Chapter 5

Renewable Energy Policies—7 Ways to Switch

Existing Policies

Over the years, state and federal governments have taken a number of actions to encourage renewable energy production. Among these were price guarantees, tax incentives, and minimum requirements for renewables. At the federal level, the Public Utility Regulatory Policy Act of 1978 (PURPA) has had the greatest effect in supporting the development of renewable energy. During the late 1990s, as the industry moved toward competition, some legislators have sought to repeal PURPA. Independent energy producers and consumer groups have defended the policy as necessary until the renewables industry is fully competitive. Renewable energy advocates also argue that PURPA should not be repealed until alternative mechanisms are in place to preserve the public benefits of renewables in a deregulated industry.

Federal tax credits for renewable energy technologies have waxed and waned. In the 1980s, investment tax credits for renewables led to some early development. Later, the Energy Policy Act of 1992 (EPAct) extended the investment tax credit for solar and geothermal power, and established a production tax credit of 1.5¢/kWh for wind and for some biomass applications. This credit has been important in sustaining some growth in the wind industry. However, the "closed loop" biomass facilities (see Appendix A for a description) that the legislation supports have remained too expensive to develop, so no facilities have been able to take advantage of the credit. The EPAct production tax credit for wind and biomass expires in July 1999. Efforts are under way to extend the tax credit for wind and to expand the credits to support conventional biomass technologies.

The federal government has also supported research and development for renewables, primarily through federal research laboratories. However, federal spending on R&D for renewable technologies has been far less than for fossil fuel and nuclear technologies, as discussed in Chapter 3.

States have taken a variety of actions to promote renewable energy.[1] Many states have offered tax breaks for renewable energy projects. But these have rarely been effective by themselves since they have usually been set too low to make renewables competitive. Only when combined with other policies have tax breaks succeeded in creating an active renewables market.

The most successful renewables efforts have been in the two states that aggressively implemented PURPA: California and Maine. In the 1980s and early 1990s, California developed almost 6,092 MW of renewables capacity—about 14 percent of the state's generation capacity. Maine developed 855 MW, providing over 35 percent of the state's power plant capacity.[2]

In the 1980s, a number of states adopted integrated resource planning (IRP) policies. IRP regulations require utility companies to consider the mix of demand-side measures (such as investments in energy-efficiency improvements) and supply options that provide electricity at the lowest cost. Some states have considered environmental costs in determining what mix of resources would produce the lowest overall costs to society. Other states, like Wisconsin, passed laws stating a preference for renewable energy sources when cost-effective. IRP frequently led utilities to invest money in energy efficiency programs, because it is often less expensive to reduce energy use by improving the efficiency of appliances, lights, motors, and other end uses than it is to generate the same amount of electricity. But because these policies went into effect during a period when existing electricity capacity exceeded demand, utilities resisted new generation. Consequently, little new capacity—renewable or fossil fuel—was developed. Where new capacity was developed to meet PURPA or IRP regulations, natural gas generators increasingly submitted the low bids and got the contracts.

In Texas, however, IRP, together with a process of "deliberative polling" to assess public opinion has led to 43 MW of wind capacity by the end of 1998, with another 75 MW scheduled to come on-line in 1999.[3] Colorado regulators approved an IRP settlement with Public Service of Colorado including 25 MW of wind development.[4]

Some states have required that their regulated utilities build a minimum amount of renewable plant capacity. The largest set-asides have been in the Midwest: Iowa's 1983 law resulted in 105 MW of wind and biomass electricity generation.[5] Minnesota's 1994 settlement with Northern States Power resulted in 425 MW of wind power and 125 MW of biomass. And Wisconsin's 1998 Reliability Act contains a 50 MW renewables requirement. One state utility, Wisconsin Electric, has announced it intends to significantly exceed the requirement.[6]

With increasing wholesale competition, many utilities have actively resisted PURPA, IRP, and set-asides. There is a need for new policies and for reconfiguring older policies to be consistent with restructured electricity markets, if renewables are to compete successfully. Realizing the full potential of renewables to provide public benefits requires either imposing the costs of pollution on those that generate it or providing equivalent support to nonpolluting sources. The remainder of this section describes seven critical ways that can advance renewable energy development in restructured electricity markets.[7]

Renewables Portfolio Standard

The renewables portfolio standard (RPS) is a requirement that a minimum percentage of each electricity generator's or supplier's resource portfolio come from renewable energy. The RPS creates a minimum commitment to a sustainable energy future. It would build on and enhance the investment already made in sustainable energy. And it would ensure that the new electricity markets recognize that clean renewable electricity is worth more than polluting fossil fuel and nuclear electricity. Further, these goals can be accomplished using a market approach that provides the greatest amount of clean power for the lowest price and an ongoing incentive to drive down costs. By using tradable "renewable energy credits" to achieve compliance at the lowest cost, the RPS would function much like the Clean Air Act credit-trading system, which permits lower-cost, market-based compliance with air pollution regulations.

As a minimum national standard, the RPS would not be new or especially notable. US citizens already benefit from similar standards in other sectors of the economy, as table 2 shows. Energy-efficiency standards for buildings, for example, are common in many states and countries. From airlines to cars to drugs, standards ensure public safety, economic health, and environmental protection. Such standards help societies achieve goals or meet needs that might otherwise go begging.

The RPS has garnered significant bipartisan political support. As of December 1998, it has been adopted in five states and is under consideration in a number of others. (See Appendix C for a comparison of state RPS

TABLE 2
Other Standards Similar to the Renewables Portfolio Standard

Building Energy Efficiency	Many states and over 25 countries require insulation or equivalent measures in all new buildings.
Automobile Fuel Efficiency	Each automaker's fleet of new cars must achieve a certain average fuel economy. Called "CAFE Standards."
Airplane Safety	Uncounted across-the-board rules. A recent rule requires that all passenger aircraft have fire detectors in their cargo holds.
Acid Rain Reduction	All major emitters of sulfur dioxide must own SO_2 allowances equal to their emissions.
Product Safety	Medicines must have childproof caps. Electronic equipment must meet standards that minimize the chance of electrical shocks or fire.
Food Safety	Standards for packaging, refrigeration, sanitation, labeling, fat content, etc.

plans.) In one state, Pennsylvania, individual utility settlements have included minimum renewables requirements for default service—i.e., customers not choosing competitive suppliers. Together with minimum requirements adopted in three states outside of restructuring, these commitments can be expected to preserve approximately 1,650 MW of existing renewables capacity, and lead to the development of 2,100 MW of new renewables (see figure 13).[8]

The RPS has also been included in six separate federal restructuring bills. Appendix C details how states and the U.S. federal government have implemented or proposed to implement the RPS as of December 1998. There is also growing support for implementing a European Union target of doubling the market share of renewables to 12 percent by 2010, with a credit trading system already implemented in the Netherlands.[9]

The RPS has proven politically attractive because if combines the use of a market-based mechanism to solve a "market failure" (i.e., it puts a competition-based price on the "green" in green electricity) with a public policy commitment to a sustainable energy future. State legislators have recognized its economic development and environmental benefits, while a growing number of federal legislators see it as a way and of supporting an emerging domestic industry and decreasing the expense of reducing greenhouse gases.

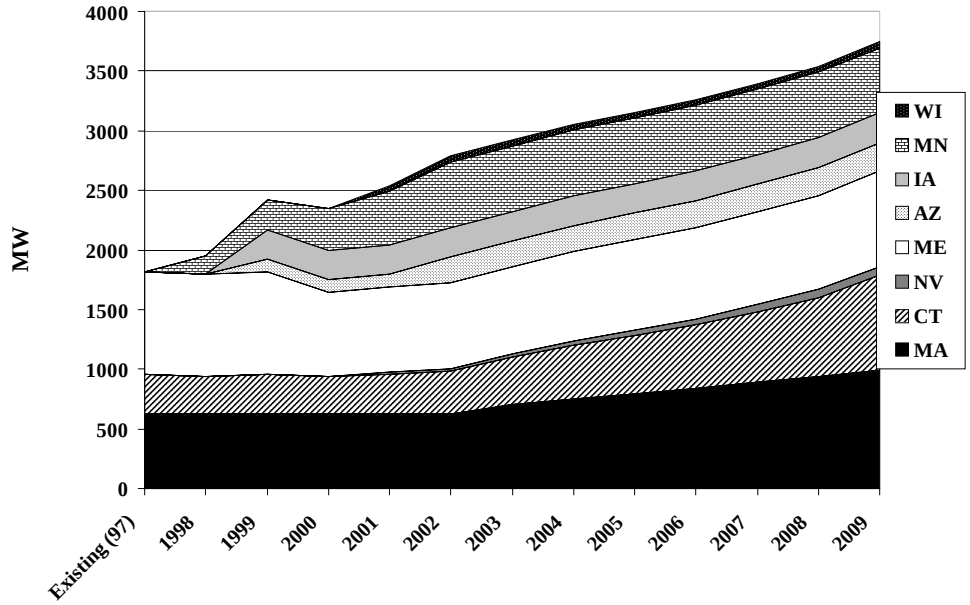
The Elements of the RPS. The renewables portfolio standard includes two elements: a standard that specifies what percent of a utility's electricity must come from renewable resources, and renewable energy credits that the utility acquires as a result of obtaining energy from those renewable sources.

The standard is simple: it requires that a certain percentage of all electricity used in the United States must come from renewable resources. That means every retail provider and generator of power would need to demonstrate once each year that a portion of the power they provided came from renewables. The amounts proposed in state and federal bills vary, but they typically start by preserving existing levels of renewables (around 2–3 percent nationally) and then increase that amount to 4–10 percent by 2010, and in two cases to 20 percent by 2020.

Renewable energy credits (RECs) correct the bias against renewable energy in the electricity market by making sure that renewable generation companies receive payment for the public benefits they produce. The fact that environmental and other benefits are not recognized in the cost of power is the starting point for creating a new commodity that represents those benefits. That commodity is the renewable energy credit.

When a fossil fuel or nuclear power plant operates, it is really creating many products: the electricity itself and all the byproducts, like air and water pollution, hazardous and radioactive waste, the risk of meltdown, and so on. Customers only pay for the electricity. Society

Figure 13. State Minimum Renewable Energy Requirements



Source: UCS Estimate

pays for the byproducts through a host of unacknowledged costs: health problems, environmental degradation, subsidies for oil and gas production, limits on liability for nuclear power plant operators, and many others.

When a renewable power plant runs, like conventional plants it creates electricity, but unlike them it also creates a *reduction* of pollution, waste, and risk. The "byproducts" are cleaner air and water, less waste, reduced fuel imports, and lower risk of catastrophic accidents. When customers buy electricity generated from renewable sources, they pay only for the power and society pays nothing. Renewable energy generators sell *cleaner power*, but are paid only for *power*.

With renewable energy credits, renewables companies will have a new product that represents the *clean*. That is, RECs represent all of the renewable energy benefits that electricity markets ignore, including environmental and energy security benefits. Table 3 outlines the "value" of a renewable energy credit, listing many of the benefits of renewable power that are "free" to society, because nobody is paying for them. But unless someone starts paying for them, many of these generators will go out of business and the benefits will be lost. By turning the value of renewable energy into a commodity traded separately from energy, RECs make that value clearly evident. The renewables premium is no longer hidden in the overall price of a renewable kilowatt hour.

TABLE 3

The "Value" of a Renewable Energy Credit

Consumers typically do not pay for these benefits of renewable energy generation. Renewable energy credits—whose cost all consumers will share—will embody these benefits.

- Less air pollution, water pollution, solid waste, radioactive waste, etc.
- Less exposure to fuel price swings and supply disruptions as a result of multiple fuel sources
- Local economic development
- Technology development benefits, including export potential
- Long-run national energy independence
- Steps toward a sustainable energy system
- A more robust transmission and distribution system as a result of distributed generation

Every unit of renewable energy generated and sold would create one renewable energy credit. A REC could take the form of a piece of paper, like a currency. It would list the number of kilowatt-hours, the year and state of origin, and the type of generation (solar, wind, etc.). Since renewable generation companies produce the power, they would be the original owners of RECs. Electricity providers could purchase these RECs to fulfill their compliance requirements. RECs could also be traded electronically, like stock.

The success of the sulfur dioxide emissions-trading program, instituted by the Clean Air Act, has shown that a systems of allowance and credit trading can be effective, easy to administer, and cheap. The sulfur-trading system works like this: every power generator must meet a certain cap on emissions of sulfur dioxide, a key source of acid rain. To meet the cap, generators can either invest in pollution-control devices (like scrubbers), buy cleaner coal, or buy credits from other generators. If they "overcomply" with the cap—that is, if they stay well under the cap, they can sell their extra credits to generators that would find meeting the cap too expensive.

The RPS applies the same logic to meeting the renewables content standard. A company on the windy Great Plains, for example, may find it easy to overcomply with the minimum renewables content by investing in wind turbines. It can then sell its extra RECs to companies that don't have as strong a renewable resource.

Appendix B provides further details about how an RPS might work, including information about participants, setting the standard, price caps for RECs, as well as how the RPS might interact with current laws and regulations, with public benefits funds, and with "green pricing" measures. Appendix C describes the RPS policies instituted or proposed by state and federal governments as of September 1998.

What the RPS would accomplish. The RPS is designed to ensure the sustained orderly development of renewable energy technologies.[10] Steady, predictable

growth will enable the industry to reduce costs by obtaining lower-cost financing, investing in research and development, and developing infrastructure—from new manufacturing plants to maintenance, repair, and marketing capacity.

The RPS will also reduce renewables prices by using market forces to create competition among renewables developers and providers to meet the standard at the lowest cost. Marketers would have a strong incentive to find the lowest-cost renewables in order to keep their prices down. The RPS will therefore enable those renewables that are most commercially ready—typically wind, biomass, or geothermal technologies—to become an integral part of the electricity market.

And the RPS minimizes administrative judgement in picking winners and losers among renewables developers and technologies. Instead, the market makes those decisions. The policy thus avoids substituting bureaucratic judgement for market discipline and minimizes political influence in determining commercial success or failure.

Public Benefits Funding

Another way of preserving the public benefits of renewable energy is to create a direct funding mechanism for renewables in the restructuring process. Public benefits funding can be provided from fees placed on electricity companies or customers. Such fees are sometimes referred to as "system benefit charges" and are analogous to funding mechanisms created during both long-distance telephone and airline deregulation. A fee on long-distance calls, for example, helps to preserve universal telephone service. A surcharge on all airline tickets helps support airport maintenance and air traffic control. The United Kingdom created a Non-Fossil Fuel Obligation (NFFO) levy to fund renewables when electricity was deregulated there in 1990.[11] Public benefits funding has been proposed to cover not only renewable energy, but energy efficiency programs, research and development, universal service, and other low-income protections.[12]

As of December 1998, seven states have adopted laws or regulations implementing public benefits funding for renewables. (See Appendix D for comparison among states.) Two states, Pennsylvania and New Mexico, have individual utility commitments, with a statewide regulation pending in New Mexico. Collectively, these states have committed approximately $1 billion over the next ten years. Based on extrapolation from California's experience, these funds are likely to leverage around $2 billion in private investment, and lead to the development of over 1,000 MW of new renewables capacity (Note: this figure does not include Connecticut or Massachusetts. For the sake of the analysis, new renewable generation in those states is attributed to their renewables portfolio standards. See previous section).

Such a direct funding mechanism has some unique advantages for preserving the public benefits of renewables. First, funds can be allocated where they are likely to be most effective. For example, they can be directed toward technologies that have great long-run potential, like solar photovoltaics, but that will not be immediately competitive even with other renewables. These technologies will have a difficult time competing for market share even with a Renewables Portfolio Standard. On a state level, funding can be targeted toward resources that provide special benefits to that state. For example, a state with excellent solar resources or with many photovoltaic manufacturing companies could target more of its funding to photovoltaics. A state with wind resources could use the fund for wind resource assessment, collaborative projects to identify and overcome obstacles to siting or permitting, or directly for wind project development.

Second, public benefits funding allows the level of the support for renewables to be precisely defined. Unlike tax credits, which may never be used if not structured appropriately, public benefits funding can assure a minimum level of market activity and renewables development. At the same time, the total cost of the program is limited by the funding levels provided.

Level of the Fund. Ideally, the level of public benefits funding should be set according to the specific objectives of the programs to be funded.

Thus far, states that have passed restructuring measures have generally set funding levels for public benefits programs at about the same level the utilities

had provided before restructuring. Some states have reduced funding for energy efficiency somewhat, but increased funding for renewables, on the assumption that the market would stimulate more efficiency investment, especially for commercial and industrial customers.[13]

Restructuring is an opportunity for optimizing the environmental performance of the electricity industry, however, not just an opportunity for preserving funding levels at an arbitrary or historical level. The funding levels adopted in Connecticut and Massachusetts are close to the level UCS had recommended, based on an analysis of commercialization needs for renewable technologies with potential for New England.[14]

Duration of the Fund. Stable, long-term funding levels are especially important for renewables, so that developers can secure long-term financing at favorable rates and manufacturers will consider investing in new plants. The market is likely to continue to ignore the environmental benefits of these technologies until pollution costs are internalized either through emission taxes or fees or through comprehensive pollution caps. Thus indefinite funding periods are warranted. Funding levels should be reviewed periodically based on ongoing evaluations of market barriers to the technologies.

As of September 1998, several states had established public benefits funds for renewables that did not include sunset provisions. Other states, however, set terms of three to five years for both renewables and energy efficiency funds.

Structure of the Charge. Most of the public benefits funds adopted and proposed at the state level charge distribution company customers a fee for each kilowatt-hour of electricity consumed. Such a distribution-related charge is both efficient and fair. The environmental, fuel diversity, and indirect economic benefits of public spending on renewables (and energy efficiency) are related to the energy usage of customers. Customers who use more energy are in effect responsible for causing more emissions, so it is reasonable for them to contribute more to developing and commercializing new clean technologies. Funding to support universal service in electricity and telecommunications has also generally been based on usage. Federal proposals for public benefits funds have also been based on usage, placing the charge on transmission sales, where federal regulators have jurisdiction. Illinois, however, has assessed funding by a flat monthly charge per customer (see Appendix D).

Administering Entity. States have generally chosen either state energy offices or economic development agencies to administer renewables funds. Where state energy agencies have been charged with this duty, they had significant renewable energy development programs prior to restructuring. Designation of economic development agencies to implement the funds reflects an intention to stimulate new renewables business development in those states. Where funds are used primarily for energy efficiency, distribution companies generally retain responsibility—with oversight by the utility commission—for fund administration.

Funding Strategies and Mechanisms. One of the advantages of public benefits funding is the variety and flexibility of options for structuring the funds. Funding can use market mechanisms, such as competitive bidding, or can rely on judgment to determine the most effective applications. Or these approaches can be combined.

One proposed market mechanism is the "auctioned renewables credit."[15] All renewables would bid against each other for financial support from the funding pool per kWh generated, with awards to the low bidders. Like the renewables portfolio standard, this approach would favor those technologies closest to competitiveness. Bidding could also be structured to ensure support for a variety of technologies or to ensure winners within designated technology categories.

California has classified technologies as belonging to one of three tiers based on their competitiveness and has set different levels of support for each tier. The Massachusetts trust fund was authorized by the state legislature to leverage private investment to create a larger pool of capital and to familiarize private investors with renewable energy. Appendix D provides more details about state public benefits funds adopted through 1998.

Many other funding mechanisms are possible. Table 4 illustrates possible applications of public benefit funds for renewables.

TABLE 4.

Possible Applications for Public Benefits Trust Funds

- Aggregate projects that are too small to attract commercial lenders in order to reduce transaction costs
- Provide low-cost financing or financing guarantees where financing is difficult to obtain
- Provide equity financing, grants, production incentives, or buydowns of a portion of a project's cost
- Build infrastructure and reduce development costs, such as siting studies for wind farms
- Develop uniform standards for siting, permitting, and connecting with the electricity grid
- Familiarizing potential customers with the benefits of renewable technologies
- Provide incentives, such as rebates or bill credits, to establish markets for new and unfamiliar products
- Directly fund installation, operation, and maintenance of renewable energy technologies

Funding could also be used to support renewable energy business development directly. (Indirectly, of course, any funding for renewables will provide some company support.) Funding for installation, operation, and maintenance of renewable energy technologies will generally bolster local businesses where the renewable energy is consumed. The Sacramento Municipal Utility District used a request for proposals to encourage establishment of a local facility to manufacture photovoltaic panels. Since the objective of any renewables support should be to create a self-sustaining industry, fund managers may also want to consider involving commercial financing institutions as partners.

State funds must be structured with federal opportunities and regulations in mind. Fund managers must be careful that state funding mechanisms do not prevent projects from also obtaining federal tax credits.[16] And funds must be structured so as not to run afoul of the US Constitution's Commerce Clause, as might happen if funds from a fee placed on electricity were to advantage in-state businesses over out-of-state competition.[17]

Net Metering

Electricity customers seeking to install renewable energy generators, like solar panels or small wind or hydro turbines, at their own buildings often face a daunting array of barriers. Some utilities have imposed expensive requirements for interconnecting with the utility grid, required separate meters for measuring the output of the renewables, and have paid little to buy back any surplus electricity generated in surplus of the customer's needs.

Under these conditions, installed systems would likely be sized not to exceed building electricity use, even when the sun or wind is at its peak. Thus, a building would be unable to use the renewable system for more than a small fraction of its overall electricity use, since there will be many hours when the sun won't be shining or the wind blowing. Fixed interconnection and metering costs would make such small systems expensive and less cost-effective.

One simple policy to overcome these barriers and encourage direct use of renewables is called "net metering" or "net billing." This policy allows customers who produce more electricity than they are using at a given moment to feed the surplus directly into the grid and run their single electricity meter backward. The customer is billed only for the net electricity consumed. In effect, the customer is trading surplus electricity to the utility at the same rate the customer buys electricity from the utility. In some cases, net billing is calculated over an entire year. Customers that produce more power than they consume over the billing period must usually sell the surplus power back to the utility at the wholesale market price.

With net billing, it makes sense to size the renewable system closer to the average use of the building. The overhead expenses of installing, reading, and billing for a separate meter are avoided. The renewable investment becomes much more cost-effective.

Net metering can mean some revenue loss for the utility. Individual renewables systems are still expensive enough, however, that they are not likely to be used by many customers and are unlikely to have much overall effect on utility revenues. An analysis of net metering in California found that the savings to the

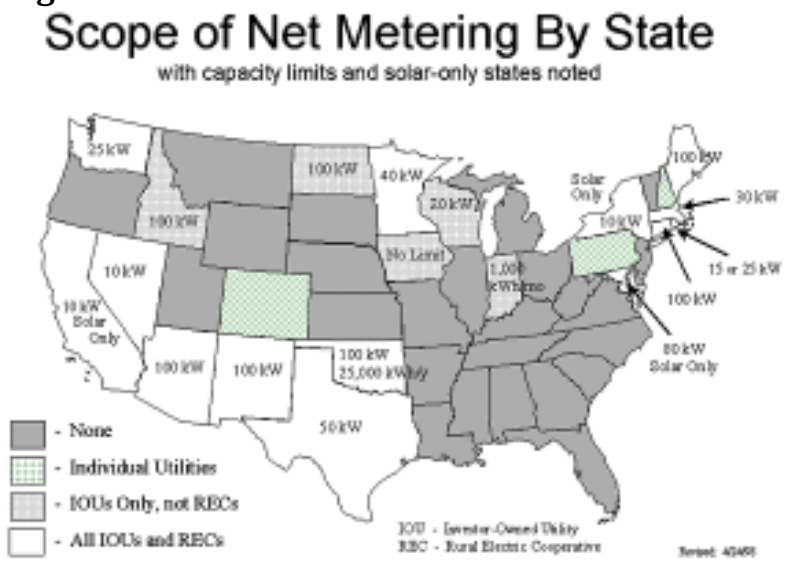
utility from avoiding the extra meter reading and billing would be about the same as the revenues lost from net metering.[18] Net billing can provide additional benefits to utilities, by encouraging distributed generation. (See section on Fair transmission and distribution rules.)

Concerns about revenue losses to utilities could be addressed by placing a cap on the number of eligible customers. In California, a limit of 0.1 percent of the peak electricity demand of each utility was deemed eligible for net metering. While this limit is small, it still allows for considerable expansion of the number of customer-owned renewable facilities. California, Maryland, Vermont, New Hampshire, Washington and New York adopted net metering during 1996–1998. Maine, Massachusetts, and Rhode Island reaffirmed their net-metering policies under restructuring regulations. Despite a challenge from its utilities, Maine broadened its net metering policy, moving to yearly averaging for net billing.[19] As of 1998, at least 21 states have allowed net metering by law or regulation. In two other states, utilities have voluntarily implemented net metering programs (See figure 14 and Appendix E).[20]

Many states adopted net metering as part of implementing federal PURPA standards. With repeal of PURPA under consideration at the federal level, inclusion of net metering under state legislation, enacted with or independent of restructuring, could put net metering on a more stable footing.

In October 1998, however, the Mid-American Energy Company, in Iowa, challenged that state's new net metering statute at the Federal Energy Regulatory Commission. The utility argued that net metering constitutes a forced purchase of electricity at a set price, a practice FERC has previously prohibited.[21] Environmental and renewable energy advocacy groups have intervened to defend net metering as sound policy falling squarely within state, rather than federal jurisdiction.

Figure 14.



Source: Yih-huei Wan and H. James Green, NREL , *Current Experience With Net Metering Programs*, WINDPOWER '98, *Bakersfield*, CA, April 27 - May 1.

Fair Transmission and Distribution Rules

Some have argued that a revolution in the way we make and move electricity is developing. New generation technologies—like fuel cells, photovoltaics, wind turbines and natural gas microturbines—are available in small modular units that can be sited in, on, and around buildings where power is used. Many "distributed" technologies also create waste heat that can be easily used on the spot for water and space heating, boosting their efficiency. These distributed technologies already offer an economical alternative to building large central station power plants and new power grids in remote areas that do not have transmission and distribution (T&D) systems. As the prices of the new technologies fall, they may completely reshape existing power networks as well. As discussed in Chapter 1, distributed generation technologies can provide substantial non-traditional benefits to utilities and their customers.[22]

Recognition of the added value that distributed technologies can provide can be critical for new technologies entering the market. UCS's 1995 Renewing Our Neighborhoods study looked at the Boston Edison service territory and compared the cost of upgrading the aging transmission and distribution system in certain neighborhoods with the cost of installing renewable technologies. Even though renewables tend to be

higher priced than central station power, UCS found that some renewable technologies may already be cost-effective in areas where particularly expensive transmission and distribution investments can be avoided.[23] Studies in other parts of the country have found similar results.

In a study of potential early markets for solar photovoltaics, the Utility Photovoltaic Group found that the potential US market for photovoltaics at a cost of $3 per watt is as high as 7,630 MW for distributed power applications, compared with 1,130 MW for the potential "green market" at this price.[24] Of course, photovoltaics is not likely to capture most or all of the potential distributed market. It must compete with other distributed technologies which can provide "distribution services." These include distributed electricity storage, such as batteries, and demand-side management technologies, such as energy efficiency investments, which can reduce demand in targeted regions or neighborhoods, extending the usefulness of existing distribution equipment.

Because many renewable energy technologies operate intermittently when the sun is shining or the wind blowing, there are added difficulties in valuing their output fairly. Traditionally, the reliability value of an electricity generator is based on the maximum output that can be turned on, or "dispatched," by the system operator, especially during periods of peak electricity demand. Because individual renewable generators may not be dispatched at will, and cannot be guaranteed to be available during peak times, they have frequently been assumed to have zero reliability value.

There is often, however, a relatively consistent relationship between the output of an intermittent renewable and the level of electricity demand over time. Solar output, for example, tends to be high on mid-afternoon on hot sunny days, which is often when air conditioning use is also high. Utilities have long used statistical methods to allocate costs to classes of customers based on a tendency to use electricity more during high-cost vs. low-cost periods. Similar methods can be used to allocate benefits to intermittent generators based on a tendency to produce electricity during high-value or low-value periods.

Few utilities have closely examined the reliability value of intermittent renewables for their systems. Fewer still have looked at the potential value of renewables in reducing peak demand on their distribution systems. Because the mix of customers and the times they use electricity may vary greatly from one neighborhood to another, the value of intermittent technologies in deferring or avoiding transmission or distribution expenditures may vary greatly from location to location.

In order to realize distributed technology benefits, however, electricity distribution companies must value distributed technologies fairly and be willing to invest in them or encourage their customers to invest in them when they can reduce system costs. Traditional cost-plus regulation has not necessarily encouraged least-cost distribution planning. Also, because methods to value distributed generation in planning distribution systems are new, few utilities have yet adopted them. Utilities are beginning to show greater interest in distributed resources, however.[25]

A restructured industry presents new opportunities and barriers for distributed generation.[26] A more competitive industry is likely lead to specific identification of cost centers and profit opportunities. Location-based transmission or distribution rates, which would be higher where there is congestion, could lead to generation being sited in areas where it has greater value. Independent companies that could profit from providing distributed generation services would have a strong incentive to seek out potential opportunities.

On the other hand, the separation of vertically-integrated utilities into separate functional units or separate companies providing generation, transmission, distribution, and retail marketing services may make it harder to identify the integrated value a distributed technology provides in each of these areas. It is uncertain which market players will have the resources and incentives to make the investments to avoid a combination of generation, transmission, and distribution costs faced by other market players. A transition to location-based distribution pricing, where separate distribution prices would be charged to different neighborhoods based on local costs, would raise significant equity

issues. Residents in a neighborhood with aging distribution facilities (who shared the cost, under regulation, of upgrading distribution facilities in other neighborhoods) may well resent seeing distribution price increases designed to induce local distributed generation.

And just as some utilities have avoided investing in new power plants that risked making existing power plants economically obsolete, some companies may resist distributed technologies that could compete with their existing transmission and distribution investments. In many cases, therefore, legislators or regulators may need to establish appropriate rules and incentives.

Many states that have shown some interest in these issues have been preoccupied with overall industry restructuring. There is therefore little experience to draw on at this time.

Connecticut and Massachusetts have addressed distributed technology issues in their restructuring processes. Connecticut's restructuring law requires "demand-side management" expenditures to be considered as alternatives to distribution expenditures. Demand-side management generally refers to technologies to reduce electricity demand, like energy efficiency investments, or to methods that shift demand from one period to another. Distributed generation technologies installed in customer buildings also reduce the system demand for electricity, however, and could be included in regulations developed to implement the Connecticut law.

In Massachusetts, the Department of Telecommunications and Energy has stated that distributed generation will be considered as part of performance-based ratemaking proceedings. This policy, as an alternative to cost-of-service regulation, seeks to induce utilities to reduce costs and improve performance by linking incentives to specific performance measures.

Performance-based ratemaking in Massachusetts and elsewhere has generally been implemented with a price cap. Under a price cap per kilowatt hour, distribution companies have an incentive to sell more kilowatt hours to increase total revenues. Price caps provide disincentives to reduce sales through distributed generation or energy efficiency investments. In contrast, under a revenue cap, total company revenues are fixed, and a company does not lose revenues from distributed technology investments. Prices are adjusted periodically to make up for any unanticipated revenue shortfalls or surpluses. Therefore, a company does not lose revenues or profits if it encourages reduced electricity demand through energy efficiency or distributed generation. Oregon has adopted a revenue cap.[27]

In California, environmental organizations and renewables companies have petitioned the Public Utilities Commission to establish distributed generation regulations. As of November 1998, however, no formal action on the petition had been taken.

One way of ensuring appropriate investment in distributed technologies would be to require regulatory review of transmission and distribution planning decisions. Such planning reviews would be analogous to "Integrated Resource Planning" (IRP) for generation, extended to the distribution planning level. Investments in the distribution system would be reviewed to ensure they have invested in the mix of demand-side and supply side options that provide electricity at the lowest cost.) While there has been a trend to reduce IRP regulatory review in favor of increasing competition in generation, it may be appropriate to retain it for regulated transmission and distribution companies.

Distribution IRP would be somewhat more complex than generation IRP. Generally, however, companies will be planning major transmission or distribution investments in only a few areas at any given time, thus limiting the complexity of the review. One potential model for distribution-level IRP has been developed for the Boston Edison Demand-Side Management Settlement Board.[28]

One way to insert distributed generation into the planning process would be to require distribution companies to competitive bids for distribution services where new investment is required. Distributed technology providers could then compete against traditional equipment upgrades. Another approach would be for the system owner to offer incentives for distributed generation in specific parts of the system that are weak or overtaxed.

One important issue likely to affect utility activities in distributed technology is whether they can own

distributed generation.[29] Distribution company ownership of these technologies raises antitrust and anticompetitive concerns. There has been some concern that allowing utility ownership could undermine the development of distributed generation by seeking to be monopoly providers of distributed generation technologies. On the other hand, allowing ownership of distributed generation provides them with an incentive to become active in this area. Massachusetts has explicitly allowed distribution companies to own distributed generation.

Transmission Rules. Renewable energy generators' unique characteristics pose challenges to designing fair transmission rules and prices. Renewables generators must be located where the natural resources are, and sometimes must be transmitted long distances. The intermittent output and low capacity factor of some renewables creates operational issues for the transmission grid (i.e., having backup capacity if the wind suddenly stops blowing) and pricing issues similar to those covered above with distributed generation.

In 1996, the Federal Energy Regulatory Commission (FERC) Order 888 required utilities to make transmission available to all generators and customers.[30] FERC has also encouraged the formation of Independent System Operators (ISOs), groups of multiple stakeholders to control the operation of the transmission network. These developments should increase renewables generators' access to customers. It should also reduce multiple transmission charges, known as "pancaking," when power is transmitted across more than one utility system and each utility exacts a toll.

Transmission service is typically specified as firm or nonfirm, with nonfirm service more interruptible in cases of transmission constraints. FERC did not specify how transmission prices should be set, but proposed that all firm transmission service be based on reservations of transmission capacity made at least one day in advance. Generators would pay for reserved transmission whether or not they used it. They would be subject to penalties if they exceeded or fell short of their reservation by more than 1.5 percent.[31]

This requirement would heavily penalize intermittent generators like wind and solar, where it is hard to predict output accurately a day in advance. If it turns out to be windier than predicted, and not enough transmission capacity is reserved, the wind generator could be unable to sell all the electricity generated. If it were less windy than expected, the generator would be stuck paying for unused transmission. Ideally, generators would be able to resell reserved transmission capacity that they could not use, but this secondary market has not really developed. Renewables generators would have to resell transmission capacity at the last minute, making it unlikely they would get a good price, and transaction costs would be high. Renewables generators could, however, bundle their output together with power sources that can be turned on and off as needed, such as gas turbines. But requiring such bundling would reduce generator and marketer flexibility and might raise total costs. [32]

Generators could also buy non-firm transmission service without a reservation. However, buyers of non-firm service can have their transmission interrupted if the lines get congested. And lenders may charge higher financing costs if renewables generators do not have firm transmission contracts.[33]

The formation of ISOs, with multiple stakeholders, has created pressure for more flexibility and options in transmission service, which may benefit renewables. ISOs that include power exchanges—spot markets for electricity sales—plan to charge spot market prices for transmission that is higher or lower than scheduled amounts, for example. California is currently operating in this manner.

However, as of the end of 1998, most ISOs are still in the process of formation, with their makeup, governance, rules and pricing still under development. The ISOs in formation generally do not include power exchanges.[34]

Some early ISO proposals have some negative implications for renewables. A Southwest proposal would require generators who want nonfirm transmission service to have backup reserve capacity. A New England ISO proposal would impose "nonusage" charges for both firm and non-firm transmission services.[35]

Another transmission issue affecting renewables is the pricing of "ancillary services" needed to maintain system reliability, such as reserve generating capacity

to compensate for plant outages. The wind industry has supported continued cost-based regulation of these services by FERC, although some analysts suggest that market-pricing may provide more flexible services for renewables.[36]

Some ISOs have proposed "postage stamp" rates—one price for transmitting power from anywhere within a region to any other point within the region. Others have proposed "megawatt mile" charges that vary with distance. Congestion charge proposals also vary. The impact of these proposals will vary with specific renewables projects. Generally, transmission costs do not increase linearly with distance, so loading all transmission charges onto a megawatt mile may not treat remote projects fairly. Having many small "postal zones" could have a similar or worse effect, however.

An analysis by the Lawrence Berkeley Laboratory (LBL) shows charging for unused transmission capacity can raise the cost of the entire electricity system. LBL developed a two-tier pricing system, which bases transmission access charges on energy transmitted and congestion charges on capacity reservations. The access charges would be used to cover fixed costs—80 to 90 percent of network costs. LBL shows that this pricing scheme would lead to a least-cost technology mix, as well as reducing the penalty for intermittent renewables, without creating a special condition for them.[37]

Fair Pollution Rules

One of the main goals of utility restructuring is to increase competition in electricity generation. With increasing competition, investment decisions will be guided by market forces. Investors will bear risks they were often insulated from under regulation, such as investing in generation that turns out to be unneeded or uneconomical.[38]

To an extent, investors will bear added environmental risks in a more competitive industry. With evolving environmental regulations, investors in a polluting technology must assume the risk that newly requirements for cleaning up emissions could make their plant less competitive in the future.

There are two major reasons, however, that market forces will still lead to investment decisions that are uneconomic and that harm the environment. First, as discussed in Chapter 1, damage from pollution produces external costs to society at large rather than directly to the investors in the polluting plant or the consumers who buy electricity from the plant. Neither investors nor consumers have the incentive to make decisions that would mean the lowest total costs for everyone, and overall economic efficiency will not be achieved unless policies are implemented to recognize the "externalities."

Second, under current environmental regulations, some plants are allowed to emit more pollutants than other plants. Plants that are allowed to emit more pollutants will have lower costs for pollution controls or for mitigation, so they can operate less expensively than plants facing tougher pollution limits. To the extent that some of these cheaper, dirtier plants are not used to their full capacity before markets open up, they could sell more electricity and increase total pollution.

Under the Clean Air Act of 1970, existing power plants were exempted from meeting emission requirements placed on new power plants. The "grandfathering" exemption was continued in the Clean Air Act Amendments of 1977 and 1990. The main reasons for exempting older plants appear to have been that installing pollution controls would be more expensive for older plants and the belief that existing plants were likely to be retired and replaced by newer, cleaner plants over time.[39]

Instead, most older coal plants have continued to operate. New "life-extension" technologies allowed older fossil plants to continue operating at a lower cost than building new plants. Now fully a quarter of the nation's fleet of fossil and nuclear plants are more than 30 years old, with some coal plants dating back more than 50 years.[40]

The correlation between age and emissions is not perfect—there is, with a number of old plants polluting less than some newer plants. But some older coal plants emit up to five times as much sulfur dioxide (SO_2) as any post-1975 plant, for example. On average, coal plants built before 1976 emitted more than twice as much SO_2 and almost twice as much nitrogen oxides (NO_x) as newer plants in 1996.[41]

The disparity in emissions leads to distortion in the electricity market price. According to an analysis by Synapse Energy Economics, if older plants had to clean up emissions of SO_2 and NO_x to the level typically required of new plants, the average cost of operating and maintaining the existing coal plants would increase by nearly 1 cent per kWh, from 2.1¢ per kWh to almost 3¢ per kWh. The total added costs for emission controls on each plant would by $9.2 billion per year, although market mechanisms such as fuel switching, improving efficiency, or allowance trading could reduce these costs. Total emissions of both NO_x and SO_2 would be reduced by about 75 percent.[42]

Under this scenario, about 6 percent of coal-fired generation would become uneconomical compared with natural gas generation.[43] There would be little effect on CO_2 emissions, because most of the emission reductions would come from pollution controls instead of switching to cleaner fuels. Under a scenario that also includes a tax of $10 per ton of carbon dioxide (CO_2), however, almost a third of current coal generation would be unable to compete with new natural gas plants, unless the coal plants could reduce costs or improve efficiency.[44]

The carbon tax scenario illustrates the benefit of reducing multiple pollutants simultaneously, instead of one after the other. If no consideration is given to carbon reductions along with SO_2 and NO_x reductions, billions of dollars could be invested installing pollution controls on coal plants that could become uneconomical if subsequent reductions in carbon emissions are required. If limits on CO_2 were are put in place along with SO_2 and NO_x reductions, then an integrated emissions reduction strategy could take advantage of opportunities for replacement by cleaner generating sources—achieving total emissions reductions at lower cost.

The 1 cent per kWh disparity in costs between the average operating costs of older coal plants and what it would cost to meet emission standards for new plants underlies the danger that deregulating electricity generation could lead to greater overall emissions. Utilities or customers could seek to buy power from cheaper, dirtier plants within a region or from outside it.

An analysis by the Federal Energy Regulatory Commission concluded that open electricity markets would not significantly increase pollution. FERC therefore declined to require environmental mitigation in its Order 888 opening up wholesale markets. The FERC analysis did find, however, that under some conditions, pollution from midwest plants could increase by more than 30 percent by 2010, an increase greater than all the pollution currently emitted by northeast plants but FERC attributed most of the added emissions to increasing competition and sales that would occur even without Order 888.[45]

FERC's analysis was criticized as underestimating potential pollution increases by environmental groups, northeast environmental regulators and governors, and the US EPA. Perhaps most importantly, even in its worst case, FERC assumed that transmission constraints would greatly limit exports of coal generation from the Midwest. Increasing market activity could lead to investments in improving transmission efficiency or increasing capacity however. A preliminary analysis by Northeast environmental regulators found that net power exports in 1996 from one large Midwest utility exceeded FERC's high-case projection for the entire Midwest for year 2000, and that generation increased at a number of high-polluting Midwest coal plants. [46]

The EPA took important steps in 1997 and 1998 to tighten emission regulations which should reduce emission disparities. They revised standards for ozone and particulates and established NO_x "budgets" for 22 midwestern and eastern states assumed to contribute most to polluting downwind neighbors, requiring all plants to average meeting "new source" standards during the peak ozone season. These measures are not expected to eliminate the disparities and will not take effect until after 2003 for the NO_x budgets, and even later for the new ozone and particulate standards.

Several mechanisms have been proposed to further reduce or eliminate these inequities in allowed pollution levels:

- emission performance standards
- cap and trade regulations
- emission taxes and fees

Emission Performance Standards. There are several variations of proposals to establish comparable emission standards for all electric generators, eliminating the disparities between plants of different ages or in different locations. Uniform standards could be applied to the average of all plants owned or controlled by a company, or to each plant or boiler individually. In certain respects, application to each boiler or plant would be simplest and, importantly, would provide emission reductions to all communities near power plants. But this approach would also be less flexible and more expensive than allowing averaging or trading among plants, and states could probably not be apply their standards to out-of-state plants. Applying standards to individual fossil plants or boilers would also not create incentives for companies to reduce emissions by incorporating more renewables into their mix.

Connecticut and Massachusetts, in their restructuring laws, both adopted emission performance standards for the generation portfolios of retail suppliers serving customers in those states. These laws apply to the overall mix of power plants, including imports from outside the region.

The Massachusetts law requires the Department of Environmental Protection to study emission performance standards for all harmful pollutants, with standards for at least one pollutant to be in place no later than 2003. If another state adopts standards before 2003, Massachusetts may emulate those.

Connecticut required its Department of Environmental Protection to establish standards by the end of 1998 for sulfur dioxide, nitrogen oxides, carbon dioxide, carbon monoxide, and mercury. However, the standards are not to go into effect until three northeast states with a population of at least 27 million people (i.e., Connecticut, Massachusetts, and New York) have adopted the same standards.

A Vermont bill, which has passed the state senate, would establish portfolio requirements for all significant environmental impacts.

Because they are applied to retail supplier portfolios, emission performance standards are similar to renewables portfolio standards. Additional incentives can be created for renewables, and potentially for energy efficiency investments, by allowing suppliers to include those resources in their portfolios as a means of lowering overall portfolio emissions.

Cap and Trade. Emission caps are limits on the total amount of emissions of a particular pollutant in a region or nationally. The Clean Air Act Amendments of 1990 created a national cap for utility sulfur dioxide emissions of 6.3 million tons per year (about half of 1980 levels), covering 110 of the largest sulfur dioxide emitters. In the year 2000, Phase 2 of the amendment will expand the program to hundreds of smaller fossil fuel plants and change the cap to 8.95 millions tons per year. The EPA is also considering another reduction in the cap in the year 2010.[47]

To meet the caps, utilities can trade emission allowances or credits. Allowances are permits that allow an electric generator to release an air pollutant. If a utility overcomplies with emission limits, it will have excess credits that it can sell to other polluters, providing an incentive for companies to reduce emissions below mandated levels.

Currently, a national market for tradable permits is in place for sulfur dioxide emissions. Thirteen states have trading mechanisms for volatile organic compounds or NO_x credits, and the EPA has encouraged the 37 easternmost states (known as the Ozone Transport Assessment Group or OTAG) to establish a cap and trading system for NO_x.

Regional "cap-and-trade" programs could be implemented through the new entities that control utility transmission systems, called independent system operators or ISOs. Richard Cowart, chair of the Vermont Public Service Board, has proposed that any generator that wants to sell power in a region would have to earn or buy enough emission allowances to gain access to the transmission system. [48, 49] Generators with high emissions would have to buy credits from those with lower or no emissions. Those with low emissions would earn credits, gaining access for low or no cost. The ISO would dispatch generators so as to avoid exceeding a regional emissions cap.

Cap-and-trade programs can be very economically efficient. The national SO_2 allowance trading system has been widely credited with producing emissions

reductions at a cost far lower than almost anyone anticipated.[50] Cap and trade programs are good solutions when they can be implemented over a geographic area affected by specific emissions. For CO_2, which affects warming over the entire globe, an international cap and trading program is appropriate. But for emissions with localized impacts, such as toxic metals, trading programs could produce heavily impacted local areas. Trading programs cannot be easily applied by a state to out-of-state sources.

Cap-and-trade programs require a fair means for allocating allowances among generators. The national SO_2 trading system has been criticized for awarding allowances based on historical emissions, rewarding high emitters and penalizing low emitters and new market entrants, which receive no allowances and must buy them from the market. Also, apart from a pool of 300,000 bonus allowances created for energy efficiency and renewables, these resources do not create additional credits or allowances for independent developers. Renewables generators receive no direct benefit for their potential emission reductions. [51] The reduction in fossil generation from the added renewables could allow fossil generators to save allowances to pollute more in the future, or even to increase their pollution rate, say, by burning a cheaper, higher sulfur fuel, while still leaving total emissions within the cap.

In early 1998, the EPA proposed NO_x trading in the OTAG region using a "fuel-neutral" approach, in which allowances would be awarded to kilowatt hours generated by any source. While such an approach would earn credits for renewables, it would also reward nuclear generators. Many environmental organizations objected to nuclear generation, with its unique environmental impacts and risks, being allowed to earn the same credits as renewables and being provided with a substantial cash windfall. The EPA subsequently dropped the proposal.

One solution would be to award credits only to fossil generators and to efficiency and renewables. Another might be to award credits to new non-fossil generation, to avoid providing windfalls to existing sources, but stimulate the development of new projects. This approach could, however, lead to a reduction of existing renewables generation. Auctions of allowances or other allocation schemes are other potential approaches.

On the federal level, cap and trade provisions for SO_2, NO_x and CO_2 were included in the restructuring bill filed by Sen. James Jeffords (R-VT). Rep. Frank Pallone (D-NJ) has introduced a bill with caps on SO_2 and NO_x. Rep. Dennis Kucinich (D-OH) would also cap CO_2, mercury, and nuclear waste. A bill sponsored by Rep. Edward Markey (D-MA) would direct the Administration to issue a rule preventing any competitive advantage from grandfathered emission standards. The Administration bill clarifies the existing authority of EPA to create a cap-and-trade program for NO_x.

Emission Taxes or Fees. A third approach to reducing emissions and emission disparities would be to assess a tax or fee per ton of pollutant emitted. Emission taxes are generally the preferred approach of economists and many environmental organizations for internalizing pollution costs efficiently.[52] They allow producers complete flexibility in whether and how to reduce costs. They require producers of the unwanted pollution to consider the risk of increases in pollution taxes if more stringent environmental goals are needed in the future. Conversely, mechanisms that provide special benefits to clean energy producers generally lead those producers to consider the risk that those benefits will be reduced or eliminated in a changing political climate.

One revenue-neutral method proposed for eliminating the disparity between old and new plants would be to assess emissions from existing sources sufficient to compensate owners of new power plants for their higher costs of meeting the more stringent new source standards. This method might not, however, actually lead to desired emission reductions in old sources.[53]

While sometimes favored in other countries, emission fees or taxes have proven difficult to implement in practice in the United States, at least on air emissions.[54] Proposals for pollution taxes have been introduced in state legislatures in Minnesota, Vermont, and Wisconsin.[55]

Customer Information

In survey after survey, people say they would prefer to receive electricity generated by clean and renewable energy technologies, and are willing to pay more for it (see figure 15).[56] Thus allowing customers to choose their electricity suppliers will provide new opportunities for renewable energy technologies. But for those opportunities to be realized, customers will need reliable information.

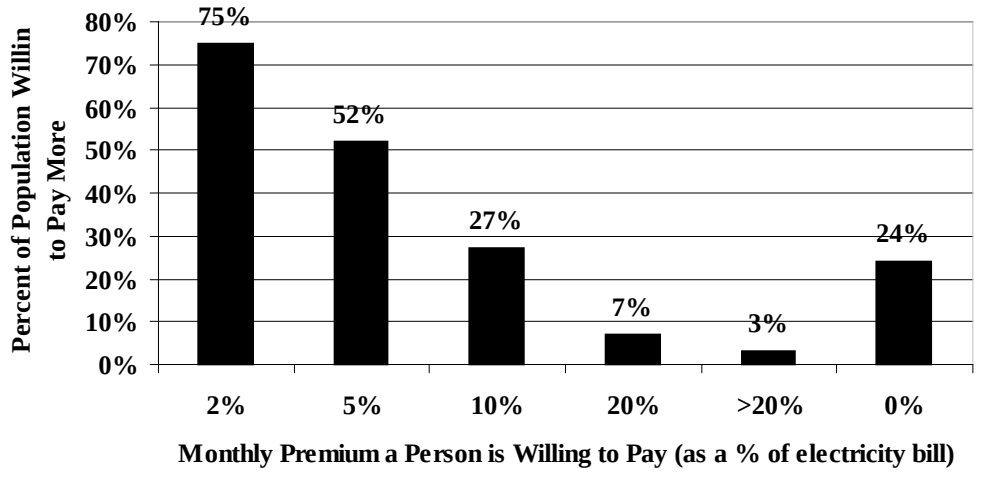
A primary barrier for any new technology entering the marketplace is consumers' unfamiliarity with it. Renewables in a competitive market face a triple barrier. First, customers do not know what sources are used today to generate their electricity, and what their environmental impacts are. Second, many customers are unfamiliar with renewable energy technologies, and may have misleading impressions of their performance. Third, customers are unaccustomed to any choice of electricity suppliers, and will be unfamiliar with many of the companies offering new energy choices in the marketplace.

Disclosure Label. Customers are not well-informed about how their electricity is generated. People generally overestimate how much of their electricity comes from renewable sources and underestimate how much comes from polluting fossil fuel and nuclear sources.[57]

To make sure that customers have the information they need to compare electricity products, the National Association of Regulatory Commissioners and others recommend that electricity suppliers be required to label their products.[58] These "disclosure" labels would be analogous to the label providing uniform information about the nutritional content of food products. Research for the National Council on Competition in the Electricity Industry found that—to make effective choices—consumers want and need labels showing standardized information about price, fuel mix, and emissions, similar to the labels for ingredients in food.[59]

The New Hampshire retail choice pilot program, which did have disclosure requirements, illustrated the importance of providing uniform information on the environmental characteristics of energy choices. Suppliers made a wide variety of confusing environmental claims, some of which were misleading. For example, one company touted electricity from its clean hydropower plant. It did not disclose that the plant was a pumped storage facility, at which coal and nuclear energy are used to pump water into a storage reservoir during the night.[60]

Figure 15. People Willing to Pay More for "Green" Electricity



Source: Sustainable Energy Coalition, Washington, DC.

Disclosure labels must be uniform, simple and easy to understand. Figure 16 shows a format for the label developed by the Regulatory Assistance Project, based on considerable research on consumer preferences and the effectiveness of various formats in helping customers pick the products that best reflects their preferences.

In order to be effective, disclosure rules need to have a practical mechanism for tracking generation sales and

purchases. They need not (and physically cannot) track electrons from generators to homes: electrons flowing in the transmission grid cannot be distinguished from one another. But they can determine that purchases by customers pay for certain kinds of generators to operate and deliver electricity to the grid. At least two kinds of workable tracking mechanisms have been proposed. One mechanism would use the same data that electric companies use to settle their own financial accounts and could be implemented by the Independent System Operators controlling the transmission grid. Another mechanism would use tags issued to identify the source of generation. The tags could then be traded independently of kilowatt hours (like renewable energy credits). The price of different kinds of tags would be determined by the market value of the generation characteristics (fuel source and emissions) represented by the tags.

The design of potential disclosure mechanisms can have major implications for renewables:

- The rules must allow disclosure of the content of different electricity products, rather than just the overall generation mix of a company, to encourage companies to enter the green market with new products. Annual reporting for overall company generation can then provide useful supplementary information to consumers.
- In order to be effective for intermittent renewables, disclosure should allow averaging of generation over a period of time. A solar generator could then receive credit for surplus sales during peak sunny hours to offset lack of output at night. Similarly, some averaging over monthly, seasonal, or even annual periods, will allow wind and hydro generators to sell more of their generation to green customers. Without such averaging, surplus green generation could have be dumped into the pool during peak generation periods.
- A mechanism to track sales to power pools or exchanges is needed to allow generators and marketers to be credited for the renewables fraction of sales to the power pool and enable them to earn a premium on a greater proportion of their total output and facilitate green marketing.[61] The New York Public Service Commission staff has designed a mechanism for attributing green generation delivered to the pool.
- Marketers prefer that disclosure be prospective, to indicate the content of electricity products customers will receive after they make their purchase decisions, as California has done. New England and Illinois regulators, however, have preferred retrospective disclosure, to ensure greater accuracy and accountability.[62]

The Edison Electric Institute has proposed that suppliers be allowed to disclose average fuel mix of the regional system, rather than their specific purchases and sales.[63] This proposal would limit the tracking needed to disclose the content of products claiming an environmental benefit. However, it would allow companies to "greenwash" especially dirty fuel mixes, by "coloring" them with the regional average mix. Using a regional default label would also prevent one tracking mechanism being used both for emissions disclosure and for verifying compliance with emission portfolio standards.

Many states are considering disclosure requirements at the legislative or regulatory level.[64] California and Maine laws currently require that fuel sources be disclosed on a customer label. Massachusetts, Illinois, and Connecticut require disclosure of fuel mix and air emissions, along with other standardized information.[65] The six New England state utility commissions have tentatively agreed on uniform regulations for the region. The administration's federal restructuring bill includes mandatory disclosure of prices, fuels, and emissions.

Education Programs. Providing information about the content of electricity supplies is a critical first step in informing customers about their choices. But many customers will be unfamiliar with the environmental and health impacts of the fuel sources and emissions identified on a label.

The Oregon voluntary disclosure label includes such information. Consumer research shows that keeping the label uncluttered, however, is important for consumers to use it. One solution, adopted by

Figure 16. Disclosure Label

Electricity Facts

Generation Price

Average price (cents per kWh) for varying levels of use. Prices do not include regulated charges for delivery service.

Average Monthly Use	250 kWh	500 kWh	1000 kWh	2000 kWh
Average Generation Price	5¢	4.5¢	4¢	3.5¢

Your average price will vary according to when and how much electricity you use. See your most recent bill for your monthly use and Terms of Service on your bill for the actual prices.

Contract

See your contractor Terms of Service for more information

- Minimum Length: 2 Years
- Price Changes: Fixed over contract period

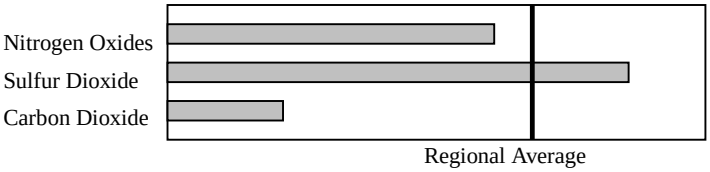
Supply Mix

We used these sources of electricity to supply this product from 6/96 to 5/97

Coal	30%
Natural Gas	20%
Nuclear	15%
Hydro	10%
Solar, Wind, Biomass	20%
Waste Incineration	5%
Total	100%

Air Emissions

Nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2) emissions relative to regional average.



Source: Center for Clean Air Policy, Disclosure in the Electricity Marketplace: A Policy Handbook for the States, March 1998.

Massachusetts regulators, is to require that brief summaries of environmental and health impacts be included on the back of the content label.

Environmental organizations are likely to be a source of such information in regions where electricity choice is enacted. These organizations will rarely have the resources, however, to provide the information to all customers seeking to make informed choices.

The Pace University Energy Project is developing a method–ology for ranking the environmental quality of products available in the electricity marketplace on behalf of the "Green Group," a coalition of national environmental organizations that in–cludes the Union of Concerned Scientists. The methodology and results are expected to be published on the PACE web site.[66]

Certification. Another approach to providing important in–formation to customers is certification. A logo provides an easily recognizable symbol to customers that an independent party has determined that certified products are environmentally superior choices.

The nonprofit Center for Resource Solutions offers a "Green-e" logo (figure 19) to products that an annual audit certifies obtain at least half of their generation from renewable resources.[67] The other half must be at least as clean as the system average. Marketers also agree to abide by a code of conduct including requiring disclosure of the fuel sources of all products, and no double-selling of renewables.[68]

As of October 1998, ten retail products and five wholesale products had been certified in the California market.[69] Many of the products initially introduced go beyond the minimum requirement of 50 percent renewables content, with several 100 percent renewables products available. The Green-e certification program was launched in Pennsylvania in June 1998, with four products from two companies certified by September.[70] Marketers and environmental groups in New England are discussing introducing Green-e certification in that region in 1999.

Some environmental groups have criticized most initial green electricity products marketed in California for not producing incremental environmental improvement.[71] Beginning in the year 2000 in California and Pennsylvania, all Green-e

Figure 17. Green-e Logo

Source: Center for Resource Solutions

products will have to include an increasing percentage of electricity from new renewable energy projects built after 1997, to ensure that Green-e products lead to development of new renewables. Five of the ten retail products available in California in October 1998 claimed to support new renewables projects. Certified products will also have to meet the new renewables standard one year after Green-e is introduced in any new regions beyond California and Pennsylvania.

Other organizations are looking to certify individual generators or to develop broader assessments of the environmental quality of electricity products. Scientific Certification Systems has developed a protocol for certifying generators as having low environmental impacts based on an evaluation of life-cycle impacts, from fuel extraction and processing through waste disposal.[72]

States have also considered certification. California certifies renewable generation facilities, but not products in the market. Early versions of Massachusetts restructuring bills included provisions for state certification of green products. These provisions were abandoned when not supported by marketers or environmental groups, because of the difficulty of coming up with appropriate standards in a legislative context and a preference for private certification efforts. A Delaware coalition has proposed state certification of green products.

Information about Renewables and Customer Choice. Some states have also included provisions in their restructuring laws or in accompanying bills for broader customer education about renewable energy.

The California public benefits fund has $5 million per year allocated to customer education about renewables. The statutes creating the renewables funds in Massachusetts and Connecticut enable the funds to be used, in part, to increase customer knowledge and expertise on renewables.

These state laws also included funding for general customer education on retail choice. These programs have been somewhat controversial to date. Special care must be taken to ensure that such programs are unbiased, timely, and well thought out. California set up an $87 million public education campaign administered by the California Energy Commission, but with a governing board consisting entirely of utilities. The program has been criticized for discouraging customers to leave their existing electricity suppliers. In Massachusetts, a television advertising campaign produced by the state Division of Energy Resources, without participation by stakeholders, began long before suppliers were ready to offer choices to residential customers. The ads, which portrayed consumers celebrating the arrival of choice by conspicuously wasting electricity, were severely criticized by consumer groups. Jurisdictions where restructuring measures have not yet been enacted have the opportunity to consider what educational approaches might prove most effective and least biased. Participation by a broad cross-section of stakeholder groups, including independent generators, marketers, consumers, and environmental organizations, should help make education efforts credible.

Putting Green Customer Demand to Work

The willingness of many electricity customers to pay more for renewable energy supplies can be tapped within any market structure. The term "green-pricing" has been used to describe programs run by regulated utilities that allow customers to contribute to the development of renewable energy projects. "Green marketing" is generally used to describe offerings by competitive suppliers in a retail competition environment.[73]

As of June 1998, there were approximately 40 utility green-pricing programs around the country, using a number of different models. The majority of programs charge a higher price per kilowatt hour to support an increased percentage of renewables or to buy discrete kilowatt-hour blocks of renewables. Other programs have fixed monthly fees, round up customer bills, charge for units of renewable capacity, or offer renewables systems for lease or purchase. Average market penetration for these programs was about one percent, with approximately 45,000 customers participating nationally, expected to lead to new renewables capacity of about 45–50 MW.[74]

Green-pricing results have varied widely, however, ranging as high as three percent. Among the important

variables influencing success are specifics of program design, the extent and quality of market research, the credibility of the utility, the simplicity of the program, the tangibility and visibility of the renewables projects, and marketing efforts, particularly with community organization partnerships.[75]

Texas has approved a green pricing rule, setting standards for eligible renewables, green pricing premiums and limits on administrative and marketing costs.[76]

Many environmental groups have actively supported green marketing. The Natural Resources Defense Council, Environmental Defense Fund, Center for Energy Efficient and Renewable Technologies and Union of Concerned Scientists all have web sites encouraging customers to choose renewable options.[77]

Green marketing has begun to develop in California and Pennsylvania. Marketers in California have cited a number of requirements for a successful retail market which are not fully established. Electricity suppliers will need access to information about existing customers and will need to be able to do metering and billing. Standard methods for switching customer accounts easily will also be needed. Marketers have complained that it has been difficult and time-consuming to switch customer accounts in the early stages of the California market.[78]

Most importantly, marketers have had a difficult time competing with artificially low generation prices offered by incumbent utilities. In California, customers who want to switch suppliers receive a credit on the bills from their utilities equal only to the *wholesale* electricity generation rate. They are free to shop for any competitive supplier who can compete against the wholesale generation rate.

But competitive suppliers must not only buy wholesale generation to resell to their customers, they must also incur marketing and overhead costs. Marketing costs to persuade customers to switch suppliers in California have exceeded $100 per customer.[79]

Utilities do not have to advertise to keep most of their existing customers. And their overhead costs—office space, equipment, telephones, customer service, etc.—continue to be paid by all customers, because even those who switch suppliers do not get any credit on their utility bills for these costs.

As a result of these unfavorable conditions, Enron, a large diversified energy company headquartered in Texas, gave up trying to compete in the California residential market only after a few months. There is little competition in California to offer residential customers lower prices than they can get staying with their utility. Ironically, about the only way marketers can compete is to offer a different kind of product—like a green product—but the cost disadvantage faced by marketers has limited competition for green customers as well.

In Massachusetts and Rhode Island, the initial competitive environment has been even worse than in California. All customers who stay with their existing utility are guaranteed a "standard offer" generation price. The standard offer starts at 2.8¢/kWh, and increases over time. But the wholesale market price in New England has been about 3.5 to 4¢/kWh. Utilities that lose money by having to sell generation at standard offer prices which are below-market are allowed to recover those losses with interest after seven years, thus subsidizing the standard offer. Not surprisingly, during the first year competition has been allowed, no companies have stepped forward to try to compete against the residential standard offer. One company, AllEnergy, a subsidiary of New England Electric, is offering a hybrid service, where standard offer customers of any utility an option to "upgrade" their service by buying blocks of renewables generation, but with limited success to date.

A solution adopted in Pennsylvania is to have the credit on utility bills for customers switching suppliers not only reflect the wholesale generation price, but retail costs that the distribution company is no longer incurring on the customer's behalf. Customers choosing to switch suppliers receive a "shopping credit" intended to cover not only generation costs, but supplier overhead and marketing. The shopping credit varies by company, and is as high as 5.2¢/kWh for customers in the Philadelphia area. As a result, customer response to early offers has been very high. One green marketer recently reported having signed up as many customers in 6–7 weeks in Pennsylvania as they have in 6–7 months in California.[80]

Another partial solution would be to require competitive bidding to serve the standard offer. Marketing and overhead costs to serve the standard offer customers would be low, and companies would be likely to include those costs in their bids.[81] However, this approach would still not create a robust market with many companies competing to provide new products and services to residential customers.

Another approach might be to require utilities to divest of their customers, requiring all customers to choose a competitive supplier. Customers who did not choose would be assigned to a competitive supplier at random.

Aggregation. Customer aggregation is another mechanism for creating a more competitive market in a way that can benefit both the environment and consumers. An aggregator organizes customers into a buying group, thus giving the buying group more bargaining clout and greatly reducing transaction costs for marketers. By combining customers who use electricity at different times of the day and week, and smoothing out sharp peaks or valleys in electricity demand, aggregators can also make it easier and less expensive for marketers to serve groups of customers.[82] Aggregation may be especially important in new markets, where choice is unfamiliar, there is great inertia in the market, and the costs of persuading customers to make any choices can be quite high.

Several different aggregation models are being developed and implemented. In California, state universities have aggregated their demand and negotiated a contract with one supplier. Water agencies throughout the state also formed an aggregation group.[83]

In Colorado, an environmental organization, the Land and Water Fund of the Rockies, is aggregating customers to participate in a wind energy green-pricing program offered by Public Service of Colorado, a regulated utility.[84]

In Massachusetts, large nonprofit electricity users of many kinds, including universities, health facilities, schools, and cultural organizations are being aggregated by the Massachusetts Health and Educational Facilities Authority. The organization, which already had a buying group for natural gas, has expanded to electricity and claims over 500 members with a combined buying power of almost $150 million.[85] Another aggregator, National Energy Choice, is offering an extra 5 percent savings on top of the standard offer discount, plus an additional 5–7 percent savings from energy efficiency improvements, to members of the Massachusetts Municipal Association and two other nonprofit associations.

On an even broader scale, 21 towns on Cape Cod and Martha's Vineyard are aggregating the electricity demand of their more than 150,000 residents, businesses, and town facilities through a municipal franchise model.[86] The towns—which have a combined peak demand of 335 MW—issued a request for proposals in August 1998 through an association known as the Cape Light Compact.[87] A number of other Massachusetts towns and counties are also in various stages of considering municipal aggregation.[88] The Massachusetts Restructuring Law specifically authorizes municipal "opt-out" aggregation. The law allows municipalities to aggregate their customers, by vote of town council or meeting, with contracts subject to approval by the Massachusetts Department of Telecommunications and Energy. Although all residents and businesses of participating towns would be automatically included in the aggregation, any customer can opt out of the aggregation and choose any licensed electricity supplier.

Municipal aggregation could be favorable for renewables in several ways. For one thing, towns may set their own minimum requirements for renewables, energy efficiency services, or other environmental criteria, to reflect the public benefits provided by clean and renewable energy options. And, by pooling large numbers of customers and by making the aggregation process automatic, municipal aggregation can greatly decrease marketing costs and ensure that most of the premium for any green electricity options goes directly to produce more renewable electricity generation. Municipal aggregation could also make it easy for customers to choose a green option merely by checking a box on a bill. Finally, customers may find a green option offered through a municipality more credible than one offered by a private company with which they are not be familiar.

Of course, municipal aggregation will not automatically favor green options. The tendency of many towns is likely to be to seek out the lowest cost electricity sources, irrespective of their environmental profile. Concerned citizens and advocacy groups may need to participate in time-consuming local forums to influence aggregation choices. In addition, towns with contracts for waste disposal with waste-to-energy facilities are likely to feel pressured to include those facilities as green options, despite objections from some environmental groups.

Buyers cooperatives, or co-ops, are another traditional form of aggregation. A Vermont group has put together a plan for a regional consumer controlled coop to reduce prices and develop cleaner energy sources.[89]

Government purchase. A related strategy is using government purchases of green electricity, or direct investment in renewables. The US government is the world's largest energy consumer, with total purchases (electricity plus fuels) of almost $10 billion.[90] State and local governments also consume large amounts of energy. Santa Monica became the first California city to buy from a green marketer to power city facilities.[91]

In Nebraska and Colorado, the governors issued Executive Orders for state agencies to look at purchasing green power supplies. In Nebraska, all state facilities to use renewables and energy efficiency where cost-effective.[92]

In 1994, the President issued Executive Order 12902, which set a goal of reducing energy use in federal buildings by 30 percent by 2005 and directing the Department of Energy to develop a Renewable Implementation Plan for increasing the use of renewables by federal buildings and agencies. A number of successful projects have since been developed.[93]

The New England regional office of the U.S. Environmental Protection Agency has made a commitment to purchase at least four percent of its electricity from renewable energy sources.

The Massachusetts restructuring law requires the state to conduct an annual study of the costs and benefits of requiring all state agencies and facilities to purchase a minimum of 10 percent of its electricity from renewable sources.[94]

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[3] Mark Crawford, "Tax Credit Expiration Threatens Gusting Wind Power Industry, *Energy Daily*, November 2, 1998, p. 1.

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