Title

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Publication Date

2016-08-16

LBNL- 1006036

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Environmental Energy Technologies Division

August, 2016

This work was supported by the Office of Energy Efficiency and Renewable Energy (Solar Technologies Office) of the U.S. Department of Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH1131

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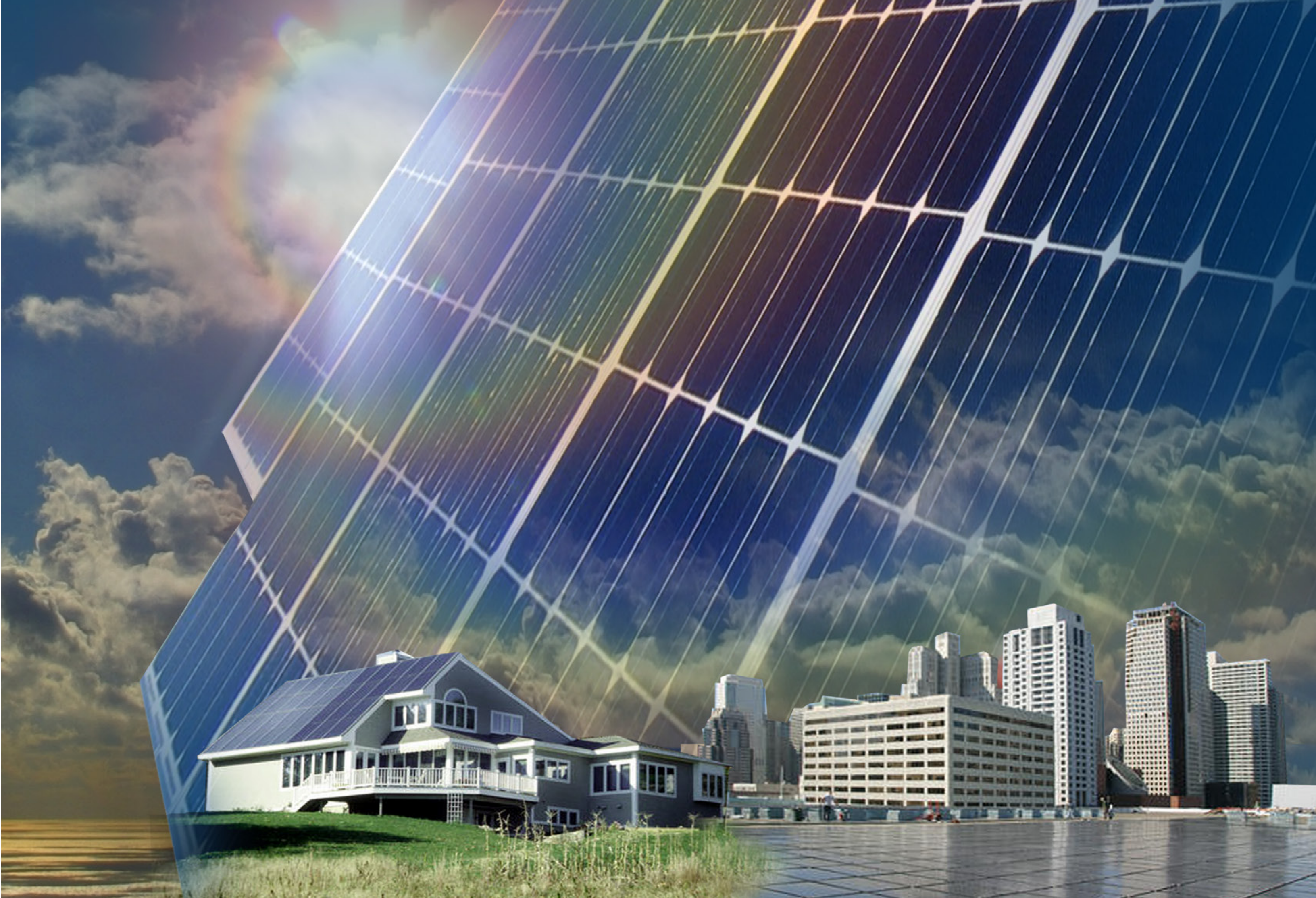

Tracking the Sun IX

The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States

Primary Authors: Galen Barbose and Naïm Darghouth
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Executive Summary

Now in its ninth edition, Lawrence Berkeley National Laboratory (LBNL)'s *Tracking the Sun* report series is dedicated to summarizing trends in the installed price of grid-connected solar photovoltaic (PV) systems in the United States. The present report focuses on residential and non-residential systems installed through year-end 2015, with preliminary trends for the first half of 2016. An accompanying LBNL report, *Utility-Scale Solar*, addresses trends in the utility-scale sector. This year's report incorporates a number of important changes and enhancements from prior editions. Among those changes, LBNL has made available a public data file containing all non-confidential project-level data underlying the analysis in this report.[1]

Installed pricing trends presented within this report derive primarily from project-level data reported to state agencies and utilities that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. Refer to the text box to the right for several key notes about these data. In total, data were collected and cleaned for more than 820,000 individual PV systems, representing 85% of U.S. residential and non-residential PV systems installed cumulatively through 2015 and 82% of systems installed in 2015. The analysis in this report is based on a subset of this sample, consisting of roughly 450,000 systems with available installed price data.

Key Points on the Data in This Report

The installed price data analyzed in this report:

- Represent the up-front price paid by the PV system owner, prior to receipt of incentives
- Are self-reported by PV installers and host customers
- Differ from the underlying cost borne by the developer and installer
- Are historical and therefore may not be indicative of prices for systems installed more recently or prices currently being quoted for prospective projects
- Exclude third-party owned (TPO) systems for which reported installed prices represent appraised values, but include other TPO systems (see Text Box 2 in the main body of the report for further details)

Key findings from this year's report are as follows, with all numerical results denoted in real 2015 dollars and direct current (DC) Watts (W):

Installed Prices Continued to Decline through 2015 and into 2016. National median installed prices in 2015 declined year-over-year by \$0.2/W (5%) for residential systems, by \$0.3/W (7%) for non-residential systems ≤500 kW, and by \$0.3/W (9%) for non-residential systems >500 kW. This continues the steady downward trend in PV system pricing, though the pace of decline is somewhat slower than in recent years. Preliminary data for the first half of 2016 show a mixed picture, but generally suggest that installed prices have continued to fall at a modest pace, at least within a number of key states and market segments. The slowing rate of decline may partly reflect a number of confounding factors could be offsetting underlying cost reductions. These include, for example, the increasing prevalence of solar loans with origination fees embedded in the installed price, greater use of module-level power electronics, module import tariffs, and a shift in the underlying geographical mix of the data sample towards more-expensive states (e.g., California).

Recent Installed Price Reductions Have Been Driven Primarily by Declines in Soft Costs. A period of rapidly falling installed prices, starting in 2009, was initiated by a steep drop in global prices for PV modules. Since 2012, however, module prices have remained relatively flat, while installed prices have continued to fall. Reductions in inverter and racking equipment costs constitute

[1] The file can be downloaded through NREL's Open PV Project.

roughly 30% of the drop in residential installed prices over that period and 66% over the last year of the analysis. Much of the remainder can be attributed to reductions in the aggregate set of "soft" costs, which have fallen partly as a result of increases in system size and module efficiency, though also reflects the broader array of efforts within the industry and among policymakers to address soft costs.

Installed Price Declines Have Been Partially Offset by Falling Incentives. Cash incentives (i.e., rebates and performance-based incentives) provided through state and utility PV incentive programs have fallen substantially since their peak a decade ago, and have been largely phased-out in many key markets. Depending on the particular program, reductions in cash incentives over the long-term equate to roughly 60% to 120% of the corresponding drop in installed prices. This trend is partly a response to installed price declines and the emergence of other forms of incentives, however it has also been a deliberate strategy by program administrators to drive cost reductions in the industry.

National Median Installed Prices Are Relatively High Compared to Other Recent Benchmarks, Particularly for Residential and Smaller Non-Residential Systems. Across all systems in the data sample installed in 2015, the median installed price was \$4.1/W for residential systems, \$3.5/W for non-residential systems ≤500 kW in size, and \$2.5/W for non-residential systems >500 kW. By comparison, a number of other recent benchmarks for PV system prices or costs range from \$2.7/W to \$4.5/W for residential systems, and from \$1.7/W to \$4.3/W for non-residential systems. Differences between national median prices and these other benchmarks reflect the diversity of underlying data sources, methodologies, and definitions. For example, national median prices are historical in nature, represent prices not costs, are heavily impacted by several large and relatively high-priced state markets, and may be subject to inconsistent reporting practices across installers. The national median prices presented in this report thus should not necessarily be taken as indicative of "typical" pricing in all contexts, nor should they be considered equivalent to the underlying costs faced by installers.

Installed Prices in the United States Are Higher than in Most Other Major National PV Markets. Compared to median U.S. prices, installed prices reported are substantially lower in a number of other key solar markets. The starkest differences are in comparison to Germany, where typical pricing for residential systems was around \$1.7/W in 2015. These pricing disparities can be attributed primarily to differences in soft costs, as hardware costs are relatively uniform between countries.

Installed Prices Vary Widely Across Individual Projects. Although installed price distributions have generally narrowed over time, considerable pricing variability continues to persist. Among residential systems installed in 2015, roughly 20% of systems were priced below \$3.3/W (the 20th percentile value), while 20% were priced above \$5.0/W (80th percentile). Non-residential systems ≤500 kW exhibit a similar spread, while the distribution for non-residential systems >500 kW is somewhat narrower. The potential underlying causes for this variability are numerous, including differences in project characteristics, installers, and local market or regulatory conditions.

Significant Scale Economies Exist for Both Residential and Non-Residential Systems. For residential systems installed in 2015, median prices for systems in the 8-10 kW range were roughly 16% lower than for 2-4 kW systems. Among non-residential systems installed in 2015, median installed prices for the largest class of systems >1,000 kW in size were 43% lower than for the smallest set of non-residential systems ≤10 kW. Even greater economies of scale may arise when progressing to utility-scale systems, which are outside the scope of this report.

Installed Prices Differ Among States, with Relatively High Prices in Some Large State Markets. For residential systems installed in 2015, median installed prices range from a low of $3.2/W in Nevada to a high of $4.8/W in Minnesota. Pricing in most states is below the aggregate national median price. This is because some of the largest state markets – California, Massachusetts, and New York – are relatively high-priced, which tends to pull overall U.S. median prices upward. Cross-state installed pricing differences can reflect a wide assortment of factors, including installer competition and experience, retail rates and incentive levels, project characteristics particular to each region, labor costs, sales tax, and permitting and administrative processes.

Third-Party Owned Systems in the Residential Sector Generally Had Lower Installed Prices in 2015 than Customer-Owned Systems. This report does not evaluate lease terms or power purchase agreement (PPA) rates for TPO systems; however, it does include data on the dollar-per-watt installed price of TPO systems sold by installation contractors to non-integrated customer finance providers. In a reversal from previous years, the national median installed price of residential TPO systems in 2015 was $0.5/W lower than for customer-owned systems. Within individual states, however, the relative installed price of residential TPO systems compared to customer-owned systems can vary quite substantially, potentially reflecting the particular installers and business models present in each state.

Prices Vary Considerably Across Residential Installers Operating within the Same State. In examining five large residential markets (Arizona, California, Massachusetts, New Jersey, and New York), installer-level median prices within each state differ by anywhere from $0.8/W to $1.2/W between the upper and lower 20th percentiles, suggesting a substantial level of heterogeneity in pricing behavior or underlying costs. Low-priced installers in these states – e.g., 20% of installers in New Jersey have median prices below $3.1/W – can serve as a benchmark for what may be achievable in terms of near-term installed price reductions within the broader market. Interestingly, however, no obvious or consistent relationship is observed between installer size and prices – i.e., high-volume installers are not associated with lower-priced systems.

Residential New Construction Offers Significant Installed Price Advantages Compared to Retrofit Applications. Within California, residential systems installed in new construction have been consistently lower-priced than those installed on existing homes, with a median differential of $0.5/W in 2015, *despite* the significantly smaller size and higher incidence of premium efficiency modules among new construction systems. If comparing among systems of similar size and module technology, the installed price of new construction systems was $0.8/W lower than for retrofits.

Installed Prices Are Higher for Systems at Tax-Exempt Customer Sites than at For-Profit Commercial Sites. Tax-exempt site hosts include schools, government facilities, religious organizations, and non-profits, and these customers collectively represent a substantial share of the non-residential data sample. Systems at tax-exempt customer sites are consistently higher priced than similarly sized systems at for-profit commercial customer sites. In 2015, the median differential was roughly $0.3/W for systems ≤500 kW and $1.1/W for >500 kW systems. Higher prices at tax-exempt customer sites reflect potentially lower negotiating power and higher incidence of prevailing wage/union labor requirements, domestically manufactured components, and shade or parking structures.

Installed Prices Are Substantially Higher for Systems with High-Efficiency Modules. Roughly one-third of the 2015 systems in the data sample have module efficiencies greater than 18%, and installed prices for systems in this class have consistently been higher-priced than those with lower- or mid-range module efficiencies (<18%). In 2015, the median differential was roughly $0.6/W within the residential segment and $0.5/W among small non-residential systems. These trends suggest that the price premium for high-efficiency modules in many cases has outweighed any offsetting reduction in the balance-of-system (BOS) costs-per-watt due to higher power density.

Module-Level Power Electronics Have a Seemingly Small Effect on Installed Prices. Microinverters and DC optimizers have made significant gains in market share in recent years, together representing more than 50% of residential systems and roughly 30% of smaller (sub-500 kW) non-residential systems in the data sample installed in 2015. Microinverter costs are higher than standard string inverters, though the data suggest that the net impact on total system prices is smaller, potentially as a result of offsetting reductions in non-inverter BOS and soft costs.

Installed Prices for Non-Residential Systems Vary with the Use of Tracking Equipment. Comparing between ground-mounted systems with and without tracking, the differential in median installed price has varied considerably from year to year, given underlying small sample sizes. On average, however, the median installed price of systems with tracking has been $0.6/W (18%) higher among the set of large non-residential systems and $0.8/W (21%) higher among small non-residential systems. These pricing differentials are significantly larger than has been reported elsewhere for larger utility-scale projects, but is roughly proportional to the increased electricity generation associated with single-axis tracking equipment.

1. Introduction

The market for solar photovoltaics (PV) in the United States has been driven, in large measure, by various forms of policy support for solar and renewable energy. A central goal of many of these policies has been to facilitate and encourage cost reductions over time. Most prominently, the U.S. Department of Energy's SunShot Initiative has sought to make solar energy cost-competitive with other forms of electricity by the end of the decade, with an initial goal of $1/W by 2020.[2] Others have argued that even deeper cost reductions may be needed over the longer-term, given the declining value of solar with increasing grid penetration, suggesting a goal of $0.25/W by 2050 (Sivaram and Kann 2016). As public and private investments in these efforts have grown, so too has the need for comprehensive and reliable data on the cost and price of PV systems, in order to track progress towards cost reduction targets, gauge the efficacy of existing programs, and identify opportunities for further cost reduction. Such data are also instrumental to cultivating informed consumers and efficient and competitive markets, which are themselves essential to achieving long-term cost reductions.

To address these varied needs, Lawrence Berkeley National Laboratory (LBNL) initiated the annual *Tracking the Sun* report series to summarize historical trends in the installed price of grid-connected, residential and non-residential PV systems in the United States. It is produced in conjunction with several other ongoing National Lab research products that also address PV system costs and pricing, including a separate LBNL report focused on trends in the utility-scale solar market (see text box to the right).

The present edition of *Tracking the Sun*, the ninth in the series, describes installed price trends for projects installed from 1998 through 2015, with preliminary data for the first half of 2016. The report thus provides an overview of both long-term and more-recent trends, highlighting key drivers for installed price declines over different time horizons. The report also characterizes extensively the widespread variability in system pricing, comparing installed prices across states, market segments, installers, and various system and technology characteristics.

Related National Lab Research Products

Tracking the Sun is produced in conjunction with several related and ongoing research activities:

- *Utility-Scale Solar* is a separate annual report series produced by LBNL that focuses on utility-scale solar and includes trends and analysis related to project cost, performance, and pricing.
- *In-Depth Statistical Analyses* of PV pricing data by researchers at LBNL and several academic institutions seek to further explore PV pricing dynamics, applying more-advanced statistical techniques to the data collected for *Tracking the Sun*. These and other solar energy publications are available at here.
- *The Open PV Project* is an online data-visualization tool developed by the National Renewable Energy Laboratory (NREL) and hosts the public version of the dataset developed for *Tracking the Sun*.
- *PV System Cost Benchmarks* developed by NREL researchers are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems, with the most recent report (Fu et al. 2016) focused on systems built in Q1 2016.

The trends presented in this report are based primarily on project-level data provided by state agencies, utilities, and other entities that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. The underlying dataset used for

[2] The $1/W target refers specifically to utility-scale PV, with correspondingly higher targets for commercial ($1.25/W) and residential ($1.5/W), all denominated in real 2010 dollars.

this year's report consists of more than 820,000 residential and non-residential PV systems[3], representing roughly 85% of all residential and non-residential PV systems installed in the United States through 2015. LBNL applies a significant level of quality control and undertakes various steps to clean these data, as described further within the report. In order to enable further analysis of these data by other researchers and facilitate greater price transparency in the solar marketplace, LBNL has also made the full cleaned dataset (excluding any confidential or otherwise sensitive data) publicly available as a downloadable file, accessible through NREL's Open PV data portal.[4]

It is essential to note at the outset what the installed price data described within this report and contained within the public data file represent. These reported prices represent the up-front price paid by the system owner, prior to receipt of incentives, and for a variety of reasons may differ from the underlying costs borne by the developer or installer. Given that they are self-reported, either by the installer or host customer, the data may also be susceptible to inconsistent reporting practices (e.g., in terms of the scope of the underlying items embedded within the reported price or whether the administrator validates reported prices against invoices). Furthermore, these data are, by their nature, historical, and therefore may not be indicative of prices for systems installed more recently or prices currently being quoted for prospective projects. Finally, the trends presented in this report exclude data for the subset of third-party owned (TPO) systems installed by integrated companies that perform both the installation and customer financing; the prices reported for these systems represent appraised values, rather than transaction prices, and thus are incommensurable to prices reported by other installers. In acknowledgment of these various limitations, the report compares the reported installed price data to several other recent benchmarks for PV system prices and costs, in order to provide a more-robust snapshot of current system costs and prices, and to illustrate the impact of the underlying characteristics of the data sample.

The remainder of the report is organized as follows. Section 2 summarizes the data sources, key methodological details, and characteristics of the data sample. Section 3 presents an overview of long-term, installed-price trends, focusing on median values drawn from the large underlying data sample. The section illustrates and discusses a number of the broad drivers for those historical installed-price trends, including reductions in module prices and reductions in non-module costs associated with increasing system sizes, increasing module efficiencies, and declining state and utility incentives. The section also compares median installed prices for systems installed in 2015 to a variety of other recent U.S. benchmarks, and to prices in other international markets. Section 4 describes the variability in installed prices within the dataset, and explores a series of specific sources of installed pricing differences across projects, including: system size, state, installer, customer-owned vs. TPO, residential new construction vs. retrofit, for-profit commercial vs. tax-exempt site host, module efficiency level, the use of module-level power electronics, and rooftop vs. ground-mounted with or without tracking. Finally, Section 5 offers brief conclusions.

Additional technical and methodological details are included in the appendix, which provides provide additional details on the data cleaning process and data sample. In addition, the values plotted in each figure are available in tabular form in an accompanying data file (e.g., for those who would like to reproduce the figures), which can be downloaded at trackingthesun.lbl.gov. Finally, as already mentioned, the underlying project-level data summarized in this report is publicly available through NREL's Open PV Project.

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[3] As explained further within the report, the analysis in this report is based primarily on a subset (approximately 450,000 systems) of the larger data sample.

[4] The public data file can be downloaded from Open PV as a stand-alone file, and has also been incorporated into the larger Open PV database and visualization tools.

2. Data Sources, Methods, and Sample Description

The trends presented in this report derive from data on individual residential and non-residential PV systems. This section describes the underlying data sources and the procedures used to standardize and clean the data, with further information provided in the Appendix. The section then describes the sample size over time and by market segment, comparing the data sample to the overall U.S. PV market and highlighting any significant gaps. Finally, the section summarizes several key characteristics of the data sample, including: trends in system size over time and by market segment, the geographical distribution of the sample across states, and the distribution between host customer-owned and TPO systems over time and across states.

Data Sources

The data are sourced primarily from state agencies, utilities, and other organizations that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. Ultimately, 61 unique organizations contributed project-level data (see Table B-1 in the Appendix for a list of data providers and associated sample sizes). A limited amount of additional project-level data for states or market segments not covered by the aforementioned set of organizations were collected from other miscellaneous sources (e.g., the U.S. Treasury Department's Section 1603 Grant Program, FERC Form 1, SEC filings, company presentations, trade press articles).

The data sources for this report series have evolved over time, particularly as incentive programs in a number of states have expired. In these instances, data collection has generally transitioned to other administrative processes, such as system interconnection or SREC registration. Of particular note, the California Solar Initiative (CSI) began to wind down in 2013, as funding within particular program categories progressively expired. At that point, the availability of installed pricing data progressively declined over time, until mid-2015, when data collection responsibilities fully transitioned to the investor-owned utilities' (IOUs') interconnection processes. In Arizona, the state's largest utilities ended their PV incentive programs, but have continued to collect project-level data through their interconnection processes, though the completeness of installed pricing data has diminished somewhat. In most other significant state markets, PV incentive and SREC programs are still offered and provide a continuing source of project-level data.

Text Box 1. Customer Segment Definitions

This report segments the data and trends according to whether the site host is residential or non-residential, with non-residential systems further segmented into those that are ≤500 kW_{DC} and those that are >500 kW_{DC}.

Residential*:* Includes single-family residences and, depending on the conventions of the data provider, may also include multi-family housing.

Non-Residential: Includes non-residential rooftop systems regardless of size, and ground-mounted systems up to 5 MW_{AC}.

Both categories consist mostly, but not exclusively, of systems installed behind the customer meter.

Ground-mounted systems larger than 5 MW_{AC} are considered **utility-scale**, regardless of whether they are installed on the utility- or customer-side of the meter. The size threshold for utility-scale is denominated in AC capacity terms, as that is more common for utility-scale systems. Those systems are not covered within this report, but are instead addressed in LBNL's companion *Utility-Scale Solar* annual report.

These customer segment definitions may differ from those used by other organizations, and therefore some care must be taken in comparisons.

Data Standardization and Cleaning

Various steps were taken to clean and standardize the raw data. First, all systems with missing data for system size or installation date, as well as any utility-scale PV systems or duplicate systems contained in multiple datasets, were removed from the raw sample. The remaining data were then cleaned by correcting text fields with obvious errors and by standardizing the spelling of installer names and module and inverter manufacturers and models. Using the module and inverter names, each PV system was then classified as building-integrated PV or rack-mounted; the module technology type and efficiency were determined; and systems with microinverters or DC optimizers were identified. In cases where data on system ownership (customer-owned vs. TPO) were not provided, system ownership was inferred, based on the installer name and state. Finally, all price and incentive data were converted to real 2015 dollars (2015$), and if necessary, system size data were converted to direct current (DC) nameplate capacity. Further details on these steps, as well as other elements of the data cleaning process, are described in Appendix A. The resulting dataset, following these initial steps, is referred to hereafter as the **full data sample** and is the basis for the public data file (which differs only in the exclusion of confidential or sensitive data).

For the purpose of the analysis presented in this report, several other categories of systems were then removed from the data. The most significant group of excluded systems are those installed by integrated TPO providers that provide both the installation service and the customer financing, as the installed price data for these systems generally represent some form of appraised value (see Text Box 2 below). Also excluded from the analysis are systems with missing installed price data, systems with battery-back up, self-installed systems, and systems with installed prices less than $1/W or greater than $20/W (assumed to be data entry errors). The resulting dataset, after these various additional exclusions, is denoted hereafter as the **final analysis sample** and is the basis for all trends presented in the report, unless otherwise indicated.

Text Box 2. Treatment of Third-Party Owned Systems in the Data Sample and Analysis

Third-party ownership of customer-sited PV systems through power purchase agreements and leases has become the dominant ownership model in many markets, and this trend has created certain complications for the tracking of installed prices. The nature of these complications, however, depends on whether the company providing the customer financing also performs the installation (i.e., an “integrated” TPO provider) or instead procures the system through an independent installation contractor.

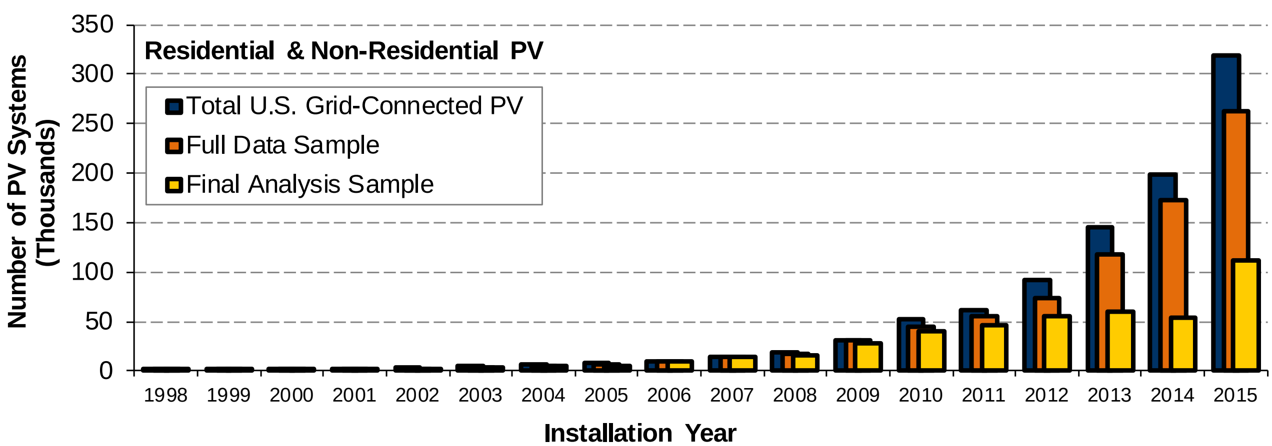
For systems financed by integrated TPO providers, installed price data reported to PV incentive program administrators generally represent appraised values, as there is no sale of the PV system from which a price is established. To the extent that systems installed by integrated TPO providers could be identified, they were removed from the final data sample. Further details on the number of excluded appraised-value systems are provided below, and details on the procedure used to identify those systems are described in Appendix A, along with data on installed prices reported for those systems. Although excluded from the installed price trends presented in this report, we do summarize installed cost data from the financial reports of several integrated TPO providers in Figure 12, as a point of comparison.

In contrast, systems financed by non-integrated TPO providers were retained in the data sample. The installed price data reported for these systems represent an actual transaction price: namely, the price paid to the installation contractor by the customer finance provider. That said, differences may nevertheless exist between these prices and those reported for customer-owned systems. Later sections compare installed prices reported for non-integrated TPO systems and customer-owned systems, in order to discern whether those differences are potentially significant.

Sample Size

The full data sample constitutes the vast majority of all U.S. grid-connected residential and non-residential PV systems. In total, the sample consists of roughly 820,000 individual PV systems installed through year-end 2015, including more than 260,000 systems installed in 2015, alone (Figure 1). This represents roughly 85% of all U.S. systems installed cumulatively through 2015 and 82% of annual 2015 installations. Coverage among the largest state markets is relatively complete, with two notable exceptions. Hawaii is largely absent from the data sample, owing in part to the fact that state's primary incentive program, a state income tax credit program, does not collect the requisite project-level data. Coverage for Maryland is also relatively low (roughly 9% of 2015 installations), as the primary data source is a state grant program, and participation in that program is limited by budgets and eligibility rules. In each of the other top-ten state markets, the full data sample includes at least 79% of all systems installed in 2015.

The final analysis sample, following removal of integrated TPO and all other excluded systems, consists of roughly 450,000 systems installed through year-end 2015 (55% of the full data sample) and more than 110,000 systems installed in 2015 (43% of the full data sample). As shown in Figure 1, the gap between the full and final data samples has expanded markedly since 2011. This is partly due to the growing market share of integrated TPO systems and thus the increasing number of such systems removed from the full data sample. The section below, *Distribution between Customer-Owned and TPO Systems*, provides further details on the quantity of integrated TPO systems removed from the sample over time and by state. In addition, a sizeable number of systems with missing installed price data were also removed from the data sample (approximately 200,000 systems in total, and 65,000 systems installed in 2015). The lion's share of those are in California and were installed during the period from 2013 to mid-2015 when data collection responsibilities were transitioning to the IOUs' interconnection processes.[5] In addition, a large portion of the data from several smaller state markets was also excluded due to missing installed price data, including all systems installed in Washington D.C. since 2013, most of the data from Ohio and Rhode Island, and all Missouri systems.



Notes: Total U.S. grid-connected PV system installations are based on data from IREC (Sherwood 2016) for all years through 2010 and data from GTM Research and SEIA (2016) for each year thereafter.

Figure 1. Comparison of Data Sample to All U.S. Residential and Non-Residential PV Systems

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[5] The IOU interconnection databases include data for all interconnected systems; however, collection of various data elements, including installed prices, began only in 2015. Our California sample includes data from the IOUs' database of interconnected systems as well as the CSI program (eliminating all duplicate systems contained within both datasets).

The analysis in this report is presented in terms of three primary market segments: residential systems, non-residential systems ≤500 kW in size, and non-residential systems >500 kW.[6] Annual sample sizes for each of these segments are summarized in Table 1. Naturally, residential systems represent the overwhelming majority of the sample, in terms of number of systems, though non-residential systems represent a much larger share of total installed capacity (not shown).

Table 1. Full Data Sample and Final Analysis Sample by Installation Year and Market Segment

Installation Year	Full Data Sample				Final Analysis Sample			
	Residential	Non-Res. ≤500 kW_{DC}	Non-Res. >500 kW_{DC}	*Total*	Residential	Non-Res. ≤500 kW_{DC}	Non-Res. >500 kW_{DC}	*Total*
1998	41	3	0	***44***	31	2	0	***33***
1999	214	10	0	***224***	163	8	0	***171***
2000	272	8	0	***280***	198	6	0	***204***
2001	1,472	24	0	***1,496***	1,313	21	0	***1,334***
2002	2,829	89	3	***2,921***	2,533	80	3	***2,616***
2003	3,532	191	6	***3,729***	3,426	185	6	***3,617***
2004	5,606	333	7	***5,946***	5,492	320	7	***5,819***
2005	5,604	504	11	***6,119***	5,450	477	11	***5,938***
2006	9,194	656	24	***9,874***	8,982	621	23	***9,626***
2007	13,837	874	34	***14,745***	13,262	818	34	***14,114***
2008	15,473	1,733	105	***17,311***	14,220	1,599	96	***15,915***
2009	28,295	2,123	121	***30,539***	25,901	1,944	96	***27,941***
2010	40,792	3,886	189	***44,867***	37,156	3,548	139	***40,843***
2011	49,984	5,277	426	***55,687***	40,943	4,632	347	***45,922***
2012	68,255	5,439	455	***74,149***	51,224	4,712	342	***56,278***
2013	113,415	4,749	431	***118,595***	55,658	3,068	322	***59,048***
2014	166,360	5,428	421	***172,209***	49,386	2,541	241	***52,168***
2015	257,290	4,746	424	***262,460***	106,983	2,880	243	***110,106***
Total	***782,465***	***36,073***	***2,657***	***821,195***	***422,321***	***27,462***	***1,910***	***451,693***

Sample Characteristics

Characteristics of the data sample provide important context for understanding installed price trends presented in this report, and in most cases correspond reasonably well to the broader market from which the sample is drawn. Below, we highlight trends associated with three key characteristics of the data sample: the evolution of system sizes over time, the geographical distribution among states, and the distribution between customer-owned and TPO systems. Unless otherwise indicated, the trends refer to the final analysis sample.

System Size Trends

As shown in Figure 2, residential systems in the data sample have grown steadily in size over the analysis time frame, rising from a median size of 2.4 kW in 1998 to 6.1 kW in 2015. As discussed further in subsequent sections, increasing residential system sizes in recent years is associated partly, though not fully, with increasing module efficiencies. System sizes for the large (>500 kW)

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[6] This group of larger non-residential systems includes systems up to 5 MW_{AC} in size if ground-mounted systems, and with no upper bound if roof-mounted. As noted previously, ground-mounted systems larger than 5 MW_{AC} are considered utility-scale and are not covered within this report.

non-residential class have also risen considerably, with a median size of roughly 1,100 kW in 2015. System sizes in this customer segment have become progressively larger with the growing prevalence of multi-MW rooftop systems and “baby ground-mount” systems in the 1-5 MW range. The class of non-residential systems ≤500 kW have not followed a regular temporal trend, but rather have vacillated between roughly 20 to 40 kW over the past decade. Thus, although the upper bound for this class of systems is 500 kW, the vast majority of systems in this group is considerably smaller, with a median size of roughly 30 kW in 2015. This customer segment is thus sometimes described in this report as “small” or “smaller” non-residential systems.

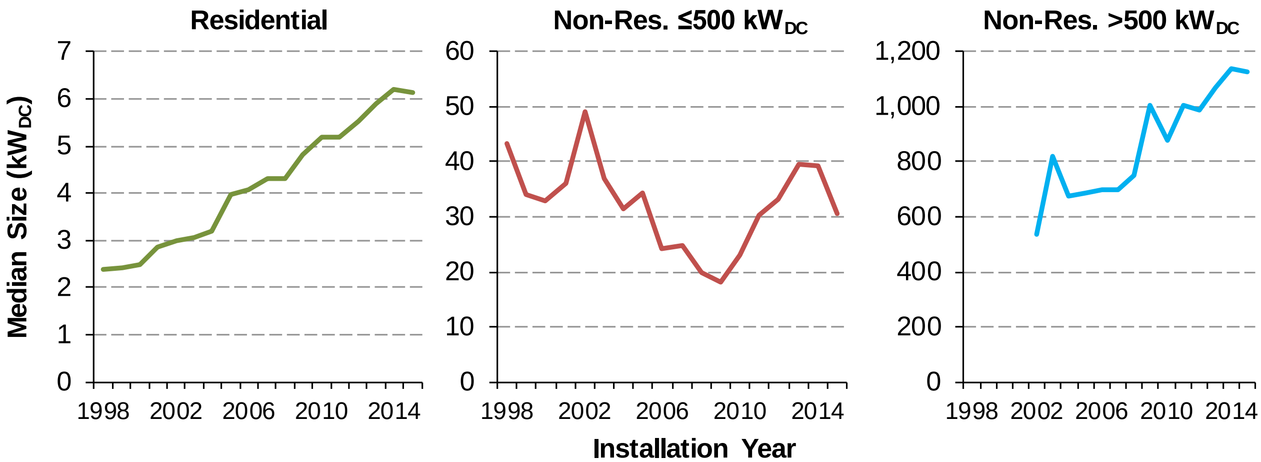


Figure 2. Median System Size over Time

Geographic Distribution

The final analysis sample includes systems installed across 33 states. As with the broader U.S. PV market, however, the sample is concentrated in a relatively small number of state markets, though it has diversified to some extent over time. This is illustrated in Figure 3, which shows the sample distribution over time, identifying the five-largest states (in terms of the number of systems) for each customer segment in 2015.

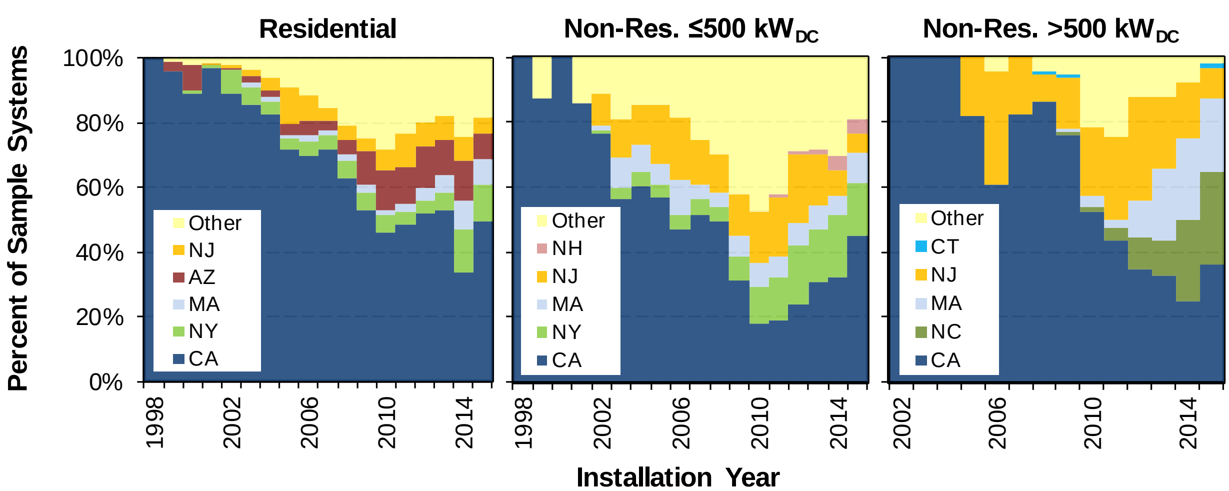
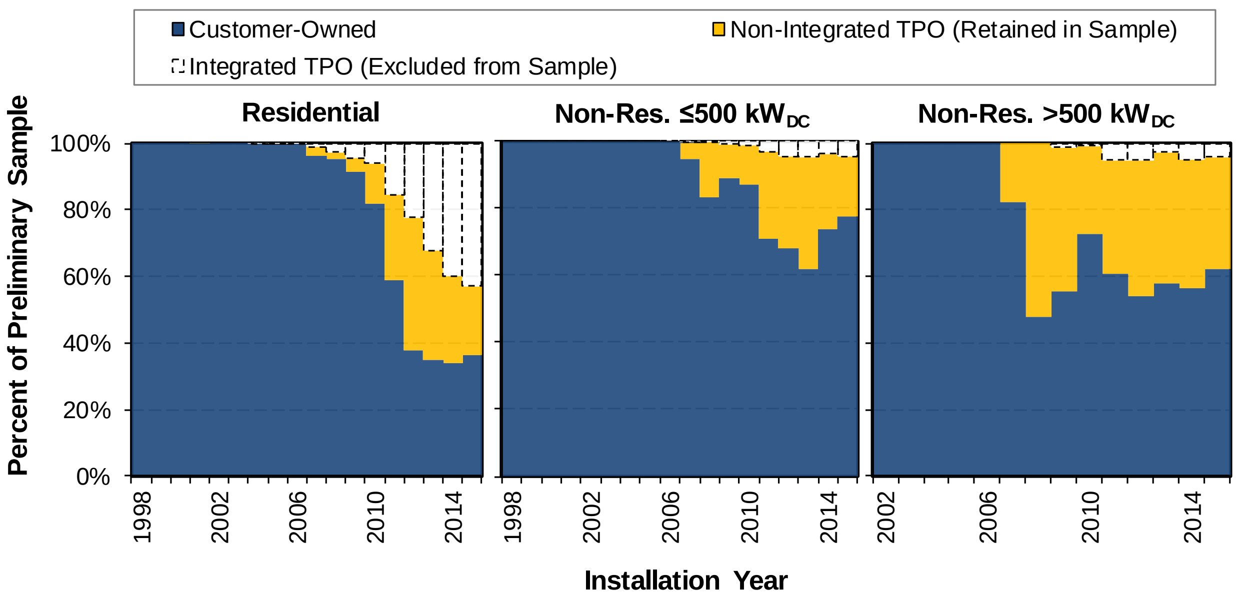


Figure 3. Sample Distribution among States (Number of Systems)

Across all three customer segments, California has remained the largest state in the data sample representing 48% of residential systems, 45% of non-residential systems ≤500 kW, and 36% of non-residential systems >500 kW installed in 2015. Although the state's share of the sample has declined over the long-term, it increased sharply in 2015—especially in the residential segment—as a result of the renewed collection of installed price data for systems installed in the IOUs' service territory. This has implications for some of the near-term trends in aggregate national-level installed pricing, discussed later in this report. New York, Massachusetts, Arizona, New Jersey, and North Carolina make up a large proportionate share of the remaining sample, though several of those states are prominent mostly within particular customer segments. For example, North Carolina constitutes a large share of non-residential systems >500 kW, but has a negligible presence within the other segments. Also worth noting is that the sample of non-residential systems >500 kW has the least geographic diversity among the three segments, with virtually all systems located in just four states (California, North Carolina, Massachusetts, and New Jersey).

Distribution between Customer-Owned and TPO Systems

The composition of the data sample reflects the growth of third-party ownership and increasing concentration of market share within the TPO segment. This is shown in Figure 4, which includes integrated TPO systems that are otherwise excluded from our final analysis sample, along with non-integrated TPO and customer-owned systems that are retained in the final sample.

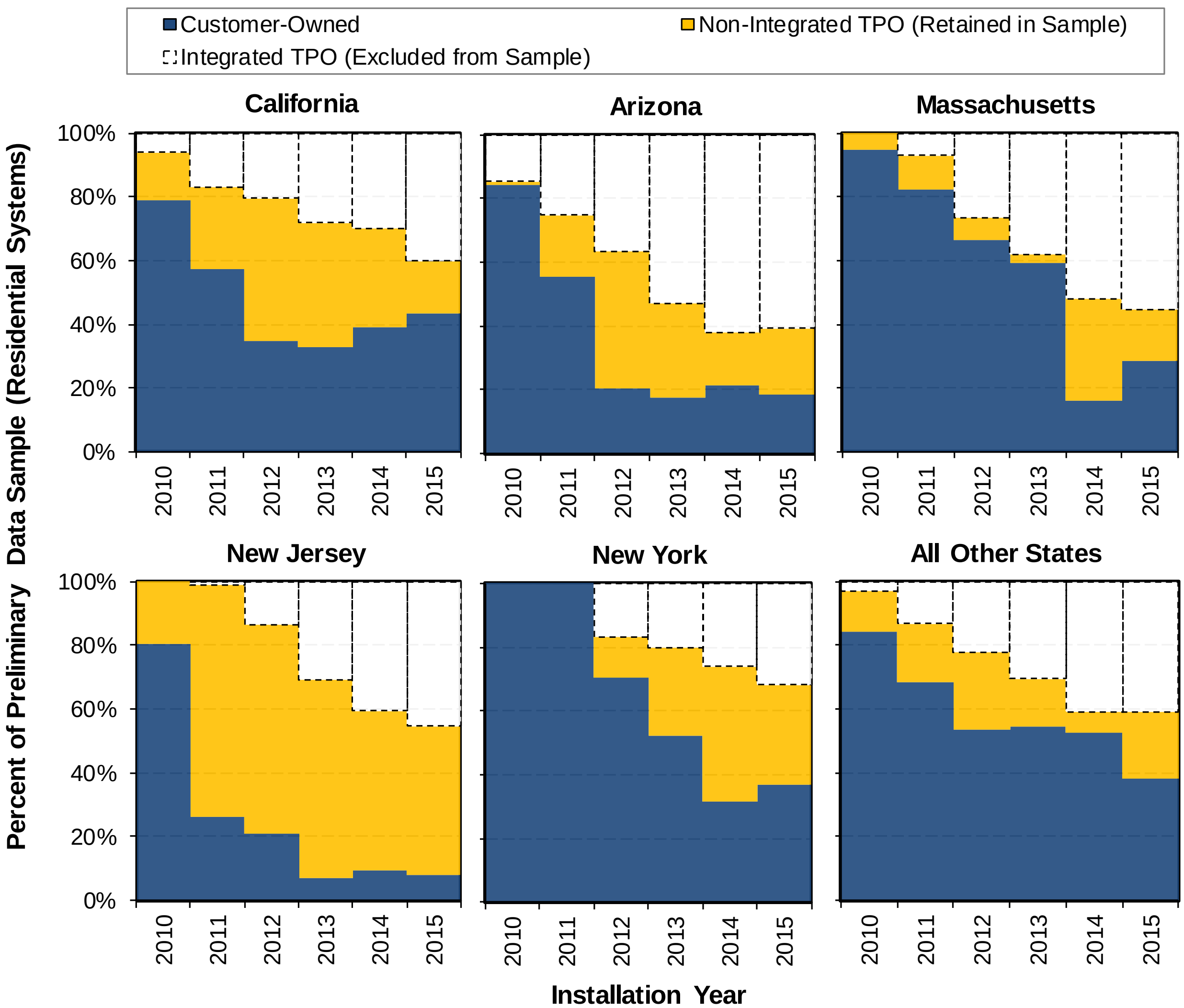


Notes: Excluded from the figure is the relatively small percentage of systems for which the ownership model is unknown or could not be readily inferred.

Figure 4. Sample Distribution between Customer-Owned and TPO Systems

Within the residential sample, the percentage of systems that are TPO increased dramatically from 2007 up until 2012, reaching 65% and remaining at roughly that level through 2015. The percentage of systems associated specifically with integrated TPO providers, however, has continued to grow even after 2012, as those companies have taken over larger shares of the residential TPO market. This growth in the market share of integrated TPO systems has thus eroded the residential sample frame for this analysis, given that those systems are excluded from the final analysis sample. The trends differ markedly within the non-residential sample. To begin, the overall percentage of systems that are TPO is considerably lower: roughly 20% of the sub-500 kW class and 40% of the >500 kW class of non-residential systems installed in 2015. More significantly, though, is that integrated TPO systems represent a quite small share of non-residential TPO systems; thus, relatively few non-residential systems were excluded from the final analysis sample.

The distribution of system ownership models also vary significantly by state, as shown in Figure 5, which focuses on the five largest state residential markets in the data sample, from 2010 onward. The figure helps to illustrate, first, which states may be most impacted by the removal of integrated TPO systems from the final sample. Of the five states highlighted, Arizona and Massachusetts are the most impacted in this respect, though all are affected to some degree. The figure also illustrates the relative balance between TPO and customer-owned systems within the final data sample, following the removal of integrated TPO systems. For Arizona and New York, the final samples of 2015 residential installations are, roughly speaking, evenly split between TPO and customer-owned. In contrast, the final samples for California and Massachusetts are mostly customer-owned, while for New Jersey, it is almost entirely TPO.



Notes: Excluded from the figure is the relatively small percentage of systems for which the ownership model is unknown or could not be readily inferred.

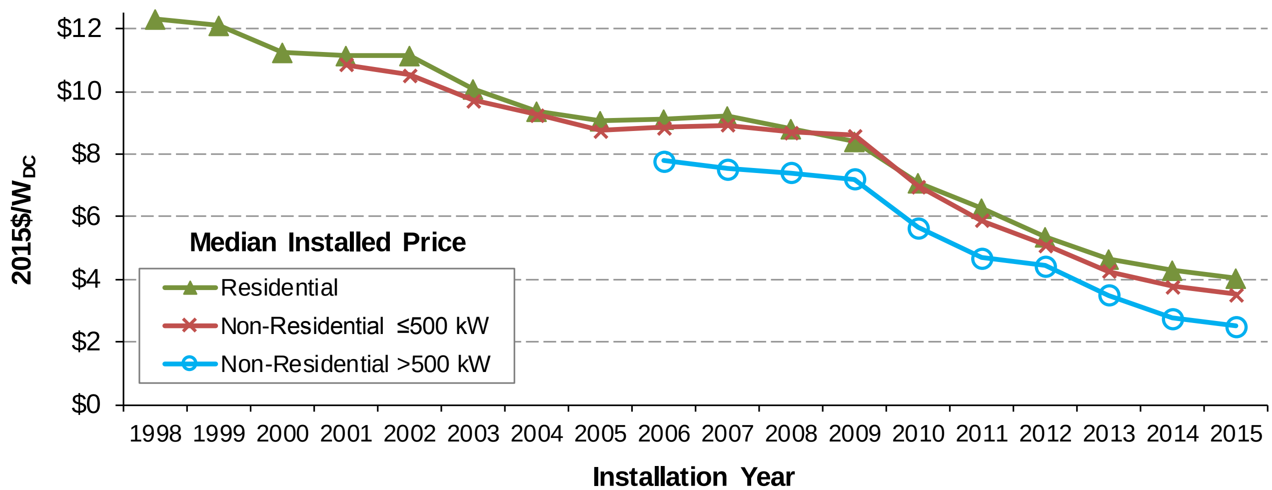
Figure 5. Residential Sample Distribution between Customer-Owned and TPO Systems

3. Historical Trends in Median Installed Prices

This section presents an overview of long-term historical trends in the installed price of residential and non-residential PV, focusing throughout on *median values* derived from the large underlying data sample. It begins by describing the installed price trajectory over the full historical period of the data sample (1998-2015), along with preliminary data for the first half of 2016. The section then discusses a number of broad drivers for those historical trends, including reductions in module prices and non-module costs, as well as declining state and utility incentives. It then compares median installed prices for systems installed in 2015 to other recent benchmarks for the installed price or cost of PV, and finally compares installed prices between the United States and other international markets.

Long-Term and Recent Installed Price Trends

Figure 6 presents trends in median installed prices from 1998 through 2015, according to the date of system installation. Over the full duration of the time series, median installed prices declined by 6% to 12% per year, on average, depending on the customer segment. Those declines, however, have not occurred at a steady rate, with the most-rapid reductions beginning after 2009. As discussed further below, declines since 2009 were spurred initially by reductions in global PV module prices but have been sustained through reductions in other hardware costs and "soft" costs.



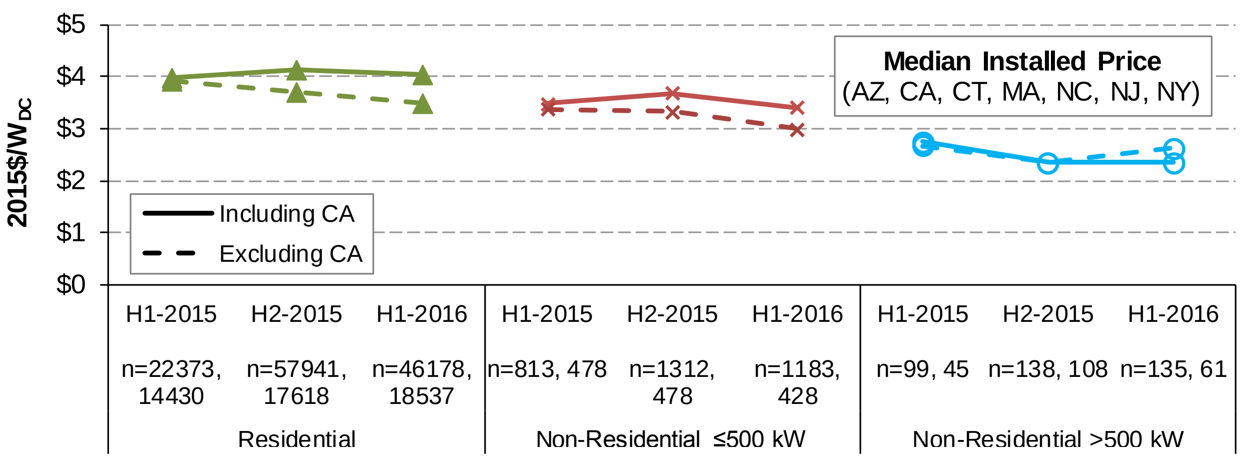
Notes: See Table 1 for sample sizes by installation year. Median installed prices are shown only if 20 or more observations are available for a given year and customer segment.

Figure 6. Median Installed Price Trends over Time

Over the last year of the analysis period, from 2014 to 2015, median prices fell by $0.2/W (5%) for residential systems, $0.3/W (7%) for non-residential systems ≤500 kW, and $0.3/W (9%) for non-residential systems >500 kW. These were the smallest year-over-year reductions in installed prices since 2009. That slowing rate of decline may be indicative of diminishing opportunities for cost reductions, though other confounding factors are also likely at play. For example, residential loan products have become more prevalent in recent years, and origination fees associated with such loans are likely to be embedded in the installed prices paid by customers in many cases. Although comprehensive data on the cost of these products is not readily available, anecdotal sources report origination fees in the range of 5-20% of the loan amount, which would add $0.2/W to $0.8/W to the installed price of customer-owned residential PV. Analysis shown later (in Figure 20) indicates that, indeed, installed prices for customer-owned systems within the residential sector and small non-residential segments remained largely flat from 2014 to 2015, while prices for non-integrated TPO systems fell quite substantially, by $0.7/W and $0.6/W, respectively. Another countervailing force is the increasing penetration of module-level power electronics, which may add $0.2/W to $0.3/W to hardware costs (GTM Research and SEIA 2016), though later analysis presented in this report suggests that the net impact on installed prices may be smaller. Finally, as noted earlier in Section 2, the underlying geographical mix of the sample has also evolved, with a marked increase in the California-share of the sample in 2015. Excluding California systems, median prices fell by somewhat larger margins than for the sample as a whole, declining by 7% for residential systems, 8% for non-residential systems ≤500 kW, and 13% for non-residential systems >500 kW.

Preliminary data for the first half of 2016 (see Figure 7) show a mixed picture in terms of the near-term trajectory of installed prices. The figure is based on data from a subset of PV incentive programs and states covered elsewhere in this report. These data should therefore be considered provisional, both because they are drawn from a limited pool of programs and because they may be impacted by seasonal trends. These trends are also heavily affected by the progressively increasing share of California systems in the sample (see figure notes). The figure thus presents two sets of median prices: one including and the other excluding California systems.

Within the residential segment, median installed prices in the first half (H1) of 2016—when including California systems—remained largely flat. When excluding California systems, however, prices show a continued decline, with median prices in H1 2016 roughly $0.4/W below the level from a year prior. The trend among small non-residential systems is similar, with flat median prices when including California systems and declining prices when excluding those system, also with a roughly $0.4/W drop from H1 2015. Finally, median prices for large non-residential systems in H1 2016 were either flat, or show a slight uptick, depending on whether California is included. However, short-term trends for this customer segment can be quite volatile, given small sample sizes and highly varied project characteristics. Collectively, these partial-year trends suggest that many state markets will likely see some modest continuation of installed price declines in 2016, at least within the residential and small non-residential segments, though those trends may be obscured within aggregate national statistics.

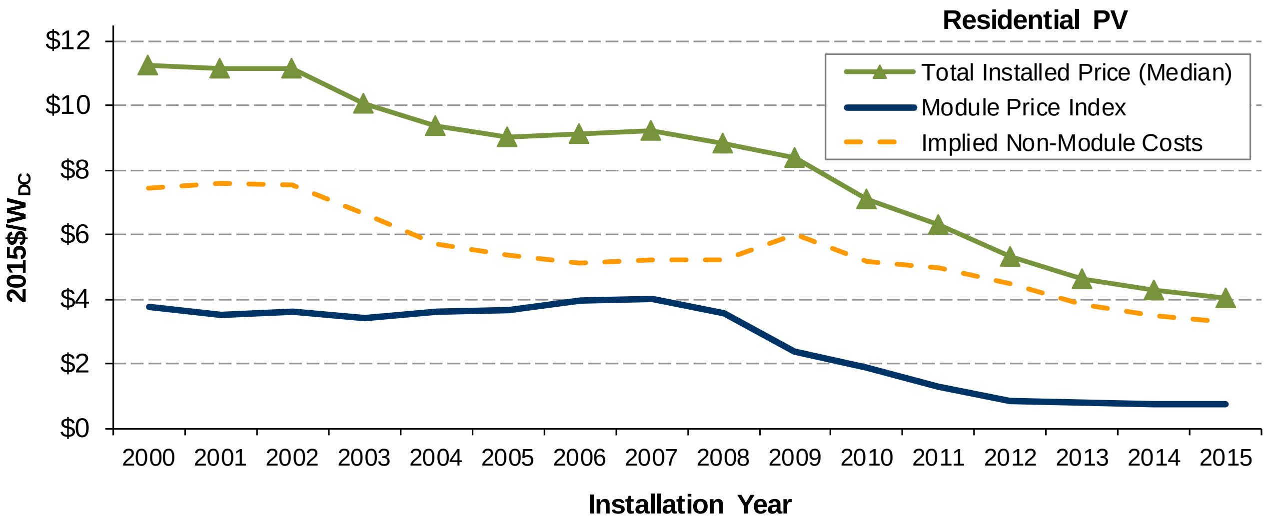


Notes: The figure is based on data from only a subset of sources used for the larger dataset, and therefore cannot be directly compared to Figure 6. Within the residential sample, the California-share grows from 36% in H1-2015 to 70% in H2-2015 and 60% in H1-2016. For the sample of smaller non-residential systems, the progression is 41%, 64%, 64%. For the larger non-residential systems, the California-share progresses from 55% to 22% to 55%.

Figure 7. Installed Prices for Systems Installed in 2015 and the First Half of 2016

Module and Non-Module Cost Reductions

Over the long-term, installed price reductions reflect a combination of declines in PV module costs; other hardware costs, such as inverters and racking equipment; and the wide assortment of soft costs, including such things as marketing and customer acquisition, system design, installation labor, permitting and inspection costs, and installer margins.[7] This is apparent in Figure 8, which focuses on residential systems, and shows the historical trajectory of module prices along with the aggregate set of non-module costs—calculated as the residual between the total installed price and module price index in each year, and therefore including whatever margin installers receive. Over the full historical period, from 1998 to 2015, module prices fell by $4.4/W, constituting just over half (53%) of the total decline in PV system installed pricing, while "implied" non-module costs fell by $3.9/W, constituting the remaining 47% of the installed-price drop.



Notes: The Module Price Index is the U.S. module price index published by SPV Market Research (Mints 2016). Implied Non-Module Costs are calculated as the Total Installed Price minus the Module Price Index, and therefore include installer profit margin.

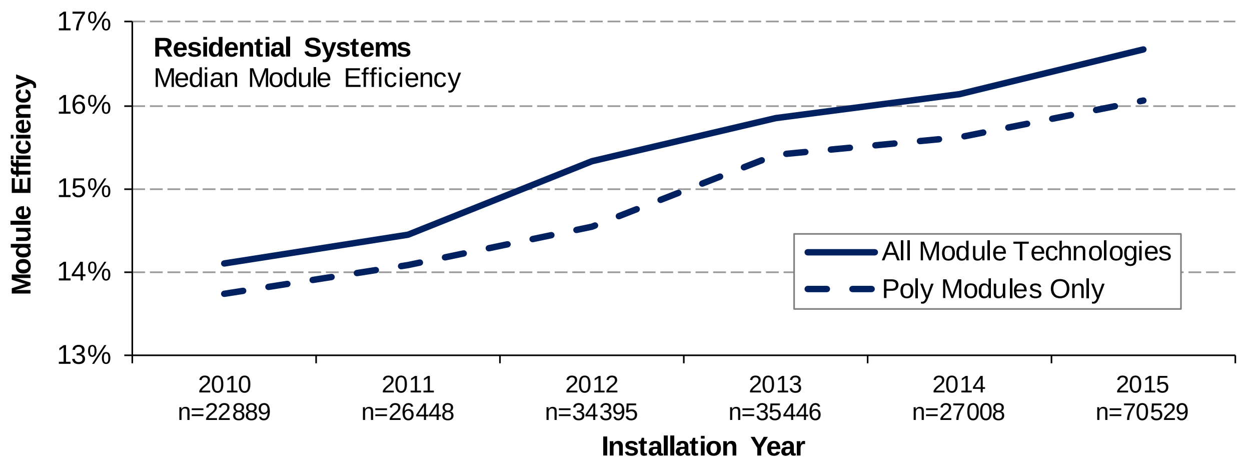
Figure 8. Installed Price, Module Price Index, and Implied Non-Module Costs over Time for Residential PV Systems

Recent years have seen several shifts in the relative importance of module and non-module cost reductions. Following a lengthy period of little price movement, module prices began a steep descent in 2008, falling by $2.7/W in real 2015 dollars from 2008 to 2012. Over this period, module price reductions were clearly the dominant driver for the overall decline in installed prices (though it is worth noting that system level pricing did not necessarily move in lock-step with module prices).[8] Since 2012, however, module prices have flattened considerably, but installed prices have continued to fall due to a steady decline in non-module costs, which re-commenced in roughly 2010

[7] The line between module costs and non-module costs can become somewhat blurred, such as for modules with integrated racking and AC modules with microinverters.
[8] In some years, system-level prices appear to lag behind movements in module prices. This could reflect differences between when installation contracts are signed and when systems are installed, excess module inventory held by installers, higher-than-normal distributor mark-ups, variation in installer purchasing power or module technologies, and the ability of some installers to potentially retain a portion of module cost reductions as increased margin.

after a period of stagnation. [9] Over the last year of the analysis period, from 2014 to 2015, residential non-module costs fell by $0.2/W, representing the entirety of the total installed price decline over that year. This is roughly equivalent to the long-term rate of decline in non-module costs, but below the pace of reductions in recent years; for example, non-module costs dropped by $0.4/W per year, on average, from 2010 to 2014.

Just as non-module costs are diverse, so too are the reasons for their recent declines. In part, these declines are the result of price reductions for key balance-of-system hardware components, the largest being inverters and racking equipment. Based on U.S. PV system component pricing data from GTM Research and SEIA (2016), the cost of inverters and racking for residential PV systems each fell by $0.07/W over the last year of the analysis period, from 2014 to 2015.[10] These hardware price reductions constitute roughly 66% of the overall decline in non-module costs over that time frame. Since 2012 (the first year in the GTM/SEIA component price series), reductions in inverter and racking costs represent a smaller share, roughly 30%, of the decline in total non-module costs. The sizeable remainder can thus be attributed largely to declines in various soft costs.



Notes: "All Module Technologies" is based on all residential systems in the data sample, regardless of module type, while "Poly Modules Only" is based on only those systems with poly-crystalline modules.

Figure 9. Module Efficiency Trends over Time within the Project Data Sample

Reductions in non-module costs, including both hardware and soft costs, have been driven partly by two inter-related changes in the technical attributes of residential systems: increasing module efficiency and increasing system size. Higher module efficiencies reduce non-module costs on a per-watt basis by allowing fixed project costs (e.g., permitting and customer-acquisition) and area-related costs (e.g., racking and installation labor) to be spread across a larger base of installed watts. As shown in Figure 9, median module efficiencies within the data sample have risen substantially over time. Based on modeled PV cost relationships developed by Fu et al. (2016), the increase in median module efficiency since 2010 corresponds to roughly a $0.15/W reduction in residential

[9] Figure 8 suggests that non-module costs spiked in 2009; however, this is likely just an artifact of the manner in which non-module costs are calculated and the lag (highlighted in the previous footnote) between module and system prices.
[10] These values are derived from quarterly component-level cost benchmarks, using a population-weighted average for microinverter and string inverter pricing.

non-module costs, representing roughly 8% of the total drop in non-module costs over that period.[11] Within the last year of the analysis period, from 2014 to 2015, median module efficiencies for residential systems rose from 16.1% to 16.7%, which would be expected to yield roughly a $0.03/W reduction in non-module costs.

Residential system sizes have also grown significantly over time, as shown earlier in Figure 2. Increases in system size are, to some extent, a direct result of higher module efficiencies: that is, higher efficiencies translate to higher-wattage panels and thus larger system sizes for a given number of panels per system. That said, the increase in residential system sizes over time is far greater than what would occur solely as a result of higher module wattage.[12] This growth in residential system sizes has enabled further scale economies and associated non-module cost reductions. Based again on cost modeling by Fu et al. (2016), the increase in residential system sizes since 2010 would be expected to yield roughly a $0.2/W reduction in non-module costs, above and beyond the effects of increased module efficiencies, representing 10% of total non-module cost reductions over that period. This is generally consistent with analysis presented later in this report comparing installed prices across residential systems of varying size.

Above and beyond the aforementioned technical factors, recent years have seen a significant shift of emphasis within the industry and among policymakers toward developing strategies to target soft costs. Although it is beyond the scope of this report to evaluate the efficacy of those varied efforts, this broad and sustained focus has undoubtedly played an important role in driving recent soft cost reductions. Furthermore, as discussed in the next section, financial incentives for PV in many states have fallen precipitously over time, potentially creating pressure on installers and others in the supply chain to streamline their business processes and reducing opportunities for value-based pricing.

State and Utility Cash Incentives

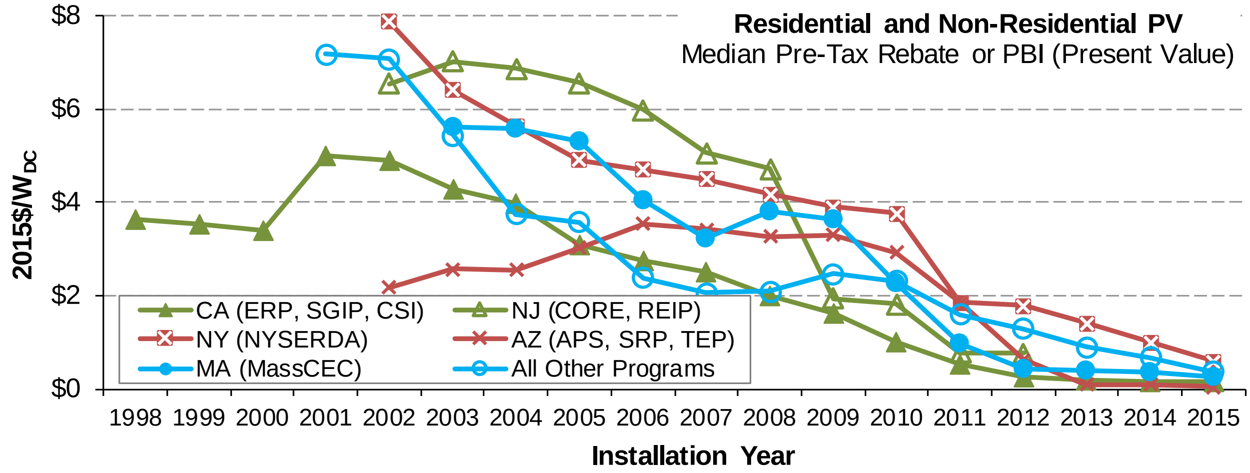
Financial incentives provided through utility, state, and federal programs have been a driving force for the PV market in the United States. For residential and non-residential PV, those incentives have – depending on the particular place and time – included some combination of cash incentives provided through state and/or utility PV programs (rebates and performance-based incentives), the federal investment tax credit (ITC), state ITCs, revenues from the sale of solar renewable energy certificates (SRECs), accelerated depreciation, and retail rate net metering.

Focusing *solely* on direct cash incentives provided in the form of rebates or performance-based incentives (PBIs), Figure 10 shows how these incentives have declined steadily and significantly over the past decade across all of the major incentive programs. At their peak, these programs were providing incentives of $3-8/W (in real 2015 dollars). By 2015, direct cash incentives were largely phased-out in many key markets – including California, Arizona, and New Jersey – and had diminished to well below $1/W elsewhere. This continued ratcheting-down of incentives is partly a response to the steady decline in the installed price of PV and the emergence of other forms of

[11] Over the full historical period of the data sample, the module efficiency gains and associated non-module cost reductions are even greater, equivalent to roughly $0.23/W. To be sure, these estimates of non-module cost reductions associated with module efficiency gains represents only the marginal effect, given all other sources of cost reduction that occurred over the corresponding time span. Had other cost reductions not occurred (e.g., no change in installation labor efficiency or reduction in permitting costs), then the effects of module efficiency improvements would be greater.

[12] For example, since 2002, median module efficiencies increased by roughly 30%, while median system sizes increased by more than 100%. In other words, residential systems are growing in the number of panels per system, not only the wattage per panel.

financial support (for example, SRECs, as discussed in Text Box 3). In many states, it is also a deliberate strategy intended to provide a long-term signal to the industry to reduce costs and improve installation efficiencies. Thus, in some sense, this steady decline in incentives is both a cause and an effect of the corresponding installed price reductions.



Notes: The figure depicts the pre-tax value of rebates and PBI payments (calculated on a present-value basis) provided through state/utility PV incentive programs, among only those systems that received such incentives. Although not shown in the figure, a growing portion of the sample received no direct cash incentive. Also note that the data are organized according to the year of installation, not the year in which incentives were reserved.

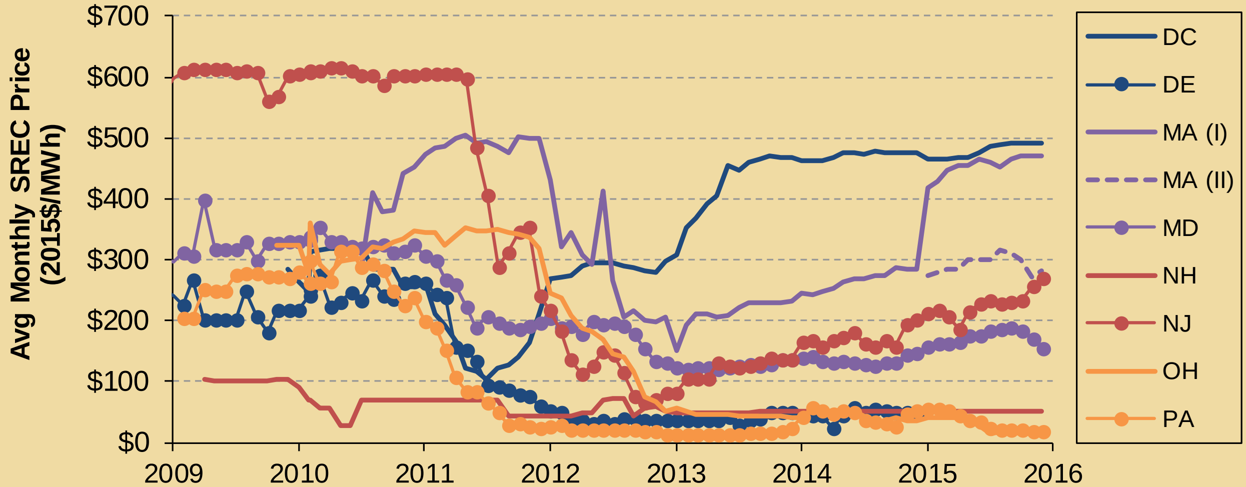
Figure 10. State/Utility Rebates and PBIs over Time

From the perspective of the customer-economics of PV, however, one thing is clear: the steady reduction in cash incentives has offset reductions in installed prices to a significant degree. Among the five markets profiled in Figure 10, the pre-tax value of cash incentives has declined by $3-7/W from each market's respective peak. This is equivalent to anywhere from roughly 60% to 120% of the drop in installed PV prices over the corresponding period of time. Of course, other forms of financial support have simultaneously become more lucrative over this period of time – for example, the increase in the federal ITC for residential solar starting in 2009 and the emergence of SREC markets – and new financing structures have allowed greater monetization of existing tax benefits. Thus, the customer economics of solar in many states and markets has undoubtedly improved, on balance, over the long-term, but the decline in state and utility cash incentives has nevertheless been a significant counterbalance to falling installed prices.

Text Box 3. SREC Price Trends

Eighteen states plus the District of Columbia have enacted renewables portfolio standards with a solar or distributed generation set-aside (also known as a "carve-out"), and many of those states have established solar renewable energy certificate (SREC) markets to facilitate compliance. PV system owners in these states, and in some cases neighboring states, may sell SRECs generated by their systems, either in addition to or in lieu of direct cash incentives received from state/utility PV incentive programs. Many solar set-aside states have transitioned away from standard-offer based incentives, particularly for larger and non-residential systems, and towards SREC-based incentive mechanisms with SREC prices that vary over time.

Prior to 2011, SREC prices in most major RPS solar set-aside markets ranged from $200 to $400/MWh, topping $600/MWh in New Jersey (Figure 11). Starting around 2011 or 2012, SREC supply began to outpace demand in these markets, leading to a steep drop in SREC pricing. As with the broader decline in solar incentives, this contraction in SREC pricing served as a source of further downward pressure on installed prices. Since then, SREC prices have generally stabilized or even risen, relieving some of that downward pressure on installed prices.



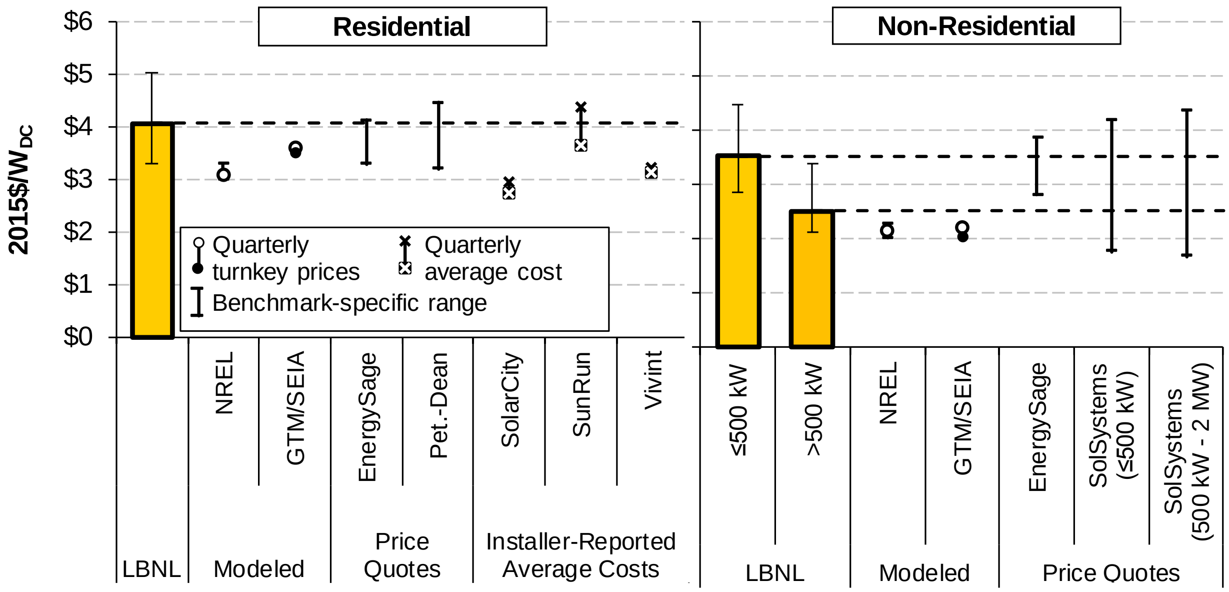
Notes: Data sourced from Marex-Spectron, SRECTrade, and Flett Exchange (data averaged across available sources). Plotted values represent SREC prices for the current or nearest future compliance year traded in each month. Data for Ohio prior to 2015 are for in-state SRECs. MA (I) and MA (II) refer to prices in the SREC I and SREC II programs, respectively.

Figure 11. Monthly Average SREC Prices for Current or Nearest Future Compliance Year

Comparison of National Installed Price Data to Other Recent U.S. Benchmarks

Across the full set of systems in the dataset installed in 2015, the median installed price was \$4.1/W for residential systems, \$3.5/W for non-residential systems ≤500 kW in size, and \$2.5/W for non-residential systems >500 kW (as shown previously in Figure 6). Importantly, these median values represent central tendencies, and considerable spread exists among the data, as will be illustrated and explained throughout much of the remainder of the report. Related, median installed prices drawn from the dataset at large are dominated by several high-cost states that constitute a large fraction of the total U.S. market (and hence the data sample). Later sections will show that prices in many other states are well below the national medians. Finally, as with any estimate or benchmark for PV system pricing, the data used in this report have their inherent limitations. Chief among these are that the data are historical and therefore do not capture more-recent trends; that the data are self-reported by installers or host customers and are therefore susceptible to inconsistent reporting practices; and that the final sample excludes integrated TPO systems (which represent some of the largest U.S. installers) and has limited coverage in several key markets.

To provide a more-robust snapshot than can be offered by any single source, Figure 12 summarizes a broad, though by no means comprehensive, set of recent PV price and cost benchmarks, and compares those benchmarks to installed price statistics derived from the LBNL data sample. These other benchmarks are varied in nature and include modeled PV system prices, price quotes for prospective PV systems, and average costs reported directly by several major residential installers. A range is presented in each case, though depending on the particular benchmark, the data points bounding the range may refer either to average quarterly prices/costs or to some benchmark-specific values, as described in the detailed notes below the figure. Each of these PV pricing and cost benchmarks, including the LBNL data, have their merits and limitations, and must be interpreted and applied appropriately.



Notes: ***LBNL*** *data are the median and 20th and 80th percentile values among projects installed in 2015.* ***NREL*** *data represent the national average and range in statewide average modeled turnkey costs, not including installer profit, for 5.2 kW residential and 200 kW commercial systems, representative of bids issued circa Q1 2015 (Chung et al. 2015).* ***GTM/SEIA*** *data are modeled turnkey prices for Q1 and Q4 2015; residential price is for 5-10 kW system with standard crystalline modules, while commercial price is for a 300 kW "minimalist" flat-roof system, with further details available from the reference source (GTM Research and SEIA 2016).* ***EnergySage*** *data are the 20th and 80th percentile range among price quotes issued in 2015, calculated by LBNL from data provided by EnergySage.* ***Petersen-Dean*** *data are the minimum and maximum values from a series of online price quotes for turnkey systems across a range of sizes (3.3 to 8.3 kW) and states (AZ, CA, and TX), queried from the company website by LBNL in May 2015.* ***SolarCity***, ***SunRun***, *and* ***Vivint*** *data are the companies' reported average costs, inclusive of general administrative and sales costs, for Q1 and Q4 2015.* ***SolSystems*** *data are the lowest and highest "developer all-in asking prices" among the company's monthly Sol Project Finance Journal reports issued in 2015.*

Figure 12. Comparison to Other Installed Price or Cost Benchmarks

Clearly, great variability exists both across and within the benchmark ranges summarized in Figure 12, reflecting a diversity of data, methods, and definitions. Among the non-LBNL sources, benchmarks for residential PV range from $2.7/W to $4.5/W. The median price of 2015 residential systems in the LBNL dataset falls within, though is closer to the upper end of, that broad range and is notably higher than several other frequently cited sources. For non-residential systems, the non-LBNL benchmarks span a particularly wide range from $1.7/W to $4.3/W. The LBNL data for large non-residential systems >500 kW fall squarely within that broader benchmark range, while the median price for sub-500 kW non-residential systems is near the upper end of (or well above) the other non-residential benchmarks.

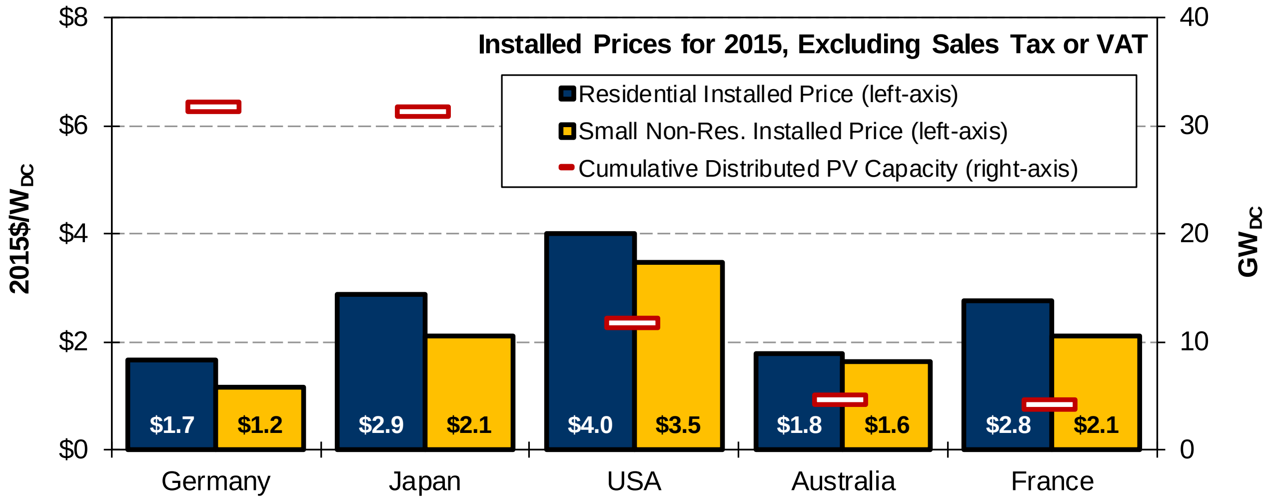
Deviations among these benchmarks arise for a number of general reasons, and in many cases help to explain why median values drawn from the LBNL data sample for residential and smaller non-residential systems are higher than some of the other benchmarks:

- *Timing*: The LBNL data in Figure 12 are based on systems installed over the course of 2015. A number of the other benchmarks cited in the figure are instead based on systems installed in Q4 2015, while others are based on price quotes, which may precede installation by several months to a year or more (for larger non-residential projects). These differences in timing can be significant given the rapid pace of cost and price declines within the industry.
- *Price versus cost:* The LBNL data represent reported prices paid to installers or project developers. Several of the other published benchmarks – in particular, the data points drawn from SolarCity's, SunRun's, and Vivint's publicly-available financial reports – represent costs borne by these companies, which exclude profit margins and, for a variety of other reasons, may differ from the prices ultimately paid by PV system owners.
- *Value-based pricing*: Benchmarks may reflect developer/installer margins based on some minimally sustainable level, as may occur in highly competitive markets. In contrast, the market price data assembled for this report are based on whatever profit margin developers are able to capture or willing to accept, which may exceed a theoretically competitive level in markets with high search costs and/or barriers to entry.
- *Location:* As noted earlier, statistics derived from the LBNL dataset are dominated by several high-cost states that constitute a large fraction of the sample (and of the broader U.S. market). Other benchmarks may instead be representative of lower-cost or lower-priced locations.
- *System size and components*: A number of the benchmarks in Figure 12 are based on turnkey project designs and prototypical system sizes. The LBNL data instead reflect the specific sizes and components of projects in the sample. For example, roughly 47% of 2015 residential systems in the sample have high efficiency modules or module-level power electronics, and most of the non-residential systems in the ≤500 kW class are, in fact, smaller than 30 kW.
- *Scope of costs included*: The set of cost components embedded in the installed price data collected for this report undoubtedly varies across projects, and in some cases may include items such as re-roofing costs or loan origination fees that typically would not be included in other benchmarks for PV pricing or costs (though, from the customer's perspective, are part of the price of "going solar").
- *Installer characteristics*: Finally, the LBNL data reflect the characteristics and reporting conventions of the particular installers in the sample, many of which are relatively small or regional. Moreover, by virtue of excluding appraised value systems, the LBNL dataset excludes several of the largest U.S. residential installers. The other benchmarks in Figure 12 may, in many cases, be reflective of relatively large and experienced installers.

The above discussion highlights and seeks to explain differences between LBNL's installed price data and other recent PV price or cost benchmarks. Much of the remaining analysis in this report, however, will show how these differences may be less significant than they first appear. Later analyses will show, for example, that pricing in many states and by many installers is well below the median values (or even below the 20th percentile values) shown in Figure 12 and aligns well with even the lowest of the other benchmarks shown. The national median installed prices in Figure 12 therefore should not necessarily be taken as indicative of "typical" pricing in all contexts.

Comparison of U.S. Median Installed Prices to Other International Markets

Notwithstanding the significant installed price reductions that have already occurred in the United States, international experience suggests that greater near-term reductions are possible. Figure 13 compares median installed prices for residential and sub-500 kW non-residential systems installed in the United States in 2015 to system prices for a number of other major national markets, in all cases excluding sales tax or value added tax (VAT). To be sure, these data are not perfectly comparable to one another. Perhaps most importantly, U.S. prices are based on median values, while prices for most of the other countries refer to "turnkey" systems, as reported for each country in its annual National Survey Report to the International Energy Agency's Photovoltaic Power Systems Programme (IEA-PVPS).[13] Nevertheless, even considering the broader set of U.S. benchmarks presented in the previous section, the data suggest that U.S. installed prices are high compared to other major markets.



Notes: Installed price data for Japan, France, and Australia are based on the IEA Photovoltaic Power Systems Programme's National Survey Reports (IEA-PVPS 2016) and for Germany are based on data compiled by the Center for Solar Energy and Hydrogen Research Baden-Württemberg (ZSW 2016). Data for cumulative distributed PV capacity additions are based on IEA-PVPS (2016) and SPE (2016).

Figure 13. Comparison of Installed Prices in 2015 across National Markets (Pre-Sales Tax/VAT)

Other than the impacts of import duties, modules and other hardware items are similarly priced across countries. Differences in total system prices among countries can thus be attributed primarily to soft costs. Indeed, installer surveys in Germany, Australia, and Japan have confirmed that soft costs in those countries, across all major soft cost elements, are substantially lower than in the United States (Seel et al. 2014, Ardani et al. 2012, Friedman et al. 2014, RMI and GTRI 2014). Several time-and-motion studies have further homed-in on installation costs, identifying specific aspects of installation practices in Germany and Australia that enable lower labor costs in those countries than in the United States (RMI and GTRI 2013, 2014).

At a high-level, differences in soft costs between countries may be attributable partly to differences in market size, on the theory that larger markets facilitate cost reductions through learning-by-doing and economies of scale that enable reductions across the broad swath of soft cost

[13] Although limited information is provided about the underlying data sources, significant differences in data quality may also exist across the turnkey system prices in the IEA country reports.

elements. Indeed, as shown in Figure 13, cumulative distributed PV capacity in Germany and Japan is significantly greater than in the United States. On the other hand, France and Australia – both of which are also relatively low-priced compared to the United States – have much smaller distributed PV markets in absolute terms (though Australia's market is significantly larger if compared on a per-capita basis). Thus, other factors, beyond absolute market size, clearly also contribute to installed price differences across countries. These may factors may include differences in: incentive levels and incentive design, solar industry business models, demographics and customer awareness, building architecture, systems sizing and design, interconnection standards, labor wages, and permitting and interconnection processes.

4. Variation in Installed Prices

While the preceding section focused on trends in median installed prices drawn from the dataset as a whole, this section instead highlights the substantial *variability* in installed prices and explores drivers for pricing differences across projects. The section begins by describing the distribution in installed prices across the dataset as a whole, and how that distribution has evolved over time. It then examines a series of specific sources of installed pricing differences across projects, including differences in: system size, state, installer, customer-owned vs. TPO, residential new construction vs. retrofit, tax-exempt vs. for-profit commercial site hosts, module efficiency, use of module-level power electronics, and rooftop vs. ground-mounted systems with and without tracking.

These comparisons focus primarily on systems installed in 2015, but include time series data in many cases as well, in order to illustrate whether the observed relationships are consistent over time. Due to limited availability of certain data elements (e.g., missing data on module models), these comparisons are, in many cases, drawn from a subset of the data sample. It should also be noted that the analysis presented here is purely descriptive in nature, and does not control for the many potential correlations among installed price drivers and other confounding dynamics. Thus the results should be construed as illustrative; other methods – such as more-advanced statistical analyses or bottom-up cost modeling – would be required to develop precise estimates of particular installed price drivers.

Overall Installed Price Variability

Considerable spread exists within the data, as clearly illustrated in Figure 14, which presents installed price distributions for systems installed in 2015 within each customer segment. Among residential systems, roughly 20% of systems installed were priced below \$3.3/W (the 20th percentile value), and 20% were above \$5.0/W (80th percentile), with the remaining 60% of systems distributed across the wide range in between. Non-residential systems in the sub-500 kW class exhibit a similar spread, with 20th and 80th percentile values of \$2.9/W and \$4.5/W, respectively. The distribution for larger >500 kW non-residential systems is somewhat narrower than for the other two segments, though by no means uniform, with a 20th-to-80th percentile band of \$2.1/W to \$3.4/W.

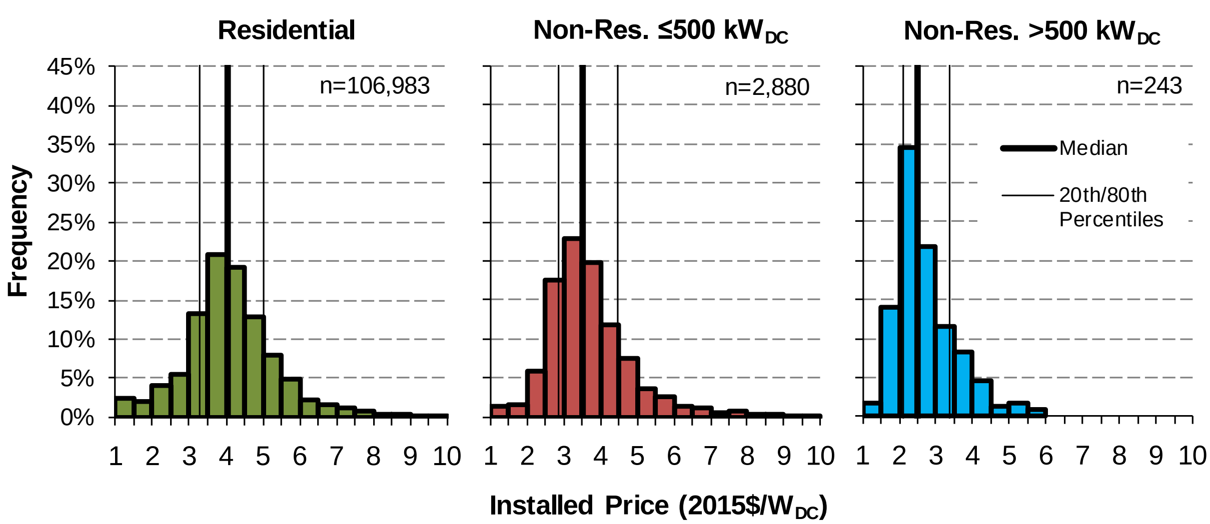
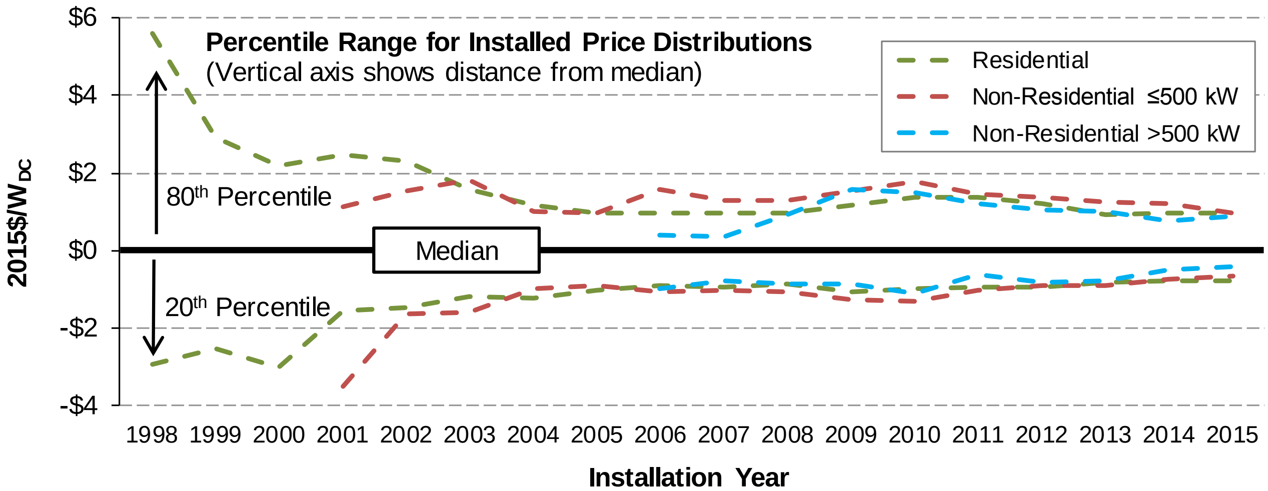


Figure 14. Installed Price Distributions for Systems Installed in 2015

Notwithstanding the significant pricing variability that exists among systems installed in 2015, installed price distributions have generally narrowed over time. This can be seen in Figure 15, which shows the range between the 20th and 80th percentiles over time, relative to the median installed price in each year. This narrowing trend was especially pronounced during the early years (1998 to 2004) of the U.S. residential market. Since then, the percentile spreads have remained relatively stable, though prices have been slowly – but steadily – converging across all three customer segments since roughly 2010. This narrowing trend is consistent with a maturing market characterized by increased competition among installers and vendors and by better-informed consumers.



Notes: See Table 1 for sample sizes by installation year. Percentile ranges are shown only if 20 or more observations are available for a given year and customer segment.

Figure 15. Installed Price Percentile Ranges over Time

The potential underlying causes for the remaining variability are numerous. These may include project characteristics (e.g., related to system size, technology type, or configuration) as well as attributes of individual installers. Installed price variation likely also reflects differences in regional or local market and regulatory conditions. For example, markets with less competition among installers, higher incentives, and/or higher electricity rates for net metering may have higher prices if installers are able to value-price their systems or if overheated demand strains the capacity of the local supply chain. Variability in prices also likely derives from differences in administrative and regulatory compliance costs (e.g., permitting and interconnection) as well as differences in labor wages and taxes. Many of these potential pricing drivers are explored throughout the remainder of this report. In addition, LBNL and its collaborators are also engaged in a series of separate analyses, using more sophisticated statistical methods, to further understand and isolate the sources of PV pricing variability (see Text Box 4). Regardless of its causes, the fact that such variability exists underscores the need for caution and specificity when referring to the installed price of PV, as clearly there is no single "price" that uniformly and without qualification characterizes the U.S. market, or even particular market segments, as a whole.

Text Box 4. Findings from Recent In-Depth Analyses of PV Pricing Dynamics

In collaboration with researchers from Yale University, University of Wisconsin, and University of Texas at Austin, LBNL has engaged in a series of in-depth analyses to better understand PV pricing dynamics. These studies leverage the dataset assembled for *Tracking the Sun* in conjunction with other data, and apply a variety of more-advanced statistical and econometric techniques. To date, several studies in this series have been completed, and several others are planned or underway.

Gillingham et al. (2014) examined a broad range of potential drivers for PV pricing variability among residential systems installed during 2010 to 2012. Of the various factors considered, the single-largest contributor was system size, with a difference of roughly $1.5/W between the smallest and largest residential systems (within an overall range of 1-10 kW). The study found that installed prices were $0.5/W lower in markets with the greatest density of installers, potentially due to greater competition, and that prices were $0.2/W lower for systems installed by the most-experienced companies. The study also found evidence that rich incentives can lead to higher prices, with a difference of more than $0.4/W between markets with the highest and lowest incentive levels (considering utility bill savings and SRECs, as well as direct incentives). As noted in the paper, that latter finding may reflect value-based pricing, though it may also simply be the result of high demand for solar enabling higher-cost installers and higher-cost systems.

More recently, Nemet et al. (2016a) sought to identify characteristics of the lowest priced systems (e.g., the lowest 10th percentile). That study found that low-priced systems are associated with experienced installers; customer ownership; larger system size; retrofits rather than new home construction; and thin-film, low-efficiency, and Chinese modules. The analysis also found that low-priced systems are much more likely to occur in some states than in others, and are more likely to occur in the presence of higher incentives, at least in California. Follow-up work by Nemet et al. (2016b) found that many of the same factors appear to drive low-priced systems to be even lower priced.

Other studies in the series have focused on narrower issues related to the installed price of residential PV. Two of these studies have examined the impact of local permitting processes on residential PV pricing. Dong and Wiser (2013) found that cities in California with the most-favorable permitting practices had installed prices $0.3/W to $0.8/W lower than in cities with the most-onerous practices. Examining a broader geographical footprint, Burkhardt et al. (2014) found that variations in local permitting procedures lead to differences in average residential PV prices of approximately $0.2/W across jurisdictions; when considering variations not only in permitting practices, but also in other local regulatory procedures, price differences grew to $0.6/W to $0.9/W between the most-onerous and most-favorable jurisdictions.

Another study, Dong et al. (2014), examined incentive pass-through – i.e., the degree to which installers pass through the value of incentives to consumers – in California's statewide rebate programs. This analysis included two wholly distinct modeling approaches, and in both cases found average pass-through rates ranging from 95% to 99%. These finding thus indicate that installers in California have not artificially inflated their prices as a result of available rebates, though the findings do not rule out the possibility of value-based pricing more generally, for example associated with utility bill savings or tax incentives.

Installed Price Differences by System Size

Larger PV installations benefit from economies of scale by spreading fixed project and overhead costs over a larger number of installed watts and, depending on the installer, through price reductions on volume purchases of materials. These scale economies are evident in preceding figures that show higher installed prices for residential systems than for non-residential systems. They also arise, to varying degrees, among both residential and non-residential systems, contributing to the overall pricing variability within each customer segment.

Among residential systems installed in 2015 (Figure 16), economies of scale are most apparent within the range of 2 kW to 10 kW, where the vast majority of residential systems reside. Across this range, median prices are roughly \$0.7/W (16%) lower for systems 8-10 kW in size, compared to 2-4 kW systems. The relatively low median price for systems ≤2 kW is associated with the high proportion of those systems installed in new construction – which are relatively low-priced, as will be shown later. Beyond 10 kW, further price declines taper off for residential systems, suggesting strongly diminishing returns to scale. These trends are generally consistent over time, as shown in Table B-2 in the appendix, which presents time series data for residential systems in each size bin.

For non-residential systems (Figure 17), economies of scale are substantial across the broad range of system sizes. Among systems installed in 2015, median installed prices were \$1.8/W (43%) lower for the largest class of non-residential systems >1,000 kW in size than for the smallest non-residential systems ≤10 kW.[14] Of course, even greater scale effects may arise when moving from large non-residential systems to utility-scale, though the latter are not covered in this report. See Table B-3 in the appendix for time series data on non-residential pricing by system size.

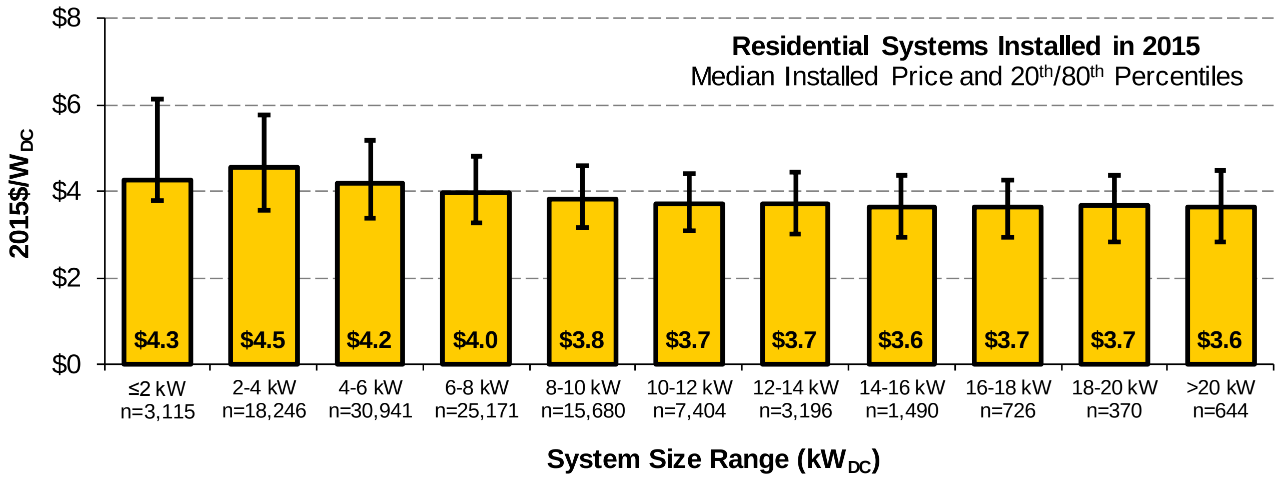


Figure 16. Installed Price of 2015 Residential Systems by Size

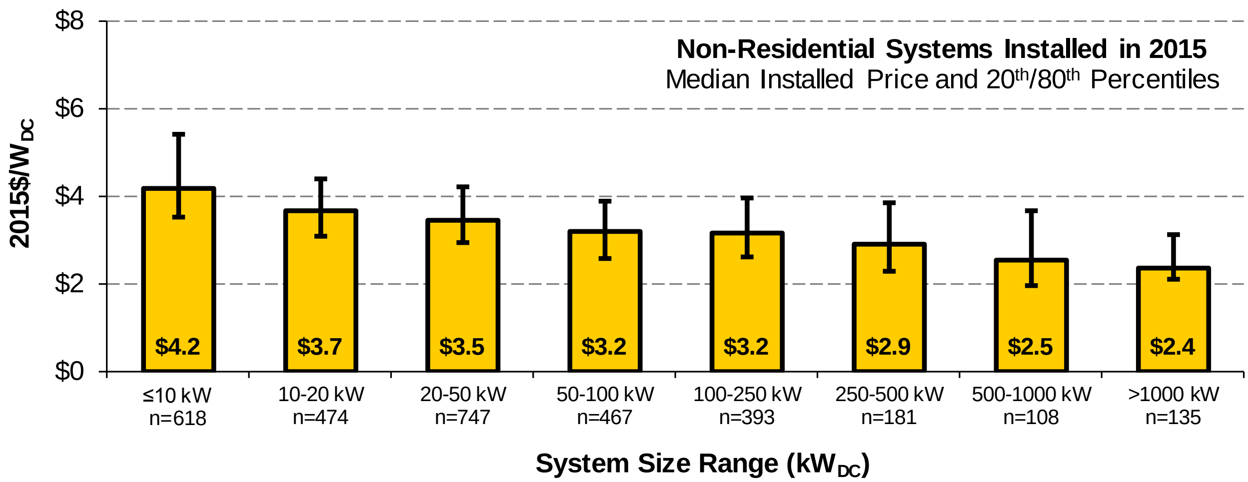


Figure 17. Installed Price of 2015 Non-Residential Systems by Size

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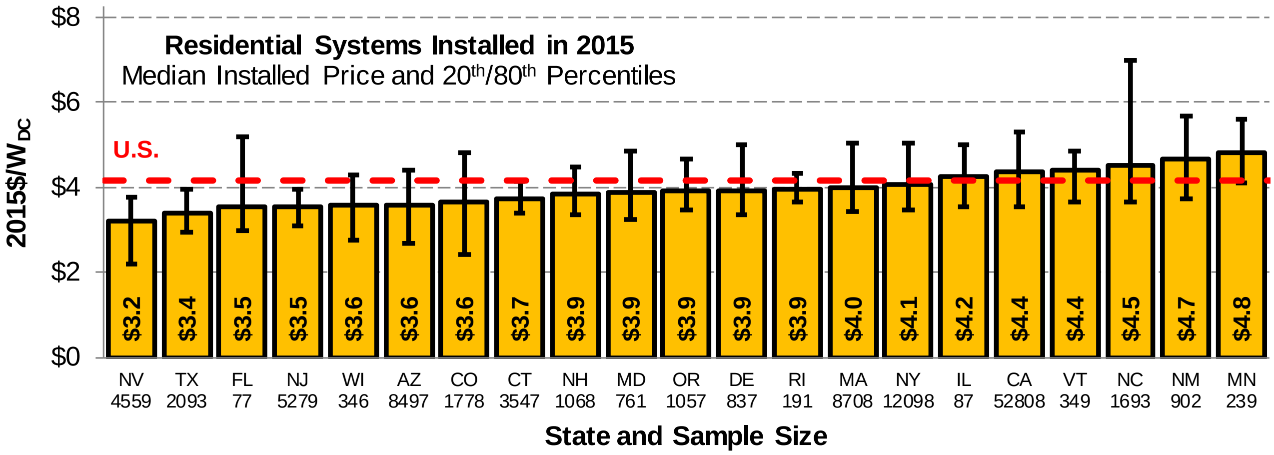
[14] Economies of scale for non-residential systems appear to become much more pronounced at system sizes beyond 500 kW. Although that may partially be true, the effect is exaggerated in the graphic due to the irregular size groupings (with much wider size bins required for large non-residential systems in order to capture a sufficient sample size).

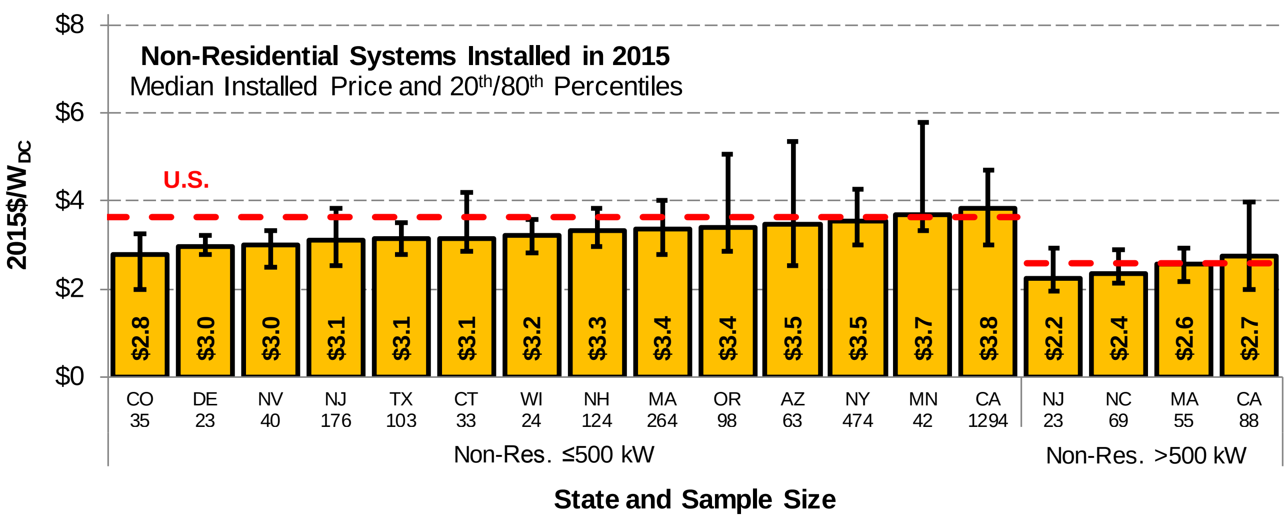
Installed Price Differences across States

The U.S. PV market is fragmented into regional, state, and local markets, each with potentially unique pricing dynamics. Figure 18 and Figure 19 focus, in particular, on state-level differences for systems installed in 2015 (see Table B-4 in the Appendix for time series data by state). Although the specific prices shown for some individual states should be interpreted with caution – either because of small sample sizes or because of potentially irregular reporting by particular installers – the figures nevertheless serve to illustrate the significant variability in pricing both across and within states.



Notes: Median installed prices are shown only if 20 or more observations were available for a given state.

Figure 18. Installed Price of 2015 Residential PV Systems by State



Notes: Median installed prices are shown only if 20 or more observations were available for a given state.

Figure 19. Installed Price of 2015 Non-Residential PV Systems by State

Among residential systems installed in 2015, median installed prices range from a low of \$3.2/W in Nevada to a high of \$4.8/W in Minnesota. Pricing for non-residential systems ≤500 kW similarly varies across a wide range, from \$2.8/W in Colorado to \$3.8/W in California. For both of these customer segments, three of the largest state markets – California, Massachusetts, and New York –

are relatively high-priced, which naturally tends to pull overall U.S. median prices upward (also shown in the figures). Pricing in most states, however, is below – in some states, far below – the aggregate national median. For larger non-residential systems >500 kW in size, the cross-state comparisons are somewhat less telling, given the limited set of states for which sufficient data are available. Nevertheless, even among this small set, median installed prices range from $2.2/W in New Jersey to $2.7/W in California.

The potential reasons for cross-state pricing differences are numerous, many of which have been explored through the research highlighted in Text Box 4. All else being equal, one would expect larger or more mature state markets to have lower prices, as a result of greater competition and experience among installers. Clearly, though, other countervailing factors can predominate, given the trends noted above. For example, higher incentives and/or higher electricity rates – often a key driver behind large state markets – may lead to higher pricing. This could reflect value-based pricing, though it may also simply be the result of the fact that rich incentives increase demand for solar, and higher demand for solar (as for any product) leads to higher prices in the short-run. Installed prices may also vary across states as a result of differences in labor costs, permitting and administrative processes, or sales tax. For example, differing sales tax rates and the fact that roughly half of the states shown in the figures exempt PV systems from state sales tax can lead to installed price differences of as much as $0.3/W between states with relatively high sales tax and those that exempt PV systems from sales tax or have no state sales taxes.[15]

State-level price variation can also arise from differences in the characteristics of systems installed in each state, such as typical system size and configuration, the prevalence of TPO, as well as differences in the composition of the PV customer base and installer base. For example, a high percentage of residential systems in California have premium-efficiency modules (26%, compared to 12% in other states). Also in California, a relatively large fraction of non-residential systems is at government, school, or non-profit facilities (24%, compared to 13% in other states), which also tend to have higher installed prices than systems at for-profit commercial facilities.

Notwithstanding the significant cross-state differences, substantial pricing variation also clearly exists *within* each state, and for many states is at least as wide as the cross-state differences. Such intra-state pricing variability likely reflects many of the same factors that contribute to pricing variability across states. For example, the particularly wide distribution among residential systems in North Carolina may be partially attributable to the abnormally large share of small systems (roughly 50% were smaller than 3 kW). Some pricing drivers, such as differences in permitting processes or installer experience, may manifest at more localized geographical scales than the individual state, contributing to intra-state pricing variability. Lastly, some pricing variability within individual states may also reflect anomalous price reporting by individual installers in a state, especially in relatively small markets where the width of the pricing distribution can be heavily impacted by a single installer.

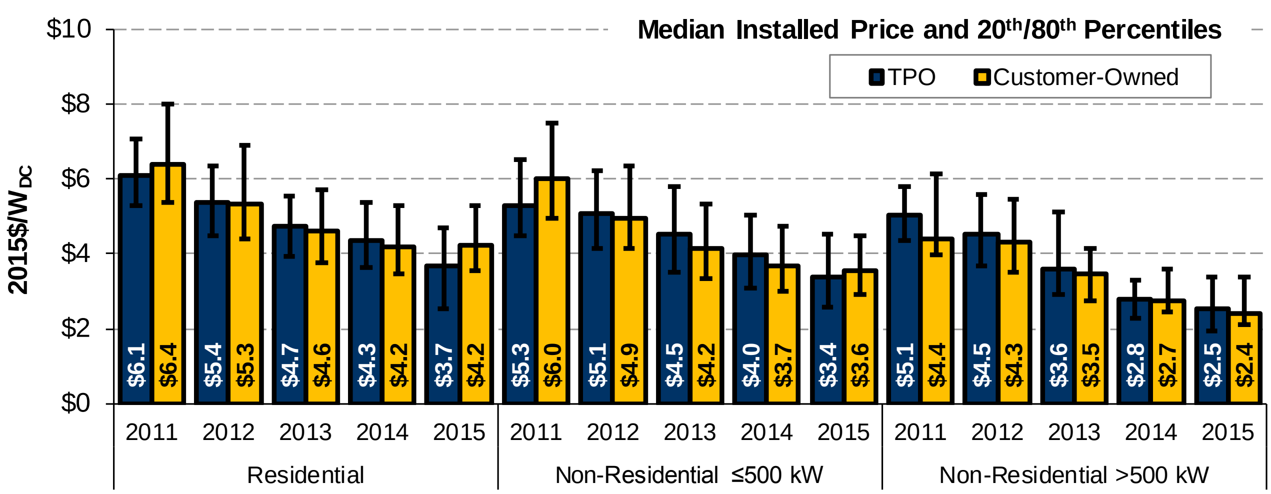
Installed Price Differences between Customer-Owned and TPO Systems

As described previously in Text Box 2, systems financed and installed by integrated TPO providers are excluded from the analysis, while those financed by non-integrated TPO providers are

[15] Most, if not all, residential and non-residential PV systems are exempt from state sales tax in AZ, CO, CT, DE, FL, MA, MD, MN, NJ, NM, NY, RI, VT, WA, and WI (DSIRE 2015). Two other states, TN and UT, also have sales tax exemptions, though they apply only to limited categories of PV systems.

retained.[16] Installed prices reported for retained TPO systems represent the price paid to the installation contractor by the customer finance provider. In principle, these prices might be either lower or higher than for similar customer-owned systems. For example, installers selling systems to TPO providers may face incremental transaction costs or a more-complicated customer sales process, which could elevate reported system prices. On the other hand, for some TPO projects, the customer acquisition and project development functions may be performed by entities other than the installer, in which case the reported price might reflect just hardware and direct installation labor costs. One might also anticipate that TPO finance providers have significant negotiating power with installation contractors, or have a preference towards relatively standardized system designs, also tending to push pricing lower compared to customer-owned systems.

At an aggregate national level, differences in installed prices between non-integrated TPO and customer-owned systems have generally been small, though the direction and magnitude of that differential has varied over time. As shown in Figure 20, installed prices for TPO systems in the residential sector were $0.5/W lower than for customer-owned systems, inverting the relationship observed in previous years, when customer-owned systems were lower-priced. A similar trend is also seen within the sub-500 kW non-residential class. In both segments, median pricing for customer-owned systems remained relatively flat from 2014 to 2015, while prices for TPO systems continued to fall. One potential explanation for this trend, as noted previously, is the growing prevalence of unsecured solar loans with origination fees, which may be dampening price declines for customer-owned systems. In contrast to the other two customer segments, prices for TPO systems among the larger class of >500 kW non-residential systems remained slightly higher than for customer-owned systems (by roughly $0.1/W), similar to the differential in previous years.



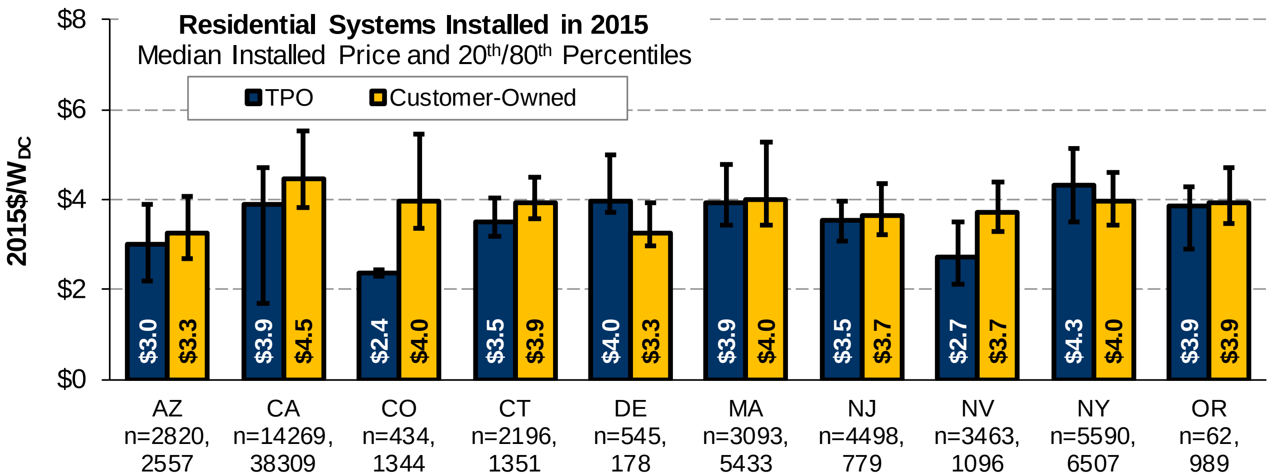
Notes: The values shown here for TPO systems are based on systems financed by non-integrated TPO providers, for which installed price data represent the sale price between the installation contractor and customer finance provider.

Figure 20. Installed Prices Reported for Customer-Owned vs. TPO Systems over Time

Comparing TPO and customer-owned system pricing at the state-level presents a somewhat scattered picture, as shown in Figure 21, which focuses on residential systems installed in ten states in 2015. In most states, TPO systems were lower-priced than customer-owned systems (sometimes

[16] For reference, installed prices reported by integrated TPO providers, which are otherwise excluded from figures in this report, are summarized in Appendix A and compared to installed prices reported for non-integrated TPO systems.

considerably so, such as in Colorado and Nevada). In several other states, however, TPO systems were higher-priced. In general, installed prices for TPO systems vary to a much greater degree across states than do prices for customer-owned systems. This may reflect differences in TPO business models across states – e.g., a greater prevalence of installation-only transactions in certain markets – though may also be symptomatic of small sample sizes and potentially idiosyncratic pricing behavior of individual installers in particular states. Whatever the cause, though, these results do suggest that differences in TPO penetration rates and pricing may contribute significantly to the broader cross-state pricing differences discussed previously.



Notes: The values shown here for TPO systems are based on systems financed by non-integrated TPO providers, for which installed price data represent the sale price between the installation contractor and customer finance provider.

Figure 21. Installed Prices Reported for Customer-Owned vs. TPO Residential Systems by State

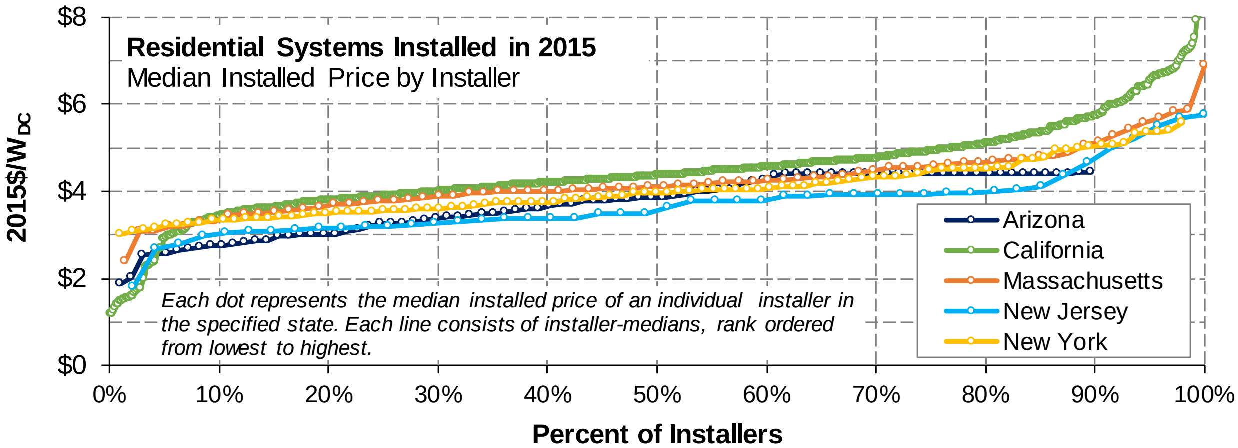
Installed Price Differences across Installers

The U.S. PV market is serviced by a large number of installers of varying size, experience, and business models. Although the residential market, in particular, has become increasingly dominated by several large national companies, a great many smaller regional players and "mom-and-pop" shops continue to operate throughout the country. The data sample assembled for this report includes more than 3,000 companies that installed PV systems in 2015, most of which were active only in the residential sector.[17] Because of the removal of integrated TPO systems, the sample is considerably less concentrated than the broader market. For example, among the 2015 residential systems in the final analysis sample, the highest installer-share is 7%, and the top-5 installers comprise 16% of systems. In comparison, the highest installer-share and top-5 installers comprise 33% and 48%, respectively, within the full data sample, which is more reflective of the U.S. residential market as a whole.

In order to illustrate how installed pricing may vary across installers, Figure 22 shows median prices for individual installers in the five largest state markets, focusing on residential systems installed in 2015. In each of these five states, installer-level median prices differ by anywhere from

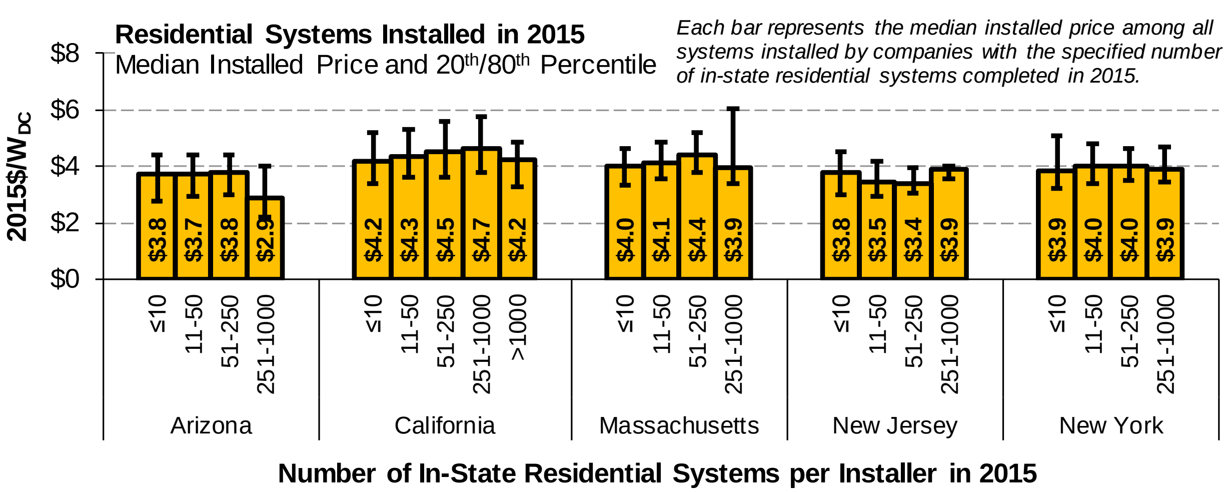
[17] The spelling of installer names often varies within the raw data received from program administrators. As part of the data cleaning, we standardize these spellings, though this process is undoubtedly imperfect and thus the actual number of unique installers within the data sample may be somewhat lower than the number cited here.

$0.8/W to $1.2/W between the upper and lower 20th percentiles of installers, demonstrating substantial heterogeneity in pricing across installers. Related, the figure serves to highlight "low-price leaders" that provide a benchmark for what may be achievable in terms of near-term installed price reductions within the broader market. In New Jersey, for example, 20% of installers have median prices below $3.1/W – compared to the median price of $3.5/W across all 2015 residential systems in the state and $4.1/W nationally. At the other end of the spectrum, of course, are the high-priced installers. In some cases, these may be companies that specialize in "premium" systems of some form, or that include in their reported prices additional items beyond what might be typically counted as part of the PV system.



Notes: Each line includes only installers that completed at least 10 residential systems in the given state in 2015.

Figure 22. Median Installed Prices by Installer for Residential Systems in 2015



Notes: Each bin includes at least 3 installers and, with the exception of the ≤10 systems bin, at least 10% of all residential systems in the sample installed in-state in 2015. Installer volumes are calculated from the full data sample, and therefore include integrated TPO systems and other excluded systems that are not used for the purpose of calculating installed price statistics.

Figure 23. Installed Prices According to Installer Volume by State

One might also anticipate that installer-level pricing varies according to the size of the company, and in particular, that larger installers may be able to offer lower pricing due to economies of scale and greater efficiency within their business operations arising through their accumulated experience. The data, however, do not necessarily bear this out. Figure 23 presents installed prices for residential systems installed in 2015, segmented according to the number of systems that the corresponding installer completed in 2015 within each of the states shown. With the exception of Arizona, where the largest installers do appear to offer notably lower pricing, no discernible or readily interpretable relationship emerges between installer volume and pricing in the other states.

It is conceivable, of course, that scale advantages do exist but are simply washed out by the greater variability in the dataset, or that they materialize over geographical scales other than the state-level (either more locally or within broader regions). It is also possible that the scale advantages of high-volume installers are offset by other competing dynamics. For example, large installers may have relatively high customer acquisition costs and other business operation costs associated with aggressive growth. It is also conceivable that high-volume installers (or, for that matter, smaller installers with a dominant presence in particular locations) may enjoy a certain degree of market power, permitting higher pricing. These competing hypotheses have, to varying degrees, been substantiated in Gillingham et al. (2014) and are a subject of continuing investigation by LBNL and its collaborators in the study series referenced in Text Box 4.

Installed Price Differences between Residential New Construction and Retrofits

Residential solar markets in some states include a sizeable contingent of systems installed in new construction. Within the data sample assembled for this report, identification of new construction systems is most complete for California, where roughly 5% of all residential systems installed in 2015 were new construction.[18] As such, the following analysis focuses specifically on California, though the results may apply elsewhere as well.

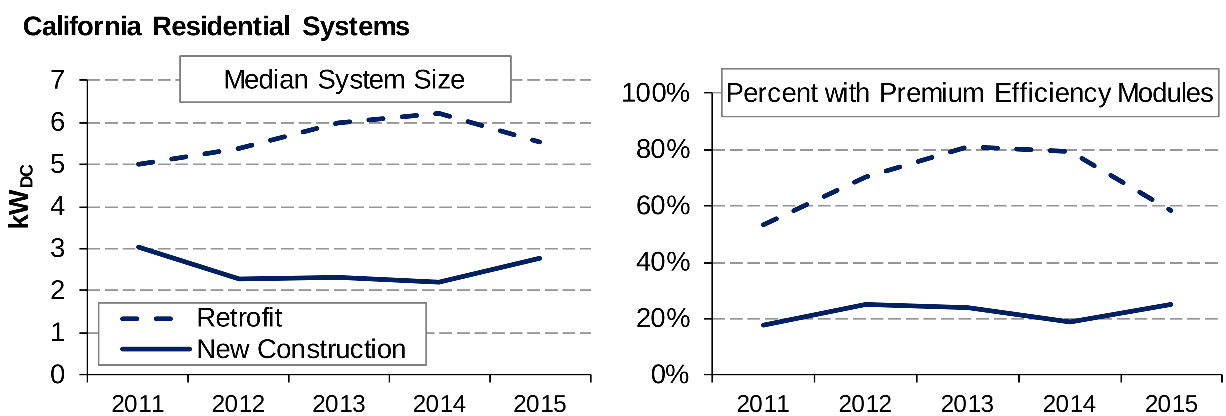


Figure 24. Key Characteristics of Residential Retrofit vs. New Construction in California

Residential systems installed in new construction differ from retrofit systems in several important ways relevant to any comparison of installed prices. First, new construction systems tend to be quite small. This is shown in the left-hand panel of Figure 24, which compares median system sizes for residential retrofit and new construction systems in California. Among systems installed in 2015, residential new construction systems had a median size of just 2.8 kW, compared to 5.5 kW for retrofits. Second, new construction systems have a much higher incidence of premium efficiency (>18%) modules and, in earlier years, building integrated PV (BIPV). This is shown in the right-

[18] Data from most other states did identify residential systems as either retrofit or new construction. California is somewhat unique in that it has a long-standing incentive program aimed specifically at residential new construction.

hand panel of the figure, where 60% of new construction systems in 2015 had premium-efficiency modules, compared to 25% for retrofit systems in California. These two differences – smaller systems and higher incidence of premium efficiency modules – would generally be expected to boost the installed price-per-watt of new construction systems relative to retrofits.

Aside from those technical differences are several other inherent features of new construction systems that may have implications for their installed price. First and foremost, perhaps, is that most new construction systems (in California, at least) are installed in new housing developments with multiple solar homes, and may therefore benefit from scale economies and bulk purchasing that reduce unit costs. New construction systems may also benefit from economies of scope, where certain labor or materials costs can be shared between PV installations and other elements of home construction. Conversely, some installers have reported more complex scheduling and logistics for new construction that might conceivably boost costs. Clearly, there are a variety of countervailing factors that could steer installed prices for new construction either higher or lower relative to systems on existing homes.

To reveal how these competing dynamics play out, Figure 25 compares the installed price of PV systems in residential retrofit and new construction in California. The left-hand half of the figure compares the two classes of systems, irrespective of key differences in their technical characteristics. As shown, new construction systems have consistently been lower-priced than retrofit systems, with a differential of roughly \$0.5/W in 2015, *despite* the smaller size and higher incidence of premium efficiency modules among new construction systems.[19]

In order to better control for the differing technical characteristics between new construction and retrofit systems, the right-hand side of Figure 25 focuses solely on 1-4 kW, rack-mounted (i.e., non-BIPV) systems with premium efficiency modules. Not surprisingly, the cost advantages of new construction appear even greater in this comparison. Among systems installed in 2015, for example, the median price of systems installed in new construction was \$0.8/W below similarly sized and configured residential retrofit systems. These trends therefore suggest that the economies of scope and scale with large developments of new solar homes may indeed offer quite substantial savings on PV system pricing.

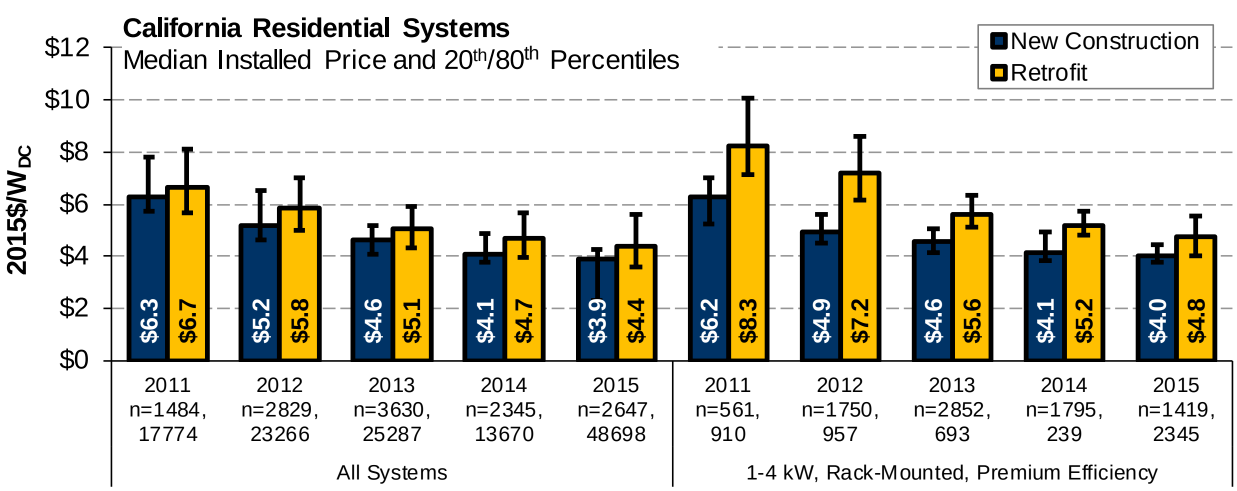


Figure 25. Installed Price of Residential Retrofit vs. New Construction in California

[19] To the extent that California's market includes a larger share of new construction systems than elsewhere, this suggests that the state might appear even higher-priced relative to others, were it not for the large number of new construction systems.

Notwithstanding the consistency of the trends exhibited in Figure 25, some degree of caution is warranted, given potential complications or ambiguities in how installed price data may be reported for new construction systems. For example, to the extent that certain costs are shared between the PV installation and other aspects of home construction (e.g., roofing and electrical work), there may be some discretion on the part of those reporting data in terms of how those costs are allocated to the PV system. It is also common practice for identical installed prices to be reported for all PV systems within an individual development, consistent with the manner in which those systems are procured by the housing developer, which partly explains the greater uniformity of pricing observed among new construction systems.

Installed Price Differences between Tax-Exempt and For-Profit Commercial Sites

The non-residential solar sector is highly diverse in terms of the composition of the underlying customer base, including not only for-profit commercial entities, but also a sizeable contingent of systems installed at schools, government buildings, religious organizations, and non-profit organizations. That latter set we collectively refer to as "tax-exempt" site hosts. In 2015, systems at tax-exempt customer sites comprised 18% of sub-500 kW non-residential systems and 26% of non-residential systems >500 kW, based on the sub-set of the sample for which data on type of site host could be obtained.

Installed prices for systems at tax-exempt customer sites are consistently higher than at for-profit commercial facilities. This is evident in Figure 26, which compares installed prices for these two sub-sectors over time. In 2015, systems at tax-exempt customer sites were roughly $0.3/W higher-priced within the sub-500 kW non-residential segment, and $1.1/W higher among >500 kW non-residential systems. Similar or larger price differentials also exist in prior years.

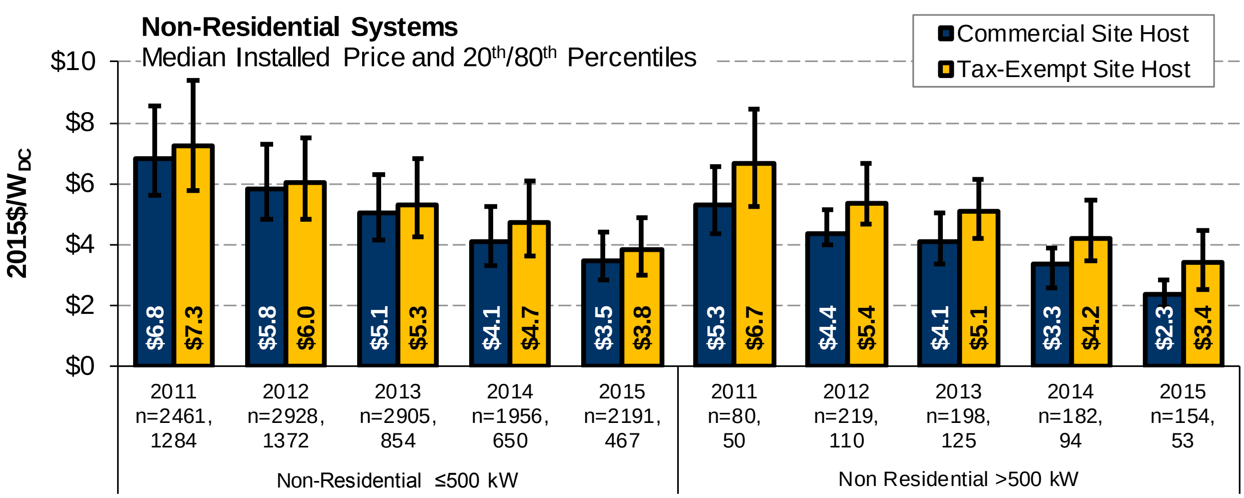
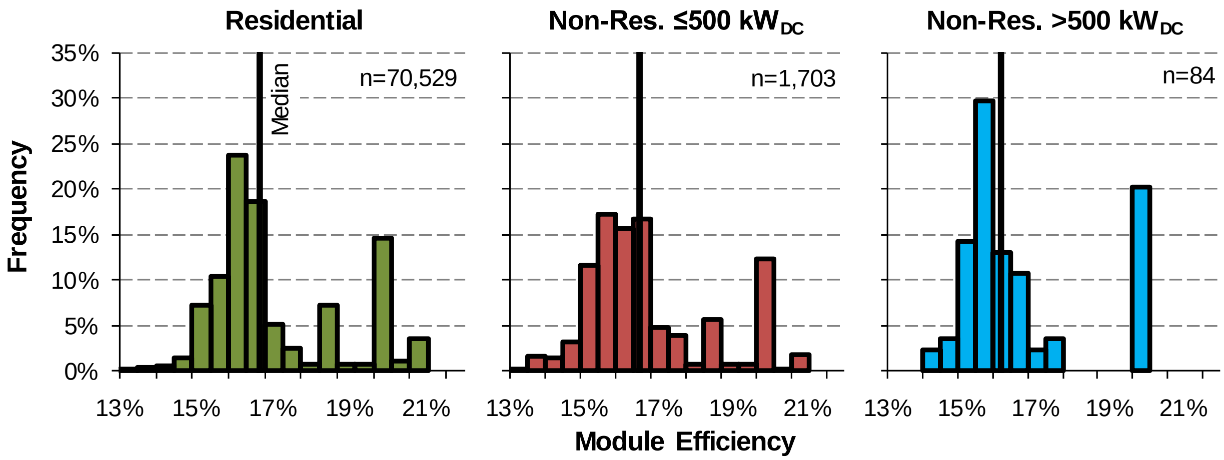


Figure 26. Installed Price Variation across Host Customer Sectors

These trends potentially reflect a number of underlying sources of higher costs or prices at tax-exempt customer sites, including prevailing wage/union labor requirements, preferences for domestically manufactured components, a high incidence of shade and parking structure PV arrays, additional permitting requirements, more complex government procurement processes, and different incentives. Tax-exempt customers may also have less negotiating power than their for-profit commercial counterparts. Systems at tax exempt sites are also generally smaller, even within the two size groupings used in the figure: within the >500 kW class, for example, the median system size was roughly 800 kW for systems installed at tax-exempt sites in 2015, compared to almost 2,000 kW at for-profit commercial sites. And finally, systems at tax-exempt customer sites are also disproportionately located in relatively high-priced states – specifically, over 60% of 2015 systems are in California, compared to roughly 45% of systems at for-profit commercial sites.[20]

Installed Price Differences by Module Efficiency

The conversion efficiency of commercially available PV modules varies considerably, from less than 13% for amorphous silicon and certain other types of thin-film modules to 20% or more for high-performance mono-crystalline silicon modules. Within the data sample for this report, the distributions of module efficiencies have several distinct "modes" or peaks (see Figure 27, which focuses on systems installed in 2015). The majority of systems within each customer segment have module efficiencies between 15.5% and 17.0%, characteristic of current poly-crystalline silicon module technology, though many mono-crystalline modules also have efficiency levels within that range. Localized peaks at higher efficiency levels consist of premium efficiency, mono-crystalline modules offered by several manufacturers. Systems with premium efficiency modules (>18%) constitute a relatively sizeable share (roughly 30%) of the residential sample in 2015, and somewhat smaller percentages of non-residential systems.



Notes: Module efficiencies were identified or estimated for systems in the 2015 sample for which data on module manufacturer and model were available.

Figure 27. Module Efficiency Distributions for Systems Installed in 2015

Module efficiency impacts the installed price of PV systems in countervailing ways. On the one hand, increased module efficiency reduces area-related balance-of-systems (BOS) costs. Cost modeling by Fu et al. (2016) estimate that, for example, an increase in module efficiency from 16% to 17% would reduce residential system costs by roughly $0.05/W. On the other hand, high-efficiency modules may be considerably more expensive than standard efficiency modules. Recent spot market prices for high-efficiency n-type monocrystalline PV modules are roughly $0.35/W

[20] Alternatively, one might reason that installed prices are higher in California because of the prevalence of tax-exempt systems. Both are true; however, the fact that installed prices for residential and commercial systems in California are also relatively high suggests that other causes are also at play, beyond the high incidence of PV systems at tax-exempt customer sites.

higher than for standard polycrystalline modules, and the differential may be considerably greater for some manufacturers of premium efficiency modules (PVInsights 2016).

To examine the net effect of these various and opposing cost drivers, Figure 28 compares installed prices according to module efficiency, focusing only on residential and sub-500 kW non-residential systems, and distinguishing between systems with module efficiencies less than 18% and those with module efficiencies greater than 18%. As shown, systems with high-efficiency modules have been consistently higher-priced than those with lower- or mid-range module efficiencies. In 2015, the median differential was roughly $0.6/W within the residential segment and $0.5/W among small non-residential systems, and was of generally similar magnitude in prior years.

Among other things, the trends exhibited in Figure 28 suggest that the price premium for high-efficiency modules has generally outweighed any corresponding reduction in BOS costs. To be clear, that implication applies to the specific mix of modules and systems represented within the data sample, and does not necessarily extend generically to a comparison between systems with poly- and mono-crystalline modules. Indeed, the installed price premium for systems with high-efficiency modules is substantially larger than the global ASP premium for mono-crystalline over poly-crystalline modules, implying that high-efficiency systems in the data sample may have even-higher priced modules, or may differ in others ways (e.g., greater prevalence of tracking systems or more complex, space-constrained installations) compared to the lower-efficiency PV systems in the data sample.

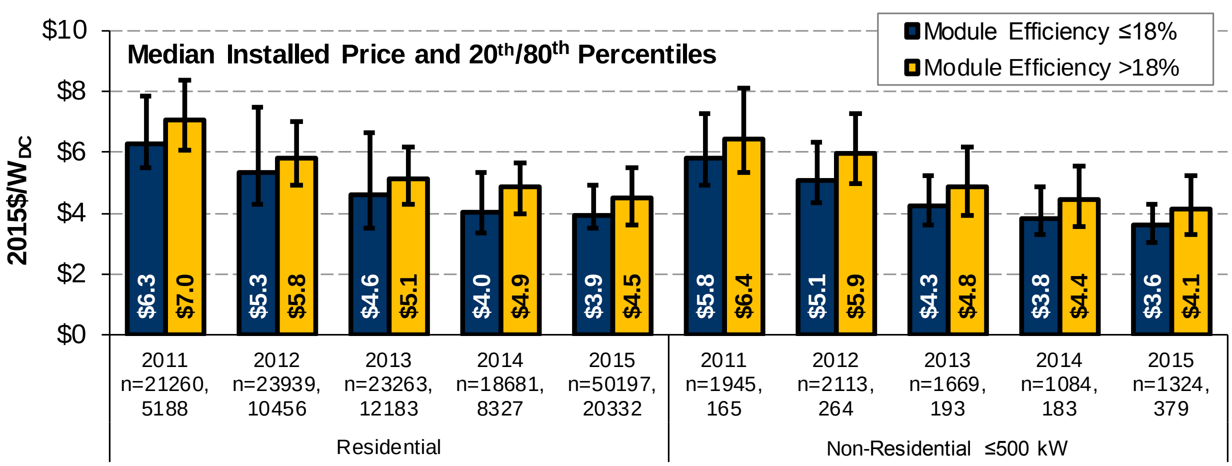


Figure 28. Installed Price Differences Based on Module Efficiency

Installed Price Differences for Systems with and without Module-Level Power Electronics

Module-level power electronics (MLPEs), including both microinverters and DC power optimizers, have become increasingly prevalent within the data sample, reflecting their growth in market share more broadly (see Figure 29). That growth has been most pronounced within the residential sector (54% of the 2015 sample), though has also been significant among sub-500 kW non-residential systems (30% of the 2015 sample). Penetration among larger non-residential systems, by comparison, has remained negligible.

Increased adoption of MLPEs has been driven by their performance advantages, though those performance gains come at some incremental up-front cost.[21] For example, microinverters cost roughly $0.26/W more than standard residential inverters and $0.31/W more than standard commercial inverters, on average, in 2015 (GTM Research and SEIA 2016). All else being equal, this would tend to increase installed prices for systems with microinverters, and dampen installed price reductions over time with the rising penetration of microinverters. However, aside from their direct impact on inverter costs, microinverters may have indirect impacts on other non-inverter balance of system (BOS) and soft costs, for example on installation labor, system design, and electrical costs. These indirect cost impacts might go in either direction, either offsetting or compounding the incremental up-front cost.

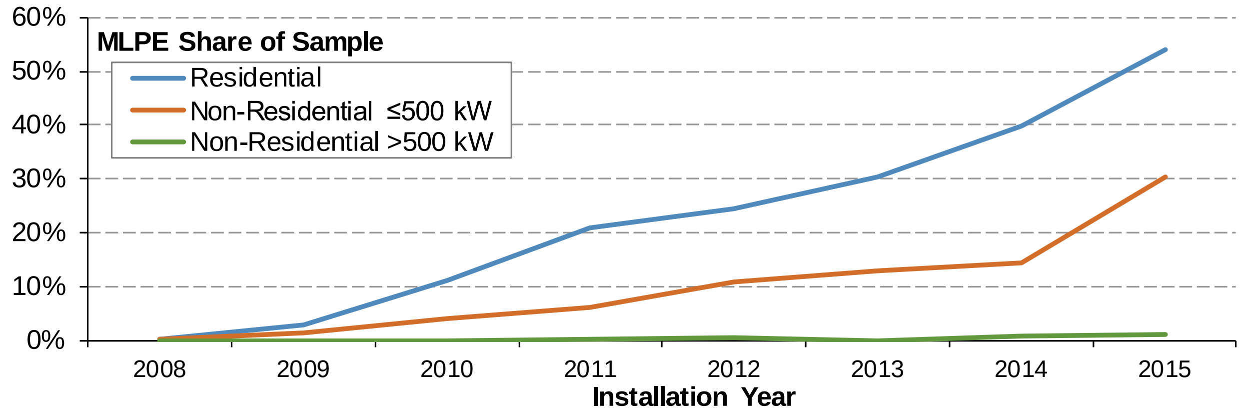


Figure 29. Penetration of Module-Level Power Electronics within the Final Analysis Sample

Ultimately, the levelized cost of electricity (LCOE) is the most meaningful metric for comparing the cost of systems with and without MLPEs; however, the up-front installed price is one key driver for that broader cost comparison. In order to discern how the impact on up-front installed prices, Figure 30 compares reported installed prices for systems with and without MLPEs. The figure focuses on residential and sub-500 kW non-residential systems. As shown, installed price differences have varied in both magnitude and direction over time, but have generally been quite small. Among residential systems with MLPEs, median installed prices have been slightly lower over the past several years (by $0.1/W) than for systems without MLPEs. However, the opposite is true for sub-500 kW non-residential systems, where systems with MLPEs have consistently been priced at a slight premium (by $0.2/W in 2015) compared to those without MLPEs.

Ultimately, these small differences in median prices are well within the noise of the overall pricing variation within the sample. However, the fact that any differences are consistently smaller than the component price premium for microinverters or DC power optimizers loosely suggests that these devices may offer some offsetting savings on non-inverter BOS costs or soft costs. This conclusion might be further justified by considering that installers may tend to choose MLPEs for more-complex installations (e.g., systems on multiple roof planes) or for small systems where space

[21] Deline et al. (2012) estimate 4-12% greater annual energy production from systems with microinverters. Such performance gains are associated primarily with the ability to control the operation of each panel independently, thereby eliminating losses that would otherwise occur on panels in a string when the output of a subset of panels is compromised (e.g., due to shading or orientation) or when mismatch exists among modules in the string.

constraints are binding. To the extent that this is the case, MLPEs might provide greater savings on non-inverter BOS and soft costs than suggested by Figure 30.

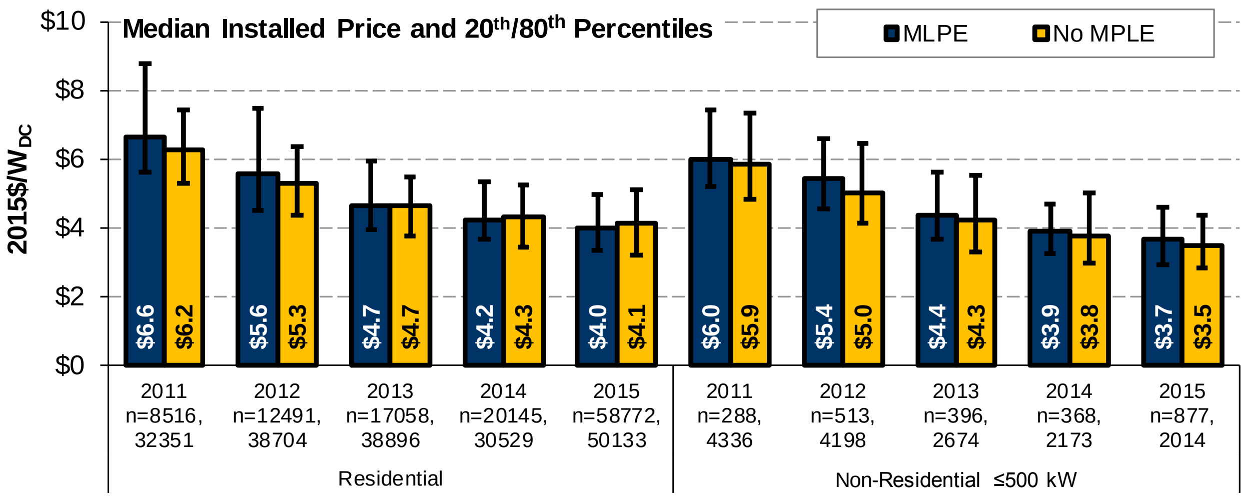
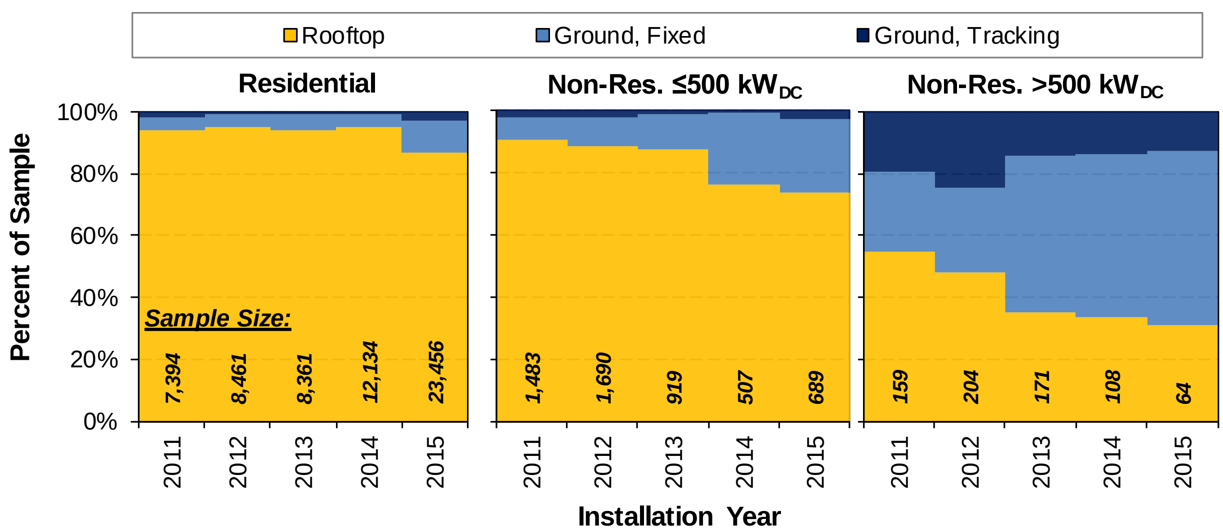


Figure 30. Installed Price Differences between Systems with and without Module-Level Power Electronics

Installed Price Differences by Mounting Configuration

Unlike residential systems, which are almost entirely roof-mounted, many non-residential systems are ground-mounted, and in the case of larger non-residential systems often include tracking equipment as well. This can be seen in Figure 31, which draws from the relatively limited set of systems in the sample for which data on mounting configuration are available. Among systems in this limited data sample installed in 2015, 26% of small non-residential systems and 68% of large non-residential systems were ground-mounted, and 13% of large non-residential systems had tracking (primarily single-axis). Many of what are referred to within this report as large non-residential systems might thus be classified elsewhere as small utility-scale systems.

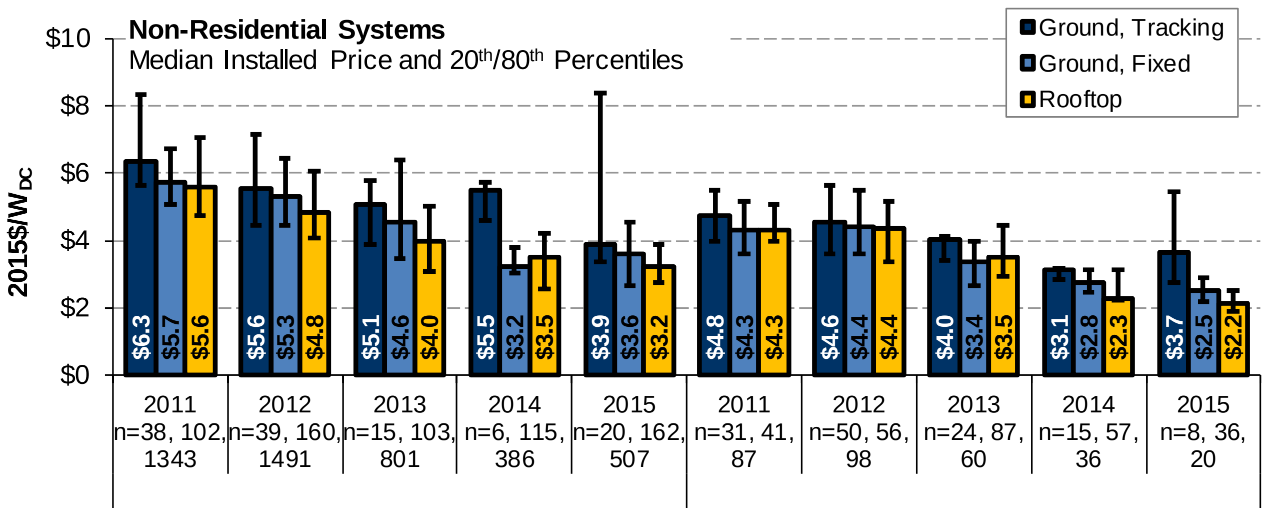


Notes: The figure is derived from the relatively small subsample of systems for which data were available indicating both whether the system is roof- or ground-mounted and whether or not it has tracking.

Figure 31. Mounting Configuration among Systems in the Data Sample

Not surprisingly, these differences in mounting configuration can impact installed prices, as shown in Figure 32. As one would expect, installed prices are consistently higher for systems with tracking than for those with fixed tilt. The differentials in median prices are relatively volatile from year-to-year, given the small underlying sample sizes. In 2015, for example, large non-residential systems with tracking had a median installed price $1.1/W greater than for fixed-tilt, ground-mounted systems, which is substantially greater than in previous years. Over the five-year period shown (2011-2015), the differential in median installed prices between systems with and without tracking averaged roughly $0.6/W (18%) for large non-residential systems and $0.8/W (21%) for smaller non-residential systems. This corresponds well to earlier cost modeling by Goodrich et al. (2012), which estimated a $0.6/W premium for tracking equipment in utility-scale applications. In contrast, more recent cost modeling by Fu et al. (2016) and by GTM Research and SEIA (2016), as well as empirical data from Bolinger and Seel (2016), suggests a much smaller incremental cost of roughly $0.1/W to $0.2/W for tracking equipment—also in utility-scale systems applications.

It is also important to stress that the purpose of tracking equipment is to increase electricity production; Drury et al. (2013) estimate that systems with single-axis tracking generate 12% to 25% more electricity than fixed-tilt systems. The relevant metric of comparison between systems with and without tracking is therefore the levelized cost of electricity (LCOE). The fact that the performance gain associated with tracking equipment is similar in magnitude to the average difference in median installed price over time illustrates (loosely) how the additional up-front cost of tracking equipment can be offset by performance gains.



Notes: The figure is derived from the relatively small subsample of systems for which data were available indicating both whether the system is roof- or ground-mounted and whether or not it has tracking.

Figure 32. Installed Price of Non-Residential Systems by Mounting Configuration over Time

5. Conclusions

The number of PV systems installed in the United States has grown at a rapid pace in recent years, driven in large measure by government incentives. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage cost reductions over time through increased deployment. Key research and development efforts to drive cost reductions have also been led by the U.S. DOE’s SunShot Initiative, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020.

Available evidence confirms that the installed price of PV systems (i.e., the up-front cost borne by the PV system owner, prior to any incentives) has declined substantially since 1998, though both the pace and source of those cost reductions have varied over time. Following a period of relatively steady and sizeable declines, installed price reductions began to stall around 2005, as the supply-chain and delivery infrastructure struggled to keep pace with rapidly expanding global demand. Beginning in 2008, however, global module prices began a steep downward trajectory, and those module price reductions were the driving force behind the decline in total system prices for PV from 2008 through 2012. Since 2012, however, module prices have remained relatively flat, yet installed prices have continued to fall as a result of a steady decline in non-module costs. Given the limits to further reductions in module prices, continued reductions in non-module costs will be essential to driving further deep reductions in installed prices.

Unlike module prices, which are primarily established through global markets, non-module costs consist of a variety of soft costs that may be more readily affected by local policies – including deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more-targeted efforts, such as training and education programs. The heightened focus on cost reductions within the solar industry and among policymakers, and recognition of the importance of soft costs for achieving further price reductions, has spurred a flurry of initiatives and activity in recent years, aimed at driving reductions in solar soft costs. The continued decline in installed prices, despite level or slightly rising module prices, suggests that these efforts have begun to bear fruit.

Nevertheless, lower installed prices in other major international markets, as well as the wide diversity of observed prices within the United States, suggest that broader soft cost reductions are possible. Although such cost reductions may accompany increased market scale, it is also evident that market size alone is insufficient to fully capture potential near-term cost reductions – as suggested by the fact that many of the U.S. states with the lowest installed prices are relatively small PV markets. Achieving deep reductions in soft cost thus likely requires a broad mix of strategies, including: incentive policy designs that provide a stable and straightforward value proposition to foster efficiency and competition within the delivery infrastructure, targeted policies aimed at specific soft costs (for example, permitting and interconnection), and basic and applied research and development.

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Appendix A: Data Cleaning, Coding, and Standardization

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

Conversion to 2015 Real Dollars: Installed price and incentive data are expressed throughout this report in real 2015 dollars (2015$). Data provided by PV program administrators in nominal dollars were converted to 2015$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.

Conversion of Capacity Data to Direct Current (DC) Watts at Standard Test Conditions (DC-STC): Throughout this report, all capacity and dollars-per-watt ($/W) data are expressed using DC-STC capacity ratings. Most PV incentive programs directly provided data in units of DC-STC; however, several provided capacity data only in terms of the California Energy Commission Alternating Current (CEC-AC) rating convention, which represents peak AC power output at PVUSA Test Conditions (PTC). DC-STC capacity ratings in these cases were calculated based on information provided about the module model (from which DC ratings could be obtained from manufacturer spec sheets) and module quantity. If this approach was not feasible for any reason, DC capacity was estimated based on an assumed conversion between $W_{DC\text{-}STC}$ and $W_{CEC\text{-}AC}$, derived from other similar systems.

Identification and Treatment of Duplicate Systems: For a number of states (California, Florida, Massachusetts, and Oregon), data provided by multiple different entities contain overlapping sets of systems. In order to avoid double-counting, duplicate observations were merged or eliminated. These duplicate observations were identified using, wherever possible, a common ID number across datasets or customer street address. In cases where neither of those pieces of information are available, more-aggressive measures were taken to avoid double counting. Within the California Public Utilities Commission's Currently Interconnected Dataset, all systems installed prior to 2013 were excluded, on the grounds that the vast majority were likely already contained within one or another of the PV incentive program datasets (which contain greater level of technical detail on individual systems). Within the Oregon Department of Energy dataset, systems were excluded if located within an investor-owned utility service territory, on the grounds that the vast majority of such systems likely would have participated in the Energy Trust of Oregon's incentive program and would be included in that program's data file.

Incorporation of Data on Module and Inverter Characteristics. The raw data provided by PV incentive program administrators generally included module and inverter manufacturer and model names. We cross-referenced that information against public databases of PV component specification data (namely, the CSI eligible equipment lists[22] and SolarHub[23]) to characterize the module technology efficiency, module technology (e.g., mono-crystalline vs. poly-crystalline, building-integrated PV vs. rack-mounted systems), and inverter technology (microinverter, DC power optimizer, or standard string/central inverter).

Identification of Customer Segment: Almost all programs provided some explicit segmentation of host customers, at least into residential and non-residential customers. In the rare cases where even this minimal level of segmentation was not provided, systems less than or equal to 20 kW in size were assumed to be residential, and those larger than 20 kW were assumed to be non-residential. The choice of this threshold was based on an inspection of data where customer segmentation was available, and is roughly the value that minimizes the error in these assignments to customer segments.

Identification of Customer-Owned vs. TPO Systems: Most programs explicitly identify the ownership type of each system as either customer-owned or TPO. Where such data were not provided, however,

[22] http://www.gosolarcalifornia.ca.gov/equipment/
[23] http://www.solarhub.com/

inferences were made wherever possible. First, systems were assumed to be customer-owned if: (a) installed in a state where TPO was not allowed at the time of installation, (b) installed in a state where TPO is technically allowed but actual market activity is known to be quite low, or (c) the PV incentive program providing data is not available to TPO systems. Next, any remaining systems with unknown ownership type were assumed to be TPO if installed by companies known to be providers almost exclusively of TPO systems, including: SolarCity, Sungevity, Vivint, SunRun, and Roof Diagnostics & Solar.

Identification and Removal of Integrated TPO Systems: A total of 221,006 integrated TPO systems were removed from the data sample, on the grounds that the installed prices reported for these systems represent appraised values. In the vast majority of cases, integrated TPO systems were identified simply based on the reported installer name and system ownership type. Specifically, all TPO systems installed by these companies were flagged as integrated TPO and removed from the data set: SolarCity, Sungevity, or Vivint.

If information on installer name was not available, appraised-value systems were identified using a "price clustering" approach. The logic for the price clustering approach is founded on the observation that systems installed by integrated TPO providers are typically clustered with an identical price reported for a large group of systems (which may reflect, for example, the average per-kW assessed fair market value of a bundle of systems sold to tax equity investors). The first step in the price clustering analysis was to identify the price clusters among the systems explicitly identified within the dataset as being TPO and installed by an integrated TPO provider. Then, among the set of systems for which data on installer name was unavailable, systems were identified as appraised value if they fell within the largest of those price clusters and were not host customer-owned. In addition, systems within those price clusters that were installed by integrated TPO providers but labeled as customer-owned were assumed to, in fact, be TPO systems and were accordingly re-classified as TPO and flagged as appraised value. This price clustering analysis resulted in 1,194 systems being identified as integrated TPO systems (out of the aforementioned total) and removed from the data sample.

For reference, Figure 33 compares the reported installed prices for these integrated TPO systems to prices for other, non-integrated TPO systems that are retained in the data sample. As shown, through 2011, installed prices reported for integrated TPO systems were dramatically higher than for non-integrated TPO systems. For many integrated TPO systems, the appraised values used as the basis for reported installed prices were an assessed "fair market value", which is often based on a discounted cash flow from the project. Starting in 2012, however, at least one major integrated TPO provider changed its installed price reporting methodology for PV incentive programs. Since then, the disparity between installed prices reported for integrated and non-integrated TPO systems has diminished significantly (though still persists).

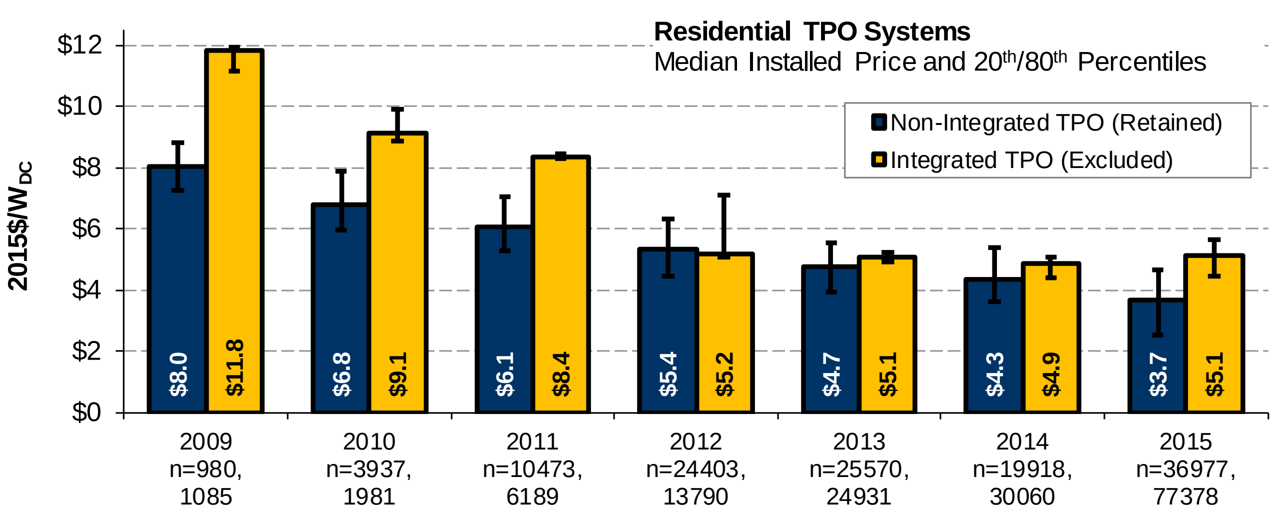

Figure 33. Installed Prices Reported for Non-Integrated and Integrated Residential TPO Systems

Identification of Self-Installed Systems: Self-installed systems were identified in several ways. In some cases, these systems could be identified based on the reported installer name (e.g., if listed as "owner" or "self"). In addition, all systems installed by Grid Alternatives or Habitat for Humanity were treated as self-installed, as these entities rely on volunteer labor for low-income solar installations.

Calculation of Net Present Value of Reported PBI Payments: A number of PV incentive programs in the data sample provided performance-based incentives (PBIs), paid out over time based on actual energy generation and a pre-specified payment rate, to some or all systems. In order to facilitate comparison with up-front rebates provided to the other systems in data sample, the net present value (NPV) of the expected PBI payments were calculated based on an assumed 7% nominal discount rate.

Appendix B: Additional Details on Final Analysis Sample

Table B-1. Sample Summary by Program Administrator

State	Data Provider	Size Range (kW_{DC})	Year Range	2015 Sample		Total Sample	
				No. of Systems	Total MW_{DC}	No. of Systems	Total MW_{DC}
AR	Arkansas Energy Office	0.5 - 25	2010 - 2011	0	0.0	97	0.7
AZ	Ajo Improvement Company	2.1 - 2.1	2012 - 2012	0	0.0	3	0.0
AZ	Arizona Public Service	0.3 - 3,247	2002 - 2015	4,398	40.2	23,004	324.5
AZ	Duncan Valley Electric Coop.	0.5 - 11	2006 - 2009	0	0.0	4	0.0
AZ	Graham County Electric Coop.	0.06 - 25	2005 - 2010	0	0.0	119	0.6
AZ	Mohave Electric Coop.	1.0 - 47	2004 - 2015	93	0.8	449	3.5
AZ	Morenci Water & Electric	5.8 - 20	2010 - 2011	0	0.0	3	0.0
AZ	Navopache Electric Coop.	1.0 - 55	2003 - 2012	0	0.0	130	0.9
AZ	Salt River Project	0.2 - 1,703	2005 - 2015	1,040	13.8	7,583	75.4
AZ	Sulpher Springs Valley Electric Coop.	0.1 - 984	2009 - 2015	85	0.6	1,055	7.7
AZ	Tucson Electric Power	0.4 - 26	2006 - 2015	165	1.1	749	4.7
AZ	Trico Electric Coop.	0.5 - 353	2008 - 2015	2,443	17.5	7,918	58.3
AZ	UniSource Electric Services	0.5 - 98	1999 - 2015	337	3.5	1,538	14.0
CA	Bear Valley Electric	1.8 - 15	2014 - 2015	66	0.4	76	0.4
CA	California Energy Commission (Emerging Renewables Program) [a]	0.07 - 670	1998 - 2008	0	0.0	27,279	144.0
CA	California Energy Commission (New Solar Homes Partnership) [a]	0.08 - 286	1999 - 2015	240	1.3	7,360	31.1
CA	California Public Utilities Commission (California Solar Initiative) [a]	0.7 - 5,946	2007 - 2015	1,953	121.6	118,837	1774.6
CA	California Public Utilities Commission (Non-CSI Net Metered Systems) [a]	0.2 - 1,042	2013 - 2015	47,583	295.5	52,860	310.8
CA	California Public Utilities Commission (Self Generation Incentive Program) [a]	34 - 1,266	2002 - 2009	0	0.0	855	159.9
CA	City of Palo Alto Utilities	0.7 - 881	1999 - 2015	20	0.5	559	5.7
CA	Imperial Irrigation District	0.9 - 1,000	2006 - 2015	236	2.5	651	11.9
CA	Los Angeles Dept. of Water & Power	0.3 - 3,966	1999 - 2015	2,920	22.3	12,680	137.6
CA	Pacific Power (California Solar Initiative)	1.3 - 257	2011 - 2015	16	0.2	151	2.1
CA	California Center for Sustainable Energy (Rebuild a Greener San Diego) [a]	1.9 - 7.1	2004 - 2008	0	0.0	154	0.8
CA	Sacramento Municipal Utility District	0.7 - 2,840	2005 - 2015	1,156	9.8	3,971	49.7
CO	Xcel Energy	0.5 - 1,998	2006 - 2015	1,813	14.9	17,708	162.4
CT	Clean Energy Finance and Investment Authority	0.5 - 1,000	2004 - 2015	3,583	34.4	8,899	93.5

DC	Department of Energy & Environment	0.9 - 101	2009 - 2013	0	0.0	763	3.8
DE	Department of Natural Resources and Environmental Control	0.2 - 1,434	2002 - 2015	860	7.1	2,681	27.8
FL	Florida Energy & Climate Commission[b]	2.0 - 1,016	2006 - 2012	0	0.0	1,201	10.0
	Gainesville Regional Utilities[b]	1.8 - 1,040	2006 - 2015	24	0.4	464	20.9
	Orlando Utilities Commission[b]	0.5 - 1,040	2008 - 2015	61	0.6	182	3.7
IL	Dept. Commerce and Economic Opportunity	0.8 - 700	1999 - 2015	92	1.1	1,111	12.6
MA	Massachusetts Clean Energy Center[c]	0.4 - 5,756	2001 - 2015	227	14.4	2,826	67.3
	Dept. of Energy Resources[c]	0.3 - 6,000	2008 - 2015	8,800	185.2	20,571	676.9
MD	Maryland Energy Administration	0.7 - 200	2005 - 2015	778	7.6	6,101	52.6
ME	Efficiency Maine	0.9 - 171	2011 - 2013	0	0.0	550	3.5
MN	Dept. of Commerce	0.5 - 40	2003 - 2015	281	3.4	832	7.2
NC	NC Sustainable Energy Association	0.7 - 5,932	2005 - 2015	1,771	332.9	4,934	924.3
NH	New Hampshire Public Utilities Commission	0.3 - 686	2002 - 2015	1,193	14.3	2,793	28.5
NJ	New Jersey Board of Public Utilities (CORE & REIP Programs)	1.0 - 2,372	2001 - 2013	0	0.0	7,671	121.5
	New Jersey Board of Public Utilities (SREC Program)	1.0 - 8,135	2007 - 2015	5,478	119.0	24,119	1008.6
NM	Energy, Minerals & Natural Resources Dept.	0.4 - 349	2007 - 2015	913	5.5	6,337	35.0
NV	NVEnergy	0.4 - 1,145	2004 - 2015	4,599	33.6	6,976	95.4
NY	New York State Energy Research and Development Authority	0.3 - 980	2000 - 2015	12,574	125.2	34,724	360.1
OH	Dept. of Development	1.0 - 1,121	2005 - 2012	0	0.0	226	9.2
OR	Energy Trust of Oregon[d]	0.5 - 5,702	2002 - 2015	1,085	10.7	6,473	64.5
	Oregon Dept. of Energy[d]	0.1 - 974	1999 - 2015	70	0.3	1,115	5.6
	Pacific Power	1.6 - 500	2010 - 2014	0	0.0	443	7.2
PA	Dept. Community and Economic Development	8.0 - 3,252	2010 - 2012	0	0.0	49	34.6
	Dept. of Environmental Protection	1.0 - 922	2009 - 2014	0	0.0	7,000	97.8
	Sustainable Development Fund	1.1 - 12	2002 - 2008	0	0.0	200	0.7
RI	Office of Energy Resources	1.0 - 242	2012 - 2015	207	2.2	320	3.1
TX	Austin Energy	0.2 - 300	1999 - 2015	1,180	9.2	5,085	39.7
	CPS Energy	0.6 - 400	2007 - 2015	946	8.3	3,201	31.0
	Clean Energy Associates (El Paso Electric)	0.9 - 168	2001 - 2015	29	0.3	347	2.8
	Clean Energy Associates (Entergy)	1.1 - 29	2009 - 2012	0	0.0	57	0.4
	Clean Energy Associates (Oncor Electric Delivery Company)	0.4 - 300	2001 - 2012	0	0.0	867	10.2
	Clean Energy Associates (Sharyland Utilities)	7.4 - 10	2014 - 2015	1	0.0	2	0.0
	Clean Energy Associates (Southwestern Electric Power Company)	2.7 - 77	2010 - 2013	0	0.0	39	0.5
	Clean Energy Associates (Texas Central Company)	1.2 - 1,219	2010 - 2015	25	1.4	144	3.4

	Clean Energy Associates (Texas New Mexico Power Company)	1.2 - 12	2010 - 2012	0	0.0	23	0.2
	Clean Energy Associates (Texas North Company)	0.9 - 95	2010 - 2015	16	0.2	74	0.8
UT	Rocky Mountain Power	0.7 - 364	2011 - 2015	26	0.5	424	5.6
VT	Vermont Energy Investment Corporation	0.2 - 389	2003 - 2015	353	2.5	3,899	27.0
WI	Focus on Energy	0.2 - 273	2002 - 2015	370	2.3	2,074	14.8
Miscellaneous other sources (multiple states)		230 - 10,150	2008 - 2013	0	0.0	103	342.9
Total		***0.1 - 10,150***	***1998 - 2015***	***110,106***	***1,469***	***451,693***	***7,537***

(a) Only a subset of data from the California Public Utilities Commission (CPUC)’s Currently Interconnected Dataset (CID) are used, in order to avoid double counting systems that are contained in the various other datasets for incentive programs within the IOUs’ service territories. In particular, we eliminate: (i) all systems in the CID for which a CSI ID number is listed, (ii) all systems installed prior to 2013, and (iii) all systems with a street address that can be matched to the street address of systems in the other datasets.

(b) A small number of PV systems that received an incentive through the Florida Energy & Climate Commission (FECC)'s statewide solar rebate program also participated in one of the Florida utility programs. Those systems were retained in the data sample for the utility program and removed from the sample for FECC’s program. The values shown here for FECC reflect the residual sample, after overlapping systems were removed.

(c) The vast majority of the systems in the data file provided by the Massachusetts Clean Energy Center (MassCEC) were also included the data provided by the Dept. of Energy Resources (DOER). Overlapping systems were removed from the MassCEC dataset (but retained in the DOER dataset). The values shown here for MassCEC reflect the residual sample, after overlapping systems were removed.

(d) Oregon systems that received incentives through both the Oregon Dept. of Energy's tax credit program and the Energy Trust of Oregon were retained in the data sample for the Energy Trust and removed from sample for the Dept. of Energy. The values shown here for the Oregon DOE reflect the residual sample, after overlapping systems were removed.

Table B-2. Median Installed Price of Residential Systems by Size over Time (2015$/$W_{dc}$)

Installation Year	≤2 kW	2-4 kW	4-6 kW	6-8 kW	8-10 kW	10-12 kW	12-14 kW	14-16 kW	16-18 kW	18-20 kW	>20 kW
2000	11.6	11.6	9.5	-	-	-	-	-	-	-	-
2001	11.7	11.2	10.5	11.4	10.6	10.8	-	-	-	-	-
2002	12.0	11.5	10.8	10.7	10.6	10.8	-	-	-	-	-
2003	11.1	10.1	10.0	9.8	9.6	9.8	9.6	-	-	-	-
2004	10.2	9.4	9.3	9.1	8.9	9.0	8.9	8.6	9.2	-	-
2005	9.8	9.1	8.9	8.7	9.0	8.9	8.5	8.4	8.4	8.3	-
2006	10.4	9.3	9.1	8.7	8.9	8.7	8.3	8.5	8.4	8.3	-
2007	10.2	9.4	9.1	8.9	9.1	8.9	8.8	8.9	8.8	8.4	9.2
2008	9.8	9.0	8.7	8.6	8.6	8.5	8.5	8.5	8.5	8.5	8.6
2009	10.0	8.8	8.3	8.1	8.1	8.2	7.8	7.9	8.0	8.0	8.0
2010	9.5	7.6	7.0	6.8	6.8	6.8	6.7	6.7	6.6	6.8	6.9
2011	7.6	6.8	6.3	6.0	5.9	5.9	5.8	5.9	5.8	5.9	5.8
2012	6.1	5.6	5.4	5.2	5.1	5.1	5.1	5.0	5.1	5.2	5.3
2013	4.7	4.9	4.8	4.6	4.4	4.3	4.3	4.2	4.3	4.3	4.5
2014	4.4	4.7	4.4	4.2	4.0	4.0	4.0	3.9	3.9	3.9	3.9
2015	4.3	4.5	4.2	4.0	3.8	3.7	3.7	3.6	3.7	3.7	3.6

Notes: Median installed price data omitted if fewer than 20 observations available. Although not presented here, large variation exists around these median values.

Table B-3. Median Installed Price of Non-Residential Systems by Size over Time (2015$/$W_{dc}$)

Installation Year	≤10 kW	10-20 kW	20-50 kW	50-100 kW	100-250 kW	250-500 kW	500-1000 kW	>1000 kW
2000	-	-	-	-	-	-	-	-
2001	-	-	-	-	-	-	-	-
2002	-	-	10.9	-	-	-	-	-
2003	10.7	-	9.6	9.5	8.5	-	-	-
2004	9.8	-	9.2	9.1	8.6	-	-	-
2005	9.5	9.5	8.5	8.7	8.4	8.4	-	-
2006	10.0	9.3	8.6	8.5	8.6	8.3	-	-
2007	9.6	9.1	8.8	8.5	8.3	7.4	7.7	-
2008	9.1	9.0	8.5	8.1	8.1	7.4	7.3	7.4
2009	9.1	8.7	8.3	8.4	8.0	7.5	7.2	7.2
2010	7.7	7.3	6.8	6.5	5.9	6.0	5.8	5.4
2011	6.6	6.2	5.8	5.6	5.2	5.1	4.8	4.6
2012	5.6	5.1	5.1	4.8	4.8	4.7	4.6	4.2
2013	4.7	4.3	4.4	4.1	4.0	3.9	3.8	3.4
2014	4.4	3.8	3.8	3.5	3.5	3.4	2.9	2.7
2015	4.2	3.7	3.5	3.2	3.2	2.9	2.5	2.4

Notes: Median installed price data omitted if fewer than 20 observations available. Although not presented here, large variation exists around these median values.

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Acknowledgments

For their support of this project, the authors thank Elaine Ulrich, Ammar Qusaibaty, Odette Mucha, Jamie Nolan, and other staff in the U.S. Department of Energy's Solar Energy Technologies Office.

For providing data and/or reviewing elements of this paper, the authors thank: Megan Addison (Public Utilities Commission of Ohio), Erik Anderson (PacifiCorp), David Bane (Sulphur Springs Valley Electric Cooperative), Jim Barnett (Sacramento Municipal Utility District), Shauna Beland (Rhode Island Office of Energy Resources), Lewis Bickhoff (California Public Utilities Commission), Marci Brunner (New York State Energy Research and Development Authority),Ted Burhans (Tucson Electric Power), Miles Cameron (Oregon Department of Energy), Jerry Carey (North Carolina Sustainable Energy Association), Lucy Charpentier (Connecticut Clean Energy Fund), Lisa Cosgrove (Ameren), Karen Crampton (New Hampshire Public Utilities Commission), Robert Del Mar (Oregon Department of Energy), Walt Dinda (Pennsylvania Dept. of Environmental Protection), John Durland (CPS Energy), Suzanne Elowson (Vermont Energy Investment Corp.), Dana Fischer (Efficiency Maine Trust), Alison Fode (Vermont Energy Investment Corp.), Roger Fujihara (District of Columbia Public Service Commission), Douglas Gagne (National Renewable Energy Laboratory), Mark Gaiser (New Mexico Energy, Minerals and Natural Resources Department), Rene Garcia (Arizona Public Service), Charlie Garrison (Honeywell), Nick Grue (National Renewable Energy Laboratory), Wayne Hartel (Illinois Dept. Commerce and Economic Opportunity), Tim Harvey (Austin Energy), Kim Havey (Minnesota Department of Commerce), Erica Hines (Massachusetts Clean Energy Center), Jeff Johnson (Gainesville Regional Utilities), Lindsay Joye (City of Palo Alto Utilities), Kaitlin Kelly (Massachusetts Dept. of Energy Resources), Kate Kennedy (Salt River Project), Rene Laffey (Roseville Electric), Peter Liang (Los Angeles Dept. of Water and Power), Phillip Marx (Shaw Group), Gaëtan Masson (International Energy Agency), Deborah Mathis (Colorado Springs Utilities), David McClelland (Energy Trust of Oregon), Lyndsay McDonald (Xcel Energy), Le-Quyen Nguyen (California Energy Commission), Elizabeth Nixon (New Hampshire Public Utilities Commission), Shannon O'Rourke (California Public Utilities Commission), Jessica Quinn (Delaware Dept. of Natural Resources and Environmental Control), Kristin Riggins (Kansas City Power & Light), Maricela Rivera (Trico Electric Cooperative), Joachim Seel (Lawrence Berkeley National Laboratory), Andrea Simpkins (Orlando Utilities Commission), Colin Smith (GTM Research), Luke Tarbi (EnergySage), Paul Tomeo (NV Energy), Hugo Valdez (Imperial Irrigation District), Steve Weise (Clean Energy Associates), Laura Williams (California Center for Sustainable Energy), Daniel White (Washington D.C. Dept. of the Environment), Ryan Wiser (Lawrence Berkeley National Laboratory), Jason Zappe (PacifiCorp), William Zhang (Los Angeles Dept. of Water and Power), and Melissa Zito (Applied Energy Group). Of course, the authors are solely responsible for any remaining omissions or errors.

Lawrence Berkeley National Laboratory's contributions to this report were funded by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Office) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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LBNL-XXXXX/August 2016