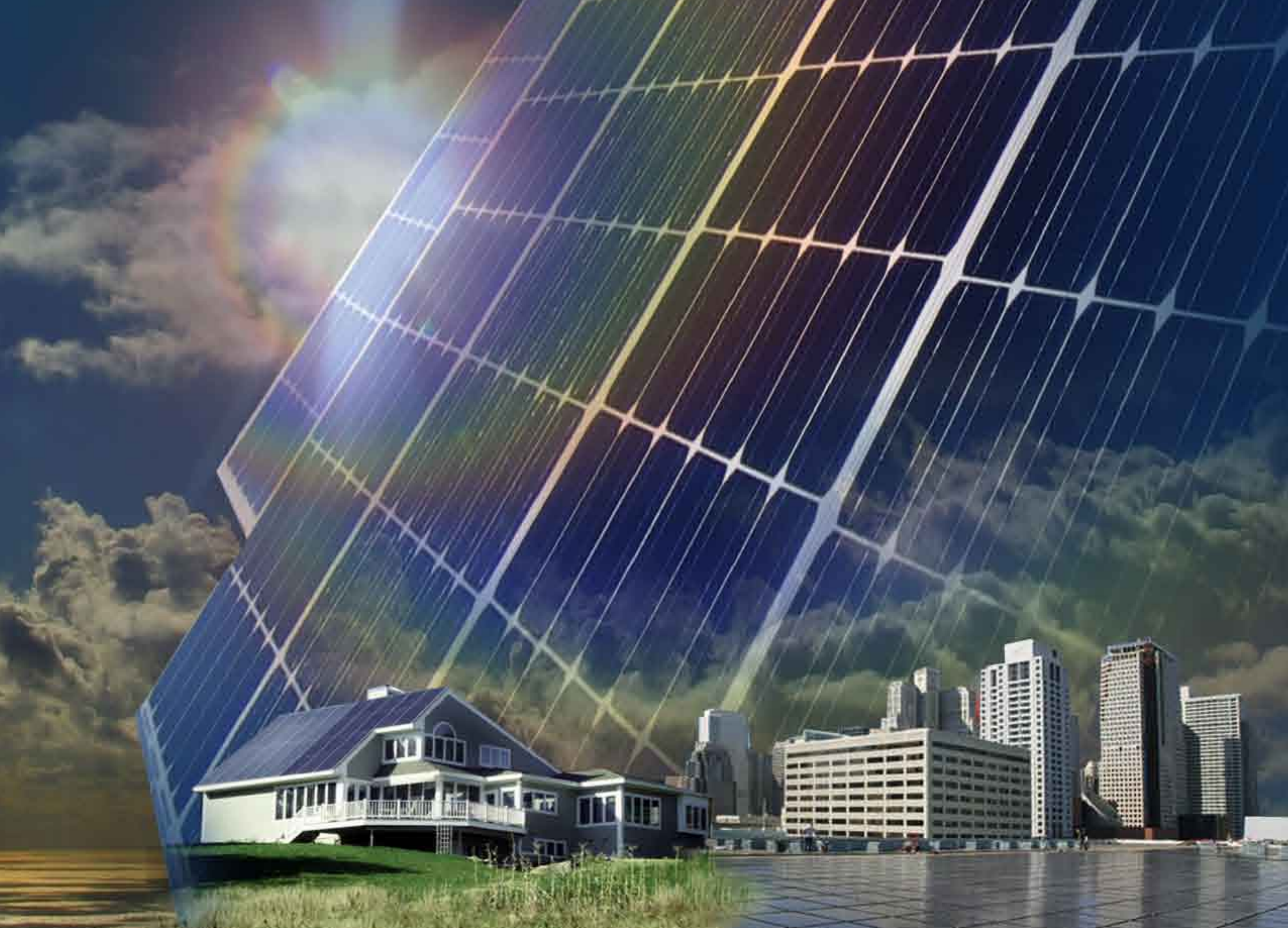
Tracking the Sun IV

An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010

Galen Barbose
Naïm Darghouth
Ryan Wiser
Joachim Seel

September 2011

BERKELEY LAB
Lawrence Berkeley
National Laboratory



LBNL-5047E

Tracking the Sun IV

An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010

Primary Authors: Galen Barbose, Naïm Darghouth, Ryan Wiser, and Joachim Seel
Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory

Contents

Executive Summary

As the deployment of grid-connected solar photovoltaic (PV) systems has increased, so too has the desire to track the installed cost of these systems over time and by location, customer type, system characteristics, and component. This report helps to fill this need by summarizing trends in the installed cost of grid-connected PV systems in the United States from 1998 through 2010, with preliminary data for 2011, and includes, for the first time, installed cost trends for utility-sector PV. The analysis is based on installed cost data for approximately 116,500 behind-the-meter (i.e., residential and commercial) and utility-sector PV systems, totaling 1,685 megawatts (MW) and representing 79% of all grid-connected PV capacity installed in the United States through 2010.[1]

It is essential to note at the outset the limitations inherent in the data presented within this report. First, the cost data are historical, focusing primarily on projects installed through the end of 2010, and therefore do not reflect the cost of projects installed more recently (with the exception of a limited set of results presented for behind-the-meter projects installed in the first half of 2011); nor are the data presented here representative of costs that are currently being quoted for prospective projects to be installed at a later date. For this reason and others (see Text Box 1 within the main body of the report), the results presented herein likely differ from current PV cost benchmarks. Second, this report focuses on the up-front cost to install PV systems; as such, it does not capture trends associated with PV performance or other factors that affect the levelized cost of electricity (LCOE) for PV. Third, the utility-sector PV cost data presented in this report are based on a small sample size (reflecting the small number of utility-sector systems installed through 2010), and include a number of relatively small projects and "one-off" projects with atypical project characteristics. Fourth, the data sample includes many third party-owned projects where either the system is leased to the site-host or the generation output is sold to the site-host under a power purchase agreement. The installed cost data reported for these projects are somewhat ambiguous – in some cases representing the actual cost to install the project, while in other cases representing the assessed "fair market value" of the project.[2] As shown within the report, however, the available data suggest that any bias in the installed cost data reported for third party-owned systems is not likely to have significantly skewed the overall cost trends presented here.

The report separately describes cost trends for behind-the-meter PV systems and utility-sector systems. Key findings regarding the installed cost of *behind-the-meter PV systems* are as follows:

- The capacity-weighted average installed cost of all behind-the-meter systems installed in 2010 – in terms of real 2010 dollars per installed watt (DC-STC)[3] and prior to receipt of any direct financial incentives or tax credits – was \$6.2/Watt, and was \$1.3/W (17%) below the average for systems installed in 2009.

[1] For the purpose of this report, "behind-the-meter" PV refers to systems that are connected on the customer-side of the meter, typically under a net metering arrangement. Conversely, "utility-sector" PV consists of systems connected directly to the utility system, and may therefore include wholesale distributed generation projects.
[2] The cost data for behind-the-meter PV systems presented in this report derive primarily from state and utility PV incentive programs. For a *subset* of the third party-owned systems – namely, those systems installed by *integrated* third party providers that both perform the installation and finance the system for the site-host – the reported installed cost may represent the fair market value claimed when the third party provider applied for a Section 1603 Treasury Grant or federal investment tax credit.
[3] Various permutations of rating conventions may be used to describe the size of PV systems. The most common rating used by PV incentive programs, which is also used throughout this report, is the nameplate capacity of the PV modules reported by manufacturers in terms of direct current (DC) watts under standard test conditions (STC).

- Partial data for the first six months of 2011 indicates that installed costs have continued to rapidly decline, with the capacity-weighted average installed cost of projects funded through the California Solar Initiative falling by an additional $0.7/W during the first half of 2011, amounting to an 11% drop from average costs in 2010.
- The recent decline in installed costs is, in large part, attributable to falling wholesale module prices, which fell by $0.9/W from 2008 to 2009, by $0.5/W from 2009 to 2010, and which have fallen further still in 2011 (based on Navigant Consulting's Global Power Module Price Index). The fact that average installed costs remained flat from 2008 to 2009, before dropping significantly in 2010, illustrates that movements in global wholesale module prices do not necessarily translate into an immediate, commensurate change in the cost borne by the final system owner; a time lag is apparent.
- The recent decline in installed costs is also attributable to falling *non-module* costs. Based on component-level cost data reported by installers to PV incentive programs, non-module and non-inverter costs (which may include such items as mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and installer profit) fell by roughly $0.6/W from 2009 to 2010.
- PV installed costs exhibit significant economies of scale, with systems ≤2 kW completed in 2010 averaging $9.8/W, while >1,000 kW behind-the-meter systems averaged $5.2/W (or about 47% less). The cost of utility-sector systems was even lower, as discussed further below. These economies of scale partially explain the long-term decline in average installed costs, as the size distribution of PV systems has shifted towards larger systems over time.
- Large systems exhibited the greatest year-over-year cost declines from 2009 to 2010. For example, the average installed cost fell by $1.9/W (26%) for behind-the-meter systems in the >500 kW size range, but fell by a lower $0.9/W (11%) for ≤5 kW systems.
- The growing prevalence of third party owned PV systems has introduced some distortion into the underlying cost trends, but at least at an aggregate sample-wide level, the magnitude of the distortion is likely to be relatively modest. Among systems of all sizes installed in 2010, the capacity-weighted average installed cost of third party owned systems was $0.3/W higher than for customer-owned systems, though the differences are somewhat larger when comparing within specific system size categories.
- Average installed costs vary widely across states; among ≤10 kW systems completed in 2010, average costs range from a low of $6.3/W in New Hampshire to a high of $8.4/W in Utah. The country's largest state PV markets, California and New Jersey, were near the center of this range, suggesting that, in addition to absolute market size, other state and local factors (e.g., permitting requirements, labor rates, the extent of third party ownership, and sales tax exemptions) also strongly influence installed costs.
- International experience suggests that greater near-term cost reductions in the United States are possible, as the average installed cost of 3-5 kW residential PV installations in 2010 (excluding sales/value-added tax) was significantly lower in Germany ($4.2/W) than in the United States ($6.9/W), where cumulative grid-connected PV capacity in the two countries through 2010 totaled roughly 17,000 MW and 2,100 MW, respectively.
- The new construction market offers cost advantages for small residential PV systems. Among 2-3 kW residential systems (the size range typical for residential new construction) installed in 2010 and funded through California's incentive programs, new construction systems cost $0.7/W less, on average, than comparably sized residential retrofit systems (or $1.5/W less if comparing only rack-mounted systems).

- Systems with crystalline (multi- or mono-crystalline) modules had lower average installed costs than those with thin-film (amorphous silicon or non-silicon) modules, when focusing on <100 kW systems installed in 2010, but average installed costs were nearly identical for crystalline and thin-film systems within the >100 kW size range.
- As to be expected, systems with tracking equipment had higher installed costs than fixed-tilt systems, with a difference of $1.0/W in average installed costs for 10-100 kW systems installed in 2010 (insufficient data were available for larger system sizes).
- The drop in installed costs in 2010 was partially offset by falling incentives. State/utility cash incentives continued their historical decline, with average residential incentives falling by $0.5/W to $1.6/W and average commercial incentives falling by $0.3/W to $1.8/W (all on a pre-tax basis).[4] The average dollar-per-watt value of the federal investment tax credit (ITC) or Treasury cash grant in lieu of the ITC also fell in 2010, due to the decline in installed costs.
- The capacity-weighted average *net installed cost* faced by PV system owners – that is, installed cost minus the combined after-tax value of state/utility cash incentives, the federal ITC (or Treasury grant), and any available state ITCs – stood at $3.6/W for residential PV and $3.0/W for commercial PV in 2010, in both cases an historic low.

This report separately summarizes installed cost data for utility-sector PV projects, but these data must be interpreted with a certain degree of caution. First, the sample size is small (31 projects in total, including 20 projects installed in 2010), and includes a number of small wholesale distributed generation projects as well as a number of "one-off" projects with atypical project characteristics. The cost of these small or otherwise atypical projects is expected to be higher than the cost of many of the larger utility-scale PV projects currently under development. Second, the installed cost of any individual utility-sector project may reflect component pricing one or even two years prior to project completion, and therefore the cost of the utility-sector projects within the data sample may not fully capture the steep decline in module prices that occurred over the study period. With these important caveats in mind, several key trends for *utility-sector PV systems* emerge from our analysis:

- The installed cost of utility-sector systems varies significantly across projects. Among the 20 utility-sector projects in the data sample completed in 2010, installed costs ranged from $2.9/W to $7.4/W, reflecting the wide variation in project size (from less than 1 MW to 34 MW), differences in system configurations (e.g., fixed-tilt vs. tracking and thin-film vs. crystalline modules), and the unique characteristics of individual projects.
- Current cost benchmarks for utility-sector PV are generally at the low-end of the range exhibited by the 2010 projects in the data sample, with various entities estimating an installed cost of $3.8/W to $4.4/W, depending on system size and configuration for utility-sector systems installed at the end of 2010 or beginning of 2011.
- The installed cost range of utility-sector systems in the data sample declines with system size, consistent with expected economies of scale. For example, among fixed-tilt, crystalline systems installed over the 2008-2010 period (we include a broader range of years here in order to increase the sample size), costs ranged from $3.7-$5.6/W for the five 5-20 MW systems, compared to $4.7-$6.3/W for the three <1 MW systems. Similarly, among thin-film systems, the installed cost of the two >20 MW projects completed in 2008-2010 ranged from $2.4-$2.9/W, compared to $4.4-$5.1/W for the two <1 MW projects.

[4] Throughout this report, the terms "residential PV" and "commercial PV" refer, respectively, to PV systems sited at residential and commercial customer facilities.

- Installed costs are lowest for thin-film systems and highest for crystalline systems with tracking. Among >5 MW systems installed from 2008-2010 (we again include a broader range of years in order to increase the sample size), installed costs ranged from $2.4-$3.9/W for the five thin-film systems, compared to $3.7-$5.6/W for the five crystalline systems without tracking and $4.2-$6.2/W for the four crystalline systems with tracking. To more comprehensively compare the cost of these alternate system configurations, one would need to also consider differences in performance and the related impact on the LCOE.
- The wide distribution in the installed cost of utility-sector systems in the data sample is partially attributable to the presence of systems with unique characteristics that increase costs. For example, among the 2010 installations in the data sample are a 10 MW tracking system built on an urban brownfield site ($6.2/W), an 11 MW fixed-axis system built to withstand hurricane winds ($5.6/W), and a collection of panels mounted on thousands of individual utility distribution poles totaling 14.6 MW ($7.4/W).

1. Introduction

Installations of solar photovoltaic (PV) systems have been growing at a rapid pace in recent years. In 2010, approximately 17,500 megawatts (MW)[5] of PV were installed globally, up from approximately 7,500 MW in 2009, consisting primarily of grid-connected applications. With 878 MW of grid-connected PV capacity added in 2010, the United States was the world's fourth largest PV market in 2010, behind Germany, Italy, and Japan.[6] Despite the significant year-on-year growth, however, the share of global and U.S. electricity supply met with PV remains small.

The market for PV in the United States is, to a significant extent, driven by national, state, and local government incentives, including up-front cash rebates, production-based incentives, renewables portfolio standards, and federal and state tax benefits. These programs are, in part, motivated by the popular appeal of solar energy, and by the positive attributes of PV – modest environmental impacts, avoidance of fuel price risks, coincidence with peak electrical demand, and the ability to deploy PV at the point of use. Given the relatively high historical cost of PV, however, a key goal of these policies is to encourage cost reductions over time. Therefore, as policy incentives have become more prevalent and as PV deployment has accelerated, so too has the desire to track the installed cost of PV systems.

To address this need, Lawrence Berkeley National Laboratory initiated an annual report series focused on describing historical trends in the installed cost of grid-connected PV systems in the United States. The present report, the fourth in the series, describes installed cost trends for projects installed from 1998 through 2010 (with some limited and preliminary results presented for projects installed in the first six months of 2011). The analysis is based on project-level cost data from approximately 116,500 residential, non-residential, and utility-sector PV systems in the United States. The inclusion of utility-sector PV is a new element in this year's report. The combined capacity of all systems in the data sample totals 1,685 MW, equal to 79% of all grid-connected PV capacity installed in the United States through 2010 and representing one of the most comprehensive sources of installed PV cost data for the U.S. Based on this dataset, the report describes historical installed cost trends over time, and by location, market segment, technology type, and component. The report also briefly compares recent PV installed costs in the United States to those in Germany and Japan, and describes trends in customer incentives for PV installations and net installed costs after receipt of such incentives. The analysis presented here focuses on descriptive trends in the underlying data, serving primarily to summarize the data in tabular and graphical form; later analysis may explore some of these trends with more-sophisticated statistical techniques.

It is essential to note at the outset the limitations inherent in the data presented within this report. First, the cost data are historical, focusing primarily on projects installed through the end of 2010, and therefore do not reflect the cost of projects installed more recently (with the exception of the limited set of results presented for behind-the-meter projects installed in the first half of 2011); nor are the data presented here representative of costs that are currently being quoted for prospective projects to be installed at a later date. For this reason and others (see Text Box 1), the results presented in this report likely differ from current PV cost benchmarks. Second, this report focuses on the up-front cost to install PV systems; as such, it does not capture trends associated with

[5] Throughout this report, all capacity numbers represent rated direct current (DC) module power output.
[6] GTM Research and Solar Energy Industries Association (SEIA). 2011. *U.S. Solar Market Insight 2010 Year-in-Review*.

PV performance or other factors that affect the levelized cost of electricity (LCOE) for PV. Third, the utility-sector PV cost data presented in this report are based on a small sample size (reflecting the small number of utility-sector systems installed through 2010), and include a number of relatively small projects and "one-off" projects with atypical project characteristics. Fourth, the data sample includes many third party-owned projects where either the system is leased to the site-host or the generation output is sold to the site-host under a power purchase agreement (PPA). The installed cost data reported for these projects are somewhat ambiguous – in some cases representing the actual cost to install the project, while in other cases representing the assessed "fair market value" of the project.[7] As shown within the main body of the report, however, the available data suggest that any bias in the installed cost data reported for third party-owned systems is <u>not</u> likely to have significantly skewed the overall cost trends presented here.

The report begins in Section 2 with a summary of the data collection methodology and resultant dataset. Cost trends are then presented separately for "behind-the-meter" systems and "utility-sector" PV systems.[8] Section 3 describes trends in the installed cost of behind-the-meter PV, prior to receipt of any financial incentives, including trends over time and by system size, component, state, system ownership type (customer-owned vs. third party-owned), host customer segment (residential vs. commercial vs. tax-exempt), application (new construction vs. retrofit), and technology type (building-integrated vs. rack-mounted, crystalline silicon vs. thin-film, and tracking vs. fixed-tilt). Section 4 presents additional findings for behind-the-meter systems related to trends in PV incentive levels over time and among states, focusing specifically on state and utility incentive programs as well as state and federal tax credits, and also describes trends in the net installed cost after receipt of such incentives. Section 5 then summarizes trends in the installed cost of utility-sector PV systems. Brief conclusions are offered in the final section, and several appendices provide additional details on the analysis methodology and additional tabular summaries of the data.

[7] The cost data presented in this report derive primarily from state and utility PV incentive programs. For a *subset* of the third party-owned systems – namely, those systems installed by *integrated* third party providers that both perform the installation and finance the system for the site-host – the reported installed cost may represent the fair market value claimed when the third party provider applied for a Section 1603 Treasury Grant or federal investment tax credit. The Treasury Department's guidelines for assessing the cost basis of solar properties identifies three allowable methods for assessing fair market value: the cost approach (based on the actual cost to install the project), the market approach (based on the sale price of comparable properties), or the income approach (based on the discounted value of future cash flows generated by and appropriately allocable to the eligible property). For additional information, see: http://www.treasury.gov/initiatives/recovery/Documents/Evaluating_Cost_Basis_for_Solar_PV_Properties%20final.doc

[8] For the purpose of this report, "behind-the-meter" PV refers to systems that are connected on the customer-side of the meter, typically under a net metering arrangement. Conversely, "utility-sector" PV consists of systems connected directly to the utility system, and therefore includes a number of rooftop wholesale distributed generation projects.

Text Box 1. Reasons for Deviations between Historical PV Cost Data and Current Cost Benchmarks

Various entities, including the Department of Energy, routinely publish benchmarks for the current cost of PV systems in the United States. The results presented in this report, however, are likely to differ from cost benchmarks issued near the time of report publication, for a variety of reasons. Differences may arise, in part, due to issues of timing. This report focuses on systems installed through the end of 2010, and the reported cost for those systems in some cases likely reflects module and other component pricing at the time that the installation contract was signed (which could precede the installation date by one year or more for relatively large projects). In contrast, current cost benchmarks are generally based on current module and other component prices, which may be significantly lower than the module and other component prices underlying the historical installed cost data presented in this report. Preliminary data for systems installed through the California Solar Initiative in the first half of 2011, for example, show that installed costs have continued to fall, relative to the values cited in this report for systems installed in 2010.

The historical cost data presented in this report may also differ from current cost benchmarks for a number of other reasons, depending upon how the benchmarks are constructed:

- *System size*: The historical data are based on the system size distribution of projects within the data sample, which reflect the size distribution of actual installed projects to date. Current cost benchmarks may, instead, be based on prototypical system sizes for individual market segments, which may differ significantly from actual average historical system sizes.
- *Utility-sector PV definition*: This report classifies all projects connected directly to the utility system as "utility-sector PV," and therefore the data sample includes a number of wholesale distributed PV systems that are considerably smaller than typical "utility-scale" systems.
- *Atypical utility-sector PV project characteristics*: The historical data includes a number of "one-off" utility-sector projects with unique characteristics that likely increased project costs (e.g., brownfield developments, systems built to withstand hurricane winds, utility pole-mounted systems, etc.). Current cost benchmarks are, instead, generally based on more prototypical project characteristics.
- *Geographic location*: The historical data reflect the geographical distribution of the population of installed PV projects in the data sample, which is weighted heavily towards states with relatively high labor and/or permitting costs (California and New Jersey). Current cost benchmarks may, instead, be based on national average costs.
- *PV component selection*: The historical data are based on the actual distribution of PV module and other component models employed within the installed projects in the data sample; the utility-sector systems in the data sample, in particular, include many systems with high-efficiency (and relatively high-cost) modules. Current cost benchmarks may, instead, be based on average component prices across the range of models available.
- *Inefficient pricing*: Current cost benchmarks are based on stipulated developer/owner profit margins. The historical cost data, in contrast, are based on whatever profit margin the developers/owners were able to capture or willing to accept, and in some cases represent the "fair market value" assessed by third-party owners. In markets with barriers to entry, developers and/or third-party owners may be able to price their projects above the theoretically "efficient" level based on underlying project costs. Conversely, some developers may be willing to accept "below-market" profit in order to capture market share. In either case, the underlying profit margin embedded in the historical cost data may differ from the assumptions within current PV cost benchmarks.

2. Data Summary

The analysis presented in this report is derived from project-level data for behind-the-meter and utility-scale PV systems collected from a variety of sources. This section describes the data sources and the procedures used to standardize and clean the data, and then summarizes the basic characteristics of the data sample, including: the number of systems and installed capacity; the sample size relative to the total U.S. grid-connected PV market; and the distribution of behind-the-meter and utility-sector PV systems in the sample by year, state, and project size.

Data Sources

Data for behind-the-meter systems were sourced primarily from state and utility PV incentive program administrators. Ultimately, 32 PV incentive program administrators, spanning 22 states, provided project-level installed cost data for PV systems funded through both current and previous programs.[9] These data represent 99% of all behind-the-meter PV systems and 95% of all behind-the-meter PV capacity in the data sample. Project-level data for behind-the-meter PV were also obtained from the U.S. Treasury Department's Section 1603 Grant Program, and were used in the analysis only if not already included within the data provided by PV incentive program administrators.[10] Finally, data for a limited number of large behind-the-meter PV systems that are not included within the other data sources were obtained from news and trade press articles.

Data for utility-sector systems were collected from a diverse set of sources, including the Section 1603 Grant Program, FERC Form 1 filings, SEC filings, company presentations, and trade press articles.

Data Standardization and Cleaning

To the extent possible, this report presents the data as provided directly by the aforementioned sources; however, several steps were taken to standardize and clean the raw data, as briefly summarized here and described in greater detail in Appendix A. Two key conventions used throughout this report and applicable to all systems deserve specific mention:

1. All cost and incentive data are presented in real 2010 dollars (2010$), which required inflation adjustments to the nominal-dollar data provided by PV programs.
2. All capacity and dollars-per-watt ($/W) data are presented in terms of rated module power output under Standard Test Conditions (DC-STC), which required that capacity data provided by several PV incentive programs that use a different capacity rating be translated to DC-STC.[11]

[9] PV incentive program administrators generally provided data to LBNL in the form of Excel spreadsheets. A number of these program administrators use PowerClerk, a commercial database product for PV incentive program tracking. We acknowledge that the use of PowerClerk and other similar products has likely increased the quantity and quality of data available for this analysis.
[10] To avoid double-counting systems that are also contained in the data provided by PV incentive program administrators, Section 1603 data was used only for states that are not covered by any of the PV incentive programs and for large projects that were clearly not included within the PV incentive program data.
[11] Various permutations of rating conventions may be used to describe the size of PV systems. The most common rating used by PV incentive programs is the total nameplate capacity of the PV modules in direct current (DC) watts under standard test conditions (STC). This is the rating convention used throughout this report. Alternatively, PV

A number of additional steps were required to clean and standardize the data on behind-the-meter systems provided by PV incentive program administrators (described further in Appendix A). First, projects with clearly erroneous cost or incentive data or with missing cost or system size data were eliminated from the data sample. The remaining data were cleaned by correcting text fields with obvious errors and by standardizing identifiers for module and inverter models. To the extent possible, each PV project contained in the PV incentive program data was classified as either building-integrated PV or rack-mounted and as using either crystalline or thin-film modules, based on a combination of information sources. Finally, data on market sector (e.g., residential, commercial, government, non-profit) were not provided for roughly 27% of the systems in the PV incentive program data; for the purpose of calculating the value of state and federal investment tax credits and net installed costs, systems ≤10 kW were assumed to be residential, and systems >10 kW were assumed to be commercial, if not identified otherwise.[12]

For behind-the-meter and utility-sector systems included in the Section 1603 Grant Program database where project cost data were not available from other sources, we estimated project cost based on the reported Section 1603 grant amount, by assuming that the grant is equal to 30% of total project costs.[13]

Sample Description

The final dataset, after all data cleaning was completed, consists of more than 116,500 behind-the-meter PV systems totaling 1,400 MW, and 31 utility-sector PV systems totaling 285 MW (see Table 1). The behind-the-meter PV systems were installed over a 13-year period, from 1998 through 2010; however, given the dramatic expansion of the U.S. solar market in recent years, the sample is skewed heavily towards projects completed during the latter years of the study period. See Appendix B for annual installation data disaggregated by system size range and by PV incentive program. The utility-sector systems have primarily been installed during the last two years of the study period.

The combined 1,685 MW of behind-the-meter and utility-sector PV in the data sample represents approximately 79% of all cumulative grid-connected PV capacity installed in the United States through 2010, and about 73% of 2010 annual capacity additions (see Figure 1). Coverage is somewhat stronger within the behind-the-meter market segment, where the data sample represents 79% of cumulative installations through 2010 and 75% of 2010 capacity additions. Within the utility-sector market segment, the data sample represents 76% of cumulative capacity through 2010 and 69% of 2010 capacity additions. The gap between the final cleaned data sample and the total U.S. grid-connected PV market consists of: PV systems that were dropped from our data sample due to data quality issues, behind-the-meter PV systems not funded by any of the PV incentive programs that contributed data to the analysis, and utility-sector PV systems for which reliable cost data could not be obtained.[14]

---

system sizes may be denominated in terms of DC watts under PVUSA test conditions (PTC), or in terms of alternating current (AC) watts under either STC or PTC.

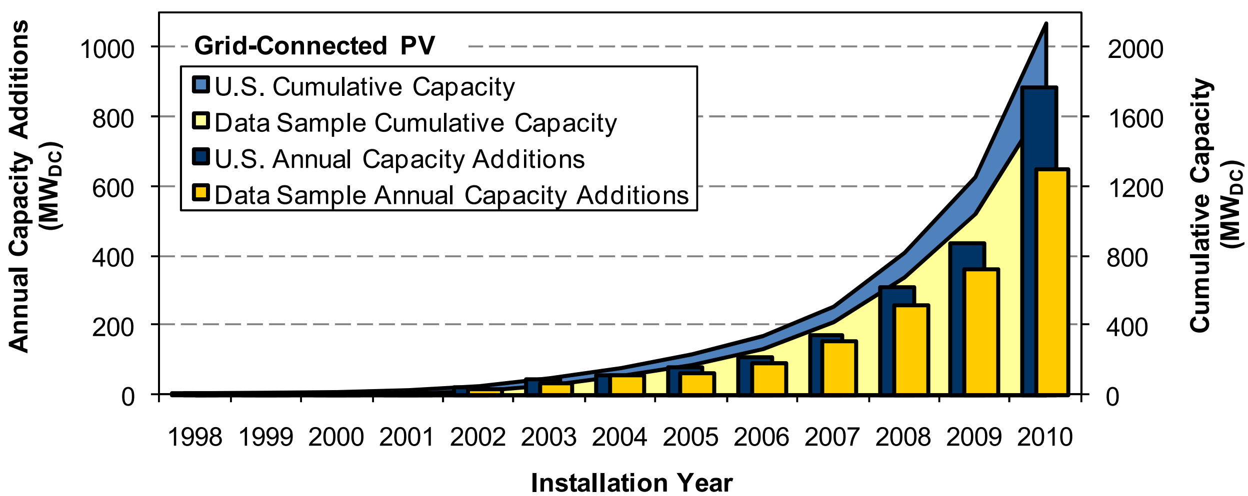
[12] 10 kW is a common, albeit imperfect, cut-off between residential and commercial PV systems.

[13] We acknowledge that this is a highly simplified assumption and ignores that (a) some project costs may be deemed ineligible for the grant, in which case the grant amount would be *less* than 30% of total project costs, and that (b) the grant amount for some projects may be based on their "fair market value," which may be *greater* than the price paid by the project owner.

[14] For example, 2010 PV capacity additions missing from the data sample consist primarily of: a single large utility-sector PV project for which reliable cost data could not be obtained (the 55 MW Copper Mountain project in Nevada),

Table 1. Data Sample by Installation Year and Market Segment

Installation Year	No. of Systems			Capacity (MW_{DC})		
	Behind-the-Meter	Utility	*Total*	Behind-the-Meter	Utility	*Total*
1998	39	0	*39*	0.2	0	*0.2*
1999	185	0	*185*	0.8	0	*0.8*
2000	224	0	*224*	1.0	0	*1.0*
2001	1,323	0	*1,323*	5.5	0	*5.5*
2002	2,540	0	*2,540*	16	0	*16*
2003	3,594	0	*3,594*	34	0	*34*
2004	5,641	2	*5,643*	45	8	*53*
2005	5,598	0	*5,598*	62	0	*62*
2006	8,788	0	*8,788*	91	0	*91*
2007	12,892	2	*12,894*	132	22	*155*
2008	14,476	3	*14,479*	238	18	*256*
2009	25,335	4	*25,339*	307	56	*363*
2010	35,869	20	*35,888*	466	180	*646*
Total	***116,504***	***31***	***116,535***	***1,400***	***285***	***1,685***



Data sources for U.S. grid-connected PV capacity additions: Larry Sherwood (Interstate Renewable Energy Council) and SEIA/GTM.

Figure 1. Data Sample Compared to Total U.S. Grid-Connected PV Capacity

Geographical and Size Distribution: Behind-the-Meter PV

The data sample includes behind-the-meter systems spanning 42 states. The majority of these systems are associated with current and historical PV incentive programs in California and New Jersey. As such, the behind-the-meter PV capacity in the data sample is heavily weighted towards these two states, which represent 61% and 15% of the sample, respectively, in terms of total installed behind-the-meter capacity (see the left-hand chart in Figure 2). Arizona, Massachusetts, Pennsylvania, Connecticut, and New York each represent 2-5% of the sample capacity, with the

behind-the-meter and utility-sector PV projects that participated in New Jersey's SREC registration program but did not submit cost data to the Market Monitor (roughly 50 MW in 2010), and behind-the-meter PV installations funded through incentive programs in Colorado and Hawaii for which cost data was not provided (45 MW and 17 MW, respectively).

remaining 35 states comprising 9% in aggregate. The U.S. PV market has diversified significantly in recent years, however, and this is reflected in the geographical distribution of the 2010 capacity additions in the data sample, as shown on the right-hand chart in Figure 2. Of particular note, California represents a significantly smaller share (41%) of this sub-set of the data sample, with correspondingly greater representation among the other leading state markets.[15]

Behind-the-meter PV systems in the data sample span a wide size range, from as small as 100 W to as large as 6 MW. In terms of the number of projects, the vast majority are relatively small systems, with roughly 90% of the projects ≤10 kW in size (see Figure 3). In terms of installed capacity, however, the sample is considerably more evenly distributed across system size ranges, with 47% of the total installed capacity in the data sample consisting of systems >100 kW, and 34% of the sample capacity consisting of systems ≤10 kW. Section 3 presents additional information describing how the distribution of the sample across system size ranges has evolved over time.

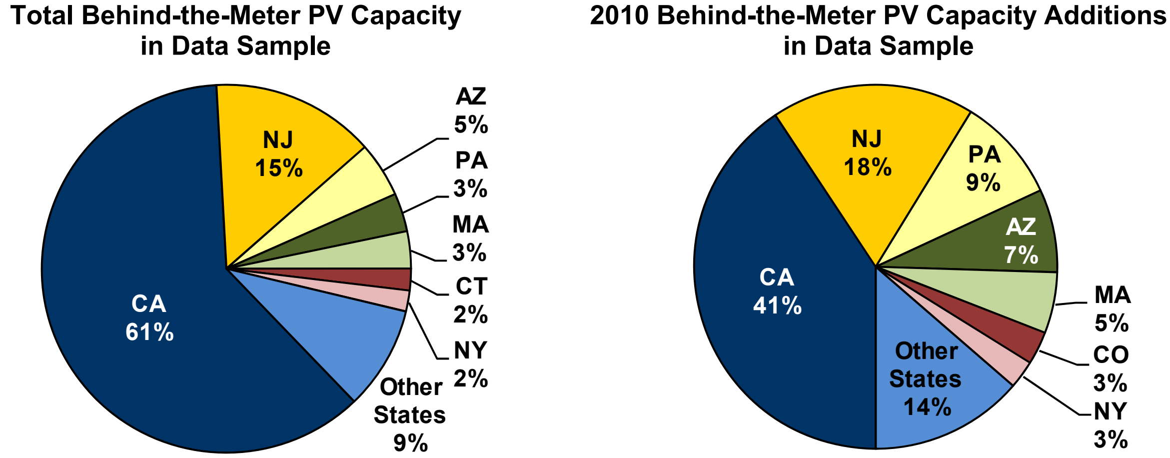


Figure 2. Behind-the-Meter PV Sample Distribution among States

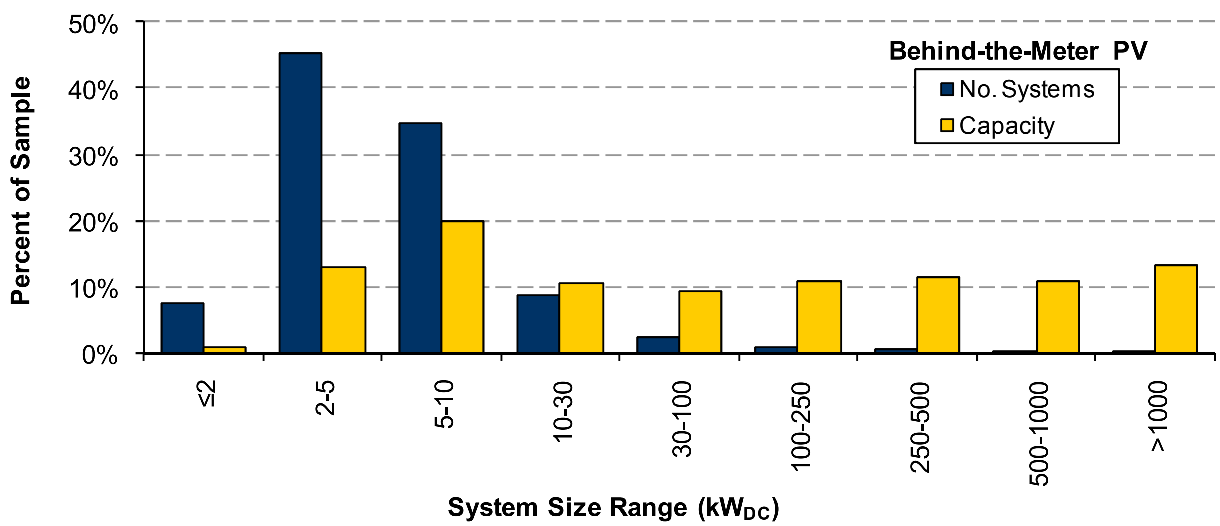


Figure 3. Behind-the-Meter PV Sample Distribution by System Size

[15] The distribution of behind-the-meter systems in the data sample comports reasonably well with the geographical distribution of the overall U.S. PV market. In 2010, SEIA/GTM report that behind-the-meter PV capacity additions in the United States were distributed among California (38%), New Jersey (18%), Arizona (8%), Pennsylvania (7%), Colorado (6%), New York (4%), Massachusetts (3%), and all other states (16%).

Geographical and Size Distribution: Utility-Sector PV

The 31 utility-sector PV systems in the data sample are located in a total of thirteen states, with 75% of the capacity distributed across six of these states (Florida, California, New Mexico, New Jersey, Colorado, and Nevada), as shown in Figure 4.[16] The remaining 25% of the sample capacity is distributed across Arizona, Illinois, Massachusetts, North Carolina, Pennsylvania, and Texas.

The size of the utility-sector PV systems in the data sample ranges from 500 kW to 34.4 MW. As indicated in Figure 5, the utility-sector PV data sample is split roughly in half between systems that are smaller than 5 MW and those that are larger than that size. The sample thus includes a fair number of small systems (both ground-mounted and roof-mounted) that would not typically be considered "utility-*scale*", though they are classified for the purposes of this report as "utility-*sector*," as they are connected directly to the utility system, rather than on the customer-side of the meter. Naturally, the large systems represent a disproportionately large share of the utility-sector PV capacity in the data sample, with 38% of this capacity consisting of systems larger than 20 MW, and roughly 78% consisting of systems larger than 10 MW.

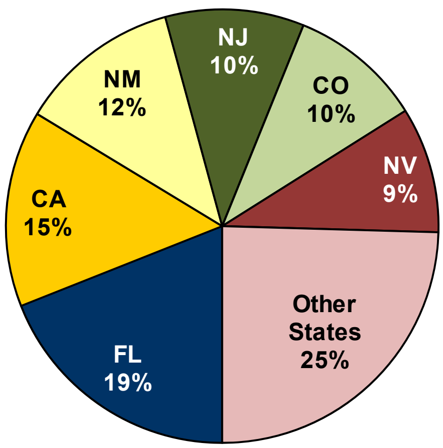


Figure 4. Utility-Sector PV Sample Distribution among States (Total Capacity)

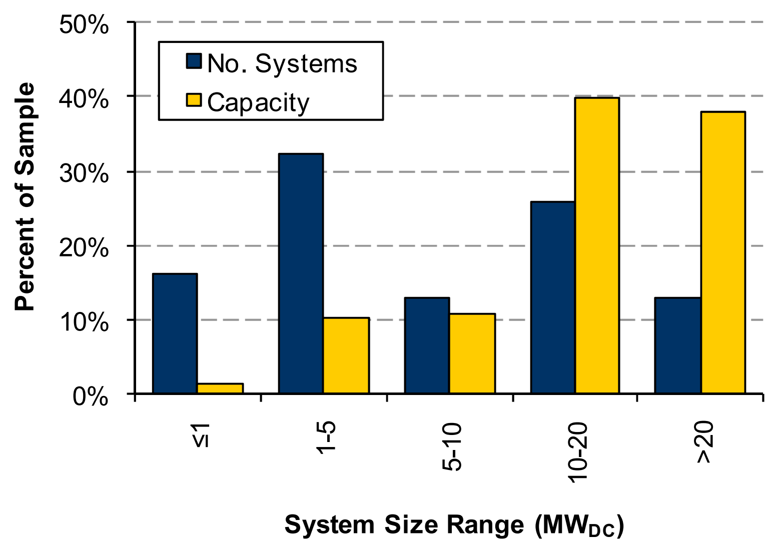


Figure 5. Utility-Sector PV Sample Distribution by System Size

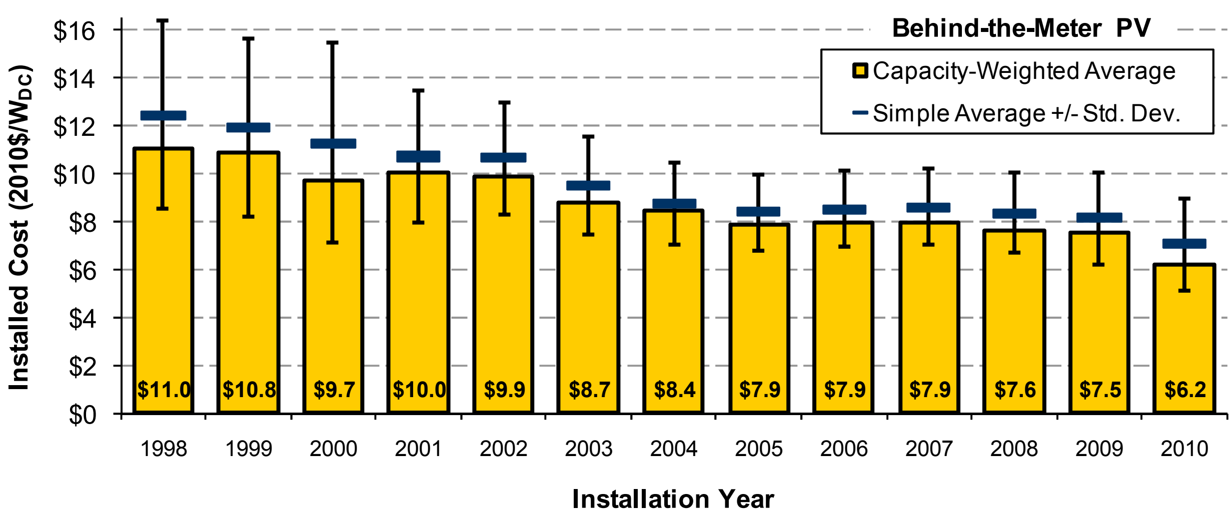
[16] The geographical distribution of the data sample differs from that of the total population of utility-sector PV systems in the U.S., as the data sample is missing a single large utility-sector PV project in Nevada, as well as a number of smaller projects in other states. Also, note that the 14.2 MW$_{DC}$ PV system at Nellis Air Force Base in Nevada is classified as a utility-sector PV system, even though it is connected on the customer-side of the meter. The same classification is used in the SEIA/GTM *U.S. Solar Market Insight* report series.

3. Installed Cost Trends: Behind-the-Meter PV

This section describes trends in the average installed cost of grid-connected, *behind-the-meter* PV systems (i.e., residential and commercial PV), based on the dataset described in Section 2, and the cost data represent reported installed costs, prior to receipt of any financial incentives (e.g., rebates, tax credits, etc.). The present section begins by describing trends in installed costs over time; by system size; by component; among the United States, Germany, and Japan; among individual states; between customer-owned and third party-owned systems; and among customer types (residential, commercial, and tax-exempt). It then compares installed costs across several types of applications and technologies – specifically, residential new construction vs. residential retrofit, BIPV vs. rack-mounted systems, systems with thin-film modules vs. those with crystalline modules, systems with varying module efficiencies, and tracking vs. fixed-tilt systems.

Overall Average Installed Costs Declined Precipitously from 2009 to 2010

Figure 6 presents the average installed cost of <u>all</u> behind-the-meter projects in the data sample installed from 1998 through 2010. Over the entirety of this thirteen-year period, capacity-weighted average installed costs declined by \$4.8/W (43%) in real 2010 dollars, from \$11.0/W in 1998 to \$6.2/W in 2010.[17] This represents an average annual reduction of \$0.4/W (4.6%) per year; however, cost reductions over this 13-year period did not occur at a steady pace. Average costs first fell by a substantial amount over the 1998-2005 period, but then stagnated through 2009, as the PV supply-chain struggled to keep pace with surging worldwide demand, despite continued upstream cost reductions. The fruits of industry expansion over the preceding years were clearly revealed in 2010, with average installed costs declining by 17% (or \$1.3/W) relative to 2009, the largest year-over-year reduction over the entirety of the historical analysis period. As shown in Text Box 2, preliminary data for the first half of 2011 indicates that installed costs continued to rapidly decline into 2011.



Notes: See Table 1 for behind-the-meter PV sample size by installation year.

Figure 6. Average Installed Cost over Time for Behind-the-Meter PV

[17] As indicated by the standard deviation bars in Figure 6, the *distribution* of installed costs across projects narrowed considerably from 1998 to 2004. This convergence of prices is consistent with a maturing market characterized by increased competition among installers and module manufacturers and by better-informed consumers.

Text Box 2. Installed Cost Trends for the CSI Program in the First Half of 2011

Figure 7 compares the average installed cost of projects funded through the California Solar Initiative (CSI) in 2010 and in the first six months of 2011. As shown, the overall capacity-weighted average installed cost fell by $0.7/W or 11% from 2010 to the first half of 2011. If cost declines were to continue at this pace through the remainder of 2011, it would equate to a 22% year-over-year drop, which exceeds even the historic reduction witnessed in 2010.

Comparing across system sizes, the cost decline for CSI projects was greatest for the largest of the three system size categories shown, with the average installed cost of systems >100 kW falling by $1.0/W or 15% from 2010 to the first half of 2011. Average installed cost fell by $0.5/W for ≤10 kW systems and by $0.3/W for 10-100 kW systems.

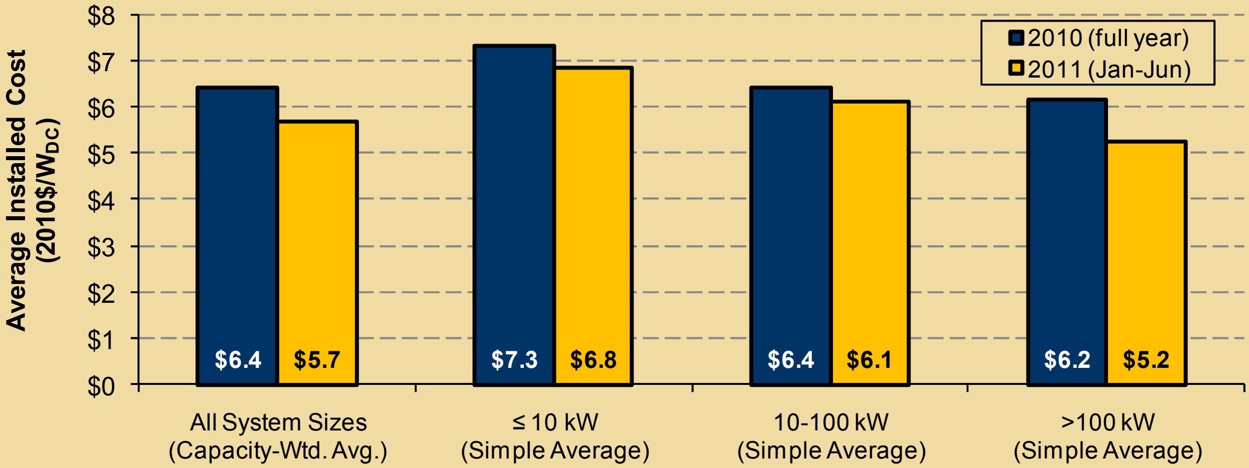
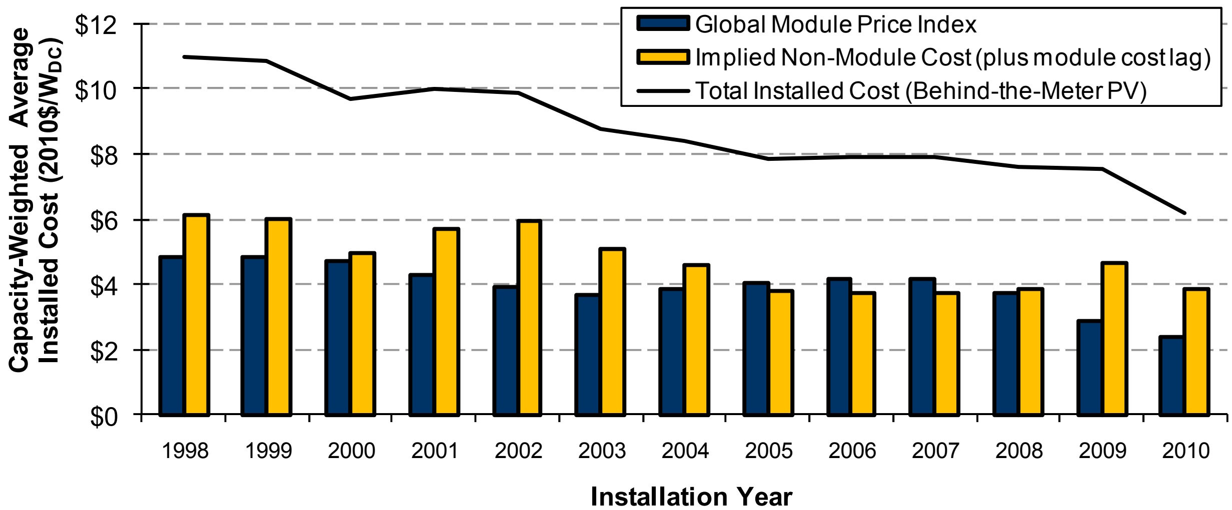


Figure 7. Average Installed Costs in the CSI Program: 2010 vs. the First-Half of 2011

The Installed Cost Decline in 2010 Followed Several Years of Falling Module Prices

Figure 8 compares the total capacity-weighted average installed cost of the systems in our data sample to Navigant Consulting's Global Power Module Price Index, which represents average *wholesale* PV module prices in each year. Over the entirety of the analysis period, the module price index fell by $2.5/W (51%), from $4.8/W in 1998 to $2.4/W in 2010. This price reduction represents 52% of the total decline in average installed costs over this period, confirming that module price reductions are a significant, but by no means the only, factor underlying the long-term decline in average installed costs.

Focusing on the more-recent past, Figure 8 shows that the module index began a steep decline after 2008, falling by $0.9/W from 2008 to 2009 and by $0.5/W from 2009 to 2010, for a total drop of $1.4/W (37%) from 2008-2010 (and module price declines have continued into 2011). The fact that the total average installed cost of behind-the-meter systems did not begin to fall until 2010 may reflect any number of underlying market dynamics, including: differences in time between when installation contracts are signed and when systems are actually installed, excess module inventory by system integrators, capacity constraints among installers or non-module component manufacturers, a lack of competitive pressure in particular markets, or a divergence between global and domestic wholesale module prices (e.g., if low-cost module suppliers were preferentially selling outside of the United States).



Notes: "Implied Non-Module Cost (plus module cost lag)" is calculated as the reported Total Installed Cost minus Navigant Consulting's Global Module Price Index.

Figure 8. Average Installed Cost, Module Price Index, and Implied Non-Module Costs over Time for Behind-the-Meter PV

Figure 8 also presents the "implied" non-module costs paid by PV system owners – which may include such items as inverters, mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and installer profit. Implied non-module costs are calculated simply as the difference between the average total installed cost and the wholesale module price index in the same year; these calculated non-module costs therefore ignore the effect of any lag between movements in the wholesale module price index and actual module costs associated with PV systems installed each year. The fact that the analytical approach used in this figure cannot distinguish between actual non-module costs as paid by PV system owners and a lag in module costs makes it challenging to draw conclusions about movements in non-module costs over short time periods. Over the longer-term, however, Figure 8 clearly shows that implied non-module costs have declined significantly over the entirety of the historical analysis period, dropping by approximately $2.3/W (37%), from $6.1/W in 1998 to an estimated $3.8/W in 2010. Given the manner in which implied non-module costs are calculated, the *actual* decline in non-module costs over the 1998-2010 period could be greater than the amount identified here, to the extent that retail installed costs in 2010 did not completely absorb declines in wholesale module prices through 2010.

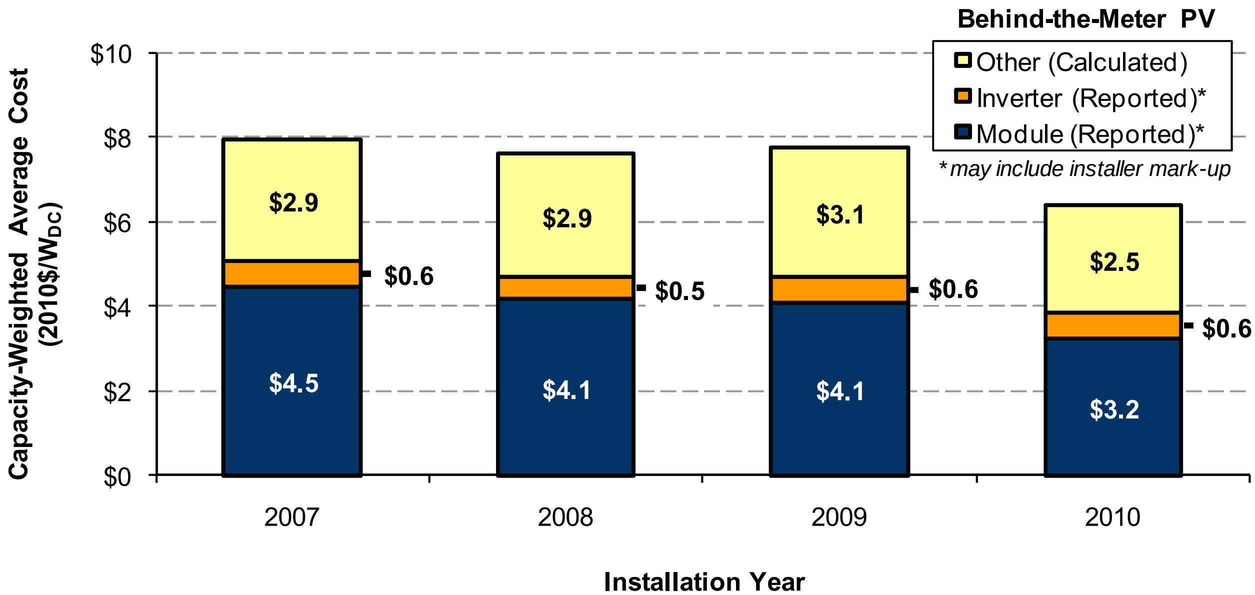
The Installed Cost Decline in 2010 Was Also the Result of Balance-of-System Cost Reductions

To discern recent changes in non-module costs for behind-the-meter PV, Figure 9 presents capacity-weighted average module, inverter, and all other costs, *as reported by PV installers* to a subset of the PV incentive program administrators in the sample.[18] It is important to note that the installer-reported module and inverter costs may include some mark-up and/or may reflect wholesale component prices at the time that the installation contract was signed (rather than at the

[18] Most of the component-level cost data is associated with systems funded through the CSI, but component-level cost data were also provided by five other PV incentive program administrators. Insufficient component-level data exists for years prior to 2007 for inclusion in the figure.

time the project was installed). Therefore, the installer-reported module and inverter cost data presented in Figure 9 should not be interpreted to represent the average wholesale prices for those components at the time of project installation.

As shown, average “other” (i.e., non-module/non-inverter) costs remained effectively flat over the 2007-2009 period, before declining by roughly \$0.6/W (18%) from 2009 to 2010. This year-over-year reduction in non-module/non-inverter costs represents roughly 40% of the total decline in average installed costs in 2010 for this subset of behind-the-meter systems, indicating that the overall decline in the installed cost of behind-the-meter PV in 2010 was the result of reductions in both module costs and non-module/non-inverter costs.[19] Figure 9 is also consistent with the earlier suggestion that the underlying module costs for installed PV systems “lag” behind movements in wholesale module prices, as the average installer-reported module costs shown in Figure 9 remained flat from 2008 to 2009 (when wholesale module prices fell by \$0.9/W, as shown previously in Figure 8), before falling by \$0.9/W in the following year.



Notes: The figure is based on those systems for which PV incentive program administrators provided installer-reported module and inverter cost data, consisting of 52% of all behind-the-meter systems in the data sample installed from 2007-2010. “Other” costs are calculated as the difference between the reported total installed cost for each system and the reported module and inverter costs. Installer-reported module and inverter cost data presented here should not be interpreted to represent the wholesale prices for those components at the time of project installation, as these data likely include some mark-up and/or may reflect wholesale component prices at the time that the installation contract was signed (rather than at the time the project was installed).

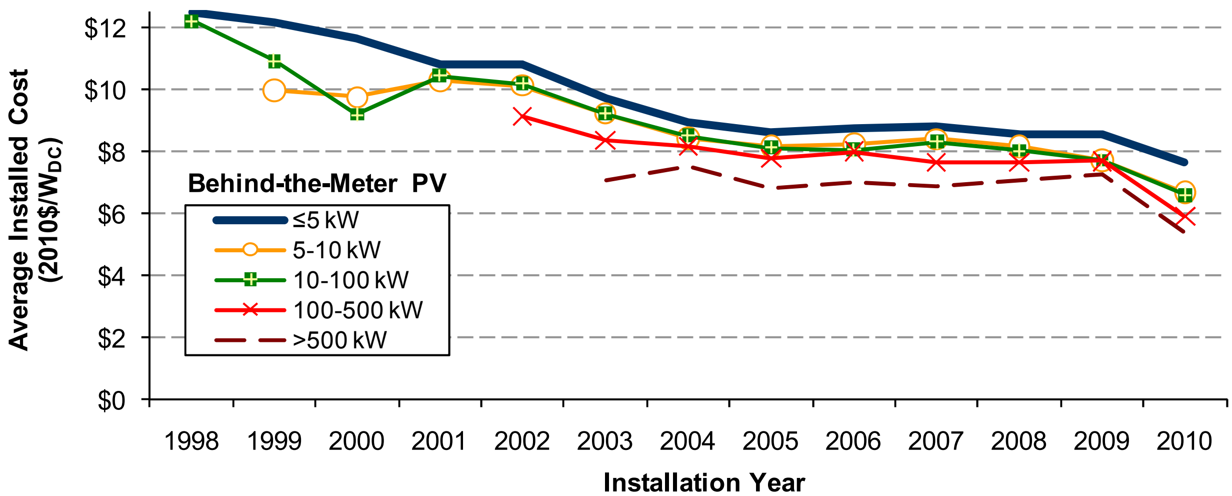
Figure 9. Installer-Reported Component-Level Costs over Time for Behind-the-Meter PV

Installed Cost Reductions in 2010 Were Greatest for Large Systems

Average installed costs for behind-the-meter PV systems declined across all size ranges from 2009 to 2010, but the cost reductions were substantially greater for relatively large systems (see Figure 10). Specifically, average installed costs declined by \$1.8/W (23%) and \$1.9/W (26%), respectively, for systems in the 100-500 kW and the >500 kW size ranges. In comparison, the

[19] Average installer-reported inverter costs, however, did not decline significantly in 2010, nor did they decline over the longer 2007-2010 period.

average installed cost of ≤5 kW systems declined by \$0.9/W (11%), while average costs for 5-10 kW and 10-100 kW systems declined by \$1.0/W (13%) and \$1.1/W (14%), respectively. The fact that larger systems experienced larger cost reductions in 2010 may be the result of greater competition or more-informed consumers within the large PV market, causing reductions in wholesale module prices to flow through more quickly or more fully to the system purchaser and/or leading to accelerated reductions in non-module costs. However, one must also be cautious in overstating the importance of year-over-year comparisons across system sizes, given differences in the lead times between small and large projects. Over the two-year period from 2008 to 2010, average installed costs declined by similar amounts across all but the smallest size range – suggesting that, in fact, the underlying cost drivers may have dropped by similar amounts across system sizes, though the observable effect on installed costs may have been somewhat delayed for the largest systems.



Notes: Averages shown only if five or more observations were available for a given size category in a given year. For sample sizes, refer to Table B-1 in the Appendix.

Figure 10. Installed Cost Trends over Time for Behind-the-Meter PV, by PV System Size

From 1999-2010, the average installed cost of systems ≤5 kW dropped by \$4.5/W, from \$12.1/W to \$7.6/W, while the average cost of systems in the 5-10 kW and 10-100 kW size ranges dropped by \$3.3/W and \$4.3/W, respectively. It is less apparent to what extent larger systems experienced cost reductions over the 1999-2010 period, given limited data availability for the early years of the analysis period. Over the historical periods for which sufficient data are available, the average cost of systems 100-500 kW declined by \$3.2/W (2002-2010), while the average cost of systems >500 kW decreased by \$1.7/W (2003-2010).

Installed Costs Exhibit Economies of Scale

Large PV installations may benefit from economies of scale through price reductions on volume purchases of materials and the ability to spread fixed costs and transaction costs over a larger number of installed watts. This expectation has generally been borne out in experience, as evident in Figure 10 from the preceding section. This trend is observed with greater resolution in Figure 11, which shows the average installed cost according to system size for all behind-the-meter PV systems completed in 2010. The smallest systems in Figure 11 (≤2 kW) exhibit the highest average installed cost (\$9.8/W), while the largest systems (>1000 kW) have the lowest average cost

($5.2/W, or about 47% below the average cost of the smallest systems). Interestingly, economies of scale do not appear to be continuous with system size, but rather, most strongly accompany increases in system size up to 5 kW (as shown more clearly in Figure 12, which focuses on systems up to 10 kW in size) and increases in system size beyond 100 kW. In contrast, the data do not show evidence of significant economies of scale within the 5-100 kW size range, perhaps reflecting the lower degree of standardization among small and mid-sized commercial systems compared to residential systems.

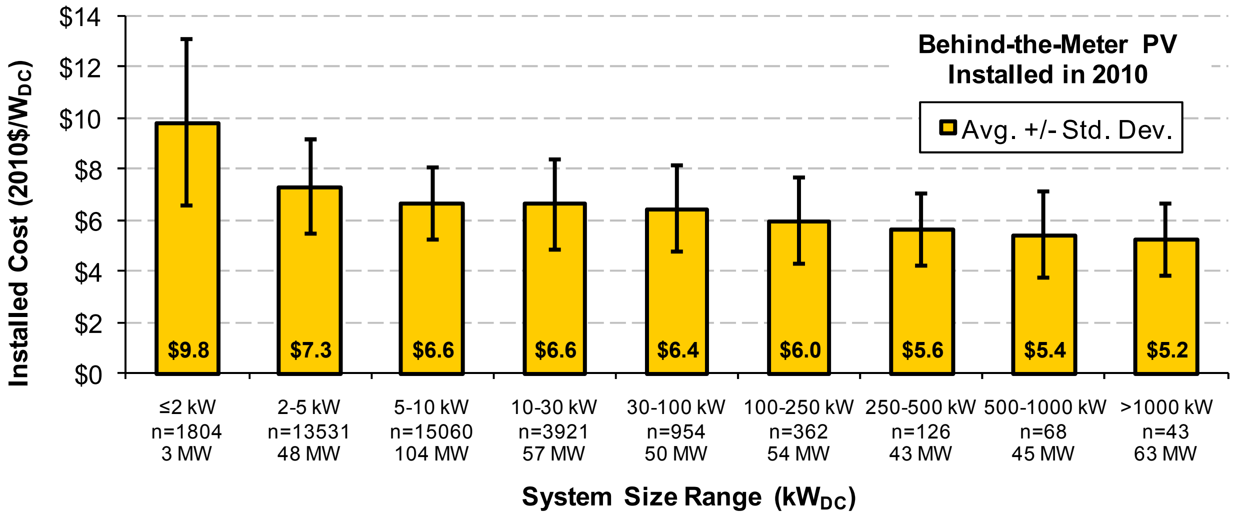


Figure 11. Variation in Installed Cost of Behind-the-Meter PV According to System Size (All Sizes)

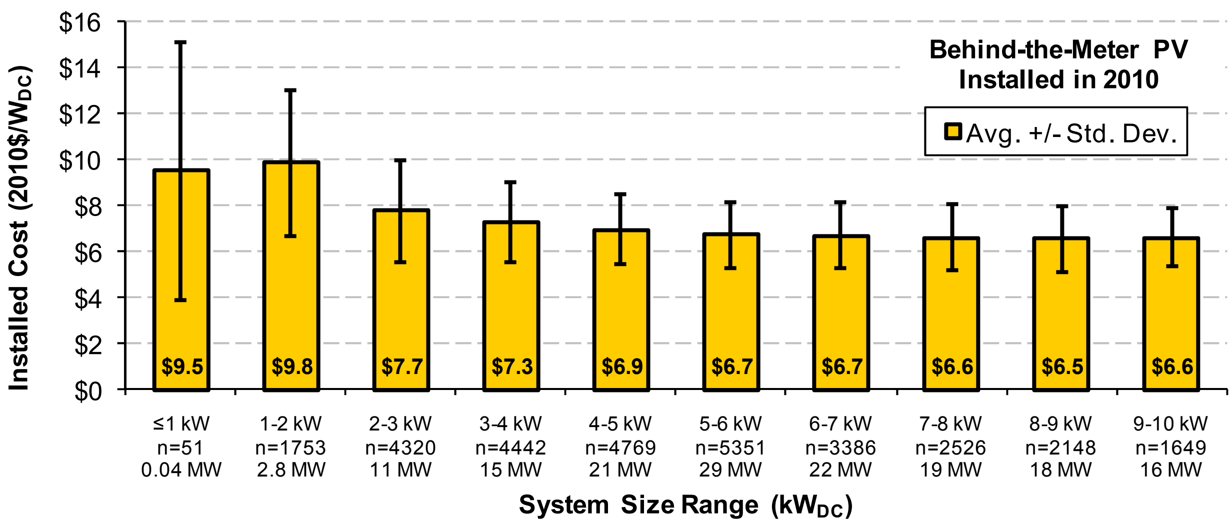


Figure 12. Variation in Installed Cost of Behind-the-Meter PV According to System Size (≤10 kW)

The economies of scale exhibited in Figure 11 and Figure 12 partially explain the decline in capacity-weighted average installed costs shown previously in Figure 6. As Figure 13 shows, an increasing portion of behind-the-meter PV capacity installed each year has consisted of relatively large systems (though the trend is by no means steady). For example, systems in the >500 kW size range represented more than 20% of behind-the-meter PV capacity in the data sample installed in 2010, compared to 0% in 1998-2001. Conversely, systems <100 kW represented 100% of the capacity installed in 1998 but only 55% of the 2010 capacity additions. The shift in the size distribution is reflected in the increase in average size of behind-the-meter systems from 5.5 kW in 1998 to 13.0 kW in 2010.[20] Though the increasing size of PV systems may have contributed to the temporal decline in capacity-weighted average costs shown in Figure 6, the trend shown previously in Figure 10 clearly demonstrates that this is not the only factor, as cost reductions have occurred across all system sizes.

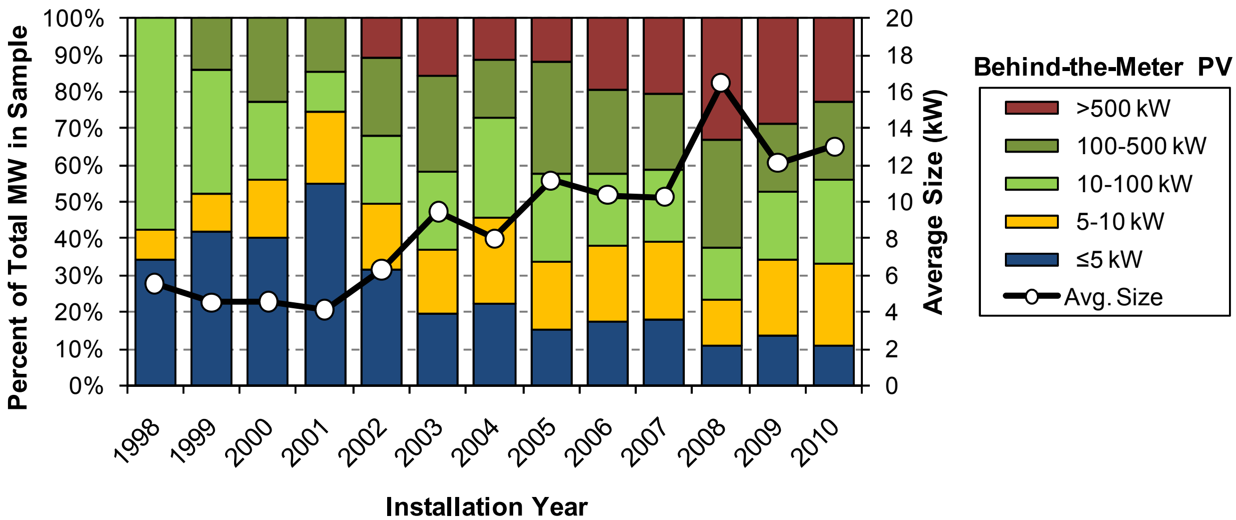
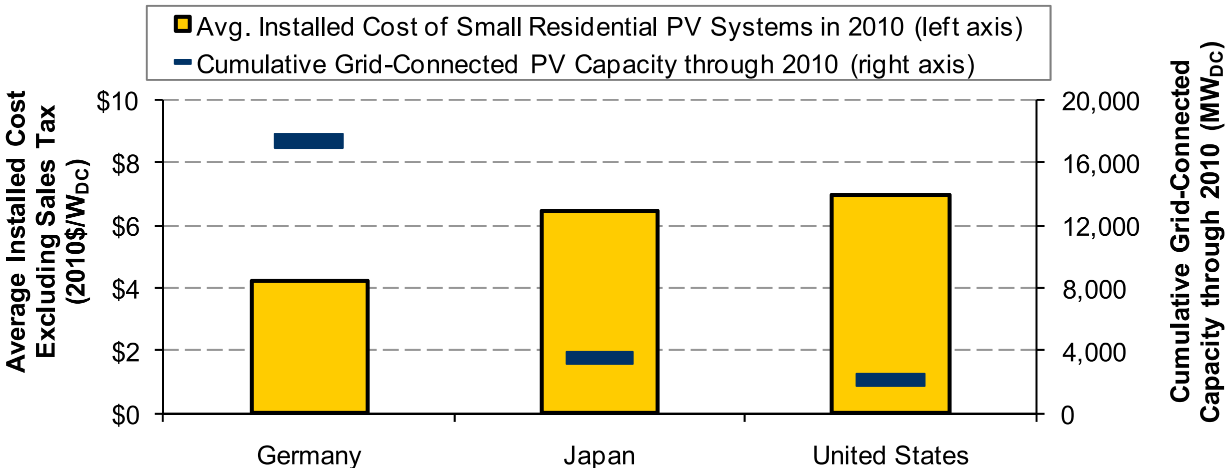


Figure 13. Behind-the-Meter PV System Size Trends over Time

Average Installed Costs for Residential Systems Are Substantially Lower in Germany than in the United States

Notwithstanding the significant cost reductions that have already occurred in the United States, international experience suggests that greater near-term cost reductions may be possible. Figure 14 compares average installed costs, excluding sales or value-added tax, in Germany, Japan, and the United States, focusing specifically on *small* residential systems (either 2-5 kW or 3-5 kW, depending on the country) installed in 2010.[21] Among this class of systems, the average installed cost in the United States ($6.9/W) was substantially greater than the average for Germany ($4.2/W), but was comparable to the average in Japan ($6.4/W). This variation across countries may be partly attributable to differences in cumulative grid-connected PV capacity in each national market, with roughly 17,000 MW installed in Germany through 2010, compared to 3,500 MW and 2,100 MW in Japan and the United States, respectively. That said, larger market size, alone, is unlikely to account for the entirety of the differences in average installed costs among countries.[22]

[20] Among systems for which customer segment data were provided, the average size of residential PV rose from 3.0 kW in 2001 to 5.9 kW in 2010, and the average size of non-residential PV rose from 65.6 kW in 2001 to 87.2 kW in 2010.
[21] Comparable data for Italy, the second largest global PV market in 2010, were not available at the time of report publication.
[22] Installed costs may differ among countries as a result of a wide variety of factors, including differences in: incentive levels; module prices; interconnection standards; labor costs; procedures for receiving incentives, permitting, and interconnection approvals; foreign exchange rates; local component manufacturing; and average system size.



Notes: Data for Germany and Japan are based on the most-recent respective country reports prepared for the International Energy Agency Cooperative Programme on Photovoltaic Power Systems. The German and U.S. cost data are for 2-5 kW systems, while the Japanese cost data are for 3-5 kW systems. The German cost data represents the average of reported year-end installed costs for 2009 ($4.7/W) and 2010 ($3.7/W).

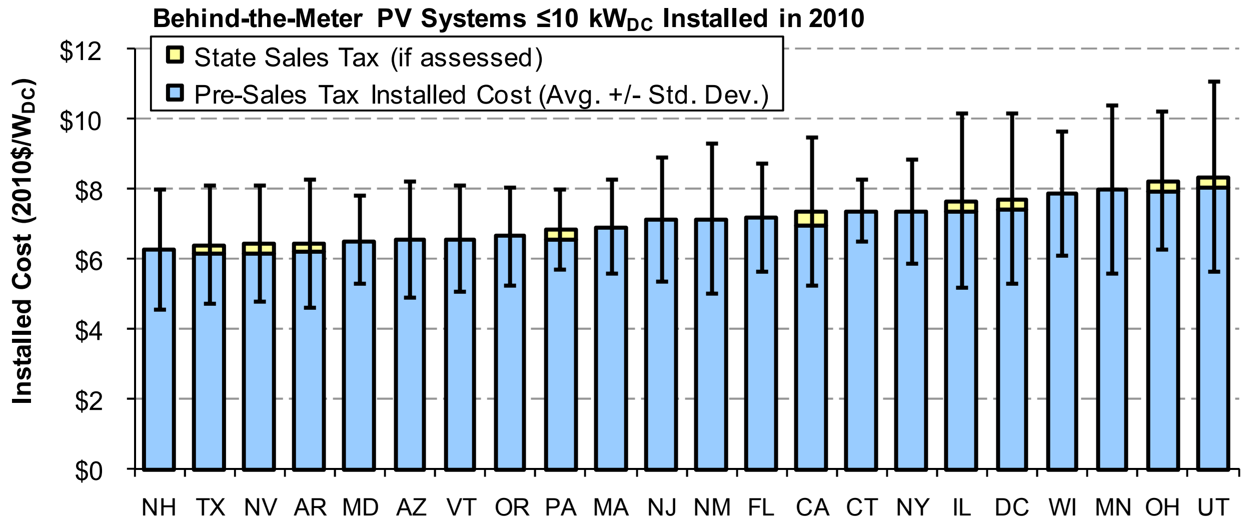
Figure 14. Comparison of Average Installed Costs (Pre-Sales Tax/VAT) for Small Residential PV Systems in Germany, Japan, and the United States

Installed Costs Vary Widely Across States

The United States is clearly not a homogenous PV market, as evidenced by Figure 15, which compares the average installed cost of systems ≤10 kW completed in 2010, across 22 states in our dataset. Among systems in this size class, average costs range from a low of $6.3/W in New Hampshire to a high of $8.4/W in Utah. Table 2 presents the same data in tabular form, along with comparative data for other system size ranges and groupings.

Differences in average installed costs across states may partially be the result of the differing size and maturity of the PV markets, where larger markets stimulate greater competition and greater efficiency in the delivery chain, and may also allow for bulk purchases and better access to lower-cost products. That said, the two largest PV markets in the country (California and New Jersey) are not among the low-cost states. Instead, the lowest cost states (New Hampshire, Texas, Nevada, and Arkansas) are relatively small markets, illustrating the influence of other state or local factors on installed costs. For example, administrative and regulatory compliance costs (e.g., incentive applications, permitting, and interconnection) can vary substantially across states and localities, as can installation labor costs. Average installed costs may also differ among states due to differences in average size or differences in the proportion of systems that are ground-mounted or have tracking equipment, which will tend to increase total installed cost. Average reported installed costs may also be higher in states where a greater proportion of systems are owned by third parties, for reasons explained in the following section – though, in that case, the cost differences would be more an artifact of how installed costs are reported for third-party systems than a result of any difference in underlying installation costs.

As illustrated directly in Figure 15, installed costs also vary across states as a result of differing sales tax treatment. Ten of the 22 states shown in the figure exempted residential PV systems from state sales tax in 2010, and Oregon and New Hampshire have no state sales tax. Assuming that PV hardware costs represent approximately 60% of the total installed cost of residential PV systems, state sales tax exemptions effectively reduce the post-sales-tax installed cost by up to \$0.4/W, depending on the specific state sales tax rate that would otherwise be levied.



Notes: The figure includes only those states for which data were provided by PV incentive program administrators and only if data were provided for at least five systems. State Sales Tax and Pre-State Sales Tax Installed Cost were calculated from sales tax rates in each state (local sales taxes were not considered). Sales tax was assumed to have been assessed only on hardware costs, which were assumed to constitute 60% of the total pre-sales-tax installed cost.

Figure 15. Variation in Installed Costs of Behind-the-Meter PV Systems ≤10 kW among U.S. States

Table 2. Average Installed Cost (\$/W$_{DC}$) of Behind-the-Meter PV by State and System Size Range

State	All Reported Yrs. Capacity-Weighted Average Cost (all sizes)		2010 Systems: Capacity-Weighted Average Cost (all sizes)		2010 Systems: Simple Average Cost ≤10 kW$_{DC}$		10 - 100 kW$_{DC}$		100 - 500 kW$_{DC}$		>500 kW$_{DC}$	
AR	\$6.2	(n=46)	\$6.2	(n=46)	\$6.4	(n=39)	\$6.1	(n=7)	*	(n=0)	*	(n=0)
AZ	\$6.8	(n=8031)	\$6.5	(n=4320)	\$6.6	(n=3900)	\$6.5	(n=403)	\$6.8	(n=12)	\$6.5	(n=5)
CA	\$7.5	(n=77842)	\$6.3	(n=18349)	\$7.3	(n=16484)	\$6.5	(n=1705)	\$6.4	(n=104)	\$5.3	(n=56)
CT	\$8.1	(n=1598)	\$7.3	(n=432)	\$7.4	(n=339)	\$7.0	(n=87)	\$7.4	(n=6)	*	(n=0)
DC	\$7.4	(n=129)	\$6.8	(n=72)	\$7.7	(n=69)	*	(n=3)	*	(n=0)	*	(n=0)
FL	\$7.0	(n=1014)	\$6.4	(n=281)	\$7.2	(n=228)	\$6.1	(n=47)	*	(n=3)	*	(n=3)
IL	\$10.8	(n=517)	\$10.0	(n=152)	\$7.7	(n=125)	\$8.6	(n=26)	*	(n=0)	*	(n=1)
MA	\$7.0	(n=2746)	\$5.9	(n=762)	\$6.9	(n=520)	\$7.0	(n=177)	\$6.0	(n=58)	\$5.2	(n=7)
MD	\$6.8	(n=1278)	\$6.0	(n=562)	\$6.5	(n=493)	\$5.6	(n=68)	*	(n=1)	*	(n=0)
MN	\$7.4	(n=409)	\$6.5	(n=187)	\$8.0	(n=161)	\$7.3	(n=25)	*	(n=0)	*	(n=1)
NH	\$6.8	(n=367)	\$6.0	(n=161)	\$6.3	(n=158)	*	(n=3)	*	(n=0)	*	(n=0)
NJ	\$6.8	(n=7683)	\$5.7	(n=2939)	\$7.1	(n=2117)	\$6.8	(n=673)	\$5.5	(n=120)	\$4.8	(n=29)
NM	\$6.5	(n=952)	\$6.2	(n=720)	\$7.2	(n=693)	\$6.4	(n=26)	*	(n=0)	*	(n=1)
NV	\$6.3	(n=884)	\$5.7	(n=360)	\$6.4	(n=231)	\$5.8	(n=122)	\$5.3	(n=7)	*	(n=0)
NY	\$8.2	(n=2973)	\$7.3	(n=972)	\$7.4	(n=715)	\$7.5	(n=256)	*	(n=1)	*	(n=0)
OH	\$6.3	(n=185)	\$6.0	(n=62)	\$8.3	(n=6)	\$6.9	(n=45)	\$6.6	(n=10)	*	(n=1)
OR	\$7.4	(n=2539)	\$6.7	(n=1170)	\$6.7	(n=1073)	\$7.2	(n=79)	\$6.6	(n=18)	*	(n=0)
PA	\$6.2	(n=3265)	\$6.0	(n=2729)	\$6.8	(n=1938)	\$6.3	(n=717)	\$5.6	(n=70)	*	(n=4)
TX	\$6.5	(n=1714)	\$5.9	(n=587)	\$6.4	(n=484)	\$6.0	(n=97)	\$5.2	(n=6)	*	(n=0)
UT	\$9.4	(n=129)	\$8.5	(n=34)	\$8.4	(n=29)	\$8.1	(n=5)	*	(n=0)	*	(n=0)
VT	\$7.5	(n=533)	\$6.2	(n=167)	\$6.6	(n=153)	\$5.7	(n=14)	*	(n=0)	*	(n=0)
WI	\$8.2	(n=1039)	\$7.2	(n=332)	\$7.9	(n=238)	\$7.3	(n=93)	*	(n=1)	*	(n=0)

Notes: The table includes only the 22 states for which data were provided by PV incentive program administrators (i.e., excludes states for which the Section 1603 Grant Program database was the only data source). Cost data for individual size bins in a given state are omitted (*) if fewer than five data points are available.

Third Party-Owned Systems Had Moderately Higher Average Reported Installed Costs than Customer-Owned Systems in 2010

Third party ownership of customer-sited PV systems through power purchase agreements and leases has become increasingly common for PV systems of all sizes and market sectors. Under such arrangements, the transaction between the host customer and the system owner consists of a series of payments over time, rather than a single up-front payment for the purchase of the PV system. As such, third party PV system owners may have some discretion in terms of how they report installed costs to PV incentive program administrators, and the reported installed cost may or may not be comparable to what would be reported under a cash sale transaction, depending on the type of third party provider.

More specifically, for systems installed by *integrated* third party providers (i.e., companies that provide both installation service and customer financing), the installed cost data reported to PV incentive program administrators may represent the assessed "fair market value" claimed by the third party provider when applying for a 1603 Treasury Grant or federal investment tax credit. Depending on how it is assessed, the fair market value – and thus the reported installed cost – may differ significantly from the underlying cost (including profit) to install the project.[23] In contrast, for systems financed by *non-integrated* third party providers (i.e., companies that provide customer financing but contract out the system installation/integration service), the installed cost data reported to PV incentive programs is generally provided by the installer/integrator, in which case it presumably represents the sale price of the system charged to the third party finance provider, and is arguably similar to what the reported installed cost would be under a cash sale transaction. Thus, while a similar "fair market value" may be reported to Treasury by both types of provider, the non-integrated providers have an intermediate documented cash sale, but the integrated providers do not.

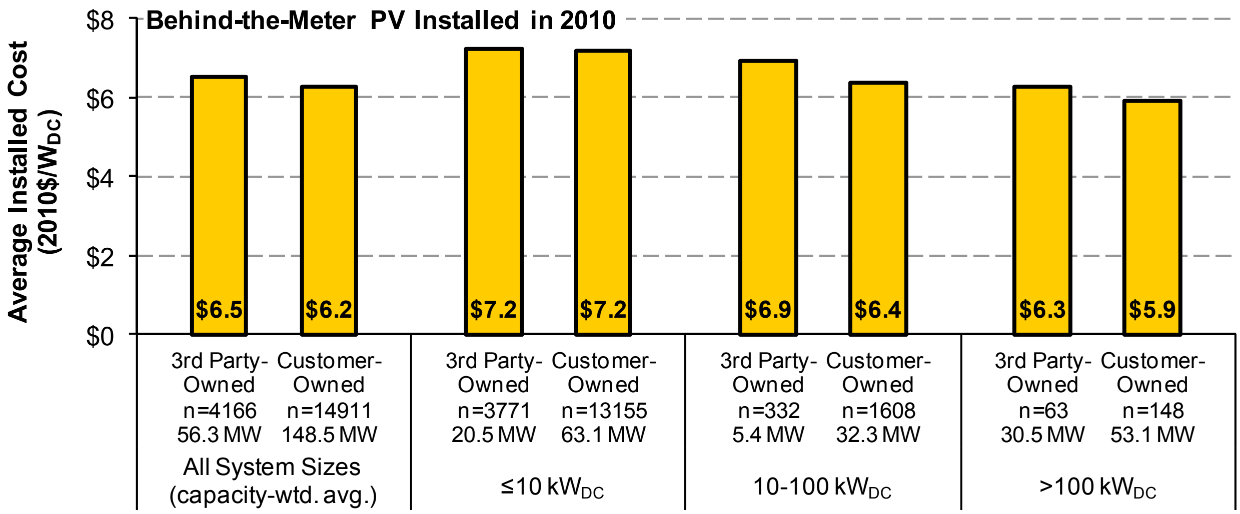
Suffice to say, the growing prominence of third party ownership creates a certain degree of ambiguity in the installed cost data summarized in this report. To provide some insight into whether the installed cost reporting practices by integrated third party providers has skewed the cost trends described elsewhere in this report, Figure 16 compares the reported installed cost of customer-owned and third party-owned behind-the-meter PV systems installed in 2010, based on only those PV incentive programs that provided data indicating whether PV systems were customer- or third party-owned and that included both types of systems.[24] Across all systems in the data sub-sample, the capacity-weighted average cost of third party-owned systems was \$0.3/W higher than for customer-owned systems (\$6.5/W vs. \$6.2/W). The cost differential varies somewhat across system sizes, with the average reported installed cost of third party-owned systems exceeding that of customer-owned systems by \$0.5/W for 10-100 kW systems and by \$0.4/W for >100 kW systems, but no difference is observed for systems within the ≤10 kW system size range. Table 3 presents similar comparisons for projects installed in each year over the 2007-2010 period and shows that the differential between the average reported installed costs for third party-owned and customer-owned systems has generally been quite negligible when aggregating all system sizes, though the cost differential for each system size range has fluctuated considerably year by year.

---

[23] The Treasury Department's guidelines for assessing the cost basis of solar properties identifies three allowable methods for assessing fair market value: the cost approach, based on the actual cost to install the project; the market approach, based on the sale price of comparable properties; or the income approach (based on the discounted value of future cash flows generated by and appropriately allocable to the eligible property). For additional information, see: http://www.treasury.gov/initiatives/recovery/Documents/Evaluating_Cost_Basis_for_Solar_PV_Properties%20final.doc

[24] Most of the PV projects in the data sample with system ownership data are associated with the CSI program, although data on system ownership were also provided for systems funded through nine other PV incentive programs.

In short, the available data do indicate that the conventions for reporting installed costs used by some third party providers has introduced some distortion into the underlying cost trends, but at least at an aggregate level, the magnitude of any distortion is likely to be relatively modest. Nevertheless, to the extent that the market share of third party ownership continues to grow, issues associated with consistent reporting of cost data may become more significant over time.



Notes: The figure is based on those systems for which PV incentive program administrators provided system ownership data, consisting of 53% of all behind-the-meter systems in the data sample installed in 2010.

Figure 16. Reported Installed Costs of Customer-Owned vs. Third Party-Owned Behind-the-Meter PV Systems

Table 3. Reported Installed Costs of Customer-Owned vs. Third Party-Owned Behind-the-Meter PV Systems over Time

Installation Year	All System Sizes (Capacity-Wtd. Avg.)		Simple Average					
			<10 kW		10-100 kW		>100 kW	
	3rd Party-Owned	Customer-Owned	3rd Party-Owned	Customer-Owned	3rd Party-Owned	Customer-Owned	3rd Party-Owned	Customer-Owned
2007	$6.9	$8.4	$8.6	$8.5	$8.4	$8.3	$6.7	$8.5
2008	$7.5	$7.6	$9.5	$8.3	$8.3	$7.9	$7.6	$7.4
2009	$7.7	$7.6	$9.1	$8.1	$8.4	$7.5	$7.8	$7.7
2010	$6.5	$6.2	$7.2	$7.2	$6.9	$6.4	$6.3	$5.9

Notes: The figure is based on those systems for which PV incentive program administrators provided system ownership data, consisting of 55% of all behind-the-meter systems in the data sample installed in 2007-2010.

Installed Costs Are Moderately Lower for Residential Systems and Higher for Tax-Exempt Systems, Compared to Other Similarly Sized Systems

Figure 17 compares the average installed cost of behind-the-meter PV across three host-customer sectors: residential, commercial, and tax-exempt (i.e., government, schools, and non-profit). The figure focuses specifically on systems installed in 2010 within the 5-10 kW, 10-100 kW, and 100-500 kW size ranges, as those are ranges for which the sample size in each relevant customer segment is sufficiently large (with the exception of residential systems in the 100-500 kW size range).

Although differences across customer sectors within each size range are relatively small, in general, installed costs tend to be lowest for residential systems compared to other similarly sized systems. For example, the average cost of residential systems installed in 2010 was $0.2/W less than commercial systems, within both the 5-10 kW size range ($6.6/W vs. $6.8/W) and the 10-100 kW size range ($6.7/W vs. $6.7/W). In prior years, the cost advantage of residential systems was somewhat greater, as indicated by Table 4, which presents similar comparisons across host customer segments for systems installed in each year from 2007 to 2010. Although apparently diminishing in importance over time, residential systems may benefit from some greater degree of standardization and lower transaction costs, compared to similarly-sized commercial and tax-exempt systems.

Figure 17 also indicates that, with the exception of systems in 5-10 kW size range, tax-exempt systems installed in 2010 had moderately higher installed costs than other similarly sized systems. For example, the average installed cost of tax-exempt systems exceeded that of commercial systems by $0.4/W within both the 10-100 kW size range ($7.1/W vs. $6.7/W) and the 100-500 kW size range ($6.2/W vs. $5.8/W). This trend has also been consistent over time, as evident in Table 4, though the magnitude of the gap between the average cost of tax-exempt systems and other similarly sized systems has similarly diminished over time. The higher reported installed costs for tax-exempt systems may be attributable to some combination of relatively high transaction costs (e.g., associated with more complex government procurement processes) and a presumed higher incidence of third party ownership to monetize tax credits for tax-exempt site hosts.

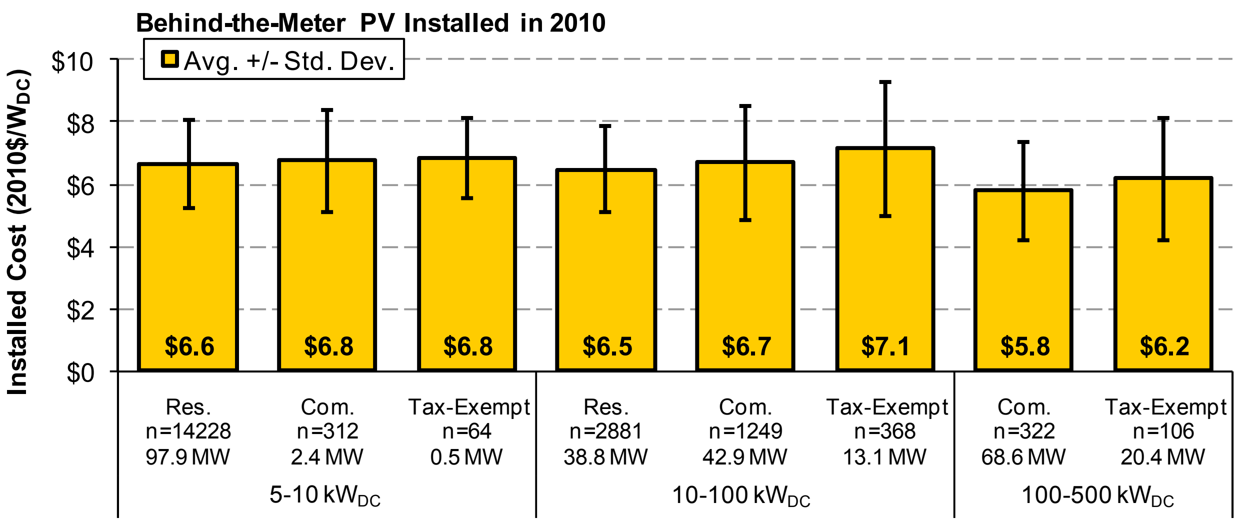


Figure 17. Variation in Installed Costs across Host Customer Sectors

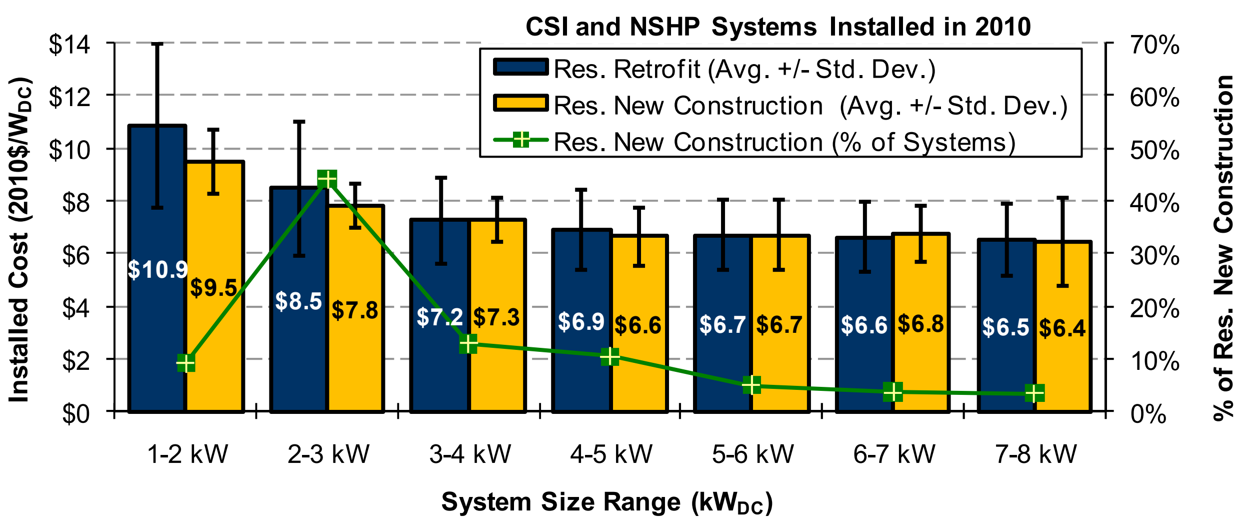
Table 4. Average Installed Cost ($\$/W_{DC}$) by Host Customer Sector over Time

Installation Year	5 - 10 kW			10 - 100 kW			100 - 500 kW	
	Residential	Commercial	Tax-Exempt	Residential	Commercial	Tax-Exempt	Commercial	Tax-Exempt
2007	$8.4	$9.0	$9.2	$8.3	$8.8	$9.2	$7.5	$8.6
2008	$8.1	$8.7	$8.5	$7.9	$8.1	$8.4	$7.2	$9.1
2009	$7.6	$8.5	$8.7	$7.4	$8.0	$8.5	$7.3	$8.1
2010	$6.6	$6.8	$6.8	$6.5	$6.7	$7.1	$5.8	$6.2

Notes: The table is based on those systems for which PV incentive program administrators provided customer data, consisting of 90% of all behind-the-meter systems in the data sample installed in 2007-2010.

The New Construction Market Offers Cost Advantages for Small Residential PV, Despite the Higher Cost of BIPV Relative to Rack-Mounted Systems

PV systems installed in residential new construction may enjoy certain cost advantages relative to systems installed as retrofits to existing homes, as a result of economies of scale (in the case of new housing developments with multiple PV homes) and economies of scope (where certain transaction and labor costs can be shared between the PV installation and other elements of home construction). To examine the extent to which this has occurred, Figure 18 compares the average installed cost of PV systems installed in 2010 in residential new construction and residential retrofit applications, based specifically on systems funded through two California programs (the CSI and the New Solar Homes Partnership [NSHP] program). The figure compares average installed costs within several system size ranges, and identifies the percentage of NSHP systems within each size range. As shown, among relatively small system sizes (1-2 kW and 2-3 kW), the average installed cost of PV in residential new construction was significantly less than in residential retrofit ($1.4/W less among 1-2 kW systems and $0.7/W less among 2-3 kW systems.) For system sizes greater than 3 kW, however, average installed costs of residential new construction and retrofit were similar.



Notes: Values shown for residential retrofits are based residential PV systems installed through CSI, and values shown for residential new construction are based on systems funded through NSHP. The data sample for the figure consists of 15,336 residential retrofit systems and 697 residential new construction systems installed in 2010.

Figure 18. Comparison of Installed Costs for Residential Retrofit vs. New Construction

Simply comparing the overall average cost of all residential new construction and all residential retrofit systems masks the fact that a much larger proportion of new construction systems are building-integrated PV (BIPV), which tend to have somewhat higher installed costs than rack-mounted systems, though the higher costs may be partially offset by avoided roofing material and labor costs. To better control for this confounding influence, Figure 19 compares the average installed cost of BIPV and rack-mounted systems installed in residential new construction in 2010, focusing solely on 2-3 kW systems (the most common size range for PV installed in residential new construction).[25] As shown in Figure 19, BIPV systems in this size range cost $1.0/W more, on average, than rack-mounted systems installed in residential new construction (i.e., $8.0/W vs.

[25] Ideally, this comparison would focus only on roof-mounted systems, as ground-mounted systems tend to have higher costs. However, the data provided by PV incentive programs generally do not distinguish between roof-mounted and ground-mounted systems.

$7.0/W) and installed in 2010. As indicated in Table 5, which presents analogous data for the 2007-2010 period, similar trends prevailed in years prior to 2010, though the differences between BIPV and rack-mounted systems in residential new construction were somewhat lower ($0.7/W in 2008 and 2009, and just $0.1/W in 2007).

To make an apples-to-apples comparison between residential new construction and residential retrofit applications, one can compare the average cost of rack-mounted systems installed in residential new construction to the average cost of residential retrofit systems (which, for all intent and purposes, are exclusively rack-mounted[26]), as also shown in Figure 19. This comparison suggest a greater cost advantage for new construction than implied by the overall averages, with rack-mounted systems installed in residential new construction in 2010 averaging $1.5/W less than residential retrofit systems ($7.0/W compared to $8.5/W). Again, Table 5 shows consistent trends in the years immediately preceding 2010 as well.

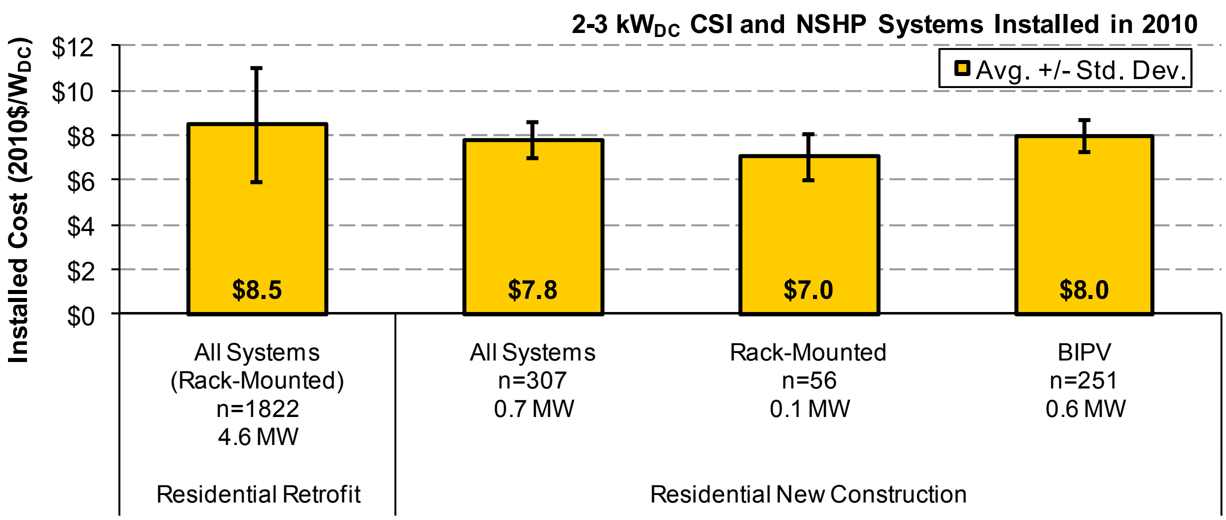


Figure 19. Installed Cost of Residential Retrofit vs. New Construction (2-3 kW systems)

Table 5. Average Installed Cost ($/W$_{DC}$) of Residential Retrofit vs. New Construction (2-3 kW systems)

Installation Year	Residential Retrofit		Residential New Construction					
	All Systems		All Systems		Rack-Mounted		BIPV	
2007	$8.7	(n=1075)	$8.5	(n=703)	$8.4	(n=218)	$8.5	(n=485)
2008	$8.8	(n=1210)	$8.0	(n=1119)	$7.5	(n=352)	$8.2	(n=766)
2009	$8.9	(n=1706)	$7.8	(n=804)	$7.3	(n=227)	$8.0	(n=577)
2010	$8.5	(n=1822)	$7.8	(n=307)	$7.0	(n=56)	$8.0	(n=251)

Notes: The results in the table are derived solely from systems funded through the CSI and NSHP programs.

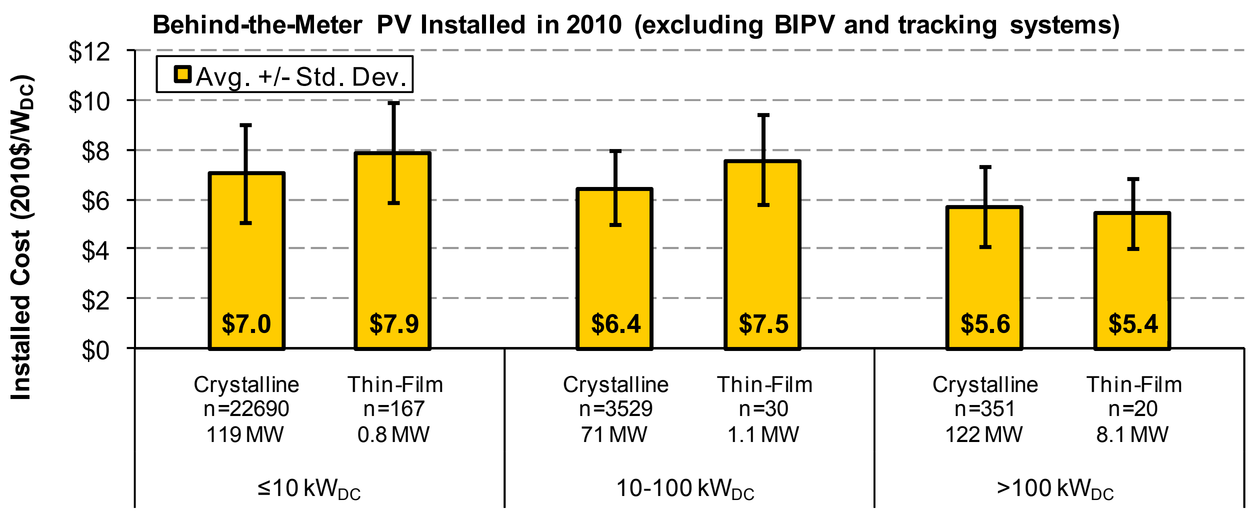
Systems with Thin-Film Modules Had Higher Installed Costs than Those with Crystalline Modules within Certain Size Ranges

A number of countervailing factors may influence the relative cost of systems employing crystalline modules (multi-crystalline or mono-crystalline silicon) and those employing thin-film (i.e., amorphous silicon and non-silicon technologies) modules. Thin-film modules are typically

[26] In fact, there are 11 BIPV systems within the set of 2-3 kW systems installed in 2010 through CSI; however, for simplicity, we consider all residential CSI systems to be rack-mounted.

lower-cost than crystalline modules but are less efficient, which would tend to engender higher balance of system costs. In addition, greater uncertainty in the long-term performance of thin-film modules on the part of consumers and potentially faster degradation rates would tend to drive down the price of thin-film systems relative to crystalline systems. However, some thin-film technologies have higher energy yields (annual kWh per installed kW) than crystalline modules, due to better performance at high temperatures or under diffuse irradiance, which would tend to increase the price that customers are willing to pay for thin-film systems.

To understand the net effect of these cost drivers, Figure 20 compares the average installed cost of crystalline and thin-film systems installed in 2010. To eliminate any biases associated with a higher incidence of BIPV among thin-film systems and a higher incidence of tracking equipment among crystalline systems, the data sample used for this comparison excludes all identifiable BIPV and tracking systems. As shown, thin-film systems in the ≤10 kW and 10-100 kW size ranges had higher average installed costs than comparably-sized crystalline systems ($0.9/W higher among ≤10 kW systems and $1.1/W higher among 10-100 kW systems). In contrast, average installed costs were nearly identical for the two technology types within the >100 kW size range. Among larger utility-sector systems, thin-film systems had lower installed costs than crystalline systems, as shown later in Section 5. As shown in Table 6, similar trends prevailed in the years immediately preceding 2010 as well, where average installed costs were generally greater for systems with thin-film modules than for those with crystalline modules. Given the small sample size of thin-film systems within this analysis, particularly within the 10-100 kW and >100 kW size ranges, some caution is warranted in generalizing from these results.



Notes: The figure is derived from those systems for which module technology type could be readily determined from module manufacturer and model data provided by PV incentive program administrators, representing 76% of all behind-the-meter systems in the data sample installed in 2010 (excluding BIPV and tracking systems).

Figure 20. Installed Costs of Crystalline vs. Thin-Film Behind-the-Meter Systems

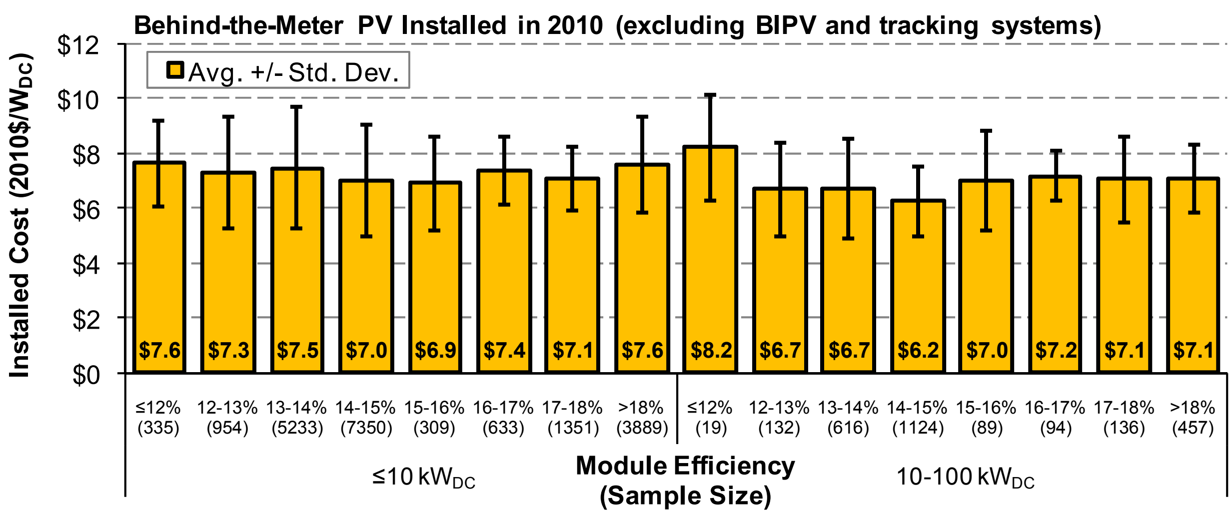
Table 6. Avg. Installed Cost ($\$/W_{DC}$) of Crystalline vs. Thin-Film Behind-the-Meter Systems over Time

Installation Year	<10 kW				10-100 kW				>100 kW			
	Crystalline		Thin-Film		Crystalline		Thin-Film		Crystalline		Thin-Film	
2007	$8.5	(n=8385)	$7.9	(n=47)	$8.2	(n=960)	$7.6	(n=6)	$7.5	(n=94)	*	(n=2)
2008	$8.3	(n=8437)	$8.7	(n=29)	$7.9	(n=979)	$6.0	(n=12)	$7.5	(n=224)	*	(n=4)
2009	$8.0	(n=13858)	$9.0	(n=416)	$7.6	(n=1669)	$8.2	(n=45)	$7.5	(n=190)	$8.1	(n=8)
2010	$7.0	(n=22690)	$7.9	(n=167)	$6.4	(n=3529)	$7.5	(n=30)	$5.6	(n=351)	$5.4	(n=20)

Notes: The table is derived from those systems for which module technology type could be readily determined from module manufacturer and model data provided by PV incentive program administrators, representing 74% of all behind-the-meter systems in the data sample installed in 2007-2010 (excluding BIPV and tracking systems). Results are omitted (*) if fewer than 5 data points are available.

Installed Costs Were Lowest for Systems Using Modules with Mid-Range Efficiencies

To examine the relationship between total installed cost and module efficiency more directly, Figure 21 compares average installed cost according to module efficiency, for all rack-mounted, fixed-tilt systems installed in 2010. In order to avoid any bias associated with higher incidence of BIPV or tracking equipment among certain module efficiency levels, the figure again excludes BIPV and tracking systems. Within both of the two system size ranges shown, average installed costs were lowest for systems with modules of mid-range efficiencies. Among systems ≤10 kW, however, the differences in average installed costs across module efficiencies were relatively small, where systems with module efficiencies of 15-16% exhibited the lowest average installed cost of $6.9/W, compared to $7.6/W for systems at either end of efficiency range shown (≤12% and >18%). Among 10-100 kW systems, the installed cost variation across module efficiency levels was somewhat greater, with the lowest average installed cost ($6.2/W) occurring among systems with module efficiencies of 14-15%, compared to $8.2/W for the lowest efficiency systems (≤12%) and $7.1/W for the highest efficiency systems (>18%).

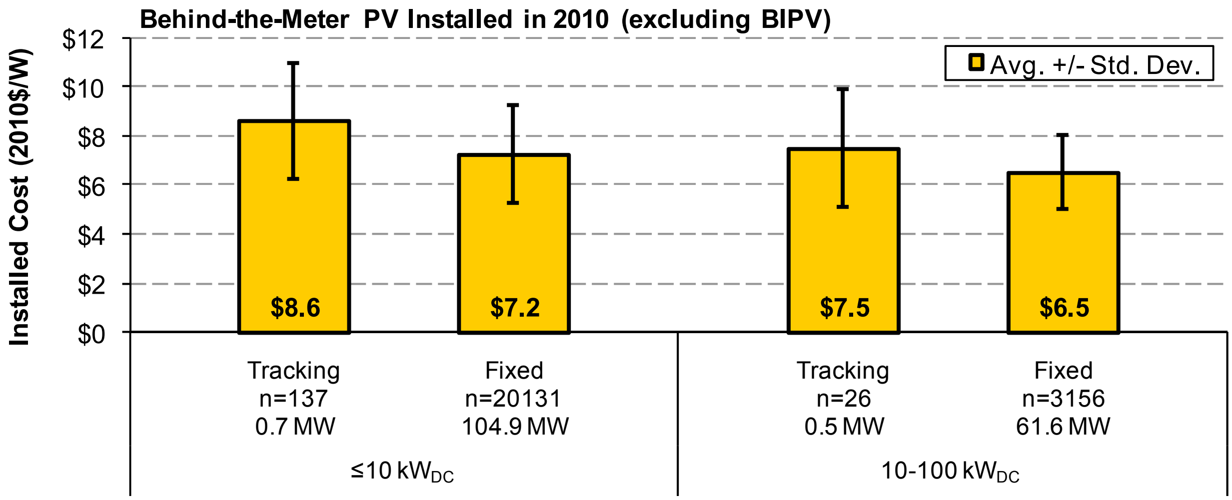


Notes: The figure is derived from those systems for which rated module efficiency could be readily determined from module manufacturer and model data provided by PV incentive program administrators, representing 66% of all behind-the-meter systems in the data sample installed in 2010 and within the size ranges depicted in the figure (excluding BIPV and tracking systems).

Figure 21. Variation in Total Installed Cost by Module Efficiency

Tracking Systems Had Higher Installed Costs than Fixed-Tilt Systems

Figure 22 compares the average cost of PV systems with tracking (both single- and double-axis tracking) to systems with fixed mounting (excluding all BIPV systems, and including both roof- and ground-mounted systems) installed in 2010.[27] As to be expected, tracking systems had higher installed costs within both size categories. Among systems ≤10 kW, the average installed cost of systems with tracking systems was $1.4/W (or 19%) higher than fixed-tilt systems, and among 10-100 kW systems, tracking systems had average installed costs $1.1/W (or 15%) higher than their fixed-tilt counterparts.[28] Qualitatively similar trends also occurred among systems installed in prior years, as shown in Table 7, although the size of the difference in average installed costs between fixed-tilt and tracking systems varied somewhat from year-to-year. Given the small number of tracking systems identified within the dataset, especially within the 10-100 kW and >100 kW size ranges, some caution is warranted in generalizing from these results.



Notes: The figure is derived from those systems for which data were available indicating whether or not tracking equipment was used, representing 68% of all behind-the-meter systems in the data sample installed in 2010 (excluding BIPV) and within the size ranges depicted in the figure.

Figure 22. Installed Costs of Tracking vs. Fixed-Tilt Behind-the-Meter Systems

Table 7. Installed Cost ($\$/W_{DC}$) of Tracking vs. Fixed-Tilt Behind-the-Meter Systems over Time

Installation Year	<10 kW				10-100 kW				>100 kW			
	Tracking		Fixed		Tracking		Fixed		Tracking		Fixed	
2007	$10.3	(n=58)	$8.6	(n=4131)	$8.6	(n=6)	$8.4	(n=357)	*	(n=0)	$7.4	(n=55)
2008	$9.7	(n=73)	$8.4	(n=8308)	$9.4	(n=15)	$8.0	(n=956)	*	(n=4)	$7.5	(n=244)
2009	$9.6	(n=116)	$8.3	(n=14233)	$8.2	(n=15)	$7.7	(n=1647)	$7.5	(n=6)	$7.5	(n=225)
2010	$8.6	(n=137)	$7.2	(n=20131)	$7.5	(n=26)	$6.5	(n=3156)	$5.8	(n=7)	$5.7	(n=378)

Notes: The table is derived from those systems for which data were available indicating whether or not tracking equipment was used, representing 64% of all behind-the-meter in the data sample installed in 2007-2010 (excluding BIPV). Results are omitted (*) if fewer than 5 data points are available.

[27] A more meaningful comparison would be between tracking systems, ground-mounted fixed-tilt systems, and roof-mounted fixed-tilt systems, in order to distinguish between the cost of the tracking equipment, itself, and any additional cost associated with ground-mounting. However, data identifying whether systems are ground-mounted or roof-mounted are available for only a negligible percentage of systems in the data sample.

[28] Results for >100 kW systems are excluded from Figure 22 due to insufficient sample size.

4. Incentive and Net Installed Cost Trends: Behind-the-Meter PV

Financial incentives provided through utility, state, and federal programs have been a major driving force for the PV market in the United States. For behind-the-meter PV systems, these incentives potentially include some combination of cash incentives provided through state and/or utility PV incentive programs, federal and/or state investment tax credits (ITCs), the U.S. Treasury grant in lieu of the ITC[29], revenues from the sale of renewable energy certificates (RECs), and accelerated depreciation of capital investments in solar energy systems. This section describes trends in incentive levels for behind-the-meter PV – focusing specifically on state/utility cash incentives, state/federal ITCs, and the Treasury grant – as well as trends in the *net installed cost* of behind-the-meter PV after receipt of these financial incentives.

Three important caveats should be noted at the outset:

- First, the set of incentives addressed in this section are necessarily limited in scope. They include only the direct cash incentives provided through the specific state/utility PV incentive programs in the dataset, plus state and federal ITCs (or the Treasury cash grant in lieu of the federal ITC). The analysis does not account for the incentive for commercial PV provided through accelerated depreciation,[30] nor for any additional incentives that projects may have received from state/utility incentive programs outside of the PV incentive programs covered in this report. The results presented in this section also do not account for revenue from the *future* sale of RECs[31], although the potential magnitude of this revenue stream is discussed in Text Box 3.
- Second, the results presented in this section are based on the subset of residential and commercial systems in the behind-the-meter PV data sample that received state/utility cash incentives and for which data on the size of the incentive was provided. As such, these results exclude all systems with tax-exempt host customers,[32] systems that receive incentives solely in the form of ongoing SREC payments, as well as those systems for which data were obtained solely from the Section 1603 Grant Program database or other supplementary data sources (as data on any state/utility cash incentive received were not available in those cases). Additional information on the screens used to exclude systems from the incentive and net installed cost analysis for this section is provided in Appendix A. The resulting reduced data sample is summarized in Table 8, and represents 96% of the systems and 78% of the installed capacity in the total behind-the-meter PV data sample previously described in Section 2.

[29] Starting in 2009 and for a limited period, the federal ITC for commercial PV could be converted to a cash grant of equal nominal value from the U.S. Treasury.

[30] For tax purposes, commercial PV owners are allowed to depreciate PV systems using an accelerated 5-year schedule. The net present value of this accelerated depreciation schedule, relative to a 20-year straight-line schedule, is equal to approximately 12% of installed costs. See: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC*. Berkeley, CA: Lawrence Berkeley National Laboratory.

[31] In some instances, the up-front cash incentives provided by the PV incentive programs in our sample serve as a lump sum payment for RECs produced by the PV system over a defined time period. In these instances, the analysis presented in this chapter would account for REC sales.

[32] Systems with tax-exempt host customers were excluded from this analysis, because in many instances, data on system ownership were not available, and therefore it could not be determined whether these systems would be eligible to receive the federal ITC/Treasury grant.

- Third, this section marks a departure from Section 3 by going beyond a simple reporting of data provided by program administrators. In particular, a variety of assumptions, as documented within this section and described further in Appendix C, were required in order to estimate the value of state and federal ITCs (or the Treasury cash grant in lieu of the federal ITC) for each project and to determine the net installed cost on an after-tax basis.

Table 8. Reduced Behind-the-Meter Data Sample for Incentive and Net Installed Cost Analysis

Installation Year	No. of Systems			Capacity (MW_{DC})			Percent of Total Behind-the-Meter PV Data Sample	
	Residential	Commercial	*Total*	Residential	Commercial	*Total*	No. of Systems	Capacity (MW_{DC})
1998	34	5	*39*	0.1	0.1	*0.2*	100%	100%
1999	174	11	*185*	0.4	0.4	*0.8*	100%	100%
2000	209	14	*223*	0.6	0.3	*0.9*	100%	88%
2001	1,280	43	*1,323*	4.1	1.4	*5.5*	100%	100%
2002	2,343	190	*2,533*	7.9	8.0	*15.9*	100%	99%
2003	3,186	393	*3,579*	12.8	21.1	*33.9*	100%	100%
2004	4,965	611	*5,576*	20.4	24.3	*44.7*	99%	99%
2005	4,819	709	*5,528*	21.9	38.4	*60.3*	99%	96%
2006	7,717	990	*8,707*	34.9	51.0	*85.9*	99%	94%
2007	11,558	1,223	*12,781*	55.0	72.7	*127.7*	99%	96%
2008	12,841	1,233	*14,074*	63.6	130.6	*194.2*	97%	82%
2009	23,054	1,291	*24,345*	125.2	94.0	*219.2*	96%	71%
2010	31,122	2,005	*33,127*	181.2	129.0	*310.2*	92%	67%
Total	**103,302**	**8,718**	***112,020***	**528**	**571**	***1,099***	**96%**	**78%**

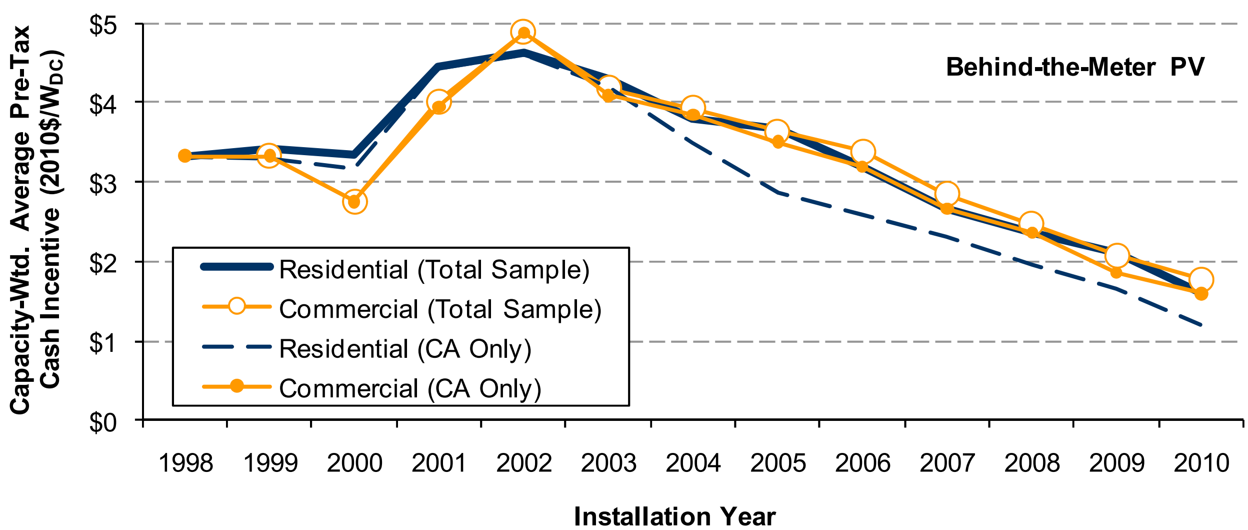
Notes: See Appendix A for further details regarding the criteria for excluding systems from the incentive and net installed cost analysis.

State/Utility Cash Incentives Continued Their Decline in 2010

The PV incentive programs represented within the dataset provide cash incentives of varying forms. Most provide up-front cash incentives (i.e., "rebates"), based either on system capacity, a percentage of installed cost, or a projection of annual energy production. Several programs, instead, provide performance-based incentives (PBIs), which are paid out over time based on a pre-scheduled PBI payment rate and actual energy production; for the purpose of our analysis, PBI payments are translated into an up-front incentive of equivalent net present value (see Appendix A for further details).

Figure 23 shows capacity-weighted average state/utility cash incentive received by residential and commercial PV systems over time. These data are presented on a *pre-tax* basis – that is, prior to assessment of state or federal taxes that may be levied if the incentive is treated as taxable income. As indicated previously, these results are based on a reduced data sample that excludes systems that did not receive any direct cash incentive and instead rely only on REC revenues. If those systems were included in Figure 23, the average cash incentive levels shown would be lower, particularly for commercial systems, as the underlying sample would include systems with zero incentive. Note also that the figure does not necessarily provide an accurate depiction of the size of the cash incentives *offered* in each year, as there is typically some lag between the time that a project reserves its incentives and the time that it is installed.

As shown in Figure 23, the capacity-weighted average pre-tax cash incentive in 2010 was \$1.6/W for residential systems and \$1.8/W for commercial systems. Compared to the prior year, average incentives dropped by \$0.5/W for residential PV and by \$0.3/W commercial PV. Looking back further in time, cash incentives have declined at an average rate of roughly \$0.3/W per year since their peak in 2002, and average incentive levels in 2010 for residential and commercial systems were equal to 35% and 46% of their respective historical peaks. As evident in Figure 23, the declining trajectory of average incentive levels partially reflects changes in incentive levels under California's incentive programs, which represent the majority of systems in the sample. Nevertheless, average incentives among all PV incentive programs in the sample have generally declined over time (see Table B-3 in Appendix B). This is a consequence of a combination of factors, including declining PV installed costs, increases in the federal ITC, and a move away from standard-offer cash incentives and toward market-based funding mechanisms in certain states (New Jersey and Massachusetts, for example).



Notes: We assume that all systems ≤10 kW are residential and all systems >10 kW are commercial, unless indentified otherwise.

Figure 23. Capacity-Weighted Average Pre-Tax State/Utility Cash Incentives for Behind-the-Meter PV

Text Box 3. Revenue from the Sale of RECs

PV system owners may be able to sell RECs generated by their system, either in addition to or in lieu of direct cash incentives received from state/utility PV incentive programs and federal or state ITCs (provided that REC ownership is not transferred to the state/utility as a condition of receiving a direct cash incentive).

In general, the potential REC revenue for PV depends on where the system is located, and consequently, what types of REC markets are available. The greatest potential revenues are available for systems that can participate in renewables portfolio standard (RPS) markets with solar set-asides. PV systems located outside of RPS solar set-aside markets may also be able to sell their associated RECs. Based on recent REC prices, however, the revenue potential in those markets is relatively modest compared to the value of cash incentives received through state/utility PV incentive programs and to the value of the federal ITC (or the Treasury cash grant in lieu of the federal ITC).

- *RPS Solar Set-Aside Markets*: Among states with RPS solar set-asides, the average price of solar RECs (or SRECs) transacted in 2010 ranged from a high of roughly $600/MWh in New Jersey to a low of roughly $60/MWh in New Hampshire, with average annual prices in most other SREC markets ranging between $300-$400/MWh (based on transactions registered with PJM-GATS and on SREC transactions brokered by Spectron). Those prices, however, represent a combination of spot market and long-term contract sales, and therefore are not necessarily indicative of SREC prices that PV projects would receive over their entire lifetime. Recently published long-term SREC contract prices in several states are significantly lower than spot market prices. In New Jersey, for example, average long-term SREC contract prices awarded through several solicitations issued by the state's regulated distribution utilities in 2010 were approximately $450/MWh, while subsequent solicitations issued in the first half of 2011 yielded average SREC prices in the $300-$350/MWh range. In Pennsylvania, prices for long-term SREC contracts recently signed by the state's utilities have ranged from $150-250/MWh, with prices declining from 2010 to 2011 (based on press releases issued by the utilities). As a purely *hypothetical* illustration, extrapolating an SREC price of $200/MWh over the 20-year lifetime of a PV system yields the equivalent to an up-front, pre-tax incentive of roughly $2.0/W on a present value basis (assuming a 10% nominal discount rate, 1,200 kWh_{AC} /kW_{DC} in Year 1, and 0.5% degradation per year), which is comparable to the size of the average state/utility cash incentive provided in 2010.
- *General RPS Markets*. Among RPS markets *without* a solar set-aside, where RECs from PV systems may be used to satisfy general RPS compliance obligations, average annual REC prices in 2010 ranged from roughly $0.9/MWh in Texas to $23/MWh in Rhode Island (based on REC trades through Spectron). If extrapolated over a 20-year period using the same assumptions as before, revenue from REC sales at these prices would be equivalent to an up-front, pre-tax payment of roughly $0.01/W to $0.23/W.
- *Voluntary REC Markets*. RECs generated by PV systems may be sold to individuals, businesses, or government agencies that are voluntarily seeking to support renewable energy. Given the elective nature of these transactions, prices in voluntary REC markets have historically been quite modest. For example, voluntary RECs traded through Spectron averaged about $0.9/MWh in 2010. If extrapolated over 20 years using the same assumptions as before, revenue from REC sales at this price would be equivalent to an up-front, pre-tax incentive of just $0.01/W on a present value basis.

Installed Cost Declines in 2010 Reduced the Value of the Federal ITC, Further Reducing Aggregate After-Tax Incentive Levels

Although direct cash incentives received from state and utility PV programs have, on average, declined over time, other sources of financial incentives have become more significant. Most notably, starting January 1, 2006, the federal ITC for commercial PV systems rose from 10% to 30% of project costs, and a 30% ITC (capped at $2,000) was established for residential PV. The *Energy Improvement and Extension Act of 2008* subsequently lifted the $2,000 cap on the residential ITC for systems installed on or after January 1, 2009. The *American Recovery and Reinvestment Act*, signed into law in 2009, provides commercial PV projects the option, for a limited period of time, to receive an up-front cash grant from the Treasury Department of equal value to the federal ITC; for the purpose of the present analysis, we assume that the Treasury grant has the same economic value as the federal ITC for commercial PV.[33] In addition to the federal ITC/Treasury grant, a number of states have, at various times, offered state ITCs for PV, although these tax credits have generally been smaller and/or available to a more-restricted set of projects than the federal ITC/Treasury grant (see Appendix C for details on the state ITCs for PV offered by the states in our dataset).

Figure 24 illustrates the combined effect of changes over time in federal and state ITCs *plus* changes to the cash incentives provided through the state/utility PV incentive programs in the dataset, expressed here on an *after-tax* basis.[34] The figure shows, for both residential and commercial PV, the capacity-weighted average value of the federal ITC (or Treasury cash grant in lieu of the ITC) as well as the total after-tax incentive, which includes the federal ITC/Treasury grant *plus* state/utility cash incentives *plus* any state ITCs available. The value of state and federal ITCs/Treasury grant is calculated for each system under the assumption that all customers take advantage of these incentives, if eligible. As noted previously, the average aggregate incentive trend ignores potential revenues from the sale of RECs over time, and the underlying data sample used to construct the figure excludes systems that did not receive any direct cash incentive through a state/utility PV incentive program.

The total after-tax incentive levels shown in Figure 24 depict a discernibly different trend than Figure 23, reflecting the introduction and subsequent increases in the federal ITC, occurring at different times for residential and commercial systems. Among residential PV systems, the decline in average aggregate incentive levels temporarily abated between 2005 and 2006 when the federal ITC was extended to these systems, though the effect was relatively small due to the $2,000 cap on the residential credit through 2008, which limited the average value of the ITC to roughly $0.5/W. After the cap on the residential ITC was lifted in 2009, the total after-tax incentive for residential PV rose substantially, by roughly $1.0/W, on average. However, that temporary boost was substantially offset in 2010 by declining state/utility cash incentives, and the average total after-tax incentive for residential PV fell to $3.2/W in 2010, a $0.7/W (17%) year-over-year reduction. With the declining cash incentives provided through state/utility PV incentive programs, the federal ITC has grown in relative significance, representing just over 50% of the average aggregate incentive for residential PV in 2010.

For commercial PV, the decline in the average after-tax incentive that began in 2002 abruptly reversed course in 2006, when the federal ITC for commercial PV increased from 10% to 30% of project costs. The total after-tax incentive for commercial PV then declined relatively slowly from 2006 to 2009, as cash incentives fell (though the decline in the after-tax value of those incentives was less than the decline in their pre-tax value shown previously in Figure 23, due to the dampening

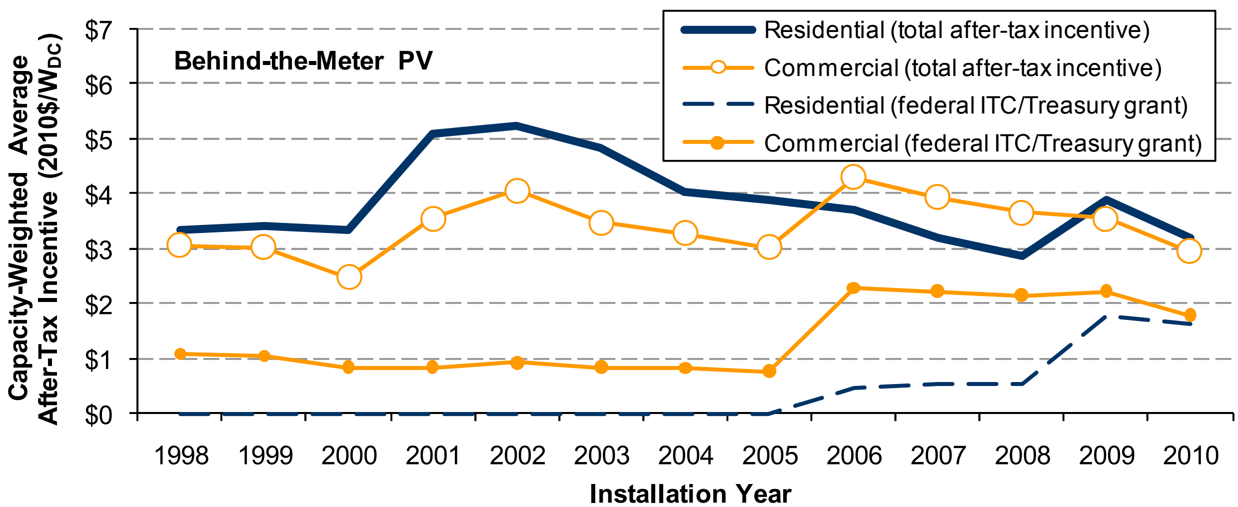
---

[33] For a more thorough comparison of the relative value of the cash grant to the ITC, see: Bolinger, M., R. Wiser, and N. Darghouth. 2009. *Preliminary Evaluation of the Impact of the Section 1603 Treasury Grant Program on Renewable Energy Deployment in 2009*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-3188E.

[34] See Appendix C for the assumptions used to calculate the after-tax value of state/utility cash incentives, state ITCs, and the federal ITC/Treasury cash grant.

effect of taxes). In 2010, however, the average total after-tax incentive for commercial PV fell by $0.6/W (17%) to $2.9 /W, with the federal ITC representing roughly 61% of the total average aggregate incentive. This sizable decline is the combined effect of the relatively steep reduction in state/utility cash incentives in 2010 along with a decline in the value of the federal ITC that resulted from the reduction in average installed costs. The value of the federal ITC for residential systems also fell for the same reason in 2010, but the effect was considerably more muted compared to commercial systems. This is because the federal ITC for most residential PV systems is assessed on the net cost of those systems after deducting the value of cash incentives (assuming that those incentives are tax-exempt, as we generally do for our analysis[35]), and the decline in the average installed cost of residential PV was, to a significant degree, offset by the decline in the value of state/utility cash incentives.

Although average incentive levels dropped significantly in 2010 on an absolute basis, total after-tax incentives as a percentage of installed cost remained relatively flat for both residential and commercial PV (equal to 47% and 49% of installed cost, respectively, in 2010), and were at or near all-time highs.



Notes: We assume that all systems ≤10 kW are residential and all systems >10 kW are commercial, unless indentified otherwise. See Appendix C for the assumptions used to calculate the after-tax value of state/utility cash incentives, state ITCs, and the federal ITC/Treasury cash grant.

Figure 24. Average Federal ITC/Treasury Grant and Average Total After-Tax Incentives for Behind-the-Meter PV (Calculated)

Net Installed Costs Declined in 2010, Though The Drop Was Significantly Dampened by Falling Incentive Levels

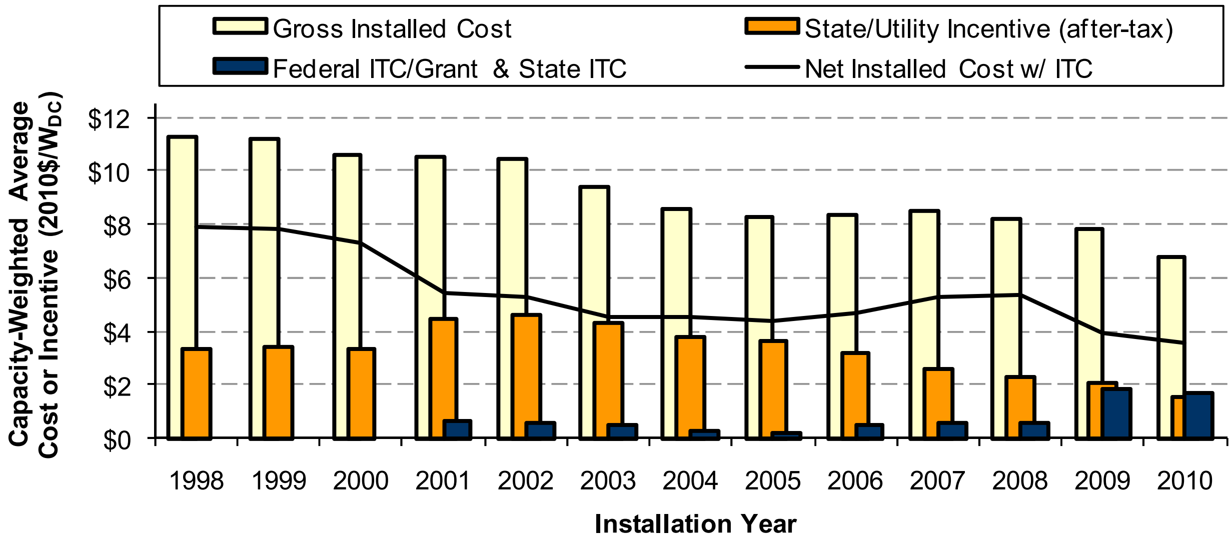
The customer economics of investing in a PV system is driven to a large degree by the *net installed cost* – that is, the installed costs minus the combined after-tax value of state/utility cash incentives and state/federal ITCs. Figure 25 and Figure 26 show the trend in capacity-weighted average net installed costs for residential and commercial PV systems, respectively, as well as the corresponding trends in gross installed costs and incentive levels. In 2010, the capacity-weighted

[35] We make an exception to this rule for third party-owned residential systems and for residential systems that receive performance-based incentive payments, rather than an up-front rebate. In these cases, we assume that the state/utility cash incentives are taxable and do not reduce the basis of the federal ITC.

average net installed cost was $3.6/W and $3.0/W for residential and commercial PV, respectively – again, based only on those systems that received state/utility cash incentives and ignoring the potential value of REC revenues generated over the life of the system. Compared to 2009, net installed costs declined by 0.4/W (9%) for residential PV and by $0.8/W (22%) for commercial PV.

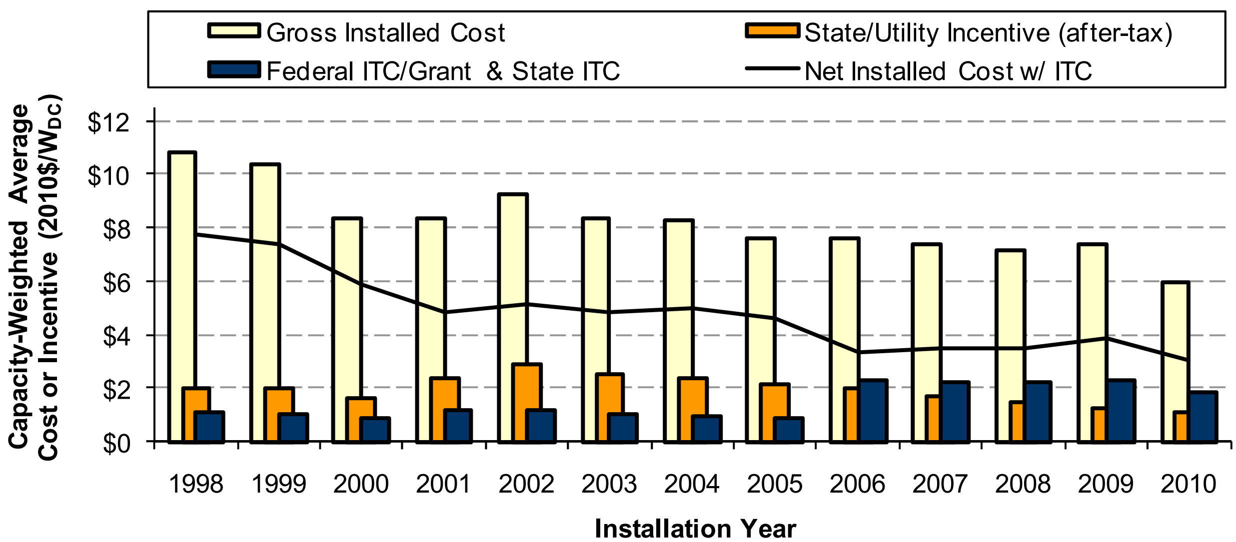
For both residential and commercial PV, the decline in net installed costs from 2009 to 2010 was significantly lower, in absolute terms, than the drop in gross installed costs, due to the offsetting effect of falling incentive levels. Among residential systems, the drop in average net installed costs was equal to just 36% of the $1.0/W reduction in gross installed costs. Among commercial systems, the decline in net installed costs was 58% of the $1.5/W decline in gross installed costs. The fact that reductions in net installed cost were less than those in gross installed cost is, of course, partly structural: the 30% federal ITC guarantees that, at most, 70% of gross installed cost reductions flow through to the PV system owner in the form of a reduction in net installed costs. The remaining difference is attributable to declining state/utility cash incentives.

For residential PV, the average net installed cost in 2010 represents an historical low, continuing the decline that occurred in 2009 as a result of the removal of the dollar cap on the federal ITC for residential systems. In the years immediately preceding 2009, the average net installed cost of residential PV had, in fact, been slowly rising, as average gross installed costs remained relatively flat, while state/utility cash incentives were declining. The average net installed cost of commercial PV in 2010 was also at an historic low, and was the first significant decline since 2006, when the federal ITC for commercial systems increased from 10% to 30%. For both residential and commercial PV, continued reductions in net installed costs will require that declines in pre-incentive installed costs keep pace with expected future reductions in state/utility cash incentives. This pressure will be particularly acute in California, where incentives for commercial PV offered through the CSI program have already been, or will soon be, exhausted.



Notes: We assume that all systems ≤10 kW are residential unless identified otherwise. See Appendix C for the assumptions used to calculate the after-tax value of state/utility cash incentives, state ITCs, and the federal ITC/Treasury cash grant.

Figure 25. Net Installed Cost of Residential PV (Calculated)



Notes: We assume that all systems >10 kW are commercial unless identified otherwise. See Appendix C for the assumptions used to calculate the after-tax value of state/utility cash incentives, state ITCs, and the federal ITC/Treasury cash grant.

Figure 26. Net Installed Cost of Commercial PV (Calculated)

Incentives and Net Installed Costs Differ Widely Across States

The preceding trends in this section are dominated by the PV incentive programs in California and New Jersey, which comprise the vast majority of the systems in the behind-the-meter PV data sample. Incentives and net installed costs, however, vary significantly across the states in the data sample, as illustrated in Figure 27 and Figure 28, which compare capacity-weighted average incentives and net installed costs across states in 2010, for residential and commercial PV, respectively.[36] As noted previously, this analysis does not capture potential revenues from ongoing sale of SRECs, given the high degree of uncertainty in future SREC prices. However, given the potential significance of SREC revenues, Figure 27 and Figure 28 segment the states into SREC and non-SREC markets, in order to more meaningfully compare incentive levels and net installed costs. For the purpose of this segmentation, SREC markets consist of those states with a solar set-aside and where active trading in unbundled SRECs is currently taking place.[37]

Among residential systems installed in 2010 in *non-SREC states*, capacity-weighted average aggregate after-tax incentives (i.e., state/utility cash incentives plus state and federal ITCs) ranged from a low of $2.9/W in California to a high of $4.7/W in Florida, as shown in Figure 27. Among these states, the average net installed cost for residential PV was lowest in Oregon ($2.2/W), owing to its relatively lucrative incentives (which include a substantial state ITC) combined with relatively low gross installed costs. At the other end of the spectrum is Minnesota, where the average net installed cost of residential PV in 2010 was almost twice as high ($4.2/W) as a result of relatively low cash incentives and high gross installed costs. The net installed cost of residential PV was also relatively high in California ($4.0/W), due to the low residential incentives available.

Across SREC states, capacity-weighted average incentive levels for residential PV (again, without considering potential SREC revenues) were slightly lower than in non-SREC states, with a low of $2.4/W in Maryland and a high of $4.0/W in Washington D.C. Average net installed costs for residential PV among the six SREC states shown in Figure 27 ranged from $3.0/W in New Hampshire to $4.0/W in New Jersey. If revenues from SRECs were included in these calculations, total average incentive levels in these states could be substantially greater and average net installed costs substantially lower (e.g., by the equivalent of roughly $1.2/W if SRECs were sold at a hypothetical average price of $200/MWh over the lifetime of the PV system[38]).

For commercial PV (Figure 28), average after-tax incentive levels and net installed costs also varied considerably across states in 2010. Among the 12 non-SREC states shown in the figure, average after-tax incentive levels ranged from $2.4/W in Vermont to $4.9/W in Florida. Average net installed costs were lowest in Nevada, at just $1.4/W, as a result of the particularly low average gross installed cost for commercial PV in that state in 2010. Among non-SREC states, capacity-weighted average net installed costs for commercial PV were highest in Illinois, at $7.0/W, though that result is due to a single, high-cost project that skewed the capacity-weighted average.

Comparing across the four SREC states in Figure 28, average aggregate incentive levels for commercial PV in 2010 ranged from $2.4/W in New Jersey to $3.5/W in Ohio, and net installed costs ranged from $2.9/W in Ohio and Massachusetts to $3.8/W in New Jersey. As noted previously, including SREC revenues in these calculations could substantially shift these results – particularly for New Jersey, where SREC prices have historically been relatively high. Also note that Figure 28 includes only systems that received a direct cash rebate through one of the PV incentive programs in the data sample. In some SREC states (New Jersey and Massachusetts, in particular), many commercial PV projects do not participate in these programs, and instead, receive incentives solely in the form of SRECs. If these SREC-only projects were included in Figure 28,

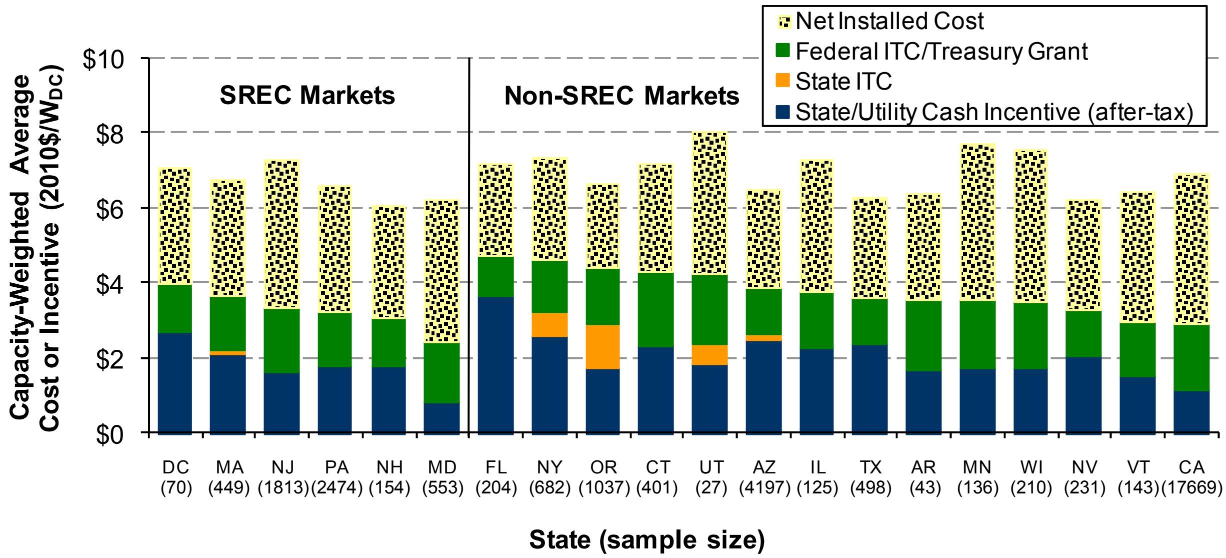
---

[36] See Table B-3 for the average annual cash incentive for each of the PV incentive programs in the sample.

[37] We acknowledge that this is an imperfect distinction, as some states with solar set-asides allow SRECs generated in other states within the same region to be used for compliance; in these cases, those other states could also be considered SREC markets. Also note that states with solar/DG set-asides where SRECs are procured only through state/utility incentive programs or through bundled electricity/SREC contracts are classified here as "Non-SREC Markets".

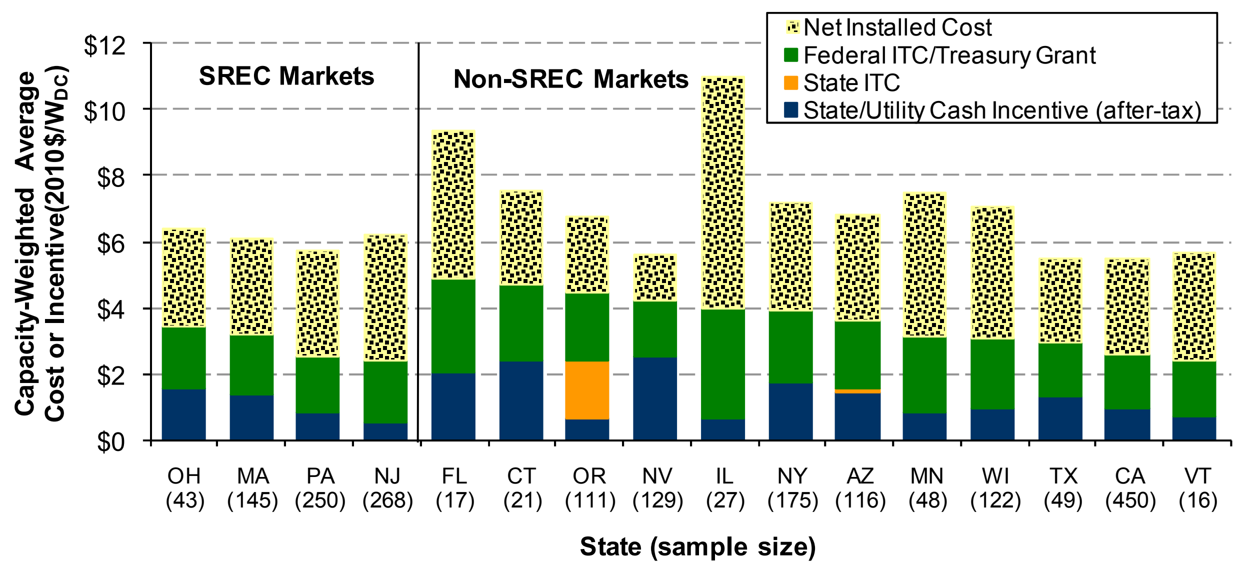
[38] $1.2/W is the estimated net present value, on an *after-tax* basis, of SREC payments made at a rate of $200/MWh over 20 years, based on the same financial assumptions identified in Text Box 3.

the average state/utility cash incentive levels for SREC states would be lower (and net installed costs higher).



Notes: We assume that all systems ≤10 kW are residential unless identified otherwise. Ohio is excluded from the figure due to an insufficient sample size. See Appendix C for the assumptions used to calculate the after-tax value of state/utility cash incentives, state ITCs, and the federal ITC/Treasury cash grant.

Figure 27. Comparison of Incentive Levels and Net Installed Cost across States for Residential PV Systems Installed in 2010 (Calculated)



Notes: We assume that all systems >10 kW are commercial unless identified otherwise. NH is excluded from the figure, because all systems in the data sample are residential; and AR, MD, and DC are excluded due to insufficient sample size. Results shown for NJ exclude systems in the SREC Registration Program that did not receive a rebate through the CORE or REIP incentive programs; similarly, results for MA exclude systems in the MA SREC program that did not receive a cash incentive through one of MassCEC's incentive programs. See Appendix C for the assumptions used to calculate the after-tax value of state/utility cash incentives, state ITCs, and the federal ITC/Treasury cash grant.

Figure 28. Comparison of Incentive Levels and Net Installed Cost across States for Commercial PV Systems Installed in 2010 (Calculated)

5. Installed Cost Trends: Utility-Sector PV

This section describes trends in the installed cost of utility-sector PV systems, based on the data sample described in Section 2. As indicated previously, utility-sector PV is defined for the purpose of this analysis to consist of systems connected directly to the utility system.[39] The section begins by describing the range in the installed cost of the utility-sector systems in the data sample, before then describing differences in installed costs according to project size and system configuration (crystalline fixed-tilt vs. crystalline tracking vs. thin-film fixed-tilt).

Before proceeding, it is important to note that the utility-sector installed cost data presented in this section must be interpreted with a certain degree of caution, for several reasons.

- *Small sample size with atypical utility PV projects*. The total sample of utility-sector projects is relatively small (31 projects in total, of which 20 projects were installed in 2010), and includes a number of small wholesale distributed generation projects as well as a number of larger "one-off" projects with atypical project characteristics (e.g., brownfield developments, utility pole-mounted systems, projects built to withstand hurricane winds, etc.). The cost of these small or otherwise atypical projects is expected to be higher than the cost of many of the larger utility-scale PV projects currently under development.
- *Lag in component pricing*. The installed cost of any individual utility-sector project may reflect component pricing one or even two years prior to project completion, and therefore the cost of the utility-sector projects within the data sample may not fully capture the steep decline in module or other component prices that occurred over the analysis period. For this reason and others (see Text Box 1 within the main body of the report), the results presented here likely differ from current PV cost benchmarks.
- *Reliability of data sources*. The cost data obtained for utility-sector PV projects are derived from varied sources and, in some instances (e.g., trade press articles and press releases), are arguably less reliable than the cost data presented earlier for behind-the-meter PV systems.
- *Focus on installed cost rather than levelized cost*. It is worth repeating again that, by focusing on installed cost trends, this report ignores performance-related differences and other factors that influence the levelized cost of electricity (LCOE), which is a more comprehensive metric for comparing the cost of utility-sector PV systems.

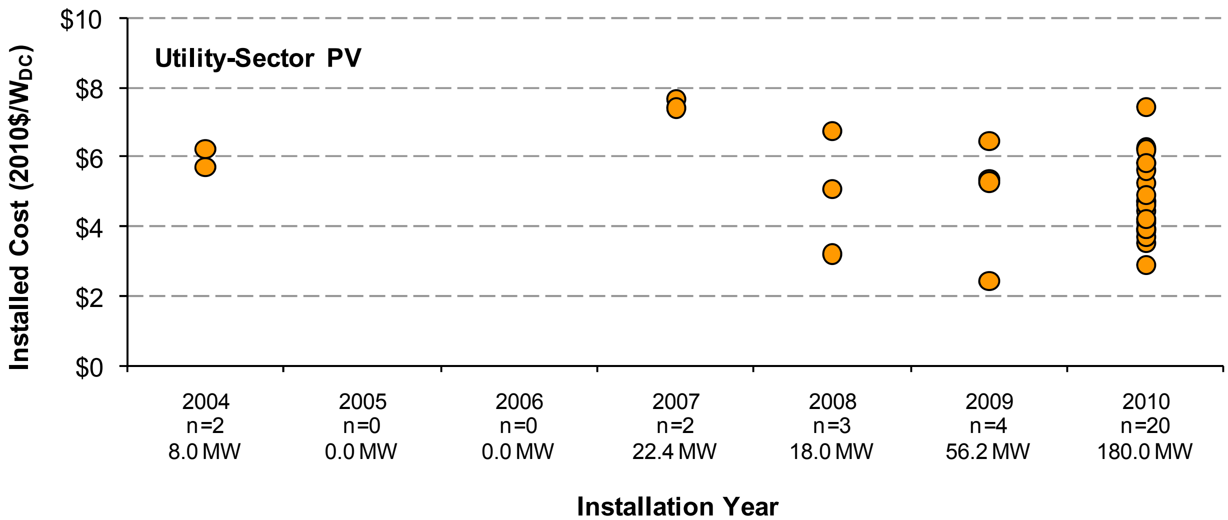
The Installed Cost of Utility-Sector PV Varies Considerably Across Projects

The installed cost of the utility-sector PV systems in the data sample varies widely, as shown in Figure 29. Among the 20 projects in the data sample completed in 2010, for example, installed costs ranged from \$2.9/W to \$7.4/W. The wide range in installed costs exhibited by utility-sector projects in the data sample invariably reflects a combination of factors, including differences in project size (which range from less than 1 MW to over 34 MW) and differences in system configuration (e.g., fixed-tilt vs. tracking systems), both of which are discussed further below. The wide cost distribution of the utility-sector PV data sample is also attributable to the presence of systems with unique characteristics that increase costs. For example, among the 2010 installations in the data sample are a 10 MW tracking system built on an urban brownfield site (\$6.2/W), an 11

[39] The only exception to this rule was for the 14.2 MW PV system installed at Nellis Air Force Base, which is connected on the customer-side of the meter but is included within the utility-sector data sample due to its large size.

MW fixed-axis system built to withstand hurricane winds ($5.6/W), and a collection of panels mounted on thousands of individual utility distribution poles totaling 14.6 MW ($7.4/W).

For the reasons described earlier in Text Box 1, many current cost benchmarks for utility-sector PV are at the low-end of the range exhibited by the projects in the data sample. Though we have not attempted a comprehensive survey, NREL[40], for example, specifies an installed cost of $3.8/W for prototypical fixed-tilt crystalline systems, $4.1/W for fixed-tilt thin-film systems, and $4.4/W for single-axis crystalline systems, all at an assumed size of 188 MW and installed in the second half of 2010. SEIA/GTM[41] cite an average cost of $3.9/W for utility-sector systems of unspecified size and configuration and installed in the first quarter of 2011. Finally, RW Beck[42] estimates the average cost of a fixed-tilt crystalline utility PV system installed in late 2010 at $3.8/W for a 188 MW system and $4.2/W for a 10 MW system.



Notes: The figure includes a number of relatively small wholesale distributed PV projects as well as several "one-off" projects. In addition, the reported installed cost of projects completed in any given year may reflect module and other component pricing at the time of project contracting, which may have occurred one or two years prior to installation. For these reasons and others (see Text Box 1), the data may not provide an accurate depiction of the current cost of typical utility PV projects and may not correspond to recent cost benchmarks for utility PV.

Figure 29. Installed Cost over Time for Utility-Sector PV

The Installed Cost of Utility-Sector Projects Depends on Project Size and System Configuration

The impact of project size and system configuration on the installed cost of utility-sector PV systems is shown explicitly in Figure 30, which presents the installed cost of utility-sector systems completed in 2008-2010 (we include three years here in order to increase the sample size) according to project size and distinguishing between three system configurations: fixed-tilt systems with

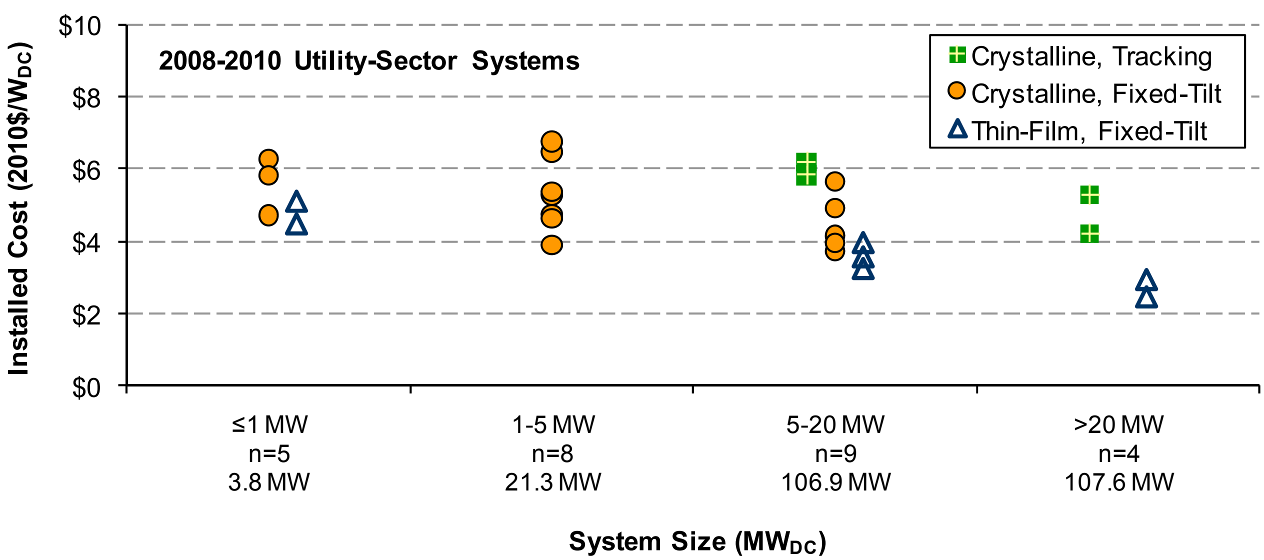
[40] Goodrich, A., James, T., Woodhouse, M. (in preparation). *Drivers of Solar Photovoltaic (PV) System Prices in the United States*. NREL Technical Report. Golden, CO: National Renewable Energy Laboratory.
[41] SEIA/GTM, *U.S. Solar Market Insight: First Quarter 2011*, Solar Electric Industries Association and GTM Research.
[42] RW Beck. 2010. *Review of Power Plant Cost and Performance Assumptions for NEMS*. Prepared for the Energy Information Administration, Office of Integrated Analysis and Forecasting. October 2010. The installed cost data presented within that report are expressed in terms of AC capacity, but are converted above into DC capacity units.

crystalline modules, fixed-tilt systems with thin-film modules, and tracking systems with crystalline modules.

The number of projects within each size range is quite small, and thus the conclusions that can be drawn from this comparison are highly provisional. Nevertheless, the figure clearly illustrates the impact of system configuration on installed cost, with thin-film systems exhibiting the lowest installed cost within each size range, and crystalline systems with tracking exhibiting the highest cost, as expected. For example, among >5 MW systems in the data sample, installed costs ranged from $2.4-$3.9/W for the five thin-film systems, compared to $3.7-$5.6/W for the five crystalline systems without tracking and $4.2-$6.2/W for the four crystalline systems with tracking. As noted previously, however, comparing only the installed cost ignores the performance benefits of high-efficiency crystalline modules and tracking equipment, which offset the higher up-front cost.

Figure 30 also illustrates the economies of scale for utility-sector PV, as indicated by the downward shift in the installed cost range for each system configuration type with increasing project size. For example, among fixed-tilt, crystalline systems installed over the 2008-2010 period, installed costs ranged from $3.7-$5.6/W for the five 5-20 MW systems, compared to $4.7-$6.3/W for the three <1 MW systems. Similarly, among thin-film systems, the installed cost of the two >20 MW projects completed in 2008-2010 ranged from $2.4-$2.9/W, compared to $4.4-$5.1/W for the two <1 MW projects.

Notwithstanding the aforementioned trends, Figure 30 also shows a high degree of "residual" variability in installed costs across projects of a given configuration and within each size range, indicating clearly that other factors (such as "atypical" project characteristics) also strongly influence the installed cost of utility-sector PV.



Notes: The figure includes a number of relatively small wholesale distributed PV projects as well as several "one-off" projects. In addition, the reported installed cost of projects completed in any given year may reflect module and other component pricing at the time of project contracting, which may have occurred one or two years prior to installation. For these reasons and others (see Text Box 1), the data may not provide an accurate depiction of the current cost of typical utility PV projects and may not correspond to recent cost benchmarks for utility PV. This figure excludes the set of utility pole-mounted PV systems installed in PSE&G's service territory; previously, those systems are counted as a single project.

Figure 30. Variation in Installed Cost of Utility-Sector PV According to System Size and Configuration

6. Conclusions and Policy Implications

The number of PV systems installed in the United States has grown at a rapid pace in recent years, driven in large measure by government incentives. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage cost reductions over time. Available evidence confirms that the installed cost of PV systems has declined substantially since 1998, though both the pace and source of those cost reductions have varied over time. Prior to 2005, installed cost reductions were associated primarily with a decline in *non-module* costs. Starting in 2005, however, cost reductions began to stall, as the supply-chain and delivery infrastructure struggled to keep pace with rapidly expanding global demand. Starting in 2008, global wholesale module prices began a steep downward trajectory. Those reductions in module prices began to drive the average installed cost of PV systems installed in the United States significantly lower in 2010, when average installed costs fell by 17%.

In addition, average *non-module* costs also fell significantly in 2010, after several years of apparent stagnation. Trends in non-module costs may be particularly relevant in gauging the impact of state and utility PV deployment programs. Unlike module prices, which are primarily established through global markets, non-module costs consist of a variety of cost components that may be more readily affected by local programs – including deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more-targeted efforts, such as training and education programs. Both the long-term and more-recent reductions in non-module costs suggests that PV deployment policies have achieved some success in fostering competition within the industry and spurring improvements in the cost structure and efficiency of the PV delivery infrastructure.

Preliminary cost data for the first half of 2011, as well as current cost benchmarks published by a variety of other entities, indicate that installed costs have continued to decline. Notwithstanding this success, further cost reductions will be necessary if the U.S. PV industry is to continue its expansion, given the expectation that PV incentive programs will also continue to ratchet down financial support. Lower average installed costs in Germany suggest that deeper near-term cost reductions in United States are, in fact, possible and may accompany increased market scale. It is also evident, however, that market size alone is insufficient to fully capture potential near-term cost reductions, as suggested by the fact that the lowest-cost state markets in the United States are relatively small PV markets. Targeted policies aimed at specific cost barriers (for example, permitting and interconnection costs), in concert with basic and applied research and development, may therefore be required in order to sustain the pace of installed cost reductions on a long-term basis.

Finally, installed costs vary substantially across system sizes, market segments, technology types, and applications. Policymakers may wish to evaluate whether differential levels of financial support are therefore warranted (e.g., to avoid over-subsidizing more cost-competitive installations while providing sufficient support for promising but less mature technologies and applications).

Appendix A: Data Cleaning, Coding, and Standardization

To the extent possible, this report presents data as provided directly by PV incentive program administrators and other data sources; however, several steps were taken to clean and standardize the data, as described below.

Projects Removed from the Data Sample: The data received from all PV incentive program administrators initially consisted of 118,253 PV systems installed through 2010. Systems missing installed cost data (1,030 systems) or system size data (376 systems) were removed from the dataset. To eliminate presumably erroneous numerical data entries, systems were also removed from the dataset if the reported installed cost was less than $2/W (52 systems) or greater than $30/W (101 systems), or if the incentive amount was greater than $30/W (28 systems). All battery back-up (294 systems) and self-installed (268 systems) were also removed from the dataset. Finally, an effort was made to identify systems that received cash incentives from more than one of the PV incentive programs in the data sample. Where these systems could be identified, duplicate entries were eliminated from the final data sample, and the cash incentive amounts listed for those systems in the final data base represent the combined cash incentive from both programs. In some cases, the raw data provided by the PV incentive programs identified systems that received cash incentives from other programs; in other cases, duplicate entries across programs were identified by matching addresses or other system characteristics. Based on this process, 260 duplicate systems were removed from the Florida Energy & Climate Commission's Solar Rebate Program (that were already contained in the data for Gainesville's or Orlando's programs), 312 duplicate systems from the Massachusetts SREC program (that were already contained in the data for the MassCEC's programs), and 106 systems were removed from the California Self Generation Incentive Program (that were already contained in the data from either SMUD's or LADWP's programs). In total, 1,749 systems from the initial sample were removed from the dataset as a result of all of the aforementioned filters.

Manual Data Cleaning: Module manufacturer/model and inverter manufacturer/model data were reviewed in order to correct obvious misspellings and misidentifications, and to create standardized identifiers for individual module and inverter models.

Completion Date: The data provided by several PV incentive programs did not identify the system completion date. In lieu of this information, the best available proxy was used (e.g., the date of the incentive payment or the post-installation site inspection).

Identification of Residential New Construction and Residential Retrofit Systems: Section 3 compares the cost of systems installed in residential new construction to those installed in residential retrofit applications, focusing specifically on systems installed through two California programs in 2010: the California Energy Commission (CEC)'s New Solar Home Partnership (NSHP) program and the California Solar Initiative (CSI). All systems installed through NSHP are assumed to be residential new construction, while all residential systems installed through CSI are assumed to be retrofit.

Identification of Building-Integrated and Rack-Mounted Residential Systems: The comparison between residential new construction and residential retrofit systems funded through NSHP and CSI is further differentiated between building-integrated PV (BIPV) and rack-mounted systems. The raw data provided by PV incentive program administrators did not include explicit identifiers for these categories; thus, systems were identified as either BIPV or rack-mounted by cross-referencing data provided on the module manufacturer and model for each system with the California Solar Initiative (CSI)'s List of Eligible Modules, which identifies whether modules are BIPV or rack-mounted.[43] Based on this procedure, 2,154 of the 2,164

[43] http://www.gosolarcalifornia.org/equipment/pvmodule.php

applicable systems in the dataset (i.e., 2-3 kW systems funded through NHSP and CSI and installed in 2010) were identified as either BIPV or rack-mounted.

Identification of Crystalline and Thin-Film Systems: Section 3 compares the installed cost of systems with thin-film modules to those with crystalline modules. The raw data provided by PV program administrators generally do not include explicit identifiers for these categories. Thus, systems were categorized as crystalline, thin-film, or hybrid by cross-referencing data provided on module manufacturer and model with the CSI's List of Eligible Modules, which identifies whether modules are crystalline, thin-film, or hybrid. Based on this procedure, 27,551 of the 35,869 systems installed in 2010 were identified as employing either thin-film or crystalline modules.

Conversion to 2010 Real Dollars: Installed cost and incentive data are expressed throughout this report in real 2010 dollars (2010$). Data provided by PV program administrators in nominal dollars were converted to 2010$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.[44]

Conversion of Capacity Data to Direct Current (DC) Watts at Standard Test Conditions (DC-STC): Throughout this report, all capacity and dollars-per-watt ($/W) data are expressed using DC-STC capacity ratings. Most programs directly provided data in units of DC-STC; however, four programs (the CEC's Emerging Renewables Program and New Solar Home Partnership program, the CPUC's Self-Generation Incentive Program, and SMUD's Residential Retrofit and Commercial PV Programs) provided capacity data only in terms of the California Energy Commission Alternating Current (CEC-AC) rating convention, which represents peak AC power output at PVUSA Test Conditions (PTC). In addition, three programs (NM's Solar Market Development Tax Credit, NVEnergy's Renewable Generations Rebate Program, and VT's RERC Small Scale Renewable Energy Incentive Program) only specified module model and number of models per system. DC-STC capacity ratings for systems funded through these seven programs were calculated according to the procedures described below.

CEC Emerging Renewables Program (ERP), CEC New Solar Home Partnership (NSHP) Program, and SMUD Residential Retrofit and Commercial PV Programs: The data provided for these programs included data fields identifying the module manufacturer, model, and number of modules for most PV systems. DC-STC ratings were identified for most modules by cross-referencing the information provided about the module type with the CSI's List of Eligible Photovoltaic Modules, which identifies DC-STC ratings for most of the modules employed in the systems funded through these programs. The DC-STC rating for each module was then multiplied by the number of modules to determine the total DC-STC rating for the system, as a whole. This approach was used to determine the DC-STC capacity rating for all of the systems in the NSHP and SMUD datasets, and for 86% of the systems in the ERP dataset. For the remaining systems in the ERP dataset, either the module data fields were incomplete, or the module could not be cross-referenced with the CSI list, or the estimated DC-STC rating for the system was grossly inconsistent with the reported CEC-AC rating. In these cases, an average conversion factor of 1.200 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$ was used, which was derived based on the averages for other systems in the ERP dataset.

CPUC Self-Generation Incentive Program (SGIP): The data provided for SGIP included data fields identifying module manufacturer and model (but not number of modules), and inverter manufacturer and model. DC-STC module ratings and DC-PTC module ratings (i.e., DC watts at PVUSA Test Conditions) were identified by cross-referencing the reported module type with the CSI's List of Eligible Photovoltaic Modules. Similarly, the rated inverter efficiency for each project was identified by cross referencing the reported inverter type with the CSI's List of Eligible Inverters, which identifies inverter efficiency ratings for

[44] ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt

most of the inverters used within the systems funded through SGIP.[45] These pieces of information (module DC-STC rating, module DC-PTC rating, and inverter efficiency rating), along with the reported CEC-AC rating for the system, were used to estimate the system DC-STC rating according to the following:

$$System_{DC\text{-}STC} = (System_{CEC\text{-}AC} / \text{Inverter Eff.}) * (Module_{DC\text{-}STC} / Module_{DC\text{-}PTC})$$

In cases where data on module manufacturer and model either was not provided or could not be matched with the CSI module list, then the DC-STC rating was calculated using the median ratio of module DC-STC to DC-PTC ratings for systems installed in the same year (0.88-0.90 $W_{DC\text{-}STC}/W_{DC\text{-}PTC}$). In cases where data on inverter manufacturer and model either was not provided or could not be matched with the CSI's inverter list, the inverter efficiency was stipulated based on the average inverter efficiency of systems in the SGIP dataset installed in the same year and for which inverter efficiency ratings could be identified. If neither the module nor inverter data were provided, then the DC-STC rating was calculated directly from the reported CEC-AC rating, using the median annual ratio of module DC-STC rating to system CEC-AC rating (1.19-1.22 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$).

NM Solar Market Development Tax Credit, NVEnergy Renewable Generations Rebate Program, and VT RERC Small Scale Renewable Energy Incentive Program: The data provided for these programs did not specify the total PV system capacity, but did specify module model and number of modules for each system. We determined the nameplate DC-STC rating for each module model, based on the CSI's List of Eligible Photovoltaic Modules and/or from module manufacturer specification sheets, and then calculated the *system* DC-STC rating as the product of the module DC-STC rating and the number of modules.

Systems Excluded from Incentive and Net Installed Cost Analysis: The results presented in Section 4 are based on the subset of residential and commercial behind-the-meter PV systems in the data sample that received state/utility cash incentives and for which data on the size of the cash incentive were provided. A total of 4,484 systems and 301.1 MW were excluded from the incentive and net installed cost analysis, consisting of:

- Systems identified within the raw data provided by PV incentive programs as having tax-exempt host customers, such as governments, schools, and non-profit organizations (1,737 systems, 156.8 MW)[46]
- Systems participating in the New Jersey SREC Registration Program (926 systems, 81.6 MW) that did not receive a rebate from either the CORE or REIP programs, and systems participating in the Massachusetts DOER's SREC program that did not receive a rebate through one of MassCEC's incentive programs (89 systems, 8.4 MW)
- Systems for which data was obtained solely from the U.S. Treasury Section 1603 Grant Program database or from other supplementary data sources (675 systems, 70.5 MW), as data on any state/utility cash incentive received were not available for those systems
- Systems for which data were provided by the New Mexico's Solar Market Development Tax Credit program (951 systems, 4.2 MW), as those systems likely received cash incentives from utility programs, but data on the size of those incentive amounts were not available
- Systems funded through Gainesville Regional Utility's Solar Feed-in Tariff program (71 systems, 3.3 MW), as the payments provided through that program include both an incentive plus a payment for electricity production (in lieu of net metering), and therefore the payments under the program cannot be meaningfully compared to the cash incentives provided through other state/utility PV

[45] http://www.gosolarcalifornia.org/equipment/inverter.php
[46] Because of overlap between systems with tax-exempt host customers and the other screens listed here, the tax-exempt host customer screen resulted in the *net* removal of 1,588 systems and 129.9 MW.

incentive programs, which do not include payment for electricity production (as that compensation is provided separately through net metering)

- Systems that were funded through one of the state/utility incentive programs in the data sample but were missing incentive data (184 systems, 3.1 MW)

Conversion of Reported PBI Payments to 2010$/W: Six PV incentive programs in the data sample provided performance-based incentives (PBIs), paid out over time based on actual energy generation and a pre-specified payment rate, to some or all systems. In order to facilitate comparison with up-front rebates and tax credits provided to the other systems in data sample, PBI payments were translated into an equivalent up-front payment by calculating the net present value (NPV) of the expected PBI payment amount. The approach taken to calculate the NPV of the PBI payment differed somewhat across programs, depending on the data provided and the nature of the PBI payment.

AR Energy Office Renewable Technology Rebate Fund: In this program, all systems receive a single PBI payment based on total energy production during the first year of operation. The program administrator provided data on the estimated or actual PBI payment for each system. These data were used as-is, with no discounting.

APS Renewable Energy Incentive Program, CPUC California Solar Initiative, and SRP EarthWise Solar Energy Program: These three programs provided PBI payments to a subset of the participating projects (typically the larger non-residential projects). The PBI payments in these programs are paid out on a monthly or quarterly basis over multi-year periods (for APS: 10, 15, or 20 years; for CSI: 5 years; and for SRP: 20 years). In the case of APS, the PBI contract period for each system was not specified, and we therefore assumed 15 years. The program administrators provided the estimated total PBI payment for each system receiving a PBI, over the duration of the PBI contract term. Lacking any specific information otherwise, we assumed that these program administrators estimated lifetime PBI payments by multiplying the estimated first-year energy production for each system by the PBI payment rate and the PBI contract term, without any discounting and without accounting for system degradation over time. As such, we calculated the NPV of the PBI payments by first dividing the estimated total PBI amount for each system by the PBI contract term, in order to estimate the first-year PBI payment. Nominal PBI payments in subsequent years were estimated by applying a 0.5% annual degradation factor to the first-year PBI payment. The NPV of annual PBI payments over the contract term was then calculated assuming a 7% nominal discount rate.

Orlando Utilities Commission Pilot Solar Program. Under this program, all participating systems receive a monthly PBI paid out over the life of the system. The data provided by the program administrator included the total annual PBI payment in 2010 for each system. For systems installed prior to 2010, we used these values to calculate the NPV of all payments over the life of the system, assuming a 20 year lifetime, a degradation factor of 0.5%/yr, and an annual discount rate of 7%. For systems installed in 2010, we could not use the provided PBI data, as these are for an incomplete year. Instead, we used the average annual PBI payment per kW ($/kW/yr) of all systems installed prior to 2010 to estimate the annual PBI payment per kW that each 2010 system would receive over the course of its first complete year of operation. We then followed the same procedure and assumptions as for the pre-2010 systems in order to estimate the NPV of the lifetime PBI payments (i.e., 20-year lifetime, 0.5% annual degradation, and 7% nominal discount rate).

Austin Energy Power Saver Program: This program provides PBI payments to a small sub-set of all participating projects, issued over a 10-year period. The program administrator, however, did not provide estimates for either estimated PBI payment or estimated annual system production. Therefore, we did not calculate the NPV of PBI payments for these systems, and treated these systems as having missing incentive data.

Appendix B: Behind-the-Meter PV Data Sample Summaries

Table B-1. Sample Size of Behind-the-Meter PV Systems by Installation Year and System Size Range

System Size Range	Installation Year													Total
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	
No. Systems														
0-5 kW	31	161	186	1,119	1,918	2,326	3,513	3,181	5,072	7,385	8,326	13,037	15,335	**61,590**
5-10 kW	3	13	24	162	435	902	1,562	1,674	2,712	4,129	4,349	9,326	15,060	**40,351**
10-100 kW	5	10	12	37	165	322	524	639	890	1,225	1,418	2,630	4,875	**12,752**
100-500 kW	0	1	2	5	19	38	35	94	92	119	294	252	488	**1,439**
>500 kW	0	0	0	0	3	6	7	10	22	34	89	90	111	**372**
Total	*39*	*185*	*224*	*1,323*	*2,540*	*3,594*	*5,641*	*5,598*	*8,788*	*12,892*	*14,476*	*25,335*	*35,869*	***116,504***
Capacity (MW)														
0-5 kW	0.1	0.4	0.4	3.0	5.1	6.6	10.1	9.4	15.6	23.6	26.0	42.2	50.5	**193**
5-10 kW	0.0	0.1	0.2	1.1	2.9	6.1	10.6	11.8	18.8	28.6	29.8	63.6	103.9	**277**
10-100 kW	0.1	0.3	0.2	0.6	2.9	7.1	12.3	15.0	18.3	25.4	33.0	56.9	106.8	**279**
100-500 kW	0.0	0.1	0.2	0.8	3.4	9.0	7.1	18.9	20.6	27.7	71.2	56.3	97.7	**313**
>500 kW	0.0	0.0	0.0	0.0	1.7	5.3	5.1	7.4	17.7	27.1	78.2	88.3	107.3	**338**
Total	*0.2*	*0.8*	*1.0*	*5.5*	*16.0*	*34.0*	*45.1*	*62.5*	*91.0*	*132.3*	*238.2*	*307.2*	*466.3*	***1,400***

Table B-2. Behind-the-Meter Data Sample Summary by PV Incentive Program

State	PV Incentive Program	No. of Systems	Total MW_{DC}	% of Total MW_{DC}	Size Range (kW_{DC})	Year Range
AR	Energy Office Renewable Technology Rebate Fund	46	0.3	0.0%	1.1 - 21	2010 - 2010
AZ	APS Renewable Energy Incentive Program	5,518	46.1	3.3%	0.4 - 2,401	2002 - 2010
	SRP EarthWise Solar Energy Program	2,510	16.7	1.2%	0.4 - 502	2005 - 2010
CA	Anaheim Solar Advantage Program	266	2.8	0.2%	1.3 - 531	1999 - 2010
	CEC Emerging Renewables Program	27,947	146.4	10.5%	0.1 - 670	1998 - 2008
	CEC New Solar Homes Partnership	3,568	12.6	0.9%	1.2 - 154	2007 - 2010
	CPUC California Solar Initiative	41,038	495.0	35.3%	1.1 - 1,308	2007 - 2010
	CPUC Self Generation Incentive Program	806	148.6	10.6%	34 - 1,266	2002 - 2009
	LADWP Solar Incentive Program	3,457	32.5	2.3%	0.3 - 1,176	1999 - 2010
	SMUD Residential Retrofit and Commercial PV Programs	758	13.2	0.9%	1.1 - 2,408	2006 - 2010
CT	CCEF Onsite Renewable DG Program	150	16.8	1.2%	1.6 - 570	2004 - 2010
	CCEF Solar PV Program	1,447	9.3	0.7%	0.8 - 19	2005 - 2010
DC	Dept. of Environment Renewable Energy Incentive Program	129	0.6	0.0%	0.9 - 56	2009 - 2010
FL	Gainesville Solar Feed-In Tariff[a]	71	3.3	0.2%	3.2 - 536	2009 - 2010
	Gainesville Solar-Electric System Rebate Program[a]	109	1.0	0.1%	2.4 - 74	2006 - 2010
	Orlando Pilot Solar Program[a]	61	1.4	0.1%	2.2 - 1,040	2008 - 2010
	Energy & Climate Commission Solar Rebate Program[a]	772	5.0	0.4%	2.0 - 74	2006 - 2010
IL	DCEO Solar and Wind Energy Rebate Program	517	3.8	0.3%	0.8 - 700	1999 - 2010
MA	MassCEC PV incentive programs (multiple programs)[b]	2,351	29.2	2.1%	0.2 - 501	2002 - 2010
	DOER SREC Registration Program only	89	8.4	0.6%	1.0 - 1,797	2008 - 2010
	Systems in both programs (MassCEC and DOER SREC)	292	5.4	0.4%	1.1 - 983	2008 - 2010
MD	MEA Solar Energy Grant Program	1,278	7.2	0.5%	0.5 - 200	2005 - 2010
MN	MSEO Solar Electric Rebate Program	405	2.0	0.1%	0.5 - 40	2003 - 2010
NH	NHPUC Renewable Energy Rebate Program	364	1.1	0.1%	0.4 - 5.0	2008 - 2010
NJ	NJCEP Customer Onsite Renewable Energy Program	4,152	84.5	6.0%	0.8 - 2,372	2001 - 2010
	NJCEP Renewable Energy Incentive Program	2,599	26.9	1.9%	0.8 - 51	2009 - 2010
	NJCEP SREC Registration Program	926	81.6	5.8%	0.4 - 2,421	2007 - 2010
NM	Solar Market Development Tax Credit	951	4.2	0.3%	0.4 - 249	2009 - 2010
NV	NVEnergy Renewable Generations Rebate Program	884	9.9	0.7%	0.4 - 175	2004 - 2010
NY	NYSERDA PV Incentive Program	2,973	25.6	1.8%	0.7 - 254	2003 - 2010
OH	ODOD multiple programs[c]	185	7.0	0.5%	1.0 - 1,121	2005 - 2010
OR	ETO Solar Electric Program	2,539	22.1	1.6%	0.4 - 859	2002 - 2010

State	PV Incentive Program	No. of Systems	Total MW_{DC}	% of Total MW_{DC}	Size Range (kW_{DC})	Year Range
PA	DEP Sunshine Solar PV Program	3,096	39.1	2.8%	1.1 - 305	2009 - 2010
	SDF Solar PV Grant Program	164	0.7	0.0%	1.2 - 12	2002 - 2008
TX	Austin Energy Power Saver Program	1,233	5.6	0.4%	0.2 - 28	2004 - 2010
	IOU Solar Incentive Programs	481	4.8	0.3%	0.4 - 251	2009 - 2010
UT	RMP Solar Incentive Program	126	0.5	0.0%	0.4 - 24	2007 - 2010
VT	RERC Small Scale Renewable Energy Incentive Program	532	2.3	0.2%	0.2 - 45	2003 - 2010
WI	Focus on Energy Renewable Energy Incentive Program	1,039	6.4	0.5%	0.2 - 273	2002 - 2010
Non PV Incentive Program Data (e.g., Section 1603 Grant Program and other sources)		675	70.5	5.0%	1.4 - 6,024	2008 - 2010
	Total	***116,504***	***1,400***	***100%***	***0.1 - 6,024***	***1998 - 2010***

[a] Systems that received an incentive from one of the Florida utility programs as well as from the Florida Energy & Climate Commission's Solar Rebate Program were retained in the data sample for the utility program and removed from the data sample for Energy & Climate Commission's program.
[b] The MassCEC PV programs include systems that were funded through predecessor programs offered by the Massachusetts Technology Collaborative, prior to creation of MassCEC.
[c] The data provided by the Ohio Department of Development includes PV systems funded through a number of programs, including State Energy Plan, Advanced Energy Fund, ARRA Block Grants, and the Energy Loan Fund.

Table B-2. Annual Summary Statistics for Behind-the-Meter PV Data Sample by Incentive Program

State	Program Administrator(s) and Program Name	Annual Summary Data	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
AR	Arkansas Energy Office Renewable Technology Rebate Fund	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	-	-	46	***46***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	-	-	0.3	***0.3***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	-	-	$6.2	***$6.2***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	-	-	$2.2	***$2.2***
AZ	APS Renewable Energy Incentive Program	*No. of Systems*	-	-	-	-	5	17	42	68	197	233	398	1,655	2,903	***5,518***
		Capacity Additions (MW)	-	-	-	-	0.0	0.1	0.2	0.4	1.0	1.4	5.1	14.5	23.5	***46.1***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	$10.6	$6.7	$7.7	$8.9	$8.0	$7.8	$7.6	$7.3	$6.7	***$7.1***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	$3.5	$2.9	$3.8	$3.5	$3.7	$2.8	$1.9	$2.2	$2.5	***$2.4***
AZ	SRP EarthWise Solar Energy Program	*No. of Systems*	-	-	-	-	-	-	-	27	127	114	124	703	1,415	***2,510***
		Capacity Additions (MW)	-	-	-	-	-	-	-	0.1	0.5	0.6	1.6	4.9	9.0	***16.7***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	$7.7	$8.2	$7.2	$7.1	$7.2	$6.2	***$6.7***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	$3.3	$3.2	$3.1	$2.7	$2.9	$2.5	***$2.7***
CA	Anaheim Solar Advantage Program	*No. of Systems*	-	2	1	3	13	12	15	3	5	3	18	55	136	***266***
		Capacity Additions (MW)	-	0.0	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.8	1.4	***2.8***
		Cap-Wtd. Avg. Cost ($/W)	-	*	*	*	$10.8	$8.4	$8.5	*	$9.7	*	$8.3	$6.9	$6.0	***$6.3***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	*	-	*	$5.0	$4.6	$8.9	*	$6.6	*	$3.6	$2.7	$3.2	***$3.1***
CA	CEC Emerging Renewables Program	*No. of Systems*	39	178	213	1,238	2,246	2,964	4,540	3,862	6,117	5,862	688	-	-	***27,947***
		Capacity Additions (MW)	0.2	0.7	0.9	4.8	9.8	15.1	22.4	20.4	34.2	34.3	3.6	-	-	***146.4***
		Cap-Wtd. Avg. Cost ($/W)	$11.0	$11.2	$9.6	$10.0	$10.2	$9.2	$8.4	$8.0	$8.1	$8.3	$8.0	-	-	***$8.5***
		Cap-Wtd. Avg. Cash Incentive ($/W)	$3.3	$3.3	$3.0	$4.1	$4.4	$4.0	$3.5	$2.9	$2.6	$2.4	$2.4	-	-	***$3.1***
CA	CEC New Solar Homes Partnership	*No. of Systems*	-	-	-	-	-	-	-	-	-	250	1,142	1,479	697	***3,568***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	0.7	3.1	5.4	3.4	***12.6***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	$8.2	$7.9	$7.7	$7.0	***$7.6***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	$2.5	$2.3	$2.5	$2.3	***$2.4***
CA	CPUC California Solar Initiative	*No. of Systems*	-	-	-	-	-	-	-	-	-	3,555	8,319	13,212	15,952	***41,038***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	33.7	143.8	154.8	162.6	***495.0***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	$7.8	$7.5	$7.7	$6.4	***$7.2***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	$2.3	$2.2	$1.7	$1.3	***$1.8***
CA	CPUC Self Generation Incentive Program	*No. of Systems*	-	-	-	-	16	71	147	191	143	141	87	10	-	***806***
		Capacity Additions (MW)	-	-	-	-	2.3	11.6	17.3	26.9	29.5	33.4	24.6	2.9	-	***148.6***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	$8.6	$7.3	$8.1	$7.5	$7.4	$7.2	$7.4	$8.2	-	***$7.5***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	$4.2	$3.4	$3.9	$3.7	$3.4	$2.8	$2.4	$2.2	-	***$3.2***
CA	LADWP Solar Incentive Program	*No. of Systems*	-	2	4	70	201	220	41	79	137	310	416	790	1,187	***3,457***
		Capacity Additions (MW)	-	0.1	0.0	0.5	3.0	5.0	0.4	1.5	1.3	1.8	3.5	6.4	9.1	***32.5***
		Cap-Wtd. Avg. Cost ($/W)	-	*	*	$8.9	$10.0	$10.3	$11.7	$8.6	$8.3	$8.9	$7.9	$8.3	$7.3	***$8.5***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	*	*	$5.7	$6.3	$6.2	$4.4	$2.6	$2.9	$3.6	$3.4	$3.4	$3.0	***$4.0***
CA	SMUD Residential Retrofit and Commercial PV Programs	*No. of Systems*	-	-	-	-	-	-	-	-	1	61	71	249	376	***758***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	0.0	0.9	0.7	4.4	7.2	***13.2***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	*	$8.3	$7.7	$6.6	$5.0	***$5.9***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	*	$2.7	$2.1	$2.4	$2.0	***$2.2***

State	Program Administrator(s) and Program Name	Annual Summary Data	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
CT	CCEF Onsite Renewable DG Program	*No. of Systems*	-	-	-	-	-	-	2	2	7	14	54	45	26	***150***
		Capacity Additions (MW)	-	-	-	-	-	-	0.0	0.0	0.3	1.6	6.2	6.7	1.9	***16.8***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	*	*	$8.2	$8.1	$7.9	$7.8	$7.5	***$7.8***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	*	*	$4.7	$4.4	$4.1	$3.9	$4.1	***$4.1***
CT	CCEF Solar PV Program	*No. of Systems*	-	-	-	-	-	-	-	32	89	168	273	479	406	***1,447***
		Capacity Additions (MW)	-	-	-	-	-	-	-	0.1	0.4	0.9	1.7	3.4	2.9	***9.3***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	$8.9	$9.2	$9.1	$8.6	$8.2	$7.2	***$8.1***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	$5.0	$4.8	$4.4	$4.2	$4.0	$3.4	***$3.9***
DC	Dept. of Environment Renewable Energy Incentive Program	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	-	57	72	***129***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	-	0.2	0.4	***0.6***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	-	$8.5	$6.8	***$7.4***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	-	$2.8	$2.3	***$2.5***
FL	Gainesville Solar Feed-In Tariff[(a)]	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	-	27	44	***71***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	-	0.6	2.7	***3.3***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	-	$6.3	$5.6	***$5.7***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	-	**	**	*****
FL	Gainesville Solar-Electric (PV) System Rebate Program[(a)]	*No. of Systems*	-	-	-	-	-	-	-	-	1	21	28	50	9	***109***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	0.0	0.1	0.3	0.5	0.1	***1.0***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	*	$8.7	$8.1	$6.3	$6.8	***$7.1***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	*	$5.6	$5.1	$4.5	$5.0	***$4.8***
FL	Orlando Pilot Solar Program[(a)]	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	11	23	27	***61***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	0.1	1.2	0.1	***1.4***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	$8.3	$7.9	$7.8	***$7.9***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	$4.4	$0.4	$4.4	***$1.0***
FL	Florida Energy & Climate Commission Solar Rebate Program[(a)]	*No. of Systems*	-	-	-	-	-	-	-	-	16	27	3	526	200	***772***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	0.1	0.2	0.1	3.3	1.3	***5.0***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	$10.2	$8.3	*	$7.5	$7.7	***$7.4***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	$4.2	$3.6	*	$3.5	$3.5	***$3.4***
IL	DCEO Solar and Wind Energy Rebate Program	*No. of Systems*	-	3	6	9	5	28	11	7	44	78	97	77	152	***517***
		Capacity Additions (MW)	-	0.0	0.0	0.1	0.1	0.5	0.3	0.1	0.1	0.2	0.3	0.3	1.7	***3.8***
		Cap-Wtd. Avg. Cost ($/W)	-	*	$18.2	$17.1	$12.6	$13.8	$13.2	$11.4	$8.9	$8.1	$9.0	$8.8	$10.0	***$10.7***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	*	$8.5	$7.5	$7.4	$7.1	$6.6	$6.4	$2.9	$2.7	$2.4	$2.5	$1.4	***$3.4***
MA	MassCEC PV incentive programs (multiple programs)[(b)]	*No. of Systems*	-	-	-	-	1	71	128	92	260	218	376	787	418	***2,351***
		Capacity Additions (MW)	-	-	-	-	0.0	0.3	0.6	0.8	1.8	1.6	3.6	9.3	11.2	***29.2***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	*	$11.7	$10.1	$9.7	$9.1	$10.6	$8.1	$7.8	$6.3	***$7.6***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	*	$10.1	$6.8	$8.8	$4.6	$4.4	$3.7	$4.0	$3.0	***$3.9***
MA	DOER SREC Registration	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	4	20	65	***89***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	0.0	0.4	8.0	***8.4***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	*	$9.3	$5.6	***$5.8***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	**	**	**	*****

State	Program Administrator(s) and Program Name	Annual Summary Data	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
MA	Systems in both MassCEC and DOER SREC Programs	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	4	17	271	***292***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	0.0	0.3	5.0	***5.4***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	*	$8.4	$5.9	***$6.0***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	*	$5.2	$0.9	***$1.2***
MD	MEA Solar Energy Grant Program	*No. of Systems*	-	-	-	-	-	-	-	7	43	45	135	486	562	***1,278***
		Capacity Additions (MW)	-	-	-	-	-	-	-	0.0	0.2	0.1	0.5	2.7	3.8	***7.2***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	$10.5	$10.3	$9.7	$9.0	$7.1	$6.0	***$6.8***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	$1.1	$0.9	$1.2	$1.5	$1.2	$0.8	***$1.0***
MN	MSEO Solar Electric Rebate Program	*No. of Systems*	-	-	-	-	-	9	14	11	20	37	50	79	185	***405***
		Capacity Additions (MW)	-	-	-	-	-	0.0	0.0	0.0	0.1	0.2	0.2	0.4	1.1	***2.0***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	$9.4	$8.1	$10.1	$8.5	$9.3	$10.2	$8.9	$7.6	***$8.4***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	$2.4	$2.1	$2.2	$2.2	$2.1	$1.9	$1.9	$1.6	***$1.8***
NH	NHPUC Renewable Energy Rebate Program	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	34	172	158	***364***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	0.1	0.5	0.5	***1.1***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	$8.8	$7.7	$6.0	***$7.0***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	$2.3	$2.0	$1.7	***$1.9***
NJ	NJCEP Customer Onsite Renewable Energy Program	*No. of Systems*	-	-	-	3	36	62	304	721	855	679	750	577	165	***4,152***
		Capacity Additions (MW)	-	-	-	0.0	0.6	0.8	2.3	9.8	18.3	15.2	14.1	15.9	7.4	***84.5***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	*	$8.3	$8.6	$9.3	$8.2	$8.1	$7.9	$8.4	$8.0	$6.1	***$8.0***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	*	$4.7	$5.3	$5.9	$5.2	$4.6	$4.0	$3.2	$3.0	$2.2	***$3.8***
NJ	NJCEP Renewable Energy Incentive Program	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	-	618	1,981	***2,599***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	-	5.5	21.4	***26.9***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	-	$7.8	$7.0	***$7.1***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	-	$1.6	$1.3	***$1.4***
NJ	NJCEP SREC Registration Program	*No. of Systems*	-	-	-	-	-	-	-	-	-	2	56	78	790	***926***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	0.0	8.4	21.0	52.2	***81.6***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	*	$7.1	$6.4	$5.1	***$5.7***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	**	**	**	**	*****
NM	Solar Market Development Tax Credit	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	-	232	719	***951***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	-	1.2	3.0	***4.2***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	-	$7.6	$6.9	***$7.1***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	-	**	**	*****
NV	NVEnergy Renewable Generations Rebate Program	*No. of Systems*	-	-	-	-	-	-	3	64	77	97	88	195	360	***884***
		Capacity Additions (MW)	-	-	-	-	-	-	0.0	0.4	0.5	0.6	0.6	1.7	6.2	***9.9***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	*	$8.5	$7.8	$7.7	$7.3	$6.8	$5.7	***$6.3***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	*	$4.3	$3.3	$2.6	$2.9	$2.9	$3.5	***$3.4***
NY	NYSERDA PV Incentive Program	*No. of Systems*	-	-	-	-	-	44	123	112	190	342	414	776	972	***2,973***
		Capacity Additions (MW)	-	-	-	-	-	0.2	0.5	0.6	1.1	2.1	2.9	6.5	11.7	***25.6***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	$9.6	$9.7	$9.3	$9.3	$9.2	$8.8	$8.6	$7.3	***$8.2***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	$5.2	$5.7	$5.0	$4.4	$4.2	$4.1	$3.9	$3.2	***$3.7***

State	Program Administrator(s) and Program Name	Annual Summary Data	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
OH	ODOD multiple programs[c]	*No. of Systems*	-	-	-	-	-	-	-	20	13	32	32	26	62	***185***
		Capacity Additions (MW)	-	-	-	-	-	-	-	0.1	0.0	0.1	0.3	0.7	5.8	***7.0***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	$11.4	$10.9	$10.5	$7.8	$7.0	$6.0	***$6.3***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	$5.9	$4.2	$3.6	$2.7	$2.9	$2.0	***$2.2***
OR	ETO Solar Electric Program	*No. of Systems*	-	-	-	-	1	56	138	89	132	214	252	487	1,170	***2,539***
		Capacity Additions (MW)	-	-	-	-	0.0	0.3	0.6	0.3	0.6	1.0	3.7	5.9	9.5	***22.1***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	*	$7.6	$7.2	$8.0	$8.6	$9.1	$8.3	$7.5	$6.7	***$7.4***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	*	$3.2	$3.3	$2.8	$1.7	$1.9	$1.4	$1.3	$1.3	***$1.5***
PA	DEP Sunshine Solar PV Program	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	-	372	2,724	***3,096***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	-	2.8	36.3	***39.1***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	-	$7.5	$6.1	***$6.2***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	-	$2.1	$1.6	***$1.6***
PA	SDF Solar PV Grant Program	*No. of Systems*	-	-	-	-	3	17	28	23	54	21	18	-	-	***164***
		Capacity Additions (MW)	-	-	-	-	0.0	0.1	0.1	0.1	0.2	0.1	0.1	-	-	***0.7***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	*	$10.8	$11.4	$10.1	$9.4	$9.5	$9.4	-	-	***$9.8***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	*	$6.7	$6.1	$5.7	$5.2	$4.9	$3.8	-	-	***$5.2***
TX	Austin Energy Power Saver Program	*No. of Systems*	-	-	-	-	-	-	50	145	145	172	259	306	156	***1,233***
		Capacity Additions (MW)	-	-	-	-	-	-	0.2	0.6	0.5	0.7	1.1	1.8	0.8	***5.6***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	$7.4	$7.1	$7.3	$7.7	$7.4	$6.7	$5.6	***$6.9***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	$5.3	$5.2	$4.3	$4.5	$4.2	$4.0	$2.9	***$4.1***
TX	IOU Solar Incentive Programs (AEP, Entergy, Oncor, SWEPCO, TNMP)	*No. of Systems*	-	-	-	-	-	-	-	-	-	-	-	50	431	***481***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	-	0.6	4.3	***4.8***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	-	$6.3	$6.0	***$6.0***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	-	$2.5	$2.0	***$2.1***
UT	RMP Solar Incentive Program	*No. of Systems*	-	-	-	-	-	-	-	-	-	28	33	33	32	***126***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	0.1	0.2	0.1	0.1	***0.5***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	$10.8	$9.6	$9.8	$8.6	***$9.6***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	$1.9	$1.6	$1.7	$1.8	***$1.7***
VT	RERC Small Scale Renewable Energy Incentive Program	*No. of Systems*	-	-	-	-	-	1	17	11	32	62	91	152	166	***532***
		Capacity Additions (MW)	-	-	-	-	-	0.0	0.1	0.0	0.1	0.2	0.3	0.6	1.0	***2.3***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	*	$9.5	$9.9	$9.4	$8.3	$9.0	$7.8	$6.2	***$7.5***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	$3.1	$2.1	$2.0	$1.4	$1.5	$1.5	$1.4	***$1.5***
WI	Focus on Energy Renewable Energy Incentive Program	*No. of Systems*	-	-	-	-	13	22	38	32	83	106	148	265	332	***1,039***
		Capacity Additions (MW)	-	-	-	-	0.0	0.0	0.1	0.1	0.3	0.5	0.8	1.7	2.9	***6.4***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	$11.2	$10.8	$9.7	$9.9	$9.0	$9.0	$9.2	$8.8	$7.2	***$8.2***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	$3.2	$2.7	$2.4	$2.6	$2.7	$2.1	$2.0	$2.0	$1.6	***$1.9***
Non PV Incentive Program Data (other sources)		*No. of Systems*	-	-	-	-	-	-	-	-	-	-	3	170	502	***675***
		Capacity Additions (MW)	-	-	-	-	-	-	-	-	-	-	6.4	17.6	46.5	***70.5***
		Cap-Wtd. Avg. Cost ($/W)	-	-	-	-	-	-	-	-	-	-	*	$6.2	$5.7	***$5.3***
		Cap-Wtd. Avg. Cash Incentive ($/W)	-	-	-	-	-	-	-	-	-	-	**	**	**	********

State	Program Administrator(s) and Program Name	Annual Summary Data	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Total		***No. of Systems***	**39**	**185**	**224**	**1,323**	**2,540**	**3,594**	**5,641**	**5,598**	**8,788**	**12,892**	**14,476**	**25,335**	**35,869**	***116,504***
		Capacity Additions (MW)	**0.2**	**0.8**	**1.0**	**5.5**	**16.0**	**34.0**	**45.1**	**62.5**	**91.0**	**132.3**	**238.2**	**307.2**	**466.3**	***1,400.2***
		Cap-Wtd. Avg. Cost ($/W)	**$11.0**	**$10.8**	**$9.7**	**$10.0**	**$9.9**	**$8.7**	**$8.4**	**$7.9**	**$7.9**	**$7.9**	**$7.6**	**$7.5**	**$6.2**	***$7.3***
		Cap-Wtd. Avg. Cash Incentive ($/W)	**$3.3**	**$3.4**	**$2.7**	**$4.3**	**$4.8**	**$4.3**	**$3.9**	**$3.7**	**$3.4**	**$2.8**	**$2.3**	**$1.9**	**$1.3**	***$2.2***

* Average cost and incentive data are omitted if the data sample consists of fewer than five systems for a given program in a given year.

**Average state/utility cash incentive data are not applicable for the following programs: the Gainesville Feed-in-Tariff program, as the payments made through that program combine both a financial incentive with payment for electricity sales to the utility; the MA DOER SREC Registration Program and the NJCEP SREC Registration Program, which do not provide any direct cash incentive, but instead, provides financial support solely though the sale of solar renewable energy certificates based on solar energy production; and the NM Solar Market Development Tax Credit Program, which provides a tax credit rather than a cash incentive.

(a) Systems that received an incentive from one of the Florida utility programs in the data sample as well as from the Florida Energy & Climate Commission's Solar Rebate Program were retained in the data sample for the utility program and removed from the data sample for Energy & Climate Commission's program. Thus, the average incentive totals shown for Gainesville's Solar Electric System Rebate Program and Orlando's Pilot Solar Program also include incentives from the Florida Energy & Climate Commission's Solar Rebate Program, for those systems that received rebates from both the utility and state programs.

(b) The MassCEC PV programs include systems that were funded through predecessor programs offered by the Massachusetts Technology Collaborative, prior to creation of MassCEC.

(c) The data provided by the Ohio Department of Development includes PV systems funded through a number of programs, including State Energy Plan, Advanced Energy Fund, ARRA Block Grants, and the Energy Loan Fund.

Appendix C: Calculating After-Tax Cash Incentives and State and Federal Investment Tax Credits

Section 4 presents trends related to combined after-tax financial incentives (direct cash incentives from state/utility PV incentive programs plus state and federal ITCs) and net installed costs after receipt of these incentives. Calculating this value required that several operations first be performed on the data provided by PV program administrators, as described below.

1. **Segmenting Systems as Residential, Commercial, or Tax-Exempt.** Data provided by many of the programs did not explicitly identify whether the PV systems were hosted by residential, commercial, or tax-exempt entities. Unless otherwise identified, we classified the host customer of all systems ≤10 kW as residential and all systems >10 kW as commercial.

2. **Estimating the After-Tax Value of Cash Incentives from State/Utility Incentive Programs.** In order to estimate the after-tax value of cash incentives provided to each PV system in the data sample, a determination was made as to whether the cash incentive provided to each system was subject to federal and/or state income taxes. Up-front cash incentives paid to residential PV system owners are exempt from federal income taxes if the incentive is considered to be a "utility energy conservation subsidy," per Section 136 of the Internal Revenue Code. A recent Internal Revenue Service (IRS) private letter ruling (PLR 201035003) clarified that payments made for renewable energy certificates do not qualify for the Section 136 exemption.[47] Despite this private letter ruling and several others of potential relevance, some uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy."[48] Notwithstanding this uncertainty, we assume that up-front cash incentives provided to customer-owned residential systems are exempt from federal income taxes. In addition, all incentives provided for systems owned by tax-exempt entities (governments, schools, and non-profits) were assumed to be exempt from federal income taxes. In all other cases (i.e., systems hosted by commercial customers, third party-owned systems,[49] and PBI payments for systems hosted by either commercial or residential customers), state/utility cash incentives were assumed to be subject to federal income taxes. The after-tax value of incentives provided for commercial and third party-owned systems was calculated based on a federal corporate tax rate of 35%. Correspondingly, the after-tax value of PBI payments provided for customer-owned residential systems was calculated based on the marginal federal personal income tax rate applicable to a married couple filing jointly with federally taxable income of $150,000 (e.g., 28% in 2010).

   The taxation of cash incentives for residential PV at the state level may vary by state, but for simplicity, we assume that all incentives exempt from federal income tax are also exempt from state income tax, and that all incentives subject to federal income tax are also subject to state income tax. In those cases where the cash incentive is assumed to be subject to state income taxes (i.e., commercial systems, third party-owned, or PBIs), the after-tax value of the incentive is calculated based on the "effective" state income tax rate, which accounts for the fact that state income taxes reduce the incentive-recipient's federally-taxable income. The effective state tax rate applied to the cash incentive is equal to 1 minus the applicable federal (corporate or personal) income tax rate multiplied by the nominal state (corporate or personal) income tax rate. [50]

---

[47] It is possible that, under some of the PV incentive programs in our data sample, REC ownership was transferred as a condition of receiving the rebate; however, we did not attempt to account for this within our estimate of the after-tax value of cash incentives.

[48] For additional information, see: Bolinger, M., G. Barbose, and R. Wiser. 2008. *Shaking Up the Residential PV Market: Implications of Recent Changes to the ITC*. Berkeley, CA: Lawrence Berkeley National Laboratory.

[49] Where system ownership data is unavailable, we assume that systems are customer-owned.

[50] Tax rates (personal and corporate, state and federal) were obtained from the Tax Foundation: http://taxfoundation.org.

3. **Estimating the Value of Federal ITCs.** Customer-owned residential systems installed between January 1, 2006 and December 31, 2008 were assumed to receive a federal ITC equal to the lesser of 30% of the tax credit basis or $2,000; customer-owned residential systems installed after December 31, 2008 were assumed to receive the full 30% ITC. Systems owned by commercial entities (including customer-owned systems sited at commercial facilities and all third party-owned systems) were assumed to receive a federal ITC equal to 10% of the tax credit basis if installed prior to January 1, 2006, or 30% of the tax credit basis if installed after that date. Commercial and third systems installed in 2009 and 2010 may have opted for the Treasury cash grant, in lieu of the ITC; for the purpose of this analysis, however, we assume that the economic value of the grant is equal to that of the ITC.

   The tax credit basis on which the federal ITC is calculated depends on whether cash incentives received by the project are federally-taxable. If the cash incentives are federally-taxable (as assumed for systems sited at commercial facilities, third-party owned systems, and systems receiving a PBI), then the federal ITC is calculated based on the full installed cost of the system. If, on the other hand, the cash incentives are not federally-taxable, as assumed for all up-front cash incentives provided for customer-owned residential systems, then the federal ITC is calculated based on the installed cost minus the value of the tax-exempt cash incentives.

4. **Estimating the Value of State ITCs.** Section 4 summarizes the estimated value of state ITCs across the 21 states for which data on state/utility cash incentives were available. We identified six of these 21 states as having offered a state ITC for PV at some point from 1998-2010. Based on the information contained in Table C-1, we determined whether each project in the dataset was eligible for a state ITC, and if so, estimated the amount of the tax credit, accounting for the particular state ITC program rules (e.g., pertaining to calculation of the tax credit basis or per-customer dollar caps). In addition, we accounted for the fact that state tax credits are financially equivalent to federally taxable income, because they increase the recipient's federally-taxable income by an amount equal to the size of the state tax credit. The net value of state ITCs was therefore reduced by the assumed federal income tax levied on the increased income. For commercial systems and third party-owned systems, we assumed a federal income tax rate of 35%. For customer-owned residential systems, we assumed that the increased income would be taxed at the marginal rate applicable to a married couple filing jointly with federally taxable income of $150,000 (e.g., 28% in 2010).

Table C-1: State ITC Details

State	Applicable Customers	System Size Cap	Applicable Period	Tax Credit Amount	Cap
AZ	Residential	None	1995-indefinite	25% of *pre-rebate* installed cost	$1,000
	Non-Residential and Tax-Exempt	None	2006-2018	10% of *pre-rebate* installed cost	$25,000
CA	All	200 kW	2001-2003	15% of *net* installed cost after state rebate and federal ITC	None
	All	200 kW	2004-2005	7.5% of *net* installed cost after state rebate and federal ITC	None
MA	Residential	None	1979-indefinite	15% of *net* installed cost after federal ITC	$1,000
NY	Residential	10 kW	1998-9/1/2006	25% of *net* installed cost after rebate	$3,750
	Residential	10 kW	9/1/2006-indefinite	25% of *net* installed cost after rebate	$5,000
OR	Residential	None	11/4/2005-indefinite	$3/W based on nameplate capacity*	$6,000 up to 50% of *pre-rebate* installed cost**
	Non-Residential and Tax-Exempt	None	1981-2006	35% of *pre-rebate* installed cost	$10,000,000
	Non-Residential and Tax-Exempt	None	2007-2017	50% of *pre-rebate* installed cost (up to maximum eligible cost***)	$10,000,000
UT	Residential	None	2007-2012	25% of *pre-rebate* installed cost	$2,000
	Commercial	None	2007-2012	10% of *pre-rebate* installed cost	$50,000

* Tax credit paid out over multiple years, with an annual limit of $1,500/yr. To calculate the after-tax value of the tax credit, the stream of credits was discounted at a 7% nominal discount rate.

** For systems that applied for the Oregon residential tax credit after August 13, 2010, the cap on the tax credit is based on *net* installed cost after deducting the value of any up-front cash incentives and the federal ITC. This provision affects a small portion of the Oregon residential systems in the data sample.

*** The maximum eligible cost varies by system size and date of installation. The tax credit is paid out over five years. To calculate the after-tax value of the tax credit, the stream of credits was discounted at a 7% nominal discount rate.

Key Report Contacts

Galen Barbose, Berkeley Lab
510-495-2593; GLBarbose@lbl.gov

Ryan Wiser, Berkeley Lab
510-486-5474; RHWiser@lbl.gov

Naïm Darghouth, Berkeley Lab
510-486-4570; NDarghouth@lbl.gov

Download the Report

http://eetd.lbl.gov/ea/emp/re-pubs.html

Disclaimer

BERKELEY LAB

Lawrence Berkeley National Laboratory

Acknowledgments

For their support of this project, the authors thank Jennifer DeCesaro of the U.S. DOE's Solar Energy Technologies Program and Mark Sinclair of the Clean Energy States Alliance.

For providing data or reviewing elements of this paper, the authors thank: John Bartlett (DOE), Justin Baca (Solar Energy Industries Association), Haley Ballinger (NV Energy), James Barnett (Sacramento Public Utilities District), Greg Bernosky, (Arizona Public Service), Preston Boone (Ohio Dept. of Development), Ron Celentano (Pennsylvania Sustainable Development Fund), Christin Cifaldi (Connecticut Clean Energy Fund), Joe Cohen (Maryland Energy Administration), Sachu Constantine (SunPower), Linda Crafton (Salt River Project), Libby Dodson (Pennsylvania Department of the Environment), Suzanne Elowson (Vermont Energy Investment Corporation), David Feldman (NREL), Steven Frantz (Sacramento Municipal Utility District), Pauline Furfaro (Orlando Utilities Commission), Charlie Garrison (Honeywell), Alan Goodrich (NREL), Wayne Hartel (Illinois Department of Commerce and Economic Opportunity), Tim Harvey (Austin Energy), Tom Hoff (Clean Power Research), Yuri Horowitz (Sol Systems), Christie Howe (Massachusetts Clean Energy Center), Scott Hunter (New Jersey Board of Public Utilities), Michael Judge (Massachusetts Department of Energy Resources), Elizabeth Kennedy (Massachusetts Clean Energy Center), Minh Le (DOE), James Lee (California Energy Commission), James Loewen (California Public Utilities Commission), JD Lowry (Arkansas Energy Office), Robert Margolis (NREL), David McLelland (Energy Trust of Oregon), Stacy Miller (Minnesota Office of Energy Security), Colin Murchie (SolarCity), Jon Osgood (New Hampshire Public Utilities Commission), Jeffrey Peterson (New York State Energy Research and Development Authority), Dina Predsik (Anaheim Public Utilities), Kenneth Pritchett (Los Angeles Department of Water and Power), Ramamoorthy Ramesh (DOE), Scott Schlossman (Gainesville Regional Utilities), Bill Schutten (Wisconsin Focus on Energy), Jigar Shah (Carbon War Room), Larry Sherwood (Interstate Renewable Energy Council), Dan Shugar (Solaria), Gabrielle Stebbins (Vermont Energy Investment Corporation), Molly Sterkel (California Public Utilities Commission), Jeremy Stone (Clean Power Research), Lucy Sullivan (Connecticut Clean Energy Fund), Travis Tanner (PacifiCorp), Mike Taylor (Solar Electric Power Association), Robert Taylor (Pennsylvania Department of the Environment), Rachel Tronstein (DOE), Mike Winka (New Jersey Board of Public Utilities), and Steve Weise (Clean Energy Associates). We also thank Anthony Ma for assistance with cover design, formatting, and production. Of course, the authors are solely responsible for any remaining omissions or errors.

Berkeley Lab's contributions to this report were funded by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Program) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231, and by the Clean Energy States Alliance.

LBNL-5047E Sept., 2011