presented in Sections 2.3.2.1 and 2.3.2.2, respectively.

2.3.2.1 Combustion Controls Cost Effectiveness. Cost effectiveness for combustion controls is shown in Figure 2-8. Figure 2-8 indicates that cost effectiveness for combustion controls is highest for the smallest turbines and decreases exponentially with decreasing turbine size. Figure 2-8 also shows that the range of cost effectiveness for water injection is similar to that for steam injection, primarily because the total annual costs and achievable controlled NO_x emission levels for water and steam injection are similar. The cost-effectiveness range for dry low-NO_x combustion is lower than that for wet injection, even though the controlled NO_x levels are similar (25 to 42 ppmv), due to the lower total annual costs for dry low-NO_x combustion.

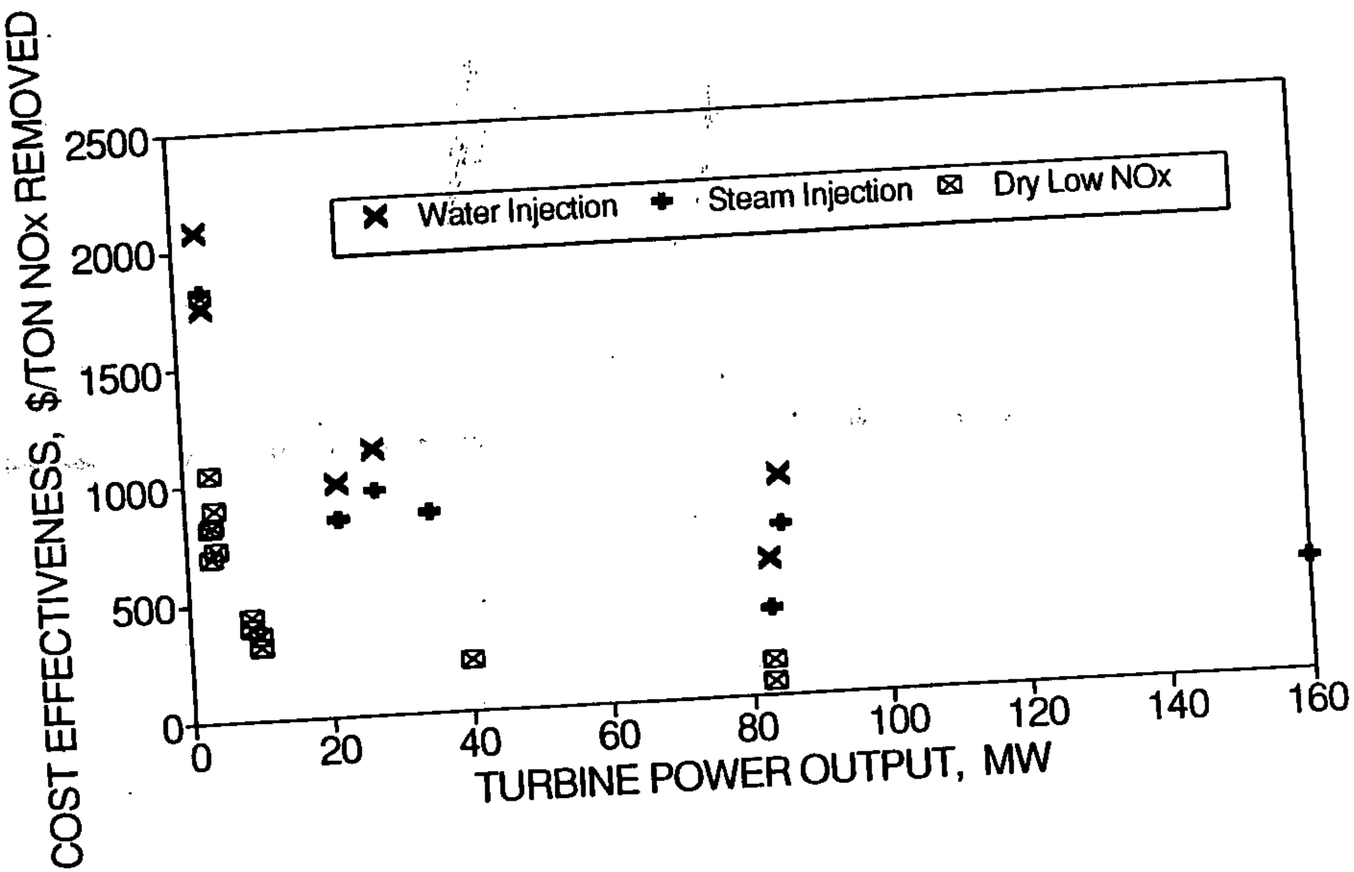


Figure 2-8. Cost effectiveness of combustion controls.

For water injection, cost effectiveness, in \$/ton of NO_x removed, ranges from \$2,080 for a 3.3 MW (4,430 hp) unit to \$575 for an 83 MW (111,000 hp) turbine and \$937 for an 85 MW (114,000 hp) turbine. For steam injection, cost effectiveness is \$1,830 for a 3.3 MW (4,430 hp), decreasing to \$375 for an 83 MW (111,000 hp) turbine, and increasing to \$478 for a 161 MW (216,000 hp) turbine. The relatively low cost effectiveness for the 83 MW (111,000 hp) turbine is due to this particular turbine's high uncontrolled NO_x emissions, which result in a relatively high NO_x removal efficiency and lower cost effectiveness. The cost effectiveness shown in Figure 2-8 corresponds to gas-fired applications. Analysis of a limited number of oil-fired applications with water injection indicates that the cost effectiveness ranges from 70 to 85 percent of the cost effectiveness for gas-fired applications due to the higher NO_x removal efficiency achieved in oil-fired applications.

For dry low-NO_x combustion, cost effectiveness, in \$/ton of NO_x removed, ranges from \$1,060 for a 4.0 MW (5,360 hp) turbine down to \$154 for an 85 MW (114,000 hp) machine. A cost effectiveness of \$57 was calculated for the 83 MW (111,000 hp) unit. Again, the relatively high uncontrolled NO_x emissions and the resulting high NO_x removal efficiency for this turbine model yields a relatively low cost-effectiveness figure. Current dry low-NO_x combustion designs do not achieve NO_x reductions with oil fuels, so the cost-effectiveness values shown in this section apply only to gas-fired applications.

2.3.2.2 <u>SCR Cost Effectiveness</u>. Cost effectiveness for SCR was calculated based on the use of combustion controls upstream of the catalyst to reduce NO_x emissions to a range of 25 to 42 ppmv at the inlet to the catalyst. This approach was used because all available SCR cost information is for SCR applications used in combination with combustion controls and all but one of the 100+ SCR installations in the United States operate in combination with combustion controls. For this cost analysis, a 5-year catalyst life and a 9 ppmv controlled NO_x emission level was used to calculate cost effectiveness for SCR.

Figure 2-9 presents SCR cost effectiveness. Figure 2-9 shows that, like combustion controls, SCR cost effectiveness is highest for the smallest turbines and decreases exponentially with decreasing turbine size. Also, because this cost analysis uses a 9 ppmv controlled NO_x emission level for SCR, NO_x reduction efficiencies are higher where the NO_x emission level into the SCR is 42 ppmv than for applications with a 25 ppmv level. Cost effectiveness corresponding to an inlet NO_x emission level of 42 ppmv, in $/ton of NO_x removed, ranges from a high of $10,800 for a 3.3 MW (4430 hp) turbine to $3,580 for a 161 MW (216,000 hp) turbine. For an inlet NO_x emission level of 25 ppmv, the cost-effectiveness range shifts higher, from $22,100 for a 3.3 MW (4,430 hp) installation to $6,980 for an 83 MW (111,000 hp) site.

The range of cost effectiveness for SCR shown in Figure 2-9 applies to gas-fired applications. Cost effectiveness developed for a limited number of oil-fired installations using capital costs from gas-fired applications yields cost-effectiveness values ranging from approximately 70 to 77 percent of those for gas-fired sites. The lower cost-effectiveness figures for oil-fired applications result primarily from the greater annual NO_x reductions for oil-fired applications; the gas-fired capital costs used for these oil-fired applications may understate the actual capital costs for these removal rates and actual oil-fired cost-effectiveness figures may be higher.

Combined cost-effectiveness figures, in $/ton of NO_x removed, were calculated for the combination of combustion controls plus SCR by dividing the sum of the total annual costs by the sum of the NO_x removed for both control techniques. The controlled NO_x emission level for the combination of controls is 9 ppmv. These combined cost-effectiveness figures are presented in Figure 2-10. For wet injection plus SCR, the combined cost effectiveness ranges from $4,460 for a 3.3 MW (4,430 hp) application to $988 for a 160 MW (216,000 hp) site. The $645 cost-effectiveness value for the 83 MW (111,000 hp) turbine is lower than the other turbine models shown in Figure 2-10 due to

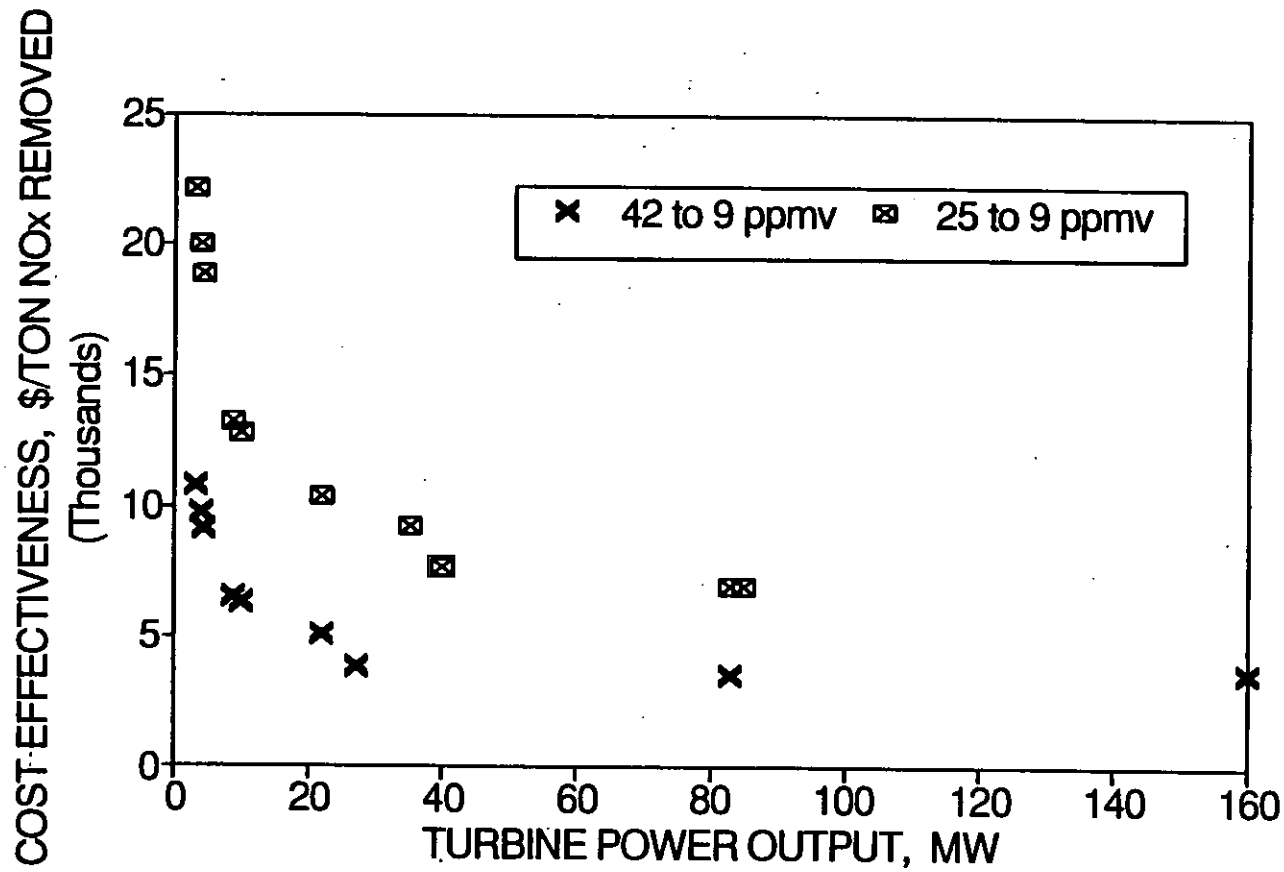


Figure 2-9. Cost effectiveness for selective catalytic reduction installed downstream of combustion controls.

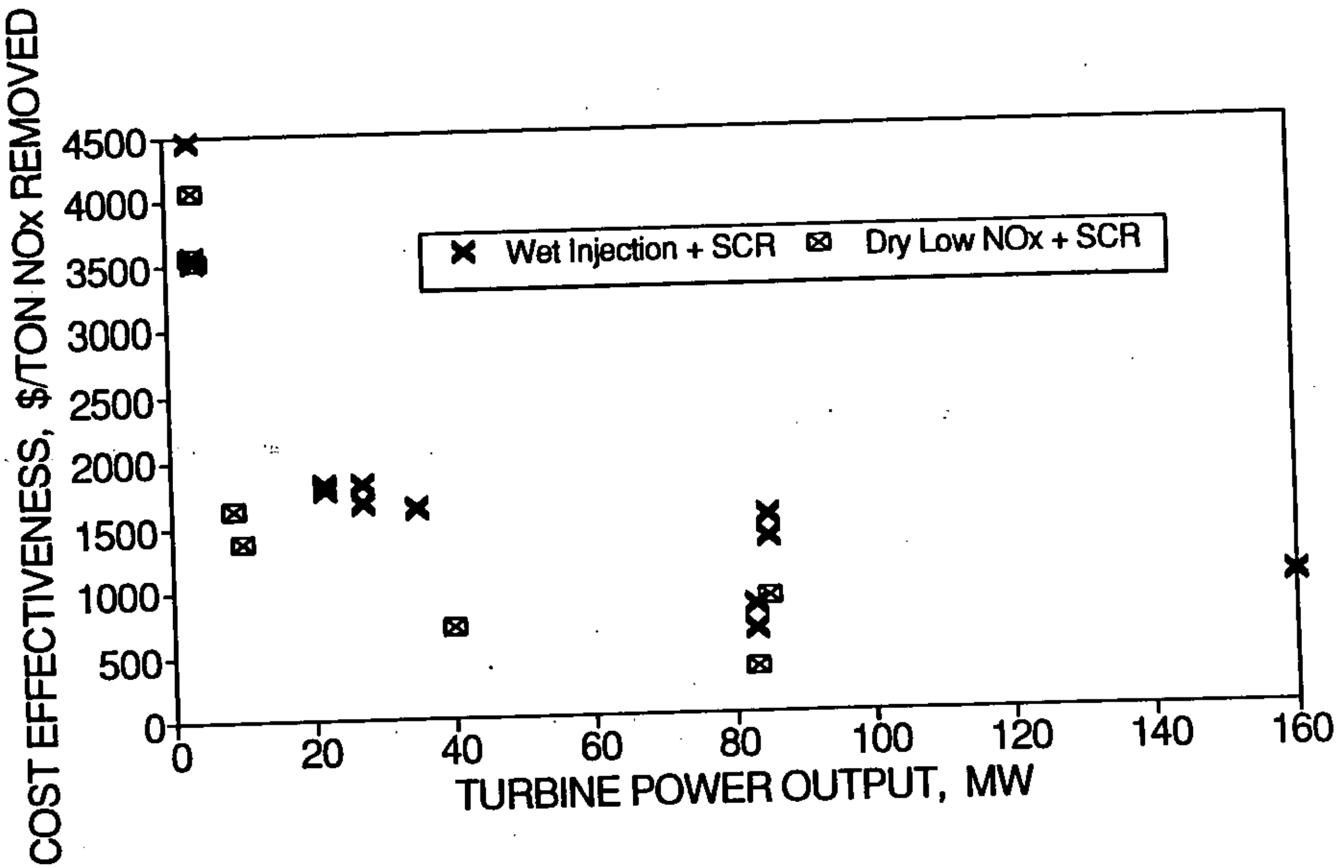


Figure 2-10. Combined cost effectiveness for combustion controls plus selective catalytic reduction.

the relatively high uncontrolled NO_x emission level for this turbine, which results in relatively high NO_x removal rates and a lower cost effectiveness. For dry low-NO_x combustion plus SCR, combined cost-effectiveness values range from $4,060 to $348 for this turbine size range.

2.4 REVIEW OF CONTROLLED NO_x EMISSION LEVELS AND COSTS

An overview of the performance and costs for available NO_x control techniques is presented in Figure 2-11. Figure 2-11 shows relative achievable controlled NO_x emission levels, capital costs, and cost effectiveness for gas-fired turbine applications. Controlled NO_x emission levels of 25 to 42 ppmv can be achieved using either wet injection or, where available, dry low-NO_x combustion. Wet injection capital costs range from $30,000 to $140,000 per MW ($22 to $104 per hp), and cost effectiveness ranges from $375 to $2,100 per ton of NO_x removed. Dry low-NO_x combustion capital costs range from $25,000 to $115,000 per MW ($19 to $86 per hp), and cost effectiveness ranges from $55 to $1,050 per ton of NO_x removed.

A controlled NO_x emission level of 9 ppmv requires the addition of SCR, except for a limited number of large turbine models for which dry low-NO_x combustion designs can achieve this level. For turbine models above 40 MW (53,600 hp), the capital costs of dry low-NO_x combustion range from $25,000 to $36,000 per MW ($25 to $27 per hp), and the cost effectiveness ranges from $55 to $138 per ton of NO_x removed. Adding SCR to reduce NO_x emission levels from 42 or 25 ppmv to 9 ppmv adds capital costs ranging from $53,000 to $190,000 per MW ($40 to $142 per hp) and yields cost-effectiveness values ranging from $3,500 to $10,500 per ton of NO_x removed. The combination of combustion controls plus SCR yields combined capital costs ranging from $78,000 to $330,000 per MW ($58 to $246 per hp) and cost-effectiveness values ranging from $350 to $4,500 per ton of NO_x removed.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

The use of the NO_x control techniques described in this document may affect the turbine performance and maintenance

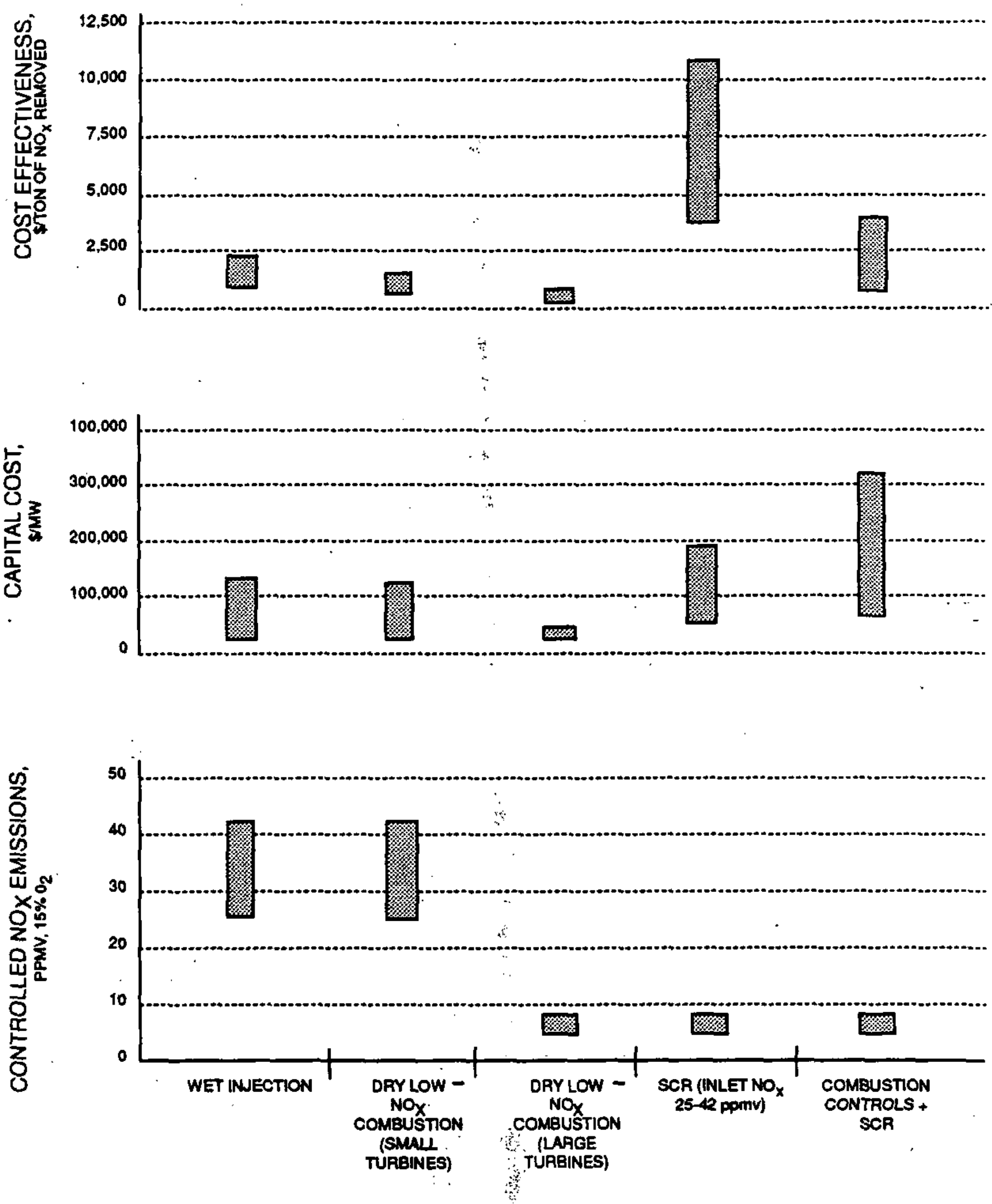


Figure 2-11. Controlled NO_x emission levels and associated capital costs and cost effectiveness for available NO_x control techniques. Natural gas fuel.

requirements and may result in increased emissions of carbon monoxide (CO), hydrocarbons (HC), and NH_3. These potential energy and environmental impacts are discussed in this section.

Water or steam injection affects turbine performance and in some turbines also affects maintenance requirements. The increased mass flow through the turbine resulting from water or steam injection increases the available power output. The quenching effect in the combustor, however, decreases combustion efficiency, and consequently the efficiency of the turbine decreases in most applications. The efficiency reduction is greater for water than for steam injection, largely because the heat of vaporization energy cannot be recovered in the turbine. In applications where the steam can be produced from turbine exhaust heat that would otherwise be rejected to the atmosphere, the net gas turbine efficiency is increased with steam injection. Injection of water or steam into the combustor increases the maintenance requirements of the hot section of some turbine models. Water injection generally has a greater impact than steam on increased turbine maintenance. Water or steam injection has the potential to increase CO and, to a lesser extent, HC emissions, especially at water-to-fuel ratios above 0.8.

Turbine manufacturers report no significant performance impacts for lean premixed combustors. Power output and efficiency are comparable to conventional designs. No maintenance impacts are reported, although long-term operating experience is not available. Impacts on CO emissions vary for different combustor designs. Limited data from three manufacturers showed minimal or no increases in CO emissions for controlled NO_x emission levels of 25 to 42 ppmv. For a controlled NO_x level of 9 ppmv, however, CO emissions increased in from 10 to 25 ppmv in one manufacturer's combustor design.

For SCR, the catalyst reactor increases the back-pressure on the turbine, which decreases the turbine power output by approximately 0.5 percent. The addition of the SCR system and associated controls and monitoring equipment increases plant maintenance requirements, but it is expected that these maintenance requirements are consistent with maintenance schedules for other plant equipment. There is no impact on CO or HC emissions from the turbine caused by the SCR system, but ammonia slip through the catalyst reactor results in NH_3 emissions. Ammonia slip levels are typically guaranteed by SCR vendors at 10 ppmv, and operating experience indicates actual NH_3 emissions are at or below this level.

3.0 STATIONARY GAS TURBINE DESCRIPTION AND INDUSTRY APPLICATIONS

This section describes the physical components and operating cycles of gas turbines and how turbines are used in industry. Projected growth in key industries is also presented.

3.1 GENERAL DESCRIPTION OF GAS TURBINES

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A common example of a gas turbine is the aircraft jet engine. In stationary applications, the hot combustion gases are directed through one or more fan-like turbine wheels to generate shaft horsepower rather than the thrust propulsion generated in an aircraft engine. Often the heat from the exhaust gases is recovered through an add-on heat exchanger.

Figure 3-1 presents a cutaway view showing the three primary sections of a gas turbine: the compressor, the combustor, and the turbine.[1] The compressor draws in ambient air and compresses it by a pressure ratio of up to 30 times ambient pressure.[2] The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. There are three types of combustors: annular, can-annular, and silo. An annular combustor is a single continuous chamber roughly the shape of a doughnut that rings the turbine in a plane perpendicular to the air flow. The can-annular type uses a similar configuration but is a series of can-shaped chambers rather than a single continuous chamber. The silo combustor type is one or more chambers mounted external to the gas turbine body. These three combustor types are shown in Figure 3-2; further discussion of combustors is found in Chapter 5.[3-5] Flame temperatures in the combustor can reach 2000°C (3600°F).[6] The hot combustion gases

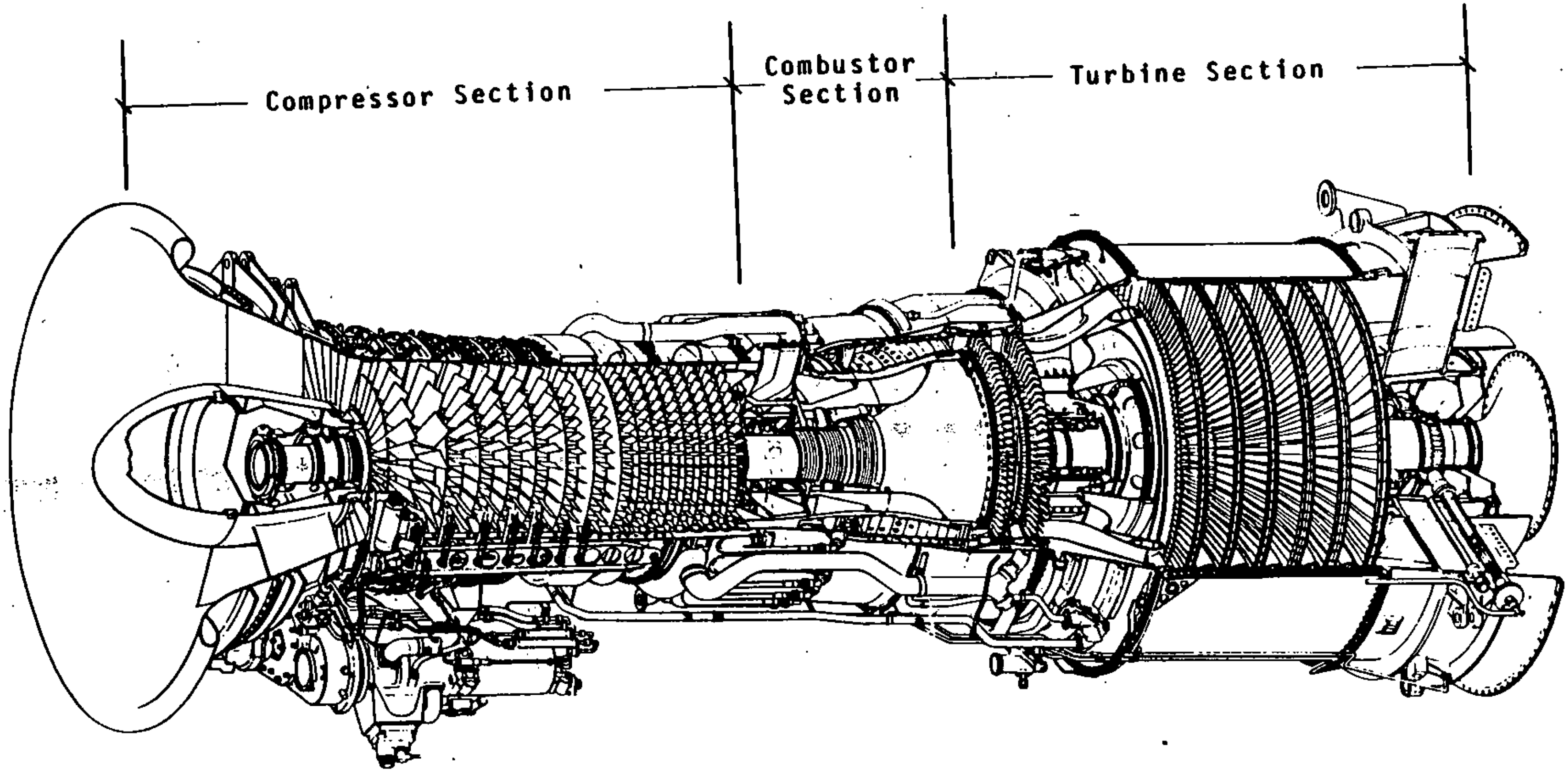
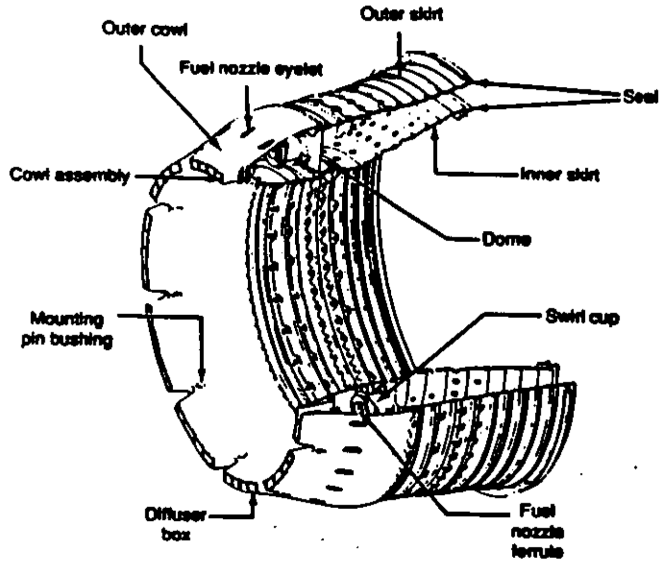
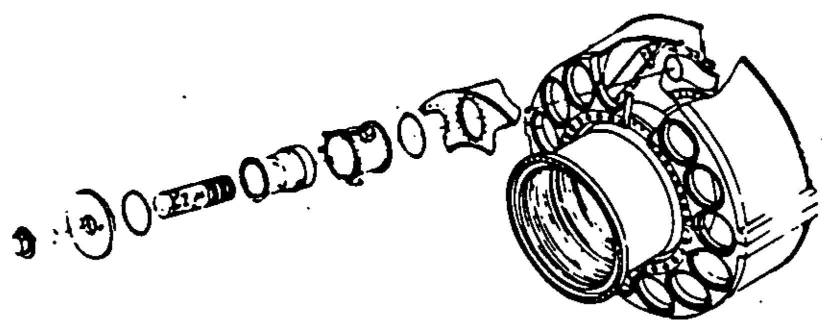


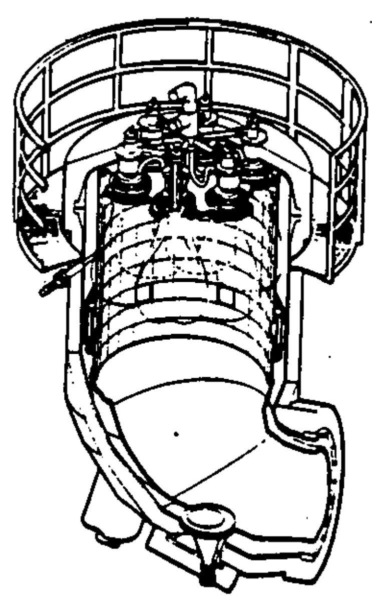
Figure 3-1. The three primary sections of a gas turbine.[1]



Annular

Can-annular





Silo

Figure 3-2. Types of gas turbine combustors.[3-5]

are then diluted with additional cool air from the compressor section and directed to the turbine section at temperatures up to 1285°C (2350°F).[6] Energy is recovered in the turbine section in the form of shaft horsepower, of which typically greater than 50 percent is required to drive the internal compressor section.[7] The balance of the recovered shaft energy is available to drive the external load unit.

The compressor and turbine sections can each be a single fan-like wheel assembly, or stage, but are usually made up of a series of stages. In a single-shaft gas turbine, shown in Figure 3-3, all compressor and turbine stages are fixed to a single, continuous shaft and operate at the same speed. A single-shaft gas turbine is typically used to drive electric generators where there is little speed variation.

A two-shaft gas turbine is shown in Figure 3-4. In this design, the turbine section is divided into a high-pressure and low-pressure arrangement, where the high-pressure turbine is mechanically tied to the compressor section by one shaft, while the low-pressure turbine, or power turbine, has its own shaft and is connected to the external load unit. This configuration allows the high-pressure turbine/compressor shaft assembly, or rotor, to operate at or near optimum design speeds, while the power turbine rotor speed can vary over as wide a range as is required by most external-load units in mechanical drive applications (i.e., compressors and pumps).

A third configuration is a three-shaft gas turbine. As shown in Figure 3-5, the compressor section is divided into a low-pressure and high-pressure configuration. The low-pressure compressor stages are mechanically tied to the low-pressure turbine stages, and the high-pressure compressor stages are similarly connected to the high-pressure turbine stages in a concentric shaft arrangement. These low-pressure and high-pressure rotors operate at optimum design speeds independent of each other. The power turbine stages are mounted on a third independent shaft and form the power turbine rotor, the speed of

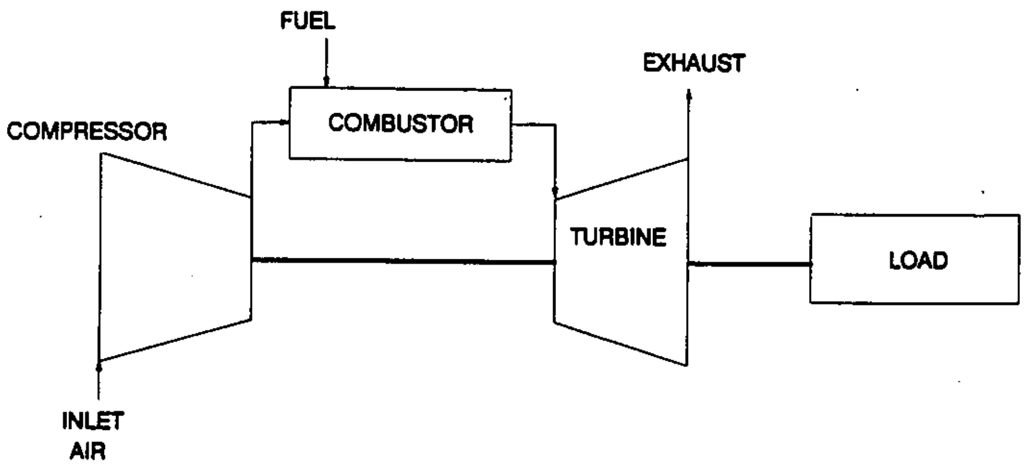


Figure 3-3. Single-shaft gas turbine.

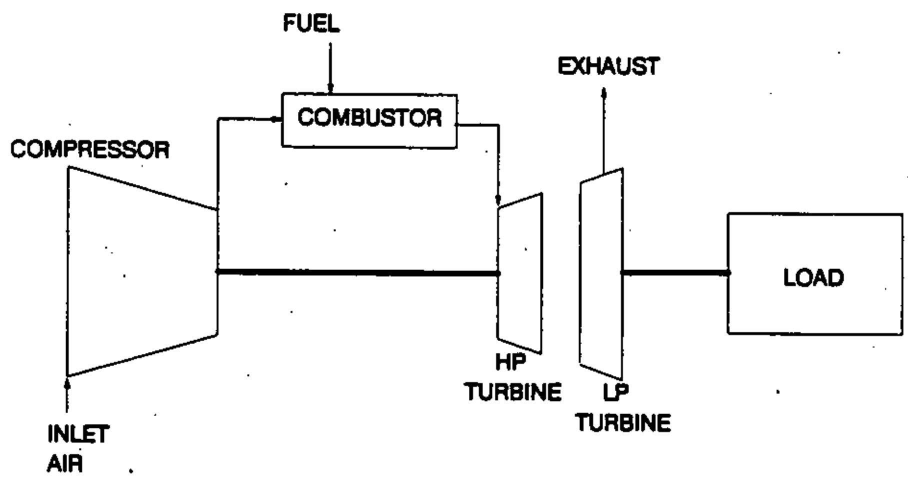


Figure 3-4. Two-shaft gas turbine.

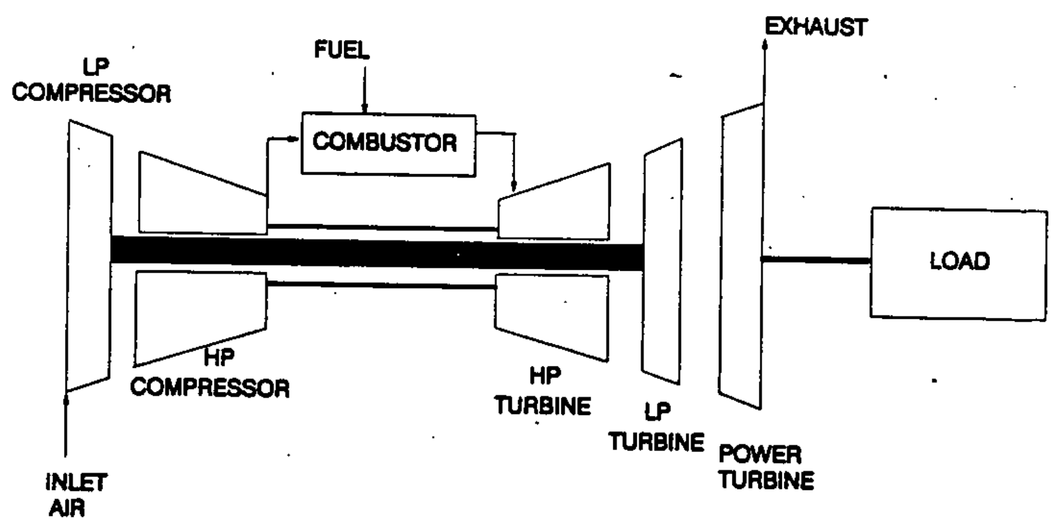


Figure 3-5. Three-shaft gas turbine.

which can vary over as wide a range as is necessary for mechanical drive applications.

Gas turbines can burn a variety of fuels. Most burn natural gas, waste process gases, or liquid fuels such as distillate oils (primarily No. 2 fuel oil). Some gas turbines are capable of burning lower-grade residual or even crude oil with minimal processing. Coal-derived gases can be burned in some turbines.

The capacity of individual gas turbines ranges from approximately 0.08 to over 200 megawatts (MW) (107 to 268,000 horsepower [hp]).[2] Manufacturers continue to increase the horsepower of individual gas turbines, and frequently they are "ganged," or installed in groups so that the total horsepower output from one location can meet virtually any installation's power requirements.

Several characteristics of gas turbines make them attractive power sources. These characteristics include a high horsepower-to-size ratio, which allows for efficient space utilization, and a short time from order placement to on-line operation. Many suppliers offer the gas turbine, load unit, and all accessories as a fully assembled package that can be performance tested at the supplier's facility. This packaging is cost effective and saves substantial installation time. Other advantages of gas turbines are:

1. Low vibration;
2. High reliability;
3. No requirement for cooling water;
4. Suitability for remote operation;
5. Lower capital costs than reciprocating engines; and
6. Lower capital costs than boiler/steam turbine-based electric power generating plants.[8]

3.2 OPERATING CYCLES

The four basic operating cycles for gas turbines are simple, regenerative, cogeneration, and combined cycles. Each of these cycles is described separately below.

3.2.1 Simple Cycle

The simple cycle is the most basic operating cycle of a gas turbine. In a simple cycle application, a gas turbine functions with only the three primary sections described in Section 3.1, as depicted in Figure 3-6.[10] Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range, although one manufacturer states an efficiency of 40 percent for an engine recently introduced to the market.[9] In addition to shaft energy output, 1 to 2 percent of the fuel input energy can be attributed to mechanical losses; the balance is exhausted from the turbine in the form of heat.[7] Simple cycle operation is typically used when there is a requirement for shaft horsepower without recovery of the exhaust heat. This cycle offers the lowest installed capital cost but also provides the least efficient use of fuel and therefore the highest operating cost.

3.2.2 Regenerative Cycle

The regenerative cycle gas turbine is essentially a simple cycle gas turbine with an added heat exchanger, called a regenerator or recuperator, to preheat the combustion air. In the regenerative cycle, thermal energy from the exhaust gases is transferred to the compressor discharge air prior to being introduced into the combustor. A diagram of this cycle is depicted in Figure 3-7.[11] Preheating the combustion air reduces the amount of fuel required to reach design combustor temperatures and therefore improves the overall cycle efficiency over that of simple cycle operation. The efficiency gain is directly proportional to the differential temperature between the exhaust gases and compressor discharge air. Since the compressor discharge air temperature increases with an increase in pressure ratio, higher regenerative cycle efficiency gains are realized from lower compressor pressure ratios typically found in older gas turbine models.[7] Most new or updated gas turbine models with high compressor pressure ratios render regenerative cycle operation economically unattractive because the capital cost of the regenerator cannot be justified by the marginal fuel savings.

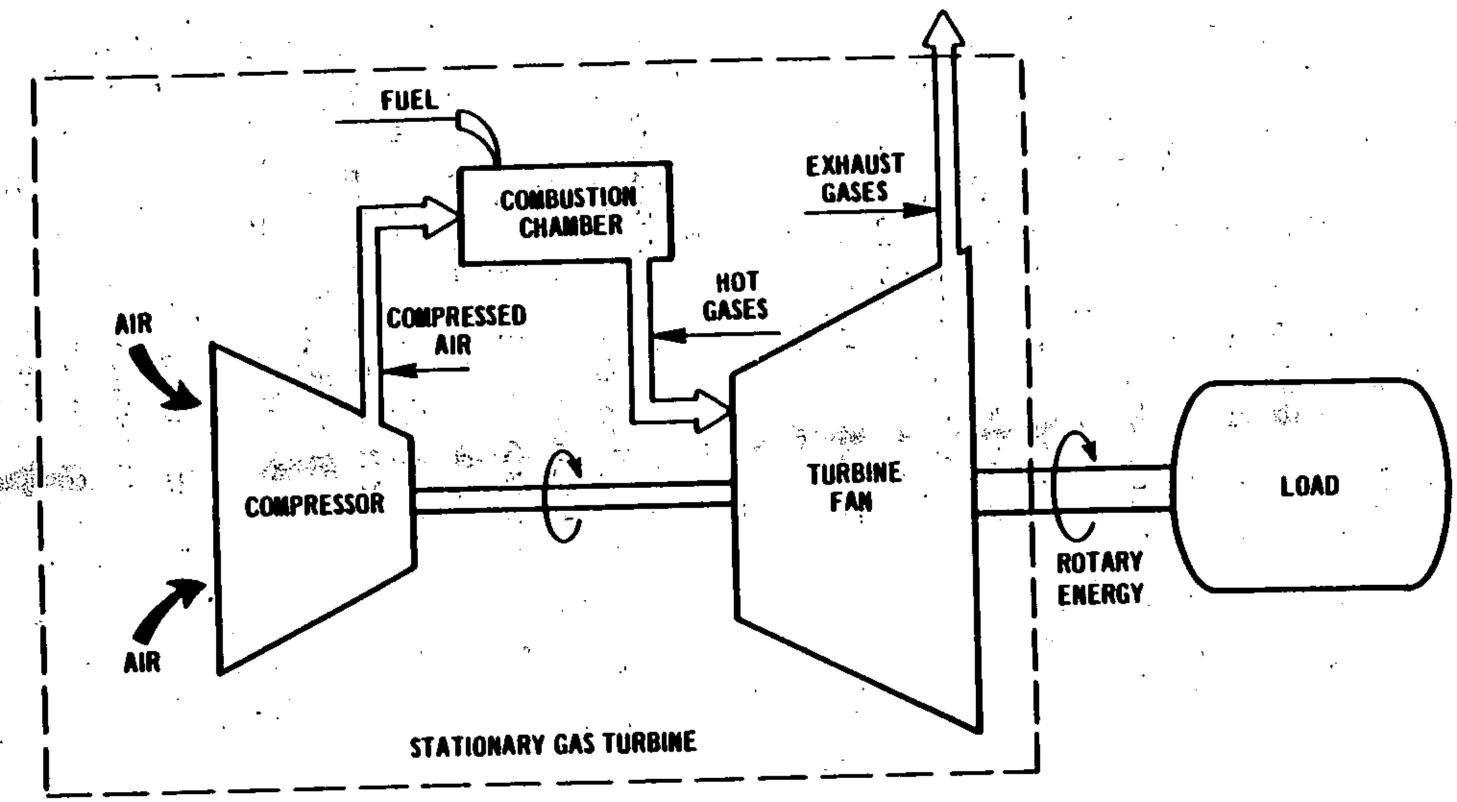


Figure 3-6. Simple cycle gas turbine application.[10]

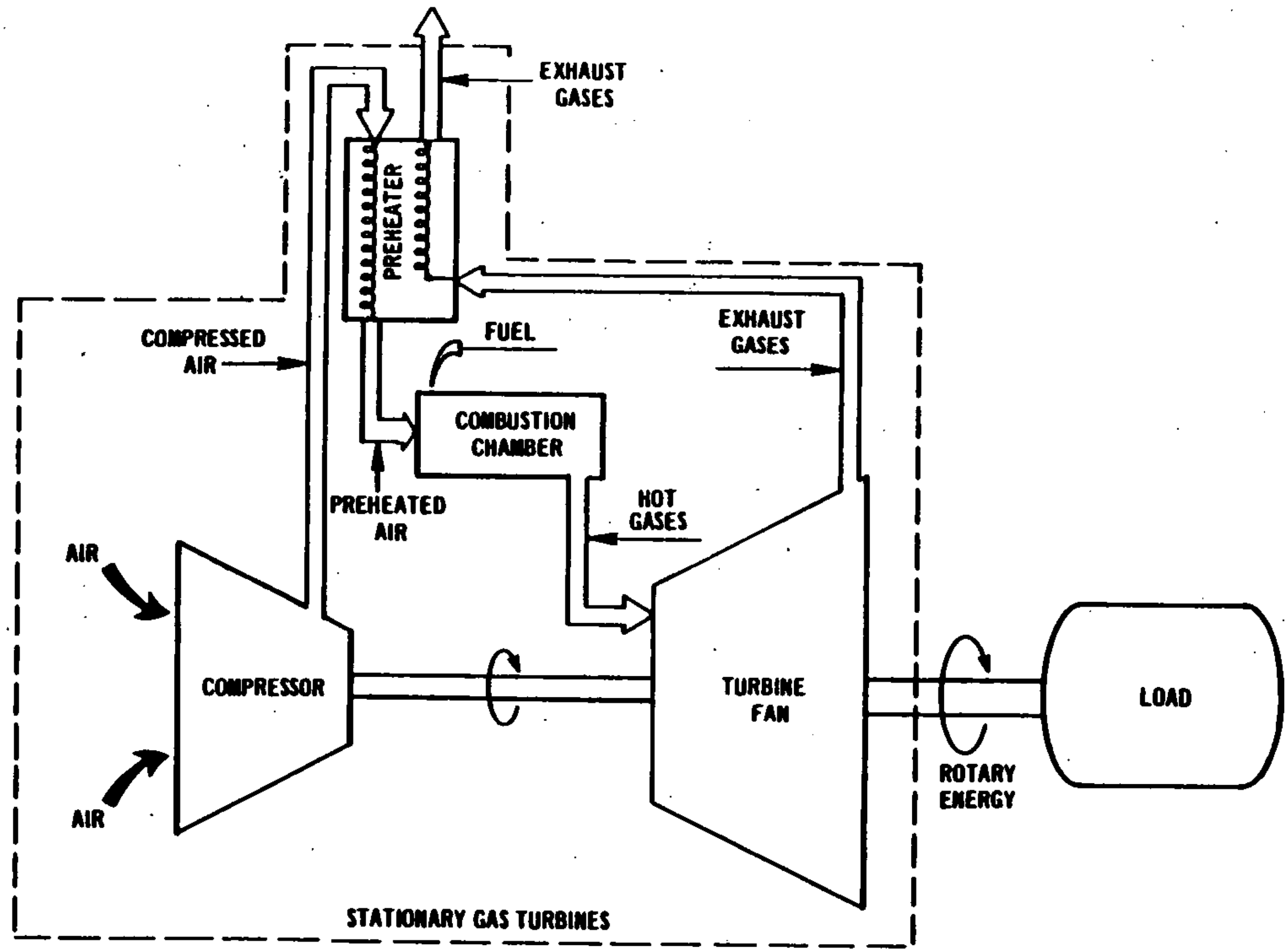


Figure 3-7. Regenerative cycle gas turbine.[11]

3.2.3 Cogeneration Cycle

A gas turbine used in a cogeneration cycle application is essentially a simple cycle gas turbine with an added exhaust heat exchanger, called a heat recovery steam generator (HRSG). This configuration is shown in Figure 3-8.[12] The steam generated by the exhaust heat can be delivered at a variety of pressure and temperature conditions to meet site thermal process requirements. Where the exhaust heat is not sufficient to meet site requirements, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Adding the HRSG equipment increases the capital cost, but recovering the exhaust heat increases the overall cycle efficiency to as high as 75 percent.[13]

3.2.4 Combined Cycle

A combined cycle is the terminology commonly used for a gas turbine/HRSG configuration as applied at an electric utility. This cycle, shown in Figure 3-9, is used to generate electric power.[12] The gas turbine drives an electric generator, and the steam produced in the HRSG is delivered to a steam turbine, which also drives an electric generator. The boiler may be supplementary-fired to increase the steam production where desired. Cycle efficiencies can exceed 50 percent.

3.3 INDUSTRY APPLICATIONS

Gas turbines are used by industry in both mechanical and electrical drive applications. Compressors and pumps are most often the driven load unit in mechanical drive applications, and electric generators are driven in electrical drive installations. Few sites have gas/air compression or fluid pumping requirements that exceed 15 MW (20,100 hp), and for this reason mechanical drive applications generally use gas turbines in the 0.08- to 15.0-MW (107- to 20,100-hp) range.[14] Electric power requirements range over the entire available range of gas turbines, however, and all sizes can be found in electrical drive applications, from 0.08 to greater than 200 MW (107 to 268,000 hp).[15]

The primary applications for gas turbines can be divided into five broad categories: the oil and gas industry,

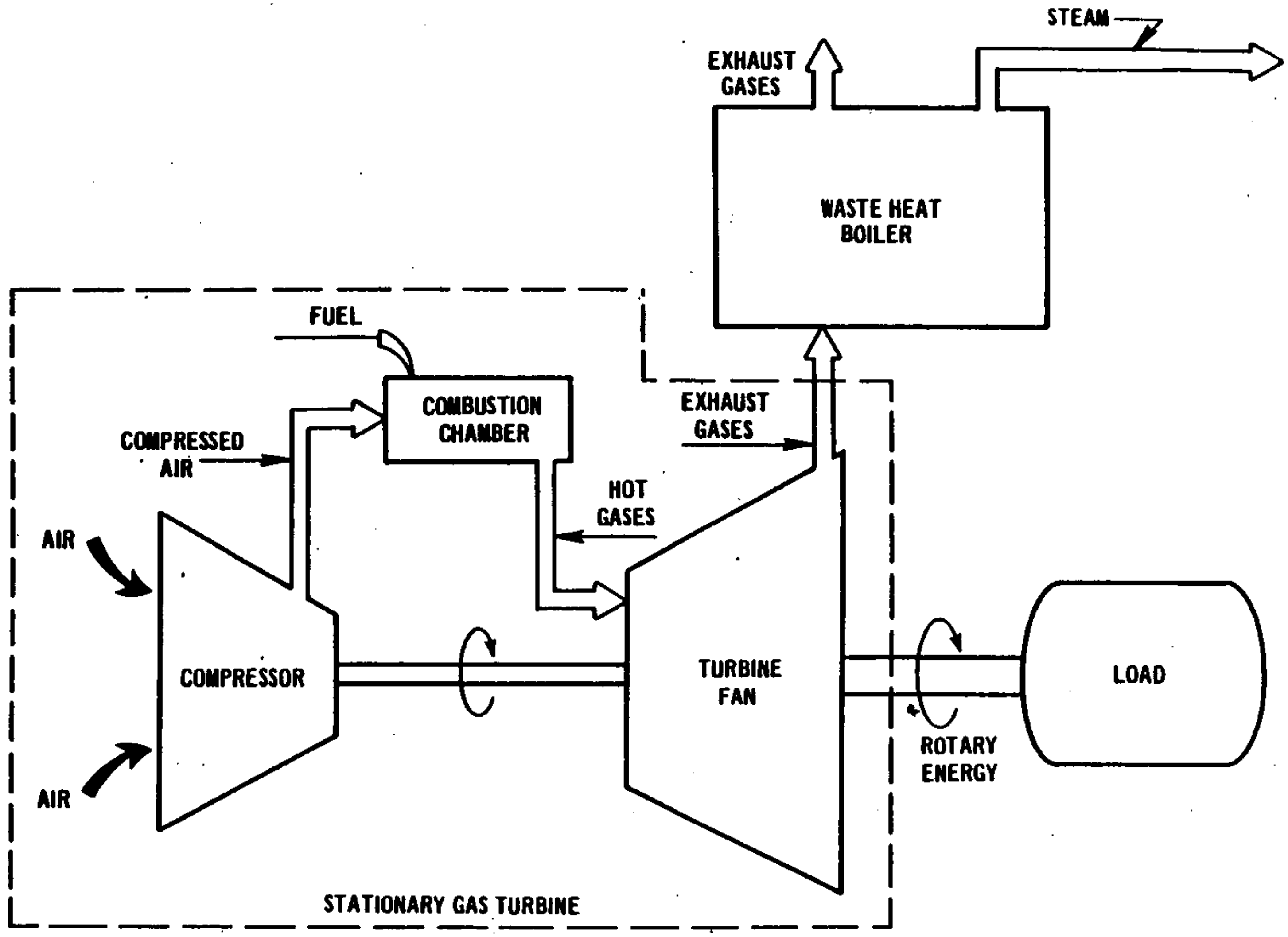


Figure 3-8. Cogeneration cycle gas turbine application.[12]

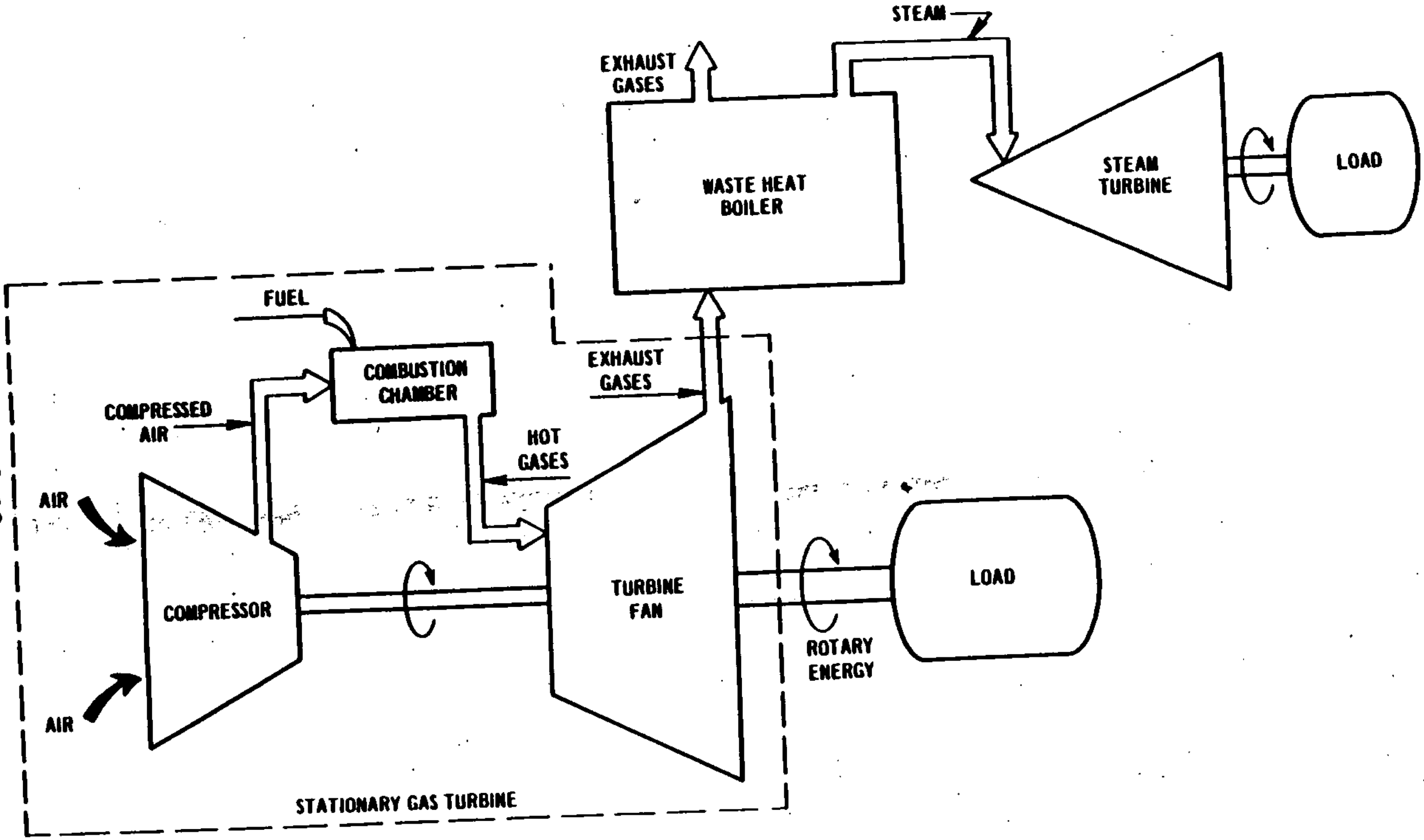


Figure 3-9. Combined cycle gas turbine application.[12]

stand-by/emergency electric power generation, independent electric power producers, electric utilities, and other industrial applications.[16] Where a facility has a requirement for mechanical shaft power only, the installation is typically simple or regenerative cycle. For facilities where either electric power or mechanical shaft power and steam generation are required, the installation is often cogeneration or combined cycle to capitalize on these cycles' higher efficiencies.

3.3.1 Oil and Gas Industry

The bulk of mechanical drive applications are in the oil and gas industry. Gas turbines in the oil and gas industry are used primarily to provide shaft horsepower for oil and gas extraction and transmission equipment, although they are also used in downstream refinery operations. Most gas turbines found in this industry are in the 0.08- to 15.0-MW (107- to 20,100-hp) range.

Gas turbines are particularly well suited to this industry, as they can be fueled by a wide range of gaseous and liquid fuels often available at the site. Natural gas and distillate oil are the most common fuels. Many turbines can burn waste process gases, and some turbines can burn residual oils and even crude oil. In addition, gas turbines are suitable for remote installation sites and unattended operation. Most turbines used in this industry operate continuously, 8,000+ hours per year, unless the installation is a pipeline transmission application with seasonal operation.

Competition from reciprocating engines in this industry is significant. Although gas turbines have a considerable capital cost advantage, reciprocating engines require less fuel to produce the same horsepower and consequently have a lower operating cost.[17] Selection of gas turbines vs. reciprocating engines is generally determined by site-specific criteria such as installed capital costs, costs for any required emissions control equipment, fuel costs and availability, annual operating hours, installation and structural considerations, compatibility with existing equipment, and operating experience.

3.3.2 Stand-By/Emergency Electric Power Generation

Small electric generator sets make up a considerable number of all gas turbine sales under 3.7 MW (5,000 hp). The majority of these installations provide backup or emergency power to critical networks or equipment and use liquid fuel. Telephone companies are a principal user, and hospitals and small municipalities also are included in this market. These turbines operate on an as-needed basis, which typically is between 75 and 200 hours per year.

Gas turbines offer reliable starting, low weight, small size, low vibration, and relatively low maintenance, which are important criteria for this application. Gas turbines in this size range have a relatively high capital cost, however, and reciprocating engines dominate this market, especially for applications under 2,000 kW (2,700 hp).[18,19]

3.3.3 Independent Electrical Power Producers

Large industrial complexes and refining facilities consume considerable amounts of electricity, and many sites choose to generate their own power. Gas turbines can be used to drive electric generators in simple cycle operation, or an HRSG system may be added to yield a more efficient cogeneration cycle. The vast majority of cogeneration installations operate in a combined cycle capacity, using a steam turbine to provide additional electric power. The Public Utility Regulatory Policies Act (PURPA) of 1978 encourages independent cogenerators to generate electric power by requiring electric utilities to (1) purchase electricity from qualifying producers at a price equal to the cost the utility can avoid by not having to otherwise supply that power (avoided cost) and (2) provide backup power to the cogenerator at reasonable rates. Between 1980 and 1986, approximately 20,000 MW of gas turbine-produced electrical generating capacity was certified as qualifying for PURPA benefits. This installed capacity by private industry power generators is more than the sum of all utility gas turbine orders for all types of central power plants during this period.[20] The Department of Energy (DOE) expects an additional 27,000 MW capacity to be purchased by private industry in the next 10 years.[21]

Gas turbines installed in this market range in power from 1 to over 100 MW (1,340 to 134,000 hp) and operate typically between 4,000 and 8,000 hours per year. While reciprocating engines compete with the gas turbine at the lower end of this market (under approximately 7.5 MW [10,000 hp]), the advantages of lower installed costs, high reliability, and low maintenance requirements make gas turbines a strong competitor.

3.3.4 Electric Utilities

Electric utilities are the largest user of gas turbines on an installed horsepower basis. They have traditionally installed these turbines for use as peaking units to meet the electric power demand peaks typically imposed by large commercial and industrial users on a daily or seasonal basis; consequently, gas turbines in this application operate less than 2,000 hours per year.[22] The power range used by the utility market is 15 MW to over 150 MW (20,100 to 201,000 hp). Peaking units typically operate in simple cycle.

The demand for gas turbines from the utility market was flat through the late 1970's and 1980's as the cost of fuel increased and the supplies of gas and oil became unpredictable. There are signs, however, that the utility market is poised to again purchase considerable generating capacity. The capacity margin, which is the utility industry's measure of excess generation capacity, peaked at 30 percent in 1982. By 1990, the capacity margin had dropped to approximately 20 percent, and, based on current construction plans, will reach the industry rule-of-thumb minimum of 15 percent by 1995.[21] The utility industry is adding new capacity and repowering existing older plants, and gas turbines are expected to play a considerable role.

Many utilities are now installing gas turbine-based combined cycle installations with provisions for burning coal-derived gas fuel at some future date. This application is known as integrated coal gasification combined cycle (IGCC). At least five power plant projects have been announced, and several more are being negotiated. Capital costs for these plants are in many cases higher than comparable natural gas-fueled applications, but future price increases for natural gas could make IGCC an attractive option for the future.[23]

Utility orders for gas turbines have doubled in each of the last 2 years. The DOE says that electric utilities will need to add an additional 73,000 MW to capacity to meet demand by the year 2000, and as Figure 3-10 shows, DOE expects 36,000 MW of combined cycle and 16,000 MW of simple cycle gas turbines to be purchased. This renewed interest in gas turbines is a result of:

1. The introduction of new, larger, more efficient gas turbines;

2. Lower natural gas prices and proven reserves to meet current demand levels for more than 100 years;

3. Shorter lead times than those of competing equipment; and

4. Lower capital costs for gas turbines.[21]

Utility capital cost estimates, as shown in Figure 3-11, are (1) $500 per KW for repowering existing plants with combined cycle gas turbines, (2) $800 per KW for new combined cycle plants, (3) $1,650 per KW for new coal-fired plants, and (4) $2,850 per KW for new nuclear-powered plants.[24]

Gas turbines are also an alternative to displace planned or existing nuclear facilities. A total of 1,020 MW of gas turbine-generated electric power was recently commissioned in Michigan at a plant where initial design and construction had begun for a nuclear plant. Four additional idle nuclear sites are considering switching to gas turbine-based power production due to the legal, regulatory, financial, and public obstacles facing nuclear facilities.[24]

3.3.5 Other Industrial Applications

Industrial applications for gas turbines include various types of mechanical drive and air compression equipment. These applications peaked in the late 1960's and declined through the 1970's.[25] With the promulgation of PURPA in 1978 (see Section 3.3.3), many industrial facilities have found it

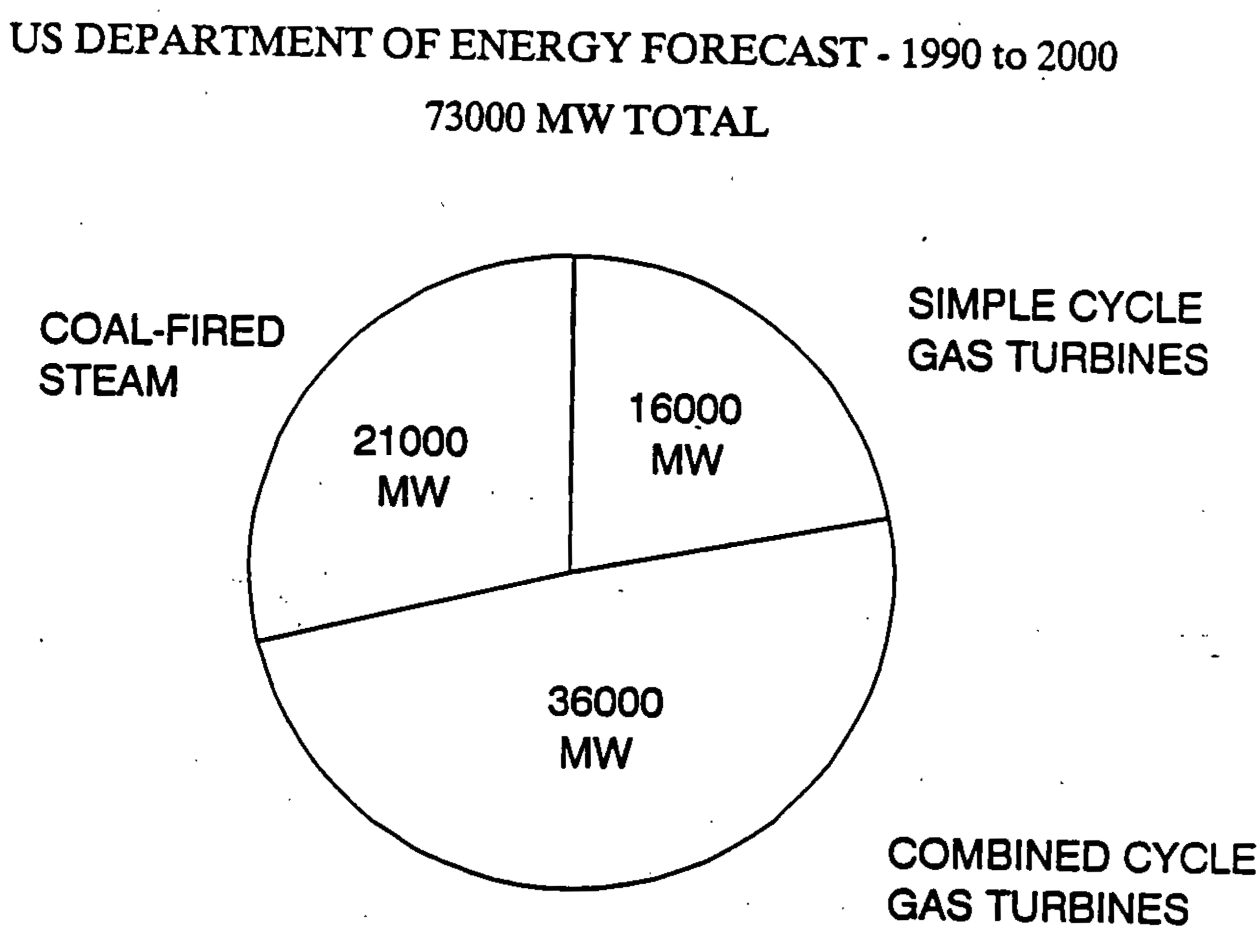
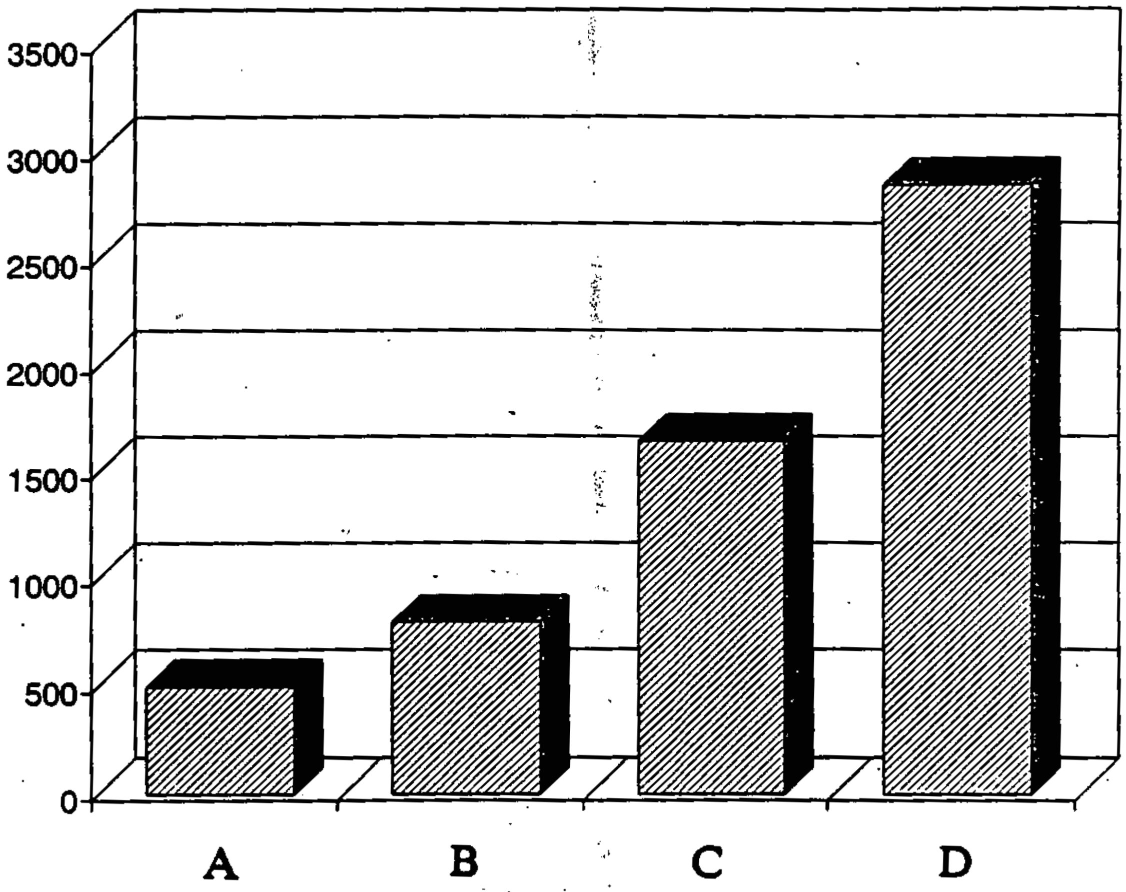


Figure 3-10. Total capacity to be purchased by the utility industry.[21]



A - Repower existing plant using combined cycle gas turbines
B - New plant using combined cycle gas turbines
C - New plant using coal fired boilers
D - New plant using nuclear power

Figure 3-11. Capital costs for electric utility plants.[24]

economically feasible to install a combined cycle gas turbine to meet power and steam requirements. Review of editions of Gas Turbine World over the last several years shows that a broad range of industries (e.g., pulp and paper, chemical, and food processing) have installed combined cycle gas turbines to meet their energy requirements.

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4.0 CHARACTERIZATION OF NO_x EMISSIONS

This section presents the principles of NO_x formation, the types of NO_x emitted (i.e., thermal NO_x, prompt NO_x, and fuel NO_x), and how they are generated in a gas turbine combustion process. Estimated NO_x emission factors for gas turbines and the bases for the estimates are also presented.

4.1 THE FORMATION OF NO_x

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of nitrogen (N_2) and oxygen (O_2) into N and O, respectively. Reactions following this dissociation result in seven known oxides of nitrogen: NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, and N_2O_5. Of these, nitric oxide (NO) and nitrogen dioxide (NO_2) are formed in sufficient quantities to be significant in atmospheric pollution.[1] In this document, "NO_x" refers to either or both of these gaseous oxides of nitrogen.

Virtually all NO_x emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule.[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). These mechanisms are discussed below.

4.1.1 <u>Formation of Thermal and Prompt NO_x</u>

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 oxides of nitrogen. The major contributing chemical reactions are known as the

Zeldovich mechanism and take place in the high temperature area of the gas turbine combustor.[3] Simply stated, the Zeldovich mechanism postulates that thermal NO_x formation increases exponentially with increases in temperature and linearly with increases in residence time.[4]

Flame temperature is dependent upon the equivalence ratio, which is the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.[5] An equivalence ratio of 1.0 corresponds to the stoichiometric ratio and is the point at which a flame burns at its highest theoretical temperature.[5] Figure 4-1 shows the flame temperature and equivalence ratio relationship for combustion using No. 2 distillate fuel oil (DF-2).[4]

The series of chemical reactions that form thermal NO_x according to the Zeldovich mechanism are presented below.[3]

1. $O_2 \rightleftharpoons 2O$;

2. $N_2 \rightleftharpoons 2N$;

3. $N + O \rightleftharpoons NO$;

4. $N + O_2 \rightleftharpoons NO + O$; and

5. $O + N_2 \rightleftharpoons NO + N$.

This series of equations applies to a fuel-lean combustion process. Combustion is said to be fuel-lean when there is excess oxygen available (equivalence ratio <1.0). Conversely, combustion is fuel-rich if insufficient oxygen is present to burn all of the available fuel (equivalence ratio >1.0). Additional equations have been developed that apply to fuel-rich combustion. These equations are an expansion of the above series to add an intermediate hydroxide molecule (OH):[3]

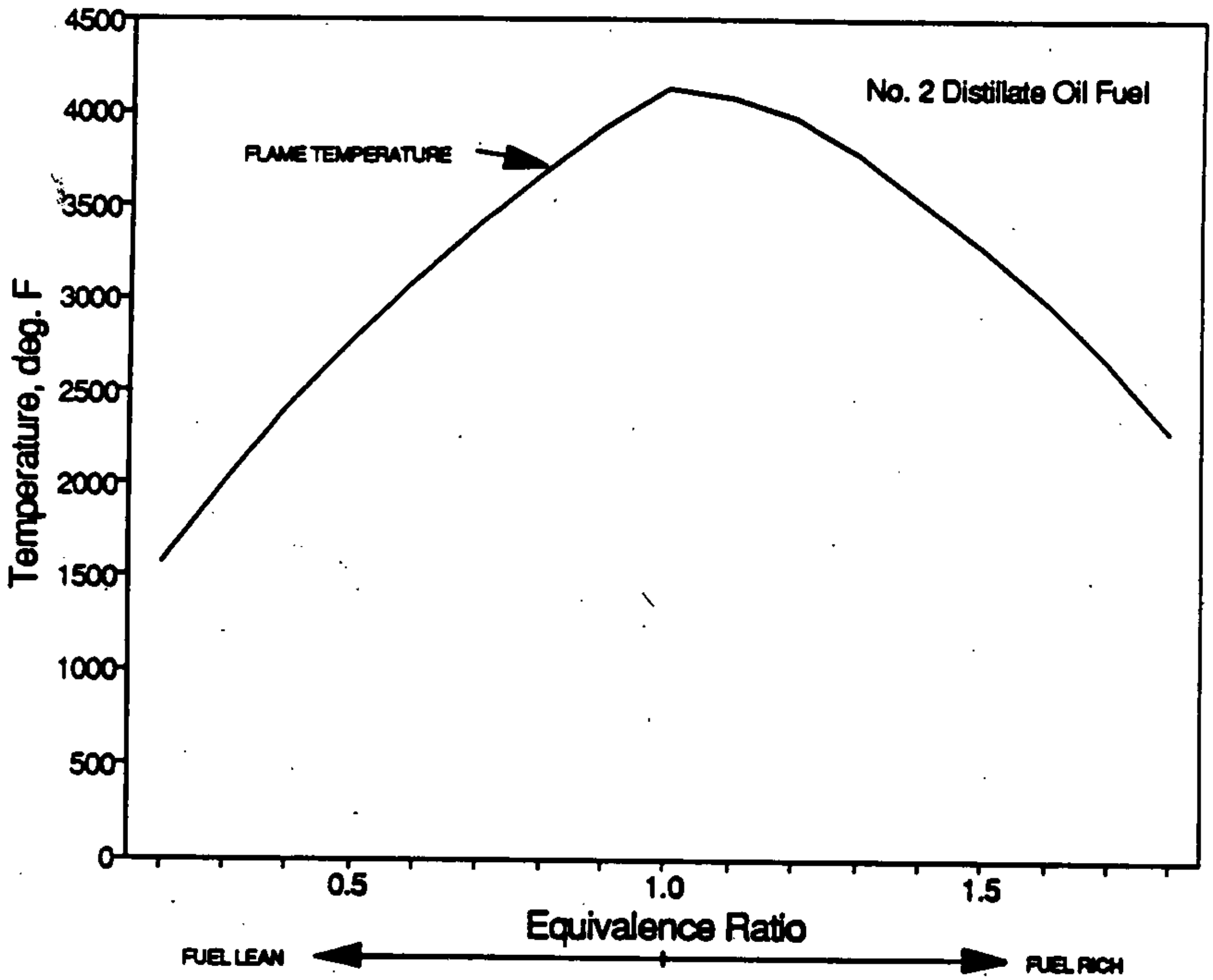

Figure 4-1. Influence of equivalence ratio on flame temperature.[4]

6. $N + OH \rightleftharpoons NO + H$,

and further to include an intermediate product, hydrogen cyanide (HCN), in the formation process:[3]

7. $N_2 + CH \rightleftharpoons HCN + N$ and

8. $N + OH \rightleftharpoons H + NO$.

The overall equivalence ratio for gases exiting the gas turbine combustor is less than 1.0.[4] Fuel-rich areas do exist in the overall fuel-lean environment, however, due to less-than-ideal fuel/air mixing prior to combustion. This being the case, the above equations for both fuel-lean and fuel-rich combustion apply for thermal NO_x formation in gas turbines.

Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_x as shown in the following equations:

1. $CH + N_2 \rightleftharpoons HCN + N$;

2. $CH_2 + N_2 \rightleftharpoons HCN + NH$; and

3. $HCN, N, NH + O_x \rightleftharpoons NO + \ldots$[6]

Prompt NO_x is formed in both fuel-rich flame zones and fuel-lean premixed combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution increases with decreases in the equivalence ratio (fuel-lean mixtures). For this reason, prompt NO_x becomes an important consideration for the low-NO_x combustor designs described in Chapter 5 and establishes a minimum NO_x level attainable in lean mixtures.[7]

4.1.2 <u>Formation of Fuel NO_x</u>

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as

N_2 in some natural gas, does not contribute significantly to fuel NO_x formation.[8] However, nitrogen compounds are present in coal and petroleum fuels as pyridine-like (C_5H_5N) structures that tend to concentrate in the heavy resin and asphalt fractions upon distillation. Some low-British thermal unit (Btu) synthetic fuels contain nitrogen in the form of ammonia (NH_3), and 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.[9] 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 fuel NO_x conversion rate. The low-percentage FBN fuel has a 100 percent conversion rate, but its overall NO_x emission level would be lower than that of the high-percentage FBN fuel with a 40 percent conversion rate.[10]

Nitrogen content varies from 0.1 to 0.5 percent in most residual oils and from 0.5 to 2 percent for most U.S. coals.[11] Traditionally, most light distillate oils have had less than 0.015 percent nitrogen content by weight. However, today many distillate oils are produced from poorer-quality crudes, especially in the northeastern United States, and these distillate oils may contain percentages of nitrogen exceeding the 0.015 threshold; this higher nitrogen content can increase fuel NO_x formation.[4] At least one gas turbine installation burning coal-derived fuel is in commercial operation in the United States.[12]

Most gas turbines that operate in a continuous duty cycle are fueled by natural gas that typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not currently a major contributor to overall NO_x emissions from stationary gas turbines.

4.2 UNCONTROLLED NO_x EMISSIONS

The NO_x emissions from gas turbines are generated entirely in the combustor section and are released into the atmosphere via the stack. In the case of simple and regenerative cycle operation, the combustor is the only source of NO_x emissions. In cogeneration and combined cycle applications, a duct burner may be placed in the exhaust ducting between the gas turbine and the heat recovery steam generator (HRSG); this burner also generates NO_x emissions. (Gas turbine operating cycles are discussed in Section 3.2.) The amount of NO_x formed in the combustion zone is "frozen" at this level regardless of any temperature reductions that occur at the downstream end of the combustor and is released to the atmosphere at this level.[1]

4.2.1 Parameters Influencing Uncontrolled NO_x Emissions

The level of NO_x formation in a gas turbine, and hence the NO_x emissions, is unique (by design factors) 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 level as a percentage of the rated full power output of the turbine. These factors are discussed below.

4.2.1.1 Combustor Design. The design of the combustor is the most important factor influencing the formation of NO_x. Design considerations are presented here and discussed further in Chapter 5.

Thermal NO_x formation, as discussed in Section 4.1.1, is influenced primarily by flame temperature and residence time. Design parameters controlling equivalence ratios and the introduction of cooling air into the combustor strongly influence thermal NO_x formation. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_x production takes place.[13] The dependence of thermal NO_x formation on flame temperature and equivalence ratio is shown in Figure 4-2 for DF-2.[4] Conversely, prompt NO_x is largely insensitive to changes in temperature and pressure.[7]

Fuel NO_x formation, as discussed in Section 4.1.2, is formed when FBN is released during combustion and oxidizes to form NO_x. Design parameters that control equivalence ratio and residence time influence fuel NO_x formation.[14]

4.2.1.2 Type of Fuel. The level of NO_x emissions varies for different fuels. In the case of thermal NO_x, this level increases with flame temperature. 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 (e.g., ethane, propane, and butane) burn at higher flame temperatures and as a result can increase NO_x emissions greater than 50 percent over NO_x levels for methane gas fuel. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons. Conversely, gas fuels that contain significant inert gases, such as CO_2, generally produce lower NO_x emissions. These inert gases serve to absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x emissions. Examples of this type of gas fuel are air-blown gasifier fuels and some field gases.[15] Combustion of hydrogen also results in high flame temperatures, and gases with significant hydrogen content produce relatively high NO_x emissions. Refinery gases can have hydrogen contents exceeding 50 percent.[16]

As is shown in Figure 4-3, DF-2 burns at a flame temperature that is approximately 75°C (100°F) higher than that of natural gas, and as a result, NO_x emissions are higher when burning DF-2 than they are when burning natural gas.[17] Low-Btu fuels such as coal gas burn with lower flame temperatures, which result in

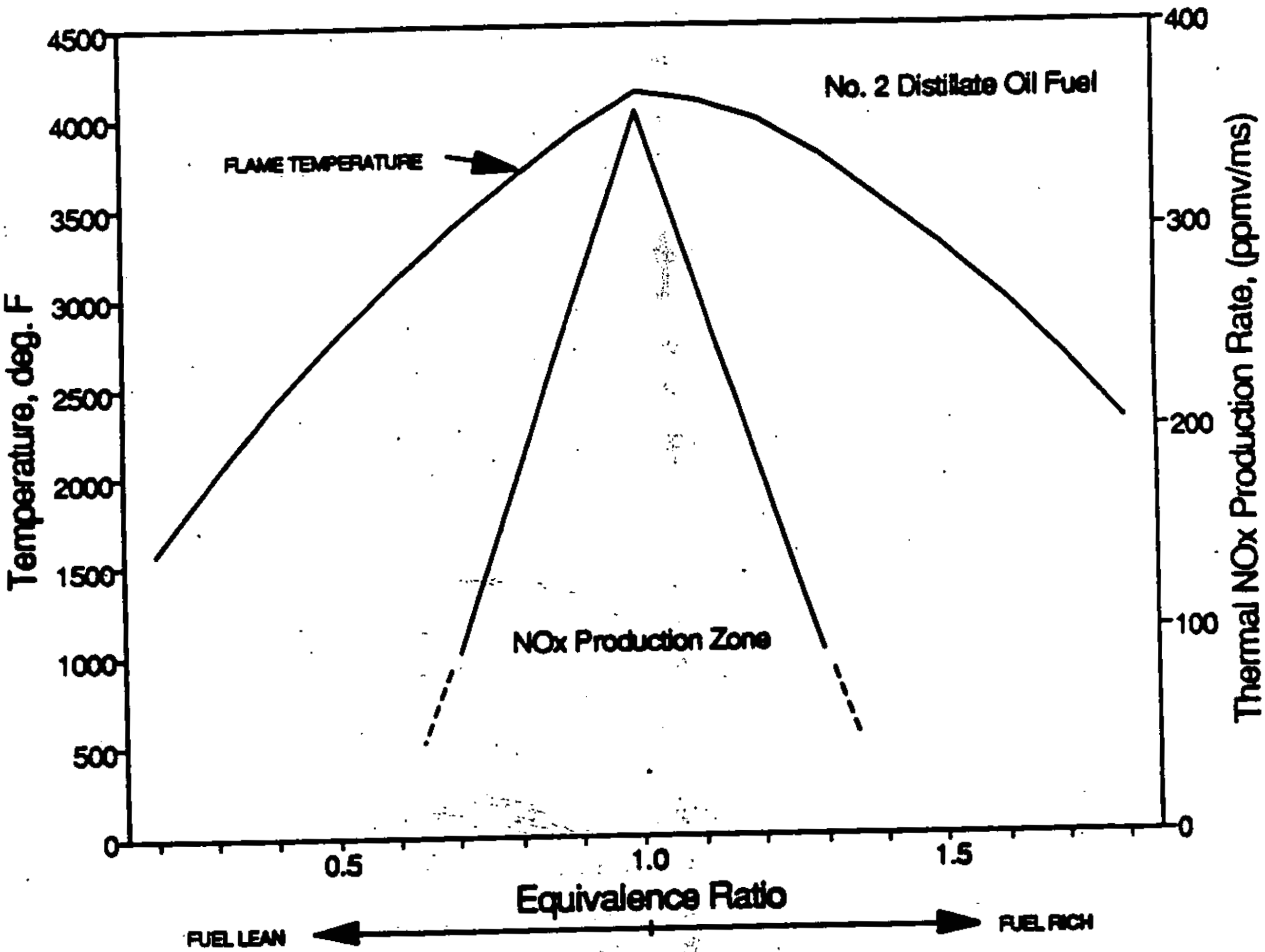

Figure 4-2. Thermal NO_x production as a function of flame temperature and equivalence ratio.[4]

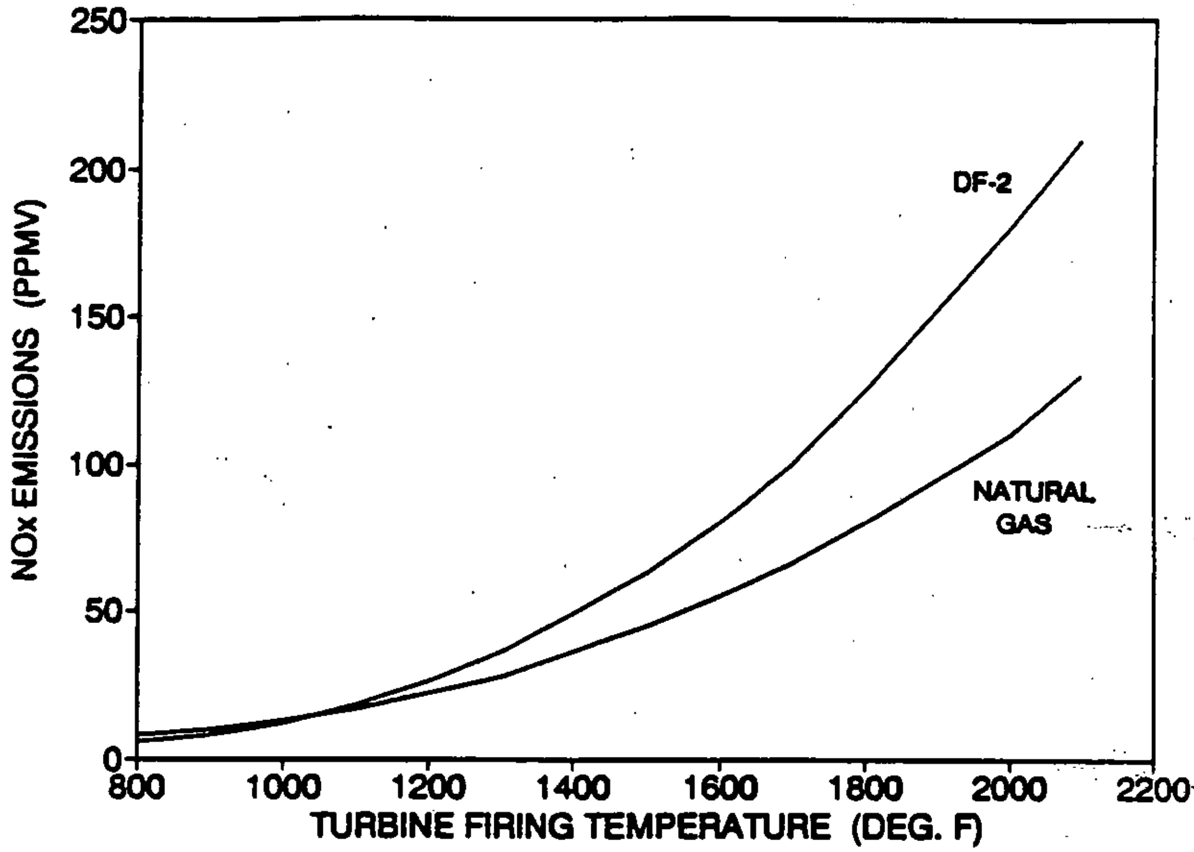

Figure 4-3. Influence of firing temperature on thermal NO_x formation.[17]

substantially lower thermal NO_x emissions than natural gas or DF-2.[18] For fuels containing FBN, the fuel NO_x production increases with increasing levels of FBN.

4.2.1.3 Ambient Conditions. Ambient conditions that affect NO_x formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NO_x formation.[19] The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures, which reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NO_x formation varies. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 10°C (50°F), NO_x emissions decrease with increasing temperature. This effect of humidity and temperature on NO_x formation is shown in Figure 4-4. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor and so No_x production levels increase with increases in ambient pressure.[19]

The influence of ambient conditions on measured NO_x emission levels can be corrected using the following equation:[20]

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5} e^{19(Ho-0.00633)} (288°K/T_a)^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O_2 and International Standards Organization (ISO) ambient conditions, volume percent;

NO_{xo} = observed NO_x concentration, parts per million by volume (ppmv) referenced to 15 percent O_2;

P_r = reference compressor inlet absolute pressure at 101.3 kilopascals ambient pressure, millimeters mercury (mm Hg);

P_o = observed compressor inlet absolute pressure at test, mm Hg;

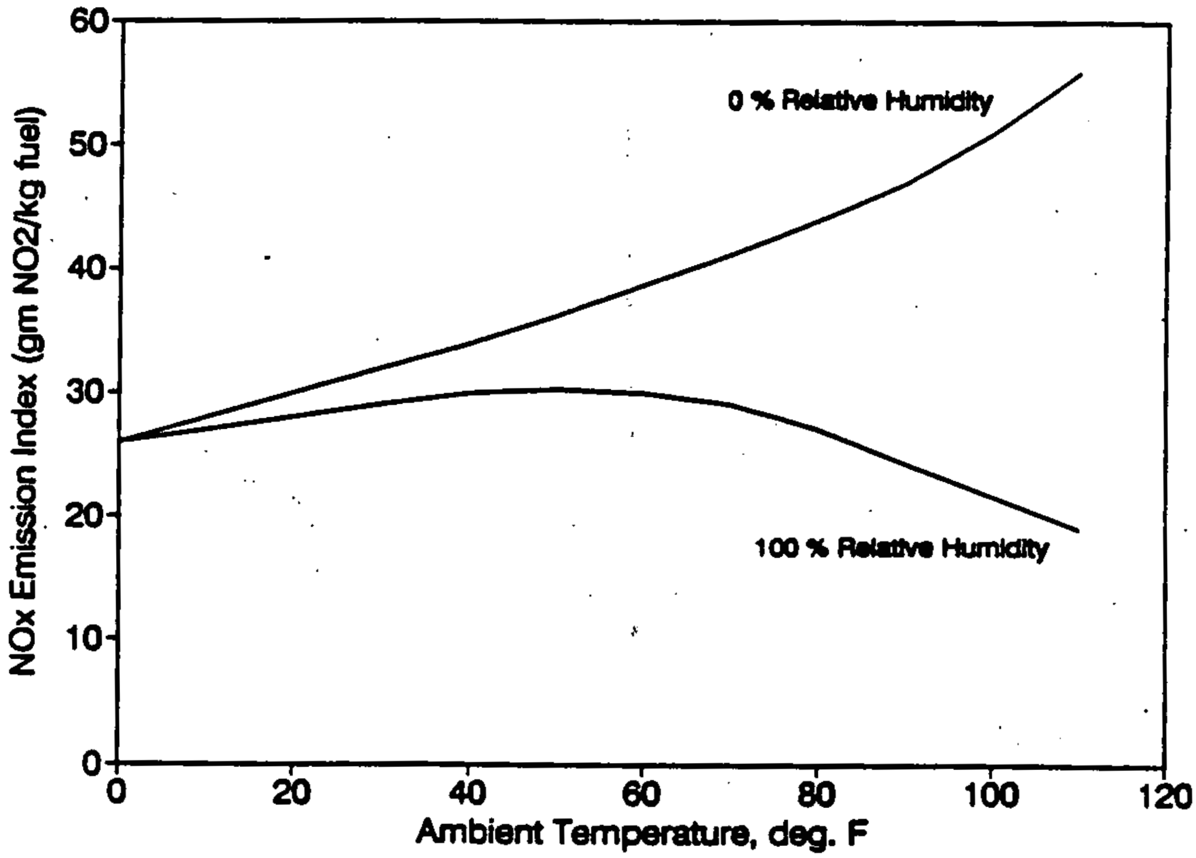

Figure 4-4. Influence of relative humidity and ambient temperature on NO_x formation.[19]

H_o = observed humidity of ambient air, g H_2O/g air;

e = transcendental constant, 2.718; and

T_a = ambient temperature, K.

At least two manufacturers state that this equation does not accurately correct NO_x emissions for their turbine models.[8,12] It is expected that these turbine manufacturers could provide corrections to this equation that would more accurately correct NO_x emissions for the effects of ambient conditions based on test data for their turbine models.

4.2.1.4 Operating Cycles. Emissions from identical turbines used in simple and cogeneration cycles have similar NO_x emissions levels, provided no duct burner is used in heat recovery applications. The NO_x emissions are similar because, as stated in Section 4.2, NO_x is formed only in the turbine combustor and remains at this level regardless of downstream temperature reductions. A turbine operated in a regenerative cycle produces higher NO_x levels, however, due to increased combustor inlet temperatures present in regenerative cycle applications.[21]

4.2.1.5 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. Each gas turbine has a base-rated power level and corresponding NO_x level. At power outputs below this base-rated level, the flame temperature is lower, so NO_x emissions are lower. Conversely, at peak power outputs above the base rating, NO_x emissions are higher due to higher flame temperature. The NO_x emissions for a range of firing temperatures are shown in Figure 4-3 for one manufacturer's gas turbine.[17]

4.2.2 NO_x Emissions From Duct Burners

In some cogeneration and combined cycle applications, the exhaust heat from the gas turbine is not sufficient to produce the desired quantity of steam from the HRSG, and a supplemental burner, or duct burner, is placed in the exhaust duct between the gas turbine and HRSG to increase temperatures to sufficient levels. In addition to providing additional steam capacity, this burner also increases the overall system efficiency since essentially all energy added by the duct burner can be recovered in the HRSG.[22]

The level of NO_x produced by a duct burner is approximately 0.1 pound per million Btu (lb/MMBtu) of fuel burned. The ppmv level depends upon the flowrate of gas turbine exhaust gases in which the duct burner is operating and thus varies with the size of the turbine.[23]

Typical NO_x production levels added by a duct burner operating on natural gas fuel are:[23]

Gas turbine output, megawatts (MW)	Duct burner NO_x, ppmv, referenced to 15 percent O_2
3 to 50	10 to 30
50+	5 to 10

4.3 UNCONTROLLED EMISSION FACTORS

Uncontrolled emission factors are presented in Table 4-1. These factors are based on uncontrolled emission levels provided by manufacturers in ppmv, dry, and corrected to 15 percent O_2, corresponding to 100 percent output load and International Standards Organization (ISO) conditions of 15°C (59°F) and 1 atmosphere (14.7 psia). Sample calculations are given in Appendix A. The uncontrolled emissions factors range from 0.397 to 1.72 lb/MMBtu (99 to 430 ppmv) for natural gas and 0.551 to 2.50 lb/MMBtu (150 to 680 ppmv) for DF-2.

TABLE 4-1. UNCONTROLLED NO_x EMISSIONS FACTORS FOR GAS TURBINES AND DUCT BURNERS[8,12,15,24-29]

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% O_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95
Duct burners	All	NA[c]	≤30	NA[b]	<0.100[d]	NA[b]

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.
[b]Not available.
[c]Not applicable.
[d]References 16 and 22.

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5.0 NO_x CONTROL TECHNIQUES

Nationwide NO_x emission limits have been established for stationary gas turbines in the new source performance standards (NSPS) promulgated in 1979.[1] This standard, summarized in Table 5-1, effectively sets a limit for new, modified, or reconstructed gas turbines greater than 10.7 gigajoules per hour (approximately 3,800 horsepower [hp]) of 75 or 150 parts per million by volume (ppmv), corrected to 15 percent oxygen (O_2) on a dry basis, depending upon the size and application of the turbine. State and regional regulatory agencies may set more restrictive limits, and two organizations have established limits as low as 9 ppmv: the South Coast Air Quality Management District (SCAQMD) has defined limits as listed in Table 5-2; and the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended limits as listed in Table 5-3.

This chapter discusses the control techniques that are available to reduce NO_x emissions for stationary turbines, the use of duct burners, the use of alternate fuels to lower NO_x emissions, and the applicability of NO_x control techniques to offshore applications. Each control technique is structured into categories to discuss the process description, applicability, factors that affect performance, and achievable controlled NO_x emission levels. Where information for a technique is limited, one or more categories may be combined. Section 5.1 describes wet controls, including water and steam injection. Section 5.2 describes combustion controls, including lean and staged combustion. Selective catalytic reduction (SCR), a postcombustion technique, is described in Section 5.3, and the

TABLE 5-1. NO_x EMISSION LIMITS AS ESTABLISHED BY THE NEW SOURCE PERFORMANCE STANDARDS FOR GAS TURBINES[1]

Fuel input MMBtu/hr	Size, MW	Application(s)	NO_x limit, ppmv at 15% O_2, dry[a b]
<10	1[c]	All	None
10-100	1-10[c]	All	150
>100	10+[c] <30[c] >30[c]	Utility[d] Nonutility Nonutility	75 150 None
<100	10[c]	Regenerative cycle	None
All	All	e	None

[a]Based on thermal efficiency of 25 percent. This limit may be increased for higher efficiencies by multiplying the limit in the table by 14.4/actual heat rate, in kJ/watt-hr.
[b]A fuel-bound nitrogen allowance may be added to the limits listed in the table according to the table listed below:

Fuel-bound nitrogen (N), percent by weight	Allowable increase, ppmv
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	$400 \times N$
$0.1 < N \leq 0.25$	$40 + [6.7 \times (N - 0.1)]$
$N > 0.25$	50

[c]Based on gas turbine heat rate of 10,000 Btu/kW-hr.
[d]An installation is considered a utility if more than 1/3 of its potential electrical output is sold.
[e]Emergency/stand-by, military (except garrison facilities), military training, research and development, firefighting, and emergency fuel operation applications are exempt from NO_x emission limits.

TABLE 5-2. NO_x COMPLIANCE LIMITS AS ESTABLISHED BY THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT (SCAQMD) FOR EXISTING TURBINES. RULE 1134. ADOPTED AUGUST 1989.[a,2]

Unit size, megawatt rating (MW)	NO_x limit, ppmv, 15% O_2 dry[b]
0.3 to <2.9 MW	25
2.9 to <10.0 MW	9
2.9 to <10.0 MW No SCR	15
10.0 MW and over	9
10.0 MW and over No SCR	12
60 MW and over Combined cycle No SCR	15
60 MW and over Combined cycle	9
Compliance limit = Reference limit X EFF/25 percent	
where:	

$$EFF = \frac{3{,}413 \times 100\%}{\text{Actual heat rate at HHV of fuel (Btu/kW-hr)}}$$

or

$$EFF^{c} = (\text{Manufacturer's rated efficiency at LHV}) \times \frac{LHV}{HHV}$$

[a]The NO_x reference limits to be effective by December 31, 1995.
[b]Averaged over 15 consecutive minutes.
[c]EFF = the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any down-stream energy recovery from the actual heat rate (Btu/kW-hr), or 1.34 (Btu/hp-hr); corrected to the higher heating value (HHV) of the fuel and ISO conditions, as measured at peak load for that facility; or the manufacturer's continuous rated percent efficiency (manufacturer's rated efficiency) of the gas turbine after correction from lower heating value (LHV) to the HHV of the fuel, whichever efficiency is higher. The value of EFF shall not be less than 25 percent. Gas turbines with lower efficiencies will be assigned a 25 percent efficiency for this calculation.

TABLE 5-3. NO_x EMISSION LIMITS RECOMMENDED BY THE NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

NEW TURBINES[3]

Fuel input, MMBtu/hr	Size, MW[a]	Fuel type	NO_x limit, ppmv[b]
1-100	1-10	Gas Oil	42 65
>100	10+	Gas Oil Gas/oil back-up	9[c] 9[c] 9[c]/18[c d]

[a]Based on gas turbine heat rate of 10,000 Btu/kW-hr.
[b]Dry basis, corrected to 15 percent oxygen.
[c]Based on use of selective catalytic reduction (SCR). Limits for operation without SCR, where permitted, should be the turbine manufacturer's lowest guaranteed NO_x limit.
[d]Based on the use of SCR and a fuel-bound nitrogen content of 600 ppm or less.

EXISTING TURBINES[4]

Operating cycle	Fuel	NO_x emission limit, ppmv, 15 percent O_2
Simple	Gas, no oil back-up	55
	Oil	75
	Gas, with oil back-up	55 (Gas fuel) 75 (Oil fuel)
Combined	Gas, no oil back-up	42
	Oil	65
	Gas, with oil back-up	42 (Gas fuel) 65 (Oil fuel)

Note: Applies to existing turbines rated at 25 MMBtu/hr or above (maximum heat input rate).

combination of SCR with other control techniques is described in Section 5.4. Emissions from duct burners and their impact on total NO_x emissions are described in Section 5.5. Section 5.6 describes NO_x emission impacts when using alternate fuels. Two control techniques that show potential for future use, selective noncatalytic reduction (SNCR) and catalytic combustion, are described in Sections 5.7 and 5.8, respectively. Control technologies for offshore oil platforms are described in Section 5.9. Finally, references for Chapter 5 are found in Section 5.10.

5.1 WET CONTROLS

The injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. This control technique is available from all gas turbine manufacturers contacted for this study.[5-11]

The process description, applicability, factors affecting performance, emissions data and manufacturers' guarantees, impacts on other emissions, and gas turbine performance and maintenance impacts are discussed in this section.

5.1.1 Process Description

Injecting water into the flame area of a turbine combustor provides a heat sink that lowers the flame temperature and thereby reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio (WFR) and are usually given on a weight basis (e.g., lb water to lb fuel).

A water injection system consists of a water treatment system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and the necessary interconnecting piping. Water purity is essential to prevent or mitigate erosion and/or the formation of deposits in the hot section of the turbine; Table 5-4 summarizes the water quality specifications for eight gas turbine manufacturers.

In a steam injection system, steam replaces water as the injected fluid. The injection system is similar to that for water injection, but the pump is replaced by a steam-producing

TABLE 5-4. WATER QUALITY SPECIFICATIONS OF SELECTED GAS TURBINE MANUFACTURERS FOR WATER INJECTION SYSTEMS[11-18]

	Turbine Manufacturer							
Element	A	B	C	D	E	F	G	H
Total solids, ppm (dissolved and nondissolved)	5	5	1	a	0.1 gram/gallon	15	5	8
Total alkali metals, ppm	0.1	0.5 (HD)[b] 0.1 (AD)[d]	0.1	--	0.5[c]	0.15	<0.05	--
Calcium, ppm	5	--	--	--	--	--	<1.0	--
Sulfates, ppm	--	--	--	--	--	--	--	0.5
Silica, ppm	0.02	--	0.02	--	--	0.1	<0.02	0.1
Silicon, ppm	--	--	--	18.0	--	--	--	--
Sulfur, ppm	0.1	--	--	--	--	1.0	--	--
Chlorides, ppm	--	--	--	6.0	--	1.0	--	0.5
Iron and copper, ppm	--	--	--	0.1	--	--	--	--
Sodium and potassium, ppm	--	--	--	--	--	--	--	0.1
Particle size, microns	10	--	10	--	5[e]	--	--	20
Total hardness, ppm	--	--	--	--	--	0.2	--	--
Oxygen[f]	--	--	--	--	--	--	--	--
Acidity, pH	7.0-8.5	6.5-7.5	7.0-8.5	7.5-8.0	--	6.5-7.5	6.5-7.0	6.0-8.0

[a]Determined by local regulations for particulates exhausted from combustion process.
[b]HD - heavy-duty turbine.
[c]Including vanadium and lead.
[d]AD - aeroderivative turbine.
[e]90 percent of 0.1 gram particles shall be less than 5 microns.
[f]As determined by O_2-saturated water.

boiler. This boiler is usually a heat recovery steam generator (HRSG) that recovers the gas turbine exhaust heat and generates steam. The balance of the steam system is similar to the water injection system. The water treatment required for boiler feed water to the HRSG yields a steam quality that is suitable for injection into the turbine. The additional steam requirement for NO_x control, however, may require that additional capacity be added to the boiler feed water treatment system.

Another technique that is commercially available for oil-fired aeroderivative and industrial turbines uses a water-in-oil emulsion to reduce NO_x emissions. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to injection. This emulsion has a water content of 20 to 50 percent by volume and is finely dispersed and chemically stabilized in the oil phase. The principle of NO_x control is similar to conventional water injection, but the uniform dispersion of the water in the oil provides greater NO_x reduction than conventional water injection at similar WFR's.[19]

A water-in-oil emulsion injection system consists of mechanical emulsification equipment, chemical stabilizer injection equipment, water metering valves, chemical storage and metering valves, and instrumentation. In most cases the emulsifying system can be retrofitted to the existing fuel delivery system, which eliminates the requirement for a separate delivery system for water injection. At multiunit installations, one emulsion system can be used to supply emulsified fuel to several turbines. For dual fuel turbines, the emulsion can be injected through the oil fuel system to control NO_x emissions.[19]

Data provided by the vendor for this technique indicates that testing has been performed on oil-fired turbines operating in peaking duty. Long-term testing has not been completed at this point to quantify the long-term effects of the emulsifier on the operation and maintenance of the turbine.

5.1.2 Applicability of Wet Controls

Wet controls have been applied effectively to both aeroderivative and heavy-duty gas turbines and to all configurations except regenerative cycle applications.[20] It is expected that wet controls can be used with regenerative cycle turbines, but no such installations were identified. All manufacturers contacted have water injection control systems available for their gas turbine models; many also offer steam injection control systems. Where both systems are available, the decision of which control to use depends upon steam availability and economic factors specific to each site.

Wet controls can be added as a retrofit to most gas turbine installations. In the case of water injection, one limitation is the possible unavailability of injection nozzles for turbines operating in dual fuel applications. In this application, the injection nozzle as designed by the manufacturer may not physically accommodate a third injection port for water injection. This limitation also applies to steam injection. In addition, steam injection is not an available control option from some gas turbine manufacturers.

5.1.3 Factors Affecting the Performance of Wet Controls

The WFR is the most important factor affecting the performance of wet controls. Other factors affecting performance are the combustor geometry and injection nozzle(s) design and the fuel-bound nitrogen (FBN) content. These factors are discussed below.

The WFR has a significant impact on NO_x emissions. Tables 5-5 and 5-6 provide NO_x reduction and WFR's for natural gas and distillate oil fuels, respectively, based on information provided by gas turbine manufacturers. For natural gas fuel, WFR's for water or steam injection range from 0.33 to 2.48 to achieve controlled NO_x emission levels ranging from 25 to 75 ppmv, corrected to 15 percent oxygen. For oil fuel, WFR's range from 0.46 to 2.28 to achieve controlled NO_x emission levels ranging from 42 to 110 ppmv, corrected to 15 percent oxygen. Nitrogen oxide reduction efficiency increases as the WFR

TABLE 5-5. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR NATURAL GAS FUEL OPERATION[5-11,21-24]

Manufacturer/model	NO_x emission levels, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	133	42[a]/68	25/81	0.61	1.49
LM2500	174	42[a]/76	25/86	0.73	1.46
LM5000	185	42[a]/77	25/87	0.63	1.67
LM6000	220	42[a]/81	25/89	0.68	1.67
MS5001P	142	42/70	42/70	0.72	1.08
MS6001B	148	42/72	42/72	0.77	1.16
MS7001E	154	42/73	42/73	0.81	1.22
MS7001F	210	42/80	42/80	0.79	1.34
MS9001E	161	42/74	42/74	0.78	1.18
MS9001F	210	42/86	42/80	NA[b]	NA[b]
Asea Brown Boveri					
GT10	150	25/83	42/72	0.93	1.07
GT8	430	25/94	29/93	1.86	2.48
GT11N	390	25/94	25/94	1.76	2.47
GT35	300	42/86	60/80	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	99	42/58	NA[c]/NA[c]	0.33	NA[c]
T-4500 Centaur	130	42/68	NA[c]/NA[c]	0.61	NA[c]
Type H Centaur	105	42/60	NA[c]/NA[c]	0.70	NA[c]
Taurus	114	42/63	NA[c]/NA[c]	0.79	NA[c]
T-12000 Mars	178	42/76	NA[c]/NA[c]	0.91	NA[c]
T-14000 Mars	199	42/79	NA[c]/NA[c]	1.14	NA[c]
Allison/GM					
501-KB5	155	42/73	42/73	0.80	1.53
501-KC5	174	42/76	NA[c]/NA[c]	NA[b]	NA[c]
501-KH	155	42/73	25/84	NA[b]	NA[b]
570-K	101	42/58	NA[c]/NA[c]	NA[b]	NA[c]
571-K	101	42/58	NA[c]/NA[c]	0.80	NA[c]
Westinghouse					
251B11/12	220	42/81	25/89	1.0	1.8
501D5	190	25/87	25/87	1.6	1.6
Siemens					
V84.2	212	42/80	55/74	2.0	2.0
V94.2	212	55/74	55/74	1.6	1.6
V64.3	380	75/80	75/80	1.6	1.4
V84.3	380	75/80	75/80	1.6	1.4
V94.3	380	75/80	75/80	1.6	1.4

[a]A NO_x emissions level of 25 ppmv can be achieved, but turbine maintenance requirements increase over those required for 42 ppmv.
[b]Data not available.
[c]Steam injection is not available from the manufacturer for this turbine operating on natural gas fuel.

TABLE 5-6. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR DISTILLATE OIL FUEL OPERATION[5-11,21-24]

Manufacturer/model	NO_x emissions level, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	237	42/82	75/70	NA[a]	NA[a]
LM2500	345	42/88	75/78	0.99	NA[a]
LM5000	364	42/88	110/70	NA[a]	NA[a]
LM6000	417	42/90	110/74	NA[a]	NA[a]
MS5001P	211	65/69	65/69	0.79	1.06
MS6001B	267	65/76	65/76	0.73	1.20
MS7001E	228	65/72	65/72	0.67	1.19
MS7001F	353	65/82	65/77	0.72	1.35
MS9001E	241	65/73	65/72	0.65	1.16
MS9001F	353	65/82	65/76	NA[a]	NA[a]
Asea Brown Boveri					
GT10	200	42/79	42/79	0.75	1.25
GT8	680	42/94	60/91	1.62	2.15
GT11N	560	42/88	42/93	1.50	2.28
GT35	360	42/88	60/83	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	150	60/60	NA[b]/NA[b]	0.46	NA[b]
T-4500 Centaur	179	60/66	NA[b]/NA[b]	0.60	NA[b]
Type H Centaur	160	60/63	NA[b]/NA[b]	0.72	NA[b]
Taurus	168	60/64	NA[b]/NA[b]	0.96	NA[b]
T-12000 Mars	267	60/78	NA[b]/NA[b]	1.00	NA[b]
T-14000 Mars	NA[a]	60/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
Allison/GM					
501-KB5	231	56/76	NA[b]/NA[b]	NA[a]	NA[b]
501-KC5	NA[a]	NA[a]/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
501-KH	231	56/76[a]	50/78	NA[a]	NA[a]
570-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
571-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
Westinghouse					
251B11/12	355	65/82	42/88	1.0	1.8
501D5	250	42/83	42/83	1.0	1.6
Siemens					
V84.2	360	42/88	55/85	1.4	2.0
V94.2	360	42/88	55/85	1.4	1.6
V64.3	530	75/86	75/86	1.2	1.4
V84.3	530	75/86	75/86	1.2	1.4
V94.3	530	75/86	75/86	1.2	1.4

[a]Data not available.

[b]Steam injection is not available from the manufacturer for this turbine operating on oil fuel.

increases. As shown in Tables 5-5 and 5-6, reduction efficiencies of 70 to 90 percent are common. Note that, in general, the WFR's for steam are higher than for water injection because water acts as a better heat sink than steam due to the heat absorbed by vaporization; therefore, higher levels of steam than water must be injected for a given reduction level.

The combustor geometry and injection nozzle design and location also affect the performance of wet controls. For maximum NO_x reduction efficiency, the water must be atomized and injected in a spray pattern that provides a homogeneous mixture of water droplets and fuel in the combustor. Failure to achieve this mixing yields localized hot spots in the combustor that produce increased NO_x emissions.

The type of fuel affects the performance of wet controls. In general, lower controlled NO_x emission levels can be achieved with gaseous fuels than with oil fuels. The FBN content also affects the performance of wet controls. Those fuels with relatively high nitrogen content, such as coal-derived liquids, shale oil, and residual oils, result in significant fuel NO_x formation. Natural gas and most distillate oils are low-nitrogen fuels. Consequently, fuel NO_x formation is minimal when these fuels are burned.

Wet controls serve only to lower the flame temperature and therefore are an effective control only for thermal NO_x formation; water injection may in fact increase the rate of fuel NO_x formation, as shown in Figure 5-1.[25] The mechanisms responsible for this potential increase were not identified.

5.1.4 <u>Achievable NO_x Emissions Levels Using Wet Controls</u>

This section presents the achievable controlled NO_x emission levels for wet injection, as guaranteed by gas turbine manufacturers. Emission test data, obtained using EPA Test Method 20 or equivalent, are also presented.

Guaranteed NO_x emission levels as provided by gas turbine manufacturers for wet controls are shown in Figures 5-2 and 5-3. These figures show manufacturers' guaranteed NO_x emission levels of 42 ppmv for most natural gas-fired turbines, and from 42 to

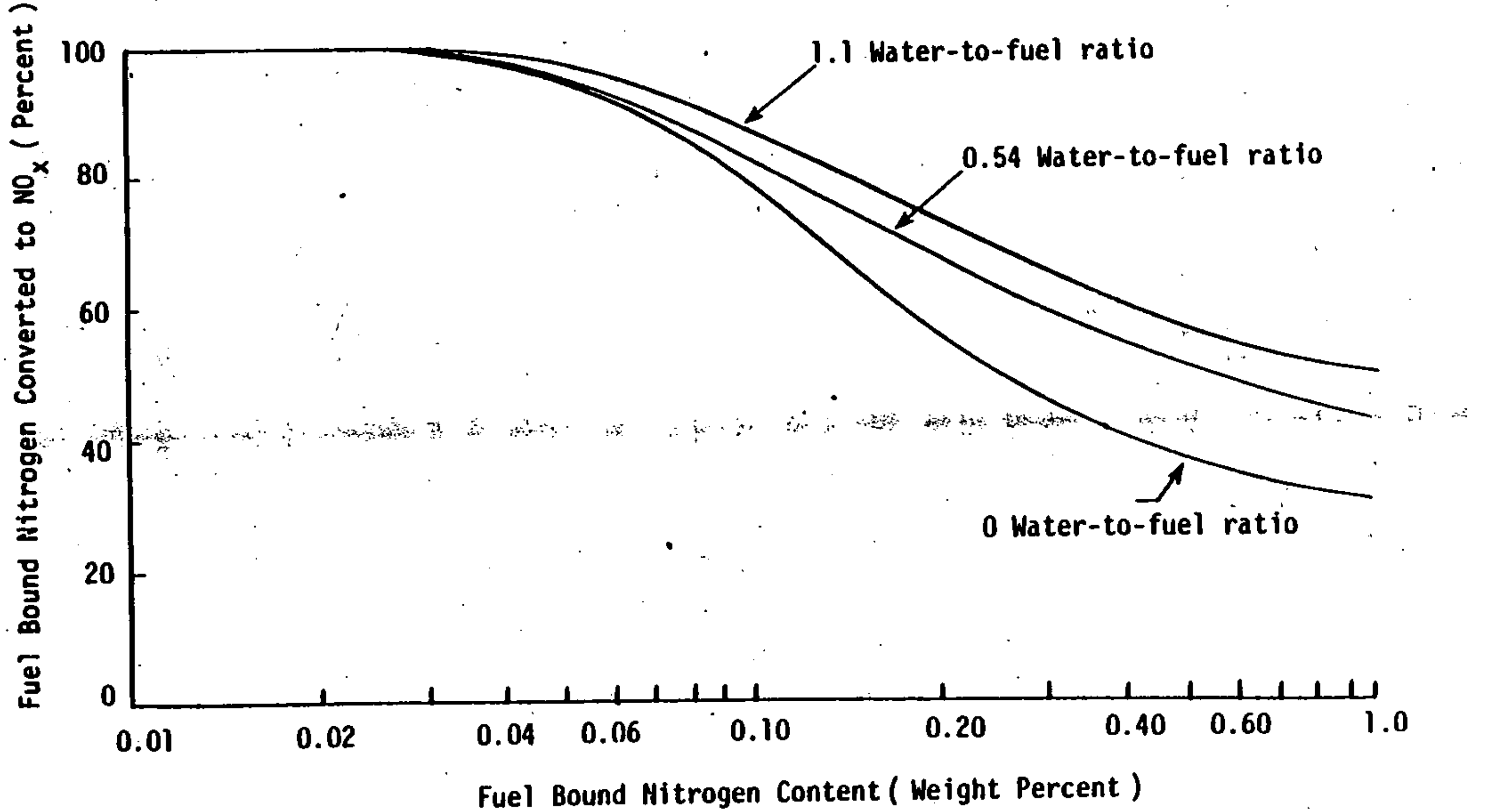


Figure 5-1. Percentage of fuel-bound nitrogen converted to NO_x versus the fuel-bound nitrogen content and the water-to-fuel ratio for a turbine firing temperature of 1000° (1840°F).[25,26]

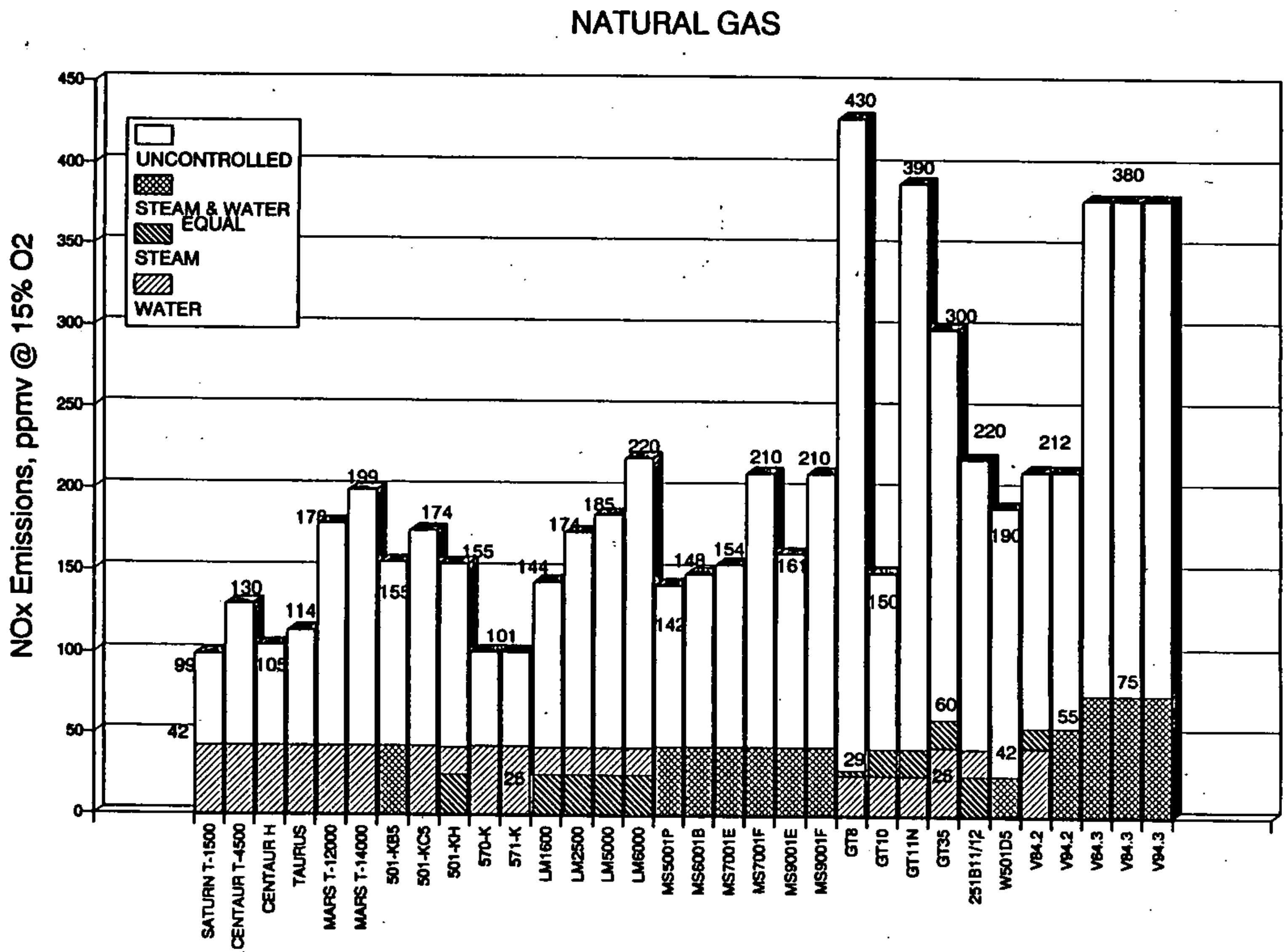


Figure 5-2. Uncontrolled NO_x emissions and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.[6-11,17,18,23]

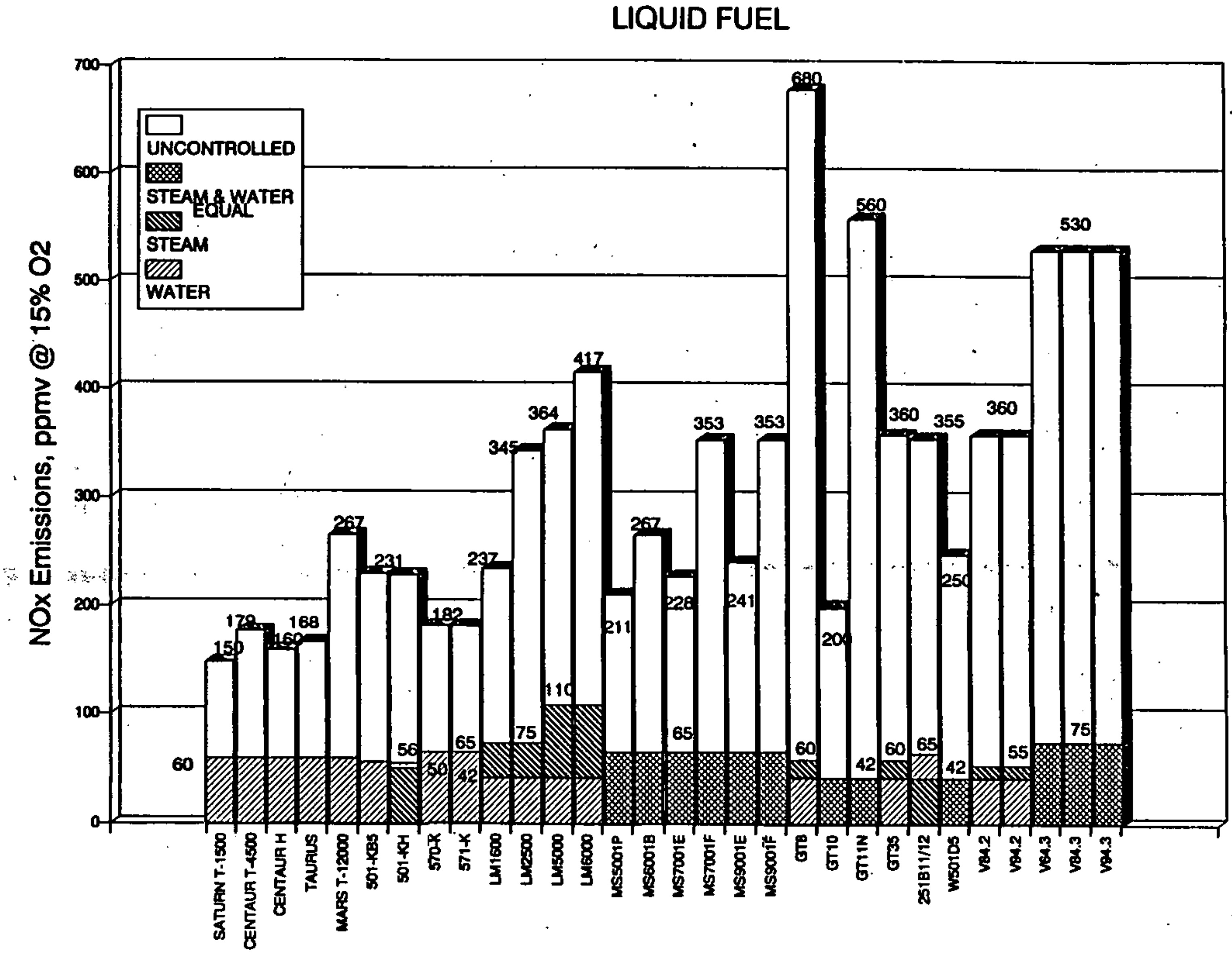


Figure 5-3. Uncontrolled NO_x emissions and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate-oil fuel.[6-11,17,18,23]

75 ppmv for most oil-fired turbines. The percent reduction in NO_x emissions varies for each turbine, ranging from 60 to 94 percent depending upon each model's uncontrolled emission level and whether water or steam is injected.

Emissions data for water and steam injection are presented to show the effects of wet injection on NO_x emissions. These data show:

1. That NO_x emissions decrease with increasing WFR's; and
2. That NO_x emissions are higher for oil fuel than for natural gas.

From the available data, reduction efficiencies of 70 to over 85 percent were achieved. The emission data and WFR's shown for specific turbine models may not reflect the emission levels of current production models, since manufacturers periodically update or otherwise modify their turbines, thereby altering specific emissions levels.

Each emission test in the following figures consists of one or more data points. Where data points were obtained under similar conditions, they are grouped together and presented as a single test. For these cases, each data point, along with the arithmetic average of all of the data points, is shown.

The nomenclature used to identify the tests consists of two letters followed by a number. The first letter of the two-letter designator specifies the turbine type. These types are as follows:

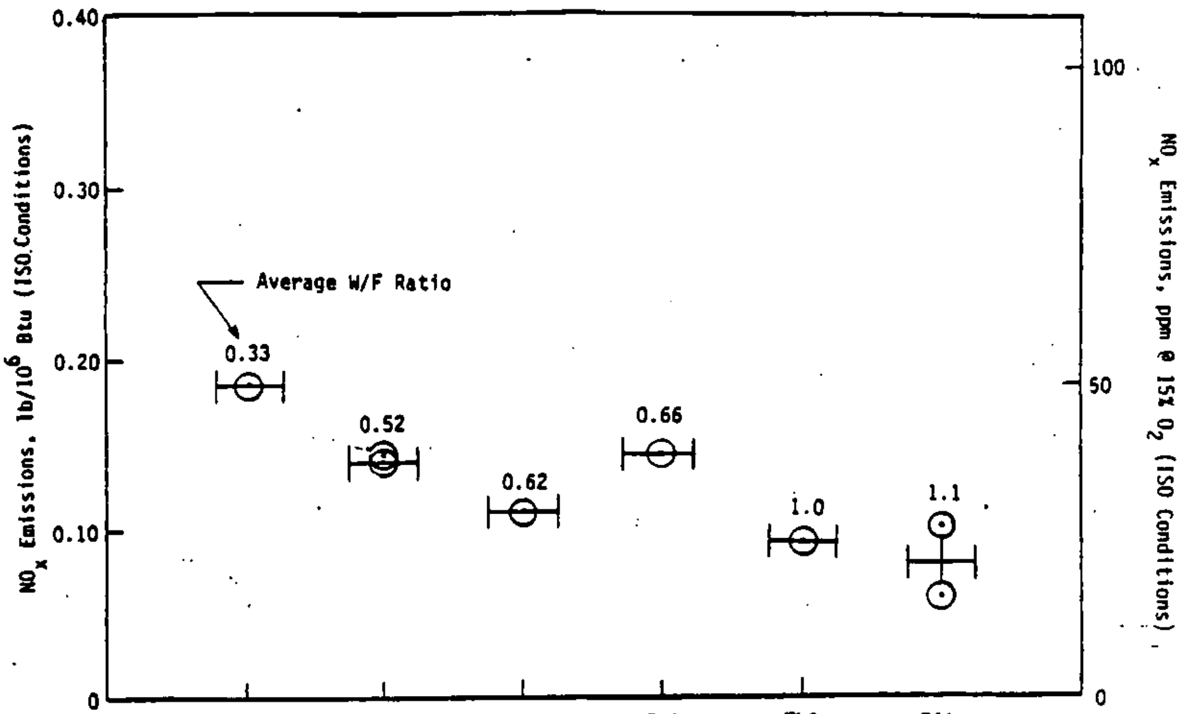
Letter	Turbine type
A	Aircraft-derivative turbine
H	Heavy-duty turbine
T	Small and low-efficiency turbine (less than 7.5 MW output, less than 30 percent simple-cycle efficiency)

The second letter identifies the facility. The number identifies the number of tests performed at the facility. Tests performed at the same facility on different turbines or at different times have the same two-letter designator but are followed by different test numbers. The short horizontal lines represent the average of the test data.

Also presented are the available data on the turbine, wet controls, uncontrolled NO_x emissions, percent NO_x reduction, and fuel type. All of the data shown are representative of the performance of wet controls when the turbine is operated at base load or peak load. These loads represent the worst-case conditions for NO_x emission reduction. Information on the WFR, turbine model, efficiency, control type, and fuel are included with the emission test data.

Figures 5-4, 5-5, and 5-6 present the emission test data for water injection on turbines fired with natural gas. These turbines have NO_x emissions ranging from approximately 20 to 105 ppm with WFR's ranging from 0.16 to 1.32. Turbine sizes range from 2.8 to 97 MW. Based on these data, water injection is effective on all types of gas turbines and NO_x emission levels decrease as the WFR increases. However, some turbines require a higher WFR to meet a specific emission level. For example, the gas turbines at sites HH and HC (Figure 5-6) require much higher WFR's to achieve NO_x emission levels similar to the other gas turbine models shown. This particular gas turbine also has the highest uncontrolled NO_x emission levels. Conversely, the gas turbine at site AH, shown in Figure 5-5, has the lowest uncontrolled NO_x emission level and requires the least amount of water to achieve a given emission level. Uncontrolled NO_x emission levels vary for different turbine models depending upon design factors such as efficiency, firing temperature, and the extent of combustion controls incorporated in the combustor design (see Section 4.2.1.1). In general, aircraft-derivative and heavy-duty gas turbines require similar WFR's to achieve a specific emission level. Small, low-efficiency gas turbines require less water to achieve a specific emission level.

The NO_x emissions for turbines firing distillate oil are shown in Figures 5-7, 5-8, and 5-9. The data range from approximately 30 to 135 ppm, with WFR's ranging from 0.24 to 1.31. The gas turbine sizes range from 19 to 95 MW. The data for distillate oil-fired turbines show the same general trends as the data for natural gas-fired turbines. Site HH (Figure 5-9)

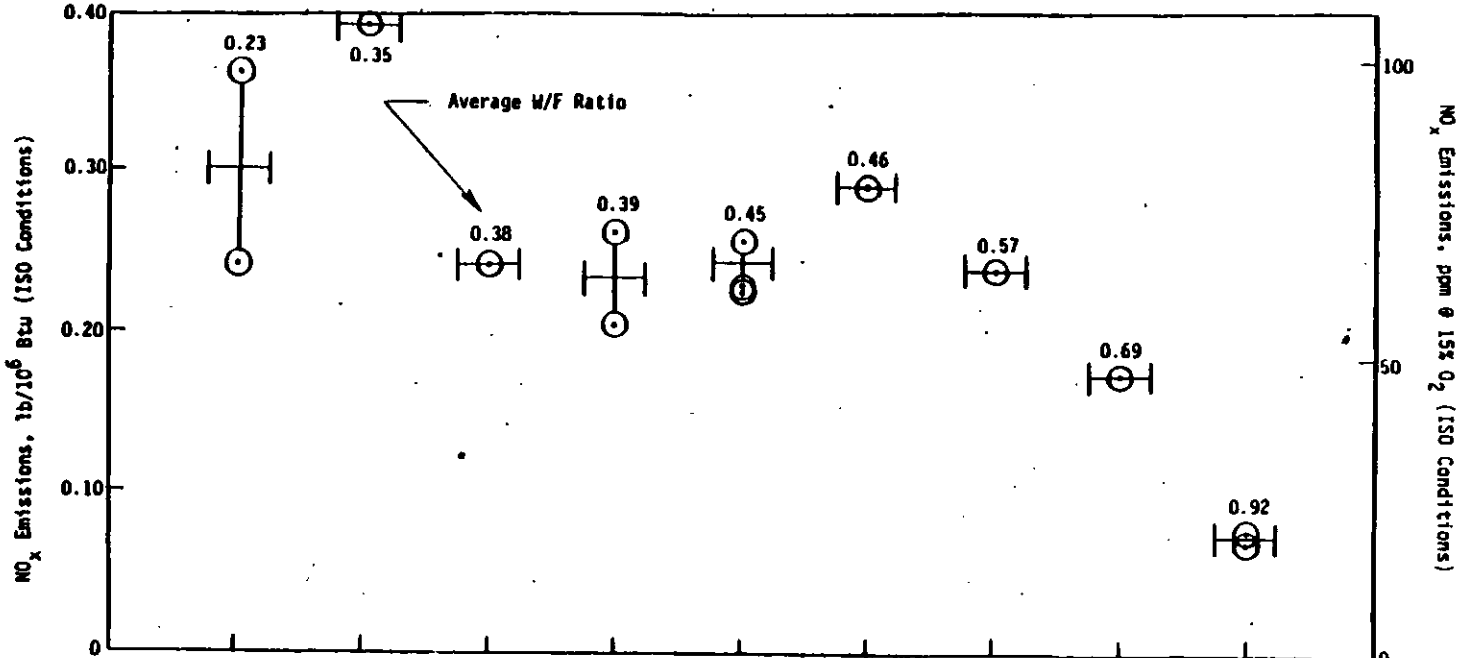


Test No.	TL1	TA2	TA4	TL2	TL3	TA1
Turbine Model	501KB	Centaur	Centaur	501KB	501KB	Centaur
Efficiency (%)	28	25	25	28	28	25
Combustor Type	CA	A	A	CA	CA	A
Baseload Rating (MW)	2.5	2.8	2.8	2.5	2.5	2.8
Type of Fuel	NG	NG	NG	NG	NG	NG
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.33	0.49-0.55	0.62	0.66	1.0	0.96-1.32
NO_x Emissions without Wet Controls (lb/MMBtu,ISO)	0.394	0.486	0.486	0.394	0.394	0.486
NO_x Reduction (%)	54.0	71.4	76.7	63.4	76.1	83.7

Notation:

NG = Natural Gas
CA = Can-annular
A = Annular

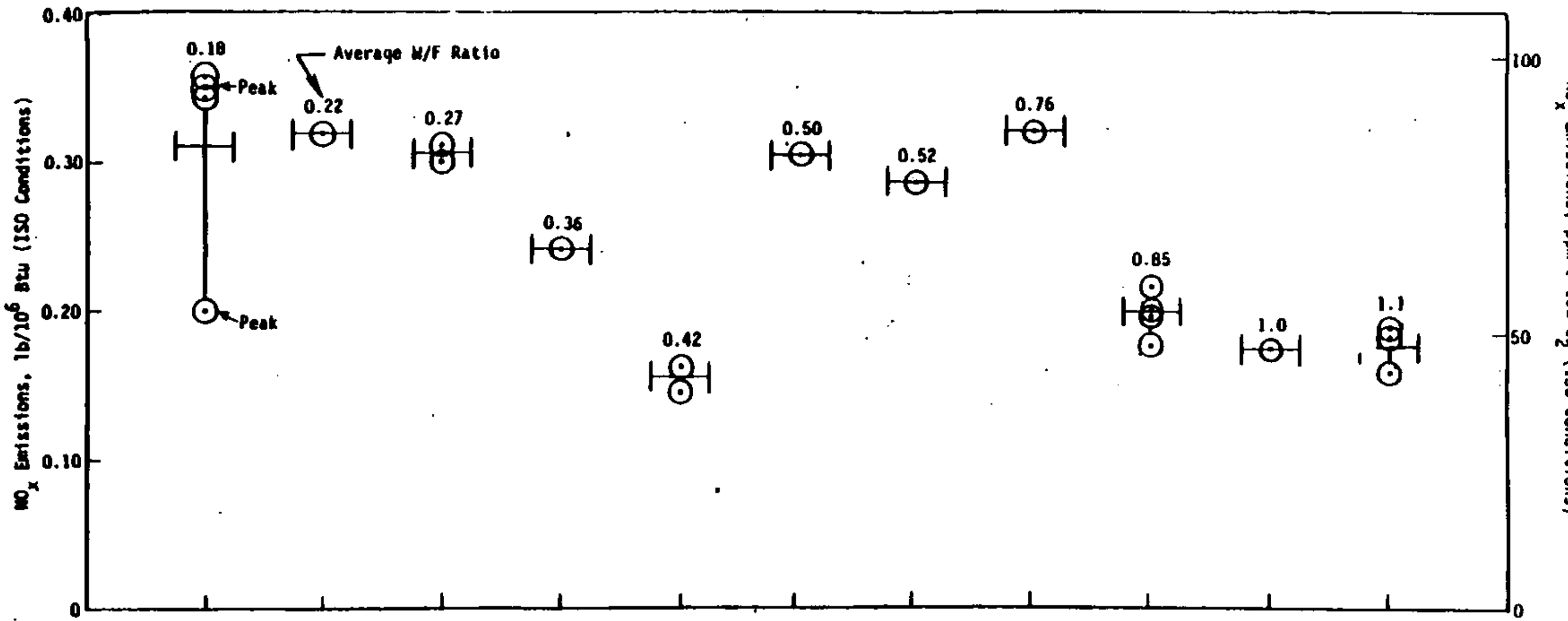
Figure 5-4. Nitrogen oxide emission test data for small, low-efficiency gas turbines with water injection firing natural gas.[27]



Test No.	AE2	AS1	AR2	AE1	AP1	AS2	AS3	AS4	AH1
Turbine Model	FT4C-1	IM5000	FT4C-3	FT4C-1	LM2500	IM5000	IM5000	IM5000	SK-30
Efficiency (%)	32	38	32	32	37	38	38	38	.31
Combustor Type	A	A	CA	A	A	A	A	A	CA
Baseload Rating (MW)	26	37	25	26	19	37	37	37	28
Type of Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.21-0.25	0.35	0.38	0.36-0.42	0.44-0.45	0.46	0.57	0.69	0.87-0.96
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.424	0.930	NA	0.424	0.680	0.930	0.930	0.930	0.285
NO_x Reduction (%)	28.8	58.1	NA	44.6	64.3	68.7	74.3	81.2	74.0

Notation:
NG = Natural Gas
CA = Can-annular
A = Annular
NA = Not Available

Figure 5-5. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing natural gas.[27]

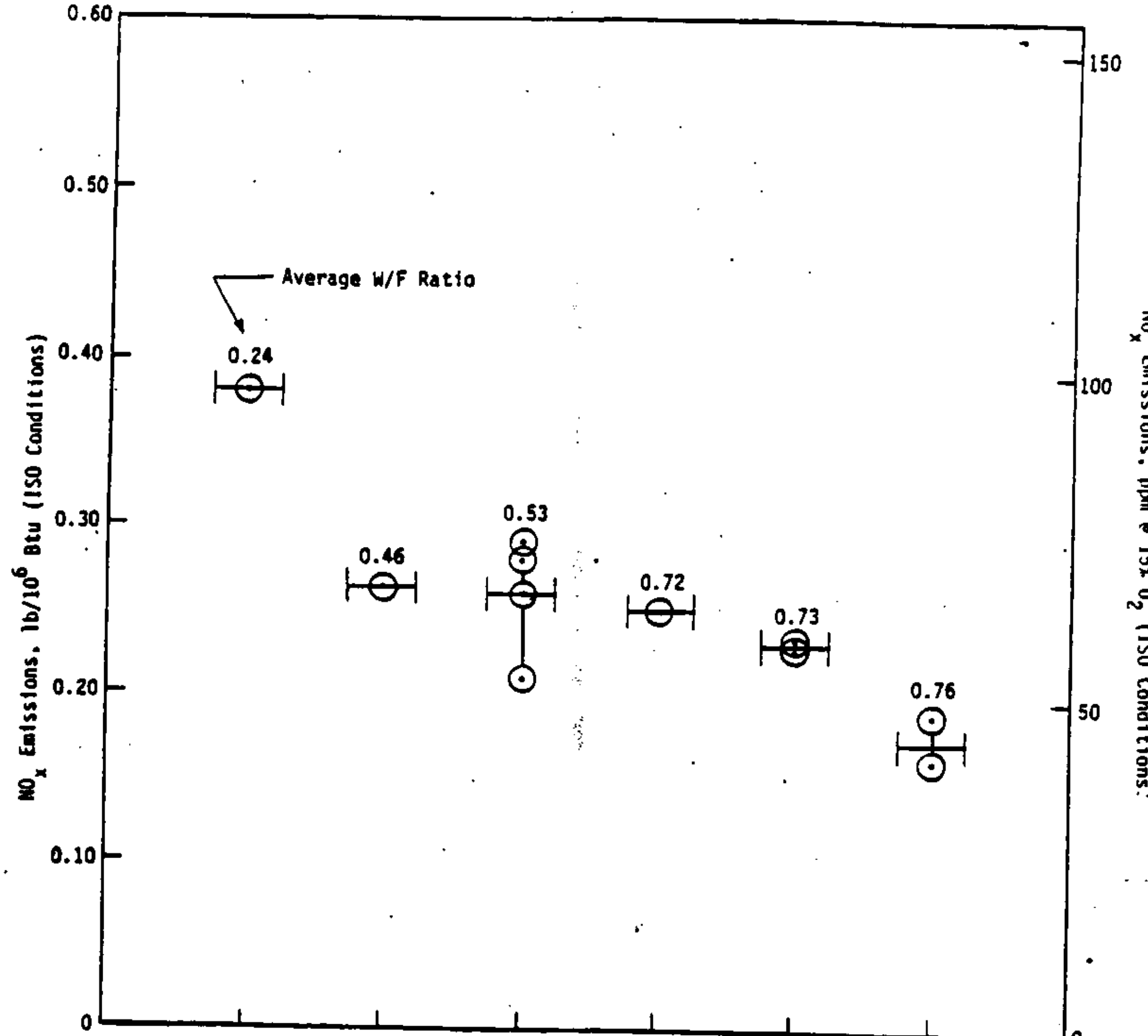


Test No.	HW1	HR1	HN2	HE1	HD1	HU2	HC4	HH5	HC6	HH4	HC5
Turbine Model	MS7001E	MS7001E	W501B	W501B	MS5001	W501D	W501B	BB Type 11	W501B	BB Type 11	W501B
Efficiency (%)	31	31	32	32	28	32	32	32	32	32	32
Combustor Type	CA	CA	CA	CA	CA	CA	CA	S	CA	S	CA
Baseload Rating (MW)	75	75	80	70	20	100	70	64	70	64	70
Type of Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.16-0.20	0.22	0.26-0.27	0.36	0.42-0.42	0.50	0.52	0.76	0.71-0.93	1.03	1.04-1.21
NO$_x$ Emissions without Wet Controls (lb/MMBtu, ISO)	0.620	0.620	NA	0.500	0.370	0.750	0.428	1.23	0.500	1.23	0.428
NO$_x$ Reduction (%)	49.4	47.7	NA	51.2	58.4	59.3	33.2	73.9	61.0	85.8	58.2

Notation:

DO = distillate oil
NG = natural gas
CA = can-annular
S = silo
A = annular
NA = not available

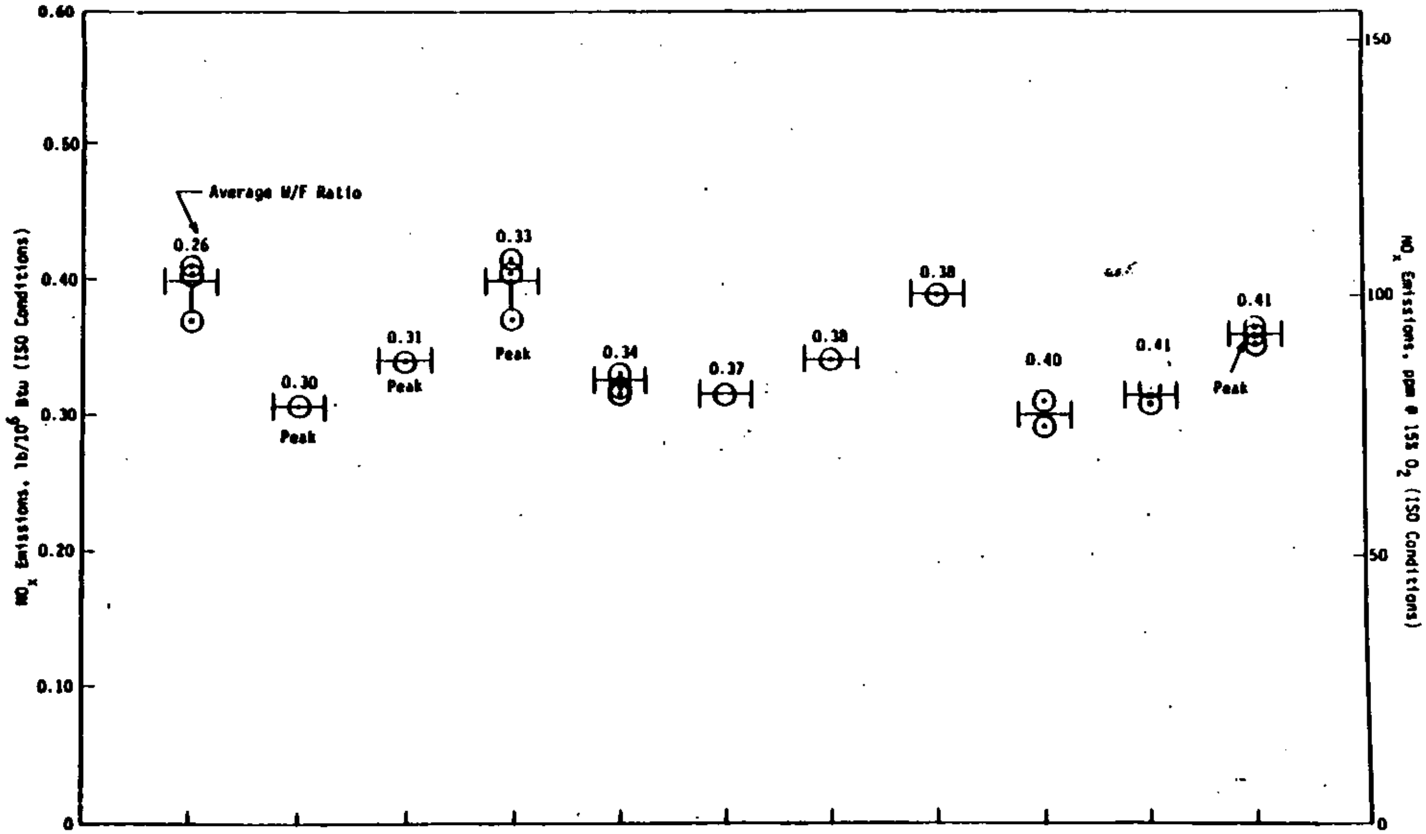
Figure 5-6. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection firing natural gas.[27]



Test No.	AH4	AH3	AE3	AR1	AP2	AH2
Turbine Model	SK-30	SK-30	FT4C-1	FT4C-3F	LM2500	SK-30
Efficiency (percent)	31	31	32	32	37	31
Combustor Type	CA	CA	CA	CA	A	CA
Base Load Rating (MW)	28	28	26	25	20	28
Type of Fuel	DO	DO	DO	DO	DO	DO
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.24	0.46	0.51-0.55	0.72	0.73-0.73	0.68-0.84
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.559	0.559	0.787	0.840	1.37	0.559
NO_x Reduction (%)	32.0	52.8	66.8	70.5	83.4	68.9

Notation:
DO = distillate oil
NG = natural gas
CA = can-annular
A = annular

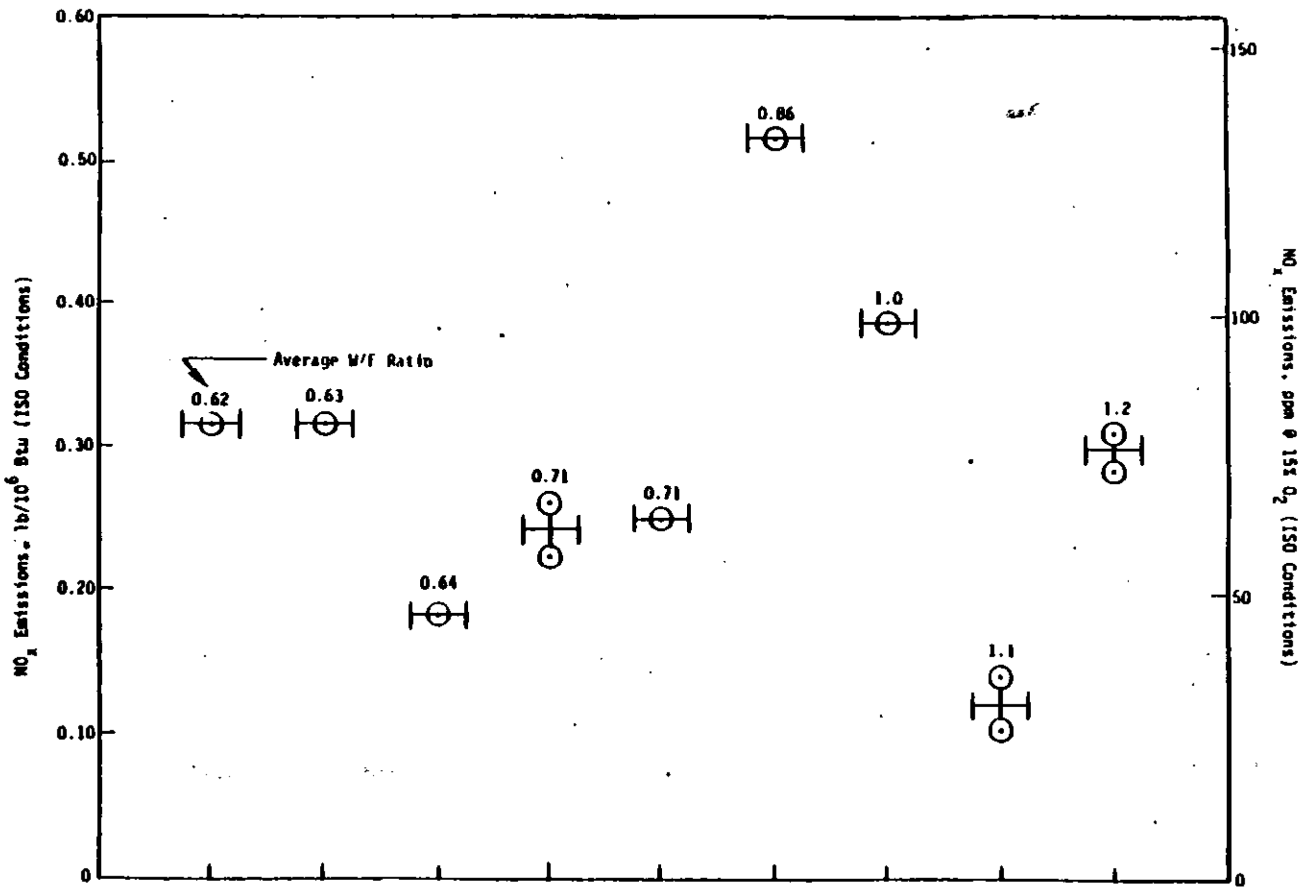
Figure 5-7. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing distillate oil.[27]



Test No.	HG2	HB1	HP1	HG1	HS1	HE2	HM1	HC3	HS7	HS3	HM2
Turbine Model	MS7001B	MS5001	MS7001E	MS7001B	MS5001	W501B	W501B	W501B	MS5001	MS5001	MS7001E
Efficiency(%)	31	28	31	31	28	32	32	32	28	28	31
Combustor Type	CA	CA	CA	CA	CA	CA	CA	CA	CA	CA	CA
Baseload Rating (MW)	49	26	60	49	25	70	80	70	25	25	75
Type of Fuel	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO
Load	Base	Peak	Peak	Peak	Base	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.26	0.30	0.31	0.32-0.34	0.34-0.34	0.17	0.37-0.38	0.38	0.40-0.40	0.41-0.41	0.39-0.44
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.640	NA	NA	NA	0.600	0.780	0.780	0.784	0.600	0.600	0.860
NO_x Reduction (%)	40.0	NA	NA	NA	46.2	59.7	56.4	50.5	49.5	47.0	55.4

Notation:
DO = Distillate Oil
CA = Can-annular
NA = Not Available

Figure 5-8. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFR's less than 0.5 and firing distillate oil.[27]



Test No.	HI1	HU1	HT1	HH4	HC1	HH2	HH1	HC2	HH3
Turbine Model	W501D	W501D	MS7001B	MS7001E	W501K	BB Type 11	BB Type 11	W501B	BB Type 11
Efficiency (%)	32	32	31	31	32	32	32	32	32
Combustor Type	CA	CA	CA	CA	CA	S	S	CA	S
Baseload Rating (MW)	90	100	55	70	70	64	64	70	64
Type of Fuel	DO	DO	DO	DO	DO	DO	DO	DO	DO
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.62	0.63	0.64	0.70-0.72	0.71	0.86	1.04	1.1-1.2	1.2-1.3
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	1.23	1.23	0.640	0.860	0.784	1.78	1.78	0.784	1.78
NO_x Reduction (%)	74.4	74.4	71.7	71.7	68.4	71.5	78.4	84.3	83.4

Notation:
DO = distillate oil
NG = natural gas
CA = can-annular
S = silo
A = annular

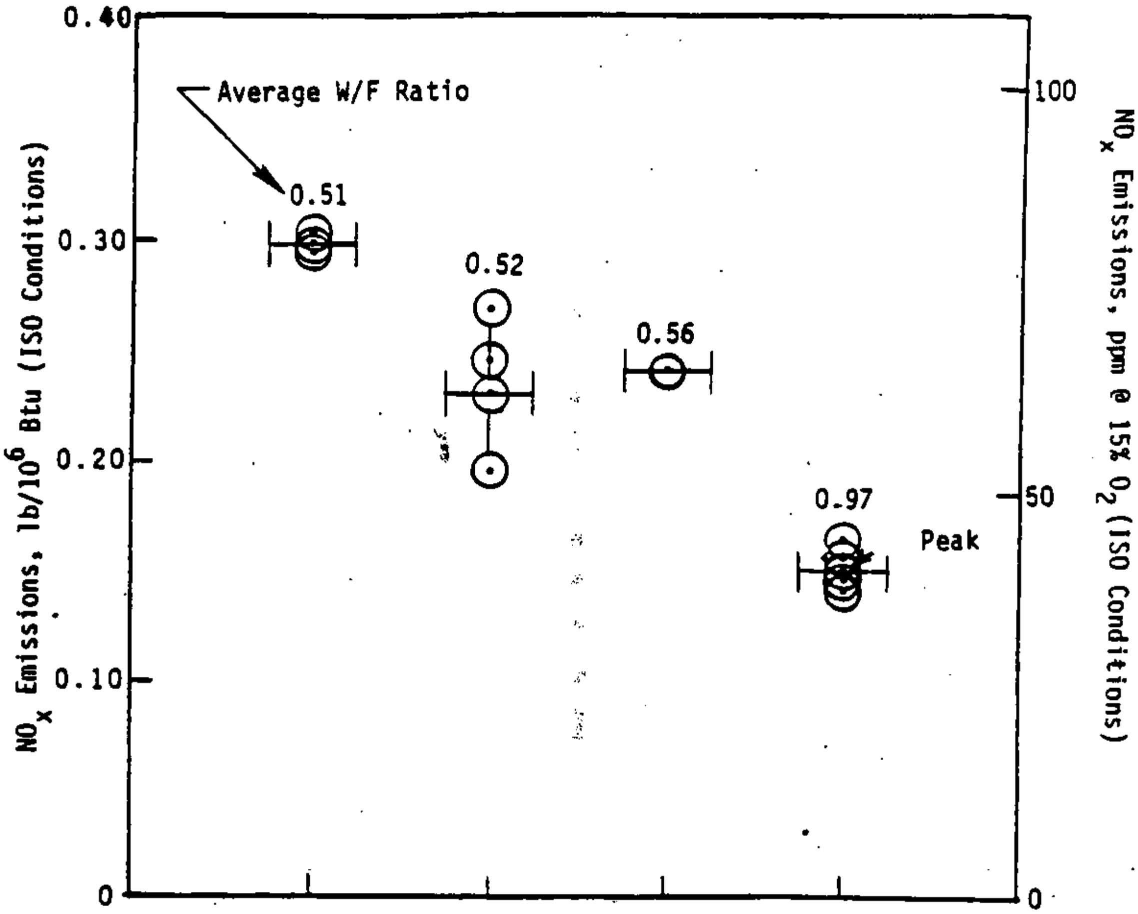
Figure 5-9. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFR's greater than 0.5 and firing distillate oil.[27]

again shows that higher WFR's are required due to the high uncontrolled NO_x emissions from this gas turbine. Also, by comparing the emission data for the distillate oil-fired turbines and natural gas-fired turbines, the data show that burning distillate oil requires higher WFR's than does burning natural gas for a given level of NO_x emissions. Higher WFR's are required because distillate oil produces higher uncontrolled NO_x levels than does natural gas (see Section 4.2.1.2).

The NO_x emission test data for steam injection are presented in Figures 5-10 and 5-11 for natural gas-fired turbines and distillate oil-fired turbines, respectively. The turbines firing natural gas have NO_x emissions ranging from approximately 40 to 80 ppm, with WFR's ranging from 0.50 to 1.02. The gas turbine sizes range from 30 to 70 MW.

The NO_x emissions for turbines firing distillate oil range from approximately 65 to 95 ppm, with WFR's ranging from 0.65 to 1.01, and the gas turbine sizes tested were 36 and 70 MW. Fewer data points are available for steam injection than for water injection. However, the available data for both distillate oil-fired and natural gas-fired turbines show that NO_x emissions decrease as the steam-to-fuel ratio increases.

Reductions in NO_x emissions similar to water injection with oil-fired turbines have been achieved using water-in-oil emulsions. Results of emission tests for four turbines are shown in Table 5-7. The controlled NO_x emissions range from 29 to 60 ppmv, corresponding to NO_x reductions of 54 to 77 percent.[19] The controlled NO_x emission levels and percent reduction are consistent with those achieved using conventional water injection. Limited testing has shown that the emulsion achieves a given NO_x reduction level with a lower WFR than does a separate water injection arrangement. Test data for one oil-fired turbine showing a comparison of the WFR's for a water-in-oil emulsion versus a separate water injection system are shown in Figure 5-12. As shown here, NO_x reductions achieved by a water injection system at a WFR of 1.0 can be achieved by a water-in-oil emulsion at a WFR of 0.6.



Test No.	HV1	HZ1	HM1	HZ2
Turbine Model	BB Type 9	MS6001B	MS7001E	MS6001B
Efficiency (percent)	29	31	32	31
Combustor Type	S	CA	CA	CA
Base Load Rating (MW)	30	36	70	36
Type of Fuel	NG	NG	NG	NG
Load	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.50-0.51	0.42-0.69	0.56	0.94-1.02
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	NA	0.423	0.620	0.423
NO_x Reduction (%)	NA	44.9	61.1	64.8

Notation:

DO = distillate (

NG = natural gas

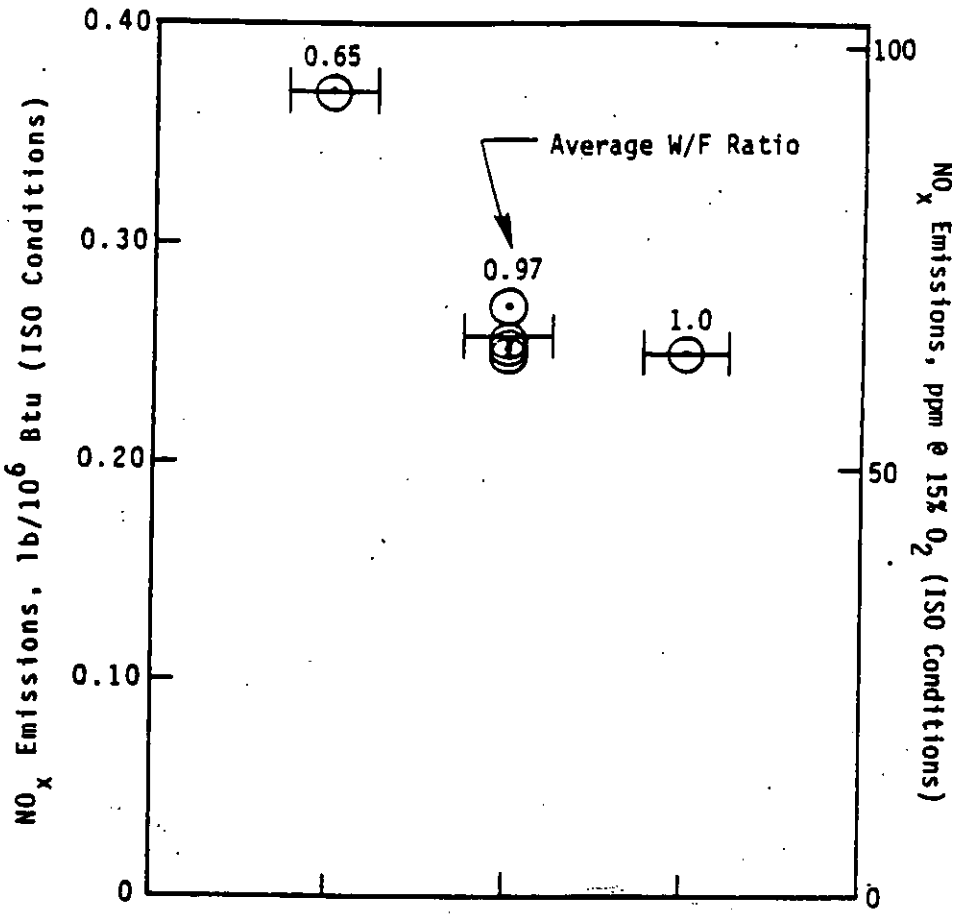
CA = can-annular

A = annular

S = silo

NA = not availabl

Figure 5-10. Nitrogen oxide emission test data for gas turbines with steam injection firing natural gas.[27]



Test No.	HM2	HM3	HZ3
Turbine Model	MS7001E	MS7001E	MS6001B
Efficiency (percent)	32	32	31
Combustor Type	CA	CA	CA
Base Load Rating, MW	70	70	36
Fuel	DO	DO	DO
Load	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.65	0.91-0.99	1.01
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.860	0.860	0.749
NO_x Reduction (%)	56.5	70.2	66.6

Notation:

DO = distillate oil
NG = natural gas
CA = can-annular
S = silo
A = annular

Figure 5-11. Nitrogen oxide emission test data for gas turbines with steam injection firing distillate oil.[27]

TABLE 5-7. ACHIEVABLE GAS TURBINE NO_x EMISSION REDUCTIONS FOR OIL-FIRED TURBINES USING WATER-IN-OIL EMULSIONS[19]

				NO_x emissions, ppmv at 15 percent O_2		
Turbine manufacturer	Turbine model	Power output, MW	Water-to-fuel ratio	Uncontrolled	Controlled	Percent reduction
Turbo Power and Marine	A4	35	0.65	184	53	68
	A9	33	0.55	150	50	66
	A9	33	0.92	126	29	77
General Electric	MS5001	15	0.49	131	60	54

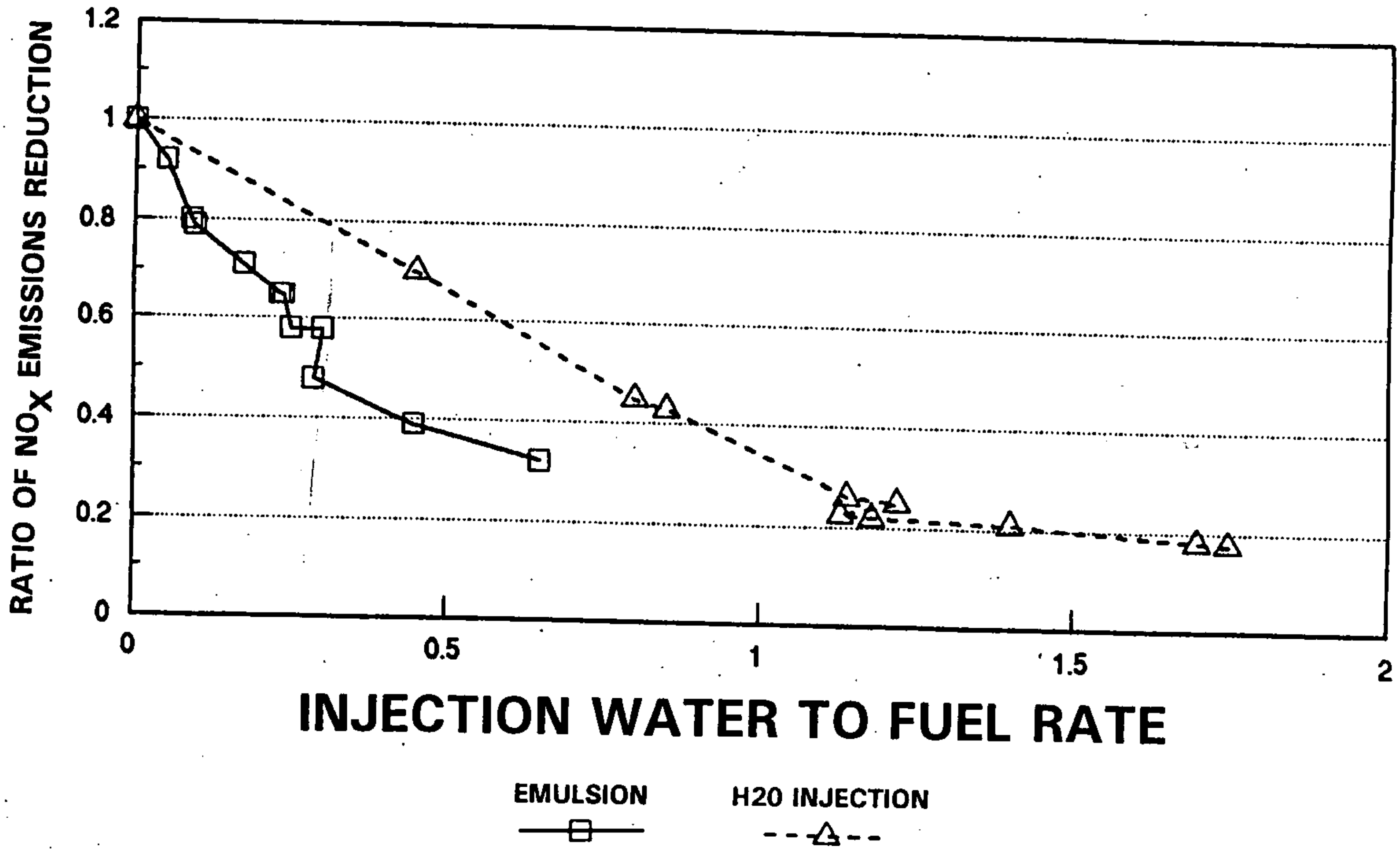


Figure 5-12. Comparison of the WFR requirement for water-in-oil emulsion versus separate water injection for an oil-fired turbine.[28]

On a mass basis, the reduction in NO_x emissions using water injection is shown in Table 5-8; Table 5-9 shows corresponding reductions for steam injection. As an example, a 21.8 MW turbine burning natural gas fuel can reduce NO_x emissions by 452 tons/yr (8,000 hours operation) using water injection and 511 tons/yr using steam injection. This same turbine burning oil fuel will reduce annual NO_x emissions by 1,040 tons using water injection and by 925 tons using steam injection.

5.1.5 Impacts of Wet Controls on CO and HC Emissions

While carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines, water injection may increase these emissions. Figure 5-13 shows the impact of water injection on CO emissions for several production gas turbines. In many turbines, CO emissions increase as the WFR increases, especially at WFR's above 0.8. Steam injection also increases CO emissions at relatively high WFR's, but the impact is less than that of water injection.[29,30]

Water and steam injection also increase HC emissions, but to a lesser extent than CO emissions.[29,30] The effect of water injection on HC emissions for one turbine is shown in Figure 5-14. Like CO emissions, hydrocarbon emissions increase at WFR's above 0.8.

For applications where the water or steam injection rates required for NO_x emission reductions result in excess CO and/or HC emissions, it may be possible to select an alternative turbine and/or fuel with a relatively flat CO curve, as indicated in Figure 5-13. Another alternative is an oxidation catalyst to reduce these emissions. This oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct or HRSG and serves to oxidize CO and HC to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium), and oxidation efficiencies of 90 percent or higher can be achieved. The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream.[31]

TABLE 5-8. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING WATER INJECTION

Gas turbine model	Power output, MW[a]	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c]	Oil fuel, tons/yr[c]
Saturn	1.1	6.4	9.9	2.8	4.1	14.3	23.3
Centaur	3.3	22.0	31.2	7.4	10.8	58.5	81.5
Centaur "H"	4.0	20.8	32.6	8.6	12.7	48.6	79.8
Taurus	4.5	24.7	37.6	9.4	13.9	61.1	94.9
Mars T-12000	8.8	69.4	107	17.0	24.9	210	329
Mars T-14000	10.0	85.4	NA[d]	18.7	NA[d]	267	NA[d]
501-KB5	4.0	31.6	48.5	8.9	12.2	90.9	145
570-K	4.9	22.7	41.0	9.8	15.2	51.8	103
571-K	5.9	24.2	44.0	10.4	16.3	55.1	111
LM1600	14.0	74.1	127	22.4	23.2	207	414
LM2500	22.7	146	301	36.4	37.9	438	1,050
LM5000	34.5	232	474	54.5	56.6	710	1,670
LM6000	43.0	310	609	61.3	63.5	996	2,180
MS5001P	26.8	181	274	55.5	87.4	503	747
MS6001B	39.0	250	459	73.2	116	704	1,370
MS7001E	84.7	544	822	154	243	1,560	2,320
MS7001F	161	1,290	2,190	267	417	4,090	7,090
MS9001E	125	810	1,320	219	369	2,370	3,820
MS9001F	229	1,850	3,150	382	600	5,850	10,200
GT8	47.4	899	1,440	54.1	92.3	3,380	5,410
GT10	22.6	143	196	24.6	42.6	472	614
GT11N	83.3	1,350	1,990	99.0	154	5,060	7,334
GT35	16.9	214	264	30.9	31.9	730	929
251B11/12	49.2	453	741	89.5	141	1,450	2,400
501D5	109	843	1,120	115	196	2,910	3,710
V84.2	105	858	1,570	176	190	2,730	5,520
V94.2	153	1,250	2,290	335	276	3,650	8,050
V64.3	61.5	859	1,290	176	188	2,740	4,390
V84.3	141	1,930	2,910	395	426	6,150	9,920
V94.3	204	2,790	4,170	571	611	8,890	14,200

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.
[c]Based on 8,000 hours operation per year.
[d]Data not available.

TABLE 5-9. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING STEAM INJECTION

Gas turbine model	Power output, MW[a]	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c d]	Oil fuel, tons/yr[c d]
Saturn	1.1	6.4	9.9	6.4	9.9	0	0
Centaur	3.3	22.0	31.2	22.0	31.2	0	0
Centaur "H"	4.0	20.8	32.6	20.8	32.6	0	0
Taurus	4.5	24.7	37.6	24.7	37.6	0	0
Mars T-12000	8.8	69.4	107	69.4	107	0	0
501-KB5	4.0	31.6	48.5	8.6	48.5	194	0
570-K	4.9	22.7	41.0	22.7	41.0	0	0
571-K	5.9	24.2	44.0	24.2	44.0	0	0
LM1600	14.0	74.1	127	13.0	40.5	245	345
LM2500	22.7	146	301	21.2	66.0	499	938
LM5000	34.5	232	474	31.7	145	802	1,320
LM6000	43.0	310	609	35.6	162	1,100	1,790
MS5001P	26.8	181	274	54.1	85.3	508	755
MS6001B	39.0	250	459	71.4	113	711	1,380
MS7001E	84.7	544	822	150	237	1,580	2,340
MS7001F	161	1,290	2,190	260	407	4,110	7,130
MS9001E	125	810	1,320	214	360	2,390	3,850
MS9001F	229	1,850	3,150	373	585	5,890	10,200
GT8	47.4	899	1,440	61.2	129	3,350	5,260
GT10	22.6	143	196	40.4	41.6	410	618
GT11N	83.3	1,350	1,990	147	151	4,830	7,350
GT35	16.9	214	264	43.1	44.4	681	878
251B11/12	49.2	453	741	52.0	88.6	1,600	2,610
501D5	109	843	1,120	112	191	2,920	3,730
V84.2	105	858	1,570	225	242	2,530	5,310
V94.2	153	1,250	3,290	327	353	3,690	7,740
V64.3	61.5	859	1,290	171	184	2,750	4,410
V84.3	141	1,930	2,910	386	415	6,190	9,960
V94.3	204	2,790	4,170	557	596	8,940	14,300

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.
[c]Based on 8,000 hours operation per year.
[d]A value of zero indicates that steam injection is not available for this gas turbine model.

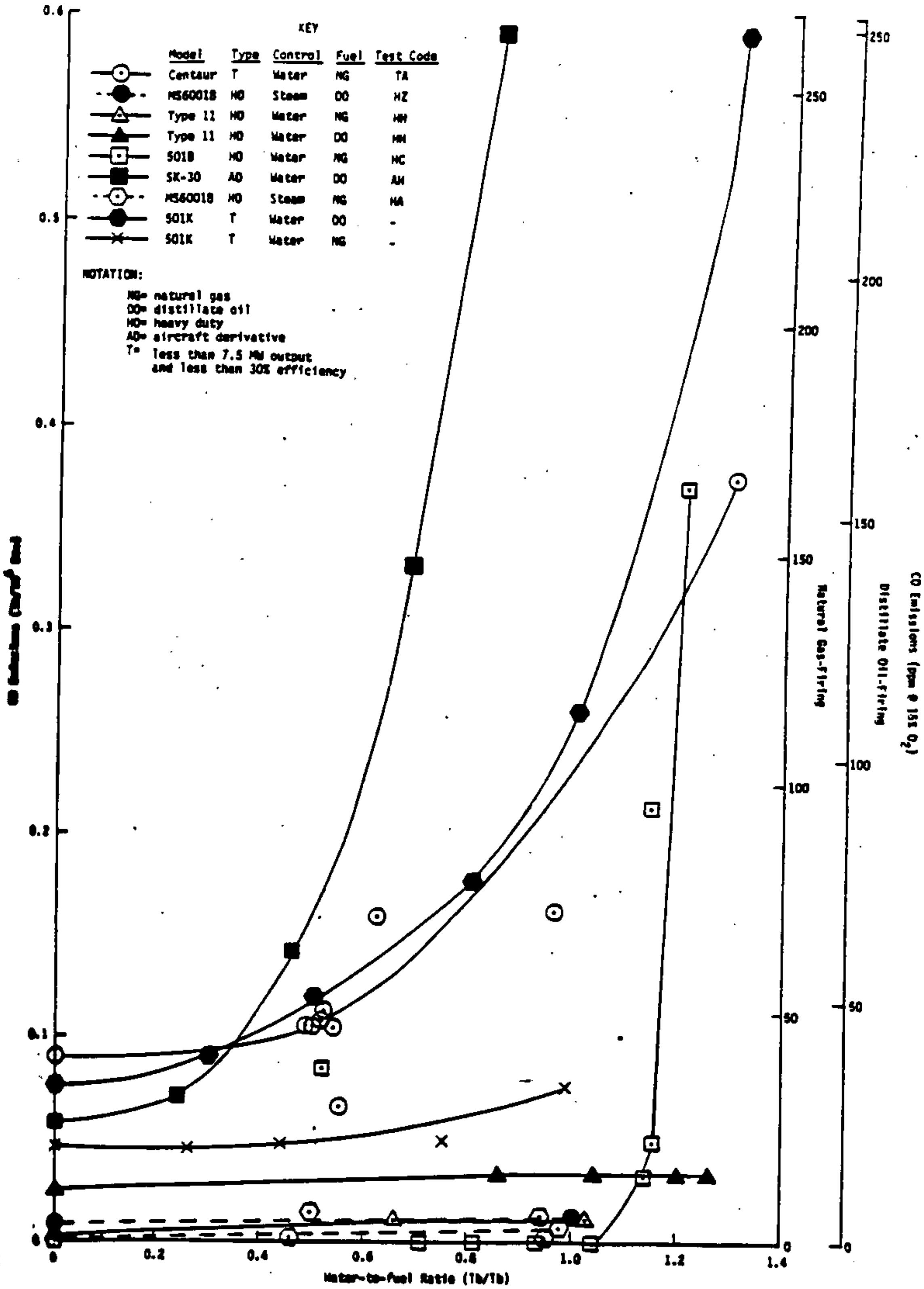


Figure 5-13. Effect of wet injection on CO emissions.[29]

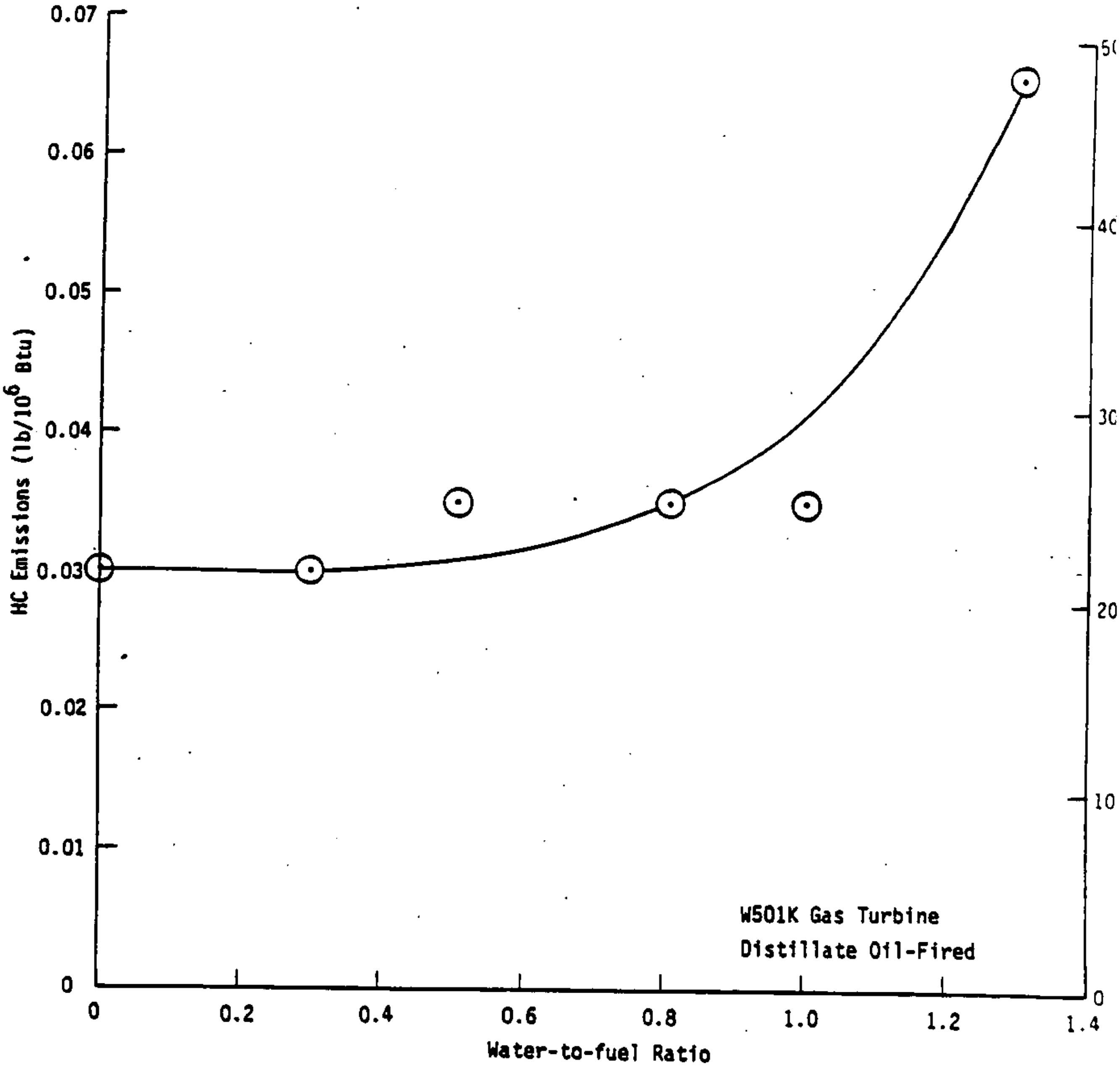


Figure 5-14. Effect of water injection on HC emissions for one turbine model.[29]

5.1.6 Impacts of Wet Controls on Gas Turbine Performance

Wet controls affect gas turbine performance in two ways: power output increases and efficiency decreases. The energy from the added mass flow and heat capacity of the injected water or steam can be recovered in the turbine, which results in an increase in power output. For water injection, the fuel energy required to vaporize the water in the turbine combustor, however, results in a net penalty to the overall efficiency of the turbine. For steam injection, there is an energy penalty associated with generating the steam, which results in a net penalty to the overall cycle efficiency. Where the steam source is exhaust heat, which would otherwise be exhausted to the atmosphere, the heat recovery results in a net gain in gas turbine efficiency.[32] The actual efficiency reduction associated with wet controls is specific to each turbine and the actual WFR required to meet a specific NO_x reduction. The overall efficiency penalty increases with increasing WFR and is usually higher for water injection than for steam injection due to the heat of vaporization associated with water. The impacts on output and efficiency for one manufacturer's gas turbines are shown in Table 5-10.

5.1.7 Impacts of Wet Controls on Gas Turbine Maintenance

Water injection increases dynamic pressure oscillation activity in the turbine combustor.[33] This activity can, in some turbine models, increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. As a result, the turbine must be removed from service more frequently for inspection and repairs to the hot section components. A summary of the maintenance impacts as provided by manufacturers is shown in Table 5-11. As this table shows, the maintenance impact, if any, varies from manufacturer to manufacturer and model to model. Some manufacturers stated that there is no impact on maintenance intervals associated with water or steam injection for their turbine models. Data were provided only for operation with natural gas.

TABLE 5-10. REPRESENTATIVE WATER/STEAM INJECTION IMPACTS ON GAS TURBINE PERFORMANCE FOR ONE MANUFACTURER'S HEAVY-DUTY TURBINES[33]

NO_x level, ppmv	Water/fuel ratio	Percent overall efficiency change	Percent output change[a]	Remarks
75 NSPS	0.5	-1.8	+3	Oil-fired, simple cycle, water injection
42	1.0	<-3	+5	Natural gas, simple cycle, water injection
42	1.2	-2	+5	Natural gas, combined cycle, steam injection
25	1.2	-4	+6	Natural gas, water injection, multinozzle combustor
25	1.3	-3	+5.5	Natural gas, steam injection, combined cycle (Frame 6 turbine model)

[a]Compared with no injection.

TABLE 5-11. IMPACTS OF WET CONTROLS ON GAS TURBINE MAINTENANCE USING NATURAL GAS FUEL[5-11,17,24]

Manufacturer/Model	NO_x emissions, ppmv @ 15% O_2			Inspection interval, hours		
	Standard combustor	Water injection	Steam injection	Standard	Water injection	Steam injection
General Electric						
LM1600	133	42/25	25	25,000	16,000[a]	25,000
LM2500	174	42/25	25	25,000	16,000[a]	25,000
LM5000	185	42/25	25	25,000	16,000[a]	25,000
LM6000	220	42/25	25	25,000	16,000[a]	25,000
MS5001P	142	42	42	12,000	6,000	6,000
MS6001B	148	42	42	12,000	6,000	8,000
MS7001E	154	42	42	8,000	6,500	8,000
MS7001F	179	42	42	8,000	8,000	8,000
MS9001E	176	42	42	8,000	6,500	8,000
MS9001F	176	42	42	8,000	8,000	8,000
Asea Brown Boveri						
GT10	150	25	42	80,000[b]	80,000[b]	80,000[b]
GT8	430	25	29	24,000	24,000	24,000
GT11N	400	25	25	24,000	24,000	24,000
GT35	300	42	60	80,000[b]	80,000[b]	80,000[b]
Siemens Power Corp.						
V84.2	212	42	55	25,000	25,000	25,000
V94.2	212	55	55	25,000	25,000	25,000
V64.3	380	75	75	25,000	25,000	25,000
V84.3	380	75	75	25,000	25,000	25,000
V94.3	380	75	75	25,000	25,000	25,000
Solar Turbines, Inc.						
T-1500 Saturn	99	42	NA[c]	NA[d]	NA[d]	NA[c]
T-4500 Centaur	150	42	NA[c]	NA[d]	NA[d]	NA[c]
Type H Centaur	105	42	NA[c]	NA[d]	NA[d]	NA[c]
Taurus	114	42	NA[c]	NA[d]	NA[d]	NA[c]
T-12000 Mars	178	42	NA[c]	NA[d]	NA[d]	NA[c]
T-14000 Mars	199	42	NA[c]	NA[d]	NA[d]	NA[c]
Allison/General Motors						
501-KB5	155	42	NA[c]	25,000	17,000	NA[d]
501-KC5	174	42	NA[c]	30,000	22,000	NA[d]
501-KH	155	42	25	25,000	17,000	20,000
570-K	101	42	NA[c]	20,000	12,000	NA[d]
571-K	101	42	NA[c]	20,000	12,000	NA
Westinghouse						
251B11/12	220	42	25	8,000	8,000	8,000
501D5	190	25	25	8,000	8,000	8,000

[a]Applies only to 25 ppmv level. No impact for 42 ppmv.
[b]This interval applies to time between overhaul (TBO).
[c]Steam injection is not available for this model.
[d]Data not available.

5.2 COMBUSTION CONTROLS

The formation of both thermal NO_x and fuel NO_x depends upon combustion conditions, so modification of these conditions affects NO_x formation. The following combustion modifications are used to control NO_x emission levels:

1. Lean combustion;
2. Reduced combustor residence time;
3. Lean premixed combustion; and
4. Two-stage rich/lean combustion.

These combustion modifications can be applied singly or in combination to control NO_x emissions.

The mechanisms by which each of these techniques reduce NO_x formation, their applicability to new gas turbines, and the design or operating factors that influence NO_x reduction performance are discussed below by control technique.

5.2.1 Lean Combustion and Reduced Combustor Residence Time

5.2.1.1 Process Description. Gas turbine combustors were originally designed to operate with a primary zone equivalence ratio of approximately 1.0. (An equivalence ratio of 1.0 indicates a stoichiometric ratio of fuel and air. Equivalence ratios below 1.0 indicate fuel-lean conditions, and ratios above 1.0 indicate fuel-rich conditions.) With lean combustion, the additional excess air cools the flame, which reduces the peak flame temperature and reduces the rate of thermal NO_x formation.[34]

In all gas turbine combustor designs, the high-temperature combustion gases are cooled with dilution air to an acceptable temperature prior to entering the turbine. This dilution air rapidly cools the hot gases to temperatures below those required for thermal NO_x formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors. Because the combustion gases are at a high temperature for a shorter time, the amount of thermal NO_x formed decreases.[34]

Shortening the residence time of the combustion products at high temperatures may result in increased CO and HC emissions if no other changes are made in the combustor. In order to avoid increases in CO and HC emissions, combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves fuel/air mixing and reduces the time required for the combustion process to be completed. These designs may also incorporate fuel/air premixing chambers. Therefore, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length.[34]

5.2.1.2 Applicability. Lean primary zone combustion and reduced residence time combustion have been applied to annular, can-annular, and silo combustor designs.[35-37] Almost all gas turbines presently being manufactured incorporate lean combustion and/or reduced residence time to some extent in their combustor designs, incorporating these features into production models since 1975.[38,39] However, the varying uncontrolled NO_x emission levels of gas turbines shown in Figures 5-2 and 5-3 indicate that these controls are not incorporated to the same degree in every gas turbine and may be limited in some turbines by the quantity of dilution air available for lean combustion.

Lean primary zone and reduced residence time are most applicable to low-nitrogen fuels, such as natural gas and distillate oil fuels. These modifications are not effective in reducing fuel NO_x.[40]

5.2.1.3 Factors Affecting Performance. For a given combustor, the performance of lean combustion is directly affected by the primary zone equivalence ratio. As shown in Figure 4-2, the further the equivalence ratio is reduced below 1.0, the greater the reduction in NO_x emissions. However, if the equivalence ratio is reduced too far, CO emissions increase and flame stability problems occur.[41] This emissions tradeoff effectively limits the amount of NO_x reduction that can be achieved by lean combustion alone.

For combustors with reduced residence time, the amount of NO_x emission reduction achieved is directly related to the decrease in residence time in the high-temperature flame zone.

5.2.1.4 <u>Achievable NO_x Emission Levels Using Lean Combustion and Reduced Residence Time Combustors</u>. Lean combustion reduces NO_x emissions, and when used in combination with reduced residence time, NO_x emissions are further reduced. Figure 5-15 shows a comparison of NO_x emissions from a combustor with a lean primary zone and NO_x emissions from the same combustor without a lean primary zone. At the same firing temperature, NO_x emissions reductions of up to 30 percent are achieved using lean primary zone combustion without increasing CO emissions. Reducing the residence time at elevated temperatures reduces NO_x emissions. One test at 1065°C (1950°F) yielded a reduction in NO_x emissions of 40 percent by reducing the residence time. Carbon monoxide emissions increased from less than 10 to approximately 30 ppm.[42-45]

5.2.2 <u>Lean Premixed Combustors</u>

5.2.2.1 <u>Process Description</u>. In a conventional combustor, the fuel and air are introduced directly into the combustion zone and fuel/air mixing and combustion take place simultaneously. Wide variations in the air-to-fuel ratio (A/F) exist, and combustion of localized fuel-rich pockets produces significant levels of NO_x emissions. In a lean premixed combustor design, the air and fuel is premixed at very lean A/F's prior to introduction into the combustion zone. The excess air in the lean mixture acts as a heat sink, which lowers combustion temperatures. Premixing results in a homogeneous mixture, which minimizes localized fuel-rich zones. The resultant uniform, fuel-lean mixture results in greatly reduced NO_x formation rates.[17]

To achieve NO_x levels below 50 ppmv, referenced to 15 percent O_2, the design A/F approaches the lean flammability limit. To stabilize the flame, ensure complete combustion, and minimize CO emissions, a pilot flame is incorporated into the combustor or burner design. In most designs, the relatively

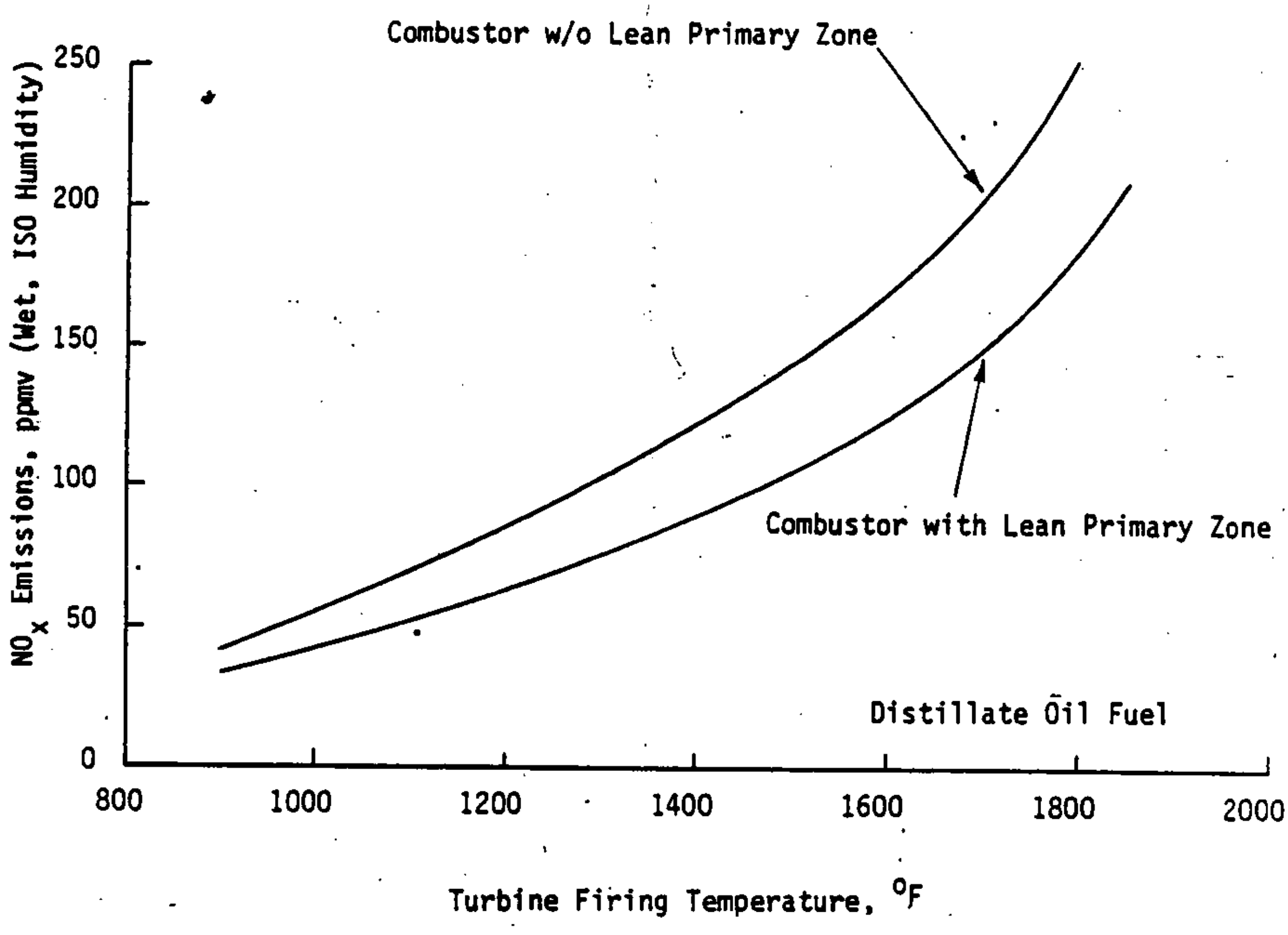


Figure 5-15. Nitrogen oxide emissions versus turbine firing temperature for combustors with and without a lean primary zone.[42]

small amount of air and fuel supplied to this pilot flame is not premixed and the A/F is nearly stoichiometric, so the pilot flame temperature is relatively high. As a result, NO_x emissions from the pilot flame are higher than from the lean premixed combustion.[46]

Virtually all gas turbine manufacturers have implemented lean premixed combustion development programs. Three manufacturers' designs that are available in production turbines are described below.

The first design uses a can-annular combustor and is shown in Figure 5-16. This is a two-stage premixed combustor: the first stage is the portion of the combustor upstream of the venturi section and includes the six primary fuel nozzles; the second stage is the balance of the combustor and includes the single secondary fuel nozzle.[33]

The operating modes for this combustor design are shown in Figure 5-17. For ignition, warmup, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, and the equivalence ratio is kept as low as stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. Again, the equivalence ratio is kept as low as possible in both stages to minimize NO_x emissions. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.[33]

For operation on distillate oil, fuel is introduced and burned only in the first stage for ignition and for loads up to approximately 50 percent. For loads greater than 50 percent, fuel is introduced and burned in both stages.[33]

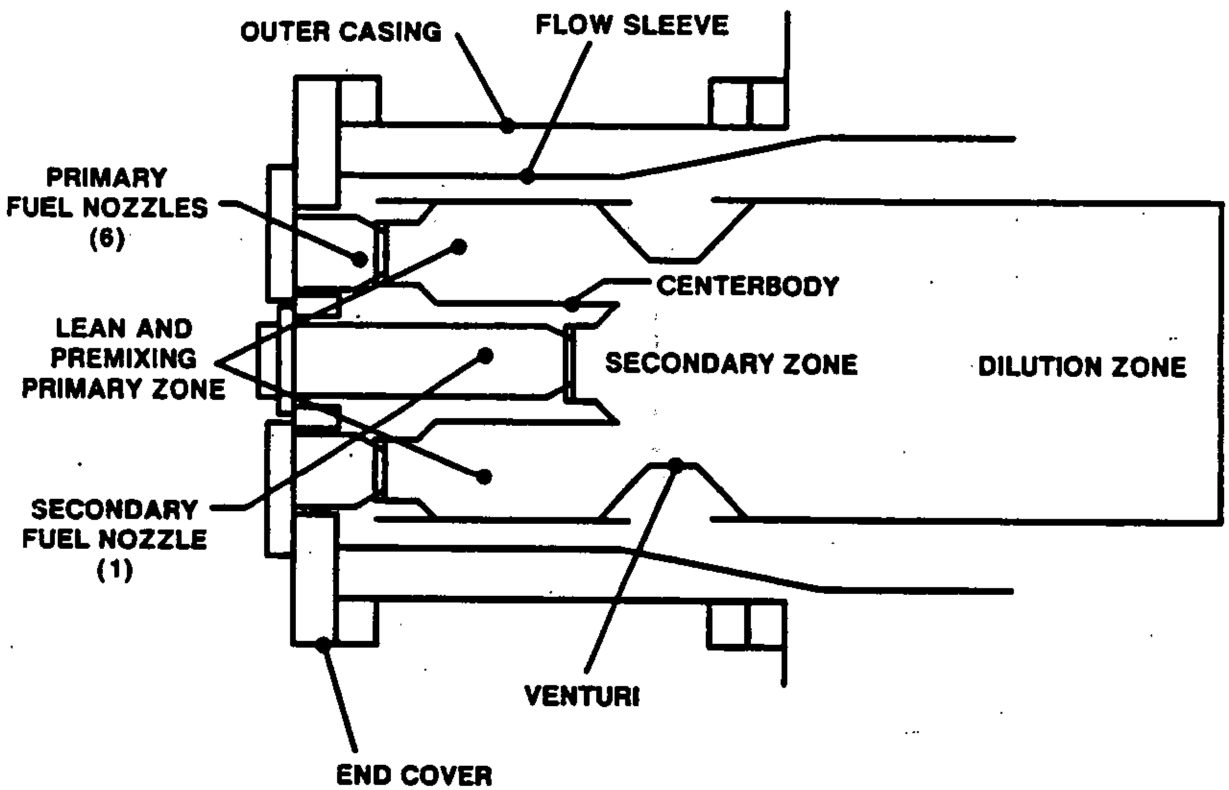


Figure 5-16. Cross-section of a lean premixed can-annular combustor.[47]

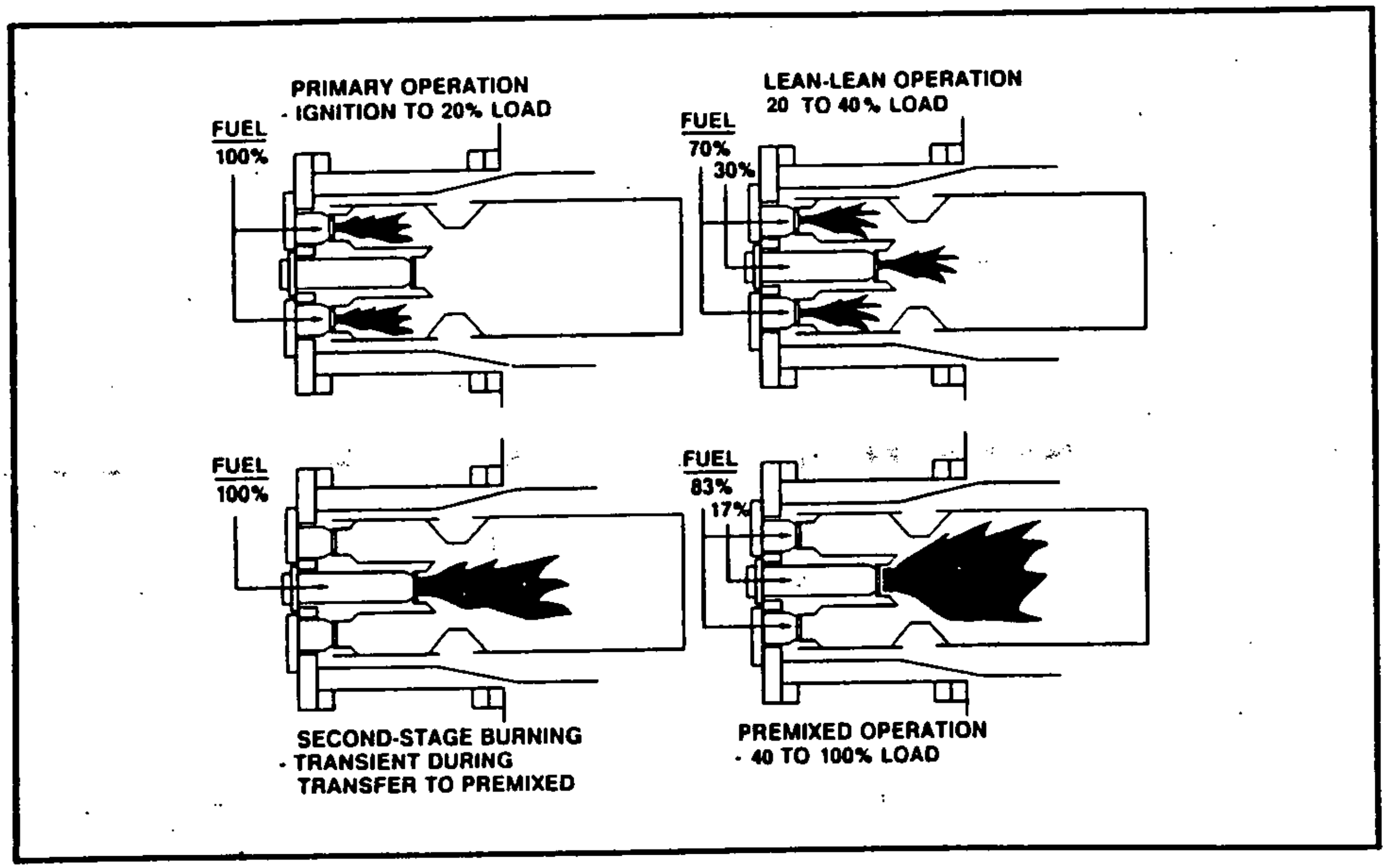


Figure 5-17. Operating modes for a lean premixed can-annular combustor.[33]

Figure 5-18 shows a lean premixed combustor design used by another manufacturer for an annular combustor. The air and fuel are premixed using a very lean A/F, and the resultant uniform mixture is delivered to the primary combustion zone where combustion is stabilized using a pilot flame. Using one or more mechanical systems to regulate the airflow delivered to the combustor, the premix mode is operable for output loads between 50 and 100 percent. Below 50 percent load, only the pilot flame is operating, and NO_x emissions levels are similar to those for conventional combustors.[46]

Another manufacturer's production low-NO_x design uses a silo combustor. Unlike the can-annular and annular designs, the silo combustor is mounted externally to the turbine and can therefore be modified without significantly affecting the rest of the turbine design, provided the mounting flange to the turbine is unchanged. In addition, this large combustion chamber is fitted with a ceramic lining that shields the metal surfaces from peak flame temperatures. This lining reduces the requirement for cooling air, so more air is available for the combustion process.[17]

This silo low-NO_x combustor design uses six burners, as shown in Figure 5-19. For operation on natural gas, each burner serves to premix the air and fuel to deliver a lean and uniform mixture to the combustion zone. To achieve the lowest possible NO_x emissions, the A/F of the premixed gases is kept very near the lean flammability limit and a pilot flame is used to stabilize the overall combustion process. This burner design is shown in Figure 5-20. Like the can-annular design, the burner in the silo combustor cannot operate over the full power range of the gas turbine in the premix mode due to inability of the premix mode to deliver suitable A/F's at low power output levels. For this reason, the burners are designed to operate in a conventional diffusion burning mode at startup and low power outputs and switch to a premix burning mode at higher power output levels.

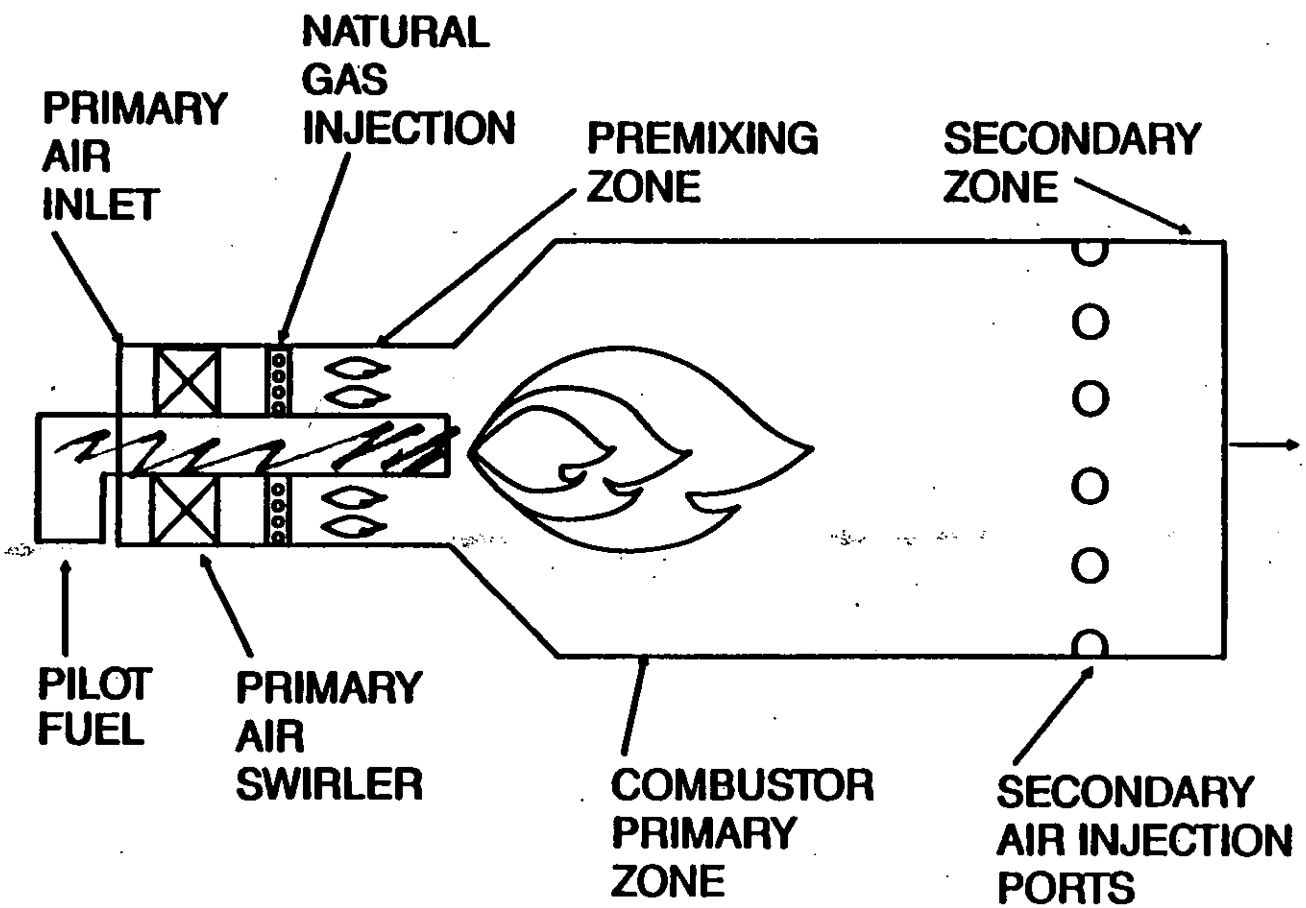


Figure 5-18. Cross-section of lean premixed annular combustion design.[47]

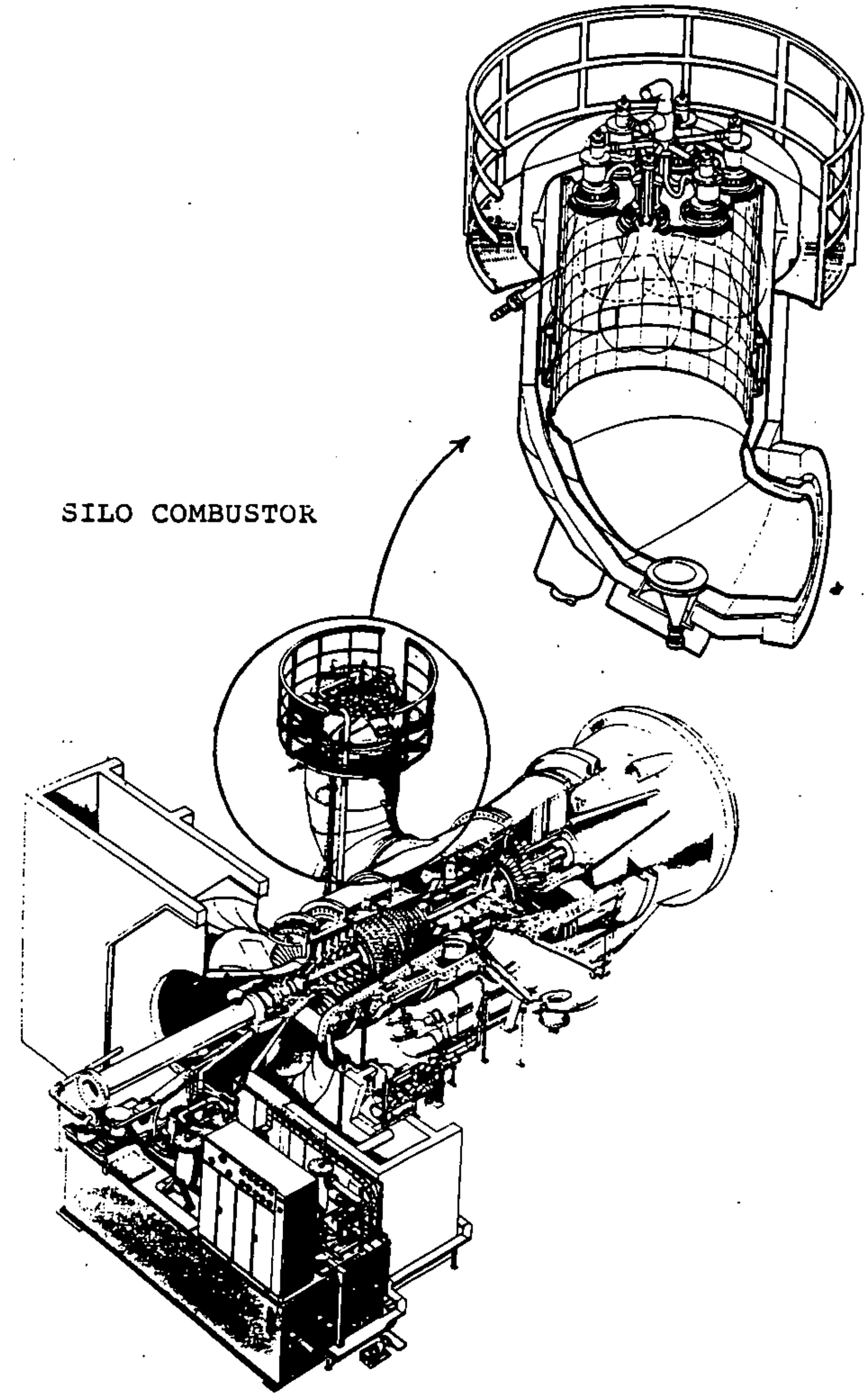


Figure 5-19. Cross-section of a low-NO_x silo combustor.[35,48]

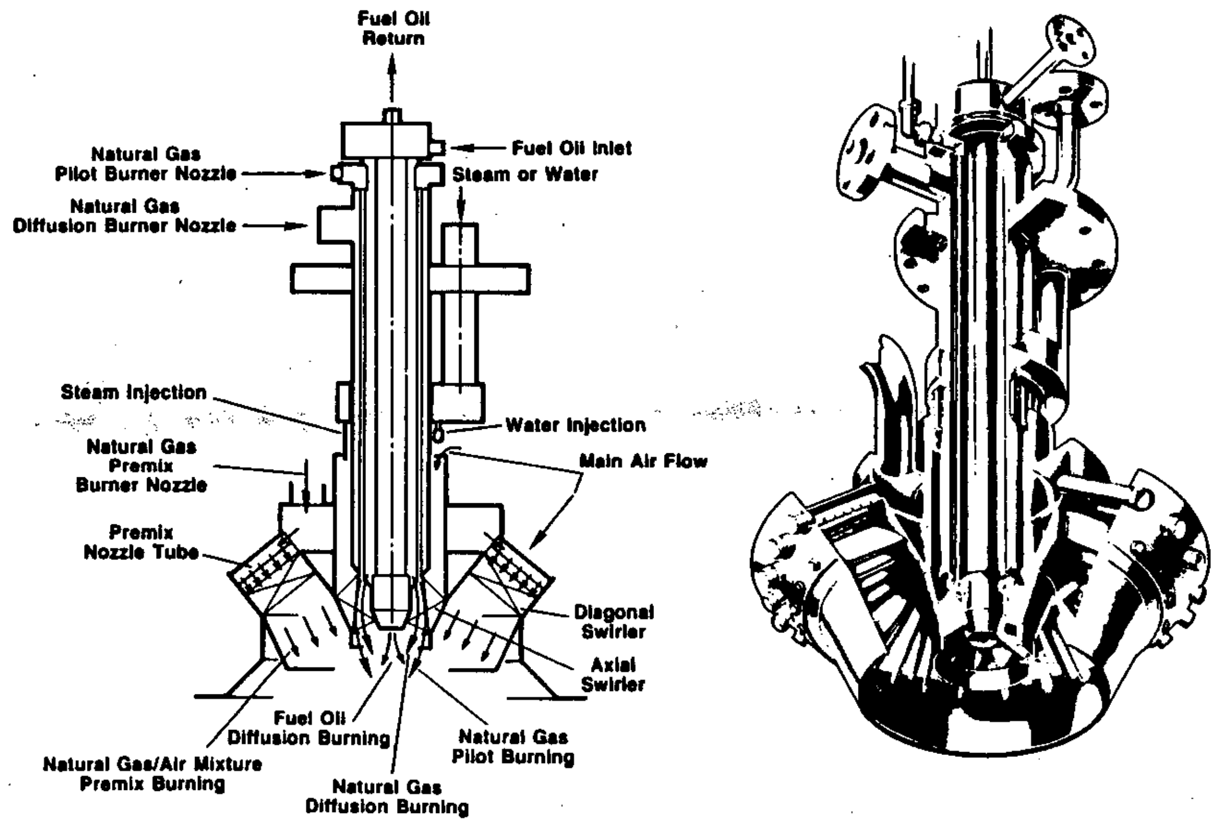


Figure 5-20. Low-NO_x burner for a silo combustor.[48]

For operation on distillate oil with the current burner design, combustion occurs only in a diffusion mode and there is no premixing of air and fuel.

5.2.2.2 Applicability. As discussed in Section 5.2.2.1, lean premixed combustors apply to can-annular, annular, and silo combustors. This combustion modification is effective in reducing thermal NO_x emissions for both natural gas and distillate oil but is not effective on fuel NO_x. Therefore, lean premixed combustion is not as effective in reducing NO_x levels if high-nitrogen fuels are fired.[49]

The multiple operating modes associated with the percent operating load results in "stepped" NO_x emission levels. To date, low NO_x emission levels occur only at loads greater than 40 to 75 percent.

Lean premixed combustors currently are available for limited models from three manufacturers contacted for this study.[6,17,24] Two additional manufacturers project an availability date of 1993 or 1994 for lean premixed combustors for some turbine models.[11,50] All of these manufacturers state that these lean premixed combustors will be available for retrofit applications.

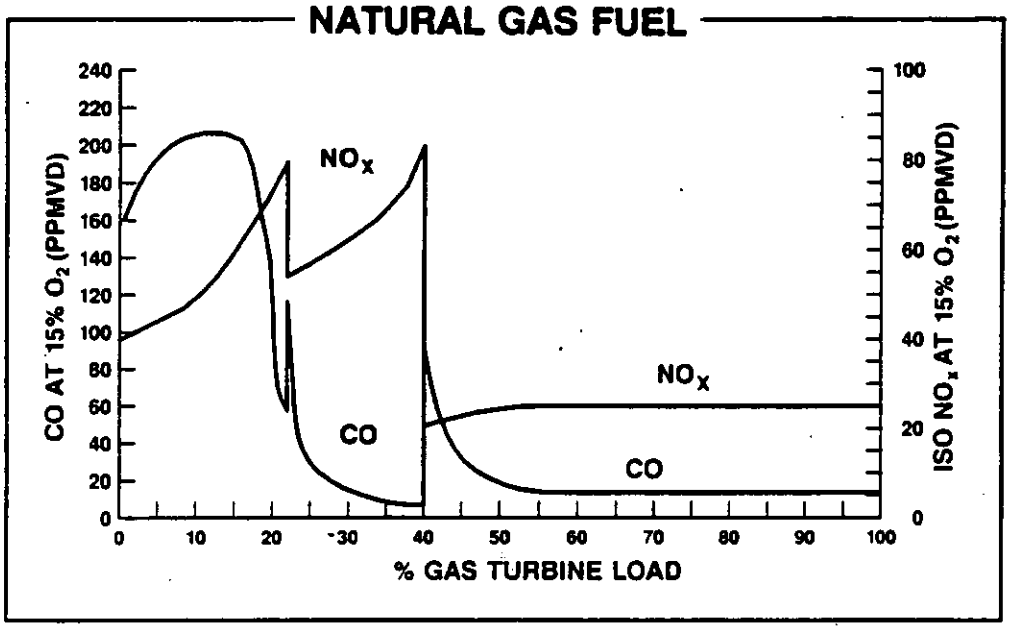
5.2.2.3 Factors Affecting Performance. The primary factors affecting the performance of lean, premixed combustors are A/F and the type of fuel. To achieve low NO_x emission levels, the A/F must be maintained in a narrow range near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this A/F at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that would occur as the A/F reaches the lean flammability limit, all manufacturers' lean premixed combustors switch to a diffusion-type combustion mode at reduced load conditions, typically between 40 and 60 percent load. This switchover to a diffusion combustion mode results in higher NO_x emissions.

Natural gas produces lower NO_x levels than do oil fuels. The reasons for this are the lower flame temperature of natural gas and the ability to premix this fuel with air prior to delivery into the second combustion stage. For operation on liquid fuels, currently available lean premixed combustor designs require water injection to achieve appreciable NO_x reduction.

5.2.2.4 Achievable NO_x Emission Levels. The achievable controlled NO_x emission levels for lean premixed combustors vary depending upon the manufacturer. At least three manufacturers currently guarantee NO_x emission levels of 25 ppmv, corrected to 15 percent O_2 for most or all of their gas turbines for operation on natural gas fuel without wet injection.[6,17,24] Each of these three manufacturers has achieved controlled NO_x emission levels of less than 10 ppmv at one or more installations in the United States and/or Europe and guarantee this NO_x level for a limited number of their gas turbine models.[51] All three manufacturers offer gas turbines in the 10+ MW (13,400 hp+) range and anticipate that guaranteed NO_x emission levels of 10 ppmv or less will be available for all of their gas turbines for operation on natural gas fuel in the next few years. These low-NO_x combustor designs apply to new turbines and existing installation retrofits.

For gas turbines in the range of 10 MW (13,400 hp) and under, one gas turbine manufacturer offers a guarantee for its lean premixed combustor, without wet injection, of 42 ppmv using natural gas fuel for two of its turbine models for 1994 delivery. This manufacturer states that a controlled NO_x emission level of 25 ppmv has been achieved by in-house testing, and this 25 ppmv level firing natural gas fuel is the goal for all of its gas turbine models, for both new equipment and retrofit applications.[50]

These controlled NO_x emission levels of 9 to 42 ppmv correspond to full output load; at reduced loads, the NO_x levels increase, often in "stepped" fashion in accordance with changes in combustor operation from premixed mode to conventional or diffusion-mode operation (see Section 5.2.2.3). Figure 5-21 shows these stepped NO_x emissions levels for a can-annular combustor for natural gas and oil fuel operation. Figure 5-22



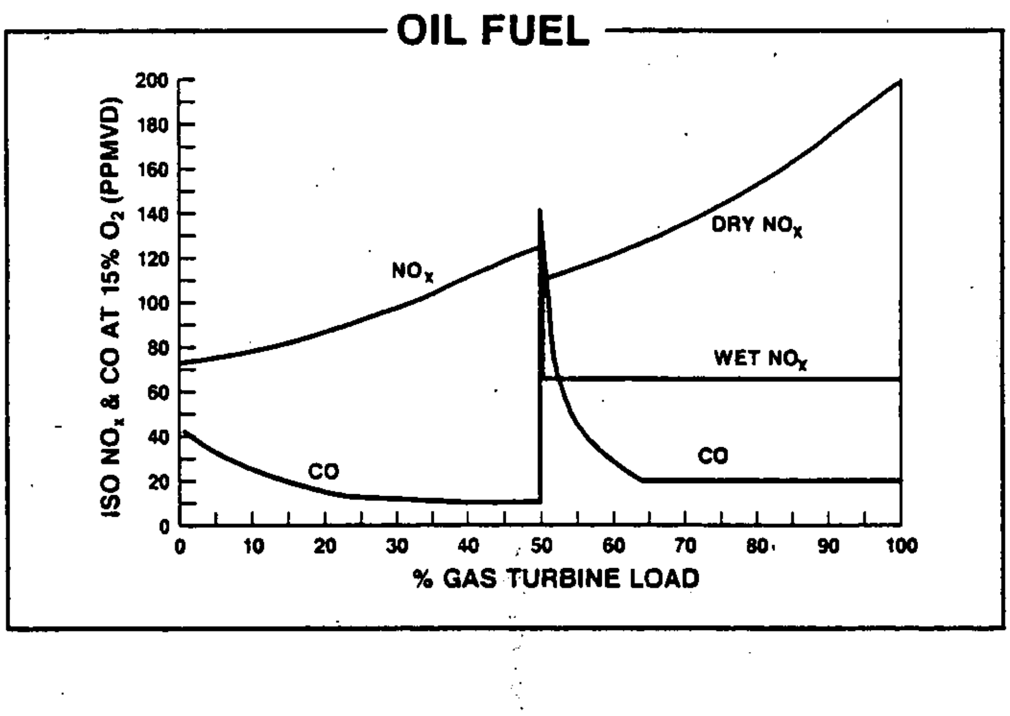
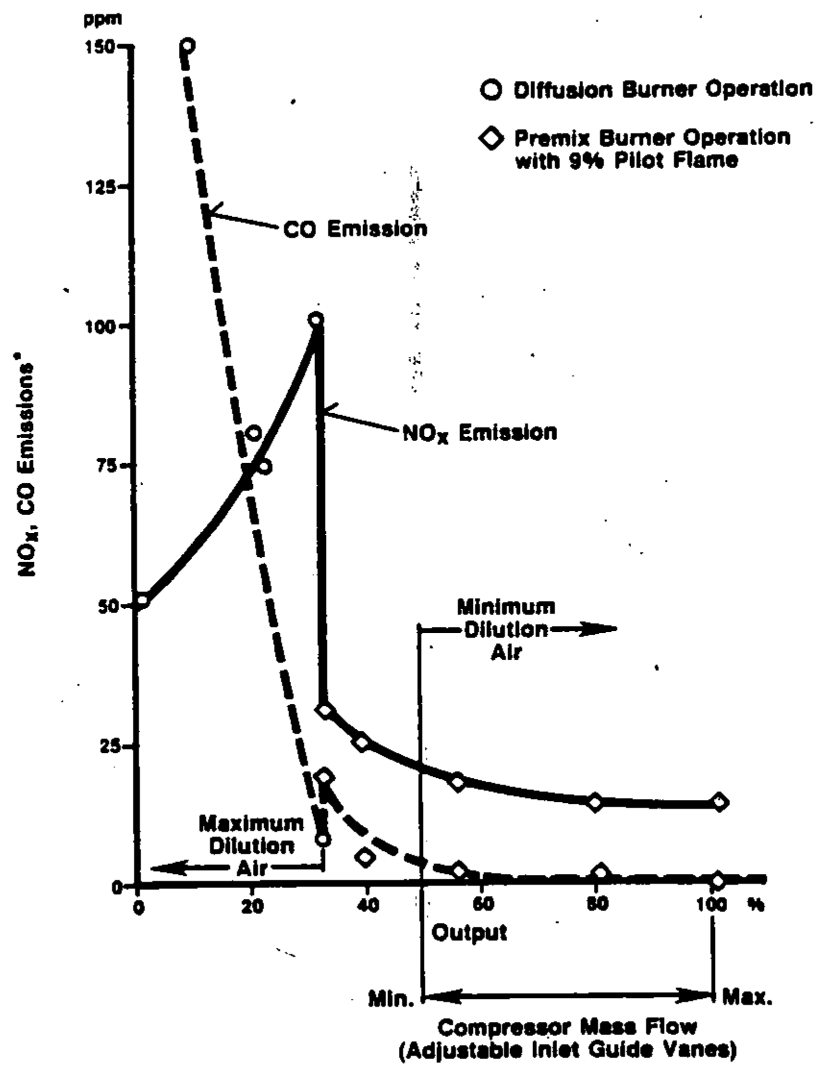


Figure 5-21. "Stepped" NO_x and CO emissions for a low-NO_x can-annular combustor burning natural gas and distillate oil fuels.[47]



*In Dry Exhaust Gas with 15% O_2 by Volume

Figure 5-22. "Stepped" NO_x and CO emissions for a low-NO_x silo combustor burning natural gas.[35]

shows the emissions for a silo combustor operating on natural gas only. The emission levels shown in Figures 5-21 and 5-22 correspond to full-scale production turbines currently available from the manufacturers.

Reduced NO_x emissions when burning oil fuel in currently available lean premixed combustor designs have been achieved only with water or steam injection. With water or steam injection, a 65 ppmv NO_x level can be achieved in the turbine with a can-annular combustor design; a 65 ppmv level can also be met with water injection in the turbine with a silo combustor at a WFR of 1.4.[48,52] This 65 ppmv level for lean premixed combustors is higher than the controlled NO_x levels achieved with water injection in oil-fired turbines using a conventional combustor design.

Modification of the existing burner design used in the silo combustor to allow premixing of the oil fuel with air prior to combustion is under development. Tests performed using a 12 MW (16,200 hp) turbine achieved NO_x emission levels below 50 ppmv without wet injection, corrected to 15 percent O_2, compared to uncontrolled levels of 150 ppmv or higher. The NO_x levels, without wet injection, as a function of equivalence ratio are shown in Figure 5-23. The design equivalence ratio at rated load is approximately 2.1. As shown in this figure, NO_x emissions below 50 ppmv were achieved at rated power output at pilot fuel flow levels of 10 percent of the total fuel input.[52]

Site test data for two turbines using silo-type lean premixed combustors, as reported by the manufacturer, are shown in Table 5-12. As this table shows, NO_x emission levels as low as 16.5 ppmv were recorded for using natural gas fuel without water injection. Subsequent emission tests have achieved levels below 10 ppmv.[51] Corresponding data for operation on oil fuel using only the pilot (diffusion) stage for combustion, and with water injection, is shown in Table 5-13. Levels of NO_x emissions at base load for No. 2 fuel oil are between 50 and 60 ppmv.

Based on information provided by turbine manufacturers, the potential NO_x reductions using currently available lean premixed

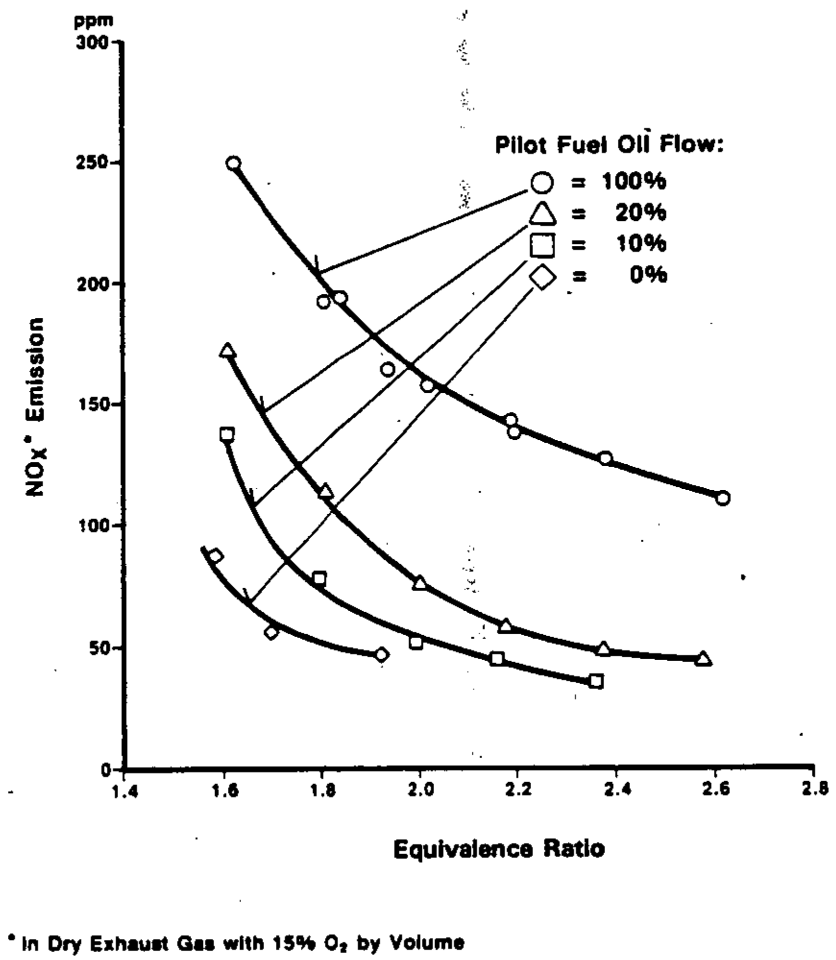


Figure 5-23. Nitrogen oxide emission test results from a lean premix silo combustor firing fuel oil without wet injection.[53]

TABLE 5-12. MEASURED NO_x EMISSIONS FOR COMPLIANCE TESTS OF A NATURAL GAS-FUELED LEAN PREMIXED COMBUSTOR WITHOUT WATER INJECTION[22]

Turbine No.	Output, percent of baseline	NO_x emission level, ppmv[a]
1	107	17.7
1	100	16.5
2	100	24.1
2	75	20.4
1	50	22.3
2	50	22.2

[a]In dry exhaust with 15 percent O_2, by volume.

TABLE 5-13. MEASURED NO_x EMISSIONS FOR OPERATION OF A LEAN PREMIXED COMBUSTOR DESIGN OPERATING IN DIFFUSION MODE ON OIL FUEL WITH WATER INJECTION[22]

Turbine No.	Output, percent of baseload	NO_x emission level, ppmv[a]
1	Peak	69.3
2	Peak	53.6
1	100	59.9
2	100	51.6
1	75	54.3
2	75	49.2
2	50	54.8

[a]In dry exhaust with 15 percent O_2, by volume.

combustors are shown in Table 5-14. As this table indicates, NO_x emission reductions range from 14.7 tons/yr for a 1.1 MW (1,480 hp) turbine to 10,400 tons/yr for a 204 MW (274,000 hp) turbine for operation on natural gas without wet injection. Corresponding NO_x emission reductions for operation on oil fuel, with water injection, range from 620 tons/yr for a 22.6 MW (30,300 hp) turbine to 7,360 tons/yr for an 83.3 MW (112,000 hp) turbine.

Limited data from two manufacturers showing the impact of lean premixed combustor designs on CO emissions are shown in Table 5-15. For natural gas-fueled turbines with rated outputs of 10 MW (13,400 hp) or less, controlled NO_x emission levels of 25 to 42 ppmv result in a rise in CO emission levels from 25 ppmv or less to as high as 50 ppmv.[43] For turbines above 10 MW (13,400 hp), controlled NO_x emission levels of 9 ppmv result in a rise in CO emissions from 10 to 25 ppmv for natural gas fuel. Conversely, for controlled NO_x emission levels of 25 ppmv, the CO emissions drop from 25 to 15 ppmv.[51] For one manufacturer's lean premixed silo combustor design, CO emissions at rated load are less than 5 ppmv, as shown previously in Figure 5-21. This limited data suggest that the effect of lean premixed combustors on CO emissions depends upon the specific combustor design and the controlled NO_x emission level.

The emission levels shown in Table 5-15 correspond to rated power output. Like NO_x emission levels, CO emissions change with changes in combustor operating mode at reduced power output. The "stepped" effect on CO emissions is shown in Figures 5-21 and 5-22, shown previously.

Operation on oil fuel with wet injection, shown previously in Figure 5-21, shows CO emission levels of 20 ppmv. Additional CO emission data were not available for operation on oil fuel with water injection in lean premixed combustors. Developmental tests for operation on oil fuel without wet injection in a silo combustor are presented in Figure 5-24. At rated load, shown in this figure at an equivalence ratio of approximately 2.1, CO emissions are less than 10 ppmv, corrected to 15 percent O_2,

TABLE 5-14. POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING LEAN PREMIXED COMBUSTORS

Turbine model	Power output, MW	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, ppmv	Oil fuel, ppvm	Gas fuel, ppmv	Oil fuel, ppmv	Gas fuel, tons/yr[a]	Oil fuel, tons/yr[a] [b]
Saturn[c]	1.1	99	150	42	NA[d]	14.7	NA[d]
Centaur T-4500[c]	3.3	130	179	42	NA[d]	59.5	NA[d]
Centaur "H"[c]	4.0	105	160	42	NA[d]	49.8	NA[d]
Taurus[c]	4.5	114	168	42	NA[d]	62.4	NA[d]
Mars T-12000[c]	8.8	178	267	42	NA[d]	212	NA[d]
Mars T-14000[c]	10.0	199	NA[d]	42	NA[d]	270	NA[d]
MS6001B	39.0	148	267	25/9[e]	65	829/937	1,139
MS7001E	84.7	154	228	25/9[e]	65	1,820/2,050	2,360
MS7001F	161	210	353	25	65	4,540	5,190
MS9001E	125	161	241	25/9[e]	65	2,740/3,060	3,490
MS9001F	229	210	353	25	65	6,500	7,250
GT10	22.6	150	200	25	42	476	620
GT11N	83.3	390	560	25/9[e]	42	5,070/5,290	7,360
V84.2	105	212	360	25/9[e]	NA[f]	3,030/3,290	NA[f]
V94.2	153	212	360	9[e]	NA[f]	4,410/4,780	NA[f]
V64.3	61.5	380	530	42	NA[d]	3,210	NA[d]
V84.3[c]	141	380	530	42	NA[d]	7,230	NA[d]
V94.3[c]	204	380	530	42	NA[d]	10,400	NA[d]

[a]Based on 8,000 hours operation per year.
[b]Requires water or steam injection.
[c]Scheduled availability is 1994 for natural gas fuel.
[d]NA = Data not available.
[e]Standard NO_x guarantee is 25 ppmv. Manufacturers offer guaranteed NO_x levels as low as 9 ppmv for these turbines.
[f]Scheduled availability 1993 for oil fuel without water injection. Reference 17.

TABLE 5-15. COMPARISON OF NO_x AND CO EMISSIONS FOR STANDARD VERSUS LEAN PREMIXED COMBUSTORS FOR TWO MANUFACTURERS' TURBINES[46,54]

	Emissions, ppmv, referenced to 15 percent O_2[a]				
		Standard combustor		Lean premixed combustor	
GT Model	Power output, MW	NO_x	CO	NO_x	CO
Centaur H	4.0	105	15	25-42	50[b]
Mars T-14000	10.0	199	5.5	25-42	50[b]
MS6001B	39.0	148	10	9	25
MS7001E	84.7	154	10	9	25
MS9001E	125	161	10	9	25
MS7001F	161	210	25	25	15
MS9001F	229	210	25	25	15

[a]For operation at ISO conditions using natural gas fuel.
[b]Maximum design goal for CO emissions. Most in-house test configurations have achieved CO emission levels between 5 and 25 ppmv.

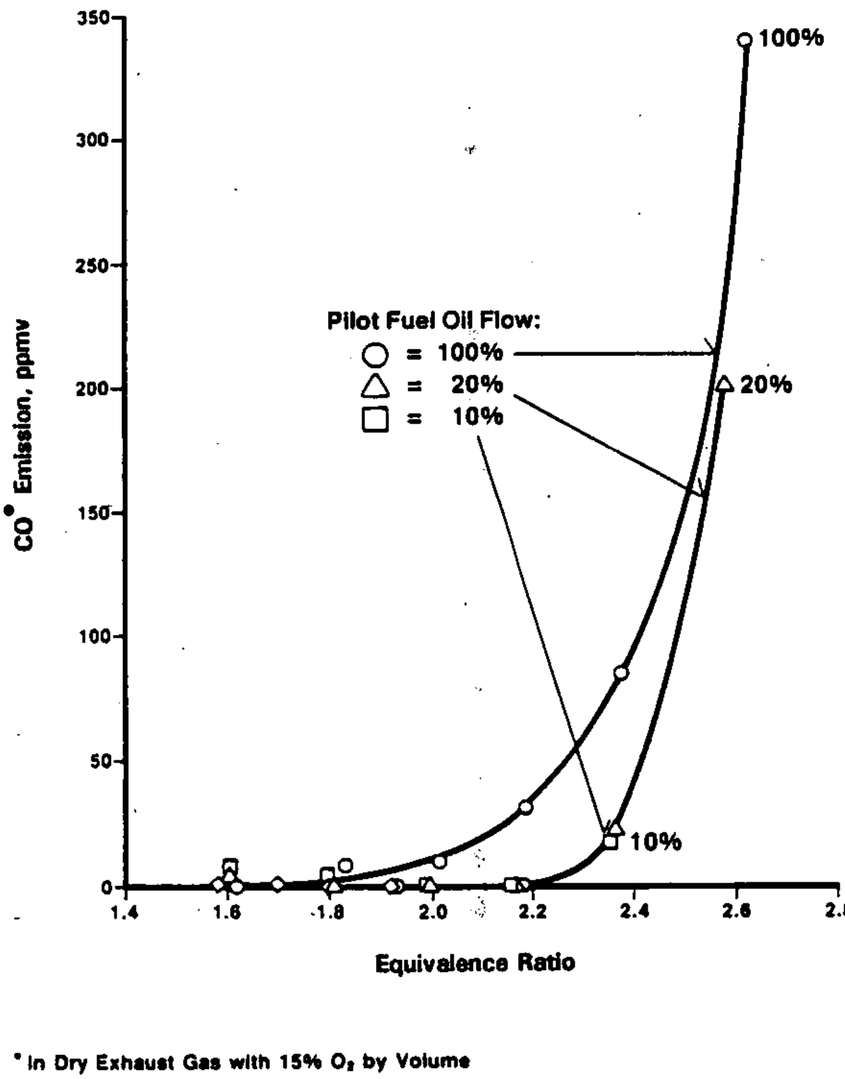


Figure 5-24. The CO emission test results from a lean premix silo combustor firing fuel oil without wet injection.[53]

are in the range of 0 to 2 ppmv for a pilot oil fuel flow of percent (representing 10 percent of the total fuel flow).[53] 10 percent pilot fuel flow corresponds to controlled NO_x sion levels below 50 ppmv, as shown previously in ure 5-22. No data for HC emissions were available for lean ixed burner designs.

3 Rich/Quench/Lean Combustion

5.2.3.1 Process Description. Rich/quench/lean (RQL) ustors burn fuel-rich in the primary zone and fuel-lean in secondary zone. Incomplete combustion under fuel-rich itions in the primary zone produces an atmosphere with a high entration of CO and hydrogen (H_2). The CO and H_2 replace of the oxygen normally available for NO_x formation and also as reducing agents for any NO_x formed in the primary zone. fuel nitrogen is released with minimal conversion to NO_x. lower peak flame temperatures due to partial combustion also ce the formation of thermal NO_x.[55]

As the combustion products leave the primary zone, they pass ugh a low-residence-time quench zone where the combustion ucts are rapidly diluted with additional combustion air or . This rapid dilution cools the combustion products and at ame time produces a lean A/F. Combustion is then completed fuel-lean conditions. This secondary lean combustion step ally contributes to the formation of fuel NO_x because most e fuel nitrogen will have been converted to N_2 prior to the combustion phase. Thermal NO_x is minimized during lean stion due to the low flame temperature.[55]

5.2.3.2 Applicability. The RQL combustion concept applies l types of gas turbines. None of the manufacturers cted for this study, however, currently have this design able for their production turbines. This may be due to lack and for this design due to the current limited use of nitrogen-content fuels in gas turbines.

.2.3.3 Factors Affecting Performance. The NO_x emissions RQL combustors are affected primarily by the equivalence in the primary combustion zone and the quench airflow rate.

Careful selection of equivalence ratios in the fuel-rich zone will minimize both thermal and fuel NO_x formation. Further NO_x reduction is achieved with increasing quench airflow rates, which serve to reduce the equivalence ratio in the secondary (lean) combustion stage.

5.2.3.4 Achievable NO_x Emissions Levels Using Rich/Quench/Lean Combustion. The RQL staged combustion has been demonstrated in rig tests to be effective in reducing both thermal NO_x and fuel NO_x. As shown in Figure 5-25, NO_x emissions are reduced by 40 to 50 percent in a test rig burning diesel fuel. At an equivalence ratio of 1.8, the NO_x emissions can be reduced from 0.50 to 0.27 lb/MMBtu by increasing the quench airflow from 0.86 to 1.4 kg/sec. Data were not available to convert the NO_x emissions figures to ppmv. The effectiveness of rich/lean staged combustion in reducing fuel NO_x when firing high-FBN fuels is shown in Figure 5-26. Increasing the FBN content from 0.13 to 0.88 percent has little impact on the total NO_x formation at an operating equivalence ratio of 1.3 to 1.4. Tests on other rich/lean combustors indicate fuel nitrogen conversions to NO_x of about 7 to 20 percent.[58,59] These fuel nitrogen conversions represent a fuel NO_x emission reduction of approximately 50 to 80 percent.

One manufacturer has tested an RQL combustor design in a 4 MW (5,360 hp) gas turbine fueled with a finely ground coal and water mixture. The coal partially combusts in a fuel-rich zone at temperatures of 1650°C (3000°F), with low O_2 levels and an extremely short residence time. The partially combusted products are then rapidly quenched with water, cooling combustion temperatures to inhibit thermal NO_x formation. Additional combustion air is then introduced, and combustion is completed under fuel-lean conditions. In tests at the manufacturer's plant, cosponsored by the U. S. Department of Energy, a NO_x emission level of 25 ppmv at 15 percent O_2 was achieved. This combustor design can also be used with natural gas and oil fuels. Single-digit NO_x emission levels are reported for operation on

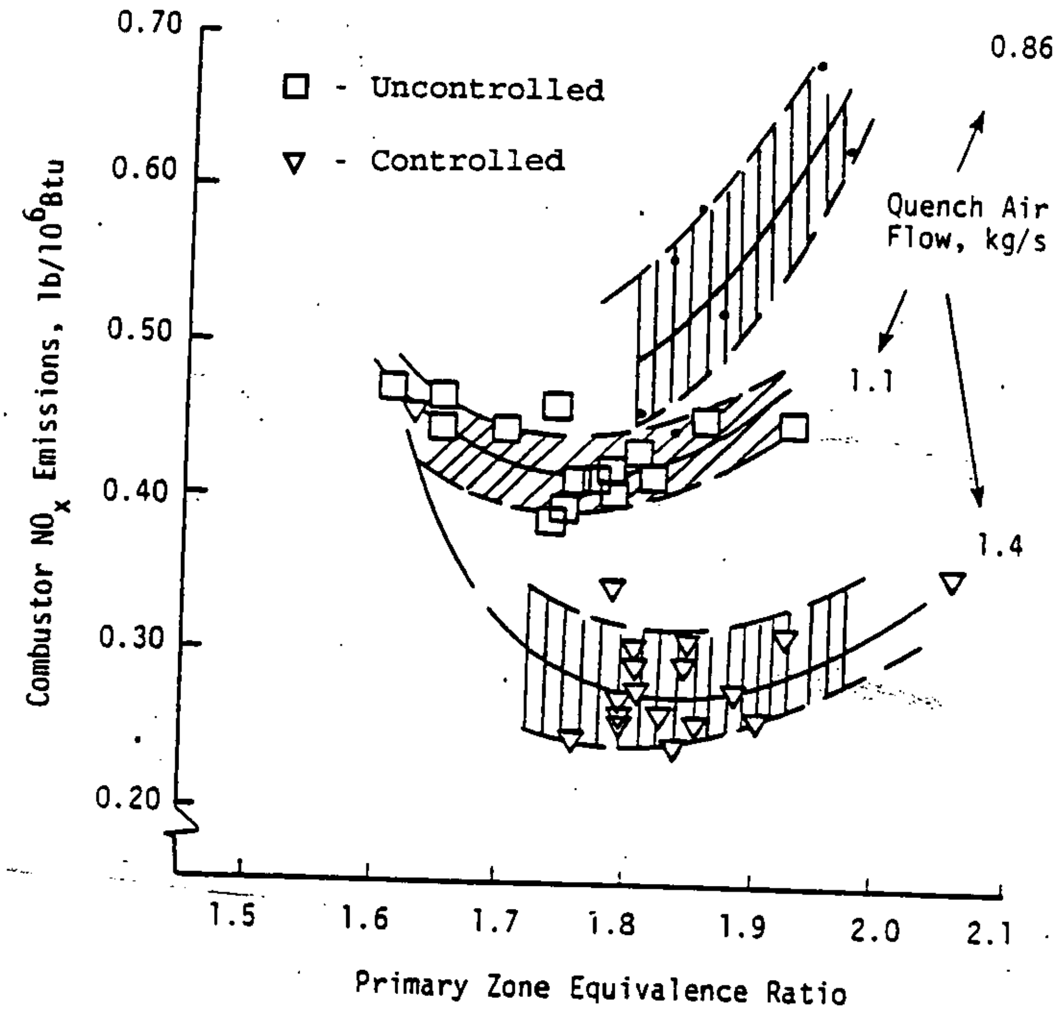


Figure 5-25. Nitrogen oxide emissions versus primary zone equivalence ratio for a rich/quench/lean combustor firing distillate oil.[56]

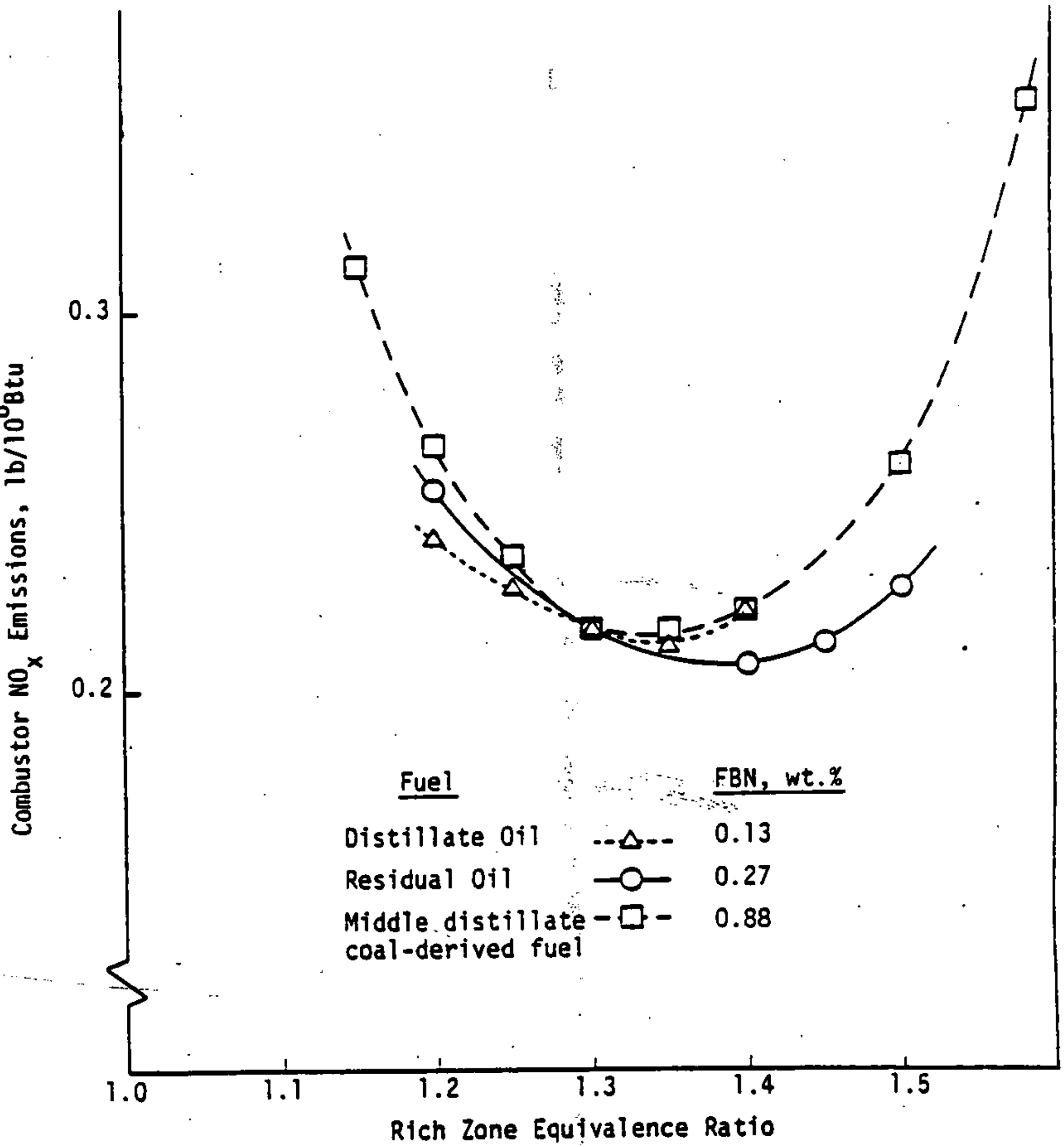


Figure 5-26. Effects of fuel bound nitrogen (FBN) content of NO_x emissions for a rich/quench/lean combustor.[57]

natural gas fuel. This combustor design is not yet available for production turbines.[60]

5.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. Over 100 gas turbine installations use SCR in the United States.[61] An SCR process description, the applicability of SCR for gas turbines, the factors affecting SCR performance, and the achievable NO_x reduction efficiencies are discussed in this section.

5.3.1 Process Description

The SCR process reduces NO_x emissions by injecting ammonia into the flue gas. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. In the catalyst unit, the ammonia reacts with NO_x primarily by the following equations:[62]

$NH_3 + NO + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O$; and

$NH_3 + 1/2\ NO_2 + 1/4\ O_2 \rightarrow 3/2\ N_2 + 3/2\ H_2O$.

The catalyst's active surface is usually either a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path to maximize conversion efficiency and minimize back-pressure on the gas turbine. The most common catalyst body configuration is a monolith, "honeycomb" design, as shown in Figure 5-27.

An ammonia injection grid is located upstream of the catalyst body and is designed to disperse the ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. In a typical ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the

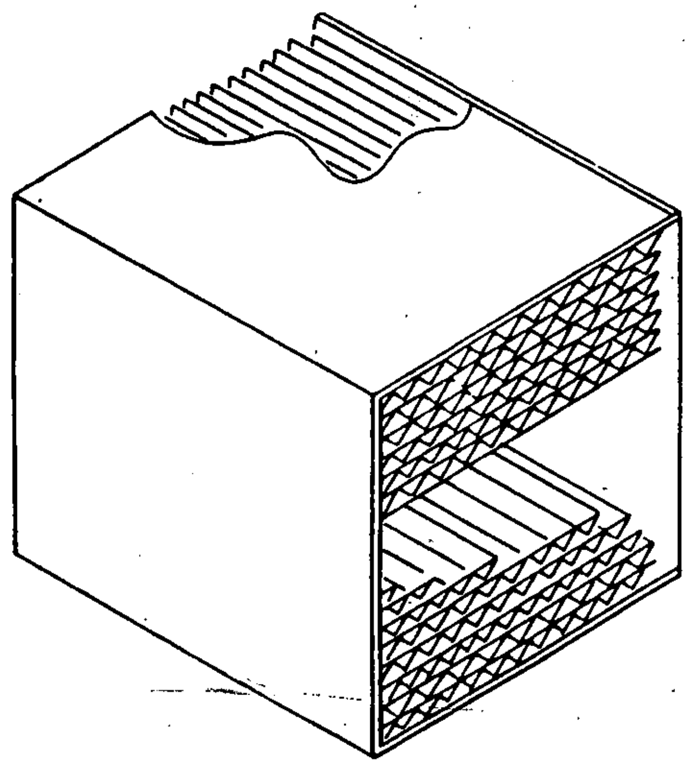


Figure 5-27. Cutaway view of a typical monolith catalyst body with honeycomb configuration.[62]

injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about 5 percent.[62]

An alternative to using the anhydrous ammonia/carrier gas system is to inject an a aqueous ammonia solution. This system is currently not as common but removes the potential safety hazards associated with transporting and storing anhydrous ammonia and is often used in installations with close proximity to populated areas.[61,62]

The NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. As indicated by the chemical reaction equations listed above, it takes one mole of NH_3 to reduce one mole of NO, and two moles of NH_3 to reduce one mole of NO_2. The NO_x composition in the flue gas from a gas turbine is over 85 percent NO, and SCR systems generally operate with a molar NH_3/NO_x ratio of approximately 1.0.[63] Increasing this ratio will further reduce NO_x emissions but will also result in increased unreacted ammonia passing through the catalyst and into the atmosphere. This unreacted ammonia is known as ammonia slip.

5.3.2 Applicability of SCR for Gas Turbines

Selective catalytic reduction applies to all gas turbine types and is equally effective in reducing both thermal and fuel NO_x emissions. There are, however, factors that may limit the applicability of SCR.

An important factor that affects the performance of SCR is operating temperature. Gas turbines that operate in simple cycle have exhaust gas temperatures ranging from approximately 450° to 540°C (850° to 1000°F). Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 260° to 400°C (400° to 800°F). For sulfur-bearing fuels that produce greater than 1 ppm SO_3 in the flue gas, the catalyst operating temperature range narrows to 315° to 400°C (600° to 800°F). The upper range of this temperature window can be increased using a zeolite catalyst to a maximum of 590°C (1100°F).[64]

Base metal catalysts are most commonly used in gas turbine SCR applications, accounting for approximately 80 percent of all U.S. installations, and operate in cogeneration or combined cycle applications. The catalyst is installed within the HRSG, where the heat recovery process reduces exhaust gas temperatures to the proper operating range for the catalyst. The specific location of the SCR within the HRSG is application-specific; Figure 5-28 shows two possible SCR locations. In addition to the locations shown, the catalyst may also be located within the evaporator section of the HRSG.

As noted above, zeolite catalysts have a maximum operating temperature range of up to 590°C (1100°F), which is compatible with simple cycle turbine exhaust temperatures. To date, however, there is only one SCR installation operating with a zeolite catalyst directly downstream of the turbine. This catalyst, commissioned in December 1989, has an operating range of 260° to 515°C (500° to 960°F) and operates approximately 90 percent of the time at temperatures above 500°C (930°F).[65]

Another consideration in determining the applicability of SCR is complications arising from sulfur-bearing fuels. The sulfur content in pipeline quality natural gas is negligible, but distillate and residual oils as well as some low-Btu fuel gases such as coal gas have sulfur contents that present problems when used with SCR systems. Combustion of sulfur-bearing fuels produces SO_2 and SO_3 emissions. A portion of the SO_2 oxidizes to SO_3 as it passes through the HRSG, and base metal catalysts have an SO_2-to-SO_3 oxidation rate of up to five percent.[64] In addition, oxidation catalysts, when used to reduce CO emissions, will also oxidize SO_2 to SO_3 at rates of up to 50 percent.[66]

Unreacted ammonia passing through the catalyst reacts with SO_3 to form ammonium bisulfate (NH_4HSO_4) and ammonium sulfate [$(NH_4)_2SO_4$] in the low-temperature section of the HRSG. The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and the formation rate increases with decreasing

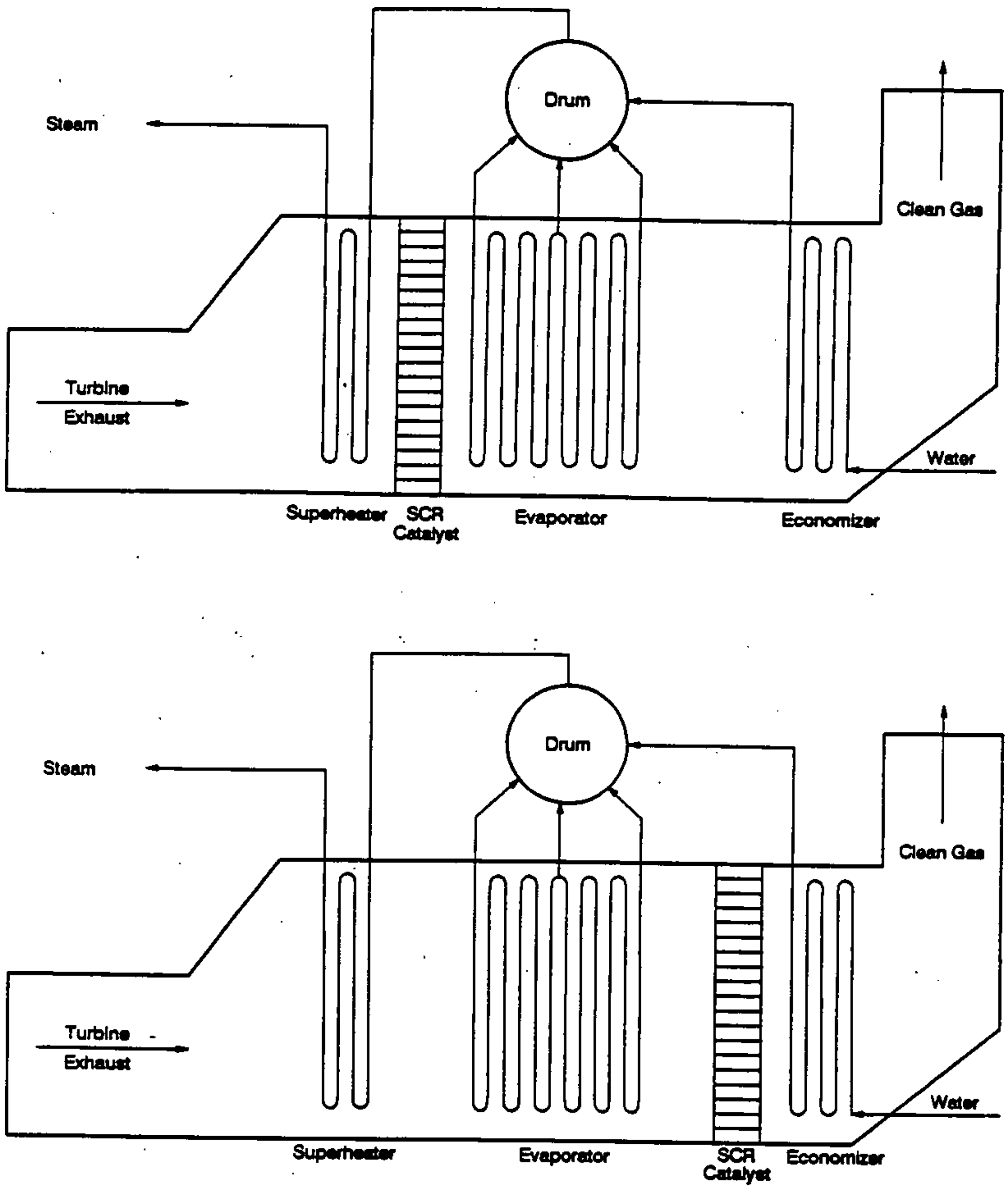


Figure 5-28. Possible locations for SCR unit in HRSG.[62]

temperature. Below 200°C (400°F), ammonium salt formation occurs with single-digit ppmv levels of SO_3 and NH_3.[66]

The exhaust temperature exiting the HRSG is typically in the range of 150° to 175°C (300° to 350°F), so ammonium salt formation typically occurs in the low-temperature section of the HRSG.[66] Ammonium bisulfate is a sticky substance that over time corrodes the HRSG boiler tubes. Additionally, it deposits on both the boiler and catalyst bed surfaces, leading to fouling and plugging of these surfaces. These deposits result in increased back pressure on the turbine and reduced heat transfer efficiency in the HRSG. This requires that the HRSG be removed from service periodically to water-wash the affected surfaces. Ammonium sulfate is not corrosive, but like ammonium bisulfate, it deposits on the HRSG surfaces and contributes to plugging and fouling of the heat transfer system.[33]

Formation of ammonium salts can be avoided by limiting the sulfur content of the fuel and/or limiting the ammonia slip. Low SO_2-to-SO_3 oxidizing catalysts are also available. Base metal catalysts are available with oxidation rates of less than 1 percent, but these low oxidation formulas also have lower NO_x reduction activity per unit volume and therefore require a greater catalyst volume to achieve a given NO_x reduction level. Zeolite catalysts are reported to have intrinsic SO_2-to-SO_3 oxidation rates of less than 1 percent.[64,66] As stated above, pipeline-quality natural gas has negligible sulfur content, but some sources of natural gas contain H_2S, which may contribute to ammonium salt formation. For oil fuels, even the lowest-sulfur distillate oil or liquid aviation fuel contains sulfur levels that can produce ammonium salts. According to catalyst vendors, SCR systems can be designed for 90 percent NO_x reduction and 10 ppm or lower NH_3 slip for sulfur-bearing fuels up to 0.3 percent by weight.[64] Continuous emission monitoring equipment has been developed for NH_3, and may be instrumental in regulating ammonia injection to minimize slip.[67]

To date, there is limited operating experience using SCR with oil-fired gas turbine installations. One combined cycle installation using oil fuel, a United Airlines facility in San Francisco installed in 1985, experienced fuel-related catalyst problems and now uses only natural gas fuel.[33] In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with oil fuels in Europe and Japan, where catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas fuel.[64] A zeolite catalyst installed on a 5 MW (6710 hp) dual fuel reciprocating engine in the northeastern United States has operated for over 3 years and burned approximately 600,000 gallons of diesel fuel while maintaining a NO_x reduction efficiency of greater than 90 percent.[3]

In its guidance to member states, NESCAUM recommends that SCR be considered for NO_x reduction in dual-fueled turbine applications. There are four combined cycle gas turbines installations operating with SCR in the northeast United States burning natural gas as the primary fuel with oil fuel as a back-up.[3] These installations, listed in Table 5-16, began operating recently and have limited hours of operation on oil fuel. As indicated in the table, two of these installations shut down the ammonia injection when operating on oil fuel to prevent potential operating problems arising from sulfur-bearing fuels. Permits issued more recently in this region for other dual-fuel installations, however, require that the SCR system be operational on either fuel.[3]

A final consideration for SCR is catalyst masking or poisoning agents. Natural gas is considered clean and free of contaminants, but other fuels may contain agents that can degrade catalyst performance. For refinery, field, or digester gas fuel applications, it is important to have an analysis of the fuel and properly design the catalyst for any identified contaminants. Arsenic, iron, and silica may be present in field gases, along with zinc and phosphorus. Catalyst life with these fuels depends upon the content of the gas and is a function of the initial

TABLE 5-16. GAS TURBINE INSTALLATIONS IN THE NORTHEASTERN UNITED STATES WITH SCR AND PERMITTED FOR BOTH NATURAL GAS AND OIL FUELS[3]

Installation	State	Gas turbine model	Output, MW[a]	NO_x emissions, ppmv (gas fuel/oil fuel)		
				Uncontrolled[b]	Wet injection[b]	Wet injection + SCR[c]
Altresco-Pittsfield	MA	MS6001	38.3	148/267	42/65	9/18[d e]
Cogen Technologies	NJ	MS6001	38.3	148/267	42/65	15/65[f]
Ocean State Power	RI	MS7001E	83.5	154/277	42/65	9/42[f]
Pawtucket Power	RI	MS6001	38.3	148/267	42/65	9/18[d]

[a]Power output for a single gas turbine. Installation power output is higher due to multiple units and/or combined cycle operation.
[b]Per manufacturer at ISO conditions.
[c]Operating permit limits.
[d]This installation requires the SCR system to be operational when burning oil fuel.
[e]This installation operated 185 hours on oil fuel in 1991, burning approximately 354,000 gallons of oil fuel.
[f]Ammonia injection is shut down during operation on oil fuel.

design parameters. With oil fuels, in addition to the potential for ammonium salt formation, it is important to be aware of heavy metal content. Particulates in the flue gas can also mask the catalyst.[64]

Selective catalytic reduction may not be readily applicable to gas turbines firing fuels that produce high ash loadings or high levels of contaminants because these elements can lead to fouling and poisoning of the catalyst bed. However, because gas turbines are also subject to damage from these elements, fuels with high levels of ash or contaminants typically are not used.

Coal, while not currently a common fuel for turbines, has a number of potential catalyst deactivators. High dust concentrations, alkali, earth metals, alkaline heavy metals, calcium sulfate, and chlorides all can produce a masking or blinding effect on the catalyst. High dust can also erode the catalyst. Erosion commonly occurs only on the leading face of the catalyst. Airflow deflectors and dummy layers of catalyst can be used to straighten out the airflow and reduce erosion. There is currently no commercial U.S. experience with coal. In Japan, which burns low-sulfur coal with moderate dust levels, catalyst life has been 5 years or more without replacement. In Germany, with high dust loadings, the experience has also been 5 years or more.[64]

Masking agents deposit on the surface of the catalyst, forming a barrier between the active catalyst surface and the exhaust gas, inhibiting catalytic activity. Poisoning agents chemically react with the catalyst and render the affected area inactive. Masking agents can be removed by vacuuming or by using soot blowers or superheated steam. Catalysts cleaned in this manner can recover greater than 90 percent of the original reduction activity. The effects of poisoning agents, however, are permanent and the affected catalyst surface cannot be regenerated.[64]

Retrofit applications for SCR may require the addition of a heat exchanger for simple cycle installations, and replacement or extensive modification of the existing HRSG in cogeneration and combined cycle applications to accommodate the catalyst body. For these reasons, retrofit applications for SCR could involve high capital costs.

5.3.3 Factors Affecting SCR Performance

The NO_x reduction efficiency for an SCR system is influenced by catalyst material and condition, reactor temperature, space velocity, and the NH_3/NO_x ratio.[63] These design and operating variables are discussed below.

Several catalyst materials are available, and each has an optimum NO_x removal efficiency range corresponding to a specific temperature range. Proprietary formulations containing titanium dioxide, vanadium pentoxide, platinum, or zeolite are available to meet a wide spectrum of operating temperatures. The NO_x removal efficiencies for these catalysts are typically between 80 and 90 percent when new. The NO_x removal efficiency gradually decreases over the operating life of the catalyst due to deterioration from masking, poisoning, or sintering.[63] The rate of catalyst performance degradation depends upon operating conditions and is therefore site-specific.

The space velocity (volumetric flue gas flow divided by the catalyst volume) is an indicator of gas residence time in the catalyst unit. The lower the space velocity, the higher the residence time, and the higher the potential for increased NO_x reduction. Because the gas flow is a constant determined by the gas turbine, the space velocity depends upon the catalyst volume, or total active surface area. The distance across the opening between plates or cells in the catalyst, referred to as the pitch, affects the overall size of the catalyst body. The smaller the pitch, the greater the number of rows or cells that can be placed in a given volume. Therefore, for a given catalyst body size, the smaller the pitch, the larger the catalyst volume and the lower the space velocity. For natural gas applications the catalyst pitch is typically 2.5 millimeters (mm) (0.10 inch [in.]), increasing to 5 to 7 mm (0.20 to 0.28 in.) for coal-fuel applications.[64]

As discussed in Section 5.3.1, the NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Increasing this ratio increases the level of NO_x reduction but may also result in higher ammonia slip levels.

5.3.4 Achievable NO_x Emission Reduction Efficiency Using SCR

Most SCR systems operating in the United States have a space velocity of about 30,000/hr, a NH_3/NO_x ratio of about 1.0, and ammonia slip levels of approximately 10 ppm. The resulting NO_x reduction efficiency is about 90 percent.[41] Reduction efficiency is the level of NO_x removed as a percentage of the level of NO_x entering the SCR unit. Only one gas turbine installation in the United States was identified using only SCR to reduce NO_x emissions. This installation has two natural gas-fired 8.5 MW gas turbines, each with its own HRSG in which is installed an SCR system. A summary of emission testing at this site lists NO_x emissions at the inlet to the SCR catalyst at 130 ppmv. Controlled NO_x emissions downstream of the catalyst were 18 ppmv, indicating a NO_x reduction efficiency of 86 percent. Maximum ammonia slip levels were listed at 35 ppmv.[68]

All other gas turbine installations identified as using SCR in the United States use this control method in combination with wet injection and/or low-NO_x combustors. The emission levels that can be achieved by this combination of controls are found in Section 5.4.

5.3.5 Disposal Considerations for SCR

The SCR catalyst material has a finite life, and disposal can pose a problem. The guaranteed catalyst life offered by catalyst suppliers ranges from 2 to 3 years.[64] In Japan, where SCR systems have been in operation since 1980, experience shows that many catalysts in operation with natural gas-fired boilers have performed well for 7 years or longer.[63,64] In any case, at some point the catalyst must be replaced, and those units containing heavy metal oxides such as vanadium or titanium potentially could be considered hazardous wastes. While the amount of hazardous material in the catalyst is relatively small, the volume of the catalyst body can be quite large, and disposal of this waste could be costly. Some suppliers provide for the removal and disposal of spent catalyst. Precious metal and zeolite catalysts do not contain hazardous wastes.

5.4 CONTROLS USED IN COMBINATION WITH SCR

With but one exception, SCR units installed in the United States are used in combination with wet controls or combustion controls described in Sections 5.1 and 5.2. Wet controls yield NO_x emission levels of 25 to 42 ppmv for natural gas and 42 to 110 ppmv for distillate oil, based on the data provided by gas turbine manufacturers and shown in Figures 5-10 and 5-11. A carefully designed SCR system can achieve NO_x reduction efficiencies as high as 90 percent, with ammonia slip levels of 10 ppmv or less for natural gas and low-sulfur (<0.3 percent by weight) fuel applications.[64]

As discussed for wet injection in Sections 5.1.4 and 5.2.2.4, controlled NO_x emission levels for natural gas range from 25 to 42 ppmv for natural gas fuel and from 42 to 110 ppmv for oil fuel. Applying a 90 percent reduction efficiency for SCR, NO_x levels can be theoretically reduced to 2.5 to 4.2 and 4.2 to 11.0 ppmv for natural gas and oil fuels, respectively. For oil fuels and other sulfur-bearing fuels, a reduction efficiency of 90 percent requires special design considerations to address potential operational problems caused by the sulfur content in the fuel. This subject is discussed in Section 5.3.2 The final controlled NO_x emission level depends upon the NO_x level exiting the turbine and the achievable SCR reduction efficiency.

Test reports provided by SCAQMD include three gas turbine combined cycle installations fired with natural gas that have achieved NO_x emission levels of 3.4 to 7.2 ppmv, referenced to 15 percent oxygen. The NO_x and CO emissions reported for these tests are shown in Table 5-17. Ammonia slip levels were not reported. Ammonia slip levels were reported, however, in a summary of emission tests for 13 SCR installations and are presented in Table 5-18.[68] For these sites, operating on natura gas fuel, the NO_x reduction efficiency of the catalyst ranges

TABLE 5-17. EMISSIONS TESTS RESULTS FOR GAS TURBINES USING STEAM INJECTION PLUS SCR[69-71]

				NO_x emissions, ppmv (lb/hr)			
Test No.	Gas turbine model	Output, MW	Fuel	Uncontrolled	Wet injection	Wet injection + SCR	CO, ppmv
1	MS7001E	82.8	Natural gas + refinery gas mixture	154	42	5.66 (25.2)	<2.00
2	MS7001E	79.7	Natural gas + refinery gas + butane mixture	148	42	7.17 (31.7)	<2.00
3	MS6001B	33.8	LPG + refinery gas mixture	148	42	3.36 (5.82)	<2.00

TABLE 5-18. SUMMARY OF SCR NO_X EMISSION REDUCTIONS AND AMMONIA SLIP LEVELS FOR NATURAL GAS-FIRED TURBINES[68]

Site	Gas turbine		Power output, MW	SCR operating temperature, °F	Maximum permit level for injection, NH_3/NO_x molar ratio	NO_x emissions, ppmv at 15% O_2			Compliance test NH_3 slip, ppmv at 15% O_2
	Manufacturer	Model				SCR in	SCR out[a]	Percent reduction	
A	GE	LM2500	22	730	1.0	50	9.0	82	10[b]
B	GE	MS5001	18	645	1.0	45	4.5	90	2
C	GE	LM2500	22	685	1.1	37	8.9	76	20[b]
D	ABB	Type 8	44	760	1.2	27	4	85	9
E	GE	LM2500	22	680	1.0	60	12.6	79	7
F	GE	MS7001E	80	630	1.0	28	8.4	70	4.1
G	GE	LM2500	22	625	0.9	68	13.6	80	1
H	Allison	501-KB	3.5	650	1.1	25	1.0	96	10[c]
I	Solar	Mars	8.5	580	1.6	130	18.2	86	35[d]
J	GE	LM2500	22	750	1.0	37	14.8	60	11[e]
K	GE	MS7001E	80	754	1.0	40	6.0	85	2
L	GE	MS6001	37	650	1.0	47	8.9	81	4
M	GE	MS6001	37	700	NA[f]	33	3.3	90	8

[a]Calculated from ppmv entering the SCR and percent reduction figures.
[b]NH_3 permit limit. Test emission level not available.
[c]Test was run at less than permit NH_3/NO_x ratio of 1.1. SCR designed for exhaust from total of 5 turbines. Only one turbine operating during test.
[d]This site does not use wet injection for gas turbine NO_x reduction.
[e]NH_3 compliance test not required. NH_3 level from NH_3 monitor testing.
[f]NA = not available.

from 60 to 96 percent, with most reduction efficiencies between 80 and 90 percent. Ammonia slip levels range from 1 to 35 ppmv. The site with the 35 ppmv ammonia slip level is unique in that it is the only site identified in the United States that uses only SCR rather than a combination of SCR and wet injection to reduce NO_x emissions. With the exception of this site, all NH_3 slip levels in Table 5-18 that are based on test data are less than 10 ppmv. Based on information received from catalyst vendors, it is expected that an SCR system operating downstream of a gas turbine without wet injection could be designed to limit ammonia slip levels to 10 ppmv or less.[64] No test data are available for SCR operation on gas turbines fired with distillate oil fuels.

5.5 EFFECT OF ADDING A DUCT BURNER IN HRSG APPLICATIONS

A duct burner is often added in cogeneration and combined cycle applications to increase the steam capacity of the HRSG (see Section 4.2.2). Duct burners in gas turbine exhaust streams consist of pipes or small burners that are placed in the exhaust gas stream to allow firing of additional fuel, usually natural gas. Duct burners can raise gas turbine exhaust temperatures to 1000°C (2000°F), but a more common temperature is 760°C (1400°F). The gas turbine exhaust is the source of oxygen for the duct burner.

Figure 5-29 shows a typical natural gas-fired duct burner installation. Figure 5-30 is a cross-sectional view of one style of duct burner that incorporates design features to reduce NO_x. In this low-NO_x design, natural gas exits the orifice in the manifold and mixes with the gas turbine exhaust entering through a small slot between the casing and the gas manifold. This mixture forms a jet diffusion flame that causes the recirculation shown in Zone "A." Due to the limited amount of turbine exhaust that can enter Zone A, combustion in this zone is fuel-rich. As the burning gas jet exits into Zone "B," it mixes with combustion products that are recirculated by the flow eddies behind the wings of the stabilizer casing. The flame then expands into the turbine exhaust gas stream, where combustion is completed.

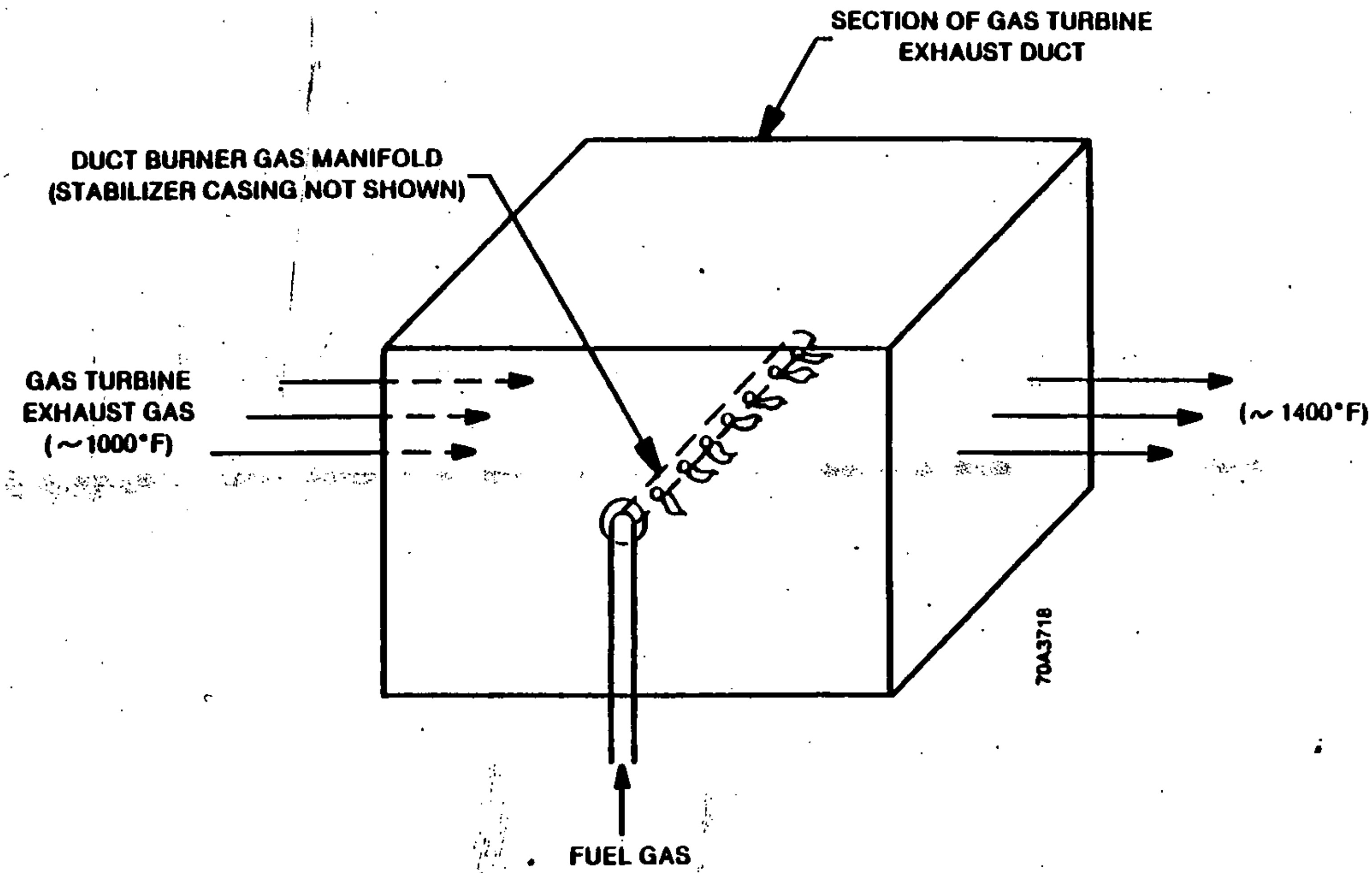


Figure 5-29. Typical duct burner for gas turbine exhaust application.[72]

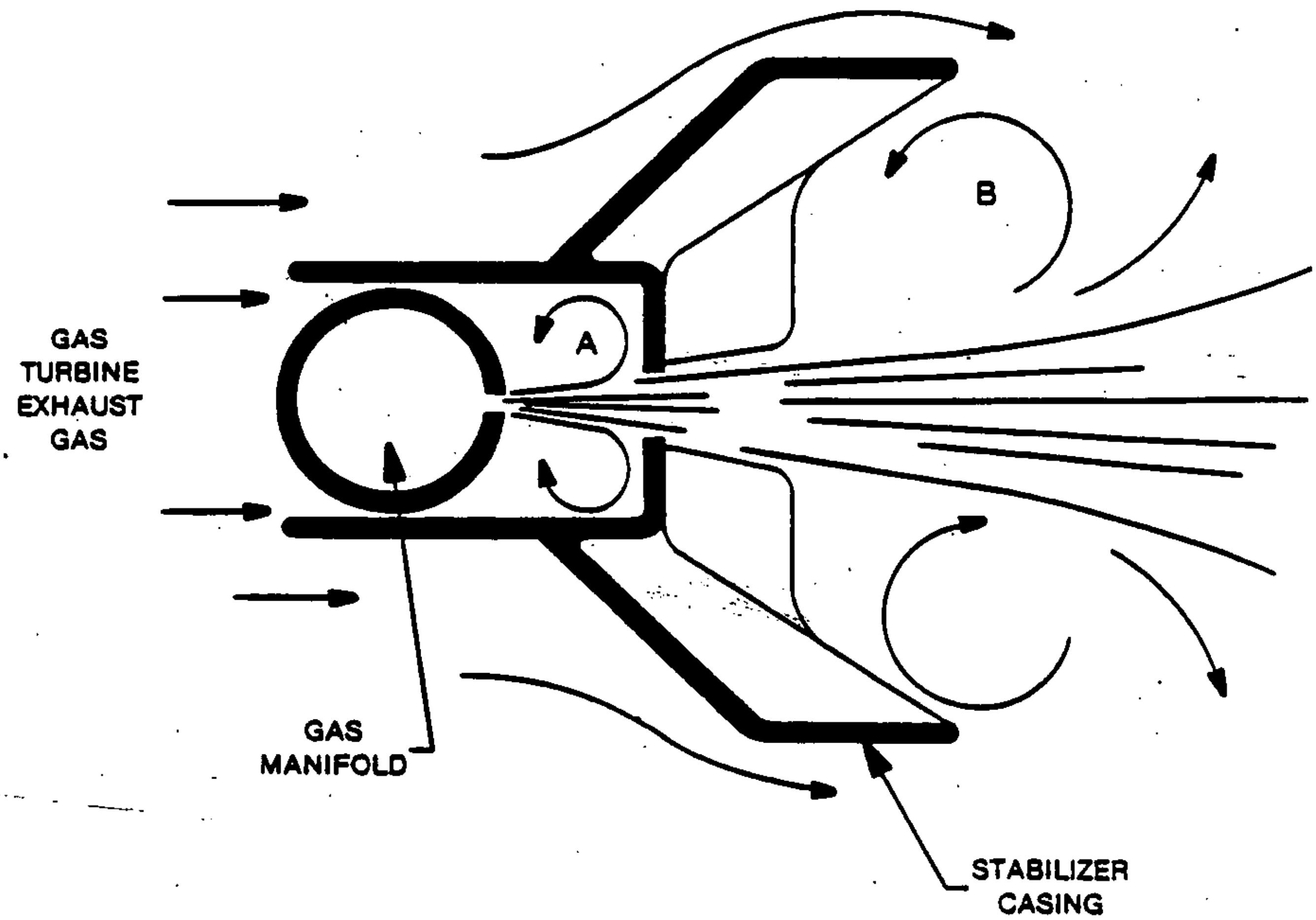


Figure 5-30. Cross-sectional view of a low-NO_x duct burner.[73,74]

For oil-fired burners, the design principles of the burner are the same. However, the physical layout is slightly different, as shown in Figure 5-31. Turbine exhaust gas is supplied in substoichiometric quantities by a slip stream duct to the burner. This slip stream supplies the combustion air for the fuel-rich Zone A. The flame shield produces the flow eddies, which recirculate the combustion products into Zone B.[76]

Most duct burners now in service fire natural gas. In all cases, a duct burner will produce a relatively small level of NO_x emissions during operation (See Section 4.2.2), but the net impact on total exhaust emissions (i.e., the gas turbine plus the duct burner) varies with operating conditions, and in some cases may even reduce the overall NO_x emissions. Table 5-19 shows the NO_x emissions measured at one site upstream and downstream of a duct burner. This table shows that NO_x emissions are reduced across the duct burner in five of the eight test runs.

The reason for this net NO_x reduction is not known, but it is believed to be a result of the reburning process in which the intermediate combustion products from the duct burner interact with the NO_x already present in the gas turbine exhaust. The manufacturer of the burner whose emission test results are shown in Table 5-19 states that the following conditions are necessary for reburning to occur:

1. The burner flame must produce a high temperature in a fuel-rich zone;

2. A portion of the turbine exhaust containing NO_x must be introduced into the localized fuel-rich zone with a residence time sufficient for the reburning process to convert the turbine NO_x to N_2 and O_2; and

3. The burner fuel should contain no FBN.[78]

In general, sites using a high degree of supplementary firing have the highest potential for a significant amount of reburning. In practice, only a limited number of sites achieve these reburning conditions due to specific plant operating requirements.[78]

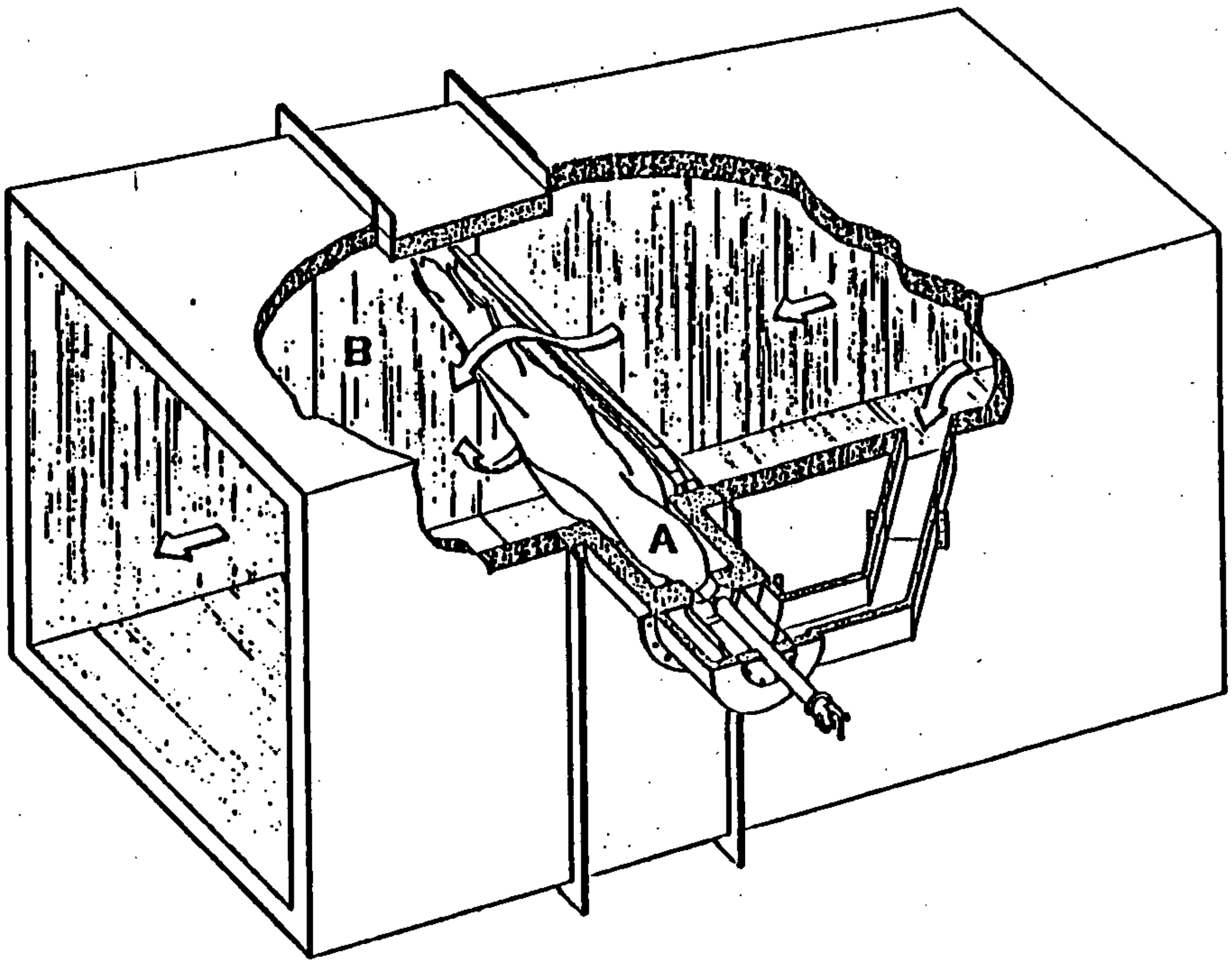


Figure 5-31. Low-NO_x duct burner designed for oil firing.[73,75]

TABLE 5-19. NO_x EMISSIONS MEASURED BEFORE AND AFTER A DUCT BURNER[77]

Gas turbine operation parameters			Duct burner operating parameters		Duct burner inlet		Duct burner outlet		Change across duct burner	
Test No.	Load, MW	Steam/fuel injection ratio, lb/lb	Heat input, MM Btu/hr	Load, percent	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr
1	33.8	0.94	133.8	82.1	0.149	61.4	0.097	55.7	-0.043	-5.7
2	35.0	0.97	93.3	57.3	0.142	58.8	0.113	58.9	0.001	0.1
3	34.5	0.95	40.8	25.0	0.134	57.5	0.118	58.7	0.029	1.2
4	32.0	0.50	137.5	84.4	0.207	85.8	0.151	83.9	-0.014	-1.9
5	32.8	0.46	43.8	26.8	0.228	95.2	0.192	94.0	-0.027	-1.2
6	31.5	0.00	136.7	83.9	0.392	159.7	0.270	156.2	-0.026	-3.5
7	33.0	0.00	42.0	25.8	0.384	166.7	0.313	156.7	-0.238	-10.0
8	11.1	0.00	140.9	86.5	0.157	29.1	0.132	42.1	0.092	13.0

5.6 ALTERNATE FUELS

Because thermal NO_x production is an exponential function of flame temperature (see Section 4.1.1), it follows that using fuels with flame temperatures lower than those of natural gas or distillate oils results in lower thermal NO_x emissions. Coal-derived gas and methanol have demonstrated lower NO_x emissions than more conventional natural gas or oil fuels. For applications using fuels with high FBN contents, switching to a fuel with a lower FBN content will reduce thermal NO_x formation and thereby lower total NO_x emissions.

5.6.1 Coal-Derived Gas

Combustor rig tests have demonstrated that burning coal-derived gas (coal gas) that has been treated to remove FBN produces approximately 30 percent of the NO_x emission levels experienced when burning natural gas. This is because coal gas has a low heat energy level of around 300 Btu or less, which results in a flame temperature lower than that of natural gas.[79] The cost associated with producing coal gas suitable for combustion in a gas turbine has made this alternative economically unattractive, but recent advances in coal gasification technology have renewed interest in this fuel.

A coal gas-fueled power plant is currently operating in the United States at a Dow Chemical plant in Placquemine, Louisiana. This facility operates with a subsidy from the Federal Government, which compensates for the price difference between coal gas and conventional fuels. Several commercial projects have been recently announced using technology developed by Texaco, Shell, Dow Chemical, and the U.S. Department of Energy. Facilities have been permitted for construction in Massachusetts and Delaware.[80]

A demonstration facility, known as Cool Water, operated using coal gas for 5 years in Southern California in the early 1980's. The NO_x emissions were reported at 0.07 lb/MMBtu.[80] Fuel analysis data is not available to convert this NO_x emission level to a ppmv figure. No other emissions data are available.

5.6.2 Methanol

Methanol has a flame temperature of 1925°C (3500°F) versus 2015°C (3660°F) for natural gas and greater than 2100°C (3800°F) for distillate oils. As a result, the NO_x emission levels when burning methanol are lower than those for either natural gas or distillate oils.

Table 5-20 presents NO_x emission data for a full-scale turbine firing methanol. The NO_x emissions from firing methanol without water injection ranged from 41 to 60 ppmv and averaged 49 ppmv. This test also indicated that methanol increases turbine output due to the higher mass flows that result from methanol firing. Methanol firing increased CO and HC emissions slightly compared to the same turbine's firing distillate oil with water injection. All other aspects of turbine performance were as good when firing methanol as when the turbine fired natural gas or distillate oil.[82] Turbine maintenance requirements were estimated to be lower and turbine life was estimated to be longer on methanol fuel than on distillate oil fuel because methanol produced fewer deposits in the combustor and power turbine.

Table 5-20 also presents NO_x emission data for methanol firing with water injection. At water-to-fuel ratios from 0.11 to 0.24, NO_x emissions when firing methanol range from 17 to 28 ppmv, a reduction of 42 to 65 percent.

In a study conducted at an existing 3.2 MW gas turbine installation in 1984, a gas turbine was modified to burn methanol. This study was conducted at the University of California at Davis and was sponsored by the California Energy Commission. A new fuel delivery system for methanol was required, but the only major modifications required for the turbine used in this study were new fuel manifolds and nozzles. Tests conducted burning methanol showed no visible smoke emissions, and only minor increases in CO emissions. Figure 5-32 shows the NO_x emissions measured while burning methanol and natural gas. Reductions of up to 65 percent were achieved, as NO_x emissions were 22 to 38 ppm when burning methanol versus

TABLE 5-20. NO_x EMISSIONS TEST DATA FOR A GAS TURBINE FIRING METHANOL AT BASELOAD[a,81]

Test	W/F ratio, lb/lb	NO_x emissions ISO conditions, ppm at 15% O_2	NO_x reduction, percent[b]
A	0	41	0
B	0	45	0
C	0	48	0
D	0	49	0
E	0	60	0
F	0	47	0
G	0	53	0
H	0	48	0
I	0	51	0
J	0	52	0
K	0	41	0
L	0	47	0
M	0	48	0
AVERAGE		49	
N	0.11	28	42.2
O	0.23	17	65.2
P	0.23	18	62.7
Q	0.24	18	62.7

[a]Baseload = 25 MW output
[b]Calculated using the average of the uncontrolled emissions.

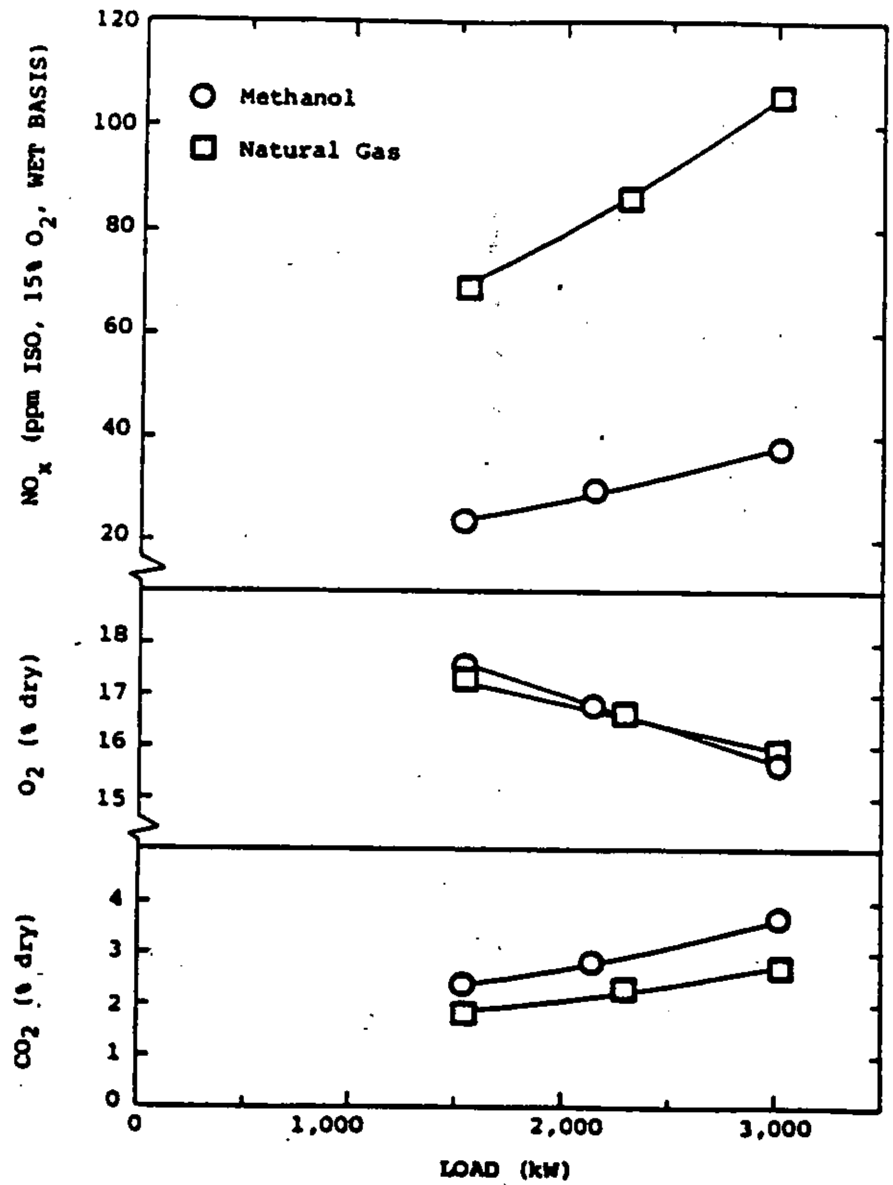


Figure 5-32. Influence of load on NO_x, O_2, and CO_2 emissions for methanol and natural gas.[83]

62 to 100 ppm for natural gas. In addition to the intrinsically lower NO_x production, water can be readily mixed with methanol prior to delivery to the turbine to obtain the additional NO_x reduction levels achievable with wet injection. Gas turbine performance characteristics, including startup, acceleration, load changes, and full load power, were all deemed acceptable by the turbine manufacturer.[83]

The current economics of using methanol as a primary fuel are not attractive. There are no confirmed commercial methanol-fueled gas turbine installations in the United States.

5.7 SELECTIVE NONCATALYTIC REDUCTION

Selective noncatalytic reduction (SNCR) is an add-on technology that reduces NO_x using ammonia or urea injection similar to SCR but operates at a higher temperature. At this higher operating temperature of 870° to 1200°C (1600° to 2200°F), the following reaction occurs:[84]

$$NO_x + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O.$$

This reaction occurs without requiring a catalyst, effectively reducing NO_x to nitrogen and water. The operating temperature can be lowered from 870°C (1600°F) to 700°C (1300°F) by injecting hydrogen (H_2) with the ammonia, as is shown in the above equation.

Above the upper temperature limit, the following reaction occurs:[84]

$$NH_3 + O_2 \rightarrow NO_x + H_2O.$$

Levels of NO_x emissions increase when injecting ammonia or urea into the flue gas at temperatures above the upper temperature limits of 1200°C (2200°F).

Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 600°C (1100°F). Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbine operating flow velocities.[85]

It may be feasible, however, to initiate this reaction in the gas turbine where operating temperatures fall within the reaction window, if suitable gas turbine modifications and injection systems can be developed.[85] This control technology has not been applied to gas turbines to date.

5.8 CATALYTIC COMBUSTION

5.8.1 Process Description

In a catalytic combustor, fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front. Peak combustion temperatures can be limited to below 1540°C (2800°F), which is below the temperature at which significant amounts of thermal NO_x begin to form.[86] An example of a lean catalytic combustor is shown in Figure 5-33.

Catalytic combustors can also be designed to operate in a rich/lean configuration, as shown in Figure 5-34. In this configuration, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.[89]

5.8.2 Applicability

Catalytic combustion techniques apply to all combustor types and are effective on both distillate oil- and natural gas-fired turbines. Because of the limited operating temperature range, catalytic combustors may not be easily applied to gas turbines subject to rapid load changes (such as utility peaking turbines).[90] Gas turbines that operate continuously at base load (such as industrial cogeneration applications) would not be as adversely affected by any limits on load following capability.[91]

5.8.3 Development Status

Presently, the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. The major problem is the development of a catalyst that will have an acceptable life in the high-temperature and -pressure environment

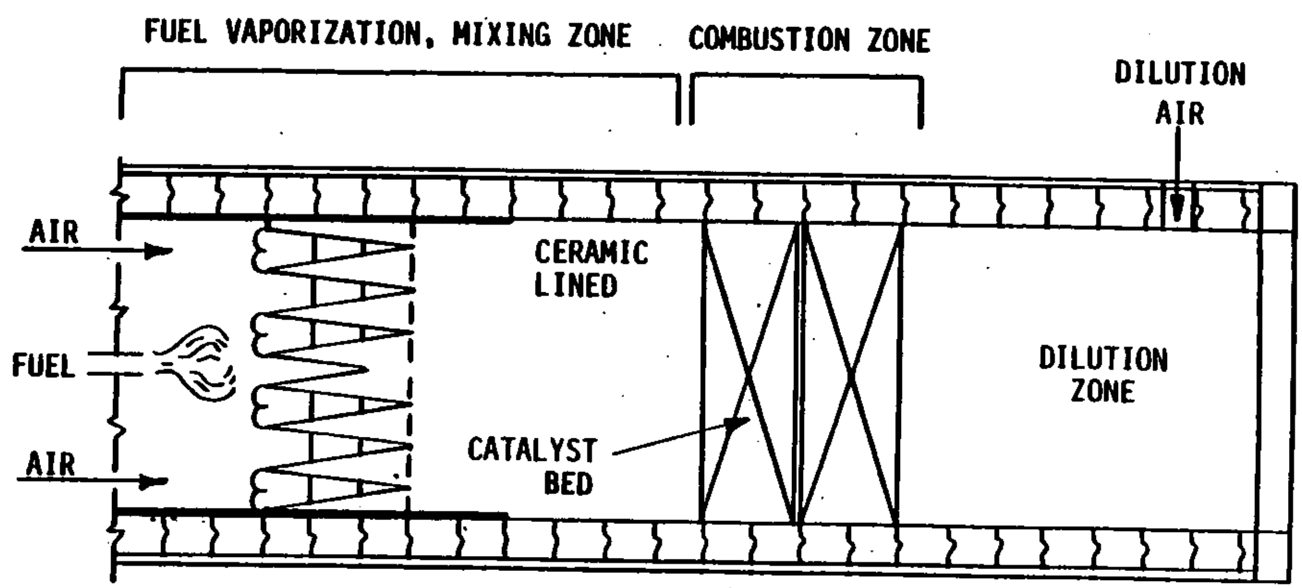


Figure 5-33. A lean catalytic combustor.[87]

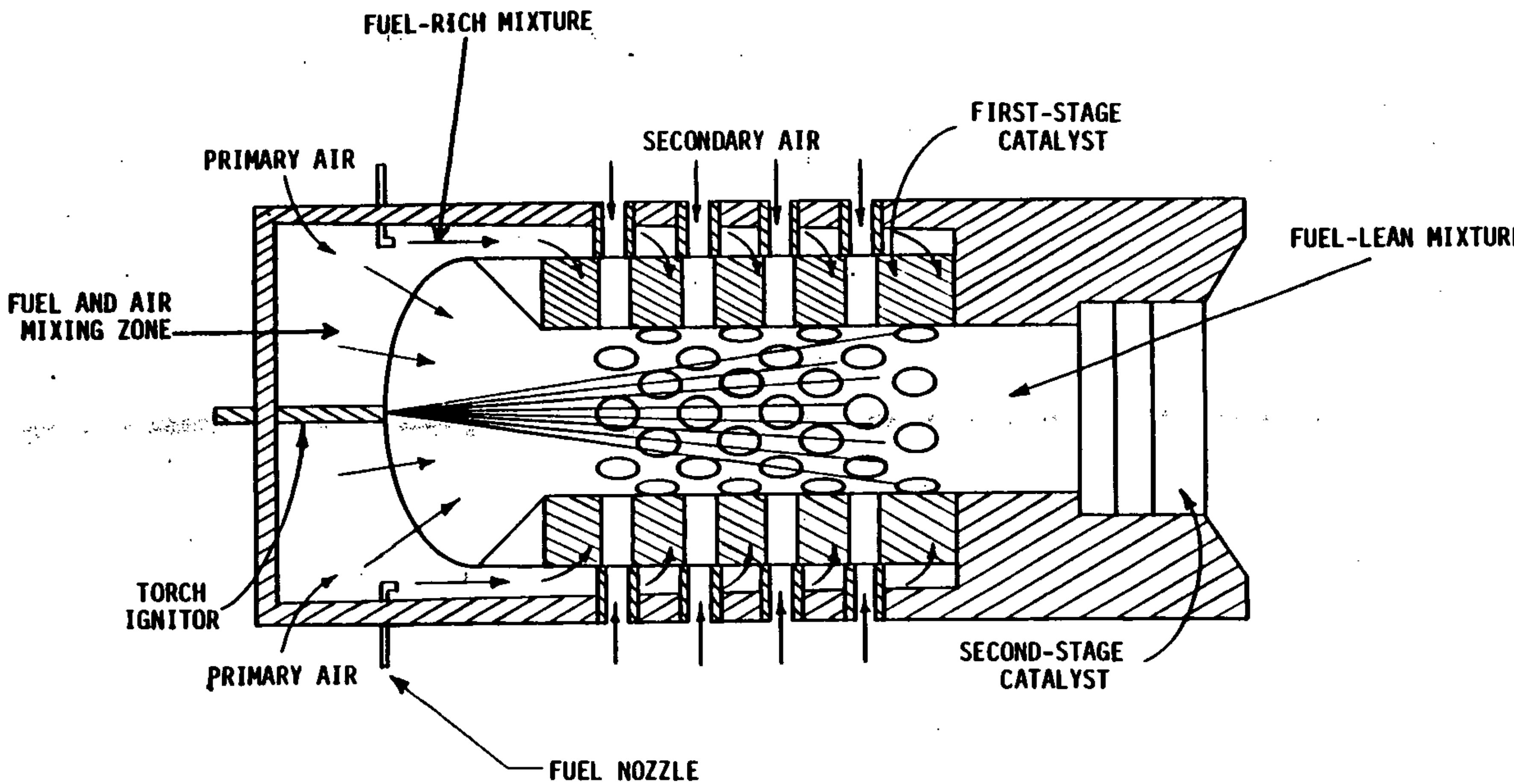


Figure 5-34. A rich/lean catalytic combustor.[88]

of gas turbine combustors. Additional problems that must be solved are combustor ignition and how to design the catalyst to operate over the full gas turbine operating range (idle to full load).[92]

5.9 OFFSHORE OIL PLATFORM APPLICATIONS

Gas turbines are used on offshore platforms to meet compression and electrical power requirements. This application presents unique challenges for NO_x emissions control due to the duty cycle, lack of a potable water source for wet injection, and limited space and weight considerations. The duty cycle for electric power applications of offshore platforms is unique. This duty cycle is subject to frequent load changes that can instantaneously increase or decrease by as much as a factor of 10.[93] Fluctuating loads result in substantial swings in turbine exhaust gas temperatures and flow rates. This presents a problem for SCR applications because the NO_x reduction efficiency depends upon temperature and space velocity (see Section 5.3.3).

The lack of a potable water supply means that water must be shipped to the platform or sea water must be desalinated and treated. The limited space and weight requirements associated with an SCR system may also have an impact on capital costs of the platform.

A 4-year study is underway for the Santa Barbara County Air Pollution Control Board to evaluate suitable NO_x control techniques for offshore applications. The goals of the study are to reduce turbine NO_x emissions at full load to 9 ppmv, corrected to 15 percent O_2, firing platform gas fuel and to achieve part load reductions of 50 percent. The study consists of two phases. The first phase, an engineering evaluation of available and emerging emission control technologies, is completed. The second phase will select the final control technologies and develop these technologies for offshore platform applications. Phase I of this study concludes that the technologies with the highest estimated probability for success in offshore applications are:

- Water injection plus SCR (80 percent);
- Methanol fuel plus SCR (70 percent);
- Lean premixed combustion plus SCR (65 percent); and
- Steam dilution of fuel prior to combustion plus SCR (65 percent).

A key conclusion drawn from Phase I of this study is that none of the above technologies or combination of technologies in offshore platform applications currently has a high probability of successfully achieving the NO_x emission reduction goals of this study without substantial cost and impacts to platform and turbine operations, added safety considerations, and other environmental concerns. These issues will be further studied in Phase II for the above control technologies.

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6.0 CONTROL COSTS

Capital and annual costs are presented in this chapter for the nitrogen oxide (NO_x) control techniques described in Chapter 5.0. These control techniques are water and steam injection, low-NO_x combustion, and selective catalytic reduction (SCR) used in combination with these controls. Model plants were developed to evaluate the control techniques for a range of gas turbine sizes, fuel types, and annual operating hours. The gas turbines chosen for these model plants range in size from 1.1 to 160 megawatts (MW) (1,500 to 215,000 horsepower [hp]) and include both aeroderivative and heavy-duty turbines. Model plants were developed for both natural gas and distillate oil fuels. For offshore oil production platforms, cost information was available only for one turbine model.

The life of the control equipment depends upon many factors, including application, operating environment, maintenance practices, and materials of construction. For this study, a 15-year life was chosen.

Both new and retrofit costs are presented in this chapter. For water and steam injection, these costs were assumed to be the same because most of the water treatment system installation can be completed while the plant is operating and because gas turbine nozzle replacement and piping connections to the treated water supply can be performed during a scheduled downtime for maintenance. Estimated costs are provided for both new and retrofit low-NO_x combustion applications. No SCR retrofit applications were identified, and costs for SCR retrofit applications were not available. The cost to retrofit an existing gas turbine installation with SCR would be considerably higher than the costs shown for a new installation, especially for combined cycle and cogeneration installations where the heat-recovery steam generator (HRSG) would have to be modified or replaced to accommodate the catalyst reactor.

This chapter is organized into five sections. Water and steam injection costs are described in Section 6.1. Low-NO_x combustor costs are summarized in Section 6.2. Costs for SCR used in combination with water or steam injection or low-NO_x combustion are described in Section 6.3. Water injection and SCR costs for offshore gas turbines are presented in Section 6.4, and references are listed in Section 6.5.

6.1 WATER AND STEAM INJECTION AND OIL-IN-WATER EMULSION

Ten gas turbines models were selected, and from these turbines 24 model plants were developed using water or steam injection or water-in-oil emulsion to control NO_x emissions. These 24 models, shown in Table 6-1, characterize variations in existing units with respect to turbine size, type (i.e., aero-derivative vs. heavy duty), operating hours, and type of fuel. A total of 24 model plants were developed; 16 of these were continuous-duty (8,000 hours per year) and 8 were intermittent-duty (2,000 or 1,000 hours per year). Thirteen of the continuous-duty model plants burn natural gas fuel; 6 of the 13 use water injection, and 7 use steam injection to reduce NO_x emissions. The three remaining continuous-duty model plants burn distillate oil fuel and use water injection to reduce NO_x emissions. Of the eight intermittent-duty model plants, six operate 2,000 hours per year (three natural gas-fueled and three distillate oil-fueled), and two operate 1,000 hours per year (both distillate oil-fueled). All intermittent-duty model plants use water rather than steam for NO_x reduction because it was assumed that the additional capital costs associated with steam-generating equipment could not be justified for intermittent service.

Costs were available for applying water-in-oil emulsion technology to only one gas turbine, and insufficient data were available to develop costs for a similar water-injected model plant for this turbine. As a result, the costs and cost

TABLE 6-1. GAS TURBINE MODEL PLANTS FOR NO_x CONTROL TECHNIQUES

Model plant[a]	GT model	Turbine output, MW	Annual operating hours	Fuel, natural gas or oil	Type of emission control	Aeroderivative (AD) or heavy-duty (HD) turbine
CON-G-W-3.3	Centaur T4500	3.3	8,000	Gas	Water	HD
CON-G-W-4.0	501-KB5	4.0	8,000	Gas	Water	AD
CON-G-W-22.7	LM2500	22.7	8,000	Gas	Water	AD
CON-G-W-26.8	MS5001P	26.8	8,000	Gas	Water	HD
CON-G-W-83.3	ABB GT11N	83.3	8,000	Gas	Water	HD
CON-G-W-84.7	MS7001E	84.7	8,000	Gas	Water	HD
CON-G-S-4.0	501-KB5	4.0	8,000	Gas	Steam	AD
CON-G-S-22.7	LM2500	22.7	8,000	Gas	Steam	AD
CON-G-S-26.8	MS5001P	26.8	8,000	Gas	Steam	HD
CON-G-S-34.4	LM5000	34.5	8,000	Gas	Steam	AD
CON-G-S-83.3	ABB GT11N	83.3	8,000	Gas	Steam	HD
CON-G-S-84.7	MS7001E	84.7	8,000	Gas	Steam	HD
CON-G-S-161	MS7001F	161	8,000	Gas	Steam	HD
CON-O-W-3.3	Centaur T4500	3.3	8,000	Oil	Water	HD
CON-O-W-26.3	MS5001P	26.3	8,000	Oil	Water	HD
CON-O-W-83.3	MS7001E	83.3	8,000	Oil	Water	HD
PKR-G-W-3.3	Centaur T4500	3.3	2,000	Gas	Water	HD
PKR-G-W-26.8	MS5001P	26.8	2,000	Gas	Water	HD
PKR-G-W-84.7	MS7001E	84.7	2,000	Gas	Water	HD
PKR-O-W-3.3	Centaur T4500	3.3	2,000	Oil	Water	HD
PKR-O-W-26.3	MS5001P	26.3	2,000	Oil	Water	HD
PKR-O-W-84.7	MS7001E	84.7	2,000	Oil	Water	HD
STD-O-W-1.1	Saturn T1500	1.0	1,000	Oil	Water	HD
STD-O-E-28.0	TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	AD

[a]Model plant legend:

First entry: annual operating hours
CON--continuous duty, 8,000 hours
PKR--peaking duty, 2,000 hours
STD--stand-by duty, 1,000 hours

Second entry: fuel type
G = natural gas fuel
O = oil fuel

Third entry: control type
W = water injection
S = steam injection
E = water-in-oil emulsion

Fourth entry: power output in MW

For example, CON-G-W-3.3 designates that the model plant is continuous-duty, uses natural gas fuel, has water injection, and has a power output of 3.3 MW.

effectiveness for the water-in-oil emulsion model plant should not be compared to those of water-injected model plants.

Capital costs are described in Section 6.1.1, annual costs are described in Section 6.1.2, and emission reductions and the cost effectiveness of wet injection controls are discussed in Section 6.1.3. Additional discussion of the cost methodology and details about some of the cost estimating procedures are provided in Appendix B.

Fuel rates and water flow rates were calculated for each model plant using published design power output and efficiency, expressed as heat rate, in British thermal units per kilowatt-hour (Btu/kWh).[1] The values for these parameters are presented in Table 6-2 for each model plant. Fuel rates were estimated based on the heat rates, the design output, and the lower heating value (LHV) of the fuel. The LHV's used in this analysis for natural gas and diesel fuel are 20,610 Btu per pound (Btu/lb) and 18,330 Btu/lb, respectively, as shown in Table 6-3.[2] Water (or steam) injection rates were calculated based on published fuel rates and water-to-fuel ratios (WFR) provided by manufacturers.[8-12] According to a water treatment system supplier, treatment facilities are designed with a capacity factor of 1.3.[13] An additional 29 percent of the treated water flow rate is discarded as wastewater.[2] Consequently, the water treatment facility design capacity is 68 percent (1.30 x 1.29) greater than the water (or steam) injection rate.

6.1.1 Capital Costs

The capital costs for each model plant are presented in Table 6-4. These costs were developed based on methodology in Reference 2, which is presented in this section. The capital costs include purchased equipment costs, direct and indirect installation costs, and contingency costs.

6.1.1.1 Purchased Equipment Costs. Purchased equipment costs consist of the injection system, the water treatment system, taxes, and freight. All costs are presented in 1990 dollars.

TABLE 6-2. FUEL AND WATER FLOW RATES FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Turbine output, kW	Heat rate (HR), Btu/kW-hr	Fuel flow		Estimated WFR, lb water/lb fuel	Water flow, gal/min[c]	Treatment system capacity, gal/min[d]
				lb/hr[a]	MMBtu/yr[b]			
CON-G-W-3.3	Centaur T4500	3,270	12,900	2,050	337,000	0.61	2.50	4.20
CON-G-W-4.0	501-KB5	4,000	12,700	2,460	406,000	0.80	3.94	6.60
CON-G-W-22.7	LM2500	22,670	9,220	10,100	1,670,000	0.73	14.8	24.7
CON-G-W-26.8	MS5001P	26,800	11,870	15,400	2,540,000	0.72	22.2	37.2
CON-G-W-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	1.83	154	258
CON-G-W-84.7	MS7001E	84,700	10,400	42,700	7,050,000	0.81	69.2	116
CON-G-S-4.0	501-KB5	4,000	12,700	2,460	406,000	1.50	7.38	12.4
CON-G-S-22.7	LM2500	22,670	9,220	10,100	1,670,000	1.46	29.5	49.5
CON-G-S-26.8	MS5001P	26,800	11,870	15,400	2,540,000	1.08	33.3	55.8
CON-G-S-34.4	LM5000	34,450	9,080	15,200	2,500,000	1.67	50.8	85.2
CON-G-S-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	2.12	178	299
CON-G-S-84.7	MS7001E	84,700	10,400	42,700	7,050,000	1.22	104	175
CON-G-S-161	MS7001F	161,000	9,500	74,200	12,240,000	1.34	199	334
CON-O-W-3.3	Centaur T4500	3,270	12,900	2,300	337,000	0.60	2.76	4.63
CON-O-W-26.3	MS5001P	26,300	11,950	17,100	2,510,000	0.79	27.0	45.3
CON-O-W-83.3	MS7001E	83,300	10,470	47,600	6,980,000	0.67	63.8	107
PKR-G-W-3.3	Centaur T4500	3,270	12,900	2,050	84,400	0.61	2.50	4.20
PKR-G-W-26.8	MS5001P	26,800	11,870	15,400	640,000	0.72	22.2	37.2
PKR-G-W-84.7	MS7001E	84,700	10,400	42,700	1,760,000	0.81	69.2	116
PKR-O-W-3.3	Centaur T4500	3,270	12,900	2,300	84,000	0.60	2.76	4.63
PKR-O-W-26.3	MS5001P	26,300	11,950	17,100	630,000	0.79	27.0	45.3
PKR-O-W-84.7	MS7001E	83,300	10,470	47,600	1,740,000	0.67	63.8	107
STD-O-W-1.1	Saturn T1500	1,130	14,200	875	16,000	0.46	0.81	1.35
STD-O-E-28.0	TPM FT4	28,000	14,500	19,700	406,000	0.55	21.7	36.4

[a]Natural gas: lb/hr = HR x kW x (lb/20,610 Btu). Diesel oil: lb/hr = HR x kW x (lb/18,330 Btu).
[b]MMBtu/yr = HR x kW x (MM/10^6) x (operating hours/year).
[c]Water (or steam) flow, gal/min = Fuel flow (lb/hr) x (1 hr/60 min) x (1 gal/8.33, lb. H_2O) x WFR.
[d]A 30 percent design factor has been included per discussion with system supplier, and the waste stream from the water treatment system is calculated to be 29 percent. The design capacity is therefore Water Flow x 1.3 x 1.29.

TABLE 6-3. FUEL PROPERTIES AND UTILITY AND LABOR RATES[a]

Fuel properties	Factor	Units	Reference
Natural gas	20,610	Btu/lb	Ref. 3
	930	Btu/scf[c] (LHV)	Ref. 3
Diesel fuel	18,330	Btu/lb (LHV)	Ref. 2
	7.21	lb/gal	Ref. 2
Utility rates			
Natural gas[b]	3.88	$/scf	Ref. 4
Diesel fuel	0.77	$/gal	Ref. 5
Electricity	0.06	$/kW-hr	Ref.'s 6 and 7
Raw water	0.384	$/1,000 gal	Ref. 2, escalated @ 5% per year
Water treatment	1.97	$/1,000 gal	Ref. 2, escalated @ 5% per year
Waste disposal	3.82	$/1,000 gal	Ref. 2, escalated @ 5% per year
Labor rate			
Operating	25.60	$/hr	Ref. 2, escalated @ 5% per year
Maintenance	31.20	$/hr	Ref. 2, escalated @ 5% per year

[a]All costs are average costs in 1990 dollars.
[b]Natural gas and electricity costs from Reference 4 are the average of the costs for industrial and commercial customers.
[c]scf = standard cubic foot.

TABLE 6-4. CAPITAL COSTS FOR WET INJECTION IN THOUSAND OF DOLLARS[a]

Model plant	GT model	Injection system (IS)[b]	Water treatment system (WTS)[c]	Total system (TS) = (IS + WTS)	Taxes and freight (TF) = (8% of TS)	Direct install. costs (DC) = (45% [TS + TF])	Indirect install. costs (IC)=(33% of [TS + TF +DC] + 5,000)	Contingency (C) = (20% of [TS + TF + DC + IC])	Total capital cost (TCC) = [TS + TF + DC + IC + C]
CON-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
CON-G-W-4.0	501-KB5	115	113	228	18.2	50.0[d]	59.2[e]	71.0	426
CON-G-W-22.7	LM2500	212	218	430	34.4	209	227	180	1,080
CON-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
CON-G-W-83.3	ABB GT11N	874	705	1,580	126	768	822	659	3,950
CON-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
CON-G-S-4.0	501-KB5	154	154	308	24.7	50.0	76.6	92.0	552
CON-G-S-22.7	LM2500	278	309	587	46.9	285	308	245	1,470
CON-G-S-26.8	MS5001P	262	328	590	47.2	287	310	247	1,480
CON-G-S-34.4	LM5000	530	405	935	74.8	454	488	391	2,340
CON-G-S-83.3	ABB GT11N	1,090	759	1,850	148	899	961	772	4,630
CON-G-S-84.7	MS7001E	715	580	1,300	104	632	677	543	3,260
CON-G-S-161	MS7001F	1,130	802	1,930	154	938	1,000	804	4,830
CON-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
CON-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
CON-O-W-83.3	MS7001E	532	454	986	78.9	479	515	412	2,470
PKR-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
PKR-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
PKR-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
PKR-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
PKR-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
PKR-O-W-84.7	MS7001E	532	454	986	78.9	479	515	412	2,470
STD-O-W-1.1	Saturn T1500	71.9	51.0	123	9.83	50.0	36.6	43.9	263
STD-O-E-28.0	TPM FT4	128	NA[f]	128	10.2	62.2	71.1	54.3	326

[a]All costs in 1990 dollars.
[b]Injection nozzle costs provided by manufacturers. Balance of water injection system calculated at a cost of \$4,200 x GPM.
[c]WTS = 43,900 x (design capacity, gal/min)$^{0.5}$
[d]Direct installation cost is estimated at \$50,000 for model plants rated at 5 MW or less.
[e]Indirect installation cost factor of 33 percent is reduced to 20 percent for model plants rated at 5 MW or less.
[f]NA = *cost calculations based on using a portable demineralizer systems during turbine operating periods.* Cost for system usage is included in Table 6-5.

6.1.1.1.1 Water injection system. The injection system delivers water from the treatment system to the combustor. This system includes the turbine-mounted injection nozzles, the flow metering controls, pumps, and hardware and interconnecting piping from the treatment system to the turbine. On-engine hardware (the injection nozzles) costs were provided by turbine manufacturers.[9,14-17] Flow metering controls and hardware, pumps, and interconnecting piping costs for all turbines were calculated using data provided by General Electric for four heavy-duty turbine models.[17] No relationship between costs and either turbine output or water flow was evident, so the sum of the four costs was divided by the sum of the water flow requirements for the four turbines. This process yielded a cost of $4,200 per gallon per minute (gal/min), and this cost, added to the on-engine hardware costs, was used for all model plants.

6.1.1.1.2 Water treatment system. The water treatment process, and hence the treatment system components, varies according to the degree to which the water at a given site must be treated. For this cost analysis, the water treatment system includes a reverse osmosis and mixed-bed demineralizer system. The water treatment system capital cost for each model plant was estimated based on an equation developed in Reference 2:

$$WTS = 43,900 \times (G)^{0.50}$$

where

WTS = water treatment system capital cost, $; and

G = water treatment system design capacity, gal/min.

This equation yields costs that are generally consistent with the range of costs presented in Reference 18.

6.1.1.1.3 Taxes and freight. This cost covers applicable sales taxes and shipment to the site for the injection and water treatment systems. A figure of 8 percent of the total system cost was used.[2,7]

6.1.1.2 Direct Installation Costs. This cost includes the labor and material costs associated with installing the foundation and supports, erecting and handling equipment, electrical work, piping, insulation, and painting. For smaller turbines, the water treatment system is typically skid-mounted and is shipped to the site as a packaged unit, which minimizes field assembly and interconnections. The cost to install a skid-mounted water treatment skid is typically $50,000, and this cost is used for the direct installation cost for model plants less than 5 MW (6700 hp).[19] For larger turbines, it is expected that the water treatment system must be field-assembled and the direct installation costs were calculated as 45 percent of the injection and water treatment systems, including taxes and freight.[2]

6.1.1.3 Indirect Installation Costs. This cost covers the indirect costs (engineering, supervisory personnel, office personnel, temporary offices, etc.) associated with installing the equipment. The cost was taken to be 33 percent of the systems' costs, taxes and freight, and direct costs, plus $5,000 for model plants above 5 MW (6,700 hp).[2] The indirect installation costs for skid-mounted water treatment systems are expected to be less than for field-assembled systems; therefore, for model plants with an output of less than 5 MW (6,700 hp), the cost percentage factor was reduced from 33 to 20 percent.

6.1.1.4 Contingency Cost. This cost is a catch-all meant to cover unforeseen costs such as equipment redesign/modification, cost escalations, and delays encountered in startup. This cost was estimated as 20 percent of the sum of the systems, taxes and freight, and direct and indirect costs.[2]

6.1.2 Annual Costs

The annual costs are summarized in Table 6-5 for each model plant. Annual costs include the fuel penalty; electricity; maintenance requirements; water treatment; overhead, general and administrative, taxes, and insurance; and capital recovery, as discussed in this section.

6.1.2.1 Fuel Penalty. The reduction in efficiency associated with water injection varies for each turbine model. Based on data in Reference 2, it was estimated that a WFR of 1.0 corresponds to a fuel penalty of 3.5 percent for water injection and 1.0 percent for steam injection. This percentage was multiplied by the actual WFR and the annual fuel cost to

TABLE 6-5. ANNUAL COSTS FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Fuel penalty (FP)[a]	Electricity (E)[b]	Added maintenance cost (M)[c]	Water treatment (WT)[d] Raw water[e]	Treatment[f]	Labor[g]	Disposal[h]	Total cost (TW)	Plant overhead (PO) = (30% of M)	G&A taxes, insurance (GATI)[i]	Capital recovery (CR)[j]	Total annual cost (TAC)[k]
CON-G-W-3.3	Centaur T4500	30,000	193	16,000	595	3,050	1,080	1,330	6,050	4,800	15,500	51,000	124,000
CON-G-W-4.0	501-KB5	47,400	304	24,000	936	4,800	1,710	2,090	9,540	7,200	17,100	56,100	162,000
CON-G-W-22.7	LM2500	178,000	1,140	28,000	3,510	18,000	6,390	7,840	35,700	8,400	43,200	142,000	436,000
CON-G-W-26.8	MS5001P	267,000	1,714	33,000	5,270	27,100	9,620	11,800	53,800	9,900	48,400	159,000	573,000
CON-G-W-83.3	ABB GT11N	1,852,000	11,884	0	36,600	188,000	66,700	81,800	373,000	0	158,000	519,000	2,910,000
CON-G-W-84.7	MS7001E	834,000	5,348	25,700	16,500	84,400	30,000	36,800	168,000	7,710	103,000	339,000	1,480,000
CON-G-S-4.0	501-KB5	25,400	571	24,000	1,760	9,010	1,600	3,930	16,300	7,200	22,100	72,600	168,000
CON-G-S-22.7	LM2500	102,000	2,280	0	7,020	36,000	6,390	15,700	65,100	0	58,800	193,000	421,000
CON-G-S-26.8	MS5001P	114,000	2,572	33,000	7,910	40,600	7,210	17,700	73,400	9,900	59,200	195,000	487,000
CON-G-S-34.4	LM5000	174,000	3,925	0	12,100	62,000	11,000	27,000	112,000	0	93,600	308,000	692,000
CON-G-S-83.3	ABB GT11N	613,000	13,768	0	42,400	217,000	38,600	94,700	393,000	0	185,000	609,000	1,810,000
CON-G-S-84.7	MS7001E	359,000	8,055	0	24,800	127,000	22,600	55,400	230,000	0	130,000	429,000	1,160,000
CON-G-S-161	MS7001F	684,000	15,374	0	47,300	243,000	43,100	106,000	439,000	0	193,000	635,000	1,970,000
CON-O-W-3.3	Centaur T4500	41,200	213	20,800	657	3,370	1,200	1,470	6,700	6,240	15,800	52,100	143,000
CON-O-W-26.3	MS5001P	404,000	2,089	42,900	6,430	33,000	11,700	14,400	65,500	12,900	52,800	174,000	754,00
CON-O-W-83.3	MS7001E	954,000	4,931	33,400	15,200	77,800	27,700	33,900	155,000	10,020	98,800	325,000	1,580,000
PKR-G-W-3.3	Centaur T4500	7,500	48.3	4,000	149	760	270	330	1,510	1,200	15,500	51,000	80,800
PKR-G-W-26.8	MS5001P	67,000	429	8,250	1,320	6,770	2,400	2,950	13,400	2,500	48,400	159,000	299,000
PKR-G-W-84.7	MS7001E	208,000	1,337	6,430	4,110	21,100	7,500	9,200	41,900	1,929	103,000	339,000	702,000
PKR-O-W-3.3	Centaur T4500	10,300	53.3	5,200	164	840	300	370	1,670	1,560	15,800	52,100	86,700
PKR-O-W-26.3	MS5001P	101,000	522	10,725	1,610	8,240	2,930	3,590	16,400	3,200	52,800	174,000	359,000
PKR-O-W-84.7	MS7001E	238,000	1,233	8,350	3,790	19,500	6,910	8,480	38,700	2,505	99,000	325,000	713,000
STD-O-W-1.1	Saturn T1500	1,500	7.78	1,300	23.9	123	43.7	53.6	244	390	10,530	34,600	48,600
STD-O-E-28.0	TPM FT4	45,500	209	0	644	51,100	1,170	1,440	54,400	0	13,000	42,900	156,000

[a]FP for water = 0.035 x WFR x (MMBtu/yr) x (ft^3/940 Btu) x ($3.88/1,000 ft^3) x (10^6/MM).
[b]E = Water flow rate (gal/min) x 0.161 x operating hours x ($0.06/kWH).
[c]Maintenance costs for the Centaur and Allison 501 turbines were obtained from the manufacturers. Costs for the MS5001 and MS7001 were estimated based on information about inspections and parts replacement presented in Appendix B. Maintenance for turbines that use diesel fuel are 30 percent higher than costs for comparable turbines using natural gas. No additional maintenance costs were assessed for steam injection.
[d]WT includes treatment chemicals, raw water, waste disposal, and operating labor.
[e]Raw Water Cost = Water Flow (gal/min) x ($0.384/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[f]Treatment Cost = Water Flow (gal/min) x ($1.97/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[g]Labor Cost for water = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29.
Labor Cost for steam = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29 x 0.5.
[h]Disposal Cost = Water Flow (gal/min) x ($3.82/1,000 gal) x (60 min/hour) x operating hours x 0.29.
[i]GATI = 0.04 x TCC (TCC is shown in Table 6-4).
[j]CR = 0.1315 x TCC based on an equipment life of 15 years and a 10 percent interest rate.
[k]TAC = FP + E + M + TW + PO + GATI + CR.

determine the fuel penalty for each model plant. The fuel flow was multiplied by the unit fuel costs to determine the annual fuel costs. As shown in Table 6-3, the natural gas cost is \$3.88/1,000 standard cubic feet (scf) and the diesel fuel cost is \$0.77/gal.[4,5]

An increase in output from the turbine accompanies the decrease in efficiency. This increase was not considered, however, because not all sites have a demand for the available excess power. In applications such as electric power generation, where the excess power can be used at the site or added to utility power sales, this additional output would serve to decrease or offset the fuel penalty impact.

6.1.2.2 Electricity Cost. The electricity costs shown in Table 6-5 apply to the feedwater pump(s) for water or steam injection. The pump power requirements are estimated from the pump head (ft) and the water flow rate as shown in the following equation:[2]

$$\text{power pump } (kW_e) = \frac{FR}{3{,}960} \times H \times (S.G.) \times \frac{1}{0.6} \times \frac{0.7457 \text{ kW}}{\text{hp}} \times \frac{1}{0.9}$$

where:

FR = feedwater flow rate, gal/min (from Table 6-2);
H = total pump head (ft);
S.G. = specific gravity of the feed water;
0.6 = pump efficiency of 60 percent;
0.9 = electric motor efficiency of 90 percent;
3,960 = factor to correct units in FR and H to hp; and
0.7457 = factor to convert hp to kW.

For water injection, the feedwater pump(s) supply treated water to the gas turbine injection system. For steam injection, the feedwater pump(s) supply treated water to the boiler for steam generation. This cost analysis uses a feedwater temperature of 55°C (130°F) with a density of 61.6 lb/ft^3 and a total pump head requirement of 200 pounds per square inch, gauge (psig)

(468 ft).[2] Based on these values, the pump electrical demand for either water or steam injection is calculated as follows:

$$\text{pump power } (kW_e) = \frac{FR \times 468}{3{,}960} \times \frac{61.6}{62.4} \times \frac{1}{0.6} \times 0.7457 \times \frac{1}{0.9}$$

$$= 0.161 \times FR$$

The electrical cost for each model plant is the product of the pump electrical demand, the annual hours of operation, and the unit cost of electricity. The unit cost of electricity, shown in Table 6-3, is $0.06/kWH.[6,7]

Maintenance costs were developed based on information from manufacturers, and water treatment labor costs were estimated based on information from a water treatment vendor. Other costs were developed based on the methodology presented in Reference 2.

No backup steam or electricity costs were developed for water or steam injection because it was assumed that no additional downtime would be required for scheduled inspections and repairs. Maintenance intervals could be scheduled to coincide with the 760 hr/yr of downtime that are currently allocated for scheduled maintenance. If this were done, the annual utilization of the backup source would not increase.

6.1.2.3 Added Maintenance Costs. Based on discussions with gas turbine manufacturers, additional maintenance is required for some gas turbines with water injection. The analysis procedures used to develop the incremental maintenance costs are presented in Appendix B.

The incremental maintenance cost associated with water injection for natural gas-fueled turbines was provided by the gas turbine manufacturers.[10,20-24] All gas turbine manufacturers contacted stated that there were no incremental maintenance costs for operation with steam injection. Two manufacturers provided maintenance costs for natural gas and oil fuel operation without water injection.[10,20] Using an average of these costs, incremental maintenance costs for water injection are 30 percent higher for plants that use diesel fuel instead of natural gas.

Costs were prorated for model plants that operate less than 8,000 hr/yr.

6.1.2.4 Water Treatment Costs. Water treatment operating costs include the cost of treatment (e.g., for chemicals and media filters), operating labor, raw water, and wastewater disposal. The raw water flow rate is equal to the treated water flow rate (the water or steam injection rate) plus the flow rate of the wastewater generated in the treatment plant. As noted in Section 6.1, the wastewater flow rate is equal to 29 percent of the injection flow rate. The annual raw water, treated water, and wastewater flow rates were multiplied by the appropriate unit costs in Table 6-3 to determine the annual costs. Water treatment labor costs were calculated at $0.70/1,000 gal for water injection.[25] This cost was multiplied by the total annual treated water flow rate to determine the annual water treatment labor cost for water injection. Labor costs for steam injection were assumed to be half as much as the costs for water injection because it was assumed that the facility already has a water treatment plant for the boiler feedwater. Therefore, the operator requirements would be only those associated with the increase in capacity of the existing treatment plant.

6.1.2.5 Plant Overhead. This cost is the overhead associated with the additional maintenance effort required for water injection. The cost was calculated as 30 percent of the annual maintenance cost from Section 6.1.2.3.[2]

6.1.2.6 General and Administrative, Taxes, and Insurance Costs (GATI). This cost covers those expenses for administrative overhead, property taxes, and insurance and was calculated as 4 percent of the total capital cost.[2]

6.1.2.7 Capital Recovery. A capital recovery factor (CRF) was multiplied by the total capital investment to estimate uniform end-of-year payments necessary to repay the investment. The CRF used in this analysis is 0.1315, which is based on an equipment life of 15 years and an interest rate of 10 percent.

6.1.2.8 Total Annual Cost. This cost is the sum of the annual costs presented in Sections 6.1.2.1 through 6.1.2.7 and is the total cost that must be paid each year to install and operate water or steam injection NO_x emissions control for a gas turbine.

6.1.3 Emission Reduction and Cost-Effectiveness Summary for Water and Steam Injection

The uncontrolled and controlled NO_x emissions and the annual emission reductions for the model plants are shown in Table 6-6. The emissions, in tons per year (tons/yr), were calculated as shown in Appendix A.

The total annual cost was divided by the annual emission reductions to determine the cost effectiveness for each model plant. For continuous-duty natural gas-fired model plants, the cost-effectiveness figures range from approximately \$600 to \$2,100 per ton of NO_x removed for water injection, and decrease to approximately \$400 to \$1,850 per ton for steam injection. The lower range of cost-effectiveness figures for steam injection is primarily due to the greater NO_x reduction achieved with steam injection. For continuous-duty oil-fired model plants, the cost effectiveness ranges from approximately \$675 to \$1,750 per ton of NO_x removed, which is comparable to figures for gas-fired model plants. The cost-effectiveness figures are higher for gas turbines with lower power outputs because the fixed capital costs associated with wet injection system installation have the greatest impact on the smaller gas turbines.

Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hr/yr, the cost-effectiveness figures are two to nearly three times higher than those for continuous-duty model plants, and increase further for model plants operating 1,000 hr/yr. For the oil-in-water emulsion model plant, the cost effectiveness corresponding to 1,000 annual operating hours is \$1,840/ton of NO_x removed. No data were available to prepare a conventional water injection model plant for this turbine to compare the relative cost-effectiveness values.

TABLE 6-6. COST-EFFECTIVENESS SUMMARY FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	NO_x emissions[a] Uncontrolled NO_x ppmv[b]	Uncontrolled NO_x tons/yr	Controlled NO_x ppmv[b]	Controlled NO_x tons/yr	Total NO_x removed, tons/yr	Total annual cost, $[c]	Cost effectiveness, $/ton
CON-G-W-3.3	Centaur T4500	130	88.1	42	28.5	59.6	124,000	2,080
CON-G-W-4.0	501-KB5	155	126	42	34.2	91.9	162,000	1,760
CON-G-W-22.7	LM2500	174	581	42	140	441	436,000	989
CON-G-W-26.8	MS5001P	142	723	42	214	509	573,000	1,130
CON-G-W-83.3	ABB GT11N	390	5,410	25	347	5,060	2,910,000	575
CON-G-W-84.7	MS7001E	154	2,170	42	593	1,580	1,480,000	937
CON-G-S-4.0	501-KB5	155	126	42	34.2	91.9	168,000	1,830
CON-G-S-22.7	LM2500	174	581	25	83.5	497	421,000	846
CON-G-S-26.8	MS5001P	142	723	42	214	509	487,000	957
CON-G-S-34.4	LM5000	185	930	25	126	804	692,000	861
CON-G-S-83.3	ABB GT11N	390	5,410	42	583	4,830	1,810,000	375
CON-G-S-84.7	MS7001E	154	2,170	42	593	1,580	1,160,000	734
CON-G-S-161	MS7001F	210	5,150	42	1,030	4,120	1,970,000	478
CON-O-W-3.3	Centaur T4500	179	125	60	41.8	82.9	143,000	1,720
CON-O-W-26.3	MS5001P	211	1,090	65	337	753	754,000	1,000
CON-O-W-83.3	MS7001E	228	3,290	65	938	2,350	1,580,000	672
PKR-G-W-3.3	Centaur T4500	130	22.0	42	7.12	14.9	80,800	5,420
PKR-G-W-26.8	MS5001P	142	181	42	53.5	127	299,000	2,350
PKR-G-W-84.7	MS7001E	154	543	42	148	395	702,000	1,780
PKR-O-W-3.3	Centaur T4500	179	31.2	60	10.5	20.7	86,700	4,180
PKR-O-W-26.3	MS5001P	211	273	65	84.2	189	359,000	1,900
PKR-O-W-84.7	MS7001E	228	822	65	234	588	713,000	1,210
STD-O-W-1.1	Saturn T1500	150	4.97	60	1.99	2.98	48,600	16,300
STD-O-E-28.0	TPM FT4	150	122	50	37.3	84.7	156,000	1,840

[a]Example NO_x emission calculations are given in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-5.

6.2 LOW-NO_x COMBUSTORS

Incremental capital costs for low-NO_x combustors relative to standard designs for new applications were provided by three manufacturers for several turbines.[3,14,26] Based on information from the manufacturers, the performance and maintenance requirements for a low-NO_x combustor are expected to be the same as for a standard combustor, and so the only annual cost associated with low-NO_x combustors is the capital recovery. The capital recovery factor is 0.1315, assuming a life of 15 years and an interest rate of 10 percent.

Table 6-7 presents the uncontrolled and controlled emission levels, the annual emission reductions, incremental costs for a low-NO_x combustor over a conventional design, and the cost effectiveness of low-NO_x combustors for all gas turbine models for which sufficient data were available. Cost-effectiveness figures were calculated for 8,000 and 2,000 hours of operation annually, using controlled NO_x emission levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, which are the achievable levels stated by the turbine manufacturers. The cost effectiveness varies according to the uncontrolled NO_x emission level for the conventional combustor design and the achievable controlled emission level for the low-NO_x design. For continuous-duty applications, cost effectiveness for a controlled NO_x emission level of 42 ppmv ranges from $353 to $1,060 per ton of NO_x removed. The cost-effectiveness range decreases to $57 to $832 per ton of NO_x removed for a controlled NO_x emission level of 25 ppmv and decreases further to $55 to $137 per ton of NO_x removed for a 9 ppmv control level. In all cases, the cost effectiveness increases as the operating hours decrease. In general, the cost effectiveness is higher for smaller gas turbines than for larger turbines due to the relatively higher capital cost per kW for low-NO_x combustors for smaller turbines.

The cost-effectiveness range is lower for low-NO_x combustors than for water or steam injection because the total annual costs are lower and, in some cases, the controlled emission levels are

TABLE 6-7. COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NO_x COMBUSTORS USING NATURAL GAS FUEL (1990 $)

Model plant[a]	GT model	Power output, MW	Annual operating hours	NO_x emissions[b]: Uncontrolled NO_x, ppmv[c]	Uncontrolled NO_x, Tons/yr	Controlled NO_x, ppmv[c]	Controlled NO_x, Tons/yr	NO_x removed, tons/yr	Incremental capital cost, $[d]	Annual cost, $[e]	Cost effectiveness, $/ton NO_x removed
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42.0	28.5	59.6	375,000	49,300	827
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42.0	33.2	49.8	400,000	52,600	1,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42.0	36.4	62.4	425,000	55,900	896
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42.0	65.5	212	700,000	92,100	434
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42.0	72.1	269	725,000	95,300	354
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25.0[f]	16.9	71.2	375,000	49,300	693
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25.0[f]	19.8	63.2	400,000	52,600	832
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25.0[f]	21.7	77.1	425,000	55,900	725
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25.0[f]	39.0	239	700,000	92,100	386
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25.0[f]	42.9	299	725,000	95,300	319
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25.0	168	1,310	1,400,000	184,000	140
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25.0	347	5,070	2,200,000	289,000	57.0
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25.0	353	1,830	2,140,000	281,000	154
CON-L-39-9	MS6000	39.0	8,000	220	1,480	9.00	60.6	1,420	1,400,000	184,000	130
CON-L-83-9	ABB GT11N	83.3	8,000	390	5,420	9.00	125	5,290	2,200,000	289,000	54.6
CON-L-85-9	MS7001E	84.7	8,000	154	2,180	9.00	127	2,050	2,140,000	281,000	137
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42.0	7.12	14.9	375,000	49,300	3,310
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42.0	8.30	12.4	400,000	52,600	4,230
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42.0	9.09	15.6	425,000	55,900	3,590
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42.0	16.4	53.1	700,000	92,100	1,740
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42.0	18.0	67.3	725,000	95,300	1,420
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25.0[f]	4.24	17.8	375,000	49,300	2,770
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25.0[f]	4.94	15.8	400,000	52,600	3,330
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25.0[f]	5.41	19.3	425,000	55,900	2,900
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25.0[f]	9.75	59.7	700,000	92,100	1,540
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25.0[f]	10.7	74.6	725,000	95,300	1,280
PKR-L-39-25	MS6000	39.0	2,000	220	371	25.0	42.1	328	1,400,000	184,000	560
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25.0	86.8	1,260	2,200,000	289,000	229
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25.0	88.3	452	2,140,000	281,000	622
PKR-L-39-9	MS6000	39.0	2,000	220	371	9.00	15.2	355	1,400,000	184,000	518
PKR-L-83-9	ABB GT11N	83.3	2,000	390	1,350	9.00	31.3	1,320	2,200,000	289,000	219
PKR-L-85-9	MS7001E	84.7	2,000	154	540	9.00	31.8	508	2,140,000	281,000	553

[a]Model plant legend: First entry: annual operating hours; CON - Continuous duty, 8,000 hours; PKR - peaking/intermittent duty, 2,000 hours. Second entry: control technique; L - dry low-NO_x combustor. Third entry: power output, in MW. Fourth entry: controlled NO_x level, ppmv at 15 percent O_2

For example, CON-L-3.3-42 designates that the model plant operates 8,000 hours per year, is fitted with a dry low-NO_x combustor, has a power output of 3.3 MW, and has a controlled NO_x level of 42 ppmv.

[b]Example NO_x emission calculations are shown in Appendix A.
[c]Referenced to 15 percent oxygen.
[d]Incremental capital costs were provided by the manufacturers.
[e]Annual cost = capital cost x 0.1315, based on an equipment life of 15 years and an annual interest rate of 10 percent.
[f]Availability date for this controlled NO_x limit is not currently available from the manufacturers.

also lower. According to two turbine manufacturers, retrofit costs are 40 to 60 percent greater than the incremental costs shown in Table 6-7 for new installations.[3,14]

6.3 SELECTIVE CATALYTIC REDUCTION

The costs for SCR for new installations were estimated for all model plants. Retrofit costs for SCR were not available bu could be considerably higher than the costs shown for new installations, especially in applications where an existing hea recovery steam generator (HRSG) would have to be moved, modifie or replaced to accommodate the addition of a catalyst reactor.

To date, most gas turbine SCR applications use a base meta catalyst with an operating temperature range that requires cooling of the exhaust gas from the turbine. For this reason, SCR applications to date have been limited to combined cycle or cogeneration applications that include an HRSG, which serves to cool the exhaust gas to temperatures compatible with the catalyst. The introduction of high-temperature zeolite catalysts, however, makes it possible to install the catalyst directly downstream of the turbine, and therefore feasible to use SCR with simple-cycle applications as well as heat recovery applications. As discussed in Section 5.3.2, to date there is a least one gas turbine installation with a high-temperature zeolite catalyst installed downstream of the turbine and upstrea of an HRSG. At present, no identified SCR systems are installed in simple-cycle gas turbine applications.

An overview of the procedures used to estimate capital and annual costs are described in Sections 6.3.1 and 6.3.2, respectively; a detailed cost algorithm is presented in Appendix B. The emission reduction and cost-effectiveness calculations are described in Section 6.3.3.

6.3.1 Capital Costs

Five documents in the technical literature contained SCR capital costs for 21 gas turbine facilities. Most of these documents presented costs that were obtained from vendors, but some may have also developed at least some costs based on their own experiences.[27-31] Most of the documents presented only the total capital costs, not costs for individual components, and they did not provide complete descriptions of what the costs included. These costs were plotted on a graph of total capital costs versus gas turbine size. To this graph were added estimates of total installed costs for a high-temperature catalyst SCR system for installation upstream of the HRSG for four turbine installations ranging in size from 4.5 to 83 MW (6,030 to 111,000 hp). These high-temperature SCR system estimates include the catalyst reactor, air injection system for exhaust temperature control, ammonia storage and injection system, instrumentation, and continuous emission monitoring equipment. These SCR costs were estimated by the California Air Resources Board (CARB) in 1991 dollars and are based on NO_x emission levels of 42 ppmv into and 9 ppmv out of the SCR.[35] These estimated costs, shown in Appendix B, fit well within the range of costs from the 21 installations discussed above, and the equation of a line determined by linear regression adequately fits the data ($R^2 = 0.76$) for all 25 points. Based on this graph, the total capital cost for either a base-metal SCR system installed within the HRSG or a high-temperature zeolite catalyst SCR system installed directly downstream of the turbine can be calculated using the equation determined by the linear regression. This equation is shown in Table 6-8 and was used to calculate the total capital investment for SCR for each model plant shown in Tables 6-9 and 6-10.

6.3.2 Annual Costs

Total annual costs for SCR control were developed following standard EPA procedures described in the OAQPS Control Cost Manual for other types of add-on air pollution control devices (APCD's). Information about annual costs was obtained from the same sources that provided capital costs.[27-31] Total annual costs consist of direct and indirect costs; parameters that make up these categories and the equations for estimating the costs are presented in Table 6-8 and are discussed below. The annual

TABLE 6-8. PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR SCR CONTROL OF NO_x EMISSIONS FROM GAS TURBINES

A. Total capital investment, \$[b]	= (49,700 x TMW) + 459,000
B. Direct annual costs, \$/yr	
1. Operating labor[c]	= (1.0 hr/8 hr-shift) x (\$25.60/hr) x (H)
2. Supervisory labor	= (0.15) x (operating labor)
3. Maintenance labor and materials	= (1,250 x TMW) + 25,800
4. Catalyst replacement	= (4,700 x TMW) + 37,200
5. Catalyst disposal[d]	= (V) x (\$15/ft^3) x (.2638)
6. Anhydrous ammonia[e]	= (N) x (\$360/ton)
7. Dilution steam[f]	= (N) x (0.95/0.05) x (MW H_2O/MW NH_3) x (\$6/1,000 lb steam) x (2,000 lb/ton)
8. Electricity[g]	= N/A
9. Performance loss[h]	= (0.005) x (TMW) x (\$0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower (if needed)	
11. Production loss[i]	= 0.1 x (Performance Loss)
	= None
C. Indirect annual costs, \$/yr	
1. Overhead	= (0.6) x (all labor and maintenance material costs)
2. Property taxes, insurance, and administration	= (0.04) x (total capital investment)
3. Capital recovery[j]	= (0.13147) x [total capital investment - (catalyst replacement/0.2638)]

[a]All costs are in average 1990 dollars.

[b]TMW=turbine output in MW for each model plant.

[c]The annual operating hours are represented by the variable H. The labor rate of \$25.60/hr is from Table 6-3

[d]The catalyst volume in ft^3 is represented by the variable V. The catalyst volume for each model plant is estimated as V = (TMW) x (6,180 ft^3/83 MW).

[e]The ammonia requirement in tons is represented by the variable N and is calculated using a NH_3-to-NO_x molar ratio of 1.0.

The annual tonnage of NO_x is taken from the controlled levels shown in Tables 6-11 and 6-12.

$$N = \text{annual tonnage of } NO_x \times \left(\frac{\text{MW of } NH_3 = 17.0}{\text{MW of } NO_x = 46.0}\right)$$

[f]The ammonia is diluted with steam to 5 percent by volume before injection.

[g]The amount of electricity required for ammonia pumps and exhaust fans is not known, but is expected to be small. The electricity cost comprised less than 1 percent of the total annual cost estimated by the South Coast Air Quality Management District (SCAQMD) for SCR applied to a 1.1 MW turbine.

[h]Based on information from three sources, the backpressure from the SCR reduces turbine output by an average of about 0.9 percent.

[i]No production losses are estimated because it is assumed that all SCR maintenance, inspections, cleaning, etc. can be performed during the 760 hours of scheduled downtime per year.

[j]The capital recovery factor for the SCR is 0.13147, based on a 15-year equipment life and 10 percent interest rate. The catalyst is replaced every 5 years. The 0.2638 figure is the capital recovery factor for a 5-year equipment life and a 10 percent interest rate.

TABLE 6-9. CAPITAL AND ANNUAL COSTS
FOR SCR USED DOWNSTREAM OF WATER OR STEAM INJECTION (1990 $)

Model plant	GT model	Total capital investment, $[a]	Operating labor, $	Supervisory labor, $	Maintenance labor & materials, $	Catalyst replacement, $	Catalyst disposal, $	Ammonia, $	Dilution steam, $	Performance loss, $	Blower (if needed), $	Overhead, $	Taxes, insurance & admin, $	Capital recovery, $	Total annual cost, $
CON-G-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	2,980	1,770	7,850	785	35,600	24,900	55,600	242,000
CON-G-W-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-W-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	14,700	8,740	54,400	5,440	50,100	63,600	137,000	568,000
CON-G-W-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-W-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-G-W-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-S-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	7,110	4,240	54,400	5,440	50,100	63,600	137,000	556,000
CON-G-S-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-S-34.4	LM5000	2,170,000	25,600	3,840	68,900	199,000	10,100	10,700	6,380	82,700	8,270	59,000	86,800	186,000	747,000
CON-G-S-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	61,000	36,300	200,000	20,000	95,700	184,000	391,000	1,600,000
CON-G-S-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-161	MS7001F	8,460,000	25,600	3,840	227,000	794,000	47,400	108,000	64,200	386,000	38,600	154,000	338,000	717,000	2,900,000
CON-O-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	3,890	2,320	7,850	785	35,600	24,900	55,600	244,000
CON-O-W-26.3	MS5001P	1,770,000	25,600	3,840	58,700	161,000	7,750	32,400	19,300	63,100	6,310	52,900	70,800	152,000	654,000
CON-O-W-83.3	MS7001E	4,600,000	25,600	3,840	130,000	429,000	24,500	90,000	53,800	200,000	20,000	95,700	184,000	391,000	1,650,000
PKR-G-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	740	440	1,960	196	8,900	24,900	75,300	141,000
PKR-G-W-26.8	MS5001P	1,790,000	6,400	960	14,800	40,800	1,970	5,600	3,330	16,100	1,610	13,300	71,600	215,000	391,000
PKR-G-W-84.7	MS7001E	4,670,000	6,400	960	32,900	109,000	6,240	15,500	9,240	50,800	5,080	24,200	187,000	560,000	1,010,000
PKR-O-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	970	580	1,960	196	8,900	24,900	75,300	141,000
PKR-O-W-26.3	MS5001P	1,770,000	6,400	960	14,700	40,200	1,940	8,100	4,830	15,800	1,580	13,200	70,800	213,000	392,000
PKR-O-W-84.7	MS7001E	4,600,000	6,400	960	32,500	107,000	6,140	22,500	13,440	50,000	5,000	23,900	184,000	552,000	1,000,000
STD-O-W-1.1	Saturn T1500	515,000	3,200	480	3,400	5,310	41.6	185	158	339	33.9	4,250	20,600	65,100	103,000
STD-O-E-28.0	TPM FT4	1,850,000	3,200	480	60,800	21,100	1,030	3,180	2,960	8,400	840	38,700	74,000	233,000	448,000

[a]Costs shown are for SCR systems used downstream of gas turbines with wet injection to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-6.

TABLE 6-10. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF LOW-NO_x COMBUSTION

Model plant[a]	GT model	Total capital invest., $[b]	Operating labor, $	Supervisory labor, $	Maintenance labor & materials, $	Catalyst replacement, $	Catalyst disposal, $	Ammonia, $	Dilution steam, $	Performance loss, $	Blower (if needed), $	Overhead, $	Taxes, insurance & admin., $	Capital recovery, $	Total annual cost, $
CON-L-3.3-42	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	2,980	1,770	7,920	790	35,600	24,900	55,500	242,000
CON-L-4.0-42	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	3,470	2,070	9,600	960	36,100	26,300	58,600	255,000
CON-L-4.5-42	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	3,800	2,270	10,800	1,080	36,500	27,300	60,700	263,000
CON-L-8.8-42	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	6,850	4,080	21,100	2,110	39,700	35,800	78,600	336,000
CON-L-10-42	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	7,530	4,490	24,000	2,400	40,600	38,200	83,700	356,000
CON-L-3.3-25	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	1,440	860	7,920	790	35,600	24,900	55,500	240,000
CON-L-4.0-25	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	1,680	1,000	9,600	960	36,100	26,300	58,600	252,000
CON-L-4.5-25	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	1,840	1,100	10,800	1,080	36,500	27,300	60,700	260,000
CON-L-8.8-25	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	3,320	1,980	21,100	2,110	39,700	35,800	78,600	330,000
CON-L-10-25	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	3,650	2,180	24,000	2,400	40,600	38,200	83,700	350,000
CON-L-39-25	MS6000	2,400,000	25,600	3,840	74,600	221,000	11,490	14,300	8,550	93,600	9,360	62,400	96,000	205,000	826,000
CON-L-83-25	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,540	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-L-85-25	MS7001E	4,670,000	25,600	3,840	132,000	435,000	24,960	30,100	17,900	203,000	20,300	96,900	186,800	397,000	1,570,000
PKR-L-3.3-42	Centaur T4500	622,000	6,400	960	7,480	55,100	2,870	740	440	1,980	200	8,900	24,900	54,300	164,000
PKR-L-4.0-42	Centaur 'H'	658,000	6,400	960	7,700	107,000	6,140	870	520	2,400	240	9,000	26,300	33,200	201,000
PKR-L-4.5-42	Taurus	683,000	6,400	960	7,860	109,000	6,240	950	570	2,700	270	9,100	27,300	35,500	207,000
PKR-L-8.8-42	Mars T12000	896,000	6,400	960	9,200	9,300	0	1,710	1,020	5,280	530	9,900	35,800	113,000	193,000
PKR-L-10-42	Mars T14000	956,000	6,400	960	9,580	13,200	240	1,880	1,120	6,000	600	10,200	38,200	119,000	207,000
PKR-L-3.3-25	Centaur T4500	623,000	6,400	960	7,480	14,600	330	360	210	1,980	200	8,900	24,900	74,600	141,000
PKR-L-4.0-25	Centaur 'H'	658,000	6,400	960	7,700	19,600	650	420	250	2,400	240	9,000	26,300	76,800	151,000
PKR-L-4.5-25	Taurus	683,000	6,400	960	7,860	21,100	740	460	270	2,700	270	9,100	27,300	79,300	156,000
PKR-L-8.8-25	Mars T12000	896,000	6,400	960	9,200	9,300	0	830	490	5,280	530	9,900	35,800	113,000	192,000
PKR-L-10-25	Mars T14000	956,000	6,400	960	9,580	13,200	240	910	540	6,000	600	10,200	38,200	119,000	206,000
PKR-L-39-25	MS6000	2,400,000	6,400	960	18,600	14,000	290	3,590	2,140	23,400	2,340	15,600	96,000	309,000	492,000
PKR-L-83-25	ABB GT11N	4,600,000	6,400	960	32,500	14,600	330	7,390	4,410	50,000	5,000	23,900	184,000	598,000	927,000
PKR-L-85-25	MS7001E	4,670,000	6,400	960	32,900	19,600	650	7,520	4,480	50,800	5,080	24,200	186,800	604,000	943,000

[a]See Table 6-7 for model plant legend.
[b]Costs shown are for SCR systems used downstream of gas turbines with dry low-NO_x combustion to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-7.

costs are shown in Tables 6-9 and 6-10 for injection and dry low-NO_x combustion, respectively, for each of the model plants.

6.3.2.1 Operating and Supervisory Labor. Information about operating labor requirements was unavailable. Most facilities have fully automated controls and monitoring/recording equipment, which minimizes operator attention. Therefore, it was assumed that 1 hr of operator attention would be required during an 8-hr shift, regardless of turbine size. This operating labor requirement is at the low end of the range recommended in the OAQPS Control Cost Manual for other types of APCD's.[7] Operator wage rates were estimated to be $25.60/hr in 1990, based on escalating the costs presented in Reference 2 by 5 percent per year to account for inflation. Supervisory labor costs were estimated to be 15 percent of the operating labor costs, consistent with the OAQPS Control Cost Manual.

6.3.2.2 Maintenance Labor and Materials. Combined maintenance labor and materials costs for 14 facilities were obtained from four articles, but almost half of the data (6 facilities) were provided by one source.[27-30] The costs were escalated to 1990 dollars assuming an inflation rate of 5 percent per year. All of the data are for facilities that burn natural gas. Provided that ammonium salt formation is avoided by limiting ammonia slip and sulfur content, the cost for operation with natural gas should also apply for distillate oil fuel.[32] Therefore, it was assumed that the cost data also apply to SCR control for turbines that fire distillate oil fuel. The costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation, shown in Table 6-8, was used to estimate the maintenance labor and materials costs shown in Table 6-9 for the model plants.

6.3.2.3 Catalyst Replacement. Replacement costs were obtained for nine gas turbine facilities, and combined replacement and disposal costs were obtained for another six gas turbine facilities.[27-30] The disposal costs were estimated for the six facilities as described below and in Appendix B. The replacement costs for these six facilities were then estimated by subtracting the estimated disposal costs from the combined costs. A catalyst life of 5 years was used. All replacement costs were escalated to 1990 dollars assuming a 5 percent annual inflation rate.

The estimated 1990 replacement costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation is shown in Table 6-8 and was used to estimate the catalyst replacement costs shown in Table 6-9 for the model plants.

6.3.2.4 Catalyst Disposal. Catalyst disposal costs were estimated based on a unit disposal cost of $15/ft^3$, which was obtained from a zeolite catalyst vendor.[32] This cost was used for each model plant, but the disposal cost may in fact be higher for catalysts that contain heavy metals and are classified as hazardous wastes. The catalyst volume for each model plant was estimated based on information about the catalyst volume for one facility and the assumption that there is a direct relationship between the catalyst volume and the turbine output (i.e., the design space velocity is the same regardless of the SCR size). At one facility, 175 m^3 (6,180 ft^3) of catalyst is used in the SCR with an 83 MW (111,000 hp) turbine.[33] The disposal cost for this catalyst would be $92,700, using a cost of $15/ft^3$.

6.3.2.5 Ammonia. The annual ammonia (NH_3) requirement is calculated from the annual NO_x reduction achieved by the SCR system. Based on an NH_3/NO_x molar ratio of 1.0, the annual ammonia requirement, in tons, would equal the annual NO_x reduction, in tons, multiplied by the ratio of the molecular weights for NH_3 and NO_x. Anhydrous ammonia with a unit cost of $360/ton was used.[34,35] The equation to calculate the annual cost for ammonia is shown in Table 6-8.

6.3.2.6 Dilution Steam. As indicated in Section 5.3.1, steam is used to dilute the ammonia to about 5 percent by volume before injection into the HRSG. According to the OAQPS Control

Cost Manual, the cost to produce steam, or to purchase it, is about $6/1,000 lb.

6.3.2.7 Electricity. Electricity requirements to operate such equipment as ammonia pumps and ventilation fans is believed to be small. For one facility, the cost of electricity to operate these components was estimated to make up less than 1 percent of the total annual cost, but it is not clear that the number and size of the fans and pumps represent a typical installation.[27] This cost for electricity is expected to be minor, however, for all installations and was not included in this analysis.

For high-temperature catalysts installed upstream of the HRSG, a blower may be required to inject ambient air into the exhaust to regulate the temperature and avoid temperature excursions above the catalyst design temperature range. The cost to operate the blower is calculated to be 10 percent of the fuel penalty.[35]

6.3.2.8 Performance Loss. The performance loss due to backpressure from the SCR is approximately 0.5 percent of the turbine's design output.[34-36] To make up for this lost output, it was assumed that electricity would have to be purchased at a cost of $0.06/kWH, as indicated in Table 6-3.

6.3.2.9 Production Loss. No costs for production losses were included in this analysis. It was assumed that scheduled inspections, cleaning, and other maintenance will coincide with the 760 hr/yr of expected or scheduled downtime. It should be recognized that adding the SCR system increases the overall system complexity and the probability of unscheduled outages. This factor should be taken into account when considering the addition of an SCR system.

6.3.2.10 Overhead. Standard EPA procedures for estimating annual control costs include overhead costs that are equal to 60 percent of all labor and maintenance material costs.

6.3.2.11 Property Taxes, Insurance, and Administration. According to standard EPA procedures for estimating annual control costs, property taxes, insurance, and administration costs are equal to 4 percent of the total capital investment for the control system.

6.3.2.12 Capital Recovery. The CRF for SCR was estimated to be 0.13147 based on the assumption that the equipment life is 15 years and the interest rate is 10 percent.

6.3.3 Cost Effectiveness for SCR

As indicated in Section 5.4, virtually all gas turbine installations using SCR to reduce NO_x emissions also incorporate wet injection or low-NO_x combustors. The NO_x emission levels into the SCR, therefore, were in all cases taken to be equal to the controlled NO_x emission levels shown for these control techniques in Tables 6-6 and 6-7. The most common controlled NO_x emission limit for gas-fired SCR applications is 9 ppmv, referenced to 15 percent oxygen. The capital costs used in this analysis are expected to correspond to SCR systems sized to reduce controlled NO_x emissions ranging from 25 to 42 ppmv from gas-fired turbines to a controlled level of approximately 9 ppmv downstream of the SCR. Based on the controlled NO_x emission limits established by the Northeast States for Coordinated Air Use Management (NESCAUM), shown in Table 5-3, these SCR systems would reduce NO_x emissions to 18 ppmv for oil-fired applications. Cost-effectiveness figures for SCR in this analysis are therefore calculated based on controlled NO_x emission levels of 9 and 18 ppmv, corrected to 15 percent oxygen, for gas- and oil-fired SCR model plants, respectively.

Cost effectiveness for SCR used downstream of wet injection or dry low-NO_x combustion is shown in Tables 6-11 and 6-12, respectively. For continuous-duty, natural gas-fired model plants using water or steam injection,the cost effectiveness for SCR ranges from approximately $3,500 to $10,800 per ton of NO_x removed.

The cost-effectiveness range for SCR installed downstream of continuous-duty, natural gas-fired turbines from 3 to 10 MW (4,000 to 13,400 hp) using dry low-NO_x combustion is $6,290 to $10,800 per ton of NO_x removed for an inlet NO_x emission level of 42 ppmv. The cost-effectiveness range for SCR increases for an

TABLE 6-11. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF GAS TURBINES WITH WET INJECTION (1990 $)

Model plant	GT model	Turbine output, MW	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $[c]	Cost effectiveness, $/ton
			Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv[b]	tons/yr			
CON-G-W-3.3	Centaur T4500	3.3	42	28.5	9.0	6.10	22.4	242,000	10,800
CON-G-W-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-W-22.7	LM2500	22.7	42	140	9.0	30.0	110	568,000	5,160
CON-G-W-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-W-83.3	ABB GT11N	83.3	25	347	9.0	125	222	1,550,000	6,980
CON-G-W-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-S-22.7	LM2500	22.7	25	83.5	9.0	30.0	53.4	556,000	10,400
CON-G-S-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-S-34.4	LM5000	34.4	25	126	9.0	45.2	80.4	747,000	9,290
CON-G-S-83.3	ABB GT11N	83.3	42	583	9.0	125	458	1,600,000	3,490
CON-G-S-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-161	MS7001F	161	42	1,030	9.0	221	809	2,900,000	3,580
CON-O-W-3.3	Centaur T4500	3.3	60	41.8	18.0	12.5	29.3	244,000	8,340
CON-O-W-26.3	MS5001P	26.3	65	337	18.0	93.3	244	654,000	2,690
CON-O-W-83.3	MS7001E	83.3	65	938	18.0	260	678	1,650,000	2,430
PKR-G-W-3.3	Centaur T4500	3.3	42	7.12	9.0	1.52	5.59	141,000	25,200
PKR-G-W-26.8	MS5001P	26.8	42	53.5	9.0	11.5	42.0	391,000	9,310
PKR-G-W-84.7	MS7001E	84.7	42	148	9.0	31.8	116	1,010,000	8,670
PKR-O-W-3.3	Centaur T4500	3.3	60	10.5	18.0	3.14	7.32	141,000	19,300
PKR-O-W-26.3	MS5001P	26.3	65	84.2	18.0	23.3	60.9	392,000	6,440
PKR-O-W-84.7	MS7001E	84.7	65	234	18.0	64.9	169	1,000,000	5,900
STD-O-W-1.1	Saturn T1500	1.1	60	1.99	18.0	0.60	1.39	103,000	74,000
STD-O-E-28.0	TPM FT4	28.0	50	37.3	18.0	13.4	23.9	448,000	18,800

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-9.

TABLE 6-12. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF DRY LOW-NO_x COMBUSTION (1990 $)

Model plant[a]	GT model	Turbine output, MW	NO_x emissions[b] Uncontrolled		Inlet to SCR		Downstream of SCR		Total NO_x removed, tons/yr	Total annual cost, $[d]	Cost effectiveness, $/ton
			ppmv[c]	tons/yr	ppmv[c]	tons/yr	ppmv[c]	tons/yr			
CON-L-3.3-42	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.1	22.4	242,000	10,800
CON-L-4.0-42	Centaur 'H'	4.0	105	83.0	42	33.2	9.0	7.1	26.1	255,000	9,780
CON-L-4.5-42	Taurus	4.5	114	98.7	42	36.4	9.0	7.8	28.6	263,000	9,200
CON-L-8.8-42	Mars T12000	8.8	178	278	42	65.5	9.0	14.0	51.5	336,000	6,530
CON-L-10-42	Mars T14000	10.0	199	341	42	72.1	9.0	15.4	56.6	356,000	6,290
CON-L-3.3-25	Centaur T4500	3.3	130	88.1	25	16.9	9.0	6.1	10.8	240,000	22,100
CON-L-4.0-25	Centaur 'H'	4.0	105	83.0	25	19.8	9.0	7.1	12.6	252,000	19,900
CON-L-4.5-25	Taurus	4.5	114	98.7	25	21.7	9.0	7.8	13.9	260,000	18,800
CON-L-8.8-25	Mars T12000	8.8	178	278	25	39.0	9.0	14.0	25.0	330,000	13,200
CON-L-10-25	Mars T14000	10.0	199	341	25	42.9	9.0	15.4	27.5	350,000	12,800
CON-L-39-25	MS6000	39.0	220	1,480	25	168	9.0	61	108	826,000	7,660
CON-L-83-25	ABB GT11N	83.3	390	5,420	25	347	9.0	125	222	1,550,000	6,970
CON-L-85-25	MS7001E	84.7	154	2,180	25	353	9.0	127	226	1,570,000	6,940
PKR-L-3.3-42	Centaur T4500	3.3	130	22.0	42	7.12	9.0	1.52	5.6	164,000	29,300
PKR-L-4.0-42	Centaur 'H'	4.0	105	20.7	42	8.30	9.0	1.78	6.5	201,000	30,800
PKR-L-4.5-42	Taurus	4.5	114	24.7	42	9.09	9.0	1.95	7.1	207,000	29,000
PKR-L-8.8-42	Mars T12000	8.8	178	69.4	42	16.4	9.0	3.5	12.9	193,000	15,000
PKR-L-10-42	Mars T14000	10.0	199	85.4	42	18.0	9.0	3.9	14.2	207,000	14,600
PKR-L-3.3-25	Centaur T4500	3.3	130	22.0	25	4.24	9.0	1.52	2.7	141,000	52,000
PKR-L-4.0-25	Centaur 'H'	4.0	105	20.7	25	4.94	9.0	1.78	3.2	151,000	47,800
PKR-L-4.5-25	Taurus	4.5	114	24.7	25	5.41	9.0	1.95	3.5	156,000	45,000
PKR-L-8.8-25	Mars T12000	8.8	178	69.4	25	9.75	9.0	3.51	6.2	192,000	30,800
PKR-L-10-25	Mars T14000	10.0	199	85.4	25	10.7	9.0	3.9	6.9	206,000	30,000
PKR-L-39-25	MS6000	39.0	220	371	25	42.1	9.0	15.2	26.9	492,000	18,300
PKR-L-83-25	ABB GT11N	83.3	390	1,350	25	86.8	9.0	31.3	55.6	927,000	16,700
PKR-L-85-25	MS7001E	84.7	154	540	25	88.3	9.0	31.8	56.5	943,000	16,700

[a]See Table 6-7 for model plant legend.
[b]Example NO_x emission calculations are shown in Appendix A.
[c]Referenced to 15 percent oxygen.
[d]From Table 6-10.

inlet NO_x emission level of 25 ppmv due to the lower NO_x reduction efficiency. For an inlet NO_x level of 25 ppmv, the cost effectiveness ranges from $12,800 to $22,100 per ton of NO_x removed for 3 to 10 MW (4,000 to 13,400 hp) turbines and decreases to $6,940 to $7,660 per ton of NO_x removed for larger turbines ranging from 39 to 85 MW (52,300 to 114,000 hp). As these ranges indicate, the cost effectiveness for SCR is affected by the inlet NO_x emission level and not the type of combustion control technique used for the turbine. The cost effectiveness for continuous-duty, oil-fired model plants ranges from approximately $2,450 to $8,350 per ton of NO_x removed. The SCR cost-effectiveness range for oil-fired applications is lower than that for gas-fired installations in this cost analysis because the same capital costs were used for both fuels (capital costs were not available for applications using only distillate oil fuel). The percent NO_x reduction for oil-fired applications is higher, so the resulting cost-effectiveness figures for oil-fired applications are lower. It should be noted that this higher NO_x reduction for oil-fired applications may require a larger catalyst reactor, at a higher capital cost. As a result, the cost-effectiveness figures may actually be higher than those shown in Table 6-11 for oil-fired applications.

The cost-effectiveness figures are higher for smaller gas turbines because the fixed capital costs associated with the installation of an SCR system have the greatest impact on smaller gas turbines. Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hours per year, cost-effectiveness figures are more than double those for continuous-duty model plants, and they increase even further for model plants operating 1,000 hr/yr.

Because virtually all SCR systems are installed downstream of controlled gas turbines, combined cost-effectiveness figures for wet injection plus SCR and also dry low-NO_x combustion plus SCR have been calculated and are shown in Tables 6-13 and 6-14, respectively. These combined cost-effectiveness figures are calculated by dividing the sum of the total annual costs by the

TABLE 6-13. COMBINED COST-EFFECTIVENESS SUMMARY FOR WET INJECTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	NO_x emissions[a]						Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton[c]
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv[b]	tons/yr	ppmv[b]	tons/yr			
CON-G-W-3.3	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.10	82.0	366,000	4,460
CON-G-W-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	417,000	3,510
CON-G-W-22.7	LM2500	22.7	174	581	42	140	9.0	30	551	1,000,000	1,820
CON-G-W-26.8	MS5001P	26.8	142	723	42	214	9.0	46	677	1,220,000	1,800
CON-G-W-83.3	ABB GT11N	83.3	390	5,410	25	347	9.0	125	5,290	4,460,000	843
CON-G-W-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	3,100,000	1,520
CON-G-S-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	423,000	3,560
CON-G-S-22.7	LM2500	22.7	174	581	25	83.5	9.0	30.0	551	977,000	1,770
CON-G-S-26.8	MS5001P	26.8	142	723	42	214	9.0	45.8	677	1,130,000	1,670
CON-G-S-83.3	LM5000	34.4	185	930	25	126	9.0	45.2	884	1,440,000	1,630
CON-G-S-84.7	ABB GT11N	83.3	390	5,410	42	583	9.0	125	5,290	3,410,000	645
CON-G-S-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	2,780,000	1,360
CON-G-S-161	MS7001F	161	210	5,150	42	1,030	9.0	220	4,930	4,870,000	988
CON-O-W-3.3	Centaur T4500	3.3	179	125	60	42	18.0	12.5	112	387,000	3,450
CON-O-W-26.3	MS5001P	26.3	211	1,090	65	337	18.0	93.3	997	1,410,000	1,410
CON-O-W-83.3	MS7001E	83.3	228	3,290	65	938	18.0	260	3,030	3,230,000	1,070
PKR-G-W-3.3	Centaur T4500	3.3	130	22.0	42	7.1	9.0	1.5	20.5	222,000	10,800
PKR-G-W-26.8	MS5001P	26.8	142	181	42	53.5	9.0	11.5	169	690,000	4,080
PKR-G-W-84.7	MS7001E	84.7	154	543	42	148	9.0	31.8	512	1,710,000	3,340
PKR-O-W-3.3	Centaur T4500	3.3	179	31.2	60	10	18.0	3.14	28.1	228,000	8,130
PKR-O-W-26.3	MS5001P	26.3	211	273	65	84	18.0	23.3	250	751,000	3,000
PKR-O-W-84.7	MS7001E	84.7	228	822	65	234	18.0	64.9	757	1,710,000	2,260
STD-O-W-1.1	Saturn T1500	1.1	150	4.97 122	60	1.99	18.0	0.60	4.4	152,000	34,700
STD-O-E-28.0	TPM FT4	28.0	150		50	37.3	18.0	13.4	109	604,000	5,563

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]Total for both wet injection plus SCR control techniques.

TABLE 6-14. COMBINED COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NOx COMBUSTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	Annual operating hours	NO_x emissions[a] Uncontrolled ppmv[b]	Uncontrolled tons/yr	Inlet to SCR ppmv[b]	Inlet to SCR tons/yr	Downstream of SCR ppmv[b]	Downstream of SCR tons/yr	Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton[c]
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42	28.5	9.0	6.1	82.0	291,000	3,550
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42	33.2	9.0	7.1	75.8	308,000	4,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42	36.4	9.0	7.8	90.9	319,000	3,510
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42	65.5	9.0	14.0	264	428,000	1,620
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42	72.1	9.0	15.4	326	451,000	1,380
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25	16.9	9.0	6.1	82.0	289,000	3,520
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25	19.8	9.0	7.1	75.8	305,000	4,020
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25	21.7	9.0	7.8	90.9	316,000	3,470
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25	39.0	9.0	14.0	264	422,000	1,600
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25	42.9	9.0	15.4	326	445,000	1,370
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25	168	9.0	60.6	1,420	1,010,000	711
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25	347	9.0	125	5,290	1,840,000	348
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25	353	9.0	127	2,050	1,850,000	902
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42	7.1	9.0	1.5	20.5	213,000	10,400
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42	8.3	9.0	1.8	19.0	254,000	13,400
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42	9.1	9.0	1.9	22.7	263,000	11,600
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42	16.4	9.0	3.5	65.9	285,000	4,320
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42	18.0	9.0	3.9	81.5	302,000	3,710
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25	4.2	9.0	1.5	20.5	190,000	9,300
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25	4.9	9.0	1.8	19.0	204,000	10,800
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25	5.4	9.0	1.9	22.7	212,000	9,300
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25	9.8	9.0	3.5	65.9	284,000	4,300
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25	10.7	9.0	3.9	81.5	301,000	3,700
PKR-L-39-25	MS6000	39.0	2,000	220	371	25	42.1	9.0	15.2	355	680,000	1,910
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25	86.8	9.0	31.3	1,320	1,220,000	924
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25	88.3	9.0	31.8	508	1,220,000	2,400

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]Total for both dry low-NO_x combustion plus SCR control techniques.

sum of the annual reduction of NO_x emissions for the combined emission control techniques. For continuous-duty, natural gas-fired model plants, the combined cost-effectiveness figures for wet injection plus SCR range from approximately $650 to $4,500 per ton of NO_x removed. For continuous-duty, oil-fired model plants, the combined cost effectiveness ranges from approximately $1,100 to $3,550 per ton of NO_x removed. The combined cost-effectiveness figures for dry low-NO_x combustion plus SCR for continuous-duty, natural gas-fired model plants range from approximately $350 to $3,550 per ton of NO_x removed.

The combined cost-effectiveness figures increase with decreasing turbine size and annual operating hours. Data were not available to quantify the wet injection requirements and controlled emissions levels for oil-fired turbines with low-NO_x combustors, so cost-effectiveness figures were not tabulated for this control scenario.

6.4 OFFSHORE TURBINES

The only available information about the cost of NO_x controls for offshore gas turbines was presented in a report prepared for the Santa Barbara County Air Pollution Control District (SBCAPCD) in California.[37] The performance and cost of about 20 NO_x control techniques for a 2.8 MW (3,750 hp) turbine were described in the report. Wet injection and SCR were included in the analysis; low-NO_x combustors were not. The costs from the report are presented in Table 6-15 without adjustment because there is insufficient cost information to know what adjustments need to be made. Additionally, insufficient information is available to scale up these costs for larger turbines. The water and steam injection costs and SCR costs for offshore applications are discussed in Sections 6.4.1 and 6.4.2, respectively.

6.4.1 Wet Injection

The report prepared for SBCAPCD assumed water injection costs are the same as steam injection costs. The report did not describe the components in the capital cost analysis for these injection systems, but the results are much lower than those that

TABLE 6-15. PROJECTED WET INJECTION AND SCR COSTS FOR AN OFFSHORE GAS TURBINE[a]

	Wet injection costs	SCR costs
Capital cost, $	70,000	585,000
Annual costs, $/yr		
Ammonia	N/A[b]	3,050[c]
Catalyst replacement	N/A	28,000
Operating and maintenance[d]	24,600	18,000
Fuel penalty[e]	10,500	5,000
Capital recovery[f]	14,000	117,000
Total annual costs, $/yr	49,100	171,000

[a]Costs are for a 2.8 MW gas turbine and are obtained from Reference 37.
[b]N/A = Not applicable.
[c]Ammonia cost is based on $150/ton and 0.4 lb NH_3/lb NO_x.
[d]Operating and maintenance cost for SCR is estimated as 3 percent of the total capital investment.
[e]Fuel penalty is estimated as 2 percent of the annual fuel consumption for wet injection and 1 percent for SCR.
[f]Capital recovery is estimated based on an equipment life of 8 years and an interest rate of 13 percent.

would be estimated by the procedures described in Section 6.1.1 of this report. The authors may have assumed that the engine-mounted injection equipment cost was included in the turbine capital cost and that a less rigorous water treatment process is installed. Annual costs are also much lower than those that would be estimated by the procedures described in Section 6.1.2 of this report. There are at least three reasons for the difference: (1) the low capital cost leads to a low CRF, even though the turbine life was assumed to be only 8 years; (2) overhead costs and taxes, insurance, and administration costs are not considered; and (3) the capacity factor is only 50 percent (i.e., about 4,400 hr/yr, vs. 8,000 hr/yr, as in Section 6.1.2). The turbine life was only 8 years, which may correspond to a typical service life of an offshore platform.

6.4.2 <u>Selective Catalytic Reduction</u>

The total capital costs presented in the report for SBCAPCD are similar to those that would be estimated by the procedures in Section 6.2.1 of this report. However, it appears that $150,000 of the total in Reference 37 is for structural modifications to the platform and $75,000 is for retrofit installation. When the difference in the load factor is taken into account, some of the annual costs are similar to those that would be estimated by the procedures in Section 6.2.2 for a similarly sized turbine. The catalyst replacement cost, however, is much lower; neither the type of catalyst nor the replacement frequency were identified. Ammonia costs are lower because the uncontrolled NO_x emission level was assumed to be 110 ppmv instead of 150 ppmv and because a unit cost of $150/ton was used instead of $400/ton. The reference does not indicate whether or not catalyst disposal, overhead, taxes, freight, and administration costs were considered. Capital recovery costs are higher because the equipment life is assumed to be only 8 years on the offshore platform.

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7.0 ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the nitrogen oxide (NO_x) emissions control techniques described in Chapter 5.0. These control techniques are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR). The impacts of the control techniques on air pollution, solid waste disposal, water pollution, and energy consumption are discussed.

The remainder of this chapter is organized in five sections. Section 7.1 presents the air pollution impacts; Section 7.2 presents the solid waste disposal impacts; Section 7.3 presents the water pollution impacts; and Section 7.4 presents the energy consumption impacts. References for the chapter are listed in Section 7.5.

7.1 AIR POLLUTION

7.1.1 Emission Reductions

Applying any of the control techniques discussed in Chapter 5 will reduce NO_x emissions from gas turbines. These emission reductions were estimated for the model plants presented in Table 6-1 and are shown in Table 7-1. For each model plant, the uncontrolled and controlled emissions, emission reductions, and percent reductions are presented. The following paragraphs discuss NO_x emission reductions for each control technique.

Nitrogen oxide emission reductions for water or steam injection are estimated as discussed in Section 6.1.3. The percent reduction in emissions from uncontrolled levels varies for each model plant ranging, from 60 to 96 percent. This reduction depends on each model's uncontrolled emissions, the

TABLE 7-1. MODEL PLANT UNCONTROLLED AND CONTROLLED NO_x EMISSIONS FOR AVAILABLE NO_x CONTROL TECHNIQUES

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year: Wet injection to levels in Table 6-6	Controlled NO_x emissions, tons/year: Dry low-NO_x combustor to 42 ppmv	Controlled NO_x emissions, tons/year: Dry low-NO_x combustor to 25 ppm	Controlled NO_x emissions, tons/year: Dry low-NO_x combustor to 9 ppmv	Controlled NO_x emissions, tons/year: NO_x emissions, wet injection + SCR[b]	SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
Centaur T4500	8,000	Water	Emissions, tons/yr	88.1	28.5	28.5	16.9	NA[d]	6.10	2.92
3.3 MW			Reduction, tons/yr		59.6	59.6	71.2	–	22.4	
Gas fuel			Total reduction, %		68%	68%	81%	–	93%	
501-KB5	8,000	Water	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		91.8	–	–	–	26.9	
Gas fuel			Total reduction, %		73%	–	–	–	94%	
LM2500	8,000	Water	Emissions, tons/yr	581	140	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		441	–	–	–	110	
Gas fuel			Total reduction, %		76%	–	–	–	95%	
MS5001P	8,000	Water	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	–	–	–	168	
Gas fuel			Total reduction, %		70%	–	–	–	94%	
ABB GT11N	8,000	Water	Emissions, tons/yr	5,410	347	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		5,060	–	5060	5290	222	
Gas fuel			Total reduction, %		94%	–	94%	98%	98%	
MS7001E	8,000	Water	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	–	1820	2040	466	
Gas fuel			Total reduction, %		73%	–	84%	94%	94%	
501-KB5	8,000	Steam	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		92	–	–	–	26.9	
Gas fuel			Total reduction, %		73%	–	–	–	94%	
LM2500	8,000	Steam	Emissions, tons/yr	581	83.5	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		498	–	–	–	53.5	
Gas fuel			Total reduction, %		86%	–	–	–	95%	
MS5001P	8,000	Steam	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	–	–	–	168	
Gas fuel			Total reduction, %		70%	–	–	–	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year: Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
LM5000	8,000	Steam	Emissions, tons/yr	930	126	NA	NA	NA	45.2	20.5
34.4 MW			Reduction, tons/yr		804	–	–	–	80.8	
Gas fuel			Total reduction, %		86%	–	–	–	95%	
ABB GT11N	8,000	Steam	Emissions, tons/yr	5,410	583	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		4830	–	5060	5290	458	
Gas fuel			Total reduction, %		89%	–	94%	98%	98%	
MS7001E	8,000	Steam	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	–	1820	2040	466	
Gas fuel			Total reduction, %		73%	–	84%	94%	94%	
MS7001F	8,000	Steam	Emissions, tons/yr	5,150	1,030	NA	610	NA	221	71.7
161 MW			Reduction, tons/yr		4120	–	4540	–	809	
Gas fuel			Total reduction, %		80%	–	88%	–	96%	
Centaur T4500	8,000	Water	Emissions, tons/yr	125	41.8	NA	NA	NA	12.5	2.9
3.3 MW			Reduction, tons/yr		83.2	–	–	–	29.3	
Oil fuel			Total reduction, %		67%	–	–	–	90%	
MS5001P	8,000	Water	Emissions, tons/yr	1,090	337	NA	NA	NA	46.6	20.4
26.3 MW			Reduction, tons/yr		753	–	–	–	290	
Oil fuel			Total reduction, %		69%	–	–	–	96%	
MS7001E	8,000	Water	Emissions, tons/yr	3,290	938	NA	NA	NA	130	49.6
83.3 MW			Reduction, tons/yr		2350	–	–	–	808	
Oil fuel			Total reduction, %		71%	–	–	–	96%	
Centaur T4500	2,000	Water	Emissions, tons/yr	22.0	7.1	NA	NA	NA	1.5	0.7
3.3 MW			Reduction, tons/yr		14.9	–	–	–	6	
Gas fuel			Total reduction, %		68%	–	–	–	93%	
MS5001P	2,000	Water	Emissions, tons/yr	181	53.5	NA	NA	NA	11.5	5.1
26.8 MW			Reduction, tons/yr		128	–	–	–	42	
Gas fuel			Total reduction, %		70%	–	–	–	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year: Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
MS7001E	2,000	Water	Emissions, tons/yr	543	148	NA	88	32	31.8	12.4
84.7 MW			Reduction, tons/yr		395	–	455	511	116	
Gas fuel			Total reduction, %		73%	–	84%	94%	94%	
Centaur T4500	2,000	Water	Emissions, tons/yr	31.2	10.0	NA	NA	NA	3.14	0.7
3.3 MW			Reduction, tons/yr		21.2	–	–	–	6.9	
Oil fuel			Total reduction, %		68%	–	–	–	90%	
MS5001P	2,000	Water	Emissions, tons/yr	273	84	NA	NA	NA	23.3	5.1
26.8 MW			Reduction, tons/yr		189	–	–	–	61	
Oil fuel			Total reduction, %		69%	–	–	–	91%	
MS7001E	2,000	Water	Emissions, tons/yr	822	234	NA	NA	NA	64.9	12.4
84.7 MW			Reduction, tons/yr		588	–	–	–	169	
Oil fuel			Total reduction, %		72%	–	–	–	92%	
SATURN T1500	1,000	Water	Emissions, tons/yr	5.00	1.99	NA	NA	NA	0.30	0.13
1.1 MW			Reduction, tons/yr		3	–	–	–	1.7	
Oil fuel			Total reduction, %		60%	–	–	–	94%	
TPM FT4	1,000	Water-in-oil emulsion	Emissions, tons/yr	977	37.3	NA	NA	NA	6.72	NC[e]
28.0 MW			Reduction, tons/yr		940	–	–	–	30.6	–
Oil fuel			Total reduction, %		96%	–	–	–	99%	–

[a]Uncontrolled and controlled NO_x emissions are from cost-effectiveness tables in Chapter 6.
[b]Controlled NO_x emission level for wet injection plus SCR is 9 ppmv for natural gas fuel and 18 ppmv for distillate oil fuel.
[c]Ammonia emissions, in tons per year = (SLIP, ppmv) x (MM/1,000,000) x (GT exhaust,lb/sec) x (MW NH3 = 15/MW exhaust = 28.6) x (3,600 sec/hr) x (ton/2,000 lb) x (annual operating hrs).
[d]NA-control technology not available for this model plant.
[e]NC-data not available to calculate emissions for this control scenario.

water-to-fuel ratio (WFR), and type of fuel and whether water or steam is injected.

Achievable emission levels from gas turbines using dry low-NO_x combustors were obtained from manufacturers. Controlled NO_x levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, were reported by the various turbine manufacturers, and each of these levels is shown in Table 7-1, where applicable, for each model plant. The percent reduction in NO_x emissions from uncontrolled levels for gas turbines using these combustors ranges from 68 to 98 percent. Virtually all SCR units installed in the United States are used in combination with either wet controls or combustion controls. For this analysis, emission reductions were calculated for SCR in combination with water or steam injection. Using the turbine manufacturers' guaranteed NO_x emissions figures for wet injection and a controlled NO_x emission level of 9 ppmv, referenced to 15 percent oxygen, exiting the SCR, the percent reduction in NO_x emissions for this combination of control techniques ranges from 93 to 99 percent.

Estimated ammonia (NH_3) emissions, in tons per year, corresponding to ammonia slip from the SCR system are also shown in Table 7-1. These estimates are based on an ammonia slip level of 10 ppmv, consistent with information and data presented in Section 5.4. For continuous-duty model plants, the annual NH_3 emissions range from approximately 3 tons for a 3.3 megawatt (MW) (4,425 horsepower [hp]) model plant to 72 tons for a 160 MW (215,000 hp) model plant.

7.1.2 Emissions Trade-Offs

The formation of both thermal and fuel NO_x depends upon combustion conditions. Water/steam injection, lean combustion, and reduced residence time modify combustion conditions to reduce the amount of NO_x formed. These combustion modifications may increase carbon monoxide (CO) and unburned hydrocarbon (HC) emissions. Using SCR to control NO_x emissions produces ammonia emissions. The impacts of these NO_x controls on CO, HC, and ammonia emissions are discussed below.

7.1.2.1 Impacts of Wet Controls on CO and HC Emissions. As discussed in Section 5.1.5, wet injection may increase CO and HC emissions. Injecting water or steam into the flame area of a turbine combustor lowers the flame temperature and thereby reduces NO_x emissions. This reduction in temperature to some extent inhibits complete combustion, resulting in increased CO and HC emissions. Figure 5-12 shows the impact of water and steam injection on CO emissions for production gas turbines.[2] The impact of steam injection on CO emissions is less than that of water injection. As seen in Figure 5-12, CO emissions increase with increasing WFR's. Wet injection increases HC emissions to a lesser extent than it increases CO emissions. Figure 5-13 shows the impact of water injection on HC emissions for one turbine. In cases where water and steam injection result in excessive CO and HC emissions, an oxidation catalyst (add-on control) can be installed to reduce these emissions by converting the CO and HC to water (H_2O) and carbon dioxide (CO_2).

7.1.2.2 Impacts of Combustion Controls on CO and HC Emissions. As discussed in Section 5.2.1, the performance of lean combustion in limiting NO_x emissions relies in part on reduced equivalence ratios. As the equivalence ratio is reduced below the stoichiometric level of 1.0, combustion flame temperatures drop, and as a result NO_x emissions are reduced. Shortening the residence time in the high-temperature flame zone also will reduce the amount of thermal NO_x formed. These lower equivalence ratios and/or reduced residence time, however, may result in incomplete combustion, which may increase CO and HC emissions. The extent of the increase in CO and HC emissions is specific to each turbine manufacturer's combustor designs and therefore varies for each turbine model. As with wet injection, if necessary, an oxidation catalyst can be installed to reduce excessive CO and HC emissions by converting the CO and HC to CO_2 and H_2O.

7.1.2.3 Ammonia Emissions from SCR. The SCR process reduces NO_x emissions by injecting NH_3 into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form H_2O and nitrogen (N_2). The NO_x removal efficiency of this process is partially dependent on the NH_3/NO_x ratio. Increasing this ratio reduces NO_x emissions but increases the probability that unreacted ammonia will pass through the catalyst unit into the atmosphere (known as ammonia "slip"). Some ammonia slip is unavoidable because of ammonia injection control limitations and imperfect distribution of the reacting gases. A properly designed SCR system will limit ammonia slip to less than 10 ppmv (see Section 5.4).

7.2 SOLID WASTE DISPOSAL

Catalytic materials used in SCR units for gas turbines include precious metals (e.g., platinum), zeolites, and heavy metal oxides (e.g., vanadium, titanium). Vanadium pentoxide, the most commonly used SCR catalyst in the United States, is identified as an acute hazardous waste under RCRA Part 261, Subpart D - Lists of Hazardous Wastes. The Best Demonstrated Available Technology (BDAT) Treatment Standards for Vanadium P119 and P120 states that spent catalysts containing vanadium pentoxide are not classified as hazardous waste.[1] State and local regulatory agencies, however, are authorized to establish their own hazardous waste classification criteria, and spent catalysts containing vanadium pentoxide may be classified as a hazardous waste in some areas. Although the actual amount of vanadium pentoxide contained in the catalyst bed is small, the volume of the catalyst unit containing this material is quite large and disposal can be costly. Where classified by State or local agencies as a hazardous waste, this waste may be subject to the Land Disposal Restrictions in 40 CFR Part 268, which allows land disposal only if the hazardous waste is treated in accordance with Subpart D - Treatment Standards. Such disposal problems are not encountered with other catalyst materials, such as precious metals and zeolites, because these materials are not hazardous wastes.

7.3 WATER USAGE AND WASTE WATER DISPOSAL

Water availability and waste water disposal are environmental factors to be considered with wet injection. The impact of water usage on the water supply at some remote sites, in small communities, or in areas where water resources may be limited is an environmental factor that should be examined when considering wet injection. The volume of water required for wet injection is shown in Table 7-2 for each model plant.

Water purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine. Water treatment systems are used to achieve water quality specifications set by gas turbine manufacturers. Table 5-4 summarizes these specifications for six manufacturers.

Discharges from these water treatment systems have a potential impact on water quality. As indicated in Section 6.1, approximately 29 percent of the treated water flow rate (22.5 percent of the raw water flow rate) is considered to be discharged as wastewater. The wastewater flow rates for each of the model plants with a water or steam injection control system are estimated using this factor, and the results are presented in Table 7-2. The wastewater contains increased levels of those pollutants in the raw water (e.g., calcium, silica, sulfur, as listed in Table 5-4) that are removed by the water treatment system, along with any chemicals introduced by the treatment process. Based on a wastewater flowrate equal to 29 percent of the influent raw water, the concentration of pollutants discharged from the water treatment system is approximately three times higher than the pollutant concentrations in the raw water.

The impacts of these pollutants on water quality are site-specific and depend on the type of water supply and on the discharge restrictions. Influent water obtained from a municipality will not contain high concentrations of pollutants. However, surface water or well water used at a remote site might contain high pollutant concentrations and may require additional pretreatment to meet the water quality specifications set by

TABLE 7-2. WATER AND ELECTRICITY CONSUMPTION FOR NO_x CONTROL TECHNIQUES

Gas turbine model[a]	Turbine power output, MW	Annual operating hours	Fuel type	Type of emission control	Total water flow, gal/min[a]	Waste water flow, gal/min[b]	Water pump power, kW[c]	Wet injection power consumption, kW-hr/yr[d]	SCR power penalty, kW-hr/yr[e]
Centaur T4500	3.3	8,000	Gas	Water inj.	2.5	0.73	0.40	3,220	132,000
501-KB5	4.0	8,000	Gas	Water inj.	3.94	1.14	0.63	5,070	160,000
LM2500	22.7	8,000	Gas	Water inj.	14.8	4.29	2.38	19,100	908,000
MS5001P	26.8	8,000	Gas	Water inj.	22.2	6.44	3.57	28,600	1,070,000
ABB GT11N	83.3	8,000	Gas	Water inj.	154	44.7	24.8	198,000	3,330,000
MS7001E	84.7	8,000	Gas	Water inj.	69.2	20.1	11.1	89,100	3,390,000
501-KB5	4.0	8,000	Gas	Steam inj.	7.38	2.14	1.19	9,510	160,000
LM2500	22.7	8,000	Gas	Steam inj.	29.5	8.56	4.75	38,000	908,000
MS5001P	26.8	8,000	Gas	Steam inj.	33.3	9.66	5.36	42,900	1,070,000
LM5000	34.4	8,000	Gas	Steam inj.	50.8	14.7	8.18	65,400	1,380,000
ABB GT11N	83.3	8,000	Gas	Steam inj.	178	51.6	28.7	229,000	3,330,000
MS7001E	84.7	8,000	Gas	Steam inj.	104	30.2	16.7	134,000	3,390,000
MS7001F	161	8,000	Gas	Steam inj.	199	57.7	32.0	256,000	6,440,000
Centaur T4500	3.3	8,000	Oil	Water inj.	2.76	0.80	0.44	3,550	132,000
MS5001P	26.3	8,000	Oil	Water inj.	26.7	7.74	4.30	34,400	1,050,000
MS7001E	83.3	8,000	Oil	Water inj.	63.8	18.5	10.3	82,200	833,000
Centaur T4500	3.3	2,000	Gas	Water inj.	2.50	0.73	0.40	3,220	33,000
MS5001P	26.3	2,000	Gas	Water inj.	22.2	6.44	3.57	28,600	263,000
MS7001E	84.7	2,000	Gas	Water inj.	69.2	20.1	11.1	89,100	847,000
Centaur T4500	3.3	2,000	Oil	Water inj.	2.76	0.80	0.44	3,550	33,000
MS5001P	26.3	2,000	Oil	Water inj.	26.7	7.74	4.30	34,400	263,000
MS7001E	84.7	2,000	Oil	Water inj.	63.8	18.5	10.3	82,200	847,000
SATURN T1500	1.1	1,000	Oil	Water inj.	0.81	0.23	0.13	1,040	5,500
TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	21.7	6.29	3.49	27,900	140,000

[a]From Table 6-2.

[b]Calculated as 29 percent of the total water flow.

[c]Power requirement for water pump is calculated as shown in Section 6.1.2.2.

[d]Wet injection electricity usage = (water pump kW) X (annual operating hours).

[e]SCR power penalty = (0.005 X turbine power output, kW) X (annual operating hours).

manufacturers. This additional pretreatment will increase the pollutant concentrations of the wastewater discharge. Wastewater discharges to publicly-owned treatment works (POTW's) must meet the requirements of applicable Approved POTW Pretreatment Programs.

7.4 ENERGY CONSUMPTION

Additional fuel and electrical energy is required over baseline for wet injection controls, while additional electrical energy is required for SCR controls. The following paragraphs discuss these energy consumption impacts.

Injecting water or steam into the turbine combustor lowers the net cycle efficiency and increases the power output of the turbine. The thermodynamic efficiency of the combustion process is reduced because energy that could otherwise be available to perform work in the turbine must now be used to heat the water/steam. This lower efficiency is seen as an increase in fuel use. Table 5-10 shows the impacts of wet injection on gas turbine performance for one manufacturer. This table shows a 2 to 4 percent loss in efficiency associated with WFR's required to achieve NO_x emission levels of 25 to 42 ppmv in gas turbines burning natural gas. The actual efficiency loss is specific to each turbine model but generally increases with increasing WFR's and is higher for water injection than for steam injection (additional energy is required to heat and vaporize the water). One exception to this efficiency penalty occurs with steam injection, in which exhaust heat from the gas turbine is used to generate the steam for injection. If the heat recovered in generating the steam would otherwise be exhausted to atmosphere, the result is an increase in net cycle efficiency.

The energy from the increased mass flow and heat capacity of the injected water/steam can be recovered in the turbine, resulting in an increase in power output accompanying the reduced efficiency of the turbine (shown in Table 5-10 for one manufacturer). This increase in power output can be significant and could lessen the impact of the loss in efficiency if the facility has a demand for the available excess power.

Water and steam injection controls also require additional electrical energy to operate the water injection feed water pumps. The annual electricity usage for each model is the product of the pump power demand, discussed in Section 6.1.2.2, and the annual hours of operation. Table 7-2 summarizes this electricity usage for each of the model plants.

For SCR units, additional electrical energy is required to operate ammonia pumps and ventilation fans. This energy requirement, however, is believed to be small and was not included in this analysis.

The increased back-pressure in the turbine exhaust system resulting from adding an SCR system reduces the power output from the turbine. As discussed in Section 6.3.2.9, the power output is typically reduced by approximately 0.5 percent. This power penalty has been calculated for each model plant and is shown in Table 7-2.

7.5 REFERENCE FOR CHAPTER 7

1. 55 FR 22276, June 1, 1990.

APPENDIX A

Exhaust NO_x emission levels were provided by gas turbine manufacturers in units of parts per million, by volume (ppmv), on a dry basis and corrected to 15 percent oxygen. A method of converting these exhaust concentration levels to a mass flow rate of pounds of NO_x per hour (lb NO_x/hr) was provided by one gas turbine manufacturer.[1] This method uses an emission index ($EINO_x$), in units of lb NO_x/1,000 lb fuel, which is proportional to the exhaust NO_x emission levels in ppmv by a constant, K. The relationship between $EINO_x$ and ppmv for NO_x emissions is stated in Equation 1 below and applies for complete combustion of a hydrocarbon fuel and combustion air having no CO_2 and an O_2 mole percent of 20.95:

$$\frac{NO_x \text{ Ref. } 15\% \; O_2}{EINO_x} = K \qquad \text{Equation 1}$$

where: NO_x Ref. 15% O_2 = NO_x, ppmvd @15% O_2 (provided by gas turbine manufacturers);

$EINO_x$ = NO_x emission index, lb NO_x/1,000 lb fuel; and

K = constant, based on the molar hydrocarbon ratio of the fuel.

The derivation of Equation 1 was provided by the turbine manufacturer and is based on basic thermodynamic laws and supported by test data provided by the manufacturer. According to the manufacturer, this equation can be used to estimate NO_x emissions for operation with or without water/steam injection.

Equation 1 shows that NO_x emissions are dependent only upon the molar hydrocarbon ratio of the fuel and are independent of the air/fuel ratio (A/F). The equation therefore is valid for all gas turbine designs for a given fuel. The validity of this approach to calculate NO_x emissions was supported by a second turbine manufacturer.[2] Values for K were provided for several fuels and are given below:[1,2]

Pipeline quality natural gas:	K = 12.1
Distillate fuel oil No. 1 (DF-1):	K = 13.1
Distillate fuel oil No. 2 (DF-2):	K = 13.2
Jet propellant No. 4 (JP-4):	K = 13.0
Jet propellant No. 5 (JP-5):	K = 13.1
Methane:	K = 11.6

The following examples are provided for calculating NO_x emissions on a mass basis, given the fuel type and NO_x emission level, in ppmv, dry (ppmvd), and corrected to 15 percent O_2.

Example 1. Natural gas fuel

Gas turbine:	Solar Centaur 'H'
Power output:	4,040 kW
Heat rate:	12,200 Btu/kW-hr
NO_x emissions:	105 ppmvd, corrected to 15 percent O_2
Fuel:	Natural gas
	- lower heating value = 20,610 Btu/lb
	- K = 12.1

Fuel flow:

$$4{,}040 \text{ kW} \times \frac{12{,}200 \text{ Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{20{,}610 \text{ Btu}} = 2{,}391 \text{ lb/hr}$$

From Equation 1:

$$\frac{105}{EINO_x} = 12.1$$

NO_x emissions, lb/hr:

$$2,391 \frac{\text{lb fuel}}{\text{hr}} \times \frac{8.68 \text{ lb } NO_x}{1,000 \text{ lb fuel}} = 20.8 \frac{\text{lb } NO_x}{\text{hr}}$$

Example 2. Distillate oil fuel

Gas turbine: General Electric LM2500

Power output: 22670 kW

Heat rate: 9296 Btu/kW-hr

No_x emissions: 345 ppmvd, corrected to 15 percent O_2

Fuel: Distillate oil No. 2

- lower heating value = 18,330 Btu/lb
- K = 13.2 •

Fuel flow:

$$22,670 \text{ kW} \times 9296 \frac{\text{Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{18,330\text{Btu}} = 11,500 \text{ lb/hr}$$

From Equation 1:

$$\frac{345}{EINO_x} = 13.2$$

NO_x emissions, lb/hr:

$$11,500 \frac{\text{lb fuel}}{\text{hr}} \times \frac{26.1 \text{ lb } NO_x}{1,000 \text{ lb fuel}} = 300 \frac{\text{lb } NO_x}{\text{hr}}$$

REFERENCES FOR APPENDIX A:

1. Letter and attachments from Lyon, T.F., General Electric Aircraft Engines, to Snyder, R.B., MRI. December 6, 1991. Calculation of NO_x emissions from gas turbines.

2. Letter and attachments from Hung, W.S., Solar Turbines, Inc., to Snyder, R.B., MRI. December 17, 1991. Calculation of NO_x emissions from gas turbines.

APPENDIX B. COST DATA AND METHODOLOGY USED TO PREPARE COST FIGURES PRESENTED IN CHAPTER 6

APPENDIX B. RAW COST DATA AND COST ALGORITHMS

The maintenance costs for water injection and several of the SCR costs presented in Chapter 5 are based on information from turbine manufacturers and other sources that required interpretation and analysis. Information about additional gas turbine maintenance costs associated with water injection is presented in Section B.1. Information on SCR capital costs, catalyst replacement and disposal costs, and maintenance costs is presented in Section B.2. References are listed in Section B.3.

B.1 WATER INJECTION MAINTENANCE COSTS

Information from each manufacturer and the applicable analysis procedures used to develop maintenance cost impacts for water injection are described in the following sections.

B.1.1 Solar

This manufacturer indicated that the annual maintenance cost for the Centaur is $16,000/year.[1] The cost for the Saturn was estimated to be $8,000.[2] This $8,000 cost was then prorated for operation at 1,000/hr/yr, and was multiplied by 1.3 to account for the additional maintenance required for oil fuel.

B.1.2 Allison

Maintenance costs for water injection were provided by a company that packages Allison gas turbines for stationary applications. This packager stated that for the 501 gas turbine model, a maintenance contract is available which covers all maintenance materials and labor costs associated with the turbine, including all scheduled and unscheduled activities. The cost of this contract for the 501 model is $0.0005 to $0.0010 per KW-hour (KWH) more for water injection than for a turbine not using water injection.[3] For an installation operating 8,000 hours per year at a base-rated output of 4,000 KW, and using an average cost of $0.00075 per KWH, the annual additional maintenance cost is $24,000. By the nature of the contract offered, this figure represents a worst case scenario and to some extent may exceed the actual incremental maintenance costs that would be expected for water injection for this turbine.

B.1.3 General Electric

General Electric (GE) offers both aero-derivative type (LM-series models) and heavy-duty type (MS-series models) gas turbines. For the aero-derivative turbines, GE states that the incremental maintenance cost associated with water injection is $3.50 per fired hour. This cost is used to calculate the maintenance cost for water injection for GE aeroderivative turbines. No figures were provided for steam injection and no maintenance cost was used for steam injection with these turbines.[4]

Water injection also impacts the maintenance costs for the heavy-duty MS-series models. Costs associated with more frequent maintenance intervals required for models using water injection have been calculated and summarized below. A GE representative stated that the primary components which must be repaired at each maintenance interval are the combustor liner and transition pieces.[5] Approximate costs to repair these pieces were provided by GE.[5] For this analysis, the maximum cost estimates were used to calculate annual costs to accommodate repairs that may be required periodically for injection nozzles, cross-fire tubes, and other miscellaneous hardware. According to GE, a rule of thumb is that if the repair cost exceeds 60 percent of the cost of a new part, the part is replaced.[5] The cost of a replacement part is therefore considered to be 1.67 times the maximum repair cost. If water purity requirements are met, there are no significant adverse impacts on maintenance requirements on other turbine components, and hot gas path inspections and major inspection schedules are not impacted.[5] Combustion repair schedules, material costs, and labor hours are shown in Table B-1. Scheduled maintenance intervals for models with water injection were provided in Reference 6. Corresponding maintenance intervals for models with steam injection were assumed to be the same as models with no wet injection; these scheduled maintenance intervals were provided in Reference 7. Using the information in Table B-1, the total annual cost is calculated and shown in Table B-2 for three GE heavy-duty turbine models.

B.1.4 Asea Brown Boveri

This manufacturer states there are no maintenance impacts associated with water injection.[8]

B.2 SCR COSTS

The total capital investment, catalyst replacement, and maintenance costs are estimated based on information from the technical literature. The cost algorithms are described in the following sections.

B.2.1 Total Capital Investment

Total capital investment costs, which include purchased costs and installation costs, were available for SCR systems for combined cycle and cogeneration applications from five sources.[9-13] These costs were scaled to 1990 costs using the Chemical Engineering annual plant cost indexes and are applicable to SCR systems in which the catalyst was placed within the heat recovery steam generator (HRSG). In addition, estimated capital investment costs were available from one source for SCR systems in which a high temperature zeolite catalyst is installed upstream of the HRSG.[14] Both the original data and the scaled costs are presented in Table B-3. The scaled costs were plotted against the turbine size and this plot is shown in Figure B-1. A linear regression analysis was performed to determine the equation for the line that best fits the data. This equation was used to estimate the total capital investment for SCR for the model plants and was extrapolated to estimate the costs for model plants larger than 90 MW.

B.2.2 Maintenance Costs

Maintenance costs for SCR controls were obtained from four literature sources, although 6 of the 14 points were obtained from one article.[9,11-13] These costs were scaled to 1990 costs assuming an inflation rate of five percent per year. All of the data are for turbines that use natural gas fuel. Because there are no data to quantify differences in SCR maintenance costs for oil-fired applications, the available data for operation on natural gas were used for both fuels. Both the original data and the scaled costs are presented in Table B-4. The scaled costs were plotted versus the turbine size in Figure B-2. The equation for the line through the data was determined by linear regression, and it was used to estimate the maintenance costs for the model plants.

B.2.3 Catalyst Replacement Costs

Catalyst replacement costs were obtained from three articles for nine gas turbine installations.[9,11,13] Combined catalyst replacement and disposal costs were obtained for another six gas turbine installations from one article.[12] The disposal costs for these six gas turbine installations were estimated based on estimated catalyst volumes and a unit disposal cost of $15/ft^3, given in Reference 15.

The catalyst volumes were estimated assuming there is a direct relationship between the volume and the turbine size; the catalyst volume stated in Reference 16 for one 83 MW turbine is 175 m^3. The resulting disposal costs for these six facilities were subtracted from the combined replacement and disposal costs to estimate the replacement-only costs. All of the replacement costs were scaled to 1990 costs assuming an inflation rate of 5 percent per year. The original data and the scaled costs are presented in Table B-5, and the scaled replacement costs were also plotted versus the turbine size in Figure B-3. Linear regression was used to determine the equation for the line through the data. This equation was used to estimate the catalyst replacement costs for the model plants.

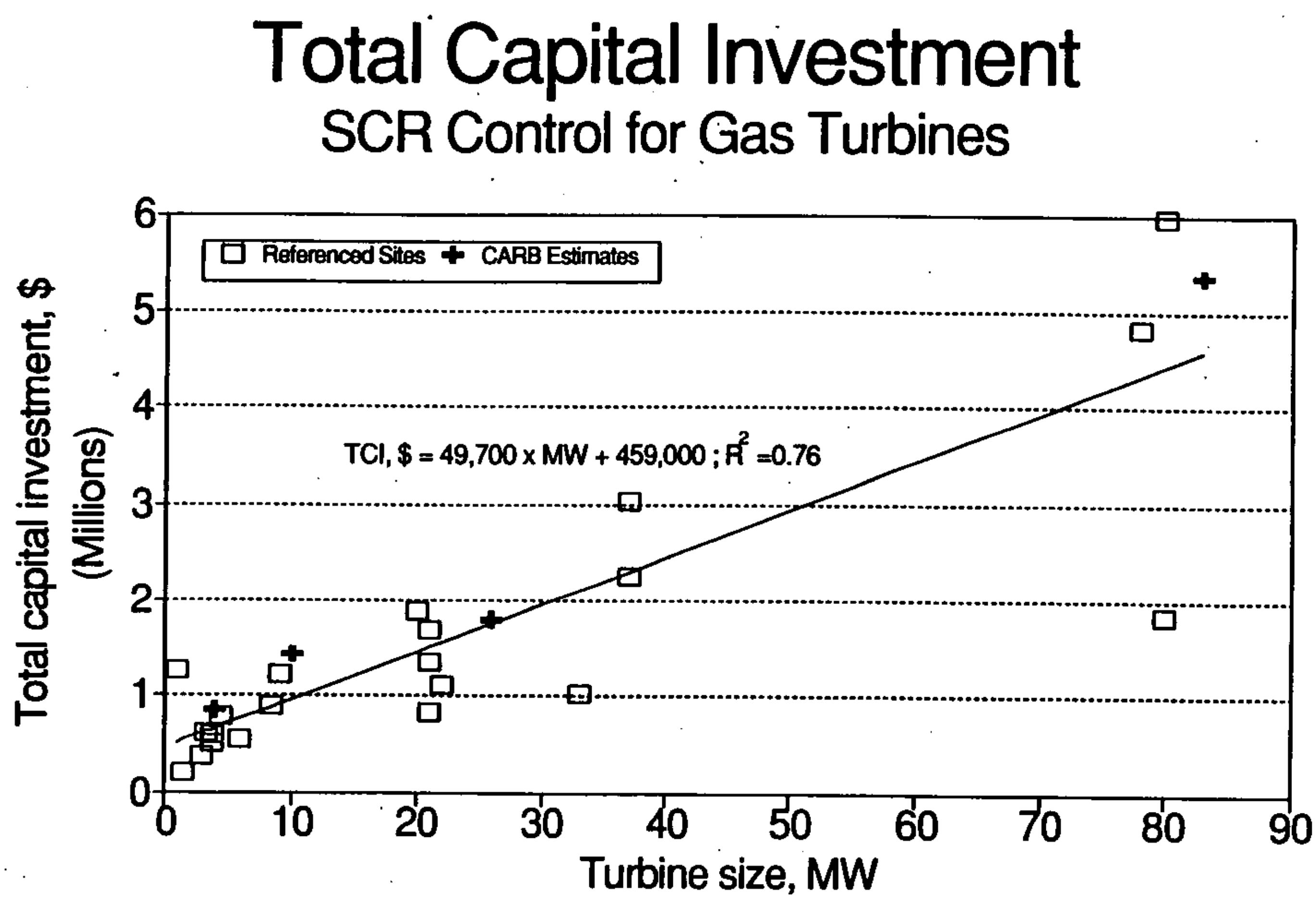

Figure B-1. Total Capital Investment for SCR Control of NOx Emissions From Gas Turbines

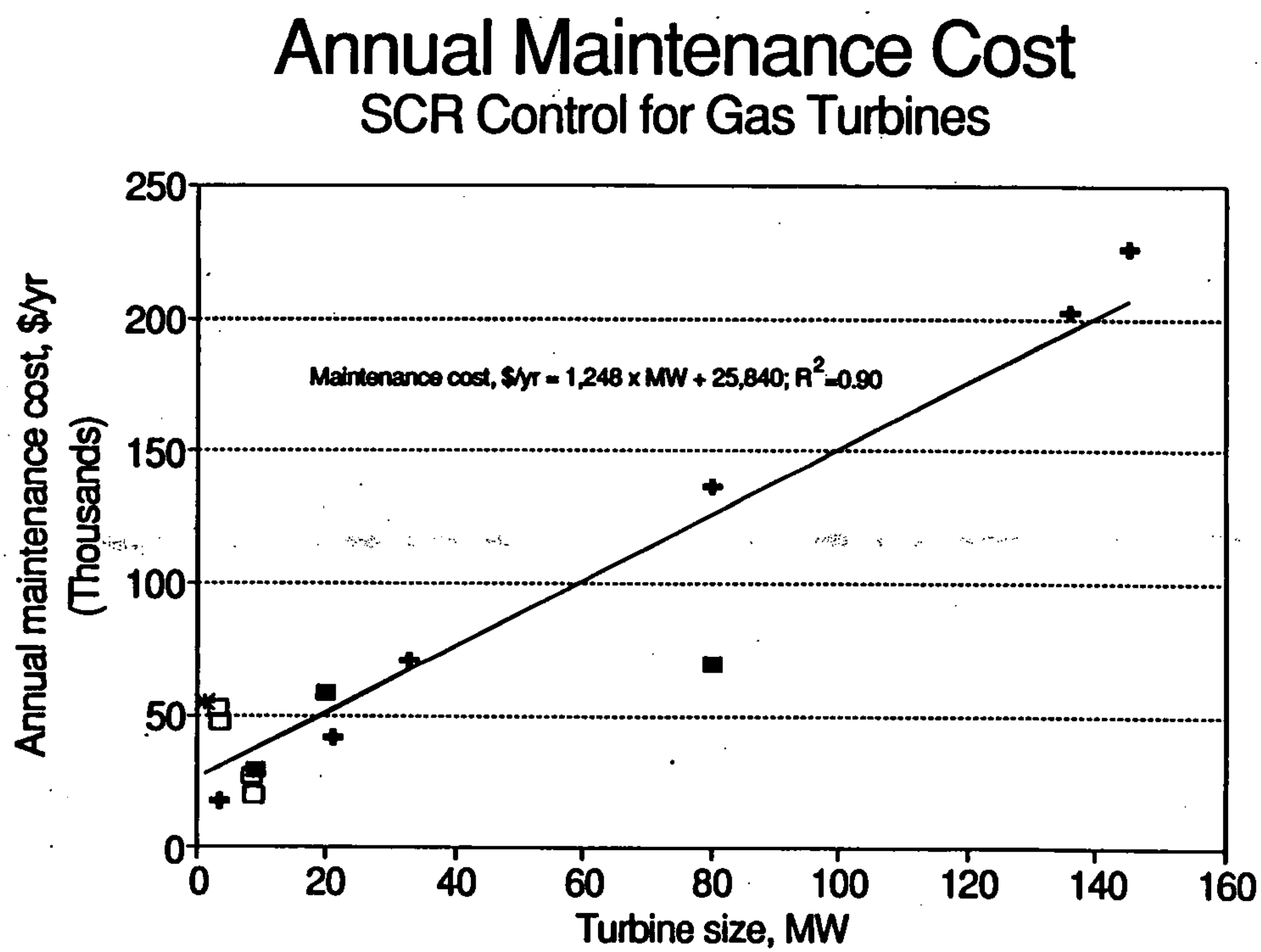

Figure B-2. Annual Maintenance Cost for SCR Control of NOx Emissions From Gas Turbines

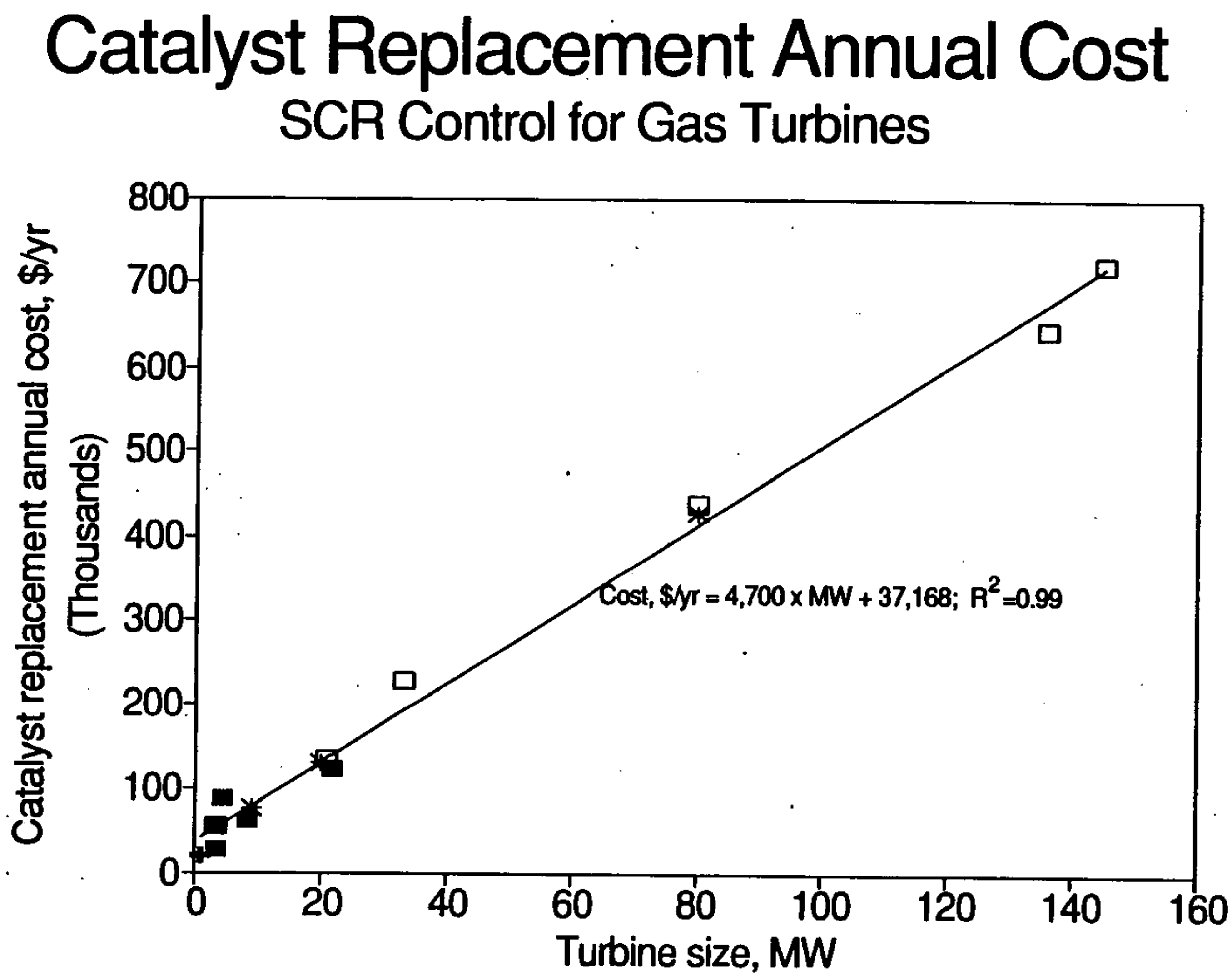

Figure B-3. Catalyst Replacement Annual Cost for SCR Control of Gas Turbines

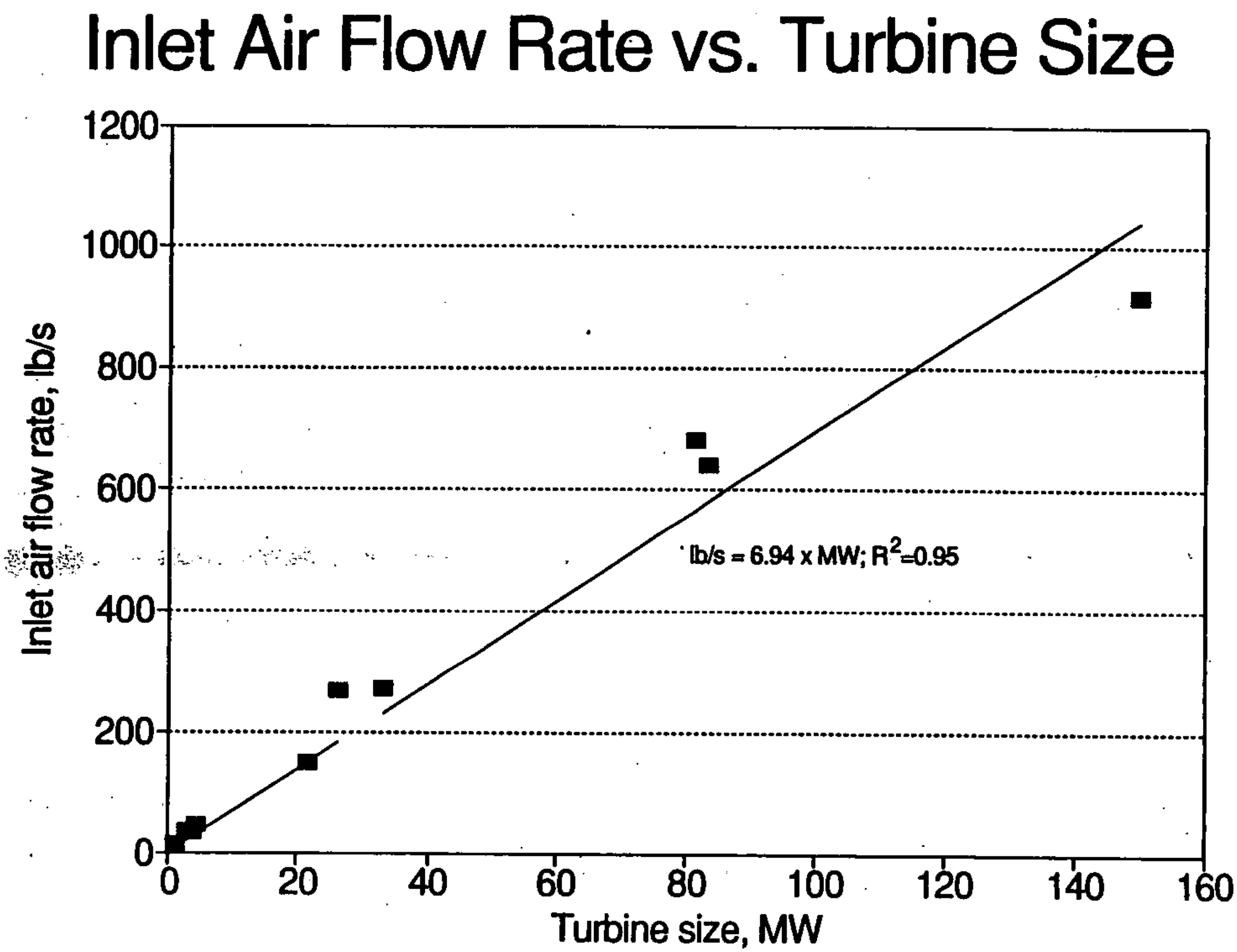

Figure B-4. Inlet Air Flow Rate for Gas Turbines

TABLE B-1. COMBUSTOR REPAIR INTERVALS, HOURS, AND MATERIAL COST

Gas turbine	Repair interval, hr		Replacement interval, hr		Repair cost, \$[d]	Replacement cost, \$[d]	Item	Labor hours[a]
	Dry[a]	Wet[b]	Dry[a]	Wet[c]				
MS5001P	12,000	6,000	48,000	24,000	10,000-15,000 15,000-20,000	25,000 42,000	Liners Transition pieces	160
MS7001E	8,000	6,500	48,000	39,000	15,000-30,000 30,000-50,000	50,000 83,000	Liners Transition pieces	576
MS9001E	8,000	6,500	48,000	39,000	31,000-62,000 62,000-124,000	103,000 206,000	Liners Transition pieces	624

[a]Reference 7.
[b]Reference 6.
[c]Scaled from Dry Repair/Replace intervals found in Reference 9.
[d]Reference 5.

TABLE B-2. ANNUAL COST OF ADDITIONAL MAINTENANCE REQUIRED FOR WATER INJECTION

	Number of inspections over 15 years						Material costs		Labor, each inspection			
	Dry		Wet		Added number for wet							
GT Model	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Hours	Cost[a]	Total added cost 15 years	Total added annual cost
MS5001P[a]												
Combustor liners	8	2	15	5	7	3	15,000	25,000			18,000[c]	
Transition pieces	8	2	15	5	7	3	20,000	42,000	160	4,998	315,980[d]	
											495,980	33,065
MS7001E[e]												
Combustor liners	12	3	15	3.5	3	0.5	30,000	50,000			115,000	
Transition pieces	13	2	15.5	3	2.5	1	50,000	83,000	576	17,994	270,979	
											385,979	25,732
MS9001E[e]												
Combustor liners	12	3	15	3.5	3	0.5	62,000	103,000			237,500	
Transition pieces	13	2	15.5	3	2.5	1	124,000	206,000	624	19,494	584,229	
											821,729	54,782

[a]Based on $31.24/hr. Since parts are normally removed and a spare set is installed at each inspection, the labor cost would be the same for either repair or replacement interval.
[b]Schedule assumes liners and transition pieces are replaced every fourth inspection interval.
[c](7 x $15,000) + (3 x $25,000) = $180,000.
[d](7 x $20,000) + (3 x $42,000) + ($4,998 x 10) = $315,980.
[e]Schedule assumes liners are replaced every fifth interval and transition pieces every sixth interval.

TABLE B-3. TOTAL CAPITAL INVESTMENT FOR SCR TO CONTROL NO_x EMISSIONS FROM GAS TURBINES

Gas turbine size, MW	SCR capital cost[a]			Scaling factor[c]	1990 SCR capital cost, $
	$	Year	Ref[b]		
1.1	1,250,000	1989	9	357.6/355.4	1,260,000
1.5	180,000	1986	10	357.6/318.4	202,000
3	320,000	1986	10	357.6/318.4	359,000
3.2	600,000	1989	11	357.6/3.554	604,000
3.7	477,000	1988	12	357.6/342.5	498,000
3.7	579,000	1989	11	357.6/355.4	583,000
4	839,000	1991	14	1.0	839,000
4.5	750,000	1988	11	357.6/342.5	783,000
6	480,000	1986	10	357.6/318.4	539,000
8.4	800,000	1986	11	357.6/318.4	898,000
9	1,100,000	1987	13	357.6/323.8	1,210,000
10	1,431,000	1991	14	1.0	1,431,000
20	1,700,000	1987	13	357.6/323.8	1,880,000
21	798,000	1988	12	357.6/342.5	833,000
21	1,500,000	1986	10	357.6/318.4	1,680,000
21	1,200,000	1986	10	357.6/318.4	1,350,000
22	1,000,000	1987	11	357.6/323.8	1,100,000
26	1,800,000	1991	14	1.0	1,800,000
33	990,000	1988	12	357.6/342.5	1,030,000
37	2,000,000	1986	11	357.6/318.4	2,250,000
37	2,700,000	1986	10	357.6/318.4	3,030,000
78	4,300,000	1986	10	357.6/318.4	4,830,000
80	5,400,000	1987	13	357.6/323.8	5,960,000
80	1,760,000	1988	12	357.6/342.5	1,840,000
83	5,360,000	1991	14	1.0	5,360,000

continued

TABLE B-3. (Continued)

[a]Total capital costs were provided by several sources, but it is not clear that they are on the same basis. For example, it is likely that the type of catalyst varies and the target NO_x reduction efficiency may also vary. In addition, some estimates may not include costs for emission monitors; auxiliary equipment like the ammonia storage, handling, and transfer system; taxes and freight; or installation.

[b]Reference 12 also provided costs for SCR used with 136 MW and 145 MW turbines. All of the costs for this reference are lower than the costs from other sources, and the differential increases as the turbine size increases. Because there are no costs from other sources for such large turbines, these two data points would exert undue influence on the analysis; therefore, they have been excluded. Costs for large model plants were estimated by extrapolating with the equation determined by linear regression through the data for turbines with capacities less than 90 MW (see Figure B-1).

[c]Costs for years prior to 1990 are adjusted to 1990 dollars based on the annual CE plant cost indexes. Costs estimated in 1991 dollars were not adjusted.

TABLE B-4. MAINTENANCE COSTS FOR SCR

Gas turbine size, MW	SCR maintenance cost[a] $/yr	Year	Ref	Scaling factor[b]	1990 SCR maintenance cost, $
1.1	52,200	1989	9	1.050	54,800
3.2	50,000	1989	11	1.050	52,500
3.7	43,000	1988	11	1.103	47,400
3.7	15,500	1988	12	1.103	17,100
8.4	22,000	1986	11	1.216	26,700
8.9	18,000	1988	11	1.103	19,800
9	25,000	1987	13	1.158	28,900
20	50,000	1987	13	1.158	57,900
21	37,900	1988	12	1.103	41,800
33	63,700	1988	12	1.103	70,200
80	124,000	1988	12	1.103	137,000
80	60,000	1987	13	1.158	69,500
136	184,000	1988	12	1.103	203,000
145	205,000	1988	12	1.103	226,000

[a]All of the maintenance costs are for turbines that are fired with natural gas. Although sulfur in diesel fuel can cause maintenance problems, there are no data to quantify the impact. Therefore, the maintenance costs presented in this table were used for both natural gas and diesel fuel applications.

[b]Scaling factors are based on an estimated inflation rate of 5 percent per year.

TABLE B-5. CATALYST REPLACEMENT AND DISPOSAL COSTS

Gas turbine size, MW	Catalyst replacement cost[a]						Catalyst disposal cost			Catalyst replacement and disposal annual cost, $/yr
	$	Year	Ref.	Scaling factor[b]	1990 catalyst cost, $	Annual cost, $/yr[c]	Catalyst volume, m^3	1990 cost, $[e]	Annual cost, $/yr[c]	
1.1	74,600	1989	9	1.050	78,300	20,700	2.32	1,230	324	21,000
3.2	200,000	1989	11	1.050	210,000	55,400	6.75	3,570	940	56,300
3.7		1988	12	1.103	215,000	56,600	7.80	4,130	1,090	57,700
3.7	100,000	1988	11	1.103	110,000	29,000	7.80	4,130	1,090	30,100
4.5	300,000	1988	11	1.103	331,000	87,300	9.49	5,030	1,330	89,000
8.4	200,000	1986	11	1.216	243,000	64,100	17.7	9,380	2,470	67,000
9	255,000	1987	13	1.158	295,000	77,800	19.0	10,100	2,660	80,000
20	434,000	1987	13	1.158	502,000	132,000	42.2	22,300	5,880	138,000
21		1988	12	1.103	512,000	135,000	44.3	23,500	6,200	141,000
22	400,000	1987	11	1.158	463,000	122,000	46.4	24,600	6,490	128,000
33		1988	12	1.103	864,000	228,000	69.6	36,900	9,700	238,000
80		1988	12	1.103	1,660,000	437,000	169	89,300	23,600	461,000
80	1,400,000	1987	13	1.158	1,620,000	427,000	169	89,300	23,600	451,000
136		1988	12	1.103	2,450,000	645,000	287	152,000	40,100	685,000
145		1988	12	1.103	2,740,000	723,000	306	162,000	42,700	766,000

[a]Reference 12 provided only combined catalyst replacement and disposal costs.

[b]Scaling factors are based on an inflation rate of 5 percent per year.

[c]Annual costs are based on the assumption that the catalyst will be replaced every 5 years. Therefore, the capital recovery factor is 0.2638, assuming an annual interest rate of 10 percent.

[d]In one SCR application, 175 m^3 of catalyst is used with an 83 MW turbine. If the space velocity is the same for any size SCR (assuming the same catalyst), then there is a direct relationship between the amount of catalyst and the exhaust gas flow rate. The exhaust gas flow rate was calculated as equal to the *inlet air flow rate, and as Figure* B-4 shows, there is nearly a direct relationship between the inlet airflow rate and turbine capacity. Therefore, the catalyst volume for the turbines in this table were estimated assuming there is a direct relationship between the catalyst volume and the turbine output.

[e]Disposal costs are estimated based on a unit cost of $15/$ft^3$.

B.3 REFERENCES FOR APPENDIX B

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EPA Work Assignment Manager: William Neuffer (919) 541-5435

16. ABSTRACT

This Alternative Control Techniques document describes available control technologies for reducing NO_x emissions levels from stationary combustion gas turbines. Information on the formation of NO_x and uncontrolled NO_x emissions from gas turbines is included. Water injection, steam injection, and low-NO_x combustors, used independently or in combination with selective catalytic reduction (SCR), are discussed. Achievable controlled NO_x emissions levels, costs and cost effectiveness, and environmental impacts are presented and applicability to new equipment as well as retrofit applications is discussed. The application of these technologies to gas turbines operating in offshore platform applications is included. Information on the use of alternate fuels, catalytic combustion, and selective noncatalytic reduction (SNCR) to reduce NO_x emissions is also briefly presented.

17. KEY WORDS AND DOCUMENT ANALYSIS

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