U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022

Vignesh Ramasamy,[1] Jarett Zuboy,[1] Eric O'Shaughnessy,[2] David Feldman,[1] Jal Desai,[1] Michael Woodhouse,[1] Paul Basore,[3] and Robert Margolis[1]

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List of Acronyms

ac	alternating current
AD/CVD	antidumping and countervailing duties
BESS	battery energy storage system
BLS	U.S. Bureau of Labor Statistics
BNEF	BloombergNEF
BOS	balance of system
CBP	U.S. Customs and Border Protection
CPI	Consumer Price Index
dc	direct current
DOE	U.S. Department of Energy
EPC	engineering, procurement, and construction
GAAP	U.S. Generally Accepted Accounting Principles
HVAC	heating, ventilating, and air conditioning
IFRS	International Financial Reporting Standards
ILR	inverter loading ratio
IRR	internal rate of return
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LFP	lithium iron phosphate
Li-ion	lithium-ion
MMP	modeled market price
MSP	minimum sustainable price
MW_{ac}	megawatts alternating current
MW_{dc}	megawatts direct current
MSRP	manufacturer's suggested retail price
NEM	net energy metering
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PII	permitting, inspection, and interconnection
PPA	power-purchase agreement
PV	photovoltaic(s)
PVCS	PV combining switchgear
Q	quarter
R&D	research and development
RTE	round-trip efficiency
SAM	System Advisor Model
SAPC	Solar Access to Public Capital
SEIA	Solar Energy Industries Association
SETO	U.S. Department of Energy Solar Energy Technologies Office
SG&A	selling, general, and administrative
SOC	state of charge
STC	standard test conditions
UFLPA	Uyghur Forced Labor Prevention Act

USD	U.S. dollars
V_{dc}	volts direct current
W_{ac}	watts alternating current
W_{dc}	watts direct current
WRO	withhold release order

Executive Summary

The U.S. Department of Energy's Solar Energy Technologies Office (SETO) aims to accelerate the advancement and deployment of solar technology in support of an equitable transition to a decarbonized economy no later than 2050, starting with a decarbonized power sector by 2035. Its approach to achieving this goal includes driving innovations in technology and soft cost reductions to make solar affordable and accessible for all. As part of this effort, SETO must track solar technology and soft cost trends so it can focus its research and development (R&D) on the highest-impact activities.

The National Renewable Energy Laboratory (NREL) publishes benchmark reports that disaggregate photovoltaic (PV) and energy storage (battery) system installation costs to inform SETO's R&D investment decisions. For this Q1 2022 report, we introduce new analyses that help distinguish underlying, long-term technology-cost trends from the cost impacts of short-term distortions caused by policy and market events.

Market and Policy Context in Q1 2022

For the U.S. PV and energy storage industries, the period from Q1 2021 through Q1 2022 featured multiple market and policy events that affected businesses and customers throughout the manufacturing and installation sectors. The ongoing COVID-19 pandemic caused or complicated multiple issues. Prices jumped throughout the economy, with industry-specific events and trade policies driving up PV and battery prices in particular. Change happened rapidly and fell unevenly across stakeholders. This volatility increased the difficulty of producing representative cost benchmarks. In accordance with established practices, we drew from updated data and conducted interviews with numerous industry participants to develop the Q1 2022 cost estimates shown in this report. Yet we acknowledge that these U.S average estimates do not reflect the observations and experiences of all stakeholders during this period.

Purpose and Scope of the NREL Benchmarks

It is important to understand what the NREL benchmarks are and are not, and for what purposes they should be used. The benchmarks are bottom-up cost estimates of all major inputs to typical PV and energy storage system configurations and installation practices. Bottom-up costs are based on national averages and do not necessarily represent typical costs in all local markets.

The primary purpose of the NREL benchmarks is to provide insight into the long-term trajectories of PV and storage system costs, including which system components may be driving installed prices and where there are opportunities for price reductions. The benchmarks are also used to project future system prices, provide transparency, and facilitate engagement with industry stakeholders.

NREL's benchmarks are often compared with other PV and storage system cost metrics, including reported prices and other modeled benchmarks. However, there is significant variation within and between these metrics because of the various methods and assumptions used to develop them, and different benchmarks are useful for different purposes.

It is also critical to understand the distinction between the two benchmark types analyzed in this report: minimum sustainable price (MSP) and modeled market price (MMP). Table ES-1 summarizes the meaning, approach, and purpose of each benchmark in comparison to reported market prices. Reported market prices and the MMP benchmark are affected by market and policy conditions unique to the analysis period. Consistent with our previous benchmarking efforts, our MMP benchmarks can be interpreted as the sales prices that a developer would have charged in Q1 2022. In contrast, our MSP benchmark is a theoretical construct meant to capture the long-term cost impacts of technological evolution while muting the impacts of policy distortions and short-term market fluctuations. It does not represent dynamic market conditions and should not be used for near-term policy or market analysis. MSP cannot be directly observed; instead, it must be deduced from observable factors such as underlying costs, market input prices (e.g., for feedstock), and feedback from industry stakeholders. In this benchmark report, we apply several methods to infer MSP. Both MSP and MMP are calculated for representative PV, storage, and PV-plus-storage systems in each market sector.

The NREL benchmarks convert complex processes and inputs into highly simplified individual estimates to facilitate the tracking and projecting of technological progress. However, no individual estimate under any approach can reflect the diversity of the PV and storage manufacturing and installation industries. For instance, MMP benchmarks are based on national average costs and do not necessarily reflect the distinct experiences of engineering, procurement, and construction contractors in local markets. The benchmarks also explicitly exclude certain costs that reflect key system components for certain customers. For instance, many residential customers finance their PV systems, yet the benchmarks exclude financing costs, which can represent around 20% of reported market prices. These caveats should be considered when interpreting the summary of results that follows.

Table ES-1. Definitions of NREL MSP and MMP Benchmarks vs. Reported Market Prices

	Minimum Sustainable Price (MSP) Benchmark	Modeled Market Price (MMP) Benchmark	Reported Market Prices*
Description	Estimated bottom-up overnight capital costs (i.e., cash costs)[1] of representative PV and storage components. To mute the short-term impacts of market and policy events, MSP is modeled at the lowest prices at which product suppliers can remain financially solvent in the long term, based on input costs that represent the lowest prices each input supplier can charge to remain financially solvent in the long term.	Estimated bottom-up overnight capital costs (i.e., cash costs) of representative PV and storage components under market conditions experienced during the analysis period.	Reported prices quoted by installers and paid by customers for a range of technologies and configurations, often inclusive of financing costs. Market prices can include items such as smaller-market-share PV systems (e.g., those with premium efficiency panels), atypical system configurations due to site irregularities (e.g., additional land grading) or customer preferences (e.g., pest traps), and regulations (e.g., unionized labor).
Approach	Distorted input costs are removed from model calculations. If there is more than one typical technology or configuration, the most common one is modeled.[2]	Based on reported market costs and prices of different subcost components for representative systems. MSP and MMP use the same technology and PV system and battery configurations.	Price metrics aggregated (e.g., median, mean) from sources that collect market price data.
Purpose	Long-term analysis and projections; informing R&D investment decisions.	Near-term policy and market analysis based on disaggregated system costs.	Near-term analysis based on reported prices.

*Only summarized in this report. For reported market price details, see Barbose et al. (2021a).

PV Benchmarks

Figure ES-1 compares our MSP and MMP benchmarks for PV systems in the residential, commercial, and utility-scale sectors. The MMP benchmark is higher than the MSP benchmark for all sectors, because the MMP benchmark captures the inflationary market distortion that occurred in Q1 2022. The MMP benchmarks in Q1 2022 are also higher than comparable benchmarks in Q1 2021 (not graphed) because of the market distortion in Q1 2022, although

[1] Cash costs do not include any financing costs, which are often eligible to be included in a system's cost basis for calculating tax credits and depreciation. In the residential sector, costs have been observed related to the setup of loan and lease products for customers as well as interest rate "buy-downs." In the utility-scale space, common financing costs also include construction loan interest payments and prepaid operations and maintenance (O&M) contracts.

[2] For example, in the residential sector, we model the installation of microinverters, although string inverters with dc optimizers are also common.

different input parameters across the two years also affect the year-to-year comparison (see Section 4.6).

For Q1 2022, our representative residential PV system uses microinverters and is installed by small-scale installers. The MMP benchmark ($2.95 per watt direct current [W_{dc}]) is 15% higher than the MSP benchmark ($2.55/$W_{dc}$) and 2% higher than our comparable microinverter-based system benchmark from Q1 2021 in 2021 U.S. dollars (USD).

For commercial systems, our MMP benchmarks ($1.84/$W_{dc}$ for rooftop and $1.94/$W_{dc}$ for ground mount) are roughly 13% higher than our MSP benchmarks ($1.63/$W_{dc}$ and $1.71/ W_{dc}, respectively), and they are approximately 8% higher than their counterparts in Q1 2021 in 2021 USD.

For utility-scale systems with one-axis tracking, our MMP benchmark ($0.99/$W_{dc}$) is 14% higher than our MSP benchmark ($0.87/$W_{dc}$) and 6% higher than its counterpart in Q1 2021 in 2021 USD.

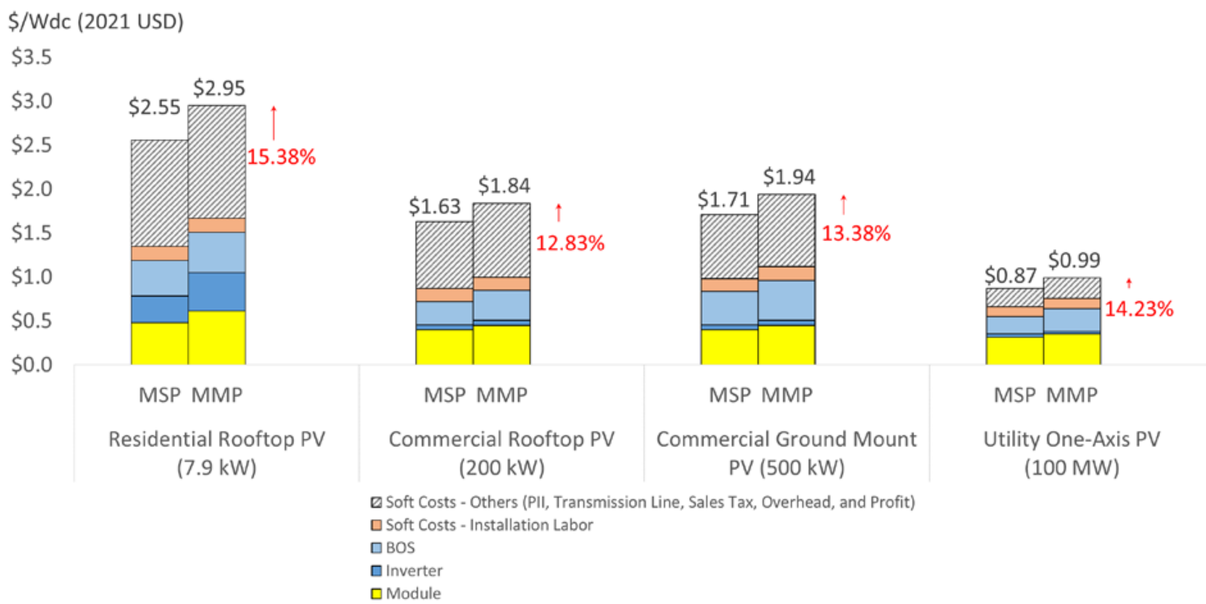

Figure ES-1. Q1 2022 U.S. PV cost benchmarks

Standalone Battery Energy Storage Benchmarks

Figure ES-2 compares our MSP and MMP benchmarks for standalone battery energy storage systems in the residential, commercial, and utility-scale sectors. Again, for all sectors, the MMP benchmarks are higher than the MSP benchmarks (and the comparable Q1 2021 benchmarks, which are not graphed here), because the MMP benchmarks capture the inflationary market distortion that occurred in Q1 2022. See Section 4.6 for the different input parameters in Q1 2022 vs. Q1 2021.

For residential systems, our MMP benchmark ($1,503/kWh) is 10% higher than our MSP benchmark ($1,371/kWh) and 2% higher than its counterpart in Q1 2021 in 2021 USD.

For commercial systems, our MMP benchmark ($672/kWh) is 10% higher than our MSP benchmark ($610/kWh). Because of a major change in system configuration between Q1 2021 and Q1 2022, the benchmark costs across those years cannot be compared directly.

For utility-scale systems, our MMP benchmark ($446/kWh) is 13% higher than our MSP benchmark ($394/kWh million) and 12% higher than its counterpart in Q1 2021 in 2021 USD.

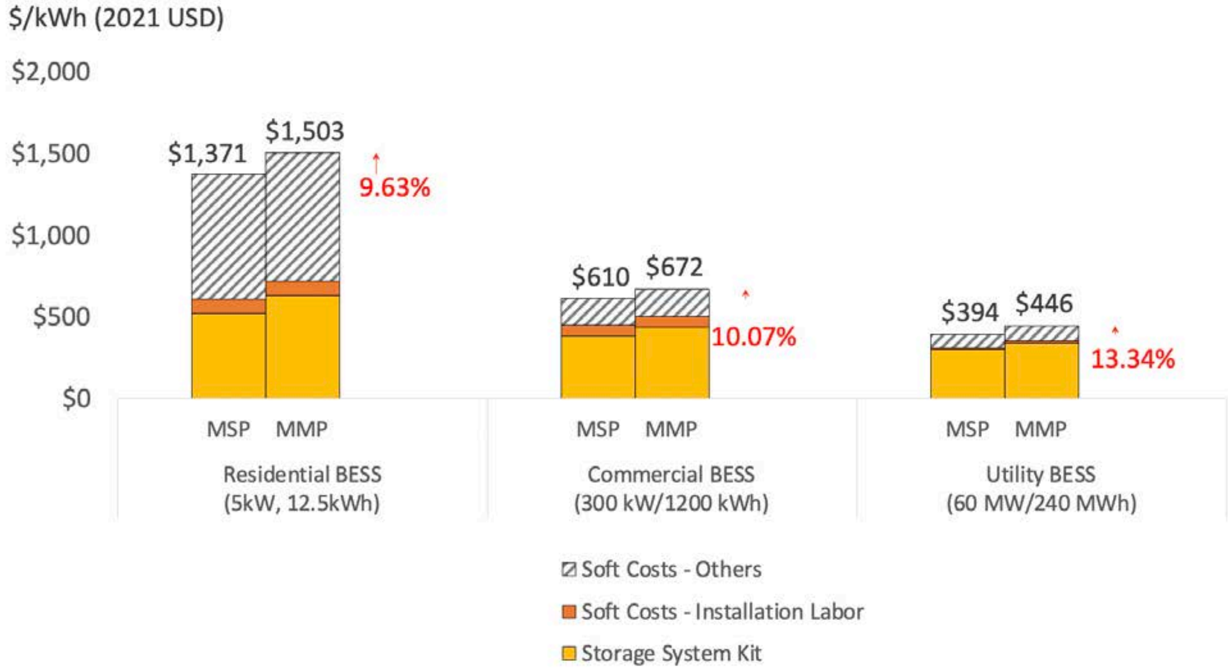

Figure ES-2. Q1 2022 U.S. standalone battery energy storage system (BESS) cost benchmarks

PV-Plus-Storage Benchmarks

Figure ES-3, Figure ES-4, and Figure ES-5 compare our MSP and MMP benchmarks—in total system cost terms—for PV-plus-storage systems in the residential, commercial, and utility-scale sectors. Again, the MMP benchmarks are higher than the MSP benchmarks (and higher than the comparable Q1 2021 benchmarks, not graphed) for all sectors, because the MMP benchmark captures the inflationary market distortion that occurred in Q1 2022. See Section 4.6 for different input parameters in Q1 2022 vs. Q1 2021.

For residential systems, our MMP benchmark ($38,295) is 13% higher than our MSP benchmark ($33,858) and 6% higher than its counterpart in Q1 2021 in 2021 USD.

For commercial systems, our MMP benchmark ($1.44 million) is 13% higher than our MSP benchmark ($1.27 million). Because of a major change in system configuration between Q1 2021 and Q1 2022, the benchmark costs across those years cannot be compared directly.

For utility-scale systems, our MMP benchmark ($195 million) is 15% higher than our MSP benchmark ($170 million) and 11% higher than its counterpart in Q1 2021 in 2021 USD.

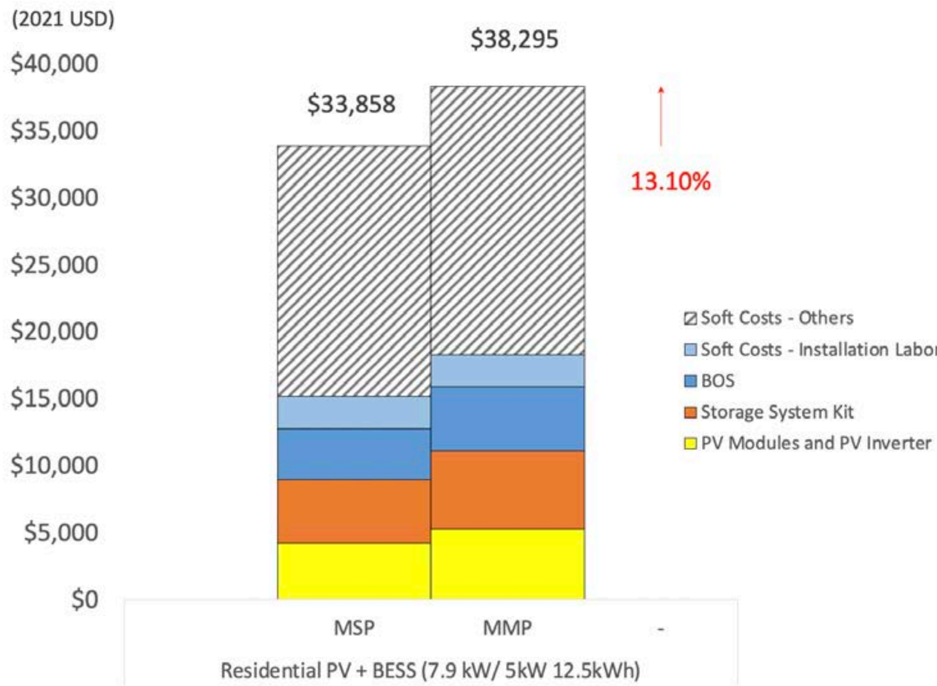

Figure ES-3. Q1 2022 U.S. benchmark: residential PV-plus-storage system

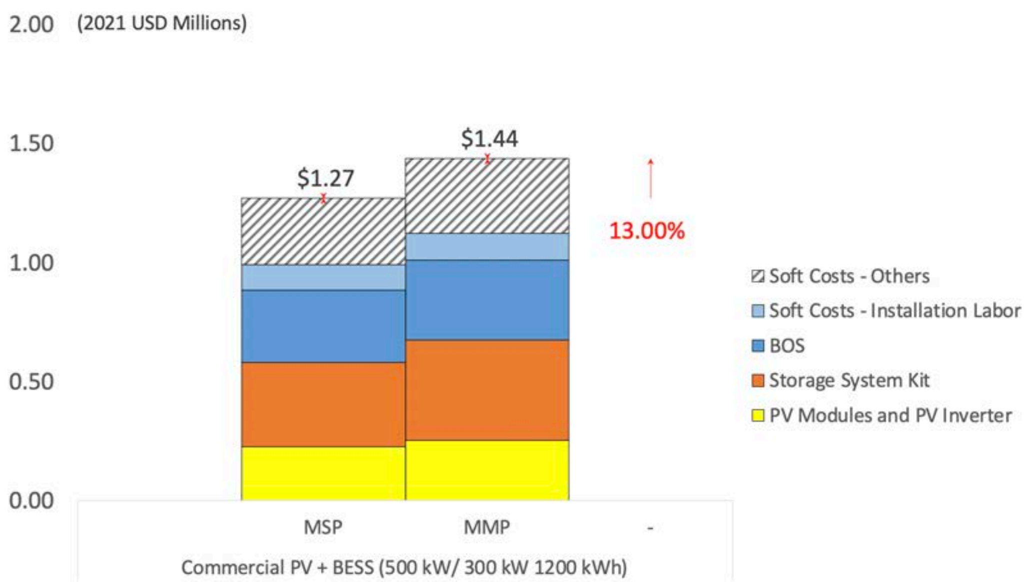

Figure ES-4. Q1 2022 U.S. benchmark: commercial ground-mounted, alternating current (ac) coupled PV-plus-storage system (4-hour duration)

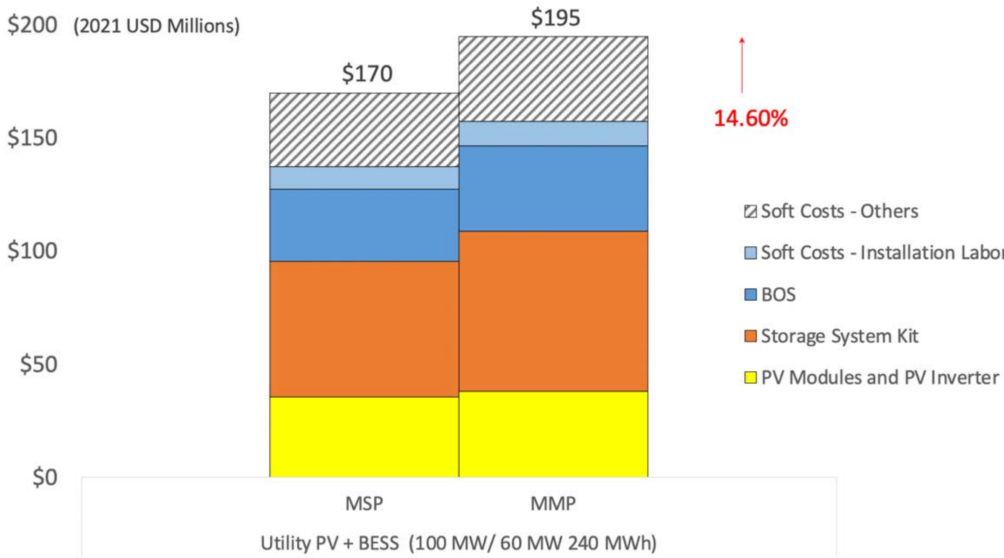

Figure ES-5. Q1 2022 U.S. benchmark: utility-scale ac-coupled tracking PV-plus-storage system (4-hour duration)

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1 Introduction

The U.S. Department of Energy's (DOE's) Solar Energy Technologies Office (SETO) aims to accelerate the advancement and deployment of solar technology in support of an equitable transition to a decarbonized economy no later than 2050, starting with a decarbonized power sector by 2035. Its approach to achieving this goal includes driving innovations in technology and soft cost reductions to make solar affordable and accessible for all. As part of this effort, SETO must track solar technology and soft cost trends so it can focus its research and development (R&D) on the highest-impact activities.

The National Renewable Energy Laboratory (NREL) facilitates SETO's decisions on R&D investments by publishing benchmark reports that disaggregate photovoltaic (PV) costs and—more recently—energy storage (battery) costs. Previous benchmark reports have sought to provide estimates of typical costs for all system components plus a sustainable margin (from the perspective of the developer/installer), relying largely on market prices for components. Using market prices to track progress has pros and cons. Tracking market prices of PV and storage systems is critical for understanding their competitiveness with other generation technologies. On the other hand, PV and storage market prices are influenced by short-term policy and market drivers that can obscure the underlying technological development that shapes prices over the longer term. For example, recent events related to trade policy, inflation, and pandemic-related supply chain constraints have pushed PV and storage prices up, even as those technologies have continued to improve. Short-term market trends are important for the PV and storage industries, as private-sector entities compete to improve their market share and profitability. SETO, however, focuses on optimizing R&D investments over the longer term to continue driving innovations in technology and soft cost reductions.

To support this longer-term perspective, NREL's Q1 2022 benchmark report is introducing new analyses, which help distinguish underlying, long-term technology-cost trends from the price impacts of short-term distortions caused by policy and market events. By muting the impacts of policy distortions and short-term market fluctuations, the new minimum sustainable price (MSP) benchmarks provide an effective basis for long-term PV cost analysis. However, they do not represent dynamic market conditions and should not be used for near-term policy or market analysis. To help provide perspective on current market conditions, the report also provides modeled market price (MMP) analysis, which is more in line with previous benchmark reports, by using similar methods to track the costs of U.S. residential, commercial, and utility-scale PV, energy storage, and PV-plus-storage systems built in Q1 2022. These methods capture the impact of market trends during this period, and the results are meant to reflect typical component costs as experienced by U.S. installers and passed on to U.S. consumers.[3]

Additional details about the goals, methods, and limitations of the Q1 2022 benchmark report—along with a brief discussion of this period's unique market and policy context—are provided in Sections 2, 3, and 4. Sections 5 through 10 present the results of our Q1 2022 capital cost modeling for residential, commercial, and utility-scale PV, energy storage, and PV-plus-storage

[3] All previous benchmark reports can be found at NREL's Solar Technology Cost Analysis web page at www.nrel.gov/solar/solar-cost-analysis.html.

systems. Section 11 presents the results of our operations and maintenance (O&M) cost analysis. Section 12 uses our capital cost and O&M cost results to calculate the levelized cost of electricity (LCOE) for PV and PV-plus-storage systems. Section 13 offers a summary and conclusions.

2 Overview of the NREL Benchmarking Process

NREL has been developing PV and storage system cost models over the past decade. Each year, we adjust model elements based on industry trends—derived from research organizations and sources such as the California net energy metering (NEM) database—as well as feedback from stakeholders. In Q1 2022, we interviewed 21 stakeholders, including third-party research organizations; PV installers and integrators; engineering, procurement, and construction (EPC) developers; advocacy groups; intergovernmental organizations; and government agencies.

We align our model inputs as closely as possible to the analysis period, which for this report is Q1 2022. We obtain most of the specific cost inputs (material costs, component and subcomponent costs, installation rental equipment rates, and labor rates) from sources such as RSMeans, the U.S. Bureau of Labor Statistics, RENVU, EcoDirect, altE Store, BloombergNEF (BNEF), Wood Mackenzie, and the Solar Energy Industries Association (SEIA). Table 3 in Section 4.4.1 provides an example of cost components that are populated using such sources. We base additional inputs—particularly soft costs such as customer acquisition costs; overhead; permitting, inspection, and interconnection (PII) costs; and profit—on analysis of multiple years of industry interviews. Currently, we model the MSP of PV modules using NREL's bottom-up module cost model. We also tailor the configuration of our representative systems to the analysis period. For example, for the residential PV sector in Q1 2022, we modeled small installers and microinverters based on the market shares of these choices.

Once we configure our representative systems and populate our models using the hundreds of inputs, the models yield disaggregated system cost results in terms of dollars per watt of direct current ($\$/W_{dc}$), dollars per kilowatt-hour ($/kWh), and dollars per system. We then send these results for validation to the stakeholders we interviewed. After making any necessary adjustments based on stakeholder feedback, we produce a draft report, which we send to industry stakeholders as well as NREL and SETO reviewers. We use feedback from this process to finalize the report, and then we publish the report on NREL's website, typically during the fourth quarter of the year (e.g., Q1 2021 results were published in November 2021). See all the reports at NREL's Solar Technology Cost Analysis web page: www.nrel.gov/solar/market-research-analysis/solar-cost-analysis.html.

3 Market and Policy Context in Q1 2022

The PV and energy storage industries are in constant flux, and each of NREL's benchmark reports has been produced within a unique historical context. By any measure, however, the period from Q1 2021 through Q1 2022 was extraordinary. Dramatic market and policy events affected businesses and customers throughout the PV and storage manufacturing and installation sectors, with the ongoing COVID-19 pandemic causing or complicating issues. Change happened rapidly and fell unevenly across stakeholders.

This volatility increased the difficulty of producing representative cost benchmarks. In accordance with established practices, we drew from updated data and conducted interviews with numerous industry participants to develop the Q1 2022 cost estimates shown in this report. Yet we acknowledge that these estimates do not reflect the observations and experiences of all stakeholders during this period. Section 4 describes the purpose, meaning, and limitations of our benchmarks in general. Below we give a brief, noncomprehensive overview of developments that characterized the period from Q1 2021 through Q1 2022 and contributed to unusually high—and highly variable—PV and storage market costs and prices in Q1 2022. Table 1 lists select events that occurred during this period.

Table 1. Select Events ca. Q1 2021–Q1 2022

Event	Date
Withhold release order (WRO) issued for PV products containing Hoshine polysilicon	June 2021
Antidumping and countervailing duties (AD/CVD) circumvention investigation requested by anonymous U.S. PV manufacturers	Aug 2021
Anonymous AD/CVD circumvention case dismissed	Nov 2021
Bifacial PV exemption from Section 201 tariffs reinstated; tariffs reduced from 18% to 15%	Nov 2021
Polysilicon spot price peak caused by constrained silicon metal and power in China	Nov 2021
Uyghur Forced Labor Prevention Act (UFLPA) signed into law (enforced as of June 2022)	Dec 2021
Section 201 tariffs extended with bifacial exemption and increased cell quota	Feb 2022
Invasion of Ukraine by Russia	Feb 2022
AD/CVD circumvention investigation requested by Auxin Solar	Feb 2022
AD/CVD circumvention investigation initiated by U.S. Department of Commerce	April 2022
Disruption of polysilicon supply and PV component shipping by COVID-19 lockdowns in China	April 2022

Costs and prices jumped throughout the economy between Q1 2021 and Q1 2022, largely driven by effects of the COVID-19 pandemic. Large influxes of government stimulus funds during the pandemic helped drive strong demand for goods and services worldwide, while pandemic-induced bottlenecks constrained supply (McCausland 2022, Thomsen 2022). As part of the supply crunch, containerized freight prices rose as much as 190% between April 2021 and April 2022, finishing the period at a 130% increase (Mercom 2022). Russia's invasion of Ukraine in February 2022 drove global oil prices up further, which added to the economywide inflation (Egan 2022, Kaplan and Hoff 2022). Between April 2021 and April 2022, the Consumer Price Index (CPI) rose 9% (FRED 2022a), and global commodity prices rose 48% (FRED 2022b). The PV industry felt the effects of these events in addition to PV-specific cost drivers. Spot prices rose across the monocrystalline silicon PV supply chain between April 2021 and April 2022: 88% for polysilicon, 29% for cells, and 19% for modules (BNEF 2022). Figure 1 illustrates some of the price increases that occurred during this period.

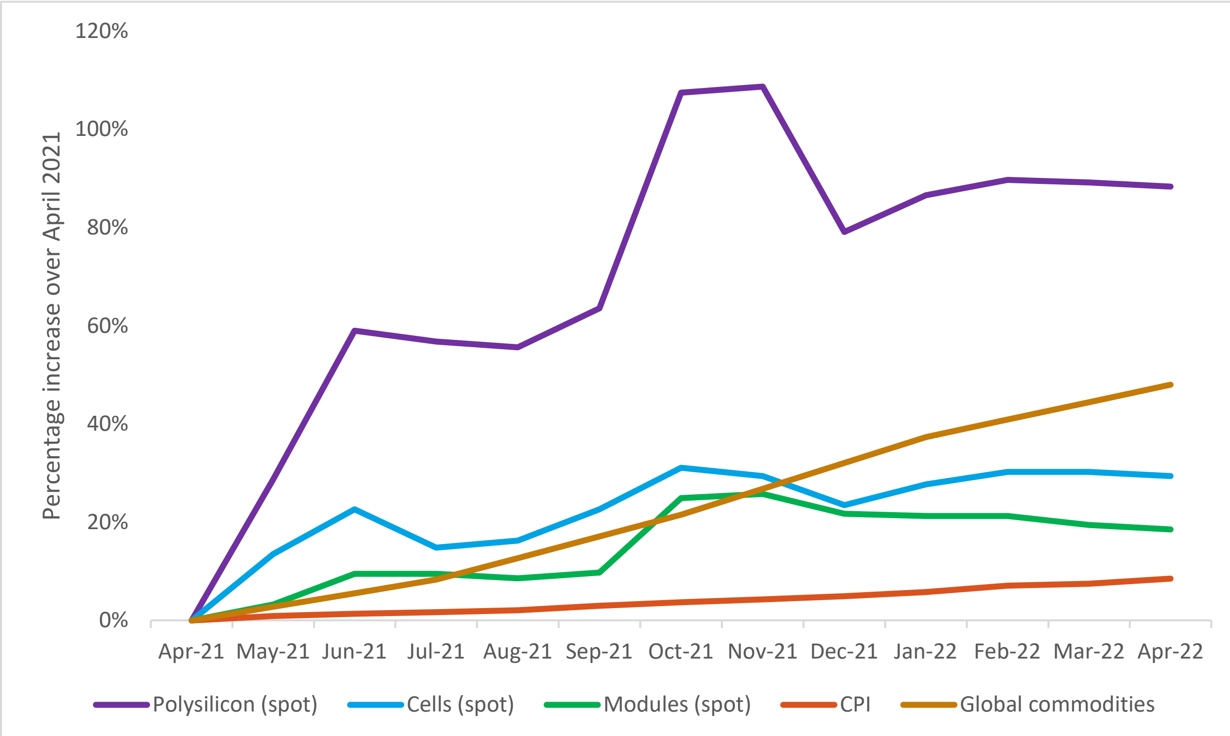

Figure 1. Select price increase indicators, April 2021–April 2022

Sources: BNEF (2022), FRED (2022a, 2022b)

The U.S. PV industry was also affected by specific trade policies. In June 2021, U.S. Customs and Border Protection issued a withhold release order (WRO) against Hoshine Silicon—instructing U.S. ports to detain shipments containing silica-based products made by Hoshine and its subsidiaries—because of published reports that Hoshine was using forced labor in China's Xinjiang Uyghur Autonomous Region (CBP 2021). In December 2021, this policy was reinforced by the passage of the Uyghur Forced Labor Prevention Act (UFLPA), which banned—beginning in June 2022—U.S. imports of products from China's Xinjiang region unless importers provide "clear and convincing evidence" that forced labor was not used in their production (CBP 2022). The detainments and uncertainty associated with the WRO and UFLPA further constrained module availability in the United States. In August 2021, an anonymous group of U.S. PV manufacturers petitioned the U.S. Department of Commerce to investigate whether Chinese PV manufacturers were circumventing antidumping and countervailing duties by working in Malaysia, Thailand, and Vietnam. Although the Department of Commerce rejected the petition in November 2021, the uncertainty created by the petition put additional pressure on the U.S. module supply chain (Woodmac and SEIA 2022). In February 2022, Auxin Solar filed a similar anticircumvention petition, which instigated a Department of Commerce investigation at the beginning of Q2 2022; the impacts of that investigation, which have been significant, are not considered in this Q1 2022 benchmark report. Also in February 2022, the U.S. Section 201 tariffs were extended along with the tariff exemption for bifacial modules. Average U.S. prices for monofacial monocrystalline silicon modules rose 9% between Q1 2021 and Q1 2022 (Woodmac and SEIA 2022). Component cost increases are reflected in our MMP benchmarks in Sections 5–10.

Component cost increases were a major topic during our Q1 2022 interviews with industry stakeholders. In addition to stating that all prices had gone up since the previous year, residential and commercial installers noted significant price increases specifically for modules, batteries, electrical panels, circuit breakers, and wire. Utility-scale stakeholders mentioned significantly higher prices for modules, inverters, site preparation, transformers, switchgears, copper, steel, PVC, and shipping. Because of tight supply chains, obtaining components in a timely manner could incur additional premiums, according to some interviewees. Some also stated that the availability and price of components could change rapidly week to week and that module price increases varied unevenly across installers. Large residential and commercial installers as well as utility-scale installers reported that they could buy containerload quantities directly from module manufacturers, which yielded the lowest costs. Smaller installers, however, said that they either could not handle enough volume to obtain direct, containerload pricing, or that warehousing costs for high-volume purchases were prohibitive. For this reason, smaller installers reported that they paid higher module prices through distributors.

Our interviews also suggested that a tightening labor market contributed to higher costs for U.S. PV systems in Q1 2022. The U.S. unemployment rate rose from 3.5% immediately before the onset of the COVID-19 pandemic to 14.7% in April 2020 and then dropped again, reaching 3.8% in February 2022. These fluctuations have been accompanied by an increased rate of workers quitting their jobs, in a phenomenon that has been called the "Great Resignation" (BLS 2022a). The tight labor market was reflected in EnergySage's 2021 installer survey, which identified a lack of trained labor as the most frequent barrier to growing installation businesses (EnergySage 2022). Our Q1 2022 industry interviews highlighted how higher labor costs contributed to higher PV system costs. Multiple participants noted significantly increased labor costs and linked them with labor shortages; in some areas, high demand for installations meant that workers could pick and choose projects and demand higher wages. Some installers also reported that, because local labor was unavailable, workers needed to travel to job sites—thus incurring additional costs for items such as hotel rooms and meals.

4 NREL Benchmarks' Purpose and Scope

In all industries, numerous metrics reflect product costs and prices. These metrics say different things and are useful for different purposes. For instance, an investor may be interested in the costs to produce a new product, a stock trader may want to know the real-time trading price of a good, and a forecaster may seek a long-term average cost. It is therefore important to understand what the NREL benchmarks are and are not, and for what purposes they should be used. This section describes the meaning of the NREL benchmarks, their intended purposes, how they vary from other market metrics, and their limitations. The final subsection notes changes to the benchmark report in Q1 2022.

4.1 Meaning of the NREL Benchmarks

Industry, analysts, policymakers, and other stakeholders are interested in the *prices* of new technologies and the underlying *costs* to produce those technologies. In the U.S. PV industry, prices are readily observable and documented in resources such as Barbose et al. (2021a). However, installed system prices do not provide insight into underlying system cost drivers. Disaggregating installed system prices into underlying cost drivers requires identifying all relevant inputs to PV installations and assigning costs to those inputs. Broadly, this cost disaggregation can be done through top-down or bottom-up cost modeling. Top-down modeling observes a final price, then develops a method to distribute that price across individual cost components. Bottom-up cost modeling estimates the costs of individual components based on how they are made, then adds those costs up to a modeled total price.

The NREL benchmarks are bottom-up cost estimates of all major inputs to PV and storage installations. Bottom-up costs are based on national averages and do not necessarily represent typical costs in all local markets. As we discuss in Section 4.4, this year's report includes two distinct sets of benchmarks: MSP benchmarks and MMP benchmarks. MSP benchmarks can be interpreted as the minimum sustainable price a company needs to charge to remain financially solvent in the long term based on the minimum sustainable prices of all inputs. MMP benchmarks can be interpreted as the actual sales price the company charges in the current market. In a stable, balanced, competitive market that is free of limited-duration trade policy distortions, MMP is equal to MSP.

4.2 Purpose

The primary purpose of the NREL benchmarks is to provide insight into the long-term trajectories of PV and storage system costs. The NREL benchmarks inform and track progress toward SETO's Government Performance and Reporting Act cost targets. Industry analysts also use NREL benchmarks to project future system prices. In addition, the benchmarks provide insight into the disaggregated costs of individual system components. Analysts use disaggregated costs to identify which system components are driving installed prices and where there are opportunities for system price reductions.

The NREL benchmarks also provide transparency and facilitate engagement with industry stakeholders. Other organizations provide bottom-up analysis of PV and storage component costs for a fee, whereas NREL's results are provided publicly and free of charge. Thus, all stakeholders can observe and comment on our assumptions, methods, and results. Opinions about the correct ways to calculate and report representative benchmark costs across the large, diverse U.S. PV and storage markets will always vary. However, NREL continues to strive for a consistent, transparent approach that can be used as a common foundation for understanding the U.S. market by all stakeholders. Understanding assumptions and methods is critical; stakeholders should not use the results without first understanding how they were developed and what they mean. To enhance this effort, NREL is developing a complementary online cost modeling tool.

4.3 NREL Benchmarks Compared With Other Metrics

Cost and price metrics can vary significantly because of the various methods and assumptions used in their development. Here, we illustrate that variation using PV metrics. Figure 2 compares 2020 metrics across several sources and all three PV market sectors. Each source contains numerous details about data and methods, which are beyond the scope of this report to list in full. Rather, we make several general observations to contextualize the benchmarks provided in our current report; for more detailed study of PV cost and price tracking, see the sources listed below.

- The Lawrence Berkeley National Laboratory (LBNL) values are based on reported prices for projects installed in 2020, and they include median values as well as 20th and 80th percentile values (Barbose et al. 2021a, Bolinger et al. 2021).
- The SunPower, Sunrun, and Vivint data are the sums of reported average installation, sales, and general and administrative costs averaged across four quarters in 2020, as derived from shareholder reports (Barbose et al. 2021a).
- The EnergySage values are median price quotes in 2020, as calculated by LBNL from EnergySage data (Barbose et al. 2021a).
- The Woodmac values are based on modeled turnkey prices averaged across quarters (Barbose et al. 2021a, Woodmac and SEIA 2021).
- The NREL values are MMP benchmarks for a 7-kW_{dc} residential system, a 200-kW_{dc} commercial system, and a 100-MW_{dc} utility-scale system (Feldman et al. 2021).

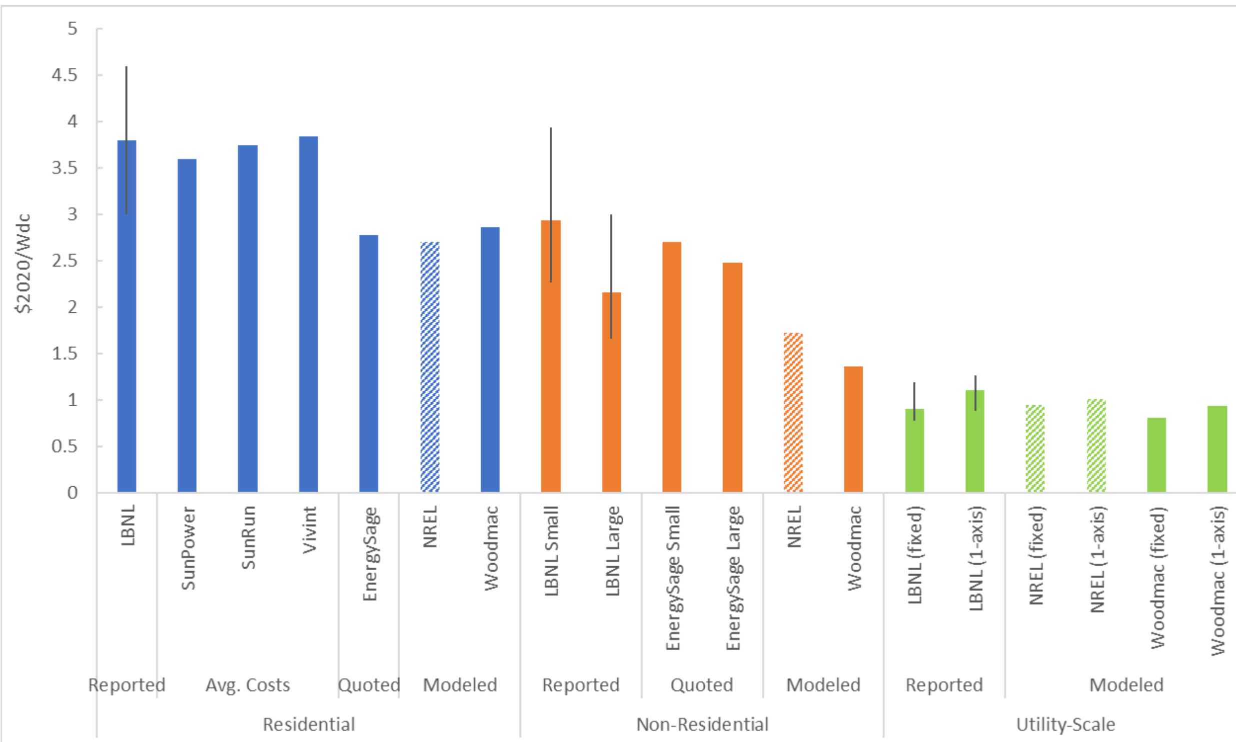

Figure 2. Comparison of 2020 PV price metrics across sources and sectors

Definitions of nonresidential systems vary across the sources, but in general, they include rooftop and ground-mounted systems that are larger than residential systems, smaller than utility-scale systems, and are not installed on residences. They often include systems that are defined as "commercial" systems.

As Figure 2 shows, price metrics can vary significantly within PV sectors, depending on the sources of those metrics. Barbose et al. (2021a) attribute this variation to differences across sources in underlying methods and inputs, including system vintage, system location, use of price versus cost, which costs are accounted for, characteristics of installers, presence of value-based pricing, system size, and system design.

Significant variation occurs even within the LBNL reported prices. The range between the 20th and 80th percentiles is about \$1.60/W_{dc} for residential systems, \$1.70/W_{dc} for small nonresidential systems, \$1.30/W_{dc} for large nonresidential systems, and \$0.40/W_{dc} for utility-scale systems. Put another way, prices within the 20th to 80th percentiles are up to 20% different from the median for residential systems, 40% different for nonresidential systems, and 30% different for utility-scale systems. For example, it would not be unusual—based on these reported data—to encounter a typical U.S. residential installation priced at \$3.00/W_{dc} and another at \$4.60/W_{dc} in 2020. This range demonstrates the limitation of representing prices with a single benchmark value. Tracking a single value consistently over time is a useful way to gauge technological progress, but when interpreting such values, the underlying variability in real-world prices should be kept in mind.

The largest absolute difference between NREL's MMP benchmark and the median reported LBNL price for a comparable system (about \$1.1/W_{dc}) is in the residential sector. There are three primary reasons for this disparity. First, the NREL MMP benchmark is based on costs incurred by a typical, experienced installer in a competitive market, whereas the U.S. residential installation industry comprises around 3,000 firms—ranging from small, local installers with diverse cost structures to large-scale firms whose prices reflect heterogeneous cost structures and long-term market strategies. Second, the MMP benchmark includes costs only for a specific, representative system installation. In contrast, reported prices may include premium system features (e.g., premium inverters) and costs of complementary services such as additional electrical work (e.g., building main panel upgrades), securing financing, additional roofing services, and other home upgrades. Thus, the MMP benchmark can be compared to the manufacturer's suggested retail price (MSRP) of a car without any premium features. Just as MSRP is consistently lower than actual car sales prices, so will MMP benchmarks be consistently lower than average PV market prices. Third, NREL does not have robust data on profit margins, and the profit margins reflected in reported system prices may be lower or higher than NREL's assumptions in any given year.

The differences between NREL's MMP benchmark and comparable median reported prices are smaller for the nonresidential sector (\$0.4/W_{dc}) and the utility-scale sector (up to \$0.1/W_{dc}). Fewer companies work on nonresidential and utility-scale projects than on residential projects, and the business operations, supply chains, and cost structures of the companies that take on larger projects are different and more uniform than those of retail-oriented residential installation companies—resulting in more standardized prices. This is particularly apparent for the utility-scale values shown in Figure 2, which are relatively consistent across the reported and modeled sources. The nonresidential sector is more heterogeneous than the utility-scale sector with regard to installers, customers, and system sizes and types, so the variation across price benchmarks is larger.

In summary, different price benchmarks are useful for different purposes. NREL's benchmarks are primarily used for long-term projections and insights into underlying cost drivers, whereas reported market prices are useful for understanding real market dynamics. NREL benchmarks should *not* be used for purposes better met by market prices and vice versa. For instance, if an analyst wants to know the actual prices paid by real customers in a specific location at a specific time, the analyst should use reported market prices. Conversely, if an analyst wants to understand the trajectory of underlying cost drivers, the analyst should use NREL benchmarks across multiple years.

It is also critical to understand the distinction between NREL's MSP and MMP benchmarks when using the benchmark results. These two types of benchmarks are described next.

4.4 Minimum Sustainable Price (MSP) and Modeled Market Price (MMP) Benchmarks

For the first time, this Q1 2022 report provides modeled capital cost results using two benchmarks:

1. An **MSP benchmark** meant to identify the lowest prices at which product suppliers can remain financially solvent in the long term, based on input costs that represent the lowest prices that each input supplier can charge to remain financially solvent in the long term.
2. An **MMP benchmark** that maintains continuity with previous benchmark reports by capturing the impact of market trends during Q1 2022, reflecting typical national system costs as experienced by U.S. installers and passed on to U.S. consumers.

Both MSP and MMP are calculated for representative systems in each PV market sector. The MSP benchmark reflects the lowest sustainable price based on a long-term view of market conditions, whereas the MMP benchmark reflects the base price of the market price distribution based on market conditions during the analysis period. Table 2 summarizes the meaning, approach, and purpose of each benchmark in comparison to reported market prices (which are only summarized in this report). The two benchmarks are described further in the following subsections.

Table 2. Definitions of NREL MSP and MMP Benchmarks vs. Reported Market Prices

	Minimum Sustainable Price (MSP) Benchmark	Modeled Market Price (MMP) Benchmark	Reported Market Prices*
Description	Estimated bottom-up overnight capital costs (i.e., cash costs)[4] of representative PV and storage components. To mute the short-term impacts of market and policy events, MSP is modeled at the lowest prices at which product suppliers can remain financially solvent in the long term, based on input costs that represent the lowest prices each input supplier can charge to remain financially solvent in the long term.	Estimated bottom-up overnight capital costs (i.e., cash costs) of representative PV and storage components under market conditions experienced during the analysis period.	Reported prices quoted by installers and paid by customers for a range of technologies and configurations, often inclusive of financing costs. Market prices can include items such as smaller-market-share PV systems (e.g., those with premium efficiency panels), atypical system configurations due to site irregularities (e.g., additional land grading) or customer preferences (e.g., pest traps), and regulations (e.g., unionized labor).
Approach	Distorted input costs are removed from model calculations. If there is more than one typical technology or configuration, the most common one is modeled.[5]	Based on reported market costs and prices of different subcost components for representative systems. MSP and MMP use the same technology and PV system and battery configurations.	Price metrics aggregated (e.g., median, mean) from sources that collect market price data.
Purpose	Long-term analysis and projections; informing R&D investment decisions.	Near-term policy and market analysis based on disaggregated system costs.	Near-term analysis based on reported prices.

*Only summarized in this report. For reported market price details, see Barbose et al. (2021a).

4.4.1 Minimum Sustainable Price Benchmark

Reported market prices and the MMP benchmark are affected by market and policy conditions unique to the analysis period. In contrast, our MSP benchmark is meant to capture the long-term cost impacts of technological evolution while muting the impacts of policy distortions and short-term market fluctuations. The MMP benchmark described in Section 4.4.2 can be thought of as the MSP distorted by short-term market and policy phenomena that occurred in Q1 2022.

[4] Cash costs do not include any financing costs, which are often eligible to be included in a system's cost basis for calculating tax credits and depreciation. In the residential sector, costs have been observed related to the setup of loan and lease products for customers as well as interest rate "buy-downs." In the utility-scale space, common financing costs also include construction loan interest payments and prepaid O&M contracts.

[5] For example, in the residential sector, we model the installation of microinverters, although string inverters with dc optimizers are also common.

The MSP is an economic concept that was developed to estimate theoretical sustainable PV prices and cost projections (Goodrich et al. 2013, Powell et al. 2013). The MSP cannot be directly observed; rather, it must be deduced from observable factors such as underlying costs, market input prices (e.g., for feedstock), and feedback from industry stakeholders. A comprehensive understanding of MSP would require in-depth knowledge about the prices each input supplier must charge to remain financially solvent in the long term within their complex and ever-changing market and policy contexts—from the company that extracts raw materials to component manufacturers, assemblers, and installers. For this reason, development of our MSP benchmarks can be thought of as a journey of continuous improvement. For the Q1 2022 MSP benchmarks, we apply two general approaches to infer MSP for the various PV and storage system components: detailed bottom-up cost modeling and mitigation of distorted input values. For all soft costs, including labor costs, we use the same values for the MSP and MMP benchmarks, because we do not currently have a basis for differentiating these values using MSP principles. These approaches represent initial efforts to characterize MSP. We will improve on them in future benchmark reports with the help of feedback from PV and energy storage stakeholders.

Detailed Bottom-Up Component Cost Modeling

We apply detailed bottom-up cost modeling to calculate module MSP. NREL has been applying bottom-up cost modeling techniques across the PV supply chain for more than 12 years. Items included within these models capture the variable and fixed costs experienced by firms following the U.S. Generally Accepted Accounting Principles (GAAP) and the International Financial Reporting Standards (IFRS). Figure 3 provides an overview of the bottom-up component cost modeling input data. We first work with researchers and companies to define the process flow. Then, we contact materials and equipment suppliers representing each step in the manufacturing process to develop inputs for the top-left box in Figure 3. The inputs needed to calculate depreciation include equipment throughput and price and floorspace requirements. The inputs needed to calculate variable (or "cash") costs include materials, utilities, labor, and maintenance. Yield losses are also incorporated into the model calculations, as are location-specific cost indices, including local labor and utility rates. Overhead and minimum sustainable profit margins are included in the calculation of factory-gate MSP, and shipping costs are included in the calculation of the final delivery price to PV and storage projects. For this year's benchmark report, we used bottom-up cost modeling only for modules. For additional details, see Smith et al. (2021) and Woodhouse et al. (2020).

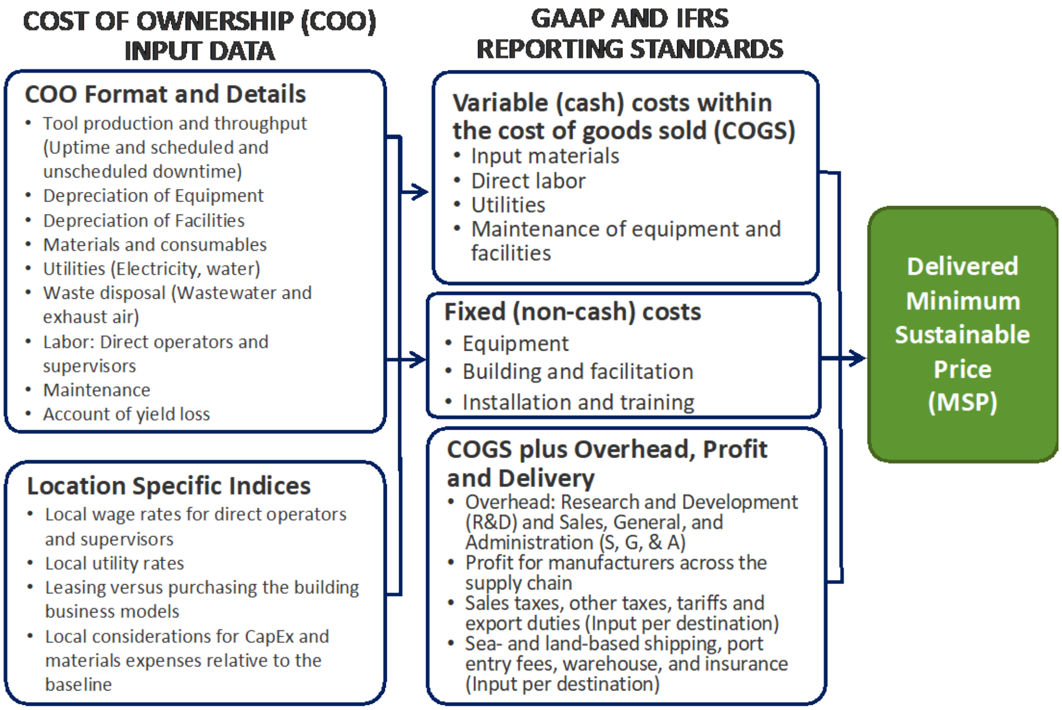

Figure 3. Overview of bottom-up cost modeling input data

Addressing Distorted Input Values

Although all market prices fluctuate with near-term changes in supply and demand, aggregated market prices in mature, competitive industries tend to follow long-term trends. Significant deviations from these long-term trends provide evidence of temporary market distortions such as supply shocks or significant policy reforms. These temporary distortions can provide important information about real-time market conditions but muddle understanding of long-term price trajectories. We use this basic concept to develop a rule for adjusting input prices that are significantly distorted by temporary market and policy shocks.

The Consumer Price Index (CPI) provides evidence of significant pandemic-driven market distortions in 2021 and 2022. As illustrated in Figure 4, the CPI in Q1 2022 was more than two standard deviations above a linear fit to 20 years of CPI data. We interpret this deviation as indicating a level of distortion that can separate PV and storage input prices from underlying cost fundamentals. While we intend to continue refining our methodology over time, we propose to use the rule of a two standard deviation variation from a 20-year linear fit as a criterion for identifying periods of significant price distortion. We apply this approach to calculate costs related to inverters, structural balance of system (BOS), electrical BOS, and transmission lines.

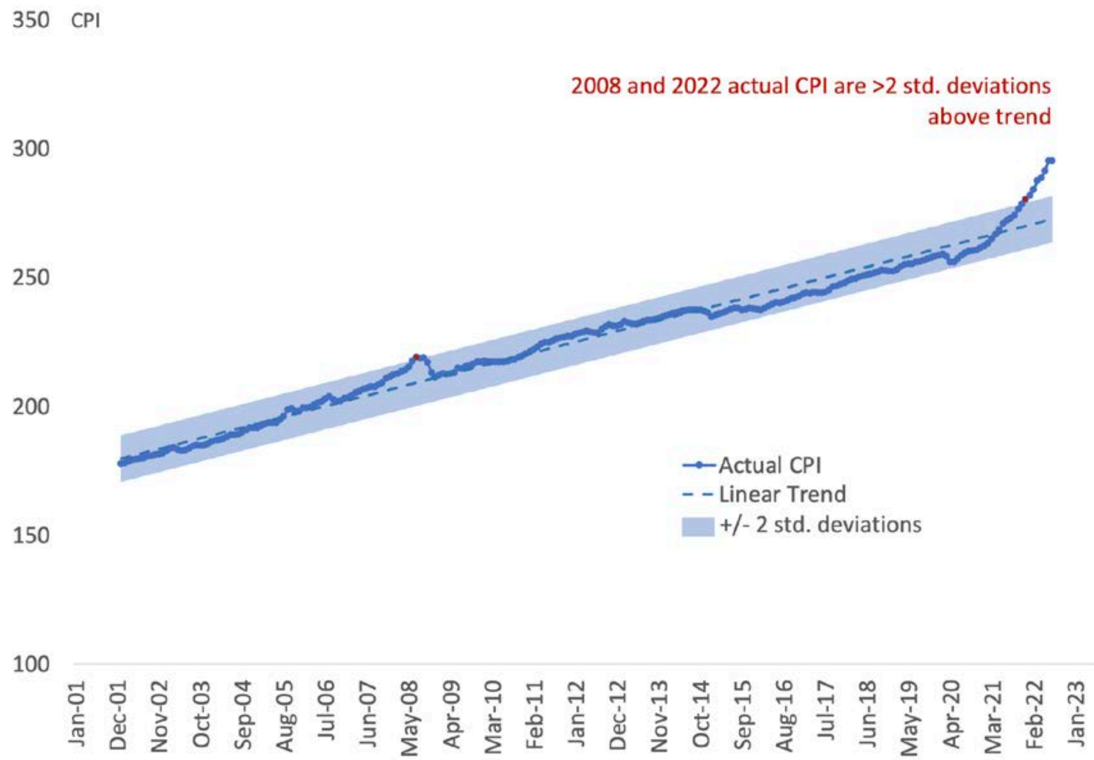

Figure 4. CPI data and linear fit, 2002–2022, showing high deviation of data from fit during 2022

Data are from "Consumer Price Index for All Urban Consumers: All Items in U.S. City Average," index 1982–1984 = 100, monthly, seasonally adjusted (FRED 2022a)

We show an example of our approach using utility-scale and commercial ground-mount systems. Table 3 lists BOS hardware, installation equipment, and transmission line cost components for these systems. We calculate prices for these inputs by excluding 2022 values and averaging values for the period the data are available between 2017 and 2021 (typically 3–5 years of data). Data are averaged because the available time series is inadequate to discern consistent time trends; this method could be modified to make MSP adjustments based on a linear fit once sufficient time-series data are available.

An example of our MSP calculation for these cost components is shown in Figure 5, for preconstruction survey material and equipment costs. In the top panel of Figure 5, the high 2022 preconstruction survey material cost of $45 per acre is excluded, and the remaining 2017–2021 costs ($19, $22, $23, $24, and $35 per acre) are averaged to yield an MSP for this component of $24 per acre. Thus, a preconstruction survey material cost of $24 per acre is input into our bottom-up cost model as part of the MSP benchmark calculation. The bottom panel shows the same process for the preconstruction survey equipment cost; here, the 2022 value is lower than the MSP calculated by averaging the 2017–2021 values. We remove the 2022 value in all cases, regardless of whether it appears to be high, low, or on-trend. We simply assume that 2022 is a distorted year and that any costs in that year are distorted. We may refine this simplification in future analyses.

Table 3. Utility and Commercial Ground-Mount PV Cost Components for BOS Hardware, Installation Equipment, and Transmission Lines

Preconstruction surveys	Staging
Access roads and parking	
Security fencing	
Temporary office	
Storage box	
O&M building	
Site preparation (geotechnical investigation)	Site preparation
Site preparation (clearing and grubbing)	
Site preparation (soil stripping and stockpiling)	
Site preparation (grading)	
Site preparation (compaction)	
Foundation for inverter/transformer/ PVCS (PV combining switchgear)	Structural work
Trenches	
Foundation for vertical support	
Horizontal support structures	
Welding or bolting	
Module mounting	
T-connection	
U-joint and driveline	Tracker
Gearbox	
Motor and controller equipment	
Conduit, wiring	dc work
Grounding, dc cable	
Junction/combiner boxes	
Inverter house	Alternating current (ac) work
On-site transmission	
PVCS	
On-site transformer and substation	
Site preparation (clearing and grubbing)	230-kV transmission line (4 miles): tower
Tower: foundation installation	
Tower: structure costs	
Tower: top assembly	
Conductor and cable	
Misc. assembly units	
Site preparation (clearing and grubbing)	35-kV distribution line (1 mile): wood pole
Wood pole: foundation installation	
Wood pole: structure costs	
Wood pole: top assembly	
Conductor and cable	
Misc. assembly units	

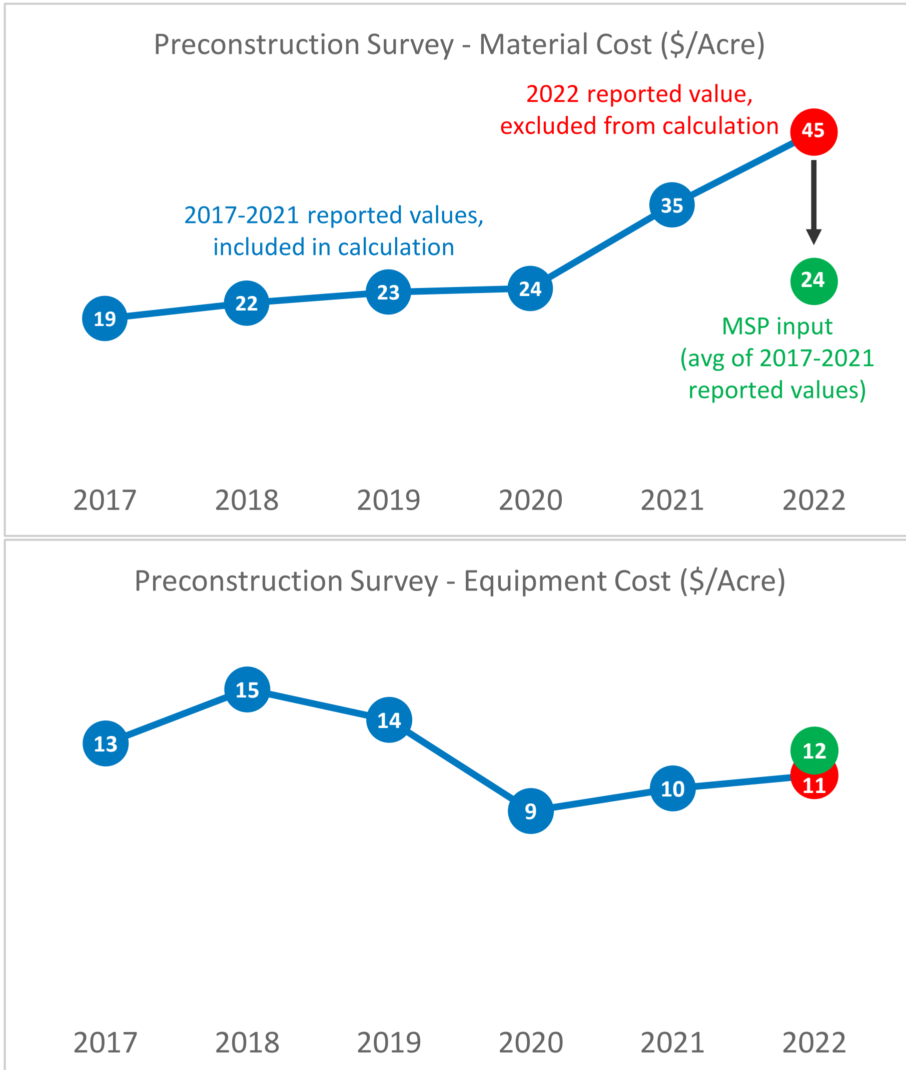

Figure 5. Example of calculating MSP inputs for a structural BOS cost

We calculate MSP inputs for installation labor costs differently. Labor wage data from the U.S. Bureau of Labor Statistics (BLS) are not available for 2022. Thus, we analyze labor wage data for distortion through 2021 (Figure 6). During this period, all data points are within the two standard deviation range. For this reason, we use the 2021 labor costs (adjusted for inflation) for 2022 in both the MSP and MMP benchmarks. This observation contributed to our decision to assume that MSP is equal to MMP for soft costs.

Likewise, battery pack and battery inverter prices were unavailable for 2022, and historical data for these components are insufficient to analyze anomalies. Thus, for the MMP benchmarks, we simply adjust the prices of these commoditized items to 2022 rates by accounting for inflation. For the battery pack MSP, we reduce the 2021 MMP by about 17% for 2022, based on the average cost reduction rate of turnkey battery systems over the past 5 years (BNEF 2021). For the battery inverter MSP, we reduce the MMP by 25% to eliminate the effect of the Section 301 tariff for residential and commercial systems; we assume that Section 301 tariffs do not apply to battery inverters used in utility-scale systems, so no adjustment is made for those system types.

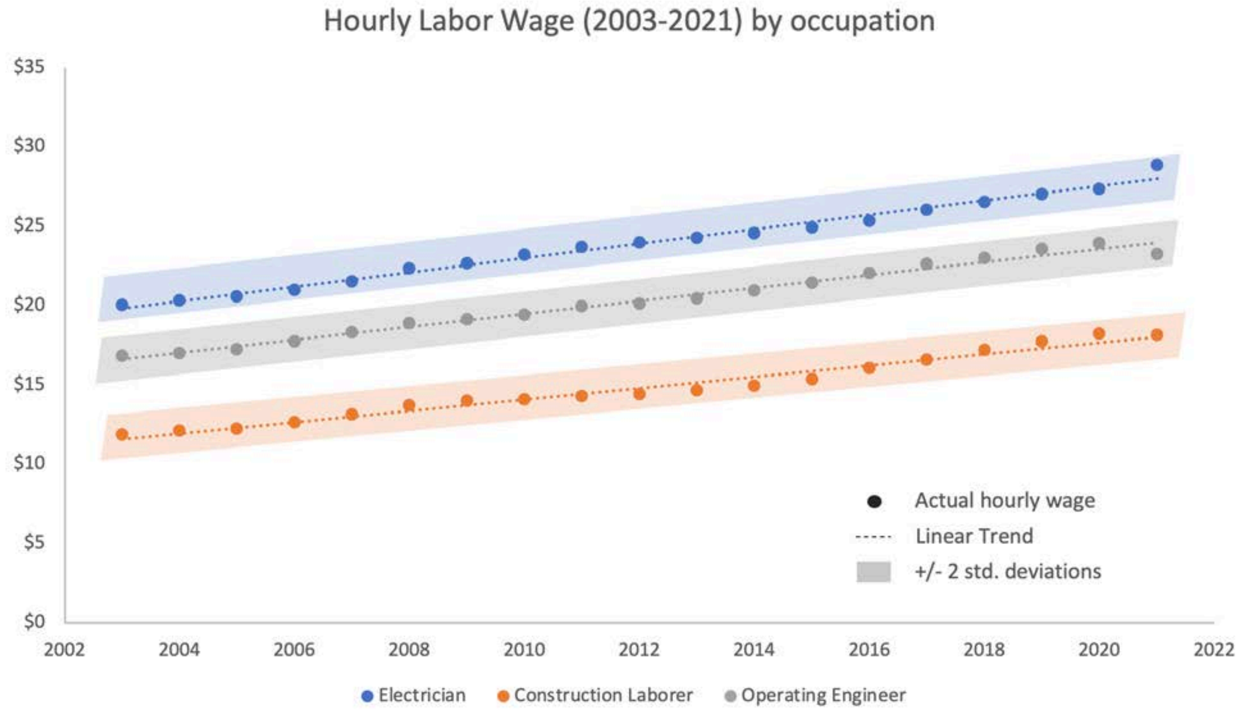

Figure 6. Example of calculating MSP inputs for installation labor

Source: BLS (2022b)

4.4.2 MMP Benchmark

The Q1 2022 MMP benchmark employs methods like those used in NREL's recent benchmarking efforts, including the Q1 2021 report (Ramasamy et al. 2021). This benchmark has been produced in conjunction with several related research activities at NREL and LBNL, which are documented by Feldman et al. (2021), Barbose et al. (2020), Bolinger et al. (2020),[6] Chung et al. (2015), Feldman et al. (2015), and Fu et al. (2016).

The MMP benchmark includes bottom-up accounting for all necessary system and project development costs incurred when installing PV and storage systems. It uses Q1 2022 costs and excludes any previous supply agreements or contracts. We attempt to model the typical installation techniques and business operations from an installed-cost perspective. All MMP benchmarks include variation—accounting for the differences in size, equipment, and operational use (particularly for storage) that are currently available in the marketplace. All MMP and MSP 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 MMP and MSP benchmarks assume the use of monofacial monocrystalline silicon PV modules. Benchmarking

[6] Lawrence Berkeley National Laboratory compares the bottom-up cost results of various entities, including our results.

using cadmium telluride or bifacial modules could result in significantly different results.[7] Likewise, the MMP and MSP benchmarks assume installation of containerized battery systems shipped as cabinets that include lithium iron phosphate (LFP) battery packs and battery racks, as well as a battery management system, thermal management system, and fire suppression system.

Our MMP benchmarks can be interpreted as sales prices that a developer would have charged in Q1 2022. There is wide variation in developer profits; project pricing depends on region and project specifics such as local retail electricity rate structures, local rebate and incentive structures, the competitive environment, and overall project or deal structures. The profit margins that we assume are meant to represent typical profit margins achieved over the long term in a competitive market.

4.5 Limitations

The NREL benchmarks convert complex processes and inputs into highly simplified individual estimates. These simplified estimates are useful for tracking and projecting technological progress. However, no individual estimate under any approach can reflect the diversity of the PV and storage manufacturing and installation industries. The MMP benchmarks are designed to reflect typical costs, but these costs do not reflect the experiences of all installers and customers. For instance, MMP benchmarks are based on national average costs and do not necessarily reflect the distinct experiences of developers in local markets (Figure 7). The benchmarks also explicitly exclude certain costs that reflect key system components for certain customers. For instance, many residential customers finance their PV systems, but the benchmarks exclude financing costs, which can represent around 20% of reported market prices. For further research on the complexity of PV markets and reported market prices, see Gillingham et al. (2016) and Barbose et al. (2021a).

[7] In this report, we focus on the installation costs of crystalline silicon modules, but a significant portion of U.S. utility-scale PV systems use cadmium telluride modules. From 2010 to 2020, cadmium telluride modules accounted for approximately 29% of U.S. utility-scale PV deployment (EIA 2021). This portion of the market is particularly notable given that cadmium telluride modules represented only 4% of global PV shipments over the same period. Similarly, a growing number of U.S. systems are beginning to use bifacial modules with transparent backs, which generate electricity from both sides of the module—as opposed to traditional monofacial modules, which typically have opaque backsheets. Because of the newness of bifacial modules, we do not have sufficient data on their current U.S. market share.

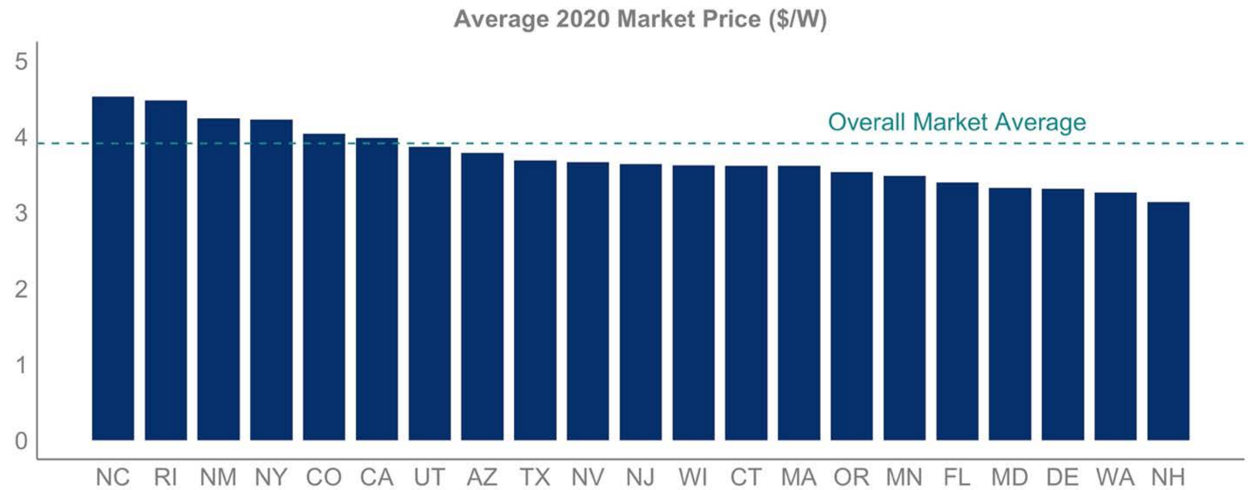

Figure 7. Average 2020 residential PV market prices by state

Based on data from Barbose et al. (2021a)

Finally, any comparison of NREL benchmarks with reported market prices or other price benchmarks should be implemented with caution. As already discussed, market prices and different price benchmarks reflect different assumptions and should be used for different purposes. In the case of the MSP benchmarks, the MSP is a theoretical construct that may never be observed in imperfectly competitive markets in the real world. The NREL MSP benchmarks are meant to provide stable estimates of input costs based on long-term trends that are useful for making long-term decisions, including R&D directions. In contrast, the NREL MMP benchmarks are meant to reflect current market conditions relevant to making short-term decisions, including policy recommendations.

4.6 Changes to the NREL Benchmark in Q1 2022

Based on our industry research, we made several changes to the NREL benchmark report between last year's report (Q1 2021) and this year's report (Q1 2022). This year, we added a supply chain premium for residential battery pack cost, commercial battery pack cost, and commercial PV module cost based on information from our stakeholder interviews. For residential systems, we assume only a microinverter option and small-scale installers, instead of the weighted approach used in Q1 2021 that assumes three inverter types and two installer types. These choices simplify the system cost analysis by focusing on the most common installation choices, making the results easier to interpret. In Q1 2022, microinverters and string inverters with power optimizers were the dominant inverter technologies for residential PV, but the share of microinverters has been increasing over the past several years, while the share of inverters with power optimizers has been declining (Wood Mackenzie 2022a). Similarly, this year, our commercial benchmark system only assumes use of a string inverter, because that technology was most common in the commercial PV sector in Q1 2022 (Wood Mackenzie 2022a). We infer the predominance of small-scale installers in the residential sector using data on residential system financing (Wood Mackenzie 2022b). The higher efficiency of modules assumed for Q1 2022 (CA NEM 2022) results in larger residential PV system sizes compared with systems in Q1 2021. Additional details on model inputs are provided in the following sections.

5 Residential PV Model

This section describes our residential PV model's structure and parameters in intrinsic units (Section 5.1) as well as its output (Section 5.2). Residential PV systems are typically in the range of 4 kW_{dc} to 10 kW_{dc} (Barbose et al. 2021a). Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

5.1 Model Structure and Representative System Parameters

We model a 22-module (7.9-kW_{dc}) residential rooftop system installed by a small enterprise using 20.3%-efficient, 1.77-m^2, 360-W_{dc} monocrystalline modules from a Tier 1 supplier (CA NEM 2022) with roughly 300-W_{ac} microinverters and a flush-mounted, pitched-roof racking system. Figure 8 presents the cost drivers, cost categories, inputs, and outputs of the model. Table 4 details the modeled parameters in their intrinsic units.

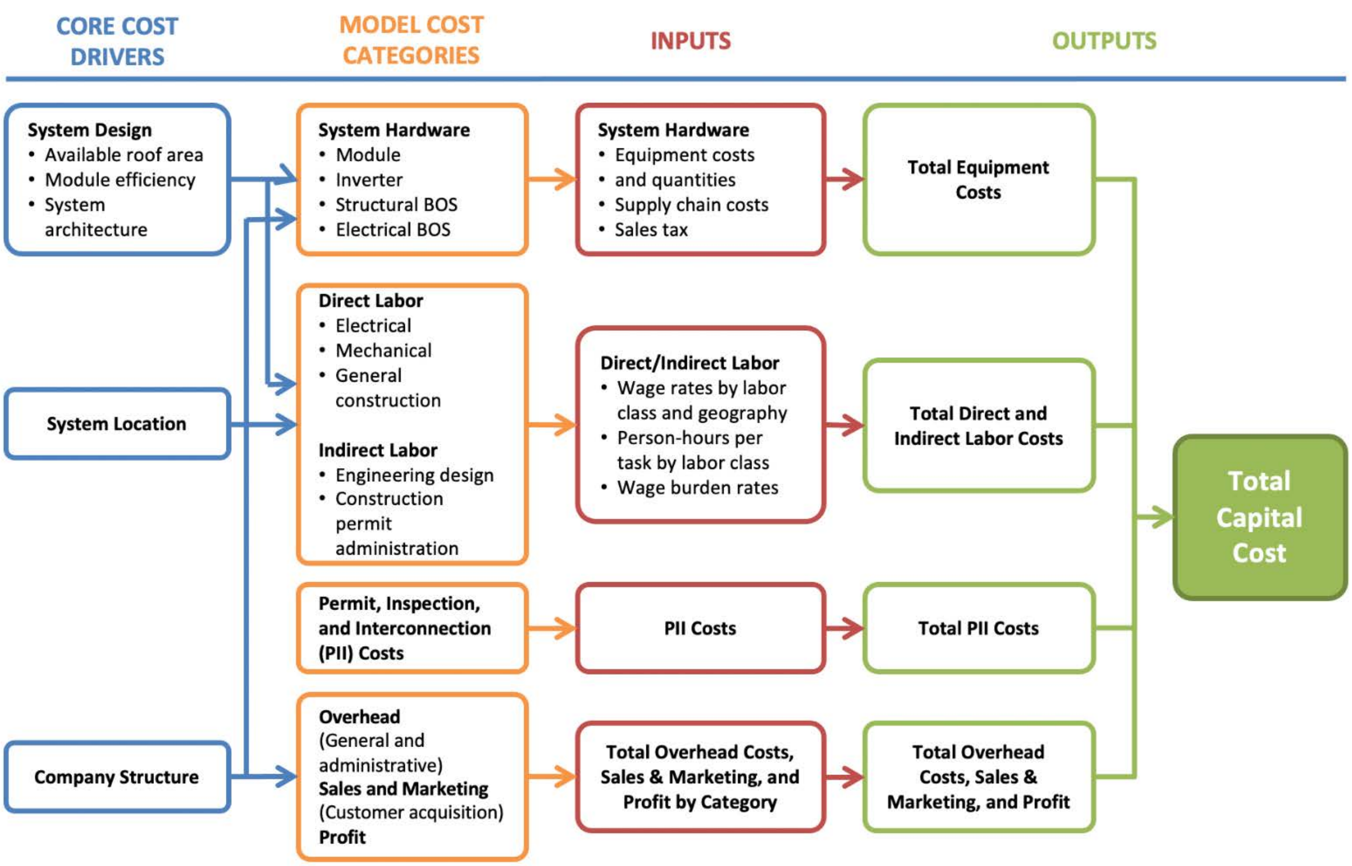

Figure 8. Residential PV: model structure

BOS = balance of system

Table 4. Residential PV: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
System size	7.9 kW_{dc}—representative 22-module system using the following formula: number of modules * module efficiency * module area * average radiation under standard test conditions (STC) = 22 * 20.3% * 1.77 m^2 * 1,000 W_{dc}/m^2 = 7.9 kW_{dc}		CA NEM (2022)
Module efficiency	20.3%—average module efficiency		CA NEM (2022)
Module power	360 W_{dc}—rated module power module efficiency * module area * average radiation under STC = 20.3% * 1.77 m^2 * 1,000 W_{dc}/m^2 = 360 W_{dc}		CA NEM (2022)
Module price	\$0.48/W_{dc} Value derived from bottom-up cost modeling Assumes modules from Southeast Asia, excludes U.S. tariffs in PV supply chain, includes supply chain premium for small installers[a]	\$0.54/W_{dc} Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules Assumes modules from Southeast Asia, influenced by U.S. tariffs in PV supply chain, includes supply chain premium for small installers[a]	MSP from NREL modeling, MMP from Woodmac and SEIA (2022)
Microinverter price	\$0.36/W_{ac} (inverter loading ratio [ILR] = 1.21) Avg of 2017–2021 costs (distorted 2022 costs removed)/(1+25%) Excludes 25% Section 301 tariff Includes supply chain premium for small installers[a]	\$0.53/W_{ac} (ILR = 1.21) Ex-factory gate (first buyer) price, Tier 1 inverters Includes supply chain premium for small installers[a]	Barbose et al. (2021a), Woodmac and SEIA (2022), USITR (2018)
Structural BOS (racking)	\$19.1/m^2 Includes flashing for roof penetrations and all rails and clamps Avg of 2019–2021 costs (distorted 2022 costs removed) Includes supply chain premium for small installers[a]	\$31.5/m^2 Includes flashing for roof penetrations and all rails and clamps 2022 online racking material cost Includes supply chain premium for small installers[a]	Online Material Cost: RENVU (2022), EcoDirect (2022), altE Store (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Electrical BOS	$\$37.2/m^2 + \$1,016$ Conductors, switches, combiners, and transition boxes, as well as conduit, grounding equipment, monitoring system or production meters, fuses, and breakers Avg of 2019–2021 costs (distorted 2022 costs removed) Includes supply chain premium for small installers[a]	$\$43.7/m^2 + \$1,231$ Conductors, switches, combiners, and transition boxes, as well as conduit, grounding equipment, monitoring system or production meters, fuses, and breakers 2022 online electrical material cost Includes supply chain premium for small installers[a]	Online Material Cost: RENVU (2022), EcoDirect (2022), altE Store (2022)
Sales tax	National average—5.1% Sales tax on materials and equipment		RSMeans (2022)
Installation labor	0.56 hours/m^2 for module and racking installation at \$24.00/hour (construction laborer), 0.51 hours/m^2 for electrical installation at \$38.15/hour (electrician)[b] Modeled national average labor rates		BLS (2022b), NREL (2022), RSMeans (2022)
Permitting, inspection, and interconnection (PII)	$1,628 per system installation Completed and submitted applications, fees, design changes, and field inspection		NREL (2022), Cook et al. (2021)
Sales and marketing (customer acquisition)	$3,139 per system installation Initial and final drawing plans, advertising, lead generation, sales pitch, contract negotiation, and customer interfacing		NREL (2022)
Overhead (general and administrative)	$2,060 per system installation Rent, building, equipment, and staff expenses not directly tied to PII, customer acquisition, or direct installation labor		NREL (2022)
Profit	17% Fixed percentage margin applied to all direct costs, including hardware, installation labor, sales tax, installation, and permitting fees		NREL (2022), Fu et al. (2017)

[a] Premiums are 53% for modules, 41% for inverters, and 15% for BOS (LMI 2022, NREL 2022). For all cost values given in dollars per square meter (\$/m^2) terms, the denominator refers to square meters of total module surface area.

[b] Labor rates include a 32.3% burden for workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability, based on the total nationwide average from RSMeans (2022).

5.2 Model Output

Figure 9 compares our MSP and MMP benchmarks for residential systems. For Q1 2022, we assume PV systems use microinverters and are installed by small-scale installers (see Section 4.6). In contrast, the Q1 2021 benchmark was derived from a weighted average of three inverter types as well as installation by small and large installers.

For Q1 2022, our MSP benchmark ($2.55/$W_{dc}$) is 14% lower than our MMP benchmark ($2.95/$W_{dc}$). Our Q1 2022 MMP benchmark is 2% higher than our comparable microinverter-based system benchmark from Q1 2021, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

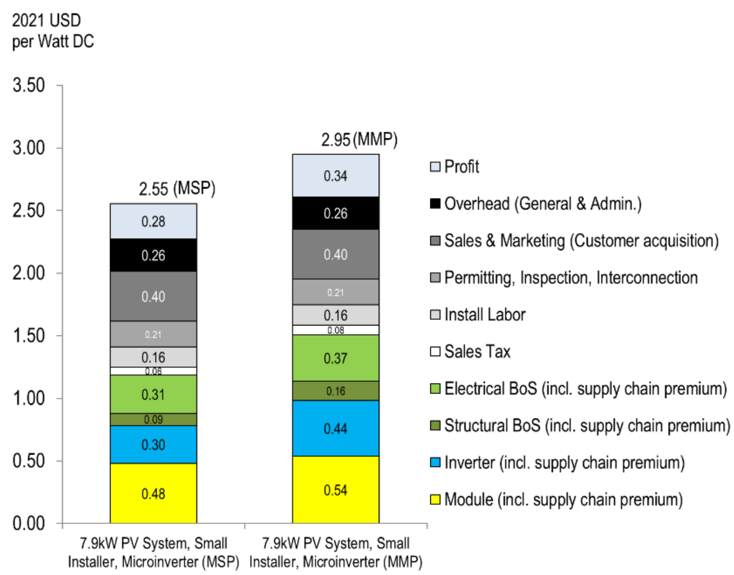

Figure 9. Q1 2022 U.S. benchmark: 7.9-kW$_{dc}$ residential PV system cost (2021 USD/W$_{dc}$)

6 Commercial PV Model

This section describes our commercial PV model's structure and parameters in intrinsic units (Section 6.1) as well as its output (Section 6.2). Commercial PV systems are roughly in the range of 100 kW$_{dc}$ (small nonresidential) to 5 MW$_{ac}$ (large nonresidential) (Barbose et al. 2021a). Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

6.1 Model Structure and Representative System Parameters

We model a 200-kW$_{dc}$, 1,000-volt dc (V$_{dc}$) commercial-scale flat-roof system using a ballasted racking solution on a membrane roof as well as a 500-kW$_{dc}$, 1,000-V$_{dc}$ commercial-scale fixed-tilt ground-mounted system using driven-pile foundations. The ground-mounted system is larger because U.S. ground-mounted systems are larger than rooftop systems on average. Both the rooftop and the ground-mounted PV systems are modeled with three-phase string inverters with an ILR of 1.23. Both use 20.3%-efficient monocrystalline silicon modules from a Tier 1 supplier (CA NEM 2022).

Figure 10 is a schematic of our commercial-scale system cost model, and Table 5 details the modeled parameters in intrinsic units. We separate our cost estimate into EPC and project development functions. Although some firms engage in both activities in an integrated manner, and potentially achieve lower costs and pricing by reducing the total margin across functions, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function.

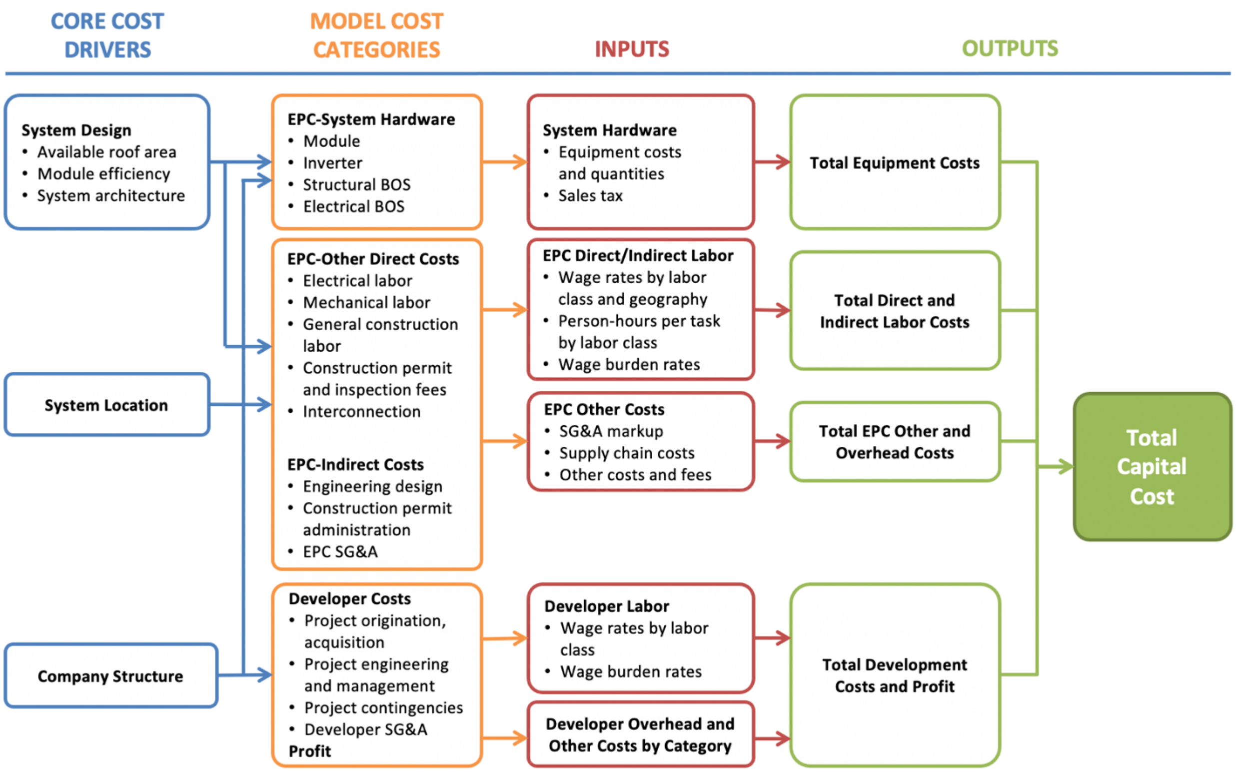

Figure 10. Commercial PV: model structure

SG&A = selling, general, and administrative

Table 5. Commercial PV: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
System size	200 kW_{dc} (rooftop) and 500 kW_{dc} (ground mount)		NREL assumption
Module efficiency	20.3%—national average module efficiency in 2021		CA NEM (2022)
Module power	405 W_{dc}—rated module power module efficiency * module area * average radiation under STC = 20.3% * 1.99 m^2 * 1,000 W_{dc}/m^2 = 405 W_{dc}		CA NEM (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Module price	$0.40/W$_{dc}$ Bottom-up cost modeling Includes supply chain premium for a local installer[a]	$0.45/W$_{dc}$ Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules Includes supply chain premium for a local installer[a]	MSP from NREL modeling, MMP from Woodmac and SEIA (2022)
Three-phase string inverter price	$0.06/W$_{ac}$ (ILR = 1.23) Avg of 2017–2021 costs (distorted 2022 costs removed)/(1+25%) Excludes 25% Section 301 Tariff	$0.07/W$_{ac}$ (ILR = 1.23) Ex-factory gate (first buyer) price, Tier 1 inverters	Barbose et al. (2021a), Woodmac and SEIA (2022), USITR (2018)
Structural BOS (racking)	$25/m^2 (rooftop), $24/m^2 (ground mount) Flat-roof ballasted racking system or fixed-tilt ground-mounted racking system Assumes national average wind and snow loading[b] Avg of 2017–2021 costs (distorted 2022 costs removed)	$27/m^2 (rooftop), $35/m^2 (ground mount) Flat-roof ballasted racking system or fixed-tilt ground-mounted racking system Assumes national average wind and snow loading[b] Q1 2022 material cost	RSMeans (2022), NREL (2022)
Electrical BOS	$27/m^2 + $2,360 (rooftop), $47/m^2 + $18,282 (ground mount) Conductors, conduit and fittings, transition boxes, switchgear, panel boards, and other parts Avg of 2017–2021 costs (distorted 2022 costs removed)	$38/m^2 + $3,816 (rooftop), $50/m^2 + $19,481 (ground mount) Conductors, conduit and fittings, transition boxes, switchgear, panel boards, and other parts Q1 2022 material cost	NREL (2022), RSMeans (2022)
Installation rental equipment	$3.85/m^2 (rooftop), $11.90/m^2 (ground mount) Avg of 2017–2021 costs (distorted 2022 costs removed)	$3.95/m^2 (rooftop), $14.60/m^2 (ground mount) Q1 2022 rental equipment cost	RSMeans (2022)
Installation labor	1.16 hours/m^2 at $22.84/hour (rooftop), 0.88 hours/m^2 at $20.19/hour (ground mount) for civil and electrical work Modeled national average, nonunionized labor rates		BLS (2022b), NREL (2022)
PII	$18,053 (rooftop) and $19,873 (ground mount) including $5,713 fixed permitting cost Construction permit fees, interconnection study fees for existing substation, testing, and commissioning		NREL (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
EPC overhead (percentage of equipment costs)	13% for module, inverter, and BOS material and equipment costs, 54% for labor costs[c] (rooftop) 13% for BOS material and equipment costs, 54% for labor costs[c] (ground mount) Costs and fees associated with EPC overhead, installation labor burden, inventory, shipping, and handling		NREL (2022)
Sales tax	National average—5.8% Sales tax on hardware, BOS materials and equipment		RSMeans (2022)
Developer overhead	30% of module, inverter, BOS materials, rental equipment, labor, and EPC overhead (rooftop) 30% of module, inverter, BOS materials, rental equipment, labor, PII, EPC overhead, and sales tax (ground mount) Assumed to include overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		NREL (2022)
Contingency	4% of module, inverter, BOS materials, rental equipment, labor, and EPC overhead (rooftop) 4% of module, inverter, BOS materials, rental equipment, labor, PII, EPC overhead, and sales tax (ground mount)		NREL (2022)
Profit	7% (rooftop), 8% (ground mount) Applies a fixed percentage margin to all costs, including module, inverter, BOS materials, installation labor and equipment, PII, EPC overhead, sales tax, contingency, and developer overhead		NREL (2022)

[a] 26.9% procurement premium for local installers (LMI 2022, NREL 2022).

[b] Racking companies currently meet the national standard, so there is not as much differentiation by state in the market within rooftop systems. The ground-mounted racking system requires more material, equipment, and labor than the ballasted racking system. However, installation of ground-mounted PV systems at utility scale helps reduce the BOS cost of these systems because of economies of scale. Note that, for all cost values given in dollars per square meter ($/m^2) terms, the denominator refers to square meters of total module surface area.

[c] The 54% for labor costs includes a labor burden rate of 41.7%—representing workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability—plus an average of 12% labor overhead (RSMeans 2022).

6.2 Model Output

Figure 11 compares our MSP and MMP benchmarks for commercial systems. For Q1 2022, our MSP benchmarks ($1.63/$W_{dc}$ for rooftop, $1.71/$W_{dc}$ for ground mount) are 11% and 12% lower than our MMP benchmarks ($1.84/$W_{dc}$ and $1.94/$W_{dc}$), respectively. Our Q1 2022 MMP benchmarks are roughly 8% higher than their counterparts in Q1 2021, because the MMP benchmarks are affected by the market distortion that occurred in Q1 2022.

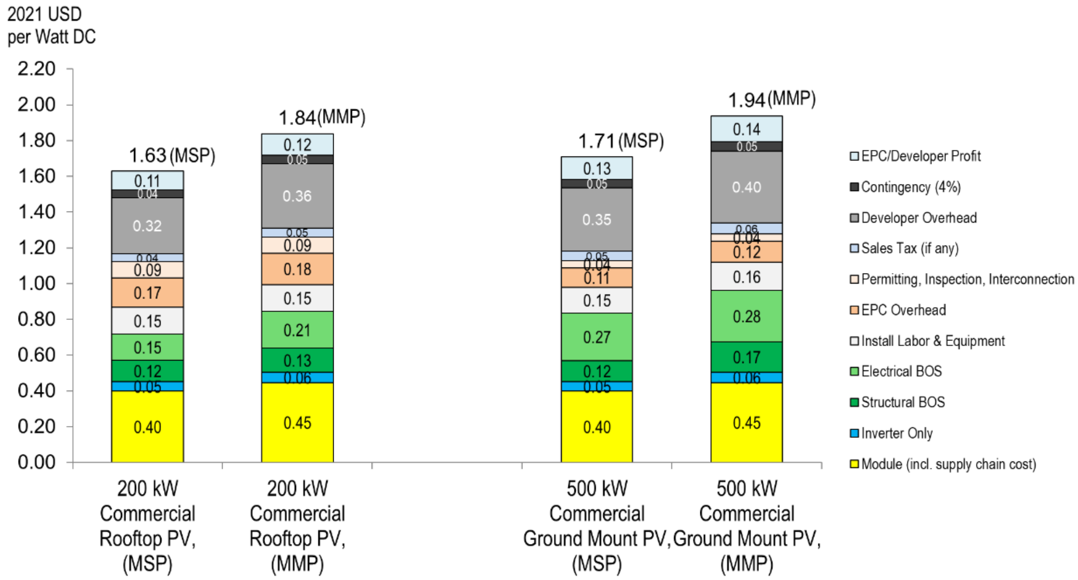

Figure 11. Q1 2022 U.S. benchmark: commercial PV system cost (2021 USD/W_{dc})

7 Utility-Scale PV Model

This section describes our utility-scale PV model's structure and parameters in intrinsic units (Section 7.1) as well as its output (Section 7.2). We assume utility-scale PV systems typically have a system size greater than or equal to 5 MW_{dc}. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

7.1 Model Structure and Representative System Parameters

We model a baseline 100-MW_{dc}, 1,500-V_{dc} tracking utility-scale system using 20.3%-efficient, 1.99-m^2 monofacial monocrystalline silicon modules from a Tier 1 supplier and three-phase central inverters with an ILR of 1.34. We separate our cost estimates into EPC and project-development functions. Although some firms engage in both activities in an integrated manner, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function. Figure 12 is a schematic of our utility-scale system cost model, and Table 6 details its parameters in intrinsic units.

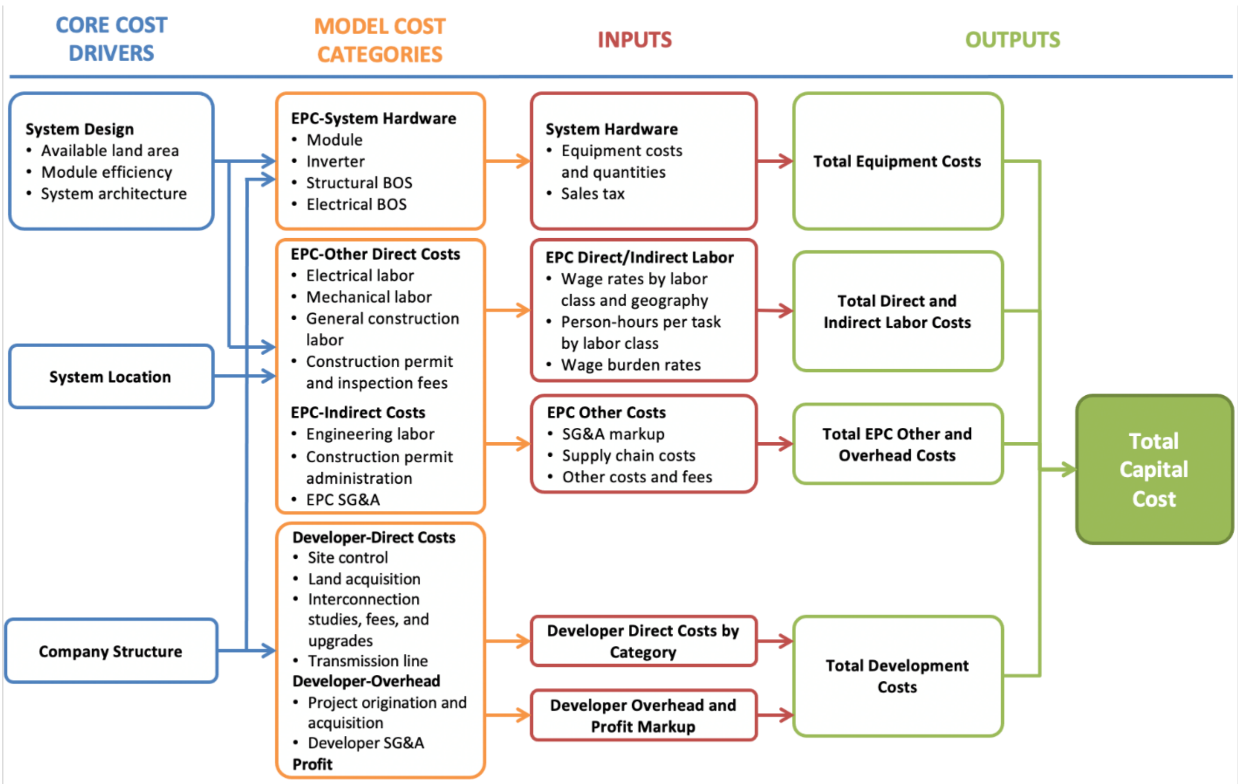

Figure 12. Utility-scale PV: model structure

Table 6. Utility-Scale PV: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
System size	100 MW_{dc}—a large single-axis tracking utility-scale system capacity		Model assumption
Module efficiency	20.3%—national average silicon module efficiency		CA NEM (2022)
Module power	405 W_{dc}—rated module power module efficiency * module area * average radiation under STC = 20.3% * 1.99 m^2 * 1,000 W_{dc}/m^2 = 405 W_{dc}		CA NEM (2022)
Module price	\$0.31/W_{dc} Bottom-up cost modeling No supply chain premium owing to large orders	\$0.35/W_{dc} Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules No supply chain premium owing to large orders	MSP from NREL modeling, MMP from Woodmac and SEIA (2022)
Inverter price	\$0.05/W_{ac} (ILR = 1.34) Avg of 2017–2021 costs (distorted 2022 costs removed)[a]	\$0.04/W_{ac} (ILR = 1.34) Ex-factory gate (first buyer) price, Tier 1 inverters	Woodmac and SEIA (2022), Bolinger et al. (2021)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Structural BOS (racking)	$24.5/m^2 (tracking)[b] Avg of 2017–2021 costs (distorted 2022 costs removed)	$35.9/m^2 (tracking) Q1 2022 material cost	Model assumptions, RSMeans (2022), NREL (2022)
Electrical BOS	$15.4/m^2 + $64,865 Modeled 1,500-$V_{dc}$ system, including conductors, conduit and fittings, transition boxes, switchgear, panel boards, on-site transmission, and other electrical connections Avg of 2017–2021 costs (distorted 2022 costs removed)	$16.2/m^2 + $73,000 Modeled 1,500-$V_{dc}$ system, including conductors, conduit and fittings, transition boxes, switchgear, panel boards, on-site transmission, and other electrical connections Q1 2022 material cost	Model assumptions, RSMeans (2022), NREL (2022)
EPC overhead (percentage of equipment costs)	$106,000 + 8.3% * (electrical BOS, structural BOS, and installation rental equipment) + 54% * direct installation labor[c] Costs associated with installation labor burden, EPC SG&A, warehousing, shipping, and logistics		NREL (2022)
Installation rental equipment	$11.1/m^2 (100-MW tracking) Avg of 2017–2021 costs (distorted 2022 costs removed)	$13.5/m^2 (100-MW tracking) Q1 2022 rental equipment cost	RSMeans (2022)
Direct installation labor	0.7 hours/m^2 for all civil and electrical work at $15.6/hour Modeled national average, nonunionized labor rates		BLS (2022b), NREL (2022)
Sales tax	National average—5.8% Sales tax on hardware, material, and equipment costs		RSMeans (2022)
PII	$0.02/$W_{ac}$ + $209,466 Construction permit fees, interconnection, testing, and commissioning		NREL (2022)
Transmission line (gen-tie line)	$600,734/mile 1.7 miles[d] Avg of 2017–2021 costs (distorted 2022 costs removed)	$765,941/mile 1.7 miles[d] Q1 2022 material cost	Model assumptions, NREL (2022), RSMeans (2022)
Developer overhead	$550,000 + 1.5% * (module, inverter, structural and electrical BOS, installation labor and equipment, EPC overhead, PII, and sales tax) Assumed to include overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		Model assumptions, NREL (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Contingency	3% Estimated as markup on module, inverter, BOS material and equipment, sales tax, EPC overhead, and permitting cost		NREL (2022)
Profit	$200,000 + 4.9% * (all system costs) Applies a percentage margin to all costs, including module, inverter, structural and electrical BOS, labor and equipment, EPC overhead, PII, sales tax, developer overhead, contingency, and transmission		NREL (2022)

[a] Most central utility-scale inverters installed in the United States are manufactured in Europe and are not subject to Section 301 U.S. tariffs on Chinese products (Wood Mackenzie 2022c, Woodmac and SEIA 2021). For this reason, we do not adjust the MSP value for Section 301 tariffs.

[b] Note that, for all cost values given in dollars per square meter ($\$/m^2$), the denominator refers to square meters of total module surface area.

[c] The 54% for labor costs includes a labor burden rate of 41.7%—representing workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability—plus an average of 12% labor overhead (RSMeans 2022).

[d] System < 10 MW_{dc} uses 0 miles for gen-tie line, thus no transmission cost; system > 200 MW_{dc} uses 5 miles for gen-tie line; and system = 10–200 MW_{dc} uses linear interpolation.

7.2 Model Output

Figure 13 compares our MSP and MMP benchmarks for single-axis-tracker 100-MW_{dc} utility-scale PV systems. For Q1 2022, our MSP benchmark with tracking ($\$0.87/W_{dc}$) is 12% lower than our MMP benchmark with tracking ($\$0.99/W_{dc}$). Our Q1 2022 MMP benchmark with tracking is 6% higher than its counterpart in Q1 2021, because of the market distortion that occurred in Q1 2022.

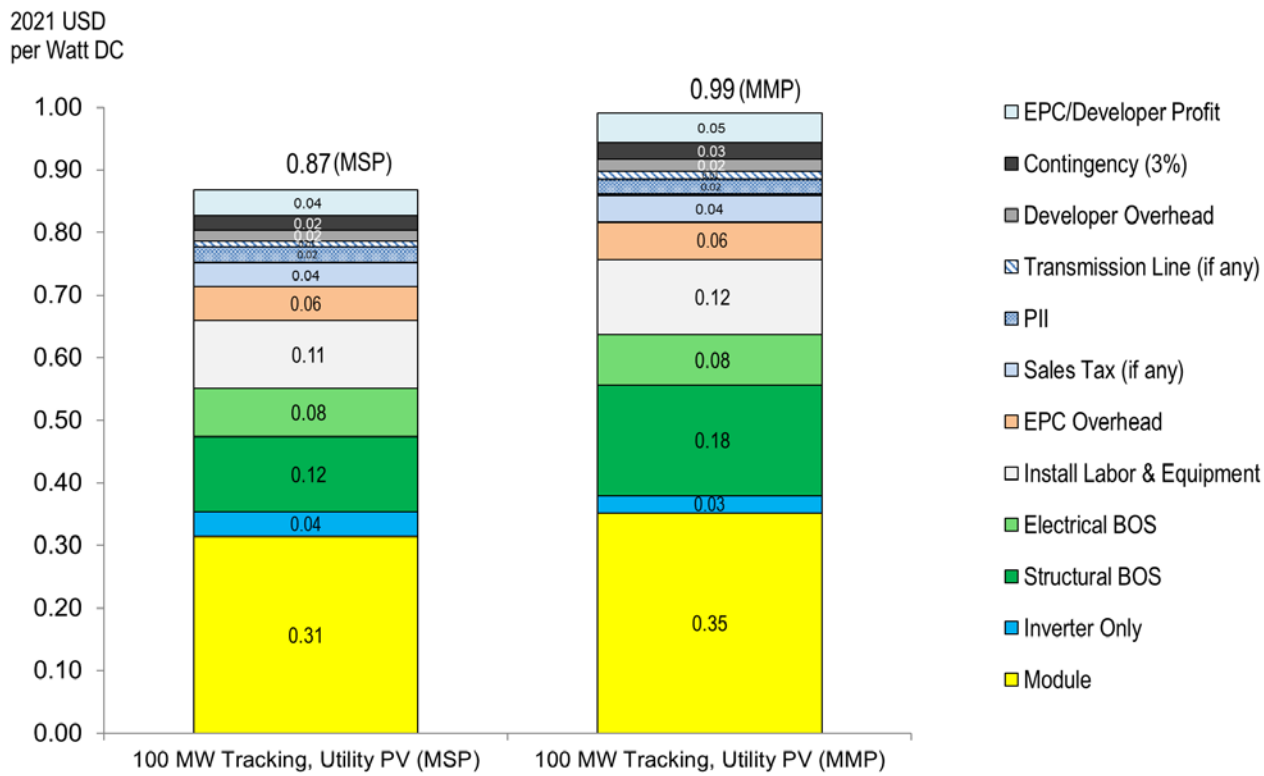

Figure 13. Q1 2022 U.S. benchmark: utility-scale PV systems (2021 USD/W_{dc})

8 Residential Storage and PV-Plus-Storage Model

To analyze component costs and system prices for PV-plus-storage systems installed in Q1 2022, we adapt NREL's component- and system-level modeling approach for standalone PV. For this report, system configuration refers to five characteristics that determine a PV-plus-storage system's functionality:

- PV system rated power capacity (kW_{dc})
- Inverter rated power capacity (kW_{ac})
- Battery energy capacity (kWh)
- Battery power capacity (kW_{dc})
- Whether the battery is dc- or ac-coupled.[8]

Customer preference for specific characteristics is based on several factors, including cost, load profile, and planned use of the system for load shifting (storing energy in one period for use in a later period). In general, customers who have loads with high peaks of short duration may desire a high-power (high-kW) battery capable of meeting the high peak. Customers who have flatter loads with lower peaks of longer duration may prefer a high-energy (high-kWh) battery capable of longer-duration energy discharge. Because of the historical levels of residential PV-plus-storage installations, we now have significantly more system characteristic data on which to base our benchmark (unlike previous benchmarking reports, in which we used optimization calculations). We benchmark a 5-kW_{dc} (12.5-kWh_{dc}) residential battery system, based on data reported by Barbose et al. (2021b).

A PV array, a battery, and at least one inverter are the fundamental components of every PV-plus-storage system. Additional component requirements are determined by whether the system is dc- or ac-coupled.[9] A dc-coupled system often requires a charge controller to step down the PV output voltage to a level that is safe for the battery, whereas an ac-coupled system requires a grid-tied inverter to feed PV output directly to the customer's load or the grid.[10] For a detailed discussion of the differences and considerations related to dc- versus ac-coupled system configurations, see Ardani et al. (2017).

Sections 8.1 and 8.2 present the residential storage and PV-plus-storage cost models, and Section 8.3 shows the model outputs. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

[8] NREL's modeled dc-coupled system includes a single dual-function inverter that is tied to both the PV array and the battery. In our ac-coupled system, to charge a battery, PV power is first converted (dc to ac) through a grid-tied inverter and then converted (ac to dc) through a battery-based inverter.
[9] Our discussion is simplified to explain the basic technical differences between ac- and dc-coupled systems. The decision to use ac- or dc-coupling might also be driven by nontechnical factors such as policy, contractual obligations, and economics.
[10] Some Li-ion battery packs have built-in safety controls, such as those integrated in a battery management system, but some do not. For consistency, our model assumes there is a dedicated charge controller.

8.1 Lithium-Ion Standalone Storage System Cost Model

The residential storage market is predominantly composed of fully integrated storage kits, which include lithium-ion (Li-ion) battery packs, inverters, field wiring, disconnect, and casing. Although this equipment is sold as one product, we model these components separately to compare costs across storage kit sizes and configurations. Table 7 presents the modeled parameters in intrinsic units for the residential standalone storage costs (no PV).

Table 7. Residential Storage Only: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Rated (nameplate) system size	5-kW_{dc}/12.5-kWh_{dc} storage with an 8-kW_{ac} inverter Typical U.S. residential battery system 1.5-m^2 footprint per battery pack		Barbose et al. (2021b)
Battery pack cost	\$235/kWh MMP*(1–17.04%) Accounts for average cost reduction rate of turnkey battery systems between 2017 and 2021	\$283/kWh 2-hour battery pack cost adjusted to inflation (+) 31.5% residential battery supply premium	BNEF (2021), NREL (2022)
Battery-based inverter cost	\$0.23/W_{ac} MMP/(1+25%) Removes Section 301 tariff	\$0.29/W_{ac} 2020 BNEF battery inverter cost adjusted for inflation	BNEF (2020), NREL (2022), USITR (2018)
BOS cost	\$1,362 (ac-coupled) 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 Avg of 2017–2021 costs (distorted 2022 costs removed)	\$1,567 (ac-coupled) 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 2022 online material cost	Online Material Cost: RENVU (2022), EcoDirect (2022), altE Store (2022)
Supply chain costs	6.5% of cost of battery, battery inverter, and BOS		NREL (2022), LMI (2022)
Engineering fee	\$95 per system Engineering design and professional engineer-stamped calculations and drawings		NREL (2022)
PII	\$1,633 including \$286 permit fee per system		NREL (2022)
Sales tax	National average—5.1% Sales tax on battery, battery inverter, BOS, and permitting cost		RSMeans (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Direct installation labor	20.8 hours/m[2] at $34.7/hour for hardware installation and electrical work[a] National average, nonunionized labor rates		BLS (2022b), NREL (2022)
Sales and marketing (customer acquisition)	$3,851 per system installation Cost associated with selling a storage system		NREL (2022)
Overhead (general and administrative)	$2,285 per system installation Assumed to include rent, building, equipment, and staff expenses not directly tied to PII, customer acquisition, or direct installation labor		NREL (2022)
Profit (%)	17% Fixed percentage margin applied to battery, battery inverter, BOS, install labor, supply chain, and sales tax		NREL (2022)

[a] Note that, for all values given in per square meter (m^2) terms, the denominator refers to square meters of battery pack footprint. The representative system has 8.3 kWh/m^2. Labor rates include a 54% burden for workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability, based on the total nationwide average from RSMeans (2022).

Figure 14 compares our MSP and MMP benchmarks for ac-coupled residential standalone storage systems. For Q1 2022, our MSP benchmark ($17,139) is 9% lower than our MMP benchmark ($18,791). Our Q1 2022 MMP benchmark is 2% higher than our benchmark from Q1 2021 in 2021 USD, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

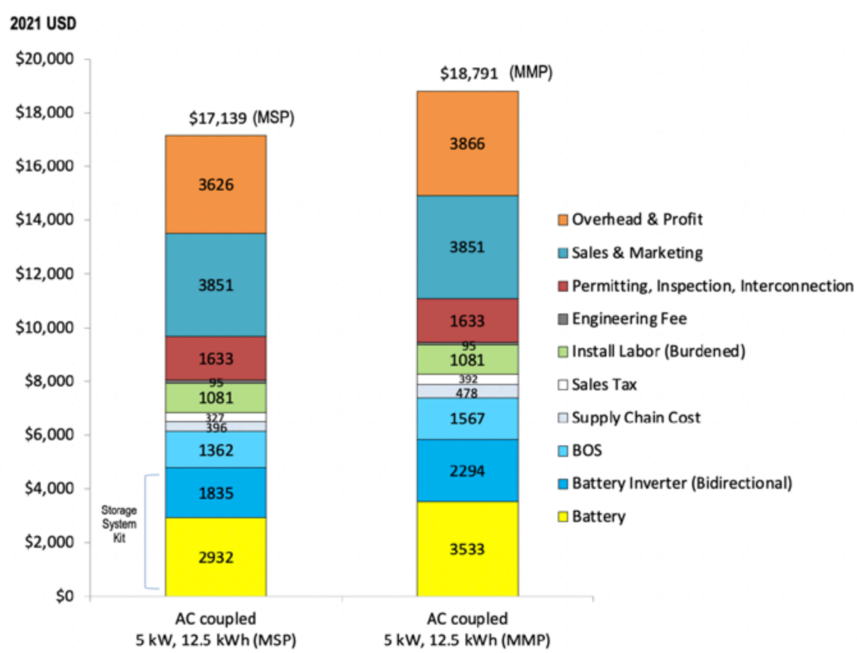

Figure 14. Q1 2022 U.S. benchmark: standalone residential storage system

8.2 PV-Plus-Storage System Cost Model

We model a 7.9-kW_{dc} PV system coupled with a 5-kW_{dc}/12.5-kWh_{dc} storage system using the same PV parameters we use with our standalone PV system and standalone storage system, except we consider the symbiotic benefit of ac coupling. Figure 20 is a schematic of typical dc- and ac-coupled PV systems with on-site battery storage. Table 8 presents changes to the standalone residential PV and storage system cost models when PV and storage are combined.

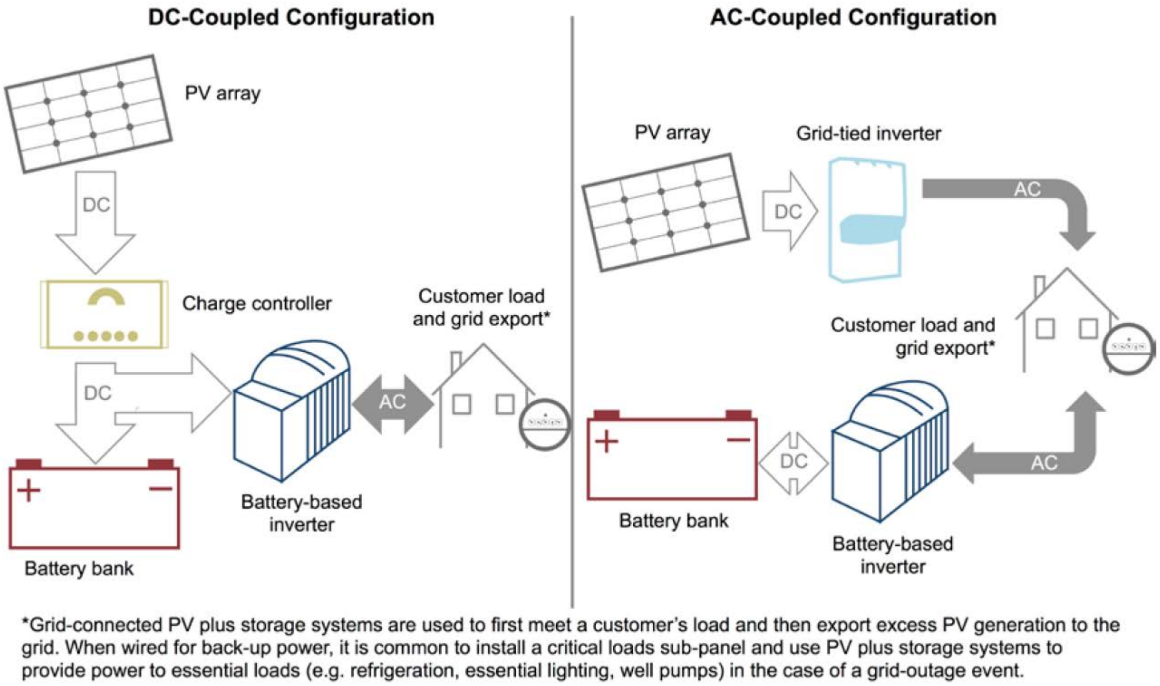

Figure 15. Modeled dc- and ac-coupled system configurations

Figure is simplified for illustrative purposes.
Source: Feldman et al. (2021)

Table 8. Changes to Residential PV and Storage Models When PV and Storage Are Combined

Category	Modeled Value	Description
Electrical BOS	90% of the combined BOS costs for PV and battery standalone systems	Duplicative parts are removed
Installation labor	90% of the combined installation labor costs for PV and battery standalone systems	Duplicative work is removed
PII	Only includes PII associated with standalone PV system	Duplicative work is removed
Profit	Assumes 15% markup on PV modules, battery, PV and battery inverter, BOS material, and installation labor	Cost of combined system is lower than the cost of separate systems, so the profit markup is lower as well

8.3 Model Output

Figure 16 compares our MSP and MMP benchmarks for ac-coupled residential PV-plus-storage systems. For Q1 2022, our MSP benchmark ($33,858) is 12% lower than our MMP benchmark ($38,295). Also, the Q1 2022 MMP of the ac-coupled PV-plus-storage system is 6% higher than the Q1 2021 benchmark system cost adjusted to 2021 USD.

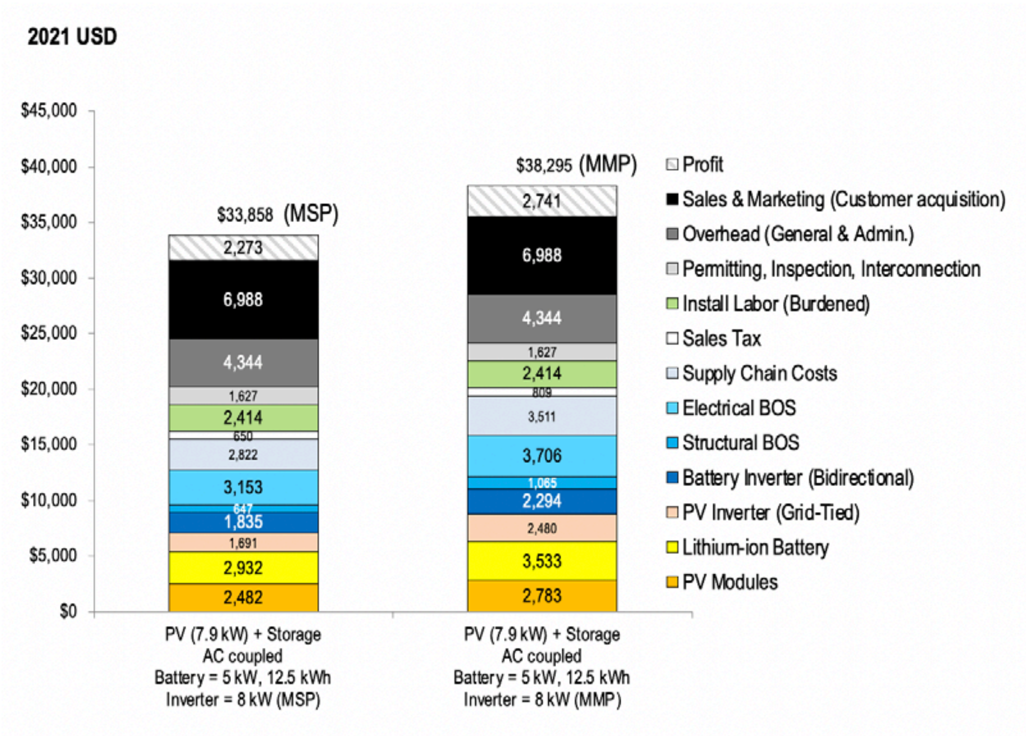

Figure 16. Q1 2022 U.S. benchmark: ac-coupled residential PV-plus-storage systems

9 Commercial Storage and PV-Plus-Storage Model

To analyze component costs and system prices for commercial PV-plus-storage systems installed in Q1 2022, we adapt NREL's component- and system-level modeling approach for standalone PV and standalone storage in a similar manner as for the residential PV-plus-storage system. Customer preference for specific characteristics is based on several factors, including cost, load profile, and planned use of the system for load shifting (storing energy in one period for use in a later period). In general, customers who have loads with high peaks of short duration may desire a high-power (high-kW) battery capable of meeting the high peak. Customers who have flatter loads with lower peaks of longer duration may prefer a high-energy (high-kWh) battery capable of longer-duration energy discharge.

Sections 9.1 and 9.2 present the commercial storage and PV-plus-storage cost models, and Section 9.3 shows the model outputs. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

9.1 Lithium-Ion Standalone Storage System Cost Model

To reduce installation costs, some battery manufacturers combine Li-ion battery cells, a battery management system, and the battery inverter in one compact unit as an ac battery (Sonnen Batterie 2018). However, in this report, we focus on traditional dc batteries typically configured with the components shown in Figure 17 and Figure 18.

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)

Figure 17. Traditional commercial and utility-scale Li-ion energy storage components

HVAC = heating, ventilating, and air conditioning

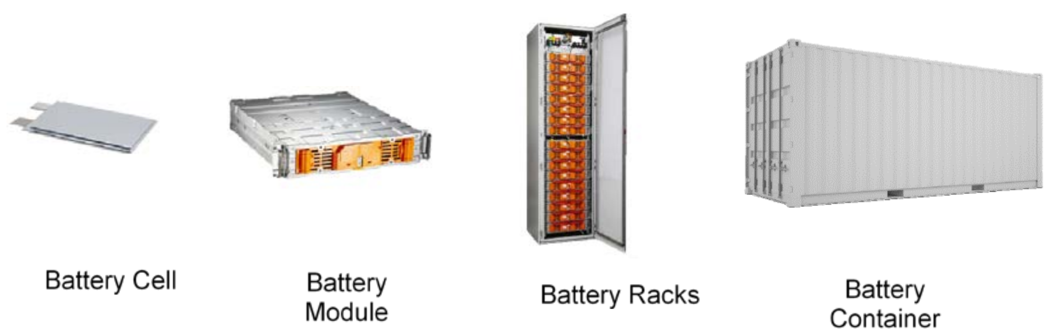

Figure 18. Battery system components

Source: 2018 North American Generator Forum/Energy Systems Integration Group Workshop

Table 9 lists our modeled parameters in intrinsic units for a commercial energy storage system. This year, we assumed the battery size to be 300 kW_{dc} because it is an appropriate match to the representative 500-kW_{dc} benchmark commercial PV system.

Table 9. Commercial Li-ion Energy Storage System: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Battery total size	300 kW rated dc power with a 300-kW$_{ac}$ bidirectional inverter 1.20 MWh rated (usable) dc energy storage		Denholm et al. (2017), NREL (2022)
Duration	4.0 hours Duration = rated energy / rated power		NREL (2022)
Battery size per container	1.8 MWh per 20-ft container with 15-m^2 footprint area[a]		NREL (2022)
Round-trip efficiency (RTE)	90% Round-trip efficiency		NREL (2022)
Min. state of charge (SOC) and max. SOC	10% and 90% Minimum and maximum state of charge Affects the usable energy storage rating		NREL (2022)
Li-ion battery price ($/kWh)	4 hours: $157/kWh MMP*(1–17.04%) Accounts for average cost reduction rate of turnkey battery systems between 2017 and 2021	4 hours: $190/kWh BNEF 2021 price adjusted for inflation (+) 15% commercial battery supply premium	BNEF (2021), NREL (2022)
Battery central inverter price	$0.05/W$_{ac}$ MMP/(1+25%) Removes Section 301 tariff	$0.06/W$_{ac}$ 2019 Woodmac battery inverter cost adjusted for inflation	Wood Mackenzie (2019)
Battery cabinet	$332/kWh For a 1,200-kWh system Includes battery packs, containers, thermal management system, and fire suppression system Battery MSP + avg of other material costs from 2017–2021 (distorted 2022 costs removed)	$393/kWh For a 1,200-kWh system Includes battery packs, containers, thermal management system, and fire suppression system 2022 typical material cost	NREL (2022)
Structural BOS	$1,681/m^2 For a 1,200-kWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers Avg of 2017–2021 material costs (distorted 2022 costs removed)	$1,377/m^2 For a 1,200-kWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers 2022 typical material cost	NREL (2022), RSMeans (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Electrical BOS	$\$5{,}503/m^2$ For a 1,200-kWh system Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing Avg of 2017–2021 material costs (distorted 2022 costs removed)	$\$5{,}533/m^2$ For a 1,200-kWh system Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing 2022 typical material cost	NREL (2022), RSMeans (2022)
Sales tax	National average—5.8% Sales tax on battery cabinet, inverter, and BOS material		RSMeans (2022)
PII	$16,348, includes $8,661 for permitting fee For a 1,200-kWh system Construction permit fees, interconnection study, interconnection inspection, and interconnection fee		NREL (2022)
Direct installation labor	223 hours/m^2 at $24/hour National average, nonunionized labor rates		BLS (2022b), NREL (2022)
Installation equipment	$\$6/m^2$ Avg of 2017–2021 costs (distorted 2022 costs removed)	$\$6/m^2$ Q1 2022 rental equipment cost	RSMeans (2022)
EPC overhead (percentage of equipment costs)	13% of BOS equipment and material costs + 54% * direct installation labor Assumes costs and fees associated with EPC overhead, inventory, shipping, and handling		NREL (2022)
Developer overhead	6% of battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, and EPC overhead Assumed to include overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		NREL (2022)
Contingency	4% Estimated as markup on the battery pack, inverter, BOS, installation labor and equipment, sales tax, and EPC overhead		NREL (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
EPC/developer net profit	5% Applies a percentage margin to all costs, including battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, contingency, EPC overhead, and developer overhead		NREL (2022)

[a] Note that, for all values given in per square meter (m^2) terms, the denominator refers to square meters of battery pack footprint. The representative system has 80 kWh/m^2.

Figure 19 compares our MSP and MMP benchmarks for a 300-kW_{dc}, 4-hour commercial standalone storage system. For Q1 2022, our MSP benchmark ($732,395) is 9% lower than our MMP benchmark ($806,132). Because of a major change in system configuration between Q1 2021 and Q1 2022 (the Q1 2021 benchmark assumes a 600-kW_{dc} system as opposed to a 300-kW_{dc} system), the benchmark costs across those years cannot be compared directly.

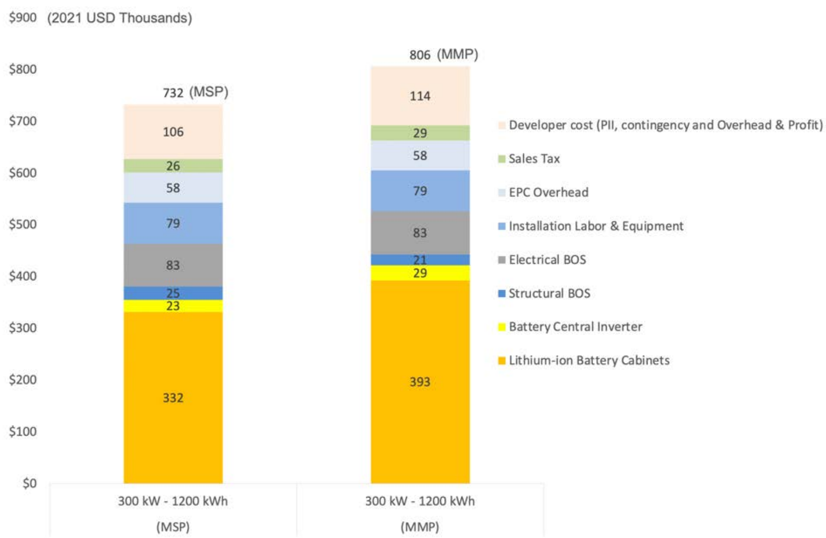

Figure 19. Q1 2022 U.S. benchmark: standalone commercial Li-ion battery storage system

9.2 PV-Plus-Storage System Cost Model

We model a 500-kW_{dc} fixed-tilt, ground-mounted commercial PV system coupled to a 300-kW_{dc} storage system, with 4 hours (1,200 kWh) of storage, using the same PV parameters we use with our standalone PV system and the same storage parameters we use with our standalone storage system, except for the effects of on-site coupling listed in Table 10.

Table 10. Changes to Commercial PV and Storage Model When PV and Storage Are Combined

Category	Modeled Value	Description
Electrical BOS	PV electrical BOS + storage electrical BOS + (3% * storage electrical BOS)	Assumes higher wiring/conduit and dc cabling requirement for coupled configurations
Installation labor	75% * (PV installation labor and equipment + storage installation labor and equipment)	Duplicative work related to site staging and site preparation are removed assuming more efficient labor utilization
EPC overhead	13% * (structural BOS + electrical BOS + installation labor)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
Sales tax	5.8% * (PV modules, battery cabinet, inverters, and BOS materials)	Cost of sales tax multipliers is lower for combined system than for separate systems, so the tax is lower
PII	Storage PII * 1.02	Assumes slightly higher PII cost than standalone storage system due to additional hardware installed at the point of interconnect
Contingency	3% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of contingency multipliers is lower for combined system than for separate systems, so the contingency cost is lower
Developer overhead	6% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
EPC/developer net profit	8% * (PV modules, battery cabinet, inverters, BOS materials, PII, contingency, developer overhead)	Cost of profit multipliers is lower for combined system than for separate systems, so the profit is lower

9.3 Model Output

Figure 20 compares our MSP and MMP benchmarks for an ac-coupled commercial storage system with a 500-kW_{dc} PV system. For Q1 2022, our MSP benchmark ($1.27 million) is 12% lower than our MMP benchmark ($1.44 million). Because of a major change in system configuration between Q1 2021 and Q1 2022 (the Q1 2021 benchmark assumes a 600-kW_{dc} storage system as opposed to a 300-kW_{dc} system), the benchmark costs across those years cannot be compared directly.

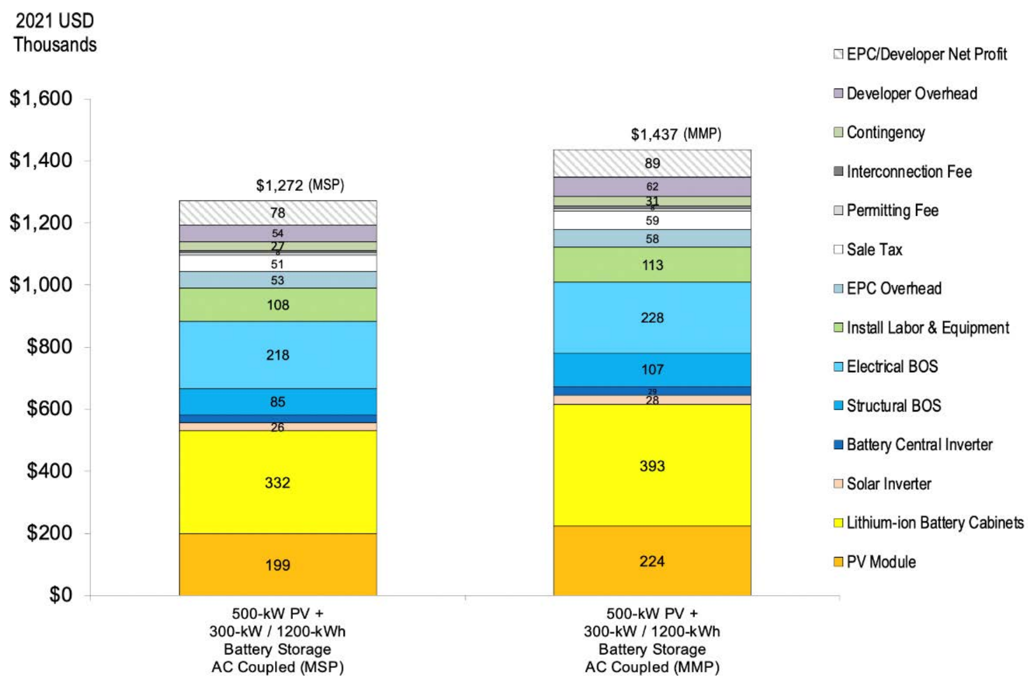

Figure 20. Q1 2022 U.S. benchmark: commercial ac-coupled PV-plus-storage systems (4-hour duration)

Figure 21 summarizes our MSP results for several system types and configurations:

- Standalone 500-kW_{dc} commercial fixed-tilt ground-mounted PV system ($0.85 million)
- Standalone 300-kW_{dc}/1.2-MWh, 4-hour-duration energy storage system ($0.73 million)
- ac-coupled PV (500 kW_{dc}) plus storage (300 kW_{dc}/1.2 MWh, 4-hour duration) system ($1.27 million)
- PV (500 kW_{dc}) plus storage (300 kW_{dc}/1.2 MWh, 4-hour duration) system with PV and storage components sited in different locations ($1.59 million).

Co-locating the PV and storage subsystems produces cost savings by reducing costs related to site preparation, permitting and interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit. The cost of the ac-coupled system is 20% lower than the cost of the system with PV and storage sited separately.

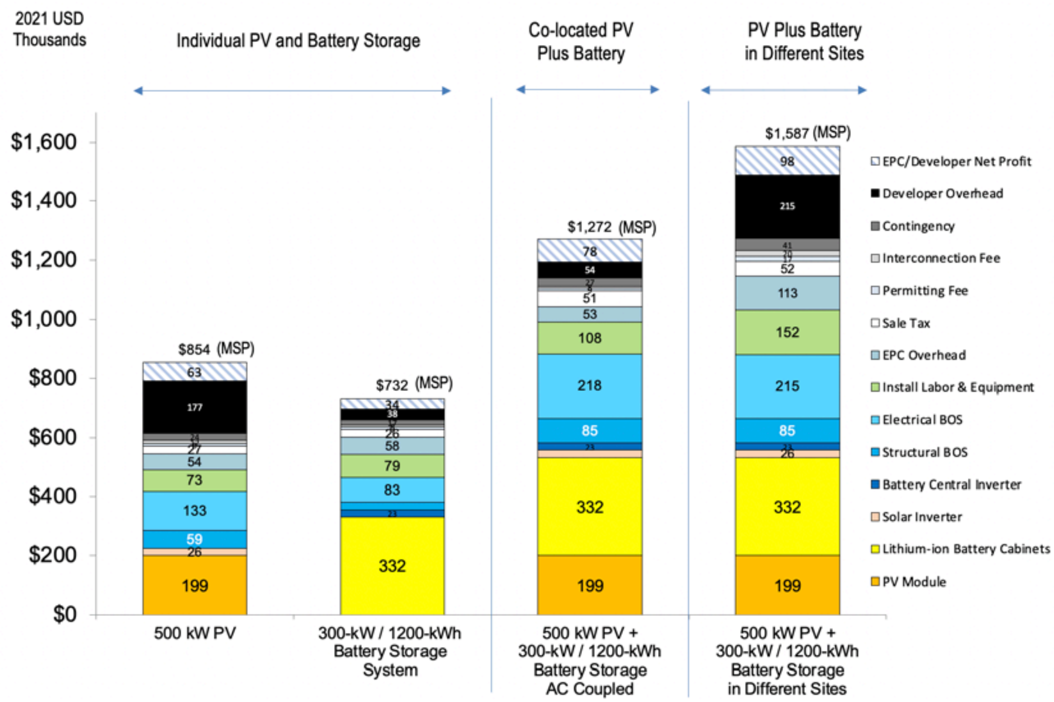

Figure 21. Q1 2022 commercial PV-plus-storage system MSP benchmark (4-hour duration) in different sites and the same site (ac-coupled)

10 Utility-Scale Storage and PV-Plus-Storage Model

To analyze component costs and system prices for utility-scale PV-plus-storage systems installed in Q1 2022, we adapt NREL's component- and system-level modeling approach for standalone PV and standalone storage in a similar manner as for the residential and commercial PV-plus-storage systems.

Sections 10.1 and 10.2 present the utility-scale storage and PV-plus-storage cost models, and Section 10.3 shows the model outputs. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

10.1 Lithium-Ion Standalone Storage System Cost Model

Figure 22 details the bottom-up cost structure of our standalone utility-scale storage model, which uses a structure like that of our bottom-up PV cost model (Ramasamy et al. 2021). Total system upfront capital costs are broken into EPC costs and developer costs. EPC nonhardware, or "soft," costs are driven by labor rates and labor productivities. We adapt engineering design and cost-estimating models from RSMeans (2022) to determine the EPC hardware costs (including module/battery racking, mounting, wiring, containerization, and foundation) and related EPC soft costs (including related labor and equipment hours).

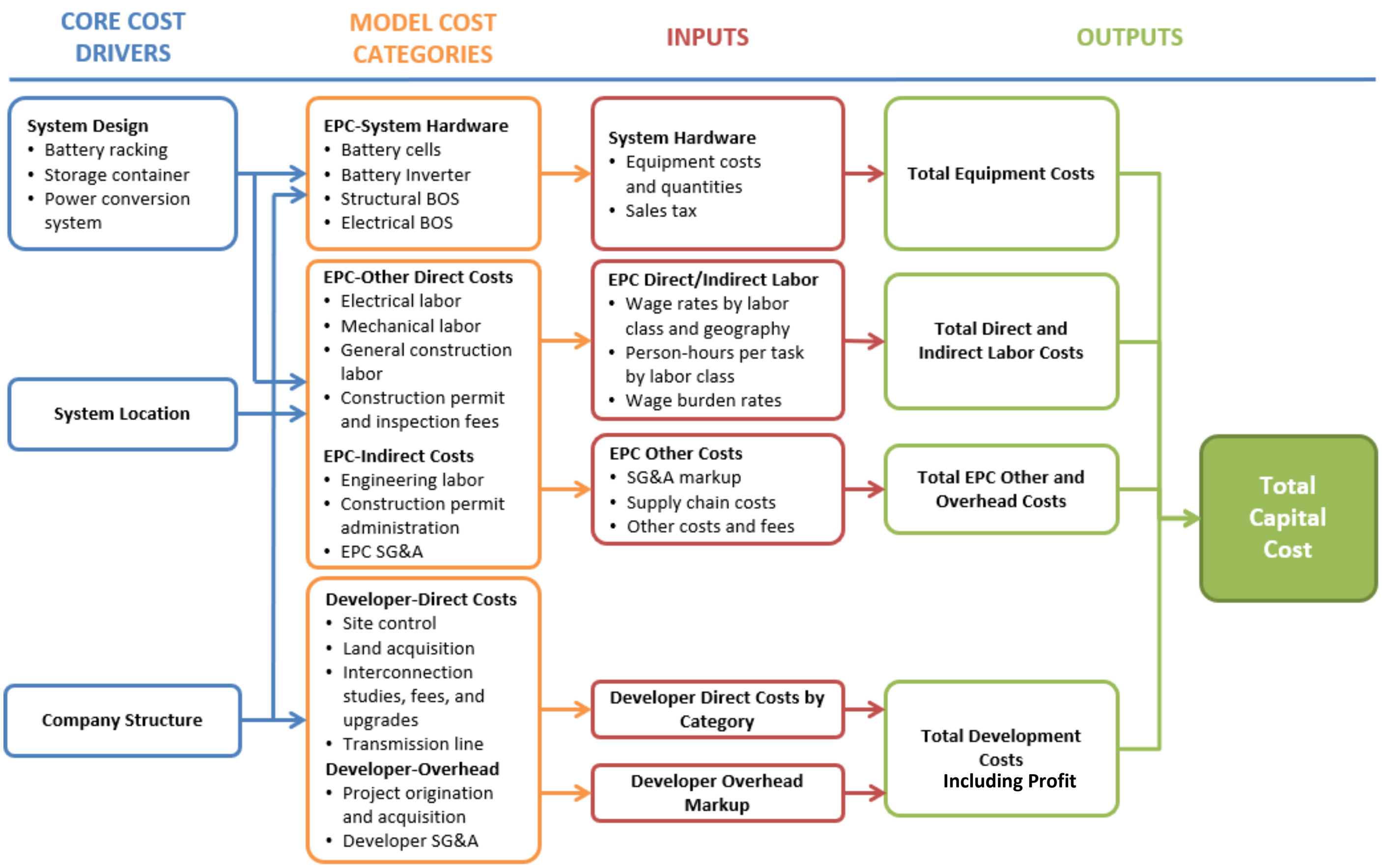

Figure 22. Utility-scale standalone storage: model structure

The major storage components we model for utility-scale standalone storage systems are the same as those summarized in Figure 17 and Figure 18 (page 36) for the commercial standalone storage model. Table 11 lists our modeled parameters in intrinsic units for such a utility-scale energy storage system. We select the battery size (60 MW_{dc} and 240 MWh) to be compatible with our benchmark utility-scale PV system.[11]

Table 11. Utility-Scale Li-ion Energy Storage System: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Battery total size	60 MW rated dc power with a 60-MW_{ac} bidirectional inverter 240 MWh rated (usable) energy storage		Denholm et al. (2017), NREL (2022)
Duration	4.0 hours Duration = rated energy / rated power		NREL (2022)
Battery size per container	4 MWh per 40-ft container with 30-m^2 footprint area[a]		NREL (2022)

[11] For a 100-MW_{dc} PV system with an ILR of 1.34.

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
RTE	90% Round-trip efficiency		NREL (2022)
Min. SOC and max. SOC	10% and 90% Minimum and maximum state of charge Used to determine rated battery energy storage		NREL (2022)
Li-ion battery price ($/kWh)	4 hours: $137/kWh MMP*(1–17.04%) Accounts for average cost reduction rate of turnkey battery systems between 2017 and 2021	4 hours: $165/kWh BNEF 2021 price adjusted for inflation	BNEF (2021), NREL (2022)
Bidirectional inverter price	$0.07/W$_{ac}$ 2019 Woodmac battery inverter cost adjusted for inflation		Wood Mackenzie (2019)
Battery cabinet	$226/kWh For a 240-MWh system Includes battery packs, containers, thermal management system, and fire suppression system Battery MSP + avg of other material costs from 2017–2021 (distorted 2022 costs removed)	$270/kWh For a 240-MWh system Includes battery packs, containers, thermal management system, and fire suppression system 2022 typical material cost	NREL (2022)
Structural BOS	$500/m^2 For a 240-MWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers Avg of 2017–2021 material costs (distorted 2022 costs removed)	$476/m^2 For a 240-MWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers 2022 typical material cost	NREL (2022), RSMeans (2022)
Electrical BOS	$5,936/m^2 Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing	$5,978/m^2 Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing	NREL (2022), RSMeans (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Sales tax	National average—5.8% Sales tax on battery cabinet, inverter, and BOS material		RSMeans (2022)
PII	\$1,549,755 per system,[b] includes a permitting fee of \$184,876 Assumed to include construction permit fees, interconnection study, interconnection inspection, and interconnection fee		NREL (2022)
Direct installation labor	95 hours/m^2 at \$17/hour National average, nonunionized labor rates		BLS (2022b), NREL (2022)
Installation equipment	\$9/m^2 Avg of 2017–2021 costs (distorted 2022 costs removed)	\$10/m^2 Q1 2022 rental equipment cost	RSMeans (2022)
EPC overhead (percentage of equipment costs)	8.67% of BOS material and equipment costs + 54% * direct installation labor costs[b] Costs and fees associated with EPC overhead, inventory, shipping, and handling		NREL (2022)
Developer overhead	3% of battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, and EPC overhead[b] Includes overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		NREL (2022)
Contingency	3% Estimated as markup on the battery pack, inverter, BOS, installation labor and equipment, sales tax, and EPC overhead		NREL (2022)
EPC/developer net profit	5%[b] Applies a percentage margin to all costs, including battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, contingency, EPC overhead, and developer overhead		NREL (2022)

[a] Note that, for all values given in per square meter (m^2) terms, the denominator refers to square meters of battery pack footprint. The representative system has 133 kWh/m^2.

[b] In contrast with the utility-scale PV parameters (Table 6), PII, EPC overhead, developer overhead, and EPC/developer net profit are given here as single values for 60-MW/240-MWh utility-scale storage systems only, because we do not have data that enables us to estimate how these values scale with different system sizes.

Figure 23 compares our MSP and MMP benchmarks for a 60-MW$_{dc}$, 4-hour utility-scale standalone storage system. For Q1 2022, our MSP benchmark (\$95 million) is 12% lower than our MMP benchmark (\$107 million). The Q1 2022 MMP benchmark is 12% higher than its counterpart in Q1 2021, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

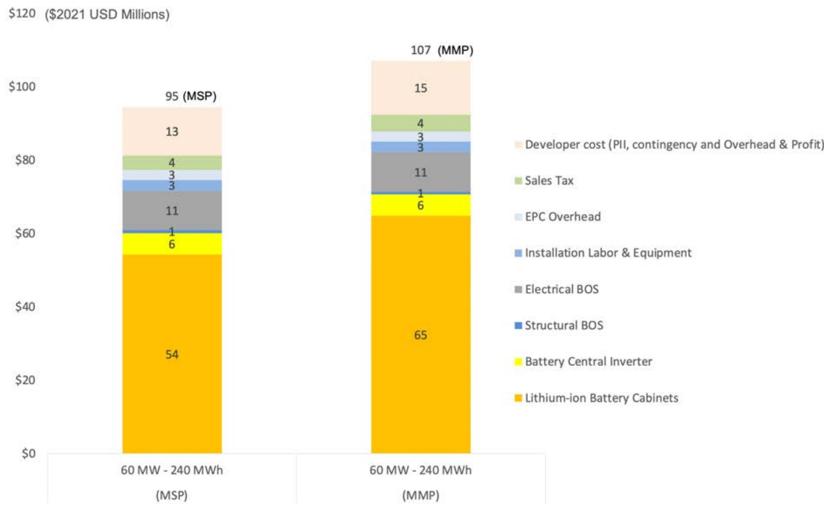

Figure 23. Q1 2022 U.S. benchmark: standalone utility-scale Li-ion battery storage system

10.2 PV-Plus-Storage System Cost Model

Here, we combine our energy storage cost model with our PV system cost model in various configurations, including PV and storage sited together versus separately. As shown in Table 12, coupling enables sharing of several hardware components by the PV and energy storage systems, which can reduce costs. Coupling can also reduce soft costs related to site preparation, land acquisition, permitting and interconnection, installation labor, and EPC/developer overhead and profit.

Table 12. Cost Factors for Siting PV and Storage Together Versus Separately

Model Component	Coupled PV Plus Storage	PV and 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.

When PV and battery storage are co-located, the subsystems can be connected in either a dc-coupled or an ac-coupled configuration (Figure 24). A dc-coupled system built using a bidirectional inverter[12] connects battery storage directly to the PV array via dc-dc converters. In contrast, an ac-coupled system needs both a PV inverter and a bidirectional inverter, and there

[12] PV inverters can be used in place of bidirectional inverters as well.

are multiple conversion steps between dc and ac to charge or discharge the battery. The bidirectional inverter used in both dc-coupled and ac-coupled configurations enables grid-charging capabilities. The transmission line can be used for both PV and battery storage systems.

We model only ac-coupled systems for this report. Table 13 shows changes to our utility-scale PV and storage model when PV and storage are combined. The advantages of the ac-coupled system include the following:

- For a retrofit project (adding battery storage to an existing PV array), an ac-coupled battery may be more practical than a dc-coupled battery, because the existing PV system may not need to be redesigned. Thus, the additional costs of 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).
- Because ac-coupled systems have independent PV and battery systems with separate inverters, this coupled configuration enables redundancy. For instance, if the battery-based inverter fails to operate, the PV system can operate independently, as long as the grid is up. In addition, the PV and storage can be upgraded independently of each other.

Reasons an installer or a developer may pursue a dc-coupled system include the following:

- Installing a dc-coupled system with a single bidirectional inverter[13] reduces additional costs for the inverter, inverter wiring, and inverter housing.
- Dc-coupled systems have higher round-trip efficiency (RTE) than ac-coupled systems because they mitigate the extra conversion of energy from dc to ac to dc. However, as power electronics are becoming more efficient, the actual efficiency difference is becoming smaller (Enphase 2019).
- Because the battery is connected directly to the PV system via the dc-dc converter, excess PV generation that falls outside the inverter limits can be sent directly to the battery, thus increasing overall output for the same interconnection capacity (DiOrio and Hobbs 2018).

[13] Dc-coupled systems can use a unidirectional inverter as well. This configuration can lead to a lower total system installed cost than a dc-coupled system using a bidirectional inverter, but at the same time, it prevents the system from grid charging.

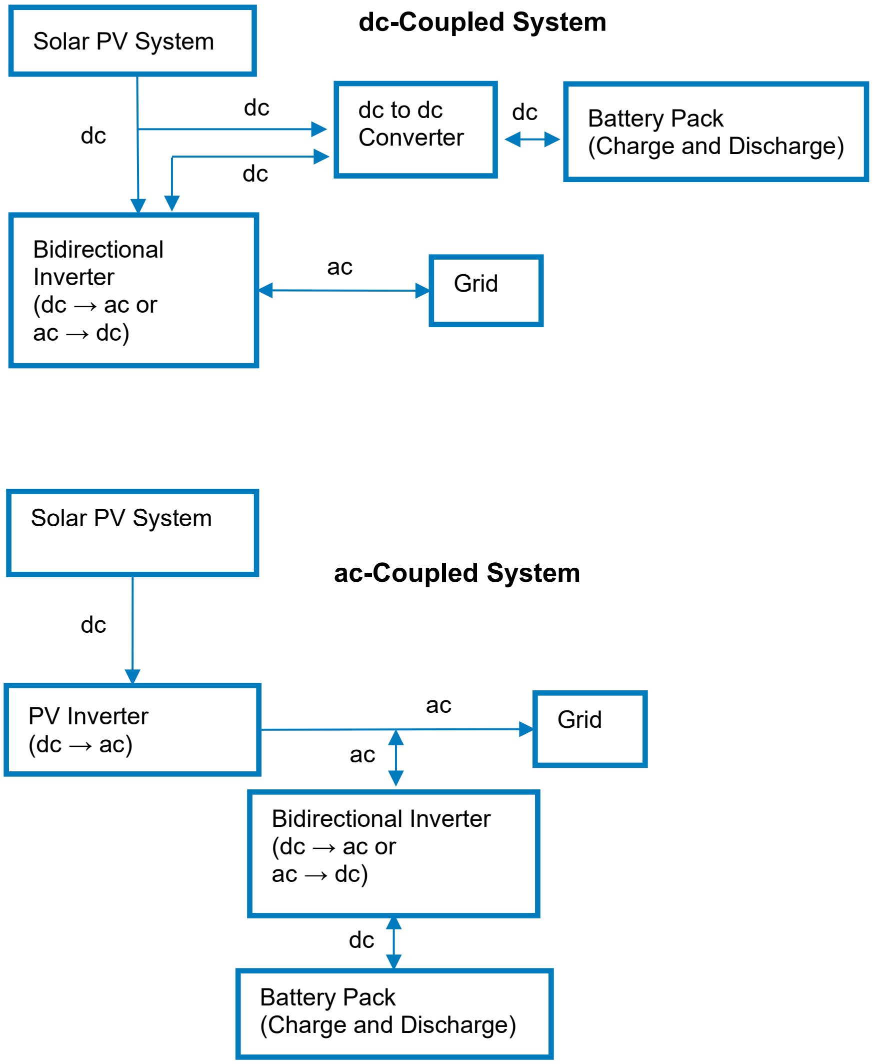

Figure 24. dc-coupled and ac-coupled PV-plus-storage system configurations

Table 13. Changes to Utility-Scale PV and Storage Model When PV and Storage Are Combined

Category	Modeled Value	Description
Electrical BOS	PV electrical BOS + storage electrical BOS + (4% * storage electrical BOS)	Assumes higher wiring/conduit and dc cabling requirement for coupled configurations
Installation labor	75% * (PV installation labor and equipment + storage installation labor and equipment)	Duplicative work related to site staging and site preparation are removed assuming more efficient labor utilization
EPC overhead	13% * (structural BOS + electrical BOS + installation labor)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
Sales tax	5.8% * (PV modules, battery cabinet, inverters, and BOS materials)	Cost of sales tax multipliers is lower for combined system than for separate systems, so the tax is lower

Category	Modeled Value	Description
PII	(Storage permitting fee + PV interconnection fee) * 1.02	Assumes slightly higher PII cost than standalone storage system due to additional hardware installed at the point of interconnect
Contingency	3% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of contingency multipliers is lower for combined system than for separate systems, so the contingency cost is lower
Developer overhead	4% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
EPC/developer net profit	5% * (PV modules, battery cabinet, inverters, BOS materials, PII, contingency, developer overhead)	Cost of profit multipliers is lower for combined system than for separate systems, so the profit is lower

10.3 Model Output

Figure 25 compares our MSP and MMP benchmarks for an ac-coupled utility-scale storage system with a 100-MW_{dc} PV system. For Q1 2022, our MSP benchmark ($170 million) is 13% lower than our MMP benchmark ($195 million). Our Q1 2022 MMP benchmark is 11% higher than its counterpart in Q1 2021, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

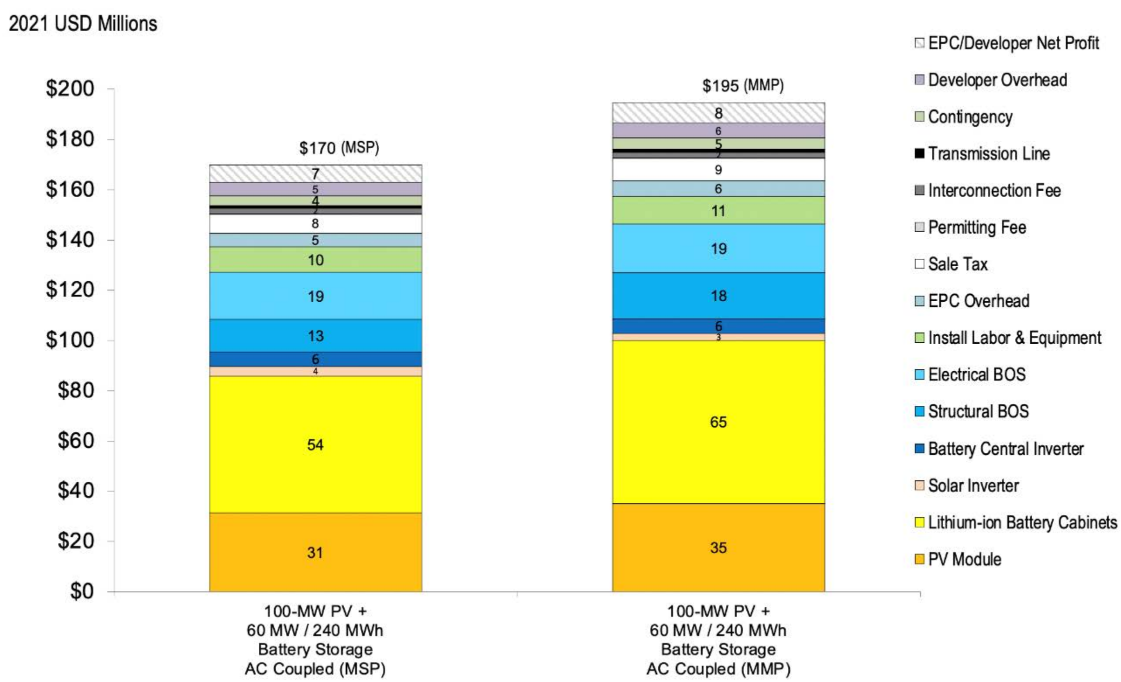

Figure 25. Q1 2022 U.S. benchmark: utility-scale ac-coupled PV-plus-storage systems (4-hour duration)

Figure 26 summarizes our MSP results for several system types and configurations:

- Standalone benchmark 100-MW_{dc} tracking ground-mounted PV system ($87 million)
- Standalone 60-MW_{dc}/240-MWh, 4-hour-duration energy storage system ($95 million)
- ac-coupled benchmark PV (100 MW_{dc}) plus storage (60 MW_{dc}/240 MWh, 4-hour duration) system ($170 million)
- Separate benchmark PV (100 MW_{dc}) and storage (60 MW_{dc}/240 MWh, 4-hour duration) systems sited in different locations ($181 million).

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

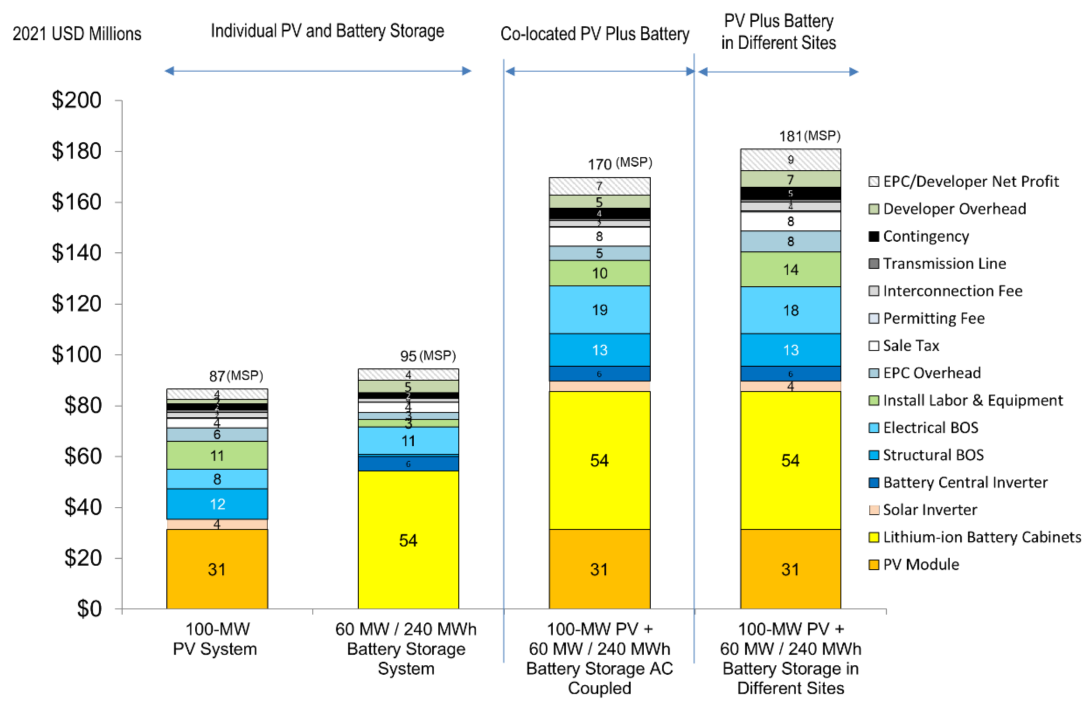

Figure 26. Q1 2022 utility-scale PV-plus-storage system MSP benchmark (4-hour duration) at different sites and at the same site (ac-coupled)

11 Operations and Maintenance

Benchmark PV operations and maintenance (O&M) costs are estimated using a model (Walker et al. 2020) that provides a line-item cost estimate of measures that correspond to the PV O&M services described in *Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems, 3rd Edition* (NREL et al. 2018). O&M cost drivers for PV modules and inverters in the model are informed by actuarial failure and repair data from Sandia National Laboratories (Klise et al. 2018). Current default values for other measures that occur on fixed intervals or for which the failure rate data are unavailable reflect the best judgement of a SETO-sponsored working group.[14]

Like the system cost modeling in this report, two sets of O&M cost numbers were estimated: one with MMP parameters and another with MSP parameters. For Q1 2022, the labor rates, discount rate, and inflation rate are updated; these items are common across the MSP and MMP calculations. In addition, MSP- and MMP-specific module and inverter replacement and capital costs are used. Actuarial failure and repair data are not updated from last year. Five additional line measures (land lease, property taxes, insurance, asset management, and security) were added in Q1 2020, based on feedback from U.S. solar industry professionals collected by Lawrence Berkeley National Laboratory (Wiser et al. 2020); of these, only the insurance line item was updated in Q1 2021. For Q1 2022, no changes are made to those line items. In Q1 2021, some of the 133 line measures were deleted if they were either outdated or not applicable to certain types of systems, especially residential and utility systems (one-axis tracking), based on high-level market research. For Q1 2022, no line measures were deleted.

The Q1 2020 benchmark O&M costs included PV module cleaning and several types of inspections in the residential case. These costs were removed from the Q1 2021 and Q1 2022 benchmarks, because residential cleaning is often not recommended, and inspections of residential systems are uncommon. Vegetation and pest control remain as annual costs in the Q1 2022 benchmark for residential PV system O&M.

Adding insurance costs increased the annual cost substantially in the Q1 2021 report. For Q1 2022, no changes are made to assumptions related to insurance. Types of insurance that may be needed by a PV plant operator are listed in *Insurance in the Operation of Photovoltaic Plants* (Schwab et al. 2020). Two major categories of insurance are (1) property insurance, which insures the PV plant hardware against hazards, and (2) liability insurance, which insures against claims of harm by others. Property insurance is included in the benchmark insurance cost because it can be associated with a single PV plant, whereas liability and other types of insurance (e.g., commercial vehicle and workers' compensation insurance) are often written as an umbrella policy to cover exposure of a company rather than a specific PV plant. Costs for these other types of insurance (i.e., other than property insurance) may be substantial, even though they are not included in this per-PV-plant benchmark cost.

The property insurance premium is estimated as a fraction multiplied by the replacement value for which the plant is insured; as a proxy for replacement value, we use the benchmark capital cost of the PV plant as the premium basis. For residential systems, the factor may vary from 0.004 to 0.006. For the benchmark value, we use 0.00454[15] times the capital cost per year, which

[14] The Solar Access to Public Capital (SAPC) Working Group was convened in 2014 to open capital market investment in the solar asset class. It consisted of solar developers, financiers and capital managers, law firms, rating agencies, accounting and engineering firms, and other stakeholders engaged in solar asset deployment. In 2016, a subset of the SAPC Working Group merged with Sandia National Laboratories' Technical O&M Working Group to unify efforts by the U.S. Department of Energy (DOE) to improve O&M practices, data standards, and costs. This combined body—the PV O&M Working Group—is administrated by NREL, Sandia National Laboratories, SunSpec Alliance, and Roger Hill.

[15] Luke Ortgessen, Country Companies, August 1, 2021.

translates to \$12.08/kW$_{dc}$/year under MSP parameters and \$13.71/kW$_{dc}$/year under MMP parameters. For commercial and utility-scale plants, the factor varies from 0.0015 to 0.009, depending on hazards in an area and the extent of coverage. We use a benchmark value of 0.0025[16] times the capital cost per year for property insurance (escalated each year for inflation and discounted for levelized cost). This translates to a range of \$2.55–\$15.3/kW$_{dc}$/year under MSP parameters and \$2.93–\$17.55/kW$_{dc}$/year under MMP parameters.

Microinverters are assumed for residential systems, and three-phase string inverters are assumed for commercial rooftop systems. A commercial rooftop string inverter with a 12-year warranty incurs a slightly higher replacement cost than a residential rooftop microinverter with a 25-year warranty. Also, the analysis period is 30 years for the commercial system and 25 years for the residential system; because of the commercial system's longer lifetime, the commercial rooftop PV project owners will need to repair the inverter more often, and the inverters are more likely to be out of the warranty period. No updates are made to the analysis and warranty period in this year's report. Table 14 summarizes key modeled O&M parameters.

Table 14. Summary of Key Modeled O&M Parameters

Category	Residential	Commercial	Utility-Scale
Property insurance premium	0.00454 * system capital cost	0.0025 * system capital cost	0.0025 * system capital cost
Inverter type	Microinverter	Three-phase string inverter	Central inverter
Inverter warranty period	25 years	12 years	10 years
PV module warranty period	25 years	25 years	25 years
Analysis period	25 years	30 years	30 years
Inflation	2.5%	2.5%	2.5%
Nominal discount rate	5.71%	6.53%	6.24%

Costs in the PV O&M model include preventive maintenance scheduled at regular intervals, with costs increasing at the rate of general inflation, as well as corrective maintenance to replace components. The model derives corrective maintenance by multiplying the replacement cost, including labor, by the probability that a failure will occur each year, based on actuarial data. Component failure probabilities for each year are calculated using a Weibull, log-normal, or other distribution based on actual data, when possible (Gunda and Homan 2020).

For MSP, the measures in the cost model are sorted into inverter replacement, operations, module and component replacement, inspection, monitoring, module cleaning, vegetation and pest control, land lease, property taxes, insurance, asset management, and security (Figure 27). The current benchmarks are \$29.49/kW$_{dc}$/yr (residential), \$18.11/kW$_{dc}$/yr (commercial, rooftop),

[16] Sara Cane, CAC Specialty Insurance, August 3, 2021.

$17.21/kW_{dc}/yr (commercial, ground-mounted), and $16.11/kW_{dc}/yr (utility-scale, single-axis tracking).

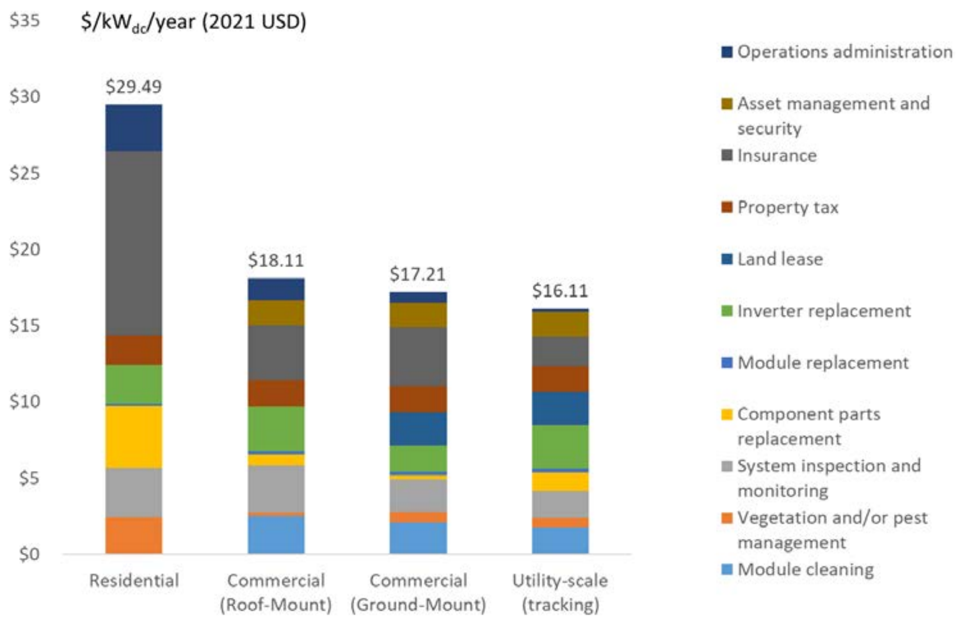

Figure 27. Q1 2022 residential, commercial, and utility-scale PV MSP O&M costs by category

For MMP, the current benchmarks are $31.12/kW_{dc}/yr (residential), $19.06/kW_{dc}/yr (commercial, rooftop), $18.03/kW_{dc}/yr (commercial, ground-mounted), and $16.42/kW_{dc}/yr (utility-scale, single-axis tracking) (Figure 28).

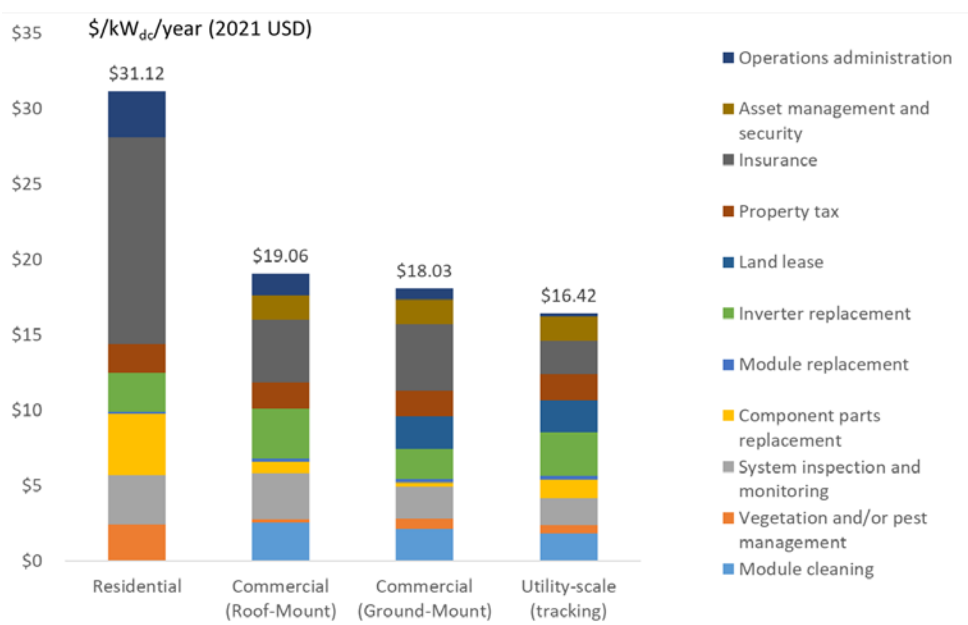

Figure 28. Q1 2022 residential, commercial, and utility-scale PV MMP O&M costs by category

As stated previously, the values in Figure 27 and Figure 28 represent line-item estimates of costs associated with best practices; therefore, actual costs may vary. For example, in a residential system, a homeowner may not increase the coverage of their property insurance after they get a system to avoid additional costs (saving money if no damages occur to the PV system, but putting themselves at risk if damages do occur). Additionally, we put a value on the time of a homeowner (i.e., "operations administration"), even though they are not getting paid for their activities. Therefore, a homeowner may only perceive O&M costs of \$14.36/kW$_{dc}$/yr,[17] but they are likely underinsuring against risk and not properly accounting for the efforts of maintaining a PV system on their home.

12 Levelized Cost of Energy of Standalone PV Systems

Although LCOE is an imperfect metric for the competiveness of PV within the energy marketplace, it does incorporate many PV metrics—beyond upfront installation costs—that are important to energy costs. We input standalone PV system parameters into NREL's System Advisor Model (SAM), a performance and financial model,[18] to calculate real LCOEs (considering inflation). In SAM, we use the PVWatts® single-owner model for estimating the LCOE of standalone PV systems for the residential, commercial, and utility-scale market sectors. While the financial parameters across these sectors and technologies vary, they remain the same as in the previous edition of the benchmark report (Ramasamy et al. 2021). We calculate LCOE assuming long-term, steady-state financing, with no investment tax credit and with interest rates higher than the previous historically low levels. The residential PV SAM model uses the default PVWatts performance model and the distributed residential owner financial model.

For the commercial and utility-scale SAM models, we specify internal rate of return (IRR) targets of 8.75% and 7.75%, respectively, to estimate the LCOE. Based on the specified IRR target, SAM optimizes for a power-purchase agreement (PPA) price to estimate the gross PPA revenue using the net energy generated by the system and made available to the grid.

Table 15 lists our parameters and results for calculating the benchmark LCOE of standalone PV. The values are based on our MSP benchmarks for system capital cost. Figure 29 shows our modeled PV LCOE estimates over time.

[17] Total residential O&M MSP (\$29.49/kW$_{dc}$/yr) – insurance cost (\$12.08/kW$_{dc}$/yr) – operations administration cost (\$3.05/kW$_{dc}$/yr) = \$14.36/kW$_{dc}$/yr.
[18] See https://sam.nrel.gov/.

Table 15. Q1 2022 LCOE Input Parameters and Results for Standalone PV, Based on MSP Benchmarks (2021 USD)

	Residential PV (7.9 kW_{dc})	Commercial PV (Rooftop, 200 kW_{dc})	Utility-Scale PV (One-Axis Tracking, 100 MW_{dc})
Installed cost ($/$W_{dc}$)	2.55	1.63	0.87
Annual degradation (%)	1.00	0.70	0.70
Levelized O&M expenses over life of asset ($/$kW_{dc}$-yr)	29	18	16
Preinverter derate (%)[a]	85.9	85.9	85.9
Inverter efficiency (%)	96.0	96.0	96.0
Inverter loading ratio	1.21	1.23	1.34
Inflation rate (%)	2.5	2.5	2.5
Equity discount rate (real) (%)	10.2	6.1	5.1
Debt interest rate (%)	4.5	5.0	5.0
Debt fraction (%)	100	71.8	71.8
Debt term (years)	25	18	18
Entity	Homeowner	Corporation	Corporation
Analysis period (years)	25	30	30
Initial energy yield (kWh/kW_{dc})	1,491	1,398	1,694
Real LCOE (2021 US$)	**11.1 ¢/kWh**	**8.7 ¢/kWh**	**4.1 ¢/kWh**

[a] We use the default values for system losses in SAM for all sectors, which sum to 14.1% (equivalent to a preinverter derate value of 85.9%): soiling (2%), shading (3%), mismatch (2%), wiring (2%), connections (0.5%), light-induced degradation (1.5%), nameplate (1%), and availability (3%).

Other key assumptions are as follows. (1) The corporation has a federal corporate tax rate of 21% and a state corporate tax rate of 6%, and uses the Modified Accelerated Cost Recovery System depreciation schedule. (2) The homeowner uses a mortgage loan that is interest deductible, with a federal personal tax rate of 15% and a personal state tax rate of 6%. (3) No state or local subsidies. (4) Corporations have a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning an interest rate of 1.75%), a 6-month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system, and $1.1 million of upfront financial transaction costs for a $100-million third-party ownership transaction of a pool of commercial projects. (5) 2022 capacity factors are based on Fredonia, Kansas (which is near the geographic center of the 48 conterminous states and corresponds with the area-weighted capacity factor of the 48 conterminous states, as outlined in the 2022 Annual Technology Baseline), with a tilt/azimuth of 20/214 (residential) (Barbose et al. 2020), 10/190 (commercial rooftop) (Barbose et al. 2020), and tracking/180 (utility-scale).

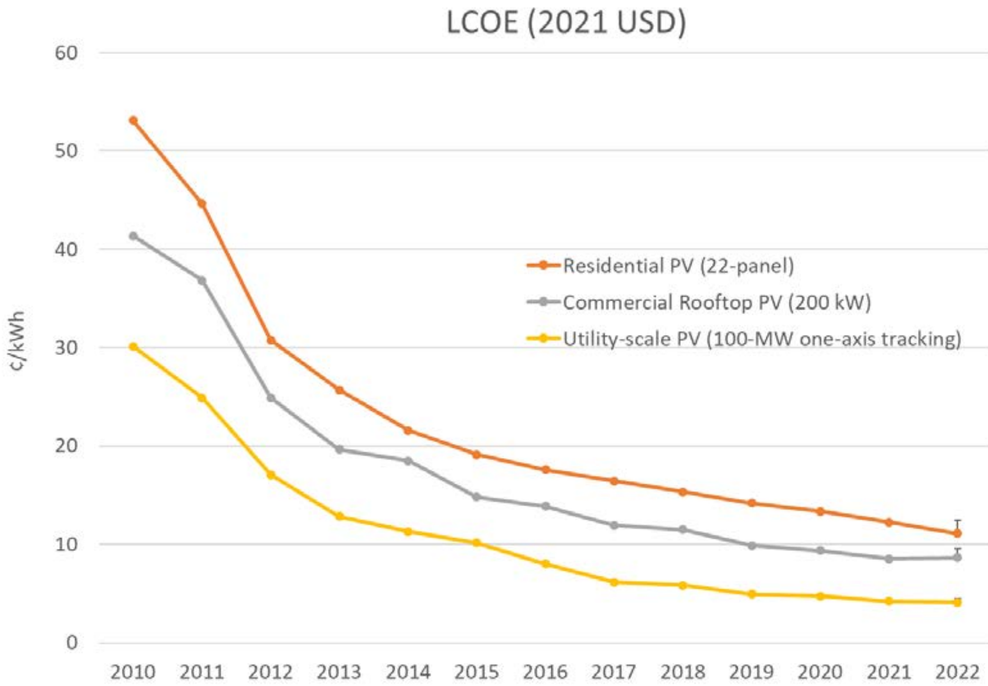

Figure 29. NREL-modeled PV LCOE over time

In 2022, the colored dots represent LCOEs calculated using MSP benchmarks, and the tops of the error bars represent LCOEs calculated using MMP benchmarks. Methods vary for calculating the LCOE values before 2022, but those methods are most similar to the MMP method used in this Q1 2022 report. In previous years, there was much less market distortion that would have affected the difference between MSP and MMP.

13 Conclusions

NREL's bottom-up cost models can be used to assess the MSP and MMP of PV, storage, and PV-plus storage systems with various configurations. While MSP can be used to estimate potential system cost-reduction opportunities—thus helping guide R&D aimed at advancing cost-effective system configuration—MMP can be used to understand system costs under recent market conditions. The MSP data in this annual benchmarking report will be used to inform and track progress toward SETO's Government Performance and Reporting Act cost targets.

Based on our bottom-up modeling, the Q1 2022 cost benchmarks are listed in Table 16.

Table 16. Q1 2022 PV and PV-Plus-Storage MSP and MMP Benchmarks (2021 USD)

MSP Benchmarks	MMP Benchmarks	System
Residential Systems		
$2.55/W_{dc}$ ($3.09/W_{ac}$)	$2.95/W_{dc}$ ($3.57/W_{ac}$)	7.9-kW$_{dc}$ rooftop PV
$33,858	$38,295	7.9-kW$_{dc}$ rooftop PV with 5 kW$_{dc}$/12.5 kWh of storage
Commercial Systems		
$1.63/W_{dc}$ ($2.00/W_{ac}$)	$1.84/W_{dc}$ ($2.26/W_{ac}$)	200-kW$_{dc}$ rooftop PV
$1.71/W_{dc}$ ($2.10/W_{ac}$)	$1.94/W_{dc}$ ($2.38/W_{ac}$)	500-kW$_{dc}$ ground-mounted PV
$1.27 million	$1.44 million	500-kW$_{dc}$ ground-mounted PV co-located with 300 kW$_{dc}$/1.2 MWh of storage
Utility-Scale Systems		
$0.87/W_{dc}$ ($1.17/W_{ac}$)	$0.99/W_{dc}$ ($1.33/W_{ac}$)	100-MW$_{dc}$ one-axis-tracking utility-scale PV
$170 million	$195 million	100-MW$_{dc}$ one-axis-tracking PV co-located with 60 MW$_{dc}$/240 MWh of storage

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