Tracking the Sun II

The Installed Cost of Photovoltaics in the U.S. from 1998-2008

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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 2008 (updating a previous report with data through 2007).[1] The analysis is based on installed cost data from more than 52,000 residential and non-residential PV systems, totaling 566 MW and representing 71% of all grid-connected PV capacity installed in the U.S. through 2008.[2]

Key findings of the analysis are as follows:[3]

- The capacity-weighted average installed cost of systems completed in 2008 – in terms of real 2008 dollars per installed watt (DC-STC)[4] and prior to receipt of any direct financial incentives or tax credits – was $7.5/Watt, a decline from $7.8/W in 2007 following several years (2005-2007) during which installed costs remained relatively flat. From 1998 to 2008, installed costs declined by about 3.6% (or $0.3/W) per year, on average, starting from $10.8/W in 1998.
- Preliminary cost data indicates that the average cost of projects installed through the California Solar Initiative program during the first 8½ months of 2009 rose by $0.4/W relative to 2008, while average costs in New Jersey declined by $0.2/W over the same period.
- The decline in installed costs from 2007 to 2008 appears to be attributable largely to a reduction in module costs, as suggested by Navigant Consulting's Global Module Price Index, which fell by approximately $0.5/W from 2007 to 2008.[5] In contrast, the decline in total installed costs from 1998 to 2005 is associated primarily with a reduction in non-module costs (which may include items such as inverters, other balance of systems hardware, labor, and overhead).
- Long-term reductions in installed cost are most evident for systems ≤100 kW, with systems ≤5 kW exhibiting the largest absolute reduction, from $12.3/W in 1998 to $8.5/W in 2008.

[1] Although the report is intended to portray national trends, with 16 states represented within the dataset, the overall sample is heavily skewed towards systems in California and New Jersey, where the vast majority of PV systems in the U.S. have been installed.
[2] Grid-connected PV represented approximately 88% of the U.S. PV market in 2008, with off-grid systems constituting the remainder. See: Sherwood, L. 2009. *U.S. Solar Market Trends 2008*. Interstate Renewable Energy Council. http://www.irecusa.org.
[3] Unless otherwise noted, the results reflect all system types represented within the sample (e.g., rack-mounted, building-integrated, tracking, non-tracking, crystalline, thin-film, etc.).
[4] 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 nameplate capacity of the PV modules, which is reported by manufacturers in terms of direct current (DC) watts under standard test conditions (STC). This is the rating convention used throughout the present report. Alternatively, module ratings may be specified in terms of DC watts under PVUSA test conditions (PTC), which are lower than STC ratings, as they account for the effect of normal operating temperature on module output. Finally, PV system ratings may be specified in terms of alternating current (AC) watts, to account for inverter losses (as well as potentially losses within other system components). AC system ratings may be specified as either STC or PTC. As one example, the California Public Utilities Commission has historically used an AC-PTC rating, which is equal to roughly 85% of DC-STC capacity.
[5] It should be noted, however, that there is likely a lag between movements in the wholesale price of PV modules and the average installed cost of PV projects, as module costs for installed projects may reflect prevailing wholesale prices at the time that contracts for system installation were signed. Thus, the decline in the Global Module Price Index from 2007 to 2008 is likely to be larger than the reduction in module costs for projects installed over the same time period.

Long-term cost reductions for systems >100 kW are less apparent, given the limited number of data points for the early years of the study period.

- The distribution of installed costs within a given system size range narrowed significantly from 1998 to 2005, with high-cost outliers becoming increasingly infrequent, indicative of a maturing market. However, little if any further narrowing of the cost distribution occurred from 2005 through 2008.
- PV installed costs exhibit significant economies of scale, with systems ≤2 kW completed in 2008 averaging $9.2/W, while 500-750 kW systems averaged $6.5/W (i.e., about 30% less than the smallest systems).
- Component-level cost data indicates that, among systems installed in 2008, module costs averaged $0.7/W less for systems >100 kW than for systems ≤10 kW, while non-module costs differed by less than $0.1/W.
- International experience suggests that greater near-term cost reductions may be possible in the U.S., as the average cost of small residential PV installations in 2008 (excluding sales/value-added tax) in both Japan ($6.9/W) and Germany ($6.1/W) was significantly below that in the U.S. ($7.9/W).
- Average installed costs vary widely across states; among ≤10 kW systems completed in 2008, average costs range from a low of $7.3/W in Arizona (followed by California, which had average installed costs of $8.2/W) to a high of $9.9/W in Pennsylvania and Ohio. This variation in average installed cost across states, as well as comparisons with Japan and Germany, suggest that markets with large PV deployment programs tend to have lower average installed costs for residential PV, though exceptions exist.
- The average installed cost of residential systems in 2008 was less than for *similarly sized* commercial systems, with the average cost of residential systems lower by approximately $0.6/W for systems within the 5-10 kW size range and by $0.3/W within the 10-100 kW range.
- The new construction market offers cost advantages for residential PV; among 1-3 kW residential systems funded through three California programs (the Emerging Renewables Program, the New Home Solar Partnership Program, and the California Solar Initiative) and installed in 2008, PV systems installed in residential new construction cost $0.8/W less than comparably-sized residential retrofit systems (or $1.2/W less if focused exclusively on rack-mounted systems).
- Among PV systems installed in residential new construction in 2008, building-integrated PV systems cost $0.9/W more, on average, than rack-mounted systems ($8.3/W vs. $7.4/W).
- Although there were relatively few thin-film systems within the sample, PV systems with thin-film modules generally had lower average installed costs in 2008 than comparably-sized crystalline systems ($1.5/W less among 10-100 kW systems and $0.6/W less among >100 kW systems).
- Among 10-100 kW systems installed in 2008, systems with tracking had average installed costs $0.5/W (or 6%) higher than fixed-axis systems.
- The average cash incentive provided by the state/utility PV incentive programs in the sample ranged from $2.1-$2.4/W for systems installed in 2008, depending on system size, representing about a 50% decline from its peak in 2002.
- In 2008, the average combined *after-tax* value of state/utility cash incentives *plus* state and Federal ITCs (but excluding revenue from the sale of renewable energy certificates or the

value of accelerated depreciation) was $2.8/W for residential PV (its lowest level since prior to 1998 and down $0.3/W from 2007) and $4.0/W for commercial PV (just below its all-time peak of $4.3/W in 2002 and down $0.2/W from 2007). The differing trajectories of after-tax incentives for residential and commercial PV is associated with the more lucrative Federal ITC adopted for commercial PV systems in 2006. However, incentive levels will converge to some extent in 2009, with the lifting of the dollar cap on the Federal residential ITC.

- In 2008, the average *net installed cost* faced by PV system owners – that is, installed cost minus after-tax incentives – stood at $5.4/W for residential PV and $4.2/W for commercial PV. For both residential and commercial PV, average net installed costs rose slightly from 2007 to 2008 (by 1% and 5%, respectively), as the annual decline in incentives outpaced the drop in installed costs.
- Financial incentives and net installed costs diverge widely across states. Among residential PV systems completed in 2008, the combined after-tax incentive ranged from an average of $2.5/W in California to $5.1/W in New York, and net installed costs ranged from an average of $3.5/W in New York to $6.9/W in Vermont. Incentives and net installed costs for commercial systems varied similarly across states.

1. Introduction

Installations of solar photovoltaic (PV) systems have been growing at a rapid pace in recent years. In 2008, 5,948 MW of PV was installed globally, up from 2,826 MW in 2007, and was dominated by grid-connected applications.[6] The United States was the world's third largest PV market in terms of annual capacity additions in 2008, behind Spain and Germany; 335 MW of PV was added in the U.S. in 2008, 293 MW of which came in the form of grid-connected installations.[7] Despite the significant year-on-year growth, however, the share of global and U.S. electricity supply met with PV remains small, and annual PV additions are currently modest in the context of the overall electric system.

The market for PV in the U.S. is driven by national, state, and local government incentives, including up-front cash rebates, production-based incentives, requirements that electricity suppliers purchase a certain amount of solar energy, 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 typical location of PV at the point of use. Given the relatively high cost of PV, however, a key goal of these policies is to encourage cost reductions over time. Therefore, as policy incentives have become more significant and as PV deployment has accelerated, so too has the desire to track the installed cost of PV systems over time, by system characteristics, by system location, and by component.

To address this need, Lawrence Berkeley National Laboratory initiated a report series focused on describing trends in the installed cost of grid-connected PV systems in the U.S. The present report, the second in the series, describes installed cost trends from 1998 through 2008.[8] The analysis is based on project-level cost data from more than 52,000 residential and non-residential PV systems in the U.S., all of which are installed at end-use customer facilities (herein referred to as "customer-sited" systems). The combined capacity of systems in the data sample totals 566 MW, equal to 71% of all grid-connected PV capacity installed in the U.S. through 2008 and representing the most comprehensive source of installed PV cost data for the U.S.[9] The report also briefly compares recent PV installed costs in the U.S. to those in Germany and Japan. Finally, it should be noted that 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.

The report begins with a summary of the data collection methodology and resultant dataset (Section 2). The primary findings of the analysis are presented in Section 3, which describes trends

[6] SolarBuzz. 2009. *MarketBuzz 2009*. http://www.solarbuzz.com/Marketbuzz2009-intro.htm.

[7] Sherwood, L. 2009. *U.S. Solar Market Trends 2008*. Interstate Renewable Energy Council. http://www.irecusa.org.

[8] To be clear, the report focuses on installed costs *as paid by the system owner*, rather than the costs born by manufacturers or installers. It is possible, especially over the past several years, that cost trends may have diverged between manufacturers and installers, or between installers and system owners. Note also that, in focusing on installed costs, the report ignores improvements in the performance of PV systems, which will tend to reduce the levelized cost of energy of PV even absent changes in installed costs.

[9] In addition to the primary dataset, which is limited to data provided directly by PV incentive program administrators and only includes customer-sited systems, the report also summarizes installed cost data obtained through public data sources for nine multi-MW grid-connected PV systems in the U.S. (several of which are installed on the utility-side of the meter). These additional large systems represent a combined 52 MW, bringing the total dataset to 619 MW, or 78% of all grid-connected PV capacity installed in the U.S. through 2008.

in installed costs prior to receipt of any financial incentives: over time and by system size, component, state, customer segment (residential vs. commercial vs. public-sector vs. non-profit), application (new construction vs. retrofit), and technology type (building-integrated vs. rack-mounted, crystalline silicon vs. thin-film, and tracking vs. rack-mounted). Section 4 presents additional findings 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 trends in the net installed cost paid by system owners after receipt of such incentives. 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.

2. Data Summary

This section briefly describes the procedures used to collect, standardize, and clean the data provided by individual PV incentive programs, and summarizes the basic characteristics of the resulting dataset, including: the number of systems and installed capacity by PV incentive program; the sample size relative to all grid-connected PV capacity installed in the U.S.; and the sample distribution by year, state, and project size.

Data Collection, Conventions, and Data Cleaning

Requests for project-level installed cost data were sent to state and utility PV incentive program administrators from around the country, with some focus (though not exclusively so) on relatively large programs. Ultimately, 27 PV incentive programs provided project-level installed cost data from 16 states. To the extent possible, this report presents the data as provided directly by these PV incentive program administrators. That said, several steps were taken to standardize and clean the data, as briefly summarized here and described in greater detail in Appendix A.

In particular, two key conventions used throughout this report deserve specific mention:

1. All cost and incentive data are presented in real 2008 dollars (2008$), which required inflation adjustments to the nominal-dollar data provided by PV programs.
2. All capacity and dollars-per-watt ($/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 programs that use a different capacity rating be translated to DC-STC. [10]

The data were cleaned by eliminating projects with clearly erroneous cost or incentive data, by correcting text fields with obvious errors, and by standardizing identifiers for module and inverter models. To the extent possible, each PV system in the dataset 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 many systems, in which case systems ≤10 kW were assumed to be residential, and those >10 kW were assumed to be commercial, when calculating the value of state and federal investment tax credits and net installed costs.[11]

[10] 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 nameplate capacity of the PV modules, which is reported by manufacturers in terms of direct current (DC) watts under standard test conditions (STC). This is the rating convention used throughout the present report. Alternatively, module ratings may be specified in terms of DC watts under PVUSA test conditions (PTC), which are lower than STC ratings, as they account for the effect of normal operating temperature on module output. Finally, PV system ratings may be specified in terms of alternating current (AC) watts, to account for inverter losses (as well as potentially losses within other system components). AC system ratings may be specified as either STC or PTC. As one example, the California Public Utilities Commission has historically used an AC-PTC rating, which is equal to roughly 85% of DC-STC capacity.

[11] 10 kW is a common, albeit imperfect, cut-off between residential and commercial PV systems. Among the approximately 23,000 systems in the dataset for which market sector data were provided, 94% of systems (and 93% of capacity) ≤10 kW are residential, while 41% of systems (and 80% of capacity) >10 kW are commercial. If the same distribution applies to the entire dataset, a total of 7% of all systems in the sample (and 8% of the total capacity) would be misclassified by using a 10 kW cut-off between residential and commercial systems.

Sample Description

The final dataset, after all data cleaning was completed, consists of more than 52,000 grid-connected, residential and non-residential PV systems, totaling 566 MW (see Table 1).[12] This represents approximately 71% of all grid-connected PV capacity installed in the U.S. through 2008, and about 67% of the 2008 capacity additions (see Figure 1). The largest state markets missing from the primary data sample, in terms of cumulative installed PV capacity through 2008, are: Hawaii (representing 1.7% of total U.S. grid-connected PV capacity), Texas (0.6%), and North Carolina (0.6%). In addition, although one Colorado program did provide data, this program constitutes a small fraction of the state's PV market. Thus, Colorado – which represents 4.5% of total U.S. grid-connected PV capacity through 2008 – is significantly under-represented within the data set.

Table 1. Data 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
AZ	APS Solar & Renewables Incentive Program	912	6.2	1.1%	0.4 - 255	2002 - 2008
	SRP EarthWise Solar Energy Program	346	1.7	0.3%	0.7 - 36	2005 - 2008
CA	Anaheim Solar Advantage Program	69	0.3	0.1%	1.4 - 18	2001 - 2008
	CEC Emerging Renewables Program	27,947	146.4	25.9%	0.1 - 670	1998 - 2008
	CEC New Home Solar Partnership	539	1.6	0.3%	1.3 - 92	2007 - 2008
	CPUC California Solar Initiative	11,533	146.7	25.9%	1.2 - 1,308	2007 - 2008
	CPUC Self-Generation Incentive Program	796	144.9	25.6%	33 - 1,239	2002 - 2008
	LADWP Solar Incentive Program	1,463	17.6	3.1%	0.6 - 1,200	1999 - 2008
	Lompoc PV Rebate Program	5	0.02	0.0%	3.0 - 5.3	2008 - 2008
	SMUD Residential Retrofit and Commercial PV Programs	170	1.0	0.2%	1.3 - 97	2005 - 2008
CO	Governor's Energy Office Solar Rebate Program	16	0.1	0.0%	2.0 - 5.4	2008 - 2008
CT	CCEF Onsite Renewable DG Program*	66	5.6	1.0%	1.6 - 480	2003 - 2008
	CCEF Solar PV Program	557	3.1	0.5%	0.8 - 17	2005 - 2008
MA	MRET Commonwealth Solar Program	1,091	8.1	1.4%	0.2 - 460	2002 - 2008
MD	MEA Solar Energy Grant Program	230	0.8	0.1%	0.5 - 45	2005 - 2008
MN	MSEO Solar Electric Rebate Program	145	0.5	0.1%	0.5 - 40	2002 - 2008
NJ	NJCEP Customer Onsite Renewable Energy Program	3,167	54.2	9.6%	0.8 - 702	2003 - 2008
	NJCEP Solar Renewable Energy Credit Program	58	8.4	1.5%	1.0 - 1,588	2007 - 2008
NV	NPC/SPPC RenewableGenerations Rebate Program	393	2.0	0.3%	0.5 - 31	2004 - 2008
NY	NYSERDA PV Incentive Program	1,158	7.2	1.3%	0.7 - 51	2003 - 2008
OH	ODOD Advanced Energy Fund Grants	35	0.3	0.0%	1.0 - 122	2005 - 2008
OR	ETO Solar Electric Program	878	6.6	1.2%	0.8 - 859	2003 - 2008
PA	SDF Solar PV Grant Program	164	0.7	0.1%	1.2 - 12	2002 - 2008
VT	RERC Small Scale Renewable Energy Incentive Program	225	0.8	0.1%	0.6 - 38	2004 - 2008
WA	Klickitat PUD Solar PV Rebate Program	5	0.01	0.0%	0.3 - 3.0	2008 - 2008
	Port Angeles Solar Energy System Rebate	2	0.004	0.0%	1.4 - 2.7	2007 - 2008
WI	Focus on Energy Renewable Energy Cash-Back Rewards	386	1.7	0.3%	0.2 - 38	2002 - 2008
	Total	***52,356***	***566.3***	***100%***	***0.1 - 1,588***	***1998 - 2008***

* This report includes within CCEF's Onsite Renewable DG Program, which was launched in 2005, systems that were funded by CCEF prior to inception of any formal PV incentive program.

[12] There may be a modest level of double-counting of systems between programs, as some systems funded by LADWP and SMUD may have also received incentive funding through the CEC's Emerging Renewables Program. Some other large systems funded by LADWP and SMUD also received funding through the CPUC SGIP; however, those systems were removed from the SGIP dataset, in order to eliminate double counting.

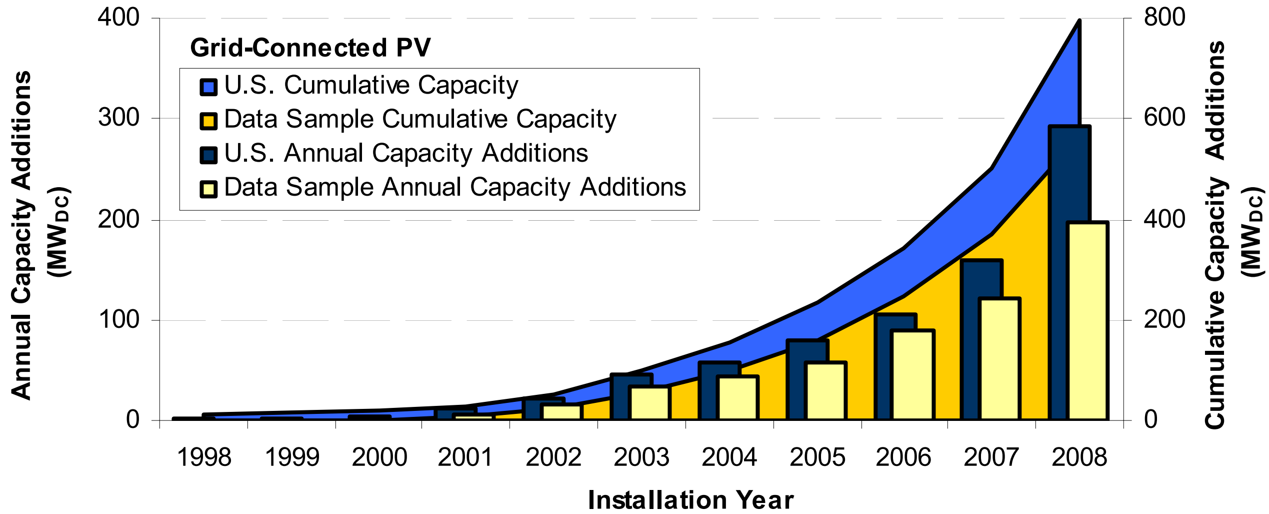


Figure 1. Data Sample Compared to Total U.S. Grid-Connected PV Capacity

Table 2. Data Sample by Installation Year

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
No. of Systems	39	180	217	1,308	2,489	3,526	5,527	5,193	8,677	12,103	13,097	***52,356***
% of Total	*<1%*	*<1%*	*<1%*	*2%*	*5%*	*7%*	*11%*	*10%*	*17%*	*23%*	*25%*	***100%***
Capacity (MW_{DC})	0.2	0.8	0.9	5.4	15	34	44	57	90	122	197	***566***
% of Total	*<1%*	*<1%*	*<1%*	*1%*	*3%*	*6%*	*8%*	*10%*	*16%*	*22%*	*35%*	***100%***

The primary sample consists only of data provided by PV incentive program administrators, all of which are for customer-sited systems. The report separately describes the installed cost of nine multi-MW grid-connected PV systems not included in the primary dataset, including the three largest PV systems installed in the U.S. through 2008.[13] Cost data for these projects were compiled from press releases and other publicly available sources. The data for these nine projects bring the total PV capacity for which cost data are presented to 619 MW, equal to 78% of all grid-connected PV capacity installed in the U.S. through 2008.

The PV systems in the primary dataset were installed over an eleven-year period, from 1998 through 2008. As to be expected, though – given the dramatic expansion of the U.S. solar market in recent years – the sample is skewed towards projects completed during the latter years of this period, with approximately half of the PV systems and half of the total capacity in the sample installed in 2007 and 2008 (see Table 2). See Appendix B for annual installation data (number of systems and capacity) disaggregated by PV incentive program and by system size range.

Among the 27 PV incentive programs that provided data for this report, the lion's share of the sample is associated with the four largest PV incentive programs in the country to-date: California's Emerging Renewables Program (ERP); California's Self-Generation Incentive Program (SGIP); the California Solar Initiative (CSI) Program; and New Jersey's Customer Onsite Renewable Energy (CORE) Program. As such, the sample is heavily weighted towards systems installed in California and New Jersey, as shown in Figure 2. In terms of installed capacity, these two states represent

[13] These three PV systems are the 8.2 MW_{DC} system installed in 2007 in Alamosa, CO, the 12.2 MW_{DC} system installed in 2008 in El Dorado, NV, and the 14.2 MW_{DC} system installed in 2007 at Nellis Air Force base in Nevada.

83% and 12% of the total data sample, respectively. Connecticut, Massachusetts, Arizona, New York, and Oregon each represent 1.2-1.5% of the sample, with the remaining nine states (Colorado, Nevada, Maryland, Minnesota, Ohio, Pennsylvania, Washington, Wisconsin, and Vermont) comprising 1.2%, in total.

The size of the PV systems in the primary dataset span a wide range, from as small as 100 W to as large as 1.6 MW, but almost 90% of the projects in the sample are ≤10 kW (see Figure 3). In terms of installed capacity, however, the sample is considerably more evenly distributed across system size ranges, with systems >100 kW comprising 45% of the total installed capacity, and systems ≤10 kW comprising 36%.

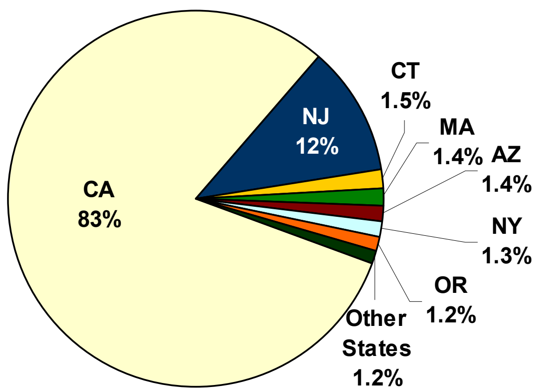


Figure 2. Data Sample Distribution among States (by Cumulative MW)

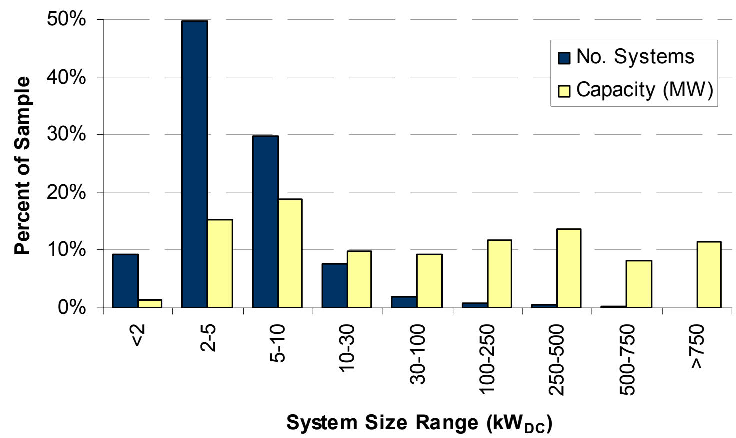


Figure 3. Data Sample Distribution by PV System Size

3. PV Installed Cost Trends

This section presents the primary findings of the report, describing trends in the average installed cost of grid-connected PV, based on the dataset described in Section 2. It begins by presenting the trends in installed costs over time; by system size; by component, between the U.S., Germany, and Japan; among individual states; and among customer types (residential, commercial, public sector, and non-profit).[14] It then compares installed costs among several specific 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, and tracking vs. fixed-axis systems. To be clear, the focus of this section is on installed costs, as paid by the system owner, prior to receipt of any financial incentives (e.g., rebates, tax credits, etc.).

Installed Costs Declined from 2007 to 2008, Following Several Years of Stagnation

Figure 4 presents the average installed cost of all projects in the primary sample completed each year from 1998-2008.[15] As shown, capacity-weighted average costs declined from \$7.8/W in 2007 to \$7.5/W in 2008 – a 4.6% year-on-year reduction. This decline is somewhat greater than the average rate of cost reductions from 1998-2008, wherein installed costs declined by \$0.3/W (3.6%) per year, on average, starting from \$10.8/W in 1998.

The reduction in installed costs from 2007 to 2008 marks an important departure from the trend of the preceding three years, during which costs remained flat, as rapidly expanding U.S. and global PV markets put upward pressure on both module prices and non-module costs. This dynamic began to shift in 2008, as expansions on the supply-side coupled with the global financial crisis led to a decline in wholesale module prices. The initial effect of this trend on retail installed costs is evident in the drop in installed costs from 2007 to 2008 shown in Figure 4, though it is important to note that the cost of many projects installed in 2008 may be based on contracts signed (and inventory stocked) prior to the global decline in wholesale module prices that began in 2008.

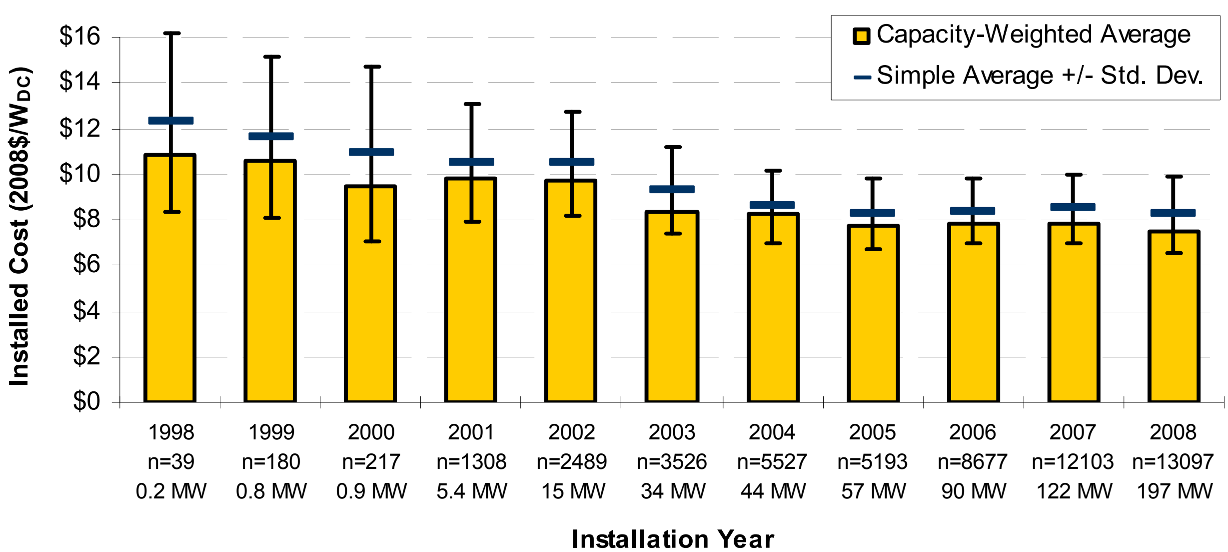


Figure 4. Installed Cost Trends over Time

[14] Unless otherwise noted, the reported results are based on all system types in the data sample (e.g., rack-mounted, building-integrated, tracking, non-tracking, crystalline, non-crystalline, etc.).
[15] See Appendix B for average annual cost data for each of the 27 PV incentive programs, individually.

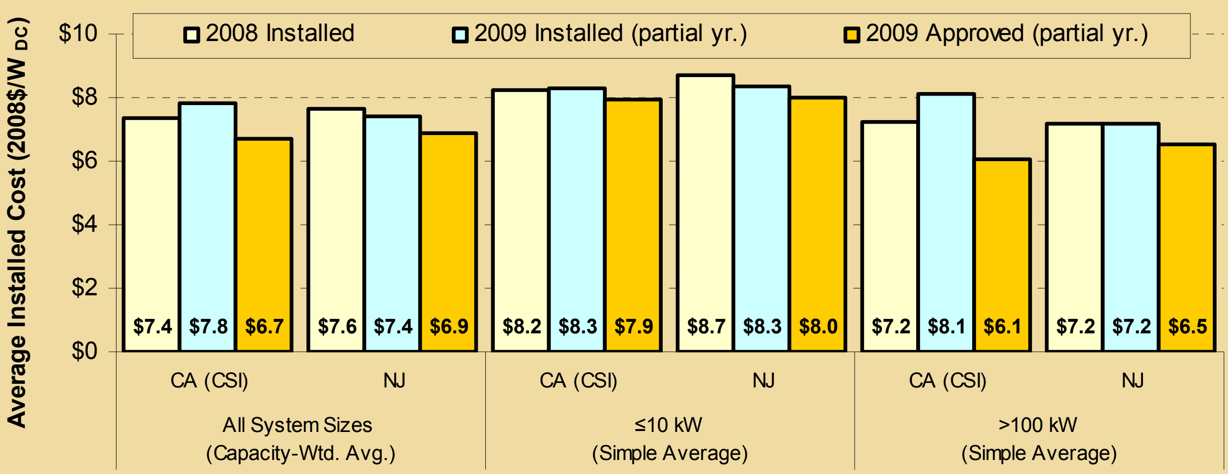
Text Box 1. Preliminary Installed Cost Trends for 2009

The dramatic and widely reported decline in wholesale module prices that began in 2008 and continued through 2009 suggests that retail installed costs should decline from 2008 to 2009. However, preliminary cost data for projects installed or approved for incentive payment in 2009 paints a more-complex picture.

Figure 5 compares the average cost of projects installed in 2008 to the cost of projects installed during approximately the first 8 months of 2009, with results presented separately for California (based on data from the CSI program through September 15, 2009) and New Jersey (based on data from all statewide incentive programs through August 31, 2009). Within California, the capacity-weighted average cost of CSI projects installed from January 1 – September 15, 2009 actually rose by \$0.4/W relative to the average in 2008. The cost increase in California was particularly significant for >100 kW projects, rising by \$0.9/W (from \$7.2/W to \$8.1/W), while ≤10 kW projects registered a smaller cost increase of \$0.1/W (from \$8.2/W to \$8.3/W).

In contrast, capacity-weighted average installed costs in New Jersey fell by approximately \$0.2/W, from \$7.6/W in 2008 to \$7.4/W during the first 8 months of 2009. The reduction in average installed costs in New Jersey occurred primarily among small systems, with the average installed cost of projects ≤10 kW in New Jersey falling by \$0.4/W (from \$8.7/W to \$8.3/W), while >100 kW systems registered no discernable change in average installed costs.

Figure 5 also presents the average reported cost of projects with incentive applications approved in 2009 but that had not yet been installed as of the aforementioned dates. Although these data are *highly provisional*, as costs may change once a project is installed, they suggest that further cost reductions are on the horizon. In California, the capacity-weighted average reported cost of 2009 approved projects is \$6.7/W, or \$0.7/W below the average for projects installed in 2008 and \$1.1/W less than for projects installed in the first 8½ months of 2009. In New Jersey, the capacity-weighted average reported cost of 2009 approved projects is \$6.9/W, compared to \$7.6/W for projects installed in 2008 and \$7.4/W for projects installed in the first 8 months of 2009. In both states, the decline is evident across system sizes, but is larger for >100 kW systems than for ≤10 kW systems.



Notes: CA data are from the CSI program (through September 15, 2009), while NJ data are from the CORE Program, SREC-Only Pilot, Renewable Energy Incentive Program, and SREC Registration Program (through August 31, 2009). Cost data for "2009 Installed (partial yr)" are based on systems installed by the aforementioned dates, while data for "2009 Approved (partial yr)" are based on systems with an approved incentive application on file (or that have registered within the NJ SREC program), but that were not yet installed by the aforementioned dates.

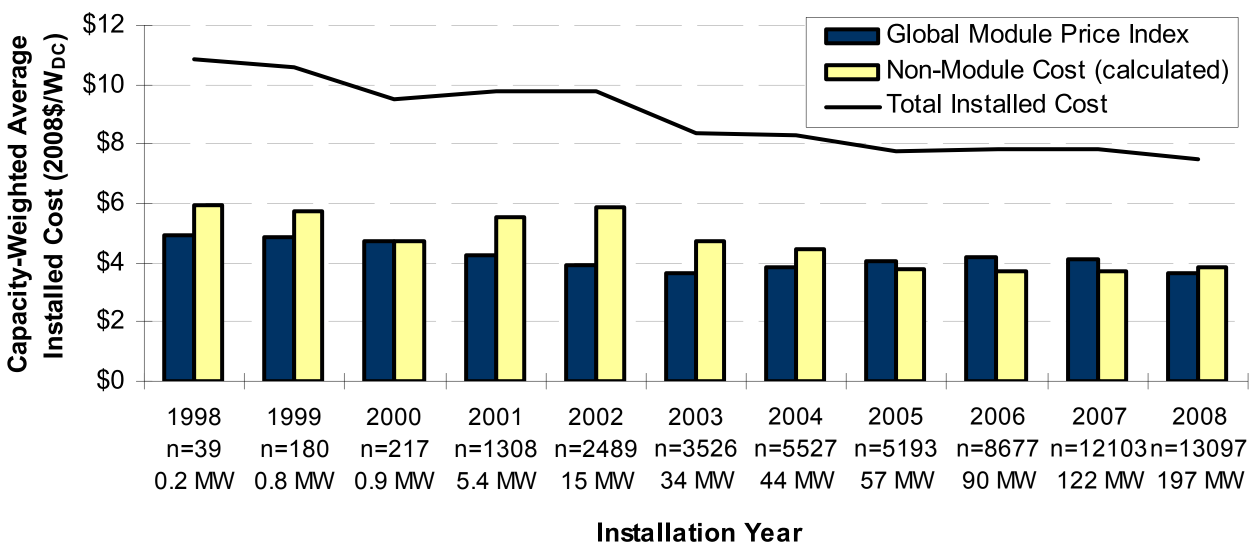
Figure 5. 2008 and Preliminary 2009 Installed Costs for California and New Jersey

Installed Cost Reductions from 2007 to 2008 Are Primarily Associated with a Decline in Module Costs

Figure 6 disaggregates average annual installed costs into average module and non-module costs. As many programs did not provide component-level cost data, Figure 5 presents Navigant Consulting's Global Power Module Price Index as a proxy for module costs. Average non-module costs (which may include such items as inverters, mounting hardware, labor, permitting and fees, shipping, overhead, taxes, and profit) shown in Figure 5 were calculated as the difference between the average total installed cost and the module price index in each year.

Based on this method, the decline in installed costs from 2007 to 2008 appears to be primarily attributable to a drop in *module* costs, which fell by approximately \$0.5/W over this period.[16] This contrasts with the longer-term historical trend, in which installed cost reductions have been associated mostly with a decline in *non-module* costs. Specifically, from 1998 to 2008, non-module costs fell by \$2.1/W, from approximately \$5.9/W in 1998 to \$3.8/W in 2008, representing 62% of the overall \$3.4/W drop in total installed costs over this period. In comparison, the module index price dropped by \$1.3/W from 1998 to 2008.

Trends in non-module costs may be particularly relevant in gauging the impact of state and utility PV programs. Unlike module prices, which are primarily established through national (and even global) markets, non-module costs consist of a variety of cost components that may be more readily affected by local programs – including both 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. Thus, the fact that non-module costs have fallen over time, at least until 2005, suggests (though does not prove) that state and local PV programs have had some success in driving down the installed cost of PV.



Note: Non-module costs are calculated as the reported total installed costs minus the global module price index.

Figure 6. Module and Non-Module Cost Trends over Time

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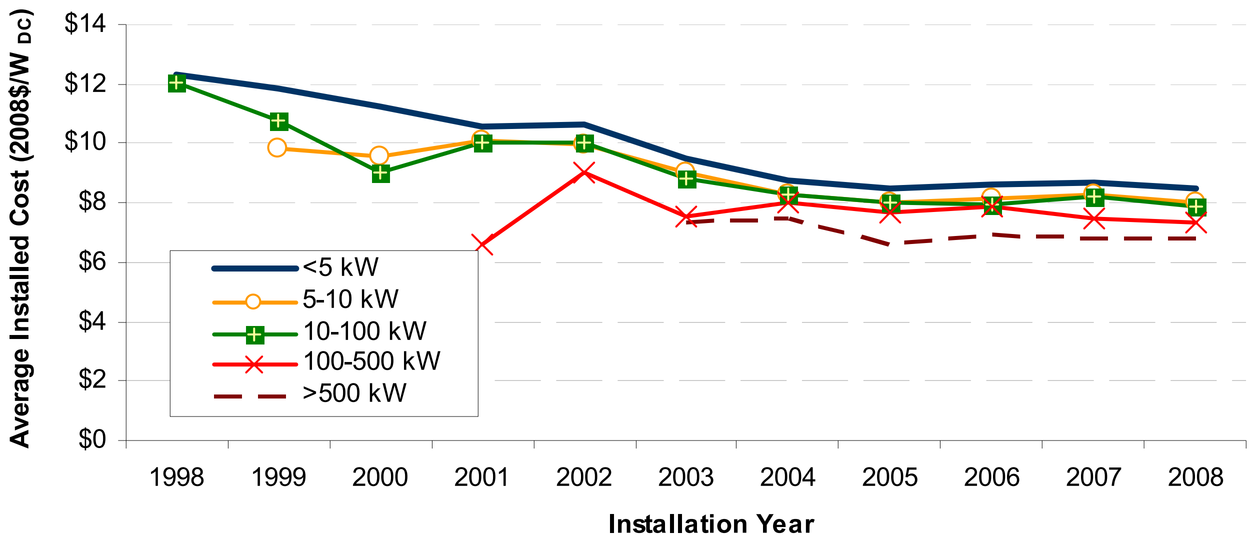
[16] It should be noted, however, that there is likely a lag between movements in the wholesale price of PV modules and the average installed cost of PV projects, as module costs for installed projects may reflect prevailing wholesale prices at the time that contracts for system installation were signed. Thus, the decline in the Global Module Price Index from 2007 to 2008 is likely to be larger than the reduction in module costs for projects installed over the same time period.

Historical Cost Reductions Are Most Evident for Systems Smaller than 100 kW

As shown in Figure 7, long-term historical cost reductions are most evident for smaller system sizes. For example, the average installed cost of systems ≤5 kW dropped from $12.3/W in 1998 to $8.5/W in 2008, equivalent to an average annual reduction of $0.4/W per year. Similar cost reductions occurred for 10-100 kW systems, and somewhat lower cost reductions occurred for 5-10 kW systems. It is less apparent whether, and to what extent, larger systems (i.e., 100-500 kW and >500 kW) have experienced long-term cost reductions, due to the limited availability of data for the early years of the analysis period. Based on the data available, systems >500 kW experienced a modest cost decline from 2003 to 2008, while the average installed cost of 100-500 kW systems actually rose from 2001 to 2008 (although this latter trend may simply be an artifact of small sample size).[17]



Note: Averages shown only if five or more observations were available for a given size category in a given year.

Figure 7. Installed Cost Trends over Time, by PV System Size

The Distribution of Installed Costs Narrowed from 1998 to 2005, But No Further Narrowing Occurred through 2008

As indicated by the standard deviation bars in Figure 4, the distribution of installed costs has narrowed considerably over time. This trend can be seen with greater precision in Figure 8 and Figure 9, which present frequency distributions of installed costs for systems less than and greater than 10 kW, respectively, installed in different time periods. Both figures show a marked narrowing of the cost distributions occurring from 1998 through 2005, although this trend largely subsided from 2005 through 2008. This convergence of prices, with high-cost outliers becoming increasingly infrequent, is consistent with a maturing market characterized by increased competition among installers and module manufacturers and by better-informed consumers. The two figures also show a *shifting* of the cost distributions to the left, as would be expected based on the previous finding that average installed costs have declined over time.

[17] Within our data set, there are five systems in the 100-500 kW size range that were installed in 2001 – the minimum sample size required for a data point to be included in Figure 7.

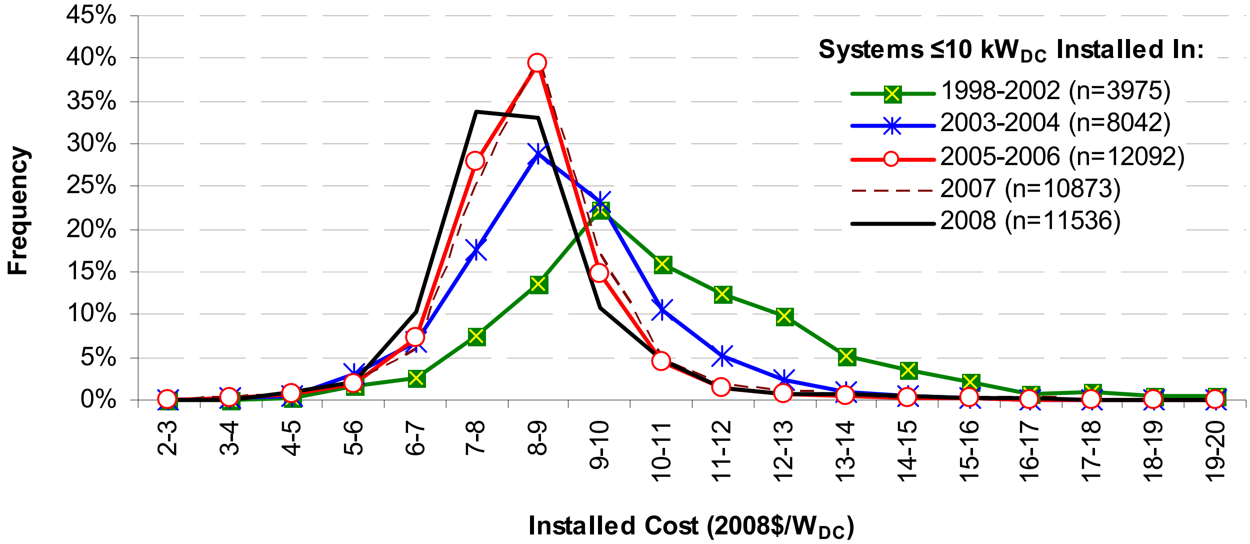


Figure 8. Distribution of Installed Costs for Systems ≤10 kW

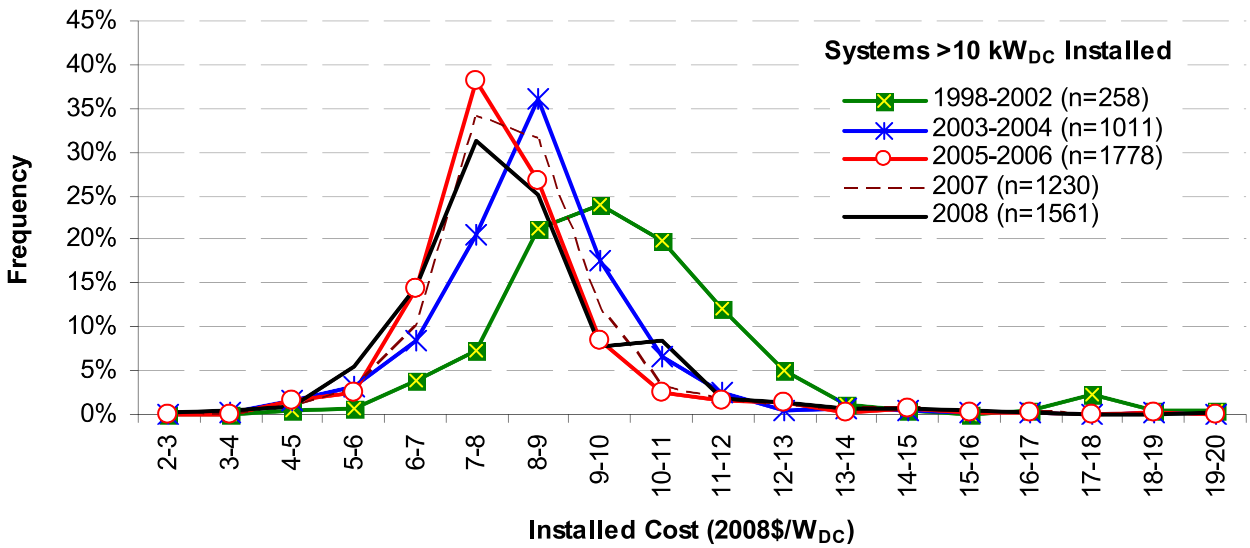


Figure 9. Distribution of Installed Costs for Systems >10 kW

Installed Costs Exhibit Economies of Scale

Large PV installations may benefit from economies of scale, through price reductions on volume purchases of materials and through 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 indicated by Figure 10, which shows the average installed cost according to system size, for PV systems completed in 2008. The smallest systems (≤2 kW) exhibit the highest average installed costs ($9.2/W), while the 500-750 kW systems have the lowest average cost ($6.5/W, or about 30% below the average cost of the smallest systems). Interestingly, the 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, and increases in system size in the 100-750 kW range. In contrast, the data do not show evidence of significant economies of scale within the 5-100 kW size range. Somewhat counterintuitively, the average installed cost of systems >750 kW is higher than for 500-750 kW systems ($6.8/W vs. $6.5/W, respectively), potentially reflecting a higher incidence of tracking systems among the >750 kW systems.

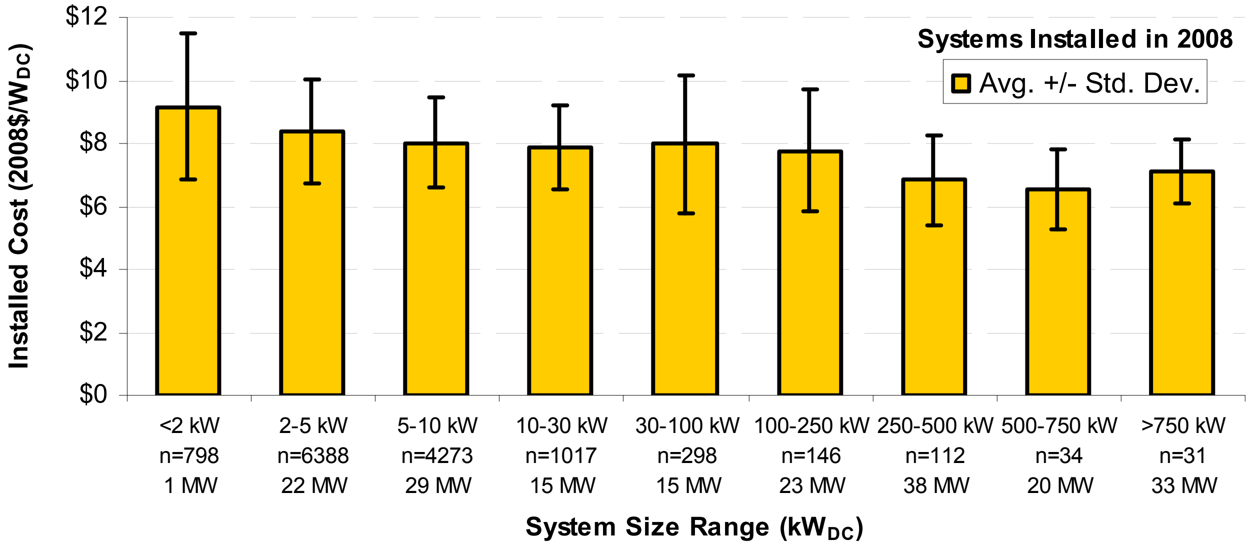


Figure 10. Variation in Installed Cost According to PV System Size

The primary dataset underlying the results shown in Figure 10 consists only of data provided by the 27 PV program administrators in our sample. Not included in this dataset are a number of large, multi-MW PV systems, several of which are installed on the utility-side of the meter. Installed cost data for nine of these projects have been reported in press releases and other public sources, and are summarized in Table 3.[18] As shown, the installed costs of these projects vary considerably. Of the four projects completed in 2008, two projects (in Boulder City, NV and Fontana, CA) have reported installed costs that are *significantly* below the average for the >750 kW systems shown in Figure 10. Also note that a number of the systems in Table 3 installed prior to 2008 have tracking systems, and are therefore likely to attain higher performance (and thus lower *levelized* costs on a $/MWh basis, even if the up-front installed costs are higher) than the large projects in the primary dataset, which are mostly fixed-axis systems.

To the extent that the economies of scale described above have persisted over time, they may partially explain the temporal decline in average installed costs, as the average size of PV systems has grown over time. As shown in Figure 11, which describes the average size of systems for which customer type (i.e., residential vs. non-residential) was explicitly provided by PV incentive programs, the average size of residential systems grew from 2.7 kW in 1998 to 5.2 kW in 2008, while the average size of non-residential systems rose from 25 kW to 88 kW over the same time period.

[18] Table 3 only includes systems >2 MW that are not in the primary dataset and for which installed cost data could be found. Note, though, that the sources of these cost data vary in quality, and therefore these data are less certain than the data in the primary sample.

Table 3. Installed Cost of Large (≥ 2 MW) Out-of-Sample PV Systems

Location	Year of Installation	Plant Size (kW_{DC})	Installed Cost ($2008\$/W_{DC}$)	Actual or Expected Capacity Factor	Tracking System Design
Boulder City, NV	2008	12,600	3.2	21%	none (fixed-axis)
Fairless Hills, PA	2008	3,000	6.7	14%	none (fixed-axis)
Fontana, CA	2008	2,400	4.3	no data	none (fixed-axis)
Riverside, CA	2008	2,000	6.5	15%	none (fixed-axis)
Nellis, NV	2007	14,200	7.3	24%	single axis
Alamosa, CO	2007	8,220	7.6	24%	none, single axis, and double axis
Fort Carson, CO	2007	2,000	6.5	18%	none (fixed-axis)
Springerville, AZ	2001-2004	4,590	6.2	19%	none (fixed-axis)
Prescott Airport, AZ	2002-2006	3,388	5.6	21%	single axis and double axis

Notes: Cost for Springerville is for capacity added in 2004. Cost for Prescott is for single-axis capacity additions in 2004.

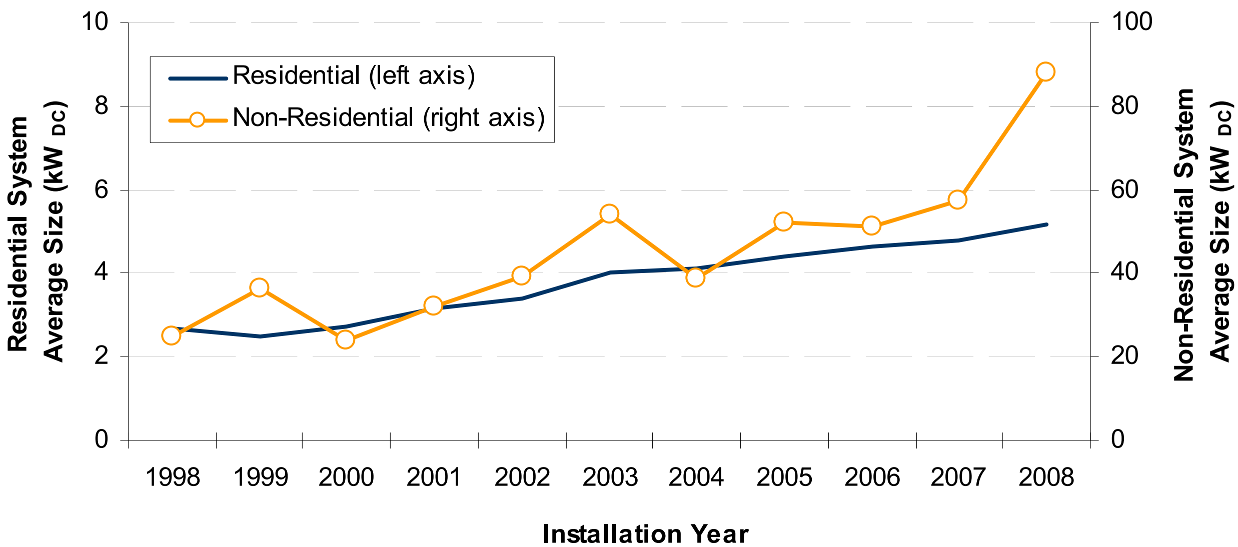


Figure 11. PV System Size Trends over Time

Module Costs Were Lower for Large Systems than for Small Systems in 2008, While Non-Module Costs Were Relatively Constant Across System Sizes

The average module and non-module costs presented in Figure 6 were estimated based on a module price index. This approach was necessitated by the fact that many of the PV incentive programs in our data sample did not provide component-level cost data. However, a number of programs did provide component-level cost data (even if at a fairly coarse level of detail), and these data lend some validation to the break-down between module and non-module costs implied in Figure 6, and also provide a moderate level of additional detail on the composition of non-module costs and the variation in component-level costs across system sizes. [19]

Figure 12 summarizes the component-level cost data provided by the PV incentive programs in our data sample, for systems installed in 2008. As shown, modules represented between 56% and 58% of total installed costs, depending on the particular size range – which is slightly higher,

[19] Component-level cost data were provided for 64% of the systems in the dataset installed in 2008. Component-level cost data are more limited for earlier year, precluding presentation of time series data on component-level costs.

though not dramatically inconsistent, with the imputed breakdown between module and non-module costs indicated in Figure 6. On average, inverter costs comprise 6-9% of the total cost, while other costs (e.g., mounting hardware, labor, overhead, profit, etc.) make up the relatively substantial remaining 34-39%.[20]

Comparing across the size ranges, Figure 12 indicates that module costs were $0.6-$0.7/W lower for systems >100 kW than for systems in the two smaller size groupings, perhaps indicative of the bulk purchasing power that larger systems may enable. The "Other" (non-module/non-inverter) costs, however, did not vary appreciably by system size (ranging from $2.6/W to $2.9/W), which is somewhat contrary to conventional wisdom, as certain non-hardware costs (e.g., labor, regulatory compliance, and overhead) are generally assumed to benefit from economies of scale.

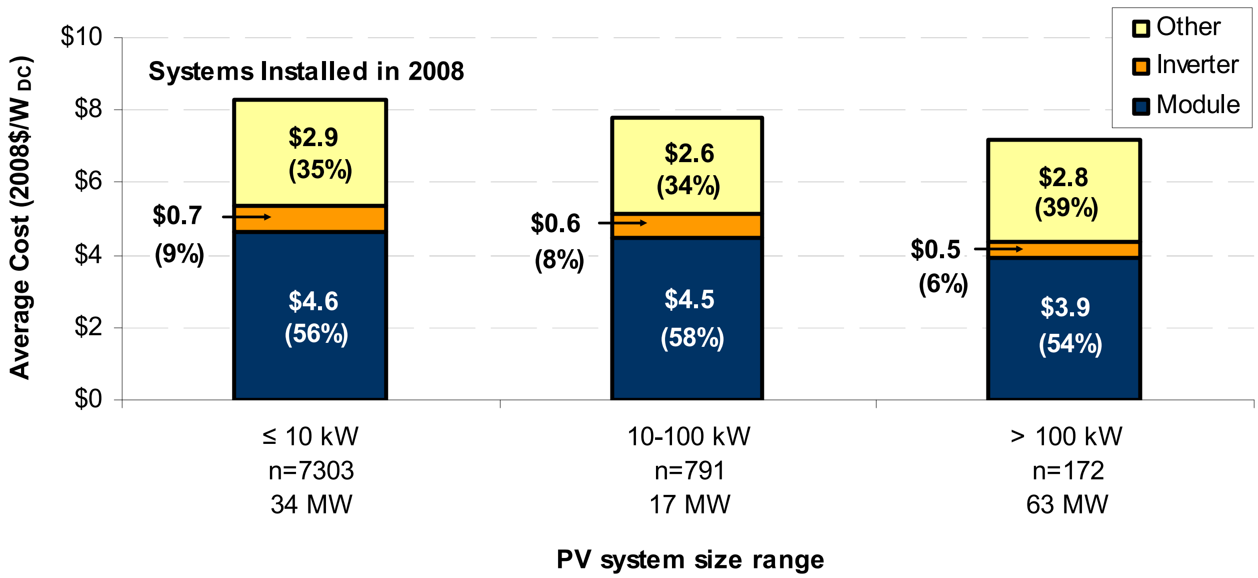


Figure 12. Module, Inverter, and Other Costs

Average Installed Costs for Residential Systems Are Lower in Germany and Japan than in the U.S.

Notwithstanding the significant cost reductions that have already occurred in the U.S., international experience suggests that greater near-term cost reductions may be possible. Figure 13 compares average installed costs in Germany, Japan, and the United States, focusing specifically on small residential systems installed in 2008 (and excluding sales or value-added tax). Among this class of systems, average installed costs were substantially lower in Germany and Japan ($6.1/W and $6.9/W, respectively) than in the U.S. ($7.9/W). These differences may be partly attributable to the much greater cumulative grid-connected PV capacity in Germany and Japan (about 5,300 MW and 2,000 MW, respectively, at the end of 2008), compared to just 800 MW in the U.S. That said, larger market size, alone, is unlikely to account for all of the variation.[21]

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[20] Some additional detail on individual component costs, although not based directly on project data, can be gleaned from the results of a survey of PV installers conducted by Berkeley Lab in 2008 and reported in Wiser, R., G. Barbose, and C. Peterman. 2009. *Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007.* Berkeley, CA: Lawrence Berkeley National Laboratory.

[21] Installed costs may differ among countries as a result of a wide variety of factors, including differences in: module prices, technical standards for grid-connected PV systems, installation labor costs, procedures for receiving incentives

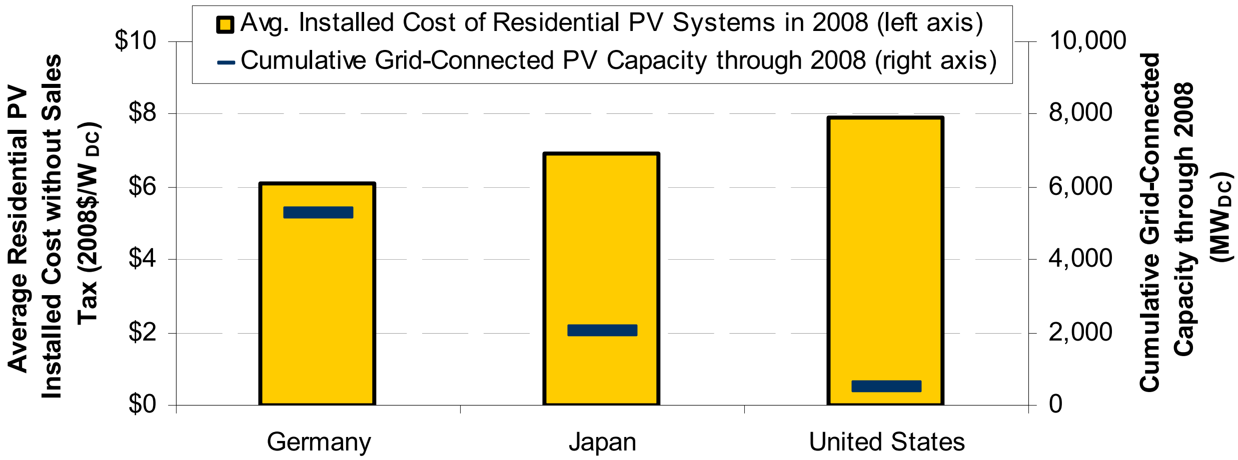

Figure 13. Comparison of Average Installed Costs in Germany, Japan, and the U.S. (Small Residential Systems Completed in 2008)[22]

Installed Costs Vary Widely Across States

The U.S. is clearly not a homogenous PV market, as evidenced by Figure 14, which compares the average installed cost of systems ≤10 kW completed in 2008, across 14 of the 16 states in our dataset.[23] Among systems in this size class, average costs range from a low of $7.3/W in Arizona to a high of $9.9/W in Pennsylvania and Ohio. Table 4 presents the same data in tabular form, along with comparative data for other system size ranges and groupings.

The variation in average installed costs across states may partially be a consequence of the differing size and maturity of the PV markets, where larger markets stimulate greater competition and hence greater efficiency in the delivery chain, and may also allow for bulk purchases and better access to lower-cost products. It therefore is perhaps not surprising that California, the largest PV market in the U.S., has among the lowest average costs, lending some credence to the premise behind state policies and programs that seek to reduce the cost of PV by accelerating deployment.[24]

However, as with the preceding international comparison, other factors also drive differences in installed costs among individual states. Incentive application procedures and regulatory compliance costs, for example, vary substantially. Installed costs also vary across states as a result of differing sales tax treatment; 7 of the 14 states shown in Figure 14 exempted residential PV systems from state sales tax throughout 2008, and Oregon has no state sales tax. If PV hardware costs represent

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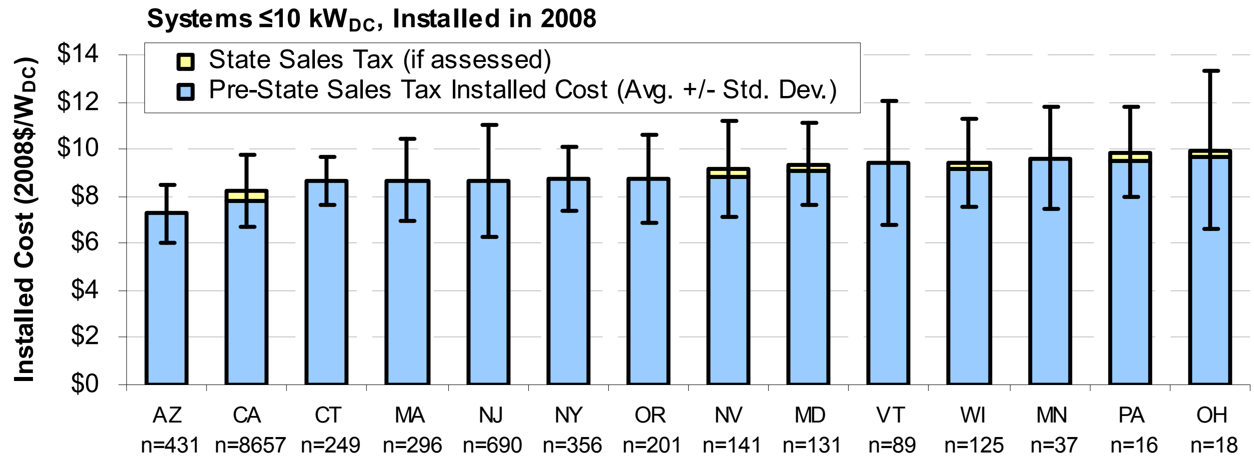
and permitting/interconnection approvals (i.e., "paperwork burden"), foreign exchange rates, and the degree to which components are manufactured locally. The lower costs of residential PV in Japan relative to the U.S. may also be partly explained by the fact that Japan's PV support policies have focused largely on the residential sector, and that a sizable amount of this market consists of pre-fabricated new homes that incorporate PV systems as a standard feature.

[22] The Japanese and U.S. cost data shown in Figure 13 are for 2-5 kW systems, while the German cost data are for 3-5 kW systems. Additionally, note that the U.S. data presented in this figure exclude sales tax, and therefore are not directly comparable to data presented elsewhere in this report. Source for Japanese price and cumulative installed capacity data: Yamamoto, M. and O. Ikki. 2009. *National survey report of PV Power Applications in Japan 2008.* Paris, France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems. Source for German price and cumulative installed capacity data: Wissing, L. 2009. *National Survey Report of PV Power Applications in Germany 2008.* Paris: France: International Energy Agency Cooperative Programme on Photovoltaic Power Systems.

[23] We exclude Colorado and Washington from the figure, as the data sample includes only a very small fraction of the 2008 capacity additions in both states, and therefore may not be indicative of average installed costs in these two states.

[24] The reason for the low average cost in Arizona – itself a relatively small PV market – is unknown.

approximately 65% of the total installed cost of residential PV systems (an assumption supported by component-level cost data presented previously), state sales tax exemptions effectively reduce the post-sales-tax installed cost by $0.2-0.4/W, depending on the specific state sales tax rate that would otherwise be levied.



Notes: State Sales Tax and Pre-State Sales Tax Installed Costs were calculated from 2008 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, in turn, were assumed to constitute 65% of the total pre-sales-tax installed cost. CO and WA are excluded from the figure due to insufficient sample size.

Figure 14. Variation in Installed Costs among U.S. States

Table 4. Average Installed Cost ($/W$_{DC}$) by State and PV System Size Range

State	**All Reported Yrs.** Capacity-Weighted Average Cost (all sizes)		2008 Systems: Capacity-Weighted Average Cost (all sizes)		2008 Systems: Simple Average Cost, 0 - 10 kW$_{DC}$		10 - 100 kW$_{DC}$		100 - 500 kW$_{DC}$		>500 kW$_{DC}$	
AZ	$7.4	(n=1258)	$6.8	(n=477)	$7.3	(n=431)	$6.8	(n=42)	*	(n=4)	*	(n=0)
CA	$7.8	(n=42522)	$7.4	(n=9845)	$8.2	(n=8657)	$7.7	(n=934)	$7.3	(n=199)	$6.8	(n=55)
CO	$8.3	(n=16)	$8.3	(n=16)	$8.3	(n=16)	*	(n=0)	*	(n=0)	*	(n=0)
CT	$8.1	(n=623)	$7.9	(n=310)	$8.6	(n=249)	$8.3	(n=49)	$7.6	(n=12)	*	(n=0)
MA	$9.1	(n=1091)	$8.0	(n=336)	$8.7	(n=296)	$8.7	(n=34)	$7.4	(n=6)	*	(n=0)
MD	$9.4	(n=230)	$9.0	(n=135)	$9.3	(n=131)	*	(n=4)	*	(n=0)	*	(n=0)
MN	$8.9	(n=145)	$9.8	(n=38)	$9.6	(n=37)	*	(n=1)	*	(n=0)	*	(n=0)
NJ	$7.9	(n=3225)	$7.6	(n=860)	$8.7	(n=690)	$8.3	(n=132)	$7.2	(n=29)	$6.9	(n=9)
NV	$9.1	(n=393)	$8.8	(n=145)	$9.2	(n=141)	*	(n=4)	*	(n=0)	*	(n=0)
NY	$8.9	(n=1158)	$8.6	(n=401)	$8.7	(n=356)	$8.8	(n=45)	*	(n=0)	*	(n=0)
OH	$9.6	(n=35)	$9.5	(n=23)	$9.9	(n=18)	*	(n=4)	*	(n=1)	*	(n=0)
OR	$8.3	(n=878)	$8.4	(n=248)	$8.7	(n=201)	$9.4	(n=39)	$8.2	(n=7)	*	(n=1)
PA	$9.3	(n=164)	$9.5	(n=18)	$9.9	(n=16)	*	(n=2)	*	(n=0)	*	(n=0)
VT	$8.7	(n=225)	$9.1	(n=94)	$9.4	(n=89)	$8.8	(n=5)	*	(n=0)	*	(n=0)
WA	$7.7	(n=7)	$7.7	(n=6)	$8.9	(n=6)	*	(n=0)	*	(n=0)	*	(n=0)
WI	$8.9	(n=386)	$9.0	(n=145)	$9.4	(n=125)	$8.6	(n=20)	*	(n=0)	*	(n=0)

* Cost data is omitted if the sample size (n) is less than five.

Installed Costs are Generally Lower for Residential Systems than for Similarly Sized Commercial and Public-Sector Systems

Figure 15 compares average installed costs across four customer segments: residential, commercial, public sector (i.e., government and schools), and non-profit. We focus on systems installed in 2008 for which customer segment data was provided, splitting those data into two size categories: 5-10 kW and 10-100 kW.[25] As shown, the differences in average costs among customer segments are generally modest, and the rank ordering of customer segments is somewhat inconsistent between the two size groups (suggesting that some of the variation may be more idiosyncratic than systematic). That said, Figure 15 does indicate that installed costs tend to be relatively low for residential systems compared to similarly sized commercial or public sector systems. Specifically, within the 5-10 kW size range, systems installed for residential customers have an average installed cost ($8.0/W) that is $0.4/W less than for public sector and non-profit customers ($8.4/W), and $0.6/W less than commercial customers ($8.6/W). Within the 10-100 kW size range, average costs are lowest for the non-profit segment ($7.5/W), followed by residential customers ($7.8/W), which is $0.3/W below the average for commercial customers ($8.1/W) and $0.8/W below the average for public sector customers ($8.6/W).

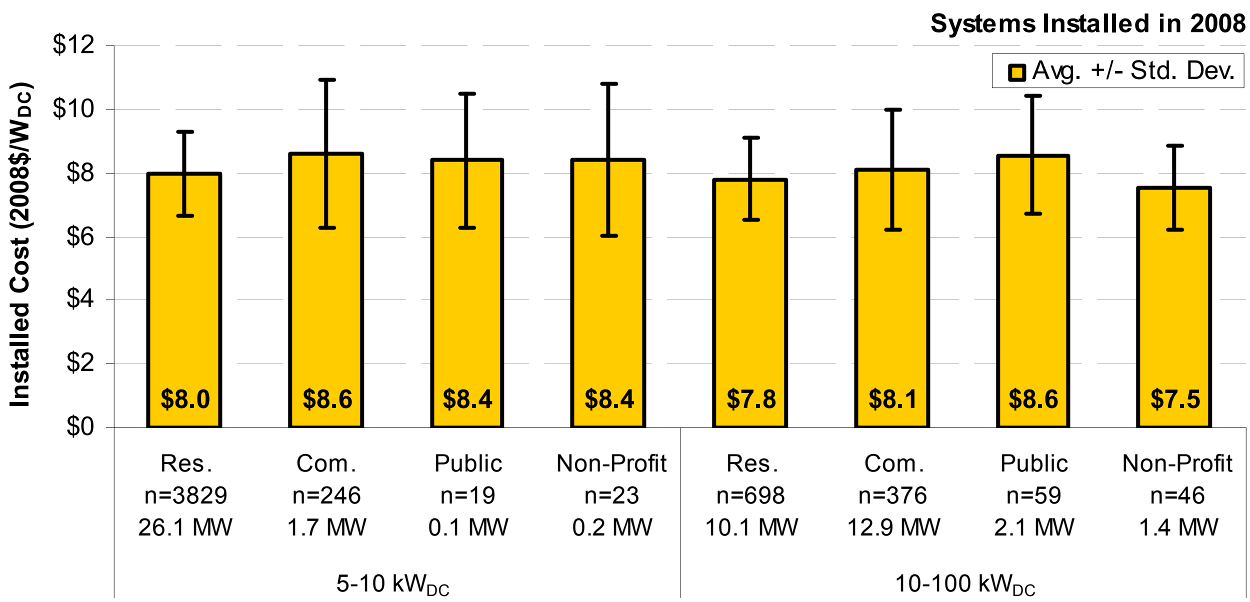


Figure 15. Variation in Installed Costs among Customer Sectors

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

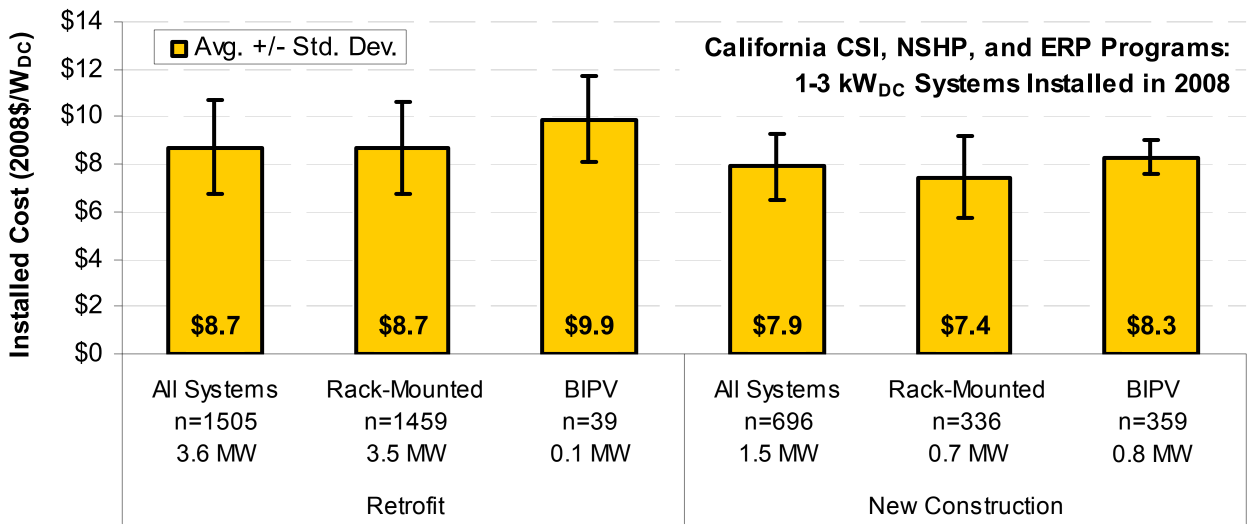
Three California incentive programs provided data on systems that could be readily identified as either residential new construction or residential retrofit: the Emerging Renewables Program (ERP), the California Solar Initiative Program (CSI), and the New Solar Homes Partnership (NSHP) program. Figure 16 compares the average installed cost of residential new construction and residential retrofit projects funded through these three California programs, focusing in particular on 1-3 kW projects (the size range typical of residential new construction[26]) completed in 2008. Among this group of PV systems, those installed in residential new construction cost $0.8/W less,

[25] Customer segment identifiers were provided by PV incentive programs for approximately 86% of all 2008 installations within the dataset. We focus on the 5-10 kW and 10-100 kW size ranges, as both are ranges within which there are limited economies of scale and for which the sample size in each customer segment is sufficiently large.
[26] Of the 820 systems within the dataset identifiable as having been installed in residential new construction in 2008, 85% are within the 1-3 kW size range.

on average, than comparably-sized residential retrofit systems ($7.9/W compared to $8.7/W), a price advantage of approximately 10%.

However, 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 costs than rack-mounted systems, though the higher installed costs may be partially offset by avoided roofing material costs. Systems within the data sample were identified as BIPV or rack-mounted based on module manufacturer and model data provided by the incentive program administrators. As shown in Figure 16, BIPV systems in the three California programs cost $0.9/W more, on average, than rack-mounted systems installed in residential new construction (i.e., $8.3/W vs. $7.4/W).

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 the two applications, which is broken out in Figure 16 from the larger sub-samples. This comparison suggest a somewhat greater cost advantage for new construction than implied by the overall averages, with rack-mounted systems installed in residential new construction averaging $1.2/W less than residential retrofit systems ($7.4/W compared to $8.7/W).[27]



Note : The number of rack-mounted systems plus BIPV systems may not sum to the total number of systems, as some systems could not be identified as either rack-mounted or BIPV.

Figure 16. Comparison of Installed Costs for Residential Retrofit vs. New Construction

Systems >10 kW with Thin-Film Modules Had Lower Installed Costs than Those with Crystalline Modules

Individual systems were identified as employing either thin-film or crystalline modules based on module manufacturer and model data provided by the PV incentive programs.[28] Figure 17

[27] Similarly, BIPV systems installed in new construction averaged $1.6/W less than BIPV systems installed in residential retrofits ($8.3/W compared to $9.9/W). However, some caution is warranted in interpreting the cost comparison for BIPV systems, as some modules made for BIPV applications may be installed as rack-mounted systems. It is therefore possible (if not likely) that some of the systems identified as residential retrofit BIPV systems may be misclassified and may, in fact, be rack-mounted installations.

[28] Thin-film systems include both amorphous silicon and non-silicon modules.

compares the average installed cost of crystalline and thin-film systems, focusing specifically on rack-mounted (i.e., not BIPV) systems installed in 2008. As shown, thin-film systems in both the 10-100 kW and >100 kW size ranges had average installed costs lower than comparably-sized crystalline systems (by \$1.5/W and \$0.6/W, respectively), while thin-film systems ≤10 kW were somewhat more costly than their crystalline counterparts.[29] Notwithstanding the fact that the number of thin-film systems within the sample is quite small, the results for the 10-100 kW and >100 kW size ranges are consistent with expectations, as thin-film modules are widely considered to be lower cost than crystalline, and the greater uncertainty in the long-term performance of thin-film modules on the part of consumers would tend to drive down the price of thin-film systems relative to crystalline systems. The differing result for the ≤10 kW size range, where thin-film systems exhibit higher average costs than crystalline systems, may be attributable to the lower efficiency of thin-film modules, leading to higher balance of system costs (which may be proportionally more significant for small systems) that offset the reduced module costs.[30]

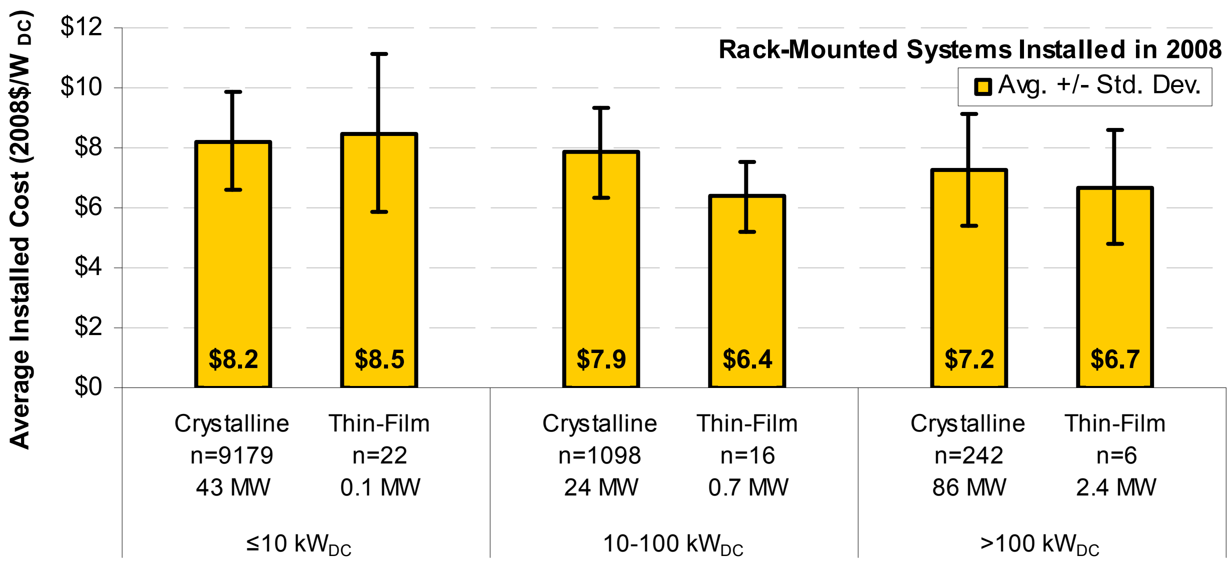


Figure 17. Comparison of Installed Costs for Crystalline vs. Thin-Film Systems

Tracking Systems Had Higher Installed Costs than Fixed-Axis Systems

Data indicating whether or not PV systems had tracking equipment were provided for a relatively small percentage of systems in the sample (e.g., 11% of systems and 9% of capacity installed in 2008). Based on the limited data available, Figure 18 compares the average cost of PV systems with tracking to those with fixed-axis mounting, focusing on rack-mounted systems (both roof- and ground-mounted) installed in 2008 within two size categories (≤10 kW and 10-100 kW).[31] As shown, tracking systems had higher installed costs within both size categories, as would be expected. Among systems ≤10 kW, tracking systems had average installed costs \$2.2/W (or 25%) higher than fixed-axis systems. In the 10-100 kW size range, the difference was significantly less,

[29] The previous edition of this report found that, across all size ranges, the average installed cost of thin-film systems was higher than for crystalline systems. However, that finding was the result of the misclassification of a single module model as thin-film.

[3030] We note, however, that the conventional belief that balance of systems costs are proportionally more significant for small systems is not borne out by the data presented earlier in Figure 12, which shows little variation in non-module/non-inverter costs across system sizes.

[31] There were insufficient data for systems >100 kW to warrant inclusion in the figure.

where tracking systems had average installed costs $0.5/W (or 6%) higher than their fixed-axis counterparts. Given that the use of tracking equipment is relatively uncommon among systems ≤10 kW, the latter comparison is arguably a more meaningful representation of the incremental cost of tracking equipment, in general. However, again, some caution is warranted in generalizing from these results, given the small sample size.

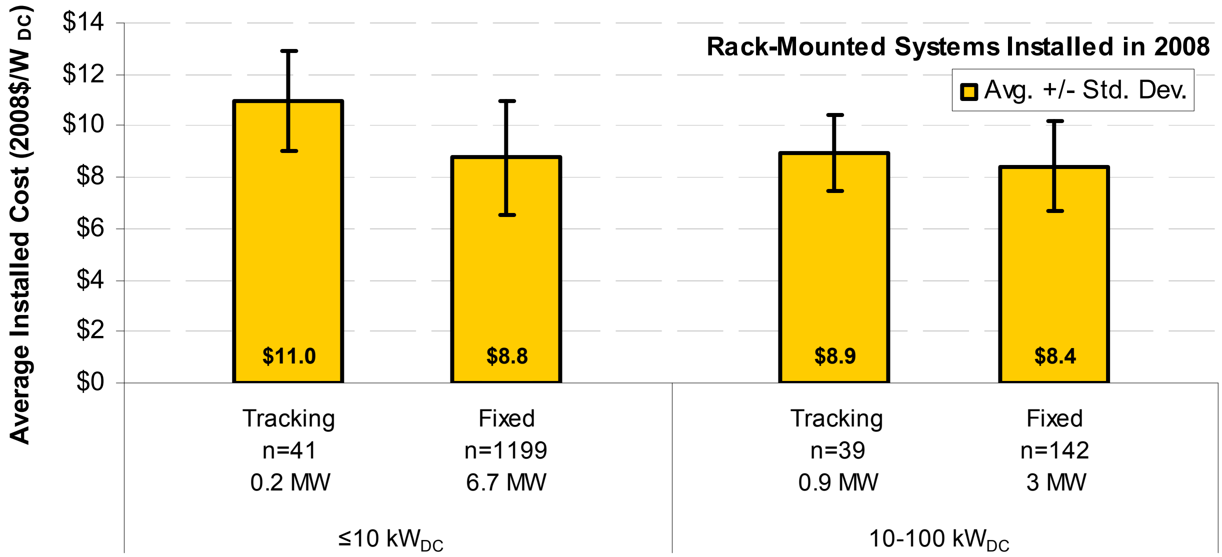


Figure 18. Comparison of Installed Costs for Tracking vs. Fixed-Axis Systems

4. PV Incentive and Net Installed Cost Trends

Financial incentives provided through utility, state, and Federal programs have been a major driving force for the PV market in the U.S. For any individual system, these incentives potentially include some combination of cash incentives provided through state or utility PV incentive programs, Federal and/or state investment tax credits (ITCs)[32], 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 (focusing specifically on state/utility cash incentives and state/federal ITCs) and net installed costs (i.e., installed costs after receipt of financial incentives) over time, by system size, and among states.

Two important caveats should be noted at the outset:

- First, the set of incentives addressed in this section are necessarily limited in scope, accounting only for the direct cash incentives provided through the specific state/utility PV incentive programs in the dataset, plus state and Federal ITCs. The analysis does not account for the incentive for commercial PV provided through accelerated depreciation (which has remained constant over the sample period),[33] nor for any additional incentives that projects may have received from state/utility incentive programs outside of the PV incentive program covered in this report.[34] The results presented in this section also do not account for revenue from the sale of RECs, although the potential magnitude of this revenue stream is briefly discussed in general terms (see Text Box 2). As such, the results presented in this section exclude New Jersey's Solar Renewable Energy Credit program (which is included in previous sections of this report), as that program provides incentives solely in the form of solar RECs, the price of which varies over time according to market conditions.
- Second, 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 Federal and state ITCs for each project and to determine the net installed cost on an after-tax basis.

State/Utility Cash Incentives Continued Their Steady Decline in 2008

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 actual energy production, as either a supplement or an alternative to an up-front rebate.[35] Figure 19 shows the average cash incentive, on a $/W basis, received by the PV systems in the dataset, over time and

[32] Starting in 2009, the federal ITC for commercial PV can be converted to a cash grant of equal value from the U.S. Treasury.

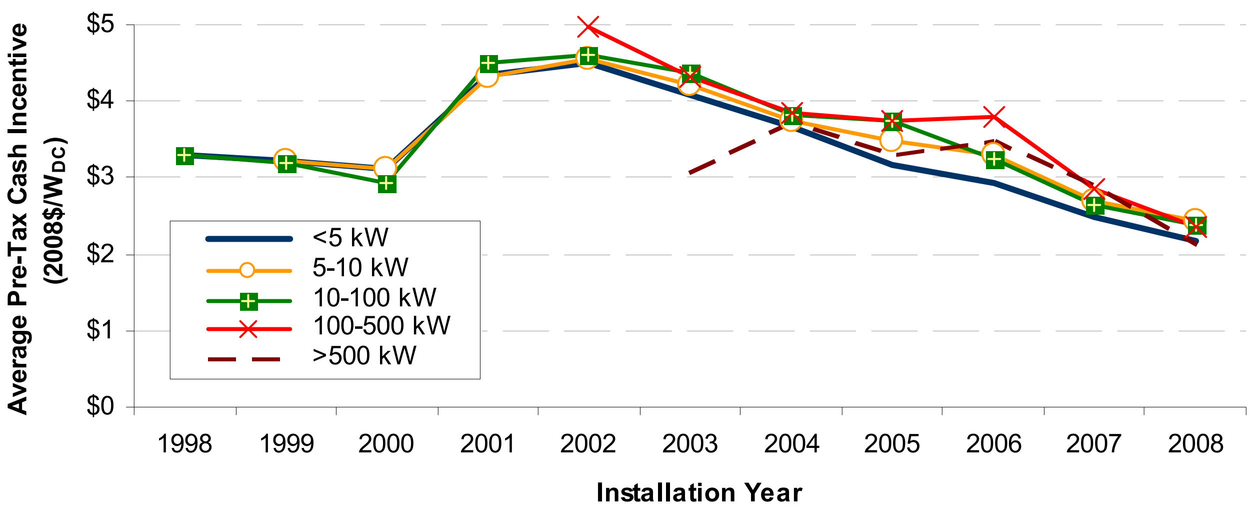
[33] For tax purposes, commercial PV owners are allowed to depreciate PV systems using an accelerated 5-year schedule. The net present value of this accelerated depreciation schedule, relative to a 20-year straight-line schedule, is equal to 12% of installed costs. See: Bolinger, M., G. Barbose, and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

[34] For example, in Pennsylvania, some projects may have received incentives through both the Sustainable Energy Fund's Solar Grant Program and the state's Energy Harvest Program (where the former is included in the dataset and the latter is not).

[35] PBI payments were reported by PV incentive program administrators on a $/W basis, based on estimated energy production. These $/W figures were used directly, without discounting, in the analysis provided in this section.

according to system size. 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.[36] Note also that the figure does not necessarily provide an accurate depiction of the size of 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 19, average cash incentives for systems installed in 2008 ranged from \$2.1/W - \$2.4/W across the system size ranges shown. Incentive levels in 2008 are roughly 50% below their peak in 2002, declining by about \$0.4/W per year, on average.[37] These trends largely reflect changes in incentives received by systems funded by California's ERP, SGIP, and CSI programs, which together represent 77% of all of the systems in the data sample. To a lesser extent, the trends in Figure 19 also reflect the growing prominence of New Jersey's CORE program, which has historically offered relatively high incentives and constitutes an increasing percentage of the sample over time, counteracting, to some degree, the decline in average incentive levels associated with the California programs. Although overshadowed by the dominant effect of the California and New Jersey programs, average incentives among other PV incentive programs in the sample also generally declined from 2002/2003 to 2008 (see Table B-3 in Appendix B).



Note: Averages shown only if five or more observations were available for a given size category in a given year.

Figure 19. Pre-Tax State/Utility Cash Incentive Levels over Time

[36] Although the IRS has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered Federally-taxable income. Cash incentives for residential PV, however, 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. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." 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.

[37] For systems >500 kW, the average cash incentive peaked at \$3.7/W in 2004, declining to \$2.1/W in 2007 (a drop of \$1.6/W). However, fewer than 10 systems in this size range were installed each year prior to 2006, and therefore the time trend during those years may not be particularly meaningful.

Text Box 2. Revenue from the Sale of RECs

PV system owners may be able to sell RECs generated by their system, adding to any direct incentives received from state/utility PV incentive programs and Federal or state ITCs (provided that REC ownership is not automatically transferred to the state/utility as a condition of providing a direct cash incentive). Projecting the value of REC sales over the lifetime of each individual PV system in our dataset would be a highly speculative task, and therefore was not undertaken for this study. Based on historical REC prices, however, the revenue potential in most states is relatively modest, compared to the value of direct cash incentives received through state/utility PV incentive programs and to the value of the Federal ITC.

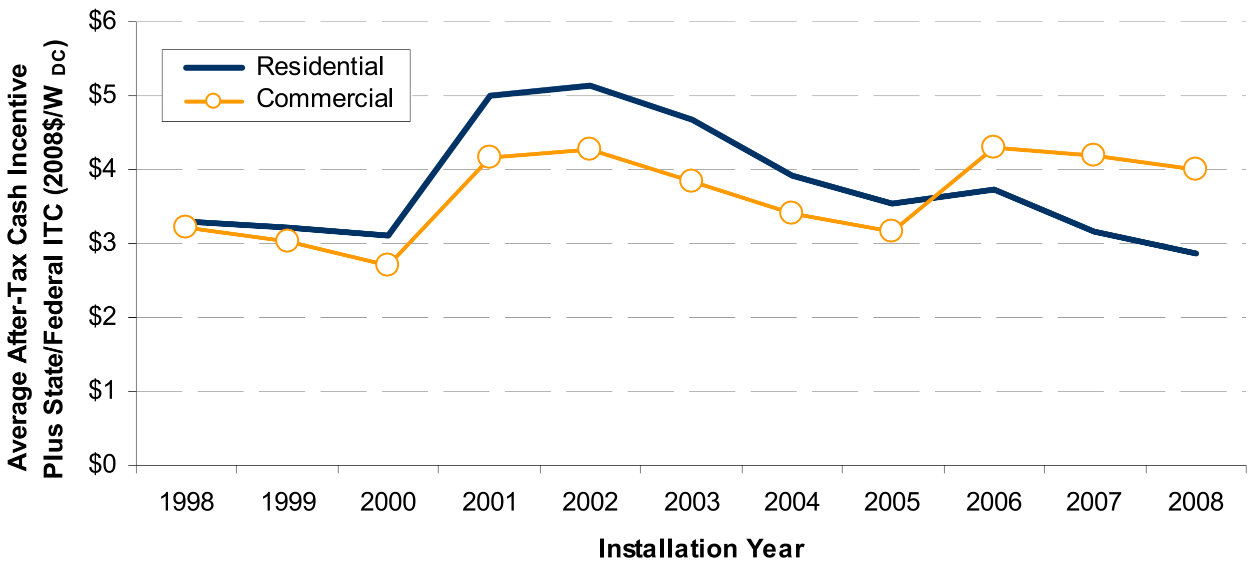
In general, the potential REC revenue for customer-sited PV depends on where the system is located, and consequently, what types of REC markets are available.

- *Voluntary REC Markets*. In most states, RECs generated by PV systems may be sold to individuals, businesses, or government agencies that are voluntarily seeking to support renewable energy. Given the voluntary nature of these transactions, prices in voluntary REC markets have historically been quite modest. For example, voluntary RECs traded through Spectron, a brokerage firm, averaged about $4/MWh in 2008. If extrapolated over 20 years, revenue from REC sales at this price would be equivalent to an up-front, pre-tax incentive of just $0.05/W on a present value basis (assuming a 10% nominal discount rate and a capacity factor of 14%).
- *General RPS Markets*. In some states, RECs generated by PV systems may be sold to electricity suppliers for compliance with state renewables portfolio standards (RPS). These markets may offer greater REC revenue potential than in voluntary markets, though REC prices in RPS markets have historically varied quite substantially across states and over time. For PV, the most critical issue typically is whether the state RPS has a specific solar requirement (i.e., a solar "set-aside" or "carve-out"). In "general" RPS markets without a solar set-aside (in which case RECs from PV systems may be used to satisfy the total renewable electricity compliance obligation), the highest average REC prices in 2008 occurred in Massachusetts, where REC prices for compliance with the state's Class I RPS requirement averaged approximately $45/MWh (again, based on REC trades through Spectron). If extrapolated over a 20-year period, using the same assumptions as before, revenue from REC sales at this price would be equivalent to an up-front, pre-tax payment of $0.52/W.
- *RPS Solar Set-Aside Markets*. Substantially greater REC revenue potential may be available in RPS states with a solar (or DG) set-aside. Through 2008, active trading of solar RECs (or SRECs) for compliance with a solar set-aside occurred primarily in New Jersey, where SRECs traded through Spectron averaged $390/MWh in 2008 (with prices rising over the course of the year to more than $600/MWh). Extrapolating this revenue stream over a 15-year period (as PV systems in New Jersey can sell SRECs for up to 15 years) yields the equivalent of an up-front, pre-tax payment of $4.0/W – a quite sizable sum that is larger than the direct cash incentives available in most states. Up until 2009, PV systems in New Jersey could receive both SREC payments and an up-front cash incentive. Starting in 2009, however, systems larger than 50 kW are no longer eligible for cash incentives, as the state shifts more fully towards an SREC-based support mechanism.

In 2008, the Combined Value of Federal & State ITCs Plus Direct Cash Incentives Was Near Its Peak for Commercial PV, but at an Historical Low for Residential PV

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. (Note that the *Energy Improvement and Extension Act of 2008* lifted the cap on the residential ITC for systems installed on or after January 1, 2009; however, this change does not pertain to the systems within our sample.) In addition to the Federal ITC, a number of states have, at various times, also 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 tax credit (see Appendix C for details on the ITCs for PV offered by the states in our dataset).

Figure 20 illustrates the combined effect of changes over time in state and Federal ITCs (assuming that all customers take advantage of available tax credits) *plus* changes to the cash incentives provided through the state and utility PV incentive programs in the dataset, expressed here on an *after-tax* basis.[38] As noted previously, this assessment ignores potential revenues from the sale of RECs, though for most of the states in our dataset (other than New Jersey), such revenues would likely add only marginally to the overall incentive received (see Text Box 2).



Notes: We assume that all systems ≤10 kW are residential and all systems >10 kW are commercial (unless indentified otherwise). For residential systems, we assume that state/utility cash incentives are non-taxable and reduce the basis of the Federal ITC. For commercial systems, we assume that state/utility cash incentives are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 20. After-Tax State/Utility Cash Incentives plus State & Federal ITCs (Calculated)

Figure 20 depicts a notably different trend for commercial PV than that exhibited in Figure 19 for larger (i.e., commercial) systems. Specifically, as shown in Figure 20, the decline in the average combined commercial 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. As a result, the average total financial incentive received by commercial PV systems in 2008 ($4.0/W) was only slightly below its peak of $4.3/W in 2002. Residential PV also saw a slight boost in overall incentive levels when the Federal ITC was extended to these systems in 2006; however, with the $2,000 cap on the residential credit (which has since been lifted for systems installed beginning in 2009), the effect was much less dramatic than for commercial PV. Consequently, the combined

[38] By expressing the incentives on an after-tax basis, we account for state and Federal income taxes that may be levied on direct cash incentives, as described in Appendix C.

after-tax incentive (cash incentives plus ITCs) for residential PV was, in 2008, at its lowest average level ($2.9/W) within the 11-year study period. The fact that combined after-tax incentives rose substantially from 2005 to 2008 for commercial PV, while declining for residential PV, may partially explain the shift towards the commercial sector within the U.S. PV market over this period. With the lifting of the cap on the Federal ITC for residential PV beginning in 2009, however, some movement back towards the residential sector may occur.

Net Installed Costs Increased Slightly from 2007 to 2008, as Declining Incentives More than Offset the Drop in Pre-Incentive Installed Costs

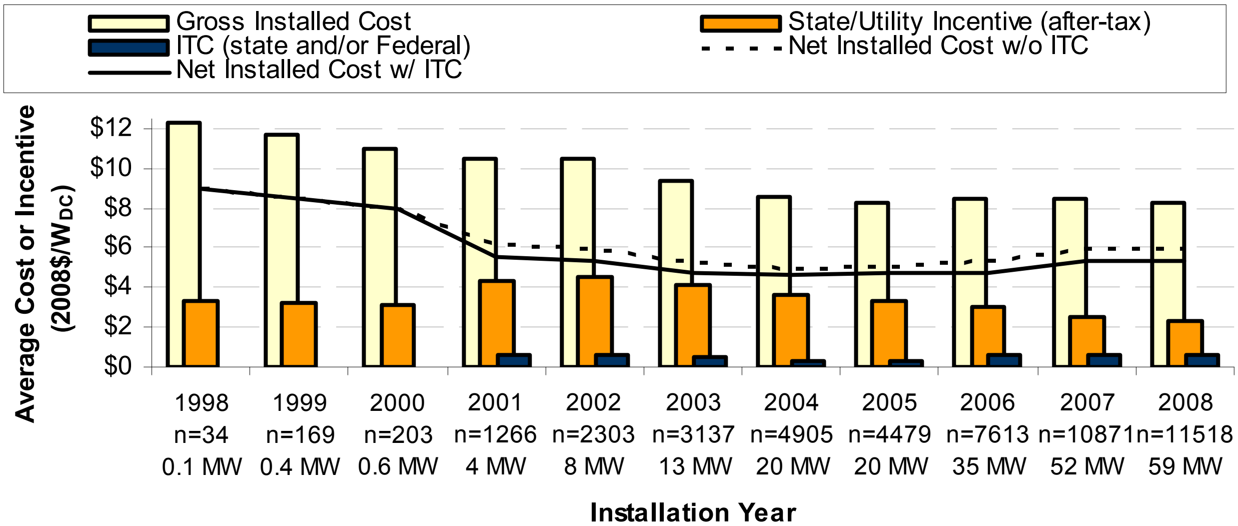
In 2008, average *net installed costs* – that is, installed costs minus the combined after-tax value of state/utility cash incentives plus ITCs – stood at $5.4/W for residential PV and $4.2/W for commercial PV, an increase over 2007 levels of 1% and 5%, respectively.

For residential PV, the average net installed cost in 2008 is effectively unchanged from its level in 2001 ($5.5/W). As discussed in Section 3, average pre-incentive installed costs declined significantly from 1998 to 2005, remained relatively stable from 2005 to 2007, and then resumed their decline from 2007 to 2008. At the same time, average after-tax incentives for residential systems steadily declined from 2002 to 2008. The net effect of these two trends, as illustrated in Figure 21, is that the net installed cost of residential PV declined by $0.9/W from 2001 to 2004 (from $5.5/W to $4.7/W), and then rose by $0.7/W from 2004 to 2008. The average net installed cost of residential PV is likely to decline substantially in 2009 compared to 2008, however, as a result of the lifting of the dollar cap on the Federal ITC for residential PV installations beginning in 2009.

As shown in Figure 22, the long-term trend for commercial PV is markedly different, by virtue of the more-lucrative Federal ITC available beginning in 2006. Specifically, in 2008, the net installed cost of commercial PV ($4.2/W) was 24% below its level in 2001 ($5.5/W). However, like residential PV, the net installed cost of commercial PV has been rising in recent years due to declining cash incentives. In 2008, the net installed cost of commercial PV was approximately 18% higher than its historical low of $3.6/W in 2006, and 5% higher than in 2007.

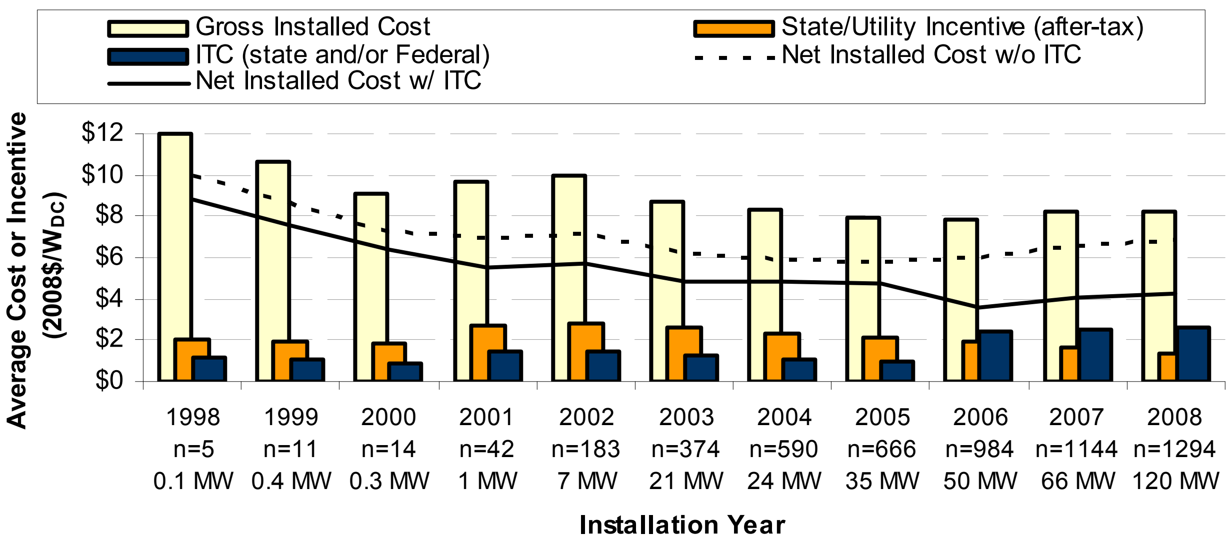
Finally, Figure 21 and Figure 22 also illustrate the potential impact of incentive levels on gross (i.e., pre-incentive) installed costs. A previous Berkeley Lab report, *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*, found a statistically significant correlation between pre-incentive installed costs in California and incentive levels under the state's two major PV incentive programs at the time (ERP and SGIP).[39] Evidence of this correlation can be seen in Figure 21 and Figure 22 (not surprisingly so, given the dominance of ERP and SGIP systems within the dataset). Most visibly, the decline in gross installed costs that had occurred during prior years ceased in 2001-2002, coinciding with a substantial increase in incentive levels under ERP and SGIP.

[39] Wiser, R., M. Bolinger, P. Cappers, and R. Margolis. 2006. *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*. LBNL-59282. Berkeley, California: Lawrence Berkeley National Laboratory.



Notes: We assume that all systems <10 kW are residential (unless identified otherwise) and that state/utility cash incentives for residential systems are non-taxable and reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 21. Net Installed Cost of Residential PV over Time (Calculated)



Notes: We assume that all systems >10 kW are commercial (unless identified otherwise) and that state/utility cash incentives for commercial systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. The value of state ITCs is calculated as described in Appendix C.

Figure 22. Net Installed Cost of Commercial PV over Time (Calculated)

Incentives Differ Widely Across States

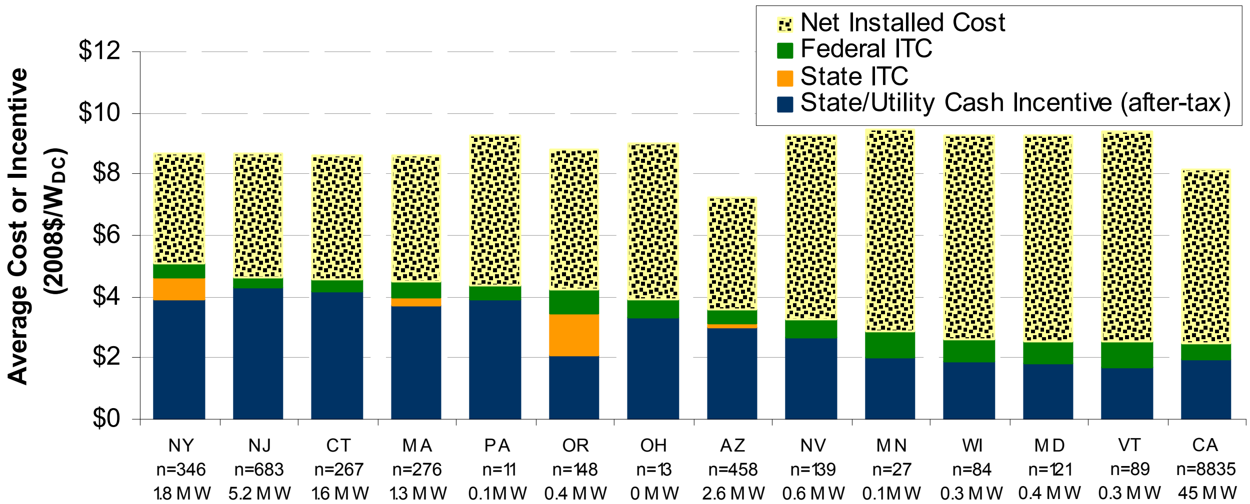
The preceding incentive-related trends are drawn from the entire dataset, and are therefore dominated by the PV incentive programs in California and New Jersey. Incentives and net installed costs, however, vary significantly across all the states in the sample. Figure 23 and Figure 24 compare average incentive levels and net installed costs across states in 2008, for residential and commercial PV systems, respectively.[40] Again, note that this analysis does not capture all types of financial incentives that may be available to PV systems in each state (e.g., incentives offered by PV incentive programs outside of those included in the data sample, or revenue from the sale of RECs). In addition, systems participating in New Jersey's SREC-Only program are excluded from the analysis in this section, and the New Jersey results presented in Figure 23 and Figure 24 are based solely on data from the state's Customer Onsite Renewable Energy (CORE) program.[41] New Jersey's position within this analysis – especially among commercial PV systems – could look substantially different if both programs were included, and if the value of SRECs (which have significant value in New Jersey, as discussed in Text Box 2) were included.

Among residential systems installed in 2008 (Figure 23), average after-tax incentives (i.e., direct cash incentives from state/utility PV incentive programs plus state and Federal ITCs, but excluding revenue from sale of RECs) ranged from a low of \$2.5/W in California to a high of \$5.1/W in New York. The high level of incentives provided in New York contributed to it being the state with the lowest net installed cost for residential PV systems installed in 2008, averaging \$3.5/W. At the other end of the spectrum was Vermont (which had the second-lowest residential incentives after California), with an average net installed cost of \$6.9/W. Of note, the two largest PV markets, California and New Jersey, fall nearly at opposite ends of the spectrum in terms the size of the incentives provided to residential PV in 2008 (\$2.5/W for California and \$4.6/W for New Jersey).

For commercial PV (Figure 24), average after-tax incentive levels and net installed costs also varied considerably across states in 2008, ranging from \$3.1/W in Vermont to \$5.7/W in Oregon. The lowest average net installed cost belongs to Connecticut, at \$3.0/W, while Vermont claims the highest net installed cost for commercial PV in 2008 (\$5.8/W).

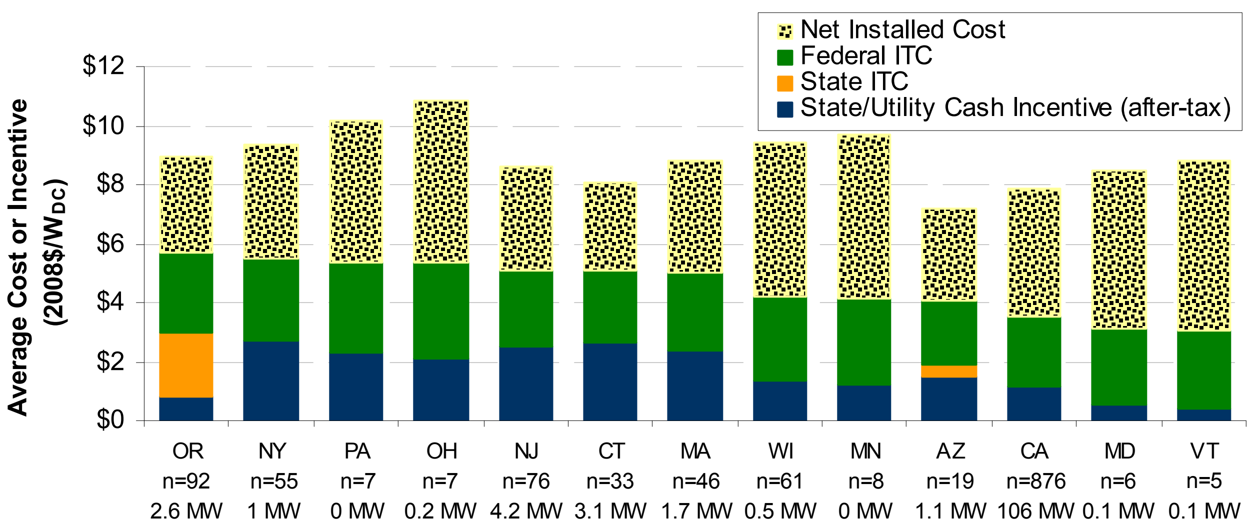
[40] See Appendix B for data on the average annual cash incentive for each of the PV incentive programs in the dataset.

[41] Within the data sample, the CORE program represents the vast majority (97%) of New Jersey residential PV systems installed in 2008. The commercial PV systems are more evenly distributed between the two programs, with CORE representing 67% of the New Jersey commercial PV systems installed in 2008, but only 33% of the capacity, with the remaining systems funded through the SREC-Only program.



Notes: We assume that all systems ≤10 kW are residential unless identified otherwise, and that direct cash incentives for residential PV are non-taxable and reduce the basis of the Federal ITC. State ITCs are calculated as described in Appendix C. Results shown for NJ are based solely on systems funded through the CORE program. CO and WA are excluded from the figure, as the sample size for both states is small relative to the number of residential PV systems installed in each state in 2008.

Figure 23. Comparison of Incentive Levels and Net Installed Cost across States for Residential PV Systems Installed in 2008 (Calculated)



Notes: We assume that all systems >10 kW are commercial unless identified otherwise, and that direct cash incentives for commercial systems are taxed at a Federal corporate tax rate of 35% plus the prevailing state corporate tax rate, and do not reduce the basis of the Federal ITC. State ITCs are calculated as described in Appendix C. Results shown for NJ are based solely on systems funded through the CORE program. States are excluded from the figure if the database contains fewer than five commercial PV systems installed in that state in 2008.

Figure 24. Comparison of Incentive Levels and Net Installed Cost across States for Commercial PV Systems Installed in 2008 (Calculated)

5. Conclusions

The number of photovoltaic systems installed in the U.S. has been growing 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. Out of this goal arises the need for reliable information on the historical installed cost of PV. To address this need, Lawrence Berkeley National Laboratory initiated a series of reports focused on describing trends in the installed cost of grid-connected PV systems in the U.S. The present report, the second in the series, describes installed cost trends from 1998 through 2008, based on project-level data for more than 52,000 grid-connected systems deployed across 16 states.

Available evidence confirms that the installed cost of customer-sited PV systems has declined substantially since 1998, though both the pace and the 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 demand. In 2008, installed costs resumed their downward trajectory, as module prices began to fall in response to expanded manufacturing capacity and the global financial crisis. Preliminary evidence and industry expectations suggest that module price will continue to fall through 2009.

The historical trend towards declining installed costs, along with the narrowing of cost distributions, suggests that PV deployment policies have achieved some success in fostering competition within the industry and in spurring improvements in the cost structure and efficiency of the PV delivery infrastructure. Moreover, the fact that states with the largest PV markets also appear to have somewhat lower average costs than most states with smaller markets lends some credence to the premise that state and utility PV deployment policies can affect local costs. Yet, even lower average installed costs in Japan and Germany suggest that deeper near-term cost reductions may be possible. Indeed, further cost reductions will be necessary if the PV industry is to continue its expansion in the customer-sited market, given the desire of PV incentive programs to ratchet down the level of financial support offered to PV installations.

Appendix A: Data Cleaning, Coding, and Standardization

To the extent possible, this report presents the data as provided directly by PV incentive program administrators. That said, several steps were taken to clean the data and standardize it across programs, described below.

Projects Removed from the Dataset: The initial data sample received from PV incentive program administrators consisted of 53,046 PV systems installed through 2008. To eliminate presumably erroneous numerical data entries, systems were removed from the dataset if the reported installed cost was less than \$2/W (63 systems) or greater than \$30/W (52 systems), or if the incentive amount was zero (25 systems) or greater than \$30/W (4 systems). For the California Self Generation Incentive Program, systems receiving incentives from other subsidy programs were dropped (89 systems). In addition, systems missing installed cost data (185 systems), incentive data (11 systems), or system size data (55 systems) were removed from the dataset. Finally, 206 systems with battery back-up were removed from the dataset. In total, 690 systems, out of an initial sample of 53,046, were removed from the dataset as a result of these filters, yielding a final sample of 52,356 systems.

Manual Data Cleaning: City, installer, zip code, 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 1-3 kW systems installed through three California programs in 2008: the California Energy Commission (CEC)'s Emerging Renewables Program (ERP), the CEC's New Home Solar Partnership (NHSP) program, and the California Solar Initiative (CSI). Residential new construction systems were identified within the ERP dataset if the data field labeled "Category" contained the value "Development," "New Home," or "n", whereas all systems installed through NHSP 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 ERP, NHSP, 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 explicitly identifies whether modules are BIPV or rack-mounted.[42] Based on this procedure, 2,193 of the 2,201 applicable systems (i.e., 1-3 kW systems funded through ERP, NHSP, and CSI and installed in 2008) 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 thin-film or crystalline by cross-referencing data provided on module manufacturer and model with the CSI's List of Eligible Modules, which explicitly identifies whether modules are crystalline or thin-

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

film. Based on this procedure, 45,586 of the 52,356 systems were identified as employing either thin-film, crystalline, or hybrid modules.

Conversion to 2008 Real Dollars: Installed cost and incentive data are expressed throughout this report in real 2008 dollars (2008$). Data provided by PV program administrators in nominal dollars were converted to 2008$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.

Conversion of Capacity Data to 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 of the capacity data were already provided in units of DC-STC; however, three programs (California's Emerging Renewables Program, Self-Generation Incentive Program, and Anaheim Solar Advantage Program) provided capacity data only in terms of the CEC-AC rating convention. Capacity data from these programs were converted to DC-STC, according to the procedures described below.

Anaheim Solar Advantage Program: The data provided for the Anaheim Solar Advantage Program included data fields identifying the module manufacturer, model, and number of modules for most PV systems. DC-STC module ratings were identified for most of these systems by cross-referencing the information provided about module type with the CSI's 2008 List of Eligible Photovoltaic Modules, which identifies DC-STC ratings for most of the modules employed in the systems funded through the Anaheim program. 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 59% of the systems in the Anaheim dataset. For the remaining systems, 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 1.128 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$ was used, which was derived based on the averages for other systems in the Anaheim dataset.

Emerging Renewables Program (ERP): The data provided for the ERP 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 2008 List of Eligible Photovoltaic Modules, which identifies DC-STC ratings for most of the modules employed in the systems funded through the ERP. 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 86% of the systems in the ERP dataset. For the remaining systems, 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.

Self-Generation Incentive Program (SGIP): The data provided for the 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 2008 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 2008 List of Eligible Inverters, which identifies inverter efficiency ratings for most of the inverters employed in the systems funded through the SGIP.[43] In cases where data on inverter manufacturer and model either was not provided or could not be matched with the CSI's list, the inverter

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

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 (ranging from 92.0% to 94.5%).

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:

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

This approach was used to determine the DC-STC capacity rating for 88% of the systems in the SGIP dataset. For the remaining systems, 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, annual average conversion factors (1.17-1.23 $W_{DC\text{-}STC}/W_{CEC\text{-}AC}$) were used, which were derived based on the other systems in the SGIP dataset.

Appendix B: Detailed Sample Size Summaries

Table B-1. Program-Level Annual Installation Data, Based on Final Study Sample

State	Program Administrator(s) and Program Name		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
AZ	APS Solar & Renewables Incentive Program	*No. Systems*	-	-	-	-	4	10	42	73	183	231	369	***912***
		MW	-	-	-	-	0.0	0.1	0.2	0.4	1.1	1.4	3.0	***6.2***
	SRP EarthWise Solar Energy Program	*No. Systems*	-	-	-	-	-	-	-	26	115	97	108	***346***
		MW	-	-	-	-	-	-	-	0.1	0.5	0.5	0.7	***1.7***
CA	Anaheim Solar Advantage Program	*No. Systems*	-	-	-	1	8	14	15	3	3	4	21	***69***
		MW	-	-	-	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.1	***0.3***
	CEC Emerging Renewables Program	*No. Systems*	39	178	213	1,238	2,246	2,964	4,540	3,862	6,117	5,862	688	***27,947***
		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***
	CEC New Home Solar Partnership	*No. Systems*	-	-	-	-	-	-	-	-	-	134	405	***539***
		MW	-	-	-	-	-	-	-	-	-	0.4	1.1	***1.6***
	CPUC California Solar Initiative	*No. Systems*	-	-	-	-	-	-	-	-	-	3,363	8,170	***11,533***
		MW	-	-	-	-	-	-	-	-	-	25.0	121.7	***146.7***
	CPUC Self-Generation Incentive Program	*No. Systems*	-	-	-	-	15	71	147	190	144	142	87	***796***
		MW	-	-	-	-	2.3	11.4	17.2	26.7	29.5	33.3	24.4	***144.9***
	LADWP Solar Incentive Program	*No. Systems*	-	2	4	69	201	220	41	77	137	308	404	***1,463***
		MW	-	0.1	0.0	0.5	2.9	5.9	0.4	1.4	1.3	1.8	3.3	***17.6***
	Lompoc PV Rebate Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	5	***5***
		MW	-	-	-	-	-	-	-	-	-	-	0.0	***0.0***
	SMUD Residential Retrofit and Commercial PV Buydown Programs	*No. Systems*	-	-	-	-	-	-	-	19	29	57	65	***170***
		MW	-	-	-	-	-	-	-	0.1	0.1	0.4	0.4	***1.0***
CO	Governor's Energy Office Solar Rebate Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	16	***16***
		MW	-	-	-	-	-	-	-	-	-	-	0.1	***0.1***
CT	CCEF Onsite Renewable DG Program	*No. Systems*	-	-	-	-	-	1	2	2	7	14	40	***66***
		MW	-	-	-	-	-	0.0	0.0	0.0	0.3	1.6	3.6	***5.6***
	CCEF Solar PV Program	*No. Systems*	-	-	-	-	-	-	-	32	86	169	270	***557***
		MW	-	-	-	-	-	-	-	0.1	0.4	0.9	1.6	***3.1***
MA	MTC Small Renewables Initiative	*No. Systems*	-	-	-	-	1	70	127	91	259	207	336	***1,091***
		MW	-	-	-	-	0.0	0.3	0.6	0.8	1.8	1.5	3.1	***8.1***
MD	MEA Solar Energy Grant Program	*No. Systems*	-	-	-	-	-	-	-	7	43	45	135	***230***
		MW	-	-	-	-	-	-	-	0.0	0.2	0.1	0.5	***0.8***
MI	MSEO Solar Electric Rebate Program	*No. Systems*	-	-	-	-	1	9	23	12	24	38	38	***145***
		MW	-	-	-	-	0.0	0.0	0.1	0.0	0.1	0.2	0.1	***0.5***
NJ	NJCEP Customer Onsite Renewable Energy Program	*No. Systems*	-	-	-	-	-	32	267	484	988	592	804	***3,167***
		MW	-	-	-	-	-	0.2	2.1	5.5	17.8	16.4	12.3	***54.2***
	NJCEP Solar Renewable Energy Credit Program	*No. Systems*	-	-	-	-	-	-	-	-	-	2	56	***58***
		MW	-	-	-	-	-	-	-	-	-	0.0	8.4	***8.4***

State	Program Administrator(s) and Program Name		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
NV	NPC/SPPC RenewableGenerations Rebate Program	*No. Systems*	-	-	-	-	-	-	5	65	73	105	145	***393***
		MW	-	-	-	-	-	-	0.0	0.3	0.4	0.6	0.7	***2.0***
NY	NYSERDA PV Incentive Program	*No. Systems*	-	-	-	-	-	43	98	94	191	331	401	***1,158***
		MW	-	-	-	-	-	0.2	0.5	0.6	1.1	2.0	2.8	***7.2***
OH	ODOD Advanced Energy Fund Grants	*No. Systems*	-	-	-	-	-	-	-	2	4	6	23	***35***
		MW	-	-	-	-	-	-	-	0.0	0.0	0.0	0.2	***0.3***
OR	ETO Solar Electric Program	*No. Systems*	-	-	-	-	-	57	138	89	131	215	248	***878***
		MW	-	-	-	-	-	0.3	0.6	0.3	0.6	1.0	3.7	***6.6***
PA	SDF Solar PV Grant Program	*No. Systems*	-	-	-	-	3	17	28	23	54	21	18	***164***
		MW	-	-	-	-	0.0	0.1	0.1	0.1	0.2	0.1	0.1	***0.7***
VT	RERC Small Scale Renewable Energy Incentive Program	*No. Systems*	-	-	-	-	-	-	31	15	24	61	94	***225***
		MW	-	-	-	-	-	-	0.1	0.0	0.1	0.2	0.4	***0.8***
WA	Klickitat PUD Solar PV Rebate Program	*No. Systems*	-	-	-	-	-	-	-	-	-	-	5	***5***
		MW	-	-	-	-	-	-	-	-	-	-	0.0	***0.0***
	Port Angeles Solar Energy System Rebate	*No. Systems*	-	-	-	-	-	-	-	-	-	1	1	***2***
		MW	-	-	-	-	-	-	-	-	-	0.0	0.0	***0.0***
WI	Focus on Energy Renewable Energy Cash-Back Rewards Program	*No. Systems*	-	-	-	-	10	18	23	27	65	98	145	***386***
		MW	-	-	-	-	0.0	0.0	0.1	0.1	0.2	0.5	0.9	***1.7***
Total		*No. Systems*	***39***	***180***	***217***	***1,308***	***2,489***	***3,526***	***5,527***	***5,193***	***8,677***	***12,103***	***13,097***	***52,356***
		MW	***0.2***	***0.8***	***0.9***	***5.4***	***15.1***	***33.5***	***44.2***	***57.1***	***89.8***	***122.3***	***196.9***	***566.3***

Table B-2. Sample Size by Installation Year and System Size Range

System Size Range	Installation Year											Total
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	
No. Systems												
0-5 kW	31	156	180	1,108	1,886	2,287	3,436	3,009	4,859	6,853	7,186	**30,991**
5-10 kW	3	13	24	159	428	887	1,540	1,512	2,791	3,932	4,273	**15,562**
10-100 kW	5	10	12	36	154	309	510	577	915	1,174	1,315	**5,017**
100-500 kW	-	1	1	5	18	36	34	87	91	114	258	**645**
>500 kW	-	-	-	-	3	7	7	8	21	30	65	**141**
Total	39	180	217	1,308	2,489	3,526	5,527	5,193	8,677	12,103	13,097	**52,356**
Capacity (MW)												
0-5 kW	0.1	0.3	0.4	3.0	5.0	6.5	9.9	8.9	15.1	22.0	23.2	**94.4**
5-10 kW	0.02	0.09	0.16	1.03	2.83	5.93	10.41	10.50	19.43	27.15	29.25	**106.8**
10-100 kW	0.1	0.3	0.2	0.6	2.5	6.6	11.9	13.8	18.4	23.9	30.1	**108.5**
100-500 kW	-	0.1	0.1	0.8	3.1	8.1	7.0	17.4	20.1	25.8	61.8	**144.2**
>500 kW	-	-	-	-	1.7	6.4	5.1	6.5	16.8	23.4	52.6	**112.5**
Total	0.2	0.8	0.9	5.4	15.1	33.5	44.2	57.1	89.8	122.3	196.9	**566.3**

Table B-3. Annual Average Installed Cost and Direct Cash Incentives, by PV Incentive Program and System Size

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
AZ	APS Solar & Renewables Incentive Program	≤10 kW	No. Systems	-	-	-	-	4	9	40	68	173	219	331
			Avg. Cost	-	-	-	-	*	10.9	7.7	7.8	8.1	7.6	7.3
			Avg. Incentive	-	-	-	-	*	3.8	3.8	3.8	3.7	3.1	3.0
		10-100 kW	No. Systems	-	-	-	-	-	1	2	5	9	11	34
			Avg. Cost	-	-	-	-	-	*	*	10.3	8.0	8.7	6.8
			Avg. Incentive	-	-	-	-	-	*	*	3.3	3.8	3.5	2.8
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	1	1	4
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	*
AZ	SRP EarthWise Solar Energy Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	26	113	93	100
			Avg. Cost	-	-	-	-	-	-	-	7.6	8.2	7.4	7.1
			Avg. Incentive	-	-	-	-	-	-	-	3.3	3.2	3.1	3.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	2	4	8
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	6.9
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	2.9
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	Anaheim Solar Advantage Program	≤10 kW	No. Systems	-	-	-	1	6	14	15	1	3	4	20
			Avg. Cost	-	-	-	*	9.9	8.3	8.3	*	*	*	8.3
			Avg. Incentive	-	-	-	*	4.9	5.0	5.0	*	*	*	3.4
		10-100 kW	No. Systems	-	-	-	-	2	-	-	2	-	-	1
			Avg. Cost	-	-	-	-	*	-	-	*	-	-	*
			Avg. Incentive	-	-	-	-	*	-	-	*	-	-	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	CEC Emerging Renewables Program	≤10 kW	No. Systems	34	168	200	1201	2107	2728	4184	3519	5498	5203	595
			Avg. Cost	12.3	11.6	11.0	10.5	10.5	9.4	8.6	8.2	8.3	8.5	8.1
			Avg. Incentive	3.3	3.2	3.1	4.3	4.4	3.9	3.5	2.9	2.6	2.4	2.3
		10-100 kW	No. Systems	5	9	12	33	135	234	356	343	619	659	93
			Avg. Cost	12.0	11.2	9.1	10.1	10.0	8.7	8.0	7.6	7.7	8.1	7.8
			Avg. Incentive	3.3	3.2	2.9	4.4	4.4	4.0	3.5	2.9	2.6	2.4	2.4
		>100 kW	No. Systems	-	1	1	4	4	2	-	-	-	-	-
			Avg. Cost	-	*	*	*	*	*	-	-	-	-	-
			Avg. Incentive	-	*	*	*	*	*	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
CA	CEC New Home Solar Partnership	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	132	398
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.0	7.9
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.3	2.3
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	7
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	6.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	2.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	CPUC California Solar Initiative	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	3104	7200
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.4	8.2
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.1	1.8
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	242	777
			Avg. Cost	-	-	-	-	-	-	-	-	-	8.2	7.7
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.1	1.8
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	17	193
			Avg. Cost	-	-	-	-	-	-	-	-	-	7.1	7.2
			Avg. Incentive	-	-	-	-	-	-	-	-	-	2.1	2.0
CA	CPUC Self-Generation Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		10-100 kW	No. Systems	-	-	-	-	9	44	109	107	73	53	30
			Avg. Cost	-	-	-	-	9.6	8.2	8.5	8.0	7.8	7.5	7.1
			Avg. Incentive	-	-	-	-	4.4	3.9	4.0	3.8	3.3	2.6	2.4
		>100 kW	No. Systems	-	-	-	-	6	27	38	83	71	89	57
			Avg. Cost	-	-	-	-	8.0	7.0	7.9	7.5	7.5	7.3	7.2
			Avg. Incentive	-	-	-	-	4.0	3.4	3.8	3.7	3.4	2.7	2.4
CA	LADWP Solar Incentive Program	≤10 kW	No. Systems	-	1	4	65	183	189	37	69	125	275	376
			Avg. Cost	-	*	*	11.0	10.7	9.6	9.2	8.0	8.6	8.8	8.4
			Avg. Incentive	-	*	*	5.7	6.4	6.0	3.8	3.2	3.6	3.7	3.7
		10-100 kW	No. Systems	-	1	-	3	7	18	3	4	9	33	24
			Avg. Cost	-	*	-	*	9.6	9.6	*	*	7.7	8.7	8.0
			Avg. Incentive	-	*	-	*	6.2	6.2	*	*	3.1	3.5	3.6
		>100 kW	No. Systems	-	-	-	1	11	13	1	4	3	-	4
			Avg. Cost	-	-	-	*	9.8	8.5	*	*	*	-	*
			Avg. Incentive	-	-	-	*	5.8	5.9	*	*	*	-	*

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
CA	Lompoc PV Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	8.1
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	3.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CA	SMUD Residential Retrofit and Commercial PV Buydown Programs	≤10 kW	No. Systems	-	-	-	-	-	-	-	16	27	55	63
			Avg. Cost	-	-	-	-	-	-	-	10.6	10.3	9.8	9.5
			Avg. Incentive	-	-	-	-	-	-	-	3.4	2.9	2.5	2.3
		10-100 kW	No. Systems	-	-	-	-	-	-	-	3	2	2	2
			Avg. Cost	-	-	-	-	-	-	-	*	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	*	*	*	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CO	Governor's Energy Office Solar Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	16
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	8.3
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	1.9
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
CT	CCEF Onsite Renewable DG Program	≤10 kW	No. Systems	-	-	-	-	-	1	1	1	1	2	7
			Avg. Cost	-	-	-	-	-	*	*	*	*	*	8.2
			Avg. Incentive	-	-	-	-	-	*	*	*	*	*	7.1
		10-100 kW	No. Systems	-	-	-	-	-	-	1	1	5	8	21
			Avg. Cost	-	-	-	-	-	-	*	*	8.8	8.5	8.2
			Avg. Incentive	-	-	-	-	-	-	*	*	4.8	4.6	4.3
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	1	4	12
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	7.6
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	4.2

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
CT	CCEF Solar PV Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	32	85	163	242
			Avg. Cost	-	-	-	-	-	-	-	9.0	9.1	9.2	8.7
			Avg. Incentive	-	-	-	-	-	-	-	5.0	4.8	4.4	4.2
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	6	28
			Avg. Cost	-	-	-	-	-	-	-	-	*	8.4	8.3
			Avg. Incentive	-	-	-	-	-	-	-	-	*	3.8	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
MA	MRET Commonwealth Solar Program	≤10 kW	No. Systems	-	-	-	-	-	65	118	74	242	194	296
			Avg. Cost	-	-	-	-	-	10.5	9.3	9.3	9.5	9.5	8.7
			Avg. Incentive	-	-	-	-	-	4.9	5.0	5.0	4.2	4.2	3.7
		10-100 kW	No. Systems	-	-	-	-	1	5	9	17	14	11	34
			Avg. Cost	-	-	-	-	*	13.0	10.9	10.3	10.6	9.1	8.7
			Avg. Incentive	-	-	-	-	*	15.2	8.5	11.2	8.3	7.9	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	3	2	6
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	7.4
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	3.3
MD	MEA Solar Energy Grant Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	7	42	44	131
			Avg. Cost	-	-	-	-	-	-	-	10.4	11.0	10.4	9.3
			Avg. Incentive	-	-	-	-	-	-	-	1.2	1.5	1.4	1.8
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	1	4
			Avg. Cost	-	-	-	-	-	-	-	-	*	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	*	*	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
MN	MSEO Solar Electric Rebate Program	≤10 kW	No. Systems	-	-	-	-	1	9	23	12	24	36	37
			Avg. Cost	-	-	-	-	*	9.9	7.8	9.6	8.6	9.2	9.6
			Avg. Incentive	-	-	-	-	*	2.3	2.2	2.2	2.1	2.0	2.0
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
NJ	NJCEP Customer Onsite Renewable Energy Program	≤10 kW	No. Systems	-	-	-	-	-	32	246	407	812	480	669
			Avg. Cost	-	-	-	-	-	9.3	9.1	8.7	8.6	8.7	8.7
			Avg. Incentive	-	-	-	-	-	6.2	6.2	6.0	5.6	5.0	4.3
		10-100 kW	No. Systems	-	-	-	-	-	-	20	69	143	81	117
			Avg. Cost	-	-	-	-	-	-	9.4	8.7	8.5	9.1	8.4
			Avg. Incentive	-	-	-	-	-	-	5.3	5.6	5.3	4.8	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	1	8	33	31	18
			Avg. Cost	-	-	-	-	-	-	*	7.5	8.0	7.3	7.4
			Avg. Incentive	-	-	-	-	-	-	*	4.3	4.5	3.5	3.5
NJ	NJCEP Solar Renewable Energy Credit Program**	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	2	21
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	8.1
			Avg. Incentive	-	-	-	-	-	-	-	-	-	**	**
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	15
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	7.5
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	**
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	20
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	6.9
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	**
NV	NPC/SPPC RenewableGenerations Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	5	57	68	98	141
			Avg. Cost	-	-	-	-	-	-	10.0	9.4	9.1	9.6	9.2
			Avg. Incentive	-	-	-	-	-	-	5.7	5.0	3.7	3.1	2.7
		10-100 kW	No. Systems	-	-	-	-	-	-	-	8	5	7	4
			Avg. Cost	-	-	-	-	-	-	-	13.9	8.3	7.6	*
			Avg. Incentive	-	-	-	-	-	-	-	5.2	4.3	3.9	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
NY	NYSERDA PV Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	37	89	79	170	305	356
			Avg. Cost	-	-	-	-	-	9.6	9.6	9.2	9.2	9.1	8.7
			Avg. Incentive	-	-	-	-	-	4.8	4.7	4.5	4.3	4.2	4.0
		10-100 kW	No. Systems	-	-	-	-	-	6	9	15	21	26	45
			Avg. Cost	-	-	-	-	-	9.6	8.5	8.7	9.3	9.4	8.8
			Avg. Incentive	-	-	-	-	-	5.6	5.4	4.7	4.4	4.2	4.1
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
OH	ODOD Advanced Energy Fund Grants	≤10 kW	No. Systems	-	-	-	-	-	-	-	2	4	6	18
			Avg. Cost	-	-	-	-	-	-	-	*	*	10.6	9.9
			Avg. Incentive	-	-	-	-	-	-	-	*	*	3.5	3.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	4
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	*
OR	ETO Solar Electric Program	≤10 kW	No. Systems	-	-	-	-	-	55	136	86	124	200	201
			Avg. Cost	-	-	-	-	-	8.1	7.4	7.8	8.6	8.9	8.7
			Avg. Incentive	-	-	-	-	-	4.7	4.1	3.2	2.1	2.0	1.9
		10-100 kW	No. Systems	-	-	-	-	-	1	1	3	7	15	39
			Avg. Cost	-	-	-	-	-	*	*	*	7.4	9.1	9.4
			Avg. Incentive	-	-	-	-	-	*	*	*	1.2	1.5	1.3
		>100 kW	No. Systems	-	-	-	-	-	1	1	-	-	-	8
			Avg. Cost	-	-	-	-	-	*	*	-	-	-	8.1
			Avg. Incentive	-	-	-	-	-	*	*	-	-	-	1.4
PA	SDF Solar PV Grant Program	≤10 kW	No. Systems	-	-	-	-	3	17	28	23	53	21	16
			Avg. Cost	-	-	-	-	*	9.2	10.9	9.5	8.9	9.2	9.9
			Avg. Incentive	-	-	-	-	*	5.7	5.1	5.1	4.9	4.7	3.9
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	1	-	2
			Avg. Cost	-	-	-	-	-	-	-	-	*	-	*
			Avg. Incentive	-	-	-	-	-	-	-	-	*	-	*
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

State	Program Administrator and Program Name	Size Range		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
VT	RERC Small Scale Renewable Energy Incentive Program	≤10 kW	No. Systems	-	-	-	-	-	-	31	15	24	60	89
			Avg. Cost	-	-	-	-	-	-	8.9	9.5	9.2	9.3	9.4
			Avg. Incentive	-	-	-	-	-	-	2.9	2.6	2.1	1.8	1.7
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	1	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	8.8
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	0.7
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
WA	Klickitat PUD Solar PV Rebate Program	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	5
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	9.4
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	0.4
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
WA	Port Angeles Solar Energy System Rebate	≤10 kW	No. Systems	-	-	-	-	-	-	-	-	-	1	1
			Avg. Cost	-	-	-	-	-	-	-	-	-	*	*
			Avg. Incentive	-	-	-	-	-	-	-	-	-	*	*
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-
WI	Focus on Energy Renewable Energy Cash-Back Rewards Program	≤10 kW	No. Systems	-	-	-	-	10	18	23	27	62	88	125
			Avg. Cost	-	-	-	-	11.1	10.9	8.0	9.9	8.8	9.2	9.4
			Avg. Incentive	-	-	-	-	3.3	2.7	2.2	2.5	2.6	2.0	2.1
		10-100 kW	No. Systems	-	-	-	-	-	-	-	-	3	10	20
			Avg. Cost	-	-	-	-	-	-	-	-	*	8.2	8.6
			Avg. Incentive	-	-	-	-	-	-	-	-	*	2.2	1.8
		>100 kW	No. Systems	-	-	-	-	-	-	-	-	-	-	-
			Avg. Cost	-	-	-	-	-	-	-	-	-	-	-
			Avg. Incentive	-	-	-	-	-	-	-	-	-	-	-

* Average cost and incentive data are omitted if there are fewer than five systems.
** The NJ SREC-Only Pilot does 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.

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 owned by residential, commercial, or tax-exempt entities. Unless otherwise identified, we classified 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.** Although the IRS has provided only limited guidance on the issue, it appears that, in most cases, cash incentives provided for commercial PV systems are considered Federally-taxable income. As such, the cash incentives provided for systems in the dataset identified as commercial PV were assumed to be taxed at a Federal corporate tax rate of 35%. The taxation of cash incentives for commercial PV at the state level may vary by state; for simplicity, we assume that all commercial PV systems are taxed at the "effective" state corporate tax rate, which accounts for the fact that state corporate taxes reduce the incentive-recipient's Federally-taxable income. The effective state corporate tax rate applied to the cash incentive is equal to 65% (i.e., 1 minus 35%) of the nominal state corporate tax rate in 2008, which ranged from 0% to 9.99% among the 16 states in our dataset.[44]

   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. Despite several IRS private letter rulings of potential relevance, uncertainty remains as to what exactly constitutes a "utility energy conservation subsidy." Notwithstanding this uncertainty, we assume that cash incentives provided to all systems in the dataset identified as residential PV are exempt from Federal income taxes. The taxation of cash incentives for residential PV at the state level may vary by state, but for simplicity, we assume that all residential PV systems are also exempt from state income tax.

3. **Estimating the Value of State ITCs.** We identified 5 of the 16 states in our dataset as having offered a state ITC for PV at some point from 1998-2008. 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. In all cases, we assumed that the size of the state ITC was not impacted by any Federal ITC received, though for several states (CA and NY), we assumed that the basis for the state ITC was reduced for any direct cash incentives ("rebates") received through the state/local PV incentive program. 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 customers, we assumed a Federal income tax rate of 35%. For residential customers, 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 2008).[45]

[44] http://www.taxadmin.org/fta/rate/corp_inc.html
[45] http://www.taxfoundation.org/taxdata/show/151.html

4. **Estimating the Value of Federal ITCs.** Projects in the dataset identified as residential PV and installed on or after January 1, 2006 were assumed to receive a Federal ITC equal to the lesser of 30% of the tax credit basis or $2,000. Projects in the dataset identified as commercial PV are 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.

   The tax credit basis on which the Federal ITC is calculated depends on whether cash incentives received by a project are Federally-taxable. If the cash incentives are Federally-taxable, as assumed for all commercial PV, 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 residential PV, then the Federal ITC is calculated based on the installed cost minus the value of the tax-exempt cash incentives.

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	2006-2012	10% of *pre-rebate* installed cost	$25,000
CA	All	200 kW	2001-2003	15% of *post-rebate* installed cost	None
	All	200 kW	2004-2005	7.5% of *post-rebate* installed cost	None
MA	Residential	None	1979-indefinite	15% of *pre-rebate* installed cost	$1,000
NY	Residential	10 kW	1998-9/1/2006	25% of *post-rebate* installed cost	$3,750
	Residential	10 kW	9/1/2006-indefinite	25% of *post-rebate* installed cost	$5,000
OR	Residential	None	11/4/2005-indefinite	$3/W based on rated capacity (DC-STC)*	$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 max. eligible cost**)	$10,000,000

* Tax credit paid out over multiple years, with an annual limit of $1,500/yr.

** Max. eligible cost varies by system size: currently $9/W for systems up to 100 kW, ramping down linearly to $7.50/W for systems >1,000 kW. The tax credit is paid out over five years.

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