chapter six

Alternative Energy Options for Buildings: Distributed Generation—Power Generation At or Near Buildings

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Introduction

The purpose of this chapter is to discuss how sources of electric and thermal energy generation can be placed within or near buildings and thus serve as an alternative to the traditional model of delivering electricity to the customer—the central station model, where large power plants in relatively remote locations generate electricity from fossil fuels (and nuclear fuel and water), and the power they generate is transmitted long distances before being stepped down in voltage for use in local distribution systems. The alternative to this model, where electricity and thermal energy are generated at or near the site where the energy is used, is called distributed generation because the generation resources are distributed around the grid. More fundamentally, every commercial and residential facility is potentially a small power plant. This is the real alternative to the central generation model. With existing and readily available technology, every office building, apartment building, hotel, campus, hospital, and factory can generate enough electricity and thermal energy on-site to meet its own basic energy needs and export some to the grid. If configured correctly, these on-site systems can also keep the power on when the grid goes down and provide a much higher level of reliability, efficiency, and even quality than grid power.

Distributed Resources

Before getting into the considerations involved in actually generating power on-site, this chapter will discuss and consider as alternatives some less complicated measures that reduce the amount of electricity buildings and facilities use. This is of interest not only because these measures drive down the cost of power for the facility owner or manager, but also because, when deployed with on-site generation, they reduce the size and increase the efficiency of the on-site capacity needed. These measures are referred to not as distributed generation, but as distributed resources, and to the extent they reduce the amount of electricity that needs to be delivered at peak times, they are as valuable in economic terms as marginal additions to electric capacity—the so-called negawatt.

Demand-Side Management

Demand-side management (DSM) has been gaining increasing attention over the past few years. The basic idea is a fairly simple one: when there is the most stress on the central distribution grid—usually on the hottest summer days—individual facilities can use less electricity or produce more of their own. Demand-side management can be a big money saver for buildings and facilities that enroll in the programs, particularly in areas of the country that have state or regional power markets. In these power markets, prices tend to spike dramatically during peak usage periods as the system operator calls on more and more inefficient stand-by generation to meet surging demand. When utilities pass these wholesale prices through to customers, there is an appreciable increase in the average price per kilowatt hour.

The most straightforward demand-side management program is one where a facility owner or manager enters into an agreement with a utility or a system operator to "shed load" when called upon. This can be as simple as turning up the temperature on air-conditioning equipment or shutting down the air-conditioning system for, say, 20 minutes an hour. In buildings with large elevator banks, one or more elevators can be shut off, another typical measure. Industrial companies and factories can even enter into agreements to shut down production lines or processing. Indeed, it is sometimes cheaper for a facility to simply shut down than to pay astronomical power costs while producing products.

The economic benefits of demand-side management are augmented when the utility or system operator pays a capacity fee to the facility. For the utility or system operator, a megawatt not used at peak times actually has an economic value that is just as high, if not higher, than the marginal cost of an additional megawatt of capacity. Therefore, it makes economic sense to pay facility owners or managers a fee to agree not to use electricity at certain times. Investigating the economic values of these fees where they exist should definitely be a part of every significant facility's energy management strategy.

Facilities that have backup diesel generators or distributed generation through one of the techniques discussed below can earn a capacity fee for using their on-site generation to cover their own needs (if the on-site generation is not already configured to run all the time), and, if they have on-site generating capacity available, they can also be paid a good price for the kilowatt hours for putting the power back to the grid or system operator.

There is, however, one environmental drawback regarding self-generation in DSM programs. Because, as pointed out below, a good deal of on-site generation capacity in the United States still tends to come from backup diesel generators, turning them on in the middle of summer is highly undesirable environmentally, and most grid operators have strict rules about how many hours per year they can run. Thus, from a policy and environmental standpoint, it is much better to have this extra capacity come from distributed natural gas combined heat and power (CHP) or renewable resources. However, it is more complicated to determine whether there is extra power capacity from these resources to feed back to the grid. As we will discuss below, most natural gas CHP systems are optimally sized to cover only their host's thermal load, which, generally speaking, means that they cannot cover their host's average electric load, let alone a peak summer load. Similarly, for solar, since most on-site solar electric systems can only cover a part of their host's average electric load, the same constraint applies. An owner of natural gas CHP or solar generation needs to look carefully at the terms of the relevant DSM program to see its benefits.

The following is a brief description of the DSM programs in the largest regional power markets in the country.

PJM Interconnection

PJM Interconnection is the largest regional power market in the United States. PJM's wholesale electricity markets provide opportunities for end-use customers to realize value for reducing their demand for electricity. Demand response is an integral part of PJM's markets for energy, day-ahead scheduling reserve, capacity, synchronized reserve, and regulation. Demand response can compete equally with generation in these markets.

In PJM's energy market, end-use customers participate in demand response by reducing their electricity use either during an emergency event or when localized marginal prices are high on the PJM system. End-use customers participate in demand response in PJM through members called curtailment service providers, who act as agents for the customers.[1]

New York

The New York independent system operator (ISO) has two demand response programs: the Emergency Demand Response Program (EDRP) and Installed Capacity Special Case Resources (SCR) program. Both programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. The EDRP is designed to reduce power usage through the voluntary shutting down of businesses and large power users during emergency conditions. Companies, mostly industrial and commercial, sign up to take part in the EDRP. The New York ISO pays companies for reducing energy consumption when the NYISO asks them to do so. Reductions are voluntary for EDRP participants.[2]

Similarly, SCR is a program designed to reduce power usage through the shutting down of businesses and large power users. Companies, mostly industrial and commercial, sign up to become SCRs. However, the companies are required, as part of their agreement, to curtail power usage, usually by shutting down when asked by the New York ISO. In exchange, they are paid in advance for agreeing to cut power usage upon request.[3]

The New York ISO's Day-Ahead Demand Response Program (DADRP) allows energy users to bid their load reductions, or negawatts, into the Day-Ahead energy market as generators do. Offers determined to be economic are paid at the market-clearing price. DADRP allows flexible loads to effectively increase the amount of supply in the market and moderate prices.

New England

ISO New England has two types of demand response programs: (i) reliability (i.e., demand) programs, where customers respond to system reliability conditions as determined by the ISO New England Control Room, and (ii) price programs, where customers respond to wholesale prices as determined by the market. Demand response enables large electricity customers or blocks of customers to receive financial incentives for reducing their electricity use during periods of either peak demand on the bulk electricity system or very high wholesale electricity prices.[4]

California

Demand-side management programs in California provide a mechanism that allows power consumers to benefit financially from their ability to reduce power consumption when called upon. It provides a flexible tool for program participants to offer their capacity into the California ISO energy market, commensurate with their ability to reduce on an hour-by hour basis. The program recognizes the value to the market for providing this service and compensates providers accordingly.

To help manage system reliability and deter severe price fluctuations, the California Consumer Power and Conservation Financing Authority, on behalf of the state of California, initiated the Demand Reserves Partnership Program (DRP) in early 2002 and contracted with APX, Inc., an independent power market service provider, to develop and host the system and to provide operational support. The California DRP is a capacity-based program that integrates retail electrical consumers with the wholesale electrical markets in California. Participants are paid a price to hold their capacity in reserve until called on by California Energy Resource Scheduling or the investor-owned utilities to deploy (commonly referred to as a curtailment event). When the state calls a curtailment event, program participants that comply receive an energy payment for the power reduced and subsequently provided to the grid. Similarly, participants are assessed a penalty if they fail to comply with the curtailment. The program was designed to utilize private business interests or demand reserve providers (also referred to as aggregators) to champion the program and enroll end-use customers such as commercial, industrial, and agricultural load.

The program consists of three market types—monthly, daily, and hourly. For each market type there are three products—nomination, reservation, and curtailment. As such, there are a total of nine markets available to participants.[5]

Smart Metering

Another new technology that works within the demand-side management framework is so-called smart metering. For the most part, utility meters are dumb in the sense that all they are designed to do is measure the amount of electricity the consumer is purchasing. With these dumb meters, it is even a challenge for the utility to run them in reverse for on-site applications. A smart meter can measure many more elements of a facility's electric usage and can serve as a point of interaction between the user and the utility. For example, a smart meter can be connected to particular energy-consuming equipment and appliances on a facility's site. Comverge, an energy services company, is offering a smart meter and a service whereby it powers down these appliances remotely during periods of high grid demand. For the most part, the facility user (who in most cases is a homeowner) doesn't even realize that the temperature on his or her air-conditioning equipment has gone up a few degrees or that it is off 20 minutes an hour (particularly because peak demand time is mid-afternoon, when many homeowners are not home), yet this technique relieves a significant amount of grid stress and saves the consumer money.

Another advantage of smart meters is that they have functions that can inform a user about the amount of power various types of appliances and equipment are using at a given time, thus allowing users to assess these things separately. A dumb meter does not have the capacity to do this. You can watch a dumb meter and have no idea if you are using a little or a lot of electricity at a given time unless you know how the speed correlates to usage. In fact, most electricity consumers have no idea how much electricity they are using and which appliances are using a lot or a little. Some studies have shown that if consumers actually know how much electricity they are using, they will use less.[6] More advanced smart meters can be hooked up to computers where there are graphic illustrations of power usage according to appliance and a control mechanism. Some have posited that every new house should have something like this.

Submetering

Finally, most multifamily buildings still do not have submeters. Electric submetering is the implementation of a system that allows a building owner or manager to bill unit owners for individually measured electric usage through meters installed in each unit. Instead, these buildings have one main meter at the utility hookup, and building managers do not charge individual units for the actual amount of electricity they use. If a multi-unit building is submetered, this alone will save a significant amount of electricity, once a resident makes a direct correlation between his or her own usage and the cost of power.

Storage Solutions

Generally speaking, there is no way to store large quantities of electricity efficiently. The basic rule is that an electric distribution system has to have more or less the same amount of electricity going on to it as is coming off to maintain its balance. Today, a tremendous amount of research is devoted to devising solutions to the electricity storage issue. Indeed, experiments are beginning to be conducted regarding battery and grid interaction on a larger utility scale. The company Grid-Point carried out a pilot program with ConEdison to install batteries in residences.[7] The batteries charge at night or other times when grid power is inexpensive, and the facility owner uses the stored electricity or makes it available to the utility when stress on the system is high and power is expensive. The stored electricity in the customer's business or residence becomes thus a distributed resource that the utility can call upon when it needs it. A corollary of this theory has to do with plug-in hybrid vehicles. If a car with a battery is plugged into its house system, the battery can store electricity and release it.

Performance Contracting/Reducing Energy Use in Existing Buildings

Demand-side management programs tend to focus on temporary reductions in energy use, which lessen stress on the grid. More permanent efficiencies and reductions in energy use are achieved through implementing energy conservation measures, often through the vehicle of an energy performance contract. Reducing energy use in existing buildings is a relatively easy—and comparatively inexpensive—direct way to reduce greenhouse gases, given the dominant role buildings play in the energy usage profile in the United States.[8]

It is interesting to consider with respect to energy efficiency and fuel choices the conclusions of a report released in early 2007 by the American Solar Energy Society titled *Tackling Climate Change in the U.S.* The report concluded that aggressively deploying currently available energy efficiency technologies can keep U.S. emissions at *current* levels for the next 24 years, while broad deployment of six renewable techniques (wind, concentrating solar power, photovoltaics, biomass, biofuels, and geothermal power) can make deep cuts in U.S. emissions over the same time period.[10] The report goes on to conclude that, in combination, energy efficiency and the deployment of these six renewable energy technologies can displace approximately 1.2 billion tons of carbon emissions per year by 2030.[11] According to the report, energy efficiency accounts for about 57 percent of the displacement, while the six renewable energy technologies account for 43 percent.[12] While one can quibble with the authors' methods or question their motives, even discounting for error or exaggeration, their conclusion is an astounding one—energy efficiency can reduce greenhouse gas emissions by more than all the main renewable techniques combined at their current levels of technological advancement.

Another widely cited study, *Reducing U.S. Greenhouse Gas Emission: How Much at What Cost?*, by McKinsey & Co. and The Conference Board, concludes that improving energy efficiency in buildings and appliances provides the largest cluster of negative-cost options (i.e., options that will lead to savings) for reducing CO_2 emissions.[13] Indeed, the theme of efficiency pervades all the clusters of abatement potential identified:

> Improving energy efficiency in the buildings-and-appliances and industrial sectors, for example, could (assuming substantial barriers can be addressed) offset some 85 percent of the projected incremental demand for electricity in 2030, largely negating the need for the incremental coal-fired power plants assumed in the government reference case.[14]

Because half of all the electricity used in the United States comes from coal, and coal-fired power generation is the biggest source of greenhouse gas emissions, it bears repeating that each unit of electricity saved or avoided immediately reduces the amount of greenhouse gases emitted.

The practices and techniques of energy efficiency contracting merit detailed discussion and are the subject of Chapter 7.

On-Site Generation of Power

Backup Diesel Generation

The most common form of building-specific distributed generation in use today is a backup diesel generator. However, this chapter will not consider backup diesel generation as an alternative energy source for buildings. Diesel generators are designed mostly as emergency backups and do not have the potential to cover building load over sustained periods of time. They have many disadvantages. One is that volatile diesel fuel must be stored in buildings to keep them running. Another is that diesel fuel (or fuel oil, which is also used) is one of the dirtiest fuels for power generation—and most states and localities have strict rules regarding how many hours a year a diesel generator can run for this reason. Finally, because most of the time diesel backup generators are not running, they need a lot of maintenance and testing to make sure that they start up and stay on when they are needed. In practice, diesel generators often do not start up when called on or fail after working for a short period of time, so a high level of redundancy is required if a user has a need for highly reliable power. Thus, given diesel's environmental profile and the fact that it is the traditional means of backup power, it will not be considered as an alternative source of energy for purposes of this chapter.[15]

Combined Heat and Power/Cogeneration

After diesel generation, the second most common form of on-site energy is combined heat and power (CHP), or cogeneration. This is power generation equipment, usually fired by natural gas, whose waste heat is captured to make thermal energy (steam or hot water) to be used by the host facility. When the waste heat is also captured to make chilled water for air conditioning, either through an absorption chiller or a steam-driven system, the process is sometimes referred to as trigeneration. While CHP is not new as a technology (indeed, it is as old as power generation itself), and while the fuel is not renewable if it is natural gas, combined heat and power in small applications creating electricity and thermal energy for host facilities is still uncommon enough in building and facility-specific applications to be considered alternative for purposes of a discussion of energy and buildings. It is also alternative in the literal sense of the word because even though these systems can provide almost all of most buildings' electricity on an ongoing basis, they are still an alternative choice as compared to simply hooking up grid power and receiving gas from the local gas utility. For the reasons discussed below, on-site CHP systems tend not to be simple to put into place, which is one reason why they are still not widespread, at least in commercial real estate. They are in wider use in industrial facilities, particularly ones that have production processes where steam can be used. They are virtually nonexistent in single-family residences.

If a CHP system is configured correctly, meaning that the electric output is sized so that the waste heat creates the right amount of thermal energy for the host facility, these systems have many benefits. They can be as much as 80 percent or more efficient, meaning that 80 percent of energy generated is used. This is dramatically better than the average efficiency of power generation in the United States (which is about 33 percent) and somewhat better than the most efficient and modern combined-cycle gas plants (which are around 60 percent), not to mention the lack of need to transmit the electricity because it is generated on-site.[16] They also can result in significant savings compared to grid power (more than enough to pay for the system over some period of time) and can serve a backup function as well, displacing the need for most diesel generation.[17] The following is a summary of the potential benefits of a correctly configured CHP system:

- Distributed generation resources can serve as backup power, ensuring continued operations during grid failures and avoiding economic losses.
- Distributed generation can save the owner of the facility money on power. Because a big part of the cost of utility power is the demand charge—that is, pricing designed to cover the facility's peak load—simply reducing the peak demand by installing on-site generation during periods of peak usage (a technique called peak shaving) saves money. Distributed generation also saves money because utility power includes the costs of transmission and distribution, which do not exist when power is generated on-site. Finally, because CHP applications can be more efficient compared to the large-scale sources of utility power, the fuel component of the utility bill can be used far more economically.
- The thermal energy or steam is very useful for running industrial equipment, supplying hot water and providing heat in winter and chilled water for air conditioning in summer.
- If a facility needs more power, distributed generation is a comparatively inexpensive and rapid way of adding capacity without having to deal with utility service upgrades in most cases. The cost, depending on the size of the plant, ranges from under $1.00/watt for larger plants (20–50 MW) to $1.70/watt for CHP applications in 100–500 kW range (typical for building applications where 400 kW systems are scalable) and $2.70/watt for the smallest microturbines (30 kW).[18]
- Energy savings realized from distributed generation and other energy efficiency measures can cover the capital cost of the new equipment and upgrades within a few years. In successful distributed generation projects, the capital cost of the equipment can be recovered through energy savings in three to seven years, a much shorter period than the useful life of the equipment.
- Many states and some municipalities have programs in place that provide cash subsidies and other incentives to cover a significant part of the capital cost of the equipment (30–60 percent), making the payback period even shorter.[19]
- Distributed generation can provide an owner with an opportunity to make money because, generally speaking, the owner can sell excess power back to the grid, into an organized market (like the local ISO), or even the utility, depending on whether the plant is interconnected to the grid, what fuel it uses, and how it is sized.
- Owners of distributed resources can join the demand reduction programs of the local ISO, which means regular cash payments to the owner for agreeing to make power available to the system operator during peak load periods, plus payments for the power when called on by the ISO.

Because most CHP or cogeneration systems use natural gas as a fuel, there is a difference of opinion among power industry experts and environmentalists over whether on-site CHP should be included in the renewable portfolio standards that 30 states have now adopted.[20] Only a few states include natural gas-fired combined heat and power applications in their renewable portfolio standards.[21] Most states do give incentives for these systems, however, depending on how efficient they are and the use for which the thermal energy is proposed.

If a CHP system meets certain efficiency and thermal output thresholds, the environmental benefits regarding emissions are significant. Even though the combustion process has the same input-based emission rates as conventional equipment, NOx emissions of a CHP system are lower because a CHP system uses less fuel and displaces higher-emitting generators on the grid. In case studies EPA conducted, use of a CHP system amounts to about half of the emissions of a central generation system.[22]

Fuel Cells

Fuel cells are making important inroads into the distributed generation market today. For many years they were considered to be too expensive to be a practical solution and mostly were installed at government facilities as demonstration projects. More recently, commercial applications are being demonstrated where they appear to be viable alternatives. Indeed, a large (4.8 MW) fuel cell array is being planned for the Freedom Tower to be constructed on the site of the World Trade Center,[23] even though it will only be able to cover about 10 percent of the tower's energy needs. Fuel cells are still far more expensive than most other types of power, so most commercial applications rely on government incentives and subsidies for their installation.

Fuel cells use an emissions-free chemical process to make electricity, even though they do need some sort of fuel to run. Most of the prototypes and systems in use today use natural gas, but they can also be run off of other types of gas, particularly the anaerobic digester gas that is a byproduct of the wastewater treatment process. Hydrogen is also being developed as a fuel source for fuel cells, and some installations are now using hydrogen.

Because fuel cells are quiet and have no emissions other than some water, they are well suited for installation inside of buildings. Fuel cells can be configured in combined heat and power applications, particularly in on-site or campus-type situations. In this regard, they have all the advantages of combined heat and power from natural gas combustion.

There are several types of fuel cells, and the differences among the technologies are complex for people who are not power engineers. The following is a very brief explanation, with a few notes about efficiencies:[24]

- *Phosphoric Acid Fuel Cells (PAFCs)*—considered the first generation of modern fuel cells with the most examples in use commercially; typically used for stationary power generation. Efficiency is 37 to 42 percent when generating electricity alone and up to 85 percent when used in combined heat and power applications.

- *Polymer Electrolyte Membrane (PEM)*, also known as proton exchange membrane fuel cells, need only hydrogen, oxygen, and water to operate and are usually fed with pure hydrogen supplied from storage tanks.
- *Molten Carbonate Fuel Cells (MCFC)* operate at high temperatures and are most suitable for utility and industrial applications. They can be up to 60 percent efficient for electric generation alone and up to 85 percent efficient in combined heat and power applications.
- *Solid Oxide Fuel Cells (SOFC)* are more experimental, operating at even higher temperatures than MCFCs, with similar efficiencies.

Until now, fuel cells have been used mostly for site-specific distributed applications, but at least one state, Connecticut, has gone a step further and actually required, per legislation passed in July 2007,[25] that electric distribution companies enter into long-term contracts with power producers using renewable resources, including fuel cells, meaning that the higher cost will be spread over the ratepayer base. In January 2008, the Department of Public Utility Control issued an order approving power sales agreements covering about 16 MW of power generated from fuel cells. One of them, the proposed Stamford Hospital Fuel Cell CHP Project, would consist of 4.8 MW of fuel cell energy DFC 3000 units with thermal application to provide heating and cooling to the hospital and have electricity left over to sell to the grid.[26]

The big drawback is their cost. They cost between $3.60 and $5.50 per watt, depending on the model.[27] In contrast, conventional electricity produced from coal-fired power plants typically costs around $2 per watt.[28] Fuel cells also are usually not as robust as engine generators or even microturbines, and for that reason they require more frequent and more expensive maintenance. Many models do not have long operating histories. However, being a practically emissions-free resource and having the potential to run on hydrogen, many states provide generous incentives to purchasers and users of fuel cell systems.[29]

Solar Energy

In the public's imagination, solar is the most widely known source of alternative energy for buildings and facilities. The most widespread application of solar energy is by means of photovoltaic panels on buildings and residences. Also well established as a technology is solar thermal, which provides heat for hot water. New applications are also being put online, such as a concentrating solar technology that focuses sunlight by mirrors onto an element to make steam for a conventional engine generator (concentrating solar). Google famously invested in eSolar, a company that is making a more utility-scale application in 25 MW modules. This section will focus on the site-specific solar technologies, specifically photovoltaics.

Large-scale application of photovoltaics has been the dream of many an environmentalist for some time. Everyone who follows energy issues is well aware of the main impediment to the larger-scale application of the technology: namely, its high up-front cost (approximately $8.50/watt without tax credits or government incentives), significantly higher than conventional sources and even most other alternative sources.[30] Also, the intermittency of the resource, or the fact that it is not available all the time, is another traditional obstacle. Photovoltaics require direct sunlight. Any shading at all prevents the affected area of a PV system from working. Thus, little power is produced when there is cloud cover, and none at night.

Regrettably, little progress has been made in the other main drawback of solar, its low efficiency. There really are no commercially available solar technologies today where the efficiency is greater than 20 percent. Many people are devoting considerable research dollars toward crossing this barrier, but without an apparent breakthrough so far that can be applied on a large commercial scale. One new development, thin film technology, actually has even lower efficiency (around 9 percent) but is attractive because it can work in diffused light, without direct sunlight. The U.S. Department of Energy has been sponsoring research toward getting solar cells past the 40 percent efficiency barrier, which would bring the cost to about $3.00 per watt. Indeed, Boeing Spectrolab claims to have developed a solar cell that achieves almost 41 percent efficiency.[31] Sharp has demonstrated a solar cell offering 36 percent efficiency. If these efficiencies can be sustained on a commercial scale, solar technologies clearly have the potential for becoming the alternative power source of choice for buildings.

Even with today's technologies, and despite the high cost, solar systems have many attractive features. First and foremost, the energy has no cost, and there are absolutely no emissions of any kind to generate electricity. In addition, PV systems work best when energy is needed the most, during the hottest periods of the year. While no one is seriously claiming today to be able to power entire commercial buildings or multifamily residences on solar power alone, an application of solar power sized to cover a portion of summer peak load can relieve stress on the grid and actually serve to lower a user's energy costs appreciably due to the decrease in the demand charge. Further, depending on the interconnection procedures of the local utility, solar systems can be configured with battery storage to provide backup power, at least for some critical loads in commercial buildings and for a residence's entire load.

A promising recent development is that there is a growing awareness that commercial buildings, warehouses, big-box stores, and other buildings have large-surface roofs that are a power-generation asset. One of the biggest hurdles in the wider use of solar applications is misconceptions and lack of knowledge. However, this is becoming less of a hurdle as more and more of these systems are installed. As discussed in more detail below, several companies have devised legal and financing structures to make these projects work and to minimize the involvement of the host owners.

Finally, to overcome the high costs, state and municipal governments have chosen to subsidize the installation of solar systems.[32] These are cash reimbursements, tax credits, and other forms of incentives to encourage owners of property to install them. As also discussed below, there are also significant federal tax credits.

Having observed the solar industry for a long time,[33] it seems as though solar is starting to gain serious traction for several reasons. First, more and more people are coming to the realization that the technology works and is reliable. This has been known for years but has been obscured by the debate over the price and the intermittency problem. Second, there are a number of projects where the scale of solar is much larger than ever before. It used to be that photovoltaics and solar thermal were thought of as very small-scale applications suited mostly for individual residences. Now, solar providers are installing distributed systems that are starting to take a real bite out of grid demand. Universities in California are making considerable strides in installing solar generating capacity. In October 2008, Governor Schwarzenegger announced an arrangement with SunEdison to bring to 8 MW of solar generating capacity to 15 California State University campuses.[34] The solar panels will be installed on rooftops, parking canopies, and in ground-mounted arrays. Earlier in 2008, Chevron Energy Solutions completed the installation of 2.65 MW of photovoltaic panels on parking canopies on the campus of three installations of the Contra Costa Community College District in California, and added another 534 kW during the year, bringing the total to about 3.2 MW.[35] Further, the California Department of General Services has negotiated a solar power purchase agreement with SunEdison for up to 12 additional MW of capacity, including 7 MW at five state prisons. While these megawatt numbers are not huge compared to the system's overall demands, more and more capacity is being added, obviating the need for additional capacity that relies on fossil fuel. Indeed, California has big plans for solar. Under the 2007 California Solar Initiative program, the goal is to have solar systems totaling 3000 MW of capacity by 2017.[36]

Private companies are also negotiating significant power purchase agreements with solar providers. In April 2009, BP Solar announced that it had entered into a power purchase agreement with Wal-Mart to install up to 10 MW of solar capacity at Wal-Mart locations in California.[37] In 2007, Kohl's Department Stores initiated a program with SunEdison to put solar installations on 63 of its 80 California locations, which, when finished, will total about 25 MW, or systems of approximately 500 kW per store.[38] And California is not the only place where solar is a realistic possibility. On-site photovoltaics is a solution that can work almost anywhere in the United States. New Jersey is promoting solar installations aggressively. In June 2008, the Atlantic City Convention and Visitors Authority entered into a 20-year power purchase agreement with Pepco Energy Services to install a 2.36 MW solar array at the Atlantic City Convention Center.[39] In August 2008, the pharmaceutical company Merck entered into a 20-year power purchase agreement with UTC Power to install a 1.6 MW ground-mounted tracking system that will have about 7,000 solar panels covering 7 acres.[40] A list of state and local incentives regarding solar is available online.[41]

For all of this progress, there still does not seem to be any immediately accessible technology that will create enough power from the sun to provide all the power buildings need, except for individual residences. There is also the intermittency problem—the sun doesn't always shine, so facilities need access to other sources of electricity (assuming the current level of battery storage technology). As a result, at present solar power cannot be considered a substitute for grid power. All of the applications that can be considered today have to work in conjunction with the traditional grid or with other distributed resources.

Geothermal Energy

Harnessing geothermal energy, which is heat naturally stored below the earth's surface, is another alternative that is gaining traction for on-site applications, particularly for heating and cooling of buildings and facilities. Geothermal energy is contained in underground reservoirs of steam, hot water, and hot dry rocks, and may be tapped for a variety of uses. For example, hot water or steam extracted from geothermal reservoirs in the earth's crust is supplied to steam turbines at electric utilities that drive generators to produce electricity.[42] The use of geothermal for electricity generation, however, is only currently viable for utility-scale applications because it requires high-temperature resources typically found only at great depths.[43] Conversely, moderate- to low-temperature geothermal resources may be used for direct-use applications, such as district and space heating, and even lower-temperature, shallow-ground, geothermal resources are used by geothermal heat pumps to heat and cool buildings.

The two most common on-site applications of geothermal energy are direct-use and geothermal heat pump systems. Geothermal heat pump systems are known more properly in the industry as geoexchange systems because their purpose is to exchange hot air for cold air or vice versa.[44]

Direct-use applications pipe hot water beneath the earth's surface directly into facilities to provide heat. Some cities pipe the hot water under roads and pavements to melt snow. District heating applications can even heat buildings in whole communities using networks of piped hot water.[45] An obvious disadvantage of direct-use geothermal is that it is limited to areas with significant hot water resources close to the earth's surface. Western states such as Colorado and California have plentiful hot springs, but these resources are scarce in other areas.[46]

Geothermal heat pumps or geoexchange systems, by contrast, have much broader application by taking advantage of the fact that the earth's surface almost everywhere maintains a nearly constant temperature between 50° and 60° F. These systems are composed of pipes buried in the shallow ground near a building, a heat exchanger, and ductwork into the building. In winter, heat from the relatively warmer ground goes through the heat exchanger into the building. In summer, hot air from the building is sucked through the heat exchanger into the relatively cooler ground. With the use of an additional component called a desuperheater, air can also be used to heat water at a low cost.

Geothermal heat pumps have many advantages over conventional heating and cooling systems, from both a cost and environmental perspective. According to the EPA, geothermal systems save homeowners 30–70 percent in heating costs and 20–50 percent in cooling costs compared to conventional systems.[47] From an ecological standpoint, geothermal heat pumps are significantly more efficient than the most efficient fuel furnace. By circulating heat that already exists in the Earth rather than burning fossil fuels, a geothermal heat pump can move up to four units of heat for every unit of electricity needed to power the system. According to one industry group, this results in a practical equivalence of over 400 percent efficiency.[48] By contrast, the most efficient fuel-burning heater can only reach efficiencies around 95 percent. Even on a source fuel basis (i.e., accounting for all losses in the fuel cycle including electricity generation at power plants), geothermal systems are much more efficient than competing fuel technologies, an average 48 percent more efficient than the best gas furnaces, and over 75 percent more efficient than oil furnaces.[49] For this reason, EPA found that geothermal heat pumps are the most energy-efficient and environmentally sensitive of all space-conditioning systems.[50]

One downside to geothermal installations is up-front costs.[51] However, a variety of incentives are available, including tax credits or deductions, rebates, special financing, and special electric rates. Significantly, a federal tax credit for geothermal systems became available for the first time in 2008. The Emergency Economic Stabilization Act of 2008 created new federal tax credits for homeowners and businesses that install geothermal heat pump systems. The tax credit is up to $2,000 for homeowners and up to 10 percent of installation costs for businesses.[52] In addition, each state sets its own incentives for renewable energy and energy efficiency. The Interstate Renewable Energy Council maintains a Database of State Incentives for Renewables and Efficiency where particular state programs may be investigated.[53] Also, any electric utilities provide assistance with geothermal heat pump systems, including rebates, special electric rates, or assistance with finding qualified contractors to design and install new systems.[54]

Regarding cost, consumers and businesses must bear in mind the life-cycle cost of their investment. When comparing heating systems, a combination of safety, installation cost, operating costs, and maintenance costs must all be considered. With the availability of new tax credits and incentives, geothermal installations are on the rise. The surge is also attributable in part to the work of the Geothermal Heat Pump Consortium, a group formed in 1993 that includes EPA, the Department of Energy, over 200 electric utilities, and 20 heat pump manufacturers. At the time of the consortium's inception, only about 150,000 geothermal systems were installed in the United States.[55] With $100 million at its disposal, the consortium embarked on a public relations campaign offering rebates, reduced utility bills, and other incentives to businesses and homeowners. As of July 2008, there were over 750,000 geothermal installations in place, a fivefold increase in 15 years.[56]

Regarding the potential for geothermal for residential, multifamily, and commercial buildings and facilities, the application of geoexchange systems has no intrinsic technological limitations—the technology is adaptable to nearly any residential or commercial structure, and all areas of the United States have nearly constant shallow-ground temperatures, which are suitable for geothermal heat pumps.

For residential buildings, a geothermal heat pump system can be installed in a structure of any size, anywhere, whether it is single-family or multifamily. The system can be installed on almost any size lot: under lawns, landscaped areas, driveways, or the house itself. In addition, an existing house can be retrofitted using the ductwork that is already there.[57]

For commercial buildings, ground-source heat pumps are appropriate for new construction as well as retrofits of older buildings. Their flexible design requirements make them a good choice for schools, high-rises, government buildings, apartments, and restaurants—almost any commercial property. Lower operating and maintenance costs, durability, and energy conservation are additional benefits for commercial applications.[58]

The main barriers, therefore, are economic and educational: (1) consumers and builders face an initial financial disincentive due to the higher up-front costs of geothermal compared to traditional systems; and (2) consumers and builders are not educated sufficiently about the potential benefits of geothermal, or mistakenly consider it a fringe technology of limited applicability. The following quote from a Japanese technical study sums up the conundrum and the opportunities quite nicely:

> In contrast to cutting-edge technologies under development that tend to attract public attention with loud fanfare and drum up expectations, however, the public has shown little interest in the fundamental mechanism of heat pump, which is a mature conventional technology. For all these reasons, the truth about heat pumps—that widespread dissemination of the heat pump technology holds a huge and realistic potential for resolving both energy and environment issues confronting humans—has not been fully understood in spite of its monumental significance.[59]

On-Site Wind

A more recent technology is small-scale, on-site wind applications. Just like its utility-scale analog, on-site wind technology uses wind turbines to convert wind energy into electricity. In on-site wind applications, the turbine, or series of turbines, is most often attached to the rooftop of the building in question—or built into the side of the building itself—poised in the optimal position to catch prevailing winds. In addition, the assemblies are designed with an eye toward aesthetic appeal, described by one author as "graceful metallic vultures"[60] lending an architectural flourish complimentary to building design.

On-site wind is still in its infancy. In fact, it is only in the past five years that a number of forward-thinking startups have initiated the research and development necessary to bring on-site wind to market. A recent article in *Distributed Energy*[61] magazine surveyed the on-site wind companies at the helm, noting that many of the designs are still only prototypes in various stages of testing and design. Moreover, for those companies furthest along that have made product sales, early experience suggests there are still kinks to work out in the technologies deployed. In addition, high manufacturing costs remain an obstacle.

The on-site wind systems currently in production or in late-stage R&D are universally used as a supplement to traditional power sources. The present technology is not yet capable of fulfilling all or even most of a facility's—whether commercial or residential—electricity needs. In fact, the examples cited in the literature seem almost negligible in their power-generating capacity, often supplying only a nominal percentage of overall energy usage.[62] It seems that many commercial purchasers of on-site wind have done so in furtherance of a broader marketing strategy to expand their green credentials. For example, Chipotle Mexican Grill unveiled plans last year to open a restaurant in Gurnee, Illinois, featuring a prominent 6-kilowatt wind turbine:

> This reality is compounded by the added probability of system malfunctions, as manufacturers continue to work out the problems in design and installation. In addition, on-site wind remains expensive relative to potential cost savings, often requiring several decades for the system to pay for itself.

Many of the pilot projects featuring on-site wind do so in tandem with other on-site generation techniques. In fact, Steve Else, the president of Broadstar Wind Systems, predicts that within 10 years, all new buildings will integrate solar, wind, and a geothermal ground loop to cool liquid underground for air conditioning. As he states, "Sensibly designed buildings should have all three."[63]

The cost of on-site wind projects varies considerably by manufacturer. Moreover, there is a general paucity of pricing information because many prospective manufacturers are postponing general release until they can substantially reduce costs and/or vouchsafe a reliable system.

Regulatory requirements for on-site wind can vary from city to city and state to state. Many are in the process of being revised to accommodate the new technologies coming on-line. For example, San Francisco is now developing permitting rules for urban wind projects, even having created an "urban wind task force" to investigate the issues fully. As the recognition of wind's on-site potential is recent, regulations are evolving, so each locale's particular requirements need to be reviewed carefully to ensure compliance.

A number of states, including New York, offer cash incentives for new on-site wind systems.[64] Incentive levels may vary depending on the size of the system, the tower height, and the class of customer. Small wind systems also benefit from federal tax credits and incentives, as discussed below.

Biomass

Biomass is an alternative fuel that is gaining wider use. Agriculture and by-products of industrial processes (such as sawmills) create a lot of biomass that in many cases is not only wasted, but the producers of it have to pay to have it taken away or landfilled.

Biomass can be burned in power plants, either in dedicated stations or mixed with other fuels. For site-specific applications relevant to real estate, biomass can also be used to fuel boilers in buildings and, depending on the cost of petroleum, can be considerably less expensive than fuel oil. Facility owners who ordered biomass boilers before petroleum prices began spiking to over $100/barrel were very glad in the winter of 2007–2008 that they did so. Of course, the economics are different with petroleum under $50/barrel, as they stood in mid-2009. Biomass can also be used as a fuel for the same type of combined heat and power applications in generators running on natural gas.

District Energy

When the heat from CHP plants that run on either conventional natural gas, biomass, or gas from some type of waste is used to make thermal energy in the form of hot water, chilled water, or steam, this energy can be exported through steam pipes within a defined geographic district and used by buildings and facilities in that district for space heating, cooling, and other applications that can make use of thermal energy. These systems are called district energy systems. They have been in use in Europe for many years, particularly in Eastern Europe and Scandinavia. Although the first such systems were demonstrated in the United States in the nineteenth century, they are not in such wide use today in North America. They do exist in a number of cities, though (Minneapolis, Trenton, Hartford, and Memphis are examples), and the world's largest district steam system is actually in New York, where the utility Con Edison manages a system consisting of high-pressure steam pipes from lower Manhattan to 96th street. These district energy systems are very efficient because they make nearly full use of the waste heat from power generation. While they will not be discussed in detail in this chapter, in principle they should always be considered in campus-type developments and in urban planning. Apart from the cost savings and greater efficiencies of energy conversion, the main advantage of district systems for building owners and managers is that they avoid the need to put boilers and site-specific air-conditioning equipment in buildings, thus gaining space.

Interaction of Distributed Resources with Central Generation

Most distributed energy solutions cannot cover all of the energy needs of their host facilities for a variety of technological and practical reasons. Therefore, the term "alternative" should not be understood to mean a way of replacing or ignoring the traditional electricity grid and natural gas distribution system. On the contrary, distributed generators need to remain connected to the grid and to rely on it to effectively deal with the capacity, reliability, and intermittency problems of the distributed resources themselves. The issue of interconnection to utility grid systems will be discussed in more detail below, but as a policy matter it should be noted here that the future wide-scale use of alternative energy solutions depends on improving the way they interact with the traditional utility distribution infrastructure—or at least to make sure that they don't interfere with those systems. The electric distribution system was designed to deliver electricity to customers from large central generating plants and to measure the amount delivered at the point of use. It was not designed to have numerous small generating systems sometimes taking electricity from and sometimes adding electricity to the grid. Making this last process a widespread reality is an important goal of the smart grid initiatives that are taking place today.

Installing On-Site Generation

This section will discuss the practical and legal issues associated with putting a distributed generation (DG) system into place, whether it is a combined heat and power (CHP) system running on natural gas, a fuel cell, a solar system, or the other types of applications discussed above.

Energy Services Agreement

While a facility owner with in-house financial, engineering, and technical resources simply can purchase and run its own on-site generation system, most companies and real estate developers and managers are not experts in energy issues and choose to confront the prospect of on-site generation by working with an intermediary, usually called an energy services company, or ESCO. The contractual document linking an owner and an ESCO is called an energy services agreement or some variant thereof, and is the blueprint for how an alternative energy system can be implemented. For solar installations, the agreement is usually called a solar power purchase agreement, or solar PPA, which has many of the same features as an energy services agreement relating to other technologies. A successful project depends a lot on having a strong and well-drafted energy services agreement or solar PPA, where the parties' expectations and the main allocations of risk are spelled out clearly. The key elements of the agreement are discussed below. Some of the steps outlined can be done by separate contracts, or they can be all rolled into one agreement with stages or phases of performance.

If self-generation is being considered, the first step is to study the facility's existing or projected electrical usage, loads, current needs, and potential, as well as the cost of power and potential financial incentives in the particular area where the facility is located. If the facility's load profile looks promising, the ESCO can put together a preliminary system design. ESCOs are also equipped to run financial scenarios that can indicate what the owner's cost of power would be with DG, what the savings might be compared to simply using grid power, and how long the owner will take to cover the capital cost of the equipment (the payback period).

At this point, the owner and the ESCO have to come to a decision about how they want to do business together. It may be advantageous for an owner to purchase the equipment by itself, in which case it can deal directly with equipment manufacturers. While there are few owners who would want to do this for a complicated CHP installation, this might be a much more viable choice for solar photovoltaic systems. They are not especially complicated and don't need a lot of maintenance. Some manufacturers give fairly long warranties (up to 25 years is not unusual), so if the manufacturer is substantial, there is someone to stand behind the product. Further, the owner in this case receives the electricity "for free" and also enjoys all the incentives, tax benefits, and carbon credits associated with ownership. Assuming, however, that the owner does not want to procure the equipment directly, there are fundamentally two choices about how to proceed—as explained below, the design-build and the energy sales models.

Design-Build Model

In this model, the ESCO acts in essence as a general contractor, an intermediary who is an expert in energy issues. In this regard, the ESCO arranges for the design and installation of the system and delivers title to the equipment to the owner at the end of the construction period. This is the design-build model. Afterward, the owner owns and operates it. From the owner's point of view, this also has the advantage of allowing the owner to capture all of the financial incentives and tax and carbon credits that are offered by self-generation of electricity. It should be noted, however, that while many owners prefer to purchase the equipment and own it themselves, few of them actually want to operate and maintain it on their own. If the owner wants to own the equipment but not operate and maintain it, the owner can contract with an ESCO or special service contractor.

Energy Sales Model

The other widely used model, the energy sales model, is where the ESCO retains ownership of the equipment on the owner's premises and runs and maintains it during the length of the contract. In this scenario, the ESCO sells the plant's output in electricity and thermal energy to the customer at a price that usually is discounted from what the customer would have to pay to the utility for the energy delivered. In many cases, the customer asks for a guaranty from the ESCO or its parent that some level of savings will be achieved. The term of an energy services agreement is usually in the range of 10 years, although arrangements between five and 15 years are not uncommon, and some solar PPAs run as long as 20 years. At the end of the term, the owner either takes title to the equipment or the ESCO has the right to remove it. Another structuring option is for title to go to a finance company either at the end of the construction period or at some defined point during the term. If it goes at the end of the construction period, a sale-and-leaseback arrangement is entered into. As discussed below in the financing section, there may be a tax "flip" at some point where the benefit of the tax credits goes from the ESCO to the financial intermediary or the owner.

Many energy services agreements have some shared-savings aspect to them where the owner and the ESCO negotiate as to how much the owner will save off grid power and what percentage of savings beyond that the ESCO can keep. This arrangement gives the ESCO an incentive to achieve the maximum possible energy savings. Another variation is an energy services agreement where the ESCO undertakes to provide the owner at the utility rate it was paying, but makes a rent payment to the owner for the use of the space where the DG system is placed. In this scenario, the rent represents the owner's energy savings. Yet another structure variant on the tariff is where the owner pays the ESCO the normal utility tariff for some period of time until the financing of the equipment is paid off.

This energy sales model in the form of a solar PPA is the norm in solar installations, while in combustion CHP projects, both the energy sales and design-build models are used, depending on the owner's preferences.

Energy services agreements can be quite complicated documents, particularly for CHP projects where a combustion turbine is making the electricity. While everyone in the industry tends to want standardized documents, and solar PPAs have achieved some level of standardization for certain companies, most energy services agreements for CHP and solar installations tend to be negotiated heavily because, for the owner, having electricity generation on-site is a crucial element of its operations, and owners tend to want them customized to their needs.

This being said, a few key factors should be kept in mind. One factor is determining who bears the risk of fuel price increases for on-site CHP. If the ESCO is guaranteeing a certain price for the sale of electricity and the price of natural gas spikes, the contract will be uneconomic for the ESCO unless the fuel cost is passed through—or the effect of fuel prices is neutralized in the savings formula. Another element that should be kept in mind, particularly if the ESCO is financing the contract, is that the ESCO will need a minimum amount of cash flow every month to meet debt service. In this regard, the ESCO should receive what is in essence a capacity payment, i.e., a payment to install the generation whether it is producing electricity or not. As mentioned below in the discussion of sophisticated energy services, there may be reasons why the parties choose not to run on-site generation. For solar PPAs, the electricity payments to the ESCO tend to be fixed over time, so this is less of an issue, but the ability to finance the project may depend on the host's credit. If the energy services agreement is used as collateral for financing, a number of other typical lender issues should be dealt with, such as lender step-in rights in case of ESCO default, lock-box or escrow arrangements, and limitations on the owner's right to terminate.[65]

Further, because an ESCO will own and maintain equipment on another company's premises, the energy services agreement should deal with this legal relationship. The ESCO will want to ensure that there is sufficient access. In this regard, it is advisable from the ESCO's point of view to have an access right that is akin to a leasehold right that can be recorded, rather than just a contractual right. This has implications in the event of a change in control of both the ESCO and the site owner, or its insolvency. Also in this regard, liability and insurance questions take on a greater importance than normal. If the ESCO owns the equipment, the owner may well want to see boiler and machinery insurance that covers the replacement cost of the equipment so that it can be replaced, because the output of the plant is important to the owner. From the point of view of the ESCO, business interruption insurance might be a good idea, because the unavailability or breakdown of the on-site equipment may disrupt the owner's business, and this eventuality may or may not be covered by the terms of the agreement or may or may not be considered a consequential, as opposed to a direct, damage—with the allocation of liability repercussions that this implies. Finally, the terms of the owner's property insurance should be investigated to see who is responsible for damage to the owner's property beyond a casualty to the equipment itself.

Construction Contract Characteristics

Particularly in the design-build model, the energy services agreement is in many important respects a construction contract. It is a fairly involved agreement because an on-site CHP plant is not a simple piece of equipment—and it has to hook into and work in tandem with the host facility's electrical and heating and air-conditioning systems.[66] Even a photovoltaic array, which is a fairly straightforward technology, must be installed correctly and be connected to the host's electrical systems. As a result, both the owner's and the ESCO's counsel should be well-versed in construction contract practices and the risk allocations typically made in construction contracts. Some energy services agreements simply refer to standard construction contract terms and conditions, while others have customized provisions. A detailed discussion of construction contracting is beyond the scope of this chapter, but following are some of the main issues and what to be aware of, because an owner's counsel usually is not expert in construction matters.

· *Scope and Testing*: It is an obvious point, but an owner needs to make sure that the ESCO is actually building what it has promised to build and that the equipment actually works before it is deemed substantially complete and accepted. In this regard, an owner should hire its own engineers to observe the construction and witness performance tests.

- *Warranty*: The industry norm is one year after substantial completion, although in some circumstances and with respect to some equipment it may be longer. From an owner's point of view, it should ensure that there are no unusual provisions for the ESCO to avoid its warranty obligations, which typically are to repair or replace defective equipment during the warranty period. From an ESCO's point of view, it normally will seek to limit the owner's remedies for defective or non-performing equipment to those specified in the contract for breach of warranty, which is the norm in construction contracting. Attention should also be paid to warranties given by the various underlying equipment manufacturers and suppliers, the benefit of which should be assigned to the owner in case the ESCO is unable to perform itself, a concern in an industry where there are a lot of new entrants who may not be well financed and able to stand behind their projects.
- *Payment*: The method of payment chosen in a contract can make a big difference in how smoothly a project proceeds. The two basic methods in construction contracting are progress payments (i.e., monthly invoicing for the cost of work

actually performed) based on a schedule of values and milestone payments. Both are widely used, although I prefer milestone payments when representing owners or even ESCOs with respect to their equipment suppliers and subcontractors because it gives the contractor more of an incentive to move toward completion, provided it is not too front-end loaded.

- *Schedule*: How the risk of delay is allocated is a key part of a construction contract. Normally, a contractor should be entitled to both extra time and costs when it cannot complete on time due to the owner's act or omission or events beyond the control of the parties. Extra time is not usually a big issue, but the costs aspect often is negotiated heavily because owners fear that if a cost-adder clause is too broadly drafted, the price will increase in ways they cannot control. Utility interconnection is discussed in more detail below, but local utility companies dragging their feet on the interconnection of the on-site resource is a common cause for delays in distributed generation projects. Typically, construction contracts have liquidated damages for late delivery. Contractors dislike these clauses and try to avoid them.
- *Changes*: Change orders often arise in construction contracts due to subsurface conditions that are different than expected and hazardous conditions on-site. Because most DG systems do not require much excavation, the subsurface is not as common an issue as it is in typical process plant construction, although for larger systems site borings should be made to determine on what sort of platform the plants should be mounted. The strength of roof structures is an important issue in solar PPAs. Who bears the financial burden of necessary roof repairs should be spelled out clearly. While working inside of existing structures, hazardous materials on-site (asbestos, lead, etc.) are a frequent problem in distributed generation projects. Each side will usually want to retain as much control over the change order process as possible.
- *Security*: Both owners and ESCOs can have performance and payment concerns regarding the other. If an ESCO is concerned about the ability of the owner to make payments when due, some underlying payment support such as a letter of credit or an escrow fund can be put into place. This is fairly rare in on-site generation projects, but ESCOs should check to make sure that the owner is a substantial entity with the financial resources to make sure that the complete system can be paid for. Many times facility owners have complicated arrangements with special-purpose vehicles owning structures or land so that recourse to a financially substantial party may be not available. These special-purpose vehicles should not be the contracting party. From the owner side, if the owner is concerned that the ESCO may not be able to carry out the project, it can seek to obtain performance and payment bonds or parent guarantees. Performance bonds carry an extra cost, and the parties will negotiate over who bears it. This is of particular interest regarding solar PPAs, where there are many new entrants and some have gone out of business already.

- *Limitation of Liability*: It is not unusual for construction contractors to limit their liability to some part of the contract price or seek to put some other cap into place, but careful attention should be paid to these and other clauses purporting to limit the liability of a party and to how these work together with the insurance policies contractors should be required to maintain. For instance, overly broad limitations of liability could in fact pose a contractual obstacle to recovering under certain policies, such as errors and omissions and professional liability.
- *Insurance*: Few things are more tedious than reviewing the insurance provisions of a contract and the underlying policies, but an owner is well advised to have an insurance expert examine an ESCO's policies to make sure that they really do provide the coverage promised and that they do not have overly broad exclusions. It is important to note whether the ESCO's policies allow naming the owner as additional insured and to follow the process that the policy lays out.
- *Dispute Resolution*: As in any contract, an efficient dispute resolution mechanism should be provided. Some sort of alternative dispute resolution, such as an initial mediation and then arbitration, is generally preferable over simple submission to court jurisdiction, but many factors can influence this choice.[67]

Operations and Maintenance (O&M)/Performance over Period of Contract

Once the equipment is installed, it will have to work (as it is supposed to) over a long period of time for the energy benefits of the contract to be realized. As mentioned above, in the design-build model, the owner may contract directly with the O&M service provider, or the installing ESCO or contractor may subcontract the O&M work to a service provider. In the energy services model, and especially with solar PPAs, the ESCO continues to own the equipment and either provides the O&M service itself or subcontracts with a service provider. Either way, the terms of the O&M arrangement merit careful attention. While distributed generation O&M and equipment-servicing contracting is not a particularly glamorous practice specialty, the service provided is crucial to the success of a project, and a well-crafted O&M agreement is a key component of that process.[68]

Most original equipment manufacturers (OEMs) provide only a one-year warranty for the equipment, although some types of equipment traditionally come with longer warranty periods, particularly boilers and photovoltaic panels. During the one-year period, the equipment must meet all performance specifications and work as promised. If it does not, the warranty provider will, at its own cost, repair or replace the defective equipment. After the one-year period, the owner or ESCO recipient of the warranty will typically have no recourse against the OEM.

Combustion turbine systems have particular performance parameters that are quite important to their continued effectiveness. The two most important are the output (how much power and thermal energy they produce) and the heat rate (the efficiency with which fuel is converted to electric and thermal energy). All power generation systems, including fuel cells and solar and wind turbines, also have a measure of availability, i.e., the percentage of the time they are producing the required amounts of power. Something like 90 percent availability is expected because equipment must be taken down for scheduled maintenance, and there are times when unexpected outages and breakdowns will occur. For combustion generation, the availability of equipment is largely in the hands of the operators. For intermittent resources, like solar and wind, the operator cannot control the weather, but the equipment should nonetheless be available to produce when the resource is available. If an owner or an ESCO wants to ensure that certain levels of performance will be maintained over a period of years, it can contract for that with the ESCO or a service provider. This is, in a sense, the highest level of performance and amounts to an extended warranty.

Certain lesser levels of service can also be obtained. For instance, an owner or ESCO might contract with a service provider just to carry out certain defined maintenance tasks on a periodic schedule without the service provider committing to any particular level of performance. This is less expensive to the owner or ESCO but gives less contractual assurance of long-term performance. It is not uncommon, though, because for certain types of equipment the maintenance parameters are well known, and the parties expect that if the periodic maintenance is indeed carried out, the equipment will perform in a certain way.

With respect to what is meant by the term "operation," most on-site CHP and fuel cell systems are designed to be running all the time, so they don't really need to be turned on and off (i.e., dispatched, as explained below). Further, most DG equipment under a certain size (say, 5 MW) does not need a full-time on-site operator, especially fuel cells and solar systems. Almost all systems use Internet-based monitoring and control systems so that the ESCO or maintenance contractor can monitor all of the various operating parameters (output, heat rate, efficiency, steam pressure, etc.) remotely. If there is some anomaly, it is flagged and then either can be corrected remotely or a technician can be dispatched to inspect it. If equipment does need to be turned on and off (dispatched), this can be done remotely as well. In sum, the term "O&M" is something of a misnomer, but it is the common usage.

While solar panels require a lot less maintenance than combustion CHP systems or fuel cells, they still require some, such as regular cleaning of the panels, preventive maintenance of the electric equipment and the inverter (and especially batteries, if there is a battery bank), and repair of any faults.

If the design-build model is used, the owner may commit to perform some service and maintenance obligations itself. The owner may want this because by having its own personnel perform certain basic inspection and regulation tasks, it can lower the cost of the service contract. These should be spelled out in detail in a schedule, and the contract should provide that if the owner does not perform the tasks, the service contractor should be relieved of the relevant performance obligations.

For combustion generation and natural gas fuel cells, the O&M agreement should also specify who is responsible for fuel procurement. The fuel procurement may be as simple as the owner buying however much is needed under the gas utility tariff in effect, or the ESCO may choose to supply it and thus more actively manage fuel costs in natural gas markets. Whatever the level of service to be provided, it is important that these provisions of the contract relating to allocation of tasks and performance be clear so that all parties are aware of what is expected of them and what the consequence is of non-performance.

Of course, an O&M agreement is a contract too, so all of the various risk allocations that go into any contract apply. In O&M contracting, the exculpatory clauses and limitations of liability should be given particularly careful scrutiny. Because the owner is relying on the O&M service provider to make sure that a crucial piece of equipment runs and works well, there should be few reasons why the O&M service provider is excused from that obligation. Overly broad force majeure clauses should be watched. It is also common for O&M contractors to want to limit their liability to the owner to the amount of fees they earn for the service, either on a yearly basis or subject to some more general cap. While this is generally the market, as with construction contracts, limitations of liability should not be so broad that the owner will not have the benefit of the O&M contractor's professional liability or errors and omissions coverage, notwithstanding any cap. The limit of liability should refer to the O&M contractor's uninsured exposures.

Sophisticated Energy Management Services

The foregoing discussion has focused on relatively straightforward operations and maintenance practices. ESCOs are also able to provide much more sophisticated energy management services. For instance, depending on market conditions, it may not always be cheaper to run an on-site CHP system than simply to buy electricity from the local distribution utility. This depends on the price of natural gas and other market conditions. For instance, if a natural gas-fired DG system is located in an energy market that is unbundled—i.e., the generation, transmission, and distribution functions are carried out by separate companies—chances are that the cost of natural gas is passed through in a utility bill. As a result, if the price of natural gas rises, distributed generation will still save money because the host would have had to pay higher electricity prices anyway even if it did not have DG. If the host is not in an unbundled market or there are utility tariffs with regulatory caps, then it will become relatively more expensive to run the distributed generator on natural gas, and it will be cheaper to buy electricity from the utility. Further, an ESCO may have a sophisticated fuel procurement strategy and engage in hedging transactions. In these cases, the ESCO will want to have the right to remotely dispatch the distributed generation resources when it is advantageous to be running the on-site system and will ramp it down when it is not.

In some energy services agreements, the ESCO does not simply guarantee the price of electric or thermal energy sold to the host, it also guarantees a certain level of savings from what the host would have paid had no on-site generation been put into place. The energy services agreement will then include some sort of formula for calculating the energy savings. This formula needs to be scrutinized to determine the elements that went into it and to what extent these vary over time or are stipulated.

Financing

Combustion DG plants generally cannot be project financed because they are too small. As a result, the credit of the owner will usually have to be tapped in some way to make the project happen. As pointed out above, in many cases, the owner purchases the equipment from either the manufacturer or an ESCO under the design-build model. In this case, the owner must arrange its own financing. Another choice would be for the owner to enter into a type of sale and leaseback arrangement if it identifies a willing financing company.

If the owner does not want to use its own credit resources, then it should look to an ESCO willing to own the equipment on the owner's premises. Under that model, the ESCO uses its own resources to purchase and finance the equipment and relies on a long-term energy services agreement where the owner purchases power from the ESCO, such that the ESCO's financing also relies in an important sense on the financial strength and credit of the owner. Many owners find these arrangements attractive because they do not require an upfront outlay from the owner or utilization of the owner's balance sheet.

Particularly with respect to solar installations, a certain practice has developed regarding the structure of projects. One basic structure that is being used increasingly is for an ESCO to form a special purpose company, usually a limited liability company (LLC) with pass-through tax characteristics, to do one or several solar installations. This company will purchase and own the equipment and enter into a solar PPA with the owner to sell the electricity at a negotiated price. One solar company finances the equipment purchase and installation cost and then sells the system to a leasing company, which then leases it back to the LLC.

After the system is commissioned, the LLC will then be entitled to whatever incentives are available, such as a renewable energy credit based on the number of kilowatt hours of electricity generated (New Jersey is one state with a strong program), any other rebates or offsets against the purchase price (e.g., those offered by NYSERDA in New York), the federal tax credit that is available (for now, 30 percent of the out-of-pocket cost after rebates and then accelerated depreciation of the rest over as little as a five-year period). This adds up to a favorable package from the point of view of the ESCO, which receives these benefits, because the LLC is a pass-through. The LLC sells electricity at a fixed rate over the term of the solar PPA (usually with some escalation factor), thus providing cash flow to repay any debt obligations undertaken to purchase the equipment. From the owner's point of view, it can be desirable because the owner merely pays a set price for electricity from a defined period of time, which will in any case be at or lower than current grid rates, and will be set for the term of the agreement, thus protecting against rate hikes for the portion of its load solar generates.[69]

Of course, it is possible for the owner to negotiate with the ESCO for some sharing of the tax benefits. Some deals have so-called tax flips, patterned after wind project finance structures, where the LLC receives the tax benefits for some defined period of time and then they revert to the owner. Similar arrangements can be made for title;

after a set period of time, the owner might have the right to purchase title at a nominal price, after which the owner receives the benefit of the "free" electricity for the rest of the useful life of the equipment.

Some venture capitalists and funds are looking at more innovative structures for DG finance. The goal is to try to obtain a portfolio of DG projects with comparatively standardized energy services agreements so that the revenues can be pooled and interests in the revenue flow can be sold to investors.

Incentives and Renewable Energy Credits

Many types of distributed generation entitle the owner to utility rebates, renewable energy credits (RECs) or carbon credits, depending on where the host is located and what utility, state, and system operator programs are in place.[70] Many states also offer significant incentives to on-site generation projects, such as cash subsidies covering the cost of the equipment. On the federal level, there are also significant incentives available, particularly investment tax credits and, beginning with the American Recovery and Reinvestment Act of 2009 (ARRA), cash grants amounting to 10 percent of the cost of a project for CHP and 30 percent for solar, fuel cells, and geothermal.[71] State and federal incentives are discussed in more detail below.

All conceivable utility and government support should be studied to help bring down the ultimate cost to the owner of an on-site generation system. The energy services agreement should provide that it is the ESCO's responsibility to investigate the availability of all utility rebates, RECs, and state and federal incentives. In the energy services model, the ESCO will generally request that it be entitled to these financial benefits because it continues to own the system and its main obligation is to sell electricity at a certain price to the owner. To make the transaction financially viable, particularly in solar PPAs, where the economics of the transaction depend on the availability and application of rebates, credits, and incentives, this is particularly important to the ESCO. In the design-build model, the ESCO should be obligated to apply for and obtain these benefits on behalf of the owner. In some cases, the financial benefit associated with utility rebates and RECs is a point of negotiation between the ESCO and the owner. This aspect of the equation will be the subject of increasing attention as more and more significant carbon reduction credit schemes are being contemplated, including on the level of federal legislation.

As mentioned above, another way for an owner or ESCO to derive a financial benefit from a distributed generator is to participate, either directly or on behalf of the host, in ISO emergency call programs. In that regard, a distribution generation resource that can be dispatched can be a real asset. This does not necessarily apply as much to solar, because most solar installations are designed to deliver to the host all the electricity they can produce; but if a combustion DG system can be ramped up to produce more electricity to deliver to the system operator in a peak demand period, or otherwise sold through an aggregator, a financial benefit can be obtained. Again, the allocation of that benefit is a matter of negotiation between the ESCO and the owner.

State and Local Incentives

In some states and municipalities, there are tremendous incentives for DG, including tax breaks, subsidies for building demonstration projects, and other rebates and credits that can make a project economically worthwhile. These can vary from municipality to municipality within the same state, so they have to be studied carefully on the most local level.[72] The timing of payment of the incentives needs to be taken into account in the planning of a project. The first 75 percent is paid when all the system components have been delivered to the site and the appropriate paperwork is submitted to NYSERDA and approved, and the remaining 25 percent when the system is connected to the grid or NYSERDA-inspected (again with the appropriate paperwork). This means that the ESCO or qualified installer must finance the system acquisition cost up-front or the facility owner must pay for it.

New York also has state tax credits for photovoltaics and fuel cells. Regarding this tax credit, a significant anomaly was corrected in 2007. The residential tax credit for solar applies up to 10kW, which does not take into account the potential size of solar systems that can be installed in multiunit apartment buildings. The law was changed to allow up to 50 kW for apartment buildings. If the building is a cooperative, the shareholders can claim a proportionate share of the credit.[73] If the building is a condominium, the law contemplates that the condominium management association is purchasing and installing the system and allows a "taxpayer who is a member of the condominium management association to claim a proportionate share of the credit."[74]

New York has many other incentives and payments related to distributed generation, particularly if it results in a permanent load reduction. In the Con Edison service territory, these payments, which the New York ISO administers, are especially generous—the lesser of 65 percent of project costs of $200/kilowatt of summer peak load curtailment or the lesser of 65 percent or $50/kilowatt outside the Con Edison service territory.

A list of state and local incentives regarding distributed generation is available online.[75]

Federal Incentives

On the federal level, the February 2009 stimulus law, known officially as the American Recovery and Reinvestment Act (ARRA),[76] provides major incentives for all forms of renewable energy, including for distributed applications that are the subject of this chapter.

Since the Energy Policy Act of 1992, the main federal government support for renewable energy projects has come in the form of tax credits, either investment tax credits (based on the amount invested in qualified property) or production tax credits (used widely for wind projects), which are tied to the number of kilowatt hours of electricity sold for a period of 10 years after a qualified facility is placed in service. The current production tax credit is 2.1 cents per kilowatt hour on sales of electricity produced from wind, solar, geothermal resources, and closed-loop biomass.[77] It is 1 cent per kilowatt hour on sales of electricity produced from open-loop biomass,[78] landfill gas, trash combustion, and qualified hydropower facilities.[79]

These incentives are changing constantly, so practitioners should check carefully as to whether these federal incentives are still current.

Extension of Production Tax Credit

The October 2008 Emergency Economic Stabilization Act contained energy provisions that extended the production tax credit for wind facilities until the end of 2009.[80] ARRA extends the wind production tax credit for another three years for facilities placed in service before the end of 2012. With respect to the production tax credit for the other types of eligible renewable energy, including geothermal, solar, landfill gas, municipal solid waste, closed- and open-loop biomass, and qualified hydropower, the placed-in-service deadline is extended for another two years to the end of 2013.[81]

Option for Investment Tax Credit

The other type of tax credit traditionally used for providing incentives to renewable energy projects is an investment tax credit. A 30 percent tax credit has been available to owners or investors in solar electric and thermal equipment, fuel cells, geothermal property, and qualified small wind property (under 100 kW in size). For CHP equipment, the credit is 10 percent. Solar and geothermal systems were the only ones that were potentially eligible for either an investment tax credit or a production tax credit, but not both, by the explicit terms of the Internal Revenue Code.[82]

The ARRA now provides the opportunity to opt for the investment tax credit, instead of the production tax credit, for types of renewable energy equipment that were not eligible previously.[83] These types of facilities include large-scale wind, closed- and open-loop biomass, landfill gas, municipal solid waste incremental hydropower, and wave energy. To be eligible for this election, facilities have to be placed in service after December 31, 2008, and before December 31, 2013.

Direct Grants Now Allowed

Further, the ARRA provides another option for receiving federal government support for renewable energy projects. Instead of receiving a production or investment tax credit for the eligible types of renewable energy property, the developer or owner may instead elect to receive a grant from the federal government as a reimbursement to the developer for a portion of the expense of that property.[84] The grant is 30 percent of the tax basis of the property for wind (both large- and small-scale), closed- and open-loop biomass, geothermal, solar, landfill gas, municipal waste, incremental hydropower, wave energy, and fuel cells. The grant is 10 percent for microturbine and combined heat and power projects, as well as for geothermal heat pump property (as opposed to power generation equipment). The secretary of the treasury must receive applications for the grant by October 1, 2011. Property must be placed in service during 2009 or 2010 or, if placed in service after 2010, construction must have started during 2009 or 2010.[85]

As for the timing of grants, the U.S. Department of the Treasury (Treasury) will make payment within 60 days after the date of application for the grant or within 60 days after the date on which the specified energy property is placed in service, whichever is later. This means that the developer of the project will have to wait until it is placed in service to receive the grant unless the project is already under way and ready to be placed in service. This last aspect is of interest to developers or owners who already have projects under development. The intent appears to be to allow grants for projects if they are placed in service in 2009 in 2010. In July 2009, Treasury issued guidance for the award of these grants.[86] Later that month, it opened the system for applications.[87]

Allowing outright grants is a significant change in federal policy. Many commentators have criticized tax incentives as a way of supporting renewable energy development because they result in complicated structures and rely, in any case, on having investors who can use the credits to offset income. Because many developers are start-ups or entrepreneurial companies that don't have income, projects often rely on recruiting a tax equity investor who can use the tax credits. Also, as has been the case recently, some existing or potential tax equity partners have been having financing problems or losing money, making the tax credits less valuable to them. If a developer is now eligible for an outright grant, this changes the landscape as to how projects will be structured.

Of course, Congress has still not taken one step that many commentators feel will really stimulate the renewable energy industry in the United States, which is to impose a "feed-in" tariff for all renewable energy produced—that is, a minimum tariff to be paid by electric utilities. This is the model in use in Germany and Spain, for instance. In that system, the generally higher cost of renewable energy sources is socialized by passing it along to ratepayers. In the United States, the higher cost is socialized by reducing the amount of revenue the federal government receives. The outright grant still falls into this latter category, but at least it shortens the amount of time the developer must wait to receive the benefit of federal government support. Another advantage of the grant is that the size and timing of it can be used to facilitate financing in ways that drawn-out production and investment tax credits may not.

Accelerated Depreciation

Another significant federal incentive is accelerated depreciation for certain eligible renewable and other distributed generation technologies, principally the main solar applications, fuel cells, geothermal, and microturbines. This can be claimed for commercial and industrial applications under the Modified Accelerated Cost Recovery System. The solar applications have benefited from this regime for many years. The Energy Policy Act of 2005 extended the definition of eligible technologies to fuel cells and microturbines.[88] The ARRA extends for one year the ability to claim the 50 percent bonus depreciation deduction on qualifying new property, which includes property that is depreciable under the Modified Accelerated Cost Recovery System and has a recovery period of 20 years or less. To qualify for the bonus depreciation deduction, the property must be new—that is, its original use must begin with the taxpayer and must be placed in service after December 31, 2007, and before January 1, 2010. However, any property that was acquired pursuant to a binding written contract that was in effect before January 1, 2008, will not qualify for bonus depreciation.

The combined effect of bonus and accelerated depreciation is quite favorable for the owner of renewable energy systems. In the first year, half of the cost of the system can be depreciated, with the rest of the cost taken over five years (including in the first year when the first 50 percent is taken).

Residential Tax Credits

The most well-known incentive for solar in residential applications has been the 30 percent residential tax credit, which, under the terms of the Energy Policy Act of 2005, had a limit of $2,000 and was set to expire at the end of 2008. The solar industry sought an eight-year extension of these credits.[89] Another issue that impeded the use of the credit for individuals was that if a company or an individual is an alternative minimum tax (AMT) payer, the credit was treated like any other tax deduction or credit, so that the credit's effectiveness is limited by the AMT. Solar industry lobbyists pushed to allow corporate and individual taxpayers to claim it against the AMT.

The ARRA extended the residential energy property credit to include property placed in service until the end of 2010.[90] With respect to the Residential Alternative Energy Credit,[91] the ARRA removed the annual credit maximums for tax years 2009 through 2016.

Things to Watch Out For in DG Projects

Despite all of the incentives, distributed generation projects are not simple to implement. Once an owner determines it wants some form of alternative energy, both the owner and the ESCO need to bear in mind several factors to make sure the potential benefits of DG are realized.

Interconnection

An issue in every project is interconnection to the local utility distribution grid. Most on-site generation systems are not sized to cover the facility's entire electric load. CHP systems are optimally designed to cover a facility's thermal load. In the case of photovoltaics, it is rarely the case that the on-site systems can cover a facility's load given the output possibilities and the intermittency of the resource. Moreover, on-site systems have to be taken down for maintenance periodically and also can fail unexpectedly. The host will then want to revert to grid power immediately to avoid interruptions.

If an on-site generator is interconnected, the interconnection can be one of two kinds, either an induction or a synchronous generator. Induction generators cannot work without the grid; they need it to be "excited," as engineers say, to start up and continue firing. Synchronous generators run in parallel to the grid and do not need the grid to work (although they still need gas delivery if they are natural gas plants). If a DG plant has induction generators, the owner may lose one of the main potential benefits of DG—backup power. Unfortunately, some utilities make it virtually impossible to synchronize a DG plant due to grid stability concerns, or they allow synchronization only with the installation of expensive protective relaying (to prevent fault current from going onto the grid), which makes the project uneconomic. This problem is particularly acute in cities that have so-called network distribution systems as opposed to radial distribution systems that are common outside of urban areas.

As a result, owners need to be well informed about how their local utility company treats grid interconnection of DG plants and what types of protective relaying schemes utilities have allowed in past interconnections. This will drive the type of equipment used. If synchronization is not a practical option, induction equipment can be outfitted with black-start capabilities—that is, a backup diesel generator for CHP—to ensure start-up in the event grid power is lost, even if this process is not instantaneous. This could be an issue for certain kinds of industrial processes. For solar systems, battery banks need to be installed if the system is going to continue delivering electricity to the host in the event of a grid outage.

Owners also need to know how long the utility approvals for interconnection tend to take, as this will drive the schedule for ordering equipment and projecting a start-up date. Sometimes long delays become an issue in the timing of the project. It is not unheard of for a DG plant to be built and then have to wait to be tested properly because the utility is still reviewing and commenting on an interconnection application.

Indeed, interconnection problems and delays are the single greatest impediment to the successful installation of DG equipment and are holding back the greater development of the distributed resources. To address this obstacle, several states have instituted standard interconnection procedures that local utilities must follow in response to applications from distributed generators. The rules of New York and California are summarized below.

New York

The New York Standard Interconnection Rules provide for an expedited approval process for DG facilities up to 2 MW.[92] A DG facility wishing to interconnect to a New York utility system must first submit a detailed application to the public utility. After an application is accepted, the next steps in the process depend on the size of the DG facility. For facilities 25 KW or less, the DG facility must then install its system according to the plans set forth in the application. The DG facility must then perform verification testing of the system, with the utility allowed to witness the testing if it so chooses. Once the testing is complete and is proven successful, the DG facility is allowed to commence parallel operation.

For DG facilities above 25 KW and up to 2 MW, there is a more detailed review period. After an application is accepted, a cost estimate for the coordinated electric system interconnection review (CESIR) takes place. During the CESIR, the utility conducts a preliminary review of the viability of the proposed interconnection mainly focusing on (i) the impact to the utility system associated with the proposed interconnection and (ii) the proposed system's compliance with various criteria (further detailed below) by the utility. If the review is favorable, a standardized contract between the DG facility applicant and the utility is executed. The DG facility provides an advance payment for the utility's estimated costs associated with the interconnection, and construction begins. The DG facility applicant is responsible for building the facility according to the design specifications described in its application, and the utility is responsible for the construction and installation of any necessary system modifications and metering requirements. Upon completion of construction, the DG facility is tested. If satisfactory to the utility, the DG facility is then allowed to commence parallel operation. There are, however, various design and operating requirements that must be met before a proposed DG facility will be allowed to interconnect to the utility system.

A DG facility owner must provide appropriate protection and control equipment in the form of an automatic disconnect device that would instantaneously disconnect the generation in the event that the utility system serving the DG facility is de-energized for any reason or due to the fault of the DG facility operator. The specific design of this device depends on the size and characteristics of the individual DG facility.

Both synchronous and induction generation may be interconnected to the utility system. Synchronous generation requires synchronizing facilities that include (i) automatic or manual synchronizing equipment, (ii) sufficient power capability to withstand normal voltage changes on the utility's system, and (iii) a grounding mechanism. Induction generation can also be interconnected and then brought up to synchronous speed if such is feasible. The same requirements as above apply to induction generation.

Interconnected DG facilities must provide 24-hour telephone contact allowing the utility to arrange access for any necessary repairs, inspections, or emergencies. They cannot supply power to the utility during any outages of the utility system that serves the PCC (point of common coupling). The DG facility's generation may be operated during an outage only with an open tie to the utility. Islanding is not permitted. A DG facility operator is not permitted to energize a de-energized utility circuit for any reason. The utility may also require the DG facility to connect to the utility system through a dedicated transformer to be provided at the expense of the DG facility owner. A disconnect switch also is required for DG facilities larger than 25 KW and must be installed, owned, and maintained by the DG facility owner. All equipment used by the DG facility must also be equipped with the minimum protective function requirements as set forth in the application materials.

California

In California, the California Public Utilities Commission (CPUC) Rule 21 governs interconnection. As in New York, a detailed application must be submitted to the local utility for approval. The process begins with an initial review. If an applicant's interconnection equipment conforms to commission-approved performance standards and is certified under Rule 21, the applicant does not plan to export power, and the generator capacity is small compared to the facility's consumption, an applicant will most likely qualify for simplified interconnection.[93] If a facility does not qualify for simplified interconnection, a more detailed supplemental review is conducted to determine whether the facility can be made to qualify for simplified interconnection by meeting additional requirements.

Once it has been determined that a DG facility is eligible to interconnect to the utility's system, the applicant must sign a CPUC-approved pro forma interconnection agreement. Collateral agreements may also be necessary to address ownership, responsibility, cost, and installation issues. After the execution of these agreements, the applicant moves forward to install the DG facility and interconnect to the grid in accordance with the agreements. After installation is complete, the DG facility undergoes the final step in the interconnection process, commissioning testing, whereby tests are performed under the supervision of the utility to locate and correct any mistakes that may be discovered and to assure the DG operator and the utility that the DG facility functions properly. Upon successful completion of the commissioning testing phase, final approval is received, and the DG facility can operate in parallel to the utility system.

Section D of Rule 21 describes the various technical requirements for interconnection. These include (i) general interconnection and protection requirements; (ii) the need for prevention of interference with the utility system so that the utility can be assured that the interconnected DG facility will not interfere with its own power quality or operation (specific details as to voltage, power factor, frequency, and distortion are set forth); and (iii) control protective function and safety requirements depending on whether the DG facility is a synchronous, induction, or inverter-based system.

Relationship with the Local Utility—Standby Tariffs

Assuming the interconnection approvals are obtained, once a facility begins to generate a part or all of its own electricity, its relationship with the local utility changes. While it is possible for a facility to be an island, with no flow of power to or from the grid, for the reasons explained above facility owners invariably wish to keep a utility service agreement in place. This changes the type of utility tariff that applies to the owner. In some places, utilities charge exit fees or impose standby tariffs. Owners need to take into account what these might be to make sure the project makes economic sense. The ESCOs should be able to analyze this aspect. Owners who install generation technologies using renewable fuels or fuel cells are sometimes exempt from exit fees or have to pay less significant standby charges.

Applicable standby tariffs need to be studied carefully. Most of them are based on the idea that the distributed generator and the utility are agreeing to a type of maximum demand that the facility might need if the on-site generation is unavailable. If this demand is exceeded for some reason, the tariffs include penalties—so-called ratchet provisions—where some multiple of the demand charge will have to be paid. Further, in some places, the new demand is set at a higher level if this happens, so that the owner has to pay more going forward. In other places, the facility owner can agree to pay a somewhat higher standby tariff on a steady-state basis but will not be subject to the ratchet charges. In essence, it is a type of insurance policy.

One interesting approach some solar installers are using is to go behind the utility meter. In a large multifamily building, for instance, it is unlikely that solar can supply more than a certain fairly low percentage of the average load—10 percent to 40 percent. In this case, the inverter can be put on the customer side of the utility meter so that the AC power goes directly to the residents' submeters. No power ever goes back on the grid, so there is no need for a costly and time-consuming interconnection exercise with the utility. From the utility's point of view, all it really notices is that a certain customer is using less electricity, which, depending on how stressed its local distribution grid is, may be fine with the utility. In any case, the customer will not have to go into a standby tariff category.

Regulatory Concerns

If a distributed generation system provides power only to the host facility and there is no sale of power to a third party off-site, the state and federal regulatory issues are not significant. If, however, the facility owner generates more electricity than it needs, which can happen, then a facility owner becomes a participant in today's complex local and regional power markets and enters the Byzantine netherworld of state and federal power law and regulation.

The issue of selling power back to the grid or in an organized market was, until the fairly recent Energy Policy Act of 2005, a potentially thorny one. This law repealed the Public Utility Holding Company Act of 1935 (PUHCA),[94] under whose terms a facility owner ran the risk of being regulated like a utility by the federal government if it sold any power at all, even though its core business might be entirely unrelated. The way to avoid this was for the owner to obtain an exemption from the application of the PUHCA. The exemption took one of two forms: certification as a qualified facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA)[95] or obtaining the status of an exempt wholesale generator (EWG). QF certification was the more typical route if waste heat was being used.

Many states conferred particular benefits to facilities that were certified as QFs, so it was quite important for a DG project to meet the PURPA criteria, which mostly concerned the efficiency of the project and the use to which the thermal energy was being put. Because of the repeal of PUHCA this is less important, but it still makes sense for projects to be certified as QFs because some states continue to confer some benefits on QFs. If maintaining QF certification is desirable in the particular jurisdiction, the host will have to ensure a certain level of thermal energy off-take and that this thermal energy will be put to use in some way that is considered beneficial. The Energy Policy Act of 2005 provisions amending PURPA made these more strict due to a view prevailing among investor-owned utilities that thermal energy was an afterthought in a project designed in fact to sell electricity back to the utility, which the utilities often did not want. In addition, most states have statutes that prohibit a sale of electricity by a non-utility generator of electricity director to another customer. This prevents a distributed generator from entering into private contractual arrangements to obtain the best price for excess electricity.

Given the constraints of these laws, distributed generators have only certain options as to sale of excess electricity they might generate. If a system is small enough, such as residential solar, the utility is normally required to buy back excess power at an established price, a process known as net metering. These net-metering laws do not apply, however, to installations large enough for multifamily housing, commercial buildings, or industrial facilities. Therefore, depending on the amount of extra electricity, these installations can either (a) enter into a power sales agreement with the local utility (which may or may not have to do so depending on how PURPA is interpreted in the relevant state or regional market); (b) sell into the applicable local or regional power market (NYISO, ISO New England, PJM, MISO, etc.); or (c) enter into an agreement with an intermediary known as an aggregator. Agreements with aggregators are used when the unit of power a distributed generator might have for sale is smaller than the minimum allowed by the market (for example, 1 MW in NYISO). The aggregator goes around to the distributed generators within a certain market and bundles together the power available so that the unit minimums are met.

Finally, there are financial advantages to a distributed generator participating in ISO demand response programs, as described above. To use New York as an example, the ISO enters into agreements with owners of distributed generators so that the generators are available at the days of highest demand during the summer. If a distributed generator has such excess capacity, or can shed load on its own site to make excess power available, the ISO will pay the owner an annual fee to make this capacity available and also pay for the power when the distributed generator delivers it.

Land Use/Permitting Issues

Land-use and permitting issues can loom large in a distributed generation (DG) project. A threshold land-use issue is whether the DG equipment is placed inside or outside of a structure. A typical natural gas CHP system can fit inside of a standard ship container. When these are placed outside, which is the preferred method for many types of owners, such as big-box department stores and industrial facilities, most local land-use rules consider them to be structures for which a building permit is required. Issues that local building departments raise can hold up projects, particularly because some kinds of CHP systems can be very noisy, so the level of sound attenuation becomes an issue.

For CHP systems that are designed to be placed inside buildings, owners should be aware that they would be combusting fuel in their basements, and that the local fire department will be interested in this. Many projects in New York City were held up in 2006 and 2007 when the fire department began objecting to the size and pressure of the gas connections. As a result, a process was launched under the direction of the fire commissioner to propose revisions to the New York City Building Code. The amendments were adopted in October 2007 to specifically address on-site power systems.[96] The size of these projects was limited to 2000 kW or 2 MW, which is not very large. A large commercial office building in New York can use much more power than that during peak demand times.

The larger issue in distributed generation projects is that, as in all projects, owners should look carefully at all potential permitting issues, beginning at the most local level and working up, because a serious land-use issue can hold up a project for a long time. Local building permit issues can kill otherwise attractive DG projects.[97] For DG plants that use combustion technologies, owners will have to comply with federal and state clean-air and local emission standards. Natural gas CHP plants do not have low SOX and NOX emission profiles. Their desirability from an environmental standpoint is their greater efficiency than central station generation and the lack of transmission losses. This being said, they generally fit within federal clean air guidelines even in non-attainment areas, and federal clean air permits rarely hold up projects. Some states have adopted or are considering specific combustion DG air-permitting rules.

Integrated Building Design

One purpose of this chapter has been to demonstrate that generating power and useful thermal energy in buildings and on the site of commercial and industrial facilities is possible and well within the reach of property owners and managers with existing technology and available financial engineering. With existing buildings, today's technologies need to be fitted into older building designs, many of which date to a time when making efficient use of energy and reducing greenhouse gases were not concerns. When owners, architects, and urban planners are contemplating new buildings and larger developments today, integrating on-site generation techniques is much easier. Thus, another purpose of this chapter and its review of the different types of on-site generation is to suggest that integrating not one but several on-site generation techniques ought to become the norm. In theory, a building can be designed to incorporate combined heat and power from either on-site turbines or fuel cells, as well as solar panels, solar thermal, heat pumps for geoexchange systems, and on-site wind. Taken together with advanced energy efficiency techniques, buildings, which today are the greatest consumers of energy and contributors to greenhouse gases, can be net zero energy, meaning that they produce as much as they consume and may well have electricity left over to export to the grid. If on-site generation of power and thermal energy becomes widespread, it will have profound implications on how we think of urban planning, the fuels used for central power generation, the role of public utilities, and the regulation of sources of greenhouse gases.

Notes

1. Additional information about PJM and its demand response program is available at http://www.pjm.com.

2. A manual explaining the EDRP is available at http://www.nyiso.com/public/webdocs/documents/manuals/planning/edrp_mnl.pdf.

3. Information about both of these programs is available at http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp.

4. Additional information about ISO New England is available at http://www.iso-ne.com.

5. Additional information about California ISO and its DRP are available at http://www.caiso.com.

6. A yearlong study by the company GridWise concluded that smart grid technology saved consumers in Seattle about 10 percent on their power bills and did ease strain on the power grid. *See* Martin LaMonica, "GridWise Trial Finds 'Smart Grids' Cut Electricity Bills," C/Net News (Jan. 9, 2008), *available at* http://news.cnet.com/8301-11128_3-9847236-54.html.

7. Information about this program is available at http://www.gridpoint.com/Home.aspx.

8. Buildings in the United States use approximately 40 percent of all energy generated and three-fourths of all electricity generated. *See* Energy Information Administration, *Annual Energy Review 2007*, at 74 (Figure 2.1a), *available at* http://tonto.eia.doe.gov/FTPROOT/multifuel/038407.pdf. The U.S. Dept. of Energy has estimated that in 2006, buildings in the United States emitted 630 million metric tons of GHG emissions, approximately equal to the combined emissions of the United Kingdom, France, and Japan. *See* U.S. Dept. of Energy, Energy Information Admin., Annual Energy Outlook 2008 (Dec. 2007).

9. American Solar Energy Society, Tackling Climate Change in the U.S.: Potential Carbon Emissions Reductions from Energy Efficiency and Renewable Energy by 2030 (Charles F. Kutscher ed., Jan. 2007), *available at* http://www.ases.org/images/stories/file/ASES/climate_change.pdf.

10. *Id.* at 3.

11. *Id*. at 4.

12. *Id*. at 3.

13. McKinsey & Co. and The Conference Board, *Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?*, U.S. Greenhouse Gas Abatement Mapping Initiative, Executive Report (Dec. 2007), p. xiv, *available at* http://www.mckinsey.com/clientservice/ccsi/pdf/US_ghg_final_report.pdf.

14. *Id*. at xv.

15. Additional information about the environmental and air quality issues associated with diesel generators is available at http://www.epa.gov/nonroad-diesel. Diesel engines are also discussed in Chapter 3.

16. *See* U.S. Envtl. Prot. Agency, *Combined Heat and Power Partnership: Efficiency Benefits*, *available at* http://www.epa.gov/chp/basic/efficiency.html.

17. *See* U.S. Envtl. Prot. Agency, *Combined Heat and Power Partnership: Economic Benefits, available at* http://www.epa.gov/chp/basic/economics.html.

18. Larger plant figures based on statistics compiled by Citi Investment Research for combined-cycle natural gas power plants. *See* Citi Investment Research, *North America Energy Merchants, Replacement Cost Analysis* (Jan. 13, 2008). The source for smaller system statistics is Danny Harvey, *Clean Building—Contribution from Cogeneration, Trigeneration and District Energy,* in Cogeneration and On-site Power Production (Sept.–Oct. 2006), at 110. Note, of course, that the cost of materials for all sorts of power plant and other construction rose rapidly due to heavy demand in international commodity markets and then fell precipitously after 2008, so the figures cited can be considered only as approximations.

19. A list of these subsidies and other incentives are available at http://www.epa.gov/chp/funding/funding.html.

20. Renewable portfolio standards are state-imposed requirements that electric distribution companies derive a certain percentage of their electricity from renewable sources.

21. As of April 2009, these states included Colorado, Connecticut, Hawaii, Maine, Massachusetts, Michigan, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, and Washington. Depending on the state, some restrictions apply, such as a minimum total efficiency and/or thermal threshold. *See generally* U.S. Envtl. Prot. Agency, *Energy Portfolio Standards and the Promotion of Combined Heat and Power* (April 2009), *available at* http://www.epa.gov/chp/documents/eps_and_promotion.pdf .

22. *Id.*

23. Dan Rafter, *Declaration of Energy Independence*, Distributed Energy (Jan./Feb. 2009).

24. Description of technologies and efficiencies derived from Justin Smith, *Hydrogen: The Fuel of Tomorrow?*, in Energy Current (Feb. 7, 2008), *available at* http://www.energycurrent.com.

25. An Act Concerning Energy Electricity and Energy Efficiency, Public Act 07-242, § 124 (Conn. 2007), modifying Conn. Gen. Stats. § 16-244c(j)(2).

26. State of Connecticut, Dept. of Pub. Util. Control, Docket No. 07-04-27, DPUC Review of Long-Term Renewable Contracts—Round 2 Results (Jan. 30, 2008).

27. Sources cited in Danny Harvey, *Clean Building: Contribution from Cogeneration, Trigeneration and District Energy*, Cogeneration and On-Site Power (Sept.–Oct. 2006), at 107.

28. *See* John Markoff, *Start-Up Sells Solar Power at Lower-Than-Usual Cost*, N.Y. Times (Dec. 18, 2007), *available at* http://www.nytimes.com/2007/12/18/technology/18solar.html?ref=technology.

29. A list of states that offer such incentives is available at http://www.dsireusa.org.

30. A good comparison of the relative prices of conventional and alternative sources of energy is available at http://peswiki.com/index.php/Directory:Cents_Per_Kilowatt-Hour.

31. Michael Kannelos, "Solar Cell Breaks Efficiency Record," C/Net News (Dec. 6, 2006), *available at* http://news.zdnet.com/2100-9596_22-150524.html.

32. For example, Berkeley, California, has approved a financing initiative for loans to homeowners who install rooftop solar panels, referred to as the Berkeley Financing Initiative for Renewable and Solar Technology (FIRST). The initiative finances city-backed solar loans through a small addition to the property taxes of each participating home. Financing of up to $37,500 per installation for either residential or commercial properties citywide is available for these projects. The special tax obligation will remain as an obligation of the property when the property is sold. If the owner sells the property before the end of the 20-year tax period, the new owner takes over the special tax obligation as part of the annual tax obligation on the property. The energy systems are part of the property, and ownership of the energy system will transfer to the new owner at the close of the real estate sale. Only residential or commercial properties located in the Berkeley are eligible for funding. A pilot version of the program initially funded 40 solar-panel installations distributed throughout Berkeley. Additional information about Berkeley's program is available at http://www.cityofberkeley.info/ContentDisplay.aspx?id=26580. This program is discussed at length in Chapter 5.

33. I remember promoting the federal incentive program for solar thermal on my college radio station during the Carter Administration and being crestfallen when it was eliminated in the early part of the Reagan Administration. One can only imagine how many BTUs of energy would have been saved and tons of carbon emissions avoided, not to mention the technological innovations that would have occurred, if this short-sighted decision had not been made in 1981.

34. Office of the Governor of California, Press Release, Governor Schwarzenegger Announces Partnership to Power CSU Campuses with Solar Energy (Oct. 21, 2008).

35. Press Release, Chevron Energy Solutions Completes First Phase of North America's Largest Solar Power Project in Higher Education (Jan. 31, 2008).

36. Information about the California Solar Initiative Program is available at http://www.gosolarcalifornia.org/csi/index.html.

37. Press Release, BP Solar to Provide PV Power Systems for Major Retailer in California (April 22, 2009), *available at* http://www.bp.com/genericarticle.do?categoryId=9024973&contentId=7052567.

38. Press Release, Kohl's Activates Largest Rooftop Solar Rollout in U.S. History (Sept. 26, 2007), *available at* http://www.sunedison.com/images/press/092607-kohls.pdf.

39. *Pepco to Install 2MW Rooftop Solar PV System in Atlantic City* (June 21, 2008), *available at* http://www.cleanedge.com/news/story.php?nID=5419

40. P. Shankar, *Merck's Solar Power System is Billed Largest in the Eastern U.S.*, NJBIZ (Aug. 14, 2008), *available at* http://www.njbiz.com/article.asp?aid=75520.

41. This list is available at http://www.dsireusa.org/incentives/index.cfm?EE=0&RE=1&SPV=0&ST=0&technology=all_solar&sh=1.

42. Geothermal electricity generation has significant benefits; chief among them being that it is virtually emissions-free and geothermal power is available 24 hours a day. It is also considered to be sustainable because the heat extraction is small compared to the size of the heat reservoir. Nevertheless, as of 2008, geothermal power provided less than 1 percent of the world's energy. The Philippines and Iceland are the only countries that generate a significant percentage of their electricity—roughly 15–20 percent—from geothermal. The largest collection of geothermal power plants in the world is located at The Geysers, a geothermal field in California.

43. "Whereas geothermal and solar energy can be used for a variety of thermal applications, electric generation is generally limited to abundant high-temperature sources. Geothermal energy sufficient for electric generation application is limited to specific regions (e.g., the Western United States), where high-temperature sources can be economically accessed." NEIL PETCHERS, COMBINED HEATING, COOLING & POWER HANDBOOK: AN INTEGRATED APPROACH TO ENERGY RESOURCE OPTIMIZATION, at 472 (Fairmont Press, Inc. 2003).

44. Additional information is available at the Geothermal Heat Pump Consortium, *available at* http://www.geoexchange.org.

45. Office of Energy Efficiency and Renewable Energy, *Geothermal Basics Overview*, *available at* http://www1.eere.energy.gov/geothermal/geothermal_basics.html.

46. *See* Office of Energy Efficiency and Renewable Energy, *Direct Use of Geothermal Energy*, March 1998, *available at* http://www1.eere.energy.gov/geothermal/pdfs/directuse.pdf (noting that direct-use geothermal has a number of commercial and industrial applications as well, including aquaculture, greenhouses, food dehydration, laundries, gold mining, grain drying, mushroom culture, and sludge digestion).

47. U.S. Envtl. Prot. Agency, Office of Air and Radiation, *Space Conditioning: The Next Frontier*, 430-R-93-004 (Apr. 1993). The article did not provide estimates of the savings that could be expected from the *commercial* application of geothermal technologies, though those savings ought to be comparable to residential use. *See also* U.S. Envtl. Prot. Agency, *Natural Disasters and Weather Emergencies*, *available at* http://www.epa.gov/NaturalEmergencies/fightfrost.html (stating that geothermal heat pumps are up to 30 percent more efficient than comparable new equipment).

48. *See* Geothermal Heat Pump Consortium, *available at* http://www.geoexchange.org.

49. *Geoexchange Systems: Renewable and Ready* (July 7, 2008), *available at* http://www.geoexchange.org/resources/publications/cat_view/62-fact-sheets.html.

50. *See id.*

51. Oak Ridge Nat'l Lab., *Geothermal (Ground Source) Heat Pumps: Market Status, Barriers to Adoption, and Actions to Overcome Barriers* (Dec. 2008) at 2, *available at* http://www.zebralliance.com/docs/geothermal_report_12-08.pdf.

52. The Emergency Economic Stabilization Act contained a section called the Energy Improvement and Extension Act of 2008 (EIEA). This tax credit is located at EIEA § 105(a).

53. This database is available at http://www.dsireusa.org.

54. *See id.*

55. Residential Environmental Design, *Geothermal Heating and Cooling Systems*, *available at* http://www.reddawn.com/featart11-98.html.

56. *Geoexchange Systems: Renewable and Ready* (July 7, 2008), *available at* http://www.geoexchange.org/geothermal/publications/cat_view/62-fact-sheets.html.

57. The system dealer/installer will be able to determine ductwork requirements and if any minor modifications are needed. Home builders and homeowners both can take advantage of the special financing that is offered in many locations through either the utility or the manufacturer. *See* Int'l Ground Source Heat Pump Ass'n, *Residential Geothermal*, *available at* http://www.igshpa.okstate.edu/geothermal/residential.htm.

58. *See* Int'l Ground Source Heat Pump Ass'n, *Commercial Geothermal*, *available at* http://www.igshpa.okstate.edu/geothermal/commercial.htm.

59. Takashi Yatabe, *The Effect and Potential of Heat Pump Technology*, Business Coordination Dept., Heat Pump & Thermal Storage Technology Center of Japan, *available at* http://www.hptcj.or.jp/about_e/iea/pdf/s2_p05.pdf.

60. Lyn Corum, *Wind on the Edge*, Distributed Energy (Jan./Feb. 2009).

61. *Id.*

62. It seems that many commercial purchasers of on-site wind have done so in furtherance of a broader marketing strategy to expand their green credentials. For example, Chipotle Mexican Grill unveiled plans last year to open a restaurant in Gurnee, Illinois, featuring a prominent six-kilowatt wind turbine:

> Although mostly a symbol for the company's efforts to create more environmentally friendly store designs, the turbine will generate 10 percent of the store's power. The Gurnee Chipotle will have some of the following green features: a 2,500-gallon underground water cistern to harvest rainwater for landscape irrigation; energy and water conservation elements, including LED lighting, highly efficient faucets and toilets, and Energy Star-rated kitchen equipment; use of recycled drywall, recycled barn metal, and primers and paints that contain fewer chemicals; native plants outside that will require less watering and fertilizer; asphalt in the parking lot that will reflect the sun's heat rather than absorb it, making the entire site cooler. Notably, as a participant in the USGBC's LEED for Retail pilot program, Chipotle is seeking LEED certification for this location, making it one of only a few restaurants to do so.

Preston Koerner, *Chipotle Green Restaurant Uses On-site Wind Power*, Jetson Green, Oct. 2008, *available at* http://www.jetsongreen.com/2008/10/chipotle-green.html.

63. Corum, *supra* note 60.

64. *See*, *e.g.*, New York State, *On-Site or Small Wind Incentives*, *available at* http://www.powernaturally.org/programs/wind/incentives.asp.

65. For a fuller description of these, see Jon Norling, *Legally Bound—The Top 10 Contractual Issues in Cogeneration Energy Services Agreements*, in Cogeneration and On-Site Power Production (Jan.–Feb. 2007), at 31.

66. A sample energy services agreement, which demonstrates their length, is available at http://www.energyservicescoalition.org/chapters/FL/manual/Appendix%20H.Contract.Services.Agreement.doc.

67. For a more complete discussion of the factors that go into choosing different methods of dispute resolution, see Frederick R. Fucci, *Getting Transactional Lawyers Thinking About Dispute Resolution* (Nov. 6, 2007), *available at* http://www.arnoldporter.com/

resources/documents/GettingTransactionalLawyersThinkingaboutDisputeResolution 110507.pdf.

68. There are many sample O&M agreements available online. One such agreement is available at http://www.doa.state.wi.us/docs_view2.asp?docid=1026.

69. A list of states and what types of incentives they offer is available at http://www.dsireusa.org.

70. RECs are discussed at length in Chapter 5.

71. ARRA § 1603 (Grants for Specified Energy Property in Lieu of Tax Credits).

72. *See* http://www.dsireusa.org.

73. 2007 N.Y. Laws, ch. 128.

74. It is unclear why only the members of the condominium management association can claim the credit. If a solar system is feeding in behind the main meter, the electricity savings, especially for common building systems, inure to the benefit of all unit owners. The management association might be an outside independent contractor or the board of managers of the condominium, which consists typically of only a few of the many unit owners.

75. This list is available at http://www.dsireusa.org.

76. Pub. L. No. 111-5.

77. Notice 2008-48 I.R.B. 2008-21, 1008 (May 27, 2008). Closed-loop biomass refers to a biomass facility that uses organic material from a plant cultivated exclusively for purposes of being used at a qualified facility to produce electricity.

78. An open-loop biomass facility is one that uses waste materials such as livestock waste and other types of existing biomass, such as wood waste and agricultural sources. *See* Internal Revenue Code (I.R.C.) § 45(c)(3).

79. The term "qualified hydropower" refers to additions to the production capacity of existing hydroelectric facilities and hydroelectric projects added to dams that exist already for other purposes. *See* I.R.C. § 45(c)(8).

80. *See The Emergency Economic Act contains Significant Energy Provisions*, Arnold & Porter Client Advisory (October 2008), *available at* http://www.arnoldporter.com/resources/documents/CA_TheEmergencyEconomicActContainsSignificant_100808.pdf.

81. ARRA § 1101 (Extension of Credit for Electricity Produced from Certain Renewable Resources).

82. I.R.C. § 48(a)(5)(B).

83. ARRA § 1102 (Election of Investment Credit in Lieu of Production Credit).

84. ARRA § 1603 (Grants for Specified Energy Property in Lieu of Tax Credits).

85. Certain types of entities are not eligible for grants. These are federal, state, or local governments (or their agencies or instrumentalities), any nonprofit corporation under § 501(c) of the Internal Revenue Code, and any cooperative utility.

86. This guidance is available at http://www.treasury.gov/recovery/docs/guidance.pdf.

87. Applications can be made through Treasury's Web site at http://www.treasury.gov/recovery/1603.shtml.

88. Energy Policy Act of 2005, § 48, modifying 26 U.S.C. § 168 and § 48(a)(3)(A).

89. Jan Pierobon, *U.S. Renewables Groups on the Offensive*, Renewable Energy Focus, Feb. 13, 2008.

90. I.R.C. § 25C.

91. I.R.C. § 25D.

92. *See* N.Y.S. Pub. Serv. Comm'n, *New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2MW or Less Connected in Parallel with Utility Distribution Systems* (revised Feb. 12, 2009), *available at* http://www.dps.state.ny.us/Final_SIR_02-12-09_Clean.pdf.

93. Simplified interconnection means that the minimum amount of review was necessary because all the thresholds set forth in the initial review process were met. It is defined in Rule 21 as interconnection conforming to the initial review requirements.

94. 15 U.S.C. § 79 *et seq.* [repealed].

95. 16 U.S.C. § 26 *et seq*.

96. RULES OF THE CITY OF NEW YORK, tit. 1, Dept. of Bldgs., § 50-01 - Requirements for the Installation of High-Pressure Natural Gas-Fired Microturbine Systems.

97. For an interesting discussion about how local building codes and restrictive covenants in developments can inadvertently or deliberately frustrate residential photovoltaic projects, see Edna Sussman, *Reshaping Municipal and County Laws to Foster Green Building, Energy Efficiency and Renewable Energy*, 16 N.Y.U. ENVTL. L. J. 1 (2008).