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.