Distributed Solar Incentive Programs: Recent Experience and Best Practices for Design and Implementation

Lori Bird, Andrew Reger, and Jenny Heeter
National Renewable Energy Laboratory

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Executive Summary

Dozens of utilities[1] throughout the United States offer incentive programs designed to encourage the adoption of solar energy, and the number has been growing as utilities respond to state solar mandates or internal goals. Rapidly changing market conditions in the past several years have made implementing solar power programs challenging. Various design and implementation methods have emerged as utilities or other program administrators have modified programs to respond to market changes, such as declining solar costs, increasing customer demand, and new business models.

Based on lessons from recent program experience, this report explores best practices for designing and implementing incentives for small and mid-sized residential and commercial distributed solar energy projects. The findings of this paper are relevant to both new incentive programs as well as those undergoing modifications. The report covers factors to consider in setting and modifying incentive levels over time, differentiating incentives to encourage various market segments, administrative issues such as providing equitable access to incentives and customer protection. It also explores how incentive programs can be designed to respond to changing market conditions while attempting to provide a longer-term and stable environment for the solar industry. The findings are based on interviews with program administrators, regulators, and industry representatives as well as data from numerous incentive programs nationally, particularly the largest and longest-running programs. These best practices consider the perspectives of various stakeholders and the broad objectives of reducing solar costs, encouraging long-term market viability, minimizing ratepayer costs, and protecting consumers.

Setting and Managing Incentive Levels

- Rebates coupled with performance guarantees can help incentivize small customer-owned systems by addressing barriers related to upfront costs.
- Performance-based incentives (PBIs) that are paid based on system output and credited on customer bills can be effective for commercial-scale and third-party owned systems. PBIs can minimize upfront impacts on program budgets by spreading incentive costs over several years.
- Appropriate incentive levels can be assessed by benchmarking against programs in neighboring states or service territories, using multiple data sources on installed costs, and limiting capacity offered in early stages of the program to test uptake rates.
- Pre-determined schedules for reducing incentives in multiple steps can establish a path for reducing incentive levels that provides market transparency, simplicity, and certainty for market participants, although they may not continuously align with market conditions.
- Competitive procurement mechanisms or auctions allow for market-based pricing, which can be important in an environment with rapidly changing pricing. These can be particularly important for large systems that require substantial incentive payments and can have cost considerations that vary by size. Auctions can also be extended to smaller

[1] In some cases, these programs are administered by independent organizations, but in most of the programs we examined, utilities were responsible for implementation. This report addresses distributed solar incentive programs broadly, whether implemented by utilities or other entities.

commercial systems if simplified processes are used -- at least one utility has used auctions for dispersing incentives to all commercial systems.

- Encouraging various market segments can be important for ratepayer considerations, grid benefits, market diversity, building support for the program, and balancing program costs. Multiple approaches may be required to encourage a diversity of systems because the costs and financing of systems vary substantially by size. For example, rebates or PBIs with pre-established step-down levels may be appropriate for small- to medium-sized systems. Competitive solicitations or auctions can be used to achieve market-based pricing for commercial systems or larger systems.
- Differentiating incentives can encourage systems to be sited in areas where they are most beneficial to the grid or to establish comparable incentives when solar resources vary.

Administrative and Consumer Protection Issues

- Consumer protection measures can encourage reputable business practices that help ensure the long-term viability of the solar industry. These can include ensuring optimal system performance through equipment, installer, or system requirements; encouraging consumers to explore energy efficiency; and protecting customers from price gouging.
- Ensuring equitable access to incentives requires fair queuing processes, particularly for programs with modest budgets that are not able to fully meet demand.
- While multi-year programs provide greater market stability, annual programs can use multiple offer periods throughout a year to increase market stability and program flexibility. Multiple offers can allow a utility to adjust incentive levels according to program uptake and market conditions, as necessary.
- Transparency and up-to-date communications are important to enable customers to evaluate projects, particularly in programs that reduce incentives when program thresholds are met.

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1 Introduction

In recent years, the number of utilities across the country offering incentives to encourage customers to adopt solar power has grown substantially. Often this is because utilities are required to meet solar energy mandates or generation targets—16 states and Washington D.C. have adopted specific targets for new solar capacity or distributed generation as part of their renewable portfolio standards (RPS), while California has a separate solar initiative. In other cases, utilities have voluntarily encouraged the adoption of solar energy or established incentive programs to meet internal clean energy goals. While solar photovoltaic (PV) system costs are rapidly falling, costs for distributed systems are still above retail rates in most jurisdictions, and require incentives to support customer adoption.

Rapidly changing market conditions in the past two or more years have made implementing incentive programs challenging. In fact, programs have had difficulty keeping up with market demand and changes in the cost of solar. Solar installed costs have declined from $7/watt in the first quarter of 2010 to less than $6/watt in the first quarter of 2012 for residential systems nationally, while nationally nonresidential systems have dropped from just under $6.50/watt to nearly $4.50/watt over the same period (SEIA/GTM Research 2012). Furthermore, new business models have emerged, most notably residential third-party ownership models (through leasing or power purchase agreements) that remove the up-front capital cost hurdles for small systems and typically cost the same or less than the electricity otherwise purchased from the local utility. Under the leasing model, customers lease solar equipment from a company, while under a power purchase agreement (PPA) model customers purchase a system's output. In either case, the third-party retains ownership of the system and responsibility for maintenance. Residential third-party ownership is growing rapidly in several states (SEIA/GTM Research 2012).

Because of changing market conditions, utilities and administrators have significantly modified existing incentive programs to respond to declining solar costs, increasing customer demand, and new business models. Some experimentation has occurred, and a number of programs have made substantial shifts over the course of several years to address the rapidly changing marketplace. In some cases, programs have been halted while a new course for the program was established—an approach that can be problematic for the continuity of the solar industry. Modifications made by program administrators have included altering incentive levels or introducing market-based mechanisms for pricing, changing the form of the incentive for certain classes of systems, and refining mechanisms for queuing customers to address high demand periods.

Earlier assessments of PV incentive options have focused on how the choice of incentive mechanism—capacity-based rebates or performance-based incentive payments—can effect program budgets and demand for residential or commercial systems (Hoff 2006). Rebates cover part of the upfront cost of systems, while performance-based incentives are paid over time based on system output. Other work has focused on the need to ensure system performance when designing PV incentive programs to ensure optimal system output (Barbose et al. 2006), and on the importance of net metering and interconnection policies for solar (Fox and Varnado 2010).

This report builds on earlier studies and explores best practices for designing and implementing solar incentives for distributed residential and commercial solar projects, based on lessons from recent utility experience.[2] The findings of this paper are relevant to both new solar incentive programs as well as those undergoing modifications. While several utility solar programs in the West are in the late stages of implementation and incentive levels are nearing zero, new programs are being launched or expanded in other areas, for example in New York, Connecticut, and Utah. In addition, many existing programs are being substantially revised.

The report covers factors to consider in setting and modifying incentive levels over time, differentiating incentives to encourage various market segments, providing equitable access to incentives, and protecting customer interests. It also explores how incentive programs can be designed to respond to changing market conditions while attempting to provide a longer-term and stable environment for the industry. The findings are based on information regarding implementation experience from interviews with program administrators, regulators, and industry representatives as well as data from incentive programs nationally, particularly the largest and longest-running programs.

[2] This report does not address incentives for utility-scale projects, nor does it cover incentives in markets where there is solar REC trading because of the different characteristics of those markets. A review of solar REC markets is available in Bird et al. (2011).

2 Key Elements to Incentive Program Success

The goal of solar incentive programs is generally to increase the amount of solar power in a utility's generation mix; however, the relative success of the program can be interpreted in different ways by various stakeholders. A utility may choose to implement a program to meet voluntary objectives for solar installation, or more commonly, to meet compliance with solar carve-outs in state renewable portfolio standards or other state mandates, such as the California Solar Initiative (CSI), which was introduced in conjunction with California's Million Solar Roofs Program. Another objective could be to encourage the installation of solar in areas where there is congestion on the electrical grid or where solar can provide other grid benefits. From the perspective of other key stakeholders, a successful program will reduce solar costs, encourage long-term solar market viability, minimize ratepayer cost, and provide consumer protection and transparency. This paper examines best practices for implementing solar incentive programs in light of these various factors.

Reducing Solar Costs: The large up-front cost of solar has historically been one of the largest impediments to residential solar gaining greater market penetration. To drive down these costs, the solar industry needs to achieve sufficient volumes to reduce equipment and installation costs. An incentive program can play a direct role in encouraging cost reductions for installers by increasing the number of solar installations over which operational fixed costs can be spread. Also, variable costs can be reduced through both efficiencies of scale and installation practices that can be realized as an installer's workforce gains experience. In addition to incentives, the availability of net energy metering, fair interconnection policies, and utility rate structures are important for the economics of solar energy projects.[3] Today, net metering is available in most (if not all) utility service territories where solar incentive programs are in place.[4]

Encouraging Long-Term Solar Market Viability: For incentive programs seeking to help permanently drive down the cost of solar, important considerations are program longevity, stability, and predictability. Short-term boosts to the market may be insufficient for installers to gain efficiencies of scale to drive down costs. However, incentive programs have not always provided solar markets with stability or longevity. The renewable energy market, in general, has experienced substantial variability in installation rates and levels, and solar incentives have in some cases contributed to and responded to these cycles.[5] A long-term perspective can help achieve both the utility's desired increase in solar generation to meet its near-term goals and help

[3] For example, see Solar Alliance "The Four Pillars of Cost Effective Solar Policy" http://www.frontpagepr.com/powerpoint/Tom%20Alston%20-%20Solar%20Alliance%20Four%20Pillars%20of%20Solar%20Success.pdf, accessed December 7, 2012.

[4] See DSIRE for additional information on where net metering is offered, http://www.dsireusa.org/summarytables/rrpre.cfm, accessed December 7, 2012.

[5] For example, several programs have sold out rapidly and have been placed on hold until further funds are available. Others have been modified midstream. For example, Xcel Energy altered its Solar Rewards incentive program in early 2011 by reducing its incentives, and then shifted its program from a rebate to a PBI program. Subsequently, residential installations in Colorado saw a 25% decrease in capacity in 2011 compared to 2010. (SEIA/GTM Research 2012). On April 8, 2011, LADWP suspended its solar program after receiving $112M in rebate requests, when it had only a $30M budget for the year. (http://www.ladwpnews.com/go/doc/1475/1061811/) The program stayed closed until September 1, 2012 (5 months closed), when it reopened and received requests for 3.25 MW of capacity in its first week of reopening. (http://www.ladwpnews.com/go/doc/1475/1187095/)

the solar installer community develop in a sustainable fashion that will lead to decreases in the installed costs of solar.

Minimizing Ratepayer Costs—When designing a program, it is important to consider the interests of the ratepayers who typically fund incentive programs. For ratepayers, the cost-effectiveness of the program is an important metric of program success. Program cost-effectiveness can be achieved by 1) managing the administrative costs of the program effectively and 2) setting an appropriate level of incentives so that the program does not overpay for solar development, therefore, maximizing the amount of installed solar capacity per the available program funding. Equity among rate classes is another consideration. Programs funded by both residential and commercial ratepayers may need to support both residential and commercial-scale solar projects to achieve equity among contributors.

Providing Consumer Protection and Transparency—A utility or entity offering a solar incentive program is uniquely positioned to help set industry standards and institute consumer protections. Consumer protection measures typically involve helping ensure system performance, but they can also relate to helping a customer purchase an appropriately sized system at a fair price. Instituting standards designed to ensure optimal system performance protects the interests of consumers who want to maximize production to recoup their costs for the system; the utility, which is often interested in maximizing system energy production to meet renewable energy goals; and the ratepayers who fund incentive programs.

3 Capacity-based Rebates versus Production-based Incentives

To stimulate solar market adoption and diminish the up-front capital costs of solar power, utilities have often developed incentive programs designed to bridge the gap between the retail rate of electricity and the cost of solar by 1) providing an up-front rebate to a developer (or system owner) based on the system capacity or expected production or 2) offering a performance-based incentive (PBI) based on the actual measured electrical production of the system over time (Hoff 2006). This section explores the benefits and tradeoffs of using rebates and PBIs as well as recent experience with these mechanisms.

3.1 Capacity-based Rebates

Rebates are often used primarily for smaller systems, for which upfront costs have historically been of greatest concern. Rebates vary by the incentive payment offered, the eligible project size, and the maximum payment available per project.

Over the past decade, solar rebate programs in the United States have dramatically reduced available incentive levels. In 2003, residential incentive levels offered in distributed solar programs generally ranged from \$4-\$6/watt, and by 2008, the average available rebate incentive had dropped to roughly \$3.50/watt. (Bolinger and Wiser 2003; Lantz and Doris 2009) Today, residential incentive levels have declined further and currently range from \$0.20-\$2.25/watt (see Table 1). [6] Table 1 presents a selected list of rebate programs representing a range of incentive levels, system sizes, location, and utility type. A full listing of the solar incentive programs analyzed for this paper can be found in the appendix. Rebates are as low as \$0.20/watt in California and Arizona, where incentive programs have been stepping down payment levels as solar capacity is installed. In most other regions, utility program incentive levels are often in the range of \$1.50- \$2/watt, and sometimes above. Of course, rebate level also depends on electricity prices and the solar resource in the region, among other factors.

Incentives are available for a wide range of system sizes. For example, Gulf Power limits rebates to systems less than 5 kilowatts (kW) while Los Angeles Department of Water and Power (LADWP) rebates are available for systems of up to 1 megawatt (MW).

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[6] Some utilities, as shown for Austin Energy, Pacific Power and Pacific Gas & Electric in California below, offer their rebate incentive on an AC, as opposed to DC-basis, to minimize conversion losses and encourage the use of efficient inverters. In some cases, the incentive level may be adjusted for system orientation and shading as well (see Section 8.1).

Table 1. Selected Residential Rebate Programs

Program Administrator	Rebate	Maximum Payment	Eligible System Size
Austin Energy	$2.00/watt AC	$15,000	1 kW – 20 kW
Gulf Power	$2.00/watt	$10,000	< 5 kW
Long Island Power Authority	$1.75/watt	$17,500 or 50%	< 10 kW
LADWP	$1.62/watt	75%	1 kW – 1,000 kW
NYSERDA	$1.50/watt	$10,500 or 40%	<7 kW
Pacific Power (CA)	$1.13/watt AC		1 kW – 5,000 kW
Arizona Public Service	$0.20/watt	$75,000 or 50%	< 30 kW
Pacific Gas and Electric Company	$0.20/watt AC		< 30 kW

Data derived from program websites and DSIRE

Rebates and System Performance

Rebates incentivize the installation of capacity *only*, as opposed to actual electricity production. As a result, a concern for rebate programs has been sub-optimal system performance based on either improper installation techniques or inadequate operation and maintenance of the system after installation, or some combination of both. This is a concern for utilities that rely on the output of incentivized systems to meet solar generation targets under an RPS. It is also a concern for ratepayers who support the incentive program, as it is in their best interest to maximize the output of the installed systems.

Many utility programs address performance concerns under capacity-based incentive programs by instituting pre-requirements that proposed systems must meet to qualify for available incentives. Performance requirements for modules and inverters often include a listing by Underwriters Laboratories (UL listed); meeting minimum equipment warranties; and certification and proper licensing of installers. Many programs also provide reduced incentive payments if a system is shaded or sub-optimally oriented, or may exclude eligibility altogether if expected performance thresholds are not met. To enforce compliance with performance requirements, most utilities will conduct a site inspection of the system. Methods that utilities use to inspect systems and encourage optimal system performance are discussed further in Sections 7.4 and 8.1.

3.2 Performance-based Incentives (PBIs)

One way to encourage optimal system performance is to offer incentives based on actual electrical production of the system. Several utilities offer PBIs, providing payments (typically in dollars per kilowatt-hour [$/kWh]) to a system owner over a certain period—anywhere from 5 to 15 years (up to 20 years for some commercial programs). PBI payments range from $.02/kWh to

$.41/kWh for residential systems with varying contract terms (see Table 2). PBIs are also used for a variety of system sizes, ranging from less than 10 kW up to 2 MW.

Table 2. Selected Residential PBI Programs

Utility	PBI	Length	Eligible System Size
PacifiCorp (OR)	$0.411/kWh	15 years	< 10 kW
Portland General Electric (OR)	$0.285/kWh	15 years	10 kW – 100 kW
Madison Gas and Electric (WI)	$0.250/kWh	10 years	< 10 kW
Xcel Energy (CO)	$0.150/kWh	10 years	0.5 kW – 10 kW
Sacramento Municipal Utility District (SMUD)	$0.100/kWh	5 years	No limit
Green Mountain Power	$0.060/kWh	10 years	< 250 kW
Orlando Utilities	$0.050/kWh	5 years	< 2 MW
Southern Cal Edison (CSI)	$0.044/kWh	5 years	< 100 kW
PG&E (CSI)	$0.025/kWh	5 years	< 100kW
Public Service New Mexico	$0.020/kWh	Ends 12/2020	100 kW – 1,000 kW

Data derived from (Database of State Incentives for Renewables & Efficiency)

System size and ownership structure are important considerations for PBI programs. For financial reasons, they have most commonly been offered for non-residential systems in the past, although they are increasingly being used for residential and smaller systems. The major consideration for their use to incentivize small systems is whether they are sufficient to address the hurdle of the initial capital outlay necessary to purchase a new system, which is a concern particularly for small customer-owned systems. PBIs, which provide only a set of future payments to the system owner and do not directly address upfront investment, may not be sufficient to drive substantial installations of residential or small commercial customer-owned solar systems. They can be effective, however, in driving third-party owned systems.

Developers of larger systems or companies that own larger portfolios of systems are often more financially sophisticated than residential customers. Consequently, large system developers are better able to evaluate the discounted present value of a PBI's future cash flows, and are better equipped to finance and depreciate a solar system's up-front investment in a way residential customers generally do not. In addition, they can also utilize accelerated depreciation tax benefits, which are not available to residential customers.

Third-party Owned Systems

Third-party owned systems—through a either a PPA or lease[7]—are more likely able to accept PBI payments than residential customer-owners who are more concerned with reducing the

[7] Solar leases and PPA agreements are similar in concept but differ contractually. A PPA agreement involves a sale of electricity from the third-party owner of the system to the entity hosting the system. Solar lease agreements involve leasing of equipment, whereby the leasing company retains ownership of the solar system in exchange for monthly lease payments from the customer for the energy produced by the system. The lessee will realize cost savings upon leasing a system if the lease payments minus any incentives or net metering benefits results in a lower

initial cost of purchasing a system. A third-party owned system is managed as a portfolio by the company retaining ownership, and can be financed like a larger system, though the introduction of financing costs may necessitate higher internal rate of return requirements if the third-party system owner must raise tax equity or other investor capital.

The rapid expansion of third-party ownership models in residential markets (leasing and PPAs) have the potential to expand the use of PBIs for residential systems. In California, third-party owned installed capacity surpassed direct ownership installed capacity for the first time in Q4 2011, and has continued to increase (Figure 1). In Colorado, the percentage of third-party owned systems applying for Xcel Energy's incentive program increased from zero in March 2010 to approximately 80% in March 2012 (SEIA/GTM Research 2012). Third-party owned systems are not allowed by law in some states, however, because such ownership arrangements can be considered to involve the sale of electricity by a non-utility (Kollins, Speer, and Cory 2010).[8]

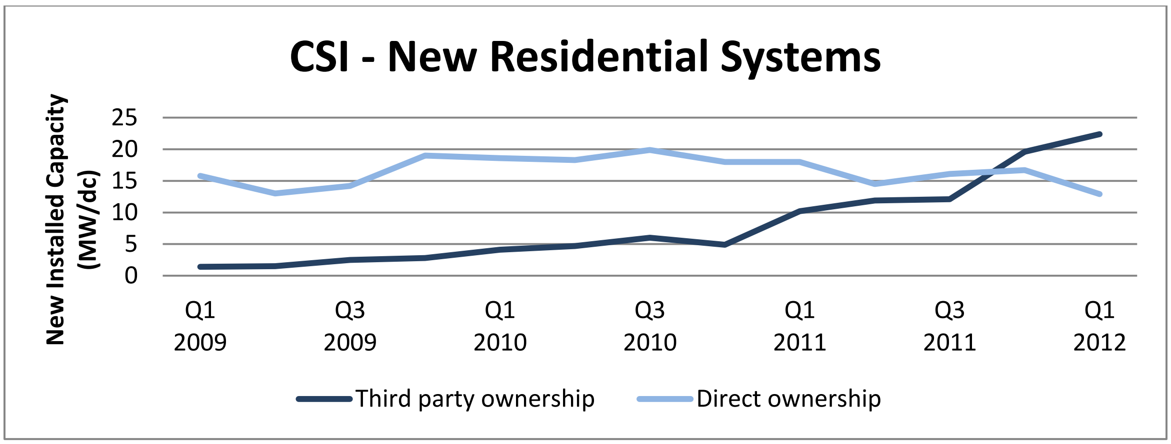

Figure 1. California Solar Initiative: Trends in third–party owned systems

(SEIA/GTM Research 2012)

One consideration for program administrators offering incentives to the residential and small commercial market segment is whether both the customer-owned and third-party ownership market segments should be developed by targeted and separate incentives. This could be accomplished in a variety of ways such as providing the option for rebates or PBIs for the smallest systems, or capping the amount of incentives available to each of the customer-owned and third-party owned market segments to encourage a diversity of ownership arrangements in the market.

monthly payment than the customer's original monthly energy bill (Cory 2009). Similarly, customers entering into PPA agreements can realize cost savings if the PPA price is less than the customer's current electricity payments. Companies that offer leases or PPA contracts to solar power customers tend to be larger organizations that are able to achieve economies of scale and more effectively monetize the tax equity and accelerated depreciation available to non-residential purchasers of a solar power system.

[8] States allowing third party ownership can be found on the DSIRE website at http://dsireusa.org/summarymaps/index.cfm?ee=0&RE=0, accessed August 2012.

3.3 Program Budgetary Considerations

Program budgetary constraints are another consideration in assessing whether to use rebates or performance-based incentives. Budgetary demands for rebate payments are much more front-loaded than performance based incentive programs (Hoff 2006). Upfront rebates require full payment up front, whereas PBI payments are often made over a period of 5 to 15 years based on system production. For PBI programs, incentive costs are shifted from the current year to future years. This can be particularly important for large systems. For example, offering a $1.00/watt rebate on a 1-MW system equals a $1,000,000 up-front rebate payment—a large cash outlay for the utility. Although PBIs shift cost burdens out over time, they do not necessarily lower program costs for ratepayers. Utilities seeking to develop new incentive programs will want to weigh budgetary considerations against the likelihood that a particular incentive type will stimulate the desired level of solar market development.

Budgetary constraints were a consideration in Xcel Energy's shift from its Solar*Rewards rebate program to a purely PBI program. Because the utility had oversubscribed its rebate offering – exceeding near term installation targets and over drawing its allotted solar incentive budget – moving to a PBI program allowed Xcel Energy to continue to offer incentive payments while addressing its near term cash situation. Stakeholders in the utility's Solar*Rewards program settlement hearings recognized that "the movement away from up-front incentive payments will defer the incurrence of a substantial level of costs to future periods." (Colorado Public Utilities Commission 2011, p. 8) Xcel Energy's move to a PBI program also allows the utility to offer an incentive more closely aligned with the actual production of a solar power system.

For the purposes of illustrating the differences in budgetary demands between a rebate and PBI program, we have developed a hypothetical scenario of an incentive program designed to spur the development of 100 MW of solar in 10 years. In this scenario, we assumed a 78% increase in solar installations each year to reach 100 MW of capacity in 10 years. This assumed solar growth rate is comparable to actual solar growth rates. While the rate of program uptake will certainly be affected by higher or lower levels of incentives, the purpose of this scenario is to highlight the difference in annual budgetary requirements between rebates and PBIs. For that reason, an additional assumption here is demand for solar is such that the full 100 MW of the program's desired capacity would be installed in the 10-year timeframe, regardless of incentive level or type.

Figure 2 illustrates the relative magnitude of payments over time for three different hypothetical programs: 1) a standard $2/watt rebate, 2) a $1/watt rebate, and 3) a fixed PBI rate of $0.10/kWh paid for 10 years. The figure shows the annual budget that each program would need to support solar installations under the assumed growth rates over time. For the PBI budget, the assumed solar capacity factor is 15%, and the assumed system degradation is .05%/year.

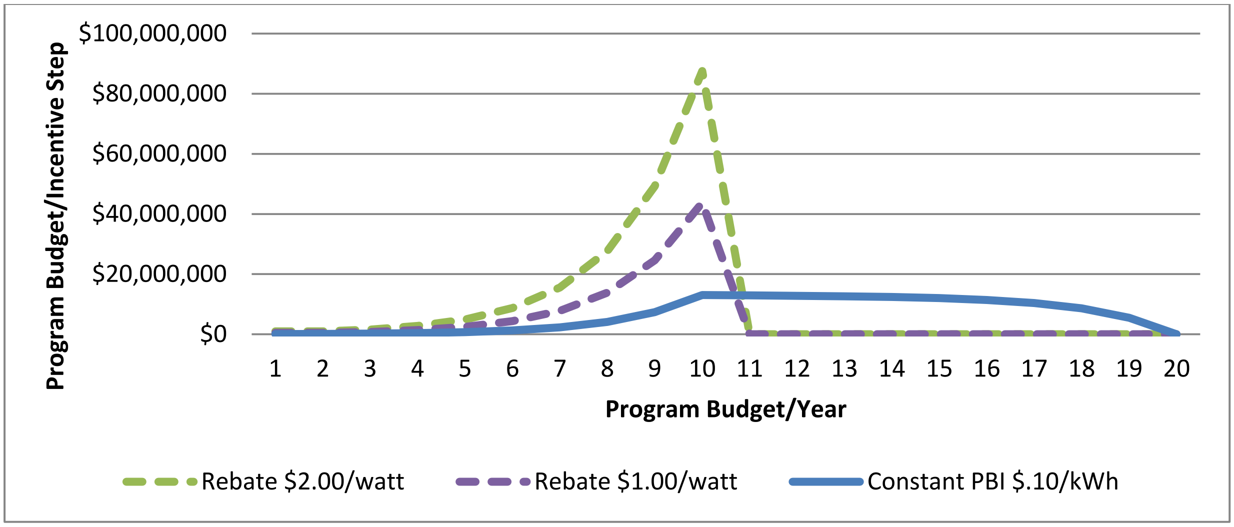

Figure 2. Rebate versus PBI: Budgetary comparison

Concept adopted from (Hoff 2006)

While a utility will have many considerations in choosing to offer a rebate or PBI (e.g., system performance and encouraging various market segments), the budgetary impacts of each option is an important consideration. Rebate programs must incur the bulk of expenses up-front, and may have higher annual budgets while the program is operational. PBI programs, on the other hand, spread the budgetary requirements of the program out over a longer period, and they extend beyond the period during which the program is accepting applications for participation in the program.

4 Establishing the Incentive Level and Designing the Program

Setting the initial incentive level can be one of the most important determinants of a solar incentive program's success and one of the most difficult elements of the overall program design. Providing incentives that are too large can cause an artificial rush to reserve incentive payments, which may overdraw the program's budget, and can lead to shorter program duration than originally planned or to overpayment for solar capacity. Alternatively, setting an incentive payment too low can lead to an undersubscribed program in which insufficient capacity is installed to meet a utility's solar targets. The goal for a utility in setting an incentive level is typically to provide sufficient payment to encourage enough customers to install solar technologies so that the utility can meet its solar capacity targets at the lowest cost (Couture et al. 2010). This section discusses targeting payback periods or returns, benchmarking incentive levels, incentivizing different market segments, and establishing rebate and PBI levels.

4.1 Targeting Payback Periods and Return on Investment

To establish an appropriate incentive level, utilities often target a specific payback period for customers or a return on investment (ROI) for installers. Other considerations for determining the level of incentive are: 1) the status and level of activity of the solar industry within the state or region, 2) the size and scope of the program, 3) budgetary constraints, and 4) customer monthly cash flow where third-party owned systems are an option (i.e., the comparison of monthly solar costs through a lease or PPA to retail rates).

Based on our discussions with program administrators, some utilities target a 10–15 year payback for consumers. For example, the Oregon Solar Incentive Program targets a 15-year payback with its "volumetric incentive rate" (PBI), which coincides with the utility's purchase of a system's renewable energy certificates (RECs) for the same 15-year period (Public Utility Commission of Oregon 2011). Utilities may also target a specific ROI for system installers. Information on these targeted returns is not widely available, but one utility indicated that it seeks to allow installers a return of 8%–10%.

We analyzed payback periods for residential programs included in the appendix and found that of the customer-owned, small system programs, only 6 utilities of 25 offered programs that yielded after-incentive payback periods of less than 15 years. Of the remaining small, residential, customer-owned solar programs analyzed, we calculated that

- Five programs offered after-incentive payback periods of 15–25 years,
- Eight programs offered after-incentive payback periods of 25–30 years, and
- Six programs offered after-incentive payback period exceeding 30 years.[9]

Calculations of payback and ROI for solar systems require data for installed capacity costs (in the case of a rebate payment) or production costs (in the case of a PBI payment); the cost of

[9] Calculations were done in NREL's System Advisor Model. We used OpenEI utility data for standard/base residential rate structure; solar cost data from SEIA/GTM for Q1 2012; weather data for a zip code in the utility's service territory; the 30% Federal Investment Tax Credit; building load data for a building in a zip code in the utility's service territory; and incentive levels available for the relevant program.

retail electricity avoided (including time of use rates, where applicable); and any other financial incentives available, including net metering, federal tax credits, and possible revenues from the sale of RECs. Models, such as the publicly available System Advisor Model (SAM) or the Cost of Renewable Energy Spreadsheet Tool (CREST),[10] can be used to determine payback periods and the impact of incentive levels on a system's net present value, given assumptions about system cost, expected performance, utility rates, and expected average annual hourly building load demand.

While targeting a specific payback or return seems straightforward, it is complicated by rapidly changing prices and differences in electricity rate structures and installed costs for various system sizes. Given the rapidly declining costs of PV and wide variations in reported prices, obtaining accurate cost data for calculating payback and returns can be particularly challenging. Prices can vary substantially even within a single utility service territory. Price fluctuations also make it difficult to maintain a targeted ROI over the duration of the program. In addition, because cost parameters differ among customer classes, incentive levels must typically be developed for various customer classes or system sizes in order to maintain the targeted customer ROI or payback period across program participants. These issues are discussed in detail in the following two sections.

4.2 Assessing Solar Costs and Benchmarking

Accurate data on solar installation and equipment costs are essential to setting appropriate incentive levels, but rapid changes in the marketplace in recent years have made it difficult for program administrators to stay abreast of current prices. Several sources have reported wide variation in installed costs—not only from state to state but also often from project to project. National data from the first quarter of 2012 shows installed costs for residential systems ranging from roughly \$4-\$8/watt (SEIA/GTM Research 2012, p. 38) and CSI's available cost data shows residential prices in the range of \$4-\$7/watt DC.[11] (Go Solar California 2012). Installed costs have been declining steadily on average, although recent studies have shown that decreases in component costs of a solar system have not translated to comparable decreases in the installed cost of solar systems (Goodrich, James, and Woodhouse 2012).

Because of challenges in obtaining accurate installed cost data, benchmarking against incentive levels, uptake rates, and installed costs of neighboring utilities can help assess appropriate incentive levels. Also, more accurate cost data can be obtained by using multiple sources, including costs from independent sources and information provided by the local installer community where available. A list of currently available incentives, which was largely gathered from publicly available data from Database of State Incentives for Renewables & Efficiency (DSIRE)[12], is available in the appendix. In addition, comprehensive data on installed solar costs is available online under the Open PV project, while CSI and other California utility programs data, including installed costs and incentives received, are also posted online.[13]

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[10] The SAM model is available at http://sam.nrel.gov/ and CREST is available at https://financere.nrel.gov/finance/content/crest-cost-energy-models.

[11] Of systems installed in 2012, 26% cost between \$4-\$5/watt DC, 34% cost from \$5-\$6/watt DC, and 18% cost from \$6-\$7/watt DC, according to statistics for the CSI program. http://www.californiasolarstatistics.ca.gov/reports/cost_per_watt/ (Go Solar California 2012).

[12] See http://www.dsireusa.org/.

[13] See Open PV at https://openpv.nrel.gov/ and the California data at http://www.californiasolarstatistics.ca.gov/.

Particularly for programs with long approval processes, another consideration is the timeliness of solar market data. The regulatory approval process for establishing or modifying programs can often take months to complete. During this period, pricing can change. Installed cost estimates that were accurate at the beginning of the process may not be accurate once final approval is granted. Therefore, mechanisms for updating and revising pricing may be necessary.

To address cost uncertainty, some utilities have tested incentive levels by making them available in the form of pilot programs, such as the Oregon Solar Volumetric Incentive Rate and the LADWP feed-in tariff. Others have limited the capacity available for the first stage of a program to similar effect. In this way, offering a given level of incentive to the market provides direct evidence with respect to its efficacy in market development.

4.3 Incentivizing Different Market Segments

Solar programs are generally designed to encourage a range of small and larger systems, and there are various reasons why such market diversity can be beneficial to the solar market. One such reason is ratepayer equity if all classes of ratepayers support the solar program. Other considerations are that encouraging larger systems can achieve solar capacity installation targets at lower cost, while many small distributed systems can provide benefits to consumers who can build support for a program. Utilities can also derive system benefits from having particular classes of systems on the grid. From an industry perspective, encouraging the development of a variety of sizes and types of systems can build a more robust and stable solar industry in the long term.

It is important to differentiate incentive levels for smaller and larger systems because of differences in system economics. Having several tiers of incentives can help utilities more accurately price and design incentives for each tier. Larger system owners likely have different electricity rates, demand charges, and perhaps greater access to financing—all of which can influence a system's economics. In addition, commercial customers and solar leasing companies can take advantage of accelerated depreciation, which is not available to residential customer-owned systems.

Accurately pricing incentives for large systems is important because of the magnitude of the payment to large system owners and its potential impact on the program budget; modest overpayment for small systems does not have such a significant impact. To accurately price incentives, some programs have instituted competitive bidding processes for their largest systems. For example, Xcel Energy historically gave rebates to small systems, a production-based incentive for the output of mid-sized systems, and used a competitive bidding process to determine awards for the largest category of systems. In addition, NYSERDA has a competitive solicitation for systems greater than 50 kW, and Arizona Public Service has an auction program for all commercial systems.

There is little consistency in where utilities draw distinctions between small and large commercial systems. Some utilities define small systems as those less than 10 kW, while others make the distinction between 30 kW and 50 kW. Further, several utilities only distinguish between small and large systems, while others have a third or fourth tier. Large system limits are often set at 1 MW, but they can vary. These categories may be designed to match net metering limits, which vary substantially from state to state. The appendix lists size categories and incentive levels for the programs examined for this report.

The cutoff for system size can be important for program uptake and establishing accurate incentives. For example, in the Delmarva solar program in Delaware, auctions were held for small systems, defined as up to 50 kW. In response, nearly all projects were sized near the 50 kW limit, and small residential systems were priced out of the market.[14]

Another example of considerations that can be made with regard to system size requirements in a solar program can be found in discussions associated with Xcel Energy's restructuring of its commercial system size requirements within its Solar*Rewards Program in the summer of 2012. In conjunction with moving from a rebate to a PBI program, Xcel proposed combining its small and large commercial incentive capacity allocations into one single commercial segment. Solar industry advocates argued that combining the two commercial programs would disproportionately favor large system installers whose economies of scale make their systems more cost effective, and would consequently bar small system installers from participating in the program.[15] Xcel argued that because the larger commercial segment was more popular than the smaller commercial segment, any greater likelihood of larger system participation would simply lead to more solar being installed more quickly in Xcel's service territory (CoSEIA/SEIA 2012).

These examples in Connecticut and Colorado show that utilities or program administrators can have substantial influence on the size of systems supported by solar programs. Key design tradeoffs can encourage market diversity and the rate of program uptake and solar installation.

4.4 Establishing Rebate and PBI Levels

Rebate incentives are generally designed to mitigate the up-front solar investment's prohibitory size and lump-sum nature. A cross-section of available residential rebate incentive offerings, expressed as a portion of the average installed cost (per watt) of solar for the relevant state based on data from SEIA/GTM Research 2012, can be seen in Figure 3. Based on our calculations, rebates represent 25% to nearly 40% of the average residential installed system costs in most jurisdictions. However, in California and Arizona, where incentive rates have declined as programs have achieved installed capacity targets, rebate levels range from 3% to 13% of average installed costs. Of course, examining a rebate as a fraction of installed cost does not capture differences in electricity prices, solar radiation, or other available incentives, which are very important for determining system economics. Also, the substantial variation in and availability of installed cost figures should also be considered in assessing system economics in a particular state or region. However, Figure 3 provides some information on the magnitude of current rebate levels relative to installed cost estimates.

[14] Personal communication with Kevin Quilliam, SRECTrade, August 10, 2012

[15] In the rehearing, industry advocates stated "with 16.4 MW approved for acquisition in the Medium Program in the Commission Decision, a mere 32 Solar*Rewards applications (for 500 kW PV systems) could easily consume roughly the entire Medium Program, leaving no capacity for the highly popular and critically important small commercial PV market of systems 10 kW–100 kW." In addition, the industry groups argued that attrition was far more common in the large system section of the incentive program, and thus by combining the two program buckets, overall attrition would likely increase and more applications for systems that would not ultimately be built would be submitted to Xcel.

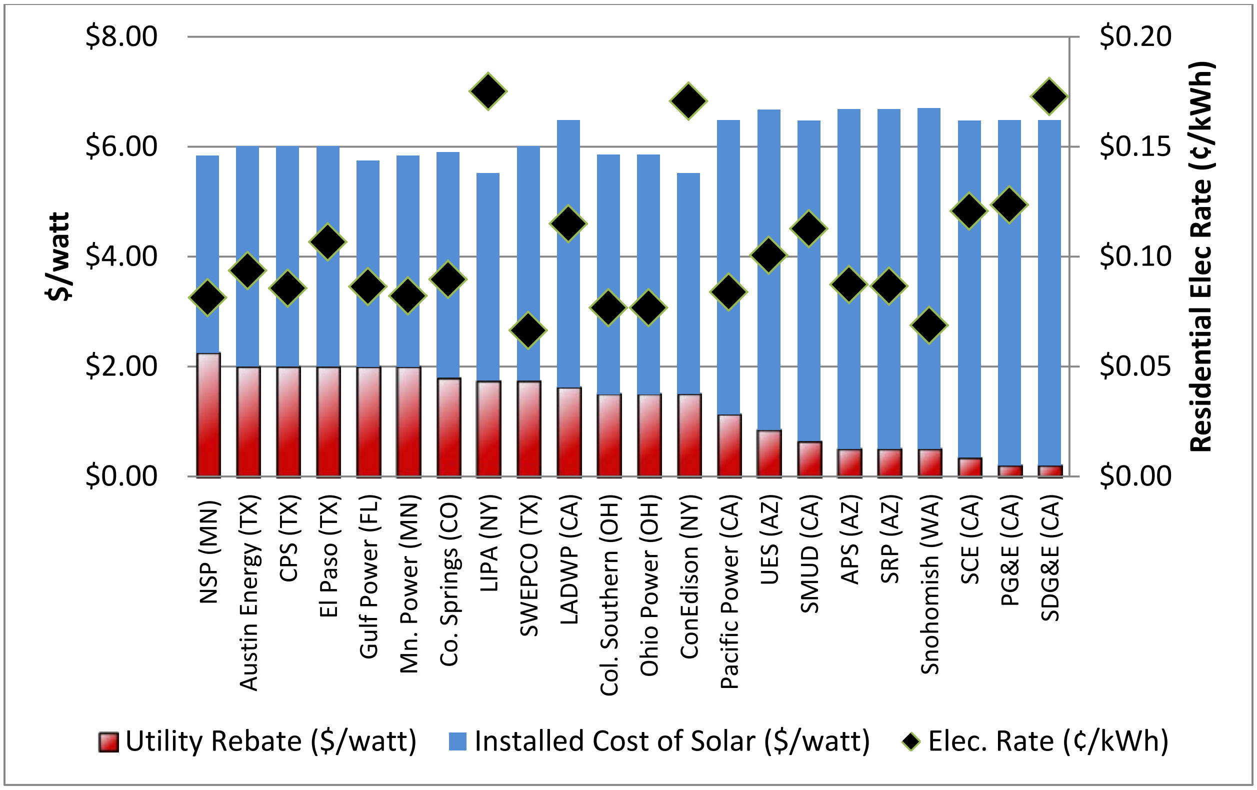

Figure 3. Residential rebate programs as a portion of installed cost of solar[16]

Installed cost data derived from (SEIA/GTM Research 2012); electricity rate data derived from (PV Watts); utility rebate level derived from (Database of State Incentives for Renewables & Efficiency)

When examined on a net present value basis, PBI payments generally represent a smaller fraction of installed costs than rebates. Figure 4 presents our estimate of the net present value of PBI payments (discounted at 5%) compared to the average installed cost of solar for programs that we examined. Figure 4 also shows an estimate of the electricity price in each utility's service territory. Our calculations show that the net present value of PBI payments ranges from roughly $1.40/watt to a very small fraction of system costs ($.09/watt).[17] When using a net present value approach, payments in late years are discounted and represent a small fraction of solar installation costs.

While other methods can be used to calculate PBI payments as a portion of solar costs, particularly a comparison of PBI levels to the levelized cost of solar electricity, discounting future PBI payments and comparing that value to average installed costs allowed for a rough *apples-to-apples* comparison to the $/watt rebate levels as a portion of installed costs displayed in Figure 4.

[16] Electricity prices are derived from PV Watts based on a single a zip code in each utility's service territory. They do not account for tiered or time of use rate structures. The electricity rate for ConEdison is from Westchester, outside of New York City. This figure does not adjust for differences in solar potential. Installed costs data were derived from SEIA/GTM Research 2012. The programs presented here vary in terms of implementation stage, which influences incentive level (i.e., some programs in advanced stages have declined incentives to substantially lower levels over time).

[17] Present values are discounted at a rate of 5% and system performance is assumed to degrade at a rate of .005% annually.

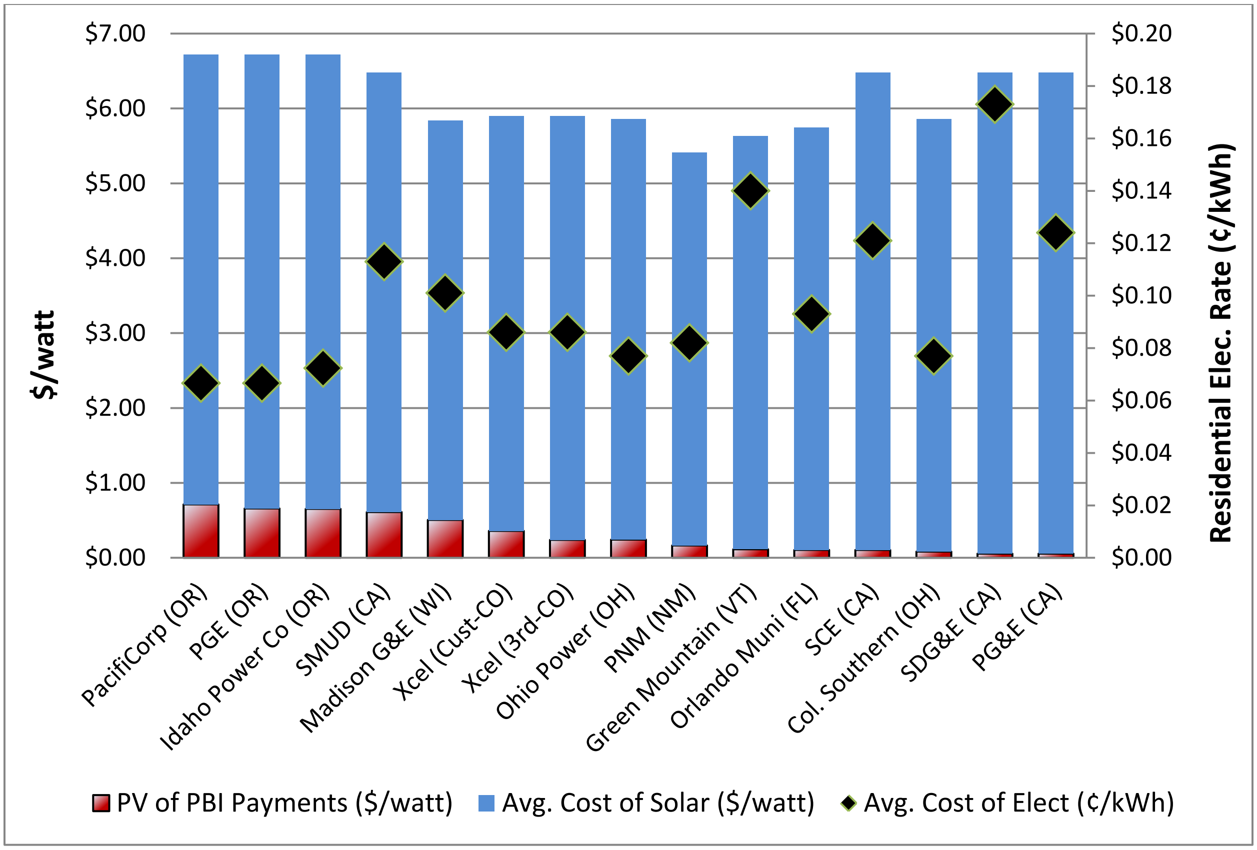

Figure 4. Present value of PBI payments as portion of installed cost of solar[18]

Installed cost data derived from (SEIA/GTM Research 2012); electricity rate data derived from (PV Watts); utility rebate level derived from (Database of State Incentives for Renewables & Efficiency)

An important consideration for establishing a PBI is the payment term. In utility programs examined for this paper, PBI payments range from 5 to 15 years, with a couple of programs offering a 20-year option to commercial customers. While solar systems have longer lifespans with module warranties generally for 20–25 years, shorter PBI payment periods can be more practical for several reasons. First, developers and customers likely discount payments in later years because of the time value of money, so later year payments may be less significant to system economics unless they are unusually large. Second, there could be substantial administrative costs associated with crediting customers (or issuing checks) over 15–20 year periods, unless the process is fully automated. Finally, if solar cost trends continue to decline and reach grid parity during a PBI's payment term, programs will continue to disburse payments to system owners under the program, when new systems are economic. Such an arrangement may not be viewed favorably by future stakeholders. While utilities may require the RECs from systems incentivized under these programs for 15–20 years to meet RPS requirements, REC ownership provisions can be separated from the incentive payment period, as is done with rebate programs that acquire system RECs for long periods of time despite a one-time, up-front incentive payment.

[18] Electricity prices are derived from PV Watts based on a single a zip code in each utility's service territory. They do not account for tiered or time of use rate structures. This figure does not adjust for differences in solar potential. Installed costs data were derived from SEIA/GTM Research 2012. The programs presented here vary in terms of implementation stage, which influences incentive level (i.e., some programs in advanced stages have declined incentives to substantially lower levels over time).

The uncertainty of actual system production and the associated budgetary impacts if production and PBI payments are higher than anticipated is another important consideration in the implementation of PBI contracts. The CSI program ran into challenges associated with its PBI payments when system production was greater than anticipated. Specifically, in 2010, CSI moved to address a roughly $260 million budgetary shortfall that stemmed partially from PBI systems over-performing expectations, especially in the case of single- or multi-axis solar tracking systems[19] (California Public Utilities Commission 2010; California Public Utilities Commission 2011, p. 44).

To avoid future budgetary challenges, some programs have based future payments on expected system production. For example, in its competitive bidding program, the New York State Energy Research and Development Authority (NYSERDA) pays system owners for actual system production for the first three years after installation, but will not provide payments beyond those requested in the bidding process. Therefore, if systems perform better than estimated in the first two years of the program, they will receive PBI payments based on actual system performance in years one and two, but will receive payments in year three that bring the aggregate incentive payment to the total incentive requested in the initial bid. In this case, the project developer will receive a portion of its requested incentive earlier in the three-year incentive payment schedule if the solar system performs better than expected. This does help the solar developer to improve their odds of getting the full amount established in the contract, and this contracted amount had (at the time of bid) been determined by the solar developer to be sufficient to leverage the project. Therefore, any additional incentive payment would be to the advantage of the solar developer at the expense of the ratepayers.

4.5 Establishing Incentive Limits per Installation

Many utilities define a maximum incentive limit per installation, particularly for smaller systems. Often, this is defined as a dollar amount, such as $25,000, but in other cases, it is defined as a percentage of the system's installed cost. Additionally, utilities often restrict system size by limiting a proposed system in relation to the customer's expected electrical demand. When they are used, limits on the fraction of installed cost that can be supported by incentive programs are generally set between 40%–60%. Dollar limits vary widely from $2,500 to more than $150,000. Where utilities limit system sizes with percent-of-electrical demand restrictions, system sizes can be capped anywhere between 80%–120% of a customer’s expected monthly load. The appendix includes details on maximum benefits.

[19] CSI also referred to a change in economic conditions and a consequent miscalculation of a discount rate used to determine PBI values based on rebate levels as another source of the PBI budget shortfall.

5 Differentiating Incentive Levels

Several utilities have offered different incentive levels to consumers based on system characteristics other than system size. At least a few utilities have offered a different level of incentive to third-party owned systems and customer-owned systems, while others vary incentive levels either based on differences in solar radiation within the utility's service territory or to encourage solar installations that provide benefits to the electrical grid. This section discusses differentiating incentives based on such system characteristics.

5.1 Differentiating Incentives for Third-Party Owned Systems

As third-party owned systems begin to dominate the solar power market (SEIA/GTM Research 2012; Go Solar California 2012), program administrators may want to differentiate incentive levels based on system ownership. A rationale for offering a lower incentive to third-party owners is that they benefit from economies of scale and financial arrangements that can reduce some financing and installation costs compared to customer-owned systems. In addition, third-party owned systems can take advantage of accelerated depreciation, which residential system owners cannot do. Differentiating incentives by ownership can be one method of maintaining a targeted ROI or payback period by market segment and minimizing incentive expenditures.

On the other hand, program administrators may wish *not* to differentiate incentives so as not to penalize financial innovations in the marketplace. The amount of installed capacity is the same, no matter whether such capacity is customer-owned or third-party owned, so distinguishing the incentive amount by system ownership may not be equitable or could diminish competition. Further, customer-owners may have access to other mechanisms that reduce financing costs, such as community bulk purchase discounts or Property Assessed Clean Energy financing, and the financial return hurdle rates for third-party investors may be higher than for customer-owned systems particularly if tax equity investors are involved. Further, differentiating incentives by ownership arrangement could create inequities if a greater proportion of lower-income homeowners take advantage of leasing (Drury et al. 2012); i.e., if larger incentives were provided to customer-owned systems purchased by higher income households, this could be perceived as inequitable. As discussed earlier, some utilities may wish to work to incentivize both types of system ownership to encourage market diversity.

Xcel Energy (CO) differentiates incentives for third-party owned and customer-owned systems, as does LADWP (see Table 3). Xcel Energy (CO) developed a lower incentive ($0.10/kWh compared to $0.15/kWh for customer-owned) and step-down schedule for third-party owned systems under 10kW. However, Xcel does not make this distinction for larger systems. For systems 10kW–500kW, incentive levels are the same at $0.09/kWh for customer- and third-party owned systems. LADWP's rebate program offers $1.50/watt for third-party owned systems compared to $1.62/watt for customer owned-systems. Finally, some utilities have not allowed third-party owned systems to participate at all. In some jurisdictions, third-party owned systems have been precluded by law because they involve the sale of electricity by an entity other than a regulated utility (Kollins, Speer, and Cory 2010). In other cases, the rationale for the exclusion is unclear. Table 3 provides an example of the manner in which various programs differentiate available incentives by ownership model, including some utilities that have precluded third-party ownership from participation even when allowed by law.

Table 3. Solar Incentive Programs' Treatment of Third-party Owned Systems

Utility	Incentive for Customer-owned Systems	Incentive for Third-party Owned Systems	Eligible System Size
Xcel Energy (CO)	$.15/kWh	$.10/kWh	0.5 kW – 10 kW
LADWP	$1.62/watt	$1.50/watt	1 kW – 1 MW
Colorado Springs Utilities	$1.80/watt	Not Allowed	0.5 kW – 10 kW
Long Island Power Authority	$1.75/watt	Not Allowed	<10 kW
CPS Energy	$2.00/watt	Not Allowed	<25 kW
Xcel Energy (MN)	$2.25/watt	Not Allowed	.5 kW – 40 kW

Source: Utility solar program websites and (Database of State Incentives for Renewables & Efficiency)

5.2 Differentiating Incentives for Grid Benefits

PV systems have the potential to provide benefits to the grid, typically involving the easing of transmission congestion or deferring transmission and distribution investments. Programs can consider providing additional incentives to projects that are sited in areas that provide substantial grid benefits. For example, NYSERDA encourages the placement of solar projects in areas that are deemed to have such benefits by providing a 15% bonus payment to the bid price in its competitive solicitation program (Levy 2012). The determination of preferred areas is based on analyses conducted by utilities (who provided data to NYSERDA) of locations where circuits have the potential to be overloaded or where the placement of solar projects could defer transmission or distribution investments. NYSERDA encourages developers to install systems in these areas.

5.3 Differentiating Incentives based on Expected Solar Radiation

If an incentive program applies to a large geographic area, incentive levels could be varied based on solar radiation. Providing incentives based on expected performance by location (based on solar radiation) can help achieve a desired ROI across program locations with dramatically different weather patterns. Such differentiation can also ensure that systems are not all located in the same area, which could put pressure on the distribution system (Couture et al. 2010).

The Oregon Solar Program's PBI differentiates incentive levels based on expected solar radiation. Because solar radiation varies across the state, incentive levels differ by customer location so that the program's targeted payback period can be maintained for all customers. The PBI program targets a 15-year payback, after which system owners will be compensated for the resource value of the electricity their systems produce (75th Oregon Legislative Assembly 2010). Table 4 shows the differentiated incentive levels for the April 2012 application period of the Oregon Solar Program based on the counties in which the proposed solar system will be installed (Oregon Public Utility Commission 2012).

Table 4. Oregon Solar Incentive Program: PBI Variation by System County

Region	Counties	Electric Companies	Incentive for Small Systems (<10 kW)	Incentive for Medium Systems (10 kW–100 kW)
1	Benton, Clackamas, Clatsop, Columbia, Lane, Lincoln, Linn, Marion, Multnomah, Polk, Tillamook, Washington, and Yamhill	Pacific Power and PGE	$0.411/kWh	$0.285/kWh
2	Coos, Douglas, and Hood River	Pacific Power and PGE	$0.346/kWh	$0.250/kWh
3	Gilliam, Jackson, Josephine, Klamath, Morrow, Sherman, Umatilla, Wallowa, and Wasco	Pacific Power	$0.346/kWh	$0.250/kWh
4	Baker, Crook, Deschutes, Jefferson, Lake	Pacific Power and Idaho Power	$0.317/kWh	$0.250/kWh

Source: (Oregon Public Utility Commission 2012)

6 Managing Incentives and Responding to Market Conditions

Over the last five years, the price of solar modules and the installed cost of solar power has been trending downward. As the installed cost of solar decreases, administrators generally wish to reduce their incentive offers in response to changing market conditions to minimize ratepayer impacts. However, the installer community prefers transparency and predictability in incentive offerings to maintain stable business operations. When incentive programs are abruptly stopped to adjust incentive levels, the solar industry has difficulty maintaining local resources and staff. To balance these interests, utilities have generally used two approaches to modify incentive levels: 1) developing a fixed schedule by which incentive levels will decline based on capacity installation, program uptake, or budgetary usage or timing, or 2) using an auction or competitive bidding mechanism to obtain market-based pricing for each enrollment period. Experience with these approaches and the relative merits and disadvantages of each option are discussed in this section.

6.1 Setting Incentive Decline Schedules

A declining incentive payment schedule—a forward-looking schedule under which incentive levels will decline based on the passage of time, meeting of installed capacity targets, the usage of available program budget, or some combination—can help minimize payments and provide predictability. Establishing and communicating a long-term schedule of incentive declines in advance benefits industry by allowing it to better anticipate and adapt to changes. A predetermined schedule for incentive decline also helps exert downward price pressure on the solar market, which can improve its cost-effectiveness (Couture et al. 2010). However, one disadvantage to predetermined program declines is that reductions in incentives will not necessarily align with market conditions. For example, market prices could fall more quickly than incentive levels, resulting in overpayment for a particular portion of installed solar capacity. On the other hand, if incentive levels decline faster than market prices, installations can halt. Thus, the lack of knowledge of future market prices makes this approach challenging. Depending on whether there are periodic limits to uptake based on timing, this approach may also make predicting annual budgets challenging.

The CSI—which is implemented by California's three investor-owned utilities: Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE)—was a leader in implementing a predetermined incentive decline schedule based on capacity, and several other utilities have followed suit. These utilities have included Xcel Energy, Roseville Electric, Pacific Power, Public Service Company of New Mexico (PNM), Ohio Power of American Electric Power, LADWP, Salt River Project, Arizona Public Service (APS), Tucson Electric Power (TEP), Austin Energy, and Sacramento Municipal Utilities District (SMUD).

When designing a step-down schedule, allocating a smaller amount of capacity or program budget for the earliest stages of the program when incentive levels are at their highest can be advantageous. In addition, offering the most profitable incentives to a relatively small segment at the outset of the program can help jump-start the market. This approach can also protect ratepayers by limiting the amount of incentive payments in the early stages of the program if the initial offering is higher than it should be and the rate of program uptake is unnaturally accelerated. Program administrators we interviewed also indicated that creating numerous steps for incentive decline can benefit the solar industry; having more steps helps the utility more effectively reduce incentives in relation to changes in the solar market, and it helps solar installers make sales to customers because solar is "on sale" before the incentives drop. In this way, installers can encourage potential customers to act quickly before incentive levels decline.

Setting an appropriate schedule for declining incentives can likely lead to lower costs as a program hits certain installation or investment milestones. However, actual annual outlays of incentive payments will depend on how quickly adoption occurs and whether there are limits on the timing of uptake. Figure 5 shows the easing of budgetary requirements when administering a rebate program with declining incentives. For Pacific Power, the program budget allocation increases in the first three steps of the program but then declines. CSI's Expected Performance-Based Buydown program budget increases through the first five steps of the program, then declines. Reductions in payment outlays in later years may help gain initial support for establishing a long-term program.

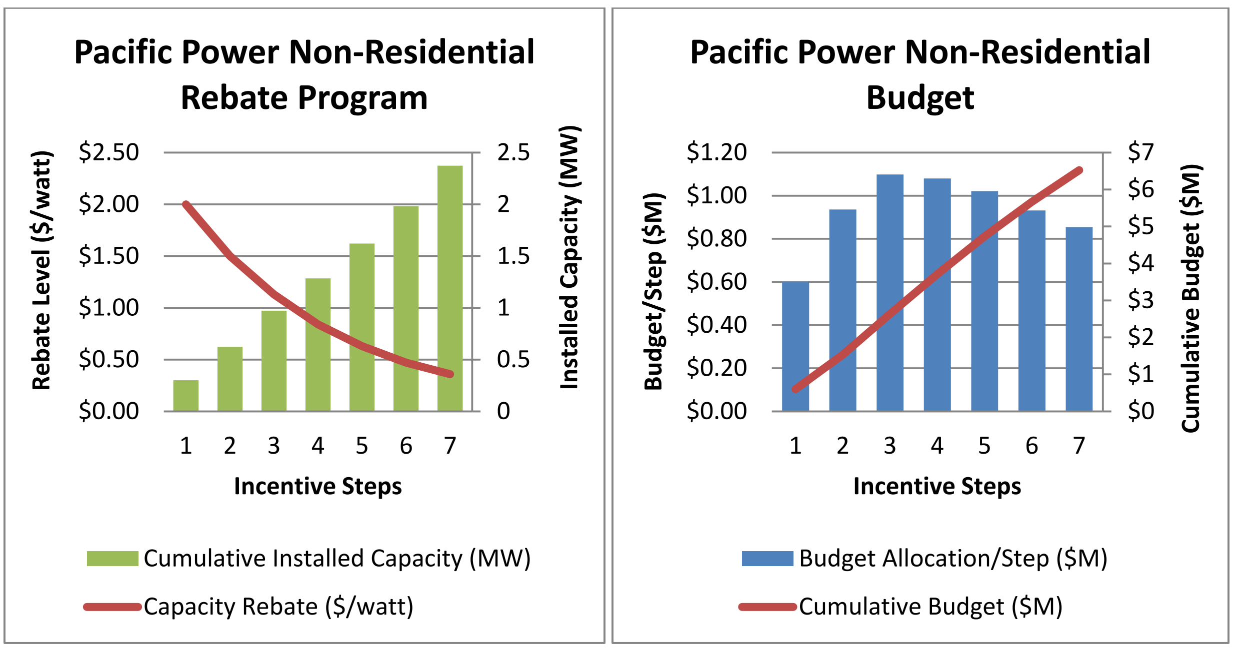

Figure 5. Pacific Power commercial rebate levels and budget

Source: Pacific Power (CA)

Programs differ in the manner in which they determine targets or the thresholds at which incentive levels will decline. The prevailing trend is to either set incentive decline targets based on meeting installed capacity goals for a particular incentive level or to set targets based on criteria related to meeting budgetary thresholds and the annual timing of the achievement of those thresholds. In either case, communicating the status of the incentive level to relevant stakeholders in real time is essential. It is important to provide potential participants with clear and up-to-date information on the remaining availability of incentives within a level. The communication of how much capacity (or budget) remains in a step and is eligible for the current level of incentives is an important element of ensuring that step-down programs work effectively.[20]

Incentive Decline Based on Capacity Targets

Capacity targets represent a common approach to stepping down the level of available incentives; once the installed capacity reaches a certain threshold of capacity, the available incentive declines to a lower level. CSI uses this approach, and each administering utility has its own capacity allocations based on the utility's size. The available capacity in each incentive step in CSI is larger than that available in the previous step, with the percentage increases in capacity targets from one step to the next being the largest early in the program.

Because there are ten steps in the program, four separate incentive decline schedules for small and large residential and small and large non-residential systems, and three administering utilities with identical incentive decline schedules, a total of 120 incentive steps occur in California. The frequency of incentive declines has led to an almost perpetual state of solar being "on sale" in some jurisdiction in California, for some customer segment, at any given time over the course of the incentive program. The incentive decline schedule for systems of less than 30 kW in CSI is shown in Figure 6.

[20] Examples of how utilities communicate the incentive step-down schedule include SMUD https://www.smud.org/en/residential/environment/solar-for-your-home/solar-basics.htm; APS http://www.aps.com/main/green/choice/solar/funding.html; and PNM http://www.pnm.com/customers/pv/rec_price_table.htm?source=solar_home.

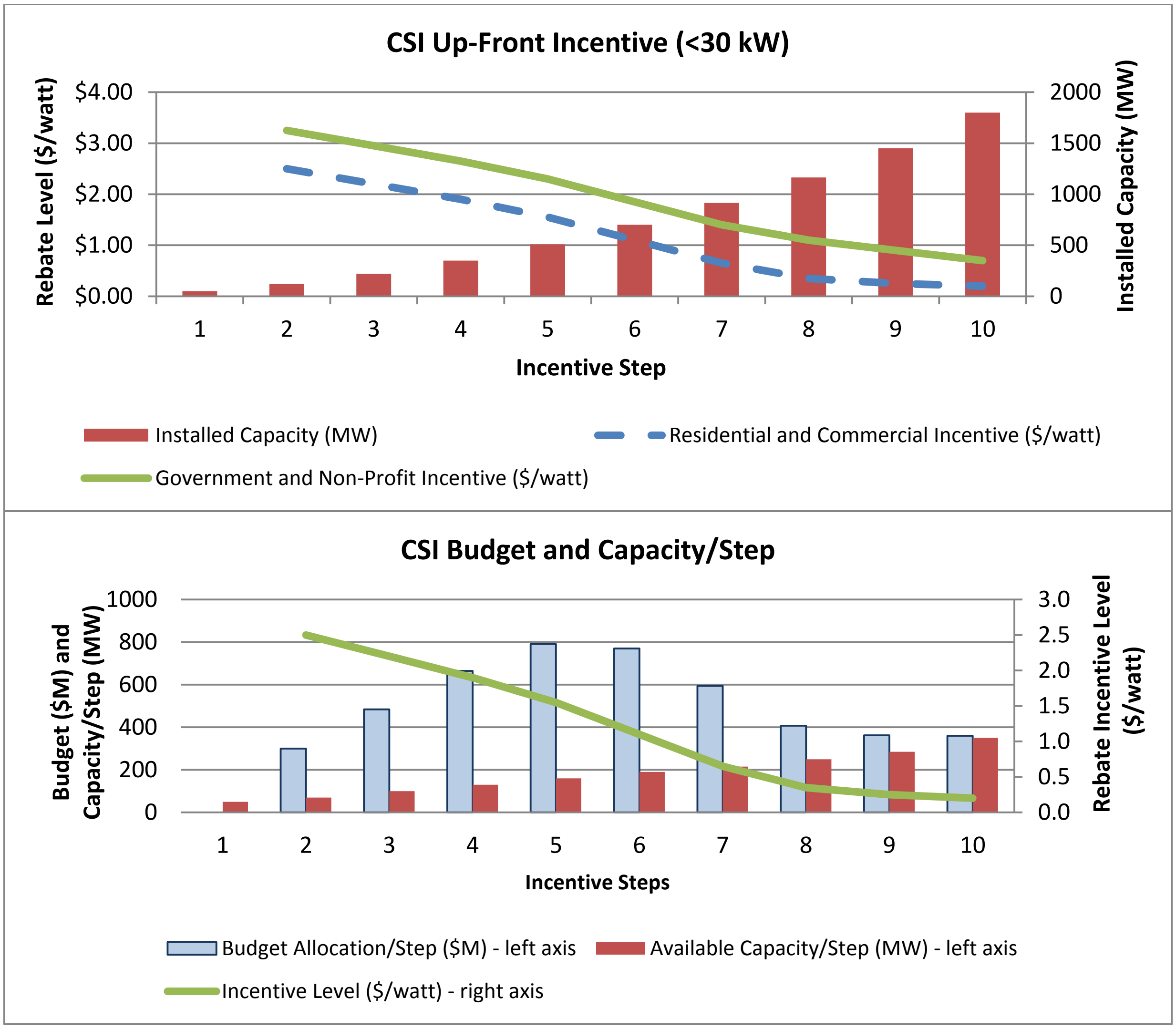

Figure 6. California Solar Initiative's Upfront Incentive Program step-down and budget (for Expected Performance Based Buydown program)

Source: (Go Solar California 2007)

Several other programs, including Pacific Power, PNM, and LADWP, have incentive decline schedules based on capacity targets. Figure 7 shows the different rates of incentive decline across programs. In the case of Pacific Power, the slope of the incentive decline is exponential whereas PNM follows a constant rate of decline for incentives from one step to the next. The shape of LADWP's incentive decline trajectory demonstrates the incentive price adjustment that LADWP undertook in moving from Step 4 to Step 5 in April 2011. At that time, LADWP suspended its incentive program to adjust to a substantial drop in solar prices, which left LADWP's incentive levels lucrative, and participation in the program had oversubscribed the program budget by a ratio of 3:1 (Los Angeles Department of Water and Power 2011). Xcel Energy in Colorado underwent a similar adjustment to its program in March of 2011, and modified the program to a PBI-only incentive that now includes a predictable incentive step-down schedule as of May 2012.

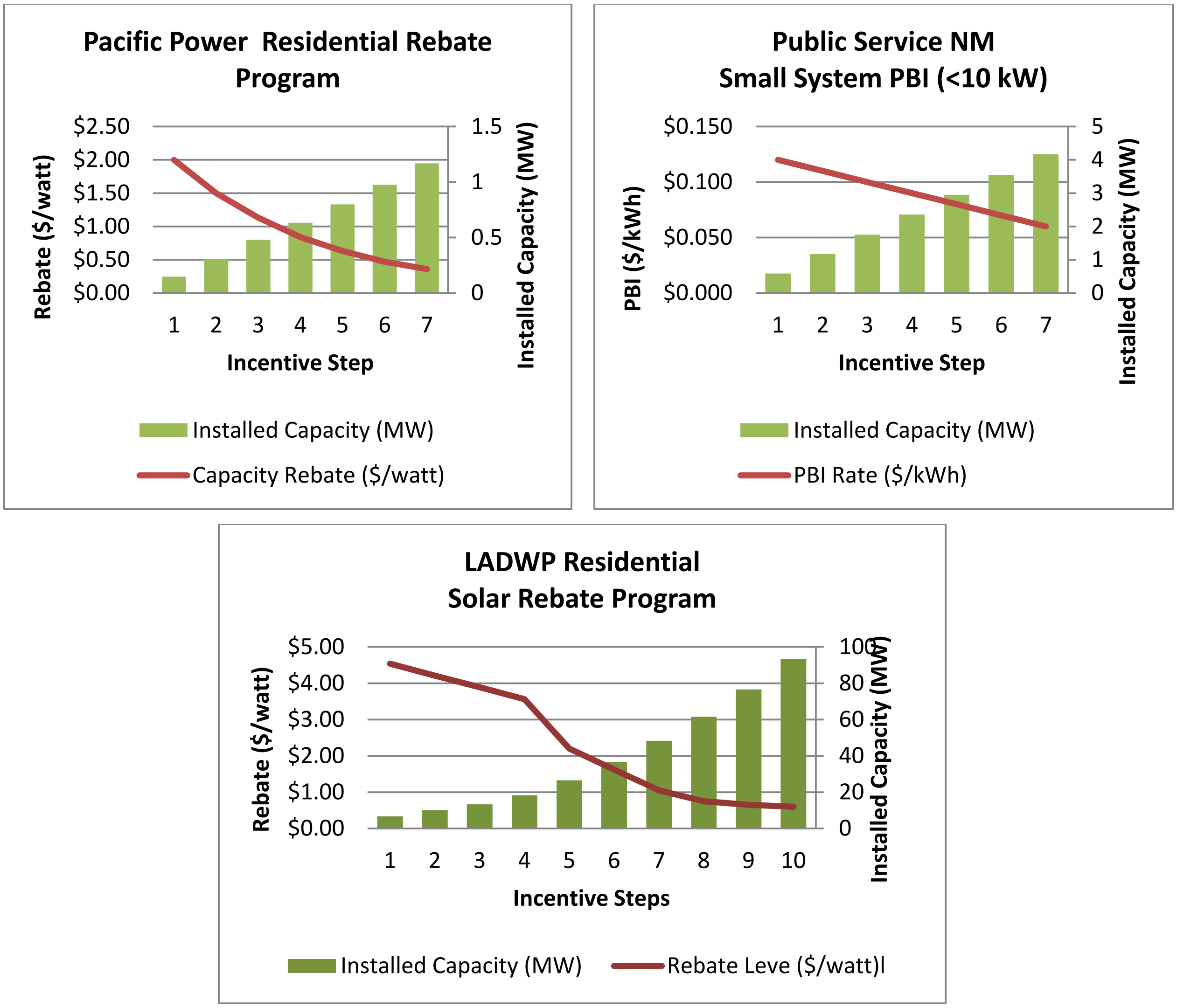

Figure 7. Incentive decline schedules: Pacific Power, PNM, LADWP

Sources: (Pacific Power (CA); Public Service Company of New Mexico 2002–2012; Los Angeles Department of Water and Power 2012)

Incentive Decline Based on the Timing of Meeting Budgetary Thresholds

For budgetary predictability, declining schedules can be based on the timing of meeting particular budget thresholds rather than capacity targets. This approach can help ensure that annual budgets are not exceeded. With capacity-based schedules, how much of the budget will be required in a particular year is unclear; the incentive payments are based on how much capacity is installed (i.e., market uptake). While capacity-based thresholds may be viable for programs that have multi-year budgets and planning horizons, a budget timing-based schedule may be needed for programs that require annual plans and/or regulatory approval.

APS and TEP are examples of programs that reduce solar incentives in accordance with annual budgetary thresholds (see Table 5). APS's solar incentive program budget is subject to annual review and approval by the Arizona Corporation Commission, and thus APS usually adjusts its incentives annually. At the outset of each year and upon regulatory approval, APS distributes the schedule for incentive decline for the following year. Table 5 shows how APS reduces its incentive level based on how much of the annual budget is consumed during certain periods in 2012, where the initial incentive level was $0.55/watt and was stepped down over the year.

From the perspective of the installer and customer side of the solar industry, such annual uncertainty poses challenges in that the solar market must endure a period of flux each year during which the level of incentives for that coming year, if any, are unknown. But, this approach does provide certainty to the utility and ratepayers with respect to program budgets, and it helps smooth access to incentives across an entire year (discussed in detail in Section 7.3).

Table 5. Arizona Public Service's Residential Incentive Step-Down Schedule

<table>
<tr><th>Budget Thresholds for Declining the Incentive Level</th><th>Reduction Amount</th><th>Incentive Rate</th></tr>
<tr><td>If 75% of funds used by 4/21/2012 incentive reduced by</td><td>$0.20</td><td rowspan="3">TBD</td></tr>
<tr><td>If 75% of funds used by 5/21/2012 incentive reduced by</td><td>$0.10</td></tr>
<tr><td>If 75% of funds used by 6/20/2012 incentive reduced by</td><td>$0.05</td></tr>
<tr><td>If 90% of funds used by 11/1/2012 and incentive is greater than or equal to $0.35 the incentive reduced to:</td><td>$0.20</td><td rowspan="2">TBD</td></tr>
<tr><td>If 90% of funds used by 11/1/2012 and incentive is less than $0.35 then incentive reduced to:</td><td>$0.10</td></tr>
</table>

Source: (Arizona Public Service 2012)

NYSERDA also bases incentive step-downs on timing and budgetary thresholds. NYSERDA operates a standard offer, up-front incentive based on capacity, which currently provides $1.50/watt to residential systems up to 7kW and commercial systems up to 50kW. As part of the New York Sun Initiative, new funds have been made availabile for administering of NYSERDA program in monthly increments according to the schedule in Table 6.

Table 6. NYSERDA Monthly Incentive Budget (2012–2015)

Year	Monthly Incentive Budget
2012	$3,500,000
2013	$3,125,000
2014	$2,000,000[21]
2015	$2,000,000[13]

Source: NYSERDA 2012

If, in two successive months, the available incentive budget is exhausted, NYSERDA will reduce the available incentive level and begin offering the lower incentive in the following month, though there is no predetermined schedule for incentive decline. In addition, if in a given month, the entire budget is not used, NYSERDA will roll that remaining budget into the next month's funds, and the entire (now-larger) monthly allocation must be exhausted to trigger an incentive decline. At the end of a program year (December), any remaining budget is removed from the program and is distributed to funding renewable generation technologies based on determinations made by the New York Public Services Commission. Depending on this

[21] Funding in 2014 and 2015 has not been finalized, although it is expected to at least equal that available in 2013.

determination, excess funding from one year could be reallocated to the solar program from which it was originally taken.

NYSERDA holds monthly webinars with the program's registered installers to communicate program uptake and guidance on budgetary availability to market participants. Currently, NYSERDA does not make the remaining budget available to the public, as other programs have done via websites, though NYSERDA has said it is moving to create such a tracking website in the future (Mace 2012). NYSERDA does not make available a predetermined schedule for incentive decline, which provides considerable flexibility for administrators to adjust to changing market conditions at some expense to providing more transparency and predictability to solar market participants that a predetermined incentive decline schedule could provide.

6.2 Employing an Auction Mechanism or Competitive Solicitation

A benefit of using a competitive bid process in allocating solar incentives is to obtain up-to-date information on installed costs, which can be important in a rapidly changing market environment. Competitive bids can be obtained through auctions or competitive solicitations such as requests for proposals. These could be used to determine incentive levels on an ongoing basis or to establish pricing at the outset of a program. In several programs, such as those run by Xcel Energy and NYSERDA larger solar projects are subject to a competitive bidding process. It is most important for programs to accurately price incentives for large projects because of the variation in installed costs, the potential impact on program budgets, and the need to ensure ratepayer protection.

A reverse auction process is a market-based mechanism for setting incentive levels that are responsive to changing solar costs. With this approach, competing bids are evaluated against each other and utilities can prioritize incentive payments to solar projects whose per-unit costs are lowest, are expected to produce more electricity per unit of capacity, or both. Reverse auctions have been used in California for utility-scale projects as well as in a number of states with solar REC markets, such as New Jersey and Ohio. Generally, auctions have not been used for residential systems and other small systems because of the complexity in administering and participating in such processes. Residential consumers may find auctions difficult to understand or may view them as prohibitively complex, although simplified processes may be feasible for small systems. The APS auction program has been used for commercial systems of all sizes (see Text Box 1), and APS has streamlined its bidding and evaluation process through many years of iterative improvements. A utility must also determine whether its solar incentive program is large enough to justify the administrative burden associated with managing an auction. For smaller programs, the incremental savings a reverse auction may enable could be offset or eliminated by the administrative costs associated with running such a process.

Text Box 1. Arizona Public Service Company's Reverse Auction Program

Arizona Public Service Company's commercial solar incentive program is a notable exception to the trend that request for proposal (RFP) and auction processes are only employed for large solar systems. APS requires *all* commercial installations, including small systems competing for up-front rebates, to bid into a reverse auction process. APS has three different auctions for systems up to 30kW, 31kW to 200 kW, and larger systems 201kW up to 2,000 kW. The auction process is as follows:

1. APS stipulates a maximum incentive level (either a capacity rebate or PBI, depending on the system size) and communicates this to prospective bidders.
2. Bidders must enter their system specs into the APS ranking calculator, which includes the technology being employed, technology type, system size (kilowatts DC), estimated annual production (kWh), the total project cost, and the requested incentive level (up to the maximum).
3. The incentive calculator assigns a score to a particular bid based on system specifics in (#2).
4. After all proposals have been received, scores are ranked and incentives disbursed at the bid price, starting with the lowest score, until the budget for that RFP subscription period has been exhausted.

The score that each bid receives is largely the result of the total incentive per kWh of production that is requested and the term of the PBI contract requested by the bidder. For upfront rebate incentives, calculations also take into account the expected performance of the system and favor systems that are expected to perform at a higher level of efficiency. For instance, if two competing rebate requests bid $1.00/watt, but one system is expected to produce 1,600 kWh per kW of capacity and the other system is expected to produce 1,500 kWh per kW of capacity, preference is given to the more efficient system (1,600 kWh per kW over 1,500 kWh per kW).

For APS's commercial PBI program, bidders can stipulate whether their PBI agreement extends for 10, 15, or 20 years. APS sets different maximum incentive payments depending on the length of the agreement, with larger incentives offered for shorter contracts and vice versa. The process of applying for APS's PBI program is much the same as the up-front incentive program in that bidders complete a spreadsheet with information required for the program, and their bids are scored in much the same way as described above. Each bid is assigned a score based on the requested level of incentive, length, and other factors, and all the bids are aggregated at the close of the reservation window. Incentives are then awarded starting with the lowest scored project moving upward until that reservation period's capacity goals are met.

Bidders in the APS auction process are free to apply for the maximum level of incentives; however, because some bidders will likely apply for lower levels of incentives, there is a chance that bidders requesting the maximum incentive level could be outbid by projects requesting less than the maximum. This feature helps APS drive down their program costs and helps incentivize bidders to reduce the level of incentive they are requesting in a given open reservation period. This downward price pressure helps APS cost-effectively allocate incentives across their entire commercial program by providing the least incentive to achieve their stated installed capacity targets for a given period of open reservations.

6.3 Transitioning to a Post-Incentives Environment

A number of incentive programs in California and in other Western states are in late stages of program implementation, after which incentives are scheduled to disappear. To maintain installations after the expiration of these programs, solar will need to compete against standard retail rates of electricity without the contribution of solar program incentives.

Currently Austin Energy offers a program with a residential rebate of $2.00/watt AC and net metering. Austin Energy is considering replacing the current program with a rebate that declines over time, at a proposed rate of 8% per year consistent with assumed solar capital cost declines, and a value of solar payment for all the generation of the system (Rabago et al. 2012). The "value of solar" payment is not tied directly to the incentive payment, but is rather based on the value of the solar generation to the utility. The program is innovative because it would offer a declining rebate level based on reductions in PV capital costs, but would also provide a value-based payment to a system owner over time. The value calculation includes utility transmission line loss savings, energy savings, generation capacity savings, the fuel price hedge value, transmission and distribution capacity savings, and environmental benefits. Austin has calculated the 2011 value of solar to be 12.8 cents/kWh (Rabago et al. 2012), though the estimated value of solar could change from year to year. The value-of-solar rate would vary annually based on Texas' nodal prices and other factors. The utility's calculations show that the value-of-solar rate ranged from 10.3cents/kWh to 16.4cents/kWh for 2006 through 2011 (Austin Energy 2012).

7 Administering the Program and Application Process

To effectively administer programs, administrators need to balance the conflicting desires to keep the process as simple as possible while conducting ample due diligence to ensure the installation of optimally performing systems. In addition, administrators need to consider how to provide equitable access to incentives; manage the queue of projects; and minimize overall administrative costs of the program. This section discusses methods of ensuring equal access to incentives, application fees, managing project flow, inspections to ensure system performance, and administering PBI payments.

7.1 Ensuring Equal Access to Available Incentives

Ensuring fair and equitable access to incentives can be crucial to the perceived success of an incentive program. The likelihood that many applicants will be denied incentives may dictate the procedure by which incentives are awarded. For larger programs that can meet customer demand, a transparent, first-come-first-served allocation method may be adequate for managing program applications. This approach has been used effectively by the CSI and others. However, even for large programs, periods of high demand, such as just before incentives are set to decline, can pose challenges. During periods of rapid up-take, it is important to have transparent procedures for determining priority and to frequently update consumers on how close the program is to achieving metrics that trigger when the incentive levels will decline. Software solutions can help manage project flow. An example of the importance of this issue is underscored by a lawsuit filed against Gainesville Regional Utilities in Florida by an applicant who claims that the utility showed favoritism in the process of awarding payments under its solar feed-in tariff program. (Smith 2011)

Some modestly sized programs that have substantially more demand than available incentive funding have used a lottery or other random selection process to address potential issues of inequity, although this approach poses challenges for the planning processes of installers. For example, the Oregon Solar Incentive Program's PBI is a small and highly popular program that instituted a lottery to manage high levels of demand. When the program was established in 2010, it opened an application period once every six months. In each open application period, available incentives were fully reserved within a matter of minutes, and many customers were turned away because they did not apply soon enough (Read 2012). Due to the extremely short duration of incentive availability and the inability for many customers to apply quickly enough, the program inadvertently favored program applicants with faster internet connections and led to some gaming of the system; larger developers helped ensure approval of more of their projects by applying from locations with faster internet connections.

In response to this level of demand, the Oregon Solar Program instituted a one-day random lottery process that allowed all applicants in a given application window an equal opportunity to have their applications queued for review. In addition, the one-day lottery allows program administrators to gauge the demand for the program, as they can see how many applications they have received and can determine the amount of capacity that could be brought online if their program budget were increased. Such lotteries or random selection processes, however, make it more difficult for installers to plan and create uncertainty regarding the number of customers that they will be able to serve. Some programs have instituted first-come, first-served programs but have limited the total installed capacity for each eligible installer, which would limit gaming concerns, but limits supplier competition as well.

7.2 Charging a Nominal but Consequential Application Fee

A major source of potential administrative inefficiency comes from the likelihood that some approved applicants may eventually drop out of the program and not install a solar power system. In such cases, the time and resources spent by program administrators to review application materials are essentially lost (i.e., these efforts do not result in installed capacity). Therefore, it is important to establish clearly defined procedures to minimize and deal with program drop-outs and any incentive payments that are now not used and available to other program participants. To address this concern, many programs have instituted a mandatory application fee that is substantial enough to discourage frivolous applications, but small enough to avoid discouraging participation of customers with viable projects.

The CSI charges a fee for all applications submitted for systems with more than 10 kW in capacity (see Table 7). The California Public Utilities Commission refunds the application fee to the program applicant after the system has been installed. All forfeited application fees are reallocated to the program administrator's CSI budget (California Public Utilities Commission 2011).

Table 7. California Solar Initiative's Application Fee Schedule

System Size	Fee
>10 kW – <50 kW	$1,250
50 kW – <100 kW	$2,500
100 kW – <250 kW	$5,000
250 kW – <500 kW	$10,000
500 kW – <1,000 kW	$20,000

Source: (California Public Utilities Commission 2011)

The Oregon Solar Incentive Program's PBI initially did not require application fees and found that the frequency of dropouts was high. In an effort to diminish dropouts, the administering utilities have instituted a deposit ($500 or $20/kWdc of capacity, whichever amount is greater) at the time of application (Pacific Power 2012). The Long Island Power Authority requires a $100 non-refundable application fee (Database of State Incentives for Renewables & Efficiency) and Xcel Energy (Minnesota) requires a $250 application fee designed to cover the engineering costs to evaluate the line diagram of the proposed system. The fee is nonrefundable once the application has been reviewed by Xcel Energy's engineers (Xcel Energy 2012).

7.3 Managing Project Flow and Incentive Offer Periods

The frequency with which a utility makes incentives available can help provide a more stable solar market. In the case of larger programs with multiple step-down targets, a certain amount of program longevity is established in the schedule. Some efforts have been made by programs that decline incentives based on reaching certain budget thresholds, as well as smaller programs with constrained budgets, to spread incentive availability more evenly across calendar years in order to provide market stability.

APS and TEP both reduce incentive levels based on when budgetary thresholds are met throughout a given calendar year. This type of incentive decline schedule helps ensure that some amount of solar incentive is available to the market throughout the year. This approach contrasts that taken by other often-smaller utilities that make the entire incentive budget available on a first-come-first-served basis at the beginning of the year. Such program administration has led to programs being exhausted early in the year and solar market instability. Offering incentives in such a way can stimulate a large amount of activity all at once and lead to a period of inactivity later in the year as project pipelines run dry. In such instances, solar market participants will likely have to wait either until new funds are made available during the year or until the next year's budget is released. Such cycles prohibit the development of a stable industry.

Basing incentive declines on budgetary availability throughout the year, is one mechanism by which APS and TEP have been able to spread incentive budgets across an entire year, even if it means offering very low levels of incentives toward the end of the year. Another approach to spreading out available incentives is to offer multiple program enrollment periods. For example, the Oregon Solar Program offers bi-annual open enrollment periods for participation in the program. Despite the likelihood that the program would sell out all of its available capacity in just one open application period, given the program's popularity, program administrators opted to spread the availability of incentives more evenly across the entire year by making capacity available every six months. Pacing the program's outlay of incentives more frequently in smaller aggregate budgetary amounts may help provide some market stability. Similarly, competitive solicitations in New York have been spread out two or more times throughout the year to provide more continuity and opportunities for developers.

7.4 Requiring Inspections and Ensuring Proper System Design and Implementation

Ensuring optimized system performance in capacity-based programs may require weighing the increased administrative costs associated with enforcing compliance against the incremental gains in system production. CSI instituted a procedure to inspect the first two solar arrays installed by a particular solar contractor under the CSI program. These inspections are meant to confirm that actual system installation specifics are the same as those provided in the application materials. If the first two inspected systems meet the program's requirements, CSI will inspect at least one in every seven systems under 30 kW for that installer going forward. For systems greater than 30kW, system inspections may be required at the discretion of the program administrator. (California Public Utilities Commission 2011)

Most rebate programs apply to small solar systems, which, by definition, are not going to produce a large amount of electricity relative to large systems, even when installed optimally. Consequently, similar approaches to selectively inspecting systems have been employed by other utilities looking to balance optimized system performance and administrative burden. NYSERDA employs a process of checking each of a particular installer's systems until the program administrators deem that process no longer necessary, at which point between 15% and 20% of that installer's systems are inspected to conserve resources over inspecting each installed system.

Salt River Project employs a different approach to monitoring system performance for its commercial solar program, which allows larger systems to receive incentive payments; Participants apply using the Power Clerk program[22], and once the system is installed and inspected, the first 30 days of actual system performance are compared to that predicted by Power Clerk's "Solar Anywhere" tool. Using actual weather data and the system specifics as a predictive model, as long as the system performed to 95% of its expected kWh output, the Salt River Project (SRP) will disburse the full incentive amount to the program participant. SRP does not employ this approach in its residential program because the number of systems are prohibitively large and the system capacity is relatively small (capped at 5kW) compared to the commercial systems that can be as large as 100kW. Because these commercial systems can be so much larger, and thus suboptimal system performance can result in a substantially larger difference in system production, SRP has determined that the additional administrative burden of monitoring commercial system performance is justified by greater assurance of optimal system performance. (Felix 2012)

SRP also performs an annual study on its aggregate residential solar production, and because past studies have consistently shown that residential systems perform at or exceed SRP's expected 1,600 kWh/kW of capacity, SRP does not conduct 30-day system performance tests on residential systems. (Felix 2012)

7.5 Administering PBI Payments

PBI programs require utilities to reimburse a system owner throughout the course of the PBI contract, which can result in significant administrative burden depending on the number of program participants and disbursement processes used by the program administrator. These disbursement processes can sometimes mean that the utility must issue a check to all participants in the program on a monthly basis, often for 10–15 years. Streamlined administrative processes are important for programs that operate over many years, and some software solutions are available to improve process efficiency. The method and frequency of crediting customers under a PBI system requires balancing administrative costs with the need for system owners to receive timely payments. In most cases, utilities disburse incentives monthly. To reduce the administrative cost of a PBI program, checks could be issued quarterly rather than monthly; however, this approach is less attractive to customer generators. Of the residential PBI programs listed in Table 8, only SMUD is disbursing PBI payments on a quarterly basis.

On-bill crediting offers the advantage of minimizing costs over writing physical checks, while providing frequent crediting to customers. Contemplation of a move to such an on-bill PBI crediting system, however, must consider the upfront costs and efforts associated with modifying a utility's billing system. However, many utilities have faced such hurdles in modifying their billing systems to implement net metering and green power options.

Of the eleven PBI programs in Table 8, three use on-bill crediting to administer PBI payments.[23] Table 8 shows the residential PBI programs we examined, the manner in which each utility disburses payments to its customers, and the length of each program's PBI contract.

[22] See http://cleanpower.com/products/powerclerk/, accessed December 15, 2012.
[23] An example of offering a PBI credit on a customer's bill can be found at the Orlando Utilities Commission website: http://www.ouc.com/en/pay_your_bill/how_to_read_your_bill.aspx?tabid=3.

Table 8. PBI Programs, Length of Program and Incentive Disbursement Method

State	Utility	PBI Payment Method[a]	Length of PBI
VT	Green Mountain Power	On Bill	10 years
FL[b]	Orlando Utilities Commission	On Bill	5 years (auto renewal)[b]
NM	Public Service of New Mexico	On Bill	All PBIs terminate 12/31/2020
CA (CSI)	San Diego Gas & Electric	Check	5 years
CA (CSI)	Southern California Edison	Check	5 years
CO	Xcel Energy	Check	10 years (RECs transfer for 20 years)
OR (OSP[c])	Idaho Power	Check	15 years
CA (CSI)	Pacific Gas and Electric	Check	5 years
OR (OSP[c])	PacifiCorp (Pacific Power)	Check	15 years
CA (CSI)	Portland General Electric	Check	15 years
CA	SMUD (Sacramento)	Quarterly check	5 years

Source: Utility websites

[a] All PBI payments are made monthly, with the exception of SMUD.

[b] Orlando PBI contracts are automatically renewed in 5-year increments, with either party having the option to cancel with 60-days' notice.

[c] Oregon Solar Incentive Program

8 Consumer Protection and Transparency

Consumer protection measures typically involve helping ensure system performance, but can also relate to fair pricing, and encouraging investments in energy efficiently to reduce the necessary size of the investment in a PV systems. Consumer protections help establish the solar power industry in a particular locale as a reputable trade, which aids the spread and adoption of solar more widely throughout communities. Such requirements can also help lead to a sustainable solar market once incentive programs are no longer needed (Airth 2012). This section describes methods of encouraging optimal system performance, price transparency, and energy efficiency, as well as considerations of REC ownership.

8.1 System Performance

Proper system performance is generally in the best interest of customers paying for systems, utilities that often need the generation to meet solar requirements, and ratepayers who fund incentive programs.

Before 2006, concerns were raised that solar incentive programs, especially rebate programs, would not effectively incentivize optimal system production, as the reward of an incentive was based solely on capacity (Hoff 2006; Barbose et al. 2006). Since then, many rebate incentive programs have instituted performance-related prerequisites that systems must meet to qualify for maximum levels of incentives (see Table 9). Examples of performance requirements within a solar program include:

- Mandatory installer certification and license requirements
- Minimum warranties on panels, inverters, and system performance
- Hardware requirements or equipment certification standards (e.g., UL listing)
- Requirements for system orientation, tilt, azimuth, and shading

Generally, utilities require applicants to comply with certification and licensing, warranties, and hardware requirements to be eligible for an incentive payment. Whereas utilities typically provide lower levels of incentives for systems that are not expected to perform optimally because of shading or sub-optimal orientation (e.g., north-facing systems). Often utilities will have a calculation for de-rating systems and adjusting incentive levels that considers system orientation, tilt, azimuth, and shading. Generally, these kinds of requirements are relatively easy for utilities to implement, although inspections may be required to ensure compliance with hardware requirements.

Table 9. Utility PV Program System Performance Requirements

State	Utility	Incentive Type	Installer Certification	Module Certification	Module Warranty (Years)	Inverter Certification	Inverter Warranty (Years)	Installer Guarantee (Years)	System Orientation
AZ	APS	PBI	✓	✓	✗	✓	✗	✗	✓
TX	Austin Energy	PBI	✓	✓	20	✓	10	5	✓
OH	Columbus Southern Power (AEP)	PBI	✗	✗	✗	✗	✗	✗	✗
OR	Idaho Power	PBI	✓	✓	✗	✓	✗	✗	✗
CA	Pacific Gas and Electric (CSI)	PBI	✓	✓	10	✓	10	10	✓
OR	PacifiCorp (Pacific Power)	PBI	✓	✓	✗	✓	✗	✗	✗
OR	Portland General Electric	PBI	✓	✓	✗	✓	✗	✗	✗
NM	Public Service Company of New Mexico	PBI	✗	✗	✗	✗	✗	✗	✗
AZ	Salt River Project	PBI	✓	✓	10[24] and 20	✓	10	2 and 5[25]	✓
CA	San Diego Gas & Electric (CSI)	PBI	✓	✓	10	✓	10	10	✓
CA	Southern California Edison (CSI)	PBI	✓	✓	10	✓	10	10	✓
OH	Ohio Power (AEP)	PBI	✗	✗	✗	✗	✗	✗	✗
AZ	UniSource Energy Services	PBI	✓	✓	20	✓	5	5	✓
VT	Green Mountain Power	PBI	Must conform with Vermont state net metering laws to acquire certificate of good standing						
FL	Orlando Utilities Commission	PBI	✓	✓	✗	✓	✗	✗	✗
CO	Xcel Energy	PBI	✓	✓	5	✓	5	5	✗
CA	Sacramento Municipal Utility District	PBI[26]	✗	✗	10	✗	10	10	✗
NY	Long Island Power Authority	PBI/FIT	✓	✓	✗	✓	✗	✗	✗
AZ	APS	Rebate	✓	✓	✗	✓	✗	✗[27]	✓
TX	Austin Energy	Rebate	✓	✓	20	✓	10	5	✓
OH	Columbus Southern Power (AEP)	Rebate	✓	✓	>5	✓	>5	>5	✓

[24] Modules must be guaranteed for 10 years against 10% degradation or worse; and must be guaranteed 20 years against 20% degradation or worse.
[25] Installation must be guaranteed for 2 years against roof leaks, and 5 years against defects in overall installation resulting in 15% or greater level of performance.
[26] PBI available for commercial customers only.
[27] For leased systems, APS requires the leasing company to guarantee the system's production and components for 20 years.

State	Utility	Incentive Type	Installer Certification	Module Certification	Module Warranty (Years)	Inverter Certification	Inverter Warranty (Years)	Installer Guarantee (Years)	System Orientation
TX	CPS Energy (San Antonio) residential	Rebate	✓	✓	20	✓	5	1	✓
CA	LADWP	Rebate	✓[28]	✓	20	✓	10	10	✓
OH	Ohio Power (AEP)	Rebate	✓	✓	5	✓	5	5	✓
CA	Pacific Gas & Electric (CSI)	Rebate	✓	✓	10	✓	10	10	✓
AZ	Salt River Project	Rebate	✓	✓	10 and 20	✓	10	2 and 5	✗
CA	San Diego Gas & Electric (CSI)	Rebate	✓	✓	10	✓	10	10	✓
WA	Snohomish County PUD No 1	Rebate	✓	✓	20	✓	5	2	✓
CA	Southern California Edison (CSI)	Rebate	✓	✓	10	✓	10	10	✓
NY	Long Island Power Authority	Rebate	✗	✓	20	✓	5	✗	✓
CA	Pacific Power	Rebate	✓[29]	✓	10	✓	10	10	✓
AZ	UniSource Energy Services	Rebate	✓	✓	20	✓	10	5	✓
FL	Gulf Power	Rebate	✓	✓	✗	✓	✗	✗	✓
CO	Colorado Springs, City of	Rebate	✗	✓	20	✓	5	5	✓
CA	Sacramento Municipal Utility District	Rebate	✓[30]	✓	10	✓	10	10	✓
TX	El Paso Electric	Rebate	✓	✓	5	✓	5	5	✓
TX	Southwestern Electric Power	Rebate	✓	✓	10	✓	10	10	✓

As an example, CSI requires that solar modules and inverters be listed on the California Energy Commission's website, possess a 10-year warranty (PBI payments are disbursed under CSI for only 5 years), and possess a UL1703 certification. Additionally, CSI stipulates that solar installers be appropriately licensed and encourages installer certification by North American Board of Certified Energy Practitioners. (California Public Utilities Commission 2011) The longevity and large size of CSI, coupled with these prerequisites for incentive payments has helped establish a high operating standard within California's solar industry, which helps lead to a reputable solar installation industry. In addition, these prerequisites for incentive program participation mean that even at low incentive levels, assuming installers are still willing to complete the CSI application process, solar customers still receive a substantial degree of consumer protection for their systems.

[28] Systems may be installed by the customer.
[29] Systems may be installed by the customer.
[30] Systems may be installed by the customer.

8.2 Installed Cost Transparency and Price Protection

A utility administering a solar incentive program is uniquely positioned to possess cost data for solar systems installed within its service territory because applicants must typically submit cost data with their application. Making data on installed costs publicly available can serve two purposes. First, doing so can protect solar customers who are unfamiliar with solar costs from extortive pricing. Second, making the data publicly available can help provide downward price pressure on the installer community, which should improve the likelihood of greater market penetration of solar in the future. Of course, competitive interests of installers should be protected, but aggregate statistics can be released without harming individual companies. For example, CSI provides extensive information on its website,[31] including installations and pricing data, although transparency could likely be achieved with less detail than CSI provides.

In addition to offering ample transparency and access to program data, CSI has instituted a cost cap for solar system applications to protect consumers from price gouging. New applicants that are quoted at an installed cost (on a per watt basis) that is greater than one standard deviation from the previous 12-month mean installation cost must submit a form signed by the customer explaining his or her understanding of that system's elevated costs. (California Public Utilities Commission 2011 §3.4.5) In addition, the cost cap is transparently communicated to interested parties via a California Solar Statistics Web page listing answers to frequently asked questions (Go Solar California 2012). Another option for protecting customers from high pressure sales is to require installers to allow a three-day right to cancel, or similar provision (Airth 2012).

8.3 Encouraging Energy Efficiency First

Investing in energy efficiency is often one of the most cost-effective measures a customer can take to decrease energy consumption. In some cases, efficiency can also help utilities shave peak demand. For consumers considering installing solar PV systems, examining all efficiency options first can help reduce the size of the PV system needed to offset a targeted portion of that customer's energy demand, which can result in substantial cost savings on a solar system (Airth 2012).

Some solar incentive programs require customers to participate in some form of baseline assessment – a full energy audit or otherwise – of the customer's building's energy efficiency in order to qualify for incentive payments. Such requirements can serve as a method of educating customers about energy efficiency options *before* making the investment in solar. Examples of utilities encouraging energy efficiency through solar incentive programs include the following:

- SMUD instituted a procedure by which all solar incentive program applicants are informed of energy efficiency measures for a building that is the site of a proposed PV system before the design and installation (Sacramento Municipal Utility District 2012).
- Gulf Power requires an on-site "energy check-up" for any property having its application approved for the receipt of incentives (Gulf Power 2012).

[31] http:/www.californiasolarstatistics.ca.gov/

- Minnesota Power offers a bonus of $1.00/watt to its program's existing $2.00/watt rebate if customers complete the ENERGY STAR Yardstick[32] with a rating of 7 or greater (Minnesota Power 2012).
- Austin Energy requires that all applicants to its residential solar rebate program meet minimum energy efficiency requirements (Austin Energy 2012).

8.4 Ownership of Renewable Energy Certificates (RECs)

In most cases, a utility administering a solar incentive program requires that RECs generated by a system receiving incentives be transferred to the utility. The utility typically uses these RECs to satisfy solar targets established within an RPS. As noted earlier, REC ownership provisions can be separated from the incentive payment period, as is done with rebate programs that acquire system RECs for long periods of time (e.g., 10-20 years) despite a one-time, up-front incentive payment.

Some programs, such as CSI, do not require systems receiving incentive payments to sign over ownership of the RECs to the administering utility. In California, the CSI funded projects generally do not contribute to utility RPS requirements. In interviews, CSI administrators indicated they opted for customers to retain the RECs because much customer appeal for installing solar is for the environmental benefits of the electricity. Selling the RECs or essentially selling the environmental attributes of that system would defy customers' desire to be "green." Certainly, CSI customers have the prerogative to sell RECs associated with their solar generation in available markets, although market opportunities are limited at present outside of established SREC markets.[33]

In addition to the investor-owned utilities operating under CSI, several other utilities allow system owners to retain the RECs generated from the system. These include Pacific Power in California, Southwestern Electric Power Company of Texas, and Green Mountain Power of Vermont. Also, CPS Energy of San Antonio, Texas allows commercial system owners to retain the RECs produced from their systems if they are needed for compliance with Leadership in Energy and Environmental Design (LEED) certification. In this event, customers are offered reduced incentives in exchange for keeping their RECs.

As solar incentives decline to zero, one consideration for program administrators is the handling of REC claims associated with solar generation. Typically, utilities have procured RECs from solar systems by offering financial incentives. TEP and APS have proposed to demonstrate compliance with solar obligations without acquiring the associated RECs – what they have termed a "track and record" approach.[34] Because the utilities would be making a claim about the solar generation, they would inherently be using the RECs for compliance, which opens the REC market to double counting. Interveners in the case have also noted that the proposal would strip solar owners of their property rights without just compensation. A similar approach has been

[32] https://www.energystar.gov/index.cfm?fuseaction=home_energy_yardstick.showgetstarted
[33] The markets available for selling SRECs outside of established SREC markets are limited, as only Missouri and North Carolina allow RECs produced by renewable generation from outside of Eastern markets to be used for RPS compliance. The California Public Utilities Commission recently allowed utilities to procure a limited amount of "unbundled" RECs to meet RPS mandates, but distributed solar would have to compete with utility-scale renewable generation for this limited market.
[34] See Dockets E-01345A-12-0290 and E-01345A-10-0394.

tried in Hawaii. As result, Green-e Energy, the leading voluntary REC certification program, does not accept RECs from customer-sited, grid-connected renewable generation in Hawaii (Quarrier 2012).

The U.S. Department of Veterans Affairs and others have noted that the Department of Energy's *Renewable Energy Requirement Guidance of EPACT 2005 and Executive Order 13423* prohibits double counting by not allowing RECs to count towards federal goals if they are being used for compliance elsewhere (Cordova 2012). The Arizona case is still pending at the Arizona Corporation Commission.

9 Best Practices for Incentivizing Solar

Dozens of utilities throughout the United States offer incentive programs designed to encourage the adoption of solar energy. In recent years, various design and implementation methods have emerged as utilities have attempted to respond to changing solar market conditions and meet consumer demand. Based on a review of existing program experience and interviews with various stakeholders including program administrators, regulators, and industry representatives, we developed the following list of best practices for designing and implementing solar incentive programs. These best practices consider the perspectives of various stakeholders and the broad objectives of reducing solar costs, encouraging long-term market viability, minimizing ratepayer costs, and protecting consumers.

- ***Consider rebates coupled with performance guarantees for incentivizing small customer-owned systems***: Rebates reduce upfront system costs, which can be very important for residential customers in particular, who may face challenges in financing systems if third-party owned options are unavailable. Because rebates based on nameplate capacity alone do not ensure performance, rebates can be coupled with pre-requirements to help ensure that solar systems are properly designed and installed, and that they use equipment that will perform effectively. Programs may wish to incentivize both customer-owned and third-party owned systems to encourage diversity in ownership models.
- ***Consider moderate-term PBIs with on-bill crediting for commercial-scale and third-party owned systems****:* PBIs can be an effective method of incentivizing third-party owned and larger-scale systems that can take advantage of future revenue streams in financing. Using PBIs can minimize the strain on limited program budgets by spreading incentive costs over several years, compared to upfront incentives, which are paid when systems are installed. Important considerations for establishing PBIs are the frequency of payments and the method of payment disbursement. While payment terms currently range from 5 to 20 years, shorter payment periods (on the order of 5 years) can minimize long-term administrative burden and the necessary duration of the program. In addition, system owners more highly value payments in early years because of the time value of money. However, for a program to be effective, payments need to be sufficient in size and duration to encourage installations, and considerations of costs to ratepayers over the period must be balanced with selection of the term of payments. Further, on-bill crediting of PBI incentives is preferable to ensure timely payment to customers as well as to minimize the administrative costs of issuing checks over the duration of the incentive payment term.

- ***Use multiple approaches and data sources to evaluate appropriate incentive levels****:* With rapidly changing market conditions, utilities can use a variety of methods to ensure that it offers accurate incentive levels. Data on installed costs can be used to calculate expected returns on investment and payback periods, with publicly available models. In addition, utilities can benchmark incentive levels and uptake in nearby utility service territories. If a program involves a long commission approval process, it may be important to maintain some flexibility in the payment levels, as market conditions could change over the course of the approval process. Furthermore, initial stages of a program can offer incentives for a limited amount of capacity to test uptake rates at a specified payment level.
- ***Consider different incentive structures to encourage various market segments:*** Because the economics of systems vary substantially by size (i.e, rate structure, financing arrangements), it is important to develop incentives that align with the needs of each market segment. The classes of systems that a program seeks to incentivize may be influenced by ratepayer considerations, grid benefits, market diversity, building support for the program, and balancing program costs. A combination of approaches is generally needed to incentivizing multiple market segments. For example, rebates or PBIs with pre-established step-down levels may be appropriate for small- to medium-sized systems, and competitive solicitations or auctions may be particularly important to competitively price incentives for larger systems. At least one utility has used a streamlined auction process for all sizes of commercial systems, thus introducing competitive pricing to the smaller system market segment as well.
- ***Modify incentive-levels to respond to changing market conditions***: To maintain appropriate incentive levels when solar costs shift, programs have found it necessary to develop processes to modify incentives levels periodically. Two primary options in use today are an established step-down schedule or a competitive solicitation or auction processes for setting market prices. The primary advantages of the step-down approach are simplicity, transparency, and certainty for market participants. Further, a step-down program can encourage consumers to act before incentives are reduced. A disadvantage to step-down schedules is that incentive levels are established in advance and may not continuously align with market conditions; thus, incentives could fall too rapidly, halting installations, or fall too slowly, resulting in overpayment for installed capacity. Alternatively, a step-down program could be implemented so that steps are adjusted over time, which could align incentive levels more directly with market conditions but reduce transparency and certainty. An auction or competitive solicitation theoretically leads to the most accurate pricing and minimizes incentive payments, but it provides less certainty to market participants about future incentive levels. Auctions may also be prohibitively complex for determining incentives for small customer-owned systems in particular, although at least one program successfully implemented a simplified auction mechanism for all sizes of commercial systems. A combination of approaches could also be used with pre-established step-down levels for small- to medium-sized systems, and auctions for larger systems.

- ***Use multiple steps and communicate progress clearly when establishing incentive step-down schedules:*** Creating multiple stages in a step-down program can create conditions, if set at appropriate levels, that encourage customers to install solar before the next decline in incentives. This can create a condition in which solar is always "on-sale." Another important aspect of this design is to ensure that customers can clearly discern how much capacity or budget is available in a particular step so that they can determine what level of incentive is currently available. Utilities can convey this information by maintaining timely and accurate information on program progress on the internet.
- ***Manage project flow and incentive offer periods to encourage a more stable market:*** For programs with limited budgets, offering incentives more frequently than annually can help promote a greater degree of market stability. In contrast to offering a limited budget for incentives once per year—allowing that budget to become exhausted and lead to periods of solar market inactivity—spreading incentive budgets over the course of the year can help encourage steady market participation throughout the year. Further, offering incentives through multiple application periods can allow a utility to adjust incentive levels according to program uptake and market conditions, as necessary.
- ***Institute consumer protection measures to encourage reputable business practices that help ensure the long-term viability of the solar industry:*** The most common consumer protection measures aim to provide checks to ensure optimal system performance and to educate customers about energy efficiency options that help them appropriately size solar systems. Other, less commonly incorporated, but potentially important measures, aim to protect customers from price gouging by making aggregate data on installed costs publicly available and alerting customers to systems that are above average cost.
- ***Consider offering bonus incentives to systems that provide grid benefits***: PV systems have the potential to offer benefits to the grid by deferring transmission and distribution investments or if sited in areas with substantial congestion. Bonus incentive payments can be offered to encourage systems to be sited in areas where they are most beneficial to the utility grid.
- ***Ensure equitable access to incentives through fair queuing processes:*** Particularly for programs with limited budgets, ensuring equitable access to incentives is important for the perceived success of the program. Transparent queuing processes and administrative processes that minimize the risk of gaming are important for encouraging market stability.
- ***Require modest fees to minimize administrative burdens:*** Most programs charge modest fees, which can be refundable, to ensure that projects submitted for incentives are viable and that project owners have some "skin in the game." This can preserve staff time and save administrative costs by helping encourage only serious project applications and focusing staff time on viable projects.

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Appendix. Solar Incentive Programs Analyzed

Tables A-1 and B-1 list the residential and commercial solar incentive programs, respectively that were analyzed for this report. Program data are from the Database of State Incentives for Renewables & Efficiency, as of July 2012.

Table A-1. Residential Incentive Programs

State	Utility/Program Administrator	System Size (kW)	Incentive Type	Rebate ($/watt) PBI ($/kWh)	PBI Length (years)	System Owner	Cost of Solar ($/W)[35]	Cost of Retail Electricity (¢/kWh)[36]	Expected Annual kWh-AC (4 kW)[37]	Max. Benefit or Capacity Limit
AZ	Arizona Public Service	< 30	Rebate	$0.20 DC		n/a	6.680	8.733	6,184	40% or $75,000
TX	Austin Energy	1 – 20	Rebate	$2.00 AC		n/a	6.010	9.365	5,359	$15,000
CO	Colorado Springs Utilities	.5 – 10	Rebate	$1.80		Customer	5.900	8.967	5,831	Size <120% of demand
OH	Columbus Southern Power	> 2	Rebate	$1.50		n/a	5.860	7.677	4,497	50% or $12,000
TX	CPS Energy	1 – 25	Rebate	$2.00		Customer	6.010	8.565	5,513	$25,000
TX	El Paso Electric	1 – 50	Rebate	$2.00 DC		n/a	6.010	10.666	6,381	$20,000
FL	Gulf Power	< 5	Rebate	$2.00		Customer	5.750	8.637	4,959	$10,000
NY	Long Island Power Authority	< 10	Rebate	$1.75 DC		Customer	5.520	17.516	4,791	50% or $17,500
MN	Minnesota Power	< 100	Rebate	$2.00 DC		Unknown	0.000	8.217	4,641	$20,000 or 60%[38]
MN	Northern States Power Co.	.5 – 40	Rebate	$2.25 DC		Customer	0.000	8.136	4,897	$90,000 or 60%
NY	New York State Energy Research & Development Authority (NYSERDA)	< 7	Rebate	$1.50		n/a	5.520	19.743 (NYC)	4,791	$10,500 or 40%
OH	Ohio Power	2 – 8	Rebate	$1.50		n/a	5.860	7.677	4,497	50% or $12,000
CA	Pacific Power	1 – 5,000	Rebate	$1.13 AC		n/a	6.480	8.388	5,267	Incentive capped at 250 kW

[35] Average cost of solar by state ($/Watt DC) (SEIA/GTM Research 2012)
[36] PV Watts (http://www.nrel.gov/rredc/pvwatts/)
[37] PV Watts (http://www.nrel.gov/rredc/pvwatts/)
[40] Auto-renewal of PBI agreement occurs in 5-year increments. PBI agreement can be voided with 60-days notice from either party.

State	Utility/Program Administrator	System Size (kW)	Incentive Type	Rebate ($/watt) / PBI ($/kWh)	PBI Length (years)	System Owner	Cost of Solar ($/W)[35]	Cost of Retail Electricity (¢/kWh)[36]	Expected Annual kWh-AC (4 kW)[37]	Max. Benefit or Capacity Limit
CA	PG&E (CSI)	< 30	Rebate	$0.20		n/a	6.480	12.354	5,737	Incentive capped at 1 MW
AZ	Salt River Project		Rebate	$0.50		n/a	6.680	8.659	6,187	$2,000
CA	SDG&E (CSI)	1 – 30	Rebate	$0.20		n/a	6.480	17.288	5,921	Incentive capped at 1 MW
WA	Snohomish County PUD No 1	< 100	Rebate	$0.50 DC		Customer	6.700	6.879	3,851	$2,500
CA	SCE (CSI)	1 – 30	Rebate	$0.35		n/a	6.480	12.070	6,105	Incentive capped at 1 MW
TX	Southwestern Elec. Power	< 2,000	Rebate	$1.75 DC		n/a	6.010	6.643	5,299	$17,500; size cannot exceed demand.
AZ	UniSource Energy Services	1.2 – 30	Rebate	$0.85 DC[39]		Unknown	6.680	10.065	6,495	50% of system cost
OH	Columbus Southern Power	< 100	PBI	$0.263	Ends 6/2013	n/a	5.860	7.677	4,497	REC purchase: $262.50
VT	Green Mountain Power	< 250	PBI	$0.060	10	Unknown	5.630	14.042	4,550	None specified
OR	Idaho Power Co	< 10	PBI	$0.317	15	n/a	6.72	7.232	5,010	
		10 – 100		$0.250						
	Los Angeles Department of Water and Power	< 1000	Rebate	$1.62 AC		Customer	6.480	11.502	5867	75%
				$1.50 AC		Third-Party				
WI	Madison Gas & Electric Co	1 – 10	PBI	$0.250	10	n/a	5.840	10.065	4,883	None specified
OH	Ohio Power Co	< 100	PBI	$0.263	Ends 6/2013	n/a	5.860	7.677	4,497	REC purchase: $262.50

[40] Auto-renewal of PBI agreement occurs in 5-year increments. PBI agreement can be voided with 60-days notice from either party.

State	Utility/Program Administrator	System Size (kW)	Incentive Type	Rebate ($/watt) PBI ($/kWh)	PBI Length (years)	System Owner	Cost of Solar ($/W)[35]	Cost of Retail Electricity (¢/kWh)[36]	Expected Annual kWh-AC (4 kW)[37]	Max. Benefit or Capacity Limit
FL	Orlando Utilities Commission	< 2,000	PBI	$0.050	5[40]	n/a	5.750	9.260	5,360	None specified
CA	PG&E (CSI)	1 – 30	PBI	$0.025	5	n/a	6.480	12.354	5,737	Incentive capped at 1 MW
		> 30								
OR	PacifiCorp	< 10	PBI	$0.411	15	n/a	6.72	6.659	4,269	
		< 10		$0.346				7.25	4,639	
		< 10		$0.317				7.232	5,010	
		10 – 100		$0.285				6.659	4,269	
		10 – 100		$0.250				7.25	4,639	
		10 – 100		$0.250				7.25	4,639	
NM	Public Service NM	< 10	PBI	$0.060	12	n/a	5.410	8.207	6,235	None specified
		10 – 100		$0.050	Ends 12/2020					
		100 – 1,000		$0.020						
		> 1,000		$0.070						
OR	Portland General Electric	< 10	PBI	$0.411	15	n/a	6.72	6.659	4,269	
		< 10		$0.346			6.72	7.232	5,010	
		10 – 100		$0.285			6.72	6.659	4,269	
		10 – 100		$0.250			6.72	7.232	5,010	
CA	SDG&E (CSI)	1 – 30	PBI	$0.025	5	n/a	6.480	17.288	5,921	Incentive capped at 1 MW
CA	SCE (CSI)	1 – 30	PBI	$0.044	5	n/a	6.480	12.070	6,105	Incentive capped at 1 MW
CO	Xcel Energy	.5 – 10	PBI	$0.150	10	Customer	5.900	8.556	5,813	Size <120% of demand
		.5 – 10		$0.100		Third-party				
		10 – 500		$0.090		n/a				

[40] Auto-renewal of PBI agreement occurs in 5-year increments. PBI agreement can be voided with 60-days notice from either party.

State	Utility/Program Administrator	System Size (kW)	Incentive Type	Rebate ($/watt) / PBI ($/kWh)	PBI Length (years)	System Owner	Cost of Solar ($/W)[35]	Cost of Retail Electricity (¢/kWh)[36]	Expected Annual kWh-AC (4 kW)[37]	Max. Benefit or Capacity Limit
OH	Duke Energy Ohio		PBI	REC prices	15	n/a	5.860	7.272	4,832	

Table A-2. Commercial Incentive Programs

State	Utility	System Size (kW)	Type	Rebate ($/watt) / PBI ($/kWh)	PBI Length (years)	System Owner	Cost of Solar ($/W)[41]	Cost of Retail Elec. (¢/kWh)[42]	Expected Annual kWh-AC (4 kW)[43]	Max. Benefit or Capacity Limitation
CO	Colorado Springs, City of	.5 – 25	Rebate	$1.80		Customer	5.050	8.967	5,831	
OH	Columbus Southern Power	> – 10	Rebate	$1.50		n/a	4.730	7.677	4,497	50% or $175,000
TX	CPS Energy	1 – 25	Rebate	$2.00		Customer	6.460	8.565	5,513	$25,000
TX	El Paso Elec. Co	1 – 50	Rebate	$1.75 DC		n/a	6.460	10.666	6,381	$87,500
FL	Gulf Power Co	< 5	Rebate	$2.00		Customer	4.270	8.637	4,959	$10,000
NY	Long Island Power Authority	< 50	Rebate	$1.30 DC		Customer	6.050	17.516	4,791	$65,000 or 50%
MN	Minnesota Power Inc.	< 100	Rebate	$2.00 DC		Unknown	0.000	8.217	4,641	$20,000 or 60% (+bonus)
OH	Ohio Power Co (AEP)	10 – 50	Rebate	$1.50		n/a	4.730	7.677	4,497	50% or $75,000
CA	PG&E (CSI)	1 – 30	Rebate	$0.20		n/a	5.140	12.354	5,737	
CA	Pacific Power	1 – 5,000	Rebate	$0.63 AC		n/a	5.140	8.388	5,267	$157,500
AZ	Salt River Project	< 100	Rebate	$0.50		n/a	5.910	8.659	6,187	
CA	SDG&E (CSI)	1 – 30	Rebate	$0.35		n/a	5.140	17.288	5,921	
WA	Snohomish City PUD No 1	< 100	Rebate	$0.50 DC		Unknown	5.190	6.879	3,851	$10,000
CA	SCE (CSI)	1 – 30	Rebate	$0.35		n/a	5.140	12.070	6,105	
AZ	UniSource Energy Services	< 70	Rebate	$0.50 DC		Unknown	5.910	10.065	6,495	50%
AZ	Arizona Public Service	30 – 2,000	PBI	Competitive Bidding	10, 15, or 20	n/a	5.910	8.733	6184	50% up to $75,000
TX	Austin Energy	< 20	PBI	$0.140	10	n/a	6.460	9.365	5359	$.035 potential bonus[44]
CO	Black Hills Energy	< 3	PBI	$0.122	10	Third	5.050	9.088	5948	
		3 – 10		$0.108						
OH	Columbus Southern Power	< 100	PBI	$0.263	Ends 6/2013	n/a	4.730	7.677	4497	REC purchase: $262.50

[41] Average cost of solar by state ($/Watt DC) (SEIA/GTM Research 2012)
[42] PVWatts (http://www.nrel.gov/rredc/pvwatts/)
[43] PVWatts (http://www.nrel.gov/rredc/pvwatts/)
[44] Bonus for locally manufactured system components

State	Utility	System Size (kW)	Type	Rebate ($/watt) PBI ($/kWh)	PBI Length (years)	System Owner	Cost of Solar ($/W)[41]	Cost of Retail Elec. (¢/kWh)[42]	Expected Annual kWh-AC (4 kW)[43]	Max. Benefit or Capacity Limitation
VT	Green Mountain Power Corp.	< 250	PBI	$0.060	10	Unknown	5.340	14.042	4550	
OR	Idaho Power Co	< 10	PBI	$0.317	15	n/a	4.94	7.232	5010	
		10 – 100		$0.250						
WI	Madison Gas & Electric Co	1 – 10	PBI	$0.250	10	Customer	6.330	10.065	4883	
NY	New York State Energy Research & Development Authority (NYSERDA)	< 50	Rebate	$1.50		n/a	5.520	19.743 (NYC)	4,791	$60,000 or 40%
NY	New York State Energy Research & Development Authority (NYSERDA)	> 50	PBI	Competitive Bidding	3	n/a	5.520	19.743 (NYC)	4,791	$1M
OH	Ohio Power Co (AEP)	< 100	PBI	$0.263	Ends 6/2013	n/a	4.730	7.677	4497	REC purchase: $262.50
FL	Orlando Utilities Commission	< 2,000	PBI	$0.050	5[45]	Customer	4.270	9.260	5360	No maximum specified
CA	PG&E (CSI)	1 – 30	PBI	$0.025	5	n/a	5.140	12.354	5737	
		30 – 1,000					5.140	12.354	5737	
OR	PacifiCorp	< 10	PBI	$0.411	15	n/a	4.94	6.659	4269	
		< 10		$0.346				7.232	5010	
		< 10		$0.317				7.232	5010	
		10 – 100		$0.285				6.659	4269	
		10 – 100		$0.250				7.232	5010	
		10 – 100		$0.250				7.232	5010	
NM	PNM	< 10	PBI	$0.050	12	Customer	4.500	8.207	6235	
		10 – 100		$0.050	Ends 12/2020					
		100 – 1,000		$0.020						
		> – 1,000		$0.070	n/a[46]					
OR	Portland Gen Electric Co	< 10	PBI	$0.411	15	n/a	4.94	6.659	4269	
		< 10		$0.346				7.232	5010	
		10 – 100		$0.285				6.659	4269	

[45] PBI agreement renews automatically after five years until terminated with 60-days notice by either party.
[46] Fully subscribed as of August 2012

State	Utility	System Size (kW)	Type	Rebate ($/watt) PBI ($/kWh)	PBI Length (years)	System Owner	Cost of Solar ($/W)[41]	Cost of Retail Elec. (¢/kWh)[42]	Expected Annual kWh-AC (4 kW)[43]	Max. Benefit or Capacity Limitation
		10 – 100		$0.250				7.232	5010	
AZ	Salt River Project	100 – 1,000	PBI	$0.050	20	n/a	5.910	8.659	6187	
CA	SDG&E (CSI)	1 – 30	PBI	$0.044	5	n/a	5.140	17.288	5921	
		30 – 1,000								
CA	SCE (CSI)	1 – 30	PBI	$0.044	5	n/a	5.140	12.070	6105	
		30 – 1,000								
AZ	UniSource Energy Services	70 – 200	PBI	$0.092	10, 15 or 20	Unknown	5.910	10.065	6495	
		201 – 400		$0.088						
		> 401		$0.084						
CO	Xcel Energy	.5 – 10	PBI	$0.150	20	Customer	5.900	8.556	5813	System <120% of annual demand
		.5 – 10		$0.100		Third-party				
		10 – 500		$0.090		Customer or Third-party				
		> 500	RFP			Customer or Third-party				
CA	SMUD	No limit	Rebate or PBI	$0.65 AC or $0.100/kWh	5	n/a	6.480	11.274	5638	No limit
AZ	Arizona Public Service	< 30	Rebate or PBI	$0.60 DC or PBI	10, 15 or 20	Customer	5.910	8.733	6184	50% or $75,000
CA	Sacramento Municipal Utilities District	< 1,000	Rebate or PBI	$0.65 AC or $0.100/kWh	5	n/a	5.140	11.274	5638	$1 million for rebate
				$0.65 AC or $0.060.kWh	10					