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Distributed Generation and Demand-Side Management

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5.1 Distributed Generation Technologies

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5.1.1 Introduction

Distributed generation (DG) can be defined as a source of electric power connected to a distribution network or a customer site, representing an innovative and efficient way to both generate and deliver electricity, since it generates electricity right where it is going to be used. Technological improvements now allow power generation systems to be built in smaller sizes with high efficiency, low cost, and minimal environmental impact.

Distributed generation can serve as a supplement to electricity generated by huge power plants and delivered through the electric grid. Located at a customer's site, DG can be used to manage energy service needs or help meet increasingly rigorous requirements for power quality (PQ) and reliability.

Distributed generation has the potential to provide site-specific reliability improvement, as well as transmission and distribution (T&D) benefits including: shorter and less extensive outages, lower reserve margin requirements, improved PQ, reduced lines losses, reactive power control, mitigation of transmission and distribution congestion, and increased system capacity with reduced T&D investment. Distributed generation also provides economic benefits because DG technologies are modular and provide location flexibility and redundancy as well as short lead times. Economic benefits can also be gained by using DG technologies for peak-shaving purposes, for combined heat and power (CHP) (cogeneration), and for standby power applications. In addition, many DG technologies provide environmental benefits including reduced land requirements, lower or no environmental emissions, and lower environmental compliance costs.

Distributed generation technologies can be divided into two different categories according to availability: firm and intermittent power. The firm power technologies are those that enable the power control of DG units that can be managed as a function of the load requirements. Firm DG plants can be utilized as backup, working only in situations of grid unavailability, in periods of high consumption (when the electricity is more expensive), working continuously, or dispatched to meet the variable load in an optimal manner.

The intermittent power technologies do not allow the management of the produced energy by themselves having a random generation character. Examples of this kind of technology are wind power or solar power that only produces energy when the wind or the sun is available. These technologies can be installed aggregated with energy storage that, by filtering the energy generation fluctuation, enables the management of the delivered energy by the combined system.

In DG applications, traditional technologies can be used, such as internal combustion engines, gas turbines, and, in large installations, steam turbines and combined-cycle turbines. Other kinds of technologies such as microturbines, Stirling engines, fuel cells, or renewable energies, including solar power, geothermal power, or wind power can also be utilized (Figure 5.1).

5.1.2 Gas Turbines

Gas turbines are an often-used electricity production technology. The first studies of gas utilization to actuate turbines started at the end of the nineteenth century; however, the first efficient gas turbines started to operate in 1930. A gas turbine consists of a compressor, a combustion chamber, and a turbine

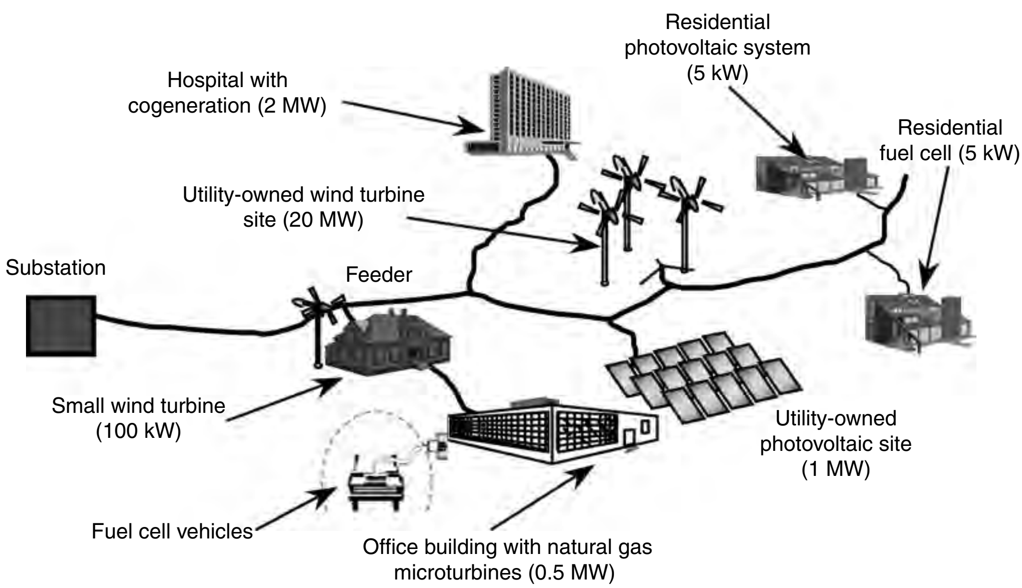


FIGURE 5.1 Power system with multiple energy sources. 1: air intake section; 2: compression section; 3: combustion section; 4: turbine section; 5: exhaust section; 6: exhaust diffuser.

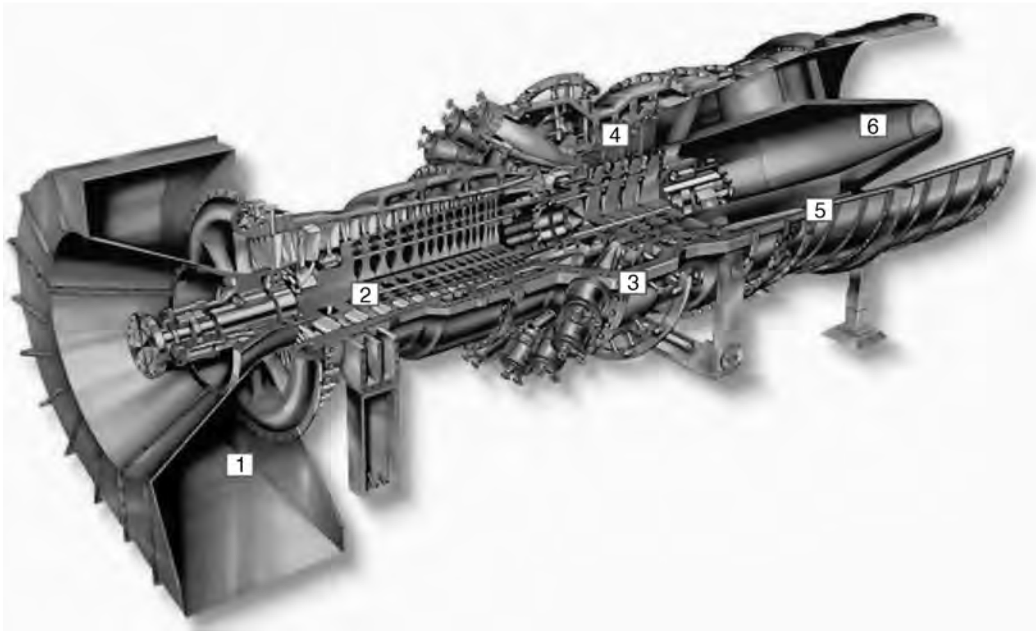


FIGURE 5.2 Combustion turbine. (From Siemens Corp., http://www.siemens.com. With permission.)

coupled to the generator. The turbines with only one axis have all the pieces associated with a continuous axis, all rotating at the same speed. This kind of architecture is used when variations in the turbine speed are not foreseeable. The rotor that drives the generator can be mechanically separated from the rotor driven by the combustion of gases, with more flexibility in the operation speed.

In contrast to internal combustion engines, the gas turbines work in continuous process and not in a repetition of a sequence of different operations. However, the operation can be viewed as a set of four stages similar to the four strokes of the internal combustion engines (Figure 5.2).

1. A compressor drives a rotor that directs the work fluid (air) to the combustion chamber, where the air is compressed, increasing the pressure up to 10 bar and the temperature to 300°C.
2. The compressed air is mixed with the burning fuel, achieving temperatures of 1250°C. This combustion occurs with controlled conditions to maximize the fuel efficiency and minimize the emissions.
3. The air, at high pressure, is passed through the turbine that converts the air energy into mechanical energy. Part of this energy is transmitted to the compressor and the remnant is used for electricity generation through a generator.
4. The exhaust gases are released to the atmosphere, or may be used for generation of process heat or to increase the electricity generated as described below.

Because gas turbines produce a large volume of exhaust gases at high temperatures, the energy of these gases can be utilized for steam production for industrial processes (cogeneration mode) or for electricity production through combined cycle.

In a combined cycle, the gas turbine is used as the first cycle, where the exhaust gases of the gas turbine are used to produce steam in a heat-recovery steam generator. This steam is then used to drive a steam turbine, increasing the electrical global efficiency of the system to values up to 60%.

In the Cheng cycle, the steam is injected in the expansion chamber of the gas turbine (superheated steam injection). In the expansion chamber, the steam is mixed with the gases of the combustion that expand and produce additional work, thereby increasing the electrical efficiency.

TABLE 5.1 General Characteristic of Gas Turbines

Commercial availability	High
Size range	0.5–250 MW
Fuel	Natural gas, biogas, oil derivatives
Efficiency	25%–45%
Environmental emissions	Very low when controls are used, high noise

In cogeneration appliances, the exhaust gases can be used to heat water for residential buildings or for steam production for industrial processes, etc. In some industrial applications of cogeneration, a global efficiency of 60% is reached.

The conversion of mechanical energy to electricity is made almost always through synchronous generators. In DG applications, the rotation speed of the turbines can be higher than the generator synchronous speed which requires a gearbox, reducing the conversion efficiency by about 3%. The generator also works as an auxiliary engine to start the turbine.

Natural gas is the fuel that enables the best efficiency in gas turbines. However, gas turbines can work with other fuels, like fuel oil, diesel, propane, J-5 (used in aeronautics), kerosene, methane, and biogas. The heavy oil utilization decreases the efficiency and the power of the turbine by 5%–8%. Because heavy oil is less expensive, it can decrease the electricity production costs, but the emissions are higher than with other fuels.

The gas turbine generators are available in a wide power range, corresponding at three types of generators:

- Microturbines (20–500 kW)
- Medium turbines (500–10,000 kW)
- Large turbines (more than 10 MW).

These generators use gas turbines with the same working principle, but with different configurations and operation characteristics. The large turbines are not normally considered DG. Table 5.1 shows the general characteristics of gas turbines.

5.1.3 Microturbines

Microturbines are small combustion turbines that produce between 25 and 500 kW of power. Microturbines were derived from turbocharger technologies found in large trucks or in the turbines found in aircraft auxiliary power units. Only the largest class of gas turbine generators, those made for central station utility application, are designed specifically for electric power production. In recent years, due to the new market requirements, microturbines have undergone significant innovations, enabling the energy production with high quality and reliability, with low greenhouse gases emissions, and with moderate costs, thus becoming a competitive technology.

Microturbines have the same working principle as the gas turbines, with various modifications in the system configuration. One of the innovations consists in the adoption of a unique shaft, on which the compressor, the turbine, and the generator are assembled (Figure 5.3). These systems eliminate the gearbox, reducing the cost, and increasing the reliability, but with a reduced overall efficiency.

The rotor rotates at a very high speed (up to 100,000 rpm). Another innovation is utilization of air bearings, avoiding the need of a fluid for refrigeration and lubrication, because the unique utilized element is the air. The air can be continuously renovated and will never be contaminated by the materials wastage and by the combustion products.

One of the key characteristics of the microturbines is heat recovery, which utilizes the thermal energy of the exhaust gases (at high temperatures) for preheating the air supply to the compressor. The mechanical energy is converted to electrical energy by a permanent magnet AC generator, which includes a low inertia rotor rotating at the turbine speed.

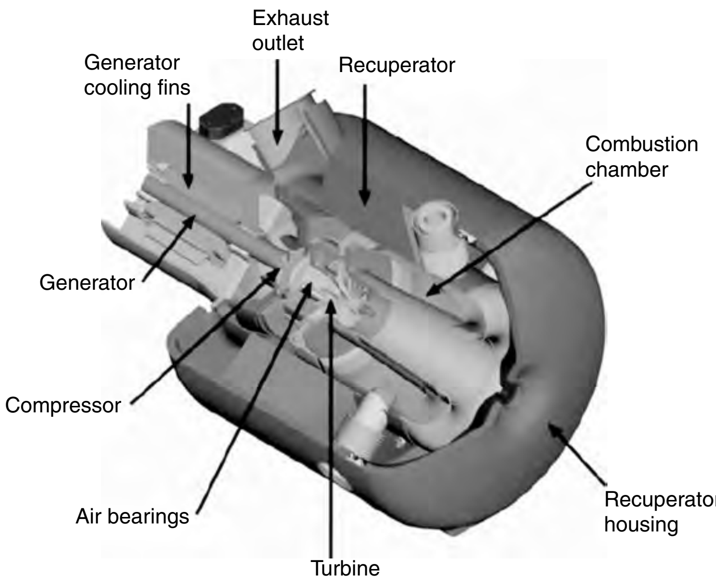


FIGURE 5.3 Microturbine. (From http://www.capstone.com. With permission.)

Because of the high rotor speed, the AC output has a frequency of approximately 2 kHz. To connect the microturbine generator with a 50 or 60 Hz network in normal applications, the microturbine voltage output must be connected to an AC–DC–AC converter. In this converter, microturbine voltage output is rectified, filtered, and converted to an AC voltage through an inverter system synchronized with the 50 or 60 Hz supply.

Microturbines can also operate with a wide variety of fuels, like natural gas (at high or low pressure), propane, diesel, gasoline, biogas (methane), or kerosene. The electrical efficiency of microturbines is between 20 and 30%, with heat-recovery utilization. If the heat recovery does not exist, this value can decrease to 15%. In cogeneration systems, the global efficiency can reach 85% (Table 5.2).

Microturbine generators can be divided into two general classes:

- Heat-recovery microturbines recover heat from the exhaust gas to boost the temperature of the air stream supplied to the combustion and increase the efficiency. Further exhaust heat recovery can be used in a cogeneration configuration.
- Microturbines, without heat recovery (or simple cycle) have lower efficiencies, but also have lower capital costs.

Other applications of microturbine technology include:

- Core power conversion element of vehicles, such as buses, trucks, helicopters, and so on. Automotive companies are interested in microturbines to provide a lightweight and efficient fuel-based energy source for hybrid electric vehicles.

TABLE 5.2 Microturbines Overview

	Yes (only a few manufacturers)
Size range	25–500 kW
Fuel	Natural gas, hydrogen, propane, diesel
Efficiency	20%–30% (recuperated)
Environmental emissions	Low ($<$9–50 ppm) NO_x
Other features	Cogeneration (50°C–80°C water)
Commercial status	Medium volume production

- Standby power, PQ, peak-shaving, and cogeneration applications. Some types of microturbines are well suited for small commercial building establishments such as: restaurants, hotels, small offices, retail stores, and many others.
- Utilization of by-products of processes in oil-processing, gas-transferring, petroleum production, industrial waste utilization for the purpose of optimizing the use of natural gas, associated gas, biogas, landfill gas, etc.

The improvement of microturbine design, resulting in lower costs and higher performance, makes microturbines a competitive DG product.

Development is ongoing in a variety of areas:

- Heat recovery/cogeneration
- Use of waste heat for absorption cooling
- Increase of the efficiency
- Fuel flexibility
- Vehicles
- Hybrid systems (e.g., fuel cell/microturbine, flywheel/microturbine)

5.1.4 Internal Combustion Engines

Internal combustion (IC) engines were one of the first technologies that used fossil fuels for electricity generation. Developed more than a century ago, IC engines are the most common of all DG technologies. They are available from sizes of a few kilowatts for residential backup generation to generators on the order of 10 MW.

An IC engine uses the thermal energy of fuel combustion to move a piston inside a cylinder, converting the linear motion of the piston to rotary motion of a crankshaft and uses that rotation to turn an AC electric generator. Internal combustion engines are also called *reciprocating engines* because of the reciprocating linear motion of the pistons.

Internal combustion engines can be fueled with gasoline, natural gas, diesel fuel, heavy oil, biodiesel, or biogas. The two primary types of IC engines used for DG applications are:

- Four-cycle spark-ignited engines (Otto cycle) that use an electrical spark introduced into the cylinder. This explosion engine, or ignition by spark, that uses the Otto cycle was invented by Nikolaus August Otto in 1867. Fast-burning fuels, like gasoline and natural gas, are commonly used in these engines. Biofuels, such as alcohols and biogas, may also be used.
- In 1892, Rudolph Diesel, developed the diesel engine, in which the combustion is initiated by compression. The compression-ignited (diesel cycle) engines, in which compression of the fuel–air mixture inside the piston cylinder rises it to a temperature where it spontaneously ignites, work best with slow-burning fuels such as diesel. Biofuels, such as biodiesel, vegetable oils, etc., may also be used.

Distributed generation engines have efficiencies that range from 25 to 45% (Table 5.3). In general, diesel engines are more efficient than Otto engines because they operate at higher compression ratios. In the future, engine manufacturers are targeting lower fuel consumption and shaft efficiencies up to 50%–55% in large engines (greater than 1 MW) by 2010. Efficiencies of Otto engines using natural gas are expected to improve and approach those of diesel engines.

Internal combustion engine generators for distributed power applications, commonly called *gensets*, are found universally in sizes from less than 5 kW to over 10 MW. Gensets are frequently used as a backup power supply in residential, commercial, and industrial applications. When used in combination with a 1–5 min uninterruptible power supply (UPS), the system is able to supply seamless power during a utility outage. In addition, large IC engine generators may be used as base-load generation, grid support,

TABLE 5.3 Internal Combustion (IC) Engines Overview

Commercially Available	Yes
Size range	0.005–10 MW
Fuel	Natural gas, diesel, heavy fuel, biogas
Efficiency	25%–45%
Environmental	Emission controls required for NO_x and CO
Other features	Cogeneration (some models)
Commercial status	Widely available

or peak-shaving devices. Internal combustion engine generators have start-up times ranging between 0.5 and 15 min, and a high tolerance for frequent starts and stops. The smaller engines, available in sizes as small as a few kilowatts, are intended for dispersed applications, such as individual homes and small businesses coping with power outages.

5.1.5 Stirling Engines

Stirling engines (Figure 5.4) are a class of reciprocating piston engines and are classed as external combustion engines, invented in 1816 by Robert Stirling. They constitute an efficient thermodynamic machine for the direct conversion of heat into mechanical work with a theoretical efficiency of 40%. Stirling engines were commonly used prior to beginning of the twentieth century. As steam engines improved and the competing compact Otto cycle engine was invented, Stirling engines lost favor. Recent developments in DG and solar thermal power have revived interest in Stirling engines. As a result, research and development efforts in this area have increased in recent years. The principles of Stirling engines are described in another chapter and will not be covered here.

The operation is reversible, i.e., by supplying thermal energy, mechanical energy is produced, and by supplying mechanical energy, thermal energy is produced. Stirling engines can be fueled by any source of

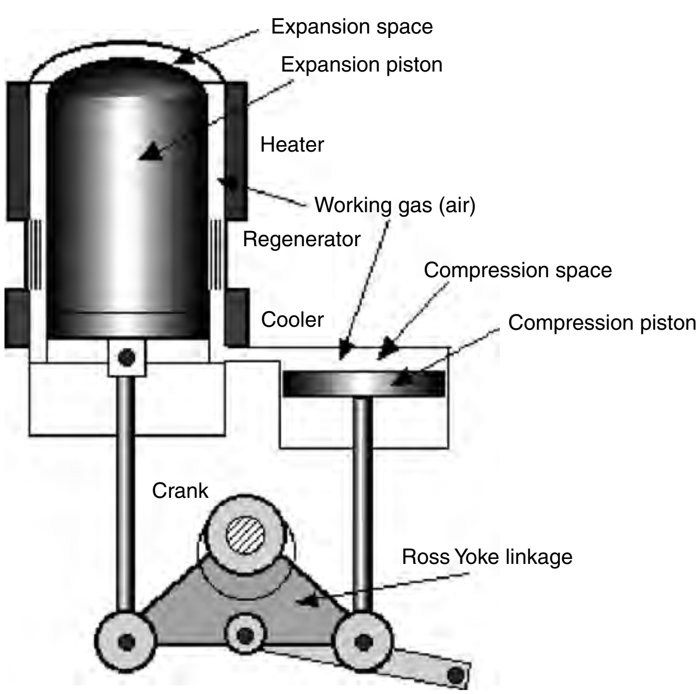


FIGURE 5.4 Stirling engine. (From http://www.ent.ohiou.edu/~urieli/stirling/engines/engines.html)

TABLE 5.4 Stirling Engine Overview

Commercially available	On a limited scale
Size range	<1–25 kW
Fuel	Fuel flexibility—fossil or renewable heat is possible
Efficiency	12%–30%
Environmental	Potential for low emissions
Other features	Cogeneration (some models)
Commercial status	Availability for specialized applications

heat (fossil fuel or renewable) and some models have possibilities to perform cogeneration. In a Stirling engine, the continuous combustion process, which is easier to optimize and control, results in lower emissions compared to the intermittent explosions of fuel air mixtures in IC Otto and diesel engines.

Stirling engines are commercially available for some marine applications and have been available for several years. Trials in domestic CHP are occurring in several countries, on the scale of hundreds of units. Usually Stirling engines are found in sizes from 1 to 25 kW and are currently being produced in small quantities for specialized applications (Table 5.4).

Large 25-kW Stirling motors have an electrical efficiency of approximately 30%, although the goal is to increase this efficiency to greater than 34% with more development. Stirling engines are ideally suited for solar thermal power. Using a gas as an operating fluid, there is no practical limit placed on the solar unit's upper temperature due to its operating fluid. Maximum temperature would be limited only by the materials used in its construction.

Recent Stirling engine developments have been directed at a wide range of applications, including:

- Small scale: residential or portable power generation.
- Solar dish applications: heat reflected from concentrating dish reflectors is used to drive the Stirling engine; several research programs are aimed at enhancing this application.
- Vehicles: auto manufacturers have investigated utilizing Stirling engines in vehicles to improve the fuel economy.
- Refrigeration: Stirling engines are being developed to provide cooling for applications, such as microprocessors and superconductors.
- Aircraft: Stirling engines could provide a quieter-operating engine for small aircraft.
- Space: Power generation units aboard space ships and vehicles.

The primary challenges faced by Stirling engines over the last two decades have been their long-term durability/reliability and their relatively high cost.

5.1.6 Fuel Cells

Fuel cells are a technology for power generation that is quiet and highly efficient with no moving parts. Fuel cells generate electricity through an electrochemical process in which the energy stored in a fuel is converted directly into DC electricity and thermal energy. The chemical energy normally comes from hydrogen contained in various types of fuels (hydrocarbon fuels, such as natural gas, methanol, ethanol, biogas, etc.), including pure hydrogen. Fuel cells are described in detail in another chapter.

Several hundred phosphoric acid fuel cell (PAFC) demonstration and test plants have been built in the mid-1990s to early twenty-first century, mostly with 200-kW capacity appropriate for DG applications, in many commercial buildings to provide premium PQ for demanding loads. The operating temperature is about 200°C, which is suitable for cogeneration applications in buildings and in small industrial plants. They do not offer opportunity of self-reforming and they require platinum for their catalyst. PAFCs' efficiency and peak output capability deteriorate by about 2% per year.

One of the most promising developments is the design of hybrid systems. Solid oxide fuel cells (SOFCs) promise top efficiency, particularly in a combined cycle operation mode, in which they can surpass conventional combined-cycle gas turbine plants. High efficiencies under part-load operation also result in high overall efficiency.

For applications in industrial heat-power cogeneration and public electricity supply, high-temperature fuel cells (SOFCs and molten carbonate fuel cells [MCFCs]) are most suitable. Both systems are still in an early stage of development, but permit the use of a wide range of fuels. Such fuel cell systems compete in the lower rating range with gas turbines and motor cogeneration plants, and in the upper rating range with combined gas and steam turbine power plants. Conventional plants have a clear advantage in terms of practical experience and in terms of comparatively low capital costs compared with fuel cell plants. High-temperature fuel cells are likely to gain market penetration due to a decrease in specific need for primary fuels and also due to a sharp decrease of specific pollutant emissions in comparison to conventional generation. This last factor is a key advantage in DG applications in urban areas.

5.1.7 Solar Photovoltaic

Photovoltaic (PV) cells, or solar cells, convert sunlight directly into electricity. Photovoltaic technology has several applications, including:

- Off-grid/remote
- Grid attached residential and commercial buildings
- Remote communication systems
- Central power plants (above 1 MW)

Traditionally, PV cells have been used to power structures such as individual homes in locations where it is expensive or impossible to send electricity through power lines. Solar power has traditionally been used in remote areas where the grid is not available; such systems store electricity in batteries for use when the sun is not shining and are called *stand-alone power systems*. Currently, PV-generated power is less expensive than conventional power where the load is small and the area is too difficult to serve by electric utilities. However, solar power is now appearing more in urban areas due to innovative policy mechanisms (rebates, feed-in tariffs) to promote PV generation. Here, the surplus solar electricity is injected into the grid. These are called *grid-connected solar systems* because the owner has the security of the grid available.

In the decade 1995–2004, average annual growth has been 20% with global sales reaching over 1000 MW per year at the end of that period. Photovoltaic is the most modular and operationally simple of the clean, distributed power technologies, with benefits that include the ability to provide power during summer peak periods, distribution congestion benefits, environmental benefits, reduced fuel price risk, and local economic development. As a result of private and government research, PV systems are becoming more efficient and affordable.

Distributed PV systems that provide electricity at the point of use are reaching widespread commercialization. Chief among these distributed applications are PV power systems for individual buildings. Interest in the building integration of photovoltaics, where the PV elements actually become an integral part of the building, often serving as the facade or exterior weather skin, is growing worldwide. Photovoltaic specialists and innovative designers in Europe, Japan, and in the U.S. are now exploring creative ways of incorporating solar electricity into their work. A building integrated photovoltaics (BIPV) system consists of integrating photovoltaics modules into the building envelope, such as the roof or the façade (Figure 5.5). By simultaneously serving as building envelope material and power generator, BIPV systems can provide savings in materials and in electricity costs.

Photovoltaics may be integrated into many different assemblies within a building envelope:

- Incorporated into the façade of a building, complementing or replacing traditional glass.
- Incorporated in the external layers of the wall of a building façade.

FIGURE 5.5 Building integrated photovoltaics in a façade and in a roof.

- Use in roofing systems providing a direct replacement for different types of roofing material.
- Incorporated in skylight systems in which part of the solar light is transmitted to the inside of the building and the other part is converted into electricity.

5.1.8 Wind Power

Wind energy became a significant research area in the 1970s during the energy crisis and the resulting search for potential renewable energy sources. Modern wind turbine technology has made significant advances over the last 25 years. Today, wind-power technology is available as a mature, environmentally sound, and convenient alternative. Generally, individual wind turbines are grouped into wind farms containing several turbines. Many wind farms are megawatt scale, ranging from 1 MW to tens of megawatts. Wind turbines may be connected directly to utility distribution systems. The larger wind farms are often connected to transmission lines.

The land can still be used for animal grazing and some agriculture operations. The small-scale wind farms and individual units are typically defined as DG. Residential systems (1–15 kW) are available (Figure 5.6). However, they are generally not suitable for urban or small-lot suburban homes due to large space requirements.

FIGURE 5.6 Building-integrated wind power. (From http://www.oksolar.com/wind/. With permission.)

Utility-scale turbines range in size from 50 to 5000 kW. Single, small turbines, below 50 kW, are used for homes, telecommunications stations, or for water pumping. A detailed description of wind-power technology is given in a different chapter.

5.1.9 Cogeneration

Combined heat and power, also known as *cogeneration*, is an efficient, clean, and reliable approach to producing both electricity and usable thermal energy (heating and/or cooling) at high efficiency and near the point of use, from a single fuel source. Because CHP is highly efficient, it reduces traditional air pollutants and carbon dioxide emissions, the leading greenhouse gas associated with climate change.

Combined heat and power can use a variety of technologies to meet an energy users needs. The range of technologies available allows the design of cogeneration facilities to meet specific onsite heat and electrical requirements. Combined heat and power systems consist of a number of individual components—prime mover, generator, heat recovery, and electrical interconnection—configured into an integrated system. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system.

Typical CHP prime movers include:

- Combustion turbines
- Reciprocating engines
- Boilers with steam turbines
- Microturbines
- Fuel cells

Combined heat and power may be used in a variety of applications ranging from small 10-kW systems to very large utility-scale applications approaching 1000 MW. The first step in assessing which CHP application is right for a particular facility is to identify whether there is coincident demand of electrical and thermal energy at the host site. The CHP project will be most economically viable when the system

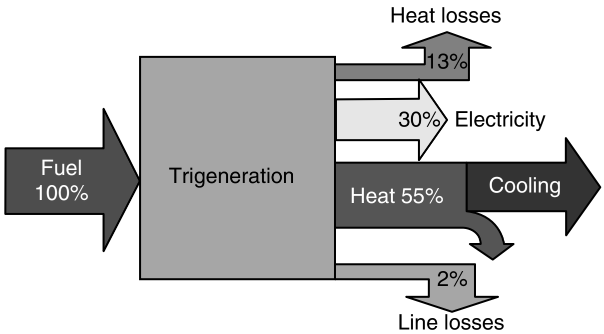


FIGURE 5.7 Trigeneration technology.

provides the maximum amount of energy that can be used. Therefore, CHP project development begins with an analysis of site electrical and thermal load profiles. Based on these profiles, the type of CHP technology which most closely matches the facility's power and demand will be chosen.

In developed countries, about 10% of all electricity is generated in CHP plants, leading to huge primary energy savings and reduction of emissions. Combined heat and power in some industries, such as the pulp and paper industry, uses biomass by-product as fuel input.

Trigeneration can provide even greater efficiency than cogeneration. Trigeneration is the conversion of a single fuel source into three useful energy products: electricity, steam or hot water, and chilled water (Figure 5.7). Trigeneration converts and distributes up to 90% of the energy contained in the fuel burned in a turbine or engine into usable energy. Introducing an absorption chiller into a cogeneration system means that the site is able to increase the operational hours of the plant with an increased utilization of heat, particularly in summer periods. Trigeneration has been applied with very positive results in buildings such as hotels and hospitals, which feature a large space conditioning load during most of the year.

5.1.10 Vehicle-to-Grid

Electric-drive vehicles (EDVs) include battery electric vehicles, hybrid vehicles, and fuel cell vehicles running on gasoline, natural gas, or hydrogen. These vehicles have gained attention in the past few years due to growing public concerns about urban air pollution and other environmental and resource problems. All these vehicles have within them power electronics that generate AC power at power levels from 10 to 100 kW; this power, with suitable electronics, can be fed into the electric grid (Figure 5.8). It allows such vehicles to use their installed power to help balance load in localized grid segments during peak load periods. This concept of bidirectional grid interface is known as *vehicle-to-grid power* or V2G. Sharing power assets between transportation and power generation functions can accelerate commercialization of battery electric vehicles, hybrid vehicles, and fuel cell vehicles.

These vehicles can be recharged during off-peak hours at cheaper rates while helping to absorb excess nighttime generation. There is a potential to supply extra power during peak demand if electric-drive vehicles are grid-connected to allow discharge from their batteries, or run their onboard generators.

To work in vehicle-to-grid power systems, each vehicle must have three required elements:

- A connection to the grid for electrical energy flow.
- Control or logical connection necessary for communication with the grid operator.
- Controls and metering onboard the vehicle.

For fueled vehicles (fuel cell and hybrid), a fourth element, a connection for gaseous fuel (natural gas or hydrogen), could be added so that onboard fuel is not depleted.

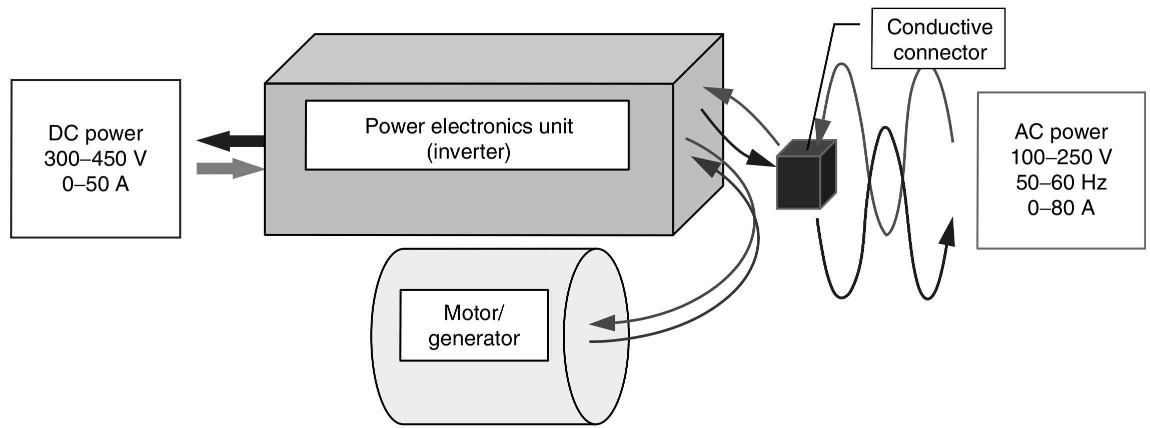


FIGURE 5.8 Vehicle-to-grid enabling technology. (From AC Propulsion. Vehicle-to-grid demonstration project: Grid regulation ancillary service with a battery electric vehicle (December 3–10, 2002, http://www.acpropulsion.com/reports/V2G%20Final%20Report%20R5.pdf. With permission.)

Vehicles with significant energy stored in batteries could perform as uninterruptible power systems for whole houses and support the grid exceptionally well by providing any of a number of functions known collectively as *ancillary services*. These services are vital to the smooth and efficient operation of the power grid. These vehicles could provide:

- Extra power during demand peaks
- Spinning reserve
- Grid regulation (automatic generation control (AGC))
- Uninterruptible power source for businesses and homes
- Active stability control of transmission lines

Hybrid vehicles with IC engines show the potential for power generation at specific emissions levels in some cases better than the best new large power plants. A continuous source of fuel for hybrid or fuel cell vehicles can be provided with a connection to low-pressure natural gas or biogas at compatible parking locations. Over just a decade or two, V2G could revolutionize the ancillary services market, improve grid stability and reliability, and support increased generation from intermittent renewables.

One conceptual barrier is an initial belief that their power would be unpredictable or unavailable because the vehicles would be on the road. Although availability of any one vehicle is unpredictable, the availability of an average number of vehicles is highly predictable and can be estimated from traffic and road-use data.

From the societal point of view, the large-scale application of V2G can lead to a much more cost-effective allocation of resources to provide highly reliable electricity to a wide range of resources.

5.1.11 Conclusions

The utilization of DG technologies enables the creation of a power system with multiple energy sources, allowing the integration conventional central power plants with dispersed DG fossil fuel-based generation, as well as with dispersed DG renewable generation. It is anticipated that DG growth and its large-scale application may lead to an improvement in reliability, to improved security of supply, to the decrease of power costs, and to the minimization of environmental impacts. In Figure 5.9 and Table 5.5, a characterization of the most important DG technologies is presented showing typical parameters associated with each technology.

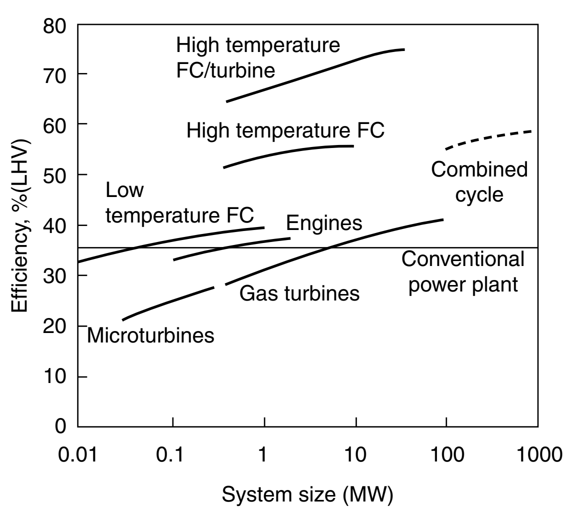


FIGURE 5.9 Distributed generation technologies comparative efficiency range.

TABLE 5.5 Distributed Generation (DG) Technologies Characterization

	Internal Combustion Engines	Gas Turbines	Microturbines	Fuel Cell	Wind Power	Photovoltaic (PV)	Stirling Engine
Power range (kW)	5–50,000	500–250,000	20–500	1–10,000	0.3–5000	0.07–1000	Up to 25
Electric efficiency (%) (LHV)	25–45	25–45	20–30	30–70	25–40	5–15	12–30
Efficiency with partial load	Reasonable until 35%–40% of the rated load	Reasonable until 40% of the rated load	Bad below 40% of the rated load	Good/reasonable until 35%–40% of the rated load	[a]	[a]	[a]
Load following capacity	Very good	Good[b]	Reasonable/low[c]	Very good	[a]	[a]	[a]
Start time	10 s to 15 min	2 min to 1 h	60 s	[a]	[a]	NA	[a]
Availability (%)	90–98	90–98	90–98	90–95	10–40[d]	5–25[d]	High[e]
Interval between the maintenance stops (×1000 h)	0.5–2	30	5–8	10–40	4	NA	[a]
Useful life time (years)	15–20	20–25	10	20[e]	20	20–30	Long [e]
Fuel flexibility	Good	Good	Good	Good	NA	Good	Excellent
Noise	High	Moderate to high	Moderate	Low	Moderate	NA	Low
Acquisition costs (€/kW)	300–900	300–1000	700–1100	> 4000	700–1300	4000	2000–50,000
O&M costs (€/kWh)	0.005–0.015	0.004–0.010	0.005–0.016[e]	0.005–0.030	[a]	[a]	[a]
Energy costs (€/kWh)	0.07–0.15	0.05–0.15	0.05–0.15	> 0.15	0.03–0.20	> 0.20	[a]
Commercial availability	High	High	Moderate	Low	High	High	Very low

[a] Dependent upon conditions.
[b] Installation costs of the system boiler/turbine.
[c] Despite present a high potential to load folowing, the actual models do not present a good fulfillment at this level.
[d] Depending on the climate condition at the location.
[e] Estimated value.
NA, not applicable.

5.2 Integration of Distributed Generation into Grid

Aníbal T. de Almeida and Pedro S. Moura

5.2.1 Introduction

Connecting a distributed power system to the electricity grid has potential impacts on the safety and reliability of the grid, which is one of the most significant barriers to the installation of DG technologies. Electric utilities have understandably always placed a high priority on the safety and reliability of their electrical systems. Faced with the interconnection of potentially large number of distributed generators, utilities have perceived DG as a threat. This has led some utilities to place overly conservative restrictions on interconnected systems, causing added costs that may make an installation economically unfeasible. Several techniques may reduce adverse network impacts allowing DG connection, but those techniques can be project specific and may be expensive, and adversely affect project economics.

Connection of DG fundamentally affects the operation of distribution networks with changes and impacts like:

- Voltage fluctuations
- Increased fault levels
- Degraded protection
- Bidirectional power flow
- Altered transient stability

To reduce the impact in the power grid several requirements are needed. Typical requirements include equipment that prevents power from being fed to the grid when the grid is de-energized, manual disconnects and PQ requirements such as limits on the interconnected system's effects on "flicker," harmonic distortion, and other types of waveform disturbance. Systems may also be required to automatically shut down in the event of electrical failures, to provide an isolation transformer for the system, as well as to provide liability insurance.

Up to recently the lack of a well-defined interconnect standard and failure to adhere to a standard can add considerably to engineering and equipment costs, making process planning difficult. Many interconnection requirements were drafted and adopted without understanding of the protection capabilities of modern DG equipment. As a result, these requirements often unnecessarily burden projects with redundant studies and hardware.

Interconnection requirements for large DG installations ($\sim$10 MW) are well understood because they are very similar to the interconnections required for central power stations. Interconnection requirements for smaller installations are more difficult because the utility must balance the desire for a safe interconnection with the plant owner's desire to have a "quick and easy" interconnection design to get the DG up and running. Interconnection complexity generally increases with project size and is technology dependent.

Grid interconnection is important for three reasons:

- The number of small generators seeking interconnection to the grid will increase in the future.
- Distributed generation advocates contend that the current interconnection requirements and processes are effectively increasing costs unfairly and pricing DG out of the market.
- Distribution companies are concerned that DG will negatively impact the safety and reliability of the grid and unfairly increase the distribution companies' costs.

5.2.2 Power Distribution

Electric grid is broadly divided into two systems: the transmission system that transfers bulk power at high voltages from power plants to utility-owned substations and a few very large customers, and the

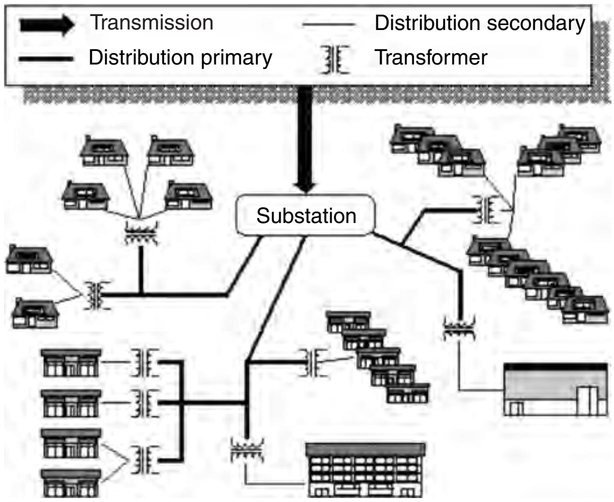


FIGURE 5.10 Radial distribution system. (From California Energy Commission, California interconnection guidebook: a guide to interconnecting customer-owned electric generation equipment to the electric utility distribution system using California's electric rule 21, California Energy Commission, Sacramento, CA, 2003. http://www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF. With permission.)

distribution system that delivers power at medium and low voltages from the substation to the majority of customers.

The utility distribution systems can be categorized as either radial or networked. Power system design is a tradeoff between complexity and cost to maximize economy and reliability. As a result, the general structure of the power delivery system has a networked nature at the transmission level and a more radial nature at distribution level.

Radial distribution refers to a system where the power lines extend from a common substation to the customer loads coming off at single nodes along the line (Figure 5.10). In these distribution systems, power can only flow in one direction: from the substation to a load. Although there can be many radial distribution lines emanating from a substation, each load is typically served by only one line. A disruption to that feed or substation will typically affect all customer loads on that line. A radial system generally offers a less reliable power source than a networked system because it lacks redundancy. However, the radial system and its protection equipment are less complex and less expensive than the networked system.

The introduction of an energy source such as DG within the radial distribution system will affect the load distribution in the system, and may even cause reverse power flow if it is large relative to the load. Introduction of a sufficiently large power source within the radial distribution normally requires some modification to the protection system.

Networked distribution refers to a system where numerous separate lines form a grid so that customer loads can tap-off of multiple independent feeds, which are then tied to a common bus on the secondary side of the transformers (Figure 5.11). These can be separate lines from a common substation or they can be from independent substations.

The networked system offers reliability advantages over the radial system because it provides multiple power sources for loads. This multipath design is sometimes referred to as a *looped* system. These systems use network protectors that quickly isolate faults to protect the grid and shift customer loads onto the remaining feeds. Understandably, utilities are reluctant to allow the interconnection of anything that they feel will endanger the integrity or safety of this system.

System protection in a networked distribution system is more complex and expensive than in the radial distribution system due to the extra intelligence needed for reliable, effective protection.

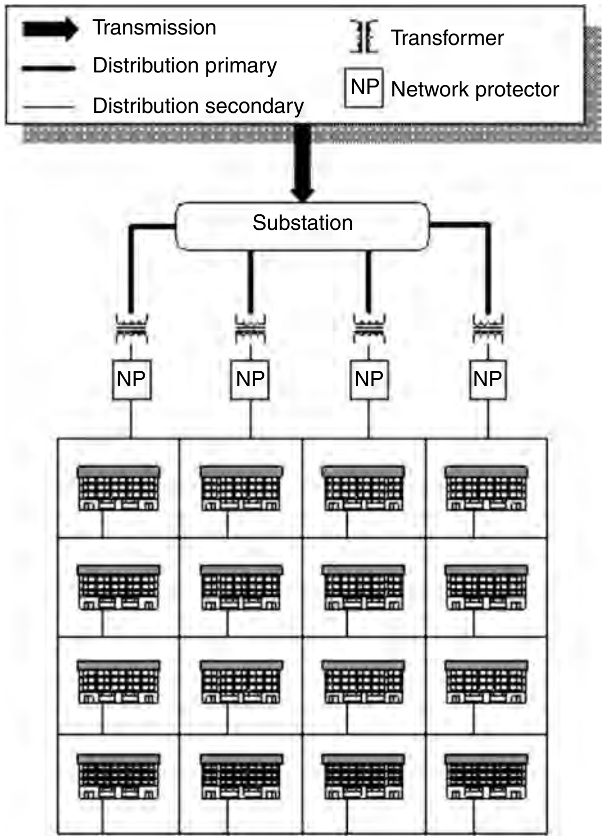


FIGURE 5.11 Networked distribution system. (From California Energy Commission, California interconnection guidebook: a guide to interconnecting customer-owned electric generation equipment to the electric utility distribution system using California's electric rule 21, California Energy Commission, Sacramento, CA, 2003. http://www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF. With permission.)

Because the networked system is specifically designed to deliver energy from multiple transformers to loads, it is capable of dealing with reverse power flow.

5.2.3 Types of Grid Connections

The electric power system interface is the means by which the DG unit electrically connects to the power system outside the facility in which the unit is installed. Depending on the application and operation of the DG unit, the interface configuration can range from a complex parallel interconnection, to being nonexistent if the DG unit is operated in isolation (Figure 5.12).

In remote applications, due to the high costs of the power grid expansion to the consumption site, the option of interconnecting with the local grid may be impractical. In these cases, the DG units become the unique means of energy supply at low cost. In this configuration, the DG unit provides power for all loads completely isolated from grid, providing the utility no backup or supplemental power.

In near-to-grid applications, the DG unit owner can opt for interconnection, by several types of connections. Depending on the application and the operation mode of the DG unit, the connection system with the grid can represent a complex parallel interconnection or can be inexistent if the DG is operating isolated from the grid. The complexity of the interconnection systems increases with the required interaction level between the DG unit and the distribution grid.

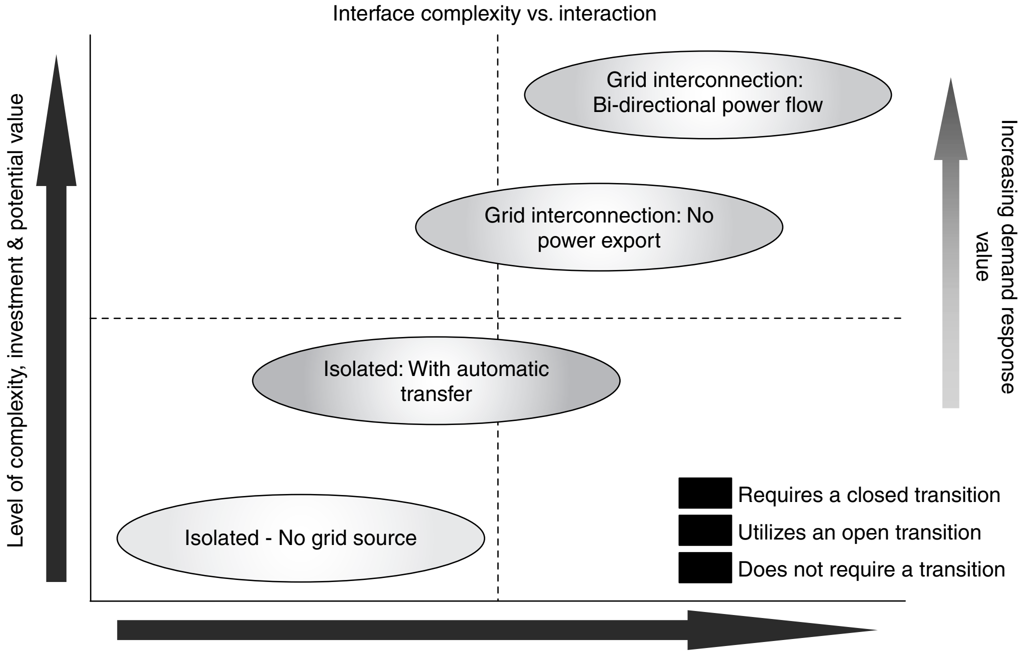


FIGURE 5.12 Complexity vs. interaction. (From Arthur D. Little, *Distributed Generation: System Interfaces*, An Arthur D. Little white paper, ADL Publishing, Boston, MA, 1999. http://www.encorp.comdwnld/pdf/whitepaper/ADLittleWhitePaperDGSystemInterfaces.pdf. With permission.)

For most customers, DG systems are most cost-effective and efficient when they are interconnected with the utility grid. In simple terms, "interconnected with the grid" means that both the DG system and the grid supply power to the facility at the same time. Paralleled systems offer added reliability, because when the DG system is down for maintenance, the grid meets the full electrical load, and vice versa.

Distributed generation systems can be designed to keep a facility up and running without an interruption if the grid experiences an outage. Also, grid-interconnected systems can be sized smaller to meet the customer's base load as opposed to its peak load. Not only is the smaller base-load system cheaper, it also runs closer to its rated capacity and, therefore, is more fuel efficient and cost-effective.

Two different types of grid interconnection are possible: parallel or roll-over. With the parallel operation, the DG system and the grid are interconnected and both are connected to the load. In the roll-over operation, the two sources are interconnected, but only one is connected with the load.

A typical interconnection system includes three kinds of equipment:

- Control equipment for regulating the output of the DG
- A switch and circuit breaker (including a "visible open") to isolate the DG unit
- Protective relaying mechanisms to monitor system conditions and to prevent dangerous operating conditions

5.2.3.1 Isolated Operation

In remote applications, the DG units become the unique means of energy supply at low cost. In this configuration, the DG unit provides power for all loads completely isolated from grid, providing the utility no backup or supplemental power (Figure 5.13). Isolated operation is also possible in sites that are normally connected to the grid but in which continuous supply is required in the event of an outage. Some generating facilities, such as a hospital emergency generator, power the customer's partial or entire load isolated from the utility.

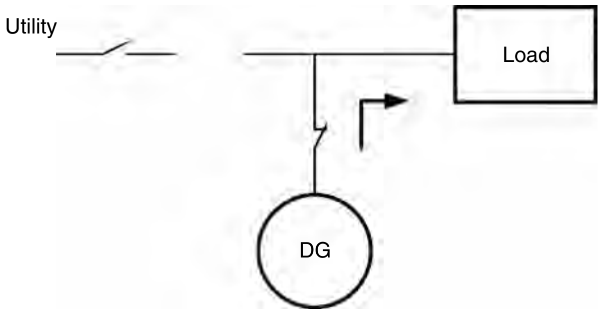


FIGURE 5.13 Isolated operation.

Isolated operation involves no interaction with the utility's distribution system because the generator does not operate in parallel with the utility. In some isolated systems, the generator is sized for a specific load that is always powered from the generator and never from the utility. There are two ways of transferring load to isolated operation:

- A break-before-make transfer switch (also known as *open transition switching*), disconnects the load from the utility prior to making the new connection with the onsite electric generating facility.
- A momentary-parallel (or closed transition) switch, a control system starts the customer's generator and parallels it with the utility's distribution system, quickly ramps the generator output power to meet the customer's load demand and then disconnects the load from the utility.

5.2.3.2 Roll-Over Operation

When a roll-over connection exists (Figure 5.14), the load can be connected only to one of the two sources (grid or DG system) at any given moment. Both the sources are connected to a load control center with a load transfer switch. When the source that is feeding the load fails, this device makes the commutation, ensuring that the other source feeds the load. This commutation can be automatic or manual, to allow the interchange between the two sources due to technical or economical reasons, even when a failure does not exist. In this configuration, the DG unit provides power to load 2 for peaking, base-load, or backup power, and the utility provides power to load 1 and occasionally to load 2.

The automatic commutation devices achieve the fast transition between sources, but there is always a time period in which the load is not fed. This kind of connection does not allow the decrease of

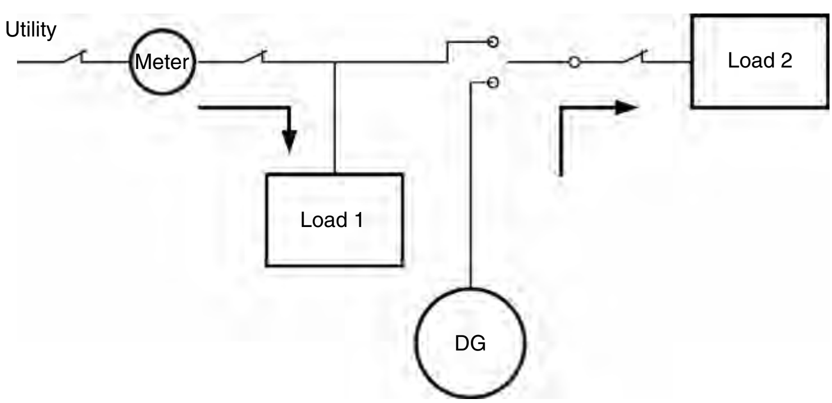


FIGURE 5.14 Roll-over operation.

the frequency of interruption, but reduces considerably their duration. To eliminate the feeding interruption, the installation of energy storage devices between the switch and the load would be necessary. In this configuration, the transfer time of the load switch is typically 0.1–0.15 s.

The roll-over operation is cheaper and simpler because it does not need a high number of control, protection, and coordination equipment. This type of operation can easily ensure the impossibility of the DG system injecting energy into the grid when the grid is out of service. This phenomenon, named *backfeed* or *islanding*, can be harmful to the grid operation and can put people and goods at risk. For example, if a line is disconnected due to technical reasons, a worker can be electrocuted by assuming that the line does not have voltage.

5.2.3.3 Parallel Operation

When a parallel operation exists, the sources are interconnected and both are connected with the load. If one of the sources fails, the load passes to be instantaneously fed exclusively by the other, without any interruption in the load supply.

The fact of the two sources operating in parallel implies that the DG unit will be in operation and in synchronism with the grid, aggregating the necessary conditions to feed the load at the moment of the grid failure. This kind of operation is more expensive because besides the necessary additional protection and control equipment, there are additional fuel and equipment wear out costs that occur in generating equipment, even without electricity generation.

The parallel operation requires a large quantity of monitoring, control, synchronization, and protection devices. Both the sources must be protected against the failures of the other, including the backfeed phenomenon. This kind of connection is necessary in the cases in which the DG unit owner wants to sell energy to the grid.

Several types of parallel connections are available (Figure 5.15), depending on the DG unit localization and the possibility of selling energy to the grid. In the first configuration, the DG unit operates in parallel with the grid, supplying energy to all the loads or to some loads, particularly providing the utility supplemental or backup power. In this configuration, it is impossible to supply energy to the grid.

In the second configuration, the DG unit operates in parallel with the grid, supplying energy to all the loads. With this configuration, it is possible to supply energy to the grid. The DG unit provides peaking or base-load power to load and exports power to the grid, providing the utility supplemental and backup power. In the third configuration, the DG unit operates in parallel with the grid, supplying energy to the grid and to the consumer. In this configuration, the DG unit does not usually belong to the consumer.

5.2.4 Ancillary Services

Ancillary services is the designation given to a number of functions that are necessary to support the reliable and efficient operations of the power system network. Besides energy (kWh) and capacity (kW), DG can provide other additional benefits, including spinning reserve capacity, peaking, load following, reactive power, and voltage support and other ancillary services.

Generally, a customer can use DG in conjunction with the traditional utility service or as a separate service. There are two ways of DG utilization: to supply power and energy during peak periods or during the entire demand period. Distributed generation equipment can also be used as backup or standby power. Some ancillary services provided by the conventional generators can also be provided by DG, thus minimizing the cost of supplying ancillary services.

In addition to generating energy, DG operation can provide the following benefits:

- Eliminate the need to upgrade the size of feeders
- Improve voltage levels at the feeder ends
- Eliminate the need for capacitor banks
- Provide reactive power compensation
- Eliminate the need for voltage regulators

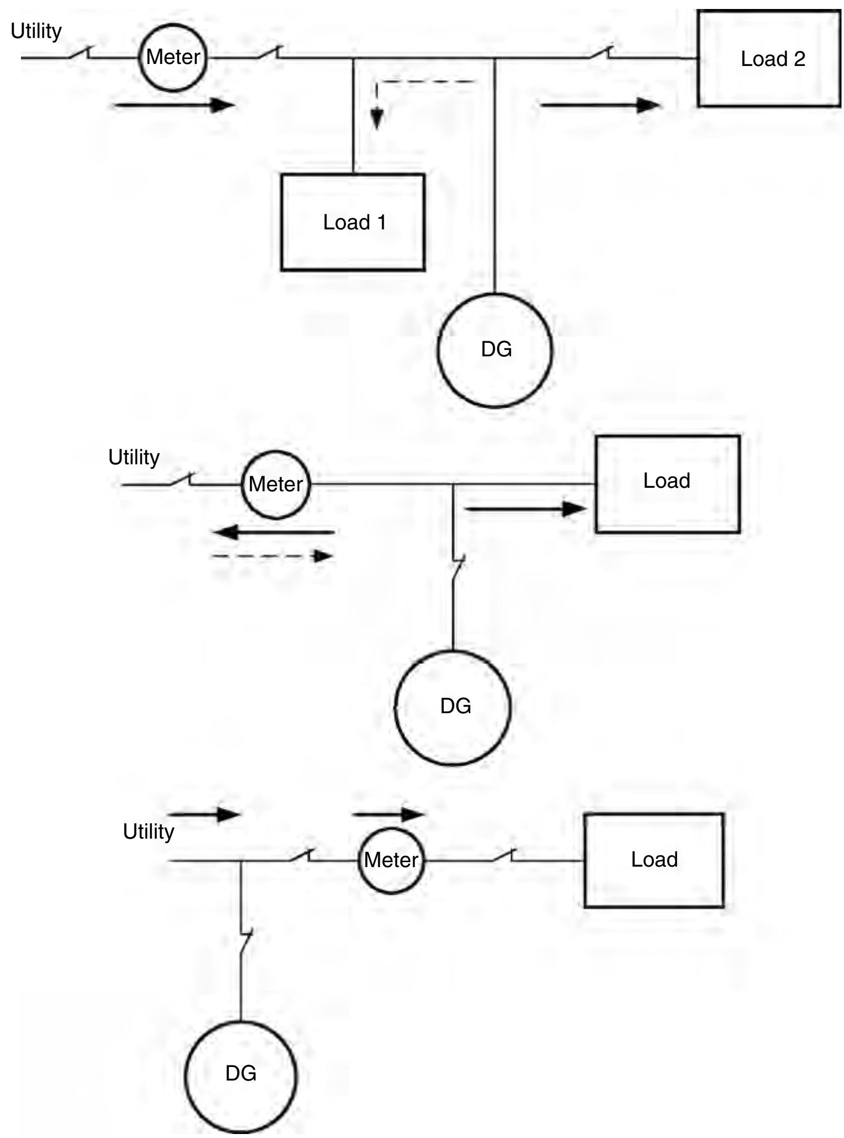


FIGURE 5.15 Parallel operation.

- Reduce feeder loading and delay replacement
- Reduce line losses and transmission system load

The main types of ancillary services, which can be provided by generators include:

Regulation Service and Frequency Response. They provide generation capacity that is available and running, and that can be used to maintain real-time balance in the transmission system. As system loads fluctuate minute-by-minute, generators must be available to match instantly the fluctuations due to the increase or decrease of the loads. An AGC reacts to perceived system fluctuations by adjusting its output to oppose or dampen the fluctuation, whether it is caused by load changes or changes in the output of other bulk system generators as they ramp up or down. Generation units equipped with automated generation control can follow load variations on the time scale of seconds. The load balance is a critical service to the stability of day-to-day grid operation.

The load-following capability service is associated with the "Regulation service and spinning reserves." Load following is the use of available generation capacity to meet the variations in system load. A more detailed description is given below.

Spinning Reserves. This refers to supplemental generation capacity that is ready to quickly ramp up at short notice. Spinning reserves is the incremental generating supply that an active unit can ramp up to within 10 min and then sustain, typically for 30–120 min.

An amount of generating capacity must be kept fully warmed up and ready to take over within seconds in the event of a generator or transmission line failure. The term *spinning* refers to the fact that the generator is on, spinning at rated speed (in the case of turbine generators), and synchronized to the grid. It only needs to adjust its power output to the prescribed level.

Large DG and aggregated small DG alike can provide spinning reserve service. Implicit in the definition, however, is the availability of the capacity to be called upon at any time. Therefore, for example, a DG unit cannot use its full capacity for peak shaving a local load, and at the same time qualify that capacity for spinning reserve.

This limitation is true for nonspinning and replacement reserve services as well. A generator designed to run at 80% of its normal capacity for local purposes can qualify the remaining 20% capacity for spinning reserve, as long as it is synchronized to the grid for the defined reserve period.

Some quick-release hydro units allow a change from zero to full power in 1 min. Alternatively, quick-response loads (using demand response controls) can also contribute to achieve a fast balance between supply and demand.

Supplementary (Nonspinning) Reserves. This refers to generation that is available but not running. Generation kept on standby so that it can be started rapidly in the event that generators or lines suddenly fail, but not as rapidly as spinning reserves above. The incremental generation that can be achieved by units with slower responses, and those requiring start-up, is considered nonspinning reserve. Jurisdictions differ as to the ramping time allowed, varying from 10 to 30 min.

Generators that can start, synchronize, and ramp to full power in short time periods can therefore participate in the quick-response reserve market without running at all times. Fast-start combustion turbines can serve this function. In addition, customers in the form of medium fast-response load may provide nonspinning reserve services.

Nonspinning reserve, in most cases, will be a more appropriate choice over spinning reserve for unused DG capacity. Most distribution level DG technologies do not require 10 min to start-up, and therefore would not gain from remaining synchronized to the grid when not needed. Nonspinning reserves further provide ample opportunity for generators installed as emergency backup systems to participate in the reserve market, where they would not under spinning reserve. These generators are designed to remain off under normal circumstances and serve the customer's load only if the utility experiences an outage; therefore, their capacity during normal utility operation is always available.

Replacement or Operating Reserves. Replacement reserve is the incremental generation that can be obtained in the next hour to replace spinning and nonspinning reserves used in the current hour. Replacement reserve is very similar to nonspinning reserve with the exception that the generator has 60 min to start- and ramp-up instead of only 10 min. Each resource providing replacement reserve must be capable of supplying any level of output up to and including its full reserved capacity within 60 min after issue of dispatch instructions by the independent system operator (ISO). Each resource providing replacement reserve must be capable of sustaining the required output for at least 2 h.

Replacement reserve may be supplied from resources already providing another ancillary service, such as spinning reserve. However, the sum of the ancillary service capacity plus the replacement reserve cannot exceed the capacity of said resource.

Replacement reserve can be provided by large and aggregated small DG that requires more than 10 min (and less than 1 h) to start and ramp to full power. This would be appropriate in cases where the generator technology itself has ramping limitations, or where the generator starting functions are not automated in response to a signal from the ISO, and therefore require delayed manual intervention.

Voltage Support. These services are required to maintain transmission voltage level margins within the criteria in force. Dispatchers at the control center alter the settings on transformers, transmission lines, and other downstream grid-connected equipment, as well as provide sufficient reactive power in areas where needed.

Reactive Power Support. Reactive power support is the injection or absorption of reactive power from generators to maintain transmission-system voltage within required ranges. Generators and loads may be dispatched and operated within a prescribed power factor range to boost the voltage during heavy load periods, or reduce the voltage during light load periods. The service can be provided by generators, loads, and utility distribution companies alike, as long as they have the proper power factor adjustment capabilities.

Black-Start Generation Capability. Black-start generation capability is the ability of a generating unit to go from a shutdown condition to an operating condition without assistance from the electrical grid and to then energize the grid to help other units start after a blackout occurs.

Generators are started in a sequence so that each subsequent generator has an energized bus with which to synchronize. Strategically located black-start generators are a key factor for ensuring timely restoration after a major outage. Each black-start generating unit must be able to start-up with a dead primary and station service bus within 10 min of issue of a dispatch instruction by the ISO requiring a black start.

Each slack-start generating unit must provide sufficient reactive capability to keep the energized transmission bus voltages within emergency voltage limits over the range of no-load to full load.

Each black-start generating unit must be capable of sustaining its output for a minimum period of 12 h from the time when it first starts delivering energy.

The other characteristics that may influence the adoption of DG technologies for ancillary service applications will vary according to the service performed and the ultimate shape of the ancillary service market. Start-up time for all electrical generators is an extremely important parameter to determine if the particular unit can be used as the reserve or can operate in the load following mode.

The part-load capabilities of DG technologies and the start-up time periods of each are presented in Table 5.6.

In addition to their high fuel efficiency, fuel cells appear to offer technical capabilities. Their flexible size enables them to be located close to the load, which can reduce energy losses and transmission and distribution costs. One of the most significant characteristics of the fuel cell is its ability to operate efficiently at part-load, i.e., to respond to sudden increases or decreases in power demands. In addition to meeting changes in power demand, the fuel cell's spinning reverse and load following capabilities enable it to complement effectively the variable output from other renewable power sources, such as solar energy and wind farms.

5.2.5 Advantages of the Grid Interconnection

5.2.5.1 Economical Advantages

The cost of the electricity provided by the grid can be smaller than the cost of the local production in some time periods. Thus, during the periods in which the marginal production cost in the local unit is superior to the grid electricity cost, it makes sense to use the grid energy. During a peak period, the cost of the grid electricity is higher when local production becomes advantageous.

Sometimes is not advantageous to size the DG unit to meet all the required power by the loads. In this situation, when the requested power is higher, the additional required energy is provided by the grid. When the unit is working below the full capacity and the marginal production cost is lesser than the grid price, it is possible to increase the local production thus increasing the profits.

5.2.5.2 Voltage Regulation

The electric power grid is projected to approach an ideal voltage source, with lower internal impedance. In this kind of source, the voltage is the same to all the connected loads, ensuring that the start of a large

TABLE 5.6 Summary Table of Some Performance Characteristics by Distributed Generation Technology Type

Technology	Steam Turbine	Diesel Engine	Natural Gas Engine	Gas Turbine	Microturbine	PAFC	MCFC	SOFC Tubular	SOFC Planar	PEMFC
Part-load	Satisfactory	Good	Satisfactory	Poor	Satisfactory	Satisfactory	Poor			Satisfactory
Start-up time	1 h–1 d	10 s	10 s	10 min–1 h	60 s	1–4 h	More than 10 h	5–10 h	Not available	<0.1 h

Source: From US Environmental Protection Agency, Introduction to CHP Technologies, California Energy Commission, DER Equipment.

load does not disturb the feeding voltage to the other loads. In a nonideal voltage source, the start of a large load (e.g., a large induction motor) causes a momentary voltage sag, affecting the other loads negatively.

In general, the grid achieves a good voltage regulation, because as the power of the load varies, the grid adjusts the power flows automatically, with very small variations in the voltage. Only at some points of the grid, especially toward the end of long lines, this variation is relatively high.

In general, DG units do not have as good a voltage regulation as the grid. As the load varies, the unit controller monitors the output voltage, that tends to decrease with the load increase and increase with the load reduction. When the voltage varies, the unit controller automatically responds, but it is almost impossible to equal the nearly instantaneous response of the grid.

The interconnection, with the DG unit working in parallel with the grid, solves the voltage regulation problem, even in the cases in which all the consumed energy is provided by the DG unit. When the load varies, the grid ensures the transitory instantaneous response, allowing the unit to make a relatively slow change.

5.2.5.3 Reliability

When properly managed, two energy sources work better together than isolated. Either with DG reserve units or with normal operating units, the DG system owner can view the grid as a reserve energy source. In fact, in almost all of the sites, the grid reliability is higher than the reliability of any isolated DG unit. In the DG projects, it is common to use values of 92%–93% for the unit's availability. Considering an availability of 99%, which is extremely difficult to obtain, the corresponding unavailability will be higher than 80 h per year, which is unacceptable to most of the appliances.

Even in areas with poor performance of the electric grid, the grid availability is normally higher than the DG unit, being many times higher than the availability of a DG system, even with several units. The grid utilization like reserve source makes sense in most of the cases, if the charged costs by the grid operator are reasonable.

5.2.6 Disadvantages of the Grid Interconnection

5.2.6.1 Costs with the Grid Operator

In any market, the grid operator will charge a considerable value for interconnection with the grid. The DG unit owner, making the interconnection, will normally pay not only for the energy supplied by the grid, but also a charge dependent upon the maximum power delivered by the grid.

5.2.6.2 Additional Equipment and Maintenance

Distributed generation system operation with interconnection with the grid is more complex than an isolated operation. Besides all the necessary equipment for the system operation, it is necessary to install additional control, metering, and protection devices to isolate the DG system from the grid. Usually the additional equipment, besides increasing the cost, increases the system complexity, thereby increasing the maintenance needs.

5.2.6.3 Increasing Maintenance Needs to Ensure High Reliability Levels

The potential reliability improvement achieved by the interconnection does not appear automatically. It is necessary to have a constrained management of the DG/grid combination to obtain the expected reliability levels. There are three essential points:

- The DG system operating in parallel with the grid needs an exhaustive monitoring of the grid operation conditions of the DG system, the load and the interconnection. The existence of two sources and a load cause a complex control problem that is easily resolved with the modern electronic devices, but is a potential weakness. Problems can occur either because the system is not correctly programmed or due to a failure in a key element of the system that can deactivate the entire system. In critical DG units interconnected with the grid, redundant control equipment is usually installed with auto-monitoring.

- Problems at grid points distant from the DG installation can cause perturbations in the DG unit operation. The most common problems are the atmospheric discharges. Reaching a line, a lightning discharge causes a current impulse that, without the appropriated protection, can reach the DG system. To mitigate this problem, additional protection equipment is needed, increasing the total cost of the system.
- Undesirable events in the grid can disturb the DG unit operation, especially if the control and protection equipment is very sensitive. Momentary failure of a line can cause an abrupt fall in the voltage that can be interpreted by the control system as a risk situation to the DG unit, resulting in its removal from service, or it may be interpreted as an abrupt increase in the load. In the last situation, the control device responds by increasing the power of the DG unit. After the automatic reclosure, the voltage level increases too fast and the DG unit cannot react in a timely manner, while it continues to try follow what it seems a load increase. An overvoltage occurs that is detected by the control system which removes the unit from service, and the installation is then supplied by the grid.

5.2.7 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

The IEEE Standards Board approved the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems (EPS) in June, 2003. It was then approved as an American National Standard in October 2003. Many of the technical concerns that the companies of distributed electricity usually raise for the DR interconnection with the grid are related to reliability, security, and quality of service. The IEEE P1547/D07 defines interconnection technical specifications and requirements that are universally needed for interconnection of DR. This standard constitutes an important step to overcome the barriers and increase the development of DG installations.

This American standard establishes criteria and requirements for interconnection of DR with EPS. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. The standard applies to all DR technologies, with aggregate capacity of 10 MVA or smaller at the point of common coupling, and to all EPS at typical primary and/or secondary distribution voltages.

The standard defines interconnection technical specifications and requirements that all interconnection systems and DRs shall meet. General requirements are related to voltage regulation, integration with area electric power system grounding, synchronization, DR on secondary grid and spot networks, inadvertent energization, and reconnection to area EPS, monitoring, and isolation device.

Abnormal conditions can arise on the area EPS that require a response from the connected DR. This response contributes to the safety of utility maintenance personnel and the general public, as well as the avoidance of damage to the connected equipment, including the DR. The abnormal conditions of concern are voltage and frequency excursions above or below the values stated in the IEEE P1547 (Table 5.7), and the isolation of a portion of the area EPS with some DR, presenting the potential for an unintended island.

TABLE 5.7 Interconnection System Response to Abnormal Voltages

Voltage Range (% of Base Voltage)	Clearing Time (s)[a]
$V < 50$	0.16
$50 \leq V < 88$	2
$110 < V < 120$	1
$V \geq 120$	0.16

[a] Clearing time: Time between the start of the abnormal condition and the DR ceasing to energize the area EPS.

TABLE 5.8 Maximum Harmonic Current Distortion in Percent of Current (I)

Individual Harmonic Order (Odd Harmonics)	<11	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h$	Total Demand Distortion (TDD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

I is the greater of the local EPS maximum load current integrated demand (15–30 min) without the DR unit, or the DR unit rated current capacity (transformed to the PCC when a transformer exists between the DR unit and the PCC); even harmonics are limited to 25% of the odd harmonic limits above.

Power quality issues are also addressed in the IEEE P1547, namely, limitation of DC injection, voltage flicker induced by the DR, harmonic current injection (Table 5.8), immunity protection and surge capabilities, as well as the islanding considerations.

The standard also provides test requirements for an interconnection system to demonstrate that it meets all the requirements. The following tests are required for all interconnection systems:

- Interconnection test
- Production tests
- Interconnection installation evaluation
- Commissioning tests
- Periodic interconnection tests

IEEE 1547 is the first in a family of IEEE interconnection standards for DR (Figure 5.16). Other standards in the family currently underway are:

- IEEE P1547.1 Draft Standard for Conformance Tests Procedures for Equipment Interconnecting DR with EPS. This standard specifies the type, production, and commissioning tests that shall be performed to demonstrate that the interconnection functions and equipment of a distributed resource conform to IEEE Standard P1547.
- IEEE P1547.2 Draft Application Guide for IEEE 1547 Standard for Interconnecting DR with EPS. This guide provides technical background and application details to support the understanding of IEEE 1547 Standard for Interconnecting DR with EPS.
- IEEE P1547.3 Draft Guide For Monitoring, Information Exchange, and Control of DR Interconnected with EPS. This document provides guidelines for monitoring, information exchange, and control for DR interconnected with EPS.
- IEEE P1547.4 Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with EPS. This document provides alternative approaches and good practices for the design, operation, and integration of distributed resource island systems with EPS.
- IEEE P1547.5 Draft Technical Guidelines for Interconnection of Electric Power Sources Greater than 10 MVA to the Power Transmission Grid. This document provides guidelines regarding the technical requirements, including design, construction, commissioning acceptance testing, and maintenance/performance requirements, for interconnecting dispatchable electric power sources with a capacity of more than 10 MVA to a bulk power transmission grid.
- IEEE P1561 Draft Guide for Sizing Hybrid Stand-Alone Energy Systems. This guide provides the rationale and guidance for operating lead-acid batteries in remote hybrid systems considering the system's load, and the capacities of its renewable-energy generator(s), dispatchable generator(s), and battery(s).

5.2.8 Power Quality Applications

Power quality-related issues are currently of great concern. The widespread use of electronic equipment, such as information technology equipment, power electronics such as adjustable speed drives (ASDs), programmable logic controllers (PLCs), and energy-efficient lighting led to a complete change of electric

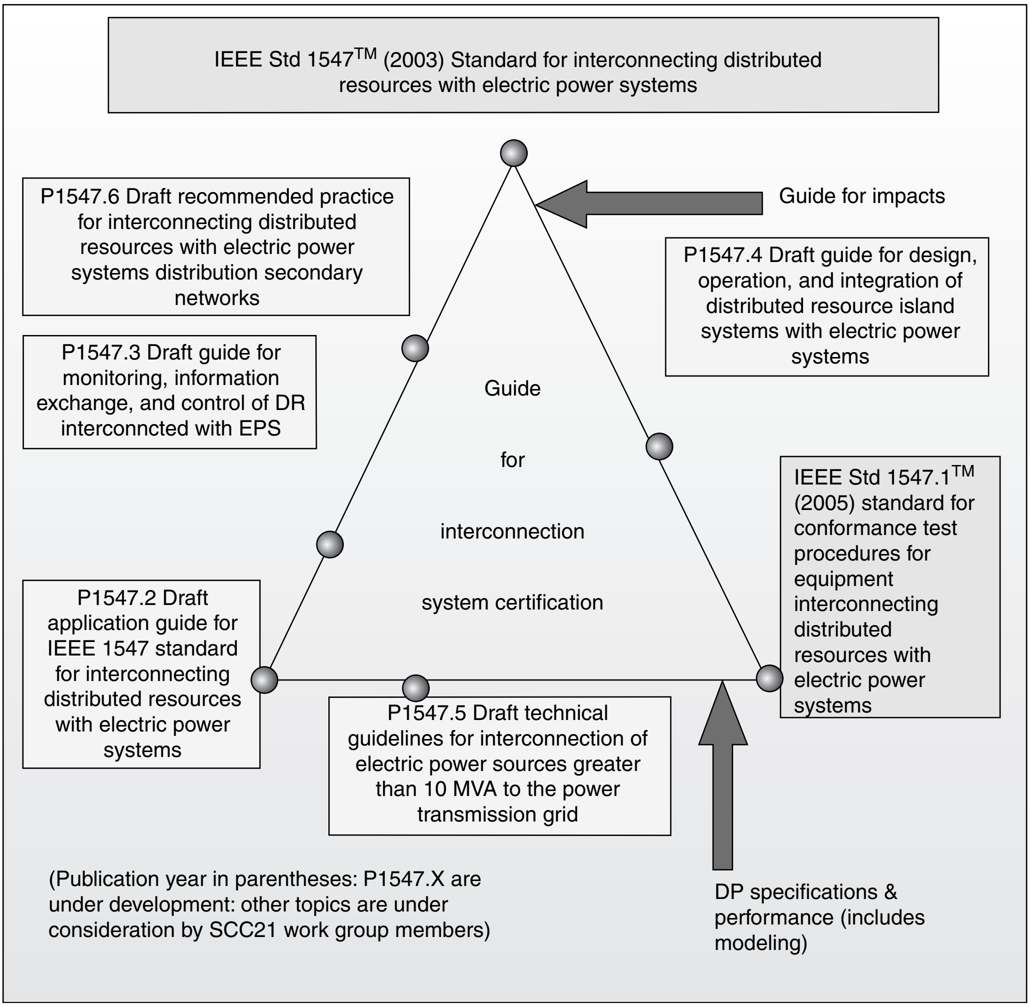


FIGURE 5.16 IEEE SCC21 1547 Series of Interconnection Standards. (From Institute of Electric and Electronics Engineers (IEEE), IEEE P1547/D07. *Standard for Interconnecting Distributed Resources with Electric Power Systems.* IEEE Standards Coordinating Committee 21 (IEEE SCC21) on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage of the IEEE Standards Association, New York, 2001. With permission.)

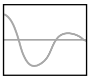
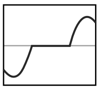
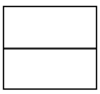
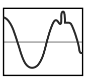
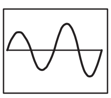
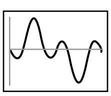
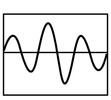
loads nature. These loads are simultaneously the major causers and the major victims of PQ problems. Due to their nonlinearity, all these loads cause disturbances in the voltage waveform.

Along with technology advance, the organization of the worldwide economy has evolved towards globalization and the profit margins of many activities tend to decrease. The increased sensitivity of the vast majority of processes (industrial, services, and even residential) to PQ problems turns the availability of electric power with quality a crucial factor for competitiveness in every activity sector. The most critical areas are the continuous process industry and the information technology services. When a disturbance occurs, huge financial losses may occur, with the consequent loss of productivity and competitiveness.

Although many efforts have been taken by utilities, some consumers require a level of PQ higher than the level provided by modern electric networks. This implies that some measures must be taken in order to achieve higher levels of PQ.

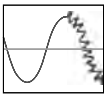
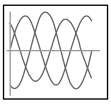
The most common types of PQ problems are presented in Table 5.9.

TABLE 5.9 Most Common Power Quality Problems

1. Voltage sag (or dip) 	*Description*: A decrease of the normal voltage level between 10 and 90% of the nominal rms voltage at the power frequency, for durations of 0,5 cycle to 1 min *Causes*: Faults in the transmission or distribution network (most of the times on parallel feeders). Faults in consumer's installation. Connection of heavy loads and start-up of large motors *Consequences*: Malfunction of information technology equipment, namely microprocessor-based control systems (PCs, programmable logic controllers (PLCs), adjustable speed drives (ASDs), etc.) that may lead to a process stoppage. Tripping of contactors and electromechanical relays. Disconnection and loss of efficiency in electric rotating machines
2. Very short interruptions 	*Description*: Total interruption of electrical supply for duration from few milliseconds to one or two seconds *Causes*: Mainly due to the opening and automatic reclosure of protection devices to decommission a faulty section of the network. The main fault causes are insulation failure, lightning, and insulator flashover *Consequences*: Tripping of protection devices, loss of information, and malfunction of data processing equipment. Stoppage of sensitive equipment, such as ASDs, PCs, PLCs, if they are not prepared to deal with this situation
3. Long interruptions 	*Description*: Total interruption of electrical supply for duration greater than 1–2 s *Causes*: Equipment failure in the power system network, storms, and objects (trees, cars, etc.) striking lines or poles, fire, human error, bad coordination or failure of protection devices *Consequences*: Stoppage of all equipment
4. Voltage spike 	*Description*: Very fast variation of the voltage value for durations from several microseconds to few milliseconds. These variations may reach thousands of volts, even in low voltage *Causes*: Lightning, switching of lines or power factor correction capacitors, disconnection of heavy loads *Consequences*: Destruction of components (particularly electronic components) and of insulation materials, data processing errors or data loss, electromagnetic interference
5. Voltage swell 	*Description*: Momentary increase of the voltage, at the power frequency, outside the normal tolerances, with duration of more than one cycle and typically less than a few seconds *Causes*: Start/stop of heavy loads, badly dimensioned power sources, badly regulated transformers (mainly during off-peak hours) *Consequences*: Data loss, flickering of lighting and screens, stoppage or damage of sensitive equipment, if the voltage values are too high
6. Harmonic distortion 	*Description*: Voltage or current waveforms assume nonsinusoidal shape. The waveform corresponds to the sum of different sine-waves with different magnitudes and phases, having frequencies that are multiples of power-system frequency *Causes*: *Classic sources*: electric machines working above the knee of the magnetization curve (magnetic saturation), arc furnaces, welding machines, rectifiers, and DC brush motors. *Modern sources*: all nonlinear loads, such as power electronics equipment including ASDs, switched mode power supplies, data processing equipment, high efficiency lighting *Consequences*: Increased probability of occurrence of resonance, neutral overload in three-phase systems, overheating of all cables and equipment, loss of efficiency in electric machines, electromagnetic interference with communication systems, errors in measures when using average reading meters, nuisance tripping of thermal protections
7. Voltage fluctuation 	*Description*: Oscillation of voltage value, amplitude modulated by a signal with frequency of 0–30 Hz *Causes*: Arc furnaces, frequent start/stop of electric motors (for instance elevators), oscillating loads *Consequences*: Most consequences are common to undervoltages. The most perceptible consequence is the flickering of lighting and screens, giving the impression of unsteadiness of visual perception

(continued)

TABLE 5.9 (***Continued***)

8. Noise 	*Description*: Superimposition of high frequency signals on the waveform of the power-system frequency *Causes*: Electromagnetic interferences provoked by Hertzian waves, such as microwaves, television diffusion, and radiation due to welding machines, arc furnaces, and electronic equipment. Improper grounding may also be a cause *Consequences*: Disturbances on sensitive electronic equipment, usually not destructive. May cause data loss and data processing errors
9. Voltage unbalance 	*Description*: A voltage variation in a three-phase system in which the three voltage magnitudes or the phase-angle differences between them are not equal *Causes*: Large single-phase loads (induction furnaces, traction loads), incorrect distribution of all single-phase loads by the three phases of the system (this may be also due to a fault) *Consequences*: Unbalanced systems imply the existence of a negative sequence that is harmful to all three-phase loads. The most affected loads are three-phase induction machines

Even the most advanced transmission and distribution systems are not able to provide electrical energy with the desired level of reliability for the proper functioning of the loads in the modern society. Modern T&D (transmission and distribution) systems are projected for 99.9%–99.99% availability. This value is highly dependant of redundancy level of the network, which is different according to the geographical location and the voltage level (availability is higher at the HV network). In some remote sites, availability of T&D systems may be as low as 99%. Even with a 99.99% level, there is an equivalent interruption time of 52 min per year. The most demanding processes in the modern digital economy need electrical energy with 99.9999999% availability (9-nines reliability) to function properly.

The mitigation of PQ problems may take place at different levels: transmission, distribution, and the end use equipment. As seen in Figure 5.17, several measures can be taken at these levels. Many PQ problems have origin in the transmission or distribution grid. Thus, a proper transmission and distribution grid, with adequate planning and maintenance, is essential to minimize the occurrence of PQ problems.

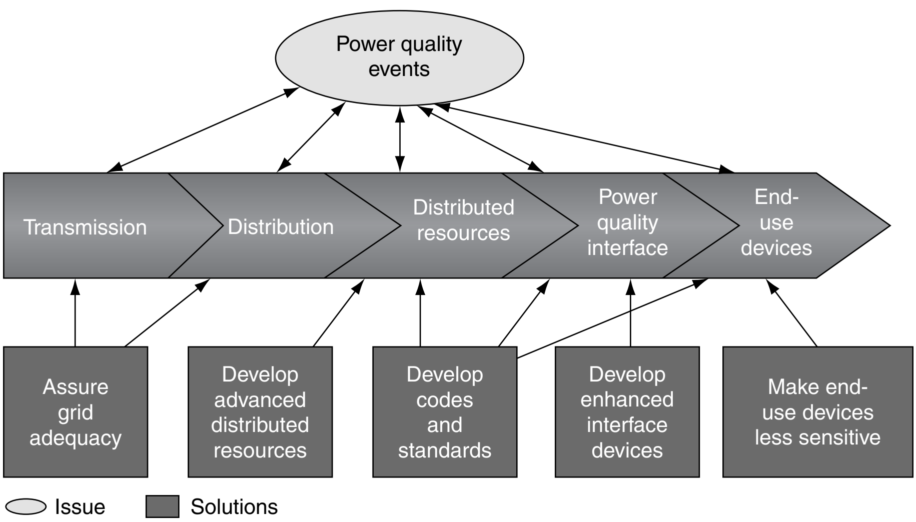


FIGURE 5.17 Solutions for digital power.

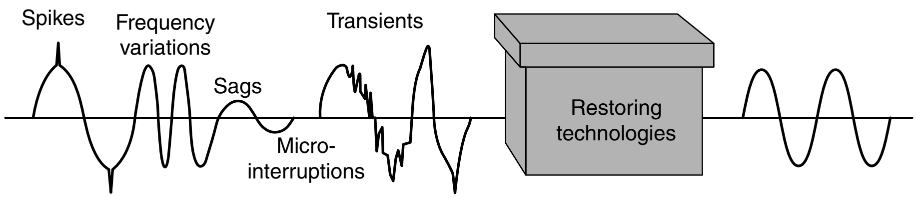


FIGURE 5.18 Restoring technologies principle.

Interest in the use of distributed energy resources has increased substantially over the last few years because of their potential to provide increased reliability. These resources include DG and energy storage systems. Energy storage systems, also known as restoring technologies, are used to provide the electric loads with ride-through capability in poor PQ environment. Recent technological advances in power electronics and storage technologies are turning the restoring technologies as one of the premium solutions to mitigate PQ problems (Figure 5.18).

Distributed generation units can be used to provide clean power to critical loads, isolating them from disturbances with origin in the grid. Distributed generation units can also be used as backup generators to assure energy supply to critical loads during sustained outages. Additionally, DG units can be used for load management purposed to decrease the peak demand.

At present, the reciprocating engine is the prevalent technology in DG market, but with technology advancements, other technologies are becoming more attractive, such as photovoltaics, microturbines, or fuel cells.

If DG units are to be used as backup generation, a storage unit must be used to provide energy to the loads during the period between the origin of the disturbance and the start-up of the emergency generator.

The most common solution is the combination of electrochemical batteries UPS and a diesel genset. At present, the integration of a flywheel and a diesel genset in a single unit (Figure 5.19 and Figure 5.20) is also becoming a popular solution, offered by many manufacturers.

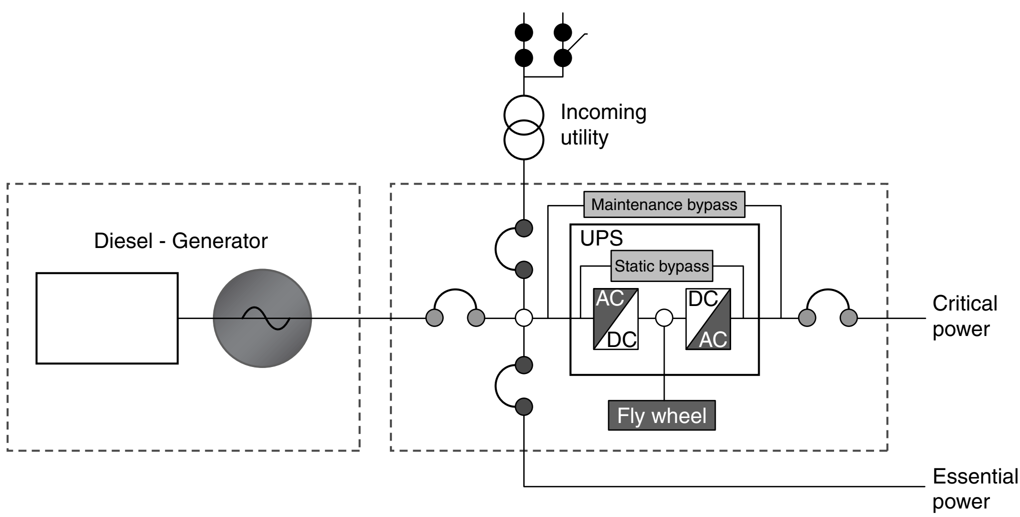


FIGURE 5.19 Scheme of a continuous power system, using a flywheel and a diesel genset. (From http://www.geindustrial.com. With permission.)

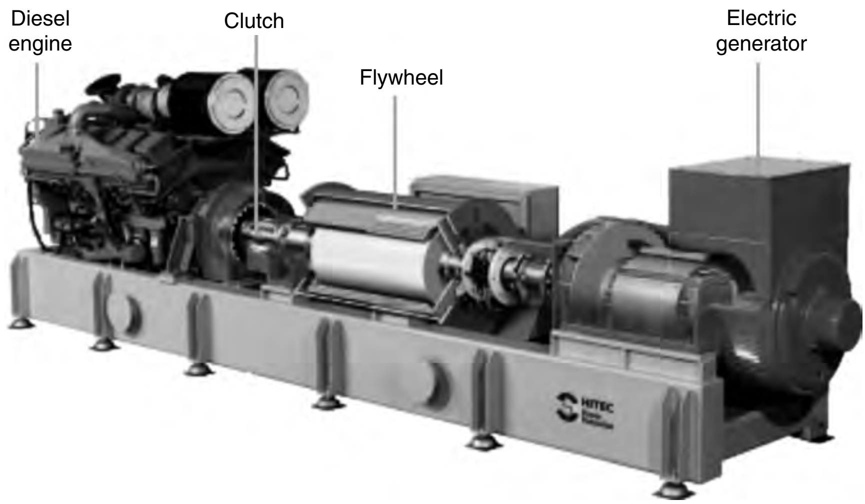


FIGURE 5.20 Dynamic UPS, by Hitec Power Protection. (From http://www.hitecups.com/?RubriekID=1991. With permission.)

5.3 Demand-Side Management

Clark W. Gellings and Kelly E. Parmenter

5.3.1 Introduction

Since the mid-1980s, demand-side management has been an important element of the electric utility planning approach referred to as "integrated resource planning." At that time, annual demand-side management expenditures in the U.S. were measured in billions of dollars, energy savings were measured in billions of kilowatts hours, and peak load reductions were stated in thousands of megawatts. Although activities nationally have slowed since then, there are a number of instances where demand-side management continued to influence the demand for electricity. This article defines demand-side management, describes the role demand-side management plays in integrated resource planning, and discusses the main elements of demand-side management programs. It then presents case studies of four successful demand-side management programs that were offered between 2001 and 2003.

5.3.2 What is Demand-Side Management?

The term *demand-side management* is the result of a logical evolution of planning processes used by utilities in the late 1980s. One of the first terms, *demand-side load management* was introduced by the author, Clark W. Gellings, in an article for IEEE's *Spectrum* in 1981. Shortly after the publication of this article, at a meeting of The Edison Electric Institute (EEI) Customer Service and Marketing Executives in 1982, Mr. Gellings altered the term to *demand-side planning*. This change was made to reflect the broader objectives of the planning process. Mr. Gellings coined the term *demand-side management* and continued to popularize the term throughout a series of more than 100 articles since that time, including the five-volume set *Demand-Side Management* that is widely recognized as a definitive and practical source of information on the demand-side management process.

Perhaps the most widely accepted definition of demand-side management is the following: "Demand-side management is the planning, implementation, and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape, i.e., changes in the time pattern and magnitude of a utility's load. Utility programs falling under the umbrella of demand-side management include: load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share" (Gellings 1984–1988). However, demand-side management is even more encompassing than this definition implies because it includes the management of all forms of energy at the demand-side, not just electricity. In addition, groups other than just electric utilities (including natural gas suppliers, government organizations, nonprofit groups, and private parties) implement demand-side management programs.

In general, demand-side management embraces the following critical components of energy planning:

1. Demand-side management will influence customer use. Any program intended to influence the customer's use of energy is considered demand-side management.
2. Demand-side management must achieve selected objectives. To constitute a "desired load shape change," the program must further the achievement of selected objectives, i.e., it must result in reductions in average rates, improvements in customer satisfaction, achievement of reliability targets, etc.
3. Demand-side management will be evaluated against non-demand-side management alternatives. The concept also requires that selected demand-side management programs further these objectives to at least as great an extent as non-demand-side management alternatives, such as generating units, purchased power or supply-side storage devices. In other words, it requires that demand-side management alternatives be compared to supply-side alternatives. It is at this stage of evaluation that demand-side management becomes part of the integrated resource planning process.
4. Demand-side management identifies how customers will respond. Demand-side management is pragmatically oriented. Normative programs ("we ought to do this") do not bring about the desired result; positive efforts ("if we do this, that will happen") are required. Thus, demand-side management encompasses a process that identifies how customers will respond not how they should respond.
5. Demand-side management value is influenced by load shape. Finally, this definition of demand-side management focuses upon the load shape. This implies an evaluation process that examines the value of programs according to how they influence costs and benefits throughout the day, week, month, and year.

Subsets of these activities have been referred to in the past as "load management," "strategic conservation," and "marketing."

5.3.3 Demand-Side Management and Integrated Resource Planning

A very important part of the demand-side management process involves the consistent evaluation of demand-side to supply-side alternatives and vice versa. This approach is referred to as "integrated resource planning." Figure 5.21 illustrates how demand-side management fits into the integrated resource planning process. For demand-side management to be a viable resource option, it has to compete with traditional supply-side options.

5.3.4 Demand-Side Management Programs

A variety of programs have been implemented since the introduction of demand-side management in the early 1980s. Mr. Gellings and EPRI have been instrumental in defining a framework for utilities and other implementers to follow when planning demand-side management programs. This section describes the main elements of the demand-side management planning framework. It then discusses the types of end use sectors, buildings, and end use technologies targeted during program development. It also lists the various entities typically responsible for implementing programs, along with several program implementation methods. Lastly, this section summarizes several representative demand-side management programs offered in the US.

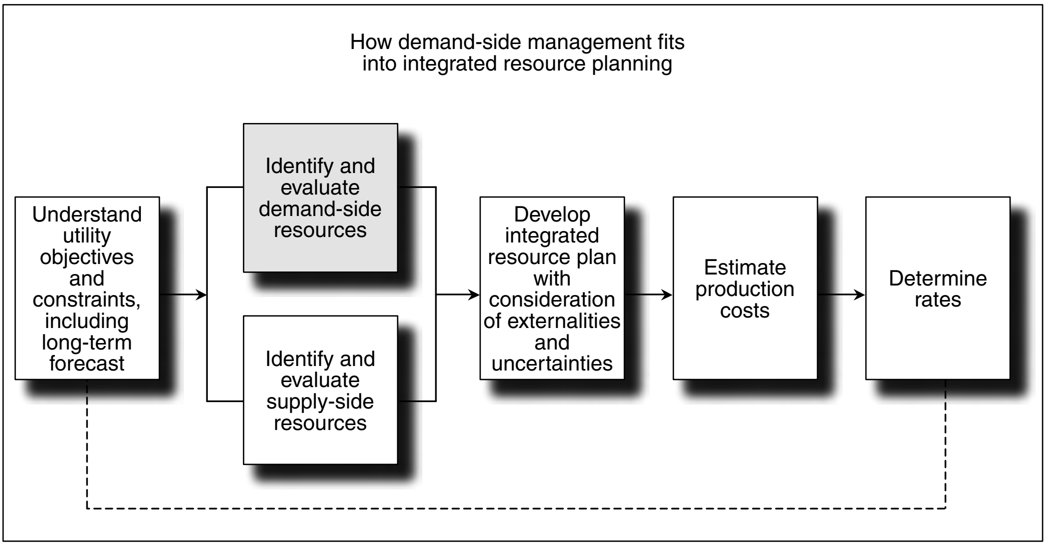


FIGURE 5.21 How demand-side management fits into integrated resources planning.

5.3.4.1 Elements of the Demand-Side Management Planning Framework

Figure 5.22 illustrates the five main elements of the demand-side management planning framework. These five elements are summarized as follows:

1. Set objectives. The first step in demand-side management planning is to establish overall organizational objectives. These strategic objectives are quite broad and generally include examples, such as reducing energy needs, reducing dependence on foreign imports, improving cash flow, increasing earnings, or improving customer and employee relations. The second level of the formal planning process is to operationalize broad objectives to guide policymakers to specific actions. It is at this operational level or tactical level that demand-side management alternatives should be examined and evaluated. For example, an examination of capital investment requirements may show periods of high investment needs. Postponing the need for new construction through a demand-side management program may reduce investment needs and stabilize the financial future of an energy company, or a utility and its state or country. Specific operational objectives are established on the basis of the conditions of the existing energy system—its system configuration, cash reserves, operating environment, and competition. Once designated, operational objectives are translated into desired demand-pattern changes or load-shape changes that can be used to characterize the potential impact of alternative demand-side management programs. Although there is an infinite combination of load-shape-changing possibilities, six have been illustrated in Figure 5.23 to show the range of possibilities, namely peak clipping, valley filling, load shifting, strategic conservation, strategic load growth, and flexible load shape. These six are not mutually exclusive, and may frequently be employed in combinations.
2. Identify alternatives. The second step is to identify alternatives. The first dimension of this step involves identifying the appropriate end uses whose peak load and energy consumption characteristics generally match the requirements of the load-shape objectives established in the previous step. In general, each end use (e.g., residential space heating, commercial lighting) exhibits typical and predictable demand or load patterns. The extent to which load pattern modification can be accommodated by a given end use is one factor used to select an end use for demand-side management. The second dimension of demand-side management alternatives involves choosing appropriate technology alternatives for each target end use. This process

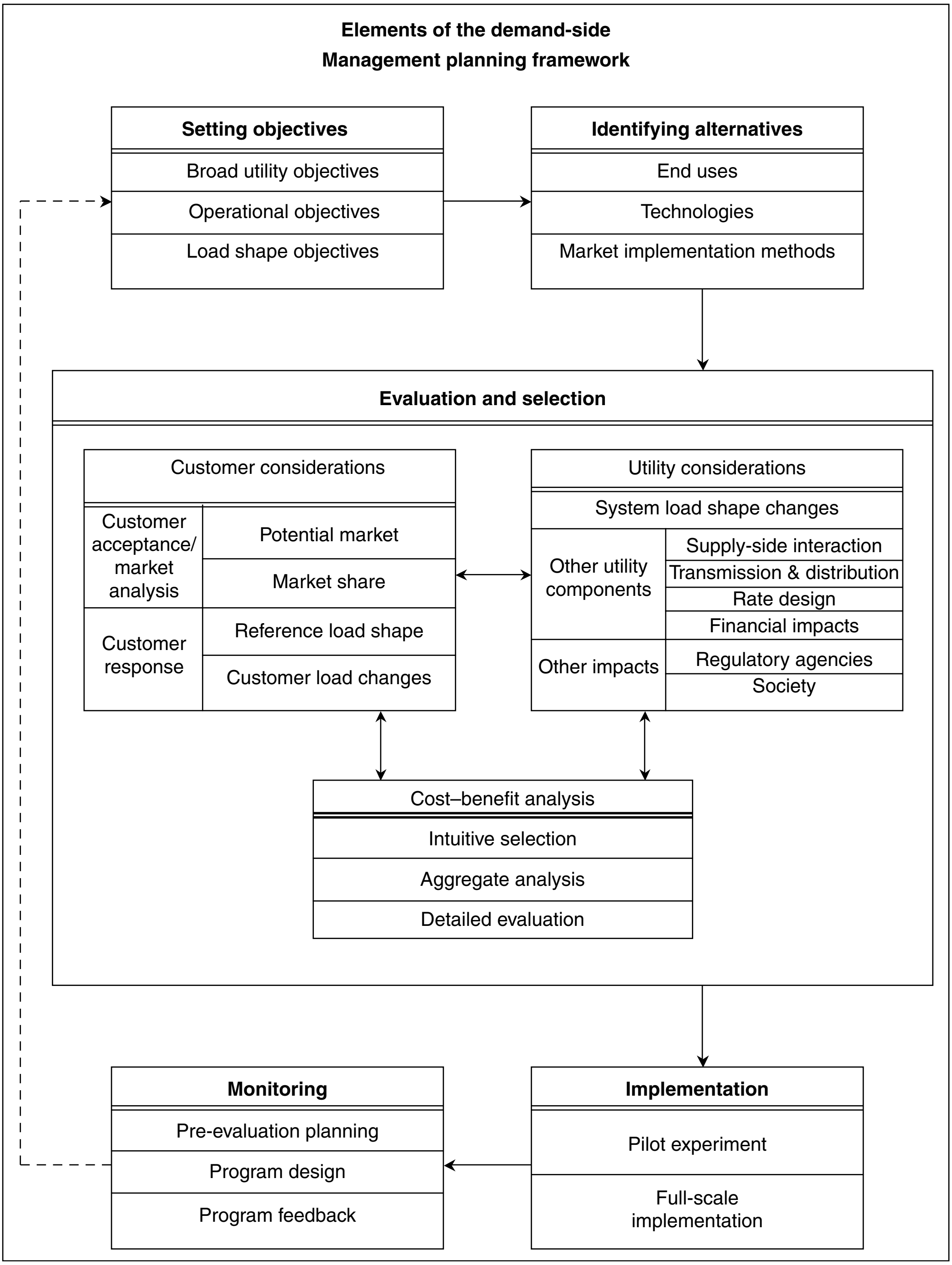


FIGURE 5.22 Elements of the demand-side management planning framework.

should consider the suitability of the technology for satisfying the load-shape objective. Even though a technology is suitable for a given end use, it may not produce the desired results. For example, although water-heater wraps are appropriate for reducing domestic water-heating energy consumption, they are not appropriate for load shifting. In this case, an option such as electric

Peak Clipping - Or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct utility control of either service to customer facilities or of customers' appliances. While many utilities consider this as means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.

Valley Filling - Is the second classic form of load management and applies to both gas and electric systems. Valley filling encompasses building off-peak loads. This may be particularly desirable where the long-run incremental cost is less than the average price of energy. Adding properly priced off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.

Load Shifting - Is the last classic form of load management and also applies to both gas and electric systems. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, coolness storage, and customer load shifts. The load shift from storage devices involves displacing what would have been conventional appliances.

Strategic Conservation - Is the load shape change that results from programs directed at end use consumption. Not normally considered load management, the change reflects a modification of the load shape involving a reduction in consumption as well as a change in the pattern of use. In employing energy conservation, the planner must consider what conservation actions would occur naturally and then evaluate the cost-effectiveness of possible intended programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.

Strategic Load Growth - Is the load shape change that refers to a general increase in sales beyond the valley filling described previously. Load growth may involve increased market share of loads that are or can be, served by competing fuels, as well as economic development. Load growth may include electrification. Electrification is the term being employed to describe the new emerging electric technologies surrounding electric vehicles, industrial process heating, and automation. These have a potential for increasing the electric energy intensity of the industrial sector. This rise in intensity may be motivated by reduction in the use of fossil fuels and raw materials resulting in improved overall productivity.

Flexible Load Shape - Is a concept related to electric system reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over some horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria he uses is reliability. Load shape can be flexible – if customers are presented with options as to the variations in quality of service that they are willing to allow in exchange for various incentives. The program involved can be variations of interruptible or curtailable load; concepts of pooled, integrated energy management systems; or individual customer load control devices offering service constraints.

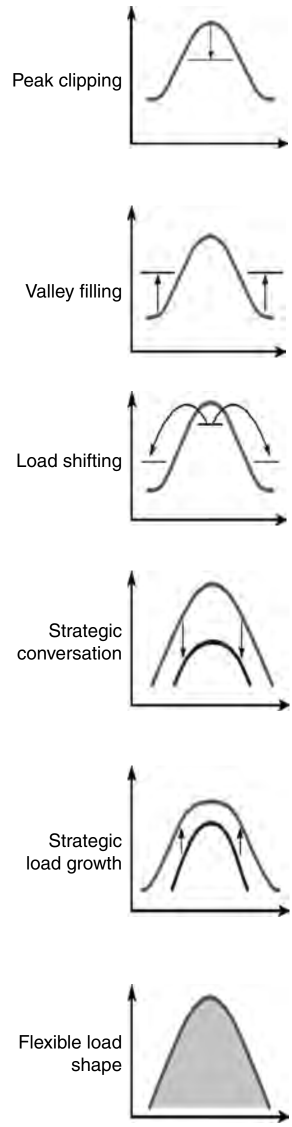


FIGURE 5.23 Six generic load shape objectives that can be considered during demand-side management planning.

water-heating direct load control via receiver/switches would be a better choice. The third dimension involves investigating market implementation methods (see Section 5.3.4.5 for a description of potential implementation methods).

3. Evaluate and select program(s). The third step balances customer considerations, supplier considerations, and cost–benefit analyses to identify the most viable demand-side management alternative(s) to pursue. Although customers and suppliers act independently to alter the pattern of demand, the concept of demand-side management implies a supplier/customer relationship that produces mutually beneficial results. To achieve that mutual benefit, suppliers must carefully

consider such factors as the manner in which the activity will affect the patterns and amount of demand (load shape), the methods available for obtaining customer participation, and the likely magnitudes of costs and benefits to both supplier and customer prior to attempting implementation.

4. Implement program(s). The fourth step, which takes place in several stages, is to implement the program(s). As a first step, a high level, demand-side management project team should be created with representation from the various departments and organizations, and with the overall control and responsibility for the implementation process. It is important for implementers to establish clear directives for the project team, including a written scope of responsibility, project team goals and time frame. When limited information is available on prior demand-side management program experiences, a pilot experiment may precede the program. Pilot experiments can be a useful interim step toward making a decision to undertake a major program. Pilot experiments may be limited either to a subregion or to a sample of consumers throughout an area. If the pilot experiment proves cost-effective, then the implementers may consider initiating the full-scale program.
5. Monitor program(s). The fifth step is to monitor the program(s). The ultimate goal of the monitoring process is to identify deviations from expected performance and to improve both existing and planned demand-side management programs. Monitoring and evaluation processes can also serve as a primary source of information on customer behavior and system impacts, foster advanced planning and organization within a demand-side management program, and provide management with the means of examining demand-side management programs as they develop.

5.3.4.2 Targeted End Use Sectors/Building Types

The three broad categories of end use sectors targeted for demand-side management programs are residential, commercial, and industrial. Each of these broad categories includes several subsectors. In some cases, the program will be designed for one or more broad sectors; in other cases, it may be designed for a specific subsector. For example, the residential sector can be divided into several subsectors including single family homes, multi-family homes, mobile homes, low income homes, etc. In addition, the commercial sector can be split into subsets, such as offices, restaurants, healthcare facilities, educational facilities, retail stores, grocery stores, hotels/motels, etc. There are also numerous specific industrial end users that may be potentially targeted for a demand-side management program. Moreover, the program designer may want to target a specific type or size of building within the chosen sector. The program could focus on new construction, old construction, renovations and retrofits, large customers, small customers, or a combination. Crosscutting programs target multiple end use sectors and/or multiple building types. Figure 5.24 illustrates the broad types of end use sectors and building types and how they relate to other aspects of demand-side management program planning.

5.3.4.3 Targeted End Use Technologies/Program Types

There are several end use technologies or program types targeted in demand-side management programs. (See Figure 5.24 for representative end use technologies and program types.) Some programs are comprehensive, and crossover between end use technologies (e.g., see case study 1 below). Other technologies target-specific end use equipment such as lighting, air conditioners, dishwashers, etc. Still others target load control measures, such as those that shift loads to off-peak hours (e.g., thermal energy storage). Figure 5.24 shows representative end use technologies or program types and how they relate to other aspects of demand-side management program planning.

5.3.4.4 Program Implementers

Implementers of demand-side management programs are often utilities. However, other possible implementers include government organizations, nonprofit groups, private parties, or a collaboration of several entities (see Figure 5.24). Utilities and governments, in particular, have a special interest in influencing customers' demand—treating it not as fate but as choice—to provide better service at lower

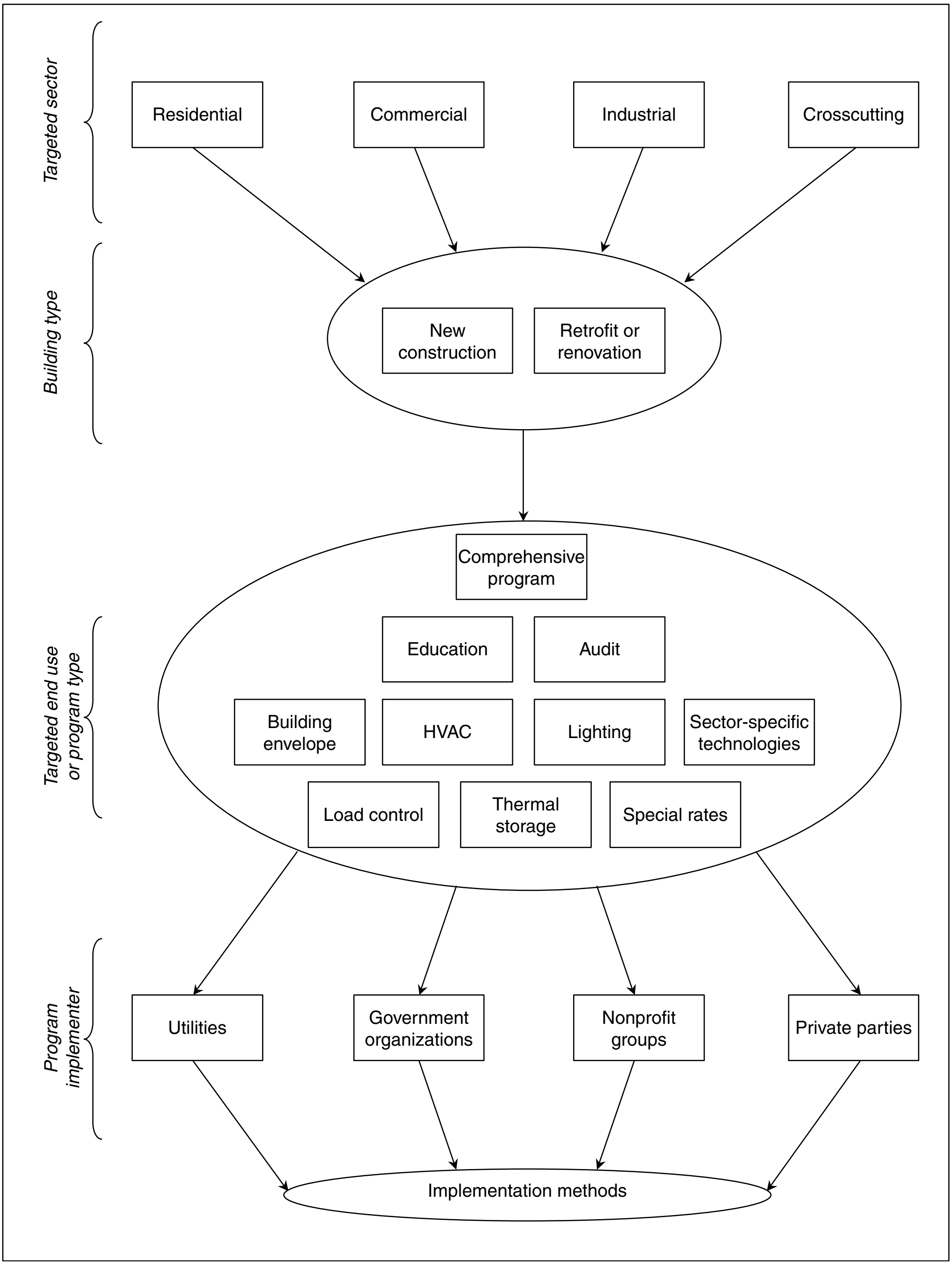


FIGURE 5.24 Relationship between end use sectors, building types, end use programs, and program implementers.

cost while increasing their own profits and reducing their business risks. Energy planners can choose from a wide range of market push and pull methods designed to influence consumer adoption and reduce barriers, as discussed in the next paragraph.

5.3.4.5 Implementation Methods

Among the most important dimension in the characterization of demand-side alternatives is the selection of the appropriate market implementation methods. Planners and policy makers can select from a variety of methods for influencing customer adoption and acceptance of demand-side management programs. The methods can be broadly classified into six categories. Table 5.10 lists examples for each category of market implementation method. The categories include:

1. Customer education. Many energy suppliers and governments have relied on some form of customer education to promote general customer awareness of programs. Brochures, bill inserts,

TABLE 5.10 Examples of Market Implementation Methods

Market Implementation Method	Illustrative Objective	Examples
Customer education	Increase perceived value of energy services Increase customer awareness of programs	Bill inserts Brochures Information packets Displays Clearinghouses Direct mailings
Direct customer contact	Through face-to-face communication, encourage greater customer acceptance, and response to programs	Energy audits Direct installation Store fronts Workshops/energy clinics Exhibits/displays Inspection services
Trade ally cooperation (i.e., architects, engineers, appliance dealers, heating/cooling contractors)	Increase capability in marketing and implementing programs Obtain support and technical advice on customer adoption of demand-side technologies	Cooperative advertising and marketing Training Certification Selected product sales/service
Advertising and promotion	Increase public awareness of new programs Influence customer response	Mass media (radio, TV, and newspaper) Point-of-purchase advertising
Alternative pricing	Provide customers with pricing signals that reflect real economic costs and encourage the desired market response	Demand rates Time-of-use rates Off-peak rates Seasonal rates Inverted rates Variable levels of service Promotional rates Conservation rates
Direct incentives	Reduce up-front purchase price and risk of demand-side technologies to the customer Increase short-term market penetration Provide incentives to employees to promote demand-side management programs	Low- or no-interest loan Cash grants Subsidized installation/modification Rebates Buyback programs Rewards to employees for successful marketing of demand-side management programs

information packets, clearinghouses, educational curricula, and direct mailings are widely used. Customer education is the most basic of the market implementation methods available and should be used in conjunction with one or more other market implementation method for maximum effectiveness.

2. Direct customer contact. Direct customer contact techniques refer to face-to-face communication between the customer and an energy supplier or government representative to encourage greater customer acceptance of programs. Energy suppliers have for some time employed marketing and customer service representatives to provide advice on appliance choice and operation, sizing of heating/cooling systems, lighting design, and even home economics. Direct customer contact can be accomplished through energy audits, specific program services (e.g., equipment servicing), store fronts where information and devices are displayed, workshops, exhibits, onsite inspection, etc. A major advantage of these methods is that they allow the implementer to obtain feedback from the consumer, thus providing an opportunity to identify and respond to major customer concerns. They also enable more personalized marketing, and can be useful in communicating interest in and concern for controlling energy costs.
3. Trade ally cooperation. Trade ally cooperation and support can contribute significantly to the success of many demand-side management programs. A trade ally is defined as any organization that can influence the transactions between the supplier and its customers or between implementers and consumers. Key trade ally groups include home builders and contractors, local chapters of professional societies, technology/product trade groups, trade associations, and associations representing wholesalers and retailers of appliances and energy consuming devices. Depending on the type of trade ally organization, a wide range of services are performed, including development of standards and procedures, technology transfer, training, certification, marketing/sales, installation, maintenance, and repair. Generally, if trade ally groups believe that demand-side management programs will help them (or at least not hinder their business), they will likely support the program.
4. Advertising and promotion. Energy suppliers and government energy entities have used a variety of advertising and promotional techniques. Advertising uses various media to communicate a message to customers in order to inform or persuade them. Advertising media applicable to demand-side management programs include radio, television, magazines, newspapers, outdoor advertising, and point-of-purchase advertising. Promotion usually includes activities to support advertising, such as press releases, personal selling, displays, demonstrations, coupons, and contest/awards. Some prefer the use of newspapers based on consumer research that found this medium to be the major source of customer awareness of demand-side management programs. Others have found television advertising to be more effective.
5. Alternative pricing. Pricing as a market-influencing factor generally performs three functions: (1) transfers to producers and consumers information regarding the cost or value of products and services being provided, (2) provides incentives to use the most efficient production and consumption methods, and (3) determines who can afford how much of a product. These three functions are closely interrelated. Alternative pricing, through innovative schemes can be an important implementation technique for utilities promoting demand-side options. For example, rate incentives for encouraging specific patterns of utilization of electricity can often be combined with other strategies (e.g., direct incentives) to achieve electric utility demand-side management goals. Pricing structures include time-of-use rates, inverted rates, seasonal rates, variable service levels, promotional rates, off-peak rates, etc., A major advantage of alternative pricing programs over some other types of implementation techniques is that the supplier has little or no cash outlay. The customer receives a financial incentive, but over a period of years, so that the implementer can provide the incentives as it receives the benefits.
6. Direct incentives. Direct incentives are used to increase short-term market penetration of a cost control/customer option by reducing the net cash outlay required for equipment purchase or by reducing the payback period (i.e., increasing the rate of return) to make the investment more

attractive. Incentives also reduce customer resistance to options without proven performance histories or options that involve extensive modifications to the building or the customer's lifestyle. Direct incentives include cash grants, rebates, buyback programs, billing credits, and low-interest or no-interest loans. One additional type of direct incentive is the offer of free, or very heavily, subsidized, equipment installation or maintenance in exchange for participation. Such arrangements may cost the supplier more than the direct benefits from the energy or demand impact, but can expedite customer recruitment and allow the collection of valuable empirical performance data.

Energy suppliers, utilities, and government entities have successfully used many of these marketing strategies. Typically, multiple marketing methods are used to promote demand-side management programs. The selection of the individual market implementation method or mix of methods depends on a number of factors, including:

- Prior experience with similar programs
- Existing market penetration
- The receptivity of policy makers and regulatory authorities
- The estimated program benefits and costs to suppliers and customers
- Stage of buyer readiness
- Barriers to implementation

Some of the most innovative demand-side marketing programs started as pilot programs to gauge consumer acceptance and evaluate program design prior to large-scale implementation.

The objective of the market implementation methods is to influence the marketplace and to change customer behavior. The key question for planners and policy makers is the selection of the market implementation method(s) to obtain the desired customer acceptance and response. Customer acceptance refers to customer willingness to participate in a market implementation program, customer decisions to adopt the desired fuel/appliance choice and efficiency, and behavior change as encouraged by the supplier, or state. Customer response is the actual load shape change that results from customer action, combined with the characteristics of the devices and systems being used.

Customer acceptance and responses are influenced by the demographic characteristics of the customer, income, knowledge, and awareness of the technologies and programs available, and decision criteria such as cash flow and perceived benefits and costs, as well as attitudes and motivations. Customer acceptance and response are also influenced by other external factors, such as economic conditions, energy prices, technology characteristics, regulation, and tax credits.

5.3.4.6 Representative Programs in the U.S.

Numerous demand-side management programs are implemented in the U.S. yearly by various organizations. In recent years, the California Best Practices Project Advisory Committee and their contractor, Quantum Consulting, Inc., have reviewed and compared many demand-side management programs that focus on energy conservation and efficiency as part of a National Energy Efficiency Best Practices Study. The results of the study are included in a series of reports. Table 5.11 provides an overview of more than 60 programs evaluated in the National Energy Efficiency Best Practices Study that were implemented between 1999 and 2004. The type of program, program name, implementer(s), achieved energy and demand savings, program cost, and review period are listed for each program. Where values were not available, the abbreviation "NA" is used. The table shows the wide variety of programs offered spanning the residential and nonresidential sectors. Some programs provide general information and training, others target specific end uses such as lighting, heating, ventilation and air conditioning (HVAC), and new construction, and still others are comprehensive in nature. Yearly costs for the programs in Table 5.11 ranged from $150,000 for a nonresidential HVAC program offered to customers in a single service territory to $25.9 million for a statewide comprehensive program.

TABLE 5.11 Examples of Recent Demand-Side Management Programs in the U.S.

Program Type	Program Name	Implementer(s)	Time Period	Cost	Energy Savings	Demand Savings
Residential lighting[a]	2002 California Crosscutting Statewide Residential Lighting Program	Pacific Gas & Electric Co. (PG&E); Southern California Edison (SCE); San Diego Gas & Electric Co. (SDG&E)	2002	$9.4 million	162,888 MWh	21,365 kW
	2002 Efficient Products Program—Lighting Component	Efficiency Vermont (EVT)	2002	$1.6 million	11,039 MWh	1740 kW winter 1074 kW summer
	2002 Massachusetts Electric—Residential Lighting Program	Massachusetts Electric	2002	$3.3 million	18,037 MWh	5084 kW
	2002 Midwest Change a Light, Change the World Campaign	Midwest Energy Efficiency Alliance (MEEA)	Fall 2002	$630,000	10,198 MWh	NA
	2001 ENERGY STAR® Residential Lighting Program	Northwest Energy Efficiency Alliance (NW Alliance)	2001	$2.6 million	271,560 MWh	NA
	2000–2001 Retail Lighting Program	United Illuminating	2000–2001	$3.0 million	7808 MWh	NA
Residential AC[b]	2002 Keep Cool Air Conditioner Bounty Program	New York State Energy Research and Development Authority (NYSERDA)	2002	NA	27,208 MWh	44,813 kW
	2002 California Statewide Single-Family Rebate Program AC Component	PG&E; SCE; SDG&E	2002	NA (included in overall Single-Family Rebate Program budget)	8399 MWh	NA
	2002 New Jersey Clean Energy™ Collaborative Residential AC Component	Conectiv Power Delivery; Jersey Central Power & Light Co. (JCP&L); Public Service Electric & Gas Co. (PSE&G); Rockland Electric Company (RECO)	2002	$24.2 million	NA	NA

(continued)

TABLE 5.11 (*Continued*)

Program Type	Program Name	Implementer(s)	Time Period	Cost	Energy Savings	Demand Savings
	2003 Air Conditioning Distributor Market Transformation Program	Oncor	2003	$5.9 million	13,478 MWh	10,800 kW
	2002 Residential Air Conditioning Program	Florida Power and Light (FPL)	2002	$18.0 million	78,957 MWh	37,360 kW
Single-Family Comprehensive[c]	2001–2002 Central Valley Hard-to-Reach Mobile Home Energy Savings Program	American Synergy Corp.	Oct. 2002–Oct. 2003	$1.4 million	3,447 MWh	1,329 kW
	2002 California Statewide Single-Family Energy Efficiency Rebate Program	PG&E; SCE; SDG&E	2002	$25.9 million	36,028 MWh	31,869 kW
	1999–2000 Residential High-Use Program	NSTAR	Aug. 1999–Aug. 2000	$3.5 million	3,179 MWh	1,164 kW winter 831 kW summer
	2001 Energy Wise Program	National Grid U.S.A.	2001	$1.2 million	3,461 MWh	743 kW
	2002 Efficiency Equipment Load Program	Sacramento Municipal Utility District (SMUD)	2002	$2.4 million	1,254 MWh	700 kW
	2002 Residential Weatherization Program	Tacoma Power	2002	$938,000	2,031 MWh	NA
Multi-Family Comprehensive[d]	2002 Multi-Family Incentive Program	Austin Energy	2002	$581,300	3,121 MWh	2,080 kW
	2002 California Statewide Multi-Family Program	PG&E; SCE; SDG&E	2002	$8.3 million	9,050 MWh gross 7,621 MWh net	1,853 kW
	2003 Home Energy Savings Program—Multi-Family Component	The City of Portland/Energy Trust of Oregon, Inc.	Jan.–Dec. 2003	$1.0 million	7,000 MWh gross 2,578 MWh net	NA
	2002–2003 Apartment & Condo Efficiency Services	Focus on Energy™/Wisconsin Energy Conservation Corp. (WECC)	Sep. 2002–Aug. 2003	$5.1 million	12,963 MWh net	2,391 kW net
	2002 Energy Wise—Multi-Family Component	National Grid	2002	$2.3 million	3,487 MWh gross 2,706 MWh net	400 kW winter 600 kW summer
	2000 Multi-Family Conservation Program	Seattle City Light (SCL)	2000	$1.2 million	2,769 MWh	NA

Audits & Information[e]	2002 Home Performance with ENERGY STAR Program	NYSERDA	2002	$4.0 million	741 MWh	80 kW
	2000 Time-of-Sale Home Inspection Program	SCE; GeoPraxis, Inc.	2000	$282,000	1,974 MWh	NA
	2002 Residential Conservation Services Audit Program	National Grid	2002	$2.8 million	2,677 MWh	406 kW
	2002 E+ Energy Audit for Your Home Program	Northwestern Energy	2002	$1.3 million	4,713 MWh	884 kW
	2002 Residential Energy Advisory Services Program	SMUD	2002	$1.1 million	400 MWh	70 kW
	2002 California Statewide Home Energy Efficiency Program	PG&E; SCE; SDG&E	2002	$2.0 million	8,700 MWh	4,190 kW
Residential New Construction[f]	2001–2002 Austin Green Building Program	Austin Energy	FY 2000–2001	$605,000	7,666 MWh	3,630 kW
	2002 California Energy Star New Homes Program	PG&E; SCE; SDG&E	2002	$15.2 million	10,655 MWh	22,262 kW
	2002 New Jersey ENERGY STAR Homes	Clean Energy for New Jersey	2002	$10.9 million	3,262 MWh	3,415 kW
	2002 Texas ENERGY STAR Homes Program	Oncor	2002	$5.2 million	24,700 MWh	7,410 kW
	2002 Tucson Guarantee Home Program	Tucson Electric Power	2002	$3.0 million	3,023 MWh	4,094 kW
	2001 Vermont ENERGY STAR Homes	EVT	2001	$920,000	841 MWh	278 kW
	2001–2002 Wisconsin ENERGY STAR Program	WECC	2002–2003	$2.9 million	1,049 MWh	247 kW
Nonresidential Lighting[g]	2003 Lighting Efficiency Program	Xcel Energy	2003	$2.3 million for all commercial & industrial $1.1 million for businesses <500kW	41,780 MWh for all commercial & industrial 19,433 MWh for businesses <500kW	7896 kW for all commercial & industrial 3928 kW for businesses <500kW
	2002–2003 Business Energy Services Team Program	KEMA-XENERGY	2002–2003	$941,000	2,704 MWh	559 kW
	2002 EZ Turnkey Program	SDG&E	2002	$1.3 million	3,121 MWh	570 kW

(continued)

TABLE 5.11 (*Continued*)

Program Type	Program Name	Implementer(s)	Time Period	Cost	Energy Savings	Demand Savings
	2003 Small Commercial Prescriptive Lighting Initiative	SMUD	2003	$2.7 million	19,865 MWh	3,920 kW
	2002 Small Business Energy Advantage Program	Connecticut Light & Power (CL&P)	2003	$4.6 million	16,167 MWh	3,570 kW
	2002 California Statewide Express Efficiency Program	PG&E; SCE; SDG&E	2002	$21.7 million	244,346 MWh	43,000 kW
Nonresidential HVAC[h]	New England Efficiency Partnership (NEEP) Cool Choice Program	CL&P; United Illuminating; Cape Light Compact; Massachusetts Electric Co.; Nantucket Electric Co.; NSTAR Electric; Western Massachusetts Electric Co.; Conectiv Power Delivery; JCP&L; PSE&G; Narragansett Electric Co.; Burlington Electric; EVT	2002	$2.3 million	3929 MWh	3518 kW
	Avista Rooftop HVAC Maintenance Program	Avista Utilities	2001	$1.8 million	13,000 MWh	NA
	California Express Efficiency HVAC Component	PG&E; SCE; SDG&E	2002	NA (included in overall Express Efficiency program budget)	2,901 MWh	NA
	Los Angeles Department of Water and Power (DWP) Chiller Efficiency	Los Angeles DWP	2003–2004	$786,430	7,174 MWh	5,666 kW
	FP&L Commercial/Industrial HVAC Program	FPL	2002	$5.4 million	NA	NA
	Glendale Water and Power Check Me!	Glendale Water and Power	2001	$150,000	25,128 MWh	358 kW
Nonresidential Large Comprehensive Incentive[i]	Non-Residential Standard Performance Contract	PG&E; SCE; SDG&E	2002	$23.0 million	167,300 MWh	28,441 kW
	Energy $mart™ C/I Performance	NYSERDA	2001–2002	$34.2 million	204,500 MWh	53,886 kW
	Energy Opportunities	United Illuminating	2002	$1.3 million	10,772 MWh	2,627 kW

	Power Smart	BC Hydro	2004	$7.8 million industrial $17.6 million commercial and government	54,000 MWh industrial 74,000 MWh commercial and government	NA
	Custom Efficiency	Xcel Energy (Colorado)	2002–2005	$12.2 million	76,167 MWh	40,077 kW
	Custom Services	CL&P	2003	$8.6 million	24,853 MWh	NA
	Energy Initiative	National Grid	2002	$9.7 million	30,862 MWh	6,089 kW
	Energy Shared Savings	WP&L (Alliant) Wisconsin	2001	$21.9 million	104,325 MWh	16,000 kW
	Business Energy Services	EVT	2002	$1.1 million	4,955 MWh	NA
	Commercial & Industrial Custom Retrofit	SMUD	2002	$7.3 million	NA	NA
New Construction Information & Services[j]	Energy Conscious Construction	Northeast Utilities	2002	$7.4 million	33,365 MWh	NA
	Energy Design Assistance	Xcel Energy	2002	$3.4 million	63,093 MWh	19,100 kW
	Design 2000 Plus	National Grid	2002	$13.9 million	31,804 MWh	6,429 kW
	Savings by Design	PG&E; SCE; SDG&E	2002	$22.6 million	82,697 MWh	18,600 kW
	Construction Solutions	NSTAR	2001	$7.9 million	14,230 MWh	1,710 kW
	Commercial & Industrial New Construction Program	Hawaiian Electric Co. (HECO)	1999	$935,000	5584 MWh	821 kW

[a] Quantum Consulting, Inc., 2004. *Residential Lighting Best Practices Report*, *Vol. 1*, *National Energy Efficiency Best Practices Study*. Quantum Consulting, Inc., Berkeley, CA.
[b] Quantum Consulting, Inc., 2004. *Residential Air Conditioning Best Practices Report*, *Vol. R2*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[c] Quantum Consulting, Inc., 2004. *Residential Single-Family Comprehensive Weatherization Best Practices Report*, *Vol. R4*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[d] Quantum Consulting, Inc., 2004. *Residential Multi-Family Comprehensive Best Practices Report*, *Vol. R5*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[e] Quantum Consulting, Inc., 2004. *Residential Audit Programs Best Practices Report*, *Vol. R7*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[f] Quantum Consulting, Inc., 2004. *Residential New Construction Best Practices Report*, *Vol. R8*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[g] Quantum Consulting, Inc., 2004. *Non-Residential Lighting Best Practices Report*, *Vol. NR1*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[h] Quantum Consulting, Inc., 2004. *Non-Residential HVAC Best Practices Report*, *Vol. NR2*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[i] Quantum Consulting, Inc., 2004. *Non-Residential Large Comprehensive Incentive Programs Best Practices Report*, *Vol. NR5*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.
[j] Quantum Consulting, Inc., 2004. *Non-Residential New Construction Best Practices Report*, *Vol. NR8*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.

Reported energy savings ranged from 400 MWh for a residential audit and information program offered in a single service territory to 271,560 MWh for a northwest regional ENERGY STAR® residential lighting program. The following section examines four of the programs from Table 5.11 in more detail.

5.3.5 Case Studies

5.3.5.1 Case Study 1: 2001 California 20/20 Rebate Program[1]

In response to a crisis of constrained supply, skyrocketing electricity prices, and fear of summer blackouts, California launched an enormous effort in 2001 to conserve energy and reduce electricity demand. This effort was primarily embodied in emergency legislation that provided additional funding and led to the rapid development and deployment of hundreds of energy efficiency programs administered and implemented by a variety of entities. One of the most successful programs was the 2001 California 20/20 Rebate Program (see Table 5.12 for program summary). This program provided rebates to residential and small commercial/industrial customers of the state's investor-owned utilities for reducing monthly electricity usage from June through September, 2001. Customers were offered a 20% rebate off of the electricity commodity portion of their energy bill for lowering their total monthly electricity use by at least 20% compared to the same month of the previous year. In addition, large commercial/industrial customers with time-of-use meters received a 20% rebate off of their summer on-peak demand and energy charges for reducing on-peak electricity use by at least 20%. The program was executed with cooperation and funding by several state agencies and organizations. Because the program overlapped with other California programs such as the "Flex Your Power" marketing campaign, it was difficult to accurately credit energy savings specifically to the 20/20 Rebate Program. In a study for the California Measurement Advisory Council (CALMAC), which involved evaluating the success of California's 2001 programs, Global Energy Partners (Global) attempted to adjust reported savings from the 20/20 Rebate Program to discount the effect of double counting. The reported accomplishments of the program were 5.3 million MWh in energy savings and 2616 MW in demand savings. With Global's adjustments for double counting among programs, the energy savings were estimated to be 3.1 MWh. The program budget for 2001 was $350 million. Although this program was hugely successful during the crisis of 2001, it is difficult to sustain a program of this type in the absence of an immediate energy crisis. As a result, it was discontinued after 2002.

5.3.5.2 Case Study 2: 2002 California Statewide Residential Lighting Program[2]

The 2002 California Statewide Residential Lighting Program was designed in response to the 2001 energy crisis experienced in California (see Table 5.13 for program summary). Its purpose was to encourage greater penetration of energy efficient lamps and fixtures into the residential sector. The products covered included compact fluorescent lamps, torchieres, ceiling fans, and complete fixtures. This was accomplished by providing rebates to manufacturers (manufacturer upstream buydown) to lower wholesale costs as well as by providing instant rebates to consumers at the point of sale. The program was implemented by three large investor-owned utilities in the state: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Each utility had in-house management responsibilities. The program leveraged on relationships with manufacturers and retailers established in previous lighting programs. Progress was tracked by using data on the number of products delivered by manufacturers and retailer sales information. In all, 5,502,518 lamps, 24,932 fixtures, 6736 torchieres, and 50 ceiling fans with bulbs were rebated during 2002. The estimated program accomplishments were 162,888 MWh in energy savings, and 21.4 MW in demand savings. The total program cost was $9.4 million.

[1]Data from Global Energy Partners, 2003. *California Summary Study of 2001 Energy Efficiency Programs*. Publication 02-1099. Global Energy Partners, LLC, Lafayette, CA.

[2]Data from Quantum Consulting, Inc., 2004. *Residential Lighting Best Practices Report*, *Vol. 1*, *National Energy Efficiency Best Practices Study*. Quantum Consulting, Inc., Berkeley, CA.

TABLE 5.12 Case Study 1: 2001 California 20/20 Rebate Program

Description

The 20/20 Rebate program was a statewide program designed to address California's energy crisis in 2001. It provided rebates to residential and small commercial/industrial customers of the state's investor-owned utilities for reducing monthly electricity usage from June through September, 2001. Customers were offered a 20% rebate off of the electricity commodity portion of their energy bill for lowering their total monthly electricity use by at least 20% compared to the same month of the previous year. In addition, large commercial/industrial customers with time-of-use meters received a 20% rebate off of their summer on-peak demand and energy charges for reducing on-peak electricity use by at least 20%

Targeted Sector/Building Type

All residential, commercial, and industrial customers of California's investor-owned utilities

Targeted End Use Technology/Program Type

Rebate for reducing electricity use by 20% relative to same month in previous year

Program Implementer

Executive order of Governor Gray Davis; included cooperation and funding by several state agencies and organizations

Budget for Year

$350 million for 2001

Program Results

Reported energy savings = 5,258,000 MWh[a]
Adjusted energy savings = 3,053,000 MWh[b]
Demand savings = 2616 MW[c]

[a] Goldman and Barbose. 2002. *California Customer Load Reductions During the Electricity Crisis: Did they Help to Keep the Lights On?* Lawrence Berkeley National Laboratories, Berkeley, CA.

[b] During an evaluation of California's 2001 energy efficiency programs for the California Measurement Advisory Council (CALMAC), Global Energy Partners adjusted the 20/20 Rebate program's energy savings to correct for double counting. *Data Source*: Global Energy Partners. 2003. *California Summary Study of 2001 Energy Efficiency Programs*. Publication 02-1099. Global Energy Partners, LLC, Lafayette, CA.

[c] This value represents "residual" peak demand reduction for September 2001 attributable to the combined effects of the 20/20 Rebate program, the *Flex Your Power* public awareness campaign, electricity rates, and voluntary demand-side management. *Data Source*: California Energy Commission. 2001. *California Market Report*. Sacramento, CA, October.

TABLE 5.13 Case Study 2: 2002 California Statewide Residential Lighting Program

Description

The 2002 California Residential Lighting program was designed to build upon the success of earlier lighting efficiency programs, while at the same time address the more immediate energy needs brought about by the 2001 energy crisis in California. The program was unique in that it was implemented identically across the State's investor-owned utility service territories. It offered point-of-sale rebates and manufacturer buy-down to reduce lighting costs to residential customers

Targeted Sector/Building type

All residential

Targeted End Use Technology/Program Type

Multiple lighting measures

Program Implementer

California investor-owned utilities; PG&E, SCE, and SDG&E

Budget for Year

$9.4 million for 2002; $7.3 million total incentives paid

Program Results

Reported energy savings = 162,888 MWh
Demand savings = 21.4 MW

Source: From Quantum Consulting, Inc., *Residential Lighting Best Practices Report*, *Vol. 1*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA, 2004.

TABLE 5.14 Case Study 3: 2003 Xcel Energy Lighting Efficiency Program

Description
The 2003 Xcel lighting efficiency program offered low-cost energy assessments, low-interest financing, and rebates for replacing lighting in existing buildings and for adding energy efficient lighting during new construction. The rebates were both prescriptive and custom in nature

Targeted Sector/Building Type
All commercial and industrial customers
Small business customers < 500 kW

Targeted End Use Technology/Program Type
Multiple lighting measures

Program Implementer
Xcel energy of minnesota

Budget for Year
All commercial and industrial customers: $2.29 million for 2003; $1.51 million total incentives paid
Small business customers < 500 kW: $1.09 million for 2003; $0.66 million total incentives paid

Program Results
Reported energy savings = 41,780 MWh (net) for all commercial and industrial customers
= 19,433 MWh for small business customers < 500 kW
Demand savings = 7.9 MW (summer) for all commercial and industrial customers
= 3.9 MW for small business customers < 500 kW
Almost 900 prescriptive rebates were offered during 2003

Source: From Quantum Consulting, Inc., *Non-Residential Lighting Best Practices Report*, *Vol. NR1*, *National Energy Efficiency Best Practices Study*. Quantum Consulting, Inc., Berkeley, CA, 2004.

5.3.5.3 Case Study 3: 2003 Xcel Energy Lighting Efficiency Program[3]

The Xcel Energy Lighting Efficiency Program was designed to encourage energy efficient lighting design for commercial and industrial customers in Minnesota (see Table 5.14 for program summary). The implementer was Xcel Energy, a utility company. The program targeted all commercial and industrial customers, as well as small (less than 500 kW) businesses. It offered prescriptive and custom rebates, energy assessments, and low-interest financing for projects. The rebates were applicable both to lighting in new construction and to replacement of lighting in existing buildings. The customers or vendors were responsible for installing the lighting equipment. Xcel Energy managed the program with in-house personnel. The program managers were responsible for approving projects, monitoring applications, and verifying and tracking installations. During 2003, almost 900 prescriptive lighting projects were undertaken. The estimated program accomplishments were energy savings of 41,780 MWh for all commercial and industrial customers and 19,433 MWh for small businesses. The estimated demand savings were 7.9 and 3.9 MW, respectively, for commercial and industrial customers and for small businesses. The program costs for the year were $2.3 million for commercial and industrial customers, and $1.1 million for small businesses.

5.3.5.4 Case Study 4: 2002 Northeast Energy Efficiency Partnership Cool Choice Program[4]

The 2002 Northeast Energy Efficiency Partnership (NEEP) Cool Choice program was designed to increase penetration of high efficiency cooling systems in commercial and industrial buildings in the Northeast states of Connecticut, Rhode Island, Vermont, Massachusetts, and New Jersey (see Table 5.15 for program summary). NEEP, which is a collaboration of over a dozen utilities in the Northeast region,

[3]Data from Quantum Consulting, Inc. 2004. *Non-Residential Lighting Best Practices Report*, *Vol. NR1*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.

[4]Data from Quantum Consulting, Inc. 2004. *Non-Residential HVAC Best Practices Report*, *Vol. NR2*, *National Energy Efficiency Best Practices Study*. Quantum Consulting Inc., Berkeley, CA.

TABLE 5.15 Case Study 4: 2002 Northeast Energy Efficiency Partnership (NEEP) Cool Choice Program

Description
The 2002 Cool Choice program was an incentive-based program that provided rebates to commercial and industrial customers who purchased high efficiency air conditioning systems. The rebates were intended to offset the higher costs associated with energy efficient units

Targeted Sector/Building Type
All commercial and industrial customers

Targeted End Use Technology/Program Type:
High efficiency direct expansion air conditioners and heat pumps; economizers

Program Implementer
NEEP

Budget for Year
$2.3 million for 2002

Program Results
Reported energy savings = 3929 MWh
Demand savings = 3.5 MW

Source: From Quantum Consulting, Inc., *Non-Residential HVAC Best Practices Report*, *Vol. NR2*, *National Energy Efficiency Best Practices Study*, Quantum Consulting Inc., Berkeley, CA, 2004.

administered the program. The 2002 program was a continuation of an on-going program established in 1998 to educate HVAC contractors in the correct installation of HVAC systems and to encourage them to up-sell high efficiency units to consumers. The program offers an incentive to customers to help offset the greater costs associated with high-efficiency air-conditioning equipment. The incentive is based on the incremental improvement in efficiency provided by the energy efficient alternative, and covered 80% of the incremental costs for air conditioning systems of 30 tn. or less. An outside implementer managed the program and outreached to HVAC contractors, who then outreached to customers. The estimated program accomplishments for 2002 were 3929 MWh in energy savings and 3.5 MW in demand savings. The total program cost for the year was $2.3 million.

5.3.6 Conclusions

Since the early 1970s, economic, political, social, technological, and resource supply factors have combined to change the energy industry's operating environment and its outlook for the future. Many are faced with staggering capital requirements for new plants, significant fluctuations in demand and energy growth rates, declining financial performance and political or regulatory and consumer concern about rising prices. Although demand-side management is not a cure-all for these difficulties, it does provide for great many additional alternatives. These demand-side alternatives are equally appropriate for consideration by utilities, energy suppliers, energy-service suppliers, and government entities. Implementation of demand-side measures not only benefits the implementing organization by influencing load characteristics, delaying the need for new energy resources, and in general improving resource value, but it also provides benefits to customers such as reduced energy bills and/or improved performance from new technological options. In addition, society as a whole receives economic, environmental, and national security benefits. For example, because demand-side management programs can postpone the need for new power plants, the costs and emissions associated with fossil-fueled electricity generation are avoided. Demand-side management programs also tend generate more jobs and expenditures within the regions where the programs are implemented, boosting local economies. Moreover, demand-side management programs can help reduce a country's dependence on foreign oil imports, improving national security. Demand-side management alternatives, particularly those focused on energy conservation and efficiency, will continue to hold an important role in resources planning in the US and abroad, and will be a critical element in the pursuit of a sustainable energy future.

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