Natural Gas

Its Role and Potential in Economic Development

EDITED BY
Walter Vergara,
Nelson E. Hay
and Carl W. Hall

Westview Special Studies in Natural Resources and Energy Management

This Westview softcover edition is printed on acid-free paper and bound in library-quality, coated covers that carry the highest rating of the National Association of State Textbook Administrators, in consultation with the Association of American Publishers and the Book Manufacturers' Institute.

Published in 1990 in the United States of America by Westview Press, Inc., 5500 Central Avenue, Boulder, Colorado 80301, and in the United Kingdom by Westview Press, Inc., 36 Lonsdale Road, Summertown, Oxford OX2 7EW

Library of Congress Cataloging-in-Publication Data
Natural gas: its role and potential in economic development/edited by Walter Vergara, Nelson Hay, Carl Hall.
p. cm.—(Westview special studies in natural resources and energy management)
Includes index.
ISBN 0-8133-7812-5
1. Gas industry—Developing countries. 2. Gas, Natural.
3. Economic development. I. Vergara, Walter, 1950– . II. Hay, Nelson E. III. Hall, Carl W. IV. Series.
HD9581.D442N38 1990
338.2'7285'091724—dc20

Contents

	Preface	vi
1	The Emergence of Natural Gas *Nelson E. Hay*	1
2	The Economics of Natural Gas Development *Afsaneh Mashayekhi*	33
3	Natural Gas and the Environment *Nelson E. Hay*	47
4	Natural Gas and Development: The Policy Issues for Developing Countries *Sergio C. Trindade*	105
5	Power Generation with Natural Gas-Fired Gas Turbines *Robert H. Williams and Eric D. Larson*	119
6	The Use of Natural Gas in the Nitrogen Fertilizer Industry *William F. Sheldrick*	171
7	Natural Gas and Natural Gas Liquids in the Chemical Industry *Walter Vergara*	219
8	Natural Gas as a Transportation Fuel *Robert J. Saunders and Rene Moreno, Jr.*	249
9	Natural Gas - Interchangeability with Other Fuels *Carl W. Hall*	273
	Appendixes	291
	About the Contributors	314
	Index	315

Westview Press
BOULDER, SAN FRANCISCO, & OXFORD

5

Power Generation with Natural Gas-Fired Gas Turbines

Robert H. Williams
Eric D. Larson

Introduction

A revolution is underway in electricity generating technology that may soon radically transform the power industry in both industrial and developing countries. This revolution involves not an exotic new technology, but rather an upgrading of the familiar but little-used gas turbine, the neglected step-sister of the steam turbine in power generation.

Though the gas turbine has always offered a low unit capital cost, it has traditionally been restricted in utility applications to peaking service -- for power plants that operate only during the short periods when the demand for electricity reaches its peak values. This is due in part to its low efficiency and in part to public policies that have constrained the use of natural gas for power generation. Its peripheral role in power generation also fostered less-than-rigorous maintenance practices, helping to give the gas turbine a reputation of poor reliability among utility planners.

Although in many parts of the world its use for cogeneration has been inhibited by institutional constraints, the simple cycle gas turbine's high thermodynamic efficiency for combined heat and power production as well as its low capital cost have long made it an economically attractive option for cogeneration applications. Nevertheless, the simple cycle gas turbine has been used mainly in cogeneration applications characterized by steady steam loads due to its poor part-load performance.

Innovations in technology, however, are making gas turbines competitive in cogeneration markets characterized by variable heat loads and in central-station applications with conventional baseload and load-following technologies. These technological innovations, a bullish outlook for natural gas supplies in many parts of the world, and tightening environmental constraints on power production are all important factors that point to future widespread use of natural gas-fired gas turbines for power generation.

It is useful to distinguish between heavy-duty industrial turbines (designed specifically for stationary applications) and aeroderivative turbines (derived from jet engines). The heavy-duty industrial turbine is quite familiar in the power sector and is the technology of choice for the gas turbine/steam turbine combined cycle systems beginning to be widely used in various parts of the world. The various configurations of aeroderivative turbines of interest -- e.g., the steam-injected gas turbine, the intercooled steam-injected gas turbine, the intercooled steam-injected gas turbine with reheat, and the intercooled steam-injected gas turbine with reheat and chemical recuperation -- are much less well-known. This chapter will focus on aeroderivative turbines, because their various cycle modifications represent relatively new and unfamiliar developments and because this class of technologies offers advantages in some important markets. Both types of turbines have major roles to play in power generation; hence in the decades ahead a more balanced mix of heavy-duty industrial and aeroderivative turbines than is anticipated by most power planners will probably evolve in power markets.

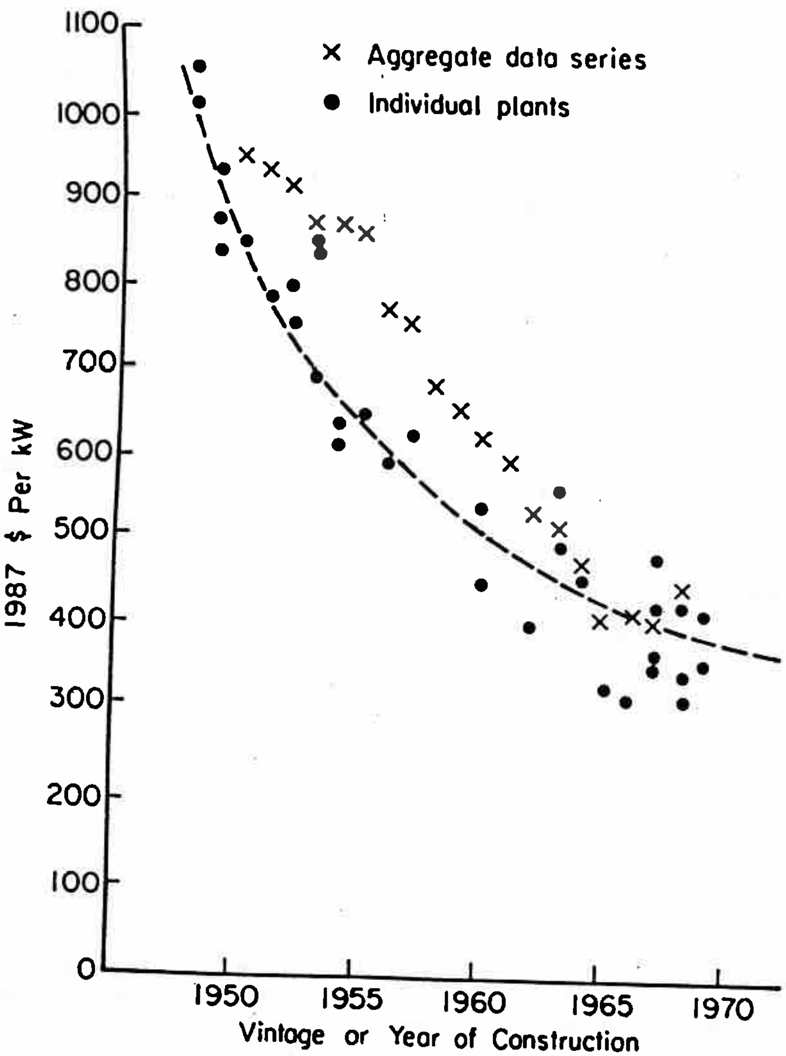
The Policy Context

The electric power industry needs a technological revolution, since business-as-usual is becoming increasingly untenable.

Public concerns about nuclear power risks and the environmental problems posed by fossil fuel power plants have made electric utility planning more and more difficult. The Chernobyl accident has led to a considerable stiffening of public opposition to nuclear power and to sharp limitations on nuclear power programs in various parts of the world. The large quantities of SO_2 and NO_x emitted by existing fossil fuel plants, especially coal-fired plants, are among the most significant pollutant emissions leading to acid deposition, which has become a serious international problem because of the transnational air transport of these pollutants. The need to control acid deposition is leading to costly proposals to reduce emissions from existing power plants in some areas. Global warming from the greenhouse effect, associated with the buildup of CO_2 in the atmosphere, has also become a major environmental concern.

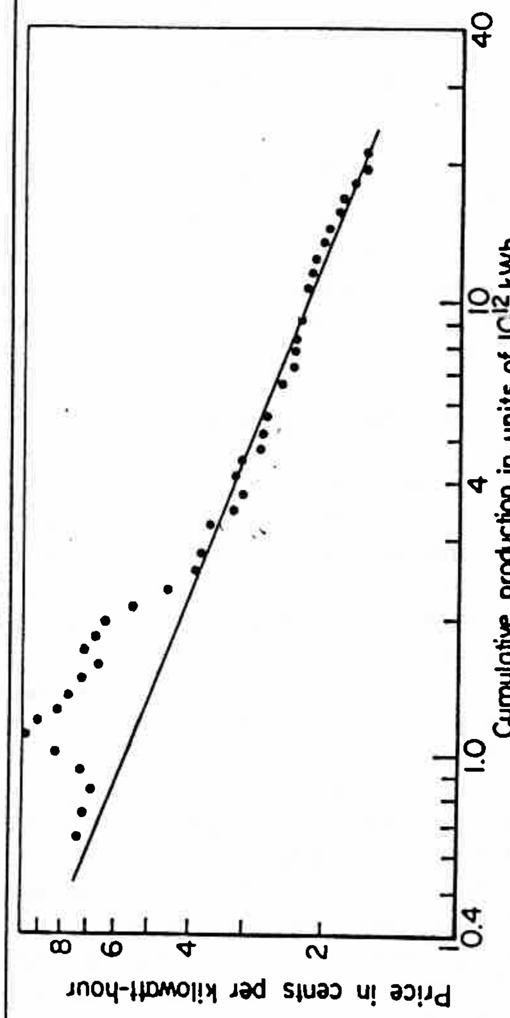
The electric utility industry has also been experiencing rising electricity costs -- a marked departure from the long-term historical trend, as illustrated by the situation in the US. Up until 1970 the outlook for electric power was bright in the US. Between 1950 and 1970, the real cost of fossil-fueled steam plants fell by more than a factor of two (Figure 5.1). Cost-cutting innovations in the US power industry persistently led to a reduction in the average real price of electricity by about 25% for each doubling of cumulative electricity production throughout the period 1926 to 1970 (Figure 5.2). If the trend up to 1970 had persisted to the present,

Figure 5.1. Cost of Capacity Additions of Fossil-Fueled Steam-Electric Plants in the US (1987 Dollars per kW)



Source: Hass, J. E., Mitchell, E. J., Stone, B. K. 1974. *Financing the Energy Industry*. Cambridge, Mass.: Ballinger.

Figure 5.2. Average Price of Electricity (1970 Cents/kWh) vs. Cumulative Production of Electricity in the US, 1926-1970*



* The trend line corresponds to a 25 percent reduction in price for each doubling of cumulative production. (The price rose above the trend line during the Great Depression in large part because of the high and relatively inflexible fixed charges associated with electricity generation that continued in the face of depression-diminished demand.)

Note: $1 of 1970 = $2.80 of 1987.

Source: Fisher, J. C. 1974. *Energy Crises in Perspective*. New York: Wiley.

the average price of electricity in the US today would be 1/3 lower than in 1970. Instead, the average electricity price in the US today is 40% higher than in 1970 or more than double what it would have been if the long-term, cost-cutting trend continued (Figure 5.3).

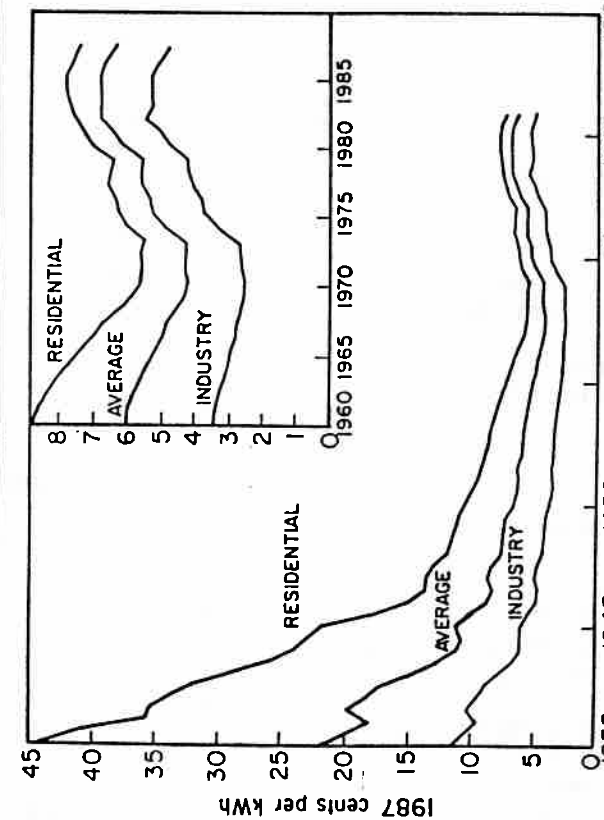
Escalating capital costs for new central station power plants have contributed greatly to these rising electricity prices. A nuclear plant ordered in the US in 1970 cost about $900 per kW.[1] [Unless explicitly indicated otherwise, all costs and prices are presented here in 1987 dollars.[2]] In a 1985 study by the International Energy Agency (IEA), it is estimated that the cost of a new nuclear plant that would be started up in 1990 in Europe would cost $1900 per kW if construction took ten years or $1700 per kW if construction could be completed in six years.[3] The Electric Power Research Institute (EPRI) has estimated that the cost of a new nuclear plant ordered today in the US would be $3060 per kW, but that this cost could be reduced to $1670 per kW in a "reborn" nuclear industry, i.e., one featuring a streamlined nuclear licensing process, a shorter construction period (six instead of eight years), and improved labor productivity.[4] The costs of coal-fired steam-electric plants with flue gas desulfurization (FGD), which cost about $500 per kW in the US in 1970,[5] have also escalated markedly. The IEA has estimated that the installed cost of a plant with two 600 MW units would be about $1230 per kW in Europe;[6] EPRI has estimated a slightly higher cost ($1340 per kW) for a plant with two 500 MW units in the US.[7]

In a 1987 World Energy Conference (WEC) study,[8] it is projected that the ongoing escalation in power generation costs will continue (Table 5.1). For industrial countries, it is projected that the share of GDP that will have to be spent on electricity supply expansion will be in the range 2.0% to 2.7% of GDP in 2000, compared to 2.2% in 1980, even though electricity demand is projected to grow only 0.65 to 0.83 times as fast as GDP, 1980-2000. For developing countries, where electricity demand growth is expected to be more rapid, it is projected that the share of GDP that will have to be spent on electricity supply expansion will increase from 1.5% of GDP in 1980 to the range of 2.6% to 5.5% in 2000. For the already capital-constrained developing countries, this means that supporting electricity demand growth rates that are modest by historical standards will be extremely difficult.[9]

The Prospects for Improving Steam-Electric Power Technology

Before discussing the opportunities for innovation afforded by advanced gas turbine technologies, let us examine the prospects for

Figure 5.3. Long-Term and Recent (*Insert*) Electricity Price Trends in the US*



* The prices shown are the total revenues divided by electricity sales, expressed in 1987 cents per kWh.
Source: Williams, R.H., Larson, E.D. 1988. Aeroderivative turbines for stationary power. *Annual Review of Energy* 13: 429-89.

Table 5.1. Capital for Electricity[a]

	1980	2000L[b]	2000H[b]
Cost for New Generating Capacity ($/kW)			
Hydroelectric	2740	3360	4110
Nuclear	2060	2540	3080
Fossil Fuel, Thermal	1030	1230	1510
Average Capital Requirements by Region ($/kW)			
Industrial Countries			
Generation	1480	2000	2390
T & D	2740	2770	3030
Developing Countries			
Generation	1690	2070	2480
T & D	810	1700	2480
Centrally Planned Economies			
Generation	1370	1810	2320
T & D	1370	1960	2620
Overall Capital Requirements for Electricity [10^9 $/year (% of GDP)]			
Industrial Countries	226 (2.2)	302 (2.0)	488 (2.7)
Developing Countries	44 (1.5)	148 (2.6)	381 (5.5)
Centrally Planned Economies	60	147	233

	1980-2000L[b]	1980-2000H[b]
Average Growth Rates (%/Year)		
For GDP		
Industrial Countries	2.0	3.0
Developing Countries	3.5	4.5
For Primary Energy Consumption		
Industrial Countries	0.15	1.3
Developing Countries	2.5	4.7
Centrally Planned Economies	1.8	2.3
For Electricity Generation		
Industrial Countries	1.3	2.5
Developing Countries	4.5	6.8
Centrally Planned Economies	2.7	3.2

[a] According to a 1987 World Energy Conference (WEC) study (Schneider, H.K. 1987. *Investment Requirements of the World Energy Industries 1980-2000*. London: World Energy Conference).
[b] 2000L (2000H) is for the WEC low (high) growth scenario.

improving the technology for nuclear and fossil fuel-based steam-electric power generation.

The cost escalations plaguing steam-electric power generation are due in part to tightening environmental and safety rules. Other important factors include inadequate quality control in equipment manufacture and construction, bottlenecks that have arisen because each big project has been in many ways unusual, and escalating labor costs arising from shortages of qualified manpower and declines in labor productivity. Many such problems result in not only direct cost increases, but also indirect cost increases associated with the accumulated interest charges from extended construction periods.

A 1974 analysis by John Fisher of the escalation in nuclear power costs in the decade leading up to the first oil crisis provides an important insight relating to these construction-related problems that seems relevant for power cost escalation generally since 1970:[10]

"When measured in constant dollars per kilowatt of capacity, the cost of constructing a nuclear power plant increased by perhaps 50 percent in the past decade... When power plant costs rise an explanation is required, as we expect all power plant costs to decline through the economies of scale and new technology. The environmental movement was responsible for part of the rise in nuclear plant costs, by causing various procedural delays and by requiring additional expensive safeguards to protect against hypothetical accidents. But there appears to be another cause for increasing construction costs, associated with a growing portion of high-cost field construction and a shrinking proportion of low-cost factory construction for the very large power plants now being built... the costs associated with a shift to field from factory can more than offset anticipated economies of scale..."

Fisher pointed out that historically, as electric utility plant capacity doubled every decade, factory capacity also doubled, as did field construction at each site. Manufacturing and construction costs per kW declined in the factory and in the field, since each of these increased its scale of operations. As long as both activities grew in proportion, the economies of scale produced similar cost reductions in each, and therefore an overall cost reduction, even though the unit cost of field construction was always higher than the unit cost of factory construction. This pattern held until plant size reached about 200 MW. Then, because design engineers felt that scale economies would be much more important for nuclear than for fossil fuel plants, nuclear power plant capacities were built in sizes of the order of 1000 MW -- shifting a greater portion of the construction from the factory to the field, upsetting the pattern of the past, with the result that a much larger fraction of the construction was carried out at smaller, less-efficient field locations. Fisher's important insight is that the widely touted economies of scale in power plant construction are illusory because: (a) field construction is inherently more costly than factory construction, and (b) with field construction it is never possible to get very far down the "learning curve," in contrast to the situation with factory production. This "diseconomy of scale" problem has persisted to the present.

The increase in scale for coal-fired power plants to the present range of 500 to 600 MW was in part a competitive response to large-scale nuclear plant construction. Also, the pursuit of scale economies was seen as an opportunity for continuing the historical reductions in the cost of electricity (Figures 5.2 and 5.3), after the long term trend toward increased thermodynamic efficiency of power generation ceased in the late 1950s (Figure 5.4). But as in the case of nuclear power, the point of diminishing returns to scale appears to have been reached or exceeded for coal plants. Even where scale economy gains might be realized in construction, these gains tend to be offset by losses in reliability for the larger units.[11]

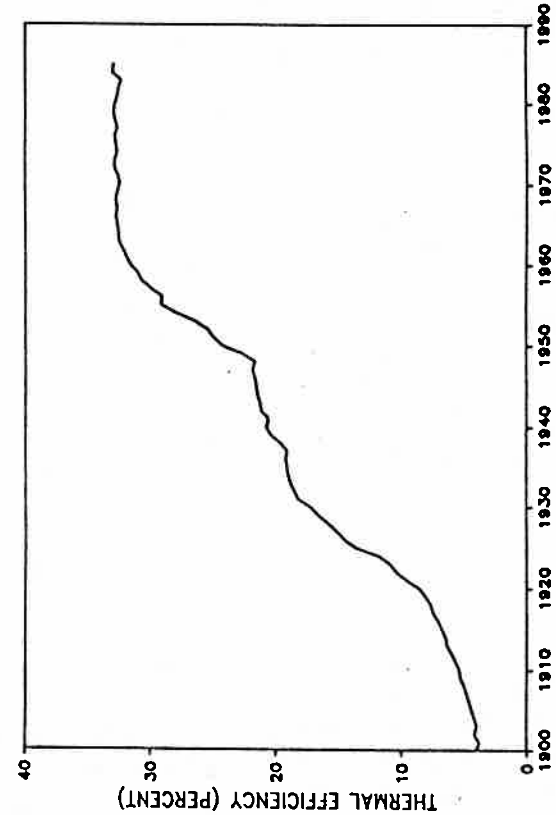
What are the prospects for improving thermodynamic efficiency? Since the 1920s, most gains in efficiency in steam-electric power plants have been due largely to increases in maximum steam temperatures and pressures. By the 1950s, peak temperatures had reached 565°C and peak pressures 165 bar for subcritical steam units and 241 bar for supercritical steam units.

There are ongoing developmental efforts aimed at improving steam-electric power plant efficiency by increasing peak steam temperatures.[12,13] But as peak steam temperatures are increased, problems of materials strength, oxidation, and corrosion rapidly become more serious, dictating shifts to more costly high-strength, oxidation and corrosion-resistant alloys for the large steam-tubing heat exchangers that transfer heat from the combustor to steam at high temperature and pressure. (See, for example, Figure 5.5, which shows, for a number of alloys used in steam tubing exposed to high temperatures, that the maximum allowable stress declines rapidly beyond a critical threshold.)

Peak steam temperatures have not increased since the 1950s, and in fact utilities today tend to choose a slightly lower peak temperature of 540°C in coal plants. They do so not only because of the lower capital cost, but also because, even with judicious choice of better tubing materials, higher temperature operating conditions have led to more forced outages, owing to tubing damage from problems such as coal-ash corrosion.[14]

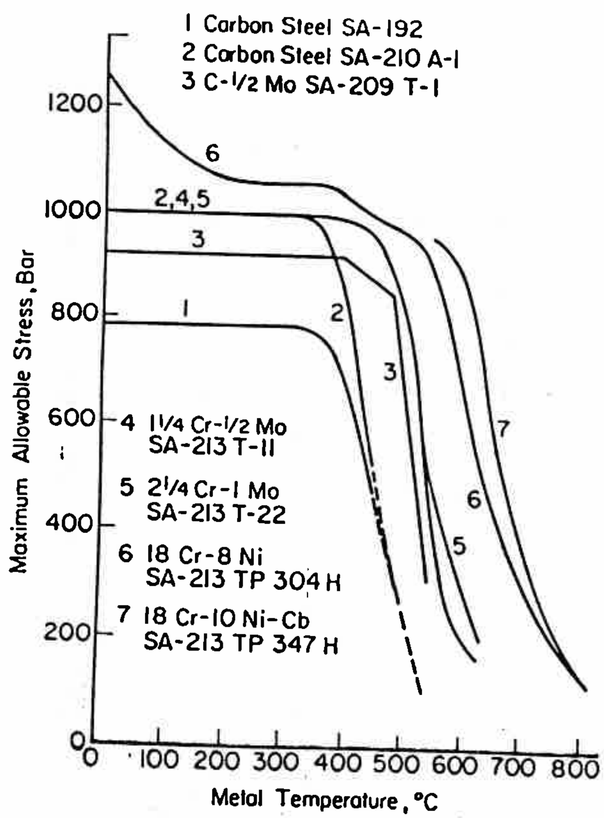
A 1976 Westinghouse study, the results of which are consistent with many other studies carried out since the 1950s,[15] indicates the magnitude

Figure 5.4. Historical Trend in Average Efficiency (Higher or Gross Heating Value Basis) of Electricity Generation in Central Station Thermal Power Plants in the US



Source: Williams, R.H., Larson, E.D. 1988. "Aeroderivative Turbines for Stationary Power."

Figure 5.5. Effect of Temperature on Maximum Allowable Stress for Different Steel Alloys Used for Steam Tubing in High Temperature Service*



*According to the Boiler Code of the American Society of Mechanical Engineer (ASME).

Notes: 1 = low strength carbon steel; 2 = intermediate strength carbon steel; 3 = a ferritic alloy containing 0.5 percent molybdenum; 4 = ferritic alloy containing 1.25 percent chromium and 0.5 percent molybdenum; 5 = ferritic alloy containing 2.25 percent chromium and 1.0 percent molybdenum; 6 = austenitic stainless alloy containing 18 percent chromium and 8 percent nickel; 7 = austenitic stainless alloy containing 18 percent chromium and 10 percent nickel.

Source: Combustion Eng., Inc. 1981. *Combustion: Fossil Power Systems.* Windsor, Conn.: Rand McNally.

of the tradeoff involved in increasing the maximum steam temperature of a 500 MW steam plant; an increase from 540 to 650°C would increase the plant efficiency by 6%, but at the cost of a 26% increase in capital cost.[16] On a lifecycle cost basis, the price of coal would have to increase from $50 to $200 per tonne before it would be worthwhile to shift to the higher peak steam temperature.

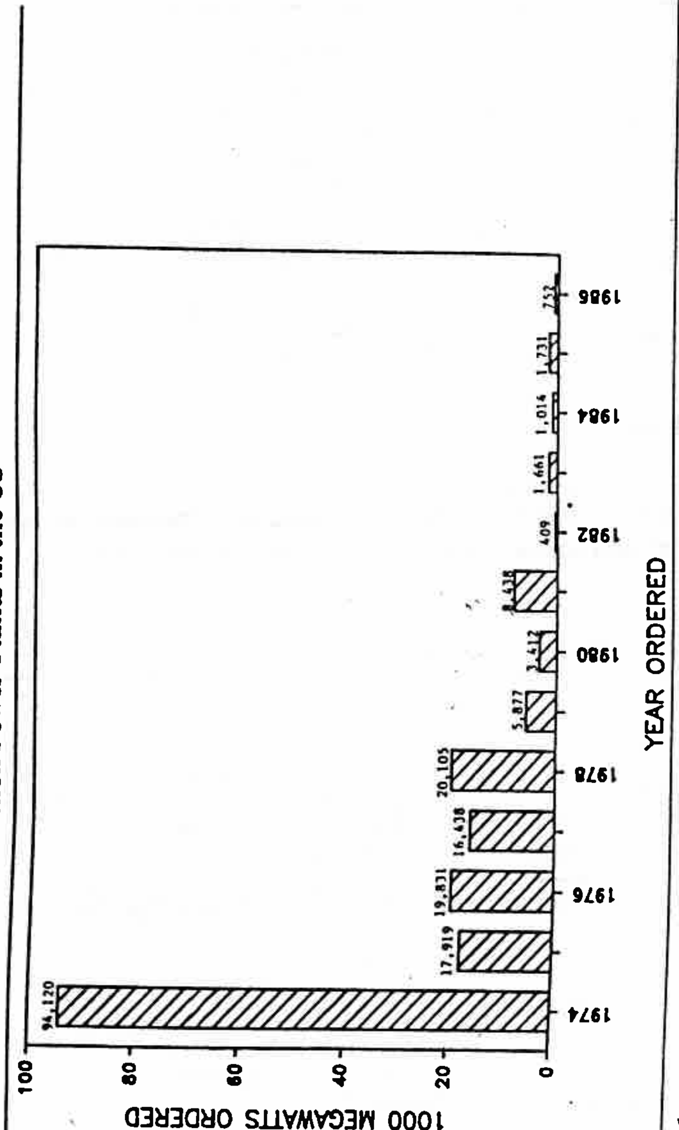
While the outlook for major improvements in steam-electric power technology is not auspicious, it may be feasible to increase efficiency without pushing peak working fluid temperatures further, through development of the recently proposed Kalina cycle.[17,18] The Kalina cycle is a novel modified Rankine cycle that uses as a working fluid a mixture of ammonia and water that is varied throughout the cycle. A 3 MW demonstration plant is being planned at the US Department of Energy's Engineering Center in Canoga Park, California.[19] The big uncertainties regarding the Kalina cycle are the complicated "plumbing" and possible difficulties associated with managing the binary working fluid at high temperatures and pressures, which might lead to capital and operating and maintenance cost penalties. Also, the performance estimates for the Kalina cycle are for very small assumed pressure drops and tight temperature differences, conditions that are difficult to achieve in practice.[20]

The Outlook for Stationary Power Applications of Gas Turbines

Rising costs of steam-electric power plants and slow, uncertain electrical load growth have led to dramatic reductions in the construction of new central station power plants in many countries; in the US, for example, there were virtually no orders for central station power plants between 1982 and 1986 (Figure 5.6). These conditions are leading utility planners to give more attention to the gas turbine for meeting future power needs. On the basis of contacts made with the majority of the large electric utilities, Gluckman at the Electric Power Research Institute estimated that some 40 GW of new gas turbine-based generating capacity is on order or being planned in the US for installation by 1995.[21]

Emerging utility interest in gas turbines is complemented by a boom in gas turbine sales to cogenerators in the US. Electric utility rate increases and the Public Utility Regulatory Policies Act of 1978 (PURPA), along with the 1982 and 1983 Supreme Court decisions upholding its provisions, have led to a competitive challenge for utilities from independent cogenerators and small power producers in the US PURPA encourages cogeneration and the production of electricity from renewable

Figure 5.6. New Orders for Central Station Power Plants in the US*



* Total in 1986 -- 752 MW -- was for 11 gas turbines. This was the first year since World War II that no steam or hydroelectric turbine units were ordered by US electric utilities.
Source: *Electric Power Annual Report*. Annual. Washington, D.C.: Edison Electr. Instit.

energy sources in small installations by requiring utilities: (a) to purchase the electricity from qualifying producers at a price equal to the cost the utility can avoid by not having to otherwise supply that power and (b) to provide back-up power at reasonable rates. Between 1980 and 1987, 62 GW of electrical generating capacity were certified as qualifying for PURPA benefits by the Federal Energy Regulatory Commission (FERC), nearly three-fourths of which is due to cogeneration (Figure 5.7). Some 20 GW of the cogeneration capacity certified in this period, more than the sum of all utility orders for all kinds of central station power plants, 1980-1986 (Figure 5.6), was based on the gas turbine (Figure 5.7).

Recent interest in the gas turbine for stationary power reflects both long-standing attractions of this technology and recent improvements that make it possible for the gas turbine to compete in a wider range of markets.

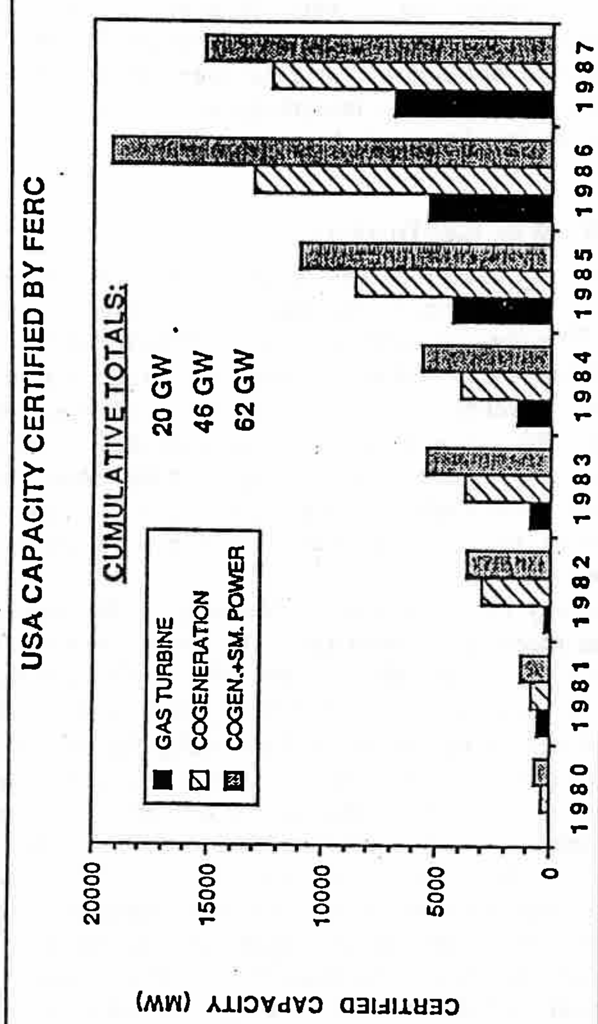
Traditional Roles for Gas Turbines

The historical attraction of the gas turbine for utilities has been its low cost, $300 per kW[22] or less, a small fraction of the cost of coal or nuclear power plants. This low cost reflects the utter simplicity of the simple cycle gas turbine. While costly heat exchangers are required in a steam turbine power plant to transfer heat from the combustor to the steam working fluid that drives the turbine, in a gas turbine power plant the hot fuel combustion products drive the turbine directly (Figure 5.8a). Also, while large condensers and often cooling towers are required to condense a steam turbine's exhaust steam, the exhaust from a gas turbine is discharged directly to the atmosphere.

But simplicity has been a mixed blessing for the simple cycle gas turbine. It has meant a low efficiency; the average efficiency of utility peaking units in the US in 1985 was only 29%.[23] [Efficiencies are given in this paper in terms of the fuel's higher (gross) heating value.] Also, clean fuels have been required to avoid damaging the turbine blades with the combustion products -- a constraint that has limited the use of the gas turbine mainly to liquid or gaseous fuels which have been costly, which have been barred from use in power generation by public policies, or whose long-term availability has been uncertain. Because of these constraints, utilities have used gas turbines mainly for peaking service.

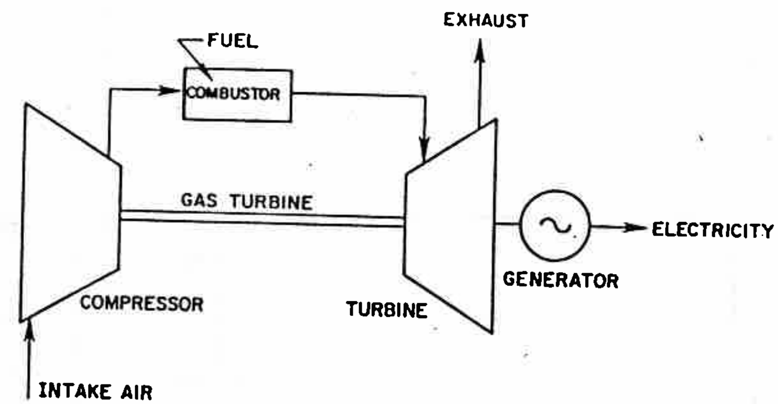
Its low unit capital cost has also helped make the gas turbine attractive for cogeneration applications. Because of the relative insensitivity of gas turbine unit costs to scale (Figure 5.9), the gas turbine tends to be favored over the steam turbine for all but the largest cogeneration installations. The use of the high-temperature (425 to 540°C) turbine exhaust to raise steam in a heat recovery steam generator (HRSG) for heating applications

Figure 5.7. Annual Cogeneration and Small Power Production Capacity for Facilities Certified by Federal Energy Regulatory Commission to be Eligible for Benefits Allowed Under Public Utility Regulatory Policies Act



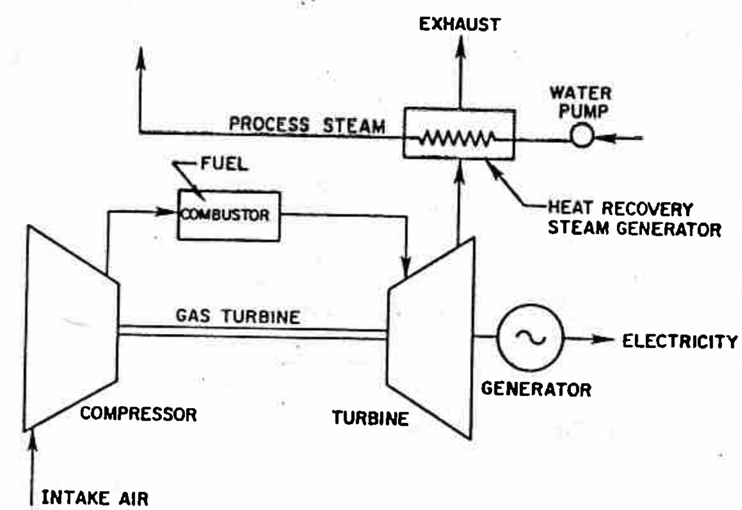
Source: Off. Electr. Power Regul. 1987. The qualifying facilities report: a cumulative list of filings made for small power production and cogeneration facilities through December 31, 1986. Washington, D.C.: Fed. Energy Regul. Comm.

Figure 5.8a. Simple Power Cycle*



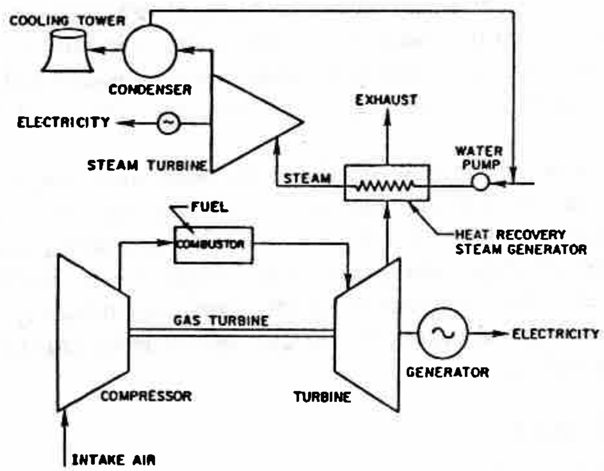
* Fuel burns in air pressurized by compressor, combustion products drive turbine, and hot turbine exhaust gases are discharged to atmosphere.

Figure 5.8b. Simple Cogeneration Cycle*



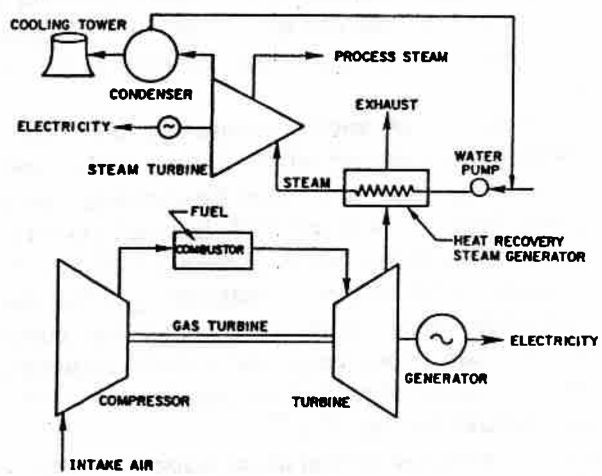
* Like simple power cycle, except that hot turbine exhaust gases are used to raise steam in HRSG for heating.

Figure 5.8c. Combined Cycle for Power*



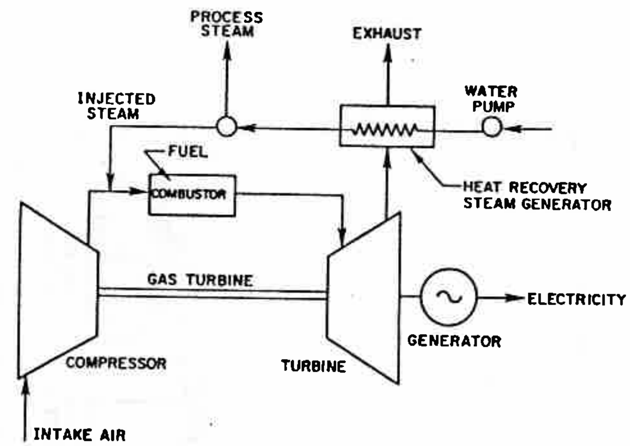
* Like simple cogeneration cycle, except that steam from HRSG is used to produce extra power in condensing steam turbine.

Figure 5.8d. Combined Cycle for Cogeneration*



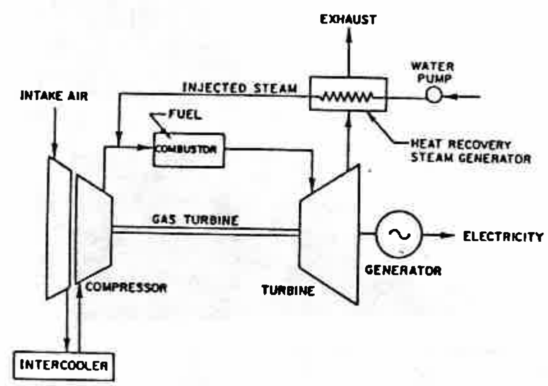
* Like combined cycle for power, except that some steam is bled from steam turbine for heating.

Figure 5.8e. Steam-Injected Gas Turbine (STIG)*



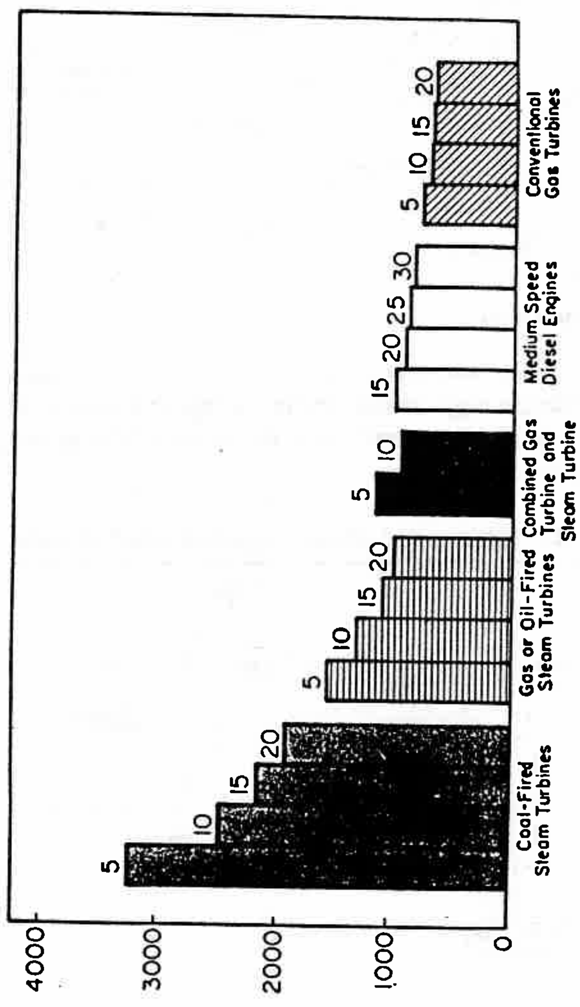
* Like simple cogeneration cycle, except that steam not needed for heating is injected into combustor for increased power output and higher electrical efficiency.

Figure 5.8f. Intercooled Steam-Injected Gas Turbine (ISTIG)*



* Like STIG with full steam injection except that intercooler between compressor stages allows for operation at much higher turbine inlet temperature because of improved air cooling of turbine blades.

Figure 5.9. Unit Installed Costs for Small-Scale Cogeneration Systems*



* The numbers at the tops of the bars are the installed electrical generating capacity in MW.

Source: Off. Ind. Programs, US Dept. of Energy. 1984. Industrial cogeneration potential, 1980-2000, DOE applications of four commercially available prime movers at the plant site. Washington, D.C.

(Figure 5.8b) makes the gas turbine a thermodynamically efficient cogeneration device, even if the efficiency of the turbine for producing power only is relatively poor.

A major shortcoming of the simple cycle gas turbine in cogeneration is that it is often uneconomical in applications involving highly variable steam loads, because achieving a high thermodynamic efficiency depends on being able to make use of the full electrical and thermal output capacities.

It is now possible to overcome the constraints which have confined gas turbines to peaking service for utilities and baseload service for cogeneration because: (a) the performance of the basic gas turbine cycle is improving steadily, and (b) various simple cycle modifications offer opportunities for both improving efficiency and reducing capital cost. A brief review of the history of the gas turbine is helpful in understanding these possibilities.

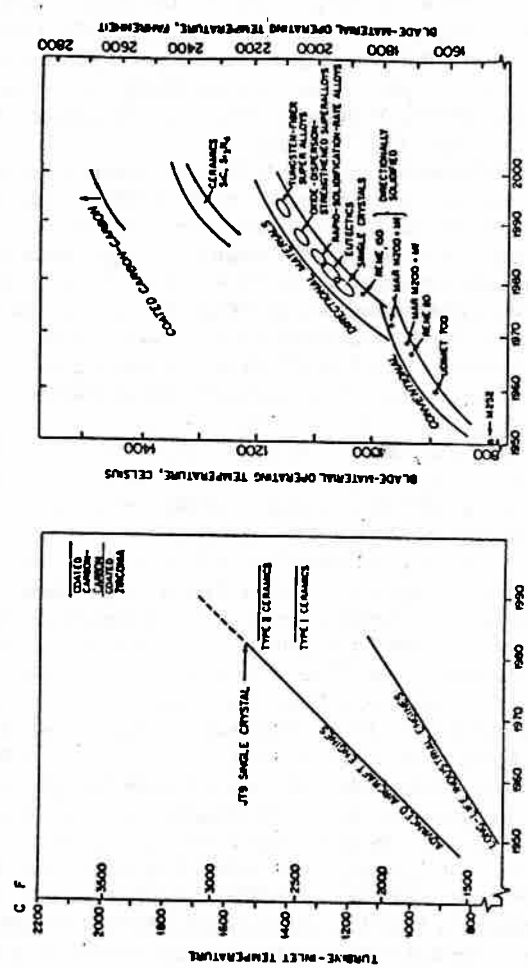
A Brief History

An early major milestone in the history of the gas turbine was the initiation of German and British programs in the mid-1930s to explore the use of gas turbines for aircraft propulsion. The success of these initial efforts led the US to launch major jet engine development programs during and following World War II: the cost of these programs between 1940 and 1980 totalled about $10 billion.[24] These efforts have been successful, both in improving jet engine reliability and thrust-to-weight ratios and in increasing efficiency by increasing turbine inlet temperatures, at an average rate of more than 20°C per year, between 1950 and 1980 (Figure 5.10).

Improvements in jet engine technology and electricity demand growth that was more rapid than expected stimulated considerable interest in the use of short lead-time gas turbines for stationary power applications in the late 1960s. Between 1965 and 1975, installed gas turbine capacity in the US electric utility industry increased from 1.3 GW to 43.5 GW.[25] But subsequently commercial interest in stationary gas turbines ground to a halt as a result of the sharp rise in oil and gas prices, concerns about gas scarcity and oil import dependency, and a sharp reduction in electricity demand growth; the installed gas turbine capacity of the US utility industry in 1985 was no greater than in 1975.[26]

The end of commercial interest in gas turbines for stationary power in the US did not slow fundamental progress in improving gas turbine technology, however. One reason is that commercial airlines pressed vendors to improve the efficiency of jet engines. The rising world oil price increased the fuel costs of air passenger travel from 11 to 32% of the total

Figure 5.10. Trend in Turbine Inlet Temperatures for Advanced Aircraft Jet Engines and Long-Life Industrial Turbines *(Left)* and Turbine Blade Material Operating Temperature *(Right)*.



Note: When an aircraft engine is modified for stationary applications the rated turbine inlet temperature is reduced about 110°C to promote long-life operation.
Source: Wilson, D.G. 1984. *The Design of High-Efficiency Turbomachinery and Gas Turbines.*

cost of air passenger service in the 1970s.[27] US Department of Defense support for research and development on jet engines for military applications also continued at a high level, averaging about $450 million per year in the decade ending in 1986.[28] Continuing R&D in this area is expected to bring significant further increases in turbine inlet temperatures by the turn of the century, as a result of major improvements in blade materials (Figure 5.10) and more effective blade-metal cooling technologies.[29]

A paradoxical aspect of the development of the stationary gas turbine is that most of the well-known "low-technology" cycle modifications available for improving performance -- e.g., steam injection, intercooling, reheat, regeneration, evaporative regeneration, and steam-reforming of the fuel--remain largely unexploited, even though enormous "high-technology" advances have been made in turbine blade materials, design, and fabrication. This is because such cycle modifications involve the introduction of heavy or bulky heat exchangers or the use of large quantities of steam or water, neither of which is relevant to aircraft applications. This situation presents an enormous opportunity because it means that major improvements can be made in the performance of gas turbines for stationary power applications with relatively modest R&D efforts.

Progress in Combined Cycle Technology

One gas turbine cycle modification is familiar to the electric utility industry: the gas turbine/steam turbine combined cycle (Figure 5.8c), which accounted for some 4.7 GW of utility generating capacity in the US in 1985.[30] With advanced gas turbines now commercially available for stationary applications,[31] a combined cycle efficiency of 45% can be realized in 200 MW plants costing $520 per kW. For comparison, a 36% efficient natural gas-fired steam-electric plant consisting of two 500 MW units would cost $760 per kW (Table 5.2). These combined cycle plants could produce electricity at a busbar cost only three-fifths of that for large new coal plants at the 1987 average natural gas price in the US (Table 5.2).

A Comparison of Industrial and Aeroderivative Turbines

The combined cycle is a good technology for beginning a transition to greater use of gas turbines in stationary power applications. It marries the new gas turbine technology to the familiar steam turbine. But it would be a mistake to limit utility use of advanced gas turbines to this option, because alternatives may offer advantages in some applications.

Table 5.2. Cost/Performance Characteristics for U.S. Central-Station Power Plants[a]

Coal and Nuclear Steam-Electric Plants

	Coal[b,c]			Light Water Reactor[d] Current	Light Water Reactor[d] Target
Unit Size (MW)	2 x 500	500	200	1100	1100
Efficiency (%)[e]	34.6	34.6	34.6	33.4	33.4
Unit Cost ($/kW)	1340	1410	1880	3060	1670
Levelized Busbar Cost (Cents/kWh)					
Capital[f]	1.61	1.69	2.25	3.66	2.00
Fuel	1.86	1.86	1.86	0.91	0.91
O&M	0.89	0.99	1.37	1.11	1.11
Total	**4.36**	**4.54**	**5.48**	**5.68**	**4.02**

Natural Gas-Fired Plants[g]

	1987 Natural Gas Price[h]				2 X 1987 Natural Gas Price			
	Steam	ACC	STIG	ISTIG	Steam	ACC	STIG	ISTIG
TIT (°C)	540	1260	1200	1370	540	1260	1200	1370
Unit Size (MW)	2 x 500	205	4 x 51	114	2 x 500	205	4 x 51	114
Efficiency (%)[e]	36.3	45.0	40.0	47.03	6.3	45.0	40.0	47.0
Unit Cost ($/kW)	760	520	410	400	760	520	410	400
Levelized Busbar Cost (Cents/kWh)								
Capital[f]	0.91	0.63	0.49	0.48	0.91	0.63	0.49	0.48
Fuel	2.08	1.68	1.89	1.61	4.17	3.36	3.78	3.22
O&M	0.49	0.29	0.29	0.29	0.49	0.29	0.29	0.29
Total	**3.48**	**2.60**	**2.67**	**2.38**	**5.57**	**4.28**	**4.56**	**3.99**

[a] All costs are in 1987 U.S. dollars.

[b] Capital costs, efficiencies, and O&M costs are EPRI estimates, for a bituminous coal-fired subcritical steam plant with flue gas desulfurization, according to EPRI, TAG 1986 (Electr. Power Res. Inst. 1986. Technical Assessment Guide. 1: Electricity Supply -- 1986. Palo Alto, Calif.).

[c] The assumed coal price is $1.79/GJ, the average U.S. utility price projected for 2000 by the U.S. Department of Energy [Energy Inf. Admin. 1988. *Annual Energy Outlook 1987*, with projections to 2000. DOE/EIA-0383(87). Washington, D.C.: U.S. GPO].

(Table 5.2 notes cont'd. next page)

Table 5.2 Notes (Cont'd.)

[d] Reactor plant size, unit capital costs, and efficiencies are EPRI estimates (EPRI, TAG 1986). The two sets of capital costs are the current cost and an EPRI target for "improved" conditions -- resulting from higher construction labor productivity, shorter construction period, streamlined licensing process, etc. The assumed nuclear fuel cycle cost is $0.84/GJ, EPRI's projection for the period 1990-2000 (EPRI, TAG 1986). The assumed O&M cost is the 1985 U.S. average for nuclear power plants [Energy Inf. Admin. 1987. Historical plant cost and annual production expenses for selected electric plants 1985. DOE/EIA-0455(85). Washington, D.C.: U.S. GPO], twice as large as the EPRI estimate for new plants (EPRI, TAG 1986).

[e] Based on the fuel's higher heating value and for operation at 100% load.

[f] For a 6.1% real discount rate [recommended by EPRI (EPRI, TAG 1986)], a 30-year plant life, and a 70% capacity factor. No taxes or tax incentives are included.

[g] The steam plant involves 165 bar, 540°C steam (with single reheat to 540°C) driving a conventional turbine/electric generator (EPRI, TAG 1986). The advanced combined cycle (ACC) is a recently commercialized 135 MW GE Frame 7F gas turbine plus a 70 MW steam turbine; the indicated performance is a General Electric estimate (Brandt, D.E. 1986. Heavy-duty turbopower: the MS7001F. Mech. Eng. July: pp. 28-36). The STIG unit is a commercial steam-injected gas turbine based on the GE LM 5000 (L. Gelfand, Manager, Advanced Programs and Ventures, General Electric Marine and Industrial Division, Cincinati, Ohio, personal communication, February 1987). The ISTIG unit is a proposed intercooled steam-injected gas turbine, based on the LM 8000 [Eng. Dept., Pacific Gas and Electr. Co. 1984. Scoping study: LM5000 steam-injected gas turbine. Based on work performed by the Mar. and Ind. Engine Proj. Dept. of the Gen. Electr. Co.; Horner, M.W. (Mar. and Ind. Eng. and Serv. Div. of the Gen. Electr. Co.). 1988. Position statement - intercooled steam-injected gas turbine. Testimony presented at the Committee Hearing for the 1988 Electricity Report of the Calif. Energy Comm., held at the So. Calif. Edison Co., November 21-22, 1988]. The unit capital costs for the steam-electric and ACC plants are EPRI estimate (EPRI, TAG 1986); that for STIG units is a Bechtel estimate [Soroka, G.E. (Bechtel Eastern Power Corp.). Sept. 1987. Modular remotely operated fully steam-injected plant for utility application. Paper presented at the ASME Cogen-Turbo Conf. Montreux, Switzerland: Am. Soc. Mech. Eng.]; that for the ISTIG is based on estimates made by GE and the staff of the California Energy Commission (M.W. Horner, 1988; Calif. Energy Comm. Staff. 1988. Resource case analysis report. Testimony presented at the Committee Hearing for the 1988 Electricity Report of the Calif. Energy Comm., held at the So. Calif. Edison Co., November 21-22, 1988). The O&M costs are EPRI estimates (EPRI, TAG 1986) for all but STIG and ISTIG units. For the latter the values are those estimated by EPRI for combined cycles (EPRI, TAG 1986), even though a Bechtel analysis indicates that steam-injected gas turbine systems offer inherent O&M cost savings compared to combined cycle units (G.E. Soroka, 1987).

[h] The average gas price for U.S. electric utilities was $2.10/GJ in 1987.

In exploring alternative gas turbine strategies, it is useful to distinguish between the characteristic features of heavy-duty industrial turbines and aeroderivative units. Various vendors offer heavy-duty industrial units in sizes ranging up to 70 to 135 MW. The tendency has been to design them with modest compression ratios (8 to 16). They are thus well-suited for combined cycle operations because the turbine exhaust gases are thereby relatively hot -- 593°C for the most recently offered advanced industrial unit[32] -- making it possible to produce high quality steam in the heat recovery steam generator (HRSG).

In contrast, aeroderivative units are lightweight and compact, with relatively small capacities -- 30 to 35 MW at the high end of available capacities -- and the trend is toward high compression ratios (18 to 30); all such characteristics reflect jet engine design requirements. Though simple cycle aeroderivatives are relatively efficient as electricity producers, such engines tend to be poor candidates for combined cycle applications, since the turbine exhaust gases are not nearly as hot as in heavy-duty industrial units. Until recently this attribute led to the neglect of aeroderivatives as a serious candidate for central station power generation. However, recent developments have shown that aeroderivatives are good candidates for other efficiency and output-augmenting cycle modifications such as steam injection, discussed below.

While aeroderivative turbines are not nearly as familiar as heavy-duty industrial turbines for stationary applications, they warrant attention not only because, with appropriate cycle modifications, they can perform as well as or better than industrial units, but also because aeroderivatives have some other important attributes.

First, aeroderivatives can bring back to power generation the advantages of cost-cutting mass production. Moreover, when an aeroderivative is introduced for power generation, it is already well-advanced on the learning curve, because large-volume production of jet engines for aircraft applications has preceded it.

Second, the aeroderivatives are expected to benefit from continuing advances in jet engine technology, which can be transfered quickly and at low incremental cost to stationary applications. While there are only modest ongoing development efforts to improve industrial turbines in the US, there is continuing heavy US government support for jet engine R&D. This includes, for example, the new $3.4 billion, 13-year Integrated High Performance Engine Technology program supported by the Department of Defense and the National Aeronautics and Space Administration.[33] Such R&D efforts are expected to lead to major improvements in aircraft engine technology, including substantial further increases in turbine inlet temperatures (Figure 5.10).

Many utility managers are reluctant to consider aeroderivatives in capacity expansion plans. One concern is that, because in their manufacture emphasis is given to the use of special materials to meet the low weight and compactness requirements of jet engines, aeroderivative engines are inherently more costly per kW than industrial turbines, where such constraints are not relevant. While the use of more costly materials does tend to raise the cost of aeroderivatives, a compensating factor is that a greater proportion of the aeroderivative power plant can be built at the factory, where costs are easier to control than in the field. Moreover, the various cycle modifications that would be employed for stationary applications of aeroderivatives tend to lower unit costs. For example, when a simple cycle gas turbine is modified for both steam injection and intercooling, its output can be tripled, resulting in a lower unit capital cost than that of a combined cycle based on an industrial turbine (Table 5.2).[34]

Another concern is that because aeroderivative engines are more delicate than heavy-duty industrial turbines, they are less reliable. This might be true if aeroderivative turbines were maintained like industrial units; instead they are maintained like jet engines. Their compact, modular construction makes it easy to remove and replace failed parts quickly.[35] In fact, the entire basic engine can be removed and replaced with a spare (flown in, if necessary) from a lease-engine pool, resulting in short downtime.[36] With aeroderivative units, it is not necessary to schedule downtime for major maintenance, as is done with heavy-duty industrial units. Also, statistical data on utility use of industrial turbines, combined cycles, and aeroderivative turbines compiled by the North American Electric Reliability Council shows no significant differences in the availabilities of the three types of engines.[37]

A closely related concern is the cost of maintenance. It is widely believed that maintenance costs of gas turbines, heavy-duty industrial as well as aeroderivative, are much higher than those of steam-electric plants. Indeed, between 1982 and 1985 maintenance costs for utility gas turbines averaged 0.76 cents per kWh, compared to 0.26 cents per kWh for coal-fired steam plants.[38] Some utilities report maintenance costs for gas turbines as high as 1.0 to 1.5 cents per kWh.[39] These statistics should be interpreted with care, though, because the data for coal-fired plants are for carefully maintained baseload units, while the gas turbine data are for peaking plants that typically operate at an average capacity factor of only 5 to 7% and are often not carefully maintained. In considering gas turbines for baseload or load-following utility service, a more appropriate historical record is that for gas turbines operated in baseload cogeneration configurations at industrial plants. Preventive maintenance programs carried out over the last 20 years for aeroderivative gas turbines used for cogeneration at the Dow Chemical Company resulted in maintenance costs of 0.2 to 0.3 cents per kWh.[40]

Another concern often expressed about aeroderivative turbines is that utilities will not be interested in them because of their small unit capacities. However, pressed by the financial risks of building large power plants, many utilities are already beginning to shift the focus of their planning efforts to smaller units. Moreover, utilities would be able to improve overall reliability with multiple small units on the same site. The ongoing trend toward more competition in power generation is also making market conditions more favorable for introducing these smaller-scale power-generating technologies.

Steam-Injected Gas Turbines

The most significant development to date relating to stationary power applications of aeroderivative gas turbines was the introduction in the early 1980s of the steam-injected gas turbine (STIG), a variant of the simple gas turbine in which high pressure steam recovered in the HRSG is injected into the combustor, where it is heated to the turbine inlet temperature and then expanded in the turbine (Figure 5.8e).[41] Steam injection can give rise to large increases in power output and electrical efficiency. The only extra work required with steam injection, compared to a simple cycle gas turbine, is that needed to pump the feedwater to boiler pressure, which is negligible compared to the work required to compress the main flow air. This and the fact that the specific heat of steam is double that of air account for the large increases in efficiency and power output that arise with steam injection.[42,43] Aeroderivative engines are chosen for steam injection, because, unlike heavy-duty industrial engines, these units are designed to accommodate mass flows considerably in excess of their nominal ratings, so that only minor modifications are required to operate them as baseload units.[44]

Injecting small amounts of steam (or water) in stationary gas turbines (heavy-duty industrial as well as aeroderivative) for the control of NOx emissions is a well-established practice.[45,46] Only recently has injecting large amounts of steam attracted serious commercial interest as a means of increasing efficiency and power output in stationary applications. Yet the concept is not new. The idea of using steam injection to increase power and efficiency is discussed in textbooks,[47,48] in various articles dating from the mid-1970s,[49-56] and in a 1951 Swedish patent application[57] that was rejected in 1953. The injection of water into gas turbines dates to the earliest use of jet engines, when water was often injected to increase thrust during takeoff.

STIG for Cogeneration

The commercialization of STIG for cogeneration applications grew out of the post-PURPA flurry of interest in gas turbine cogeneration in the US The STIG concept was introduced to cope with the most troublesome problem for simple cycle gas turbines in cogeneration applications, that of their poor part-load performance. With a STIG unit, steam not needed for process applications can be injected back into the combustor to produce more electric power. The provisions of PURPA often make it attractive to sell this extra power to the utility, thus extending the economic viability of gas turbine cogeneration to a wide range of variable-load applications.[58] [A combined cycle with a condensing steam turbine using steam extraction to provide steam for process (Figure 5.8d) can also be used economically in variable steam-load applications: steam not needed for process is expanded through the lower turbine stages and condensed to produce more power. But the scale economies associated with steam turbines limit the economical use of the combined cycle to relatively large installations. STIG technology allows the gas turbine to be used in small- scale, variable steam-load applications.]

The first commercially operated STIG cogeneration units involved the use of the Cheng cycle, a patented version of STIG introduced by International Power Technology, Inc.[59,60] Cheng cycle units have been marketed using the Detroit Diesel Allison 501-KH turbine. Without steam injection, this turbine is rated to produce about 3.5 MW of electric power at 24% efficiency when producing power only. With full steam injection, it will produce about 6 MW at 34% efficiency.[61] As of mid-1989, six units based on the Allison 501-KH had been installed and two more ordered; three larger STIG units based on General Electric's LM-5000 had been installed at industrial sites [the first involving an in-the-field modification of a simple cycle cogeneration unit[62]] and fourteen more were either under construction or on order; and seven STIG units based on GE's LM-2500 were being planned (personal communication from M. Homer, Marine and Industrial Turbine Division, General Electric Company, Cincinnati, Ohio, December 13, 1988, and William Flye, Stewart & Stevenson Services, Inc., Houston, December 7, 1988).

The LM-5000, derived from the CF6-50 high-bypass-ratio turbofan engine used in wide-body commercial airplanes (e.g., the DC-10 Series 30, the Boeing 747, and the Airbus A300), is a 33.1 MW unit with a compression ratio of 25:1 and an efficiency of 33% when operated as a simple cycle on natural gas. With full steam injection the output and efficiency of the LM-5000 increase to 51.4 MW and 40% respectively.[63] The LM-2500 is a 21.4 MW simple cycle unit with a compression ratio of

18.5:1 and an efficiency of 33%; with full steam injection it has an output and an efficiency of 26.8 MW and 36%, respectively.[64]

Advanced STIG Cycles for Central-Station Power

The use of steam injection for cogeneration has stimulated interest for central station applications, in which all the steam raised in the HRSG is injected for power and efficiency augmentation. A paper by a Bechtel analyst indicates that STIG plants based on the LM-5000 and using once-through steam generators would have several advantages over combined cycle units with cooling towers -- including a unit capital cost lower by one-sixth, water requirements less by one-third, a 6% higher availability, and the possibility of remote operation without operators in continuous attendance.[65] A major drawback of STIG is that it is less energy-efficient than combined cycle technology now on the market.[66] Accordingly, despite a modest capital cost advantage for STIG, the busbar cost would usually be lower for combined cycles (Table 5.2).

A more interesting candidate for central-station applications is a proposed modified STIG using intercooling between the two compressor stages (Figure 5.8f).[67] One result of intercooling is that less power is needed to run the compressor. The addition of an intercooler to a simple gas turbine increases the power output but decreases the efficiency; the reduced compressor work requirements would be more than offset by the extra fuel requirements for heating the cooled air exiting the compressor up to the turbine inlet temperature. But modern aeroderivative turbines use air bled from the high-pressure compressor to cool the turbine blades, so that intercooling leads to an efficiency gain as well. Because of the lower temperature of the air used to cool the blades, the metal temperatures can be kept acceptably low, while the turbine inlet temperature is raised. Detailed design work carried out at General Electric indicates that an intercooled STIG (ISTIG) based on the LM- 8000[68] will be able to operate at a turbine inlet temperature of 1370°C and produce about 114 MW with an average efficiency of 48.3% and a guaranteed efficiency of 47.0%, at an installed capital cost of $400 per kW.[69]

The projected ISTIG efficiency is somewhat higher than that for an advanced combined cycle and its estimated capital cost is somewhat less, leading to a lower busbar cost (Table 5.2). The busbar cost would probably be less than for a large coal-fired steam-electric plant with flue gas desulfurization even if the natural gas price is double the average for 1986 (Table 5.2).

The indicated efficiency advantage of the ISTIG compared to the combined cycle is not the result of a systematic comparison of

steam-injected and combined cycle designs. Moreover, the estimated performance difference is too small to declare unequivocally that steam-injected designs are more efficient. In looking to the future, the balance could tip in favor of combined cycles, for example, if the Kalina cycle were successfully developed and used instead of the steam Rankine cycle in combined cycles. But there are also many possible modifications to the ISTIG cycle.

One such cycle modification involves reheat, or the addition of an additional combustor after the higher pressure turbine stages and before the power turbine. (The power turbine generates the net cycle power; the output of the higher pressure turbine stages drives the compressor.) Since combustion in the gas turbine takes place with a large amount of excess air (needed to keep the combustion product gases sufficiently cool that the metallurgical temperature limits on the turbine blades are not exceeded), there is oxygen available to burn more fuel in a reheat combustor. If a reheat combustor is added to an ISTIG unit based on General Electric's LM-8000, the power output would increase to 180 MW and the efficiency to 52%.[70] The cycle efficiency would increase because the average temperature at which heat is added to the cycle would thereby increase, while the temperature of the heat discharged to the atmosphere would remain the same.

With reheat, not only do the power output and efficiency increase, but also the temperature of the exhaust gases from the power turbine increases enough that it becomes feasible to use some of the turbine exhaust heat to reform the fuel with steam in the presence of an appropriate catalyst.[71,72,73,74] When methane fuel is reacted with steam in the reformer, some of the methane is converted into a mixture of hydrogen, carbon monoxide, and carbon dioxide. As the steam-reforming reaction is highly endothermic, the chemical energy content of the products is greater than that of the fuel from which it is derived; thus through steam reforming, low-quality heat can be converted into high-quality chemical energy. To the extent that some of the turbine exhaust heat can be used for chemical recuperation as an alternative to heat recuperation through steam injection, there would be a net cycle efficiency improvement because of the reduction of the latent heat loss to the stack. (More than half the heat used to raise steam in the HRSG is the latent heat needed to evaporate water, which is lost to the stack in a STIG cycle.) It is estimated that the addition of a steam reformer to an LM-8000-based, natural gas-fired ISTIG unit with reheat increase the efficiency to 54% but reduce its output to about 160 MW.[75]

Thus, the performance of both combined cycles and advanced STIG units could be improved, even without further improvements in turbine inlet temperature or turbine blade cooling technology. Because of the uncertainties relating to an efficiency comparison of advanced STIG and combined cycle designs, decisions to commercialize advanced STIG technologies should be made on grounds other than efficiency alone.

An ISTIG has several advantages over a combined cycle unit: it is simpler, requiring no steam turbine, condenser, or cooling tower; pollution controls would be less costly than with combined cycle units; the small unit capacities of ISTIG units implies flexibility in capacity planning, improved reliability, and ease of maintenance through lease-pool arrangements; their small size also makes them good candidates for cost-cutting innovations and the economies of mass production; and steam-injected gas turbines will continue to benefit quickly from expected continuing improvements in jet engine technology.

A drawback of STIG cycles is that significant quantities of steam are exhausted to the atmosphere. While the absolute level of makeup water requirements actually favors steam-injected cycles, some 0.6 kg per kWh for an ISTIG unit, compared to 4.1, 1.8, and 0.8 kg per kWh, for a nuclear plant, a large fossil-fuel fired steam-electric plant, and an advanced combined cycle, respectively,[76] all the water required for STIG cycles must be processed to boiler quality. In fact, STIG cycles require about five times the high-quality water and demineralization processing capacity required for combined cycles.[77] Although these water processing requirements typically would not give rise to significant economic penalties,[78] it could be a source of concern in water-scarce situations. But in such instances makeup water requirements could be reduced to zero by condensing water vapor out of the exhaust stream of the heat recovery steam generator for reuse, using a condensing heat exchanger. For STIG units, it has been estimated that complete water recovery could be achieved for an 11% increase in capital cost and a 1.2% increase in fuel requirements per kWh.[79,80]

Such considerations, collectively considered, suggest that advanced STIG cycles warrant development. It has been estimated that to develop ISTIG would take four to five years and cost $100 million, including the cost ($40 million) for the first unit.[81] As no proof-of-concept is involved, only good engineering design, the technological risk associated with development is small. Accordingly, bringing the technology to market requires only the sale of a few units to pay for the relatively modest development costs.

Gas Turbines and Long-Term Natural Gas Supply Considerations

Gas turbines have not been exploited much for power generation in part because of concerns by some energy planners about the long-term availability of natural gas. But such concerns are becoming less and less important in decisions relating to power generation, for several reasons.

First, the natural gas supply outlook is now quite favorable for the decades immediately ahead -- especially in many developing countries, but even in the United States[82] and Western Europe,[83] where concerns about natural gas supply have led to public policies restricting the use of natural gas for power generation.

Second, the prospect of a continuing stream of innovations in gas-turbine power-generating technology while steam-electric technology stagnates has prompted massive investments in research and development aimed at marrying coal to the gas turbine through the use of integrated coal gasifier/gas turbine power systems, in the United States, Western Europe, and Japan.[84,85] These efforts led to a commercial demonstration project proving the technology in the 100 MW integrated coal gasifier/combined cycle power plant at Cool Water, California, and to extensive follow-on developmental efforts that hold forth the promise that second-generation coal-gasifier/gas turbine power generating technology is likely to be both cleaner and less costly than coal-fired steam-electric power generation with flue gas desulfurization.[86]

The future of coal gasifier/gas turbine power generation is uncertain because technologies for efficiently removing sulfur are not yet commercially proven,[87] because low natural gas prices make it hard for coal gasifier/gas turbines to compete, and because growing concerns about the greenhouse warming may lead to constraints on coal use in many parts of the world. But if coal is to have a significant future in power generation, the coal-based technologies of choice will probably be configurations involving integrated coal gasifier/gas turbine systems, because they offer both higher efficiencies (and thus lower CO_2 emissions per kWh) and lower unit capital costs than alternative coal-based power generation technologies.[88] In any case, a prudent "evolutionary" strategy for introducing coal-fired gas turbines would involve widespread initial use of natural gas-fired gas turbines in power generation. This strategy would help create a dynamic, rapidly growing gas-turbine manufacturing industry that would be a favorable theater for innovation, and it would provide utilities with a broad base of experience with gas turbine technology before shifting to more complicated coal-based gas-turbine systems. Various strategies have been advanced in recent years that would enable utilities to start up their gas turbine systems with natural gas, with the flexibility of shifting later to coal, if natural gas prices rise too much.[89,90]

Third, the power generation options for the long term are much broader than was once thought. Most of the developments relating to coal gasifier/gas turbine technology are readily adaptable to firing with biomass. STIG and ISTIG technologies, in particular, offer relatively low unit capital costs and high thermodynamic efficiencies at the modest sizes (less than 100 MW) needed for biomass applications. The prospects are good for bringing to market in the early 1990s biomass-fired versions of such turbines that will be able to compete with both coal and nuclear power technologies in many circumstances.[91,92] Biomass-fired gas turbines will be important in many parts of the world not only because biomass resources are more widely available than natural gas and coal resources, but also because they offer a strategy for helping to cope with the problem of global warming. If the biomass is grown renewably, its use results in no net buildup of carbon dioxide in the atmosphere. Moreover, if the biomass is grown in plantations on previously deforested or unforested land, the buildup of the biomass inventory will extract CO_2 from the atmosphere, and the steady-state inventory will be a reservoir of sequestered carbon.

It is also very likely that solar photovoltaic (PV) technology will begin to be used in power-generating applications, beginning in the 1990s, as rapid progress is being made in both high-efficiency, concentrating crystalline solar cell and low-cost, thin-film technologies.[93,94]

All of these future developments mean that emphasis on low capital-cost, energy-efficient, gas turbines fired with natural gas will make good sense for power generation in most parts of the world in the decades immediately ahead, regardless of the long-term outlook for natural gas supplies and natural gas prices. Natural gas is likely to be the fossil fuel of choice during the transition to the post-fossil fuel era, and during this transition, gas turbine-based power generation is likely to be one of the most important markets of natural gas.

Environmental Aspects of Advanced Gas Turbine Technologies

Natural gas-fired gas turbines emit negligible amounts of sulfur oxides and particulates. The high combustion temperatures lead to high emissions of nitrogen oxides (NO_x), however. Their uncontrolled NO_x emissions (Table 5.3) exceed the levels established in the federal New Source Performance Standards (NSPS) for natural gas-fired gas turbines

Table 5.3. Estimated NO_x Emissions for Alternative Cycles Based on the LM-5000[a]

	Adiabatic Flame Temperature (T^oK)		NO_x Emission Rate (ppm @ 15% O_2)	
Uncontrolled Simple Cycles[b]	2530		260	
Steam-Injected Cycles	STIG	ISTIG	STIG	ISTIG
Dry[c]	2548	2471	301	159
S/Fc = 1.0	2406	2329	89.5	43.6
S/Fc = 2.0	2274	2199	25.3	11.6
S/Fc = 3.0	2158	2085	7.4	3.2
Chemically Recuperated, Steam-Injected Cycles	CRSTIG	CRISTIG	CRSTIG	CRISTIG
Dry[c]	2223	2161	15	7.6
S/F[c] = 0.2	2107	2048	4.1	2.0
S/F[c] = 0.3	2055	1997	2.2	1.0
S/F[c] = 0.5	1959	1905	0.63	0.29

[a] The adiabatic flame temperature (AFT) is calculated for stoichiometric conditions -- for methane @ 300°K in simple and dry STIG/ISTIG cycles; for methane @ 400°K in wet STIG/ISTIG cycles; for a mixture (@ 950°K) of 10% methane, 62% steam, 22% hydrogen, 1% carbon monoxide, and 5% carbon dioxide (a typical fuel composition expected from the steam-reforming of natural gas) for CRSTIG/CRISTIG cycles. (A reheat turbine would be needed to achieve the turbine exhaust temperature needed for steam reforming. Because of the reduced oxygen level in the reheat combustion "air," the AFT and hence NO_x formation in the reheat combustor would be significantly lower than in the primary combustor. This effect is neglected here.) The temperature of steam for NO_x control is assumed to be 578°K. For the calculated AFT, the indicated NO_x emission level is obtained from an empirical relationship between AFT and NOx emissions (Sidebotham, G.S., Williams, R.H. 1989. Preliminary report on NO_x and cogeneration in New Jersey. Princeton, N.J.: Cent. Energy and Environ. Stud., Princeton Univ.) For the lowest AFTs considered, empirical data are not yet available, and the indicated NO_x emissions, obtained by extrapolation, may underestimate actual emissions. While thermal NO_x emissions are strongly correlated with AFT, prompt NO_x emissions are not. At high AFT, thermal emissions dominate; at low AFT, prompt NO_x emissions become more important. For a compression ratio of 27.6:1, 31.3:1, and 33.5:1, and an air temperature at the compressor exit of 787°K, 816°K, and 658°K, for the simple cycle, STIG/CRSTIG cycles, and ISTIG/CRISTIG cycles, respectively.

[b] The uncontrolled NO_x emissions rate for this simple cycle turbine is higher than for the turbines used in combined cycles, because the low pressure ratio of the gas turbines used in combined cycles leads to a lower compressor exit temperature and hence a lower AFT.

[c] "Dry" means that all steam is injected with the dilution air (i.e. no steam is injected into the primary combustion zone). S/F is the molar ratio of steam/fuel for steam injected into the primary combustion zone for NO_x control.

promulgated in the US in 1977[95] and are far in excess of the standards in some states with especially severe air quality problems.[96]

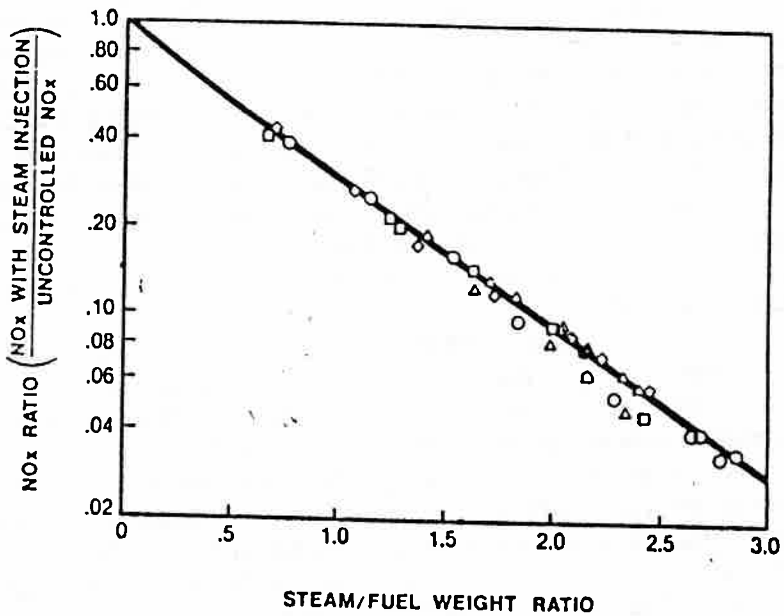
Among available technologies for reducing NOx emissions, a well-established approach involves the injection of steam or water into the primary combustion zone. NOx emissions tend to fall exponentially with the ratio of steam or water injected in the primary combustion zone to fuel, as demonstrated empirically for steam in the first field-modified STIG unit derived from the LM-5000 (Figure 5.11). NOx is controlled when steam or water is injected into the primary combustion zone because so doing reduces the flame temperature (Table 5.3).

With water injection, the percentage increase in fuel required to bring the mixture up to the turbine inlet temperature exceeds the percentage increase in power output resulting from the increased turbine mass flow, so that the electrical efficiency is reduced. With steam injection, the electrical efficiency is also reduced for combined cycle systems (where the optimal use of the steam produced in the HRSG is for power generation in the steam turbine),[97] but not for STIG or ISTIG cycles, where NOx control is an automatic benefit.

Dramatic reductions in NOx emissions are also possible with chemically recuperated gas turbine cycles, with and without additional steam injection for NOx control, as indicated for chemically recuperated STIG and ISTIG (CRSTIG and CRISTIG) cycles in Table 5.3. As with steam and water injection, the chemically recuperated cycles achieve low NOx emissions levels because with steam-reformed fuel, flame temperatures are lower than with natural gas fuel (since the heating value of the steam-reformed fuel is much lower *per mole* than that of the fuel from which it is derived). CRSTIG and CRISTIG cycles are also more efficient electricity generators than cycles that do not use steam-reformed fuel.[98] The combination of low NOx emissions and high efficiency achievable with these cycles has led the South Coast Air Quality Management District (SCAQMD) in California and the California Energy Commission to examine chemically recuperated gas turbine cycles as a promising technological strategy for reducing NOx emissions in Southern California while simultaneously controlling costs (personal communication from Jack Janes, California Energy Commission, December 15, 1988).

CO emissions increase as the level of steam injection increases, while NOx emissions are declining. Figure 5.12 shows, for example, that if NOx is controlled in a natural gas-fired LM-5000 to levels below 25 ppm, the CO emissions would be in excess of 50 ppm. Determining the optimal level of steam injection into the primary combustion zone involves balancing considerations of both NOx and CO emissions. If, by the time

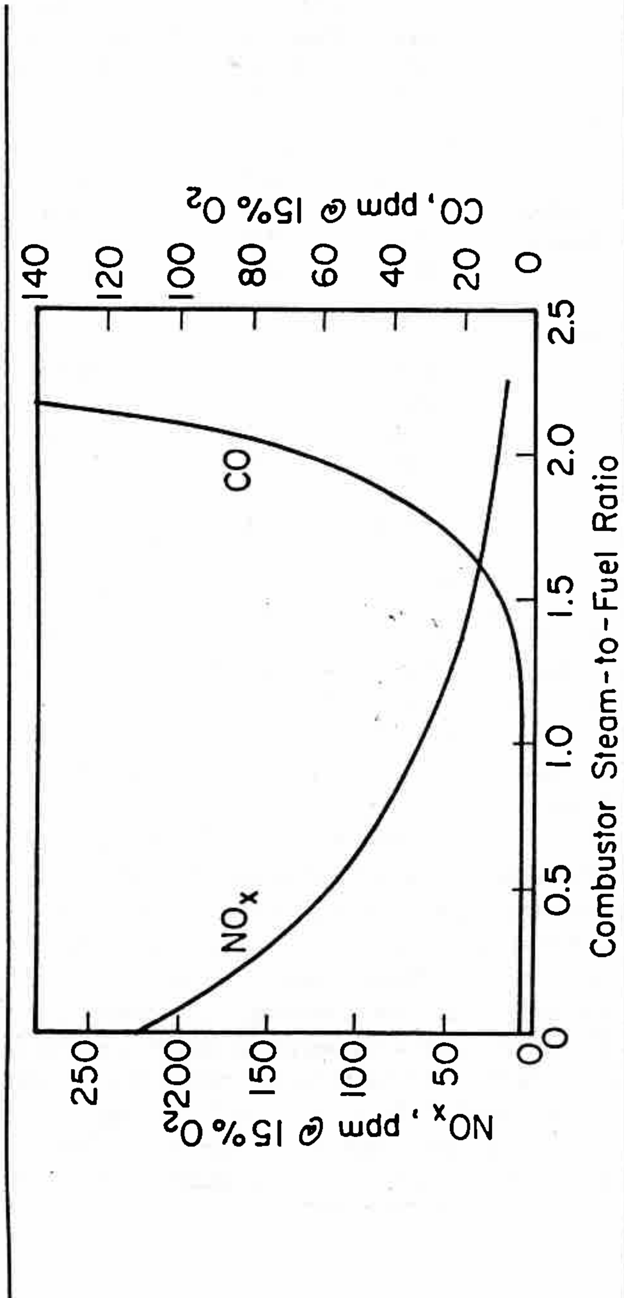
Figure 5.11. NOx Reduction Ratio as a Function of Ratio of Weight of Steam Injected into Primary Combustion Zone to Weight of Fuel*



* Measured at the First Field-Modified STIG Unit Based on the LM-5000, at Simpson Paper Co., Anderson, Calif.

Source: Burnham, J.B., Giuliani, M.H., Moeller, D.J. June 8-12, 1986. Development, installation, and operating results of a steam injection system (STIG) in a General Electric LM 5000 gas generator. Paper 86-GT-231. Presented at the Int. Gas Turbine Conf. and Exhib., Dusseldorf, West Germany: Am. Soc. Mech. Eng.

Figure 5.12. Typical Effects of Combustor Steam Injection on NO_x and CO Emissions at Full Load Operation.



Source: Horner, M.W. [Mar. and Ind. Eng. and Serv. Div. (Cincinnati, Ohio) of the Gen. Electr. Co.]. 1988. Position statement - intercooled steam-injected gas turbine. Testimony presented at the Committee Hearing for the 1988 Electricity Report of the Calif. Energy Comm., held at the So. Calif. Edison Co., November 21-22, 1988.

the maximum acceptable CO emissions level is reached, still higher levels of steam injection are desired for power and efficiency augmentation, extra steam is injected sufficiently far from the primary combustion zone so as not to affect pollutant emissions further.

Achieving extremely low levels of NO_x emissions with steam injection might require supplemental control of carbon monoxide emissions. Catalytic oxidation of the exhaust gas (the technology used in the US to control CO emissions from cars) is a promising, relatively low-cost strategy for accomplishing this.[99]

Since natural gas contains virtually no sulfur and since very low levels of NO_x emissions can be achieved with natural gas-fired gas turbine systems, natural gas-fired gas turbines can also be used to cope with the problem of acid rain. In the United States, the large quantities of SO_2 and NO_x emitted by existing coal-fired steam-electric power plants are among the most significant pollutant emissions leading to acid rain (100). Growing concern about acid rain will probably lead to US legislation in the not-too-distant future aimed at curbing these emissions. While much of the emphasis in the ongoing debates is on requiring the retrofitting of control systems such as stack gas scrubbers on these old power plants, the only benefit that would be gained thereby is a reduction of the pollutant emissions -- at a considerable cost, estimated to be some \$340 to \$640 per tonne of SO_2 removed, for an average sulfur content in coal of 3.1%.[101]

An alternative would be to encourage scrapping existing coal-fired steam plants (regardless of their remaining useful lives) and replacing them at the same sites with new advanced natural gas-fired gas turbine power plants. With all the incremental costs of the new facilities allocated to sulfur removal (giving no credit for reduced NO_x emissions or other benefits), the cost of this scrap-and-build strategy would cost \$340 and \$640 per ton, if the gas turbine systems were ISTIG units and if the lifecycle average natural gas price were \$3 per GJ and \$4 per GJ, respectively -- prices that were 50% and 100% higher than the average 1987 utility gas price in the United States.[102]

Still another important environmental benefit of advanced gas turbine power generating technologies is the potential for reduced emissions of carbon dioxide, which is desirable in light of heightened concerns about the global greenhouse warming. In general, emphasis on natural gas fuel for the transition to the post-fossil fuel era would help slow the atmospheric build-up of carbon dioxide. Burning one energy unit of natural gas releases just 0.55 times as much CO_2 as the combustion of one energy unit of coal. Furthermore, generating electricity with natural gas in gas turbines as efficient as ISTIG would release just 0.4 times as much CO_2 per kWh generated as a conventional coal-fired steam plant.

Potential Applications of Advanced Gas Turbines

Natural Gas Resources

Natural gas will dominate initial applications of advanced gas turbines, because gas supplies will be abundant in many parts of the world in the decades immediately ahead. According to estimates by the US Geological Survey, there is about as much conventional natural gas left in the world as conventional crude oil, but globally gas is used at just half the rate oil is (Table 5.4; see also Chapter 1). Remaining gas resources for the US and Canada are about 50% greater than oil resources, while for all industrialized countries remaining gas resources are more than twice as large as remaining oil resources (Table 5.4).

The outlook for gas is especially promising for developing countries. Natural gas resources exist in about 50 developing countries, including 30 that import oil.[103] Also, gas resources are large in relation to gas production in developing countries; although they have about as much gas as industrialized countries, they produce it at just one-fifth the rate it is produced in industrialized countries. Outside the Middle East, developing country gas resources are equivalent to more than a 200-year supply at the current rate of production (Table 5.4).

US Applications

Even in the US, where natural gas resources are more fully developed than in most of the rest of the world, natural gas-fired gas turbines can play important roles in power generation in the decades immediately ahead.

One important initial application for ISTIG technology would involve replacing the 127 GW of existing oil and gas-fired steam-electric plants expected to be operating in the US in 2000[104] with natural gas-fired ISTIG units. While these are load-following steam plants typically operated at low capacity factor [projected by DOE to average 46% in 2000[105]], they are so inefficient (32%) that it would be worthwhile replacing them with ISTIG units, even with fuel prices as low as $2 per GJ ($12 per barrel of oil equivalent).[106] Doing so for all oil and gas-fired steam plants in the US would lead to producing the same amount of electricity as DOE projected for such plants in 2000[107] while saving the fuel equivalent to 0.82 million barrels per day of oil. Considerations of both the cost savings potential and the large NO_x reduction potential (especially important in Southern California) of ISTIG technology, led the staff of the California Energy Commision to a recommmendation along these lines -- that Southern California Edison Company retire some 5700

Table 5.4. Natural Gas and Oil Resources and Production

	Natural Gas Resources[a] (EJ)	Natural Gas Production[b] (EJ/Year)	Crude Oil Resources[a] (EJ)	Crude Oil Production[b] (EJ/Year)
Industrialized Countries				
US/Canada	1079.0[c]	21.0	720.2	23.3
Western Europe	481.6	7.3	318.8	8.6
Australia/New Zealand	149.3	0.6	36.7	1.3
USSR/Eastern Europe	2757.6	27.1	991.9	25.9
Subtotal	4467.5	56.0	2067.6	59.1
Developing Countries				
Central America	228.3	1.3	342.7	6.5
South America	290.4	1.7	523.8	7.7
Asia	779.5	3.9	641.3	11.6
Africa	620.9	2.0	627.2	11.1
Middle East	2316.8	2.6	3175.1	23.0
Subtotal	4235.9	11.5	5310.1	59.9
Global Total	8703.4	67.5	7377.7	119.0

[a] Proved reserves plus estimated reserve appreciation in discovered fields plus estimated recoverable undiscovered resources, as of January 1, 1985 (Masters, C.D., Attanasi, E.D., Dietzman, W.D., Meyer, R.F., Mitchell, R.W., Root, D.H. 1987. *World Resources of Crude Oil, Natural Gas, Natural Bitumen, and Shale Oil*. Paper prepared for the 12th World Petrol. Cong. Houston, Tex.).

[b] Production in 1985 [Energy Inf. Admin. 1987. *International Energy Annual 1986*. DOE/EIA-0219(86). Washington, D.C.: US GPO].

[c] The resource estimate given here for the US (650 EJ) may underestimate remaining gas resources. A more recent assessment carried out for the US Department of Energy under the auspices of the Argonne National Laboratory estimated that remaining gas resources in the lower 48 states of the US. recoverable at wellhead prices less than $2.75/GJ amount to 633 EJ, with 189 EJ of additional resources recoverable at costs in the range $2.75/GJ to $4.60/GJ (Argonne National Laboratory. May 1988. An assessment of the natural gas resource base of the United States. Washington, D.C.: Off. Policy, Planning, and Analysis, US Dept. Energy).

MW of existing gas-fired steam-generating capacity in favor of ISTIG plants.[108]

Developing Country Applications

While the abundance of their natural gas resources (Table 5.4; see also Chapter 1) suggests that natural gas could play a major role in the energy economies of many developing countries, the use of natural gas is presently inhibited by the lack of gas transmission and distribution infrastructure, which is costly to develop. This problem could often be overcome if power generation were emphasized as an initial market. Some of the large revenues generated in power sales could be used to pay for the construction of the gas delivery system, thereby helping to make gas available to other users at reasonable cost.[109]

Its low capital cost makes the gas turbine an especially attractive technology for developing countries in light of the unaffordabiliy of capital investments for electricity based on conventional sources (Table 5.1).

Not only are the overall capital requirements small for these advanced gas turbine power plants, but also, many industrializing countries could draw on indigenous management and engineering talent for much of the design and construction effort required. The power turbine, the heat recovery steam generator, and the electrical generator, as examples, are system components that can be readily manufactured in many parts of the world. The part of the system for which it may be difficult to avoid expenditures of foreign exchange is the "gas generator," the "high technology" part of the system that is derived from a jet engine. The gas generator actually accounts for only a modest fraction of the total power plant cost; the mass-produced CF6 jet engine, from which LM-5000 STIG and ISTIG units would be derived, costs only about $6 million -- thus contributing only $53 per kW to the cost of the ISTIG unit.[110]

The scale characteristics of aeroderivative turbines are also well suited to developing countries. In most developing countries, the total utility grid capacity is too small to be well matched to much larger hydroelectric or steam-electric power plants. Adding new capacity in small increments with gas turbines makes it possible to avoid the alternating periods of power glut and power shortage associated with utility planning based on large plants and can lead to improved system reliability.

The compact, modular nature of aeroderivative turbines makes it possible to replace failed parts and even whole engines quickly with replacements flown or trucked in from centralized maintenance facilities.[111] This feature of the aeroderivatives is especially attractive for many developing countries, where sophisticated maintenance capability is typically unavailable at power generating sites. The required maintenance

network is already in place in most developing countries that have their own commercial airlines; their planes are typically maintained through centralized lease-pool arrangements. This advantage is reflected, for example, in the fact that of the 210 General Electric LM-2500 aeroderivative turbines in service throughout the world as of 1986, 54, 8, and 26 were being used in developing countries of Latin America, Africa, and Asia, respectively (personal communication from L. Gelfand, Marine and Industrial Turbine Division, General Electric Company, Cincinnati, Ohio, February 1987).

Conclusion

For the next two to four decades, advanced gas turbines offer multiple benefits for power generation. The prospects of reducing electric power costs in both industrial and developing countries, of reducing local air pollution and acid rain emissions to low levels, of reducing carbon dioxide emissions to levels considerably below those associated with coal-fired steam-electric plants, and of avoiding the risks of expanded dependence on nuclear power, are benefits not easily matched by alternatives.

While the benefits resulting from the wide use of heavy-duty industrial gas turbines would be large, there are good reasons for also bringing advanced aeroderivative turbines into wide use. It appears that controlling pollutant emissions responsible for acid rain to very low levels would be more readily accomplished with various advanced aeroderivative turbines than with combined cycles. Also, with aeroderivatives the advantages of high efficiency and low unit capital costs can be extended to modest scale, resulting in greater flexibility in capacity planning, improved reliability, and ease of maintenance. And the small size of aeroderivatives makes it possible to reverse the trend in power technology toward costly field construction and bring most construction work back to the factory, where the economies of mass production can be exploited. Moreover, aeroderivative turbines will continue to benefit more directly from improvements in jet engine technology than heavy-duty industrial turbines.

Wide use of advanced gas turbines would *not* solve the electric power problem for all time. Eventually, the tightening of world gas supplies and concerns about the atmospheric buildup of carbon dioxide will limit the attractiveness of further expanding the use of these engines for power generation with fossil fuels. However, a major shift to fossil fuel-fired gas turbines for power generation in the decades immediately ahead would buy time to develop alternative clean power sources for the long term.

1. Hass, J.E., Mitchell, E.J., and Stone, B.K., *Financing the Energy Industry*. Cambridge, Mass., Ballinger, 1974.

2. In this paper conversions to 1987 dollars were made using the US gross national product deflator, if original data were in the nominal dollars of other years.

3. International Energy Agency, *Electricity in IEA Countries: Issues and Outlook*, Paris, 1985.

4. Electric Power Research Institute, *Technical Assessment Guide. 1: Electricity Supply -- 1986*, Palo Alto, Calif, 1986.

5. Hass, et al., op. cit.

6. International Energy Agency, op. cit.

7. Electric Power Research Institute, op. cit.

8. Schneider, H.K., *Investment Requirements of the World Energy Industries 1980-2000*. London, England, World Energy Conference, 1987.

9. The WEC capital expenditure estimates are for electricity demand growth rates for developing countries in the range of 4.5% to 6.8% per year, 1980-2000. For comparison, the growth rate has averaged about 7% since 1980, and the long-term historical average growth rate has been about 9% per year.

10. Fisher, J.C., *Energy Crises in Perspective*, New York, Wiley, 1974.

11. Loose, V.W., and Flaim, T., "Economies of Scale and Reliability: the Economics of Large Versus Small Generating Units." *Energy Systems and Policy*, Vol. No. 4 (1-2), pp. 37-56, 1980.

12. Duffy, T.E., Schneider, P.H., and Campbell, A.H, *Advanced High Performance Steam Systems for Industrial Cogeneration*, Solar Turbines International, Washington, D.C., US Dept. of Energy, 1986.

13. Electric Power Development Co., Ltd., *Wakamatsu 50 MW Demonstration Plant for Fluidized-Bed Combustion Boiler and Ultrasuper Critical Turbine*. Kyushu, Japan, Wakamatsu Coal Utilization Center, 1988.

14. Combustion Eng., Inc., *Combustion: Fossil Power Systems*, Windsor, Conn., Rand McNally, 1981.

15. Fraas, A.P., *Engineering Evaluation of Energy Systems*, New York, McGraw-Hill, 1982.

16. Wolfe, W.R., *Energy Conversion Alternatives Study (ECAS), Westinghouse Phase I Report, vol. XI: Advanced Steam Systems*, NASA, 1976.

17. El-Sayed, Y.M., and Tribus, M., *A Theoretical Comparison of the Rankine and Kalina Cycles*, Cambridge, Mass., Center for Advanced Engineering Study, Massachusetts Institute of Technology, 1986.

18. Mechanical Technology, Inc., *Technology Assessment of Advanced Power Generation Systems II -- Kalina Bottoming Cycle*, Palo Alto, Calif., Electric Power Research Institute, 1986.

19. Rankin, B., "Revolutionary Power Plant to Get Its Day in the Sun, *New Technology Week*, Dec. 21, 1987, p. 5.

20. Mechanical Technology, Inc., op. cit.

21. Gluckman, M.J., *The Future of Gas Turbine-based Power Generation in the United States*, Paper presented at the 1988 ASME COGEN-TURBO II International Symposium & Exposition, Montreux, Switzerland, American Society of Mechanical Engineers, 1988.

22. Electric Power Research Institute, op. cit.

23. Energy Information Administration, *Historical Plant Cost and Annual Production Expenses for Selected Electric Plants 1985*, Washington, D.C., 1987.

24. Fraas, op. cit.

25. Ibid.

26. Energy Information Administration, 1987, op. cit.

27. Bureau of the Census, US Dept. Commerce, *Statistical Abstract of the United States, 1987*. Washington, D.C., 1987.

28. Directorate for Inf. Oper. and Rep. Annual. Prime contractor awards by service category and federal supply classification. Washington, D.C., US Dept. of Defense.

29. A significant difference between the steam turbine and the gas turbine is that the maximum temperatures of the metal and the working fluid are oppositely related for these technologies. In steam turbine systems the maximum temperature of the metal is always higher than that of the working fluid; thus metallurgical contraints that limit the maximum metal temperature make it difficult to increase efficiency by increasing the working fluid temperature. But in gas turbine-based cycles the metal temperature is lower than that of the working fluid, and the difference between these temperatures is increasing continually with improvements in turbine blade cooling technology, leading to continual improvements in efficiency.

30. Energy Information Administration, *Annual Energy Outlook 1987*, with projections to 2000, Washington, D.C.

31. Brandt, D.E., "Heavy-Duty Turbopower: the MS7001F." *Mechanical Engineering*, July, 1986, pp. 28-36.

32. Ibid.

33. "Can Gas Turbines Be Twice as Good?" *Global Gas Turbine News*, April 1987.

34. General Electric's LM-5000 is the 33 MW aeroderivative gas turbine which provided the basis for the first design of a 110 MW intercooled steam-injected gas turbine (ISTIG). [See Engineering Department, Pacific Gas and Electric Co., *Scoping Study: LM5000 Steam-Injected Gas Turbine*. Based on work performed by the Mar. and Ind. Engine Proj. Dept. (Evendale, Ohio) of the General Electric Co., 1984.] The LM-5000 in turn is derived from the CF6 turbofan jet engine which sells for $6 million. (See Ungeheuer, F. 1988, and "They Make Good Things for Flying," *Time*, May 2, p. 55.) As the CF6 weighs 4770 kg, it is indeed costly on a per unit mass basis -- $1260 per kg. (For comparison, at the time of this writing, gold and silver were selling on the world market for $14,500 and $225 per kg, respectively.) But this "high technology" part of ISTIG contributes only $53 per kW or 13% of its estimated installed cost of $400 per kW (Table 5.2).

35. Complete inspection (with any necessary replacements) of the hot section of a GE LM-2500 aeroderivative turbine requires a crew of five working 100 person-hours. [See Jackson, J., *Aircraft-Derivative Gas Turbine Maintenance Practices*, Schenectady, N.Y., General Electric Gas Turbine Division, 1984.] The same job requires a six-person crew working 480 person-hours for a GE Series 5000 industrial turbine that has a comparable output. [See Knorr, R., *Heavy-Duty Gas Turbine Maintenance Practices, Schenectady, N.Y., General Electric Gas Turbine Division, 1984.]*

36. This possibility arises because the gas generator, the "high technology" part of an aeroderivative engine, for which maintenance is most crucial, is easily transported. The gas generator for the largest aeroderivative turbine available, General Electric's LM-5000, weighs just 4770 kilograms and measures only 1.8 m x 2.1 m x 4.6 m.

37. N.J. Energy Conservation Laboratory, *Report on the NJECL Workshop on Steam-Injected Gas Turbines for Central Station Power Generation, eds. Larson, E.D., and Williams, R.H., Princeton, N.J., Center for Energy and Environmental Studies, Princeton University, 1986.*

38. Energy Information Administration, 1987, op. cit.

39. N.J. Energy Conservation Laboratory, op. cit.

40. Ibid.

41. The injected water must be treated to avoid turbine blade corrosion problems. Because the minimum water treatment level required is not yet known (N.J. Energy Conserv. Lab., op. cit.), present practice is to be conservative. Even so, water treatment costs are minor. For STIG cogeneration units based on the Allison 501-KH, water treatment costs

have been estimated to be 0.09 cents per kWh (for 1.63 liters per kWh and water treatment costs of 0.05 cents per liter, personal communication from Koloseus, C., International Power Technology, Inc., April 1985). For central- station STIG units based on the GE LM-5000, the capital cost for make-up and waste-water treatment (based on typical river water quality in the Eastern US) has been estimated to be less than $20 per kW, some 5% of the total installed cost. (See Soroka, G.E., Bechtel Eastern Power Corp., Modular Remotely Operated Fully Steam-Injected Plant for Utility Application, Paper presented at the ASME Cogen-Turbo Conf. Montreux, Switzerland, American Society of Mechanical Engineers, Sept. 1987.

42. Larson, E.D., and Williams, R.H., "Steam-Injected Gas Turbines," *ASME J. Eng. for Gas Turbines and Power*, Vol. 109, No. 1, 1987, pp. 55-63.

43. Larson, E.D., and Williams, R.H., *A Primer on the Thermodynamics and Economics of Steam-Injected Gas-Turbine Cogeneration*, PU/CEES Report No. 192. Princeton, N.J.: Center for Energy and Environmental Studies, Princeton University, 1985.

44. Leibowitz, H., and Tabb, E., "The Integrated Approach to a Gas Turbine Topping Cycle Cogeneration System," *ASME J. Eng. Gas Turbines and Power*, Vol. 106, 1984, pp. 731-36.

45. Allen, R., and Kovacik, J., "Gas Turbine Cogeneration -- Principles and Practice," *ASME J. Eng. Gas Turbines and Power*, Vol 106, 1984, pp. 725-30.

46. Touchton, G., "Influence of Gas Turbine Combustor Design and Operating Parameters on Effectiveness of NOx Suppression by Injected Steam or Water." *ASME J. Eng. Gas Turbines and Power*, Vol. 107, 1985, pp. 707-13.

47. Diamant, R.M.E., *Total Energy*, New York, Pergamon, 1970.

48. Hayward, R.W., *Analysis of Engineering Cycles*, New York, Pergamon, 1980.

49. Leibowitz and Tabb, op. cit.

50. Maslennikov, V., and Shterenberg, V.Y., "Power Generating Steam Turbine-Gas Turbine Plant for Covering Peak Loads," *Thermal Eng*, Vol. 21, No. 4, 1974, pp. 82-88.

51. Fraize, W.E., and Kinney, C., "Effects of Steam Injection on the Performance of Gas Turbine Power Cycles," *J. Eng. Power*, Vol 101, 1979, pp. 217-27.

52. Davis, F., and Fraize, W., *Steam-Injected Coal-Fired Gas Turbine Power Cycles*, MTR-79W00208. McLean, Va., Mitre Corp., 1979.

53. Brown, D.H., and Cohn, A., "An Evaluation of Steam-Injected Combustion Turbine Systems." *J. Eng. Power*, Vol. 103, 1981, pp. 13-19.

54. Kosla, L., Hamill, J., and Strothers, J., "Inject Steam in a Gas Turbine -- But Not Just for NO_x Control." *Power*, Feb. 1983.

55. Digumarthi, R., and Chang, C.N. 1984. "Cheng-Cycle Implementation on a Small Gas Turbine Engine," *J. Eng. Gas Turbines and Power*, Vol. 106, 1984, pp. 699-702.

56. Jones, J.L., Flynn, B.R., and Strother, J.R., *Operating Flexibility and Economic Benefits of a Dual-Fluid Cycle 501-kb Gas Turbine Engine in Cogeneration Applications*, Paper 82-GT-298. N.Y., American Society of Mechanical Engineers, 1984.

57. Nicolin, C., "A Gas Turbine with Steam Injection," *Swedish Patent Application No. 8112/51*, Stockholm, 1951.

58. Larson and Williams, 1987, op. cit.

59. Cheng, D.Y., "Regenerative Parallel Compound Dual-Fluid Heat Engine," *US Patent No. 4,128,994*. Washington, D.C., 1978.

60. Cheng, D.Y., "Control System for Cheng Dual-Fluid Cycle Engine System," *US Patent No. 4,297,841*. Washington, D.C., 1981.

61. Larson and Williams, 1987, op. cit.

62. Burnham, J.B., Giuliani, M.H., and Moeller, D.J., *Development, Installation, and Operating Results of a Steam Injection System (STIG) in a General Electric LM 5000 Gas Generator*, Paper 86-GT- 231, presented at the International Gas Turbine Conference and Exhibition, Dusseldorf, West Germany, American Society of Mechanical Engineers, June 8-12, 1986.

63. Oganowski, G., *LM 5000 and LM 2500 Steam Injection Gas Turbine*, presented at the International Gas Turbine Congress, Tokyo, Gas Turbine Society of Japan, Oct. 26-31, 1987.

64. Ibid.

65. Soroka, G.E. (Bechtel Eastern Power Corp.), *Modular Remotely Operated Fully Steam-Injected Plant for Utility Application*, paper presented at the ASME Cogen-Turbo Conference, Montreux, Switzerland, American Society of Mechanical Engineers, Sept. 1987.

66. Brandt, op. cit.

67. The intercooled STIG could also be used for cogeneration. An ISTIG unit based on the LM-5000 would produce about twice as much steam in the heat recovery steam generator as a STIG unit, largely because the turbine exhaust flow would be increased 26%, and its temperature would be increased from 395 to 441°C. [See Eng. Dept., Pacific Gas and Electr. Co. 1984. Scoping study: LM5000 steam-injected gas turbine. Based on work performed by the Mar. and Ind. Engine Proj. Dept. (Evendale, Ohio) of the Gen. Electr. Co.] About 44% of the produced steam would have to be injected for NO_x control and cooling of the combustor. The rest, some 27,200 kg/hour at 41.3 bar plus 15,400 kg/hour

at 13.8 bar, could be used for process. In the full cogeneration mode the electrical output of the ISTIG unit would be 97 MW, and electricity production would represent 42.3% of the higher heating value of the fuel input (personal communication from M. Horner, General Electric Company, September 1988).

68. The LM-8000 is based on an upgraded version of the CF6 jet engine, the CF6-80C2, for which production totalled 110 engines in 1987 and is expected to be 260 engines in 1988. (See Ungeheuer, F., "They Make Good Things for Flying," *Time*, May 2, 1988, p. 55.)

69. Horner, M.W. [Mar. and Ind. Eng. and Serv. Div. (Cincinnati, Ohio) of the Gen. Electr. Co.]. 1988. Position statement - intercooled steam-injected gas turbine. Testimony presented at the Committee Hearing for the 1988 Electricity Report of the Calif. Energy Comm., held at the So. Calif. Edison Co., November 21-22, 1988.

70. Rice, I.G., "Combined Cycle, Reheat Gas Turbine, and Steam Cooling," testimony before the California Energy Commission, Hearing Docket No. 89-FR-1, Sacramento, Calif., July 17, 1989.

71. Janes, C.W., "Increasing Gas Turbine Efficiency Through the Use of a Waste Heat Methanol Reactor," *Proc. 14th Intersoc. Energy Convers. Eng. Conf.* 2: 1968-1972, 1979.

72. Tsuruno, S., and Fujimoto, S., "Gas Turbine Cycle with Steam Reforming of Methanol," Paper 87-Tokyo-IGTC-83, presented at the 1987 Tokyo International Gas Turbine Congress, Tokyo, Japan, Gas Turbine Society of Japan, Oct. 26-31, 1987.

73. Klaeyle, S., Laurent, R., Nandjee, F. May 31 - June 4, 1987. *New Cycles for Methanol-Fueled Gas Turbines*. Paper 87-GT-12. Presented at the Int. Gas Turbine Conf. and Exhib. Anneheim, Calif.: Am. Soc. Mech. Eng.

74. Mar. and Ind. Eng. and Serv. Div. (Cincinnati, Ohio) of the Gen. Electr. Co., *Advanced Chemically Recuperated Gas Turbine Cycle Evaluation Project: Preliminary Assessment of the System Concept*, Work sponsored by the Calif. Energy Commission, December 1988.

75. Rice, op. cit.

76. Engineering Department, Pacific Gas and Electric Co., *Scoping Study: LM5000 Steam-Injected Gas Turbine*, based on work performed by the Mar. and Ind. Engine Proj. Dept. (Evendale, Ohio) of General Electric Co., 1984.

77. Cohn, A., *Steam-Injected Gas Turbines Versus Combined Cycles. EPRI J.* Vol., 13, No. 5, 1988, p. 40.

78. See note 41.

79. Cohn, op. cit.

80. For an ISTIG unit operated on natural gas about two-thirds of the water vapor in the exhaust stream would have to be recovered to reduce makeup water requirements to zero, at zero relative humidity. The rest of the water vapor in the exhaust is a product of fuel combustion.

81. Corman, J.C., *System Analysis of Simplified IGCC Plants*, report prepared for the US Department of Energy by General Electric Corp. Research and Development, Schenectady, N.Y., 1986.

82. Argonne National Laboratory, *An Assessment of the Natural Gas Resource Base of the United States*. Washington, D.C.: Off. Policy, Planning, and Analysis, US Department of Energy, 1988.

83. Adelman, M.A., and Lynch, M.C., "Natural Gas Supply in Western Europe." *Western Europe Natural Gas Trade, Final Report*. Cambridge, Mass., International Natural Gas Trade Project, Center for Energy Policy Research, Energy Laboratory, Massachusetts Institute of Technology, 1986.

84. Williams, R.H., and Larson, E.D., "Expanding Roles for Gas Turbines in Power Generation," *Electricity: Efficient End-Use and New Generation Technologies, and Their Planning Implications*, eds. T.B. Johansson, B. Bodlund, and R.H. Williams, Lund, Sweden, Lund University Press, 1989.

85. Peters, W., "Coal Gasification Technologies for Combined Cycle Power Generation." *Electricity: Efficient End-Use and New Generation Technologies, and Their Planning Implications*, eds. T.B. Johansson, B. Bodlund, and R.H. Williams, Lund, Sweden, Lund University Press, 1989.

86. Williams and Larson, 1989, op. cit.

87. The technology proven at Cool Water achieves sulfur removal through the use of a scrubber. Though effective in removing sulfur, this approach requires a cooling of the gas exiting the gasifier and thus a loss of energy efficiency. More advanced techniques that remove the sulfur without cooling the gas ("hot-gas cleanup") are in an advanced state of development but are unproven at commercial scales. (See R.H. Williams and E.D. Larson, 1989, op. cit.)

88. R.H. Williams and E.D. Larson, 1989, op. cit.

89. Fluor Engineering, Inc., *Planning Data Book for Gasification-Combined Cycle Plants: Phased Capacity Additions*, EPRI AP-4395. Palo Alto, Calif., Electric Power Research Institute, 1986.

90. Catina, J.L., and Fortune, H.J. Jr. (Virginia Power), Soroka, G.E. (Bechtel Eastern Power Corp.), *Repowering Chesterfield 1 and 2 with Combined Cycle*, Paper 87-GT-12, presented at the International Gas Turbine Conference and Exhibition, Anaheim, Calif., American Society of Mechanical Engineers, May 31-June 4, 1987.

91. Larson, E.D., Svenningsson, P., and Bjerle, I., "Biomass Gasification for Gas Turbine Power Generation," *Electricity: Efficient End-Use and New Generation Technologies, and Their Planning Implications*, eds. T.B. Johansson, B. Bodlund, and R.H. Williams, Lund, Sweden, Lund University Press, 1989.

92. Williams, R.H., *Biomass Gasifier/Gas Turbine Power and the Greenhouse Warming*, paper presented at the Expert Seminar on Energy Technologies for Reducing Emissions of Greenhouse Gases. Paris, France: IEA/OECD, April 1989.

93. Hubbard, H.M., "Photovoltaics Today and Tomorrow," *Science* Vol. 244, 1989, pp. 297-304.

94. Carlson, D.E., "Low-Cost Power from Thin-Film Photovoltaics," *Electricity: Efficient End-Use and New Generation Technologies, and Their Planning Implications*, eds. T.B. Johansson, B. Bodlund, and R.H. Williams, Lund, Sweden, Lund University Press, 1989.

95. For utility gas turbines consuming more than 100 million Btu per hour (approximately 10 MW) the standard is 75 ppm x (n/25) by volume (@ 15% O_2), where n is the turbine efficiency in percent. The standard for all other continuous-duty gas turbines consuming more than 10 million Btu per hour and producing less than 30 MW is 150 ppm x (n/25).

96. The toughest proposed standards in the US are those proposed in August, 1988, by the South Coast Air Quality Management District (SCAQMD) in California: an emission level of 9 ppm x (n/25) for all new stationary gas turbines with capacities greater than 0.3 MW (tentative adoption date: January 1989) and an emission level of 12 ppm x (n/25) for existing turbines, within 30 months of the adoption date. The proposed standards are part of the proposed SCAQMD plan to bring the greater Los Angeles area into compliance with the US ambient air quality regulations established under the Clean Air Act. (See South Coast Air Quality Management District (El Monte, Calif.). May 13, 1988. Proposed Rule 1134 -- *Control of Oxides of Nitrogen Emissions from Stationary Sources*.)

97. Fraize and Kinney, op. cit.

98. Rice, op. cit.

99. Sidebotham, G.S., and Williams, R.H., *Preliminary Report on NO_x and Cogeneration in New Jersey*, Princeton, N.J., Center for Energy and Environmental Studies, Princeton University, 1989.

100. Office of Technology Assessment, *Acid Rain and Transported Air Pollutants: Implications for Public Policy*. Washington, D.C., 1984.

101. Williams and Larson, op. cit.

102. Ibid.

103. World Bank, *The Energy Transition in Developing Countries*, Washington, D.C., 1983.

104. Energy Information Administration, 1988, op. cit.

105. Ibid.

106. The breakeven price is determined by setting the levelized busbar cost from a natural gas-fired ISTIG unit equal to the operating cost of an existing steam-electric plant, assuming a 46% capacity factor for the ISTIG unit, the same fuel price for both plants, and an O&M cost of 4.0 mills per kWh for the existing steam plants [the average value in the US in 1985 (Energy Inf. Admin., 1987, op. cit.)].

107. Energy Information Administration, 1988, op. cit.

108. California Energy Commission Staff, *Resource Case Analysis Report*, testimony presented at the Committee Hearing for the 1988 Electricity Report of the California Energy Commission, held at Southern California Edison Co., November 21-22, 1988.

109. Schramm, G., "The Changing World of Natural Gas Utilization," *Natural Resources Journal*, Vol. 24, 1984, pp. 405-36.

110. See note 34.

111. See note 36.

ACKNOWLEDGMENT

The authors gratefully acknowledge partial support from the Office of Energy of the US Agency for International Development for the research upon which this chapter is based.