

Tracking the Sun 10

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

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September 2017



Lawrence Berkeley
National Laboratory



SunShot
U.S. Department of Energy



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Executive Summary

Now in its tenth edition, Lawrence Berkeley National Laboratory (LBNL)'s *Tracking the Sun* report series summarizes trends in the installed price of grid-connected, residential and non-residential solar photovoltaic (PV) systems in the United States. The present report focuses on systems installed through year-end 2016, with preliminary trends for the first half of 2017. An accompanying LBNL report, *Utility-Scale Solar*, addresses trends in the utility-scale sector.

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 the data. In total, data were collected and cleaned for more than 1.1 million individual PV systems, representing 83% of U.S. residential and non-residential PV systems installed through 2016. The analysis in this report is based primarily on a subset of this sample, consisting of roughly 630,000 systems with available installed price data, representing 47% of all installed systems. LBNL has made the full dataset publicly available through the National Renewable Energy Laboratory (NREL)'s Open PV data portal.

Key Points on the Data in This Report

Installed price data presented in this report:

- Represent the up-front price paid by the PV system owner, prior to receipt of incentives
- Are self-reported by installers and 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 those 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 2016 dollars and direct current (DC) Watts (W):

Installed Prices Continued to Decline through 2016 and into 2017. National median installed prices in 2016 declined year-over-year by \$0.1/W (2%) for residential systems, by \$0.1/W (3%) for non-residential systems ≤ 500 kW, and by \$0.2/W (8%) for non-residential systems > 500 kW. These were the smallest year-over-year reductions since 2009, partly reflecting changes in the underlying population of the data sample (namely, a sharp increase in the proportion of the sample from California, a relatively high-priced state). Preliminary data for the first six months of 2017 show the pace of price reductions picking back up. Extrapolated over a full year, those partial-year price declines correspond to year-over-year installed price reductions of at least 10% for each customer segment, consistent with the long-term historical rate of decline.

Recent Installed Price Reductions Have Been Driven by Declining Hardware Costs. Over the long-term, both hardware and non-hardware (i.e., soft) costs have fallen substantially, contributing in almost equal measure to overall reductions in installed prices. Since 2000, for example, roughly 53% of the total decline in residential system installed prices can be attributed to falling module and inverter prices, while the remaining 47% is associated primarily with reductions in the aggregate set of soft costs. More recently, however, hardware costs have been the dominant driver for installed price declines. In fact, the aggregate drop in module, inverter, and racking prices over the 2015 to 2016 period exceeded the observed decline in total system-level installed prices over the same span. That apparent disconnect reflects a natural lag between changes in component prices and system prices, and is consistent with the larger installed-price decline observed in the first half of 2017.

Increasing Module Efficiencies and System Sizes Contribute to Installed Price Declines. Many soft costs, as well as some secondary hardware costs, are either fixed in nature or scale with the physical dimensions of the system. Accordingly, these costs can be directly reduced (on a per-watt) basis through increases in module efficiency and system size, which spread such costs out over a larger number of installed watts. Among projects in the data sample, median module efficiencies grew from 12.7% to 17.3% from 2002 to 2016, while the median size of residential systems grew from 2.9 kW to 6.2 kW. Together, these two dynamics are ostensibly responsible for roughly a \$1.0/W reduction in residential system costs over the long-term (about 12% of the total decline in residential installed prices). Within the last year of the analysis period, median module efficiencies increased from 17.0% to 17.3%, and median system sizes remained constant (with negligible year-over-year effects on installed prices).

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 70% 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. Median installed prices of systems in the LBNL dataset installed in 2016 were \$4.0/W for residential systems, \$3.4/W for small (≤ 500 kW) non-residential systems, and \$2.3/W for large (> 500 kW) non-residential systems. These values are high compared to many other recently published PV pricing and cost benchmarks. These apparent discrepancies can be traced to a variety of differences in underlying data, methods, and conventions. Many of the other published benchmarks, instead, align more closely with 20th percentile pricing levels observed within the LBNL data, highlighting the wide variability in installed prices described further below.

Installed Prices in the United States Are Higher than in Many Other Major National PV Markets. Compared to median U.S. prices, installed prices reported for a number of other key national solar markets are substantially lower. In Australia, for example, typical pricing for residential systems was reported to be around \$1.8/W in 2016 (i.e., less than half the median price observed within the LBNL dataset). Though data comparability across countries may be imperfect, 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. Among residential systems installed in 2016, roughly 20% of systems were priced below \$3.2/W (the 20th percentile value), while 20% were priced above \$5.0/W (80th percentile). Non-residential systems also exhibit wide pricing variability, with the 20th-to-80th percentile ranging from \$2.7/W to \$4.4/W for smaller (≤ 500 kW) projects and from \$1.9/W to \$3.2/W for larger (> 500 kW) projects. The potential underlying causes of this variability are numerous, including differences in project characteristics, installers, and local market or regulatory conditions. The wide pricing distributions also serve to demonstrate the potential for low-cost installations. For example, more than 15,000 residential systems installed in 2016 (9%) were priced below \$2.5/W, and 8,000 (5%) were below \$2.0/W.

Strong Economies of Scale Exist Among Both Residential and Non-Residential Systems. Among residential systems installed in 2016, median prices were roughly \$0.8/W (19%) lower for systems in the 10-12 kW size range compared to 2-4 kW systems. For non-residential systems, median prices were \$1.9/W (46%) lower for systems $> 1,000$ kW in size compared to the smallest 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 Vary Widely Among States, with Relatively High Prices in Some Large State Markets. For residential systems installed in 2016, median installed prices range from a low of \$2.9/W in Nevada to a high of \$5.0/W in Delaware. 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 Were Significantly Lower-Priced than Host-Owned Systems in 2016. 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. Nationally, the median installed price among residential TPO systems in 2016 was \$0.7/W lower than for host-owned residential systems. The lower installed prices for TPO systems may reflect a combination of factors: loan origination fees rolled into the price of some host-owned systems, customer acquisition and other project development costs that may be borne by the TPO financier (and thus not captured in the installed price), negotiating power of TPO financiers, and potentially greater standardization among TPO systems.

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 \$0.7/W to \$1.4/W between the upper and lower 20th percentiles, suggesting a substantial level of heterogeneity in pricing behavior or underlying costs from one installer to another. Low-priced installers in each state—e.g., 20% of installers in New York had median residential prices below \$3.3/W in 2016, compared to the overall state median price of \$3.8/W—can serve as a benchmark for near-term price reduction potential in each state. The data show no clear evidence that installer-level pricing differences are the result of differences in installer size, though other more-depth analyses have found relationships in both directions.

Installed Prices Are Substantially Higher for Systems with Premium-Efficiency Modules. As noted earlier, higher module efficiencies allow for lower balance-of-system (BOS) costs, and increasing module efficiencies over time has contributed to declining system costs and prices. At any given point in time, however, various module efficiencies are commercially available, and higher efficiency products tend to sell for a premium. Among the 2016 systems in the data sample, roughly one-third have module efficiencies greater than 18%, and installed prices for these systems have consistently been higher-priced than for those with lower- or mid-range module efficiencies (<18%). In 2016, the differential in median prices was roughly \$0.5/W among both residential systems and small non-residential systems. These trends suggest that the price premium for high-efficiency modules available on the market tends to outweigh any offsetting reduction in BOS costs.

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 \$0.1/W in 2016, *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 Continue to Be Higher for Systems at Tax-Exempt Customer Sites than at For-Profit Commercial Sites. Roughly 18% of all 2016 non-residential systems in the data sample were installed at tax-exempt site hosts, including schools, government facilities, religious organizations, and non-profits. These systems are consistently higher priced than similarly sized systems at for-profit commercial customer sites. In 2016, the differential in median prices was roughly \$0.2/W for systems ≤ 500 kW and \$0.8/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.

Module-Level Power Electronics Have a Seemingly Small Effect on Installed Prices. Module-level power electronics (MLPEs), including both microinverters and DC optimizers, have made substantial gains in market share in recent years. Despite higher hardware costs associated with these devices, installed prices for systems with MLPEs have generally been nearly identical to, or even less than, installed prices for systems without MLPEs. For example, among residential systems installed in 2016, median installed prices were identical for systems with microinverters and those with no MLPE, while the median price of systems with DC optimizers was \$0.3/W lower. The negligible (or negative) installed price premium exhibited by the data suggest that MLPEs may offer some savings on non-inverter BOS costs or soft costs.

Non-Residential Systems with Tracking and Ground-Mounting Are Generally Higher Priced than Rooftop Systems. Among both small and large non-residential systems installed in 2016, the median installed price was roughly \$0.3/W higher for fixed, ground-mounted systems than for rooftop systems. Tracking equipment adds additional costs, though this is not always readily or precisely discernible with the installed price data. Within the small non-residential segment, the median installed price of systems with tracking was about \$0.4/W higher in 2016 than for fixed, ground-mounted systems. However, within the large non-residential segment, systems with tracking actually had a lower median price in both 2015 and 2016 than fixed-tilt, ground-mounted projects.

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, and an additional 50% reduction by 2030.¹ 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 companion 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 tenth in the series, describes installed price trends for projects installed from 1998 through 2016, with preliminary data for the first half of 2017. The report is intended to provide an overview of both long-term and more-recent trends, highlighting key drivers for installed price declines over different time horizons. The report also seeks to highlight *variability* in system pricing, comparing installed prices across states, market segments, installers, and various system and technology characteristics. Other LBNL research products have also explored pricing variability using more complex statistical methods.

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 (ground-mounted projects larger than 5 MW_{AC}) 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 [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 *Tracking the Sun* dataset.
- *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 (for example, see Fu et al. 2017).

¹ The \$1/W target for 2020 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. The 2030 goals are specified in terms of the levelized cost of energy (LCOE), with targets of 5 ¢/kWh (residential), 4 ¢/kWh (commercial), and 3 ¢/kWh (utility-scale), all denominated in real 2016 dollars.

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 this year's report consists of more than 1.1 million residential and non-residential PV systems,² representing roughly 83% of all residential and non-residential PV systems installed in the United States through 2016. LBNL applies a substantial degree of quality control and undertakes numerous 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.³

Essential to note at the outset are several important characteristics of the installed price data described within this report. These reported prices represent the up-front price paid by the system owner, prior to receipt of incentives; for a variety of reasons, such prices may differ from the underlying costs borne by the developer or installer. The data are also self-reported, and therefore may be subject 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 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 installation and customer financing; the prices reported for these systems represent appraised values rather than transaction prices. Partly in recognition of these limitations, the report compares reported installed price data to several other recent benchmarks for PV system prices and costs, in order to provide a broader snapshot of current system costs and prices.

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 underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. The section also compares median installed prices for systems installed in 2016 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, host-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 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, which can be downloaded at trackingthesun.lbl.gov. Finally, as mentioned above, the underlying project-level data summarized in this report are publicly available through NREL's Open PV Project.

² As explained further within the report, the analysis in this report is based primarily on a subset (approximately 630,000 systems) of the larger data sample.

³ 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-owned and TPO systems.

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 (see Table B-1 in the Appendix for a list of data providers and associated sample sizes).

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. One significant data gap that did emerge, albeit temporarily, was in California, where the state's primary incentive began to wind down in 2013. Data collection responsibilities were eventually transitioned to the investor-owned utilities' (IOUs') interconnection processes; however, in the intervening period, installed pricing data was unavailable for a sizeable fraction of the California market. Further discussion of this issue, and its impact on the trends presented in this report, are provided below.

Data Standardization and Cleaning

Various steps were taken to clean and standardize the raw data. First, all systems 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 module and inverter names, each PV system was then classified as building-integrated PV or rack-mounted; module technology type

Text Box 1. Customer Segment Definitions

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

and efficiency were determined; and systems with microinverters or DC optimizers were identified. Finally, all price and incentive data were converted to real 2016 dollars (2016\$), and if necessary system size data were converted to direct current nameplate capacity under standard test conditions (DC-STC). 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 where reported prices are assumed to represent an appraised value, rather than a transaction price (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 is 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, reported installed price data generally represent appraised values, as no sale of the individual PV system occurs 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 11, as a point of comparison.

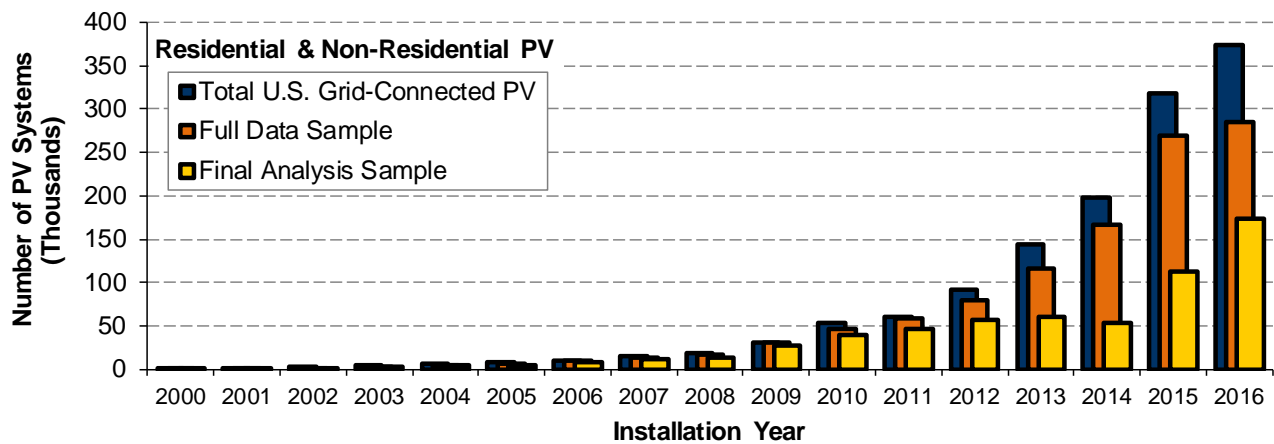
In contrast, systems financed by non-integrated TPO providers were retained in the data sample. The installed price data reported for these systems represent an actual transaction price: namely, the price paid to the installation contractor by the customer finance provider. That said, differences may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

Sample Size

The full data sample includes the majority of all U.S. grid-connected residential and non-residential PV systems. In total, it consists of roughly 1.1 million individual PV systems installed through year-end 2016, including more than 280,000 systems installed in 2016 (Figure 1 and Table 1). This represents roughly 83% of all U.S. residential and non-residential systems installed cumulatively through 2016 and 76% of installations in 2016. The largest gaps in the 2016 sample are for Hawaii, which is wholly absent from the sample, and Maryland and Utah, which have quite

low coverage (roughly 3% of systems installed in 2016 in those states).⁴ Coverage among other large state markets is relatively complete, with at least 50% of all systems in each of the other top-10 state markets contained within the sample.

The final analysis sample, following removal of appraised-value and all other excluded systems, consists of roughly 630,000 systems installed through year-end 2016 (56% of the full sample and 47% of all U.S. systems) and more than 170,000 systems installed in 2016 (61% of the full sample and 47% of all U.S. systems installed in that year). The gap between the full and final data samples consists primarily of appraised-value systems (approximately 250,000 systems) and systems missing installed price data (approximately 210,000 systems). The latter includes all systems from several states for which installed price data are wholly unavailable, as well as a sizeable number of California systems installed from 2013 through 2015, during which time the state’s incentive program was winding down and the new data collection process had not yet been fully implemented. As shown in Figure 1, the gap between the full and final data samples narrowed in 2016, primarily due to the increased availability of installed price data for California.



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 (2017) for each year thereafter.

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

⁴ In the case of Hawaii, none of the available data sources track the minimal set of data fields needed for inclusion in the full data sample. For Maryland and Utah, we rely on data from incentive programs that have limited budgets and therefore cover only a small portion of each state’s market.

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	18	3	0	21	12	1	0	13
1999	162	10	0	172	131	7	0	138
2000	145	9	0	154	97	7	0	104
2001	1,142	40	0	1,182	977	32	0	1,009
2002	2,153	171	2	2,326	1,916	142	1	2,059
2003	3,188	278	3	3,469	2,903	236	3	3,142
2004	5,159	416	6	5,581	4,799	362	6	5,167
2005	5,480	446	7	5,933	5,125	370	7	5,502
2006	8,910	512	22	9,444	8,367	433	20	8,820
2007	12,945	845	35	13,825	11,910	679	30	12,619
2008	15,356	1,572	88	17,016	12,629	1,389	74	14,092
2009	29,239	2,027	87	31,353	25,319	1,768	56	27,143
2010	42,360	3,761	199	46,320	37,034	3,344	135	40,513
2011	53,076	6,230	403	59,709	41,754	5,095	314	47,163
2012	72,907	6,068	408	79,383	51,884	4,762	293	56,939
2013	111,680	4,707	422	116,809	56,871	3,137	316	60,324
2014	160,898	5,445	442	166,785	50,819	2,532	270	53,621
2015	264,517	5,185	510	270,212	109,240	3,005	309	112,554
2016	277,118	6,832	722	284,672	168,976	4,986	506	174,468
Total	1,066,453	44,557	3,356	1,114,366	590,763	32,287	2,340	625,390

Notes: See Text Box 1 for an explanation of the three customer segments delineated in this table and used throughout the report.

Sample Characteristics

Characteristics of the data sample provide important context for understanding installed price trends presented in this report. Generally, these characteristics 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 host-owned and TPO systems. Unless otherwise indicated, the trends refer to the final analysis sample.

System Size Trends

System sizes have grown over time within each of the three customer segments used in this report, as shown in Figure 2. In particular, residential systems have more-than-doubled in size, rising from a median of 2.9 kW per system in 2000 to 6.2 kW in 2016. The class of non-residential systems ≤ 500 kW have grown from a median size of 5 kW in 2000 to 32 kW in 2016. Irrespective of this growth, it is worth noting that the vast majority of systems in this class are well below the 500 kW mark; as such, this customer segment is sometimes described in the report as “small” or “smaller” non-residential systems. Finally, system sizes for the large (> 500 kW) non-residential class have also generally risen over time, with a median size of roughly 970 kW in 2016, reflecting the growing prevalence of multi-MW rooftop systems and “baby ground-mount” systems in the 1-5 MW range. Year-over-year trends for this size class can be volatile, however, as a result of small sample sizes.

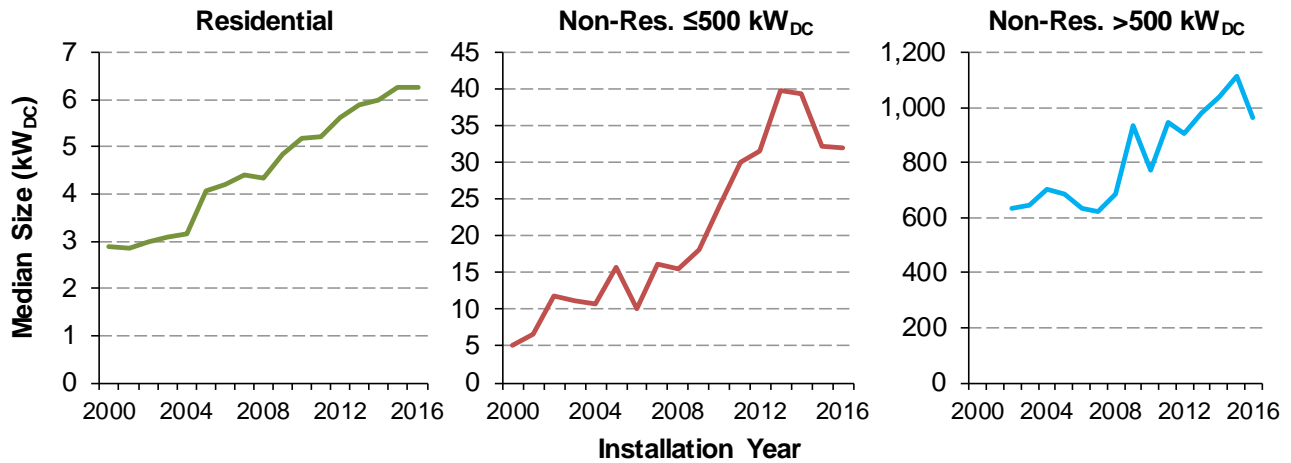


Figure 2. Median System Size over Time

Geographic Distribution

The final analysis sample includes systems installed across 25 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 2016.

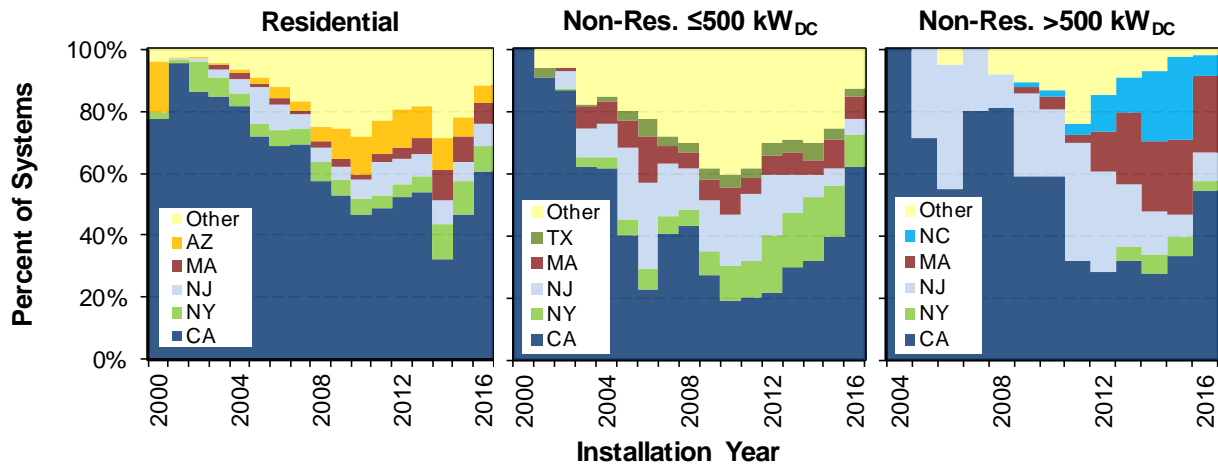


Figure 3. Sample Distribution among States

Across all three customer segments, California has remained the largest state in the data sample representing 61% of residential systems, 62% of non-residential systems ≤500 kW, and 54% of non-residential systems >500 kW installed in 2016. Although the state's share of the sample has generally declined over the long-term, it increased sharply in 2016, as a result of the renewed collection of installed price data for systems installed in the IOUs' service territories. As discussed later in the report, this has implications for recent trends in aggregate national installed pricing.

New York, New Jersey, Massachusetts, Arizona, Texas, and North Carolina make up the bulk of the remaining sample, though each of the latter three states are prominent mostly within particular customer segments. For example, North Carolina constitutes a large share of non-residential

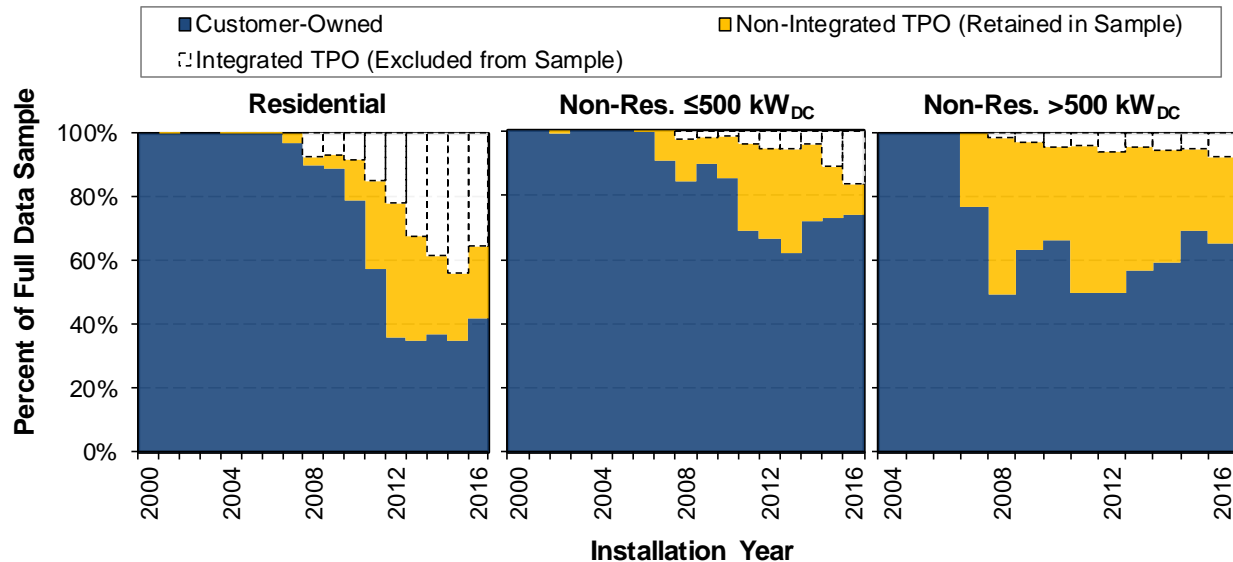
systems >500 kW, but has a negligible presence within the other segments. Also worth noting is that the sample of non-residential systems >500 kW has the least geographic diversity among the three segments, with virtually all 2016 installations in the sample located in the five states shown in Figure 3.

Distribution between Host-owned and TPO Systems

The composition of the data sample reflects the growth of third-party ownership (TPO) and increasing concentration of market share within the TPO segment. This is shown in Figure 4, which is based on the full data sample in order to illustrate growth of both integrated and non-integrated TPO systems (unlike most other figures in the report, which exclude integrated TPO systems).

Within the residential data sample, the TPO share grew dramatically from 2007 up until 2012, reaching 65% and remaining at roughly that level through 2015. Consistent with movement in the broader market back towards customer ownership, the TPO share of the data sample shrank slightly in 2016, constituting 58% of all residential systems in the full data sample. Of the TPO systems in the sample, the integrated TPO share continued to grow through 2015, as the U.S. market consolidated among several large residential installers. That fraction receded as well in 2016, with 35% of residential systems in the full data sample installed by an integrated TPO provider.

The trends differ markedly within the non-residential sample, in two respects. First, the overall TPO percentages are considerably lower: 26% of the sub-500 kW class and 34% of the >500 kW class of non-residential systems installed in 2016. Second, and more importantly, is that integrated TPO systems represent a small share of non-residential TPO systems, and thus relatively few non-residential systems were excluded from the final analysis 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.

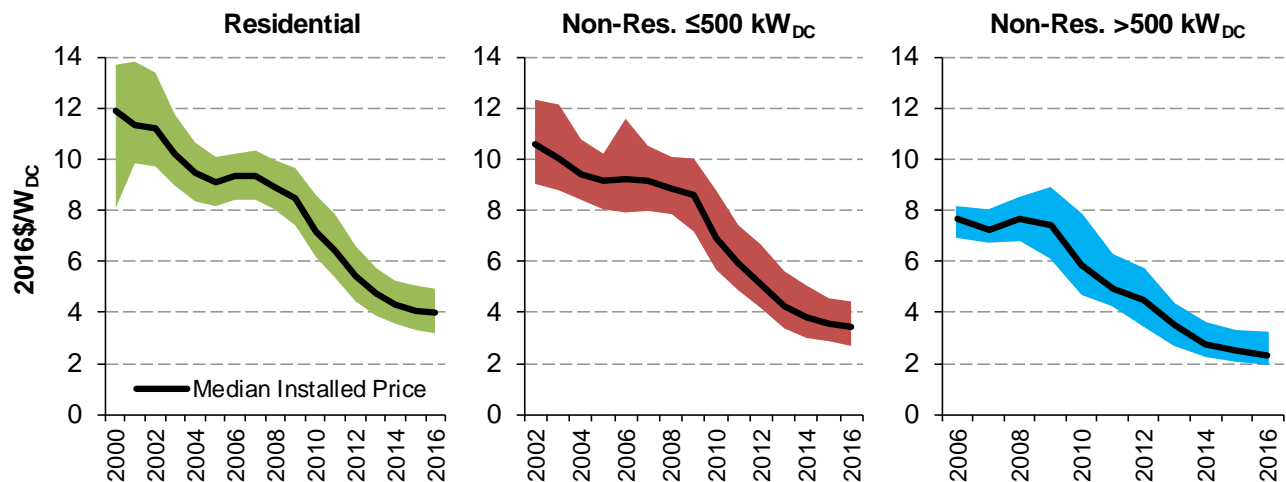
Figure 4. Sample Distribution between Host-owned and TPO Systems

3. Historical Trends in Median Installed Prices

This section presents an overview of both long-term and more-recent historical trends in the installed price of residential and non-residential PV, based 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 through 2016, along with preliminary data for the first half of 2017. The section then discusses a number of broad drivers for those historical trends, including reductions in underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. It then compares median installed prices for systems installed in 2016 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

Installed prices for both residential and non-residential PV have fallen dramatically over time, as shown in Figure 5. Over the full duration of the available time series, median installed prices fell by roughly \$0.5/W per year on average, for each of the three customer segments shown, equating to an average annual percentage drop of 7% per year for residential and small (≤ 500 kW) non-residential systems, and 11% per year for large (>500 kW) non-residential systems. The trajectory, however, has not been smooth. Prices fell rapidly in the early years through 2004, followed by little price movement over the 2005-2009 period, and then a resumption of price declines in 2010. Though prices have fallen each year since 2010, the pace has slowed in recent years. Over the last year of the analysis period, from 2015 to 2016, median prices fell by just \$0.1/W (2%) for residential, \$0.1/W (3%) for small non-residential, and \$0.2/W (8%) for large non-residential systems. These were the smallest year-over-year reductions in all three segments since 2009. As discussed further below, installed prices tend to lag behind movements in underlying component prices; the data in Figure 5 therefore likely do not fully capture reductions in the price of PV modules and other hardware components that occurred over the course of 2015 and 2016.

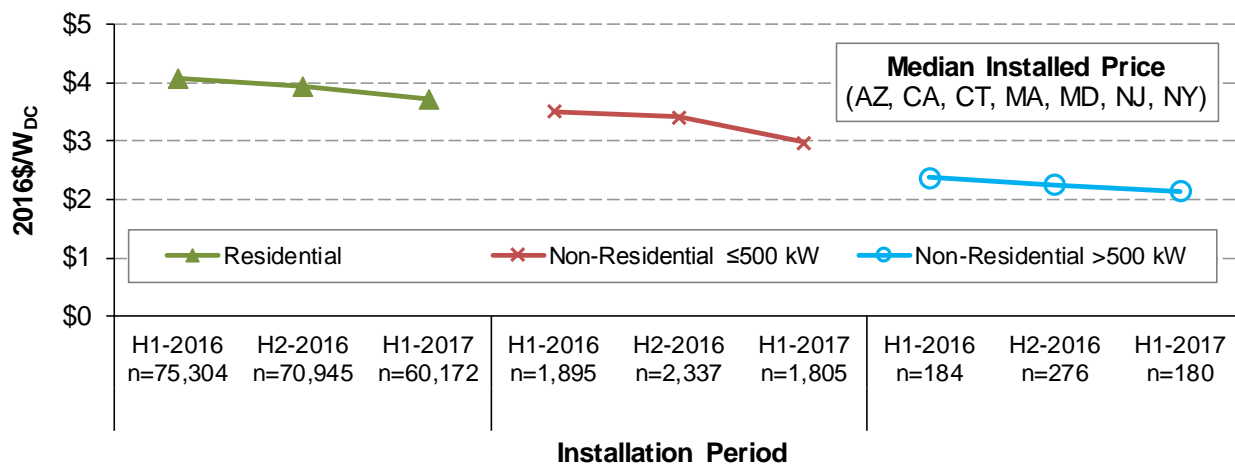


Notes: Solid lines represent median prices, while shaded areas show 20th-to-80th percentile range. See Table 1 for annual sample sizes. Summary statistics shown only if at least 20 observations are available for a given year and customer segment.

Figure 5. Installed Price Trends over Time

More generally, the slowing rate of price declines over the past several years likely reflects several factors. In part, it may be the natural result of diminishing opportunities for cost reductions and growing customer acquisition costs as early adopters are converted. However, two other factors—both artifacts of the data—are likely also at play. The first is an increasing proportion of the sample from California, as shown earlier in Figure 3. This is particularly true in the residential sector, where 61% of all systems in the sample were from California in 2016, compared to 47% in 2015 and 32% in 2014. As shown in later sections, California is a relatively high-priced state, and thus its growing proportion of the sample tends to dampen the decline in national median prices. In addition, price declines in California have also been relatively slow, with median residential system prices falling by just 2% from 2015 to 2016, compared to at least 5% in most other states. A second factor behind the apparent slowing in the decline of national median prices is the growing share of loan-financed systems. Residential loan products have become more prevalent, comprising 18% of all residential systems installed in 2016, or roughly 40% of all host-owned systems (Shao and Mond 2017). Dealer origination fees associated with such loans—which can range from 15-20% of the loan amount, adding \$0.6 to \$0.8/W to a median-priced system—are often embedded in the installed prices paid by customers and reported to PV incentive program administrators.

Preliminary data for the first six months of 2017 suggest that the pace of price reductions is picking back up. As shown in Figure 6, median installed prices for the first half (H1) of 2017 fell by an additional \$0.2/W for residential systems, by \$0.4/W for small non-residential systems, and by \$0.1/W for large non-residential systems, relative to the second half (H2) of 2016. Extrapolated over a full year, these installed price declines would yield an 11% year-over-year decline for residential, 25% for small non-residential, and 10% for large non-residential systems. These percentage reductions are greater than or equal to the long-term average rate of decline, though should be considered somewhat provisional, given the more-limited sample used for this partial-year analysis, and potential seasonality in installed price trends.



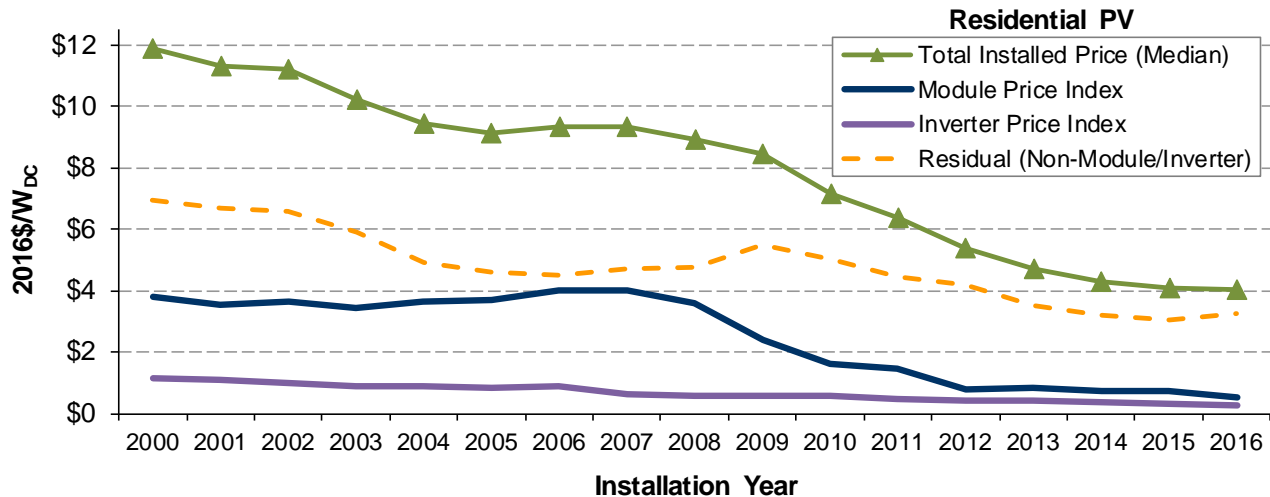
Notes: The figure is based on a subset of states and data sources used for the larger dataset, and therefore cannot be directly compared to Figure 5.

Figure 6. Median Installed Prices for Systems Installed in 2016 and the First Half of 2017

Underlying Hardware and Soft Cost Reductions

The decline in system-level installed prices over the last year of the analysis period, from 2015 to 2016, would appear to be primarily attributable to reductions in hardware costs. Benchmark prices for the three primary hardware components—modules, inverters, and racking—fell in aggregate by

roughly \$0.3/W for residential systems over that time span (GTM Research and SEIA 2017). That aggregate drop in hardware costs is actually greater than the decline in total residential system prices observed within the LBNL dataset. This apparent disconnect may be partially the result of a lag between changes in component prices and installed system prices, arising due to the gap in time between when installers purchase equipment and when that equipment is installed at customer sites.⁵ Accordingly, the more substantial reduction in installed prices during the first half of 2017 is suggestive of a latent effect of hardware cost reductions during the prior year.



Notes: The Module Price Index is the global module price index for large quantity buyers, published by SPV Market Research (2017). The Inverter Price Index is a weighted average of residential string inverter and microinverter prices published by GTM Research and SEIA (2017); that price series begins in 2010, and we extend it backwards in time using inverter costs reported for individual systems within the LBNL data sample. The Residual term is calculated as the Total Installed Price minus the Module Price Index and Inverter Price Index.

Figure 7. Installed Price, Module Price Index, Inverter Price Index, and Residual Costs over Time for Residential PV Systems

Over the long-term, however, both hardware and non-hardware (i.e., soft) costs have fallen substantially, contributing in almost equal measure to overall reductions in system-level installed prices. Among hardware costs, PV modules have been, far and away, the largest single driver for system-level installed price declines over the long-term. Since 2000, module prices have fallen by roughly \$3.3/W (based on a global module pricing index), equating to 41% of the decline in total residential installed system prices over that time. As shown in Figure 7, most of that drop occurred between 2008 and 2012, when total installed prices fell more or less in tandem. Second in significance among hardware cost reductions are inverters, which have fallen by roughly \$0.9/W since 2000, representing 12% of the long-term decline in residential system prices.⁶

The remaining 47% of long-term installed price declines is therefore associated primarily with 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. These soft costs are captured by the “residual” term plotted in Figure 7 (which also includes other ancillary

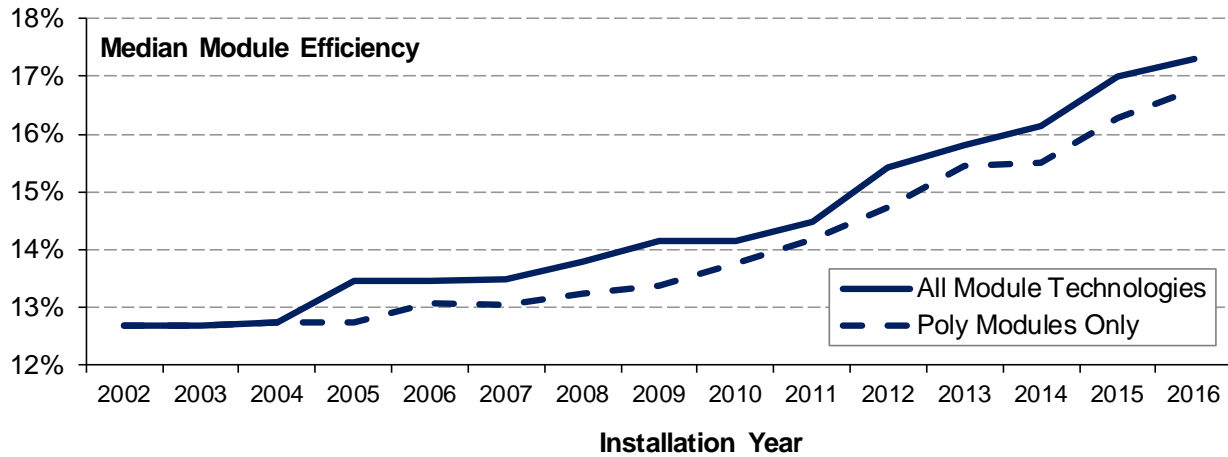
⁵ The disconnect between changes in component prices and observed system prices may reflect a number of other factors as well, for example: changes in the composition of module technologies and installer base within the sample over time, and the ability of some installers to potentially retain a portion of component cost reductions in their margin.

⁶ Long-term, time-series data for other hardware elements are not available. For residential racking equipment, index data published by GTM Research and SEIA (2017) suggest roughly a \$0.3/W reduction from 2012 to 2016.

hardware costs, such as racking and wiring).⁷ Long-term reductions in soft costs reflect a combination of factors. Recent years have seen significant emphasis in the industry and among policymakers on reducing soft costs, and those efforts have likely borne some fruit. Financial incentives for PV in most states have also fallen substantially over time, placing further pressure on installers and others in the supply chain to streamline business processes. Finally, two technical factors—increasing module efficiency and increasing system size—have also helped to reduce soft costs (on a per-watt basis). These underlying drivers are explored further in the following sections.

Impacts of Increasing Module Efficiency on Installed Prices

Installed price declines over time are partly tied to increasing PV module efficiency: higher module efficiencies reduce installed prices on a per-watt basis by spreading fixed project costs (e.g., permitting and customer-acquisition) and area-related costs (e.g., racking and installation labor) across a larger base of installed watts. As shown in Figure 8, median module efficiencies among systems in the LBNL dataset rose from 12.7% in 2002 to 17.3% in 2016. Based on modeled residential PV cost relationships developed by Fu et al. (2017), this increase in module efficiency corresponds to roughly a \$0.3/W reduction in fixed and area-related costs—equivalent to 8% of all non-module/non-inverter cost declines over the same time period.⁸ Within the last year of the analysis period, from 2015 to 2016, median module efficiencies rose from 17.0% to 17.3%, which would be expected to yield about a \$0.01/W reduction in fixed and area-related costs.



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

Figure 8. Module Efficiency Trends over Time within the Project Data Sample

⁷ This residual term has risen at various points in time, including in 2009 and again in 2016. Although some soft costs, such as customer acquisition, indeed may have risen, these apparent “spikes” should be viewed primarily as an artifact of the lag between component prices and total installed prices.

⁸ The estimated non-module cost reduction associated with module efficiency gains represent 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), the effects of module efficiency improvements would be greater.

Impacts of Increasing System Size on Installed Prices

A second technical factor behind the long-term decline in residential system prices, and soft costs in particular, has been the steady growth in system sizes. Larger systems enable lower installed prices (on a per-watt basis) for reasons similar to those noted above for module efficiency: namely, the ability to spread fixed project costs over a larger base of installed watts. As shown previously in Figure 2, the median size of residential systems in the data sample grew from 2.9 kW in 2000 to 6.2 kW in 2016. Roughly one-third of that growth is nominally the result of increasing module efficiencies (i.e., higher wattages per panel). The remainder is instead associated with growth in the number of panels per system.

Relying again on the modeled cost relationships developed by Fu et al. (2017), the increase in residential system sizes since 2000 would be expected to yield roughly a \$1.0/W reduction in non-module/inverter costs (inclusive of the effects of increasing module efficiency).⁹ This equates to 12% of the total decline in residential installed prices over that period, and 26% of the decline in non-module/non-inverter costs (i.e., the residual term in Figure 7). Within the final year of the analysis period, median residential system sizes remained effectively unchanged, thus no further cost reductions can be attributed to system size increases in the most recent year.

State and Utility Cash Incentives

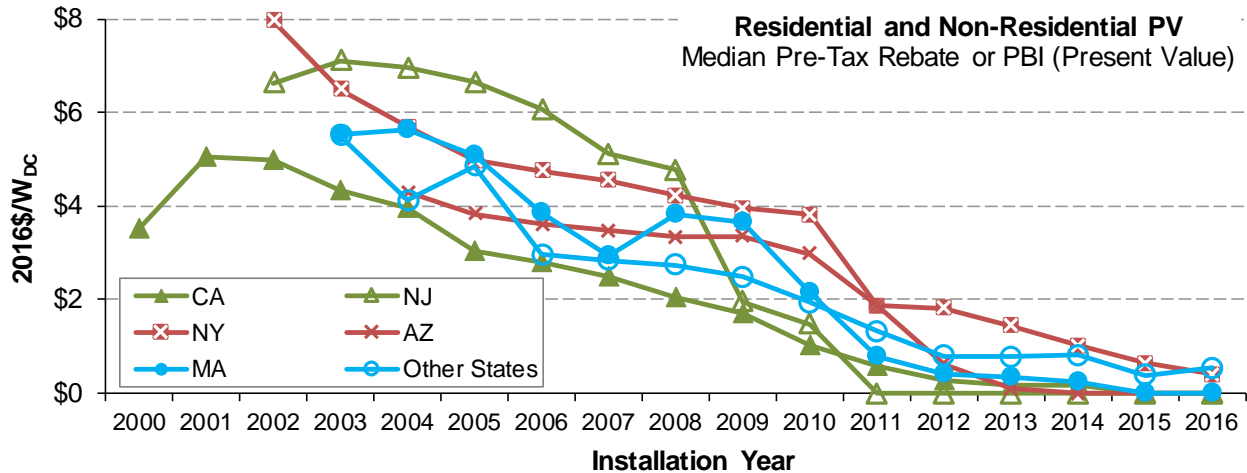
Financial incentives provided through utility, state, and federal programs have been a driving force for the PV market in the United States. For residential and non-residential PV, those incentives have – depending on the particular place and time – included some combination of cash incentives provided 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 9 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 \$4-8/W (in real 2016 dollars). By 2016, direct rebates and performance-based incentives were largely phased-out in many key markets – including Arizona, California, Massachusetts, 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 financial support (for example, SRECs, as discussed in Text Box 3). In many states, it has also been a deliberate strategy to provide a long-term signal to the industry to reduce costs and improve installation efficiencies. The steady decline in incentives is thus both a cause and an effect of installed price reductions 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 state markets profiled in Figure 9, the decline in incentives from each market's respective peak is equivalent to anywhere from 70% to 120% of the drop in installed PV prices over the corresponding time period. 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

⁹ This estimated impact of system size increases 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), the effects of system size increases would be greater.

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.



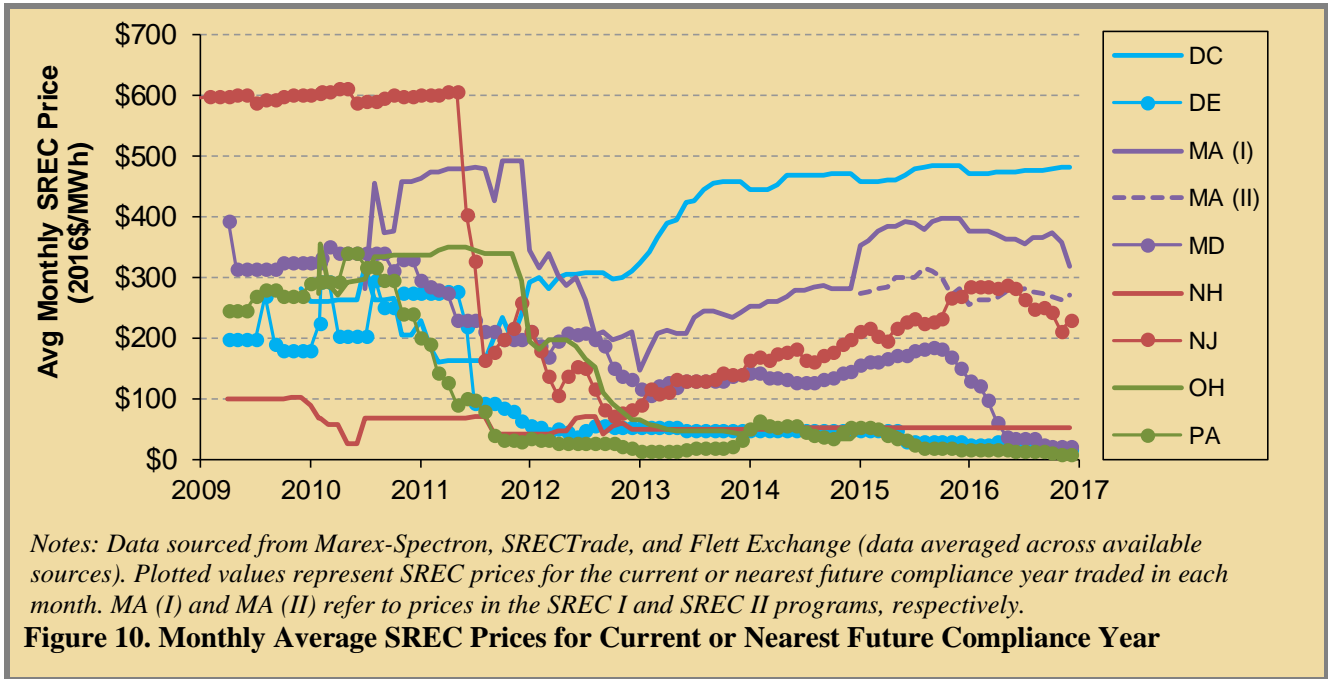
Notes: The figure depicts the pre-tax value of rebates and PBI payments (calculated on a present-value basis) provided through state/utility PV incentive programs.

Figure 9. State/Utility Rebates and PBIs over Time

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 10). 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.

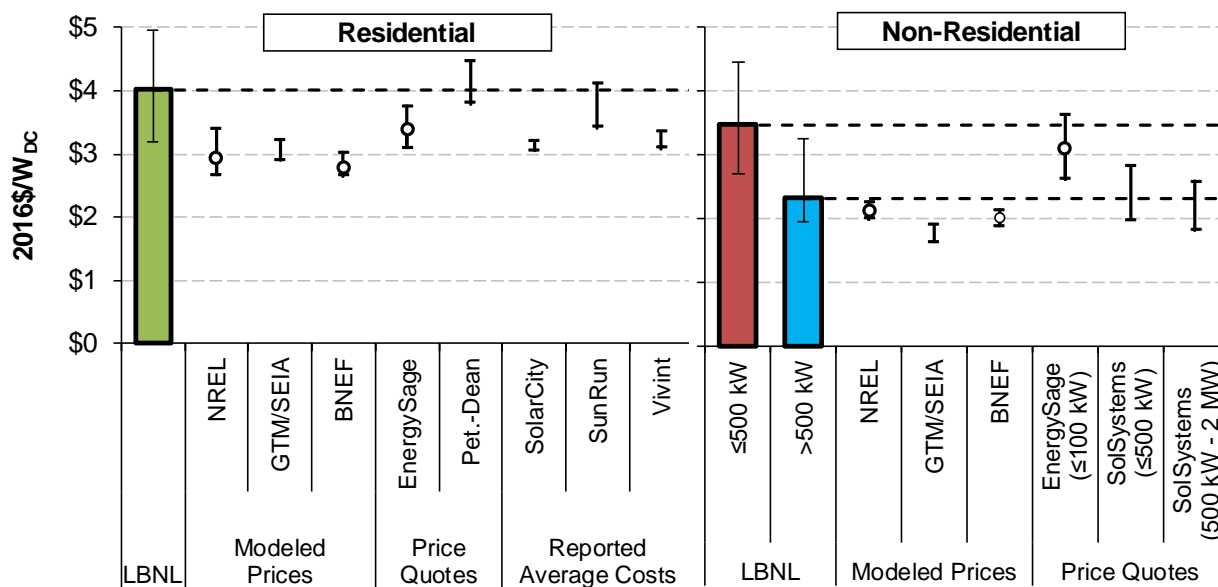


Comparison of Median Installed Prices to Other Recent U.S. Benchmarks

National median prices can provide a useful metric for tracking temporal trends, but may or may not provide a relevant benchmark for system prices in all contexts. To provide a broader view of current PV system pricing, Figure 11 compares median installed prices of 2016 systems in the LBNL data sample to a diverse set of other recent PV price and cost benchmarks. These other benchmarks include modeled PV system prices, price quotes for prospective PV systems, and average costs reported directly by several major residential installers (see the notes below the figure for further details).

As evident in Figure 11, these various benchmarks vary substantially from one another, reflecting their underlying diversity of data, methods, and definitions. Of particular note is that median prices drawn from the LBNL dataset are generally higher than the other benchmarks shown. Among residential systems, for example, the median installed price within the LBNL sample was \$4.0/W in 2016. The other residential benchmarks vary from \$2.7/W to \$4.5/W, though most are clustered at the lower end of that range. Similarly, national median prices for non-residential systems in the LBNL dataset (\$3.4/W for systems ≤ 500 kW and \$2.3/W for systems > 500 kW) are also higher than most of the other benchmarks shown, which range from \$1.6/W to \$3.6/W. These differences between the LBNL median values and other benchmarks occur for a number of reasons, as described more fully in Text Box 4.

Notwithstanding the divergence noted above, many systems in the LBNL dataset exhibit prices well aligned with the other PV pricing and cost benchmarks. Indeed, the 20th percentile pricing levels for both residential systems (\$3.2/W) and large non-residential systems (\$1.9/W) fall squarely in the range of the other benchmarks. Later sections of this report will further explore the wide spread in the data, and will show that prices observed in many contexts—i.e., for certain states, installers, module technologies, and TPO systems—are substantially below the national median, and correspond closely to the other benchmarks shown in Figure 11.



Notes: **LBNL** data are the median and 20th and 80th percentile values among projects installed in 2016. **NREL** data represent modeled turnkey costs in Q1 2016 for a 5.6 kW residential system (range across system configuration and installer type, with weighted average) and a 200 kW commercial system (range across states and national average) (Fu et al. 2016). **GTM/SEIA** data are modeled turnkey prices for Q1 and Q4 2016; their residential price is for a 5-10 kW system with standard crystalline modules, while the commercial price is for a 300 kW flat-roof system (GTM Research and SEIA 2017). **BNEF** data are estimated PV capex with developer margin in 2016 (US averages and range across states/regions) (Serota and Bromley 2016). **EnergySage** data are the median and 20th and 80th percentile range among price quotes issued in 2016, calculated by Berkeley Lab from data provided by EnergySage; quote data for non-residential systems are predominantly from small (<100 kW) projects. **Petersen-Dean** data are the minimum and maximum values from a series of online price quotes for turnkey systems across a range of sizes (3.4 to 8.4 kW) and states (CA and TX), queried from the company website by Berkeley Lab in June 2016. **SolarCity**, **SunRun**, and **Vivint** data are the companies' reported average costs, inclusive of general administrative and sales costs, for Q1 and Q4 2016 (or Q3 2016 for SolarCity). **SolSystems** data are averages of the 25th and 75th percentile values of "developer all-in asking prices" published in the company's monthly Sol Project Finance Journal reports throughout 2016.

Figure 11. Comparison to Other Installed Price or Cost Benchmarks

Text Box 4. Reasons for Differences between LBNL Median Values and Other Benchmarks

Variation across the benchmarks shown in Figure 11 arise for a number of reasons, and in general explain why median values drawn from the LBNL data sample are higher than the other benchmark values:

- **Timing:** The LBNL data in Figure 11 are based on systems installed over the course of 2016. A number of the other benchmarks cited in the figure are instead based on price quotes issued in 2016, which may precede installation by several months to even a year or more (especially for 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, like the modeled prices and price-quote data, represent prices paid by PV system owners to installers or project developers. In contrast, 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 11 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 35% of 2016 residential systems in the sample have high efficiency modules, 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 PV pricing benchmarks (though, from the customer's perspective, are nevertheless 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 11 may, in many cases, be reflective of relatively large and experienced installers.

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

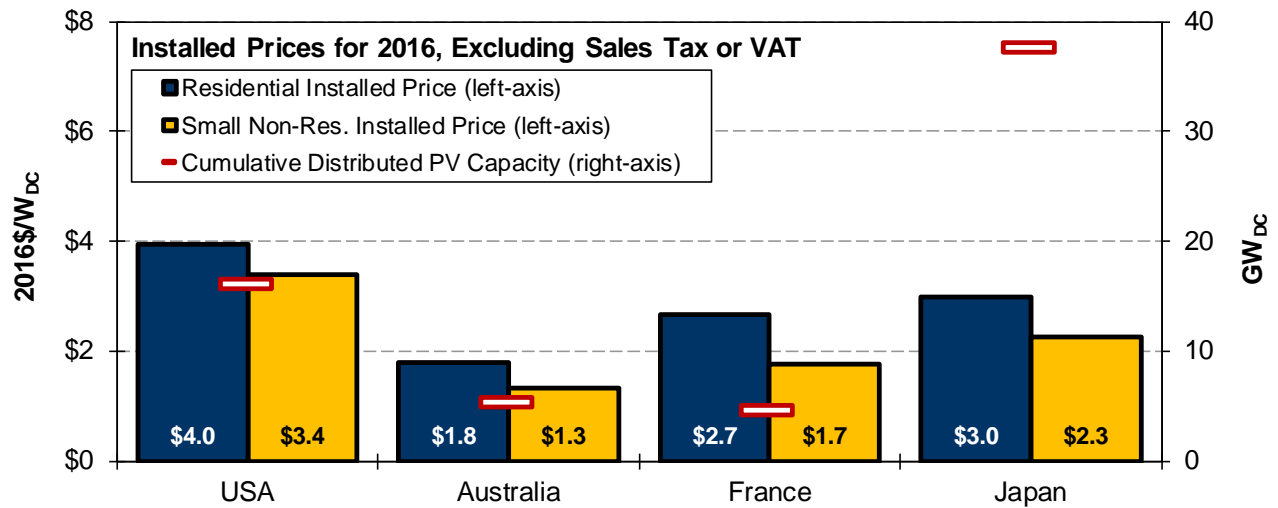
Notwithstanding the significant installed price reductions that have already occurred in the United States, international experience suggests that greater near-term reductions are possible. Figure 12 compares median installed prices for residential and sub-500 kW non-residential systems installed in the United States in 2016 to system prices for a number of other major national markets, in all cases excluding sales tax or value added tax (VAT). In Australia, for example, typical pricing for residential systems was reported to be around \$1.8/W in 2016: less than half the median price observed within the LBNL dataset.

To be sure, these data are not perfectly comparable to one another.¹⁰ 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). However, even considering the broader set of U.S. benchmarks presented in the previous section, the data suggest that U.S. installed prices are still higher than in other major markets.

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 Australia and Japan (as well as Germany, which is not included in the above figure) have confirmed that soft costs in those countries 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 Australia and Germany that enable lower labor costs in those countries than in the United States (RMI and GTRI 2013, 2014).

¹⁰ The figure compares across those countries for which IEA PVPS 2016 national country reports were published as of August 2017.

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 elements. Indeed, as shown in Figure 12, cumulative distributed PV capacity in Japan is significantly greater than in the United States. On the other hand, Australia and France—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 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.



Notes: Data for Australia, France, and Japan are based on each country’s respective IEA Photovoltaic Power Systems Programme’s (PVPS) 2016 National Survey Report (Johnston and Egan 2017, L’Epine 2017, and Yamada and Ikki 2017).

Figure 12. Comparison of Installed Prices in 2016 across National Markets (Pre-Sales Tax/VAT)

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 potential drivers for installed price differences across projects. The section begins by describing the overall 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 variation, including differences in: system size, state, installer, host-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.

Overall Installed Price Variability

Considerable spread exists within the pricing data, which has persisted over time, despite continuing maturation of U.S. PV markets. This is evident in Figure 5, presented earlier, which shows the 20th-to-80th percentile installed-price range for each customer segment over time. Those percentile bands have shifted downward over time as prices have fallen, but the overall spread in pricing for each customer segment has remained relatively unchanged.

Figure 13 provides further detail on the pricing distribution for systems installed in 2016. Among residential systems, roughly 20% were installed at prices below \$3.2/W (the 20th percentile value) and 20% were above \$5.0/W (the 80th percentile), with the remaining 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 \$2.7/W and \$4.4/W, respectively. The distribution for larger non-residential systems >500 kW is somewhat narrower, with a 20th-to-80th percentile band of \$1.9/W to \$3.2/W.

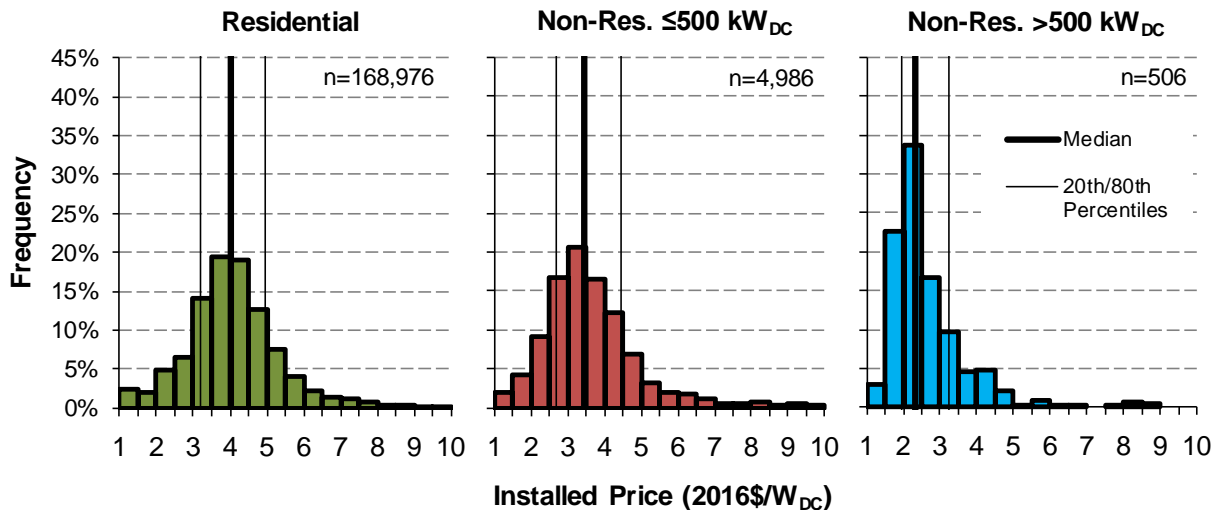


Figure 13. Installed Price Distributions for Systems Installed in 2016

The potential underlying causes for this persistent pricing variability are numerous, including differences in 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 using simple descriptive methods, and are also the subject of a series of econometric studies that LBNL and its collaborators have undertaken to better isolate the impacts of individual pricing drivers (see Text Box 5).

The wide pricing distributions observed within the data sample also serve to demonstrate the potential for low-cost installations. For example, though small in percentage terms, it is notable that more than 15,000 residential systems installed in 2016 (9%) were priced below \$2.5/W, and 8,000 (5%) were priced below \$2.0/W. The lower tail of the pricing distribution may offer insights into opportunities for broader price reductions, as LBNL and others have explored elsewhere.

Text Box 5. 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 and NREL have 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 sources, and apply a variety of statistical and econometric methods to explore PV pricing issues. To date, a number of studies in this series have been completed, and others are planned or underway.

Nemet et al. (2017) analyzed price dispersion in U.S. residential PV installations. The study found that price dispersion—defined as the variability in prices among systems installed within a given county and quarter—has increased over time. It further found that factors that increase consumer access to information—such as neighbors who have recently installed PV and the availability of third-party quotes—are associated with less price dispersion. These results provide support for the importance of efforts to enhance access to price information, especially in nascent PV markets where access to experiences of neighbors is unavailable.

O’Shaughnessy et al. (2016) developed a new approach to delineating solar PV market boundaries based on the spatial distribution of installer firms (instead of the more-typical approach using political boundaries, such as county or zip code).

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.

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 (\$1.5/W effect). The study also found that installed prices were lower in markets with the greatest density of installers (\$0.5/W effect), potentially due to greater competition, and that prices were lower for systems installed by the most-experienced companies (\$0.2/W effect). The study also found evidence that rich incentives can lead to higher prices (\$0.4/W effect). That latter finding may reflect value-based pricing, though it may also simply be the natural result of high demand for solar enabling higher-cost installers and higher-cost systems.

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 findings 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 by enabling volume purchases of materials. These scale economies are evident in the preceding figures that show lower installed prices for non-residential systems than for residential systems. They also arise within each customer segment, contributing to the observed pricing variability.

Among residential systems installed in 2016 (Figure 14), system sizes range from less than 2 kW to 20 kW and above, though the vast majority of systems fall within the range of 2-12 kW. Across that range, median prices are roughly \$0.8/W (19%) lower for systems at the upper end of that range than for those at the lower end.¹¹ Beyond 16 kW, further price declines appear to taper off for residential systems, indicative of strongly diminishing returns to scale (though sample sizes also become progressively thinner as well). These trends are generally consistent over time, as shown in Table B-2 in the appendix, which presents time series data across residential system sizes.

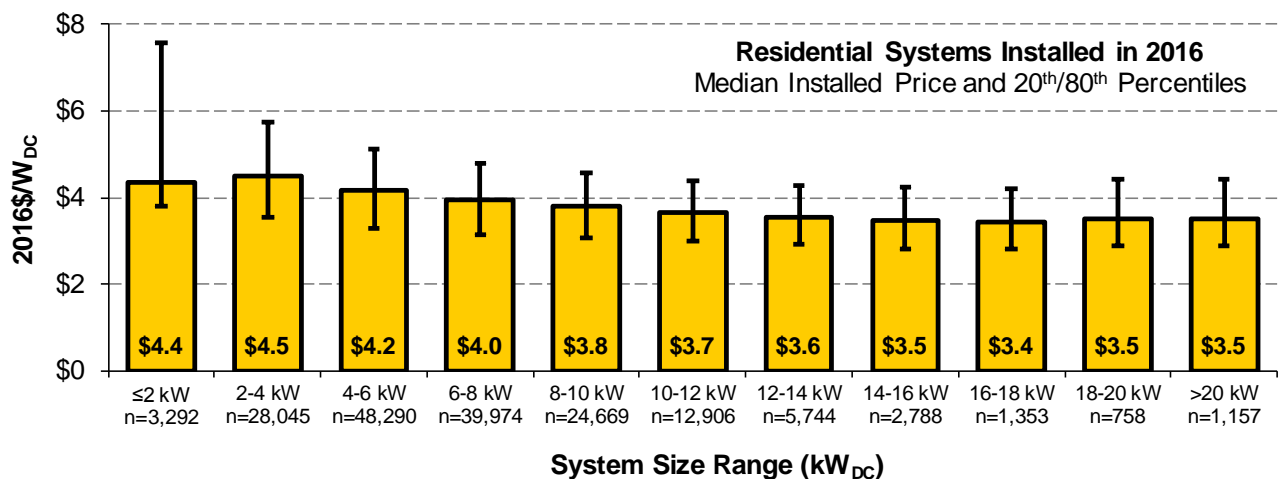


Figure 14. Installed Price of 2016 Residential Systems by Size

For non-residential systems (Figure 15), which span a wide range of system sizes, even more-pronounced economies of scale occur. Among systems installed in 2016, median installed prices

¹¹ Median prices for systems ≤2 kW are relatively low as a result of the high proportion of systems in that size range installed in new construction (which tend to be low-priced).

were \$1.9/W (46%) lower for the largest class of non-residential systems >1,000 kW in size than for the smallest non-residential systems ≤10 kW.¹² Even greater scale effects may arise when moving from large non-residential systems to utility-scale, though the latter are outside the scope of this report. See Table B-3 in the appendix for time series data on non-residential pricing by system size.

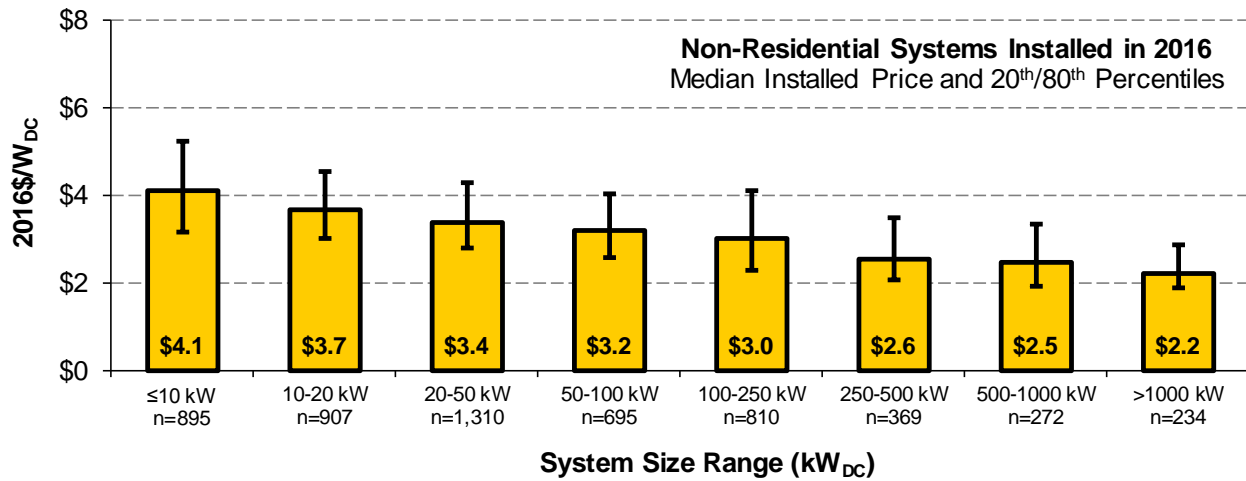


Figure 15. Installed Price of 2016 Non-Residential Systems by Size

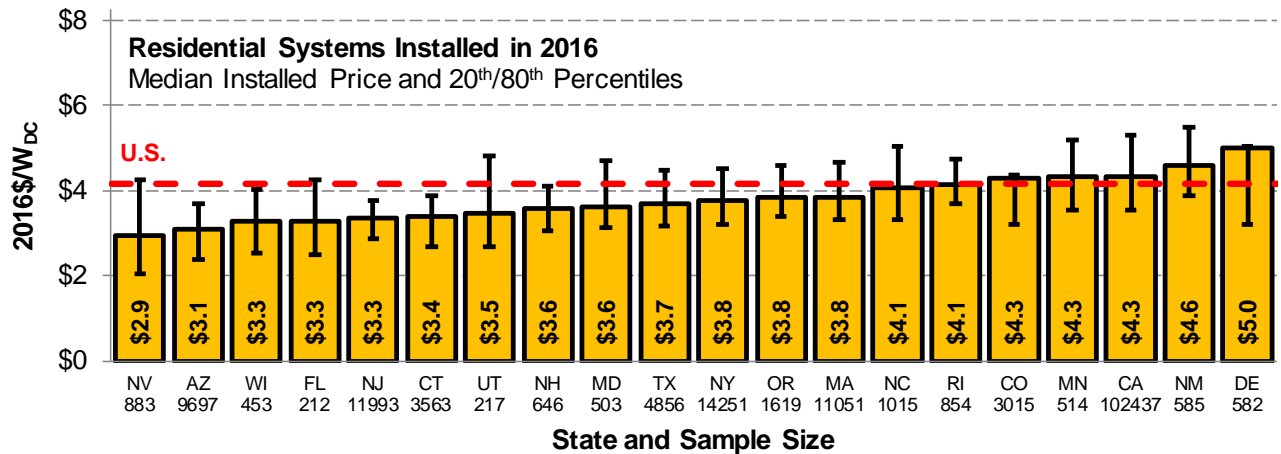
Installed Price Differences across States

The U.S. PV market is fragmented into regional, state, and local markets, each with potentially unique pricing dynamics. Figure 16 and Figure 17 focus, in particular, on state-level differences for systems installed in 2016.

As shown, installed priced can differ quite substantially across states (though significant variability clearly also exists *within* most states). Among residential systems installed in 2016, median installed prices range from a low of \$2.9/W in Nevada to a high of \$5.0/W in Delaware.¹³ Pricing for non-residential systems ≤500 kW similarly varies across a wide range, from \$2.8/W in Colorado to \$4.2/W in Minnesota. 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. Among this small set of states, median installed prices vary across a considerably narrower range, from \$2.2/W in New Jersey to \$2.5/W in Massachusetts.

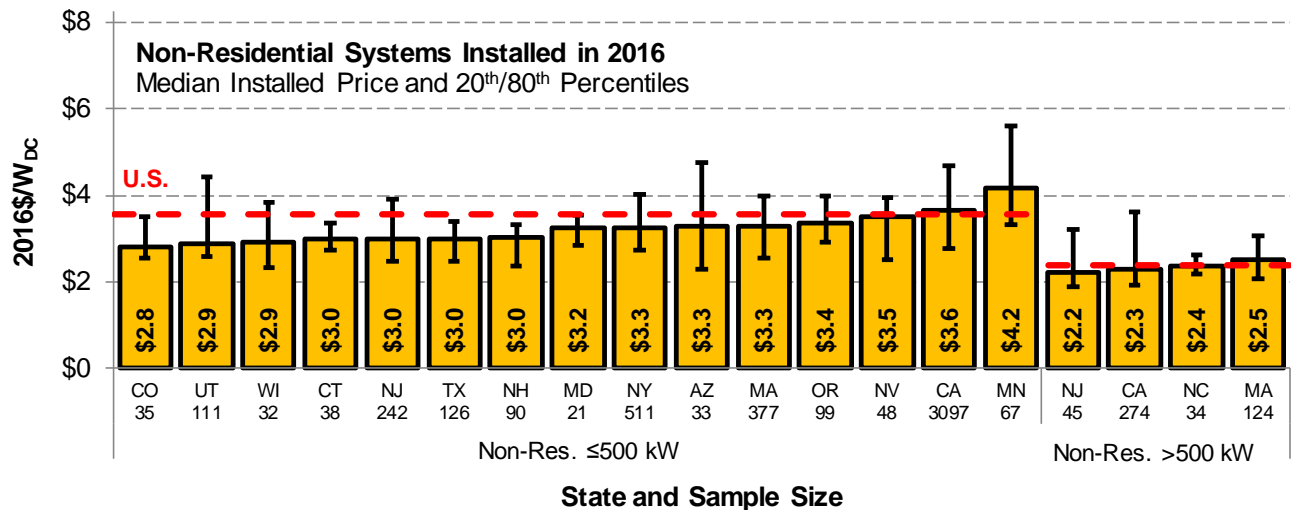
¹² Note that non-residential systems also exhibit diminishing returns to scale, though this is not readily observable in the figure, because the bin intervals become progressively wider at larger system sizes.

¹³ The median price for residential systems in Delaware is driven by a large contingent of systems with an installed price of \$5.0/W. These could not be confirmed as appraised value and were therefore retained in the sample, but are nevertheless somewhat suspect.



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

Figure 16. Installed Price of 2016 Residential PV Systems by State



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

Figure 17. Installed Price of 2016 Non-Residential PV Systems by State

Some of the observed pricing differences across states may be idiosyncratic (e.g., due to small sample sizes or anomalous reporting by a single large installer); however, other factors may also be at play. 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 may be the result of value-based pricing, or simply the fact that rich incentives increase demand, supporting higher-cost systems. 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.

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 (40% in 2016, compared to 25% in other states).

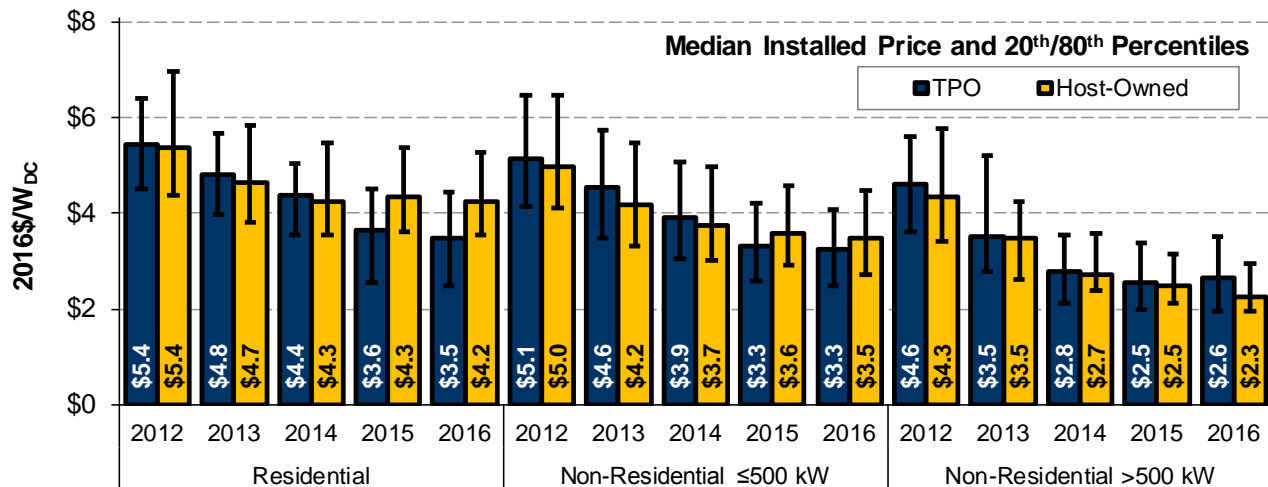
Notwithstanding the significant cross-state differences, substantial pricing variation also clearly exists *within* each state, and for many states is at least as wide as the cross-state differences. Such intra-state pricing variability likely reflects many of the same factors that contribute to pricing variability across states. 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 Host-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 retained.¹⁴ 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 host-owned systems. On the one hand, installers selling systems to TPO providers may face incremental transaction costs or a more-complicated customer sales process, which could elevate system prices. On the other hand, customer acquisition and project development functions for some TPO projects may be performed by entities other than the installer, in which case the reported price might reflect just hardware and direct installation labor costs. TPO finance providers likely also have greater negotiating power with installation contractors, and may have a preference towards relatively standardized system designs, also tending to push pricing lower compared to host-owned systems. In addition, a growing share of host-owned systems may include loan origination fees in the installed price paid by the site host.

For residential systems, the data suggest that installed prices have become substantially lower for TPO systems than for host-owned systems (Figure 18). In particular, the median price of TPO systems was roughly \$0.7/W below that of host-owned systems, in both 2016 and 2015. This marks a reversal from prior years, when median prices were slightly higher for TPO than for host-owned systems. A similar, though less dramatic, trend can be seen among small non-residential systems, with TPO systems dropping below the price of host-owned systems over the last two years of the analysis period. In part, these trends may reflect the growing prevalence of unsecured solar loans with origination fees, which may be dampening price declines for host-owned residential systems, resulting in virtually no price decline for those systems over the 2014-2016 timeframe. For large non-residential systems, Figure 18 instead shows higher median prices for TPO over host-owned systems in 2016, though in prior years median prices were virtually identical between TPO and host-owned systems in this size class.

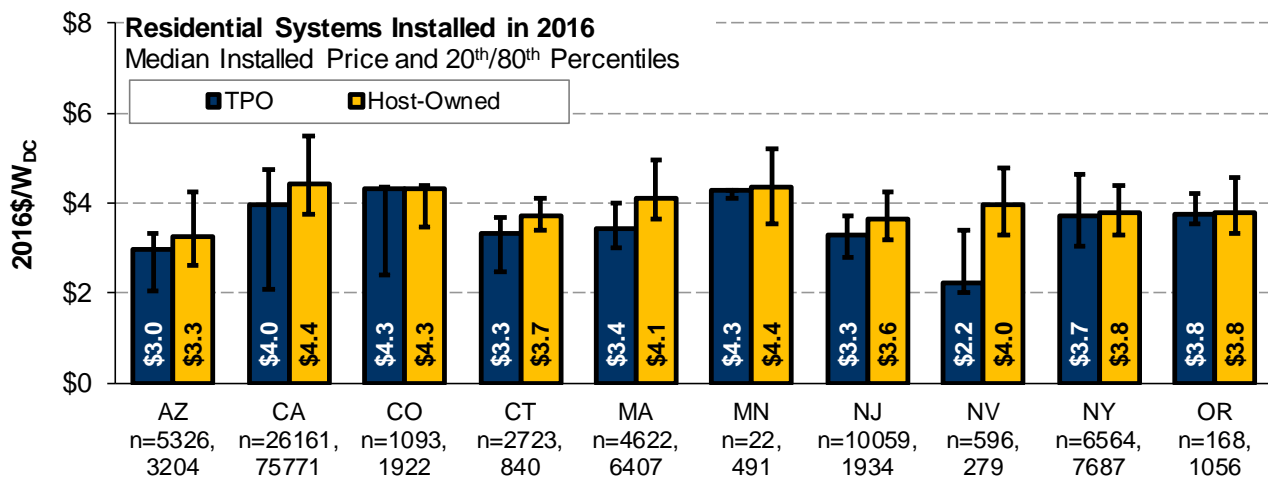
¹⁴ For reference, installed prices reported by integrated TPO providers, otherwise excluded from the analysis presented in this report, are summarized in Appendix A and compared to prices reported for non-integrated TPO systems.



Notes: Data presented for TPO systems represent transaction prices between installation contractors and third-party finance providers; data from integrated companies that perform both installation and financing are excluded.

Figure 18. Installed Prices Reported for Host-Owned vs. TPO Systems over Time

The trend in the residential sector toward lower prices for TPO than for host-owned systems is relatively consistent across states, as shown in Figure 19. In all of the states shown, TPO systems were lower-priced than host-owned systems (even if only marginally so in several cases). It is also evident that installed prices for TPO systems vary to a much greater degree across states than do prices for host-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.



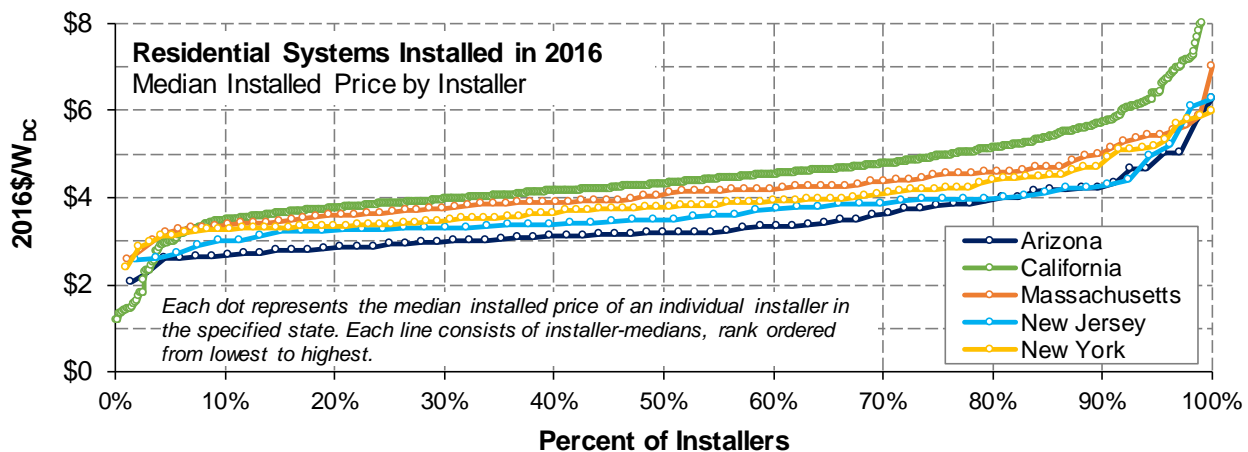
Notes: Data presented for TPO systems represent transaction prices between installation contractors and third-party finance providers; data from integrated companies that perform both installation and financing are excluded.

Figure 19. Installed Prices Reported for Host-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 2016, active primarily in the residential sector.¹⁵

In order to illustrate how installed pricing may vary across installers, Figure 20 shows median prices for individual installers in the five largest state markets, focusing on residential systems installed in 2016. In each of these five states, installer-level median prices differ by anywhere from \$0.7/W to \$1.4/W between the upper and lower 20th percentiles of installer-medians, demonstrating substantial heterogeneity in pricing across installers. Related, the figure serves to highlight “low-price leaders” that could serve as benchmarks for what may be achievable more broadly in each state. In New York, for example, 20% of installers had median prices below \$3.3/W in 2016; this compares to a median price of \$3.8/W across all residential systems installed in the state in 2016. Even in California—a generally high-priced state—more than 40 installers, many with hundreds of systems installed in 2016, had median residential prices below \$3.0/W in 2016. At the other end of the spectrum, of course, are high-priced installers; 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.



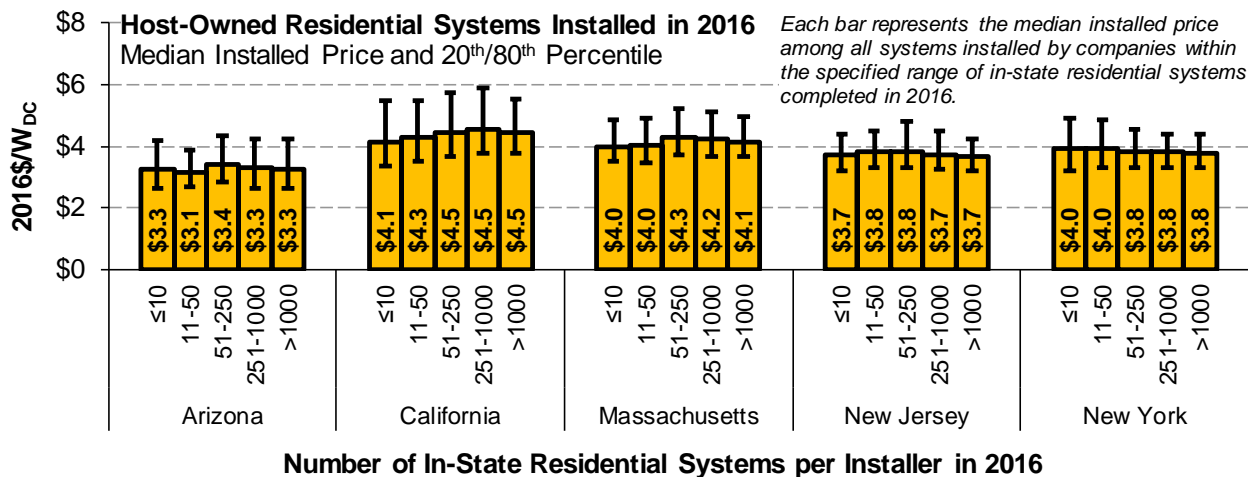
Notes: Includes only installers with at least 10 residential systems installed in the given state in 2016.

Figure 20. Median Installed Prices by Installer for Residential Systems in 2016

One other potential reason for pricing differences among installers is the size of the company, though the data present no clear pattern in this regard. Figure 21 shows installed prices for host-owned residential systems installed in 2016, segmented according to installer volume in each of the top-five states. As shown, pricing is generally quite similar across installer sizes in each state (with the possible exception of California, where larger-volume installers appear to be somewhat higher-priced). In part, this may be due to several competing dynamics. On the one hand, high-volume

¹⁵ 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.

installers may enjoy economies of scale and potentially greater efficiency in certain business operations as a result of accumulated experience. On the other hand, they may also face relatively high customer acquisition costs and other business operation costs associated with aggressive growth. High-volume installers (as well as smaller installers with a dominant presence in particular locations) may also possess a degree of market power and/or reputational advantages, enabling higher pricing. These competing dynamics have, to varying degrees, been substantiated in Gillingham et al. (2014) and O’Shaughnessy and Margolis (2017).



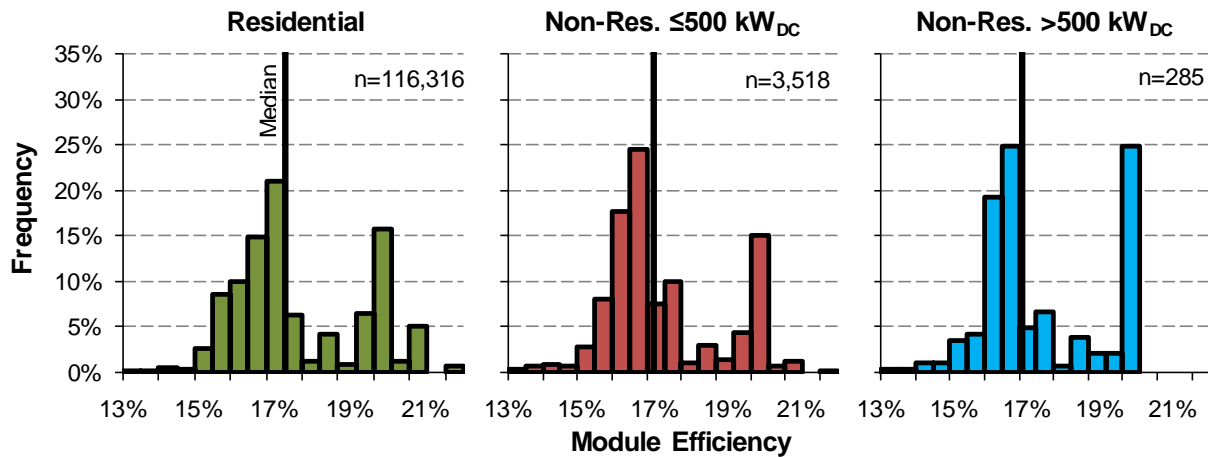
Notes: Installer volumes are calculated from the full data sample, and therefore include integrated TPO systems and other excluded systems that are not used for the purpose of calculating installed price statistics.

Figure 21. Installed Prices of Host-Owned Systems According to State-Level Installer Volume

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 22, which focuses on systems installed in 2016). The majority of systems within each customer segment have module efficiencies between 15.5% and 17.5%, typical of current poly-crystalline silicon technology. Localized peaks at higher efficiency levels represent premium efficiency, mono-crystalline modules offered by several manufacturers. Systems with premium efficiency modules (>18%) constitute a relatively sizeable share (roughly 35%) of the residential sample in 2016, and somewhat smaller percentages of non-residential systems.

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 by shrinking the footprint of the system. Cost modeling by Fu et al. (2017) estimates that, for example, an increase in module efficiency from 16% to 20% would reduce residential system costs by roughly \$0.2/W. On the other hand, premium-efficiency modules tend to be more expensive than standard efficiency modules. Recent spot market prices for high-efficiency n-type monocrystalline PV modules are roughly \$0.3/W higher than for standard polycrystalline modules, and the differential may be considerably greater for some manufacturers of premium efficiency modules (PVInsights 2017).



Notes: Module efficiencies were pulled from manufacturer spec sheets for those systems with data on module manufacturer and model.

Figure 22. Module Efficiency Distributions for Systems Installed in 2016

To examine the net effect of these various and opposing cost drivers, Figure 23 compares installed prices according to module efficiency. The figure focuses on just residential and smaller (sub-500 kW) non-residential systems, and distinguishes between module efficiencies less than or 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 2016, the median differential was roughly \$0.5/W among both residential small non-residential systems, and was of generally similar magnitude in prior years. The implication of these findings is that—at least among the specific mix of modules and systems within this data sample—the price premium for high-efficiency modules has generally outweighed any corresponding reduction in BOS costs.¹⁶ This is distinct from the trend noted earlier, that increasing efficiencies over time across all module technologies have contributed to declining installed prices.

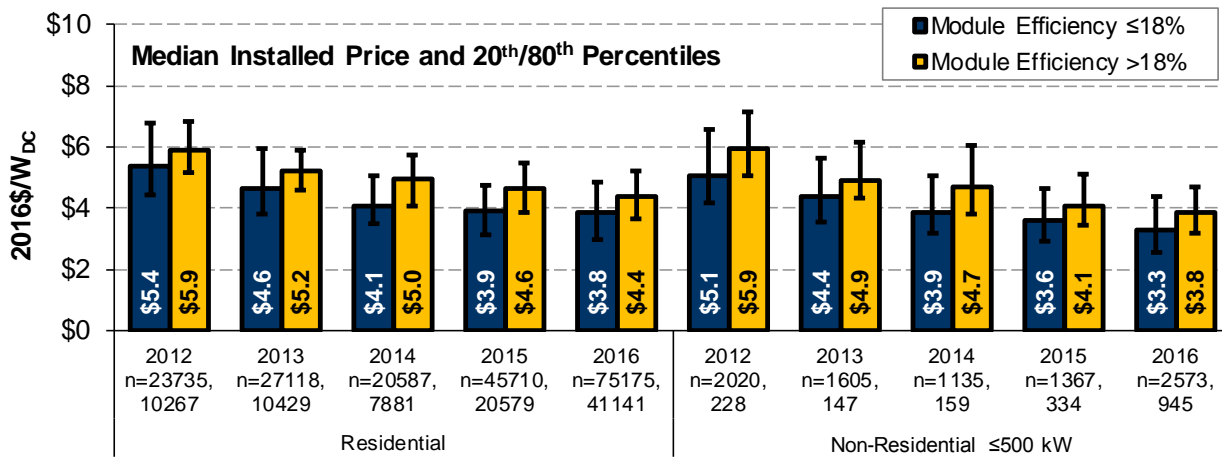


Figure 23. Installed Price Differences Based on Module Efficiency

¹⁶ Indeed, the installed price premium for systems with high-efficiency modules is substantially greater 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.

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, new construction systems are most readily identifiable for California, where roughly 3% of 2016 residential systems in the final analysis sample were new construction. As such, the following analysis focuses specifically on California, though the results may apply elsewhere as well.

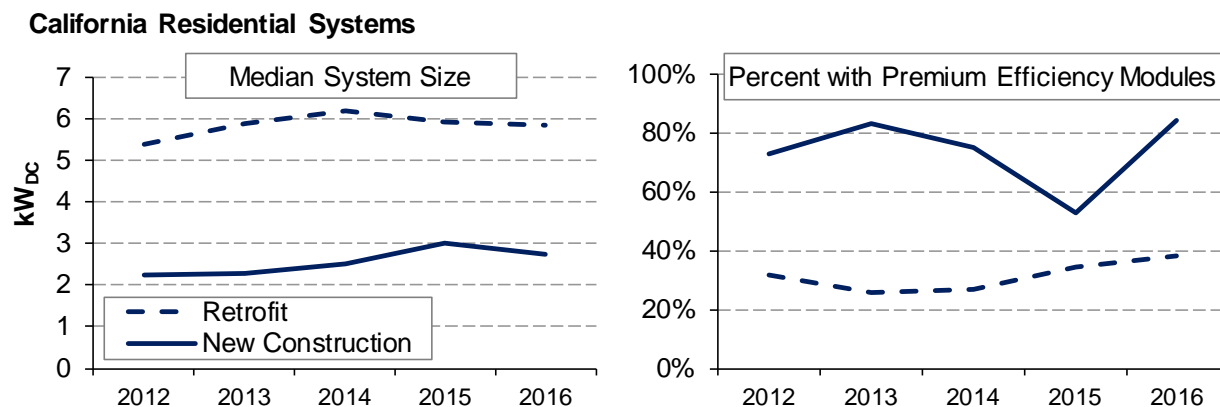


Figure 24. Key Characteristics of Residential Retrofit vs. New Construction in California

Residential systems installed in new construction differ from retrofit systems in several ways relevant when comparing 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 2016, residential new construction systems in California had a median size of just 2.8 kW, compared to 5.9 kW for residential retrofit systems in the state. 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-hand panel of the figure, where more than 80% of new construction systems in 2016 had premium-efficiency modules, compared to roughly 40% of retrofit systems. All else being equal, these two differences—smaller systems and higher incidence of premium efficiency modules—would tend to boost the 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 in installation 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.

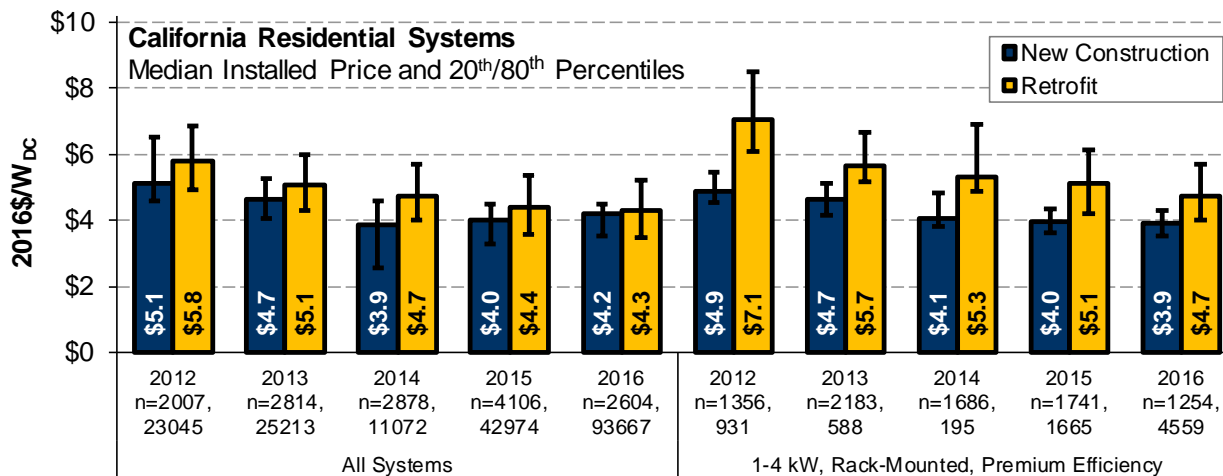


Figure 25. Installed Price of Residential Retrofit vs. New Construction in California

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, *despite* the smaller size and higher incidence of premium efficiency modules among new construction systems.

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 2016, 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.¹⁷

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 2016, systems at tax-exempt customer sites comprised 18% of sub-500 kW non-residential systems and 17% 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.

¹⁷ Notwithstanding the general consistency of 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), those reporting data may have some discretion in terms of how those shared 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.

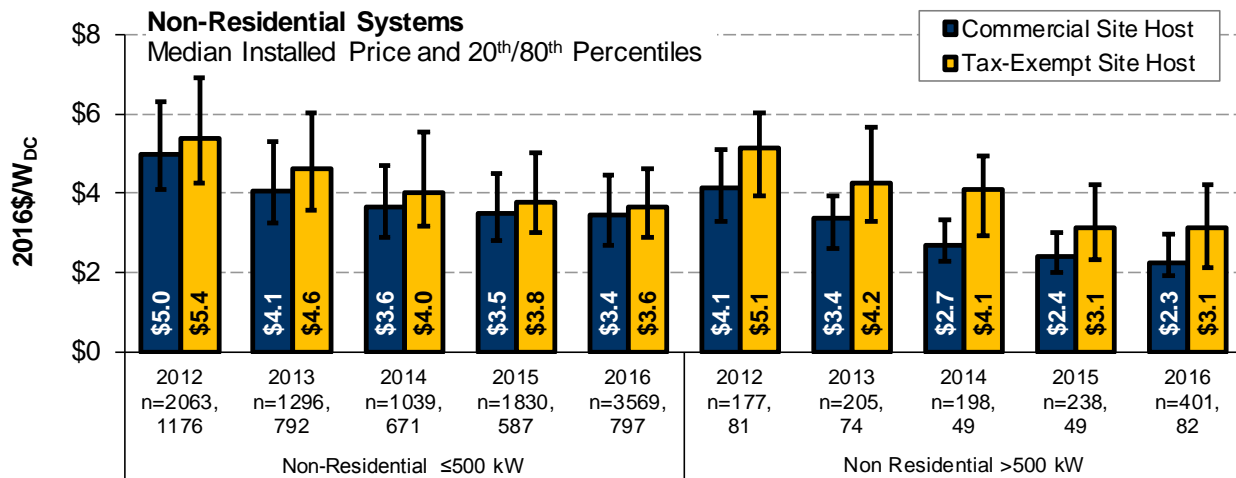


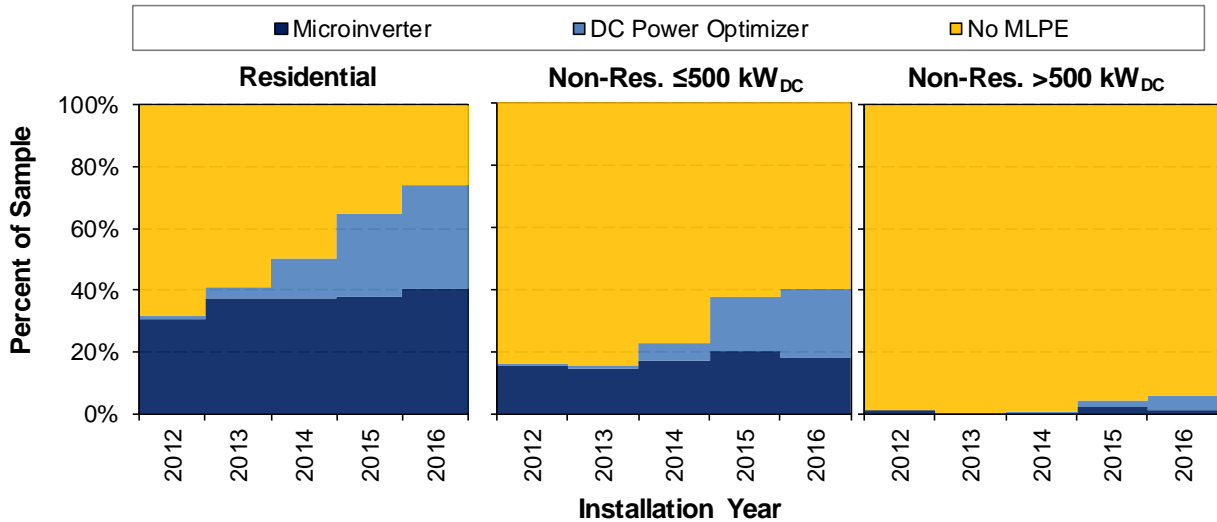
Figure 26. Installed Price Variation across Host Customer Sectors

Installed prices are consistently higher for systems at tax-exempt customer sites than at for-profit commercial facilities. This is evident in Figure 26, which compares installed prices for these two sub-sectors over time. In 2016, systems at tax-exempt customer sites were roughly \$0.2/W higher-priced within the sub-500 kW non-residential segment, and \$0.8/W higher among >500 kW non-residential systems. Similar price differentials also exist in most prior years. Higher prices at tax-exempt customer sites may reflect a number of underlying factors: prevailing wage/union labor requirements, preferences for domestically manufactured components, a high incidence of shade and parking structure PV arrays, additional permitting requirements, and potentially more complex government procurement processes. Tax-exempt customers may also have less stringent financial criteria than their for-profit commercial counterparts.

Installed Price Differences for Systems with Module-Level Power Electronics

Module-level power electronics (MLPEs), which include both microinverters and DC power optimizers, and offer performance advantages over standard string inverters, have been steadily gaining market share in recent years.¹⁸ This is reflected in the final analysis sample used in this report, which shows rapidly increasing penetration, particularly in the residential sector, where 74% of all 2016 systems had some form of MLPE (see Figure 27). Less pronounced, though still significant, growth has also occurred among smaller non-residential systems, where microinverters and DC power optimizers together represent almost 40% of sub-500 kW non-residential systems in the final analysis sample installed in 2016. By comparison, penetration among larger non-residential systems >500 kW in size has remained negligible.

¹⁸ 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, eliminating losses that would otherwise occur on a string of panels when the output of a subset of the panels is compromised (e.g., due to shading or orientation) or when mismatch exists among modules in the string.



Notes: The DC power optimizer share includes only systems with SolarEdge inverters, and thus likely understates the actual share of DC power optimizers in the data sample.

Figure 27. Penetration of Module-Level Power Electronics within the Final Analysis Sample

In terms of their impacts on up-front installed prices, MLPEs can have both direct and indirect impacts. The direct impact comes in the form of a price premium over standard string inverters: roughly a \$0.2/W premium for microinverters and a \$0.1/W premium for DC optimizers (GTM Research and SEIA 2017). MLPEs can also have indirect cost impacts—both positive and negative—related to installation labor, system design, and electrical balance-of-system costs. These indirect cost impacts can be positive or negative.

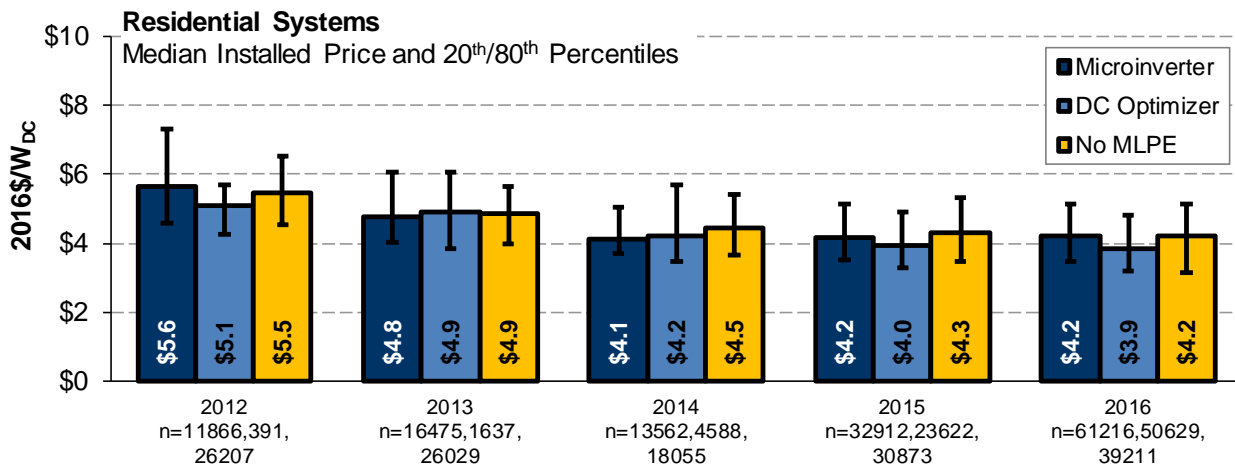


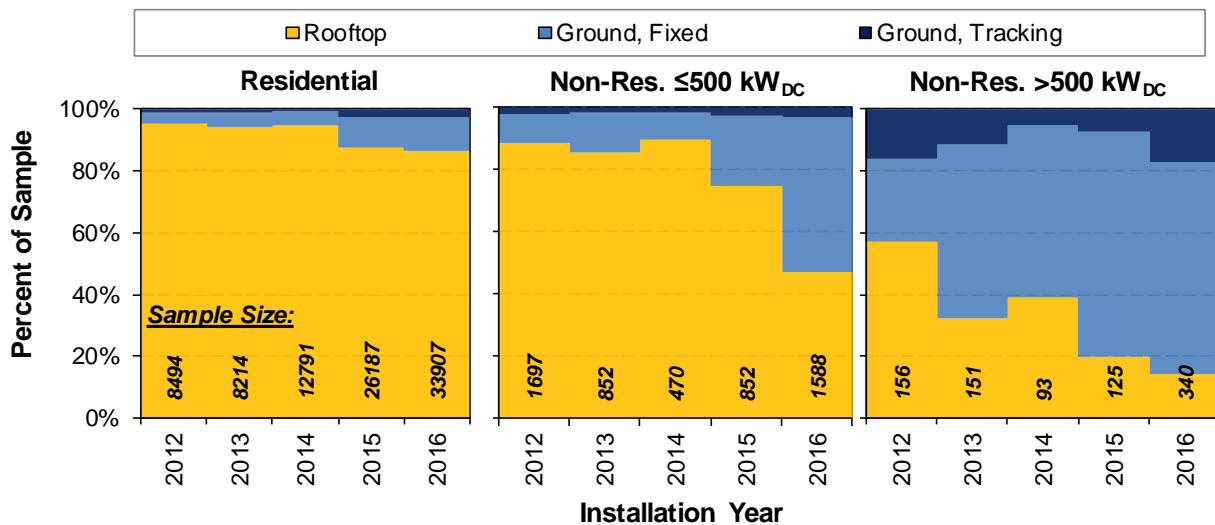
Figure 28. Installed Price Differences between Residential Systems with and without MLPEs

As shown in Figure 28, installed price differences between residential systems with and without MLPEs is quite small. Among residential systems installed in 2016, median installed prices were essentially identical for systems with microinverters and those with no MLPE, while those with DC power optimizers were roughly \$0.3/W lower-priced than the other two groups. Similarly small differences occurred in prior years as well. Ultimately, the net effect of MLPEs on total installed

prices is too small to reliably discern within these data without the use of more sophisticated statistical analysis. However, the fact that the total installed price premium for systems with MLPs is consistently less than the incremental cost of MLPs themselves suggests that these devices likely offer some offsetting savings on other balance-of-system or labor costs. This inference may be further justified when considering that installers tend to use MLPs for more-complex installations (e.g., systems on multiple roof planes) or when space constraints are binding.

Installed Price Differences by Mounting Configuration

Unlike residential systems, which are predominantly roof-mounted, many non-residential systems are ground-mounted and may also include tracking equipment. Among the relatively limited set of systems in the sample with data on mounting configuration, 53% of small non-residential systems and 86% of large non-residential systems installed in 2016 were ground-mounted, while 3% and 17%, respectively, had tracking (see Figure 29). Many of what are referred to within this report as large non-residential systems might thus be classified elsewhere as small utility-scale systems.



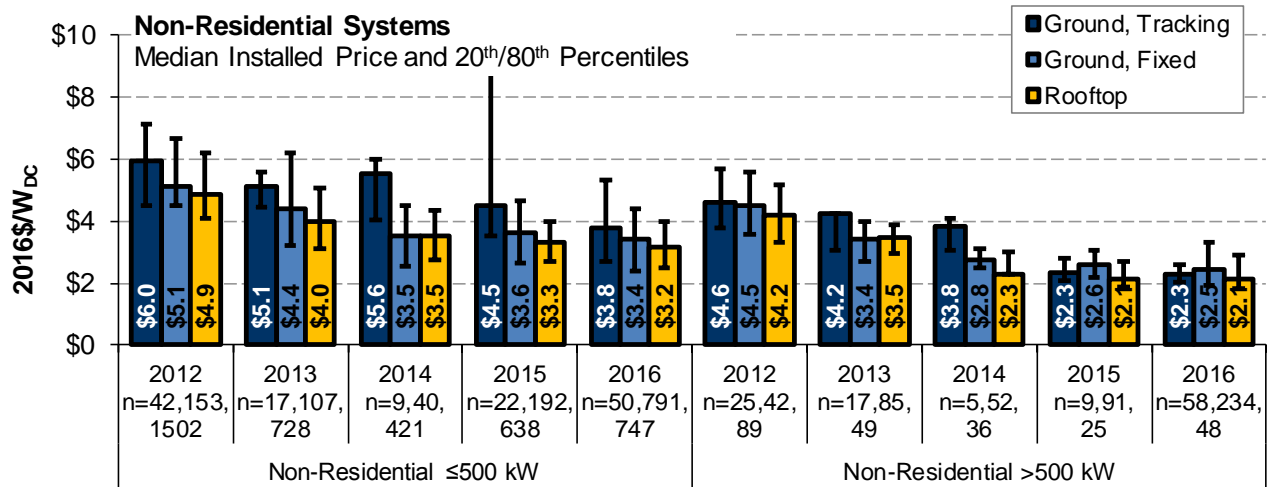
Notes: The figure is derived from the relatively small subsample of systems for which data were available specifying whether the system is roof- or ground-mounted and whether or not it has tracking.

Figure 29. Mounting Configuration among Systems in the Data Sample

As shown in Figure 30, installed prices for fixed ground-mounted systems tend to be somewhat higher than for rooftop systems, potentially reflecting additional costs associated with trenching and foundation work. In 2016, the median installed price of fixed, ground-mounted systems was roughly \$0.3/W higher than for rooftop systems, in both the small and large non-residential categories. This is generally consistent with earlier years, though the trends exhibit a certain level of volatility from year to year as a result of small sample sizes.

Tracking equipment adds further to the cost of ground-mounted systems, though this is not always readily or precisely discernible with the installed price data. Within the small non-residential segment, the median installed price of systems with tracking was about \$0.4/W higher in 2016 than for fixed, ground-mounted systems. This differential is smaller than in previous years, potentially reflecting the declining cost of tracking equipment. Within the large non-residential segment,

however, systems with tracking actually had a lower median price in both 2015 and 2016 than fixed-tilt, ground-mounted projects. Clearly, this particular trend is the result of other unrelated factors that outweigh any cost impacts associated with tracking equipment. As a point of reference, cost modeling by Fu et al. (2016) and by GTM Research and SEIA (2017), as well as empirical data from Bolinger and Seel (2016), suggests an incremental cost of roughly \$0.1/W to \$0.2/W for tracking equipment (albeit in utility-scale systems applications).



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

Figure 30. 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 both by declining costs and supportive policies. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage further cost reductions over time through increased deployment. Research and development (R&D) efforts within the industry have also focused on cost reductions, 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, and by an additional 50% by 2030.

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, installed prices have continued to fall, partly due to continued progress in targeting soft costs.

Given the limits to further reductions in module and other hardware component prices, continued reductions in soft costs will be essential to driving further deep reductions in installed prices. Unlike module prices and other hardware component costs, which are primarily established through global markets, soft costs 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 soft cost reductions within the solar industry and among policymakers has spurred a flurry of initiatives and activity in recent years. The continued decline in installed 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 costs thus likely requires a broad mix of strategies, including: 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 2016 Real Dollars: Installed price and incentive data are expressed throughout this report in real 2016 dollars (2016\$). Data provided by PV program administrators in nominal dollars were converted to 2016\$ 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 data providers directly provide system capacity in units of DC-STC; however, several did not. In those cases, PV system DC-STC capacity was calculated from the nameplate rating of the modules (by cross-referencing the module model name against manufacturer spec sheets) and module quantity.

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. For systems within the California investor-owned utilities’ service territories, the California Public Utilities Commission’s Currently Interconnected Dataset was used as the base data sample, and additional data for those systems was incorporated from the various incentive program datasets (CSI, NSHIP, SGIP, and ERP) based on CSI ID numbers and street addresses. 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.

Incorporating 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 lists¹⁹ and SolarHub²⁰) 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 or standard string/central inverter). All systems with SolarEdge inverters were assumed to also be equipped with DC power optimizers.

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 Host-Owned vs. TPO Systems: Most programs explicitly identify the ownership type of each system as either host-owned or TPO. Where such data were not provided, however, inferences were made wherever possible. First, systems were assumed to be host-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

¹⁹ <http://www.gosolarcalifornia.ca.gov/equipment/>

²⁰ <http://www.solarhub.com/>

TPO systems. Next, any remaining systems with unknown ownership type were assumed to be TPO if installed by companies known to be providers mostly of TPO systems, including: SolarCity/Tesla, Sungevity, Vivint, SunRun, and Roof Diagnostics & Solar.

Identification and Removal of Appraised Value Systems: A total of 249,910 systems were removed from the final data sample, on the grounds that installed prices reported for these systems were appraised values, rather than transaction prices. The vast majority of these systems were identified simply based on reported installer name and system ownership type. Specifically, prices reported for TPO systems installed by the three integrated TPO providers—SolarCity/Tesla, Sungevity, and Vivint—were assumed to be appraised values and removed from the final data sample. Upon inspection of the data, prices reported for host-owned systems installed by SolarCity/Tesla were also deemed likely to be appraised values and were thus also removed from the data sample.

If data on installer name were 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 identical prices are reported for large clusters of systems installed by individual integrated TPO providers. These prices 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 in the dataset as TPO and installed by an integrated TPO provider. Then, for systems where installer name data were unavailable, reported prices were assumed to be appraised value if they fell within the aforementioned set of price clusters and the system was not explicitly identified as host-owned. In addition, systems within those price clusters installed by integrated TPO providers but labeled as host-owned were assumed to, in fact, be TPO systems and were accordingly re-classified as TPO and flagged as appraised value.

For reference, Figure 31 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, installed prices reported for integrated TPO systems in 2010 and 2011 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 are an assessed “fair market value”, often based on the discounted cash flow from the project (or a bundle of projects). Starting in 2012, at least one major integrated TPO provider changed its installed price reporting methodology for PV incentive programs. Following that, the disparity between installed prices reported for integrated and non-integrated TPO systems initially diminished (during 2012-2013), but has grown over the last several years of the analysis period as integrated TPO prices remained flat.

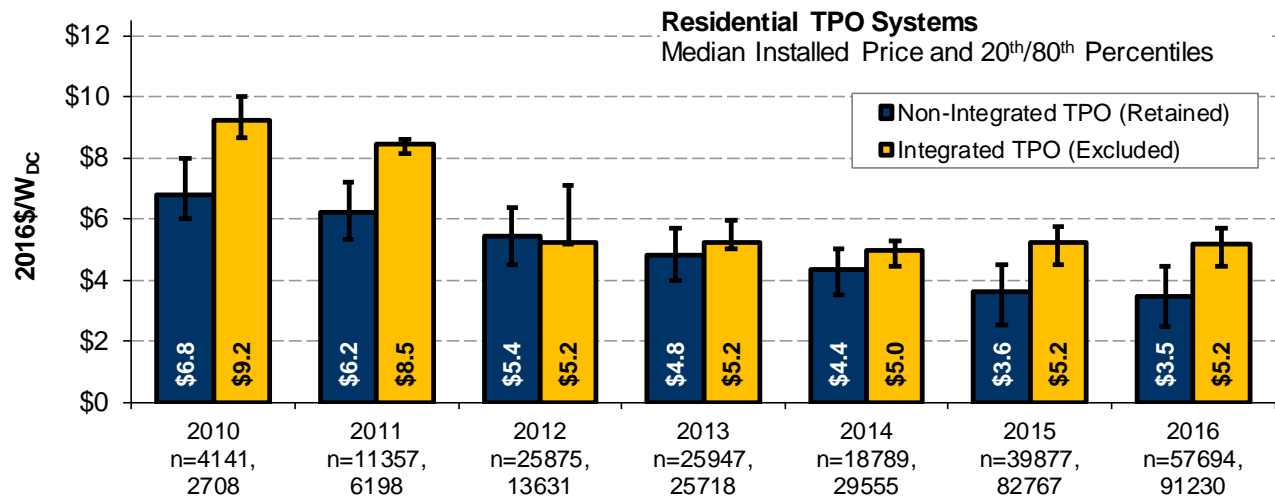


Figure 31. Installed Prices Reported for Non-Integrated and Integrated Residential TPO Systems

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.

45 **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	2016 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
	Arizona Public Service	0.4 - 3,903	2002 - 2016	8,003	66.0	30,432	415.3
	Duncan Valley Electric Coop.	0.5 - 11	2006 - 2009	0	0.0	4	0.0
	Graham County Electric Coop.	0.06 - 25	2005 - 2010	0	0.0	119	0.6
	Mohave Electric Coop.	1.0 - 47	2008 - 2016	53	0.5	222	1.6
	Morenci Water & Electric	5.8 - 20	2014 - 2015	0	0.0	3	0.0
	Navopache Electric Coop.	1.0 - 55	2007 - 2016	38	0.3	130	0.9
	Salt River Project	0.2 - 1,703	2005 - 2016	552	7.0	8,074	81.9
	Sulpher Springs Valley Electric Coop.	1.0 - 984	2009 - 2016	16	0.2	1,078	7.9
	Tucson Electric Power	0.4 - 1,000	2006 - 2016	124	1.2	882	7.3
	Trico Electric Coop.	0.3 - 353	1999 - 2016	943	6.6	6,464	46.6
	UniSource Electric Services	0.5 - 98	1999 - 2016	4	0.0	1,541	14.1
CA	California Center for Sustainable Energy (Bear Valley Electric)	1.5 - 20	2015 - 2016	27	0.2	37	0.2
	California Center for Sustainable Energy (Pacific Power)	1.3 - 257	2011 - 2016	10	0.4	165	2.7
	CPUC and CEC (Currently Interconnected Dataset, CSI, NSHP, ERP, SGIP) ^(a)	0.1 - 4,597	1998 - 2016	99,886	1072.2	300,660	3313.7
	Imperial Irrigation District	1.0 - 1,152	2005 - 2016	491	7.7	1,405	36.9
	Los Angeles Dept. of Water & Power	0.3 - 3,377	1999 - 2016	4,328	29.2	17,128	155.8
	Palo Alto Utilities	0.7 - 881	1999 - 2016	6	0.2	579	5.9
	Sacramento Municipal Utility District	0.7 - 2,840	2005 - 2016	1,060	7.6	5,010	57.3
CO	Xcel Energy	0.5 - 1,998	2006 - 2016	3,050	19.8	27,126	222.8
CT	Clean Energy Finance and Investment Authority	0.5 - 1,000	2004 - 2016	3,602	36.8	12,687	132.4
DE	Department of Natural Resources and Environmental Control	0.2 - 1,434	2002 - 2016	600	5.2	2,657	28.4
FL	Florida Energy & Climate Commission ^(b)	2.0 - 283	2006 - 2012	0	0.0	1,203	9.1
	Gainesville Regional Utilities ^(b)	1.8 - 1,277	2006 - 2016	37	2.2	501	23.1
	Orlando Utilities Commission ^(b)	0.5 - 1,040	2008 - 2016	181	1.2	363	5.0
IL	Dept. Commerce and Economic Opportunity	0.8 - 700	1999 - 2016	15	0.1	1,175	13.0

State	Data Provider	Size Range (kW _{DC})	Year Range	2016 Sample		Total Sample	
				No. of Systems	Total MW _{DC}	No. of Systems	Total MW _{DC}
MA	Massachusetts Clean Energy Center ^(c)	0.3 - 5,756	2001 - 2016	22	0.2	3,072	73.7
	Dept. of Energy Resources ^(c)	0.3 - 6,000	2008 - 2016	11,530	306.5	32,605	1007.6
MD	Maryland Energy Administration	0.1 - 200	2005 - 2016	524	5.1	7,146	63.2
ME	Efficiency Maine	0.9 - 171	2011 - 2013	0	0.0	550	3.5
MN	Dept. of Commerce	0.5 - 40	2001 - 2016	354	4.5	1,138	10.9
	Xcel Energy	0.5 - 40	2012 - 2016	227	2.2	957	12.9
NC	NC Sustainable Energy Association	0.7 - 5,932	2005 - 2016	1,069	172.6	5,320	1154.3
NH	New Hampshire Public Utilities Commission	0.3 - 653	2001 - 2016	737	9.0	3,491	30.2
NJ	New Jersey Board of Public Utilities (CORE & REIP Programs)	0.7 - 2,372	2001 - 2012	0	0.0	7,718	122.4
	New Jersey Board of Public Utilities (SREC Program)	0.4 - 8,135	2007 - 2016	12,280	215.0	38,990	1259.1
NM	Energy, Minerals & Natural Resources Dept.	0.4 - 349	2007 - 2016	590	3.6	7,283	40.8
NV	NVEnergy	0.4 - 1,145	2004 - 2016	934	11.5	8,882	122.9
NY	New York State Energy Research and Development Authority	0.3 - 2,827	2000 - 2016	14,780	180.0	47,877	609.3
OR	Energy Trust of Oregon ^(d)	0.8 - 5,702	2002 - 2016	1,268	15.1	7,553	81.6
	Oregon Dept. of Energy ^(d)	0.1 - 5,702	1999 - 2016	429	2.1	1,885	17.8
	Pacific Power	1.6 - 500	2010 - 2016	23	0.2	531	8.3
PA	Dept. Community and Economic Development	8.0 - 3,252	2010 - 2012	0	0.0	49	34.9
	Dept. of Environmental Protection	1.0 - 922	2009 - 2014	0	0.0	7,041	98.1
	Sustainable Development Fund	1.1 - 12	2002 - 2008	0	0.0	200	0.7
RI	National Grid	0.8 - 384	2010 - 2016	865	7.2	1,166	9.7
TX	Austin Energy	0.2 - 364	1999 - 2016	997	12.0	6,152	52.2
	CPS Energy	0.6 - 400	2007 - 2016	3,954	31.9	7,019	61.7
	Clean Energy Associates (El Paso Electric)	0.9 - 168	2001 - 2015	0	0.0	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	868	10.2
	Clean Energy Associates (Sharyland Utilities)	7.4 - 10	2014 - 2016	1	0.0	3	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 - 259	2010 - 2016	30	0.7	175	2.9
	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	0	0.0	74	0.8
UT	Rocky Mountain Power	0.7 - 364	2011 - 2016	328	5.6	945	14.3

State	Data Provider	Size Range (kW _{DC})	Year Range	2016 Sample		Total Sample	
				No. of Systems	Total MW _{DC}	No. of Systems	Total MW _{DC}
VT	Vermont Energy Investment Corporation	0.2 - 389	2003 - 2016	15	0.1	3,916	27.1
WI	Focus on Energy	0.2 - 273	2002 - 2016	485	3.5	2,573	18.5
Total		0.1 - 8,135	1998 - 2016	174,468	2,253	625,390	9,537

^(a)Data for California's three large investor owned utilities (PG&E, SCE, and SDG&E) are developed by merging the CPUC's Currently Interconnected Data Set with data from the various incentive programs that have been or are currently offered in the utilities' service territories. See Appendix A for more details on this merging process.

^(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 (2016\$/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	12.0	11.9	-	-	-	-	-	-	-	-	-
2001	11.9	11.4	11.0	11.3	10.3	-	-	-	-	-	-
2002	11.9	11.5	10.9	10.8	10.5	10.6	-	-	-	-	-
2003	11.6	10.3	10.0	9.8	9.7	9.6	-	-	-	-	-
2004	10.2	9.4	9.4	9.2	9.0	9.0	8.8	8.7	-	-	9.3
2005	10.3	9.1	9.1	8.8	9.1	9.1	8.6	8.6	8.7	8.6	8.6
2006	10.5	9.5	9.4	9.0	9.2	8.9	8.6	8.6	8.7	8.4	8.7
2007	10.4	9.5	9.2	9.0	9.2	9.1	9.0	9.0	9.0	9.0	9.2
2008	10.0	9.1	8.8	8.7	8.8	8.7	8.6	8.5	8.7	8.5	8.5
2009	10.1	8.8	8.3	8.2	8.2	8.3	7.9	7.9	8.0	8.0	8.2
2010	9.8	7.7	7.1	6.9	6.9	6.9	6.7	6.7	6.7	6.9	7.0
2011	7.8	6.9	6.4	6.1	6.0	6.0	5.8	6.0	5.8	6.0	6.0
2012	6.2	5.7	5.5	5.3	5.1	5.1	5.1	5.0	5.2	5.2	5.2
2013	5.0	5.0	4.9	4.6	4.4	4.4	4.2	4.2	4.3	4.2	4.6
2014	4.6	4.7	4.5	4.2	4.0	4.0	4.0	4.0	4.0	4.0	4.0
2015	4.3	4.5	4.3	4.0	3.9	3.8	3.7	3.6	3.7	3.8	3.7
2016	4.4	4.5	4.2	4.0	3.8	3.7	3.6	3.5	3.4	3.5	3.5

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 (2016\$/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	11.2	10.9	10.4	-	-	-	-	-
2003	10.6	9.6	10.0	9.6	-	-	-	-
2004	9.8	9.3	9.3	9.2	-	-	-	-
2005	9.6	9.6	8.7	8.8	8.6	-	-	-
2006	10.0	9.3	9.1	8.8	8.6	-	-	-
2007	9.7	9.1	9.0	8.6	8.5	7.5	7.4	-
2008	9.2	9.1	8.6	8.5	8.3	7.9	7.9	7.6
2009	9.1	8.7	8.4	8.4	8.1	7.5	7.6	7.1
2010	7.7	7.4	6.9	6.5	5.9	5.9	5.9	5.7
2011	6.5	6.3	5.9	5.6	5.3	5.1	5.1	4.8
2012	5.7	5.2	5.1	4.9	4.7	4.7	4.6	4.3
2013	4.6	4.3	4.4	4.2	4.1	3.9	3.7	3.4
2014	4.1	3.9	3.9	3.6	3.5	3.2	2.8	2.7
2015	4.3	3.7	3.5	3.2	3.2	2.8	2.8	2.4
2016	4.1	3.7	3.4	3.2	3.0	2.6	2.5	2.2

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, Jennifer Bristol, 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), Shauna Beland (Rhode Island Office of Energy Resources), Erin Boedecker (U.S. Energy Information Administration), Ted Burhans (Tucson Electric Power), Miles Cameron (Oregon Department of Energy), Jerry Carey (North Carolina Sustainable Energy Association), Paola Corona (NV Energy), Lucy Charpentier (Connecticut Clean Energy Fund), Lisa Cosgrove (Ameren), Karen Crampton (New Hampshire Public Utilities Commission), Benjamin Dickson (CBI), Asal Esfahani (California Public Utilities Commission), Alison Fode (Vermont Energy Investment Corp.), Luke Forster (New York Energy Research and Development Authority), Ran Fu (National Renewable Energy Laboratory), Roger Fujihara (District of Columbia Public Service Commission), Mark Gaiser (New Mexico Energy, Minerals and Natural Resources Department), Kristin Gaspar (Xcel Energy), Rene Garcia (Arizona Public Service), 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), Elizabeth Hutchison (California Energy Commission), Jeff Johnson (Gainesville Regional Utilities), Lindsay Joye (City of Palo Alto Utilities), Kaitlin Kelly (Massachusetts Dept. of Energy Resources), Kate Kennedy (Salt River Project), Jane Langdon (Kansas City Power & Light), Donald K. Leming (Public Utilities Commission of Ohio), Ricardo Luna (CPS Energy), David McClelland (Energy Trust of Oregon), Diana Naatz (Xcel Energy), Sherrill Neidich (California Energy Commission), Elizabeth Nixon (New Hampshire Public Utilities Commission), Julian Pabicon (Los Angeles Dept. of Water and Power), Will Patterson (SolSystems), Nathan Phelps (Vote Solar), Samantha Prest (NV Energy), Jessica Quinn (Delaware Dept. of Natural Resources and Environmental Control), Annie Ratanasim (Rhode Island Commerce Corporation), Kristin Riggins (Kansas City Power & Light), Jennifer Rosser (NV Energy), Carey Salaz (Public Service Company of New Mexico), Andrea Simpkins (Orlando Utilities Commission), Lauren Silva (Imperial Irrigation District), Brent Sloan (Sacramento Municipal Utility District), John Sullivan (PacifiCorp), Luke Tarbi (EnergySage), Tanya Wayland (New Hampshire Public Utilities Commission), Steve Weise (Clean Energy Associates), Laura Williams (California Center for Sustainable Energy), Ryan Wiser (Lawrence Berkeley National Laboratory), 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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