POLICIES TO SUPPORT A DISTRIBUTED ENERGY SYSTEM

THOMAS J. STARRS
Kelso Starrs & Associates, LLC
14502 SW Reddings Beach Road
Vashon, WA 98070
(206) 463-7571; kelstar@nwrain.com

HOWARD J. WENGER
AstroPower, Inc.
32 Valla Court
Walnut Creek, CA 94596
(925) 937-1750; hwenger@AstroPower.com

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I. INTRODUCTION

Distributed generation—the location of electric generating facilities close to the end-user—provides benefits to utilities and customers which are not available from traditional central-station generation. Because PV technology is highly modular, with applications scaleable from 5 watts to 5 megawatts (MW) or more, it is the quintessential technology for distributed applications. In this paper, we explore how recognition of the benefits of distributed generation by utilities, utility regulators, and other stakeholders in the electricity industry, combined with policies to support a distributed energy system, could encourage the expansion of PV markets.

A. The Distributed Generation Paradigm: Theory and Practice

Historically, electric utilities have satisfied customer demand by generating electricity centrally and distributing it through an extensive transmission and distribution (T&D) network. An alternative to traditional, large-scale, centralized power plants is decentralized or "distributed" energy generation. The paradigm of distributed generation emerged in the early 1990's out of research suggesting that the use of small-scale electric generating facilities dispersed or "distributed" throughout the utility network provided direct, measurable technical and economic benefits to the electricity system that were not available under the traditional central-station generation paradigm.

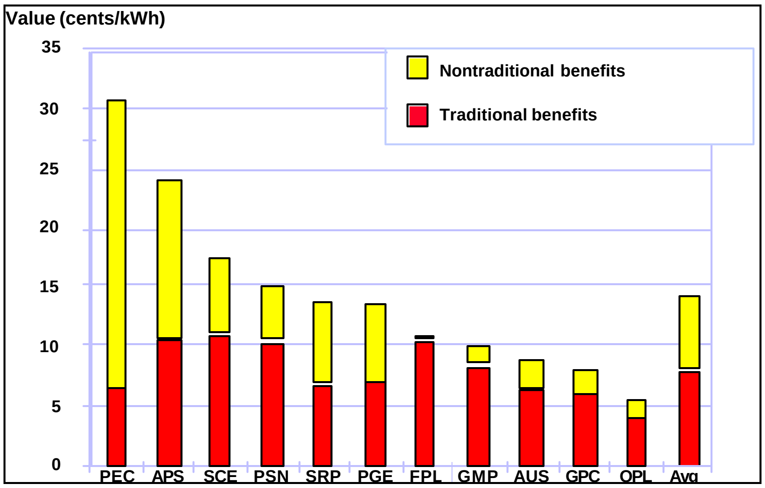
A number of studies—including several sponsored by utilities—have identified direct, measurable economic benefits of having generation sources located close to the end-user.[1] Distributed generation reduces energy losses in transmission and distribution lines, provides voltage support, reduces reactive power losses, defers substation upgrades, defers the need for new transmission capacity, and reduces the demand for spinning reserve capacity.[2] Where the distributed generating technology is fueled by a renewable resource, it offers the additional benefit of displacing fossil-fuel generation or other generation technologies with greater environmental impacts.

[1] See D. Shugar, "Photovoltaics in the Utility Distribution System: The Evaluation of System and Distributed Benefits," *Research & Development Report* (San Ramon, Calif.: Pacific Gas & Electric Company, July 1991); R. Lambeth and T. Lepley, Distributed Photovoltaic Evaluation by Arizona Public Service Company," paper presented at the 23rd International Institute of Electrical and Electronics Engineers (IEEE) PV Specialists Conference, Louisville, Ky., May 1993 (copies on file with the Renewable Energy Policy Project).

[2] Howard J. Wenger, Thomas E. Hoff , and Brian K. Farmer, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project," *First World Conference on Photovoltaic Energy Conversion Conference Proceeding* (Waikaloa, Hawaii, December 1994), p. 793**;** D. Keane, *Grid-Support Photovoltaics: Summary of Case Studies*, prepared for Pacific Gas & Elecric Company, San Ramon, Calif., 1994.

Figure 1 shows the results of 11 different utility studies that have concluded that in some circumstances (particularly where the utility's distribution system is operating near capacity) nontraditional distributed benefits are comparable in scale to traditional energy and capacity benefits.[3] Distributed nontraditional benefits are large for 10 of 11 utilities studied.

Figure 1: Comparison of Nontraditional Distributed Energy Benefits and Traditional Energy Benefits: Results from 11 Utility Studies



A great deal of effort has gone into validating the theoretical benefits of distributed generation, and we will not revisit these issues in this report. Instead, we will assume for the purposes of the ensuing discussion that the benefits of distributed generation are substantial enough, and widespread enough, to justify the design and implementation of policy incentives to encourage distributed applications. These incentives are likely to dovetail nicely with the goal of encouraging the expansion of PV markets.

B. Encouraging Distributed Generation: Institutional Context

Given the structural changes now occurring in the electricity industry, one of the key issues in encouraging the broader use of distributed generation technologies is what the focus of policies should be.

- Should it be on encouraging or requiring distribution utilities to invest in distributed generation where appropriate as a lower cost and environmentally preferred mechanism for providing enhanced distribution services?

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[3] See E. Prabhu, "Finding High Value for Grid-Connected PV: Southern California Edison's Innovative Solar Neighborhood Program," paper presented at the American Solar Energy Society Annual Conference, Minneapolis, Minn., 1995; J. Oppenheim, "PV Value Analysis: Progress Report on PV-COMPACT Coordinating Council's Consensus Research Agenda," paper presented at the American Solar Energy Society Annual Conference, Minneapolis, Minn., 1995; Howard J. Wenger, Thomas E. Hoff, and Brian K. Farmer, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project," *First World Conference on Photovoltaic Energy Conversion Conference Proceedings* (Waikaloa, Hawaii: December 1994).

- Or should it be on encouraging utility customers to invest directly in distributed generation where appropriate for producing their own electricity in a manner that increases self-sufficiency, reduces vulnerability to utility power outages,[4] and provides opportunities for environmentally preferred electricity generation?
- Or should it be on encouraging or removing barriers to new market entrants—i.e., energy companies—to offer and provide distributed generation services?

Determining the appropriate role for distribution utilities in the development of distributed generation has become a highly controversial issue. The California Alliance for Distributed Energy Resources (CADER) spent over a year trying to develop a consensus position on this topic and never succeeded. One faction of CADER argues that distribution utilities should be flatly precluded from participating in markets for distributed generation; this faction's arguments are rooted in the idea that distribution utilities continue to exercise monopoly control over the distribution network, that distributed generating technologies do not exhibit natural monopoly characteristics and therefore should be subject to competition, and that distribution utilities will inevitably use their monopoly control over the distribution system to unfair advantage if they are allowed to participate in competitive markets. The opposing faction of CADER argues that distribution utilities are in a unique position to identify and evaluate opportunities for capturing distributed benefits, and that prohibiting utilities from participating in distributed generation markets will reduce or eliminate incentives for utilities to promote the use of distributed generation.

We believe that the undue emphasis on the role for existing distribution utilities in encouraging distributed energy generation distracts from the fact that there are a number of policy mechanisms available to encourage distributed generation, regardless of whether or not existing utilities are active participants in distributed generation markets. Mechanisms to encourage distributed PV development could be effective whether utilities or nonutility companies are selling, installing, and servicing PV systems. Some of the mechanisms for encouraging distributed generation and their potential role in expanding PV markets are discussed below.

[4] For intermittent resources such as solar energy, capturing these benefits requires the use of batteries or other on-site storage.

II. POLICIES THAT PROMOTE OR PENALIZE DISTRIBUTED ENERGY GENERATION

Because PV technology is so well suited for distributed applications, policies that promote distributed generation will, as a practical matter, promote PV. In the discussion that follows, we describe the following policies that could be used—by local, state, and national government policy-makers, by state and federal utility regulators, by utilities themselves, and by the solar energy industry—to promote the development of distributed energy systems:

- requiring utilities to offer net metering or other pricing policies that recognize the higher value of distributed generation;
- instituting standardized technical standards for utility interconnection of distributed systems;
- requiring utilities to offer simplified power purchase agreements (PPAs) between electricity service providers and the owners of distributed PV systems;
- requiring utilities to minimize the imposition of additional fees and other charges associated with the permitting, installation, and/or operation of distributed systems;
- ensuring that homeowners associations' rules and other private codes, covenants, and restrictions (CC&Rs) do not prohibit or inappropriately discourage the use of solar distributed systems in residential housing developments;
- enacting and enforcing solar zoning laws to protect solar access rights for PV system owners; and
- developing new regulatory regimes for distribution utilities that encourage—or at least do not discourage—customers that seek to generate part or all of their own electricity using PV or other distributed generating technologies.

Several electricity industry stakeholders may have an interest in encouraging (or discouraging) the expanded use of distributed generation. In this paper, we suggest that the PV industry collaborate with advocates for other distributed technologies to pursue common interests. Finally, we discuss the need for collaboration among different stakeholders to develop a coherent and consistent set of policies to promote distributed PV development. Ultimately, the question is whether public support for solar energy will translate into an integrated set of policies necessary to develop and expand distributed PV markets.

A. Requiring Utilities to Offer Net Metering

For small-scale renewable generating facilities, including distributed PV systems, two metering options are generally available: net purchase and sale and net metering.

- ***Net purchase and sale***: This metering option, which is available to most Public Utility Regulatory Policy Act (PURPA) qualifying facilities (QFs), allows individual customers to use the electricity they generate to supply their own needs at the moment it is being generated. Customers purchase any shortfall from the utility at the regular retail rate. If customers generate electricity but do not immediately use it, the electricity is sold back to the utility at the PURPA "avoided cost" rate.[5] The avoided cost rate is much lower than the retail rate—about 2¢/kWh as opposed to 5¢-20¢/kWh. As a result, customers who are generating electricity have a strong incentive to use all the electricity they generate as it is generated, so that it offsets electricity that otherwise would have been purchased at the retail rate. Otherwise, much of the value to the customer of generating the electricity is lost because the utility pays only the avoided cost rate. Net purchase and sale requires the use of dual meters: one to measure the flow of electricity into the building, and the other to measure the flow of electricity out of the building and into the utility grid. For most PURPA QFs, including industrial cogenerators and large-scale renewable generating facilities whose on-site use is incidental, this "dual-metering" arrangement is still the norm.

- ***Net metering***: For small-scale renewable generators in 23 states, there is a much simpler and more favorable metering approach called net metering. Net metering allows eligible customer-generators to interconnect using their existing meter. The meter spins forward when electricity is flowing from the utility into the building, and spins backward when power is flowing from the building to the utility.[6] At the end of the billing period, the customer is charged for the "net" energy consumed, or is paid for the "net" energy produced. Net metering simplifies both the metering process (by eliminating the need for a second meter) and the accounting process (by largely or entirely eliminating the need for the utility to purchase excess power).

Box A below illustrates the difference between these two approaches.

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[5] The avoided cost rate is roughly equivalent to a wholesale rate, except that it is administratively determined. In the future, the avoided cost rate is likely to be supplanted by some wholesale market rate.

[6] The vast majority of electricity meters used for residential and small commercial customers (nondemand customers) are bidirectional, and require no modification to measure the flow of energy in either direction. Although new metering technologies may or may not share this attribute, the installed base of bidirectional meters is extremely large and is unlikely to be swapped out for new meters in the absence of some economic imperative.

Box A: Net Purchase and Sale vs. Net Metering: An Illustration of the Differences

For small-scale renewable generating facilities, there are two metering options: 1) net purchase and sale and 2) net metering. The following simple example illustrates the differences between these two options.

Assume that Sally Solar installs a 2 kilowatt (kW) photovoltaic (PV) system on the roof of her new house in the sunny southwest. The system generates 260 kilowatt hours (kWh)/month. Sally's average electricity consumption is 500 kWh/month. Sally's utility charges 10¢/kWh for the energy she buys, and pays 2¢/kWh for the excess energy she produces.

Without the PV system, Sally's monthly bill would have been 500 kWh x 10¢/kWh, which amounts to $50/month. What will Sally's monthly bill be with the PV system on her roof under each metering option?

Net Purchase and Sale

With net purchase and sale, Sally can offset some of her consumption with some of her electricity generation, but only by consuming electricity *at the same time* that her PV system is generating electricity. Sally works during the week, but with clever use of her weekends and with timers on some of her major appliances she manages to use about 40% of the electricity from her PV system as it is generated, or 100 kWh. This means she is still buying 400 kWh from the utility at retail (500 kWh used - 100 kWh used on-site), and she is selling 160 kWh back to the utility (260 kWh generated - 100 kWh used on site). Sally then calculates

Net Bill = (400 kWh x 10¢/kWh) - (160 kWh x 2¢/kWh) = $40.00 - $3.20 = $36.80/month

Net Metering

With net metering, Sally can use all of the output from her PV system to offset her electricity consumption (as long as total generation is below total consumption). Sally calculates

Net Bill = (500 kWh - 260 kWh) x 10¢/kWh = 240 kWh x 10¢/kWh = $24.00/month

Another way of looking at these numbers is to think of Sally's return on investment for her PV system being equal to the money she avoids paying to the utility each month. Sally calculates the savings in her monthly bill for each option: Under net purchase and sale, the PV system saves her about $13/month, while under net metering, the PV system saves her $26/month. This means that having net metering doubles Sally Solar's effective return on her investment in the PV system.

Net metering simplifies both the metering process (by eliminating the need for a second meter) and the accounting process (by largely or entirely eliminating the need for the utility to purchase excess power). Perhaps most importantly, net metering also is easy for customer generators (the end-users) to understand. Net metering eliminates the need for complicated buy/sell agreements and complicated contracts that require specialized attorneys to review and interpret.

Critics are quick to point out that net metering is inconsistent with the move towards competition and market pricing of wholesale energy supplied to the grid. In particular, they object to net metering because it allows customers to use excess energy being fed back into T&D system at one point in time to offset energy dispatched and delivered at another point in time.

These arguments have a certain legitimacy on the surface, because net-metering customers are in effect "free riding" by making additional use of the distribution system (to "bank" their excess electricity) without compensating the distribution utility for the value of this service; however, the arguments need to be evaluated in a deeper context. The fact is that the effects of net metering on utility revenues are closely analogous to the effects of customer investments in energy efficiency. For instance, from the utility's perspective, the effects of a customer's installation of a net-metered 2 kW PV system are similar to the effects of a customer's installation of all compact fluorescent lights in a house.[7] Utilities are not allowed to penalize customers for efficiency investments such as the installation of compact fluorescent lights, so what is the rationale for penalizing them for PV investments?

Some observers make the argument that energy efficiency and PV investments are fundamentally different because a PV system has the ability to actually feed energy back to the grid—something which no energy-saving device can do. In our view, this is a distinction without any real difference: As long as the amount of power being fed back to the grid is negligible in relation to the amount of power flowing through the distribution line, it makes no difference to the utility's operations. The extra power simply goes to the customer next door, and the utility gets to charge the neighbor for the electricity produced by the generating customer without generating the electricity itself, making the transaction a wash from an economic perspective.

In any event, it is important to note that a utility may actually be coming out ahead financially since PV generates power when utilities need it the most—during hot summer days when air-conditioning demand drives up the cost of generating and delivering electricity. The value of on-peak PV power is reflected in utility time-of-use rates which are two to three times higher than baseline rates. So- called revenue losses caused by net metering may actually be revenue gains when peak-shaving and peak-dispatching benefits of PV are considered.

A common concern regarding net metering that utilities raise is that if some dramatic innovation in PV technology led every customer to install a PV system, then net metering would become untenable because at that point everyone would be a "free rider" and no one would be left to cover the costs of maintaining the distribution network—that is, the revenue impacts that are inconsequential with low PV market penetration become untenable at much higher levels of PV market penetration.

A simple solution to this unlikely scenario has already been adopted by several states—that is, capping the amount of net-metered generating capacity or the number of net-metered generating systems at a number low enough so that even if the cap is reached the revenue impacts will be insignificant. In testimony to the Iowa Utilities Board, the Solar Energy Industries Association (SEIA) and the American Wind Energy Association concluded that even with 20 MW of additional net-metered generating capacity in Iowa—roughly 10 times the current net-metering generating capacity in the entire country—the revenue loss to the Iowa utilities, if amortized in the utilities' rate base, would increase rates by an average of .0068¢/kWh. Thus, a residential customer using 600 kWh/month would see a bill increase of 4¢ on a base bill of $49 per month, and an industrial customer using 600,000 kWh/month would see a bill increase of $40 on a base bill of $23,400 per month.

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[7] A 1 kW PV system will produce roughly 140 kWh/month. Replacing eight 100-watt incandescent bulbs that are used 8 hours a day with 23-watt compact fluorescent lights will save about 150 kWh/month [8 bulbs x (100 watts - 23 watts) x 8 hrs/day x 30 days/month x 1 kW/1000 watts = 148 kWh/month].

Although net-metering caps may be expressed as a limit on the number of net-metering customers (Nevada has limited net metering to 100 households per utility), they are more typically expressed as a limit on the total installed generating capacity for which net metering will be made available. These capacity limits are expressed as a percentage of each utility's peak demand, and range from a low of 0.1% (California, New York, Washington) to a high of 1.0% (Vermont). It is worth noting that even the lowest capacity limits provide tremendous opportunity for expansion of distributed PV. In California, for example, the 0.1% limit equals over 50 MW of installed PV generating capacity, equivalent to 25,000 residential PV systems with 2 kW peak generating capacity. At the same time, these limits are modest enough that even if the cap were reached, the revenue impacts on utilities would remain modest by any measure.

In short, net metering provides a simple, inexpensive, and easily administered mechanism for encouraging distributed PV development, particularly in residential applications. Although it does not by itself make grid-connected PV economic, it improves the economics of residential PV generation by an average of about 20-25%, depending on the differential between retail and avoided cost prices, the size of the PV system, and the customer's pattern of electricity use.[8]

1. Current Status of Net Metering

Following the enactment of the Public Utility Regulatory Policy Act (PURPA) in 1978, some states began requiring utilities to provide net-metering options for certain small-scale renewable generating facilities. By 1995, 13 states had imposed net-metering requirements by regulation, and one state (Minnesota) had enacted a "mini-PURPA" statute that explicitly required net metering. Net-metering eligibility was typically limited to a subgroup of PURPA facilities, usually renewable generators with maximum generating capacities between 10 and 100 kW (depending on the state). The wind energy industry provided the impetus for a number of these early policies, and even today most net-metering customers are concentrated in rural portions of a few windy states, using farm- and ranch-scale wind turbines to provide their own power and feeding any excess back to their local utility.

The past few years have seen a strong resurgence of interest in net metering, driven primarily by the PV industry and solar advocates around the country. Since 1995, the year California enacted a net-metering law for residential PV systems, 10 additional states have enacted net-metering requirements—mostly by legislation—and a handful of additional states either have considered or are considering new net-metering policies. Appendix A lists states in which net-metering requirements have been established. Appendix B lists states that have proposed net-metering requirements. Each appendix identifies some of the characteristics of each of these programs.

Beyond generating interest in the states, net metering has for the first time caught the eye of the federal government: At least three of the draft utility restructuring bills introduced in Congress in 1998

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[8]In general, the greater the differential between retail and avoided cost prices; the larger the system; and the lower the direct PV-to-load percentage the greater the value of net metering. A study by the Pacific Energy Group for the Sacramento Municipal Utility District (SMUD) found that a range of 0-45% increase in annual bill savings from net metering. For a typical 2 kW system, the increase in annual bill savings was 18%. See Howard Wenger, Tom Hoff, and Donald E. Osborn, "A Case Study of Utility PV Economics," *American Solar Energy Society Conference Proceedings* (Washington, DC: American Solar Energy Society, 1997), p. 4.

have incorporated net-metering requirements, including the Clinton Administration's proposed Comprehensive Electricity Competition Act (CECA), which calls for electric service providers to offer net metering for all renewable generating facilities sized 20 kW or smaller.

Interestingly, net-metering proposals have attracted the support of a broader constituency than just solar advocates:

- The National Association of Regulatory Utility Commissioners (NARUC) passed a resolution supporting net metering for small-scale renewables at its annual convention in November 1997.
- The National Association of State Utility Consumer Advocates (NASUCA) passed a similar resolution a few months later.[9]
- The Utility Photovoltaic Group (UPVG), an organization of utilities and other energy service providers supporting the commercialization of PV technology, is supporting net metering as a mechanism for expanding PV markets.

On the other hand, the number of customers taking advantage of net-metering policies has been very limited. Reliable data are very difficult to come by. In a 1996 study, the National Renewable Energy Laboratory (NREL) identified fewer than 100 customers enrolled under state net-metering programs,[10] but the authors of that study recently discovered that one state alone (Minnesota) has 110 customers with net metered facilities.[11] There have been approximately 60 net metered PV systems installed in California during the past 3 years; and it is anticipated that growth in the number of PV systems in that state will accelerate in coming years as a result of California's Emerging Renewables Buydown Program and recently changed net-metering law that allows annualization. We believe that there are between 400 and 1,000 enrolled net-metering customers in the United States.[12]

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[9]Also, in several regulatory proceedings around the country—including California, Iowa, Maine, Nevada, and New York—utility consumer advocates have submitted written or oral testimony in support of net metering.

[10]Yih-huei Wan, "Net Metering Programs," NREL Topical Issues Brief, NREL/SP-460-21651, National Renewable Energy Laboratory, Golden, Colo., December 1996, p. 9-14.

[11]See Minnesota Department of Public Service, *1997 Electric Utility Qualifying Facilities Report* (St. Paul: Nov. 5, 1997), obtained from Jim Green of NREL's National Wind Technology Center. All 110 of the listed facilities were wind energy systems.

[12]Part of the uncertainty regarding the number of net-metered facilities stems from the fact that many customers—particularly those with solar PV systems—apparently choose not to inform their local utility that they are generating some of their own electricity. These customers are benefiting from *de facto* net metering—an unintended consequence of the fact that the vast majority of electricity meters used in residential applications happen to be bidirectional, so that customers can install their systems without the utility's knowledge or consent and enjoy the benefits of net metering. Anecdotal evidence suggests that these customers choose not to inform the utility because of the administrative and/or cost burden associated with obtaining the utility's approval and/or the fear that the utility would not allow them to interconnect.

Three key factors appear to have limited the number of customers taking advantage of net metering:

- First, the economics of small-scale renewables—though much improved in recent years—are still not attractive enough to create substantial markets without additional financial incentives.
- Second, other barriers discussed below have made it exceedingly difficult and expensive for customers to get their systems interconnected, even where net metering is available as an added incentive.
- Third, utilities rarely take the initiative to inform customers that net metering is available. Indeed, there have been many reports of customers contacting their utilities after becoming aware of net-metering laws in their states, only to have their utilities insist that no such law exists.

In our view, the modest level of participation in net-metering programs to date should not be seen as a reason for abandoning net-metering policies. Instead, net metering should be thought of as a fundamental building block in whatever policy framework federal and state governments decide to develop for encouraging distributed PV.

As net metering is combined with other incentives to further improve PV economics, and as other barriers to PV investment are overcome, net-metering policies will play an increasingly visible and important role in encouraging distributed PV development. Other policy measures—including those discussed in other parts of this report—can make a more important contribution to the long-term expansion of PV markets. However, while these other measures require substantial time and resources to develop, net metering reflects a modest change in policy that can be easily implemented by an individual utility, a state public utility commission, or a state legislature. Thus, the advantage of net metering in comparison to these other measures is that it is both simple and easy to administer.

2. Potential for Expansion of Net Metering

Net metering—though not a "silver bullet" that will make PV economically viable—is a simple, inexpensive, and easily administered mechanism for improving the economics of customer-sited PV generation and reducing the complexity of power purchase agreements (PPAs) with utilities and other energy service providers. Thus, we consider it a key element in the mix of policy options needed to promote the expansion of PV markets.

There are two possibilities for making net metering more widely available for small-scale PV systems: 1) continuation of the current trend toward the implementation of net metering at the state level, or 2) federalization of net metering through a national mandate.

Although both possibilities appear to be feasible, broader implementation of net metering at the state level appears likely. Over the last 3 years, 10 states have added net-metering requirements, bringing the total number of states from 13 to 23 (an increase of over 50%). Most of the new state programs have been enacted legislatively, with broad bipartisan support. In 1998, for example, the Republicancontrolled Washington state legislature unanimously passed a net-metering law that was signed by the Democratic governor.[13]

By the end of 1998, it seems likely that a majority of states will have net-metering programs in place. The recent resurgence of interest in net metering is attributable to several factors.

- First, costs for small-scale PV and wind systems have declined to the point where metering methods have a substantial effect on cost-effectiveness.

- Second, grassroots groups have latched onto net metering as a simple, easily administered method for encouraging small-scale renewables. Successful efforts to enact or expand net metering at the state level have been initiated and led by local or regional solar advocates in each state, rather than by a coordinated national effort.

- Third, national groups such as the American Solar Energy Society (ASES), the Solar Energy Industries Association (SEIA), the American Wind Energy Association, the Interstate Renewable Energy Council (IREC), and the Utility Photovoltaic Group (UPVG) have provided indirect support for the efforts of grassroots advocates by educating stakeholders—including renewable energy advocates, utilities, regulators, and legislators—about the benefits and costs of net metering.

B. Standardizing Technical Requirements for Utility Interconnection of Distributed Systems

Economic incentives, no matter how substantial, will not increase market penetration of PV technology if other institutional barriers discourage customers from investing in PV technology. Foremost among these barriers is the absence of uniform, standardized requirements for utility interconnection of small-scale PV systems.

Although nationally recognized, standard-setting organizations such as the Institute of Electrical and Electronics Engineers (IEEE) and Underwriters Laboratory (UL) have developed safety and power quality standards for utility interconnection of small-scale PV systems, utilities have the discretion to accept or reject these standards. The result is a confusing mix of requirements that vary not only from state to state, but even from utility to utility within a state.

The lack of uniform requirements for utility interconnection of small-scale PV systems results in a variety of problems:

- First, both utilities and their customers face much higher costs than they would with uniform interconnection requirements. As it stands, utilities tend to treat small-scale PV systems the same way they treat large-scale PURPA facilities, with engineers reviewing system designs, engineering diagrams, even wiring schematics on a system-by-system basis. Sometimes they

[13] In fact, the only states in which efforts to enact statewide net metering laws have failed are Hawaii, Iowa, and Colorado—and in all three of these states, net metering is already available in some form from some utilities.

pass these costs onto customers; other times they do not. In either case, the increased burden on utility personnel and the PV system owner is substantial.

- Second, PV system installers face increased costs because they have to deal with interconnection requirements that vary from utility to utility, even within the same state.

- Third, PV equipment manufacturers and system integrators also face increased costs, because they cannot manufacture standardized or "packaged" systems and be assured that these systems will comply with utility requirements within a single state, much less in 50 states. This limits the ability of PV manufacturers to capture economies of scale associated with developing packaged systems.

In addition, we suspect (though without any evidence) that the lack of standardization actually increases the likelihood of poorly designed or poorly installed PV systems. The analogy would be to two automobile assembly lines: one assembly line dedicated to producing an exactly identical car with the same features and options; and the other assembly line dedicated to producing the same model car, but with each vehicle being custom-assembled with different options (perhaps this vehicle has air conditioning, leather upholstery, and a sunroof, while the next vehicle has automatic transmission, a fancy stereo system, and cruise control). It seems likely to us that the first assembly line will see better performance both in the initial assembly process and also in the quality control and inspection process. Currently, however, PV system integration and installation more closely resembles the second assembly line.

We believe that the solution to the problem is uniform adherence to the technical standards for utility interconnection from IEEE, Underwriters Laboratory, and the National Electric Code. The organizations that set these standards are best suited to balance potentially conflicting interests: on the one hand, PV manufacturers seeking to minimize manufacturing costs and complexity, and on the other, utilities and municipalities seeking to ensure that safety and power quality concerns are addressed regardless of cost.

In general, these standards-setting organizations appear to command considerable respect among utilities—and we have yet to hear of a utility arguing for standards from IEEE, Underwriters Laboratory, or the National Electric Code. On the other hand, utilities are reluctant as a matter of principle (and perhaps as a matter of self-preservation)[14] to cede control over interconnection, so convincing them to rely entirely on third-party standards will be a challenge.

That challenge can be met in one of two ways: 1) utilities voluntarily accept third-party standards for utility interconnection; or 2) legislators or regulators mandate that utilities comply with third-party standards.

- ***Voluntary acceptance of third-party interconnection standards by utilities***. Encouraging utilities to voluntarily adopt these recommended standards would be less confrontational and

[14]The more charitable view regarding the utilities' reluctance to cede control over interconnection is that utilities are very conservative and extremely protective regarding the safety and integrity of "their" utility grid. The less charitable view is that utilities use their control over interconnection to stifle competition from customers interested in generating their own electricity instead of buying it from the utility. Most likely both these views are correct, with the balance varying substantially from one utility to the next.

adversarial. On the other hand, encouraging voluntary adoption on a utility-by-utility basis would be extremely cumbersome. The process could be facilitated through the support of the Utility Photovoltaic Group (UPVG), the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and other utility industry associations. These organizations do not have the power to prescribe policy among their member utilities, though, so the effort ultimately would depend on voluntary acceptance by the utilities.

- ***Mandated compliance with third-party standards by utilities.*** Some states already have chosen to rely on mandates to get utilities to adopt third-party standards. In particular, net-metering laws enacted recently in four states (California, Maryland, Nevada, and Washington) have included provisions specifying that PV (and other eligible) systems must comply with all applicable standards from the IEEE, Underwriters Laboratory, and the National Electric Code. Most of these provisions go on to specify that systems meeting these standards are exempt from any additional requirements imposed by utilities. Other net-metering laws have specified that utility regulators must develop "reasonable" interconnection requirements for safety and power quality (New Hampshire), or that utilities must provide interconnection for PV systems "manufactured, installed, and operated in accordance with applicable government and industry standards" (New York).

There are some indications that the federal government may step into the fray by proposing national interconnection standards, at least for some technologies. The Clinton Administration's proposed Comprehensive Electricity Competition Act, for instance, calls for the Federal Energy Regulatory Commission (FERC) to "prescribe safety and power quality standards and rules necessary to carry out" the act's net-metering provisions. It also states that a distribution utility must permit the interconnection to its distribution system of "an onsite generating facility if the facility meets the safety and power quality requirements established by the Commission."[15] National standards, of course, would ensure uniformity not just within a single state, but among all 50 states.

On balance, we feel that a "carrot and stick" approach in which utilities, regulators, and the PV industry are brought together in an effort to reach a consensus on uniform standards may succeed, particularly if the utilities recognize the threat of legislative or regulatory mandates that would eliminate any discretion or control the utilities might retain through voluntary adoption. If voluntary adoptions are unsuccessful, the PV industry and advocates can continue to press for regulatory or statutory mandates, particularly at the federal level.

C. Simplifying Power Purchase Agreements (PPAs)

Another interconnection-related barrier to distributed PV is the absence of simplified power purchase agreements (PPAs) between PV system owners and their utilities and/or their energy service providers. PPAs are enforceable contracts between parties that describe the terms and conditions of their bilateral relationship. PPAs may cover technical requirements for interconnection (discussed in

[15]Comprehensive Electricity Competition Act (proposed), Section 303(c) & (d), text available on the Internet at Web site: http://www.hr.doe.gov/electric/cecp.htm.

the previous section), but commonly they also cover much more: metering requirements, payment for excess energy, imposition of standby and other charges, service interruption or curtailment, permitting and maintenance obligations, access provisions, indemnity and liability provisions, notification requirements, and nontransferrability provisions.

PPAs are a barrier to distributed PV for two main reasons:

- First, most PPAs are very complex, incorporating legal obligations, procedural obligations, and technical requirements that are beyond the ability of the average utility customer to understand. Simply put, if potential purchasers of rooftop PV systems feel compelled to retain an attorney and a consulting engineer in order to get their systems up and running, one can be sure that the number of systems installed will be extremely limited.

- Second, the terms and conditions of most PPAs were developed by utilities (which historically have had little reason to encourage competing generators from coming on-line) with large Public Utility Regulatory Policy Act (PURPA) generating facilities in mind. The problem is that the contract terms and conditions appropriate for a 200 MW cogeneration facility are almost certainly not appropriate for a 2 kW PV system, yet many utilities use the same PPAs for all nonutility generators. Regulators have jurisdiction over the terms and conditions of PPAs, and some public utility commissions have required utilities to develop simpler PPAs for PURPA facilities sized, for instance, 100 kW or smaller. Even so, these simplified agreements often impose requirements that have a dramatic effect on the cost of interconnecting and operating an on-grid PV system.

1. Case Study of PPAs: New York

A recent case in New York illustrates the difficulties associated with inappropriate contract terms and conditions. In 1997, New York enacted a net-metering law for solar electric (PV) systems sized 10 kW or smaller. When utilities submitted their proposed tariffs and interconnection agreements for implementing the state's net-metering law, the terms and conditions in the agreements were so onerous that two organizations felt compelled to intervene in the regulatory proceeding.

In written comments to the Public Service Commission, the Natural Resources Defense Council (NRDC) and the New York Consumer Protection Board claimed that the proposed contract terms were burdensome and unnecessary. They suggested that major modifications were needed to ensure effective implementation of the state's net-metering law.

In February 1998, the New York Public Service Commission issued an order on the implementation of the state's net-metering law that was by far the most high-profile and far-reaching decision to address the unique issues associated with the interconnection of small-scale distributed generating facilities. The Public Service Commission rejected various elements of the utilities' proposed contract as overly burdensome—among them liability insurance requirements, indemnification requirements, easement requirements, additional interconnection requirements (beyond those negotiated in a collaborative process), additional interconnection charges (beyond those specified in the net-metering law), and termination/modification provisions in which the utilities had proposed that interconnection agreements terminate automatically upon sale of the residence (NRDC argued successfully that the agreements should be transferable to the new owner, contingent on the new owner's acceptance of the terms and conditions of the agreements).

The New York Public Service Commission's treatment of the liability insurance requirements is representative of the rest of the order. Utilities frequently require large-scale generating facilities to carry liability insurance protecting the facility owner and the utility against property damage, personal liability claims, and personal injury lawsuits associated with the operation of the generating facility. Renewable energy advocates have long argued that high amounts of insurance coverage are unnecessary for small-scale renewable generating facilities, and that insurance coverage requirements are a substantial barrier to investment in these facilities. Several utilities in New York proposed that net-metering customers carry liability insurance in amounts between $500,000 and $1,000,000, and further proposed that the insurance be from a utility-approved carrier. NRDC objected, arguing that the amount of coverage was excessive. The Public Service Commission agreed, noting that the "utility proposals on liability insurance are clearly burdensome and overly costly," and at least in one case the requirements "are practically impossible for residential customers to meet." It concluded that utilities were limited to requiring customers to demonstrate that they carry at least $100,000 in liability coverage through their homeowners' policies. This limit is within the conventional coverage that most homeowners already carry.

2. Case Study of PPAs: California

A case in California illustrates a different problem with PPAs: the imposition of additional fees and charges on small-scale generators. Such charges can quickly eat up the energy savings from a rooftop PV system, particularly the modest savings associated with a smaller system.

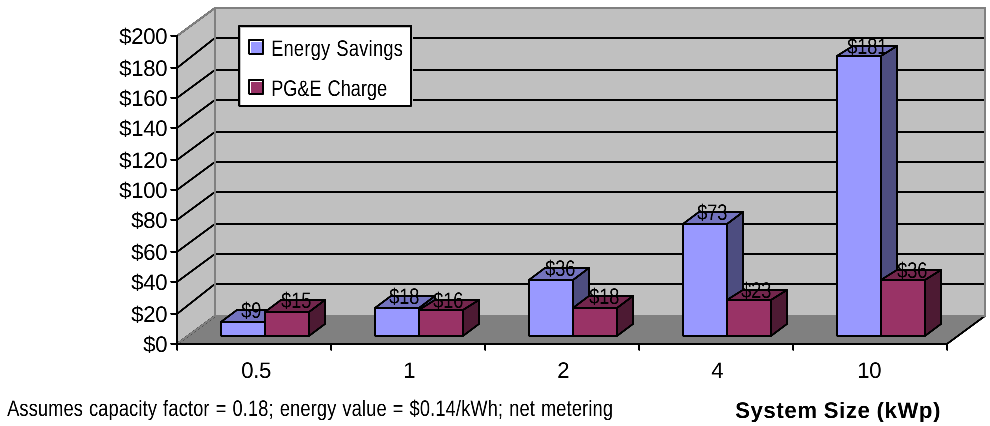
When California's net-metering law was enacted in 1995, Pacific Gas & Electric Company (PG&E) was the only investor-owned utility in the state that opposed the law in the state legislature. Having failed to prevent the law from passing, PG&E apparently decided to prevent the law from being effectively implemented.

The course PG&E chose was to propose additional charges for net-metering customers that seemed neatly designed to offset any net-metering benefits to customers investing in solar energy. Specifically, PG&E proposed a tariff that included an additional fixed "customer charge" of $14 per month, plus a variable "reservation" (standby) charge of $2.15 per kW of generating capacity per month.[16]

Figure 2 compares the amount of the proposed PG&E customer charge and the energy savings as a function of PV system size. As the figure shows, for a 500-watt PV system, the additional charges more than offset the energy savings from the PV system. In fact, it would take nearly *2 months* of energy savings to pay for the additional *monthly* charge. For a 2-kW system, the additional charges eat up half of the energy savings. Even for the largest PV systems allowed under the net-metering law (10 kW), the charges would still offset 10% of the energy savings.

[16] PG&E Advice 1549-E to the Public Utilities Commission of the State of California, Nov. 21, 1995.

Figure 2. Proposed PG&E Customer Charges vs. Energy Savings As a Function of PV System Size



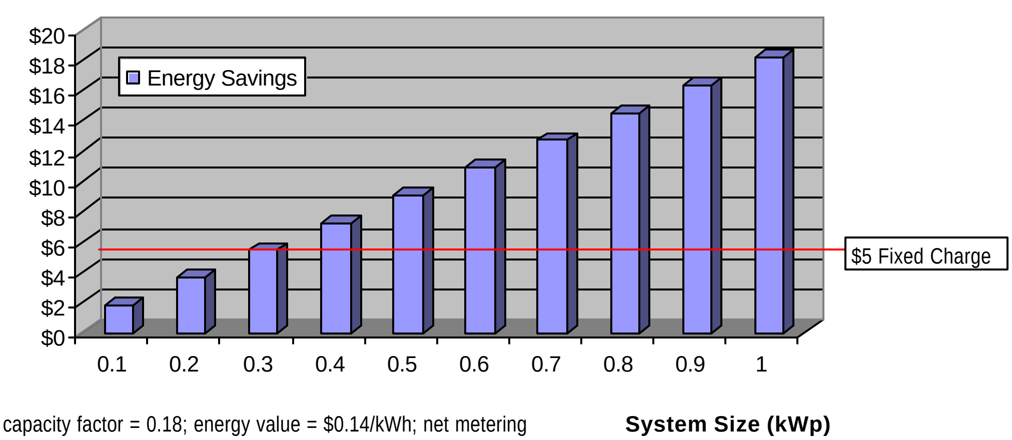
Clearly, this was no way to encourage the use of PV. In fact, the charges were difficult to justify as anything other than an attempt to discourage customers from reducing their electricity bills by investing in solar energy. Customers who reduced their electricity bills by investing in energy efficiency measures, for instance, faced no such punitive charges. The imposition of a standby charge was particularly repugnant; the idea of a standby charge is that self-generating customers are burdening the utility by requiring the utility to provide standby service if the customer's generating facility goes out of service. Standby charges may be appropriate for large industrial cogeneration facilities where a plant failure may trigger a sudden demand surge of hundreds of megawatts, but a standby charge for a customer whose peak generating capacity is many orders of magnitude less than the natural fluctuations in demand to which the utility constantly responds is indefensible.

To put this issue in context, the increase in utility demand when a residential PV system cuts out is less than the increase in demand when the same customer's air conditioner cycles on. When California's PV advocates voiced their objections, the California Public Utility Commission rejected PG&E's proposed tariff as being inconsistent with the intent of the net-metering law and required the utility to drop the charges from its final version of the tariff.

D. Minimizing Various Fees and Charges

If the optimal path to PV commercialization is indeed to capture economies of scale associated with producing large numbers of small systems, then the imposition of even seemingly modest fees creates a substantial economic hurdle. Utilities that use dual-metering for most Public Utility Regulatory Policy Act (PURPA) facilities often impose an additional metering charge—ostensibly to cover the cost of meter reading and accounting. If PV markets evolve to favor smaller, modular systems based on the so-called "AC modules," customers will have the opportunity to make modest, incremental investments in PV starting with units as small as 100 watts. Even a modest additional charge can put a serious dent in the energy savings of small PV systems. Figure 3 illustrates the impact of additional charges on energy savings by showing that a $5 monthly charge requires 300 watts of generating capacity just to compensate for the charge. This 300 watts of capacity will cost

Figure 3. Energy Savings vs. Fixed $5 Monthly Charge for Small-Scale PV Systems



Assumes capacity factor = 0.18; energy value = $0.14/kWh; net metering

roughly $2,500 at current prices, making the incremental investment hard to justify.

Another common fee imposed by utilities is a fee for engineering design review. Public Service Company of New Hampshire, for example, charged a residential customer $900 for a design review of his 900-watt PV system—adding $1/watt (roughly 12%) to the installed cost of his system. Public Service Company of New Hampshire then required the customer to purchase and install mechanical relays to protect against over/under voltage and over/under frequency conditions, although the customer's inverter already contained the necessary relays.[17] The price for the relays was $450, or another $50¢/watt. Finally, because the mechanical relays were less sophisticated than the electronic relays built into the customer's inverter, they required annual calibration—a service Public Service Company of New Hampshire agreed to provide for another $100 per year. The cost of this annual test effectively offset half of the annual energy production from this modest-sized PV system.

[17] Some utilities claim to be uncomfortable relying on the electronic protective relays built into new inverters, favoring instead the old-fashioned mechanical relays with which they are more familiar. There appears to be little legitimacy to their arguments that the mechanical relays provide superior reliability or performance.

Additional metering charges, fees for engineering design review, and the other fees imposed in the example above are arguably discriminatory and arbitrary, at least to the extent that they are not commensurate with the size and scale of the PV facility. PV advocates can argue that these costs should be reduced or eliminated for equitable reasons, in order to "level the playing field."

Some PV advocates may want to go further to argue that rather than leveling the playing field, policy-makers should indeed be skewing the playing field—skewing it *in favor* of PV and other renewable energy technologies. Just in case PV advocates are interested in pursuing this "counterstrike" strategy, we have identified four other types of fees that add significantly to the cost of distributed PV systems: building permit fees, property taxes, sales taxes, and competitive transition charges (CTCs):

- ***Building permit fees.*** Municipalities often require building permits for the installation of PV systems, with permitting fees based on a flat-fee or on the value of the property addition. Although we are unaware of any survey documenting permitting fees in different jurisdictions, anecdotal evidence suggests that fees of several hundred dollars are common.[18]

- ***Property taxes.*** Because PV systems are considered improvements to real property their cost is added to the assessed value of the home or business on which property taxes are based. The tax increase can be severely punitive: A property tax rate of 1%, for example, results in increased property taxes that offset most of the bill savings from a residential PV system.

- ***Sales taxes.*** Sales taxes are assessed on the initial purchase price of the system, which some advocates argue is inappropriate since sales taxes are usually not assessed on electricity purchases from the utility that the PV system is offsetting.

- ***Competitive transition charge (CTC).*** The fourth type of fee—the competitive transition charge (CTC)—is a recent invention that has become a popular vehicle for supporting so-called uneconomic "stranded costs" and "stranded benefits" associated with utility restructuring.[19] CTCs reflect historical costs that utilities traditionally financed through rates, but that have been deemed unsupportable under competition.[20] Because CTCs are intended to be nonbypassable in order to spread the costs of the programs they support as widely as possible, they frequently penalize customers who decide to self-generate. In California, for example, self-generating customers will be required to pay the CTC based on their historical electricity usage. This may be a significant deterrent to potential distributed PV investments, because one of the principal motivations for distributed PV applications is the ability to fully offset the bundled retail price of electricity.

[18] Permitting fees are often tied to the value of the building improvement.

[19] There is a growing lexicon to describe nonbypassable charge programs imposed on ratepayers to recover stranded costs and benefits, including competition transition charge, system benefits charge, public purpose charge, and transfer trust charge. Although the words differ, the net function of these programs is generally the same: to recover funds from ratepayers as a result of a restructuring settlement.

[20] So far, nine states—California, Connecticut, Illinois, Massachusetts, Montana, New York, Pennsylvania, Rhode Island, and Wisconsin—either already have established or have proposed nonbypassable competitive transition charges (CTCs) to support utility stranded cost recovery and nonbypassable public purpose program charges to support social, environmental, and other public benefit programs.

Because the CTC is a political creation, it frequently turns out that there are degrees of nonbypassability. In California, for example, there are CTC exemptions for new or incremental loads served by “direct transactions” and not otherwise requiring use of the utility grid, for loads served by cogeneration facilities that began operation within certain date ranges (but not between January 1998 and July 2000), for loads served by emergency generation, and for “changes in usage.” Changes in usage include (among other things) modifications to equipment or operations, changes in production or manufacturing, fuel switching (including fuel cells), increased efficiency of cogeneration, replacement of cogeneration, demand-side management or other conservation, and “other similar factors.” If the last two sentences leave you with more questions than answers, you are not alone: An attorney who has closely scrutinized the California CTC provisions has concluded that the exemptions are “complex, uncertain, and subject to interpretation.”[21] Our own cynical view is that the bill drafters made the CTC exemptions so incoherent that utilities would be able to litigate any request for an exemption; but because the CTC is only in place for a 4-year transitional period, few stakeholders are going to be motivated to spend half of the transitional period in litigation, especially when the results are so uncertain.

With respect to distributed PV applications, the California CTC appears to provide an exemption only for residential applications.[22] This means that PV systems in commercial and industrial applications will cost their owners approximately 4¢ for each kilowatt-hour (kWh) generated by the PV system. These are not trivial sums: For a 100-kW system on the roof of a commercial or industrial facility, for instance, the CTC is an extra expense of more than $160,000 per year.[23]

Table 1 summarizes these “hidden costs” of owning a distributed PV system. The sum of these hidden costs—assuming they were all to be imposed on a given system—is shocking: They completely offset all the energy savings associated with the PV system for about 40 years, which is more than the normal expected life of the system. In fact, on a nominal (nondiscounted) basis, the sum of these costs is higher than the initial capital cost of the PV system.

Table 1: “Hidden Costs” for the Owner of a Rooftop PV System[a]

[21]John Nimmons, John Nimmons & Associates, “Impact of California’s Competitive Transition Charges on Distributed Resources,” *Conference Proceedings, California Alliance of Distributed Energy Resources* (Olympia, Wash.: September 1997).

[22]The apparent exemption for residential PV systems is contained in Section 371(c) of the California Public Utilities Code, which states: “Nothing in this section [imposing the CTC on all customers subject to changes in usage] shall be construed as a limitation on the ability of residential customers to alter their pattern of electricity purchases by activities on the customer side of the meter.” Commercial and industrial PV systems could argue that their PV systems qualify as “installation[s] of demand-side management equipment or facilities, energy conservation efforts, or other similar factors.” Public Utilities Code Section 371(b). Making such an argument may lead to litigation.

[23]Ironically, the California CTC is in place during the same transitional period that California’s Emerging Renewables Buydown Program funds are available, so that these two elements of the same restructuring law are at odds with one another: The law spurs renewable energy development by providing financial incentives for renewable energy investments, while at the same time it stifles renewable energy development by requiring renewable self-generators to pay the CTC on the electricity they generate.

Item	Cost	Years of PV Savings
Permitting fee	$300 (one-time) *(1.5% of PV system cost)*	0.75
Property taxes	$340 per year (recurring) *(1.2 % of PV system cost)*	25.5
Sales taxes	$1,400 (one-time) *(7% of PV system cost)*	3.50
Utility design review	$500 to $1,000 (one-time)	1.25 – 2.50
Utility metering, interconnection, and protection fees	$200 to $1,000 (one-time)	0.50 – 2.50
Utility minimum charges and standby charges	$5 to $15 per month (recurring)	4.50 – 13.50
Utility insurance requirements	$5 to $25 per month (recurring)	4.50 – 22.50
Competitive transition charge (CTC)	Varies, ~ 4¢/kWh in CA	1.5
TOTAL	$3,000 one-time, plus ~ $300 per year	Equal to about 40 years of energy savings!!

[a]Assumes a 2.5 kW PV system costing $20,000, electricity rate is 12¢/kWh. The figures in the table do not take into account the added time and resource cost for PV suppliers to "deal" with these hidden cost issues.

SOURCE: Derived from Howard Wenger, Presentation to Technology and Partnership Training, Million Solar Roofs Initiative, Denver, Colorado, April 1998.

What the figures in Table 1 suggest, above all, is that efforts to advance PV commercialization are largely pointless if they focus exclusively on advancements in the technology without addressing institutional issues that are an important contributor to overall costs. Accordingly, our view is that PV systems—particularly small-scale distributed applications that are disproportionately affected by these additional costs—will never achieve significant market penetration until most of these costs are either reduced or altogether eliminated.

Reducing or eliminating these costs, however, is a daunting task because the costs are being imposed by different entities and agencies within utilities, municipal governments, and state governments. Addressing this problem universally would require some sort of national consensus that expansion of PV markets is strongly in the public interest. Reaching this consensus would require a concerted effort that crossed political party lines, and crossed local, state, and federal jurisdictional boundaries. We appear to be nowhere near that kind of consensus at this point, so a second-best, piecemeal approach is likely to be the result.

E. Ensuring that Private Codes, Covenants, and Restrictions Do Not Prohibit or Restrict Solar Systems in Residential Housing

Throughout the United States, housing project developers are using deed restrictions known as covenants, codes, and restrictions (CC&Rs) in an effort to maintain a uniform appearance for housing developments, both throughout the construction phase and beyond. Many different elements of the development may be covered by CC&Rs, including the number and location of parked automobiles, the type of landscaping, the color of house paint, or the type of roofing material. In addition, CC&Rs

frequently prohibit or severely restrict the location and orientation of solar equipment, including PV arrays.[24]

The developers' motivation for including solar equipment in restrictive CC&Rs is a concern that the solar system will be perceived as an eyesore by a prospective homebuyer touring the housing development. Once the development is "built out" or completed, the developer typically loses interest in the appearance of the project, but the CC&Rs remain in place under the control of a homeowners' association.

Homeowners interested in utilizing solar energy have the choice of trying to design and install a system that complies with the CC&Rs, or trying to amend the CC&Rs to eliminate the restrictions on solar energy. According to a recent statement by several state chapters of the Solar Energy Industries Association (SEIA):

> The impact of [the CC&Rs] is that getting the necessary approvals allowing one to install a solar system can be extremely arduous, if not impossible, and the process tests the patience of contractors and prospective solar system purchasers to the point that, in quite a number of cases, the effort to install a system is simply abandoned. In some developments contractors will not even attempt to sell a solar system, knowing that the effort would be too time consuming and prone to failure.[25]

In response to the stifling influence of CC&Rs on solar energy development, a number of states have enacted laws that prohibit such restrictions.[26] According to solar industry representatives, however, these laws have not prevented CC&Rs from being a continuing barrier to residential solar development.

Arizona, for instance, enacted legislation in 1979 that made "void and unenforceable any deed covenant or restriction that effectively prohibits the use of a solar energy device." Yet according to the Arizona SEIA chapter the law is "virtually ignored by most builders, developers, and homeowners associations."[27] Apparently, developers and homeowners' associations claim that severe restrictions—such as requiring solar panels to be installed on the ground, or on the north side of a roof (away from the street, for instance, but also away from the optimal solar orientation) do not constitute an effective prohibition against solar energy. Any such disputes end up being presented to the homeowners' association's architectural review committee, which may take months to meet and decide the issue; and then to court, which will take even longer.

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[24] Solar Energy Industries Association (SEIA) Chapters in Arizona, California and Florida, *Education of Homeowner Associations on Solar Energy*, draft proposal, Sacramento, Calif., 1998.

[25] Solar Energy Industries Association (SEIA) Chapters in Arizona, California and Florida, *Education of Homeowner Associations on Solar Energy*, draft proposal, Sacramento, Calif., 1998, p. 1.

[26] Among the states prohibiting or limiting CC&Rs that restrict solar access are Arizona and California (discussed below), Colorado, Hawaii, Indiana, Massachusetts, and Nevada. See Chris Larsen, Henry Rogers, and Larry Shirley, *National Summary Report on State Regulatory Incentives for Renewable Energy*, prepared for the Interstate Renewable Energy Council by the North Carolina Solar Center, Raleigh, N.C., 1998, p. 90-95.

[27] Solar Energy Industries Association (SEIA) Chapters in Arizona, California and Florida, *Education of Homeowner Associations on Solar Energy*, draft proposal, Sacramento, Calif., 1998, p. 1

In California, over 30,000 housing developments with approximately 6 million homes are governed by homeowners' associations, and the vast majority of new housing tract developments built in the state over the past 15 to 20 years have some sort of CC&R.[28] California sought to avoid the problems that arose in Arizona by enacting a Solar Rights Law that allows reasonable restrictions on solar energy systems, but defines a "reasonable" restriction as one that does not increase the cost of the system by more than 20% or decrease the system's efficiency by more than 20%.[29] However, most homeowners' associations are unaware of the Solar Rights Law, and conflicts between individual homeowners and their associations are common.

Appropriate legal remedies are clearly a necessary element in solving the problem of restrictive CC&Rs. On the other hand, the evidence from Arizona and California suggests that legal remedies are not enough because homeowners' associations still include—and try to enforce—provisions in CC&Rs restricting solar energy development.

In our view, what is needed is an educational campaign targeted at three different groups: 1) home builders associations; 2) homeowners' associations; and 3) the attorneys who draft the CC&Rs. Home builders may need both a carrot and a stick. The carrot needs to be dangled by the solar industry and other solar advocates, who need to provide home builders with an incentive to include solar energy in the portfolio of options available to purchasers of their homes.

The stick is quick and effective enforcement against homeowners' associations that ignore legal prohibitions against restrictive CC&Rs. The solar trade associations are an obvious choice for this task, since there are economies and synergies in having form letters and, if necessary, experienced attorneys available to advise homeowners' associations of the consequences of inappropriate restrictions on solar energy development. Three state SEIA chapters—Arizona, California, and Florida—have gotten off to a promising start in addressing these issues by proposing a marketing and education program targeted at homeowners' associations through the Community Association Institute and its state and local chapters. If funded, the campaign will include general information about solar technologies, discuss the benefits of installing solar systems, showcase appropriate installations, discuss siting and permitting issues, describe technical standards and certification programs, review CC&R law in lay terms, and provide information on community-based solar energy programs such as those sponsored by the Interstate Renewable Energy Council (IREC).

F. Enacting and Enforcing Solar Zoning Laws to Protect Solar Access Rights

As early as the 13th century, English common law decreed that the rights to sunlight falling on a parcel of land accompany the rights to the land itself.[30] This doctrine eventually evolved into the Doctrine of

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[28]Solar Energy Industries Association (SEIA) Chapters in Arizona, California and Florida, *Education of Homeowner Associations on Solar Energy*, draft proposal, Sacramento, Calif., 1998, p. 2.

[29]California Civil Code Section 714.

[30]The legal maxim was "*Cujus est solum, ejus est usque ad coelum et ad inferos*," which translates "To whomsoever the soil belongs, he also owns to the sky and to the depths." See Thomas Starrs, "Solar, Wind and Geothermal Energy,"in *Sustainable Environmental Law* (St. Paul, Minn.: West Publishing Co., 1993), p. 748.

Ancient Lights, which allowed a property owner to acquire a negative easement, or prescriptive right, over adjoining land for the unobstructed passage of light into his own land.

Early U.S. law rejected the Doctrine of Ancient Lights in favor of an absolute right to build on one's property regardless of the impact on the light, air, or views of adjacent landowners. Thus, property owners in the United States cannot be assured of a right to continued solar access under traditional common-law nuisance doctrines.

As a result, solar energy advocates have had to rely on solar easements and other methods for securing an enforceable right to sunlight:

- ***Solar easements.*** Solar easements, the most common approach, are voluntary but legally binding agreements between two adjacent landowners whereby the "burdened" party agrees never to build a structure or other impediment that interferes with access to sunlight for the "benefiting" party.[31] Solar easements are considered valid in 29 states. Solar easements are of limited utility, however, because 1) they have to be individually negotiated, sometimes with multiple adjoining landowners; 2) adjoining landowners may simply refuse to negotiate, or may demand too high a price; 3) litigation is required to enforce the easement; and 4) monetary damages, rather than injunctions to prevent the offending use, are usually the only available remedy.[32]

- ***Land-use planning and zoning laws***. The use of land-use planning and zoning laws has emerged as the most efficient method for protecting solar access. Such laws rely on the power of municipalities to regulate the use of property for the benefit of the public health, safety, and welfare. Land use laws provide superior solar access protection because they apply universally within the municipality, because they can be more responsive to regional needs than state or federal laws, and because they can be closely integrated with other planning and zoning policies, such as building height, setback, and orientation. Three different approaches have evolved for protecting solar access through land use laws: 1) a permitting system, 2) a "solar envelope" system, and 3) "solar fences." Under a solar permitting system, parties apply for permits to construct solar projects, and when the permits are granted, they are registered with the municipality to prevent any future construction from intruding on the permit holder's solar access. Under a solar envelope system, solar building envelopes are defined in three dimensions of land, area, and air space. These envelopes define the developable area for a parcel of land, and any development outside these envelopes is prohibited. Solar fences prohibit landowners from placing any obstructions—either building components, trees, or shrubs—that cast a shadow on neighboring property longer than the shadow cast by a hypothetical perimeter fence of a specified height between certain hours on the shortest day of the year. Although this approach sounds complicated, the calculations

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[31]See Chris Larsen, Henry Rogers, and Larry Shirley, *National Summary Report on State Regulatory Incentives for Renewable Energy,* prepared for the Interstate Renewable Energy Council by the North Carolina Solar Center), p. 89.

[32]Thomas Starrs, "Solar, Wind and Geothermal Energy," *Sustainable Environmental Law* (St. Paul, Minn.: West Publishing Co., 1993), p. 749-50.

involved are simple and uniform for a specified fence height throughout the municipality, making it simple to administer.[33]

Securing solar access is a serious long-term concern for solar energy development, particularly in urban and suburban settings where property owners are more likely to interfere with solar access on neighboring properties. Although a majority of states now recognize the validity of solar easements, we feel that land use planning and zoning laws are a better vehicle for protecting solar access because of their broader application, simpler implementation, and more effective enforcement.

G. Developing New Regulatory Regimes for Distribution Utilities

Traditional approaches to price regulation give electric utilities an incentive to discourage customer self-generation. The utilities' rate-based capital expenditures and their operating expenses are combined to create their "revenue requirement." This revenue requirement is divided by customer class and ultimately by kilowatt-hour (kWh) sales of electricity within each class.[34]

Because the electric utility industry is so capital intensive, most of the revenue requirement consists of fixed rather than variable costs. This means that a reduction in kilowatt-hour sales does not lead to a proportional reduction in total costs. Because these costs have to be spread out over fewer kilowatt hours, rates have to go up. An increase in rates, however, gives more customers an incentive to conserve or to self-generate, leading to still fewer kilowatt-hour sales and still greater rate increases.

When customers install energy-generating (or energy-conserving) equipment on their premises, the utility loses revenue needed to cover the fixed costs of its investment in capital expenditures on plant and equipment, called its "rate-base." The utility, in turn, is compelled to seek higher rates from its remaining customers in order to recover the same fixed costs from a smaller customer base. This creates an undesirable spiral as higher rates encourage additional self-generation and bypass, leading once again to higher rates. Again, the point is that under traditional regulatory regimes, utilities have an incentive to discourage conservation and self-generation by their customers because their revenues are tied to their sales of energy.

One might expect that the introduction of retail competition as part of the electricity industry's restructuring would eliminate the distribution utilities' incentive to discourage self-generation, since under current forms of restructuring, the retail energy service provider is separate from the distribution company. In theory, the energy service provider sells end-use customers the energy, while the distribution company sells the energy service providers access to its distribution system. In practice, however, most post-restructuring regulatory regimes still compensate the distribution company based on the amount of energy flowing through its system. This means that the distribution company still has an incentive to discourage self-generation, since most of the kilowatt-hours generated from rooftop PV systems, for example, are consumed on-site and never reach the utility's distribution system.

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[33] Several municipalities have adopted this approach, including Boulder, Colo., and Los Alamos and Taos, N.M. See Thomas Starrs, "Solar, Wind and Geothermal Energy," *Sustainable Environmental Law* (St. Paul, Minn.: West Publishing Co., 1993), with imposing additional fees and charges on distributed PV system, p. 750-51.

[34] Large commercial customers and industrial customers typically pay demand charges (based on peak energy demand) as well as energy charges (based on total energy use).

There are, however, several regulatory policies that could provide incentives for distributed generation: 1) revenue caps; 2) true cost of service; 3) portfolio standards; 4) buydowns and production incentives; 5) line extensions and replacements; and 6) microgrids.

1. Alternative Regulation in Practice: Revenue Caps

We are aware of only one exception to traditional distribution system regulation in practice today. The State of Oregon recently approved a new plan for price regulation of PacifiCorp's distribution system.[35] The alternative regulatory mechanism applies a revenue cap to the distribution system functions in order to sever the link between profits and kilowatt-hour sales. Under the mechanism, temperature-adjusted actual sales revenues from each major customer class will be compared to a predetermined revenue cap for that class. Any differences between actual revenues and the cap are set aside in a balancing account each year. The following year, this difference is either given back to the utility (if sales are lower than projected) or given back to customers (if sales are higher than projected). Ralph Cavanagh of the Natural Resources Defense Council (NRDC) characterized the Oregon decision as "a wonderful new regulatory precedent," suggesting that it might be an appropriate model for other states.

2. True Cost of Service

Currently, distribution companies provide service on an average pricing basis that ignores location-specific cost-of-service differences. Although a rural area is more expensive to serve than an urban one, rural customers enjoy the same distribution price as their urban neighbors. The average pricing approach does provide a simple universal pricing structure that is not regressive from a consumer perspective. The downside is that average pricing does not reward distribution companies for finding innovative ways to reduce distribution costs.

Further, distribution companies do not take into account time-specific costs of providing distribution service. Most energy companies do offer time-of-use rates, however these are primarily based on generation costs, not distribution costs. New regulation that incorporates location- and time-specific cost-of-service will automatically reward distributed generation (and energy efficiency) technologies that operate where and when they are most needed. The evolution to a true cost of generation, transmission, and distribution service approach, at least for planning and performance-based rate-making purposes, is economically most efficient and will naturally and optimally provide distributed generation incentives.

3. Renewables Portfolio Standards (RPSs)

Some states have incorporated renewables portfolio standards (RPSs) into restructuring implementation. Most RPS proposals have been structured in such a way as to favor the deployment

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[35] Oregon Public Utility Commission, *In the Matter of the Revised Tariff Schedules in Oregon Filed by PacifiCorp, dba Pacific Power & Light Company*, Order No. 98-191 (May 5, 1998).

of least cost bulk power renewables.[36] States (and the federal government) can encourage specific technologies, resources, and applications to be developed via the portfolio's standard implementation rules. Arizona, for example, has established a solar-only portfolio standard that provides extra credit multipliers to encourage in-state manufacturing and assembly, as well as multipliers for distributed customer-sited generation.[37] Every kilowatt-hour that is generated by, say, a rooftop PV system is actually credited with 1.5 kWh towards fulfilling the minimum solar generation that must be supplied by the energy provider; however, a kilowatt-hour generated by a central-station solar plant does not enjoy a multiplier. This approach effectively provides a 50% cost advantage for on-site generation. The downside to this strategy is that less total solar capacity may be built. But this downside risk may be completely offset by providing an implementation structure that works and fulfills the portfolio standard mission to enable a self-sustaining solar market.

4. Buydowns and Production Incentives

Upfront capital cost buydowns and per-KWh production incentives are policy instruments that reduce the cost of owning and operating distributed PV systems.[38] These are transitional policy vehicles to jump-start markets and help bridge the cost-effectiveness gap for renewable and distributed generation technologies. As can portfolio standards, providing direct incentives for environmentally preferred, modular generation can be an effective policy to support a distributed energy system.

5. Distribution Line Extensions and Replacements

Some states, as a matter of regulatory policy, require utilities to compare the cost of extending a distribution line with the cost of a PV/hybrid system to serve new customer load.[39] The policy can be expanded to require consideration of distributed generation as an alternative to distribution line replacement—an approach that may be particularly effective for rural electric cooperatives.[40] An old decaying line that delivers electricity to a minimal load that is consequently expensive to serve will eventually need to be replaced. It may be better to remove the old line and serve the load with an on-site PV/hybrid system.

The policy of requiring comparison of line extension and replacements with a PV system is strictly driven from an economics perspective. It is unique to policies previously discussed in this paper in that it encourages off-grid, not grid-connected, PV deployment. Much like grid-connected PV policies, however, this policy would require new regulations to change the way most distribution companies currently do business.

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[36]For further discussion of a national renewables porfolio standard (RPS), see Ray T. Williamson, "Appendix A: A Portfolio Approach to Developing Renewable Resources," *Expanding Markets for Photovoltaics* (Washington, D.C.: Renewable Energy Policy Project, 1998).

[37]Arizona Corporation Commission, Electric Competition Rules A.A.C. R14-2-1600 *et seq.*, Aug. 5, 1998, see Web site: www.cc.state.az.us/utility

[38]For further discussion of buydowns, see Thomas J. Starrs and Vincent Schwent, "Government Buydowns for the Residential Market," *Expanding Markets for Photovoltaics* (Washington, D.C.: Renewable Energy Policy Project, 1998).

[39]Arizona and Colorado are examples of states with line extension versus PV policies.

[40]T.E. Hoff and M. Cheney, "An Historic Opportunity for Photovoltaics and Other Distributed Resources in Rural Electric Cooperatives," submitted to *The Energy Journal*, 1998.

6. Microgrids

Microgrids are islands of end-user loads that are served by a combination of modular distributed generation technologies.[41] For example, a new housing development might obtain electricity by locating a microturbine or fuel cell in each basement (or larger units centrally located within the development), in combination with a PV array on each roof with batteries. The homes might still be wired together to provide added reliability. The hypothesis is that a microgrid (or "minigrid") could provide cleaner, more reliable power at a competitive price.

A potential policy is to encourage or at least facilitate the creation of microgrids. Microgrids exist today, to a certain extent, in some larger commercial facilities that are interconnected and served by on-site cogeneration facilities. It is not difficult to imagine existing residential neighborhoods evolving to microgrids, but the transition is perhaps more than a decade away. Already, however, individual homeowners are purchasing and installing on-site generation in increasing numbers. In any case, it is incumbent upon regulators to recognize that innovation in the distribution system must be allowed to flourish. At the leading edge of technological innovation is clean distributed generation that may ultimately lead to the creation of microgrids.

III. THE PLAYERS: WHO WILL CALL THE SHOTS ON DISTRIBUTED GENERATION?

A. Who Has the Authority and the Jurisdiction?

Federal and state legislators and regulators all have the potential to influence the extent to which distributed generation emerges as the dominant paradigm for encouraging decentralized renewables. Federal and state legislators interested in promoting distributed technologies can tailor economic incentives toward these technologies. An example at the federal level is the Clinton Administration’s call for the availability of standardized interconnection requirements and net metering for renewable generating facilities sized 20-kW or smaller.[42] At the state level, an example is the California legislature’s requirement that most of California’s Emerging Renewables Buydown Program funds be reserved for small-scale systems.[43]

As a practical matter, it is worth noting that because of the general hostility towards “green” initiatives among the Republican leadership in the present Congress, solar energy advocates expect little in the way of significant new initiatives from the federal government. Although the Clinton Administration has expressed support for new solar initiatives—including the Million Solar Roofs program and a

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[41]T.E. Hoff, H.J. Wenger, C. Herig, and R. W. Shaw, Jr., “A Micro-Grid with PV, Fuel Cells, and Energy Efficiency,” presented at the 1998 Annual Conference, American Solar Energy Society, Albuquerque, N.M., June 1998.

[42]Details of the Administration’s Comprehensive Electricity Competition Plan, including full text of the accompanying draft bill, are available on the Internet at the following Web site: http://www.hr.doe.gov/electric/cecp.htm.

[43]The California legislature specified that at least 60% of the buydown funds have to be awarded to systems sized 10 kW or smaller, and an additional 15% of the funds to systems sized 100 kW or smaller. See California Energy Commission, *Renewable Technology Program Guidebook, Volume 3: Emerging Renewable Resources Account* (Sacramento: January 1998).

package of tax and other financial incentives—such initiatives are hamstrung because key elements require congressional assent. State legislatures have taken up at least some of the slack by developing some innovative policies for promoting solar and other renewable energy technologies. These include the state portfolio standards and buydown programs mentioned previously and discussed in other papers in this document.[44,45]

Apart from legislators, federal and state utility regulators have the potential to affect the nature and pace of distributed PV development. Some of the structural and jurisdiction questions that have been raised in the context of state restructuring efforts have important implications for distributed generation.

Perhaps the most important question regulators will address is whether and, if so, to what extent distributed generating facilities will be treated for regulatory purposes as either 1) generation assets (and therefore out of bounds for many distribution utilities forced to divest themselves of generation), or 2) transmission and distribution assets (and therefore falling within the scope of the regulated monopoly franchise), or perhaps as some unique hybrid. As esoteric as this definitional question may sound, it could very well shape future patterns of investment in distributed PV and other distributed generation.

Federal and state regulators will also affect distributed PV development by shaping the restructuring proposals that come before them, pursuant either to their independent regulatory jurisdiction or their authority over implementation of legislative acts. Sometimes the regulators' role will be prominent and visible, as it was in the case of the implementation of the Energy Policy Act of 1992 by the Federal Energy Regulatory Commission (FERC). At other times, the regulators' role will be more subtle.

Even in the absence of any prominent legislative mandate, federal and state regulators are routinely making decisions that define the regulatory framework in which distributed generation technologies must compete. Accordingly, we feel it is important to ensure that utility regulators are kept apprised and well informed of the evolution of distributed generation, from both legal and technical perspectives. This will help avoid the possibility that regulators will act inadvertently to shut off opportunities for distributed generation because they are unaware of the impacts of their actions on the nascent markets for distributed technologies.

B. Who Has an Interest in Encouraging Distributed Generation?

The most obvious constituencies for encouraging distributed generation are the businesses that are manufacturing or selling distributed generating equipment. These constituencies are far broader than just the PV industry. They are not restricted to companies involved in the commercialization of other small-scale renewable technologies (particularly wind and hydro), but also include companies promoting fuel cells, microturbines, and micro-cogenerators. They also include companies that may

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[44] For discussion of a national renewables porfolio standard, see Ray T. Williamson, "Appendix A: A Portfolio Approach to Developing Renewable Resources," *Expanding Markets for Photovoltaics* (Washington, D.C.: Renewable Energy Policy Project, 1998).

[45] For discussion of buydowns, see Thomas J. Starrs and Vincent Schwent, "Government Buydowns for the Residential Market," *Expanding Markets for Photovoltaics* (Washington, D.C.: Renewable Energy Policy Project, 1998).

have a more peripheral, but ultimately quite substantial, interest in distributed generation such as the natural gas industry, which would stand to gain tremendously if customers began using natural gas to generate their own electricity using distributed fuel cells or gas turbines.

This diversity of interests suggests that PV proponents might gain from encouraging collaborative efforts between these various constituencies. For the most part, however, such collaborative efforts have failed to emerge. There are a couple of exceptions.

One is the California Alliance for Distributed Energy Resources (CADER), which emerged during the regulatory and legislative debates on electricity industry restructuring in California. Although CADER has been akin to a rudderless ship over the past year, it has been influential in some important respects. CADER was partially responsible, for instance, for an effort to encourage the California Public Utilities Commission to issue an "Order Instituting Rulemaking" regarding the unbundling of energy and ancillary services at the distribution level, and the role of utility distribution companies with respect to the optimal utilization of distributed generation.[46]

The second exception is the Distributed Power Coalition of America (DPCA). Incorporated in February 1997, DPCA describes itself as the first national group incorporated to advocate for distributed power. Its mission statement declares that the organization "provides the integrated industry leadership to assure that stakeholders fully recognize and consider the many advantages of distributed power." In addition, DPCA serves as a clearinghouse for information on distributed power. Interestingly, DPCA's membership is overwhelmingly dominated by natural gas interests, including gas turbine manufacturers, gas companies, and gas utilities. Not a single PV company or other renewable energy company is in its membership.

In our view, collaborative efforts among a wider range of distributed generation proponents would bring important synergies. The PV industry, which is notoriously underfunded with respect to its political activities at both state and federal levels, would benefit because some of the other distributed generation technologies are being developed by deep pockets with substantial political clout, including Allied Signal, Caterpillar, Enron, and Lockheed Martin.[47] The distributed natural gas technologies, on the other hand, would benefit because PV and other renewables have a level of grassroots political support and popular appeal that their technologies are unlikely to reach. The PV industry has leveraged this popular support into an impressive record of political success given the anemic level of support for political activities. For instance, according to a pair of recent studies prepared on behalf of

[46]This effort resulted in the preparation of a letter from a variety of stakeholders to the California Public Utilities Commission (PUC), asking the PUC to initiate the rulemaking proceeding. Accompanying the letter was a lengthy, detailed statement outlining distributed generation regulatory issues that the stakeholders believe "are integral to electric restructuring and to optimal [distributed generation] implementation." Draft letter from California stakeholders to Richard Bilas, President of the California Public Utilities Commission, June 5, 1998.

[47]One indication of the perceived difference in clout is the array of financial interests that have taken an interest in distributed generation. For example, the 1997 conference of the California Alliance for Distributed Energy Resources' (CADER) was attended by representatives from Bear Stearns, Goldman Sachs, Lehman Brothers, Merrill Lynch, and Paine Webber. Few, if any, of these financial powerhouses have ever expressed a similar level of interest in PV technology.

the Interstate Renewable Energy Council (IREC), 40 states offer financial incentives for renewable energy, while 46 states offer regulatory incentives.[48]

C. Who Has an Interest in Blocking Distributed Generation?

There are very few constituencies inherently opposed to distributed generation. The most obvious candidates are owners of central-station power plants threatened by competition from distributed generating facilities, and utility distribution companies wary of losing the only remaining remnant of their regulated monopoly enterprises.

The expansion of distributed PV generation markets is unlikely to pose a significant incremental threat to the operators of existing central-station power plants within the next decade. Large power plant owners are already threatened by a combination of forces, including wholesale competition that has made plants producing power at an above-market price uneconomic, and new generating technologies (particularly gas turbines) that have lowered the incremental price of new power. As a result, companies invested in central-station power plants face enough existing competitive threats that they probably are untroubled by the threat of PV technology.

On the other hand, there are already some signs that utilities are concerned about the threat associated with distributed generating technologies other than PV. The Utility Photovoltaic Group (UPVG), for example, supports the availability of net metering for PV systems but not for other small-scale generating technologies. Similarly, the utilities' position on net metering in individual states often has turned on the question of which technologies would be eligible for net metering. This points to a potential downside from having PV advocates affiliate themselves too closely with other distributed generating technologies that do not enjoy the same level of political and public support.

In the long run, it seems clear that distributed generation poses a significant economic threat not only for central-station generation, but also potentially for the high-voltage transmission network. If future capacity shortages in a transmission-constrained region can be resolved more simply and more cheaply by siting a gas turbine, a fuel cell, or a PV system in the immediate area than by constructing additional transmission capacity to the region, then the balance of power in the electricity industry will shift quickly away from the current emphasis on transmission access for bulk power generation. As this era approaches, those companies with a stake in the existing central-station paradigm will feel increasingly threatened. For some of these companies, the response will be to hunker down and protect their traditional turf. For others, the response will be to embrace the new era and compete aggressively in the market for these emerging technologies. The choice these companies make will be strongly influenced by the eventual course of the restructuring debate, and in particular by the degree to which the existing industry is given the opportunity to participate in the new markets.

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[48] See Henry Rogers, Chris Larsen, and Larry Shirley, *National Summary Report on State Financial Incentives for Renewable Energy* (Raleigh, N.C.: Interstate Renewable Energy Council & North Carolina Solar Center, July 1997); Chris Larsen, Henry Rogers, and Larry Shirley, *National Summary Report on State Regulatory Incentives for Renewable Energy* (Raleigh, N.C.: Interstate Renewable Energy Council & North Carolina Solar Center, December 1997). Most, but not all, of these incentives are available for PV technology.

D. Shifting Allegiances: Can Opponents of Distributed Generation Be Turned into Fans?

As the preceding discussion suggests, one of the most intriguing opportunities for accelerating the deployment of distributed PV is to provide opportunities for existing industry participants to compete in new markets for distributed generation. As the debate among California Alliance for Distributed Energy Resources (CADER) members illustrates, however, this approach is highly controversial. A thorough discussion of the pros and cons of this issue could easily occupy volumes longer than this entire report, and in our view there is no simple answer.

The complexity of this issue is well illustrated by looking at an interesting analog: The Federal Communications Commission's (FCC) debate regarding the allocation of wireless (cellular) telephone franchises between existing wireline companies (particularly the regional Bell companies) and nonutility companies. The FCC originally favored granting licenses exclusively to wireline providers on the grounds that only they had the technical and financial resources to develop the necessary infrastructure for cellular service. Shortly thereafter, the FCC completely reversed itself, concluding that only nonwireline companies should be allowed to compete because of concerns that wireline carriers would extend their monopoly power from wireline markets into wireless service, and because of the possibility that wireline carriers might have an incentive to inhibit rather than advance the development of wireless services. Finally, the FCC in effect threw up its hands and essentially split the difference, settling on a policy that granted cellular franchises to one wireline carrier and one nonwireline carrier in each geographic region, with the licenses being freely exchangeable after 5 years. One indication that the FCC's approach was successful is that 10 years later, markets for wireless telephony are considered both highly innovative and at least moderately competitive, with the market share of wireline providers holding roughly steady at 60%.[49]

The issues surrounding distributed generation and the electricity industry, while not identical, raise many of the same concerns for PV advocates and policy-makers. Electric utilities are well established, highly experienced, well capitalized, and technologically savvy. They control access to their distribution networks and are likely to pursue market opportunities that can be smoothly integrated into their existing networks. On the other hand, companies developing PV and other distributed generating technologies are likely to be more innovative, entrepreneurial, and creative. They also are more likely to pursue market opportunities that compete directly with traditional utility service, even to the point of displacing or supplanting existing transmission and distribution networks.

The challenge is determining how best to balance opportunities to participate in distributed generation markets between utility and nonutility companies. PV advocates need to carefully consider the ramifications of either 1) relying exclusively on utilities to pursue opportunities for distributed PV development, or 2) relying entirely on nonutility companies to create opportunities for distributed PV development, with utilities flatly prohibited from participating in, and profiting from, these opportunities.

[49] For a more thorough discussion of these issues, see Thomas J. Starrs, "Regulating Innovation and Competition in Emerging Technology Markets: The Effects of Utility Participation in the Market for Remote Photovoltaic Systems," Ph.D. Dissertation, University of California at Berkeley, December 1996, p. 83-92.

In our view, both of these extreme positions are likely to slow the development of distributed PV markets. A better strategy is one that provides opportunities for all potential market participants, while ensuring that utilities are not allowed to use their control over distribution networks to unfair competitive advantage.

IV. ACTION RECOMMENDATIONS: POLICIES TO SUPPORT A DISTRIBUTED ENERGY SYSTEM

Ultimately, the emergence of distributed generation as a new paradigm for the electricity industry is likely to depend on the nature and pace of innovation among various distributed technologies, not necessarily PV. The inherent advantages of PV technology—its modularity, its environmental advantages, and its use of a ubiquitous energy source—may justify the implementation of policies that favor PV above other distributed generating technologies that rely on fossil fuels, even if those technologies are cleaner and more efficient than current fuel-burning power plants.

Encouraging the development of distributed energy systems will require the concerted efforts not only of various levels of government—from city councils and state legislatures to the U.S. Congress—but also of state and federal utility regulators, the utilities themselves, and the solar energy industry. Whether public support for solar energy is strong enough and pervasive enough to encourage these various actors to work together remains to be seen, but there are promising signs of progress. Our recommendations, which are summarized in Table 2, are as follows:

⇒ ***State and federal policy-makers should require utilities to offer net metering and/or other pricing policies that recognize the value of distributed generation.*** Net metering, the simplest of these policies, allows owners of distributed systems to use their excess electricity to offset retail electricity purchases from their local electric company and to buy any required shortfall for the same price, thus paying only for the "net" electricity consumed. Policy-makers can cap the amount of net metering on any one company's electric system at a level high enough to stimulate the PV market while small enough not to be noticeable compared to the utility's revenues.

⇒ ***Federal and state policy-makers should institute standardized technical requirements for utility interconnection of distributed systems***. Although standard-setting organizations such as Underwriters Laboratories (UL) and the Institute of Electrical and Electronics Engineers (IEEE) have developed standards for the safe interconnection of PV systems to the electric grid, utilities have the discretion to accept or modify such standards. The result is a melange of requirements that differ from state to state and even within states—a situation that prevents PV manufacturers from developing products for a national market. Electric companies should be encouraged to agree on an industry standard, as an alternative to a standard mandated by the federal government or state governments.

⇒ ***Individual utilities and state regulators should simplify power purchase agreements (PPAs) between electric service providers and the owners of distributed systems.*** To attach a PV system to the grid, PV system owners must sign a PPA with their local utility.

Unfortunately, utilities developed their PPAs for facilities with capacities up to hundreds of megawatts (MW) rather than PV systems of perhaps a few kilowatts (kW). Understanding PPAs requires specialized—and expensive—legal expertise, presenting a substantial and unnecessary obstacle to PV market development. State policy-makers must require that utilities offer simple, straightforward contracts to customers installing their own PV systems.

⇒ ***State and local governments should minimize the various fees and charges associated with permitting, installing, and/or operating distributed systems.*** Utilities frequently impose various fees, for example for engineering design reviews, metering fees, permitting and utility insurance fees that are arguably discriminatory and, at least, often incongruously onerous for small PV systems. Policy-makers desirous of promoting PV development must minimize these "hidden" costs, which otherwise will thwart even the best designed program.

⇒ ***State legislators, state and regional solar energy industry groups, and possibly the U.S. Congress should ensure that homeowners' association rules and other private codes, covenants, and restrictions (CC&Rs) do not prohibit or inappropriately discourage the use of distributed systems in residential housing developments***. In many cases, developers of residential real estate institute covenants restrict property modifications or other behavior perceived to lessen a community's aesthetic appeal, and thereby its commercial value. Often, homeowners' associations continue these restrictions after a development is completed. According to solar professionals, these regulations constitute a large and unaddressed barrier to PV market development. Removing this barrier will require a combination of state legislation and education for associations of home builders and owners, along with coordinated legal intervention by state or regional solar trade associations when the presence of the state proves an insufficient safeguard.

⇒ ***Municipal and state governments should enact and enforce solar zoning laws to protect solar access rights.*** U.S. law generally permits the right of property owners to build as they please over the right of adjoining property owners to air, wind, light or sunshine. Although a majority of states now recognize the validity of solar easements—voluntary agreements, negotiated individually—land use planning and zoning laws may prove a better vehicle for protecting solar access because of their broader application, simpler implementation, and more effective enforcement.

⇒ ***State legislators and regulators should develop new regulatory regimes that encourage—or at least do not discourage—customers that seek to generate part or all of their electricity using PV or other distributed generating technologies and encourage unregulated energy companies that seek to provide distributed generation services to customers.*** Today's integrated utilities—i.e., firms that generate, transmit, and distribute power—may perceive an incentive to discourage distributed, customer-owned generation such as PV, in that regulators calculate the utilities' allowed profits on the basis of the capital equipment they install. Restructuring of the electric system will pare the regulated portion of many integrated electric companies into residual distribution utilities. Although not interested in generation per se, these firms will remain regulated entities; regulators will peg their allowed rates to the amount of electricity they deliver. Thus, the distribution firms will retain a financial incentive to discourage self-generation. Federal and state regulators must restructure the distribution system so that distribution utilities perceive incentives to encourage—or, at least, not to discourage—PV and other distributed technologies.

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Table 2: Summary of Action Recommendations: Potential Policy Incentives for Distributed PV Development

Policy	Approach	Primary actor	Secondary actor
Net metering: Require utilities to offer net metering	Legislation/regulation	State legislatures/regulators	Congress/Federal Energy Regulatory Commission
Interconnection standards: Standardize technical requirements for utility interconnection	Legislation/regulation	Congress/ Federal Energy Regulatory Commission	State legislatures/regulators
Power purchase agreements: Simplify power purchase agreements between electric service providers and owners of distributed systems	Utility tariffs	Individual utilities/state regulators	N/A
Fees and charges: Minimize various fees and charges associated with permitting, installing, and/or operating distributed systems	Various: Municipal permitting fees, local property taxes, state sales taxes, utility tariffs, state restructuring laws	Various	N/A
Codes, covenants, and restrictions (CC&Rs): Ensure that private CC&Rs don't block solar systems in residential developments	Legislative prohibition combined with education and outreach programs	State legislatures, state and regional solar energy industry groups	Congress
Solar access: Enact and enforce laws that protect solar access	Land use planning and zoning laws	Municipal governments, state governments	N/A
New regulatory regimes: Develop new regulatory regimes for distribution utilities	State regulation of distribution utilities in the form of revenue caps, true cost-of-service, portfolio standards, buydowns and production incentives, line extension and replacement policy, and microgrids	State legislators/regulators	N/A

In supporting the development of a distributed energy system, the PV industry and advocates must decide whether and how to ally themselves with other distributed resource interests. Models for collaboration include the California Alliance for Distributed Energy Resources (CADER) and the Distributed Power Coalition of America. We acknowledge the controversial nature of such alliances: There is a possibility that other, better funded technologies—for example gas-fired microturbines or fuel cells—could use the political appeal of PV to advance the cause of distributed energy and subsequently squeeze PV out of the market. Nevertheless, we believe that such alliances are well worth considering, owing to the very weak financial and political position of the PV community— PV is in a tough spot, and this requires some tough choices.

In the long term, supporters of PV must consider what kind of entity can best bring PV to market: established utilities, or the more entrepreneurial companies developing PV and other distributed generating technologies, or perhaps these entities will form alliances and work together. Electric utilities are well established, highly experienced, well capitalized, technologically savvy and, from many customers' point of view, trustworthy and likely to remain in business indefinitely. They control access to distribution networks, and are likely to pursue market opportunities that can be smoothly integrated into their existing networks. On the other hand, companies developing PV and other distributed generating technologies are likely to be more innovative, entrepreneurial, and creative, and they have no complicating commitment to central-station technology. Complicating the issue, distributed generation in general, by virtue of its real technical and economic advantages, poses a genuine threat to the established, central-station paradigm of how electricity is made and delivered. Thus, established utilities could become potent enemies of distributed energy if policy-makers freeze them out of the market for distributed generation. For this reason, we believe that it is wisest to provide opportunities for all potential market participants to bring PV to market, while ensuring through policy safeguards that established utilities cannot to use their control over distribution networks to unfair competitive advantage.

The challenge in promoting distributed PV is to weave a coherent and consistent set of policies out of a disparate group of decision-makers at different levels of government, and to ensure that those policies support the development in the private sector of a healthy and viable market structure that will endure long after any short-term financial incentives have come and gone.

APPENDIX A: EXISTING STATE NET-METERING PROGRAMS

State	Allowable Fuel Type	Allowable Customers	Allowable Capacity	Pricing Policy	Source of Authority	Enacted	Citation / Reference
Arizona	Renewables & cogeneration	All customer classes	≤ 100 kW	NEG(*) purchased at avoided cost	Arizona Corporations Commission	1981	Corp. Comm. Decision No. 52345
California	Solar only	Residential only	≤ 10 kW	NEG purchased at avoided cost; month-to-month carryover allowed w/ utility consent	California Legislature	1995	Public Utilities Code § 2827
Colorado	All resources	All customers	≤ 10 kW	NEG carried over month-to-month	Public Service Company of Colorado	1994	Advice Letter 1265; Decision C96-901
Connecticut	Renewables & cogeneration	All customer classes	≤ 50 kW for cogeneration; ≤ 100 kW for renewables	NEG purchased at avoided cost	Department of Public Utility Control	1990	CPUCA No. 159
Idaho	Renewables & cogeneration	Residential and small commercial	≤ 100 kW	NEG purchased at avoided cost	Public Utilities Commission	1980	ID PUC Orders No. 16025 (1980); 26750 (1997)
Indiana	Renewables & cogeneration	All customer classes	≤ 1,000 kWh/month	No purchase of NEG; excess is "granted" to the utility.	Indiana Utility Regulatory Commission	1985	170 IN Admin Code § 4-4.1-7
Iowa	Renewables	All customer classes	No limit	NEG purchased at avoided cost	Iowa Legislature and Iowa Utilities Board	1983	Utilities Division Rules § 15.11(5)
Maine	Renewables & cogeneration	All customer classes	≤ 100 kW	NEG purchased at avoided cost	Public Utilities Commission	1987	Code Me. R. Ch. 36, § 1(A)(18) & (19), § 4(C)(4)
Maryland	Solar only	Residential only	≤ 80 kW	NEG carried over to following month; otherwise not specified	Maryland Legislature	1997	Art. 78, Sec. 54M
Massachusetts	Renewables & cogeneration	All customer classes	≤ 60 kW	NEG purchased at avoided cost	Massachusetts Legislature	1997	Mass. Gen. L. ch. 164, § 1G(g); Dept. of Tel. & Energy 97-111
Minnesota	Renewables & cogeneration	All customer classes	< 40 kW	NEG purchased at "average retail utility energy rate"	Minnesota Legislature	1983	Minn. Stat. § 261B.164(3)
Nevada	Solar and wind	All customer classes	≤ 10 kW	NEG purchased at avoided cost; annualization allowed	Nevada Legislature	1997	Nev. Rev. S. Ch. 704
New Hampshire	Solar, wind & hydro	All customer classes	≤ 25 kW	PUC may require 'netting' over 12-month period; retailing wheeling allowed for up to 3 customers	New Hampshire Legislature	1998	H.B. 485
New Mexico	Renewables & cogeneration	All customer classes	≤ 100 kW	Either single meter with no purchase of NEG; or dual meter with NEG purchased at avoided cost	Public Utility Commission	1988	NM PUC Rule 570
New York	Solar only	Residential only	≤ 10 kW	NEG credited to following month; unused credit is granted to utility at end of 12-month period	New York Legislature	1997	Public Service Law § 66-j
North Dakota	Renewables & cogeneration	All customer classes	≤ 100 kW	NEG purchased at avoided cost	Public Services Commission	1991	North Dakota Admin. Code § 69-09-07-09

Oklahoma	Renewables & cogeneration	All customer classes	≤ 100 kW and annual output ≤ 25,000 kWh	No purchase of NEG; excess is "granted" to the utility.	Corporations Commission	1990	Schedule QF-2
Pennsylvania	Renewables only	All customer classes	≤ 50 kW	NEG purchased at wholesale rate	Philadelphia Electric Company	<1996	PECO Rate R-S, Supp. 5 to PA Tariff PUC No. 2, Page 43A
Rhode Island	Renewables & cogeneration	All customer classes	≤ 25 kW for larger utilities; ≤ 15 kW for smaller utilities	NEG purchased at avoided cost	Public Utilities Commission	1985	Supplementary Decision and Order, Docket No. 1549
Texas	Renewables only	All customer classes	≤ 50 kW	NEG purchased at avoided cost	Public Utilities Commission	1986	PUC of Texas, Substantive Rules, § 23.66(f)(4)
Vermont	Solar, wind, fuel cells using renewable fuel, anaerobic digestion	Residential, commercial, and agricultural customers	≤ 15 kW, except ≤ 100 kW for anaerobic digesters	NEG carried over month-to-month; any residual NEG at end of year is "granted' to the utility	Vermont Legislature	1998	H. 605
Washington	Solar, wind and hydropower	All customer classes	≤ 25 kW	NEG credited to following month; unused credit is granted to utility at end of 12-month period	Washington Legislature	1998	House Bill 2773
Wisconsin	All Resource	All retail customers	≤ 20 kW	NEG purchased at retail rate for renewables, avoided cost for non-renewables	Public Services Commission	1993	Schedule PG-4

(*) "NEG" refers to the "net excess generation" of electricity by the customer-generator (i.e., generation exceeds consumption) during the billing period.

APPENDIX B: PROPOSED STATE NET-METERING PROGRAMS

State	Allowable Fuel Type	Allowable Customers	Allowable Capacity	Pricing Policy	Source of Authority	Proposed	Citation / Reference
California (proposed) [amends existing law]	Solar and wind	Residential & commercial customers	≤ 10 kW	NEG carried over month-to-month; any residual NEG at end of year is "granted' to the utility	California Legislature	1998	A.B. 1755
Connecticut (enacted) [replaces existing rule after 1/1/2000]	Solar, wind, hydro, fuel cell, sustainable biomass	Residential only	No limit	Not specified	Connecticut Legislature	1998	Public Act 98-28
Hawaii (pending)	Solar only	All customer classes	≤ 250 kW	NEG carried over month-to-month; any residual NEG at end of year is "granted' to the utility	Hawaii Legislature	1998	H.B. No. 3410
Iowa (not enacted) [amends existing rule]	Solar, wind, biomass or hydropower	All customers	No limit	NEG carried over month-to-month; any residual NEG at end of year is purchased at avoided cost	Iowa Legislature	1998	S.F. 2390
Illinois (pending)	Solar and wind	All retail customers	≤ 40 kW	NEG carried over month-to-month; any residual NEG at end of year is purchased at avoided cost	Illinois Legislature	1998	S.B. 1228
Maine (not enacted) [amends existing rule]	Renewables only	All customer classes	≤ 100 kW	NEG purchased at avoided cost	Maine Legislature	1997	L.D. 2043
Nebraska (not enacted)	Wind & biomass	All customer classes	No limit	Not specified	Nebraska Legislature	1997	LB501
Puerto Rico (pending)	Renewables only	Residential customers	≤ 50 kW	NEG carried over month-to-month; any residual NEG at end of year is purchased at avoided cost	Puerto Rico Legislature	1998	[TBD]