Title
Utility-Scale Solar, 2024 Edition: Empirical Trends in Deployment, Technology, Cost, Performance, PPA Pricing, and Value in the United States

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Utility-Scale Solar, 2024 Edition

Empirical Trends in Deployment, Technology, Cost, Performance, PPA Pricing, and Value in the United States

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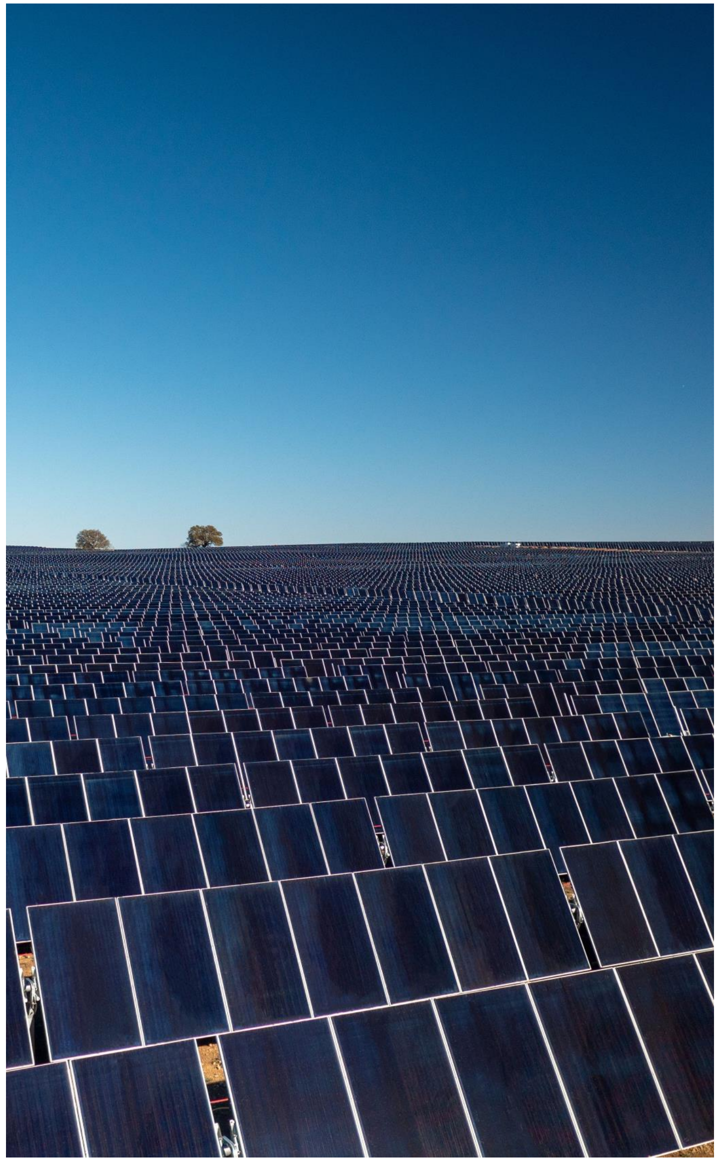
Photo credit: Intersect Power

Utility-Scale Solar, 2024 Edition



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The authors thank Ammar Qusaibaty, Juan Botero, Michele Boyd, and Becca Jones-Albertus of the U.S. Department of Energy Solar Energy Technologies Office for supporting this work. The authors also thank the many individuals from utilities, the solar industry, state agencies, and other organizations who contributed data to this report and/or who responded to numerous inquiries and requests. Without the contributions of these individuals and organizations, this report would not be possible.

Photo credit:
Intersect Power's 415 MW_{DC}/320 MW_{AC} Radian solar facility, completed in 2023.

Utility-Scale Solar, 2024 Edition

Purpose and Scope:

- Summarize public and private data on key trends in U.S. utility-scale solar sector
- Focus on ground-mounted projects >5 MW_{AC}
  - There are separate DOE-funded data collection efforts on distributed PV (e.g., trackingthesun.lbl.gov)
- Focus on historical data, emphasizing the most-recent full calendar year

Data and Methods:

- See summaries at the beginning of each section

Funding:

- U.S. Department of Energy's Solar Energy Technologies Office

Products in addition to this slide deck:

- This report deck is complemented by an Excel data file that lists all data behind each graph (and more), a written executive summary, and interactive visualizations. All products are available at: utilityscalesolar.lbl.gov

New in this year's edition:

- Analyses of PV projects in newly designated Energy Communities
- Discussion of PV performance degradation rates
- Comparison of Berkeley Lab's PPA data with data from LevelTen[1] and Trio[2]
- Comparison of PV market value with generation costs and climate + health benefits
- Discussion of solar withdrawal rates and study status in interconnection queues

These two companies operate renewable energy marketplaces and publish PPA pricing trends:
[1] https://www.leveltenenergy.com/ppa
[2] https://www.trioadvisory.com/publications

Other recent publications from our team related to utility-scale solar

Annual Reports

[Queued Up: 2024 Edition]

Berkeley Lab's annual report documents the growing backlog of new power generation, particularly solar, wind, and storage, seeking transmission connections.

[Hybrid Power Plants: 2024 Edition]

This annual briefing tracks existing hybrid plants in the U.S. while also synthesizing data from PPAs and interconnection queues to shed light on future growth.

[U.S. State Renewables Portfolio & Clean Electricity Standards: 2024 Status Update]

This report provides a status update on state renewable portfolio and clean electricity standards.

[U.S. Large-Scale Solar Photovoltaic Database]

In collaboration with the USGS, the USPVDB creates an accurate, comprehensive, and publicly accessible national large-scale PV database of large-scale PV facilities.

Siting and Community Engagement

[Developer Practices and Perspectives on Community Engagement for Utility-Scale Renewable Energy in the United States]

A survey of professionals shows that renewable developers use community engagement strategies but favor limited public input, falling short of full citizen empowerment.

[Laws in Order: An Inventory of State Renewable Energy Siting Policies]

This report outlines state and territorial authorities responsible for siting and permitting large-scale wind and solar projects, alongside an interactive map for exploring state-specific information.

[Perceptions of Large-Scale Solar Project Neighbors]

A survey of residents living near large-scale solar projects provides insights into local perceptions that can inform future large-scale solar deployment.

Value of Renewable Energy

[The Renewables and Wholesale Electricity Prices (ReWEP) Tool]

The ReWEP tool allows users to explore trends in nodal wholesale energy pricing and their relationship to renewable generation.

[Grid Value and Cost of Utility-Scale Wind and Solar: Potential Implications for Consumer Electricity Bills]

This research quantifies the market value of wind and solar over time, exploring how contractual and market structures influence consumers' ability to benefit from cost savings.

[Renewable-Battery Hybrid Power Plants in Congested Electricity Markets]

Berkeley Lab's analysis of hybrid renewable-battery plants in congested U.S. regions reveals optimal energy and capacity value for solar and wind hybrid projects.

[Solar and Storage Integration in the Southeastern U.S.]

This study evaluates how varying levels of solar and storage would affect electricity system costs, reliability, and operations in the Southeast U.S. by 2035.

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Report Contents

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Wholesale Market Value, Air and Climate Benefits, and Net Value

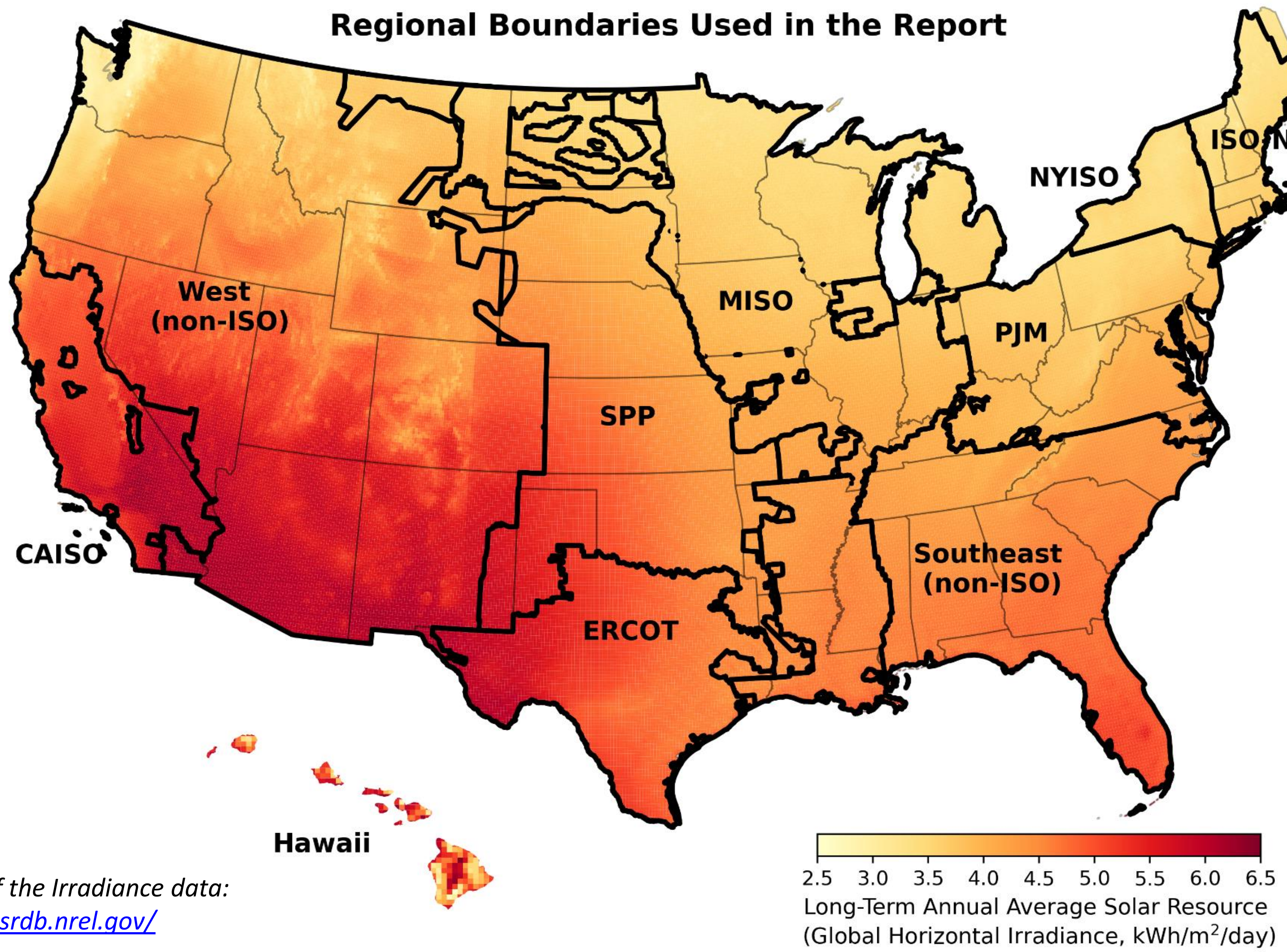
PV+Battery Hybrid Plants

Concentrating Solar Thermal Power (CSP) Plants

Capacity in Interconnection Queues

Summary

Regional boundaries applied in this analysis include the seven independent system operators (ISO) and two non-ISO regions



Source of the Irradiance data:
https://nsrdb.nrel.gov/

Deployment and Technology Trends

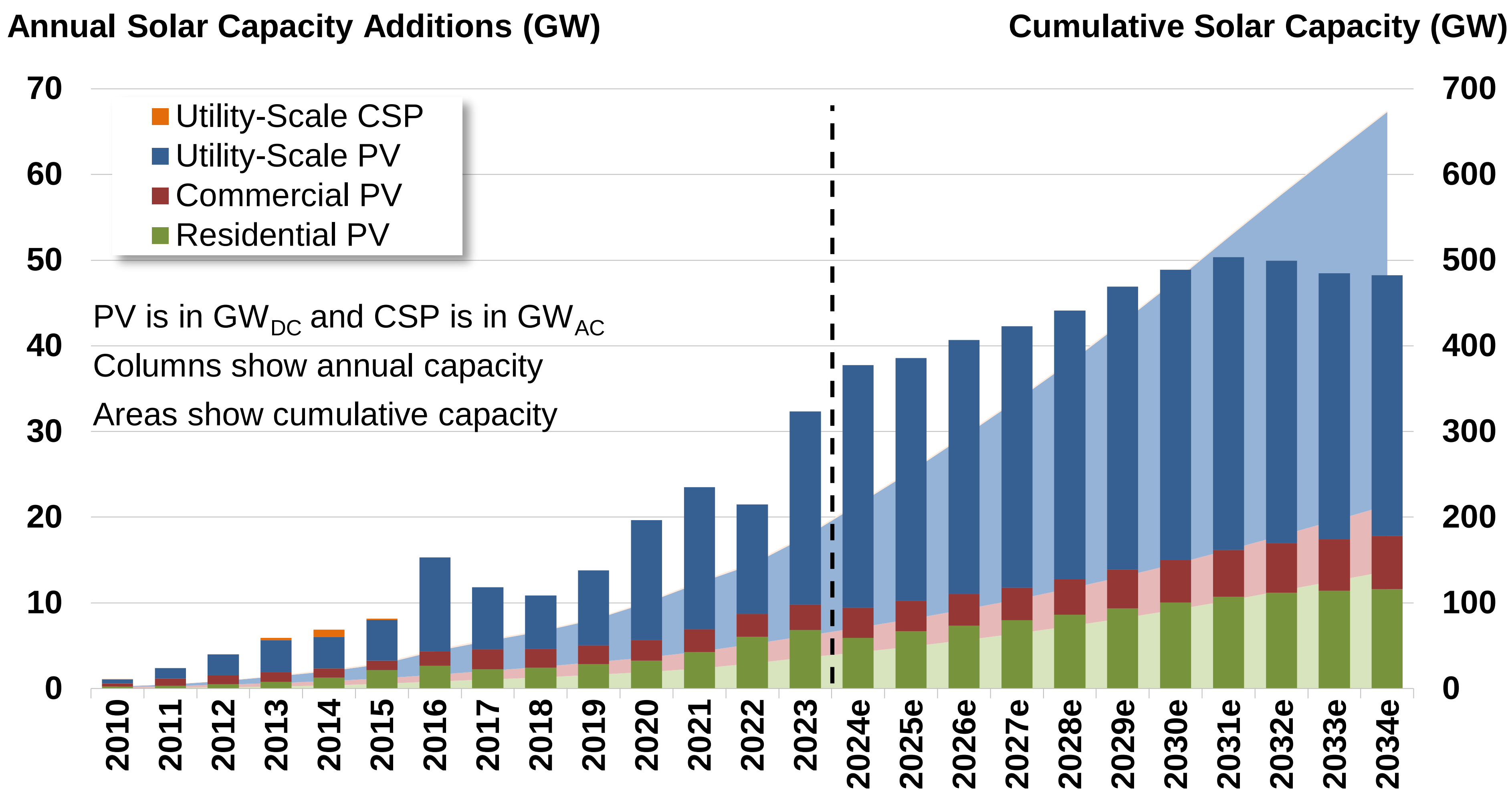
Deployment and Technology Trends: data and methodology

Deployment Trends Data: National and state-level deployment data are sourced from the Energy Information Administration (EIA), the American Clean Power Association (ACP), Wood Mackenzie/SEIA Solar Market Insight Reports, and Berkeley Lab datasets.

Technology Trends Data: Project-level metadata are sourced from a combination of Form EIA-860, FERC Form 556, state regulatory filings, interviews and websites of project developers and owners, and news and trade press articles. We independently verify much of the metadata—such as project location, fixed-tilt vs. tracking, azimuth—via satellite imagery.

Methods: Because we collect data from a variety of unaffiliated and incongruous sources, the data must be synthesized and cleaned in multiple steps before becoming useful for analytic purposes. In some cases, we essentially create new data by piecing together various snippets of information that are of less consequence on their own.

The utility-scale sector has the greatest share of the U.S. solar market



***Sources:** Wood Mackenzie/SEIA Solar Market Insight Reports, Berkeley Lab*

Wood Mackenzie and SEIA report that the utility-scale sector added 22.5 GW$_{DC}$ of new solar capacity in 2023, accounting for **70% of all new solar** capacity. Annual growth rose by 77% compared to 2022 and set a new record.

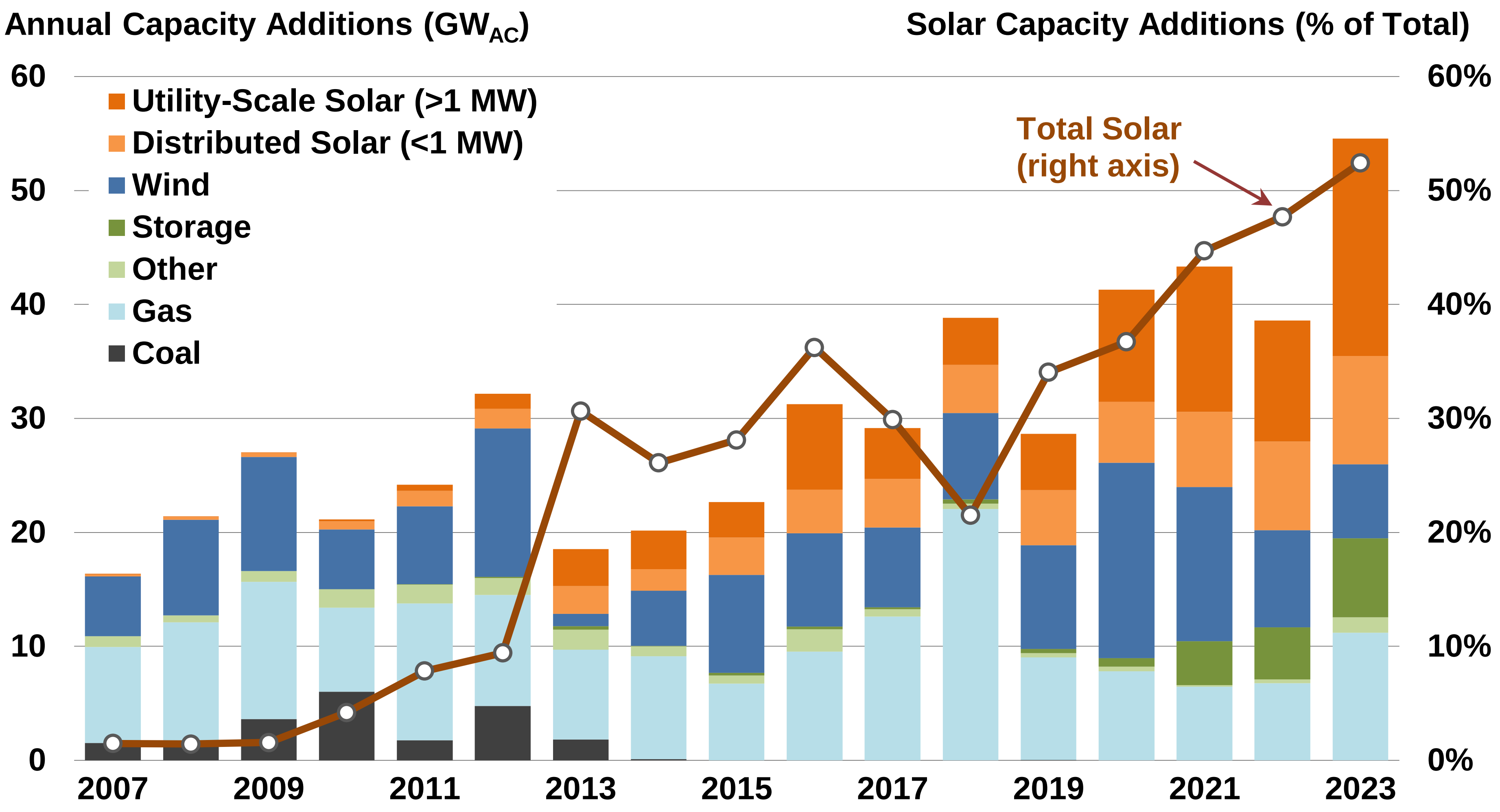
Utility-scale solar contributed **65% of cumulative solar** capacity (and 69% of solar generation) in 2023; this share is projected to rise to nearly 70% by 2027.

Our data analysis focuses on a subset of this sample—all projects larger than 5 MW$_{AC}$—based on their completion date:

- **2022**: 153 new projects totaling 10.4 GW$_{AC}$ or 13.4 GW$_{DC}$
- **2023**: 221 new projects totaling 18.5 GW$_{AC}$. The subset of 217 projects with known DC capacity total 23.9 GW$_{DC}$.

Note: Graph above shows utility-scale solar as >1 MW$_{DC}$ while most of this report uses >5 MW$_{AC}$.

More than 50% of new U.S. grid capacity came from solar in 2023



Bars represent annual capacity additions in GW_{AC} (left axis),
Line represents solar's capacity share of annual additions (right axis)

Utility-scale (35%) and distributed (17%) solar accounted for a combined 52% of all capacity added to U.S. grids in 2023.

It is the first year that solar made up more than half of new US grid capacity.

Solar has added more capacity than any other fuel since 2021, contributing >40% of capacity additions each year, >30% in 7 of the last 8 years, and >20% in each of the last 11 years.

Storage continues to expand as well: 6.9 GW of storage were added to U.S. grids in 2023, up from 4.6 GW in 2022 and 3.9GW in 2021.

Note: Graph above shows utility-scale solar as >1 MW_{AC} while most of this report uses >5 MW_{AC}.

Solar generation's market share was 5.6% across the U.S. in 2023, but reached >25% in California and Nevada

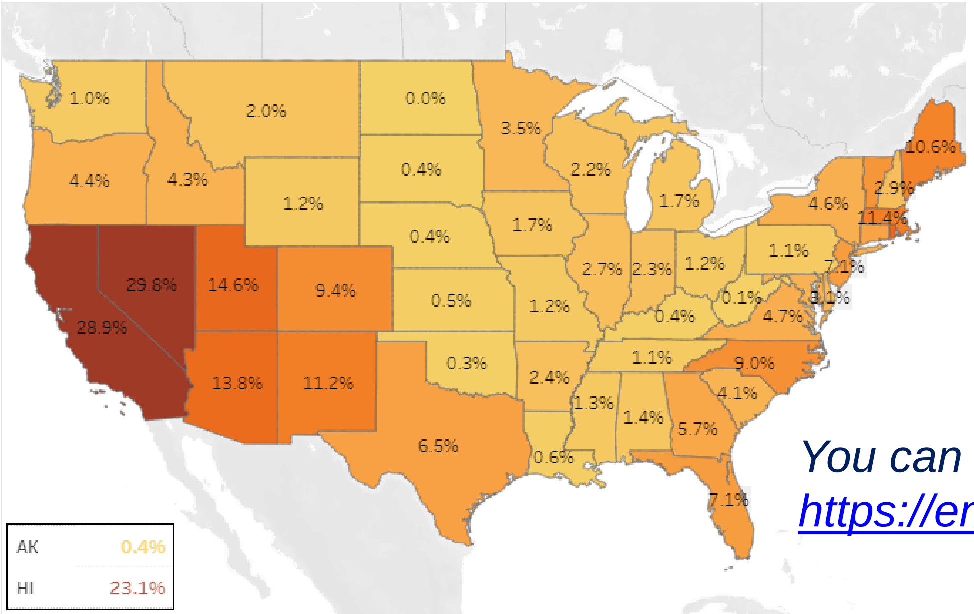
	Preliminary 2023			
Top 20 States	**Solar generation as a % of in-state generation**		**Solar generation as a % of in-state load**	
	All Solar	**Utility-Scale Solar Only**	**All Solar**	**Utility-Scale Solar Only**
California	28.2%	16.7%	28.9%	17.1%
Nevada	25.9%	22.1%	29.8%	25.4%
Massachusetts	24.4%	8.6%	11.4%	4.0%
Vermont	18.9%	8.6%	8.2%	3.7%
Hawaii	18.9%	5.9%	23.1%	7.2%
Utah	13.9%	11.3%	14.6%	11.9%
Rhode Island	11.8%	5.1%	14.7%	6.4%
Arizona	10.2%	6.3%	13.8%	8.6%
Maine	9.9%	4.9%	10.6%	5.2%
North Carolina	9.3%	8.8%	9.0%	8.4%
Colorado	9.0%	6.1%	9.4%	6.4%
New Mexico	8.2%	6.4%	11.2%	8.8%
New Jersey	7.4%	2.4%	7.1%	2.3%
Delaware	7.0%	3.1%	3.1%	1.4%
Idaho	6.9%	5.4%	4.3%	3.3%
Florida	6.7%	5.3%	7.1%	5.6%
Virginia	6.6%	5.8%	4.7%	4.2%
Maryland	6.3%	2.6%	4.2%	1.7%
Georgia	6.1%	5.7%	5.7%	5.4%
Texas	5.8%	5.0%	6.5%	5.6%
TOTAL U.S.	**5.6%**	**3.9%**	**6.2%**	**4.3%**

Solar market share can vary considerably depending on whether it is calculated as a percentage of total generation or load (e.g., Vermont).

As a percentage of in-state generation, California's solar market share reached 28% in 2023, while Nevada, Massachusetts, Vermont, and Hawaii all surpassed 15%.

The utility-scale sector's contribution varies by state: a minority in the Northeast and Hawaii, a majority in Southwest states and the overall U.S.

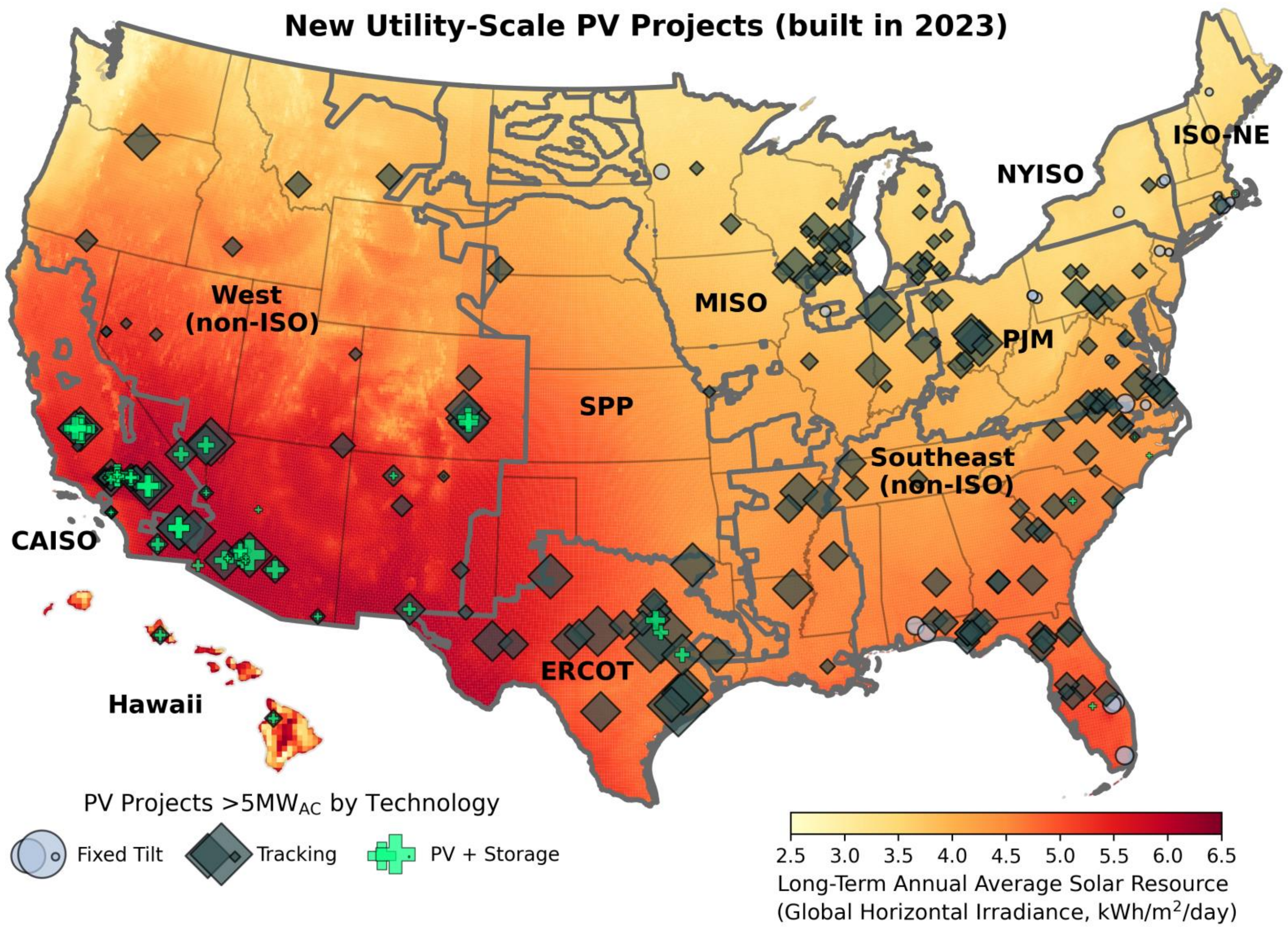
Percentage of In-State Electricity Sales and Generation from Solar PV, as of 2023



You can explore this data over time at https://emp.lbl.gov/capacity-and-generation-state

Note: Table above shows utility-scale solar as >1 MW_{AC} (most of this report uses >5 MW_{AC}). Percentages represent annual averages. Data is based on an early EIA data for 2023, findings may be revised with final data.

New utility-scale solar projects were built in the eastern Midwest, the mid-Atlantic, and southern United States in 2023



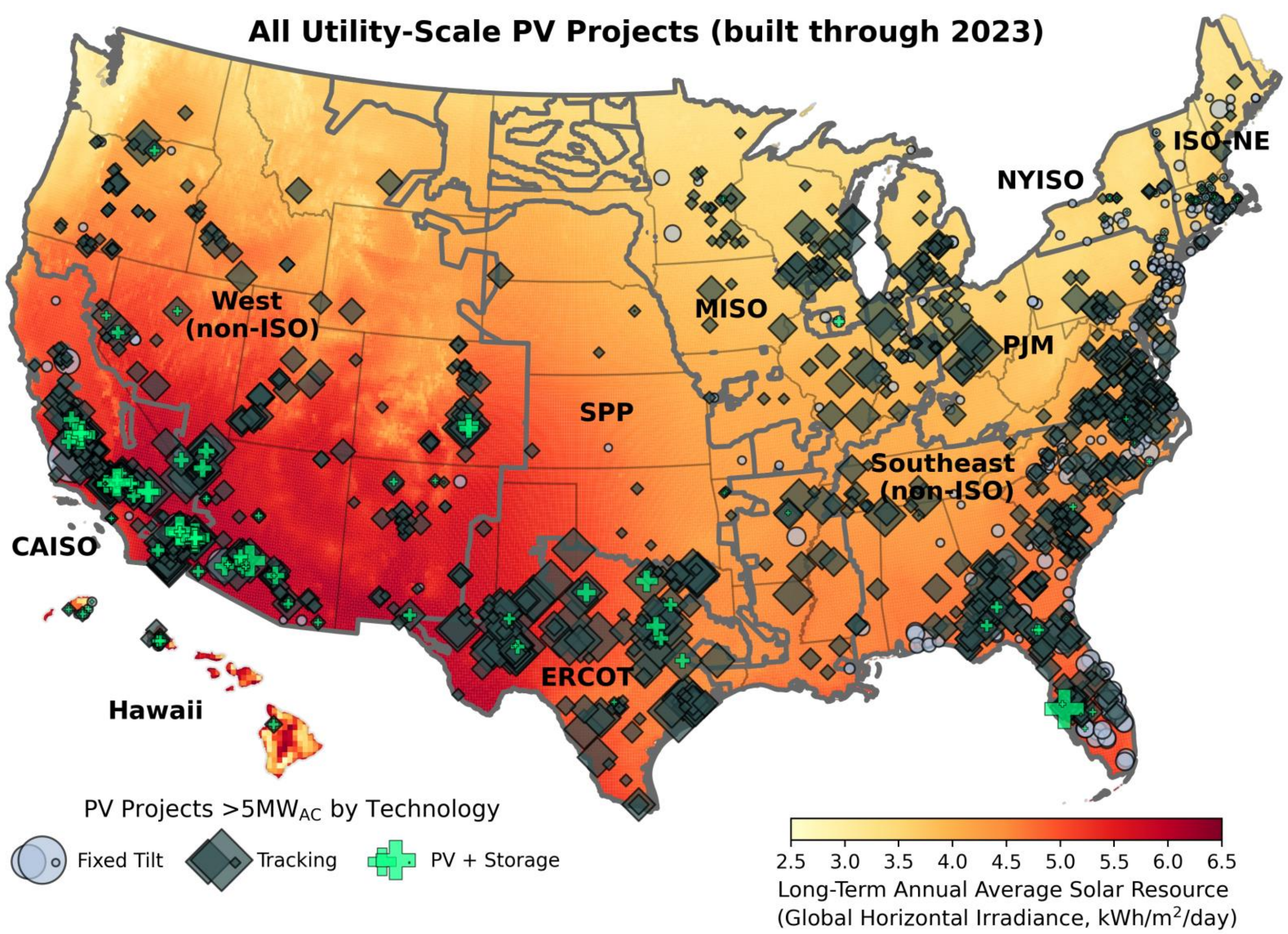
Fixed-tilt ( ) projects are increasingly only being built on particularly challenging sites (e.g., due to terrain or wind loading) or in the least-sunny regions in the northeast.

Other high-latitude states such as Oregon, Minnesota, Wisconsin, and Michigan, added predominantly **tracking** projects in 2023 ( ).

In 2023, storage ( ) hybrid projects hit the ground in record numbers. Batteries were added to already existing (15) and new (37) PV projects. Solar-rich CA added the most storage capacity (1657 MW), followed by the non-ISO West (1046 MW).

Note: A 6MW_{AC} project in Alaska is not shown in the map above. Larger icons represent greater capacity.
You can explore this data interactively at https://emp.lbl.gov/technology-trends

Utility-scale solar has been built throughout the United States



Utility-scale PV is well-represented throughout the nation, with the exception of the central "wind belt" states in SPP, Montana, and Wyoming.

Projects larger than 100 MW were built in 2023 in northern MISO, with solar growth in PJM occurring in Virginia, Ohio, and Pennsylvania, and solar expansion in Texas extending beyond the panhandle.

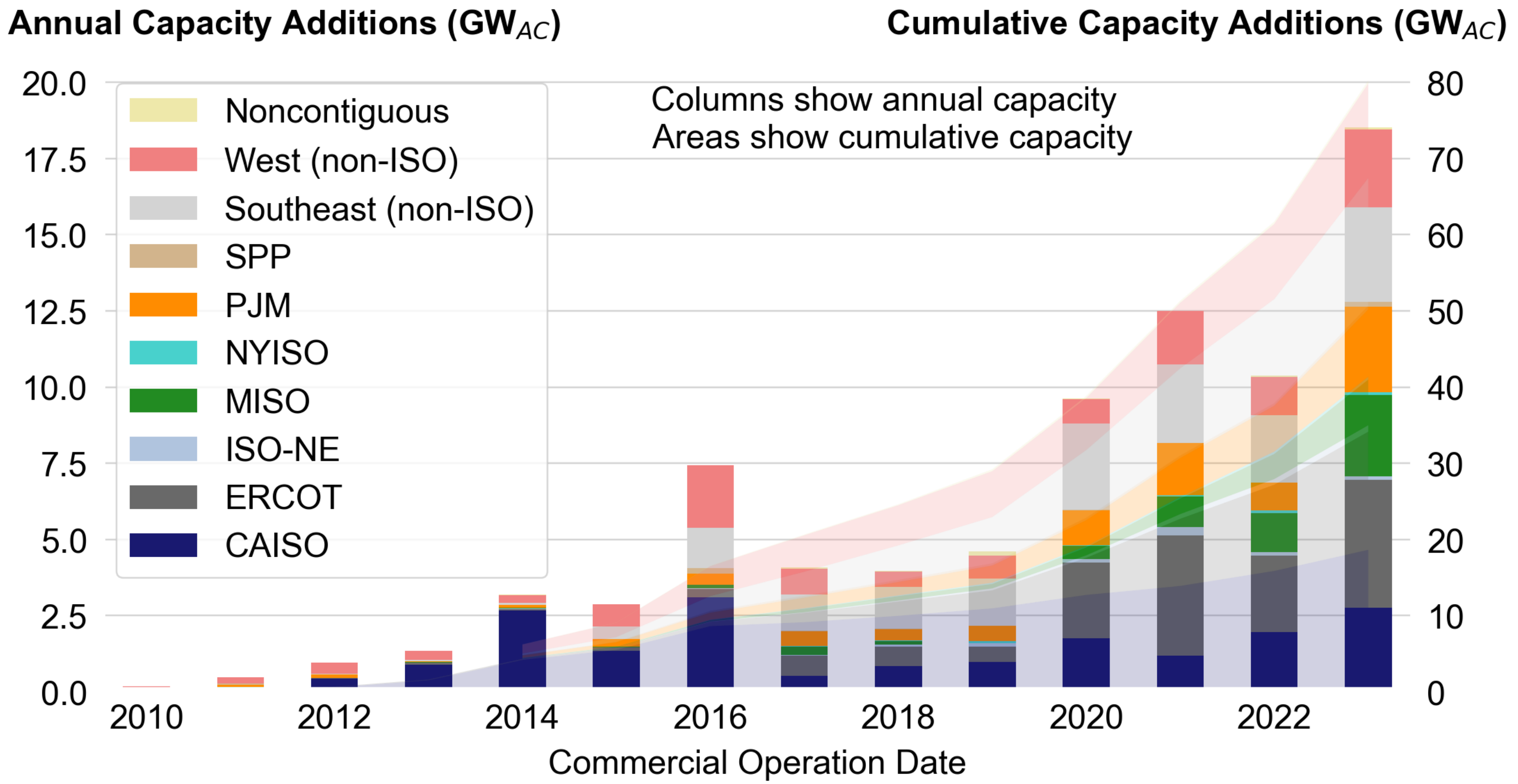
Montana and South Dakota had their first large solar projects (3x80 MW) in 2023, as did Alaska (6 MW). West Virginia's first project was completed in 2024 (80 MW).

Only North Dakota and New Hampshire still await their first utility-scale solar projects in our sample.

You can explore this data interactively at https://emp.lbl.gov/technology-trends

Texas and the non-ISO Southwest added the most utility-scale solar capacity in 2023

PV project population: 1,506 projects totaling 80.2 GW_{AC}



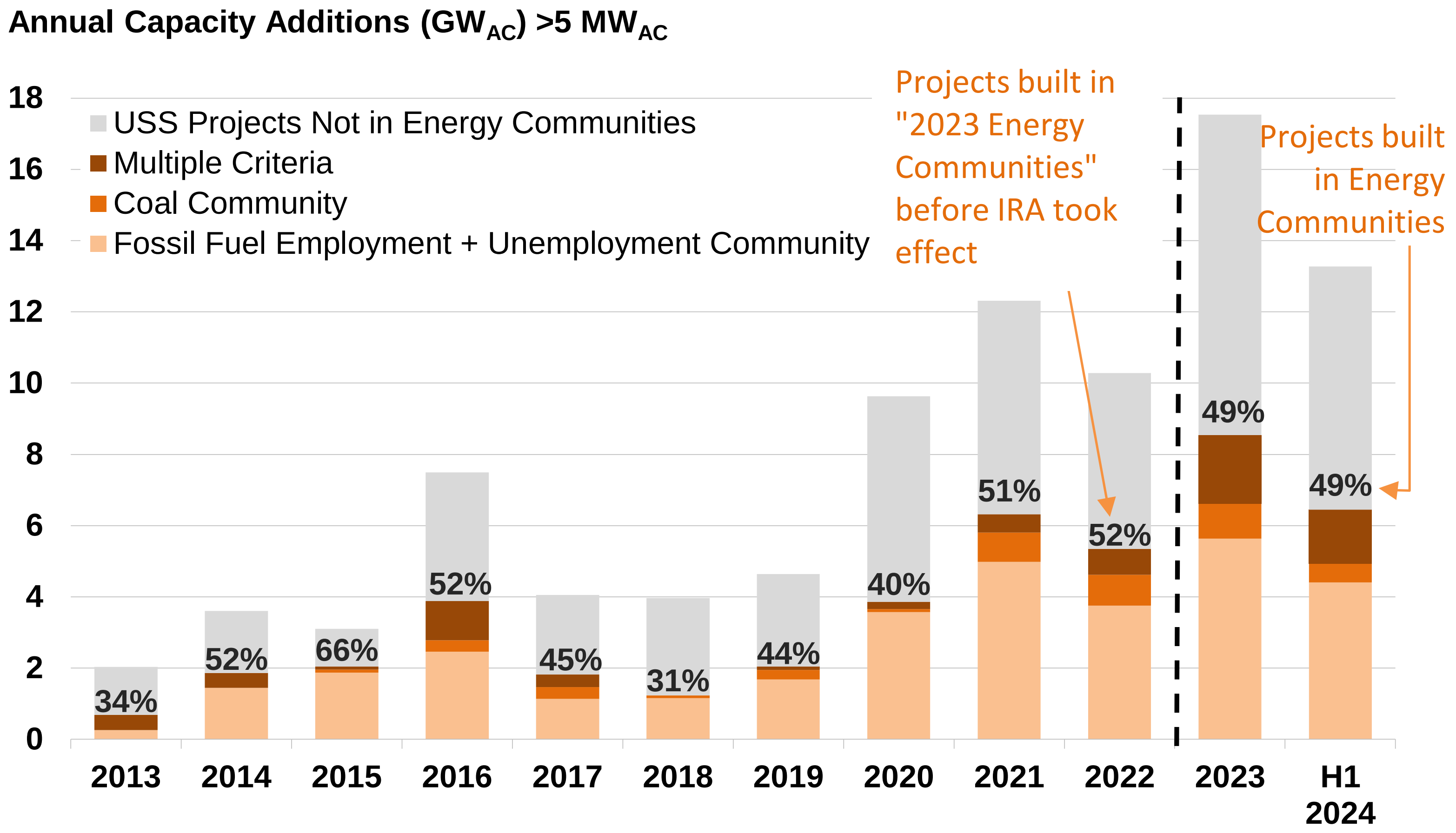
After a temporary decline in 2022, utility-scale solar deployment set again new records in 2023, with multiple GW of additions in ERCOT (4.2 GW_{AC}), the non-ISO Southeast (3.1 GW_{AC}), PJM (2.8 GW_{AC}), CAISO (2.7 GW_{AC}), MISO (2.7 GW_{AC}) and the non-ISO West (2.5 GW_{AC}) regions.

Taking a state perspective, **Texas** led the nation with 4.3 GW_{AC}. **California's** USS growth accelerated in 2023 to 2.6 GW_{AC}—its greatest deployment since 2016. **Florida** (1.8 GW_{AC}), **Ohio** (0.9 GW_{AC}), and **Wisconsin** (0.8 GW_{AC}) scored 3rd to 5th place.

In cumulative deployment, ERCOT (15 GW_{AC}) is still lagging CAISO (19 GW_{AC}), and the non-ISO Southeast (17 GW_{AC}) although the gap is narrowing.

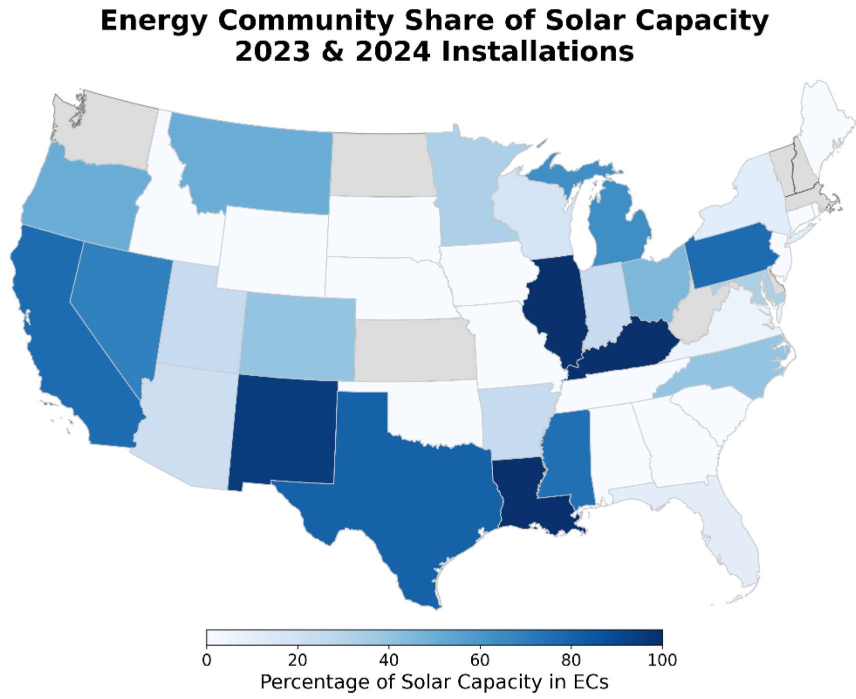
You can explore this data interactively at https://emp.lbl.gov/capacity-and-generation-state

Half of new solar capacity is built in Energy Communities



The Inflation Reduction Act offers a tax credit adder for new solar projects located in "**Energy Communities**", which are areas with:

- Employment or tax revenue from coal, oil, natural gas and greater unemployment than national mean
- A closed coal mine or coal power plant
- Contaminated properties (brownfields)

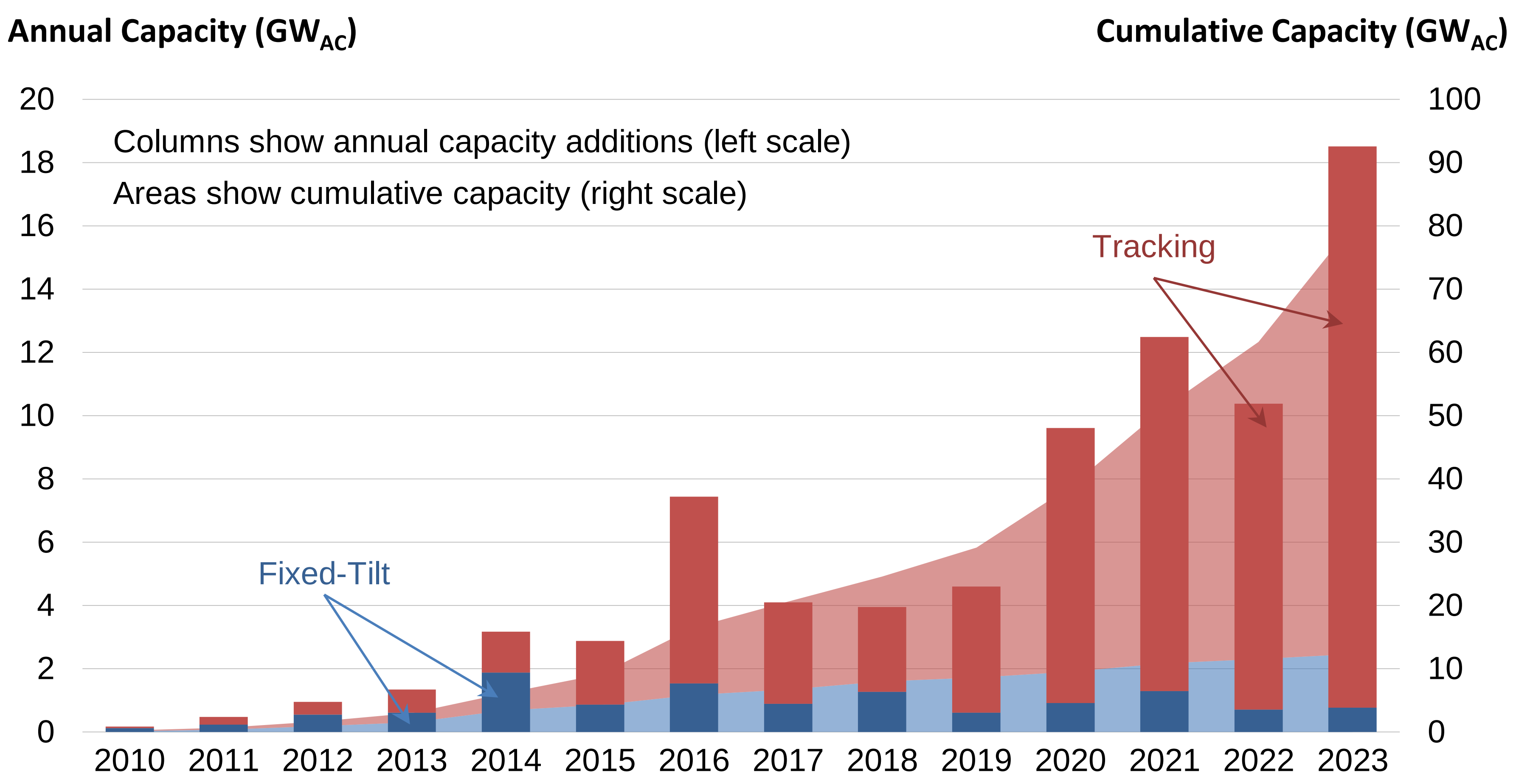


New projects built since the passing of the IRA may not yet have been intentionally sited to capture the bonus (interconnection processes take several years). Nearly half of the new solar capacity built since 2022 is located in areas qualifying as Energy Communities.

Note: Some solar projects developed on brownfield sites may not be accurately classified as part of an Energy Community due to data availability issues. *H1 2024 data is preliminary from EIA 860M.

Projects with tracking technology dominated 2023 additions

PV project population: 1,504 projects totaling 80.2 GW_{AC}



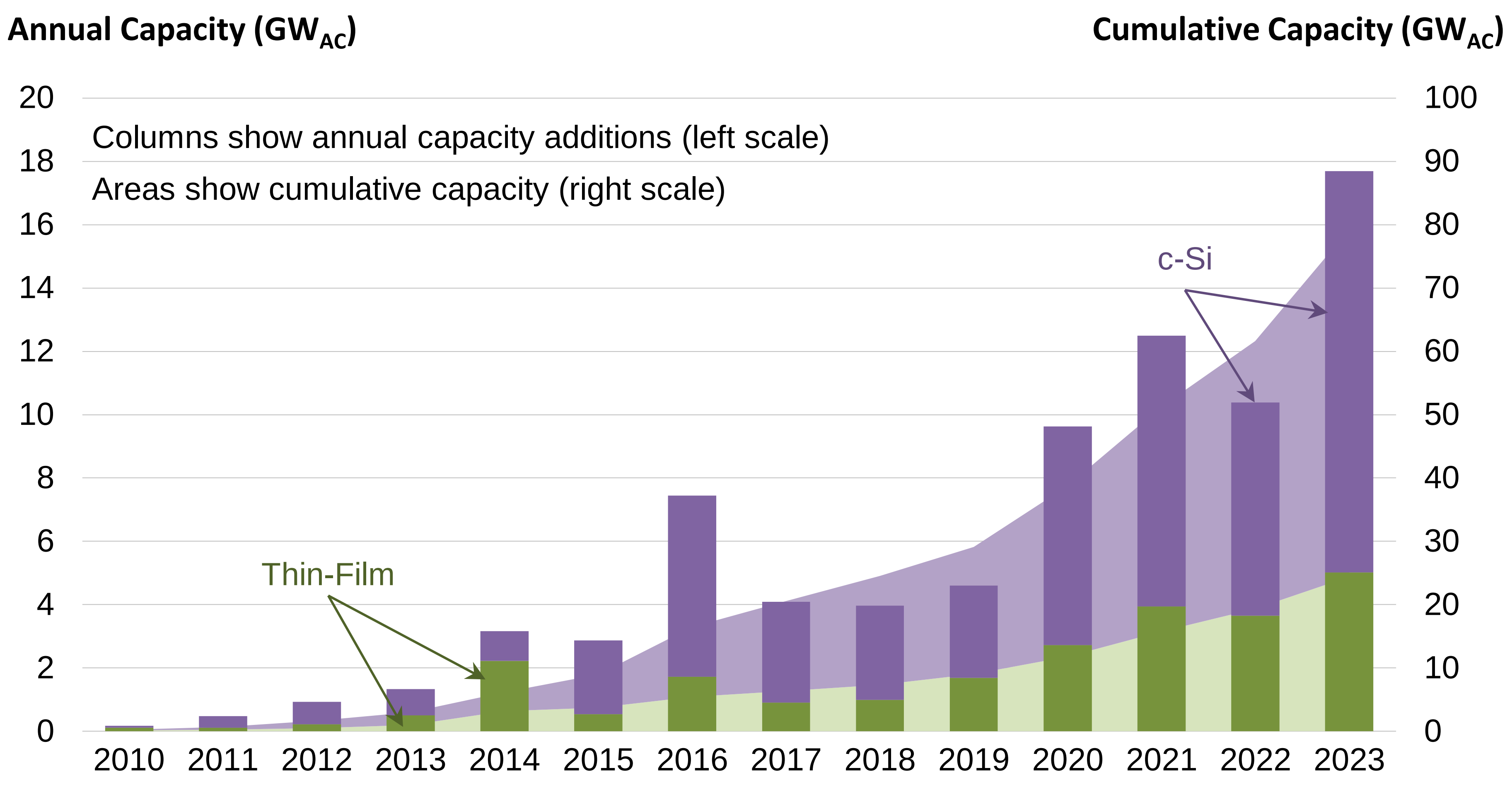
Projects using single-axis **tracking** have consistently exceeded **fixed-tilt** installations since 2015, and dominated again in 2023, with 96% of all new capacity using tracking—the greatest ever.

Upfront cost premiums for trackers have generally fallen over the years, resulting in favorable economics in most of the United States thanks to increased generation (though 2023 saw again an uptick in cost premiums—discussed later).

You can explore this data interactively at https://emp.lbl.gov/technology-trends

Use of c-Si modules grew again in 2023

PV project population: 1,494 projects totaling 79.3 GW_{AC}



c-Si modules have been the dominant module technology at large-scale solar projects in the US since 2015. After a temporary decline in relative growth in 2022, c-Si modules expanded their market share again in 2023 to 72% of newly installed capacity.

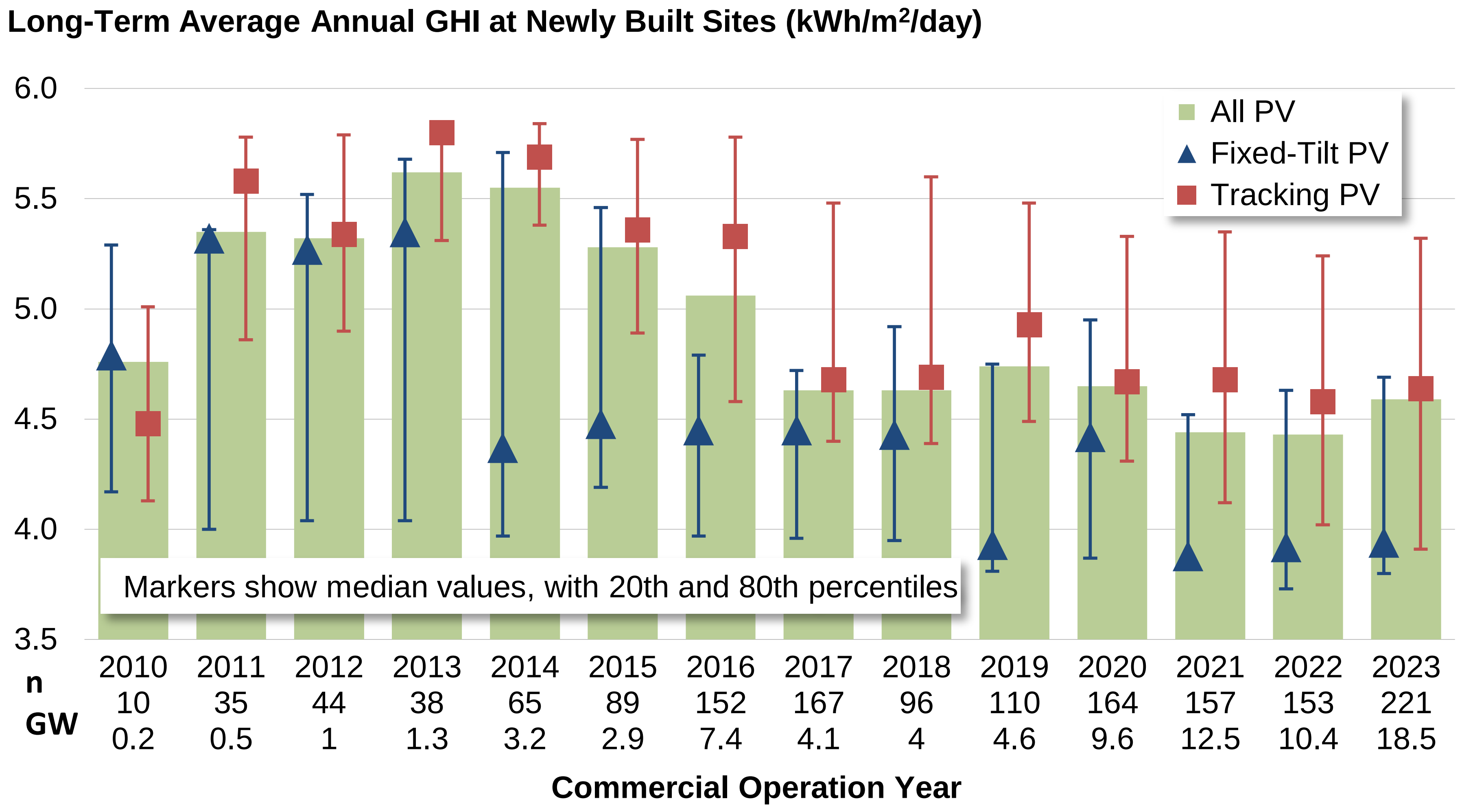
Thin-film modules grew in popularity between 2018 and 2021 as they were not subject to Section 201 import tariffs. In 2023 they reached a new record annual deployment of 5 GW_{AC}.

Note: The 2023 sample includes 6 projects (0.8GW_{AC}) without conclusive module type data which are excluded from the graph above

You can explore this data interactively at https://emp.lbl.gov/technology-trends

Solar projects built were built in very solar rich areas in the early 2010s. Project locations and associated resource quality have become much more diverse since then.

PV project population: 1,506 projects totaling 80.2 GW_{AC}



The average long-term global horizontal irradiance (**GHI**) at newly built sites declined from 2013 through 2017 as the market expanded to less-sunny states. This metric rebounded slightly in 2023 to 4.59 $kWh/m^2/day$.

Fixed-tilt PV is increasingly relegated to lower-insolation sites, while **tracking** PV is increasingly pushing into those same areas (note the decline in its 20th percentile).

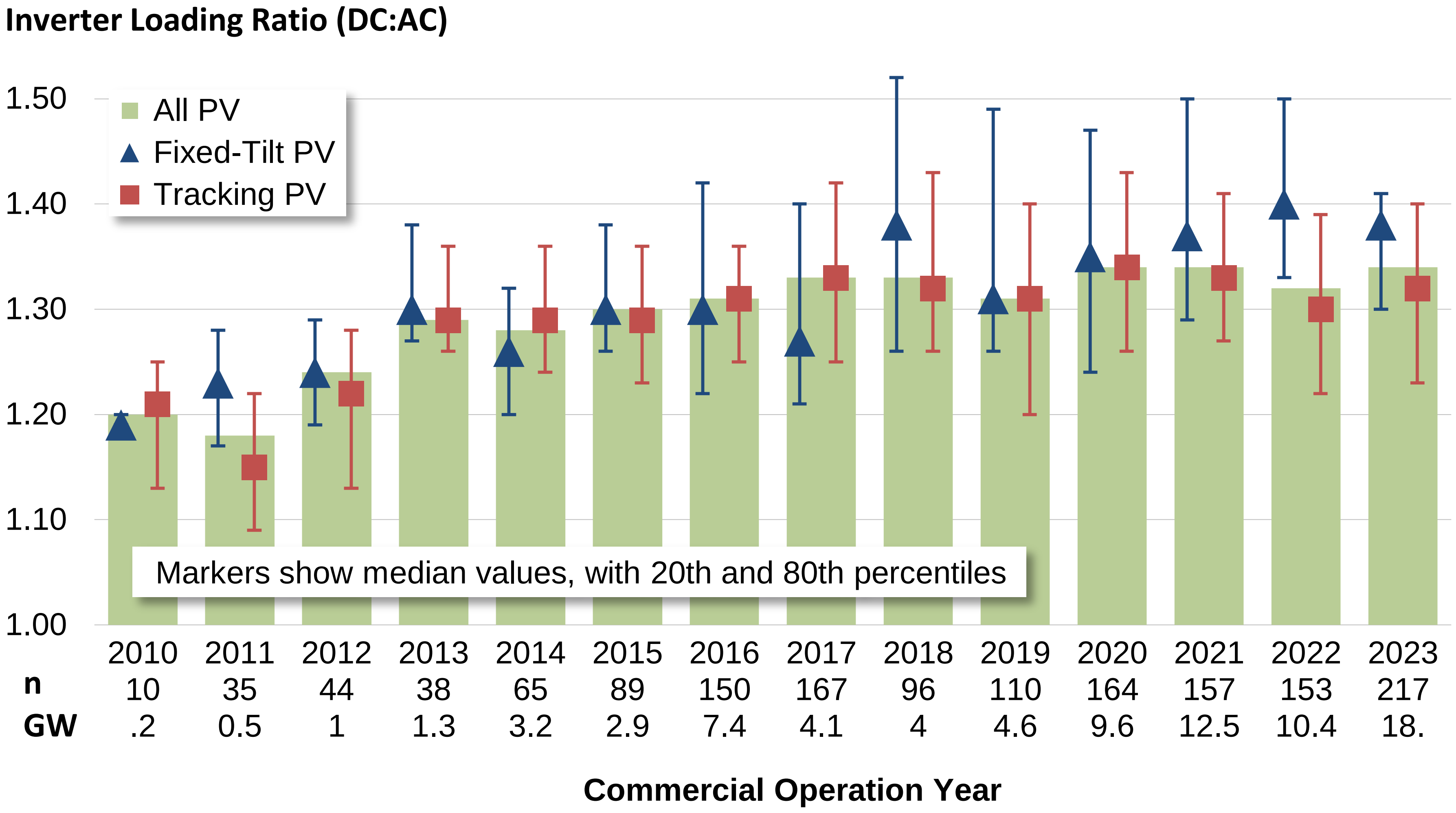
Exceptions are fixed-tilt installations in windy regions (Florida), on brownfields and landfill sites, and on particularly challenging terrain. About 25% of these projects now have a south-western orientation to maximize evening production.

All else equal, the buildout of lower-GHI sites dampens sample-wide capacity factors (reported later).

Note: We use NREL's NSRDB to estimate long-term solar resource quality for each new USS project. Bars are sample-wide medians, markers show distribution for fixed-tilt and tracking projects.

The median inverter loading ratio (ILR) is higher for fixed-tilt projects than tracking projects

PV project population: 1,500 projects totaling 79.6 GW_{AC}



As module prices have fallen (faster than inverter prices), developers have oversized the DC array capacity relative to the AC inverter capacity to enhance revenue and reduce output variability.

In 2023, the median inverter loading ratio (**ILR:** MW_{DC} to MW_{AC} ratio) was 1.34, and was higher for fixed-tilt installations (1.38) than for tracking projects (1.32).

All else equal, a higher ILR should boost capacity factors (denominated in AC terms and discussed later in the report).

Capital Costs (CapEx)
and
Operation & Maintenance (O&M) Costs

Capital and Operation & Maintenance Costs: data and methodology

CapEx Data:

- Project-level capital expenditure (CapEx) estimates are sourced from a combination of Form EIA-860, Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, trade press articles, and data previously gathered by NREL.
- CapEx estimates for projects built from 2013-2022 have been cross-checked against confidential EIA-860 data obtained under a non-disclosure agreement. The close agreement between the confidential EIA data and our other sources in most cases provides comfort that our data collection process yield reputable CapEx estimates.

CapEx Methods:

- We present data in $/W$_{AC}$ terms to facilitate cost comparison between generators of multiple fuel types. The accompanying data file on our project website also provides detailed data in $/W$_{DC}$ terms.
- We define cost scope in close alignment with EIA's 860 Schedule 5B (p29) to include:
  - construction costs (civil and structural costs, equipment and installation, electrical and instrumentation, indirect costs (incl. overhead and profits) and owner costs (incl. tie-in and potential transmission network upgrades)). For a detailed analysis of interconnection costs of utility-scale solar see https://emp.lbl.gov/interconnection_costs.
  - construction finance costs.

O&M Data:

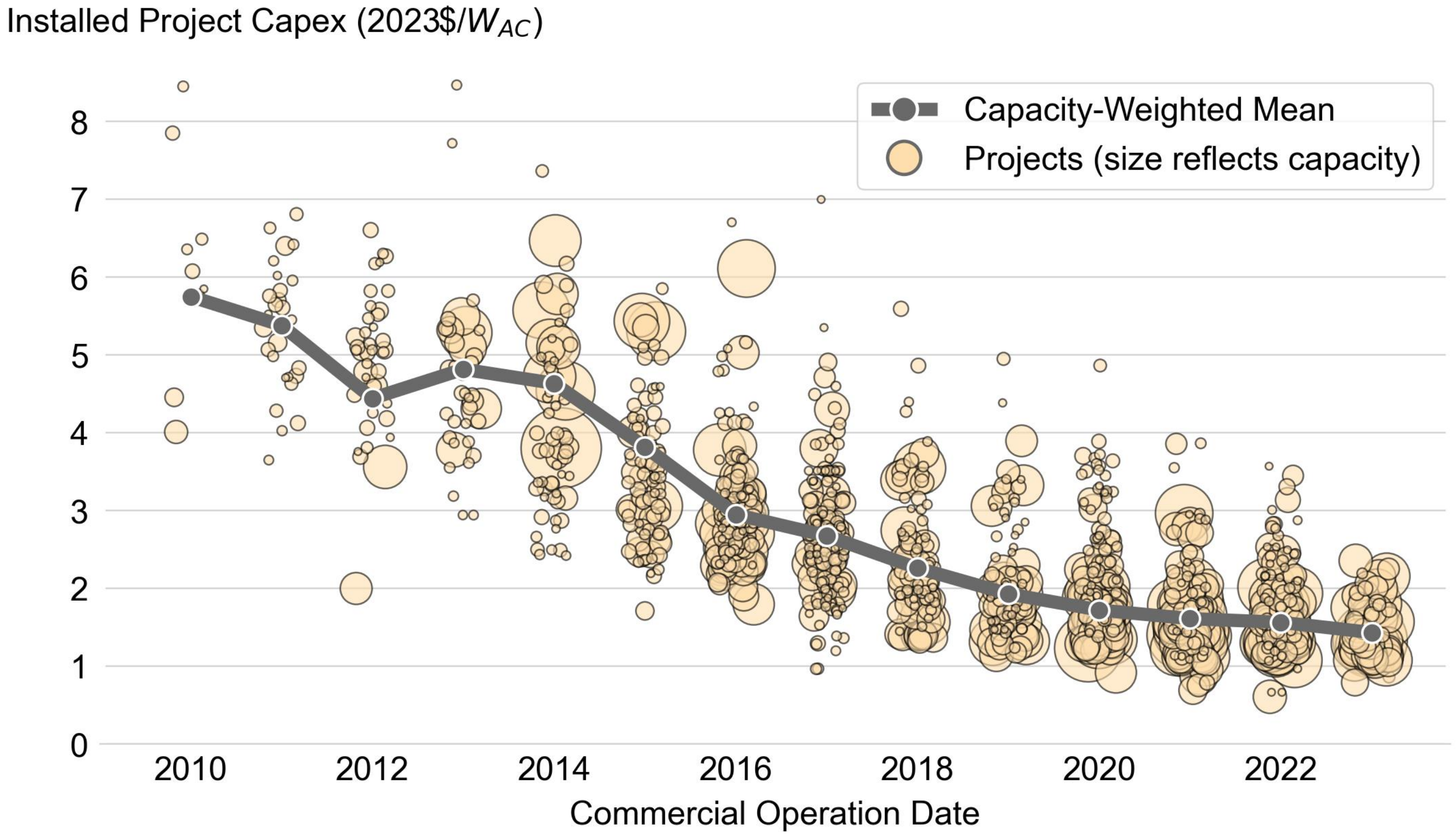
- Plant-level operation and maintenance costs, capacity, net generation, and construction year are sourced from FERC Form 1 Annual Reports, which are filed by major electric utilities.

O&M Methods:

- We exclude O&M cost observations from the year a plant was constructed to avoid data based on a partial year of operations.
- We also exclude projects ≤5 MW in size, consistent with our definition of utility-scale.
- We present data for combined operations and maintenance costs in $/kW$_{AC}$ (capacity denomination) and $/MWh (generation denomination) terms.

Installed costs of PV have fallen by 8% since 2022, to $1.43/W$_{AC}$ ($1.08/W$_{DC}$) in 2023

Sample: 1,279 projects totaling 66.5 GW$_{AC}$



Note: The 2023 sample does not yet include data contributions from EIA 860, cost findings may thus be revised as higher quality data will become available.

Since 2010, costs for installed utility-scale PV have fallen by 75% (or 10% annually):

- **Capacity-weighted means** (reflecting the average costs of solar capacity) decreased in real terms from $1.56/W$_{AC}$ in 2022 to $1.43/W$_{AC}$ in 2023.
- **Medians** (reflecting typical project costs) decreased from $1.61/W$_{AC}$ in 2022 to $1.33/W$_{AC}$ in 2023.

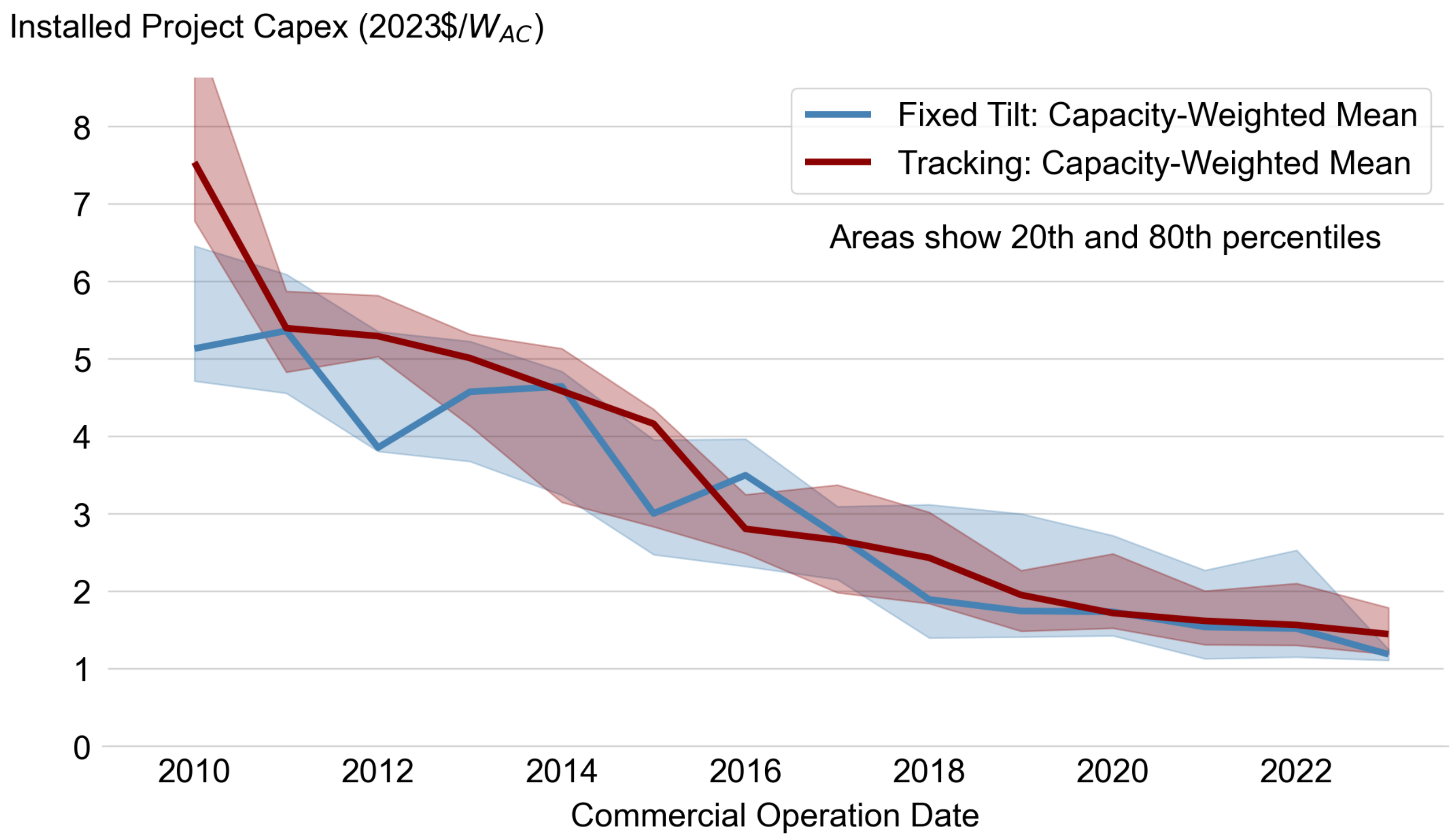
Despite strong inflationary pressures, we have not observed cost increases in real dollar terms in recent years, unlike some other industry observers.

The lowest 20th percentile of project costs fell in real terms from $1.3/W$_{AC}$ ($1.0/W$_{DC}$) in 2022 to $1.2/W$_{AC}$ ($0.9/W$_{DC}$) in 2023.

Historical sample is robust (covering 96% of installed capacity through 2022). 2023 data covers 34% of new projects (75) or 37% of new capacity (6.9 GW$_{AC}$).

Tracking projects cost $0.2/W more than fixed-tilt projects on average

Sample: 1,279 projects totaling 66.5 GW_{AC}



We focus here on cost differences between projects using tracking and fixed-tilt mounting. The graph shows capacity-weigthed average costs by mounting type across our sample but does not control for other factors that influence total project costs (equipment, labor, land, grid interconnection, project size…).

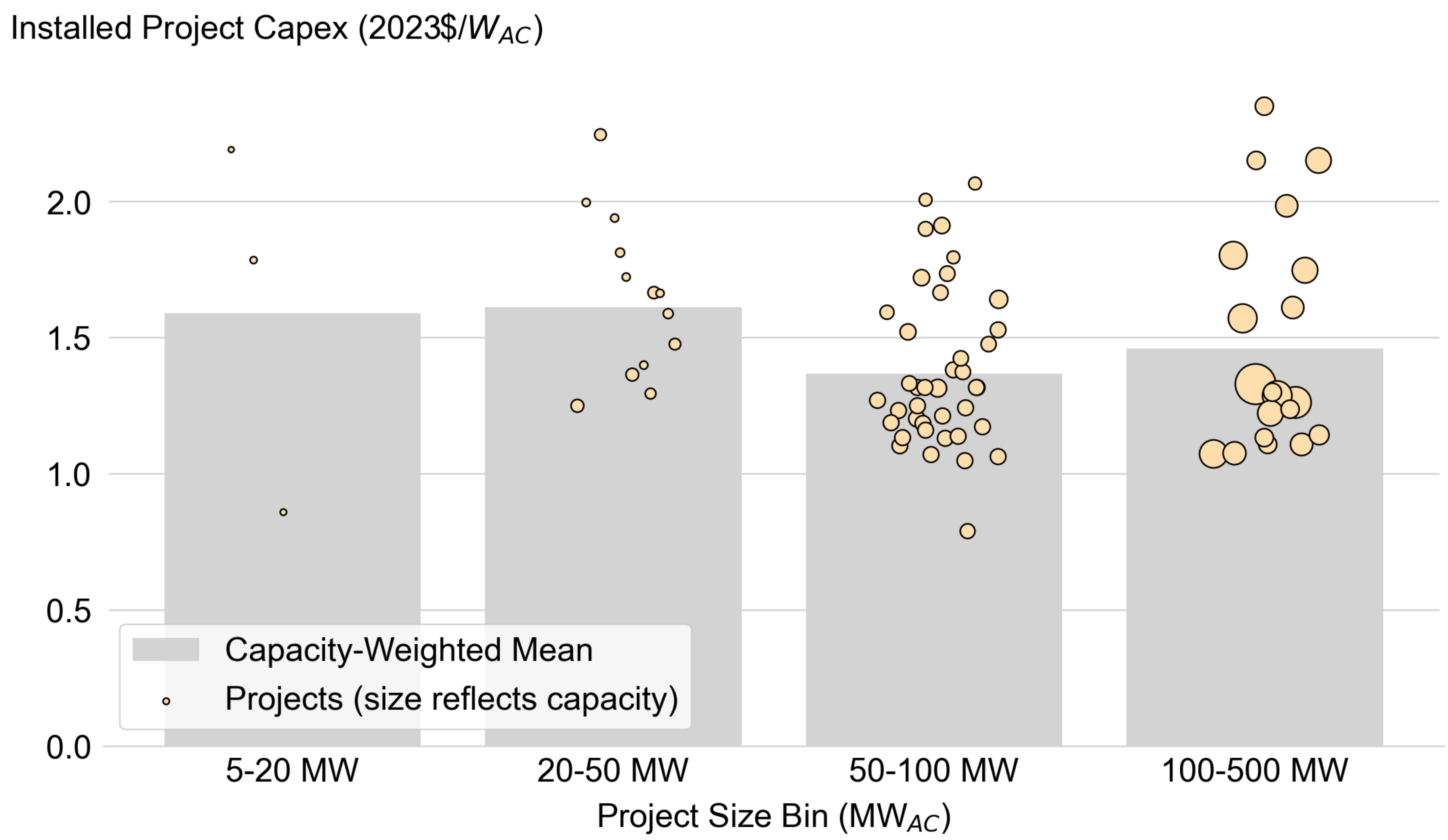
Trackers can sustain some higher upfront costs because they deliver more energy per installed capacity.

Over time tracking projects have often been more expensive, at least on average across our sample, but the cost premium has fluctuated and at times even reversed (like in 2016).

Beginning in 2020, tracker installations boomed. By 2023, 96% of all new capacity used trackers, and tracking projects ($1.4/$W_{AC}$ or $1.1/$W_{DC}$) were slightly more expensive than fixed-tilt projects ($1.2/$W_{AC}$ or $0.9/$W_{DC}$).

Larger solar projects (>50 MW) cost 13% less than smaller (5-50 MW) per MW of installed capacity in 2023

Sample in 2023: 76 projects totaling 7.1 GW_{AC}



Differences in project size could potentially explain cost variation—we focus only on 2023 for this slide.

Cost savings seem to occur especially in projects larger than 50 MW_{AC} at ~\$1.4/W_{AC} vs. \$1.6/W_{AC} for smaller projects.

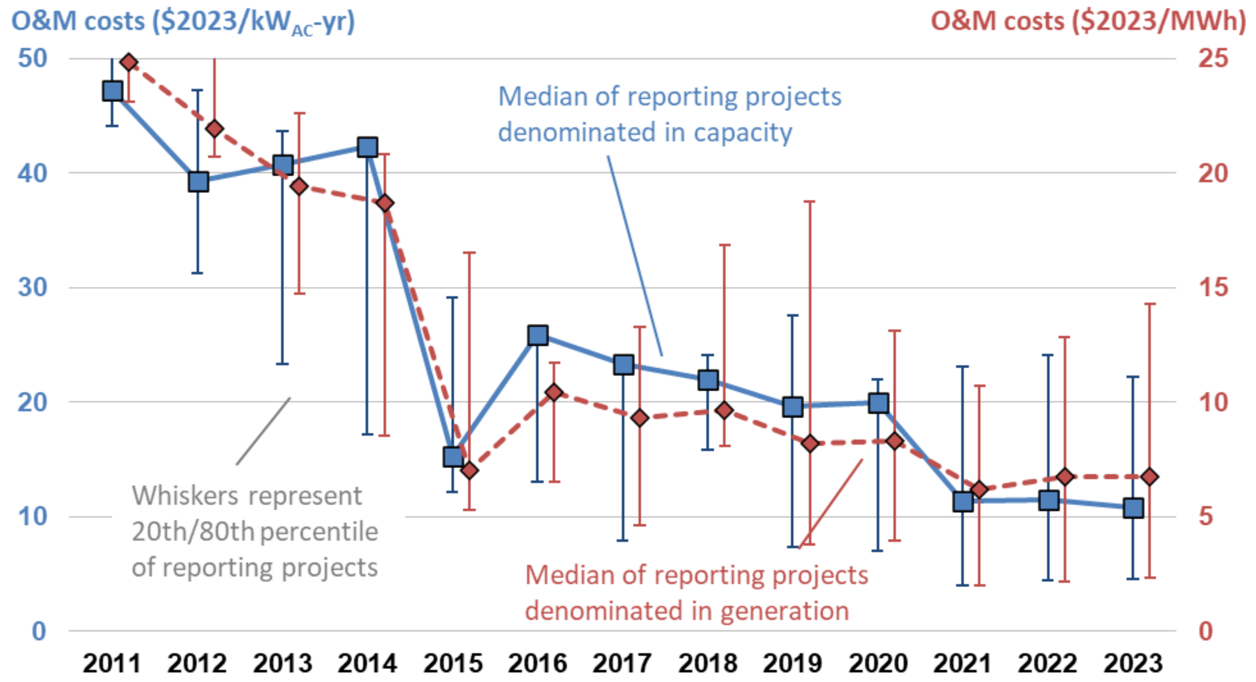
In \$/W_{DC} terms, prices seem to decline especially among the largest projects:

- \$1.28/W_{DC} for 5-20 MW
- \$1.23/W_{DC} for 20-50 MW
- \$1.18/W_{DC} for 50-100 MW
- \$1.05/W_{DC} for 100-700 MW

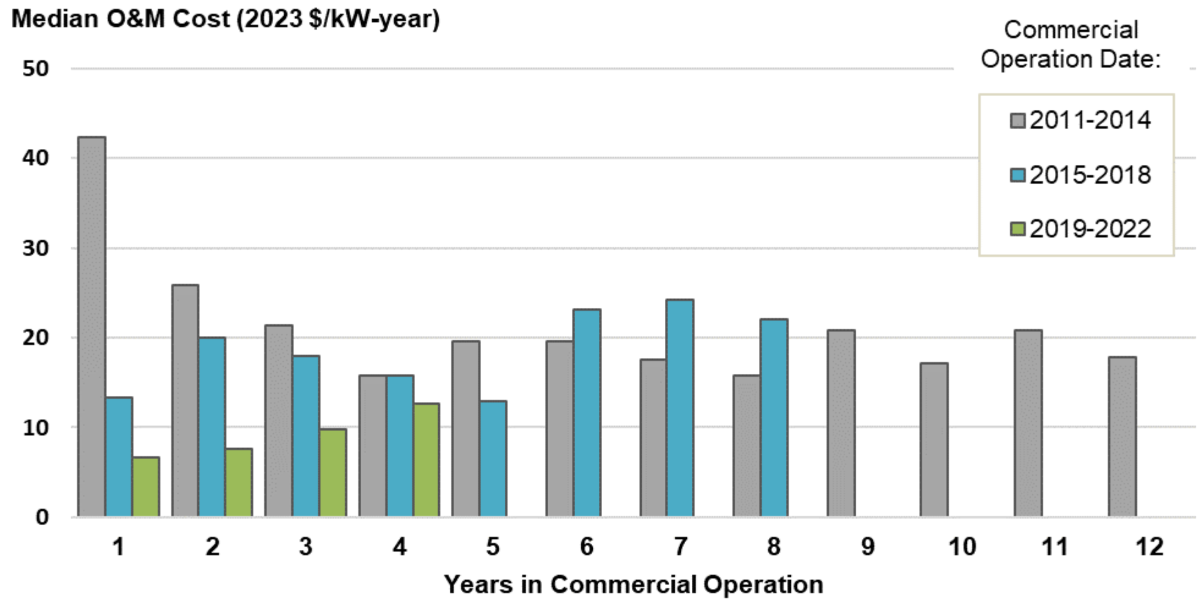
Operation and maintenance (O&M) costs have decreased by 73% since 2012, but remained flat the past 3 years

PV project population in 2023: 145 projects totaling 7.4 GW_{AC}

Regulated utilities report solar O&M costs for plants that they own, representing a mix of technologies and at least one full operational year. These O&M costs are only one part of total operating expenses.	<u>Cost Scope</u> (per guidelines for FERC Form 1): • **Includes** supervision and engineering, maintenance, rents, and training • **Excludes** payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead



Median O&M costs for the cumulative sample have declined from about $39/kW$_{AC}$-year or $22/MWh in 2012 to about **$11/kW$_{AC}$-year or $7/MWh in 2023**.



Projects built since 2019 report much lower O&M costs in their first three years of operation compared to older ones, potentially due to a narrower scope of service agreements. Starting in year 6 of a project's life there does not appear to be a sustained upward or downward trend in O&M costs.

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Note: Detailed project-level data are shown in the accompanying data workbook.

Performance (Capacity Factors)

PV performance analysis: data and methodology

Net generation data are sourced largely from EIA Form 923. These data reflect net generation and thus exclude energy used by the plant itself. They also exclude energy that was curtailed (for economic or system stability reasons). Outliers and low-quality data are dropped from the analysis. We exclude observations from the first calendar year of the plant's operation.

Net Capacity Factors (AC) measure a plant's performance, representing the ratio of its actual annual generation delivered to the grid to the maximum possible annual output if it operated continuously every hour of the year.

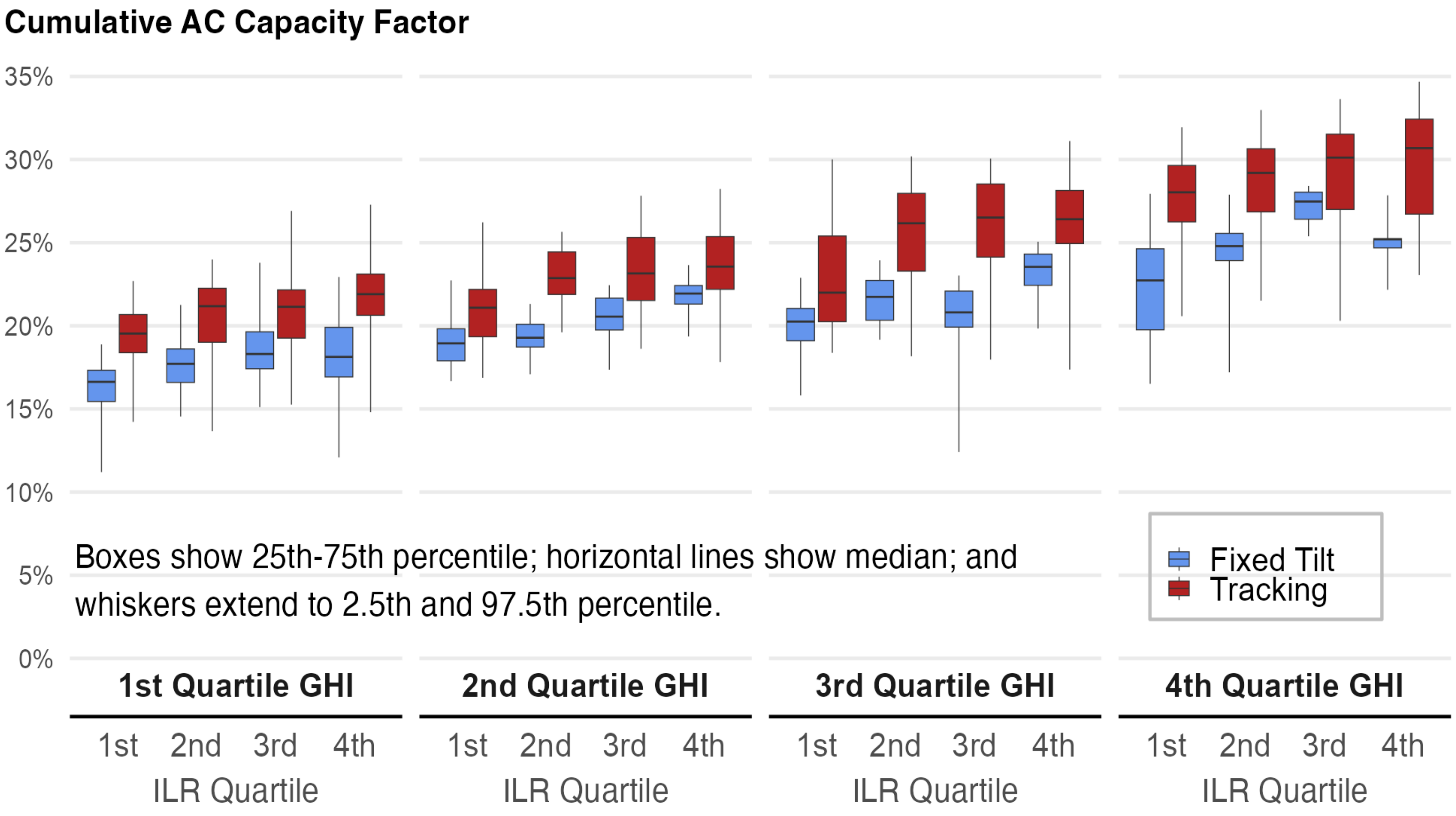
$$Annual\ Net\ Capacity\ Factor = \frac{Annual\ Net\ Generation\ (MWh)}{Capacity\ (MW_{AC}) * number\ of\ hours\ in\ year}$$

We use MW_{AC} capacity terms in our capacity factor calculations to facilitate comparisons with other bulk system generator types.

Annual generation can vary based on weather and climate variability, system degradation, system uptime, or curtailment. We thus present primarily **cumulative net capacity factors**, which represent the average capacity factor over the lifetime of a project up until the most recent reported period (i.e., no future modeled generation data).

PV performance varies widely among projects, driven by resource availability and project design choices

Sample: 1,253 plants totaling 61.4 GW_{AC}



The cumulative net capacity factor is typically around 24% but ranges from 7% to 35% among all projects in our sample.

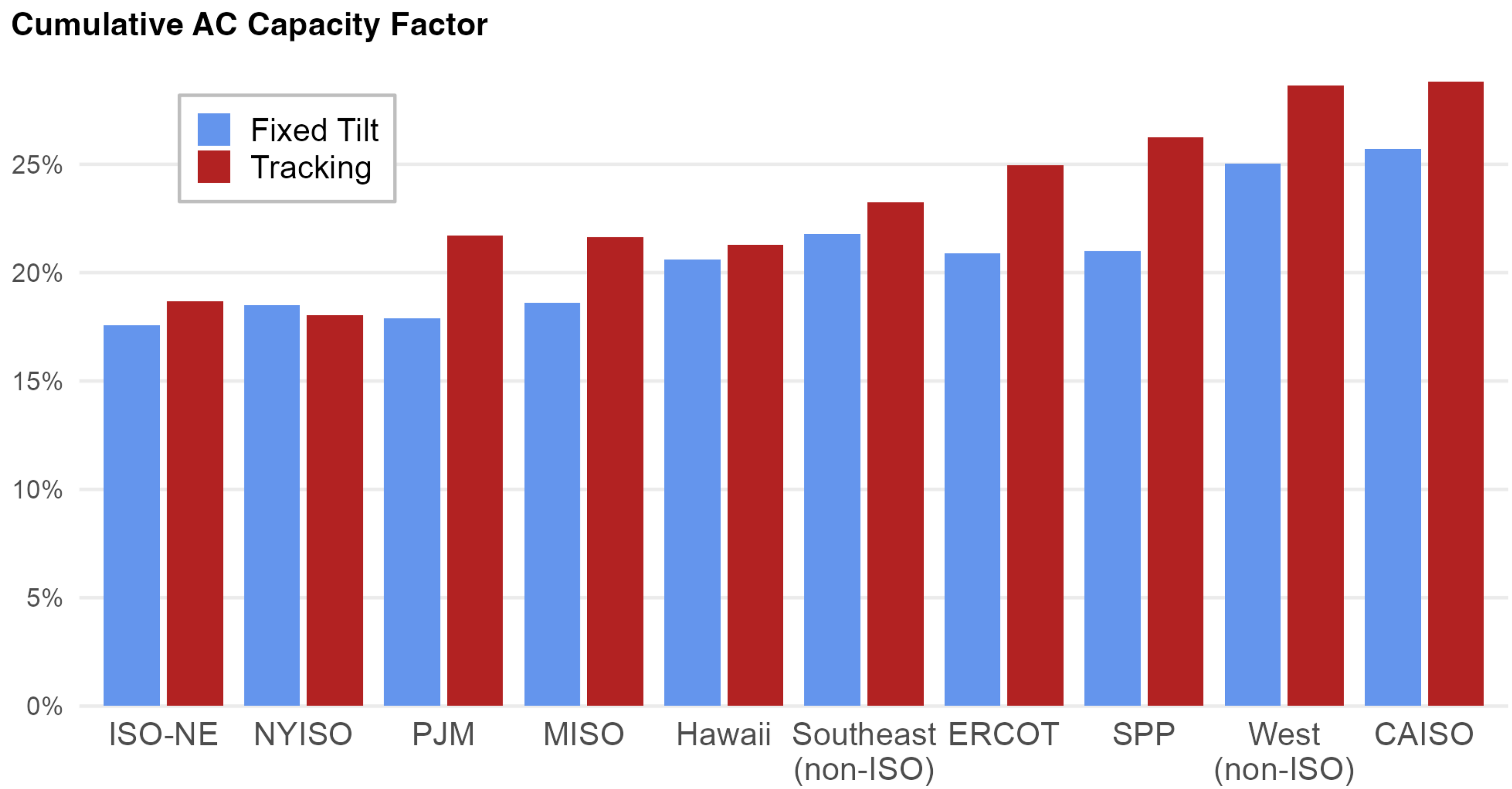
Project-level variation in PV capacity factor is driven by:

- **Solar Resource (GHI)**: Strongest solar resource quartile has ~9 percentage point higher capacity factor than lowest resource quartile
- **Tracking**: Adds ~4 percentage points to capacity factor on average, with improvement from tracking more pronounced in higher solar resource areas
- **Inverter Loading Ratio (ILR)**: Highest ILR quartiles have on average ~2 percentage point higher capacity factors than lowest ILR quartiles

You can explore this data interactively at https://emp.lbl.gov/pv-capacity-factors

Tracking boosts capacity factors by roughly 5 percentage points in high-insolation regions

Sample: 1,253 plants totaling 61.4 GW_{AC}



Notes: The NYISO tracking sample comprises just projects, possibly driving unexpected results. Capacity factors represent weighted means by capacity (MW_{AC}).

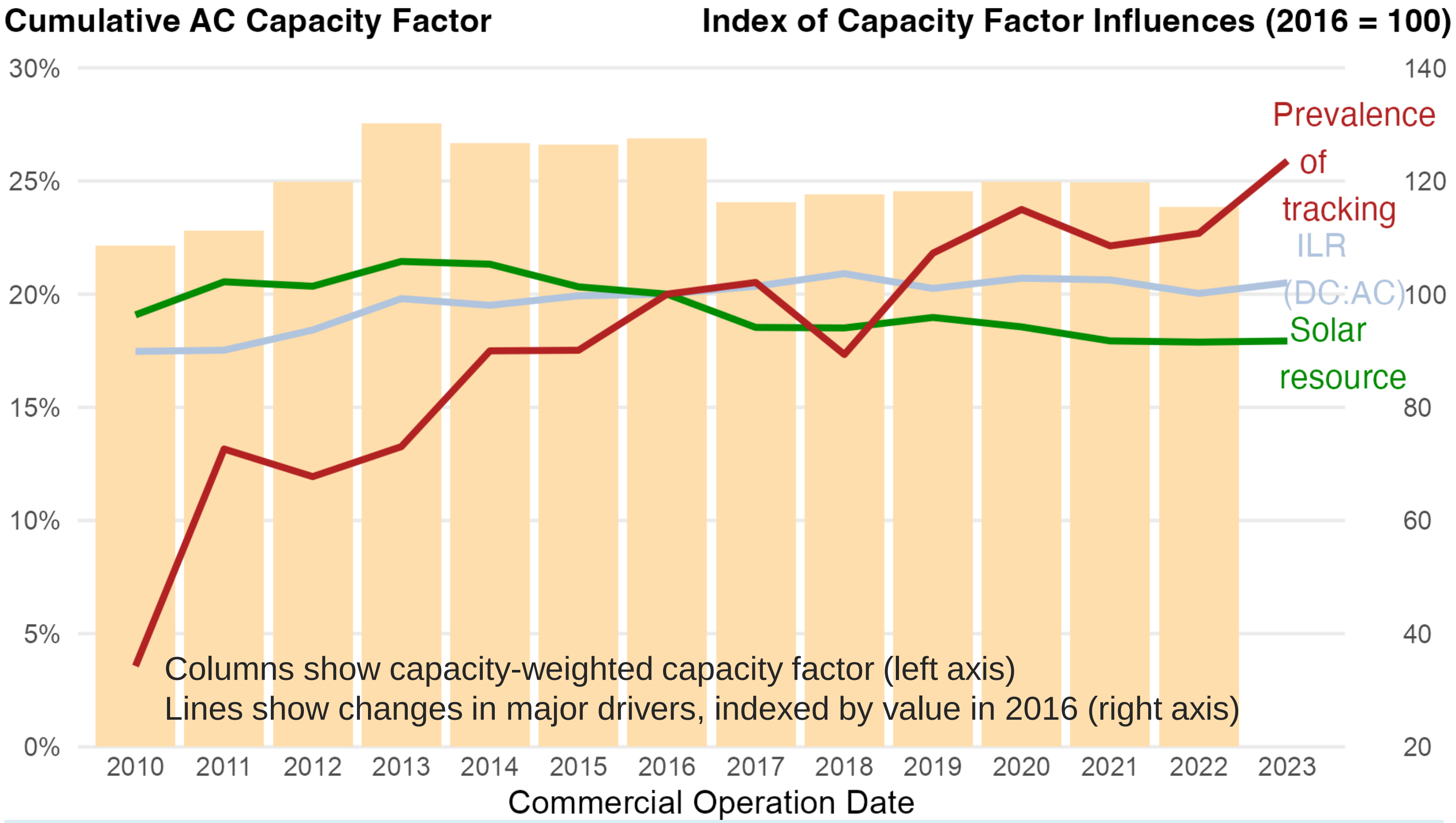
Not surprisingly, capacity factors are highest in California and the non-ISO West, and lowest in the Northeast (ISO-NE and NYISO).

Tracking yields more benefits compared with fixed-tilt installations in regions with strong solar resources, leading to a greater proportion of tracking projects in those regions.

You can explore this data interactively at https://emp.lbl.gov/pv-capacity-factors

Since 2013, competing drivers have caused average capacity factors by plant vintage to stabilize

Sample: 1,253 plants totaling 61.4 GW_{AC}



Flat trend since 2014 is not necessarily negative, but rather a sign of a market that is expanding geographically into less-sunny regions

Cumulative capacity-weighted capacity factors improved for projects from 2010 to 2013 due to increased DC-oversizing, adoption of single-axis tracking, and better solar resources.

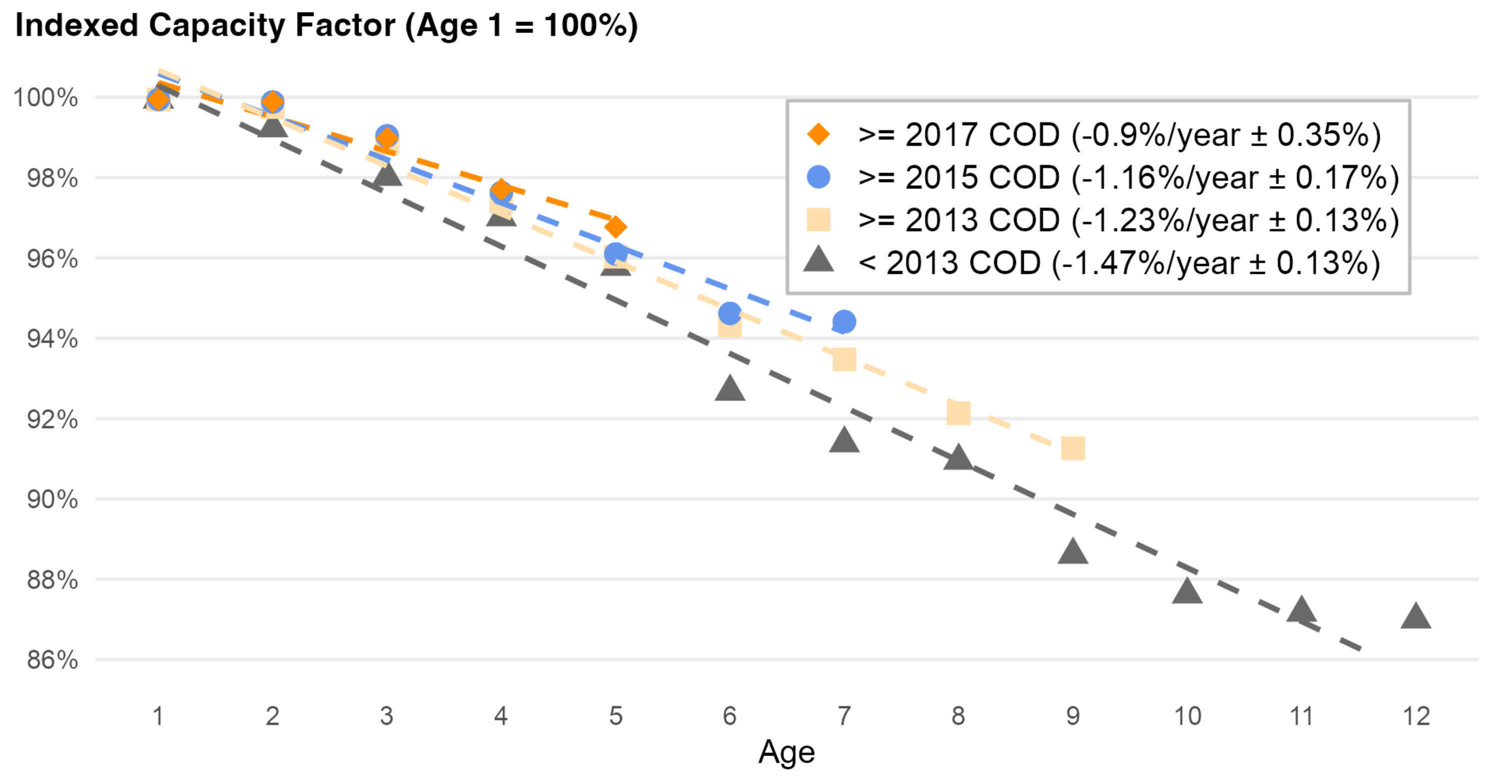
Since 2013, capacity factors have stagnated due to mixed factors: while tracking has become widespread (50% to 90%) and ILR has seen minor growth, new projects have expanded into less sunny regions (average GHI decreased from 5.30 to 4.32 kWh/m²/day).

In our latest cohort (145 projects, 2022 vintage), annual output declined by 1% (absolute) or 4% (relative) compared to 2021 projects. Key drivers remained stable, and irradiance-based modeling even suggested a slight performance increase. We will continue monitoring potential performance issues as more data emerges.

You can explore this data interactively at https://emp.lbl.gov/pv-capacity-factors

Plant output declines with age, but the performance of newer projects has fallen at a slower rate compared to older projects

Sample: 905 plants totaling 37.4 GW_{AC}



Note: Sample includes plants built through 2020 (model requires two years of performance with weather data available through 2022). All four slopes are statistically significant, but commercial operation date (COD) ≥ 2015 is not statistically different from COD ≥ 2013 or ≥ 2017.

Annual system-level performance degradation varies by cohort, with newer plants degrading 0.9% per year compared to 1.47% for older plants.

Fixed effects regression model defined by:

$$CF_{f,t}{}^{actual} = CF_{f,t}{}^{ideal} + S_f + A_T + \epsilon_{f,t}$$

where:

$CF_{f,t}{}^{actual}$ = Actual capacity factor of plant f at time t (raw empirical data, but grossed up for curtailment in CAISO and ERCOT)

$CF_{f,t}{}^{ideal}$ = "Ideal" capacity factor of plant f at time t, estimated based on physical plant characteristics and solar resource at the site

S_f = Site-level fixed effects of plant f to control for differences in capacity factor across plants

A_T = Age fixed effects at time t to control for differences in capacity factor within plants

$\epsilon_{f,t}$ = Residual of plant f at time t

Note: For greater detail on methods, see [Bolinger et al. (2020) System-level Performance and Degradation of 21 GW_{DC} of Utility-Scale PV Plants in the United States].

Levelized Cost of Energy (LCOE) and Power Purchase Agreement (PPA) Prices

LCOE analysis: data sets and methodology

Methods:

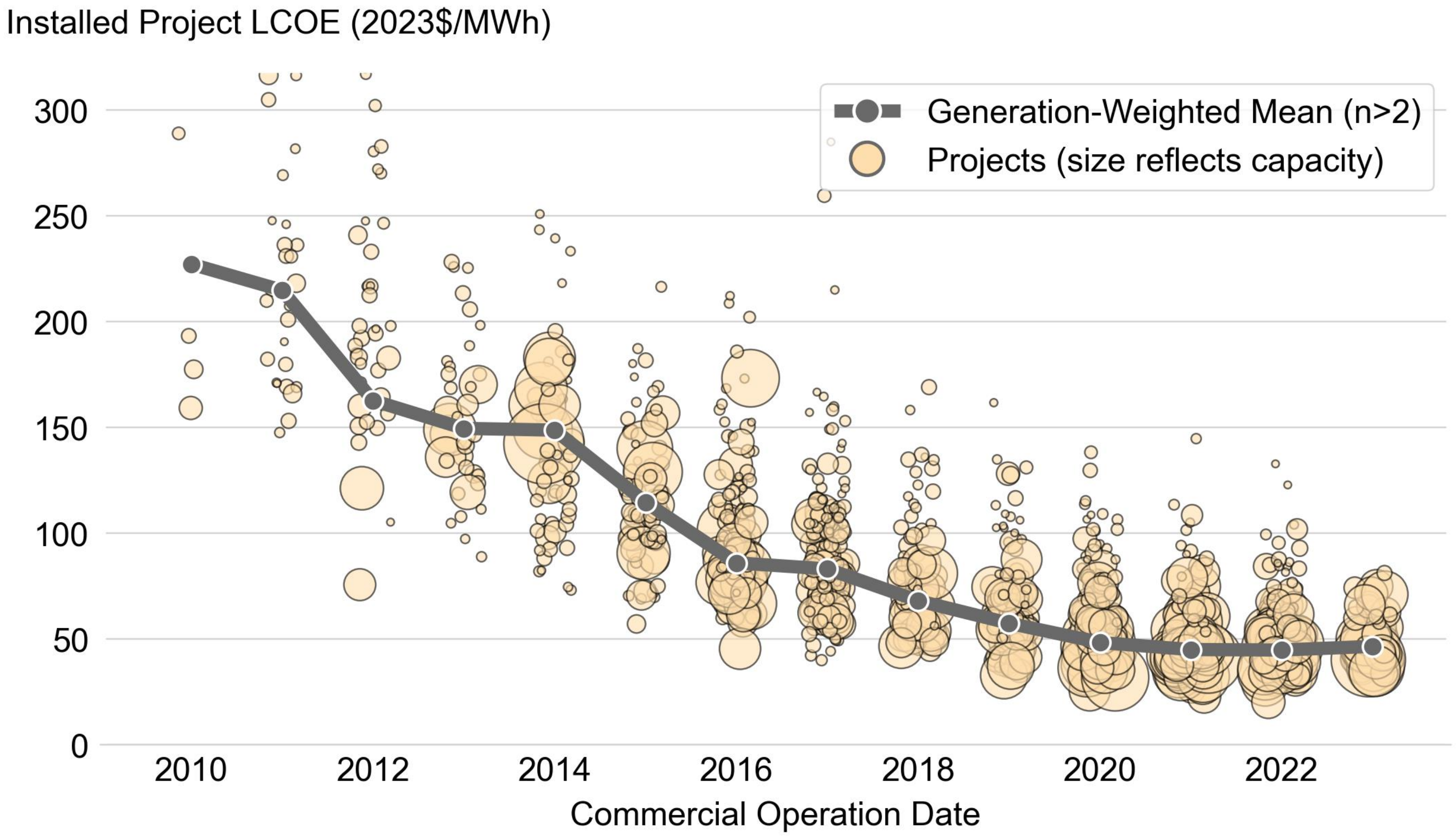
- For our project-level LCOE estimates of solar projects we follow the formula published in NREL's Annual Technology Baseline.
- We use LCOE as proxy for generation costs in later parts of this presentation. It is important to note that additional integration costs (transmission needs beyond what is captured via interconnection costs and LMP congestion components or ancillary service costs) are not fully accounted for here.

Data and Assumptions:

- LCOE will be presented first without and then later with inclusion of federal tax credits (assuming labor requirements for ITC and PTC are met, including Energy Community adders where applicable, but assuming no Domestic Content adders).
- Project-level variation:
  - **Capex:** LCOE is only calculated for projects with empirical cost estimates, only costs of solar components are used for PV-battery projects.
  - **Net Capacity Factor:** We use empirical annual NCF estimates based on EIA 923 data when available. For missing and future years we assume annual degradation rates ranging between 1.47% (pre-2013) and 0.9% (post-2016). For projects without any reported generation (e.g., most recent COD cohort) we use the regional average NCF of recent projects. NCF is levelized over the project design life.
- Cohort-level variation:
  - **OpEx** is levelized and declines from $41/kW$_{DC}$-yr in 2007 to $16/kW$_{DC}$-yr in 2023 (in 2023$, based on prior LBNL and NREL Benchmarks)
  - **Project design life** increases from 21.5 years in 2007 to 35 years in 2021 and thereafter (prior LBNL research).
  - **Weighted average cost of capital (WACC):**
    - based on a constant 70%/30% debt/equity ratio and time-varying market rates.
    - Combined income tax rate of 38.25% pre-2018 and 24.95% post-2017.
    - 5-yr MACRS; forward-looking inflation expectations range from -0.2% (early Covid pandemic) to 4.2%.
    - Real WACC for 2023 COD projects is 2.58%.

Average LCOE (without the ITC/PTC) has been largely stable since 2021

Sample: 1,261 projects totaling 66.3 GW_{AC}



Note: LCOE estimates depicted here do not include tax credit benefits.
Only preliminary data is available for new solar projects coming online in 2023.
Findings may shift as more Capex and project-specific performance data become available.

Utility-scale PV's average LCOE has fallen by 80% since 2010, driven by lower capital costs and operating expenses, as well as increased project design life.

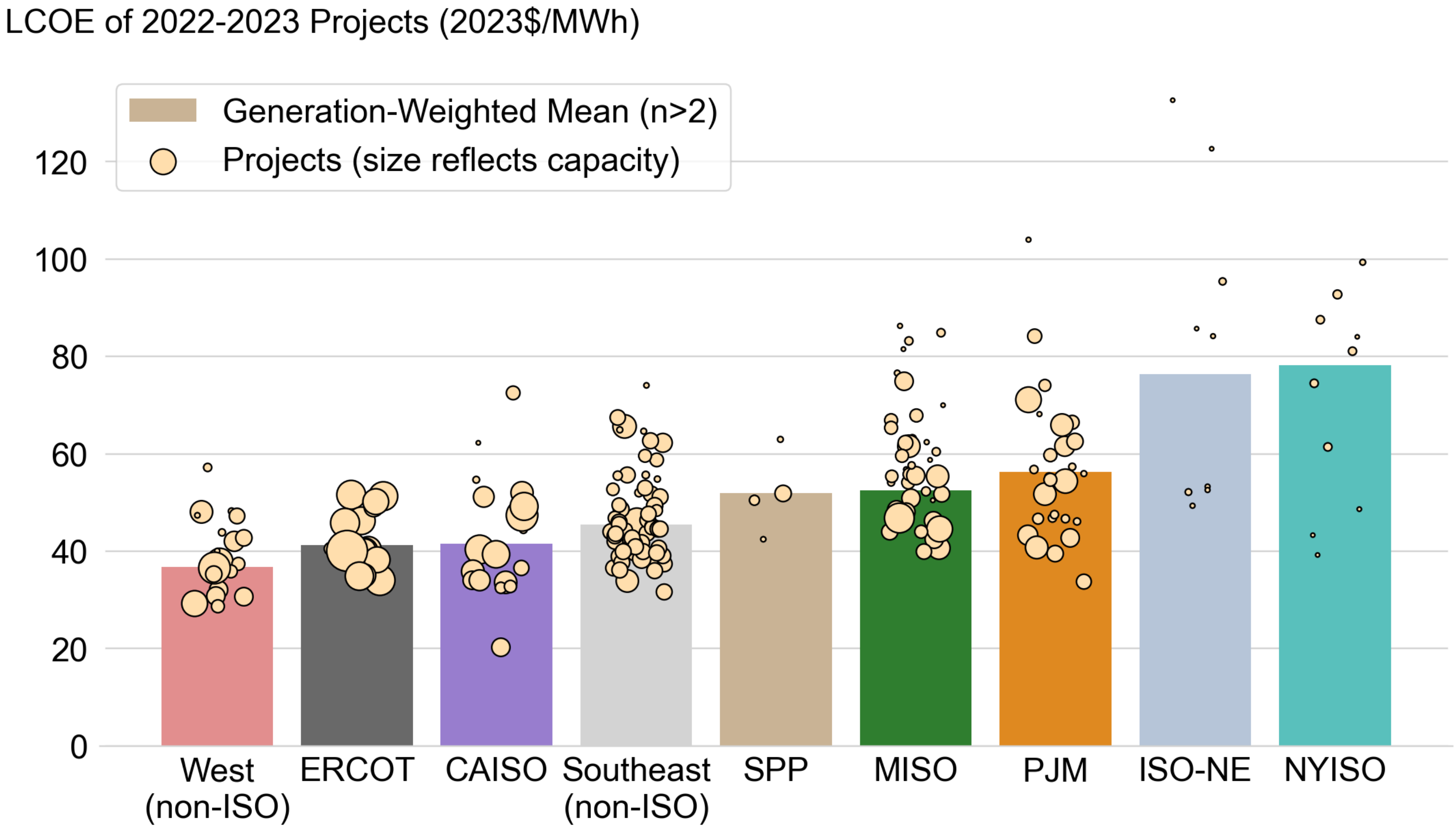
Counteracting these beneficial longer-term trends are falling national average capacity factors since 2016 and less favorable financing terms since 2020.

Average LCOE (not including any tax credits) increased slightly among projects coming online recently, from \$45/MWh in 2022 to \$46/MWh in 2023.

See interactive visualization at https://emp.lbl.gov/capex-lcoe-and-ppa-prices-region

LCOE varies between regions due to differences in solar resource quality, project costs, and system size

Sample: 214 projects totaling 16.9 GW_{AC}



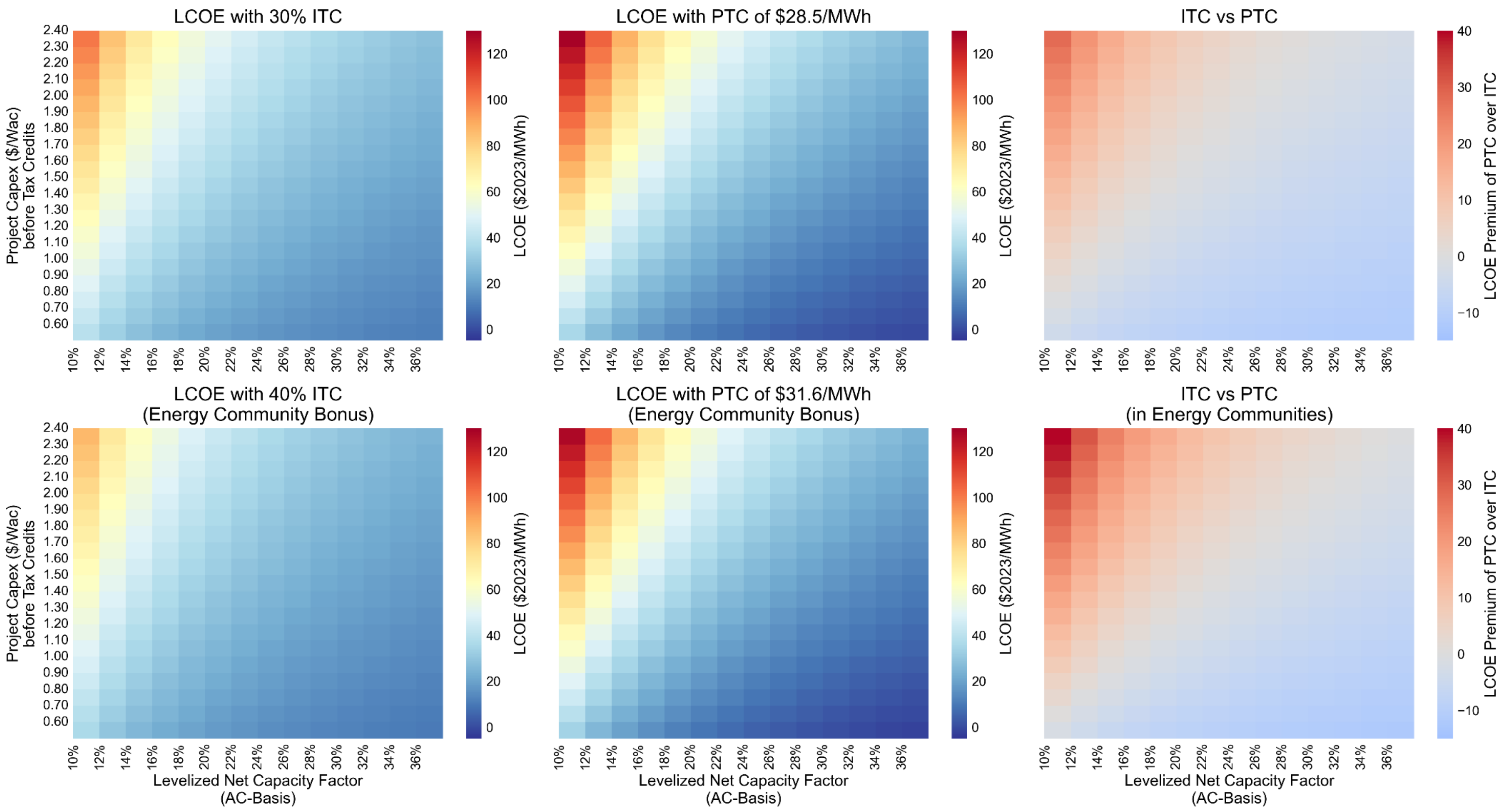
Note: LCOE estimates depicted here do not include tax credit benefits.
Only preliminary data is available for new solar projects coming online in 2023.
Findings may shift as more Capex and project-specific performance data become available.

Lower-insolation regions (ISO-NE, NYISO, PJM, MISO) will always have higher LCOEs than higher-insolation regions (ERCOT, CAISO, the non-ISO West and Southeast), but the difference has narrowed over time.

Among projects coming online in 2022 and 2023, large projects in the non-ISO West, ERCOT, and CAISO had the lowest cost ($37, 41 and $42/MWh), while smaller projects in ISO-NE and NYISO had the highest cost in our sample ($76 and $78/MWh).

See interactive visualization at https://emp.lbl.gov/capex-lcoe-and-ppa-prices-region

Most projects installed in 2023 seem to benefit more from the Production Tax Credit than the Investment Tax Credit



Available federal tax credits lower the effective LCOE shown on the previous slides. The graphs show post-incentive LCOE variation by project capex and performance, both for the Investment Tax Credit (ITC, left) and the new Production Tax Credit (PTC, center). Introduced by the Inflation Reduction Act, the PTC is paid for the first 10 years ($28.5/MWh and rising with inflation) – levelized over a 35-year project lifetime it reduces LCOE by ~$14.5/MWh.

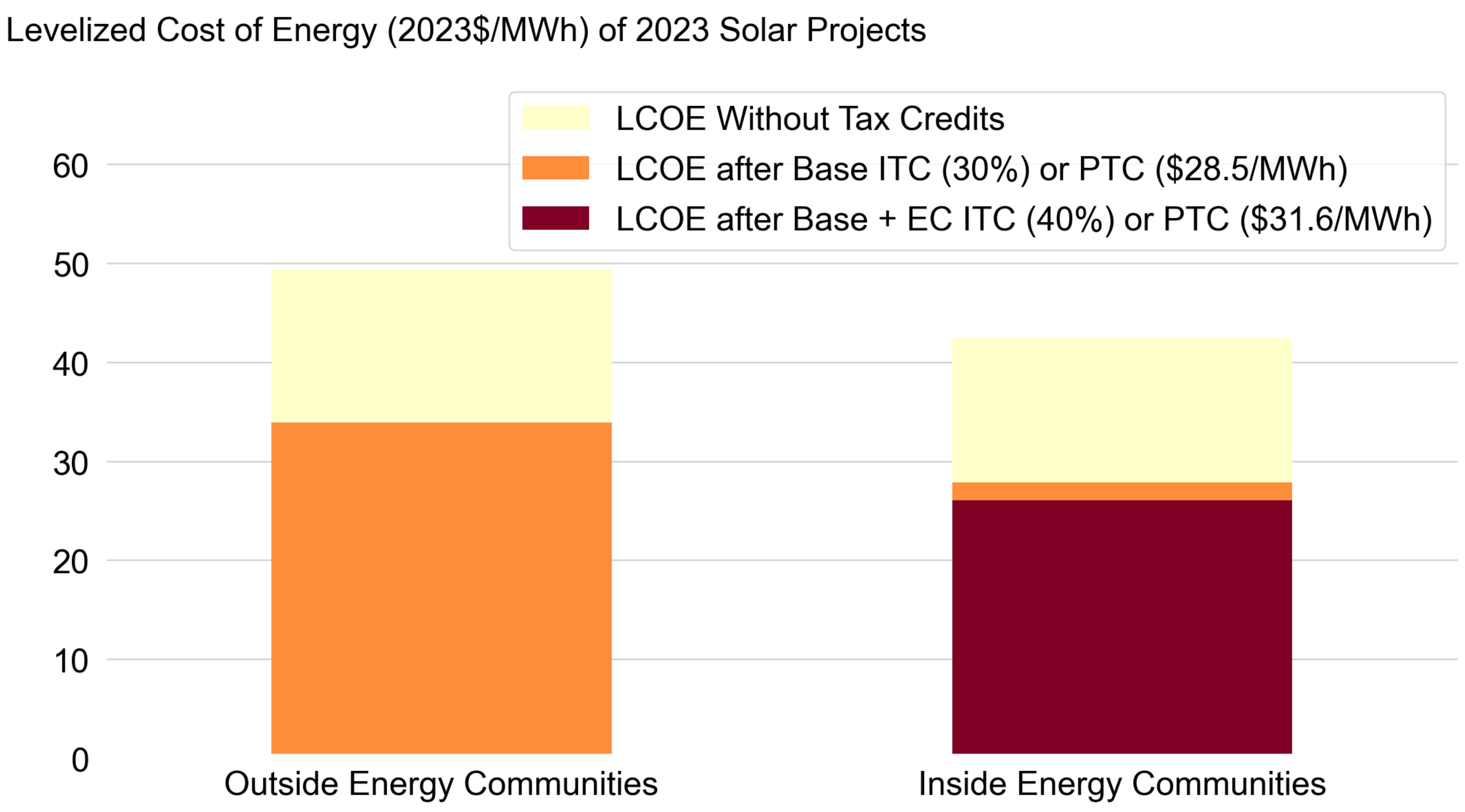
The right column compares the benefit of each tax credit, with red squares showing where the ITC results in a lower LCOE (higher-cost, lower-performing projects) and the blue squares showing where the PTC is preferable (lower-cost, higher-performing projects).

For the 2023 COD cohort, preliminary data indicates that most projects (54 out of 74) would benefit more from the Base PTC than the ITC (although the PTC comes with some challenges such as greater performance risk that we do not account for in this comparison).

The lower column repeats the analyses but includes the bonus adder available for projects sited in Energy Communities (more details on the next slide).

2023 solar projects in Energy Communities have an average after-tax credit LCOE of $26/MWh, compared to $34/MWh in the rest of the country

Sample: 75 projects totaling 7.1 GW_{AC} (23 EC projects, 3.1 GW_{AC})



Note: Only preliminary data is available for new solar projects coming online in 2023. Findings may shift as more Capex and project-specific performance data become available.

About half of all new utility-scale solar capacity in 2023 qualifies for the Energy Community Tax Credit Adder. Not considering potential Domestic Content adders, these project are eligible for a 40% ITC or a $31.6/MWh PTC over the first 10-years ($2023) – equivalent to $16.1/MWh levelized over a project's lifetime.

Using a simple multivariate regression model, solar projects in Energy Communities in our sample are on average $0.22/$W_{AC}$ cheaper than similarly designed projects outside of Energy Communities, contributing to a lower LCOE before any tax credits are applied.

The ITC benefit over the PTC increases if additional adders (like Energy Community or Domestic Content) are available for a project, but even among our 23 projects in Energy Communities, 16 have a lower LCOE with the PTC than the ITC.

Power Purchase Agreement (PPA) price analysis: data sets and methodology

PPA prices are from utility-scale solar plants built since 2007 or planned for future installation, and include:

- 472 PV-only contracts totaling 36.8 GW_{AC}
- 104 PV+battery contracts totaling 13.0 GW_{AC} of PV capacity and 7.8 GW_{AC} / 30.9 GWh of battery capacity (presented in a later section)
- 5 concentrating solar thermal power (CSP) contracts totaling 1.2 GW_{AC} (presented in a later section)

PPA prices reflect the bundled price of electricity and RECs as sold by the project owner under the PPA

- Dataset excludes merchant plants, projects that sell renewable energy certificates (RECs) separately, and most direct retail sales
- PPAs are priced to recover both capital and other ongoing operational costs while accounting for the receipt of state and federal incentives (e.g., the ITC) and, as a result, do not simply reflect solar generation *costs.* Ultimately PPA prices reflect marketplace conditions, including the supply of ready-to-build plants, cost of capital, and demand for energy, capacity, and RECs.

Data collection

- We gather PPA price data from a combination of FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, and trade press articles. We prioritize data quality over quantity in this process. That is, we only include a PPA within our sample if we have high confidence in all of the key variables such as execution date, starting date, starting price, escalation rate (if any), time-of-day factor (if any), and term.
- To augment our PPA price sample, and to gain visibility into corporate PPA pricing (which is not well-represented within our sample), we also compile LevelTen Energy[1] and Trio[2] data on PPA offers (25th percentile). These often reflect shorter contract durations and target voluntary and corporate offtakers, though fewer contract specifics are known relative to the PPA data we collect directly.

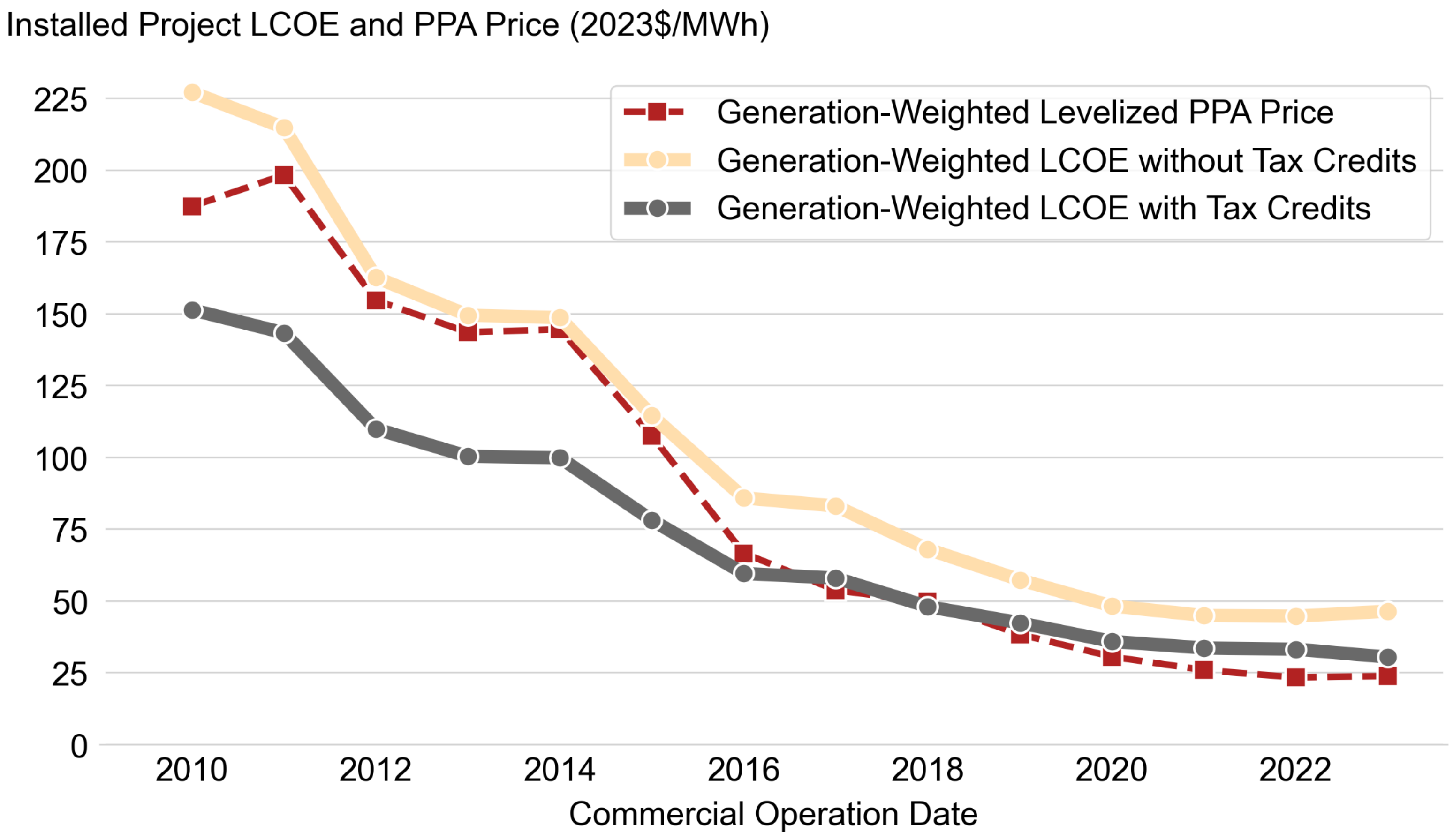
Levelization methodology

- We deflate the nominal dollar price series to 2023 dollars using a GDP deflator (actual deflators historically, along with projected future deflators), and then levelize the resulting price series using a 4% real discount rate.
  - For PPA prices we collect, prices are levelized over the full term of each contract, after accounting for any escalation rates and/or time-of-delivery factors.
  - For LevelTen Energy and Trio, we assume the reported prices are for 12-year, flat-priced (in nominal dollars) PPAs that commence in the following calendar year.

[1] https://www.leveltenenergy.com/ppa
[2] https://www.trioadvisory.com/publications

Since 2016, levelized PPA prices have tracked the LCOE accounting for tax credits of utility-scale PV

Sample: 1,266 projects totaling 66.3 GW_{AC}



Note: Only preliminary data is available for new solar projects coming online in 2023. Findings may shift as more Capex and project-specific performance data become available.

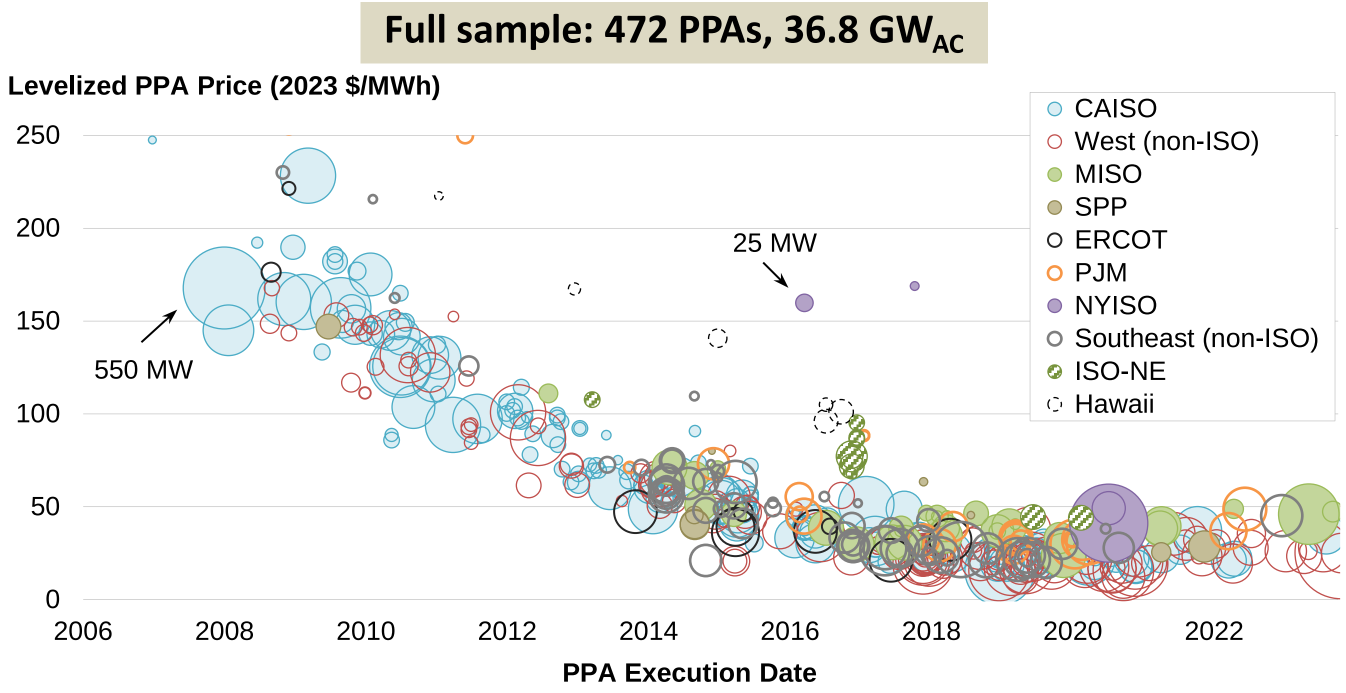
This graph contrasts solar LCOE with and without tax credits - choosing either PTC or ITC for each project that results in lowest cost (not including Domestic Content adder).

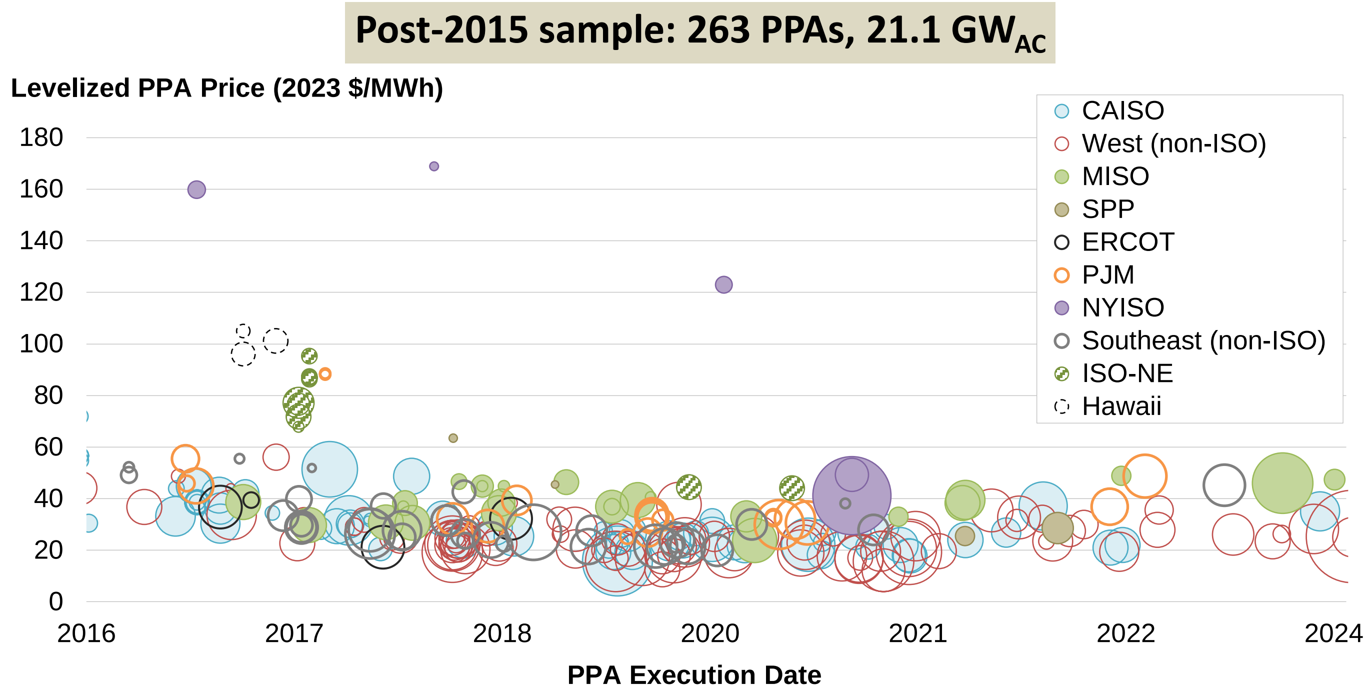
With new tax credits becoming available in 2023 we see for the first time since 2010 a widening gap between pre- and post-incentive LCOE.

While generation-weighted average LCOE increased slightly in 2023 before the application of tax credits ($46.5/MWh vs. $44.8 in 2022), post-credit LCOE continued to fall ($30.5/MWh vs. $33.3/MWh).

Since 2016, levelized PPA prices charted by plant COD have closely tracked or hovered slightly below the LCOE with tax credits. This suggests a pass-through of these tax credits and a competitive PPA market.

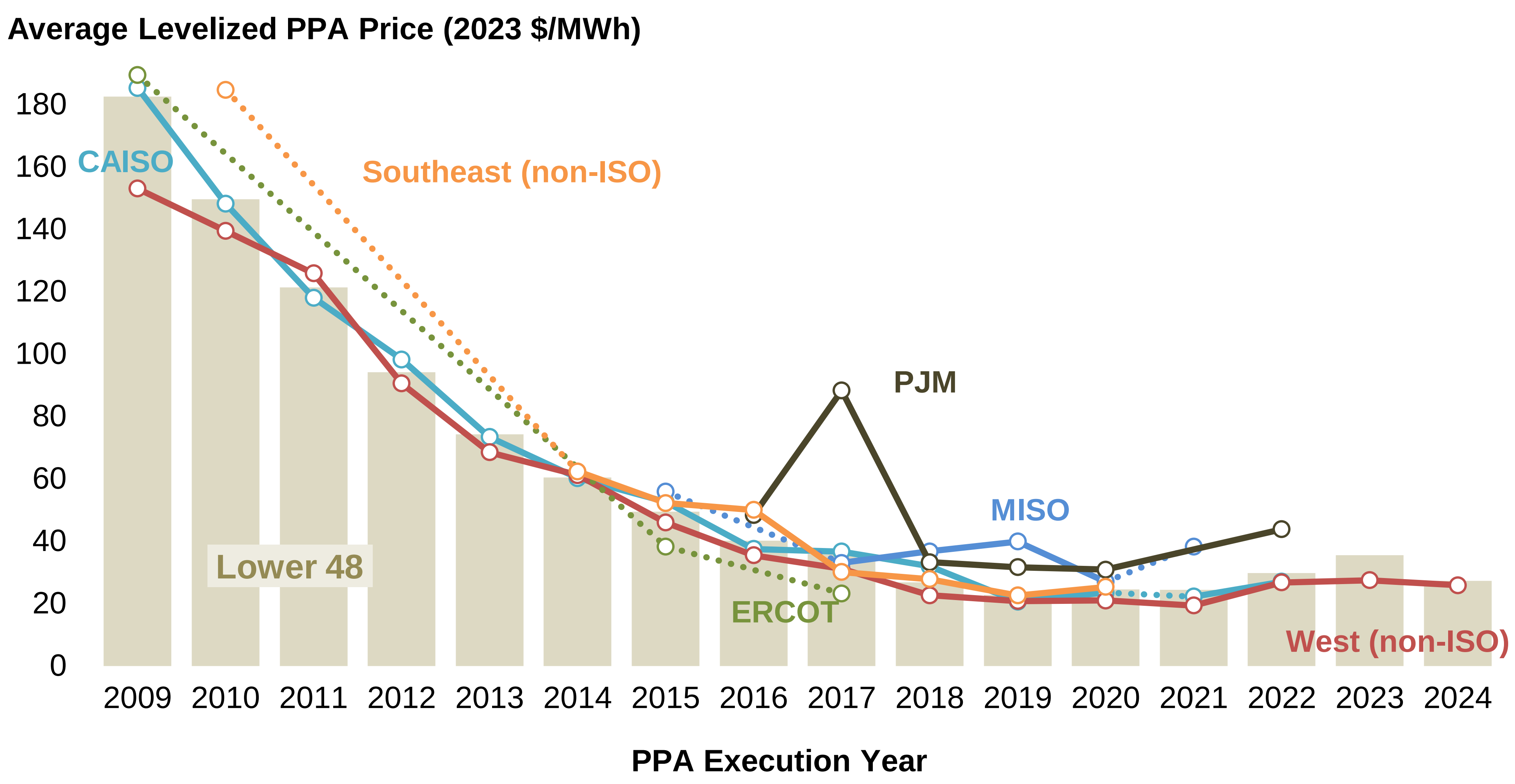
Individual PPAs typically follow the national price trend, though there are high-price outliers for projects in NY, HI, and New England





- Power Purchase Agreement (PPA) prices are levelized over the full term of each contract, after accounting for any escalation rates and/or time-of-delivery factors, and are shown in real 2023 dollars
  - Contract term is between 20 and 25 years (inclusive) for 76% of projects in the full sample
- >95% of the sample is currently operational
- Aided by the 30% ITC, PPAs in our sample executed in 2021 or later are usually priced around $20-$30/MWh for projects in CAISO and the non-ISO West, and $35-$47/MWh for projects elsewhere in the continental United States

Average PPA prices in the Lower 48 fell by ~88% (or ~19%/year) from 2009-2019, but have been stagnant or rising ever since



This graph focuses on national and regional average PPA prices, rather than project-level (as in the prior slide).

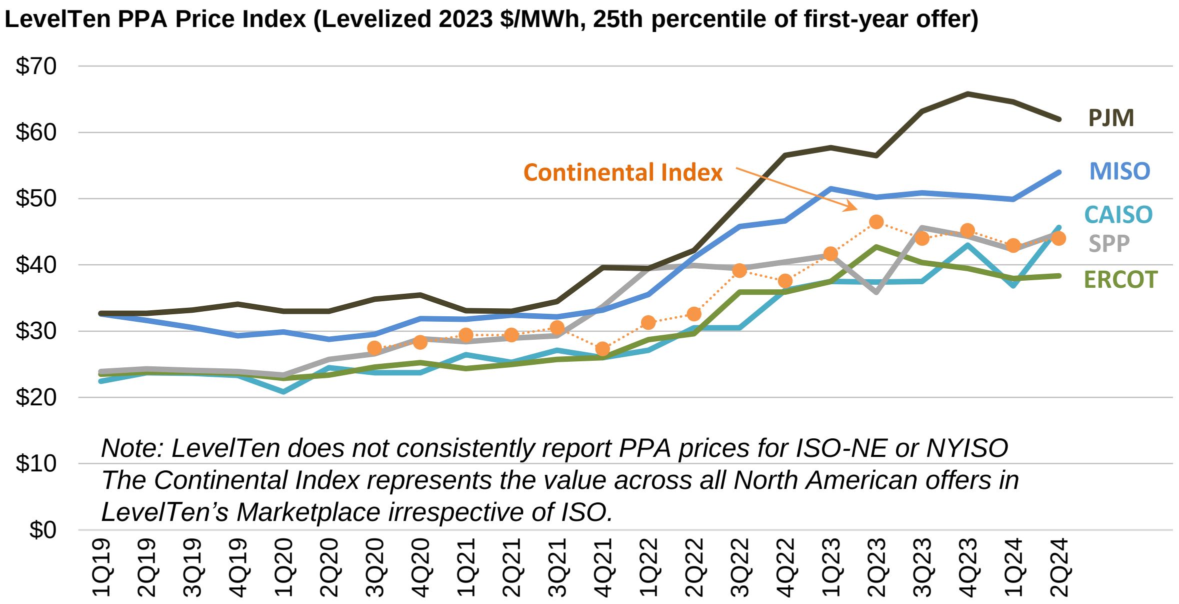
The generation-weighted national average was $35/MWh in 2023 (based on a small sample of 7 PPAs), up considerably from 2019's low of $23/MWh.

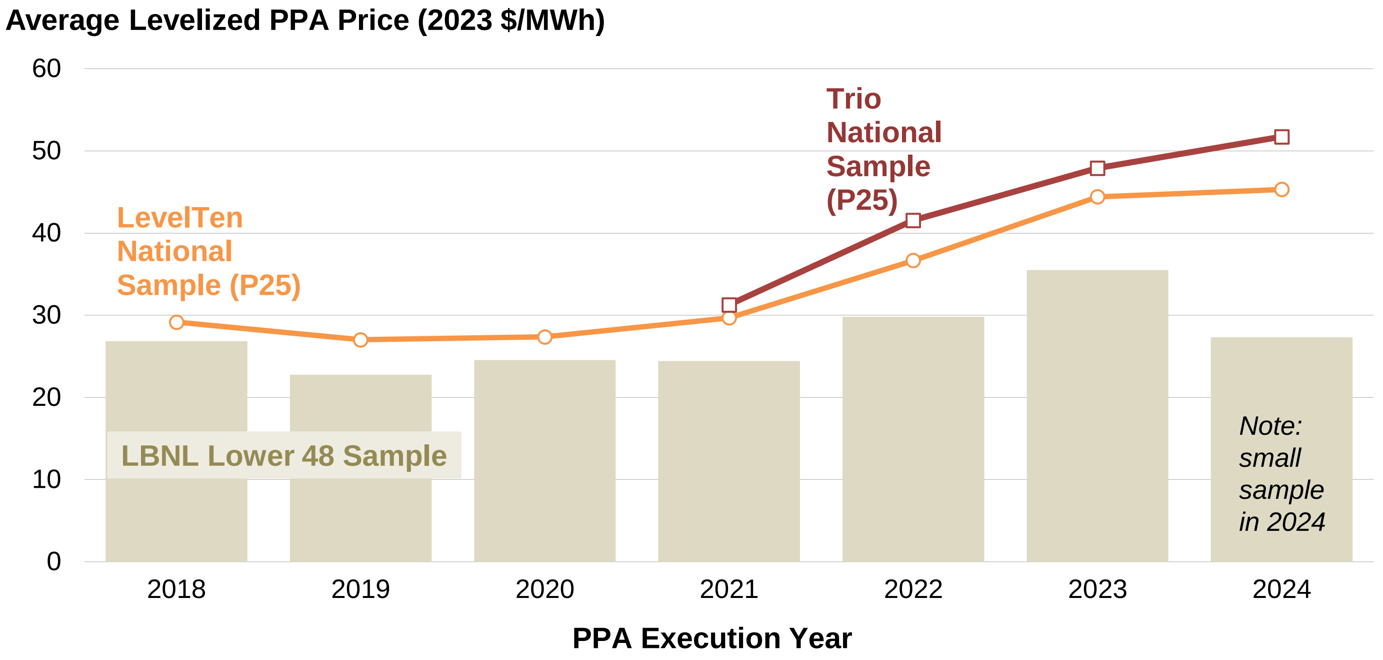
Year-Region combinations with fewer than 2 PPAs are excluded from the graph (dashed line segments indicate that the line is skipping over such years).

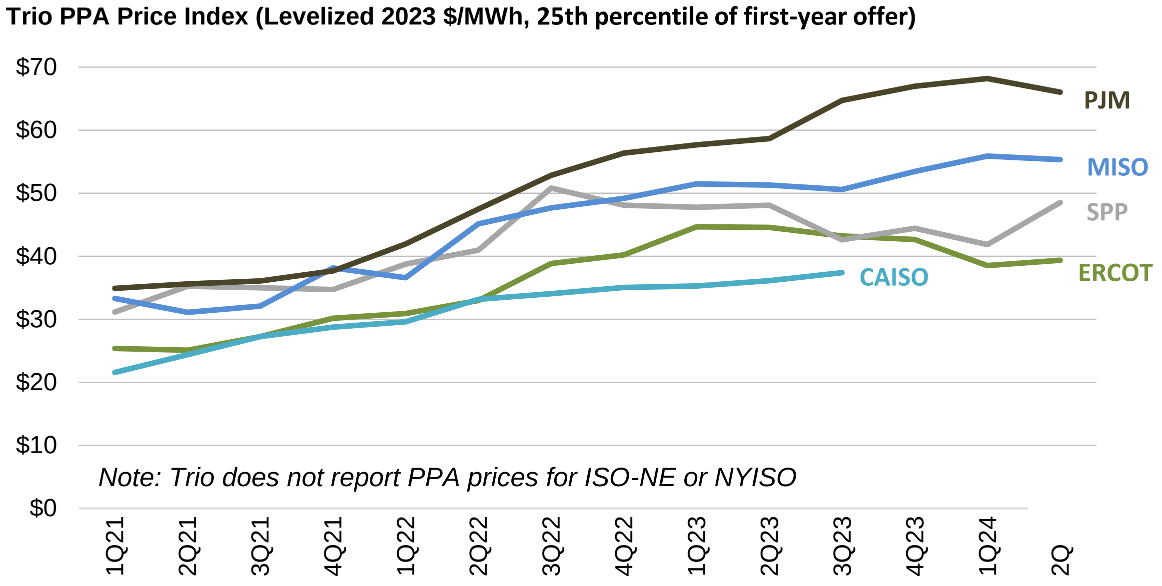
The graph reflects PV-only pricing, not PV+battery (PV+battery PPA prices are presented separately, in a later section).

You can explore this data interactively at https://emp.lbl.gov/pv-ppa-prices

LevelTen Energy and Trio's utility-scale PV PPA price indices match the increasing trend seen in the LBNL sample since 2021





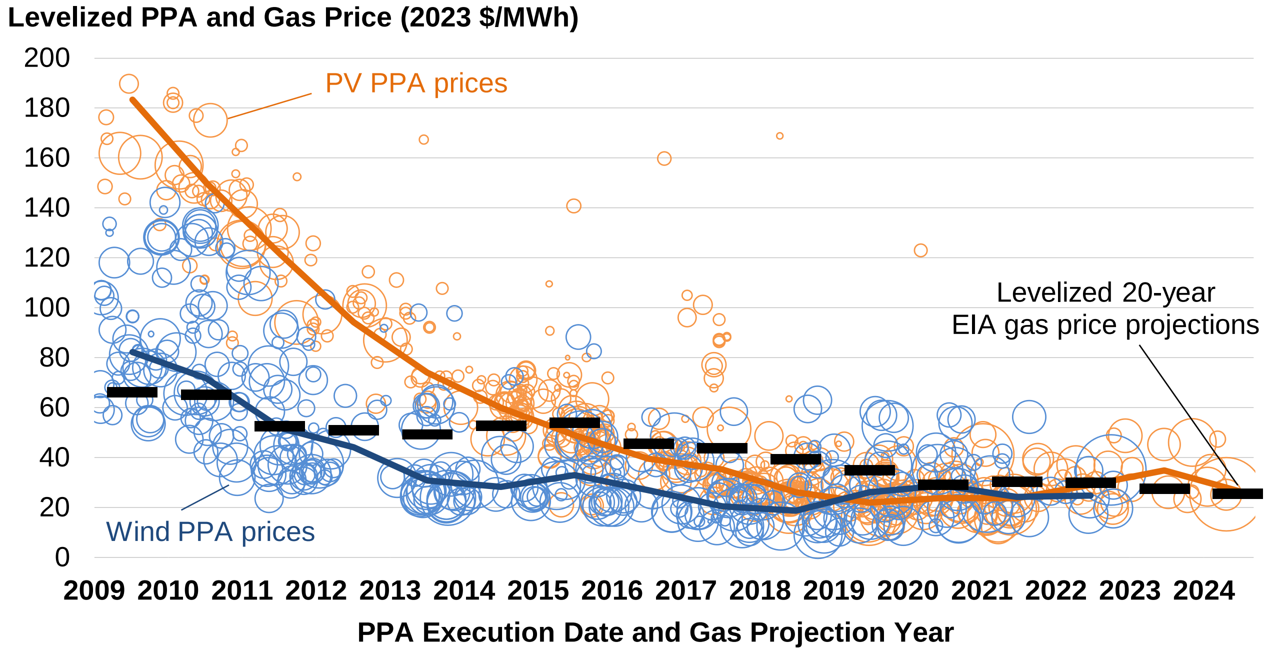


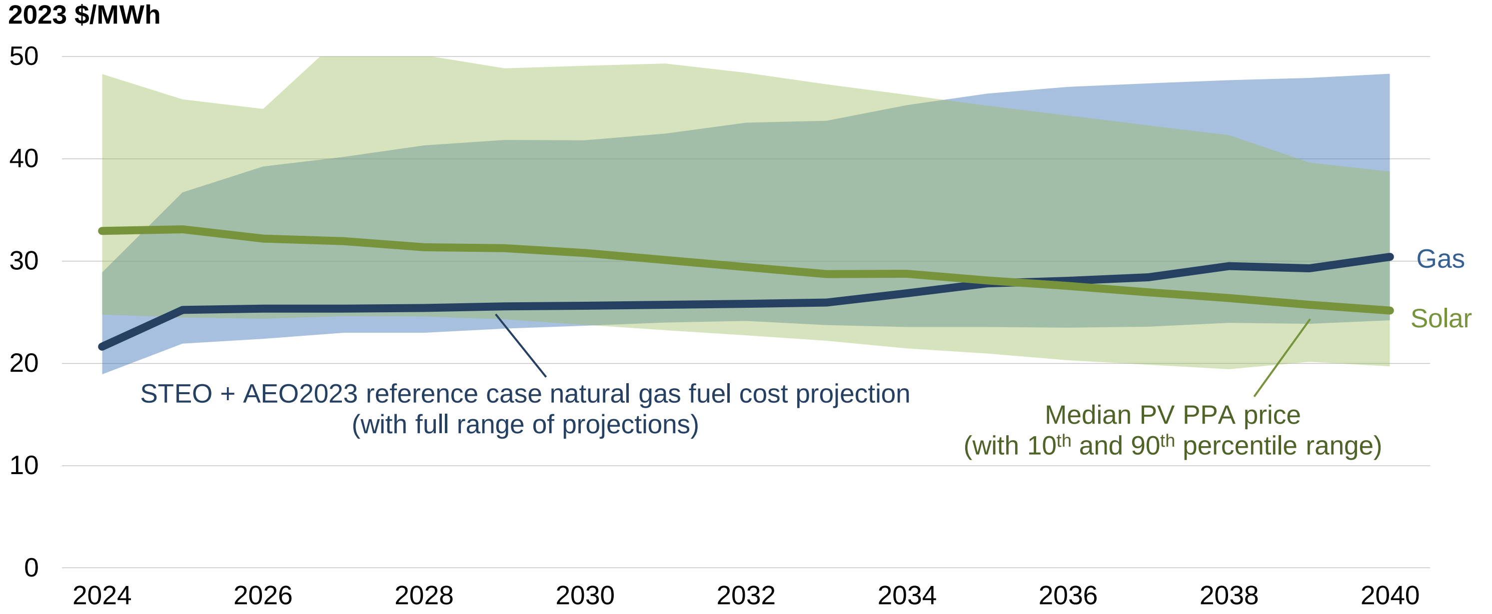
To augment our PPA price sample, and to gain visibility into corporate PPA pricing (which is not well-represented within our sample), we present LevelTen Energy and Trio's PPA price indices.

Drivers of PPA price increases in recent years include:

- High interest rates leading to higher financing costs
- Long lead times for high- and medium-voltage equipment
- Supply constraints by these equipment lead times and long interconnection and permitting timelines
- High demand from corporations and utilities in advance of 2025 and 2030 emissions targets

Solar PPA prices are competitive with wind. Recent declines in natural gas prices give *existing* gas-fired generators a near-term cost advantage.





The left graph shows that solar PPA prices have largely closed the gap with wind, and some contracts are competitive with levelized gas price projections.

The right graph compares recent (2022-24 execution date) solar PPA prices (extending over their contract terms through 2040) to the range of gas price projections from the EIA's Annual Energy Outlook 2023 (AEO 2023) and Short-Term Energy Outlook (STEO). Gas price projections through 2025 have dropped considerably compared to expectations one year ago. PV can help hedge against fuel price risk in the short to medium-term, and by the mid-2030s most PV is projected to be competitive with the cost of burning fuel in an ***existing*** combined-cycle natural gas unit (NGCC).

Note that PV PPAs are priced to recover both *capital* and other *ongoing operational costs*—for a new NGCC, this would add another ~$20-$80/MWh (per *Lazard* data) to the projected fuel costs shown in the graphs.

Wholesale Market Value, Air and Climate Benefits, and Net Value

Wholesale market value analysis: data sets and methodology

We estimate the wholesale market value for each utility-scale PV project larger than 1 MW (as reported on Form EIA-860). Each project-level estimate may be prone to some biases - greater emphasis should thus be placed on the aggregate generation-weighted averages which we calculate for all seven ISOs and ten additional balancing authorities.

We draw from project-level modeled hourly solar generation (using NREL's System Advisor Model and site- and year-specific insolation data from NREL's National Solar Radiation Database and NOAA's High Resolution Rapid Refresh Model) and de-bias the generation by leveraging ISO-reported aggregate solar generation and plant-level reported generation by Form EIA-923. Hourly curtailment data is either derived from plant-level reports (ERCOT: HSL minus MW) or allocated from ISO-level reports (CAISO).

Energy value is the product of hourly solar generation by plant or county and concurrent wholesale energy prices

- Plant-level debiased hourly solar generation
- Real-time energy price from
  - nearest LMP node (ISOs, CAISO's + SPP's EIM BAs)
  - gateway node from nearby ISO / FERC Lambda for some BAs

$$Energy\ Value = \frac{\sum Postcurtailment\ Generation_h * Wholesale\ RT\ Energy\ Price_h}{\sum Precurtailment\ Generation_h}$$

Capacity value is the product of a plant's or county's capacity credit and capacity prices

- Capacity credit based on plant-level profile; varies by month, season, or year
- Capacity prices from respective ISO region; prices vary by month, season, or year
- Estimate bilateral capacity prices for regions without organized capacity markets
- Focus on annual value of solar for projects with a full calendar year of operation
- Calculate capacity value for all solar, even if some solar does not participate in capacity markets

$$Capacity\ Value = \frac{\sum Capacity\ Credit_T * Nameplate * Capacity\ Price_T}{\sum Precurtailment\ Generation_T}$$

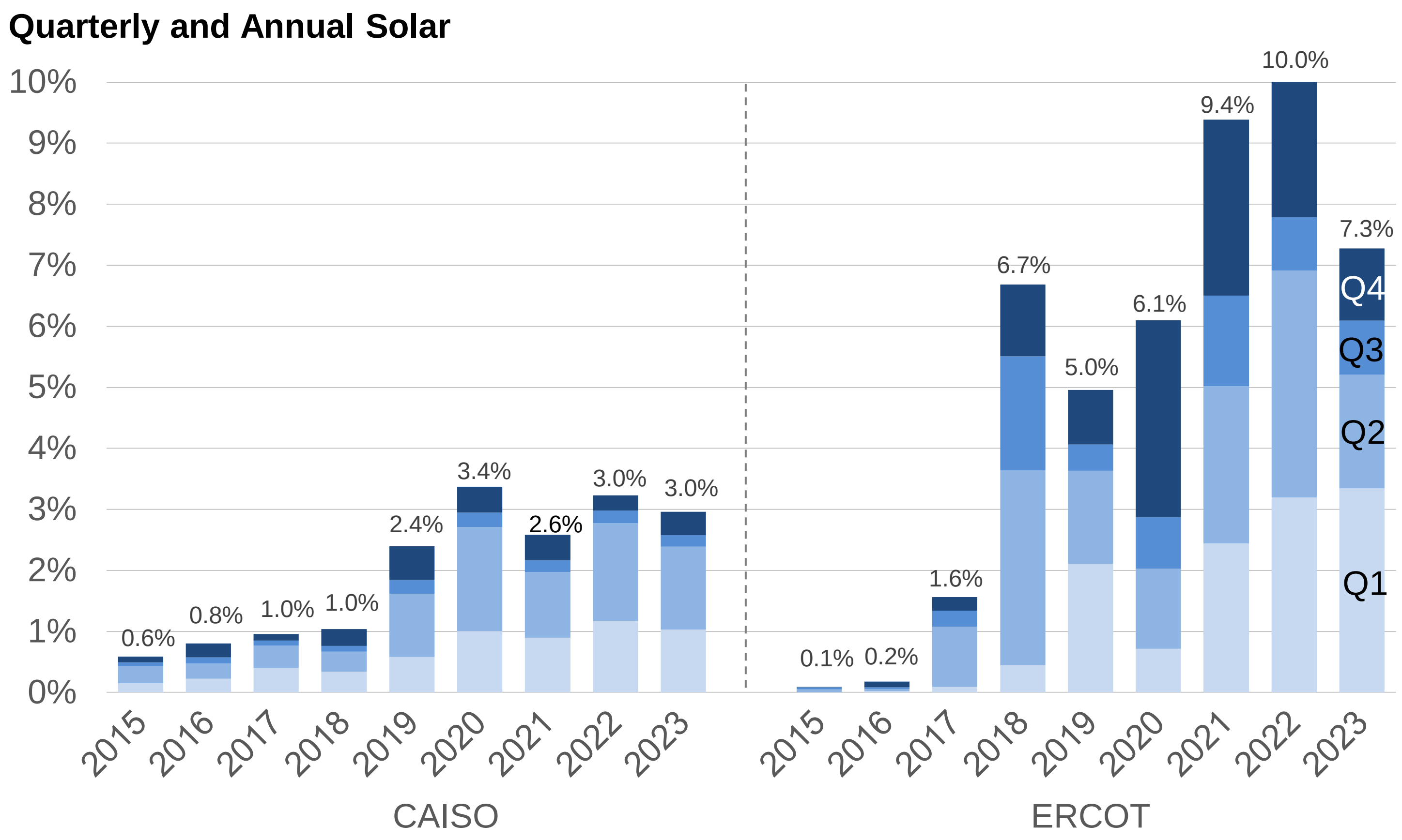
Market value vs. Generation costs and Environmental benefits: Scope of value comparisons and methods

- **Total wholesale market value** is simply the sum of solar's energy and capacity value
  - It represents the "replacement costs" of what an offtaker would have to pay in the wholesale market had they not procured solar generation. Revenues for a solar project owner are set by their PPA terms and may differ from our estimate. However, in a market with little friction, we expect long-term convergence.
  - It does not include any potential additional revenue streams (ancillary service (AS) revenues, renewable energy credits, infrastructure deferral, or resilience that are not already internalized in wholesale energy and capacity markets).
  - It is based on the real-time LMP market and thus reflects the marginal solar value. It does not fully consider sub-hourly variability and forecast errors.
  - It excludes broader sectoral impacts such as merit-order effect on power prices or reduced natural gas demand and associated price declines.

- **Generation costs** are approximated by LCOE (with and without tax credits), but do not include:
  - Full integration costs (AS) or transmission needs (beyond LMP congestion components and interconnection network upgrade costs).
  - The full cost to the Treasury of federal investment and production tax credits.
  - Other costs and benefits to local communities and ecosystems.
  - LCOE sample is matched to market value sample on slide 53, but only reflects a subset of solar projects that contribute to the environmental benefits on slide 54 (LCOE projects are greater than $5MW_{AC}$ with some 2022 COD projects missing).

- **Health and climate benefits** are approximated by the marginal avoided emission rate * damage per ton of pollutant emitted
  - Avoided emissions rates are regression results leveraging hourly generation data by source type, accounting for imports and exports between regions, and time shifting of impacts through redispatch of hydropower. Coal and gas emissions data are used to determine the emissions avoided from solar in each region.
  - Health benefits are a function of the total mass of pollutants avoided and where those reductions occur based on a suite of reduced-complexity air quality health impact models.
  - Climate benefits are calculated as a function of the social cost of carbon, as described in EPA's Report on Social Cost of Greenhouse Gases (2023).
  - We represent central estimates ($125/MWh) from range of plausible values (5%: $38/MWh , 95%: $303/MWh)

Solar curtailment was 3.0% in CAISO and 7.3% in ERCOT in 2023. Other ISOs and regions do not yet report curtailment.



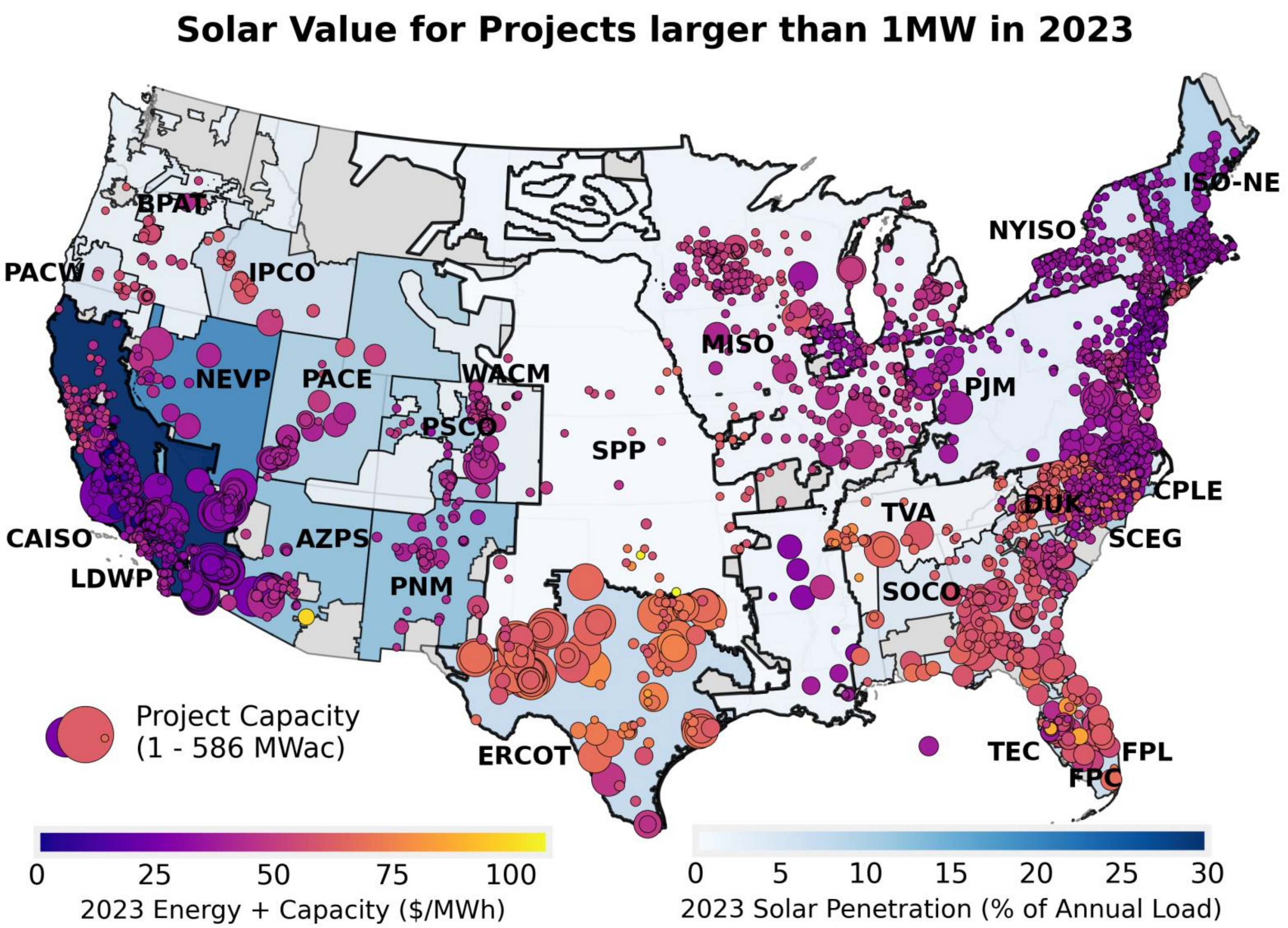
The *rate of curtailment* was much higher in ERCOT (7.3%) than in CAISO (3.0%) in 2023, even though solar's penetration rate is far lower in ERCOT (7%) than CAISO (27%). Most of ERCOT's curtailment occurs in the western part of Texas, driven by transmission/pipeline congestion and excess local electricity production (prices for natural gas, a byproduct of oil production, were at times negative in 2023 in the Permian Basin).

CAISO had 2,051 GWh of solar curtailed in 2023, equivalent to the annual output of a hypothetical 816 MW_{AC} tracking PV project operating at an average CA capacity factor of 28.7% (which would have been 29.6% if not for curtailment).

ERCOT had 2,500 GWh of solar curtailed in 2023, equivalent to the annual output of a hypothetical 1142 MW_{AC} tracking PV project operating at an average TX capacity factor of 25.0% (which would have been 27.0% if not for curtailment).

Note: The data shows ISO-wide solar curtailment relative to total solar production (sum of utility-scale and distributed solar)

Solar's energy and capacity value varied by location



Note: Marker size shows project capacity while marker color shows market value.

Solar's average energy and capacity value in 2023 varies from one region to another: It was lower in CAISO at $27/MWh, but high in many southeastern balancing authorities ($48-65/MWh), ERCOT ($67/MWh), SPP ($58/MWh), and the Pacific Northwest ($48-58/MWh).

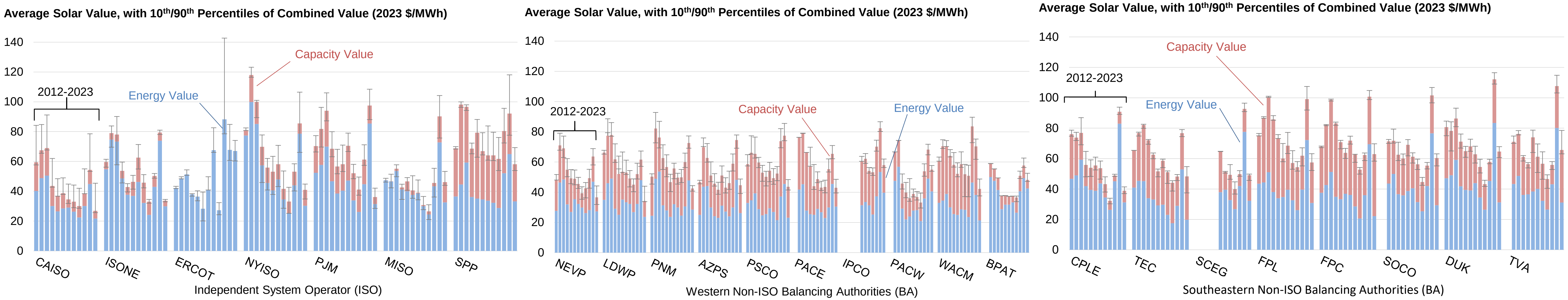
But value also varies within regions, driven by transmission congestion, solar resource quality or differing use of technology like trackers.

For example, in CAISO the northern zone has typically higher average values than the southern zone. Solar in southern SPP and NYISO was nearly $20/MWh more valuable than solar in the north of the ISOs.

Other markets like ISO-NE show very little variation in annual average value between projects (10^{th} vs. 90^{th} percentile had a difference of less than $2/MWh).

You can explore this data interactively at https://emp.lbl.gov/utility-scale-solar-value

Solar's average energy and capacity value across the U.S. was $45/MWh in 2023, similar to pre-pandemic levels



Energy value typically makes up the bulk of total market value. After high natural gas prices in 2022, solar's average energy value across the US returned to more normal levels in 2023 of $34/MWh.

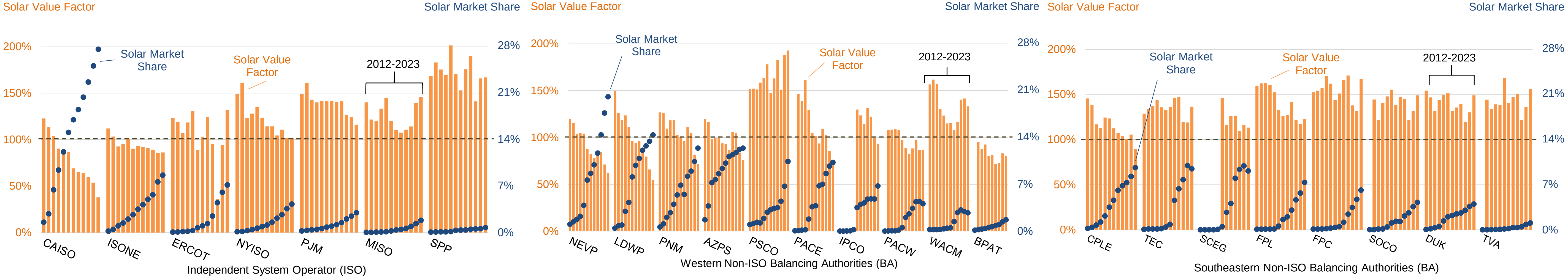
Capacity value is more significant in the non-ISO regions and can add $30-40/MWh in some BAs, where capacity prices are high (e.g., SERC region) and where the solar profile is still well aligned with peak netload hours.

Variation across years mostly reflects fluctuations in wholesale power prices, but also shows how increasing solar penetration can dampen solar's value (e.g., CAISO).

In 2023, combined energy and capacity value was lowest in CAISO ($27/MWh) and highest in ERCOT ($67/MWh). Even though ERCOT reduced its price cap from $9000/MWh to $5000/MWh in 2023, summer heat waves and associated record demand levels contributed to high prices that allowed solar to capture value at 2022 levels.

Note: The data shows generation-weighted average annual market value of all large-scale (1 MW+) solar projects in select Balancing Authorities.

Solar’s value factor tends to decline as solar serves a higher share of a region’s load



The columns represent the solar value factor (left axis), the dots show growth in solar market share (right axis)

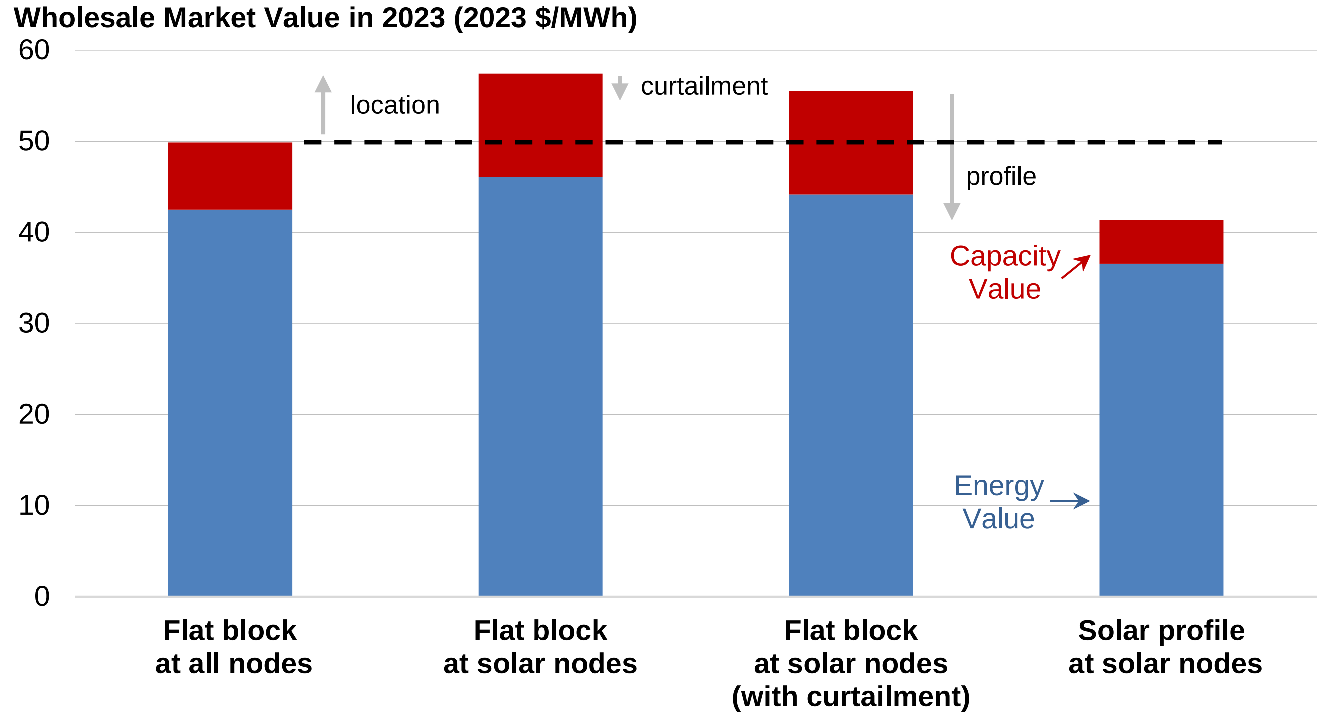
The 'Value Factor' is defined as the ratio of solar’s total market value (including both energy and capacity) to the market value of a 'flat block' of power (i.e., a 24x7 block). It indicates whether solar’s total revenue is above or below the average wholesale revenue, with generators delivering electricity during high-value hours achieving a value factor above 100%.“

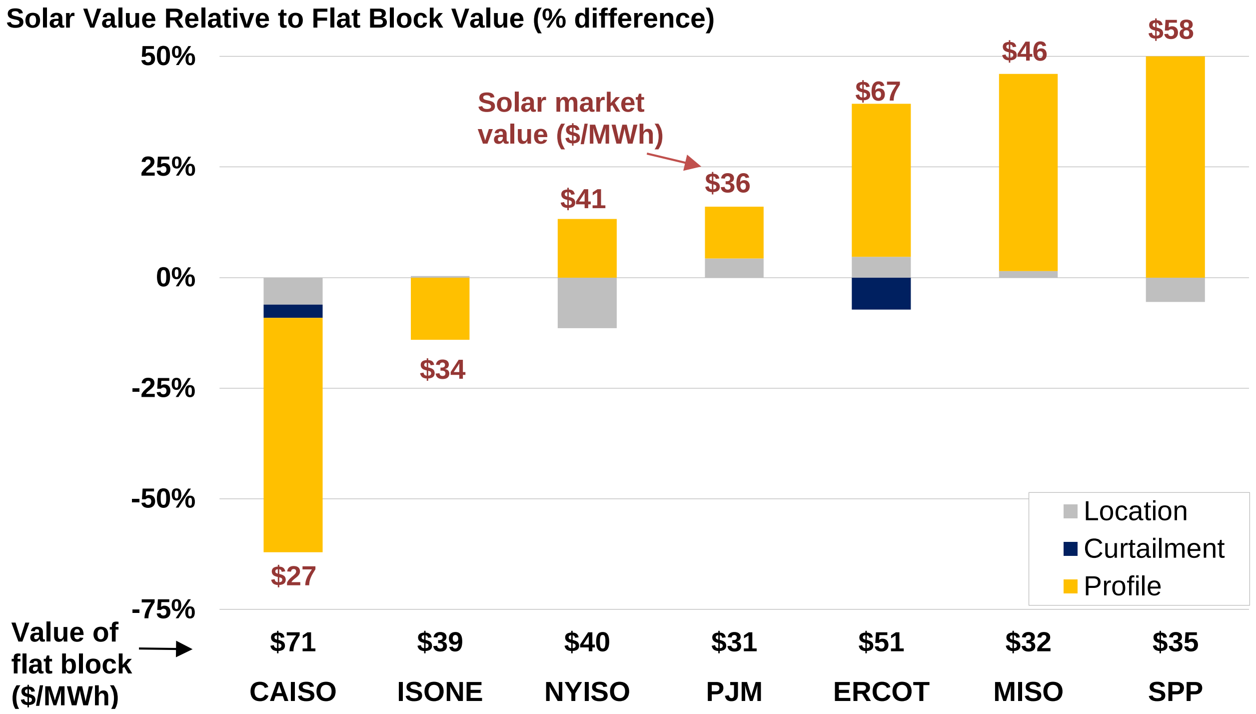
It controls for fluctuations in energy and capacity prices across years (and across ISOs) and focuses instead on the impact of solar’s generation profile (and penetration) on value.

Most regions with the highest solar market shares show Value Factors less than 100%, even just 38% in CAISO. However, in many southeastern BAs solar still provides above-average value despite approaching 10% penetration.

Note: IPCO and SCEG did not have solar projects larger than 1 MW_{AC} operating in the early years. Solar market share in those years only reflects contribution of distributed PV.

Solar’s generation profile was the largest source of value differences between solar and a flat block in 2023

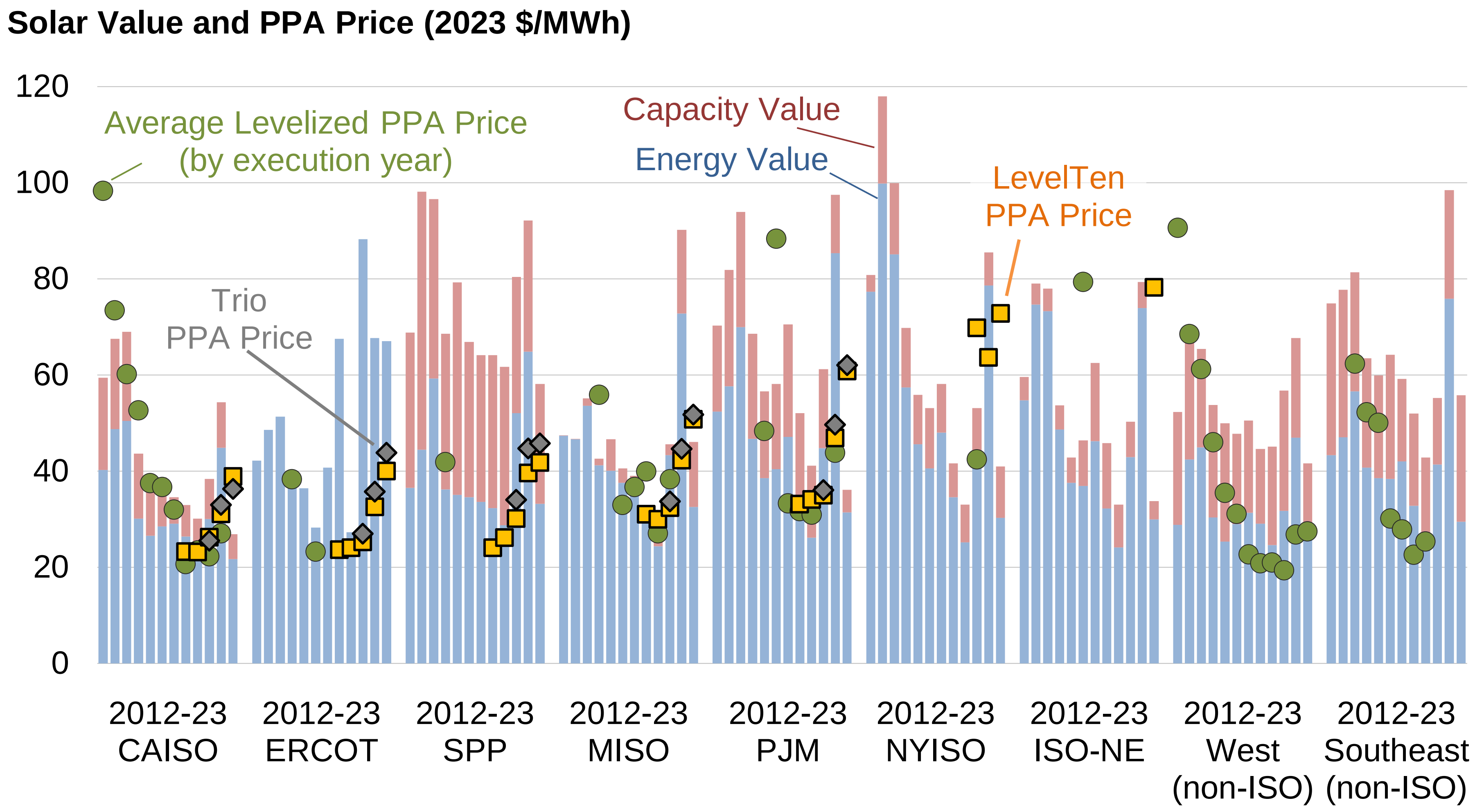




Across the seven ISOs, solar projects were usually sited at locations with above average energy values. The large amount of solar deployed in areas with lower relative value (particularly CAISO) yields a value factor of 82% across all solar projects in the ISOs.

Solar’s generation profile has the largest impact and either hurts (in CAISO, ISO-NE) or helps (in SPP, MISO, ERCOT, PJM, NYISO) solar’s value relative to a flat block. Curtailment is becoming a growing issue for solar in ERCOT.

Market Value vs. PPAs: Rising prices for new PPAs started to exceed solar's wholesale market value in some regions in 2023



PPAs provide the power purchaser a hedge value for price fluctuations over 10 to 20 years. While we show price trends by individual years, a true benefit accounting should span the length of the PPA contract. PPA prices are influenced by solar's generation costs, solar's wholesale market "replacement costs", and broader supply and demand dynamics.

Solar's market value has declined over time within several regions. Falling PPA prices had largely kept pace until PPAs started rising in 2021.

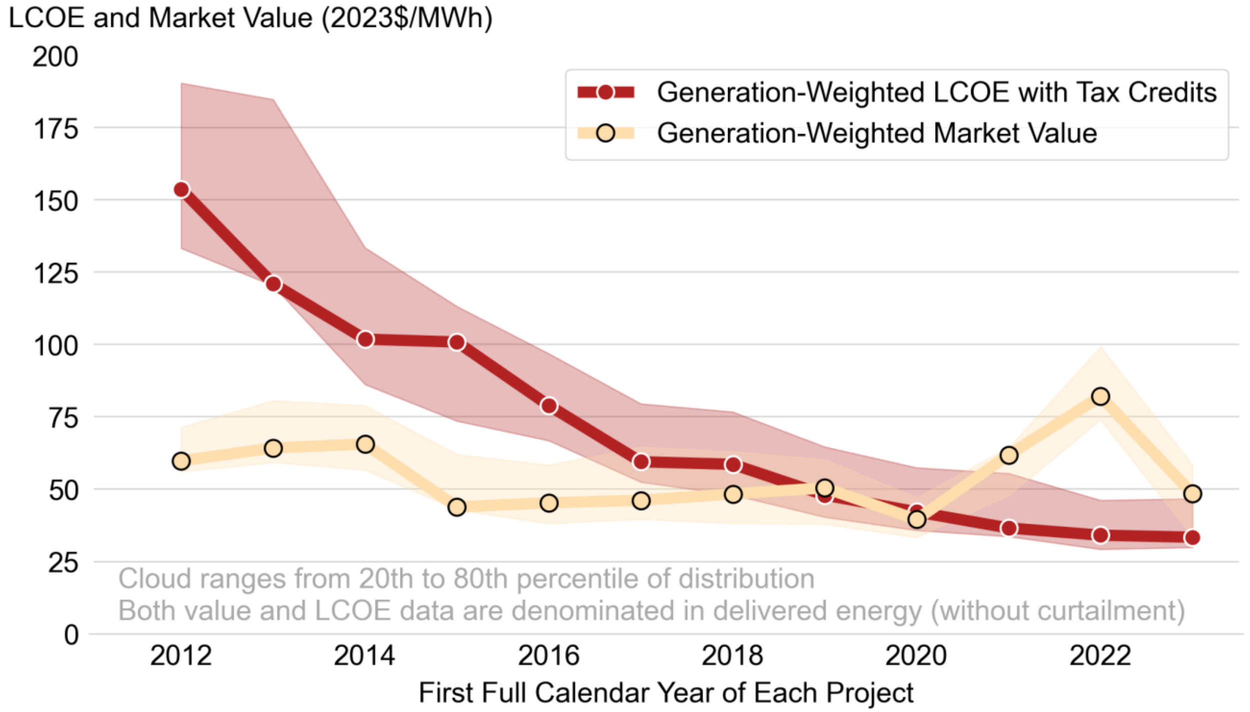
Temporarily high energy prices in 2022 more than compensated for emerging PPA price increases, but PPAs have begun to exceed wholesale market value in 2023 in CAISO, MISO, PJM, and NYISO, indicating potential future economic challenges based on solar's wholesale market value in these regions.

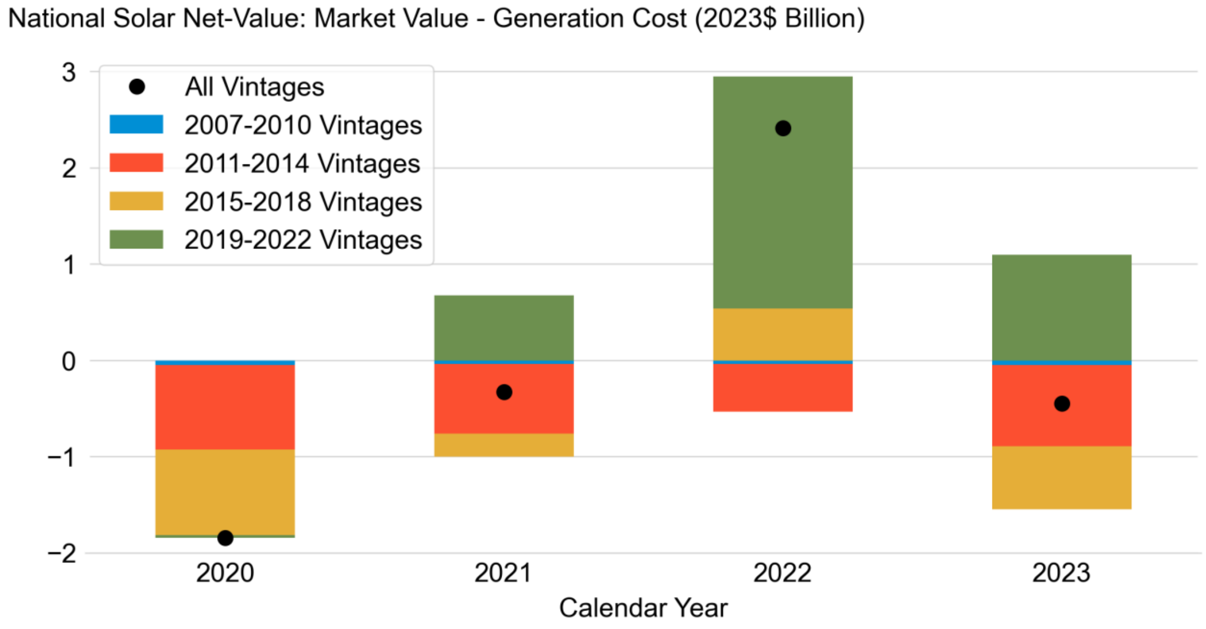
In contrast, solar offered greater value than what it is paid for in PPAs in ERCOT and SPP in 2023.

Note: We do not have sufficient PPA data to present robust trends for every balancing authority. PPAs are indexed here by execution date and span a longer time than the annual wholesale market value estimates.

Market Value vs. LCOE (with tax credits): Newer solar projects had greater value than their generation costs in 2023, yielding over $1BN in benefits

Sample: Only includes >5 MW_{AC} projects with LCOE and wholesale market value data: 1,079 projects totaling 55.9 GW_{AC}





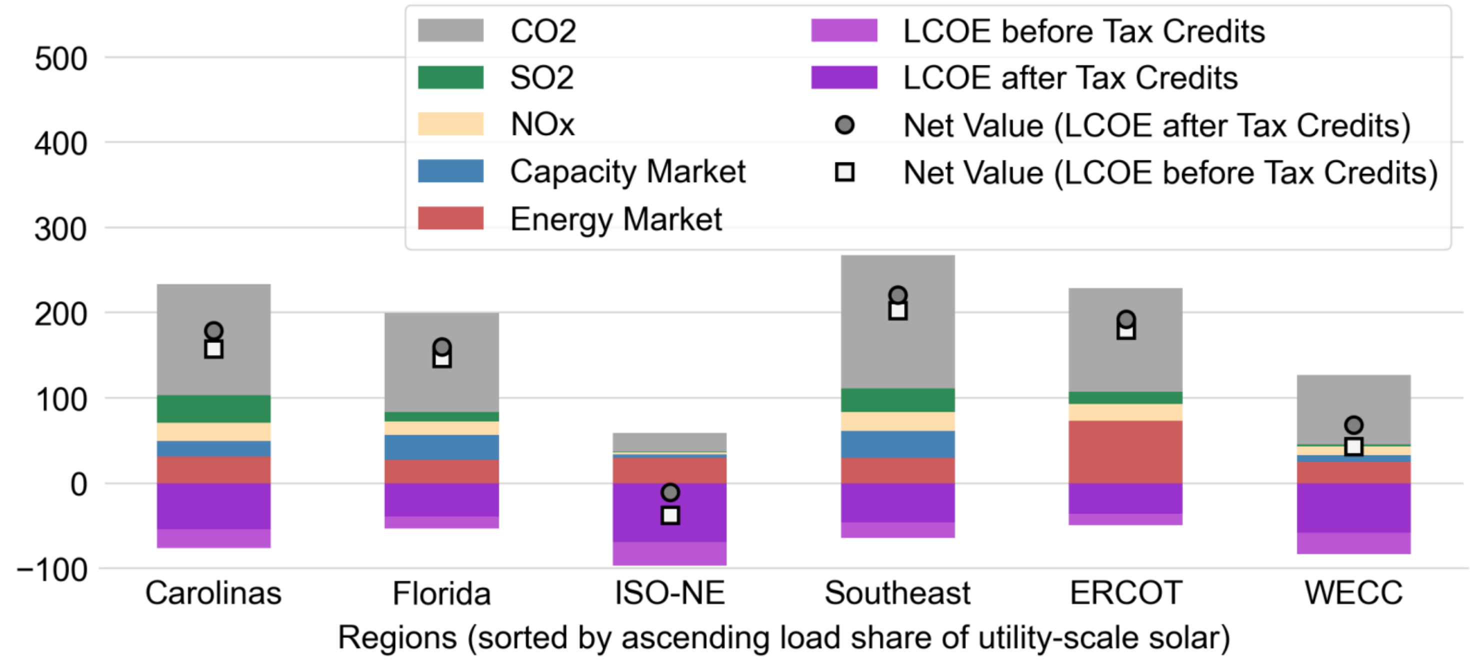
National average energy and capacity market value has been greater than levelized generation costs (after tax credits) for new utility-scale solar projects since 2020. Plants built in 2022 delivered on average $15/MWh more wholesale market value in 2023 than their LCOE.

In 2023, recent projects in our sample offer, in aggregate, a net market value of about $1.1 billion that could be passed on to end-use customers. Older projects had generation costs that were higher than their wholesale market revenues alone in 2023.

Note: For greater detail on methods and impacts, see Wiser et al (2024) Grid Value and Cost of Utility-Scale Wind and Solar: Potential Implications for Consumer Electricity Bills.

Combined climate, air quality, and market values of historical solar fleet are greater than generation costs and incentives in most regions in 2023

Electricity Market and Environmental Value vs. average LCOE of total USS Generation in 2023 (2023$/MWh)



The estimated aggregate net value of utility-scale solar generation across the examined regions was $13.7 BN in 2023 (or $16.5 BN when using after tax credit LCOE).

Solar is offsetting electricity generation by coal and natural gas plants, thereby reducing emission-associated health and climate damages.

Employing statistical analyses of empirical generation and emission records, we can infer impacts for regions with greater solar generation share (shown in graph).

Using avoided emission values from the scientific literature and air quality models, we estimate the U.S. health benefits from solar generation in 2023 equaled $24/MWh, based on reductions to SO2 and NOx emissions. Solar also reduced global damages caused by climate change at $101/MWh, based on reductions of CO2 emissions and standard estimates of the Social Cost of Carbon.

We can subsequently compare market and environmental value with the weighted generation costs of the solar projects that contribute to these benefits (COD 2007-2022). The net value is positive in all regions except ISO-NE (which has both higher solar costs and a relatively clean grid in 2023).

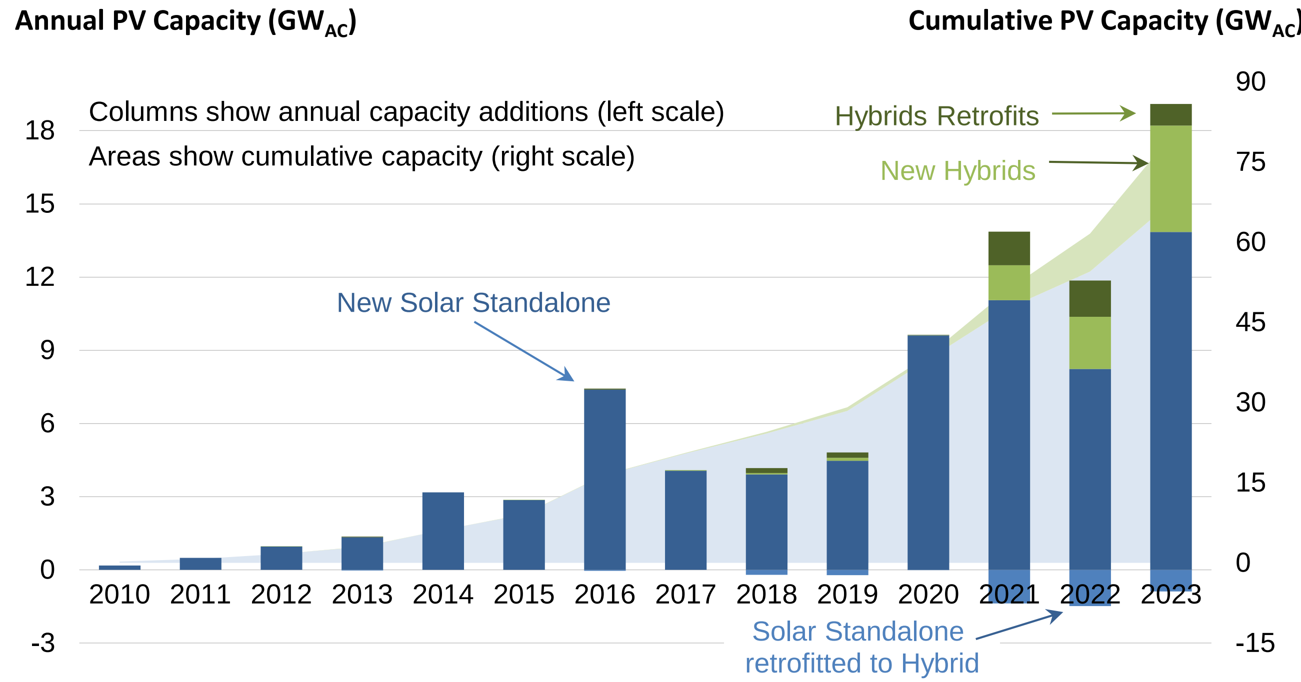
Note: For more detail on methods and discussion of caveats, see Millstein et al (2024) Climate and air quality benefits of wind and solar generation in the United States from 2019 to 2022.

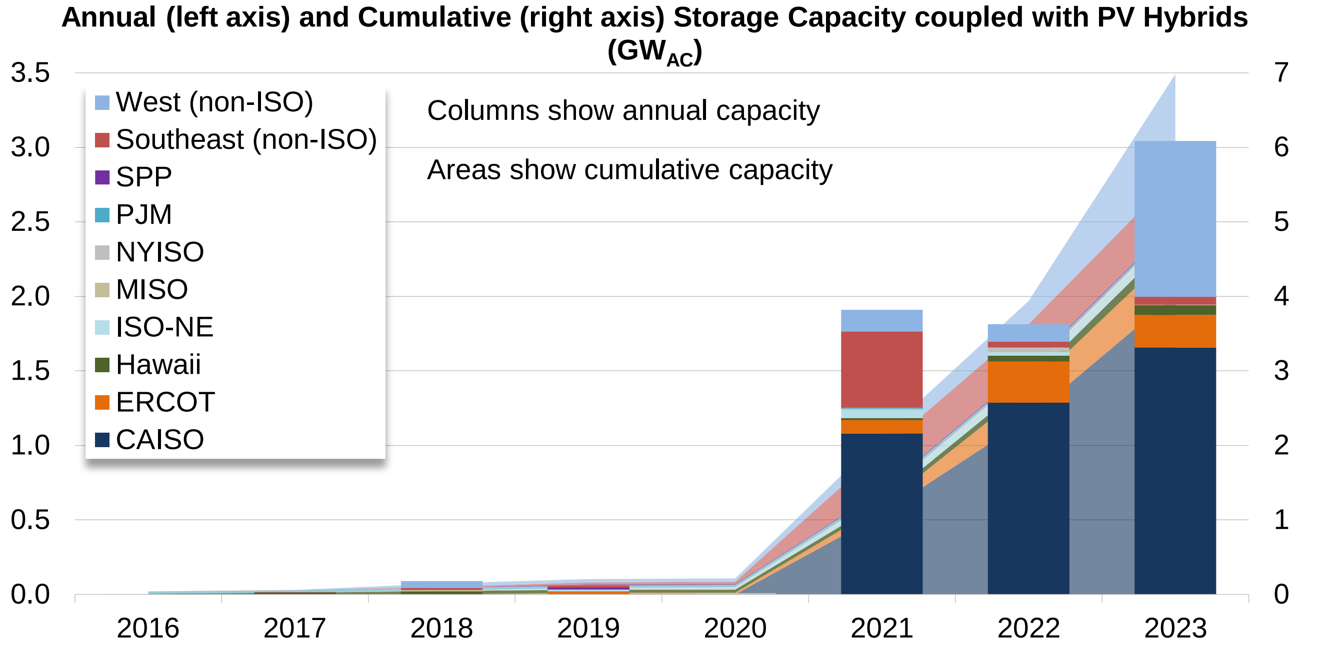
PV+Battery Hybrid Plants

(for more of Berkeley Lab's analysis of hybrid power plants, see https://emp.lbl.gov/hybrid)

Deployment of PV-battery hybrid plants set a record with 5.3GW greenfield and retrofit capacity in 2023

Sample: 155 projects totaling 12.4 GW_{AC} of PV, 7.0 GW_{AC} of battery capacity, and 22.7 GWh of battery energy



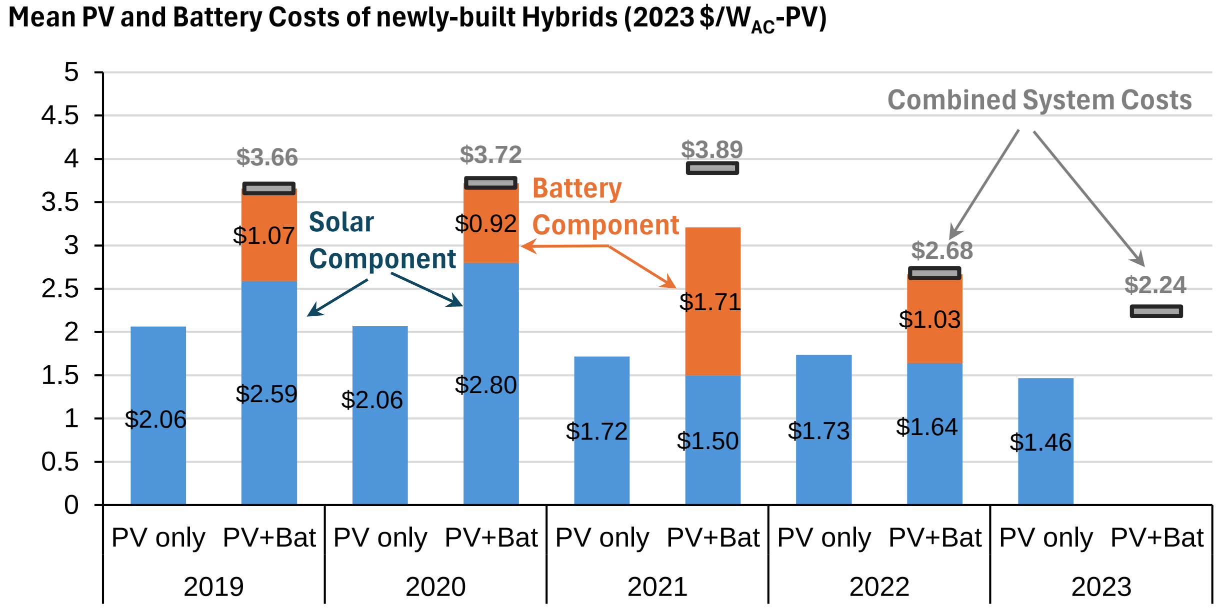


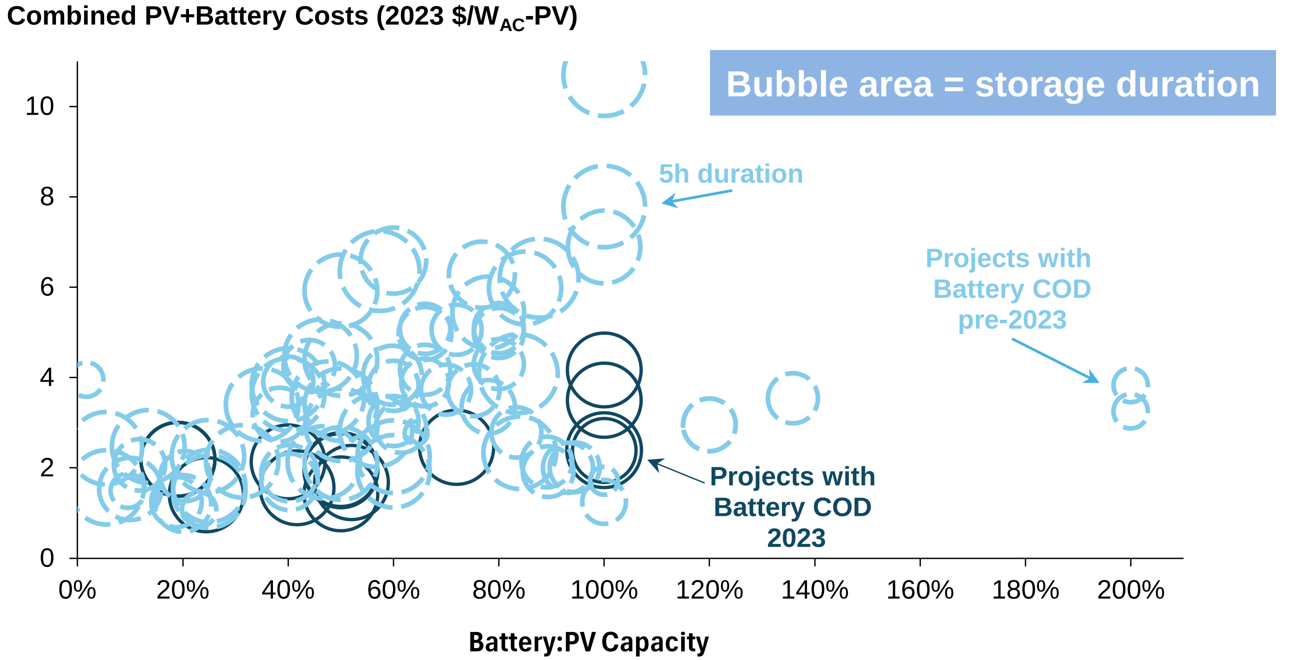
The large-scale PV+battery hybrid build-out started slowly in 2016, with just 1-12 plants/year built through 2020. The market started in earnest in 2021 with 39 hybrid installations. Following steady growth in 2022, 2023 was another record year for newly built hybrids (37 plants, 4.4 GW_{AC}-PV) while storage retrofits to existing stand-alone solar projects declined a bit (15 plants, 0.9 GW_{AC}-PV).

Most of the new hybrid storage was built in CAISO (22 plants, 1.7 GW storage capacity with ~3.5h storage energy). Hybrids had their first big year in the solar rich non-ISO West (20 plants, 4.0 GW capacity with ~3.8h energy). Hybrid additions declined slightly in ERCOT (3 plants, 0.2 GW storage capacity with ~1.3h energy) and ISO-NE (only 1 project in the MA Smart program).

Greenfield PV+battery project costs fell 15% in 2023 relative to 2022

Sample: 91 plants totaling 9,605 MW_{AC} of PV and 5,360 MW / 16,854 MWh of batteries with CODs from 2018-2023





In our newly-built hybrid sample, average combined costs have fallen 11% from \$2.68/W_{AC}-PV in 2022 (n=22) to \$2.24/W_{AC}-PV in 2023 (n=16).

Associated average storage duration in our cost sample increased from 2.9h in 2022 to 3.2h in 2023, and the battery:PV capacity ratio increased from 0.6 in 2022 to 0.7 in 2023.

Unfortunately, we do not have a robust sample of separate battery and PV costs among recent newly-built projects (2023) as recent EIA 860 capex data is not yet available. In 2022, median storage costs were $500/kWh. As shown above, combined PV+battery costs generally scale with increased battery capacity (relative to the PV capacity) and storage duration.

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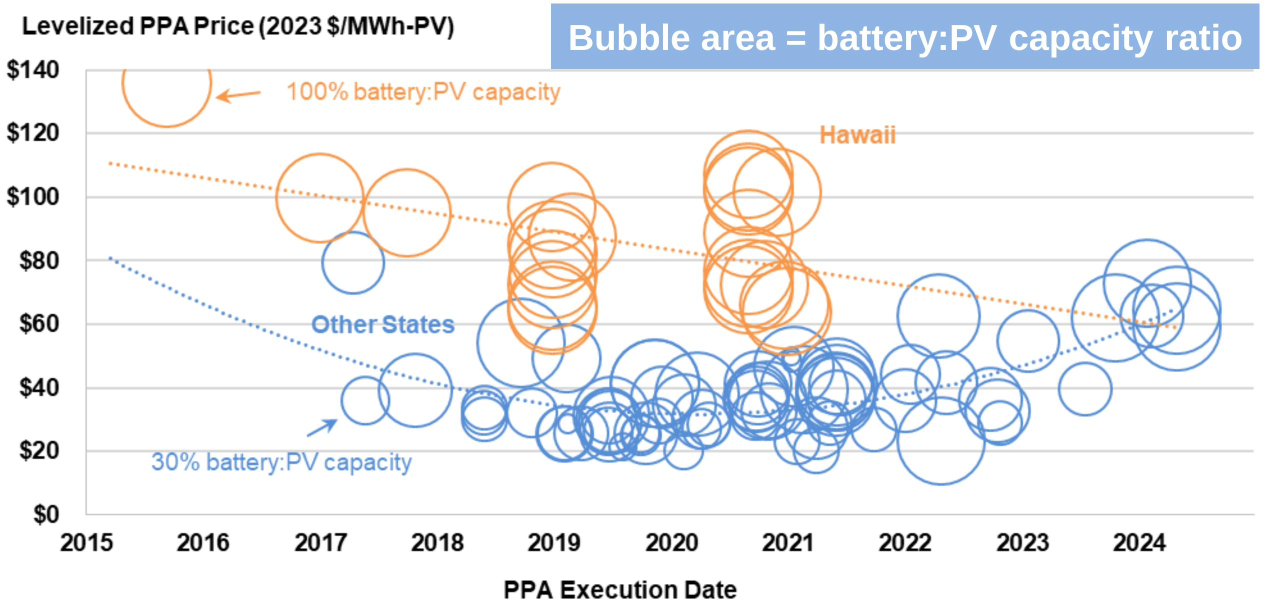
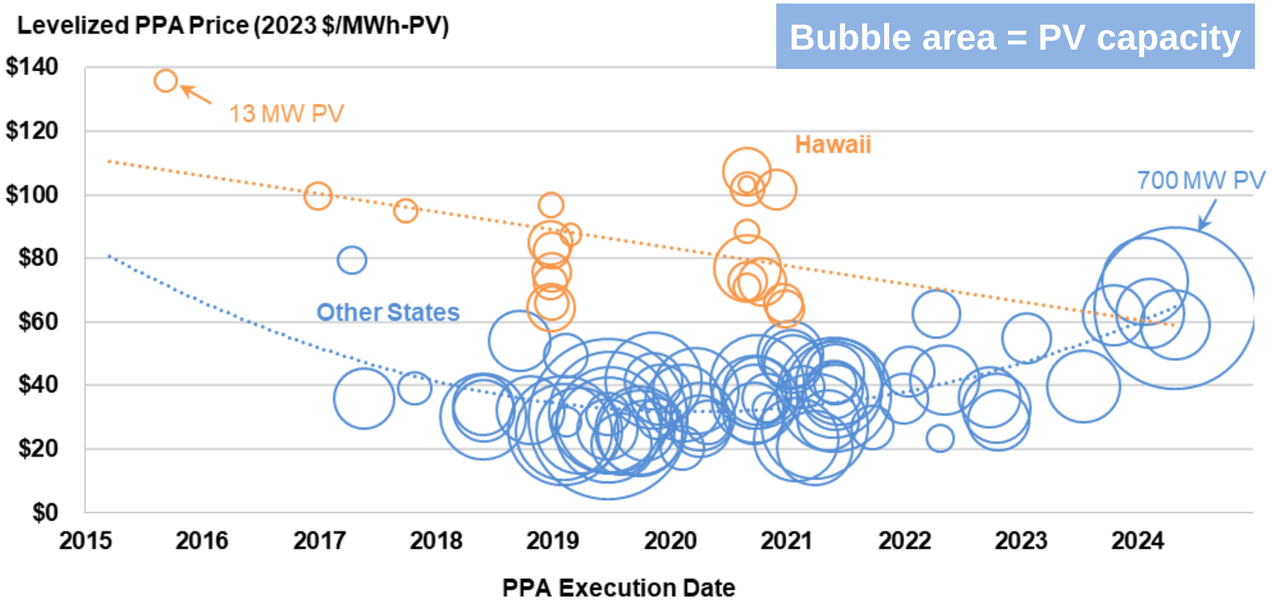
Note: “Combined System Costs” and “Component System Costs” in left graph may deviate due to different sample sizes contributing to each cost estimate.

PPA prices for PV+battery have approximately doubled since 2019/20 lows; Hawaii historically at a premium

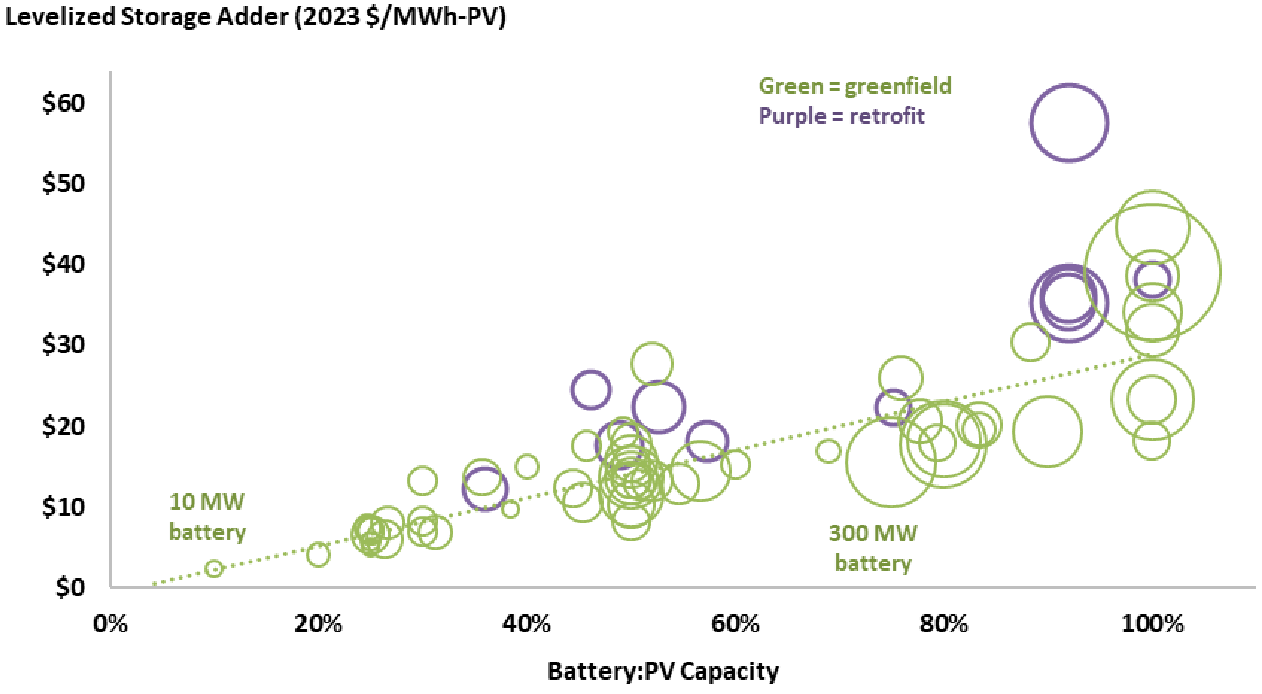


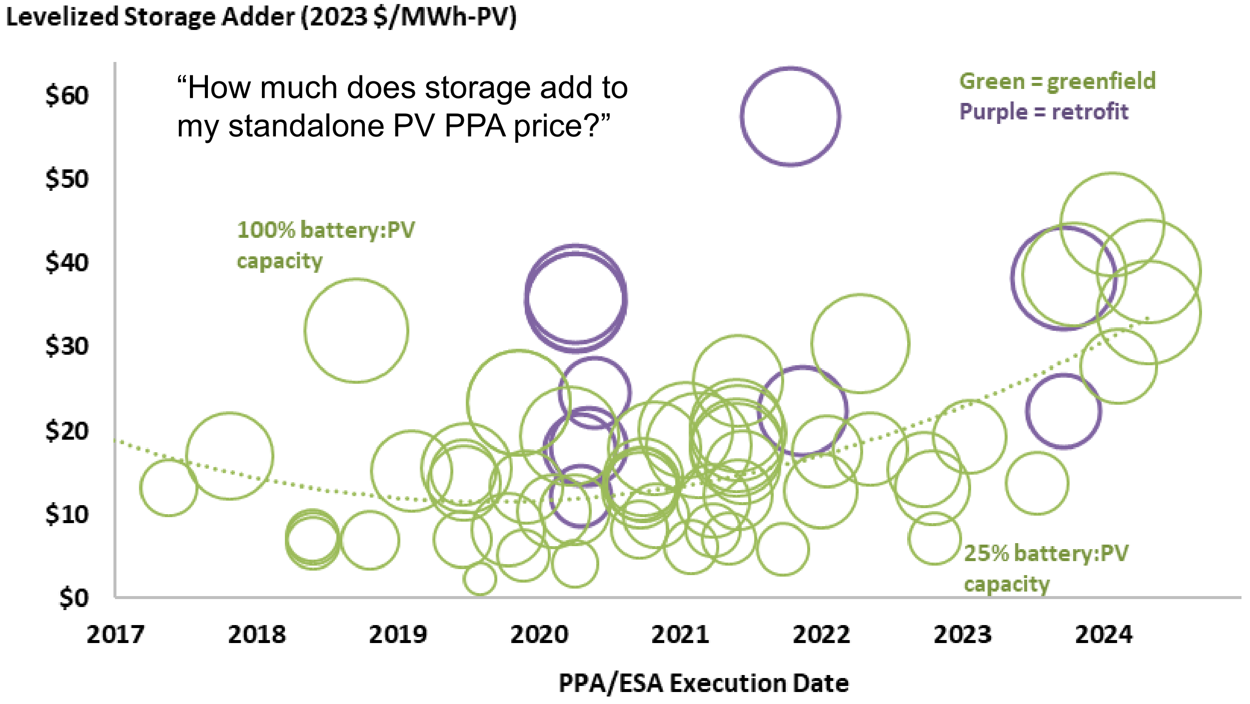


- Both graphs show same data from sub-sample of 93 plants (retrofits not included); the only difference is what the bubble size represents
  - Hawaii (orange): 22 plants, 0.8 GW_{AC} PV, 0.8 GW_{AC} battery (third round of Hawaii PPAs expected soon)
  - Other States (blue): 71 plants, 10.5 GW_{AC} PV, 5.8 GW_{AC} battery
  - Storage duration ranges from 2-8 hours; 80 plants have 4-hr duration (the other 13 are 5x2 hr, 1x2.5, 1x3, 1x3.7, 4x5, and 1x8 hr)
- Upward price trend among PPAs on the mainland, with prices in 2024 approximately twice typical prices in 2020
  - Rate of hybrid PPA price growth exceeds that of stand-alone solar, which saw increases of ~50-65% since 2020/2021 (see previous “LCOE & PPA Prices” section)

PPAs that price the PV and storage separately enable us to calculate a "levelized storage adder," which has increased in recent years

Graph Sample: 66 PV hybrid projects with 5.9 GW_{AC} of batteries (all 4h duration) in CA (35), NV (16), NM (11), AZ (3) and OR (1)





A larger capacity battery adds more to a PPA price than a smaller battery, when normalized for the PV plant size. This relationship between "levelized storage adders" and Battery-to-PV capacity ratios is roughly linear.

Retrofits tend to have higher "levelized storage adders" than greenfield projects.

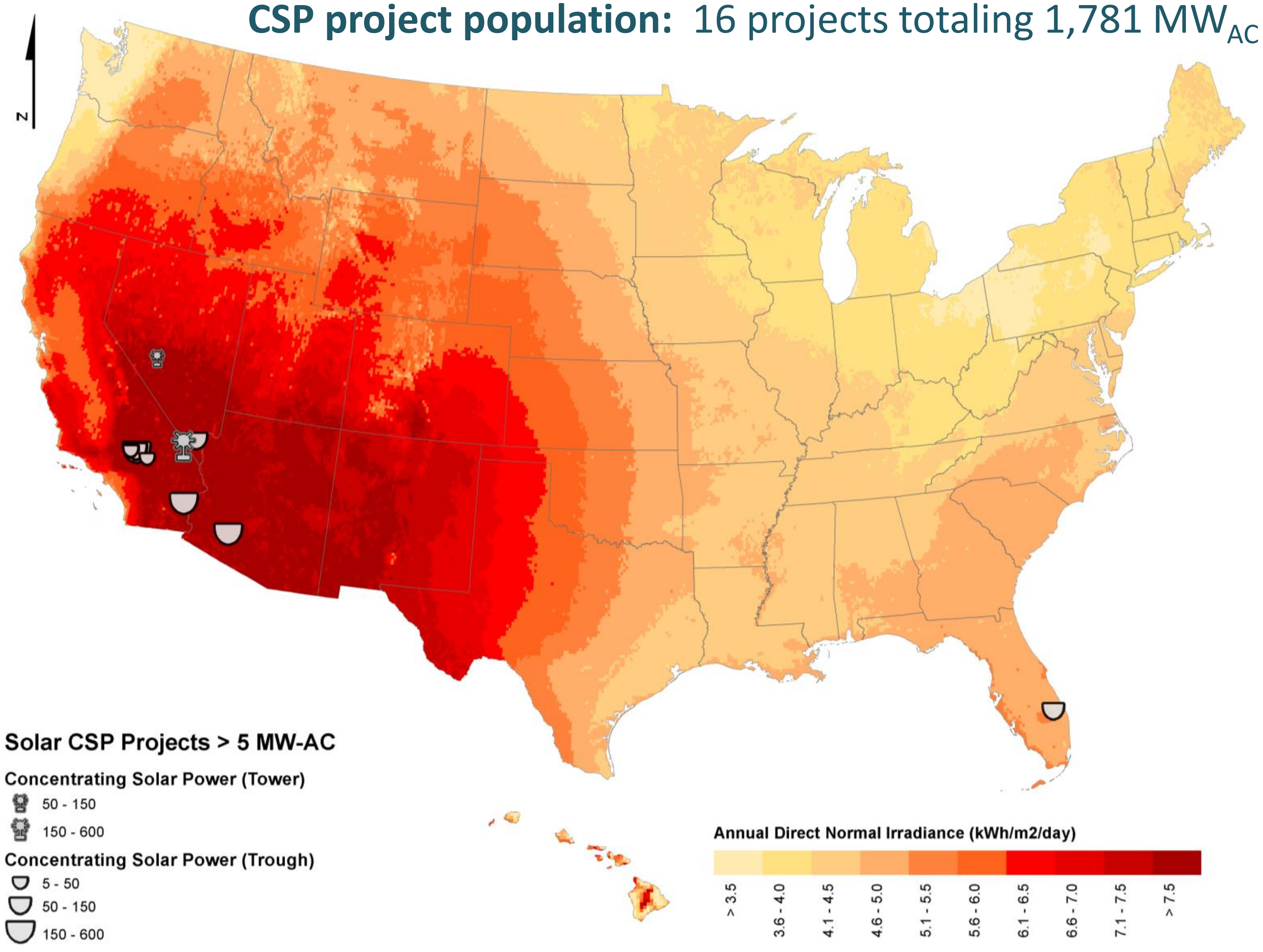
Increased PPA prices for the battery component explain some, but not all, of the recent increase in hybrid PPA prices. Levelized price increase since 2020 ($2023):

- Hybrid PPAs: ~$30/MWh-PV (see prior slide)
- Storage Adder: ~$23/MWh-PV
- All PV PPAs (not just hybrid): ~$10/MWh-PV

Concentrating Solar Thermal Power (CSP) Plants

Sample description of CSP projects

CSP project population: 16 projects totaling 1,781 MW_{AC}



After nearly 400 MW_{AC} built in the late-1980s and early-1990s, no new CSP was built in the U.S. until 2007 (68 MW_{AC}), 2010 (75 MW_{AC}), and 2013-2015 (1,237 MW_{AC}).

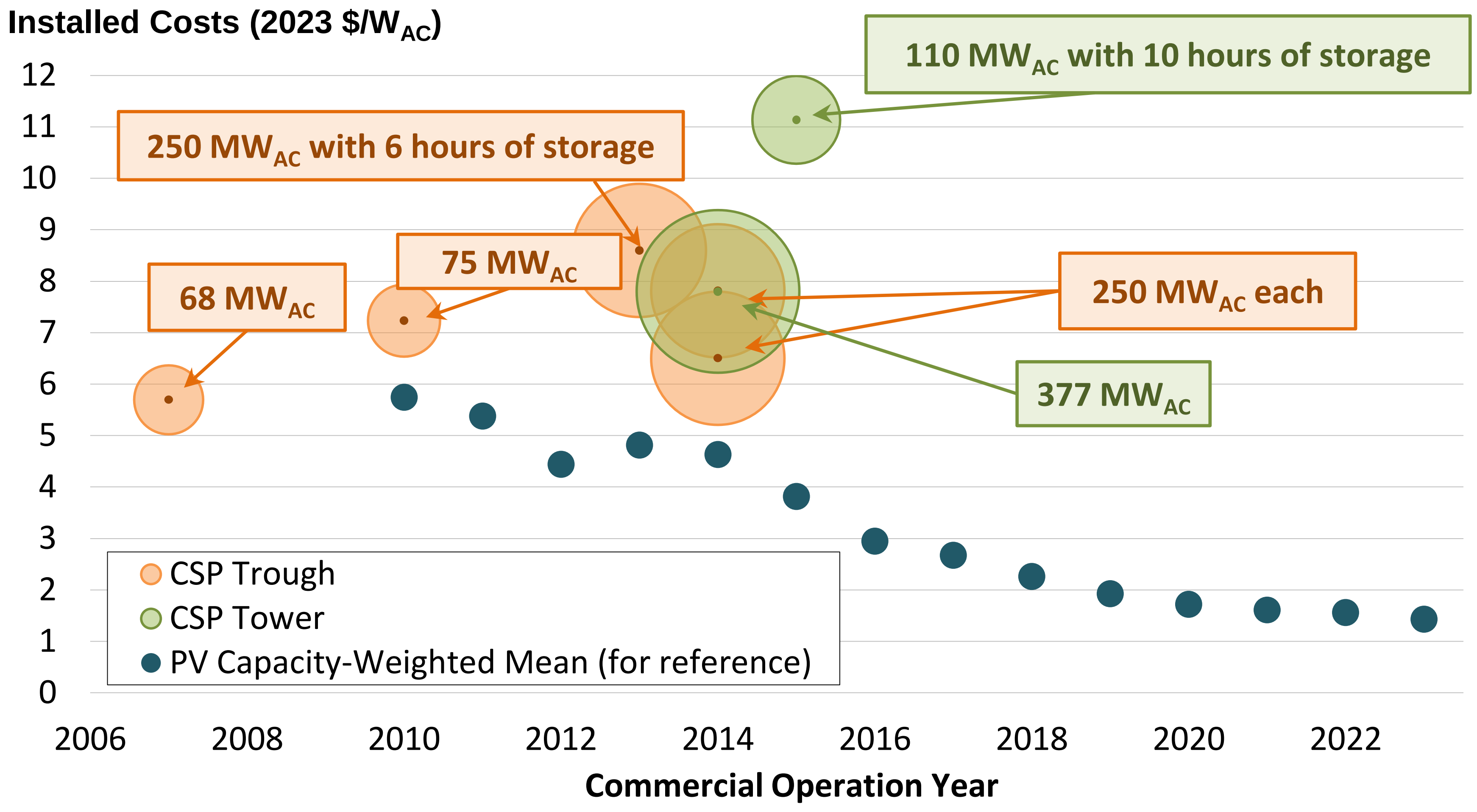
Prior to the large 2013-15 build-out, all utility-scale CSP projects in the U.S. used parabolic trough collectors.

The five 2013-2015 projects include:

- 3 parabolic troughs (one with 6 hours of storage) totaling 750 MW_{AC} (net) and
- 2 “power tower” projects (one with 10 hours of storage) totaling 487 MW_{AC} (net).

With no recent CSP installations in the U.S., empirical installed cost data are dated

CSP cost sample: 7 projects totaling 1,381 MW_{AC}

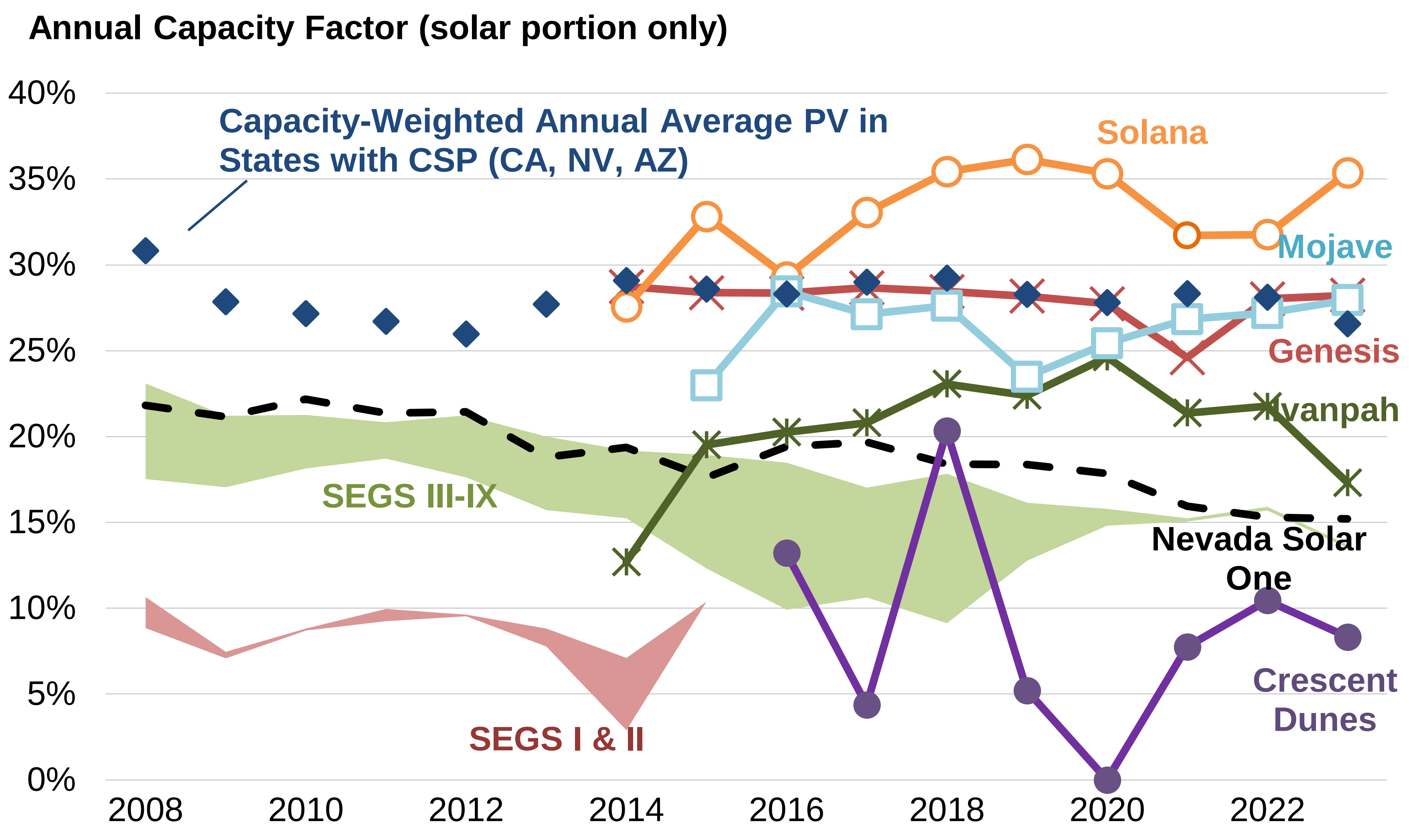


Small sample of 7 projects using different technologies makes it hard to identify trends. Newer projects (5 built in 2013-15) did not show cost declines, though some included storage or used new technology (power tower).

PV costs have continuously declined and are now far below the historical CSP costs. While international CSP projects seem to be more competitive with PV, no new CSP projects are currently under active development in the U.S.

Most newer CSP projects continue to underperform relative to long-term expectations

CSP capacity factor sample: 7 projects totaling 1,394 MW_{AC}



Power Towers: Ivanpah's (377 MW) capacity factor fell in 2023 to just 17.3%, well below long term expectations of 27%. Two of Ivanpah's generators reported no power generation over a combined three-month period in 2023. Crescent Dunes (110 MW with 10 hours of storage) performed at just 8.3% capacity factor in 2023.

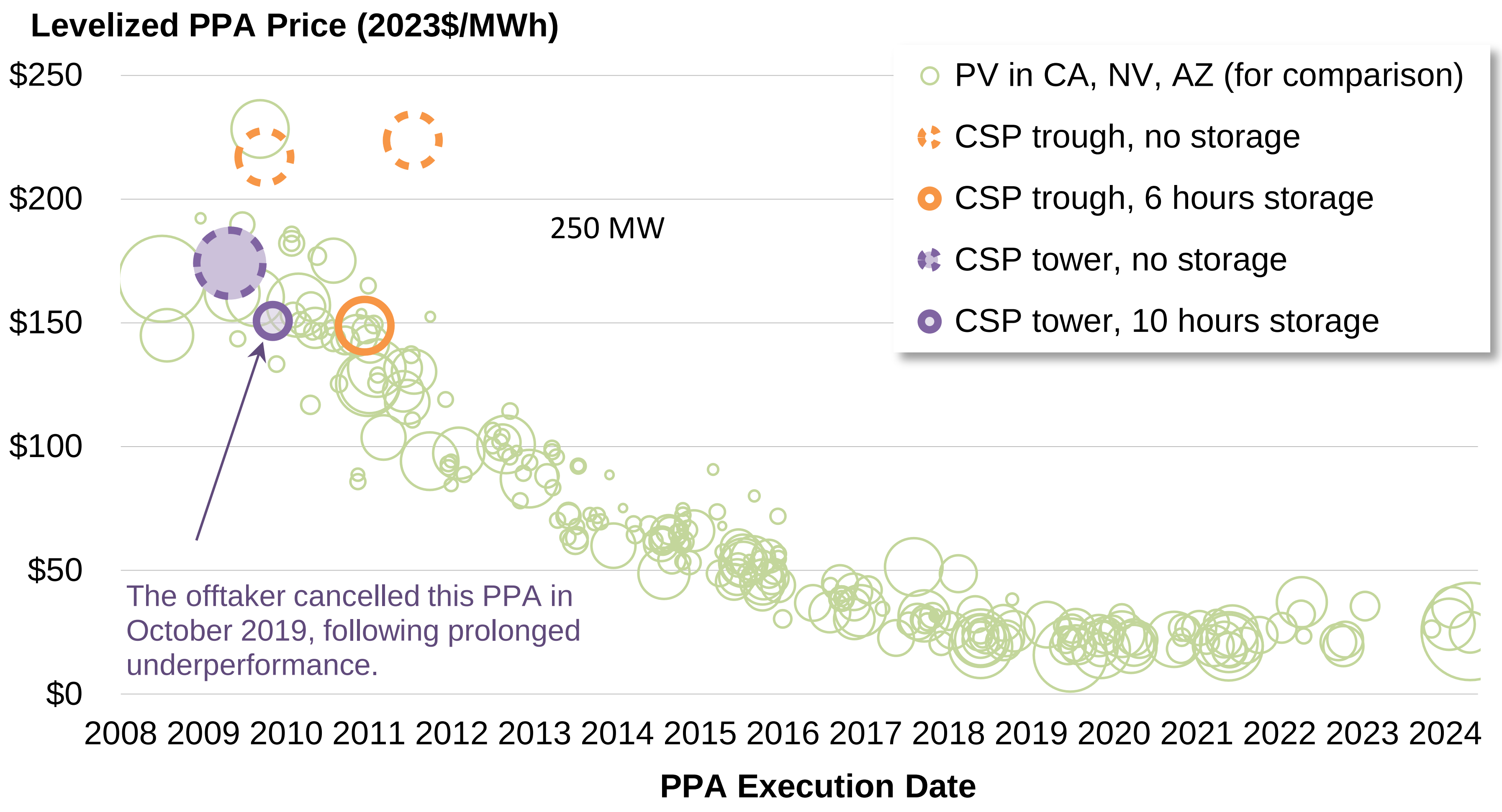
Trough with storage: Solana (250 MW trough project with 6 hours of storage) performed at 35.4% capacity factor in 2023, an increase from the previous two years but below long-term expectations of >40%.

Troughs without storage: Mojave and Genesis (both 250 MW net) were at 27-28% capacity factor in 2023. Both have performed better than the old SEGS projects (now decommissioned and repowered with PV) and the 2007 Nevada Solar One project.

Only Solana, Genesis, and Mojave have matched or exceeded the average capacity factor among utility-scale PV projects across CA, NV, and AZ.

Though CSP was once competitive, PV PPA prices have declined dramatically. Without new CSP PPA data, current comparisons are difficult

CSP PPA price sample: 5 projects totaling 1,237 MW_{AC}



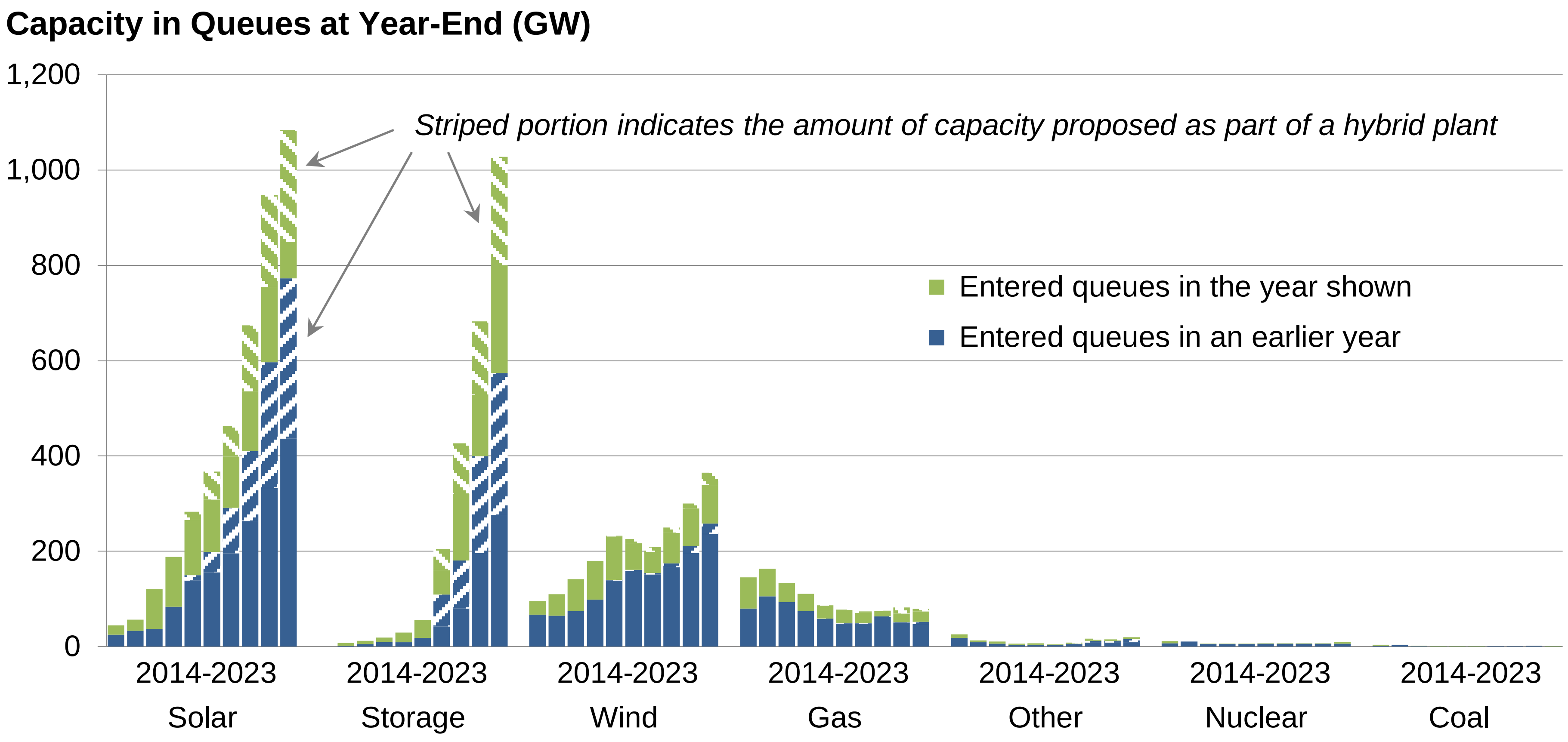
When PPAs for the most recent batch of CSP projects (with CODs of 2013-15) were signed back in 2009-2011, they were still mostly competitive with PV.

But CSP has not been able to keep pace with PV's price decline. Partly as a result, no new PPAs for CSP projects have been signed in the U.S. since 2011 – though the technology continues to advance overseas.

Capacity in Interconnection Queues

Looking ahead: Strong growth in the utility-scale solar pipeline

Sample: Active bulk-power interconnection requests from 51 interconnection queues.



1085 GW of solar was in the queues at the end of 2023—312 GW of this total entered the queues in 2023 (the remainder entered in earlier years and remain active).

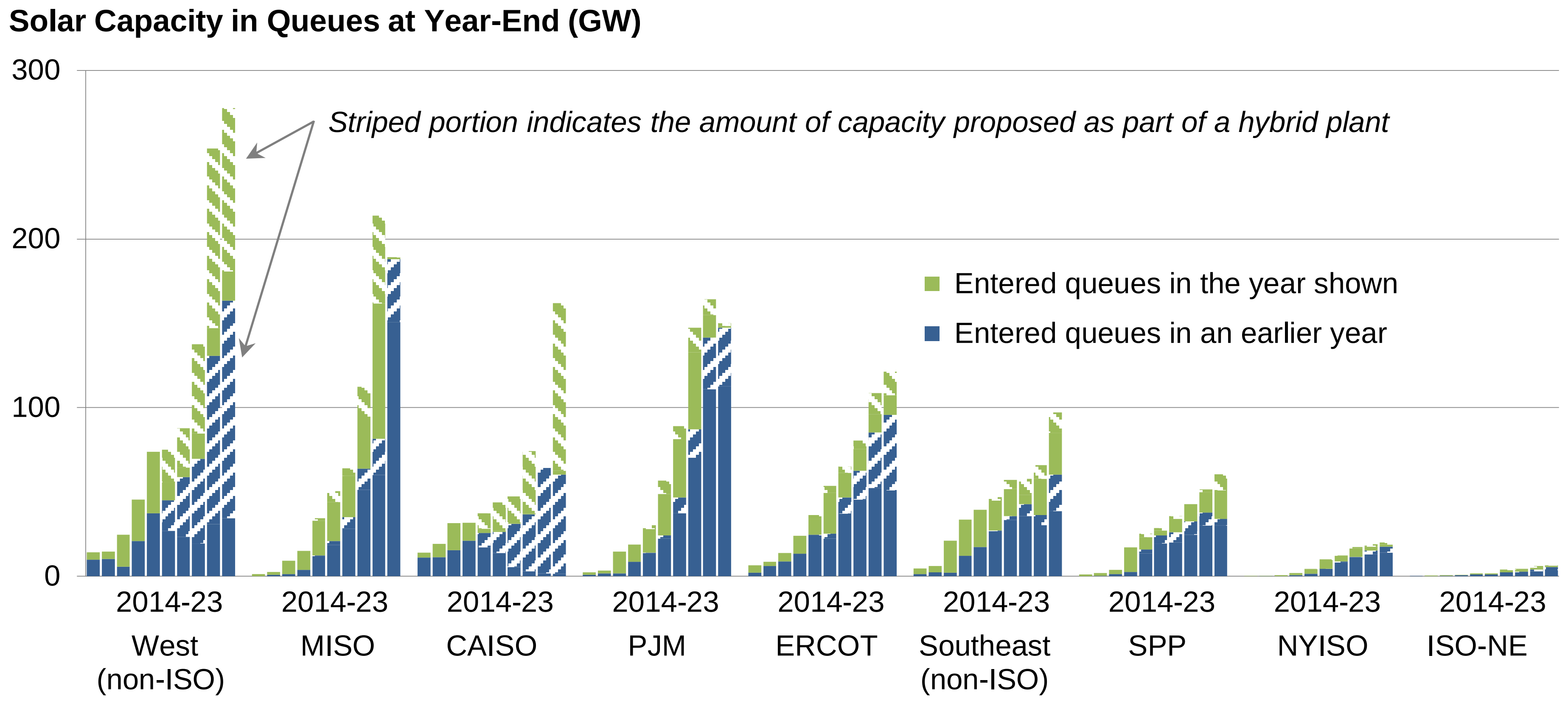
571 GW of the 1085 GW of solar in the queues (i.e., 53%) includes a battery in a PV hybrid configuration.

Solar (both in standalone and hybrid form) is the largest resource within these queues, followed closely by storage, with wind and gas a distant 3rd and 4th. (All other resources are negligible in comparison.)

Note: Not all projects will ultimately be built as many withdraw during the interconnection process. For more details on methods see Berkeley Lab's Annual Queued Up Report.

Looking ahead: Continued broadening of the market

Sample: Data from 51 interconnection queues across the U.S.



Most regions of the country saw growth in the amount of queued solar, with CAISO, the non-ISO West and Southeast leading the way in 2023

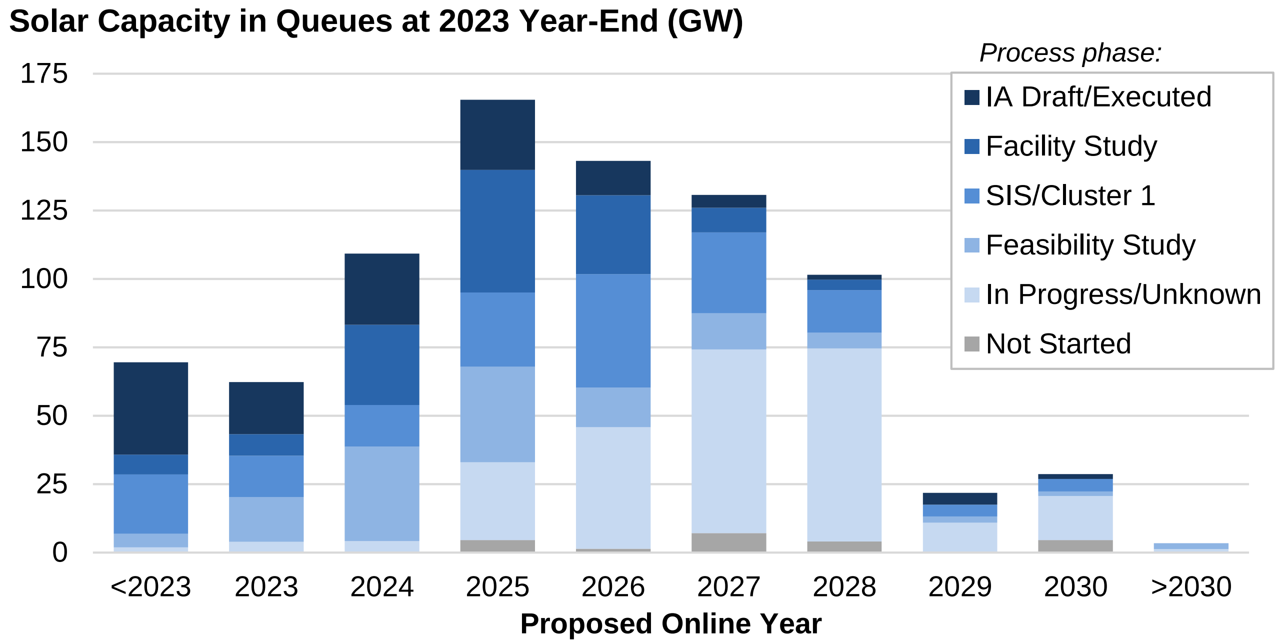
- MISO and PJM did not accept new interconnection requests in 2023, so all solar in those queues entered in an earlier year

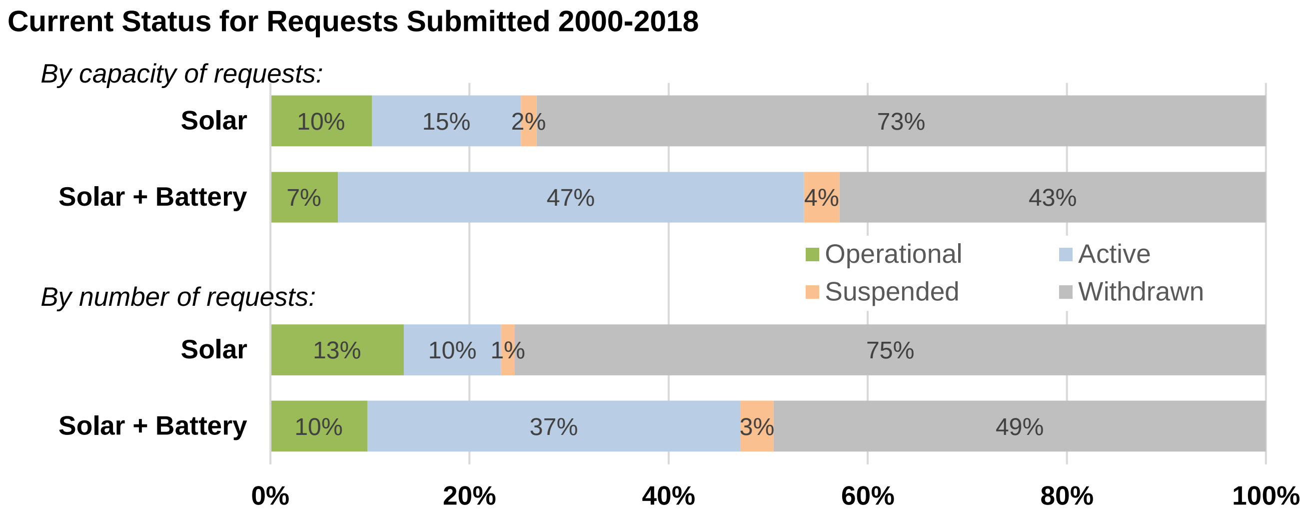
98% of the solar capacity in CAISO's queue at the end of 2023 was paired with a battery; in the non-ISO West, that number was also high, at 81%

- Both regions are grappling with "duck curve" issues due to solar's relatively high market share

Note: Not all projects will ultimately be built as many withdraw during the interconnection process. For more details on methods see Berkeley Lab's Annual Queued Up Report.

Most active solar proposes to be online by 2028, but the historical completion rate for solar projects requesting interconnection is low





- Few solar projects have requested interconnection with a proposed online date of 2029 or later
- Proposed online dates are included in the developer's original interconnection request and may differ from actual online date
  - ❑ 132 GW of active solar requests were already past their proposed online date at the end of 2023
- 130 GW of solar capacity have an interconnection agreement (either draft or executed) – these projects are the most likely to be completed

- If historical patterns persist, only ~10% of solar capacity requesting interconnection will ultimately get built and become operational
- Developers withdraw interconnection requests for myriad reasons:
  - ❑ Some reasons are based in the interconnection process, such as high cost to interconnect and study delays
  - ❑ Some reasons arise outside of the interconnection process, such as failure to secure financing or an offtaker, permitting issues, or insufficient resources to complete all proposed projects

Note: Not all projects will ultimately be built as many withdraw during the interconnection process. For more details on methods see Berkeley Lab's Annual Queued Up Report.

Summary

- Utility-scale PV continued to lead solar deployment in 2023, with Texas adding the most new capacity. 89% of new projects and 96% of new capacity feature single-axis tracking.
- The capacity-weighted installed cost of solar projects that came online in 2023 fell to $1.43/W_{AC}$ ($1.08/W_{DC}$), down 8% from 2022 and 75% from 2010. Median prices (perhaps better reflecting typical project costs) fell from $1.61/W_{AC}$ to 1.33/W_{AC}$.
- Average capacity factors range from 17% in the least-sunny regions to 31% in the sunniest. Single-axis tracking adds more than five percentage points to capacity factors in the regions with the strongest solar resource.
- The generation-weighted LCOE from utility-scale PV has declined by 80% since 2010 to $46/MWh (without tax credits) or $31/MWh (with tax credits) in 2023. Levelized PPA prices have kept pace, but prices on newly executed agreements have trended upward the last few years. Since 2021 prices have typically ranged from $20-45/MWh in CAISO and the non-ISO West to $35-$85/MWh elsewhere, with the highest prices in PJM and MISO.
- The market value of solar fell in 2023 to $44/MWh on average, as energy prices returned to more normal levels. The generation costs of newer projects is less than their wholesale market replacement costs. Rising prices for new PPAs are now higher in some regions than solar's energy and capacity market value in 2023. When accounting for climate and health benefits, solar generation delivered nearly $14 billion net-value in 2023.
- Interest in hybridization (pairing PV with batteries) continued to set new records in 2023 (37 new greenfield plants, 4.4 GW$_{AC}$-PV and 15 project retrofits, 0.9 GW$_{AC}$-PV). Recent (2022-2024) PV+battery hybrid PPAs in the continental US had a capacity-weighted average of $55/MWh-PV.
- Across all 7 ISOs and 44 additional utilities, there were 1085 GW of solar in interconnection queues at the end of 2023. More than half of this proposed solar capacity is paired with battery storage, with the highest concentration of these PV+battery hybrid plants in CAISO (98%) and the non-ISO West (81%).

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For more information

Explore this report deck, a written technical brief, an extensive workbook with all underlying data, and interactive visualizations: http://utilityscalesolar.lbl.gov

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