Catalog of CHP Technologies

Section 3. Technology Characterization – Combustion Turbines

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

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The September 2017 revision incorporated a new section on packaged CHP systems (Section 7).

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Section 3. Technology Characterization – Combustion Turbines

3.1 Introduction

Gas turbines have been in use for stationary electric power generation since the late 1930s. Turbines went on to revolutionize airplane propulsion in the 1940s, and since the 1990s through today, they have been a popular choice for new power generation plants in the United States.

Gas turbines are available in sizes ranging from 500 kilowatts (kW) to more than 300 megawatts (MW) for both power-only generation and combined heat and power (CHP) systems. The most efficient commercial technology for utility-scale power plants is the gas turbine-steam turbine combined-cycle plant that has efficiencies of more than 60 percent (measured at lower heating value [LHV][35]). Simple-cycle gas turbines used in power plants are available with efficiencies of over 40 percent (LHV). Gas turbines have long been used by utilities for peaking capacity. However, with changes in the power industry and advancements in the technology, the gas turbine is now being increasingly used for base-load power.

Gas turbines produce exhaust heat at high temperatures that can be recovered in a CHP configuration to produce steam for process use. Such CHP configurations can reach overall system efficiencies (electricity and useful thermal energy) of 70 to 80 percent. By the early 1980s, the efficiency and reliability of smaller gas turbines (1 to 40 MW) had progressed sufficiently to be an attractive choice for industrial and large institutional users for CHP applications.

Gas turbines have very low emissions compared to other fossil-powered generation technologies. With catalytic exhaust cleanup or lean pre-mixed combustion, some large gas turbines achieve emissions of oxides of nitrogen (NO_x) well below 10 parts per million (ppm).[36] Because of their relatively high efficiency and the reliance on natural gas as a primary fuel, gas turbines emit substantially less carbon dioxide (CO_2) per kilowatt-hour (kWh) generated than other fossil technology in commercial use.[37]

3.2 Applications

Gas turbines are used in a variety of stationary applications:

- **Electric utility central station power generation** – Gas turbines are used widely by the electric utility industry. Combined cycle turbine plants contribute to base-load power needs, and simple cycle turbines are used for meeting peak-load. Today, gas turbines comprise 32 percent, or 315 gigawatts (GW), of central station power plant capacity

[35] Most of the efficiencies quoted in this report are based on higher heating value (HHV), which includes the heat of condensation of the water vapor in the combustion products. In engineering and scientific literature concerning heat engine efficiencies the lower heating value (LHV – which does not include the heat of condensation of the water vapor in the combustion products) is usually used. The HHV is greater than the LHV by approximately 10 percent with natural gas as the fuel (e.g., 50 percent LHV is equivalent to 55 percent HHV). HHV efficiencies are about 8 percent greater for oil (liquid petroleum products) and 5 percent for coal.

[36] Volumetric emissions for gas turbines are measured at 15 percent oxygen in the exhaust.

[37] Fuel cells, which produce electricity from hydrogen and oxygen, emit only water vapor. There are emissions associated with producing the hydrogen supply depending on its source. However, most fuel cell technologies are still being developed, with only one type (phosphoric acid fuel cell) commercially available in limited production.

- **Combined heat and power** – Gas turbines are used extensively for CHP applications providing efficient, economic, and reliable service. Gas turbines comprise 63 percent, or 51.5 GW, of total installed CHP capacity in the U.S.[38] Close to 80 percent of this gas turbine CHP capacity is in large combined cycle plants that maximize the export of power to the electrical grid.[39] The remaining GT CHP capacity is made up of simple-cycle gas turbine based CHP systems, typically less than 40 MW.

- **Mechanical drive** – Oil and gas production, processing, transmission, and some process industries use gas turbines for pumping, compression, and other mechanical drive operations. In mechanical power applications, the turbine shaft power is used directly. There is no electrical generator, though there can be heat recovery, and such systems can be classified as CHP.

- **Distributed power-only** – Gas turbines are used for distributed power generation at remote oilfield facilities and can be used by industry and utilities alike for portable power generation. Large industrial facilities install simple-cycle gas turbines without heat recovery to provide peaking power in capacity constrained areas, and utilities often place gas turbines in the 5 to 40 MW size range at substations to provide incremental capacity and grid support. A number of turbine manufacturers and packagers offer mobile turbine generator units in the 5-40 MW size range that can be used in one location during a period of peak demand and then transported to another location for the following season.

Gas turbines are ideally suited for CHP applications because their high-temperature exhaust can be used to generate process steam at conditions as high as 1,200 pounds per square inch gauge (psig) and 900 °F or used directly in industrial processes for heating or drying. A typical industrial CHP application for gas turbines is a chemical plant with a 25 MW simple cycle gas turbine supplying base-load power to the plant with an unfired heat recovery steam generator (HRSG) on the exhaust. This gas turbine CHP system will produce approximately 29 MW thermal (MW_{th}) of steam for process use within the plant.

A typical commercial/institutional CHP application for gas turbines is a college or university campus with a 5 MW simple-cycle gas turbine. Approximately 8 MWth of 150 psig to 400 psig steam (or hot water) is produced in an unfired heat recovery steam generator and sent to a central thermal loop for campus space heating during the winter, or to single-effect absorption chillers to provide cooling during the summer.

3.3 Technology Description

3.3.1 Basic Process

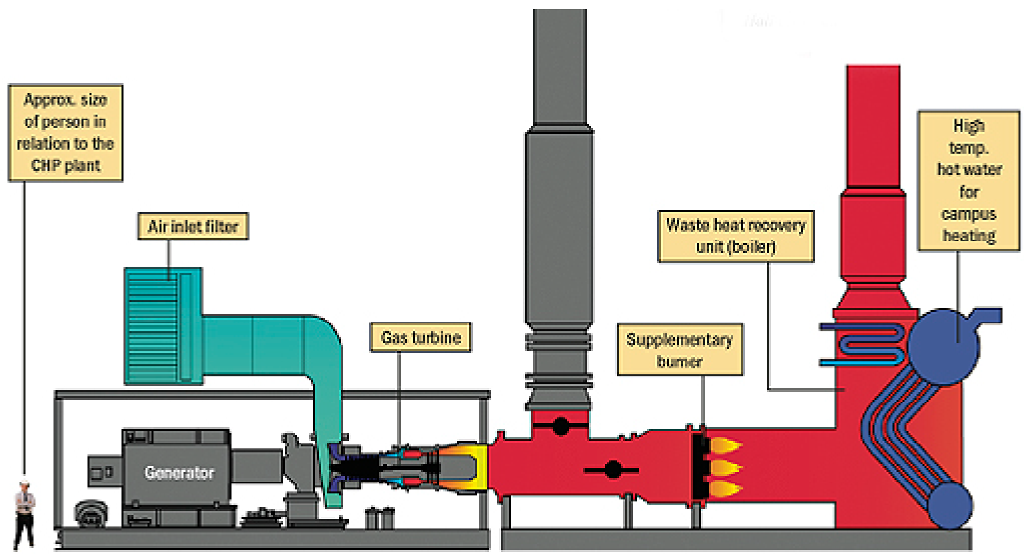
Gas turbine systems operate on the Brayton thermodynamic cycle, a constant pressure open cycle heat engine. The Brayton cycle consists of a compressor, a combustion chamber, and an expansion turbine. The compressor heats and compresses the inlet air which is then further heated by the addition of fuel in the combustion chamber. The hot air and combustion gas mixture drives the expansion turbine producing enough energy to provide shaft-power to the generator or mechanical process and to drive the compressor as well. The power produced by an expansion turbine and consumed by a compressor is

[38] Electric utility sector gas turbine capacity is from EIA data (2014). CHP gas turbine total capacity based on the ICF CHP Installations database.
[39] ICF CHP Installations Database, 2014

proportional to the absolute temperature of the gas passing through the device. Consequently, it is advantageous to operate the expansion turbine at the highest practical temperature consistent with economic materials and internal blade cooling technology and to operate the compressor with inlet air flow at as low a temperature as possible. As technology advances permit higher turbine inlet temperature, the optimum pressure ratio also increases.

There are several variations of the Brayton cycle in use today. Fuel consumption may be decreased by preheating the compressed air with heat from the turbine exhaust using a recuperator or regenerator. The compressor work may also be reduced and net power increased by using intercooling or precooling techniques. In a combined cycle, the exhaust may be used to raise steam in a boiler and to generate additional power. **Figure 3-1** shows the configuration for an unrecuperated industrial gas turbine with shaft power, driving an electric generator and the exhaust heat powering a heat recovery steam generator (HRSG) with supplementary firing capability.

Figure 3-1. Gas Turbine Configuration with Heat Recovery



Source: University of Calgary

Gas turbine exhaust is quite hot, up to 800 to 900°F for smaller industrial turbines, and up to 1,100°F for some new, large central station utility machines and aeroderivative turbines. Such high exhaust temperatures permit direct use of the exhaust for applications such as combustion air preheating, drying, or other applications requiring hot air stream. Such direct use of the exhaust is also called *closely coupled* CHP. More commonly, the exhaust heat is recovered with the addition of a heat recovery steam generator, which produces steam or hot water. A portion or all of the steam generated by the HRSG may be used to generate additional electricity through a steam turbine in a combined cycle configuration.

A gas turbine system is considered to be a combined heat and power (CHP) configuration if the waste heat (i.e., thermal energy) generated by the turbine is applied in an end-use. For example, a simple-cycle gas turbine using the exhaust in a direct heating process is a CHP system. A gas turbine system that uses the turbine exhaust in a HRSG, and then uses the steam from the HRSG to produce electricity in a steam turbine is a combined cycle unit, and is not considered to be CHP (no end-use thermal need). This latter configuration is a waste heat-to-power (WHP) system.

Key gas turbine design characteristics are shown in **Table 3-1.**

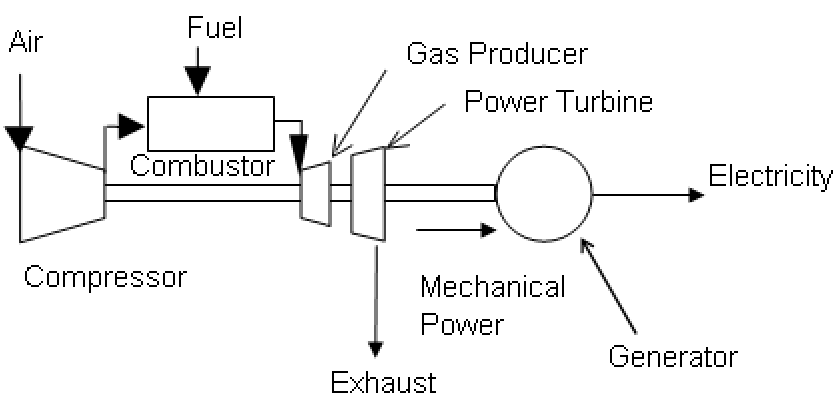
Table 3-1. Gas Turbine Design Characteristics

Thermal output	Gas turbines produce a high quality (high temperature) thermal output suitable for most combined heat and power applications. High-pressure steam can be generated or the exhaust can be used directly for process drying and heating. The exhaust can also be used to produce chilled water using an absorption chiller.
Fuel flexibility	Gas turbines operate on natural gas, synthetic gas, landfill gas, and fuel oils. Plants typically operate on gaseous fuel with a stored liquid fuel for backup to obtain the less expensive, interruptible rate for natural gas.
Reliability and life	Modern gas turbines have proven to be reliable power generators given proper maintenance. Time to overhaul is typically 25,000 to 50,000 hours.
Size range	Gas turbines are available in sizes from 500 kW to over 300 MW.
Emissions	Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x combustors) that produce NO_x emissions below 25 ppm, with laboratory data showing emissions down to 9 ppm, and simultaneous low CO emissions in the 10 to 50 ppm range.[40] Selective catalytic reduction (SCR) or catalytic combustion can further reduce NO_x emissions. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve single-digit (below 9 ppm) NO_x emissions.
Part-load operation	Because gas turbines reduce power output by reducing combustion temperature, efficiency at part load can be substantially below that of full-power efficiency.

3.3.2 Components

Figure 3-2 shows the primary components of a simple cycle gas turbine.

Figure 3-2. Components of Simple Cycle Gas Turbine



Higher temperature and pressure ratios result in higher efficiency and specific power, or power-to-weight ratio. Thus, the general trend in gas turbine advancement has been towards a combination of

[40] Gas turbines have high oxygen content in their exhaust because they burn fuel with high excess air to limit combustion temperatures to levels that the turbine blades, combustion chamber and transition section can handle without compromising system life. Consequently, emissions from gas turbines are evaluated at a reference condition of 15 percent oxygen. For comparison, boilers use 3 percent oxygen as the reference condition for emissions, because they can minimize excess air and thus waste less heat in their stack exhaust. Note that due to the different amount of diluent gases in the combustion products, the NO_x measurement of 9 ppm @ 15 percent oxygen is approximately equivalent to 27 ppm @ 3 percent oxygen.

higher temperatures and pressures. While such advancements increase the manufacturing cost of the machine, the higher value, in terms of greater power output and higher efficiency, provides net economic benefits.

3.3.2.1 Types of Gas Turbines

Aeroderivative Gas Turbines

Aeroderivative gas turbines for stationary power are adapted from their jet and turboshaft aircraft engine counterparts. While these turbines are lightweight and thermally efficient, they are usually more expensive than products designed and built exclusively for stationary applications. The largest aeroderivative generation turbines available are 40 to 50 MW in capacity. Many aeroderivative gas turbines for stationary use operate with compression ratios in the range of 30:1, requiring a high-pressure external fuel gas compressor. With advanced system developments, larger aeroderivative turbines (>40 MW) have achieved over 43 percent simple-cycle efficiency (LHV).

Industrial Gas Turbines

Industrial gas turbines, or frame gas turbines, are exclusively for stationary power generation and are available in capacities from 1 to over 300 MW. They are generally less expensive, more rugged, can operate longer between overhauls, and are more suited for continuous base-load operation with longer inspection and maintenance intervals than aeroderivative turbines. However, they are less efficient and much heavier. Industrial gas turbines generally have more modest compression ratios (up to 16:1) and often do not require an external fuel gas compressor. Larger industrial gas turbines (>100 MW) are approaching simple-cycle efficiencies of approximately 40 percent (LHV) and combined-cycle efficiencies of 60 percent (LHV).

Industrial plants use gas turbines between 500 kW to 40 MW for on-site power generation and for direct mechanical drive applications. Small gas turbines also drive compressors on long distance natural gas pipelines. In the petroleum industry, turbines drive gas compressors to maintain well pressures and provide compression and pumping for refineries and petrochemical plants. In the steel industry, turbines drive air compressors used for blast furnaces. In process industries such as chemicals, refining and paper, and in large commercial and institutional applications turbines are used in combined heat and power mode generating both electricity and steam for use on-site.

3.4 Performance Characteristics

The efficiency of the Brayton cycle is a function of pressure ratio, ambient air temperature, turbine inlet air temperature, the efficiency of the compressor and turbine elements, turbine blade cooling requirements, and also any other performance enhancements (i.e., recuperation, intercooling, inlet air cooling, reheat, steam injection, or combined cycle). All of these parameters, along with gas turbine internal mechanical design features, continue to improve with time. Therefore newer machines are usually more efficient than older ones of the same size and general type.

Table 3-2 summarizes performance characteristics for typical commercially available gas turbine CHP systems over the 3 to 45 MW size range. In the table, note that:

- Heat rates shown are from manufacturers' specifications and are net of losses due to inlet and outlet pressure drop and parasitic power.
- Available thermal energy (steam output) was calculated from information provided by the vendors or published turbine data on turbine exhaust temperatures and flows.
- CHP steam estimates are based on an unfired HRSG producing dry, saturated steam at 150 psig.
- Total efficiency is defined as the sum of the net electricity generated plus steam produced for plant thermal needs divided by total fuel input to the system. Higher steam pressures can be obtained but at slightly lower total efficiencies. Additional steam can be generated and total efficiency further increased with duct firing in the HRSG (see heat recovery section).
- To estimate fuel savings effective electrical efficiency is a more useful value than overall efficiency. Effective electric efficiency is calculated assuming the useful thermal output from the CHP system would otherwise be generated by an 80 percent efficient boiler. The theoretical boiler fuel is subtracted from the total fuel input and the remaining fuel input used to calculate the effective electric efficiency which can then be compared to traditional electric generation.
- The ratings in the table are all for systems operating in baseload (continuous) duty. Peaking and emergency power units generally have lower efficiency, lower capital cost, higher emissions, and are limited in their run hours.

The data in the table show that electrical efficiency generally increases as combustion turbines become larger. As electrical efficiency increases, the absolute quantity of thermal energy available to produce steam decreases per unit of power output, and the ratio of power to heat for the CHP system increases. A changing ratio of power to heat impacts project economics and may affect the decisions that customers make in terms of CHP acceptance, sizing, and the desirability of selling power. It is generally recommended to size a CHP system based on a site's thermal load demand; therefore, such power to heat ratios are important characteristics to consider.

Table 3-2. Typical Performance for Gas Turbines in CHP Operation

Cost & Performance Characteristics[41]	System				
	1	2	3	4	5
Net Electricity Capacity (kW)	3,304	7,038	9,950	20,336	44,488
Installed Cost (2013 $/kW)[42]	$3,281	$2,080	$1,976	$1,518	$1,248
Electric Heat Rate (Btu/kWh), HHV[43]	14,247	11,807	12,482	10,265	9,488
Electrical Efficiency (%), HHV	23.95%	28.90%	27.34%	33.24%	35.96%
Fuel Input (MMBtu/hr), HHV	47.1	83.1	124.2	208.7	422.1
Required Fuel Gas Pressure (psig)	166.8	299.4	362.3	405.2	538

[41] Data based on: 3 MW – Solar Turbines Centaur 40, 7 MW – Solar Taurus 70, 10 MW – Solar Mars 100, 20 MW – Solar Titan 250, 45 MW – GE LM6000.

[42] Installed costs based on CHP system producing 150 psig saturated steam with an unfired heat recovery steam generator, gas compression, building, with SCR/CO/CEMS exhaust gas treatment in an uncomplicated installation at a customer site.

[43] All turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. Electric utilities measure power plant heat rates in terms of HHV and fuel prices are given in terms of the HHV. The ratio of LHV to HHV is approximately 0.9 for natural gas.

Table 3-2. Typical Performance for Gas Turbines in CHP Operation

Cost & Performance Characteristics[41]	System				
	1	2	3	4	5
CHP Characteristics					
Exhaust Flow (1,000 lb/hr)	149.2	211.6	334	536	1047
GT Exhaust Temperature (Fahrenheit)	838	916	913	874	861
HRSG Exhaust Temperature (Fahrenheit)	336	303	322	326	300
Steam Output (MMBtu/hr)	19.66	34.44	52.36	77.82	138.72
Steam Output (1,000 lbs/hr)	19.65	34.42	52.32	77.77	138.64
Steam Output (kW equivalent)	5,760	10,092	15,340	22,801	40,645
Total CHP Efficiency (%), HHV[44]	65.7%	70.4%	69.5%	70.5%	68.8%
Power/Heat Ratio[45]	0.57	0.70	0.65	0.89	1.09
Net Heat Rate (Btu/kWh)[46]	6,810	5,689	5,905	5,481	5,590
Effective Electrical Efficiency (%)[47]	50%	60%	58%	62%	61%
Thermal Output as Fraction of Fuel Input	0.42	0.41	0.42	0.37	0.33
Electric Output as Fraction of Fuel Input	0.24	0.29	0.27	0.33	0.36

Source: Compiled by ICF from vendor-supplied data

3.4.1 Fuel Supply Pressure

As shown previously in **Figure 3-2**, the fuel gas is mixed with the combustion air after it has been heated and compressed. Therefore, the fuel gas must also be compressed to a pressure somewhat higher than the combustion air. This pressure is determined by the turbine pressure ratio. The fuel gas compressor size and energy requirements are determined not only by the required outlet conditions but also by the delivery pressure. Depending on the supply pressure of the gas being delivered to the site, the cost and power consumption of the fuel gas compressor can be a significant consideration. **Table 3-3** shows the power required to compress natural gas from supply pressures typical of commercial and industrial service to the pressures required by typical industrial gas turbines. Required supply pressures generally increase with gas turbine size.

[44] Total Efficiency = (net electric generated + net steam produced for thermal needs)/total system fuel input
[45] Power/Steam Ratio = CHP electrical power output (Btu)/ useful steam output (Btu)
[46] Net Heat Rate = (total fuel input to the CHP system - the fuel that would be normally used to generate the same amount of thermal output as the CHP system output assuming an efficiency of 80 percent)/CHP electric output (kW).
[47] Effective Electrical Efficiency = (CHP electric power output) / (total fuel into CHP system – total heat recovered/0.8); Equivalent to 3,412 Btu/kWh/Net Heat Rate.

Table 3-3. Power Requirements for Natural Gas Fuel Compression[48]

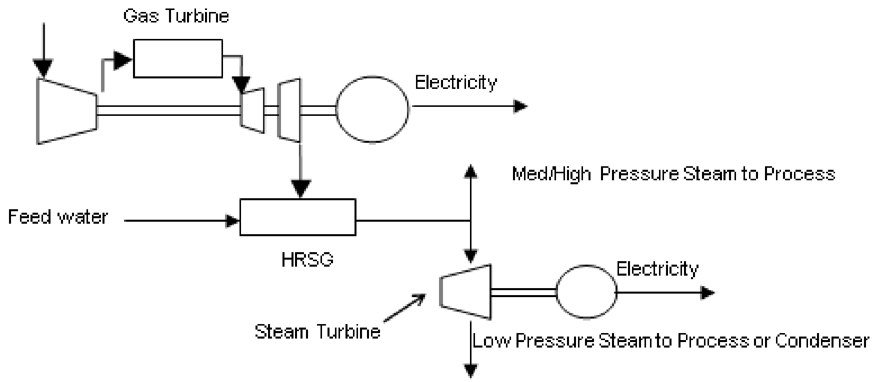
Turbine Conditions	System				
	1	2	3	4	5
Turbine Electric Capacity (kW)	3,304	7,038	9,950	20,336	44,488
Turbine Pressure Ratio	10.1	17.6	17.7	24	31.9
Pressure Required, psig	167	299	362	405	538
Required Compression Power (kW)					
55 psig gas supply pressure	51	162	289	538	1,370
150 psig gas supply pressure	21	63	113	211	510
250 psig gas supply pressure	NA	39	70	131	310

Source: Compiled by ICF from vendor supplied data

3.4.2 Heat Recovery

The economics of gas turbines as CHP in process applications are highly dependent on effective use of the thermal energy contained in the exhaust gas. **Figure 3-3** provides a schematic representation of a gas turbine generator with exhaust heat recovery transferring energy to a heat recovery steam generator (HRSG) that can provide steam for process use or to drive a steam turbine generator. Thermal energy generally represents 60 to 70 percent of the inlet fuel energy. The most common use of this energy is for steam generation in unfired or supplementary fired heat recovery steam generators. However, the gas turbine exhaust gases can also be used as a source of direct process energy, for unfired or fired process fluid heaters, or as preheated combustion air for power boilers. An unfired HRSG is the simplest steam CHP configuration and can generate steam up to approximately 1,200 psig.

Figure 3-3. Heat Recovery from a Gas Turbine System



As the quality of the steam required satisfying a thermal load increases, the overall system efficiency decreases. Even with a counter-flow heat exchanger, the HRSG stack temperature increases when the steam quality increases. For the Solar Taurus 70, an overall efficiency of 80.5 percent is possible with a HRSG producing 15 psig steam (LHV basis). A system producing 900 psig steam has an overall efficiency

[48] Fuel gas supply pressure requirements calculated assuming delivery of natural gas at an absolute pressure 35 percent greater than the compressor discharge in order to meet the requirements of the gas turbine flow control system and combustor mixing nozzles. Mass flow of fuel based on the fuel flow of reference gas turbines in the size range considered, and assuming an electric motor of 95 percent efficiency driving the booster compressor. Gas supply pressures of 50 psig, 150 psig and 250 psig form the basis of the calculations.

of 72.8 percent (LHV basis.) The low pressure steam can extract the exhaust energy down to a HRSG stack temperature of 275 °F; for the high (900 psig) steam requirement, energy can only be extracted down to a HRSG stack temperature of 380 °F.[49]

Overall CHP efficiency generally remains high under part load conditions because the lower efficiencies of electric generation at part load create more heat available for recovery steam making. The same low pressure steam system described above has an overall efficiency at 50 percent output that is virtually unchanged from full load operation even though the generation efficiency has dropped from 32.8 percent to 24.8 percent (LHV basis.) However, at 50 percent load the power to heat ratio has dropped from the full load value of 0.70 to 0.46 indicating that a much higher share of the total energy recovered is in the form of heat.

Gas turbines operate with a high degree of excess air compared to the stoichiometric ratio[50] required for combustion of the input fuel. Turbine exhaust is typically about 15 percent oxygen. Since very little of the available oxygen in the turbine air flow is used in the combustion process, the oxygen content in the gas turbine exhaust permits supplementary fuel firing ahead of the HRSG to increase steam production relative to an unfired unit. Supplementary firing can raise the exhaust gas temperature entering the HRSG up to a maximum of 2,800°F and increase the amount of steam produced by the unit by more than a factor of four. Moreover, since the turbine exhaust gas is essentially preheated combustion air, the fuel consumed in supplementary firing is less than that required for a stand-alone boiler providing the same increment in steam generation. The HHV efficiency of incremental steam production from supplementary firing above that of an unfired HRSG is often 85 percent or more when firing natural gas.

Supplementary firing also increases system flexibility. Unfired HRSGs are typically convective heat exchangers that respond solely to exhaust conditions of the gas turbine and do not easily allow for steam flow control. Supplementary firing capability provides the ability to control steam production, within the capability of the burner system, independent of the normal gas turbine operating mode. Low NO_x duct burners with guaranteed emissions levels as low as 0.08 lb NO_x/MMBtu can be specified to minimize the NO_x contribution of supplemental firing.

3.4.3 Part-Load Performance

When less than full power is required from a gas turbine, the output is reduced by lowering the turbine inlet temperature. In addition to reducing power, this change in operating conditions also reduces efficiency. **Figure 3-4** shows a typical part-load derate curve. Emissions are generally increased at part load conditions, especially at half load and below.

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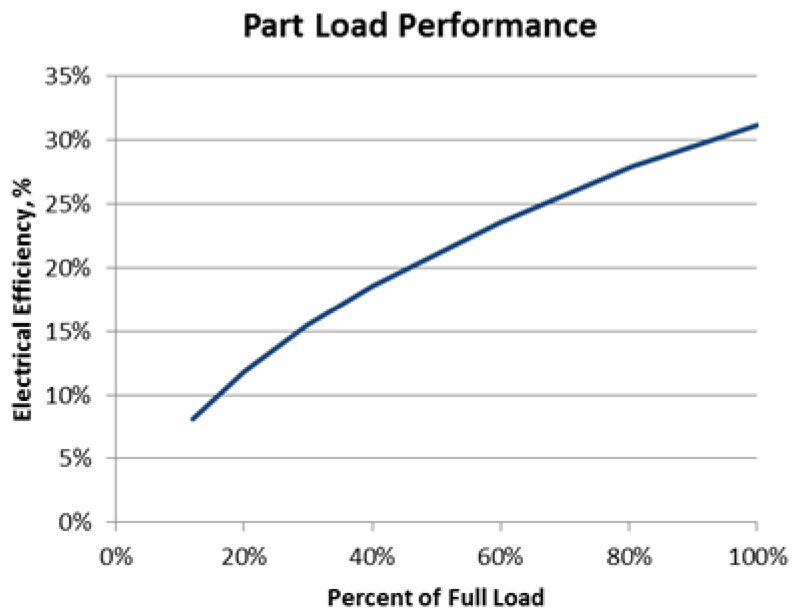
49 Vendor supplied performance data.

50 The stoichiometric ratio refers to the amount of one reactant necessary to completely react with other reactant, without having any input leftover once the reaction has completed.

Figure 3-4. Effect of Part Load Operation on Electrical Efficiency



Source: Solar Turbines, Mars 100[51]

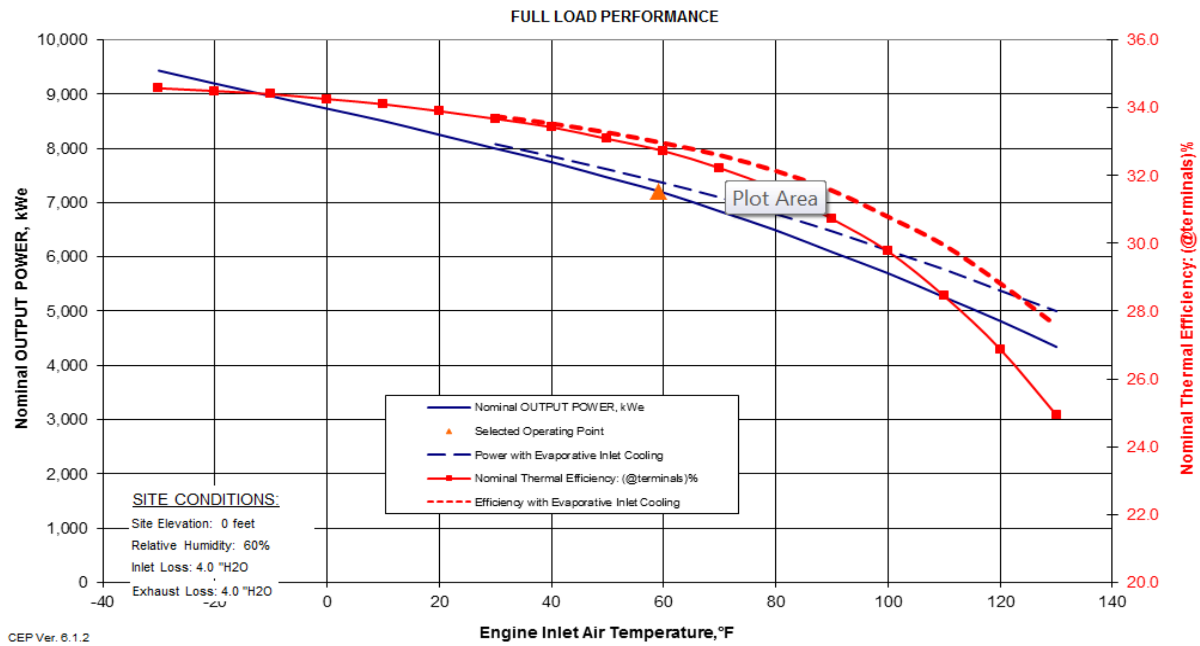
3.4.4 Effects of Ambient Conditions on Performance

3.4.4.1 Ambient Air Temperature

The ambient conditions under which a gas turbine operates have a noticeable effect on both the power output and efficiency. At elevated inlet air temperatures, both the power and efficiency decrease. The power decreases due to the decreased air flow mass rate (the density of air declines as temperature increases), and the efficiency decreases because the compressor requires more power to compress air of higher temperature. Conversely, the power and efficiency increase when the inlet air temperature is reduced. **Figure 3-5** shows the variation in power and efficiency for the nominal 7.5 MW Solar Taurus 70 gas turbine as a function of ambient temperature. ISO rating conditions for gas turbines are at sea level and 59 °F. Compared to this rating point, power output drops to 80 percent at 100 °F and increases to 107 percent at 40 °F. The corresponding efficiency effects are down 8 percent and up 2 percent for 100 and 40 °F respectively. The effects of ambient temperature on output and efficiency need to be considered in the design and evaluation of a gas turbine CHP system because in many parts of the country, electric prices are highest in the summer when performance of the system is at its lowest.

[51] "Mars 100 Gas Turbine Generator Set", Solar Turbines *A Caterpillar Company*. *https://mysolar.cat.com/cda/files/126902/7/ds100pg.pdf*

Figure 3-5. Effect of Ambient Temperature on Capacity and Efficiency



Source: Solar Turbines, Taurus 70[52]

Figure 3-5 also shows how inlet air cooling can help to moderate the loss of power and efficiency at higher ambient temperatures. The figure shows that cooling the air entering the turbine by 40 to 50°F on a hot day can increase power output by 15 to 20 percent. The decreased power and efficiency resulting from high ambient air temperatures can be mitigated by any of several approaches to inlet-air cooling, including refrigeration, evaporative cooling, and thermal-energy storage using off-peak cooling.

With refrigeration cooling, either a compression driven or thermally activated (absorption chiller) refrigeration cycle cools the inlet air through a heat exchanger. The heat exchanger in the inlet air stream causes an additional pressure drop in the air entering the compressor, thereby slightly lowering cycle power and efficiency. However, as the inlet air is now substantially cooler than the ambient air there is a significant net gain in power and efficiency. Electric motor compression refrigeration requires a substantial parasitic power loss. Thermally activated absorption cooling can utilize waste heat from the gas turbine, reducing the direct parasitic loss. However, the complexity and cost of this approach pose potential drawbacks in many applications.

Evaporative cooling, which is widely used due to its low capital cost, uses a spray of water directly into the inlet air stream. Evaporation of the water reduces the temperature of the air. Since cooling is limited to the wet bulb air temperature, evaporative cooling is most effective when the wet bulb temperature is appreciably below the dry bulb (ordinary) temperature. Evaporative cooling can consume large

[52] "Taurus 70 Gas Turbine Generator Set", Solar Turbines *A Caterpillar Company*. *https://mysolar.cat.com/cda/files/1987672/7/ds70gs.pdf*

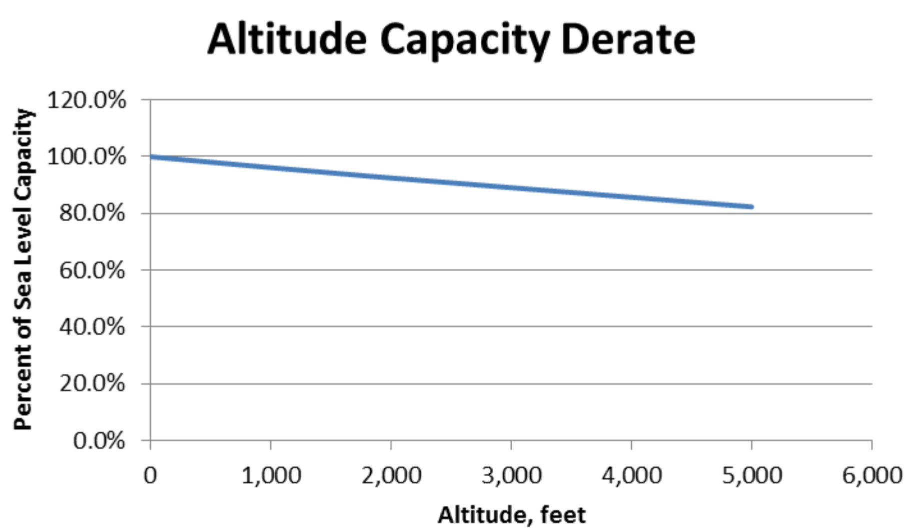
quantities of water, making it difficult to operate in arid climates. A few large gas turbines have evaporative cooling, which is expected to be used more frequently on smaller machines in the future.

The use of thermal-energy storage systems, such as ice, chilled water, or low-temperature fluids, to cool inlet air can eliminate most parasitic losses from the augmented power capacity. Thermal energy storage is a viable option if on-peak power pricing only occurs a few hours a day. In that case, the shorter time of energy storage discharge and longer time for daily charging allow for a smaller and less expensive thermal-energy storage system.

3.4.4.2 Site Altitude

The density of air decreases at altitudes above sea level reducing the mass of air that the compressor section of the turbine can introduce into the combustor. The reduced mass of air flow produces a corresponding reduction in the power (capacity) that the turbine can generate as shown in **Figure 3-6.** The percentage power reduction is the same for all turbines and is not dependent on the turbine size or the pressure ratio of the compressor. Unlike the effects of increased ambient temperature, which also produces a reduction in the efficiency of electricity production, altitude changes have only a very slight impact on efficiency.

Figure 3-6. The Effect of Altitude on Gas Turbine Capacity



3.4.5 Capital Costs

A gas turbine CHP plant is a complex process with many interrelated subsystems. The basic package consists of the gas turbine, gearbox, electric generator, inlet and exhaust ducting, inlet air filtration, lubrication and cooling systems, standard starting system, and exhaust silencing. The basic package cost does not include extra systems such as the fuel-gas compressor, heat-recovery system, water-treatment system, or emissions-control systems such as selective catalytic reduction (SCR) or continuous emission monitoring systems (CEMS). Not all of these systems are required at every site. The cost of the basic turbine package plus the costs for added systems needed for the particular application comprise the total equipment cost.

Installed capital costs can vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, emissions control requirements, prevailing labor rates, whether the system is a new or retrofit application, and whether the site is a greenfield, or is located at an established industrial site with existing roads, water, fuel, electric, etc. The cost estimates presented here are meant to represent a basic installation at an established site. The parameters for the cost estimation are shown in **Table 3-4**.

Table 3-4. Cost Estimation Parameters

Site Conditions	
Fuel	Pipeline quality natural gas
Altitude, temp, RH	ISO rating conditions
Inlet and Outlet Pressure Drop	As operated for CHP with HRSG and SCR
Site Fuel Gas Pressure	55 psig (gas compression required)
Steam Requirements	Max unfired steam flow, 150 lbs, saturated
Condensate Conditions	60% condensate return
	212° F condensate return
	70° F makeup water
Emissions Requirements	Dry Low NO_x combustion with SCR/CO/CEMS
Scope of Supply	
Project Management	Engineer, procure, construct, manage
Civil	Buildable site with infrastructure available
Electrical	Switchgear, interconnection, control, transformer
Fuel System	Fuel gas compressor, fuel gas filter, regulator, heater
Building	Building at $100/square foot
Steam System	Assume the CHP system is tying into an existing steam system with existing water treatment, de-aerator, and feed-water pumps

Table 3-5 details estimated capital costs (equipment and installation costs) for the five representative gas turbine CHP systems**.** The table shows that there are definite economies of scale for larger turbine power systems. Turbine packages themselves decline in cost only slightly between the range of 5 to 40 MW, but ancillary equipment such as the HRSG, gas compression, water treatment, and electrical equipment are much lower in cost per unit of electrical output as the systems become larger.

Table 3-5. Estimated Capital Cost for Representative Gas Turbine CHP Systems[53]

Cost Component	System				
	1	2	3	4	5
Nominal Turbine Capacity (kW)	3,510	7,520	10,680	21,730	45,607
Net Power Output (kW)	3,304	7,038	9,950	20,336	44,488
Equipment					
Combustion Turbines	$2,869,400	$4,646,000	$7,084,400	$12,242,500	$23,164,910
Electrical Equipment	$1,051,600	$1,208,200	$1,304,100	$1,490,300	$1,785,000
Fuel System	$750,400	$943,000	$1,177,300	$1,708,200	$3,675,000
Heat Recovery Steam Generators	$729,500	$860,500	$1,081,000	$1,807,100	$3,150,000
SCR, CO, and CEMS	$688,700	$943,200	$983,500	$1,516,400	$2,625,000
Building	$438,500	$395,900	$584,600	$633,400	$735,000
Total Equipment	$6,528,100	$8,996,800	$12,214,900	$19,397,900	$35,134,910
Installation					
Construction	$2,204,000	$2,931,400	$3,913,700	$6,002,200	$10,248,400
Total Installed Capital	$8,732,100	$11,928,200	$16,128,600	$25,400,100	$45,383,310
Other Costs					
Project/Construction Management	$678,100	$802,700	$1,011,600	$1,350,900	$2,306,600
Shipping	$137,600	$186,900	$251,300	$394,900	$674,300
Development Fees	$652,800	$899,700	$1,221,500	$1,939,800	$3,312,100
Project Contingency	$400,700	$496,000	$618,500	$894,200	$1,526,800
Project Financing	$238,500	$322,100	$432,700	$899,400	$2,303,500
Total Installed Cost					
Total Plant Cost	$10,839,800	$14,635,600	$19,664,200	$30,879,300	$55,506,610
Installed Cost, $/kW	$3,281	$2,080	$1,976	$1,518	$1,248

Source: Compiled by ICF from vendor-supplied data.

3.4.6 Maintenance

Non-fuel operation and maintenance (O&M) costs are presented in **Table 3-6**. These costs are based on gas turbine manufacturer estimates for service contracts, which consist of routine inspections and scheduled overhauls of the turbine generator set. Routine maintenance practices include on-line running maintenance, predictive maintenance, plotting trends, performance testing, fuel consumption, heat rate, vibration analysis, and preventive maintenance procedures. The O&M costs presented in **Table 3-6** include operating labor (distinguished between unmanned and 24 hour manned facilities) and total maintenance costs, including routine inspections and procedures and major overhauls.

[53] Combustion turbine costs are based on published specifications and package prices. Installation estimates are based on vendor cost estimation models and developer-supplied information.

Table 3-6. Gas Turbine Non-Fuel O&M Costs

Cost Component	System				
	1	2	3	4	5
Net Operating Capacity (kW)	3,304	7,038	9,950	20,336	44,488
Turbine O&M ($/kWh)	$0.0090	$0.0090	$0.0089	$0.0062	$0.0062
BOP O&M ($/kWh)	$0.0036	$0.0033	$0.0031	$0.0031	$0.0030
Total O&M ($/kWh)	**$0.0126**	**$0.0123**	**$0.0120**	**$0.0093**	**$0.0092**

Source: Compiled by ICF from vendor-supplied data

Daily maintenance includes visual inspection by site personnel of filters and general site conditions. Typically, routine inspections are required every 4,000 hours to insure that the turbine is free of excessive vibration due to worn bearings, rotors, and damaged blade tips. Inspections generally include on-site hot gas path boroscope inspections and non-destructive component testing using dye penetrant and magnetic particle techniques to ensure the integrity of components. The combustion path is inspected for fuel nozzle cleanliness and wear, along with the integrity of other hot gas path components.

A gas turbine overhaul is needed every 25,000 to 50,000 hours depending on service and typically includes a complete inspection and rebuild of components to restore the gas turbine to nearly original or current (upgraded) performance standards. A typical overhaul consists of dimensional inspections, product upgrades and testing of the turbine and compressor, rotor removal, inspection of thrust and journal bearings, blade inspection and clearances and setting packing seals.

Gas turbine maintenance costs can vary significantly depending on the quality and diligence of the preventative maintenance program and operating conditions. Although gas turbines can be cycled, cycling every hour triples maintenance costs versus a turbine that operates for intervals of 1,000 hours or more. In addition, operating the turbine over the rated capacity for significant periods of time will dramatically increase the number of hot path inspections and overhauls. Gas turbines that operate for extended periods on liquid fuels will experience shorter than average overhaul intervals.

3.4.7 Fuels

All gas turbines intended for service as stationary power generators in the United States are available with combustors equipped to handle natural gas fuel. A typical range of heating values of gaseous fuels acceptable to gas turbines is 900 to 1,100 Btu per standard cubic foot (scf), which covers the range of pipeline quality natural gas. Clean liquid fuels are also suitable for use in gas turbines.

Special combustors developed by some gas turbine manufacturers are capable of handling cleaned gasified solid and liquid fuels. Burners have been developed for medium Btu fuel (in the 400 to 500 Btu/scf range), which is produced with oxygen-blown gasifiers, and for low Btu fuel (90 to 125 Btu/scf), which is produced by air-blown gasifiers. These burners for gasified fuels exist for large gas turbines but are not available for small gas turbines.

Contaminants in fuel such as ash, alkalis (sodium and potassium), and sulfur result in alkali sulfate deposits, which impede flow, degrade performance, and cause corrosion in the turbine hot section.

Fuels must have only low levels of specified contaminants in them (typically less than 10 ppm total alkalis, and single-digit ppm of sulfur).

Liquid fuels require their own pumps, flow control, nozzles and mixing systems. Many gas turbines are available with either gas or liquid firing capability. In general, gas turbines can convert for use with one fuel to another quickly. Several gas turbines are equipped for dual firing and can switch fuels with minimal or no interruption.

Lean burn/dry low NO_x gas combustors generate NO_x emissions levels as low as 9 ppm (at 15 percent O_2). Liquid fuel combustors have NO_x emissions limited to approximately 25 ppm (at 15 percent O_2). There is no substantial difference in general performance with either fuel. However, the different heats of combustion result in slightly higher mass flows through the expansion turbine when liquid fuels are used, and thus result in a small increase in power and efficiency performance. In addition, the fuel pump work with liquid fuel is less than with the fuel gas booster compressor, thereby further increasing net performance with liquid fuels.

3.4.8 Gas Turbine System Availability

Operational conditions affect the failure rate of gas turbines. Frequent starts and stops incur damage from thermal cycling, which accelerates mechanical failure. The use of liquid fuels, especially heavy fuels and fuels with impurities (alkalis, sulfur, and ash), radiates heat to the combustor walls significantly more intensely than the use of clean, gaseous fuels, thereby overheating the combustor and transition piece walls. On the other hand, steady operation on clean fuels can permit gas turbines to operate for a year without need for shutdown. Based on a survey of 41 operating gas turbine systems shown in **Table 3-7**, the average availability of gas turbines operating on clean gaseous fuels, like natural gas, is around 95 percent.

Table 3-7. Gas Turbine Availability and Outage Rates

Gas Turbines	0.5 to 3 MW	3 to 20 MW	20 to 100 MW
Systems Surveyed	11	21	9
Availability, %	96.12%	94.73%	93.49%
Forced Outage Rate, %	2.89%	2.88%	1.37%
Scheduled Outage Rate, %	0.99%	2.39%	5.14%

Source: ICF

3.5 Emissions and Emissions Control Options

3.5.1 Emissions

Table 3-8 shows typical emissions for each of the five typical turbine systems. Typical emissions presented are based on natural gas combustion showing emissions before and after exhaust treatment using SCR and CO oxidation.

Table 3-8. Gas Turbine Emissions Characteristics

Emissions Characteristics	System				
	1	2	3	4	5
Electricity Capacity (kW)	3,304	7,038	9,950	20,336	44,488
Electrical Efficiency (HHV)	24.0%	28.9%	27.3%	33.3%	36.0%
Emissions Before After-treatment					
NO_x (ppm)	25	15	15	15	15
NO_x (lb/MWh)	1.31	0.65	0.69	0.57	0.52
CO (ppmv)	50	25	25	25	25
CO (lb/MWh)	1.60	0.66	0.70	0.58	0.53
NMHC (ppm)	5	5	5	5	5
NMHC (lb/MWh)	0.09	0.08	0.08	0.07	0.06
Emissions with SCR/CO/CEMS					
NO_x (ppm)	2.5	1.5	1.5	1.5	1.5
NO_x (lb/MWh)	0.09	0.05	0.05	0.05	0.05
CO (ppmv)	5.0	2.5	2.5	2.5	2.5
CO (lb/MWh)	0.11	0.05	0.05	0.05	0.05
NMHC (ppm)	4.3	4.3	4.3	4.3	2.0
NMHC (lb/MWh)	0.08	0.06	0.07	0.06	0.02
CO_2 Emissions					
Generation CO_2 (lb/MWh)	1,667	1,381	1,460	1,201	1,110
Net CO_2 with CHP (lb/MWh)	797	666	691	641	654

Source: Compiled by ICF from vendor supplied data, includes heat recovery

Table 3-8 also shows the net CO_2 emissions after credit is taken for avoided natural gas boiler fuel. The net CO_2 emissions range from 641-797 lbs/MWh. A natural gas combined cycle power plant might have emissions in the 800-900 lb/MWh range whereas a coal power plant's CO_2 emissions would be over 2000 lb/MWh. Natural gas fired CHP from gas turbines provides savings against both alternatives.

3.5.2 Emissions Control Options

Emissions control technology for gas turbines has advanced dramatically over the last 20 years in response to technology forcing requirements that have continually lowered the acceptable emissions levels for nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs). When burning fuels other than natural gas, pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) can be an issue. In general, SO_x emissions are greater when heavy oils are fired in the turbine. SO_x control is generally addressed by the type of fuel purchased, than by the gas turbine technology. Particulate matter is a marginally significant pollutant for gas turbines using liquid fuels. Ash and metallic additives in the fuel may contribute to PM in the exhaust.

A number of control options can be used to control emissions. Below are descriptions of these options.

3.5.2.1 Diluent Injection

The first technique used to reduce NO_x emissions was injection of water or steam into the high temperature flame zone. Water and steam are strong diluents and can quench hot spots in the flame reducing NO_x. However, because positioning of the injection is not precise some NO_x is still created. Depending on uncontrolled NO_x levels, water or steam injection reduces NO_x by 60 percent or more. Water or steam injection enables gas turbines to operate with NO_x levels as low as 25 ppm (@ 15 percent O_2) on natural gas. NO_x is reduced only to 42 to 75 ppm when firing with liquid distillate fuel. Both water and steam increase the mass flow through the turbine and create a small amount of additional power. Use of exhaust heat to raise the steam temperature also increases overall efficiency slightly. The water used needs to be demineralized thoroughly in order to avoid forming deposits and corrosion in the turbine expansion section. This adds cost and complexity to the operation of the turbine. Diluent injection increases CO emissions appreciably as it lowers the temperature in the burnout zone, as well as in the NO_x formation zone.

3.5.2.2 Lean Premixed Combustion

Lean premixed combustion (DLN/DLE[54]) pre-mixes the gaseous fuel and compressed air so that there are no local zones of high temperatures, or "hot spots," where high levels of NO_x would form. Lean premixed combustion requires specially designed mixing chambers and mixture inlet zones to avoid flashback of the flame. Optimized application of DLN combustion requires an integrated approach for combustor and turbine design. The DLN combustor becomes an intrinsic part of the turbine design, and specific combustor designs must be developed for each turbine application. While NO_x levels as low as 9 ppm have been achieved, most manufacturers typically offer a range of 15-25 ppm DLN/DLE combustion systems when operating on natural gas.

3.5.2.3 Selective Catalytic Reduction (SCR)

The primary post-combustion NO_x control method in use today is SCR. Ammonia is injected into the flue gas and reacts with NO_x in the presence of a catalyst to produce N_2 and H_2O. The SCR system is located in the exhaust path, typically within the HRSG where the temperature of the exhaust gas matches the operating temperature of the catalyst. The operating temperature of conventional SCR systems ranges from 400 to 800°F. The cost of conventional SCR has dropped significantly over time—catalyst innovations have been a principal driver, resulting in a 20 percent reduction in catalyst volume and cost with no change in performance. SCR reduces between 80 to 90 percent of the NO_x in the gas turbine exhaust, depending on the degree to which the chemical conditions in the exhaust are uniform. When used in series with water/steam injection or DLN combustion, SCR can result in low single digit NO_x levels (1.5 to 5 ppm). SCR requires on-site storage of ammonia, a hazardous chemical. In addition, ammonia can “slip” through the process unreacted, contributing to environmental and health concerns.[55]

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[54] Dry low NO_x/Dry low emissions

[55] The SCR reaction, with stoichiometric ammonia (for NO_x reduction) or other reagent should eliminate all NO_x. However, because of imperfect mixing in the combustor the NO_x is not uniformly distributed across the turbine exhaust. Additionally, the ammonia, or other reagent, also is not injected in a precisely uniform manner. These two non-uniformities in chemical composition cause either excess ammonia to be used, and to consequently "slip" out of the exhaust, or for incomplete reaction of the NO_x in the turbine exhaust.

3.5.2.4 CO Oxidation Catalysts

Oxidation catalysts control CO in gas turbine exhaust. Some SCR installations incorporate CO oxidation modules along with NO_x reduction catalysts for simultaneous control of CO and NO_x. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the exhaust stream passes through the catalyst bed. The oxidation process takes place spontaneously so no reactants are required. The catalyst is usually made of precious metal such as platinum, palladium, or rhodium. Other formations, such as metal oxides for emission streams containing chlorinated compounds, are also used. CO catalysts also reduce VOCs and organic hazardous air pollutants (HAPs). CO catalysts on gas turbines result in approximately 90 percent reduction of CO and 85 to 90 percent control of formaldehyde (similar reductions can be expected on other HAPs).

3.5.2.5 Catalytic Combustion

Catalytic combustion systems oxidize the fuel at lean conditions in the presence of a catalyst. Catalytic combustion is a flameless process, allowing fuel oxidation to occur at temperatures below 1,700°F, where NO_x formation is low. The catalyst is applied to combustor surfaces, which cause the fuel air mixture to react with the oxygen and release its initial thermal energy. The combustion reaction in the lean premixed gas then goes to completion at design temperature. Data from ongoing long term testing indicates that catalytic combustion exhibits low vibration and acoustic noise, only one-tenth to one-hundredth the levels measured in the same turbine equipped with DLN combustors. Catalytic combustors capable of achieving NO_x levels below 3 ppm are entering commercial production.[56] Similar to DLN combustion, optimized catalytic combustion requires an integrated approach for combustor and turbine design. Catalytic combustors must be tailored to the specific operating characteristics and physical layout of each turbine design.

3.5.2.6 Catalytic Absorption Systems

SCONO$_x$™, patented by Goal Line Environmental Technologies (currently EmerChem), is a post-combustion alternative to SCR that reduces NO_x emissions to less than 2.5 ppm and almost 100 percent removal of CO. SCONO$_x$™ combines catalytic conversion of CO and NO_x with an absorption/regeneration process that eliminates the ammonia reagent found in SCR technology. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO catalytically oxidize to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONO$_x$™ catalyst. The system does not require the use of ammonia, eliminating the potential for ammonia slip associated with SCR. The SCONO$_x$™ system is generally located within the HRSG, and under special circumstances may be located downstream of the HRSG. The system operates between 300-700ºF. U.S. EPA Region 9 identified SCONO$_x$™ as "Lowest Achievable Emission Rate (LAER)" technology for gas turbine NO_x control in 1998. The SCONO$_x$™ technology is still in the early stages of market introduction. Issues that may impact application of the technology include relatively high capital cost, large reactor size compared to SCR, system complexity, high utilities cost and demand (steam, natural gas, compressed air and electricity are required), and a gradual rise in NO emissions over time that requires a 1 to 2 day

[56] For example, Kawasaki offers a version of their M1A 13X, 1.4 MW gas turbine with a catalytic combustor with less than 3 ppm NO_x guaranteed.

shutdown every 6 to 12 months (depending on fuel quality and operation) to remove and regenerate the absorption modules ex-situ.[57]

3.6 Future Developments

In the last twenty years, there have been substantial improvement in gas turbine technology with respect to power, efficiency, durability, green operation, and time/cost to market. These improvements have been the combined results of collaborative research efforts by private industry, universities, and the federal government. Public private partnerships such as the DOE Advanced Turbine Systems Program and the Next Generation Turbine program have advanced gas turbine technology by meeting goals including:

- Combined cycle electric efficiency of 60 percent (LHV)
- NO_x emissions of less than 10 ppm
- 10 percent reduction in the cost of electricity
- Improvement in reliability, availability, and maintainability (RAM)
- Development of the recuperated 4.6 MW Solar Mercury gas turbine with low emissions and electrical efficiency of 37.5 percent (LHV) compared to an unrecuperated gas turbine of similar size having an electric efficiency of 28.5 percent

Current collaborative research is focusing on both large gas turbines and those applicable for distributed generation. Large gas turbine research is focused on improving the efficiency of combined cycle plants to 65 percent (LHV), reducing emission even further, and integrating gas turbines with clean coal gasification and carbon capture. The focus for smaller gas turbines is on improving performance, enhancing fuel flexibility, reducing emissions, reducing life cycle costs, and integration with improved thermal utilization technologies. Continued development of aeroderivative gas turbines for civilian and military propulsion will provide carryover benefits to stationary applications.

Long term research includes the development of hybrid gas turbine fuel cell technology that is capable of 70 percent (LHV) electric efficiency.[58]

[57] Resource Catalysts, Inc.
[58] DOE turbine/fuel cell hybrid program, *http://www.netl.doe.gov/technologies/coalpower/fuelcells/hybrids.html*