U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020

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Introduction

NREL has been modeling U.S. solar photovoltaic (PV) system costs since 2009. This year, our report benchmarks costs of U.S. PV for residential, commercial, and utility-scale systems, with and without storage, built in the first quarter of 2020 (Q1 2020).

Our benchmarking method includes bottom-up accounting for all necessary system and project-development costs incurred when installing residential, commercial, and utility-scale systems, and it models the Q1 2019 and Q1 2020 costs for such systems, excluding any previous supply agreements or contracts. In general, we attempt to model the typical installation techniques and business operations from an installed-cost perspective, and our benchmarks are national averages. The residential PV-only benchmark and the commercial rooftop PV-only benchmark average costs by inverter type (string inverters, string inverters with direct current [DC] optimizers, and microinverters), weighted by inverter market share. The residential PV-only benchmark is further averaged across small installer and national integrator business models, weighted by market share. All benchmarks include variations—accounting for the differences in size, equipment, and operational use (particularly for storage)—that are currently available in the marketplace. All benchmarks assume nonunionized construction labor; residential and commercial PV systems predominantly use nonunionized labor, and the type of labor required for utility-scale PV systems depends heavily on the development process. All benchmarks assume the use of monofacial monocrystalline silicon PV modules. Benchmarks using cadmium telluride (CdTe) or bifacial modules could result in significantly different results. The data in this annual benchmark report inform the formulation of and track progress toward the U.S. Department of Energy (DOE) Solar Energy Technologies Office's (SETO's) Government Performance and Reporting Act (GPRA) cost targets.

Introduction

The benchmark report builds on several previous publications from NREL and Lawrence Berkeley National Laboratory:

- Barbose, Galen and Naïm Darghouth. 2019. *Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States 2019 Edition*. Berkeley, CA: Lawrence Berkeley National Laboratory. November 2019. https://eta-publications.lbl.gov/sites/default/files/tracking_the_sun_2019_report.pdf.
- Bolinger, Mark, Joachim Seel, and Dana Robson. 2019. *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States: 2019 Edition.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/utility-scale-solar-empirical-trends.
- Fu, Ran, David Feldman, and Robert Margolis. 2018. *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018*. NREL/TP-6A20-72399. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/72399.pdf.
- Fu, Ran, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. NREL/TP-6A20-71714. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/71714.pdf.
- Ardani, Kristen, Eric O'Shaughnessy, Ran Fu, Chris McClurg, Joshua Huneycutt, and Robert Margolis. 2017. *Installed Cost Benchmarks and Deployment Barriers for Residential Solar Photovoltaics with Energy Storage: Q1 2016*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A20- 67474. https://www.nrel.gov/docs/fy17osti/67474.pdf.
- 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. https://www.nrel.gov/docs/fy15osti/64898.pdf.

Introduction

Download the full technical report and the data file:

- **Full report:** https://www.nrel.gov/docs/fy21osti/77324.pdf
- **Data file:** https://doi.org/10.7799/1762492

Acronyms are defined at the end of this publication.

Key Definitions

Unit	Description
Value	2019 U.S. dollar (USD)
System Size	PV systems are quoted in direct current (DC) terms; inverter prices are converted by DC-to-alternating current (AC) ratios; storage systems are quoted in terms of kilowatt-hours or megawatt-hours (kWh or MWh) of storage or the number of hours of storage at peak capacity.

Sector Category	Description	Size Range
Residential PV	Residential rooftop systems	4 kW–7 kW
Commercial PV	Commercial rooftop systems, ballasted racking	100 kW–2 MW
Utility-Scale PV	Ground-mounted systems, fixed-tilt and one-axis tracker	5 MW–100 MW

Key Changes from Previous Reports

- Values are inflation-adjusted using the CPI (2019). Thus, historical values from our models are adjusted and presented as real USD instead of nominal USD.
- Our Q1 2019 and Q1 2020 benchmarks use monocrystalline PV modules, whereas all historical benchmarks used multicrystalline PV modules. This switch reflects the overall trend occurring in the U.S. market.
- In the Q1 2020 residential benchmark analysis, we expand our modeling of customer acquisition, engineering, PII, and overhead. In addition to providing finer cost granularity, we include additional costs borne by many U.S. installers that were not captured in previous editions; therefore, our benchmarked soft costs in this report are higher than those in previous reports.
- For previous editions of this report, we assumed a land acquisition cost of $0.03/W. Based on Wiser et al. (2020), which stated that most utility-scale PV projects do not own the land on which PV systems are placed, we have reclassified land costs from an up-front capital expenditure (land acquisition) to an operating expenditure (lease payments) for 2019 and 2020.
- The current versions of our cost models make a few significant changes from the versions used in our Q1 2018 benchmark report (Fu, Feldman, and Margolis 2018). To better distinguish the historical cost trends over time from the changes to our cost models, we also calculate Q1 2019 and Q1 2020 PV benchmarks using the Q1 2018 versions of the residential, commercial, and utility-scale PV models.

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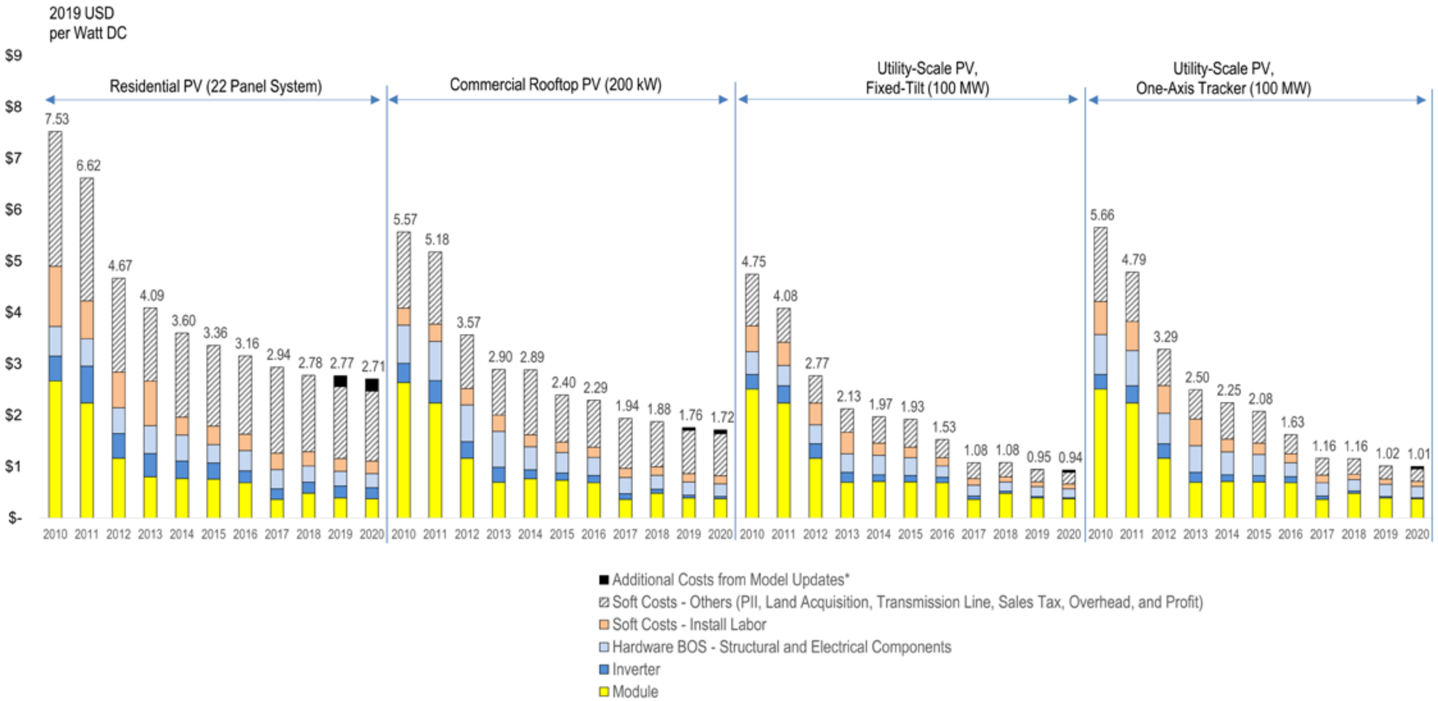
Overall Stand-Alone PV Model Results (Total Installed Cost)

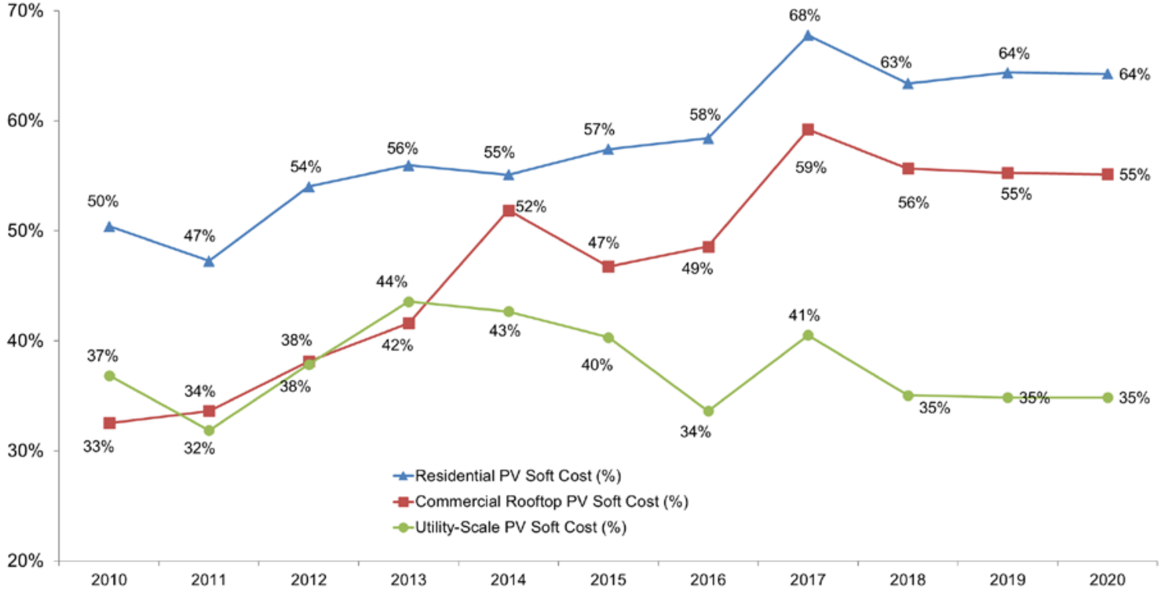


1. Values are inflation adjusted using the CPI (2019). Thus, historical values from our models are adjusted and presented as real USD instead of nominal USD.
2. Cost categories are aggregated for comparison purposes. “Soft Costs – Others” represent PII; land acquisition; sales tax; and EPC/developer overhead and net profit.
3. The current versions of our cost models make a few significant changes from the versions used in our Q1 2018 benchmark report (Fu, Feldman, and Margolis 2018) and incorporate costs that had previously not been benchmarked in as much detail. To better distinguish the historical cost trends from the changes to our cost models, we also calculate Q1 2019 and Q1 2020 PV benchmarks using the Q1 2018 versions of the residential, commercial, and utility-scale PV models. The “Additional Costs from Model Updates” category represents the difference between modeled results.

Overall Stand-Alone PV Model Results (Q1 2019 vs. Q1 2020)

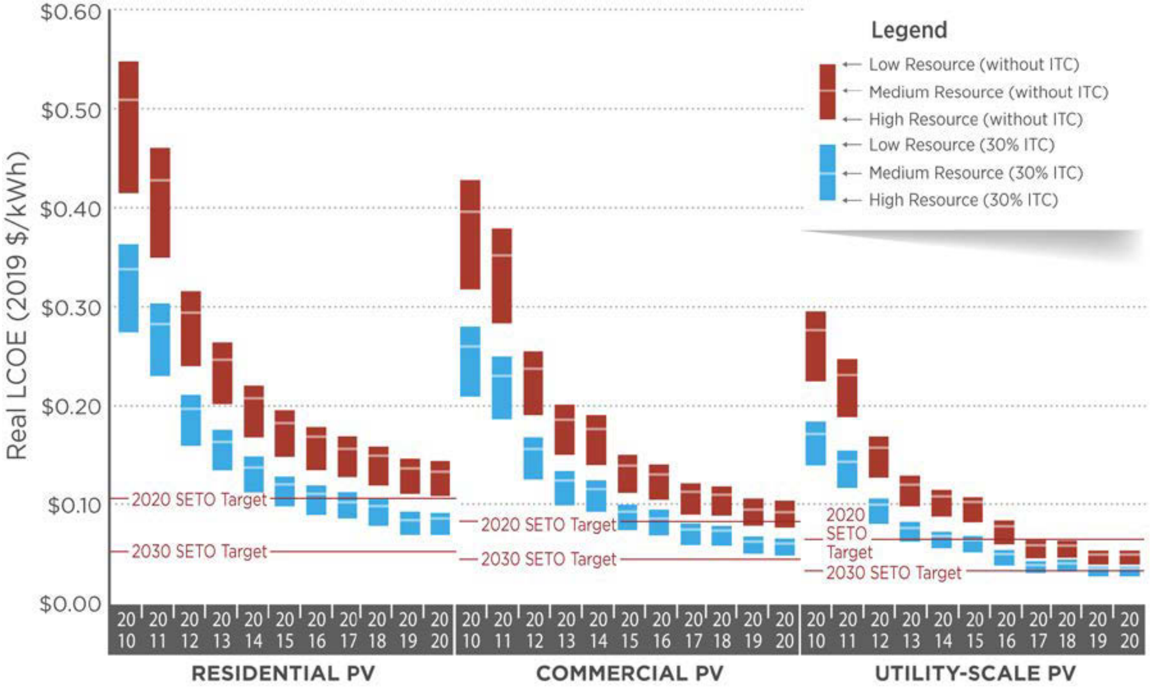
Sector	Residential PV	Commercial PV	Utility-Scale PV, One Axis Tracking
Q1 2019 benchmarks in 2019 USD/W_{DC}	$2.77	$1.76	$1.02
Q1 2020 benchmarks in 2019 USD/W_{DC}	$2.71	$1.72	$1.01
Drivers of Cost Decrease	• Higher module efficiency (from 19.2% to 19.5%) • Decrease in BOS hardware and supply chain costs	• Higher module efficiency • Lower material and equipment costs in some categories	• Higher module efficiency • Lower material and equipment costs in some categories • Movement of land acquisition cost from upfront capital expenditures into operation and maintenance
Drivers of Cost Increase	• Higher labor wages • Higher module costs	• Higher labor wages • Higher module costs	• Higher labor wages • Higher steel prices • Higher module and inverter costs

Overall Stand-Alone PV Model Results (Soft Cost)



1. A "soft cost" in the benchmark report is defined as a nonhardware cost—i.e., "Soft Cost" = Total Cost - Hardware Cost (module, inverter, and structural and electrical BOS).
2. The residential and commercial sectors have larger soft cost percentages than the utility-scale sector.
3. Soft costs and hardware costs 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.

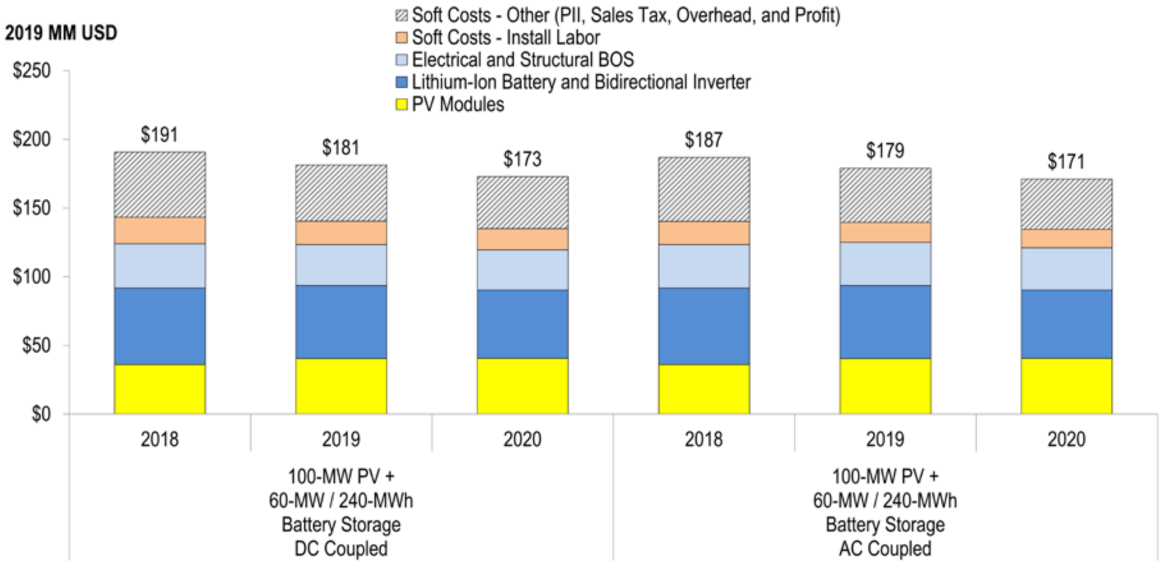
Overall Stand-Alone PV Model Results (LCOE)



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 93% and 97% toward achieving SETO's 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SETO target three years early.

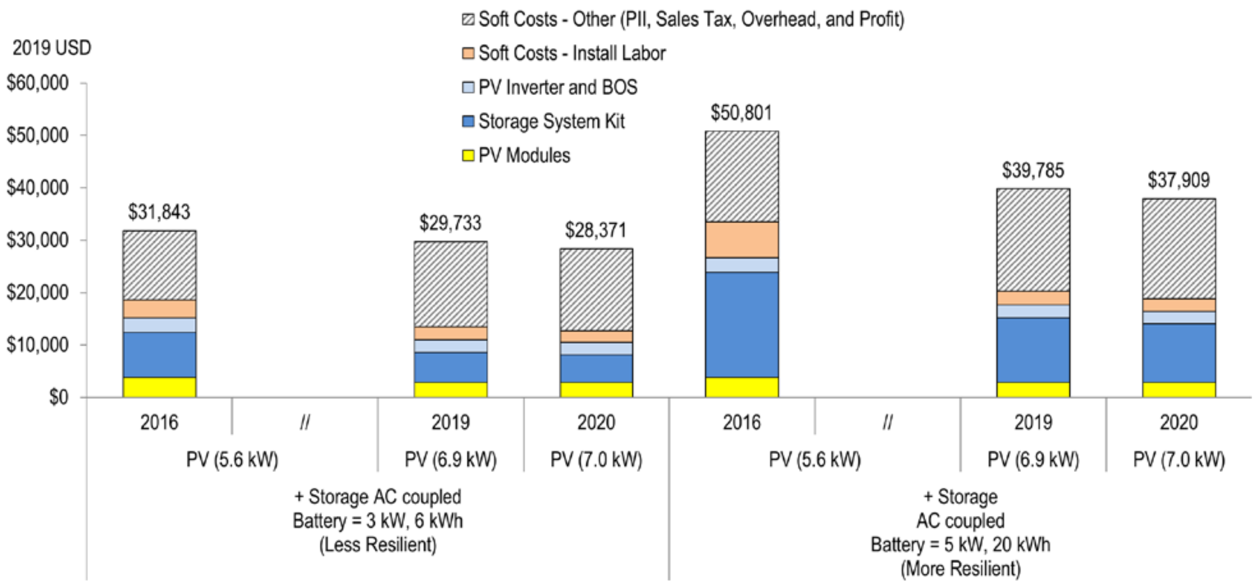
Note that we use fixed-tilt systems for LCOE benchmarks from 2010 to 2015 and then switch to one-axis tracking systems from 2016 to 2020 to reflect the market share change in the utility-scale PV sector. All detailed LCOE values can be found in the appendix.

Utility-Scale PV-Plus-Storage Model Results (Total Installed Cost)



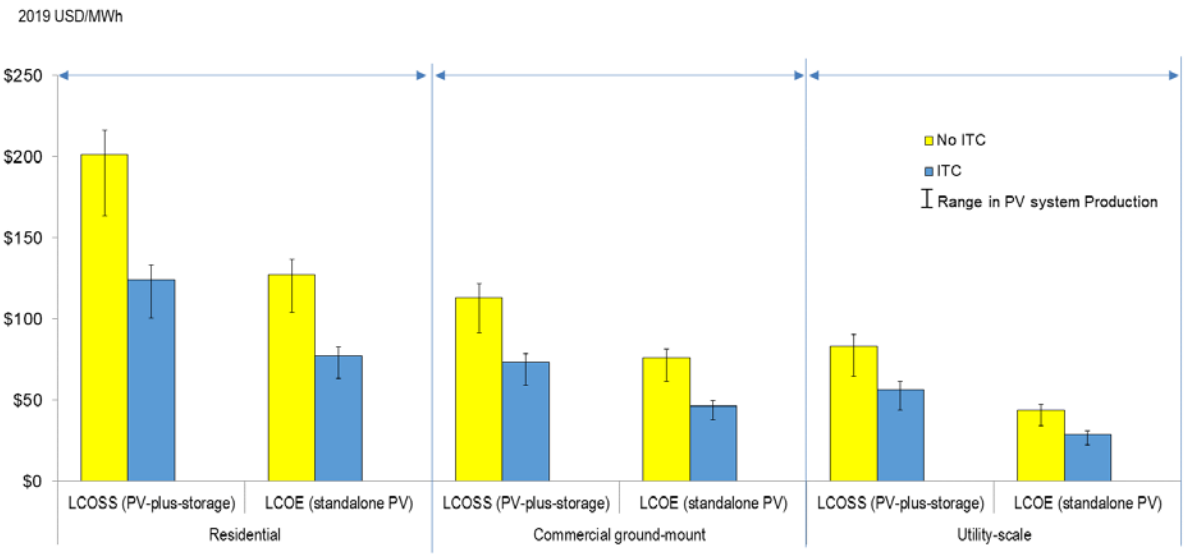
1. There were 9% and 8% reductions in utility-scale PV-plus-storage benchmarks between 2018 and 2020 for DC-coupled and AC-coupled systems respectively.
2. Approximately 28%–30% of total cost reductions can be attributed to lithium-ion battery and bidirectional inverter cost reductions.
3. Although there are some configuration differences between AC-coupled and DC-coupled systems (e.g., the inverter, structural BOS, and electrical BOS), the total cost difference between them is only 1%.

Residential PV-Plus-Storage Model Results (Total Installed Cost)



1. There were 11% and 25% reductions in residential PV-plus-storage benchmarks between 2016 and 2020 for AC-coupled less-resilient and more-resilient cases respectively.
2. Most of these reductions can be attributed to reductions in the cost of PV modules and AC-coupled batteries.
3. The cost reductions occurred despite the rated capacity of the 22-module system increasing from 5.6 kW to 7.0 kW between 2016 and 2020.

Overall PV-Plus-Storage Model Results (LCOSS)



For the Q1 2020 benchmark report, we derive a formula for the levelized cost of solar-plus-storage (LCOSS) to better demonstrate the total cost of operating a PV-plus-storage plant, on a per-megawatt-hour basis. The above figure shows the resulting LCOSS for colocated AC-coupled PV-plus-storage systems for each market segment, as well as the LCOE of stand-alone PV systems.

For residential PV-plus-storage, LCOSS is calculated to be $201/MWh without the federal ITC and $124/MWh with the 30% ITC. For commercial PV-plus-storage, it is $113/MWh without the ITC and $73/MWh with the 30% ITC. For utility-scale PV-plus-storage, it is $83/MWh without the ITC and $57/MWh with the 30% ITC.

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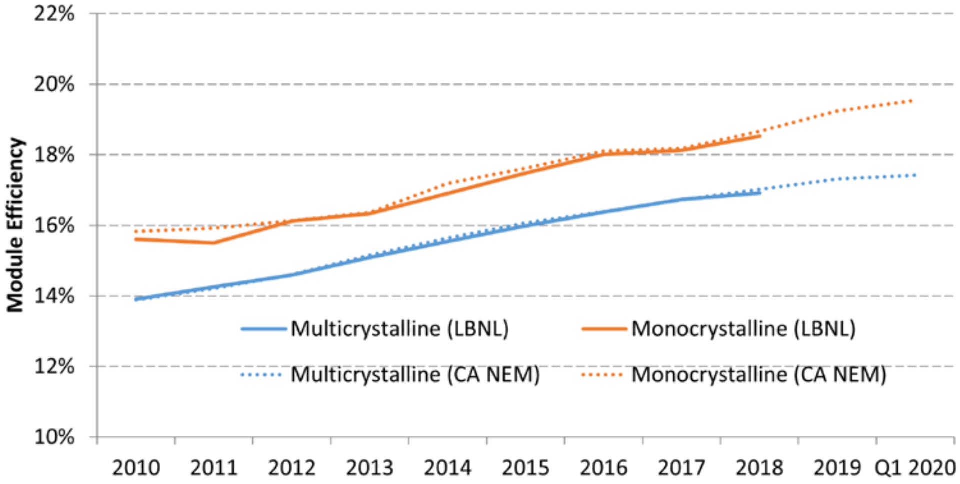
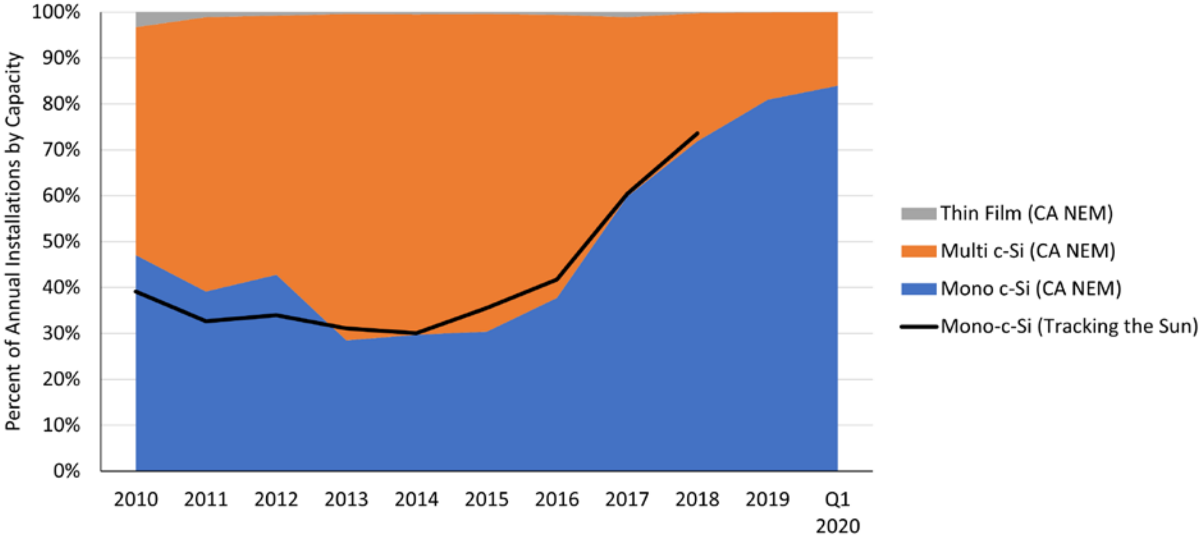
Module Efficiency Trends



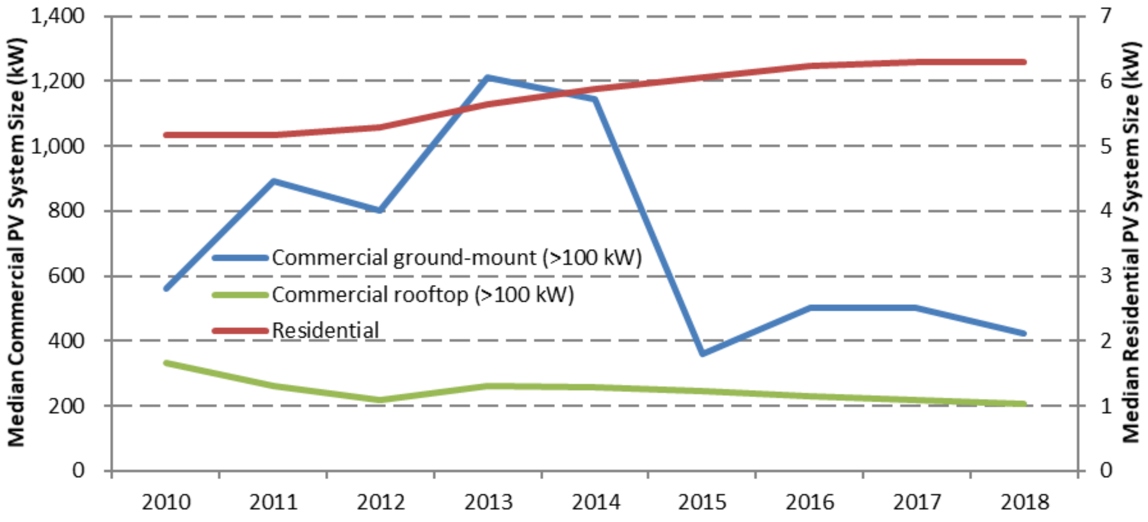
Since 2010, efficiencies for monocrystalline and multicrystalline modules have steadily improved, with the capacity-weighted average multicrystalline module efficiency for 60- and 72-cell modules increasing 0.3%–0.4% each year in absolute terms, on average. CA NEM values line up very closely with the national averages reported in *Tracking the Sun*. CA NEM reports a Q1 2020 capacity-weighted average monocrystalline module efficiency of 19.5%. Because module selection may vary by region and sector, the capacity-weighted average module efficiencies (and module prices) may be different in some regions and sectors.

PV Installations by Technology



In the Q1 2020 benchmark report, we model systems using monocrystalline PV modules rather than the multicrystalline modules we modeled previously, because of the overall shift in the United States to using more monocrystalline modules since 2016.

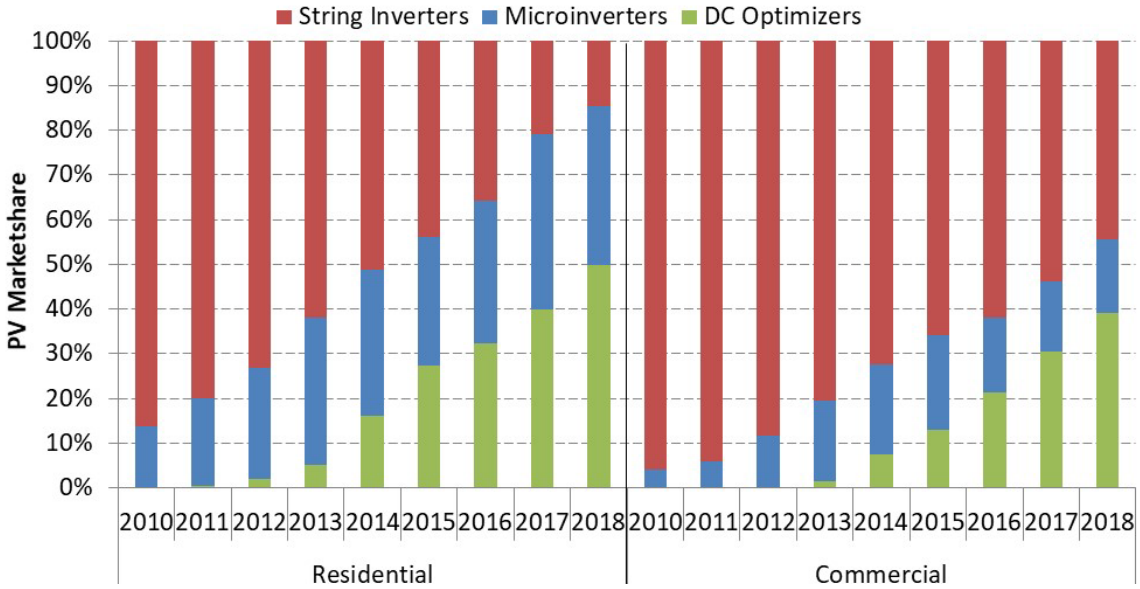
PV System Size Trend



This figure displays average system sizes from the Tracking the Sun data set. As in previous years, we assume a 22-module design for our residential PV system benchmark, which results in a system size of 7.0 kW, based on the assumed Q1 2020 average monocrystalline module efficiency.

Commercial system sizes have varied more, which likely reflects the wide range of users (e.g., office buildings, malls, and retail stores). We use 200 kW and 500 kW as the baseline cases in our commercial rooftop and ground-mounted PV models respectively.

U.S. Residential and Commercial Inverter Market

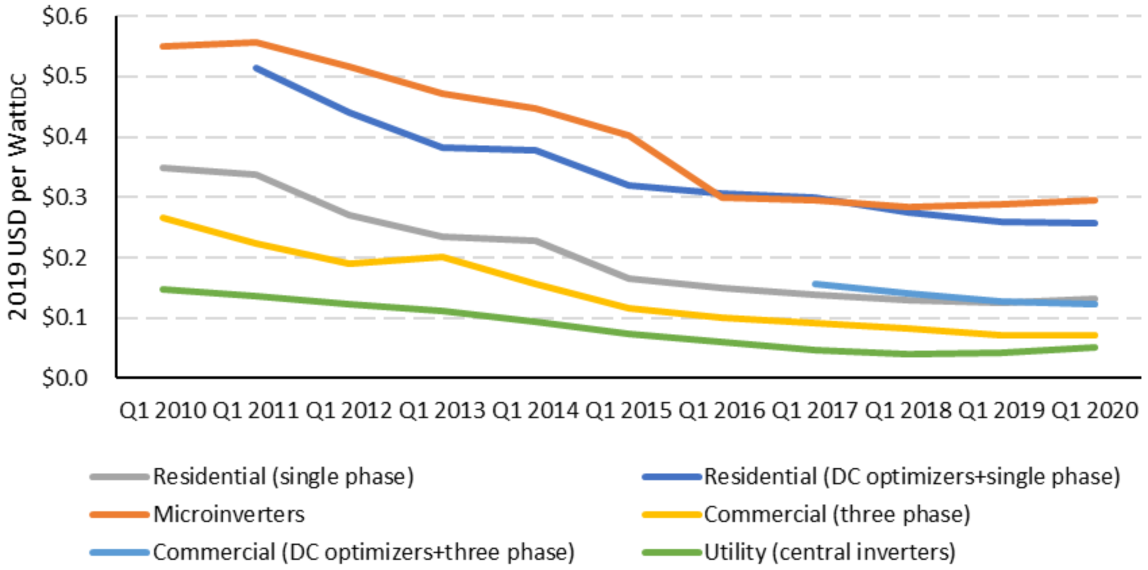


Market uptake of MLPE has been growing rapidly since 2010 in California's residential sector. This increasing market growth may be driven by decreasing MLPE costs and by the "rapid shutdown" of PV output from buildings required by Article 690.12 of the National Electric Code (NEC) since 2014—MLPE inherently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

For residential system costs, we model the string inverter, power optimizer, and microinverter options separately, and we use their market shares (14.6%, 49.8%, and 35.6%) in our Q1 2020 model for the weighted-average case.

In past years, we only assumed string inverters for the commercial PV benchmark, rather than weighting by MLPE share; this year, we also weight the commercial rooftop PV benchmark by MLPE share (45% for three-phase string inverters, 39% for power optimizers, and 16% for microinverters), because of changes to the NEC.

Inverter Price



We source inverter prices from Wood Mackenzie (2014a, 2014b, 2019a, 2020) and Wood Mackenzie and SEIA (2020). Data are also supplemented, in 2010 and 2011, using revenue per-watt shipped data from Enphase (2019) for microinverters.

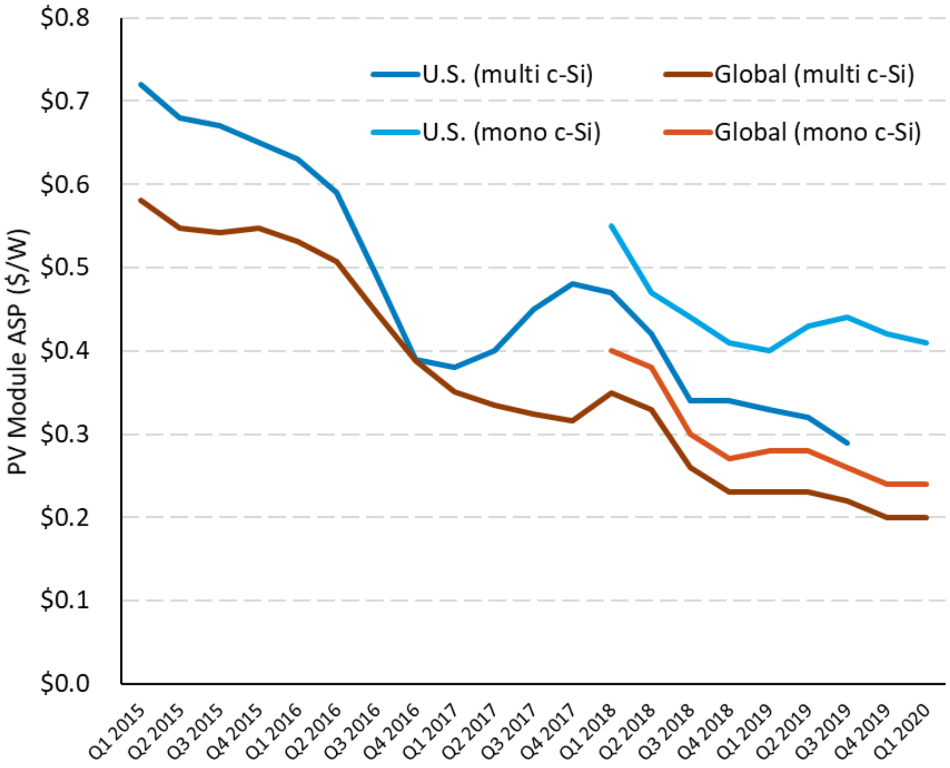
Inverter Price and DC-to-AC ratios

Inverter Type	Sector	\$ per $Watt_{AC}$	DC-to-AC Ratio	\$ per $Watt_{DC}$
Single-phase string inverter	Residential PV (non-MLPE)	0.15	1.11	0.14
Microinverter	Residential and commercial PV (MLPE)	0.34	1.16	0.29
DC power optimizer, single-phase string inverter	Residential PV (MLPE)	0.30	1.16	0.26
Three-phase string inverter	Commercial PV (non-MLPE)	0.08	1.11	0.07
DC power optimizer, three-phase string inverter	Commercial PV (MLPE)	0.14	1.16	0.12
Central inverter	Utility-scale PV (fixed-tilt)	0.07	1.37	0.05
Central inverter	Utility-scale PV (1-axis tracker)	0.07	1.34	0.05

All inverter prices include the cost of monitoring equipment.

We convert the USD/W_{AC} inverter prices from previous inverter price figures to USD per $Watt_{DC}$ (W_{DC}) using different DC-to-AC ratios (table above). In our benchmark, we use USD/W_{DC} for all costs, including inverter prices. Note that we updated the central inverter DC-to-AC ratios using Lawrence Berkeley National Laboratory data (Bolinger, Seel, and Robson 2019; Barbose and Darghouth 2019).

Module Price (U.S. vs. Global)

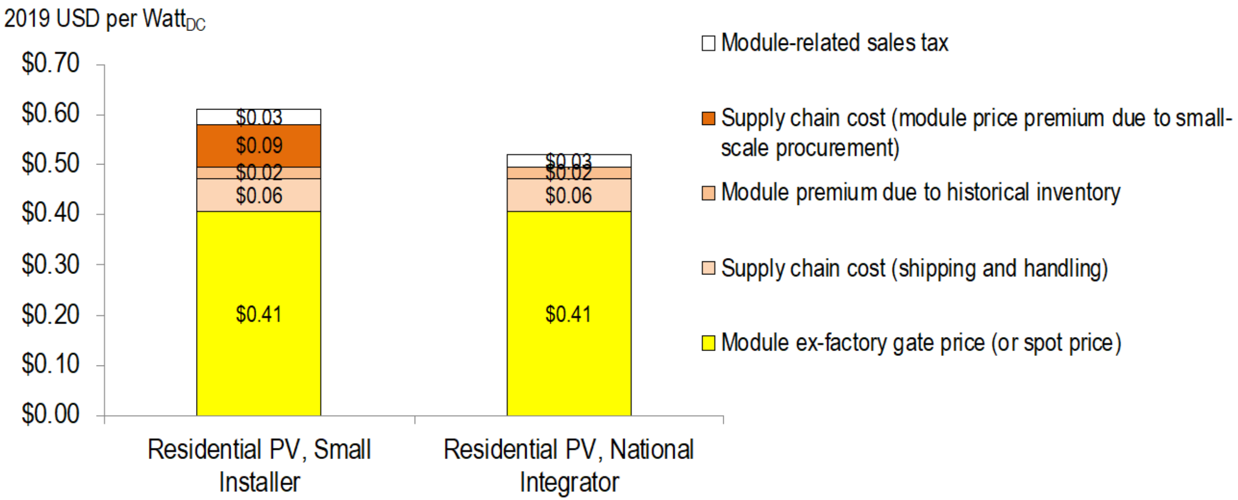


We assume an ex-factory gate (spot or first-buyer) price of $0.41/W$_{DC}$ for Tier 1 monocrystalline-silicon PV modules in Q1 2020. U.S. spot prices rose in 2017 as global spot prices continued to decline. Several factors, including U.S. policy on imported modules, may have contributed to the divergence between U.S. and global spot prices. In early 2018, U.S. spot prices began to drop again; in Q1 2020, U.S. module prices continued to fall, dropping close to their lowest recorded levels, but monocrystalline modules were still trading at a significant premium over the global module average selling price (ASP).

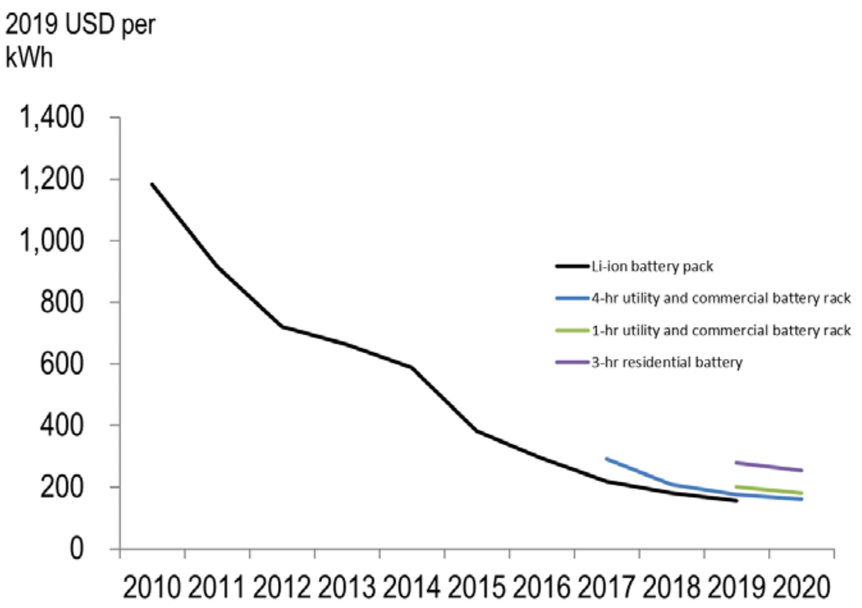
In the past few years, the U.S. market has had such an increasing demand for monocrystalline modules that by 2020 there was not enough demand for multicrystalline modules to give an “apples-to-apples” comparison of U.S. spot pricing in Q1 2020; therefore, when comparing the two technologies, we model Q1 2019 costs. In Q1 2019, we assume an ex-factory gate price of $0.40/W$_{DC}$ for Tier 1 monocrystalline modules and $0.33/W$_{DC}$ for Tier 1 multicrystalline modules, based on Wood Mackenzie and SEIA (2020).

Module Price Inputs: Q1 2020

Although commercial and utility-scale PV developers typically can procure modules at or near the spot price, residential integrators and installers incur additional supply chain costs (see below). Historical inventory price can create a price lag (approximately 6 months) for the market module price in the residential sector when the modules from previous procurement are installed in today's systems. In our Q1 2020 residential PV benchmark, this supply chain cost equates to a $0.02/W (6%) premium. We assume small installers and national integrators are both subject to a 15% ($0.06/W) premium on the spot price for module shipping and handling, consistent with Q1 2018 residential PV benchmark. Small installers are subject to an additional 20% ($0.09/W) premium owing to small-scale procurement (Bloomberg 2018). Both types of companies are also subject to 5% sales tax (weighted national average), bringing the small installer module cost to $0.61/W and the national integrator cost to $0.52/W.

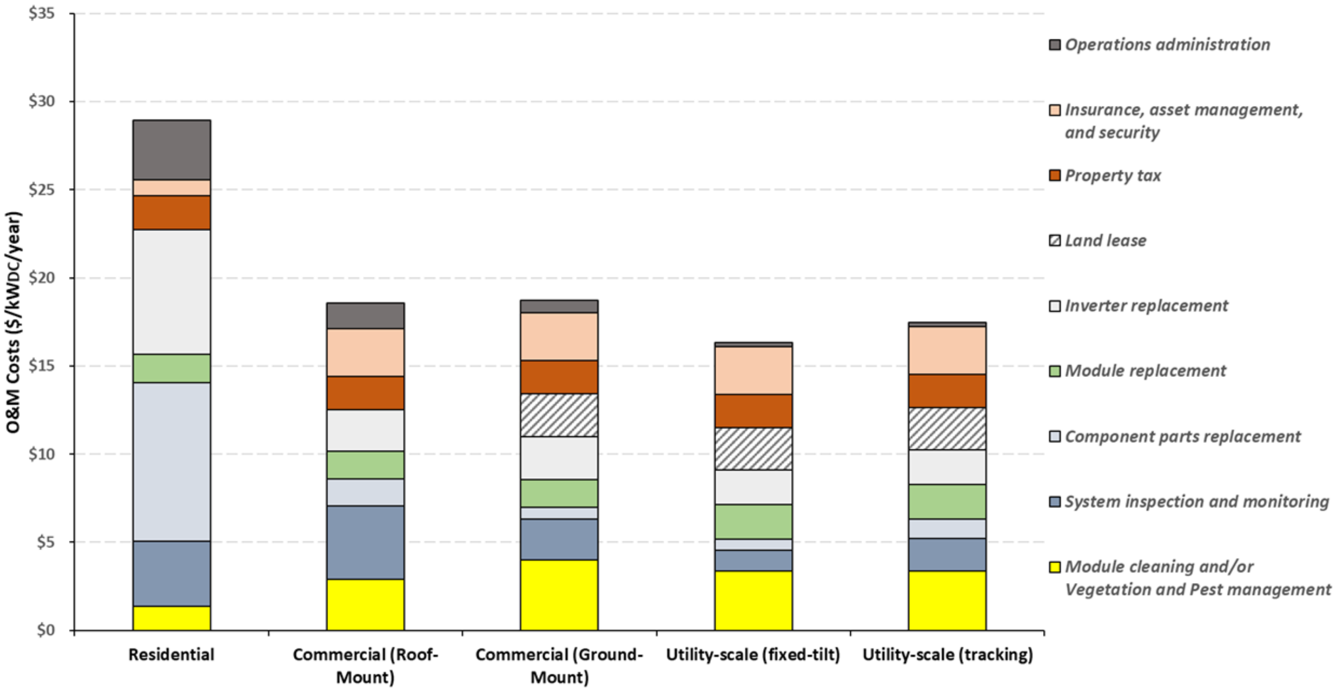


Li-ion Battery Price by Product



Lithium-ion battery spot prices declined substantially (87%) between 2010 and 2019. From 2018 to 2019 alone, prices dropped 13%. The Li-ion battery pack price from Bloomberg New Energy Finance (BNEF) refers to the volume-weighted average of automotive and stationary storage. In previous years, we used the volume-weighted average (i.e., the “Li-ion battery pack” price) because of a lack of data for stationary storage with different durations. In the Q1 2020 benchmark report, we use BNEF (2019b) stationary storage cost data, differentiated by market segment and hours of storage. Although not referenced in this benchmark report, BNEF also provides commercial and utility battery rack data for 30-minute and 2-hour storage products.

Operation and Maintenance



In Fiscal Year 2018, a PV operation and maintenance (O&M) working group that was convened under the sponsorship of DOE's SETO developed a model to calculate the cost associated with PV system O&M (Walker et al. 2020). A total of 133 measures in the cost model are sorted into 9 O&M cost categories: inverter replacement, operations administration, module replacement, components parts replacement, system inspection and monitoring, module cleaning and/or vegetation and pest management, land lease, property tax, and insurance, asset management, and security. The current benchmarks are \$28.94/kW$_{DC}$/yr (residential), \$18.55/kW$_{DC}$/yr (commercial; roof-mounted), \$18.71/kW$_{DC}$/yr (commercial; ground-mounted), \$16.32/kW$_{DC}$/yr (utility-scale, fixed-tilt), and \$17.46/kW$_{DC}$/yr (utility-scale, single-axis tracking).

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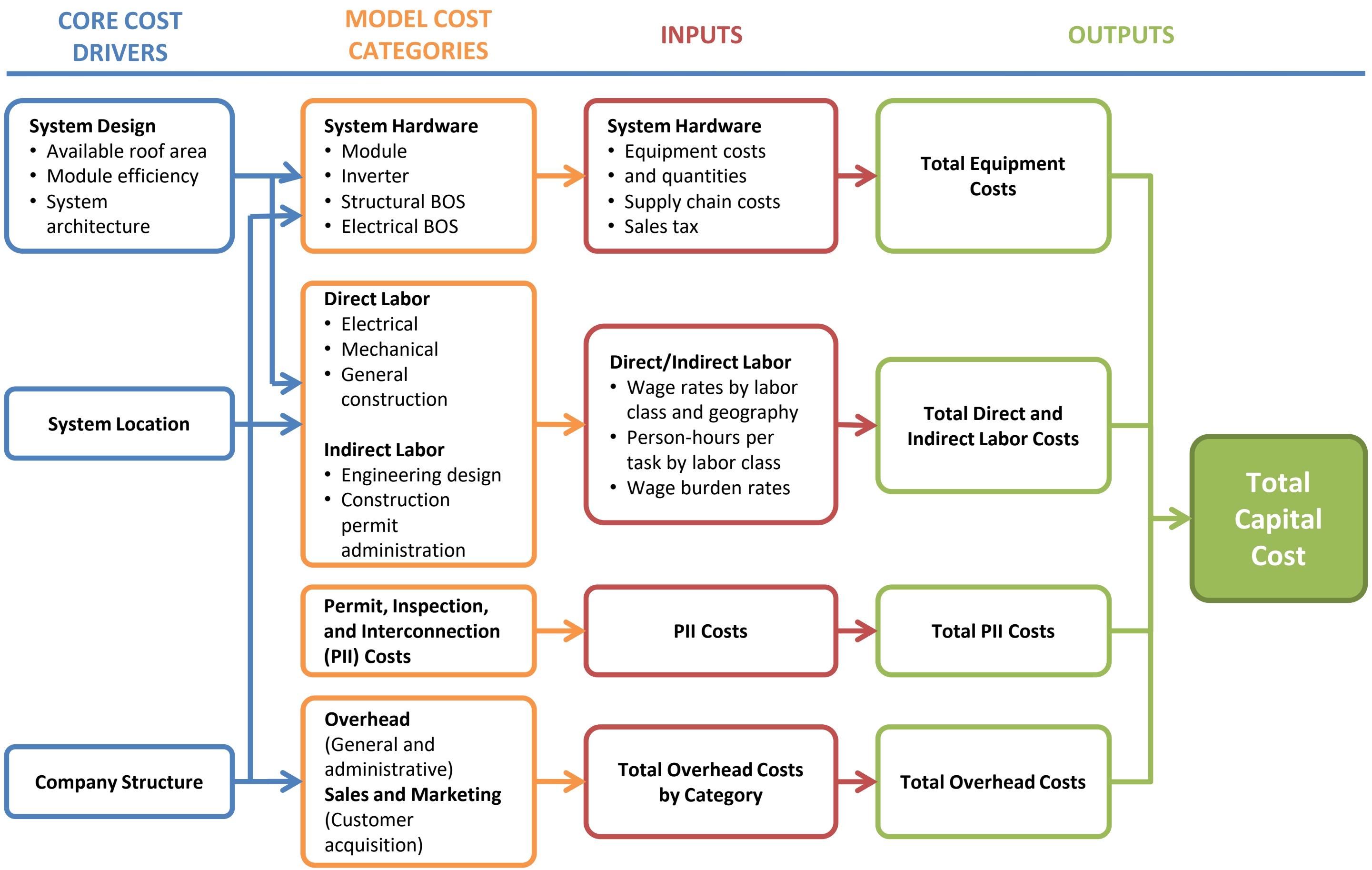
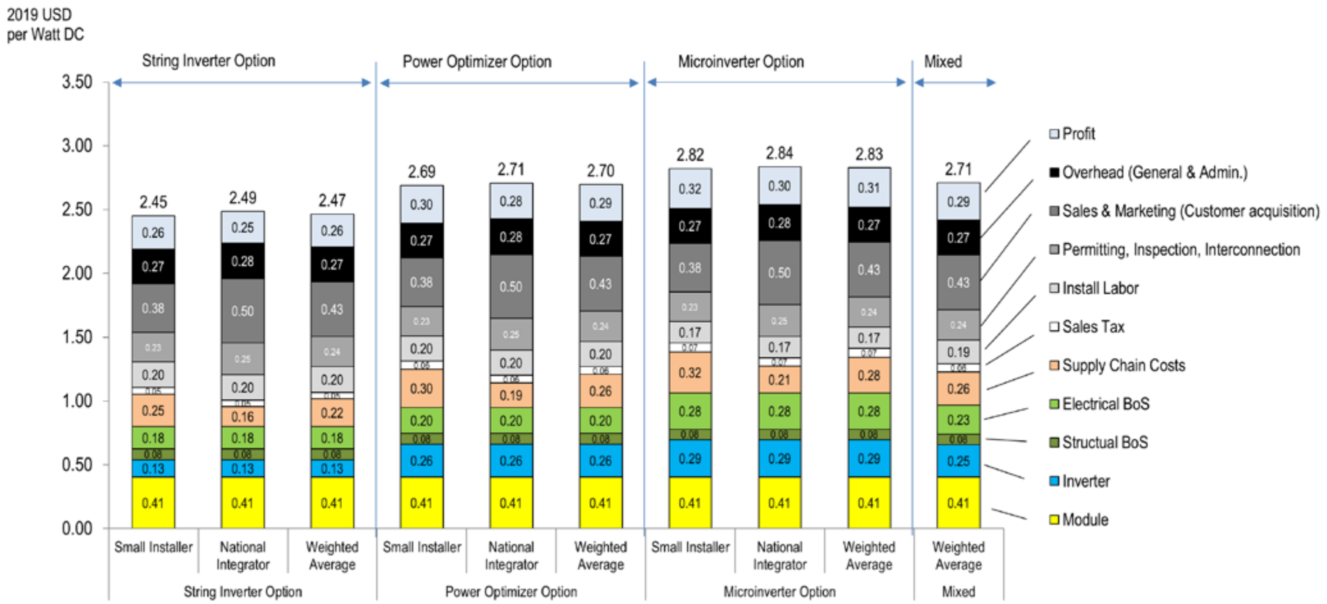
Residential PV: Model Structure



Residential PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	7.0 kW	Average installed size per system	Barbose and Darghouth 2019; CA NEM 2020
Module efficiency	19.5%	Average module efficiency	CA NEM 2020
Module price	$\$0.41/W_{DC}$	Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules	Wood Mackenzie and SEIA 2020
Inverter price	Single-phase string inverter: $\$0.14/W_{DC}$ DC power optimizer single-phase string inverter: $\$0.26/W_{DC}$ Microinverter: $\$0.29/W_{DC}$	Ex-factory gate (first buyer) prices, Tier 1 inverters	Wood Mackenzie 2020; Wood Mackenzie and SEIA 2020
Structural BOS (racking)	$\$0.08/W_{DC}$	Includes flashing for roof penetrations and all rails and clamps	NREL 2020
Electrical BOS	$\$0.18–\$0.28/W_{DC}$ 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 2020
Supply chain costs (percentage of equipment costs)	Varies by installer type and location	15% costs and fees associated with shipping and handling of equipment Additional 6% cost for historical inventory Additional 20% small-scale procurement for module-related supply chain costs for small installers Additional 20% for inverter-related supply chain costs for small installers and 10% for national integrators	BLS 2019; NREL 2020; model assumptions
Sales tax	National average: 5.1%	Sales tax on the equipment	RSMeans 2017
Direct installation labor	Electrician: \$27.47 per hour Laborer: \$18.17 per hour Hours vary by inverter option	Modeled national average labor rates	BLS 2019; NREL 2020
Burden rates (percentage of direct labor)	Total nationwide average: 18%	Workers compensation, federal and state unemployment insurance, Federal Insurance Contributions Act (FICA), builder's risk, and public liability	RSMeans 2017
PII	$\$0.23/W_{DC}$ for small installers $\$0.25/W_{DC}$ for national integrators Varies by location	Completed and submitted applications, fees, design changes, and field inspection	NREL 2020
Sales and marketing (customer acquisition)	$\$0.38/W_{DC}$ (small installer) $\$0.50/W_{DC}$ (national integrator) Varies by location	Initial and final drawing plans, advertising, lead generation, sales pitch, contract negotiation, and customer interfacing	NREL 2020
Overhead (general and administrative)	$\$0.27/W_{DC}$ (small installer) $\$0.28/W_{DC}$ (national integrator) Varies by location	Rent, building, equipment, staff expenses not directly tied to PII, customer acquisition, or direct installation labor	NREL 2020
Profit (%)	17%	Fixed percentage margin applied to all direct costs including hardware, installation labor, direct sales and marketing, design, installation, and permitting fees	Fu et al. 2017

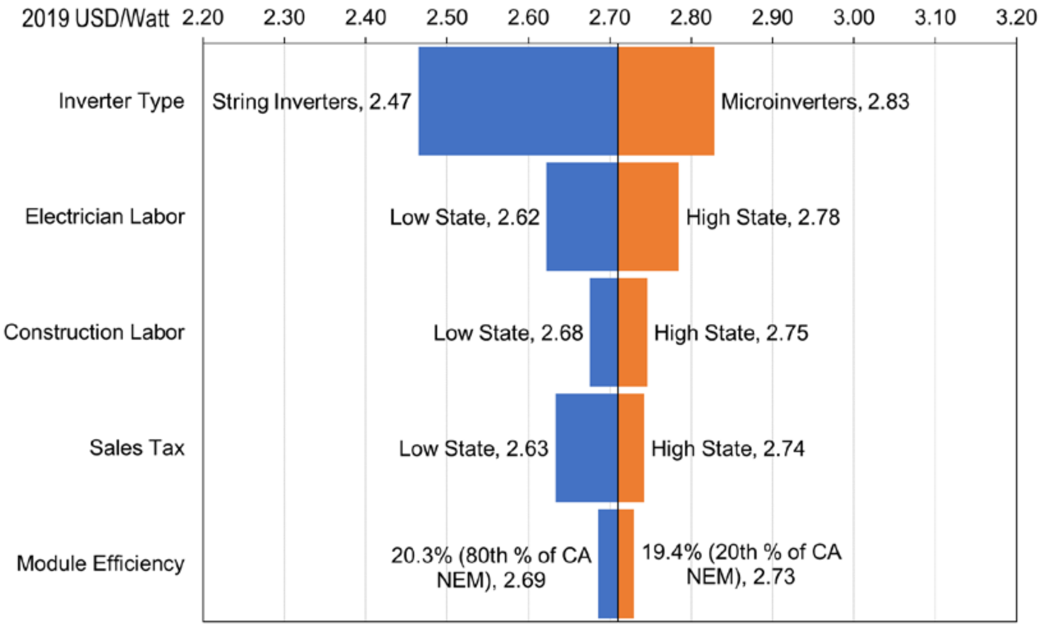
Residential PV: Model Outputs



Q1 2020 U.S. benchmark: 7.0-kW residential system cost (2019 USD/W_{DC})

This figure presents the U.S. national benchmark from our residential model. Market shares of 62% for installers and 38% 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 (14.6%, 49.8%, and 35.6%) as weightings.

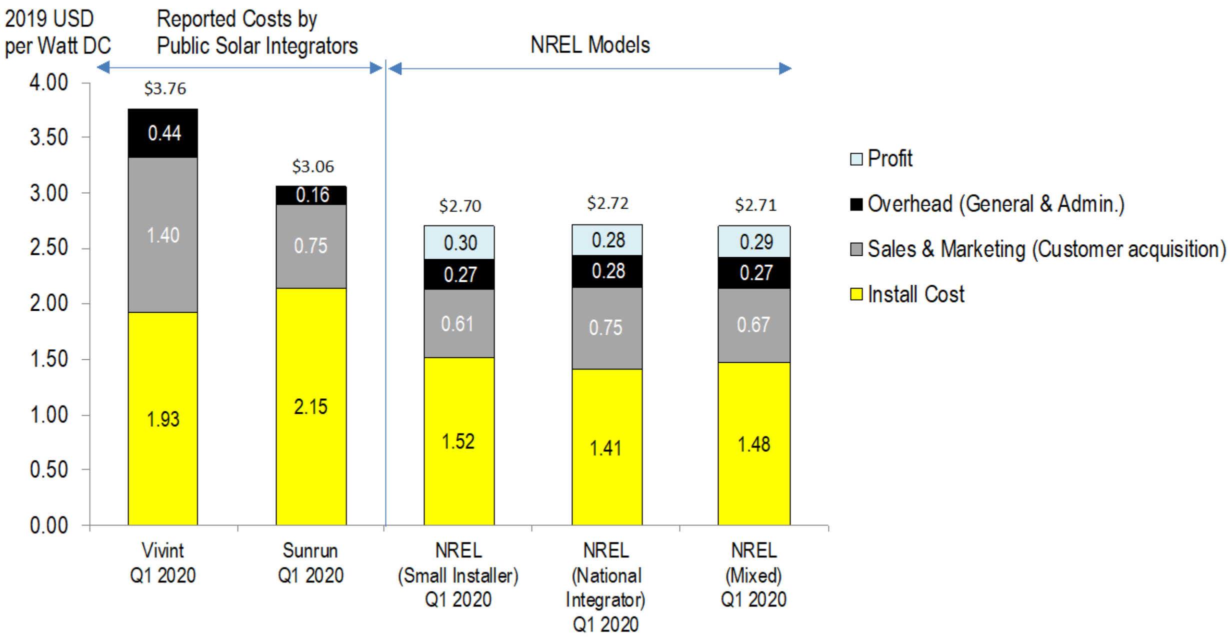
Residential PV: Model Outputs



Sensitivity analysis for Q1 2020 benchmark: Mixed 7.0-kW residential system cost (2019 USD/W_{DC})

This figure presents a sensitivity analysis of the benchmark for the mixed case, with cost categories that vary by location and hardware specification. Inverter type has the largest impact on installed system cost, with the use of string inverters resulting in \$2.47/W_{DC} and the use of microinverters resulting in \$2.83/W_{DC}.

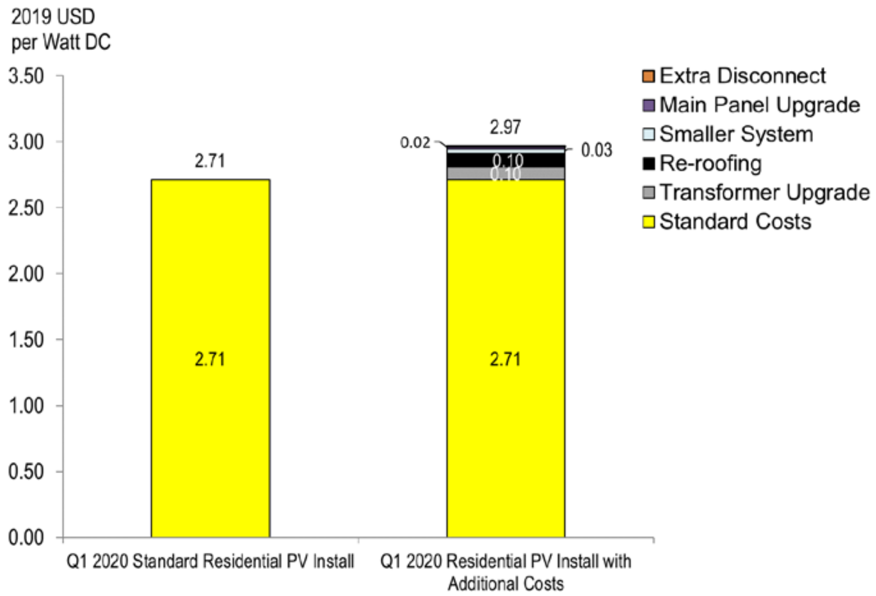
Residential PV: Model Outputs



Q1 2020 NREL modeled cost benchmark (2019 USD/W_{DC}) vs. Q1 2020 company-reported costs

Our bottom-up modeling approach yields a cost structure that is different than those reported by public solar integrators in their corporate filings (Sunrun 2020; Vivint Solar 2020). 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. Part of the difference in installation costs could come from preexisting contracts or older inventory that national integrators used in systems installed in Q1 2020.

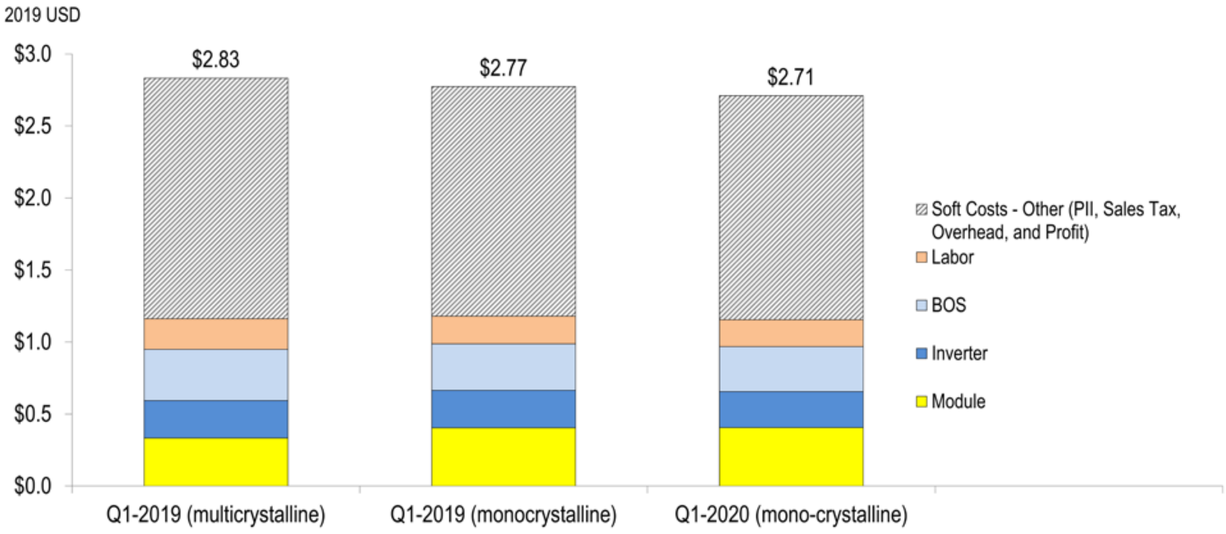
Residential PV: Model Outputs



Standard residential PV installation costs versus cost for systems with necessary additions

Our benchmarking method includes bottom-up accounting for all necessary system and project-development costs incurred when installing U.S. residential PV systems. This year, we calculate additional hardware, installation labor, and roofing costs that are often incurred for many PV systems. Because of the requirements of some authorities having jurisdiction, or for a particular building, additional hardware and installation labor costs must be incurred. Not all U.S. projects must incur these costs, so the average additional contribution to total PV system cost for each step is calculated by multiplying the average cost per occurrence (either material costs or hourly wage multiplied by the number of hours) by the estimated percentage of national sales that use this step, divided by the average conversion from this step to an installed system. The extra cost categories can add 10% to the benchmark system cost.

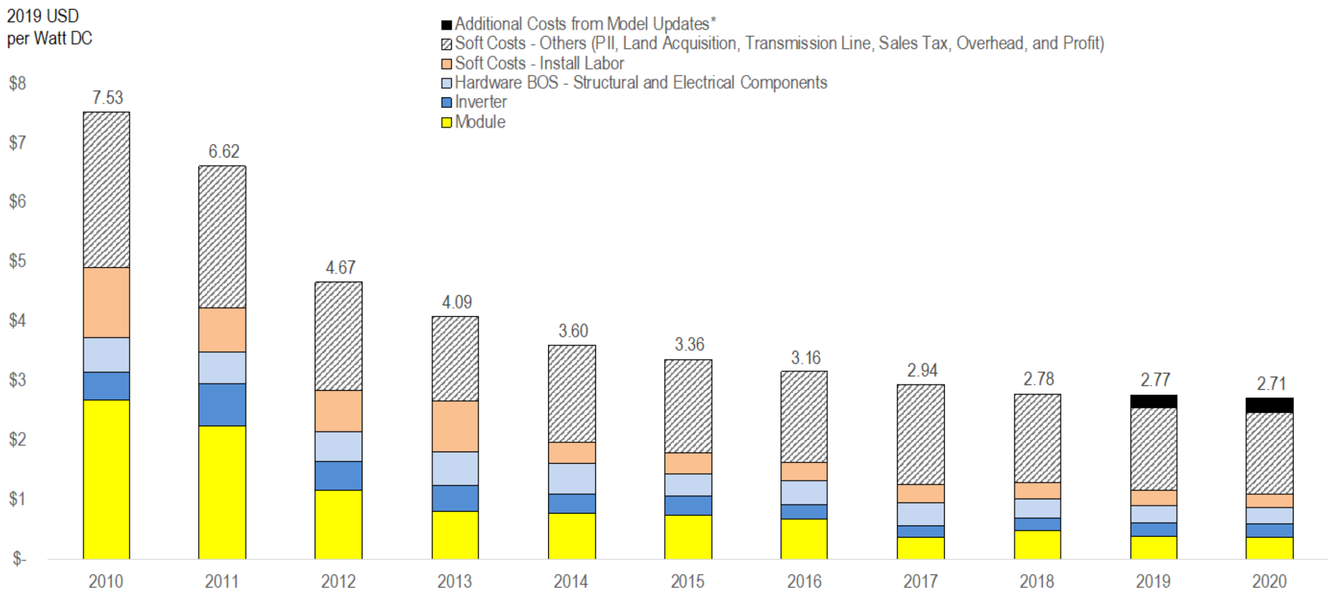
Residential PV: Model Outputs



Q1 2019 cost for a residential multicrystalline PV system and Q1 2019 and Q1 2020 costs for a residential monocrystalline PV system

In the Q1 2020 benchmark report, we model systems using monocrystalline PV modules, unlike previous editions of this report (Fu et al. 2018), for which we modeled multicrystalline PV modules. In the past few years, the U.S. market has had an increasing demand for monocrystalline modules. As shown above, in Q1 2019, there was a $0.06/W system price premium from using multicrystalline modules over monocrystalline modules for residential PV systems. The total system cost reductions achieved by increasing efficiency with monocrystalline modules outweighed the premium in monocrystalline module price. Residential PV systems using monocrystalline modules achieved a $0.06/W (2%) reduction in price from Q1 2019 to Q1 2020.

Residential PV: Capital Cost Benchmark Historical Trends



From 2010 to 2020, there was a 64% reduction in the residential PV system cost benchmark. Approximately 57% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 85% over that period. An additional 20% can be attributed to labor, which dropped 84% over the period, and the final 22% is attributed to other soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2019 to 2020, there was a 2% reduction in the residential PV system cost benchmark.

* The current version of our cost model makes a few significant changes from the version used in our Q1 2018 benchmark report (Fu, Feldman, and Margolis 2018), and it incorporates costs that had previously not been benchmarked in as much detail. To better distinguish the historical cost trends from the changes to our cost models, we calculate Q1 2019 and Q1 2020 PV benchmarks using the Q1 2018 version of the residential PV model. The “Additional Costs from Model Updates” category represents the difference between modeled results. Using the previous cost model, the Q1 2019 and Q1 2020 benchmarks are calculated to be $2.56/W_{DC}$ and $2.47/W_{DC}$ respectively.

Residential PV: LCOE Assumptions

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Benchmark Report											
Installed cost ($/W)	7.53	6.62	4.67	4.09	3.60	3.36	3.16	2.94	2.78	2.77	2.71
Inverter loading ratio	1.10	1.11	1.12	1.13	1.13	1.14	1.15	1.15	1.15	1.15	1.15
Ongoing NREL Benchmarking											
Annual degradation (%)	1.00	0.95	0.90	0.85	0.80	0.75	0.75	0.75	0.70	0.70	0.70
O&M expenses ($/kW-yr)	56	49	42	36	31	26	25	25	22	27	29
Preinverter derate (%)	90.0	90.1	90.2	90.3	90.4	90.5	90.5	90.5	90.5	90.5	90.5
Inverter efficiency (%)	94.0	94.8	95.6	96.4	97.2	98.0	98.0	98.0	98.0	98.0	98.0
Inflation rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Market Case											
Equity discount rate (real) (%)	9.0	8.6	8.3	7.9	7.6	7.3	6.9	6.9	6.9	6.1	6.1
Debt interest rate (%)	5.5	5.4	5.3	5.2	5.0	4.9	4.8	4.8	4.8	4.0	4.0
Debt fraction (%)	34.2	35.2	36.1	37.1	38.1	39.0	40.0	40.0	40.0	53.7	53.7
Steady-State Financing (No ITC)											
Equity discount rate (real) (%)	—	—	—	—	—	—	—	—	—	—	6.1
Debt interest rate (%)	—	—	—	—	—	—	—	——	—	—	5.0
Debt fraction (%)	—	—	—	—	—	—	—	—	—	—	71.8

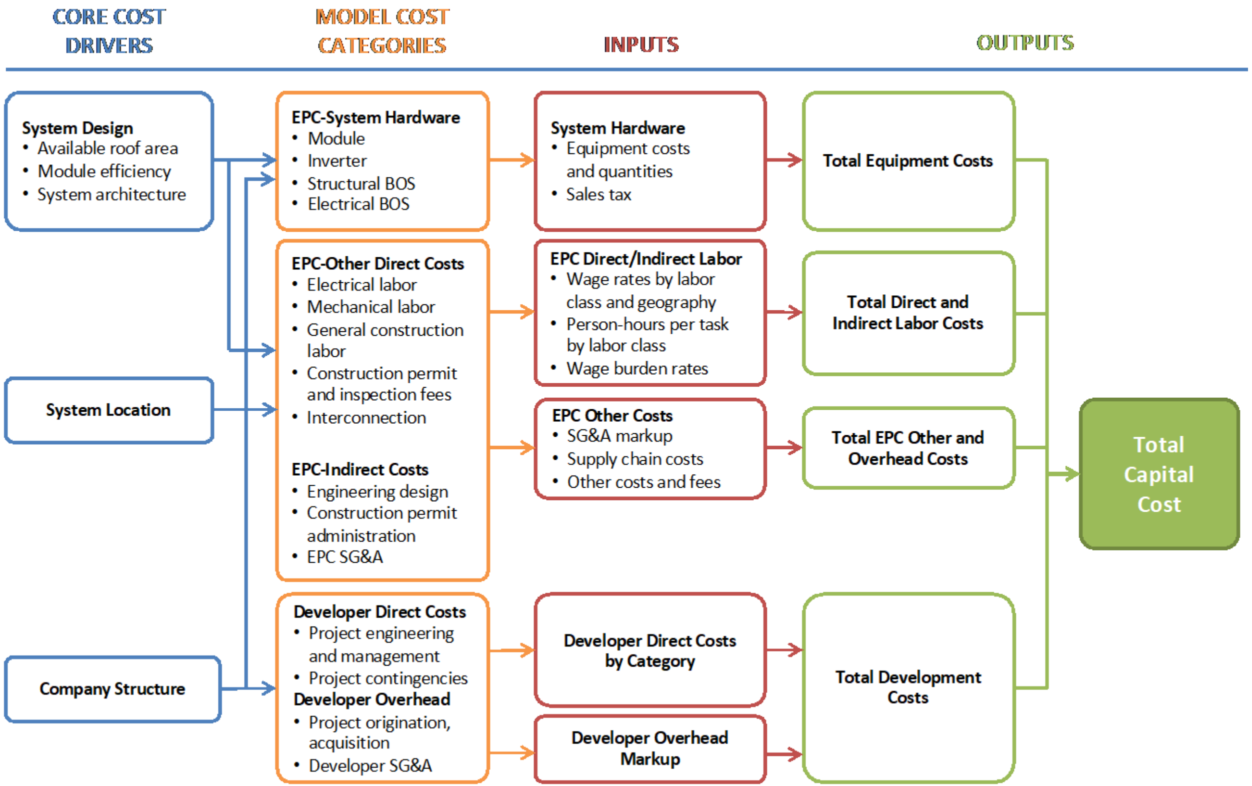
All 2010–2018 data are from Fu, Feldman, and Margolis (2018), and they are adjusted for inflation. Residential PV system LCOE assumes: (1) system lifetime of 30 years; (2) federal tax rate of 21%; (3) state tax rate of 6%; (4) Modified Accelerated Cost Recovery System (MACRS) depreciation schedule; (5) no state or local subsidies; (6) a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning an interest rate of 1.75%); (7) three-month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system; (8) module tilt angle of 25 degrees, and an azimuth of 180 degrees; (9) debt with a term of 18 years; (10) $1.1 million of up-front financial transaction costs for a $100 million TPO transaction of a pool of residential projects; (11) 2019 and 2020 financial assumptions from Feldman, Bolinger, and Schwabe (2020).

Residential PV: LCOE Benchmark Historical Trends

From 2010 to 2020, there was a 74% reduction in the residential PV system electricity cost benchmark (a 1% reduction was achieved from 2019 to 2020), bringing the unsubsidized LCOE between $0.11/kWh to $0.16/kWh ($0.07/kWh to $0.09/kWh when including the federal ITC). This reduction is 93% toward achieving SETO's 2020 residential LCOE goal, which is 10.6 cents/kWh in 2019 USD. We also calculate PV LCOE without the ITC using steady-state financing assumptions. Under these assumptions, unsubsidized residential PV LCOE ranges from $0.10/kWh to $0.14/kWh in Q1 2020.

Contents

Commercial PV: Model Structure

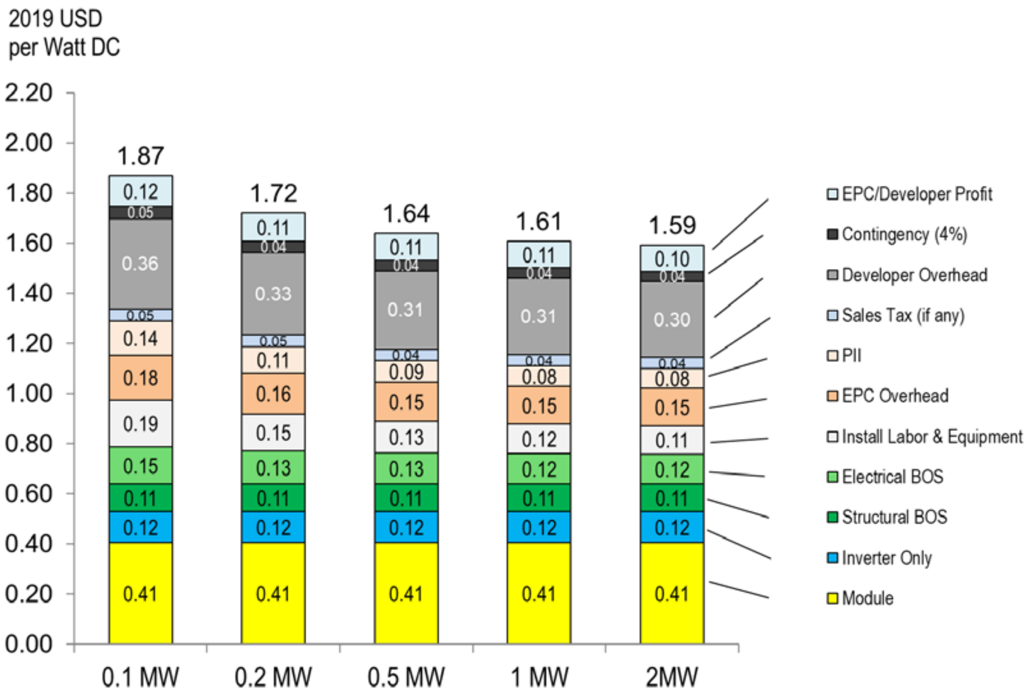


Commercial PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	200 kW (rooftop) and 500 kW (ground-mounted); range (100 kW–2 MW)	Average installed size per system	Barbose and Darghouth 2019
Module efficiency	19.5%	Average monocrystalline module efficiency	CA NEM 2020
Module price	$0.41/W_{DC}$	Ex-factory gate (first buyer) ASP, Tier 1 monocrystalline modules	Wood Mackenzie and SEIA 2020
Inverter price	Three-phase string inverter: $0.07/$W_{DC}$ DC power optimizer three-phase string inverter: $0.12/$W_{DC}$ (rooftop only) Microinverter: $0.29/$W_{DC}$ (rooftop only)	Ex-factory gate prices (first buyer) ASP, Tier 1 inverters	Wood Mackenzie 2020; Wood Mackenzie and SEIA 2020
Structural components (racking)	$0.11–$0.17/W_{DC}; assumes national average wind and snow loading[a]; varies by racking type (ground-mounted versus rooftop-ballasted)	Ex-factory gate prices; flat-roof ballasted racking system or fixed-tilt ground-mounted racking system	MEPS 2019; model assumptions; NREL 2019
Electrical components	$0.13–$0.24/W_{DC}	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, and other parts	Model assumptions; NREL 2020; RSMeans 2017
EPC overhead (percentage of equipment costs)	13%	Costs and fees associated with EPC overhead, inventory, shipping, and handling	NREL 2020
Sales tax	National average: 5%	Sales tax on equipment costs	RSMeans 2017
Direct installation labor	Electrician: $27.47 per hour Laborer: $18.17 per hour	Modeled labor rate assumes national average nonunionized labor rates	BLS 2019; NREL 2020
Burden rates (percentage of direct labor)	Total nationwide average: 18%	Workers compensation, federal and state unemployment insurance, FICA, builders' risk, public liability	RSMeans 2017
PII	$0.11/$W_{DC}$	For construction permits fee, interconnection study fees for existing substation, testing, and commissioning	NREL 2020
Developer overhead	$0.30–$0.36/W Varies by system size (30% developer overhead)	Includes overhead expenses such as payroll, facilities, travel, legal fees, administrative, business development, finance, and other corporate functions	Model assumptions; NREL 2020
Contingency	4%	Estimated as markup on EPC cost; value represents actual cost overruns above estimated cost	NREL 2020
Profit	7%	Applies a fixed percentage margin to all costs, including hardware, installation labor, EPC overhead, and developer overhead	NREL 2020

[a] Racking companies currently meet the national standard, so there is not as much differentiation by state in the market within rooftop systems. The ground-mount racking system requires more material, equipment, and labor compared than the ballasted racking system. However, installation of ground-mount PV systems at utility scale helps reduce the BOS cost of these systems owing to economies of scale.

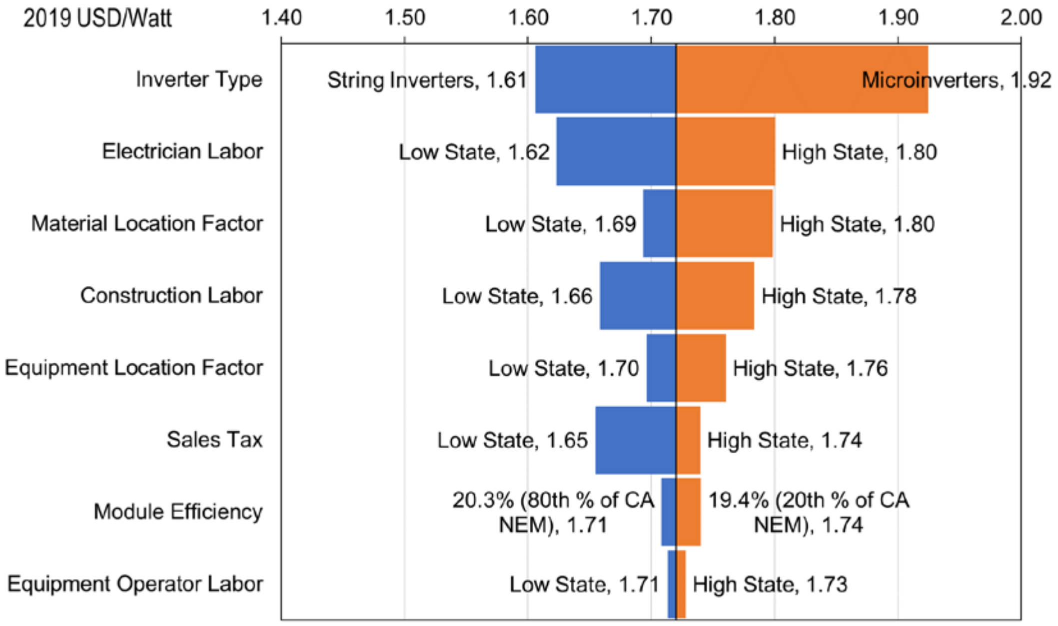
Commercial PV: Rooftop Model Outputs



Q1 2020 U.S. benchmark: Commercial rooftop PV system cost (2019 USD/WDC)

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. Owing to the adoption of the 2017 and 2020 NEC in many states, three-phase string inverter, power optimizer, and microinverter options are each modeled individually for the commercial rooftop model, and the "mixed" case applies their market shares (45%, 39%, and 16% respectively) as weightings.

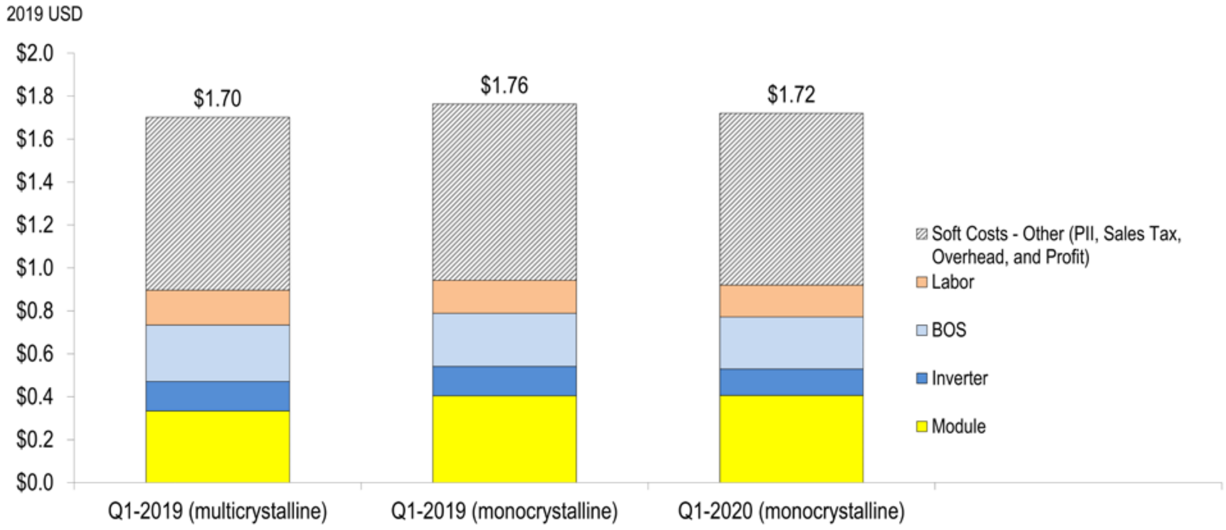
Commercial PV: Rooftop Model Outputs



Q1 2020 benchmark by location: 200-kW commercial rooftop system cost (2019 USD/W_{DC})

This figure presents a sensitivity analysis of the benchmark for the mixed case, with cost categories that vary by location and hardware specification. Inverter type has the largest impact on installed system cost, with use of string inverters resulting in \$1.61/W_{DC} and use of microinverters resulting in \$1.92/W_{DC}.

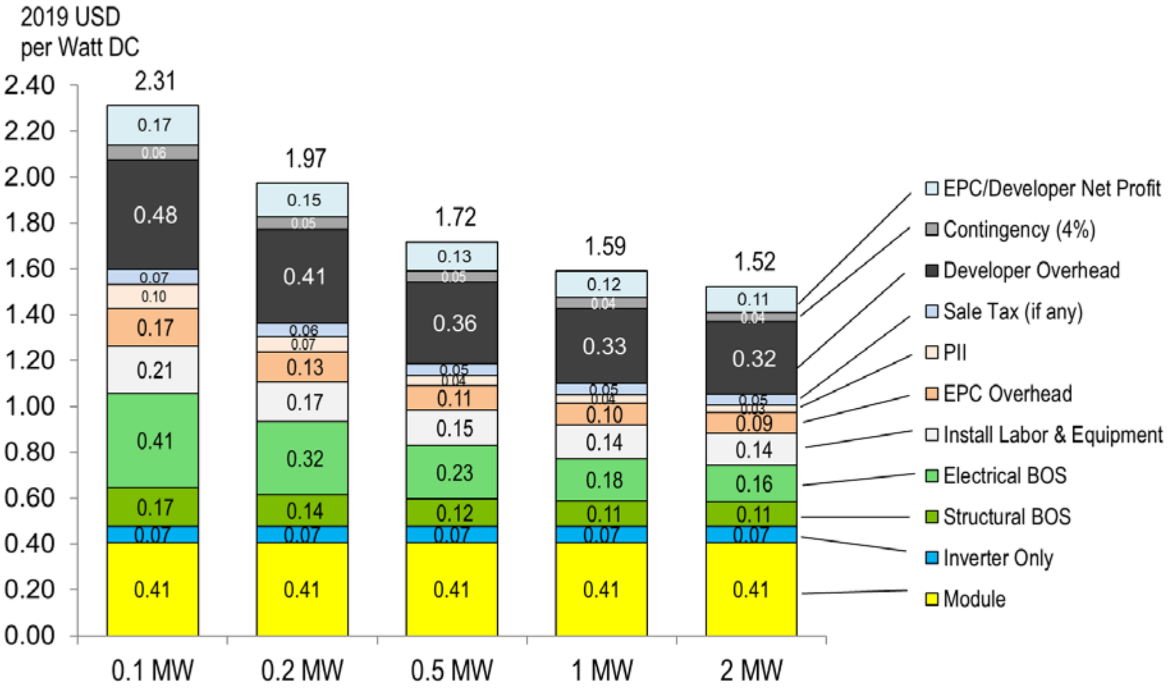
Commercial Rooftop PV: Model Outputs



Q1 2019 cost for a commercial rooftop multicrystalline PV system and Q1 2019 and Q1 2020 costs for a commercial rooftop monocrystalline PV system

In the Q1 2020 benchmark report, we model systems using monocrystalline PV modules, unlike previous editions of this report (Fu et al. 2018), for which we modeled multicrystalline PV modules. In the past few years, the U.S. market has had an increasing demand for monocrystalline modules. As shown above, in Q1 2019 there was a $0.06/W system price premium from using monocrystalline modules over multicrystalline modules for commercial rooftop PV systems. The system cost reductions achieved by increased monocrystalline module efficiency were counterbalanced by the higher module price. Commercial rooftop PV systems using monocrystalline modules achieved a $0.04/W (2.4%) reduction in price from Q1 2019 to Q1 2020.

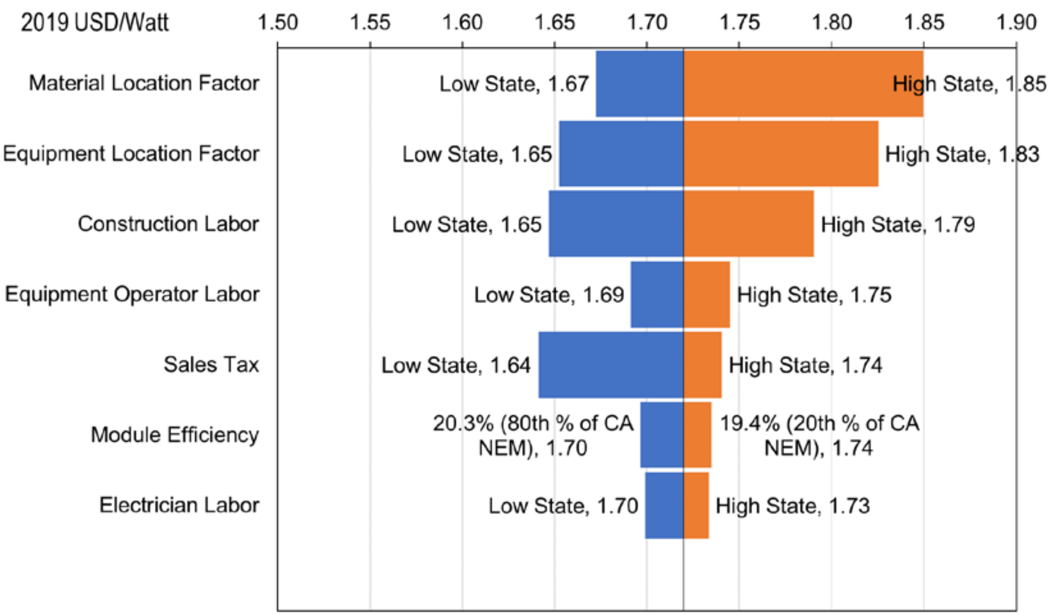
Commercial PV: Ground-Mounted Model Outputs



Q1 2020 U.S. benchmark: Commercial ground-mounted PV system cost (2019 USD/W_{DC})

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. Compared with rooftop systems, ground-mounted applications have higher material, equipment, and labor costs associated with pile-driven mounting. As PV system size increases, the per-watt cost of pile-driven mounting is significantly reduced through economies of scale. Ground-mounted commercial PV systems also benefit from lower inverter costs owing to the rapid shutdown requirements for commercial rooftop systems.

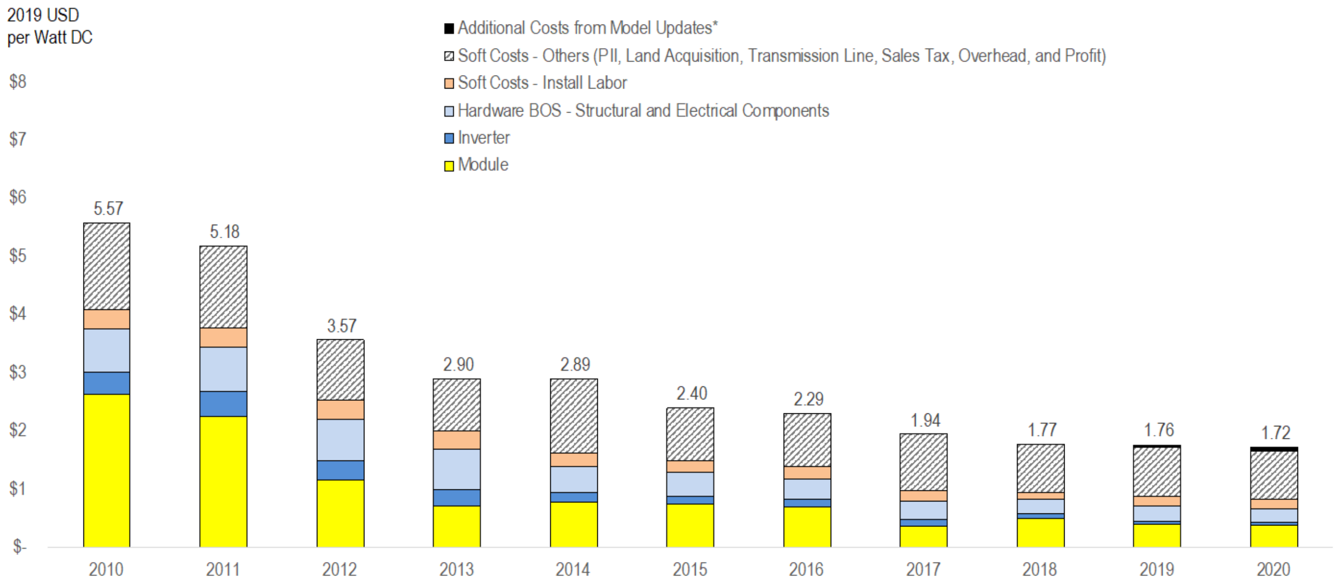
Commercial PV: Ground-Mounted Rooftop Model Outputs



Q1 2020 benchmark by location: 500-kW commercial ground-mounted system cost (2019 USD/W_{DC})

This figure presents a sensitivity analysis of the benchmark for the mixed case, with cost categories that vary by location and hardware specification. Material location factor has the largest impact on installed system cost, with the lowest cost state resulting in \$1.67/W_{DC} and the highest cost state resulting in \$1.85/W_{DC}.

Commercial Rooftop PV: Capital Cost Benchmark Historical Trends



From 2010 to 2020, there was a 69% reduction in the commercial PV system cost benchmark. Approximately 78% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 85% over that period. The final 22% is attributable to labor and soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2019 to 2020 there was a 2.4% reduction in the commercial PV system cost benchmark that was largely driven by reductions in inverter and BOS hardware costs.

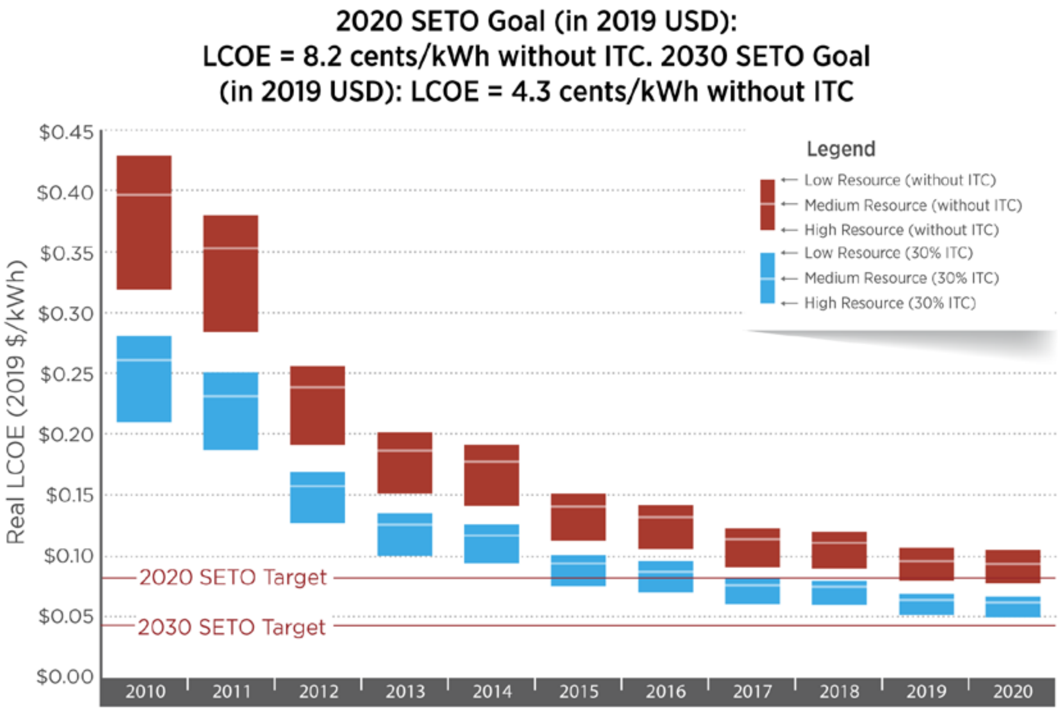
* The current version of our cost model makes a few significant changes from the version used in our Q1 2018 benchmark report (Fu, Feldman, and Margolis 2018), and it incorporates costs that had previously not been benchmarked in as much detail. To better distinguish the historical cost trends from the changes to our cost models, we calculate Q1 2019 and Q1 2020 PV benchmarks using the Q1 2018 version of the commercial rooftop PV model. The “Additional Costs from Model Updates” category represents the difference between modeled results. Using the previous costs model, the Q1 2019 and Q1 2020 benchmarks are calculated to be $1.71/W$_{DC}$ and $1.64/W$_{DC}$ respectively.

Commercial PV: LCOE Assumptions

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rooftop (200 kW)											
Installed cost ($/W)	5.57	5.18	3.57	2.90	2.89	2.40	2.29	1.94	1.77	1.76	1.72
Inverter loading ratio	1.10	1.11	1.12	1.13	1.13	1.14	1.15	1.15	1.15	1.15	1.15
Annual degradation (%)	1.00	0.95	0.90	0.85	0.80	0.75	0.75	0.75	0.70	0.70	0.70
O&M expenses ($/kW-yr)	35	32	29	26	23	20	19	19	18	19	19
Preinverter derate (%)	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5
Inverter efficiency (%)	95.0	95.6	96.2	96.8	97.4	98.0	98.0	98.0	98.0	98.0	98.0
Ground-Mounted (500 kW)											
Installed cost ($/W)	—	—	—	—	—	—	—	—	—	—	1.72
Inverter loading ratio	—	—	—	—	—	—	—	—	—	—	1.11
Annual degradation (%)	—	—	—	—	—	—	—	—	—	—	0.70
O&M expenses ($/kw-yr)	—	—	—	—	—	—	—	—	—	—	18.71
Preinverter derate (%)	—	—	—	—	—	—	—	—	—	—	90.5
Inverter efficiency (%)	—	—	—	—	—	—	—	—	—	—	98.0
Financing Assumptions											
Inflation rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Market Case											
Equity discount rate (real) (%)	9.0	8.6	8.3	7.9	7.6	7.3	6.9	6.9	6.9	6.1	6.1
Debt interest rate (%)	5.5	5.4	5.3	5.2	5.0	4.9	4.8	4.8	4.8	4.0	4.0
Debt fraction (%)	34.2	35.2	36.1	37.1	38.1	39.0	40.0	40.0	40.0	53.8	53.8
Steady-State financing											
Equity discount rate (real) (%)	—	—	—	—	—	—	—	—	—	—	6.1
Debt interest rate (%)	—	—	—	—	—	—	—	—	—	—	5.0
Debt fraction (%)	—	—	—	—	—	—	—	—	—	—	71.8

All 2010–2018 data are from Fu, Feldman, and Margolis (2018), and they are adjusted for inflation. Commercial PV system LCOE assumes: (1) System lifetime of 30 years; (2) Federal tax rate of 21%; (3) Sate tax rate of 6%; (4) MACRS depreciation schedule; (5) No state or local subsidies; (6) A working capital and debt service reserve account for 6 months of operating costs and debt payments (earning an interest rate of 1.75%); (7) Six-month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system; (8) Module tilt angle of 10 degrees and an azimuth of 180 degrees; (9) Debt with a term of 18 years; (10) $1.1 million of up-front financial transaction costs for a $100 million TPO transaction of a pool of commercial projects; (11) 2019 and 2020 financial assumptions from Feldman, Bolinger, and Schwabe (2020).

Commercial PV: LCOE Benchmark Historical Trends

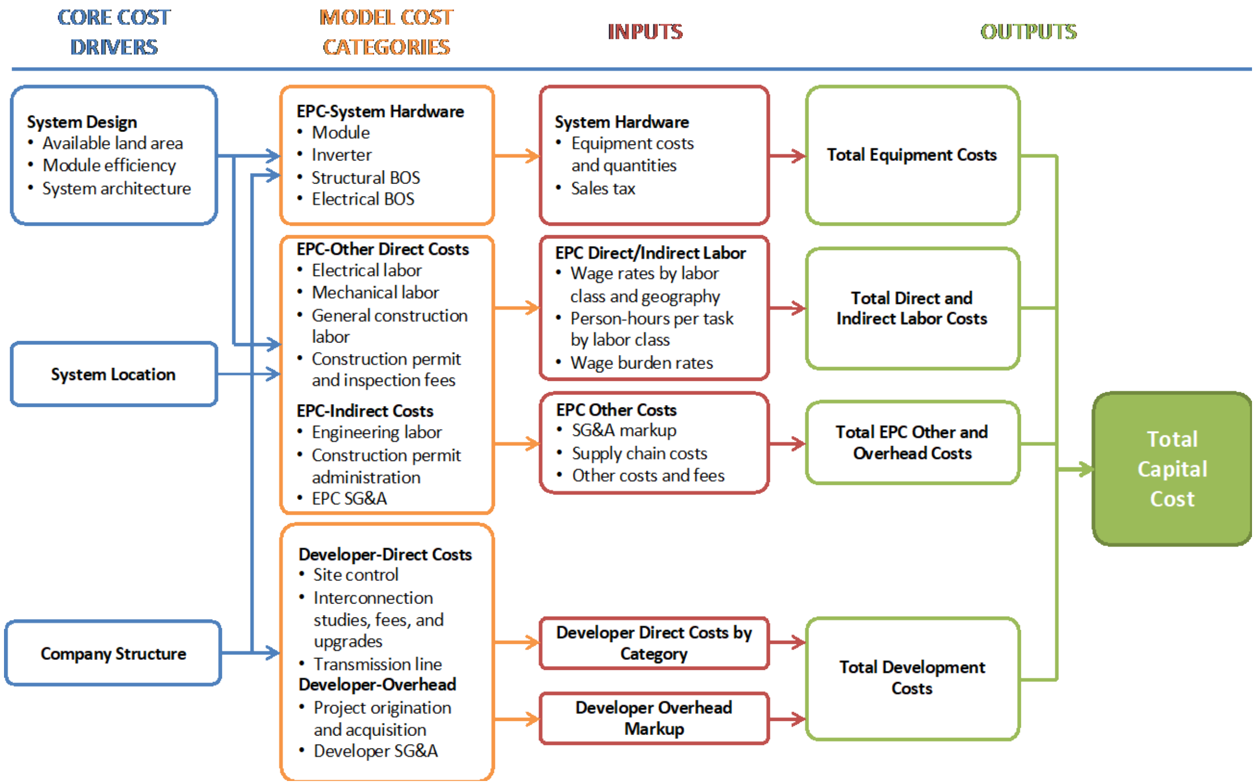


From 2010 to 2020, there was a 77% reduction in the commercial PV system electricity cost benchmark (a 3% reduction was achieved from 2019 to 2020), bringing the unsubsidized LCOE between $0.08/kWh to $0.10/kWh ($0.05/kWh to $0.07/kWh when including the federal ITC). This reduction is 97% toward achieving SETO's 2020 commercial PV LCOE goal, which is 8.2 cents/kWh in 2019 USD.

Commercial ground-mounted PV systems, which we began benchmarking this year, are calculated to have a 2020 unsubsidized LCOE of $0.07–$0.09/kWh ($0.05–$0.06/kWh when including the federal ITC). We also calculate PV LCOE without the ITC using steady-state financing assumptions. Under these assumptions, the commercial rooftop PV LCOE ranges from $0.07 kWh to $0.10/kWh, and the commercial ground-mounted PV LCOE ranges from $0.07/kWh to $0.10/kWh in Q1 2020.

Contents

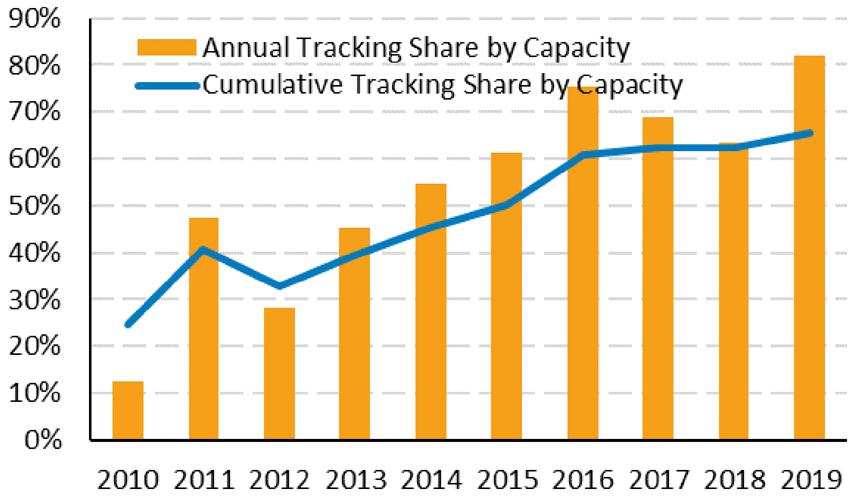
Utility-Scale PV: Model Structure



Utility-Scale PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	100 MW; range: 5 MW–100 MW	A large utility-scale system capacity	Model assumption
Module efficiency	19.5%	Average monocrystalline module efficiency	CA NEM 2020
Module price	$0.41/W_{DC}$	Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules	Wood Mackenzie and SEIA 2020; NREL 2020
Inverter price	$0.05/W_{DC}$ (fixed-tilt)$0.05/W_{DC}$ (one-axis tracker)	Ex-factory gate (first buyer) price, Tier 1 inverters DC-to-AC ratio = 1.37 for fixed-tilt and 1.34 for one-axis tracker	Wood Mackenzie and SEIA 2020; Bolinger, Seel, and Robson 2019
Structural components (racking)	$0.12/W_{DC}$ for a 100-MW system	Fixed-tilt racking or one-axis tracking system	MEPS 2019; model assumptions; NREL 2020
Electrical components	$0.07–$0.13/W_{DC}$ Varies by system size	Model was upgraded to a 1,500-V_{DC} system that includes conductors, conduit and fittings, transition boxes, switchgear, panel boards, onsite transmission, and other electrical connections	Model assumptions; NREL 2020; RSMeans 2017
EPC overhead (percentage of equipment costs)	8.67%–13% for equipment and material (except for transmission line costs); 23%–69% for labor costs; varies by system size and labor activity	Costs associated with EPC SG&A, warehousing, shipping, and logistics	NREL 2020
Sales tax	National average: 5%	Sales tax on equipment costs	RSMeans 2017
Direct installation labor	Electrician: $27.47 per hour Laborer: $18.17 per hour	Modeled labor rate assumes national average nonunionized labor	BLS 2019; NREL 2020
Burden rates (percentage of direct labor)	Total nationwide average: 18%	Workers compensation, federal and state unemployment insurance, FICA, builders' risk, public liability	RSMeans 2017
PII	$0.03–$0.07/W_{DC}$ Varies by system size	For construction permits fee, interconnection, testing, and commissioning	NREL 2020
Transmission line (gen-tie line)	$0.00–$0.02/W_{DC}$ Varies by system size	System size < 10 MW uses 0 miles for gen-tie line System size > 200 MW uses five miles for gen-tie line System size = 10–200 MW uses linear interpolation	Model assumptions; NREL 2020
Developer overhead	2%–12% Varies by system size (100 MW uses 2%; 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 2020
Contingency	3%	Estimated as markup on EPC cost	NREL 2020
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, and developer overhead	NREL 2020

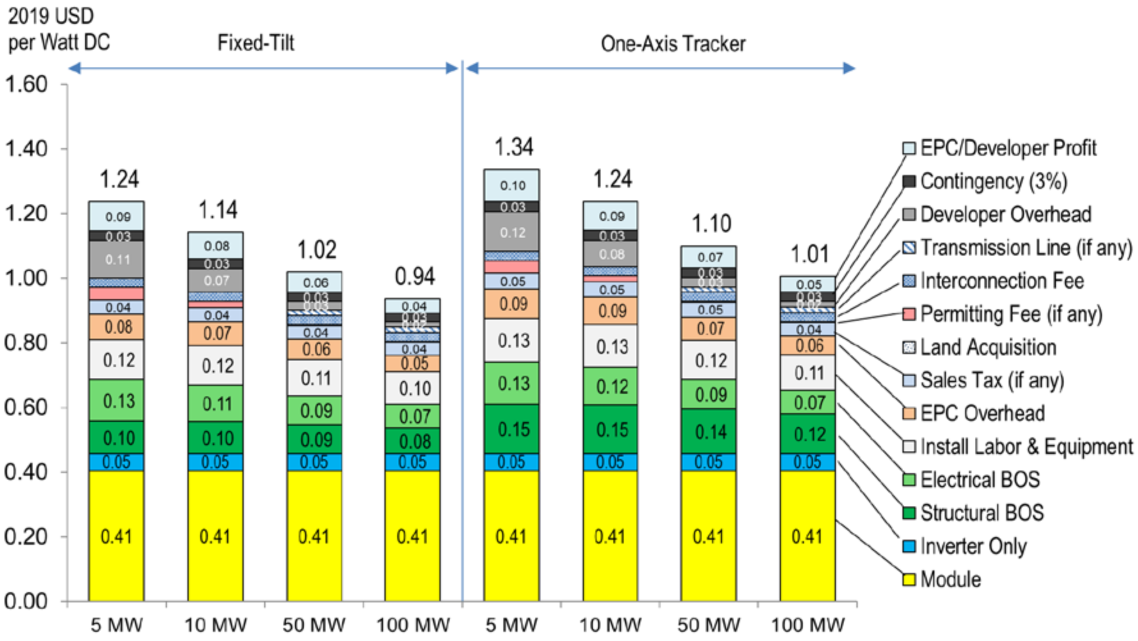
Utility-Scale PV: U.S. Fixed-Tilt vs. Tracking Systems



Percentage of U.S. utility-scale PV systems using tracking systems, 2010–2019 (EIA 2020)

This figure shows the percentage of U.S. utility-scale PV systems using tracking systems for 2010–2019. 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 (EIA 2020). Cumulative tracking system installation reached 65% by 2019.

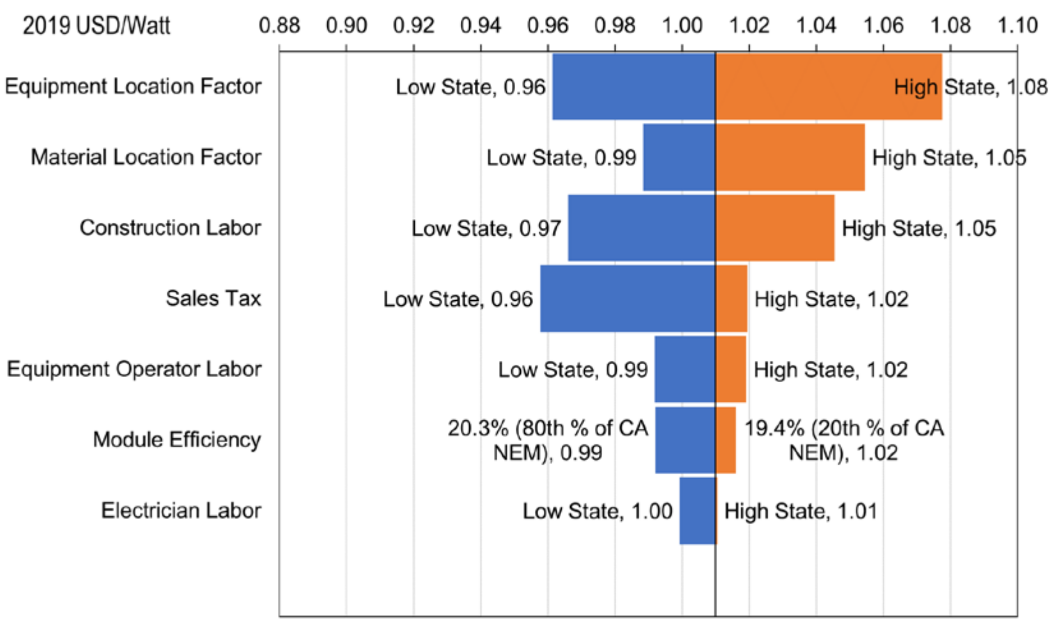
Utility-Scale PV: Model Outputs



Q1 2020 U.S. benchmark: Utility-scale PV total cost (EPC + developer) 2019 USD/W_{DC}

(1) Nonunion labor is used.
(2) Economies of scale—driven by BOS, labor, related markups, and development cost—are demonstrated.

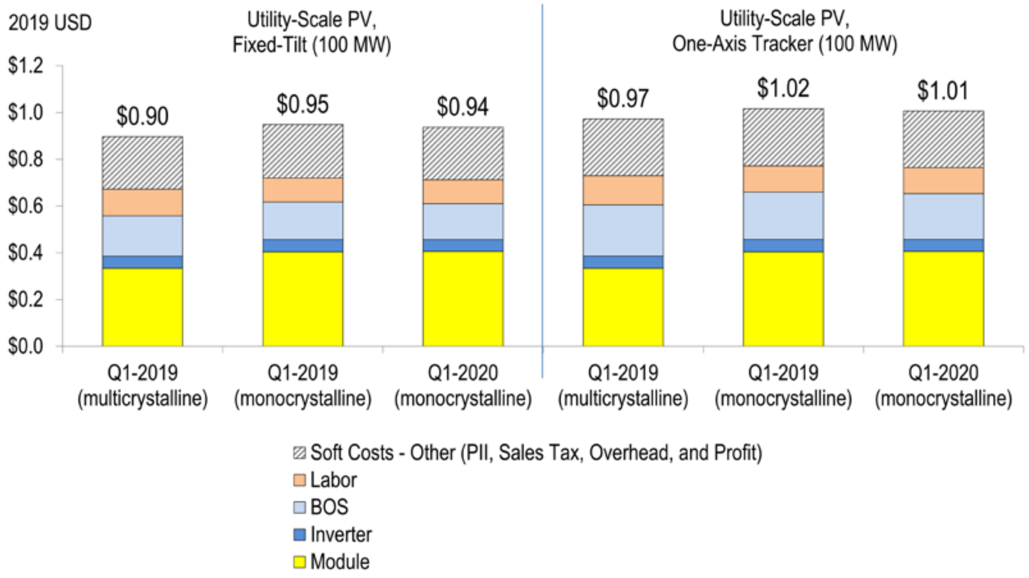
Utility-Scale PV: Model Outputs



Q1 2020 benchmark by location: 100-MW one-axis utility-scale PV system cost (2019 USD/W_{DC})

This figure presents a sensitivity analysis of the benchmark for the mixed case, with cost categories that vary by location and hardware specification. Equipment location factor has the largest impact on installed system cost, with the lowest cost state resulting in \$0.96/W_{DC} and the highest cost state resulting in \$1.08/W_{DC}.

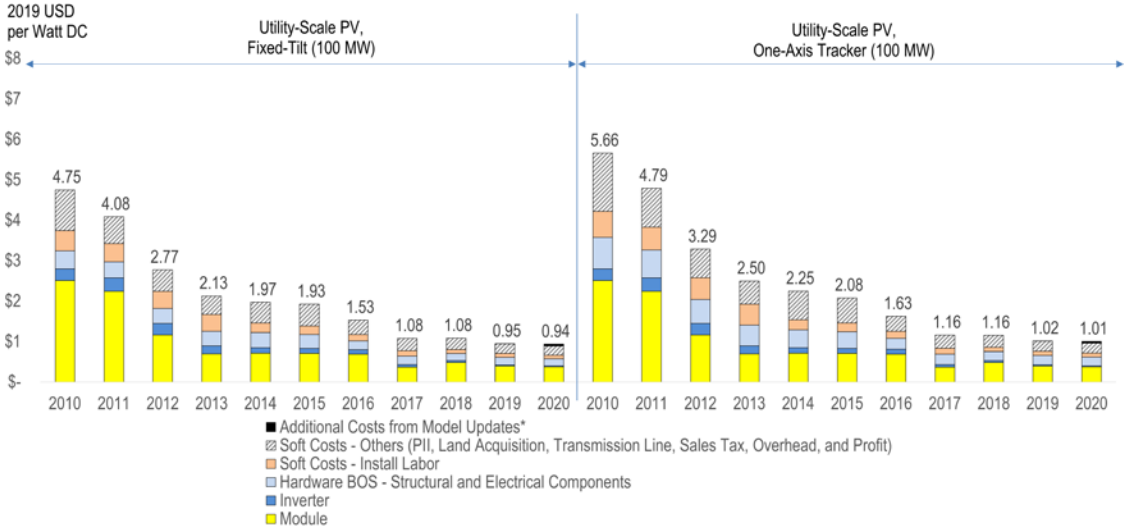
Utility-Scale PV: Model Outputs



Q1 2019 cost for a utility-scale PV multicrystalline PV system and Q1 2019 and Q1 2020 costs for a utility-scale PV monocrystalline PV system

In the Q1 2020 benchmark report, we model systems using monocrystalline PV modules, unlike previous editions of this report (Fu et al. 2018), for which we modeled multicrystalline PV modules. In the past few years, the U.S. market has had an increasing demand for monocrystalline modules. As shown above, in Q1 2019 there was a $0.05/W_{DC}$ system price premium for using monocrystalline PV modules over multicrystalline PV modules in utility-scale PV systems. The system cost reductions achieved by increased monocrystalline module efficiency were counterbalanced by the higher module price. The price of utility-scale PV systems using monocrystalline modules decreased by $0.01/W_{DC}$ from Q1 2019 to Q1 2020.

Utility-Scale PV: Capital Cost Benchmark Historical Trends



From 2010 to 2020, there was an 80% reduction in the utility-scale (fixed-tilt) PV system cost benchmark, and an 82% reduction in the utility-scale (one-axis) PV system cost benchmark. Approximately 70% and 64 of that reduction can be attributed to total hardware costs (for fixed-tilt and one-axis systems respectively), as module prices dropped 85% over that period. An additional 11% (fixed-tilt) to 12% (one-axis tracking) reduction can be attributed to labor, which dropped over that period. For previous editions of this report, we assumed a land acquisition cost of $0.03/W. Based on Wiser et al. (2020), which stated that most utility-scale PV projects do not own the land on which the PV system is placed, we have reclassified land costs from an up-front capital expenditure (land acquisition) to an operating expenditure (lease payments) for 2019 and 2020. Therefore, approximately 1% of the reduction in cost is attributed to the reclassification of land costs. The final 20% (fixed-tilt) and 25% (one-axis tracker) is attributable to other soft costs, including PII, sales tax, overhead, and net profit. From 2019 to 2020, overall, there was a 1% reduction in the cost benchmarks for both utility-scale PV systems (fixed-tilt and one-axis tracking).

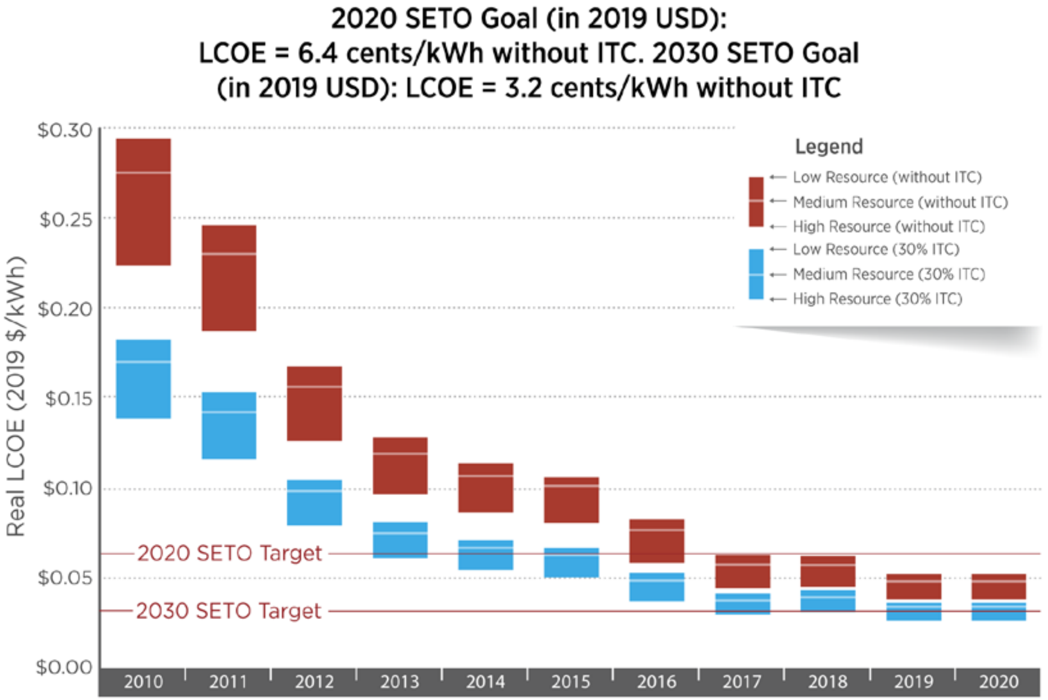
* The current version of our cost model makes a few significant changes from the version used in our Q1 2018 benchmark report (Fu, Feldman, and Margolis 2018) and incorporates costs that had previously not been benchmarked in as much detail. To better distinguish the historical cost trends from the changes to our cost models, we calculate Q1 2019 and Q1 2020 PV benchmarks using the Q1 2018 versions of the utility-scale PV model. The "Additional Costs from Model Updates" category represents the difference between modeled results. Using the previous costs model, the Q1 2019 and Q1 2020 benchmarks are calculated to be $0.94/W_{DC}$ and $0.89/W_{DC}$ (fixed-tilt) as well as $1.01/W_{DC}$ and $0.96/W_{DC}$ (one-axis) respectively.

Utility-Scale PV: LCOE Assumptions

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
One-Axis Tracker											
Installed cost ($/W)	5.66	4.79	3.29	2.50	2.25	2.08	1.63	1.16	1.16	1.02	1.01
Annual degradation (%)	1.00	0.95	0.90	0.85	0.80	0.75	0.75	0.75	0.70	0.70	0.70
O&M expenses ($/kW-yr)	29	28	26	25	24	22	22	21	15	17	17
Preinverter derate (%)	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5
Inverter efficiency (%)	96.0	96.4	96.8	97.2	97.6	98.0	98.0	98.0	98.0	98.0	98.0
Inverter loading ratio	1.10	1.12	1.13	1.15	1.17	1.18	1.20	1.30	1.30	1.34	1.34
Fixed-Tilt											
Installed cost ($/W)	4.75	4.08	2.77	2.13	1.97	1.93	1.53	1.08	1.08	0.95	0.94
Annual degradation (%)	1.00	0.95	0.90	0.85	0.80	0.75	0.75	0.75	0.70	0.70	0.70
O&M expenses ($/kW-yr)	29	27	25	23	21	19	19	18	13	16	16
Preinverter derate (%)	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5	90.5
Inverter efficiency (%)	96.0	96.4	96.8	97.2	97.6	98.0	98.0	98.0	98.0	98.0	98.0
Inverter loading ratio	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.30	1.36	1.37	1.37
Financing Assumptions											
Inflation rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Market Case											
Equity discount rate (real) (%)	7.4	7.2	7.0	6.9	6.7	6.5	6.3	6.3	6.3	5.1	5.1
Debt interest rate (%)	5.5	5.3	5.2	5.0	4.8	4.7	4.5	4.5	4.5	4.0	4.0
Debt fraction (%)	34.2	35.2	36.1	37.1	38.1	39.0	40.0	40.0	40.0	51.9	51.9
Steady-State Financing											
Equity discount rate (real) (%)	—	—	—	—	—	—	—	—	—	—	5.1
Debt interest rate (%)	—	—	—	—	—	—	—	—	—	—	5.0
Debt fraction (%)	—	—	—	—	—	—	—	—	—	—	71.8

All 2010–2018 data are from Fu, Feldman, and Margolis (2018), and they are adjusted for inflation. Utility-scale PV system LCOEs assume: (1) system lifetime of 30 years; (2) federal tax rate of 21%; (3) state tax rate of 6%; (4) MACRS depreciation schedule; (5) no state or local subsidies; (6) a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning interest of 1.75%); (7) six-month construction loan with an interest rate of 4% and a fee of 1% of the cost of the system; (8) system size of 100 MW; (9) debt with a term of 18 years; (10) $1.1 million of up-front financial transaction costs; (11) 2019 and 2020 financial assumptions from Feldman, Bolinger, and Schwabe (2020).

Utility-Scale PV: LCOE Benchmark Historical Trends

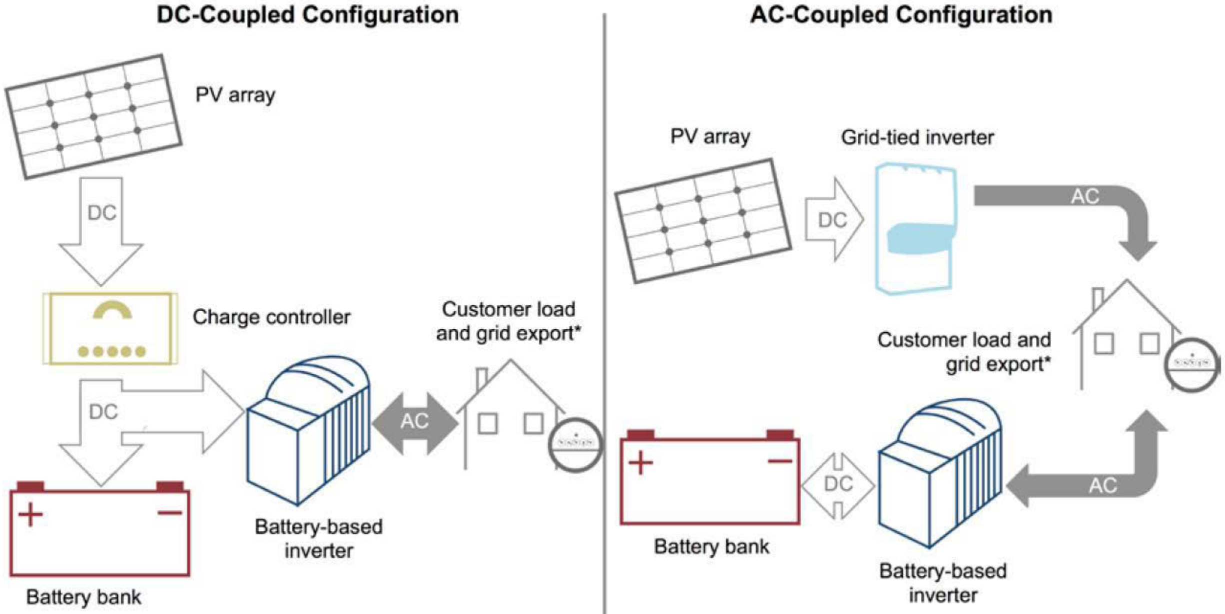


We use the fixed-tilt systems for LCOE benchmarks from 2010 to 2015 and then switch to one-axis tracking systems from 2016 to 2020 to reflect the market share change in the utility-scale PV sector. All detailed LCOE values can be found in the appendix.

From 2010 to 2020, utility-scale PV LCOE declined 83% (0% from 2019 to 2020), resulting in an unsubsidized LCOE of $0.04–$0.05/kWh ($0.025–$0.035/kWh when including the federal ITC). This reduction signifies the achievement of SETO's 2020 utility-scale PV goal. We also calculate PV LCOE without the ITC using steady-state financing assumptions. Under these assumptions, utility-scale (one-axis and fixed-tilt) PV LCOE ranges from $0.04 kWh to $0.05/kWh in Q1 2020.

Contents

Residential PV-Plus-Storage: System Configurations



*Grid-connected PV plus storage systems are used to first meet a customer's load and then export excess PV generation to the grid. When wired for back-up power, it is common to install a critical loads sub-panel and use PV plus storage systems to provide power to essential loads (e.g. refrigeration, essential lighting, well pumps) in the case of a grid-outage event.

Residential Storage-Only: Modeling Inputs and Assumptions

Category	Modeled Value	Description
System size	3-kW/6-kWh storage 5-kW/20-kWh storage	Less-resilient system More-resilient system
Battery pack cost	$253/kWh	Battery pack only
Battery-based inverter cost	$174/kWh	6-kW, 48-V bidirectional inverter (less resilient) 8-kW, 48-V bidirectional inverter (more resilient)
Electrical BOS cost	$1,830 (DC-coupled) $1,520 (AC-coupled) Assumes higher electrical BOS costs for DC-coupled systems that are due to the need for a charge controller	Revenue-grade meter, communications device, AC main panel, DC disconnect, maximum power point tracking, charge controller, subpanel (breaker box) for critical load, conduit, wiring, DC cable
Supply-chain costs	5% of cost of equipment	Includes costs of inventory, shipping, and handling of equipment
Sales tax	5.1% (national average)	Sales tax on the equipment
Installation labor cost	Electrician: $27.47 per hour Laborer: $18.17 per hour AC systems require more hours of work to integrate with an existing inverter and monitoring system	Assumes national average pricing
Engineering fee	$99	Engineering design and professional engineer-stamped calculations and drawings
PII	$297 permit fee $594–$951 in labor	20–32 hours (DC-coupled/AC-coupled) of commissioning and interconnection labor, and permit fee
Sales and marketing (customer acquisition)	$0.61/$W_{DC}$	20 hours more time for DC system, and 32 hours more for AC system, per closed sale, associated with selling a storage systems versus selling a PV system
Overhead (general and administrative)	$0.28/$W_{DC}$	Rent, building, equipment, staff expenses not directly tied to PII, customer acquisition, or direct installation labor
Profit (%)	17%	Fixed percentage margin applied to all direct costs including hardware, installation labor, direct sales and marketing, design, installation, and permitting fees

Residential Storage-Only: Model Outputs

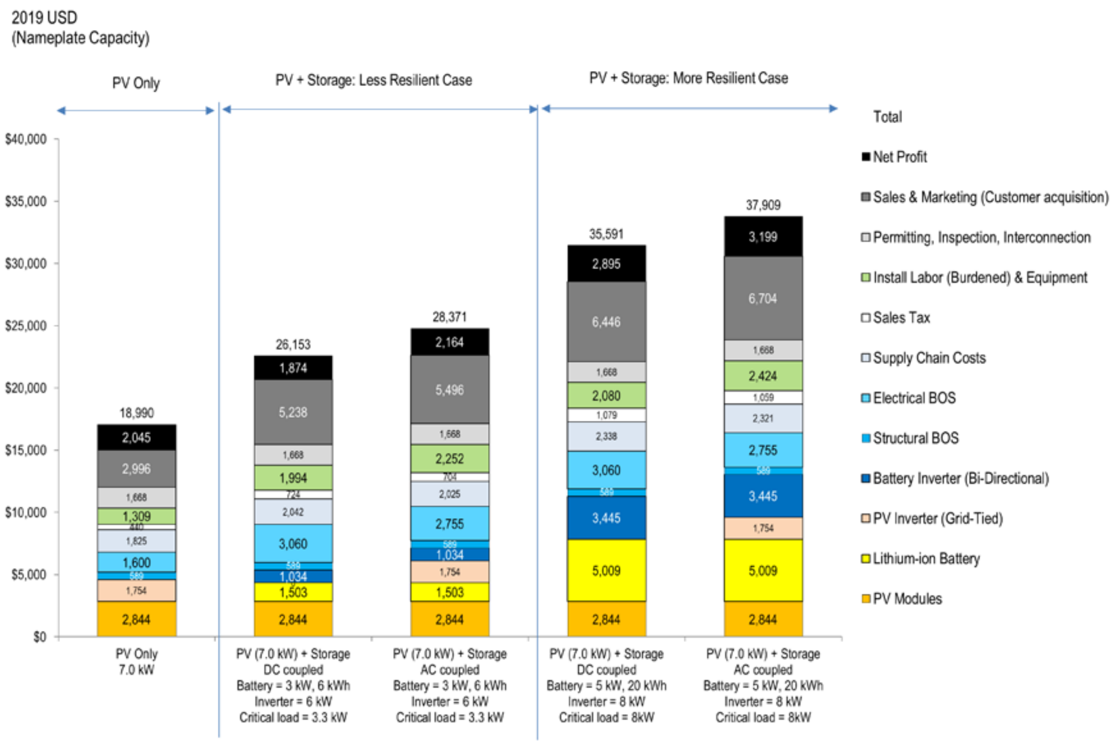
Q1 2020 U.S. benchmark: Residential storage-only system cost (2019 USD/W_{DC})

As demonstrated above, the kit for a 3-kW/6-kWh storage system costs approximately $4,200–$4,600, with a total installed cost of $11,823 (DC-coupled) to $12,287 (AC-coupled). The kit for a 5-kW/20-kWh storage system costs approximately $10,400–$10,800, with a total installed cost of $21,471 (DC-coupled) to $22,041 (AC-coupled).

Changes to Residential PV and Storage Models When They Are Combined

Category	Modeled Value	Description
Electrical BOS	90% of the combined BOS costs for PV and battery stand-alone systems	Duplicative parts are removed.
Installation labor	90% of the combined BOS costs for PV and battery stand-alone systems	Duplicative work is removed.
Sales and marketing	20 hours more time for DC system, and 32 hours more for AC system, per closed sale, associated with selling a PV system with storage	Additional explanation, calculations, and a lower close rate, and the AC system requires more customer site assessment.

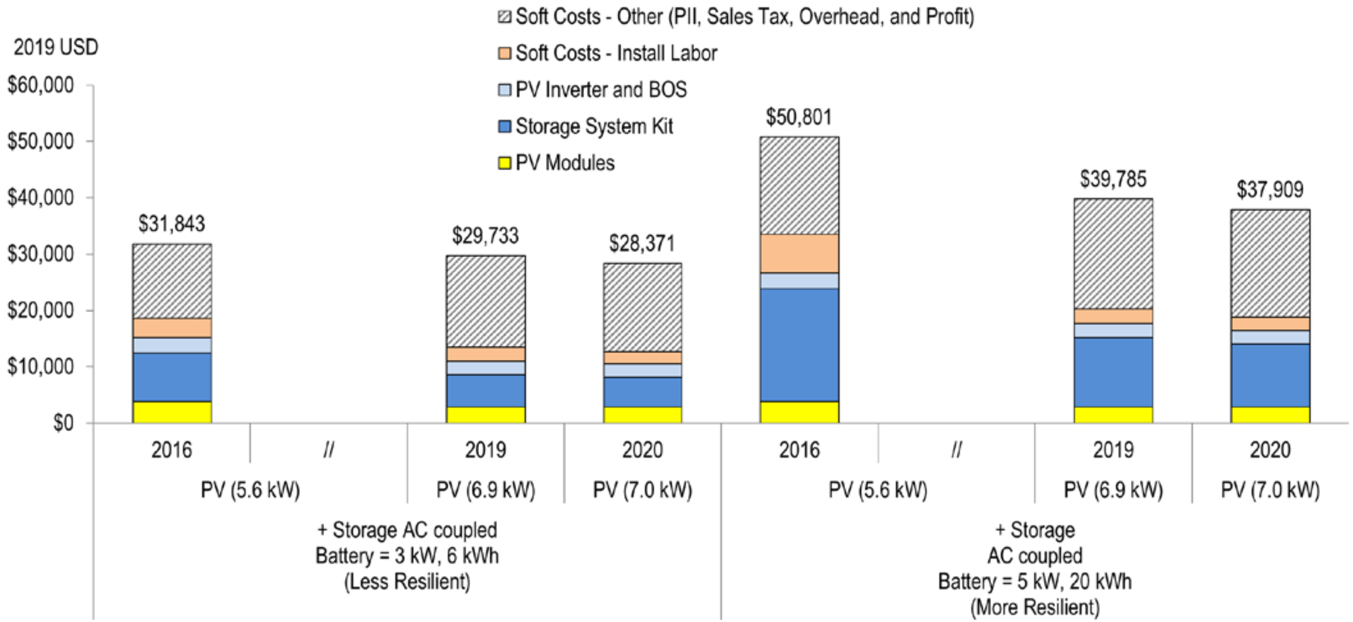
Residential PV-Plus-Storage: Model Outputs



Q1 2020 U.S. benchmark: Residential PV-plus-storage system cost (2019 USD/W_{DC})

With DC-coupling, the price of the more-resilient system is $35,591, which is $9,438 (36%) more than the price of the DC-coupled less-resilient system. With AC-coupling, the price of the more-resilient battery system is $37,909, which is $9,538 (34%) more than the price of the DC-coupled less-resilient battery system. The premium is due to the more-resilient systems' higher battery, inverter, BOS, and labor costs plus indirect costs (profit, sales tax, and supply-chain costs).

Residential PV-Plus-Storage: Capital Cost Benchmark Historical Trends



From 2016 to 2020, there were 11% and 25% reductions in residential PV-plus-storage benchmarks, for the AC-coupled less-resilient and more-resilient cases respectively. The reduction is due to a 26% reduction in PV module costs, 38% and 44% reduction in costs associated with the storage system kit (including a bidirectional inverter), a 16% reduction in hardware BOS, and a 34% and 65% reduction in labor costs. These cost reductions are partially offset by 18% and 10% increases in other soft costs (including PII, sales tax, overhead, and net profit). Other soft costs increased between 2016 and 2020 because of a change in methodology and because the rated capacity of the 22-module system increased from 5.6 kW to 7.0 kW between 2016 and 2020. From 2019 to 2020, the residential PV-plus-storage system cost benchmarks decreased by 5%, mostly owing to lower storage system kit prices.

Residential PV-Plus-Storage: LCOSS Assumptions

Model Component	Model Input	Description
System size	7-kW PV plus 3-kW/6-kWh storage system	
Initial investment	$28,371	2020 residential PV-plus-storage benchmark, AC-coupled
First follow-on investments (inverter, battery replacements)	$240 in year 10	20% of the batteries are replaced after 10 years due to battery capacity dropping 20%. We assume costs for battery and bidirectional inverters drop 20% in the next 10 years.
Second follow-on investments (inverter, battery replacements)	$180 in year 20	20% of the batteries are replaced after 20 years due to battery capacity dropping 20%. We assume costs for battery and bidirectional inverters drop 40% in the next 20 years.
Real discount rate	3.1%	Consistent with LCOE formula
Tax rate	25.7%	21% federal, 6% state
Residual value	$0	
Initial annual PV system production	High resource: 1,892 MWh/MW Medium resource: 1,546 MWh/MW Low resource: 1,440 MWh/MW	
Percentage of generated solar electricity fed to battery	High resource: 25% Medium resource: 31% Low resource: 33%	Assumes a 75% discharge per day for a 2-hour, 3-kW battery
Roundtrip energy losses from PV/battery/grid	10%	
Roundtrip energy losses from grid/battery/grid	8%	
Charging cost	$0	Battery charged solely by PV due to ITC considerations
O&M ($/kW/yr)	$39	Assumes storage O&M adds $10/kW-yr to PV costs
Annual PV degradation	0.70%	
Annual electricity purchased from grid	0	
System lifetime	30 years	
Inflation	2.5%	

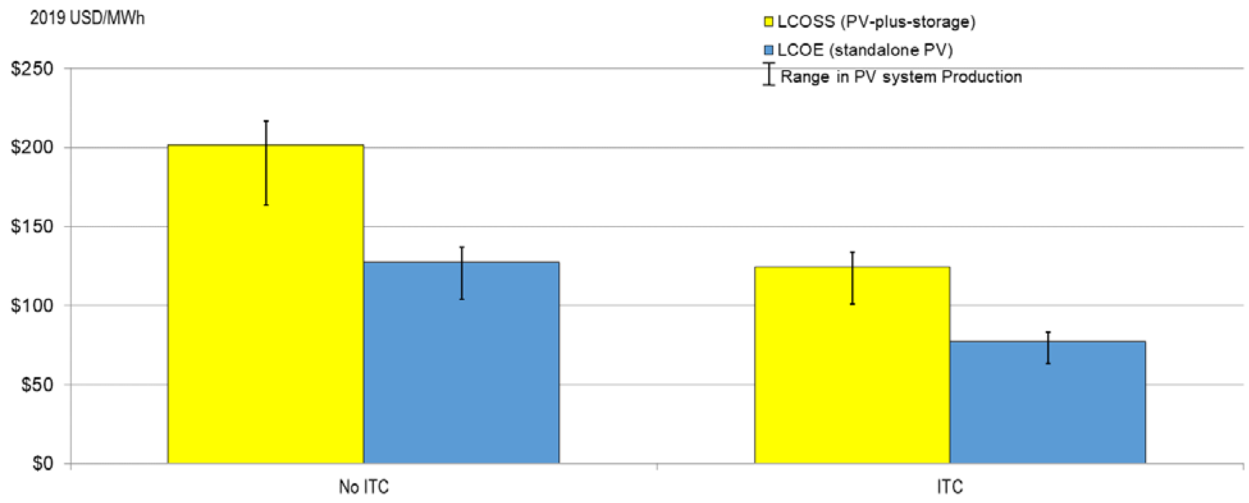
For the Q1 2020 benchmark report, we derive a formula for the levelized cost of solar-plus-storage (LCOSS) to contextualize our up-front PV-plus-storage system benchmarks and better represent the total cost of operating a PV-plus-storage system, on a per-kWh basis. Similar to LCOE, LCOSS does not focus on value but rather can help track improvements to all costs associated with residential PV-plus-storage systems over time (as opposed to just up-front costs), and the metric can provide limited comparisons with other dispatchable electricity generation technologies (e.g., PV-plus-generator systems).

LCOSS Formula

$$LCOSS = \frac{E + \frac{F^n}{(1+R)^n} - \sum_{n-1}^{N} \frac{(D+DF)^n}{(1+Rn)^n} \times (T) + \sum_{n-1}^{N} \frac{(O+C+I)^n}{(1+Rn)^n} \times (1-T) - \frac{Rv^n}{(1+R)^n} \times (1-T) + \sum_{n-1}^{N} \frac{(P)^n}{(1+Rn)^n} \times (1-T)}{\left(\sum_{n-1}^{N} \frac{P \times (1-Dr)^n}{(1+R)^n} \times (1-B) + \sum_{n-1}^{N} \frac{P \times (1-Dr)^n}{(1+R)^n} \times (B) \times (1-Lp) + \sum_{n-1}^{N} \frac{G}{(1+R)^n} \times (1-Lg) \right) \times (1-\mathrm{T})}$$

E = Initial equity investment of solar and storage
I = Debt interest payments
P = Debt principal payments
C = Charging cost
F = Follow-on investments (inverter, battery replacements)
D = Depreciation of solar and storage (which may include depreciation from follow-on investments)
R = Real discount rate
Rn = Nominal discount rate
T = Tax rate
O = O&M
Dr = Degradation of PV
Rv = Residual value
P = Initial annual system production
B = Percentage of generated solar electricity fed to battery
Lp = Roundtrip energy losses from PV-storage-grid
Lg = Roundtrip energy losses from grid-storage-grid
G = Annual electricity purchased from grid

Residential PV-Plus-Storage: LCOSS Benchmark Results



The figure above shows the LCOSS for a residential AC-coupled PV (7 kW) plus-storage (3 kW/6 kWh, 2-hour duration) system, as well as the LCOE of a 7-kW stand-alone PV system. LCOSS is calculated to be $201/MWh without the federal ITC and $124/MWh with the 30% ITC for the PV-plus-storage system, with a medium resource for PV electricity production. The PV-plus-storage LCOSS is $74/MWh higher than the stand-alone-PV LCOE without the ITC, and $47/MWh higher with a 30% ITC.

Contents

Commercial PV-Plus-Storage: Li-ion Battery Energy Storage Components

Battery cells → modules → packs → racking system (DC)

↓

Storage container
(HVAC system, thermal management, monitors and controls, fire suppression, switchgear, and energy management system)

↓

Power conversion system
(bidirectional inverter to convert AC to DC for battery charging and DC to AC for discharging)

↓

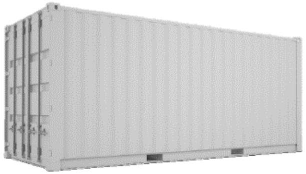
Transformer (to step up 480-V inverter output to 12–66 kV)

Commercial PV-Plus-Storage: System Components

Battery Cell

Battery Module

Battery Racks



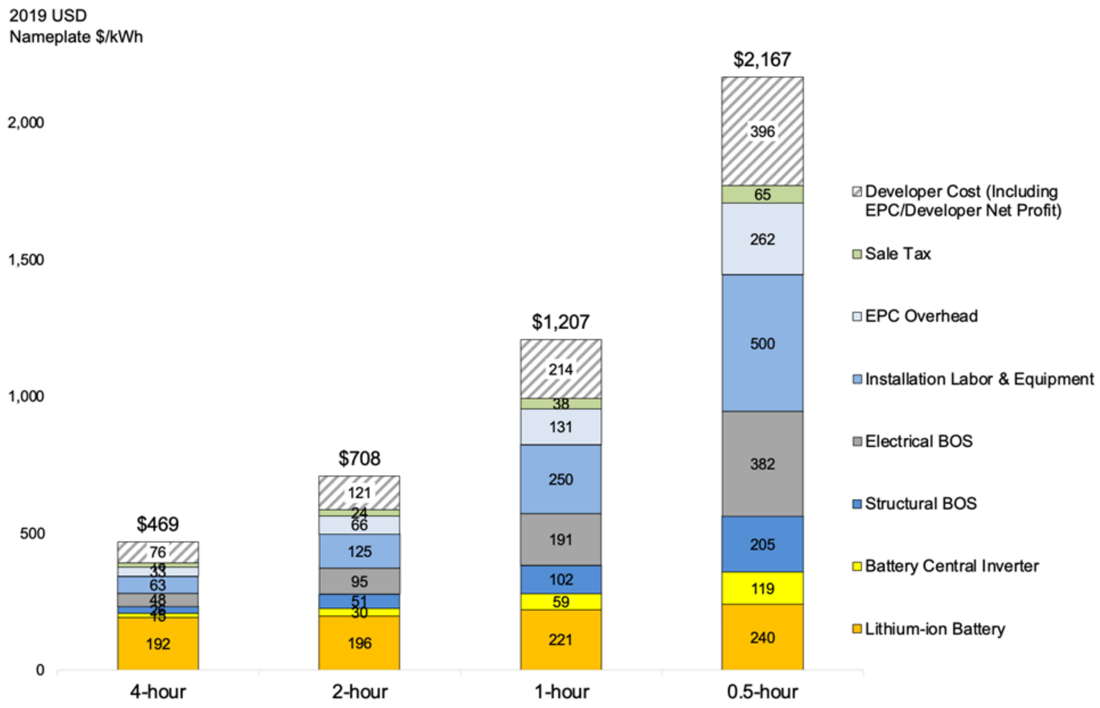
Battery Container

Commercial Storage-Only: Modeling Inputs and Assumptions

Model Component	Modeled Value	Description	Sources
Battery total size	600 kW_{DC}	Baseline case to match a 1-MW PV system	NREL 2020
Battery size per container	2.4 MWh per 40-ft container	1 container	NREL 2020
Li-ion battery price	0.5 hours: $242/kWh 1 hour: $223/kWh 2 hours: $198/kWh 4 hours: $194/kWh	Ex-factory gate (first buyer) prices	BNEF 2019b
Duration	0.5–4.0 hours	Duration determines energy (MWh)	NREL 2020
Battery central inverter price	$0.06/W	Ex-factory gate (first buyer) prices	Wood Mackenzie 2019
Electrical BOS	$0.19/W	Includes conduit, wiring, DC cable, energy management system, switchgear, transformer, and monitor and controls for each container. Costs impacted by the number of containers, transformers, and row spacing	NREL 2020
Structural BOS	$0.10/W	Includes foundation, battery containers, and inverter house. Costs impacted by the number of containers, inverters, transformers, and the spacing between containers	NREL 2020
Installation labor	Electrician: $27.47 per hour Laborer: $18.17 per hour	National average modeled labor rate assumes nonunionized labor	BLS 2019
Sales tax	5% (national average)	Sales tax on the equipment	RSMeans 2017
EPC overhead and profit	8.67% for equipment and material; 23%–69% for labor costs; varies by system size, labor activity, and location	Costs associated with EPC SG&A, warehousing, shipping, and logistics	NREL 2020
Developer cost: developer overhead	6% of total installation cost	Includes overhead expenses such as payroll, facilities, travel, legal fees, administrative, business development, finance, and other corporate functions	NREL 2020
Developer cost: PII	$0.06/W	Construction permits fee, interconnection study, interconnection inspection, and interconnection fee	NREL 2020
Developer cost: contingency	4%	Estimated as markup on the total EPC cost	NREL 2020
Developer cost: EPC/developer net profit	5%	Applies a percentage margin to all costs including hardware, installation labor, EPC overhead, and developer overhead	NREL 2020

We determine the battery size (600 kW_{DC}) using an inverter loading ratio of 1.3 and an inverter/storage size ratio of 1.67, based on Denholm, Eichman, and Margolis (2017).

Commercial Storage-Only: Model Outputs



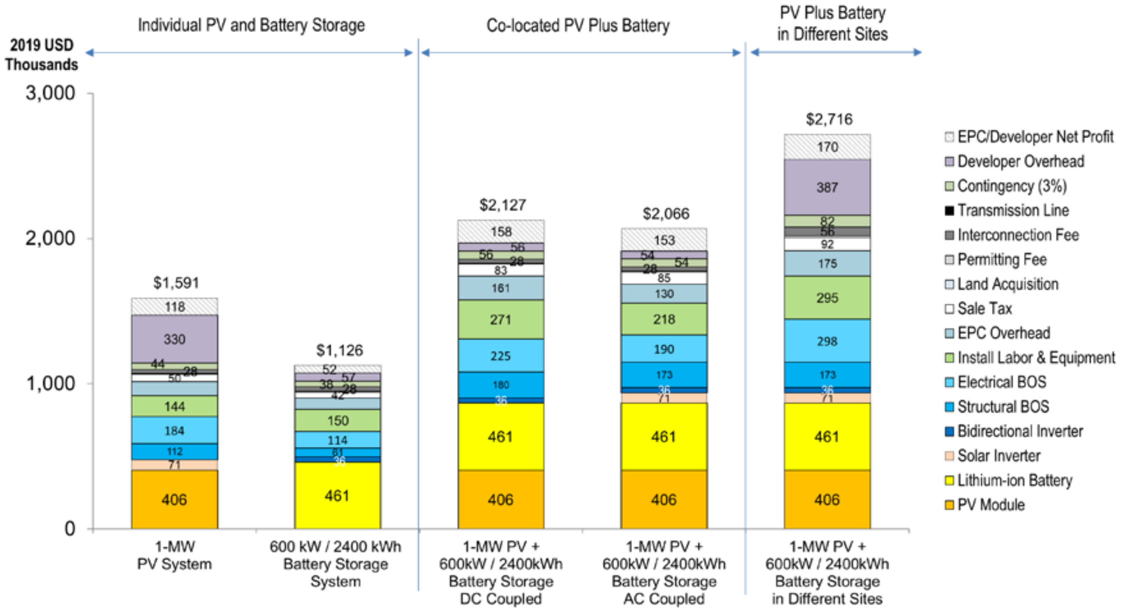
Q1 2020 U.S. benchmark: Commercial storage-only system cost (2019 USD/W_{DC})

The modeled $/kWh costs for 600-kW Li-ion energy storage systems vary from $469/kWh (4-hour duration) to $2,167/kWh (0.5-hour duration). The battery cost accounts for 41% of total system cost in the 4-hour system, but only 11% in the 0.5-hour system. At the same time, nonbattery cost categories account for an increasing proportion of the system cost as duration declines.

Changes to Commercial PV and Storage Models When They Are Combined

Category	Modeled Value	Description
Electrical BOS	90% of the combined BOS costs for PV and battery stand-alone systems	Duplicative parts are removed
Installation labor	90% of the combined BOS costs for PV and battery stand-alone systems	Duplicative work is removed
Sales and marketing	20 hours more time for DC system, and 32 hours more for AC system, per closed sale, associated with selling a PV system with storage	Additional explanation, calculations, and a lower close rate; also, the AC system requires more customer site assessment

Commercial PV-Plus-Storage: Model Outputs



Q1 2020 U.S. benchmark: Commercial PV-plus-storage system cost (2019 USD/W_{DC})

Colocating the PV and storage subsystems produces cost savings by reducing costs related to site preparation, permitting, interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit. The cost of the colocated AC-coupled system is 24% lower than the cost of the system with PV and storage sited separately.

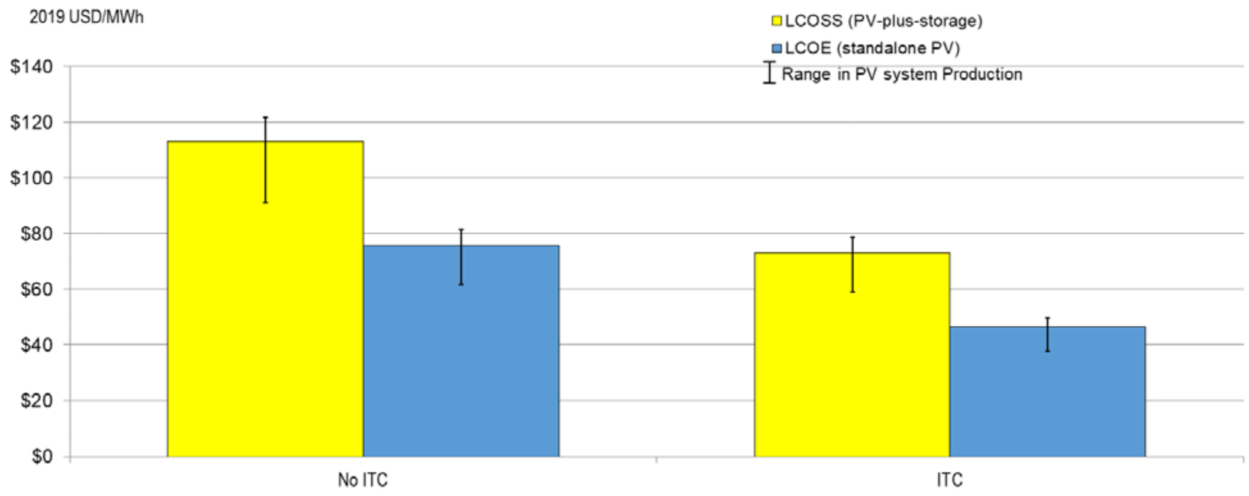
Using DC-coupling rather than AC-coupling results in a 2.8% higher total cost, which is the net result of cost differences between DC-coupling and AC-coupling in the categories of solar inverter, structural BOS, electrical BOS, labor, EPC and developer overhead, sales tax, contingency, and profit. For an actual project, however, cost savings may not be the only factor in choosing DC- or AC-coupling. Additional factors—such as retrofit considerations, system performance (including energy loss due to clipping), design flexibility, and O&M—should be considered.

Commercial PV-Plus-Storage: LCOSS Assumptions

Model Component	Model Input	Description
System size	1-MW fixed-tilt ground-mounted PV plus 600-kW/2.4-MWh storage system	
Initial investment	$2,066,408	2020 commercial PV-plus-storage benchmark, AC-coupled
First follow-on investments (inverter, battery replacements)	$73,747 in year 10	20% of the batteries are replaced after 10 years due to battery capacity dropping 20%. We assume costs for battery and bidirectional inverters drop 20% in the next 10 years.
Second follow-on investments (inverter, battery replacements)	$55,310 in year 20	20% of the batteries are replaced after 20 years due to battery capacity dropping 20%. We assume costs for battery and bidirectional inverters drop 40% in the next 20 years.
Real discount rate	3.1%	Consistent with LCOE formula
Tax rate	25.7%	21% federal, 6% state
Residual value	$0	
Initial annual system production	High resource area: 1,894 MWh/MW Medium resource area: 1,541 MWh/MW Low resource area: 1,438 MWh/MW	
Percentage of generated solar electricity fed to battery	High resource area: 35% Medium resource area: 43% Low resource area: 46%	Assumes a 75% discharge per day for a 4-hour, 600-kW battery
Roundtrip energy losses from PV/battery/grid	10%	
Roundtrip energy losses from grid/battery/grid	8%	
Charging cost	$0	Battery is charged solely by PV due to ITC considerations
O&M ($/kW/yr)	$29	Assumes storage O&M adds $10/kW-yr to PV costs
Annual PV degradation	0.70%	
Annual electricity purchased from grid	0	
System lifetime	30 years	
Inflation	2.5%	

For the Q1 2020 benchmark report, we calculate the LCOSS for our commercial PV-plus-storage system with the same formula and caveats we use for our residential PV-plus-storage system.

Commercial PV-Plus-Storage: LCOSS Benchmark Results



The figure above shows the resulting LCOSS for a commercial AC-coupled fixed-tilt ground-mounted PV (1 MW) plus storage (600 kW/2.4 MWh, 4-hour duration) system, as well as the LCOE of a 1-MW fixed-tilt ground-mounted stand-alone PV system. LCOSS is calculated to be $113/MWh without the federal ITC and $73/MWh with the 30% ITC for commercial PV-plus-storage, with a medium resource for PV electricity production. The PV-plus-storage LCOSS is $37/MWh higher than the stand-alone-PV LCOE without the ITC, and $27/MWh higher with a 30% ITC.

Contents

Utility-Scale PV-Plus-Storage: Li-ion Battery Energy Storage Components

Battery cells → modules → packs → racking system (DC)

Storage container
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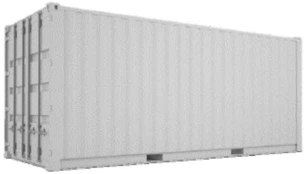
Utility-Scale PV-Plus-Storage: System Components

Battery Cell

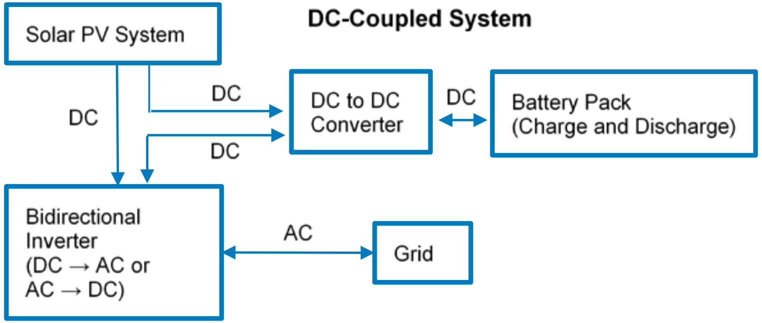
Battery Module

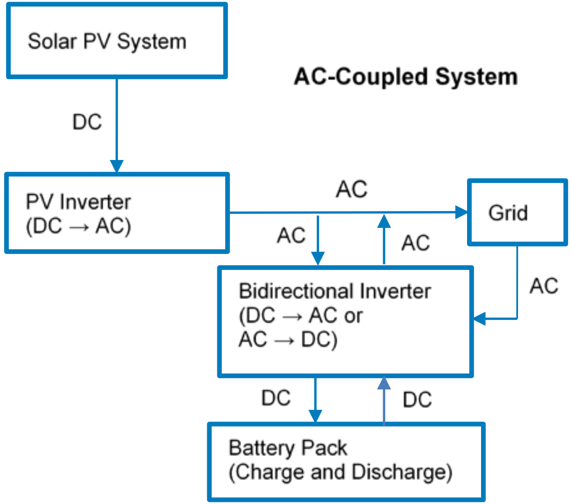
Battery Racks



Battery Container

Utility-Scale PV-Plus-Storage: System Configurations



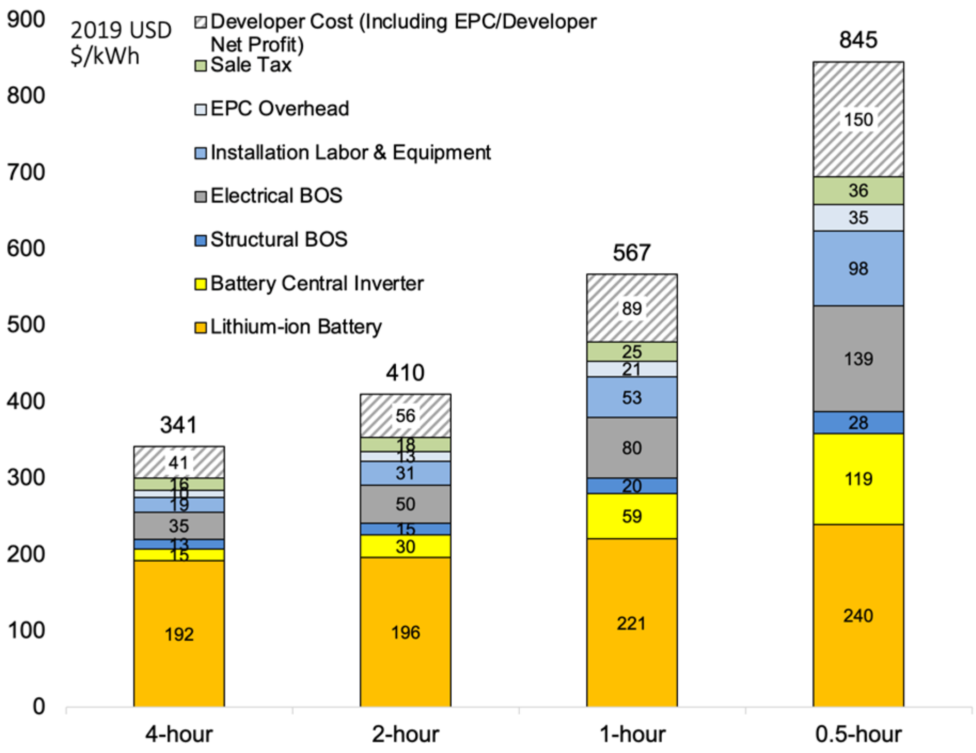


Utility-Scale Storage-Only: Modeling Inputs and Assumptions

Model Component	Modeled Value	Description	Source
Battery total size	60 MW_{DC}	Baseline case to match a 100-MW PV system	NREL 2020
Battery size per container	2.5 MWh per 40-ft container	Assumption to compute the number of containers	NREL 2020
Li-ion battery price	0.5 hours: $242/kWh 1 hour: $223/kWh 2 hours: $198/kWh 4 hours: $194/kWh	Ex-factory gate (first buyer) prices	BNEF 2019b
Duration	0.5–4.0 hours	Duration determines energy (MWh)	NREL 2020
Battery central inverter price	$0.06/W	Ex-factory gate (first buyer) prices	Wood Mackenzie 2019
Inverter size	2.5 MW per inverter	Used to determine the number of battery inverters	NREL 2020
Electrical BOS	$0.07–$0.14/W	Includes conduit, wiring, DC cable, energy management system, switchgear, transformer, and monitor and controls for each container. Determined by the number of containers, transformers, and row spacing.	NREL 2020
Structural BOS	$0.01–$0.05/W	Includes foundation, battery containers, and inverter house. Determined by the number of containers, inverters, transformers, and the spacing between containers.	NREL 2020
Installation labor	Electrician: $27.47 per hour Laborer: $18.17 per hour	National average modeled labor rate assumes nonunionized labor	BLS 2019
Sales tax	5% (national average)	Sales tax on the equipment	RSMeans 2017
EPC overhead and profit	8.67% for equipment and material; 23%–69% for labor costs; varies by system size, and labor activity	Costs associated with EPC SG&A, warehousing, shipping, and logistics	NREL 2020
Developer cost: developer overhead	3% of total installation cost	Includes overhead expenses such as payroll, facilities, travel, legal fees, administrative, business development, finance, and other corporate functions	NREL 2020
Developer cost: PII	$0.03/W	Construction permits fee, interconnection study, interconnection inspection, and interconnection fee	NREL (2020
Developer cost: contingency	3%	Estimated as markup on the total EPC cost	NREL 2020)
Developer cost: EPC/developer net profit	5%	Applies a percentage margin to all costs including hardware, installation labor, EPC overhead, and developer overhead	NREL 2020

We determine the battery size (60 MW_{DC}) using an inverter loading ratio of 1.3 and an inverter/storage size ratio of 1.67, based on Denholm, Eichman, and Margolis (2017).

Utility-Scale Storage-Only: Model Outputs



Q1 2020 U.S. benchmark: Utility-scale storage-only system cost (2019 USD/W_{DC})

The modeled $/kWh costs for 60-MW Li-ion energy storage systems, which vary from $341/kWh (4-hour duration) to $845/kWh (0.5-hour duration). While the per-energy-unit battery cost increases as system duration decreases, the total battery cost—and the proportion of the cost attributed to the battery—decrease as system duration decreases. For example, the battery cost accounts for 56% of total system cost in the 4-hour system but only 28% in the 0.5-hour system. At the same time, nonbattery cost categories account for an increasing proportion of the system cost as duration declines.

Cost Factors for Siting PV and Storage Together versus Separately

Model Component	Colocated PV-Plus-Storage	PV-Plus-Storage at Different Sites
Site preparation[a]	Once	Twice
Land acquisition cost	Lower	Higher
Hardware sharing between PV and energy storage	Yes (step-up transformer, switchgear, monitor, and controls)	No
Installation labor cost	Lower (due to hardware sharing and single labor mobilization)	Higher
EPC/developer overhead and profit	Lower (due to lower labor cost, BOS, and total system cost)	Higher
Interconnection and permitting	Once	Twice

[a] Site preparation is a subcategory of labor cost, so it is not shown in the cost breakdown chart.

Comparison of DC- and AC-Coupling for Utility-Scale PV-Plus-Storage Systems

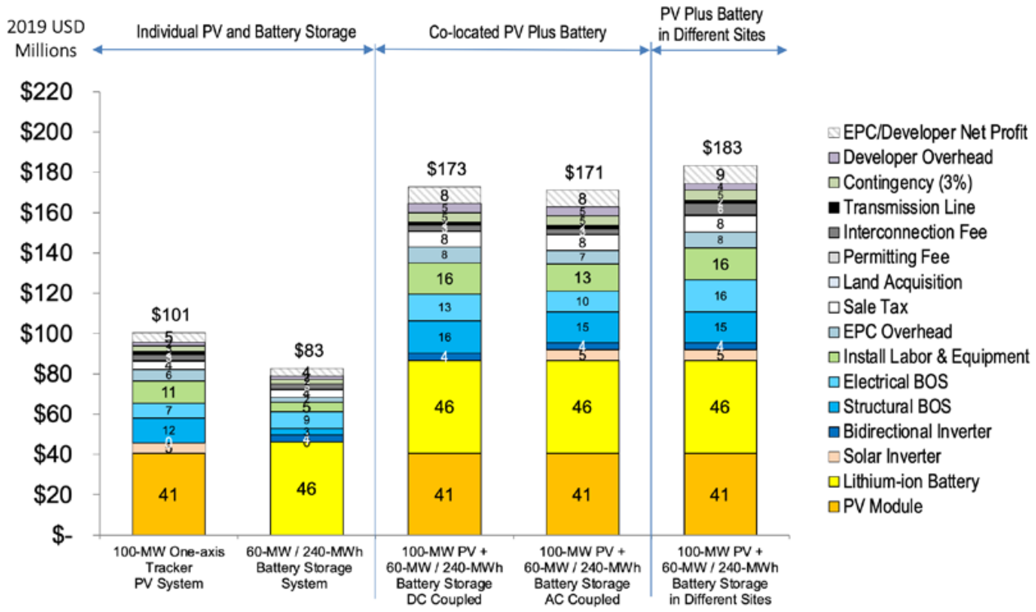
Model Component	DC-Coupled Configuration	AC-Coupled Configuration
Number of inverters	1 (bidirectional inverter for battery)	2 (bidirectional inverter for battery plus grid-tied inverter for PV), resulting in higher costs for the inverter, inverter wiring, and inverter housing
Battery rack size	Smaller (because battery is directly connected to PV),[a] resulting in more HVAC and fire-suppression systems required	Larger
Structural BOS	More (due to smaller battery rack size)	Less
Electrical BOS	Less (but needs additional DC-to-DC converters)	More (due to additional wiring for inverters)
Installation labor cost	More (due to smaller battery rack size and more skilled labor and labor hours required for DC work)	Less
EPC overhead	More (due to higher installation labor cost)	Less
Sales tax	Less	More (due to higher total hardware costs)
EPC/developer profit	Less	More (due to higher total EPC and developer costs)

[a] Because a PV system is not directly connected to a battery in an AC-coupled configuration, the battery racks are fewer and larger; this configuration is less costly than a DC-coupled system in which multiple distributed battery racks are deployed and managed. For example, using five smaller battery racks rather than one large rack requires five fire-suppression systems and five air conditioning systems.

Advantages of the AC-Coupled System

1. Because the battery racks are not directly connected to the PV system in AC-coupled systems, these systems can use larger battery racks and thus reduce the number of HVAC and fire-suppression systems in the containers. This feature also reduces installation labor costs compared with DC-coupled systems.
2. For a retrofit (i.e., adding battery storage to an existing PV array), an AC-coupled battery may be more practical than a DC-coupled battery, because DC-coupled systems require installers to replace the existing PV inverter with a bidirectional inverter. Thus, the additional costs that are due to replacing the inverter and rewiring the system could make retrofit costs higher for a DC-coupled system than for an AC-coupled system (Ardani et al. 2017). In addition, AC-coupled systems enable the option of upgrading the PV and battery separately, because these systems are independent of one another.
3. Because AC-coupled systems have separate PV and battery systems, installers have more flexibility to adjust the battery location. For instance, DC-coupled systems require batteries to be installed next to the bidirectional inverter, and the resulting need for maintenance crews to enter the PV field can make maintenance more time consuming. Because AC-coupled systems can have batteries located outside the PV field, maintenance work can be quicker and easier.

Utility-Scale PV-Plus-Storage: Model Outputs

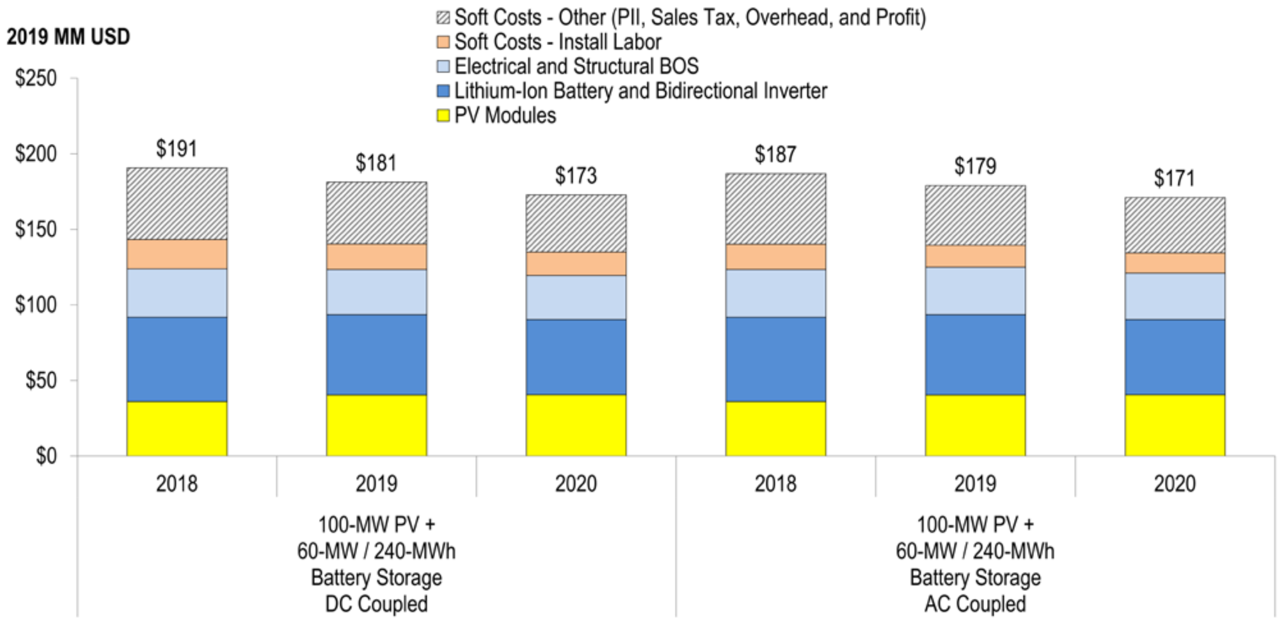


Q1 2020 U.S. benchmark: Utility-scale PV-plus-storage system cost (2019 USD/W_{DC})

Colocating the PV and storage subsystems produces cost savings by reducing costs related to site preparation, land acquisition, permitting, interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit. The cost of the colocated AC-coupled system is 7% lower than the cost of the system with PV and storage sited separately.

Using DC-coupling rather than AC-coupling results in a 1% higher total cost, which is the net result of cost differences between DC-coupling and AC-coupling in the categories of solar inverter, structural BOS, electrical BOS, labor, EPC and developer overhead, sales tax, contingency, and profit. For an actual project, however, cost savings may not be the only factor in choosing DC- or AC-coupling. Additional factors—such as retrofit considerations, system performance (including energy loss due to clipping), design flexibility, and O&M—should be considered.

Utility-Scale PV-Plus-Storage: Capital Cost Benchmark Historical Trends



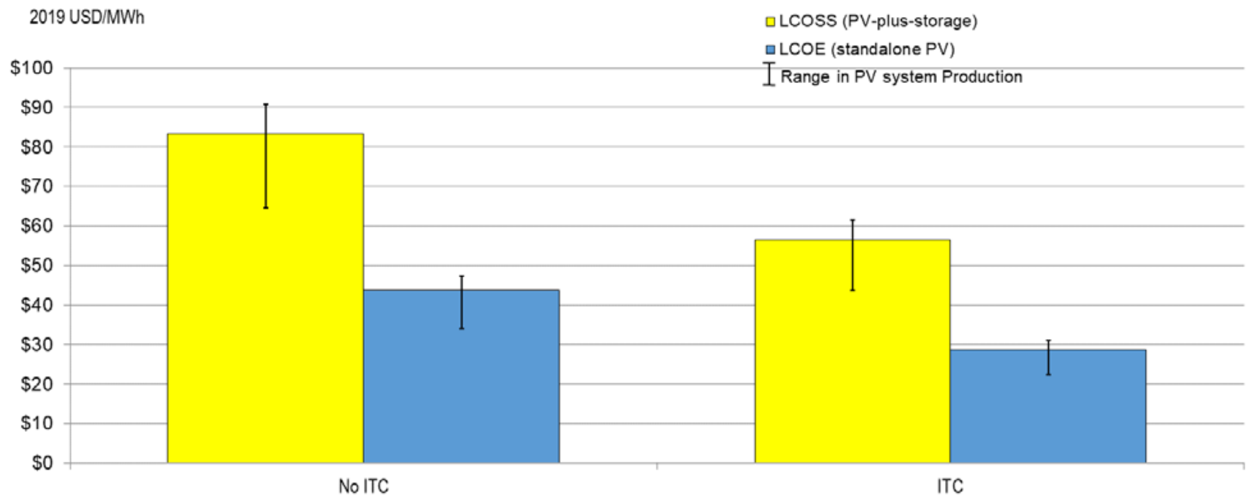
From 2018 to 2020, there were 9% and 8% reductions in utility-scale PV-plus-storage benchmarks for DC-coupled and AC-coupled systems respectively. For the DC-coupled system, approximately 28% of that reduction can be attributed to the Li-ion battery plus bidirectional inverter, while electrical and structural BOS decreased system cost by 13%; an additional 17% can be attributed to lower labor costs, and the final 42% is attributable to other soft costs, including PII, sales tax, overhead, and net profit. For the AC-coupled system, approximately 30% of the reduction can be attributed to the Li-ion battery plus bidirectional inverter, and 4% to electrical and structural BOS; an additional 16% can be attributed to lower labor costs, and the final 49% is attributable to other soft costs, including PII, sales tax, overhead, and net profit.

Utility-Scale PV-Plus-Storage: LCOSS Assumptions

Model Component	Model Input	Description
System size	100-MW PV plus 60-MW/240-MWh battery storage, AC-coupled	
Initial investment	$171 million	2019 utility-scale PV-plus-storage benchmark, AC-coupled
First follow-on investments (inverter, battery replacements)	$7.4 million in year 10	20% of batteries replaced after 10 years due to battery capacity dropping 20%. We assume costs for battery and bidirectional inverters drop 20% in the next 10 years.
Second follow-on investments (inverter, battery replacements)	$5.5 million in year 20	20% of batteries replaced after 20 years due to battery capacity dropping 20%. We assume costs for battery and bidirectional inverters drop 40% in the next 20 years.
Real discount rate	2.7%	Consistent with LCOE formula
Tax rate	25.7%	21% federal, 6% state
Residual value	$0	
Initial annual system production	High resource area: 2,185 MWh/MW Medium resource area: 1,707 MWh/MW Low resource area: 1,572 MWh/MW	
Percentage of generated solar electricity fed to battery	High resource area: 30% Medium resource area: 39% Low resource area: 42%	Assumes a 75% discharge per day for a 4-hour, 60-MW battery
Roundtrip energy losses from PV/battery/grid	10%	
Roundtrip energy losses from grid/battery/grid	8%	
Charging cost	$0	Battery is charged solely by PV due to ITC considerations
O&M ($/kW/yr)	$27	Assumes storage O&M adds $10/kW-yr to PV costs
PV Degradation	0.70%	
Annual electricity purchased from grid	0	
System lifetime	30 years	
Inflation	2.5%	

For the Q1 2020 benchmark report, we calculate the LCOSS for our utility-scale PV-plus-storage system, with the same formula and caveats we use for our residential PV-plus-storage system. Similar to LCOE, LCOSS does not focus on value but rather can help track improvements to all costs of a utility-scale PV-plus-storage system over time (as opposed to just up-front costs), and the metric can provide limited comparisons with other dispatchable electricity generation technologies (e.g., natural gas).

Utility-Scale PV-Plus-Storage: LCOSS Benchmark Results



The figure above shows the resulting LCOSS for a colocated AC-coupled PV (100 MW) plus storage (60 MW/240 MWh, 4-hour duration) system, as well as the LCOE of a 100-MW PV-stand-alone system, with one-axis tracking. LCOSS is calculated to be $83/MWh without the federal ITC and $57/MWh with the 30% ITC, with a medium resource for PV electricity production. Based on these calculations, PV-plus-storage LCOSS is $40/MWh higher than stand-alone-PV LCOE without the ITC, and $28/MWh higher with a 30% ITC.

Bolinger, Seel, and Robson (2019) reported a storage premium of $10–$15/MWh for PPAs with a 30% ITC, for systems that have a 4-hour battery sized to 50%–75% of the PV capacity.

Contents

Conclusions

Based on our bottom-up modeling, the Q1 2020 cost benchmarks are:

- $2.71/$W_{DC}$ (or $3.12/$W_{AC}$) for residential PV systems
- $1.72/$W_{DC}$ (or $1.96/$W_{AC}$) for commercial rooftop PV systems
- $1.72/$W_{DC}$ (or $1.91/$W_{AC}$) for commercial ground-mounted PV systems
- $0.94/$W_{DC}$ (or $1.28/$W_{AC}$) for fixed-tilt utility-scale PV systems
- $1.01/$W_{DC}$ (or $1.35/$W_{AC}$) for one-axis-tracking utility-scale PV systems
- $26,153–$28,371 for a 7-kW residential PV system with 3 kW/6 kWh of storage and $35,591–$37,909 for a 7-kW residential PV system with 5 kW/20 kWh of storage]
- $2.07 million–$2.13 million for a 1-MW commercial ground-mounted PV system colocated with 600 kW/2.4 MWh of storage
- $171 million–$173 million for a 100-MW PV system colocated with 60 MW/240 MWh of storage. The dollar-per-watt total cost value is benchmarked as three significant figures, because the model inputs, such as module and inverter prices, use three significant figures.

From 2010 to 2020, there were 64%, 69%, and 82% reductions in the residential, commercial rooftop, and utility-scale (one-axis) PV system cost benchmark respectively. The inflation-adjusted system cost differences between Q1 2019 and Q1 2020 are a $0.06/$W_{DC}$ reduction for residential PV, a $0.04/$W_{DC}$ reduction for commercial rooftop PV, and a $0.01/$W_{DC}$ reduction for utility-scale PV.

BOS hardware cost reductions in Q1 2020 were counterbalanced by higher module costs, and soft costs remained relatively unchanged, year over year; this resulted in a steady percentage of soft costs as a percentage of total costs. The historical increase in soft cost proportion for residential and commercial PV systems indicates soft costs declined more slowly than did hardware costs over time; it does not indicate soft costs increased on an absolute basis.

More Information

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

- Download the full report: https://www.nrel.gov/docs/fy21osti/77324.pdf
- Download the data file: https://doi.org/10.7799/1762492

(2) Contact the authors:

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Appendix: PV System LCOE Benchmarks in 2018 USD

	Market Financing Rates											Steady-State Financing		
Reporting Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2020	2020 Goal	2030 Goal
Benchmark Date	Q4 2009	Q4 2010	Q4 2011	Q4 2012	Q4 2013	Q1 2015	Q1 2016	Q1 2017	Q120 18	Q1 2019	Q1 2020	Q1 2020		
Residential (6.9 kW)														
High resource (CF 21.6%), no ITC	41.6	35.0	24.1	20.2	16.9	15.0	13.8	12.9	12.0	11.2	11.0	10.5	—	—
Medium resource (CF 17.6%), no ITC	50.9	42.8	29.5	24.7	20.8	18.4	16.9	15.8	14.8	13.7	13.5	12.8	10.6	5.3
Low resource (CF 16.4%), no ITC	54.7	46.0	31.7	26.6	22.3	19.7	18.1	17.0	15.9	14.7	14.5	13.8	—	—
High resource (CF 21.6%), ITC	27.6	23.2	16.1	13.5	11.3	9.9	9.1	8.6	8.0	7.1	7.1	—	—	—
Medium resource (CF 17.6%), ITC	33.9	28.4	19.8	16.5	13.8	12.1	11.2	10.5	9.8	8.7	8.7	—	—	—
Low resource (CF 16.4%), ITC	36.4	30.5	21.2	17.7	14.8	13.0	12.0	11.3	10.5	9.4	9.3	—	—	—
Commercial Rooftop (200 kW)														
High resource (CF 20.4%), no ITC	32.0	28.5	19.2	15.2	14.3	11.5	10.7	9.2	8.9	7.9	7.7	7.3	—	—
Medium resource (CF 16.4%), no ITC	39.7	35.4	23.9	18.8	17.8	14.2	13.3	11.5	11.0	9.5	9.3	9.0	8.2	4.3
Low resource (CF 15.3%), no ITC	42.8	38.1	25.7	20.3	19.2	15.3	14.3	12.4	11.9	10.6	10.3	9.7	—	—
High resource (CF 20.4%), ITC	21.1	18.8	12.8	10.1	9.5	7.6	7.1	6.2	5.9	5.1	4.9	—	—	—
Medium resource (CF 16.4%), ITC	26.2	23.3	15.9	12.6	11.8	9.5	8.8	7.7	7.4	6.3	6.1	—	—	—
Low resource (CF 15.3%), ITC	28.2	25.1	17.1	13.5	12.7	10.2	9.5	8.3	7.9	6.8	6.6	—	—	—
Commercial Ground-Mounted (500 kW)														
High resource (CF 21.6%), no ITC	—	—	—	—	—	—	—	—	—	—	7.1	6.7	—	—
Medium resource (CF 17.6%), no ITC	—	—	—	—	—	—	—	—	—	—	8.7	8.2	—	—
Low resource (CF 16.4%), no ITC	—	—	—	—	—	—	—	—	—	—	9.3	8.8	—	—
High resource (CF 21.6%), ITC	—	—	—	—	—	—	—	—	—	—	4.5	—	—	—
Medium resource (CF 17.6%), ITC	—	—	—	—	—	—	—	—	—	—	5.6	—	—	—
Low resource (CF 16.4%), ITC	—	—	—	—	—	—	—	—	—	—	6.0	—	—	—
Utility-Scale (100 MW One-Axis Tracking)														
High resource (CF 25.2%), no ITC	22.5	18.6	12.7	9.6	8.5	7.6	6.0	4.6	4.4	3.7	3.7	3.6	—	—
Medium resource (CF 19.6%), no ITC	28.9	23.9	16.4	12.4	10.9	9.8	7.8	5.9	5.6	4.7	4.7	4.6	6.4	3.2
Low resource (CF 18.2%), no ITC	31.4	26.0	17.8	13.4	11.8	10.6	8.4	6.4	6.1	5.1	5.1	4.9	—	—
High resource (CF 25.2%), ITC	13.9	11.5	8.0	6.1	5.4	4.8	3.9	3.1	3.0	2.5	2.5	—	—	—
Medium resource (CF 19.6%), ITC	17.9	14.8	10.3	7.8	6.9	6.2	5.0	3.9	3.8	3.3	3.3	—	—	—
Low resource (CF 18.2%), ITC	19.4	16.1	11.1	8.5	7.5	6.7	5.4	4.3	4.2	3.5	3.5	—	—	—
Utility-Scale (100 MW Fixed-Tilt)														
High resource (CF 21.3%), no ITC	22.5	18.9	12.8	9.8	8.8	8.2	6.6	5.0	4.7	4.0	4.0	3.7	—	—
Medium resource (CF 17.3%), no ITC	27.7	23.2	15.7	12.0	10.8	10.1	8.1	6.1	5.8	4.9	4.9	4.6	—	—
Low resource (CF 16.2%), no ITC	29.6	24.8	16.9	12.9	11.5	10.8	8.7	6.5	6.2	5.2	5.2	4.9	—	—
High resource (CF 21.3%), ITC	14.0	11.7	8.1	6.2	5.6	5.2	4.2	3.3	3.0	2.5	2.5	—	—	—
Medium resource (CF 17.3%), ITC	17.2	14.4	9.9	7.6	6.8	6.4	5.2	4.0	3.7	3.1	3.1	—	—	—
Low resource (CF 16.2%), ITC	18.4	15.5	10.6	8.2	7.3	6.8	5.5	4.3	3.9	3.3	3.3	—	—	—

Acronyms and Abbreviations

AC	alternating current
ASP	average selling price
BNEF	Bloomberg New Energy Finance
BOS	balance of system
CA NEM	California Net Energy Metering
CdTe	cadmium telluride
CF	capacity factor
CPI	Consumer Price Index
c-Si	crystalline silicon
DC	direct current
DOE	U.S. Department of Energy
EPC	engineering, procurement, and construction
FICA	Federal Insurance Contributions Act
GPRA	Government Performance and Reporting Act
HVAC	heating, ventilating, and air conditioning
ITC	investment tax credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LCOSS	levelized cost of solar-plus-storage
MACRS	Modified Accelerated Cost Recovery System
MLPE	module-level power electronics
MM	million
MW_{AC}	megawatts alternating current
MW_{DC}	megawatts direct current
NEC	National Electrical Code
NEM	net energy metering
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PII	permitting, inspection, and interconnection
PPA	power-purchase agreement
PV	photovoltaic(s)
Q	quarter
SETO	Solar Energy Technologies Office (DOE)
SG&A	selling, general, and administrative
TPO	third-party ownership
USD	U.S. dollars
V_{DC}	volts direct current
W_{AC}	watts alternating current
W_{DC}	watts direct current
W_p	watts peak

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