Catalog of CHP Technologies
Part 2 of 2

Florida Board of Professional Engineers
Approved Course No. 0010329

4 PDH Hours

A test is provided to assess your comprehension of the course material – 24 questions have been chosen from each of the above sections. You will need to answer at least 17 out of 24 questions correctly (>70%) in order to pass the overall course. You can review the course material and re-take the test if needed.

You are required to review each section of the course in its entirety. Because this course information is part of your Professional Licensure requirements it is important that your knowledge of the course contents and your ability to pass the test is based on your individual efforts.

Course Description:

This course is based entirely on the information published in a report prepared By ICF International with funding from the U.S. Environmental Protection Agency and the U.S. Department of Energy.

This course is 1 of a 2 Part Series that will review the core CHP technologies in place today. Inside the report is a discussion of the benefits of CHP technologies, a summary comparison of the five main prime-mover technology systems, and a discussion of key CHP benefits. There is also an appendix that provides formulas for the various performance measurements used in the Guide.

PART 1 of the Series will cover:

- Technology Characterization – Reciprocating Internal Combustion Engines
- Technology Characterization – Combustion Turbines

PART 2 of the series will cover: (this course)

- Technology Characterization – Steam Turbines
- Technology Characterization – Microturbines
- Technology Characterization – Fuel Cells
- Packaged CHP Systems

How to reach Us …

If you have any questions regarding this course or any of the content contained herein you are encouraged to contact us at Easy-PDH.com. Our normal business hours are Monday through Friday, 10:00 AM to 4:00 PM; any inquiries will be answered within 2 days or less. Contact us by:

EMAIL: bajohnstonpe@aol.com
Phone: 813-398-9380

Refer to Course No. 0010329

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How the Course Works…

What do you want To do?	LOOK For This!
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Phone: 813-398-9380

24 QUESTIONS

Q1:	**The first steam turbine used for power generation was invented in what year:**

(A)	1875
(B)	1884
(C)	1899
(D)	1912

Q2:	**The thermodynamic cycle for the steam turbine is known as the:**

(A)	Rankine Cycle
(B)	Brayton Cycle
(C)	Steam Cycle
(D)	Carnot Cycle

Q3:	**Compared to reciprocating steam engines of comparable size, steam turbines rotate at what speed:**

(A)	Higher rotational speeds
(B)	Lower rotational speeds
(C)	The same speed
(D)	NA – there is no rotational comparison

Q4:	**In the operation of a condensing turbine, non-condensable gases that are present include:**

(A)	Air
(B)	Nitrogen
(C)	Hydrogen
(D)	A and C

Q5:	**In the operation of an extraction turbine, extracted steam may be used for:**

(A)	Processes purposes in a CHP facility
(B)	Feedwater heating
(C)	For generation of additional electricity
(D)	All of the Above

Q6:	**Steam turbine CHP systems are generally characterized by very low power to heat ratios, typically with a range of:**

(A)	.05 to 0.2
(B)	0.2 to 0.4
(C)	0.4 to 0.5
(D)	0.5 to 0.55

Q7:	**Because of the high pressures used in steam turbines, the casing is quite thick and large steam turbines can take over HOW MANY hours to warm up:**

(A)	6 hours
(B)	8 hours
(C)	10 hours
(D)	12 hours

Q8:	**Steam turbines are very rugged units, with operational life often exceeding 50 years Steam turbine maintenance costs are typically below:**

(A)	.1 dollars per kWh
(B)	.01 dollars per kWh
(C)	.001 dollars per kWh
(D)	.0001 dollars per kWh

Q9:	**Boilers are fired with excess air to ensure complete combustion. However, excess air levels greater than WHAT can result in increased NOx formation:**

(A)	55 percent
(B)	50 percent
(C)	45 percent
(D)	40 percent

Q10:	**The U.S. Department of Energy is funding technology development of an ultra-supercritical (USC) steam turbine that can withstand temperatures up to 1400 F and are targeting a prototype delivery by:**

(A)	2024
(B)	2025
(C)	2027
(D)	2029

Q11:	**Exhaust temperatures from microturbines are in the range of:**

(A)	400 to 500 F
(B)	500 to 600 F
(C)	600 to 700 F
(D)	700 to 800 F

Q12:	**The heart of the microturbine is the compressor-turbine package and the shaft rotates at speeds upwards of:**

(A)	36000 rpm
(B)	48000 rpm
(C)	60000 rpm
(D)	72000 rpm

Q13:	The microturbine produces electrical power through a conventional generator that rotates at what speed:

(A)	1200 rpm
(B)	2400 rpm
(C)	3600 rpm
(D)	4800 rpm

Q14:	The performance characteristics of a microturbine are measured at full load at:

(A)	59 F
(B)	60 percent relative humidity
(C)	14.7 psia
(D)	All of the Above

Q15:	Which is a low cost technique to lower the inlet temperature of air entering a microturbine:

(A)	Evaporative cooling
(B)	Refrigeration cooling
(C)	Thermal energy storage systems
(D)	Inlet fogging cooling

Q16:	Microturbines are capable of operating on a variety of fuels including ALL of the following EXCEPT:

(A)	Liquified Petroleum Gas
(B)	No 2 Diesel
(C)	Sour Gas
(D)	Industrial Waste Gas

Q17:	In fuel cell, Two electrodes (a cathode and anode) pass charged ions in an electrolyte to generate electricity and heat. What can be used to enhance this process:

(A)	Steam
(B)	Nitrogen Gas
(C)	A Catalyst
(D)	Sulfuric Acid

Q18:	Phosphoric acid fuel cells have a disadvantage of requiring the use of what type of catalyst:

(A)	Vanadium
(B)	Strontium
(C)	Unobtanium
(D)	Platinum

Q19:	Which part of a fuel cell provides the interface between the fuel and the electrolyte:

(A)	The anode
(B)	The cathode
(C)	The Oxygen matrix
(D)	The Combustion medium

Q20:	**Fuel Cells are generally rated at ISO conditions of:**

(A)	77 F
(B)	60 percent relative humidity
(C)	1 bar
(D)	A and C

Q21:	**Fuel cell maintenance can either be performed by in-house personnel or contracted out to manufacturers but are estimated to be as high as:**

(A)	2.0 cents per kWh
(B)	2.3 cents per kWh
(C)	2.7 cents per kWh
(D)	3.0 cents per kWh

Q22:	**Many manufacturers and developers offer standardized, ready-to-install packaged CHP systems and as of 2016 there is a total of how much capacity installed in the US:**

(A)	185 MW
(B)	195 MW
(C)	215 MW
(D)	235 MW

Q23:	**The largest market segment for Total Installed Capacity of Packaged CHP systems in the US is:**

(A)	Agriculture
(B)	Multifamily buildings
(C)	Supermarkets
(D)	Wastewater treatment

Q24:	**Heat rate**, which is used to express efficiency in power generation systems is represented in terms of:

(A)	BTUs of fuel consumed
(B)	kWh of electricity generated
(C)	Net useful thermal output of steam
(D)	A and B

End of Test Questions

Catalog of CHP Technologies

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

September 2017

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Section 4. Technology Characterization – Steam Turbines

4.1 Introduction

Q1

Steam turbines are one of the most versatile and oldest prime mover technologies still in general production used to drive a generator or mechanical machinery. The first steam turbine used for power generation was invented in 1884. Following this initial introduction, steam turbines rapidly replaced reciprocating steam engines due to their higher efficiencies and lower costs. Most of the electricity produced in the United States today is generated by conventional steam turbine power plants. The capacity of steam turbines can range from 50 kW to several hundred MWs for large utility power plants. Steam turbines are widely used for combined heat and power (CHP) applications in the United States and Europe.

Unlike gas turbine and reciprocating engine CHP systems, where heat is a byproduct of power generation, steam turbine generators normally generate electricity as a byproduct of heat (steam) generation. A steam turbine is captive to a separate heat source and does not directly convert fuel to electric energy. The energy is transferred from the boiler to the turbine through high pressure steam that powers the turbine and generator. This separation of functions enables steam turbines to operate using a large variety of fuels, from clean natural gas to solid waste, including all types of coal, wood, wood waste, and agricultural byproducts (sugar cane bagasse, fruit pits and rice hulls). In CHP applications, steam at lower pressure is extracted from the steam turbine and used directly in a process or for district heating, or it can be converted to other forms of thermal energy including hot or chilled water.

Steam turbines offer a wide array of designs and complexity to match the desired application and/or performance specifications ranging from single stage backpressure or condensing turbines for low power ranges to complex multi-stage turbines for higher power ranges. Steam turbines for utility service may have several pressure casings and elaborate design features, all designed to maximize the efficiency of the power plant. For industrial applications, steam turbines are generally of simpler single casing design and less complicated for reliability and cost reasons. CHP can be adapted to both utility and industrial steam turbine designs.

Table 4-1 provides a summary of steam turbine attributes described in detail in this chapter.

Table 4-1. Summary of Steam Turbine Attributes

Size range	Steam turbines are available in sizes from under 100 kW to over 250 MW. In the multi-megawatt size range, industrial and utility steam turbine designations merge, with the same turbine (high pressure section) able to serve both industrial and small utility applications.
Custom design	Steam turbines can be designed to match CHP design pressure and temperature requirements. The steam turbine can be designed to maximize electric efficiency while providing the desired thermal output.

Table 4-1. Summary of Steam Turbine Attributes

Thermal output	Steam turbines are capable of operating over a very broad range of steam pressures. Utility steam turbines operate with inlet steam pressures up to 3500 psig and exhaust at vacuum conditions as low as 2 psia. Steam turbines can be custom designed to deliver the thermal requirements of the CHP application through use of backpressure or extraction steam at appropriate pressures and temperatures.
Fuel flexibility	Steam turbines offer a wide range of fuel flexibility using a variety of fuel sources in the associated boiler or other heat source, including coal, oil, natural gas, wood and waste products, in addition to waste exhaust heat recaptured in a heat recovery steam generator.
Reliability and life	Steam turbine equipment life is extremely long. There are steam turbines that have been in service for over 50 years. When properly operated and maintained (including proper control of boiler water chemistry and ensuring dry steam), steam turbines are extremely reliable with overhaul intervals measured in years. Larger turbines require controlled thermal transients as the massive casing heats up slowly and differential expansion of the parts must be minimized. Smaller turbines generally do not have start-up restrictions.

4.2 Applications

Steam turbines are well suited to medium- and large-scale industrial and institutional applications, where inexpensive fuels, such as coal, biomass, solid wastes and byproducts (e.g., wood chips), refinery residual oil, and refinery off gases are available. Applications include:

- **Combined heat and power** – Steam turbine-based CHP systems are primarily used in industrial processes where solid or waste fuels are readily available for boiler use. In CHP applications, steam may be extracted or exhausted from the steam turbine and used directly. Steam turbine systems are very commonly found in paper mills as there is usually a variety of waste fuels from hog fuel to black liquor. Chemical plants are the next most common industrial user of steam turbines followed by primary metals. There are a variety of other industrial applications including the food industry, particularly sugar and palm oil mills.

- **Mechanical drive** – Instead of producing electric power, the steam turbine may drive equipment such as boiler feedwater pumps, process pumps, air compressors and refrigeration chillers. Such applications, usually accompanied by process use of steam are found in many of the CHP industries described above.

- **District heating and cooling systems** – There are cities and college campuses that have steam district heating systems where adding a steam turbine between the boiler and the distribution system or placing a steam turbine as a replacement for a pressure reducing station may be an attractive application. Often the boiler is capable of producing moderate-pressure steam but the distribution system needs only low pressure steam. In these cases, the steam turbine generates electricity using the higher pressure steam, and discharges low pressure steam into the distribution system. Such facilities can also use steam in absorption chillers to produce chilled water for air conditioning.

- **Combined cycle power plants** – The trend in power plant design is to generate power with a gas turbine and use the exhaust heat to generate steam that provides additional power through a steam turbine. Such combined-cycle power plants are capable of achieving electric generation efficiencies of over 50 percent. For large industrial CHP applications, an extraction-condensing type of steam turbine can be used in a combined cycle plant with the steam turbine extracting a portion of the steam for process use. There are many large independent power producers (IPP) using combined cycle power plants operating on natural gas to provide power to the electric grid and steam to one or more industrial customers.

4.3 Technology Description

4.3.1 Basic Process

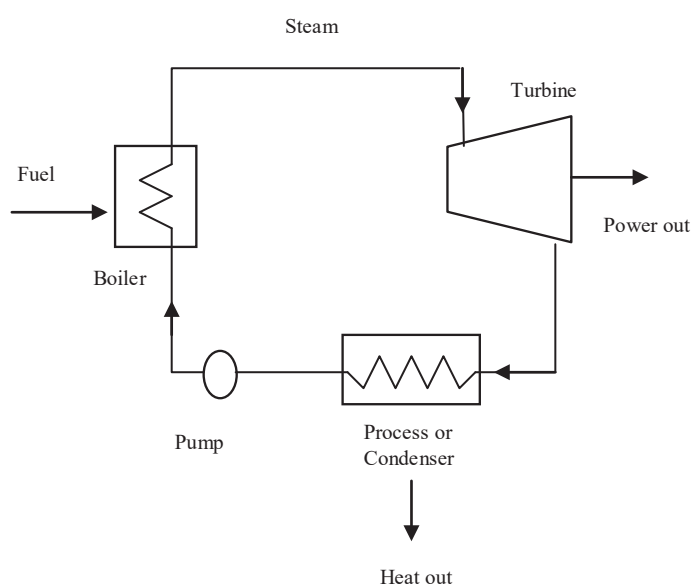
Q2

The thermodynamic cycle for the steam turbine is known as the Rankine cycle. This cycle is the basis for conventional power generating stations and consists of a heat source (boiler) that converts water to high pressure steam. In the steam cycle, water is first pumped to elevated pressure, which is medium to high pressure, depending on the size of the unit and the temperature to which the steam is eventually heated. It is then heated to the boiling temperature corresponding to the pressure, boiled (heated from liquid to vapor), and then most frequently superheated (heated to a temperature above that of boiling). The pressurized steam is expanded to lower pressure in a turbine, then exhausted either to a condenser at vacuum conditions, or into an intermediate temperature steam distribution system that delivers the steam to the industrial or commercial application. The condensate from the condenser or from the industrial steam utilization system is returned to the feedwater pump for continuation of the cycle.

4.3.2 Components

A schematic representation of a steam turbine power system is shown in **Figure 4-1**.

Figure 4-1. Boiler/Steam Turbine System



In the simple schematic shown, a fuel boiler produces steam which is expanded in the steam turbine to produce power. When the system is designed for power generation only, such as in a large utility power

system, the steam is exhausted from the turbine at the lowest practical pressure, through the use of a water-cooled condenser to extract the maximum amount of energy from the steam. In CHP plants or district heating systems, the steam is exhausted from the steam turbine at a pressure high enough to be used by the industrial process or the district heating system. In CHP configuration, there is no condenser and the steam and condensate, after exiting the process, is returned to the boiler.

There are numerous options in the steam supply, pressure, temperature and extent, if any, for reheating steam that has been partially expanded from high pressure. Steam systems vary from low pressure lines used primarily for space heating and food preparation, to medium pressure and temperature used in industrial processes and cogeneration, and to high pressure and temperature use in utility power generation. Generally, as the system gets larger the economics favor higher pressures and temperatures, along with their associated heavier walled boiler tubes and more expensive alloys.

4.3.2.1 Boiler

Steam turbines differ from reciprocating engines, internal combustion engines, and gas turbines in that the fuel is burned in a piece of equipment, the boiler, which is separate from the power generation equipment. The energy is transferred from the boiler to the steam turbine generator by an intermediate medium, typically steam under pressure. As mentioned previously, this separation of functions enables steam turbines to operate with an enormous variety of fuels. The topic of boiler fuels, their handling, combustion and the cleanup of the effluents of such combustion is a separate and complex issue that is addressed in the fuels and emissions sections of this report.

For sizes up to (approximately) 40 MW, horizontal industrial boilers are built. This enables them to be shipped via rail car, with considerable cost savings and improved quality, as the cost and quality of factory labor is usually both lower in cost and greater in quality than field labor. Large shop-assembled boilers are typically capable of firing only gas or distillate oil, as there is inadequate residence time for complete combustion of most solid and residual fuels in such designs. Large, field-erected industrial boilers firing solid and residual fuels bear a resemblance to utility boilers except for the actual solid fuel injection. Large boilers usually burn pulverized coal; however, intermediate and small boilers burning coal or solid fuel employ various types of solids feeders.

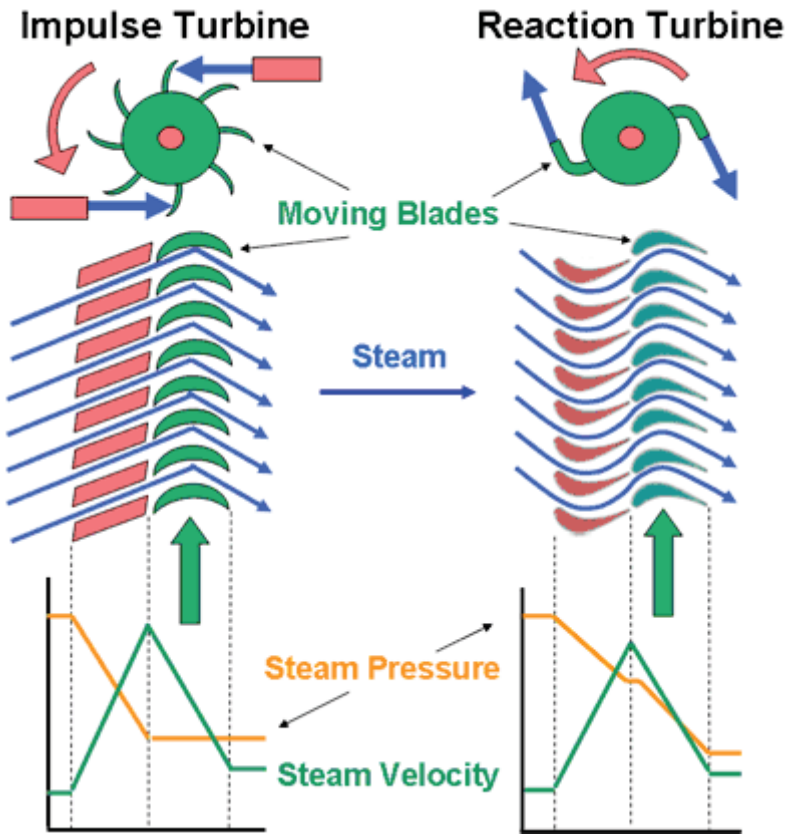
4.3.2.2 Steam Turbine

In the steam turbine, the steam is expanded to a lower pressure providing shaft power to drive a generator or run a mechanical process.

There are two distinct designs for steam turbines – *impulse* and *reaction* turbines. The difference between these two designs is shown in **Figure 4-2**. On impulse turbines, the steam jets are directed at the turbine's bucket shaped rotor blades where the pressure exerted by the jets causes the rotor to rotate and the velocity of the steam to reduce as it imparts its kinetic energy to the blades. The next series of fixed blades reverses the direction of the steam before it passes to the second row of moving blades. In Reaction turbines, the rotor blades of the reaction turbine are shaped more like airfoils, arranged such that the cross section of the chambers formed between the fixed blades diminishes from the inlet side towards the exhaust side of the blades. The chambers between the rotor blades essentially form nozzles so that as the steam progresses through the chambers its velocity increases while at the

same time its pressure decreases, just as in the nozzles formed by the fixed blades. The competitive merits of these designs are the subject of business competition, as both designs have been sold successfully for well over 75 years.

Figure 4-2. Comparison of Impulse and Reaction Turbine Design



Source: Electropaedia, http://www.mpoweruk.com/steam_turbines.htm

The stationary nozzles accelerate the steam to high velocity by expanding it to lower pressure. A rotating bladed disc changes the direction of the steam flow, thereby creating a force on the blades that, because of the wheeled geometry, manifests itself as torque on the shaft on which the bladed wheel is mounted. The combination of torque and speed is the output power of the turbine. A reduction gear may be utilized to reduce the speed of the turbine to the required output speed for the generator.

Q3

The internal flow passages of a steam turbine are very similar to those of the expansion section of a gas turbine (indeed, gas turbine engineering came directly from steam turbine design around 100 years ago). The main differences are gas density, molecular weight, isentropic expansion coefficient, and to a lesser extent, the viscosity of the two fluids.

Compared to reciprocating steam engines of comparable size, steam turbines rotate at much higher rotational speeds, which contribute to their lower cost per unit of power developed. In addition, the inlet and exhaust valves in reciprocating steam engines cause steam pressure losses that don't contribute to power output. Such losses do not occur in steam turbines. As a result of these design

differences, steam turbines are more efficient than reciprocating steam engines operating from the steam at the same inlet conditions and exhausting into the same steam exhaust systems.

There are numerous mechanical design features that have been created to increase efficiency, provide for operation over a range of conditions, simplify manufacture and repair, and achieve other practical purposes. The long history of steam turbine use has resulted in a large inventory of steam turbine stage designs that can be used to tailor a product for a specific application. For example, the division of steam acceleration and change in direction of flow varies between competing turbine manufacturers under the identification of impulse and reaction designs. Manufacturers tailor clients' design requests by varying the flow area in the stages and the extent to which steam is extracted (removed from the flow path between stages) to accommodate the client specifications.

When steam is expanded through a very high pressure ratio, as in utility and large industrial steam systems, the steam can begin to condense in the turbine if the temperature of the steam drops below the saturation temperature at that pressure. If water drops were allowed to form in the turbine, they would impact the blades and would cause blade erosion. At this point in the expansion, the steam is sometimes returned to the boiler and reheated to high temperature and then returned to the turbine for further (safe) expansion. In a few very large, very high-pressure utility steam systems, double reheat systems are installed.

With these choices the designer of the steam supply system and the steam turbine have the challenge of creating a system design which delivers the (seasonally varying) power and steam, that also presents the most favorable business opportunity to the plant owners.

Between the power (only) output of a condensing steam turbine and the power and steam combination of a back pressure steam turbine, essentially any ratio of power to heat output can be supplied to a facility. Moreover, back pressure steam turbines can be obtained with a variety of back pressures, further increasing the variability of the power-to-heat ratio.

4.3.2.3 Condensing Turbine

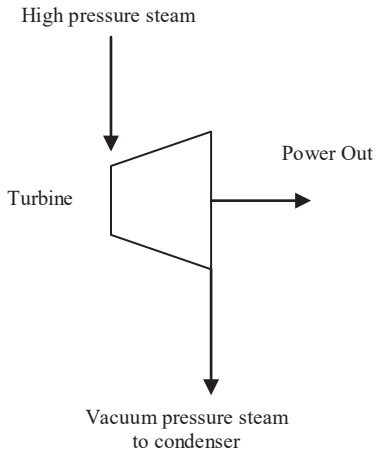
Q4

The primary type of turbine used for central power generation is the condensing turbine shown schematically in **Figure 4-3.** These power-only utility turbines exhaust directly to condensers that maintain vacuum conditions at the discharge of the turbine. An array of tubes, cooled by water from a river, lake or cooling tower, condenses the steam into (liquid) water.[59] The vacuum conditions in the condenser are caused by the near ambient cooling water causing condensation of the steam turbine exhaust steam in the condenser. As a small amount of air is known to leak into the system when it is below atmospheric pressure, a relatively small compressor or steam air ejector may be used to remove non-condensable gases from the condenser. Non-condensable gases include both air and a small amount of the corrosion byproduct of the water-iron reaction, hydrogen.

[59] At 80° F, the vapor pressure of water is 0.51 psia, at 100° F it is 0.95 psia, at 120° F it is 1.69 psia and at 140° F Fahrenheit it is 2.89 psia

The condensing turbine processes result in maximum power and electrical generation efficiency from the steam supply and boiler fuel. The power output of condensing turbines is sensitive to ambient conditions.[60]

Figure 4-3. Condensing Steam Turbine

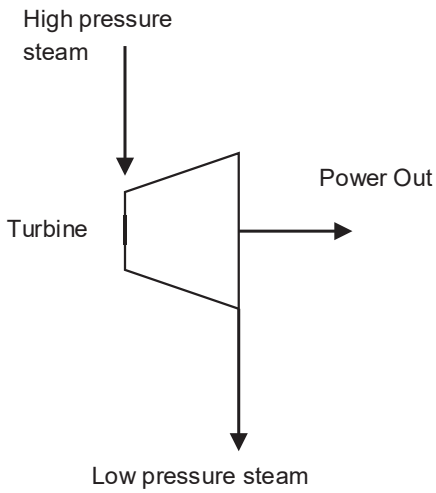


Steam turbines used for CHP can be classified into two main types: non-condensing and extraction, which will be discussed in the following two sections.

4.3.2.4 Non-Condensing (Back-pressure) Turbine

A non-condensing turbine (also referred to as a back-pressure turbine) exhausts some or all of its steam flow to the industrial process or facility steam mains at conditions close to the process heat requirements, as shown in **Figure 4-4.**

Figure 4-4. Non-Condensing (Back-pressure) Steam Turbine



[60] From a reference condition of condensation at 100° F, 6.5 percent less power is obtained from the inlet steam when the temperature at which the steam is condensed is increased (because of higher temperature ambient conditions) to 115° F. Similarly, the power output is increased by 9.5% when the condensing temperature is reduced to 80° F. This illustrates the influence of steam turbine discharge pressure on power output and, consequently, net heat rate and efficiency.

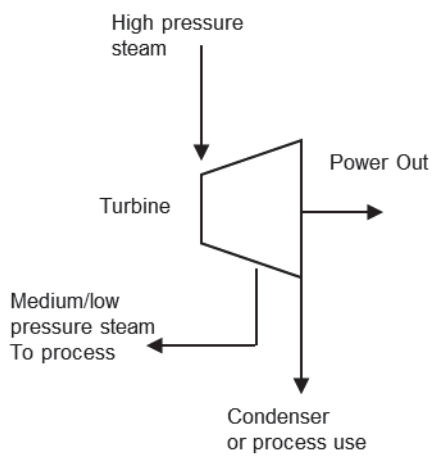
Usually, the steam sent into the mains is not much above saturation temperature.[61] The term back-pressure refers to turbines that exhaust steam at atmospheric pressures and above. The discharge pressure is established by the specific CHP application. The most typical pressure levels for steam distribution systems are 50, 150, and 250 psig. The lower pressures are most often used in district heating systems, while the higher pressures are most often used in supplying steam to industrial processes. Industrial processes often include further expansion for mechanical drives, using small steam turbines for driving heavy equipment that is intended to run continuously for very long periods. Significant power generation capability is sacrificed when steam is used at high pressure, rather than being expanded to vacuum conditions in a condenser. Discharging steam into a steam distribution system at 150 psig can sacrifice slightly more than half the power (compared to a vacuum exhaust) that could be generated when the inlet steam conditions are 750 psig and 800° F, typical of small steam turbine systems.

4.3.2.5 Extraction Turbine

An extraction turbine has one or more openings in its casing for extraction of a portion of the steam at some intermediate pressure. The extracted steam may be used for process purposes in a CHP facility, or for feedwater heating, as is the case in most utility power plants. The rest of the steam can be expanded to below atmospheric pressure to a condenser, or delivered to a low pressure steam application as illustrated in **Figure 4-5**.

Q5

Figure 4-5. Extraction Steam Turbine



The steam extraction pressure may or may not be automatically regulated depending on the turbine design. Regulated, or controlled extraction permits more steam to flow through the turbine to generate additional electricity during periods of low thermal demand by the CHP system. In utility type steam turbines, there may be several extraction points, each at a different pressure corresponding to a different temperature at which heat is needed in the thermodynamic cycle. The facility's specific needs

[61] At 50 psig (65 psia) the condensation temperature is 298° F, at 150 psig (165 psia) the condensation temperature is 366° F, and at 250 psig (265 psia) it is 406° F.

for steam and power over time determine the extent to which steam in an extraction turbine will be extracted for use in the process, or be expanded to vacuum conditions and condensed in a condenser.

In large, complex industrial plants, additional steam may be admitted to the steam turbine by flowing into the casing to increase the flow in the steam path. Often this happens when multiple boilers are used at different pressures, because of their historical existence. These steam turbines are referred to as admission *or* reheat turbines. At steam extraction and admission locations, there are usually steam flow control valves that add to the steam and control system cost.

4.4 Performance Characteristics

Q6

Boilers and steam turbines used for large, central station electric power generation can achieve electrical efficiencies of up to 45 percent HHV[62] though the average efficiency of all units in the field is around 33 percent.[63] Backpressure steam turbines used in CHP applications extract only a portion of the steam energy to generate electricity, delivering the rest for process use. Consequently, the electric generation efficiencies for the examples shown are all below 10 percent HHV. However, when the energy value of the steam delivered for process use is considered, the effective electrical efficiency is over 75 percent.

Table 4-2 summarizes performance characteristics for typical commercially available backpressure steam turbines used in CHP applications between 500 kW to 15 MW size range.

Isentropic steam turbine efficiency refers to the ratio of power actually generated from the turbine to what would be generated by a perfect turbine with no internal flowpath losses using steam at the same inlet conditions and discharging to the same downstream pressure. Turbine efficiency is not to be confused with electrical generating efficiency, which is the ratio of net power generated to total fuel input to the cycle. Steam turbine efficiency is a measure of how efficiently the turbine extracts power from the steam itself and is useful in identifying the conditions of the steam as it exhausts from the turbine and in comparing the performance of various steam turbines. Multistage (moderate to high pressure ratio) steam turbines have thermodynamic efficiencies that vary from 65 percent for very small (under 1,000 kW) units to over 90 percent for large industrial and utility sized units. Small, single stage steam turbines can have efficiencies as low as 40 percent.

Heat recovery methods from a steam turbine use back pressure exhaust or extraction steam. However, the term is somewhat misleading, since in the case of steam turbines, it is the steam turbine itself that can be defined as a heat recovery device.

Steam turbine CHP systems are generally characterized by very low power to heat ratios, typically in the 0.05 to 0.2 range. This is because electricity is a byproduct of heat generation, with the system

[62] All turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. However, the usable energy content of fuels is typically measured on a higher heating value basis (HHV). In addition, electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content of natural gas is 1,030 Btu/scf on an HHV basis and 930 Btu/scf on an LHV basis – or about a 10 percent difference.

[63] Technology Roadmap: High-Efficiency, Low-Emissions Coal-Fired Power Generation, International Energy Agency, December 4, 2012.

optimized for steam production. Hence, while steam turbine CHP system electrical efficiency[64] may seem very low, it is because the primary objective is to produce large amounts of steam. The effective electrical efficiency[65] of steam turbine systems, however, is generally very high, because almost all the energy difference between the high pressure boiler output and the lower pressure turbine output is converted to electricity. This means that total CHP system efficiencies[66] are generally very high and approach the boiler efficiency level. Steam boiler efficiencies range from 70 to 85 percent HHV depending on boiler type and age, fuel, duty cycle, application, and steam conditions.

Table 4-2. Backpressure Steam Turbine Cost and Performance Characteristics*

Steam Turbine Parameters[67]	System		
	1	2	3
Nominal Electricity Capacity (kW)	500	3,000	15,000
Typical Application	Industrial, PRV application	Industrial, universities, hospitals	Industrial, universities, hospitals
Equipment Cost ($/kW)[68]	$668	$401	$392
Total Installed Cost ($/kW)[69]	$1,136	$682	$666
O&M Costs ($/kW)[70]	$0.010	$0.009	$0.006
Turbine Isentropic Efficiency (%)[71]	52.5%	61.2%	78.0%
Generator/Gearbox Efficiency (%)	94%	94%	96%
Steam Flow (lbs/hr)	20,050	152,600	494,464
Inlet Pressure (psig)	500	600	700
Inlet Temperature (° Fahrenheit)	550	575	650
Outlet Pressure (psig)	50	150	150
Outlet Temperature (° Fahrenheit)	298	373	379.7
CHP System Parameters	**1**	**2**	**3**
Boiler Efficiency (%), HHV	80%	80%	80%
Electric Efficiency (%), HHV[72]	6.27%	4.92%	7.31%
Fuel Input (MMBtu/hr)	27.2	208.3	700.1
Steam to Process (MMBtu/hr)	19.9	155.7	506.8
Steam to Process (kW)	5,844	45,624	148,484
Total CHP Efficiency (%), HHV[73]	79.60%	79.68%	79.70%

[64] Net power output / total fuel input into the system.
[65] (Steam turbine electric power output) / (Total fuel into boiler – (steam to process/boiler efficiency)).
[66] Net power and steam generated divided by total fuel input.
[67] Characteristics for "typical" commercially available steam turbine generator systems provided by Elliott Group.
[68] Equipment cost includes turbine, gearbox, generator, control system, couplings, oil system (if required), and packaging; boiler and steam system costs are not included.
[69] Installed costs vary greatly based on site-specific conditions; installed costs of a "typical" simple installation were estimated to be 50-70% of the equipment costs.
[70] Maintenance assumes normal service intervals over a 5 year period, excludes parts.
[71] The Isentropic efficiency of a turbine is a comparison of the actual power output compared to the ideal, or isentropic, output. It is a measure of the effectiveness of extracting work from the expansion process and is used to determine the outlet conditions of the steam from the turbine.
[72] CHP electrical efficiency = Net electricity generated/Total fuel into boiler. A measure of the amount of boiler fuel converted into electricity.

Table 4-2. Backpressure Steam Turbine Cost and Performance Characteristics*

Steam Turbine Parameters[67]	System		
	1	2	3
Power/Heat Ratio[74]	0.086	0.066	0.101
Net Heat Rate (Btu/kWh)[75]	4,541	4,540	4,442
Effective Electrical Efficiency (%), HHV	75.15%	75.18%	76.84%
Heat/Fuel Ratio[76]	0.733	0.748	0.724

* For typical systems available in 2014.

Equipment costs shown include the steam turbine, gearbox, generator, control system, couplings, oil system (if required), and packaging. Installed costs vary greatly based on site-specific conditions. Installed costs of a "typical" simple installation were estimated to be 50-70 percent of the equipment costs. Boiler and steam system costs are not included in these estimates.

4.4.1 Performance Losses

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Steam turbines, especially smaller units, may leak steam around blade rows and out the end seals. When the turbine operates or exhausts at a low pressure, as is the case with condensing steam turbines, air can also leak into the system. The leakages cause less power to be produced than expected, and the makeup water has to be treated to avoid boiler and turbine material problems. Air that has leaked needs to be removed, which is usually done by a steam air ejector or a fan removing non-condensable gases from the condenser.

Because of the high pressures used in steam turbines, the casing is quite thick, and consequently steam turbines exhibit large thermal inertia. Large steam turbines must be warmed up and cooled down slowly to minimize the differential expansion between the rotating blades and the stationary parts. Large steam turbines can take over ten hours to warm up. While smaller units have more rapid startup times or can be started from cold conditions, steam turbines differ appreciably from reciprocating engines, which start up rapidly, and from gas turbines, which can start up in a moderate amount of time and load follow with reasonable rapidity.

Steam turbine applications usually operate continuously for extended periods of time, even though the steam fed to the unit and the power delivered may vary (slowly) during such periods of continuous operation. As most steam turbines are selected for applications with high duty factors, the nature of their application often takes care of the need to have only slow temperature changes during operation, and long startup times can be tolerated. Steam boilers similarly may have long startup times, although rapid start-up boilers are available.

[73] Total CHP efficiency = (Net electricity generated + Net steam to process)/Total fuel into boiler.
[74] Power/Heat Ratio = CHP electrical power output (Btu)/useful heat output (Btu).
[75] Net Heat Rate = (total fuel input to the boiler - the fuel that would be required to generate the steam to process assuming the same boiler efficiency)/steam turbine electric output (kW).
[76] Effective Electrical Efficiency = (Steam turbine electric power output) / (Total fuel into boiler – (steam to process/boiler efficiency)). Equivalent to 3,412 Btu/kWh/Net Heat Rate.

4.4.2 Performance Enhancements

In industrial steam turbine systems, business conditions determine the requirements and relative values of electric power and process, or steam for heating. Plant system engineers then decide the extent of efficiency enhancing options to incorporate in terms of their incremental effects on performance and plant cost, and select appropriate steam turbine inlet and exhaust conditions. Often the steam turbine is going into a system that already exists and is being modified so that a number of steam system design parameters are already established from previous decisions, which exist as system hardware characteristics and the turbine must be properly matched to these conditions.

As the stack temperature of the boiler exhaust combustion products still contain some heat, tradeoffs are made regarding the extent of investment in heat reclamation equipment for the sake of efficiency improvement. Often the stack exhaust temperature is set at a level where further heat recovery would result in condensation of corrosive chemical species in the stack, with consequential deleterious effects on stack life and safety.

4.4.2.1 Steam Reheat

Higher pressures and temperatures along with steam reheat are used to increase power generation efficiency in large industrial (and utility) systems. The higher the pressure ratio (the ratio of the steam inlet pressure to the steam exit pressure) across the steam turbine, and the higher the steam inlet temperature, the more power it will produce per unit of mass flow, provided that the turbine can reliably accommodate the pressure ratio and that the turbine is not compromised by excessive condensation within the last expansion stage. To avoid condensation within the flowpath or to maximize available steam energy, the inlet steam temperature is increased until the economic life limit of turbine materials is reached. This limit is now generally in the range of 900° F for small industrial steam turbines using typical materials.

Expanding steam can reach a condition of temperature and pressure where condensation to (liquid) water begins. Small amounts of water droplets can be tolerated in the last stages of a steam turbine provided that the droplets are not too large or numerous. Turbine flowpaths can employ features for extracting a portion of the condensate form the flowpath in order to limit water droplet impingement on the blading. Also, protective blade treatments such as Stellite are often employed to harden the blading surfaces exposed to the droplet impingement and reduce blade material erosion. For turbines using a reheat cycle, steam is extracted after it has partially expanded, heated in a heat exchanger, and returned to the turbine flowpath for further expansion.

4.4.2.2 Combustion Air Preheating

In large industrial systems, air preheaters recover heat from the boiler exhaust gas stream, and use it to preheat the combustion air, thereby reducing fuel consumption. Boiler combustion air preheaters are large versions of the heat wheels used for the same purpose on industrial furnaces.

4.4.3 Capital Costs

A steam turbine-based CHP plant is a complex process with many interrelated subsystems that must usually be custom designed. In a steam turbine CHP plant burning a solid biomass fuel, the steam turbine generator makes up only about 10 percent of the total plant equipment costs – the solid fuel

boiler makes up 45 percent and the prep yard, electrostatic precipitator, and other equipment each adding about 15 percent.[77] Engineering and construction add 70 percent to equipment costs.

The cost of complete solid fuel CHP plants varies with many factors—fuels handling, pollution control equipment and boiler cost are major cost items. Because of both the size of such plants and the diverse sources of the components, solid fuel cogeneration plants invariably involve extensive system engineering and field labor during construction. Typical complete plant costs can be over $5,000/kW, with little generalization except that for the same fuel and configuration, costs per kW of capacity generally increase as size decreases. While the overall cost of plants with a given steam output would be similar, the amount of steam extracted for process use, and thus not available for power generation, has a significant effect on the costs quoted in $/kW of electricity out.

Steam turbine costs exhibit a modest extent of irregularity, as steam turbines are made in sizes with finite steps between the sizes. The cost of the turbine is generally the same for the upper and lower limit of the steam flowing through it, so step-like behavior is sometimes seen in steam turbine prices. Since they come in specific size increments, a steam turbine that is used at the upper end of its range of power capability costs less per kW generated than one that is used at the lower end of its capability. Additionally, raw material cost, local labor rates, delivery times, availability of existing major components, and similar business conditions can affect steam turbine pricing.

Often steam turbines are sold to fit into an existing plant. In some of these applications, the specifications, mass flow, pressure, temperature and backpressure or extraction conditions are customized and therefore do not expose themselves to large competition. These somewhat unique machines may be more expensive per kilowatt than other machines that are more generalized, and therefore face greater competition. This is the case for three reasons: 1) a greater amount of custom engineering and manufacturing setup may be required; 2) there is less potential for sales of duplicate or similar units; and 3) there are fewer competitive bidders. The truly competitive products are the “off-the-rack” type machines, while “custom” machines are naturally more expensive.

Because of the relatively high cost of the system, high annual capacity factors are required to enable a reasonable recovery of invested capital.

However, retrofit applications of steam turbines into existing boiler/steam systems can be cost competitive options for a wide variety of users depending on the pressure and temperature of the steam exiting the boiler, the thermal needs of the site, and the condition of the existing boiler and steam system. In such situations, the decision is based only on the added capital cost of the steam turbine, its generator, controls and electrical interconnection, with the balance of plant already in place. Similarly, many facilities that are faced with replacement or upgrades of existing boilers and steam systems often consider the addition of steam turbines, especially if steam requirements are relatively large compared to power needs within the facility.

In general, steam turbine applications are driven by balancing lower cost fuel or avoided disposal costs for the waste fuel, with the high capital cost and (preferably high) annual capacity factor for the steam

[77] “Cogeneration and Small Power Production Manual,” Scott Spiewak and Larry Weiss, 1997. Data for a 32.3 MW multi-fuel fired, 1,250 psig, 900 °F, 50 psig backpressure steam turbine used in an industrial cogeneration plant.

plant, and the combined energy plant-process plant application through CHP. For these reasons, steam turbines are not normally direct competitors of gas turbines and reciprocating engines.

Steam turbine prices vary greatly with the extent of competition and related manufacturing volumes for units of desired size, inlet and exit steam conditions, rotational speed and standardization of construction. Prices are usually quoted for an assembled steam turbine-electrical generator package. The electrical generator can account for 20 percent to 40 percent of the assembly. As the steam turbine/electrical generator package is heavy, due in large part to the heavy walled construction of the high pressure turbine casing, it must be mounted carefully on an appropriate pedestal or baseplate. The installation and connection to the boiler through high pressure-high temperature steam pipes must be performed with engineering and installation expertise. As the high pressure steam pipes typically vary in temperature by 750° F between cold standby/repair status and full power status, care must be taken in installing a means to accommodate the differential expansion accompanying startup and shutdown to minimize induced stress on the turbine casing. Should the turbine have variable extraction, the cost of the extraction valve and control system adds to the installation.

Small steam turbine generators of less than 1,000 kW are generally more expensive on a per KW basis. However, products have been developed and are being marketed specifically for small market applications.

As the steam for a steam turbine is generated in a boiler by combustion and heat transfer, the temperature of the steam is limited by furnace heat transfer design and manufacturing consideration and boiler tube bundle design. Higher heat fluxes in the boiler enable more compact boilers, with less boiler tube material to be built, however, higher heat fluxes also result in higher boiler tube temperature and the need for the use of a higher grade (adequate strength at higher temperature) boiler tube material. Such engineering economic tradeoffs between temperature (with consequential increases in efficiency) and cost appear throughout the steam plant.

4.4.4 Maintenance

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Steam turbines are very rugged units, with operational life often exceeding 50 years. Maintenance is simple, comprised mainly of making sure that all fluids (steam flowing through the turbine and the oil for the bearing) are always clean and at the proper temperature with low levels of moisture or high steam quality or superheat. The oil lubrication system must be clean and at the correct operating temperature and level to maintain proper performance. Other items include inspecting auxiliaries such as lubricating-oil pumps, coolers and oil strainers and checking safety devices such as the operation of overspeed trips.

In order to obtain reliable service, steam turbines require long warm-up periods so that there are minimal thermal expansion stress and wear concerns. Steam turbine maintenance costs are typically below $0.01/kWh. Boilers and any associated solid fuel processing and handling equipment that is part of the boiler/steam turbine plant require their own types of maintenance which can add $0.02/kWh for maintenance and $0.015/kWh for operating labor.

One maintenance issue with steam turbines is that solids can carry over from the boiler and deposit on turbine nozzles and other internal parts, degrading turbine efficiency and power output. Some of these

are water soluble but others are not. Three methods are employed to remove such deposits: 1) manual removal; 2) cracking off deposits by shutting the turbine off and allowing it to cool; and 3) for water soluble deposits, water washing while the turbine is running.

An often-overlooked component in the steam power system is the steam (safety) stop valve, which is immediately ahead of the steam turbine and is designed to be able to experience the full temperature and pressure of the steam supply. This safety valve is necessary because if the generator electric load were lost (an occasional occurrence), the turbine would rapidly overspeed and destroy itself. Other accidents are also possible, supporting the need for the turbine stop valve, which may add significant cost to the system.

4.4.5 Fuels

Industrial boilers operate on a wide variety of fuels, including wood, coal, natural gas, oils (including residual oil, the leftover material when the valuable distillates have been separated for separate sale), municipal solid waste and sludge. The fuel handling, storage and preparation equipment needed for solid fuels considerably adds to the cost of an installation. Thus, such fuels are used only when a high annual capacity factor is expected of the facility, or when the solid material has to be disposed of to avoid an environmental or space occupancy problem.

4.4.6 System Availability

Steam turbines are generally considered to have 99 percent plus availability with longer than one year between shutdowns for maintenance and inspections. This high level of availability applies only to the steam turbine, not to the boiler or HRSG that is supplying the steam. For complete systems, the complexity of the fuel handling, combustion, boiler, and emissions, especially for solid fuels, brings overall availability down below that of reciprocating engines and gas turbines. As shown in **Table 4-3**, a survey of 16 small steam turbine power systems showed an average availability of 90.6 percent with a range of 72.4-99.8 percent. The best system ran for a period of two years without a forced outage.

Table 4-3. Steam Turbine Availability

Other Technologies	Steam Turbines <25MW		
Number Sampled	16		
	Min.	Avg.	Max.
Availability (%)	72.37	90.59	99.82
Forced Outage Rate (%)	0.00	3.12	16.41
Scheduled Outage Factor (%)	0.00	6.88	27.63
Service Factor (%)	3.37	78.72	99.65
Mean Time Between Forced Outages (hrs)	120	828	16,600

Source: ICF[78]

4.5 Emissions and Emissions Control Options

Emissions associated with a steam turbine are dependent on the source of the boiler input fuel. Steam turbines can be used with a boiler firing any one or a combination of a large variety of fuel sources, or

[78] *Distributed Generation Operational Reliability and Availability Database*, EEA, Inc. (now part of ICF) for ORNL, 2003.

they can be used with a gas turbine in a combined cycle configuration. Boiler emissions vary depending on fuel type and environmental conditions.

Table 4-4 illustrates typical emissions of NO_x, PM, and CO for boilers by size of steam turbine system and by fuel type. SO_x emissions are not based on the size of the boiler; rather, they are a function of the sulfur content of the fuel and the fuel combustion rate. Based on using the average fuel heat content assumptions, uncontrolled input emissions for SO_x range from 0.49-1.9 lbs/MMBtu from coal,[79] 1.16-2.22 lbs/MMBtu from wood,[80] 1.53lbs/MMBtu from fuel oils,[81] and very little to insignificant levels from natural gas combustion.

Table 4-4. Typical Boiler Emissions Ranges

Boiler Fuel	System 1 500 kW			Systems 2 and 3 3 MW / 15 MW		
	NO_x	CO	PM	NO_x	CO	PM
Coal (lbs/MMBtu)	N/A	N/A	N/A	0.20-1.24	0.0.02-0.7	
Wood (lbs/MMBtu)	0.22-0.49	0.6	0.33-0.56	0.22-0.49	0.06	0.33-0.56
Fuel Oil (lbs/MMBtu)	0.15-0.37	0.03	0.01-0.08	0.07-0.31	0.03	0.01-0.08
Natural Gas (lbs/MMBtu)	0.03-0.1	0.08	-	0.1 – 0.28	0.08	-

Note: all emissions values are without post-combustion treatment.

Source: EPA, Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources

4.5.1 Boiler Emissions Control Options - NO_x

NO_x control has been a focus of emission control research and development in boilers. The following provides a description of the most prominent emission control approaches.

4.5.1.1 Combustion Process emissions Control

Combustion control techniques are less costly than post-combustion control methods and are often used on industrial boilers for NO_x control. Control of combustion temperature has been the principal focus of combustion process control in boilers. Combustion control requires tradeoffs – high temperatures favor complete burn up of the fuel and low residual hydrocarbons and CO, but promote NO_x formation. Very lean combustion dilutes the combustion process and reduces combustion temperatures and NO_x formation, and allows a higher compression ratio or peak firing pressures resulting in higher efficiency. However, if the mixture is too lean, misfiring and incomplete combustion occurs, increasing CO and VOC emissions.

[79] *http://www.eia.gov/coal/production/quarterly/co2_article/co2.html*

[80] *http://www20.gencat.cat/docs/dmah/Home/Ambits%20dactuacio/Medi%20natural/Gestio%20forestal/Funcions%20dels%20boscos/Funcions%20productores%20del%20bosc/Biomassa%20forestal/Activitats%20realitzades/Curs%20daprofitament%20de%20biomassa%20forestal/2_ncp.pdf*

[81] *http://www.imo.org/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Sulphur-oxides-(SOx)-%E2%80%93-Regulation-14.aspx*

4.5.1.2 Flue Gas Recirculation (FGR)

FGR is the most effective technique for reducing NO_x emissions from industrial boilers with inputs below 100 MMBtu/hr. With FGR, a portion of the relatively cool boiler exhaust gases re-enter the combustion process, reducing the flame temperature and associated thermal NO_x formation. It is the most popular and effective NO_x reduction method for firetube and watertube boilers, and many applications can rely solely on FGR to meet environmental standards.

External FGR employs a fan to recirculate the flue gases into the flame, with external piping carrying the gases from the stack to the burner. A valve responding to boiler input controls the recirculation rate. Induced FGR relies on the combustion air fan for flue gas recirculation. A portion of the gases travel via ductwork or internally to the air fan, where they are premixed with combustion air and introduced into the flame through the burner. Induced FGR in newer designs utilize an integral design that is relatively uncomplicated and reliable.

The physical limit to NO_x reduction via FGR is 80 percent in natural gas-fired boilers and 25 percent for standard fuel oils.

4.5.1.3 Low Excess Air Firing (LAE)

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Boilers are fired with excess air to ensure complete combustion. However, excess air levels greater than 45 percent can result in increased NO_x formation, because the excess nitrogen and oxygen in the combustion air entering the flame combine to form thermal NO_x. Firing with low excess air means limiting the amount of excess air that enters the combustion process, thus limiting the amount of extra nitrogen and oxygen entering the flame. This is accomplished through burner design modification and is optimized through the use of oxygen trim controls.

LAE typically results in overall NO_x reductions of 5 to 10 percent when firing with natural gas, and is suitable for most boilers.

4.5.1.4 Low Nitrogen Fuel Oil

NO_x formed by fuel-bound nitrogen can account for 20 to 50 percent of total NO_x levels in oil-fired boiler emissions. The use of low nitrogen fuels in boilers firing distillate oils is one method of reducing NO_x emissions. Such fuels can contain up to 20 times less fuel-bound nitrogen than standard No. 2 oil.

NO_x reductions of up to 70 percent over NO_x emissions from standard No. 2 oils have been achieved in firetube boilers utilizing flue gas recirculation.

4.5.1.5 Burner Modifications

By modifying the design of standard burners to create a larger flame, lower flame temperatures and lower thermal NO_x formation can be achieved, resulting in lower overall NO_x emissions. While most boiler types and sizes can accommodate burner modifications, it is most effective for boilers firing natural gas and distillate fuel oils, with little effectiveness in heavy oil-fired boilers. Also, burner modifications must be complemented with other NO_x reduction methods, such as flue gas recirculation, to comply with the more stringent environmental regulations. Achieving low NO_x levels (30 ppm) through burner modification alone can adversely impact boiler operating parameters such as turndown, capacity, CO levels, and efficiency.

4.5.1.6 Water/Steam Injection

Injecting water or steam into the flame reduces flame temperature, lowering thermal NO_x formation and overall NO_x emissions. However, under normal operating conditions, water/steam injection can lower boiler efficiency by 3 to 10 percent. Also, there is a practical limit to the amount that can be injected without causing condensation-related problems. This method is often employed in conjunction with other NO_x control techniques such as burner modifications or flue gas recirculation.

When used with natural gas-fired boilers, water/steam injection can result in NO_x reduction of up to 80 percent, with lower reductions achievable in oil-fired boilers.

4.5.2 Post-Combustion Emissions Control

There are several types of exhaust gas treatment processes that are applicable to industrial boilers.

4.5.2.1 Selective Non-Catalytic Reduction (SNCR)

In a boiler with SNCR, a NO_x reducing agent such as ammonia or urea is injected into the boiler exhaust gases at a temperature in the 1,400 to 1,600° F range. The agent breaks down the NO_x in the exhaust gases into water and atmospheric nitrogen (N_2). While SNCR can reduce boiler NO_x emissions by up to 70 percent, it is very difficult to apply this technology to industrial boilers that modulate or cycle frequently because the agent must be introduced at a specific flue gas temperature in order to perform properly. Also, the location of the exhaust gases at the necessary temperature is constantly changing in a cycling boiler.

4.5.2.2 Selective Catalytic Reduction (SCR)

This technology involves the injection of the reducing agent into the boiler exhaust gas in the presence of a catalyst. The catalyst allows the reducing agent to operate at lower exhaust temperatures than SNCR, in the 500 to 1,200° F depending on the type of catalyst. NO_x reductions of up to 90 percent are achievable with SCR. The two agents used commercially are ammonia (NH_3 in anhydrous liquid form or aqueous solution) and aqueous urea. Urea decomposes in the hot exhaust gas and SCR reactor, releasing ammonia. Approximately 0.9 to 1.0 moles of ammonia is required per mole of NO_x at the SCR reactor inlet in order to achieve an 80 to 90 percent NO_x reduction.

SCR is however costly to use and can only occasionally be justified on boilers with inputs of less than 100 MMBtu/hr. 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.

4.5.2.3 Boiler Emissions Control Options – SO_x

The traditional method for controlling SO_x emissions is dispersion via a tall stack to limit ground level emissions. The more stringent SO_x emissions requirements in force today demand the use of reduction methods as well. These include use of low sulfur fuel, desulfurizing fuel, and flue gas desulfurization (FGD). Desulfurization of fuel, such as in FGD, primarily applies to coal, and is principally used for utility boiler emissions control. Use of low sulfur fuels is the most cost effective SO_x control method for industrial boilers, as it does not require installation and maintenance of special equipment.

FGD systems are of two types: non-regenerable and regenerable. The most common non-regenerable results in a waste product that requires proper disposal. Regenerable FGD converts the waste product into a product that is saleable, such as sulfur or sulfuric acid. SO_x emissions reductions of up to 95 percent can be obtained with FGD.

4.6 Future Developments

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While steam turbines are a mature technology, their importance in worldwide power generation makes incremental improvements in cost and performance very beneficial. Higher efficiencies reduce fuel consumption, emissions of air pollutants and greenhouse gases, and cooling water requirements. Since commercial introduction, efficiencies for large condensing steam turbines have increased from the mid-teens to up to 48 percent. The U.S. Department of Energy funds collaborative research and development toward the development of improved ultra-supercritical (USC) steam turbines capable of efficiencies of 55-60 percent that are based on boiler tube materials that can withstand pressures of up to 5,000 psi and temperatures of 1,400° F. To achieve these goals, work is ongoing in materials, internal design and construction, steam valve development, and design of high pressure casings. A prototype is targeted for commercial testing by 2025.[82]

Research is also underway to restore and improve the performance of existing steam turbines in the field through such measures as improved combustion systems for boilers, heat transfer and aerodynamics to improve turbine blade life and performance, and improved materials to permit longer life and higher operating temperatures for more efficient systems.[83]

The focus on renewable markets, such as waste heat recovery, biomass fueled power, and CHP plants, is stimulating the demand for small and medium steam turbines. Technology and product development for these markets should bring about future improvements in steam turbine efficiency, longevity, and cost. This could be particularly true for systems below 500 kW that are used in developmental small biomass systems, and in waste-heat-to-power systems, as the latter is designed to operate in place of pressure reduction valves in commercial and industrial steam systems operating at multiple pressures.

[82] Advanced Turbines Technology Program Plan, National Energy Technology Laboratory, Clean Coal Research Program, U.S. Department of Energy, January 2013.
[83] Energy Tech, *http://www.energy-tech.com/article.cfm?id=17566*

Section 5. Technology Characterization – Microturbines

5.1 Introduction

Microturbines, as the name implies, are small combustion turbines that burn gaseous or liquid fuels to drive an electrical generator, and have been commercially available for more than a decade. Today's microturbine technology is the result of development work in small stationary and automotive gas turbines, auxiliary power equipment, and turbochargers, much of which took place in the automotive industry beginning in the 1950s. The development of microturbine systems was accelerated by the similarity of design to large engine turbochargers, and that provided the basis for the engineering and manufacturing technology of microturbine components.

During the 1990s several companies developed competing microturbine products and entered, or planned to enter, the market. As the market matured, the industry underwent a consolidation phase during which companies merged, changed hands, or dropped out of the market. In the United States today, this has led to two main manufacturers of stationary microturbine products – Capstone Turbine Corporation and FlexEnergy.

Table 5-1 provides a summary of microturbine attributes. Microturbines range in size from 30 to 330 kilowatts (kW). Integrated packages consisting of multiple microturbine generators are available up to 1,000 kW, and such multiple units are commonly installed at sites to achieve larger power outputs. Microturbines are able to operate on a variety of fuels, including natural gas, sour gas (high sulfur, low Btu content), and liquid petroleum fuels (e.g., gasoline, kerosene, diesel fuel, and heating oil).

Table 5-1. Summary of Microturbine Attributes

Electrical Output	Available from 30 to 330 kW with integrated modular packages up to 1,000 kW.
Thermal Output	Exhaust temperatures in the range of 500 to 600 °F, suitable for supplying a variety of site thermal needs, including hot water, steam, and chilled water (using an absorption chiller).
Fuel Flexibility	Can utilize a number of different fuels, including natural gas, sour gas (high sulfur, low Btu content), and liquid fuels (e.g., gasoline, kerosene, diesel fuel, and heating oil).
Reliability and life	Design life is estimated to be 40,000 to 80,000 hours with overhaul.
Emissions	Low NO_x combustion when operating on natural gas; capable of meeting stringent California standards with carbon monoxide/volatile organic compound (CO/VOC) oxidation catalyst.
Modularity	Units may be connected in parallel to serve larger loads and to provide power reliability.
Part-load Operation	Units can be operated to follow load with some efficiency penalties.
Dimensions	Compact and light weight, 2.3-2.7 cubic feet (cf) and 40-50 pounds per kW.

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5.2 Applications

Microturbines are ideally suited for distributed generation applications due to their flexibility in connection methods, their ability to be stacked in parallel to serve larger loads, their ability to provide

stable and reliable power, and their low emissions compared to reciprocating engines. Important applications and functions are described below:

- **Combined heat and power (CHP)** – microturbines are well suited to be used in CHP applications because the exhaust heat can either be recovered in a heat recovery boiler, or the hot exhaust gases can be used directly. Typical natural gas fueled CHP markets include:
    - Commercial – hotels, nursing homes, health clubs
    - Institutional – public buildings
    - Industrial – small operations needing hot water or low pressure steam for wash water as in the food and manufacturing sectors

- **Combined cooling heating and power (CCHP)** – The temperature available for microturbine exhaust allows effective use with absorption cooling equipment that is driven either by low pressure steam or by the exhaust heat directly. Cooling can be added to CHP in a variety of commercial/institutional applications to provide both cooling and heating.

- **Resource recovery** – the ability of microturbines to burn a variety of fuels make it useful for resource recovery applications including landfill gas, digester gas, oil and gas field pumping and power applications, and coal mine methane use.

- **Peak shaving and base load power** (grid parallel).

- **Thermal oxidation of very low Btu fuel or waste streams** – Microturbine systems have been designed to provide thermal oxidation for applications needing methane or volatile organic compound destruction such as for landfill gas or other waste gases.

- **Premium power and power quality** – due to the inverter based generators, power quality functionality can be added to CHP, and power-only applications allowing the system to be part of an overall uninterruptible power supply (UPS) system providing black start capability and back-up power capability to provide power when the electrical grid is down. The system can also provide voltage and other power quality support. Such functions are useful for applications with high outage costs and sensitive power needs including small data centers, hospitals, nursing homes, and a variety of other applications that have critical service requirements.

- **Power only applications** – microturbines can be used for stand-alone power in remote applications where grid power is either unavailable or very high cost. The systems can also run as back-up power or in peak-shaving mode, though such use is limited.

- **Microgrid** – Microturbines are inverter based generation, and are therefore well-suited for application in utility microgrids, providing grid support and grid communication functions. This area of use is in a development and demonstration phase by electric power companies.

5.3 Technology Description

5.3.1 Basic Process

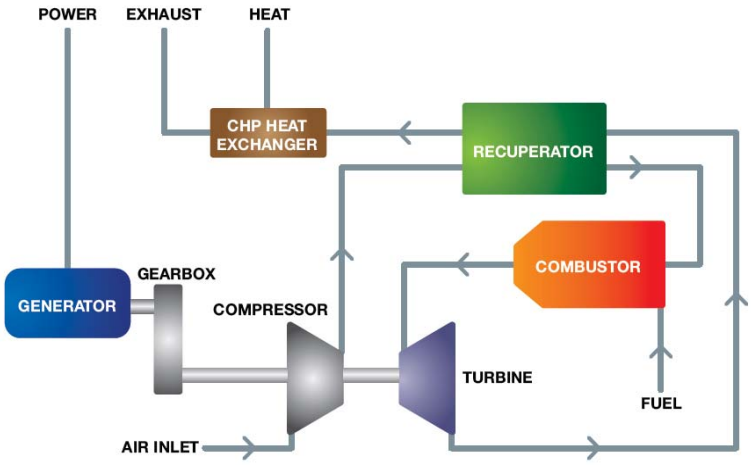
Microturbines operate on the same thermodynamic cycle (Brayton Cycle) as larger gas turbines and share many of the same basic components. In this cycle, atmospheric air is compressed, heated (usually

by introducing and burning fuel), and then these hot gases drive an expansion turbine that drives both the inlet compressor and a drive shaft capable of providing mechanical or electrical power. Other than the size difference, microturbines differ from larger gas turbines in that they typically have lower compression ratios and operate at lower combustion temperatures. In order to increase efficiency, microturbines recover a portion of the exhaust heat in a heat exchanger called a recuperator, to increase the energy of the gases entering the expansion turbine thereby boosting efficiency. Microturbines operate at high rotational speeds of up to 60,000 revolutions per minute. Of the two primary players in the domestic industry, Capstone couples this shaft output directly to a high speed generator and uses power electronics to produce 60 Hz electricity. FlexEnergy uses a gearbox to reduce the drive speed to 3600 rpm to power a synchronous electric generator.

5.3.2 Components

Figure 5-1 shows a schematic diagram of the basic microturbine components, which include the combined compressor/turbine unit, generator, recuperator, combustor, and CHP heat exchanger. Each of these primary components is described further below.

Figure 5-1. Microturbine-based CHP System Schematic



Source: FlexEnergy

5.3.2.1 Turbine & Compressor

Q12

The heart of the microturbine is the compressor-turbine package (or turbocompressor), which is commonly mounted on a single shaft along with the electric generator. The shaft, rotating at upwards of 60,000 rpm, is supported on either air bearings or conventional lubricated bearings. The single moving part of the one-shaft design has the potential for reducing maintenance needs and enhancing overall reliability.

Microturbine turbomachinery is based on single-stage radial flow compressors and turbines, unlike larger turbines that use multi-stage axial flow designs. Radial design turbomachinery handles the small volumetric flows of air and combustion products with reasonably high component efficiency.[84] Large-

[1] With axial flow turbomachinery, blade height would be too small to be practical.

size axial flow turbines and compressors are typically more efficient than radial flow components. However, in the size range for microturbines – 0.5 to 5 lbs/second of air/gas flow – radial flow components offer minimum surface and end wall losses thereby improving efficiency.

As mentioned earlier, microturbines operate on either oil-lubricated or air bearings, which support the shaft. *Oil-lubricated bearings* are mechanical bearings and come in three main forms – high-speed metal roller, floating sleeve, and ceramic surface. Ceramic surface bearings typically offer the most attractive benefits in terms of life, operating temperature, and lubricant flow. While they are a well-established technology, they require an oil pump, oil filtering system, and liquid cooling that add to microturbine cost and maintenance. In addition, the exhaust from machines featuring oil-lubricated bearings may not be useable for direct space heating in cogeneration configurations due to the potential for air contamination.

Air bearings allow the turbine to spin on a thin layer of air, so friction is low and rpm is high. They have been in service on airplane cabin cooling systems for many years. No oil or oil pump is needed. Air bearings offer simplicity of operation without the cost, reliability concerns, maintenance requirements, or power drain of an oil supply and filtering system.

5.3.2.2 Generator

Q13

The microturbine produces electrical power either via a high-speed generator turning on the single turbo-compressor shaft or through a speed reduction gearbox driving a conventional 3,600 rpm generator. The high-speed generator single-shaft design employs a permanent magnet, and an air-cooled generator producing variable voltage and high-frequency AC power. This high frequency AC output (about 1,600 Hz for a 30 kW machine) is converted to constant 60 Hz power output in a power conditioning unit. Power conditioning involves rectifying the high frequency AC to DC, and then inverting the DC to 60 Hz AC. However, power conversion comes with an efficiency penalty (approximately 5 percent). In addition to the digital power controllers converting the high frequency AC power into usable electricity, they also filter to reduce harmonic distortion in the output. The power conditioning unit is a critical component in the single-shaft microturbine design and represents significant design challenges, specifically in matching turbine output to the required load. To accommodate transients and voltage spikes, power electronic units are generally designed to handle seven times the nominal voltage. Most microturbine power electronics generate three-phase electricity.

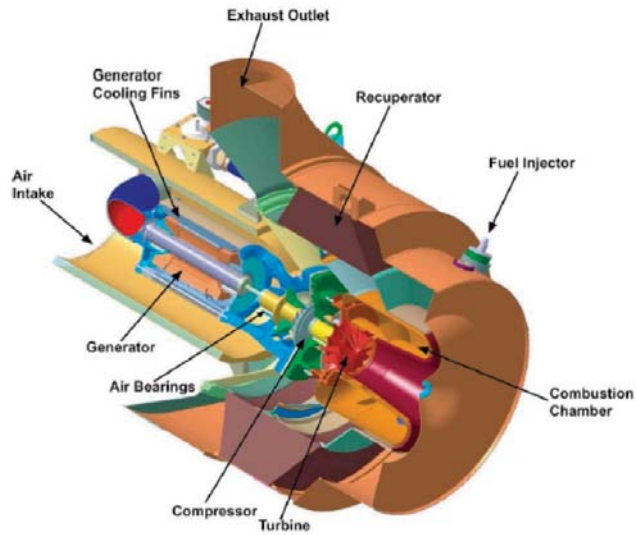
To start-up a single shaft design, the generator acts as a motor turning the turbo-compressor shaft until sufficient rpm is reached to start the combustor. If the system is operating independent of the grid (black starting), a power storage unit (typically a battery) is used to power the generator for start-up.

Electronic components also direct all of the operating and startup functions. Microturbines are generally equipped with controls that allow the unit to be operated in parallel or independent of the grid, and internally incorporate many of the grid and system protection features required for interconnection. The controls also allow for remote monitoring and operation.

Figure 5-2 provides an example of the compact design of the basic microturbine components (in this case, for the Capstone model C200 (200 kW)). The turbocompressor section, riding on air bearings,

drives the high speed, air cooled generator. The entire assembly is surrounded by a can-like structure housing the recuperator and the combustion chamber.

Figure 5-2. Compact Microturbine Design



Source: Capstone Turbines, C200

5.3.2.3 Recuperator & Combustor

The recuperator is a heat exchanger that uses the hot turbine exhaust gas (typically around 1,200ºF) to preheat the compressed air (typically around 300ºF) going into the combustor, thereby reducing the fuel needed to heat the compressed air to the required turbine inlet temperature. Depending on microturbine operating parameters, recuperators can more than double machine efficiency. However, since there is increased pressure drop on both the compressed air and turbine exhaust sides of the recuperator, this increased efficiency comes at the expense of about a 10-15 percent drop in power output.

5.3.2.4 CHP Heat Exchanger

In CHP operation, microturbines offer an additional heat exchanger package, integrated with the basic system, that extracts much of the remaining energy in the turbine exhaust, which exits the recuperator at about 500-600º F. Exhaust heat can be used for a number of different applications, including potable water heating, space heating, thermally activated cooling and dehumidification systems (absorption chillers, desiccant dehumidification). Because microturbine exhaust is clean and has a high percentage (15 percent) of oxygen, it can also be used directly for process applications such as driving a double-effect absorption chiller or providing preheat combustion air for a boiler or process heat application.

5.4 Performance Characteristics

Q14

Table 5-2 summarizes cost and performance characteristics for typical microturbine CHP systems ranging in size from 30 kW to 1 MW. Heat rates and efficiencies are based on manufacturers' specifications for systems operating on natural gas, the predominant fuel choice in CHP applications. The table assumes that natural gas is delivered at typical low delivery pressures which require a booster

compressor to raise the gas pressure to the point at which it can be introduced into the compressed inlet air-stream. Electrical efficiencies and heat rates shown are net of power losses from the gas booster compressor. Customers that have, or can gain access to, high pressure gas from their local gas utility can avoid the capacity and efficiency losses due to fuel gas compression. Capital costs, described in more detail in a later section, are based on assumptions of a basic grid connect installation. Installation costs can vary widely depending on site conditions and regional differences in material, labor, and site costs. Available thermal energy is calculated based on manufacturer specifications on turbine exhaust flows and temperatures. CHP thermal recovery estimates are based on producing hot water for process or space heating applications. All performance specifications are at full load International Organization for Standards (ISO) conditions (59 °F, 60 percent RH, 14.7 psia).

The data in the table show that electrical efficiency generally increases as the microturbine becomes larger. Microturbines have lower electrical efficiencies than reciprocating engines and fuel cells, but are capable of high overall CHP efficiencies. The low power to heat ratios (P/H) of microturbines (which implies relatively more heat production), makes it important for both overall efficiency and for economics to be sited and sized for applications that allow full utilization of the available thermal energy.

As shown, microturbines typically require 50 to 140 psig fuel supply pressure. Local distribution gas pressures usually range from 30 to 130 psig in feeder lines and from 1 to 50 psig in final distribution lines. If available, sites that install microturbines will generally opt for high pressure gas delivery rather than adding the cost of a booster compressor with its accompanying efficiency and capacity losses.

Estimated installed capital costs range from $4,300/kW for the 30 kW system down to $2,500/kW for the 1,000 kW system – described in more detail in Section *Capital Cost.*

Table 5-2. Microturbine Cost and Performance Characteristics

Microturbine Characteristics [1]	System					
	1	2	3	4	5	6
Nominal Electricity Capacity (kW)	30	65	200	250	333	1000
Compressor Parasitic Power (kW)	2	4	10	10	13	50
Net Electricity Capacity (kW)	28	61	190	240	320	950
Fuel Input (MMBtu/hr), HHV	0.434	0.876	2.431	3.139	3.894	12.155
Required Fuel Gas Pressure (psig)	55-60	75-80	75-80	80-140	90-140	75-80
Electric Heat Rate (Btu/kWh), LHV [2]	13,995	12,966	11,553	11,809	10,987	11,553
Electric Efficiency (%), LHV [3]	24.4%	26.3%	29.5%	28.9%	31.1%	29.5%
Electric Heat Rate (Btu/kWh), HHV	15,535	14,393	12,824	13,110	12,198	12,824
Electric Efficiency (%), HHV	21.9%	23.7%	26.6%	26.0%	28.0%	26.6%
CHP Characteristics						
Exhaust Flow (lbs/sec)	0.68	1.13	2.93	4.7	5.3	14.7
Exhaust Temp (°F)	530	592	535	493	512	535
Heat Exchanger Exhaust Temp (°F)	190	190	200	190	190	200
Heat Output (MMBtu/hr)	0.21	0.41	0.88	1.28	1.54	4.43

Table 5-2. Microturbine Cost and Performance Characteristics

Microturbine Characteristics [1]	System					
	1	2	3	4	5	6
Heat Output (kW equivalent)	61.0	119.8	258.9	375.6	450.2	1,299.0
Total CHP Efficiency (%), HHV [4]	70.0%	70.4%	63.0%	66.9%	67.5%	63.1%
Total CHP Efficiency (%), LHV	77.3%	77.8%	69.6%	73.9%	74.6%	69.8%
Power/Heat Ratio [5]	0.46	0.51	0.73	0.64	0.71	0.73
Net Heat Rate (Btu/kWh) [6]	6,211	5,983	6,983	6,405	6,170	6,963
Effective Electric Eff. (%), HHV [7]	54.9%	57.0%	48.9%	53.3%	55.3%	49.0%
Cost						
CHP Package Cost ($/kW) [8]	$2,690	$2,120	$2,120	$1,840	$1,770	$1,710
Total Installed Cost ($/kW) [9]	$4,300	$3,220	$3,150	$2,720	$2,580	$2,500

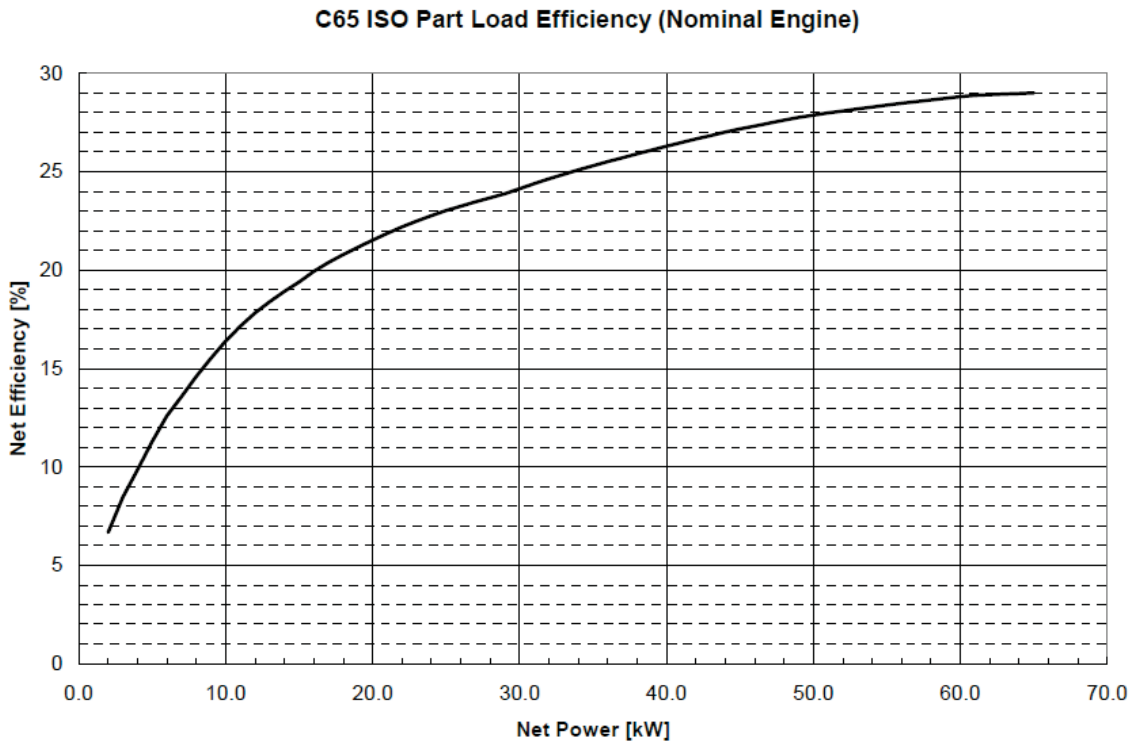
Notes:

1. Characteristics presented are representative of commercially available microturbine systems. Table data are based from smallest to largest: Capstone C30,; Capstone C65 CARB, Capstone C200 CARB, FlexEnergy MT250, FlexEnergy MT330, Capstone C1000-LE
2. Turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. Gas utilities typically report the energy content on a higher heating value (HHV) basis. In addition, electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content is near 1,030 Btu/scf on an HHV basis and about 930 Btu/scf on an LHV basis – a ratio of approximately 0.9 (LHV / HHV).
3. Electrical efficiencies are net of parasitic and conversion losses. Fuel gas compressor needs based on 1 psi inlet supply.
4. Total Efficiency = (net electricity generated + net heat produced for thermal needs)/total system fuel input
5. Power/Heat Ratio = CHP electrical power output (Btu)/ useful heat output (Btu)
6. 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).
7. Effective Electrical Efficiency = (CHP electric power output) / (total fuel into CHP system – total heat recovered/0.8).
8. Equipment cost only. The cost for all units, except the 30 kW size, includes integral heat recovery water heater. All units include a fuel gas booster compressor.
9. Installed costs based on CHP system producing hot water from exhaust heat recovery in a basic installation in grid connect mode.

5.4.1 Part-Load Performance

Microturbines that are in applications that require electric load following must operate during some periods at part load. Although, operationally, most installations are designed to operate at a constant output without load-following or frequent starts and stops. Multiple unit installations can achieve load following through sequentially turning on more units requiring less need for part load operation. When less than full electrical power is required from a microturbine, the output is reduced by a combination of mass flow reduction (achieved by decreasing the compressor speed) and turbine inlet temperature reduction. In addition to reducing power, this change in operating conditions also reduces efficiency. **Figure 5-3** shows a sample part-load efficiency curve for the Capstone C65. At 50 percent power output, the electrical efficiency drops by about 15 percent (decline from approximately 30 percent to 25 percent). However, at 50 percent power output, the thermal output of the unit only drops 41 percent resulting in a net loss of CHP efficiency of only 5 percent.

Figure 5-3. Part Load Efficiency at ISO Conditions, Capstone C65



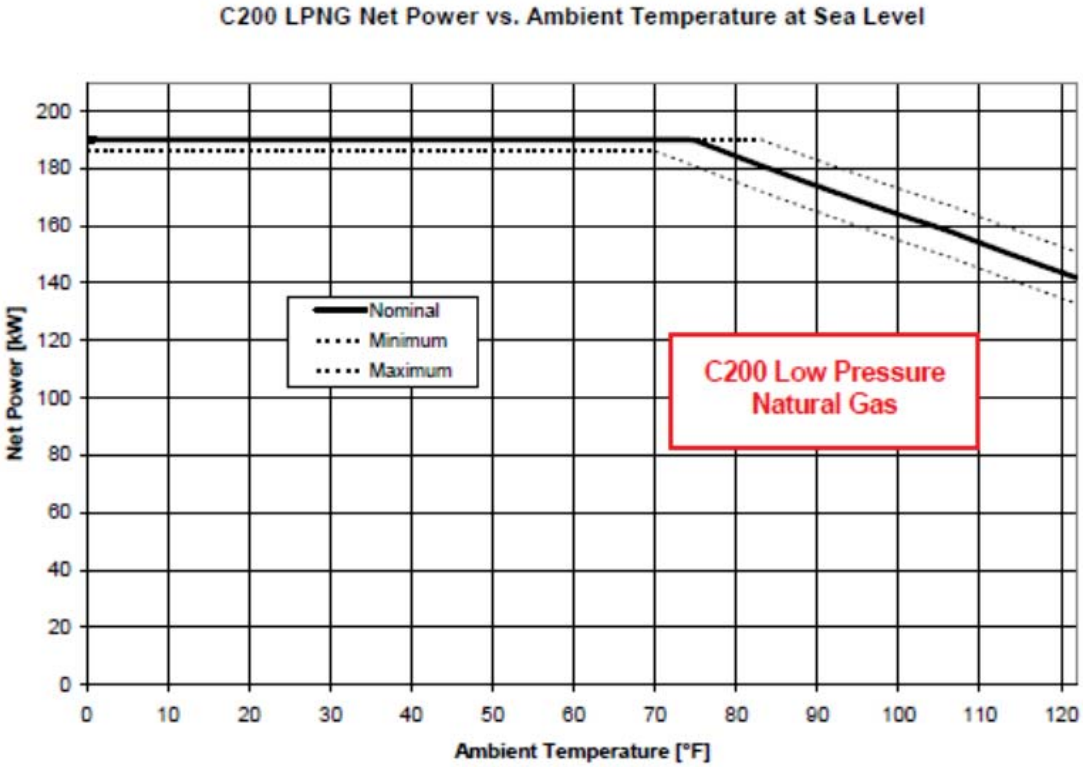
Source: Capstone, C65 Technical Reference

5.4.2 Effects of Ambient Conditions on Performance

The ambient conditions (temperature and air pressure) under which a microturbine operates have a noticeable effect on both the power output and efficiency. This section provides a better understanding of the changes observed due to changes in temperature and air pressure. At elevated inlet air temperatures, both the power and efficiency decrease. The power decreases due to the decreased mass flow rate of air (since the density of air declines as temperature increases), and the efficiency decreases because the compressor requires more power to compress air that is less dense. Conversely, the power and efficiency increase with reduced inlet air temperature.

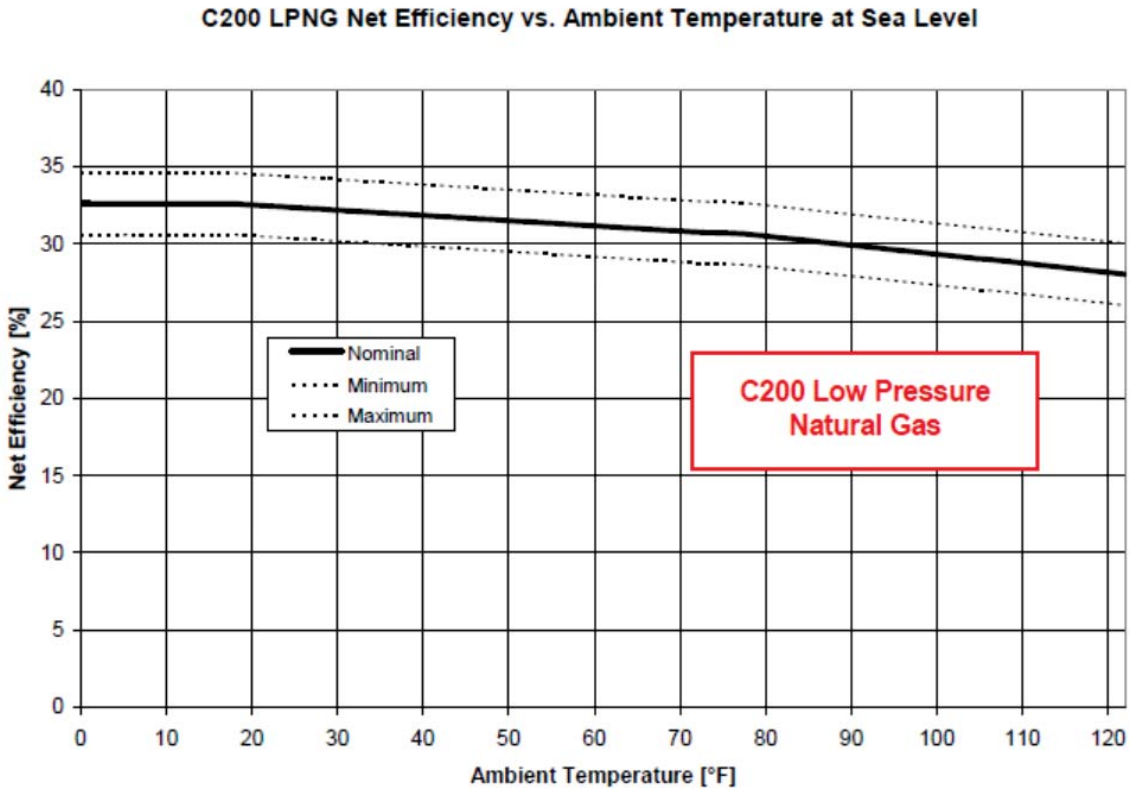
Figure 5-5 shows the variation in power and efficiency for a microturbine as a function of ambient temperature compared to the reference International Organization for Standards (ISO) condition of sea level and 59°F. The density of air decreases at altitudes above sea level. Consequently, power output decreases. **Figure 5-4** shows the effect of temperature on output, and **Figure 5-5** shows the effect on efficiency for the Capstone C200. The Capstone unit maintains a steady output up to 70-80 °F due to a limit on the generator output. However, the efficiency declines more uniformly as ambient temperature increases. **Figure 5-6** shows a combined power and efficiency curve for the FlexEnergy MT250. For this model, both power output and efficiency change more or less uniformly above and below the ISO rating point.

Figure 5-4. Temperature Effect on Power, Capstone C200-LP



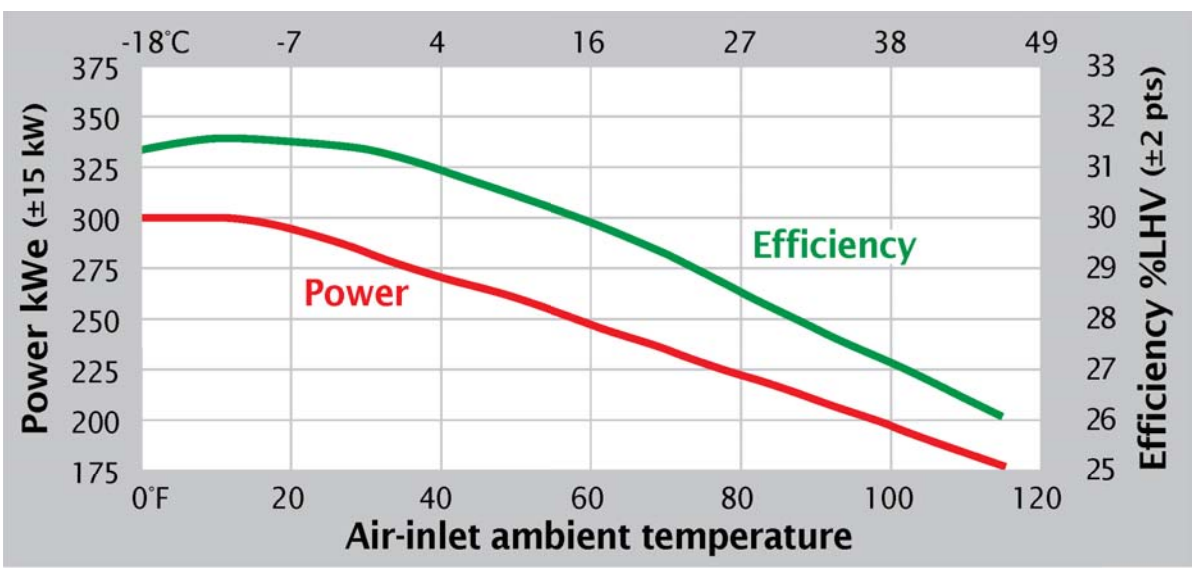
Source: Capstone Turbines

Figure 5-5. Temperature Effect on Efficiency, Capstone C200-LP



Source: Capstone Turbines

Figure 5-6. Temperature Effect on Power and Efficiency, FlexEnergy MT250



Source: FlexEnergy

Inlet air cooling can mitigate the decreased power and efficiency resulting from high ambient air temperatures. While inlet air cooling is not a feature on today's microturbines, cooling techniques now entering the market, or being employed, on large gas turbines may work their way into next generation microturbine products.

Q15

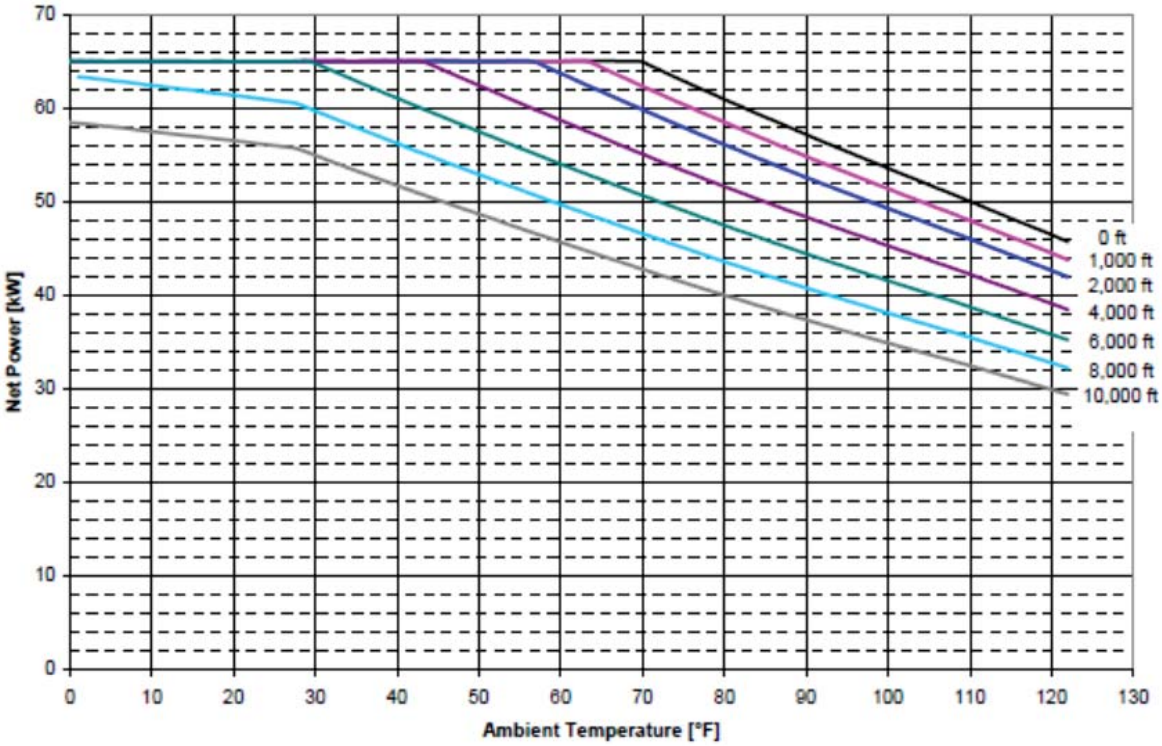
Evaporative cooling, a relatively low capital cost technique, is the most likely inlet air cooling technology to be applied to microturbines. It uses a very fine spray of water directly into the inlet air stream. Evaporation of the water reduces the temperature of the air. Since cooling is limited to the wet bulb air temperature, evaporative cooling is most effective when the wet bulb temperature is significantly below the dry bulb temperature. In most locales with high daytime dry bulb temperatures, the wet bulb temperature is often 20ºF lower. This temperature difference affords an opportunity for substantial evaporative cooling. However, evaporative cooling can consume large quantities of water, making it difficult to operate in arid climates.

Refrigeration cooling in microturbines is also technically feasible. In refrigeration cooling, a compression-driven or thermally activated (absorption) 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 driven refrigeration results in a substantial amount of parasitic power loss. Thermally activated absorption cooling can use waste heat from the microturbine, reducing the direct parasitic loss. The relative complexity and cost of these approaches, in comparison with evaporative cooling, render them less likely.

Finally, it is also technically feasible to use thermal energy storage systems – typically ice, chilled water, or low-temperature fluids – to cool inlet air. These systems 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.

The density of air also decreases with increasing altitude. The effect of altitude derating on the Capstone C65 is shown in **Figure 5-7**. An installation in the mile high city of Denver would have a capacity of only 56 kW – a 14 percent drop in capacity. Unlike the effects of temperature rise, an increase in altitude at a given temperature does not have much impact on energy efficiency. The units operate at nearly the same efficiency, though at a lower output.

Figure 5-7. Ambient Elevation vs. Temperature Derating, Capstone C65



Source: Capstone Turbines

Gas turbine and microturbine performance is also affected by inlet and exhaust back-pressure. ISO ratings are at zero inlet pressure with no exhaust back-pressure. Adding the additional CHP heat exchanger definitely produces some increase in exhaust back pressure. Pressure drops on the inlet side from air filters also reduces the system output and efficiency. For the C65 shown in the previous figure, every 1" pressure drop on the inlet side produces roughly a 0.6 percent drop in power and a 0.2 percent drop in efficiency. A 1" pressure drop on the exhaust side produces about a 0.35 percent drop in power and a 0.25 percent drop in efficiency.

It is important when evaluating microturbine performance at a given site to consider all of the derating factors that are relevant: site altitude, average temperature and seasonal temperature swings, and pressure loss derating resulting from filters and the CHP heat recovery system. The combination of these factors can have a significant impact on both capacity and efficiency. Reduction in capacity also impacts the unit costs of the equipment because the same costs are being spread over fewer kilowatts.

5.4.3 Capital Cost

This section provides study estimates of capital costs for basic microturbine CHP installations. It is assumed that the thermal energy extracted from the microturbine exhaust is used for producing hot water for use on-site. Equipment-only and installed costs are estimated for each representative microturbine system. It should be emphasized that installed 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, and whether the system is a new or a retrofit application.

Table 5-3 provides cost estimates for combined heat and power applications, assuming that the CHP system produces hot water and that there is no fuel pretreatment. Thermal recovery in the form of cooling can be accomplished with the addition of an absorption chiller – not included in this comparison. The basic microturbine package consists of the microturbine and power electronics. All of the commercial and near-commercial units offer basic interconnection and paralleling functionality as part of the package cost. All but one of the systems offers an integrated heat exchanger heat recovery system for CHP within the package.

There is little additional equipment that is required for these integrated systems. A heat recovery system has been added where needed, and additional controls and remote monitoring equipment have been added. The total plant cost consists of total equipment cost plus installation labor and materials (including site work), engineering, project management (including licensing, insurance, commissioning and startup), and financial carrying costs during a typical 3-month construction period.

The basic equipment costs represent material on the loading dock, ready to ship. It includes the cost of the generator package, the heat recovery, the flue gas compression and interconnection equipment cost. As shown in the table, the cost to a customer for installing a microturbine-based CHP system includes a number of other factors that increase the total costs by 70-80 percent.

Labor/materials represent the labor cost for the civil, mechanical, and electrical work and materials such as ductwork, piping, and wiring. A number of other costs are also incurred. These costs are often referred to as *soft costs* and they vary widely by installation, by development channel and by approach to project management. Engineering costs are required to design the system and integrate it functionally with the application's electrical and mechanical systems. In this characterization, environmental permitting fees are included. Project and construction management also includes general contractor markup, and bonding and performance guarantees. Contingency is assumed to be 5 percent of the total equipment cost in all cases. An estimated financial interest of 5 percent during a 3-month construction period is also included.

The cost estimates shown represent a basic installation. In the California Self-Generation incentive Program (SGIP) the average installation cost for 116 non-renewable fuel microturbine systems between 2001-2008 was $3,150/kW. For 26 renewable fueled systems over the same time period, the average installed cost was $3,970/kW.[85]

Table 5-3. Equipment and Installation Costs

	System					
	1	2	3	4	5	6
Electric Capacity						
Nominal Capacity (kW)	30	65	200	250	333	1000
Net Capacity (kW)	28	61	190	240	320	950

[85] *CPUC Self-Generation Incentive Program: Cost Effectiveness of Distributed Generation Technologies*, ITRON, Inc., 2011.

Table 5-3. Equipment and Installation Costs

	System					
	1	2	3	4	5	6
Equipment Costs						
Gen Set Package	$53,100	$112,900	$359,300	$441,200	$566,400	$1,188,600
Heat Recovery	$13,500	$0	$0	$0	$0	$275,000
Fuel Gas Compression	$8,700	$16,400	$42,600	$0	$0	$164,000
Interconnection	$0	$0	$0	$0	$0	$0
Total Equipment ($)	***$75,300***	***$129,300***	***$401,900***	***$441,200***	***$566,400***	***$1,627,600***
($/kW)	***$2,689***	***$2,120***	***$2,120***	***$1,840***	***$1,770***	***$1,710***
Installation Costs						
Labor/Materials	$22,600	$28,400	$80,400	$83,800	$101,900	$293,000
Project & Construction Mgmt	$9,000	$15,500	$48,200	$52,900	$68,000	$195,300
Engineering and Fees	$9,000	$15,500	$44,200	$48,500	$56,600	$162,800
Project Contingency	$3,800	$6,500	$20,100	$22,100	$28,300	$81,400
Financing (int. during const.)	$700	$1,200	$3,700	$4,100	$5,100	$14,800
Total Other Costs ($)	*$45,100*	*$67,100*	*$196,600*	*$211,400*	*$259,900*	*$747,300*
($/kW)	*$1,611*	*$1,100*	*$1,035*	*$881*	*$812*	*$787*
Total Installed Cost ($)	**$120,400**	**$196,400**	**$598,500**	**$652,600**	**$826,300**	**$2,374,900**
($/kW)	**$4,300**	**$3,220**	**$3,150**	**$2,720**	**$2,580**	**$2,500**

Source: Microturbine package costs and equipment from the vendors; installation costs developed by ICF.

As the table shows, there are economies of scale as sizes get larger. From 30 to 333 kW capital costs increase as the 0.8 power factor of the capacity increase[86] – a 100 percent increase in size results in an 80 percent increase in capital cost. Similar scale economies also exist for multiple unit installations such as the 1,000 kW unit comprised of five 200-kW units. The unit cost of the larger system is only 80 percent of the cost of the single unit.

5.4.4 Maintenance

Maintenance costs vary with size, fuel type and technology (air versus oil bearings). A typical maintenance schedule is shown in **Table 5-4.**

Table 5-4. Example Service Schedule, Capstone C65

Maintenance Interval	Component	Maintenance Action	Comments
24 months	UCB Battery	Replace	---
4,000 hours	Engine Air Filter	Inspect	Replace if application requires
	Electronics Air Filter	Inspect	Clean if necessary
	Fuel Filter Element (external)	Inspect	Replace if application requires (not required for gas pack)

[86] $(Cost_1/Cost_2) = (Size_1/Size_2)^{0.8}$

Table 5-4. Example Service Schedule, Capstone C65

Maintenance Interval	Component	Maintenance Action	Comments
	Fuel System	Leak Check	---
8,000 hours	Engine Air Filter	Replace	---
	Electronics Air Filter	Clean	---
	Fuel Filter Element (external)	Replace	Not required for gas pack
	Igniter	Replace	---
	ICHP Actuator	Replace	---
20,000 hours or 3 years	Battery Pack	Replace	---
20,000 hours	Injector Assemblies	Replace	---
	TET Thermocouple	Replace	---
	SPV	Replace	Replace with Woodward valve upgrade kit
40,000 hours	Electronic Components: ECM, LCM, & BCM Power Boards, BCM & ECM Fan Filters, Fans, EMI Filter, Frame PM	Replace	Kits available for each major configuration
	Engine	Replace	Remanufactured or new

Source: Adapted from Capstone C65 User's Manual.

Most manufacturers offer service contracts that cover scheduled and unscheduled events. The cost of a full service contract covers the inspections and component replacements outlined in **Table 5-5**, including replacement or rebuild of the main turbocompressor engine components. Full service costs vary according to fuel type and service as shown.

Table 5-5. Maintenance Costs Based on Factory Service Contracts

Maintenance Costs	System					
	1	2	3	4	5	6
Nominal Electricity Capacity (kW)	30	65	200	250	333	1000
Fixed ($/kW/yr)	---	---	---	$9.120	$6.847	---
Variable ($/kWh)	---	---	---	$0.010	$0.007	---
Average @ 6,000 hrs/year operation ($/kWh)	---	$0.013	$0.016	$0.011	$0.009	$0.012

Source: Compiled by ICF from vendor supplied data

Maintenance requirements can be affected by fuel type and site conditions. Waste gas and liquid fuel applications may require more frequent inspections and component replacement than natural gas systems. Microturbines operating in dusty and/or dirty environments require more frequent inspections and filter replacements.

5.4.5 Fuels

Q16

Stationary microturbines have been designed to use natural gas as their primary fuel. Microturbines designed for transportation applications typically utilize a liquid fuel such as methanol. As previously noted, microturbines are capable of operating on a variety of fuels including:

- **Liquefied petroleum gas (LPG)** – propane and butane mixtures
- **Sour gas** – unprocessed natural gas as it comes directly from a gas well
- **Biogas** – any of the combustible gases produced from biological degradation of organic wastes, such as landfill gas, sewage digester gas, and animal waste digester gas
- **Industrial waste gases** – flare gases and process off-gases from refineries, chemical plants and steel mills
- **Manufactured gases** – typically low- and medium-Btu gas produced as products of gasification or pyrolysis processes

Some of the elements work as contaminants and are a concern with some waste fuels, specifically the acid gas components (H_2S, halogen acids, HCN, ammonia, salts and metal-containing compounds, halogens, nitrogen compounds, and silicon compounds) and oils. In combustion, halogen and sulfur compounds form halogen acids, SO_2, some SO_3, and possibly H_2SO_4 emissions. The acids can also corrode downstream equipment. Solid particulates must be kept to low concentrations to prevent corrosion and erosion of components. Various fuel scrubbing, droplet separation, and filtration steps are required if fuel contaminant levels exceed manufacturer specifications. Landfill gas in particular often contains chlorine compounds, sulfur compounds, organic acids, and silicon compounds which dictate fuel pretreatment. A particular concern with wastewater treatment and landfill applications is the control of siloxane compounds. Siloxanes are a prevalent manmade organic compound used in a variety of products, and they eventually find their way into landfills and waste water. When siloxanes are exposed to high temperatures inside the combustion and exhaust sections of the turbine, they form hard silicon dioxide deposits that can eventually lead to turbine failure.

5.4.6 System Availability

Microturbine systems in the field have generally shown a high level of availability.[87] The basic design and low number of moving parts is conducive to high availability; manufacturers have targeted availabilities of 98-99 percent. The use of multiple units or backup units at a site can further increase the availability of the overall facility.

5.5 Emissions

Microturbines are designed to meet State and federal emissions regulations including more stringent State emissions requirements such as in California and other states (e.g., the Northeast). All microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology. All of the example commercial units have been certified to meet extremely stringent standards in Southern California of less than 4-5 ppmvd of NO_x (15 percent O_2.) After employing a CO/VOC oxidation catalyst, carbon monoxide (CO) and volatile organic compound (VOC) emissions are at

[87] Availability refers to the percentage of time that the system is either operating or available to operate. Conversely, the system is unavailable when it is shut down for maintenance or when there has been a forced outage.

the same level. "Non-California" versions have NO_x emissions of less than 9 ppmvd. The emissions characteristics are shown in **Table 5-6**.

Table 5-6. Microturbine Emissions Characteristics

	System					
	1	2	3	4	5	6
Nominal Electric Capacity (kW)	30	65	200	240	320	1,000
Recovered Thermal Energy (kW)	61.0	119.8	258.9	376	450	1,299.0
Nominal Electrical Efficiency, HHV	23.6%	25.3%	28.1%	27.2%	29.2%	28.1%
NO_x (ppm @ 15% O_2, dry) [1]	9	4	4	5	9	4
NO_x (lb/MWh) [2]	0.49	0.17	0.14	0.23	0.39	0.14
NO_x (lb/MWh with CARB CHP credit)	0.16	0.06	0.06	0.09	0.16	0.06
CO (ppm @ 15% O_2, dry) [1]	40	8	8	5	10	8
CO (lb/MWh) [3]	1.8	0.24	0.2	0.14	0.26	0.2
CO (lb/MWh with CARB CHP credit)	0.59	0.08	0.09	0.06	0.11	0.09
VOC (ppm @ 15% O_2, dry) [1, 4]	9	3	3	5	9	3
VOC (lb/MWh) [5]	0.23	0.05	0.2	0.08	0.13	0.2
VOC (lb/MWh with CARB CHP credit)	0.08	0.02	0.09	0.03	0.06	0.09
CO_2 (lb/MWh electric only) [6]	1,814	1,680	1,497	1,530	1,424	1,497
CO_2 (lb/MWh with CARB CHP credit)	727	700	817	749	722	815

Notes:

1. Vendor estimates for low emission models using natural gas fuel. For systems 1, 2, 3, and 6 the vendor provided both input- (ppmv) and output-based emissions (lb/MWh.) For units 4 and 5, the output emissions were calculated as described below.
2. Output based NO_x emissions (lb/MWh) = (ppm @15% O_2) X 3.413) / ((272 X (% efficiency HHV))
3. Output based CO emissions (lb/MWh) = (ppm @15% O_2) X 3.413) / ((446 X (% efficiency HHV))
4. Volatile organic compounds.
5. Output based VOC emissions (lb/MWh) = (ppm @15% O_2) X 3.413) / ((782 X (% efficiency HHV))
6. Based on 116.39 lbs CO_2 / MMBtu.

The CO_2 emissions estimates with CHP show the potential of microturbines in CHP applications to reduce the emissions of CO_2. Coal fired generation emits about 2,000 lb/MWh, and even state of the art natural gas combined cycle power plants produce CO_2 emissions in the 800-900 lb/MWh range, even before transmission line losses are considered.

5.6 Future Developments

Microturbines first entered the market in the 30-75 kW size range. Of the last several years, microturbine manufacturers have developed larger capacity products to achieve better economics of operation through higher efficiencies and lower capital and maintenance costs.

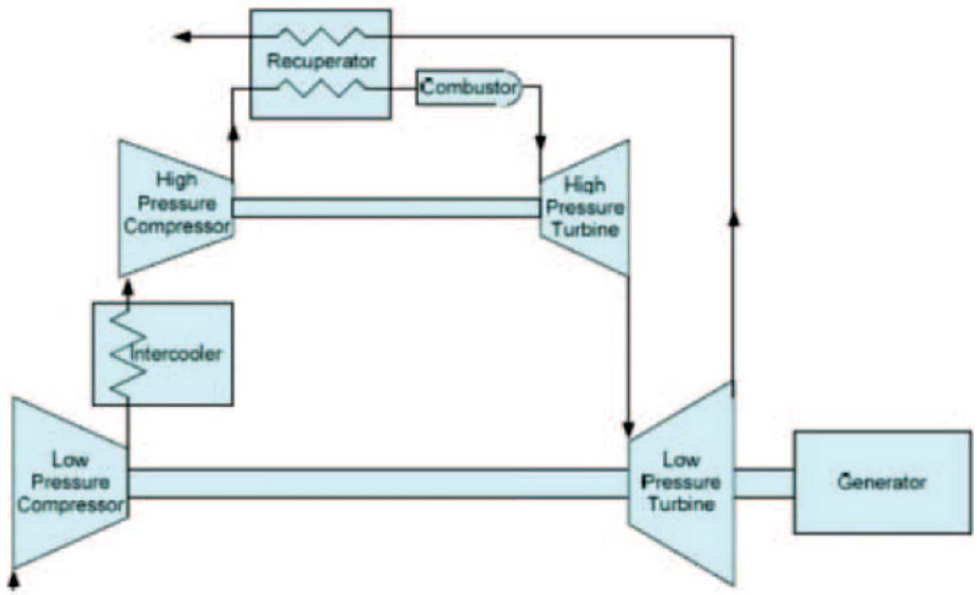
Manufacturers are continuing to develop products with higher electrical efficiencies. Known developments include a model Capstone is developing, with the Department of Energy, on a 250 kW model with a target efficiency of 35 percent (gross output, LHV) and a 370 kW model with a projected 42 percent efficiency. The C250 is intended to feature an advanced aerodynamic compressor design,

engine sealing improvements, improved generator design with longer life magnet, and enhanced cooling.

Key technical developments of the C370 model, shown schematically in **Figure 5-8**, include:

- Dual property, high-temperature turbine
- High-pressure compressors (11:1) and recuperator
- Dual generators – both low pressure and high-pressure spool
- Dual spool control development
- High-temperature, low emissions combustor
- Inter-state compressor cooling

Figure 5-8. Capstone C370 Two-shaft High Efficiency Turbine Design



Source: DOE, Energy Efficiency and Renewable Energy Fact Sheet

The C370 model will use a modified Capstone C200 turbocompressor assembly as the low-pressure section of a two shaft turbine. This low-pressure section will have an electrical output of 250 kW. A new high-temperature, high-pressure turbocompressor assembly will increase the electrical output to 370 kW.

Section 6. Technology Characterization – Fuel Cells

6.1 Introduction

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Fuel cell systems employ an entirely different approach to the production of electricity than traditional combustion based prime mover technologies. Fuel cells are similar to batteries in that they both produce a direct current (DC) through an electrochemical process without direct combustion of a fuel source. However, whereas a battery delivers power from a finite amount of stored energy, fuel cells can operate indefinitely, provided the availability of a continuous fuel source. Two electrodes (a cathode and anode) pass charged ions in an electrolyte to generate electricity and heat. A catalyst enhances the process.

Fuel cells offer the potential for clean, quiet, and efficient power generation. Because the fuel is not combusted, but instead reacts electrochemically, there is minimal air pollution associated with its use. Fuel cells have been under development for over 40 years as an emerging power source however, fuels cells of many different sizes are commercially available now. Based on their environmental benefits, high efficiency and virtually no emissions of criteria pollutants, fuel cells are supported by a number of state and federal tax incentive programs that help to offset the overall system costs. These incentives have been designed to promote continued fuel cell development, cost reductions, and overall market deployment.

The inventor of fuel cell technology was Sir William Grove, who demonstrated a hydrogen fuel cell in London in the 1830s. Grove's technology remained without a practical application for over 100 years. Fuel cells returned to the laboratory in the 1950s when the United States space program required the development of new power systems with low to no air emissions. Today, the topic of fuel cells encompasses a broad range of different technologies, technical issues, and market dynamics that make for a complex but promising outlook. Significant public and private investment are being applied to the development of fuel cell products for both stationary and transportation applications.

There are four primary types of fuel cells that are used for stationary combined heat and power (CHP) applications. These include: 1) phosphoric acid (PAFC), 2) molten carbonate (MCFC), 3) solid oxide (SOFC), and 4) proton exchange membrane (PEMFC). Two additional primary fuel cell types - direct methanol (DMFC) and alkaline (AFC) - are used primarily in transportation and non-stationary fuel cell applications, in addition to PEMFC.

The electrolyte and operating temperatures vary for each of the fuel cell types. Operating temperatures range from near-ambient to 1,800°F, and electrical generating efficiencies range from 30 percent to over 50 percent on a Higher Heating Value (HHV) basis. As a result, fuel cells can have different performance characteristics, advantages, and limitations, which can be suited to distributed generation applications in a variety of approaches. **Table 6-1** provides a summary of the primary advantages and disadvantages of the various types of fuel cells.

Table 6-1. Comparison of Fuel Cell Applications, Advantages, and Disadvantages

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	Applications	Advantages	Disadvantages
Alkaline (AFC)	• Military • Space	• Cathode reaction faster in alkaline electrolyte, leads to high performance • Low cost components	• Sensitive to CO_2 in fuel and air • Electrolyte management
Direct Methanol (DMFC)	• Backup power • Portable power • Military	• No need for reformer (catalyst separates H2 from liquid methanol) • Low temperature	• Expensive catalysts • Low temperature waste heat
Phosphoric Acid (PAFC)	• Auxiliary power • Electric utility • Distributed generation	• Higher temperature enables CHP • Increased tolerance to fuel impurities	• Platinum catalyst • Startup time • Low current and power
Proton Exchange Membrane (PEMFC)	• Backup power • Portable power • Distributed generation • Transportation • Specialty vehicles	• Solid electrolyte reduces corrosion & electrolyte management problems • Low temperature • Quick startup	• Expensive catalysts • Sensitive to fuel impurities • Low temperature waste heat
Molten Carbonate (MCFC)	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Can use a variety of catalysts • Suitable for CHP	• High temperature corrosion and breakdown • Long startup time • Low power density
Solid Oxide (SOFC)	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Can use a variety of catalysts • Solid electrolyte • Suitable for CHP & Combined heat, hydrogen, and powerHybrid/GT cycle	• High temperature corrosion and breakdown of cell components • High temperature operation requires long startup time and limits

Source: DOE Fuel Cell Technologies Program[88]

While there are many different types of fuel cells, there are a few important shared characteristics. Instead of operating as Carnot cycle engines, or thermal energy-based engines, fuel cells use an electrochemical or battery-like process to convert the chemical energy of hydrogen into water and electricity and through this process achieve high electrical efficiencies. Second, fuel cells use hydrogen as the input fuel, which is typically derived from a hydrocarbon fuel such as natural gas or biogas. Third, most, but not all, fuel cell systems are composed of three primary subsystems: 1) the fuel cell stack that generates direct current electricity; 2) the fuel processor that converts the fuel (i.e. natural gas) into a hydrogen-rich feed stream; and 3) the power conditioner that processes the electric energy into alternating current or regulated direct current. There are a small number of special application fuel cell systems that are designed to operate on stored hydrogen fuel, and those fuel cells are configured to utilize the DC power output directly.

As previously mentioned, all types of fuel cells also have low emissions profiles. This is because the only combustion processes are the reforming of natural gas or other fuels to produce hydrogen and the burning of a low energy hydrogen exhaust stream to provide heat to the fuel processor.

Current CHP fuel cell installations total about 83.6 MW domestically.[89] California leads the nation in fuel cell installations, with just under 45 MW, roughly split half natural gas and half biogas. Connecticut and New York follow as the second and third-ranked states with current fuel cell installations at 25 MW and 10 MW, respectively. Those three states comprise 95 percent of the current domestic fuel cell market.

There is a significant amount of biogas fuel cells in California (representing almost a quarter of all fuel cell installations domestically by MW). Many of these systems were developed recently (i.e. 2010) as a result of additional incentives stemming from the California Self-Generation Incentive Program (SGIP).[90] Specifically, "directed biogas" projects (i.e. projects that consume biogas fuel produced at a different location) are eligible for higher incentives under the SGIP. Both CHP and electric-only fuel cells qualify for the SGIP incentive.

6.2 Applications

Fuel cells are either available or being developed for a number of stationary and vehicle applications. The power applications include commercial and industrial CHP (200-2800 kW), pure electrical generation[91] (105-210 kW), residential and commercial systems for CHP (3-10 kW), back-up and portable power systems (0.25-5 kW). In DG markets, the primary characteristic driving early market acceptance is the ability of fuel cell systems to provide reliable premium power. The primary interest drivers have been their ability to achieve high efficiencies over a broad load profile and low emission signatures without additional controls. **Figure 6-1** illustrates an actual site with a fuel cell system functioning in CHP configuration.

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[88] *http://energy.gov/eere/fuelcells/comparison-fuel-cell-technologies*

[89] CHP Installation Database. Maintained by ICF International for Oak Ridge National Laboratory. 2014. *http://www.eea-inc.com/chpdata/index.html*

[90] "2012 SGIP Impact Evaluation and Program Outlook" Itron. February 2014

[91] Based on Bloom Energy models ES-5700, ES-5400, and UPM-570

Figure 6-1. Commercial Fuel Cell for CHP Application

Source: FuelCell Energy

6.2.1 Combined Heat and Power

Due to the high installed cost of fuel cell systems, the most prevalent and economical DG application is CHP. CHP applications are on-site power generation in combination with the recovery and use of by-product heat. Continuous baseload operation and the effective use of the thermal energy contained in the exhaust gas and cooling subsystems enhance the economics of on-site generation applications.

Heat is generally recovered in the form of hot water or low-pressure steam (<30 psig), but the quality of heat is dependent on the type of fuel cell and its operating temperature. PEMFC and DMFC operate at temperatures below 200°F, and therefore have low quality heat. Generally, the heat recovered from fuel cell CHP systems is appropriate for low temperature process needs, space heating, and potable water heating. In the case of SOFC and MCFC technologies, medium pressure steam (up to about 150 psig) can be generated from the fuel cell's high temperature exhaust gas, but the primary use of this hot exhaust gas is in recuperative heat exchange with the inlet process gases.

The simplest thermal load to supply is hot water. Primary applications for CHP in the commercial/institutional sectors are those building types with relatively high and coincident electric and hot water/space heating demand such as colleges and universities, hospitals, nursing homes, and lodging. Technology developments in heat activated cooling/refrigeration and thermally regenerated desiccants will enhance fuel cell CHP applications by increasing the thermal energy loads in certain building types. Use of these advanced technologies in applications such as restaurants, supermarkets, and refrigerated warehouses provides a base-thermal load that opens these applications to CHP.

6.2.2 Premium Power

Consumers who require higher levels of reliability or power quality, and are willing to pay for it, often find some form of DG to be advantageous. These consumers are typically less concerned about the initial prices of power generating equipment than other types of consumers. Premium power systems generally supply base load demand. As a result, and in contrast to back-up generators, emissions and efficiency become more significant decision criteria.

Fuel cell systems offer a number of intrinsic features that make them suitable for the premium power market. These market-driving features include low emissions/vibration/noise, high availability, good power quality, and compatibility with zoning restrictions. As emissions become more relevant to a

business's bottom line in the form of zoning issues and emissions credits, fuel cells become a more appealing type of DG.

Some types of fuel cell systems have already demonstrated high availability and reliability. As fuel cells further mature in the market, they are expected to achieve the high reliability associated with fewer moving parts.

While fuel cells require significant power conditioning equipment in the form of direct current to alternating current conversion, power from fuel cell systems is clean, exhibiting none of the signal disturbances observed from grid sources.

Finally, zoning for fuel cell systems is easier than other types of DG systems. Fuel cell systems can be designed for both indoor and outdoor installation, and in close proximity to sensitive environments, people, or animals.

6.2.3 Remote Power

In locations where power from the local grid is unavailable or extremely expensive to install, DG is a competitive option. As with premium power, remote power applications are generally base load operations. Consequently, emissions and efficiency become more significant criteria in much of the remote power DG market. Coupled with their other potential advantages, fuel cell systems can provide competitive energy into certain segments of the remote power DG market. Where fuel delivery is problematic, the high efficiency of fuel cell systems can also be a significant advantage.

6.2.4 Grid Support

One of the first applications that drew the attention of electric utilities to fuel cell technologies was grid support. Numerous examples of utility-owned and operated distributed generating systems exist in the U.S. and abroad. The primary application in the U.S. has been the use of relatively large diesel or natural gas engines for peaking or intermediate load service at municipal utilities and electric cooperatives. These units provide incremental peaking capacity and grid support for utilities at substations. Such installations can defer the need for T&D system expansion, can provide temporary peaking capacity within constrained areas, or be used for system power factor correction and voltage support, thereby reducing costs for both customers and the utility system. The unique feature of fuel cell systems is the use of power conditioning inverters to transform direct current electricity into alternating current. These power conditioners can be operated almost independent of the fuel cell to correct power factors and harmonic characteristics in support of the grid if there is enough capacity.

6.2.5 Peak Shaving

In certain areas of the country, customers and utilities are using on-site power generation to reduce the need for costly peak-load power. Peak shaving is also applicable to customers with poor load factor and/or high demand charges. Typically, peak shaving does not involve heat recovery, but heat recovery may be warranted where the peak period is more than 2,000 hours/year. Since low equipment cost and high reliability are the primary requirements, equipment such as reciprocating engines are ideal for many peak-shaving applications. Emissions may be an issue if operating hours are high. Combining peak shaving and another function, such as standby power, enhances the economics. High capital cost and

relatively long start-up times (particularly for MCFC and SOFC) will most likely prevent the widespread use of fuel cells in peak shaving applications.

6.2.6 Resiliency

Fuel cells can be configured to operate independently of the grid, and can therefore provide emergency power during outages. This was evident particularly during recent hurricane events, where significant power outages occurred. For instance, during Hurricanes Irene and Superstorm Sandy, fuel cells helped keep communication lines open for different communications service providers.[92] Fuel cells are also generally resilient based on the undergrounded natural gas supply.

6.3 Technology Description

Fuel cells produce direct current electricity through an electrochemical process, much like a standard battery. Unlike a standard battery, a fuel supply continuously replenishes the fuel cell. The reactants, most typically hydrogen and oxygen gas, are fed into the fuel cell reactor, and power is generated as long as these reactants are supplied. The hydrogen (H_2) is typically generated from a hydrocarbon fuel such as natural gas or LPG, and the oxygen (O2) is from ambient air.

6.3.1 Basic Processes and Components

Fuel cell systems designed for DG applications are primarily natural gas or LPG fueled systems. Each fuel cell system consists of three primary subsystems: 1) the fuel cell stack that generates direct current electricity; 2) the fuel processor that converts the natural gas into a hydrogen rich feed stream; and 3) the power conditioner that processes the electric energy into alternating current or regulated direct current.

Figure 6-2 illustrates the electrochemical process in a typical single cell, acid-type fuel cell. A fuel cell consists of a cathode (positively charged electrode), an anode (negatively charged electrode), an electrolyte and an external load. The anode provides an interface between the fuel and the electrolyte, catalyzes the fuel reaction, and provides a path through which free electrons conduct to the load via the external circuit. The cathode provides an interface between the oxygen and the electrolyte, catalyzes the oxygen reaction, and provides a path through which free electrons conduct from the load to the oxygen electrode via the external circuit. The electrolyte, an ionic conductive (non-electrically conductive) medium, acts as the separator between hydrogen and oxygen to prevent mixing and the resultant direct combustion. It completes the electrical circuit of transporting ions between the electrodes.

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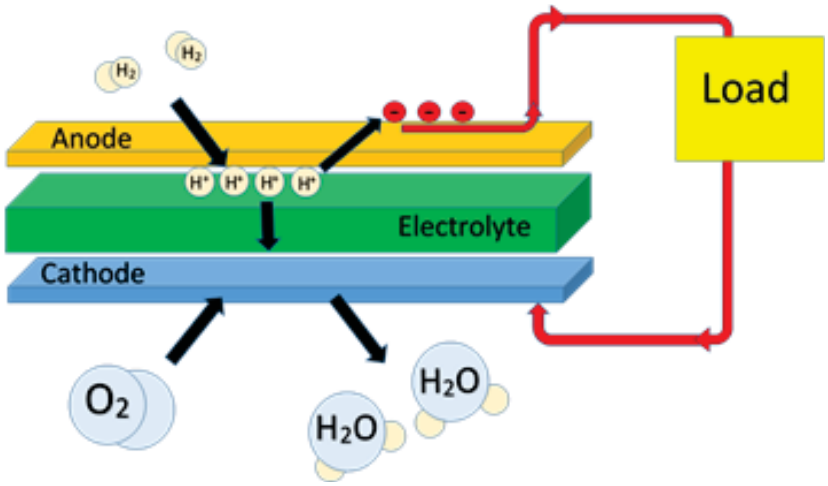
[92] *The Business Case for Fuel Cells, Reliability, Resiliency & Savings (2013)*. See www.fuelcells.org.

Figure 6-2. Fuel Cell Electrochemical Process



Source: ICF

The hydrogen and oxygen are fed to the anode and cathode, respectively. However, they do not directly mix, and result in combustion. Instead, the hydrogen oxidizes one molecule at a time, in the presence of a catalyst. Because the reaction is controlled at the molecular level, there is no opportunity for the formation of NO_x and other pollutants.

At the anode the hydrogen gas is electrochemically dissociated (in the presence of a catalyst) into hydrogen ions (H_+) and free electrons (e_-).

Anode Reaction: $2H_2 \rightarrow 4H^+ + 4e^-$

The electrons flow out of the anode through an external electrical circuit. The hydrogen ions flow into the electrolyte layer and eventually to the cathode, driven by both concentration and potential forces. At the cathode the oxygen gas is electrochemically combined (in the presence of a catalyst) with the hydrogen ions and free electrons to generate water.

Cathode Reaction: $O_2 + 4H^+ + 4e^- \rightarrow 2H_2O$

The overall reaction in a fuel cell is as follows:

Net Fuel Cell Reaction: $2H_2 + O_2 \rightarrow 2H_2O$ (vapor) + Energy

When generating power, electrons flow through the external circuit, ions flow through the electrolyte layer and chemicals flow into and out of the electrodes. Each process has natural resistances, and overcoming these reduces the operational cell voltage below the theoretical potential. There are also irreversible processes[93] that affect actual open circuit potentials. Therefore, some of the chemical potential energy converts into heat. The electrical power generated by the fuel cell is the product of the

[93] An irreversible process is a change in the potential energy of the chemical that is not recovered through the electrochemical process. Typically, some of the potential energy is converted into heat even at open circuit conditions when current is not flowing. A simple example is the resistance to ionic flow through the electrolyte while the fuel cell is operating. This potential energy "loss" is really a conversion to heat energy, which cannot be reconverted into chemical energy directly within the fuel cell.

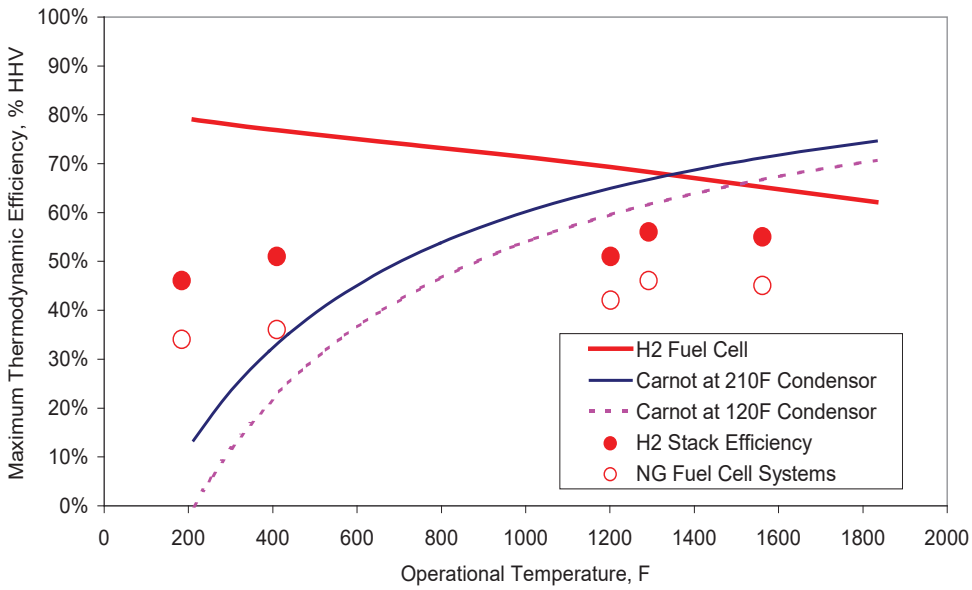
current measured in amps and the operational voltage. Based on the application and economics, a typical operating fuel cell will have an operating voltage of between 0.55 volts and 0.80 volts. The ratio of the operating voltage and the theoretical maximum of 1.48 volts represents a simplified estimate of the stack electrical efficiency on a HHV[94] basis.

As described above, resistance heat is also generated along with the power. Since the electric power is the product of the operating voltage and the current, the quantity of heat that must be removed from the fuel cell is the product of the current and the difference between the theoretical potential and the operating voltage. In most cases, the water produced by the fuel cell reactions exits the fuel cell as vapor, and therefore, the 1.23-volt LHV theoretical potential is used to estimate sensible heat generated by the fuel cell electrochemical process.

The overall electrical efficiency of the cell is the ratio of the power generated and the heating value of the hydrogen consumed. The maximum thermodynamic efficiency of a hydrogen fuel cell is the ratio of the Gibbs free energy and the heating value of the hydrogen. The Gibbs free energy decreases with increasing temperatures, because the product water produced at the elevated temperature of the fuel cell includes the sensible heat of that temperature, and this energy cannot be converted into electricity without the addition of a thermal energy conversion cycle (such as a steam turbine). Therefore, the maximum efficiency of a pure fuel cell system decreases with increasing temperature. **Figure 6-3** illustrates this characteristic in comparison to the Carnot cycle efficiency limits through a condenser at 50 and 100°C[95]. This characteristic has led system developers to investigate hybrid fuel cell-turbine combined cycle systems to achieve system electrical efficiencies in excess of 70 percent HHV.

[94] 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 products.
[95] Larminie, James and Andrew Dicks, Fuel Cell Systems Explained. John Wiley & Sons, Ltd., West Sussex, England, 2000.

Figure 6-3. Effect of Operating Temperature on Fuel Cell Efficiency



Source: Larminie, James and Andrew Dicks, Fuel Cell Systems Explained. John Wiley & Sons, Ltd., West Sussex, England, 2000.

6.3.1.1 Fuel Cell Stacks

Practical fuel cell systems require voltages higher than 0.55 to 0.80. Combining several cells in electrical series into a fuel cell stack achieves this. Typically, there are several hundred cells in a single cell stack. Increasing the active area of individual cells manages current flow. Typically, cell area can range from 100 cm^2 to over 1 m^2 depending on the type of fuel cell and application power requirements.

6.3.1.2 Fuel Processors

In distributed generation applications, the most viable fuel cell technologies use natural gas (CH_4) as the system's fuel source. To operate on natural gas or other fuels, fuel cells require a fuel processor or reformer, a device that converts the natural gas fuel into a hydrogen-rich gas stream. While adding fuel flexibility to the system, the reformer also adds significant cost and complexity. There are three primary types of reformers: steam reformers, autothermal reformers, and partial oxidation reformers. The fundamental differences are the source of oxygen used to combine with the carbon within the fuel to release the hydrogen gases and the thermal balance of the chemical process. Steam reformers use steam, while partial oxidation units use oxygen gas, and autothermal reformers use both steam and oxygen.

Steam reforming is extremely endothermic and requires a substantial amount of heat input. Autothermal reformers typically operate at or near the thermal neutral point, and therefore, do not generate or consume thermal energy. Partial oxidation units combust a portion of the fuel (i.e. partially oxidize it), releasing heat in the process. When integrated into a fuel cell system that allows the use of anode-off gas, a typical natural gas reformer can achieve conversion efficiencies in the 75 to 90 percent LHV range, with 83 to 85 percent being an expected level of performance. These efficiencies are defined as the LHV of hydrogen generated divided by the LHV of the natural gas consumed by the reformer.

Some fuel cells can function as internally steam reforming fuel cells. Since the reformer is an endothermic catalytic converter and the fuel cell is an exothermic catalytic oxidizer, the two combine into one with mutual thermal benefits. More complex than a pure hydrogen fuel cell, these types of fuel cells are more difficult to design and operate. While combining two catalytic processes is difficult to arrange and control, these internally reforming fuel cells are expected to account for a significant market share as fuel cell based DG becomes more common.

It is also during this process, depending on the efficiency of the fuel cell, that CO_2 is emitted as part of the reforming of the natural gas into usable hydrogen. CO_2 emissions range between 700 to 900 lb/MWh depending on the fuel cell technology used.

6.3.1.3 Power Conditioning Subsystem

Fuel cells generate direct current electricity, which requires conditioning before serving a load. Depending on the cell area and number of cells, this direct current electricity is approximately 200 to 400 volts per stack. If the system is large enough, stacks can operate in series to double or triple individual stack voltages. Since the voltage of each individual cell decreases with increasing load or power, the output is considered an unregulated voltage source. The power conditioning subsystem boosts the output voltage to provide a regulated higher voltage input source to an electronic inverter. The inverter then uses a pulse width modulation technique at high frequencies to generate alternating current output. The inverter controls the frequency of the output, which can be adjusted to enhance power factor characteristics. Because the inverter generates alternating current within itself, the output power is generally clean and reliable. This characteristic is important to sensitive electronic equipment in premium power applications. The efficiency of the power conditioning process is typically 92 to 96 percent, and is dependent on system capacity and input voltage-current characteristic.

6.3.1.4 Types of Fuel Cells

There are four basic types of fuel cells most suitable for stationary CHP applications. The fuel cell's electrolyte or ion conduction material defines the basic type. Two of these fuel cell types, polymer electrolyte membrane (PEMFC) and phosphoric acid fuel cell (PAFC), have acidic electrolytes and rely on the transport of H_+ ions. Carbonate fuel cell (MCFC) has basic electrolytes that rely on the transport of $CO3^2$ions. The fourth type, solid oxide fuel cell (SOFC), is based on a solid-state ceramic electrolyte in which oxygen ions (O_2^-) are the conductive transport ion.

Each fuel cell type operates at an optimum temperature, which is a balance between the ionic conductivity and component stability. These temperatures differ significantly among the four basic types, ranging from near ambient to as high as 1800°F. The proton conducting fuel cell type generates water at the cathode and the anion conducting fuel cell type generates water at the anode.

Table 6-2 presents fundamental characteristics for the primary fuel cell types most suitable for stationary CHP.

Table 6-2. Characteristics of Major Fuel Cell Types

	PEMFC	PAFC	MCFC	SOFC
Type of Electrolyte	H^+ ions (with anions bound in polymer membrane)	H^+ ions (H_3PO_4 solutions)	$CO_3^=$ ions (typically, molten $LiKaCO_3$ eutectics)	$O^=$ ions (Stabilized ceramic matrix with free oxide ions)
Common Electrolyte	Solid polymer membrane	Liquid phosphoric acid in a lithium aluminum oxide matrix	Solution of lithium, sodium, and/or potassium carbonates soaked in a ceramic matrix	Solid ceramic, Yttria stabilized zirconia (YSZ)
Typical construction	Plastic, metal or carbon	Carbon, porous ceramics	High temp metals, porous ceramic	Ceramic, high temp metals
Internal reforming	No	No	Yes, good temp match	Yes, good temp match
Oxidant	Air to O_2	Air to Enriched Air	Air	Air
Operational Temperature	150- 180°F (65-85°C)	302-392°F (150-200°C)	1112-1292°F (600-700°C)	1202-1832°F (700-1000°C)
DG System Level Efficiency (% HHV)	25 to 35%	35 to 45%	40 to 50%	45 to 55%
Primary Contaminate Sensitivities	CO, Sulfur, and NH3	CO < 1%, Sulfur	Sulfur	Sulfur

Source: DOE Fuel Cells Technology Program[96]

6.3.1.5 PEMFC (Proton Exchange Membrane Fuel Cell or Polymer Electrolyte Membrane)

NASA developed this type of fuel cell in the 1960s for the first manned spacecraft. The PEMFC uses a solid polymer electrolyte and operates at low temperatures (less than 200°F). Due to their modularity and simple manufacturing, reformer/PEMFC systems for residential DG applications (i.e. micro CHP) have enjoyed considerable market success, particularly in Asia. PEMFC's have high power density and can vary their output quickly to meet demand. This type of fuel cell is highly sensitive to CO poisoning. PEMFCs have historically been the market leader in terms of number of fuel cell units shipped. There is a wide range of PEMFC manufacturers.

6.3.1.6 PAFC (Phosphoric Acid Fuel Cell)

PAFC uses phosphoric acid as the electrolyte and is one of the most established fuel cell technologies. The first PAFC DG system was designed and demonstrated in the early 1970s. PAFCs are capable of fuel-to-electricity efficiencies of 36 percent HHV or greater. The current 400 kW product has a stack lifetime of over 40,000 hours and commercially based reliabilities in the 90 to 95 percent range. ClearEdge

[96] "2012 Fuel Cell Technologies Market Report" U.S. Department of Energy, October 2013. *http://energy.gov/sites/prod/files/2014/03/f11/2012_market_report.pdf*

Power is a primary US manufacturer of PAFC systems after buying the PAFC assets from United Technologies. Recently however ClearEdge has encountered financial problems.[97]

6.3.1.7 MCFC (Molten Carbonate Fuel Cell)

The MCFC uses an alkali metal carbonate (Li, Na, K) as the electrolyte and has a developmental history that dates back to the early part of the twentieth century. Due to its operating temperature range of 1,100 to 1,400°F, the MCFC holds promise in CHP applications. This type of fuel cell can be internally reformed, can operate at high efficiencies (50 percent HHV), and is relatively tolerant of fuel impurities. Government/industry R&D programs during the 1980s and 1990s resulted in several individual pre-prototype system demonstrations. Fuel Cell Energy is one of the primary manufacturers of commercially available MCFCs, ranging from 300 kW to 2800 kW.

6.3.1.8 SOFC (Solid Oxide Fuel Cell)

SOFC uses solid, nonporous metal oxide electrolytes and is generally considered less mature in its development than the MCFC and PAFC technologies. SOFC has several advantages (high efficiency, stability and reliability, and high internal temperatures) that have attracted development support. The SOFC has projected service electric efficiencies of 45 to 60 percent and higher, for larger hybrid, combined cycle plants. Efficiencies for smaller SOFC units are typically in the 50 percent range.

Stability and reliability of the SOFC are due to an all-solid-state ceramic construction. Test units have operated in excess of 10 years with acceptable performance. The high internal temperatures of the SOFC are both an asset and a liability. As an asset, high temperatures make internal reforming possible. As a liability, these high temperatures add to materials and mechanical design difficulties, which reduce stack life and increase cost. While SOFC research has been ongoing for 30 years, costs of these stacks are still comparatively high. Currently, two of the primary SOFC manufacturers include Bloom Energy, which is a pure electric fuel cell (i.e. no waste heat is captured) and Ceramic Fuel Cells.

Design Characteristics

The features that have the potential to make fuel cell systems a leading prime mover for CHP and other distributed generation applications include:

Size range	Fuel cell systems are constructed from individual cells that generate 100 W to 2 kW per cell. This allows systems to have extreme flexibility in capacity. Multiple systems can operate in parallel at a single site to provide incremental capacity.
Thermal output	Fuel cells can achieve overall efficiencies in the 65 to 95% range. Waste heat can be used primarily for domestic hot water applications and space heating.
Availability	Commercially available systems have demonstrated greater than 90% availability.
Part-load operation	Fuel cell stack efficiency improves at lower loads, which results in a system electric efficiency that is relatively steady down to one-third to one-quarter of rated capacity. This provides systems with excellent load following characteristics.
Cycling	While part-load efficiencies of fuel cells are generally high, MCFC and SOFC fuel cells require long heat-up and cool-down periods, restricting their ability to operate in many cyclic applications.

[97] ClearEdge Power filed for Chapter 11 bankruptcy in May of 2014. *http://www.oregonlive.com/business/index.ssf/2014/05/clearedge_power_files_for_bankruptcy_as_financial_woes_mount.html*

High-quality power	Electrical output is computer grade power, meeting critical power requirements without interruption. This minimizes lost productivity, lost revenues, product loss, or opportunity cost.
Reliability and life	While the systems have few moving parts, stack assemblies are complex and have had problems with seals and electrical shorting. Recommended stack rebuilds required every 5-10 years are expensive.
Emissions	The only combustion within a fuel cell system is the low energy content hydrogen stream exhausted from the stack when using pure hydrogen as a fuel source. This stream is combusted within the reformer and can achieve emissions
	Signatures of < 2 ppmv CO, <1 ppmv NO_x and negligible SO_X (on 15% O2, dry basis). However most fuel cells need to convert natural gas (CH_4) to hydrogen (H_2). During this process CO_2 is emitted at varying levels based on the efficiency of the fuel cell.
Efficiency	Different types of fuel cells have varied efficiencies. Depending on the type and design, electric efficiency ranges from 30% to close to 50% HHV.
Quiet operation	Conversational level (60dBA @ 30 ft.), acceptable for indoor installation.
Siting and size	Indoor or outdoor installation with enclosure.
Fuel use	The primary fuel source for fuel cells is hydrogen, which can be obtained from natural gas, coal gas, methanol, and other fuels containing hydrocarbons.

6.4 Performance Characteristics

Fuel cell performance is a function of the type of fuel cell and its capacity. Since the fuel cell system is a series of chemical, electrochemical, and electronic subsystems, the optimization of electric efficiency and performance characteristics can be a challenging engineering task. The electric efficiency calculation example provided in the next section illustrates this.

Table 6-3 summarizes performance characteristics for representative commercially available and developmental natural gas fuel cell CHP systems over the 0.7 kW to 1,400 kW size range. This size range covers the majority of the market applications. All systems included in **Table 6-3** are commercially available as of 2014.

Table 6-3. Fuel Cell CHP - Typical Performance Parameters

Performance Characteristics	System 1	System 2	System 3	System 4	System 5
Fuel Cell Type	PEMFC	SOFC	MCFC	PAFC	MCFC
Nominal Electricity Capacity (kW)	0.7	1.5	300	400	1,400
Net Electrical Efficiency (%), HHV)	35.3%	54.4%	47%	34.3%	42.5%
Fuel Input (MMBtu/hr), HHV	0.0068	0.0094	2.2	4.0	11.2
Total CHP Efficiency (%), HHV	86%	74%	82%	81%	82%
Power to Heat Ratio	0.70	2.78	1.34	0.73	1.08
Net Heat Rate (Btu/kWh), HHV	9,666	6,272	7,260	9,948	8,028
Exhaust Temperature (°F)	NA	NA	700	NA	700
Available Heat (MMBtu/hr)	NA	NA	0.78 (to 120°F)	0.88 (to 140°F)	3.73 (to 120°F)
Sound (dBA)	NA	47 (at 3 feet)	72 (at 10 feet)	65 (at 33 feet)	72 (at 10 feet)

NA = not available or not applicable
Source: ICF, specific product specification sheets

Heat rates and efficiencies shown were taken from manufacturers' specifications and industry publications or are based on the best available data for developing technologies. CHP thermal recovery estimates are based on producing low quality heat for domestic hot water process or space heating needs. This feature is generally acceptable for commercial/institutional applications where it is more common to have hot water thermal loads.

Generally, electrical efficiency increases as the operating temperature of the fuel cell increases. SOFC fuel cells have the highest operating temperatures (which can be advantageous as well as disadvantageous) and they also have the highest electric efficiencies. In addition, as electrical efficiency increases, the absolute quantity of thermal energy available to produce useful thermal energy decreases per unit of power output, and the ratio of power to heat for the CHP system generally 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.

6.4.1 Electrical Efficiency

As with all generation technologies, the electrical efficiency is the ratio of the power generated and the heating value of the fuel consumed. Because fuel cells have several subsystems in series, the electrical efficiency of the unit is the multiple of the efficiencies of each individual section. The electric efficiency of a fuel cell system is calculated as follows:

$$Eff_{Elec} = (Eff_{FPS} * H_2 \text{ Utilization} * Eff_{Stack} * Eff_{PC})*(\text{HHV/LHV ratio of the fuel})$$

Where:

Eff_{FPS}	=	Fuel Processing Subsystem Efficiency, LLV (LHV of H2 Generated/LHV of Fuel Consumed)
H_2 Utilization	=	% of H_2 actually consumed in the stack
Eff_{Stack}	=	(Operating Voltage/Energy Potential ~1.23 volts)
Eff_{PC}	=	AC power delivered/(dc power generated) (auxiliary loads are assumed dc loads here)

For example, the electrical efficiency of a PAFC can be calculated as follows:

$$Eff_{Elec} = (84\%FPS)*(83\% \text{ util})*(0.75V/1.25V)*(95\%PC)*(0.9HHV/LHV)$$
$$= 36\% \text{ electric efficiency HHV}$$

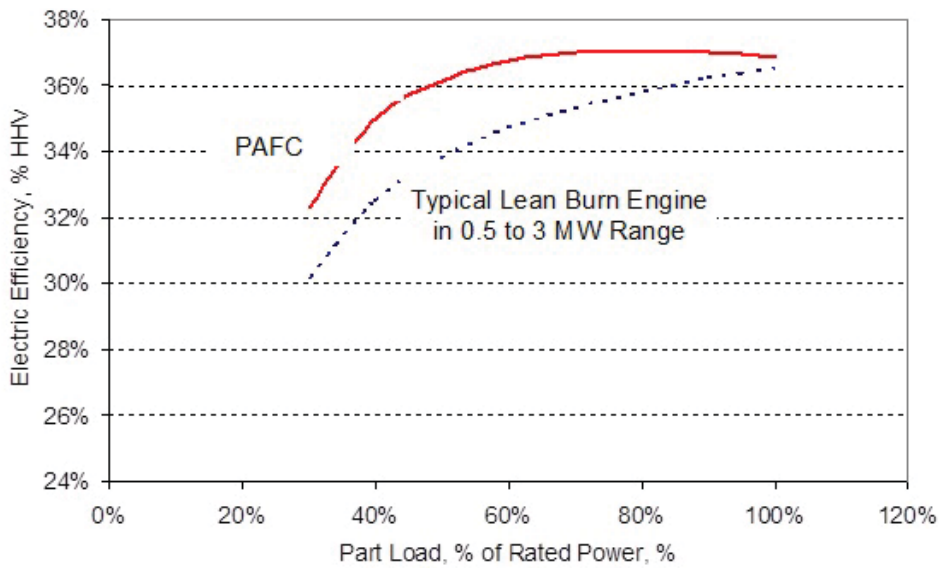
As the operating temperature range of the fuel cell system increases, the electric efficiency of the system tends to increase. Although the maximum thermodynamic efficiency decreases as shown in **Figure 6-3**, improvements in reformer subsystem integration and increases in reactant activity balance out to provide the system level increase. Advanced high temperature MCFC and SOFC systems can achieve simple cycle efficiencies in the range of 50 to 60 percent HHV, while hybrid combined fuel cell-heat engine systems are calculated to achieve efficiencies above 60 percent in DG applications.

6.4.2 Part Load Performance

In CHP applications, fuel cell systems are expected to follow the thermal load of the host site to maximize CHP energy economics. **Figure 6-4** shows the part load efficiency curve for a PAFC fuel cell in the 100 kW to 400 kW size range in comparison to a typical lean burn natural gas engine. It shows that

fuel cells maintain efficient performance at partial loads better than reciprocating engines. The fuel cell efficiency at 50 percent load is within 2 percent of its full load efficiency characteristic. As the load decreases further, the curve becomes somewhat steeper, as inefficiencies in air blowers and the fuel processor begin to override the stack efficiency improvement.

Figure 6-4. Comparison of Part Load Efficiency Derate



Source: Gas Technology Institute, Caterpillar, Energy Nexus Group.

6.4.3 Effects of Ambient Conditions on Performance

Fuel cells are generally rated at ISO conditions of 77° F and 0.987 atmospheres (1 bar) pressure. Fuel cell system performance – both output and efficiency – can degrade as ambient temperature or site elevation increases. This degradation in performance is related to ancillary equipment performance, primarily the air handling blowers or compressors. Performance degradations will be greater for pressurized systems operating with turbo-chargers or small air compressors as their primary air supply components.

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6.4.4 Heat Recovery

The economics of fuel cells in on-site power generation applications depend less on effective use of the thermal energy recovered than is the case with lower efficiency prime movers, but thermal load displacements can improve operating economics as in any CHP application. Generally, 25 percent of the inlet fuel energy is recoverable from higher quality heat from the stack and reformer subsystems, and another 25 percent is contained in the exhaust gases that include the latent heat of the product water generated in the fuel cell. The most common use of this heat is to generate hot water or low-pressure steam for process use or for space heating.

Heat can generally be recovered in the form of hot water or low-pressure steam (< 30 psig), but the quality of heat is very dependent on the type of fuel cell and its operating temperature. The one exception to this is that some manufactures of SOFC do not recover the heat for use in other

applications but use the heat to boost the internal process and to improve electrical generation efficiencies.

As an example, there are four primary potential sources of usable waste heat from a fuel cell system: exhaust gas including water condensation, stack cooling, anode-off gas combustion, and reformer heat. A sample PAFC system achieves 36 percent electric efficiency and 72 percent overall CHP efficiency, which means that it has a 36 percent thermal efficiency or power to heat ratio of one. Of the available heat, 25 to 45 percent is recovered from the stack-cooling loop that operates at approximately 400° F and can deliver low- to medium-pressure steam. The balance of heat is derived from the exhaust gas-cooling loop that serves two functions. The first is condensation of product water, thus rendering the system water self-sufficient, and the second is the recovery of by-product heat. Since its primary function is water recovery, the balance of the heat available from the PAFC fuel cell is recoverable with 120° F return and 300° F supply temperatures. This tends to limit the application of this heat to domestic hot water applications. The other aspect to note is that all of the available anode-off gas heat and internal reformer heat is used internally to maximize system efficiency.

In the case of SOFC and MCFC fuel cells, medium-pressure steam (up to about 150 psig) can be generated from the fuel cell's high temperature exhaust gas, but the primary use of these hot exhaust gases is in recuperative heat exchange with the inlet process gases. Like engine and turbine systems, fuel cell exhaust gas can be used directly for process drying.

6.4.5 Performance and Efficiency Enhancements

Air is fed to the cathode side of the fuel cell stack to provide the oxygen needed for the power generation process. Typically, 50 to 100 percent more air is passed through the cathode than is required for the fuel cell reactions. The fuel cell can be operated at near-ambient pressure, or at elevated pressures to enhance stack performance. Increasing the pressure, and therefore the partial pressure of the reactants, increases stack performance by reducing the electrode over potentials associated with moving the reactants into the electrodes where the catalytic reaction occurs. It also improves the performance of the catalyst. These improvements appear to optimize at approximately three atmospheres pressure if optimistic compressor characteristics are assumed.[98] More realistic assumptions often result in optimizations at ambient pressure where the least energy is expended on air movement. Because of these characteristics, developers appear to be focused on both pressurized and ambient pressure systems.

6.4.6 Capital Cost

This section provides estimates for the installed cost of fuel cell systems designed for CHP applications. Capital costs (equipment and installation) are estimated in **Table 6-4** for five representative CHP fuel cell systems**.** Estimates are "typical" budgetary price levels. Installed costs can vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, prevailing labor rates, and whether the system is a new or retrofit application.

[98] Larminie, James and Andrew Dicks, Fuel Cell Systems Explained. John Wiley & Sons, Ltd., West Sussex, England, 2000. , p. 90.

Table 6-4. Estimated Capital and O&M Costs for Typical Fuel Cell Systems in Grid Interconnected CHP Applications (2014 $/kW)

Installed Cost Components	System 1 Residential	System 2 Residential	System 3 C&I	System 4 C&I	System 5 C&I
Fuel Cell Type	PEMFC	SOFC	MCFC	PAFC	MCFC
Nominal Electricity Capacity (kW)	0.7	1.5	300	400	1400
Total Package Cost (2014 $/kW)[99]	$ 22,000	$ 23,000[100]	$10,000	$ 7,000	$ 4,600
O&M Costs (2014 $/MWh)	$ 60	$ 55	$45	$ 36	$ 40

Source: ICF Manufacturer Data Collection

6.4.7 Maintenance

Maintenance costs for fuel cell systems will vary with type of fuel cell, size and maturity of the equipment. Some of the typical costs that need to be included are:

- Maintenance labor.
- Ancillary replacement parts and material such as air and fuel filters, reformer igniter or spark plug, water treatment beds, flange gaskets, valves, electronic components, etc., and consumables such as sulfur adsorbent bed catalysts and nitrogen for shutdown purging.
- Major overhauls include shift catalyst replacement (3 to 5 years), reformer catalyst replacement (5 years), and stack replacement (5 to 10 years).

Maintenance can either be performed by in-house personnel or contracted out to manufacturers, distributors or dealers under service contracts. Details of full maintenance contracts (covering all recommended service) and costing are not generally available, but are estimated at 0.7 to 2.0 cents/kWh excluding the stack replacement cost sinking fund. Maintenance for initial commercial fuel cells has included remote monitoring of system performance and conditions and an allowance for predictive maintenance. Recommended service is comprised of routine short interval inspections/adjustments and periodic replacement of filters (projected at intervals of 2,000 to 4,000 hours).

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6.4.8 Fuels

Since the primary fuel source for fuel cells is hydrogen produced from hydrocarbon fuels, fuel cell systems can be designed to operate on a variety of alternative gaseous fuels including:

- **Natural Gas** – methane from the pipeline.
- **Liquefied petroleum gas (LPG)** – propane and butane mixtures.
- **Sour gas** - unprocessed natural gas as it comes directly from the gas well.
- **Biogas** – any of the combustible gases produced from biological degradation of organic wastes, such as landfill gas, sewage digester gas, and animal waste digester gas.
- **Industrial waste gases** – flare gases and process off-gases from refineries, chemical plants and steel mill.

[99] Total package cost includes all equipment (including heat recovery) as well as estimated labor and installation costs.
[100] Total package costs for larger (i.e. 200 kW) SOFC systems are significantly less expensive than $23,000, however those data were not made available to us for estimation.

- **Manufactured gases** – typically low- and medium-Btu gas produced as products of gasification or pyrolysis processes.

Factors that impact the operation of a fuel cell system with alternative gaseous fuels include:

- **Volumetric heating value** – Since fuel is initially reformed by the fuel cell's fuel processing subsystem, the lower energy content fuels will simply result in a less concentrated hydrogen-rich gas stream feeding the anode. This will cause some loss in stack performance, which can affect the stack efficiency, stack capacity or both. Increased pressure drops through various flow passages can also decrease the fine balance developed in fully integrated systems.

- Contaminants are the major concern when operating on alternative gaseous fuels. If any additional sulfur and other components (e.g., chlorides) can be removed prior to entering the fuel processing catalyst, there should be no performance or life impact. If not, the compounds can cause decreased fuel processor catalyst life and potentially impact stack life.

6.4.9 System Availability

Fuel cell systems are generally perceived as low maintenance devices. Fuel cells in North America have been recorded achieving more than 90 percent availability. In premium power applications, 100 percent customer power availability, and 95 percent+ fleet availability has been reported during the same time period. Fuel cells can provide high levels of availability, especially in high load factor (i.e. baseload) applications.

6.5 Emissions and Emissions Control Options

As the primary power generation process in fuel cell systems does not involve combustion, very few emissions are generated. In fact, the fuel processing subsystem is the only source of emissions. The anode-off gas that typically consists of 8 to 15 percent hydrogen is combusted in a catalytic or surface burner element to provide heat to the reforming process. The temperature of this very lean combustion can be maintained at less than 1,800° F, which also prevents the formation of oxides of nitrogen (NO_x) but is sufficiently high to ensure oxidation of carbon monoxide (CO) and volatile organic compounds (VOCs – unburned, non-methane hydrocarbons). Other pollutants such as oxides of sulfur (SO_x) are eliminated because they are typically removed in an absorbed bed before the fuel is processed.

6.5.1 Primary Emissions Species

6.5.1.1 Nitrogen Oxides (NO_x)

NO_x is formed by three mechanisms: thermal NO_x, prompt NO_x, and fuel-bound NO_x. Thermal NO_x is the fixation of atmospheric oxygen and nitrogen, which occurs at high combustion temperatures. Flame temperature and residence time are the primary variables that affect thermal NO_x levels. The rate of thermal NO_x formation increases rapidly with flame temperature. Prompt NO_x is formed from early reactions of nitrogen modules in the combustion air and hydrocarbon radicals from the fuel. It forms within the flame and typically is on the order of 1 ppm at 15 percent O_2, and is usually much smaller than the thermal NO_x formation. Fuel-bound NO_x forms when the fuel contains nitrogen as part of the hydrocarbon structure. Natural gas has negligible chemically bound fuel nitrogen. Fuel-bound NO_x can be at significant levels with liquid fuels.

6.5.1.2 Carbon Monoxide (CO)

CO and VOCs both result from incomplete combustion. CO emissions result when there is inadequate oxygen or insufficient residence time at high temperature. Cooling at the combustion chamber walls and reaction quenching in the exhaust process also contribute to incomplete combustion and increased CO emissions. Excessively lean conditions can lead to incomplete and unstable combustion and high CO levels.

6.5.1.3 Unburned Hydrocarbons

Volatile hydrocarbons, also called volatile organic compounds (VOCs), can encompass a wide range of compounds, some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some portion of the fuel remains unburned or just partially burned. Some organics are carried over as unreacted trace constituents of the fuel, while others may be pyrolysis products of the heavier hydrocarbons in the gas. Volatile hydrocarbon emissions from reciprocating engines are normally reported as non-methane hydrocarbons (NMHCs). Methane is not a significant precursor to ozone creation and smog formation and is not currently regulated. Methane is a greenhouse gas and may come under future regulations.

6.5.1.4 Carbon Dioxide (CO_2)

Carbon dioxide (CO_2) emissions are of concern due to its contribution to global warming. Atmospheric warming occurs since solar radiation readily penetrates to the surface of the planet but infrared (thermal) radiation from the surface is absorbed by the CO_2 (and other polyatomic gases such as methane, unburned hydrocarbons, refrigerants and volatile chemicals) in the atmosphere, with resultant increase in temperature of the atmosphere. The amount of CO_2 emitted is a function of both fuel carbon content and system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/MMBtu; oil is 48 lbs carbon/MMBtu; and (ash-free) coal is 66 lbs carbon/MMBtu.

6.5.2 Fuel Cell Emission Characteristics

Table 6-5 illustrates the emission characteristics of fuel cell systems. Fuel cell systems do not require any emissions control devices to meet current and projected regulations. As previously noted, fuel cells generally have very low emissions.

Table 6-5. Estimated Fuel Cell Emission Characteristics without Additional Controls

Emissions Characteristics	System 1	System 2	System 3	System 4	System 5
Fuel Cell Type	PEMFC	SOFC	MCFC	PAFC	MCFC
Nominal Electricity Capacity (kW)	0.7	1.5	300	400	1,400
NO_x (lb/MWh)	Negligible	Negligible	0.01	0.01	0.01
SO_x (lb/MWh)	Negligible	Negligible	0.0001	Negligible	0.0001
CO (lb/MWh)	Negligible	Negligible	Negligible	0.02	Negligible
VOC (lb/MWh)	Negligible	Negligible	Negligible	0.02	Negligible
CO_2 (lb/MWh)	1,131	734	980	1,049	980
CO_2 with heat recovery (lb/MWh)	415	555	520-680	495	520

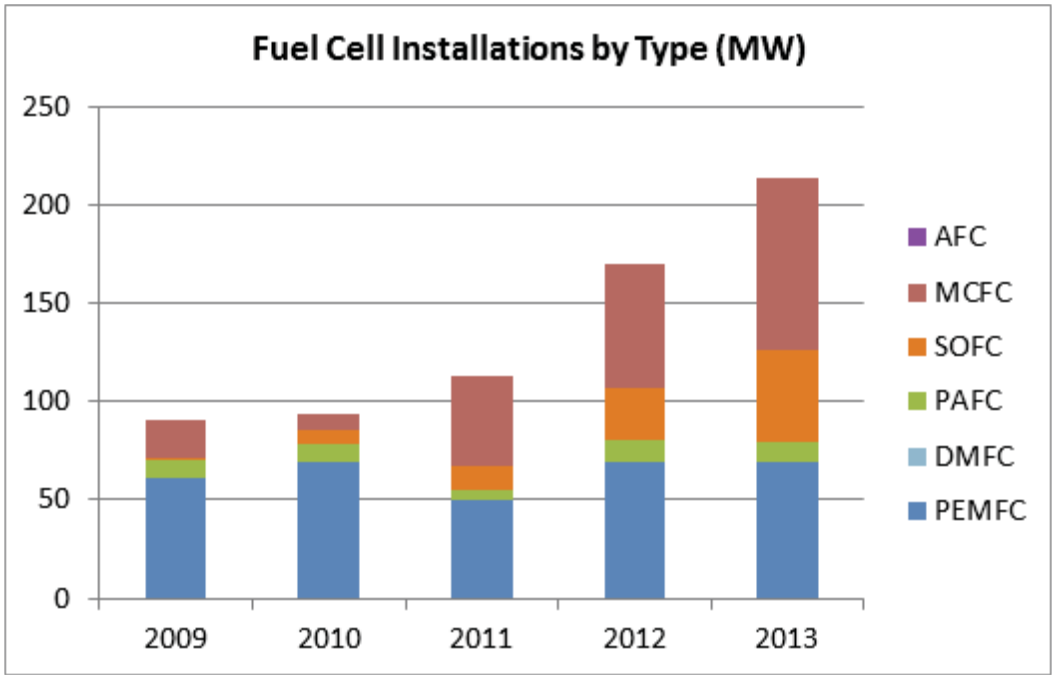
Source: ICF Manufacturer Data Collection

6.6 Future Developments

Over the past years fuel cell capital costs have decreased and their use in multiple applications have increased. In 2007, SOFC were not even commercially shipping and now there are many of them being shipped in multiple sizes globally. In the US multiple factors point towards continued levels of fuel cell market penetration. These factors include: relatively low domestic natural gas prices, continued fuel cell technological advancements reducing capital costs and new business models such as leasing, favorable incentives and policies, continued desire for low emissions profiles, and general resiliency and reliability advantages of distributed energy.

Globally, MCFC shipments by MW have been on par with that of vehicle PEMFC, as shown in **Figure 6-5**. As the only commercial developer of MCFCs in the United States, Fuel Cell Energy is uniquely positioned to continue its successes, both domestically and internationally.

Figure 6-5. Recent Worldwide Fuel Cell Installations by Fuel Cell Type, in Megawatts



Source: Fuel Cell Today[101]

Large-scale stationary fuel cells for CHP have also been successfully deployed in Asia (specifically Korea and Japan). Europe could also be a growth opportunity as FuelCell Energy has formed joint ventures in the European continent.[102] It is likely through these international joint ventures that US-based fuel cell manufacturers can leverage local market experience and technological expertise in international markets. These sales opportunities will also increase demand leading to potentially more reductions in costs as we have seen in solar photovoltaic panels and now batteries.

[101] "The Fuel Cell Industry Review 2013", Fuel Cell Today. *http://www.fuelcelltoday.com/media/1889744/fct_review_2013.pdf*
[102] "FuelCell Energy Announces Completion of Asset Acquisition and German Joint Venture with Fraunhofer IKTS", June 26, 2012. *http://fcel.client.shareholder.com/releasedetail.cfm?releaseid=686425*

What may be the next significant growth engine for fuel cells is the development of micro-CHP fuel cells. According to a 2013 report from Fuel Cell Today, residential micro-CHP fuel cells outsold conventional micro-CHP boilers for the first time in 2012 in Japan. The report elaborates that this micro-CHP application is migrating to Europe and it may become a trend in the US with both PEMFC and SOFC technologies.

Section 7. Packaged CHP Systems

Acknowledgements

This section of the Catalog was prepared by David Jones (ICF International), Anne Hampson (ICF International), Charlie Goff (ERG), Gary McNeil (U.S. Environmental Protection Agency), and Neeharika Naik-Dhungel (U.S. Environmental Protection Agency).

7.1 Introduction

The purpose of this section of the Catalog is to introduce packaged CHP systems and their unique attributes to facility owners and operators, real estate developers, CHP project developers, architects, engineers, and policymakers.

Depending on the application, packaged systems can be cheaper and easier to install and operate than conventional CHP systems (i.e., unique site-specific systems involving the integration of different components — prime mover, generator, heat recovery equipment, electrical switchgear, emissions control devices, and controls). Also, because packaged systems are standardized, they can be good choices for organizations with multiple facilities with similar electrical and thermal requirements.

> This section of the Catalog of CHP Technologies is different than the other sections of the Catalog, in that it addresses a new CHP system configuration, whereas the other sections characterize specific CHP prime mover technologies. Accordingly, this section includes material such as installations and technical potential by market segment, which are not found in the other sections.

Packaged systems include a prime mover (i.e., reciprocating engine, microturbine, or fuel cell), a generator, heat recovery equipment, electrical switchgear, emissions control devices, and controls, sometimes packaged in a weather-resistant sound-attenuating enclosure. These systems can be installed as single units or combined to form larger systems. Product offerings for packaged systems have been focused on relatively small (≤ 500 kW) sizes.

This section of the Catalog provides an overview of packaged systems, including:

- The evolution of packaged CHP systems
- Significant attributes
- Applications
- Technology description
- Cost and performance characteristics
- Emissions and emissions control options

7.2 The Evolution of Packaged CHP Systems

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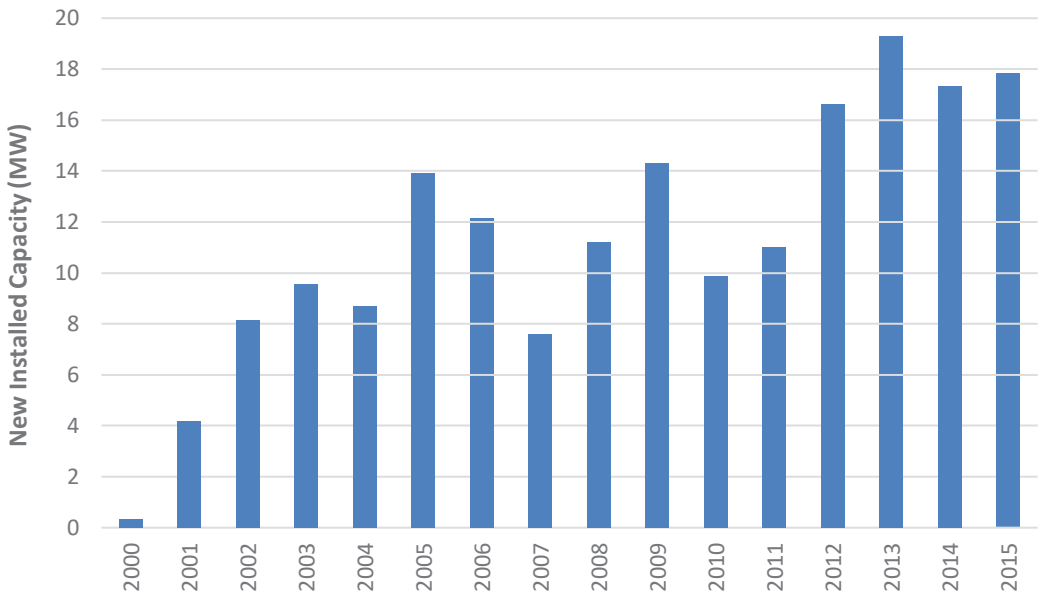
Until relatively recently, nearly all CHP installations were unique site-specific conventional CHP systems. In the late 1990s, as the market for CHP applications boomed, many manufacturers and developers started offering standardized factory-built, ready-to-install packaged CHP systems that simplified, and

shortened the time required for, CHP system procurement and installation. Today there are 27 packaged system vendors in the United States, according to a 2016 survey[103] of the packaged CHP industry.

In 2016 an estimated 950 packaged systems are installed in the United States, totaling 215 MW of capacity.[104] Annual additions of packaged system capacity are increasing, as shown in **Figure 7-1**.[105]

Figure 7-1. Annual U.S. Capacity Additions: Packaged CHP Systems



Source: ICF/U.S. DOE Combined Heat and Power Installation Database, February 2017, https://doe.icfwebservices.com/chpdb/.

[103] Compiled by ICF from vendor-supplied data, 2016.
[104] ICF/U.S. DOE Combined Heat and Power Installation Database, February 2017, *https://doe.icfwebservices.com/chpdb/*.
[105] Ibid.

Examples of Packaged CHP Systems

Figure 7-2. Aegis ThermoPower (TP-75), 75 kW

Figure 7-3. Tecogen Tecopower CM-75, 75 kW

Figure 7-4. MTU 12V400 GS, 358 kW

Figure 7-5. Capstone C65 ICHP, 65 kW

Figure 7-6. Amerigen 8150 (Using the MAN E2876 E312 Engine), 150 kW

Figure 7-7. Energy Choice EC 190 Natural Gas system, 190 kW

Figure 7-8. 2G Avus 800, 800 kW

Figure 7-9. Siemens SGE-36SL, 676 kW

7.3 Significant Attributes

Packaged systems have certain important attributes:

- Standardization
- Black start/islanding capability (sometimes optional)
- Acoustic enclosure (sometimes optional)
- Modularity
- Third-party own/operate business arrangements (may be available)
- Replicability

7.3.1 Standardization

Because packaged systems are built and delivered in accordance with published specifications, their configuration and performance can be well understood before the purchase decision is made. This facilitates many elements of the procurement process, including equipment selection, financial analysis before purchase, site-specific engineering, permitting and site modifications, as well as system installation. Site-specific engineering is typically limited to designing connections to the fuel supply, water supply, thermal loads, electrical system, and building control system.

Customers can choose several options. These include:

- Type of generator (synchronous, induction, or inverter)
- Black start/islanding capability
- Enhanced sound attenuation
- Additional emissions controls
- Specialized heat recovery options, such as an absorption chiller to produce chilled water for cooling applications or a steam boiler to make steam from the prime mover exhaust

NYSERDA CHP Program

The standardization of CHP equipment can make it easier for programs such as the New York State Energy Research and Development Authority's (NYSERDA's) CHP Program to pre-approve projects for incentives. Programs like NYSERDA's provide a level of assurance that the pre-approved systems meet the requirements of the approving organization.
Information about NYSERDA's CHP Program is available at:
https://portal.nyserda.ny.gov/CORE_Solicitation_Detail_Page?SolicitationId=a0rt0000000QnqyAAC

7.3.2 Black Start/Islanding Capability

Several packaged system vendors offer models with black start/islanding capability. These systems can disconnect from the utility grid using an automatic transfer switch and run independently during power outages (i.e., in "island mode"). While CHP systems are not typically intended to meet a facility's full load requirements, they can provide electricity to critical loads when the electric grid is not available.

CHP systems with black start/islanding capability can supplement traditional diesel standby generators, providing an added level of redundancy during long-term outages and natural disasters when diesel fuel

can become scarce (e.g., Hurricane Sandy). Also, in certain circumstances, CHP can replace diesel standby generators.

Black start/islanding capability requires additional components, which may increase equipment cost and/or installation cost. The extent to which black start/islanding capability adds to installation costs depends on factors such as the existing electrical system in the host facility, the switchgear required, and the size of the electrical loads to be served when the system is islanding.[106]

7.3.3 Acoustic Enclosure

Systems may include a sound attenuation enclosure—as standard equipment or as an option—consisting of sound-absorbing material surrounded by a metal cover. Optional enhanced sound attenuation capability may be available.

7.3.4 Modularity

Because of their modular design, packaged systems can be installed as single units, or several can be connected to create larger multiple-unit systems. Systems using multiple modular units can have a number of additional significant attributes:

- Under certain circumstances, multiple-unit systems can be more efficient than a conventional CHP system of the same size. Conventional systems lose efficiency when slowed down to follow load fluctuations. In multiple-unit systems, individual units can be shut down to reduce system output to follow load fluctuations, allowing remaining operational units to function at higher efficiencies.
- Systems using multiple modular units can also improve reliability and system availability, since one unit can be taken off line for maintenance while the others continue to operate.
- Additional units can be added over time to increase output as electrical and/or thermal loads increase.[107]

CHP Project Development

Taking a CHP project from conception to completion involves five steps:

- Qualification/screening
- Level 1 feasibility analysis
- Level 2 feasibility analysis (investment grade analysis)
- Procurement, including installation
- Operations and maintenance

Depending on the nature of the facility and the performance objectives of a CHP system being considered, each of the five steps may be performed by the facility's manager or agent, consultants, or vendors.

Learn more about these steps, including goals, timeframes, typical costs, and facility level of effort required on the *EPA CHP Partnership website*.

A disadvantage of using multiple modular units instead of one large unit is that the installed cost per kW is typically higher. In addition, in full-load operation, a conventional CHP system will typically be more efficient than a system of equal size comprising multiple packaged system units.

[106] Based on data collected from EPA CHP Partners that manufacture packaged CHP systems.

[107] Often up to five or six units may be operated together, depending on the equipment specifications.

7.3.5 Third-Party Own/Operate Business Arrangements

Many packaged system vendors offer "own and operate" business arrangements, which can be structured as agreed upon by the host facility and the vendor. One model is for the vendor or a third party to install, own, operate, and maintain the system, and provide the system outputs to the host facility under terms established in a contract. In this way, the facility can have on-site power production and other CHP benefits without a capital expenditure or the risks and responsibilities of ownership. The contract may include an option for the host facility to purchase the system at specified terms.

7.3.6 Replicability

Operators of multifamily buildings, big box stores, hotels, restaurants, and supermarkets often manage many buildings with similar electrical and thermal requirements. Because a specific packaged system model will perform consistently when installed in facilities with comparable layouts and electric/thermal requirements, that model can become a known quantity for the building operator. With this experience, the building operator can confidently choose the same system for other buildings with similar electrical/thermal requirements.

7.4 Applications

While conventional CHP applications have been concentrated in the industrial/heavy manufacturing sector, packaged CHP applications are most often used in the commercial, multifamily, institutional, and light manufacturing sectors. Attributes of facilities that make them good matches for packaged systems include:

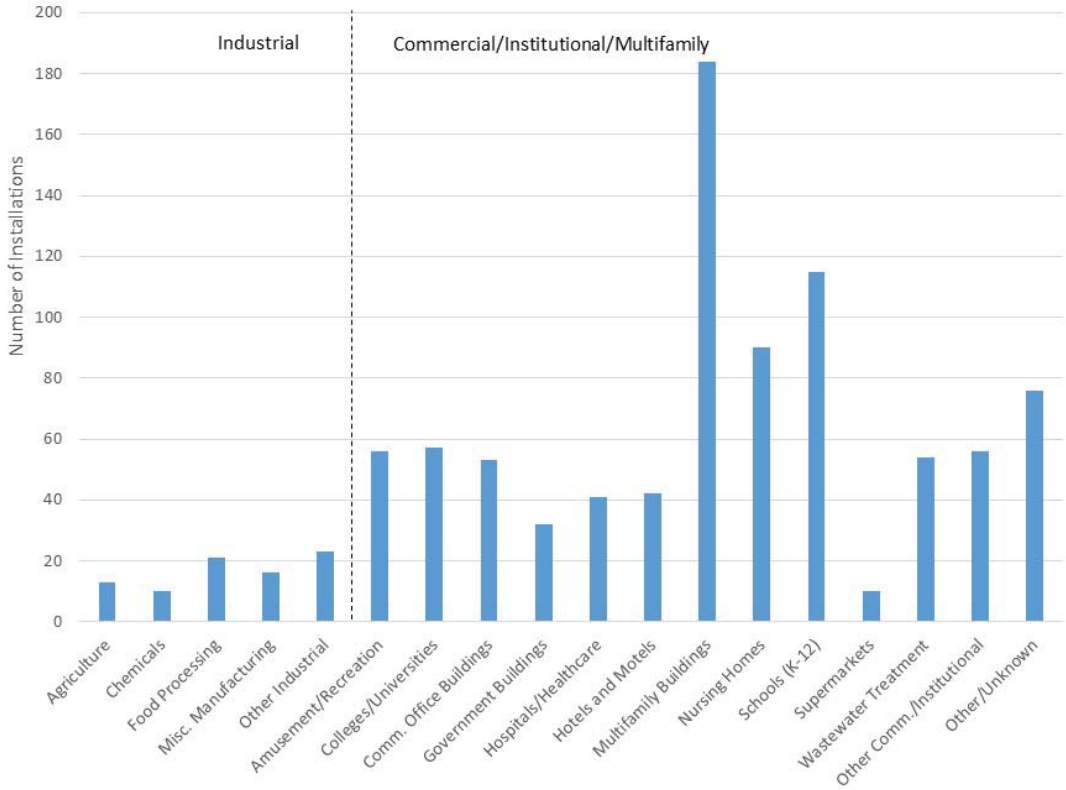
- **Electrical and thermal load and profiles that match packaged system outputs.** Most packaged systems are under 500 kW in size, which is a good match for the electrical and thermal loads of commercial, multifamily, and institutional buildings.
- **Space constraints** – Many facilities have constraints on the physical size of units that can be installed, and packaged systems tend to have a relatively small footprint.
- **Building owners who place a high value on ease of installation and operation** – The standardization of packaged systems means an easier procurement process compared to conventional CHP systems.
- **Need for flexible financing options** – CHP projects are capital-intensive, which can be a problem for some market sectors. Many packaged systems are available through "own and operate" arrangements, where the vendor retains ownership and is responsible for installation, operation, and maintenance, if the building owners do not want to perform this function.
- **A building that is one of several similar facilities in the same enterprise –** If a packaged system is a good fit for one facility, it becomes a known quantity that can be confidently deployed at other facilities with similar load requirements and layouts.

Larger energy users, such as industrial/manufacturing facilities and some large institutional facilities might not find as much value in a packaged system as they would in a custom-engineered conventional CHP system that can be precisely tailored to their specific facility needs.

7.4.1 Installed Packaged Systems

Figure 7-10 presents packaged system installations by market segment, and **Table 7-1** presents total installed packaged system capacity and the median system size by market segment.

Figure 7-10. Packaged System Installations by Market Segment



Source: ICF/U.S. DOE Combined Heat and Power Installation Database, February 2017 https://doe.icfwebservices.com/chpdb/.

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Table 7-1. Packaged Systems Total Installed Capacity and Median Size by Market Segment

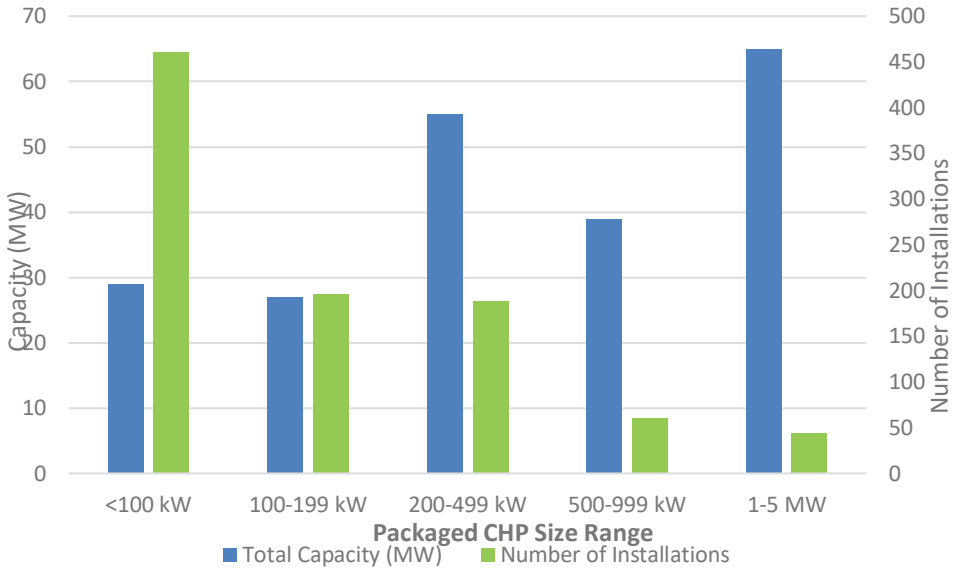
Sector	Market Segment	Installed Capacity (MW)	Median Size (kW)
Industrial	Agriculture	4.5	100
	Chemicals	5.0	180
	Food Processing	10.9	300
	Misc. Manufacturing	8.0	390
	Other Industrial	9.8	180
Commercial Institutional Multifamily	Amusement/Recreation	7.6	75
	Colleges/Universities	14.5	180
	Commercial Office Buildings	21.4	75
	Government Buildings	6.4	90
	Hospitals/Healthcare	15.7	220
	Hotels and Motels	7.8	100
	Multifamily Buildings	22.3	75
	Nursing Homes	10.8	75
	Schools (K-12)	17.7	75
	Supermarkets	4.2	320
	Wastewater Treatment	14.1	130
	Other Comm./Institutional	16.3	170
	Other/Unknown	18.6	140

Source: ICF/U.S. DOE Combined Heat and Power Installation Database, February 2017 https://doe.icfwebservices.com/chpdb/.

The packaged system market has been dominated by market segments in the commercial/institutional/multifamily sector. More than 91 percent of installations are contained in these sectors. Multifamily buildings have the highest number of packaged system installations, followed by schools and nursing homes. These market segments, as well as hotels, government buildings, and amusement and recreation facilities, tend to use smaller systems, with median sizes of 100 kW or less, than the other market segments. Industrial market segments have fewer installations but tend to have larger capacities, with median sizes greater than 100 kW.

Figure 7-11 presents packaged system installations and capacity by size range. Almost 90 percent of the packaged system installations are applications under 500 kW in size (although packaged system are available in sizes up to several MW). Note that the total installed capacity of systems under 500 kW is approximately equal to that of systems > 500 kW.

Figure 7-11. Packaged System Installations and Capacity by Size Range



Source: ICF/U.S. DOE Combined Heat and Power Installation Database, February 2017, https://doe.icfwebservices.com/chpdb/.

7.4.2 Technical Potential

Technical potential is an estimate of market size constrained only by technological limits—the ability of CHP technologies to fit customer energy needs without regard to economic for market factors. For this reason, actual potential will be less than technical potential, but in some cases, it may still be a useful indicator of relative economic potential.

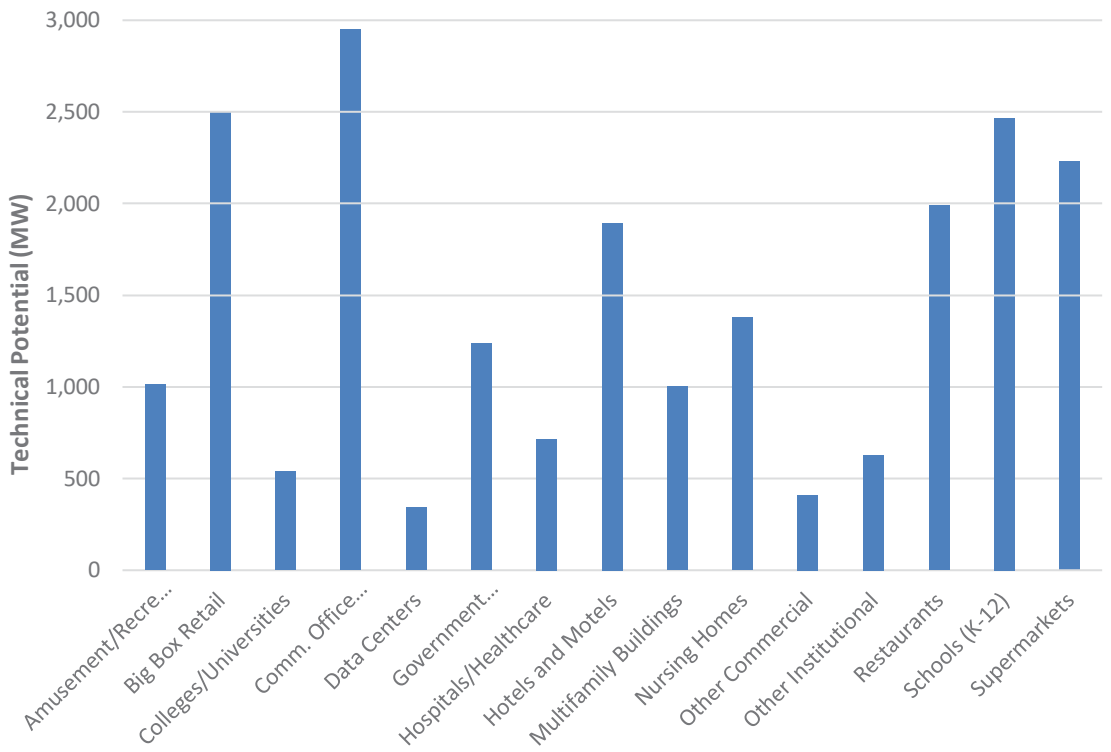
Ninety percent of packaged system installations are units under 500 kW. There is currently 21.3 GW of technical potential for systems under 500 kW in the U.S. commercial, institutional, and multifamily sectors[108], at more than 100,000 facilities. The technical potential for <500 kW packaged system applications is greatest in the following ten market segments:

- Amusement/recreation
- Big box retail
- Commercial office buildings
- Government buildings
- Hotels and motels
- Multifamily buildings
- Nursing homes
- Restaurants
- Schools
- Supermarkets

[108] ICF, CHP Technical Potential Database, 2016.

Each of these market segments is estimated to contain over 1 GW of technical potential for systems <500 kW. **Figure 7-12** breaks down the technical potential for packaged systems <500 kW.

Figure 7-12. Technical Potential for <500 kW Packaged CHP Applications in the Commercial and Institutional Sectors, by Market Segment



Source: ICF, 2016.

More information on the technical potential for CHP applications – including the industrial sector and larger size ranges – can be found in the Department of Energy's 2016 CHP Technical Potential Report.[109]

7.5 Technology Description

The general design of packaged systems is relatively consistent throughout all packaged products. The main components of packaged systems include:

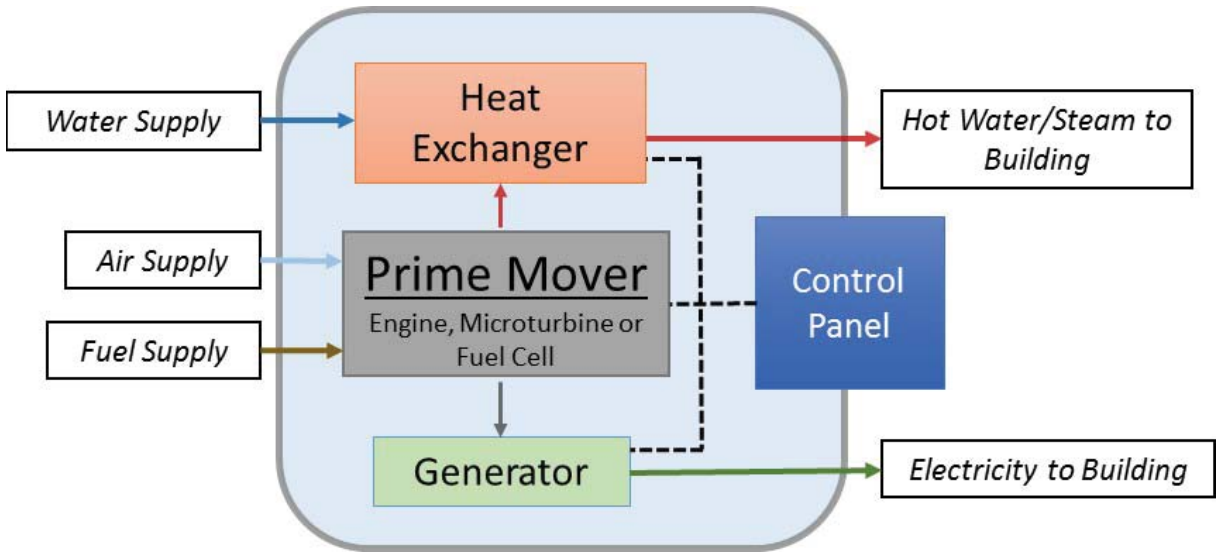
- **Prime mover** – the power-producing machine (or chemical process, in the case of fuel cells) that drives the electric generator.
- **Generator** – a device that converts mechanical energy into electricity.
- **Heat exchanger –** a device that transfers heat from the prime mover exhaust gas and/or the engine block to water, to produce hot water or steam.

[109] U.S. Department of Energy, *Combined Heat and Power (CHP) Technical Potential in the United States,* March 2016, *http://energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf*.

- **Control panel** – controls and monitoring instruments.

Figure 7-13 provides a process diagram that shows how these different components interact in a packaged system.

Figure 7-13. Packaged CHP System Diagram



Source: EPA CHP Partnership

7.5.1 Heat Recovery

A defining characteristic of CHP systems is their ability to recover and put to beneficial use otherwise-wasted heat. Most packaged systems use recovered heat to produce hot water, but steam and chilled water options are also available.

To produce chilled water, packaged systems are coupled with an absorption chiller, which converts recovered heat into chilled water that can be used for air conditioning or other cooling loads. In this way, more of the system's thermal output can be used, which increases system efficiency. Packaged systems with absorption chillers are well-suited for applications that consistently require chilled water, such as supermarkets and data centers, as well as buildings with seasonal heating and cooling needs, like multifamily buildings, hotels, health clubs and health care facilities.

Specifying Packaged CHP System Capacity Based on Thermal and Electric Requirements

Sizing decisions are best made based on an understanding of facility electrical and thermal loads (hot water, heating cooling), and how they match with the outputs of available packaged systems. Typically, packaged CHP capacity is selected in a way that allows facilities to utilize all of the electric and thermal energy on site, while operating at or near full load. Building energy modeling can be used to determine the system that best meets the facility's needs while operating efficiently and providing an acceptable return on investment. Energy models often used include eQUEST and EnergyPlus.

7.6 Cost and Performance Characteristics

When making a purchase decision, the cost and performance characteristics presented in this section should be considered in conjunction with other factors, such as expected service life, guarantees, and availability of service and support, along with performance characteristics not presented here, such as noise and vibration.

Table 7-2 summarizes the performance characteristics for packaged systems consisting of a single reciprocating engine or microturbine. Data were gathered from the seven EPA CHP Partner companies that manufacture packaged systems and that responded to a data request.[110]

Fuel Cells: Efficient Operation and Environmental Benefits

Fuel cell CHP systems can be designed to operate with high electric efficiencies—potentially over 50 percent—and can maintain high efficiency at partial loads. Most fuel cells convert natural gas to hydrogen using a reformer, which emits carbon at a lower rate than other prime mover technologies. Nearly all fuel cell CHP is sold as packaged systems.

Table 7-2. Packaged CHP Systems – Performance Characteristics

Performance Characteristic	Size Range (kW)[111]				
	30-99	100-199	200-499	500-1,000	>1,000
Electrical Heat Rate (Btu/kWh), HHV	10,000 - 12,600	9,800 - 12,600	9,200 - 10,800	9,000 - 11,000	8,200 - 10,400
Electrical Efficiency (%), HHV	24-32%	27-35%	32-37%	28-38%	33-41%
Total Heat Recovered (Btu/kWh)	5,300 - 7,000	4,600 – 6,400	3,600 - 5,400	3,600 - 4,700	3,400 - 5,600
Typical form of Recovered Heat[112]	H_2O	H_2O	H_2O	H_2O	H_2O, Steam
Total CHP Efficiency[113] (%), HHV	73-82%[114]	67-86%	76-82%	67-82%	78-87%
Power/Heat Ratio	0.49-0.64	0.52-0.73	0.64-0.95	0.72-0.96	0.61-1.01

Source: Compiled from data supplied by the seven EPA CHP Partner companies that manufacture packaged systems and that responded to a data request.

[110] These seven companies manufacture systems using reciprocating engines or microturbines, which account for 97 percent of packaged systems in the United States (fuel cell systems account for the remaining three percent). One additional company, which manufactures packaged systems using fuel cells, responded to the data request. However, because fuel cells have different characteristics, and tend to be used in different applications than reciprocating engine and microturbine systems, they are not a focus of this section. Fuel cell cost and performance characteristics can be found in the Fuel Cells section of the Catalog.

[111] Size ranges reflect the large majority of packaged systems sold. However, some vendors sell systems as small as 5 kW.

[112] Although hot water is the typical form of recovered heat for most size ranges, steam may be an option for all ranges.

[113] Total CHP efficiency for reciprocating engines is approximately 80 percent, while the total CHP efficiency for microturbines tends to be close to 70 percent.

[114] One vendor reports offering a 50 kW system with 92 percent efficiency. The system has unique attributes and certain limitations compared to typical systems.

Some key takeaways from **Table 7-2** are:

- Electric efficiencies and total CHP efficiencies tend to increase with system size.
- As systems get larger, the power-to-heat ratio tends to increase (i.e., more electricity is delivered relative to recovered heat).
- Performance varies within a given size range due to different prime mover and heat recovery technologies, and different system designs.
- Recovered heat from packaged systems is typically in the form of hot water.

More details on the characteristics of efficiency, thermal output, and other technical information for reciprocating engines and microturbine technologies are provided in their respective Catalog sections.

7.6.1 Part-Load Operation

In most packaged systems, reciprocating engines or microturbines drive generators at a constant speed to produce steady alternating current (AC) power. As load is reduced, generator speed decreases, the heat rate of the prime mover increases, and electrical efficiency decreases. Electrical efficiency at half load is typically 10 to 25 percent less than full-load efficiency, with efficiencies falling more steeply for loads lower than half of the unit's rated capacity.

Systems comprising multiple units can reduce part-load efficiency penalties, which is especially important for commercial applications. Electric loads for commercial buildings tend to vary more than they do in manufacturing facilities. Because individual units can be put in standby mode when the building load drops, the other units can continue to operate at or near peak efficiency. In the same circumstances, a single-unit system might need to operate at reduced electrical efficiency.

More information on part-load performance for reciprocating engines and microturbines can be found in their respective sections of the Catalog.

7.6.2 Installed Costs

Installed costs include equipment and installation costs. Equipment costs vary depending on factors such as:

- Emissions controls (included as standard equipment or as options)
- Sound attenuation performance level
- Generator type (induction/synchronous/inverter)
- Black start/islanding capability
- Specialized heat recovery equipment (e.g. absorption chiller)

Table 7-3 presents typical equipment costs for packaged systems. These costs represent cost data provided by EPA CHP Partner companies that manufacture packaged systems and reflect difference in features provided as standard equipment.

Installation costs are not presented. Packaged system vendors report large variations in installation costs, based on such factors as:

- Variables based on the location of the equipment, such as ventilation routing, or rigging or cranes that might be required for installation. Also, installation costs may be higher for retrofits of existing buildings compared to new construction.
- Insurance requirements for contractors and subcontractors.
- Bonding requirements.
- Restrictions on working hours and access to site.
- Metering, permitting, and utility interconnection requirements.
- Local labor rates or minimum rates required by the Davis-Bacon and Related Acts, where applicable.
- Black start/islanding capability, which adds to installation costs depending on factors such as the existing electrical system in the host facility, switchgear required, and the size of the electrical loads to be served when the system is islanding.

Installation costs for packaged systems tend to be less than for conventional systems of similar size. For example, for a 1,000 kW packaged system, installation costs can be as low as $150,000 compared to $700,000 for conventional systems.

Table 7-3. Packaged CHP Systems – Equipment Costs

Packaged System Costs	Size Range (kW)				
	30-99	100-199	200-499	500-1,000	>1,000
Equipment Cost ($/kW)	$1,000 - $2,850	$1,400 - $3,100	$1,000 - $2,000	$900 - $1,850	$650 - $1,100

Source: Compiled from data supplied by the seven EPA CHP Partner companies that manufacture packaged systems and that responded to a data request.

7.6.3 Maintenance Costs

Unlike for conventional systems, maintenance for packaged systems is typically performed by the system vendor or a third party. Maintenance costs vary depending on factors such as type of CHP technology, remote monitoring, and performance guarantees. The ranges of maintenance costs for different sizes of packaged system reciprocating engines and microturbines are shown in **Table 7-4** (while costs here are presented in $/kWh, note that some vendors price maintenance in $/run hour, not $/kWh). For more information on maintenance requirements for reciprocating engines and microturbines, refer to their respective sections of the Catalog.

Table 7-4. Packaged CHP Systems – Maintenance Costs

	Size Range (kW)				
	30-99	100-199	200-499	500-1,000	>1,000
Maintenance Costs ($/kWh)	$0.013 - $0.025	$0.018 - $0.025	$0.017 - $0.021	$0.010- $0.016	$0.002- $0.016

Source: Compiled from data supplied by the seven EPA CHP Partner companies that manufacture packaged systems and that responded to a data request. vendors.

7.6.4 Fuels

Packaged systems generally use natural gas as fuel. However, other fuels, such as propane and biogas, can be used. Biogas fuels (e.g., anaerobic digester gas and landfill gas) may require pretreatment to remove moisture, hydrogen sulfide and siloxanes. The extent of pretreatment depends on the quality of the fuel and the prime mover technology. More details on fuels that can be used for different prime movers can be found in their respective technology characterizations in the Catalog.

7.7 Emissions, Emissions Control Options, and Prime Mover Certification

Most CHP systems emit certain pollutants–carbon dioxide[115], oxides of nitrogen (NO_X), carbon monoxide (CO), and volatile organic compounds. Emissions can vary depending on the prime mover technology, fuel type, and the emissions controls that are applied. Many packaged systems are equipped with emissions controls to reduce NO_X, CO and VOC emissions. Additional emissions controls may be available as options.

Packaged system vendors may offer systems with engines certified to comply with U.S. EPA regulations for stationary engines. A certificate of conformity with the Clean Air Act is supplied with these engines. Owners of systems with non-certified engines are responsible for having the engines individually performance-tested using the required EPA-approved test protocol (some vendors who sell uncertified systems perform emissions testing on systems after they are installed).

A thorough discussion of emissions and control options for each prime mover technology is provided in its respective technology characterization sections of the Catalog.

[115] While there is no currently viable technology to reduce CO_2 emissions from fossil fuel combustion, emissions can be reduced by increasing the useful outputs from a given amount of fuel burned. CHP is a highly cost-effective way to achieve this objective.

Appendix A: Expressing CHP Efficiency

Appendix A: Expressing CHP Efficiency

A.1 Expressing CHP Efficiency

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Many of the benefits of CHP stem from the relatively high efficiency of CHP systems compared to other systems. Because CHP systems simultaneously produce electricity and useful thermal energy, CHP efficiency is measured and expressed in a number of different ways[116] **Table A-I** summarizes the key elements of efficiency as applied to CHP systems.

As illustrated in **Table A-I** the efficiency of electricity generation in power-only systems is determined by the relationship between net electrical output and the amount of fuel used for the power generation. **Heat rate**, the term often used to express efficiency in such power generation systems, is represented in terms of Btus of fuel consumed per kWh of electricity generated. However, CHP plants produce useable heat as well as electricity. In CHP systems, the **total CHP efficiency** seeks to capture the energy content of both electricity and usable steam and is the net electrical output plus the net useful thermal output of the CHP system divided by the fuel consumed in the production of electricity and steam. While total CHP efficiency provides a measure for capturing the energy content of electricity and steam produced it does not adequately reflect the fact that electricity and steam have different qualities. The quality and value of electrical output is higher relative to heat output and is evidenced by the fact that electricity can be transmitted over long distances and can be converted to other forms of energy. To account for these differences in quality, the Public Utilities Regulatory Policies Act of 1978 (PURPA) discounts half of the thermal energy in its calculation of the efficiency standard (Eff_{FERC}). The EFF_{FERC} is represented as the ratio of net electric output plus half of the net thermal output to the total fuel used in the CHP system. Opinions vary as to whether the standard was arbitrarily set, but the FERC methodology does recognize the value of different forms of energy. The following equation calculates the FERC efficiency value for CHP applications.

$$EFF_{FERC} = \frac{P + Q/2}{F}$$

Another definition of CHP efficiency is **effective electrical efficiency**, also known as **fuel utilization effectiveness (FUE)**. This measure expresses CHP efficiency as the ratio of net electrical output to net fuel consumption, where net fuel consumption excludes the portion of fuel that goes to producing useful heat output. The fuel used to produce useful heat is calculated assuming typical boiler efficiency, generally 80 percent. The effective electrical efficiency measure for CHP captures the value of both the electrical and thermal outputs of CHP plants. The following equation calculates FEU.

$$FUE = \frac{P}{F - Q/EFF_Q}$$

[116] Measures of efficiency are denoted either as lower heating value (LHV) or higher heating value (HHV). HHV includes the heat of condensation of the water vapor in the products. Unless otherwise noted, all efficiency measures in this section are reported on an HHV basis.

FUE captures the value of both the electrical and thermal outputs of CHP plants and it specifically measures the efficiency of generating power through the incremental fuel consumption of the CHP system.

EPA considers fuel savings as the appropriate term to use when discussing CHP benefits relative to separate heat and power (SHP) operations. Fuel savings compares the fuel used by the CHP system to a separate heat and power system (i.e. boiler and electric-only generation). The following equation determines percent fuel savings (S).

$$S = 1 - \left[\frac{F}{P/Eff_P + Q/Eff_Q} \right]$$

In the fuel saving equation given above, the numerator in the bracket term denotes the fuel used in the production of electricity and steam in a CHP system. The denominator describes the sum of the fuel used in the production of electricity (P/Eff_P) and thermal energy (Q/Eff_Q) in separate heat-and-power operations. Positive values represent fuel savings while negative values indicate that the CHP system in question is using more fuel than separate heat and power generation.

Table A-1. Measuring the Efficiency of CHP Systems

System	Component	Efficiency Measure	Description
Separate heat and power (SHP)	Thermal Efficiency (Boiler)	$EFF_Q = \frac{\text{Net Useful Thermal Output}}{\text{Energy Input}}$	Net useful thermal output for the fuel consumed.
	Electric-only generation	$EFF_P = \frac{\text{Power Output}}{\text{Energy Input}}$	Electricity Purchased From Central Stations via Transmission Grid.
	Overall Efficiency of separate heat and power (SHP)	$EFF_{SHP} = \frac{P + Q}{P/EFF_{Power} + Q/EFF_{Thermal}}$	Sum of net power (P) and useful thermal energy output (Q) divided by the sum of fuel consumed to produce each.
Combined heat and power (CHP)	Total CHP System Efficiency	$EFF_{Total} = (P + Q)/F$	Sum of the net power and net useful thermal output divided by the total fuel (F) consumed.
	FERC Efficiency Standard	$EFF_{FERC} = \frac{(P + Q/2)}{F}$	Developed for the Public Utilities Regulatory Act of 1978, the FERC methodology attempts to recognize the quality of electrical output relative to thermal output.

Table A-1. Measuring the Efficiency of CHP Systems

System	Component	Efficiency Measure	Description
	Effective Electrical Efficiency (or Fuel Utilization Efficiency, FUE):	$FUE = \frac{P}{F - Q/EFF_{Thermal}}$	Ratio of net power output to net fuel consumption, where net fuel consumption excludes the portion of fuel used for producing useful heat output. Fuel used to produce useful heat is calculated assuming typical boiler efficiency, usually 80 percent.
	Percent Fuel Savings	$S = 1 - \frac{F}{P/EFF_P + Q/EFF_Q}$	Fuel savings compares the fuel used by the CHP system to a separate heat and power system. Positive values represent fuel savings while negative values indicate that the CHP system is using more fuel than SHP.

Key:
P = Net power output from CHP system
Q = Net useful thermal energy from CHP system
F = Total fuel input to CHP system
EFF_P = Efficiency of displaced electric generation
EFF_Q = Efficiency of displaced thermal generation