U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023

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

1 National Renewable Energy Laboratory
2 Clean Kilowatts, LLC
3 U.S. Department of Energy Solar Energy Technologies Office

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-7A40-87303
September 2023

U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023

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

1 National Renewable Energy Laboratory
2 Clean Kilowatts, LLC
3 U.S. Department of Energy Solar Energy Technologies Office

Suggested Citation
Ramasamy, Vignesh, Jarett Zuboy, Michael Woodhouse, Eric O'Shaughnessy, David Feldman, Jal Desai, Andy Walker, Robert Margolis, and Paul Basore. 2023. *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-87303. https://www.nrel.gov/docs/fy23osti/87303.pdf.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-7A40-87303
September 2023

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

NOTICE

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Solar Energy Technologies Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

Acknowledgments

Because our Q1 2023 benchmarking methods required more direct input from the photovoltaic (PV) and storage industries, this year we engaged with more expert participants than in recent years. In February 2023, we attended Intersolar North America and Energy Storage North America in Long Beach, California, where we gathered on-the-spot data and insights from more than 100 exhibitors. After the conference, we conducted in-depth interviews and correspondence with about 40 experts connected to the manufacturing and sale of modules, inverters, energy storage systems, and balance-of-system components as well as the installation of PV and storage systems. We thank all these participants for their assistance. The resulting data are aggregated and anonymized in this report to develop our Q1 2023 cost benchmarks. However, to respect the wishes of participants who may want to remain fully anonymous, here we only list those who agreed to be acknowledged.

- **Alencon Systems**, Derek Walker, Director of Sales
- **American Battery Solutions**, Michael Hoff and Bud Collins
- **Anderson Optimization**, Jake Anderson, Co-Founder and CEO
- **Bergstrom Inc.**, Stephan Erbe, Program Manager for Business Development
- **DEHN, Inc.**, Ryan Fitzgerald, Business Development Manager Utilities Sector
- **Jurchen Technology US Corp.**
- **JUWI Inc.**, James Antin, Project Developer
- **KerTec, LLC**
- **Kore Power**, Gregg Noble, VP of Strategic Partnerships
- **Lawrence Berkeley National Laboratory**, Galen Barbose, Research Scientist
- **LG Energy Solution**, Sarthak Rokade
- **Nexamp, Inc.**
- **Perch Energy, Inc.**
- **PI Berlin**, Don Cowan
- **Redaptive, Inc.**, Ben Peters, Senior Manager – Solar and Storage Products
- **Simple Solar**, Scott Thompson, Owner
- **Solar Gain Inc.**, Cole Morelli, Residential Sales Manager
- **SolarPod**, Mouli Vaidyanathan, President
- **Solartime USA**, Martyna Kowalczyk, CEO
- **SunCentral**, Pivot Energy's community solar management team
- **Strata Clean Energy**

We also thank the reviewers who provided comments on our draft report, including Jake Anderson (Anderson Optimization), Nate Blair (NREL), Jenny Chase (BloombergNEF), Don Cowan (PI Berlin), Michael Hoff (American Battery Solutions), Brian Mirletz (NREL), Ben Peters (Redaptive Inc.), Sarthak Rokade (LG Energy Solutions), Ashok Sekar (NREL), Brittany Smith (NREL), and Adam Warren (NREL). Finally, we thank NREL's Heidi McKenna for logistical support and Emily Laidlaw for editing.

List of Acronyms

ac	alternating current
AD/CVD	antidumping and countervailing duties
BLS	U.S. Bureau of Labor Statistics
BNEF	BloombergNEF
BOS	balance of system
COO	cost of ownership
CPI	consumer price index
dc	direct current
DOE	U.S. Department of Energy
EBOS	electrical balance of system
ESS	energy storage system
FRED	Federal Reserve Economic Data
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
IMF	International Monetary Fund
ILR	inverter loading ratio
IRA	Inflation Reduction Act
IREC	Interstate Renewable Energy Council
kWh	kilowatt-hour
LMI	low- and moderate-income
MMP	modeled market price
MSP	minimum sustainable price
MW_{dc}	megawatts direct current
NEM	net energy metering
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PII	permitting, inspection, and interconnection
PV	photovoltaic(s)
Q	quarter
R&D	research and development
SBOS	structural balance of system
SEIA	Solar Energy Industries Association
SETO	U.S. Department of Energy Solar Energy Technologies Office
USD	U.S. dollars
V_{dc}	volts direct current
W_{ac}	watts alternating current
W_{dc}	watts direct current

Executive Summary

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, hardware, and soft cost reductions to make solar even more affordable and accessible for all. As part of this effort, SETO tracks solar cost trends to focus its research and development (R&D) investments 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. This year, we introduce a new PV and storage cost modeling approach. The PV System Cost Model (PVSCM) was developed by SETO and NREL to make the cost benchmarks simpler and more transparent, while expanding to cover components not previously benchmarked. High-level inputs and results are presented in this report, and the full set of PVSCM inputs and results for Q1 2023 is available at https://data.nrel.gov/.

In addition to the new modeling approach, this year's benchmark report includes new analyses. We show bottom-up manufacturing analyses for modules, inverters, and energy storage components, and we model unique costs related to community solar installations. We also account for PV manufacturing tax incentives available under the Inflation Reduction Act (IRA).

Purpose and Scope of NREL Benchmarks

The benchmarks in this report are bottom-up cost estimates of all major inputs to PV and energy storage system (ESS) installations. Bottom-up costs are based on national averages and do not necessarily represent typical costs in all local markets. Like last year's report, this year's report includes two distinct sets of benchmarks—minimum sustainable price (MSP) benchmarks and modeled market price (MMP) benchmarks:

- **MSP benchmarks** are 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.
- **MMP benchmarks** maintain continuity with previous benchmark reports by capturing macroeconomic factors and the impact of market trends, reflecting typical national system cash costs experienced by U.S. installers and passed on to U.S. consumers within the analysis period.

These simplified estimates are useful for tracking technological progress, but they do not reflect all experiences. In fact, no individual estimate under any approach can reflect the diversity of the PV and storage manufacturing, installation, and maintenance industries.

The primary purpose of NREL's benchmarks is to document and provide insight into the long-term trajectories of PV and storage system costs. The benchmarks also can be used to provide insight into the disaggregated costs of individual system components. These benchmarks should not be used for purposes better met by local- and customer-specific market prices and vice versa. For instance, if a firm would like to know component prices for a specific location and time, then the firm should contact multiple vendors for each component. Further, the NREL benchmarks typically differ from reported price data in sources such as Lawrence Berkeley National Laboratory's *Tracking the Sun* series. This disparity is expected because of the difference in methods and purposes across the reports. For example, NREL's bottom-up benchmarks intentionally exclude optional yet common items that are included in reported system prices, such as the costs of additional electrical work, financing, and additional roofing services. See Section 3 for additional discussion of the purpose and scope of NREL's benchmarks.

PV Installed Cost Benchmarks

Figure ES-1 compares our Q1 2023 MSP and MMP benchmarks for PV systems in the residential, community solar, and utility-scale sectors. The MMP benchmark is higher than the MSP benchmark for all sectors, because the MMP benchmark captures the inflationary market distortions that occurred in Q1 2023.

Our MMP benchmark for an 8-kW_{dc} residential PV system ($2.68 per watt direct current [W_{dc}]) is 15% higher than the MSP benchmark ($2.34/$W_{dc}$) and 15% lower than our MMP benchmark ($3.18/$W_{dc}$) from Q1 2022 in 2022 U.S. dollars (USD).

Our MMP benchmark for a 3-MW_{dc} fixed-tilt community solar system ($1.76/$W_{dc}$) is 18% higher than our MSP benchmark ($1.49/$W_{dc}$). Our Q1 2022 benchmark report has no community solar system for comparison.

Our MMP benchmark for a 100-MW_{dc} utility-scale system with one-axis tracking ($1.16/$W_{dc}$) is 19% higher than our MSP benchmark ($0.97/$W_{dc}$) and 8% higher than its counterpart ($1.07/$W_{dc}$) in Q1 2022 in 2022 USD. Compared with Q1 2022, higher inverter and EBOS costs plus new network upgrade costs more than offset lower module and SBOS costs in Q1 2023.

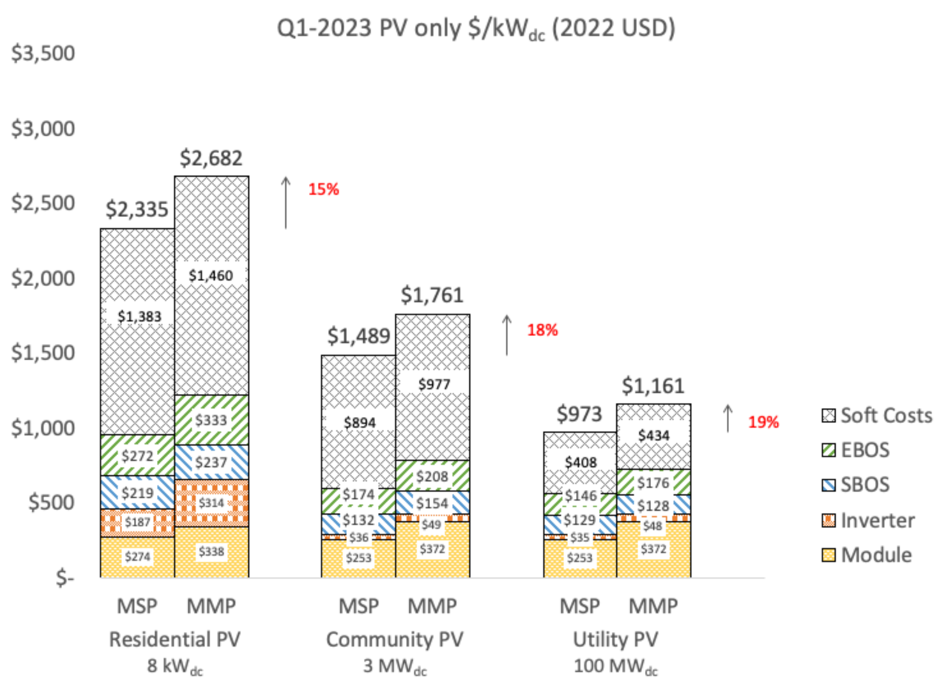

Figure ES-1. Q1 2023 U.S. PV cost benchmarks

PV-Plus-Storage Installed Cost Benchmarks

Figure ES-2 compares our Q1 2023 MSP and MMP benchmarks for PV-plus-storage systems in the residential, community solar, and utility-scale sectors. Again, the MMP benchmarks are higher than the MSP benchmarks for all sectors.

Our MMP benchmark for an 8-kW_{dc} residential system with a 5-kW/12.5-kWh ESS (\$4.70/W_{dc}) is 21% higher than our MSP benchmark (\$3.88/W_{dc}) and 9% lower than its counterpart (\$5.17/W_{dc}) in Q1 2022 in 2022 USD.

Our MMP benchmark for a 3-MW_{dc} fixed-tilt community solar system with a 1.8-MW/7.2-MWh ESS (\$2.94/W_{dc}) is 26% higher than our MSP benchmark (\$2.33/W_{dc}). Our Q1 2022 benchmark report has no community solar system for comparison.

Our MMP benchmark for a 100-MW_{dc} utility-scale system with one-axis tracking and a 60-MW/240 MWh ESS (\$2.11/W_{dc}) is 28% higher than our MSP benchmark (\$1.65/W_{dc}) and roughly 0.2% higher than its counterpart (\$2.10/W_{dc}) in Q1 2022 in 2022 USD.

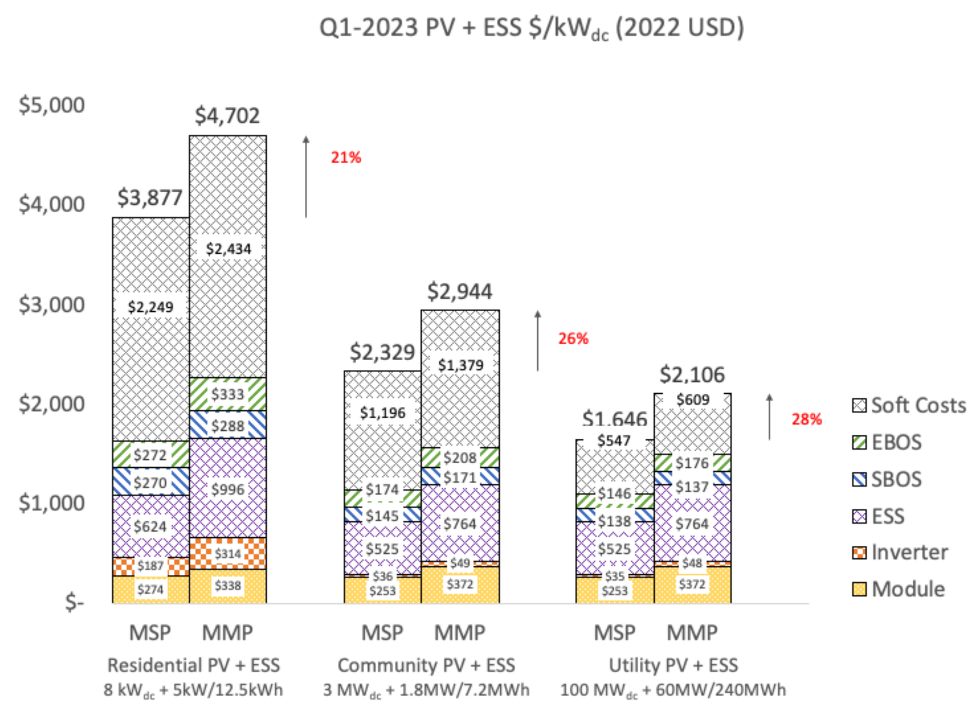

Figure ES-2. Q1 2023 U.S. PV-plus-storage cost benchmarks

PV Operations and Maintenance Cost Benchmarks

Our operations and maintenance (O&M) analysis breaks costs into various categories and provides total annualized O&M costs. The MSP results for PV systems (in units of 2022 real USD/kW_{dc}/yr) are \$28.78 (residential), \$39.83 (community solar), and \$16.12 (utility-scale). The MMP results are \$30.36 (residential), \$40.51 (community solar), and \$16.58 (utility-scale). The community solar O&M cost is higher than the O&M cost for a single-customer commercial PV system of similar configuration because of the community solar subscriber management cost, which accounts for about 40% of the total community solar O&M cost.

PV-Plus-Storage Operations and Maintenance Cost Benchmarks

The MSP benchmarks for PV-plus-storage systems (in 2022 real USD/kW_{dc}/yr) are $61.28 (residential), $75.25 (community solar), and $50.73 (utility-scale). For MMP, the benchmarks are $65.04 (residential), $76.79 (community solar), and $51.88 (utility-scale). ESS replacement constitutes the largest share of O&M costs for all the PV-plus-storage systems modeled.

Table of Contents

List of Figures

List of Tables

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. The approaches used to achieve the goal of more affordable solar that is accessible to all include driving innovations in technology, hardware, and soft cost reductions. As part of this effort, SETO tracks solar 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) and energy storage (battery) costs.[1] Because SETO focuses on optimizing R&D investments over the longer term, NREL's benchmark reports also help distinguish underlying, long-term technology-cost trends from the price impacts of short-term distortions caused by policy and market events. 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 reflects typical component costs experienced by U.S. installers and passed on to U.S. consumers during the benchmark period.

This year, we introduce a new PV and storage cost modeling approach that builds on the detailed bottom-up models and methods we have developed over the past decade. The new approach includes additional information about key component and system parameters. Compared with previous benchmarking efforts, this year's effort relies more on direct system design and cost inputs from the PV and storage industries. Subcomponent values displayed in intrinsic units (dollars per kilogram, dollars per square meter, etc.) are meant to aid with sensitivity analysis. For the first time, this report shows bottom-up manufacturing analyses for modules, inverters, and energy storage components. Also, for the first time, we model unique costs related to community solar installations.

Additional details about the goals, methods, and limitations of the Q1 2023 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 7 present the results of our Q1 2023 capital cost modeling for residential, community solar, and utility-scale PV and PV-plus-storage systems. Section 8 presents the results of our operations and maintenance (O&M) cost analysis. Section 9 offers a summary and conclusions. The appendix shows an example of our cost-modeling process. The full set of benchmark inputs and results for Q1 2023 is available at https://data.nrel.gov/.

[1] All previous benchmark reports can be found at NREL's Solar Technology Cost Analysis webpage, www.nrel.gov/solar/market-research-analysis/solar-cost-analysis.html.

2 Market and Policy Context in Q1 2023

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. The period leading up to last year's report (Q1 2021 through Q1 2022) witnessed significant volatility as the effects from the COVID-19 pandemic combined with market and policy events to disrupt the availability of components and increase system prices (Ramasamy et al. 2022). Volatility continued during the period between Q1 2022 and Q1 2023, but some stakeholders reported moderating price impacts—if not a return to the pre-pandemic status quo. Our industry interviews, supporting data, and analytical approach are designed to yield typical PV and storage prices in Q1 2023. However, these estimates do not reflect the observations and experiences of all stakeholders during this period. Section 3 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 2022 through Q1 2023 and likely had an influence on PV system costs. Table 1 lists select events that occurred during this period.

Table 1. Select U.S. Events ca. Q1 2022–Q1 2023

Event	Date
Antidumping and countervailing duties (AD/CVD) circumvention investigation initiated by U.S. Department of Commerce (DOC)	April 2022
AD/CVD tariffs on Southeast Asian modules waived by executive action for 24 months	June 2022
Uyghur Forced Labor Prevention Act implemented	June 2022
Inflation Reduction Act signed into law	Aug 2022
Companies in Southeast Asia preliminarily found by DOC to be circumventing AD/CVD	Dec 2022
Net metering rules in California revised, solar compensation reduced	Dec 2022
New net metering rules in California effective	April 2023
Waiver of AD/CVD tariffs on Southeast Asian modules repealed by U.S. Congress, but repeal vetoed by the president	May 2023
Final determination of companies and circumstances subject to AD/CVD tariffs beginning June 2024 (after expiration of executive waiver) made by DOC	Aug 2023

Economywide inflation moderated between Q1 2022 and Q1 2023. From April 2022 to April 2023, the Consumer Price Index for All Urban Consumers: All Items in U.S. City Average (consumer price index—CPI) rose about 5%, compared with about 8% between April 2021 and April 2022 (FRED 2023a). The 5% change was the smallest 12-month increase since April 2021 and included a 5% decrease in consumer prices for energy (BLS 2023a). The slowing inflation was due in part to easing of the high demand for goods and services as well as supply constraints that had been spurred by the COVID-19 pandemic, government stimulus programs, and Russia's invasion of Ukraine (Ramasamy et al. 2022, Smialek and Zhang 2023). In addition, the Federal Reserve raised interest rates throughout 2022 and into 2023 to mitigate inflation (FRED 2023b, Ngo and Casselman 2023). However, the 5% increase was still about twice as large as the annual average CPI increase over the last 20 years and well above the Federal Reserve's target rate of 2% (BLS 2023b, Ngo and Casselman 2023).

More striking were global commodity price fluctuations, which resulted in lower commodity prices in Q1 2023 compared with Q1 2022. Primary commodity prices rose 49% between April 2021 and April 2022 but fell 30% between April 2022 and April 2023 (FRED 2023c, IMF 2023). Energy prices were particularly volatile. After dropping at the beginning of the COVID-19 pandemic in spring 2020, crude oil prices mostly rose as economies recovered and then jumped after Russia's invasion of Ukraine in February 2022. Oil prices began dropping in summer 2022 because of a slowing global economy, recession fears, tighter monetary policy in many major economies, and a relatively stable global oil supply. Natural gas and coal prices followed similar overall patterns. Commodity metal prices were down about 7% between Q1 2022 and Q1 2023 (IMF 2023).

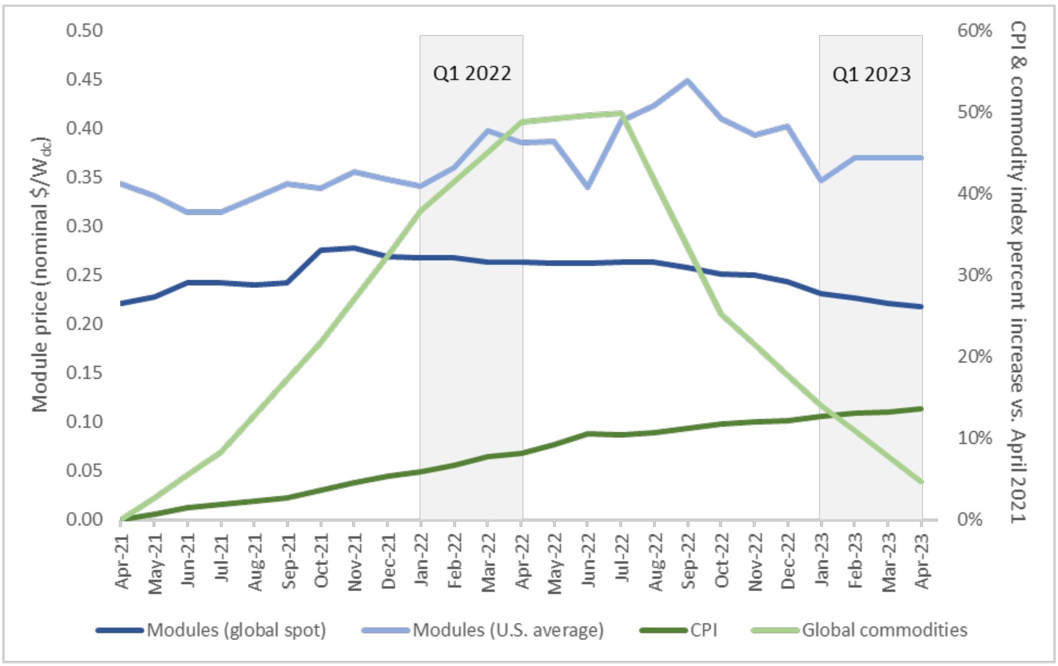

Figure 1. Select PV system price influences, April 2021–April 2023

Sources: BNEF (2023), EIA (2023), FRED (2023a, 2023c)

In addition to effects from these broader economic trends, the U.S. PV industry was impacted by solar-specific issues between Q1 2022 and Q1 2023. Spanning the entire period was a U.S. Department of Commerce (DOC) investigation into whether Chinese PV manufacturers were circumventing antidumping and countervailing duties (AD/CVD) by working through Cambodia, Malaysia, Thailand, and Vietnam. Initiation of the investigation in April 2022 stalled module shipments from Southeast Asia (Wood Mackenzie and SEIA 2022a). In June 2022, an executive order waived the duties on Southeast Asian modules for 2 years, which caused a spike in demand and prices from that region (Wood Mackenzie and SEIA 2022a). Later that same month, implementation of the Uyghur Forced Labor Prevention Act—which was unrelated to the AD/CVD investigation—further constrained module supply and increased prices by requiring proof that modules imported into the United States were unconnected to forced labor in China's Xinjiang region (Wood Mackenzie and SEIA 2022a). In December 2022, DOC issued a preliminary determination that certain module manufacturers in Southeast Asia were circumventing tariffs (Weaver 2022), which was made final in August 2023 (DOC 2023). The impact of this determination was mitigated by the AD/CVD tariff waiver issued in June 2022.

Although Congress voted to overturn that waiver in May 2023, a presidential veto will keep the waiver in place through June 2024 (DiGangi 2023). These tumultuous events are reflected in the U.S. module prices (Figure 1), which fluctuated substantially even as global module prices followed a steadily declining trend.

Additional solar-relevant U.S. policies instituted between Q1 2022 and Q1 2023 included the Inflation Reduction Act (IRA) and California's revised net metering rules. The IRA, which was passed into law in August 2022, created incentives for domestic PV manufacturing and deployment that analysts expect to drive significant increases in U.S. PV installations and use of domestically manufactured components (Feldman et al. 2022). The resulting changes in the U.S. PV industry may affect PV system prices, but any effects will likely become more apparent in the years to come, as U.S. companies ramp up their activities with the aid of IRA incentives. Net metering rules in California—the largest U.S. PV market—were revised in December 2022 and became effective for new PV system interconnection applications in April 2023. The new rules reduce the rates paid for exporting solar electricity and are meant to encourage electrification and use of energy storage. This change boosted PV deployment in California in Q1 2023 as customers sought to buy systems under the previous net metering rules. In the longer term, analysts expect the new rules to constrain PV-only deployment in California and ultimately spur the deployment of PV-plus-storage systems, which have higher upfront costs (Wood Mackenzie and SEIA 2022b).

Our interviews also indicated market and policy trends affecting system costs between Q1 2022 and Q1 2023. According to several installers and developers, features that characterized 2022—including high and volatile component prices, limited component supplies, and outsized profits made by some companies because of constrained competition—moderated in 2023. However, others reported few or no component cost reductions in 2023 as well as ongoing cost uncertainties related to trade policies and IRA implementation. Some companies reported using new strategies to secure component supplies, such as developing relationships with additional module manufacturers and working through equipment distributors. High wages and strong competition for labor were also noted as challenges. Additional issues reported for community solar and utility-scale systems included the higher cost and/or time required for land acquisition and interconnection studies as well as more expensive civil contracting requirements.

Finally, our interview participants noted trends that could have potentially fundamental impacts on PV and storage system costs going forward. In the residential sector, one of the most frequently mentioned ways to reduce costs was by increased adoption of SolarAPP+ by authorities having jurisdiction. SolarAPP+ is a web-based program that automates plan review, permit approval, and project tracking for PV and PV-plus-storage systems. Its effectiveness in terms of time and cost savings has been documented (Cook et al. 2023). The other most frequently mentioned cost-reduction trend was the emergence of technologies for connecting PV and battery systems to the grid through a simple connection to the electric meter, which residential installers said could reduce electrical labor costs substantially; examples given by participants included Tesla's Backup Switch and ConnectDER's meter socket adapters. Additional cost-reduction opportunities mentioned by residential installers included platforms that allow customers to design their rooftop PV systems online and increased use of racking without rails. In the commercial sector, technologies with reported cost-reduction potential included rooftop mounting systems that eliminate the need for racking, ballast, or anchors

(Maxeon's Air system was given as an example) or that use batteries as ballast (Yotta Energy's SolarLEAF was given as an example).

3 Purpose and Scope of NREL Benchmarks

This section describes the meaning of the NREL benchmarks, their intended purposes, how they vary from other market metrics, and their limitations.

3.1 Meaning of the NREL Benchmarks

Industry players, analysts, policymakers, and other stakeholders are interested in the *prices* of new technologies and the underlying *costs* to produce those technologies. Market prices for the U.S. PV industry are readily observable and documented in resources such as Barbose et al. (2022). However, installed system prices do not provide direct insight into underlying system cost structures or the prices for specific components. 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 to manufacture and deliver all the individual components and sums those costs to derive a modeled total price.

The benchmarks in this report are bottom-up cost estimates of all major inputs to PV and energy storage system (ESS) 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 3.4, this year's report includes two distinct sets of benchmarks: MSP benchmarks and MMP benchmarks. MSP benchmarks can be interpreted as the minimum price a company needs to charge to remain financially solvent in the long term based on the minimum sustainable prices of all inputs including minimum sustainable profit margins. MMP benchmarks can be interpreted as the actual cash sales price the company charges in the given benchmark period. In a stable, balanced, competitive market that is free of limited-duration trade policy distortions, MMP is equal to MSP.

3.2 Purpose of the NREL Benchmarks

The primary purpose of these benchmarks is to provide insight into the long-term trajectories of PV and storage system costs. These benchmarks are uniquely tailored to meet SETO's evolving programmatic needs. Last year's addition of MMP and MSP benchmarks met SETO's need to distinguish near-term prices for policy guidance from long-term prices for R&D guidance. This year, we provide component costs in intrinsic units to analyze cost impacts due to variation in individual system parameters. We also provide detailed manufacturing cost analyses for modules, inverters, and ESSs for the first time. In addition, the benchmarks provide insight into the disaggregated costs of individual system components, which can be used to identify the system components driving installed prices and opportunities for system price reductions.

3.3 Benchmark Comparison With Other Metrics

Cost and price metrics can vary significantly because of the various methods, time frames, and calculation methods used in their development. For example, median residential PV system prices from Lawrence Berkeley National Laboratory's *Tracking the Sun* series—which are based on values reported by installers or customers—are consistently higher than NREL's residential MMP benchmarks (e.g., see Barbose et al. 2022). There are three main reasons for this disparity.

First, the NREL benchmark is based on costs incurred by a typical, experienced installer in a competitive market, whereas the U.S. residential installation industry includes a wide range of companies with different cost structures and market strategies. Second, the MMP benchmark includes costs only for a representative system installation, whereas reported prices may include premium system features (such as premium inverters) and costs of complementary services such as additional electrical work, securing financing, additional roofing services, and other home upgrades. 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. For an illustration of variation across several sources and all three PV market sectors, see our Q1 2022 report (Ramasamy et al. 2022).

Overall, different price benchmarks are useful for different purposes. Our benchmarks are primarily used to understand market dynamics and provide insights into underlying cost drivers. These benchmarks should not be used for purposes better met by local- and customer-specific market prices and vice versa. For instance, if a firm would like to know component prices for a specific location and time, then the firm should contact multiple vendors for each component. Conversely, our benchmarks can inform an understanding of the potential trajectory of underlying cost drivers in a stabilized market. It is also critical to understand the distinction between our MSP and MMP calculation methods when using the benchmark results. These two metrics are described next.

3.4 Minimum Sustainable Price and Modeled Market Price Benchmarks

Beginning with the Q1 2022 report, we have provided capital cost results using two metrics:

1. **MSP benchmarks** are 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. **MMP benchmarks** maintain continuity with previous benchmark reports by capturing macroeconomic factors and the impact of market trends, reflecting typical national system cash costs experienced by U.S. installers and passed on to U.S. consumers within the analysis period (Q1 2023 in this report).

Both MSP and MMP are calculated for representative components and systems in each PV market sector. Table 2 summarizes the meaning, approach, and purpose of each benchmark in comparison to reported market prices (which are not shown 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)[2] 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 specific project requirements (e.g., unionized labor).
Approach	Distorted input costs are removed from model calculations, and minimum sustainable margins are used to estimate price. If there is more than one typical technology or configuration, the most common one is modeled.[3]	The mean reported market costs and prices for subcomponents for representative systems are based on aggregated interview data. MSP and MMP use the same technology configurations.	Price metrics aggregated (e.g., median, mean) from sources that collect market price data.
Purpose	Long-term analysis; informing R&D investment decisions.	Near-term policy and market analysis based on disaggregated system costs.	Near-term analysis based on reported prices.

*For reported market price details, see Barbose et al. (2022).

3.4.1 Minimum Sustainable Price Benchmarks

Reported market prices and MMP benchmarks are affected by market and policy conditions unique to the analysis period. In contrast, our MSP benchmarks are 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 benchmarks described in Section 3.4.2 can be thought of as MSPs distorted by short-term market and policy phenomena that occurred in Q1 2023.

---

[2] 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.

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

The MSP is an economic concept that was first used by NREL 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 derived from observable factors such as the underlying cost drivers, market input prices (e.g., for raw materials and equipment), and additional 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, equipment suppliers, assemblers, and installers. For the Q1 2023 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.

Calculating MSP Directly: Bottom-Up Cost Modeling for Component Manufacturing

We apply detailed bottom-up cost modeling to calculate MSP directly for modules, inverters, and battery storage components. NREL has been applying bottom-up cost modeling techniques across the PV supply chain for more than 13 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 2 provides an overview of the input data needed for bottom-up component cost modeling and representation of results following the GAAP and the IFRS. 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 2. 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 additional details, see Smith et al. (2021) and Woodhouse et al. (2020).

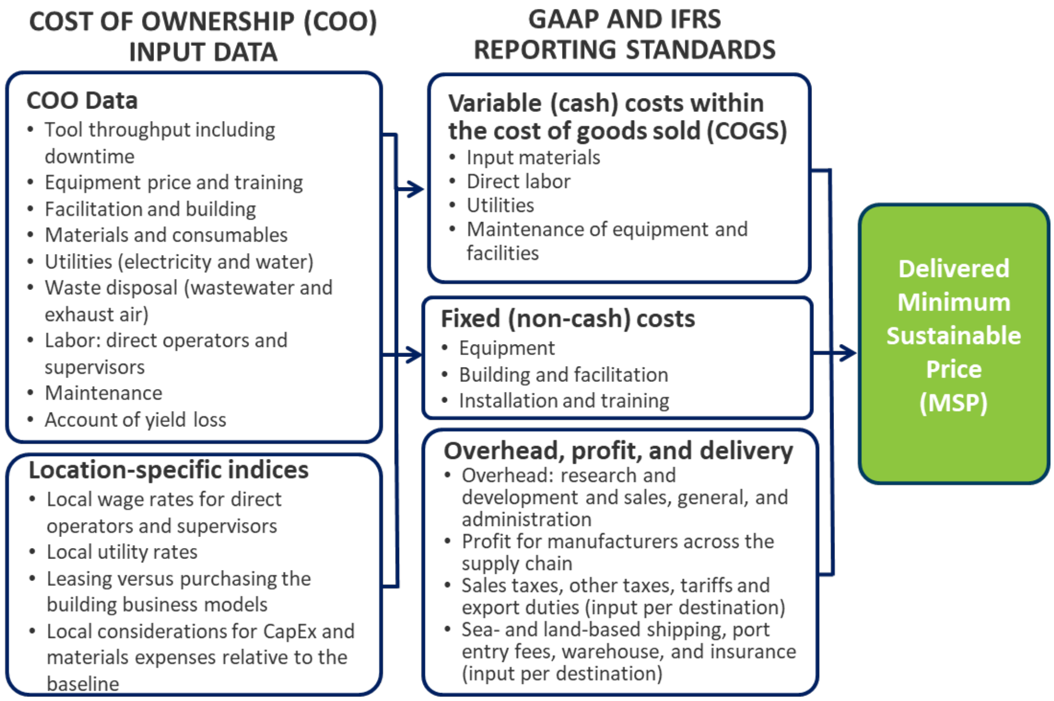

Figure 2. Overview of bottom-up cost modeling input data used to calculate the MSP for components

Converting MMP to MSP: Addressing Distorted Input Values for Other Cost Categories

Although all market prices fluctuate due to near-term changes in supply and demand, aggregated market prices in mature, competitive industries tend to follow long-term trends. Deviations from long-term technology costs and overall inflation 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 obscure understanding of long-term price trajectories. We use this basic concept to develop rules for adjusting input prices that are significantly distorted by temporary market and policy shocks. We apply these rules to structural balance of system (SBOS), electrical balance of system (EBOS), and labor costs, because we collect original values for these categories in MMP terms. Our calculations for manufacturing modules, inverters, and battery storage components result directly in MSP values, as noted above, and thus require no adjustments.

In last year's report, we inferred equipment cost distortions based on changes in the CPI, and we excluded distorted values from our cost calculations. For labor, we used the most recent available data from the Bureau of Labor Statistics (BLS) to determine that labor costs were within a historically typical range and thus needed no adjustments (Ramasamy et al. 2022). This year, we refine our method by using three indexes to evaluate and adjust (if necessary) component-specific distortions:

- For SBOS, the Producer Price Index by Commodity: Metals and Metal Products: Cold Rolled Steel Sheet and Strip (FRED 2023d)
- For EBOS, the Producer Price Index by Industry: Electrical Equipment Manufacturing (FRED 2023e)

- For labor, the Employment Cost Index: Wages and Salaries: Private Industry Workers (FRED 2023f).

Figure 3 compares actual values versus the 20-year linear trend for the Producer Price Index by Commodity: Metals and Metal Products: Cold Rolled Steel Sheet and Strip, adjusted to 2022 values using the CPI. Although this index spiked from mid-2021 through mid-2022, it returned to a historically typical range in late 2022 through early 2023.[4] For this reason, we consider the SBOS costs that we collected for Q1 2023 to be undistorted by market fluctuations. We only adjust MMP to MSP by accounting for costs associated with the Section 301 tariff and manufacturing tax incentives for applicable components.

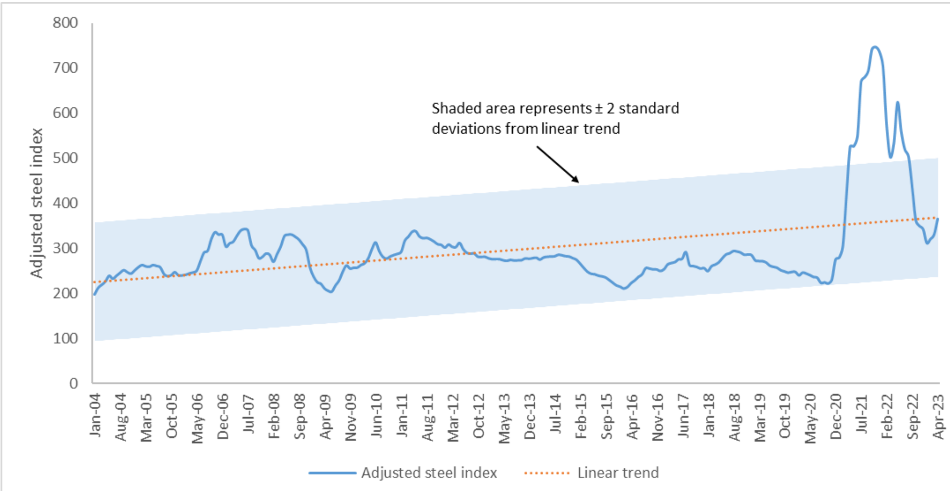

Figure 3. Steel index (adjusted to 2022 values using CPI) data and linear fit, 2003–2023

Data are from "Producer Price Index by Commodity: Metals and Metal Products: Cold Rolled Steel Sheet and Strip," index Jun 1982 = 100, not seasonally adjusted (FRED 2023d). The upward trajectory of the trend line becomes slightly negative if data beyond January 2020 (onset of the COVID-19 pandemic) are removed.

Figure 4 compares actual values versus the 20-year linear trend for the Producer Price Index by Industry: Electrical Equipment Manufacturing, adjusted to 2022 values using the CPI. The actual values in Q1 2023 are more than two standard deviations above a linear fit to 20 years of index data. We interpret this deviation as indicating a level of distortion that can separate EBOS input prices from underlying cost fundamentals. We adjust for this distortion by reducing EBOS MMP values by 8.25%—the difference between the actual electrical equipment index and the linear trend in Q1 2023—when calculating EBOS MSP values. We also adjust MMP to MSP by removing costs associated with the Section 301 tariff for applicable components.

Finally, Figure 5 compares actual values versus the 20-year linear trend for the Employment Cost Index: Wages and Salaries: Private Industry Workers, adjusted to 2022 values using the CPI. Although this index spiked in 2020 and early 2021, it returned to a historically typical range in late 2021 through early 2023. For this reason, we consider the labor costs that we collected for

[4] To analyze all three indexes discussed in this section, we define a historically typical range as two standard deviations above and below a linear fit to 20 years of inflation-adjusted index data. We generate the distribution by subtracting the adjusted index value from the linear-fit value for each date and taking the absolute value.

Q1 2023 to be undistorted by market fluctuations, and our labor MMPs are equal to our labor MSPs.

For other upfront costs (e.g., distributor costs, profit) and O&M costs (e.g., insurance) that are factors of system capital costs, MMPs are calculated using MMP capital costs, and MSPs are calculated using MSP capital costs.

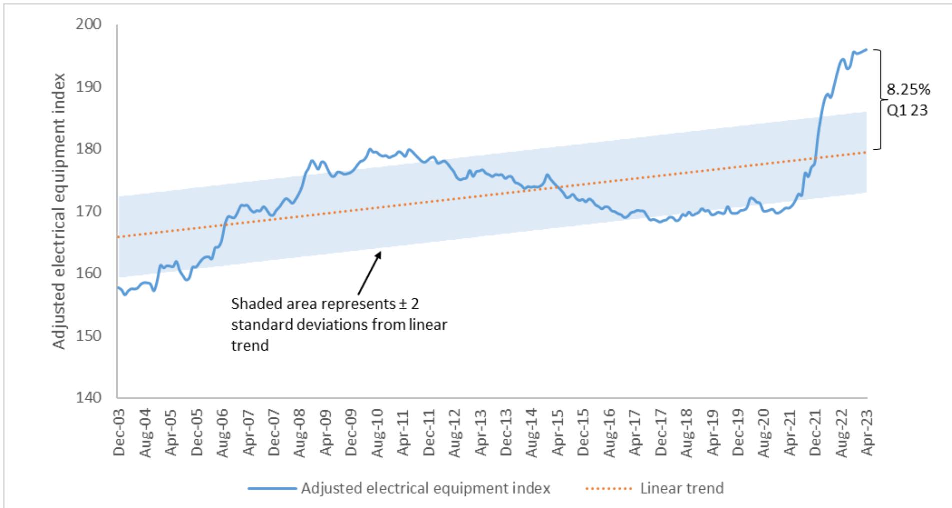

Figure 4. Electrical equipment manufacturing index (adjusted to 2022 values using CPI) data and linear fit, 2003–2023, showing deviation of data from fit during Q1 2023

Data are from "Producer Price Index by Industry: Electrical Equipment Manufacturing," index Dec 2003 = 100, not seasonally adjusted (FRED 2023e). The modest upward trajectory of the trend line decreases, to a compound annual growth rate of about 0.3%, if data beyond January 2020 (onset of the COVID-19 pandemic) are removed.

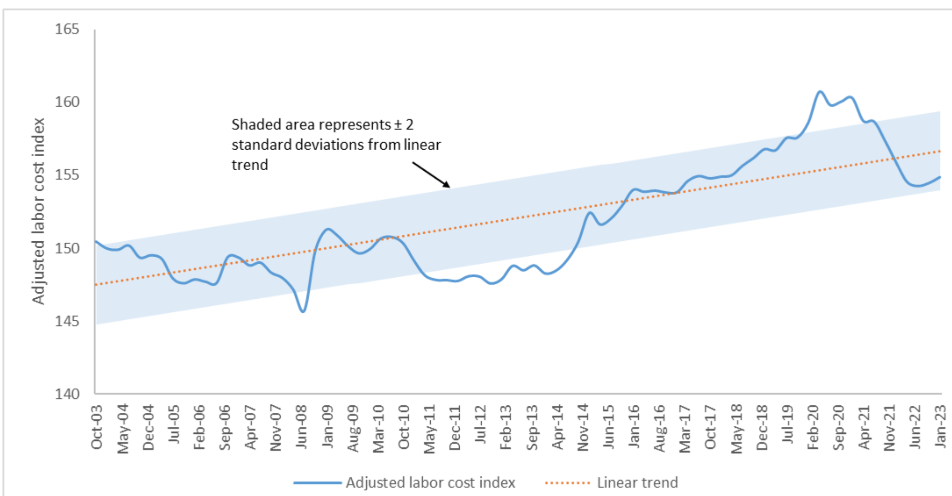

Figure 5. Labor cost index (adjusted to 2022 values using CPI) data and linear fit, 2003–2023

Data are from "Employment Cost Index: Wages and Salaries: Private Industry Workers," index Dec 2005 = 100, seasonally adjusted (FRED 2023f). The upward trajectory of the trend line represents a compound annual growth rate of about 0.3%.

3.4.2 Modeled Market Price Benchmarks

Our MMP benchmarks can be interpreted as the average sales prices that a typical U.S. installer would have charged in Q1 2023. As described in Section 3.4.1, we calculate MSP values directly for the manufacturing of modules, inverters, and battery storage components. We then derive MMP values for these components using reported market prices (including data from BloombergNEF (BNEF), InfoLink, and PV Tech), interview data, and financial statements of representative firms. Also as described in Section 3.4.1, we collect original values for SBOS, EBOS, and labor costs in MMP terms.

3.5 Treatment of Tax Incentives

Under the U.S. tax code (and expanded by IRA), several U.S. tax credits are available to owners of PV and ESSs as well as manufacturers of PV and energy storage components (DOE 2023a). The credits for PV system owners are based either on the upfront cost of the system (Section 48/48E Investment Tax Credit or ITC) or the electricity generated by the system (Section 45(d)/45Y Production Tax Credit or PTC). These credits, along with related bonus credits,[5] affect the prices U.S. customers will pay for PV systems and thus could impact installer and manufacturer margins as well as the size of the U.S. PV market. However, the impact of the tax credits is unclear because market competition within the U.S. PV sector—and from competing sources of energy—already creates margin pressure. In addition, because these tax credits have existed for well over a decade and will continue for a decade or more, they are part of the long-term market that our MSP benchmarks aim to capture. For these reasons, we do not include the credits for system owners explicitly in our cost modeling.

The credits for manufacturers are based either on the cost of building a manufacturing facility (Section 48C Advanced Energy Project ITC) or for domestically producing and selling clean energy components (Section 45X Advanced Manufacturing PTC). No companies have received Section 48C credit to date under IRA, so we exclude this credit from our cost modeling. However, numerous U.S. manufacturers are likely taking advantage of the Section 45X credit, and the reduced costs of producing the resulting components could directly impact system installers. For this reason, we account for the Section 45X Advanced Manufacturing PTC credit in our modeling of domestic components.

To determine the impact of the 45X credit, we follow four steps:

1. **Identify domestically manufactured components.** In Q1 2023, we model the following components as U.S. manufactured: PV modules (assembly, residential installations), microinverters (assembly, residential installations), battery modules (assembly, all sectors), and torque tubes and structural fasteners of a tracking system (utility-scale installations).
2. **Determine how to adjust domestic components based on the tax credit.** We use bottom-up manufacturing models to calculate PV module, inverter, and battery MSPs. We adjust the MMP of these components (for sectors specified in step #1) by the 45X

[5] For more information, see the SETO guide to federal solar tax credit resources at https://www.energy.gov/eere/solar/articles/federal-solar-tax-credit-resources.

credit, because the credit may affect the component prices paid by installers. In contrast, we calculate BOS costs—including the cost of domestically manufactured torque tubes and fasteners—based primarily on interviews with industry stakeholders. Those estimates represent final prices paid by installers, so any impact from the 45X credit is already incorporated into the MMP; thus, we adjust the MSP based on the credit.

3. **Calculate production-based credit amounts for each domestic component.** IRA specifies the credit amounts by component, including \$0.07/W_{dc} for PV modules, \$0.11/W_{ac} for microinverters, \$10/kWh for battery modules, \$0.87/kg for torque tubes, and \$2.28/kg for structural fasteners of a tracking system (DOE 2023b).
4. **Allocate credit values between the component seller (manufacturer) and buyer (installer).** The component manufacturer claims the production-based credit and decides how its value is allocated. At one end of the spectrum, the manufacturer could pass the entire value of the credit through to the buyer as a lower component price. At the other end, the manufacturer could leave the component price unchanged and retain the entire credit as part of its margin. No data on how manufacturers are allocating the 45X credit are available. For Q1 2023, we assume that half of each credit amount is passed along to the installer as a lower component price, and half is retained by the manufacturer.

3.6 Limitations

Our benchmarks convert complex processes and inputs into highly simplified individual estimates. These simplified estimates are useful for tracking technological progress. However, no individual estimate under any approach can reflect the diversity of the PV and storage manufacturing, installation, and maintenance industries. Our MMP benchmarks are designed to reflect typical costs experienced by installers, but these costs do not reflect all experiences. For instance, MMP benchmarks based on national average costs do not reflect the distinct experiences of developers in local markets and at different purchasing volumes. 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. (2022).

Finally, any comparison of our 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. The MSP benchmarks deviate from imperfect markets in the real world, and they have been lower than MMP benchmarks for the past few years. In an oversupplied market and in the absence of trade distortions, MSPs could become higher than MMPs in future. Our 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, our MMP benchmarks are meant to reflect current market conditions relevant to making short-term decisions, including policy recommendations.

3.7 Changes to Benchmarking Assumptions in Q1 2023

In addition to changing our data collection and analysis approach (see Section 4), we made several changes to our benchmarked systems this year. In Q1 2023, we do not model a commercial rooftop system or relatively small (500 kW_{dc}) commercial ground-mounted system, as we did in Q1 2022. Instead, we model a 3-MW_{dc} ground-mounted community solar system, owing to the growing public- and private-sector interest in this application. We chose 3 MW_{dc} based on industry feedback indicating increasing system sizes as well as the mean community solar system size (2.5 MW_{dc}) in 2022 in New York (New York State 2023), where 52% of U.S. community solar capacity was installed in 2022 (Wood Mackenzie and SEIA 2023). Community solar has additional cost categories beyond those for typical commercial PV systems, including subscriber acquisition and maintenance costs, which we analyze in detail (see Sections 6 and 8).

Modules for residential PV systems and utility-scale PV systems are substantially larger this year: 1.97 m^2 and 410 W_{dc}, and 2.57 m^2 and 525 W_{dc}, respectively in Q1 2023, compared with 1.8 m^2 and 360 W_{dc}, and 2.0 m^2 and 405 W_{dc}, in the Q1 2022 report. In addition, the representative utility-scale modules in the Q1 2023 report are bifacial, rather than monofacial as in the Q1 2022 report. Comprehensive national statistics on U.S. utility-scale module specifications are not yet available. However, evidence—including U.S. tariff data (Feldman et al. 2023), the International Technology Roadmap for Photovoltaic (ITRPV 2023), trade publications including *Taiyang News* (e.g., Chunduri 2022), and industry interviews—suggests that large bifacial modules have become dominant in the utility-scale sector. We use the utility-scale module assumptions for our benchmark 3-MW_{dc} community solar system as well.

4 New in 2023: PV System Cost Model

For this Q1 2023 benchmark report, a new bottom-up PV and storage cost model is used for the first time. The PV System Cost Model (PVSCM) was developed by SETO and NREL to make the cost benchmarks simpler and more transparent, while expanding to cover PV product components not previously benchmarked. PVSCM can also facilitate sensitivity analysis based on key system parameters in their intrinsic units.

Our new PVSCM-based benchmarking approach shares similarities with and builds on the cost models and methods we have used over the past decade. We develop representative system parameters in multiple sectors based on industry trends. We collect data from multiple sources, aligning our model inputs as closely as possible to the analysis period (Q1 2023 for this report). We use those data to build subsystem and system costs from the bottom up and then validate results with industry experts. After adjusting 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 later in the year (e.g., Q1 2022 results were published in September 2022). See all the reports at NREL's Solar Technology Cost Analysis webpage: https://www.nrel.gov/solar/market-research-analysis/solar-cost-analysis.html.

However, our new benchmarking approach also differs from our past approaches. Our previous bottom-up capital cost models consisted of specific, detailed system designs, which we populated with inputs in the form of material costs, component and subcomponent costs, installation rental equipment rates, and labor rates from data sources such as RSMeans, the U.S. Bureau of Labor Statistics, RENVU, EcoDirect, altE Store, BNEF, Wood Mackenzie, and the Solar Energy Industries Association (SEIA). For example, our utility-scale PV design included a specific number of module mounting structures, linear feet of trenches, days of geotechnical investigation, and so forth—all the many items needed to build a complete utility-scale system. We input per-unit material, equipment, and labor costs associated with each item based on the data sources noted above, and the model calculated total costs for each item. We based 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. The final results were disaggregated system costs in terms of dollars per direct-current watt of PV system power rating ($\$/W_{dc}$), dollars per kilowatt-hour of energy storage ($/kWh), and dollars per installed system. We sent these results for validation to industry stakeholders. We did not publish detailed subcomponent cost data, such as torque tube or rail contributions to SBOS costs, transformer or substation contributions to EBOS costs, and so forth.

In contrast, this year's capital cost benchmarking approach using PVSCM *starts* with direct cost inputs from interviews with industry stakeholders, and results are provided at the subcomponent level. Figure 6 is a schematic of the process using a utility-scale system as an example. The colored boxes inside the dashed line represent the PVSCM data we publish. Limiting the number of cost elements in each box to 10 strikes a balance between level of detail and usability. The gray boxes outside the dashed line represent data and analysis that feed into PVSCM but are not published. For capital costs, we start with the gray "Component Cost Data" box. Here, our primary data source consists of interviews with industry stakeholders. In February 2023, we attended Intersolar North America and Energy Storage North America in Long Beach, California, where we gathered on-the-spot data and insights from more than 100 exhibitors. After the conference, we conducted in-depth interviews and correspondence with about 40 experts connected to the manufacturing and sale of modules, inverters, ESSs, and balance-of-system components, as well as the installation of PV and storage systems. We supplemented and cross-checked the interview-based data using reports, data, and tools including Barbose et al. (2022), Bolinger et al. (2022), CA NEM (2023), PEguru (2023), RENVU (2023), and Roth MKM (2023). We convert these data into intrinsic units to be input into PVSCM using system and component specifications. Then various factors in PVSCM—derived from interviews, reports, and the detailed bottom-up model used for our Q1 2022 benchmark report—are used to convert the intrinsic units into system capital costs in dollars per kilowatt dc. The appendix shows an example of the process, for SBOS components in a residential PV system. The full set of PVSCM inputs and results for Q1 2023 is available at https://data.nrel.gov/.

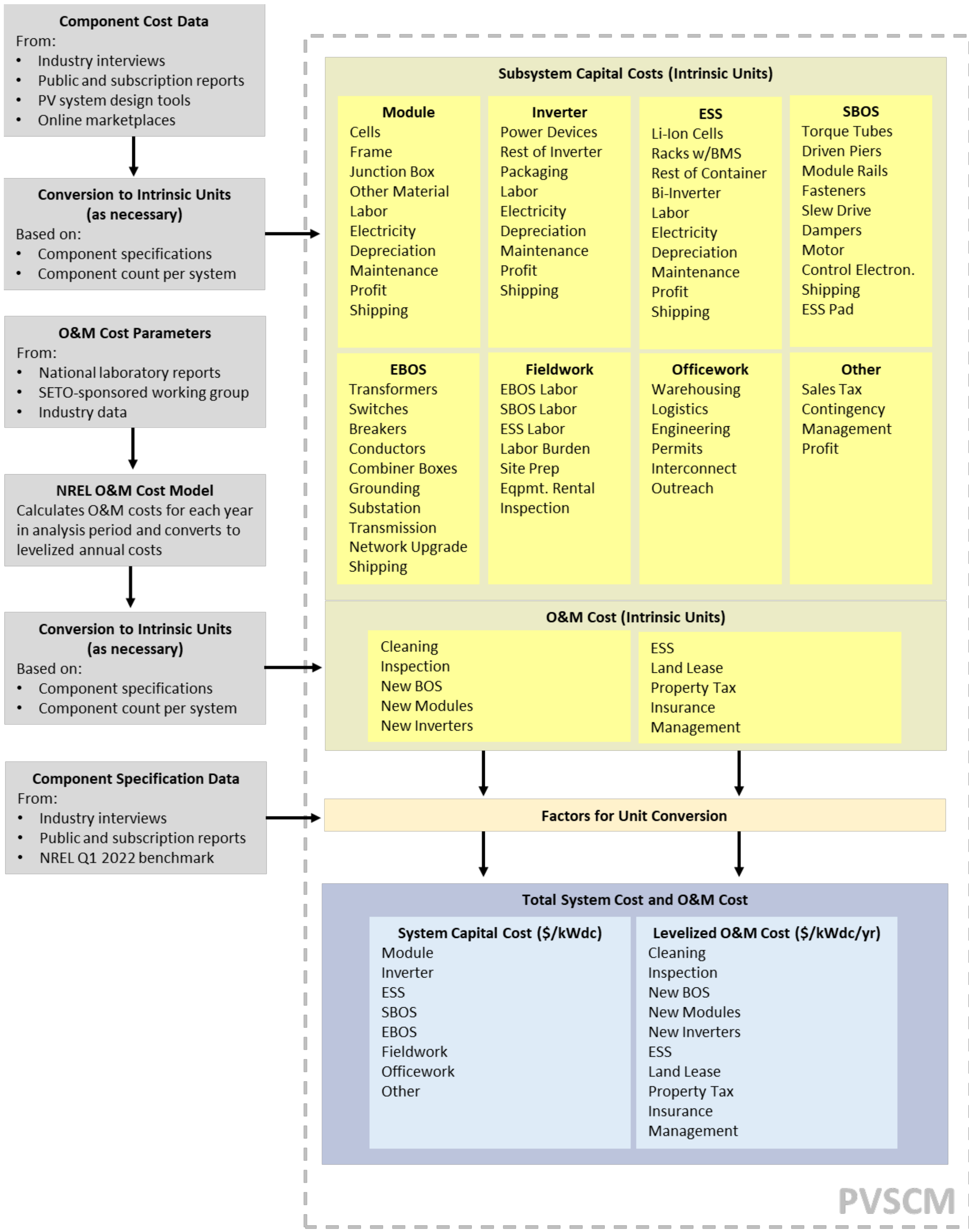

Figure 6. Schematic of benchmark analysis using PVSCM (for utility-scale system)

5 Residential Model

This section describes our residential PV and PV-plus-storage parameters (Section 5.1) and outputs (Section 5.2 and Section 5.3). The cost results are in 2022 real U.S. dollars (USD).[6] If the results were in Q1-2023 nominal USD, they would be about 3% higher.

5.1 Representative System Parameters

We model a baseline 8-kW_{dc} rooftop PV system using 20.8%-efficient, 1.97-m^2 monofacial monocrystalline silicon modules from a Tier 1 U.S. supplier, microinverters with an inverter loading ratio (ILR) of 1.21 imported from China with the Section 301 tariff, and a 5-kW/12.5-kWh alternating-current (ac) coupled lithium-ion storage system. The per-unit cost results are meant to be generally applicable to systems with PV sizes between about 4 and 16 kW_{dc}. Module, inverter, and battery costs represent the costs to manufacture the components and ship them to a distributor's warehouse. SBOS and EBOS costs represent the costs for small but experienced residential PV installers to procure these components. The fieldwork, office work, and other costs relate to installation and overhead labor, PII, customer acquisition, logistics, sales tax, and profit.

5.2 System Costs

Figure 7 compares our MSP and MMP benchmarks for rooftop 8-kW_{dc} residential PV systems with and without a 12.5-kWh capacity storage system. For Q1 2023, our MMP benchmark for PV ($2.68/$W_{dc}$) is 15% higher than our MSP benchmark ($2.34/$W_{dc}$). Likewise, our PV-plus-storage MMP benchmark ($4.70/$W_{dc}$) is 21% higher than our MSP benchmark ($3.88/$W_{dc}$). Without the 45X credit eligible for domestically assembled modules, inverters, and battery packs the MMP of the residential PV and PV-plus-storage system would have been $2.90/$W_{dc}$ and $4.93/$W_{dc}$, respectively.

Our Q1 2023 MMP benchmarks are 16% lower (PV) and 9% lower (PV-plus-storage) than their counterparts in Q1 2022, in 2022 USD. Higher BOS costs in Q1 2023 were more than offset by lower module, inverter, battery pack, logistics, and customer acquisition costs.

[6] Throughout the report, we adjust nominal cost data collected in Q1 2023 to 2022 real USD based on the 2022 average CPI (292.6) and Q1 2023 average CPI (301.3) from FRED (2023a), resulting in an inflation factor of 0.97.

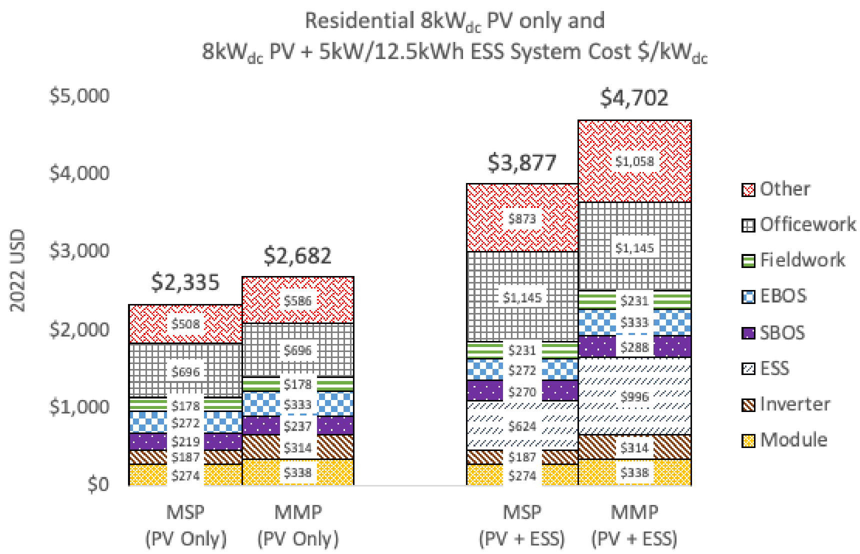

Figure 7. Q1 2023 U.S. residential benchmarks (8-kW$_{dc}$ PV, 12.5-kWh ESS)

5.3 Component Costs

Figure 8 and Figure 9 show the component costs for our residential benchmark, with each graph displayed in the intrinsic units corresponding to the component shown.

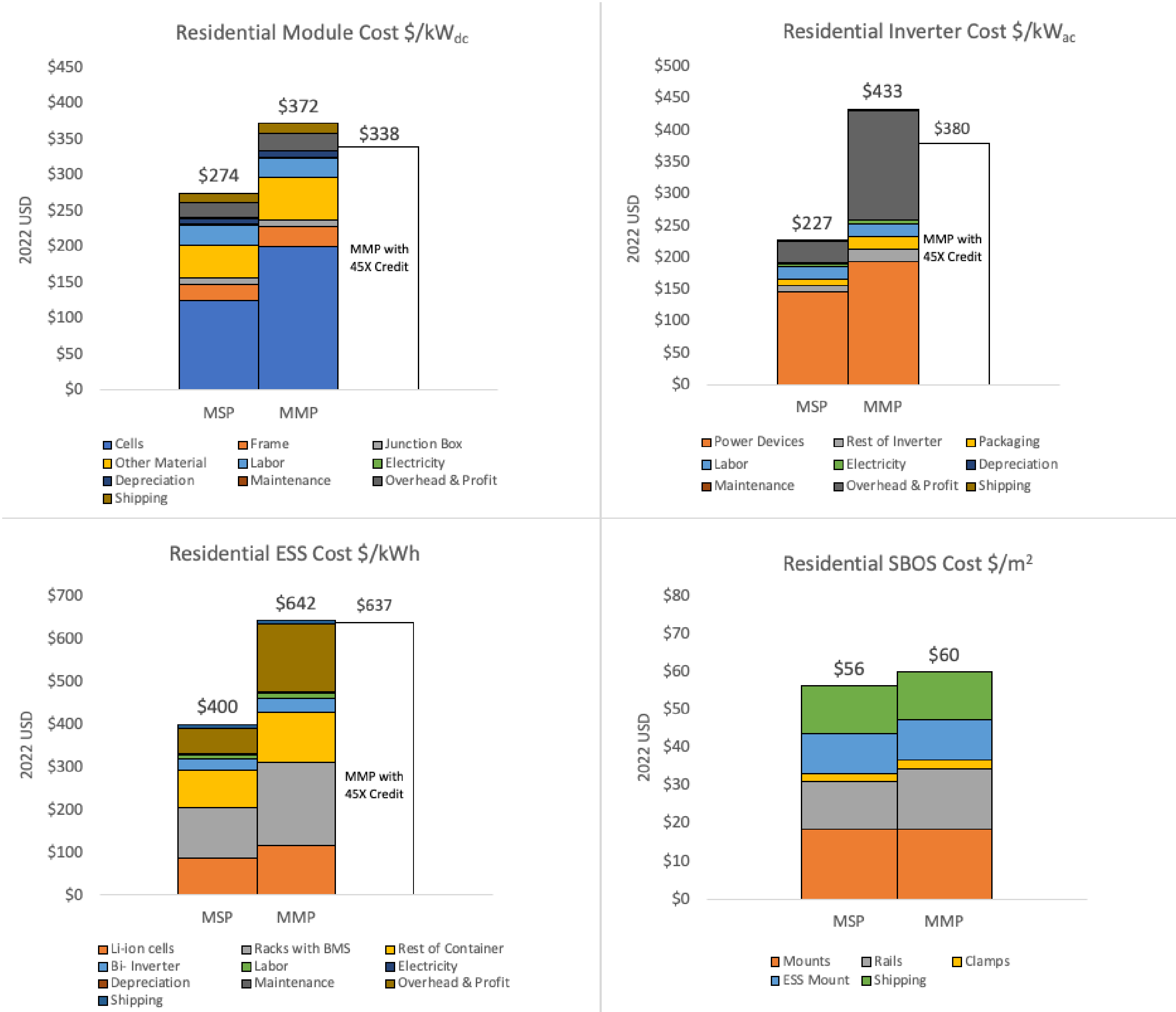

Figure 8. Residential module, inverter, energy storage, and SBOS costs

The results shown here are for PV-plus-storage systems; PV-only results are not shown here but are available at https://data.nrel.gov/. In addition to the ESS cost itself, adding ESS affects the SBOS category (ESS mount cost). The module "other material" category includes the front glass, backsheet, and encapsulant. The "rest of inverter" category includes the sensors, fuses, software, and cooling system.

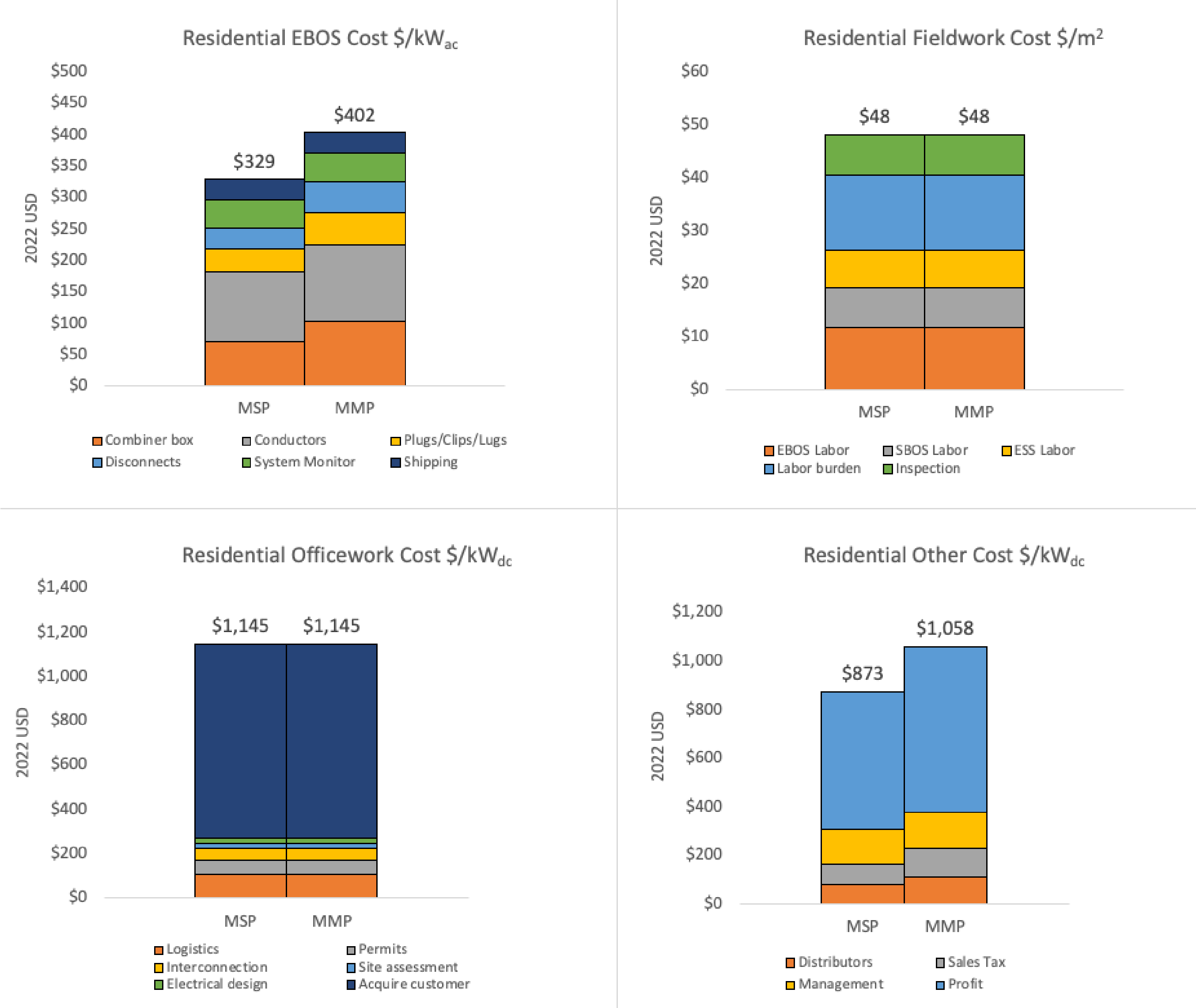

Figure 9. Residential EBOS, fieldwork, office work, and other capital costs

The results shown here are for PV-plus-storage systems; PV-only results are not shown here but are available at https://data.nrel.gov/. Adding ESS affects multiple cost categories: fieldwork (ESS labor), office work (customer acquisition), and other costs (distributors, sales tax, management, profit).

6 Community Solar Model

This year, we model a community solar system for the first time. With community solar, customers can buy or lease a share of a large off-site PV or PV-plus-storage system, typically receiving a monthly bill credit for their share of the electricity generation. In this section, we describe our community solar parameters (Section 6.1) and outputs (Section 6.2 and Section 6.3). The cost results are in 2022 real USD. If the results were in Q1-2023 nominal USD, they would be about 3% higher.

The community solar cost structure resembles that of a comparably sized commercial ground-mounted, fixed-tilt PV system, with two distinctions. Community solar systems incur initial costs to acquire numerous subscribers, unlike residential or commercial systems, which entail acquiring only a single customer. Community solar systems also incur unique costs for ongoing subscriber management, such as bill management, ongoing marketing, and customer acquisition costs to manage customer turnover. We build benchmark estimates for both cost components based on insights from the literature and interviews with three developers. In Section 6.3, we discuss initial subscriber acquisition costs. Ongoing subscriber management costs are discussed in Section 8.

6.1 Representative System Parameters

We model a 3-MW_{dc}, 1,000-V_{dc} fixed-tilt community solar system using 20.5%-efficient, 2.57-m^2 bifacial monocrystalline silicon modules from a Tier 1 supplier imported from Southeast Asia with a Section 201 tariff exception, three-phase string inverters with an ILR of 1.34 imported from China with the Section 301 tariff, and a 1.8-MW/7.2-MWh ac-coupled containerized lithium-ion storage system. We chose a 3-MW_{dc} PV system based on industry feedback indicating increasing system sizes as well as the mean community solar system size (2.5 MW_{dc}) in 2022 in New York (New York State 2023), where 52% of U.S. community solar capacity was installed in 2022 (Wood Mackenzie and SEIA 2023). The per-unit cost results are meant to be generally applicable to systems with PV sizes between about 1.5 and 6 MW_{dc}. Module, inverter, and battery costs represent the costs to manufacture the components and ship them to a warehouse. SBOS and EBOS costs represent the costs for developers to procure these components. The fieldwork, office work, and other costs relate to installation and overhead labor, PII, subscriber acquisition, logistics, sales tax, and profit.

6.2 System Costs

Figure 10 compares our MSP and MMP benchmarks for ground-mounted fixed-tilt 3-MW_{dc} community solar systems with and without a 7.2-MWh storage system. For Q1 2023, our MMP benchmark for PV ($1.76/$W_{dc}$) is 18% higher than our MSP benchmark ($1.49/$W_{dc}$). Likewise, our PV-plus-storage MMP benchmark ($2.94/$W_{dc}$) is 26% higher than our MSP benchmark ($2.33/$W_{dc}$). Without the 45X credit for locally assembled battery packs, the MMP of the PV-plus-storage system would have been $2.96/$W_{dc}$.

Our Q1 2022 benchmark report has no community solar system to enable a comparison over time. Text Box 1 compares our Q1 2023 community solar benchmarks with the cost of similar commercial PV and PV-plus-storage systems.

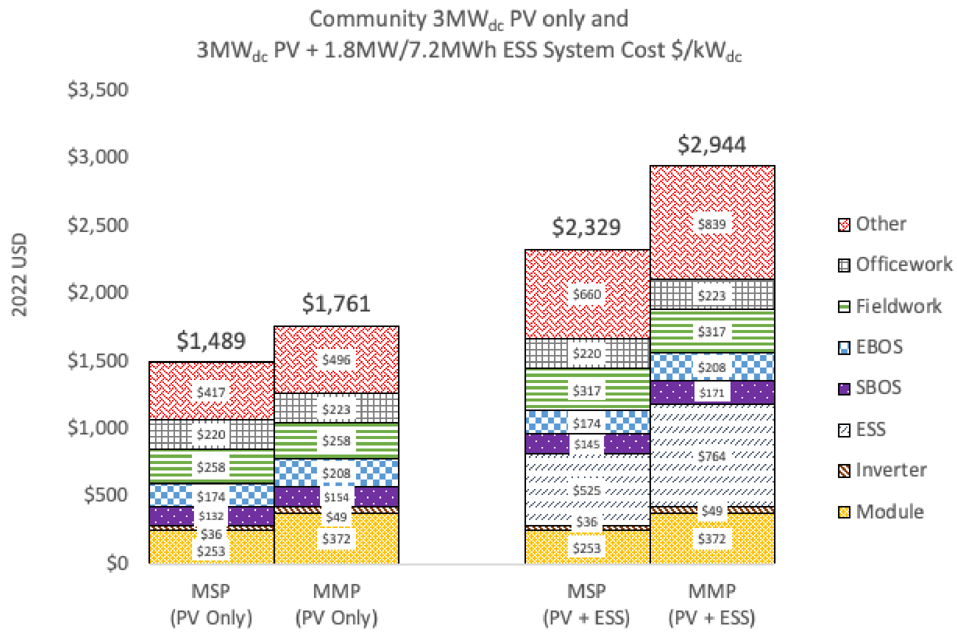

Figure 10. Q1 2023 U.S. community solar benchmarks (3-MW_{dc} PV, 7.2-MWh ESS)

Text Box 1. Commercial PV and PV-plus-storage system costs
Previous NREL benchmark reports have provided cost results for commercial PV and PV-plus-storage systems: rooftop or ground-mounted systems serving a single commercial customer. Although we do not explicitly model commercial benchmarks for Q1 2023, the cost of 3-MW_{dc} commercial ground-mounted systems can be estimated from our community solar benchmarks by adjusting the subscriber recruitment cost. As described in Section 6.3, we estimate the community solar subscriber recruitment cost at $\$0.08/W_{dc}$, based on a mix of subscriber types. We estimate that the cost to acquire a single large customer for a comparable commercial system is equivalent to the cost of recruiting a large commercial subscriber for a community solar system, at $\$0.041/W_{dc}$. After accounting for changes to other costs that are affected by the subscriber cost (management, profit, etc.), our community solar benchmarks are about $\$0.05/W_{dc}$ higher than the upfront costs of similar commercial PV and PV-plus-storage systems. The O&M costs also vary across system types (see Section 8).

6.3 Component Costs

Wood Mackenzie (2023) estimates community solar customer acquisition costs of $\$0.141/W_{dc}$ for low- and moderate-income (LMI) residential subscribers, $\$0.078/W_{dc}$ for non-LMI residential subscribers, $\$0.063/W_{dc}$ for small commercial subscribers, and $\$0.041/W_{dc}$ for large commercial subscribers. Project-level customer acquisition costs are thus determined by the composition of the subscriber base. Large commercial or industrial customers typically compose significant portions of community solar capacity by acting as "anchor" tenants. Several state policies limit anchor tenant subscriptions to 40% of project capacity, and several developers confirmed that 40% is an appropriate benchmark assumption. For the remaining 60%, the key question is how much capacity is reserved for LMI subscribers. Based on feedback from developers and policy trends (see Text Box 2), we estimate that 30% of our benchmark community solar project's capacity is reserved for LMI subscribers. Assuming the benchmark project includes a large commercial anchor tenant subscribed to 40% of capacity, LMI subscribers subscribed to 30% of capacity, and an even mix of residential and small commercial customers subscribed to the remaining 30% of capacity, we estimate a project-level customer acquisition rate of $0.08/$W_{dc}$, which represents a $0.04/$W_{dc}$ premium over a single-offtaker large commercial PV system. Figure 11 and Figure 12 show the component costs for our community solar benchmark, with each graph displayed in the intrinsic units corresponding to the component shown.

Text Box 2. Community solar as a tool for LMI solar access

Community solar is broadly theorized as a way to promote solar access to underserved populations, such as LMI households and renters. Policy reinforces the potential access benefits of community solar. The federal IRA includes tax credits for community solar projects that serve LMI customers or communities. At least 17 states mandate or incentivize community solar to serve LMI customers (IREC 2020, Xu et al. 2023). LMI community solar policy has become more ambitious over time. Recent reforms, such as in California and New Jersey, call for LMI subscription targets as large as 50%. Two developers interviewed for this study reported LMI targets of 15%–40%.

LMI community solar policies and business models pose unique challenges. LMI customers are typically costlier to acquire (Wood Mackenzie 2023). LMI customer acquisition cost premiums reflect several factors, including LMI household budget constraints and ingrained distrust in energy marketers and institutions (Lydersen 2023). Subscriber managers can also incur additional costs to comply with LMI mandates, such as requirements to verify household income. One developer noted that LMI customers may be more likely to unsubscribe, although further research is required to estimate a precise impact of LMI subscription rates on customer turnover.

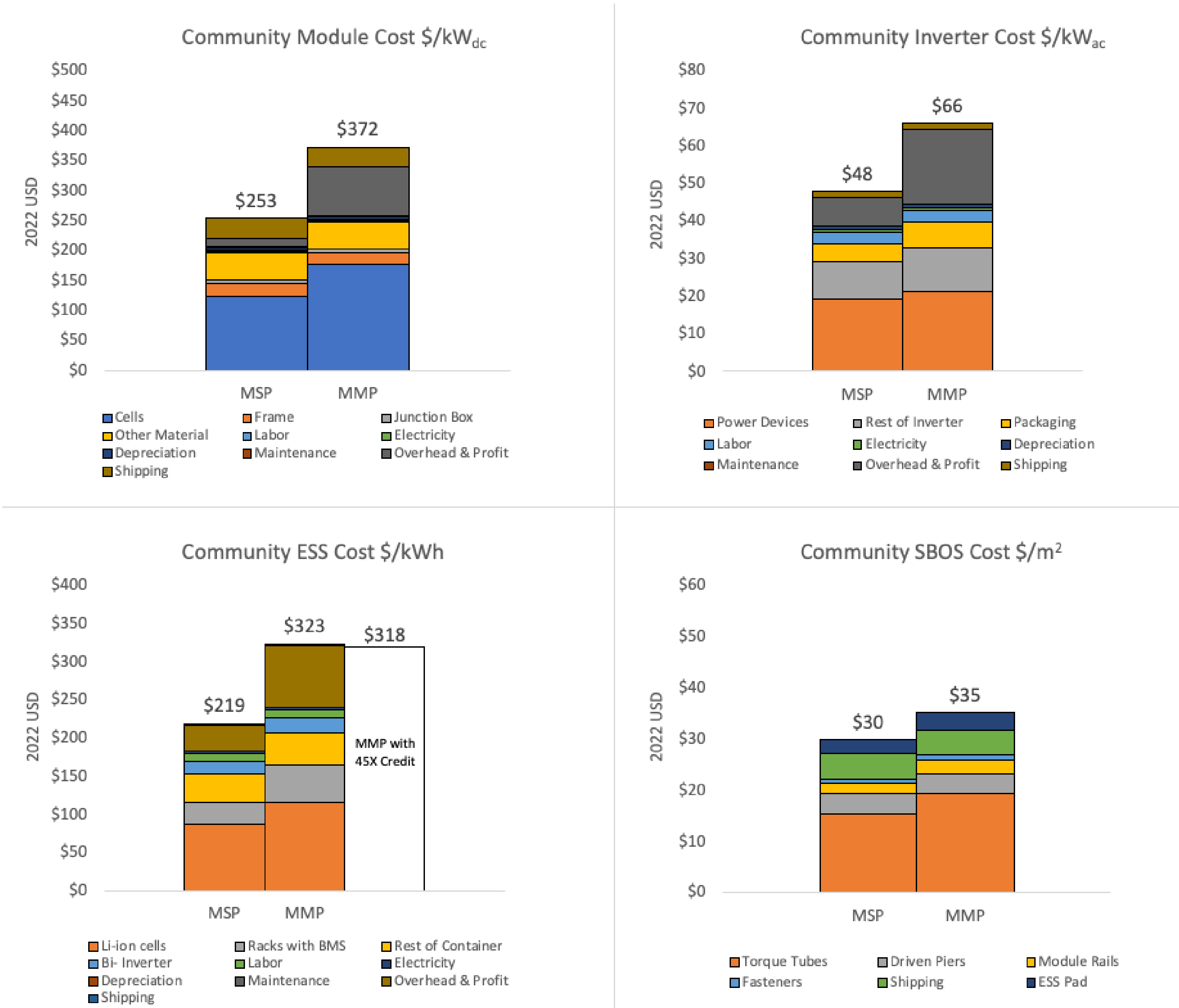

Figure 11. Community solar module, inverter, energy storage, and SBOS costs

The results shown here are for PV-plus-storage systems; PV-only results are not shown here but are available at https://data.nrel.gov/. In addition to the ESS cost itself, adding ESS affects the SBOS category (ESS pad cost). The module "other material" category includes the front and back glass as well as encapsulant. The "rest of inverter" category includes the sensors, fuses, software, and cooling system.

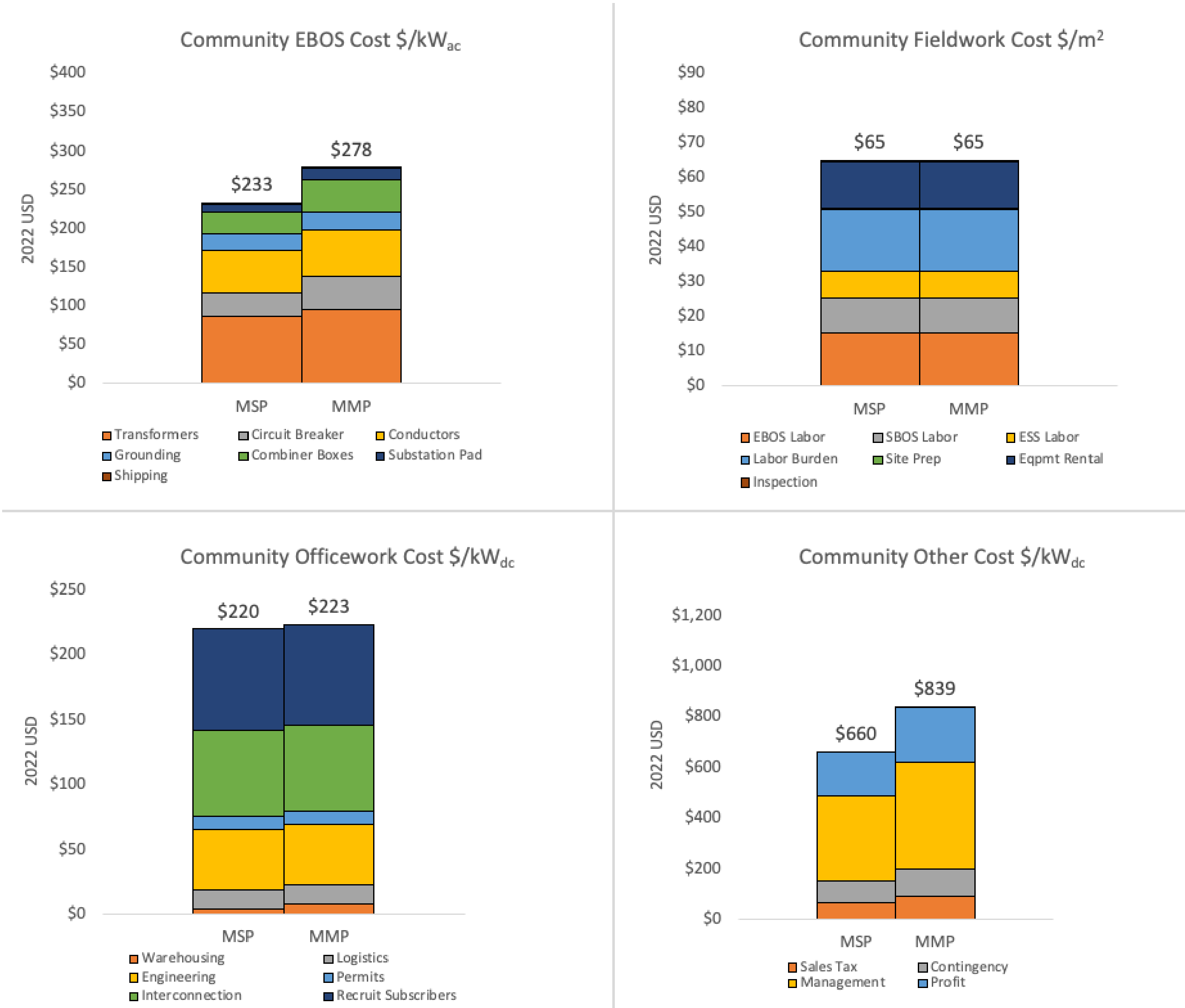

Figure 12. Community solar EBOS, fieldwork, office work, and other capital costs

The results shown here are for PV-plus-storage systems; PV-only results are not shown here but are available at https://data.nrel.gov/. Adding ESS affects two cost categories: fieldwork (ESS labor) and other costs (contingency, sales tax, management, profit).

7 Utility-Scale Model

This section describes our utility-scale PV and PV-plus-storage parameters (Section 7.1) and outputs (Section 7.2 and Section 7.3). The cost results are in 2022 real USD. If the results were in Q1-2023 nominal USD, they would be about 3% higher.

7.1 Representative System Parameters

We model a 100-MW_{dc}, 1,500-V_{dc} decentralized single-axis tracking utility-scale PV system using 20.5%-efficient, 2.57-m^2 bifacial monocrystalline silicon modules from a Tier 1 supplier imported from Southeast Asia with Section 201 tariff exemption. We also model three-phase central inverters with an ILR of 1.34 imported from Europe with no tariff and a 60-MW/240 MWh ac-coupled containerized lithium-ion storage system. We chose a 100-MW_{dc} PV system because that was the approximate average size of U.S. utility-scale systems reported in EIA (2022). The per-unit cost results are meant to be generally applicable to systems with PV sizes between about 50 and 200 MW_{dc}. Module, inverter, and battery costs represent the costs to manufacture the components and ship them to a warehouse. SBOS and EBOS costs represent the costs for developers to procure these components. The fieldwork, office work, and other costs relate to installation and overhead labor, PII, logistics, sales tax, and profit.

7.2 System Costs

Figure 13 compares our MSP and MMP benchmarks for single-axis-tracker 100-MW_{dc} utility-scale PV systems with and without a 240-MWh capacity storage system. For Q1 2023, our MMP benchmark for PV ($1.16/$W_{dc}$) is 19% higher than our MSP benchmark ($0.97/$W_{dc}$). Likewise, our PV-plus-storage MMP benchmark ($2.11/$W_{dc}$) is 28% higher than our MSP benchmark ($1.65/$W_{dc}$).

Our Q1 2023 MMP benchmarks are 8% higher (PV) and 0.2% higher (PV-plus-storage) than their counterparts in Q1 2022, in 2022 USD. Higher inverter and EBOS costs plus new network upgrade costs more than offset lower module and SBOS costs in Q1 2023.

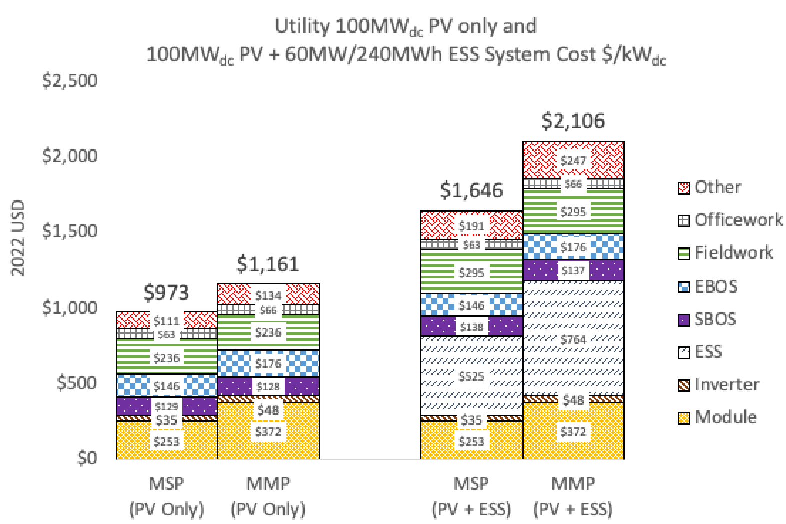

Figure 13. Utility-scale Q1 2023 U.S. benchmarks (100-MW_{dc} PV, 240-MWh ESS)

7.3 Component Costs

Figure 14 and Figure 15 show the component costs for our utility-scale benchmark, with each graph displayed in the intrinsic units corresponding to the component shown.

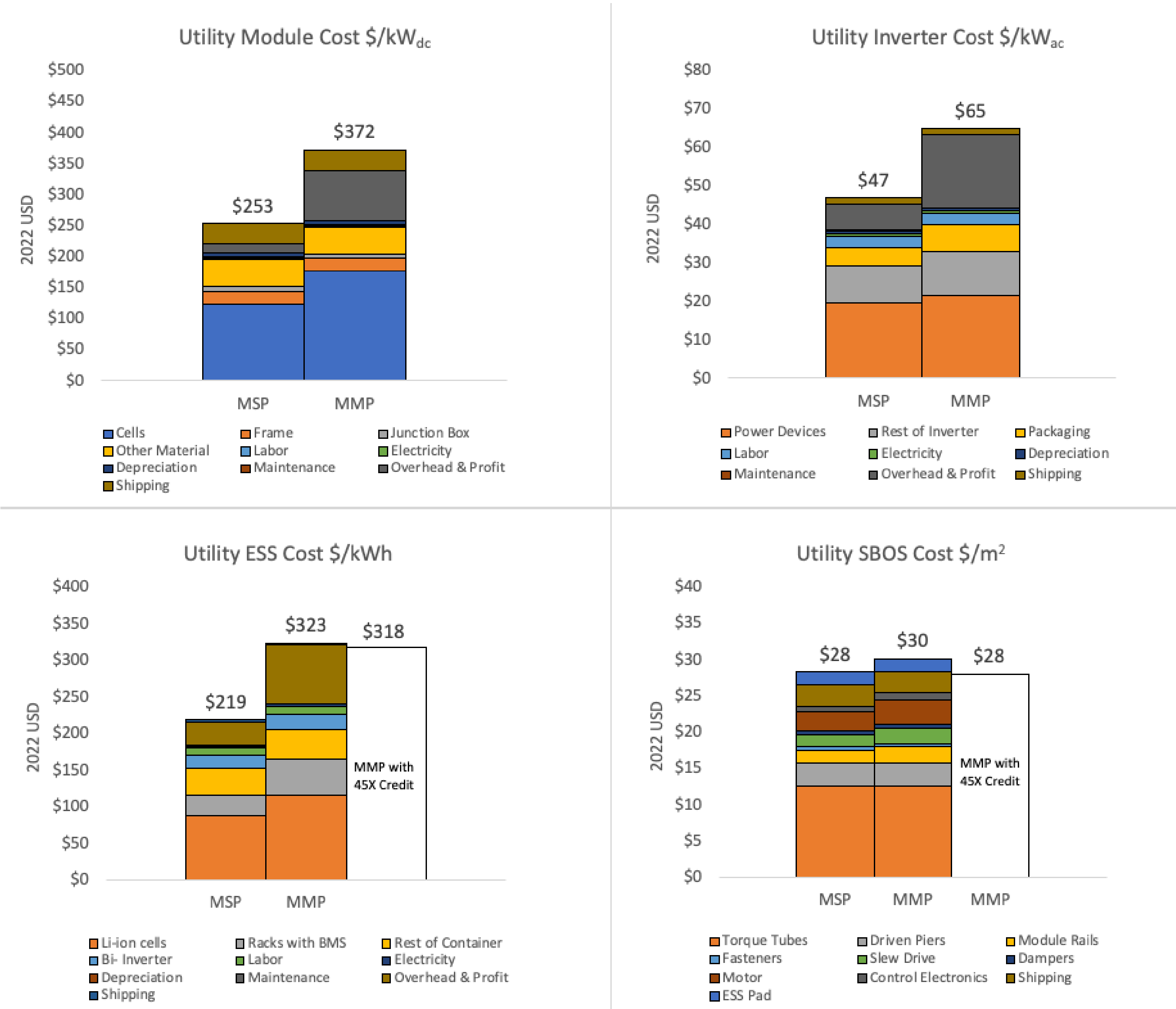

Figure 14. Utility-scale module, inverter, energy storage, and SBOS costs

The results shown here are for PV-plus-storage systems; PV-only results are not shown here but are available at https://data.nrel.gov/. In addition to the ESS cost itself, adding ESS affects the SBOS category (ESS pad cost). The module "other material" category includes the front and back glass as well as encapsulant. The "rest of inverter" category includes the sensors, fuses, software, and cooling system.

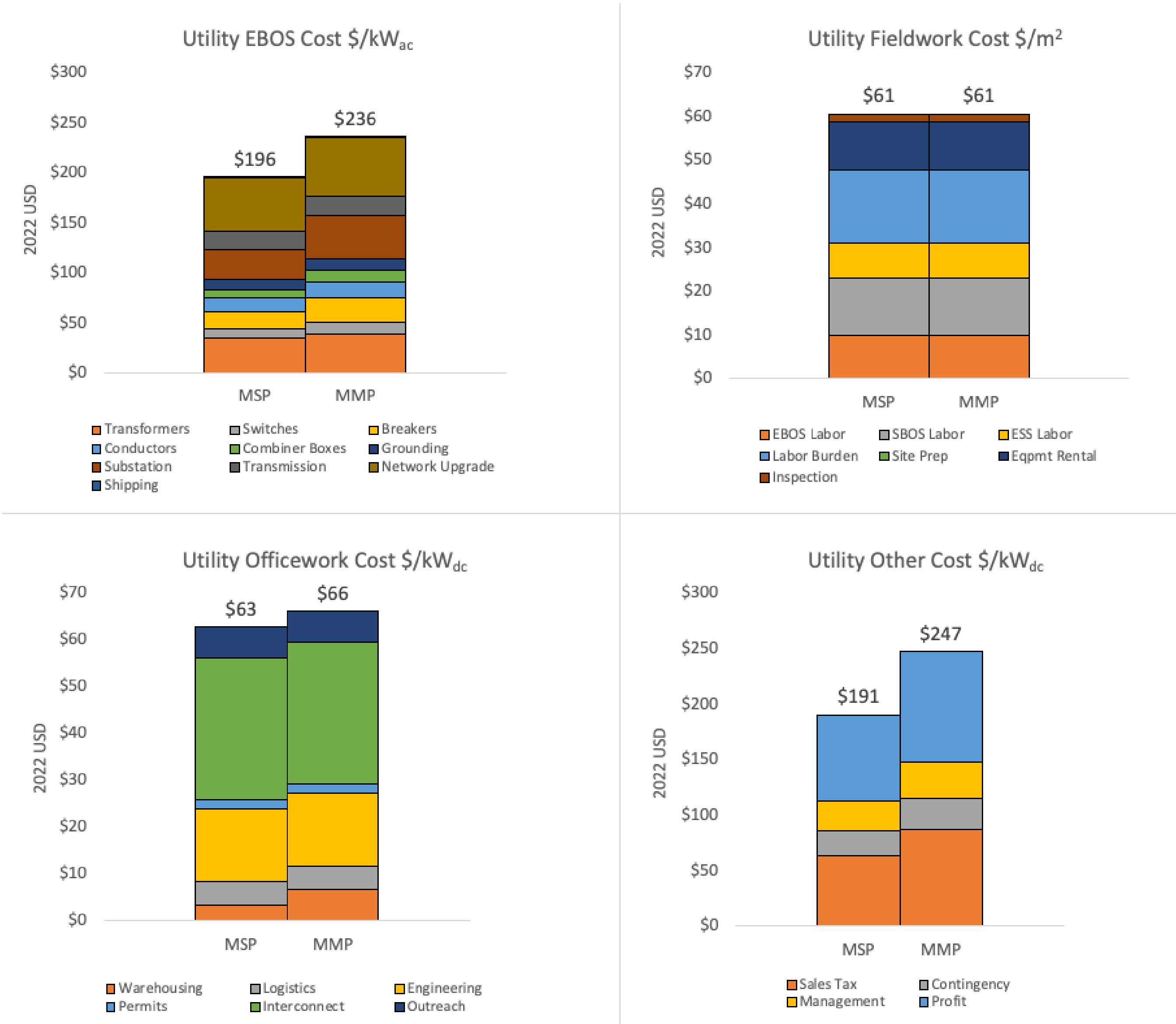

Figure 15. Utility-scale EBOS, fieldwork, office work, and other capital costs

The results shown here are for PV-plus-storage systems; PV-only results are not shown here but are available at https://data.nrel.gov/. Adding ESS affects two cost categories: fieldwork (ESS labor) and other costs (contingency, sales tax, management, profit).

8 Operations and Maintenance

Benchmark PV O&M costs are estimated using a PV O&M cost 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, Lavrova, and Gooding 2018), but 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 Solar Energy Technologies Office-sponsored working group.

Like the system cost modeling in this report, we estimate two sets of O&M cost numbers: one with MMP parameters and another with MSP parameters. For Q1 2023, the labor rates, discount rate, and inflation rate are updated; these items are common across the MSP and MMP calculations. O&M costs associated with future replacement of hardware use the component's MSP even when calculating O&M MMP, because MSP is a better estimate of future component cost than this year's MMP. 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 2023, 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 2023, no line measures were deleted. In Q1 2023, O&M was estimated for residential, community solar, and utility-scale systems.

O&M costs in the PV O&M cost model include preventative 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).

We use the Elevate community solar cost model as a basis to estimate subscriber management costs (Elevate 2021). We use default values for all inputs—assuming a 5-MW system and a 40% anchor tenant—with one exception. The Elevate model uses a default value of 1.5% for customer turnover rates, meaning that about 1.5% of subscribers end their subscriptions each year. However, feedback from developers suggested a range from 2%–8%, and Martin (2022) estimates a community solar customer turnover rate of 5%. One developer noted that customer turnover rates vary with how customers are billed. Turnover tends to be lower when subscribers receive a single community solar and utility bill (consolidated billing) and higher where customers receive separate community solar and utility bills (dual billing). While dual billing remains common, consolidated billing has emerged as a best practice in key markets such as New York (Martin 2022). In our forward-looking benchmark, we estimate a 3% customer turnover rate to reflect a turnover rate consistent with consolidated billing. We estimate a 25-year lifetime and a 6.5% discount rate to estimate the net present value of ongoing subscriber management costs. Finally, we estimate that 30% of subscribers entail an 80% management cost premium, reflecting the acquisition cost difference between non-LMI and LMI customers estimated by Wood Mackenzie (2023).

The current MSP benchmarks for PV systems in 2022 real USD are \$28.78/kW_{dc}/yr (residential), \$39.83/kW_{dc}/yr (community solar), and \$16.12/kW_{dc}/yr (utility-scale, single-axis tracking). For MMP, the current benchmarks are \$30.36/kW_{dc}/yr (residential), \$40.51/kW_{dc}/yr (community solar), and \$16.58/kW_{dc}/yr (utility-scale, single-axis tracking). Most of the management cost (\$17.41/kW_{dc}/yr) for community solar systems is allocated to ongoing subscriber management, while only \$5.05/kW_{dc}/yr is allocated to asset management. These PV systems results are shown in the top half of Figure 16.

The bottom half of Figure 16 shows O&M results for PV-plus-storage systems. The MSP benchmarks in 2022 real USD are \$61.28/kW_{dc}/yr (residential), \$75.25/kW_{dc}/yr (community solar), and \$50.73/kW_{dc}/yr (utility-scale, single-axis tracking). For MMP, the benchmarks are \$65.04/kW_{dc}/yr (residential), \$76.79/kW_{dc}/yr (community solar), and \$51.88/kW_{dc}/yr (utility-scale, single-axis tracking). ESS replacement constitutes the largest share of O&M costs for all the PV-plus-storage systems modeled.

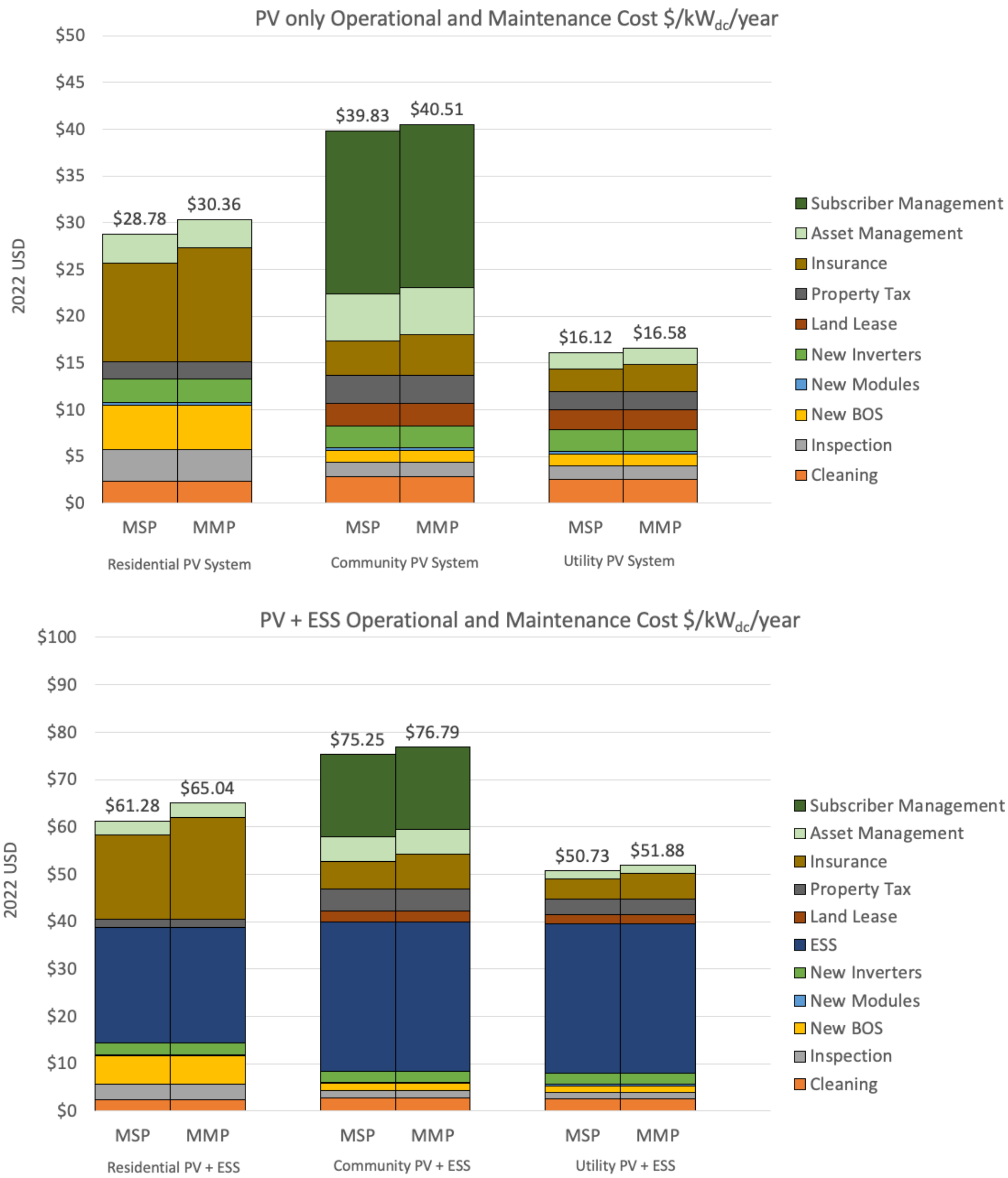

Figure 16. MSP and MMP O&M benchmarks for all modeled systems

9 Conclusions

Our bottom-up cost models can be used to assess the MSP and MMP of PV 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.

Based on our bottom-up modeling, the Q1 2023 cost benchmarks are listed in Table 3. The full set of benchmark inputs and results for Q1 2023 is available at https://data.nrel.gov/.

Table 3. Q1 2023 PV and PV-Plus-Storage MSP and MMP Benchmarks (2022 USD)

MSP Benchmarks	MMP Benchmarks	System and Cost Type
Residential Systems		
$2.34/W$_{dc}$	$2.68/W$_{dc}$	8-kW$_{dc}$ rooftop PV system cost
$3.88/W$_{dc}$	$4.70/W$_{dc}$	8-kW$_{dc}$ rooftop PV with 5-kW$_{dc}$/12.5-kWh ESS system cost
$28.78/kW$_{dc}$/yr	$30.36/kW$_{dc}$/yr	PV O&M cost
$61.28/kW$_{dc}$/yr	$65.04/kW$_{dc}$/yr	PV-plus-storage O&M cost
Community Solar Systems		
$1.49/W$_{dc}$	$1.76/W$_{dc}$	3-MW$_{dc}$ ground-mounted community PV system cost
$2.33/W$_{dc}$	$2.94/W$_{dc}$	3-MW$_{dc}$ ground-mounted community PV with 1.8-MW$_{dc}$/7.2-MWh ESS system cost
$39.83/kW$_{dc}$/yr	$40.51/kW$_{dc}$/yr	PV O&M cost
$75.25/kW$_{dc}$/yr	$76.79/kW$_{dc}$/yr	PV-plus-storage O&M cost
Utility-Scale Systems		
$0.96/W$_{dc}$	$1.17/W$_{dc}$	100-MW$_{dc}$ one-axis-tracking PV system cost
$1.64/W$_{dc}$	$2.13/W$_{dc}$	100-MW$_{dc}$ one-axis-tracking PV with 60-MW$_{dc}$/240-MWh ESS system cost
$16.12/kW$_{dc}$/yr	$16.58/kW$_{dc}$/yr	PV O&M cost
$50.73/kW$_{dc}$/yr	$51.88/kW$_{dc}$/yr	PV-plus-storage O&M cost

References

Barbose, Galen, Naïm Darghouth, Eric O'Shaughnessy, and Sydney Forrester. 2022. *Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States*. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2022_report.pdf.

BLS (U.S. Bureau of Labor Statistics). 2023a. "Consumer Prices up 4.9 Percent from April 2022 to April 2023." *TED: The Economics Daily*, May 15, 2023. www.bls.gov/opub/ted/2023/consumer-prices-up-4-9-percent-from-april-2022-to-april-2023.htm.

BLS. 2023b. "Databases, Tables & Calculators by Subject: CPI for All Urban Consumers (CPI-U)." Accessed July 2023. https://data.bls.gov/cgi-bin/surveymost?bls.

BNEF. 2023. *Bimonthly PV Index, April 2023*. New York: BloombergNEF.

Bolinger, Mark, Joachim Seel, Cody Warner, and Dana Robson. 2022. *Utility-Scale Solar, 2022 Edition*. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/utility_scale_solar_2022_edition_slides.pdf.

CA NEM. 2023. "NEM Currently Interconnected Data Set." California Distributed Generation Statistics. Accessed June 2023. http://www.californiadgstats.ca.gov/downloads.http://www.californiadgstats.ca.gov/downloads

Chunduri, Shravan. 2022. "Modules Using Large Wafers to Attain High Power Rating Has Become Common Practice for Large Power Plant Applications." *Taiyang News*, September 19, 2022. https://taiyangnews.info/technology/powerful-modules-for-utility/.

Cook, Jeff, Rosalie Yu, Kaifeng Xu, Sushmita Jena, Tim Rivard, and Jessica de la Paz. 2023. *SolarAPP+ Performance Review (2022 Data)*. Golden, CO: National Renewable Energy Laboratory. www.nrel.gov/docs/fy23osti/85827.pdf.

DiGangi, Diana. 2023. "House Fails to Overturn Biden's Veto on Congressional Resolution to End Southeast Asia Solar Panel Tariff Pause." *Utility Dive*, May 17, 2023. www.utilitydive.com/news/biden-veto-resolution-tariff-solar-panels-commerce-asia/650450/.

DOC (U.S. Department of Commerce). 2023. "Department of Commerce Issues Final Determination of Circumvention Inquiries of Solar Cells and Modules from China." Press Release. www.commerce.gov/news/press-releases/2023/08/department-commerce-issues-final-determination-circumvention-inquiries.

DOE (U.S. Department of Energy). 2023a. "Federal Solar Tax Credit Resources." Accessed August 2023. www.energy.gov/eere/solar/articles/federal-solar-tax-credit-resources.

DOE. 2023b. "Federal Tax Credits for Solar Manufacturers." Accessed August 2023. www.energy.gov/eere/solar/federal-tax-credits-solar-manufacturers.

EIA (U.S. Energy Information Administration). 2022. "2021 Form EIA-860 Data." Accessed December 2022. www.eia.gov/electricity/data/eia860.

EIA. 2023. "Monthly Solar Photovoltaic Module Shipments Report." Accessed April 2023. www.eia.gov/renewable/monthly/solar_photo/pdf/pv_table3.pdf.

Elevate. 2021. *Community Solar Pro Forma, v1.1*. Chicago: Elevate. www.elevatenp.org/publications/elevate-community-solar-pro-forma.

Feldman, David, Krysta Dummit, Jarett Zuboy, and Robert Margolis. 2022. *Fall 2022 Solar Industry Update*. Golden, CO: National Renewable Energy Laboratory. www.nrel.gov/docs/fy23osti/84515.pdf.

Feldman, David, Krysta Dummit, Jarett Zuboy, and Robert Margolis. 2023. *Spring 2023 Solar Industry Update*. Golden, CO: National Renewable Energy Laboratory. www.nrel.gov/docs/fy23osti/86215.pdf.

FRED (Federal Reserve Economic Data). 2023a. "Consumer Price Index for All Urban Consumers: All Items in U.S. City Average." Accessed July 2023, https://fred.stlouisfed.org/series/CPIAUCSL.

FRED. 2023b. "Federal Funds Effective Rate." Accessed July 2023, https://fred.stlouisfed.org/series/fedfunds.

FRED. 2023c. "Global Price Index of All Commodities." Accessed July 2023. https://fred.stlouisfed.org/series/PALLFNFINDEXQ.

FRED. 2023d. "Producer Price Index by Commodity: Metals and Metal Products: Cold Rolled Steel Sheet and Strip." Accessed July 2023. https://fred.stlouisfed.org/series/WPU101707.

FRED. 2023e. "Producer Price Index by Industry: Electrical Equipment Manufacturing." Accessed July 2023. https://fred.stlouisfed.org/series/PCU3353133531.

FRED. 2023f. "Employment Cost Index: Wages and Salaries: Private Industry Workers." Accessed July 2023. https://fred.stlouisfed.org/series/ECIWAG.

Gillingham, Kenneth, Hao Deng, Ryan Wiser, Naïm Richard Darghouth, Gregory Nemet, Galen Barbose, Varun Rai, and Changgui Dong. 2016. "Deconstructing Solar Photovoltaic Pricing: The Role of Market Structure, Technology, and Policy." *Energy Journal* 37(3): 231–250.

Goodrich, Alan C., Douglas M. Powell, Ted L. James, Michael Woodhouse, and Tonio Buonassisi. 2013. "Assessing the Drivers of Regional Trends in Solar Photovoltaic Manufacturing." *Energy & Environmental Science* 6: 2811–2821. https://pubs.rsc.org/en/content/articlepdf/2013/ee/c3ee40701b.

Gunda, Thushara, and Rachel Homan. 2020. *Evaluation of Component Reliability in Photovoltaic Systems Using Field Failure Statistics*. Albuquerque, NM: Sandia National Laboratories. SAND2020-9231. https://doi.org/10.2172/1660804.

IMF (International Monetary Fund). 2023. "Commodity Special Feature: Market Developments and the Macroeconomic Impact of Declines in Fossil Fuel Extraction." World Economic Outlook Special Feature, April 2023. www.imf.org/-/media/Files/Research/CommodityPrices/WEOSpecialFeature/CSFApril2023.ashx.

IREC (Interstate Renewable Energy Council). 2020. Shared Renewables Policy Catalog. Albany, NY: IREC. https://irecusa.org/resources/shared-renewables-policy-catalog/.

ITRPV. 2023. *International Technology Roadmap for Photovoltaic (ITRPV): 2022 Results*. VDMA. www.vdma.org/international-technology-roadmap-photovoltaic.

Klise, Geoffrey T., Olga Lavrova, and Renee Gooding. 2018. *PV System Component Fault and Failure Compilation and Analysis*. Albuquerque, NM: Sandia National Laboratories. SAND2018-1743. https://doi.org/10.2172/1424887.

Lydersen, Kari. 2023. "Bringing Community Solar to Low-Income Customers is Harder Than it Looks." *Canary Media*, April 11, 2023. www.canarymedia.com/articles/solar/bringing-community-solar-to-low-income-customers-is-harder-than-it-looks.

Martin, Keith. 2022. "Taking Stock of Community Solar." *Norton Rose Fulbright*, June 23, 2022. www.projectfinance.law/publications/2022/june/taking-stock-of-community-solar.

New York State. 2023. "Solar Electric Programs Reported by NYSERDA: Beginning 2000." Accessed March 2023. https://data.ny.gov/Energy-Environment/Solar-Electric-Programs-Reported-by-NYSERDA-Beginn/3x8r-34rs.

Ngo, Madeleine, and Ben Casselman. 2023. "Inflation Inched Higher in April, Reflecting Challenge for the Fed." *New York Times*, May 26, 2023. www.nytimes.com/2023/05/26/us/politics/inflation-april-federal-reserve.html.

NREL (National Renewable Energy Laboratory), Sandia National Laboratories, SunSpec Alliance, and the SunShot National Laboratory Multiyear Partnership (SuNLaMP) PV O&M Best Practices Working Group. 2018. *Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems, 3rd Edition*. NREL/TP-7A40-73822. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/73822.pdf.

PEguru. 2023. "Substation Cost Estimator." Accessed 2023. https://peguru.com/substation-cost-estimator/.

Powell, Douglas M., Mark T. Winkler, Alan Goodrich, and Tonio Buonassisi. 2013. "Modeling the Cost and Minimum Sustainable Price of Crystalline Silicon Photovoltaic Manufacturing in the United States." *IEEE Journal of Photovoltaics* 3(2): 662–668.

Ramasamy, Vignesh, Jarett Zuboy, Eric O'Shaughnessy, David Feldman, Jal Desai, Michael Woodhouse, Paul Basore, and Robert Margolis. 2022. *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy22osti/83586.pdf.

RENVU. 2023. "Solar Design & Quote Tool." Accessed 2023. www.renvu.com/solar-kit-guide.

Roth MKM. 2023. *Company Note, Equity Research: Daqo New Energy Corp*. Newport Beach, CA: Roth MKM.

Smialek, Jeanna, and Christine Zhang. 2023. "Inflation Is Still High. What's Driving It Has Changed." *New York Times*, April 27, 2023. http://www.nytimes.com/2023/04/27/business/economy/what-causes-inflation.html.

Smith, Brittany L., Michael Woodhouse, Kelsey A.W. Horowitz, Timothy J. Silverman, Jarett Zuboy, and Robert M. Margolis. 2021. *Photovoltaic (PV) Module Technologies: 2020 Benchmark Costs and Technology Evolution Framework Results*. NREL/TP-7A40-78173. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy22osti/78173.pdf.

Walker, Andy, Eric Lockhart, Jal Desai, Kristen Ardani, Geoff Klise, Olga Lavrova, Tom Tansy et al. 2020. *Model of Operation and Maintenance Costs for Photovoltaic Systems*. NREL/TP-5C00-74840. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy20osti/74840.pdf.

Weaver, John F. 2022. "Commerce Clarifies that Recent Module Manufacturing Ruling Only Applies to Four Nations." *PV Magazine USA*, December 21, 2022. https://pv-magazine-usa.com/2022/12/21/commerce-clarifies-that-recent-module-manufacturing-ruling-only-applies-to-four-nations/.

Wiser, Ryan H., Mark Bolinger, and Joachim Seel. 2020. *Benchmarking Utility-Scale PV Operational Expenses and Project Lifetimes: Results from a Survey of U.S. Solar Industry Professionals*. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/benchmarking-utility-scale-pv.

Woodhouse, Michael, Brittany Smith, Ashwin Ramdas, and Robert Margolis. 2020. *Crystalline Silicon Photovoltaic Module Manufacturing Costs and Sustainable Pricing: 1H 2018 Benchmark and Cost Reduction Road Map*. NREL/TP-6A20-72134. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/72134.pdf.

Wood Mackenzie. 2023. *US Community Solar Market Outlook: H1 2023*. Edinburgh: Wood Mackenzie.

Wood Mackenzie and SEIA (Solar Energy Industries Association). 2022a. *US Solar Market Insight: Q3 2022*. Edinburgh: Wood Mackenzie.

Wood Mackenzie and SEIA. 2022b. *US Solar Market Insight: Q4 2022*. Edinburgh: Wood Mackenzie.

Wood Mackenzie and SEIA. 2023. *US Solar Market Insight: 2022 Year in Review*. Edinburgh: Wood Mackenzie.

Xu, Kaifeng, Jenny Sumner, Emily Dalecki, and Robin Burton. 2023. *Expanding Solar Access: State Community Solar Landscape*. Golden, CO: National Renewable Energy Laboratory. www.nrel.gov/docs/fy23osti/84247.pdf.

Appendix A: Example of PV System Cost Model Calculations

Figure A-1 shows an example of PVSCM calculations, for SBOS components in a residential PV system. At step (1), data from industry stakeholders and other sources are used to generate representative costs and quantities for mounts, rails, clamps, and shipping. The table in Figure A-1 contains illustrative data for the purpose of this example. These are market costs, aligned with our MMP benchmark. These costs are converted into intrinsic units and MSPs (2). The shipping cost is already in its intrinsic units ($/kg). The costs for mounts, rails, and clamps are converted into their intrinsic units ($\$/m^2$) by dividing the total cost per 8-kW system by the total area of modules in that system. Because PVSCM receives cost inputs as MSP values, we now convert the MMPs to MSPs. We identify no distortions for mounts and shipping, so those values are transferred directly into the PVSCM SBOS worksheet (3). However, 25% Section 301 tariffs apply to rails and clamps, so we divide the MMPs by 1.25 to calculate MSPs and then transfer those values into the SBOS worksheet (4). At the same time, we convert the data from nominal USD to 2022 USD for entry into the PVSCM worksheet.

The remaining calculations are performed automatically in PVSCM. Mount, rail, and clamp costs are already in the final units for the SBOS worksheet ("Intrinsic Units per m^2" = 1), so they are directly transferred into the "Cost Element per m^2" column for MSP (5). The mount cost is also transferred directly into the "Price Element per m^2" column for MMP. However, because rails and clamps are subject to the Section 301 tariff, that tariff—from the Factors worksheet—is applied to generate the MMP values (6). The shipping cost is converted into $\$/m^2$ based on a value in the Factors worksheet before being transferred into the MSP and MMP columns (7). All the $\$/m^2$ values in the SBOS worksheet are summed for MSP and MMP and transferred into the SBOS row of the System worksheet (8). Those $\$/m^2$ values are then converted to $\$/kW_{dc}$ values using the inverse of the module efficiency from the Factors worksheet to show the contribution of SBOS costs to total system costs in those units (9).

The use of intrinsic units is important because it facilitates analysis of variations in component costs. For example, the residential SBOS MSP is $\$219/kW_{dc}$, as shown in Figure A-1. Mounts account for $\$88/kW_{dc}$ of this cost. Assume that hypothetically the PV industry will report a 10% reduction in mount costs next year. If system component costs were only available in $\$/kW_{dc}$, a 10% reduction in mount costs would yield a total SBOS MSP of $\$210/kW_{dc}$. However, the cost of mounts—and other SBOS components—depends on the area of the system's modules, not on their power capacity. If next year the reported average efficiency of modules were to increase from 20.8% to 21.8%, the SBOS MSP calculated using intrinsic units would be $\$201/kW_{dc}$, or about 4% lower than the MSP calculated using values in $\$/kW_{dc}$. The use of intrinsic units and conversion factors in PVSCM makes analysis more accurate by making the relationships between component costs and specifications transparent, while also providing cost outputs in traditional $\$/kW_{dc}$ terms.

Such unit conversions are also used for the O&M analysis in PVSCM. Otherwise, our methods for calculating O&M costs are similar to those used in last year's benchmark report. See Section 8 for additional information on the O&M analysis.

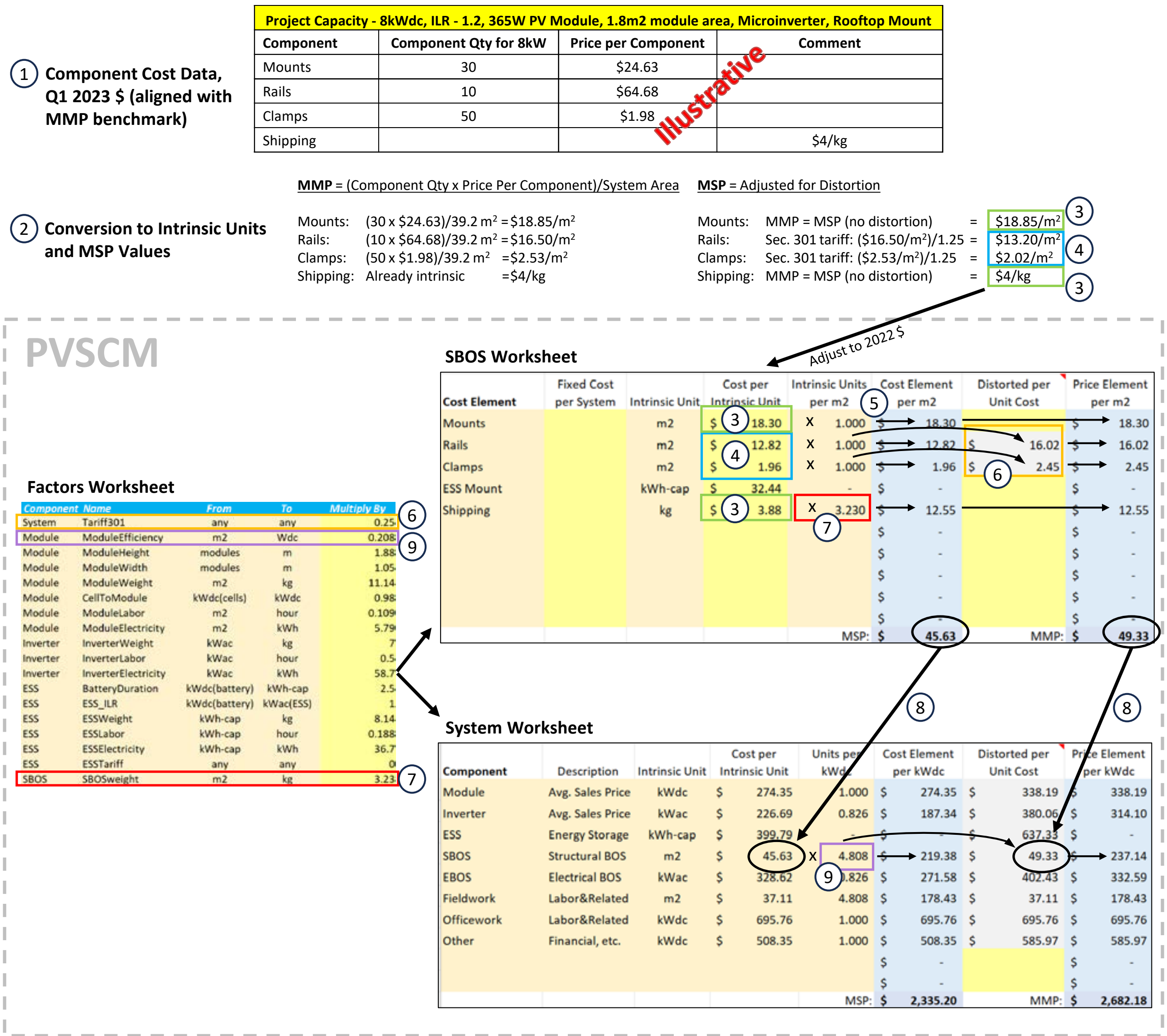

Figure A-1. Illustration of the PVSCM analysis process (for SBOS in a residential PV system)