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GE Power Generation

Cogeneration Application Considerations

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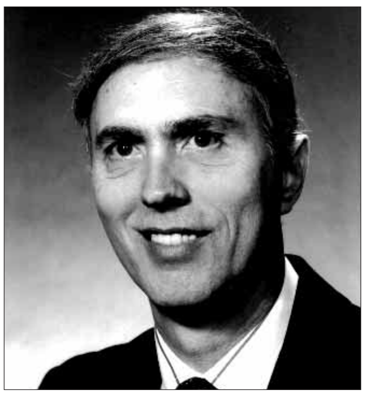
Robert W. Fisk

Robert W. Fisk joined the Corporate Research and Development Center in Schenectady in 1972 as a Development Engineer. He worked at Heat Transfer Products, Large Steam Turbine Division, from 1977 to 1981. In 1981, he moved to Energy Applications Program Department in Schenectady. In 1983, he was appointed Manager – Project Evaluation and Analysis, and in 1992 he was named Manager – Application and Analysis, responsible for providing project application engineering support as well as economic evaluation and screening for all classes of power generation opportunities around the globe. In 1996, Bob's current role was shifted to focus on Global Pricing for units and systems for the Power Systems Business



Robert L. VanHousen

Robert L. VanHousen joined the General Electric Co. in 1969. His experience includes systems application and marketing of gas and steam turbines for electric power generation and mechanical drive applications.

In his present position as Application and Performance Manager, Evaluation and Analysis, he is responsible for system engineering and economic studies relating to the use of turbines in global power generation applications.

He is past chairman of the Industrial and Cogeneration Committee of the International Gas Turbine Institute, American Society of Mechanical Engineers. Bob has developed data books and computer programs, authored numerous technical papers and articles, and conducted training courses relating to the economic selection of turbines in power generation systems.

A list of figures and tables appears at the end of this paper.

COGENERATION APPLICATION CONSIDERATIONS

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INTRODUCTION

Cogeneration is a technology used by many industrials since the beginning of the century as an economic means of meeting plant energy requirements. Prior to the passage of the National Energy Act (NEA), in 1978, most systems within the United States were developed based on site specific heat and power demands. The resultant facilities were commonly referred to as "by-product power generation," or "in-plant generation," and, in some cases, "total energy" systems. More recently, during the 1980's, cogeneration had become a term frequently used to describe projects selling power to US electric utility companies under the provisions of the Public Utilities Regulatory Policy Act (PURPA) of 1978. However, power sale contracts to the local utility are not a prerequisite for cogeneration.

The PURPA legislation provided the user with a greater degree of freedom in developing the cogeneration system since the industrial plant electric power and steam requirements were no longer a constraint on system design.

The NEA and PURPA have spawned an industry in the United States where entrepreneurial firms actively pursue utility power sales opportunities with the steam host assuring the thermal demand necessary for steam qualification (a QF or qualifying facility) as a cogenerator under PURPA. Frequently, large power generation systems are developed with relatively small steam demands.

Prior to 1960, most cogeneration applications were developed based on steam turbine cogeneration systems. More recently, the economic benefits resulting from high power-to-heat ratios, the wide range of system integration options and attractive cogeneration system performance levels have made gas turbines highly desirable prime movers in applications where suitable fuels are economically available. These characteristics have also been instrumental in the development of many large systems involving power sales to electric utility companies.

In 1992, the U.S. Congress passed the Energy Policy Act which amended the Public Utility Holding Company Act of 1935 and created a new class of Independent Power Producers (IPP) called Exempt Wholesale Generators (EWG). The most often stated purpose of the 1992 act is to promote competition in the electric utility industry and allow non-utility producers to compete in this market.

The most recent actions by the (U.S) Federal Energy Regulatory Commission are the Electricity Competition Act of 1996 and Commission Order 888, both of which have further opened the electricity wholesale generation market to virtually all power generation technologies, sizes and applications. These new acts will further initiate changes in ownership of power plants, increase interest in IPPs (power plants with no steam exported to process), increase viability of small generation and cogeneration on-site systems for small industrial, commercial and educational establishments, and change how developers market their power to potential utility buyers. While it is too early to know the impact of this latest piece of legislation, projects within the US will be forced to respond and adapt in their structure and operation. Globally, many countries are beginning to choose privatization or IPPs as a way to achieve energy development in their areas. Governments in many countries are beginning the difficult task of protecting the environment while reaping the benefits of high fuel efficiency with cogeneration.

This paper will review many of the technical considerations in the development of cogeneration systems.

COGENERATION

Cogeneration is frequently defined as the sequential production of necessary heat and power (electrical or mechanical) or the recovery of low-level energy for power production. This sequential energy production yields fuel savings relative to separate energy production facilities. With rapid changes in energy prices in the 1970s and the desire to become more independent of foreign oil in the U.S., the fuel-conserving aspect of cogeneration became a major driver for the increased interest in this technology.

Power can be cogenerated in topping or bottoming cycles. In a topping cycle, power is generated prior to the delivery of thermal energy to the process. Typical examples are non-condensing steam turbine cycles (commonly used in the pulp and paper industry), gas turbine heat recovery and combined cycles (applied in many chemical plants), where the gas turbine exhaust energy is ultimately used for process requirements. In European urban locations where electric power stations also supply city central heating requirements, the exhaust energy from gas turbines can be used as an efficient heat source. In bottoming cycles, power is produced from the recovery of process thermal energy which would normally be rejected to the heat sink. Bottoming cycle examples include power generation resulting from recovery of excess thermal energy and exothermic process reactions, and heat recovery from kilns, process heaters and furnaces. This paper will focus primarily on application considerations for topping cogeneration cycles.

The fuel utilization effectiveness for a modern coal-fired utility plant and an industrial facility utilizing a non-condensing cogenerating steam turbine generator is illustrated in Figure 1. This diagram suggests that the power generation cycle energy losses can be reduced from 65% to 16% of the fuel input through use of cogeneration. In reality, the process becomes the heat sink for the cogeneration cycle, thus minimizing the power cycle energy losses.

Similar performance benefits are also available in gas turbine cogeneration systems. For example, a natural gas-fired MS7001EA gas turbine generator in a combined cycle providing 150 psig/10.3 bars process steam can yield an overall energy effectiveness of about 75% on a higher heating value basis. Clearly, this cogeneration system performance is significantly better than typical steam turbine or gas turbine combined cycles which are designed to only produce power.

The influence of decreasing the thermal energy to a process from a steam turbine cycle is illustrated in Figure 2. As less steam is delivered to process, the electrical output ratio (relative to the electrical output at 100% steam-to-process) increases, becoming a maximum of about 2.0 for the steam conditions noted if no steam is delivered to process. The overall efficiency decreases from 84% to 35% as process steam delivery is eliminated.

Similar evaluations for gas turbine cogeneration systems with unfired heat recovery generally yield overall efficiencies in excess of 70% if all thermal energy generated is delivered to process. This is in contrast to about 50% thermal efficiency on a higher heating value basis for a natural gas-fired STAG 107FA combined-cycle system. In the U.S., this STAG cycle can qualify under PURPA as a cogenerator by providing about 6% of its steam generation to process. At this operating condition, the overall performance approaches that of a STAG 107FA power generation cycle. Later in this paper, guidelines will be given that demonstrate the flexibility in the design of cogeneration systems with gas turbines.

For purposes of the following discussions, "thermally optimized" cogeneration systems are defined as those developed using non-condensing steam turbine generators or condensing units operated at minimum flow to the condenser for cooling purposes.

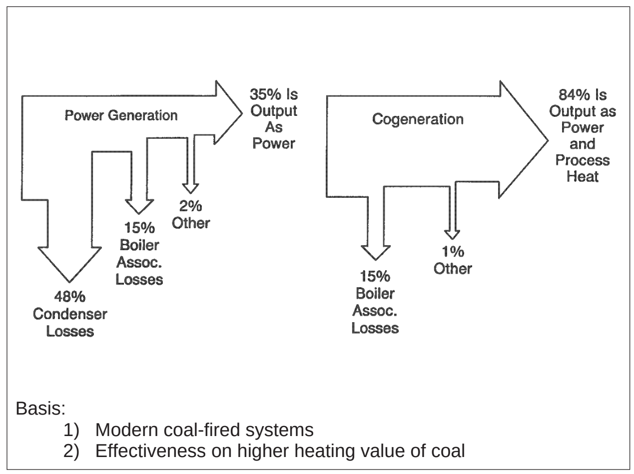

Figure 1. Fuel utilization effectiveness

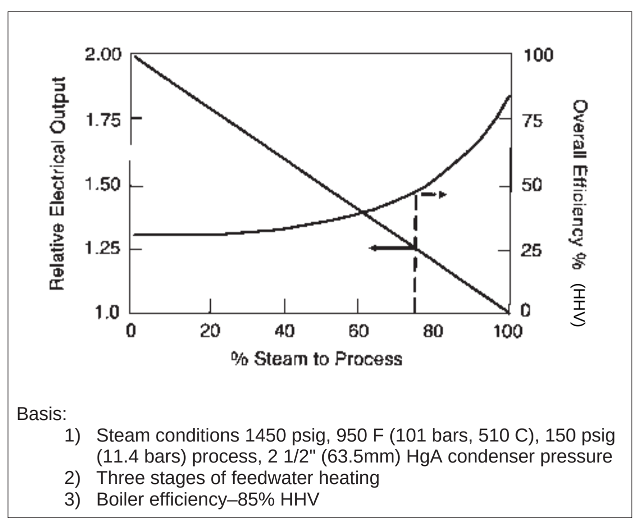

Figure 2. Steam turbine cycle performance at various process steam demands

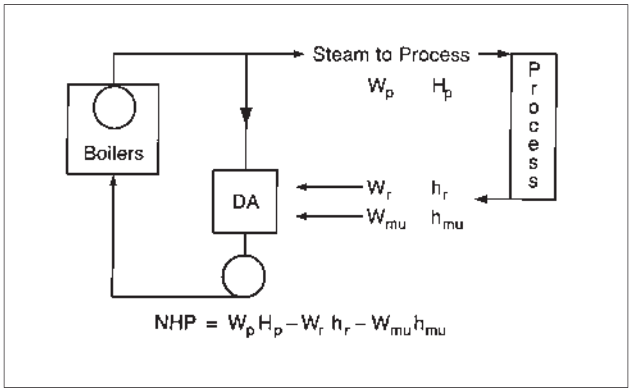

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Figure 3. Net heat to process (NHP)

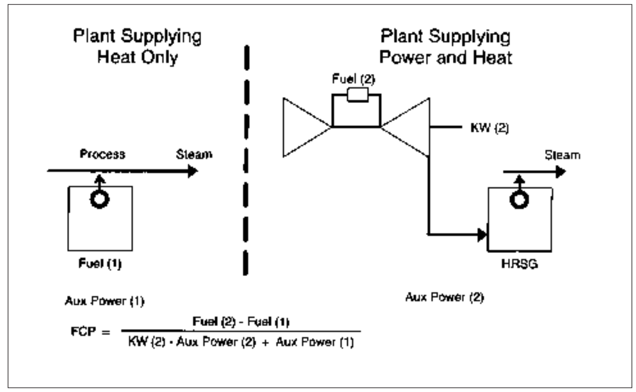

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Figure 4. Fuel chargeable to power (FCP)

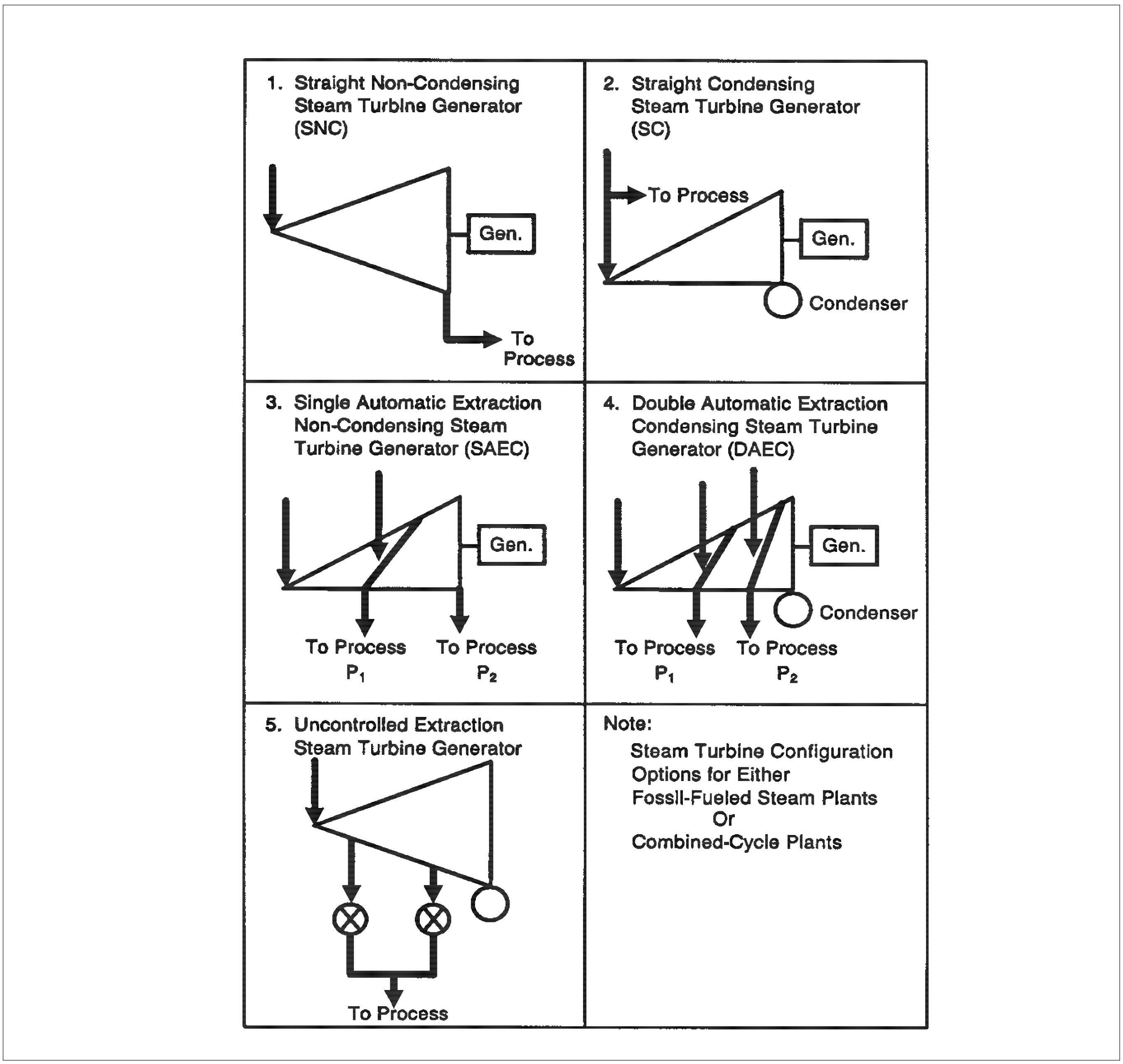

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Figure 5. Steam turbine configurations for power generation and process needs

NET HEAT TO PROCESS AND FUEL CHARGEABLE TO POWER

In evaluating and comparing alternative cogeneration cycles, two concepts are key. Net Heat to Process (NHP) and Fuel Chargeable to Power (FCP) are "Btu accounting methods" that make technical sense when comparing the performance of different sized cogeneration systems and even different technologies. They also form the basis for the data that is the input for whatever economic model is used.

Net Heat to Process is defined as the net energy supplied by the cogeneration system to the process load, as depicted in Figure 3. It is necessary to maintain a constant NHP for all systems being considered, especially when different gas and steam turbine configurations export energy to process at different conditions.

A parameter used to define the thermal performance of a topping cogeneration system is the Fuel Chargeable to Power (FCP). The FCP is defined as the incremental fuel for the cogeneration system relative to the fuel needs of a heat only system divided by the net incremental power produced by the Cogeneration System. Simply put, FCP is the incremental fuel divided by the incremental power, (i.e. the incremental heat rate). For a plant generating electric power only (an industrial or a utility), the Fuel-Chargeable-to-Power and net plant heat rate are interchangeable terms commonly expressed in Btu/kWh or kJ/kWh. The FCP concept is illustrated in Figure 4.

STEAM TURBINES FOR COGENERATION

Figure 5 shows several steam turbine configurations that can be used to generate power while satisfying a process need for steam. Steam turbines can generally be designed to meet the specific process heat needs. Unlike gas turbines that are sold in specific sizes or frame sizes, steam turbine generators are custom designed machines and seldom have 100% identical components or capabilities.

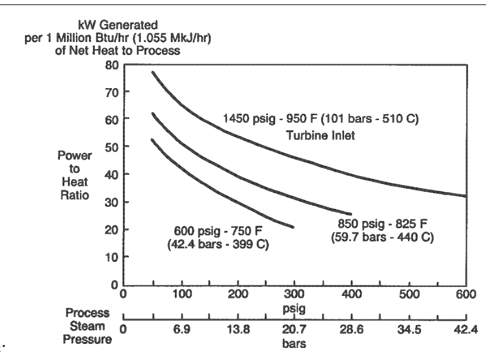
The configurations 1, 3 and 4 (in Figure 5) provide steam at a "controlled" pressure, consistent with the process header requirements. Configuration 5 includes two uncontrolled extraction openings in the steam turbine generator and provides steam that would be taken to a common line and pressure reduced if necessary to meet the pressure requirements in the process. The higher uncontrolled opening would be used during lighter load operation of the turbine when the pressure at the lower opening is too low for process use. Typically, uncontrolled extraction turbines of this type are used when process extractions are small compared to total turbine flow or when process needs are fairly constant except during start up, shut down or emergency situations.

Turbines represented in configurations 1 and 3 will yield power dependent directly on process demands since no condensing section capability exists. Their power production depends on the rise and fall of the steam demand. The addition of condensing capability (configurations 2, 4 and 5) provides added power generating flexibility. When a condenser is used, power can be generated independently from the process steam demand.

In "thermally optimized" steam turbine cogeneration cycles, steam is expanded in non-condensing or automatic-extraction-non-condensing steam turbine-generators that extract and/or exhaust into the process steam header(s). The FCP for these systems is typically in the 4000 to 4500 Btu/kWh HHV (4220 to 4750 kJ/kWh) range. The influence of initial steam conditions and process steam pressure on the amount of cogenerated power per 100 million Btu/h (105.5 x 10^9 J/h) NHP is shown in Figure 6. The increase in cogenerated power through use of higher initial steam conditions, and lower process pressures, is readily apparent.

Studies have shown that higher steam conditions can be economically justified more easily in industrial plants having relatively large process steam demands. Data given in Figure 7 provide guidance with regard to the initial steam conditions that are normally considered for industrial cogeneration applications. Higher energy costs experienced since the mid-1970s are favoring the upper portion of the bands shown in Figure 7.

Even through the use of the most effective ther-



Basis:
1) Average temperature of process returns and makeup is 165 F (74 C)
2) Power cycle credited for feedwater heating to:
455 F (235 C) for 1450 psig (101 bars)
400 F (204 C) for 850 psig (59.7 bars), and
370 F (188 C) for 600 psig (42.4 bars) systems
3) Turbine efficiency 75%

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Figure 6. Cogeneration power with steam turbines

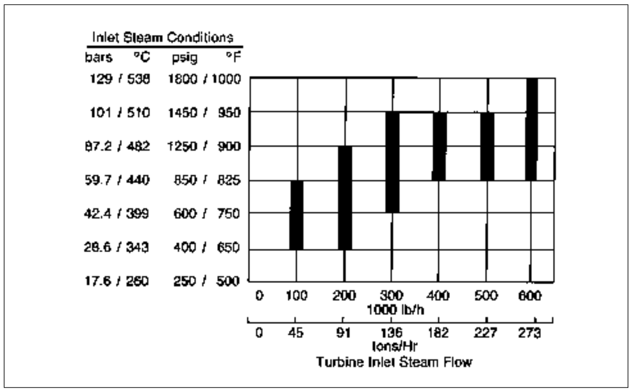

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Figure 7. Range of initial steam conditions normally selected for industrial steam turbines

mally optimized steam turbine cogeneration systems, the amount of power that can be cogenerated without a condensing section to the steam turbine per unit of heat energy delivered to process will usually not exceed about 85 kW per million Btu/0.6 kW/10^9J net heat supplied. This is generally less power than that required to satisfy most industrial plant electrical energy needs. Thus, with thermally optimized steam turbine cogeneration systems, a purchased power tie or additional condensing steam turbine is necessary to provide the balance of the industrial plant power needs.

Condensing power generation, although not necessarily energy efficient, has proven economic in many industrial applications. Favorable economics are often associated with systems where:

- Condensing power is used to control purchased power demand
- Low-cost fuels or process by-product fuels are available
- Adequate low-level process energy is available for a bottoming cogeneration system
- Condensing provides the continuity of service in critical plant operations where loss of the electric power can cause a major disruption in process operations and/or plant safety
- Utility specific situations favoring power sales, particularly if low cost fuels are available.

STEAM TURBINE PERFORMANCE FLEXIBILITY

Significant flexibility is achieved when combining a non-condensing turbine with a condensing steam turbine or when a steam turbine supplies controlled pressure steam to more than one process header. This is accomplished with a single- or double-auto extraction condensing steam turbine generator (See Figure 5). Figure 8 shows a performance map (flow versus kilowatt output) for a single auto extraction steam turbine generator. This is a generic performance map and applies equally to single auto non-condensing as well as single auto condensing steam turbine generators. The maximum throttle flow line (B-C) defines the maximum guarantee steam flow that can be admitted to the high pressure inlet of the steam turbine, whereas the zero extraction line (E-D) shows the performance of the steam turbine with zero extraction. The line on the far left (A-B) defines the performance of the steam turbine with minimum flow to exhaust. This portion of the curve denotes a turbine operating with only cooling steam being sent to the exhaust of the steam turbine and the balance of steam is extracted. In this area of the curve, the steam turbine is essentially operating as a non-condensing turbine. The sloping lines in the center of the performance map (E'-D') are lines of constant extraction flow.

This map, or envelope, of flows and kilowatt production accurately defines the flexibility of the steam turbine, and in the case of a combined cycle, defines much of the flexibility of that cycle as well. It is possible to design the steam turbine for higher maximum throttle flow. In doing so, the high pressure section of the steam turbine is enlarged and the flow that can be admitted to that section of the turbine is increased. Likewise, the maximum throttle flow line may be lowered making the inlet capability less. A similar change is possible by extending the zero extraction line to the right allowing the turbine to produce additional kilowatts with zero extraction flow. In this case, the exhaust section of the steam turbine is enlarged.

This tailoring of the steam turbine capability to the needs of the industrial process steam user is critical to maximizing the flexibility of the cogeneration project as well as optimizing the efficiency of the cogeneration system.

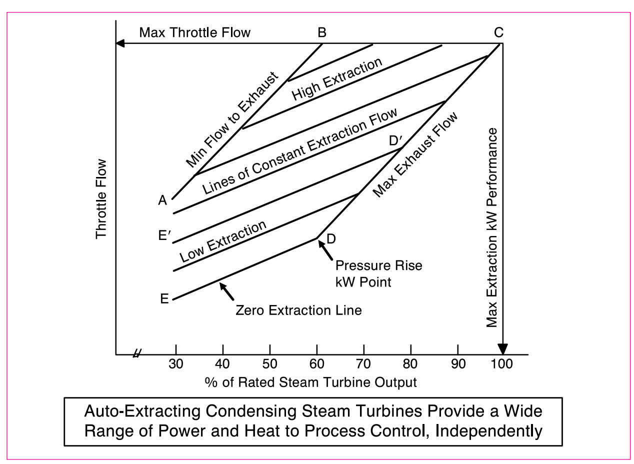

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Figure 8. Typical single automatic extraction turbine performance map

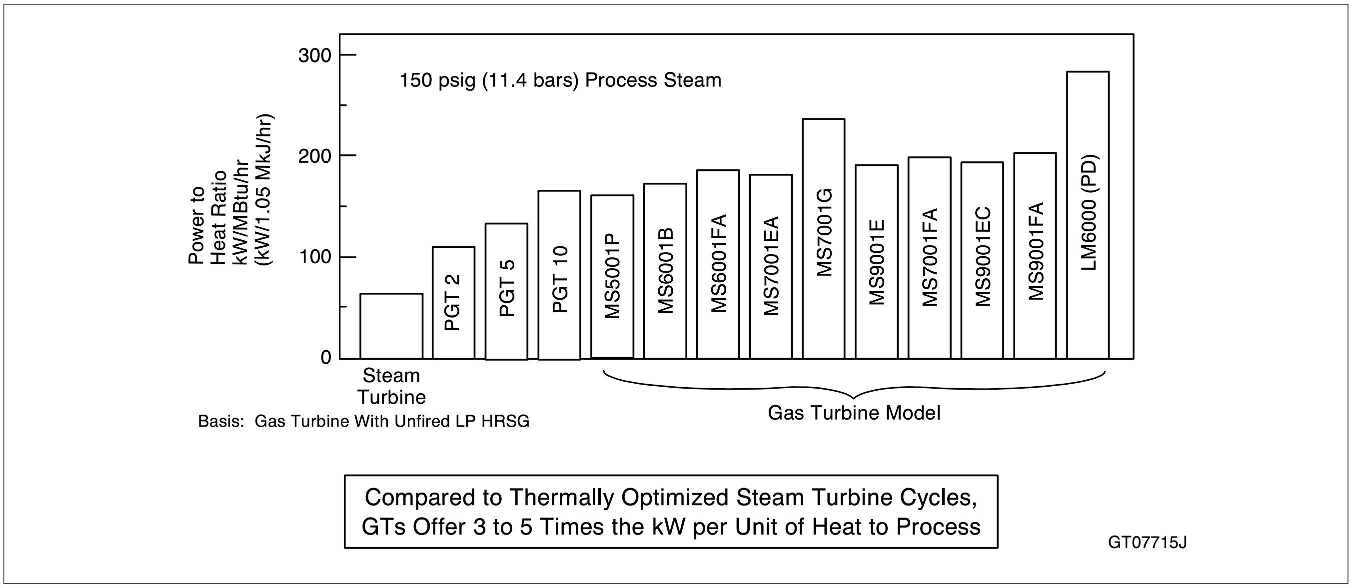

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Figure 9. Power to heat ratio

COGENERATION AND REHEAT STEAM TURBINE CYCLES

In most instances, thermal energy in the form of steam is utilized in industrial plants by condensing steam in process heat exchangers. Since most processes require heat transfer at a constant temperature, high degrees of steam superheat are not desirable and desuper-heating (steam attemporation) stations are commonly applied to control steam temperatures.

In a steam turbine cogeneration cycle, considerable de-super heater spray water would be required if reheat was considered. In fact, in most instances the amount of "thermally optimized" cogenerated power would be less in a reheat cycle compared to a non-reheat cycle assuming inlet steam conditions are held constant. For example, assuming a 500,000 lb/hr/227 metric ton/hr process steam demand at 150 psig saturated 10.3 bars saturated, a non-reheat cycle with 1450 psig, 950 F/100 bars, 510 C initial steam conditions would deliver about 28 MW. A reheat cycle with 1450 psig/950 F/950 F (100 bars/510 C/510 C) would generate about 27.3 MW, or 2.5% less power. In addition, the cycle complexity due to reheat would increase the cost of the turbine, boiler and associated systems relative to the non-reheat case. The economics of reheat steam turbines are enhanced in cogeneration when most of the steam is expanded to the condenser to produce electric power.

GAS TURBINE AND COMBINED CYCLES

Gas turbine cycles provide the opportunity to generate a larger power output per unit of heat required in process relative to noncondensing steam turbine cogeneration systems (Figure 9). This characteristic, combined with a favorable FCP and proven reliability, has made this prime mover widely accepted in applications where suitable fuels are economically available.

As shown in Figure 9, gas turbines can generally offer 2.5 to 4 times the power per unit of heat to process compared to thermally optimized steam turbine cycles.

GAS TURBINE POWER ENHANCEMENT

The gas turbine is an air breathing engine that responds to the mass flow entering its compressor. For constant speed units, the gas turbine output

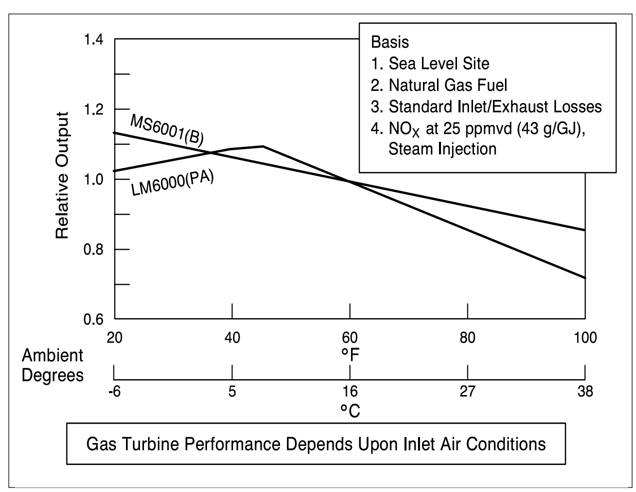

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Figure 10. Gas turbine ambient output characteristics

will generally vary in proportion to the inlet air temperature (density) as shown for the MS6001B in Figure 10. For gas turbine designs where mechanical limitations exist, the characteristic may be similar to that shown for the diluent injected LM6000 in Figure 10.

The gas turbine output may be enhanced at high ambient temperatures and low humidity levels by application of an evaporative cooler. This system decreases the compressor inlet temperature by evaporating water introduced into the inlet airflow upstream of the compressor. This approach frequently can be economically justified for MS and LM units in both base load and peaking applications. Output increases of about 9% can be experienced on heavy duty (MS) units at a 90 F /32 C ambient temperature at a relative humidity of 20%. For the LM6000, the use of an 85% effective evaporative cooler will increase its output about 22% at a 90 F/32 C temperature and 20% relative humidity ambient condition.

Another alternative considered mainly for LM6000 units, due to their relatively larger output decrease at increased ambient temperatures, is the use of an inlet chiller. This alternative cools the incoming air thus increasing the output relative to the gain available with an evaporative cooler. For the LM6000 in base load applications, chilling to the maximum power output, which occurs at an inlet temperature around 45 F to 50F/7.2 to 10 C, is usually desirable. Frequently, the energy for cooling can be supplied by a mechanical or absorption refrigeration system that receives its steam from a low pressure section in the gas turbine heat recovery steam generator (HRSG).

For the diluent injected LM6000, the normal decrease in power output at ambient temperatures less than about 50 F/10 C can be mitigated through inlet air heating to the maximum power output temperature. Low level energy recovery from the HRSG can accomplish this task. The net effect is to drive the performance characteristics for the LM6000 flat over the ambient temperature range (Figure 11).

The example gas turbine output enhancements are not limited to LM units only, and should be evaluated for all gas turbines to ensure that the maximum economic benefits are realized.

The greater the output change (loss) with changing ambient temperature, the larger the economic potential associated with various power enhancement alternatives.

GAS TURBINE EXHAUST HEAT RECOVERY

The economics of gas turbines in process applications usually depend on effective use of the exhaust energy, which generally represents 60% to 70% of the inlet fuel energy. The increase in overall system efficiency as the exhaust temperature is decreased through use of effective heat recovery is illustrated in Figure 12. The most common use of this energy is for steam generation in HRSGs, with unfired as well as fired designs. However, the gas turbine exhaust gases can also be used as a source of direct energy, for unfired and fired process fluid heaters, as well as preheated combustion air for power boilers.

HEAT RECOVERY STEAM GENERATORS

The overall FCP in a gas turbine-HRSG system is a function of the amount of energy recovered from the turbine exhaust gas. The greater the

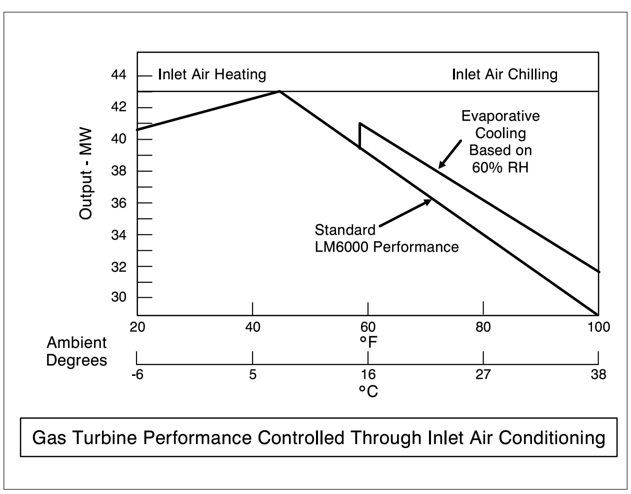

Figure 11. LM6000 (PA) output enhancements

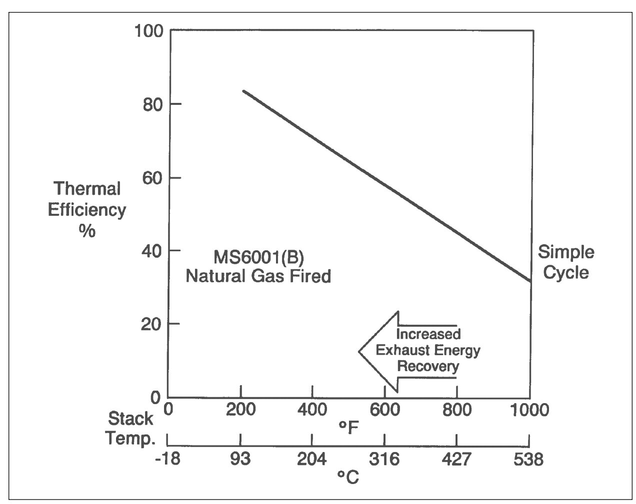

Figure 12. Thermal efficiency versus stack temperature

amount of energy recovered, the lower the HRSG stack temperature, and the better the FCP. Thus, gas turbine-HRSG cycles should use the lowest practical feedwater temperature to the economizing section of the HRSG, within constraints imposed due to gas side corrosion considerations. The typical feedwater temperature is 230 F/110 C if corrosion is not a problem. With an integral deaerating section or deaerating condenser, the inlet water temperatures can be much lower. For applications using sulfur bearing fuels, a feedwater temperature of about 270-290 F/132-143 C should be used to ensure metal temperatures remain above the condensation temperature of the sulfurous products of combustion. These feedwater temperatures are in contrast to steam turbine cycles, which provide increased cogenerated power as more regenerative feedwater heating (higher feedwater temperature to the boiler) is incorporated into the cycle.

HRSG units are available in unfired, supplementary-fired and fully-fired designs. The appropriate selection is established through economic evaluations of various potential configurations for the application.

UNFIRED HRSG

An unfired unit is the most simple HRSG configuration. Characteristically, steam conditions range from 150 psig/10.3 bars saturated to approximately 1450 psig, 950 F/100 bars, 510 C. Steam temperatures are usually 50 F/10 C or more below the turbine exhaust gas temperature. With the introduction of "F" technology gas turbines, exhaust conditions will permit superheated steam temperatures of 1000-1050 F/538-566 C, and reheat steam cycles if the application warrants that approach.

Generally speaking, unfired units can be economically designed to recover approximately 95% of the energy in the turbine exhaust gas available for steam generation. Higher performance levels are possible; however, the increased cost of the heat transfer surface and possible larger gas side pressure drop must be evaluated versus the additional energy recovered to establish whether the higher costs are warranted.

When unfired units are designed with higher steam conditions for a combined cycle, multiple-pressure units are usually applied to increase exhaust heat recovery and enhance system performance. The intermediate level may be that required for steam injection for NO_x control and/or a process level. In applications using natural gas, a third pressure level, will further enhance overall system performance. Typical design practice is that unfired HRSGs are convective heat exchangers that respond to the exhaust conditions of the gas turbine. Thus, the performance of unfired HRSG units are driven by the gas turbine operating mode and cannot easily provide steam flow control.

SUPPLEMENTARY-FIRED HRSG

Since gas turbines generally consume very little of the available oxygen within the gas turbine air flow, the oxygen content of the gas turbine exhaust generally permits supplementary fuel firing ahead of the HRSG to increase steam production rates relative to an unfired unit. A supplementary-fired unit is defined as an HRSG fired to an average temperature not exceeding about 1800 F/982 C.

Since the turbine exhaust gas is essentially preheated combustion air, the supplementary-fired HRSG fuel consumption is less than that required for a power boiler providing the same incremental increase in steam generation. Characteristically, the incremental steam production from supplementary firing above that of an unfired HRSG will be achieved at 100% efficiency based on the lower heat value of the fuel fired. The amount of incremental fuel will be about 10% to 20% less than for a natural-gas-fired power boiler providing the same incremental increase in steam produced.

As stated above, the unfired HRSG with higher steam conditions is often designed with multiple pressure levels to recover as much energy as possible from the gas turbine exhaust. This adds cost to the unfired HRSG, but the economics are often enhanced for the cycle. In the case of the supplementary-fired HRSG, if the HRSG is to be fired during most of its operating hours to the 1400 F to 1800 F/760 C to 982 C range, then a suitably low stack temperature can usually be achieved with a single pressure level unit. This is the result of increased economizer duty as compared to the unfired HRSG.

A supplementary-fired HRSG is basically a convective unit with a design quite similar to an unfired HRSG. However, the firing capability provides the ability to control the HRSG steam production, within the capability of the burner system, independent of the normal gas turbine operating mode.

FULLY-FIRED HRSG

A few industrials have used the exhaust of the gas turbine as preheated combustion air for a fully-fired HRSG. A fully fired HRSG is defined as

TABLE

STEAM GENERATION AND FUEL CHARGEABLE TO POWER WITH GAS TURBINE AND HEAT RECOVERY BOILERS

Generator Drives - Natural Gas Fuel - Dry Performance - English Units

Gas Turbine Type	MS5001(PA)		MS6001(B)		MS6001(FA)		MS7001(EA)		MS9001(E)		MS7001(FA)		MS9001(EC)		MS9001(FA)	
Gas Turbine Model	PG5371(PA)		PG6551(B)		PG6101(FA)		PG7121(EA)		PG9171(E)		PG7231(FA)		PG9231(EC)		PG9331(FA)	
ISO Base Rating (KW)	25,810		39,110		69,500		85,000		122,400		166,200		169000		240000	
Performance at 59 F, Sea Level, Natural Gas Fuel	50 / 60 Hz		50 / 60 Hz		50 / 60 Hz		60 Hz		50 Hz		60 Hz		50 Hz		50 Hz	
Output - KW																
- Unfired, 1 PL	25,470		38,770		69,080		84,620		121,700		165,400		167,800		239,000	
- Unfired, 2 PL	25,380		38,670		68,890		84,450		121,500		165,100		167,200		238,500	
- Supp Fired	25,290		38,580		68,700		84,280		121,200		164,700		166,700		238,000	
- Fully Fired	25,020		38,290		68,130		83,760		120,400		163,500		165,100		236,300	
Power Turbine Speed - rpm	5,100		5,100		5,250		3,600		3,000		3,600		3,000		3,000	
Fuel - MBtu/h (HHV)	349.0		468.1		773.8		986.1		1382.0		1746.0		1833.7		2508.6	
Exhaust Flow - lb/h	985,000		1,144,000		1,621,000		2,367,000		3,257,000		3,545,000		4,075,000		5,120,000	
Exhaust Temp - F																
- Unfired, 1 PL	914		994		1098		1000		1012		1105		1036		1107	
- Unfired, 2 PL	915		995		1100		1001		1013		1107		1037		1108	
- Supp Fired	916		996		1101		1002		1014		1108		1039		1109	
- Fully Fired	920		999		1106		1004		1018		1112		1044		1113	
HRSG Performance Fuel - MBtu/h (HHV)																
- Supp Fired	225.9		234.0		277.7		480.0		648.2		600.1		778.5		864.5	
- Fully Fired	845.9		916.6		1182.4		1877.6		2557.7		2529.1		3080.7		3677.8	
Steam Conditions (Psig / F)	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh
- Unfired																
150 / 365 1 PL	155	5860	210	5100	347	4740	439	4980	616	4840	766	4600	804	4760	1110	4520
400 / 650 1 PL	124	6620	172	5620	296	4970	360	5470	507	5300	656	4790	666	5160	950	4720
600 / 750 1 PL	113	7010	159	5890	278	5140	333	5720	471	5520	616	4940	620	5360	893	4870
850 / 825 1 PL	104	7390	149	6130	264	5300	313	5940	442	5740	587	5080	585	5540	850	5000
850 / 825 2 PL	104	6110	149	5350	265	4860	313	5210	443	5170	589	4800	586	5090	852	4740
150 / 365	25.7	-	24.0	-	23.0	-	48.8	-	53.6	-	34.0	-	60.0	-	48.7	-
1250 / 900 2 PL	-	-	139	5330	252	4870	291	5220	414	5170	560	4810	550	5100	810	4750
150 / 365	-	-	33.0	-	31.6	-	67.0	-	78.4	-	52.9	-	88.7	-	75.9	-
1450 / 950 2 PL	-	-	132	5380	244	4870	279	5210	396	5180	541	4820	528	5100	783	4760
150 / 365	-	-	37.4	-	36.2	-	76.1	-	91.0	-	63.3	-	104	-	90.9	-
- Supp Fired																
150 / 365	349	4970	406	4660	577	4500	841	4560	1158	4460	1264	4370	-	-	-	-
400 / 650	310	4910	360	4640	511	4500	746	4530	1027	4440	1120	4360	1286	4460	1617	4300
600 / 750	299	4910	348	4610	494	4470	720	4520	991	4430	1081	4360	1241	4450	1561	4290
850 / 825	292	4900	340	4590	482	4480	703	4520	968	4420	1056	4350	1213	4440	1525	4280
1250 / 900	286	4900	333	4590	473	4450	689	4510	949	4400	1036	4330	1189	4420	1495	4270
1450 / 950	282	4840	328	4560	465	4450	678	4490	933	4400	1018	4330	1169	4420	1470	4270
- Fully Fired																
400 / 650	763	3470	859	3580	1173	3710	1766	3570	2421	3520	2530	3670	-	-	-	-
600 / 750	737	3410	829	3560	1133	3670	1705	3540	2338	3490	2443	3650	2872	3570	3540	3620
850 / 825	720	3370	810	3530	1107	3640	1666	3500	2284	3460	2387	3620	2806	3550	3458	3600
1250 / 900	705	3360	794	3490	1085	3620	1633	3470	2239	3420	2340	3590	2751	3510	3391	3570
1450 / 950	694	3300	781	3470	1067	3610	1607	3440	2203	3390	2302	3580	2705	3500	3335	3560

* Gas turbines and boilers fueled with natural gas and all fuel data based on higher heating value (HHV)
* Gas Turbines equipped with DLN combustors
* Fuel chargeable to gas turbine power assumes GT credit with PH auxiliaries and equivalent boiler fuel required to generate steam in an 84% efficient boiler (HHV)
* Standard inlet losses; exhaust losses 10 "H2O for unfired 1PL, 12" H2O for unfired 2 PL, 14" H2O for supplementary fired, 20" H2O for fully fired
* Assumes 0% exhaust bypass stack damper leakage, 0% blowdown, and 150 F condensate return for all cases
* Unfired boiler design based on a 15 F pinch point / 15 F subcool approach temperature, with criteria to limit the stack temperature to a minimum of 220 F for all cases
*Supplementary firing based on average gas temperature of 1600 F
* Lower heating value (LHV) - 21515 Btu/lb, HHV = LHV x 1.11

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TABLE 2

STEAM GENERATION AND FUEL CHARGEABLE TO POWER WITH GAS TURBINE AND HEAT RECOVERY BOILERS

Generator Drive - Natural Gas Fuel - Dry Performance - SI Units

Gas Turbine Type	MS5001(PA)		MS6001(B)		MS6001(FA)		MS7001(EA)		MS9001(E)		MS7001(FA)		MS9001(EC)		MS9001(FA)	
Gas Turbine Model	PG5371(PA)		PG6551(B)		PG6101(FA)		PG7121(EA)		PG9171(E)		PG7231(FA)		PG9231(EC)		PG9331(FA)	
ISO Base Rating (KW)	25810		39110		69500		85000		122400		166200		169000		240000	
Performance at 15 C, Sea Level, Natural Gas Fuel	50 / 60 Hz		50 / 60 Hz		50 / 60 Hz		60 Hz		50 Hz		60 Hz		50 Hz		50 Hz	
Output - KW																
- Unfired, 1 PL	25470		38770		69080		84620		121700		165400		167800		239000	
- Unfired, 2 PL	25380		38670		68890		84450		121500		165100		167200		238500	
- Supp Fired	25290		38580		68700		84280		121200		164700		166700		238000	
- Fully Fired	25020		38290		68130		83760		120400		163500		165100		236300	
Power Turbine Speed - rpm	5100		5100		5250		3600		3000		3600		3000		3000	
Fuel - MKJ/h (HHV)	368.2		493.8		816.3		1040.4		1458.0		1842.1		1934.6		2646.6	
Exhaust Flow - Tons/h	447		519		735		1,073		1,477		1,608		1,848		2,322	
Exhaust Temp - C																
- Unfired, 1 PL	490		534		592		538		544		596		558		597	
- Unfired, 2 PL	491		535		593		538		545		597		558		598	
- Supp Fired	491		536		594		539		546		598		559		598	
- Fully Fired	493		537		597		540		548		600		562		601	
HRSG Performance																
Fuel - MKJ/h (HHV)																
- Supp Fired	238.3		246.9		293.0		506.4		683.8		633.2		821.4		912.1	
- Fully Fired	892.4		967.0		1247.4		1980.8		2698.4		2668.2		3250.2		3880.1	
Steam Conditions (bara / C)	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh
- Unfired																
11.4 / 185 1 PL	70.3	6180	95.2	5380	157.4	5000	199.1	5250	279.4	5110	347.4	4850	364.6	5020	503.4	4770
28.6 / 343 1 PL	56.2	6980	78.0	5930	134.2	5240	163.3	5770	229.9	5590	297.5	5050	302.0	5440	430.8	4980
42.4 / 399 1 PL	51.2	7400	72.1	6210	126.1	5420	151.0	6030	213.6	5820	279.4	5210	281.2	5650	405.0	5140
59.7 / 441 1 PL	47.2	7800	67.6	6470	119.7	5590	142.0	6270	200.5	6060	266.2	5360	265.3	5840	385.5	5280
59.7 / 441 2 PL	47.2	6450	67.6	5640	120.2	5130	142.0	5500	200.9	5450	267.1	5060	265.8	5370	386.4	5000
11.4 / 185	11.7	-	10.9	-	10.4	-	22.1	-	24.3	-	15.4	-	27.2	-	22.1	-
87.2 / 482 2 PL	-	-	63.0	5620	114.3	5130	132.0	5500	187.8	5450	254.0	5060	249.4	5370	367.3	5000
11.4 / 185	-	-	15.0	-	14.3	-	30.4	-	35.6	-	24.0	-	40.2	-	34.4	-
101 / 510 2 PL	-	-	59.9	5680	110.7	5140	126.5	5510	179.6	5450	245.4	5070	239.5	5380	355.1	5010
11.4 / 185	-	-	15.0	-	16.4	-	34.5	-	41.3	-	28.7	-	47.2	-	41.2	-
- Supp Fired																
11.4 / 185	158.3	5240	184.1	4920	261.7	4750	381.4	4810	525.2	4710	573.2	4610	-	-	-	-
28.6 / 343	140.6	5180	163.3	4900	231.7	4750	338.3	4780	465.8	4680	507.9	4600	583.2	4710	733.3	4540
42.4 / 399	135.6	5180	157.8	4860	224.0	4720	326.5	4770	449.4	4670	490.2	4600	562.8	4690	707.9	4530
59.7 / 441	132.4	5170	154.2	4840	218.6	4730	318.8	4770	439.0	4660	478.9	4590	550.1	4680	691.6	4520
87.2 / 482	129.7	5170	151.0	4840	214.5	4690	312.5	4760	430.4	4640	469.8	4570	539.2	4660	678.0	4500
101 / 510	127.9	5110	148.8	4810	210.9	4690	307.5	4740	423.1	4640	461.7	4570	530.2	4660	666.7	4500
- Fully Fired																
28.6 / 343	346.0	3660	389.6	3780	532.0	3910	800.9	3770	1098.0	3710	1147.4	3870	-	-	-	-
42.4 / 399	334.2	3600	376.0	3760	513.8	3870	773.2	3730	1060.3	3680	1107.9	3850	1302.5	3770	1605.4	3820
59.7 / 441	326.5	3560	367.3	3720	502.0	3840	755.6	3690	1035.8	3650	1082.5	3820	1272.6	3750	1568.3	3800
87.2 / 482	319.7	3540	360.1	3680	492.1	3820	740.6	3660	1015.4	3610	1061.2	3790	1247.6	3700	1537.9	3770
101 / 510	314.7	3480	354.2	3660	483.9	3810	728.8	3630	999.1	3580	1044.0	3780	1226.8	3690	1512.5	3760

* Gas turbines and boilers fueled with natural gas and all fuel data based on higher heating value (HHV)
* Gas turbines equipped with DLN combustors
* Fuel chargeable to gas turbine power assumes GT credit with PH auxiliaries and equivalent boiler fuel required to generate steam in an 84% efficient boiler (HHV)
* Standard inlet losses; exhaust losses 254 mm H2O for unfired 1PL, 305 mm H2O for unfired 2 PL, 356 mm H2O for supplementary fired, 508 mm H2O for fully fired
* Assumes 0% exhaust bypass stack damper leakage, 0% blowdown, and 65.6 C condensate return for all cases
* Unfired boiler desi ed on a 8.3 C pinch point / 8.3 C subcool approach temperature, with criteria to limit the stack te[redacted]ature to a minimum of 104.4 C for all cases
* Supplementary fir d on average gas temperature of 871 C
* Lower heating value ...V) - 50031 kJ/kg, HHV = LHV x 1.11

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TABLE 3

STEAM GENERATION AND FUEL CHARGEABLE TO POWER WITH GAS TURBINE AND HEAT RECOVERY BOILERS

Generator Drives - Natural Gas Fuel - Dry Performance - English Units

Gas Turbine Type	LM2500(PJ)	LM2500(PR)	LM6000(PB)	LM6000(PD)	LM2500(PJ)	LM2500(PY)	LM6000(PB)	LM6000(PD)
Gas Turbine Model	PGLM2500(PJ)	PGLM2500(+)	PGLM6000(PB)	PGLM6000(PD)	PGLM2500(PJ)	PGLM2500(+)	PGLM6000(PB)	PGLM6000(PD)
ISO Base Rating (KW)**	22790	27080	38600	42270	21820	27550	38020	41640
Performance at 59 F, Sea Level, Natural Gas Fuel	60 Hz	60 Hz	60 Hz	60 Hz	50 Hz	50 Hz	50 Hz	50 Hz
Output - KW								
- Unfired, 1 PL	22,150	26,390	37,770	41,180	21,200	26,750	37,200	40,560
- Unfired, 2 PL	22,090	26,330	37,700	41,090	21,140	26,680	37,130	40,470
- Supp Fired	22,030	26,270	37,630	41,000	21,080	26,600	37,070	40,380
- Fully Fired	21,850	26,100	37,430	40,720	20,900	26,380	36,870	40,100
Power Turbine Speed - rpm	3,600	3,600	3,600	3,600	3,000	6,100	3,600	3,600
Fuel - MBtu/h (HHV)	240.1	276.3	379.3	394.9	238.2	277.6	379.3	394.9
Exhaust Flow - lb/h	538,600	631,600	973,400	978,800	540,600	635,100	973,400	978,800
Exhaust Temp - F								
- Unfired, 1 PL	993	959	883	852	1001	946	883	852
- Unfired, 2 PL	994	960	885	853	1003	947	885	853
- Supp Fired	996	962	886	855	1004	949	886	855
- Fully Fired	1000	966	889	859	1008	953	889	859
HRSG Performance Fuel - MBtu/h (HHV)								
- Supp Fired	110.6	136.6	233.6	246.0	109.6	140.2	233.6	246.0
- Fully Fired	410.8	487.2	800.0	792.9	415.5	489.6	800.0	792.9

Steam Conditions (Psig / F)		LM2500(PJ) 60 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh	LM2500(PR) 60 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh	LM6000(PB) 60 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh	LM6000(PD) 60 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh
- Unfired									
150 / 366	1 PL	98.9	5090	109	5150	145	5100	136	5340
400 / 650	1 PL	81.0	5520	88.4	5600	114	5650	106	5850
600 / 750	1 PL	74.9	5740	81.3	5820	103	5930	94.7	6120
850 / 825	1 PL	70.2	5940	75.6	6040	93.9	6200	-	-
1250 / 900	1 PL	65.1	6200	69.5	6310	-	-	-	-
850 / 825	2 PL	70.4	5280	75.9	5320	94.3	5260	-	-
150 / 365		11.4	-	14.7	-	27.3	-	-	-
1250 / 900	2 PL	65.3	5300	69.8	5320	-	-	-	-
150 / 365		15.6	-	20.2	-	-	-	-	-
- Supp Fired									
150 / 366		192	4700	225	4690	347	4420	350	4650
400 / 650		170	4700	200	4650	308	4390	310	4640
600 / 750		164	4700	193	4650	297	4400	299	4640
850 / 825		160	4700	188	4670	290	4390	292	4640
1250 / 900		157	4680	185	4610	284	4390	287	4590
1450 / 950		155	4630	182	4600	280	4350	282	4600
- Fully Fired									
400 / 650		389	3930	456	3870	721	3530	710	3840
600 / 750		376	3870	440	3860	696	3510	685	3840
850 / 825		367	3870	430	3830	680	3480	670	3780
1250 / 900		360	3820	422	3770	667	3430	657	3740
1450 / 950		354	3810	415	3760	656	3420	646	3740

Steam Conditions (Psig / F)		LM2500(PJ) 50 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh	LM2500(PY) 50 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh	LM6000(PB) 50 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh	LM6000(PD) 50 Hz HRSG Steam 1000 lb/h	FCP GT Btu/kWh
- Unfired									
150 / 366	1 PL	101	5100	107	5230	145	5180	136	5420
400 / 650	1 PL	82.6	5570	86.5	5670	114	5740	106	5940
600 / 750	1 PL	76.5	5790	79.3	5910	103	6020	94.7	6220
850 / 825	1 PL	71.8	6000	73.6	6130	93.9	6290	-	-
1250 / 900	1 PL	66.8	6260	67.3	6410	-	-	-	-
850 / 825	2 PL	72.0	5330	73.8	5390	94.3	5350	-	-
150 / 365		11.1	-	15.3	-	27.3	-	-	-
1250 / 900	2 PL	67.0	5340	67.6	5390	-	-	-	-
150 / 365		15.2	-	21.0	-	-	-	-	-
- Supp Fired									
150 / 366		193	4720	227	4720	347	4490	350	4720
400 / 650		171	4710	201	4720	308	4460	310	4710
600 / 750		165	4710	194	4720	297	4460	299	4710
850 / 825		161	4710	189	4740	290	4460	292	4710
1250 / 900		158	4680	186	4680	284	4450	287	4660
1450 / 950		155	4700	183	4670	280	4420	282	4670
- Fully Fired									
400 / 650		394	3890	457	3920	721	3590	710	3900
600 / 750		380	3900	441	3910	696	3560	685	3900
850 / 825		372	3820	431	3870	680	3530	670	3840
1250 / 900		364	3830	423	3810	667	3480	657	3800
1450 / 950		358	3820	416	3800	656	3470	646	3790

* Gas turbines and boilers fueled with natural gas and all fuel data based on higher heating value (HHV)
* Gas turbines equipped with DLN combustors
* Fuel chargeable to gas turbine power assumes GT credit with PH auxiliaries and equivalent boiler fuel required to generate steam in an 84% efficient boiler (HHV)
* Standard inlet losses; exhaust losses 10 "H2O for unfired 1PL, 12" H2O for unfired 2 PL, 14" H2O for supplementary fired, 20" H2O for fully fired
* Assumes 0% exhaust bypass stack damper leakage, 0% blowdown, and 150 F condensate return for all cases
* Unfired boiler design based on a 15 F pinch point / 15 F subcool approach temperature, with criteria to limit the stack temperature to a minimum of 220 F for all cases
* Supplementary firing based on average gas temperature of 1600 F
* Lower heating value (LHV) - 21515 Btu/lb, HHV = LHV x 1.11
** Rating based on 0/0 inlet/exhaust pressure drops

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TABLE 4

STEAM GENERATION AND FUEL CHARGEABLE TO POWER WITH GAS TURBINE AND HEAT RECOVERY BOILERS

Generator Drive - Natural Gas Fuel - Dry Performance - SI Units

Gas Turbine Type	LM2500(PJ)		LM2500(PR)		LM6000(PB)		LM6000(PD)	
Gas Turbine Model	PGLM2500(PJ)		PGLM2500(+)		PGLM6000(PB)		PGLM6000(PD)	
ISO Base Rating (KW)	22790		27080		38600		42270	
Performance at 15 C, Sea Level, Natural Gas Fuel	60 Hz		60 Hz		60 Hz		60 Hz	
Output - KW								
- Unfired, 1 PL	22,150		26,390		37,770		41,180	
- Unfired, 2 PL	22,090		26,330		37,700		41,090	
- Supp Fired	22,030		26,270		37,630		41,000	
- Fully Fired	21,850		26,100		37,430		40,720	
Power Turbine Speed - rpm	3,600		3,600		3,600		3,600	
Fuel - MKJ/h (HHV)	253.3		291.5		400.1		416.7	
Exhaust Flow - Tons/h	244		286		441		444	
Exhaust Temp - C								
- Unfired, 1 PL	534		515		473		456	
- Unfired, 2 PL	534		516		474		456	
- Supp Fired	536		517		474		457	
- Fully Fired	538		519		476		459	
HRSG Performance Fuel - MKJ/h (HHV)								
- Supp Fired	116.6		144.1		246.4		259.5	
- Fully Fired	433.4		514.0		844.0		836.5	
Steam Conditions (bars / C)	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh
- Unfired								
11.4 / 185 1 PL	44.9	5370	49.4	5430	65.8	5380	61.7	5630
28.6 / 343 1 PL	36.7	5820	40.1	5910	51.7	5960	48.1	6170
42.4 / 399 1 PL	34.0	6060	36.9	6140	46.7	6260	42.9	6460
59.7 / 441 1 PL	31.8	6270	34.3	6370	42.6	6540	-	-
87.2 / 482 1 PL	29.5	6540	31.5	6660	-	-	-	-
59.7 / 441 2 PL	31.9	5570	34.4	5610	42.8	5550	-	-
11.4 / 185	5.2	-	6.7	-	12.4	-	-	-
87.2 / 482 2 PL	29.6	5590	31.7	5610	-	-	-	-
11.4 / 185	7.1	-	9.2	-	-	-	-	-
- Supp Fired								
11.4 / 185	87.1	4960	102.0	4950	157.4	4660	158.7	4910
28.6 / 343	77.1	4960	90.7	4910	139.7	4630	140.6	4900
42.4 / 399	74.4	4960	87.5	4910	134.7	4640	135.6	4900
59.7 / 441	72.6	4960	85.3	4930	131.5	4630	132.4	4900
87.2 / 482	71.2	4940	83.9	4860	128.8	4630	130.2	4840
101 / 510	70.3	4880	82.5	4850	127.0	4590	127.9	4850
- Fully Fired								
28.6 / 343	176.4	4150	206.8	4080	327.0	3720	322.0	4050
42.4 / 399	170.5	4080	199.5	4070	315.6	3700	310.7	4050
59.7 / 441	166.4	4080	195.0	4040	308.4	3670	303.9	3990
87.2 / 482	163.3	4030	191.4	3980	302.5	3620	298.0	3950
101 / 510	160.5	4020	188.2	3970	297.5	3610	293.0	3950

Gas Turbine Type	LM2500(PJ)		LM2500(PY)		LM6000(PB)		LM6000(PD)	
Gas Turbine Model	PGLM2500(PJ)		PGLM2500(+)		PGLM6000(PB)		PGLM6000(PD)	
ISO Base Rating (KW)	21820		27550		38020		41640	
Performance at 15 C, Sea Level, Natural Gas Fuel	50 Hz		50 Hz		50 Hz		50 Hz	
Output - KW								
- Unfired, 1 PL	21,200		26,750		37,200		40,560	
- Unfired, 2 PL	21,140		26,680		37,130		40,470	
- Supp Fired	21,080		26,600		37,070		40,380	
- Fully Fired	20,900		26,380		36,870		40,100	
Power Turbine Speed - rpm	3,000		6,100		3,600		3,600	
Fuel - MKJ/h (HHV)	251.3		292.9		400.1		416.7	
Exhaust Flow - Tons/h	245		288		441		444	
Exhaust Temp - C								
- Unfired, 1 PL	538		508		473		456	
- Unfired, 2 PL	539		508		474		456	
- Supp Fired	540		509		474		457	
- Fully Fired	542		512		476		459	
HRSG Performance Fuel - MKJ/h (HHV)								
- Supp Fired	115.6		147.9		246.4		259.5	
- Fully Fired	438.4		516.5		844.0		836.5	
Steam Conditions (bars / C)	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh
- Unfired								
11.4 / 185 1 PL	45.8	5380	48.5	5520	65.8	5460	61.7	5720
28.6 / 343 1 PL	37.5	5880	39.2	5980	51.7	6060	48.1	6270
42.4 / 399 1 PL	34.7	6110	36.0	6240	46.7	6350	42.9	6560
59.7 / 441 1 PL	32.6	6330	33.4	6470	42.6	6640	-	-
87.2 / 482 1 PL	30.3	6600	30.5	6760	-	-	-	-
59.7 / 441 2 PL	32.7	5620	33.5	5690	42.8	5640	-	-
11.4 / 185	5.0	-	6.9	-	12.4	-	-	-
87.2 / 482 2 PL	30.4	5630	30.7	5690	-	-	-	-
11.4 / 185	6.9	-	9.5	-	-	-	-	-
- Supp Fired								
11.4 / 185	87.5	4980	102.9	4980	157.4	4740	158.7	4980
28.6 / 343	77.6	4970	91.2	4980	139.7	4710	140.6	4970
42.4 / 399	74.8	4970	88.0	4980	134.7	4710	135.6	4970
59.7 / 441	73.0	4970	85.7	5000	131.5	4710	132.4	4970
87.2 / 482	71.7	4940	84.4	4940	128.8	4690	130.2	4920
101 / 510	70.3	4960	83.0	4930	127.0	4660	127.9	4930
- Fully Fired								
28.6 / 343	178.7	4100	207.3	4140	327.0	3790	322.0	4110
42.4 / 399	172.3	4110	200.0	4130	315.6	3760	310.7	4110
59.7 / 441	168.7	4030	195.5	4080	308.4	3720	303.9	4050
87.2 / 482	165.1	4040	191.8	4020	302.5	3670	298.0	4010
101 / 510	162.4	4030	188.7	4010	297.5	3660	293.0	4000

* Gas turbines and boilers fueled with natural gas and all fuel data based on higher heating value (HHV)
* Gas turbines equipped with DLN combustors
* Fuel chargeable to gas turbine power assumes GT credit with PH auxiliaries and equivalent boiler fuel required to generate steam in an 84% efficient boiler (HHV)
* Standard inlet losses; exhaust losses 254 mm H2O for unfired 1PL, 305 mm H2O for unfired 2 PL, 356 mm H2O for supplementary fired, 508 mm H2O for fully fired
* Assumes 0% exhaust bypass stack damper leakage, 0% blowdown, and 65 C condensate return for all cases
* Unfired boiler design based on a 8.3 C pinch point / 8.3 C subcool approach temperature, with criteria to limit the stack temperature to a minimum of 104 C for all cases
* Supplementary firing based on average gas temperature of 871 C
* Lower heating value ([illegible]V) - 50031 kJ/kg, HHV = LHV x 1.11
** Rating based on C[illegible] exhaust pressure drops

6/96 lm96.xls

TABLE 5

STEAM GENERATION AND FUEL CHARGEABLE TO POWER WITH GAS TURBINE AND HEAT RECOVERY BOILERS

Generator Drives - Natural Gas Fuel - Dry Performance - English Units

Gas Turbine Type	PGT2		PGT5		PGT10	
Gas Turbine Model	PGT2		PGT5		PGT10	
ISO Base Rating (KW) **	2000		5200		10140	
Performance at 59 F, Sea Level, Natural Gas Fuel	50 / 60 Hz		50 / 60 Hz		50 / 60 Hz	
Output - KW						
- Unfired, 1 PL	1,920		5,010		9,860	
- Unfired, 2 PL	1,910		4,990		9,820	
- Supp Fired	1,900		4,960		9,790	
- Fully Fired	1,880		4,890		9,680	
Power Turbine Speed - rpm	22,500		11,140		7,900	
Fuel - MBtu/h (HHV)	30.0		72.9		122.7	
Exhaust Flow - lb/h	83,880		193,460		330,480	
Exhaust Temp - F						
- Unfired, 1 PL	986		985		912	
- Unfired, 2 PL	988		986		914	
- Supp Fired	989		988		915	
- Fully Fired	993		993		919	
HRSG Performance						
Fuel - MBtu/h (HHV)						
- Supp Fired	17.3		39.9		75.9	
- Fully Fired	71.7		161.7		277.0	
Steam Conditions (Psig / F)	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh	HRSG Steam 1000 lb/h	FCP GT Btu/kWh
- Unfired						
150 / 365 1 PL	15.1	5500	34.8	5600	51.9	5660
400 / 650 1 PL	12.4	6230	28.4	6300	41.5	6320
600 / 750 1 PL	11.4	6670	26.3	6630	37.8	6660
850 / 825 1 PL	10.7	7010	24.6	6960	34.7	7000
600 / 750 2 PL	11.5	5750	26.4	5880	37.9	5870
150 / 365	1.3	-	2.9	-	6.1	-
850 / 825 2 PL	10.7	5840	24.7	5900	34.9	5870
150 / 365	1.8	-	4.1	-	8.6	-
1250 / 900 2 PL	-	-	22.9	5890	-	-
150 / 365	-	-	5.7	-	-	-
- Supp Fired						
150 / 365	29.7	4760	68.6	4930	117	4900
400 / 650	26.3	4760	60.8	4920	104	4840
600 / 750	25.4	4740	58.7	4900	100	4890
850 / 825	24.8	4730	57.3	4900	98.1	4810
1250 / 900	24.3	4710	56.2	4870	96.2	4790
1450 / 950	23.9	4700	55.2	4880	94.6	4780
- Fully Fired						
150 / 365	74.5	3240	169	3530	284	3560
400 / 650	66.1	3030	150	3430	252	3480
600 / 750	63.9	2920	145	3330	243	3490
850 / 825	62.4	2890	141	3490	238	3360
1250 / 900	61.2	2800	138	3500	233	3360
1450 / 950	60.1	2850	136	3390	229	3370

* Gas turbines and boilers fueled with natural gas and all fuel data based on higher heating value (HHV)
* Gas turbines equipped with DLN combustors
* Fuel chargeable to gas turbine power assumes GT credit with PH auxiliaries and equivalent boiler fuel required to generate steam in an 84% efficient boiler (HHV)
* Standard inlet losses; exhaust losses 10 "H2O for unfired 1PL, 12" H2O for unfired 2 PL, 14" H2O for supplementary fired, 20" H2O for fully fired
* Assumes 0% exhaust bypass stack damper leakage, 0% blowdown, and 150 F condensate return for all cases
* Unfired boiler design based on a 15 F pinch point / 15 F subcool approach temperature, with criteria to limit the stack temperature to a minimum of 220 F for all cases
* Supplementary firing based on average gas temperature of 1600 F
* Lower heating value (LHV) - 21515 Btu/lb, HHV = LHV x 1.11

** Rating based on 0/0 inlet/exhaust pressure drops

TABLE 6

STEAM GENERATION AND FUEL CHARGEABLE TO POWER WITH GAS TURBINE AND HEAT RECOVERY BOILERS

Generator Drive - Natural Gas Fuel - Dry Performance - SI Units

Gas Turbine Type	PGT2		PGT5		PGT10	
Gas Turbine Model	PGT2		PGT5		PGT10	
ISO Base Rating (KW) [illegible]	2000		5200		10140	
Performance at 15 C, Sea Level, Natural Gas Fuel	50 / 60 Hz		50 / 60 Hz		50 / 60 Hz	
Output - KW						
- Unfired, 1 PL	1,920		5,010		9,860	
- Unfired, 2 PL	1,910		4,990		9,820	
- Supp Fired	1,900		4,960		9,790	
- Fully Fired	1,880		4,890		9,680	
Power Turbine Speed - rpm	22,500		11,140		7,900	
Fuel - MKJ/h (HHV)	31.7		76.9		129.4	
Exhaust Flow - Tons/h	38		88		150	
Exhaust Temp - C						
- Unfired, 1 PL	530		529		489	
- Unfired, 2 PL	531		530		490	
- Supp Fired	532		531		491	
- Fully Fired	534		534		493	
HRSG Performance						
Fuel - MKJ/h (HHV)						
- Supp Fired	18.2		42.1		80.1	
- Fully Fired	75.6		170.6		292.3	
Steam Conditions (bara / C)	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh	HRSG Steam Tons/h	FCP GT KJ/kWh
- Unfired						
11.4 / 185 1 PL	6.8	5800	15.8	5910	23.5	5970
28.6 / 343 1 PL	5.6	6570	12.9	6650	18.8	6670
42.4 / 399 1 PL	5.2	7040	11.9	6990	17.1	7030
59.7 / 441 1 PL	4.9	7400	11.2	7340	15.7	7390
59.7 / 441 2 PL	5.2	6070	12.0	6200	17.2	6190
11.4 / 185	0.6	-	1.3	-	2.8	-
87.2 / 482 2 PL	4.9	6160	11.2	6220	15.8	6190
11.4 / 185	0.8	-	1.9	-	3.9	-
101 / 510 2 PL	-	-	10.4	6210	-	-
11.4 / 185	-	-	2.6	-	-	-
- Supp Fired						
11.4 / 185	13.5	5020	31.1	5200	53.1	5170
28.6 / 343	11.9	5020	27.6	5190	47.2	5110
42.4 / 399	11.5	5000	26.6	5170	45.4	5160
59.7 / 441	11.2	4990	26.0	5170	44.5	5070
87.2 / 482	11.0	4970	25.5	5140	43.6	5050
101 / 510	10.8	4960	25.0	5150	42.9	5040
- Fully Fired						
11.4 / 185	33.8	3420	76.6	3720	128.8	3760
28.6 / 343	30.0	3200	68.0	3620	114.3	3670
42.4 / 399	29.0	3080	65.8	3510	110.2	3680
59.7 / 441	28.3	3050	63.9	3680	107.9	3540
87.2 / 482	27.8	2950	62.6	3690	105.7	3540
101 / 510	27.3	3010	61.7	3580	103.9	3560

* Gas turbines and boilers fueled with natural gas and all fuel data based on higher heating value (HHV)
* Gas turbines equipped with DLN combustors
* Fuel chargeable to gas turbine power assumes GT credit with PH auxiliaries and equivalent boiler fuel required to generate steam in an 84% efficient boiler (HHV)
* Standard inlet losses; exhaust losses 254 mm H2O for unfired 1PL, 305 mm H2O for unfired 2 PL, 356 mm H2O for supplementary fired, 508 mm H2O for fully fired
* Assumes 0% exhaust bypass stack damper leakage, 0% blowdown, and 65.6 C condensate return for all cases
* Unfired boiler design based on a 8.3 C pinch point / 8.3 C subcool approach temperature, with criteria to limit the stack temperature to a minimum of 104.4 C for all cases
* Supplementary firing based on 871.1 C
* Lower heating value (LHV) - 50031 kJ/kg, HHV = LHV x 1.11

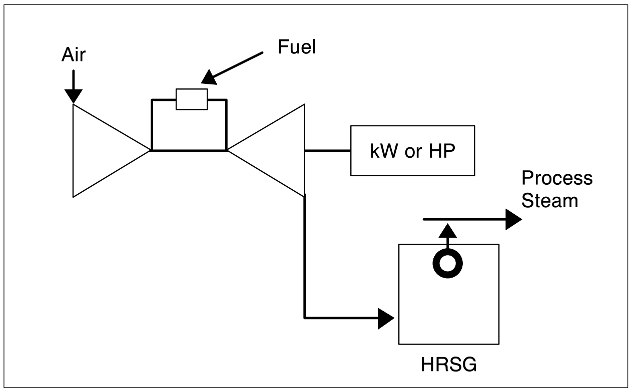

Figure 13. Gas turbine with LP HRSG

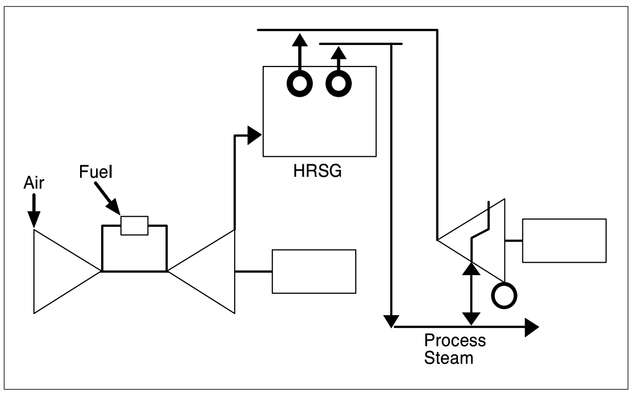

Figure 14. Typical industrial gas turbine cycle

a unit having the same amount of oxygen in its stack gases as an ambient-air-fired power boiler. The HRSG is essentially a power boiler with the gas turbine exhaust as its air supply.

Steam production from fully fired HRSGs (10% excess air) may range up to six or seven times the unfired HRSG steam production rate. The actual increase is a function of the oxygen remaining for combustion and the gas turbine exhaust temperature. Because of the use of preheated combustion air, fuel requirements for fully fired units will usually range between 7.5% and 8% less than those of an ambient-air-fired boiler providing the same incremental steam generating capacity. With the more efficient gas turbines (higher firing temperatures resulting in lower oxygen content in the exhaust gases), the ability to ignite and maintain stable combustion in the HRSG should be confirmed with the HRSG manufacturer.

Even though fully fired units can provide a significant amount of steam, few applications of this type can be found in industry. Evaluations show that the higher power-to-heat ratio available using unfired or supplementary fired HRSGs is usually economically preferred over fully fired HRSGs and lower amount of power generated.

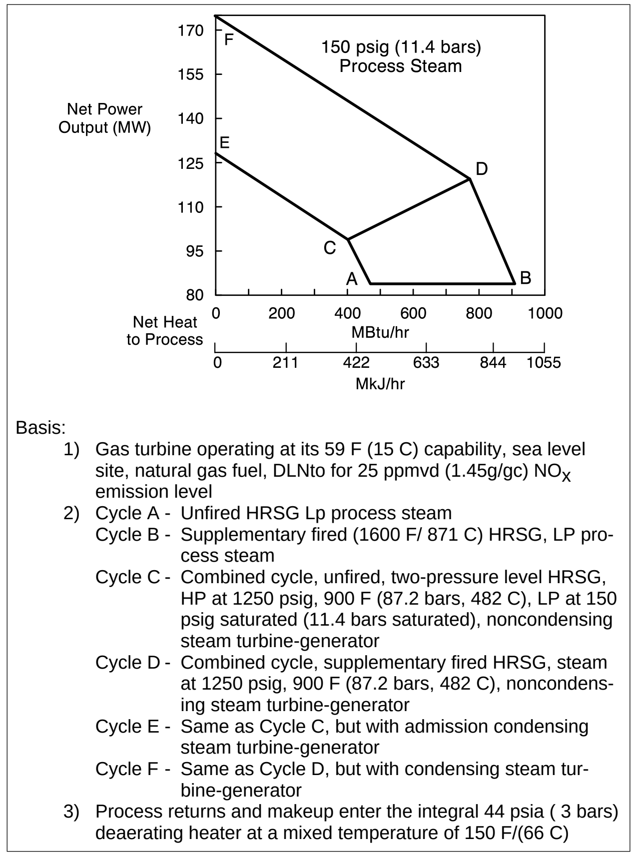

Figure 15. Performance envelope for gas turbine cogeneration system

HRSG STEAM PRODUCTION RATES

The amount of steam that can be generated using the exhaust gas from various GE gas turbine-generators frequently considered in industrial cogeneration systems is given in Tables 1, 2, 3, 4, 5 and 6.

In addition, the FCP is shown for the combination of the gas turbine and HRSG. This data is useful in performing gas turbine cogeneration feasibility studies to obtain a rough estimation of the cycle overall FCP. Simply take the gas turbine kilowatts generated and the tabulated FCP from Tables 1 through 6 and add the non-condensing steam turbine kilowatts generated at the before mentioned 4000 to 4500 Btu/kWh/4219 to 4747 kJ/kWh and the condensing steam turbine kilowatts generated (if there is a condenser in the cycle being considered) at 12,000 to 14,000 Btu/kWh/12,658 to 14,767 kJ/kWh. The weighted average of the FCP for the amount of power produced in the above three modes (gas turbine, non-condensing steam turbine and condensing steam turbine) will be a close estimate of the overall FCP for the system being considered.

Table 7
PERFORMANCE OF MS7001EA GAS TURBINE CYCLES

Cycle	A	B	C	D	E	F
Net Output - MW	84.4	84.3	98.6	119.7	128.1	174.4
NHP - MBtu/h	473	906	402	769	0	0
MkJ/h	499	956	424	811	0	0
FCP-Btu/kWh HHV	5010	4590	5150	4590	7700	8410
kJ/kWh HHV	5290	4840	5430	4840	8120	8870

Basis:
1) Cycle definitions as given in Figure 15
2) Net output is the total power credited to the cogeneration cycle
3) Net fuel includes credit for the Net Heat to Process (NHP) at an 84% process boiler efficiency (HHV)

CYCLE CONFIGURATIONS

The most simple gas turbine cogeneration cycle is one where the exhaust energy is used to generate steam at conditions suitable for the process steam header (Figure 13).

Generation of steam at higher initial steam conditions than those required in process will allow use of a steam turbine in addition to the gas turbine in the cogeneration cycle (Figure 14). This configuration derives the benefits of both gas and steam turbine cogeneration and yields a higher power-to-heat ratio than the arrangement given in Figure 13.

A multi-pressure HRSG system is shown in Figure 14. This arrangement is common for unfired and moderately fired (~1200 F/654 C) HRSG systems. The multi-pressure HRSG provides increased recovery of the gas turbine exhaust energy, and thus contributes to the favorable FCP associated with these cycles. For example, an unfired multi-pressure HRSG used in conjunction with an MS7001EA combined cycle supplying steam to process at 150 psig (10.3 bars) will yield about 5150 Btu/kWh HHV(5430 kJ/kWh HHV) FCP, whereas a single pressure, unfired HRSG used in a combined cycle, with the same gas turbine, would have a FCP of 6030 Btu/kWh HHV/6360 kJ/kWh HHV.

The steam turbine design shown schematically in Figure 14 provides considerable cycle flexibility in cogeneration applications. The condenser provides a heat sink for HRSG steam generating capability in excess of that extracted from the turbine for process use. Furthermore, the admission capability will permit the introduction of lower-pressure steam into the turbine for expansion to the condenser during periods when excess HRSG steam at the process pressure level is available.

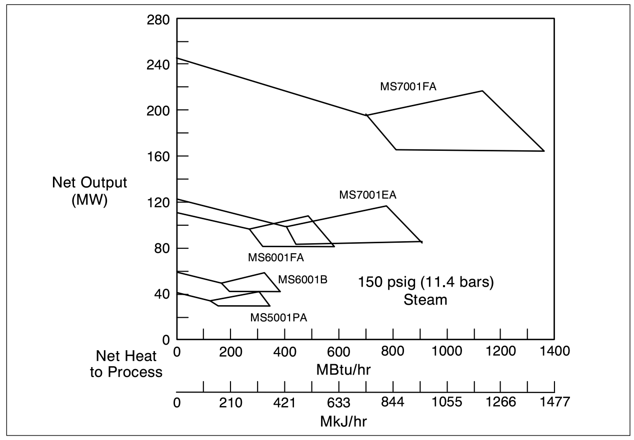

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Figure 16. Gas turbine cogeneration systems MS options, 60 Hz

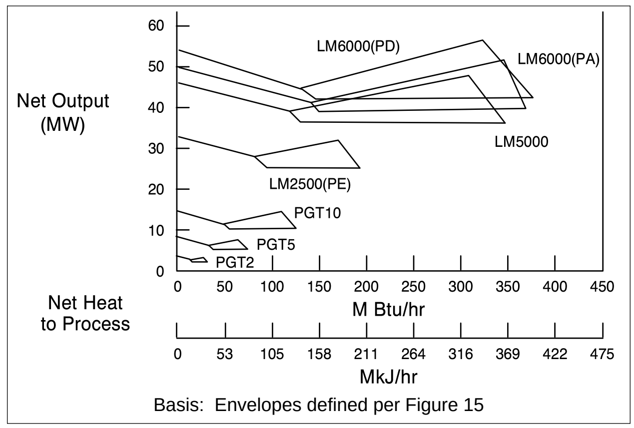

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Figure 17. Gas turbine cogeneration systems LM options, 60 Hz

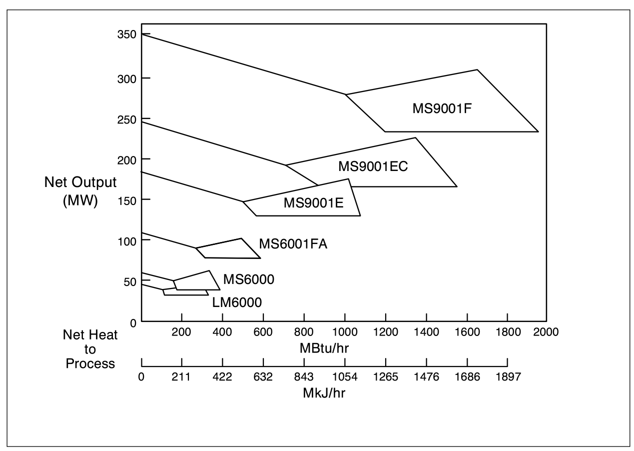

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Figure 18. Gas turbine congeneration systems options, 50 Hz

COMBINED-CYCLE DESIGN FLEXIBILITY

One method of displaying the many options available using a gas turbine in a cogeneration application is shown in Figure 15. This diagram has been developed for the GE MS7001EA gas turbine-generator (85,000 kW ISO, natural-gas-fired). A summary of the performance used to develop the envelope given in Figure 15 is presented in Table 7.

Point A represents the MS7001EA gas turbine-generator exhausting into an unfired low-pressure HRSG. Point C is a combined-cycle configuration based on use of a two-pressure-level unfired HRSG. The steam turbine in the C cycle is a non-condensing unit expanding the HP HRSG steam to the 150 psig/10.3 bar process steam header.

Points B and D in Figure 15 represent operation of the HRSG with supplementary firing to a 1600 F/871 C average exhaust gas temperature entering the heat transfer surface. The temperature used for the HRSG firing in Figure 15 has been arbitrarily limited to 1600 F/871 C even though higher firing temperatures (and thus higher steam production rates) are possible in the exhaust of this unit.

The envelope defined by A, B, C, D in Figure 15 represents the most thermally optimized use of a gas turbine in a cogeneration application (i.e., provides the lowest FCP). Operation along the line CE, DF or any intermediate point to the left of line CD represents use of condensing steam turbine power generation with the E and F points applicable for combined-cycle operation without any heat supplied to process. Thus, the cycles along line EF are combined cycles providing power alone.

Performance envelopes for many of the gas turbines included in Tables 1-6 are presented in Figures 16, 17 and 18. These data are on the same basis as Figure 15 except for point C. Point C for all units except the various MS7001 models is based on 850 psig, 825 F/59 bars, 440 C initial steam conditions to the non-condensing steam turbine. Furthermore, the only condensing power

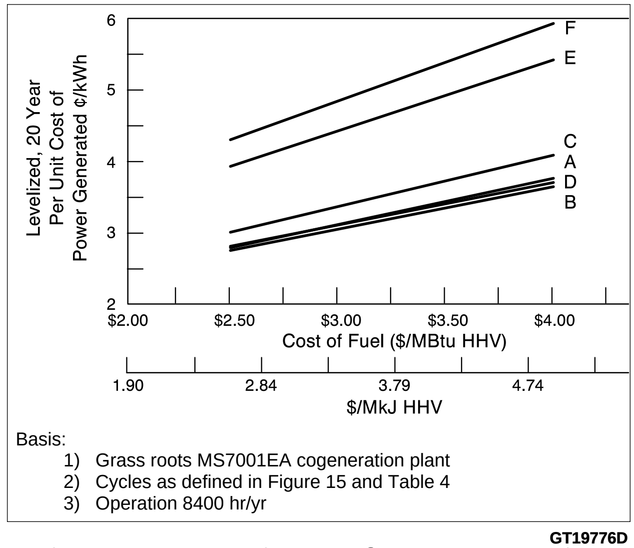


Figure 19. Per unit cost of power generation

Table 8
MS7001EA COGENERATION EXAMPLE

Case	1	2	3	4
Gas Turbine Units	1	1	2	4
HRSG- Pressure Levels	1	2	2	2
Steam Turbine	None	Noncondensing	Extraction Condensing	Extraction Condensing
Net Fuel- MBtu/hr HHV	508	508	1494	3466
MkJ/hr HHV	536	536	1576	3657
Net Power- MW	84.4	98.6	228.5	488.9
Fuel Chargeable to Power- Btu/kWh HHV	6020	5150	6540	7090
kJ/kWh HHV	6350	5430	6900	7480
Estimated Installed Cost-$ Millions (1996)	Base	16	85	203
Discounted Rate of Return-%	25.0	22.2	17.6	17.5

GT25452

Basis:
1) Process steam demand at 150 psig saturated (11.4 bars saturated) is 373,000 lb/hr (169,160 tons/h)
2) All HRSG units are unfired designs
3) Net fuel includes credit for process steam delivered at 84% boiler efficiency (HHV)
4) All comparisons with existing facility generating steam for direct use in process, 8400 hrs/yr operation assumed
5) Fuel cost $3.0/MBtu HHV; power value 4.0¢/kWh
6) Incremental costs for operating labor, water and maintenance are included
7) DRR based on 100% equity financing, 150% declining balance depreciation, 15 year economic life, 2% local property taxes and insurance, 40% combined income tax (federal and state), 4% annual escalation on fuel and power

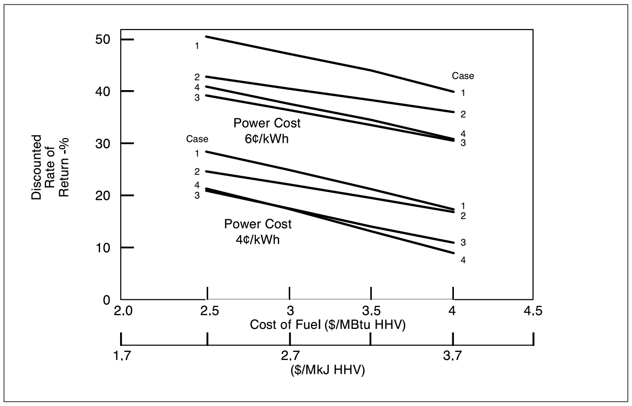
Table 9
FEASIBILITY GRADE
INSTALLED COST COMPARISONS

Grass Roots Facility

Alternative	Base	MS7001EA
Generation - MW	NA	84.1
Estimated Total Installed Cost - $ Millions, 1992	14	39
Incremental Investment $ Millions, 1992	Base	25
Unit Cost - $/KW	NA	464
Incremental Unit Cost - $/KW	Base	297

GT25453

Basis:
1) Plant requires 490,000 lb/hr (222,220 tons/h) of 150 psig (11.4 bars) saturated steam, 85 MW electric power
2) Gas turbine performance based on sea level site, 59 F(15 C) ambient, 60% relative humidity, natural gas fuel, DLN for NO_X control to 25 ppmvd NO_X(1.45 g/gc)
3) Costs are feasibility grade values that do not include escalation, interest during construction, spares or project soft costs



GT19775D

Figure 20. Economic performance at various fuel and power costs – MS7001EA cogeneration example

illustrated is based on unfired, two-pressure-level HRSG designs.

The per unit cost of power generation for cycles A through F given in Figure 15 is illustrated in Figure 19. The per unit costs are based on a 16.5% fixed charge rate for invested capital and other operating costs such as fuel, operating labor and maintenance. The plant costs, not given, are based on separate stand-alone facilities, i.e., no "investment credit" applied to any of the cogeneration cases (Cases A through D).

Per unit costs given in Figure 19 define two distinct performance levels. The "thermally optimized" cogen cases, Cases A through D, result in per unit costs that are about 20-30% lower than the unfired power generation case, Case E. And, if the thermally optimized cogen cases were considered as additions to an existing facility, part of a major plant expansion, or used to displace new boilers which are intended to replace aging equipment, the comparisons would be more dramatic. That is the incremental capital costs for the cogen systems might be 25% to 40% less than those used for Figure 19 due to significant savings represented by the use of existing infrastructure. Even so, site-specific fuel and power costs, or power sales opportunities may dictate cycles with considerable condensing power as the appropriate economic choice.

An example illustrating the performance and economics of various MS7001EA gas turbine cogeneration cycles is given in Table 8 and Figure 20. Cycles range from the "thermal match" examples, Cases 1 and 2, to configurations including considerable steam turbine condensing power, Cases 3 and 4.

The evaluation given in Table 8 shows that Case 1 is economically preferred when a $3.00/MBtu HHV ($2.80/10^{9}J HHV) fuel and 4.0¢/kWh power cost are assumed. Data presented in Figure 20 also shows that there may be combinations of fuel and power costs that favor gas turbine cogeneration systems developed to provide large quantities of steam turbine condensing power.

COGENERATION OPPORTUNITIES

Circumstances under which cogeneration should be considered include:

- Development of new industrial or commercial facilities
- Major expansions to existing industrial facilities
- Expansion of large commercial and educational institutions such as universities, hospitals and shopping malls needing power, heat and/or cooling
- Replacement of aging steam generation equipment
- Significant changes in energy costs (fuel and power)
- Power sale opportunities

New industrial plants or major expansions to existing facilities having large process heat demands and continuous process operations provide ideal opportunities to evaluate cogeneration. In these instances, cogeneration is compared to a Base Case where process heat is produced on-site with power requirements purchased from the utility. Cogeneration represents an incremental investment relative to the Base Case with significant infrastructure savings and thus the capital cost on a $/kW basis is less than for a grass roots Base Case facility without this "investment credit." For example, assuming a new facility requires 490,000 lb/hr (222,220 Tons/hr) of gas-fired boiler capacity at 150 psig/11.4 bars, and 85 MW, the incremental investment for an MS7001EA with an unfired HRSG providing a portion of the required steam may be about $300/kW. Whereas, installation of a separate facility with the MS7001EA and supplementary-fired HRSG system may approach $460-470/kW making a potential project more difficult to economically justify (see Table 9).

Replacement of old low-pressure process steam boilers, or even boilers with higher steam conditions used to support a steam turbine cogeneration system often provides an attractive cogeneration opportunity. Boiler steam capacity can be replaced by a gas turbine/HRSG system significantly increasing the system power to heat ratio at an attractive FCP. In addition, the "investment credit" for the replacement boiler generally assures that the $/kW cost can be reasonable.

When a facility anticipates a significant change in energy costs, the economic potential of cogeneration should be examined. This is particularly true in locations where purchased power costs may be increasing much faster than fuel costs. A cogeneration evaluation may suggest attractive economics even if there are no offsetting investments. Furthermore, if the cogeneration system results in an attractive FCP, the profitability may increase as fuel costs increase.

Many projects have been developed resulting from favorable power sales opportunities. Some projects are of a size that could have simple displaced power purchases. Others are based on circumstances where large process heat demands permit generation of electric power significantly in excess of plant power needs, such as the enhanced oil recovery projects using steam injection.

Many cogeneration projects have been developed where the value is driven by the revenues from power sales to the utility grid. Frequently the steam host is simply the mechanism for qualification and revenue from steam sales is incidental to the financial success of the project. Through the use of financial leverage, projects can be developed yielding returns that, on a 100% equity basis, are lower than that considered acceptable by many industrials for discretionary investments, yet based on the leverage, are quite attractive as independent investments.

CONCLUSION

Cogeneration continues to play an important role in controlling industrial or commercial energy costs through the effective integration of power generation options into the plant energy supply system. The overall performance and application flexibility of the cogeneration equipment and system is critical to the success of these ventures. The use of automatic extraction steam turbines to control process pressures, integration of gas turbine exhaust energy for process steam generation, process fluid heating and preheated combustion air for fired process heaters are a few examples of the many options available.

As more and more industrials, commercial/educational establishments, developers and utilities around the world search for low cost electric energy and process heat, cogeneration is found to offer high efficiency and possibly environmental benefits as well. The industrial steam host is one important key to success. The host provides the thermal energy demands that can be leveraged to highly efficient cogeneration systems as well as land for utilities and developers to site new generation facilities.

This paper has shown the large array of choices available to those configuring a future power system. Optimizing a cogeneration system is a complicated process that is usually most satisfactorily addressed when the turbine supplier, permitting engineer, steam host, system owner and utility work hand in hand. Application engineering decisions should be made with as much knowledge as possible. Each project has its own unique drivers such as redundancy, maximum kilowatt capability, pollution issues, reliability of steam or kilowatt supply or part load operational flexibility. To respond to these issues, the application engineering team must “know” the project.

We remain committed to the development of effective and efficient cogeneration systems that provide the user the operational and service characteristics necessary for successful applications. It is vital to these projects that the cycles envisioned will be viewed as reliable steam supplies by the industrial hosts and, at the same time, be solid reliable capacity in the eyes of the industrial or utility that is utilizing that electric power. We offer our application resources to develop potential alternatives and identify those systems that most economically satisfy specified energy requirements.

LIST OF FIGURES

LIST OF TABLES

For further information, contact your GE Field Sales Representative or write to GE Power Generation Marketing

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