Sustainable, Multi-Segment Market Design

for Distributed Solar Photovoltaics

Prepared by
Interstate Renewable Energy Council

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Solar America Board for Codes and Standards

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Solar America Board for Codes and Standards Report

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Executive Summary

There are two important and distinct markets for solar photovoltaic (PV) investment—a retail market and a wholesale market. In areas of the United States that are experiencing the most significant growth in PV investment, state and local policy makers have taken important differences between retail and wholesale markets into account in establishing policies that promote growth in both of these market segments. This multi-segment approach allows interrelated policies to function best in their designated roles, extending the benefits of PV to the widest possible range of participants.

Retail market policies include net metering and meter aggregation policies; community solar policies such as joint billing, virtual net metering, and joint ownership; and PV incentive programs. These successful retail policies allow retail customers to generate and use PV power to serve their electric power needs with minimal effort. They also provide easy enrollment, have minimal ongoing obligations and no hidden fees, and avoid the creation of taxable benefits and regulatory requirements that can often accompany participation in wholesale market programs.

Wholesale market policies include avoided cost pricing mechanisms, renewable energy credit (REC) markets, feed-in tariffs (FITs), and market-based procurement mechanisms such as auctions and requests for proposals (RFPs). Successful wholesale policies create opportunities to optimally locate distributed PV projects in a way that maximizes benefits to ratepayers while minimizing cost. An important consideration in establishing wholesale market policies is minimizing costs to ratepayers who pay for utility procurement decisions. To address this concern, successful wholesale programs create sustainable markets that avoid boom-bust development cycles and promote and capture cost reductions through market-responsive pricing mechanisms.

This paper discusses the important differences between retail and wholesale PV markets and provides examples of policies that have been implemented in the United States in both of these markets. The Retail Market Policies section discusses policies that enable end-use retail electric customers to invest in PV systems to meet some or all of their electricity needs. The Wholesale Market Policies section, by comparison, discusses policies that enable small and medium scale project developers to develop distributed generating facilities that will serve nearby retail electric utility load. Building upon those sections, a final Recommendations section examines the ways in which decision-makers in leading U.S. markets for PV market growth are implementing a range of interrelated policies that can support sustainable, multi-segment market growth for distributed PV.

Author Biographies

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Kevin Fox, co-founder of Keyes & Fox LLP, has developed a highly specialized legal practice that focuses on assisting clients with achieving regulatory goals and objectives, in particular energy market transformation efforts that facilitate growth in distributed energy resource markets. His firm has represented clients before more than 35 state public utility commissions. He received a J.D. from the University of California, Berkeley, and a B.S. from the University of California, Davis.

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Laurel Varnado is a policy analyst at the North Carolina Solar Center at North Carolina State University. Focusing on net metering and interconnection issues, she publishes the Interstate Renewable Energy Council's monthly Connecting to the Grid newsletter. Previously, she worked as an analyst for the Database of State Incentives for Renewables and Efficiency (DSIRE), and spent three years as an eco-tourism extension agent in West Africa. She holds a M.A. from the School for International Training and a B.A. from the University of North Carolina at Chapel Hill.

Solar America Board For Codes And Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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INTRODUCTION

During the past 10 years, there has been a significant increase in photovoltaic (PV) system investment in the United States. Recent trends, including a steady reduction in the cost of PV system components, suggests that this growth is likely to continue for the next decade and beyond.

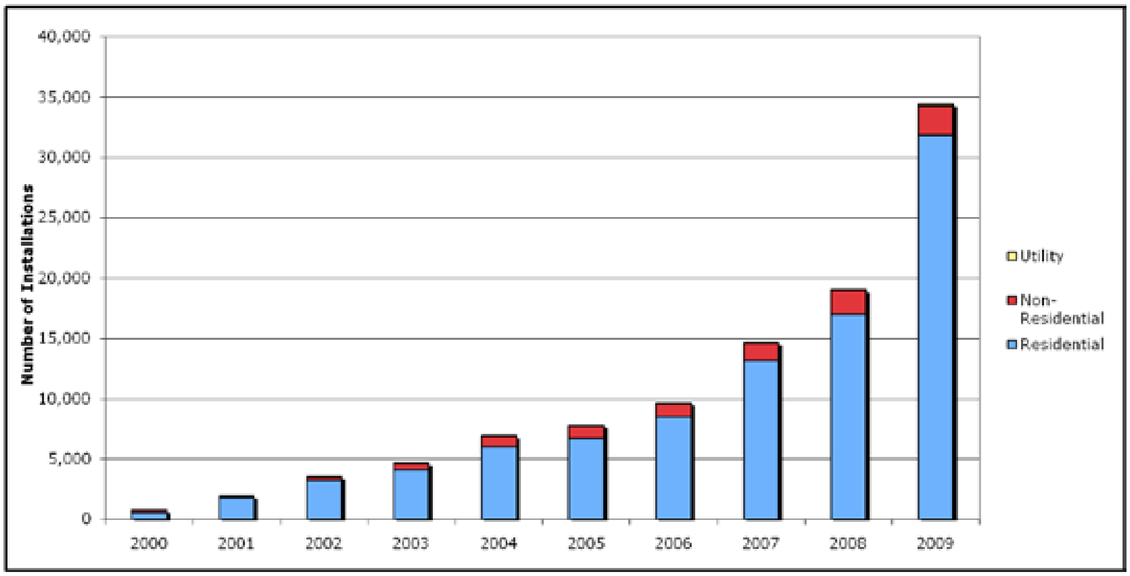

Figure 1: Number of Annual Grid-Connected Distributed and Utility-Scale PV Installations (1999-2009)[1]

A number of foundational policies have been implemented at federal, state, and local levels to facilitate the steady increase in PV system investment. At a federal level, tax incentives have proven instrumental to making PV systems cost-effective across a range of applications. At a state and local level, a range of important policies—including standardized interconnection procedures, streamlined permitting requirements, sales and property tax exemptions, net-metering policies, PV-friendly retail electric rate design, and incentive programs—has further stimulated investment in PV systems.

Among these policy tools, net metering has proven particularly important in facilitating U.S. PV system investment. In large part, the importance of net metering to U.S. PV system installations has been due to an absence of effective policies that otherwise might encourage development of a stronger wholesale PV market. There are many reasons why wholesale markets have failed to develop, but these are beyond the scope of this paper. What is important is that in the absence of effective wholesale policies, U.S. PV market growth has instead relied on retail policies, such as net metering, to facilitate customer investment in PV systems. In fact, in 2009, 85% of installed PV system capacity in the United States was customer-sited and most of those system owners enrolled in net metering programs.

Policies that support growth in U.S. PV markets are in many cases different than those that have been used to facilitate PV market development in other countries. While the United States has relied on retail market policies, such as net metering, some other countries have relied heavily on wholesale policies, such as feed-in tariffs (FITs), to facilitate investment in PV.

This paper originated as an effort to examine whether U.S. net-metering policy has been evolving in the direction of wholesale policies, such as FITs, that have facilitated PV market growth outside of the United

"... in the absence of effective wholesale policies, U.S. PV market growth has instead relied on retail policies, such as net metering, to facilitate customer investment in PV systems."

States. What the authors found in conducting research for this paper is that U.S. net-metering policies are indeed evolving but not toward wholesale policies that have been deployed in other countries. Rather, net metering policies have expanded to become more available to a wider group of participants. Net-metering is currently available in 43 states, the District of Columbia, and Puerto Rico. During the past two years, more than half of these jurisdictions have revisited and expanded their net metering policies. As a result, 18 states plus D.C. and Puerto Rico now allow systems larger than one megawatt (MW) to be net metered and 19 states plus D.C. and Puerto Rico have removed their program enrollment caps.[2]

State and local policy makers have also expanded retail policies to allow generation from a single PV system to be used for self-supply purposes at multiple locations. This evolution appears to be driven by a recognition that many customers who are interested in investing in a PV system are not able to host an onsite system. For example, renters and occupants of multi-tenant residential and commercial buildings often lack the control of their premises necessary to host an onsite PV system. Shading and structural concerns may also prevent some customers from installing an onsite system. Furthermore, customers may have load from multiple properties they wish to offset with a single PV system.

There has also been significant interest in developing wholesale policy options to expand market opportunities beyond retail, self-generation markets. Interest in expanding wholesale market opportunities appears to be motivated by four key considerations: (a) a desire to support investment in larger PV systems beyond those that primarily serve onsite load; (b) a recognition that existing wholesale procurement mechanisms tend to favor very large generators to the near exclusion of distributed systems; (c) an appreciation that the unique benefits of distributed PV generation may justify payment of a higher wholesale price than is provided to larger grid-scale power projects; and (d) a realization that FIT programs have brought large amounts of distributed PV capacity online in European countries such as Germany and Spain.

Retail Market Policies

Consumers in retail PV markets are end-use electricity consumers who, for a variety of reasons, want to self-supply some or all of their electricity with PV generation. The pursuit of self-sufficiency means consumers in this market are interested in investing in a PV system that is sized to meet some portion of their personal electricity needs. For these consumers, PV system cost-effectiveness is measured against other options that are available for meeting personal electricity needs. Typically, such options are limited to retail rate options that are available through an electric utility.

Policies that have proven successful in motivating consumer investment in this market allow retail customers to generate and use PV power with minimal effort. These policies provide easy enrollment, minimal ongoing obligations, and no hidden fees. They also avoid the creation of taxable benefits and regulatory requirements that can often accompany participation in wholesale market programs. Successful retail policies are designed to ensure that all interested customers have an opportunity to invest in a solar system for self-generation purposes. This often includes customers with multiple meters and customers who cannot directly host a PV system.

> "Policies that have proven successful in motivating consumer investment in this market allow retail customers to generate and use PV power with minimal effort."

To the extent an intermittent PV system generates more electricity than is needed at any given point in time, successful retail policies satisfy customer expectations that self-generation will result in reduced electricity purchases from the local electric utility. Customers who generate their own power expect that a kilowatt-hour (kWh) of PV energy that is self-generated will result in an avoided kWh purchase from a utility. To address mismatches between intermittent PV generation and variable consumption needs, these successful retail policies provide a retail rate credit for excess electricity that is exported to the grid.

Successful policies also provide a value proposition that makes a PV investment cost-competitive with electricity supplied by retail electric service providers. Providing such a value proposition often requires a well-considered mix of retail rate design, targeted incentives, and policy options that provide consumers with the expected benefits of self-generation.

The policy options discussed in the Retail Market Policies section of this paper include net metering and meter aggregation policies; community solar policies such as joint billing, virtual net metering, and joint ownership; and PV incentive programs. Because these are retail policies, they can be designed and implemented by state and local policy makers whose jurisdiction includes oversight of retail electricity service.

Wholesale Market Policies

Typically, participants in wholesale PV markets are independent power project developers—not end-use electricity customers—who develop projects that are principally designed to sell power at wholesale prices to an electric utility. Wholesale market policies may be designed to allow a wholesale system to supply onsite electricity needs with excess electricity production sold at wholesale rates. However, many wholesale projects are located where there is little to no onsite electricity demand.

Although the benchmark for solar cost-effectiveness in retail PV markets occurs when the cost of solar generated power is at or below the retail rates offered by a retail electricity provider—a utility, for example—the benchmark for cost-effectiveness in wholesale PV markets is measured against wholesale power prices with similar hourly supply characteristics such as daytime generation that is located close to end-use retail electric load. This is the cost with which PV generation must compete in wholesale markets to be considered cost-effective. Retail electricity prices from a utility or retail electricity provider may be as much as two or three times the price of wholesale electricity prices.

Policies that have proven successful in supporting wholesale market development are designed to provide a level of compensation that ensures PV systems may be developed and operated profitably while also minimizing procurement costs to ratepayers. To achieve these twin goals, successful wholesale programs employ a streamlined procurement process that lowers transaction costs to developers while also ensuring that only the most viable and cost-effective projects are awarded contracts to supply utility ratepayers.

The policies discussed in the Wholesale Market Policies section of this paper include avoided cost pricing mechanisms, renewable energy credit (REC) markets, FITs, and market-based procurement mechanisms such as auctions and requests for proposals (RFPs). State and local policy makers may be limited in their ability to deploy FITs that feature prices that exceed utility avoided costs because the Federal Energy Regulatory Commission (FERC) exercises exclusive jurisdiction over wholesale electricity markets. FERC jurisdiction limits the ability of state policy makers to establish wholesale power prices.

“FERC jurisdiction limits the ability of state policy makers to establish wholesale power prices.”

Recommendations

In the final Recommendations section of this paper, we examine the billing and payment options that have been adopted in the 10 states that have the largest base of installed PV capacity. A number of these states have taken a multi-segment approach to developing sustainable markets for distributed PV development. This demonstrates that retail and wholesale market policies do not represent alternatives so much as complementary means for promoting growth in different PV market segments. Drawing upon lessons learned from the leading state markets for PV deployment, the final section of this paper recommends a sustainable, multi-segment distributed PV market design.

RETAIL MARKET POLICIES

During the past decade, advances in PV technology and implementation of supportive government and utility policies have allowed PV to reach a price point in many areas of the country where customers can cost-effectively generate electricity to serve much of their own personal energy needs. The pace of PV market growth during the last 10 years demonstrates that many retail electricity consumers in the United States have embraced this option. Their reasons for investing in PV are varied and the benefits of their investment in clean, renewable energy capacity are only beginning to be fully appreciated.

In this section, we focus on retail market policies for PV to help policy makers and interested stakeholders better understand how well designed retail market policies for PV can further encourage customer investment in these technologies. Figure 1 shows that a large percentage of PV systems are installed at residential locations, which are well suited for retail market policies.

This section begins with a discussion of net metering, the most widely adopted retail policy for facilitating growth in retail PV markets. In the subsections that follow, we discuss the importance of utility retail rate levels and residential and commercial retail rate design in making PV cost-effective from a customer's perspective. We also address the importance of considering a full range of PV system benefits in determining the cost effectiveness of net metering and retail rate design. Too often these important considerations are ignored in looking at the cost-effectiveness of policies that support retail PV deployment.

Next, we discuss meter aggregation and community solar options, such as joint billing and virtual net metering, that many states have recently implemented to expand retail markets for PV. Many retail customers interested in supporting or investing in a PV system to green their power supply and pursue self-sufficiency are not able to install an onsite system because they do not own residential or commercial property or don't control their residential or commercial building. Other challenges include shading issues or inadequate roof structural support. The policies discussed in this section of the paper address this problem by providing the benefits of onsite solar generation to participants that invest in or support an offsite system.

This section concludes with a discussion of incentive programs that are often used in concert with the above policies to make investment in PV cost-effective from a customer's perspective.

1. NET METERING

Net metering is very well suited to promoting onsite generation because it allows utility customers to host an onsite system and receive a simple, direct, and timely financial benefit in the form of a reduced utility bill. To many customers, this is preferable to the taxable income and regulatory compliance requirements that arise from selling power to a utility under the wholesale programs that are discussed in the Wholesale Market Policies section of this paper.

Net metering is available in some form in 43 states and the District of Columbia.[3] Net metering allows customers with PV systems and other types of distributed generation systems to send excess power to the utility grid and receive a 1:1 kWh credit for use at a time when a system is not producing as much electricity as a customer needs. By providing a 1:1 kWh credit for electricity that is not immediately needed, net metering allows customers to receive the same financial value for all energy produced onsite—a value equivalent to a customer's savings from avoided electric utility power purchases.

a. Carrying Over Monthly and Annual Excess Generation

Most state net metering policies are uniform with respect to netting utility-supplied electricity against customer-exported electricity on a 1:1 kWh basis across a billing period to determine a net-metered customer's monthly retail electric bill. If a customer consumes more electricity onsite than he or she generates, that customer pays a utility for supplying the extra kWh needed to supplement onsite generation. On the other hand, if a customer generates more electricity than is needed onsite, that customer is a net excess generator for the billing period.

A key consideration in establishing successful net metering programs is what to do if a customer generates more electricity during a billing period than that customer consumes. State policies differ with respect to how they treat monthly net excess generation (NEG). Most states roll over monthly NEG onto a customer's next utility bill as either a kWh or dollar credit. Thirty-eight states currently use a full retail credit rollover approach. Only Alaska, Minnesota, and North Dakota do not rollover monthly NEG as a credit onto the customer's next bill and instead require a monthly payment for NEG. Oklahoma and New Mexico allow utilities discretion to either credit the next bill or provide a payment.[4]

From a customer's perspective, a simple rollover of NEG onto a customer's next month's bill has significant value. This allows customers the flexibility to size a system to meet onsite needs even if those needs vary from month to month. This can be particularly helpful for customers with electricity needs that vary significantly by month or season. Schools and agricultural customers are good examples. Schools have reduced electricity needs when school is not in session. Likewise, agricultural customers often require greater electricity use during certain seasons. Without monthly rollover at retail value, customers such as these may have insufficient financial incentive to size a system to meet full onsite energy needs and may instead only install a system that meets energy needs during the lowest month of electricity usage during the year. This may significantly impede the growth of retail PV markets.

For the majority of states that allow monthly rollover of NEG at retail rate value, a question arises as to whether monthly excess generation may continue to rollover in perpetuity or whether credits may be treated differently at the end of an annual period. State policies generally fall into four categories with regard to treatment of annual NEG.

First, 14 states plus the District of Columbia allow indefinite rollover of credits with no annual true up. These include Colorado (customer may opt for indefinite rollover), Delaware (customer may opt for indefinite rollover), District of Columbia, Indiana, Iowa, Kentucky, Louisiana, Massachusetts, Michigan, Minnesota (reconciled monthly at average retail energy rate with no annual true up), Nevada, New Hampshire, New Jersey (optional for customer), New York (for non-residential customers with wind and solar), and Wisconsin (reconciled monthly at retail rate for renewable generators with no annual true up).[5]

"A key consideration in establishing successful net metering programs is what to do if a customer generates more electricity during a billing period than that customer consumes. State policies differ with respect to how they treat monthly net excess generation (NEG). Most states roll over monthly NEG onto a customer's next utility bill as either a kWh or dollar credit."

Second, 15 states provide payment for annual NEG at a utility avoided cost rate (see Avoided Cost section of this paper for more information on avoided cost rates). These states are Alaska (reconciled monthly at avoided cost), Arizona, Colorado (optional for customer), Connecticut (avoided cost for non-PV customers and time-of-use [TOU] generation rate for PV customers), Delaware (optional for customer), Florida, Nebraska (reconciled monthly at avoided cost), New Jersey, New Mexico (reconciled monthly at avoided cost), New York (residential customers), North Dakota (reconciled monthly at avoided cost), Ohio (reconciled monthly at "unbundled generation rate" or energy-only component of the retail rate), Virginia, Wisconsin (reconciled monthly at avoided cost for non-renewable generators), and Wyoming.[6]

Third, Pennsylvania and Puerto Rico provide payment at some other amount. In Pennsylvania, PV customer accounts are reconciled annually at the "price to compare," which includes generation and transmission components of the retail rate, and in Puerto Rico, the utility purchases 75% of outstanding NEG credits at a minimum rate of $0.10/kWh, and the remaining 25% of credits are donated to public schools.[7]

Fourth, 17 states and the Virgin Islands grant annual NEG to a utility with no compensation provided to a customer-generator. These include Arkansas, Hawaii, Georgia, Illinois, Kansas, Maine, Maryland, Missouri, Montana, North Carolina, Oregon (donated to low income program), Rhode Island, South Carolina, Utah, Vermont, Virgin Islands, Washington, and West Virginia.[8]

From a net-metered customer's perspective, the decision to provide rollover of monthly NEG on a 1:1 kWh basis is likely to be of greater financial importance than the treatment of annual NEG. Monthly rollover smoothes out mismatches between monthly onsite generation and energy needs, which are common to many customers. Annual rollover, by comparison, helps smooth out variations in onsite electricity needs that may occur from one year to the next. This can be important for customers like commercial building owners that may have annual variation in onsite electricity needs due to building occupancy changes. However, most net-metering policies restrict the size of a net-metered system to what is necessary to supply onsite electricity needs on an annual basis. As a consequence, most net-metered systems do not generally generate more energy than is needed on an annual basis. This means that state net-metering policy treatment of annual NEG does not impact the majority of net-metered customers. That said, 14 states plus the District of Columbia have chosen to maximize customer flexibility in sizing a system to meet onsite needs by allowing indefinite rollover of credits with no annual true up.

b. Valuing Net Metering with Retail Rate Design

From a participating customer's perspective, the value of onsite generation and net metering is dependent on the electric retail rates a customer would otherwise pay in the absence of self-generation. Higher retail rates provide more motivation to install onsite generation in order to avoid paying those rates.

At the time of this writing (July 2010), state average retail electricity prices in the United States ranged from $0.061 in Wyoming to $0.237 per kWh in Hawaii, with an overall average retail price of electricity to the consumer across all end-use sectors (residential, commercial, industrial, and transportation) of $0.094 per kWh.[9] The variation in state retail rates provides for widely different outcomes in the financial payback of PV projects and helps explain why states with relatively low electricity prices have generally lagged behind in terms of installed PV capacity.

Table 1 (on the following page) provides information on the average retail rates in the top 10 states with the most installed PV capacity.

Table 1: Average retail electricity rates for top solar states[10]

State	2009 Cumulative Installed MW Capacity	Average Retail Rate, June 2010, cents/kWh
1. California	768	13.22
2. New Jersey	128	14.37
3. Colorado	59	9.14
4. Arizona	46	9.36
5. Florida	39	10.31
6. Nevada	36	9.58
7. New York	34	16.02
8. Hawaii	26	24.71
9. Connecticut	20	17.54
10. Massachusetts	18	14.52

Many states that have a gap between cost of generation from a PV system and prevailing retail rates have sought to close that gap by adopting PV incentive programs. This helps explain why states such as Colorado and Arizona have robust retail markets for PV systems despite having retail electric rate levels that are below the U.S. average. For an extensive discussion of state incentives that aim to close the gap between PV cost and PV value please see the section on Incentives.

A recent study by the National Renewable Energy Laboratory (NREL)(Denholm, Margolis, Ong, and Roberts, 2009) highlights the importance of state retail electricity price differences on the attractiveness of residential customer investment in PV systems. This report concluded that the difference in the break-even cost of PV is "largely driven by incentives, which can exceed $5/W, and the difference in electricity prices, which can vary by a factor of eight (or more when considering the range of tiered rates in California)."

c. Using Time-of-Use Pricing to Incentivize PV Deployment

Although state average retail electricity rates offer a rough rule of thumb for states in which retail PV systems are likely to be more cost-effective, the design of retail rates is also important in determining customer motivation to invest in PV systems. Well-designed TOU pricing, in particular, can allow customers with PV systems to offset high on-peak retail prices and may play an important role in making net-metered PV systems financially attractive to participating customers.

Although TOU structures with high on-peak to off-peak pricing differentials are likely to be financially attractive to many customers, load profiles of PV customers can vary widely, as can the size of onsite systems. As a result, a PV installation may offset anywhere from a few percent to more than 100% of a customer's onsite energy needs. At lower percentages, standard tariff options may be more favorable to customers than TOU rate structures. In fact, the NREL break-even report (Denholm et al., 2009) found that:

> "TOU rates do not always result in a net benefit to a customer even when PV has higher value on TOU rates. We found that about 20% of TOU rates evaluated showed decrease in PV values when shifting the customer from a flat rate to a TOU rate."

Therefore, although TOU rates can be an important tool in incentivizing PV system deployment, retail tariff choice is also important, particularly for customers with PV systems that are sized to serve a small percentage of onsite electricity needs.

d. Reducing Demand Charges that Undermine PV System Economics

At a more granular level, the components or structure of retail rates may be as important as average rates—or even on-peak TOU rate levels—in understanding customer motivation to invest in a PV system. Demand charges are a particularly important consideration in rate design for net-metered customers. Demand-based charges are based on the maximum kilowatt (kW) demand served by a utility, typically measured by a customer's highest usage during a 15-minute period within a monthly billing period or annual billing cycle.

Due to the intermittent nature of PV production, customers with PV systems have a difficult time lowering demand charges. As a consequence, rate structures that place a significant percentage of electricity service charges into a demand-based billing component measured in kW, instead of volumetric energy charges measured in kWh, can undermine the economics of investing in a PV system. Although demand charges are less common in residential retail rates, they are ubiquitous in commercial and industrial rates.

A Lawrence Berkeley National Laboratory (LBNL) report (Wiser, Mills, Barbose, and Golove, 2007) confirms that demand charges can represent a significant barrier to the penetration of commercial PV systems. This report studied a broad range of retail rate options available to commercial PV customers in California and concluded that solar output often will not result in significant reductions in a customer's demand charges, particularly for PV systems that are sized to meet a large percentage of a customer's onsite energy needs. For these customers, demand charges can significantly undermine the financial case for investing in PV, or—at a minimum—can compel customers to invest in smaller PV systems that only meet a small percentage of onsite electric energy needs.

Demand charges also make it difficult for a PV customer to monitor, anticipate, and control demand for grid power. This creates a disincentive for a net-metered customer to lower demand and increase generation to the maximum extent possible during all on-peak periods. A TOU tariff with low or no demand charges, on the other hand, provides a strong incentive for a customer to reduce demand and increase generation (if possible) during on-peak periods. In aggregate, such actions increase customer incentives to invest in larger PV systems that, in turn, may reduce the need for new distribution, transmission, and generation capacity, as well as scale down a utility's long-run marginal cost of providing service.

> "... rate structures that place a significant percentage of electricity service charges into a demand-based billing component measured in kW, instead of volumetric energy charges measured in kWh, can undermine the economics of investing in a PV system."

e. Weighing the Costs and Benefits of Net Metering

It is clear that more work is needed to demystify the unique costs and benefits of customer investment in PV systems. An NREL report (Johnston, Takahashi, Weston, and Murray, 2005) found that "[a]lthough the benefits of [distributed generation] have been generally acknowledged by policy makers, methods of accounting for those benefits, in ratemaking as well as planning, are not yet well developed." Without a full and fair accounting of these benefits, it is exceedingly difficult to determine whether customer investment in PV systems creates a net benefit or net cost from the utility perspective.

A number of important considerations must be taken into account to accurately measure the societal and utility-side benefits and costs of customer-owned net-metered PV. More than a simple "back of the envelope" comparison of high-tiered retail electricity rates and utility avoided cost rates is needed (see the Avoided Cost section for more information).

First, it is important to consider that a customer who invests in and maintains net-metered PV may have a lower cost of service than a customer without onsite PV. This is because PV is a reliable source of daytime generation. Although the generation of any particular solar system may vary with local weather conditions, PV production is available at times of the day when electricity demand and the cost of meeting that demand is highest. This means that customers who install PV may have a lower average cost of service because they are meeting some or all of their own needs at times of the day when utility provision of service would be most costly.

Second, it is important to consider the precise cost of providing a net-metering credit. It is fair to question the extent to which the highest retail rate that may be in effect at the time of *any* net-metered export accurately reflects the cost to a utility of providing net metering credits. Only a portion of net-metered energy exports occurs during on-peak periods. In fact, many TOU tariff structures lack on-peak rates for entire months or seasons of the year, and many TOU tariffs exclude from on-peak periods morning or afternoon hours during which net-metered PV systems may be exporting. As a corollary, customers on inclining block rate structures, which charge consumers who use a lot of energy more for their higher energy usage, may not use enough power to reach higher-tiered rates. Therefore these customers do not receive a credit that is used to offset power use in the highest block. In addition, some net-metering programs apply on-peak TOU credits against off-peak usage. In such cases, lower priced off-peak prices are a better reflection of both the value to a participating customer and the cost to a participating utility.

Third, customer investment in distributed PV may help utilities reduce long run marginal costs, which decrease the costs that must ultimately be recovered in retail rates that all customers pay. These avoided costs include: (a) increased electricity supplies, placing downward pressure on electricity market prices; (b) reduced need for electricity from natural gas fired power plants, placing downward pressure on natural gas market prices; (c) reduced loading on transformers and substations, delaying the need for replacements or upgrades; (d) deferred or avoided distribution line and substation upgrades; (e) fuel diversity benefits; (f) enhanced grid reliability; and (g) environmental benefits such as reduced greenhouse gas emissions and emissions of criteria pollutants (Iannucci, Cibulka, Eyer, and Pupp, 2003).

In light of the above considerations, a simple TOU rate with low demand charges and a high on-peak to off-peak price differential may be justified. It may also align financial incentives of participating customers with benefits to non-participating customers by creating an incentive to install PV systems for which peak production coincides with utility peak electricity demand.

Recognizing these benefits, the California Legislature adopted California's $3 billion CSI PV incentive program, which directed the state's public utility commission (PUC) to adopt rates for participating customers that:

> "create the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands and that assures that ratepayers receive due value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently."

Public Utilities Code Sec. 2851(a)(4)(a), from which this quote is taken, originally required the California Public Utility Commission (CPUC) to create such rates. In 2008, however, the California Legislature amended this section to make the creation of such rates optional and to eliminate the requirement that all CSI participants take service under time–of-use rates.

A companion paper to this one, titled *Rate Impacts of Net Metering*, soon to be published by the Solar ABCs, provides a further elaboration of how PV benefits may be appropriately considered in designing rates for customers with net-metered PV generation.

2. METER AGGREGATION

Meter aggregation is an expansion of net metering that facilitates customer investment in PV systems that are not located at the site where the customer wants to use the electricity. Meter aggregation programs allow a customer to generate bill credits from a PV system and apply those bill credits to multiple electric utility billing accounts that are under a single customer's name.

State and utility meter aggregation policies differ in how geographically dispersed meters may be from a site where a PV system is located. Some meter aggregation policies require that dispersed meters (and hence billing accounts) be located on the same property or property that is adjacent to where a net-metered facility is located. For example, Oregon's net-metering policy allows a single customer's meters to be aggregated as long as they are on contiguous properties owned by that customer.[11] Pennsylvania and West Virginia allow meters to be located within two miles of a net-metered generator.[12] Agricultural customers, universities, municipalities, and other large customers with dispersed operations are often primary beneficiaries of meter aggregation policies.

Meter aggregation is currently allowed for at least some customer classes in California, Delaware, Pennsylvania, Washington, Oregon, Vermont, Rhode Island, West Virginia, and New Jersey.[13] At the time of this writing, meter aggregation programs were also under consideration in Maryland, Connecticut, and Arizona.

3. COMMUNITY SOLAR

Community solar expands on meter aggregation by allowing multiple customers to come together and support a single PV system. Many definitions have been applied to community solar. This paper adopts a definition used by the Bonneville Environmental Foundation in its *Northwest Community Solar Guide* (Bonneville Environmental Foundation):

> "a solar-electric system that, through a voluntary program, provides power and/or financial benefit to, or is owned by, multiple community members."

A number of states and utilities have recently implemented community solar programs as a means of facilitating customer investment in renewable energy. Interest in these programs appears to come from recognition that while current policies that promote onsite generation have benefited many homeowners and businesses, many utility customers are not able to host an onsite system. For example, renters and many occupants of multi-tenant residential and commercial buildings may lack necessary control of their premises to host an onsite PV system. Add to that shading and onsite structural concerns, and it becomes clear that many would-be solar supporters may not be able to install an onsite system. In fact, a 2008 NREL study (Denholm and Margolis, 2008) found that only 22% to 27% of residential buildings are suitable for hosting an onsite PV system. Thus, the market for PV that could be supported by well-designed community solar policies is considerable.

There have been a number of approaches taken by state policy makers to establish community solar programs that bring solar options to a broader group of participants. The following sub-sections group these approaches into four broad categories:

- joint billing policies
- virtual net metering
- joint ownership
- utility programs

We introduce each of these approaches below and discuss the financial advantages of each approach from a participant's perspective. This section concludes with a discussion of approaches states have taken in compensating utilities for administering community solar programs.

a. Joint Billing

Joint billing acts much like master-metering in a multi-tenant building, a situation in which landlord receives a single bill for all tenant electricity usage, and then determines how to parcel out costs to individual tenants. Joint billing for community projects works the same way in that the electricity use of participants is aggregated into a joint bill. However, participants do not need to reside in a single building and may instead be more dispersed.

Output from a shared PV system is netted against a joint bill. This allows multiple participants to receive financial benefits equivalent to net metering from a single PV facility. Vermont, for example, has enacted a joint billing program for shared systems in which a group of customers may combine meters and form a single billing entity to offset their joint bill with generation from a net-metered system.[14]

A downside of this approach is that a customer representative must serve as a point of contact and intermediary between a group of participants and a utility by taking on such tasks as billing and dispute resolution.

b. Virtual Net Metering

Similar to meter aggregation and joint billing, virtual net metering (VNM) allows a renewable energy system to offset load at multiple electric accounts. Massachusetts, Rhode Island, California and Maine have all implemented virtual net metering programs.

Massachusetts has implemented the most expansive virtual net metering policy to date.[15] Massachusetts' "neighborhood net metering" program allows neighborhood-based facilities to serve the energy needs of a group of at least 10 residential customers in a neighborhood. Under Massachusetts statute, a neighborhood is defined as a geographic area including and limited to a unique community of interests that is recognized as such by residents and which, in addition to residential and undeveloped properties, may encompass commercial properties. A neighborhood must also remain within a utility's electric service territory.

A neighborhood system must be behind a participating customer's meter, but only a minimal amount of load needs to be located onsite. Participating utilities allocate kWh credits to participating customer accounts based on allocations provided by a customer representative. To account for distribution of electricity to participants, utilities are not required to issue the distribution component of a bundled retail rate, which includes all other service and administrative charges, in neighborhood net metering credits that are applied to participants' bills. This results in a credit that is substantially (as much as 40%) below the credit typically provided through net metering.

Massachusetts also allows customers with traditional net-metered systems to allocate excess monthly generation to one or more other customers of the same distribution company. Under this method, distribution utilities apply the allocated credits to the bills of designated customers. Credits for these non-neighborhood systems reflect a fully bundled retail rate credit and are allocated as a dollar-denominated credit based on the retail rate of the customer account where a net-metered system is located (i.e. using the retail rate of the host customer in $/kWh multiplied by the kWh allocation).

Rhode Island has also implemented an extensive virtual net-metering policy.[16] It allows cities, towns, schools, farms, non-profit affordable housing, and state agencies to participate. Under Rhode Island's program, customers may either install a renewable energy system and receive a monthly check (at a rate slightly less than retail) or apply excess kWh credits to up to 10 other accounts they own. If a non-profit affordable housing agency chooses compensation, it is obligated to use the money to benefit residents.[17]

California and Maine have also implemented virtual net metering programs. California allows multi-family, low-income residents to receive bill credits from a single onsite PV system.[18] Maine's program is open to a broader group of participants. It works like the virtual net metering programs discussed above except that Maine requires participants to have an ownership stake in a shared net-metered system.[19] Generation is then virtually net metered to joint owners in proportion to their ownership stake in a system. For example, a 50% owner would receive 50% of the virtually net-metered bill credits generated by a system.[20] This makes Maine's program a hybrid approach that couples virtual net metering with joint ownership, which is discussed in the next subsection.

c. Joint Ownership

Taking a page from successful community wind programs, some states have begun to explore community ownership programs for PV systems. For example, Maine has both a retail and wholesale program for community solar. Both require joint ownership. Maine's joint ownership net-metering program was discussed in the prior subsection. Maine's wholesale program is called a Community-Based Renewable Energy Pilot Program.[21] It allows "locally owned electricity generating facilities" with at least 51% ownership by "qualifying local owners" to elect one of two incentive mechanisms: (a) a long-term contract to sell the output of a facility to a transmission and distribution utility; or (b) a REC multiplier in which the value of RECs generated by a locally owned system are valued at 150% of the amount of electricity produced. The contract price for solar energy may vary over the course of a year, but the average price, weighted on the expected output of a facility, may not exceed $0.10/kWh. Although this is a relatively low price compared to some state FIT prices, this price is for electricity only and does not include an additional REC purchase.

The State of Washington is also establishing a community solar program that relies on community ownership to impart a community flavor. Whereas most community solar programs allow participants to receive bill credits as a benefit of participation, community participants in Washington will install a PV system on property owned by a cooperating local government entity and will sell electricity from that system to the government entity. Participants, who are owners of the system, receive incentive payments through Washington's state incentive program (see the following Incentive section for more on the incentive program) and also receive income from the sale of power to the onsite local government entity. Participants may also receive revenue from the sale of RECs.

d. Utility Programs

A number of utilities have independently implemented community solar options as a way to satisfy customer interest in PV systems and diversify their generation base. From a utility's perspective, community solar programs can allow for voluntary customer participation as opposed to passing through PV system costs to all ratepayers. From a customer's perspective, contributing to a single, larger PV system that is installed by a utility can significantly decrease the obstacles of purchasing, interconnecting, and maintaining an individual system on his or her property.

The City of Ellensburg, Washington, was the first utility in the country to set up a virtual net metering, community ownership PV system.[22] Ellensburg's municipal utility enrolled over 70 community investors who contributed a minimum of $250 each, but some contributed over $11,000. A contribution allows each investor to receive a bill credit on his or her electric bill proportionate to the investment for 20 years. (Nystedt, 2008).

For example, if a customer's contribution represents 3% of the total funds contributed by utility customers, that customer would receive 3% of the power produced by the PV project, applied as a credit to offset his or her electric bill (Nystedt, 2008).

The City of Seattle is developing a local community solar program that will be managed by its municipal utility, Seattle City Light. Under this community solar program, Seattle City Light will finance up-front investment in a PV system, but will be reimbursed by customer participants who will contribute financial support in exchange for a payment or a credit on a utility bill. The amount of the payment or credit will be based on the value of electricity produced by a system. This follows a virtual net metering approach similar to one that has been implemented by the Sacramento Municipal Utility District, which is called "Solar Shares."

The City of St. George, Utah offers a similar community program called "SunSmart." Through this program, utility customers purchase PV units ranging from $3,000 to $24,000, and in return receive a bill credit "pro-rata share of the net electrical output of the SunSmart project" for the commercial life of the system (projected for 19 years).[23] Because customers are purchasing panels, customers are eligible to take the state's 25% tax credit, up to $2,000, on their purchase.

While most utility programs have been initiated by municipal utilities, in early 2010, the Florida Keys Electric Cooperative (FKEC) was the first non-municipal utility to offer a community solar program. Through FKEC's "Simple Solar Program," co-op members can lease one or more solar panels in a utility-owned array for $999 each. In return, members receive monthly bill credits for the full retail value of the electricity generated by leased panel(s) for 25 years.[24] FKEC estimates that each $999 investment will return about $1,280 in credits over the life of the lease, assuming a 3% annual increase in electricity prices.

e. The Value of Participation

The above examples illustrate that a number of approaches have been explored in facilitating community solar projects. The compensation level provided through these efforts largely depends on whether a program allows a participating customer to use generation to offset retail electricity consumption (joint billing or virtual net metering programs) or to sell power at wholesale to a participating utility (Maine's Community-Based Renewable Energy Pilot Program) or at retail to an onsite customer (Washington's community solar program). The compensation level also depends on whether community projects are able to receive available incentives, which is discussed in the next section.

Programs that allow participating customers to offset retail electricity purchases offer a value proposition similar to net metering. In other words, the value from a participating customer's perspective is highly correlated with retail rates a customer is able to avoid paying. Higher retail rates, and more advantageous retail rate structures, provide additional incentive for retail customers to participate in a community solar system.

Programs that are structured as a wholesale program, like Maine's Community-Based Pilot Program, compensate community solar participants by setting a level of wholesale payment. Maine's program limits this value to an average price, weighted on the expected output of a facility, which may not exceed $0.10/kWh. A significant downside of this approach is that, like the wholesale options discussed later in this report, and unlike the self-generation programs discussed above (net metering, meter aggregation, joint billing, and virtual net metering), payment from power sales to a wholesale or retail purchaser results in taxable income at a federal level and possibly also at a state level. The taxable status of these sales may significantly decrease the size of benefits available to participating customers and may act as a deterrent to an average utility customer who does not want to complicate his or her tax filings.

f. Compensating Utilities

With regard to meter aggregation, joint-billing and virtual net-metering programs, a question arises as to whether a utility should be compensated for providing the distribution and billing services necessary to facilitate self-generation programs. Different states have taken different approaches.

In Massachusetts, bill credits created by a "neighborhood net-metered facility" do not contain the distribution portion of a fully bundled retail rate. As a result, participants in a "neighborhood" facility pay distribution charges for the use of a utility's distribution system. Participants do not, however, pay transmission fees. This seems reasonable given that neighborhood systems are limited to 2 MW and participating customers must be located within a distribution utility's service territory. As a result, these systems will likely be located on distribution circuits near the load, and therefore will not require transmission infrastructure to distribute power to program participants.

California's virtual net metering takes a different approach. California conveys a fully bundled rate credit, including the distribution charge component, in virtual net-metering credits. However, unlike the Massachusetts' program, California's virtual net-metering program is available only to occupants of multi-tenant buildings. In other words, participating customers are likely to be centrally located on a single distribution circuit. Massachusetts' neighborhood net-metering program, by comparison, allows bill credits to be distributed more widely to participants who may not be within the same geographic proximity. Given these differences in potential geographic dispersal of program participants, it seems reasonable that California's program, which allows for significantly less geographic dispersal, would provide the financial benefit of a fully bundled retail credit while Massachusetts' programs subtracts a distribution fee from the value of bill credits.

4. INCENTIVE PROGRAMS

Financial incentives for distributed PV come in a wide variety of forms, including tax credits, rebates, grants, and performance-based incentives. This paper is predominantly concerned with state incentives that provide either an up-front rebate based on the size of a system or an on-going payment based on system output. State incentives of this sort can reduce the cost of a PV system by up to 50%—although most state rebate program caps are in the 25% to 35% range—and are important components of retail market design for PV. Tax credits and other forms of incentives are also valuable parts of the financial equation, but they are outside the scope of this report.

The goal of a well-designed PV incentive program is to provide sufficient compensation to a customer to make a PV system investment cost-effective, given available retail rate levels and structures and the availability of net-metering programs. As a corollary, retail electric rate design that reflects the costs and benefits of serving customers with PV systems can be coupled with effective net metering to reduce the level of incentives needed to make a PV system investment cost-effective. Thus, net metering, retail rate design, and incentives are all essential components of comprehensive retail market design for PV systems.

In this section, we discuss some of the key variations in state incentives programs, including:

- which system types are eligible for state incentives;
- whether participation in a state incentive program necessitates a transfer of the renewable attributes of power (via RECs) to a utility providing incentives;
- whether incentives are paid as a lump sum or up-front payment or are based on the performance of a system over a period of time; and
- whether incentive amounts are determined administratively or by a market mechanism.

a. *Eligibility for State Incentives*

State PV incentives are often only available to customer-generators who use distributed generation to serve onsite load. CSI is perhaps the most well-known example of such an incentive program. The CSI was launched in 2006 with an aim of providing more than $3 billion in incentives to spur 3,000 MW of solar installations by 2016 (2,550 MW of which are PV systems).[25] To be eligible for CSI incentives, a system must be "sized so that the amount of electricity produced by the system primarily offsets part or all of the Host Customer's electrical needs at the Project Site."[26]

North Carolina's NC GreenPower incentive program represents the other end of the spectrum, in that only customer-generators taking service under specific avoided cost tariffs (see Avoided Cost section of this report) are eligible for state incentives. NC GreenPower is not a state-sponsored program. It is administered by a non-profit organization supported by voluntary contributions from customers.

Coupling incentive payments—particularly production-based incentives—with a wholesale payment for power duplicates the financial incentives provided under a FIT (see Feed-in Tariff section of this report for a further discussion). Net-metered customers in North Carolina may not receive NC GreenPower incentives.[27]

Arizona's state-mandated PV incentive program represents a sort of hybrid of the CSI and NC GreenPower approaches. In Arizona, state-mandated incentives are only available to systems located on a customer's premises. However, unlike California's CSI program, there is no requirement in Arizona that a system must serve onsite load.[28] Like NC GreenPower, customer-sited systems may instead provide wholesale power to a utility.

It is also important to consider whether incentives are available to community PV systems. Washington's incentive program is available to onsite net-metered systems as well as community PV systems. Under Washington's program, utilities provide incentives to eligible generators and in return utilities receive a tax credit equal to the cost of providing incentive payments. Incentive amounts start at a base rate of $0.15/kWh and are adjusted by multipliers (for using locally produced system components) that result in an incentive range of $0.12 to $0.54 per kWh. Community PV projects are eligible to receive incentives that begin at a base rate of $0.30/kWh. With multipliers, incentives for community PV can reach $1.08/kWh.[29]

Community systems may have a difficult time achieving cost-effectiveness without access to state incentive programs. State incentives generally reduce the cost of a PV system by roughly 30%. A community system may enjoy certain economies of scale compared to a smaller onsite system, but it is unlikely those economies of scale alone can close a gap of 30% of system cost left by lack of availability of incentives. It is therefore essential that policy makers contemplating community solar policies consider extending state incentive payments to community systems. Without incentive eligibility, community solar programs may not be able to expand to their full market potential.

There is also a fairness consideration to extending incentives to community systems. Typically, all ratepayers (or taxpayers depending on the incentive program structure) contribute to funding PV incentive programs, yet not all ratepayers are able to host a PV system, and, as previously noted (Denholm and Margolis, 2008), only 22% to 27% of residential buildings are suitable for hosting an onsite PV system. For the majority of customers that cannot host a PV system, community solar programs may be the only means of participating in a PV system. Incentives for these systems provide a mechanism for all customers to participate in incentive programs they help fund.

b. Transfer of Renewable Energy Certificates or No Transfer

State incentive programs are often connected with renewable portfolio standard (RPS) policies that require utilities to incorporate PV or distributed generation into their resource mix. Seventeen states have created solar targets within their RPS programs.[30] Nine states have created distributed generation procurement targets or allow utilities a RPS credit multiplier for customer-sited systems.[31] Utilities subject to RPS requirements often offer incentives to renewable energy generators and incentive recipients convey renewable attributes of their generation (through RECs) to the utility for the utility's use in demonstrating compliance with its RPS obligations. This approach provides a financial incentive to customers to invest in renewable generation capacity and assists utilities in meeting their RPS policy goals.

Although many states have structured their incentive programs as a means of achieving RPS goals, other states have structured their incentive programs to achieve state objectives other than RPS goals. For example, California's CSI program is designed to achieve 3,000 MW of solar installations by 2016. This goal is separate from and in addition to California's RPS goal of procuring 20% of its wholesale electricity from eligible renewable sources by 2020. (California's governor has issued an executive order extending state renewable procurement requirements to 33% by 2020, but this gubernatorial policy has yet to be codified in state law.) Recipients of CSI incentives are not required to convey RECs to a utility in exchange for incentive payments.

Washington's production incentive program (discussed above) is similarly not tied to REC purchases and instead is designed, in part, to create a market for locally produced PV system components. Vermont, Wisconsin, Pennsylvania, and New Jersey also do not require a REC transfer in exchange for incentives.[32] In these states, policy makers have determined that incentives should be provided to support state goals other than achieving state RPS requirements.

c. Up-Front Incentives versus Performance-Based Incentives

Incentive payments can be structured as either up-front incentives (UFIs) or performance-based incentives (PBIs). UFIs are paid in a lump-sum amount, typically at the time a system is installed or begins operation. PBIs are paid over time and are based on metered output of a system. Often, state incentive programs provide UFIs to smaller systems and PBIs to larger, commercially owned systems.

For example, Maryland utilities purchase RECs from PV systems of 10 kW or less through a single up-front payment. The California CSI program provides UFIs to systems up to 30 kW and PBIs to those larger than 30 kW. PBI payments are paid monthly over a five-year period.[33]

From a public policy perspective, PBI payments provide a significant incentive for customer-generators to maintain a system and maximize output. This protects ratepayers who fund PV incentive programs from overpaying for poorly performing systems. PBI payments also make sense from a financing perspective. The stable and predictable income stream provided by a PBI payment is often sufficient to facilitate financing of larger commercial systems. Smaller systems, by comparison, are more likely to be acquired through an up-front payment. A UFI can assist in lowering that up-front cost.

d. Predetermined Pricing or Market-Based Pricing

Another respect in which state incentive programs vary is whether incentives are available at a predetermined price or whether incentives are only available through participation in a competitive auction. As with UFIs versus PBIs, states often make this determination based on system size, offering a predetermined, fixed-price incentive to smaller systems while using competitive markets to determine incentive levels for larger systems. North Carolina, Colorado, Maryland, and New Jersey all use this approach.

North Carolina's NC GreenPower program offers a fixed incentive for PV systems 10 kW or smaller.[34] Colorado's IOUs offer REC-purchase incentives for PV systems less than 100 kW, which is paid in the form of an up-front rebate for 20 years of REC generation.[35] North Carolina and Colorado both use a market-based approach for larger projects, allowing PV system owners to bid RECs into an auction.

Maryland has similarly created a market-based approach to REC purchases for systems larger than 10 kW. If a PV generator opts to sell RECs, he or she must first offer to sell RECs to utilities by posting them for a minimum of 10 days on the Maryland Public Service Commission's website. New Jersey also uses a competitive purchase program for RECs from larger PV systems. New Jersey's program provides a means for solar RECs to be created and verified and requires electric suppliers to participate in this program in order to meet solar RPS requirements. In March 2009, the weighted average price of 2009 solar RECs was approximately $467/MWh ($0.47/kWh), with some trades as high as $680/MWh. New Jersey is the only state that has REC auction-price transparency, so it is hard to compare New Jersey prices with those from other regions.

IOUs in Arizona, by comparison, offer predetermined incentive payments to all grid-connected PV systems regardless of size, in addition to small off-grid systems. California also offers an administratively determined fixed-price incentive to all PV systems eligible for the state's CSI incentives. Both Arizona and California employ mechanisms to adjust incentive levels downward as PV prices decline. This captures some of the benefits of a market-based approach to setting incentive levels.

RETAIL MARKET POLICY CONCLUSIONS

Although the policies discussed in this Retail Market Policies section are varied, similarities in policy design suggest that successful retail policies have three characteristics in common:

- **Ease of Enrollment:** Successful policies allow retail customers to generate and use PV power with minimal hassle. In particular, they provide easy enrollment, minimize ongoing obligations, and avoid the creation of taxable benefits and regulatory requirements that can often accompany the wholesale power sale options discussed in the next section.

- **Benefits of Self-Generation:** Successful policies are designed to satisfy customer expectation that self-generation will result in reduced electricity purchases from an incumbent utility. Customers who generate their own power expect that a kWh of PV power that is self-generated will result in an avoided kWh purchase from their electric utility.

- **Cost Effectiveness:** Successful policies provide a value proposition that makes a PV investment cost-competitive with electricity supplied by either regulated or competitive retail electric service providers. Providing this value proposition often requires a well-considered mix of retail rate design, targeted incentives, and policy options that provide customers with the expected benefits of self-generation.

WHOLESALE MARKET POLICIES

PV system costs have dropped considerably in recent years and are expected to decline for the foreseeable future. In some markets, wholesale PV generation prices have become competitive with other sources of wholesale peaking power. California utilities, for example, have signed contracts for more than seven gigawatts of PV and concentrating solar power. Utilities in Arizona, Nevada, and New Mexico have also signed a significant number of contracts for wholesale solar capacity. As seen in Figure 2, utility-owned and commercial systems are accounting for an increasingly large percentage of installed PV capacity.

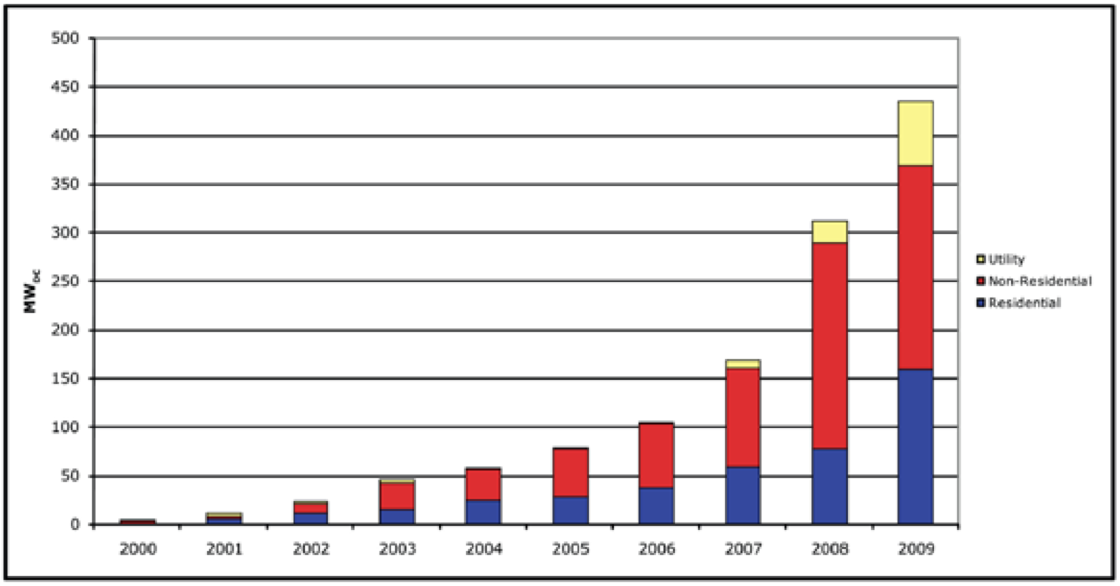

Figure 2: Annual Installed Grid-Connected PV Capacity by Sector (2000-2009)[36]

Utility motivations for entering wholesale contracts with PV facilities are varied. Cost effectiveness and peaking supply are only two of the benefits of PV. Distributed PV systems can also be deployed quickly, scaled to most any size, and sited almost anywhere. The flexibility to locate PV generation where needed, when needed, and in the size needed offers grid benefits that other sources of renewable generation cannot offer. Moreover, the smaller footprint of distributed PV systems means they can be deployed close to the loads they serve, avoiding transmission constraints and lengthy environmental review processes.

Many of these benefits are currently overlooked in utility procurement practices. However, that paradigm is beginning to shift in many markets that have seen significant retail PV market growth. Policy makers and utilities in these markets have begun to appreciate the many benefits of distributed PV systems. They have also begun to appreciate the need for targeted procurement mechanisms that fully value the range of benefits provided by PV. The result has been movement in many areas toward policies that increase procurement of wholesale power from distributed PV.

> "The flexibility to locate PV generation where needed, when needed, and in the size needed offers grid benefits that other sources of renewable generation cannot offer."

This section discusses four approaches that support distributed PV wholesale market development in the United States. These procurement mechanisms are often part of an implementation strategy for achieving identified goals, particularly technology-specific or resource-specific carve-outs within RPS policies. Most often these carve-outs take the form of solar or distributed generation targets. As evidence of this, 17 states have created solar targets within their RPS programs, and nine states have created distributed generation procurement targets or allow utilities an RPS credit multiplier for customer-sited systems.[37]

First, we discuss the wholesale market policy that has been in place the longest. Avoided cost mechanisms came into existence in 1978 when Congress enacted the Public Utilities Regulatory Policies Act (PURPA). PURPA required utilities to purchase electric generation from small power production facilities and cogeneration qualifying facilities (QFs) at a price equal to a utility's "avoided cost." Avoided cost is set at a level that reflects the lowest cost supply option available to a utility. It is often set at price that reflects the cost of generating from a conventional fuel facility, which has lead PURPA to be roundly criticized as being outdated and inadequate to achieving state policy goals. We discuss these criticisms below as well as how some states have attempted to address shortcomings of avoided cost pricing by providing additional payment for renewable attributes of power generation.

Feed-in tariffs are similar to avoided cost mechanisms in that they obligate a utility to purchase power from eligible generators at predetermined prices. However, whereas avoided cost rates are set at a level that reflects the lowest cost resource available to supply a utility, FIT pricing is technology-specific and intended to reflect a level that is sufficient to ensure that developers can build and operate a project and be profitable.

Another key difference is that avoided cost pricing is intended to hold a utility and its ratepayers indifferent to the source of power by setting price levels equal to the lowest cost resource available to supply power to a utility. By holding ratepayers indifferent to cost, PURPA could be implemented without placing a cap on program enrollment. So long as a utility needs electric power supply, it is required to buy available QF power. In contrast, FITs may set price levels well above the cost of alternative resources. To limit ratepayer exposure to higher cost sources of power, jurisdictions that have enacted FITs in the United States have all imposed caps that limit FIT system deployment on the basis of installed capacity, total cost, or allowable rate impacts.

Although avoided cost rates and FIT programs use administratively determined prices, market-based procurement uses competitive means, such as auctions and RFPs, to determine price levels. This approach provides a mechanism for choosing among eligible projects when there is more developer interest than program caps can accommodate—contracts are awarded on the basis of lowest price. A downside of this approach is that it may increase the administrative cost of obtaining a wholesale contract compared to PURPA and FIT programs that do not require participation in an auction or RFP prior to the awarding of a contract. Thus, RFP or auction-based programs may place smaller systems and emerging technologies at a disadvantage because administrative costs represent a larger percentage of project revenue than for larger PV projects.

We discuss each of these options—avoided cost, FITs, and auctions/RFPs—below.

1. AVOIDED COST

State avoided cost rates find their origins in PURPA, which was enacted against the backdrop of 1970s foreign oil embargoes of the United States. PURPA was enacted as a means of diversifying the nation's electric generation sources and was intended to reduce the nation's reliance on fossil fuels. To accomplish this goal, PURPA directed FERC to issue rules and regulations that require electric utilities to purchase energy from certain QFs, which include cogeneration and small power production facilities, including solar electric generation facilities up to 80 MW in capacity.[38]

Although Congress intended to create a market for QF power and diversify the nation's electric power resources, Congress also sought to limit electric utility and ratepayer cost exposure to purchases of QF power. In an effort to hold utilities and ratepayers indifferent to PURPA's obligations, Congress required that rates for QF purchases not exceed a utility's "incremental cost" of generation.[39] According to FERC's regulations, this means rates cannot exceed the cost the electric utility would pay for generating its own power or purchasing it from another source.[40] State regulatory authorities and non-regulated utilities establish utility-specific avoided costs, with FERC regulations leaving considerable flexibility to state regulatory authorities and non-regulated utilities in doing so, so long as the rates that are established reflect avoided cost ratemaking principals and meet the requirements established in FERC's PURPA regulations (Independent Energy Producers Association, Inc. v. California Public Utility Commission, 36 F.3d 848, 856, 1994).

It is also important to note that the federal Energy Policy Act of 2005 (EPAct 2005) eliminated a key provision of PURPA with respect to QFs. Prior to EPAct 2005, a utility had a mandatory purchase obligation to purchase power from a QF facility at avoided cost. After EPAct 2005 took effect—in those areas where an effective wholesale market exists—utilities may be relieved of their obligation to make a purchase or enter into a contract with a QF. The thinking is that if there is an effective wholesale market, QFs will have no more difficult time selling their power in the market than any other generation source, and all generators will receive the same price for their power.

a. Variations in State Avoided Cost Programs

Avoided cost programs differ on whether they allow a customer to serve onsite energy needs. Some avoided cost programs require all customer-generated energy to be exported to the grid without allowing customers to use generation to serve onsite electrical needs. Other programs resemble net metering in that they allow customers to offset instantaneous onsite electricity needs first, before exporting excess electricity to the grid.

Regardless of whether generation may be used to offset onsite electricity needs first, what avoided cost mechanisms have in common is that all energy exported to the grid is compensated at a utility's avoided cost rate. This differs from net metering, in which most electricity exported to the grid has a retail value—the customer can use a kWh credit received for exported electricity to offset a kWh purchase. This retail value is typically well above a utility's avoided cost. The following examples may help illustrate this wholesale policy option.

Since deregulation, fully integrated IOUs serve less than 25% of the state of Texas. Integrated utilities in non-competitive areas of the state (El Paso Electric Company, Entergy Texas, Southwestern Electric Power Company, and Xcel Energy, for example) that are not under Electric Reliability Council of Texas (ERCOT) control maintain an offering for QFs up to 100 kW powered by any type of distributed generation, and to QFs up to 50 kW powered by renewable energy resources. Owners or developers of QFs have several options. They can use onsite generation to supply onsite needs and receive a utility's avoided cost rate for any energy exported to the grid. A second option is a buy-all, sell-all arrangement in which all energy generated onsite is sold to a utility with none of the generation used onsite. Under the second option, a seller may qualify for a capacity credit if a facility results in avoided capacity costs for a utility.

Another example can be found in North Carolina with Duke Energy's Small Customer Generator (SCG) Tariff.[41] Residential customers with PV systems up to 20 kW and non-residential customers with PV systems up to 1 MW or customer's contract demand, whichever is less, are eligible to participate in this arrangement. The contract demand is the maximum demand to be delivered under normal conditions to the utility customer excluding output from the customer's installed electric energy system. A generating facility may be used to offset a facility owner's electricity consumption and, if feasible, demand charges. Excess generation is then purchased by Duke Energy through a variable rate structure that adjusts every two years based on state regulatory commission hearings.

There are two options under this tariff—A and B. Option A offers a lower price per kWh of production, but has a wider range of on-peak hours. Option B offers higher rates, but uses a much more complex equation of on- and off-peak hours that results in a reduced window of on-peak periods. About half of all PV generators in Duke's North Carolina service territory take service under the SCG rider and all of those choose option B because of the higher price for peak hours. Note that the SCG rider is not available in all states in which Duke operates. This example is taken from North Carolina's offer.

Duke Energy also offers a buy-all, sell-all option for customer generators as determined by their Purchased Power Non-Hydroelectric (PP-N) and Purchased Power Hydroelectric (PP-H) tariffs. (Hydroelectric facilities are allowed different rates based on whether or not they have energy storage capabilities.) The PP riders offer, in addition to an avoided cost payment, an energy capacity credit. There is also a possibility for long-term fixed price contracts under these buy-all, sell-all schedules.

b. Establishing Utility Avoided Cost Rates

State PUCs set avoided cost rates for utilities that fall under their jurisdiction—most often IOUs—pursuant to avoided cost rules established by FERC. Utilities that are not regulated by state public utility commissions establish their own avoided cost rates. FERC's avoided cost rules provide flexibility to allow a wide variety of approaches in setting avoided cost rates, but avoided cost may not exceed the cost an electric utility would pay for generating its own power or purchasing it from another source, [42] and the types of values that may be incorporated into an avoided cost calculation are limited by FERC's PURPA regulations.[43] So, for example, local economic and job creation benefits may not be taken into account in setting avoided cost rates. This limits the extent to which avoided cost rates can be set at a level sufficient to allow all potential generation sources to operate profitably while selling under avoided cost rates.

There are many ways to set avoided cost rates. For example, FERC has recognized that competitive bidding can be a valid way for a state commission to determine the avoided cost of generation by ascertaining the market value of the next incremental addition to capacity.[44] However, if avoided cost rates are determined by competitive bidding, all sources of generation available to a utility must be able to participate in the competitive bidding. Participation cannot be limited to QFs or particular types of generators.[45] These rules make it impractical to develop avoided cost pricing that reflects the value of renewable energy purchases, which can often be higher in price than conventional fuel generation. Other means of setting avoided cost include use of a proxy plant, administrative determination, or tying to a market index.[46]

Determining the price level of a utility's avoided cost can be difficult and state rulemakings aimed at determining avoided cost can be contentious. Utilities often calculate avoided cost as the cost of future production by the next plant to come online (often an inexpensive combined-cycle plant) and add that to the average price of different types of fuel costs (rather than using only what the combined cycle would actually use, natural gas). Furthermore, this price does not include administrative or transmission and distribution costs that the utility incurs in the delivery of power. As a result, avoided cost is often significantly lower than a utility's fully bundled retail rate.

True avoided cost prices are not widely publicized, but information from a number of sources, such as *Avoided Energy Supply Costs in New England: 2009 Report*,[47] estimate that they range around from about 30% to 50% of a utility's retail price. Avoided cost is typically well below the price a utility may otherwise pay for renewable power through FITs or targeted RFPs issued in connection with RPS or distributed generation procurement, both of which are discussed in the following subsections.

A final consideration that is important with respect to avoided cost procurement is the extent to which additional fees and charges, such as standby charges, may be assessed on customers participating in such programs. Duke Energy's Rider SCG contains standby charges of $1.11/kW that apply to systems larger than 100 kW.[48] This charge is based on the installed capacity of a system and is assessed regardless of whether a system operates at full rating during a billing period or whether a retail customer sees any reduction in demand charges after installing a PV system.

For customers with intermittent generation, standby charges can be duplicative of charges that a customer-generator pays through demand charges on his or her electricity bill. Standby and demand charges both compensate a utility for investments in installing and maintaining facilities needed to provide electric utility service. In other words, charging a customer both standby and demand charges can result in a double billing for maintaining the same facilities.

c. Is PURPA Relevant Now That States Have Enacted RPS Standards?

PURPA was enacted in 1978, well before states began implementing RPS standards that require utilities to procure a certain percentage of their power from renewable resources. RPS programs recognize that the cost of generation for renewable resources is different—and can be higher—than the cost of generation using conventional resources. Rather than allow price alone to determine the appropriate composition of a utility's generation portfolio, RPS policies determine a minimum percentage of a utility's portfolio that must be supplied by renewable generation of various types. It also allows the identified renewable resources to compete to satisfy that requirement, even if the price paid for the renewable generation exceeds the price that may otherwise be paid for generation from conventional resources.

In addition, a number of states have sought to further diversify utility generation portfolios to include larger amounts of distributed generation resources. As we noted earlier, seventeen states have created solar generation targets within their RPS programs and nine states have created distributed generation targets or have allowed utilities a RPS credit multiplier for customer-sited systems.[49] As a result of these programs, utilities now routinely procure electric generation and RECs in sub-markets that may feature different market clearing prices. Establishing a single procurement method or price to achieve multiple program procurement goals does not reflect this market reality.

This has led many renewable energy advocates to criticize PURPA as providing a price that is not designed to accomplish the myriad environmental and fuel diversity goals that have been put in place since PURPA's enactment in 1978. They claim that PURPA procurement is intended to hold ratepayers indifferent to the source of power, whereas RPS and targeted procurement programs are designed to ensure that a utility pays what is necessary to meet customer supply needs with identified percentages of power from renewable resources. Criticisms such as these have led policy makers in many areas of the country to adopt targeted wholesale procurement mechanisms that support renewable power development and enable states to meet their renewable power policy goals.

d. Supplementing Avoided Cost with Payment for Renewable Attributes?

A utility's avoided cost of meeting identified procurement goals, such as those adopted through RPS policies, may be quite different than a utility's avoided cost of meeting the demands of its customers with the lowest cost resource available to serve that demand. As discussed above, it also seems fair to question whether conventional fuel resources like oil and natural gas should be used to determine avoided cost compensation levels for PV and other renewable resources, given that these resources have different supply characteristics, have different costs of generation, provide price stability benefits when under long-term contract, and provide environmental benefits beyond what avoided cost rates are intended to reflect.

To the extent a utility faces actual, quantifiable costs associated with environmental compliance requirements, those costs may be included in an avoided cost determination. However, such costs can be very difficult to quantify, particularly with regard to greenhouse gas emissions, an area in which regulatory regimes and compliance costs are still being determined. Avoided cost rates are also technology neutral and not designed to help achieve policy goals such as diversifying generation resources, promoting customer investment in renewable energy, delaying or avoiding transmission upgrades, achieving renewable portfolio standard goals, reducing greenhouse gas emissions, or any number of other policy goals.

> "... it also seems fair to question whether conventional fuel resources like oil and natural gas should be used to determine avoided cost compensation levels for PV and other renewable resources, given that these resources have different supply characteristics, have different costs of generation, provide price stability benefits when under long-term contract, and provide environmental benefits beyond what avoided cost rates are intended to reflect. ."

Avoided cost programs such as Duke's Rider SCG appear to recognize that avoided cost rates do not provide adequate compensation for the unique costs and benefits of renewable and distributed power generation. Duke's program allows participating customers to sell RECs associated with Rider SCG and Rider PP-N and PP-H generation into North Carolina's NC GreenPower incentive program. This allows customers to receive compensation in addition to avoided costs for a customer's contribution toward helping North Carolina achieve its renewable power policy goals.

Providing an avoided cost payment for wholesale power and supplementing that with a REC payment that reflects the market price of renewable energy attributes can be a viable approach to supporting wholesale market development of renewable and distributed generation. However, an important consideration is whether this approach is authorized under state law. Whether RECs are created or conveyed in an avoided cost transaction is left to state discretion.[50] If RECs are not conveyed in an avoided cost transaction, they may be sold through a state incentive program or a REC purchase program. However, that is not always the case, and state law should be reviewed carefully to determine whether a REC purchase program may be used to supplement avoided cost pricing. In California, state public utility statutes state that, "no renewable energy credits shall be created for electricity generated under any electricity purchase contract executed after January 1, 2005, pursuant to the federal Public Utility Regulatory Policies Act of 1978."[51] This may preclude QFs in California that are participating in avoided cost programs from selling RECs to utilities for RPS compliance, because those RECs are essentially considered to have been conveyed in the underlying avoided cost sale.

2. RENEWABLE ENERGY CREDIT MARKETS

As discussed in the Retail Market Policies section of this paper, most state performance-based and up-front incentives for PV systems are only available for systems that produce energy that is used for onsite consumption. Systems that sell power under a wholesale arrangement, such as an avoided cost program, are often unable to receive PV incentive payments. California's CSI incentive program is an example of an incentive program that is only available for PV systems that supply power to onsite load, with any excess generation credited under a net-metering program. Wholesale generators may not receive CSI incentives.

Although wholesale generators may not take advantage of PV incentives in California and other states, some states have established markets that allow PV system developers to sell RECs to utilities who may then use those RECs for RPS compliance purposes. In some states, RECs may be used to meet identified solar and distributed generation procurement and load service policy goals. For example, Arizona, North Carolina, Colorado, and New Jersey all allow systems selling power under wholesale arrangements to sell their RECs to a utility to meet identified solar and distributed generation requirements. Through the use of these programs, PV system developers may be able to supplement an avoided cost payment with a REC payment so that overall compensation more accurately reflects the market price of PV generation, thereby ensuring that procurement mechanisms are designed to achieve policy goals. For this approach to be viable from a project development standpoint, it is critical that payment for RECs be offered through a long-term contract so that the income stream from RECs is sufficiently stable to allow for project financing.

For wholesale generators participating in programs other than avoided cost mechanisms, RECs are typically conveyed to a utility as a part of a wholesale power transaction. For example, California, Vermont, and Hawaii all require a transfer of RECs as a requirement for participating in their state FIT programs (discussed below). On the other hand, and to underscore the diversity of incentive programs, several municipal utilities in Washington and Alaska offer payment for energy fed onto the grid from renewable energy systems up to 25 kW. These municipal programs do not specify the inclusion of RECs in the payment. In this case, a system owner has the option of retiring RECs or selling them to a willing purchaser. The amount paid to participating renewable energy producers depends on the total amount contributed by local financial supporters, but cannot exceed $1.50/kWh. In 2009, the Chelan County Public Utility District's program was offering $0.22/kWh, and the Okanogan County Public Utility District, also in Washington State, was offering $0.198/kWh. Golden Valley Electric Association in Alaska provides an annual payment based on contributors' participation in the program.

Wholesale generators are also eligible for other incentives that this paper does not address, such as tax credits, grants, and low-cost loans that can have a significant impact on the cash-flow analysis of a project.

3. FEED-IN TARIFFS

A FIT is an obligation that is placed on an electric utility to purchase wholesale electricity from an eligible seller of electricity at specified prices. FIT prices are administratively determined and are typically set at a level that is intended to be sufficiently high to attract the types and quantities of renewable energy desired.

In many ways, FITs are a logical evolution of PURPA's compelled-purchase requirement for utilities. They provide the administrative ease and certainty of a PURPA "must buy" program, but adopt higher prices that are more akin to price levels associated with renewable energy purchases obtained through RPS procurement mechanisms.

Recent movement toward FITs for distributed PV systems appears to be motivated by four considerations: (a) a desire to support investment in larger PV systems beyond those that primarily serve onsite load; (b) a recognition that existing wholesale procurement mechanisms tend to favor very large generators to the near exclusion of distributed systems; and (c) an appreciation that distributed generation has benefits that may justify a higher price than is paid for larger grid-scale power projects; and (d) a perception that FIT programs have brought large amounts of distributed PV capacity online in European countries such as Germany and Spain.

At present, policy makers in most states in the United States are limited in their ability to adopt FITs for IOUs at rates that exceed utility avoided cost. Congress has vested FERC with exclusive authority over wholesale markets. FERC has determined that state authority to determine wholesale market prices is limited to implementing PURPA and determining avoided cost prices for QFs.[52]

There are three important exceptions. First, the states of Alaska, Hawaii, and Texas are not subject to FERC's wholesale pricing authority, and so policy makers in these states may set wholesale electricity prices in excess of avoided cost. Second, municipal or publicly owned utilities are not subject to FERC oversight and so state legislatures (and public utility commissioners in states where state utility commissioners have jurisdiction over municipal utilities and electric cooperatives) may require such utilities to adopt FITs at prices that exceed avoided cost. Third, state policy makers can establish a FIT that exceeds avoided cost if a state provides an incentive, tax credit, or REC payment to compensate for the portion of a tariff that exceeds avoided cost.

The above limitations make FIT policies a limited wholesale market option in much of the United States. However, because FITs are potentially feasible in some locations, the following subsections discuss the limited FIT programs that have been implemented and the methods that have been applied to determine FIT rates.

a. *Existing State and Utility Feed-in Tariff Programs*

Although there has been much discussion in the United States about establishing FITs at a federal, state, or local level, few have actually been implemented. Gainesville Regional Utility (GRU), a publicly-owned utility in Florida, made news in early 2009 when it arguably became the first utility in the United States to adopt a FIT. GRU's program, capped at 4 MW per year, features rates starting at $0.26 for systems larger than 25 kW and $0.32/kWh for systems less than 25 kW, and ramps down each year until 2016.[53]

Other municipal utilities have also proposed and/or implemented FIT programs. The Sacramento Municipal Utility District (SMUD) recently implemented a FIT program that is capped at 100 MW of qualifying renewable and combined heat and power generating facilities. The SMUD FIT targeted systems up to 5 MW and the application queue to meet SMUD's procurement target was filled within a day, all with PV capacity.[54] The SMUD tariff is based on a time-differentiated avoided cost calculation, but rates are levelized and locked in for the life of a power purchase agreement.[55] Estimates show that expected PV output under the time-differentiated levelized rate would be about $.14/kWh with a 20-year term.

Other utilities that have adopted voluntary FITs include San Antonio's municipal utility (CPS Energy) and Indianapolis Power & Light.[56] Because these are voluntary programs that are merely approved and not compelled by state or local policy makers, they are not preempted by FERC.

There has also been activity at a state level, most notably in Vermont, Hawaii, and California. In May 2009, Vermont enacted a law that requires all retail electricity providers to purchase renewable electricity through a Sustainably Priced Energy Enterprise Development Program.[57] This program provides long-term contracts with fixed standard offer rates for renewable energy fed into the grid, capped at 50 MW of installed capacity. In 2009, the Vermont Public Service Board adopted interim prices for this program that included $0.30/kWh for solar installations up to 2.2 MW.[58] The technology-specific cap of 12.5 MW was maxed out the first day applications were accepted. However, if any of those projects are not built, further contracts may be issued at $0.24/kWh.[59]

In October 2009, the Hawaii PUC issued a decision and order outlining general principles for the creation of a statewide FIT to be offered by the state's IOUs.[60] The FIT will offer a fixed rate over a 20-year contract and will allow projects up to 5 MW for Oahu, and up to 2.72 MW for Maui and Hawaii Island. Hawaii's FIT is capped at 5% of 2008 peak demand over a 3-year period. The Hawaii legislature also passed legislation in 2009 that allows the PUC to set preferential prices for renewable energy from agricultural lands.[61] Hawaii is not subject to FERC's wholesale pricing authority, and so FIT rates in Hawaii may exceed utility avoided cost.

California enacted a limited FIT in 2006 that applies to RPS-eligible generators less than 1.5 MW in capacity and does not feature pricing that is differentiated by generation source.[62] This legislation was amended in 2009 to increase eligible system size to 3 MW for participating generators and to expand statewide enrollment limits.[63] Under the current program, generators may enter into 10, 15, or 20-year contracts and receive a payment based on an administratively determined market price referent (MPR), a benchmark price that the CPUC uses to determine price reasonableness in annual RPS solicitations.[64]

Because California's MPR is based on the projected 20-year levelized cost of building a new combined-cycle natural gas turbine, it represents the long-run avoided cost of new gas-fired generation, and is therefore more of an example of an avoided cost implementation than a FIT. As such, the ability to require California utilities to offer this price may be found under California's authority to implement PURPA. California's MPR-based tariff is available until the combined statewide cumulative capacity of eligible installed generation equals 750 MW.[65]

b. Establishing Feed-in Tariff Rates

Designers of FITs typically aim to provide a payment level that is sufficiently high to spur renewable development. There are basically two approaches to determining a market-clearing price for renewable and/or distributed generation. FITs use an administratively determined price. Auctions and RFPs, by comparison, use market mechanisms to establish a price. Another important difference is that in a capped program, FITs use a first-come, first-served approach to rationing available capacity while auctions and RFPs ration available capacity on the basis of achieving the lowest cost to ratepayers.

Determining electricity prices administratively can be a challenging task. In the section on Avoided Costs we mentioned that determining the price level of a utility's avoided cost can be difficult and state rulemakings aimed at determining avoided cost can be contentious. Many of the FIT programs that have been implemented in the United States have involved publicly owned utilities or were offered voluntarily by an IOU. It remains to be seen whether setting and adjusting FIT rates in states such as Vermont and Hawaii, which have imposed FIT obligations on utilities, proves to be contentious.

In the long term, establishing and adjusting FIT rates could prove to be more labor intensive than setting an avoided cost rate. Technology-differentiated tariffs could prove particularly challenging to implement, because a standardized cost of production would need to be determined for all participants in a FIT program. Most FIT programs are structured to offer targeted pricing that varies depending on the renewable generation source—solar, wind, biomass, biogas, etc.

Costs of production can also vary significantly within each of these generation sources. For example, a number of technologies exist for converting solar resources into electric energy, with varying costs of generation. Cost of generation can also differ for a single technology based on where a generator is located and how it is installed. For example, a ground-mounted PV system in an inland location in California will certainly have a different cost of generation than a roof-mounted system installed along the foggy Northern California coast, even if the same PV panel technology is used.

A FIT price that adequately compensates one installation may under- or overcompensate another installation, and a FIT price that aims to compensate all of these installations may generate interest that exceeds program availability, which has been the case with all FIT programs implemented in the United States thus far. For example, Vermont's FIT set an initial price for solar technology of $0.30/kWh and generated contract requests totaling 175 MW for 12.5 MW of available capacity (Wilson, 2009). This led some to question whether the same amount of solar capacity could have been installed at a lower cost (Graham, 2009). Feed-in tariffs offered by GRU, SMUD, and CPS Energy also resulted in significantly more interest than initial program caps could accommodate on the first day tariffs were available (Yarrow, 2009).

By comparison, California implemented a FIT program in 2007[66] that was based on the administratively determined MPR. Compared to GRU and Vermont, which set prices that resulted in too much interest, the California program set price at a level that under-stimulated participation. What this illustrates is that it can be difficult to administratively determine a price that simultaneously guarantees developers an opportunity to operate profitably and procures wholesale power at the lowest cost to ratepayers.

Although it can be administratively difficult to determine appropriate price levels, feed-in and fixed-price tariffs, like avoided cost tariffs, are likely the most efficient means to enroll projects quickly. FITs provide price-transparency to developers and therefore enable a good projection of project revenue prior to incurring any costs in developing a site or installing a system. Market-based mechanisms that feature an RFP or auction, by comparison, may require project development expenditures, such as obtaining a site control agreement or an interconnection request, prior to obtaining a power sale contact.

> "... feed-in and fixed-price tariffs, like avoided cost tariffs, are likely the most efficient means to enroll projects quickly."

One way of addressing the difficulty of administratively setting FIT rates is to predetermine a market-responsive payment digression method that adjusts the level of FIT rates at predetermined time intervals or once predetermined thresholds—installed capacity, as one example—are met. California's CSI incentive program adjusts incentive levels when installed capacity goals are achieved. This approach is particularly well suited to setting prices for technologies such as PV, which are experiencing rapidly declining costs. This approach may not work as well for technologies where costs are not decreasing rapidly or may even increase, which could conceivably apply to any technology, including PV. To ensure that prices can adjust upwards, FIT price adjustments could instead be linked to a market-index such as one resulting from an RPS solicitation for renewable generation.

Despite the potential benefits of FITs, state policy makers in the United States are presently limited in their ability to establish an administratively determined price for wholesale power that exceeds a utility's avoided cost. Outside of Hawaii, Alaska, and Texas, FIT obligations may only be imposed on municipal utilities and electric cooperatives, unless payment in excess of avoided cost is provided through a REC payment or is credited through tax and/or incentive mechanisms, or when a FIT is voluntarily offered by a utility.

4. MARKET-BASED PROCUREMENT METHODS (RFPs/AUCTIONS)

Rather than set wholesale prices administratively, as is done with avoided cost rates or FITs, state policy makers can instead use market mechanisms, such as auctions or RFPs, to determine a price appropriate to meet an identified procurement requirement. Several state policy makers have used this approach to establish REC prices, avoided cost rates, wholesale power prices, and renewable power prices pursuant to RPS procurement. In fact, market-based methods are the predominant means of wholesale power procurement in the United States. This approach incentivizes market entry by higher efficiency generators and ensures prices that support development and produce the least cost for ratepayers.

In the remainder of this report, we provide several examples of RFP programs that are targeted toward PV procurement. We also discuss some disadvantages of RFPs that may make such policies better suited for larger systems.

a. Existing State and Utility Targeted RFP Programs

On June 18, 2009, the CPUC authorized Southern California Edison (SCE) to implement a 500 MW PV program.[67] This program allows SCE to build, own, and operate 250 MW of PV capacity and procure an addition 250 MW from independent power producers (IPPs) through a competitive bid program targeted at PV systems in the 1 to 2 MW capacity range. The program will focus on developing PV systems on commercial rooftops. Ground-mounted generation may account for up to 10% of the competitive solicitation. SCE will hold two competitive solicitations per year, with contracts awarded to bidders who meet minimum project viability standards, pass several specific screening criteria, and offer the lowest price. If a bid is selected, SCE and the seller may then enter into a standard, non-negotiable contract.

On April 22, 2010, the CPUC authorized Pacific Gas & Electric (PG&E) to develop up to 500 MW of PV over five years, consisting of projects between 1 and 20 MW.[68] PG&E will own up to 250 MW of PV and procure an additional 250 MW from IPPs through competitive solicitations. PG&E will develop projects at a rate of approximately 100 MW per year (50 MW per year for each portion). Successful bidders for the IPP portion will enter into standard, 20-year power purchase agreements (PPAs) with PG&E.[69]

On July 13, 2010, the CPUC issued a proposed decision that would authorize San Diego Gas & Electric (SDG&E) to develop 56 MW of PV over a five-year period.[70] SDG&E is authorized to own up to 26 MW of PV generation, while IPPs will own the remaining 26 MW. The program would have a spending cap of $250 million and will focus on 1 to 2 MW projects. SDG&E will hold a competitive solicitation at least once per year. Pricing for the solicitations will be capped at $235 per MWh, which is based on an installed cost of $3.50/W. Projects must achieve commercial operation within 18 months.

The CPUC is also considering a proposed decision that would create a renewable auction mechanism for renewable generators from 1 to 20 MW in capacity that would contribute to California's RPS goals.[71] The program would require California's three largest IOUs to hold periodic auctions separately from the general RPS procurement process that is required annually. This would allow smaller projects to compete among themselves on price rather than competing against larger projects in the annual RPS solicitation. Developers would submit non-negotiable bids for long-term contracts and lowest-cost projects that meet specific viability criteria would be awarded contracts. Sellers must bring a project online within 18 months (with extensions available for delays that occur through no fault of a developer). The program would be capped at 1,000 MW and procurement would be spread over a four-year period.

Arizona and Oregon have moved forward with market-based wholesale procurement programs that target distributed PV systems. In 2008, Arizona Public Service (APS) created an RFP program for DG projects to meet an annual DG procurement goal of 200,000 MWh. APS received offers from 12 bidders who submitted 22 qualified proposals that exceeded the target capacity nearly three times over.[72] Another large Arizona utility, Salt River Project (SRP), has also issued an RFP targeted at distributed PV.[73] SRP will procure up to 50 MW of ground-mounted PV capacity in the third quarter of 2012 and up to 50 MW in the third quarter of 2013. SRP has indicated a particular interest in projects between 5 and 20 MW in capacity to be located in the Phoenix metropolitan area.

In Oregon, the PUC recently approved a market-based procurement mechanism for PV systems between 100 kW and 500 kW in capacity.[74] Oregon utilities Pacific Power and Portland General Electric have subsequently issued RFPs to accept competitive bids pursuant to this program.[75]

b. Establishing Market-Based Rates

Market-based procurement mechanisms, such as auctions and RFPs, are more likely to capture market price fluctuations than an administratively derived price. This is primarily due to sellers in the market having more information than regulators, because sellers have a better understanding of their costs and means of mitigating them. Market participants are also able to optimally design the size a facility to maximize economies of scale appropriate to their particular capabilities and project locations.

Assuming a market participant bids a price that is sufficient to satisfy his or her financial objectives for developing a project, the price achieved through a market-based procurement mechanism should be sufficient to financially support the project. However, this is not always the case. Developers may lack experience and unintentionally underbid the price necessary to bring a project to financial viability. There is also a possibility that unanticipated circumstances may lead project development costs to exceed diligent cost projections and may therefore leave a project unable to operate profitably despite the anticipated viability of the price bid.

Of course, the risk of cost overruns and lack of experience in understanding project development costs are not problems that are unique to participation in market-based procurement programs. These challenges may also arise in programs that use an administrative approach to determining a fixed price.

Large projects are complex endeavors that require a significant amount of sophistication regarding permitting, environmental requirements, interconnection, financing, taxes, regulatory approvals, and a plethora of other issues. It seems reasonable to expect that market participants developing projects above a nominal size should have the sophistication necessary to forecast costs and meet delivery obligations agreed upon under a power sale arrangement.

To ensure that participants have the experience necessary to develop a project and that a developer can meet financial obligations arising under a wholesale contract, California's targeted RFP programs all require bidders to satisfy minimum project viability prerequisites. Developers are also required to post reasonable development security, which acts as a deposit that is returned if a project achieves commercial operation within identified timeframes, but is forfeited if a project does not achieve a minimum level of commercial operation.

Although market-based procurement mechanisms can facilitate procurement at lowest cost to ratepayers, and can be implemented without the difficulty of administratively determining a price, market-based procurement also has disadvantages, particularly for developers and installers of smaller systems. Specifically, these mechanisms offer no up-front certainty regarding the price level that may be obtained. Additionally, bidders in market-based procurement programs must incur development and transaction costs prior to submitting a bid. Having to incur these initial costs without any certainty of project revenue can make participation difficult, particularly for developers of small systems that will generate less revenue from which to repay those costs. It can also be difficult for small projects to compete on price against larger projects that may realize larger economies of scale. In light of these considerations, market-based procurement methods may be better suited for procurement from developers of larger generation facilities. Notably, the California market-based programs discussed above target systems larger than 1 MW.

WHOLESALE MARKET POLICY CONCLUSIONS

As with retail market policies, key similarities help identify essential components of successful wholesale market policy:

- **Financial incentives:** Successful programs provide a level of payment that ensures PV systems may be developed and operated profitably while limiting cost exposure of ratepayers.
- **Streamlined procurement processes:** Successful programs employ a streamlined procurement process that lowers the transaction costs of obtaining a wholesale contract while also ensuring that the most viable and cost-effective projects move forward.
- **Creating sustainable markets:** Successful programs create sustainable markets that avoid boom-bust development cycles, promote cost reduction, and capture cost reduction through market-responsive pricing mechanisms.

RECOMMENDATIONS

The terms net metering, community solar, feed-in tariff, and incentive imply more uniformity than in fact exists in state PV policies. State net-metering policies take different approaches with regard to compensating PV system owners for monthly and yearly excess generation. Community solar policies use a variety of billing mechanisms to facilitate participation and distribute benefits to the participants. Feed-in tariff prices have been set using various approaches, and state incentive programs come in a number of different shapes and sizes.

Table 2 shows which of the policies discussed in this paper have been adopted in the top 10 states for installed PV capacity.

State	Installed MW	Net Metering	Community Solar	Meter Aggregation	Incentive	Avoided Cost	Wholesale Option
1. California	528	yes	VNM	limited	UFI, PBI	yes	FIT, RFP
2. New Jersey	70	yes		pilot program	UFI	yes	RECs
3. Colorado	36	yes	VNM		RECs	yes	RFP
4. Nevada	34	yes			UFI	yes	
5. Arizona	25	yes	?	under consideration	UFI, PBI	yes	FIT, RFP
6. New York	22	yes			UFI	yes	
7. Hawaii	14	yes			UFI	yes	FIT
8. Connecticut	9	yes		under development	UFI	yes	
9. Oregon	8	yes		yes	UFI/PBI	yes	RFP
10. Massachusetts	8	yes	VNM		UFI	yes	Backstop auction

Table 2: Policy options employed by the top 10 solar states. Acronyms include: Virtual net metering (VNM), feed-in tariff (FIT), request for proposals (RFP), up-front incentive (UFI), performance-based incentive (PBI), renewable energy credit (REC), volumetric incentive rate (VIR)

Table 2 illustrates that many of the top 10 states for installed PV capacity have implemented a range of policies to facilitate growth in both retail and wholesale PV markets. The table also illustrates that the policies discussed in this paper are not alternatives but rather are complementary policies that facilitate PV growth in different market segments.

Retail Market Recommendations

Given the widespread implementation of net metering policies across the United States, it appears many state and local policy makers have embraced net metering to facilitate investment in onsite PV systems. Net metering allows utility customers who are able to host an onsite PV system to receive a simple, direct and timely financial benefit in the form of a reduced utility bill.

To make PV investment a cost-effective option for retail customers, many states have also implemented a well-balanced mix of net-metering policy, retail rate design and financial incentives. As discussed in the Retail Market Policies section of this paper, TOU rates, in particular, send a clear price signal that encourages efficient energy use and increases deployment of clean PV resources. However, to be effective, TOU rates must contain low demand charges and have a relatively high on-peak to off-peak price ratio. This creates an incentive for net-metered customers to lower consumption and increase generation to the maximum extent possible during all on-peak periods.

Although TOU structures with low demand charges and high on-peak to off-peak pricing ratios are likely to be financially attractive to many utility customers, retail tariff choice is also important, particularly for customers with PV systems that are sized to serve a small percentage of onsite electricity needs. Rate impacts and cross-subsidy concerns can be addressed in utility rate cases where the lower cost of servicing net-metered customers and the benefits of customer investment in distributed PV generation can be taken into account.

To supplement retail market policies, well-designed meter aggregation and community solar programs can extend the simple, direct, and immediate financial benefit associated with net metering to customers who are not able to host an onsite system for any number of reasons. Virtual net metering, in particular, appears well suited to facilitating investment by community members who would like to make a commitment to solar generation but lack the ability to host an onsite system. Utility billing systems, however, must be capable of dealing with complex financial arrangements that might be required for such an agreement.

Finally, a key consideration for state and local policy makers in designing successful community solar programs is allowing community participants to take advantage of incentive programs that are available for onsite generation. It is also important to ensure that a variety of financing options are available to customers looking to invest in a community system, including direct ownership, third party financing and utility ownership.

Wholesale Market Recommendations

Wholesale procurement mechanisms, like FITs, auctions, and RFPs, appear well suited to facilitating development where there are no onsite energy needs. In such situations, wholesale procurement represents the only option that allows a PV system installation to move forward. The key question for policy-makers is what is the right wholesale market design?

Given the pros and cons of fixed-pricing versus market-based pricing, which is discussed in the Wholesale Market Policies section of this paper, it appears fixed-price procurement mechanisms are more appropriate for smaller systems and market-based procurement mechanisms, such as auctions and RFPs, are better suited for larger wholesale systems. This recommendation is reflected in a recent National Regulatory Research Institute (NRRI) report (Pollock and McNamara, 2010). The NRRI report recommends that state policy makers "[e]mploy competitive bidding for larger projects, initially limiting the feed-in tariff to smaller projects."

Fixed-price wholesale offerings can be structured as an avoided cost payment plus a payment for RECs or a fixed-price for wholesale power and environmental attributes combined. However, the latter option is only viable in Alaska, Hawaii, or Texas, or in connection with approval of voluntary utility proposals, or if imposed solely on municipal or publicly-owned utilities that are not subject to FERC's exclusive wholesale pricing authority. Accordingly, state policy makers in most jurisdictions will need to structure fixed-price wholesale offerings by combining an avoided cost payment and a REC payment.

Although PURPA avoided cost programs exist in all of the top 10 states for installed PV, very little PV capacity is currently being installed under PURPA avoided cost rates alone. Avoided cost rates reflect the price level associated with the lowest-cost resource available to sell to a utility and are not intended to reflect market costs for renewable generation and are likely inadequate to facilitate growth in PV markets.

For this reason, policy makers may wish to structure avoided cost programs so that renewable qualifying facility sellers may sell the environmental attributes associated with their power production via RECs to utilities or other third parties. State policy makers may also wish to develop valuation methodologies that add to avoided costs, avoided line losses, and deferred or avoided transmission and distribution system investments so that avoided cost rates reflect the full value of energy and capacity that PV systems provide.

RFPs and auctions are more appropriate for larger systems that involve sophisticated system integrators who have the ability to successfully estimate system costs and have the capability to quantify all costs and benefits into a successful bid. This paper does not attempt to determine the difference between "big" and "small" PV systems for the purpose of determining when market-based versus fixed-price approaches are more reasonable. State policy makers are sure to have their own conception of that difference. For example, California's targeted market-based procurement mechanisms, which are discussed in the Market-Based Procurement Methods section of this paper, target systems 1 MW and larger. Likewise, the Arizona Corporation Commission recently proposed a comprehensive approach to wholesale distributed generation market development that would use fixed-priced arrangements for systems less than 1 MW and market-based procurement for systems larger than 1 MW.[76] Oregon, on the other hand, recently implemented a market-based procurement mechanism for systems between 100kW and 500kW.[77] Thus, what constitutes a small or large PV system varies from state to state.

Regardless of the approach taken to establish wholesale prices, there are certain key elements that have proven essential to successful wholesale market policies. Leading elements are streamlined interconnection procedures, standard power sale contracts, and reasonable development security requirements. These added elements reduce transaction costs associated with project development while also helping to ensure that only viable projects should move forward.

Incentive Policy Recommendations

State incentive programs have the potential to spur investment across multiple markets and are complementary to many of the policy options that have been described in this paper. State incentive programs typically provide up-front, fixed-price incentives for smaller PV systems and performance-based incentives, paid over an extended period of time, to larger PV systems. Many states have structured incentive levels to decline at pre-determined rates over time as PV costs move lower. Many states also use market-based mechanisms to determine which larger PV systems will receive performance-based incentive payments. Regardless of the pricing mechanism used, it is important that incentive payments be firm over an extended period of time, perhaps five years or more, in order to facilitate PV system financing and "bankability."

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Final Recommendations

Although the contours of policy design may vary within the policy categories discussed in this paper (net metering, meter aggregation, community solar, incentives, avoided cost, REC markets, FITs, auctions, and RFPs), there are three ingredients that appear essential to establishing robust retail and wholesale markets for PV systems at a state level.

First, <u>successful market design</u> makes investment in a PV system cost-effective by closing the gap between PV system costs and relevant retail or wholesale cost-effectiveness benchmarks. In retail PV markets, cost-effectiveness occurs when the levelized cost of PV is at or below the retail rates offered by a retail electricity provider. In wholesale PV markets, cost-effectiveness occurs when the the cost of PV production reaches wholesale power prices with similar hourly supply characteristics—that is, daytime generation that is located in proximity to end-use retail electric loads. Achieving cost-effectiveness often requires implementation of a well-considered mix of the policies discussed in this paper.

The second key ingredient is that successful policies provide market participants with clarity and stability regarding the financial benefits that will result from a PV system investment. Clarity and stability are particularly important to facilitating PV system investment because the initial investment cost of a PV system is considerable and the benefits of that investment will manifest themselves over an extended period of time. Without transparency and predictability regarding the financial benefits that will result from an investment, market participants will lack the ability to make an economically rational assessment when evaluating a PV system investment opportunity.

Third, successful policies structure retail rates to reflect the actual costs and benefits provided by customers who invest in PV systems to meet their onsite electrical energy needs (including transmission costs that may or may not be avoided/added) so as to facilitate wise choices that drive PV markets in a direction that can most quickly move away from incentives.

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Acronyms

APS	Arizona Public Service
CPUC	California Public Utility District
CSI	California Solar Initiative
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FIT	feed-in tariff
FKEC	Florida Keys Electric Cooperative
GRU	Gainesville Regional Utility
IPP	independent power producers
IREC	Interstate Renewable Energy Council
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
MPR	market price referent
MW	megawatt
NEG	net excess generation
NREL	National Renewable Energy Laboratory
PBI	performance-based incentive
PG&E	Pacific Gas & Electric
PP	Purchased Power
PPA	power purchase agreement
PUC	Public Utilities Commission
PURPA	Public Utilities Regulatory Policies Act
PV	photovoltaic
QF	qualifying facility
REC	renewable energy credit
RFP	request for proposal
RPS	renewable portfolio standard
SCE	Southern California Edison
SCG	Small Customer Generator
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
SRP	Salt River Project
TOU	time of use
UFI	up-front incentive
VIR	volumetric incentive rate
VNM	virtual net metering

Endnotes

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