Laboratories for the 21st Century: Best Practices

This combined heat and power system at the Bristol-Myers Squibb laboratory in Wallingford, Connecticut, could meet 100% of the lab's power requirement, if necessary.

ONSITE DISTRIBUTED GENERATION SYSTEMS FOR LABORATORIES

Introduction

Laboratories have unique requirements for lighting, ventilation, and scientific equipment with each requiring a considerable amount of energy. The reliability of that energy is very important. Laboratories must be able to conduct research without power interruptions, which can damage both equipment and experiments. Generating power and heat on site is one good way to enhance energy reliability, improve fuel utilization efficiency, reduce utility costs, and mitigate greenhouse gas (GHG) emissions.

EPA United States Environmental Protection Agency

U.S. DEPARTMENT OF ENERGY

This best practices guide introduces onsite distributed generation (DG) systems. Specific technology applications, general performance information, and cost data are provided to educate and encourage laboratory energy managers to consider onsite power generation or combined heat and power (CHP) systems for their facilities. After conducting an initial screening, energy managers are encouraged to conduct a detailed feasibility study with actual cost and performance data for technologies that look promising.

This guide is one in a series on best practices for laboratories. It was produced by Laboratories for the 21st Century (Labs 21), a joint program of the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE). Geared toward architects, engineers, and facility managers, these guides provide information about technologies and practices that can be used to design, construct, and operate safe, sustainable, high-performance laboratories.

A rooftop photovoltaic system produces electricity on site at the Environmental Protection Agency's facility in Research Triangle Park, North Carolina. *Photo from Environmental Protection Agency, NREL/PIX 12662*

Technology Description

Onsite distributed generation systems are small, modular, decentralized, grid-connected, or off-grid energy systems. These systems are located at or near the place where the energy is used. These systems are also known as distributed energy or distributed power systems. DG technologies are generally considered those that produce less than 20 megawatts (MW) of power. A number of technologies can be applied as effective onsite DG systems, including:

- Diesel, natural gas, and dual-fuel reciprocating engines;
- Combustion turbines and steam turbines;
- Fuel cells;
- Biomass heating;
- Biomass combined heat and power;
- Photovoltaics; and
- Wind turbines.

These systems can provide a number of potential benefits to an individual laboratory facility or campus, including:

- High-quality, reliable, and potentially dispatchable power;
- Low-cost energy and long-term utility cost assurance, especially where electricity and/or fuel costs are high;
- Significantly reduced greenhouse gas (GHG) emissions. Typical CHP plants reduce onsite GHG by 40 to 60 percent;
- Peak demand shaving where demand costs are high;
- CHP where thermal energy can be used in addition to electricity;
- The ability to meet standby power needs, especially where utility-supplied power is interrupted frequently or for long periods and where standby power is required for safety or emergencies; and
- Use for standalone or off-grid systems where extending the grid is too expensive or impractical.

Because they are installed close to the load, DG systems avoid some of the disadvantages of large, central power plants, such as transmission and distribution losses over long electric lines.

Combined Heat and Power Systems

CHP systems typically produce two forms of useful energy – electricity and heat. Both are generated simultaneously from a single fuel source. Because CHP systems capture the waste heat of electricity production to offset a facility's thermal energy needs, these systems are typical-

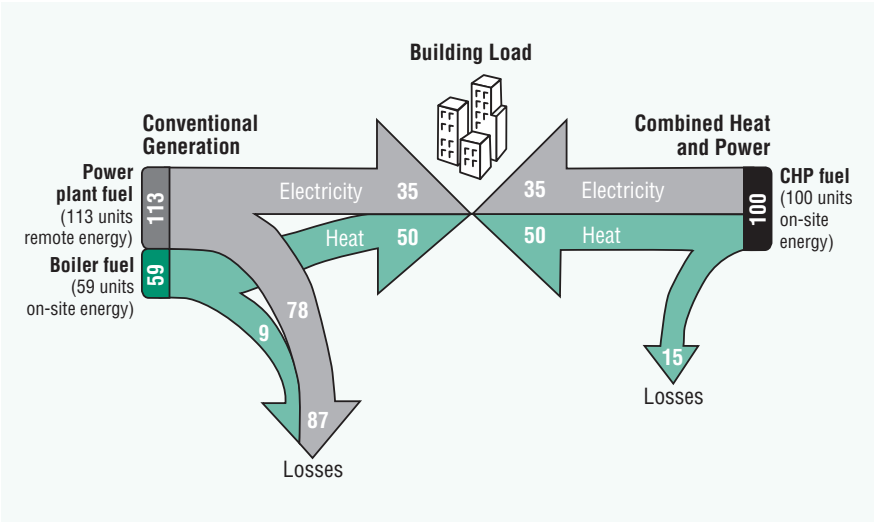

Figure 1. Conventional generation versus CHP

ly 70 to 85 percent efficient. Figure 1 illustrates the energy utilization profiles typical of conventional generation systems versus onsite CHP systems.

The conventional approach to meeting facility energy requirements is to purchase electricity from a central utility and generate heat separately on site using a fossil fuel fired boiler. This approach requires 72 more units of input energy to produce the same 35 units of electricity and 50 units of heat that the hypothetical CHP system produces. The inefficiencies of the conventional approach are the result of:

- Thermal inefficiencies in the combustion process of the central generating plant;
- The inability to use the waste heat of the central generating plant;
- Transmission and distribution losses from the central generating plant to the load; and
- Thermal inefficiencies of the onsite boiler.

Because they are located close to the load and allow optimum use of waste heat, properly designed CHP systems can be more than twice as efficient as the average U.S. fossil fuel power plant. Laboratories in particular are excellent candidates for CHP systems for several reasons:

- Power interruptions or power quality problems can have negative impacts on sensitive electronic equipment. For example, an unexpected outage can undo months of scientific work or damage important laboratory specimens.
- Laboratories typically use more energy per square foot than commercial facilities. As a result, onsite generation can result in substantial energy cost savings.
- Laboratories tend to have a good mix of onsite thermal and electric needs.

CHP systems are typically more cost effective in facilities that have central heating systems or process heating loads because much of the infrastructure needed for heat and power generation is already in place. A brief summary of typical cost and performance characteristics of CHP technologies are provided in Table 1.[2]

Table 1. Summary of typical CHP technology cost and performance characteristics

Technology	Steam Turbine	Intrnl. Combustion	Gas Turbine	Micro Turbine	Fuel Cell
Power Efficiency (HHV)	15% – 38%	22% – 40%	22% – 45%	18% – 27%	30% – 63%
Overall Efficiency (HHV)	80%	70% – 80%	70% – 85%	65% – 75%	55% – 80%
Typical Capacity (MWe)	0.5 – 250	0.01 – 5	0.5 – 250	0.03 – 0.25	0.005 – 2
Part Load	OK	OK	Poor	OK	Good
CHP Installed Costs ($/kW)	430 – 1,100	1,100 – 2,200	970 – 1,300 (5 – 40 MW)	2,400 – 3,000	5,000 – 6,500
O&M Costs ($/kWh)	Less than 0.005	0.009 – 0.022	0.004 – 0.011	0.012 – 0.025	0.032 – 0.038
Availability	Near 100%	92% – 97%	90% – 98%	90% – 98%	Greater than 95%
Startup Time	1 hrs – 1 day	10 secs	10 mins – 1 hr	1 min	3 hrs – 2 days
Fuels	All	Natural gas, biogas, propane, landfill gas	Natural gas, biogas, propane, landfill gas	Natural gas, biogas, propane, landfill gas	Hydrogen, natural gas, propane, methanol
Thermal Output Uses	Low-pressure (LP) – high-pressure (HP) steam	Hot water, LP steam	Heat, hot water, LP – HP steam	Heat, hot water, LP steam	Hot water, LP – HP steam

Combustion Turbines

Natural gas fired combustion turbines are one of the most widely accepted power generation technologies in the world.[1] Gas turbines, including micro turbines are available in sizes ranging from 30 kilowatts (kW) to 250 MW. Gas turbines can be used as an electrical power generation technology or used in CHP applications. Gas turbines can also be used in conjunction with steam turbines in a combined cycle power plant. Most distributed CHP gas turbine applications are 20 MW or less in electrical capacity.

Gas turbines have historically been used by utilities for peak power applications, but are increasingly being applied for onsite base load power generation. Gas turbines are ideally suited for laboratory applications where the high temperature exhaust gas can be used to generate steam for onsite heating or process loads. The waste heat recovery temperatures for gas turbines are hot enough to create high- or low-pressure steam. Locations with significant heating loads, such as cold locations, or high process heating loads are ideally suited for CHP gas turbine applications.

Technology Description

Simple cycle gas turbines operate on the Brayton power cycle where atmospheric air is compressed, heated, and then expanded. The turbine generator converts the rotational energy of the turbine into electrical power and exhaust gas/waste heat is used for heating purposes in CHP applications. Gas turbines typically have the following general characteristics:

- Electrical efficiency: 30 to 45 percent
- Exhaust temperature: 700°F to 1,100°F
- Total CHP efficiency: 70 to 85 percent

The operational efficiency of a natural gas turbine is primarily a function of the following:

- ***Altitude:*** The overall capacity of the turbine decreases as altitude increases and ambient air density decreases. For example, a 5 MW turbine installed at 5,000 feet will only produce 4.25 MW at 100 percent load, or 85 percent of the nameplate capacity.
- ***Inlet Air Temperature:*** The gas turbine heat rate increases as a function of inlet air temperature. The heat rate of CHP technology is defined as the ratio of British thermal units (Btu) into the unit divided by kilowatt-hours (kWh) of electricity output by the unit. The heat rate of a turbine or internal combustion (IC) engine is the measure of the electrical efficiency of the unit. Therefore, the colder the inlet air temperature, the lower the turbine heat rate and higher the overall electrical efficiency.
- ***Part Load Performance:*** The efficiency of a turbine is a function of the electrical part load performance of the turbine. In some cases, the part load profile will follow a linear profile with load. In other cases, it will follow a polynomial distribution. A generic part load profile versus turbine efficiency is provided in Figure 2. The electrical efficiency of the unit decreases as the load on the unit decreases.[2]

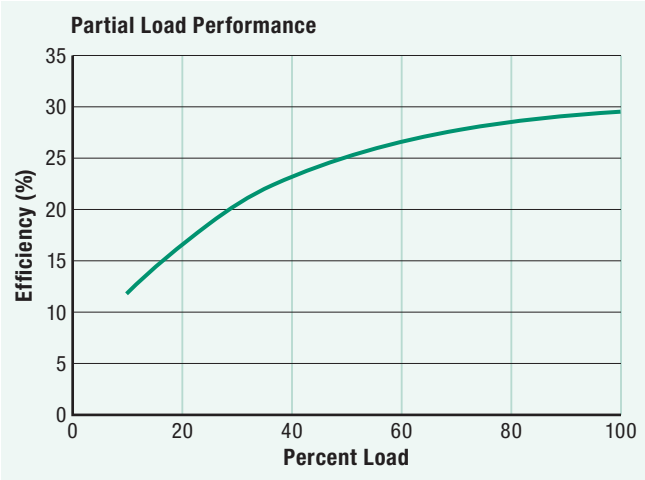

Figure 2. Gas turbine part load performance

Cost and Performance Characteristics

Conventional gas turbines have comparatively low installed costs, lower emissions than internal combustion engines due to the combustion temperatures within the turbine, high exhaust gas temperatures, and are available in a wide range of sizes. Natural gas turbines larger than 5 MW typically have relatively low heat rates and good electrical efficiencies and are typically the CHP technology of choice at capacities equal to or greater than 5 MW. Typically, the heat rate decreases and electrical efficiency increases as the gas turbine gets larger, although this is manufacturer dependant. The financial value of electrical energy is typically greater than the thermal energy in the majority of U.S. utility markets. Therefore, the higher the electrical efficiency, the higher the overall cost savings, and the better the overall system economics.

Table 2 provides the budgetary cost estimates for a gas turbine installation, including the turbine, electrical equipment, fuel system, heat recovery system, construction, and facility enclosure, for three gas turbines.

Table 2. Gas turbine budgetary cost estimate
(March 2010)

Gas Turbine Size (MW)	1.2	3.5	4.6
Cost Per kW	$2,954	$1,093	$1,098

Smaller gas turbines with capacities ranging from 800 kW to 1 MW typically cost as much as three times the cost of a 5 MW turbine on a dollar per kW basis. Significant economies of scale exist at higher capacities, as well as higher electrical efficiencies for larger gas turbines.

A combined heat and power system at the USDA National Animal Disease Center, Ames, Iowa
Photo by Dennis Jones, NREL/PIX 12537

Emissions

Gas turbines are one of the cleanest fossil fuel powered DG technologies. The main pollutants from gas turbines are oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOCs), oxides of sulfur (SO_X) and particulate matter (PM). Larger gas turbines can achieve single digit NO_X emissions at approximately 5 parts per million (ppm) with no post combustion emissions control technologies. Although gas turbines are typically powered by natural gas, they can reduce total GHG emissions by 40 to 60 percent when used in CHP applications to meet the majority of site electrical and thermal loads. This type of DG technology can typically go further to meet agency GHG reduction goals than any other single measure. Typical emissions profiles for a gas turbine with a NO_X rating of 15 ppm are provided in Table 3.[3]

Table 3. Emission characteristics of gas turbine with a NO_X rating of 15 ppm

CO_2 Emission Factor (Tons/MMBtu)	SO_2 Emission Factor (Tons/MMBtu)	N_2O Emission Factor (Tons/MMBtu)
0.05835	0.000207745	0.0000099

In summary, gas turbines are proven technologies that provide a number of potential benefits, including:

- Low NO_X emissions with no post combustion emissions control technologies and significant greenhouse gas savings;
- High-grade waste heat and high overall efficiencies;
- Proven technology; and
- Lower maintenance than an IC engine.

The main disadvantages of gas turbines include:

- Potentially lower electrical efficiencies at capacities less than 5 MW (dependant on manufacturer); and
- Potentially marginal economic returns at smaller capacities.

Case Studies

A variety of onsite CHP projects utilizing gas turbines are operating successfully at a number of laboratory facilities across the country. Three good examples include a Bristol-Myers Squibb laboratory in Wallingford, Connecticut, the Agricultural Research Service (ARS) National Animal Disease Center (NADC) in Ames, Iowa, and the Princeton University system in New Jersey.

Bristol-Myers Squibb Laboratory: A 4.8 MW gas turbine system is operating successfully at the Bristol-Myers Squibb laboratory facility in Wallingford, Connecticut. Despite relatively low energy costs at the site – approximately $0.07 per kWh blended rate – the system has a payback period of just five years. The project team paid close attention to steam loads at the facility and considered the cooling side as well as the heating side. By accounting for all chiller plant loads and other steam-driven equipment, they were able to optimize waste heat utilization year-round for improved system economics. Should utility power be lost, the CHP system with backup generator sets can supply 100 percent of the facility's energy needs. A knowledgeable facility engineer and project manager as well as reliable data have been the keys to success for this installation.

Agricultural Research Service National Animal Disease Center: The ARS NADC in Ames, Iowa, is a major U.S. Department of Agriculture (USDA) center for research on livestock and poultry diseases. A 1.2 MW cogeneration system now provides highly reliable power and helps the NADC control utility costs in several ways. For example, NADC was able to purchase

electricity at less expensive, interruptible rates by generating power on site. Furthermore, the steam generated by combustion process waste heat is a byproduct that can be used year-round for the thermal loads associated with sterilizers, hot water, and wastewater pretreatment. Using the technical resources and expertise of the unregulated subsidiary of the serving utility while designing, installing, and interconnecting the CHP system helped make the project a success. Because capital funds were limited, the project was completed with financing through an energy savings performance contract (ESPC) coordinated by the DOE Federal Energy Management Program (FEMP).

Princeton University: Princeton University renovated a 1923 cogeneration plant in 1996. The new cogeneration plant utilizes a General Electric LM-1600 15 MW gas turbine operating at a heat rate of 9,750 Btu per kWh. The gas turbine system includes inlet cooling for improved power and efficiency, anti-ice heating, dual-fuel firing, and water injection for NO_X reduction. The system also includes a heat recovery steam generator, two steam boilers, 15,000 chiller tons, and a state of the art thermal energy storage system for the chilled water plant.

Princeton University installed this CHP system in 1996. *Photo from Princeton University*

Internal Combustion Engines

Spark ignition internal combustion engines are the most mature power generation technology and have been successfully used as automobile engines for more than 100 years. IC engines are available in sizes ranging from 1 kW to larger than 5 MW and are the dominant CHP technology at capacities below 1 MW. IC engines can be used as an electric power generation technology or in CHP applications. Natural gas fired IC engines are more prevalent than compression ignition diesel generators in continuous operation applications because strict air emissions regulations typically make diesel engines impractical for continuous operation.

IC engine technology is ideally suited for laboratory applications where the medium temperature waste heat can be used to generate low-pressure steam or hot water for onsite heating or process loads. IC engines produce lower temperature waste heat than gas turbines and can be used in low-pressure steam heating applications or tied into hot water distribution systems.

Technology Description

Internal combustion engines operate on the Otto cycle, and four-stroke engines are the most prevalent IC engine technology for stationary power applications. A four-stroke IC engine completes the power cycle in four strokes of the piston within the cylinder – intake, compression, power, and exhaust. In DG applications, the rotary motion of the crankshaft drives the electric generator. Spark ignition IC engines typically have the following general characteristics:

- Installed cost: $900 per kW to $3,000 per kW
- Electrical efficiency: 21.3 to 44 percent
- Exhaust temperature: 850°F to 950°F
- Total CHP efficiency: Up to 70 to 80 percent

The operational efficiency of an IC engine is primarily a function of the following:

- ***Altitude:*** The overall capacity of an IC engine is reduced by approximately four percent per 1,000 feet of altitude above 1,000 feet.
- ***Inlet Air Temperature:*** The overall efficiency of an IC engine is reduced by approximately 1 percent for every 10°F the inlet air temperature is above 77°F. Thus, the colder the inlet air temperature the higher the efficiency of the unit.

- *Part Load Performance:* The overall efficiency of an IC engine is a function of the electrical part load performance of the engine. In general, IC engines have part load performance curves similar to gas turbines.

Cost and Performance Characteristics

Internal combustion engines typically have lower installed costs than gas turbines, higher electrical efficiencies than gas turbines, and good part load efficiencies. A prominent feature of internal combustion engines at lower capacities is the significantly lower heat rates and higher electrical efficiencies – approaching 46 percent. IC engines also start quickly, follow load well, and have high reliability rates.

IC engines typically have slightly lower overall efficiencies than gas turbines based on the quality of the lower grade waste heat. Waste heat can be recovered from the engine jacket water cooling at temperatures around 200°F to 300°F and exhaust gases at around 700°F to 850°F. In general, the waste heat available from IC engines contains about half the energy of the waste heat from gas turbines. This can lead to use in lower grade waste heat applications and smaller absorption chilling applications. IC engines typically provide better economics than gas turbines at capacities below 5 MW.

Table 4 provides the budgetary cost estimates for an IC engine installation, including the engine/genset, electrical equipment, fuel system, heat recovery system, construction, and facility enclosure, for three IC engines.

Table 4. IC engine budgetary cost estimate (March 2010)

Generator Size (MW)	1.8	2.39	3
Cost Per kW	$918	$835	$795

Smaller IC engines have slightly higher installed costs, but the installed costs are not as sensitive to capacity as gas turbines.

Emissions

IC engines have slightly higher GHG emissions than gas turbines due to the combustion temperatures within the IC engine. The main pollutants from IC engines are NO_X, CO, VOCs, SO_X, and PM. A number of post combustion emission control technologies can be applied to reduce the emissions of an IC engine. For example, a selective catalyst reduction (SCR) unit can be used to reduce NO_X emissions to below 15 ppm. An SCR unit injects ammonia into the flue gas, which reacts with NO_X in the presence of a catalyst to produce N_2 and H_2O. SCR requires storage of onsite ammonia, which is considered a hazardous chemical and could trigger internal environmental reviews. Typical emission profiles for an IC engine are provided in Table 5 without post combustion emissions control technologies.[4]

Table 5. Emission characteristics of IC engines

CO_2 Emission Factor (Tons/MMBtu)	SO_2 Emission Factor (Tons/MMBtu)	N_2O Emission Factor (Tons/MMBtu)
0.0584	0.000207745	0.000128

In summary, IC engines are a proven technology that provide a number of potential benefits, including:

- Low first cost and high electrical efficiencies;
- Proven technology; and
- Good economic returns.

The main disadvantages of IC engines include:

- May require post combustion emission control technology, which introduces environmental concerns to achieve the same emissions profile as gas turbines; and
- Higher maintenance costs than gas turbines.

Fuel Cells

Fuel cells are relatively new and considered an emerging DG technology. Fuel cells are available in distributed generation capacities ranging from 1 kW to 3 MW. Fuel cells can be used as an electrical power generation technology or in CHP applications.

Fuel cells are ideally suited for laboratory applications where the medium temperature waste heat can be used to generate low-pressure steam or hot water for onsite heating or process loads. Fuel cells produce lower grade waste heat at temperatures similar to IC engines. The waste heat from fuel cells can be used in low-pressure steam heating applications or tied into hot water distribution systems.

Technology Description

A fuel cell is an electrochemical device that converts fuel energy into electricity. Fuel cells operate on hydrogen and typically utilize an onboard natural gas reformer to convert natural gas into hydrogen. Two electrodes – a cathode and anode – pass charged ions in an electrolyte to generate electricity and heat. The fuel reacts electrochemically and is not combusted, resulting in significantly less emissions than a standard CHP plant. A comparison of fuel cell technologies, their applications, and system output is provided in Table 6.[5]

Table 6. Fuel cell technologies comparison

Fuel Cell Type	Operating Temp	System Output	Efficiency	Applications
Alkaline (AFC)	194°F – 212°F	10 kW – 100 kW	60%	• Military • Space
Phosphoric Acid (PAFC)	302°F – 392°F	50 kW – 1 MW (250 kW module typical)	Greater than 40%	• DG
Polymer Electrolyte Membrane (PEM)	122°F – 212°F	Less than 1 kW – 250 kW	53% – 58% (transp.) 25% – 35% (stationary)	• Backup power • Portable power • Small DG • Transportation • Specialty Vehicles
Molten Carbonate (MCFC)	1,112°F – 1,292°F	Less than 1 kW – 1 MW (250 kW module typical)	45% – 47%	• Electric utility • Large DG
Solid Oxide (SOFC)	1,202°F – 1,832°F	Less than 1 kW – 3 MW	35% – 43%	• Auxiliary power • Electric utility • Large DG

Phosphoric acid (PAFC), polymer electrolyte membrane (PEM), molten carbonate (MCFC) and solid oxide (SOFC) are most applicable to laboratory DG systems. In particular, PAFC and MCFC are some of the most prevalent CHP technologies for 200 kW to 1 MW applications.

Cost and Performance Characteristics

Fuel cells are the most expensive distributed CHP technology on a dollar per kW basis, but produce the lowest emissions of any fossil fuel CHP technology. Fuel cells typically have relatively high electrical efficiencies at greater than 40 percent and overall efficiencies of approximately 65 percent. The general cost and performance characteristics for a representative PAFC and MCFC fuel cell are provided in Table 7.

Table 7. PAFC and MCFC cost and performance characteristics

Characteristics	PAFC	MCFC
Output Power (kW)	400	1,400
Stack Life (yrs)	10	5
System Life (yrs)	20	20
Electrical Efficiency (%)	42%	47%
Overall Efficiency ($)	67%	67%
Capital Costs ($/kW)	$7,000	$4,600
O&M Costs ($/kWh)	0.027*	0.0402*

*Includes stack replacement cost

Emissions

Fuel cells are the cleanest fossil fuel powered distributed generation technology. This is because a fuel cell does not combust the fuel and the fuel subsystem processing system is the only source of emissions. Typical emissions profiles for a fuel cell operating on natural gas are provided in Table 8.[3]

Table 8. Emission characteristics of fuel cell with a NO_X rating of 15 ppm

Fuel Cell Technology	CO_2 Emission Factor (lb/MWh)	SO_2 Emission Factor (lb/MWh)	N_2O Emission Factor (lb/MWh)
PAFC	1,100	0.02	0.02
MCFC	980	0.0001	0.01

In summary, fuel cells provide a number of potential benefits, including:

- Lowest emissions of all CHP technologies; and
- High electrical efficiencies.

The main disadvantages of fuel cells include:

- High first cost and maintenance costs; and
- Higher risk with centralized system liability issues.

Case Studies

Although fuel cells used in stationary power applications are considered an emerging market, there are more than 50 documented case studies available through the U.S. Army Engineer Research and Development Center (ERDC) Fuel Cell website.[5]

COMBINED HEAT AND POWER

A number of design options should be considered when evaluating CHP system feasibility. The three main categories of CHP system modifications are fuel supply, energy storage, and thermally activated cooling technologies.

The most common addition/modification to a CHP plant is the incorporation of thermally activated technologies, such as desiccant dehumidifiers, service water heaters, and absorption chillers. Absorption chillers use heat instead of mechanical energy to provide cooling. The mechanical vapor compressor is replaced by a thermal compressor that consists of an absorber, a generator, a pump, and a throttling device. The two most common refrigerant/absorbent mixtures used in absorption chillers are water/lithium bromide and ammonia/water. Compared to mechanical chillers, absorption chillers have a low coefficient of performance (COP = chiller load/heat input). Nonetheless, they can substantially reduce operating costs because they are energized by low-grade waste heat.

Low-pressure, steam-driven absorption chillers are available in capacities ranging from 100 to 1,500 tons. Absorption chillers come in two commercially available designs – single-effect and double-effect. Single-effect machines provide a thermal COP of 0.7 and require approximately 18 pounds of 15-pounds-per-square-inch-gauge (psig) steam per ton-hour of cooling. Double-effect machines are approximately 40 percent more efficient, but require a higher grade of thermal input using approximately 10 pounds of 100- to 150-psig steam per ton-hour and are only applicable to combustion turbine CHP systems.[8] This type of configuration is common in laboratories that have significant cooling loads.

CHP system waste heat can also be used in heat-powered liquid-desiccant air conditioners to provide independent control of indoor humidity with up to 100 percent of their capacity dedicated to outside air dehumidification. By processing all building ventilation air and exchanging electric load for a waste heat load, these systems reduce peak electrical demand and energy charges, improve occupant comfort, and allow electric air conditioners to run at their most efficient operating points avoiding wasteful reheating.

A number of renewable fuel options are available to power CHP plants, including biogas, renewable methane, and landfill gas. Each fuel option changes the performance and emissions characteristics of the CHP technology and needs to be carefully designed to account for these operational changes. The primary benefit of a renewable fuel is potential cost savings and substantial GHG emissions savings.

Energy storage technologies, such as batteries and flywheels, often complement DG systems. A wide range of energy storage technologies are in development at research organizations throughout the world, but initial costs are traditionally prohibitive in most on-grid applications. As these technologies mature, energy storage systems will become more prevalent in CHP plants.

In addition to the three design considerations presented above, some additional design considerations during the evaluation process include:

Minimize electric loads with energy-efficient equipment and practices before implementing CHP or other forms of onsite generation. This may allow a smaller generator to be specified, minimizing the capital investment required for the DG or CHP project.

Know current utility costs, including energy and demand costs. These rates help determine whether a DG or CHP system will be cost effective. Often, the spark spread between the cost of electricity and the cost of natural gas determines cost effectiveness. However, other impacts, such as power quality and emissions, should also be taken into account. The effect of the project on the facility load profile must be carefully evaluated for savings to be estimated accurately.

Consider anticipated changes in facility energy requirements over the life of the DG or CHP system.

Determine fuel costs and availability at the site. Fuel costs and availability will help decide which DG technologies and applications are most appropriate in the area. Complete a fuel cost sensitivity analysis to see how changes in fuel prices will affect the economics of the proposed system. If possible, consider long-term gas contracts to reduce the volatility of fuel costs over time. High fuel costs combined with low electric rates make many forms of DG uneconomical. In addition, fluctuations in gas pressure, flow, and heating value must be considered concerning fueling DG and CHP systems.

Make the CHP system cost effective by optimizing the amount and use of waste heat. CHP systems are usually sized to accommodate the thermal energy needs of a facility rather than the electricity needs, but this is not a fixed rule. To improve project economics, consider every possible option for using the waste heat, such as space heating and cooling, hot water, chilled water, steam, process needs, and other uses.

Know local air quality requirements as they play an important role in technology selection for a particular DG or CHP application. An air permit may be required to construct, replace, and operate this equipment. Permits can be costly and difficult to obtain if not specified and planned for early in the design process. Additional equipment, operations, and material handling issues also need to be considered in areas where tailpipe treatments are required to meet air quality requirements.

Investigate potential interconnection requirements early in the project evaluation process as they vary from state to state and utility to utility. It can be costly and time-consuming to delay finding out about requirements for interconnecting a DG system to the local electric grid.

Become familiar with utility rate structures. Utilities often have complicated rate structures with fixed charges, demand charges, block charges, and time-of-use rates that can affect the economics of onsite generation. For example, installing a CHP system may allow a facility to purchase energy under interruptible rates. An interruptible rate is a less expensive rate structure that allows the utility to interrupt electric service for a brief time. During that time, facility energy needs would be met by the onsite generation system. On the other hand, potentially expensive backup or standby charges may be imposed if there is a need for electric service when a generator goes down for maintenance or repair. Not all utility rate structures are designed to provide affordable standby power service.

Plan for adequate maintenance. Onsite generation requires additional maintenance. The site should consider a post-installation maintenance contract that ensures seamless operation and maintenance of the new equipment while providing training for onsite staff to maintain equipment in the future if no trained, onsite maintenance staff currently exist.

Biomass Heat and Power

Biomass is widely used for facility heating and, to a lesser extent, for electric power generation and combined heat and power. Biomass encompasses a large variety of materials, including wood, agricultural residues, and waste products. Municipal solid waste and landfill gas are often considered biomass. This section, however, focuses on woody biomass.

Technology Description

Biomass heating systems typically include a fuel storage, handling, and feed system; burner or gasifier (plus boiler for hydronic systems); heat distribution system; ash handling and removal; emissions controls; operations controls and notification system; and a backup heating system.

A fossil fuel backup system is typically recommended. In larger systems, the backup boiler is integrated into the biomass system controls, which can automatically turn on the backup boiler when the load is not being met by the biomass system. This allows the biomass system to be undersized. Having a properly sized backup system reduces capital costs of the biomass system, improves operating efficiency, and reduces uncertainties due to fuel supply disruptions or system mechanical issues.

Woody biomass is common for facility heating across three forms – whole logs/firewood, wood chips, and wood pellets. Chips or pellets are typically used for power generation or CHP.

Biomass heat and power can be divided into three main phases:

1. Resource procurement (harvesting, collecting, transporting, and delivery of the biomass);
2. Storage, processing, and conveyance; and
3. Conversion to energy (burning or gasifying to produce heat or to drive a steam turbine, gas turbine, or internal combustion engine).

Direct combustion is the most common method of biomass heating and CHP. In a direct combustion system, biomass is burned to generate hot gas, which is either used directly to provide heat or fed into a boiler to generate hot water or steam. In a boiler system, the steam can be used to provide process or space heating and a steam turbine can be used to generate electricity. The biomass can also be gasified and burned for heat. In a power generation application, the biogas can also be used to fuel an IC engine or gas turbine.

The two principle direct combustion biomass boiler systems are fixed-bed (stoker) and fluidized-bed systems. In a fixed-bed system, biomass is fed onto a grate where it combusts as air passes through the fuel. This releases hot flue gases into the heat exchanger to generate steam. A fluidized-bed system feeds biomass into a hot bed of suspended, incombustible particles, such as sand, where the biomass combusts to release hot flue gases. Fluidized-bed systems produce a more complete combustion of the feedstock, resulting in reduced emissions and improved system efficiency. Compared to fixed-bed systems, fluidized-bed boilers can also utilize a wider range of feedstocks.

Cost and Performance Characteristics

The efficiency of biomass gasification or direct combustion systems is influenced by a number of factors, including feedstock moisture content, amount and distribution of combustion air, operating temperatures and pressure, and flue gas temperatures. A typical biomass system operating on fuel with a moisture content of 40 percent has a net efficiency of approximately 60 to 65 percent.

Biomass heating plants have average installed costs of $260,000 per million Btu (MMBtu) per hour. The cost of fuel and labor make up a majority of operations and maintenance (O&M) costs A well-operated and maintained

University of Iowa uses local biomass feedstock in this power plant. *Photo from University of Iowa, NREL/PIX 19255*

wood chip fired heating system typically requires two to five hours of O&M per week during the heating season. This includes fuel ordering and a daily walkthrough inspection. Equipment maintenance supplies cost $500 to $1,000 per year. Additional maintenance costs include removing wood onsite and loading the hopper from a larger storage area. This handling can cost approximately $2,000 per year for a medium chip system.

The type of system best suited to a particular application depends on many factors, including feedstock cost and availability, competing fuel costs, thermal peak and annual load, building size and type, space availability, O&M staff availability, and local emissions regulations.

For buildings/campuses with more than 100,000 square feet in a moderately cold climate, a wood chip system is typically the best option assuming a stable feedstock supply. The economics are even more favorable with buildings that require year-round hot water or steam, or systems that compete against high-priced fossil fuels.

A wood pellet system is typically the best option for buildings with less than 10,000 square feet in a moderately cold climate. These systems can be loaded manually with 40-pound bags of pellets, but larger systems typically have bulk delivery systems (not bagged) where bulk delivery is available. These systems use a pellet silo or bunker to store large quantities of pellets, which are automatically conveyed from the silo to the pellet stove, pellet furnace, or pellet boiler.

Cordwood systems are another option for smaller buildings. The best of these have a burner surrounded by a large water jacket. Cordwood is loaded in batches and burned at full fire, which heats the water. The hot water acts as a thermal energy storage medium and is circulated through the building space as demanded by the thermostat. Cordwood heaters do not generally include fuel storage and handling. The fuel must be loaded by an operator, making these systems very labor intensive.

Some cordwood systems reduce burn rate by throttling combustion air, but this results in low efficiency and very high emissions of particulate matter and unburned hydrocarbons. These systems are not recommended, and are illegal in many jurisdictions.

Most biomass power generation facilities in the U.S. are combustion/steam turbine systems. These systems have a conversion efficiency of 15 to 35 percent depending on system size and operating parameters. A steam CHP system can reach system efficiency of up to 85 percent. Installed costs range from $1,700 to $3,500 per kW and typically produce energy at a cost of $0.06 to $0.20 per kWh.

Table 9. Air emissions for a typical biomass heating system (lbs/green ton)

	PM10	NOX	VOC	CO
Typical Biomass System Emissions	2.1	2.8	0.6	1.7

Emissions

Biomass emissions depend on the system size, design, and fuel characteristics. Table 9 shows typical emissions for a biomass heating system operating on 40 percent moisture content pine. If necessary, emissions control systems can be used to reduce PM and NO_X. Sulfur emissions depend on the sulfur content of the biomass, which is typically very low.

Forests sequester carbon as a natural byproduct of tree growth. Through photosynthesis, trees remove carbon from the atmosphere and store it in wood. If dead trees are left in a forest, they generally decompose and produce large quantities of carbon dioxide and methane, which are significant GHGs. When a tree is cut, only that aboveground portion is typically removed, leaving the carbon in the belowground material untouched. To calculate GHGs, the wood mass of a tree is divided between aboveground mass (approximately 64 percent) and belowground biomass (approximately 36 percent). Because of these two factors, biomass is considered either GHG neutral or negative, meaning that using biomass to produce energy and offsetting fossil fuel use reduces the amount of GHGs entering the atmosphere.

Case Study

The University of Iowa power plant uses a local biomass feedstock in its circulating fluidized-bed boiler that saves hundreds of thousands of dollars in fuel costs each year.[7] The system uses oat hulls and other fuel sources to operate a CHP system on campus.

Photovoltaic Systems

Photovoltaics (PV) are semiconductor devices that convert sunlight directly into electricity. They do so without any moving parts and without generating any noise or pollution. They must be mounted in areas with no shade. Rooftops, carports, and ground-mounted arrays are common mounting locations.

Technology Description

The amount of energy produced by a PV panel depends on several factors. These factors include sunlight levels, the type of collector, the tilt and azimuth of the collector, and temperature and weather conditions. An inverter is

required to convert the direct current (DC) to alternating current (AC) of the desired voltage compatible with building and utility power systems. The remaining system components include conductors/conduit, switches, disconnects, and fuses. Grid-connected PV systems feed power into the facility's electrical system and do not include batteries. Figure 3 shows the major components of a grid-connected PV system and illustrates how these components are interconnected in a grid-connected PV system.

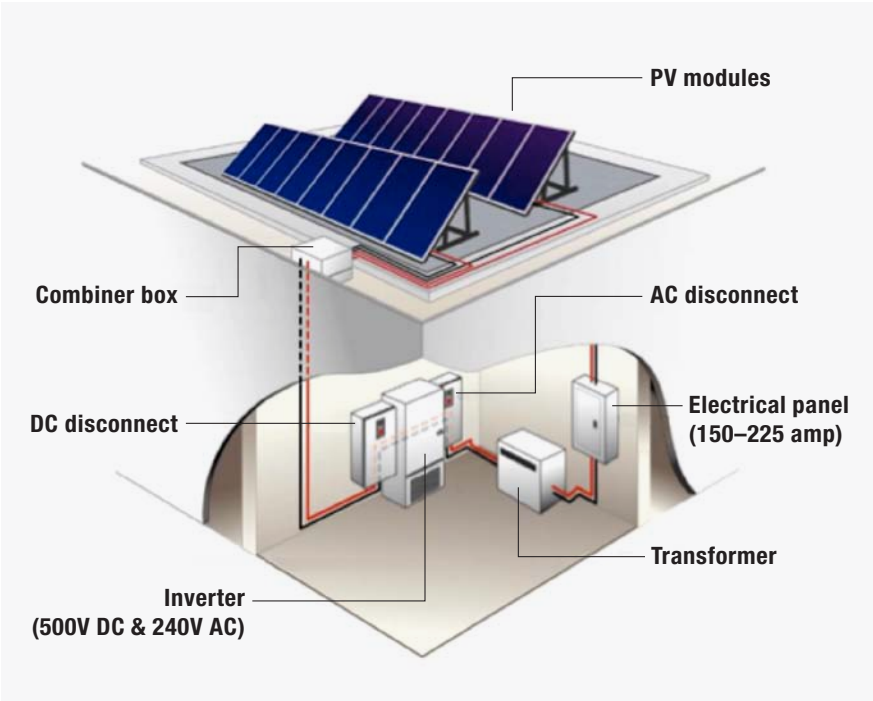

Figure 3. Depiction of major components of grid-connected PV systems

PV panels are very sensitive to shading. When shade falls on a panel, that portion of the panel is no longer able to collect the high-energy beam radiation from the sun. PV panels are made up of many individual cells that all produce a small amount of current and voltage. These individual cells are connected in series to produce a larger current. If an individual cell is shaded, it will act as resistance to the whole series circuit, impeding current flow and dissipating power rather than producing it.

If a site is found to have good potential for a PV system, the next step is to determine the size of that system. This is highly dependent on the average energy use of the site. It is generally not advisable to provide more energy than the site will use due to the economics of most net metering agreements.

Types of Photovoltaic Systems

PV systems typically fall under ground-mounted or roof-mounted categories.

Ground-mounted PV systems are usually the lowest cost option to install on a dollar per DC-Watt (W) basis. There are several mounting options available, each having different benefits for different ground conditions. Table 10 outlines energy density values that can be expected from each of the different system types.

To get the most out of available ground area, consider whether the site layout can be improved to incorporate a PV system better. The unshaded area can be increased to incorporate more PV panels if there are unused structures, fences, or electrical poles that can be removed. When considering a ground-mounted system, an electrical tie-in location should be identified to determine how the energy would be fed back into the grid. Fixed tilt systems are installed at a specified tilt, and are fixed at that tilt for the life of the system. Single axis tracking systems have a fixed tilt on one axis, and a variable tilt on the other axis. The system is designed to follow that sun in its path through the sky. This allows the solar radiation to strike the panel at an optimum angle for a larger part of the day than can be achieved with a fixed axis system. A single axis tracking system can collect up to 30 percent more electricity per capacity than a fixed tilt system. The drawbacks include increased O&M costs, less capacity per unit area (DC-W per square foot), and greater installed cost (dollar per DC-W).

Roof-mounted PV systems are usually more expensive than ground-mounted systems, but roofs are a convenient location because they are out of the way and usually unshaded. Large areas with minimal rooftop

Table 10. Power density by panel and system for ground mounted PV

System Type	Fixed Tilt Power Density (DC-W/ft2)	Single Axis Tracking Power Density (DC-W/ft2)
Crystalline Silicon	4	3.3
Thin Film	3.3	2.7
Hybrid High Efficiency	4.8	3.9

equipment are preferred, but equipment can sometimes be worked around if necessary. If a building has a sloped roof, flush-mounted installations can achieve power densities of 11 DC-W per square foot when installing a typical crystalline silicon panel. If the roof of the building is flat, rack-mounted systems can achieve power densities of 8 DC-W per square foot for a crystalline silicon panel. Typically, PV systems are installed on roofs that are less than five years old or on roofs with more than 30 years left before replacement.

Cost and Performance Characteristics

The PV systems considered here has the following components:

PV Array: The primary component of a PV system, the PV array, converts sunlight to electrical energy. All other components simply condition or control energy use. Most PV arrays consist of interconnected PV modules that range in size from 50 to 300 peak DC-W. Peak Watts are the rated output of PV modules at standard operating conditions of 77°F and insolation of 1,000 W per square meter. Because these standard operating conditions are nearly ideal, the actual output will be less under typical environmental conditions. PV modules are the most reliable components in any PV system. They are engineered to withstand extreme temperatures, severe winds, and impacts. *ASTM E 1038-93* subjects modules to impacts from one-inch hail at terminal velocity (55 mph) at various parts of the module. PV modules have a life expectancy of 25 to 30 years and manufacturers typically guarantee them to produce at least 80 percent power in 25 years.

NREL implemented this PV system on its S&TF through a power purchase agreement. *Photo by Brent Nelson, NREL/PIX 17091*

The array is also usually the most expensive component of a PV system. It accounts for approximately two-thirds the cost of a grid-connected system. Several manufacturer choices exist, but it is recommended that the PV array be approved by Go Solar California[9] and that the system undergo a competitive bid process.

Inverters: PV arrays provide DC power at a voltage that depends on the configuration of the array. This power is converted to AC power at the required voltage and number of phases by the inverter. Inverters enable the operation of commonly used equipment, such as appliances, computers, office equipment, and motors. Current inverter technology provides true sine wave power at a quality often better than that of the serving utility. A location for the inverter along with the balance of the system equipment should be considered.

Inverters are available that include most or all of the control systems required for operation, including some metering and data-logging capabilities. Inverters must provide several operational and safety functions for interconnection with the utility system. The Institute of Electrical and Electronics Engineers (IEEE) maintains standard *P929 Recommended Practice for Utility Interface of Photovoltaic Systems*, which allows manufacturers to write "Utility-Interactive" on the listing label if an inverter meets the requirements of frequency and voltage limits, power quality, and non-islanding inverter testing. Underwriters Laboratory (UL) maintains *UL Standard 1741, Standard for Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*, which incorporates the testing required by *IEEE 929* and includes design (type) testing and production testing. Several manufacturer choices exist, but it is recommended that the inverter be approved by Go Solar California and that the system undergo a competitive bid process.

Operation and Maintenance: PV panels come with a 25-year performance warranty. Inverters come standard with a five- or 10-year warranty, with extended warranties available, and should be expected to last 10 to 15 years. System performance should be verified on a vendor provided website. Wire and rack connections should be checked. For economic analysis, an annual

O&M cost of $12.50 per DC-kW is typically used for fixed axis grid tied PV systems. For the case of single axis tracking, an annual O&M cost of $20 per DC-kW should be used based on existing single axis tracking system O&M.

Photovoltaic Size and Performance

PV arrays must be installed in unshaded locations on the ground or on building roofs that have an expected life of at least 25 years. The predicted array performance can be found using PVWATTS Version 1,[10] a performance calculator for grid-connected PV systems created by the NREL Renewable Resources Data Center. A table of 2009 installed cost estimates by state and system size is provided in Table 11.[11]

Case Study

PV systems have been installed on many laboratory buildings. One example is the NREL Science and Technology Facility (S&TF).[12] The NREL S&TF was designed to be solar ready by orienting the building facing south and leaving large, flat, open roof areas for solar. The roof was designed for the three pounds per square foot load of the future PV system. NREL did not have the budget to include a PV system as part of the original construction, so it added a 94 kW grid-connected roof-mounted PV system under a power purchase agreement (PPA).

Wind Energy

Wind turbines turn wind into electricity. The amount of wind at a particular site varies with the season, time of day, and weather events. Collected wind data focuses on two primary considerations – average annual wind speed and a frequency distribution of the wind at various speeds. The wind speed at any given time determines the amount of power available in the wind, and subsequently the power that can be captured using a wind turbine generator.

Cost and Performance Characteristics

Wind power production varies significantly from one site to another. For feasibility and scoping studies, NREL publishes wind energy resource maps of the U.S.[13]

Evaluating the economic feasibility for wind turbine installation involves assessing the site's wind resource,

Table 11. PV system installed costs (2009)

State	All Reported Years Capacity-Weighted Average Cost (All Sizes)*		2009 Systems									
			Capacity-Weighted Average Cost (All Sizes)*		0 – 10 kW DC*		10 – 100 kW DC*		100 – 500 kW DC*		More Than 500 kW DC*	
AZ	$7.2	(n=3330)	$7.1	(n=2048)	$7.2	(n=1858)	$6.9	(n=187)	*	(n=3)	*	(n=0)
CA	$7.7	(n=58991)	$7.6	(n=15376)	$8.1	(n=13882)	$7.5	(n=1326)	$8.1	(n=106)	$7.2	(n=62)
CT	$7.9	(n=946)	$7.6	(n=306)	$8.3	(n=226)	$8.1	(n=61)	$7.3	(n=19)	*	(n=0)
FL	$7.5	(n=577)	$7.5	(n=575)	$7.6	(n=536)	$7.3	(n=38)	*	(n=0)	*	(n=1)
MA	$8.1	(n=1990)	$7.4	(n=860)	$8.4	(n=740)	$8.0	(n=92)	$6.8	(n=26)	*	(n=2)
MD	$9.0	(n=546)	$8.6	(n=316)	$8.8	(n=307)	$8.4	(n=9)	*	(n=0)	*	(n=0)
MN	$9.1	(n=198)	$9.3	(n=54)	$9.6	(n=49)	$9.6	(n=5)	*	(n=0)	*	(n=0)
NH	$7.6	(n=189)	$7.5	(n=157)	$7.9	(n=157)	*	(n=0)	*	(n=0)	*	(n=0)
NJ	$7.7	(n=4634)	$7.4	(n=1292)	$8.1	(n=964)	$7.9	(n=253)	$7.5	(n=62)	$7.2	(n=13)
NV	$8.7	(n=499)	$8.2	(n=183)	$8.8	(n=167)	$8.8	(n=16)	*	(n=0)	*	(n=0)
NY	$8.7	(n=1990)	$8.4	(n=779)	$8.6	(n=654)	$8.3	(n=125)	*	(n=0)	*	(n=0)
OR	$7.9	(n=1321)	$7.3	(n=473)	$8.0	(n=385)	$7.7	(n=76)	$6.9	(n=11)	*	(n=1)
PA	$7.9	(n=536)	$7.4	(n=372)	$7.7	(n=305)	$7.4	(n=66)	*	(n=1)	*	(n=0)
TX	$7.0	(n=1226)	$6.7	(n=459)	$7.1	(n=406)	$6.4	(n=51)	*	(n=2)	*	(n=0)
VT	$8.4	(n=365)	$7.9	(n=139)	$8.3	(n=134)	$7.2	(n=5)	*	(n=0)	*	(n=0)
WI	$8.7	(n=614)	$8.6	(n=264)	$8.8	(n=225)	$8.6	(n=39)	*	(n=0)	*	(n=0)

*n = number of systems included in averages

selecting and collecting cost and performance data on suitable wind turbine models, estimating the wind turbine energy production, reviewing integration requirements, and researching available incentives and net metering policies. The first step of the process is to determine the local wind resource and size of the turbine that would be appropriate for the specific application. This is determined by looking at several critical siting parameters, including:

- ***Wind Resource Exposure:*** An exposed ridge or hill is better than flat land or a valley.
- ***Good Fetch in the Primary Wind Directions:*** Fetch is an unobstructed pathway for wind. Good fetch includes no tall trees, buildings, cities, cliffs, etc.
- ***Proximity to Existing Roads:*** Sites with paved or improved gravel roads in reasonable condition close to the available land will have lower construction costs.
- ***Distance to Homes:*** Avoiding negative impacts to neighbors, such as shadow flicker and sound, is a necessary component of gaining local support. Adequate distance reduces the potential impact of these issues.
- ***Potential Radar Impacts:*** Proximity to Federal Aviation Administration (FAA) radar and airport runways, Department of Defense (DOD) flight operations and radar, and the Next-Generation Weather Radar Program (NEXRAD) are roadblocks to wind turbine deployment.
- ***Turbine Size and/or Height Limitations:*** Some sites may have height constraints due to potential radar interference.
- ***Onsite Electric Energy Use:*** Depending on specific state ordinances and interconnection requirements, the wind turbine should be sized to maximize energy capture while limiting the excess energy sent to the local power company.
- ***Electric Infrastructure:*** Unless it is used specifically for an off-grid application, a wind turbine must be connected to a local electric utility service, which may have specific limitations, such as distribution carrying capacity, phase, and voltage.

Once a site has demonstrated potential for wind energy applications, an onsite anemometer is typically installed to measure wind speeds at a number of heights over a one- to two-year period. This information is used to determine applicable turbine sizes. A specific turbine or several potential size options must be considered. This process is addressed in the *Wind Turbine Buying Guide*[14] by small wind industry expert Mick Sagrillo. Currently, small wind turbines can be tested to standards adopted by the International Electrotechnical Commission (IEC) and in compliance with the draft American Wind Energy Association (AWEA) standards for small wind turbine systems.[15] These standards ensure turbines are designed to proper safety levels and that performance is verified independently. As part of a separate process, the resulting test data may be used by the Small Wind Certification Council,[16] a recently organized nonprofit organization formed with support from DOE, AWEA, state energy offices, and turbine manufacturers to certify small wind turbine systems. Small wind turbines that are tested and certified give consumers greater confidence that the installed systems will perform within specified wind regimes as advertised by the manufacturer.

The current installed cost for large (1.5 MW and larger) turbines on large wind farms ranges from approximately $1,800 to $2,000 per kW. Smaller projects (a few mid-scale turbines) are more expensive, ranging from $3,000 and $5,000 per kW depending on mobilization costs, distance to transmission, and electrical infrastructure costs for the installation. Small, residential-scale wind turbines are more expensive, ranging from $4,000 to $7,000 per kW. Generally, the installed cost-per-kilowatt increases the smaller the wind turbine.

Wind turbines at the National Wind Technology Center at NREL pull double duty – generating power while serving as a test bed for essential research. *Photo by Patrick Corkery, NREL/PIX 17691*

Operation and Maintenance:

Wind turbines have an expected life of 30 years depending on the level of preventative maintenance. For small projects (one-to-five turbines), the approximate annual O&M cost is dependent on turbine size:

- 100kW: $3,000 to $4,000 per year
- 400kW/600kW: $10,000 to $13,000 per year

- 1.5 MW and larger: $40,000 to $60,000 per year for integrated service

Integrated service is broad reaching service performed by factory technicians, covering all O&M costs except major failures such as gearbox or large bearing failures. The $50,000 per year estimate is comprised of a $20,000 to $25,000 per year fixed cost and an escalating cost depending on energy production of approximately $0.005 per kWh.

Due to the wide variety of factors needing evaluation in siting wind turbines, energy managers are encouraged to analyze wind resource using NREL wind resource maps in addition to contacting a wind energy consultant to perform a feasibility assessment if the site has a good wind resource and meets the siting criteria on the previous page.

Interconnection Standards

Interconnection standards specify the technical and procedural process by which a customer connects a system that generates electricity to the grid. While providing uniform processes and requirements for connecting to the electric utility grid and ensuring safety, standard interconnection rules encourage DG by reducing inherit uncertainty.

Interconnection standards cover the technical and contractual arrangements by which system owners and utilities must abide. State public utility commissions typically establish standards for interconnection to the distribution grid, while the Federal Energy Regulatory Commission (FERC) has adopted standards for interconnection at the transmission level. Many states have adopted interconnection standards, but some state standards apply only to investor-owned utilities and not to municipal utilities or electric cooperatives. Several states have adopted interconnection guidelines, which are weaker than standards and generally only apply to net-metered systems. A listing of interconnection standards by state is provided in Figure 4.[17]

More than 40 states have interconnection standards, some of which have no limit on system capacity while others limit the system size to as low as 25 kW. These state interconnection requirements ensure interconnection costs are the same throughout the state and are commensurate with the nature, size, and scope of the DG project. They also help DG project developers accurately predict the time and costs involved in the application process as well as the technical requirements for interconnection. Finally, standard rules ensure that the project interconnection meets safety and reliability needs of both the energy end-user and the utility. If a state sets artificially low interconnection limits, it makes interconnection of a larger DG system difficult and adds additional administrative costs to the overall installed costs.

Net Metering Agreements

For electric customers generating their own electricity, net metering enables electricity flow to and from the customer – typically through a single, bi-directional meter. When customer generation exceeds customer use, electricity flows back to the grid, offsetting electricity consumed by the customer at a different time during the same billing cycle. In effect, the customer uses excess

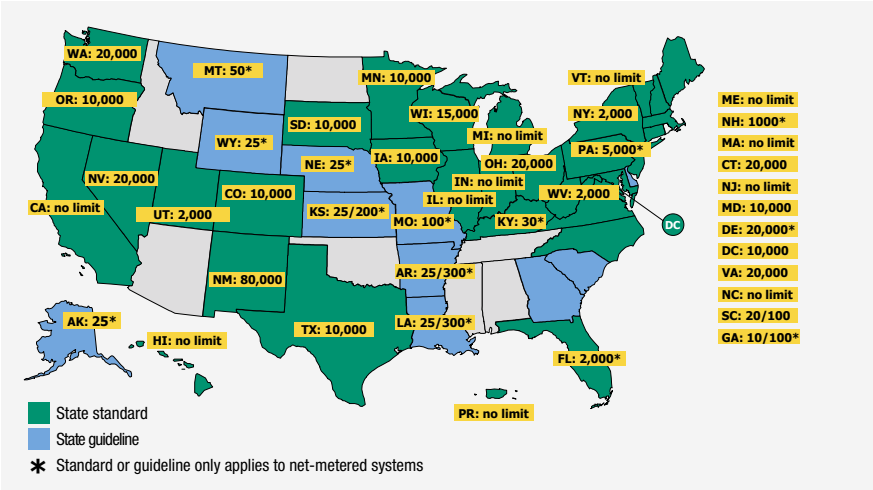

Figure 4. State interconnection standards (DSIRE, June 2011)

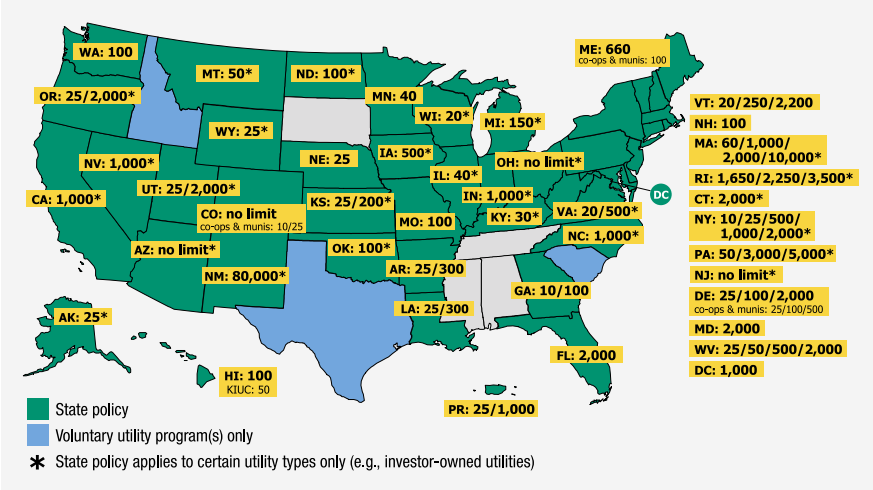

Figure 5. State net metering standards

generation to offset electricity that the customer otherwise would have to purchase at the full retail rate. Net metering is required by law in most U.S. states, but these policies vary widely. A listing of the net metering policies by state is provided in Figure 5.[18]

These net metering agreements have the potential to affect the economics of onsite DG systems. For example, the net metering agreement in Wyoming is set to 25 kW. As a result, if a customer installs a DG systems larger than 25 kW, the local utility is not required to pay the customer for excess electricity beyond the 25 kW limit. This significantly affects the economics of a large PV array that produces more electricity during sunlit hours than the facility is consuming because the site will not receive an economic incentive for this electricity production.

Codes and Standards

In general, DG and CHP system installations are subject to the same permitting and evaluation process as other site or facility modifications. The National Electric Code; the National Life-Safety Code; and the International Fuel Gas, Plumbing, Mechanical, Building, and Fire Codes are the references for local code officials. These codes do not address some of the newer DG technologies, such as micro turbines and fuel cells. In addition, most code officials have little or no experience with issuing permits for such installations. Therefore, code officials may require a number of design, test, and documentation reviews before approving a DG system.

Several standards authored by UL, IEEE, and the National Fire Protection Association (NFPA) specifically address the installation of DG and CHP systems:

- *UL 2200* is commonly cited for combustion engines and gas turbines in stationary power applications. It does not specifically refer to micro turbines, but that technology could be considered as included.
- *NFPA 853, Standard for the Installation of Fuel Cells*, covers the design, construction, and installation of fuel cell power plants larger than 50 kW. It covers natural gas and a number of other fuel sources.
- *NFPA 3, Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*, works in conjunction with *UL 2200* to apply the installation and operation of CHP technologies. Like *UL 2200*, *NFPA 3* can be extended to micro turbines.
- *IEEE 1547, Standard for Distributed Resources Interconnected with Electric Power Systems*, addresses technical requirements for the safe interconnection of DG systems to local electric distribution systems.

Federal, State, and Local Incentives

The Database of State Incentives for Renewables and Efficiency (DSIRE)[18] summarizes available incentives by state. While state and local incentives vary by utility provider, numerous federal incentives are available. In addition to tax credits and exemptions, federal grant and loan programs, depreciation deductions, and the Renewable Energy Production Incentive (REPI) are available to facilitate implementation and offset costs of renewable energy projects. The federal Business Energy Investment Tax Credit (ITC), for example, provides a 30 percent tax credit for PV, fuel cell, wind, and biomass systems; a 10 percent tax credit for CHP and micro turbines; and a seven-year accelerated depreciation schedule. In some cases, additional utility and local incentives cover 30 to 50 percent of the total installed costs and have a significant impact on DG system economics. Federal and utility incentives can also be the main determinant for DG project lifecycle cost effectiveness.

ONSITE DISTRIBUTED GENERATION SYSTEM COST EFFECTIVENESS

Several simple indicators can be used to evaluate if a distributed generation or combined heat and power system will be cost effective at a particular site, including:

- Electricity prices are high, typically more than $0.10 per kWh, or when most of the facility's annual energy costs go to demand charges.
- The ratio of average electric load to peak load is greater than 0.7.
- A central or district heating and/or cooling system is already in place, or there is a need for process heat, typically hot water or steam.
- The spark spread is greater than $12 per MMBtu. The spark spread is specific to CHP systems and compares the difference in price per MMBtu between gas and electricity.
- The CHP system will operate more than 6,000 hours per year.
- Thermal energy is required throughout the year.
- High quality, reliable power is mission-critical.
- Existing equipment, such as boilers, chillers, or backup/standby generators, are old, inefficient, and need to be replaced.
- New facilities are in early design stages.
- The facility has GHG goals and is located in a region where grid electricity has a high GHG content.[17]

Financing Options for the Federal Sector

Projects reaching the financing and contracting point in the process have typically been proven cost effective through the initial screening process and project team deliberations. Unless direct funding is designated for the project, the financing process can be a complex decision.

If no direct funding is available, financing options must be considered. Before choosing an available financing option, the site should review options presented in this guide and contact a financing specialist to discuss project specifics and confirm financing mechanism appropriateness. Additional financing information is provided in the resources section. The financing options considered in this guide include:

Agency/Site Funding

In an agency- or site-funded project, funding has been designated for the outright purchase of a system. The site owns the system, its energy production, and all attributes of the system – including the renewable energy certificates (RECs). The main advantage of this financing mechanism is that it is well understood. It does not incur additional financing costs and is a common financing option for most agencies and laboratory sites. This mechanism also has the potential to provide the greatest cost savings over the life of the project.

The disadvantages of agency-funded projects include:

- The site is responsible for O&M arrangements, such as PV inverter replacement, but can purchase an O&M service contract.
- There is no assurance of long-term performance. The agency can purchase optional long-term performance guarantees that differ from a manufacturer's warranty.
- The agency may not be able to monetize available tax incentives.

The main disadvantage of this approach is that government agencies do not typically have the ability to monetize available tax incentives. For renewable energy projects, tax incentives can cover 30 to 50 percent of the total project cost.

Power Purchase Agreements

Power purchase agreements (PPAs) have been used to finance distributed generation projects since 2003 and are now driving most commercial solar installations. Under a PPA, a private entity – typically a group of developers, construction companies, and finance companies – installs, owns, operates, and maintains customer-sited, behind the meter DG equipment. The site purchases electricity or thermal energy through a long-term contract with specified energy prices. Payment is based on actual energy generated from the DG equipment and consumed by the site.

So far, PPAs have primarily been applied to electricity purchases, but there is no reason why a PPA could not be used to purchase thermal energy as well. Note that some of the obstacles to PPAs, such as their legality in certain states, do not apply to thermal projects because thermal energy is not regulated in the same manner as electricity production.

The primary advantages of PPAs include:

- The developer is eligible for tax incentives and accelerated depreciation, which could lead to reduced energy costs.
- The agency/site is not required to provide upfront capital.
- The developer provides O&M for the duration of the contract. The site has limited O&M responsibilities.
- The agency/site typically receives a known long-term electricity or thermal energy price for a portion of the site load, which reduces the price risk of fluctuating utility energy prices.
- The developer has incentives to maximize production by the system.
- The agency/site can potentially use available funds for a front-end buy down to get a better PPA price or a larger system.

The disadvantages of PPAs include:

- Transaction costs include a significant learning curve and time investment.
- PPA utility contracts are often limited. DOD has 2922A authority, which permits 30-year terms.
- Site-access issues can be complex.
- Management and ownership structures can be complex.

Energy Savings Performance Contracts

Energy savings performance contracts (ESPC) have a long history in the federal sector for energy efficiency projects. ESPCs are starting to be used by the private sector as well, and are increasingly being seen as a long-term financing method for DG projects. An ESPC is a guaranteed savings contract that requires no upfront cost. An energy service company (ESCO) incurs the cost of implementing a range of energy conservation measures (ECMs), which can include DG, and is paid from the energy, water, and operations savings resulting from these ECMs. The ESCO and the agency negotiate to decide who maintains the ECMs. Payments to the contractor cannot exceed savings in any one year.

KEY QUESTIONS FOR PROJECT TEAMS

Project teams must continually ask questions to ensure projects are designed, implemented, and executed to meet their needs. These questions cover the following areas:

Pre-Design: As facility managers progress through the evaluation of onsite DG system options, they should find out if other facilities in their area have installed onsite generation. Find the contact person at each facility and ask what lessons have been learned, including:

- Are the distributed generation systems functioning as expected?
- What is the actual payback using measured performance data and O&M costs?
- What lessons were learned throughout the project?
- What would they have done differently?

Investigating opportunities for onsite generation can involve many different specialists or contracting firms. For example, an engineering firm is usually hired to perform the initial scoping study. Design engineering documents are put together by a qualified architectural/engineering firm. A construction firm or general contractor is typically responsible for building the system. Many utilities also support CHP projects, offer valuable expertise, and may even offer incentives.

Energy managers are encouraged to follow the general five-step process outlined on the NREL Climate Neutral Research Campus site[17] when evaluating an onsite distributed generation system.

Selecting Consultants: When selecting a contractor to design and install the onsite generation system, be sure to ask the following questions:

- How many DG or CHP systems have you designed and installed? What types of technologies and what system sizes have you worked with?
- Will you be able to secure all necessary permits and interconnection studies for this project?
- Have you ever experienced problems with interconnecting DG or CHP systems to the grid? Were they showstoppers? If not, how did you solve them?
- Who will be responsible for system maintenance?

Sites are encouraged to develop and compete a request for proposal (RFP) to select an appropriate developer. Review criteria should also be developed that includes the questions listed above in addition to:

- Installed cost (dollar per kW);
- Annual O&M cost (dollar per kW);
- Equipment warranty (in years); and
- Parts and service warranty (in years).

Multiple contracting options are available to sites interested in an ESPC. DOE offers an indefinite delivery, indefinite quantity (IDIQ) contract designed to make ESPCs as cost effective and easy to implement as possible. Sixteen prequalified ESCOs have accepted the terms of the IDIQ contract and can respond to project requests. The U.S. Army also has an IDIQ contract in place as an alternative to the DOE option. Additional information is available in the resources section.

Utility Energy Service Contracts

Utility energy service contracts (UESC), like ESPCs, have a history of use in the federal sector for energy efficiency projects. These contracts are also seen as a method of long-term financing with a typically added benefit of being a sole source contract. A UESC is an agreement that allows a serving utility to provide an agency with comprehensive energy and water efficiency improvements and demand-reduction services. The utility could partner with an ESCO to provide the installation, but the contract is between the agency and the serving utility. The UESC process is well defined, but utilities might describe them differently. Additional information is available in the resources section.

Enhanced Use Leases

In the federal sector, enhanced use leases (EULs) have a history of being used to implement infrastructure-building projects. They are also being used for DG projects, particularly solar and wind projects. An EUL is a real estate agreement that focuses on underutilized land. Prospective developers compete for the lease, and payment can be either monetary or in-kind consideration, such as renewable power. The value of the lease is used to determine the amount of the consideration. An EUL typically is used for large projects, for example, those having a capacity greater than the site load. Few agencies have the authority to execute EULs, including DOD, DOE, the National Aeronautics and Space Administration (NASA), and the U.S. Department of Veterans Affairs (VA).

Conclusion

Installing an onsite DG or CHP system can be a good way to trim utility costs, reduce GHG emissions, and enhance energy reliability at laboratory facilities. Numerous siting, permitting, and interconnection issues can be involved. However, these issues do not need to be barriers for laboratories that want to control costs, reduce environmental emissions, enhance fuel efficiency, and ensure reliable heat and power for sensitive equipment and important research projects. The information presented in this guide walks laboratory energy managers through the process of evaluating and implementing DG and CHP systems.

Resources

The following resources are presented to provide laboratories additional information on key distributed generation and combined heat and power topics as outlined in this guide.

DG and CHP

- DOE FEMP: *Using Distributed Energy Resources: A How-To Guide for Federal Facility Managers*, *www.eere.energy.gov/femp/pdfs/31570.pdf*
- NREL: Climate Neutral Research Campuses, *www.nrel.gov/applying_technologies/climate_neutral/*
- EPA: Combined Heat and Power Partnership, *www.epa.gov/chp/*
- DOE Industrial Technologies Program (ITP): Industrial Distributed Energy, *www.eere.energy.gov/industry/distributedenergy/*
- American Council for an Energy-Efficient Economy, *Combined Heat and Power*, *www.aceee.org/topics/chp/*

Biomass

- NREL: *Renewable Fuel Heating Plant*, *www.nrel.gov/sustainable_nrel/pdfs/42649.pdf*
- NREL: *Performance Assessment of a Desiccant Cooling System in a CHP Application Incorporating an IC Engine*, *www.nrel.gov/docs/fy05osti/36974.pdf*
- DOE Office of Energy Efficiency and Renewable Energy (EERE): Biomass, *www.eere.energy.gov/topics/biomass.html*
- DOE Biomass Program, *www.eere.energy.gov/biomass/*
- EPA: Biomass CHP, *www.epa.gov/chp/basic/renewable.html*
- Colorado Governor's Energy office: *Evaluating and Implementing Biomass Heating*, *http://rechargecolorado.com/images/uploads/pdfs/Cashing_Chips.pdf*

Photovoltaic

- NREL: *Solar Ready Buildings Planning Guide*, *www.nrel.gov/docs/fy10osti/46078.pdf*
- NREL: The Open PV Project, *http://openpv.nrel.gov/*
- DOE Solar Energy Technologies Program (SETP), *www.eere.energy.gov/solar/*
- DOE SETP: Procuring Solar for Federal Facilities, *www.eere.energy.gov/solar/federal_guide/*
- NREL: PV System Applications for Laboratories, *www.nrel.gov/applying_technologies/climate_neutral/photovoltaics.html*
- DOE FEMP: Renewable Energy Resources, *www.eere.energy.gov/femp/technologies/renewable_energy.html*

Wind Energy

- NREL: Wind Energy, *www.nrel.gov/applying_technologies/climate_neutral/wind_energy.html*
- DOE Wind and Hydro Program, *www.eere.energy.gov/windandhydro/*
- American Wind Energy Association, *www.awea.org/*

Fuel Cells

- DOE Hydrogen and Fuel Cells Program, *www.eere.energy.gov/hydrogenandfuelcells/*
- U.S. Army: ERDC-CERL Fuel Cell, *http://dodfuelcell.cecer.army.mil/index.php*
- Energy Power Research Institute, *www.epri.com*
- Fuel Cells 2000, *www.fuelcells.org/*
- Fuel Cell Today, *www.fuelcelltoday.com/*

Financing Mechanisms

- DOE FEMP: Alternative Financing, *www.eere.energy.gov/femp/financing/mechanisms.html*
- DOE FEMP: Training Opportunities, *www.eere.energy.gov/femp/services/training.html*
- DOE FEMP: Energy Savings Performance Contracts, *www.eere.energy.gov/femp/financing/espcs.html*
- DOE FEMP: Utility Energy Service Contracts, *www.eere.energy.gov/femp/financing/uescs.html*
- DOE FEMP: Power Purchase Agreements, *www.eere.energy.gov/femp/financing/power_purchase_agreements.html*

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4. DOE Hydrogen Program: *www.eere.energy.gov/hydrogenandfuelcells/pdfs/doe_h2_fuelcell_factsheet.pdf* (February 2011)
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7. University of Iowa: *www.facilities.uiowa.edu/ec/docs%5CBiomass ProjectDescription.pdf* (February 2011)
8. NREL: *www.nrel.gov/docs/fy06osti/39316.pdf* (February 2011)
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11. Lawrence Berkeley National Laboratory: *http://eetd.lbl.gov/ea/emp/reports/lbnl-4121e.pdf* (February 2011)
12. Labs21: *www.labs21century.gov/pdf/cs_nrel_508.pdf*
13. NREL: *www.nrel.gov/gis/wind.html* (February 2011)
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16. Small Wind Certification Council: *www.smallwindcertification.org* (February 2011)
17. NREL: *www.nrel.gov/applying_technologies/climate_neutral/* (February 2011)
18. DSIRE: *www.dsireusa.org*

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