STEAM-INJECTED GAS TURBINES

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ABSTRACT

Among cogeneration and central station power generating technologies, gas turbine systems are attractive largely because of their low capital cost and simplicity. However, poor part-load efficiencies have restricted simple cycle gas turbines largely to baseload cogeneration applications, while relatively low efficiencies for the production of power only have restricted gas turbines largely to peaking central station applications. Steam-injected gas-turbines overcome cogeneration part-load problems by providing for steam in excess of process requirements to be injected into the combustor to raise electrical output and generating efficiency. For central station applications, proposed steam-injected gas turbines would achieve higher efficiencies at smaller capacities than any existing commercial technology, including combined cycles. Their high efficiency and expected low capital cost would make them highly competitive for baseload power generation.

This paper provides an overview of steam-injection technology, including detailed calculations of performance and an assessment of the economic significance of the technology for cogeneration and central station power generating applications.

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INTRODUCTION

Rising electricity prices, the near-term prospect of surplus natural gas supplies, and the provisions of the Public Utility Regulatory Policies Act (PURPA) and ensuing regulations that encourage cogeneration have stimulated a wave of innovation in gas turbine technology. Here the significance of one of these innovations, the steam-injected gas turbine, is assessed for both cogeneration and central station power generation.

STEAM-INJECTED GAS-TURBINE TECHNOLOGY

The steam-injected gas turbine (STIG) cycle involves a variation on the simple gas turbine cycle, wherein steam recovered in a turbine exhaust heat recovery steam generator (HRSG) is injected into the combustor to augment power output and the efficiency of power generation (Fig. 1). Aircraft-derivative units are chosen for this modification because they are designed to produce output considerably in excess of their nominal ratings.

History. Injecting water or steam into a gas turbine is not a new idea. Water injection for short periods of thrust augmentation was at one time common in jet-aircraft engines, although fans now usually serve this purpose (1). It is now standard practice to inject water or steam into stationary gas turbines to control NOx emissions (2,3).

In 1951 a Swedish patent application was filed dealing with steam injection as a means of augmenting power output and efficiency in gas turbine applications (4), but it was rejected in 1953. The STIG cycle is discussed in textbooks (5,6), and the number of publications on the subject has been increasing rapidly (7-14).

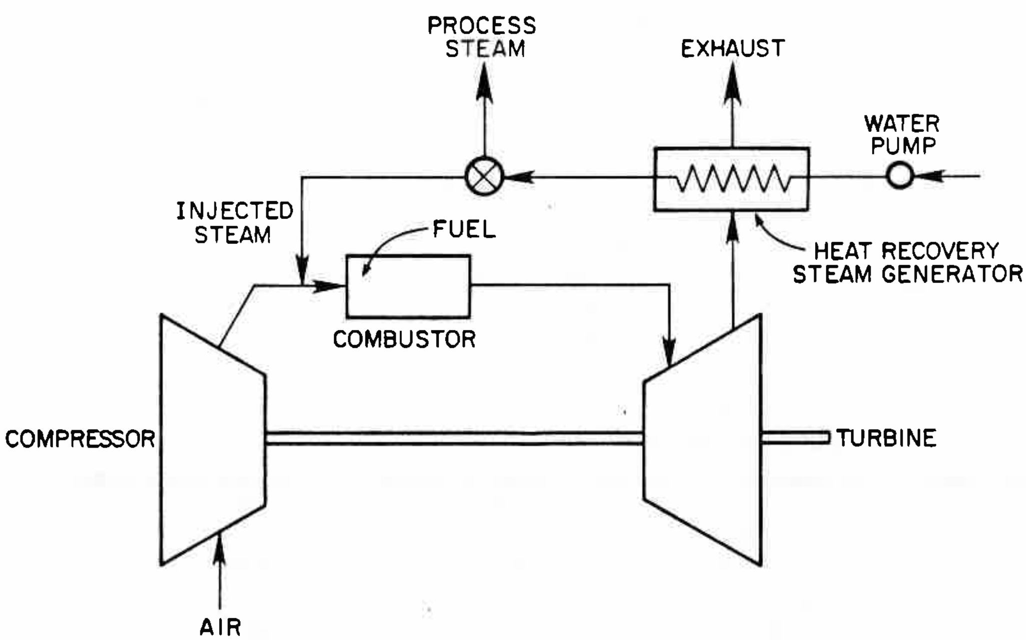

Fig. 1. Schematic of a steam-injected gas turbine cycle.

It is only recently that steam injection for power and efficiency augmentation has attracted commercial interest, following the awarding of several US patents in this area (15,16). Two US companies -- International Power Technology (IPT), Palo Alto, CA (17) and Mechanical Technology, Inc. (MTI), Latham, NY (18) -- now offer packaged STIG cogeneration systems based on the Detroit Diesel Allison 501-KH turbine. As of July 1985, IPT had installed a single unit at San Jose State University, San Jose, California and dual units at a Sunkist Growers, Inc. processing plant in Ontario, CA (19). Also, in 1985 a General Electric LM-5000, which had operated for about a year in a simple-cycle cogeneration mode at a Simpson Paper Company plant in Anderson, California (20), was modified for steam-injected operation.

There are currently no utilities operating steam-injected gas turbines, although at least one large utility is interested in seeing the technology developed (21).

Performance Estimate. The performance of the STIG cycle can be estimated with a "back-of-the-envelope" calculation based on the operating characteristics of the Allison 501-KB (Table 1). As subsequent calculations will show, the peak electrical efficiency for such a system occurs when a mass flow of steam somewhat greater than 15% of the compressor inlet flow is injected into the combustor, which provides a point of departure for this calculation, details of which are given elsewhere (24).

Step 1: Reference: A simplified calculation indicates that an Allison 501-KB turbine in a simple cycle with air as the working fluid will produce about 3350 kW of electricity at an efficiency of 24%.*

Table 1. Estimated operating characteristics of simple-cycle Detroit-Diesel Alison 501-KB and General Electric LM-5000 turbine-generator sets.

	Allison 501-KB (a)	GE LM-5000 (b)
Compressor		
Pressure Ratio	9.3	27.6
Air Flow [kg/s (lb/s)]	14.7 (32.3)	126 (277)
Adiabatic Efficiency	0.83	0.88
Turbine		
Turbine Inlet Temperature [^{o}C (^{o}F)]	982 (1800)	1205 (2200)
Adiabatic Efficiency	0.90	0.91
Gearbox-Generator Efficiency	0.93	0.98

(a) Data are compiled from references 13,14,22, and 23.
(b) Data are estimated from reference 21.

Step 2: "Free" Extra Mass: One result of injecting steam is to increase the mass flow through the turbine. Suppose first that 15% additional air, not steam, is supplied in an unspecified manner to the turbine inlet at the required temperature and pressure. The added mass causes back-pressuring of the compressor and hence an increase of about 22% in the compression ratio. The net effect of the increased compression

* Higher heating values are used for fuels in this paper.

ratio and turbine mass flow would be to increase the output and efficiency to 4625 kW and 34%, respectively.

Step 3: Paying for the Extra Mass: The efficiency increase is large in step 2 because no account was taken of the heat needed to raise the extra mass to the turbine inlet conditions.* While enough energy can be recovered from the turbine exhaust to create steam for injection, additional heat must be supplied in the combustor to heat the steam from its injection temperature to the turbine inlet temperature. Providing the fuel for this extra heating reduces the efficiency to 31%.

Step 4: The Specific Heat Effect: Because the constant pressure specific heat of steam is about double that of air, the specific heat of the mass flowing through the turbine is about 25% higher than that for air alone. The effect of the higher specific heat is to raise output to 5420 kW and efficency to 35%

Summary: This "back-of-the-envelope" calculation illustrates that the most significant contribution to enhanced efficiency and output is the provision of extra working fluid without additional compressor work, and that the high specific heat of steam leads to still further gains.

More Formal Calculations. To more accurately calculate STIG-cycle performance requires detailed information on the operating characteristics of particular engines and HRSGs. The results of a more formal calculation for the Allison 501-KH (24), based on reasonable estimates for these, will now be summarized.

A parameter which serves to illustrate well the operation of a STIG unit is the injected steam flow, expressed as a fraction of the compressor air flow. To calculate cycle efficiency and net power output as functions of this parameter, the compressor discharge temperature and work requirements are first determined as in the case of a simple Brayton cycle, but with the compression ratio expressed as a function of the steam-air ratio. Then, with the turbine inlet temperature specified, the turbine calculation can be performed to give the turbine outlet temperature and work output, also using the simple-cycle procedure, but adjusted values for the specific heat parameters to account for the added steam.

With the turbine exhaust temperature, the HRSG pressure, and the steam flow rate specified, the enthalpy of steam exiting the HRSG (typically through a superheater to recover as much heat as possible) is determined by the HRSG pinch-point temperature difference (25). If the difference between the turbine outlet temperature and the temperature of the injected steam calculated for the specified enthalpy and pressure is less than a specified minimum (set by hardware considerations), then the steam temperature is instead set equal to the turbine outlet temperature minus the specified minimum, which implies an increase in the pinch point temperature difference. The total energy added in the combustor to heat the compressor discharge air and the injected steam up to the specified turbine inlet temperature can then be calculated.

Figure 2 shows the results of a sample calculation based on an Allison

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* Since the injected fluid is actually steam, the work required to raise the injected mass to the turbine inlet pressure can be neglected, as pumping the feedwater to boiler pressure requires negligible work compared to compressing air.

501-KH turbine (Table 1) and a HRSG consisting of an economizer, boiler, and superheater. The calculated peak cycle efficiency occurs at a steam-to-air ratio of about 0.17. Up to this value, the superheat temperature of the steam is constrained by the specified minimum temperature difference between the turbine exhaust and the superheater exit, as there is enough energy and "temperature" in the turbine exhaust to heat all of the steam to the maximum allowable value. At low steam-air ratios, the pinch-point temperature difference is far above the assumed design value, indicating that much of the turbine exhaust heat is not being recovered. An increasing steam-air ratio implies a falling pinch point temperature difference, and hence greater heat recovery.

When the steam fraction passes beyond a critical value, the temperature difference between the turbine exhaust and the superheated steam rises dramatically, indicating that there is insufficient energy in the turbine exhaust to raise all of the steam to the specified maximum temperature. Beyond this critical value, the design pinch point temperature difference constrains the exit steam temperature. The additional energy input required to the combustor as a result of the lower injection-steam temperature is not offset by the additional work derived from the larger mass flow through the turbine, resulting in a drop in cycle efficiency.

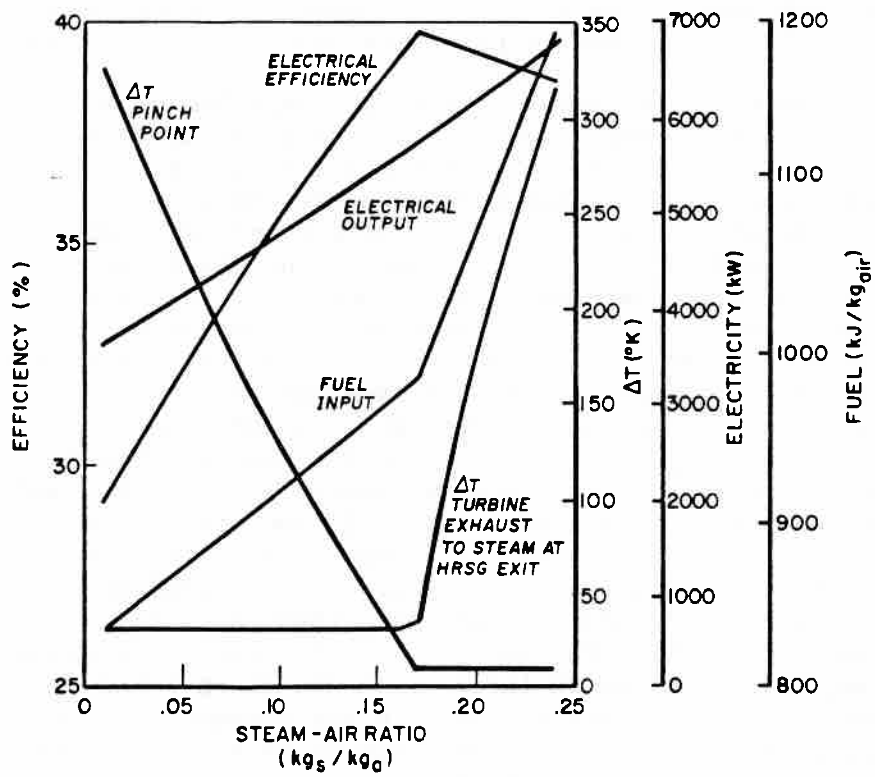

Fig. 2. Illustration of the performance of a steam-injected gas turbine cycle, based on the Allison 501-KH turbine.

Larger STIGs. Detailed performance calculations for larger steam-injected gas turbines, such as ones based on GE's LM-5000, are more complicated than for the Allison 501-KH, in part because they require better accounting for the multiple cooling flows from the compressor to the turbine. A particularly interesting modification of the LM-5000 is a proposed intercooled steam-injected gas turbine (ISTIG). In the ISTIG, steam enters at several points -- into the compressor bleed air used to cool the turbine blades, at the compressor discharge into the combustor, and directly into one or more turbine stages (21). Because of the lower temperature of the compressor bleed air than with the simple cycle (due to intercooling) and the higher heat-carrying capacity of the steam that mixes with the cooling

Table 2. Simplified assumptions of operating characteristics of the LM-5000 ISTIG used for rough calculation of performance (a).

Low pressure compressor:	Pressure ratio	2.8
	Air flow	157 kg/s (345 lb/s)
	Efficiency	0.89
Intercooler:	Air temperature at exit	25°C (76°F)
	Pressure loss	8.3 kPa (1.2 psi)
High pressure compressor:	Efficiency	0.87

Main and cooling air	flow, kg/s (lb/s)	comp. ratio
	123 (271)	12.8
	18.7 (41.2)	8.55
	8.6 (18.8)	5.72
	4.2 (9.3)	2.96
	0.4 (0.8)	1.53
	1.6 (3.5)	1.06

Combustor:	Pressure loss	136 kPa (19.7 psi)
	Injected steam (b): flow	18.1 kg/s (39.7 lb/s)
	temperature	424°C (795°F)
Turbine:	(HP, LP, and Power turbines treated as single unit)	
	Inlet temperature	1355°C (2470°F)
	Efficiency	0.91

Main and cooling air	flow, kg/s (lb/s)	exp. ratio	inlet temp.
4.8 kg/s fuel +	141 (310)	31.14	1628°C (2470°F)
	18.7 (41.2)	20.79	1018 (1864)
	8.6 (18.8)	13.88	951 (1743)
	4.2 (9.3)	7.17	821 (1509)
	1.6 (3.5)	3.73	684 (1263)
	0.4 (0.8)		unrecovered

Gearbox-Generator Efficiency:	0.98

(a) Estimates developed based on reference 21.
(b) For the calculation described in the text, it is assumed that all of the steam is injected into the combustor. The calculation of actual performance is more complicated, largely because multiple steam-injection points are used, including ones leading to entrainment of steam into the cooling air.

air, turbine blade temperatures are expected to remain at an acceptable level, with a turbine inlet temperature of 1355°C (2470°F) (21), up from about 1205° (2200°F) for the simple-cycle LM-5000.

An indication of cycle performance can be obtained using estimated operating characteristics of the LM-5000 and assuming that all of the steam is injected at the compressor discharge. Using the assumptions given in Table 2, the gross electrical output and generating efficiency of the ISTIG cycle are estimated to be 108 MW and 50%, respectively. Detailed evaluations by General Electric indicate that the actual efficiency of the LM-5000 ISTIG will be 47-48%, with an output of 110 MW (26).

COGENERATION

Attraction of Gas Turbines. Historically, the predominant cogeneration technology was the steam turbine, which produces a relatively small amount of electricity per unit of process heat and usually does not lead to electricity production rates in excess of onsite needs. Gas turbines, with electricity-to-process heat ratios typically 4-5 times those of steam-turbines, have a greater potential for generating electricity in excess of onsite needs (27).

With low unit capital costs, even at small scales, and good thermodynamic performance, the simple cycle gas turbine is well suited for cogeneration in capital-intensive, energy-intensive industries characterized by relatively constant steam loads. PURPA, which facilitates the sale of excess electricity to the utility, has made gas turbine cogeneration technology more popular.

Part-Load Operation. The performance of gas-turbines degrades substantially at part-load, however, which reduces the attractiveness of the technology for applications characterized by variable steam loads. For example, Fig. 3, Case C, shows for the Allison 501-KB that the second law

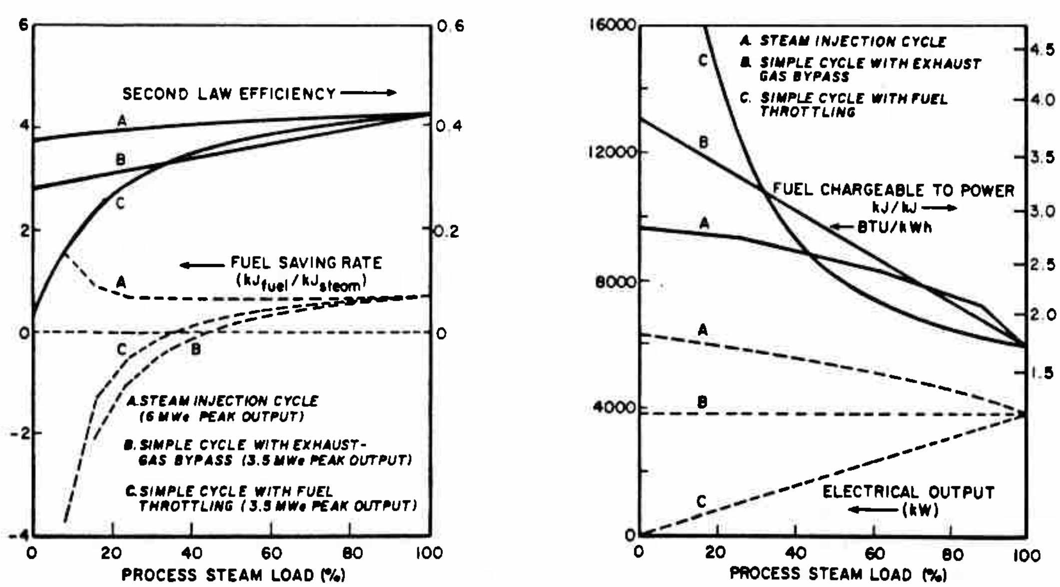

Fig. 3. Estimated part-load performance of a simple-cycle and STIG-cycle gas turbine, based on the Allison 501-KH turbine.

efficiency (24), the fuel savings rate (FSR) (defined as the amount of fuel saved in displacing central station electricity with cogenerated electricity), and the electrical output fall off while the fuel chargeable to power (FCP) rises sharply, as the process steam demand drops and the fuel input to the turbine is throttled. For the more commmon mode of operation, where the hot exhaust gases bypass the HRSG to allow full electrical production to continue at the expense of an increasing FCP, the second law efficiency falls off somewhat more slowly, but the FSR drop is equally sharp (Fig. 3, Case B).

Steam-injected gas-turbines extend the useful range of gas turbines to variable heat load applications by injecting steam not needed for process. With steam injection, as the process load drops, net electrical output increases significantly, the FCP increases only moderately, the second law efficiency remains essentially constant, and the FSR actually rises (Fig. 3, Case A).

Table 3 summarizes the actual performance of an Allison 501-KH turbine exhausting to an unfired HRSG for both the simple and STIG cycles. In the simple-cycle mode, when all steam is directed to process use, the performances of the two systems are indistinguishable. When the process steam load is reduced 50%, however, the steam-injected unit produces 4,750 kW with a FCP of 6220 BTU/kWh (1.82 kJ/kJ), compared to 3,500 kW at 10260 BTU/kWH (3.01 kJ/kJ) for the simple-cycle. In addition, there is only a modest reduction in the second law efficiency (from 37 to 34%) with the STIG compared to the simple cycle (to 30%), reflecting the high thermodynamic value of the extra electricity produced. Furthermore, the simple cycle is saving no fuel compared to the separate generation of steam and electricity, while the STIG cycle saves somewhat more fuel per unit of process steam than when it is supplying the full process steam load. When the process steam load is eliminated, the STIG cycle performance is enhanced further relative to the simple cycle: electrical output is up to 6 MW, and the FCP is still only 9840 BTU/kWh (2.88 kJ/kJ), lower than for large existing central station power plants.

Larger steam-injected gas turbines can perform even better. Rated to produce 33 MW at 33% efficiency in simple cycle operation, the GE LM-5000 has a FCP of 5880 BTU/kWh (1.72 kJ/kJ), a second law efficiency of 42%, and a fuel savings rate double that of the Allison 501-KH. With no process steam demand and full steam injection, it produces 14 additional megawatts with a FCP of 9020 BTU/kWh (2.64 kJ/kJ), compared to 10,210 BTU/kWh (2.99 kJ/kJ) for the simple cycle.

Economics. The good part-load performance of STIG cogeneration systems contributes to attractive economic performance. Consider an application in California, where several STIG units are already installed. Suppose a STIG cogeneration unit replaces purchased electricity and a stand-alone natural-gas fired boiler (83% efficient) producing process steam. To simplify the analysis, a two-level plant load profile is assumed (Table 4).

The installed capital cost incurred to replace an existing stand-alone boiler is estimated to be $5 million for an Allison 501-KH STIG system, with operation and maintenance costs in excess of those for the stand-alone boiler as estimated in Table 4. All subsidies and taxes (investment tax credit, property taxes, etc.) are neglected. Operating cost savings accrue from no longer having to purchase electricity and from being able to sell

Table 3. Performance of gas-turbines in cogeneration using unfired heat recovery steam generators (higher heating value basis).

	Electrical Output (kW)	Effi-ciency	Fuel Charged to Power, BTU/kWh (kJ/kJ) (d)	Electricity-Heat Ratio, kWh/MBTU (kJ/kJ)	Second Law Effi-ciency (e)	Fuel Saving Rate (f)
Allison 501-KH (a)						
Process Steam (c)						
Full						
Simple	3500	0.24	6220 (1.82)	150 (0.51)	0.37	0.57
STIG	3500	0.24	6220 (1.82)	150 (0.51)	0.37	0.57
Half						
Simple	3500	0.24	10260 (3.01)	300 (1.02)	0.30	-0.08
STIG	4750	0.30	8490 (2.49)	400 (1.36)	0.34	0.60
None						
Simple	3500	0.24	14330 (4.20)	--	0.22	--
STIG	6000	0.35	9840 (2.88)	--	0.33	--
GE LM-5000 (b)						
Process Steam (c)						
Full						
Simple	33000	0.33	5880 (1.72)	280 (0.96)	0.42	1.14
STIG	33000	0.33	5880 (1.72)	280 (0.96)	0.42	1.14
Half						
Simple	33000	0.33	8070 (2.37)	560 (1.91)	0.37	1.08
STIG	40000	0.36	7810 (2.29)	670 (2.29)	0.38	1.47
None						
Simple	33000	0.33	10210 (2.99)	--	0.31	--
STIG	47000	0.38	9020 (2.64)	--	0.35	--

(a) Performance figures developed from reference 17.
(b) Performance figures developed from reference 26.
(c) Process steam is saturated at 1.4 MPa (200 psig). Full steam production is estimated to be 9,850 kg/hr (21,670 lb/hr) in the Allison 501-KH and 50,000 kg/hr (110,000 lb/hr) in the GE LM-5000. Feedwater is assumed to be at 65°C (148°F). Injected steam is generally superheated, but accounting for the relatively small difference in enthalpy has little effect on the performance indicators in this table.
(d) Assuming a stand-alone boiler efficiency of 83%.
(e) Assuming feedwater at 65°C (148°F) and an ambient temperature of 15°C (59°F).
(f) The fuel savings rate is a dimensionless ratio defined as the fuel saved by producing electricity (by cogeneration rather than central station generation) per unit of process steam produced.

electricity to the grid at the utility's avoided cost. The rate structure of the Pacific Gas & Electric (PG&E) Company is assumed (28). With prices constant at January 1985 values of $4.46/MBTU ($4.23/GJ) for gas, 10.6¢/peak kWh for purchased electricity, and 8.6¢/peak kWh for the avoided cost payment to cogenerators (28) the real internal rate of return on investment for the STIG system is about 21% per year. However, the rate of return for a simple-cycle system (Table 4) is about as high. Thus, for the assumed rate structure and load profile, there appears to be no great incentive for a plant owner to invest in the STIG system.

However, the cogeneration systems were sized to operate with relatively high capacity factors for a situation involving predictable steam and electricity loads. Actual load profiles may be more variable due to unexpected shut-downs and other load changes that may occur in the future, e.g., due to plant equipment failures, strikes, process changes, steam load reductions from investments in energy efficiency, etc. By expressing such possible load variations in terms of an effective plant idle time, their influence on the internal rate of return can be discerned.

Table 4. Estimated capital and operating costs (1985$) of two gas-turbine cogeneration systems operating in simple-cycle or steam-injected mode.

Turbine	ALLISON 501-KH (a)		GE LM-5000 (b)	
	Simple Cycle	Steam Injected	Simple Cycle	Steam Injected
Gross peak output (MW)	3.5	6.0	33	47
Installed capital cost (million $)	3.6	5.0	21	22
Incremental O&M costs (c)			2 mills/kWh	
Turbine overhaul once every 3 years	$220,000			
Non-turbine maintenance	60,000/yr.			
Technical supervision	40,000/yr.			
Insurance	37,500/yr.			
Treated Water	$2/1000 gal.		$3/1000 gal.	
Plant Life (years)	20		30	
Plant Load Profiles:				
Monday - Friday 7a.m.-6p.m.				
Electricity (kW)	3,500		33,000	
Sat. steam, 1.4 MPa (200 psig), kg/hr (lbs/hr)	9,850 (21,670)		50,000 (110,000)	
All other times				
Electricity (kW)	1,750		16,500	
Sat. steam, 1.4 MPa (200 psig) kg/hr (lbs/hr)	4,925 (10,835)		25,000 (55,000)	

(a) Estimates are from reference 19, except for the capital cost of the simple-cycle unit, which is taken to be 60% of the steam-injected unit's cost (13).
(b) Estimates are from reference 26.
(c) Incremental O&M costs are costs in excess of those incurred to produce steam in an existing boiler.

As the effective idle time increases, the rate of return in a simple-cycle unit drops substantially, but in the STIG system it is largely unaffected, since steam not needed for process can be redirected to produce additional electricity for sale to the utility (Fig. 4). Thus investment in the STIG system instead of the simple-cycle unit under the provisions of PURPA can virtually eliminate the financial risks associated with unforeseen changes in a plant's steam and/or electricity load.

Even under a no idle-time scenario, the STIG system will annually produce about 25% more electricity and save nearly twice as much fuel per unit of process steam generated as the simple-cycle unit. As idle-time rises, the electricity produced increases still further. At 20 weeks, the STIG system will produce 40% more electricity than the simple cycle.

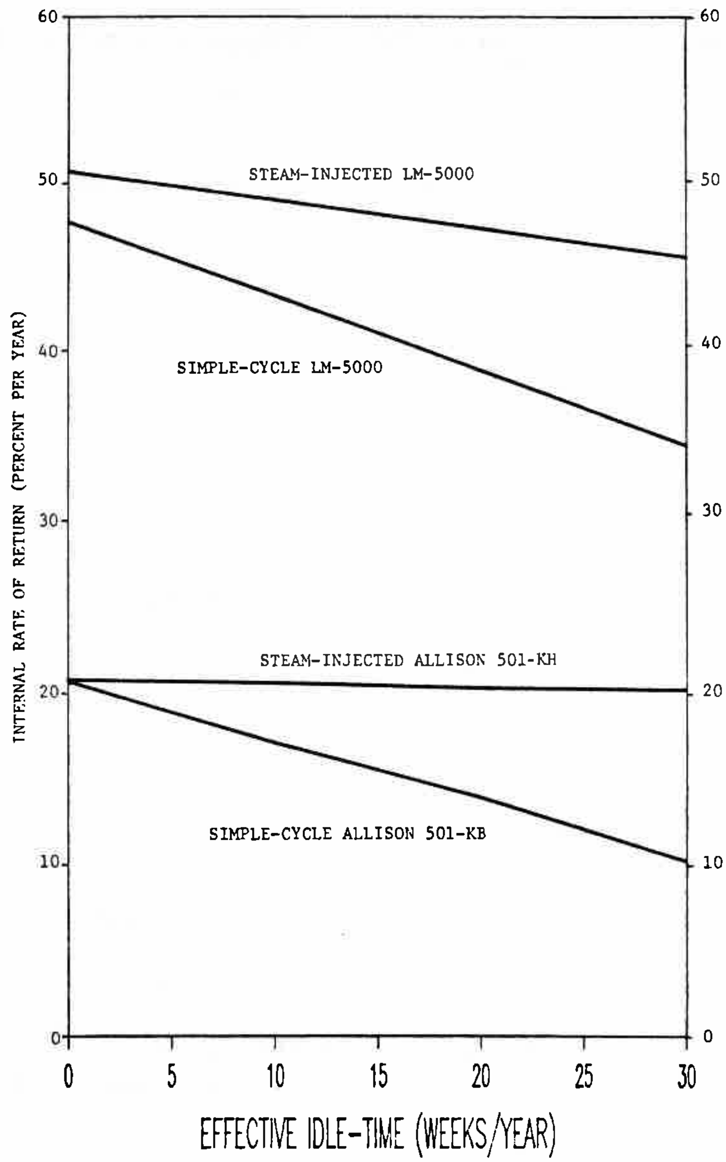

Fig. 4. Internal rates of return on investments in STIG and simple-cycle gas-turbine cogeneration plants.

Higher efficiency and lower unit capital cost lead to a rate of return of over 50% per year under a no idle-time scenario for the LM-5000, based on assumptions similar to those used for the Allison 501-KH (Table 4). For the LM-5000 STIG to give a rate of return as low as 20% in this case would require a real escalation in gas prices of some 3.5-4% per year over the next 30 years, with electricity prices fixed. The rate of return for the simple-cycle starts somewhat lower than for the STIG and falls off more rapidly with increasing idle time (Fig. 4). The LM-5000 STIG will produce annually about 20% more electricity than the simple-cycle, assuming no idle time, while saving nearly 50% more fuel per unit of process steam.

These analyses show that, relative to simple cycle systems, STIG cogeneration systems benefit both the user, through reduced financial risk, and society, through the greater power generating and fuel saving potential.

The economics of STIG cogeneration can also be analyzed in terms of the short-run marginal cost (SRMC) of generation, i.e., the cost of fuel associated with generating excess electricity, to determine when it would be profitable to generate excess electricity for sale to the grid.

Case A -- Without Supplemental Firing: When the process steam load falls in a STIG system, the extra fuel required to produce extra power, when the steam not needed for process is injected, is about 3550 BTU/kWh (1.04 kJ/kJ) for the Allison 501-KH turbine (17) and about 6400 BTU/kWh (1.88 kJ/kJ) for the LM-5000 (based on Table 3). [The lower FCP value is associated with the less efficient machine because of a lower turbine exhaust temperature, by about 60^{o}C (100^{o}F), in the higher pressure ratio LM-5000, which leads to lower injected-steam temperatures. Assuming similar HRSG characteristics, the LM-5000 combustor requires more additional fuel per kg of compressor flow than the Allison 501-KH when operating in the steam-injected mode.]

At the June 1985 US average industrial gas price of $4.09/MBTU ($3.88/GJ) (29), the avoided cost need be only 1.5¢/kWh to make it economical to produce additional electricity for sale to the grid with the Allison system, but about 2.6¢/kWh for the LM-5000.

Case B -- With Supplemental Firing: In the case where excess steam generated in the unfired HRSG is already being injected, the SRMC will determine whether to use supplemental firing to generate even more electricity for sale to the grid.

Supplemental firing in a duct burner can lead to a considerable expansion of the operating regime of a STIG system, defined in terms of electrical output and steam generation. The high air-fuel ratio and turbine exhaust temperature in a gas turbine cycle lead to high combustion efficiencies and corresponding steam-generating efficiencies as high as 86% (11). Duct burners are standard equipment on the systems offered by IPT (17) and MTI (18). IPT advertises that their system, based on the Allison 501-KH, can simultaneously produce between 3.5 and 6 MW of electricity and 0-45 MBTU/hr (13 MW) of process steam (17).

With supplemental firing the incremental FCP is about 15,000 BTU/kWh (4.4 kJ/kJ) and 15,900 BTU/kWh (4.7 kJ/kJ) for the Allison 501-KH and LM-5000, respectively. Using supplemental firing to produce additional electricity for sale to the grid will only make sense therefore if avoided costs are considerably higher than in Case A. However, these values of the FCP are only 10-15% higher than the annual average heat rate for peaking turbines used by utilities (30). Thus, steam-injected cogeneration systems with supplemental firing capability could be used as "zero capital cost" peaking capacity by the utility, provided an agreement could be reached with the cogenerator to make the capacity available on demand.

Significance. Steam-injected gas turbine cogeneration systems are already commercially available in small sizes (17,18) and commercialization of larger units is not far off, as demonstrated by the recent trial operation of an LM-5000 modified for steam-injection at the Simpson Paper plant in California (20), and current active negotiations between General Electric and interested customers for the sale of LM-5000 units delivered as STIGs (31).

This technology increases dramatically the potential for electricity generation via cogeneration, both because it can lead to higher electrical output in situations where simple cycles are economical and because it extends the economic viability of cogeneration to variable load applications. Assessments of the cogeneration potential that do not take this technology into account thus need to be redone.

CENTRAL STATION POWER GENERATION

Status. Further development of steam injection technology could lead to unprecedented power generating efficiencies in small central station power plants. The high efficiency and expected low capital costs of these systems (Table 5) would make them competitive with alternatives under a wide range of conditions.

Recent assessments of the ISTIG concept indicate that with 3-4 years of development work, General Electric's LM-5000 could be developed into an ISTIG producing 110 MW at 47-48% efficiency (26) for an installed capital cost of $400/kW (26) to $500/kW (21).

Potential for Replacing Natural Gas Generating Capacity. Despite the glut in electrical generating capacity in most parts of the US, a signficant near term market for ISTIG could be the displacement of the existing, inefficient, steam-electric generating capacity.

The levelized busbar cost of electricity from an ISTIG plant (including fuel costs, O&M costs, and capital charges) would be less than the operating cost of existing steam plants for gas prices in excess of about $3.20/MBTU ($3.03/GJ).* Since this is less than the average cost of gas to utilities in 1984, some $3.60/MBTU ($3.41) (36), it would typically be worthwhile to retire existing gas-fired steam-electric plants in favor of new ISTIG plants, even for steam-electric plants with many years of remaining useful life.

Shifting to ISTIG systems the 300 TWh of electricity produced in gas-fired steam-plants in 1984 would require some 400 ISTIG units @ 110 MW each, thereby freeing up for other purposes gas supplies equivalent to more than 1/2 million barrels of oil per day. Alternatively, using in ISTIGs the same amount of gas now used for electricity generation would result in

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* Assuming for new ISTIG plants the economic conditions indicated in note (b) to Table 6 and for existing gas-fired steam-electric plants an average heat rate of 10,800 BTU/kWh and an O&M cost of 2 mills per kWh.

additional electricity equivalent to the output of 26 large (1000 MW) coal or nuclear power plants.

ISTIGs Compared to Coal and Nuclear Plants. Even with considerable escalation in the price of natural gas, ISTIGs could compete in many parts of the country with new coal and nuclear plants, the lower fuel costs of which would be more than offset by significantly higher capital costs and lower generating efficiencies (Table 5).

Estimates by the US Department of Energy (DOE) of the levelized busbar costs from power plants entering service in 1995 in different regions of the US, range from 5.2 to 5.8¢/kWh for nuclear electricity and from 3.8 to

Table 5. Comparison of central-station electricity generating technologies.

Technology	Capacity (MW)	Installed Capital Cost 1985 $/kW(a)	Full-Load Heat Rate (HHV) (BTU/kWh) (b)	Time to Install (yrs) (c)	Operating Availabity (%) (d)
Nuclear	1200	2000 (e)	10700	11	61.8
Coal	1200	1200 (e)	10340	8	69.5
Combined Cycle	250	500-600 (f)	8390	4	81.5
Peaking Gas Turb.	150	300 (g)	11600	3	80.6
ISTIG	110	400-500 (h)	7108	3	89.2 (i)

(a) Estimates have been converted to 1985 dollars using the GNP deflator (32).
(b) Estimates of the Electric Power Research Institute (30) except for the steam-injected gas turbine, which is from reference 26.
(c) Estimate of the minimum time required for design, licensing, pre-construction, and construction (30). Time to install the ISTIG is estimated from reference 21.
(d) Data are from the North American Electric Reliability Council (NERC) for the period 1974-1983 (33). The NERC classifies combined cycles with miscellaneous cycles.
(e) Installed capital costs include direct, indirect, contingency, escalation, and interest during construction and are DOE's estimate for the US average for plants entering service in 1995 (34).
(f) The lower estimate is for the 240 MW rated GE Frame 7-E (35). The higher is an estimate for a 2-250 MW unit plant (30).
(g) The estimate is for a 2-75 MW unit plant (30).
(h) Estimated fully-installed capital cost for General Electric's LM-5000 intercooled steam-injected gas turbine ISTIG. The lower estimate is from reference 26. The higher is from reference 21.
(i) The value for ISTIG is actually the NERC data point for aircraft-derivative units (33). The Simpson Paper Company recently completed one year of operating a simple-cycle LM-5000 cogeneration plant with an availability in excess of 98% (20). In their study of the ISTIG, the Pacific Gas and Electric Co. indicates that availabilities in excess of 90% should be attainable with ISTIG (21).

6.0¢/kWh for coal, as shown in Table 6.

Also shown in Table 6 are busbar electricity costs for ISTIG units that would be brought on line in 1990 at a cost of $500/kW. The natural gas prices used in these calculations are the levelized electric utility gas prices, assuming a real gas price escalation rate of 3% per year, 1990-2020, a 10% real discount rate, and base year gas price estimates of the American Gas Association (37). In most regions, the cost of ISTIG-produced electricity would be lower than the DOE estimates for both coal and nuclear power. In some regions ISTIG units would remain competitive at considerably higher gas price escalation rates (Table 6).

Complementing the economic advantages of ISTIG is the flexibility the technology offers utility planners with its short lead times and relatively small size (Table 5), which enable the utility to better match supply expansion to evolving demand, especially in the climate of uncertainty about the future that utility planners face today. In addition, ISTIGs would be nearly as simple as simple-cycle gas turbine plants and would probably have operating availabilities at least as high (Table 5).

ISTIG Compared to Combined Cycles. The ISTIG would far outperform the presently commercialized GE 207-E combined cycle, which produces about 220 MW at 40% efficiency (38) and costs about $500/kW (Table 5). The technology which will come closest to matching the performance and cost of

Table 6. Comparison of estimated regional busbar electricity costs from nuclear, coal, and ISTIG central station power plants.

Region	1985 cents/kWh Nuclear(a)	1985 cents/kWh Coal(a)	1985 cents/kWh ISTIG(b)	Projected 1990 gas prices in 1985$/MBTU ($/GJ) (c)	Real gas escalation rate (%/yr) 1990-2020 for ISTIG cost to match coal cost
New England	5.5	6.0	5.5	4.31 (4.09)	4.3
Middle Atlantic	5.8	5.7	5.2	4.03 (3.82)	3.5
East North Central	5.6	5.5	5.5	4.38 (4.15)	2.2
West North Central	5.5	5.5	4.4	3.15 (2.99)	5.5
South Atlantic	5.4	5.3	4.4	3.15 (2.99)	5.0
East South Central	5.2	5.7	4.5	3.42 (3.24)	5.1
West South Central	5.2	3.8	4.7	3.63 (3.44)	-
Mountain	5.5	4.0	4.7	3.68 (3.49)	-
Pacific	5.8	6.0	6.0	4.91 (4.65)	2.2
U.S. Average			5.1	3.94 (3.73)	

(a) Nuclear and coal busbar electricity costs are for plants entering service in 1995 (34), converted to 1985$ using the GNP deflator (32).
(b) For an ISTIG plant entering service in 1990 and a real gas-price escalation of 3% per year thereafter. An installed capital cost of $500/kW, fixed O&M cost $10.00/kW/yr, and variable O&M cost of 4 mills/kWh are assumed (21). In addition, a discount rate of 10% per year, a plant life of 30 years, a 75% capacity factor, and an ISTIG output of 110 MW @ 48% efficiency are assumed.
(c) From reference 37.

the ISTIG may be the next generation of combined cycles. The Electric Power Research Institute projects that advanced combined cycles firing at 1200^{o}C (2200^{o}F) would have an efficiency of 45%, at a capital cost of about $500/kW (30). The capital cost of the 110 MW ISTIG is estimated to be close to this (Table 5), but its efficiency will be 2-3 percentage points higher. Since another generation of combined-cycle plants will be commercially available within the next 3-4 years, it is reasonable to question the merit of developing an entirely new ISTIG machine, at a cost of perhaps $100 million, for an efficiency gain of only 2-3 percentage points.

If it is assumed that the capital and O&M costs for ISTIGs and the next generation of combined cycles are the same, the efficiency advantage of a 48% efficient ISTIG unit would result in a levelized busbar cost of 5.4¢/kWh, about 5% lower than that of a 45% efficient combined cycle plant, assuming US average natural gas prices for plants brought on line in 1990 (Table 6).

Alternatively, if the busbar costs are equated, the discounted fuel savings over the life of the ISTIG plant would justify a "capital cost premium" of about $170/kW for ISTIG units. Thus, the sale of only 5 or 6 ISTIGs at this extra capital cost would be sufficient to recover $100 million in R&D expenditures.

In addition to the lower busbar costs and the energy savings that would result with ISTIG, a number of other advantages suggest the desirability of developing the technology.

The modular construction of the aircraft-derivative turbines used in STIG systems permits repairs/replacements to be made more rapidly than comparable repairs on the heavy-duty industrial gas turbines typically used in combined cycles: complete inspection (with any necessary replacements) of the hot section of an LM-2500 aircraft-derivative turbine requires a crew of 5 working 100 person-hours (39), compared to a similar procedure on a comparable-output, GE Series 5000 industrial turbine, which requires a 6-person crew working 480 p-hrs (40). Availabilities of aircraft-derivative gas turbine generating plants averaged 89.2%, compared to 80.6% for industrial turbines between 1974 and 1983 (Table 5). The availabilities of the turbines themselves over this period differed even more: 93.7 for aircraft-derivative units, versus 83.5 for industrial turbines (33).

Another practical benefit of steam injection is a relatively low level of NOx emissions, which results from suppression of high flame temperatures in the combustor. It appears that no special stack-gas treatment, e.g., selective catalytic reduction, would be required with STIG units to meet NOx limits imposed by current regulations (21). In recent trial operation of a steam-injected LM-5000 cogeneration unit at the Simpson Paper Company in Anderson, California, NOx emissions were lower than predicted and easily met Northern California's regulations (20,26). Of course, provisions can be made to use steam for NOx control in a combined cycle, but control is inherent in an ISTIG.

Research is continuing on more effective means of turbine blade cooling, which would permit the use of higher turbine inlet temperatures without increases in turbine metal temperatures, holding forth the possibility of still higher efficiencies for the ISTIG (21). Such advances could, of course, benefit combined cycles as well, but because of demanding performance requirements, commercial aircraft-gas turbine technology is already further advanced than industrial turbine technology. Indeed, industrial turbine designers have been borrowing some of the air-cooling technologies originally developed for aircraft engines (41).

Perhaps the most advanced combined cycle power plant in the near future will be one under development by the Japanese as part of a national project that was initiated in 1978. The project centers on the development of a 122 MW advanced reheat gas turbine, consisting of two axial flow compressors, an evaporative-spray intercooler, three turbines, a high-pressure (5.4 MPa) combustor, and a reheater, with a projected efficiency of 47-48 percent (42), in the same range as projected for the ISTIG. The Japanese plan to couple 5 such turbines to one large reheat steam turbine in a 1000 MW combined cycle to reach an efficiency of about 50% (43). This would surpass the efficiency of the first generation of ISTIGs, but would probably do so only at a higher capital cost (21), increased complexity, and much larger size.

If a serious effort were undertaken to develop the ISTIG in this country, the performance of the large Japanese combined cycle might be approached or even exceeded in a simple, compact, 100 MW machine.

Institutional Obstacles. The Power Plant and Industrial Fuel Use Act passed in 1978 (FUA) prohibited the use of natural gas in newly constructed powerplants and required that existing power plants be "off gas" by 1990. Subsequently, the Ommnibus Budget Reconciliation Act of 1981 repealed the requirement that existing power plants be off gas by 1990. Present law thus prohibits the use of natural gas in efficient new utility plants (like ISTIG plants), but permits continued inefficient use of gas in steam-electric plants.

The prospects for repeal of the FUA to permit more efficient use of gas by utilities are uncertain. The law does stipulate that an exemption is obtainable for up to ten years (and possibly beyond) if a plan is in place to convert to an alternative fuel at a later time. The relative ease with which an ISTIG plant can be converted to operation on synthetic gas derived from coal is a particularly important attribute of this technology which may lead some utilities to pursue the technology despite the constraints of the FUA, and indeed is one reason behind PG&E's interest in ISTIG (21). Nevertheless, FUA is an obstacle that will limit the potential markets for ISTIG technology in the US.

POTENTIAL GLOBAL APPLICATIONS

There are vast potential markets for steam-injected gas turbines world-wide, for both cogeneration and central station applications.

Natural gas reserves exist in 50 developing countries, including 30 which import oil. Wellhead gas recovery costs in developing countries have been estimated to be in the range \$0.20 to \$1.40/MBTU (\$0.19-\$1.33/GJ) (44), far lower than the US average wellhead price of \$2.50/MBTU (\$2.37/GJ) in 1984 (36). With such low gas prices ISTIG power plants would often prove to be competitive even with hydroelectric power, currently the lowest cost electricity. In Brazil, for example, the busbar cost of firm baseload power from new hydro-electric facilities in the southeast is about 3¢/kWh (45). ISTIG would be competitive if the utility gas price were less than \$2.30/MBTU (\$2.18/GJ).

It may prove to be feasible to use steam-injected gas turbines with biomass feedstocks as well. The Aerospace Research Corporation (ARC) recently began trial operation of a direct-fired wood sawdust-burning Allison 501-KG at Red Boiling Springs, Tennessee (46), and plans call for increasing output and efficiency with steam injection (47). If the ARC facility proves viable, the availability of biomass-fired STIG plants would be especially important for the many oil-importing developing countries that do not have alternative fossil fuel resources but have the potential for producing wood at relatively low cost on biomass farms or plantations. The use of biomass (a low cost feedstock) in gas turbines (a low capital cost technology) operated with steam injection (providing high efficiency) would be a combination hard to beat, suggesting the importance of developmental efforts in this area (48).

CONCLUSION

The steam-injected gas turbine is an attractive electrical generating technology for mitigating the impacts of rising energy prices. The technology greatly extends the range of cost-effective gas-turbine based cogeneration to include many applications that involve variable and unpredictable process steam loads. For central station applications, the high efficiency of this technology makes it possible to produce electric power competitively and with low environmental impacts when fired with natural gas and relatively costly synthetic fuels. Emphasis on this technology would also stretch out limited oil and gas supplies, buying time to develop alternative electrical technologies for the long term. The steam-injected gas turbine thus stands out as an important technology for the transition to the Post-Petroleum Era.

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