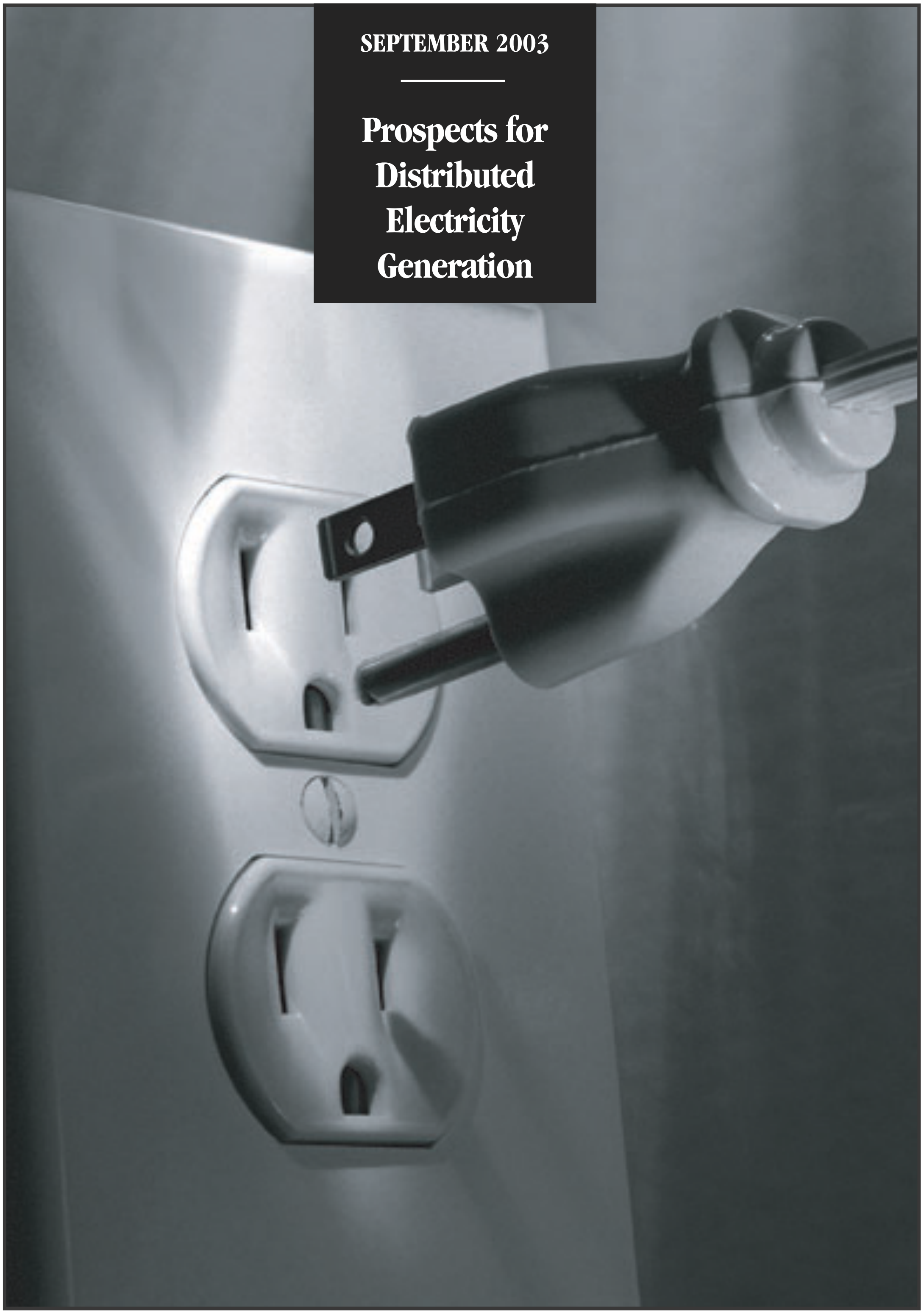
CONGRESS OF THE UNITED STATES
CONGRESSIONAL BUDGET OFFICE

A CBO PAPER

SEPTEMBER 2003

Prospects for Distributed Electricity Generation



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September 2003

The Congress of the United States ■ Congressional Budget Office

Preface

In the aftermath of the recent electricity blackout that affected major portions of the Midwest and Northeast, many commentators have argued that distributed generation—the small-scale production of electricity at or near customers' homes and businesses—could improve electricity reliability and ease the strain on the nation's electricity transmission system.

This Congressional Budget Office (CBO) paper examines the current state of and prospects for distributed generation, its benefits and risks, and barriers to the wider adoption of small-scale, customer-owned technologies. The paper also discusses what types of policy changes could help reduce barriers while limiting the downside risks of greater reliance on distributed generation. The analysis was prepared at the request of the Ranking Member of the Senate Committee on Energy and Natural Resources.

Andrew Goett of CBO's Microeconomic and Financial Studies Division wrote the paper, with contributions from Richard Farmer, under the supervision of David Moore and Roger Hitchner. Robert Shackleton and Dennis Zimmerman of CBO and Henry Lee of the John F. Kennedy School of Government at Harvard University provided useful comments.

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Douglas Holtz-Eakin
Director

September 2003

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Distributed generation, the small-scale production of electricity at or near customers' homes and businesses, has the potential to improve the reliability of the power supply, reduce the cost of electricity, and lower emissions of air pollutants. The recent disruption in electricity service throughout major portions of the upper Midwest and the Northeast has reminded policymakers of the importance of a very reliable supply of power. The high price of electricity in certain regions and problems with emissions from older power plants have stimulated interest in alternatives to traditional utility-supplied power. Distributed generation could provide benefits in all of those areas. Energy legislation under consideration in this session of Congress includes provisions that will encourage wider use of distributed generation. This paper explores the context in which policymakers may be addressing distributed generation issues in the near future.

Distributed generation can come from conventional technologies, such as motors powered by natural gas or diesel fuel, or from renewable technologies, such as solar photovoltaic cells. Over the past two decades, declines in the costs of small-scale electricity generation, increases in the reliability needs of many customers, and the partial deregulation of electricity markets have made distributed generation more attractive to businesses and households as a supplement to utility-supplied power. Some policymakers believe, however, that various rules, restrictions, and prices set by utilities, regulators, or administrative bodies do not reflect the net economic benefits of distributed generation and act as barriers to its cost-effective adoption and operation. Those barriers could be lowered significantly by clarifying and standardizing the rules for connecting distributed generators to the electricity supply network (the grid) and by setting prices for basic electricity services (access to the grid, the electric power itself, and the transportation of that power) that reflect their costs.

If the new rules and prices are well designed, the cost of providing highly reliable electricity service to customers who desire it and the total cost of serving all customers will probably fall as distributed generation becomes more widely used. But initiatives to reduce barriers to widespread adoption have costs and risks, which will pose a challenge to electric utilities, regulatory bodies, and other public agencies that must develop and enforce the rules governing interconnection and establish prices for electricity from those new sources of power. If customers are allowed to connect their distributed generators to the grid without adequate safeguards, the overall performance of the electric system can be impaired. Changes that can promote cost-effective distributed generation, such as the adoption of economically sound pricing, may increase rates for customers who currently pay prices that are below the utilities' costs for providing service. If the new rules and prices are poorly designed, the changes that benefit distributed generators will raise the overall cost of electricity and increase rates to most other customers. Aside from those risks, separate technological and regulatory changes that would significantly lower the future cost of utility-supplied electricity (for example, additional cost reductions in large-generation technologies and extensive competition in wholesale markets) could lessen the attractiveness of some new investments in distributed generation.

To investigate those issues, this paper addresses four questions. What are the current status of and prospects for distributed generation technologies, particularly in terms of their costs as compared with those of utility-supplied power? What are the benefits and risks of a wider adoption of distributed generation in restructured electricity markets? What specific utility practices, local government regulations, and electricity pricing methods may be acting as barriers to adoption? And what types of policy changes could help reduce those barriers while limiting the downside risks of greater reliance on distributed generation? Although many of those policy changes could be the concern of state and local authorities, this paper highlights the federal role—particularly those aspects that might receive legislative attention.

The Current Status of and Prospects for Distributed Generation

Distributed generation is an important, although small, component of the nation's electricity supply. The principal source of electricity today continues to be large central facilities that generate electricity from steam plants (fueled by coal, natural gas, or nuclear power) and hydroelectric power. Historically, most steam plants were operated by large investor-owned utilities that were responsible for generating electricity, transmitting it from the central generating facilities to communities, and, in many regions, distributing it to retail customers within those communities. The federal government has had an important role in producing most of the nation's hydroelectric power, and local governments own many of the distribution systems that deliver the power supplied by the investor-owned utilities and the federal government.

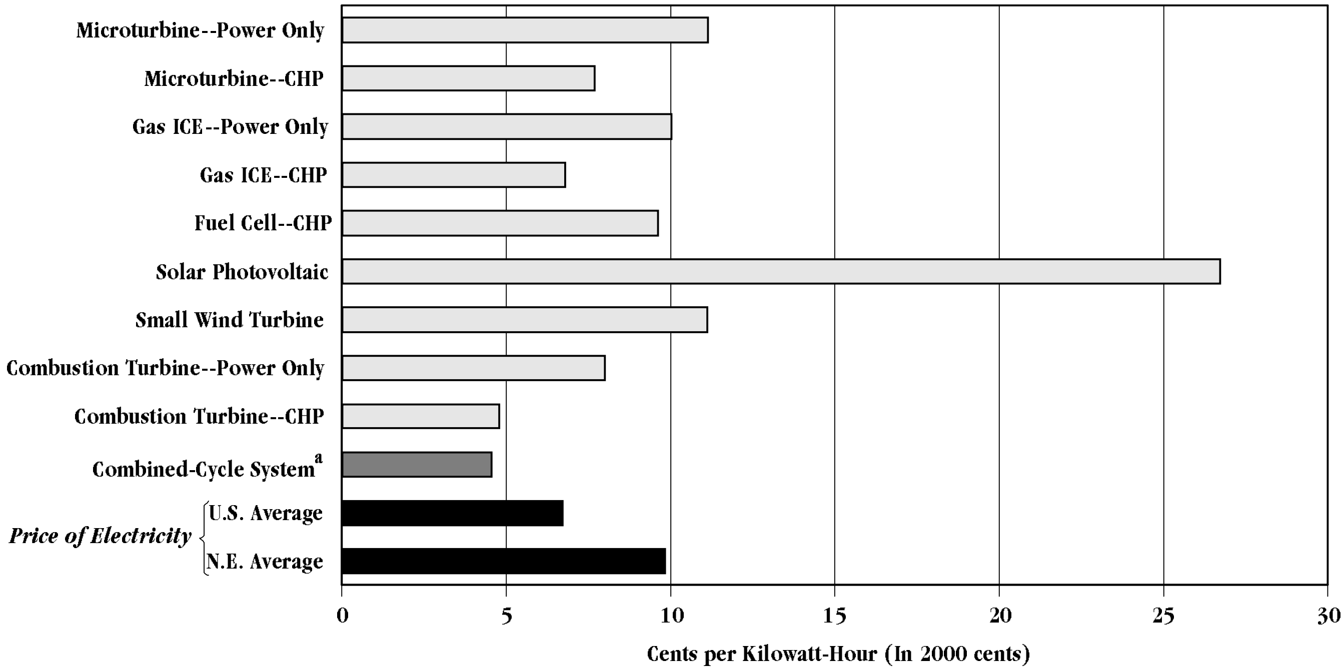
Among distributed generation technologies, the most important in terms of their capacity to generate electricity are customer-owned generators that produce both electricity and steam for on-site use (called combined heat and power, or cogeneration) and emergency backup generators. Together, those two sources account for more than 95 percent of the customer-owned generation capacity in the United States. For the most part, the cogeneration plants that have been built to date are large facilities that sell the majority of their output to utilities. Natural gas fuels most of those plants, but coal and biomass also power a significant percentage of the total capacity. Most backup generators are internal combustion engines fueled by diesel oil or gasoline. Diesel-fired backup generators are commonly used in high-rise buildings for safety reasons (as required by local building codes), in hospitals, and in manufacturing facilities that depend on a highly reliable supply of power.

Renewable technologies that are currently used to generate electricity at homes and businesses include wind turbines and solar photovoltaic systems. Those technologies produce electricity intermittently and generally are not available to operate continuously. Fuel cells and small turbines (called microturbines) are frequently mentioned, newly emerging high-efficiency technologies. Although they account for very little of the nation's existing electricity supply, proponents believe they will contribute significantly in the future.

Four developments over the past decade have spurred interest in moving distributed power beyond the limited markets that it now serves and integrating it more fully into the nation's electricity supply. First, the costs of renewable technologies and high-efficiency technologies that are suitable for operation by households and small businesses have fallen. Typical costs of electricity from certain distributed generation systems are now within range of those of electricity from large generators, and they are below the average prices of electricity in some regions of the United States (*see Summary Figure 1*). Second, the introduction of competition to wholesale electricity markets has increased the possibilities for sales of customer-owned distributed power. Those newly competitive markets feature prices that vary hourly and that are high during periods of peak demand (times at which distributed generators would be most profitable to operate). Third, many commercial and industrial customers place increasing importance on highly reliable electricity service, which can be provided by on-site generation. Fourth, building new transmission lines to meet growing demand has been a contentious issue for local, state, and federal regulators and among power producers. Wider adoption of distributed generation can in some cases obviate the need for new transmission capacity.

Summary Figure 1.

Levelized Cost of Selected Technologies Suitable for Distributed Generation



Source: Congressional Budget Office using data on electricity prices from Department of Energy, Energy Information Administration, *Electric Power Annual 2000* (August 2001), Table 21.

Notes: CHP = combined heat and power (also known as cogeneration); ICE = internal combustion engine; N.E. = New England.

The levelized cost is the average cost of electricity (cents per kilowatt-hour) over the operating life of the generation equipment. Future costs and output flows are based on data in Table 2 and are discounted at 7 percent from their present values. The cost estimates assume that the systems powered by fossil fuels will be operated 90 percent of the time and that the wind and solar photovoltaic systems will run 40 percent and 27 percent of the time, respectively. Levelized cost comparisons do not include the effects of tax credits or other direct subsidies for specific technologies.

"Large wind turbine" is not included in the figure (as it is in Table 2) because it is not generally considered to be well-suited to distributed generation applications (typically, it is not located near customers).

a. In a combined-cycle system, a combustion turbine is operated in tandem with a steam turbine. The system is included here as a benchmark for the cost of power from new large-scale generators. Transmission and distribution expenses would add an estimated 2.4 cents per kilowatt-hour, on average, to the marginal cost of delivered power.

Those developments have prompted discussions about using distributed generation differently from how it is typically used today. Rather than just serving as emergency backup or exploiting large commercial cogeneration opportunities, small generation systems could operate regularly. Customers could use distributed generation to meet most of their on-site requirements while relying on the grid as a source of additional power and as an outlet for excess power that they might generate. Utilities that distributed power to retail customers could use distributed generators to meet local peak loads (consumption) or to provide highly reliable electricity service to customers that required it.

Conventional fossil fuels, such as natural gas and diesel oil, power the most common distributed generation technologies, and they are likely to account for most of any growth in distributed generation that operates regularly and is connected to the grid. Renewable sources that produce electricity intermittently, especially wind and solar, will be used more if customers can rely on the traditional utility system to eliminate deficits and to absorb excesses from on-site power production.

The Benefits and Risks of Distributed Generation

Nonutility owners of distributed generation units could individually benefit from structural changes that allowed their power generation activities to be integrated with those of utilities. By spreading their capital costs (the costs of acquiring and installing the generating unit) over an increased number of operating hours, they could lower their average generation costs. They could also earn revenues from their sales of electricity to utilities or other customers, further improving the returns on their investments in distributed generation. But the economy at large might also benefit from a more widespread adoption of distributed generation technologies. Such adoption would lower the overall cost of electricity for all customers, enhance the reliability of the power supply, reduce the need for transmission and distribution investments to serve growing demand, and improve environmental quality through the increased use of renewable energy sources and fuel-efficient technologies.

If distributed generators are operated in situations in which their costs are lower than those of centrally supplied power, the overall cost of supplying electricity will fall. Those situations often occur during periods of peak electricity use (at certain times of the day or seasons of the year). At those times, relatively small reductions in demand for utility-supplied power (if the owners of distributed generators produce additional electricity for their own use) or increases in the utilities' supply (if the owners produce additional electricity for sale to the utilities) will reduce wholesale prices considerably. The availability of additional electricity during peak periods may help enhance the reliability of the power supply. A further benefit of increased supply and flexibility in demand on the part of owners of distributed generators would be a reduction in electricity price volatility (because extreme price spikes would be eliminated).

Distributed generation could also encourage efficient investments in electricity reliability by offering a cost-effective alternative in many situations to constructing new transmission and distribution power lines and transformers. Those investments might make the electric system more secure and less vulnerable to widespread service disruptions. In addition, a healthy distributed generation industry could put competitive pressure on transmission utilities to expand service and reduce congestion.

Changes that generally facilitate the integration of customer-owned distributed generation with the grid could also encourage the adoption of specific renewable energy and high-efficiency technologies, including solar photovoltaic systems, fuel cells, and microturbines. Shifting to sources of electricity that made greater use of nonfossil fuels or less-polluting forms of fossil fuels or that made more efficient use of conventional fuels might produce regional and global environmental benefits.

The widespread adoption of distributed generation technologies poses risks, however. The reliability of power to all customers might be diminished rather than bolstered if the operators of electric systems found it difficult to manage a much greater number of power sources— suppliers that were adding electricity to or drawing electricity from the grid at will. Equivalently, the retail price of electricity could rise if ratepayer-funded investments were necessary to maintain power quality. And operation of large numbers of small customer-owned generators —especially those fueled by diesel oil—could be detrimental to local air quality. Finally, poorly designed policies to encourage distributed generation might bring unexpected costs. In particular, liberalizing the rules that govern the connection of distributed generators to the grid under traditional regulatory methods of electricity pricing (whereby utilities set power rates to recover past costs and earn an allowed return on capital investments) could encourage some customers to invest in distributed generators whose power was more expensive than new, centrally supplied power. That outcome could increase the overall cost of electricity to the utilities' remaining customers (ones who did not operate distributed generators).

Increased competition in wholesale electricity markets and reforms in retail electricity pricing could significantly reduce the number of situations in which distributed generation was profitable to owners. Competition in wholesale markets could lower electricity prices to the point at which many investments in distributed generation would no longer be attractive. Widespread application of real-time pricing, which could provide incentives for the operation of distributed generators, could also end up making many of them unprofitable. Real-time pricing and other tariffs (rate schedules) that encouraged retail customers to vary their demand for electricity in response to price changes could significantly lessen price volatility as well as average prices. That result would reduce the number of hours per year that many distributed generators could operate profitably.

Barriers That Impede Widespread Adoption of Distributed Generation

Proponents of distributed generation argue that significant barriers impede the widespread adoption of distributed generation technologies. Most, if not all, of those barriers are related to the risks cited earlier. They include utilities' pricing and operational practices and local governments' rules about reliability and safety, cost, or environmental quality. A common theme of the complaints against those practices or rules is that they result in restricted access to the grid and protect the utilities' current investment in central generation capacity and transmission lines.

Four types of barriers are frequently cited. The first type is contractual and technical interconnection requirements for the installation of protective equipment and safety devices to protect the grid and ensure power quality; distributed generation proponents argue that those requirements are often duplicative, excessive, and time-consuming. The second type is surcharges imposed by utilities on operators of distributed generators (who are still utility customers) for standby service; proponents contend that those surcharges often do not reflect the actual cost of the service and do not give credit for the ways in which distributed generation benefits the grid. The third type is pricing of electricity that is based on the utilities' average cost rather than their marginal cost (the cost of supplying an additional unit of electricity). Proponents contend that average-cost pricing does not give owners an incentive to operate their distributed generators during periods when doing so will lower the overall cost of electricity. The fourth type is environmental and permitting requirements of local governments, which, in the proponents' view, broadly restrict the installation and operation of electricity-generating equipment or impose burdensome approval processes on applicants.

Achieving the potential cost and reliability benefits from widespread adoption of distributed generation technologies may depend on retail competition and unrestricted customer choice. The competitive positions of many utilities are already weakening with the restructuring of wholesale electricity markets and increased use of the most widespread form of distributed generation (cogeneration for customers' own use and for sale to the utilities). Broader adoption of distributed generation by customers could be an important part of what many analysts believe will be the next level of market restructuring—the introduction of retail competition. Such competition would give customers the ability not only to choose their electricity suppliers but also to elect to generate electricity on their own.

Policy Options

The barriers that certain industry practices and governmental rules present to customers' potential investments in distributed generation could be lowered in two general ways. One would be to standardize and clarify the rules and procedures governing the installation and operation of distributed generators and their interconnection with the grid. That approach could streamline the approval process and help to reduce uncertainty about the requirements and costs of compliance. The second would be to set the prices that operators of distributed generators pay and receive for electric power, connection to the grid, and transmission and distribution services at levels consistent with the actual costs borne by utilities to provide those services. That change could give customers incentives to install and operate distributed generators at a level that would help to ensure the lowest cost of electricity for all customers. Specific changes would require utilities and government agencies to:

- Grant nondiscriminatory access to the grid under a system of well-defined, uniform technical and contractual terms and cost-based interconnection fees—so that operators would know in advance what was required to run their distributed generators at the same time they were taking power from or supplying power to the grid;

- Establish clear, explicit rates for standby electricity service that are based on the cost of the equipment utilities require to meet infrequent demand—so that operators of distributed generators would know those surcharges in advance and receive rate treatment comparable to that of regular customers;

- Purchase excess power from operators of distributed generators at prices consistent with utilities' wholesale cost of power in real time in circumstances in which no competitive markets for distributed generation power exist—so that operators could sell their power at prices consistent with the savings to the utilities;

- Establish real-time pricing for utilities' sales to retail customers based on the wholesale price of electricity as it varies over time and across delivery locations—so that operators of distributed generators could decide on the basis of market signals whether to purchase or generate power; and

- Develop uniform national environmental standards for distributed generation that would allow precertification of equipment—so that manufacturers could design units to national specifications and distributed generators would not need to qualify on a case-by-case permitting basis.

It is not clear where any initiative to require those types of changes might best originate—whether in the Congress, the Federal Energy Regulatory Commission (under existing authorities), or state governments. The 108th Congress has shown interest in fostering distributed generation through various legislative proposals that contain provisions for nondiscriminatory access to the grid and real-time pricing. Under existing legislative authority, the design of any policy initiative affecting distributed generation is complicated by the division of regulatory responsibilities among the federal, state, and local governments. Under the original framework established by the Federal Power Act of 1935, the federal government has responsibility for the regulation of pricing and access in the wholesale power markets, and the states have responsibility for the retail markets served by investor-owned utilities. The state-owned, municipal, and cooperative utilities that also serve retail customers set their own rules for pricing and service. Decisions about the siting of power plants—in consideration of safety, air quality, noise, and local congestion—are generally in the domain of state and local governments, subject to certain federal regulations. The issue of promoting distributed generation, whether by small independent suppliers of cogeneration electricity or households with solar panels, cuts across all those jurisdictions.

In terms of economic efficiency, it does not matter which level of government is responsible for making those changes. But it is important that broad changes to pricing and to operational practices occur together. Unless fundamental changes in access, pricing, and siting are addressed concurrently, the goals of promoting the use of and gaining the benefits of distributed generation may not advance noticeably. An argument for the Congress to take a lead in this area could be based on the value of standardizing the approach across regions of the country and of possibly enhancing the ability of the federal government to achieve balance among the many vested interests that stand to gain or lose from those changes.

CHAPTER

1

Introduction

The electric power industry in the United States is undergoing fundamental changes—from being an industry dominated by regulated monopolies that own entire electricity systems (vertical integration) to one featuring a mix of competitive electricity generation companies, common-carrier transmission organizations, and regulated distribution companies. Spurred by technological advances and a public policy strategy at the federal and state levels, those changes are transforming both wholesale and retail power markets. At the wholesale level, independent power producers now generate more than 14 percent of the nation's electricity for sale at market-based rates to utility distribution companies.[1] At the retail level, 23 states and the District of Columbia have already passed legislation or issued regulatory orders supporting the ability of customers to choose their electricity suppliers.[2] (See the appendix for a brief summary of the history of electricity market organization in the United States.)

One of the powerful forces driving that transition in market structure has been advances in electricity generation technologies that have reduced the costs of smaller-capacity systems—generally those under 2 megawatts. (*See Box 1 for an explanation of the characteristics of electric power.*) Technologies such as microturbines are available in capacities under 100 kilowatts (roughly the size of an automobile engine). Large-scale power plants (100 megawatts or greater), which are typically used by vertically integrated utilities, no longer have significantly lower costs than smaller plants do. That change has weakened one of the main rationales for maintaining electric power production as a regulated monopoly—namely, that the exclusive franchise was necessary to fully exploit the savings in generation and transmission costs from large-scale, centrally located power plants.

The first entities to take advantage of those cost reductions in a significant way have been certain independent power producers, or businesses that generate electricity primarily to sell to the utilities. Most of those producers use generation units with capacities in excess of 1 megawatt. But the cost reductions extend to even smaller generation units (less than 1 megawatt), many of which are suitable for producing power to serve small businesses, commercial buildings, and homes. That development has added one more dimension to the effort to capture the benefits of competitive markets in the electric power industry—the prospect that local small-scale generation could compete with electric power from large, central power plants.

In contrast to the power supplied by utilities and many of the large independent producers, which is often generated away from population centers and moved over extensive transmission and distribution networks, small customer-owned generators are sited at or near the locations where the electricity is used. Those small generators are often not fully integrated with the utilities'

1. Department of Energy, Energy Information Administration, *Electric Power Annual 2000* (August 2001), Table 1, available at www.eia.doe.gov/cneaf/electricity/epav1/intro.html#tab1.

2. Department of Energy, Energy Information Administration, *Status of State Electricity Industry Restructuring Activity—as of February 2003,* available at www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html. According to Energy Information Administration statistics, retail choice is available to some or all of the customers (or will soon be available) in 17 states and the District of Columbia. In the remaining six states, retail competition has been delayed or suspended.

Box 1.

Electricity Basics

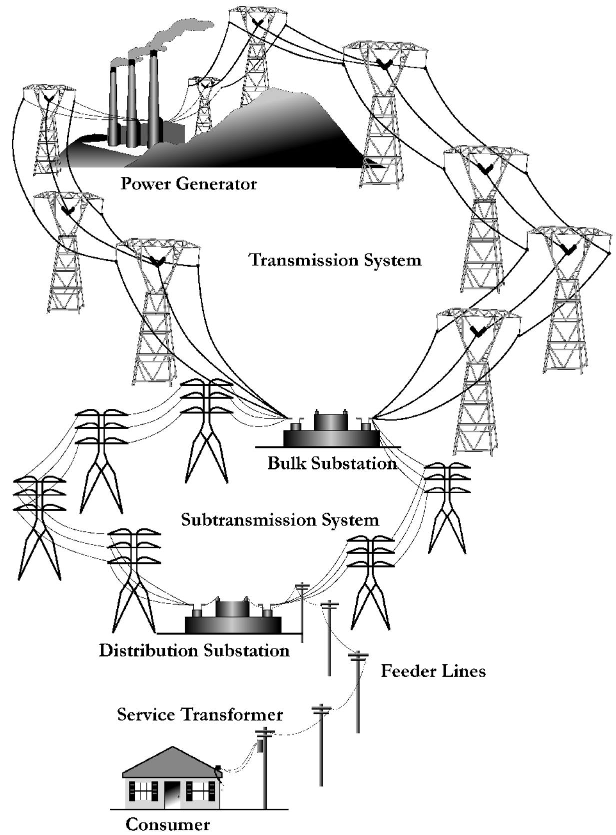
The basic unit of electric power is a watt, which is a rate of producing or consuming energy. A typical lightbulb, for example, consumes electricity at the rate of 75 watts, or 75 watt-hours of electricity in one hour of operation. One kilowatt is 1,000 watts. The average household in the United States uses almost 12,000 kilowatt-hours (12 million watt-hours) per year. A power plant with a 1-megawatt capacity (1,000 kilowatts), operating continuously (8,760 hours) for a year would generate enough electricity to supply approximately 750 households. (A different way to understand what those units of electricity represent is to relate them to horsepower, another measure of power. A kilowatt is roughly equivalent to 1.3 horsepower; a 1-megawatt plant is equal in power to approximately 10 medium-sized automobile engines.)

Another characteristic of electric power is voltage, which is a measure of electromotive force. Electricity is usually generated and transported at very high voltages (more than 100,000 volts). Electric voltage is lowered, by a series of transformers in the substations and on feeder lines close to where it is consumed, until it reaches 120 volts (in the United States) at electrical outlets in a typical household.

In the United States, the electric power system generates a form of electricity, termed alternating current, in which voltage oscillates in a regular cycle. The frequency of that cycle is 60 times per second, referred to as 60 hertz. Electric motors and other devices in the United States are designed to use 60-hertz alternating current. If the electric current deviates significantly from that designed frequency, it can seriously damage motors and appliances.

At any time, the amount of electric power (the number of watts) that is being consumed on a utility network (the system of generation and consumption points connected by wires and other transmission equipment) must be nearly equal to the amount of power that is being generated. The voltage and frequency of the current will adjust according to physical laws to maintain a balance. If a sudden change in consumption occurs without an adjustment in generation (or vice versa),

An Electric Power System



Source: Congressional Budget Office based on a figure from EPRI PEAC Corporation.

the voltage will change, possibly damaging equipment throughout the network. Certain types of generators have controls that automatically adjust output to match consumption. Utility networks also have many protective devices that minimize any damage from a rapid change in voltage. For example, electric fuses or circuit breakers automatically cut off electricity when they detect a large voltage change caused by, say, a lightning strike or short circuit that could damage equipment.

Electricity consumption at any point in time is referred to as the load. On a typical utility network, the load fluctuates continuously as customers start and stop their equipment. Network operators continually adjust

Box 1.

Continued

production to match those fluctuations. When consumption is low, they use plants that are designed to run continuously at a low operating cost. As consumption rises, they add production from other plants—whose operating costs are higher—that are designed to start and stop and adjust output quickly. In periods of extremely high consumption, they use older plants that are less efficient and even more expensive to operate. As a result, the cost of supplying an additional unit of electricity (the marginal cost) typically rises as consumption increases. That cost depends on many factors, including the characteristics of available power plants, the price of fuel, and the location of plants relative to the places where electricity is consumed.

An electric power system has two major functions—generation and transportation *(see the figure at left)*. The United States today has approximately 750,000 megawatts of generating capacity, most of which comes from large commercial power plants with capacities of more than 100 megawatts. Those plants are powered largely by coal or other fossil fuels, although nuclear and hydroelectric power also account for a significant portion of capacity and annual output. In 2000, those plants produced a combined total of 3.8 trillion kilowatt-hours of electricity.

The transportation of electricity is typically broken down into transmission, which is the high-voltage transport of electricity over long distances, and distribution, which is the transport at lower voltages over the last few miles to the point of consumption. No clear line divides the two components, but transmission networks in the United States typically have at least two electric paths between any two points (a loop configuration), whereas the distribution system has a single path between the substation and the consumer (a hub-and-spokes configuration).

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electricity networks, which produce power around the clock or on demand from central dispatching stations—although the prospects for fuller integration of such distributed generation with the grid may be desirable.[3]

Policymakers have an interest in the future of distributed generation, not only for the cost savings it can provide to the homes and businesses that produce it but also for the cost savings and additional reliability that it may be able to offer to the entire electricity market. Distributed generation may play a larger role, along with demand-management techniques and further innovations in wholesale and retail markets, in reducing the cost of electricity when traditional supply is tight or market demand is strong. For example, distributed generation may offer retail customers greater flexibility to alter their demand for electricity in response to hourly changes in prices (real-time pricing), thereby promoting the efficient operation and stability of energy markets as they become increasingly competitive. Some observers expect distributed generation to play a role in the commercial development of renewable energy and high-efficiency technologies, adding the associated environmental and safety benefits.

The prospects for distributed generation will be strongly influenced by the outcomes of several policy initiatives. Specifically, the wider adoption of distributed generation and its associated benefits may depend significantly on the structure of deregulated electricity markets, in which the federal government plays a central legislative and regulatory role. Recent legislative proposals considered in the Congress have contained provisions—for example, requirements for nondiscriminatory interconnection with the grid and real-time pricing of electricity—that would directly affect the viability of distributed generation. Also, the federal government has taken an active role in developing and commercializing renewable energy technologies, some of which are well-suited to distributed generation.

This paper analyzes distributed generation by answering four general questions:

- What are the current state of and prospects for distributed generation technologies, particularly in

3. The grid refers generally to a self-contained local or regional network of electric power plants and the high- and low-voltage power lines and transformer stations that deliver the power generated by those plants to customers.

comparison with the conventional supply of electricity? (Chapter 2 addresses that topic.)

- What are the benefits and risks of a wider adoption of distributed generation in a restructured electricity market? (See Chapter 3.)
- What are the barriers to adoption and efficient use of distributed generation technologies? (See Chapter 4.)
- What legislative, regulatory, and administrative initiatives can help lower those barriers while avoiding or limiting the downside risks of greater reliance on distributed generation? (See Chapter 5.)

CHAPTER

2

The Current Status of and Prospects for Distributed Generation

Distributed generation refers to the production of electricity at or near the place of consumption.[1] Examples of distributed generation include backup generators at hospitals, solar photovoltaic systems on residential rooftops, and combined heat and power (CHP) systems (also known as cogeneration) in industrial plants and on university campuses. Those applications differ from the infrastructure for supplying electricity that utilities in the United States have built over the past five decades. Under that infrastructure, utilities typically have built power plants away from centers of consumption, on the basis of such factors as fuel transportation costs and environmental regulations, and then moved that electricity long distances over high-voltage transmission lines to local distribution systems, which then reduce the voltage and deliver the power to retail consumers.

Although some types of distributed generators have been around for a long time (the earliest generators were largely "distributed" in the sense that they were located near the points of consumption), total customer-owned generation as a percentage of all output is small. The Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), estimates that in 2000 (the latest year for which data are available), only 0.5 percent of total U.S. electricity generation (21 billion of 3,800 billion kilowatt-hours) was from "nonutility generation for [customers'] own use." In addition, cogeneration systems in the commercial and industrial sectors produced 135 billion kilowatt-hours (3.6 percent of U.S. generation) for their own use.[2]

Three basic characteristics differentiate most distributed generation from traditional electricity supply: location, capacity, and grid connection. Distributed generators are located at or near the point at which the power is used. They are typically on-site generators, owned and operated by retail customers, that are used to meet a portion of the customers' demand or to provide backup service for customers that need highly reliable power. Applications of distributed generation could include combined heat and power operations—for example, a university could use CHP to generate electricity on campus and then use waste steam from the boiler to heat buildings.

Electric utilities can also install their own small generators near customers. Such installations relieve congestion in power lines during periods of peak demand, helping to defer investments in additional transmission and distribution capacity. They may also be used to boost the

1. Although there is no universally accepted definition of distributed generation, most of the policy issues surrounding distributed generation concern small customer-owned units that are connected to the grid at the distribution level and that primarily serve on-site needs. In this report, that is how the term is used, except when utility-owned applications are being discussed.

2. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2003, with Projections to 2025,* DOE/EIA-0383(2003) (December 2002), Table A8. "Combined heat and power plants whose primary purpose is to sell electricity, or electricity and heat, to the public (NAICS [North American Industrial Classification System] code 22)" produced an additional 4.2 percent.

quality and reliability of local electricity service by providing voltage control and backup power to customers who require such "premium" service.

The second defining characteristic of most distributed generation is its size. Generation capacities of customer-owned units, used primarily to meet on-site requirements, typically range from a few kilowatts to several hundred kilowatts. Generators in that range are typically best suited to applications that meet the energy demands of individual homes and businesses or of small groups of customers. Very few customers require generators larger than 1 megawatt to serve only their on-site needs.[3]

The level of their connection with the local or regional electric grid is the third characteristic that distinguishes distributed generators from traditional suppliers. Traditional suppliers are connected to the grid at the transmission level (the high-voltage portion of the delivery network). If distributed generation came into widespread use, most distributed generators would be connected to the grid at the distribution level, which is the portion of the delivery network, built with limited capacity, that transports electricity at low voltages for the final few miles to the customer. (That is also the portion of the network that is owned and operated by local retail utilities, most of which are regulated by state agencies.)

Most of the policy debate surrounding distributed generation concerns small (less than 2 megawatts) customer-owned systems that primarily serve on-site loads and are connected to the utility network at the distribution level. The debate has arisen in part because of technical issues surrounding distribution-level connections to the grid and possible conflicts between local utilities and generators that are both producers of electricity and retail utility customers. Both of those matters are discussed in Chapter 4.

How Distributed Generation Contributes to the Nation's Power Supply

The applications that account for the largest portion of the customer-owned power production by distributed generation in the United States are cogenerators used in industrial or commercial operations or primarily to generate electricity for sale. Those cogenerators typically range in size from 1 to 500 megawatts, and they are capable of producing enough electricity to serve 500 to 25,000 households. According to the EIA, slightly more than 27,000 megawatts of cogeneration capacity existed in the commercial and industrial sectors in 2000.[4] That is 3.4 percent of the total regularly operated generating capacity in the country. Most cogeneration is accounted for by systems of more than 50 megawatts, concentrated in such industries as paper products, chemicals, and petroleum refining.[5]

After cogeneration, backup units that are operated only in emergencies account for the most distributed generation capacity. Backup generators used by such businesses as hospitals and large commercial buildings typically range in size from a few to several hundred kilowatts. According to a 1995 survey by the EIA, nearly one-fourth of the commercial floor space in the country had some capacity to generate electricity on-site.[6] But less than 1 percent of that capacity was ever used to generate electricity to meet peak demand or to operate continuously; in essence, it constitutes a large reservoir of capacity that is virtually untapped as a regular source of power. The Gas Research Institute has estimated that up to 40,000 megawatts of backup generation capacity exist in the United States, compared with a total of 808,000 megawatts of regularly

3. Most cogeneration (combined heat and power) applications are considered distributed generation because they typically are located on a customer's premises and serve on-site electricity and thermal needs. On the basis of those criteria, cogenerators account for almost all existing distributed generation production. But those plants are mostly large generators (at least 50 megawatts), often owned by third parties, that earn significant revenues by selling most of their output to utilities.

4. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2003*, Table A9. There are another 27,400 megawatts of cogeneration capacity in the utility sector.

5. Department of Energy, Energy Information Administration, *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* (prepared by Onsite Sycom Energy Corporation, January 2000), p. 17.

6. Department of Energy, Energy Information Administration, *Modeling Distributed Electricity Generation in the NEMS Buildings Models* (August 2000), which is available at www.eia.doe.gov/oiaf/analysispaper/electricity_generation.html.

operated electricity generating capacity.[7] Available state-level data show a similar relationship. The California Energy Commission (CEC) has compiled an inventory of backup generators that individually have at least 300 kilowatts of capacity.[8] It found more than 4,000 such generators in the state in 2001, with a total capacity of 3,200 megawatts. Those generators could, if available, boost the state's total installed capacity of 54,000 megawatts by more than 5 percent, the CEC estimated. Those data suggest that gross available capacity in the United States could be increased by 5 percent to 10 percent if all emergency backup generators were adapted to operate regularly.

Looking to the future, the EIA projects that additions of electricity generating capacity between 2000 and 2025 will total almost 450,000 megawatts.[9] According to the EIA's Reference Case Mid-Term Energy Forecast, more than 11 percent of that capacity will come from distributed generation (defined here as the additions of cumulative capacity in the nonutility sectors plus electric power sector cogeneration and natural gas distributed generation).[10] The electric power sector will add another 3 percent of the total in the form of renewable energy sources (biomass, municipal solid waste, and solar photovoltaic), most of which would be distributed generation. The EIA reference case forecast implicitly assumes no major changes in legislation or regulations that would encourage increased reliance on distributed generation.

But there are reasons to expect that distributed generation could meet a significantly greater portion of future electricity demand in the United States, at costs that could compete with those of generation from new central power plants. The first reason is the existence of the considerable amount of backup generation capacity (discussed above) that is not included in the EIA's estimates of existing or projected capacity. Backup capacity represents a sunk cost to its owners, who have typically installed the generators to meet reliability needs or building code requirements. In the absence of environmental prohibitions or other restrictions, many of those generators could be adapted to operate regularly, at the cost of modest investments in improved electronic power controls and pollution control equipment.

Studies commissioned by DOE on the market and technical potential for combined heat and power in the commercial and industrial sectors identify another reason.[11] The studies found 163,000 megawatts of remaining CHP potential in the commercial and industrial sectors combined, in addition to more than 49,000 megawatts of currently installed CHP (*see Table 1*). That potential is spread across all major commercial building types and industrial activities, with concentrations in paper products, schools, and office buildings. The EIA reference case forecast projects that only 20 percent of that potential will be realized in the next two decades. Policy changes that encouraged distributed generation could increase that percentage significantly.

A Description of Selected Electricity Generation Technologies

Several technologies are frequently mentioned as well suited to small and medium-sized distributed generation applications. Among the technologies fueled by fossil energy are conventional steam turbines, combustion turbines, internal combustion engine generators, microturbines, and fuel cells. The renewable technologies are

7. Anne-Marie Borbely and Jan F. Kreider, eds., *Distributed Generation: The Power Paradigm for the New Millennium* (Boca Raton, Fla.: CRC Press, 2001), p. 65.

8. California Energy Commission, *Database of Public Back-Up Generators (BUGS) in California,* available at www.energy.ca.gov/database.

9. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2003.*

10. EIA's forecast breaks out distributed generation in the electric power sector as a separate technology. It defines distributed generation as "primarily peak load capacity fueled by natural gas."

11. Department of Energy, Energy Information Administration, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* and *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* (both prepared by Onsite Sycom Energy Corporation, January 2000). Those studies defined the technical market potential as "an estimation of the market size constrained only by technological limits—the ability of combined heat and power technologies to fit existing customer energy needs." (See p. 9 of the commercial/institutional sector report.)

Table 1.

Installed and Potential Combined Heat and Power Generation

(In megawatts)

	Installed	Remaining Potential	Total
Industrial	44,242	88,341	132,583
Commercial	4,926	74,638	79,564
Total	**49,168**	**162,979**	**212,147**

Source: Congressional Budget Office based on Department of Energy, Energy Information Administration, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* and *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* (both prepared by Onsite Sycom Energy Corporation, January 2000).

photovoltaic cells, wind-powered generators, and biomass-fueled generators.

Conventional steam turbines and combustion turbines are well-developed technologies that are widely used for medium-sized and large power systems (more than 500 kilowatts). In very large systems, typically built by commercial generators, combustion turbines are often operated in tandem with steam turbines that use waste heat from the combustion turbine to fire a boiler (that combination is referred to as a combined-cycle system). Conventional combustion turbines produce low emissions, given standard control equipment, and they have low maintenance and operating costs relative to those of most other generating technologies. Those characteristics, along with the short lead times needed to build units, make them the preferred technology for most conventional generation applications requiring more than several megawatts of power. Such large units are used by industrial plants in combined heat and power configurations that generate excess power for sale to utilities.

Internal combustion engine generators, including diesel cycle and spark ignition motors, are the most commonly used technology providing backup power for reliability or emergency-supply purposes. Units range in size from 5 kilowatts to 7 megawatts. They can burn refined petroleum products (diesel and gasoline) or natural gas. Models that burn natural gas have very low emissions because of improved design of the combustion process and their use of catalytic converters. The costs per installed kilowatt for units with capacities suitable for distributed generation are among the lowest of all the mature technologies.

Microturbines are small combustion-turbine generators that were developed on the basis of the turbocharger technology used in trucks and airplanes. The capacity range of microturbines (30 kilowatts to 400 kilowatts) covers the average load requirements (consumption needs) of most commercial and light industrial customers. Microturbines have low emissions of pollutants, especially nitrogen oxides, which would permit their installation in urban areas with restrictive emissions standards. Microturbine electricity generators are in the early stages of commercial development; studies commissioned by DOE predict that their installed equipment costs (costs of equipment plus installation) will fall significantly in the future.[12]

Fuel cells use an advanced electrochemical process to generate electricity. The process is comparable to that used in conventional batteries, except that the reactant material in fuel cells can be replenished so that the units will not run down. Fuel cells produce virtually no emissions of air pollutants or greenhouse gases. Because their costs per installed kilowatt are still high relative to those of conventional technologies, commercially available fuel cells currently suit only very specialized applications. But some companies have developed new fuel cell technologies that they project will lower costs significantly.[13]

12. See, for example, Department of Energy, National Renewable Energy Laboratory, *Gas Fired Distributed Generation Technology Characterizations: Microturbines* (prepared by Energy and Environmental Analysis, November 30, 2002), which projects declines of 50 percent or more in installed capital costs by 2030.

13. For example, the California Distributed Energy Resource Guide (a Web site on distributed energy run by the California Energy

Photovoltaic cells convert sunlight directly into an electric current. A panel of semiconductor material sandwiched between two conducting layers absorbs solar energy and releases electrons to produce the current. Photovoltaic systems can be small, which is why they are widely used in residential settings, particularly in the Southwest and California. Because photovoltaic systems, by their nature, produce electricity intermittently, they require battery storage or a supplemental power source to provide continuous electricity service. Photovoltaic cells produce no direct emissions, and they have low maintenance requirements. Improvements in manufacturing processes have reduced the costs of photovoltaic systems significantly in the past decade. But their acquisition and installation costs, per kilowatt, are still almost an order of magnitude (10 times) greater than those of conventional systems, and their costs per kilowatt-hour of delivered electricity are three to four times the current average price of electricity in the United States.

Wind generators are turbines powered by windmills. A mature technology, wind turbines have been widely used in California and Europe by utilities and independent power producers to generate electricity to be sold over the grid. In California, wind farms have total generating capacities ranging from 15 megawatts to more than 600 megawatts (individual turbines at those sites have capacities of more than 1 megawatt). Most analysts would not consider large wind turbines to be a type of distributed generation because they are not typically located near customers. (Advocates of commercial wind power share many of the same policy concerns as advocates of distributed generation, however.) As with photovoltaic cells, the potential of wind generators is limited by available wind resources and by issues related to the siting of these large towers with their rotating wind blades (including noise and threats to migrating birds).

Small wind turbines designed for residential and rural applications to date account for only a limited share of the market. For residential and small commercial distributed generation applications, suitable wind turbine capacities are 5 kilowatts to 50 kilowatts. The installed costs per kilowatt for those smaller systems are much higher than for the large systems. Because of the large amount of space they require, small wind generators are generally appropriate for applications in rural areas with good wind resources.

Biomass refers to a renewable fuel rather than to a particular technology. The EIA defines biomass as "organic nonfossil material of biological origin constituting a renewable energy source." Wood products, animal and plant agricultural waste, and municipal solid waste are all examples of biomass. Electric generators use biomass as fuel, often mixed with other fossil fuels. The most common use of biomass is to heat a conventional boiler directly. Another possible application is biomass gasification, in which the product would be used in place of natural gas. Although biomass may provide environmental benefits by displacing coal-fired generation, the burning of biomass and the production of animal wastes (as two examples) can create air and water quality problems of their own. The financial attractiveness of biomass depends on such factors as the availability and cost of the organic material, the avoided cost of alternative disposal of the material, and the need for residual heat to warrant cogeneration.[14]

The Cost Structure of Distributed Generation

The direct costs of distributed generation to customers include the installed cost of the equipment, fuel costs, nonfuel operation and maintenance (O&M) expenses, and certain costs that the customers' utility imposes. The cost estimates that follow have been compiled from authoritative sources, but they must be considered as indicative of the relative magnitudes of costs across technologies rather than as point estimates. The values of each

Commission) states that most manufacturers, once the cells can be produced in volume, are aiming for fuel cell capital costs below $1,500 per kilowatt; see www.energy.ca.gov/distgen for more information.

14. Because of the wide range of ways in which biomass fuels could be used in distributed generation, this paper omits cost estimates for "typical" biomass applications. Most of the barriers and policy issues that apply to other distributed generation technologies, however, especially those relating to environmental and siting requirements, also apply to biomass.

cost's components may vary substantially from one application to another, on the basis of several factors, some of which are discussed below. The contribution of utility charges to the total costs of generation are not included in the estimates (they are discussed in Chapter 4, which describes barriers to adoption).

To make this comparison of costs most useful, the Congressional Budget Office (CBO) assumed for each technology an installed capacity, a rate of utilization, and (in some cases) a geographic location that would be suitable for serving the electricity needs of individual customers. For example, the costs for the wind turbine discussed here are for a size that might be used in a small rural business (such as a farm) in a location with favorable wind resources. On that basis, data compiled from various industry and government sources describe the current costs of the most common types of electricity generation technologies (*see Table 2*). Data for a combined-cycle unit are presented as well; as the largest source of additional electricity from utilities and independent power producers, combined-cycle systems provide a representative benchmark against which the costs of other technologies can be measured.

Capital Costs

The costs of acquiring and installing a generating unit vary widely, depending on technology, capacity, and other factors. The Department of Energy estimates that the typical installed capital costs for distributed generators range from under $1,000 per kilowatt for a combustion turbine to almost $7,000 per kilowatt for a solar photovoltaic system.[15] Among small-capacity technologies, internal combustion engines (fueled by diesel and gasoline) have the lowest capital costs and highest operating costs. Renewable technologies (using wind and solar power) have the highest capital costs and lowest operating costs. New high-efficiency technologies (microturbines and fuel cells) fall in between.

For customers who maintain emergency backup generation on-site, the relevant capital cost for choosing the least expensive source of electricity is not the total cost but rather the additional investment needed to operate an on-site generator at the same time they are connected to the utility network (termed parallel operation). (Currently, many institutions and office buildings that are required to have backup generators are permitted to operate those generators only when they are disconnected from their utility network.) That extra investment may include such costs as equipment upgrades to meet environmental requirements for regular operation and additions of power controls and metering to permit parallel operation. Those additional costs would typically be small relative to the basic investment costs—especially for installations in new buildings, as opposed to retrofit upgrades.

Long-Run Costs of Production

Although consideration of a technology's capital costs can be important when choosing to invest in distributed generation, estimates of what economists refer to as long-run average costs—costs per unit of output that reflect capital and operating expenses—are generally the more important for investment decisions. Perhaps more relevant for comparing distributed generation technologies with one another and with utility costs and residential prices is a commonly used index of long-run costs known as the "levelized" cost. Levelized cost is a summary measure of the average cost of electricity per kilowatt-hour, expressed in current dollars. It is defined as the net present value of all direct costs (for capital, fuel, and O&M) over the expected lifetime of the system, divided by the system's total lifetime output of electricity.[16]

A key input to those calculations is the assumption about capacity utilization (the percentage of time that the unit typically operates) for each technology. For purposes of these comparisons, CBO's estimates assume that all fossil-fueled systems will be operated 90 percent of the time

15. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations,* EPRI-TR-109496 (December 1997); and Department of Energy, Energy Information Administration, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector.*

16. The output stream is discounted at the same rate as the costs, to keep the two comparable. The present value is a single number that expresses a flow of current and future income (or payments) in terms of an equivalent lump sum received (or paid) today.

Table 2.

Comparison of Selected Electricity Generation Technologies

	Capacity (kW)	Capital Cost[a] ($/kW)	Fuel Cost ($/kWh)	O&M Cost ($/kWh)	Service Life (Years)	Heat Rate[b] (Btu/kWh)
Microturbine—Power Only	100	1,485	0.075	0.015	12.5	13,127
Microturbine—CHP	100	1,765	0.035	0.015	12.5	6,166
Gas ICE—Power Only	100	1,030	0.067	0.018	12.5	11,780
Gas ICE—CHP	100	1,491	0.027	0.018	12.5	4,717
Fuel Cell—CHP	200	3,674	0.029	0.010	12.5	5,106
Solar Photovoltaic	100	6,675	0	0.005	20	n.a.
Small Wind Turbine	10	3,866	0	0.005	20	n.a.
Large Wind Turbine	1,000	1,500	0	0.005	20	n.a.
Combustion Turbine—Power Only	10,000	715	0.067	0.006	20	11,765
Combustion Turbine—CHP	10,000	921	0.032	0.006	20	5,562
Combined-Cycle System[c]	100,000	690	0.032	0.006	20	5,642

Source: Congressional Budget Office based on data from the Department of Energy's National Renewable Energy Laboratory and Energy Information Administration; Bergey Windpower Company; and the California Energy Commission.

Notes: kW = kilowatt; kWh = kilowatt-hour; O&M = operation and maintenance; Btu = British thermal unit; CHP = combined heat and power (also known as cogeneration); ICE = internal combustion engine; n.a. = not applicable.

All costs are in 2000 dollars. Fuel costs were calculated on the basis of national average prices for natural gas delivered to commercial customers in 2000.

a. The cost of acquiring and installing the generating unit. It does not include effects of tax credits or other direct subsidies for specific technologies.

b. High heat value.

c. In a combined-cycle system, a combustion turbine is operated in tandem with a steam turbine.

(termed "base load" operation), whereas wind and photovoltaic systems will run 40 percent and 27 percent of the time, respectively. The rates for wind and solar power are consistent with conditions favorable for their use.[17] No tax credits or other subsidies are included in the calculations for any technology or fuel source.

The costs per kilowatt-hour of power for most electricity generation technologies are at least 70 percent greater than those for a combined-cycle plant (*see Figure 1*). The single exception to that comparison is the combustion-turbine technology in a CHP configuration (its costs are only 5 percent greater), which would be used only by large customers with significant steam or hot water requirements. Although the comparisons do not take into account transmission and distribution costs for utility-supplied power, those would typically add 25 percent to 50 percent. The costs of power from distributed generation would be higher still.

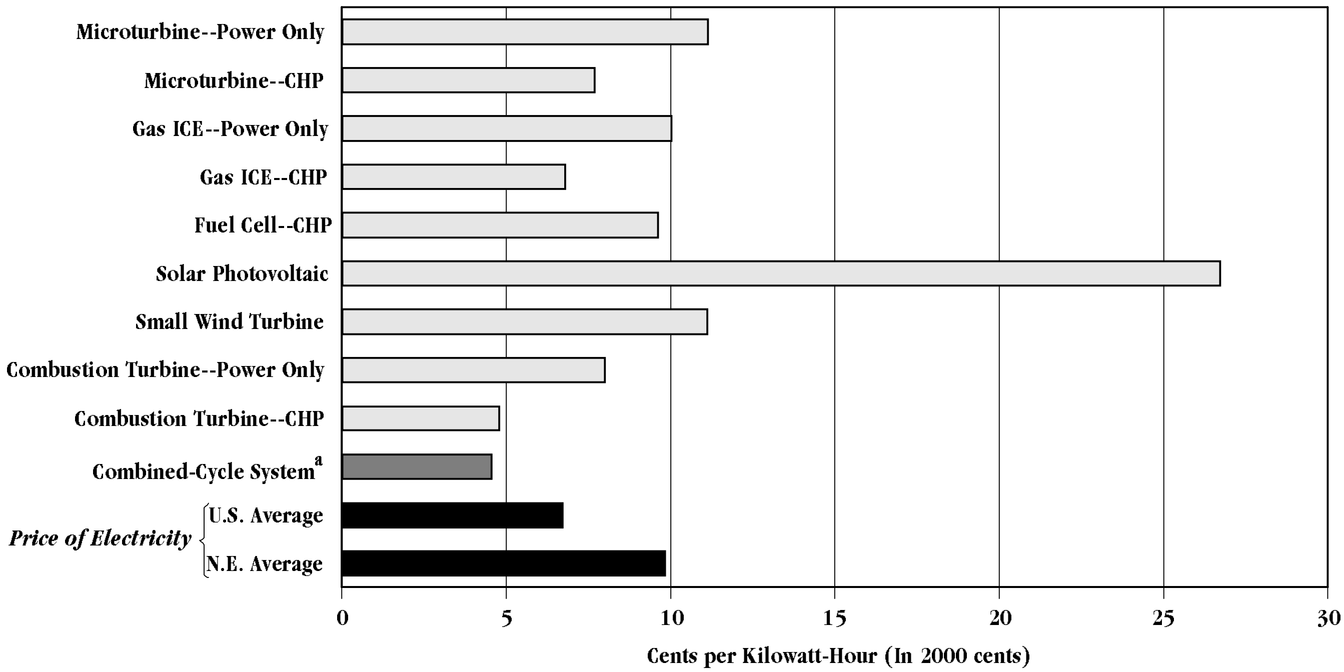
The most cost-competitive distributed generation technologies are fossil-fuel engines—diesel motors (internal combustion engines) and microturbines—in combined heat and power configurations. The fuel costs of producing the electricity for those systems, as for all CHP technologies, are net of the fuel costs of producing the steam or hot water alone. That calculation implicitly assumes that the customer can use the steam or hot water productively and will incur the cost of producing it even without the combined heat and power system.

Aside from the CHP systems and both kinds of large combustion turbines, other distributed generation tech-

17. For the wind technology, a usage rate of 40 percent is the high end of the range of capacity factors cited by the California Energy Commission in its California Distributed Energy Resource Guide, which is available at www.energy.ca.gov/distgen/equipment/wind/performance.html. For the solar photovoltaic technology, a usage rate of 27 percent corresponds to locations where a one-kilowatt array can produce 6.5 kilowatt-hours per day, on average. In the United States, these are places with the highest levels of sun exposure, such as Phoenix, Arizona, and Albuquerque, New Mexico.

Figure 1.

Levelized Cost of Selected Technologies Suitable for Distributed Generation



Source: Congressional Budget Office using data on electricity prices from Department of Energy, Energy Information Administration, *Electric Power Annual 2000* (August 2001), Table 21.

Notes: CHP = combined heat and power (also known as cogeneration); ICE = internal combustion engine; N.E. = New England.

The levelized cost is the average cost of electricity (cents per kilowatt-hour) over the operating life of the generation equipment. Future costs and output flows are based on data in Table 2 and are discounted at 7 percent from their present values. The cost estimates assume that the systems powered by fossil fuels will be operated 90 percent of the time and that the wind and solar photovoltaic systems will run 40 percent and 27 percent of the time, respectively. Levelized cost comparisons do not include the effects of tax credits or other direct subsidies for specific technologies.

"Large wind turbine" is not included in the figure (as it is in Table 2) because it is not generally considered to be well-suited to distributed generation applications (typically, it is not located near customers).

a. In a combined-cycle system, a combustion turbine is operated in tandem with a steam turbine. The system is included here as a benchmark for the cost of power from new large-scale generators. Transmission and distribution expenses would add an estimated 2.4 cents per kilowatt-hour, on average, to the marginal cost of delivered power.

nologies have electricity costs that are more than twice those of the combined-cycle technology. The combustion turbines, which utilities themselves often use to meet certain new consumption needs (loads), would be suitable only for large commercial or industrial customers. Among the remaining technologies, conventional engines (those marked "power only" in Figure 1) are the closest in cost to the combined-cycle technology. But they are still at least 120 percent more expensive than power from new utility plants. Advanced high-efficiency technologies (microturbines and fuel cells) and renewable technologies (small wind and solar photovoltaic) are even more expensive.

Nonetheless, the costs of some distributed generation technologies, especially those in combined heat and power systems, are below the retail price of utility-supplied electricity in many parts of the United States. For example, the average price of electricity for all sectors in New England in 2000 was 9.8 cents per kilowatt-hour. In the same year, the average price of electricity in the commercial sector in the United States was 7.2 cents per kilowatt-hour. The estimated cost per kilowatt-hour for a CHP internal combustion engine system (7.1 cents) was lower than both prices.

The average price of electricity in the United States greatly exceeds the cost of power from new generation for at least two reasons. First, the average price includes the costs of transmission and distribution, which add approximately 25 percent to 50 percent to the delivered cost of power. Second, the prices charged by most regulated utilities are set to recover their past investments, whose costs—especially those for generation—exceed the current costs of new plants.

That comparison may explain much about the contrasting incentives of utilities and customers to invest in distributed generation. Regulated utilities are concerned about retaining their sales base in order to recover the costs of past investments. Customers are concerned about lowering their electricity costs without sacrificing the reliability of their utility service connection.

Trends in Costs

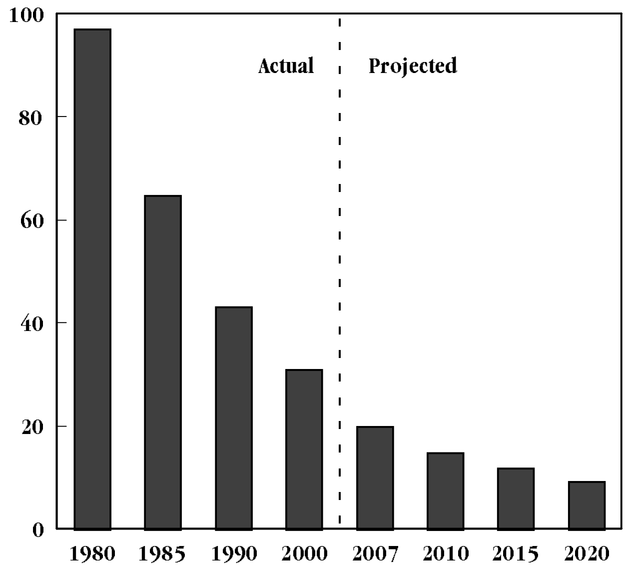
The capital and operating costs of certain distributed generation technologies have fallen significantly in recent years and can be expected to continue to do so. In the case of one technology, photovoltaic systems, the cost per delivered kilowatt-hour in suitable applications has plummeted by almost 70 percent since 1980, and it is projected to decline by another 70 percent from current levels by 2020 (*see Figure 2*).[18]

Similarly, developers forecast that fuel cells will improve in performance and decline in cost over the next several years to the point that they will soon be suitable for widespread use in distributed generation. A recent study by Lawrence Berkeley National Laboratory projected that the installed cost per kilowatt for a 200-kilowatt fuel cell would drop from $3,500 in 2000 to $1,300 (in 2000 dollars) by 2010.[19] That projection, and similar ones from other sources, are based on "target forecasts for installed

Figure 2.

Levelized Cost of Solar Photovoltaic Electricity, 1980 to 2020

(Cents per kilowatt-hour)



Source: Congressional Budget Office based on data from Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (December 1997).

costs from developers of [advanced technology] solid oxide and molten carbonate fuel cell systems."[20]

Whether the direct costs of distributed generation will continue to fall relative to the costs of utility-supplied power is another matter. Electricity prices have generally dropped as a result of competition—although California's experience of high prices and rolling blackouts in 2000 and 2001 is a notable exception—and are likely to benefit from further market restructuring in coming years. Technical improvements in large-capacity generation technologies used by utilities are also likely to lower the costs of supplying power. The EIA projects in its reference case forecast, however, that the average price of electricity in the United States will remain virtually constant over the next two decades, indicating at least in that case that neither competition nor cost-saving technical change is

18. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations.*

19. Consortium for Electric Reliability Technology Solutions, *Modeling of Customer Adoption of Distributed Energy Resources*, LBNL-49582 (August 2001), Tables 1 and 2.

20. Department of Energy, Energy Information Administration, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, p. 24.

likely to have much effect on the economics of utility-supplied power.

Other Economic Considerations in Installing Distributed Generators

Although a comparison of typical costs for various distributed generation technologies can be useful, it tends to obscure several important facts. Distributed power can differ qualitatively from central power or can save money in other ways, and that value may outweigh any direct cost difference. Moreover, certain distributed generation technologies or energy sources can benefit from existing federal and state incentives (including investment tax credits or mandates on utilities to purchase power generated from renewable sources).

The significance of those quality and cost advantages is demonstrated by the fact that distributed generation applications are already widely available in several niche markets. Commercial and small industrial customers with significant hot-water needs can use microturbines in combined heat and power configurations. Customers who have on-site emergency backup generators may be able to run them regularly during periods of peak demand, when wholesale prices are high. Customers in environmentally sensitive areas can use fuel cells that produce extremely low emissions and no noise. Photovoltaic systems and wind turbines can be used in rural applications, reducing the need for capital spending to extend power lines to remote sites.

Distributed generation can also protect against service interruptions or variations in voltage or frequency that can harm equipment. The majority of those interruptions are due to equipment failures or power line breaks close to customers' premises. The value of improved reliability is difficult to quantify; it depends largely on the reliability of the regular electricity supply.[21] Local building ordinances and safety concerns dictate most of the backup power needs in the nation—for example, for hospitals and high-rise buildings. But the value of backup capability would also be great wherever a manufacturing process depended on the continuous operation of power-sensitive equipment, such as in the production of computer chips. Generally, those backup units would be available to operate whenever interruptions occurred in utility-supplied power. During California's recent electricity crisis, many businesses in that state purchased (or rented) diesel units just to ensure continuity of operations.

Besides possibly saving on their own electricity costs (as output from distributed generators displaced utility-supplied power provided at retail rates), some owners of distributed generators might be able to earn money by selling their excess power to the utilities. Federal law requires utilities to purchase power from cogeneration facilities and generators powered by renewable fuels at prices reflecting the utility's own long-run marginal costs of supply. And many states require utilities to give credit at retail rates for excess power from certain small distributed generators (termed net metering). But those requirements are often limited to generators that use renewable fuels or high-efficiency technologies. Initiatives to broaden the sale of excess power by operators of distributed generators to regional wholesale spot markets at prices that varied hourly (real-time pricing) could benefit the operators while increasing the available power supply.

Businesses and households that are considering investing in distributed power may also benefit from other programs that the federal government and many states have developed. At the federal level, the Energy Policy Act of 1992 provides tax credits for certain investments in solar, wind, and biomass-fueled electricity generation. At the state level, renewable portfolio standards mandate that a certain percentage of electricity generation come from renewable energy sources. Several states, including New York and California, have adopted such renewable portfolio requirements. Many states also offer tax credits for investment in certain renewable technologies. For example, the 10 percent corporate tax credit for investment in solar, wind, and biomass technologies that is offered in Texas is typical.[22]

21. Service quality refers to the stability of the voltage and frequency at which electricity is delivered. Reliability refers to the frequency and duration of service interruptions.

22. See the Database of State Incentives for Renewable Energy's Web site (www.dsireusa.org/dsire/), funded by DOE's Office of Power Technologies, for a complete summary of federal, state, local, and utility programs that promote renewable energy.

CHAPTER

3

The Benefits and Risks of Distributed Generation

In combination, falling costs, concerns about the reliability of utility-supplied power, and opportunities associated with electricity market restructuring have stimulated interest in using distributed generation technologies differently in the future from how they are typically used today. Rather than supplying emergency backup or exploiting only the largest-scale combined heat and power projects, small customer-owned generators could run regularly as a complement to utility-supplied power.

That new role could be filled in a number of ways, depending on the utility tariff, the technology used to generate electricity, and customers' power needs.[1] For example, with a utility tariff under which retail prices varied between on-peak and off-peak periods of demand (called a time-of-use tariff), operators of distributed generators could provide power during periods of peak demand when prices were high but rely on electricity from the grid to meet their "base load" (basic power) needs. Alternatively, under a non-time-of-use tariff, operators could run their distributed generators continuously to supply base loads and rely on grid-supplied power to meet peak needs. Or, in a third configuration, wind- or solar-powered systems could generate power intermittently, with operators buying supplemental power from the grid when on-site production was low and selling excess power over the grid when production exceeded on-site loads. Each of those new ways of integrating distributed generation and utility operations shares the features that the generator would operate regularly and would primarily serve the customer's own load, running in parallel (that is, while interconnected) with regular service to and from the grid.

Distributed generation, operated as a complement to traditionally supplied power, may offer significant benefits. It could lower the nation's overall costs of producing and delivering power. It could also promote the development and use of renewable energy sources and fuel-efficient technologies, which could improve the quality of the air and the security of the nation's energy supply.

Initiatives to realize those broader benefits entail risks, however. If rules and incentives intended to encourage the cost-effective installation and operation of distributed generation are poorly designed, they may raise the total costs of producing and delivering power. Depending on the outcome of the ongoing restructuring of electricity markets and other developments, such as the course of technological innovation, the potential economic benefits of distributed generation may diminish. There is also a significant likelihood that, among the several distributed generation technologies, systems fueled by fossil energy will dominate because they cost less than renewable technologies in most situations. In that case, the environmental benefits that some proponents of distributed power expect may not be realized.

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1. A utility tariff is a schedule of prices for electricity, which may include such components as a minimum or fixed monthly fee for service, different prices per kilowatt-hour for electricity consumed in defined periods and quantity ranges, and a price per kilowatt for the maximum consumption (termed a demand charge) during a short (for example, 15-minute) interval per billing period.

Potential Savings in the Production and Delivery of Electricity

Systemwide cost savings may be possible if the ability to generate their own electricity leads retail customers to reduce their demand for utility-supplied power when wholesale electricity costs are high. The savings could result from the substitution of low-cost generating technologies for higher-cost ones and the avoidance of some costs associated with transmission and distribution.

Lower Costs of Generation

Whenever homes and businesses produce electricity on their own, utilities avoid the costs of purchasing or directly producing that electricity for those customers but lose the revenues from those sales. Under current cost-of-service regulations, any net savings or losses are typically passed on to all the utilities' customers through lower or higher retail prices. Thus, if customers can be induced to install and run distributed generators when their operating costs are lower than the utilities' wholesale costs, the retail price of electricity will fall for all customers.

Systemwide savings may be enhanced if the generation of electricity for customers' own use is flexible—the generator can increase output at certain times of the day or in certain seasons, when the demand from all customers for utility-supplied power is greatest. Additional savings will result because utilities generally operate their most expensive power plants during those peak periods. The unit costs of electricity production increase as utilities successively call on base-load generators, "peaking" generators, and older units, as well as push the utilization of all units to high levels. Because they can be switched on and off easily, distributed generators powered by internal combustion engines are most likely to help "shave" the peak and allow utilities to avoid using generators with very high marginal costs (the costs of supplying an additional unit of electricity).

Avoided Investment and Operating Losses in Transmission and Distribution

Distributed generation can reduce the need for sometimes significant investment in transmission and distribution lines and equipment to meet growing loads or to relieve congestion at certain points in the electric system. The costs of those investments can add significantly to the price of power delivered by utilities to retail customers. For example, in regions where transportation charges are broken out from the charges for the electric power itself, the average charge for transmitting and distributing the electricity (2.4 cents per kilowatt-hour) is more than 30 percent of the average price of delivered electricity (7.9 cents per kilowatt-hour).[2]

Retail electric utilities as well as their customers could use distributed generators to avoid or defer investments at the local level. For example, to meet seasonally high demand, a utility could install a small-capacity generator at a site on the distribution portion of its network instead of investing in increased capacity of "upstream" power lines and transformers. Utilities have recognized that small generators can be used to relieve periodic local congestion in the subtransmission and distribution portions of the electricity network. Such use can be a cost-effective alternative to investment in additional transformer capacity and other distribution infrastructure—often delaying the need for such upgrades.

In other cases, local utilities may want to install and operate distributed generators because building new transmission capacity raises environmental concerns. That use of distributed generation could prove especially valuable in places where opposition from environmental groups was constraining or delaying the construction of additional transmission capacity.

Wider adoption of distributed generation also would reduce power losses from the transmission and distribution of electricity between central power plants and customers. Those losses result from electrical resistance in the transmission and distribution system and from changes in voltage as the power approaches the point of consumption. The Energy Information Administration estimates that transmission and distribution losses in the United States averaged almost 7 percent of gross production (in gen-

2. Department of Energy, Energy Information Administration, *Electric Sales and Revenue 2000,* DOE/EIA-0540(00) (January 2002), Table C-1, p. 256.

erated kilowatt-hours) in 1999.[3] During hot weather (which is typical of summer peak periods), power lines stretch and conductivity diminishes, causing losses that can exceed 15 percent.

Additional Savings from Incentives for Adjusting Demand

Distributed generation gives customers an alternative to traditional utility-supplied electricity. Customers could use that on-site power source to increase the reliability of their electricity supply. That use could bolster economic efficiency because only customers who required increased reliability would have to pay for it. Customers could also generate their own power to help offset the impact of high electricity prices. More generally, that approach would provide a means by which retail customers and utilities could curtail their demand for power in regional electricity markets and possibly avert disruptions and price spikes. Even moderate changes in demand and supply, net of customer-owned generation, could significantly lower electricity prices in regional spot markets during periods of peak demand.

Improved Reliability of Service

Under the current supply system for electric power, utility distribution companies largely determine the basic level of service reliability for all customers in a given area. Utility planners typically establish a reliability target for their power generation and distribution network. They design and build the network with capacity margins and redundancies to meet that target, given estimated probabilities of failures and of capacity deficits for each component of the system. As a result, most customers receive electricity service with a similar reliability level, and the cost of that reliability is typically borne by all customers through their general charges. A customer not wanting that level of reliability cannot avoid its cost. If a customer needs a higher level of reliability, the utility can provide it only at a cost that is imposed on all customers.

Distributed generation offers an alternative solution. Customers who need highly reliable power can install distributed generators, allowing them to obtain uninterrupted service without imposing their requirements and associated costs on other customers. In California, for example, where customers have historically had an average of fewer than two significant outages per year (defined as outages of at least five minutes' duration, as measured by the system average interruption frequency index), there are more than 4,000 backup generators larger than 300 kilowatts (approximately equivalent to a 450-horsepower motor).[4] That 300-kilowatt capacity is large enough to supply most large commercial and medium-sized industrial customers.

The potential for using distributed generation to meet reliability needs could be enhanced through measures that permitted nonemergency operation of the units. Such an approach would allow owners to operate their generators when it was cost-effective and to reduce the net cost of reliable service.

Reductions in the Volatility of Wholesale Prices

The limited incentive for retail electricity customers to reduce consumption when wholesale prices rise contributes to the volatility of wholesale electricity prices. If retail customers had the capability to adjust their net demand for utility-supplied power through distributed generation and had the necessary incentives to do so through time-varying tariffs, such as real-time pricing or time-of-use tariffs, then wholesale prices would be less volatile and lower, on average.[5] In particular, wider use of distributed generation would tend to reduce the size and frequency of extreme short-term price spikes.

Several benefits would flow from the type of diminished price volatility that distributed generators would provide. In the short run, less price volatility would reduce the risk of increases in retail utilities' power costs that could jeopardize their financial viability. That situation arose

3. Department of Energy, Energy Information Administration, *Annual Energy Review 2000* (August 2001), Table 8.1.

4. Those numbers do not include mobile generators. See California Energy Commission, *Database of Public Back-Up Generators (BUGS) in California*, available at www.energy.ca.gov/database.

5. Distributed generation is only one means by which customers could adjust their demand for utility-supplied power. Another is a demand-management program that provides incentives to customers to reduce consumption during critical periods.

in the California electricity crisis of 2000 to 2001, when large wholesale price increases forced one utility into bankruptcy.[6] In the long run, reduced volatility would encourage independent (nonutility) generators to accept lower prices in long-term contracts by eliminating opportunities for them to gain "windfall" profits by selling electricity in the short-term spot market.

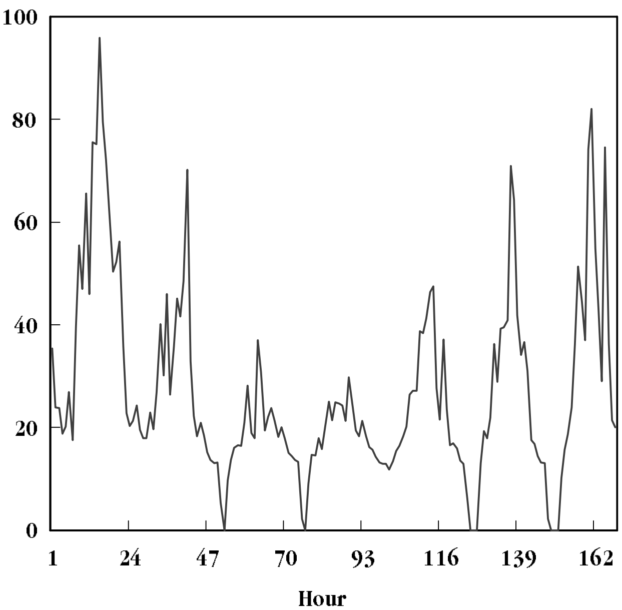
Spot market prices in wholesale electricity markets are highly volatile. During a typical summer week, the average hourly price of electricity in the PJM spot market may vary from as little as zero to more than $100 per megawatt-hour.[7] For example, the zone-weighted average hourly spot price for the week of August 5, 2002, ranged from zero to $96 per megawatt-hour, with an average price of $27.30 per megawatt-hour (*see Figure 3*).

Even those hourly prices understate the volatility of wholesale electricity prices because they are averages of values at different delivery points on the transmission system. Prices at individual delivery points deviate from the system average because of congestion in specific portions of the system during periods of heavy transmission. Such congestion forces the system operator to run more expensive generators in other locations. The differences in the costs of the generation with and without the transmission constraint are captured in the price differentials across delivery points. For example, on Monday, August 5, 2002, when the peak average price was $96 per megawatt-hour, the price at several delivery points was $650 per megawatt-hour.[8]

Figure 3.

Volatility in the Spot Price of Electricity

(Dollars per megawatt-hour)



Source: Congressional Budget Office based on data from the PJM Independent System Operator.

Notes: The figure shows the PJM zone-weighted hourly spot price of electricity over the week of August 5, 2002. PJM is the organization responsible for wholesale power sales and transmission in major portions of five mid-Atlantic states and the District of Columbia. The data are available at www.pjm.com.

Hourly prices can fall as low as zero because some generators that must run continuously, such as nuclear plants, offer to supply electricity regardless of the price. During some hours, those generators' output may exceed the total demand, resulting in a clearing price of zero.

During periods of peak demand, even modest changes in the demand for and supply of wholesale power could significantly reduce electricity prices in regional spot markets. For example, one study estimated that a 5 percent reduction in peak demand in California during 2000 would have lowered wholesale spot prices by more than 50 percent.[9] Another study of emergency demand

6. See Congressional Budget Office, *Causes and Lessons of the California Electricity Crisis* (September 2001), for a detailed discussion of that state's experience.

7. The PJM Independent System Operator is responsible for wholesale power sales and transmission in major portions of five mid-Atlantic states and the District of Columbia.

8. The delivery points that experience extreme prices tend to have deficient transmission capacity, which creates chronic congestion. The high prices provide incentives for investment in additional generation and transmission infrastructure sited in locations that might relieve the congestion.

9. Eric Hirst and Brendan Kirby, *Retail-Load Participation in Competitive Wholesale Electricity Markets* (report prepared for Edison Electric Institute and Project for Sustainable FERC [Federal Energy Regulatory Commission] Energy Policy, January 2001), p. 5.

response in New York during critical periods in 2001 found that a demand reduction of as little as 400 megawatts (1.3 percent of annual peak demand) lowered wholesale prices by 28 percent in certain areas.[10] The widespread adoption of distributed generation could provide an important means for realizing those types of reductions.

Any diminishment in price volatility of the type that distributed generators are likely to produce can yield savings for customers as a group. The reason is that the beneficial operation of distributed generators will tend to reduce prices in long-term contracts for electricity. By operating during periods of extreme price increases, distributed generators would tend to reduce the frequency and duration of those price spikes. Investors in new independent power plants would be more inclined to enter into long-term contracts at lower prices because their opportunity to earn large profits in the spot market would be diminished significantly. Any savings on long-term prices would, under cost-of-service regulations or with retail competition, be passed on to retail customers.

Potential Benefits for the Environment and National Security

Many environmental and energy-conservation advocates believe that distributed generation could offer significant benefits—ones that are not fully reflected in the value of that electricity to the market. Benefits for environmental quality may come from distributed generation's role in promoting renewable energy sources, less-polluting forms of fossil energy, and high-efficiency technologies. Security benefits may come from increasing the geographic dispersion of the nation's electricity infrastructure and from reducing its vulnerability to terrorist attacks that could interrupt electricity service over large areas.

Distributed generation technologies that relied on renewable energy sources could yield environmental benefits in the form of reduced emissions of pollutants and greenhouse gases if those technologies displaced utility-supplied power, much of which is generated from coal. Technologies that relied on conventional fuels would yield environmental benefits if they resulted in a shift to less-polluting energy sources—for example, natural gas rather than coal. High-efficiency technologies could yield benefits by reducing the amount of energy required to produce a unit of electricity.

Security benefits of distributed generation relate to the current vulnerability of the nation's electricity infrastructure to terrorist attacks. Most of the nation's electricity comes from large central generation plants and moves over an extensive network of transmission lines, which would be difficult to defend against a physical attack. The operation of that system relies on telecommunications and computers to relay instructions to dispatch generating units and route power supplies. Those controls are increasingly tied to the on-line operation of regional wholesale markets that balance supply and demand and set prices. If more of the nation's electricity supply originated in the homes and businesses where it was consumed, the adverse consequences of any attack that disrupted the network would be diminished.

Uncertainties and Risks

The prospects for widespread adoption of distributed generation technologies are not at all certain. Nor is it clear that those technologies will be used in ways that achieve their full potential economic benefits. Moreover, this new source of electricity poses a distinct risk of negative impacts that may be difficult to anticipate or expensive to avoid. Those effects include potential degradation in the performance of the electricity distribution network, inequitable and possibly inefficient redistribution of the costs of electricity service among customers, and a decline in environmental quality. Measures to mitigate those adverse impacts could significantly limit the adoption of distributed generation or increase costs to the point at which most applications would no longer be financially viable. In fact, many such restrictions on the use of distributed generators have been imposed and are discussed in the next chapter.

Uncertainty Related to Market Restructuring

The likelihood of achieving the potential benefits from widespread adoption and efficient use of distributed gen-

10. Neenan Associates, "Executive Summary," *NYISO* [New York Independent System Operator] *Price-Responsive Load Program Evaluation Final Report* (January 2002).

eration technologies is closely related to the continued restructuring of the electric power industry. If competitive wholesale markets for electricity develop with nondiscriminatory access and hourly prices determined by supply and demand, those markets will give operators of distributed generators an incentive to run their units when such operation will reduce the overall cost of supplying electricity. But if wholesale markets do not develop efficiently—for example, because of restricted access or regulated prices—the benefits of distributed generation may not be fully realized.

The restructuring of retail electricity markets could also affect the prospects for distributed generation. If state regulators "unbundled" electricity generation from other services (such as transmission and distribution) and introduced competition in the generation portion of the market, then suppliers would be pressured to make their pricing consistent with the pricing in wholesale markets. That development would accelerate the introduction of real-time pricing and other electricity rate offerings that promoted flexible demand, providing additional incentives to operators of distributed generators to run their units efficiently. But if regulators constrained retail competition by restricting price flexibility or by imposing surcharges on customers who adopted distributed generation, then the technology might not achieve its full market potential and operational benefits.

Finally, the restructuring of wholesale and retail markets could reduce the attractiveness of distributed generation to many customers. (See the appendix for a discussion of restructuring and its effect on prices.) If electricity prices fell because of greater competition and initiatives to increase demand flexibility at the retail level, that decline could diminish the value of existing distributed generator systems and reduce the profitability of new ones.

Uncertainty About Market Potential

Besides uncertainty related to market restructuring, other types of uncertainty will affect the potential growth of distributed generation applications. Such uncertainty includes the actual costs of installing and operating distributed generation technologies relative to central power technologies, the actual value to individual customers of improvements in reliability of service, and variations in the financial benefits for individual customers, which are difficult to capture in an overall analysis such as this one.

The costs of the various distributed technologies themselves are uncertain. The two most widely mentioned high-efficiency technologies—microturbines and fuel cells—either are not yet commercially available or are in the early stages of commercialization.[11] Although their proponents predict that installed equipment costs will decline substantially in the future as commercial production increases, such an outcome cannot be known in advance. Other technologies—such as photovoltaic systems—have been in commercial production for some time, but proponents still forecast that their costs will fall considerably as manufacturing processes continue to improve and production increases.

A second uncertainty surrounding the market potential of distributed generation concerns the benefits from improved reliability of service, which are often difficult to value. The main appeal of distributed generation for many customers in the current regulatory environment is that its use can avoid or minimize the effects of electricity service interruptions. On-site generation is often used in hospitals, where interruptions in electric service could endanger patients, and in high-technology companies, where power interruptions could damage sensitive equipment, cause losses of important computer data, or spoil manufacturing processes. Many of those costs are hard to quantify.

Finally, the financial benefits that customers will weigh to decide whether to invest in and operate distributed generators are much more diverse that those summarized here. Conditions will vary widely from customer to customer—depending on such factors as the customer's economic activity, size, location, and load profile—and many technologies will not prove suitable. For example, a large commercial customer with significant air conditioning needs and hot-water requirements, facing a time-of-day tariff with high rates during peak periods, might find it economically beneficial to install a distributed generator to serve part of those needs at peak times while

11. The fuel cell technologies with the greatest potential to reduce costs are not yet commercially available.

producing hot water as a by-product. In contrast, for smaller customers with a flat-rate tariff, the cost to install and operate distributed generation equipment would make it economically unattractive.

Threats to the Performance of Electric Systems

Without adequate upgrades to the electricity supply network, widespread adoption of distributed generation could adversely affect regional electricity distribution systems. For example, with many customers switching their generators on and off, the quality of the power and the reliability of the systems could be degraded. Moreover, because utilities could have difficulty pinpointing the sources of the degradation, they might not be able to allocate to the owners of distributed generators the costs of preventive actions.

It may be difficult to develop economically sound policies on how to pay for any required upgrades in the utility infrastructure to protect against those risks. Experts generally agree that the current risks to the distribution system from the parallel operation of small generators, representing only a small fraction of a local distribution network's capacity, are usually manageable.[12] But the cumulative effects of many generators would be another matter. The utility network might require significant upgrades and additional protective devices to manage distributed generators that could use a large fraction of the local distribution network's capacity.

Traditionally, many utility commissions have adopted a "user-pays" policy under which the interconnection applicant bears the costs of any network upgrades to prevent potential problems. That policy favors early connectors, who can take advantage of excess network capacity; later connectors are at a disadvantage because they must pay for necessary upgrades. Advocates argue that credits for interconnection charges should be given for distributed generation because its use defers investment in transmission and distribution networks. But the deferrals are difficult to quantify and extremely variable from case to case, so it would be hard to craft a set of clear rules for such credits. A policy under which costs were recovered through higher transmission and distribution rates for all customers would conflict with the user-pays policy, which many regulators have adopted on the basis of equity considerations. Moreover, independent generators would have no incentive to locate plants where they would minimize the need for infrastructure upgrades, because the generators would not bear the costs of the upgrades.

Difficulties in Recovering Utility Costs and Paying for Public Benefit Programs

Distributed generation effectively allows customers to bypass utility-supplied power, avoiding various surcharges that are not related to the current cost of production—for example, charges to recover past utility investments (so-called embedded costs) that have proven uneconomic and charges to fund energy-efficiency programs or subsidies to small or low-income users. Increased adoption of distributed generation would limit the ability of regulators to use their ratemaking authority to distribute those costs according to equity considerations. It would also impose the burden of paying for embedded costs on customers who depended most on utility-supplied power.

Historically, state regulators have allowed utilities to set retail prices to recover the actual costs of investments that were deemed prudent and necessary to the provision of electricity, even when subsequent developments made some of those investments uneconomic. For example, in the 1980s, when wholesale electricity prices plummeted, utilities set rates that allowed them to recover the costs of their existing high-priced long-term contracts to secure electricity. State regulators have also frequently used the ratemaking process to achieve certain equity objectives. For example, "baseline" rates are intended to provide a basic level of electricity service at a below-average cost. Regulators often include charges in general tariffs

12. For example, FERC's recent "Advance Notice of Proposed Rulemaking on Standardization of Small Generator Interconnection Agreements and Procedures" (Docket No. RM02-12-000, August 16, 2002) stated that "[a] presumption of 'no impact' will normally be made if the following conditions are met: (1) the project's export of electricity (net of on-site load) would not exceed, cumulatively with all prior small resources on the system, (a) 15 percent of the peak load on a radial feeder or (b) 25 percent of the minimum load on a network link, and (2) the project's capability does not exceed 25 percent of the maximum short circuit potential."

to cover the costs of energy-conservation or low-income assistance programs.[13]

Distributed generation could provide customers with a means to circumvent part of those costs. For example, under tariffs that increase as consumption rises (boosting the cost per kilowatt-hour), a customer could use distributed generation to avoid buying electricity at the higher prices. The financial attractiveness of investment in distributed generators would probably diminish if utilities were allowed to assess distributed generation customers for such costs.

Risks to Air Quality and National Security

The distributed generation technologies with the greatest market potential are probably those fueled by fossil energy (backup generators powered by diesel fuel and cogenerators powered by natural gas), not renewable energy. The potential for customer-owned wind and solar power will probably continue to be realized only in limited circumstances, unless the capital costs of those technologies fall considerably. High-efficiency microturbine and fuel cell technologies are still at the earliest stages of commercialization, so their potential is largely unknown. Thus, the immediate promise of improved air quality from wider adoption of distributed generation may be limited, and improvements would probably come primarily from substituting natural gas- and diesel-fired generators for coal-fired generators. On the downside, those new generators might end up displacing power from units that were already fired by natural gas. And if some generators switched from relatively clean-burning natural gas to diesel, local air quality could worsen.

Another risk is that widespread adoption of gas-fired distributed generators could necessitate construction of additional pipeline capacity. The EIA's Reference Case Mid-Term Energy Forecast projects that electricity generated from natural gas will climb from 17 percent in 2001 to 29 percent in 2025. If that increase largely takes the form of distributed generation near growing population centers, additional pipeline capacity will be needed to supply those generators. Any savings in investments in electricity transmission and distribution networks would be partially offset by the need for investments in new natural gas pipelines.

Other adverse (or at least costly to control) effects also could result. They might include damage from unconventional forms of pollution such as waste heat and noise —problems that have been associated with diesel-powered backup generators and cogeneration plants sited in urban settings. Even windmills have environmental drawbacks, including detracting from the aesthetics of the landscape. Such impacts might not be easy to anticipate or be readily apparent for a small number of units, but the cumulative effect of many dispersed generators could be significant. In geographic areas with strict emissions standards, it would be necessary to inspect distributed generators regularly to monitor their compliance with those standards. Under the scenario of widespread use of small-scale generators envisioned by proponents, the cost of that monitoring could be steep.

13. For example, Pacific Gas and Electric Company's residential tariff includes a charge for "Public Purpose Programs" of 0.4 cents per kilowatt-hour.

CHAPTER

4

Barriers That Impede Widespread Adoption of Distributed Generation

Advocates of distributed generation contend that many industry practices and government restrictions discourage investment in and beneficial operation of customer-owned generators that could, without adverse effects, lower the costs of electricity for all customers. Opponents argue that such practices and restrictions are necessary to protect utilities and general ratepayers from increased costs, to maintain the reliability of the electric system, and to protect the environment. Four areas of contention are frequently mentioned:

- Requirements and charges for the installation of protective equipment as a precondition to interconnection with the grid;
- Surcharges on the electricity bills of operators of distributed generators (those who remain utility customers);
- Prices established for the distributed power that utilities purchase; and
- Environmental siting restrictions and permitting requirements.

Proponents of wider adoption say that well-crafted reforms in those areas would benefit not only customers who adopted distributed generation but also electricity customers as a group. Critics argue that such reforms would shift the burden of paying for the fixed costs of the electricity supply network from owners of distributed generation to other ratepayers. Distributed generators would continue to benefit from the network—as a source of supplemental power, for example—without paying their fair share of those fixed costs.

Protecting the Grid: Interconnection Requirements and Costs

The most commonly cited category of industry practices that proponents of distributed generation claim presents a barrier to adoption comprises the technical restrictions, contractual requirements, and associated costs for connecting customer-owned generators to the grid. Proponents claim that, for many types of distributed generation, the requirements are often excessive and time-consuming, resulting in additional unwarranted costs and significant project delays.

The stated purpose of the technical interconnection restrictions and requirements is to ensure the safety and quality of the electric power system and to avoid possible damage to equipment. Those restrictions often prohibit small generators from connecting to the grid at the distribution level of the network. For example, under existing rules in some utilities' service territories, customers with on-site generation must disconnect completely from the grid before starting their generators, to protect against accidental transmission of power onto the grid or possible voltage and frequency disturbances from the new power.

In the absence of outright prohibitions, however, operators of distributed generation units may want to remain connected to the grid while producing power (termed parallel operation)—whether to draw supplemental power from the grid or to transmit excess power onto it. In that case, utilities generally require operators to install additional controls and equipment in order to protect the network from feedbacks or disturbances. That additional site-specific equipment may include voltage regulators, frequency synchronizers, isolation devices, monitoring devices, and network protectors. Because the number and types of devices that utilities require vary widely and depend on many factors, utilities often demand specialized studies—typically paid for by the operator—to determine the equipment necessary in each case. Utilities may also require upgrades to the distribution system itself to support the power supplied by the distributed generators and to protect neighboring customers from disruptions or variations in power quality. Operators typically bear the cost of such site-specific equipment and any system upgrades, too.

In general, utilities require that operators of distributed generators execute contracts governing the interconnection of their equipment with the distribution and transmission network. Distributed generation proponents complain that provisions in those contracts are often one-sided or overly burdensome. They include insurance requirements that may boost operators' costs significantly and indemnification and dispute-resolution provisions that proponents say unfairly favor the utilities.

Many observers argue that those technical and contractual interconnection requirements are often excessive. For example, the electronic control equipment built into most small generators effectively protects against electricity feedbacks and other technical problems, so industry requirements for additional equipment are often redundant. A recent study from the National Renewable Energy Laboratory (NREL) documented several cases in which utilities insisted on separate equipment when generators already had such protection.[1] Similarly, specialized interconnection studies may be unnecessary for broad classes of generating equipment and operating conditions. Such studies not only add costs but also can delay the start-up of distributed generation projects. For the operators of small-scale distributed generators—especially in residential or small commercial settings—those costs can represent a sizable part of the total cost of interconnecting with the grid, and in many cases they are steep enough to jeopardize the economic viability of using distributed generation in those applications.

The NREL study documented numerous instances in which developers of distributed generation projects faced interconnection costs that they viewed as "above normal." In 12 out of 42 projects, developers cited excessive technical costs. Another six projects were abandoned because of barriers. The "above normal" costs ranged from \$20 per kilowatt to more than \$1,000 per kilowatt. Smaller projects tended to face higher per-kilowatt interconnection costs because some of those charges do not vary depending on the size of the generator.

Utility Surcharges: Paying for Stranded Costs and Standby Service

Under the electric utility regulations in most states, utilities may levy surcharges on customers who install distributed generators and operate them regularly. Typically, the surcharges take the form of flat monthly charges based on customers' past maximum usage. Monthly charges may be used to help utilities cover the costs of public benefits programs (such as purchasing renewable power or providing service to remote customers). Regulators in every state require utilities to conduct such programs, which are otherwise financed by electricity sales. More commonly, however, monthly charges are used to pay for past capital investments and for standby service.

Helping utilities recover some portion of their past capital investments is part of the purpose behind those monthly charges. Normally, a utility makes a capital investment (for example, to build a new generation plant) and then sets electricity rates at a level that will ensure recovery of those costs over time. But if electricity sales are lower than the utility expected—perhaps because rules change to allow some customers to generate power themselves—the utility's rates will not be sufficient to

1. Department of Energy, National Renewable Energy Laboratory, *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*, NREL/SR-200-28053 (May 2000).

pay off the investment. Revenues from so-called exit fees (surcharges imposed on customers who shift from full service to backup service) can help make up that deficit. Proponents of distributed power argue that the unrecoverable (or "stranded") costs covered by exit fees often do not reflect the actual costs of past investments, which have become uneconomic with the drop in customer demand.[2]

The more common purpose of the recurring monthly charge that some utilities impose on operators of distributed generators is to pay the utility's cost of maintaining standby generating capacity and distribution lines to serve that household or business. As retail utility customers, operators are able to purchase electricity whenever their on-site generators experience an outage (for whatever reason), and the utility must provide service to them. For example, Pacific Gas and Electric Company charges $2.55 per kilowatt per month for standby service to customers "who require PG&E to provide reserve capacity and stand ready at all times to supply electricity on an irregular or noncontinuous basis."[3] If those surcharges exceed the cost to the utility of providing standby service, they will discourage the efficient siting of distributed generators.

For nonresidential customers, the charge for standby service is often based on the maximum amount of electricity that the business draws from the grid in a short interval, such as 15 minutes. That maximum is often determined by the customer's past consumption. If a customer had drawn electricity at a maximum rate of 50 kilowatts for 15 minutes in the past three years, for instance, then that kilowatt level would be used to set the monthly charge. The utility would charge, say, $2 per month per kilowatt, or a total of $100 per month, for that customer's standby service. For a typical customer, the charge would amount to roughly one-half cent per kilowatt-hour.

Proponents of distributed generation argue that standby charges often overstate the cost of the service provided by the retail utility and fail to account for the benefits that distributed generators provide to the system. Because the probability of broad unscheduled outages by distributed generators is slight, the extra capacity needed to serve those customers is only a small fraction of the standby service (the maximum potential draw on the system) for which they are charged. Utilities can benefit from distributed generation by deferring some spending on transmission and distribution upgrades that would otherwise be needed to serve new customers. In general, however, such benefits are not subtracted from customers' monthly charges.

The Public Utility Regulatory Policy Act (PURPA) specifically requires utilities to provide standby service for cogenerators and others that use certain renewable fuels at nondiscriminatory rates. But many utilities only have pro forma tariffs for standby service, and they set the actual rates on a case-by-case basis.[4] As a result, rates vary widely; in many cases, they can significantly increase the costs of distributed generation projects. The NREL study on barriers to adoption of distributed generation documented charges for standby service that ranged from less than zero (a credit) to more than $18.75 per kilowatt per month. In New York, charges for standby service range from $4 to $16 per kilowatt per month. For the average residential customer or small commercial enterprise that may draw a maximum of only about 2 kilowatts, a monthly charge at the high end of those ranges could boost its electricity bills by as much as 20 percent. The NREL noted that such wide variations "demonstrate a lack of consistency and an absence of regulatory oversight of [standby] tariffs." According to the study, "the lack of appropriate regulatory principles or standards . . . creates uncertainty" that increases the financial risk for distributed power projects.[5]

2. For a discussion, see Congressional Budget Office, *Electric Utilities: Deregulation and Stranded Costs* (October 1998).

3. That charge is equivalent to approximately 35 cents per kilowatt-hour per month for customers who operate their equipment continuously.

4. A pro forma tariff contains general language authorizing the utility to charge for a service on the basis of defined conditions and cost categories. The actual price is determined on a case-by-case basis, consistent with the conditions stated in the tariff.

5. Department of Energy, National Renewable Energy Laboratory, *Making Connections*, pp. 21 and 24.

Compensating for Avoided Costs: Prices for Power Sold to Utilities

A third category of barriers identified by proponents of distributed generation is the price operators receive for selling their excess electricity to the utilities. To date, markets for excess power from small distributed generators are underdeveloped in many areas of the country. In those areas, there are no standardized rules that allow most operators to sell electricity onto the power grid, and no generally accepted mechanism is in place to set the prices for such sales. In some cases, federal and state rules have mandated that utilities purchase power from certain distributed generators, but the administratively set prices for that output generally do not induce producers to operate efficiently.

PURPA requires utilities to purchase electricity from independent generators that use cogeneration or various renewable energy technologies at prices based on the utilities' wholesale cost of power (their "avoided cost"). In the past, utilities have often determined their avoided costs on the basis of the least expensive alternative source of power, regardless of when it was generated. Independent power producers have complained that those prices are unreasonably low. Utilities frequently fail to provide credits for reducing costs during peak periods of consumption and for deferring upgrades to transmission and distribution networks.

Another way that certain operators receive credit for power they supply to the grid is through net metering. As of 2001, 33 states had mandated some type of net-metering through legislation or regulation.[6] Under a typical net-metering tariff, a customer's electricity meter is allowed to run backwards when it supplies power, reducing the customer's net consumption. This device effectively provides a credit for the generated power at the retail electricity rate, up to the point at which the customer generates more power than he or she consumes in a billing period. Some states require utilities to purchase power beyond that point at avoided costs, whereas other states do not require any additional compensation for customers. Most states with net-metering tariffs limit eligibility to small generators (typically, maximum sizes range from 10 kilowatts to 100 kilowatts) using renewable and high-efficiency technologies.

PURPA-mandated purchases and net-metering tariffs create the only organized markets for the sale of excess power from most operators of small distributed generators in the United States today. For operators who do not qualify for those markets (because their generators use conventional technologies such as internal combustion engines), often no outlet exists through which they can sell excess power. Such outlets may develop in the future, along with the establishment of wholesale power markets that compete in each region. Until they do, however, customers considering distributed generation must assess its financial attractiveness without the option of selling excess power. That limitation will constrain customers to considering generators that serve only their needs, even though larger-capacity generators could be more cost-effective, both for the customer and for all ratepayers.

For operators who do qualify to sell their excess power to the utilities, the prices they receive may not offer sufficient incentives to install and operate their distributed generators in a cost-effective manner. That is because the prices in those markets generally do not reflect the costs of the additional utility-supplied power that would have been produced in the absence of power from the distributed generators. At the wholesale level, the costs of producing and delivering electricity vary continuously by time and location, as consumption fluctuates in real time. During periods of peak demand, the cost of electricity typically rises as less-efficient generators are placed in service. The costs also vary by location because of constraints in the capacity of the transmission and distribution system that affect deliveries during periods of peak demand.

But at the retail level, prices generally do not vary by time or location.[7] Similarly, administratively set "avoided cost" payments to qualifying operators of distributed generators are often fixed, with predetermined prices in

6. For a summary of state net metering programs through May 2001, see www.awea.org/policy/netmeter.html.

7. Many retail customers are billed under time-of-use tariffs, which charge fixed prices only during predefined periods.

defined periods. Whether the cost of power is high or low during a given period, retail customers typically pay the same price per kilowatt-hour for electricity, and net-metered customers receive the same credit per kilowatt-hour. Under cost-of-service regulated rates, that price may include charges for past investments that have little relation to the cost of additional power.

That disparity between the wholesale cost of electricity and the prices that operators of distributed generators receive may raise the overall cost of electricity by limiting operators' incentives to run their units most efficiently. Distributed generators may operate during periods when it is less expensive to supply additional power from the grid, or they may remain idle when they could be producing electricity at a cost lower than that of additional grid-supplied power. In the long run, customers might install distributed generators even though the long-run marginal costs of grid-supplied power would be lower (a situation known as uneconomic bypass), or they might decide not to install generators even though the costs of distributed power would be lower.

Environmental Concerns: Siting Restrictions and Permitting Requirements

Almost all states, counties, and cities regulate the installation and operation of electricity generators. Those regulations, which vary widely across the country, are often enforced by multiple, and sometimes overlapping, jurisdictions.[8] Some analysts argue that the lack of standardized environmental regulations for distributed generation inappropriately hinders its development by making it impossible for national manufacturers to design equipment to meet a set of clear, uniform requirements. They also contend that most air quality programs fail to recognize the environmental benefits of distributed generation in reducing emissions from other sources that may be less efficient, including central power plants and customer-owned boilers. An NREL study of environmental regulations surrounding distributed generation recommended that "air quality permitting should provide credit for avoided or displaced emissions" from distributed generation.[9]

Air quality issues are one component of the permitting process for installing distributed generators. The other components are land-use approvals and building codes. Local governments require land-use approvals to ensure that a project conforms to zoning ordinances governing allowable uses for a property. Typically, ordinances do not identify electricity generating plants as a permissible land use, so jurisdictions usually require a review to weigh benefits and drawbacks and determine whether a permit should be granted. In some states, the land-use review may trigger an environmental impact review if the project might be detrimental to air and water quality, for example.

The building permit process—a separate requirement—ensures that a project conforms to certain safety standards. Those standards are described in building codes governing such characteristics as fire protection, plumbing, electric power, and mechanical equipment. Building permits are required for all new construction and most substantial building improvements and equipment additions. Building codes usually require that developers submit plans for review and approval before installation. In the case of distributed generation, building code departments may require additional information if the equipment has not been certified by an independent testing organization, such as Underwriters Laboratories.

Many building codes include specific regulations for on-site generators. Codes often require that certain building classifications be equipped with an emergency power supply to generate electricity when normal service is interrupted. Those generators must typically be powered by a fuel supply that is on the premises, such as diesel fuel or gasoline. That requirement can preclude the use of distributed generation technologies fueled by natural gas (which must be piped in), even though they can be less

8. For a detailed discussion of environmental issues surrounding the siting of distributed generation, see California Energy Commission, *Distributed Generation: CEQA Review and Permit Streamlining*, Report No. P700-00-019 (December 2000).

9. Department of Energy, National Renewable Energy Laboratory, *The Impact of Air Quality Regulations on Distributed Generation*, NREL/SR-200-31772 (October 2002).

costly to operate and are associated with fewer harmful emissions than diesel fuel or gasoline. For buildings that are required to have an emergency power supply, natural gas could be used only if the operator installed a dual-fuel generator—burning natural gas for nonemergency power needs (and sales to utilities) and burning diesel or gasoline for backup power.

State air control agencies and regional air quality management districts usually oversee the permit process for emissions. Regulations vary widely, although most districts restrict diesel-fueled backup generators to no more than 200 hours per year of operation, and only under emergency conditions. In areas that are out of compliance with air quality standards, nonexempt (large) generators must use the "best available control technology" to limit emissions and may be required to purchase rights to emit nitrogen oxides. Those requirements represent a barrier to the adoption of distributed generation because they can substantially increase the installed capital and effective operating costs of conventional internal combustion generators.

Although building standards and regulations on land use and air quality are designed to protect against significant environmental risks, some observers argue that the existing regulations governing distributed generation are often too broad or are inconsistent from site to site. The NREL study on environmental regulations and distributed generation concluded that "the complex, case-by-case permitting process designed for 'large' generators is inherently incongruous with application to small, standardized distributed generation technologies." Examples of such regulations include blanket prohibitions on electricity generation, limits on operation of backup generators, and height restrictions on towers needed for wind generators. The applicant bears the burden of obtaining an exception to those regulations, increasing the cost and time needed for approval. At a minimum, the regulations increase the uncertainty on the part of prospective owners and operators about the costs of adoption for all technologies.

Future Competitiveness: Uncertainty Surrounding Costs

With the elimination of arbitrary barriers, the market circumstances in which distributed generation technologies can compete favorably with centrally generated power, supplied by utilities, are likely to expand. But even so, the costs of power from new large generators, favored by utilities and independent producers, will probably be lower than those of distributed generation technologies in most applications. The costs of utility-supplied power are not likely to remain constant either, especially if further advances in wholesale competition or moves toward retail competition take place. The future prospects for distributed generation will depend greatly on just how the costs of utility-supplied power change. If current constraints on electricity transmission are eased or the marginal costs of producing and delivering power from central generators decline, the attractiveness of investing in distributed generation will probably diminish. It is also possible that some forms of distributed generation—especially in small-scale applications—may not fare as well as others. The bottom line is that today's investors in distributed generation technologies must be concerned not only about current barriers but also about uncertainty regarding the technologies' future competitiveness.

CHAPTER

5
Policy Options

The barriers discussed in the previous chapter could be lowered in several ways without jeopardizing other important social goals of state regulators and local governments. The most important initiatives that would allow an economic and wider use of distributed generation include the following:

- Ensure access to the grid for distributed generators under uniform technical and contractual terms and charges for interconnection that are based on economic costs—so that owners know in advance the requirements for parallel interconnection and manufacturers can design standard packages to meet technical requirements;

- Establish prices that owners of distributed generators both pay and receive for electricity at levels consistent with utilities' wholesale hourly costs to deliver power to different locations, and set uniform, explicit rates for standby electricity service based on costs—so that owners can decide between purchasing or generating power on the basis of prices that reflect utilities' incremental costs of serving them; and

- Set uniform requirements for emissions, land use, and building codes that are based on the technology of electricity generation—so that manufacturers can design suitable units and owners of distributed generators are not restricted in their siting and operating decisions relative to other new sources of generation.

The design of any policy initiative in those areas is complicated by the division of regulatory authority among the federal, state, and local governments. Under the regulatory framework for electricity markets that has evolved from the Federal Power Act of 1935, the federal government has primary responsibility for the regulation of pricing and access in the wholesale power markets, and the states have responsibility for the retail markets served by investor-owned utilities. The state-owned, municipal, and cooperative utilities that also serve retail customers generally regulate themselves. Decisions about the siting of power plants—in consideration of safety, air quality, noise, and local congestion—are generally in the domain of state and local governments. The issue of reducing barriers to distributed generation, no matter whether the power comes from small independent suppliers of cogeneration electricity or households with solar panels, cuts across all those jurisdictions.

In terms of economic efficiency, it may not matter which level of government is responsible for effecting those types of regulatory change. But it is important that broad changes to operational practices and rules occur together. Unless fundamental changes in restrictions on siting and operation, access to the grid, and pricing are all addressed, the prospect of improving the economic efficiency of electricity generation through wider adoption of distributed generation may not advance noticeably.

Access to the Grid: Reducing Technical, Contractual, and Cost Barriers

The ability of owners of distributed generators to gain full access to the local distribution grid—whether to continue receiving utility power or to provide distributed generation power—can be impeded by poorly defined technical requirements for interconnection, contractual conditions that impose onerous liability and insurance provisions, or arbitrary charges for special services required as a condition for interconnection. Those barriers could be lowered by specifying the requirements, conditions, and charges more clearly and grounding them in sound principles of economic costs.

Prescriptive technical standards for interconnection would clearly define the conditions under which utilities allowed broad classes of distributed generators to connect to local power grids without customized equipment or special studies.[1] Standards could help reduce uncertainty about the costs of the controls and equipment necessary for connection and ensure that customers' costs for connecting reflected the actual costs of those controls and equipment.

Such standards could also lower costs by fostering a market for packaged controls and interconnection equipment. In such packages, the controls that ensure the safety of the system and protect the quality of the power would be incorporated in distributed generation equipment at the factory rather than custom designed and built for each application on the basis of case-by-case requirements from the utility. Regulatory authorities or other public agencies could establish rules requiring utilities to expedite interconnections with customers who installed such equipment. A market for standard packages could also help the industry achieve design and manufacturing economies that would lower the total costs of distributed generation equipment and connecting to the grid.

In an effort to clarify and tighten interconnection standards, the regulatory bodies in some states have adopted rules that limit the conditions under which interconnection studies are required or prescribe the conduct of such studies. The New York Public Service Commission exempts customers from the need for utility interconnection studies if their generators have capacities below 10 kilowatts—generally enough power to supply a small commercial building or a block of homes. Additional exemptions can apply to customers with generators as large as 150 kilowatts, depending on the type of interconnection they have with the grid. Similarly, the Texas Public Utility Commission (PUC) prohibits utilities from charging for interconnection studies for customers that request parallel service but do not export power to the grid and customers that have precertified generators under 500 kilowatts that contribute less than 25 percent of the maximum current on a radial grid connection.[2] If an interconnection study is needed, the Texas PUC requires that the customer receive an estimate of the study's cost, that the study be completed within four weeks, and that it consider benefits to the utility system from the interconnection.

In addition to technical standards, uniform contracts would help prospective investors in distributed generation by clarifying the liability, insurance, and other conditions for interconnection and their costs. Those contracts could be developed under the auspices of regulatory bodies to ensure the even-handedness of the provisions. Such contracts would tend to lower the costs of insurance, because they would clearly define the conditions under which owners would be liable and the procedures under which disputes would be resolved.

The Federal Energy Regulatory Commission is in the early stages of developing standard procedures and agreements for the interconnection and parallel operation of generators and utility transmission systems.[3] Those proceedings have produced proposals for draft contracts that spell out the responsibilities of the interconnection customer and transmission provider in the design and operation of their facilities, the liabilities of each party, procedures for testing and inspection, insurance obligations, and other relevant provisions. Other organizations have developed their own procedures and agreements for interconnecting generators

1. Interested parties are already actively developing technical standards under the auspices of the Institute of Electrical and Electronics Engineers (IEEE). The IEEE subcommittee responsible for that work has published draft standards that provide technical specifications and test requirements for connecting distributed generation technologies under 10 megawatts in capacity to electric power systems at low voltages. See Institute of Electrical and Electronics Engineers, "Draft Standard for Interconnecting Distributed Resources with Electric Power Systems," IEEE P1547/D08 (August 29, 2001).

2. A radial connection has only a single path on the grid between the point of consumption and the substation.

3. Department of Energy, Federal Energy Regulatory Commission, "Advance Notice of Proposed Rulemaking on Standardization of Small Generator Interconnection Agreements and Procedures," Docket No. RM02-12-000 (August 16, 2002).

and transmission providers. Such organizations include the Electric Reliability Council of Texas, the California Public Utilities Commission, the Edison Electric Institute (a trade organization representing investor-owned utilities), and the Electric Power Supply Association (a trade association representing independent power producers).[4]

All of those initiatives would, at a minimum, reduce important types of uncertainty on the part of customers about the costs of distributed generation. They would also eliminate the time and expense of negotiating terms of interconnection for each proposed project. That would allow customers to make meaningful comparisons of the merits of distributed generation relative to utility-supplied power.

At some point, further progress on national technical and contractual standards and utility charges might require the impetus of federal legislation—for example, in the form of directions to FERC to establish a standard contract or federal assistance to state and private efforts to agree on prescriptive standards. The different versions of energy legislation in the 108th Congress contain language that requires utilities to provide distributed generation systems with competitive access to the local distribution grid, offer simplified standard contracts for the interconnection of small generators, and not charge distributed generation customers for interconnections.

Real-Time Prices Based on Wholesale Costs: Reducing Pricing Barriers

The prices that operators of distributed generators pay and receive for electricity are also key to achieving potential benefits in electricity markets. Electricity services fall into three major categories—electric energy, transportation, and so-called ancillary services. Electric energy is the power that generators produce. Transportation is the high-voltage transmission and local distribution of power from the point of generation to the place of consumption. Ancillary services encompass various support functions that ensure the delivered electric power meets certain levels of quality and reliability. For operators of distributed generators, the most important of those functions is standby service, which allows them to draw power from the grid whenever they need it and thus protects them against losses from unplanned outages of their generators. If the prices for those electricity services—power, transportation, and support functions—reflected the incremental costs to utilities of providing them, then customers would have incentives to install and operate distributed generators only in situations in which their costs were lower.

Real-time tariffs for electricity sales both to and from operators of distributed generators could provide the appropriate price signals for electric power and transmission services. Under real-time pricing, the retail rate for electricity varies hourly and geographically in accordance with the utilities' wholesale cost of power. With that form of pricing, customers would have a financial incentive to install distributed generators in locations where prices were chronically high as a result of transmission congestion. They would operate their units at times when the price of electricity exceeded their operating costs and would purchase utility-supplied power when the price fell below those costs. Relative to the current situation, that behavior would reduce net demand (and possibly increase net supply) for electricity from the utility network during periods of high prices, which would reduce local congestion on the grid. It would also displace more expensive central generation during periods of peak demand and tend to reduce wholesale electricity prices. Those reductions would typically be passed on to all retail customers in the form of lower rates.

Putting real-time pricing into practice on a wider basis has implications for the economic efficiency of electricity markets. Potential benefits to consumers that flow from offering tariffs under which prices vary according to wholesale costs in real time may exceed those from an economically efficient adoption of distributed generation. Nevertheless, real-time pricing would send market signals that would encourage investment in and use of distributed generation.

How Would Prices Be Set?

The development of prices that encourage efficient siting and operation of distributed generators has been the shared

4. All of the agreements are available under FERC's "Advance Notice of Proposed Rulemaking on Standardization of Small Generator Interconnection Agreements and Procedures."

responsibility of legislators and regulatory bodies at both the federal and state levels. A recent federal legislative proposal (S.14 in the 108th Congress) includes provisions that will require state regulatory bodies to consider real-time tariffs. FERC has recently proposed creating regional wholesale markets for power throughout the United States that would feature different prices at each delivery point. And at least one state regulatory body, the California PUC, has instituted general proceedings to set policies for real-time pricing for all customers. Several utilities (including Georgia Power and Niagara Mohawk) have designed and offered voluntary real-time tariffs to large customers.

Developing tariffs that reflect efficient pricing is not a simple matter. In the retail electricity market, where regulators typically approve utility tariffs, the goal of promoting economic efficiency must be reconciled with other ratemaking principles, including the recovery of embedded costs and the allocation of fixed costs on the basis of consumption. Conflicting interests—for example, those of distributed generation customers who want prices to reflect generation and transmission costs and a utility that is required to subsidize the cost of power to rural households—may be difficult to reconcile at the state or local level. That difficulty suggests that the federal government may need to step in to resolve pricing issues.

Specific suggestions for federal intervention are related to the need for marginal cost-based prices that vary frequently to reflect current market circumstances and the installation of net-metering service to facilitate such pricing. The Congress has recently considered those proposals as a part of comprehensive energy legislation.

The technical feasibility of identifying marginal cost-based prices in real time is supported by information processed by transmission systems owned by individual utilities, as well as by regional transmission networks in which several utility and nonutility generators participate. Both of those operating models produce values for time-varying costs by location, which could be the basis for designing real-time tariffs. In many utility transmission systems today, operators calculate the values of electricity at different locations almost continuously as demand fluctuates in real time. Computer programs perform those calculations to determine the least expensive mix of electricity generation from available plants at any time, given the level of demand, capacities of transmission lines, and other operating constraints. The same calculations—typically performed at very short time intervals, as frequently as every five minutes—also yield an estimate of the cost of supplying an additional kilowatt at each delivery point in the network.

A second source of such real-time, marginal cost-based prices is the bidding systems of the integrated transmission networks, jointly owned by several utilities and run by a single operator. Those networks include such entities as the PJM Independent System Operator, which manages the transmission system covering several mid-Atlantic states, and the New York Independent System Operator, which manages the transmission system in the state of New York. Those networks have developed systems to operate power plants and handle power exchanges among members as well as purchases from independent producers. Several use bidding systems in which producers offer to generate power at prices above a set minimum. Operators select plants to run on the basis of those prices (from lowest to highest) in place of the operating cost schedules used under a single owner/operator system. The end result is similar, with a price for each delivery point, referred to as locational marginal prices.

FERC is encouraging all transmission owners in the United States to form integrated networks and designate independent operators to run them under such a bidding system. The real-time prices that could come out of those systems would track wholesale costs as they varied at short time intervals. Those prices would give owners of distributed generators the price signals and incentives they needed to operate during periods of critical consumption. In the long term, price differentials across locations would give customers an incentive to build new distributed generation plants in places where they could reduce transmission congestion and losses to the greatest extent.[5]

Other Issues Related to Pricing

At least three practical considerations must be accounted for in designing real-time pricing for owners of distributed

5. Under FERC's proposal, the price differentials would only apply to the transmission portion of the electricity network. Retail utilities would need to associate those prices with delivery points in the distribution system and possibly add location-specific surcharges for distribution congestion.

generators. First, owners are both consumers and producers of electricity. If the prices they pay for electricity differ from the prices they receive, the differences may distort their incentives. (See the appendix for a discussion of the relationship between market reform and the pricing of electricity for distributed generation customers.) For example, industrial customers with multiple meters could shift loads, buying power at low average cost-based rates while selling power at high real-time prices. Those types of distortions can be avoided if distributed generators are obliged to buy and sell power at the same real-time prices.

Second, the costs for data collection and administration of real-time tariffs are significantly higher than those of traditional tariffs. Meters that record electricity consumption in short time intervals (hourly or in 15-minute periods) range in cost from $200 to $3,700, depending on their features.[6] Recently, in California, real-time meters and automated communications systems were installed for more than 20,000 large customers, whose electricity consumption represents almost 30 percent of the state's annual peak demand. The average cost per installed meter was approximately $1,600. That figure provides a reasonable estimate of the cost of the metering equipment that would be needed for a large number of installations for large customers. Metering equipment with fewer features, which would be suitable for smaller customers, would cost much less. One study estimated that the monthly cost of an interval meter used for a simple form of real-time pricing would be less than $5 per month under a five-year contract.[7]

Data acquisition, processing, and reporting can add significantly to the costs of administering real-time tariffs. All those costs must be recovered from customers billed under the real-time tariffs. Utilities offering such tariffs today typically recover metering and administrative costs through fixed monthly charges. Georgia Power levies a fixed charge of $175 per month on its customers billed under real-time pricing who have peak demand that exceeds 250 kilowatts per month. That fixed charge, which covers billing, administrative, and communications costs for the program as well as costs for the metering and communications equipment, represents less than 5 percent of the monthly bill for a typical qualifying customer.

Third, real-time tariffs must incorporate other ratemaking principles in regulated markets. Those principles include embedded cost recovery and standards of equity in sharing common costs. In some cases, reconciling those principles with real-time prices based on wholesale costs may be very difficult. For example, many regulatory bodies have adopted a standard of equity that reflects the notion of sharing common costs in proportion to consumption. Under that standard, small users in a customer class pay the same rate per kilowatt-hour as large users. When customers install on-site generators to meet their own demand, their share of the common costs is shifted to the remaining ratepayers, unless the utility charges a standby service fee or exit fee. Those fees may discourage the installation of distributed generators, even if their electricity is the cheapest to produce.

One possible solution to that last problem, discussed by some analysts, is to levy a fixed monthly charge—paid by all customers, not just operators of distributed generators, on the basis of capacity—to recover common costs.[8] The fixed charge would cover network costs that do not vary with the level of electricity usage, replacing standby tariffs for distributed generation customers. A two-part tariff with such a fixed charge and a per-kilowatt-hour price equal to the marginal wholesale cost is known as a Coase tariff, named after the economist who proposed it. As long as the fixed charge did not prevent customers from connecting to the electricity network, that price schedule would promote the efficient consumption and production

6. For a discussion of those issues, see Robert Staunton and others, "Demand Response: An Overview of Enabling Technologies," *Public Utilities Fortnightly,* vol. 139, no. 20 (November 1, 2001), pp. 32-39.

7. That cost is equivalent to approximately $250 in real (inflation-adjusted) capital expense at an 8 percent discount rate. See California Energy Commission, *Meter Scoping Study* (report prepared by Levy Associates for the Public Interest Energy Research Program, February 2002).

8. For an extensive discussion of efficiency and equity issues surrounding multipart electricity tariffs, see James C. Bonbright, Albert L. Danielson, and David R. Kamerschen, *Principles of Public Utility Rates* (Arlington, Va.: Public Utilities Reports, 1988).

of electricity.[9] Such a tariff may be considered inequitable in many jurisdictions, however, because it violates the principle of cost sharing in proportion to use.

Local Government Permits: Reducing Siting and Environmental Barriers

Federal, state, and local rules surrounding the installation and operation of distributed generators, although intended to protect the public, can create costs and uncertainty for investors in distributed power. The American Council for an Energy Efficient Economy has identified the Environmental Protection Agency's (EPA's) New Source Review process as a significant barrier to the growth of combined heat and power systems, a key distributed generation technology, and has complained that the current requirements fail to credit CHP for emissions reductions from increased efficiency. The California Energy Commission has investigated the local environmental review process for the siting of certain types of distributed generators with the objective of streamlining the local permit process. That initiative is one effort to lower the costs and uncertainty associated with complying with environmental and other siting and operating restrictions without materially increasing risks to the community. In general, that result could be achieved by clarifying and rationalizing the regulations affecting land use, building safety, and air quality. More specifically, such an approach would require local governments to replace general restrictions with regulations that clearly specify the technologies, operating characteristics, and conditions for which distributed generation applications would be permitted.

The existing general regulations include such provisions as blanket prohibitions on electricity generation in many land-use categories, restrictions on the operation of backup generators, and height limits for towers used by wind generators. Those regulations could be replaced with rules that permitted the installation and operation of certain small-scale, generally benign technologies—such as solar photovoltaic systems and fuel cells—under defined operating conditions. Other high-efficiency technologies—such as microturbines and natural gas-fueled internal combustion generators—could be included along with standards for emissions thresholds, noise levels, and aesthetics. In addition, revised regulations could specify standard mitigation measures and testing procedures for distributed generators in cases in which conditional-use permits were required.

Much of the direct responsibility for those types of changes currently lies with local governments—including cities, counties, and regional air resource boards—although those bodies may be acting in response to broader state and federal mandates. For example, the federal Clean Air Act requires local governments to establish programs to bring local air quality into compliance with standards enforced by the EPA. The federal government or state public agencies could take additional steps to encourage or require local governments to make those types of changes.

Among the options available to the federal government is directly assisting in the streamlining of the local environmental permit process by developing model regulations and certification guidelines or by providing technical support to local enforcement offices. For example, the government could develop uniform building code requirements for various classes of distributed generation. Such codes could streamline the approval process for installing distributed generators, reducing both the uncertainty about the requirements and the typical cost of compliance. Federal support could also include recommendations for updating zoning ordinances to identify where and under what conditions distributed generators would be allowed. Those new guidelines could cover recommended standards for emissions and other environmental impacts, as well as specify the testing procedures that would be used to verify compliance. Technical support could include information for building departments and other local enforcement offices about the checking of plans and the inspecting of newly installed distributed generation technologies.

9. Bridger Mitchell and Ingo Vogelsang, *Telecommunications Pricing: Theory and Practice* (Cambridge, England: Cambridge University Press, 1991), p. 36.

APPENDIX

Electricity Market Restructuring and Distributed Generation

The ongoing deregulation of the generation portion of electricity markets in the United States strongly affects the prospects for distributed generation and its potential to reduce electricity costs. The structure of deregulated wholesale power markets will influence the prices for distributed generation output and for related electricity services. The levels of those prices relative to retail electricity prices will determine whether distributed generators can be used in a manner that benefits their owners without raising costs for other customers. In particular, when a retail customer can also act as a supplier of electricity by operating distributed generation, differences between prices in the retail and wholesale markets may create incentives that increase costs for other customers.

Changes in How Utilities Are Structured

The structure of wholesale and retail electricity markets varies widely throughout the United States. Historically, investor-owned utilities have supplied most of the electric power. The federal government has played a key role in developing and managing hydroelectric power in several regions. Municipal and cooperative utilities also are significant suppliers, especially of distribution services in rural areas. Many aspects of this structure have changed dramatically in the past two decades, and more changes are expected in the future.

Investor-owned utilities, which typically own an entire system of generators, transmission and distribution lines, and equipment (referred to as vertical integration), are regulated by federal and state bodies. The Federal Energy Regulatory Commission (FERC) oversees the transmission system and wholesale electricity markets. State public utility commissions govern retail markets. Traditionally, state regulators have authorized the tariffs that investor-owned retail utilities can charge, setting rates that allow recovery of past investments and a reasonable return on those investments. That structure of regulated, vertically integrated monopolies that supply electricity at prices based on embedded (historical) costs has dominated electricity markets in the United States for most of the 20th century.

But over the past few decades, the vertical structure has changed in several important ways. First, utilities have integrated the interconnection and operation of their transmission networks substantially. That integration has allowed them to provide more reliable service at lower costs by taking advantage of generation from diverse sources and "gains from trade" (agreements to exchange power) with other utilities. Approximately 150 control areas have been organized in the United States under which a single operator manages an interconnected transmission grid and power plant system, using computerized controls to balance supply and demand and maintain the system's safety and reliability. Power exchanges and sales in those areas are governed by negotiated agreements and operating rules, subject to FERC's approval.

Second, starting in the late 1970s with enactment of the Public Utilities Regulatory Policies Act (PURPA), federal and state legislatures and regulatory bodies established rules for utilities to buy power at negotiated rates from independent, nonutility producers. What has gradually emerged since then is a mixed system of utility-owned generation, bilateral transactions for power at negotiated (market-based) prices, and several regional wholesale markets for electricity organized around interconnected transmission systems. The regional markets that have developed as a result of PURPA feature power exchanges in which prices fluctuate hourly, on the basis of supply and demand.

Third, in 1999, FERC called for the establishment of independent transmission organizations throughout the United States that would operate regional wholesale electricity markets. In July 2002, the commission presented its proposal on how those markets would function. The operation that FERC envisions is similar to the way in which some regional markets, including PJM (covering several mid-Atlantic states) and the New York Independent System Operator, currently operate.

Under FERC's proposed system, generators would bid to sell power in the regional markets on an hourly basis. Bids would vary widely because of differences in the operating costs of available generators. Starting with the lowest bid and moving higher, the transmission system operator would select the generators to produce sufficient electricity to meet final demand each hour.[1] All generators selected to run would be paid the value of the highest accepted bid. If congestion on a segment of the transmission system forced the operator to run a generator whose bid was above the highest accepted bid, prices of power at the delivery points served by the congested segment would be raised to reflect the difference. As a result, the price of electricity would vary each hour depending on the incremental generation costs incurred to serve the load, and it would vary by delivery point depending on transmission congestion. Price differences resulting from congestion would be managed through a market for transmission rights between the point of generation and the point of delivery.

In FERC's system, individual generators and wholesale customers could have bilateral contracts at fixed rates. If the generator failed to meet its contracted obligation, then it would buy power in the spot market to eliminate the deficit. If the customer used more than its contracted load, then the customer would buy the excess power in the spot market.

The competitive spot market for power would establish an unambiguous incremental wholesale cost of electric power. The market-clearing (highest accepted) price in the spot market would be the cost of an additional kilowatt-hour in each hour and at each delivery point, even when the majority of the power was transmitted under long-term bilateral contracts at fixed prices.[2] The (realized or avoided) cost of an additional kilowatt-hour would be the short-term spot price.

The Impact of Electricity Pricing on Distributed Generation

Most retail electricity customers in the United States face prices that are the same during predefined periods, regardless of the wholesale cost of power in a given hour. In states that continue to set electricity prices on the basis of traditional cost-of-service regulation, those prices are based on past investments. The rates may include charges that are unrelated to the current incremental cost of production—for example, charges to recover past investments in power plants that have proven uneconomic or charges for previously signed long-term contracts with prices above those for newly constructed generation. In states that have introduced competition in retail markets, suppliers are free to offer electricity at any price, with a regulated surcharge for the transportation of the power. That surcharge may include an additional component to recover the "stranded" costs of past investments made by the old regulated utility before the switch to competition.

The difference between wholesale and retail electricity prices may induce customers to install and operate distributed generators in a manner that fails to lower, and possibly raises, costs for other retail customers. For example, a customer in a state with high rates stemming from expensive past investments can avoid those rates by operating a distributed generator and shifting the burden of recovering those past investments to the remaining ratepayers. That shift can happen even when the cost of wholesale power is below that of distributed power. Such situa-

1. In the wholesale market, the customers are retail distribution utilities. They act as intermediaries, buying electricity at wholesale prices to meet the final demands of their retail customers.

2. In the geographic area managed by the PJM Independent System Operator, for example, more than 80 percent of the power is either owned by the retail utility or purchased under long-term contracts.

tions are referred to as "uneconomic bypass" because they raise the total cost of supplying electricity to ratepayers as a group.

Even when regulated retail rates are not burdened by expensive past investments, they may fail to offer customers the incentive to operate distributed generators during periods of peak demand and high wholesale prices. That is because regulated retail electricity prices generally do not track hourly variations in wholesale prices. If a customer faces a constant retail price, as most do, it has an incentive to operate its distributed generator either continuously or not at all. As a consequence, the distributed generator may run even when the wholesale cost is lower, and it may not run even when the wholesale cost is higher.

Several strategies have been proposed to price electric power from distributed generators. One widely used method for small distributed generators is called net metering. In its simplest form, net metering allows a retail customer's electricity meter to run backwards, so that transmission onto the grid offsets purchases from the grid. The customer receives a credit from its energy service provider, at the same rate it pays to buy power, for the electricity it supplies onto the grid. Many states have already ordered private utilities to offer net metering to certain small, qualifying customers. Those customers include solar and wind generators that operate intermittently. Through 2000, 33 states had mandated some form of net metering.

Although net metering provides a ready market for distributed generation output at retail prices, its simple application does not address the problems described earlier, namely, uneconomic bypass and a lack of incentives to operate during peak periods. A second approach, advocated by many analysts, is known as real-time, or dynamic, pricing. Under real-time pricing, retail rates fluctuate at short time intervals according to variations in wholesale spot-market prices. Such rates provide the price incentives for customers to operate their units during peak periods, when wholesale prices are highest. Those rates could be offered in conjunction with net metering; in that case, credits would be based on the wholesale price of electricity in each hour rather than the average price for the month.

A range of technical and regulatory issues surrounds the design of real-time retail tariffs. Those issues include recovering the costs of special metering equipment required for tariffs and reconciling real-time rates with embedded-cost recovery. Some analysts have recommended adding a fixed charge to real-time rates to cover those costs and offering the tariffs on a voluntary basis to make them more acceptable to customers. Analysts expect that the average price of electricity under real-time rates would be lower than it would be under the current flat monthly rates. Customers who elected to receive service under the lower real-time rates would assume the risks associated with the price volatility.

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