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U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017

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Contents

Introduction

NREL has been modeling U.S. photovoltaic (PV) system costs since 2009. This year, our report benchmarks costs of U.S. solar PV for residential, commercial, and utility-scale systems built in the first quarter of 2017 (Q1 2017). We use a bottom-up methodology, accounting for all system and project-development costs incurred during the installation to model the costs for residential, commercial, and utility-scale systems. In general, we attempt to model the typical installation techniques and business operations from an installed-cost perspective. Costs are represented from the perspective of the developer/installer, thus all hardware costs represent the price at which components are purchased by the developer/installer, not accounting for preexisting supply agreements or other contracts. Importantly, the benchmark also represents the sales price paid to the installer; therefore, it includes profit in the cost of the hardware, along with the profit the installer/developer receives, as a separate cost category. However, it does not include any additional net profit, such as a developer fee or price gross-up, which are common in the marketplace. We adopt this approach owing to the wide variation in developer profits in all three sectors, where project pricing is highly dependent on region and project specifics such as local retail electricity rate structures, local rebate and incentive structures, competitive environment, and overall project or deal structures. Finally, our benchmarks are national averages weighted by state installed capacities.

Introduction

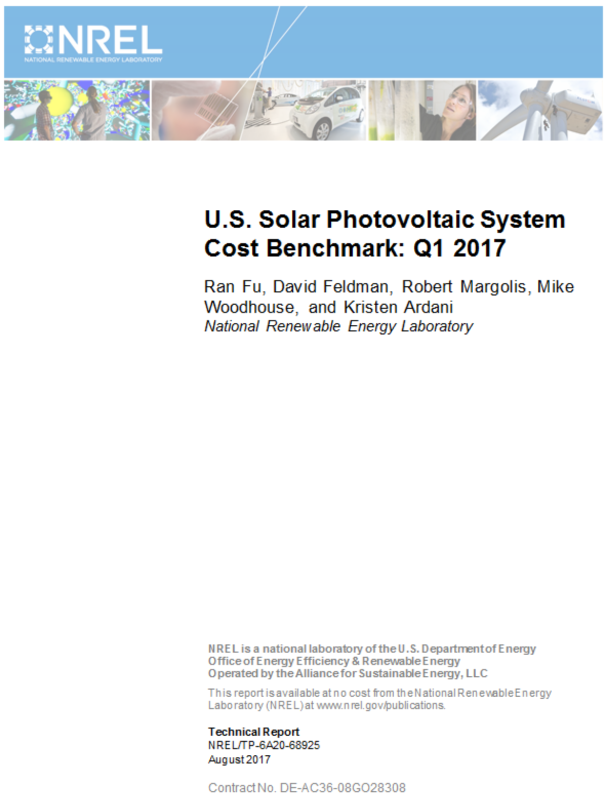
This report was produced in conjunction with several related research activities at NREL and Lawrence Berkeley National Laboratory (LBNL):

- Fu, Ran, Donald Chung, Travis Lowder, David Feldman, Kristen Ardani, and Robert Margolis. 2016. *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-66532.
- Barbose, Galen, and Naïm Darghouth. 2016. *Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States*. Berkeley, CA: Lawrence Berkeley National Laboratory.
- Bolinger, Mark, and Joachim Seel. 2016. *Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.* Berkeley, CA: Lawrence Berkeley National Laboratory.
- Chung, Donald, Carolyn Davidson, Ran Fu, Kristen Ardani, and Robert Margolis. 2015. *U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-64746.
- Fu, Ran, Ted James, Donald Chung, Douglas Gagne, Anthony Lopez, and Aron Dobos. 2015. *Economic Competitiveness of U.S. Utility-scale Photovoltaics Systems in 2015: Regional Cost Modeling of Installed Cost ($/W) and LCOE ($/kWh)*. IEEE 42nd Photovoltaic Specialist Conference, New Orleans, LA.
- Feldman, David, Galen Barbose, Robert Margolis, Mark Bolinger, Donald Chung, Ran Fu, Joachim Seel, Carolyn Davidson, Naïm Darghouth, and Ryan Wiser. 2015. *Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections*. Golden, CO: National Renewable Energy Laboratory. NREL/PR-6A20-64898.

Introduction

Download the full technical report along with the data file:

- Download the full report: https://www.nrel.gov/docs/fy17osti/68925.pdf
- Download the data file: https://data.nrel.gov/submissions/73



Key Definitions

Unit	Description
Value	2017 U.S. dollar (USD)
System Size	In direct current (DC) terms; inverter prices are converted by DC-to-alternating current (AC) ratios.

Sector Category	Description	Size Range
Residential PV	Residential rooftop systems	3 kW – 10 kW
Commercial PV	Commercial rooftop systems, ballasted racking	10 kW – 2 MW
Utility-Scale PV	Ground-mounted systems, fixed-tilt and one-axis tracker	> 2 MW

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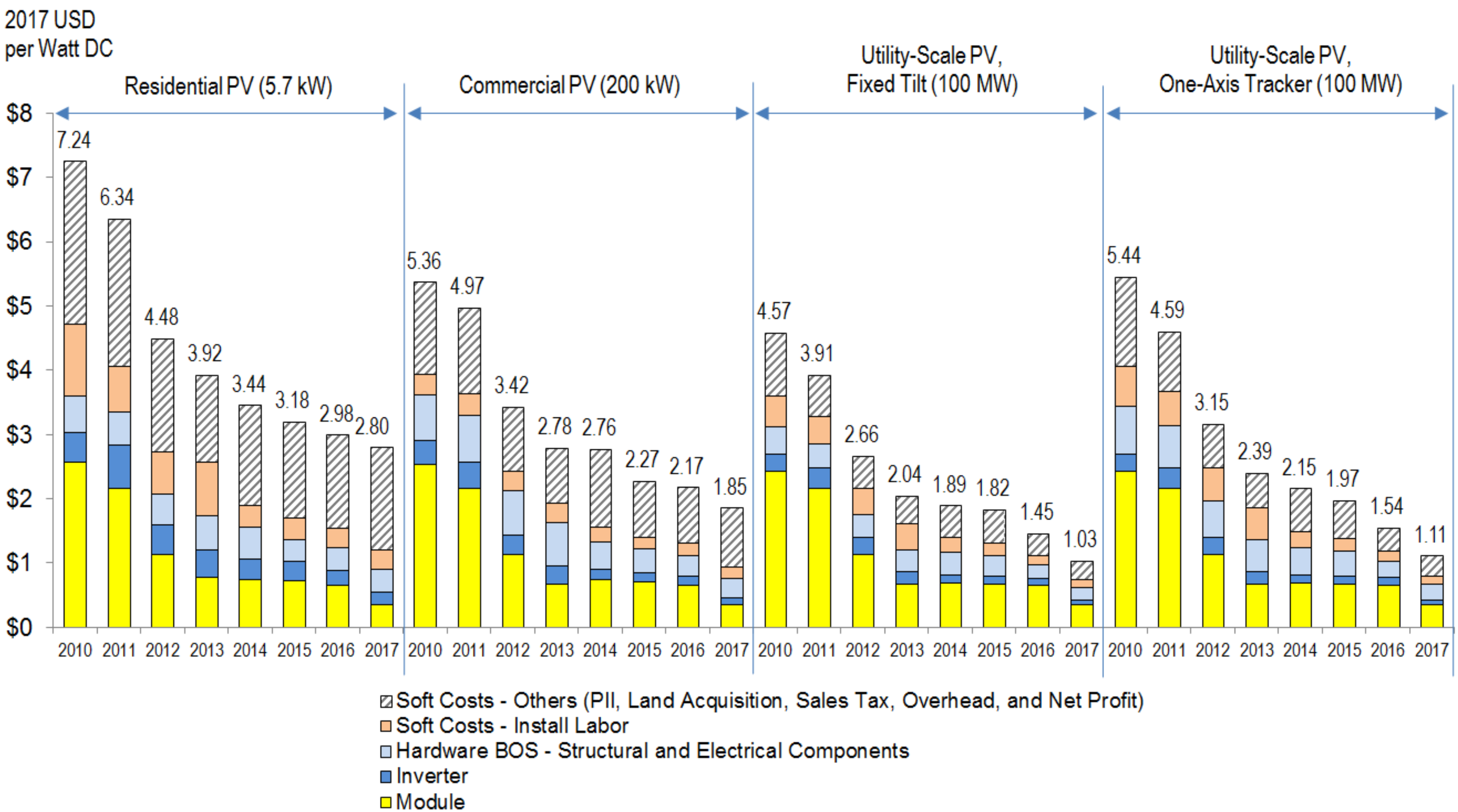
Overall Model Results (Total Capital Cost)

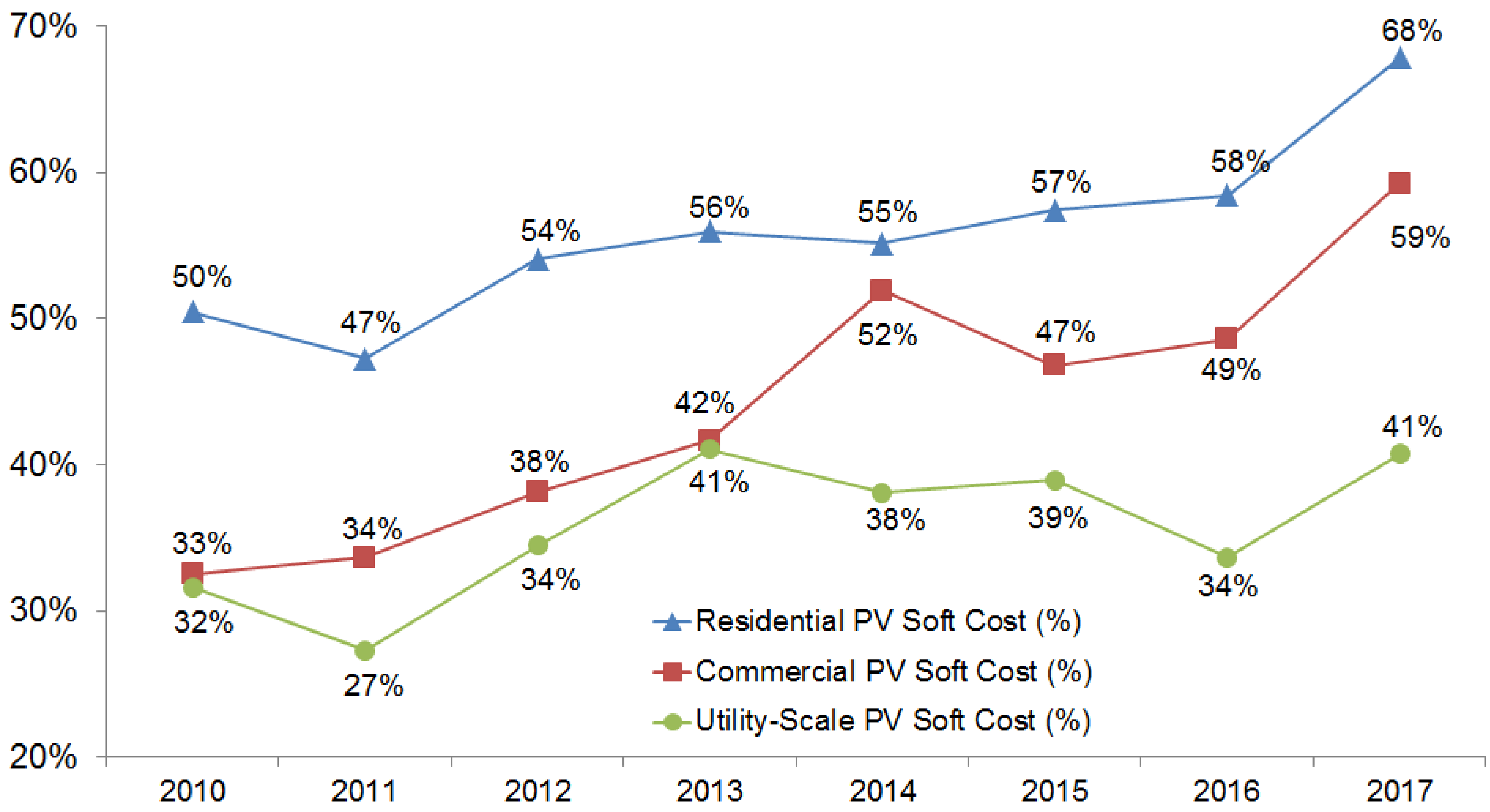


1. Values are inflation adjusted using the Consumer Price Index. Thus, historical values from our models are adjusted and presented as real USD instead of nominal USD.
2. Cost categories are aggregated for comparison purposes. “Soft Costs – Others” represents permitting, inspection, and interconnection (PII); land acquisition; sales tax; and engineering, procurement, and construction (EPC)/developer overhead and net profit.

Overall Model Results (Q1 2016 vs. Q1 2017)

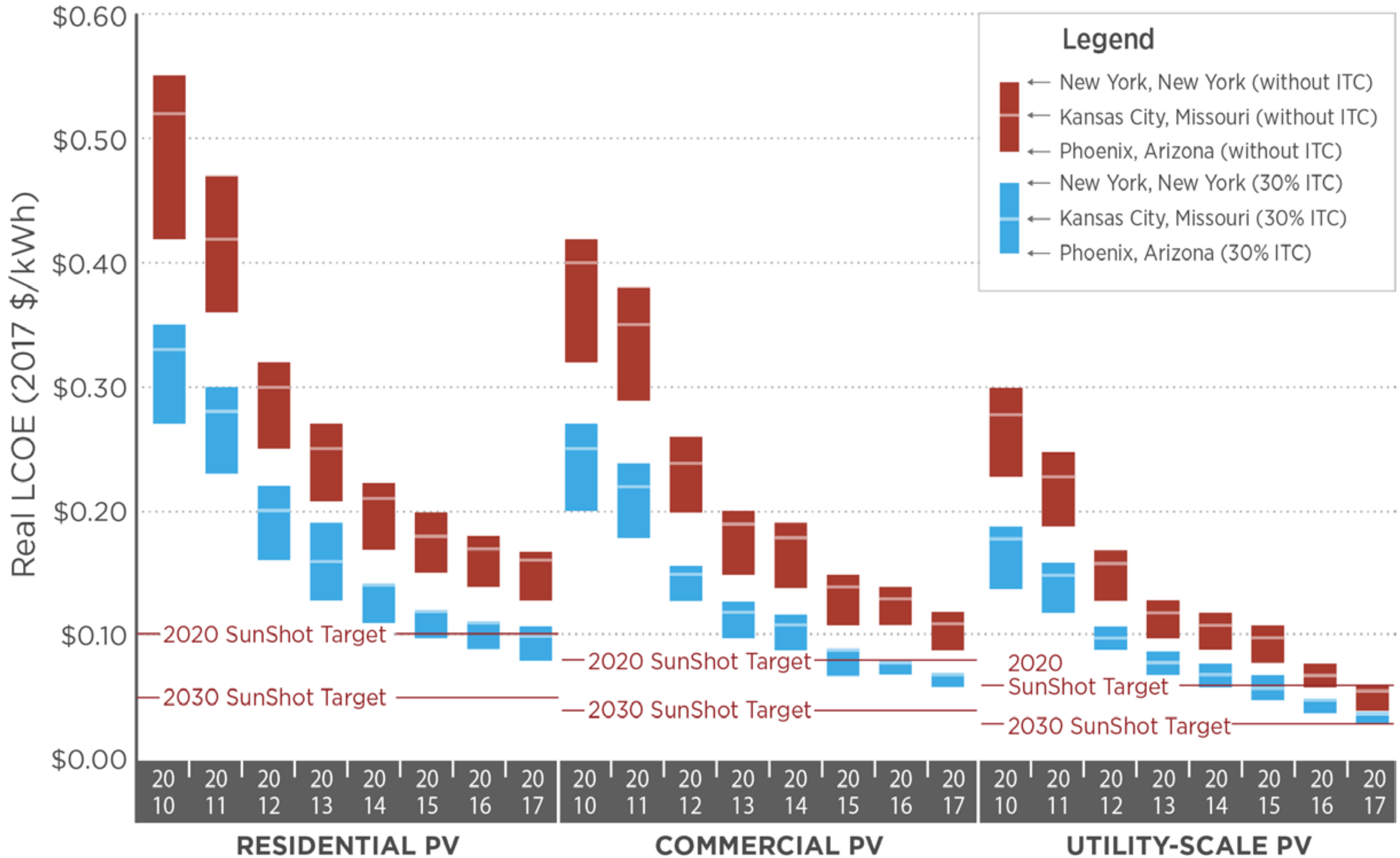
Sector	Residential PV	Commercial PV	Utility-Scale PV, Fixed-Tilt
Q1 2016 Benchmarks in 2016 USD/W DC	2.93	2.13	1.42
Q1 2016 Benchmarks in 2017 USD/W DC	2.98	2.17	1.45
Q1 2017 Benchmarks in 2017 USD/W DC	2.80	1.85	1.03
Drivers of Cost Decrease	• Lower module price • Lower inverter price • Higher module efficiency • Lower electrical BOS commodity price • Higher small installer market share • Lower sales & marketing costs • Lower overhead (general & administrative)	• Lower module price • Lower inverter price • Higher module efficiency • Smaller developer team	• Lower module price • Lower inverter price • Higher module efficiency
Drivers of Cost Increase	• Higher labor wages • Higher advanced inverter adoption • More BOS components for rapid shutdown • Higher supply-chain costs	• Higher labor wages • Higher PII costs • Higher net profit to EPC/developer	• Higher labor wages • Higher net profit to EPC/developer

Overall Model Results (Soft Cost)



1. "Soft Cost" in this report is defined as non-hardware cost—i.e., "Soft Cost" = Total Cost - Hardware Cost (module, inverter, and structural and electrical BOS).
2. Residential and commercial sectors have larger soft cost percentage than the utility-scale sector.
3. Soft costs and hardware costs also interact with each other. For instance, module efficiency improvements have reduced the number of modules required to construct a system of a given size, thus reducing hardware costs, and this trend has also reduced soft costs from direct labor and related installation overhead.
4. An increasing soft cost proportion in this figure indicates that soft costs declined more slowly than hardware costs; it does not indicate that soft costs increased on an absolute basis.

Overall Model Results (LCOE)



The reductions in total capital cost, along with improvements in operation, system design, and technology have resulted in significant reductions in the cost of electricity. U.S. residential and commercial PV systems are 86% and 89% toward achieving SunShot's 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SunShot target three years early.
Note that we use the fixed-tilt systems for LCOE benchmarks from 2010 to 2015 and then switch to one-axis tracking systems from 2016 to 2017 to reflect the market share change in the utility-scale PV sector. All detailed LCOE values can be found in Appendix.

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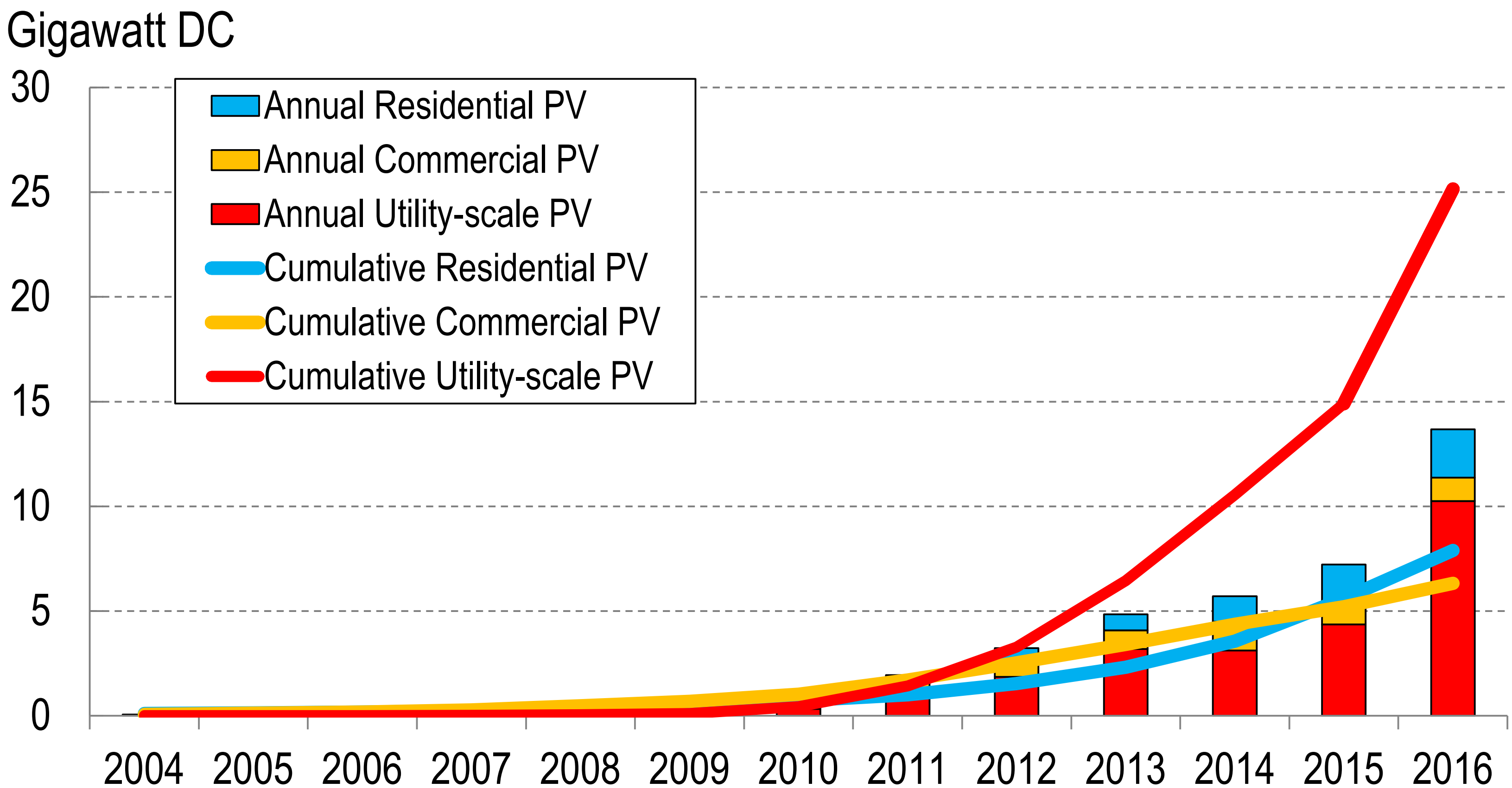
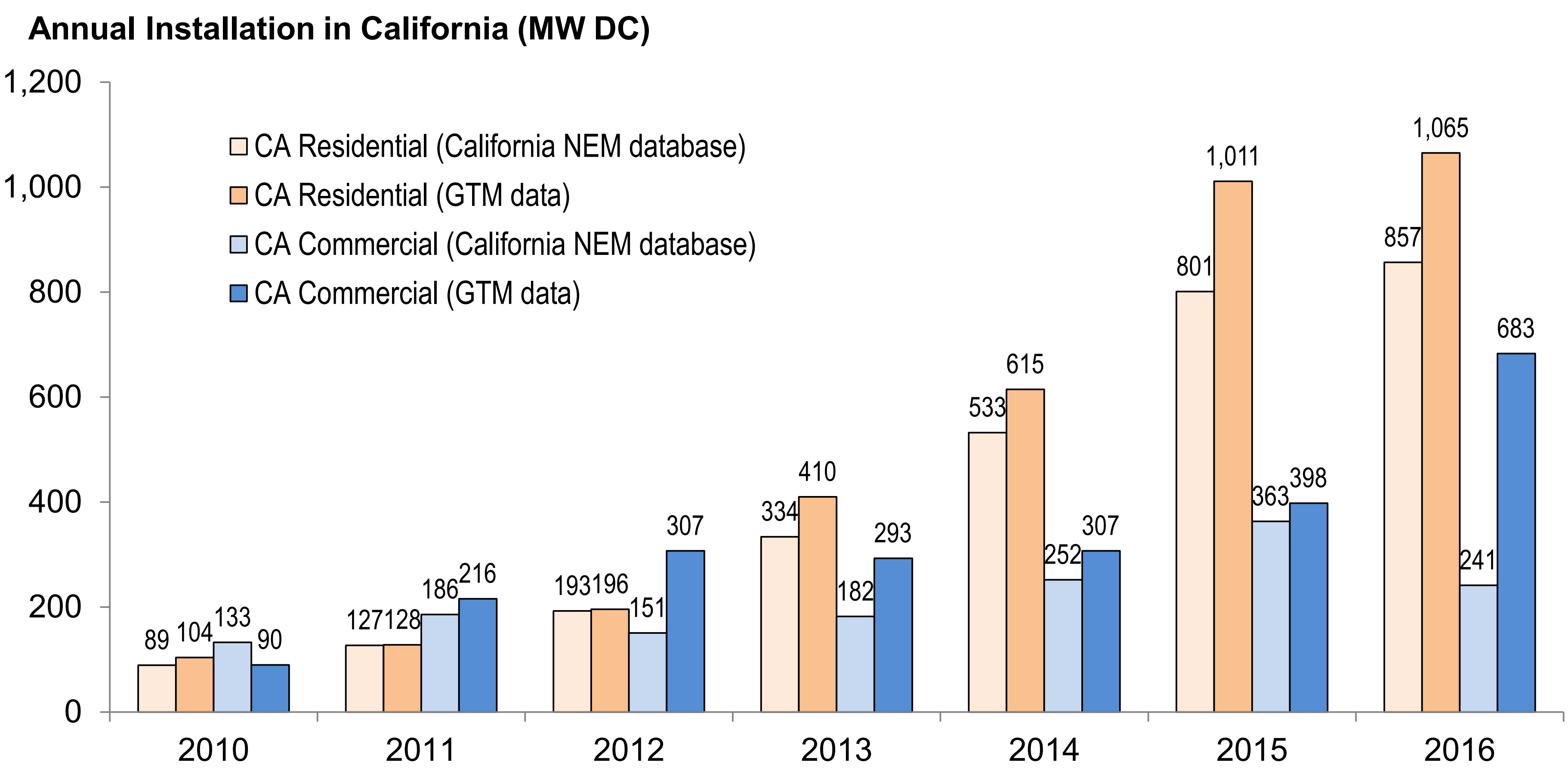
US Solar PV Market Growth



U.S. PV market growth, 2004–2016, in gigawatts of direct-current (DC) capacity (Bloomberg 2017)

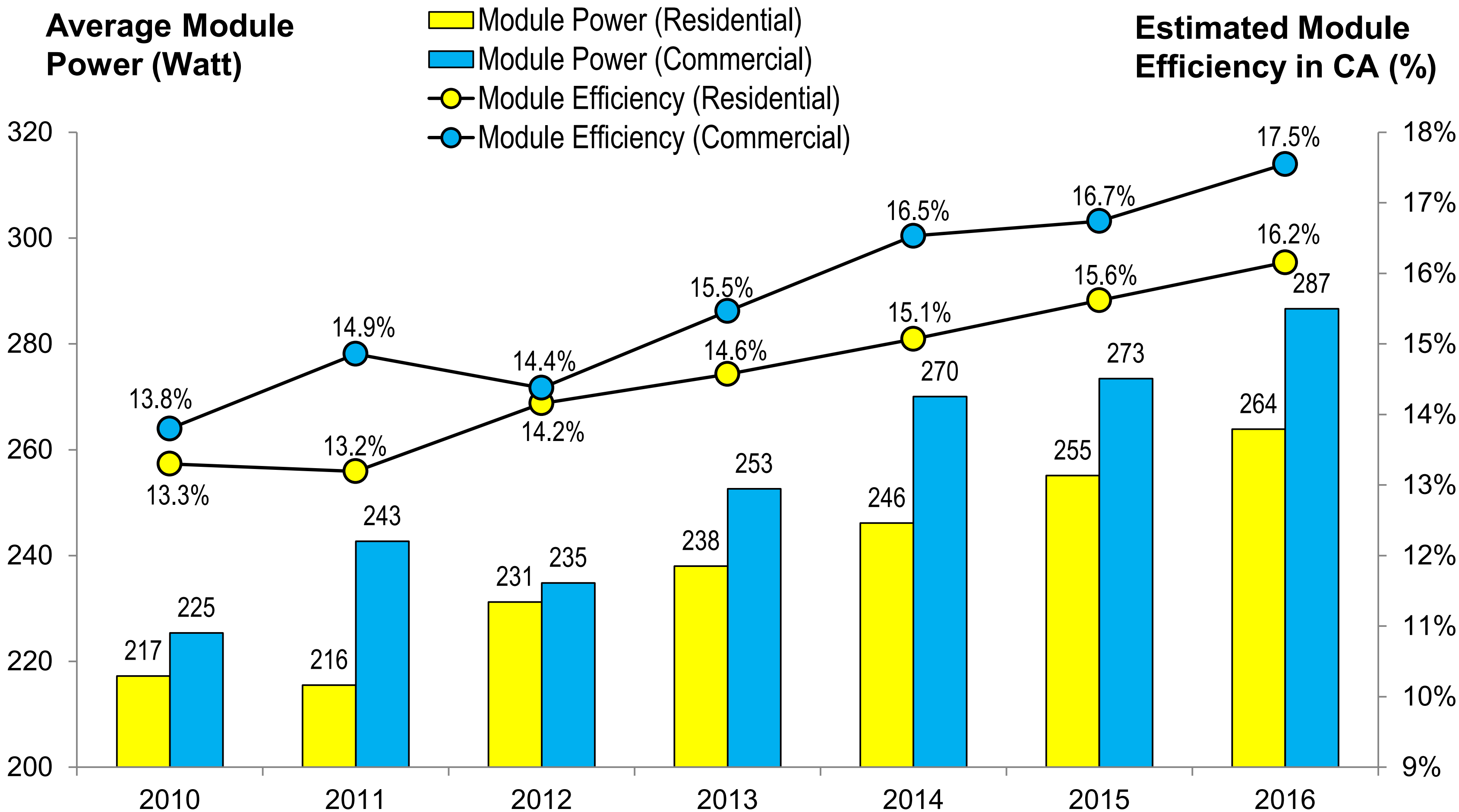
Solar photovoltaic (PV) deployment has grown rapidly in the United States over the past several years. As the figure shows, in 2016 new U.S. PV installations included 2.3 gigawatts (GW) in the residential sector, 1.1 GW in the commercial sector, and 10.2 GW in the utility-scale sector—totaling 13.7 GW across all sectors (Bloomberg 2017). At the same time, PV system costs have continued to decline. Previous modeling (Fu et al. 2016) by the National Renewable Energy Laboratory (NREL) shows system cost reductions of about 60%–80% across sectors between 2010 and 2016.

Database for Residential and Commercial Sectors



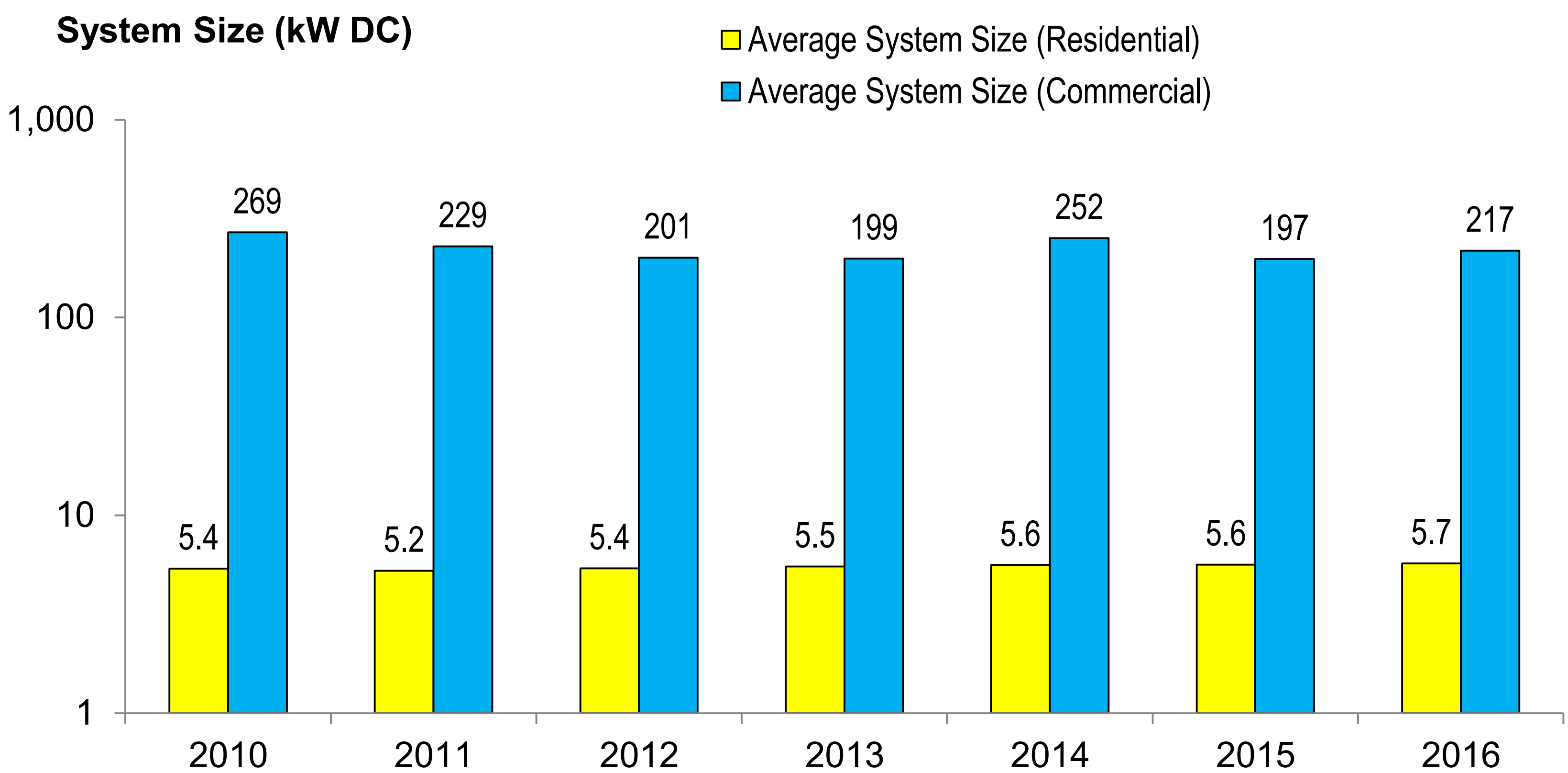
We use the California NEM Interconnection Applications Data Set (CSI 2017) to benchmark generic system characteristics, such as system size, module power and efficiency, and choice of power electronics. This database is updated monthly and contains all interconnection applications in the service territories of the state's three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric). Although there are other databases for other markets, such as Massachusetts and New York, we use only the California NEM database because of its higher granularity and greater consistency. However, we do not use the California NEM database for regional cost analyses; inputs and sources for regional analyses are described in subsequent sections of this report.

Module Power and Efficiency Trend (California)



This figure displays module power and efficiency data from the California NEM database. Since 2010, module power and efficiency in both sectors have been steadily improving. We use the values of 16.2% (residential) and 17.5% (commercial and utility-scale) module efficiency in our models. Also note that since module selection may vary in different regions, the actual module efficiencies in other regions than CA may be different.

PV System Size Trend (California)



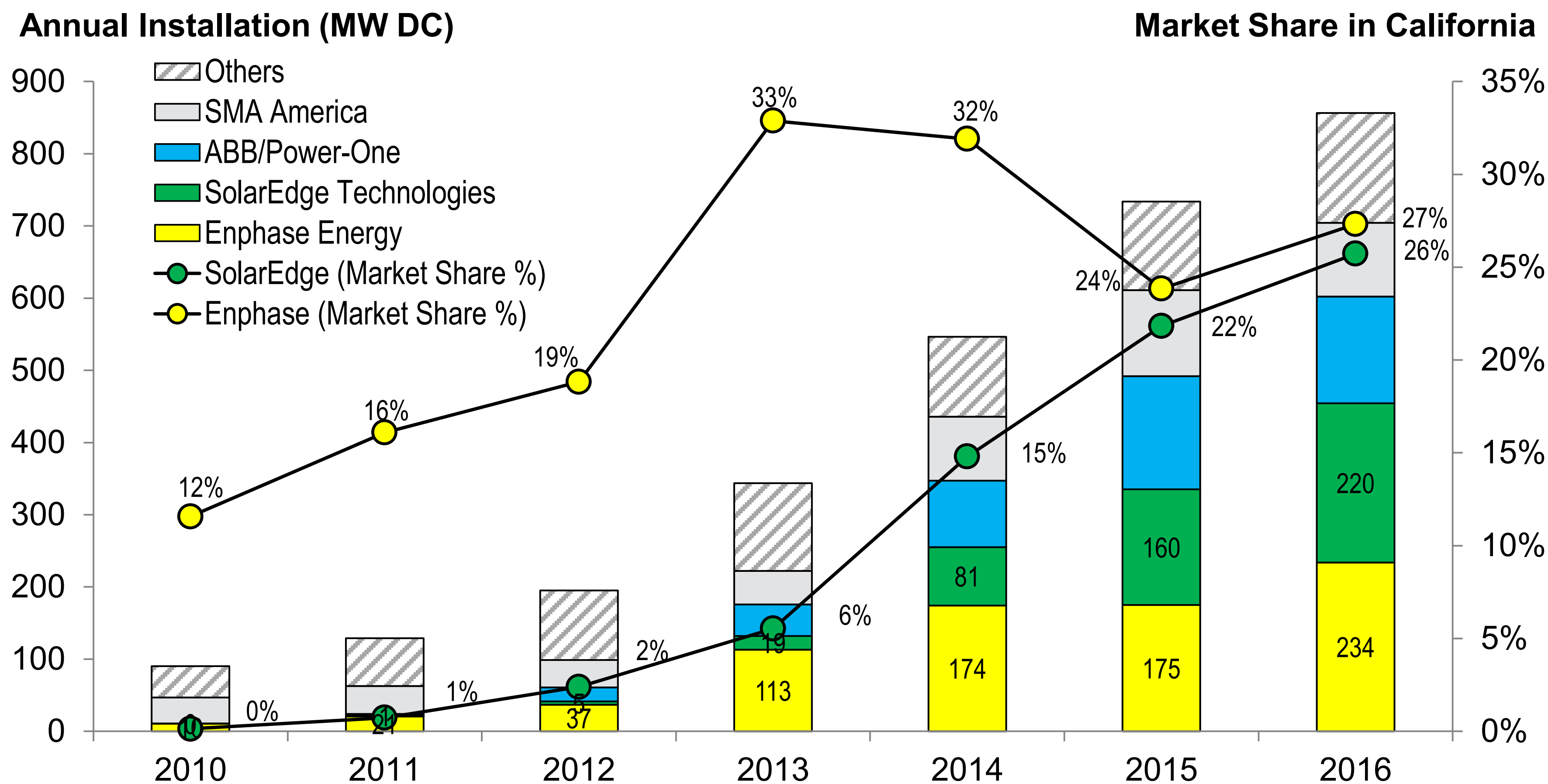
This figure displays average system sizes from the California NEM database. Average residential system sizes have not changed significantly over the past 6 years. We use the 2016 value of 5.7 kW as the baseline case in our residential cost model. Conversely, commercial system sizes have changed more frequently, likely reflecting the wide scope for “commercial customers,” which include schools, office buildings, malls, retail stores, and government projects. We use 200 kW as the baseline case in our commercial model.

Inverter Solutions — Microinverter and DC Power Optimizer

Microinverters and DC power optimizers are collectively referred to as module-level power electronics (MLPE). By allowing designs with different roof configurations (orientations and tilts) and constantly tracking the maximum power point for each module, MLPE provide an optimized design solution at the module level. This table provides a brief comparison between traditional string inverters and MLPE.

	String Inverter	DC Power Optimizer	Microinverter
Function	PV modules are connected in parallel by one or multiple strings and then directly connected to the string inverter for DC-to-AC conversion. If one module is shaded, the whole string is impacted.	Each PV module has one power optimizer for DC-to-DC conversion, so the traditional junction box is replaced, and all modules are connected by string inverter for DC-to-AC conversion. Shading only impacts individual modules.	Each PV module has one microinverter for DC-to-AC conversion, and thus no string inverter is used. Shading only impacts individual modules.
Relative product price	Low (without rapid shutdown) Medium (with rapid shutdown)	Medium	High
Performance in shading	Poor	More efficient	More efficient
Performance in various directions or on irregular roofs	Low	Medium	High
Module-level monitoring and troubleshooting	No	Yes (e.g., SolarEdge Cellular Kit)	Yes (e.g., Enphase "Envoy + Enlighten")
Improved energy yield from module mismatch reduction	No	Yes	Yes
Number of electronic components	Normal	Greater (thus may have some component risks)	Greater (thus may have some component risks)
Safety for installation	Normal	Safer; easier wiring work	Safest; use only AC cable with no high-voltage DC power

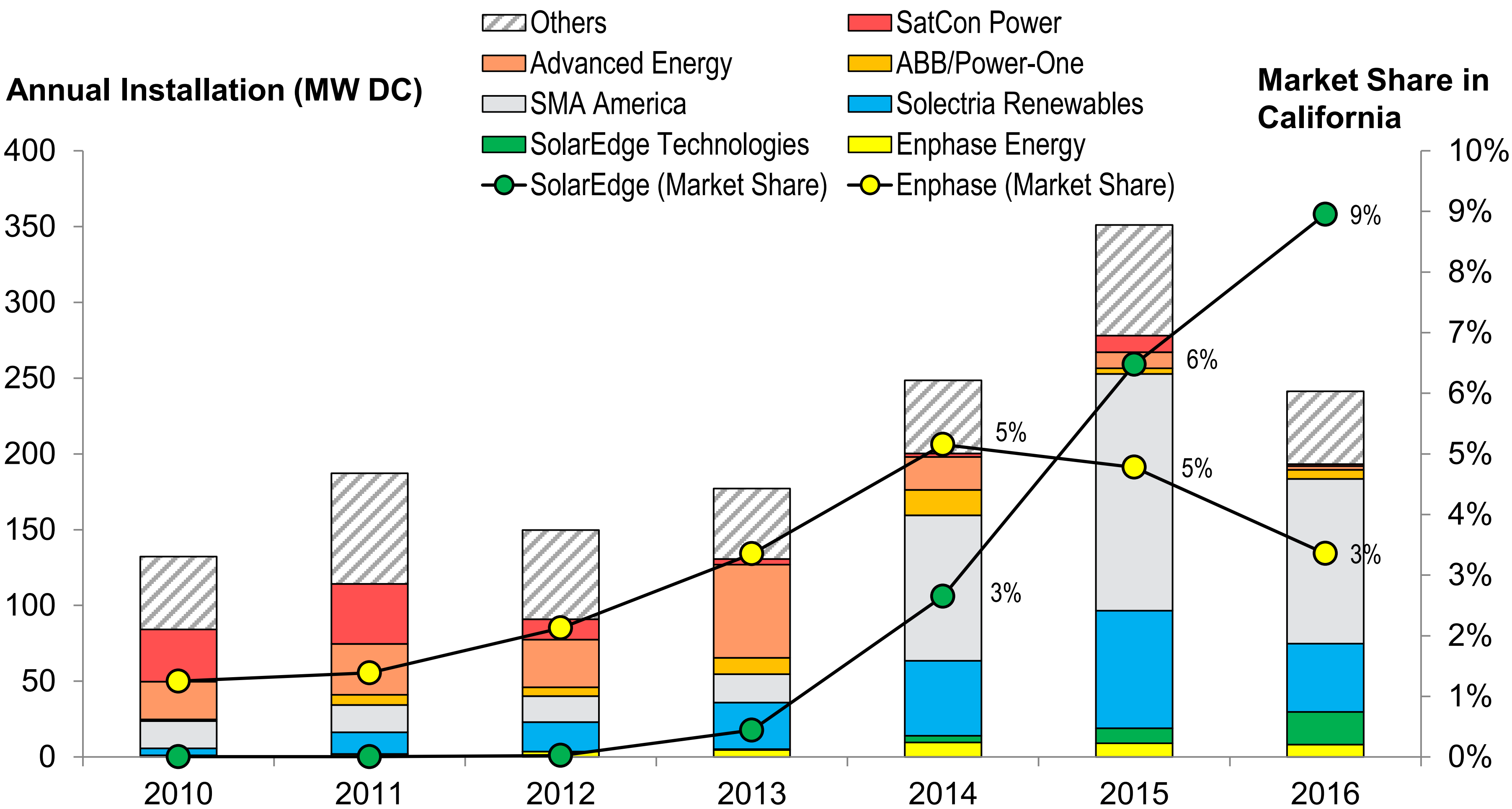
Inverter Market — Residential PV Sector (California)



According to the California NEM database, market uptake of MLPE has been growing rapidly since 2010 in California's residential sector. This increasing market growth may be driven by decreasing MLPE costs and by the "rapid shutdown" of PV output from buildings required by Article 690.12 of the National Electric Code (NEC) since 2014—MLPE inherently meet rapid-shutdown requirements without the need to install additional electrical equipment.

In 2016, MLPE—represented by the combined share of Enphase and SolarEdge inverter solutions—reached 53% of the total California residential market share. Therefore, in our residential system cost model, string inverter, power optimizer, and microinverter options are modeled separately and their market shares (47%, 26%, and 27%) are used for the weighted average case.

Inverter Market — Commercial PV Sector (California)



Conversely, MLPE growth (represented by Enphase and SolarEdge) has been slow in California's commercial sector, reaching a share of only 12% in 2016. Thus, we do not build MLPE inverter solutions into our commercial model.

Rapid Shutdown — Background

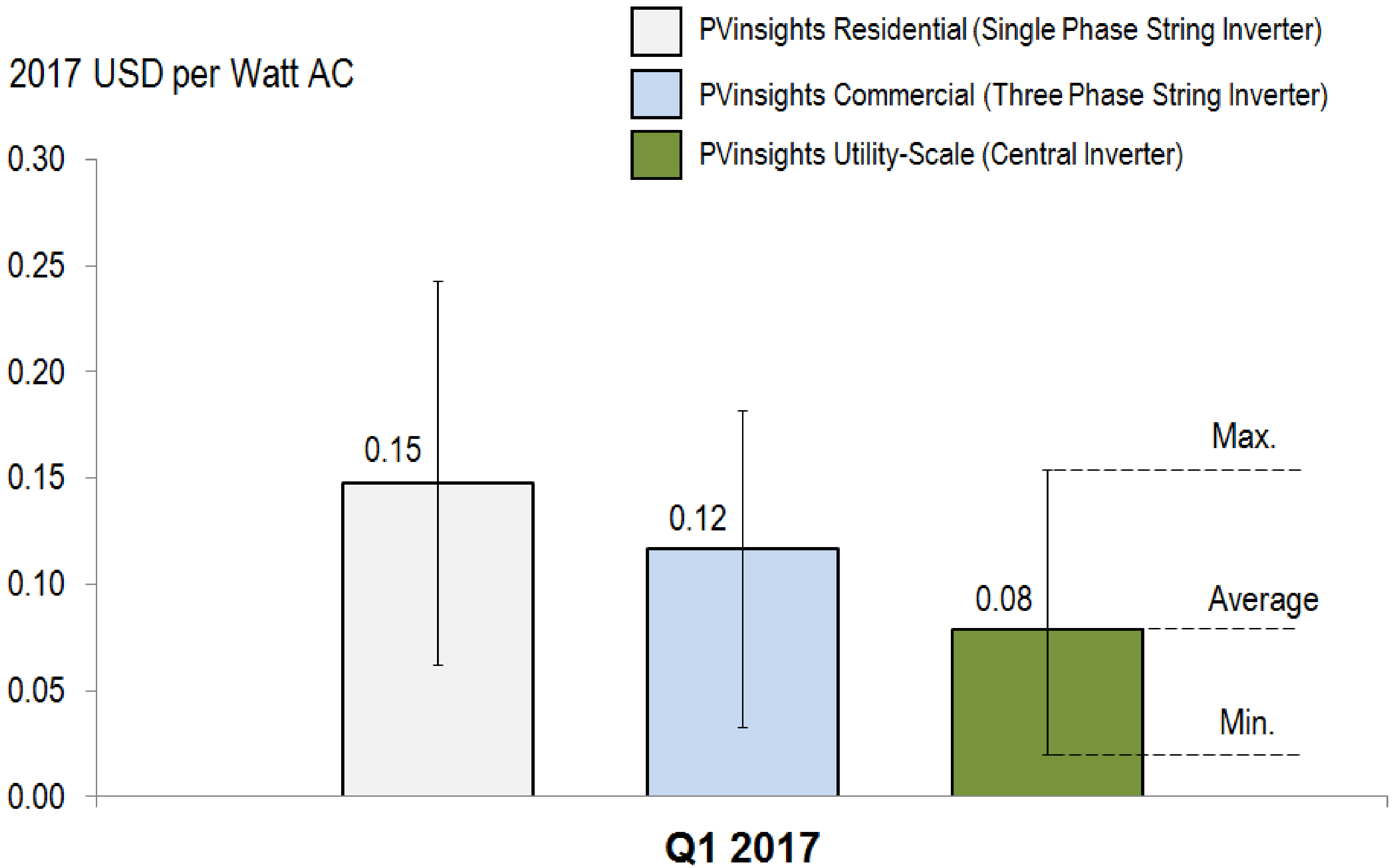
- **Code:** NEC 2014: Article 690.12 **Rapid Shutdown** of PV system.
- **Scope:** Only applies to PV system circuits **"on or in buildings."** Thus, ground-mounted system is not required to have rapid shutdown capability.
- **Requirement:** "Conductors more than **5 feet** inside a building or more than **10 feet** from an array will be limited to a maximum of 30 V and 240 VA within 10 seconds of shutdown."
- **Goal**: During power shutdown (i.e. fire on the building or utility power loss), for first responders (such as fire fighters), DC conductors in each string of PV arrays are most dangerous: Because DC side can still be energized even if inverter is shut down. The goal is to decrease the risk first responders face by having PV system conductors at a certain distance away from the PV arrays so that conductors are de-energized to a safe level.
- **Progress:** As of January 1, 2017, the 2017 NEC is in effect in one state, the 2014 NEC is in effect in 35 states, the 2011 NEC is in effect in five states and the 2008 NEC is in effect in six states. In our cost model, we assume 2014 NEC adoptions.

Codes	Rapid-Shutdown Requirement	States
2017 NEC	Yes	Massachusetts
2014 NEC	Yes	Alabama, Alaska, Arkansas, California, Colorado, Connecticut, Delaware, Georgia, Idaho, Iowa, Kentucky, Maine, Maryland, Michigan, Minnesota, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, West Virginia, Wyoming
2011 NEC	No	Florida, Louisiana, Virginia, Wisconsin, Nevada
2008 NEC	No	Hawaii, Illinois, Indiana, Kansas, Pennsylvania, Tennessee
No statewide NEC adoption	No	Arizona, Mississippi, Missouri

Rapid Shutdown — Different Solutions

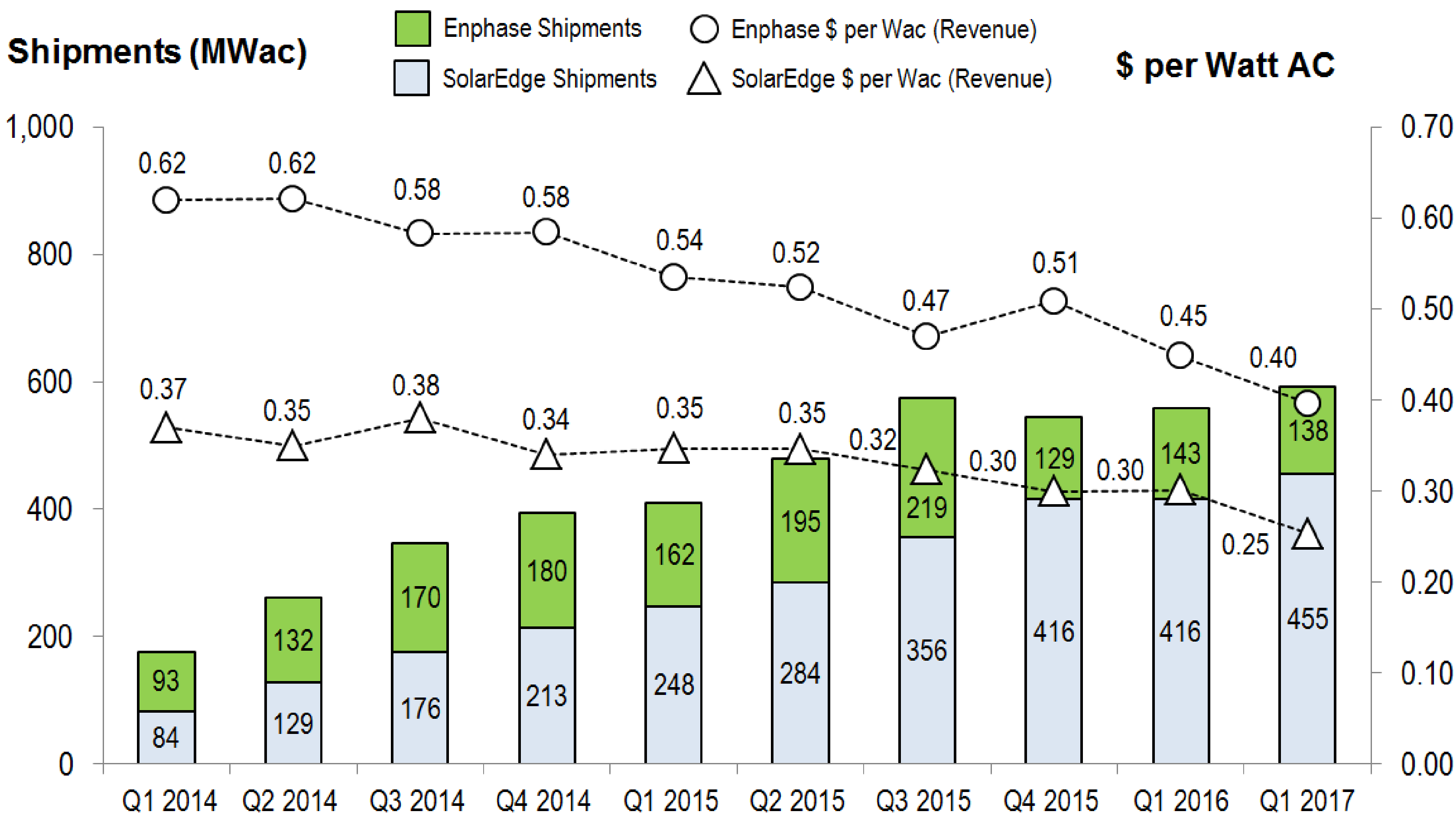
	String Inverter	DC Power Optimizer	Microinverter
Solution for Rapid Shutdown requirement	**A rapid-shutdown box** must be mounted directly to the PV mounting rail and fit under the PV modules. **A rapid-shutdown controller** must be mounted so it is visible and freely accessible to first responders.	**A rapid-shutdown cable** must be installed in the inverter box. No additional roof-mounted devices are required.	**Microinverters inherently meet rapid-shutdown requirements** without any additional electrical equipment, because the DC side (which has low voltage) is de-energized as soon as the grid or power from the grid is interrupted.
Additional BOS costs	Rapid shutdown box Rapid shutdown controller Cable between box and controller Total BOS increase = $0.08/W	One rapid shutdown cable in each inverter Total BOS increase = $0.01/W	None
Additional direct labor costs	Electrician for cabling between box and controller Common labor for racking box and controller Total labor increase = $0.01/W	Electrician for setting up internal cable in each inverter Total labor increase = $0.01/W	None
Q1 2016 – Benchmark (no rapid shutdown consideration)	$2.78/W	$2.94/W	$3.28/W
Q1 2016 – Benchmark (if rapid shutdown is considered)	$2.90/W	$2.95/W	$3.28/W
Cost change in 2016 models due to Rapid Shutdown only	0.12/W = 0.08/W (electrical BOS) + 0.01/W (direct labor) + 0.03/W (other related costs)	0.01/W = 0.01/W (electrical BOS and direct labor)	No change

Inverter Price for non-MLPEs



We source non-MLPE inverter prices from the PVinsights (2017) database, which contains typical prices between Tier 1 suppliers and developers in the market.

Inverter Price for MLPEs



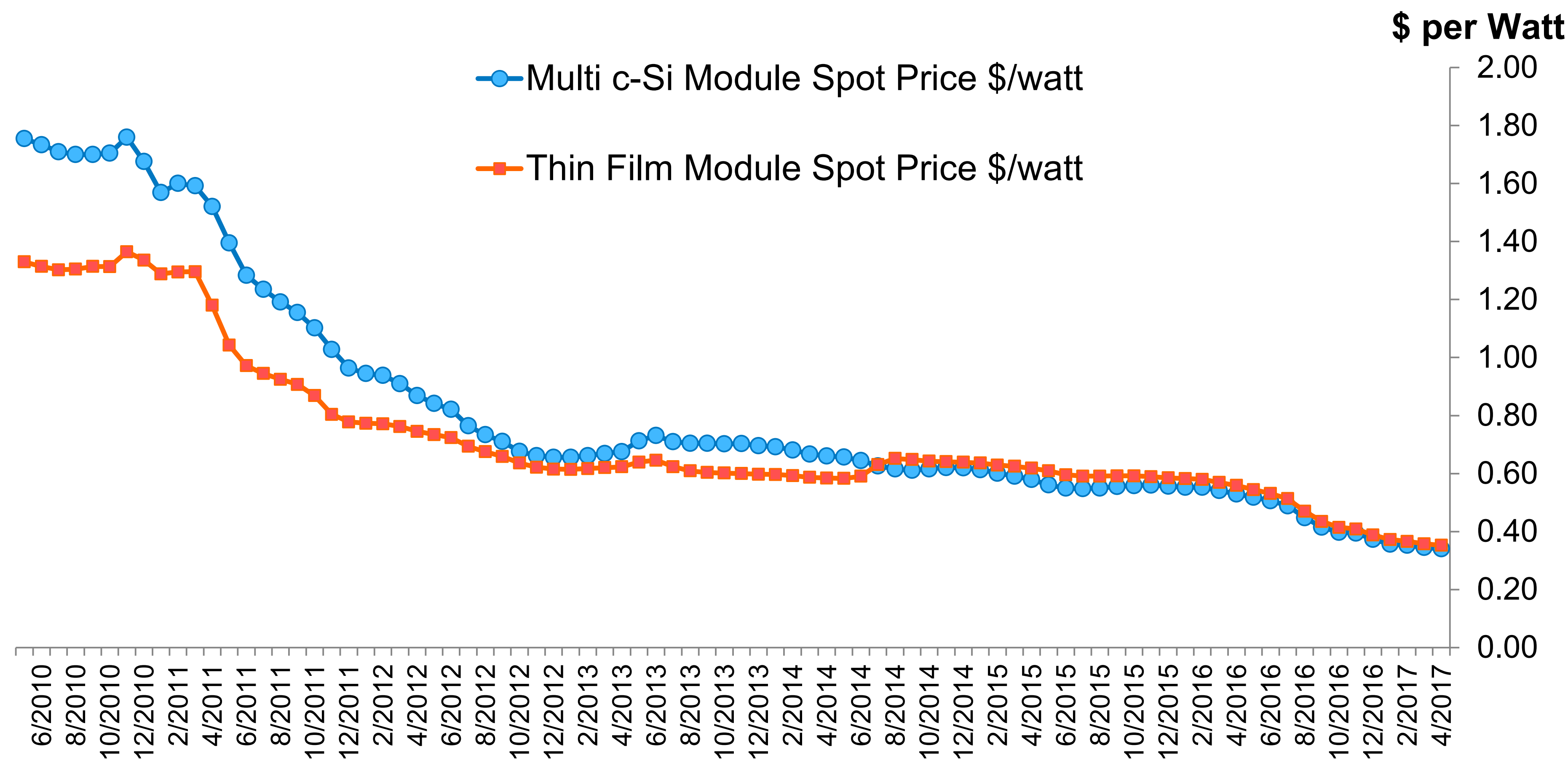
For MLPE inverter prices, we use data from public corporate filings, shown in this figure (Enphase 2017; SolarEdge 2017). Enphase's Q1 2017 revenue was $0.40/Wac, which represents the typical microinverter price. SolarEdge's Q1 2017 revenue was $0.25/Wac, including sales from DC power optimizers, string inverters, and monitoring equipment, which are typically included in one product offering. GTM Research estimates a DC power optimizer cost of $0.08/Wac (GTM Research 2017), implying a string inverter and monitoring equipment price of $0.17/Wac. This is close to the Q1 2017 non-MLPE string inverter costs of $0.15/Wac shown in the previous figure (assuming a $0.02–$0.03/Wac cost for monitoring equipment) (GTM Research and SEIA 2017).

Inverter Price and DC-to-AC ratios

We convert the USD/Wac inverter prices from previous inverter price figures to USD per watt DC (Wdc) using different DC-to-AC ratios (table below). In our benchmark, we use USD/Wdc for all costs, including inverter prices. Note that we updated the central inverter DC-to-AC ratios using Lawrence Berkeley National Laboratory data (Bolinger and Seel 2017); for the ratios in residential and commercial sectors, we use the estimates based on interview feedback (NREL 2017).

Inverter Type	Sector	$ per Watt AC	DC-to-AC Ratio	$ per Watt DC
Single Phase String Inverter	Residential PV (non-MLPE)	0.15	1.15	0.13
Microinverter	Residential PV (MLPE)	0.40	1.15	0.34
DC Power Optimizer String Inverter	Residential PV (MLPE)	0.17	1.15	0.15
Three Phase String Inverter	Commercial PV (non-MLPE)	0.12	1.15	0.10
Central Inverter	Utility-scale PV (fixed-tilt)	0.08	1.3 (Oversized)	0.06
Central Inverter	Utility-scale PV (1-axis tracker)	0.08	1.3 (Oversized)	0.06

Module Price (Monthly, May 2010–April 2017)



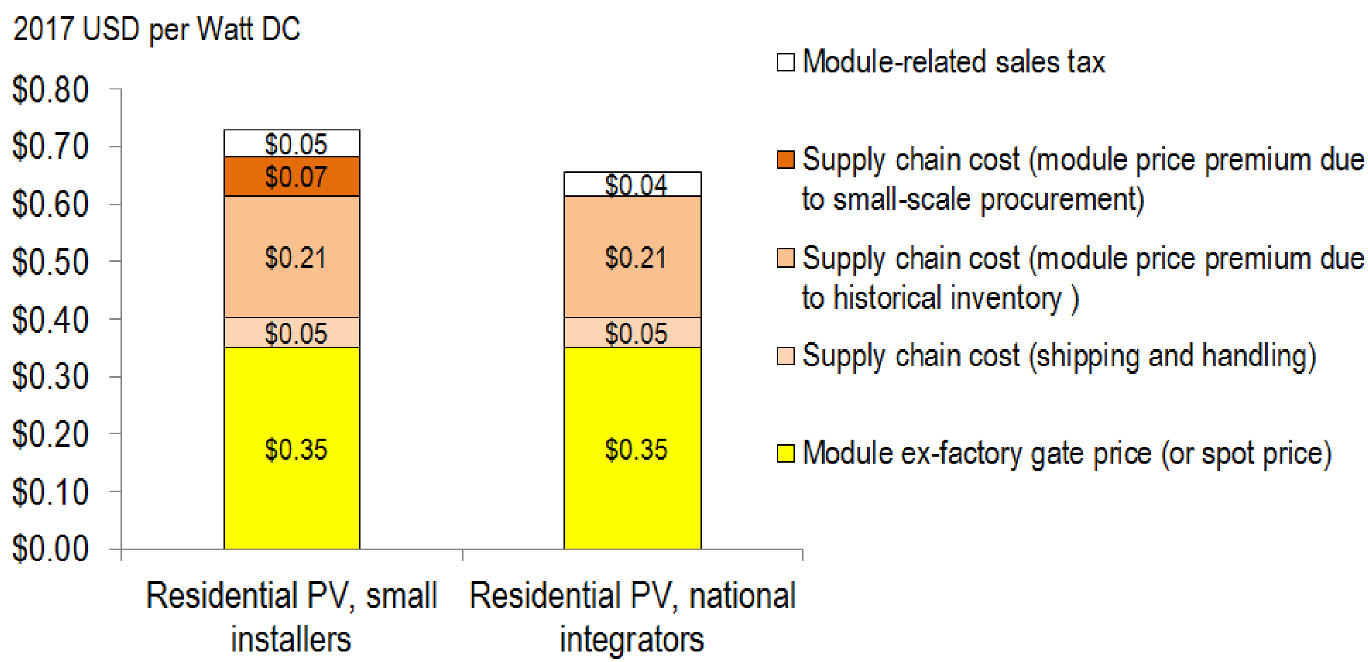
(1) We use $0.35/W—the spot price of U.S. crystalline-silicon modules in March 2017—to represent the ex-factory gate price between Tier 1 module suppliers and first buyers in all sectors, based on Bloomberg (2017) data. Because we model ex-factory gate price in Q1 2017, actual market pricing may vary owing to previously signed supply agreements or installer/distributor inventory lags. In addition, the actual market price may vary by market segment because of increased supply-chain costs as well as the price premium for small-scale procurement

(2) Module spot prices in 2017 have also been influenced by changes in currency exchange rates. The USD appreciated against the Chinese Yuan by 6% between Q1 2016 and Q1 2017 (XE Currency Charts 2017).

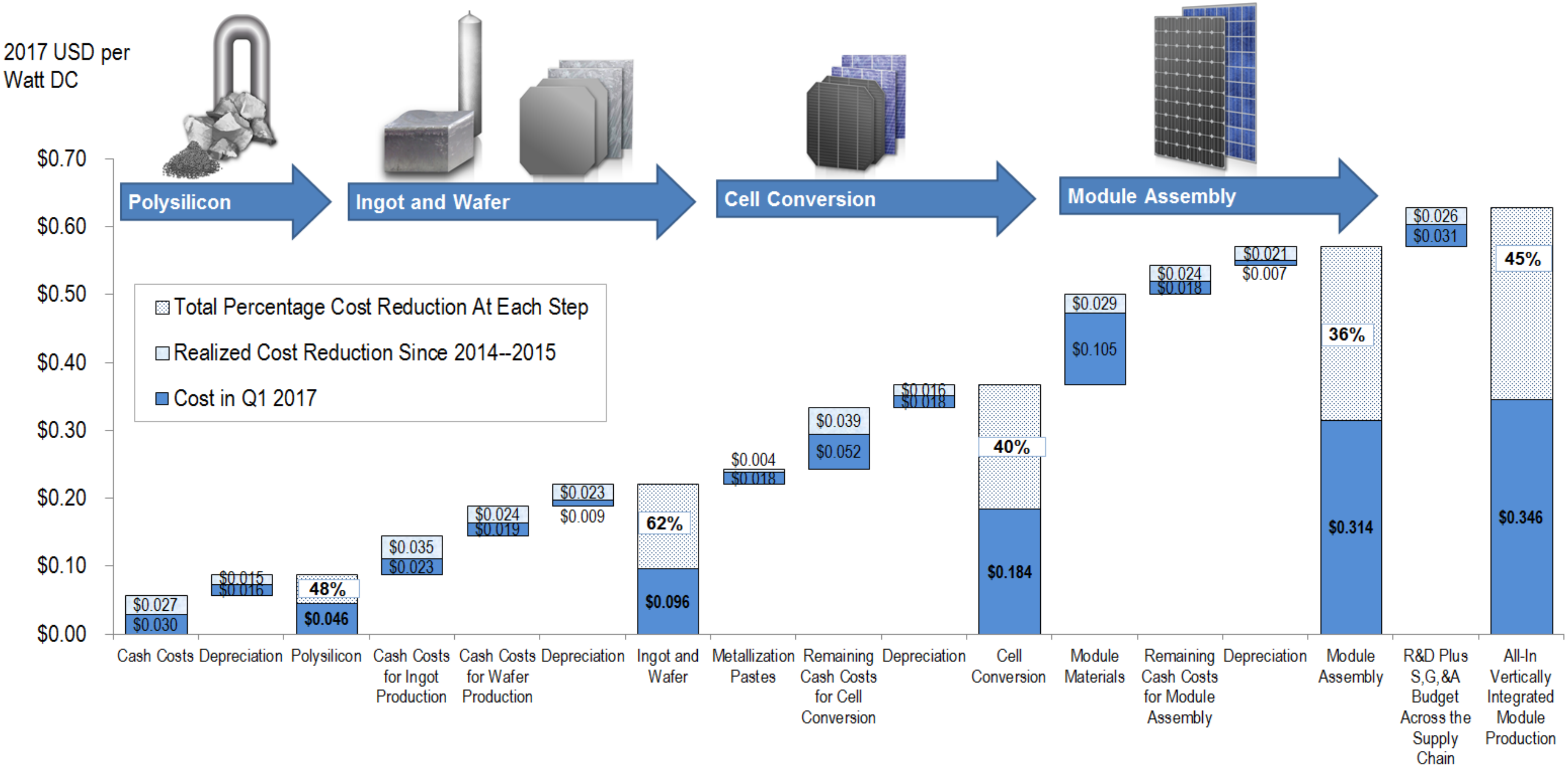
Module Price Inputs: Q1 2017

(1) Despite a $0.35/W factory gate module price, additional module costs increase national integrators' total module costs to $0.65/W (86% price premium) and small installers' total module costs to $0.73/W (109% price premium). These additional costs consist of shipping and handling (a 15% price premium above factory gate pricing for national integrators and small installers respectively [NREL 2017]), historical inventory (a 60% price premium above factory gate pricing [NREL 2017]), a sales-tax of 6.7%, and, for small installers, a 20% price premium above factory gate pricing due to small-scale procurement (Bloomberg 2017).

(2) In Q1 2017 historical inventory represented the largest supply-chain cost for residential installers. While we do not include pre-existing supply agreements or other contracts into our benchmark, historical inventory is a necessary cost for residential installers. Because homeowners of residential rooftop PV systems have different preferences for module brand, both small installers and national integrators tend to diversify their module procurement. Furthermore, since rooftop PV system sizes are relatively small (5.7 kW in our benchmark), the various module brands procured may not be fully consumed and installed instantly. Thus, the historical inventory price creates a price lag (approximately six months) for the market module price in residential sector when the modules from previous procurement are installed in today's systems.

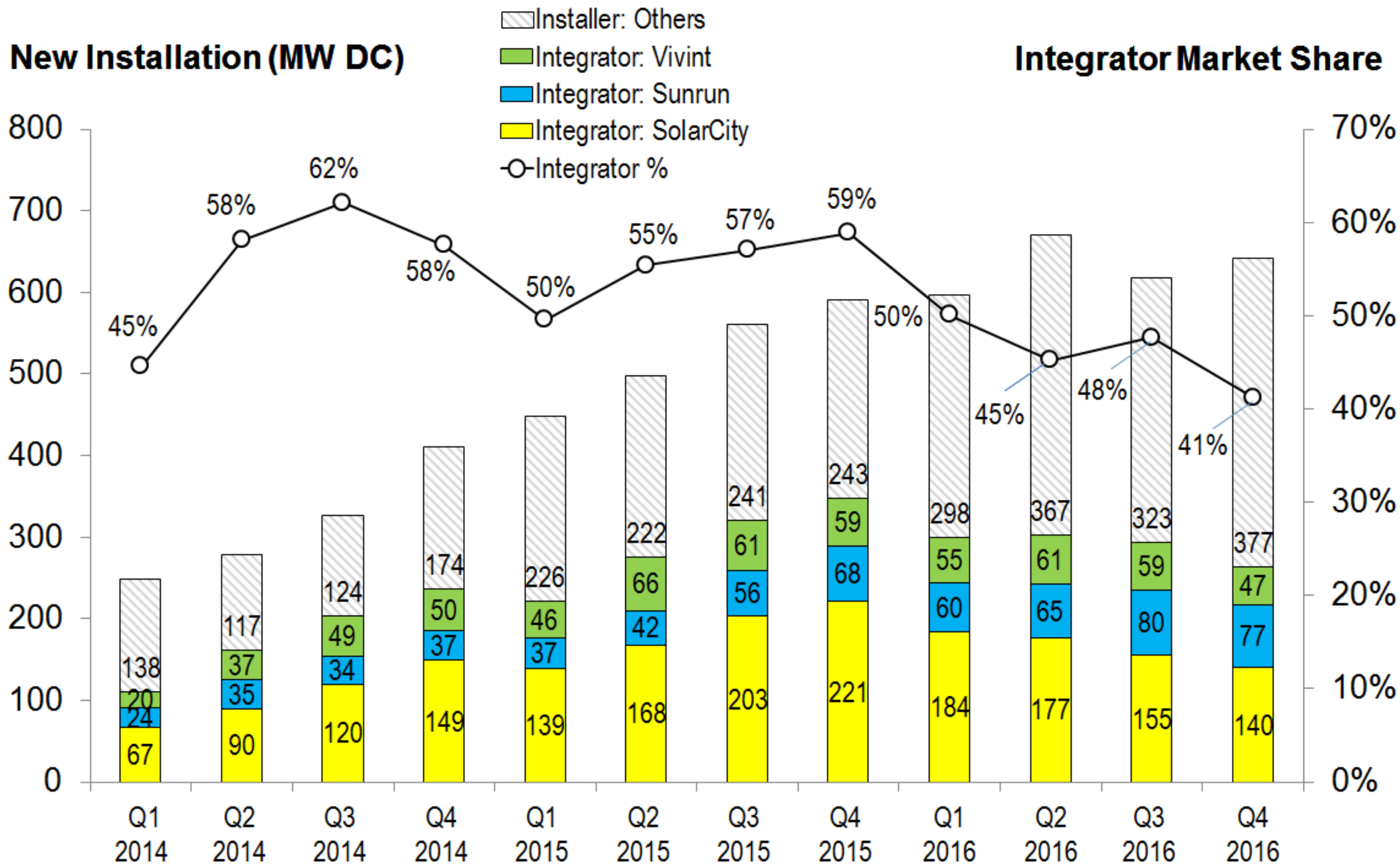


Module Level Bottom-Up Manufacturing Cost Model Results



This figure shows our most recent module manufacturing cost analysis, for passivated emitter and rear cells (PERC) and modules manufactured in Southeast Asia. The dark blue bars show the Q1 2017 cost contributions for each step: about $0.05/W for polysilicon, $0.05/W for ingot and wafer production, $0.08/W for cell conversion, $0.13/W for module assembly, and $0.03/W for an industry-average budget for research and development (R&D) plus sales, general, and administrative (SG&A). The all-in module manufacturing cost is about $0.35/W. It also shows the cost reductions since our last detailed module manufacturing analysis in 2014 and the first half of 2015, when we calculated an all-in module manufacturing cost of about $0.63/W. This 45% reduction in costs over 2–3 years was enabled by improving silicon utilization (principally reducing kerf loss), converting from slurry-based wafer slicing to diamond-wire-based wafer slicing, and reducing costs for cell conversion and module assembly principally via improved efficiency and capital investment requirements (the depreciation expenses shown in the figure). In a forthcoming paper, we will detail additional technology-improvement opportunities that could lead to even lower costs in the future.

Residential PV: Integrator vs. Installer



Our residential PV benchmark is based on two different business structures: “small installer” and “national integrator.” We define small installers as businesses that engage in lead generation, sales, and installation, but do not provide financing solutions. The national integrator performs all of the small installer’s functions, and provides financing and system monitoring for third-party-owned systems. In our models, the difference between small installers and national integrators manifests in the overhead and sales and marketing cost categories, where the national integrator is modeled with higher expenses for customer acquisition, financial structuring, and asset management. To estimate the split in market share between small installers and national integrators, we use data compiled from corporate filings (Sunrun 2017; Vivint Solar 2017) and GTM Research and SEIA (2017). As shown in this figure, small installers gained more market share than national integrators did during 2016, because the direct ownership business model, led by installers, became more popular than third-party ownership.

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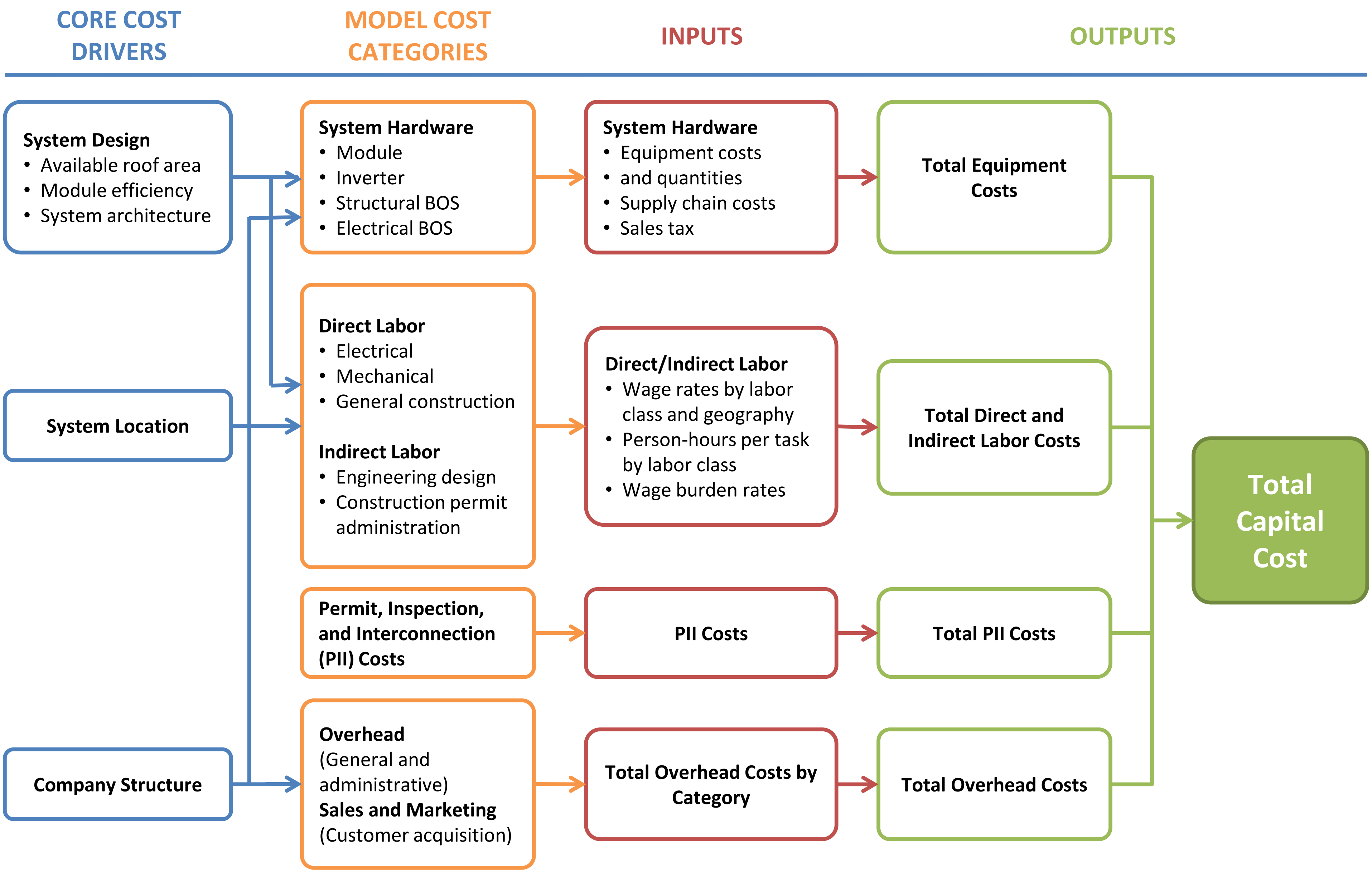
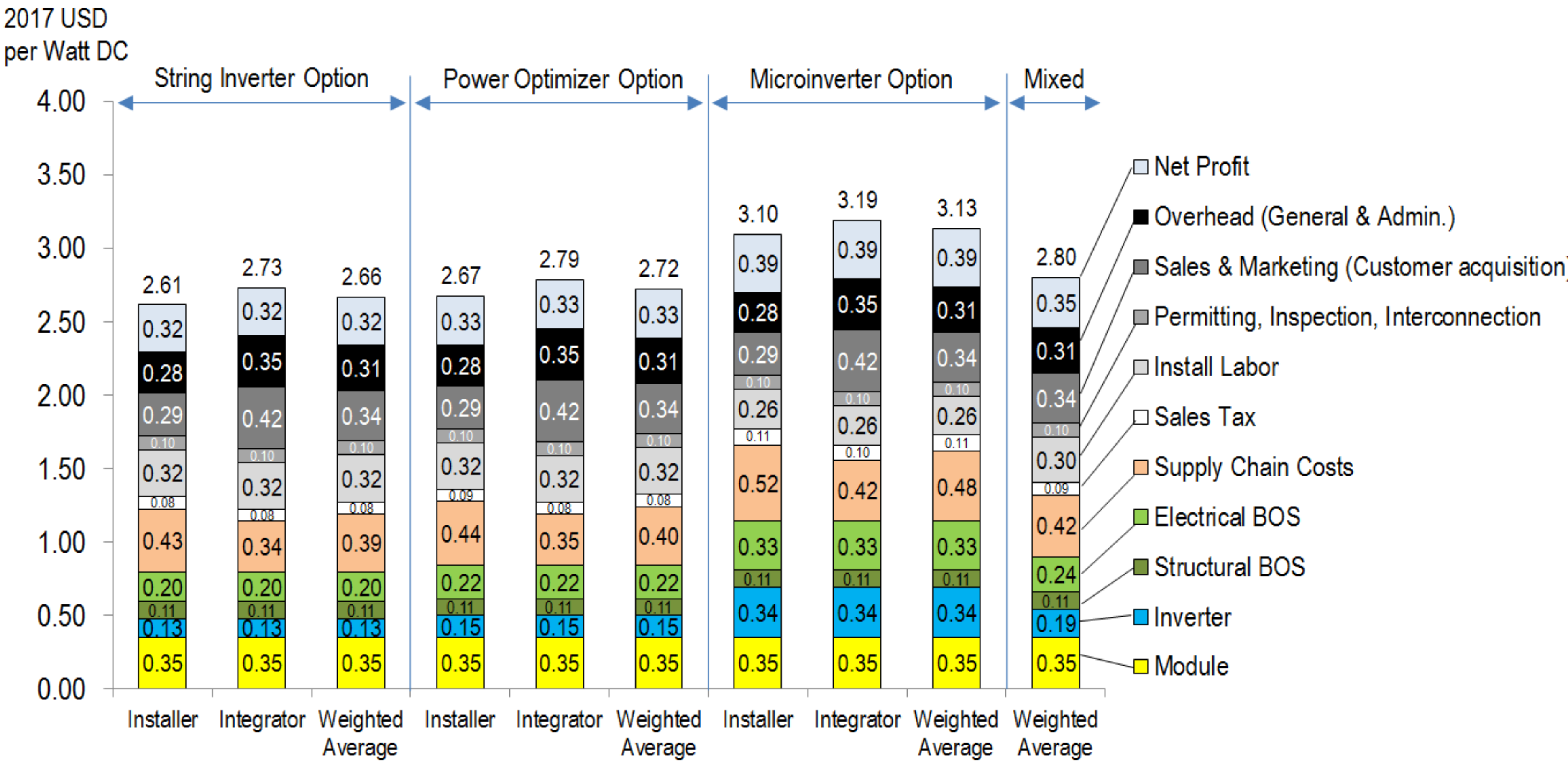
Residential PV: Model Structure



Residential PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	5.7 kW	Average installed size per system	Go Solar CA (2017)
Module efficiency	16.2%	Average module efficiency	Go Solar CA (2017)
Module price	\$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	Single-phase string inverter: \$0.13/Wdc DC power optimizer string inverter: \$0.15/Wdc Microinverter: \$0.34/Wdc	Ex-factory gate (first buyer) prices, Tier 1 inverters	Go Solar CA (2017), NREL (2017), PVinsights (2017), corporate filings (Enphase 2017, SolarEdge 2017)
Structural BOS (racking)	\$0.11/Wdc	Includes flashing for roof penetrations	Model assumptions, NREL (2017)
Electrical BOS	\$0.20–\$0.33/Wdc Varies by inverter option	Conductors, switches, combiners and transition boxes, as well as conduit, grounding equipment, monitoring system or production meters, fuses, and breakers	Model assumptions, NREL (2017), RSMeans (2016)
Supply chain costs (% of equipment costs)	Varies by installer type	15% costs and fees associated with shipping and handling of equipment multiplied by the cost of doing business index (101%) Additional 80% (60% historical inventory + 20% small-scale procurement) for module-related supply chain costs for small installers and 60% (historical inventory) for national integrators Additional 20% for inverter-related supply chain costs for small installers and 10% for national integrators	NREL (2017), model assumptions (2017)
Sales tax	Varies by location	Sales tax on the equipment; national benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMeans (2016)
Direct installation labor	Electrician: \$19.37–\$38.22 per hour; Laborer: \$12.64–\$25.09 per hour; Varies by location and inverter option	Modeled labor rate depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, Federal Insurance Contributions Act (FICA), builders risk, public liability	RSMeans (2016)
Permitting, inspection, and interconnection (PII)	\$0.10/Wdc	Includes assumed building permitting fee of \$400 and six office staff hours for building permit preparation and submission, and interconnection application preparation and submission	NREL (2017), Vote Solar (2015), Vote Solar and IREC (2013)
Sales & marketing (customer acquisition)	\$0.29/Wdc (installer) \$0.42/Wdc (integrator)	Total cost of sales and marketing activities over the last year—including marketing and advertising, sales calls, site visits, bid preparation, and contract negotiation; adjusted based on state "cost of doing business" index	NREL (2017), Sunrun (2017), Vivint Solar (2017), Feldman et al. (2013)
Overhead (general & administrative)	\$0.28/Wdc (installer) \$0.35/Wdc (integrator)	General and administrative expenses—including fixed overhead expenses covering payroll (excluding permitting payroll), facilities, administrative, finance, legal, information technology, and other corporate functions as well as office expenses; adjusted based on state "cost of doing business" index	NREL (2017), Sunrun (2017), Vivint Solar (2017), Feldman et al. (2013)
Profit (%)	17%	Applies a fixed percentage margin to all direct costs including hardware, installation labor, direct sales and marketing, design, installation, and permitting fees	Fu et al. (2016)

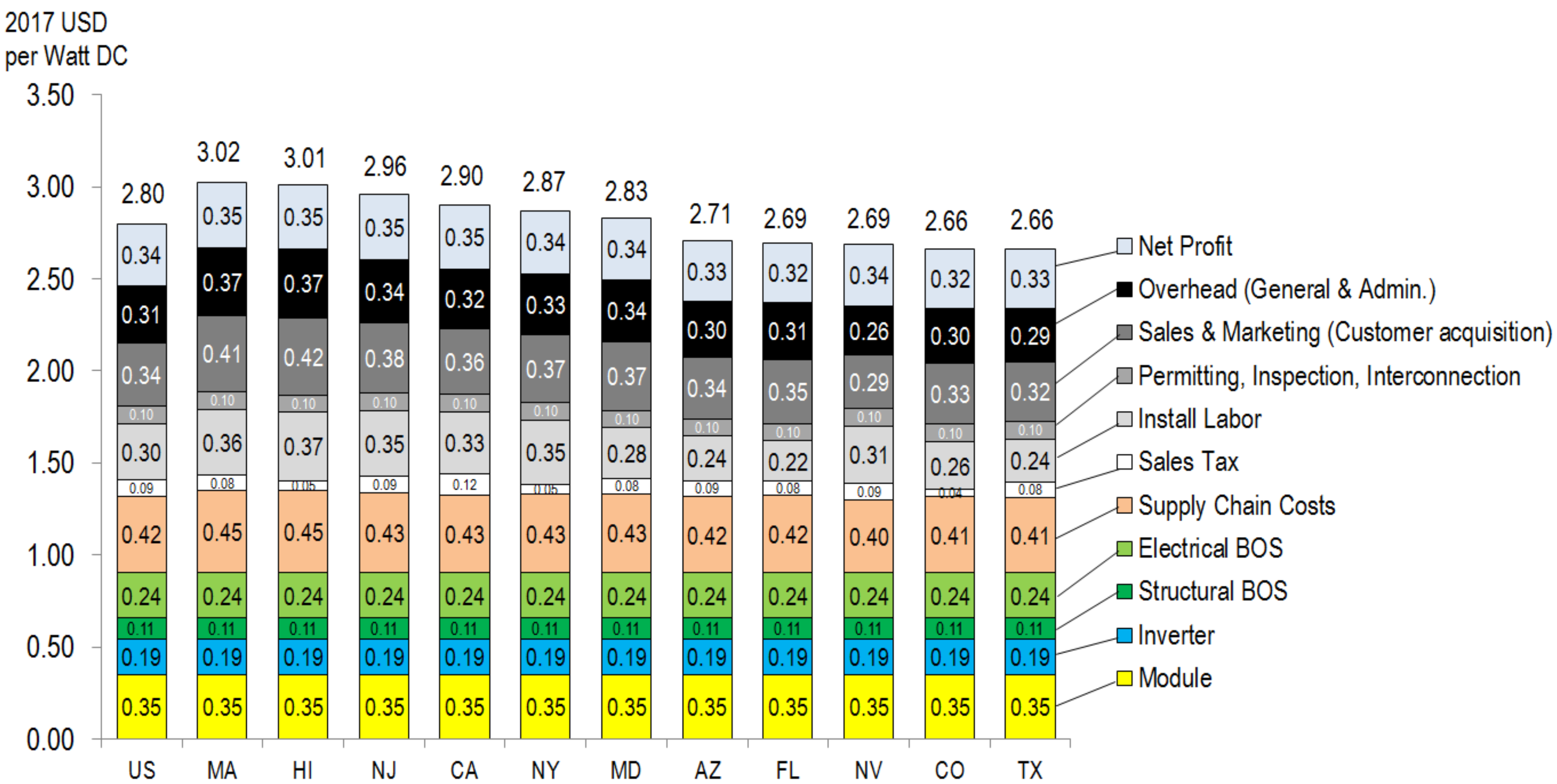
Residential PV: Model Outputs



Q1 2017 U.S. benchmark: 5.7-kW residential system cost (2017 USD/Wdc)

This figure presents the U.S. national benchmark from our residential model. The national benchmark represents an average weighted by 2016 state installed capacities. Market shares of 59% for installers and 41% for integrators are used to compute the national weighted average. String inverter, power optimizer, and microinverter options are each modeled individually, and the “mixed” case applies their market shares (47%, 26%, and 27%) as weightings.

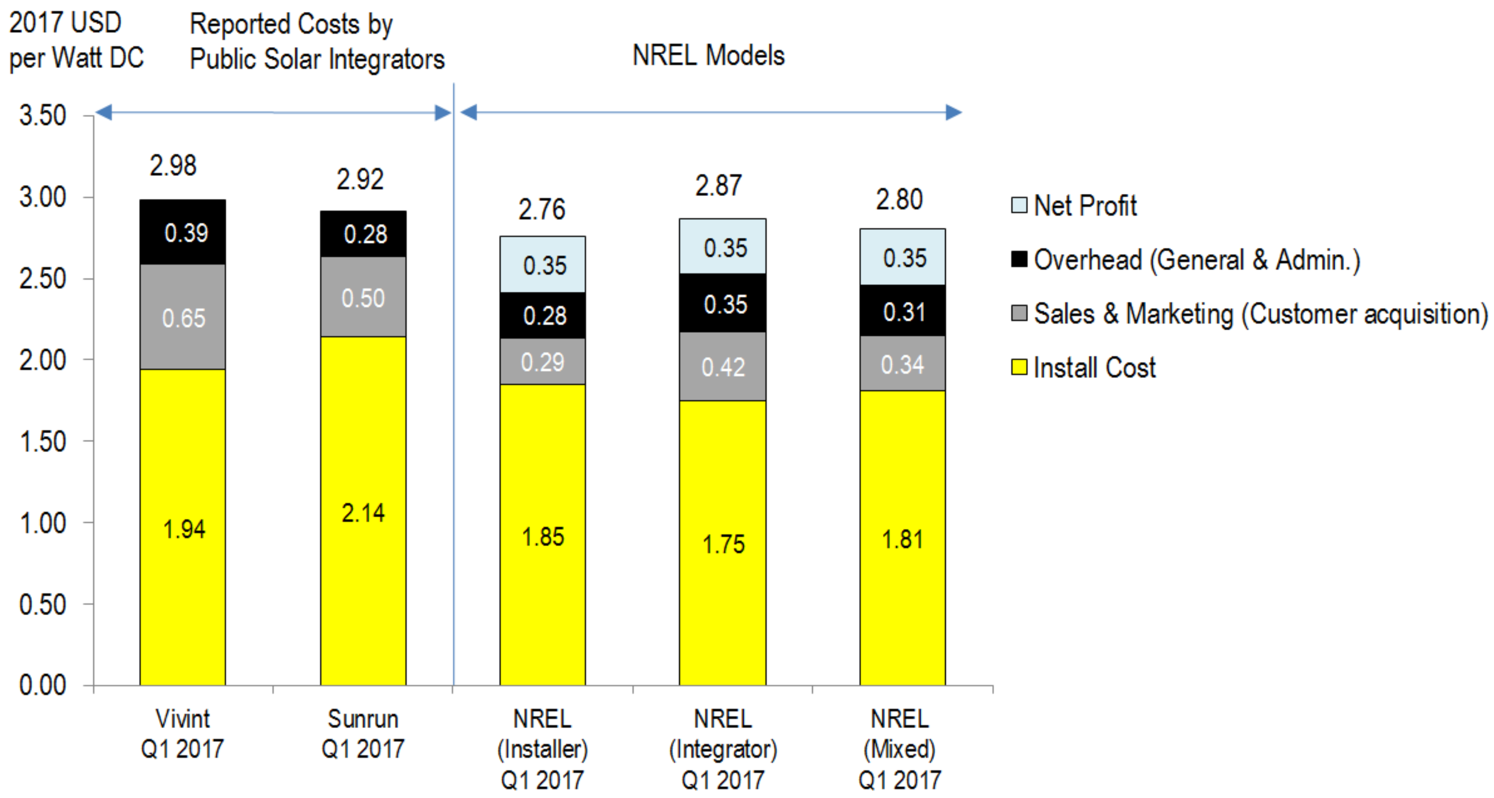
Residential PV: Model Outputs



Q1 2017 benchmark by location: 5.7-kW residential system cost (2017 USD/Wdc)

This figure presents the benchmark in the top U.S. solar markets (by 2016 installations), reflecting differences in supply chain and labor costs, sales tax, and SG&A expenses—that is, the cost of doing business (Case 2012).

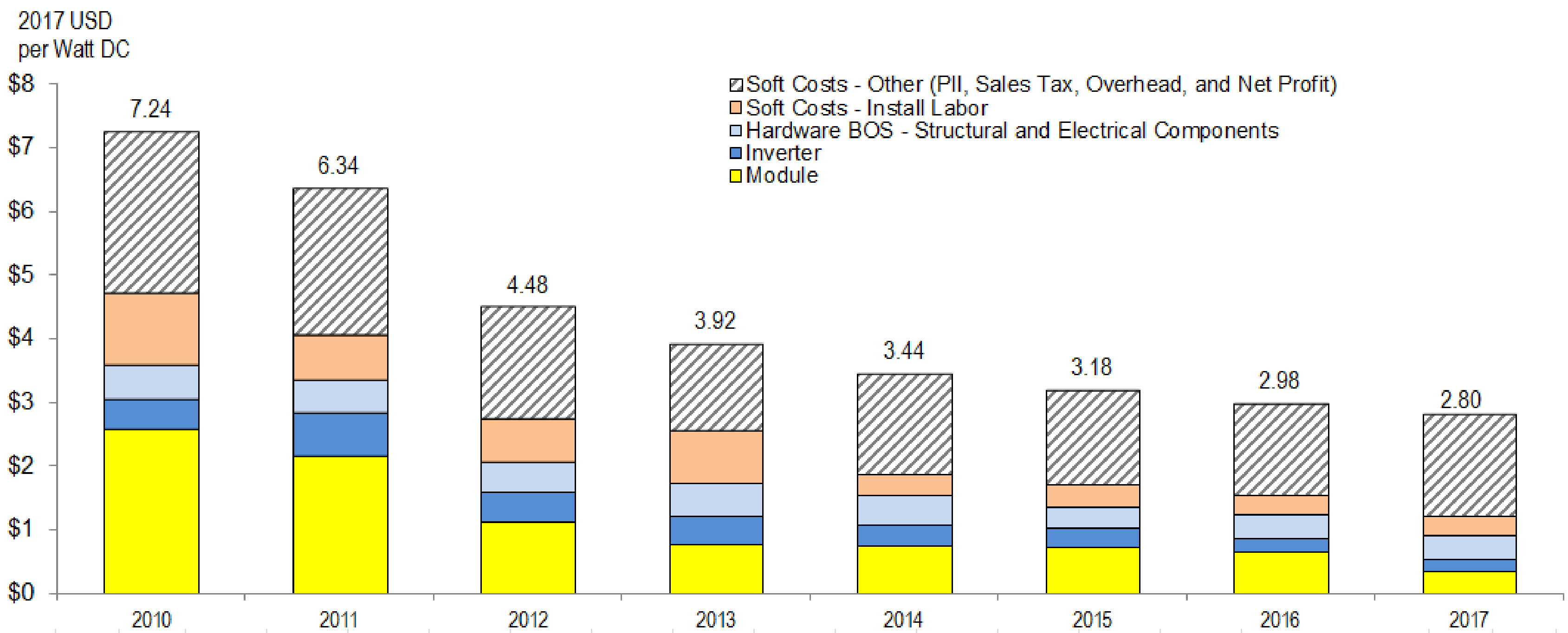
Residential PV: Model Outputs



Q1 2017 NREL modeled cost benchmark (2017 USD/Wdc) vs. Q4 2016 company-reported costs

Our bottom-up modeling approach yields a different cost structure than those reported by public solar integrators in their corporate filings (Sunrun 2017; Vivint Solar 2017). Because integrators sell and lease PV systems, they practice a different method of reporting costs than do businesses that only sell goods. Many of the costs for leased systems are reported over the life of the lease rather than the period in which the system is sold; therefore, it is difficult to determine the actual costs at the time of the sale. Although the corporate filings from Sunrun and Vivint Solar report system costs on a quarterly basis, the lack of transparency in the public filings makes it difficult to determine the underlying costs as well as the timing of those costs.

Residential PV: Capital Cost Benchmark Historical Trends



From 2010 to 2017, there was a 61% reduction in the residential PV system cost benchmark. Approximately 61% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 86% over that time period. An additional 18% can be attributed to labor, which dropped 73% over that time period, with the final 21% attributed to other soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2016 to 2017 there was a 6% reduction in the residential PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, moderated by the increase in module supply chain costs discussed earlier (shown here in “Soft Costs – Other”).

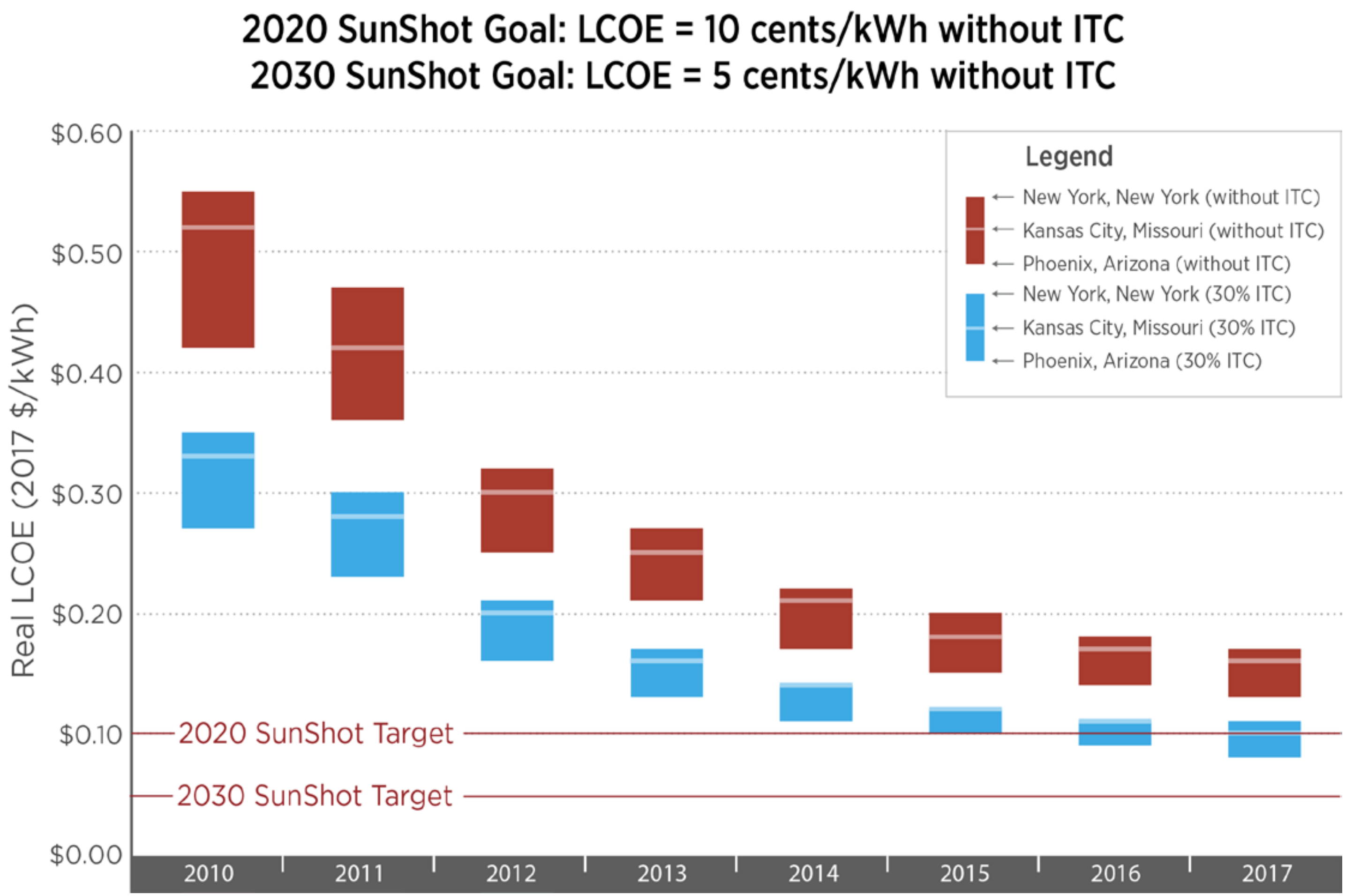
Residential PV: LCOE assumptions

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	$7.24	$6.34	$4.48	$3.92	$3.44	$3.18	$2.98	$2.80
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[c]	0.75%	0.75%
Inverter replacement price ($/W)	$0.41[a]	$0.36	$0.31	$0.26	$0.21	$0.15[c]	$0.14[e]	$0.13
Inverter lifetime (years)	10[a]	11	12	13	14	15[c]	15	15
O&M expenses ($/kw-yr)	$37[a]	$33	$30	$27	$24	$21[c]	$21	$21
Pre-inverter derate (%)	90.0%[a]	90.10%	90.20%	90.30%	90.40%	90.5%[c]	90.5%	90.5%
Inverter efficiency (%)	94.0%[a]	94.80%	95.60%	96.40%	97.20%	98.0%[c]	98.0%	98.0%
System size (kw-DC)	5.0[a]	5.0	5.1	5.1	5.2	5.2[c]	5.6[e]	5.7
Inverter loading ratio	1.1[a]	1.11	1.12	1.13	1.13	1.14	1.15[e]	1.15
Equity discount rate (real)	9.0%[c]	8.6%	8.3%	7.9%	7.6%	7.3%	6.9%[d]	6.9%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%[c]	5.4%	5.3%	5.2%	5.0%	4.9%	4.8%[d]	4.8%
Debt fraction	34.2%[b]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%

Other important assumptions: residential PV system LCOE assume a 1) system lifetime of 30 years[b], 2) federal tax rate of 35%[b], 3) state tax rate of 7%[b], 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)[b], 7) a three month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system[b], 8) a module tilt angle of 25 degrees, and an azimuth of 180 degrees, 9) debt with a term of 18 years[b], and 10) $1.1 MM of upfront financial transaction costs for a $100 MM TPO transaction of a pool of residential projects[d].

Sources: [a]SunShot Vision Study 2010, [b]On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; [c]On the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); [d]Terms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), [e]U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016

Residential PV: LCOE Benchmark Historical Trends

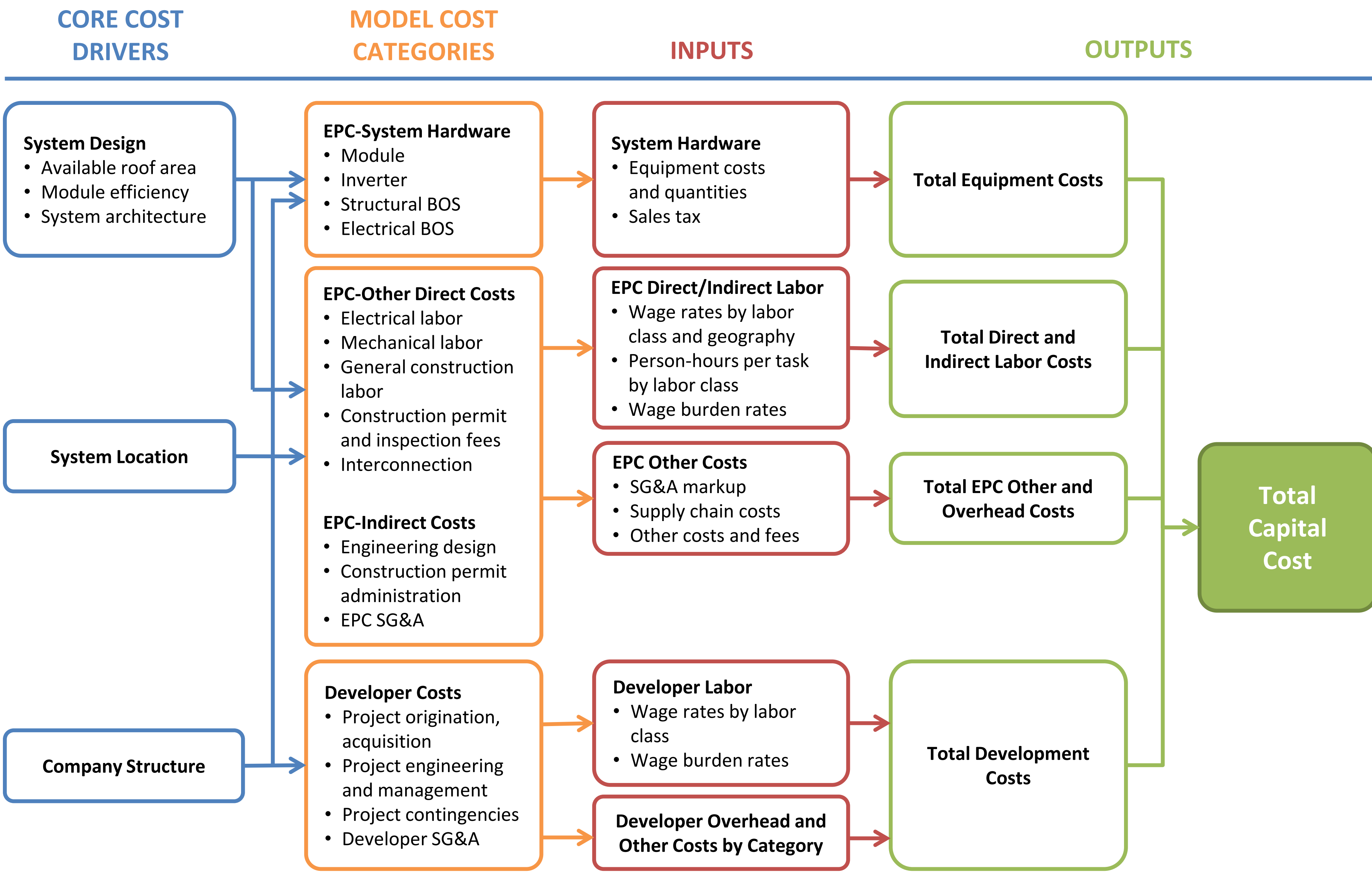


From 2010 to 2017, there was a 70% reduction in the residential PV system electricity cost benchmark (a 5% to 6% reduction was achieved from 2016 to 2017), bringing the unsubsidized LCOE between $0.13/kWh to $0.17/kWh ($0.08/kWh to $0.11/kWh when including the federal ITC). This reduction is 86% toward achieving SunShot's 2020 residential LCOE goal, which is 10 cents/kWh in 2017 USD.

Note: For LCOE Kansas City, MO, without ITC cases are $0.52/kWh in 2010 and $0.16/kWh in 2017 in 2017 USD from Appendix. Thus, calculation is: (0.52 – 0.16)/(0.52 – 0.10) = 86%.

Contents

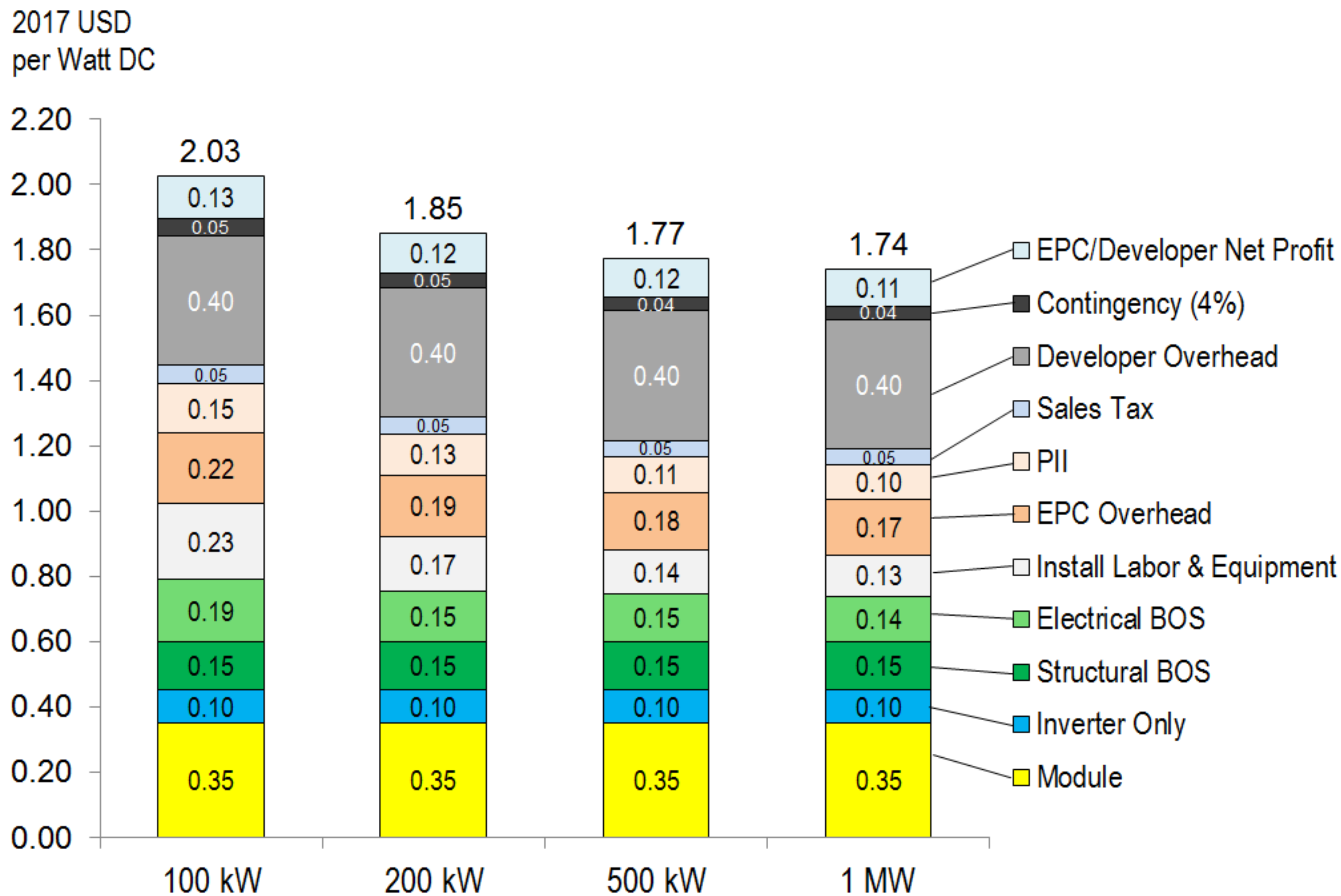
Commercial PV: Model Structure



Commercial PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	10 kW–2 MW	Average installed size per system	Go Solar CA (2017)
Module efficiency	17.5%	Average module efficiency	Go Solar CA (2017)
Module price	$0.35/Wdc	Ex-factory gate (first buyer) ASP, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	Three-phase string inverter: $0.10/Wdc	Ex-factory gate prices (first buyer) ASP, Tier 1 inverters	Bloomberg (2017), NREL (2017)
Structural components (racking)	$0.13–$0.28/Wdc; varies by location and system size	Ex-factory gate prices; flat-roof ballasted racking system	ASCE (2006), model assumptions, NREL (2017)
Electrical components	Varies by location and system size	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, etc.	Model assumptions, NREL (2017), RSMeans (2016)
EPC overhead (% of equipment costs)	13%	Costs and fees associated with EPC overhead, inventory, shipping, and handling	NREL (2017)
Sales tax	Varies by location	Sales tax on equipment costs; national benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMeans (2016)
Direct installation labor	Electrician: $19.37–$38.22 per hour Laborer: $12.64–$25.09 per hour Varies by location and inverter option	Modeled labor rate assumes non-union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, Federal Insurance Contributions Act (FICA), builders risk, public liability	RSMeans (2016)
PII	$0.11–$0.16/Wdc	For construction permits fee, interconnection study fees for existing substation, testing, and commissioning	NREL (2017)
Developer overhead	Assume 10-MW system development and installation per year for a typical developer	Includes fixed overhead expenses such as payroll, facilities, travel, insurance, administrative, business development, finance, and other corporate functions; assumes 10 MW/year of system sales	Model assumptions, NREL (2017)
Contingency	4%	Estimated as markup on EPC price; value represents actual cost overruns above estimated price.	NREL (2017)
Profit	7%	Applies a fixed percentage margin to all costs including hardware, installation labor, EPC overhead, developer overhead, etc.	NREL (2017)

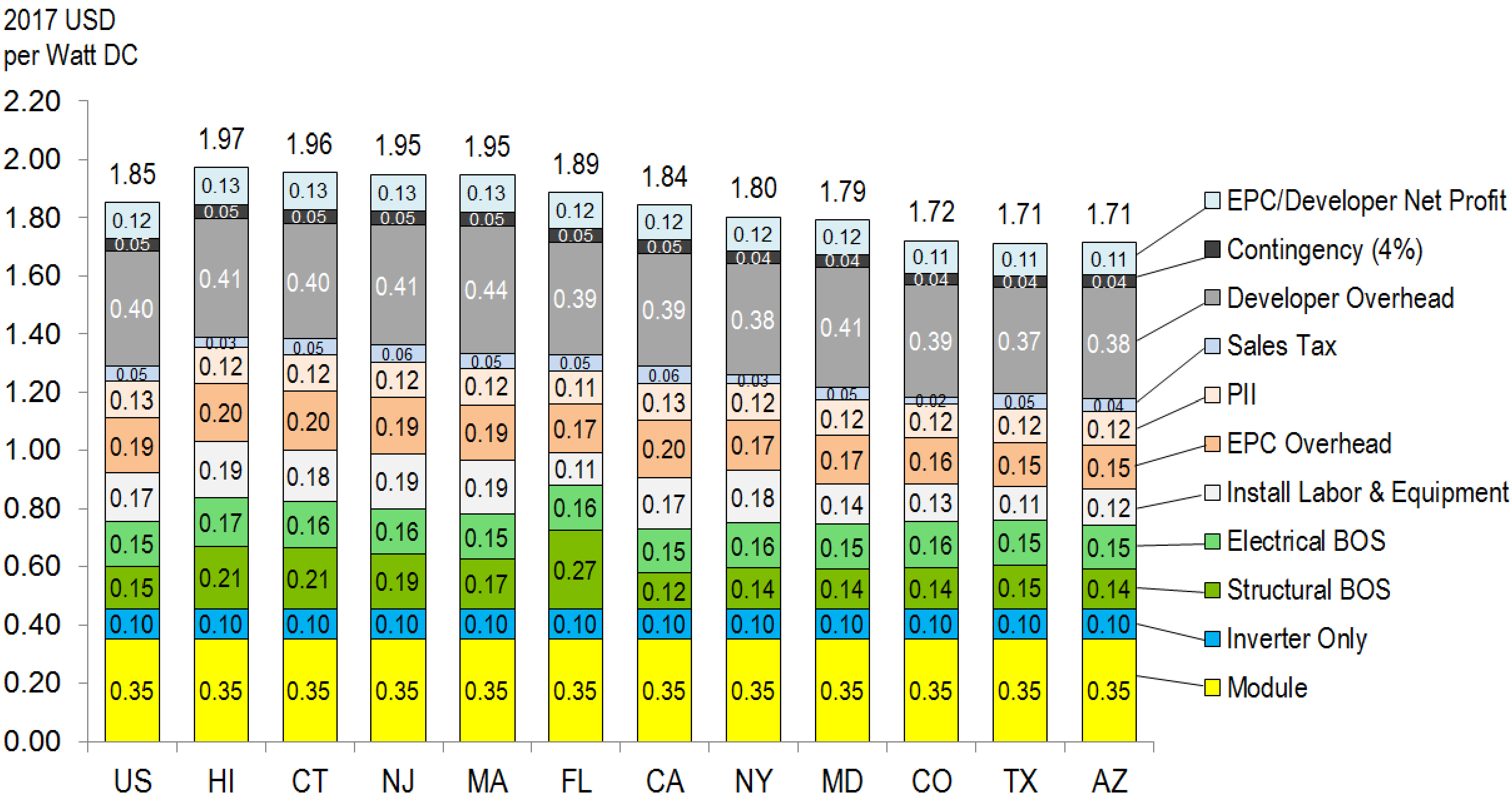
Commercial PV: Model Outputs



Q1 2017 U.S. benchmark: commercial system cost (2017 USD/Wdc)

As in the residential model, the national benchmark represents an average weighted by 2016 state installed capacities. We model different system sizes because of the wide scope of the “commercial” sector, which comprises a diverse customer base occupying a variety of building sizes. Also, economies of scale—driven by hardware, labor, and related markups—are evident here. That is, as system sizes increase, the per-watt cost to build them decreases. Meanwhile, because we assume that a typical developer has 10 MW of system development and installation per year, the developer overheads on this 10 MW total capacity do not vary for different system sizes. When a developer installs more capacity annually, that developer’s overhead per watt in each system declines (shown in Figure 18 in our Q1 2015 benchmark report, Chung et al. 2015).

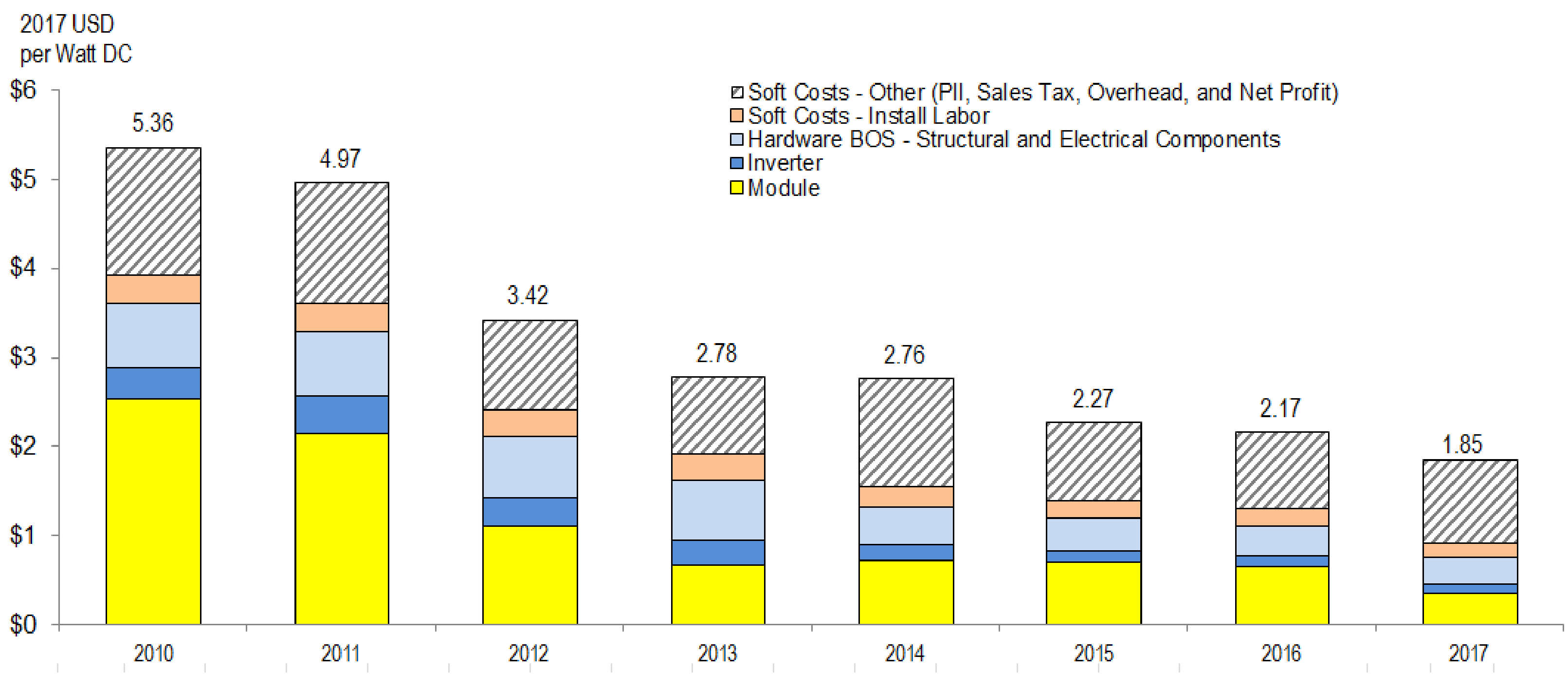
Commercial PV: Model Outputs



Q1 2017 benchmark by location: 200-kW commercial system cost (2017 USD/Wdc)

This figure presents the benchmark from our commercial model by location in the top U.S. solar markets (by 2016 installations). The main cost drivers for different regions in the commercial PV market are the same as in the residential model (labor rates, sales tax, and cost of doing business index), but also include costs associated with wind or snow loading.

Commercial PV: Capital Cost Benchmark Historical Trends



From 2010 to 2017, there was a 65% reduction in the commercial PV system cost benchmark. Approximately 82% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 86% over that time period. An additional 4% can be attributed to labor, which dropped 47% over that time period, with the final 14% attributable to other soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2016 to 2017 there was a 15% reduction in the commercial PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, moderated by an increase in PII and installer profit.

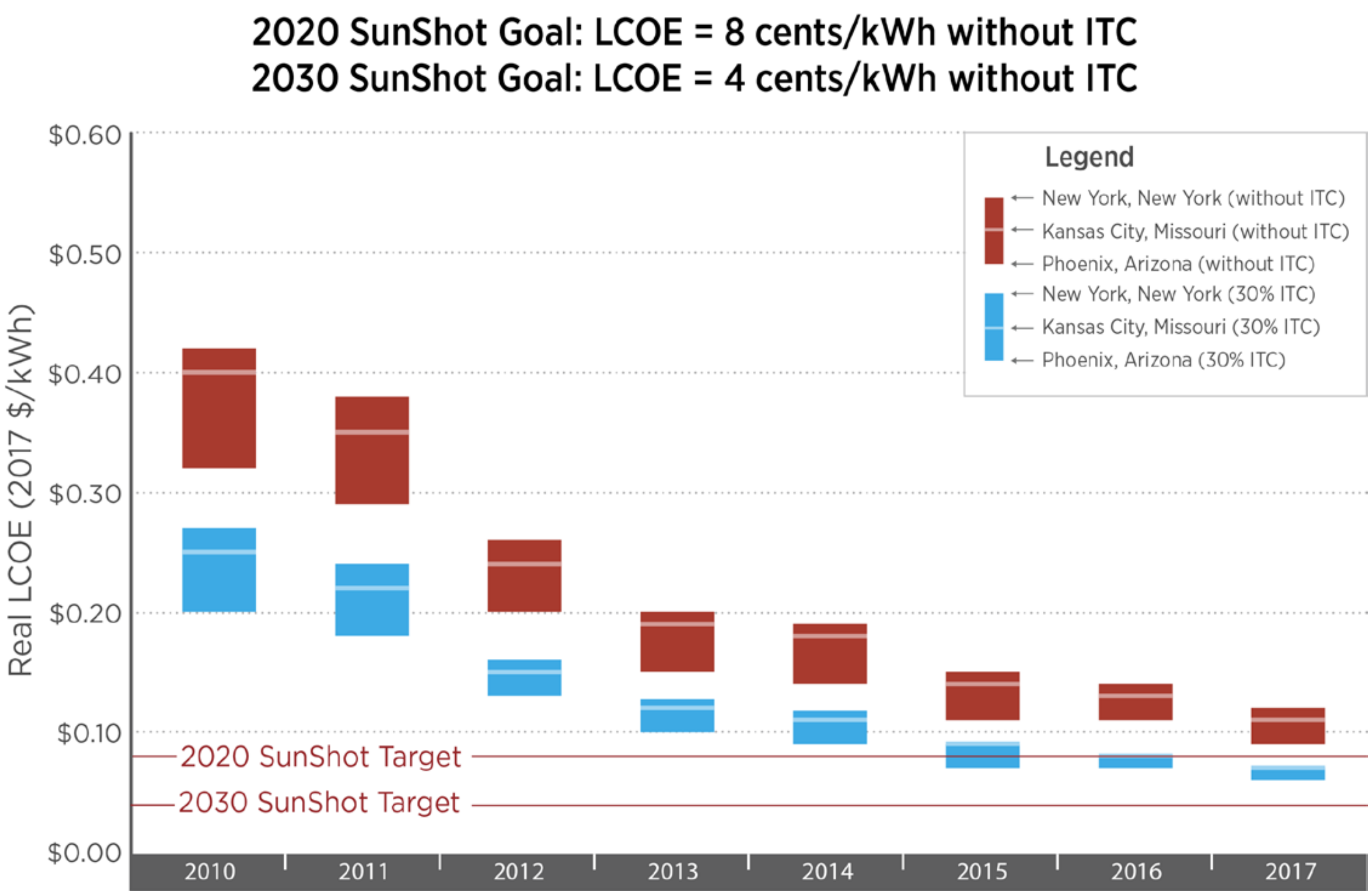
Commercial PV: LCOE Assumptions

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	$5.36	$4.97	$3.42	$2.78	$2.76	$2.27	$2.17	$1.85
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[b]	0.75%	0.75%
Inverter replacement price ($/W)	$0.24[a]	$0.22	$0.19	$0.17	$0.15	$0.12[b]	$0.11[e]	$0.10
O&M expenses ($/kw-yr)	$26[a]	$24	$22	$20	$18	$15[b]	$15	$15
Pre-inverter derate (%)	90.5%[a]	90.50%	90.50%	90.50%	90.50%	90.5%[b]	90.5%	90.5%
Inverter efficiency (%)	95.0%[a]	95.60%	96.20%	96.80%	97.40%	98.0%[b]	98.0%	98.0%
Inverter loading ratio	1.10[a]	1.11	1.12	1.13	1.13	1.14	1.15[e]	1.15
Equity discount rate (real)	9.0%[c]	8.6%	8.3%	7.9%	7.6%	7.3%	6.9%[d]	6.9%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%[c]	5.4%	5.3%	5.2%	5.0%	4.9%	4.8%[d]	4.8%
Debt fraction	34.2%[c]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%

Other important assumptions: commercial PV system LCOE assume a 1) system lifetime of 30 years[b], 2) federal tax rate of 35%[b], 3) state tax rate of 7%[b], 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)[b], 7) a six month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system[b], 8) a system size of 200 kW[a], 9) an inverter lifetime of 15 years[a], 10) a module tilt angle of 10 degrees, and an azimuth of 180 degrees, 11) debt with a term of 18 years[b], and 12) $1.1MM of upfront financial transaction costs for a $100 MM TPO transaction of a pool of commercial projects[d].

Sources: [a]SunShot Vision Study 2010, [b]On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; [c]On the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); [d]Terms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), [e]U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016

Commercial PV: LCOE Benchmark Historical Trends

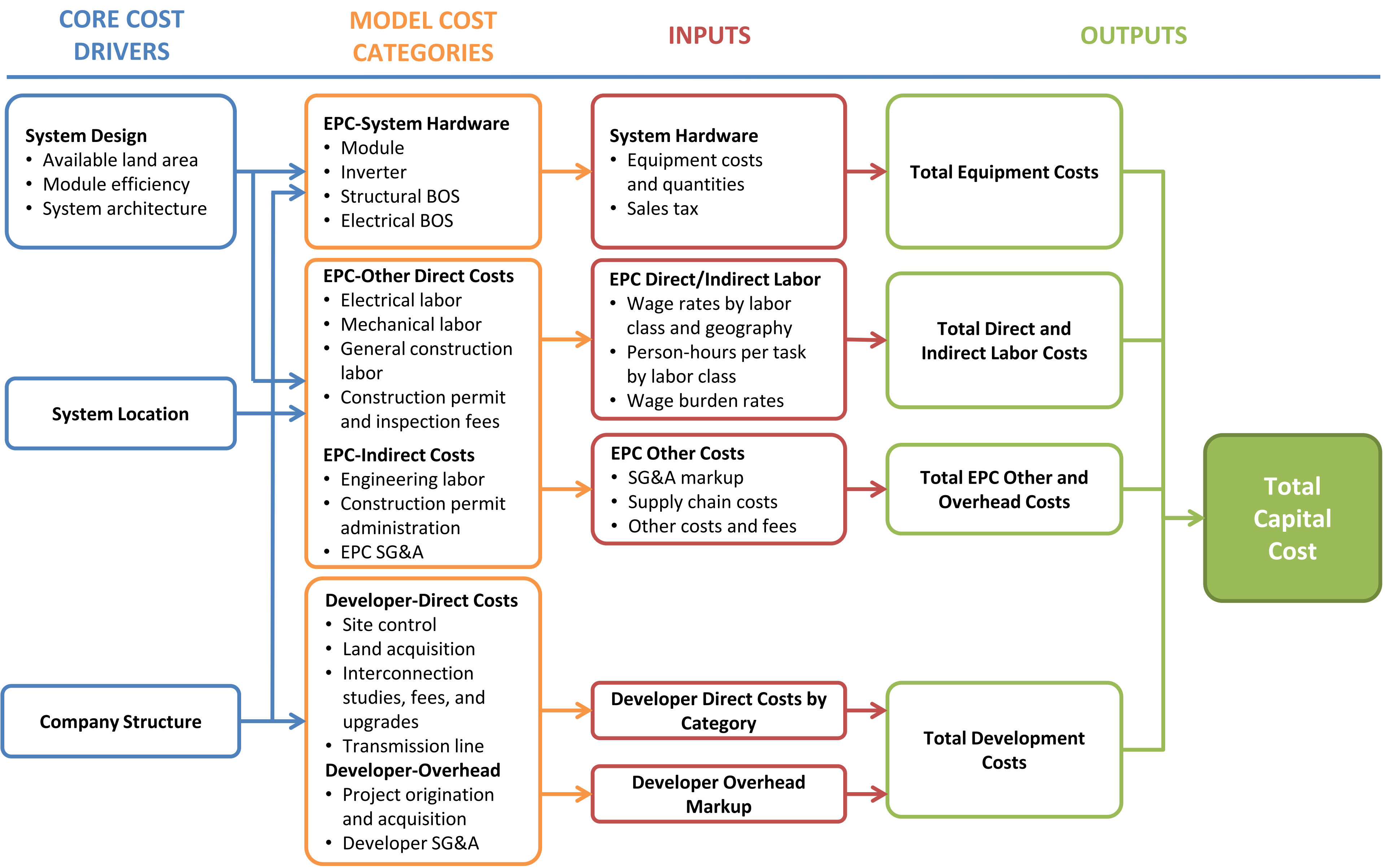


From 2010 to 2017, there was a 71% - 72% reduction in the commercial PV system electricity cost benchmark (a 12%–13% reduction was achieved from 2016 to 2017), bringing the unsubsidized LCOE between $0.09/kWh to $0.12/kWh ($0.06/kWh to $0.08/kWh when including the federal ITC). This reduction is 89% toward achieving SunShot's 2020 commercial PV LCOE goal, which is 8 cents/kWh in 2017 USD.

Note: For LCOE Kansas City, MO, without ITC cases are $0.40/kWh in 2010 and $0.11/kWh in 2017 in 2017 USD from Appendix. Thus, calculation is: (0.40 – 0.11)/(0.40 – 0.08) = 89%.

Contents

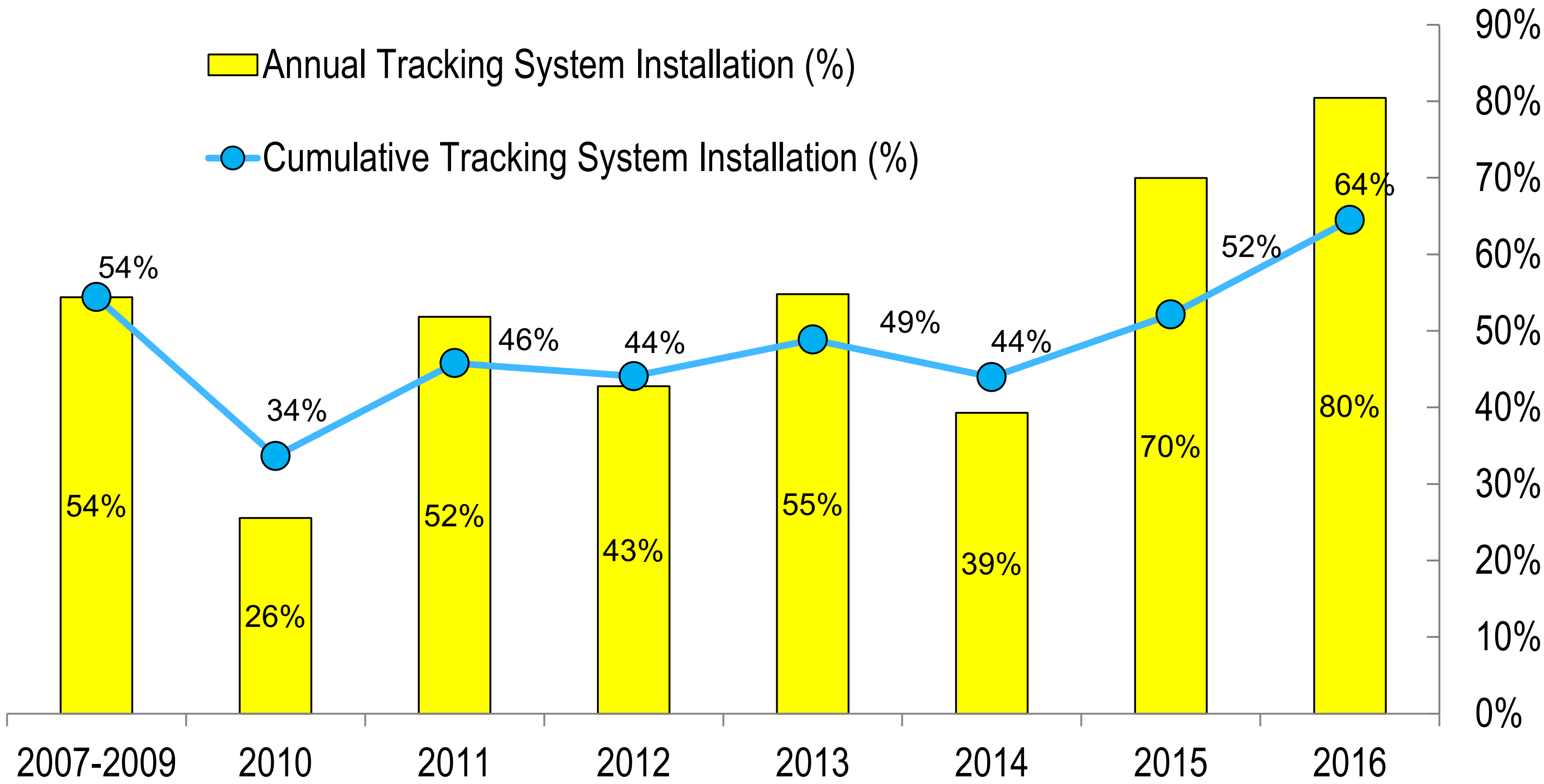
Utility-Scale PV: Model Structure



Utility-Scale PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	>2 MW	A large utility-scale system capacity	Model assumption
Module efficiency	17.5%	Average module efficiency	NREL (2017)
Module price	$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	$0.06/Wdc (fixed-tilt) $0.06/Wdc (one-axis tracker)	Ex-factory gate prices (first buyer) price, Tier 1 inverters DC-to-AC ratio = 1.3 for both fixed-tilt and one-axis tracker	Bloomberg (2017), NREL (2017), Bolinger and Seel (2017)
Structural components (racking)	$0.10–$0.21/Wdc for a 100-MW system; varies by location and system size	Fixed-tilt racking or one-axis tracking system	ASCE (2006), model assumptions, NREL (2017)
Electrical components	Varies by location and system size	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, onsite transmission, etc.	Model assumptions, NREL (2017), RSMeans (2016)
EPC overhead (% of equipment costs)	8.67%–13% for equipment and material (except for transmission line costs); 23%–69% for labor costs; varies by system size, labor activity, and location	Costs associated with EPC SG&A, warehousing, shipping, and logistics	NREL (2017)
Sales tax	Varies by location	National benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMeans (2016)
Direct installation labor	Electrician: $19.37–$38.22 per hour Laborer: $12.64–$25.09 per hour Varies by location and inverter option	Modeled labor rate assumes non-union and union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, FICA, builders risk, public liability	RSMeans (2016)
PII	$0.03–$0.09/Wdc Varies by system size and location	For construction permits fee, interconnection, testing, and commissioning	NREL (2017)
Transmission line (gen-tie line)	$0.00–$0.02/Wdc Varies by system size	System size < 10 MW, use 0 miles for gen-tie line System size > 200 MW, use 5 miles for gen-tie line System size = 10–200 MW, use linear interpolation	Model assumptions, NREL (2017)
Developer overhead	3%–12% Varies by system size (100 MW uses 3%; 5 MW uses 12%)	Includes overhead expenses such as payroll, facilities, travel, legal fees, administrative, business development, finance, and other corporate functions	Model assumptions, NREL (2017)
Contingency	3%	Estimated as markup on EPC cost	NREL (2017)
Profit	5%–8% Varies by system size (100 MW uses 5%; 5 MW uses 8%)	Applies a percentage margin to all costs including hardware, installation labor, EPC overhead, developer overhead, etc.	NREL (2017)

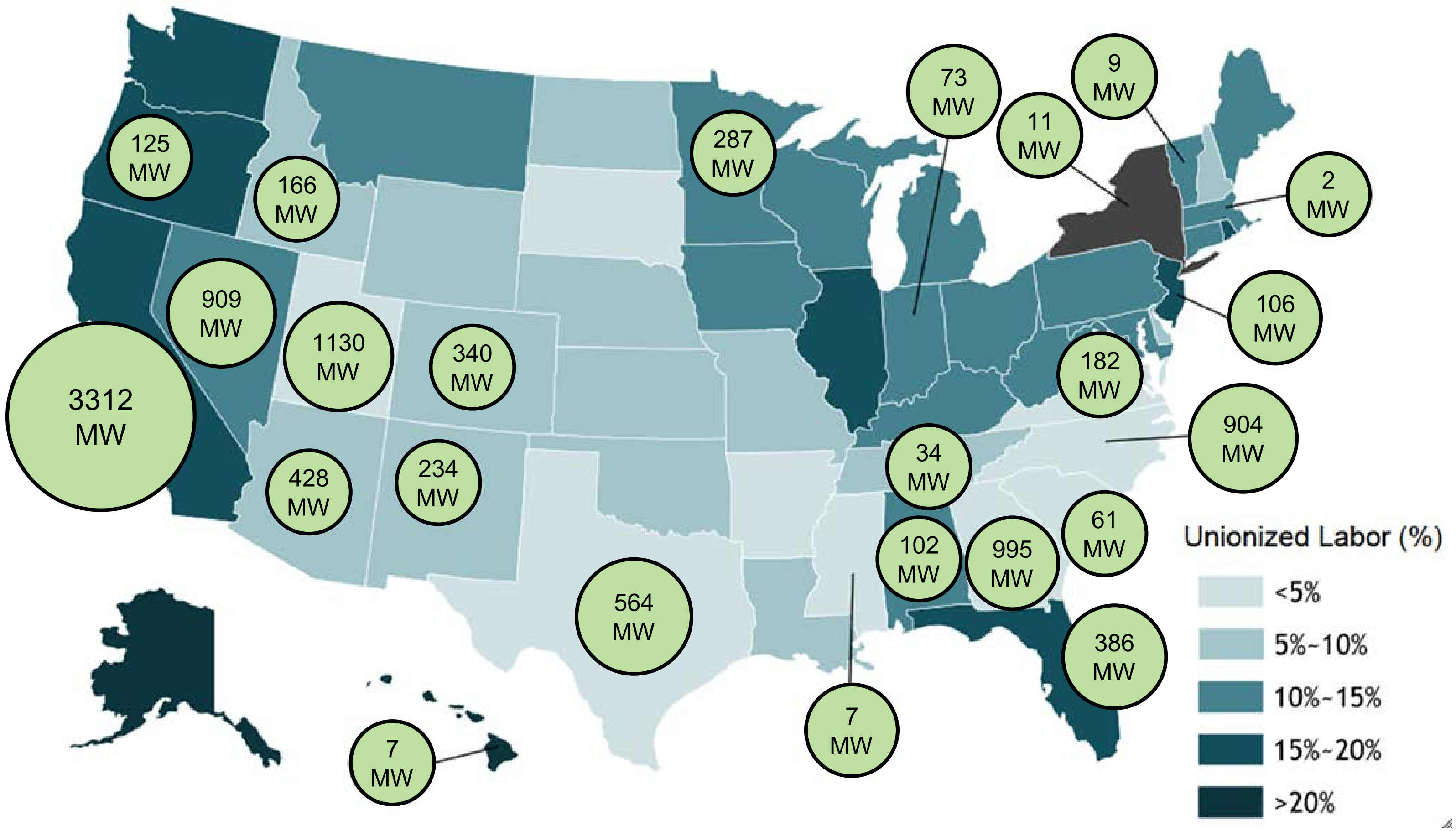
Utility-Scale PV: U.S. Fixed-Tilt vs. Tracking Systems



Percentage of U.S. utility-scale PV systems using tracking systems, 2007–2016 (Bolinger and Seel 2017)

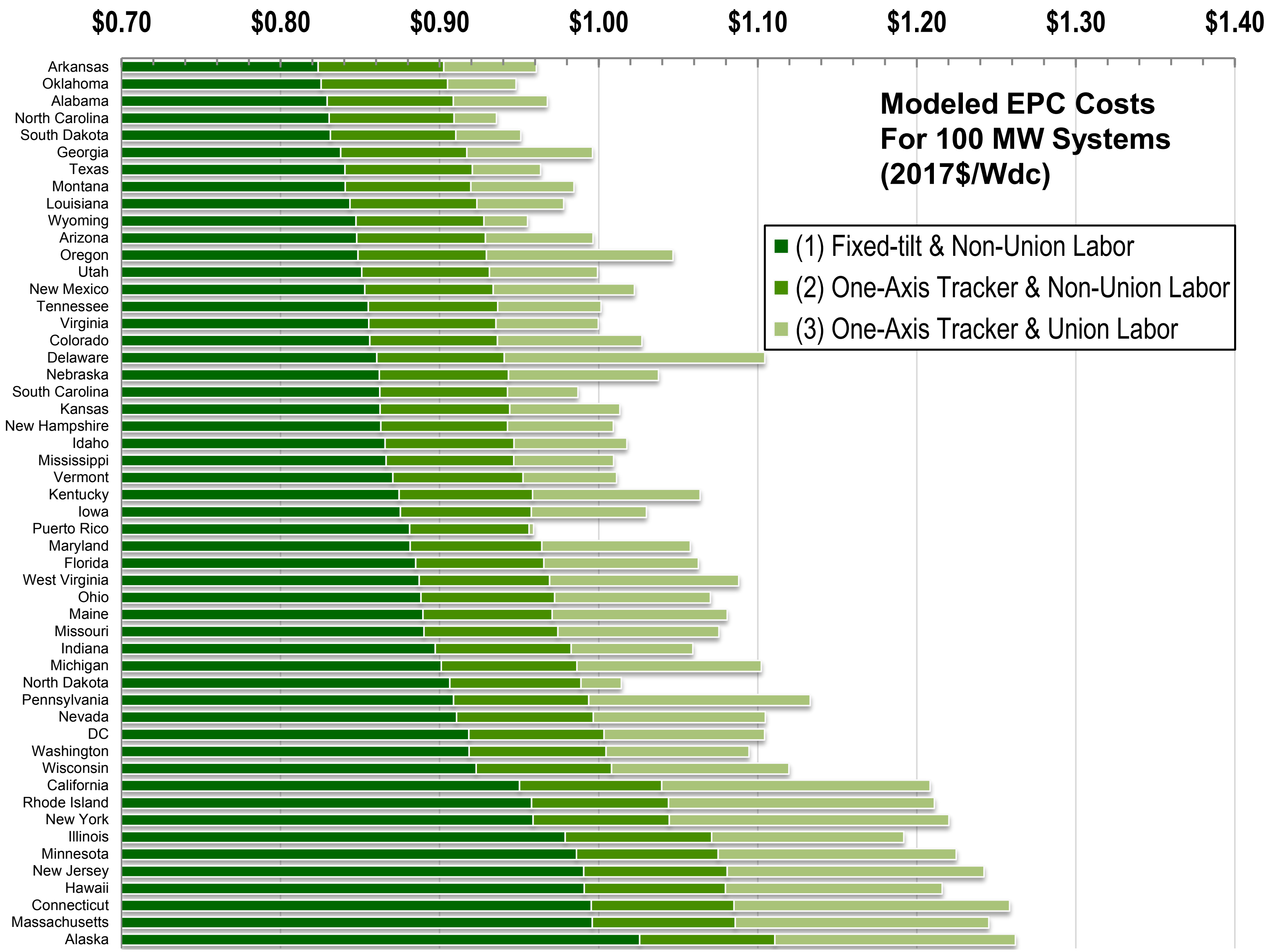
This figure shows the percentage of U.S. utility-scale PV systems using tracking systems for 2007–2016. Although the data include one-axis and dual-axis tracking systems in the same “tracking” category, there are many more one-axis trackers than dual-axis trackers (Bolinger and Seel 2017). Cumulative tracking system installation reached 64% in 2016.

Utility-Scale PV: Union Labor Case

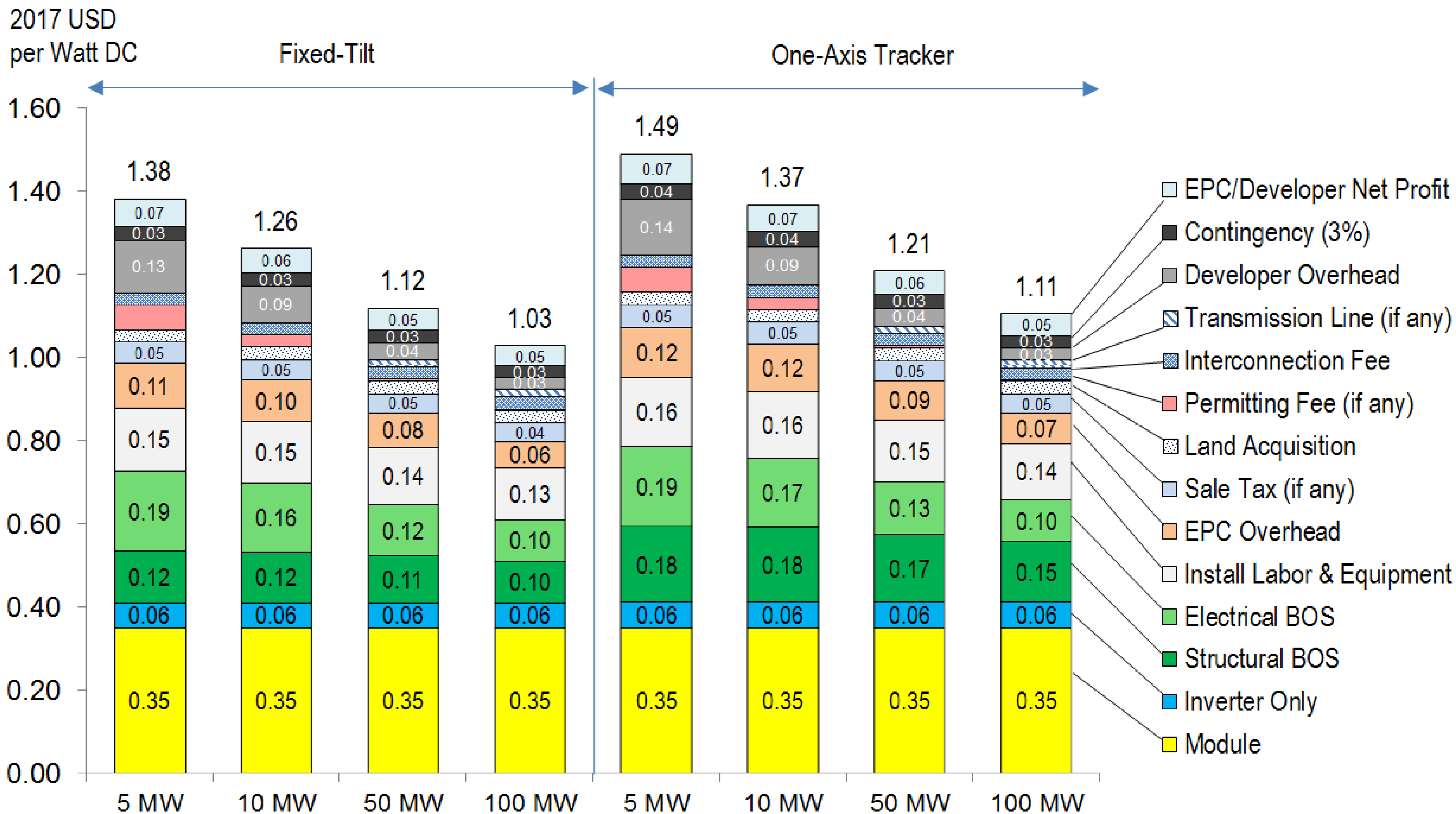


Although EPC contractors and developers tend to employ low-cost, non-union labor (based on data from BLS 2017) for PV system construction when possible, union labor is sometimes mandated. Construction trade unions may negotiate with the local jurisdiction and EPC contractor/developer during the public review period of the permitting process. This figure shows 2016 utility-scale PV capacity installed (GTM Research and SEIA 2017) and the proportion of unionized labor in each state (BLS 2017). The unionized labor number represents the percentage of employed workers in each state's entire construction industry who are union members. In our utility-scale model, both non-union and union labor rates are considered.

Utility-Scale PV: Model Outputs, EPC Only



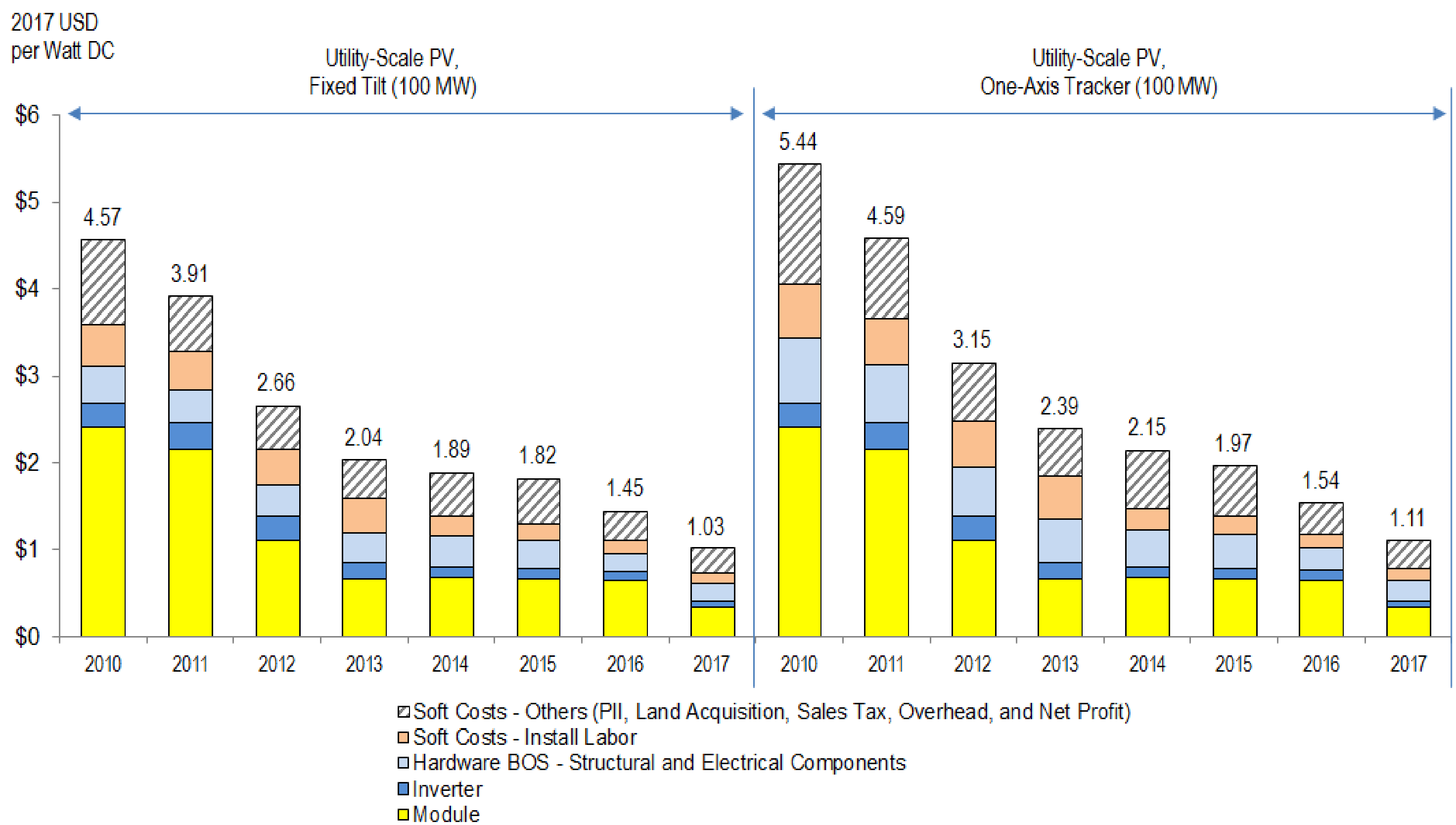
Utility-Scale PV: Model Outputs, EPC + Developer



Q1 2017 U.S. benchmark: utility-scale PV total cost (EPC + developer) 2017 USD/Wdc

(1) The national benchmark applies an average weighted by 2016 installed capacities.
(2) Non-union labor is used.
(3) Economies of scale—driven by BOS, labor, related markups, and development cost—are demonstrated.

Utility-Scale PV: Capital Cost Benchmark Historical Trends



From 2010 to 2017, there was a 77% reduction in the utility-scale (fixed-tilt) PV system cost benchmark, and an 80% reduction in the utility-scale (one-axis) PV system cost benchmark. Approximately 71% and 64% of that reduction can be attributed to total hardware costs (for fixed-tilt and one-axis systems respectively), as module prices dropped 86% over that time period. An additional 10%/11% can be attributed to labor, which dropped 74%/78% over that time period, with the final 19%/25% attributable to other soft costs, including PII, sales tax, overhead, and net profit (for fixed-tilt and one-axis systems respectively).

Looking at this past year, from 2016 to 2017 there was a 29% reduction in the utility-scale (fixed-tilt) PV system cost benchmark, and an 28% reduction in the utility-scale (one-axis) PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, and a 45%/41% reduction in inverter factory gate price.

Utility-Scale PV (One-Axis Tracker): LCOE assumptions

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	$5.44	$4.59	$3.15	$2.39	$2.15	$1.97	$1.54	$1.11
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[b]	0.75%	0.75%
Inverter replacement price ($/W)	$0.19[a]	$0.17	$0.15	$0.14	$0.12	$0.10[b]	$0.08[e]	$0.06
O&M expenses ($/kw-yr)	$22.2[a]	$21.5	$20.7	$20.0	$19.2	$18.5[b]	$18.5	$18.5
Pre-inverter derate (%)	90.5%[a]	90.50%	90.50%	90.50%	90.50%	90.5%[b]	90.5%	90.5%
Inverter efficiency (%)	96.0%[a]	96.40%	96.80%	97.20%	97.60%	98.0%[b]	98.0%	98.0%
Inverter loading ratio	1.10[a]	1.12	1.13	1.15	1.17	1.18	1.20[e]	1.30
Equity discount rate (real)	7.4%[c]	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%[d]	6.3%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%[c]	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%[d]	4.5%
Debt fraction	34.2%[c]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%

Other important assumptions: utility-scale PV system LCOE assume a 1) system lifetime of 30 years[a], 2) federal tax rate of 35%[b], 3) state tax rate of 7%[b], 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)[b], 7) a six month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system[b], 8) a system size of 100 MW[b], 9) an inverter lifetime of 15 years[a], 10) debt with a term of 18 years[b], and 11) $1.1MM of upfront financial transaction costs[d].

Sources: [a]SunShot Vision Study 2010, [b]On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; [c]On the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); [d]Terms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), [e]U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016

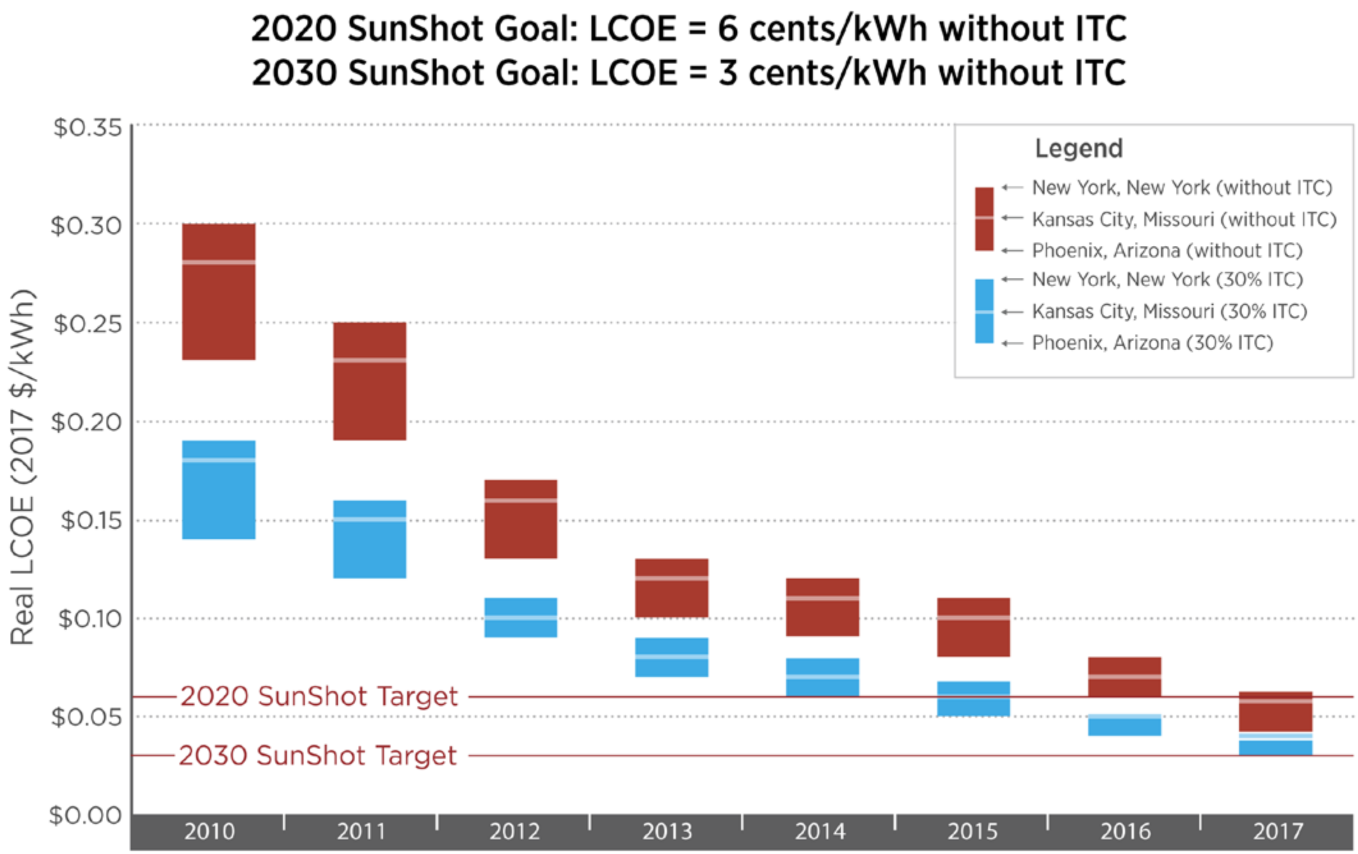
Utility-Scale PV (Fixed-Tilt): LCOE Assumptions

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	$4.57	$3.91	$2.66	$2.04	$1.89	$1.82	$1.45	$1.03
Annual degradation (%)	1.00%[a]	0.95%	0.90%	0.85%	0.80%	0.75%[b]	0.75%	0.75%
Inverter replacement price ($/W)	$0.19[a]	$0.17	$0.15	$0.14	$0.12	$0.10[b]	$0.08[e]	$0.06
O&M expenses ($/kw-yr)	$22.2[a]	$20.9	$19.5	$18.1	$16.8	$15.4[b]	$15.4	$15.4
Pre-inverter derate (%)	90.5%[a]	90.50%	90.50%	90.50%	90.50%	90.5%[b]	90.5%	90.5%
Inverter efficiency (%)	96.0%[a]	96.40%	96.80%	97.20%	97.60%	98.0%[b]	98.0%	98.0%
Inverter loading ratio	1.10[a]	1.15	1.2	1.25	1.3	1.35	1.40[e]	1.3
Equity discount rate (real)	7.4%[c]	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%[d]	6.3%
Inflation rate	2.5%[a]	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%[c]	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%[d]	4.5%
Debt fraction	34.2%[c]	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%[d]	40.0%

Other important assumptions: utility-scale PV system LCOE assume a 1) system lifetime of 30 years[a], 2) federal tax rate of 35%[b], 3) state tax rate of 7%[b], 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)[b], 7) a six month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system[b], 8) a system size of 100 MW[b], 9) an inverter lifetime of 15 years[a], 10) debt with a term of 18 years[b], and 11) $1.1MM of upfront financial transaction costs[d].

Sources: [a]SunShot Vision Study 2010, [b]On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; [c]On the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); [d]Terms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), [e]U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016

Utility-Scale PV: LCOE Benchmark Historical Trends

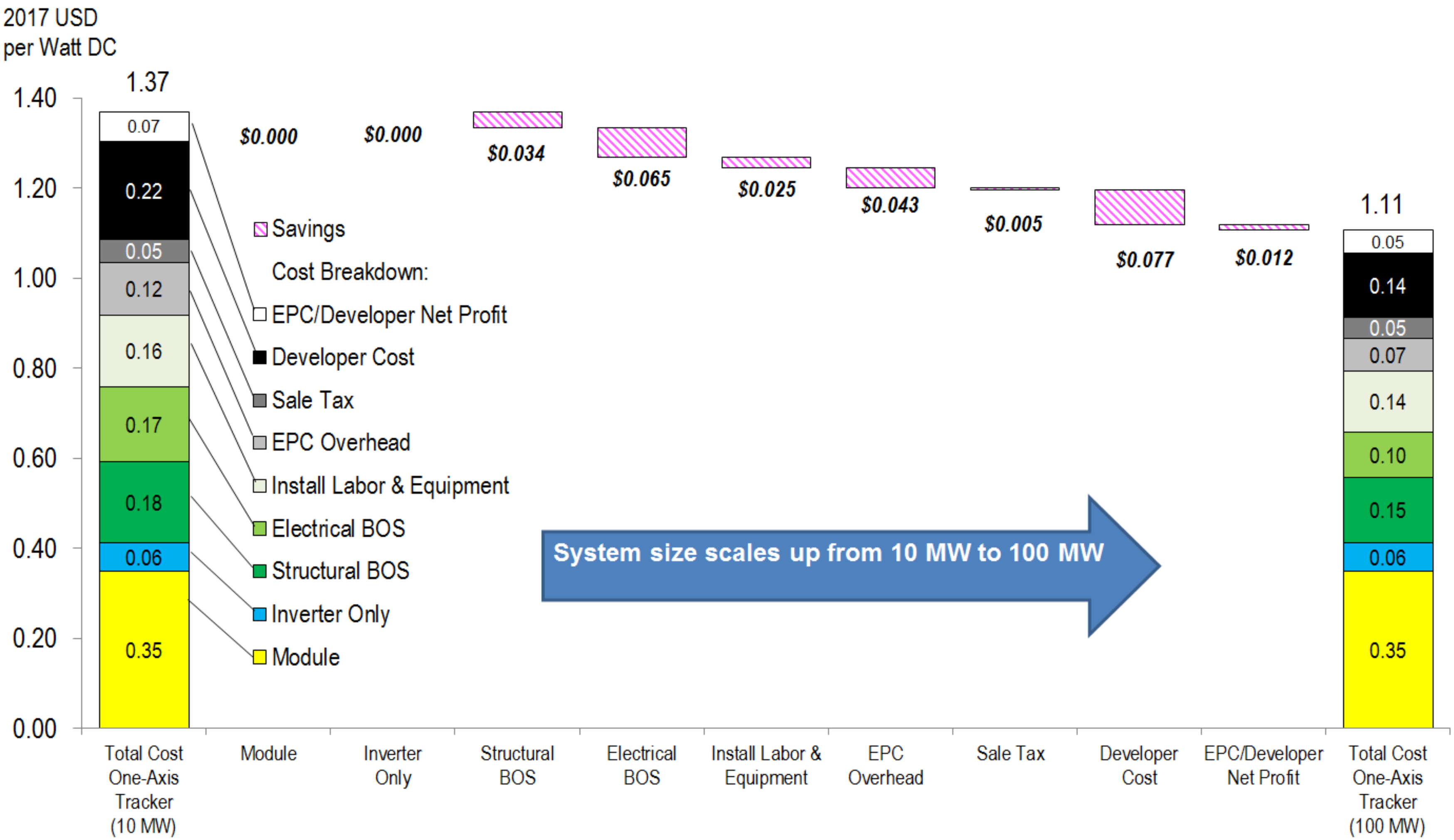


We use the fixed-tilt systems for LCOE benchmarks from 2010 to 2015 and then switch to one-axis tracking systems from 2016 to 2017 to reflect the market share change in the utility-scale PV sector. All detailed LCOE values can be found in Appendix.

From 2010 to 2017, there was a 78%–79% reduction in the utility-scale PV system electricity cost benchmark (a 20%–23% reduction was achieved from 2016 to 2017), bringing the unsubsidized LCOE between $0.04/kWh to $0.06/kWh ($0.03/kWh to $0.04/kWh when including the federal ITC). This reduction signifies the achievement of SunShot’s 2020 utility-scale PV goal, which is 6 cents/kWh without subsidies.

Contents

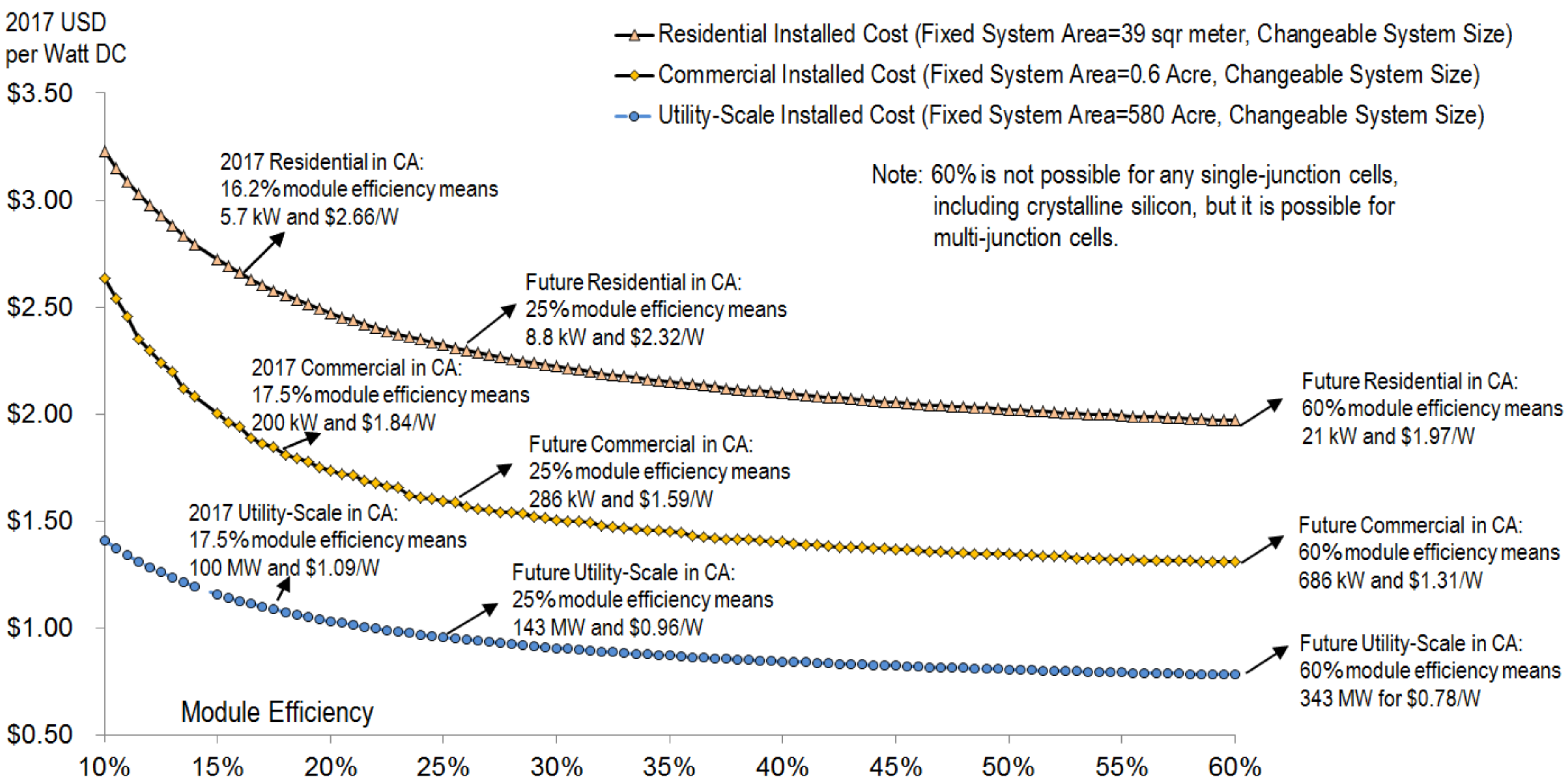
Model Application — Economies of Scale



Model application: U.S. utility-scale one-axis tracking PV system cost reduction from economies of scale (2017 USD/Wdc)

This figure demonstrates the cost savings from increased system size. Scaling up the system size from 10 MW to 100 MW reduces related costs in several ways: per-watt BOS costs because of bulk purchasing, labor costs because of learning-related improvements, and EPC overhead and developer costs because these fixed costs are spread over more installed watts. Note that non-union labor is used in this figure.

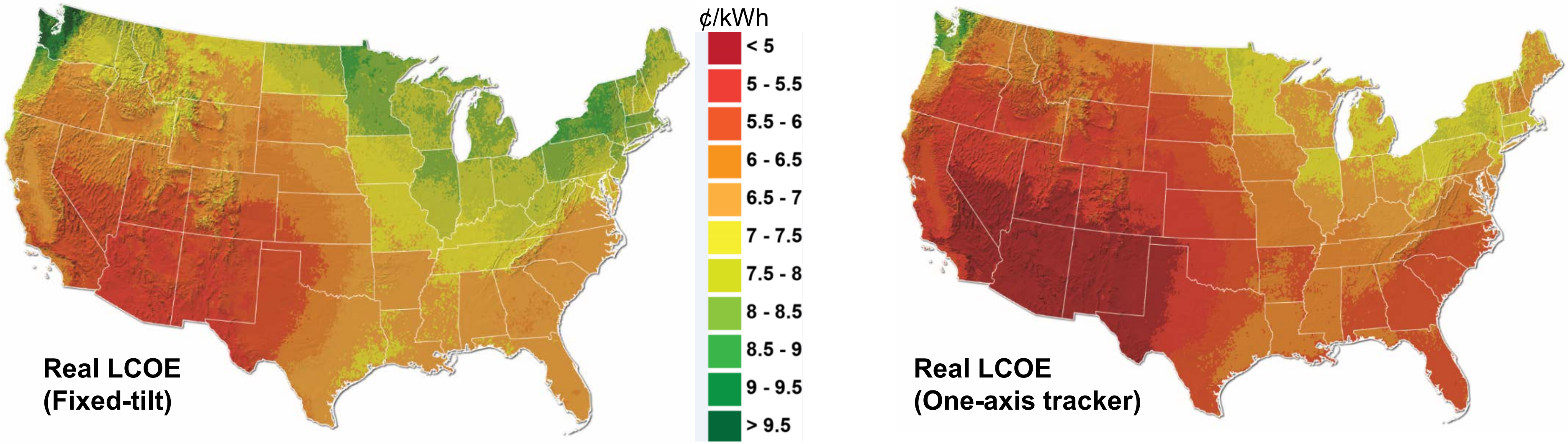
Model Application — Module Efficiency Impacts



Modeled impacts of module efficiency on total system costs, 2017

Our system cost models can also assess the economic benefits of high module efficiency. Because higher module efficiency reduces the number of modules required to reach a certain system size, the related racking or mounting hardware, foundation, BOS, EPC/developer overhead, and labor hours are reduced accordingly. This figure presents the relation between module efficiency and installed cost (with module prices held equal for any given efficiency) and demonstrates the cost-reduction potential due to high module efficiency. Note that fixed-tilt system is used in utility-scale curve and string inverter is used in residential curve.

Model Application — Utility-Scale PV Regional LCOE (ITC = 0%), 2017



2017 USD		Fixed-Tilt			One-Axis Tracker			One-Axis Tracker vs. Fixed-Tilt		
State	Location	Total Installed Costs ($/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Total Installed Costs ($/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Installed Costs Premium (%)	Nominal LCOE Change (%)	Real LCOE Change (%)
CA	Bakersfield	1.09	7.26	5.68	1.18	6.44	5.04	8.26%	-11.29%	-11.27%
CA	Imperial	1.09	6.64	5.19	1.18	5.76	4.50	8.26%	-13.25%	-13.29%
AZ	Prescott	0.98	6.20	4.85	1.06	5.47	4.27	8.16%	-11.77%	-11.96%
AZ	Tucson	0.98	6.01	4.70	1.06	5.29	4.14	8.16%	-11.98%	-11.91%
NV	Las Vegas	1.05	6.33	4.95	1.13	5.54	4.33	7.62%	-12.48%	-12.53%
NM	Albuquerque	0.99	6.05	4.73	1.06	5.39	4.21	7.07%	-10.91%	-10.99%
CO	Alamosa	0.99	6.05	4.73	1.07	5.33	4.16	8.08%	-11.90%	-12.05%
NC	Jacksonville	0.96	7.25	5.67	1.03	6.56	5.13	7.29%	-9.52%	-9.52%
TX	San Antonio	0.97	7.11	5.56	1.04	6.55	5.12	7.22%	-7.88%	-7.91%
NJ	Newark	1.13	9.15	7.16	1.22	8.59	6.71	7.96%	-6.12%	-6.28%
FL	Orlando	1.02	8.47	6.63	1.09	7.51	5.87	6.86%	-11.33%	-11.46%
HI	Kona	1.14	8.08	6.32	1.22	7.41	5.79	7.02%	-8.29%	-8.39%

- Our model can demonstrate regional LCOE by using modeled regional installed costs and localized solar irradiance and weather data (NREL SAM).
- ITC = 0%, Real discount rate = 6.3%, IRR target = 6.46%, Inflation = Price escalator = 2.5%, Analysis period = 30-yr, Degradation rate = 0.75% per year. System size = 100 MW utility-scale PV, Project debt = 40%, Debt interest rate = 4.5%.
- Fixed-tilt: DC-to-AC ratio = 1.3 and Fixed O&M cost = $15/kW per year. One-axis tracker: DC-to-AC ratio = 1.3 and Fixed O&M cost = $18.5/kW per year.

Contents

Conclusions

(1) Based on our bottom-up modeling, the Q1 2017 PV cost benchmarks are $2.80/Wdc ($3.22/Wac) for residential systems, $1.85/Wdc ($2.13/Wac) for commercial systems, $1.03/Wdc ($1.34/Wac) for fixed-tilt utility-scale systems, and $1.11/Wdc ($1.44/Wac) for one-axis-tracking utility-scale systems. Overall, modeled PV installed costs continued to decline in Q1 2017 for all three sectors.

(2) Lower module and inverter prices and higher module efficiencies contributed to these cost reductions across all three sectors. Increased module efficiency, smaller developer teams, lower electrical BOS commodity price, higher small installer market share, lower sales & marketing costs, lower overhead (general & administrative) also contributed. On the other hand, higher labor wages, higher advanced inverter adoption, additional balance-of-system (BOS) components required for rapid shutdown, higher supply-chain costs, higher net profit, and higher PII costs partially offset the cost reductions across the various sectors.

(3) Our bottom-up system cost models enable us to investigate regional variations, system configurations (such as MLPE vs. non-MLPE, fixed-tilt vs. one-axis tracker, and small vs. large system size), and business structures (such as installer vs. integrator, and EPC vs. developer).

(4) U.S. residential and commercial PV systems are 86% and 89% toward achieving SunShot's 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SunShot target three years early.

For More Information

(1) Download the full technical report along with the data file:

- Download the full report: https://www.nrel.gov/docs/fy17osti/68925.pdf
- Download the data file: https://data.nrel.gov/submissions/73

(2) Contact the authors:

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Appendix: PV System LCOE Benchmarks in 2017 and 2010 USD$

LCOE (2017 cents/kWh)										
Reporting Year	2010	2011	2012	2013	2014	2015	2016	2017	2020 Goal	2030 Goal
Benchmark Date	Q4 2009	Q4 2010	Q4 2011	Q4 2012	Q4 2013	Q1 2015	Q1 2016	Q1 2017		
Residential										
Phoenix, AZ, NO ITC	42.1	35.7	24.9	20.7	17.3	15.0	13.6	12.9		
Kansas City, MO, NO ITC	51.8	43.6	30.4	25.3	21.1	18.3	16.7	15.7	10.0	5.0
New York, NY, NO ITC	55.2	46.5	32.4	26.9	22.4	19.5	17.7	16.7		
Phoenix, AZ, ITC	26.9	22.8	16.1	13.4	11.1	9.5	8.7	8.2		
Kansas City, MO, ITC	33.1	27.9	19.7	16.3	13.5	11.6	10.6	10.0		
New York, NY, ITC	35.3	29.7	21.0	17.4	14.4	12.3	11.3	10.7		
Commercial										
Phoenix, AZ, NO ITC	32.3	28.6	19.5	15.4	14.4	11.2	10.5	9.2		
Kansas City, MO, NO ITC	40.0	35.3	24.1	19.0	17.8	13.9	13.0	11.3	7.8	4.0
New York, NY, NO ITC	42.4	37.5	25.6	20.2	18.9	14.8	13.8	12.0		
Phoenix, AZ, ITC	20.4	18.0	12.5	9.9	9.2	7.1	6.7	5.9		
Kansas City, MO, ITC	25.2	22.2	15.4	12.3	11.4	8.9	8.3	7.3		
New York, NY, ITC	26.8	23.6	16.4	13.0	12.0	9.4	8.8	7.7		
Utility-scale (1-axis tracker)										
Phoenix, AZ, NO ITC	21.2	17.5	12.1	9.2	8.1	7.2	5.7	4.4		
Kansas City, MO, NO ITC	26.8	22.1	15.3	11.7	10.2	9.1	7.2	5.6	6.0	3.0
New York, NY, NO ITC	29.5	24.3	16.8	12.9	11.3	10.0	7.9	6.1		
Phoenix, AZ, ITC	13.4	11.0	7.8	6.0	5.3	4.7	3.8	3.0		
Kansas City, MO, ITC	16.9	13.9	9.8	7.6	6.7	5.9	4.8	3.8		
New York, NY, ITC	18.6	15.4	10.8	8.4	7.4	6.5	5.3	4.2		
Utility-scale (fixed-tilt)										
Phoenix, AZ, NO ITC	22.6	18.9	13.0	10.1	9.0	8.4	6.8	5.0		
Kansas City, MO, NO ITC	27.7	23.1	15.9	12.3	11.0	10.2	8.3	6.1		
New York, NY, NO ITC	29.6	24.7	17.0	13.2	11.8	10.9	8.8	6.6		
Phoenix, AZ, ITC	14.4	12.0	8.5	6.6	5.9	5.4	4.5	3.4		
Kansas City, MO, ITC	17.6	14.7	10.4	8.1	7.3	6.7	5.4	4.2		
New York, NY, ITC	18.9	15.8	11.1	8.7	7.8	7.1	5.8	4.4		

LCOE (2010 cents/kWh)										
Reporting Year	2010	2011	2012	2013	2014	2015	2016	2017	2020 Goal	2030 Goal
Benchmark Date	Q4 2009	Q4 2010	Q4 2011	Q4 2012	Q4 2013	Q1 2015	Q1 2016	Q1 2017		
Residential										
Phoenix, AZ, NO ITC	37.8	32.0	22.3	18.5	15.5	13.4	12.2	11.5		
Kansas City, MO, NO ITC	46.4	39.1	27.3	22.7	18.9	16.4	14.9	14.1	9.0	5.0
New York, NY, NO ITC	49.5	41.6	29.0	24.1	20.1	17.4	15.9	15.0		
Phoenix, AZ, ITC	24.1	20.4	14.5	12.0	9.9	8.5	7.8	7.4		
Kansas City, MO, ITC	29.7	25.0	17.7	14.6	12.1	10.4	9.5	9.0		
New York, NY, ITC	31.6	26.6	18.8	15.6	12.9	11.1	10.1	9.6		
Commercial										
Phoenix, AZ, NO ITC	29.0	25.6	17.5	13.8	12.9	10.1	9.4	8.2		
Kansas City, MO, NO ITC	35.8	31.7	21.6	17.0	16.0	12.5	11.7	10.1	7.0	4.0
New York, NY, NO ITC	38.0	33.6	22.9	18.1	16.9	13.3	12.4	10.7		
Phoenix, AZ, ITC	18.3	16.1	11.2	8.9	8.2	6.4	6.0	5.3		
Kansas City, MO, ITC	22.6	19.9	13.8	11.0	10.2	8.0	7.4	6.5		
New York, NY, ITC	24.0	21.1	14.7	11.6	10.8	8.4	7.9	6.9		
Utility-scale (1-axis tracker)										
Phoenix, AZ, NO ITC	19.0	15.6	10.8	8.3	7.2	6.4	5.1	3.9		
Kansas City, MO, NO ITC	24.0	19.8	13.7	10.5	9.2	8.1	6.4	5.0	6.0	3.0
New York, NY, NO ITC	26.4	21.8	15.1	11.5	10.1	9.0	7.1	5.5		
Phoenix, AZ, ITC	12.0	9.9	7.0	5.4	4.7	4.2	3.4	2.7		
Kansas City, MO, ITC	15.1	12.5	8.8	6.8	6.0	5.3	4.3	3.4		
New York, NY, ITC	16.7	13.8	9.7	7.6	6.6	5.9	4.7	3.7		
Utility-scale (fixed-tilt)										
Phoenix, AZ, NO ITC	20.3	16.9	11.6	9.0	8.1	7.5	6.1	4.5		
Kansas City, MO, NO ITC	24.8	20.7	14.3	11.1	9.9	9.2	7.4	5.5		
New York, NY, NO ITC	26.5	22.1	15.3	11.8	10.6	9.8	7.9	5.9		
Phoenix, AZ, ITC	12.9	10.8	7.6	6.0	5.3	4.9	4.0	3.0		
Kansas City, MO, ITC	15.8	13.2	9.3	7.3	6.5	6.0	4.9	3.7		
New York, NY, ITC	16.9	14.1	9.9	7.8	7.0	6.4	5.2	4.0		

Acronyms and Abbreviations

AC	alternating current
BOS	balance of system
DC	direct current
EPC	engineering, procurement, and construction
FICA	Federal Insurance Contributions Act
GW	gigawatt
ILR	inverter loading ratio
ITC	investment tax credit
LCOE	levelized cost of energy
MACRS	Modified Accelerated Cost Recovery System
MLPE	module-level power electronics
NEC	National Electric Code
NEM	net energy metering
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PERC	passivated emitter and rear cells
PII	permitting, inspection, and interconnection
PV	photovoltaic(s)
Q	quarter
R&D	research and development
SAM	System Advisor Model
SG&A	sales, general, and administrative
TPO	third party ownership
USD	U.S. dollars
Vdc	volts direct current
Wac	watts alternating current
Wdc	watts direct current