Title

U.S. Utility-Scale Solar, 2025 Data Update

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Publication Date

2025-10-15

U.S. Utility-Scale Solar
2025 Data Update

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October 2025

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This material is based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under Solar Energy Technologies Office (SETO) Agreement Number 38444 and Contract No. DE-AC02-05CH11231.

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U.S. Utility-Scale Solar - 2025 Data Update

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Acknowledgements

The authors thank the U.S. Department of Energy Solar Energy Technologies Office for supporting this work. The authors also thank the many individuals from utilities, project developers, state agencies, and other organizations who contributed to this data update. Without the contributions of these individuals and organizations, this data update would not be possible.

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SOLV Energy, Brian Doll.
Mammoth North Solar, completed in 2024.

U.S. Utility-Scale Solar - 2025 Data Update

About This Publication:

This publication presents an annual snapshot of trends in utility-scale solar generators, defined as ground-mounted projects larger than $5MW_{AC}$. It summarizes public empirical data, especially from the U.S. Energy Information Administration (EIA) and the U.S. Federal Energy Regulatory Commission (FERC). For the CapEx analysis we leverage additional (non-public) data provided to LBNL through Non-Disclosure Agreements to fill in gaps from the public data. A separate data collection on distributed solar and storage data is available here.

The 2025 edition of the publication summarizes data for generators coming online through the end of 2024 with a focus on the most recent full calendar year. We neither directly comment on nor recommend any specific policies but simply summarize and explain data trends.

This year's update is divided into two parts: The **summary section** spotlights key 2024 data changes upfront, while the **extensive appendix** provides additional analyses and longer-term trends.

Funding:

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

Products in addition to this slide deck:

The 2025 Data Update consists of this file, interactive visualizations, and an Excel data file containing the data behind each graph (and more). All products are available at: utilityscalesolar.lbl.gov

New in this year's update:

- Executive Summary with 2024 Data Highlights
- Project size distributions
- Expanded capex sample from EIA enabling more refined cost analyses for PV standalone and PV+battery projects
- Increased details on technological design choices for PV+battery projects
- Levelized cost of energy estimates for PV+battery projects
- Levelized solar market value estimates by commercial operation date and net-value analyses
- Comparison of actual year 1 performance to idealized year 1 performance

U.S. Utility-Scale Solar - 2025 Data Update

- Deployment Trends (Appendix: Technology Trends)
- Capital Costs (CapEx) (Appendix: Operation & Maintenance Costs)
- Performance (Capacity Factors)
- Levelized Cost of Energy (LCOE) and Power Purchase Agreements (PPA)
- Wholesale Market Value and Net Value
- PV+Battery Hybrid Plants
- Capacity in Interconnection Queues
- Appendix: Concentrating Solar Thermal Power (CSP) Plants

Executive Summary

- Utility-scale PV continued to lead solar deployment in 2024 (80% of new solar and 54% of all new capacity). Texas added the most new capacity in 2024 and now leads the nation with the greatest cumulative solar capacity as well. 99% of new projects feature single-axis tracking.
- The capacity-weighted installed cost of solar projects that came online in 2024 increased slightly to $1.61/W_{AC}$ ($1.22/W_{DC}$), up 1% from 2023 but down 73% from 2010. Strong economies of scale explain a quintupling of the average project size over the past eight years.
- 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. Year 1 performance indices indicate recent project vintages performing worse than older vintages, compared with a modeled output.
- The generation-weighted LCOE from utility-scale PV has increased by 25% since 2022 to $60/MWh (without tax credits) or $41/MWh (with tax credits) in 2024. Levelized PPA prices have also trended upward the last few years. Since 2021 prices have typically landed between $20-30/MWh in CAISO and the non-ISO West and between $40-$80/MWh elsewhere, with the highest prices in the Northeast.
- The market value of solar fell in 2024 to $32/MWh on a national-average basis, as energy prices fell. Rising PPA prices and generation costs are now higher in some regions than solar's energy and capacity market value for the newest solar projects.
- Interest in hybridization (pairing PV with batteries) continued to grow in 2024 (33 new projects). All in battery CapEx increased to $458/kWh in 2024. Added costs for a PV system grow with greater storage capacity ratio (0.57) and duration (3.3h) and were $1/W_{AC-PV}$ in 2024 - equivalent to an LCOE adder of $25/MWh (after tax credits).
- Across all 7 ISOs and 49 additional utilities, there were 956GW of solar in interconnection queues at the end of 2024 (-12% vs. 2023). 47% of this proposed solar capacity is paired with battery storage, with the highest concentration of these PV+battery hybrid plants in CAISO (93%) and the non-ISO West (83%).

Data and Methods
(additional details are found in each section in the Appendix)

Solar Deployment: Primary data sources are EIA 860, FERC 556, and primary research.

Capital Expenditure (CapEx): Primary data sources are EIA 860 Schedule 5B (not public and acquired via NDA), FERC Form 1, and primary research. New CapEx estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA. We present data in $\$/W_{AC}$ terms (detailed $\$/W_{DC}$ costs in the online data file). CapEx is adjusted from nominal to real $ using BEA's implicit GDP price deflator.

Performance: Primary data source is EIA 923, reflecting net generation (excluding energy used by the plant itself and curtailment). Outliers and low-quality data are dropped from the analysis. Since we require one full year of generation data, our performance sample includes projects built through 2023, with generation data through 2024. Net Capacity Factors (NCF) represent 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.

LCOE: LCOE estimates are derived with formulas following NREL's Annual Technology Baseline, describing the average costs to generate a MWh over the lifetime of a project. CapEx and NCF use project-specific data, while OpEx, design life, degradation, and WACC rely on industry averages and vary by commercial operation year.

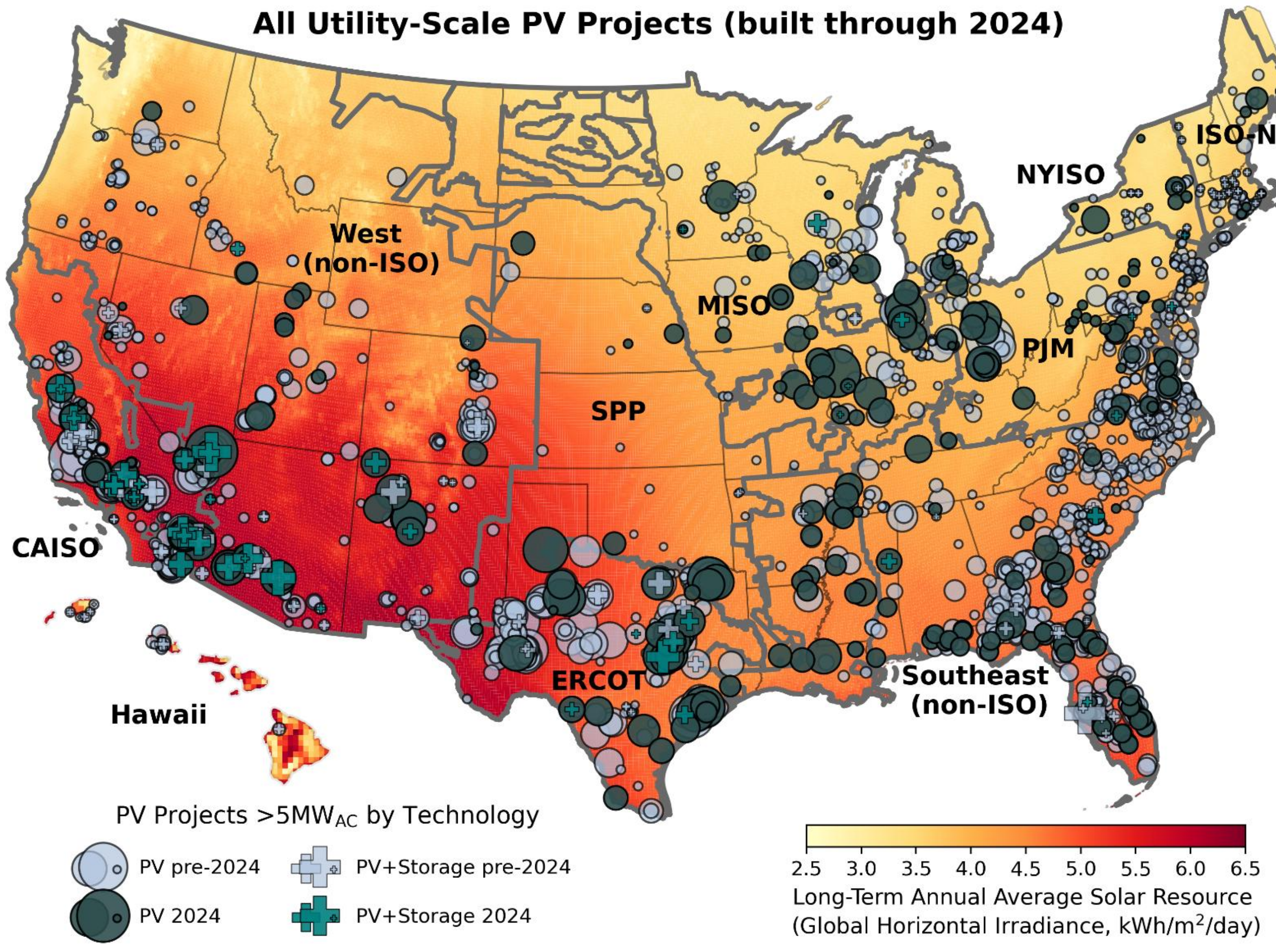
PPA: Primary data sources are FERC Electric Quarterly Reports, FERC Form 1, and state regulatory filings. Annual PPA data is converted to real $ and levelized using WACC.

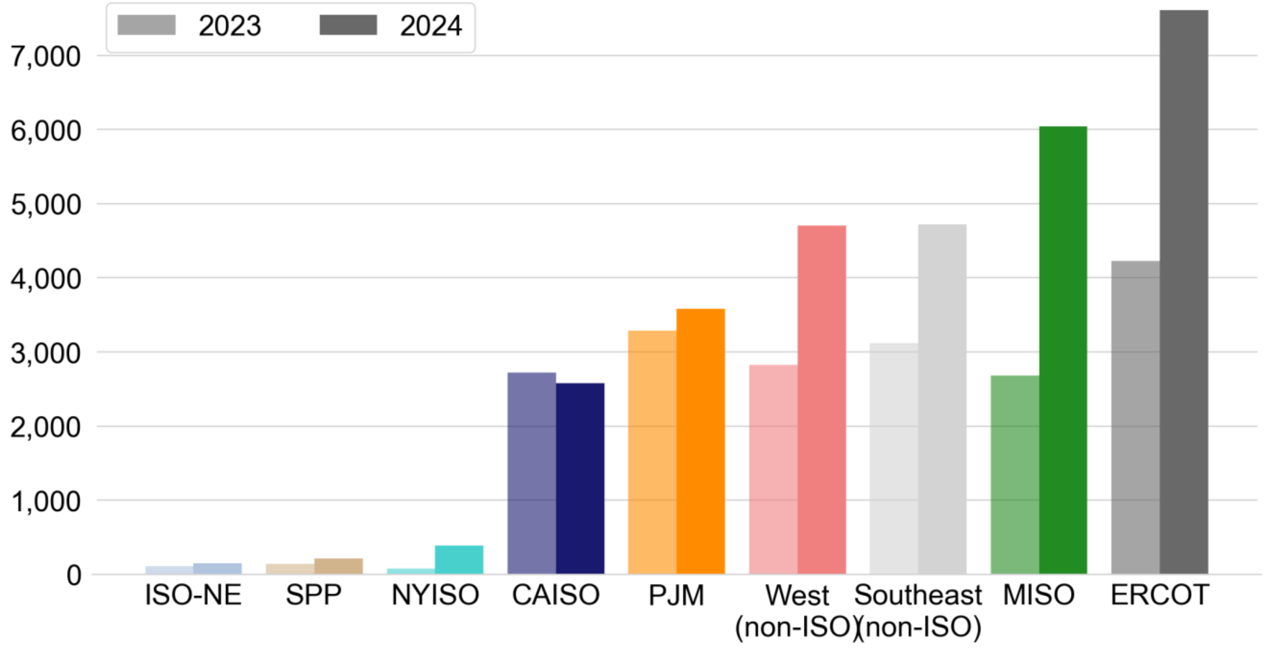
Value: We model hourly solar profiles using NREL's System Advisory Model and debias generation with ISO and EIA 923 data. Energy value is derived from LMPs or FERC System Lambdas, capacity value from BA-specific capacity accreditation rules and capacity prices (from central markets or bilateral transactions). The value represents the marginal "replacement costs" of what an offtaker would pay in short-term wholesale markets. It does not include any additional revenues or costs (Ancillary Services, Renewable Energy Credits, infrastructure impacts…).

Interconnection Queues: Primary data comes from interconnection queues from 7 ISOs/RTOs and 49 non-ISO BAs, collected via interconnection.fyi. We focus on projects connecting to the bulk-power system (not distribution-connected / behind-the-meter).

Utility-scale solar deployment grew by 56% from 19 to 30 GW_{AC} in 2024 in the United States

Sample: 1,759 projects totaling 111 GW_{AC}





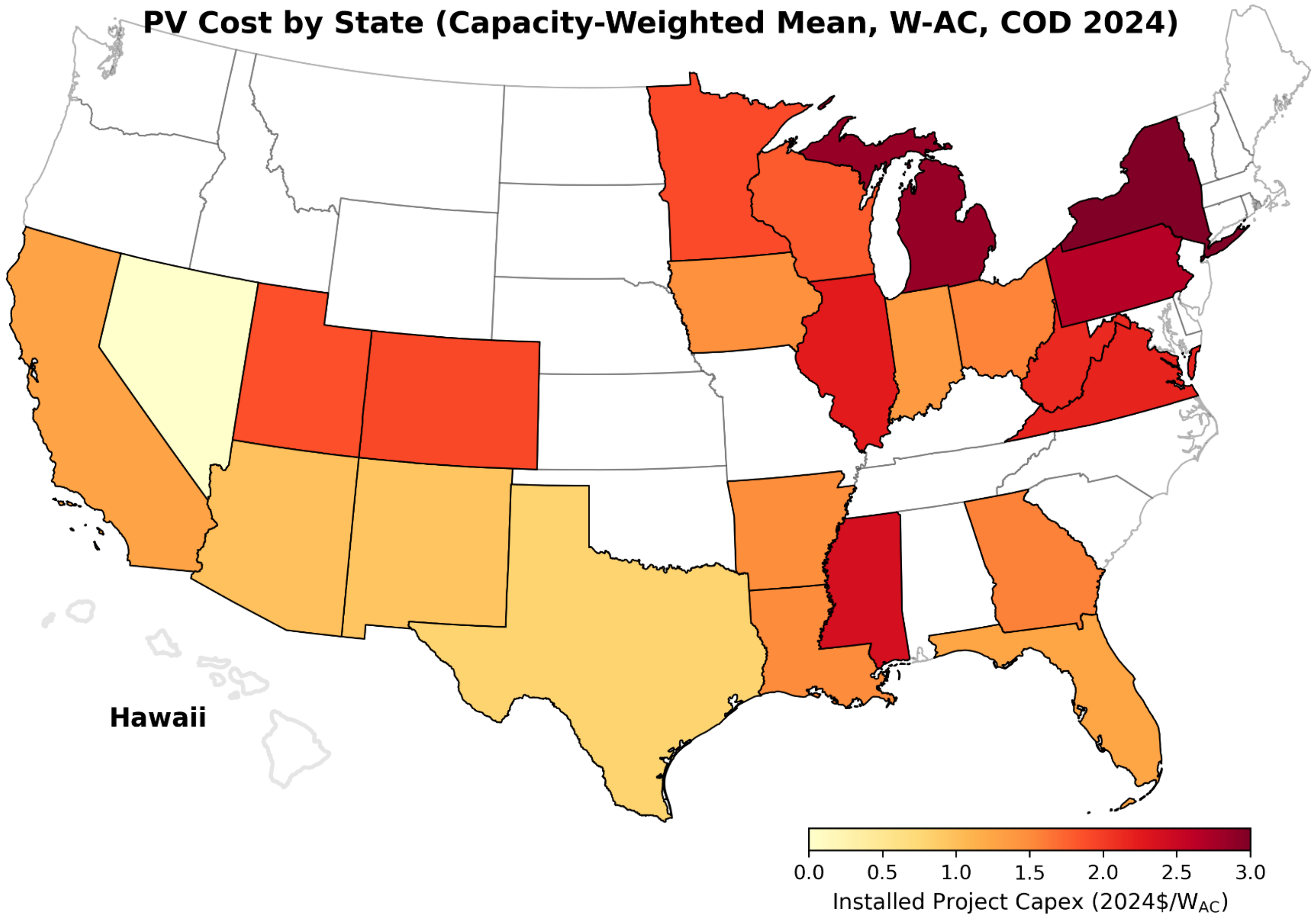
We define utility-scale solar as ground-mounted projects with a nameplate capacity >5 MW_{AC}. Annual capacity additions increased in 2024 to 30 GW_{AC} (or 35 GW_{DC}) and accounted for 54% of all new grid-connected capacity.

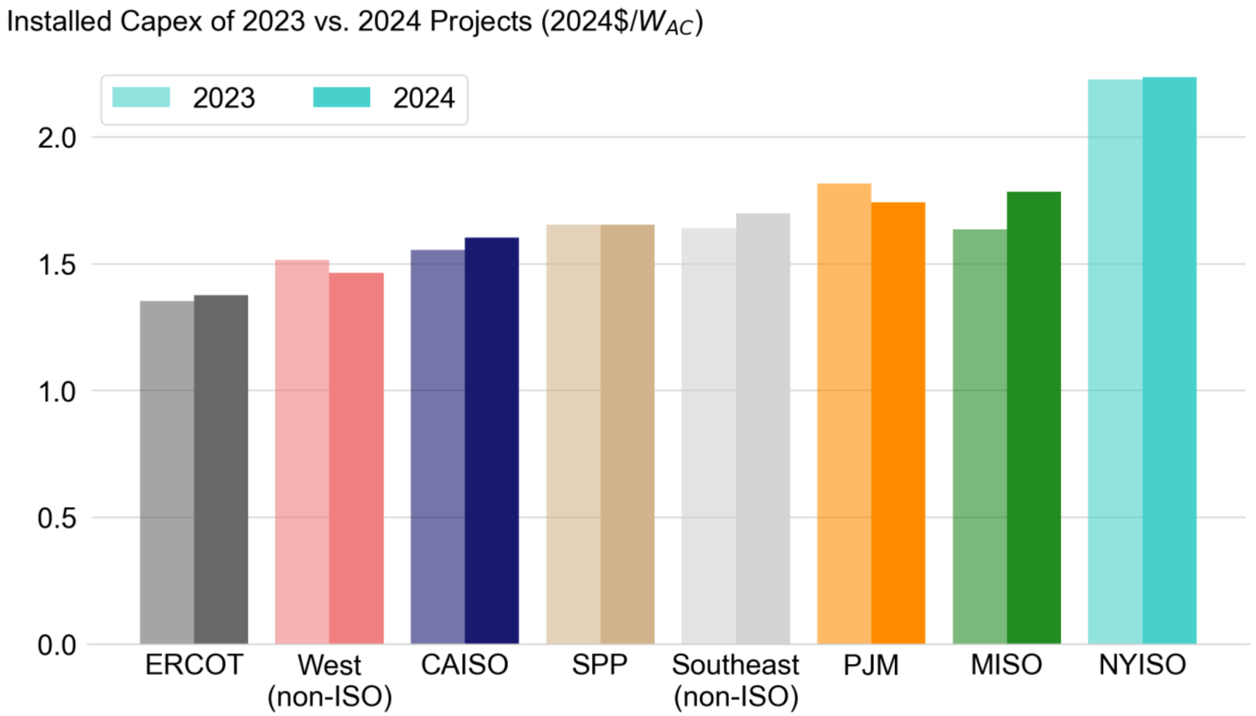
The new capacity is not uniformly spread across the U.S. – growth is concentrated in ERCOT (7.6 GW_{AC}), MISO (6 GW_{AC}), and the non-ISO West and Southeast (both 4.7 GW_{AC}).

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

Installed costs of PV were \$1.6/W_{AC} (\$1.2/W_{DC}) in 2024, similar to the year before

Sample: 425 projects totaling 44.2 GW_{AC}



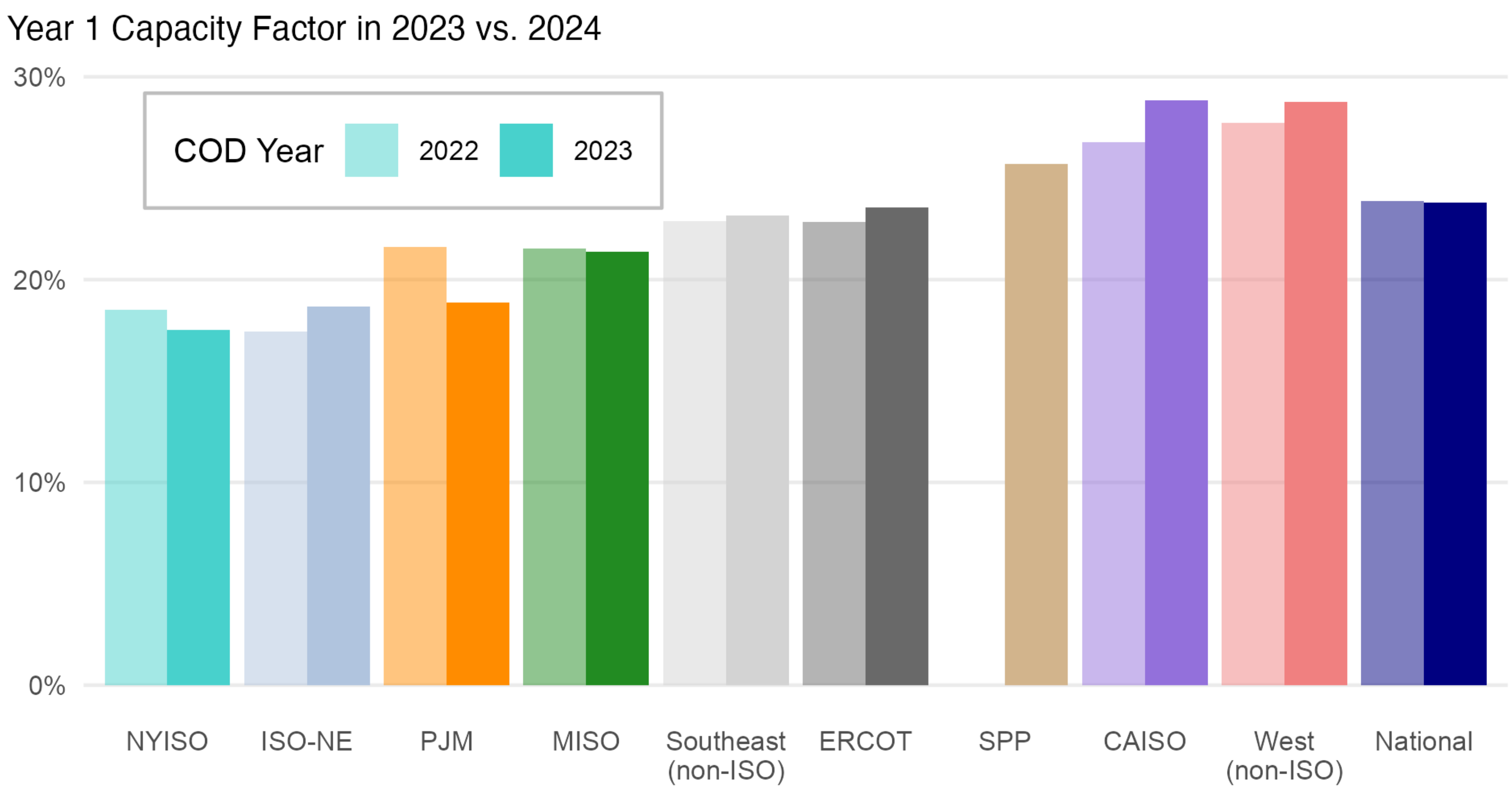


Capacity-weighted PV costs increased from \$1.59/W_{AC} in 2023 to \$1.61/W_{AC} in 2024. Our CapEx sample is robust, with 2024 data covering 92% of new projects. Costs vary by region, driven by differing project sizes (economies of scale), land availability, prevailing labor rates, and transmission network upgrade costs.

Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

First-year performance of newly built projects was stable in 2024, with variation by region

Sample: 342 plants totaling 29 GW_{AC}



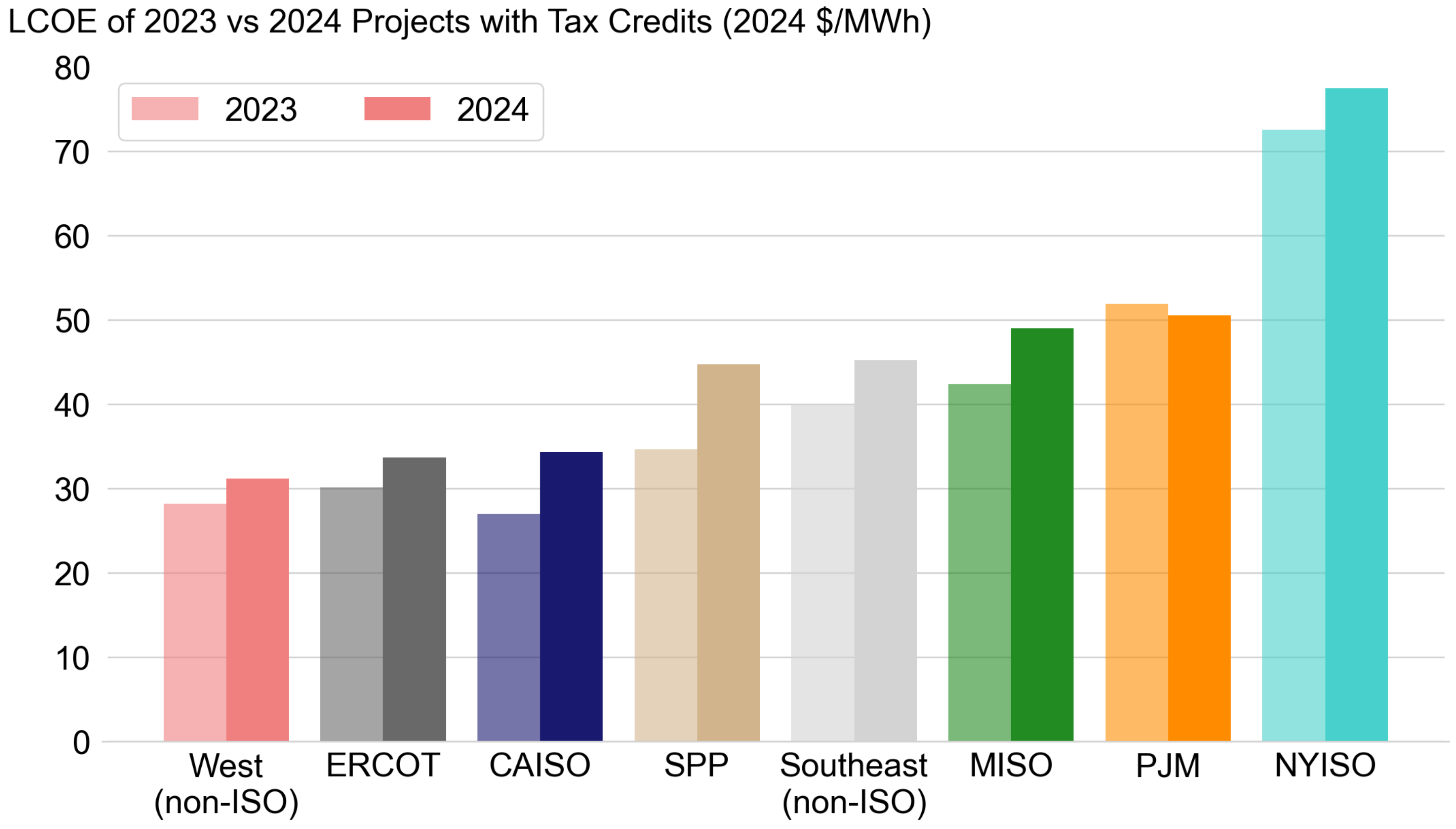
Solar plant performance is influenced by technical design (e.g., the share using single-axis tracking), interannual variation in the solar resource, and extreme weather (e.g., storm damage or wildfire smoke).

Performance remained relatively stable between 2023 (COD 2022 plants) and 2024 (COD 2023 plants), with regional variation. In 2024, the non-ISO West's capacity factor was 11 percentage points higher than that of NYISO.

Note: Only region/year combinations with at least four plants are included. Bars show capacity-weighted averages.

National average solar generation costs rose by 13% to $60/MWh (without tax credits) or $41/MWh (with tax credits) in 2024

Sample: 425 projects totaling 44.2 GW_{AC}



Higher financing costs, increasing CapEx and slightly lower estimated performance increased the national average levelized cost of energy (LCOE) of standalone PV from $53 in 2023 to $60/MWh in 2024 (without tax credits). Accounting for available tax credits (ITC, PTC, energy community bonus), LCOE rose from $36 to $41/MWh.

Average LCOE ranged from $31 in the non-ISO West to $77/MWh in NYISO (with tax credits), driven by regional differences in CapEx and performance.

Note: Only preliminary data is available for new solar projects coming online in 2024. Findings may shift as more final EIA Capex and project-specific performance data become available.

PPA prices of $22-40/MWh were typical for utility-scale PV projects that came online in 2024, with wide differences between regions

Sample: 2023 – 72 PPAs, 2024 – 41 PPAs

Power purchase agreement (PPA) prices reflect the bundled price of electricity and RECs as sold by the project owner.

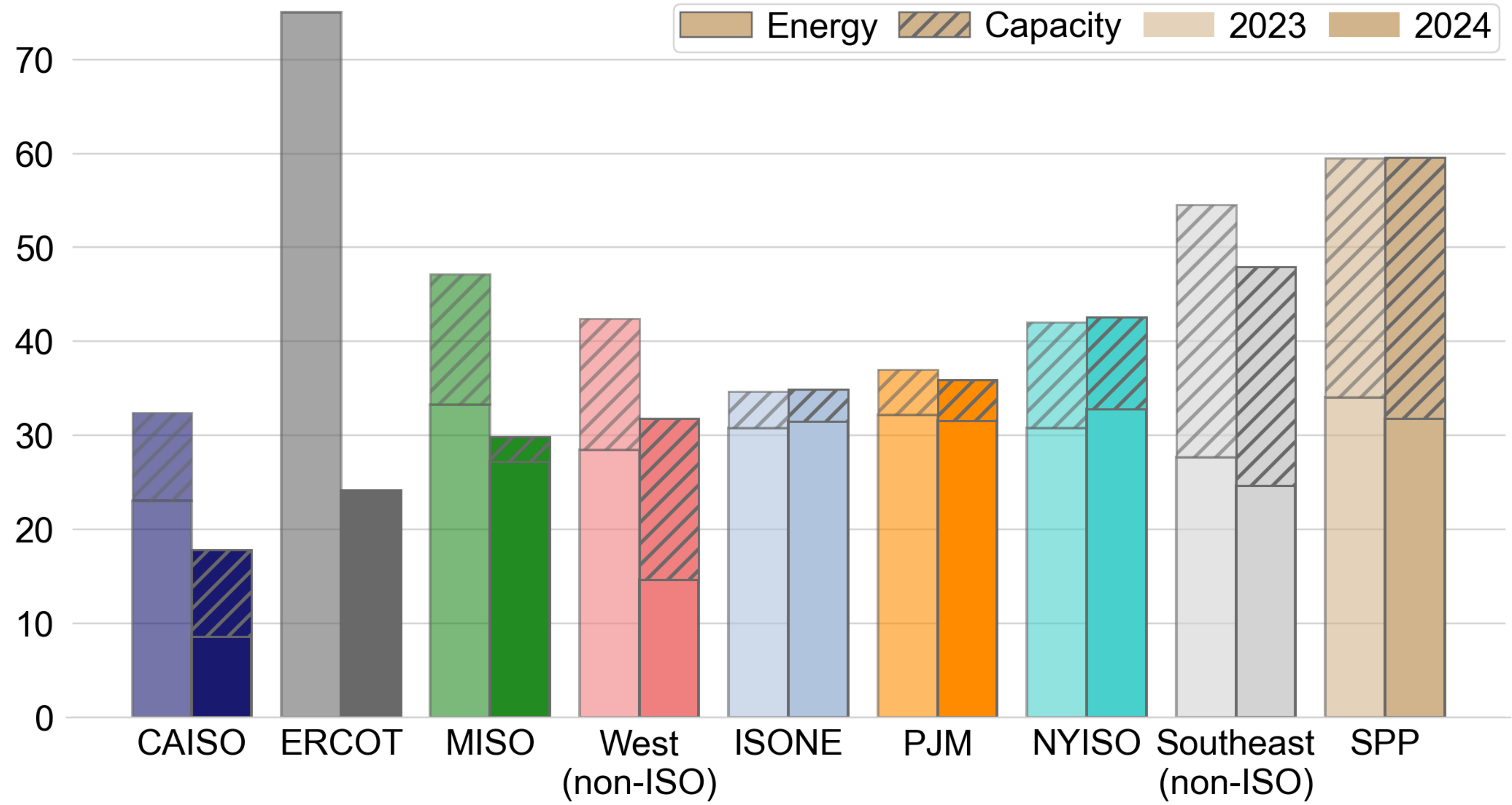
Not all projects sign a PPA and not all PPA terms are publicly available. PPAs for projects in our sample that commenced operations in 2024 had an average levelized price of $29/MWh. This is a 14% increase from 2023, driven by the sample shifting towards higher-priced regions. NYISO saw the highest average price in 2024 ($59/MWh) while the non-ISO West had the lowest ($24/MWh).

Note: $22-40/MWh range reflects 25th-75th percentiles of levelized PPA prices. Year-Region combinations with fewer than 2 PPAs are excluded from the graph. The PPAs shown here are typically executed 2-4 years before the commercial operation date.

PV's wholesale energy + capacity value declined by 35% to $32/MWh in 2024 and was less than generation costs for recent projects

Sample: 5,474 projects totaling 88.4 GW_{AC}

Energy and Capacity Value of 2023 vs 2024 Projects (2024 $/MWh)



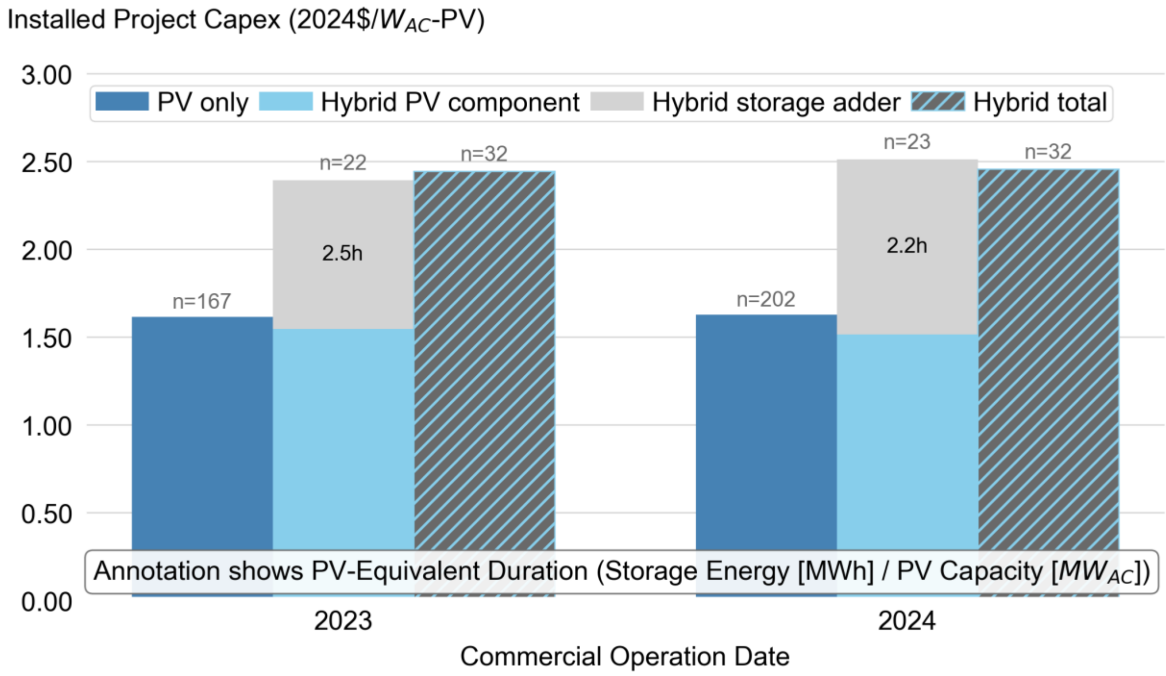
Driven by declining natural gas prices, fewer summer heat waves, and increasing solar penetration, PV's average market value decreased from $48/MWh in 2023 to $32/MWh in 2024. CAISO with 30% solar penetration had the lowest standalone solar value at $18/MWh, while high capacity values supported greater total values in SPP ($60/MWh) and many southeastern BAs.

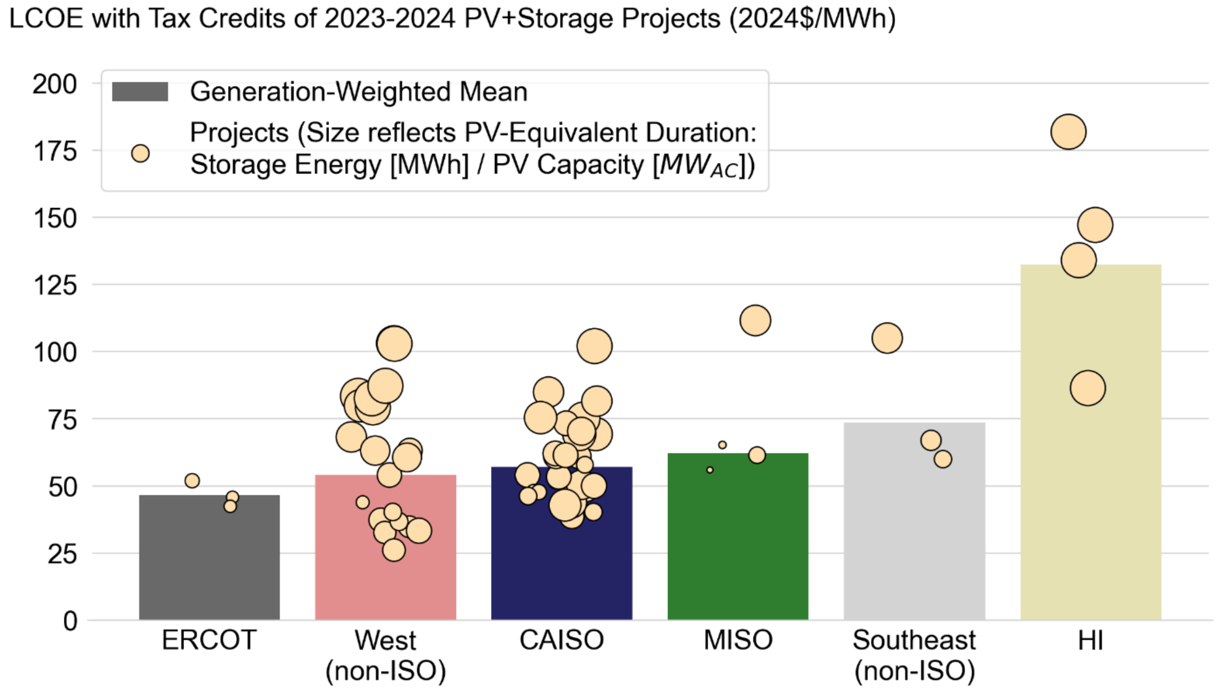
National average net value (levelized energy+capacity value minus LCOE) for solar standalone turned from $5/MWh for 2022 COD to $-7/MWh for 2023 COD projects (after accounting for tax credits). Net value ranges from -$34/MWh in NYISO to $17/MWh in SPP. 9 out of 30 BAs have positive net values in 2024, the rest negative net values.

Note: The data shows generation-weighted average annual market value of all large-scale (1 MW+) solar projects in select balancing authorities. Non-ISO BA results are shown in the accompanying data file.

Costs of PV+battery projects remained stable at \$2.5/$W_{AC\text{-}PV}$ in 2024, LCOE rose by 13% to \$87/MWh (before) or \$59/MWh after tax credits)

Sample: 64 greenfield plants totaling 9.4 GW_{AC} of PV and 5.4 GW / 19.7 GWh of batteries

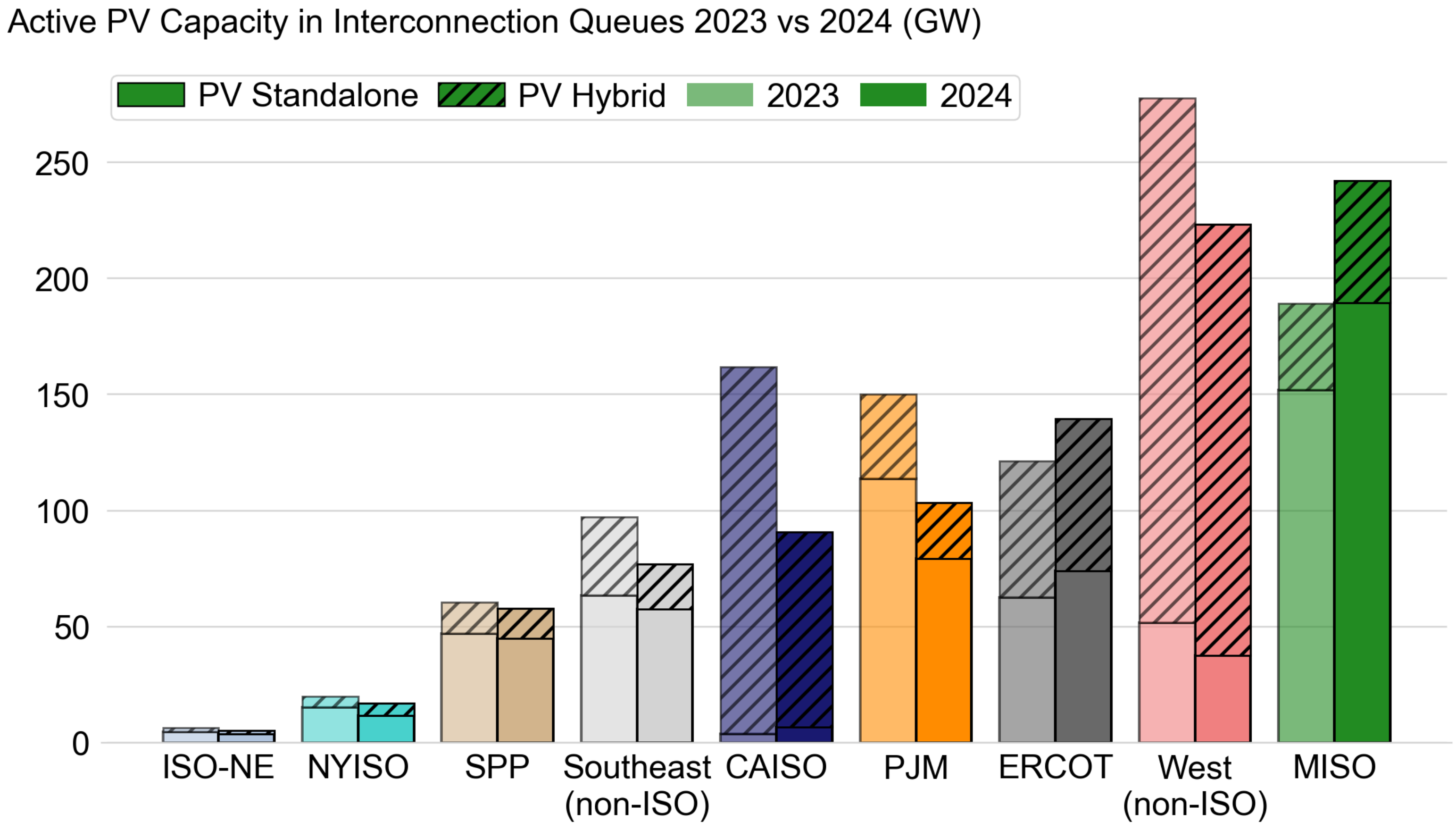




Capital costs for newly built PV–battery hybrids remained roughly flat in 2024. Among projects with component-level cost data, the battery contributed \$1.0/$W_{AC\text{-}PV}$ to total system cost. For hybrids without a component breakdown, we report only total system cost (hatched), which was \$2.46/$W_{AC\text{-}PV}$ in 2024.

Batteries added \$36/MWh (before) or \$25/MWh (after tax credits) to the LCOE of a PV project in 2024. The battery cost adder grows with the storage capacity ratio (battery capacity relative to PV capacity) and storage duration (larger bubbles in the graph above).

Active PV capacity in interconnection queues declined by 12% to 956 GW in 2024



7 out of 9 regions had contracting interconnection queues as a potential early result from FERC 2023 reforms. 161 GW of solar capacity entered the queues in 2024 (the remainder entered in earlier years), with MISO and the non-ISO West having over 200 GW of active solar requests. CAISO and PJM did not accept new interconnection applications in 2024, contributing to a decline in their pipeline.

Nationwide, 452 GW of queued solar includes a battery (47%). Hybridization is more common in regions with larger solar deployment like CAISO (93%) and the non-ISO West (83%).

If historical patterns persist, only ~9% of solar capacity requesting interconnection will ultimately get built and become operational.

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

Explore this briefing, an extensive workbook with all underlying data, and interactive visualizations: utilityscalesolar.lbl.gov

For questions or technical assistance requests, contact:

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See the following appendix for additional analyses

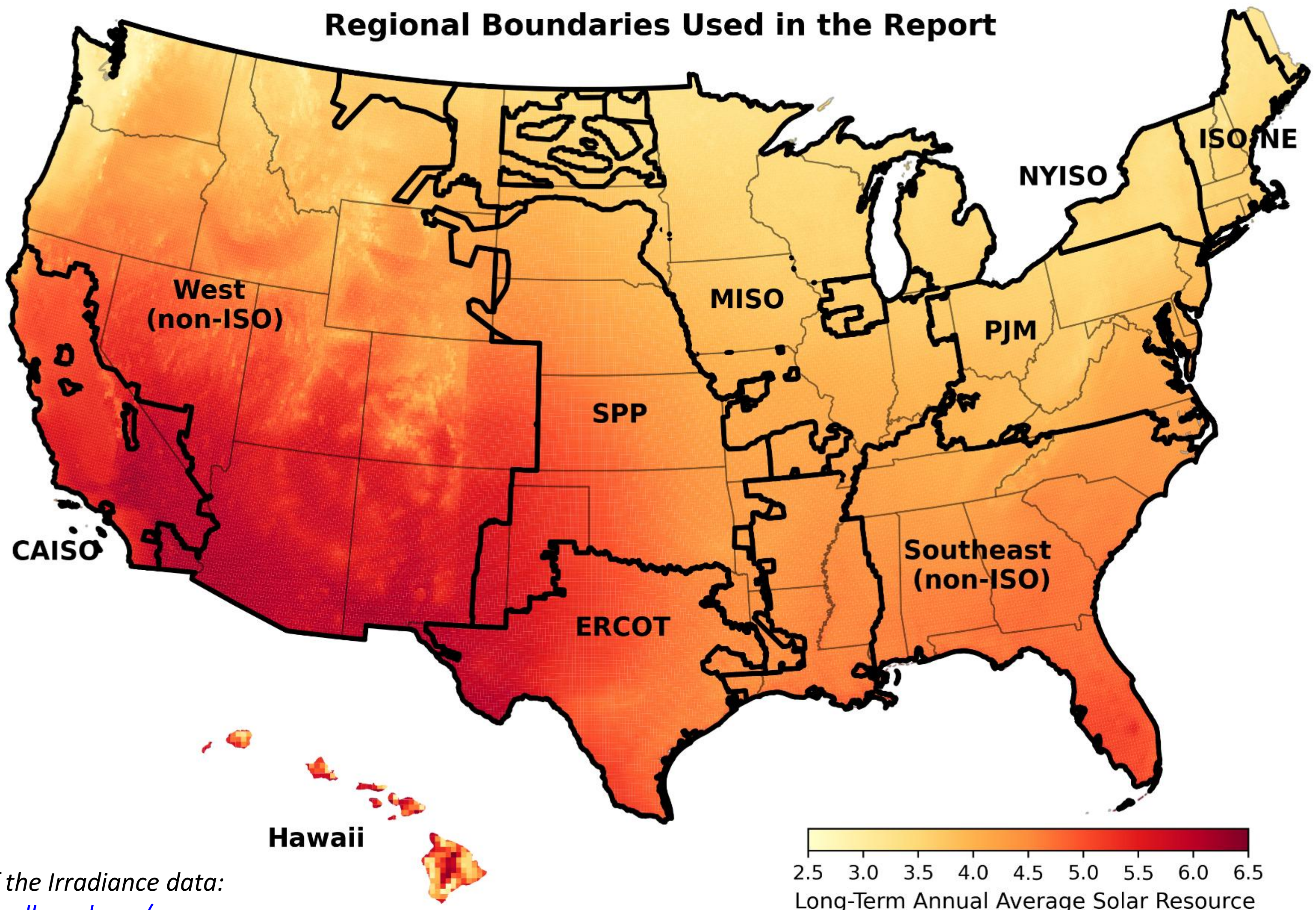
This material is based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under Solar Energy Technologies Office (SETO) Agreement Number 38444 and Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

Photo credit: SOLV Energy. Brian Doll.

Appendix to U.S. Utility-Scale Solar - 2025 Data Update

- Deployment and Technology Trends
- Capital Costs (CapEx) and Operation & Maintenance (O&M) Costs
- Performance (Capacity Factors)
- Levelized Cost of Energy (LCOE) and Power Purchase Agreements (PPA)
- Wholesale Market Value and Net Value
- PV+Battery Hybrid Plants
- Concentrating Solar Thermal Power (CSP) Plants
- Capacity in Interconnection Queues

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

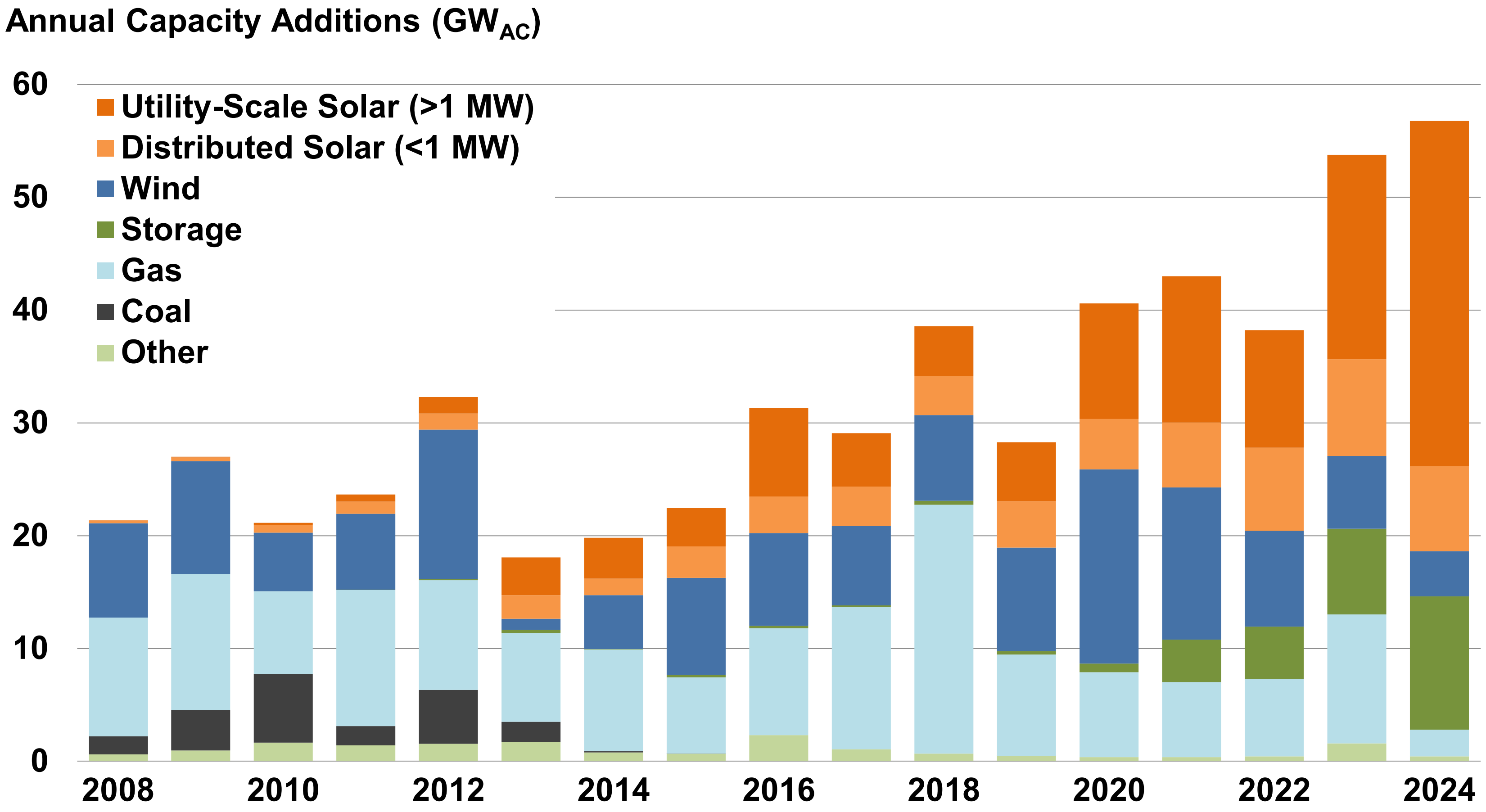
Deployment Trends Data: National and state-level deployment data are sourced from the Energy Information Administration (EIA) and LBNL datasets.

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.

Data Sample: Our data analysis focuses on a subset of the EIA 860 solar sample (all projects larger than 5 MW_{AC}):

- **2023**: 223 new projects totaling 19.3 GW_{AC} or 24.7 GW_{DC}
- **2024**: 248 new projects totaling 30 GW_{AC}. 221 projects with known DC capacity sum to 35.3 GW_{DC}

More than 50% of new U.S. electric nameplate generating capacity came from utility-scale solar in 2024



Utility-scale (54%) and distributed (13%) solar accounted for a combined 67% of all capacity added to U.S. grids in 2024. Over the first 7 months of 2025, utility-scale solar capacity additions are on par with the same period in 2024 (both 13.1 GW_{AC}).

Nameplate generating *capacity* is the maximum power output a generator is capable of. It is different from the amount of *energy* produced over time and the *capacity credit* – a measure of a generator's contribution to a system's resource adequacy – which are discussed later (capacity factors, capacity value).

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

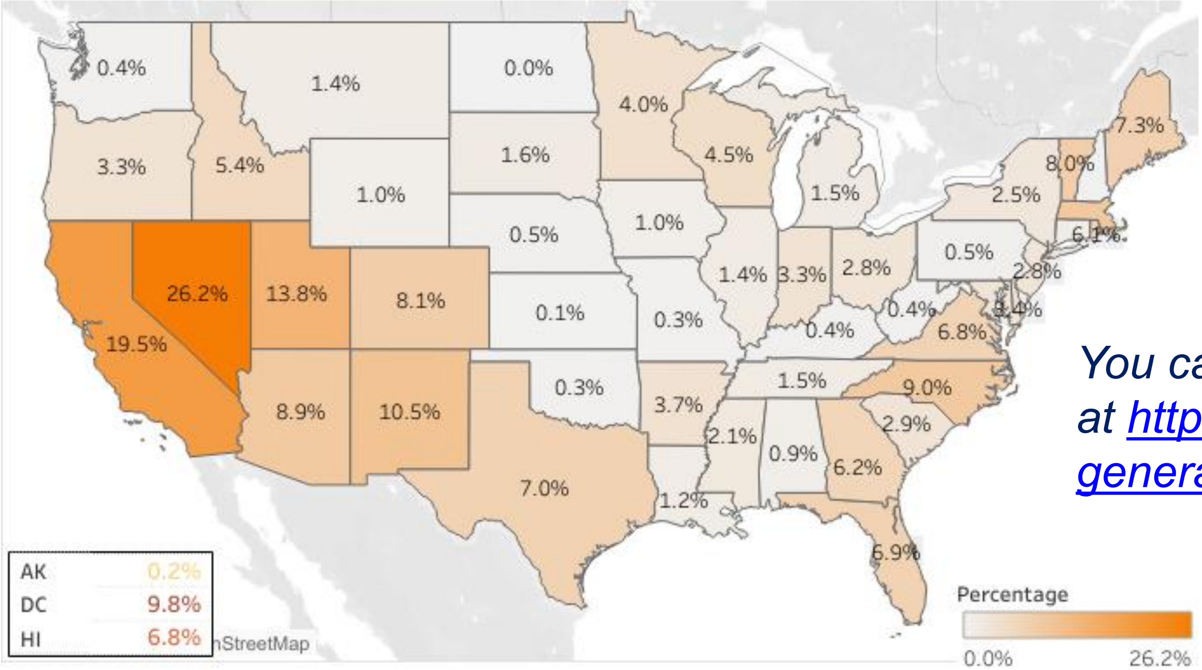
Utility-scale solar was responsible for 5% of U.S. electricity generation in 2024, and >25% of generation in Nevada

State	Preliminary 2024: Solar generation as a % of in-state generation – All Solar	Preliminary 2024: Solar generation as a % of in-state generation – Utility-Scale Solar Only	Preliminary 2024: Solar generation as a % of in-state load – All Solar	Preliminary 2024: Solar generation as a % of in-state load – Utility-Scale Solar Only
District of Columbia	64.8	9.8	2.9	0.4
California	32.4	19.5	28.8	17.3
Nevada	30.5	26.2	34.0	29.2
Massachusetts	25.6	9.1	11.8	4.2
Hawaii	21.5	6.8	22.1	7.0
Vermont	16.8	8.0	8.2	3.9
Utah	16.6	13.8	16.7	13.9
Maine	14.2	7.3	17.1	8.8
Arizona	13.3	8.9	17.0	11.3
Rhode Island	13.1	6.1	16.4	7.7
New Mexico	12.5	10.5	16.4	13.9
Colorado	11.5	8.1	11.9	8.4
North Carolina	9.7	9.0	9.6	8.9
Florida	8.6	6.9	9.0	7.2
New Jersey	8.0	2.8	6.8	2.3
Virginia	7.8	6.8	5.9	5.1
Texas	7.8	7.0	8.9	7.9
Delaware	7.5	3.4	3.2	1.4
Maryland	7.0	3.0	4.3	1.8
Idaho	6.9	5.4	4.9	3.8
Georgia	6.6	6.2	6.3	5.9
TOTAL U.S.	**6.9**	**5.0**	**7.5**	**5.4**

Solar's generation market share varies considerably depending on whether it is calculated as a percentage of total generation or load (e.g., D.C., Vermont).

As a percentage of in-state generation, California and Nevada's utility-scale solar market share exceeded 19% in 2024, while North Carolina, Massachusetts, D.C., New Mexico, and Utah all surpassed 9%.

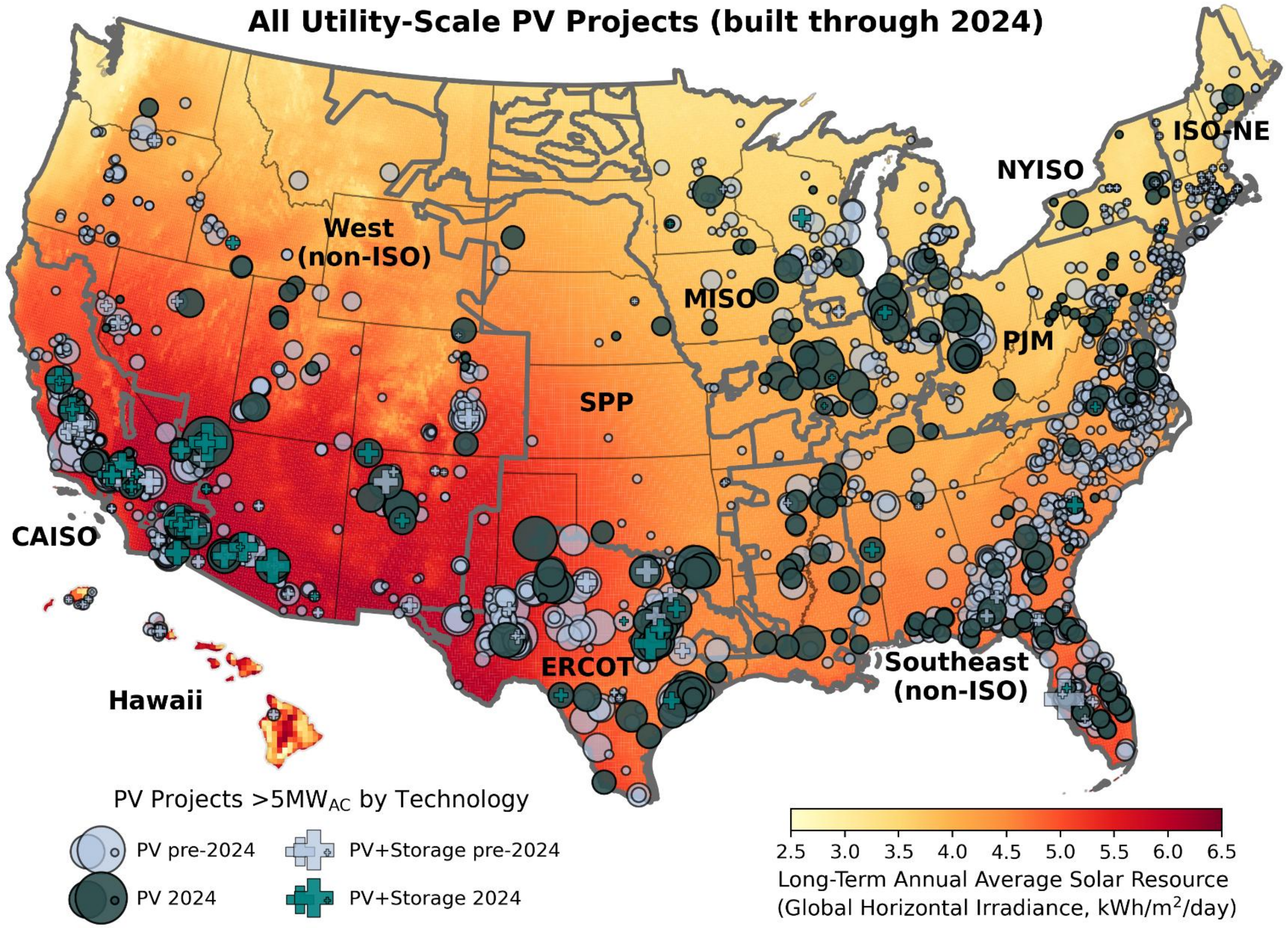
The utility-scale's contribution to total solar varies by state: a minority in the Northeast and Hawaii, a majority elsewhere in the U.S.



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 document uses >5 MW_{AC}). Percentages represent annual averages. Load is defined as electricity sales plus small-scale solar PV generation. Data is based on early release EIA data for 2024. Findings may be revised with final data.

Utility-scale solar has been built throughout the United States, but remains concentrated in some regions



Utility-scale PV is found throughout the nation, except for North Dakota and New Hampshire, which do not have any utility-scale solar projects in our sample.

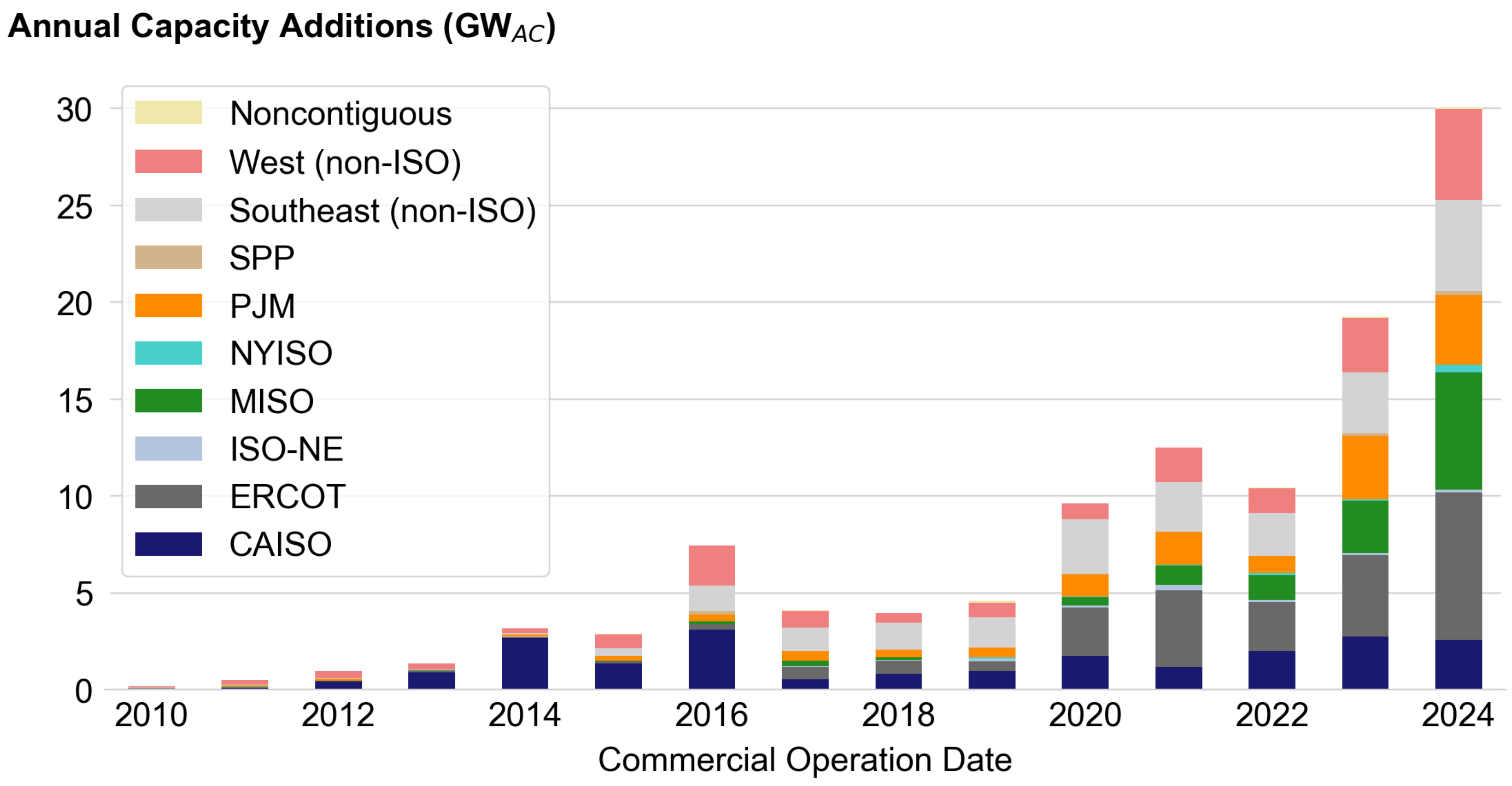
West Virgina had their first large solar projects (up to 80 MW) in 2024. 14 states more than doubled their solar capacity in 2024, led by Missouri, Nebraska, Oklahoma, Kentucky.

In 2024, PV+storage ( ) hybrid projects continued to grow. Batteries were added to already existing (14) and new (35) PV projects. Solar-rich non-ISO West added the most PV-coupled battery capacity (1,905 MW), followed by CAISO (1,465 MW).

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

ERCOT and MISO added the most utility-scale solar capacity in 2024. ERCOT and the Southeast have the most total deployment.

PV project sample: 1,759 projects totaling 111 GW_{AC}



Utility-scale solar deployment in 2024 represents multiple GW of additions in ERCOT (7.6 GW_{AC}), MISO (6.0 GW_{AC}), the non-ISO Southeast and West (both 4.7 GW_{AC}), PJM (3.6 GW_{AC}), and CAISO (2.6 GW_{AC}).

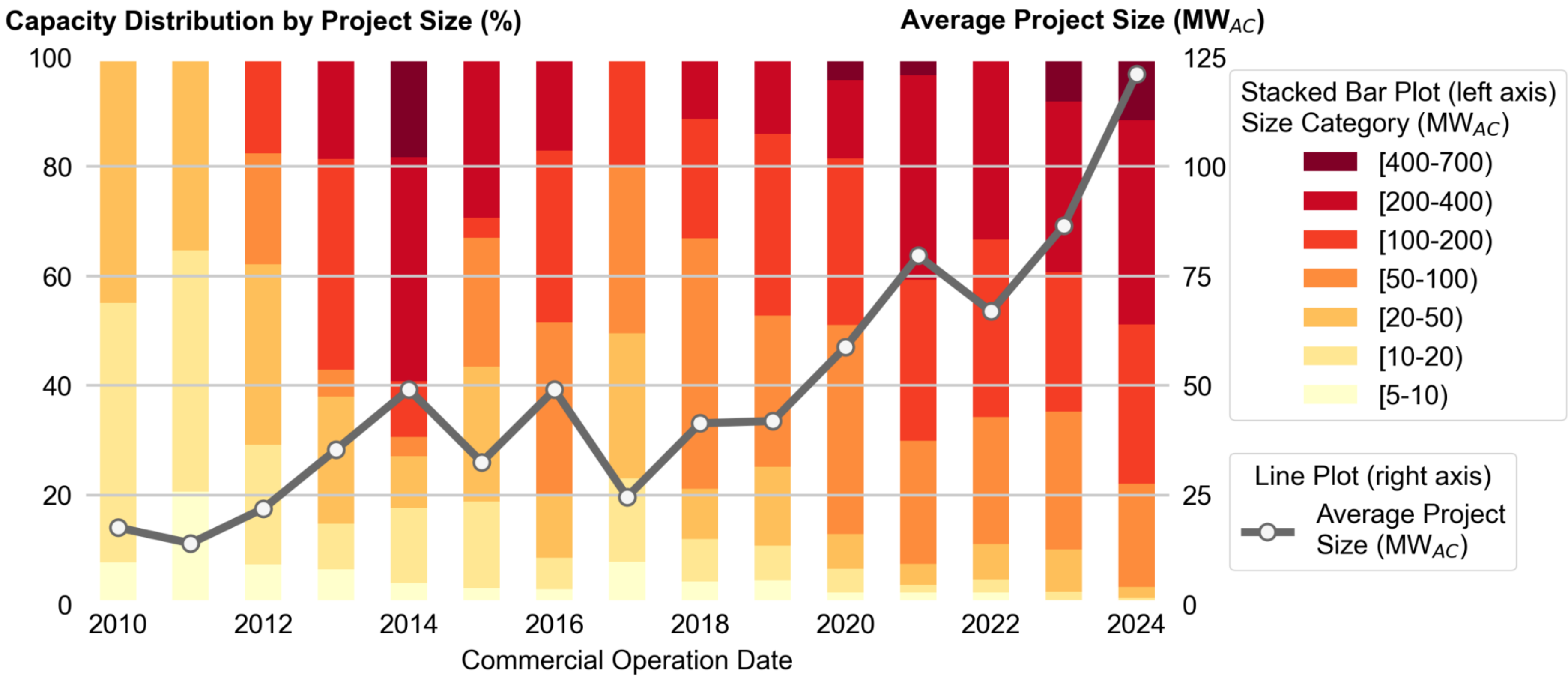
Taking a state perspective, **Texas** added the most with 7.7 GW_{AC} followed by **Florida** (3.2 GW_{AC}), **California** (2.5 GW_{AC}), **Illinois** (1.6 GW_{AC}) and **Ohio** (1.5 GW_{AC}). 9 states added more than 1 GW_{AC} of new capacity.

In cumulative deployment, ERCOT (23 GW_{AC}), the non-ISO Southeast (21 GW_{AC}), and CAISO (also 21 GW_{AC}) have the most. The non-ISO West (17 GW_{AC}) is following closely.

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

New solar projects are now 120MW$_{AC}$ on average, 40% larger than in 2023 and much larger than in the 2010s

PV project sample: 1,759 projects totaling 111 GW$_{AC}$



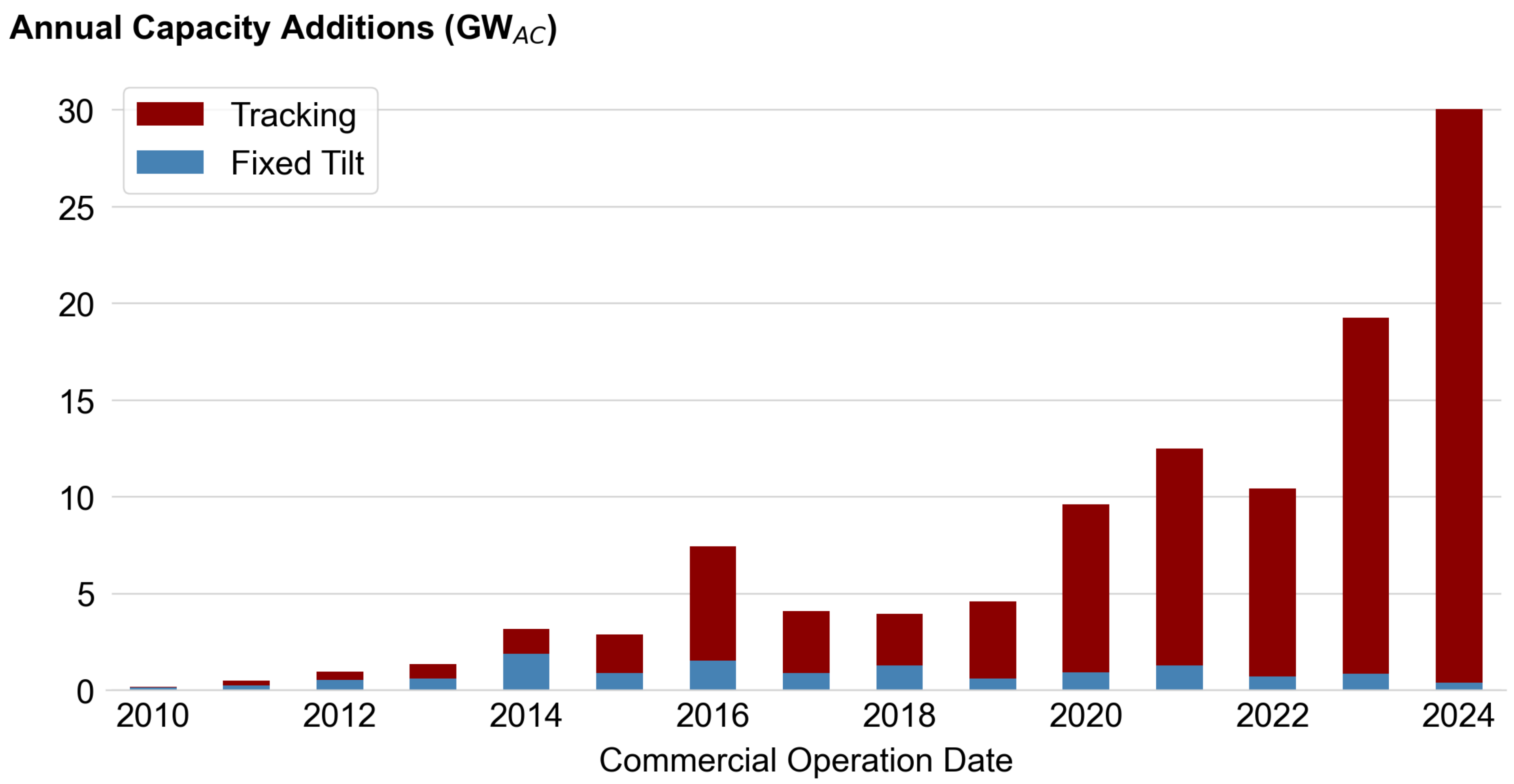
Average project size has grown 7x since 2010 to 120MW$_{AC}$. 2024 saw 52 projects >200MW$_{AC}$ come online.

The Gemini Solar project (690MW$_{AC}$) built in 2024 in NV is the largest to date.

Multiple projects larger than 1GW$_{AC}$ are in the pipeline. Greater project size coincides with slow-moving interconnection queues and economies of scale (discussed later).

99% of new project capacity chose single-axis tracking over fixed-tilt racking

PV project sample: 1,757 projects totaling 111 GW_{AC}



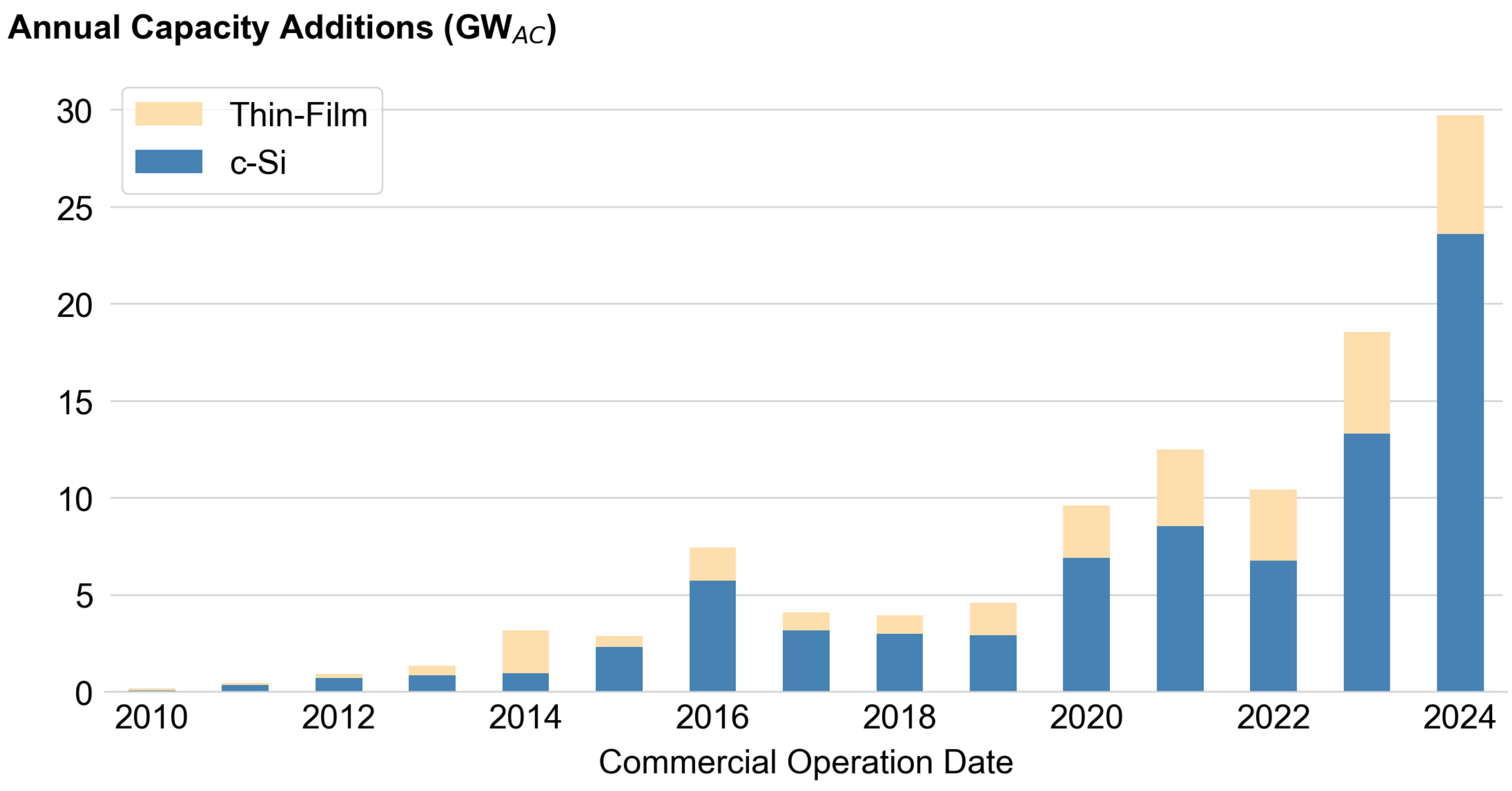
The upfront cost premium for **trackers** faded over time, resulting in favorable overall economics (discussed [later](#)).

Fixed-tilt installations are now only chosen in a few edge cases (challenging terrain or high wind loading).

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

Use of c-Si modules grew in 2024 to 79% of added capacity

PV project sample: 1,747 projects totaling 110 GW_{AC}



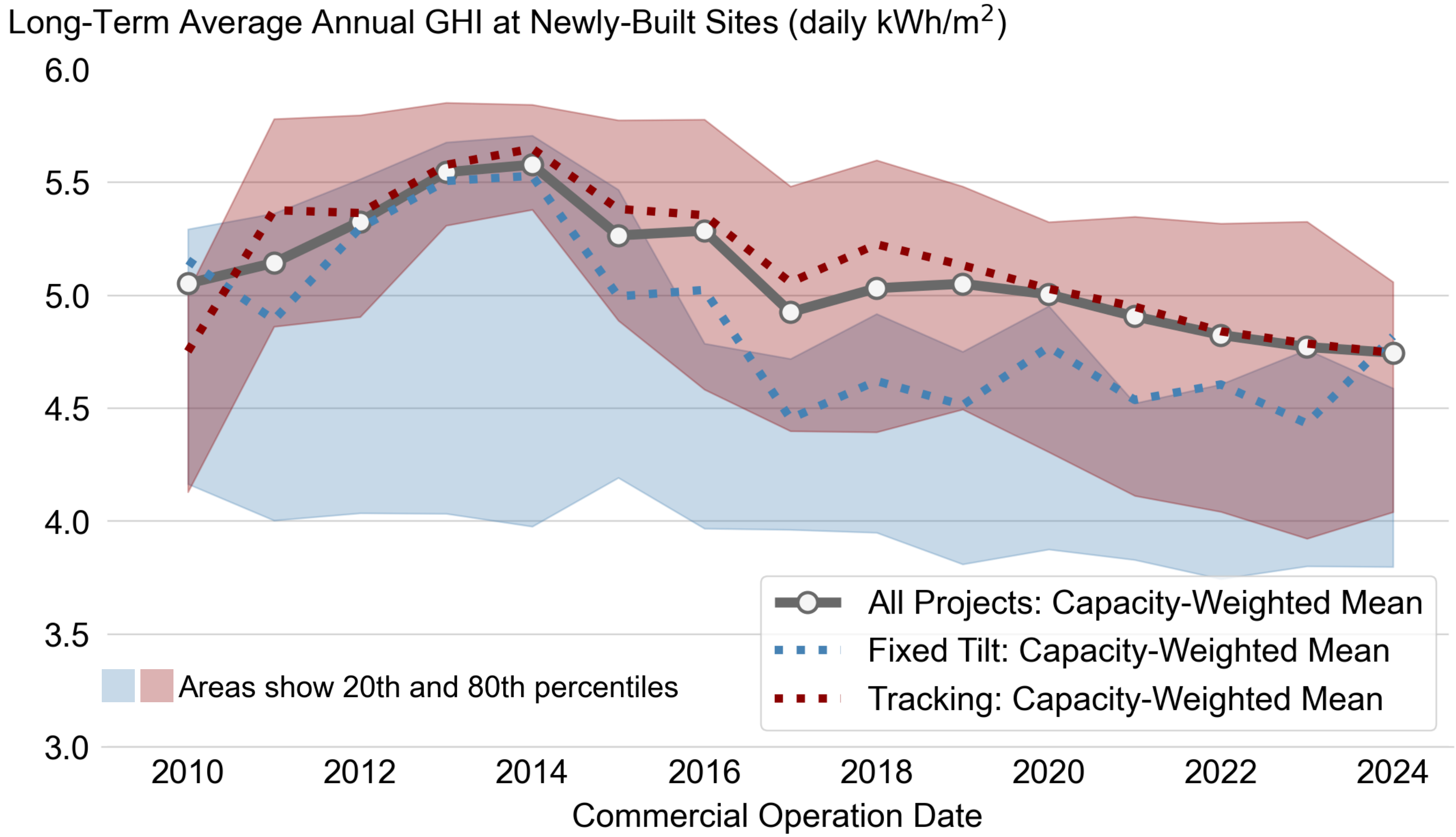
Note: The 2024 sample includes 2 projects (0.3GW_{AC}) without conclusive module type data which are excluded from the graph above

c-Si modules have been the dominant module technology at large-scale solar projects in the US since 2015. After a temporary decline in 2022, c-Si modules expanded their market share in 2024 to 79% of newly installed capacity.

Thin-film modules grew in popularity between 2016 and 2022. In 2024 they reached a new annual deployment record of 6 GW_{AC}, even though their market share declined.

Solar projects were built in very solar-rich areas in the early 2010s. Since then, utility-scale solar projects have expanded to regions with lower resource quality.

PV project sample: 1,758 projects totaling 111 GW_{AC}



Sites built in 2014 had the highest average long-term global horizontal irradiance (**GHI**). Since then, the market has expanded to less-sunny states and the long-term GHI at sites built in 2024 was down to 4.75 kWh/m^2/day.

Fixed-tilt PV is now primarily built at lower-insolation sites, while **tracking** PV is increasingly deployed in those same areas (note the decline in its 20th percentile).

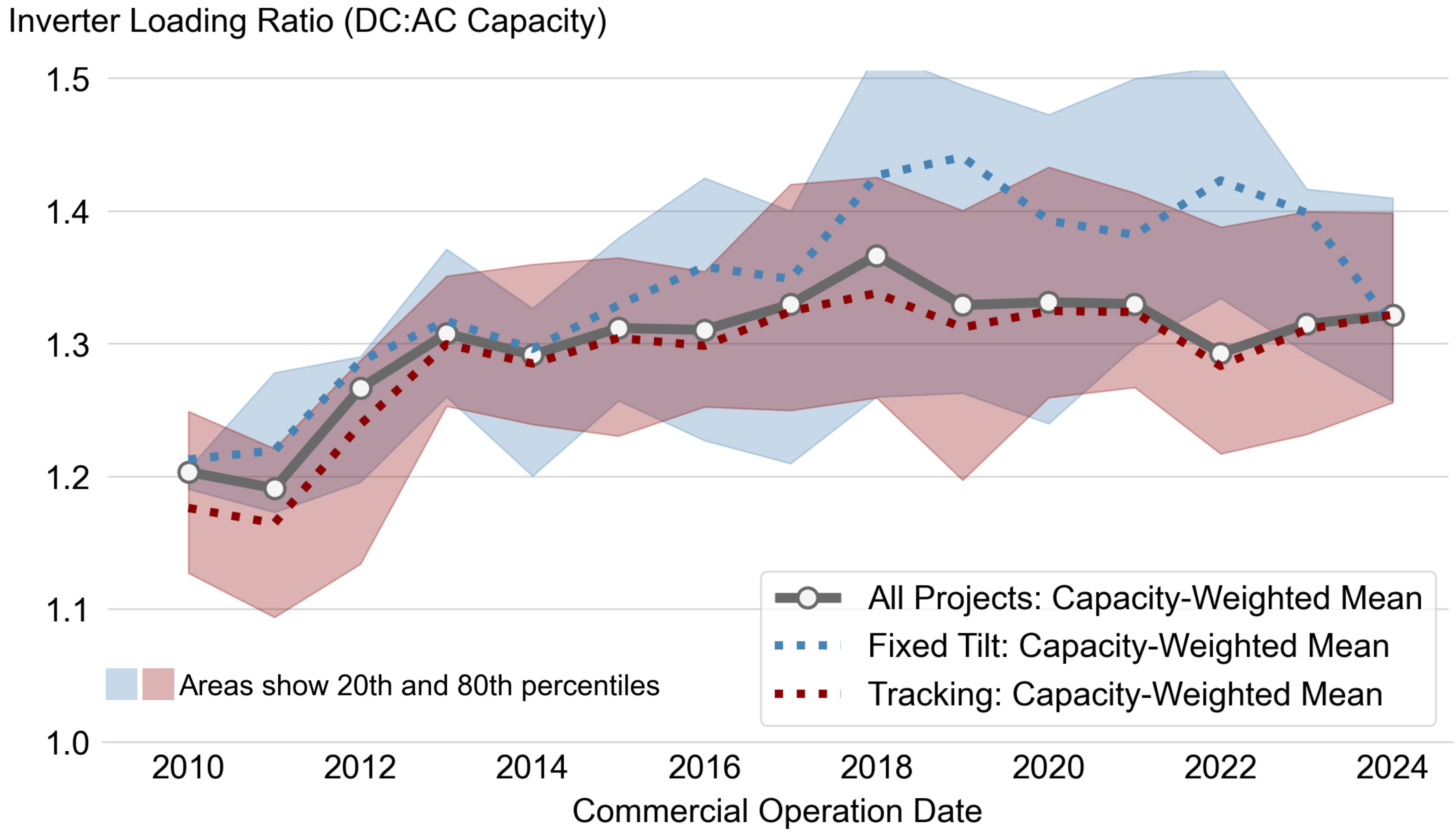
Exceptions are fixed-tilt installations in windy regions (Florida), on brownfields and landfill sites, and on particularly challenging terrain. Only 2 out of 13 of these new 2024 projects have a south-western orientation to maximize evening production.

All else equal, the buildout of lower-GHI sites dampens solar energy production per installed capacity (shown in sample-wide capacity factors later).

Note: We use NREL's NSRDB to estimate long-term solar resource quality for each new USS project.

The average inverter loading ratio (ILR) has held steady since 2017

PV project sample: 1,726 projects totaling 107 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 2024, the capacity-weighted average *inverter loading ratio* (**ILR:** MW_{DC} to MW_{AC} ratio) did not differ meaningfully between fixed-tilt installations and tracking projects.

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

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, and trade press articles.
- CapEx estimates for projects built from 2013-2024 have been cross-checked against confidential EIA-860 data obtained under a non-disclosure agreement. Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA. LBNL did not include all preliminary data points after a data review and will provide revised estimates in a later update.

CapEx Methods:

- We present data in $\$/W_{AC}$ terms to facilitate cost comparison between generators of multiple fuel types. The accompanying data file on utilityscalesolar.lbl.gov also provides detailed data in $\$/W_{DC}$ terms. CapEx is adjusted from nominal to real $ using BEA's implicit GDP price deflator (Table 1.1.9).
- 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.
- We first show costs for PV standalone projects (or PV component costs of hybrid projects). Storage costs are discussed later in the hybrid section.

O&M Data:

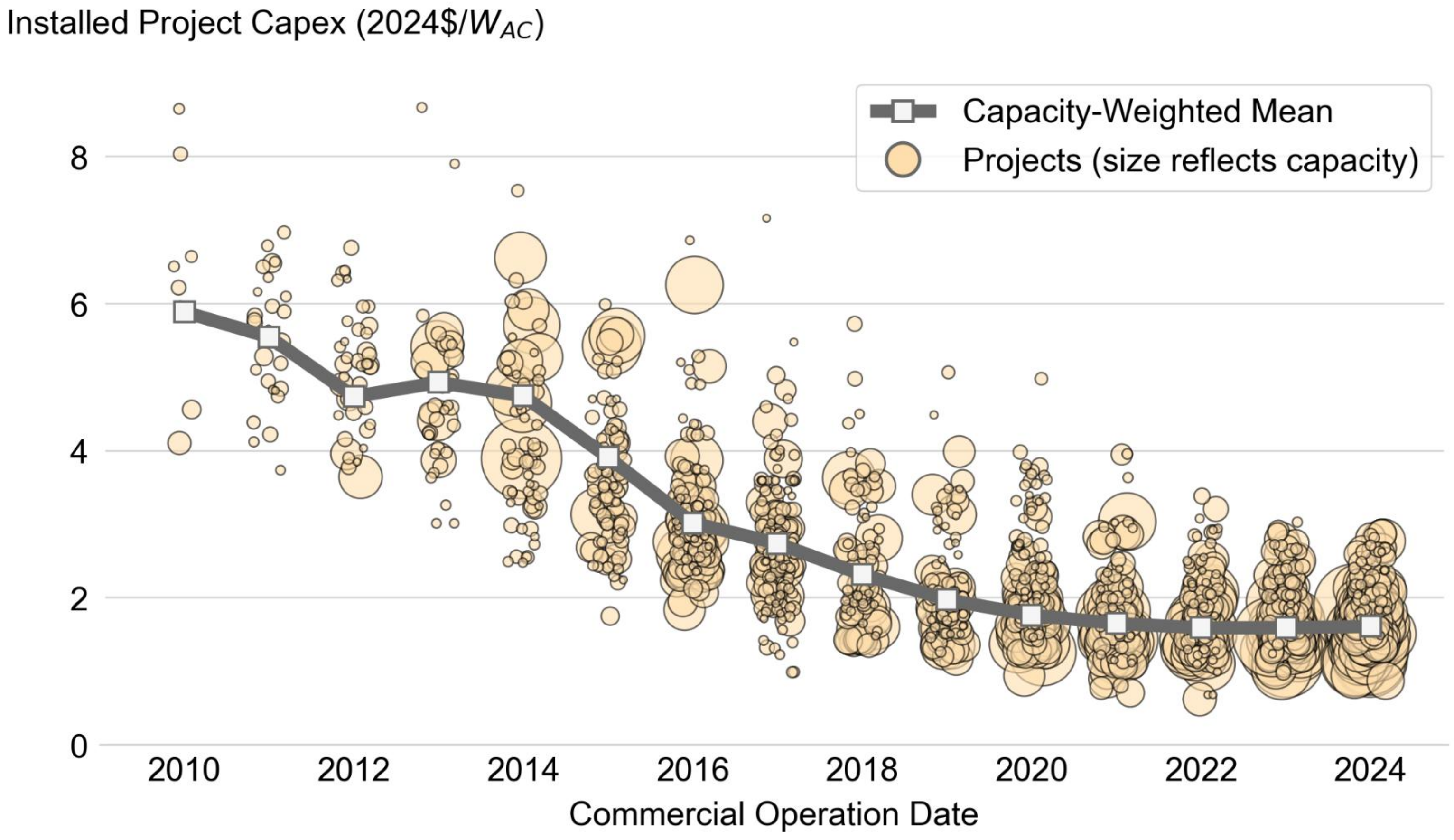
- Plant-level operation and maintenance costs, capacity, net generation, and construction year are sourced from FERC Form 1 Annual Reports, which are filed by major electric utilities.

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 were $1.6/W_{AC}$ ($1.2/W_{DC}$) in 2024

PV project sample: 1,629 projects totaling 104 GW_{AC}



Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

Costs for installed utility-scale PV fell by 73% between 2010 and 2022 but have been flat or slightly increased since then in real dollar terms.

Capacity-weighted means (reflecting the average costs of solar capacity) increased from $1.59/$W_{AC}$ in 2023 to $1.61/$W_{AC}$ in 2024.

Medians (reflecting typical project costs, not shown in graph) increased from $1.64/$W_{AC}$ in 2023 to $1.70/$W_{AC}$ in 2024.

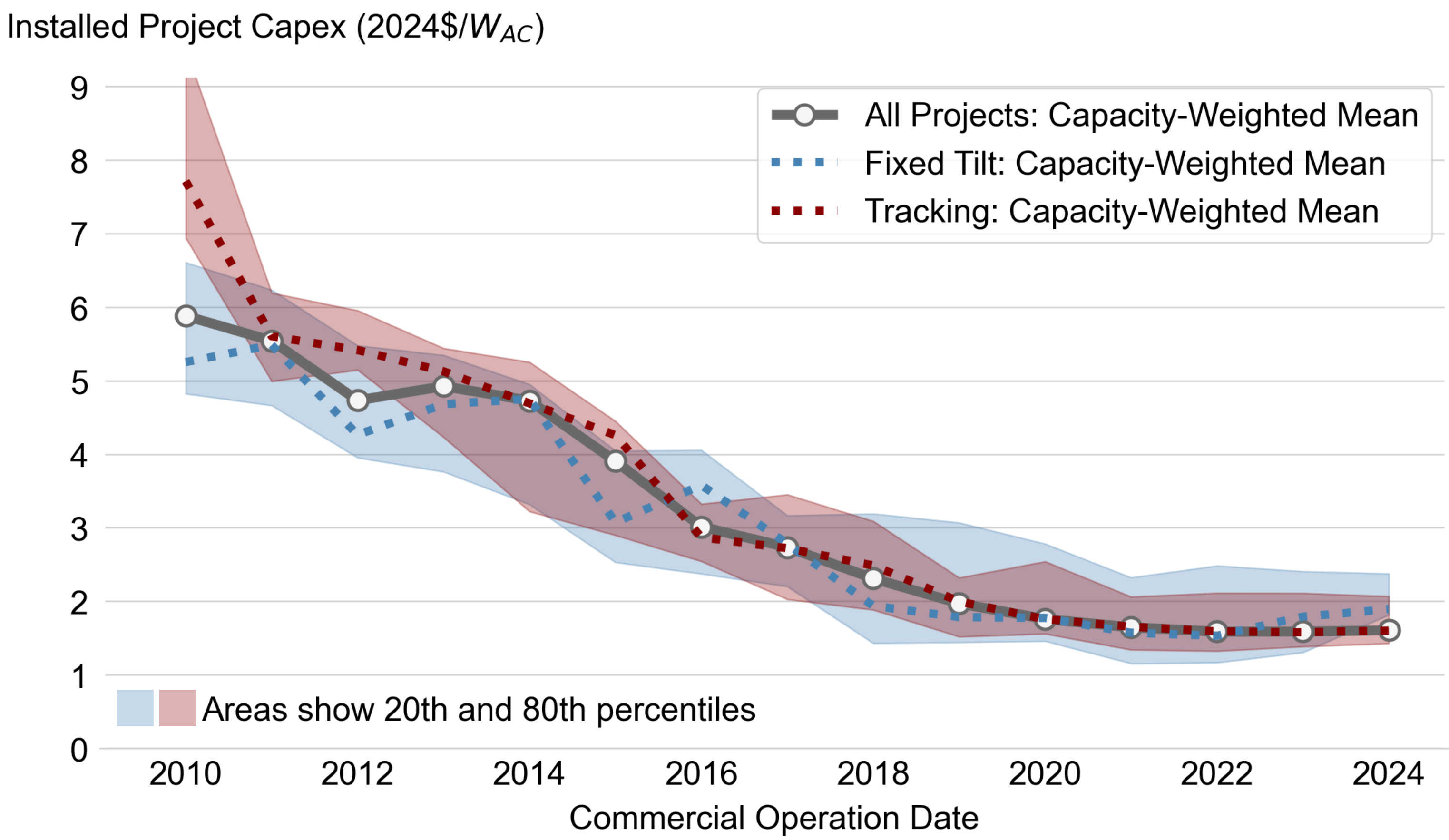
Our sample is robust, covering 93% of installed capacity through 2024. 2024 data covers 92% of new projects (227) or 88% of new capacity (26.4 GW_{AC}).

Data presented here refers only to PV costs (additional battery costs of hybrid projects are discussed later).

Detailed statistics in $/$W_{DC}$ are shown in the accompanying data workbook.

2024 tracking projects cost less than fixed-tilt projects

PV project sample: 1,629 projects totaling 104 GW_{AC}



Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

We focus here on cost differences between projects using tracking and fixed-tilt mounting. The graph shows capacity-weighted 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…).

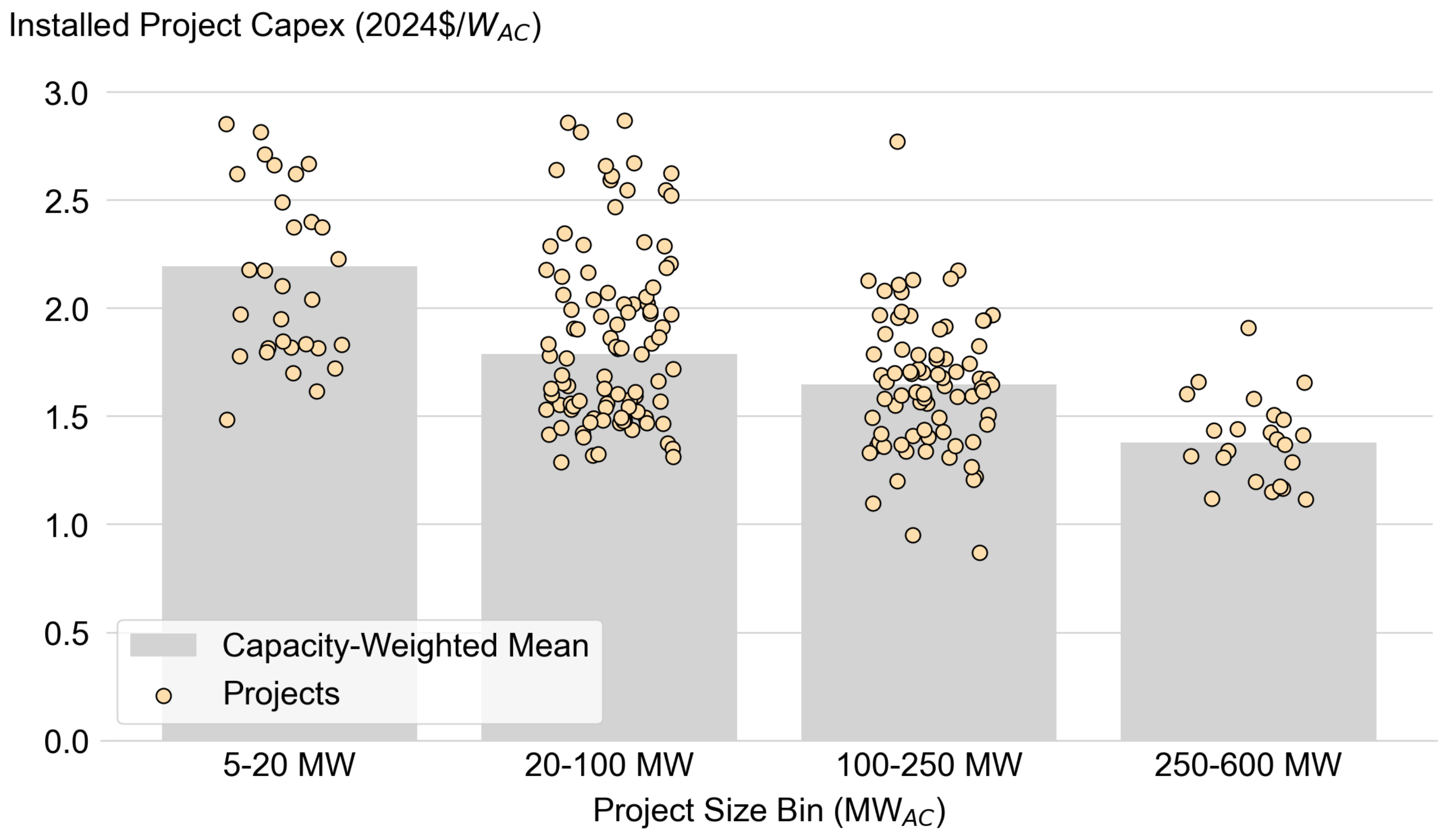
Trackers can sustain some higher upfront costs because they deliver more energy per installed capacity. Historically, tracking projects have often been more expensive, but the cost premium has fluctuated and at times even reversed (like in 2016 and now in 2024).

Beginning in 2020, tracker installations grew rapidly. By 2024, 99% of all new capacity used trackers, and fixed-tilt has only been used at particularly challenging sites (see earlier slide).

Tracking projects ($1.61/$W_{AC}$ or $1.22/$W_{DC}$) had lower overall costs than fixed-tilt projects ($1.90/$W_{AC}$ or $1.35/$W_{DC}$) in 2024.

Larger solar projects (>250 MW) cost 37% less than smaller (5-20 MW) projects per MW of installed capacity in 2024

PV project sample in 2024: 227 projects totaling 26 GW_{AC}



Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

Differences in project size are one major driver in explaining cost variation—we focus only on 2024 for this slide. The apparent economies of scale are likely one reason why average project sizes have grown by a factor of five since 2017.

Projects larger than 250 MW_{AC} at \$1.38/W_{AC} cost substantially less than projects smaller than 20MW_{AC} at \$2.19/W_{AC}.

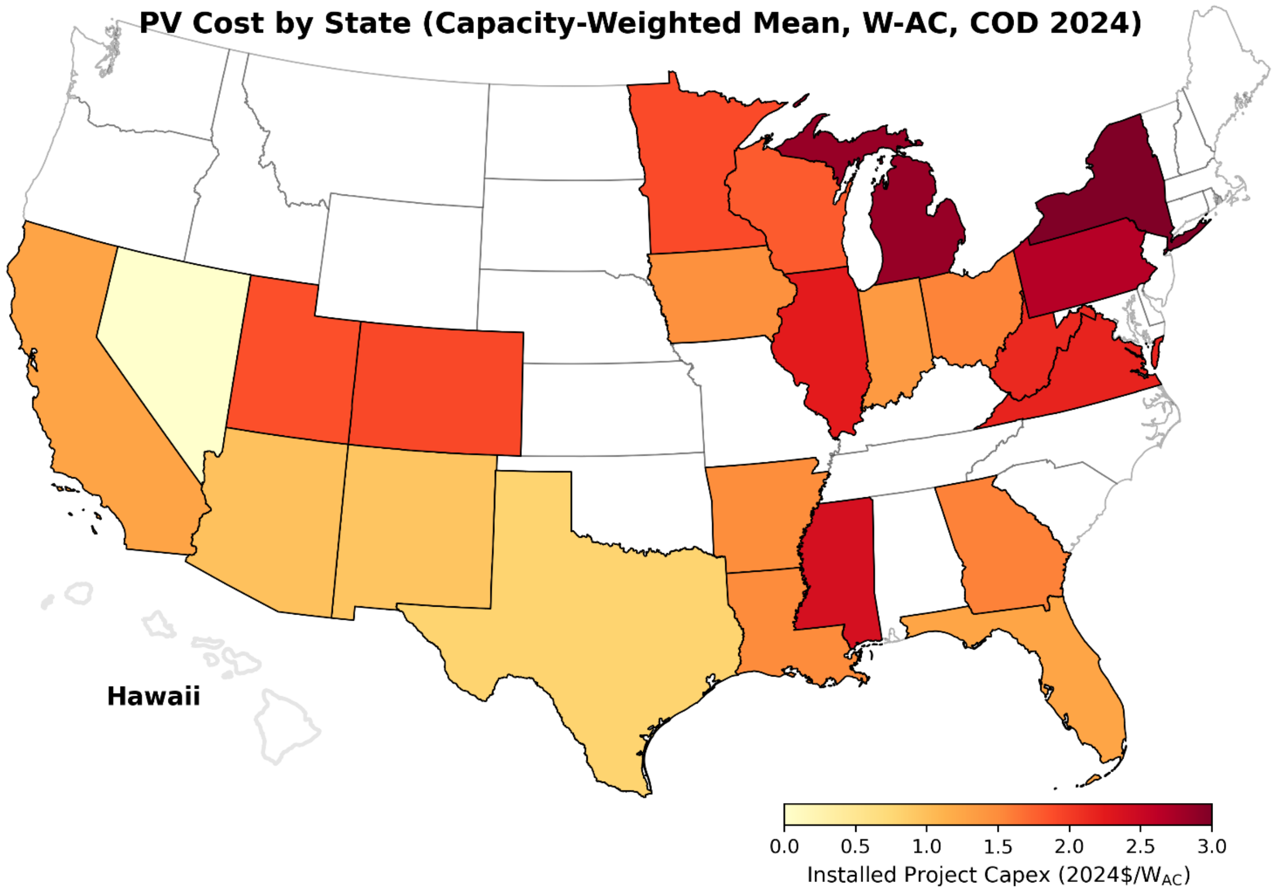
In \$/W_{DC} terms, prices seem to decline especially among projects larger than 100MW_{DC}:

- \$1.62/W_{DC} for 5-20 MW
- \$1.53/W_{DC} for 20-100 MW
- \$1.28/W_{DC} for 100-250 MW
- \$1.10/W_{DC} for 250-800 MW

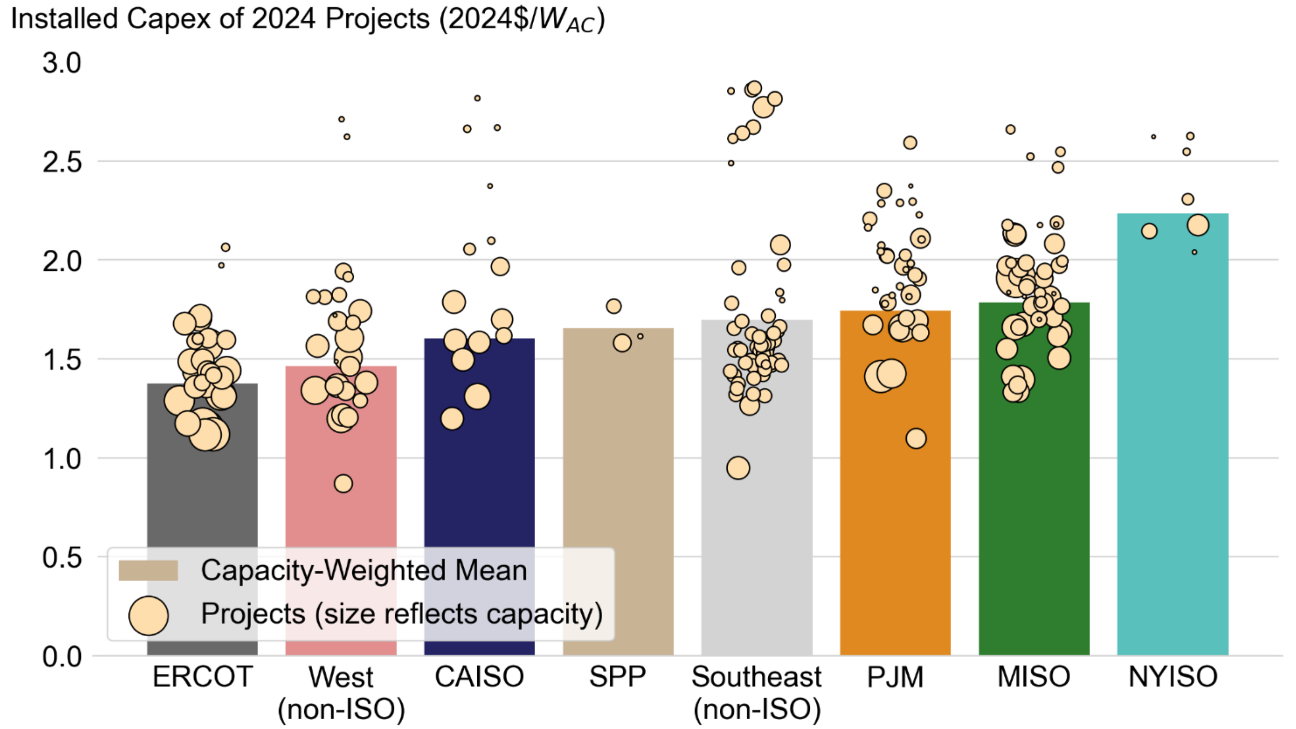
Detailed statistics in \$/W_{DC} are shown in the accompanying data workbook.

2024 solar projects in ERCOT and the Southwest were usually cheaper than in the North and East

PV project sample in 2024: 227 projects totaling 26 GW_{AC}



Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.



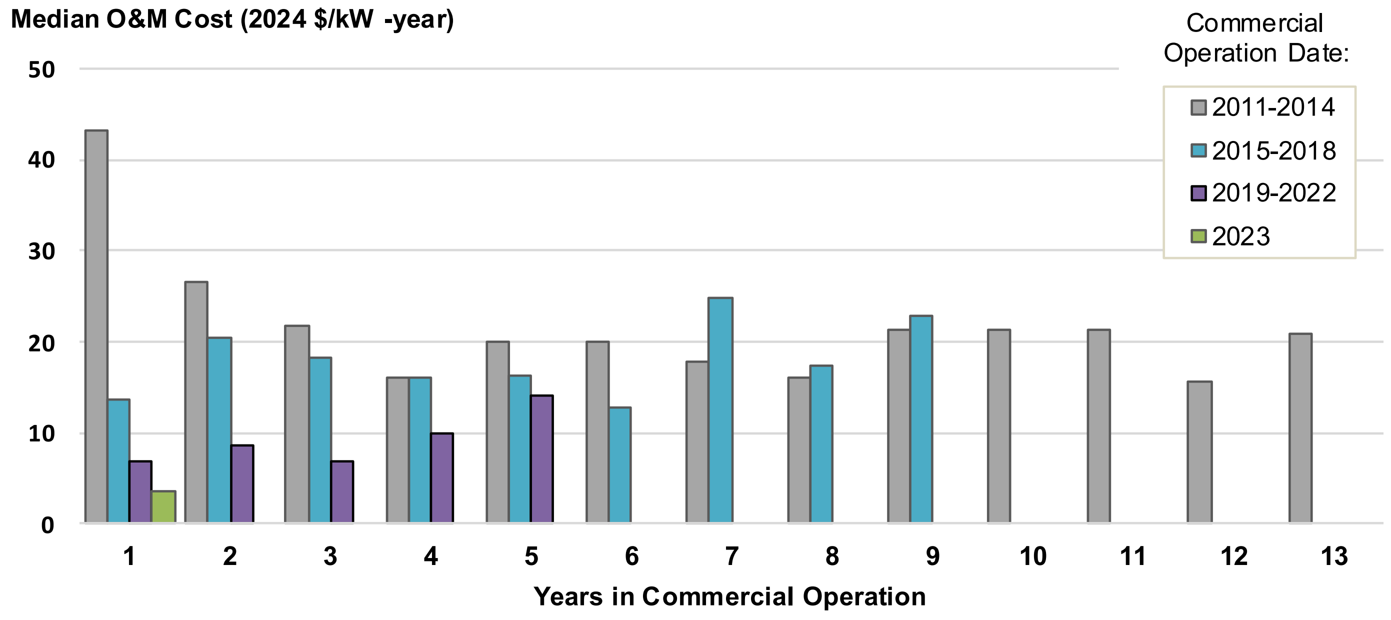
Utility-scale solar project costs also vary by region, driven in part by differing project sizes coupled with the previously discussed economies of scale, but also due to land availability, prevailing labor rates and transmission network upgrade costs. Projects in ERCOT ($1.38/$W_{AC}$ or $1.06/$W_{DC}$) and the non-ISO West have lower costs than the northeastern U.S.

Detailed statistics in $/$W_{DC}$ are shown in the accompanying data workbook.

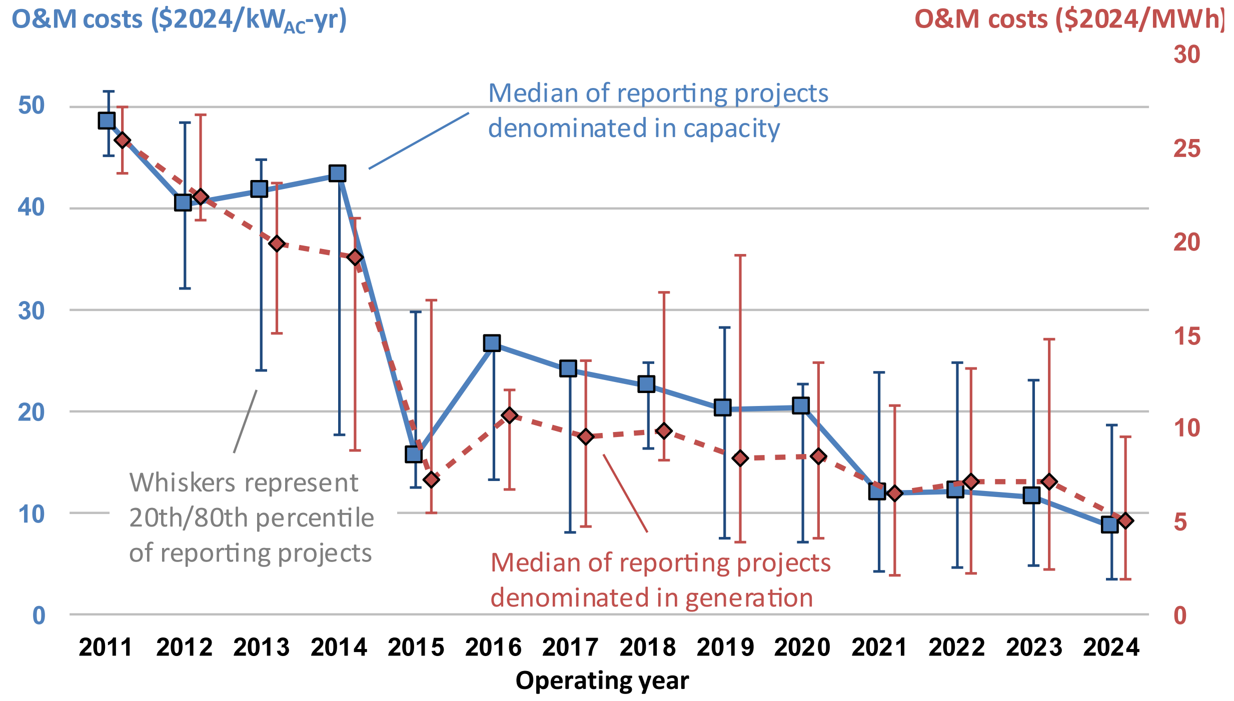
PV projects now spend much less on operation and maintenance (O&M) during their first few years than projects built in the 2010s

PV project sample in 2024: 187 projects totaling 10.0 GW_{AC}

Regulated utilities report annual 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.	Cost Scope (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



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 5 of a project's life there does not appear to be a sustained upward or downward trend in O&M costs.



Median O&M costs for the cumulative sample have declined from about \$40/kW_{AC}-year or \$22/MWh in 2012 to about **\$11/kW_{AC}-year or \$5/MWh in 2024**.

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. Since we require one full year of generation data, our performance sample includes projects built through 2023, with generation data through 2024.

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.

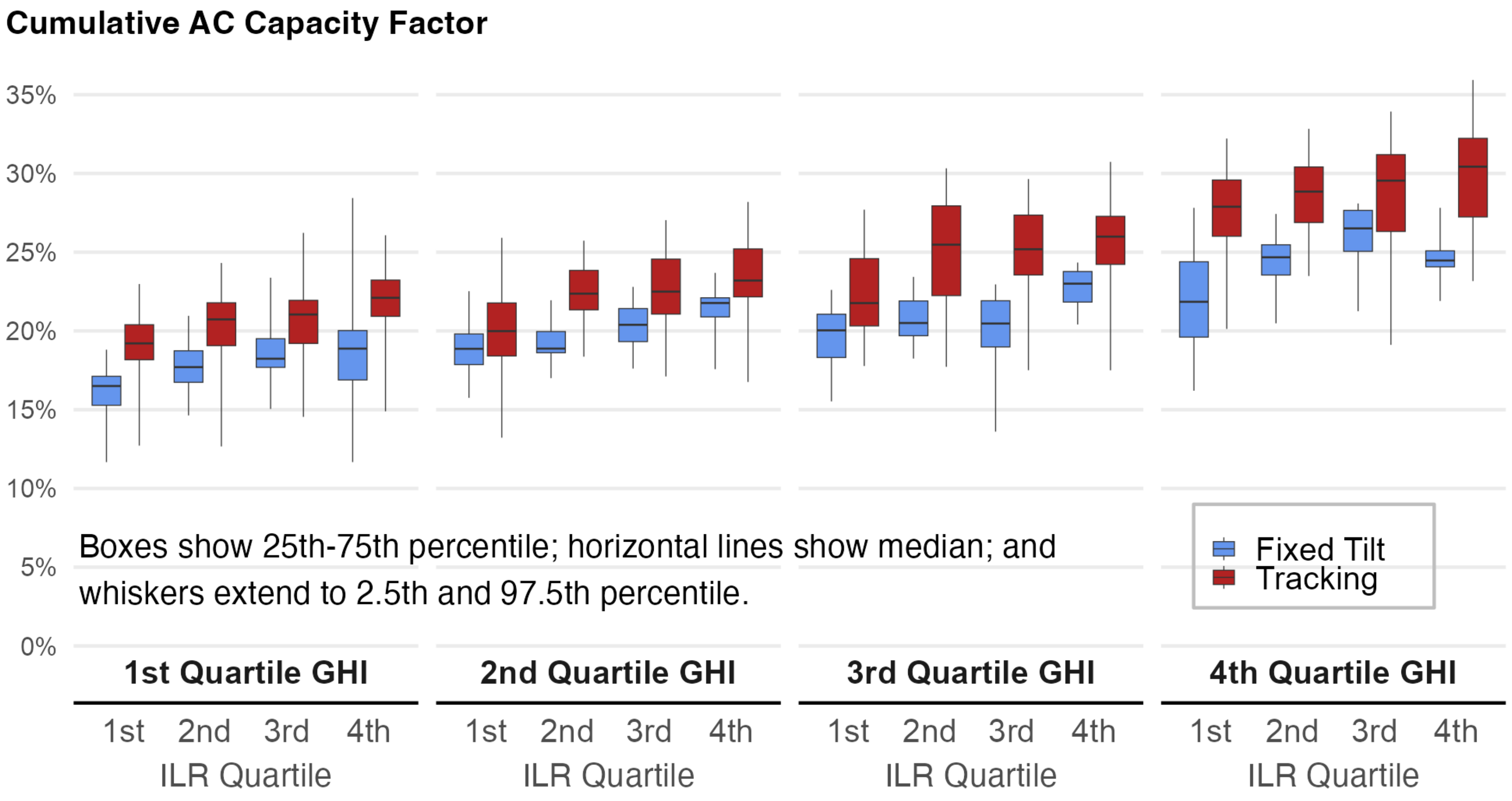
$$Annual\ Net\ Capacity\ Factor = \frac{Annual\ Net\ Generation\ (MWh)}{Capacity\ (MW_{AC}) * number\ of\ hours\ in\ year}$$

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

PV project sample: 1,461 projects totaling 79.3 GW_{AC}



The cumulative net capacity factor is typically around 25% but ranges from 7% to 37% among all projects in our sample.

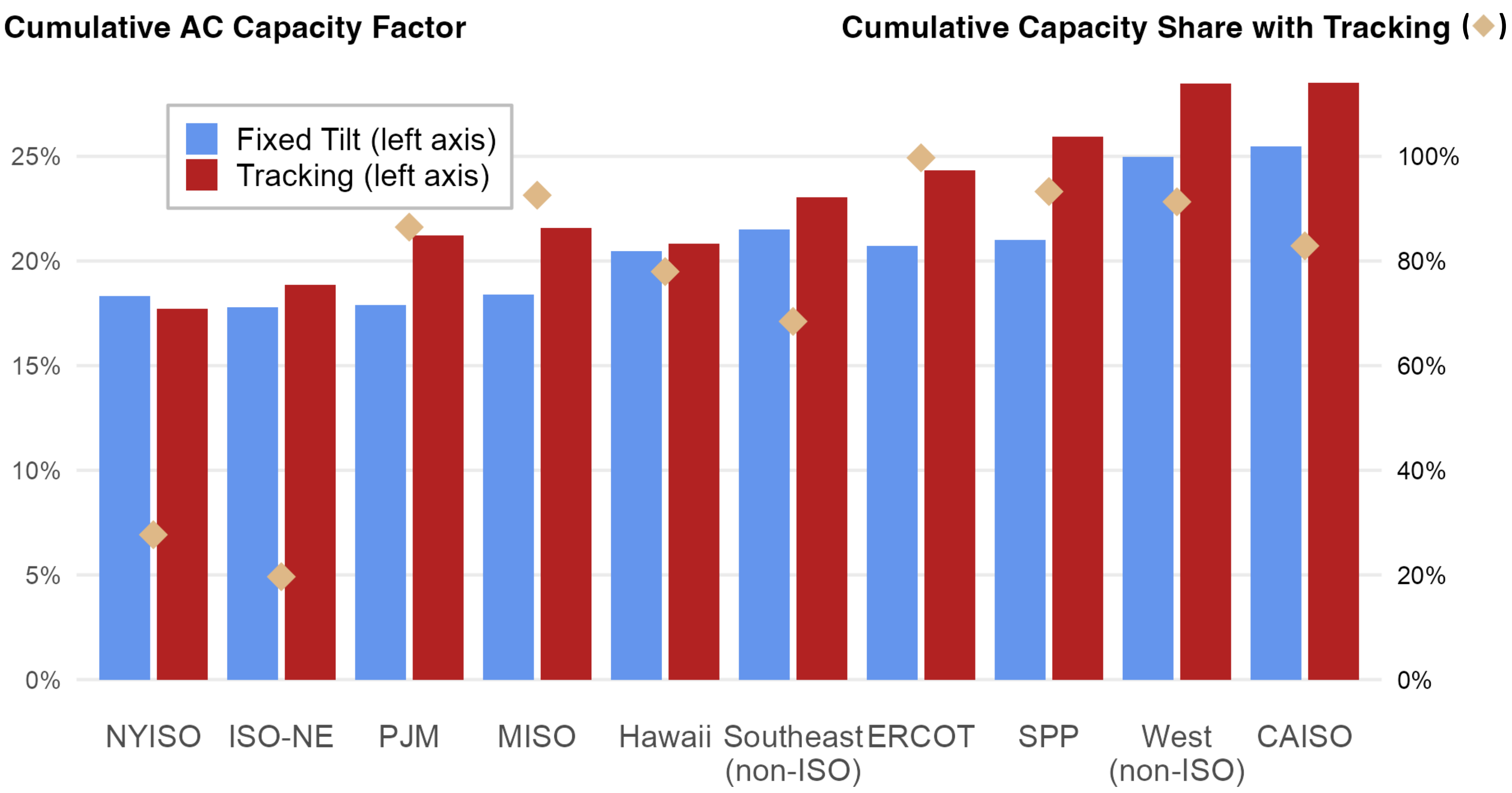
Project-level variation in PV capacity factor is driven by:

- **Solar Resource (GHI)**: Strongest solar resource quartile (right-most panel) has 9 percentage point higher median capacity factor than lowest resource quartile (left-most panel)
- **Tracking**: **Tracking** adds 5 percentage points to median capacity factors on average vs. **fixed tilt**, with improvement from tracking more pronounced in higher solar resource areas
- **Inverter Loading Ratio (ILR)**: Highest ILR (DC/AC ratio) quartiles (right-most within each panel) have on average 1 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 5 percentage points in high-insolation regions

PV project sample: 1,465 projects totaling 79.9 GW_{AC}



Capacity factors are highest in California and the non-ISO West, and lowest in the Northeast (ISO-NE and NYISO).

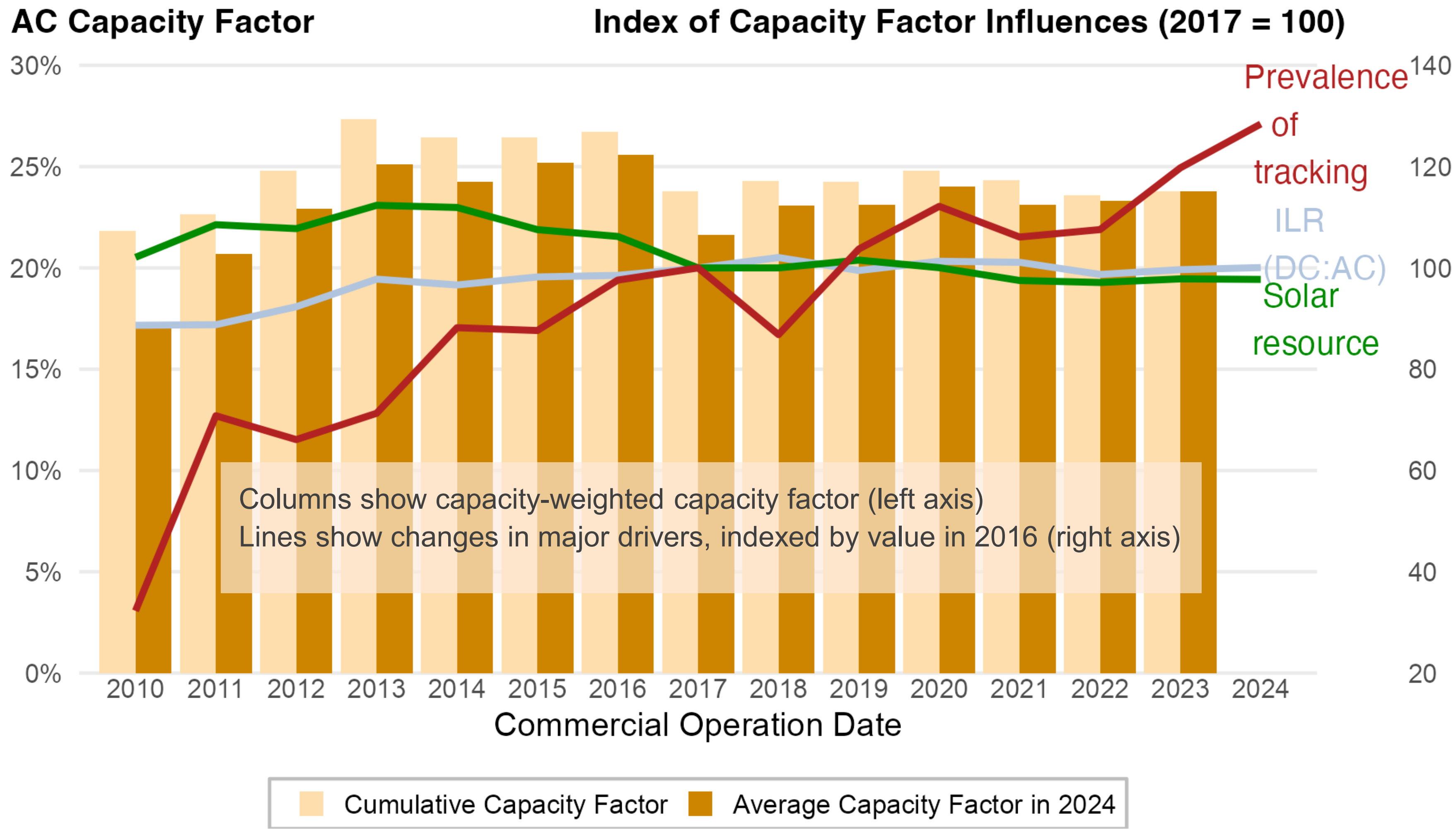
Tracking yields more benefits compared with fixed-tilt installations in regions with strong solar resources, leading to a greater proportion of tracking projects in those regions.

Notes: Capacity factors represent weighted means by capacity (MW_{AC}) across all years of data. The one utility-scale solar project in Alaska is excluded from this plot.

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

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

PV project sample: 1,462 projects totaling 79.7 GW_{AC}



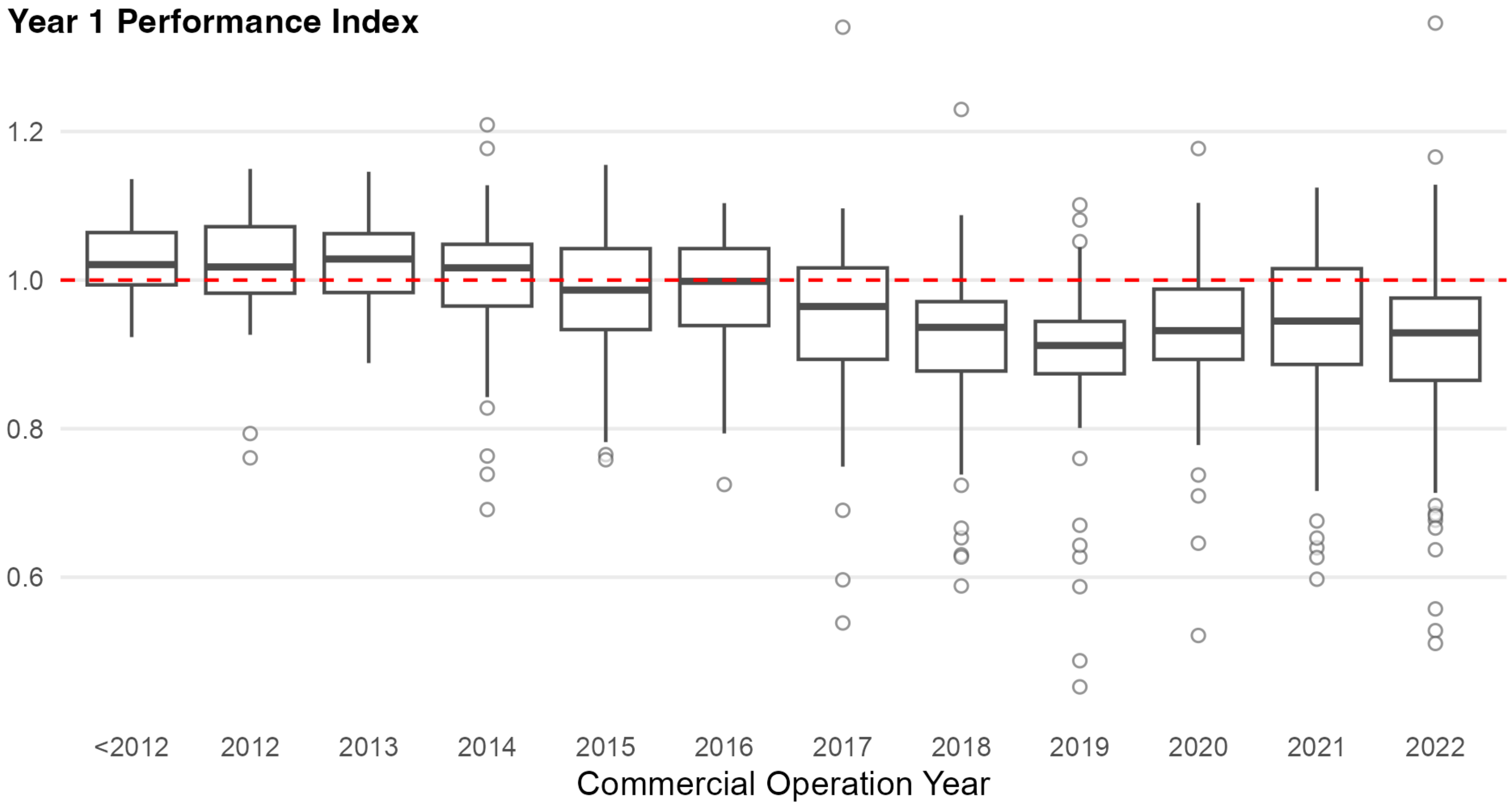
Cumulative capacity-weighted capacity factors increased from 2010 to 2013 due to greater DC-oversizing, adoption of single-axis tracking, and better solar resource sites.

Since 2013, capacity factors have declined and stagnated due to mixed factors: while tracking has become widespread (53% to 95%) and ILR has seen minor growth, new projects have expanded into less sunny regions (average capacity-weighted site GHI decreased from 5.55 to 4.76 kWh/m²/day between 2013 and 2023).

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

First-year performance index—actual vs. modeled capacity factor—declines in more recent project vintages

PV project sample: 1,149 projects totaling 60 GW_{AC}



Notes: We use site-level weather data from NREL's [National Solar Radiation Database] (NSRDB) and plant-specific characteristics to model plant output using NREL's [System Advisor Model] (SAM). SAM and NSRDB are models and may have biases.

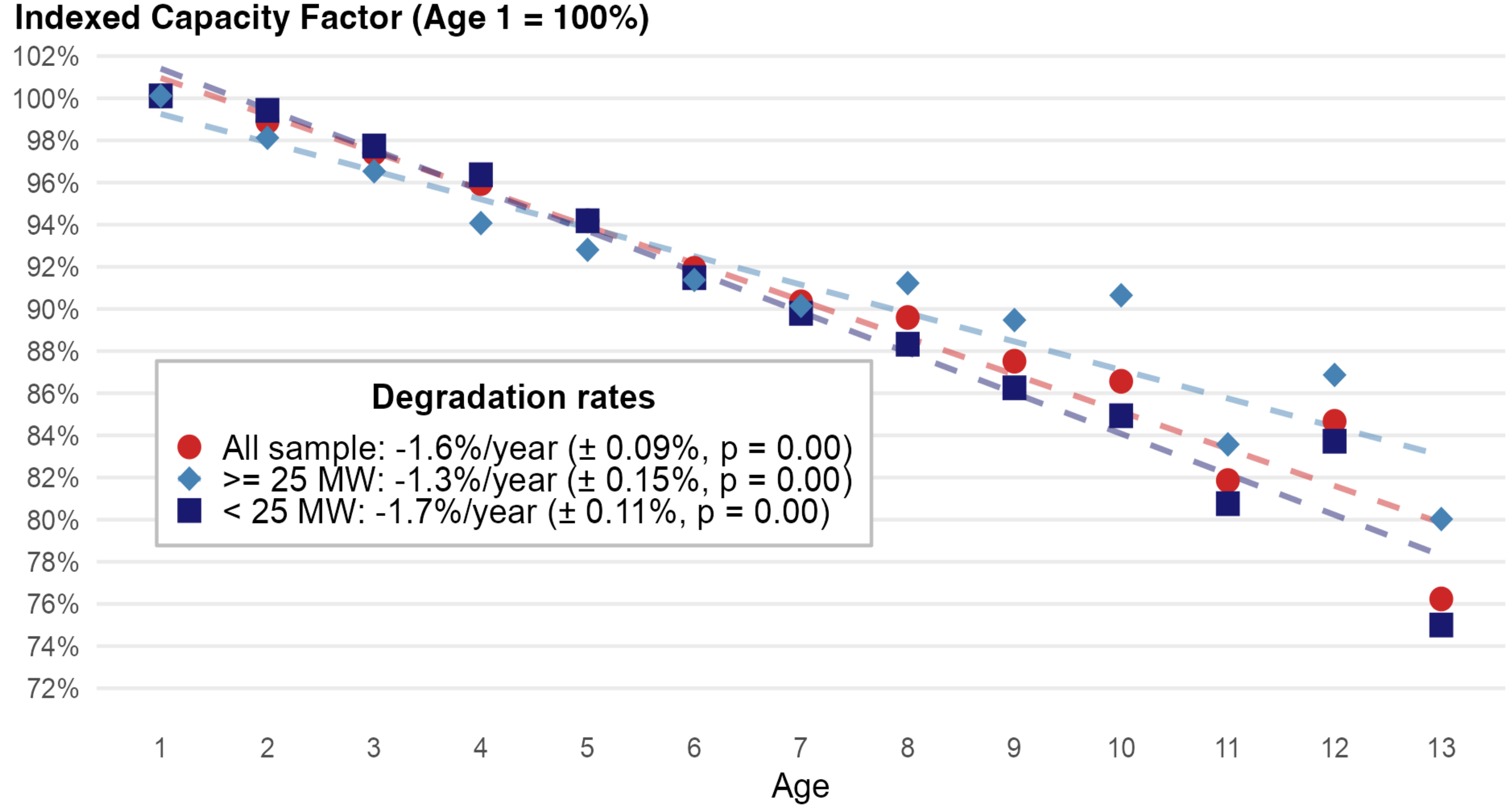
The Performance Index (PI) compares real-world operations of a PV project to simulated generation using location and year-specific weather data. An index smaller than 1 indicates underperformance. We focus on the first operational year after COD to sidestep early teething issues and long-term degradation effects. For projects in CA and TX, we adjust for curtailment effects.

More recent vintages have lower year one PIs than older ones, with 2022 plants having a median PI of 93%. This decline in newer vintages may be driven by factors that have become more common over time, including weather impacts (wildfire smoke, hailstorms, hurricanes, etc.) and/or higher DC:AC ratios (sub-hourly clipping is not captured well by hourly modeling).

Sample includes plants built through 2022 due to availability of NSRDB data (through 2023).

Project output declines with age at an average annual degradation rate of 1.6%, but larger projects degrade more slowly

PV project sample: 1,045 projects totaling 51 GW_{AC}



Note: Sample includes plants built through 2021 with performance data through 2023 (model requires two years of performance and weather data, and public weather data from NSRDB is only available through 2023 at time of analysis).

Our degradation analysis measures total project-level performance, including possible impacts from module degradation, inverter or breaker failure, stuck trackers, or soiling. We find an annual degradation rate of 1.6%, with variation by project size: larger projects (≥25 MW_{AC}) average 1.3%, while smaller projects (<25 MW_{AC}) average 1.7%. While we attempt to correct for curtailment in CA and TX, limited high-quality project-level curtailment data and increasing curtailment in other regions may contribute to the apparent decline in performance.

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 project f at time t (raw empirical data, but grossed up for curtailment in CAISO and ERCOT)

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

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

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

$\epsilon_{f,t}$ = Residual of project 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:

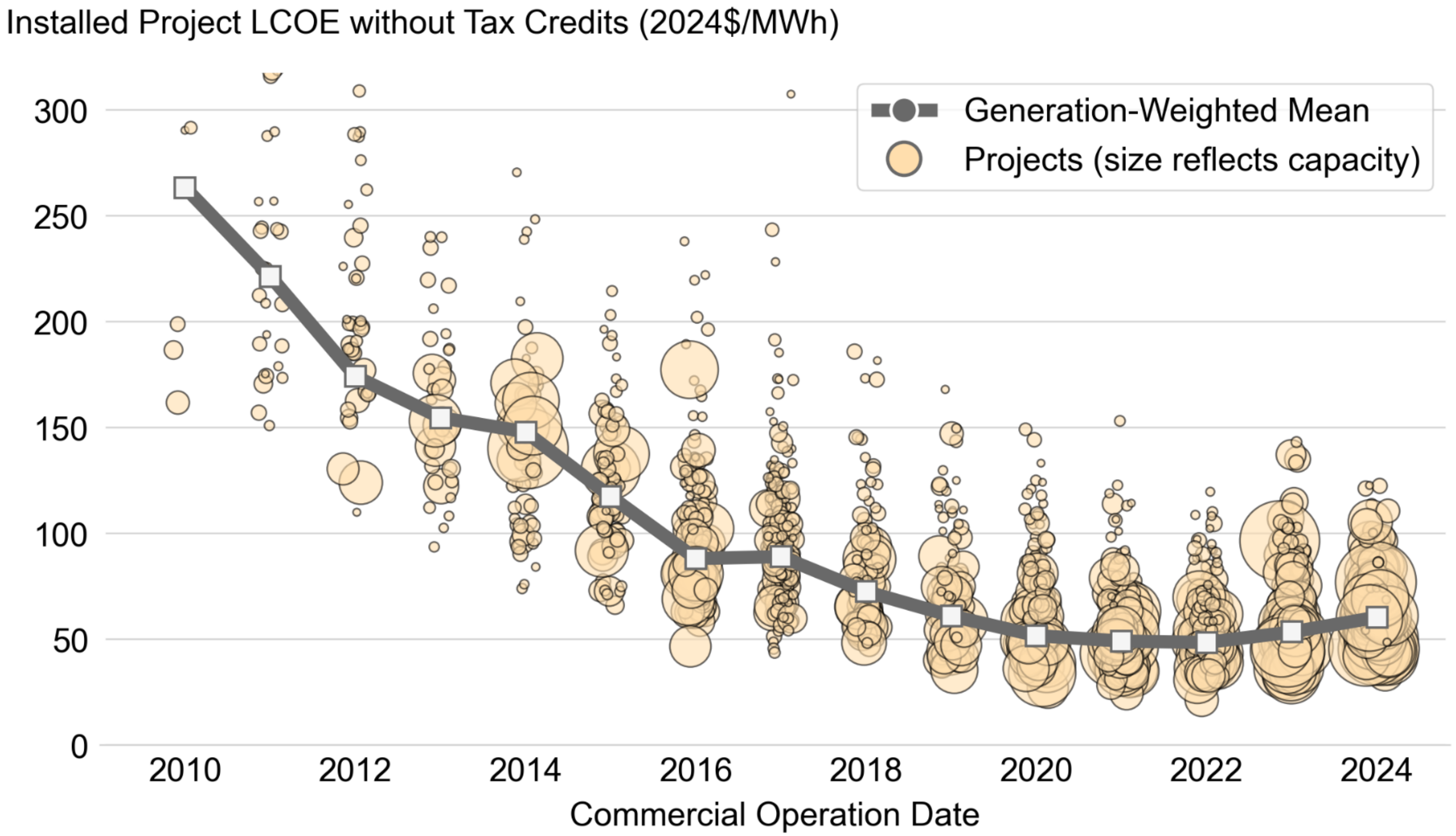
- For our project-level LCOE estimates of solar projects we follow the formula published in NREL's Annual Technology Baseline, describing the average costs to generate a MWh over the lifetime of a project.
- We use LCOE as proxy for direct generation costs in later parts of this publication. It is important to note that additional "system" or "integration" costs (transmission needs beyond what is captured via interconnection costs, resource adequacy /capacity needs, LMP congestion components or ancillary service costs) are not 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 1.74% (projects <25MW) and 1.28% (projects >=25MW). 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. For hybrid projects we decrease the solar NCF to account for round-trip efficiency losses, assuming a battery cycling of once a day.
- Cohort-level variation:
  - **OpEx** is levelized and declines from \$50/kW_{DC}-yr in 2007 to \$25/kW_{DC}-yr in 2024 (in 2024\$, based on prior LBNL and NREL Benchmarks). For hybrid projects we assume a battery replacement after 15 years with replacement costs derived from NREL ATB (80% of moderate cost scenario, scaled to capacity and duration).
  - **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 annual inflation expectations range from -0.2% (early Covid pandemic) to 4.2%.
    - Real WACC for 2024 COD projects is 3.26%.

Average LCOE (without the ITC/PTC) has increased 25% since 2022

Sample: 1,628 projects totaling 104 GW_{AC}



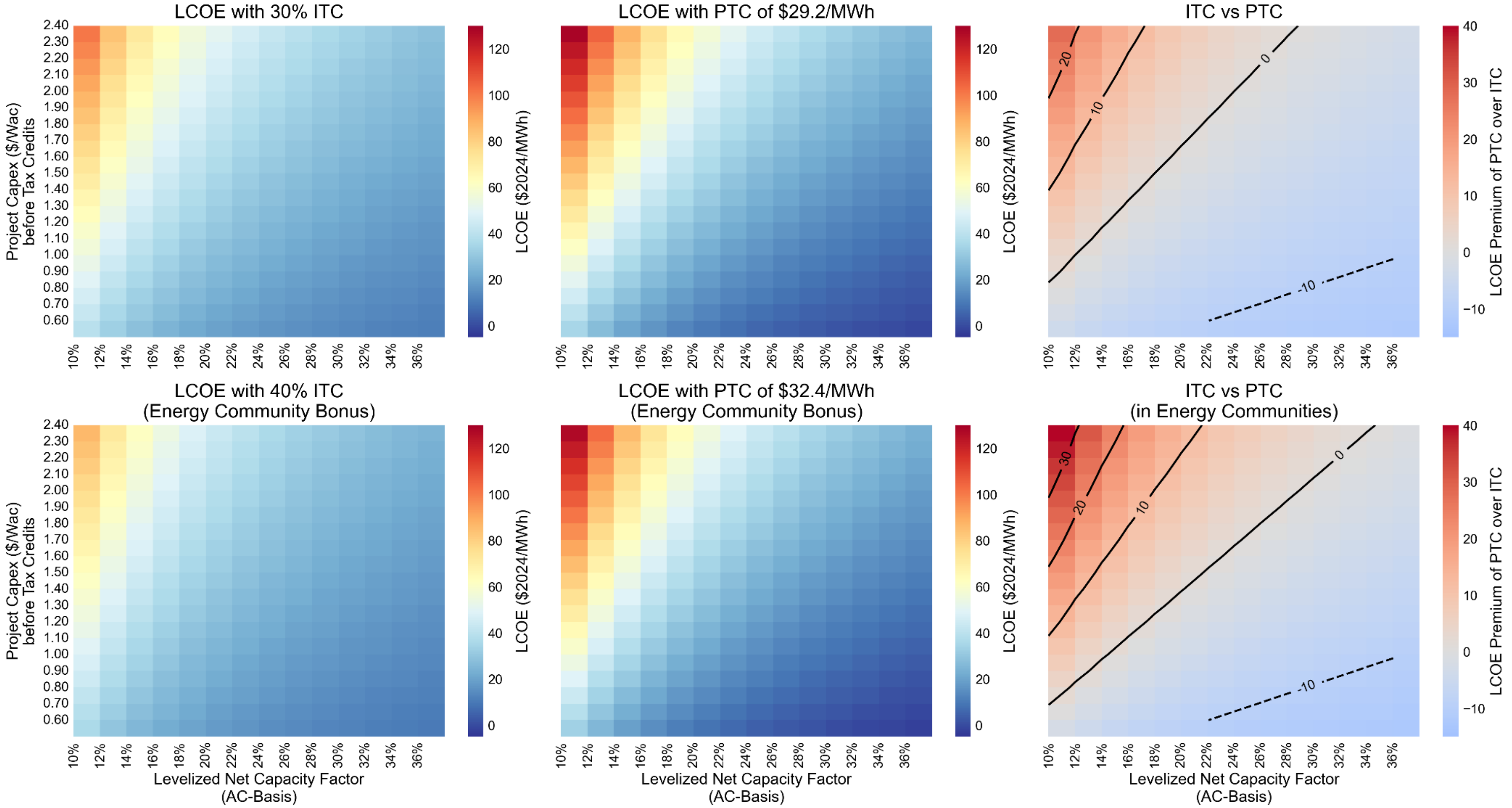
Note: LCOE estimates depicted here do not include tax credit benefits.
Only preliminary data is available for new solar projects coming online in 2024.
Findings may shift as more final EIA Capex and project-specific performance data become available.

Utility-scale PV's average LCOE fell by 82% between 2010 and 2022 to $48/MWh, driven by lower capital costs and operating expenses, as well as increased project design life.

Counteracting these longer-term trends are falling national average capacity factors since 2016, higher financing costs since 2020, and most recently, increasing CapEx. As a result, average LCOE (not including any tax credits) increased by 25% since 2022 to $60/MWh in 2024.

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

The Production Tax Credit lowers post-credit LCOE more than the Investment Tax Credit for 55% of projects since 2023



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 Production Tax Credit (PTC, center). The PTC is paid for the first 10 years ($29.2/MWh and rising with inflation) – levelized over a 35-year project lifetime it reduces LCOE by ~$15.8/MWh.

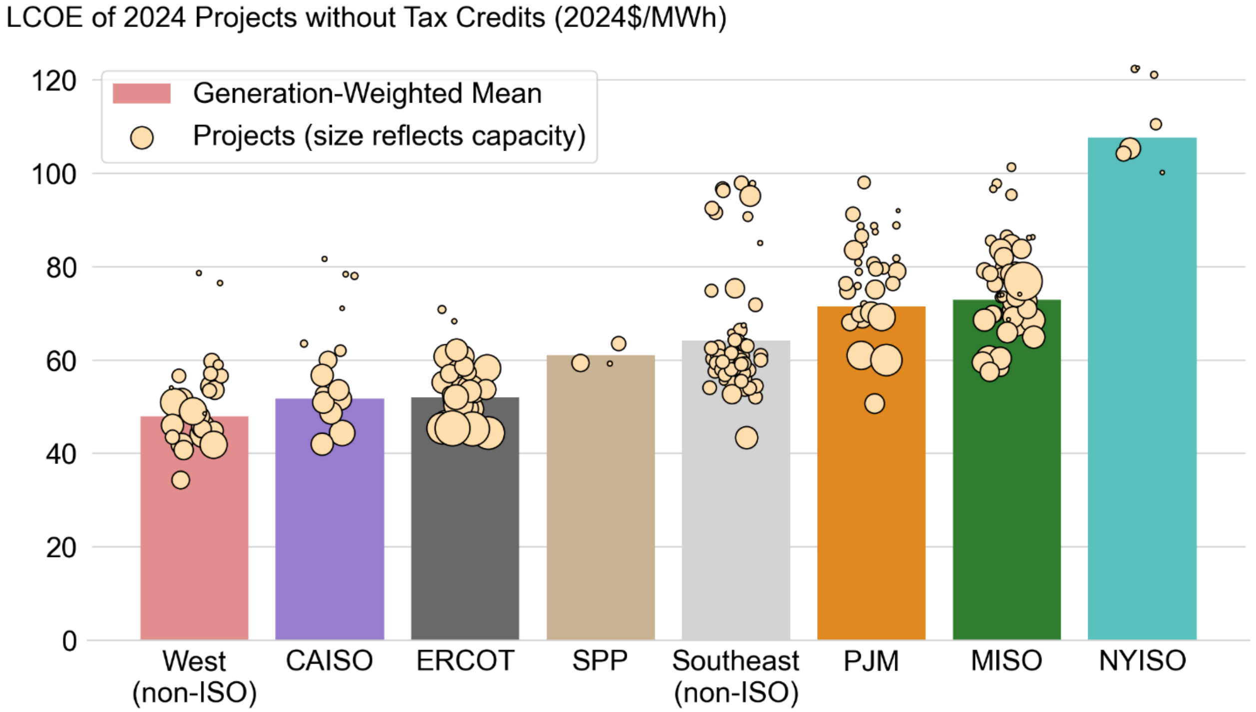
The right column compares the benefit of each tax credit, with red squares showing where the ITC results in a lower LCOE (higher-cost, lower-performing projects) and the blue squares showing where the PTC results in a lower LCOE (lower-cost, higher-performing projects). The bottom row repeats the analyses but includes the bonus adder available for projects sited in Energy Communities.

For the 2023 and 2024 COD cohort, preliminary data indicates that about half of all projects (233 out of 424) would benefit more from the Base PTC than the ITC.

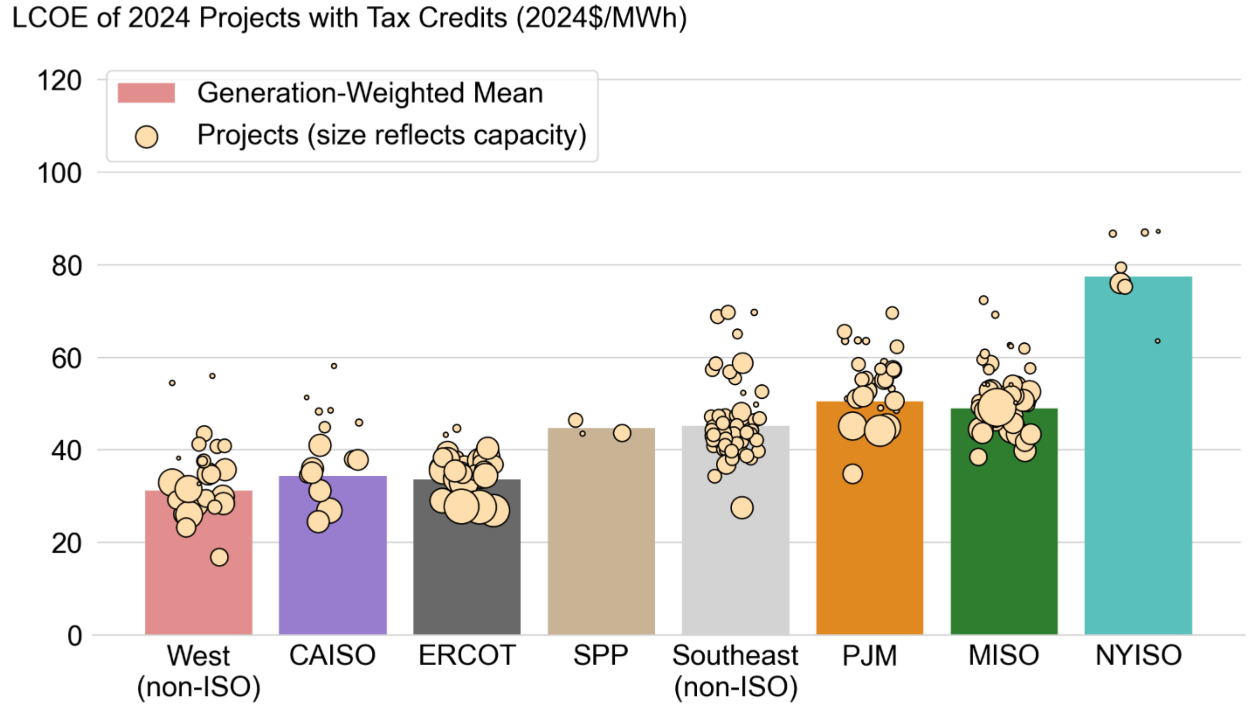
LCOE varies between regions due to differences in solar resource quality, project costs, and system size

Sample: 225 projects totaling 26.4 GW_{AC}

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



Higher insolation regions will always have lower LCOEs compared to less sunny parts of the country. Among projects coming online in 2024, large projects in the non-ISO West ($48/MWh), and CAISO and ERCOT ($52/MWh for both) had the lowest cost, while smaller projects in NYISO had the highest cost ($108/MWh).



Accounting for either the ITC or PTC (whichever results in lower costs), post-incentive LCOE of 2024 projects are $31/MWh in the non-ISO West, $34/MWh in CAISO and ERCOT, $45-50/MWh in SPP, Southeast, MISO and PJM, and $77/MWh in NYISO.

Note: Only preliminary data is available for new solar projects coming online in 2024. Findings may shift as more final EIA Capex and project-specific performance data become available.

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:

- 546 PV-only contracts totaling 41.6 GW_{AC}.
- 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 or PTC) 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 and award data, 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.

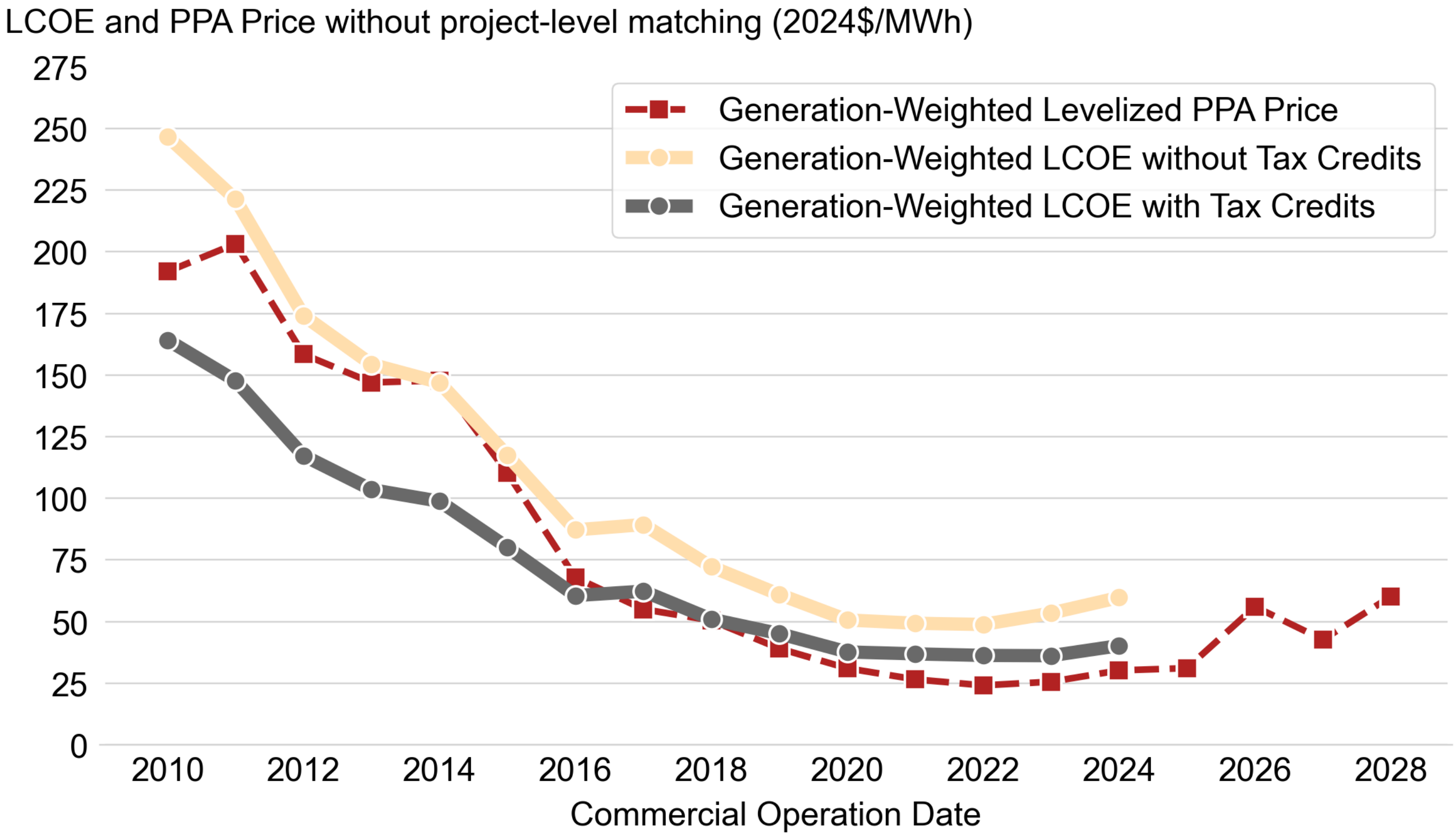
Levelization methodology

- We deflate the nominal dollar price series to 2024 dollars using a GDP deflator (actual deflators historically, along with projected future deflators), and then levelize the resulting price series using the real weighted average cost of capital (described in the LCOE methods) corresponding to the PPA execution date.
  - 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 LCOE after accounting for tax credits

Sample: 1,631 projects totaling 108 GW_{AC}



This graph contrasts solar LCOE with and without tax credits - choosing either PTC or ITC for each project that results in lowest cost (including the Energy Community but excluding the Domestic Content adder).

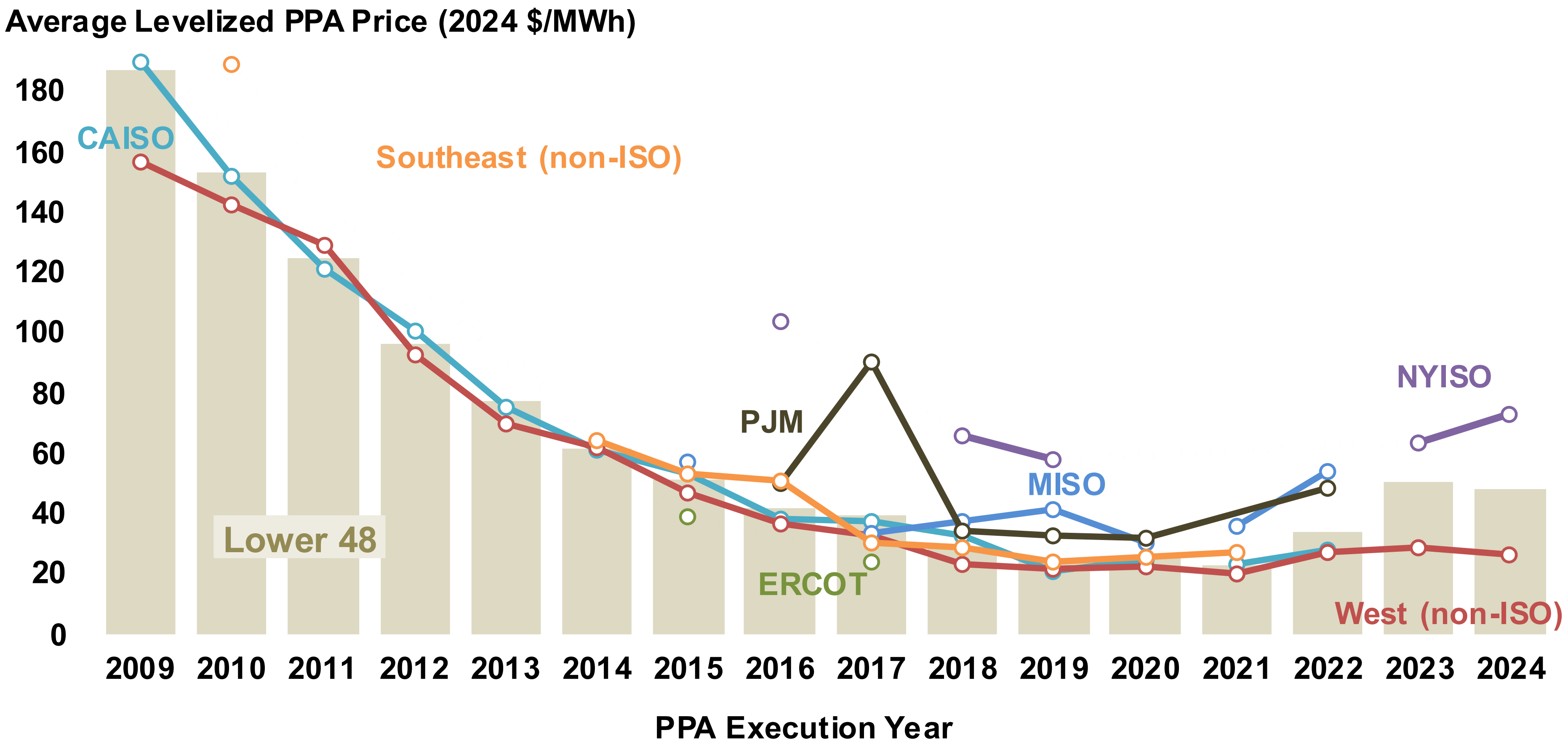
Generation-weighted average LCOE increased since 2022 both before the application of tax credits ($60/MWh in 2024 vs. $49 in 2022) and after ($41/MWh vs. $36/MWh).

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.

The depicted PPA sample is smaller than the shown LCOE sample. When performing a project-level match the gap between PPA and LCOE decreases further (see accompanying workbook).

Note: Only preliminary data is available for new solar projects coming online in 2024.
Findings may shift as more final EIA Capex and project-specific performance data become available.

Average PPA prices in the Lower 48 fell by ~87% (or ~19%/year) from 2009-2019 and have been flat or rising in the 2020s



This graph focuses on national and regional average PPA prices, rather than project-level prices (shown in the next slide). In 2023 and 2024 the Lower 48 average is heavily weighted toward NYISO – specifically NYSERDA REC strike prices – due to the sample composition.

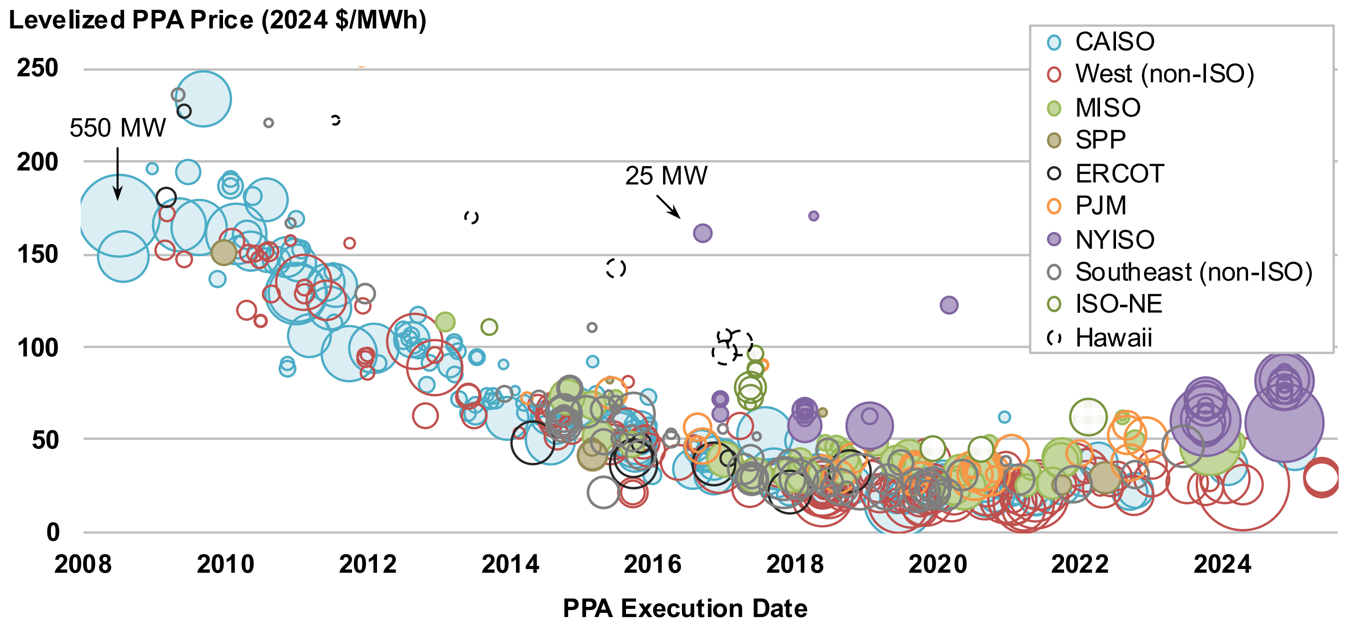
Year-Region combinations with fewer than 2 PPAs are excluded from the graph (dashed line segments indicate that the line is skipping over such years).

The graph reflects PV-only pricing, not PV+battery.

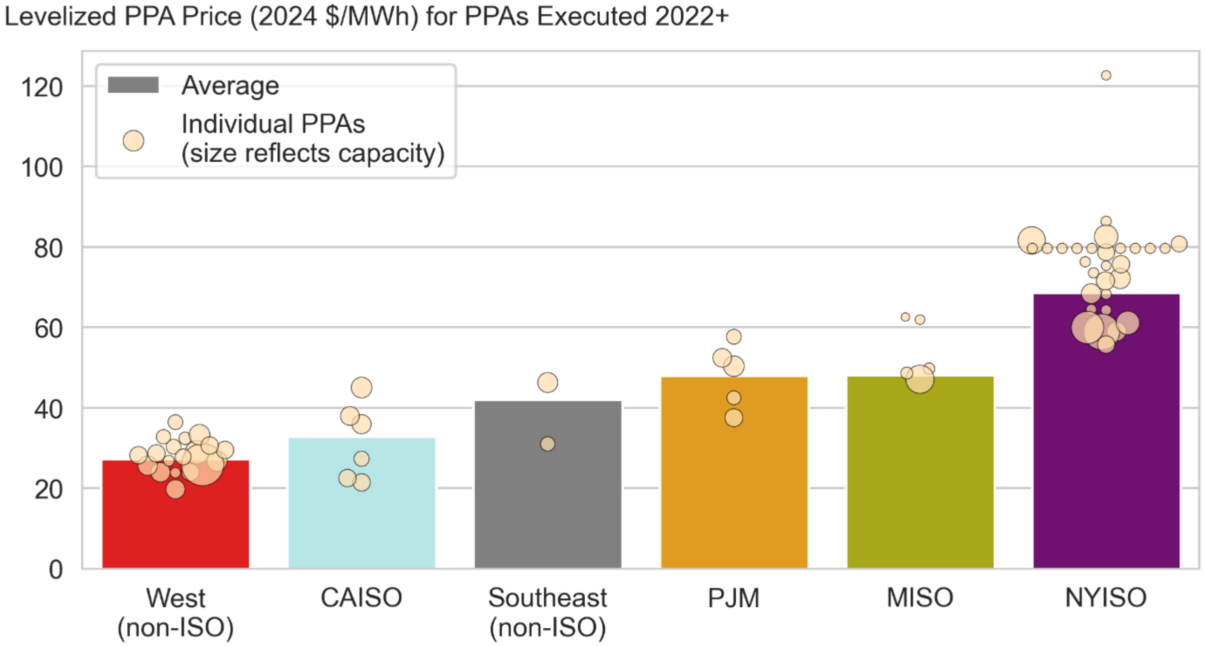
You can explore this data interactively at https://emp.lbl.gov/pv-ppa-prices

Individual PPA prices vary, even within the same region

Full sample: 546 PPAs, 41.6 GW_{AC}



2022-present sample: 69 PPAs, 7.2 GW_{AC}



- 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 2024 dollars
- Characteristics of projects in the full sample:
  - Contract term is between 20 and 25 years (inclusive) for 77% of PPAs
  - >90% of the sample is currently operational
  - PPAs are typically executed 1.5-3 years before a project's commercial operation date

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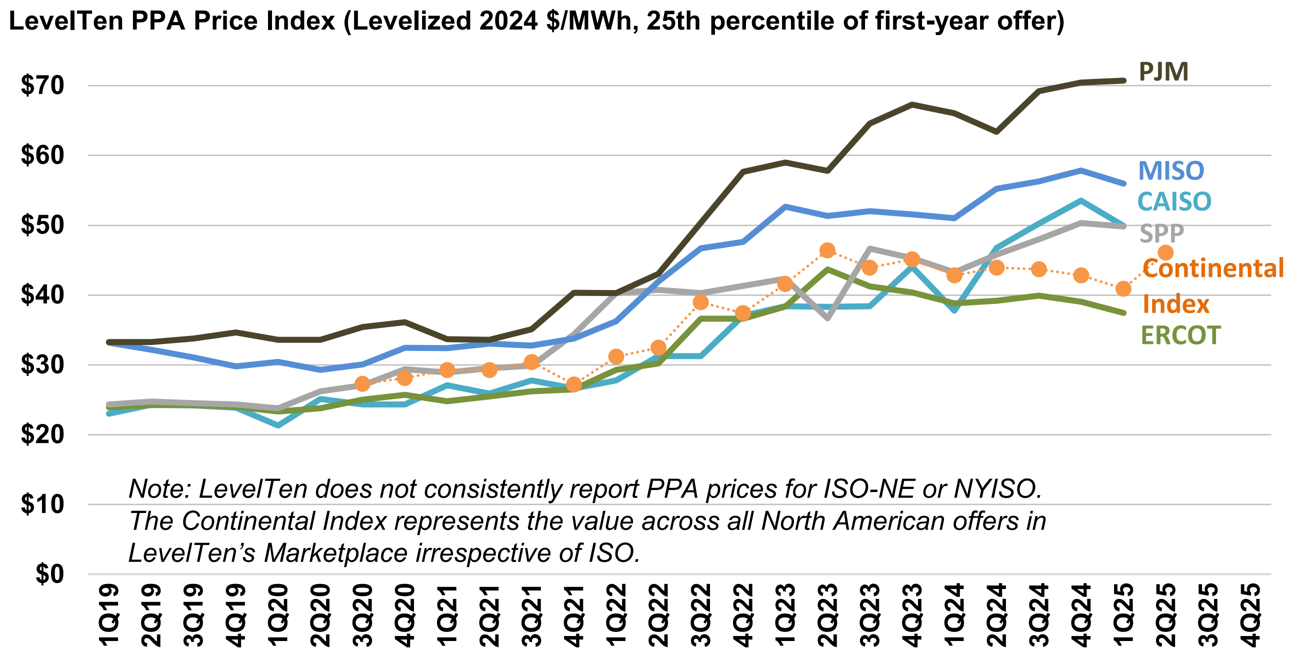
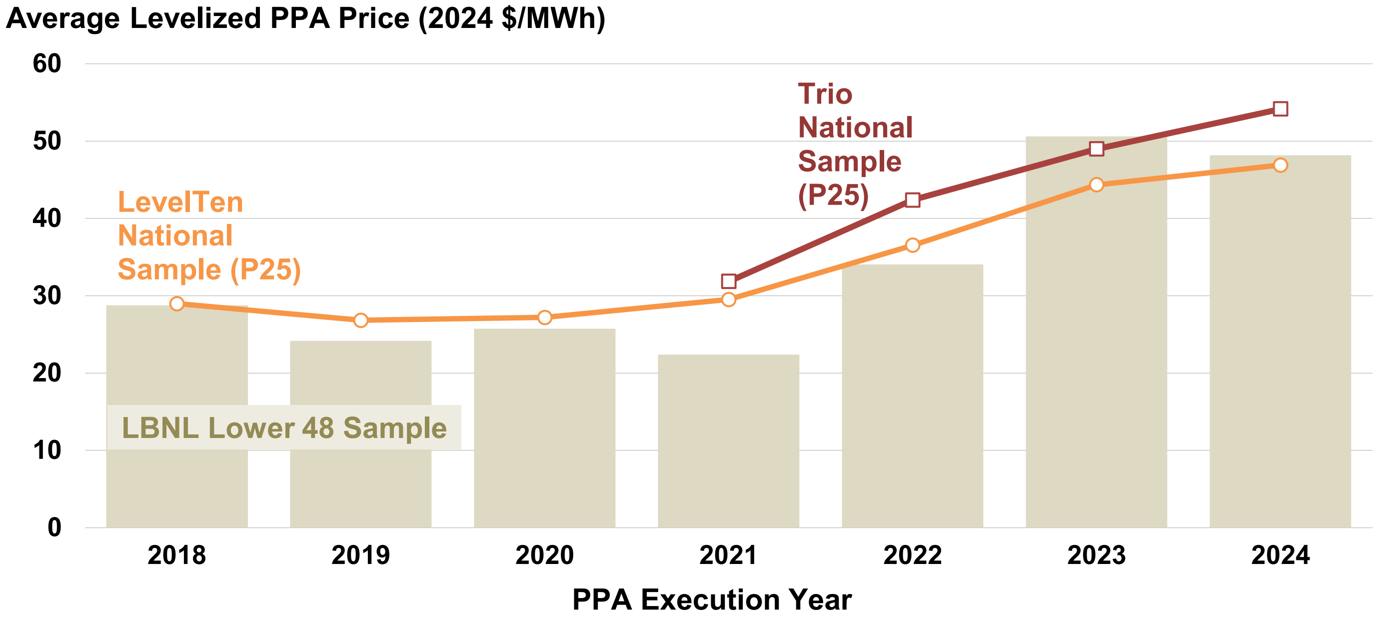
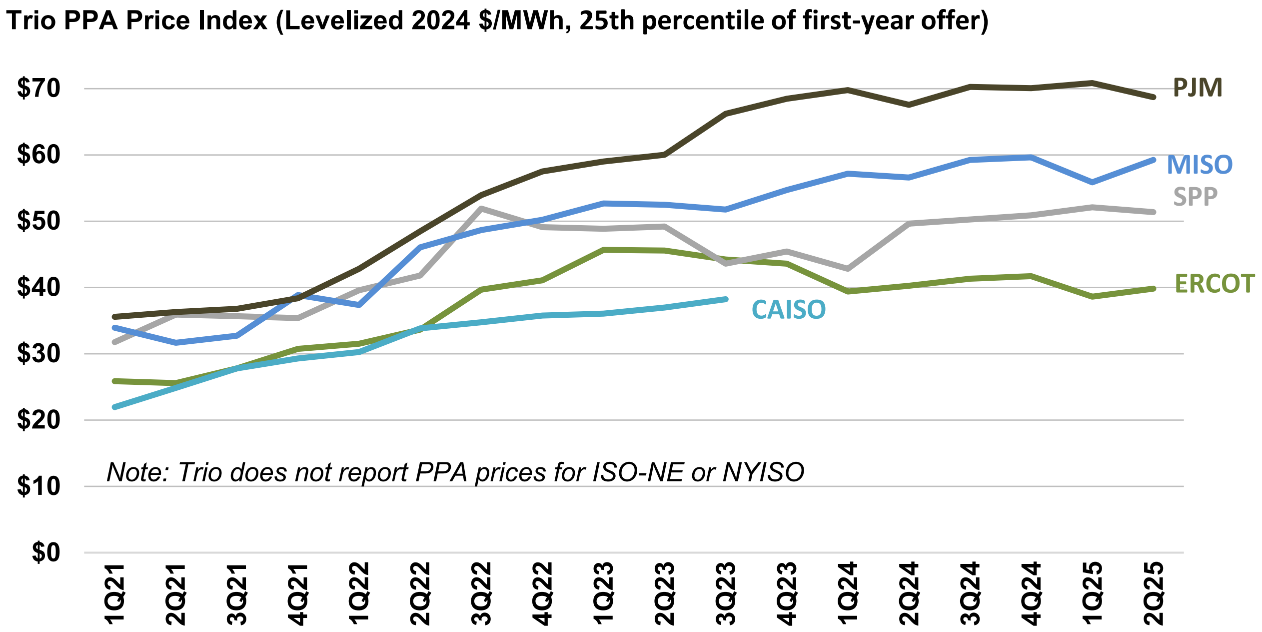
You can explore this data interactively at https://emp.lbl.gov/pv-ppa-prices

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

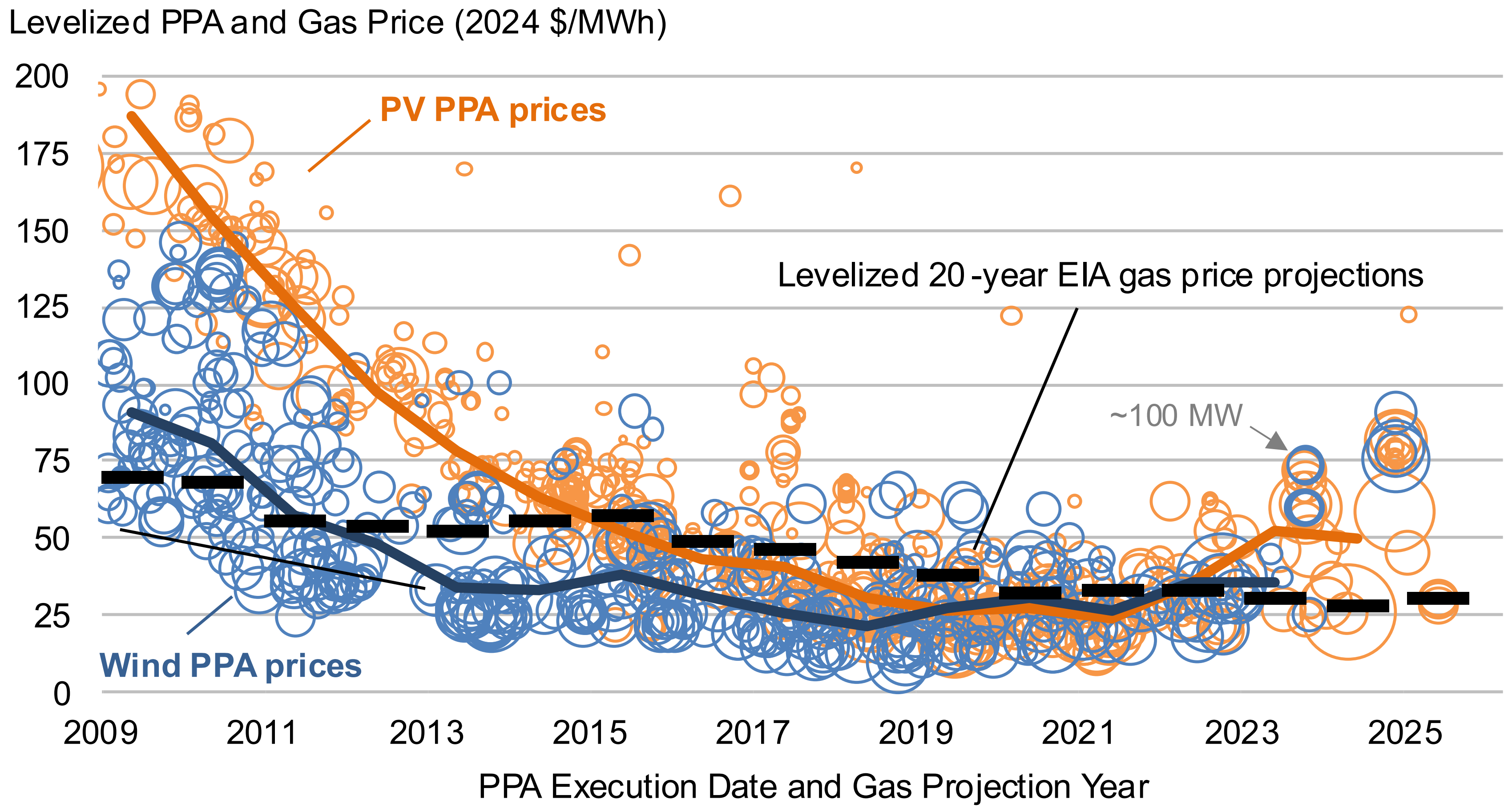






To augment our PPA price sample, and to gain visibility into corporate PPA pricing (which is not well-represented within our sample), we present LevelTen Energy and Trio's PPA price indices.

Solar PPA prices can be compared with wind PPA prices and gas price projections



The graph shows levelized solar PPA prices, levelized wind PPA prices, and levelized gas price projections from the EIA's Annual Energy Outlook.

PPAs are priced to recover both capital and other ongoing operational costs.

Gas prices capture the cost of burning fuel in an existing combined-cycle natural gas unit (NGCC), but not the capital cost of a new plant.

Wholesale Market Value and Net Value

Wholesale market value analysis: data sets and methodology (I of II)

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 23 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: High Sustained Limit - MW) or allocated from ISO-level reports (CAISO and SPP).

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/EIS BAs)
  - FERC Lambda for some BAs without ISO connection

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

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

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

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For more information, see LBNL's publication: "Solar-to-Grid: Trends in System Impacts, Reliability, and Market Value in the United States with Data Through 2020." https://emp.lbl.gov/publications/solar-grid-trends-system-impacts-0

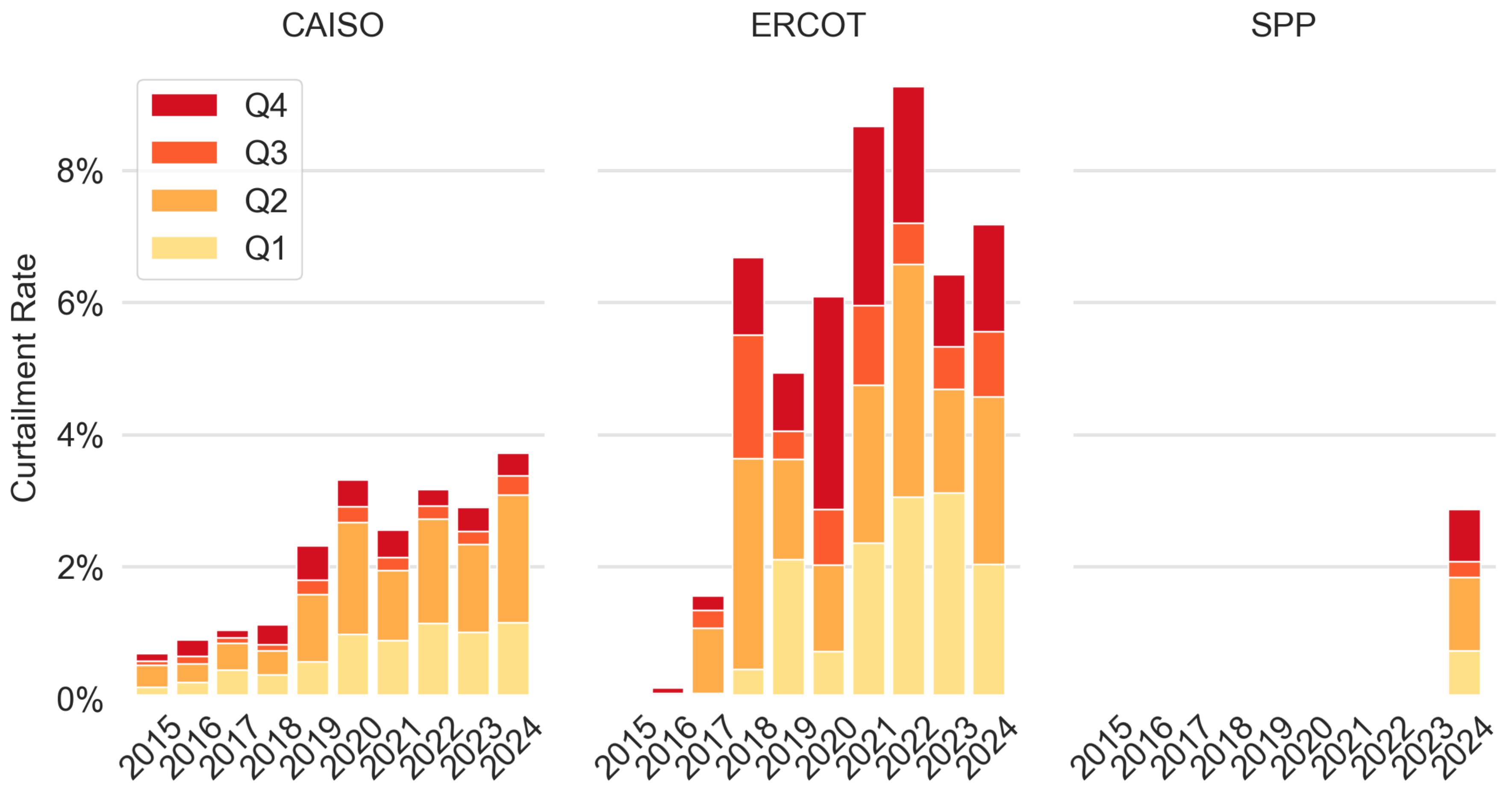
Wholesale market value analysis: data sets and methodology (II of II)

- **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 short-term 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.
  - It does not include any potential additional revenue streams or costs (ancillary service (AS) revenues or costs, renewable energy credits, infrastructure deferral or imposition 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 the 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 social costs and benefits beyond the grid system.

- The **Value Factor** is defined as the ratio of solar's average market value to the BA-average market value of a 'flat block' of power (i.e., a 24x7 block).
  - It indicates whether solar's total value is above or below the average wholesale value, with generators delivering electricity primarily 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 location on value, allowing for derivate penetration and congestion analyses.

Solar curtailment varied by region in 2024. Most ISOs and regions do not yet report curtailment.

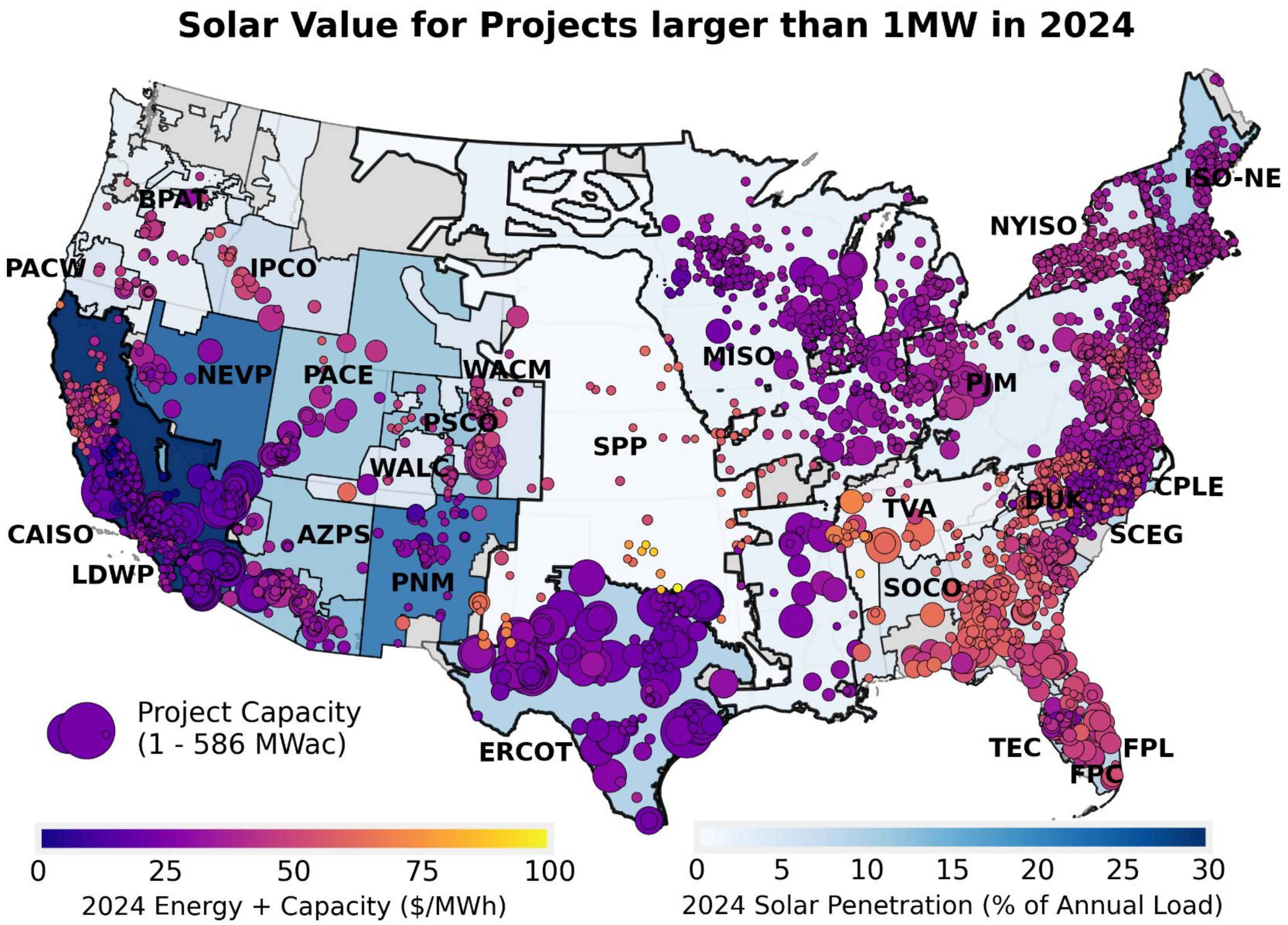


The *rate of solar curtailment* was much higher in ERCOT (7.1%) than in CAISO (3.7%) and SPP (2.8%) in 2024, even though solar's penetration rate is far lower in ERCOT (10%) than CAISO (30%).

Most of ERCOT's curtailment occurs in the western part of Texas, driven by transmission/pipeline congestion and excess local electricity production.

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



We estimate solar wholesale market value for 5,571 projects in 30 balancing authorities (subset shown on the left map).

Value varies both between and within regions, driven by generator supply curves, transmission congestion, solar resource quality or differing use of technology like trackers.

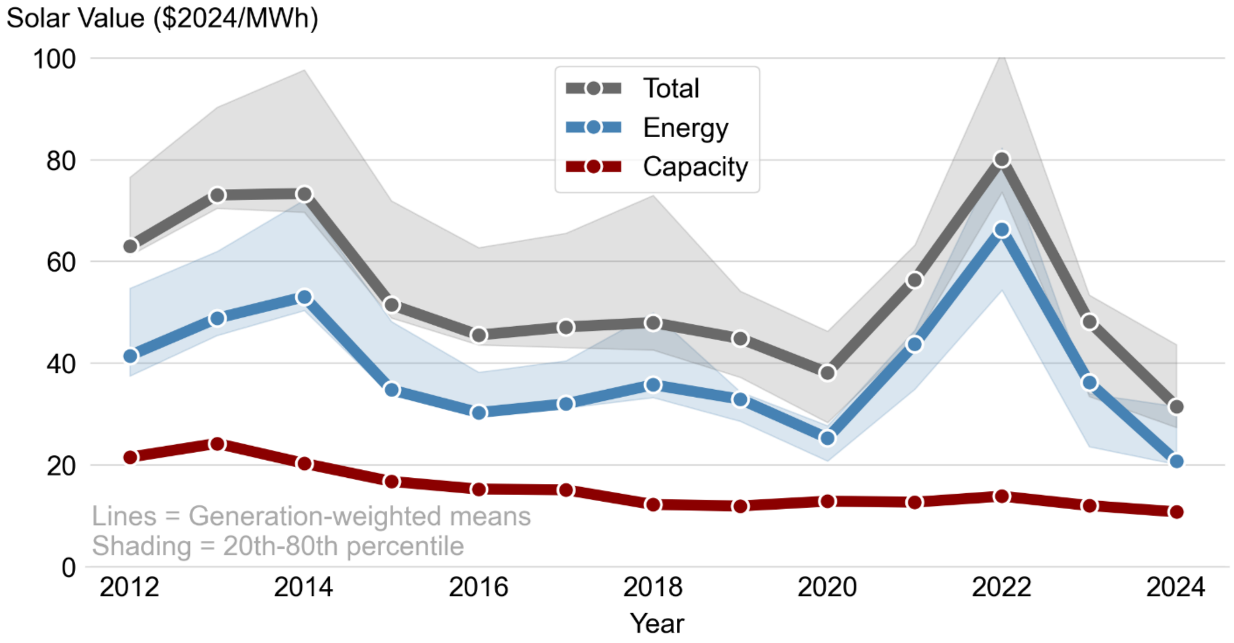
For example, in CAISO the northern zone has typically higher average values than the southern zone. Similarly, in SPP and NYISO solar in the southern part of the footprint was much more valuable than solar in the northern part.

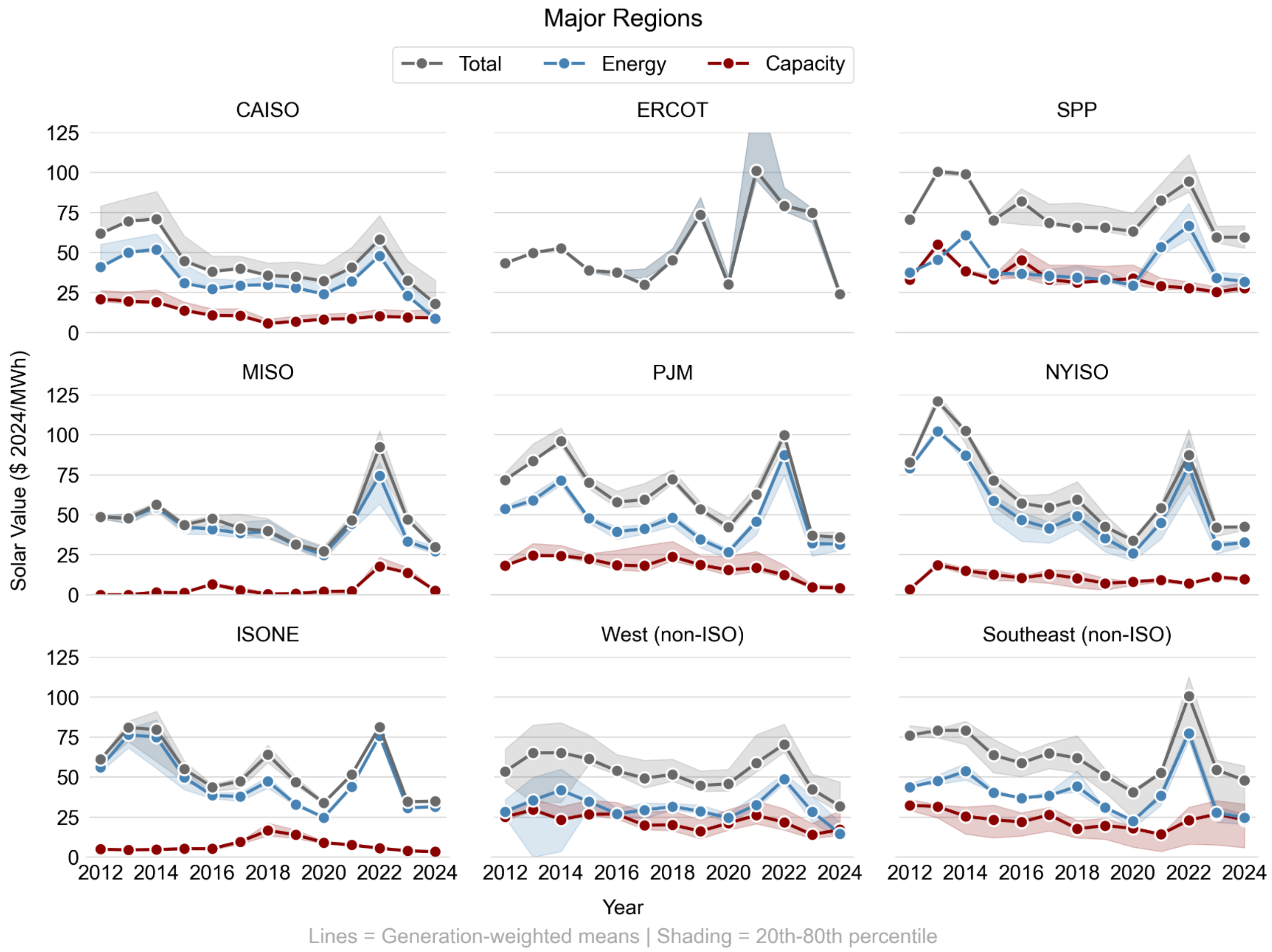
Other markets like ISO-NE show very little variation in annual average value between projects (20th vs. 80th percentile had a difference of less than $2/MWh).

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

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

Solar's energy plus capacity value declined to a record-low national average of $32/MWh in 2024



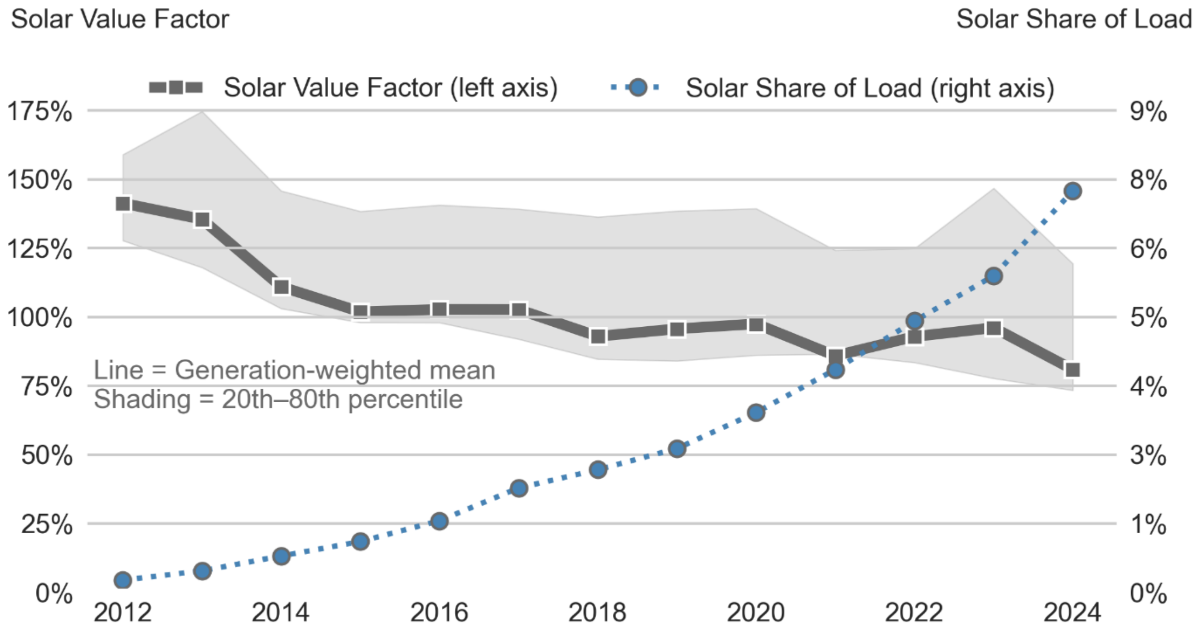


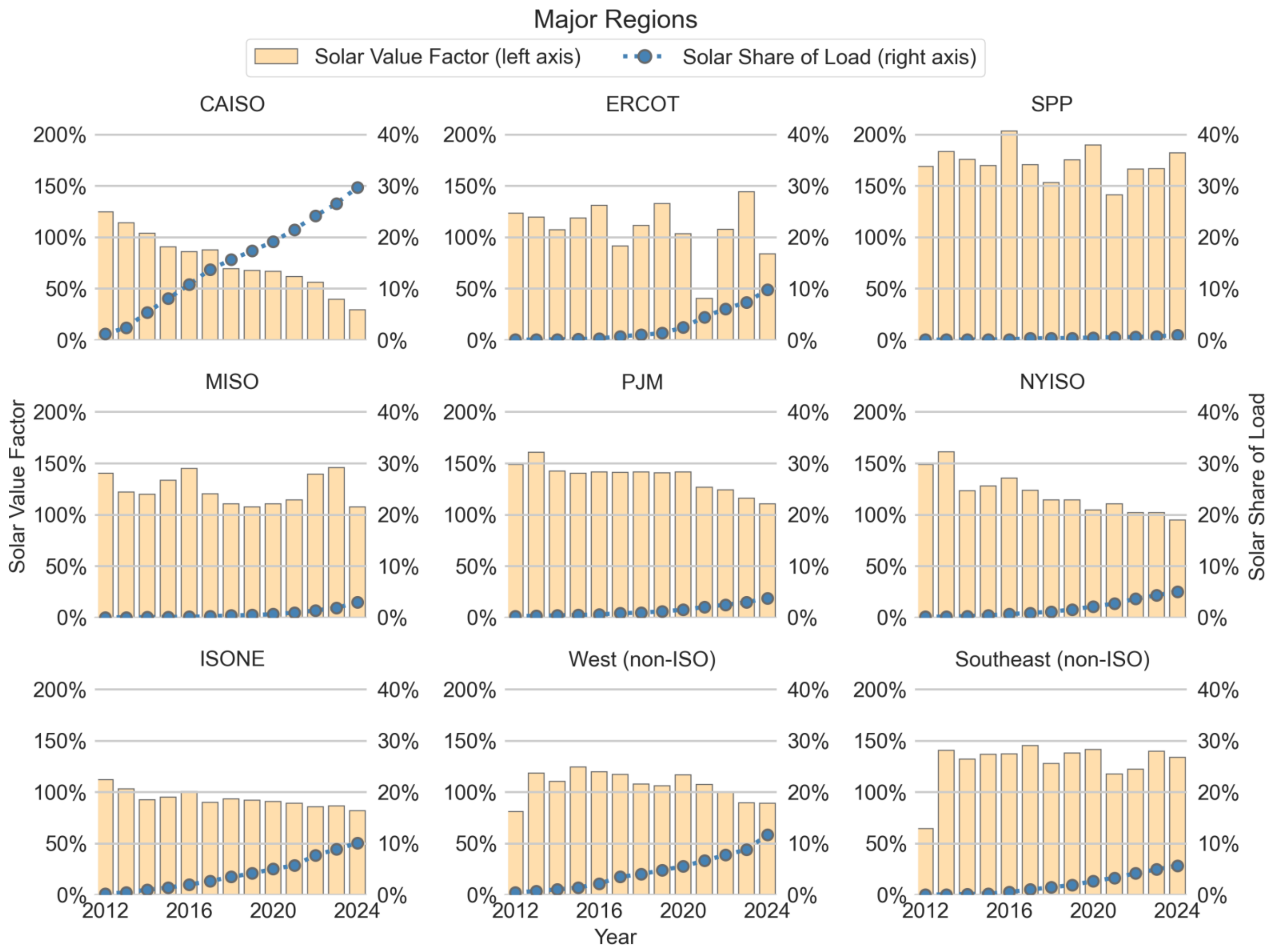
Driven by declining natural gas prices, fewer summer heat waves, and increasing solar penetration, PV’s average market value decreased from $48/MWh in 2023 to $32/MWh in 2024.

CAISO had the lowest standalone solar value at $18/MWh, while a high capacity value supported a higher total value in SPP ($60/MWh) & many southeastern BAs.

Note: The data shows generation-weighted average annual market value of all large-scale (1 MW+) solar projects in select balancing authorities. Non-ISO BA results are shown in the accompanying data file.

Solar's value factor declines as solar serves a higher share of a region's load; as a national average, it fell to 80% in 2024

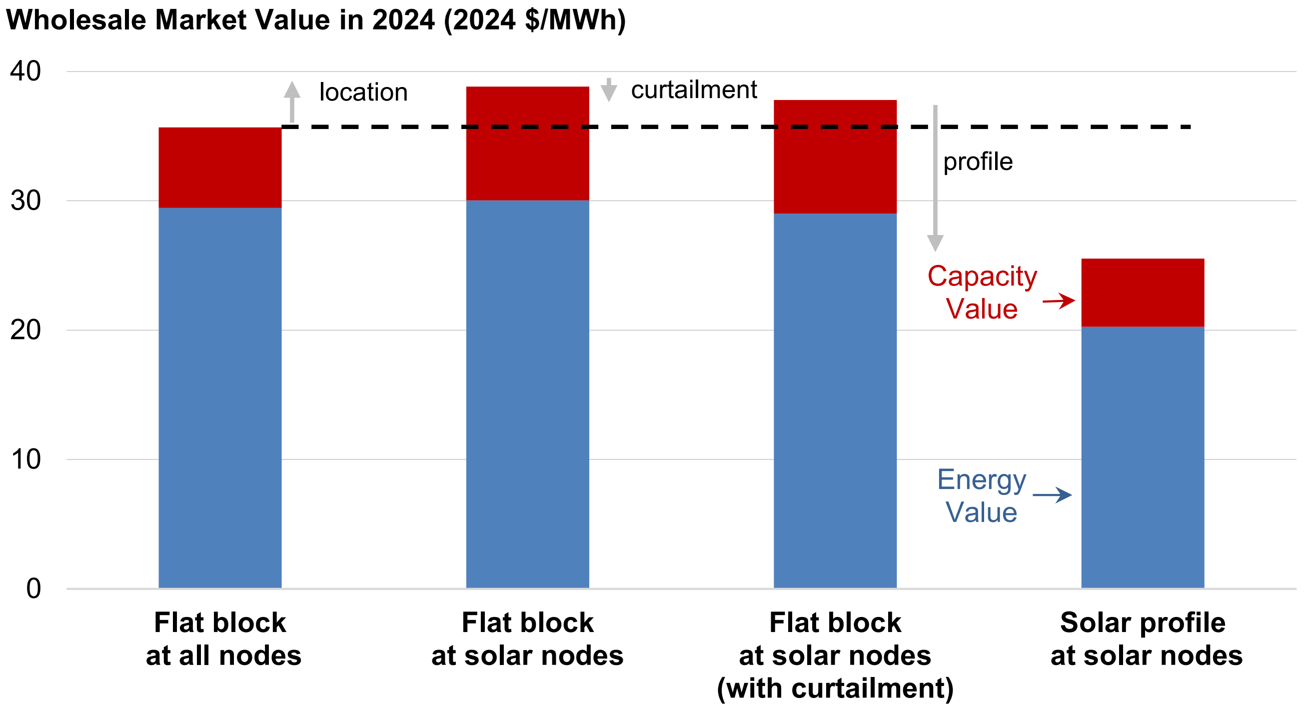


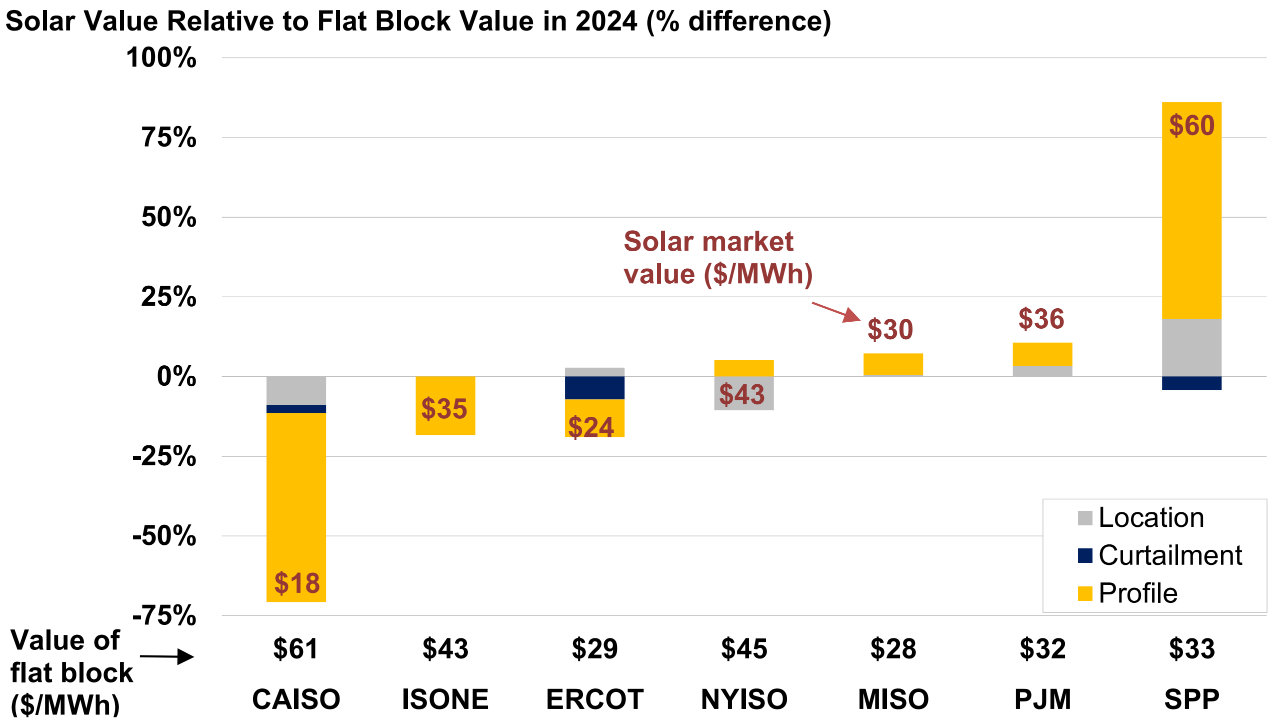


Solar's value factor has fallen over time as solar serves a greater share of load, reaching 80% in 2024 as the national average. It is lowest at 30% in CAISO (at 30% penetration) and Nevada Power (49%). The value factor is highest at 181% in SPP (at 1% penetration) and is still above 100% in MISO, PJM, Northern California BA, WAPA Desert Southwest and Rocky Mountains, Public Service Colorado, and most southeastern BAs.

Note: Solar market share in those years only reflects contribution of distributed PV. Non-ISO BA results are shown in the accompanying data workbook.

Solar's generation profile was the largest source of value differences between solar and a flat block in 2024



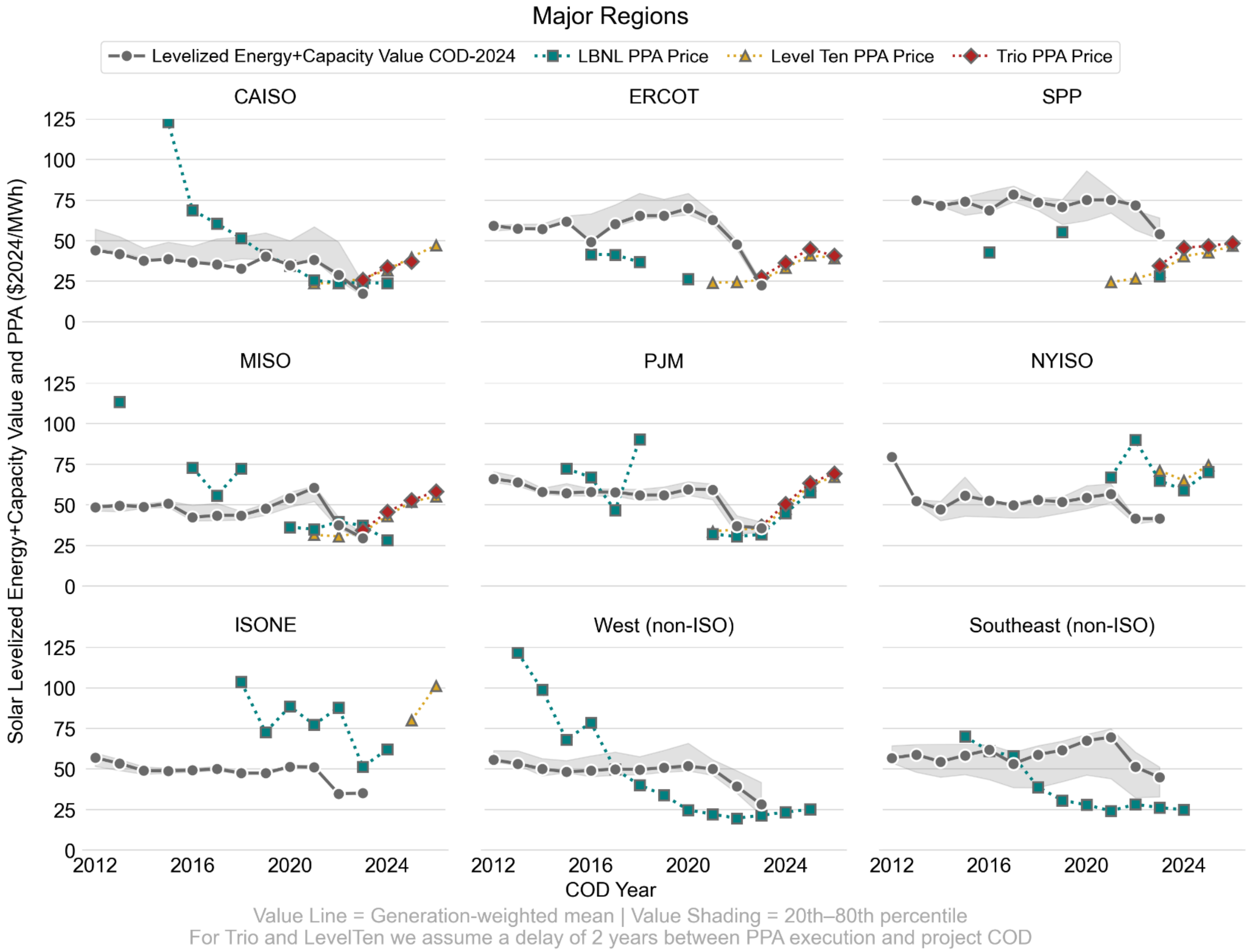


Across the seven ISOs, solar projects were usually sited at locations with average energy values. The large amount of solar deployed in areas with lower relative value (particularly CAISO and driven by profile impacts) yields a value factor of 72% across all solar projects in the ISOs.

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

Note: Numbers and figures shown here only reflect market value in the year 2024 in the seven ISOs and do not include data from other years or non-ISO regions.

Market Value vs. PPAs: Rising prices for new PPAs exceed falling wholesale market value in some regions in 2024



PPAs provide the power purchaser a hedge for price fluctuations over 10 to 20 years. A true benefit accounting should span the length of the PPA contract. However, we do not project future revenue (which will change with solar penetration, load growth and natural gas prices) and simply levelize wholesale market revenue between COD and 2024 as a proxy. PPA prices are also presented in levelized terms. They are influenced by solar's generation costs, solar's wholesale market "replacement costs", and supply and demand dynamics.

Falling PPA prices had largely kept pace with falling market value until PPAs started rising in 2021. Elevated energy prices in 2022 offset rising PPA prices, but in several regions (CAISO, ERCOT, MISO, PJM, NYISO, and ISO-NE) PPA prices are now higher than the wholesale market value. In contrast, solar offered greater value than what is paid for it via PPAs in SPP and many non-ISO BAs in 2024.

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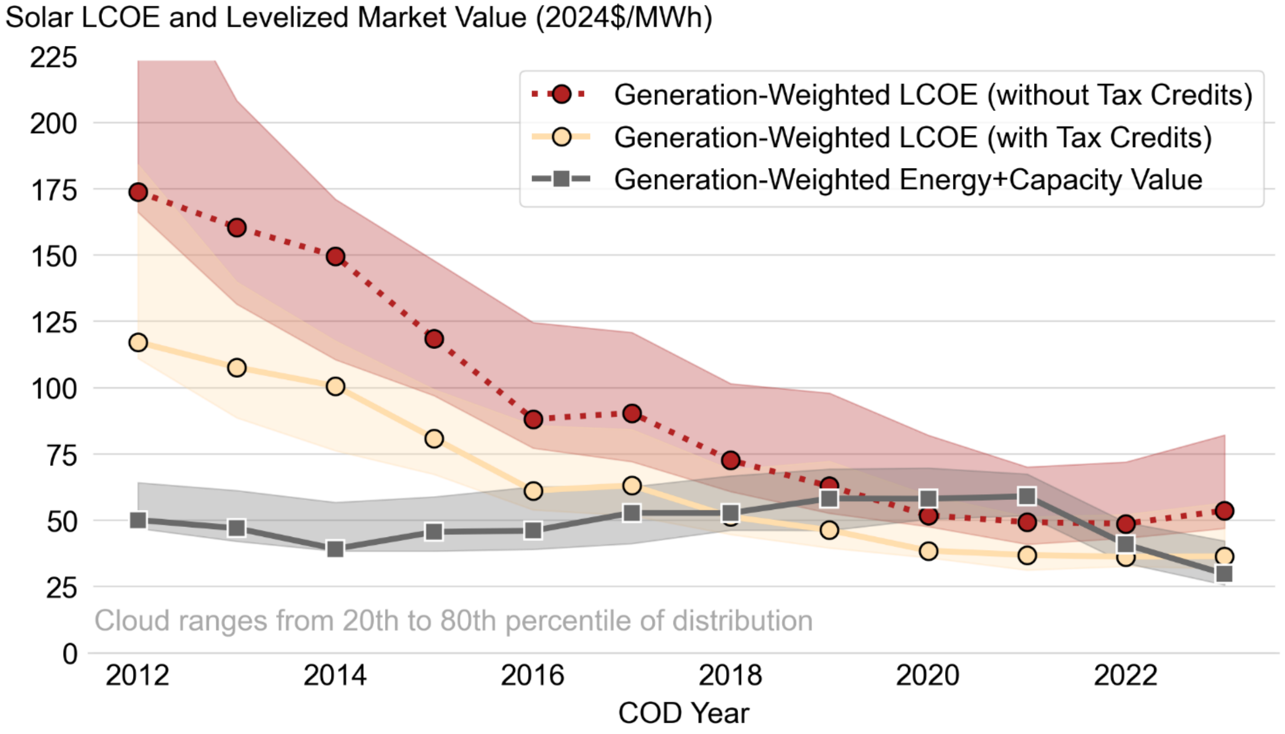
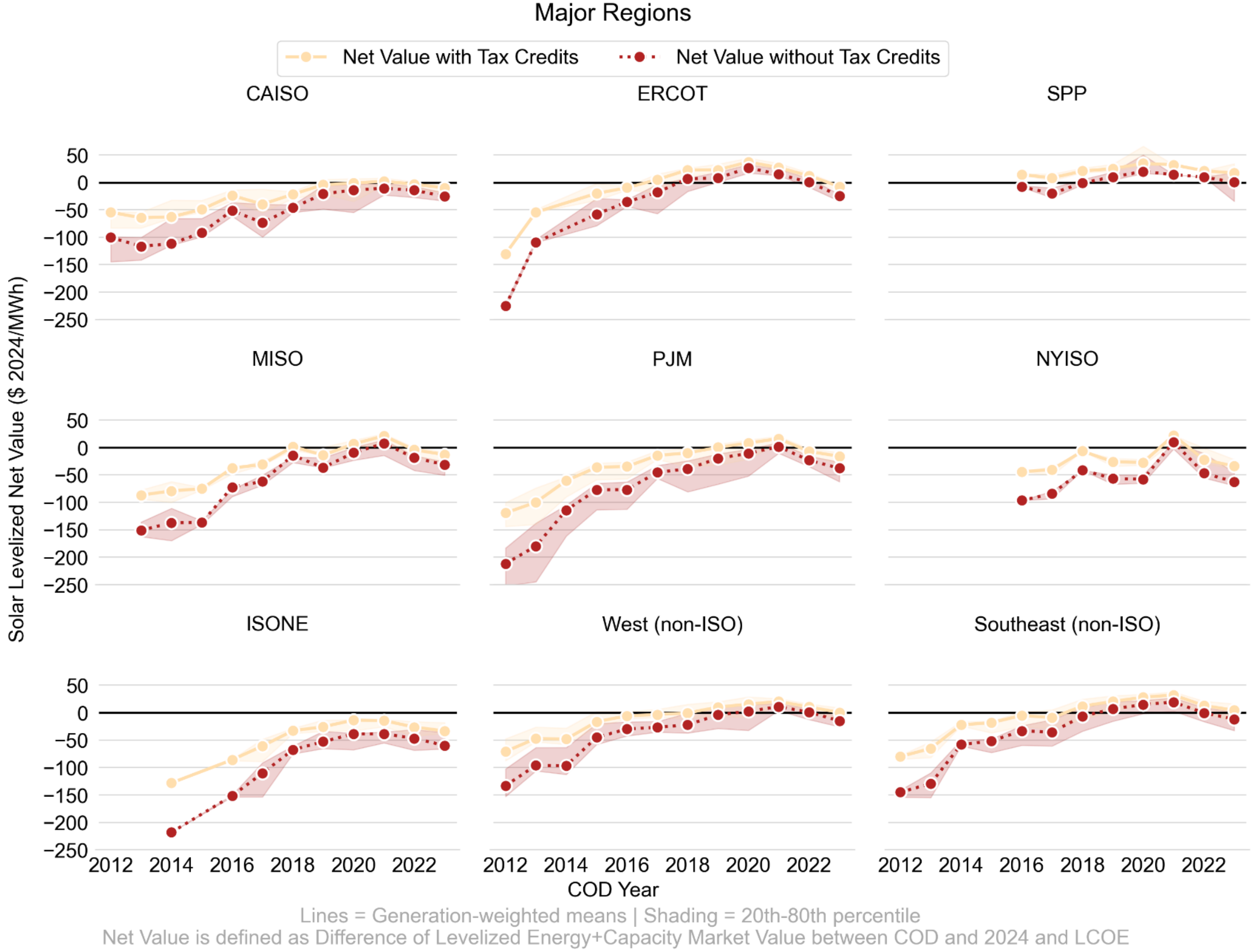
Note: We do not have sufficient PPA data to present robust trends for every balancing authority. PPAs are indexed here by Commercial Operation Date and span a longer time than the wholesale market estimates.

Historically, solar's generation costs (after tax credits) exceeded market value, after 2018 the balance turned net-positive (except COD 2023 so far).



National average net value (energy+capacity value minus LCOE) for 2023 COD solar standalone projects is slightly negative (-$7/MWh) even after accounting for tax credits.

Net value varies by region from -$34/MWh in NYISO to $17/MWh in SPP. 9 out of 30 BAs have positive net values in 2024, the rest negative net values.



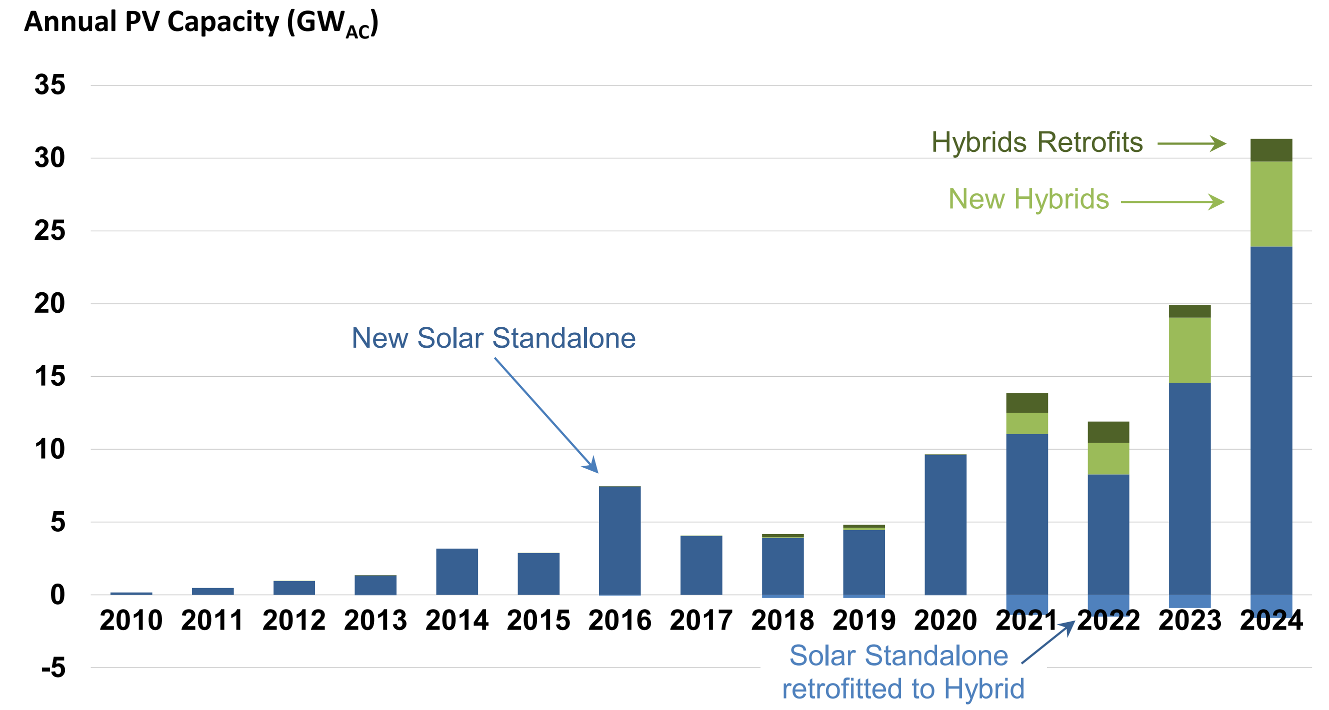
Note: For greater detail on methods and impacts, see Wiser et al (2024) Grid Value and Cost of Utility-Scale Wind and Solar: Potential Implications for Consumer Electricity Bills.

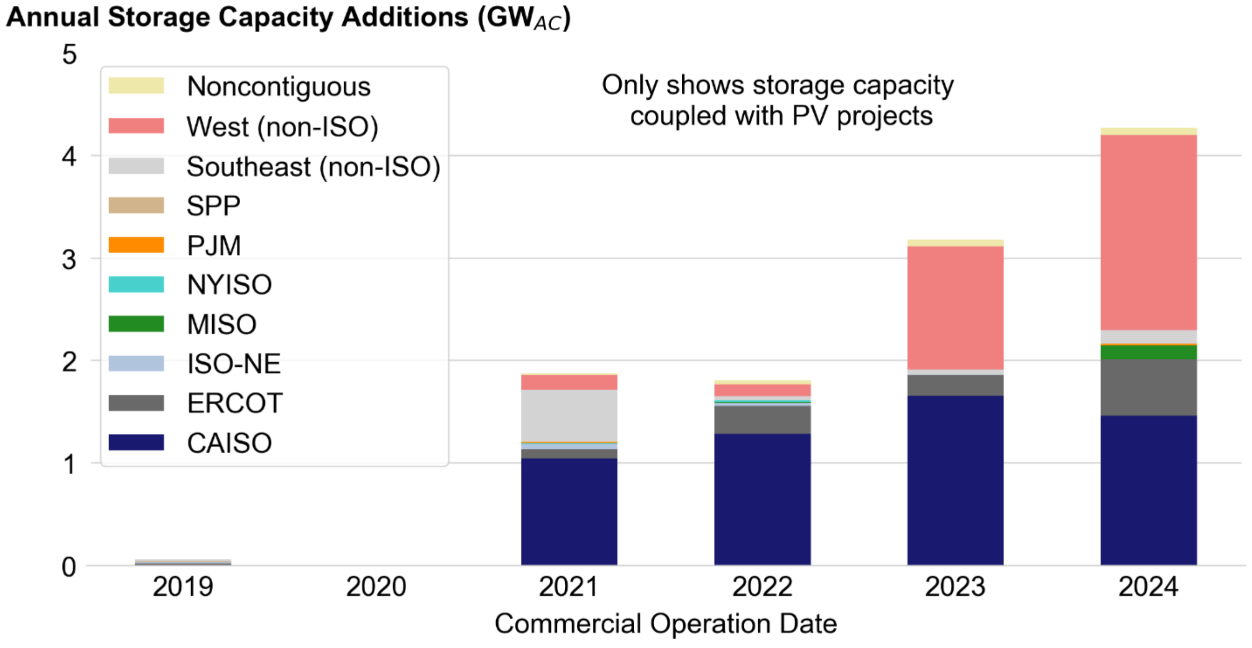
PV+Battery Hybrid Plants

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

PV+battery hybrid plants added 7.4 GW_{AC-PV} and 4.3 $GW_{Storage}$ greenfield and retrofit capacity in 2024

Sample: 201 projects totaling 19.9 GW_{AC} of PV, 11.4 GW_{AC} of battery capacity, and 36.3 GWh of battery energy



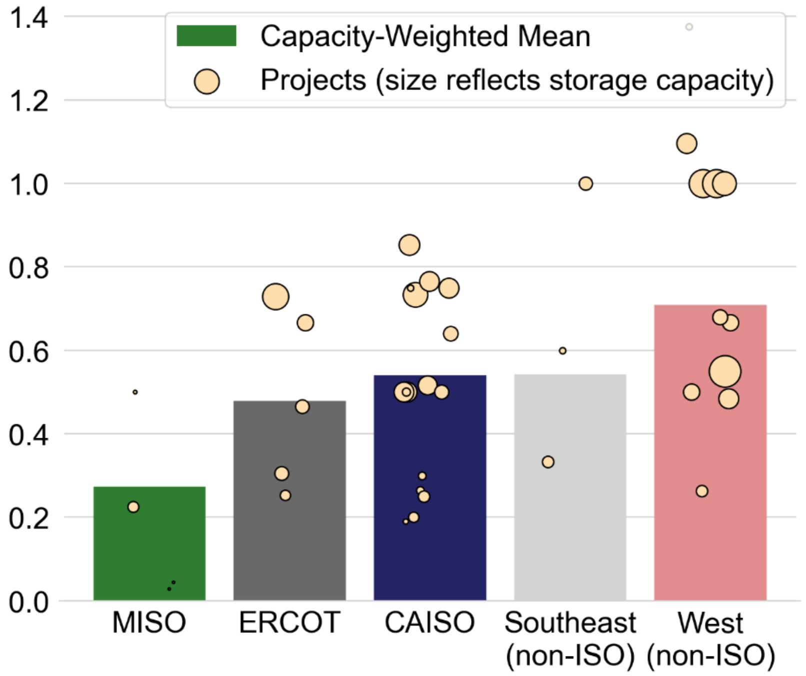


The large-scale PV+battery hybrid market started in earnest in 2021 with 39 hybrid installations. 2024 added the most capacity both for newly built hybrids (33 plants, 5.8 GW_{AC-PV}) and for storage retrofits to existing stand-alone solar projects (14 plants, 1.6 GW_{AC-PV}).

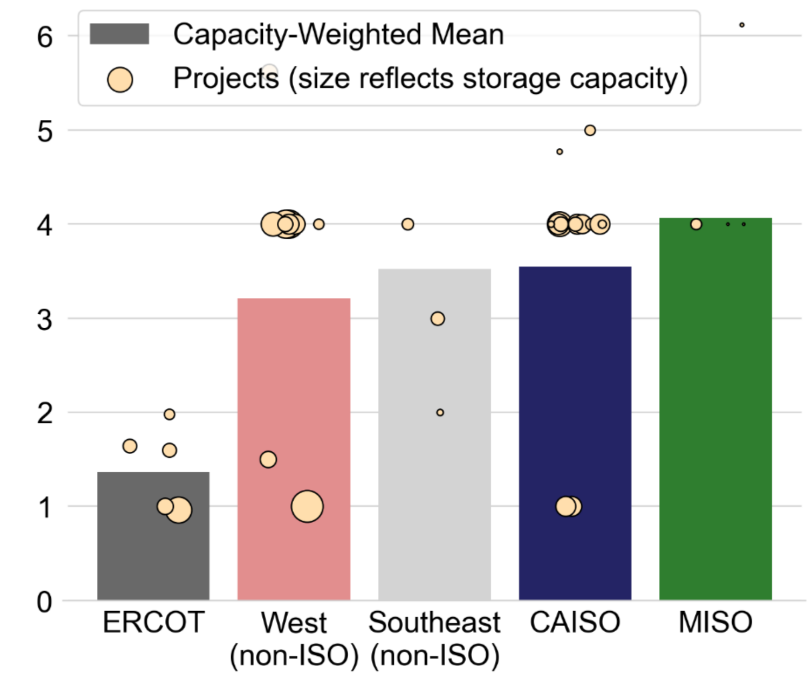
Most of the new hybrid storage was built in the solar-rich non-ISO West (13 plants, 1.9 $GW_{storage}$) followed by CAISO (16 plants, 1.5 $GW_{storage}$). ERCOT grew rapidly (6 plants, 0.5 $GW_{storage}$) and MISO had its first larger deployment (5 plants, 0.1 $GW_{storage}$).

The average storage:PV capacity ratio grew to 0.57 with 3.3 hours of duration in 2024

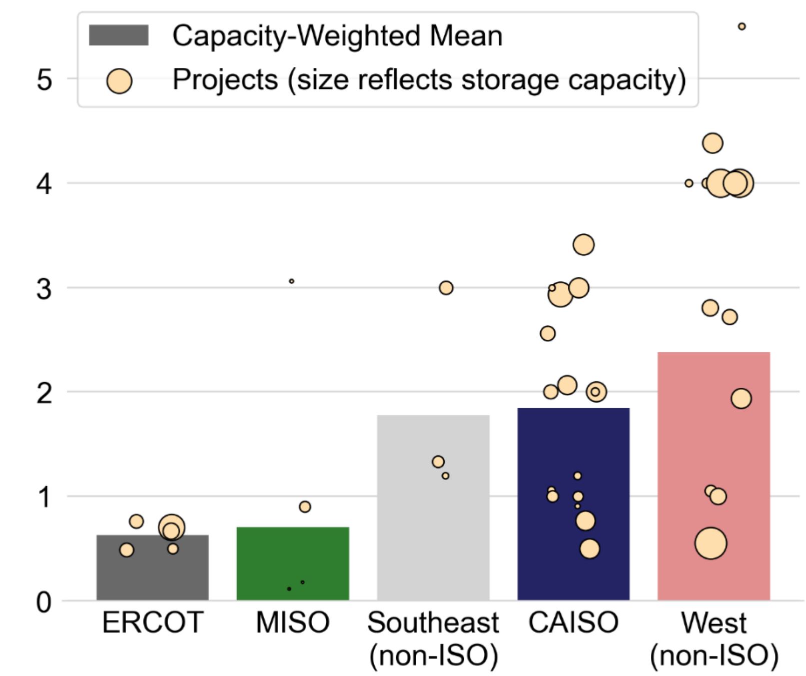
Storage Capacity Ratio
(Storage Capacity [MW] / PV Capacity [MW_{AC}])
of Projects Hybridizing in 2024



Storage Duration [Hours]
(Storage Energy [MWh] / Storage Capacity [MW])
of Projects Hybridizing in 2024



PV-Equivalent Duration [Hours]
(Storage Energy [MWh] / PV Capacity [MW_{AC}])
of Projects Hybridizing in 2024

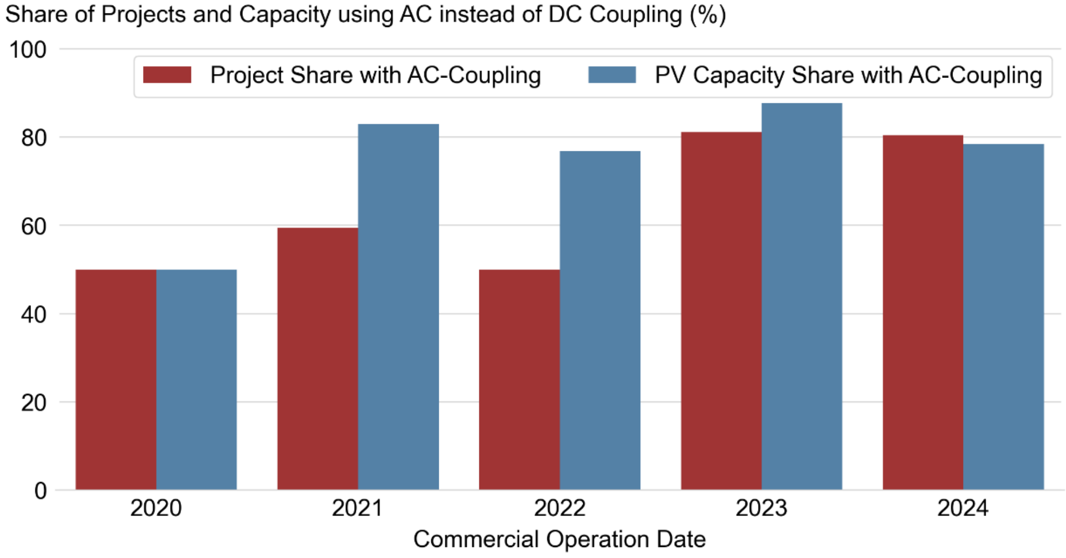


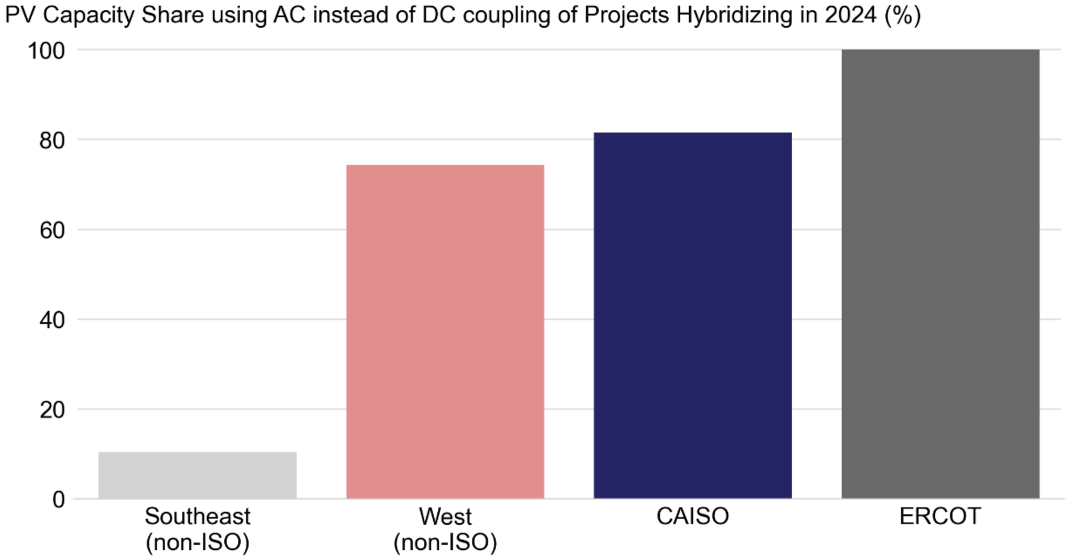
Storage capacity ratio (SCR) describes the battery capacity relative to solar capacity (MW_{AC}). In 2024 it is greatest in the non-ISO West and lowest in MISO.

Storage duration at full rated battery capacity is shortest in ERCOT and often above 3h in the rest of the country.

PV-equivalent duration combines SCR and storage duration and describes theoretical battery duration at PV capacity. We will use this term as proxy for battery size.

80% of new PV+battery projects used AC-coupling in 2024





PV and batteries can be **AC-coupled**

- requiring separate dedicated inverters
- often featuring a centralized battery yard
- common among retrofits

or **DC-coupled**

- only using one inverter setup but a separate DC/DC converter
- often having higher ILR as battery can capture clipped energy

Despite theoretical cost savings of DC-coupling, most of the recent projects use AC-coupling (except in Florida).

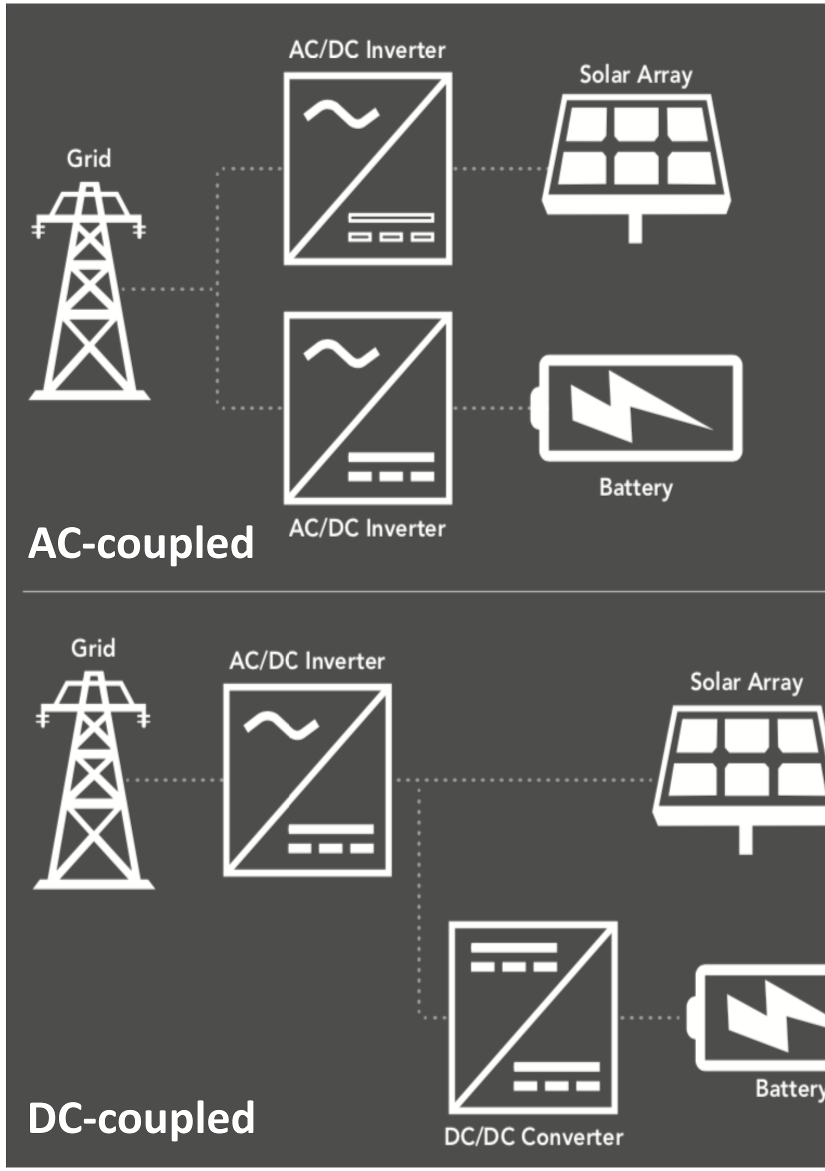
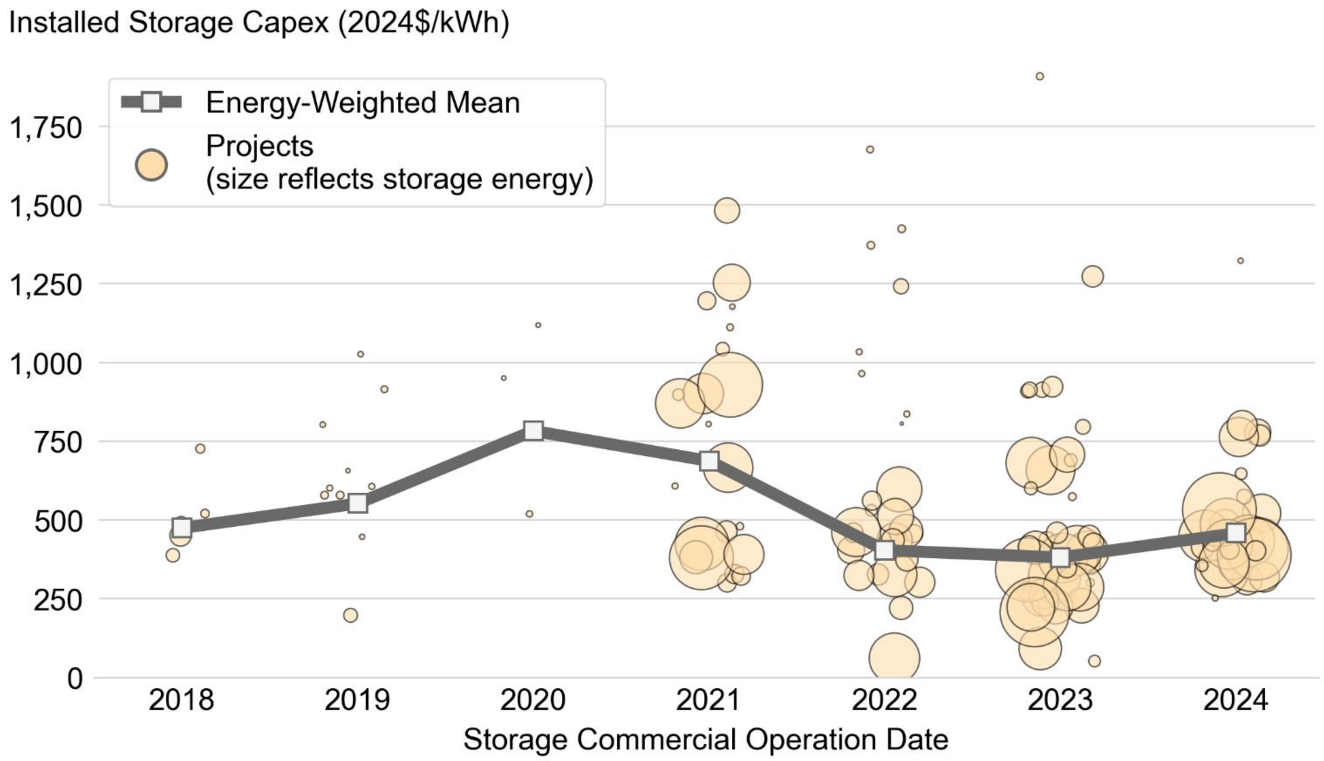
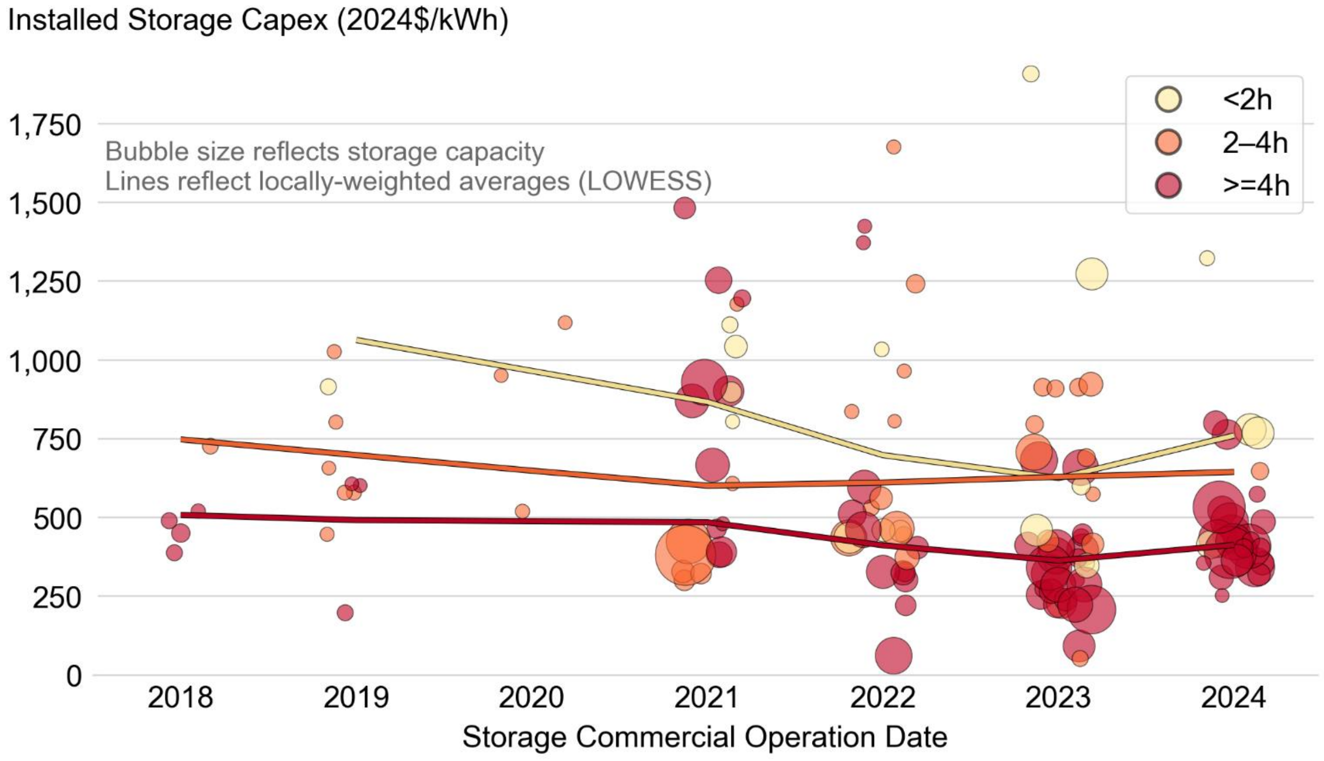


Figure credit: Verbruggen, S. 2019. "Go big, go DC: an in-depth look at DC-coupled solar-plus-storage." Energy Storage News, October 9, 2019, https://www.energy-storage.news/go-big-go-dc-an-in-depth-look-at-dc-coupled-solar-plus-storage/

Costs of co-located batteries increased to $458/kWh in 2024

Sample: 138 projects totaling 8.5 GW and 29.5 GWh of batteries





Capacity-weighted average costs increased from $381/kWh in 2023 to $458/kWh in 2024. Costs are lowest in MISO ($351/kWh) and greatest in the non-ISO Southeast ($473/kWh).

Longer duration storage is cheaper on a per kWh basis than shorter duration storage, indicating economies of scale.

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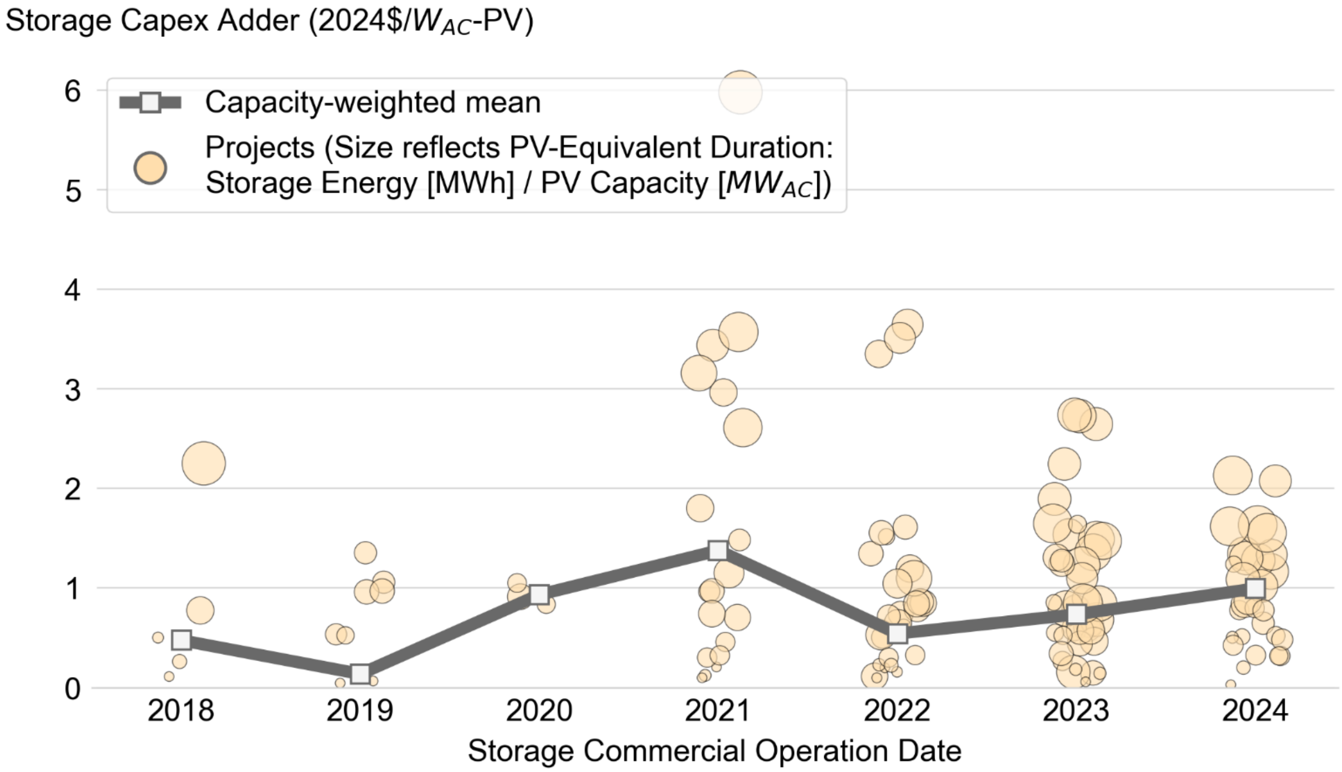
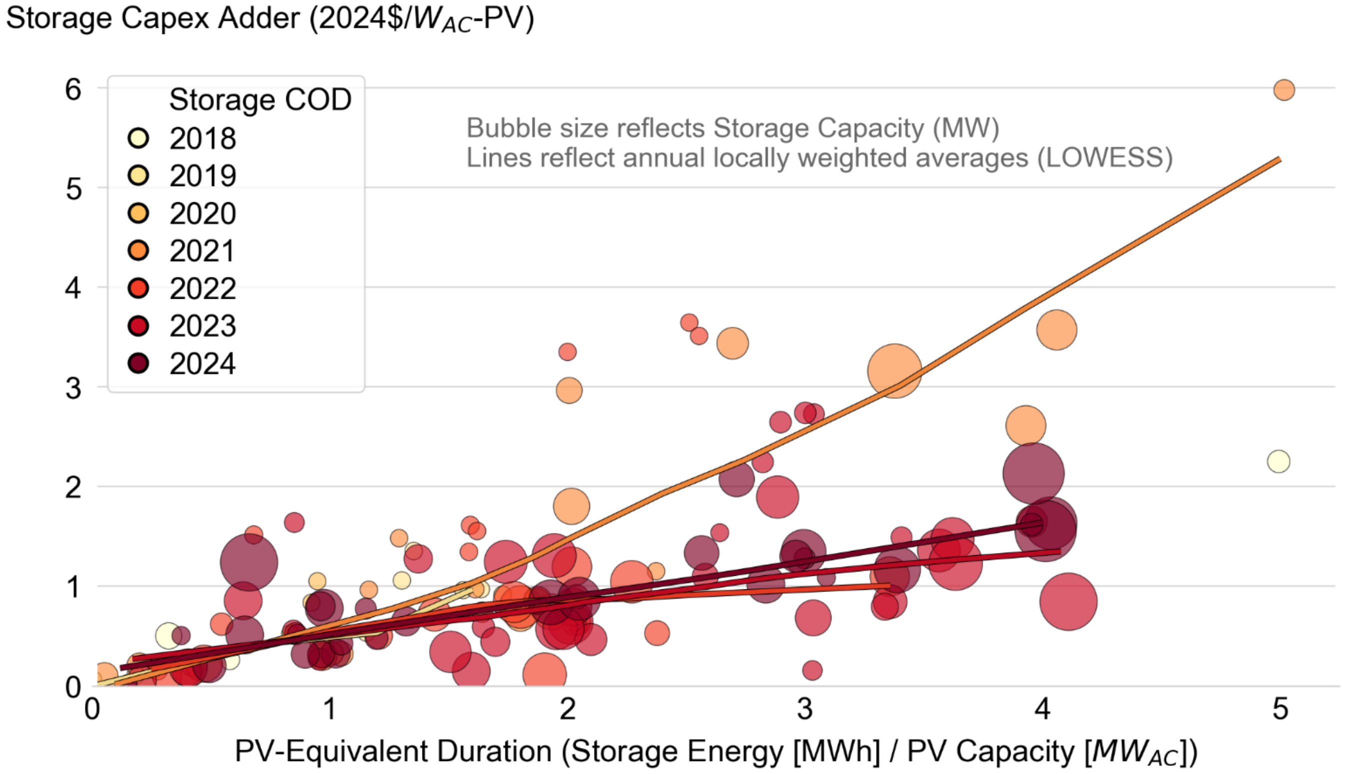
Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

The storage CapEx adder to PV projects depends on battery sizing

Sample: 131 projects totaling 8 GW and 27.4 GWh of batteries





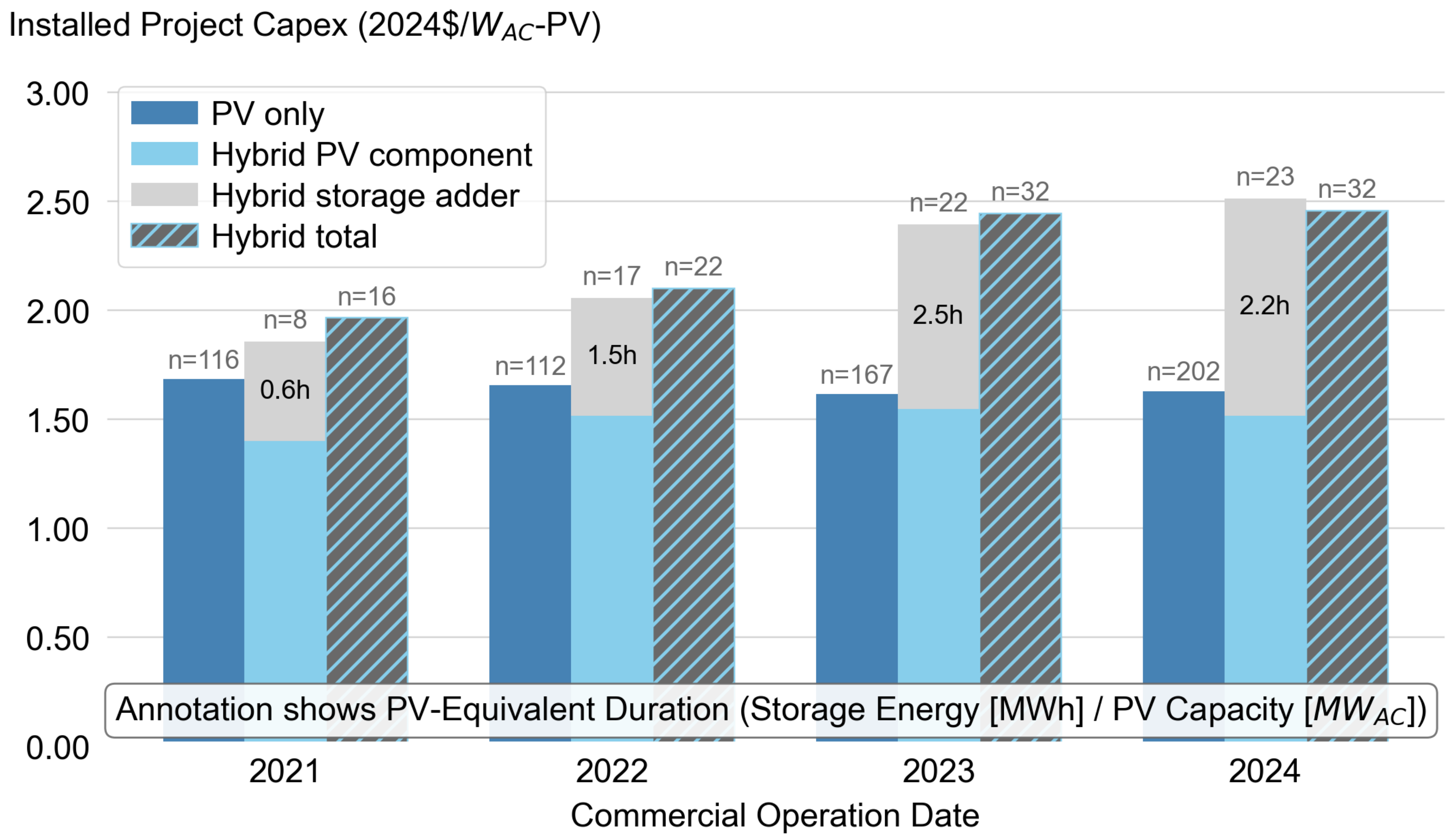
Storage sizes have increased by nearly 50% since 2022, explaining in part the growth of the storage cost adder to \$1.00/$W_{AC\text{-}PV}$ in 2024.

Accounting for storage size variations, storage capex adders in 2024 (**dark red line**) are slightly greater than over the past three years.

Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

Costs of PV+battery projects remained stable at $2.46/W$_{AC\text{-}PV}$ in 2024

Sample: 102 greenfield plants totaling 12.4 GW$_{AC}$ of PV and 6.6 GW / 23.1 GWh of batteries



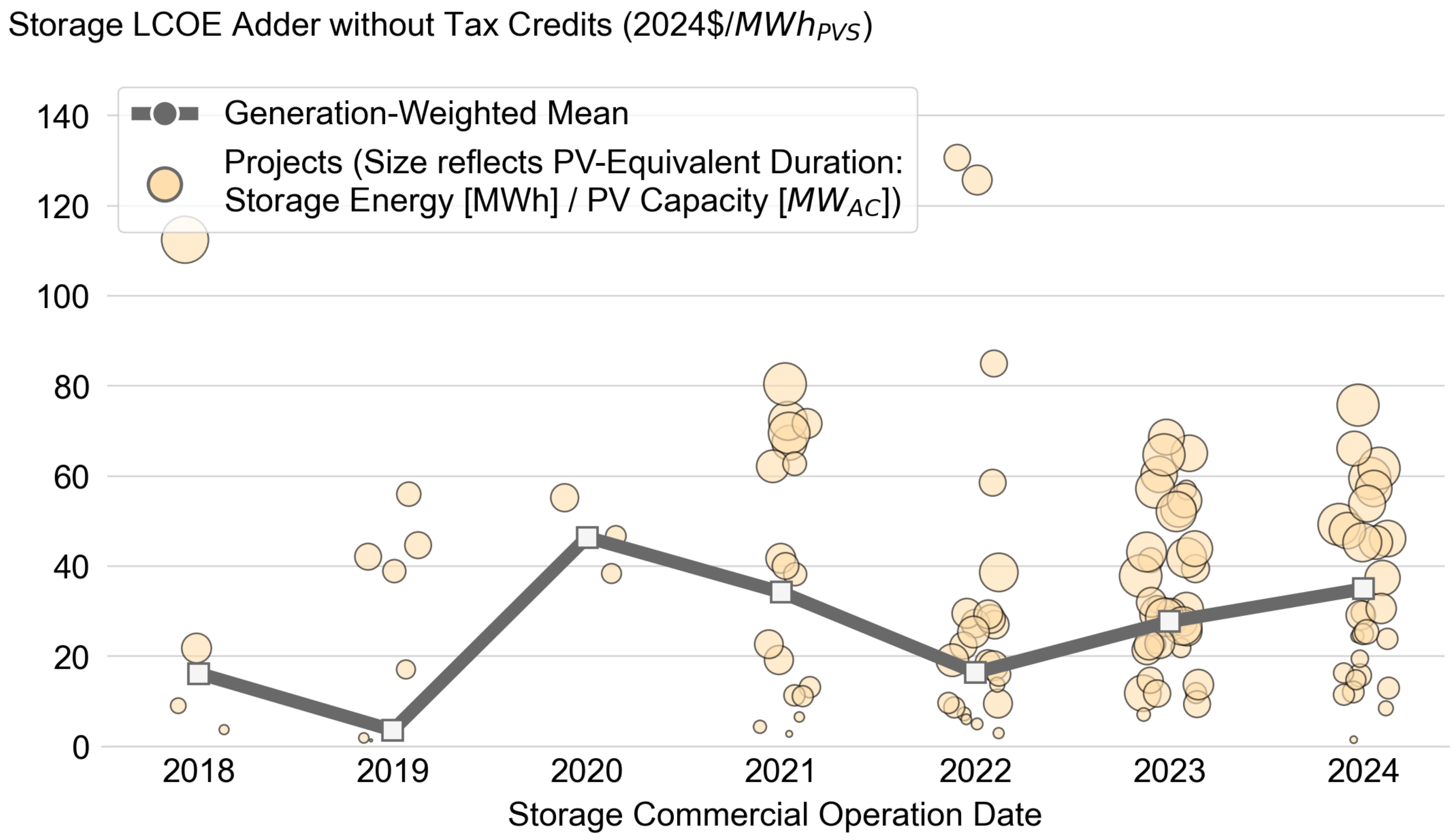
Focusing only on greenfield hybrid developments (excluding retrofits), average cost of PV components of a co-located project are slightly lower than for a PV-standalone project (driven by project size, geographics or shared infrastructure with storage components like inverters for DC-coupled installations).

For some hybrid projects we lack component-level costs and can only report total system costs (hatched) – they were thus excluded from previous slides. These sample differences explain slightly diverging trends (cost increase in center bars vs. stability in right-most bars for the years 2023 vs. 2024).

Note: Estimates for projects with 2024 COD are still preliminary both in scope and accuracy of individual data points and may not be representative of final numbers that will be published later by EIA.

The battery LCOE adder to PV projects scales with battery sizing, like the capex adder before

Sample: 122 projects totaling 7.5 GW and 26.9 GWh of batteries (including storage retrofits)



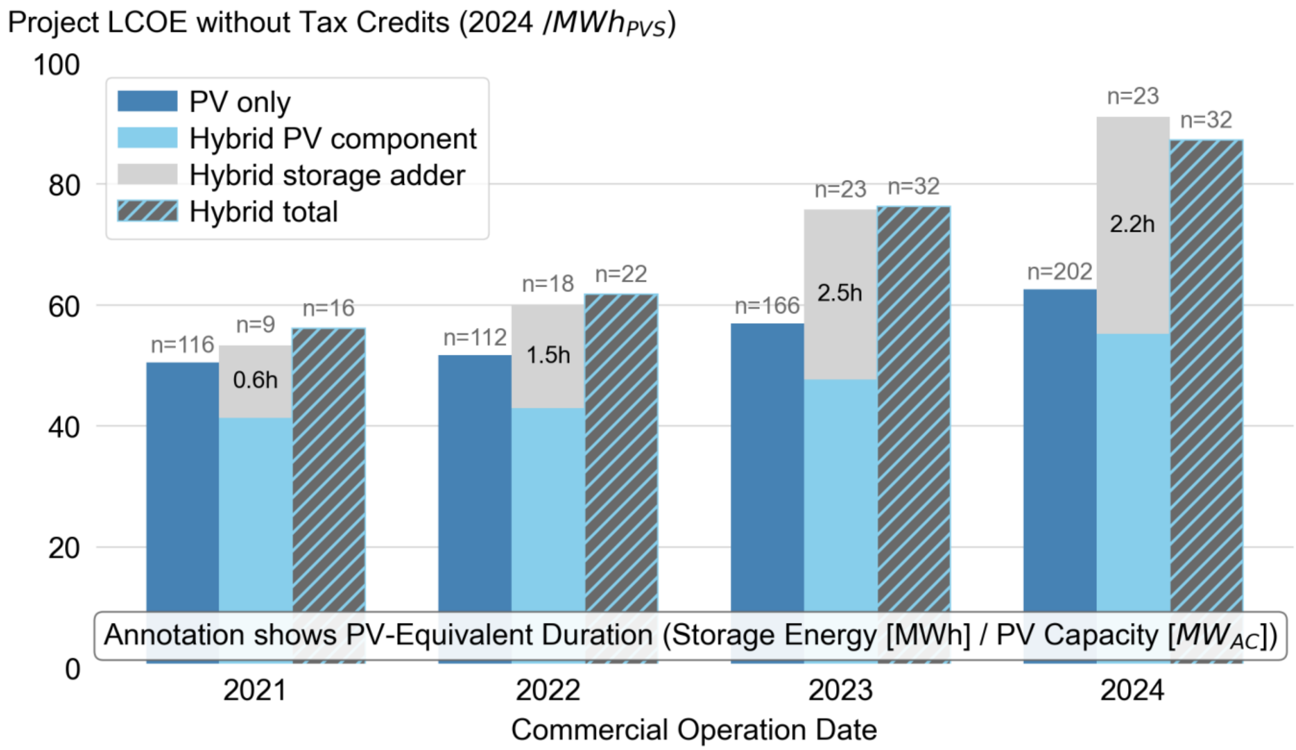
Battery LCOE adders (for both newly built co-located projects and retrofits to existing PV projects) have grown since 2022, driven by larger battery sizes and increased financing costs.

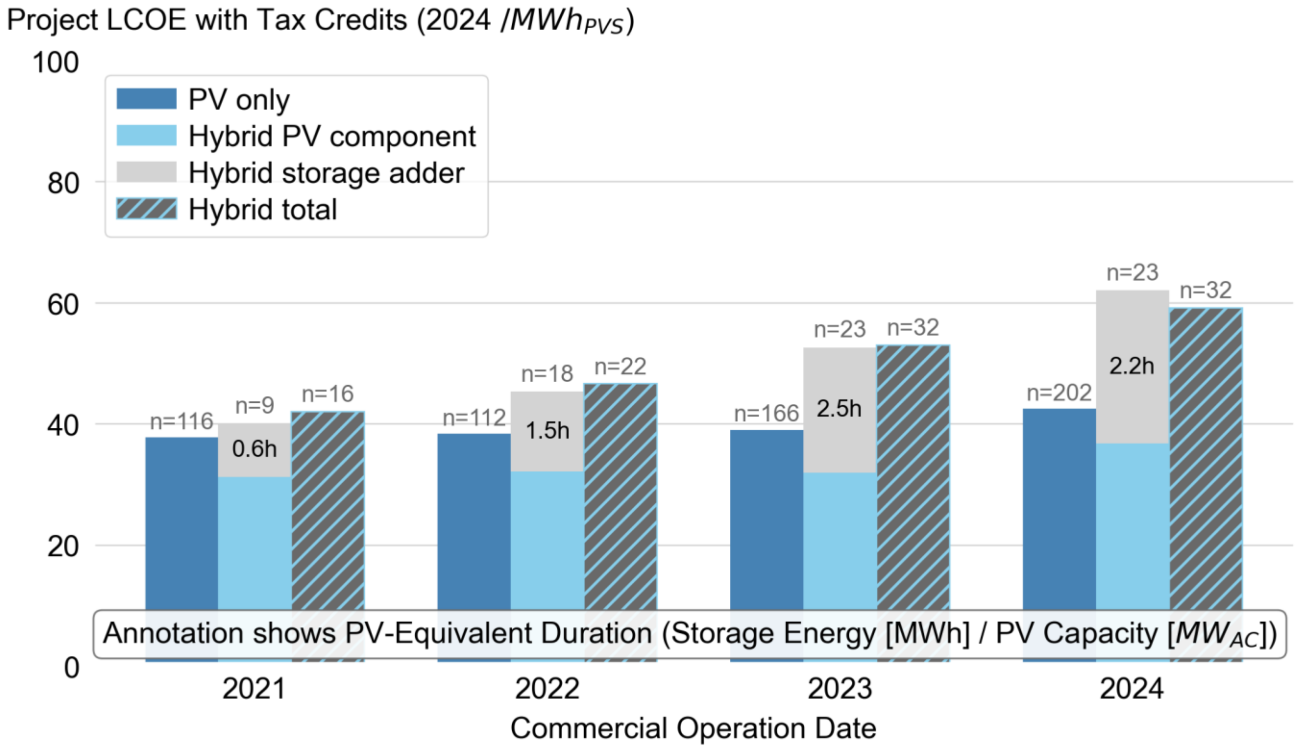
In 2024 the adder was \$35/MWh_{PVS} before tax credits (shown in graph) and \$25/MWh_{PVS} after tax credits.

Note: LCOE estimates shown in graph here <u>do not include tax credit benefits</u>.
Findings may shift as final EIA Capex and project-specific performance data become available.

PV+battery projects had a LCOE of $87/MWh without and $59/MWh with tax credits

Sample: 102 greenfield plants totaling 12.4 GW_{AC} of PV and 6.6 GW / 23.2 GWh of batteries (excluding retrofits)





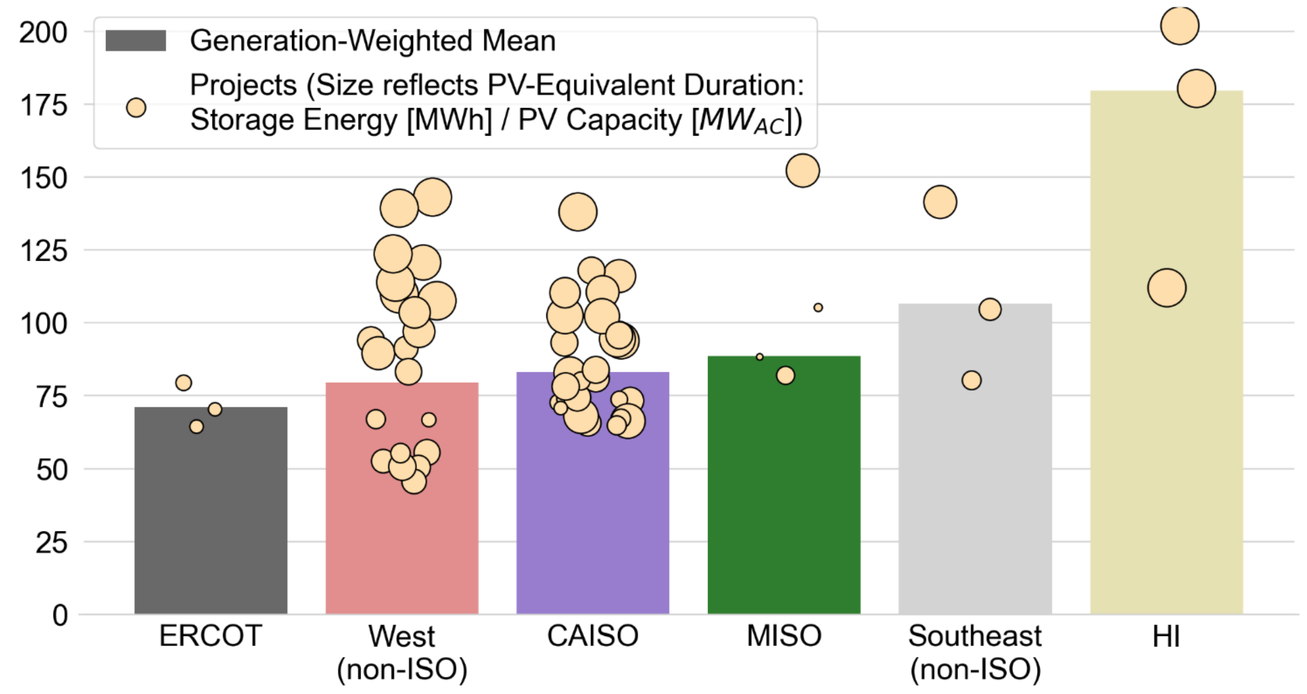
This sample excludes projects with storage retrofits (unlike previous slide). PV component LCOE of a co-located project is lower than PV only as hybrids are usually in sunnier regions.

The battery LCOE adder has grown to $36/MWh before tax credits (left graph) and $25/MWh after tax credits (right graph) in 2024.

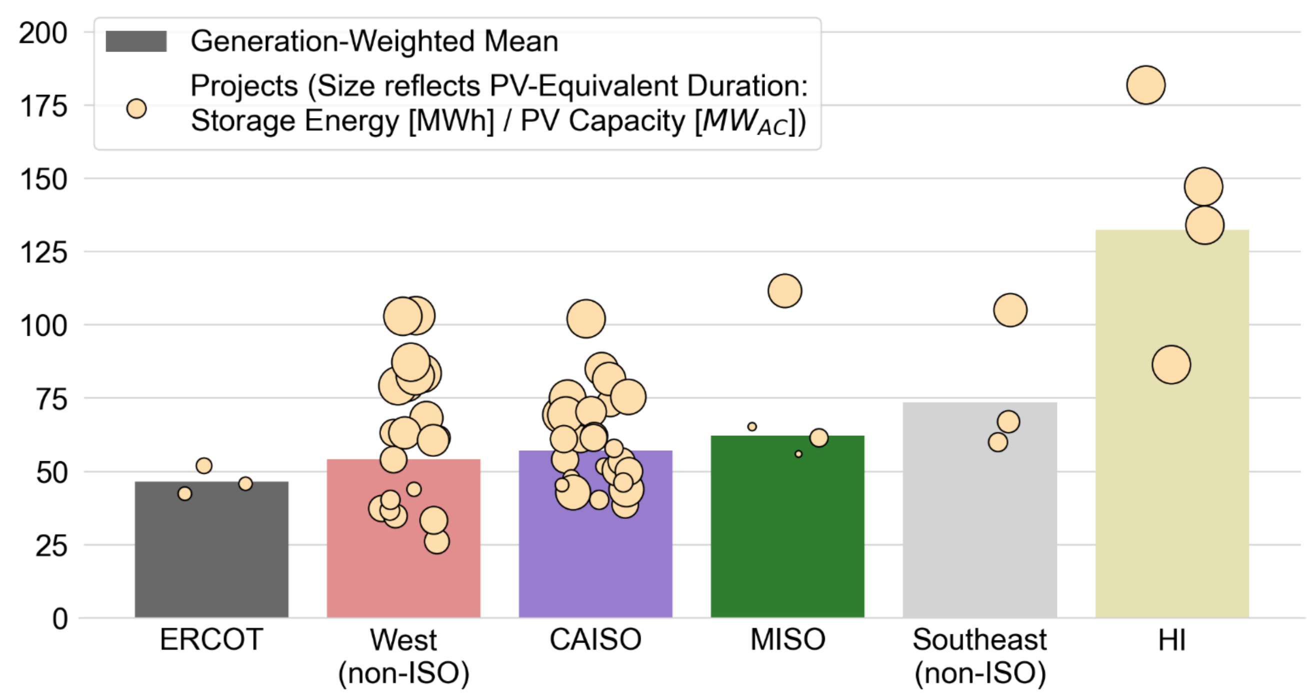
Recent PV+battery LCOE was lowest in Texas and greatest in Hawaii

Sample: 63 greenfield plants totaling 9.4 GW_{AC} of PV and 5.5 GW / 19.7 GWh of batteries (excluding retrofits)

LCOE without Tax Credits of 2023-2024 PV+Storage Projects (2024$/MWh)



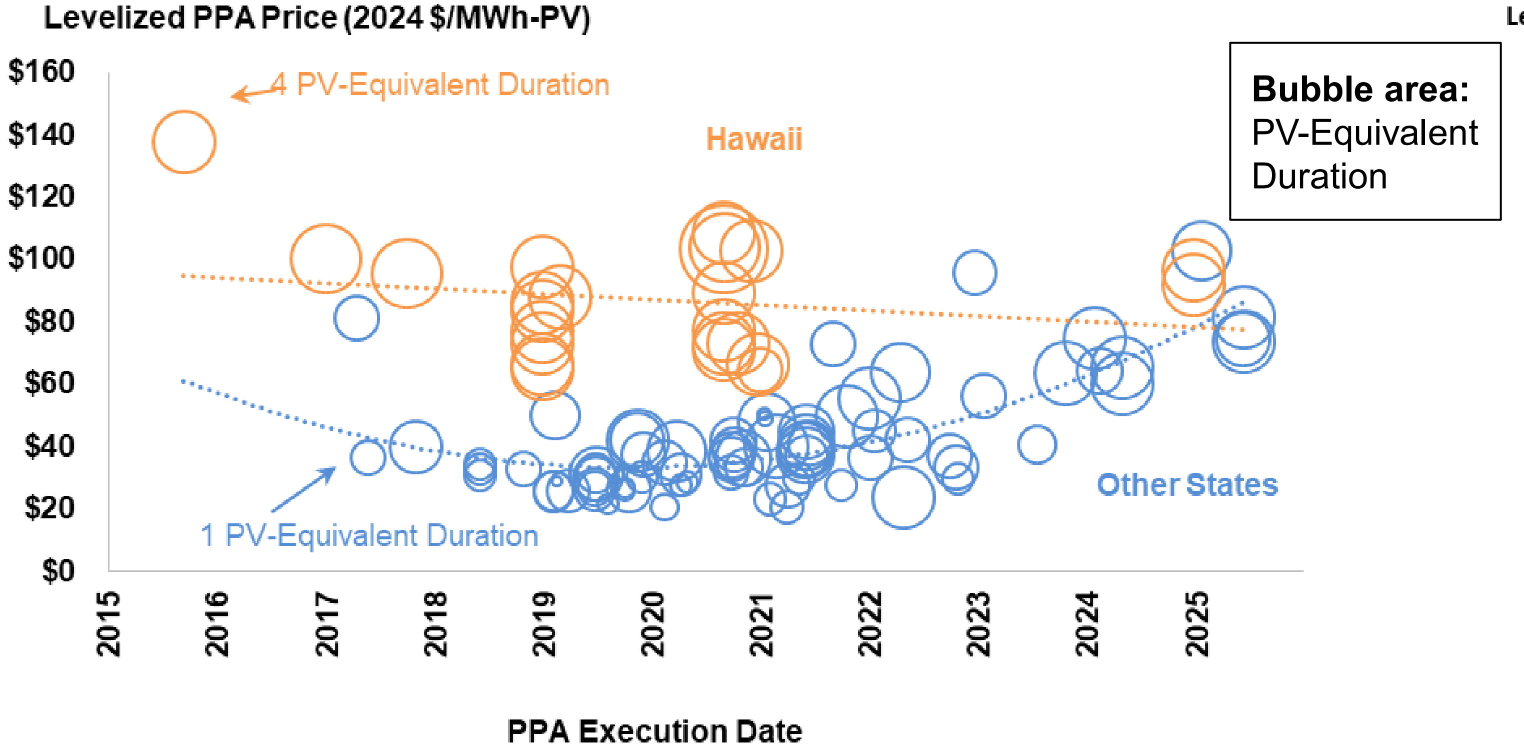
LCOE with Tax Credits of 2023-2024 PV+Storage Projects (2024$/MWh)

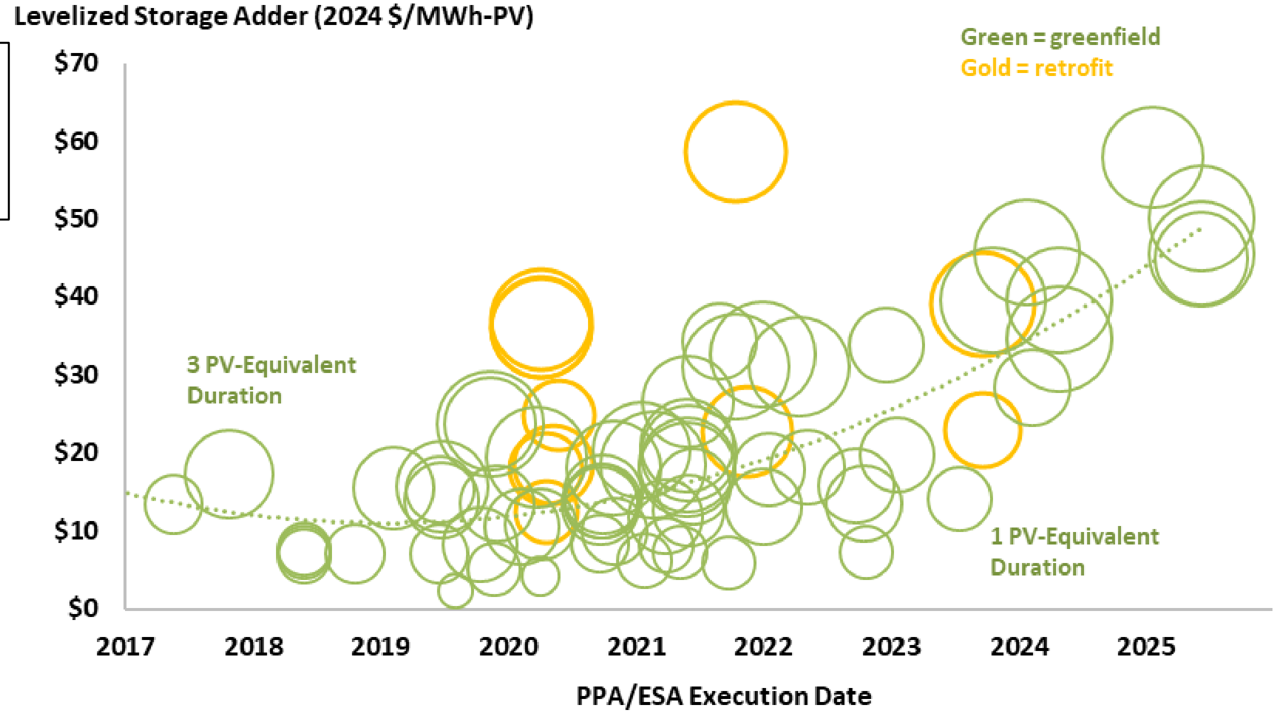


Average PV+battery LCOE in ERCOT was $71/MWh compared to $180/MWh in Hawaii in 2023/2024 (HI storage is sized to 100% PV capacity with 4h duration).

After accounting for available tax credits (excluding potential domestic content bonuses), average LCOE fell to a range $47/MWh to $132/MWh.

PPA prices for PV+battery have increased significantly from 2019/2020 lows; Hawaii prices converging overtime





Left graph is sub-sample of 103 plants (retrofits not included)

- Hawaii (orange): 24 plants, 0.9 GW_{AC} PV, 0.9 GW_{AC} battery
- Other States (blue): 78 plants, 11.3 GW_{AC} PV, 6.5 GW_{AC} battery
- Storage duration ranges from 2-8 hours

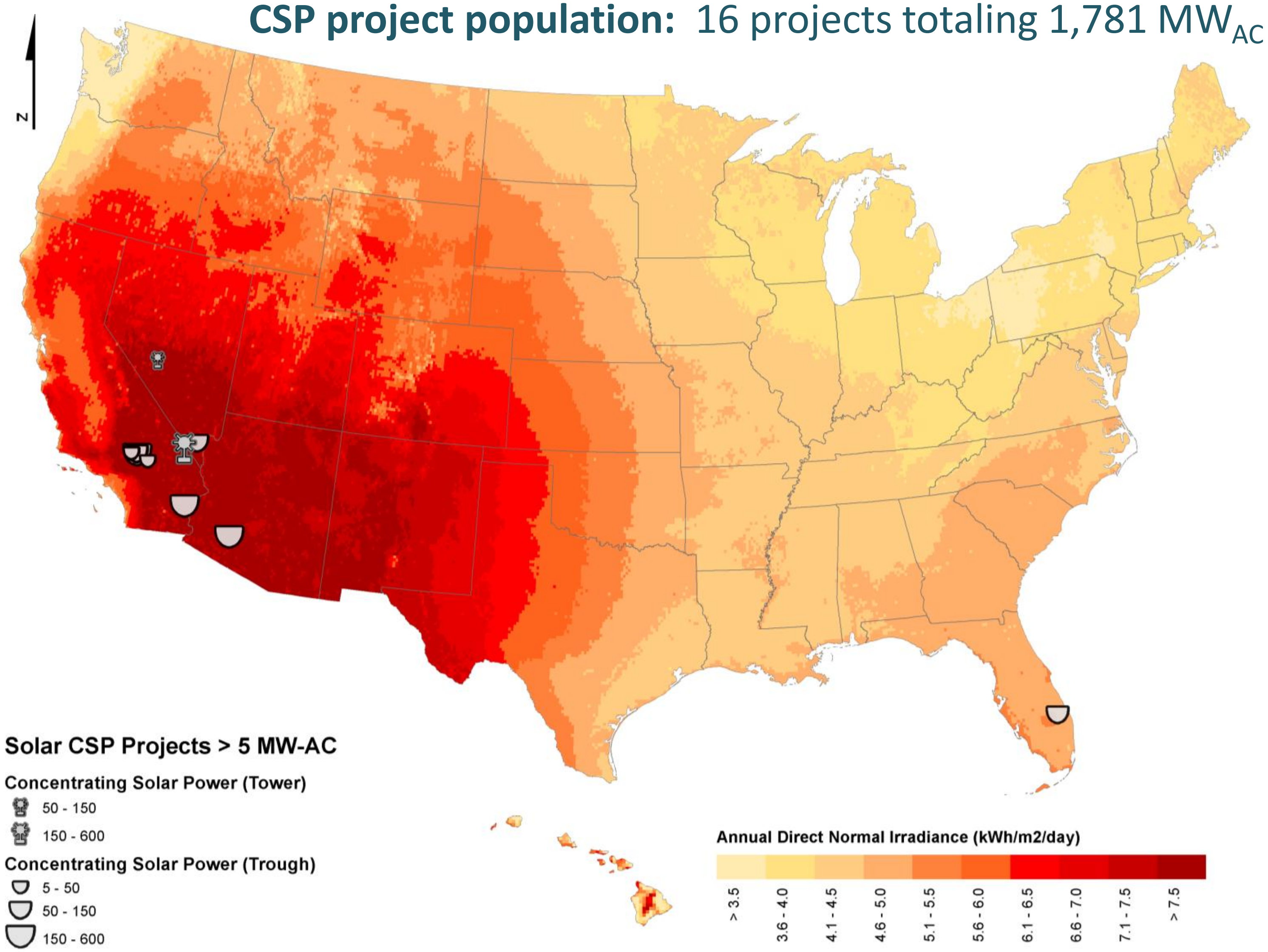
Right graph is sub-sample of 74 plants (6.6 GW_{AC}) that provide enough information to calculate a levelized storage adder

- CA: 38 plants; NV 14 plants; NM 16 plants; AZ 5 plants; OR 1 plant

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.

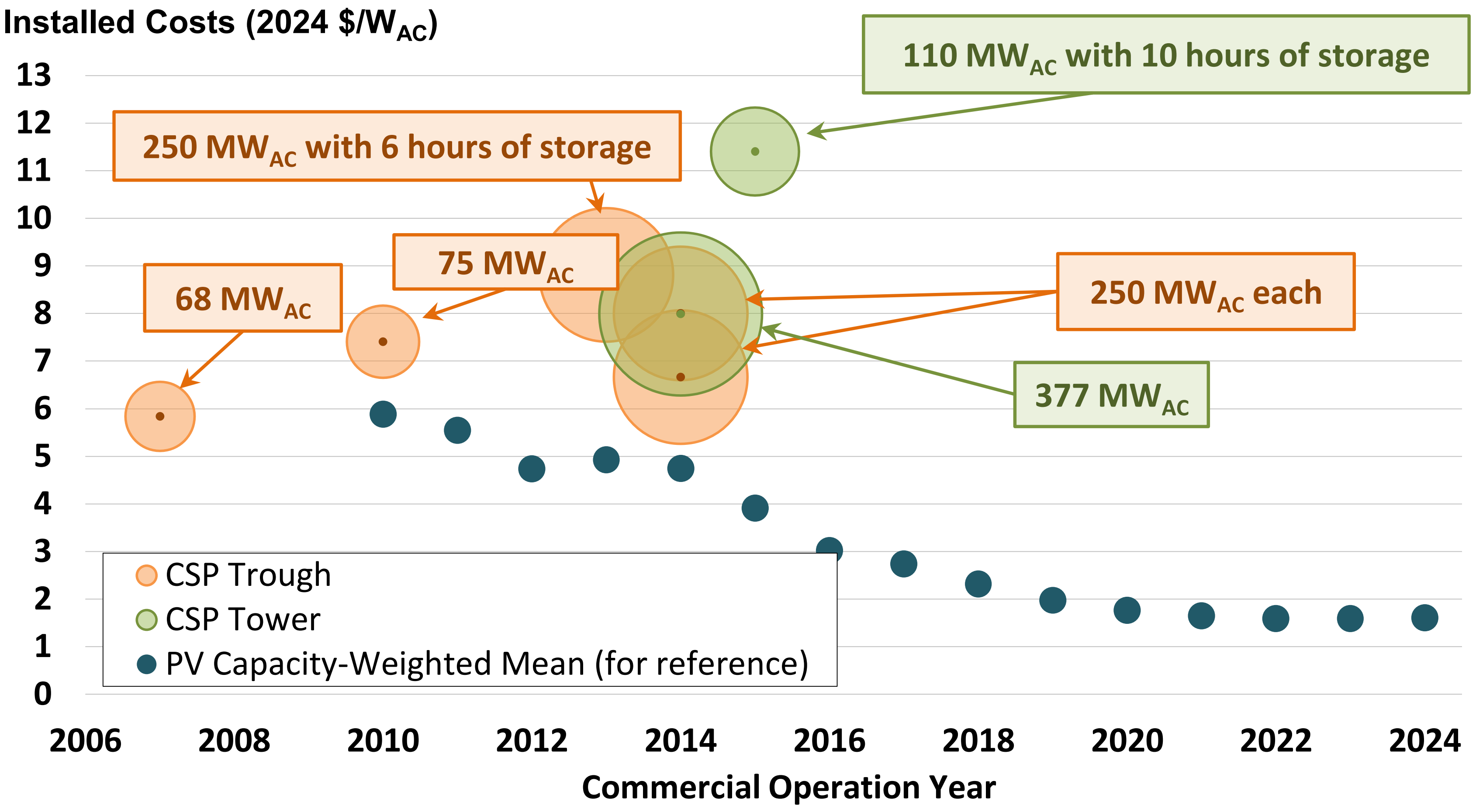
The five 2013-2015 projects include:

– 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}

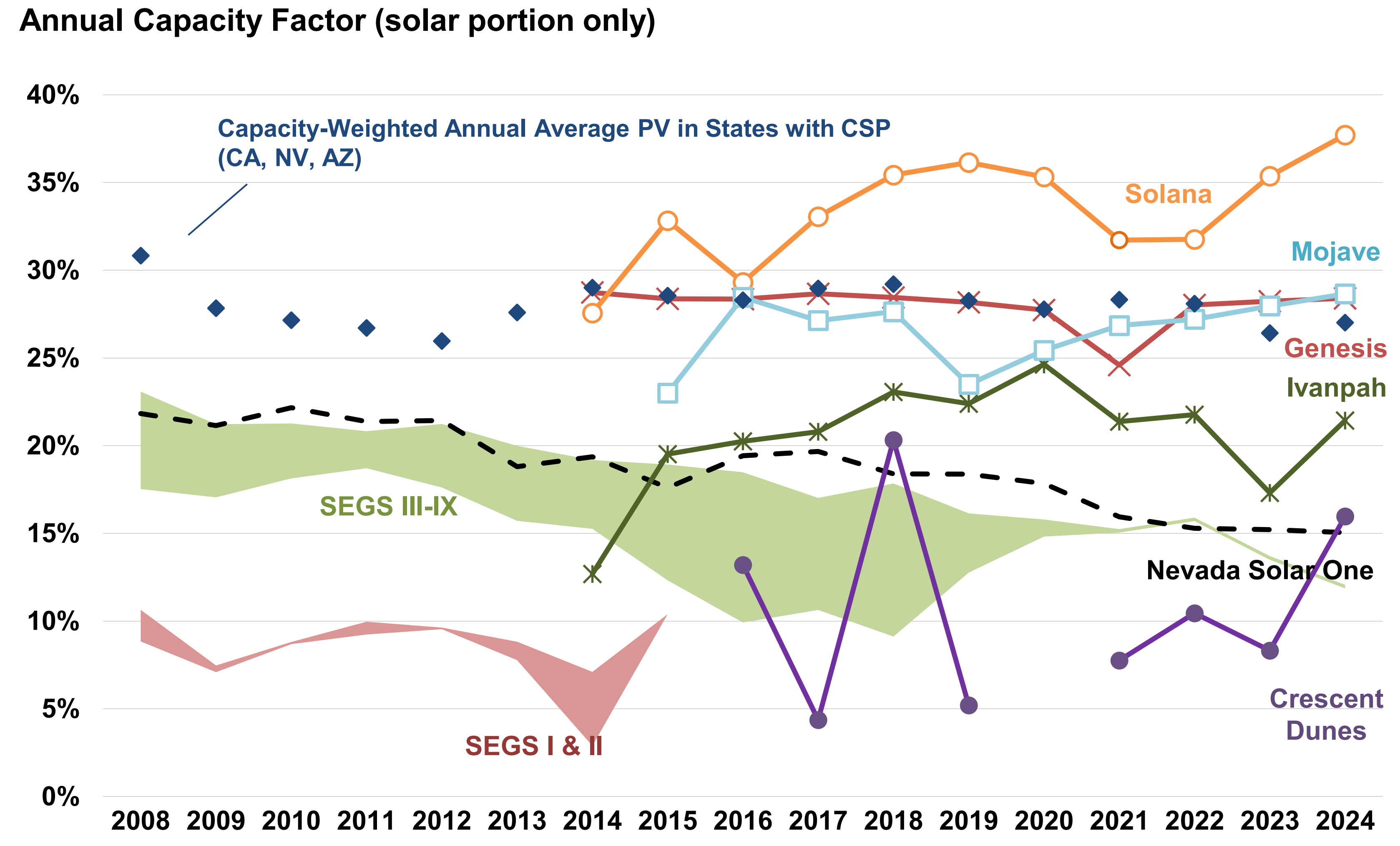


Small sample of 7 projects using different technologies makes it hard to identify trends. Newer projects (5 built in 2013-15) did not show cost declines, though some included storage or used new technology (power tower).

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

CSP projects show modest performance improvements in 2024 despite continued underperformance relative to expectations

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



Power Towers: Ivanpah's (370 MW) capacity factor increased in 2024--21.4%, up from 17.3% in 2023. The facility is expected to begin decommissioning in 2026, following the termination of its contract with PG&E. Crescent Dunes (110 MW with 10 hours of storage) performed at 16.0% capacity factor in 2024, up from 8.3% in 2023, but still well below expectations.

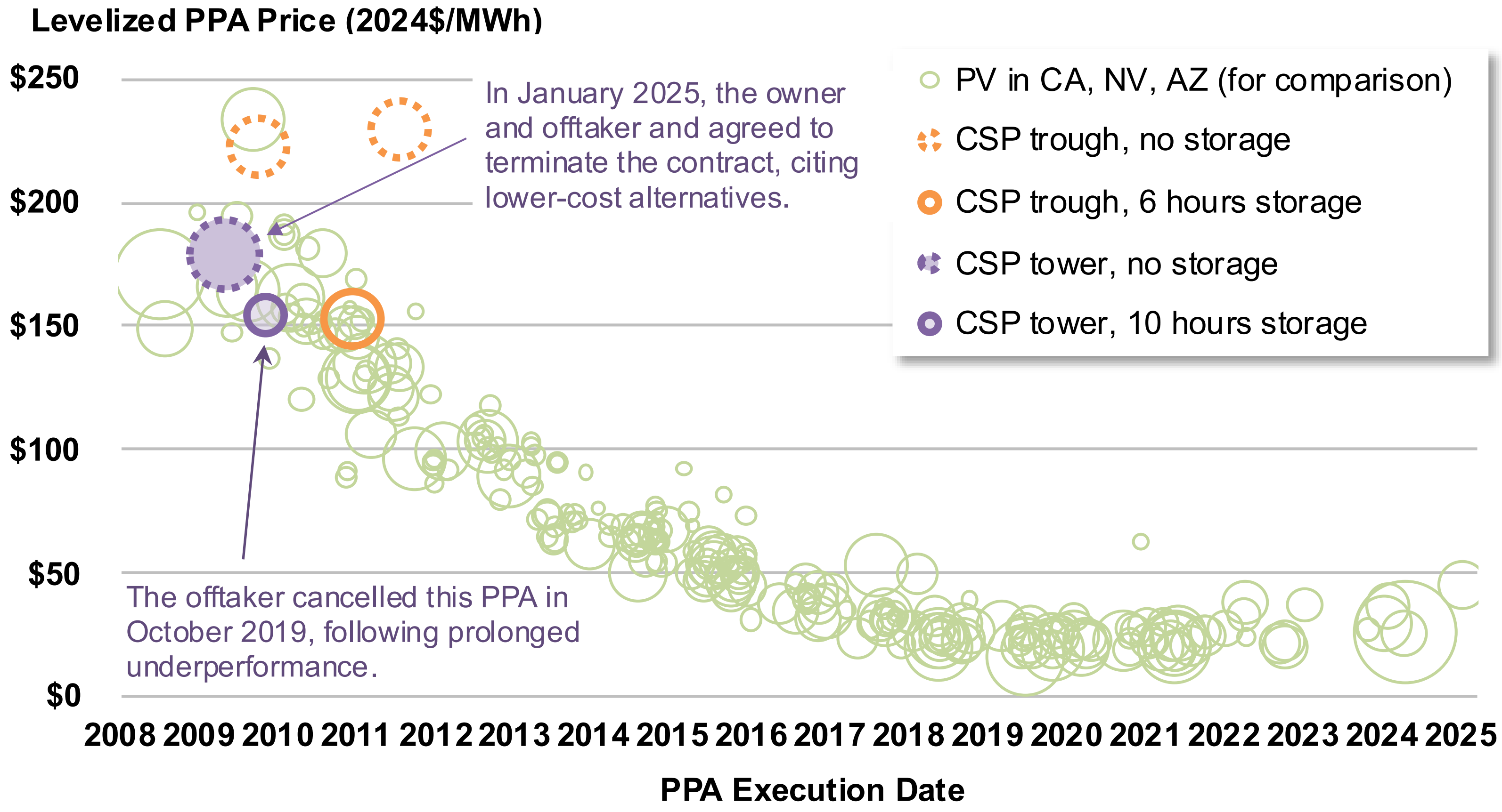
Trough with storage: Solana (250 MW trough project with 6 hours of storage) performed at 37.7% capacity factor in 2024, inching closer to expectations of >40%.

Troughs without storage: Mojave and Genesis (both 250 MW net) were at 28-29% capacity factor in 2024. 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}



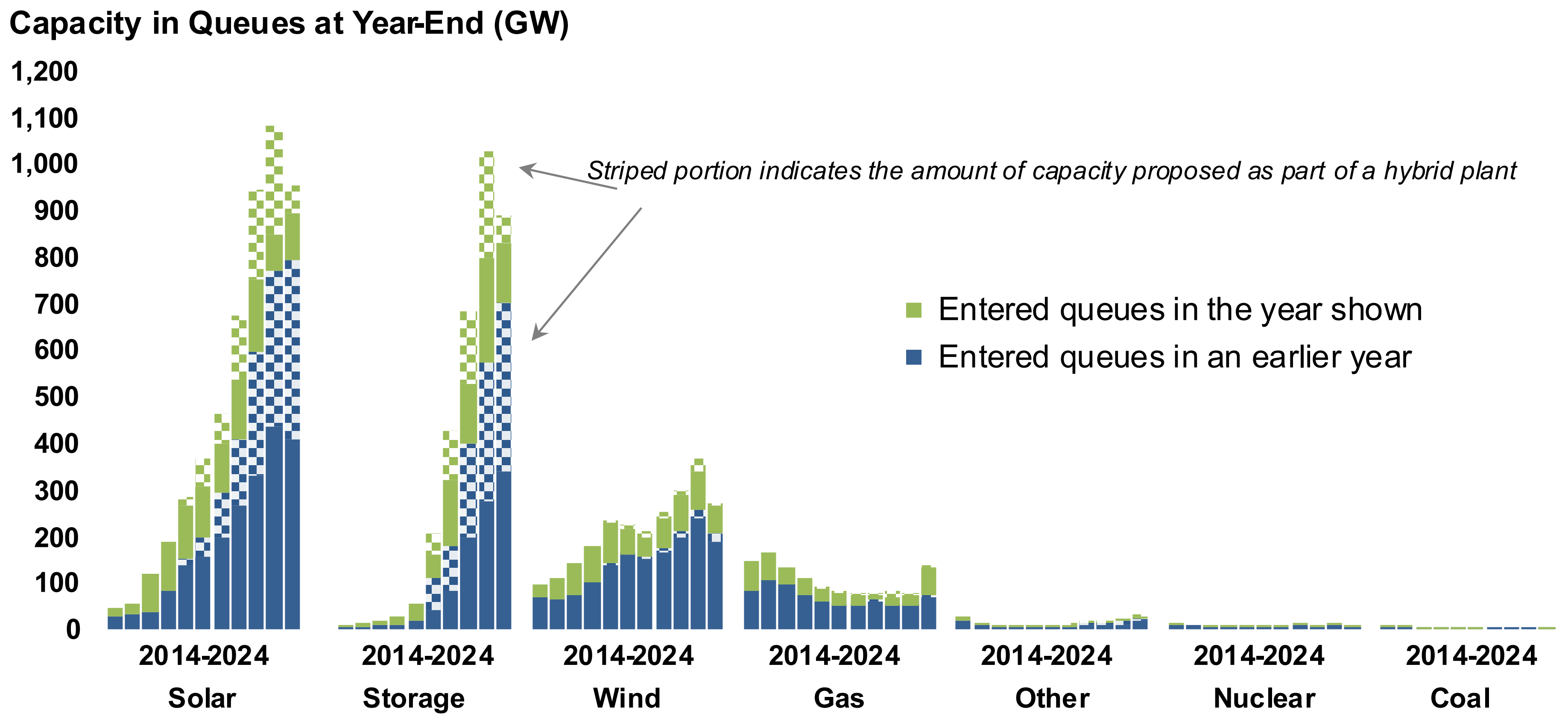
When PPAs for the most recent batch of CSP projects (with CODs of 2013-15) were signed back in 2009-2011, they had similar prices as PV PPAs.

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 and some of the PPAs have been cancelled.

Capacity in Interconnection Queues

Nearly 1 TW of solar is active in the interconnection queues, a decline from the previous year

Sample: Active bulk-power interconnection requests from 56 interconnection queues.



956 GW of solar was in the queues at the end 2024, down 12% from 2023 as a potential early result from FERC 2023 reforms. 161 GW entered the queues in 2024 while the remainder entered in earlier years and remained active.

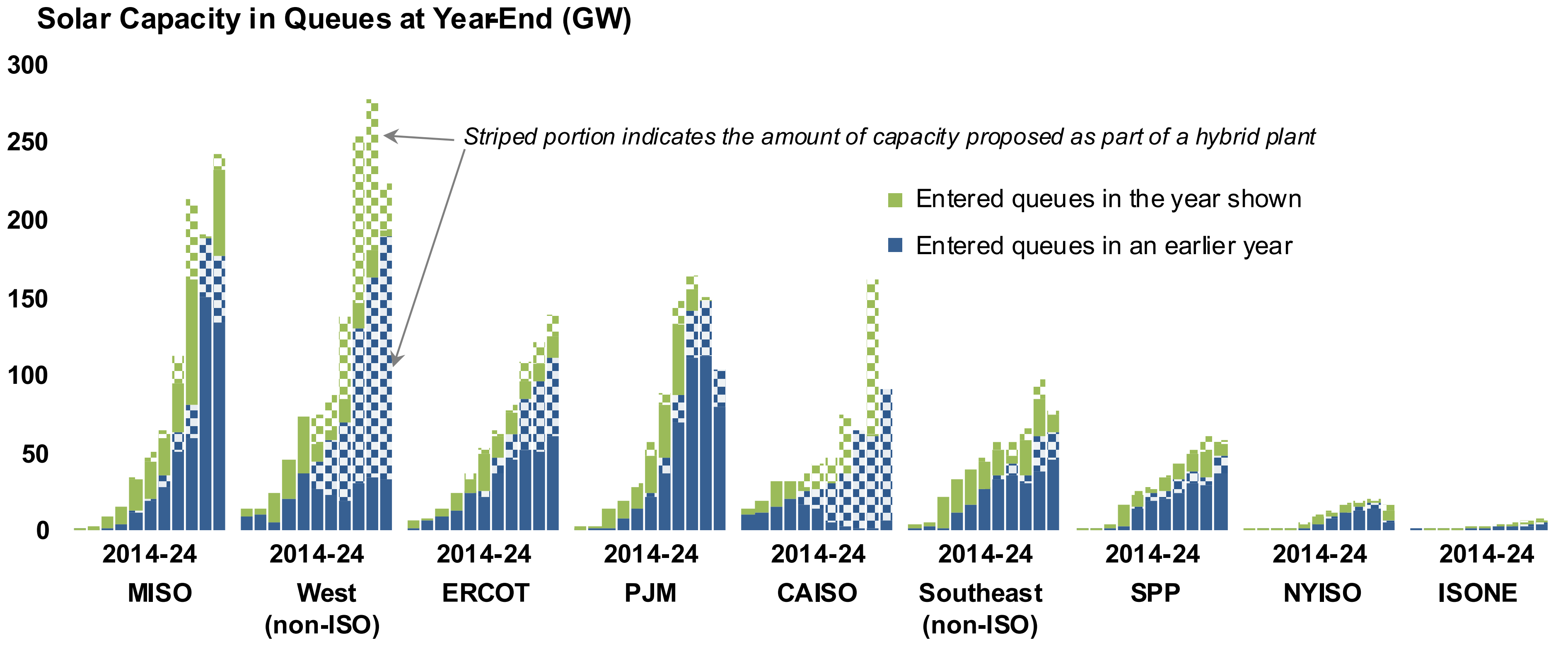
452 GW of solar in the queues (47%) includes a battery.

Solar (both in standalone and hybrid form) is the largest resource within these queues, followed closely by storage, with wind and gas as 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 LBNL's Annual Queued Up Data Update.

MISO has the most queued solar capacity in the nation

Sample: Data from 56 interconnection queues across the U.S.



7 out of 9 regions saw contractions in the total amount of queued solar in 2024. MISO and the non-ISO West had more than 200GW in 2024.

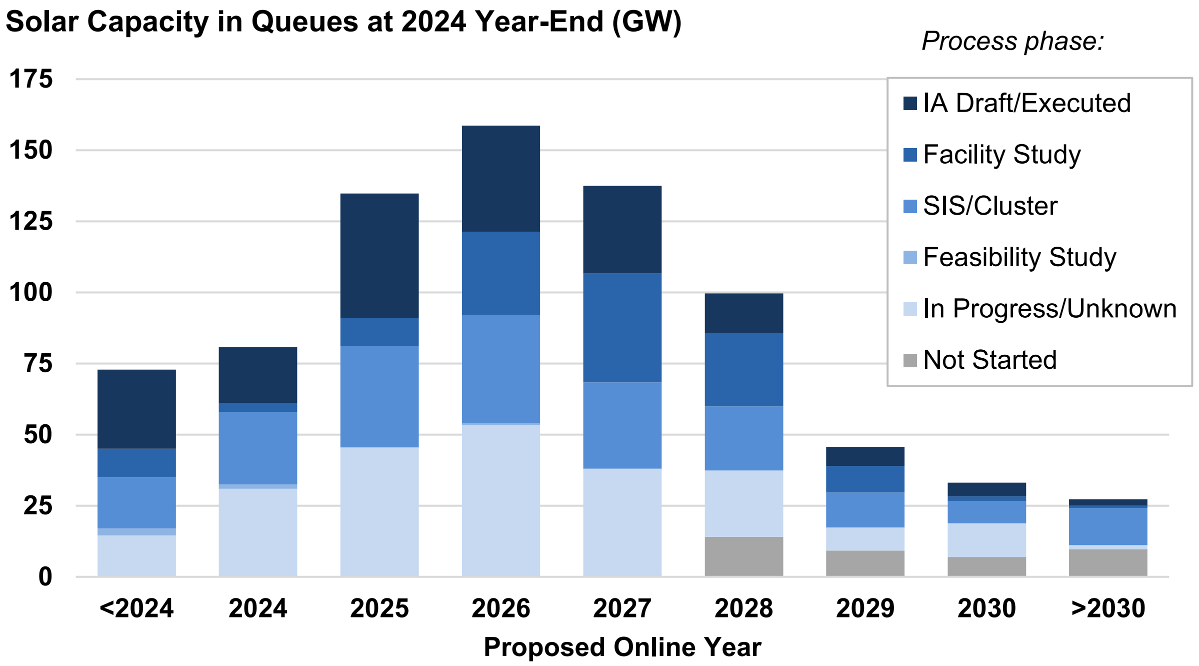
- CAISO and PJM did not accept new interconnection requests in 2024, so all solar in those queues entered in an earlier year

93% of the solar capacity in CAISO's queue at the end of 2024 was paired with a battery; in the non-ISO West, that number was also high, at 83%

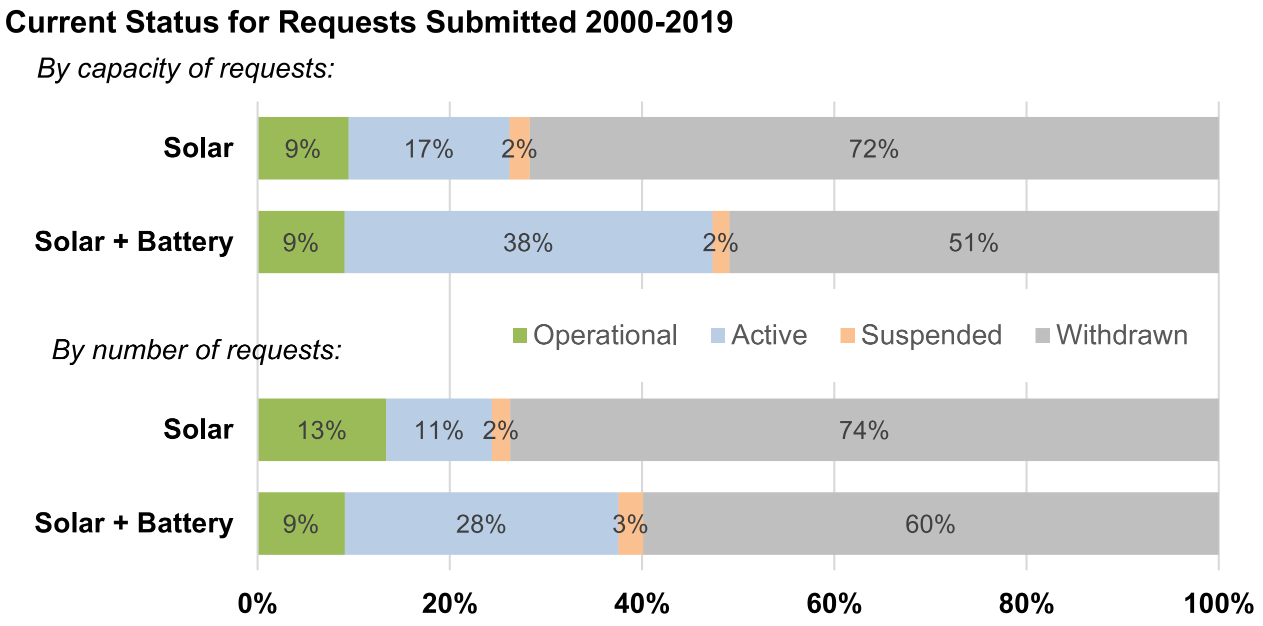
- Both regions are seeing solar value factors decline due to solar's relatively high market share (as discussed previously)

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 Data Update.

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
  - 154 GW of active solar requests were already past their proposed online date at the end of 2024
- 187 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 ~9% of solar capacity requesting interconnection will ultimately get built and become operational
- Developers withdraw interconnection requests for many 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 LBNL's [Annual Queued Up Data Update]().

For more information

Explore this briefing, an extensive workbook with all underlying data, and interactive visualizations: utilityscalesolar.lbl.gov

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This material is based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under Solar Energy Technologies Office (SETO) Agreement Number 38444 and Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

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