U.S. Utility-Scale Solar
2026 Edition

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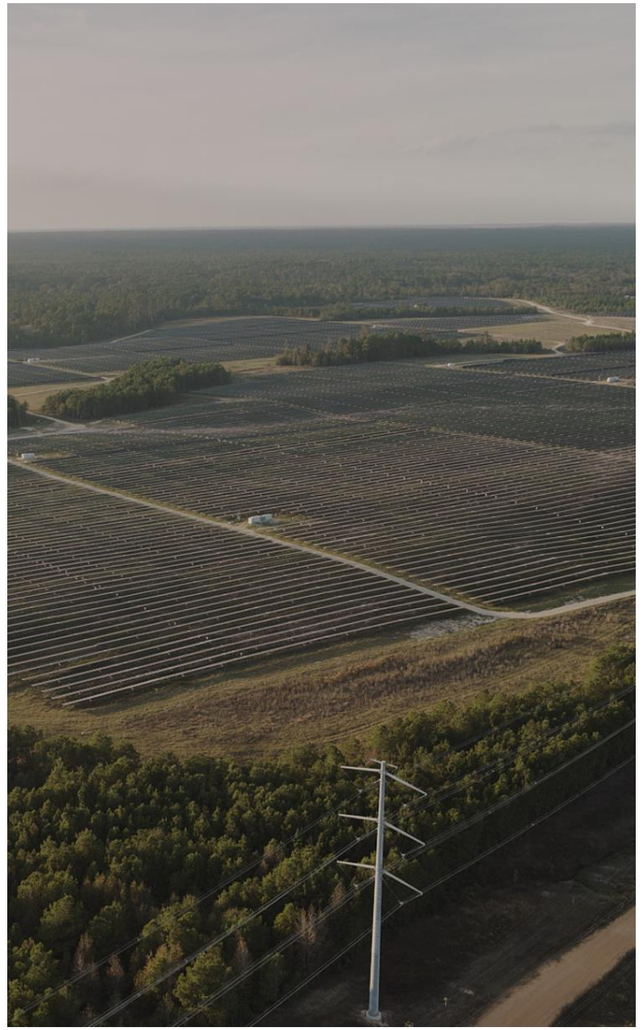

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Parliament Energy.
Parliament Solar, completed in 2025.

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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 2026 edition of the publication summarizes data for generators coming online through the end of 2025 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 2025 data changes upfront, while the **extensive appendix** provides additional analyses and longer-term trends.

Funding:

U.S. Department of Energy's Office of Critical Minerals and Energy Innovation (CMEI)

Products in addition to this slide deck:

The 2026 Edition 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:

- Reporting net-capacity changes, planned generator additions, and generation by fuel type.
- Illustration of O&M cost breakdown based on new FERC Form 1 data.
- Refined solar generation and modeling.
- Solar+storage wholesale market value estimates and net-value analyses.
- Deeper analyses of solar capacity changes in interconnection queues.

Executive Summary

- Utility-scale PV continued to lead solar deployment in 2025 (83% of new solar and 50% of all new capacity). Texas added the most capacity in 2025 and leads the nation with the most installed solar capacity. 92% of new projects feature single-axis tracking.
- The capacity-weighted installed cost of solar projects that came online in 2025 increased slightly to \$1.69/W_{AC} (\$1.31/W_{DC}), up 2% from 2024 but down 72% from 2010. Strong economies of scale explain a continued increase in average project size to 127MW_{AC}.
- Average capacity factors range from 16% in the least-sunny regions to 33% 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 metrics suggest that recently built projects may underperform relative to older vintages when benchmarked against a modeled output.
- The generation-weighted LCOE from utility-scale PV has increased by 24% since 2022 to \$61/MWh (without tax credits) or \$41/MWh (with tax credits) in 2025. Levelized PPA prices have also trended upward the last few years. Since 2022, PPA prices have typically landed between \$25-35/MWh in CAISO and the non-ISO West and between \$45-\$80/MWh elsewhere, with the highest prices in the Northeast.
- The wholesale energy and capacity market value of solar increased 32% in 2025 to \$41/MWh on a national-average basis as gas prices rose. The market value exceeded the generation costs of newly built projects with COD 2024 during their first operational year. Increasing market value also kept pace with rising prices for new PPAs in most regions in 2025.
- Interest in pairing PV with batteries continued to grow in 2025 (48 new projects). All-in battery CapEx increased to \$413/kWh in 2025. Added costs for a hybrid system grew with greater storage:PV capacity ratio (0.67) and duration (3.4h) and were \$0.97/$W_{AC\text{-}PV}$ in 2025 - equivalent to an LCOE adder of \$24/MWh (after tax credits). Idealized battery operations can double solar's wholesale market value to a national average of \$79/MWh in 2025.
- Across all 7 ISOs and 50 utilities, there were 772GW of solar in interconnection queues at the end of 2025, down 19% from 2024. 49% of this proposed solar capacity is paired with battery storage, with the highest concentration of these PV+battery hybrid plants in CAISO (91%) and the non-ISO West (84%).

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 2025 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 are included 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 2024, with generation data through 2025. Net Capacity Factors (NCF) represent the ratio of each plant's 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 NLR'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.

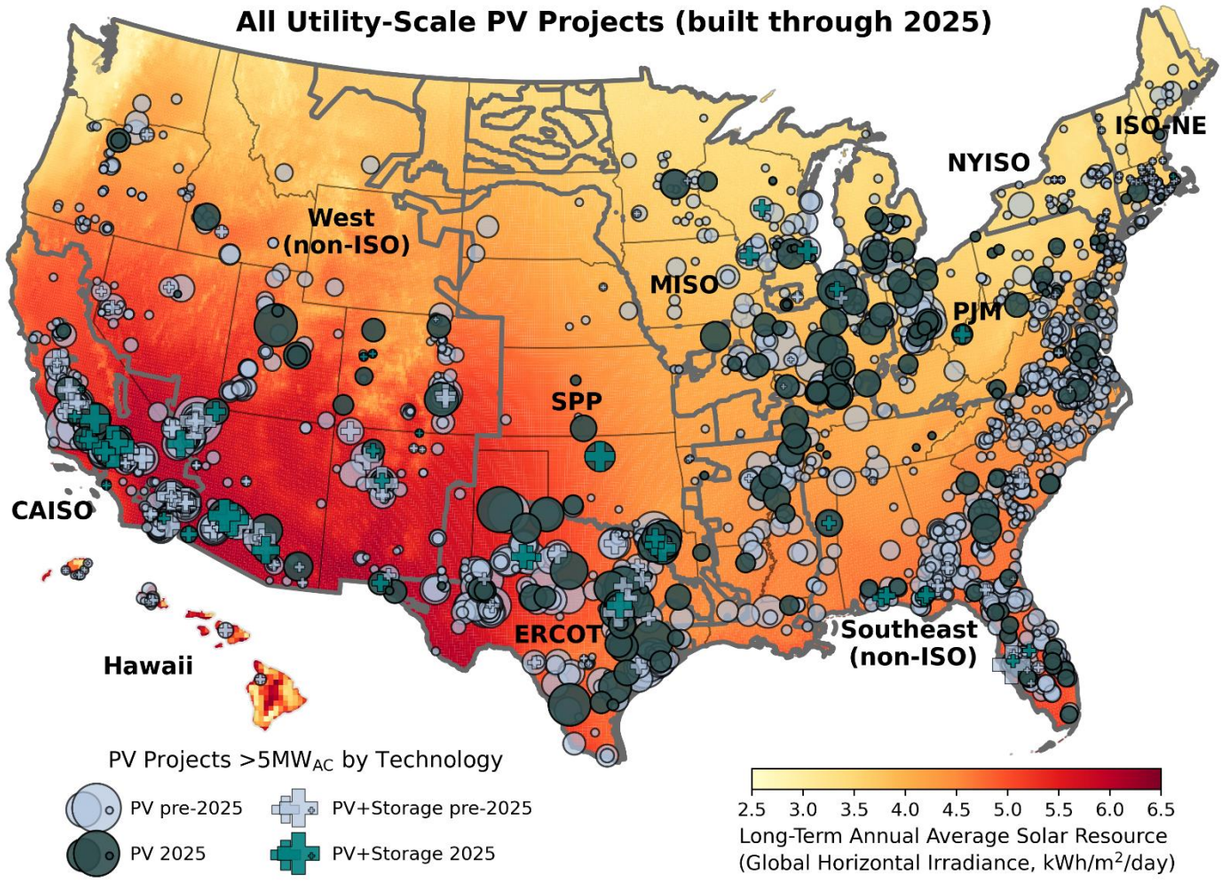
PPA: Primary project-level data sources are FERC Electric Quarterly Reports, FERC Form 1, and state regulatory filings, which we compare with market averages from Level10 and Trio. Annual PPA data is converted to real $ and levelized using WACC.

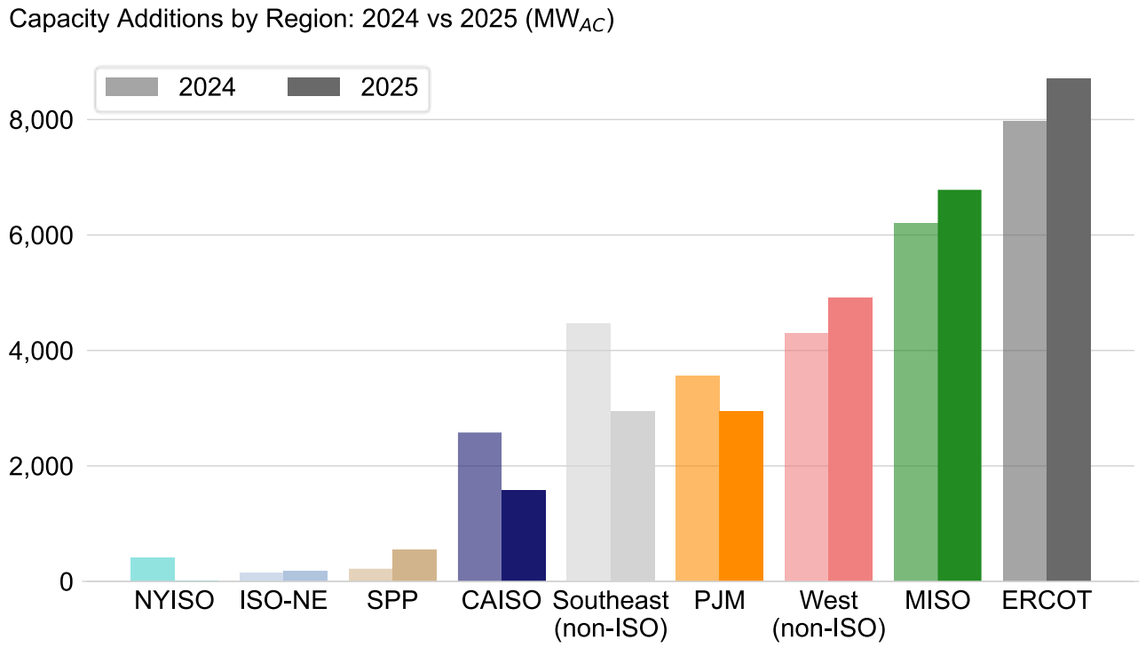
Value: We model hourly solar profiles using NLR's System Advisory Model and de-bias generation with ISO and EIA 923 data. Energy value is derived from LMPs or FERC System Lambdas, capacity value from BA-specific capacity accreditation rules and capacity prices (from central markets or bilateral transactions). 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, etc.).

Interconnection Queues: Primary data comes from interconnection queues from 7 ISOs/RTOs and 50 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 in the United States fell slightly from 30 GW_{AC} in 2024 to 29 GW_{AC} in 2025

Sample: 1,989 projects totaling 139 GW_{AC}





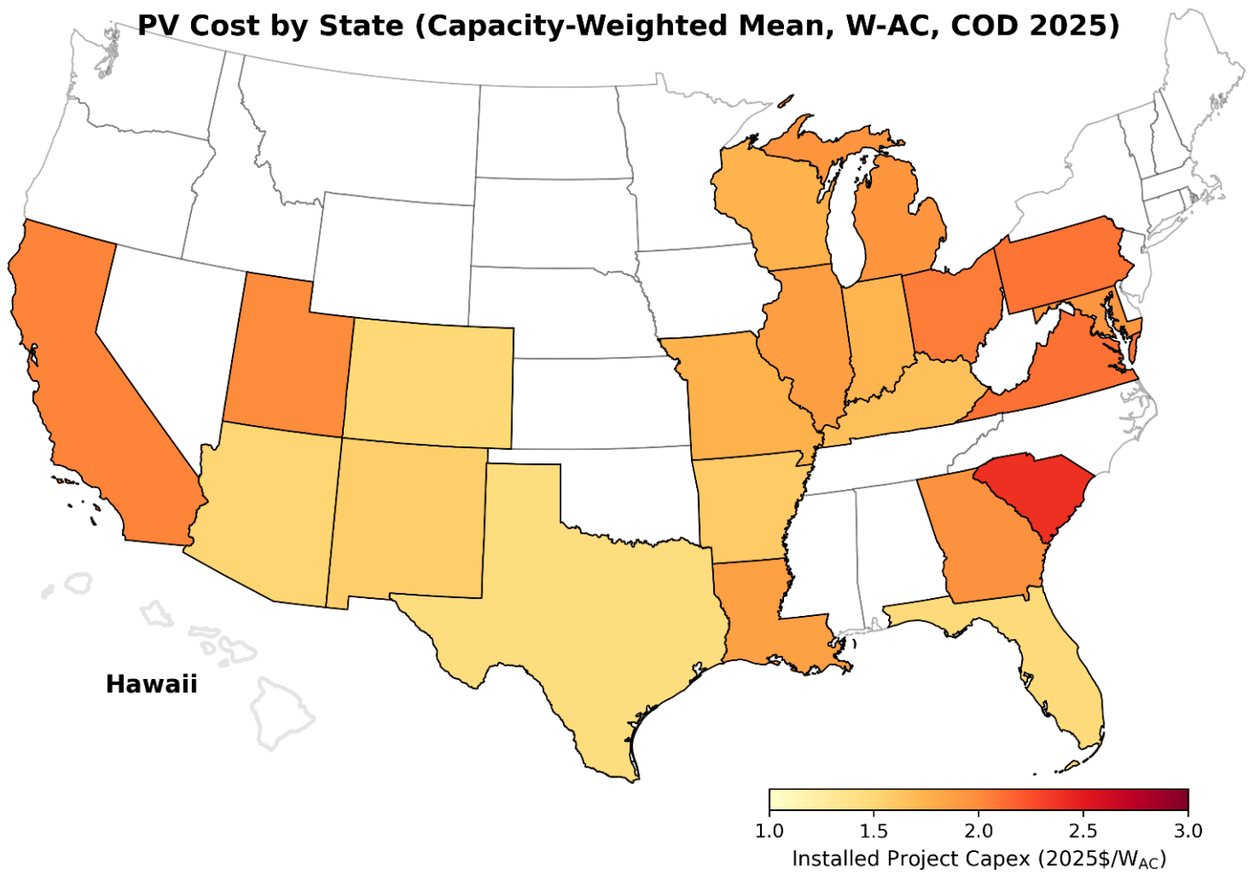
We define utility-scale solar as ground-mounted projects with a nameplate capacity >5 MW_{AC}. Annual capacity additions decreased in 2025 to 29 GW_{AC} (or 36 GW_{DC}) and accounted for 47% of all new grid-connected capacity.

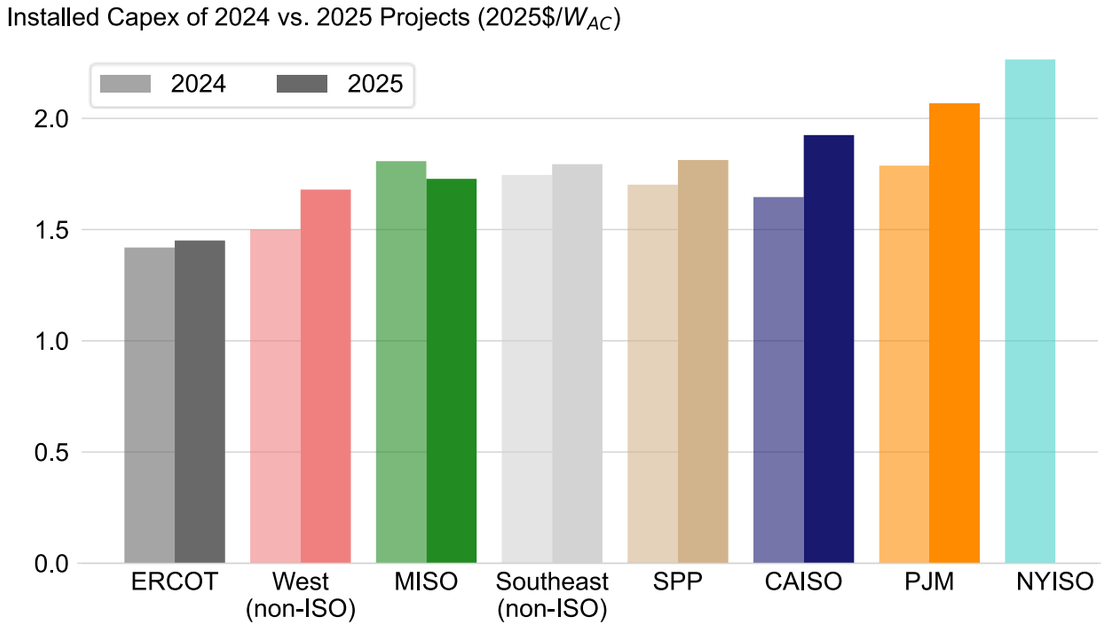
The new capacity is not uniformly spread across the U.S. – growth is concentrated in ERCOT (8.7 GW_{AC}), MISO (6.8 GW_{AC}), and the non-ISO West (4.9 GW_{AC}).

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

Installed costs of new PV were \$1.7/W_{AC} (\$1.3/W_{DC}) in 2025, 2% higher than in 2024

Sample: 407 projects totaling 49.4 GW_{AC}



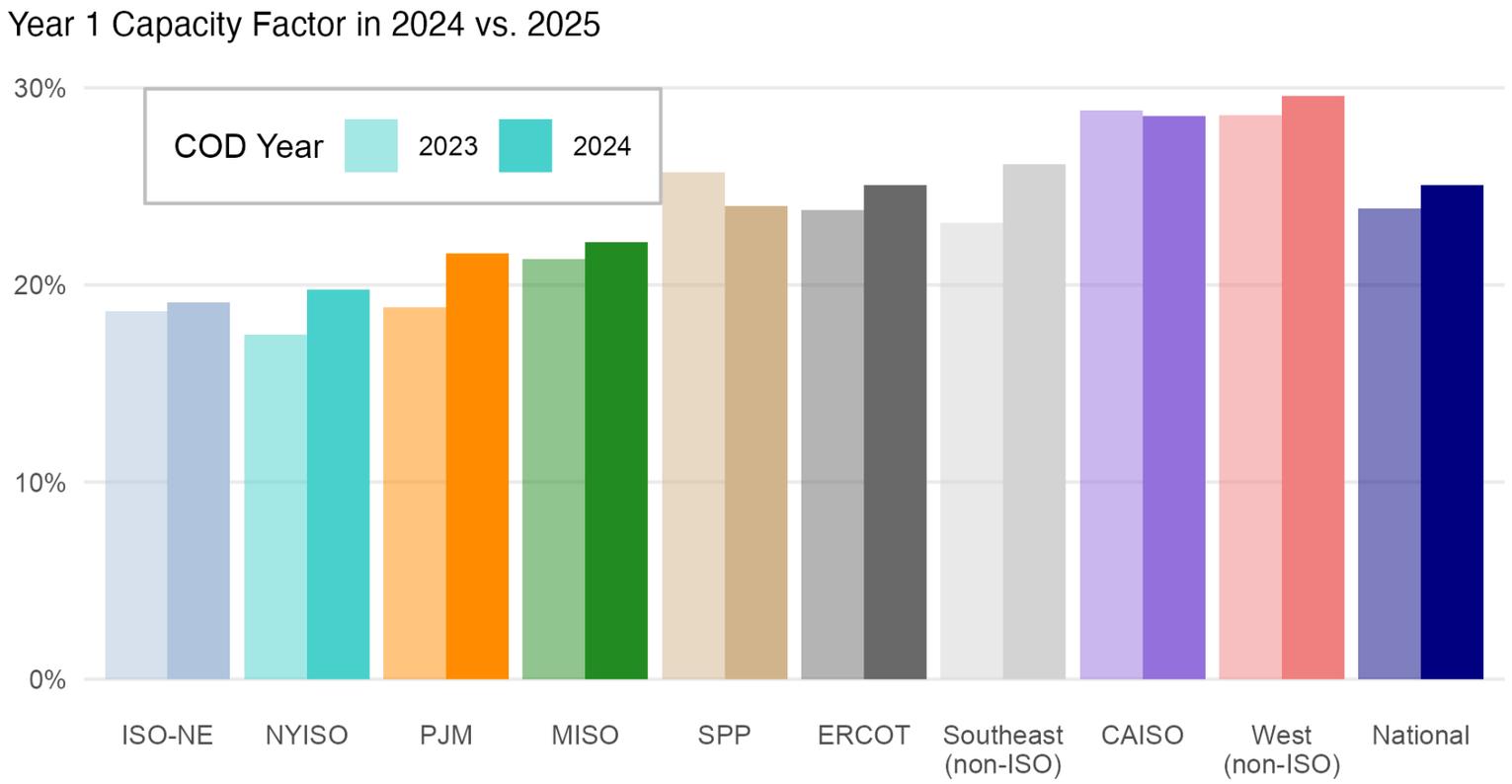


Capacity-weighted PV costs increased from \$1.65/W_{AC} in 2024 to \$1.69/W_{AC} in 2025. Our CapEx sample is robust, with 2025 data covering 80% of new projects. Costs vary by region, driven by differing project sizes (economies of scale), land availability, prevailing labor rates, and transmission network upgrade costs.

Note: Estimates for projects with 2024 and 2025 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 improved in 2025 in most regions, from an average capacity factor of 24% to 25%.

Sample: 449 projects totaling 48 GW_{AC}



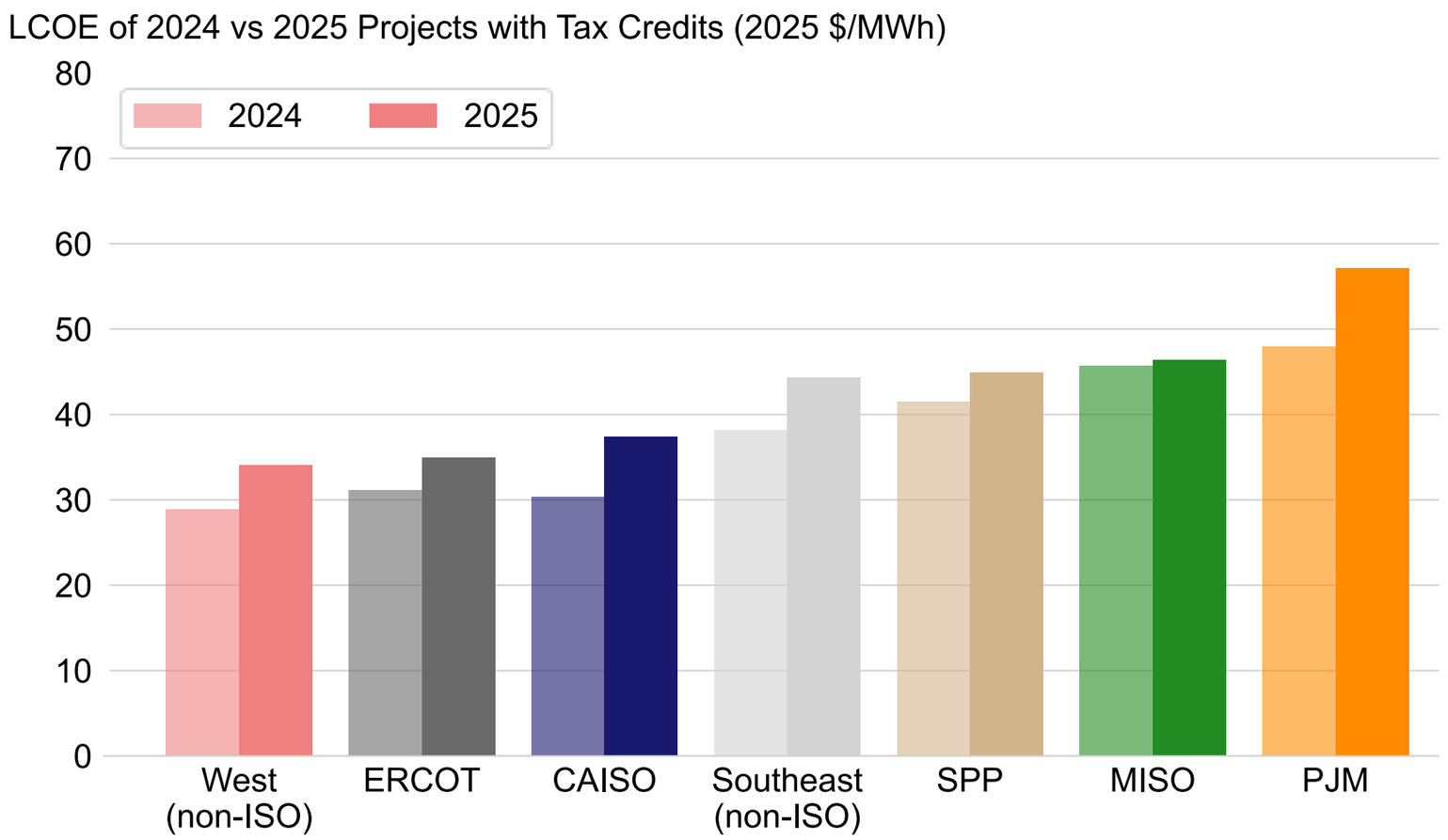
Solar plant performance is influenced by technical design (e.g., the share using single-axis tracking), variation in solar resource strength, and extreme weather (e.g., storm damage or wildfire smoke).

Nationally, first-year performance improved between 2024 (COD 2023 plants) and 2025 (COD 2024 plants), from an average of 24% to 25%. In 2025, first-year capacity factors in the non-ISO West were 11 percentage points higher than those of ISO-NE.

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

Generation costs rose by 7% to $61/MWh (without tax credits) or $41/MWh (with tax credits) for solar projects coming online 2025

Sample: 407 projects totaling 49.4 GW_{AC}



Higher CapEx and financing costs coupled with lower expected performance of the COD 2025 fleet (due to increasing deployment in lower irradiance regions) increased the national average levelized cost of energy (LCOE) of standalone PV from $57 in 2024 to $61/MWh in 2025 (without tax credits). Accounting for available tax credits (ITC, PTC, energy community bonus), LCOE rose from $37 to $41/MWh.

Average LCOE ranged from $35 in the West to $57/MWh in PJM (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 and 2025. Findings may shift as more final EIA Capex and project-specific performance data become available.

PPA prices of $27-47/MWh were typical for utility-scale PV projects that came online in 2025, with wide differences between regions

Sample: 2024 – 72 PPAs, 2025 – 40 PPAs

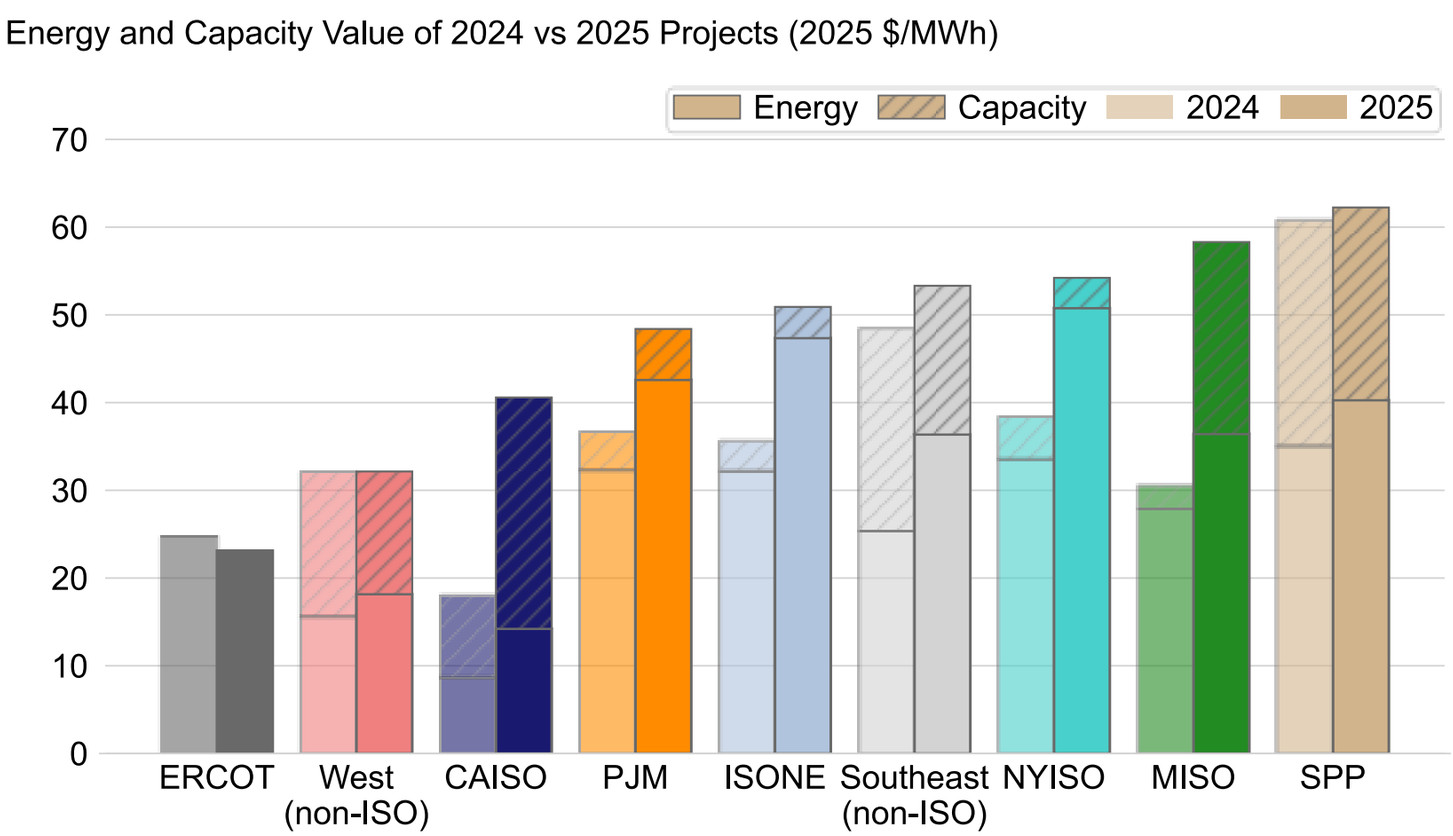
Power purchase agreement (PPA) prices reflect the bundled price of electricity and RECs as sold by the project owner.

Not all projects sign a PPA and not all PPA terms are publicly available. PPAs for projects in our sample that commenced operations in 2025 had an average levelized price of $34/MWh. This is a 12% increase from 2024, with increases observed in all regions except the Southeast. NYISO saw the highest average price in 2025 ($72/MWh) while the Southeast had the lowest ($26/MWh).

Note: $27-47/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 1.5-4 years before the commercial operation date.

PV's wholesale energy + capacity value grew by 32% to $41/MWh in 2025 and was greater than generation costs for COD 2024 projects

Sample: 6,391 PV projects totaling 121.2 GW_{AC}



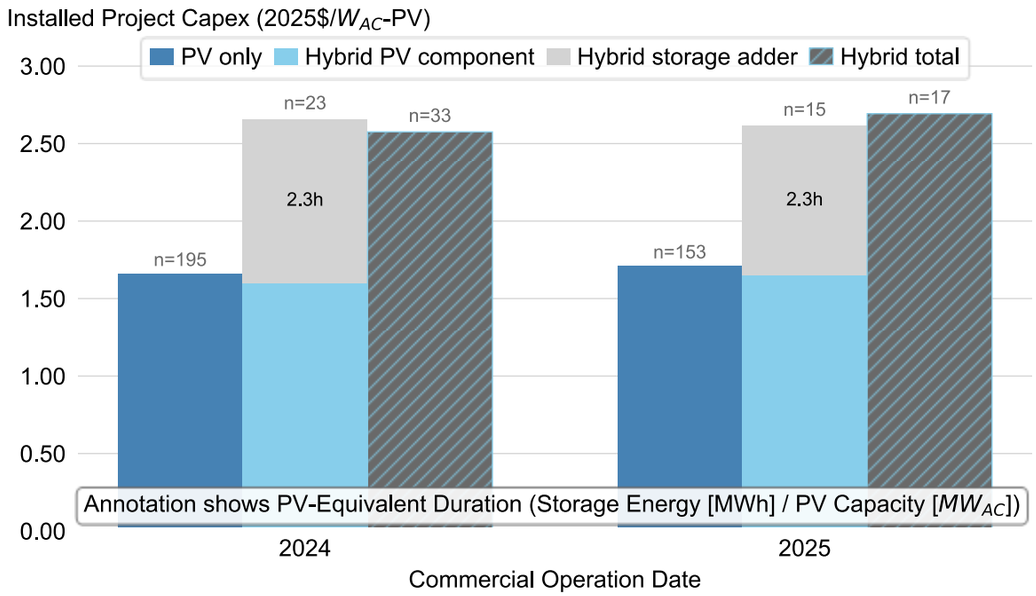
Strongly rebounding natural gas prices and emerging load growth led to higher electricity prices in 2025. Greater battery deployment in many solar-heavy regions meanwhile eased negative price events and improved solar's market environment. Therefore, PV's average wholesale value increased from $31/MWh in 2024 to $41/MWh in 2025. ERCOT had the lowest standalone solar value at $23/MWh, while high capacity values supported greater total values in SPP ($62/MWh) MISO, and CAISO.

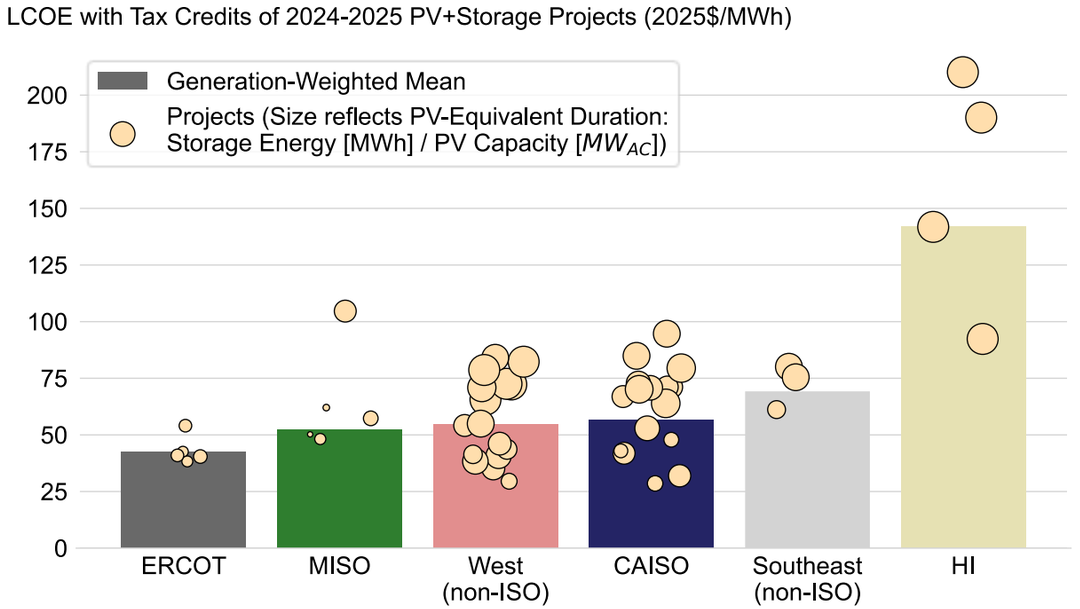
National average net value (levelized energy + capacity value minus LCOE) for solar standalone rose from $0/MWh for 2023 COD to $3/MWh for 2024 COD projects (after accounting for tax credits). Net value ranges from -$34/MWh in NYISO to $19/MWh in SPP. 13 out of 25 BAs have positive net values in 2025.

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 increased 4% to $2.7/$W_{AC\text{-}PV}$ in 2025, LCOE rose by 22% to $95/MWh (w/o tax credits) or $63/MWh (with)

Sample: 50 greenfield plants totaling 8.6 GW_{AC} of PV and 5.1 GW / 19.2 GWh of batteries





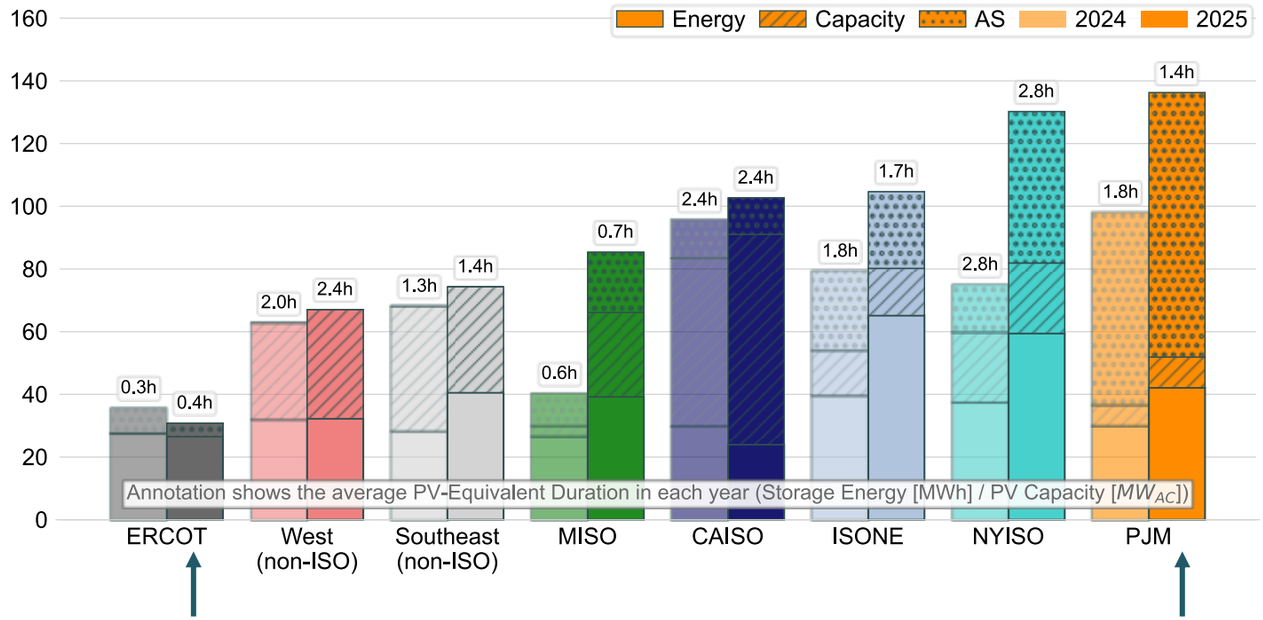
Capital costs for newly built PV–battery hybrids remained roughly flat in 2025. Among projects with component-level cost data, the battery contributed $1.0/$W_{AC\text{-}PV}$ to total system cost. For hybrids without a component breakdown, we report only total system cost (hatched), which was $2.69/$W_{AC\text{-}PV}$ in 2025.

Combined PV+battery generation costs (LCOE) increased to $95/MWh without and $63/MWh with tax credits in 2025. LCOE rose with the increasing storage capacity ratio (battery capacity relative to PV capacity) and storage duration (larger bubbles in the graph above).

PV+battery projects' wholesale market value potential was $79/MWh in 2025, based on energy, capacity and ancillary service markets

Sample: 349 PV+battery projects: 20.1 GW_{PV} , 11.5 GW_{Bat} / 38.7GWh

PV+Battery market value potential based on idealized operations, 2024 vs 2025
(2025$/MWh of PV production)



At $31/MWh, ERCOT had the lowest PV+battery value potential due to small batteries, saturated AS markets, and no capacity market.

At $136/MWh, PJM had the highest PV+battery value potential largely due ancillary service market opportunities.

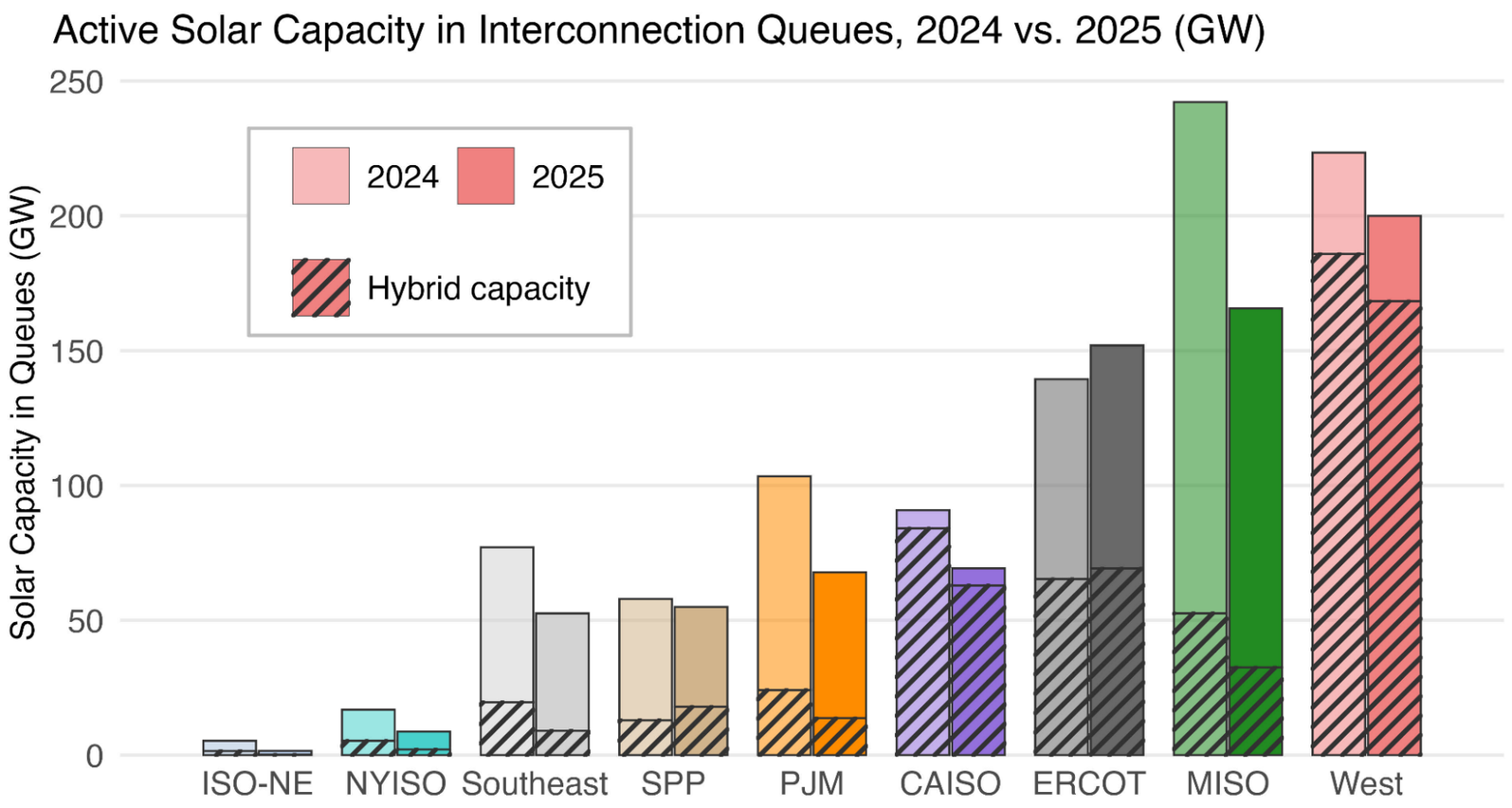
Estimating wholesale market value for PV+battery projects requires assumptions about storage operations. We present their value potential – an upper bound associated with idealized operations in hindsight. The idealized approach assumes each project is a price-taker and maximizes its total revenue across energy, capacity, and multiple ancillary service markets. Actual revenue is expected to be lower because operators lack perfect information, often under-participate in lucrative ancillary-service (AS) markets, and dispatch less flexibly than the idealized model.

Comparing 2025 to 2024:

- National average PV+battery value remained at $79/MWh, as sample growth from 285 to 349 projects was concentrated in the lower-value regions of the non-ISO West and ERCOT.
- PV+battery projects benefited from higher 2025 energy prices in most regions.
- AS value rose in PJM and NYISO, while higher capacity prices aided MISO projects.

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

PV capacity seeking interconnection declined 19% to 773 GW, marking the second consecutive year of queue capacity declines



Between 2024 and 2025, total active queue capacity declined 10%. Solar, the largest technology type by capacity, fell more steeply, dropping 19%. 126 GW of solar entered interconnection queues in 2025.

Hybridization is more common in regions with large solar deployment, including CAISO, the non-ISO West, and ERCOT. Not all of the capacity in the interconnection queue will ultimately become operational.

Note: For more details on methods see LBNL's Annual Queued Up Data Update.

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

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See the following appendix for additional analyses

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Appendix to U.S. Utility-Scale Solar - 2026 Data Update

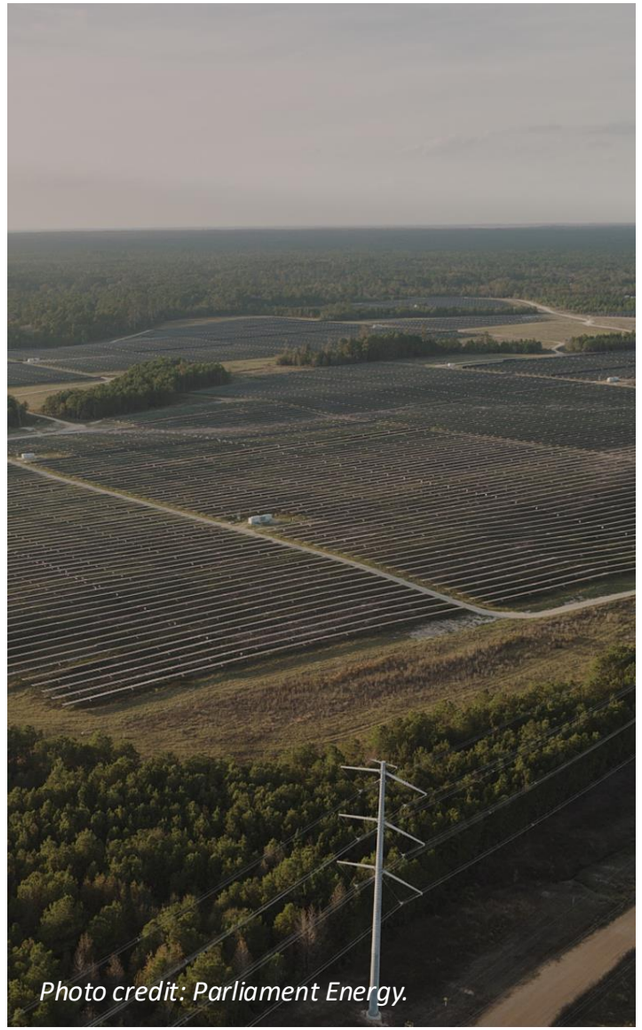
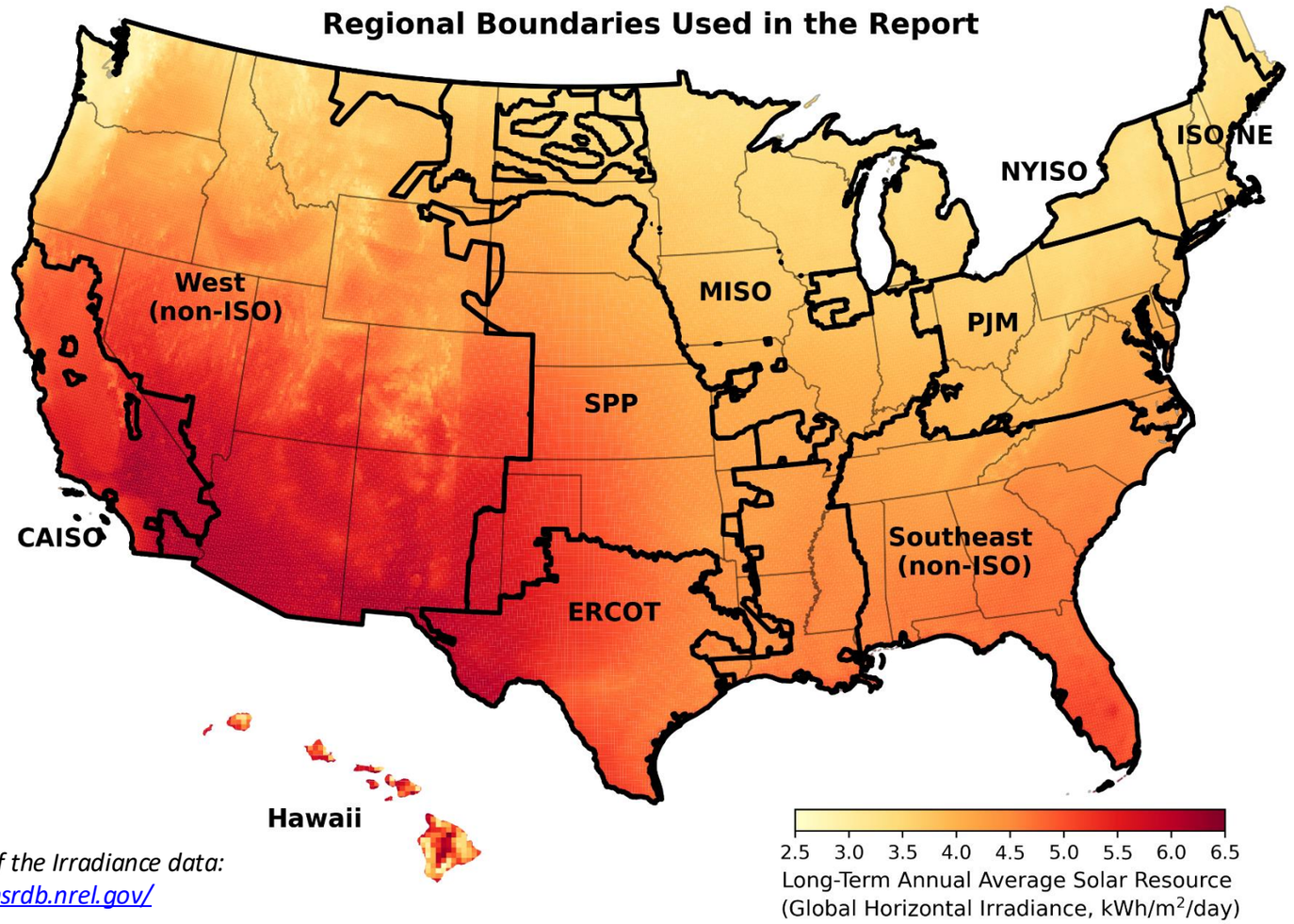


Photo credit: Parliament Energy.

- 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.

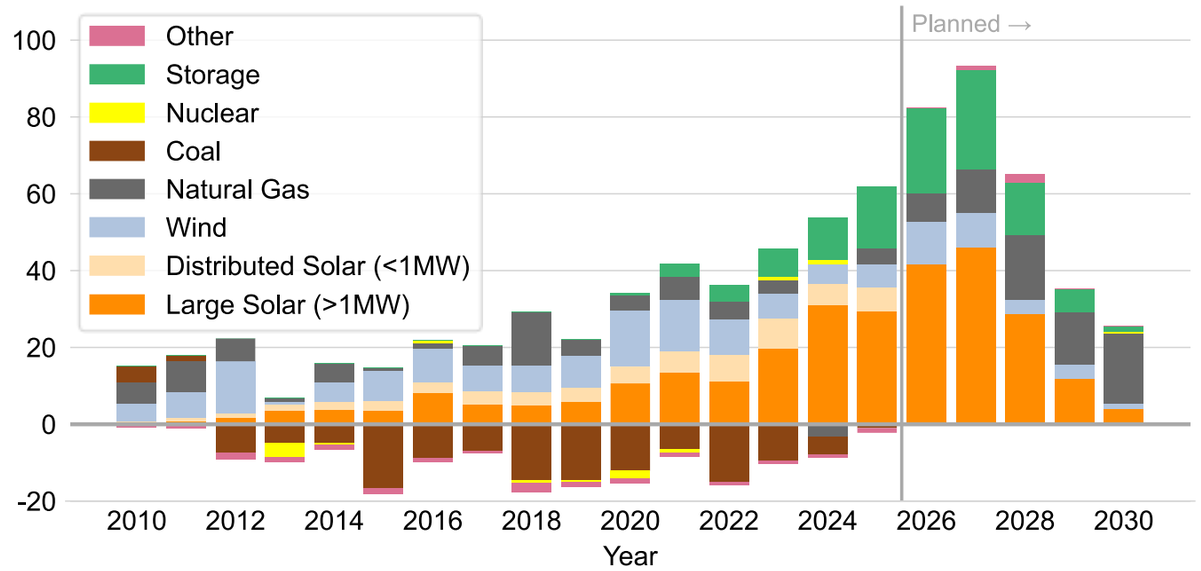
Technology Trends Data: Project-level metadata are sourced from a combination of Form EIA-860, FERC Form 556, state regulatory filings, interviews and websites of project developers and owners, and news and trade press articles. We independently verify much of the metadata such as project location, fixed-tilt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

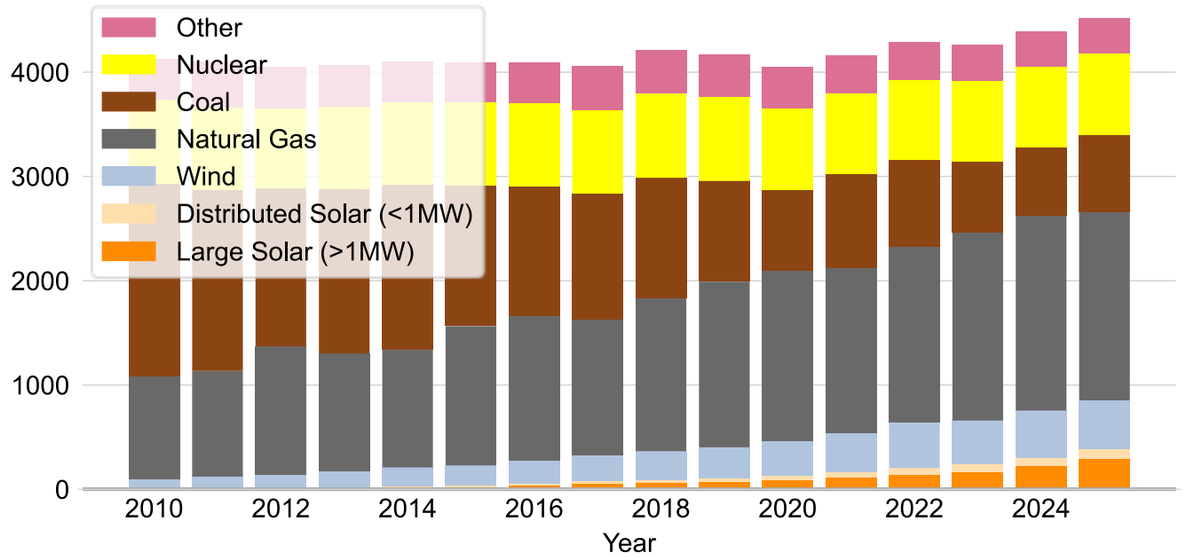
- **2024**: 252 new projects totaling 29.9 GW_{AC} or 38.9 GW_{DC}
- **2025**: 225 new projects totaling 28.6 GW_{AC}. 221 projects with known DC capacity sum to 36.2 GW_{DC}

Nearly 50% of new U.S. electric nameplate generating capacity came from utility-scale solar in 2025

Annual Net-Change of Nameplate Capacity in the US (GW_{AC})



Annual Net-Generation in the US (TWh)



Utility-scale (50%) and distributed (10%) solar accounted for a combined 61% (36GW_{AC}) of all net-capacity changes in U.S. grids in 2025. EIA lists 135GW_{AC} of planned solar additions by 2030. 243 GW_{AC} of solar have already passed through interconnection queues and have a draft/final interconnection agreement.

Capacity is different from the amount of *energy* produced over time and the *capacity credit (*a generator's contribution to resource adequacy) – which are discussed later (capacity factors, capacity value). Utility-scale and distributed solar contributed 7% and 2%, respectively, to 2025 U.S. electricity generation.

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

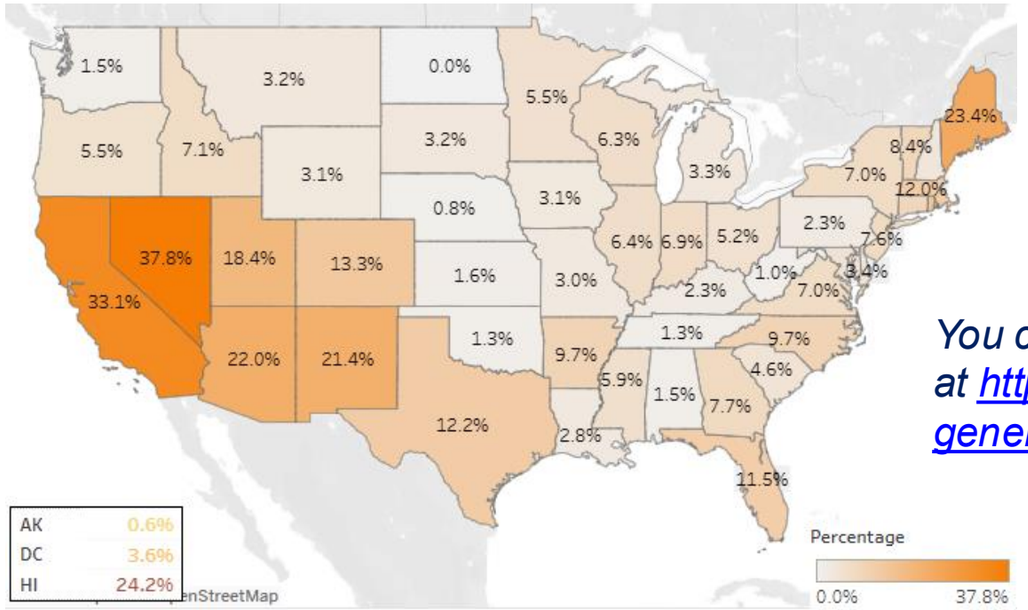
Utility-scale solar was responsible for 6.5% of U.S. electricity generation in 2025, and >23% of generation in Nevada and California

State	Preliminary 2025			
	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
District of Columbia	73.4	9.7	3.6	0.5
California	37.5	23.1	33.1	20.4
Nevada	33.6	28.8	37.8	32.4
Massachusetts	24.6	9.3	12.0	4.5
Hawaii	23.7	8.8	24.2	9.0
Vermont	19.2	9.4	8.4	4.1
Maine	17.9	9.6	23.4	12.5
Arizona	17.5	12.7	22.0	16.0
New Mexico	17.4	15.3	21.4	18.8
Utah	17.3	14.4	18.4	15.4
Colorado	13.2	9.5	13.3	9.5
Florida	11.0	9.1	11.5	9.5
Rhode Island	10.8	7.7	13.9	9.8
Texas	10.7	9.8	12.2	11.2
North Carolina	10.1	9.3	9.7	9.0
Virginia	9.5	8.5	7.0	6.2
Idaho	9.2	7.7	7.1	6.0
New Jersey	9.0	3.1	7.6	2.6
Georgia	8.1	7.7	7.7	7.3
Arkansas	7.7	6.9	9.7	8.6
U.S. Total	**8.6**	**6.5**	**9.4**	**7.1**

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 23% in 2025, while Arizona, New Mexico, and Utah all surpassed 12%.

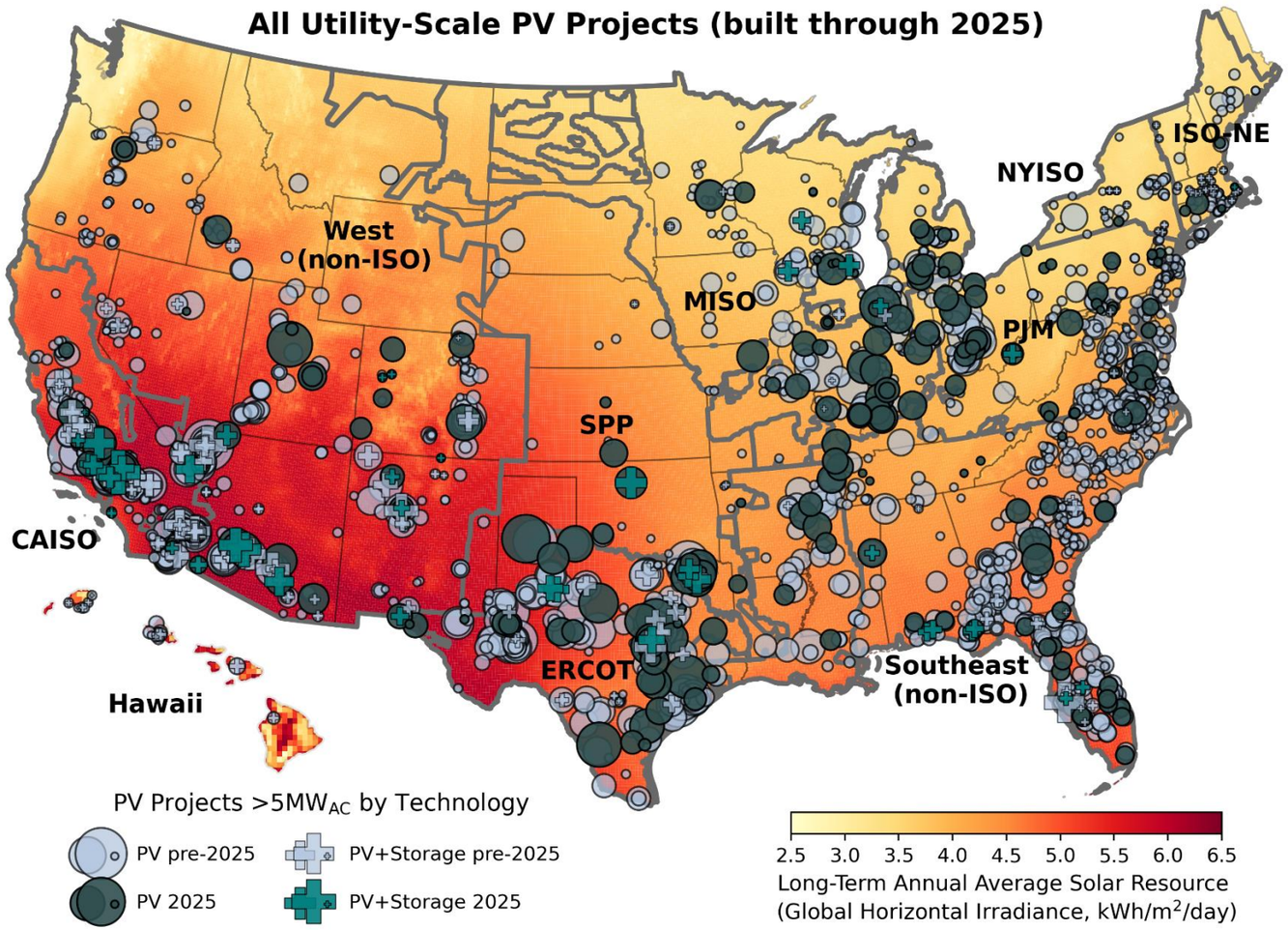
The utility-scale's contribution to total solar varies by state: a minority in the Northeast and Hawaii, a majority elsewhere in the U.S.



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 2025. Findings may be revised with final data. The map shows all solar generation as a percentage of in-state load.

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.

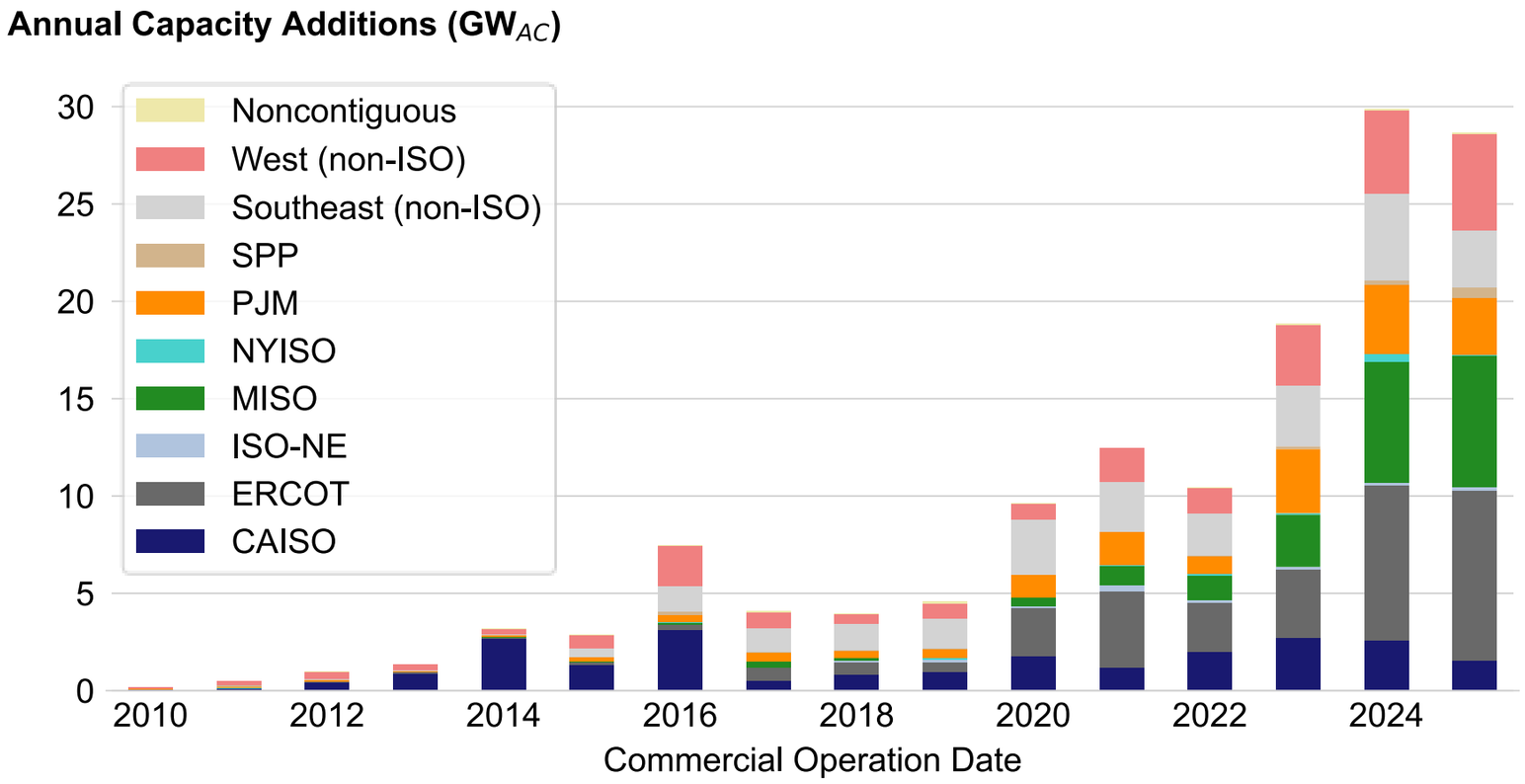
Four states more than doubled their utility-scale solar capacity in 2025—all in the central United States. Kansas grew ninefold (to 235 MW_{AC}); Oklahoma more than tripled (to 495 MW_{AC}); and Missouri and Kentucky each nearly tripled, reaching 1.3 GW_{AC} and 1.1 GW_{AC}, respectively.

In 2025, PV+storage (✚) hybrid projects continued to grow. Batteries were added to already existing (16) and new (32) PV projects. Solar-rich CAISO and non-ISO West added the most PV-coupled battery capacity (1.4 GW each) followed by ERCOT (0.9 GW).

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

ERCOT and MISO added the most utility-scale solar capacity in 2025. ERCOT and the Southeast have the most total deployment.

PV project sample: 1,989 projects totaling 139 GW_{AC}



Utility-scale solar deployment in 2025 represents multiple GW of additions in ERCOT (8.7 GW_{AC}), MISO (6.8 GW_{AC}), the non-ISO West (4.9 GW_{AC}), PJM and the non-ISO Southeast (both 2.9 GW_{AC}), and CAISO (1.6 GW_{AC}).

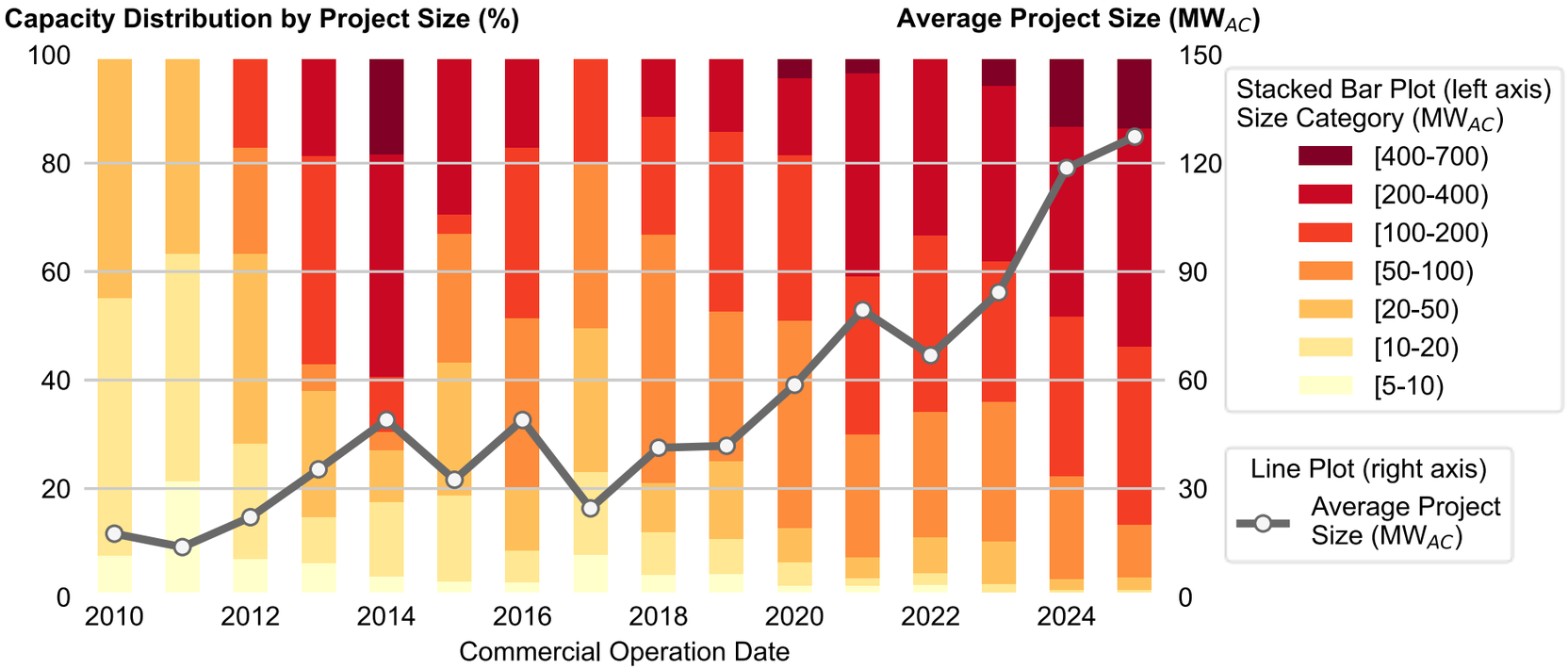
Taking a state perspective, **Texas** added the most with 8.9 GW_{AC} followed by **Indiana** (2.0 GW_{AC}), **California** (1.9 GW_{AC}), **Arizona** (1.5 GW_{AC}), **Ohio** (1.4 GW_{AC}) and **Florida** (1.3 GW_{AC}).

In cumulative deployment, ERCOT (32 GW_{AC}), the non-ISO Southeast (24 GW_{AC}), and CAISO (23 GW_{AC}) have the most. The non-ISO West (22 GW_{AC}) and MISO (19 GW_{AC}) are following closely.

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

New solar projects are now 127 MW_{AC} on average, 7% larger than in 2024 and much larger than in the 2010s

PV project sample: 1,989 projects totaling 139 GW_{AC}



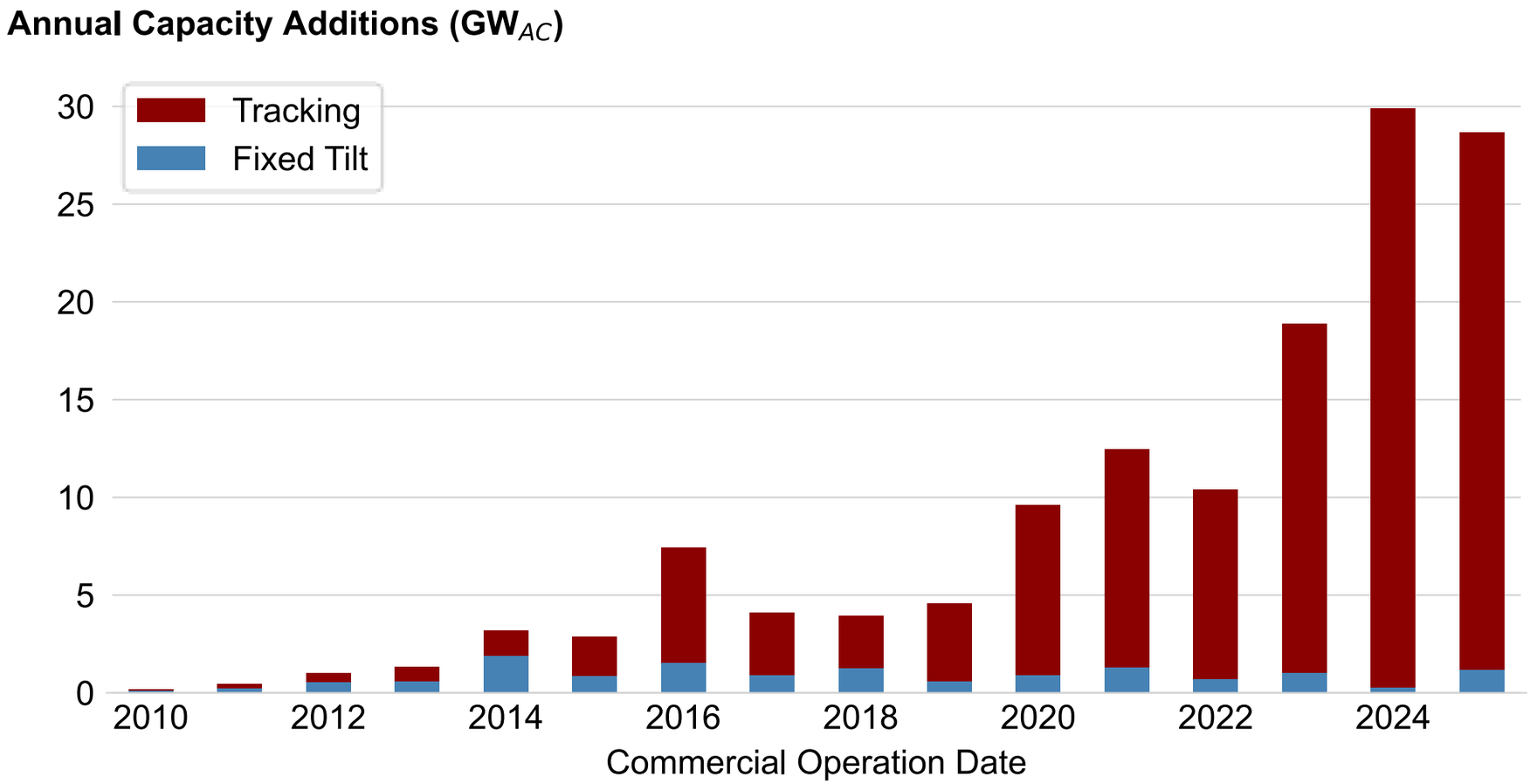
Average project size has grown 7x since 2010 to 127MW_{AC}. 2025 saw 55 projects >200MW_{AC} come online.

Hornet Solar (600MW_{AC}) built in TX is the largest project of 2025.

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).

96% of new solar capacity used single-axis tracking over fixed-tilt racking

PV project sample: 1,987 projects totaling 139 GW_{AC}



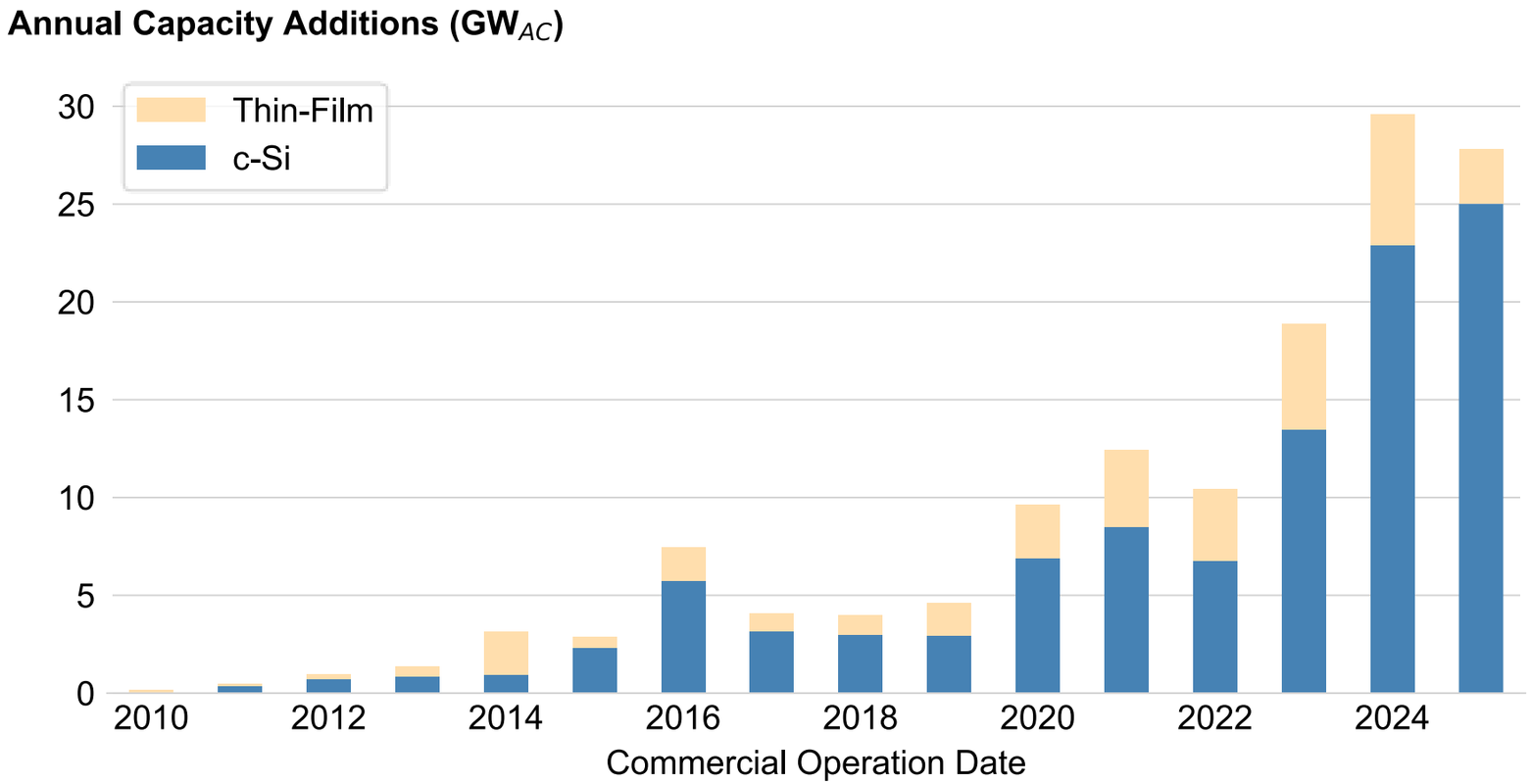
The upfront cost premium for **trackers** faded over time, resulting in favorable overall economics (discussed later).

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 2025 to 86% of added capacity

PV project sample: 1,973 projects totaling 138 GW_{AC}



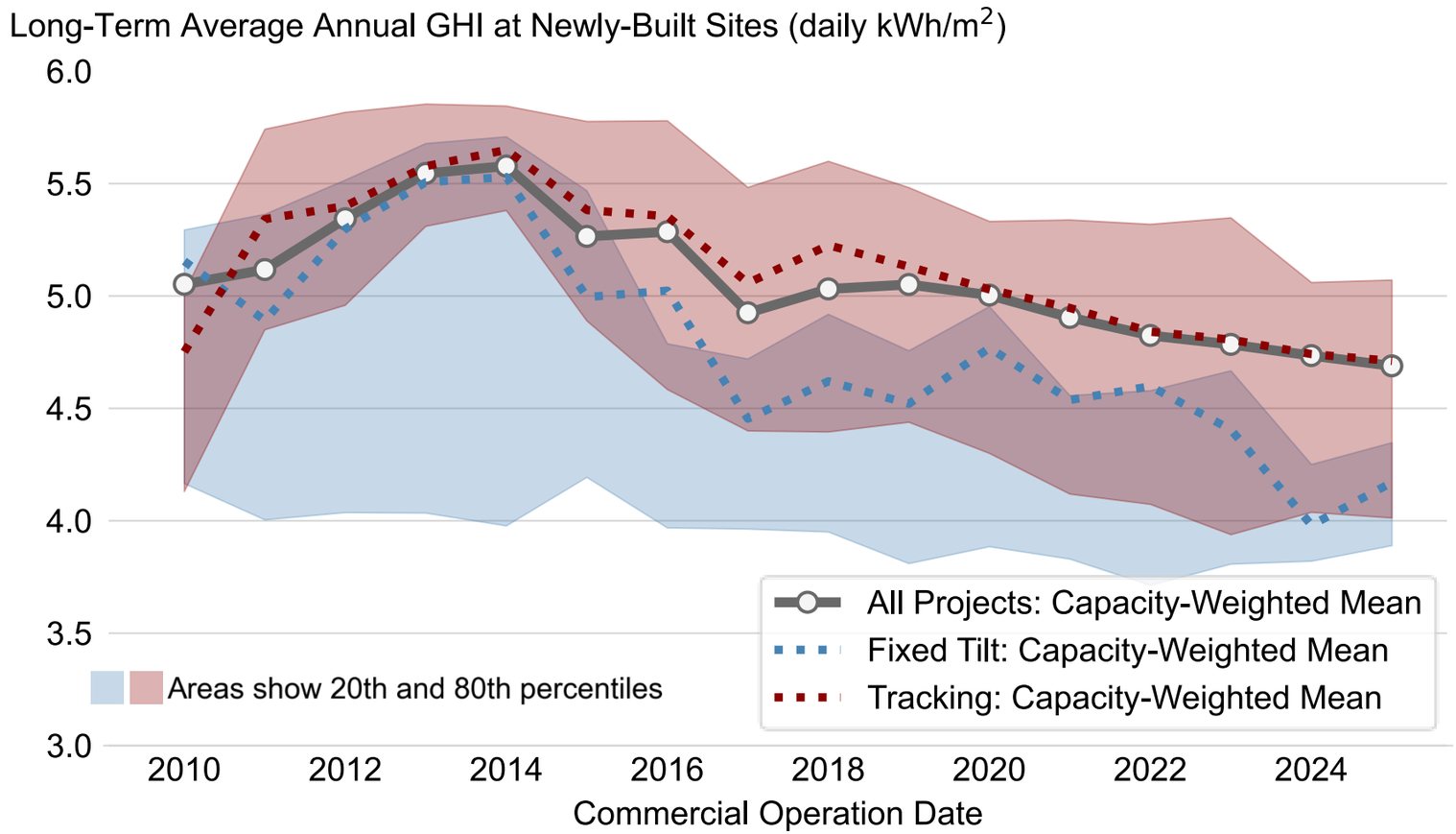
Note: The 2025 sample includes 8 projects (0.8GW_{AC}) without conclusive module type data which are excluded from the graph above

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 2025 to 86% of newly installed capacity.

Thin-film modules grew in popularity between 2016 and 2024, but declined in 2025.

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: 1,988 projects totaling 139 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 2025 was down to 4.69 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).

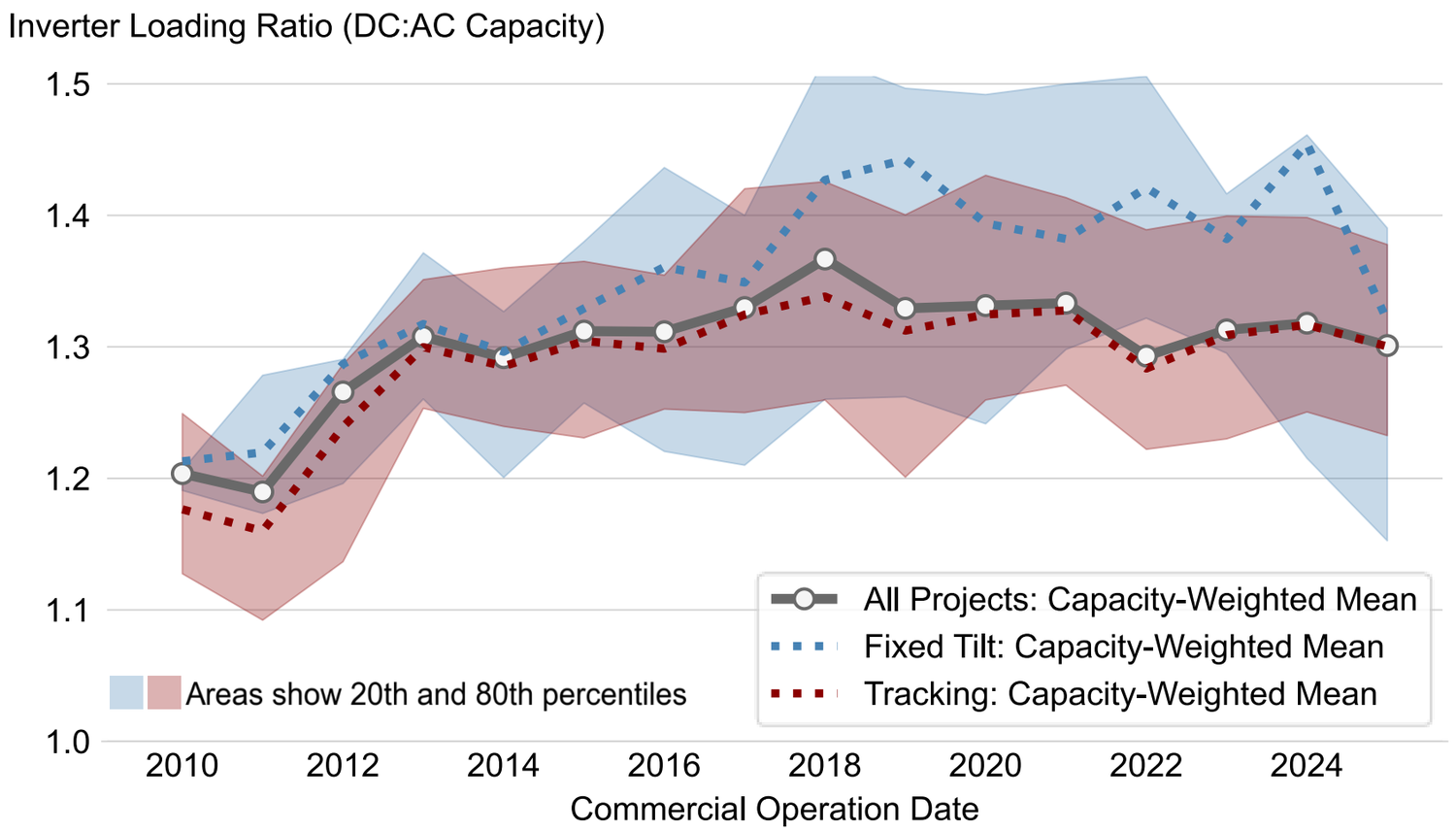
Exceptions are fixed-tilt installations in windy regions (Florida), on brownfields and landfill sites, and on particularly challenging terrain. All 19 new 2025 fixed-tilt projects have a due southern orientation.

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 NLR's NSRDB to estimate long-term solar resource quality for each new USS project.

The average inverter loading ratio (ILR) has held steady around 1.3 since 2017

PV project sample: 1,981 projects totaling 138 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 2025, 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 2013-2025 have been cross-checked against confidential EIA-860 data obtained under a non-disclosure agreement. Estimates for projects with 2024 and 2025 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:

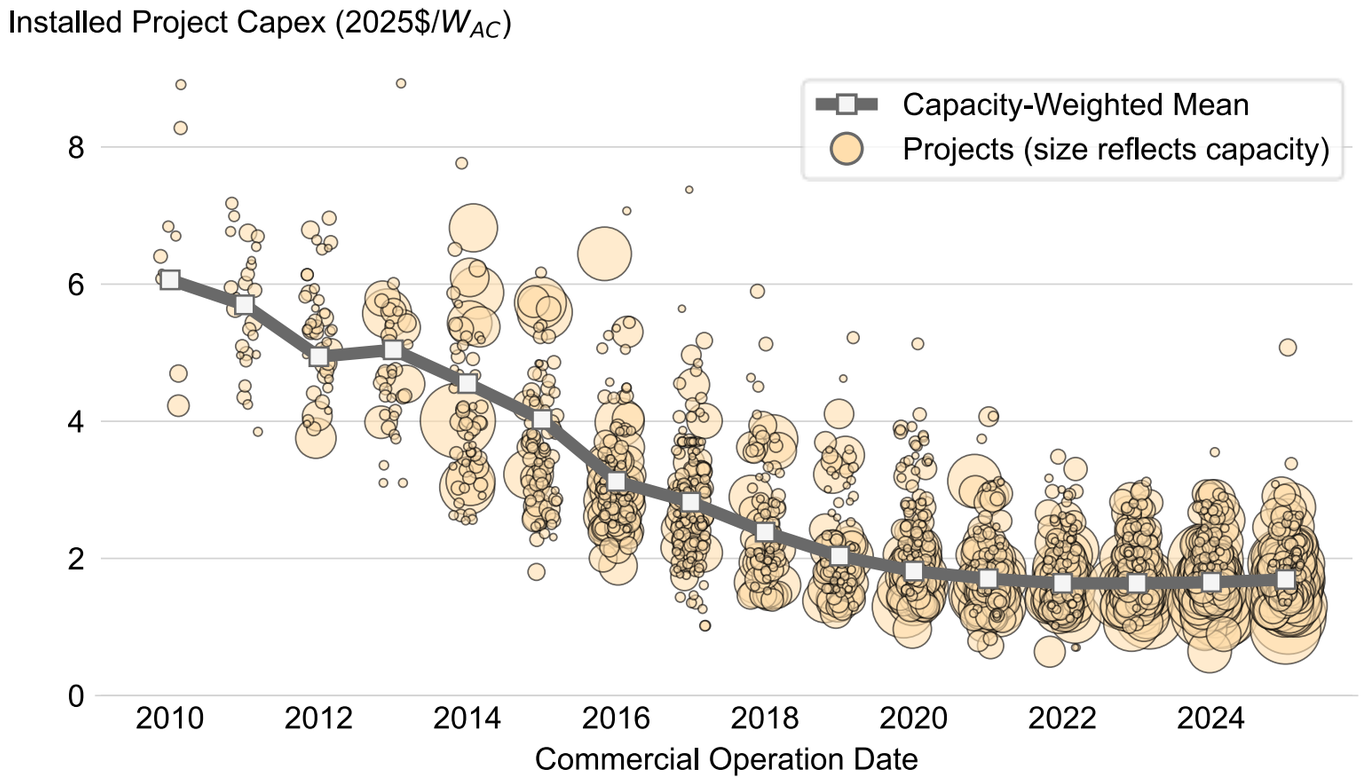
- Plant-level operation and maintenance costs, capacity, net generation, and construction year are sourced from FERC Form 1 Annual Reports, which are filed by major electric utilities.

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 \$1.7/W_{AC} (\$1.3/W_{DC}) in 2025

PV project sample: 1,810 projects totaling 127 GW_{AC}



Note: Estimates for projects with 2024 and 2025 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 \$1.65/W_{AC} in 2024 to \$1.69/W_{AC} in 2025.

Medians (reflecting typical project costs, not shown in graph) increased from \$1.74/W_{AC} in 2024 to \$1.77/W_{AC} in 2025.

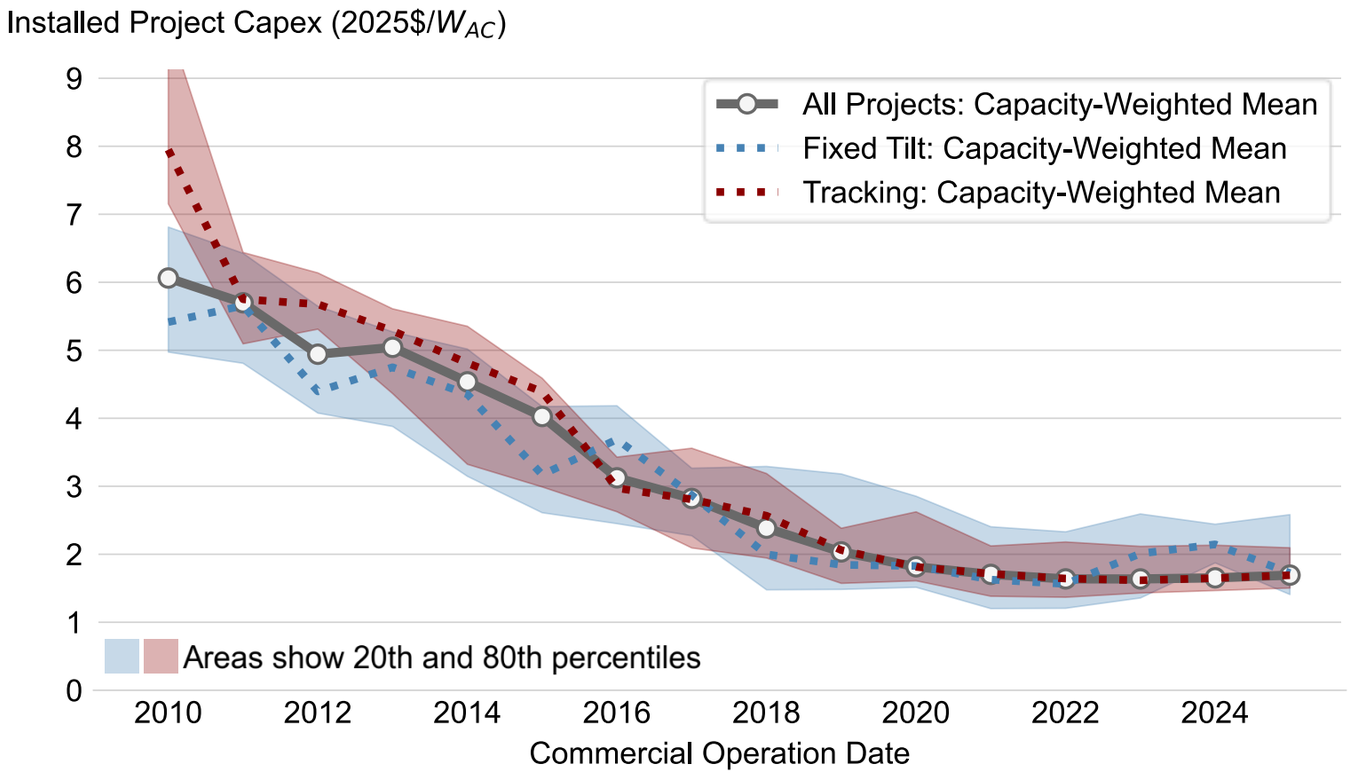
Our sample is robust, covering 91% of installed capacity through 2025. 2025 data covers 80% of new projects (181) or 82% of new capacity (23.4 GW_{AC}).

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.

2025 tracking projects cost about the same as fixed-tilt projects

PV project sample: 1,810 projects totaling 127 GW_{AC}



Note: Estimates for projects with 2024 and 2025 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 between 2023 and 2025).

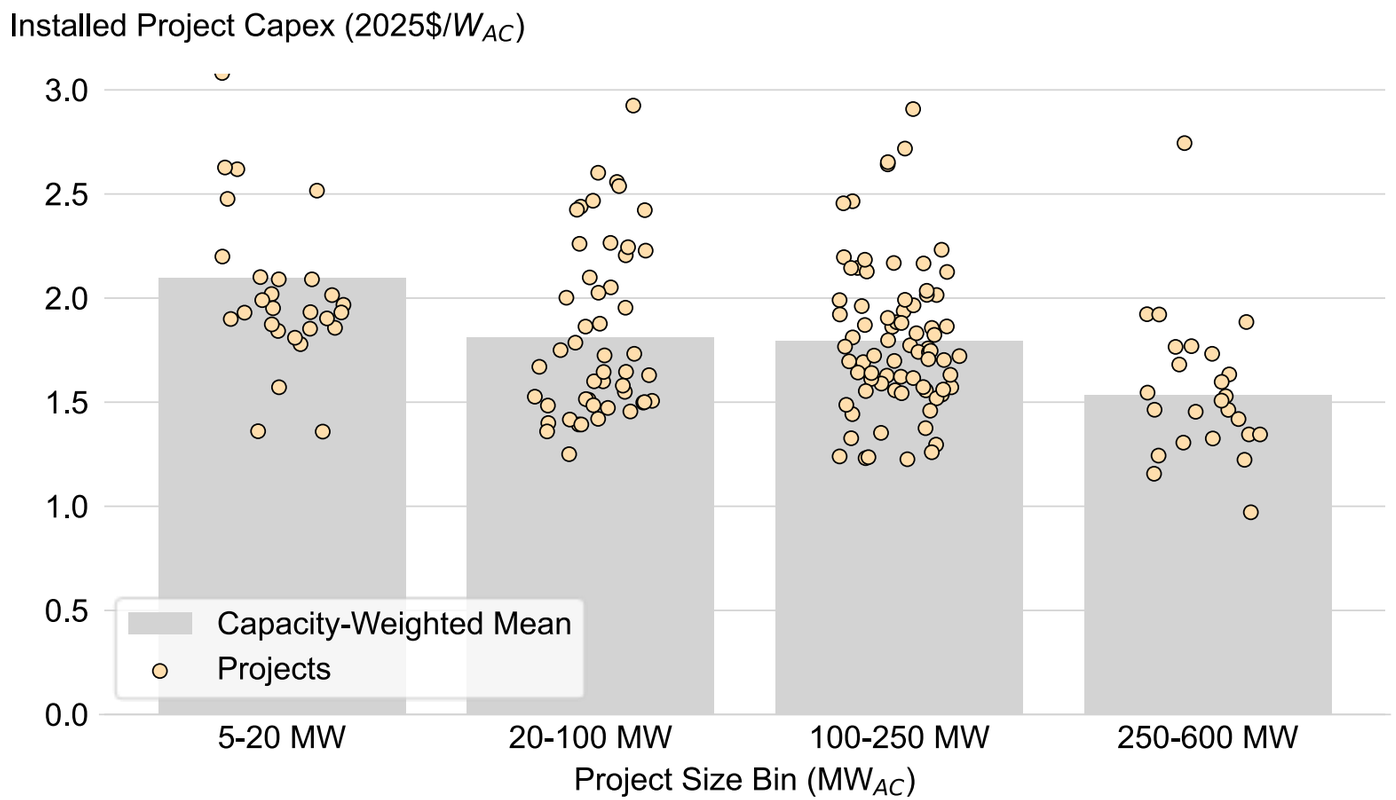
Beginning in 2020, tracker installations grew rapidly. In 2025, 96% of all new capacity used trackers, and fixed-tilt has only been used at particularly challenging sites (see earlier slide).

Tracking projects had slightly lower overall costs than fixed-tilt projects in $/$W_{AC}$ terms (1.69 vs 1.72) but higher in $/$W_{DC}$ terms (1.31 vs 1.30) in 2025.

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

Larger solar projects (>250 MW) cost 27% less than smaller (5-20 MW) projects per MW of installed capacity in 2025

PV project sample in 2025: 181 projects totaling 23.4 GW_{AC}



Note: Estimates for projects 2025 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 2025 for this slide. The apparent economies of scale are likely one reason why average project sizes have grown by a factor of more than five since 2017.

Projects larger than 250 MW_{AC} at \$1.53/W_{AC} cost substantially less than projects smaller than 20MW_{AC} at \$2.10/W_{AC}.

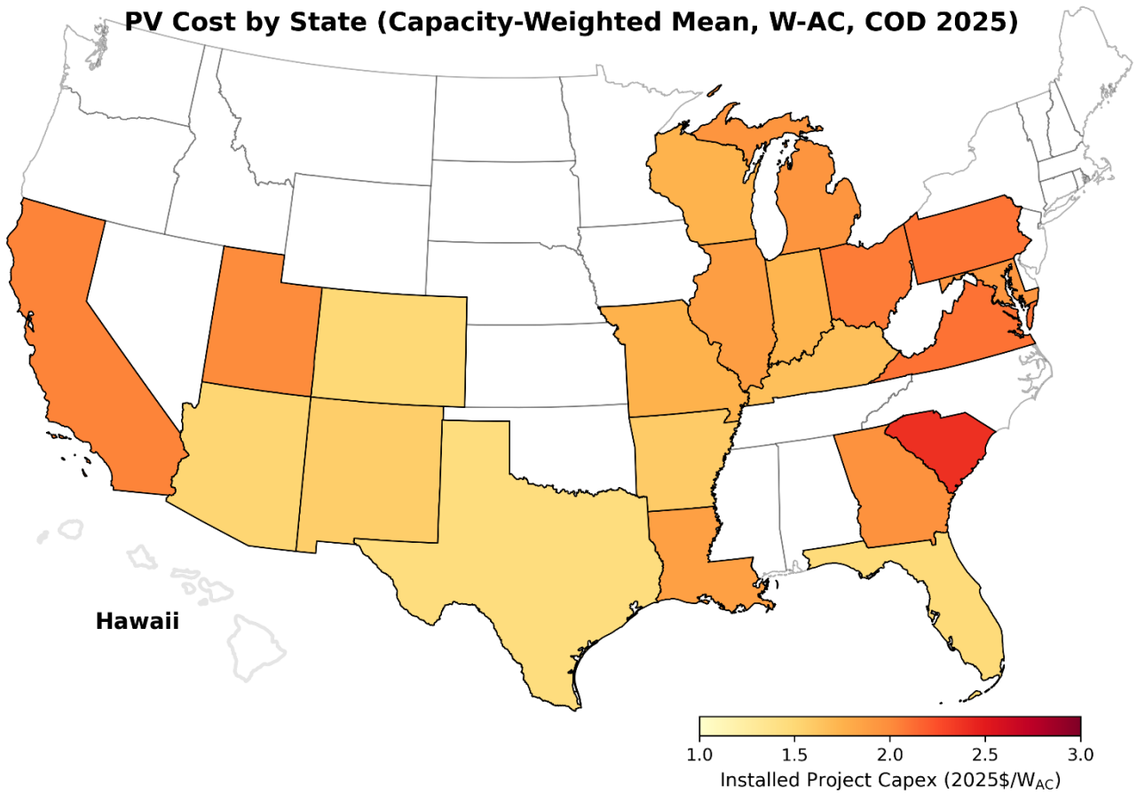
In \$/W_{DC} terms, prices decline continuously with increasing project size:

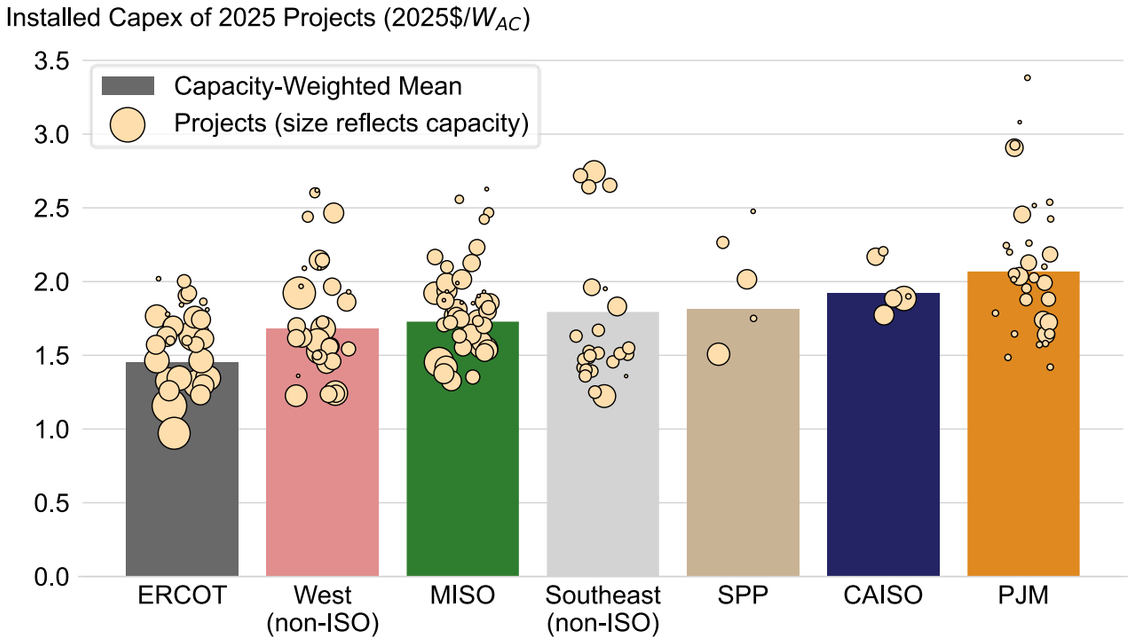
- \$1.65/W_{DC} for 5-20 MW
- \$1.54/W_{DC} for 20-100 MW
- \$1.38/W_{DC} for 100-250 MW
- \$1.21/W_{DC} for 250-800 MW

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

2025 solar projects in ERCOT were usually cheaper than in other regions

PV project sample in 2025: 181 projects totaling 23.4 GW_{AC}



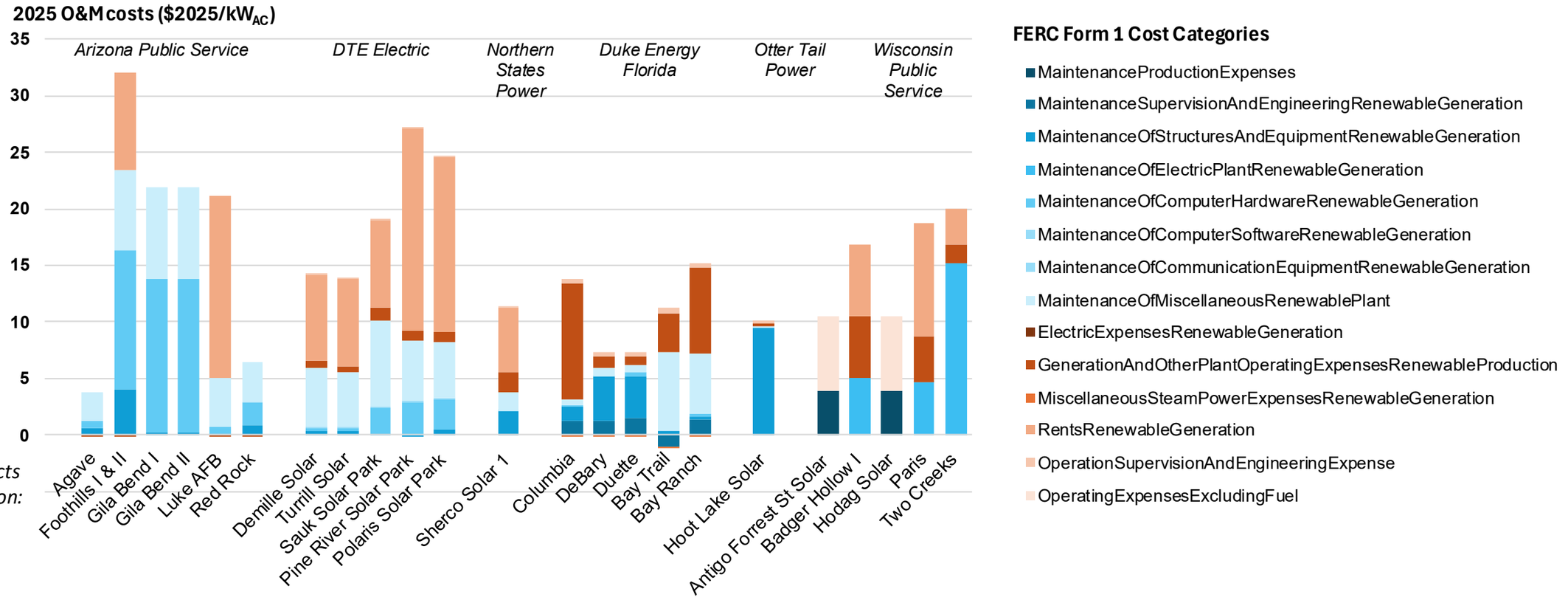


Utility-scale solar project costs also vary by region, driven in part by differing project sizes coupled with the previously discussed economies of scale, but also due to land availability, prevailing labor rates and transmission network upgrade costs. Projects in ERCOT ($1.45/$W_{AC}$ or $1.13/$W_{DC}$) have lower costs than all other regions.

Note: Estimates for projects 2025 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.

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

O&M data note: The *Renewable Generating Plant Statistics* added to FERC Form 1 in 2025 include numerous new cost categories



The new, detailed cost categories reported in Form 1 may enable new analyses. However, as illustrated in the graph above for a sample of the full dataset, they do not appear to be used consistently across utilities yet, making comparisons challenging. The results on the next slide focus on aggregated total O&M costs.

Note: Only a sample of utilities and plants are shown

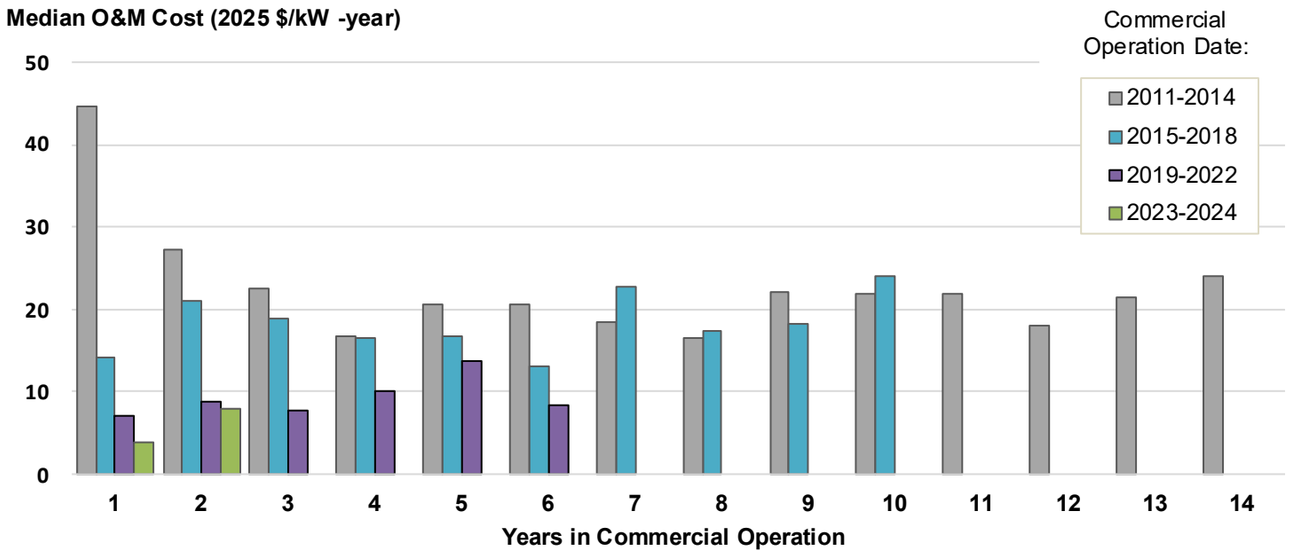
PV projects now spend much less on operation and maintenance (O&M) during their first few years than projects built in the 2010s

PV project sample in 2025: 173 projects totaling 9.1 GW_{AC}

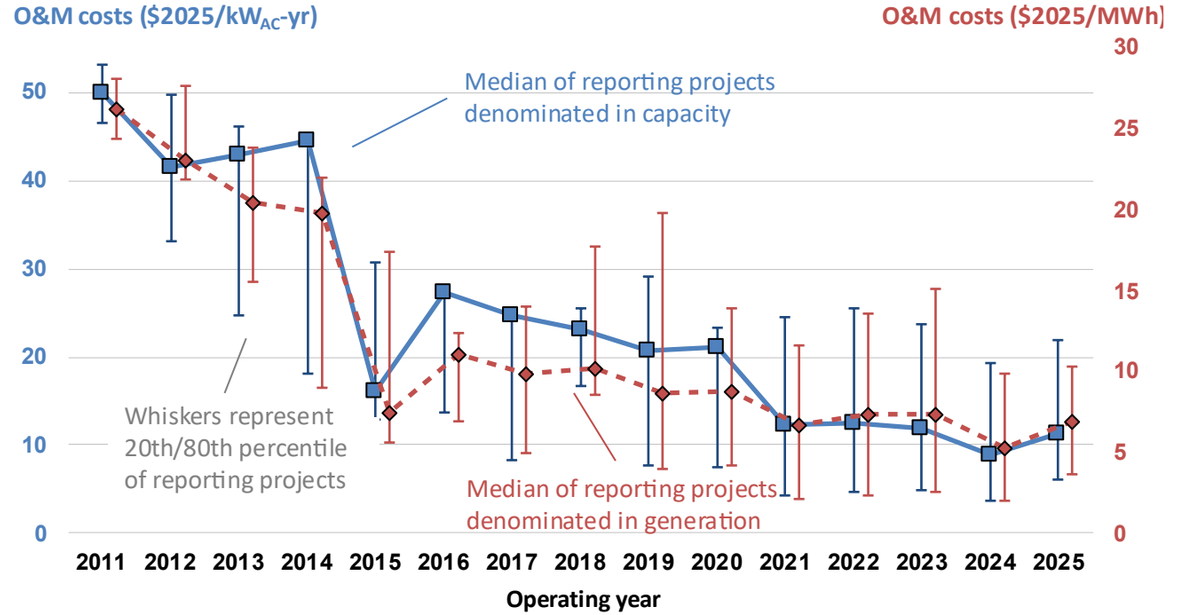
Regulated utilities report annual solar O&M costs for plants that they own, representing a mix of technologies and at least one full operational year.

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 six years of operation compared to older ones, potentially due to a narrower scope of service agreements.



After declining in the 2010s, median O&M costs for the cumulative sample have been stable since 2021 and were about **$11/kW$_{AC}$-year or $7/MWh in 2025**.

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 primarily 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 2024, with generation data through 2025.

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.

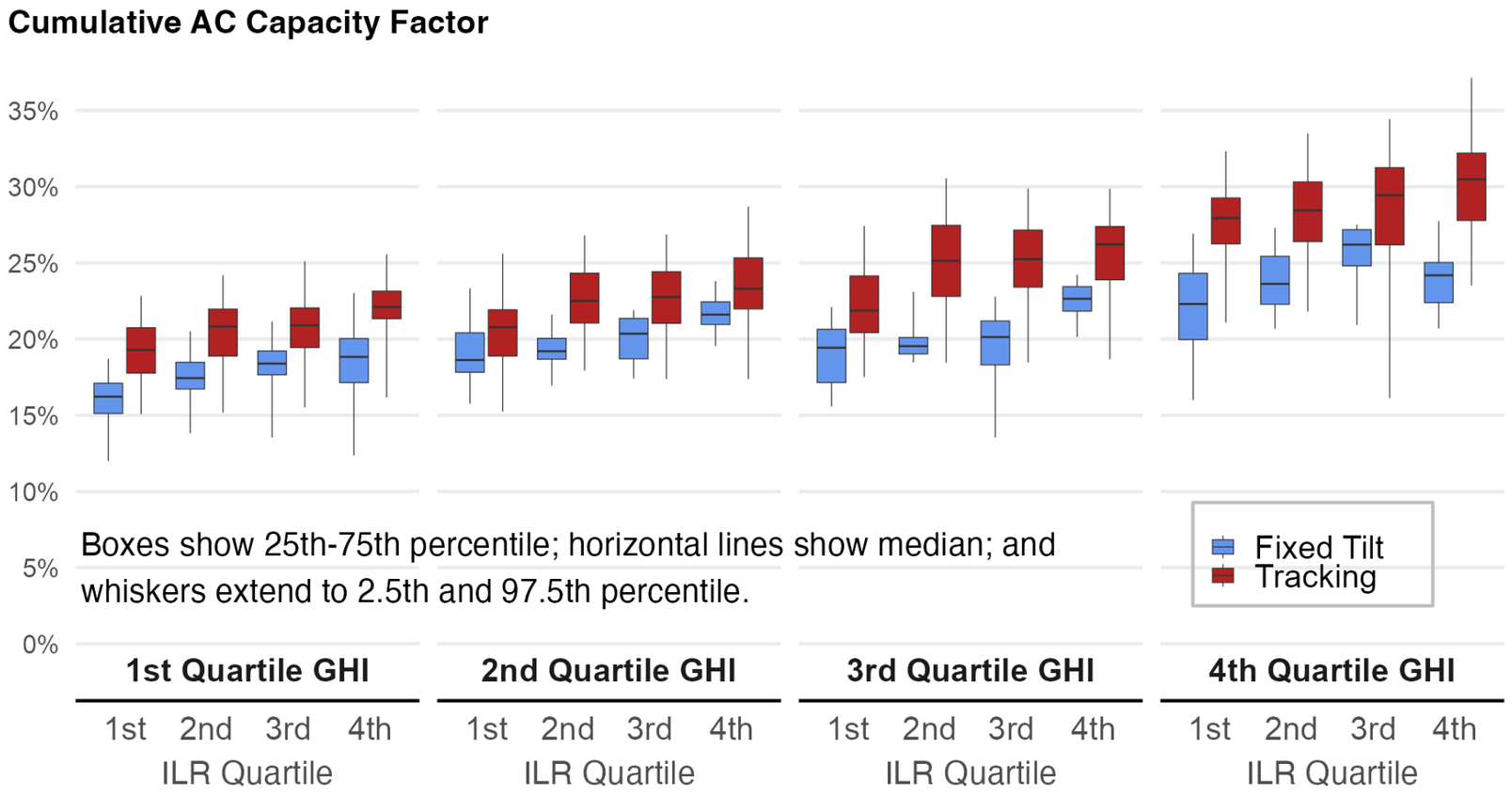
$$Annual\ Net\ Capacity\ Factor = \frac{Annual\ Net\ Generation\ (MWh)}{Capacity\ (MW_{AC}) * number\ of\ hours\ in\ year}$$

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 recently reported period.

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

PV project sample: 1,713 projects totaling 108 GW_{AC}



The cumulative net capacity factor across the full sample is 23% but ranges from 6% to 40% among all projects in our sample.

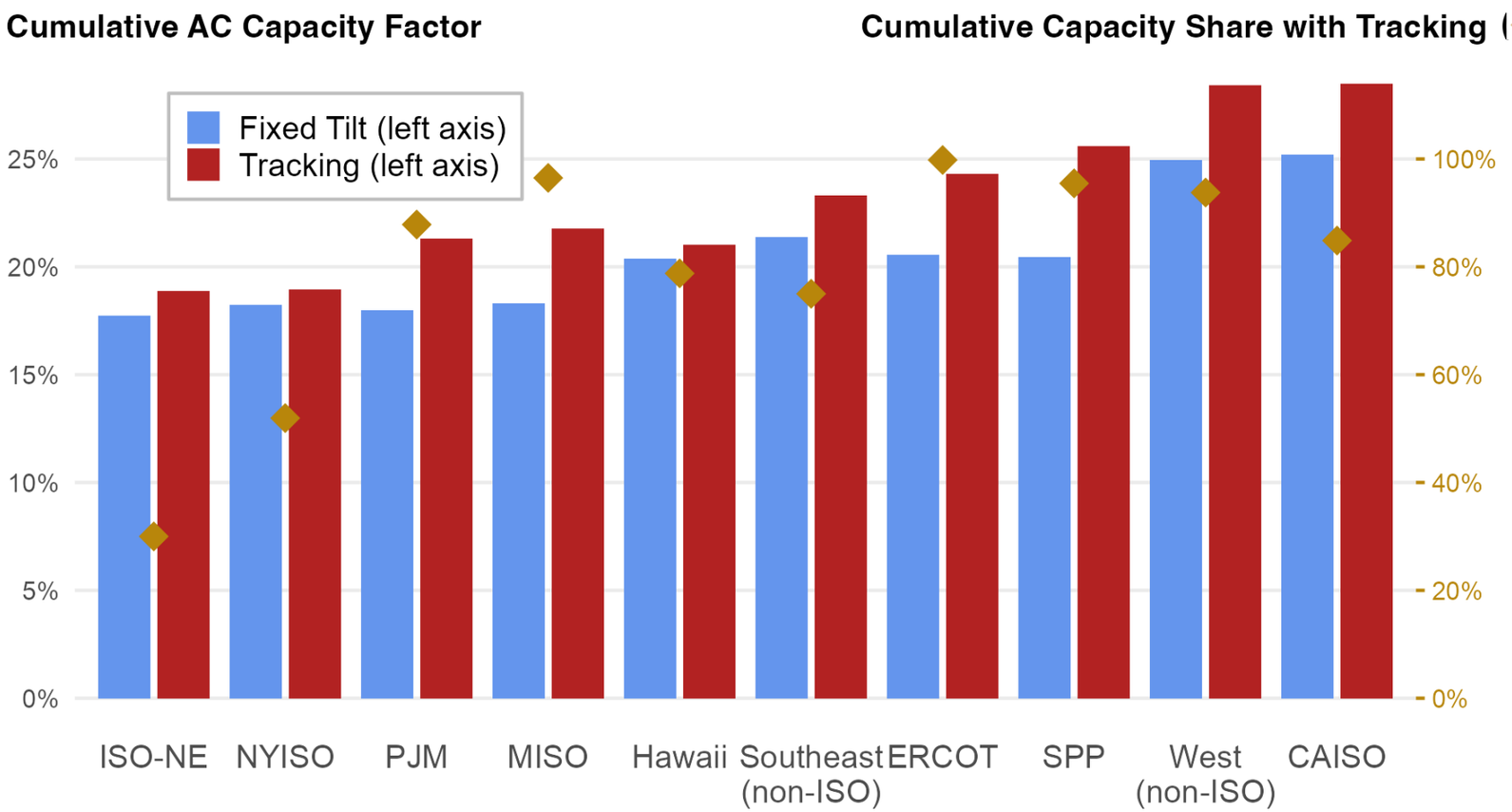
Project-level variation in PV capacity factor is driven by:

- **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 2 percentage point higher capacity factors than lowest ILR quartiles

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

Within individual regions, tracking increases capacity factors by an average of 3 percentage points

PV project sample: 1,730 projects totaling 110 GW_{AC}



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 figure.

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

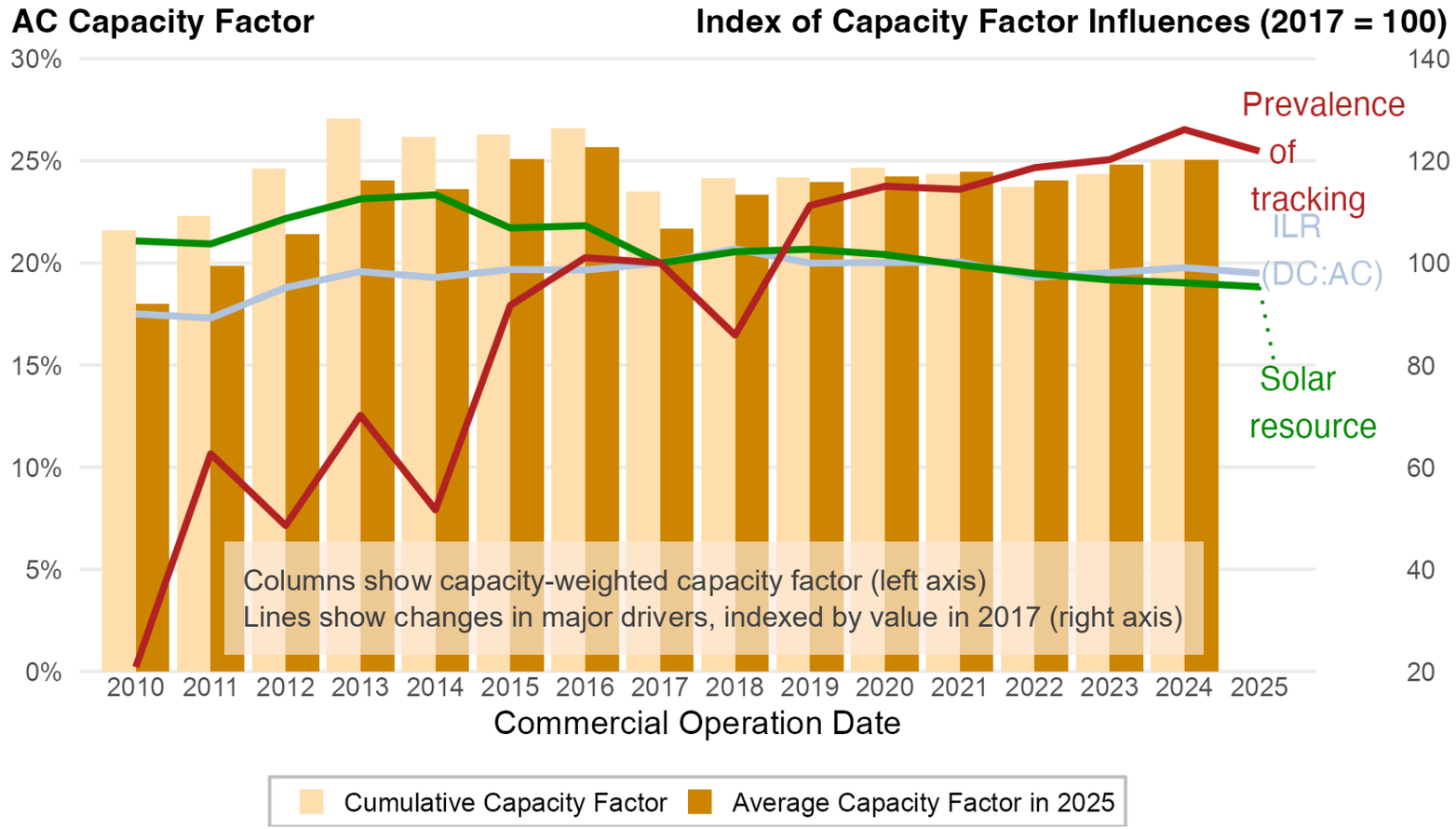
Because tracking can yield greater benefits than fixed-tilt installations in regions with strong solar resources, tracking accounts for a larger share of capacity in those markets. Tracking accounts for just 30% of cumulative capacity built in ISO-NE, the lowest share among regions, compared to virtually all capacity in ERCOT, the highest.

Although fixed tilt systems have a slight upfront cost advantage, in practice, tracking systems compensate with an increase in lifetime generation, leading to a higher share of new projects built with tracking. Tracking accounted for 96% of capacity and 92% of projects built in 2025.

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: 1,727 projects totaling 110 GW_{AC}



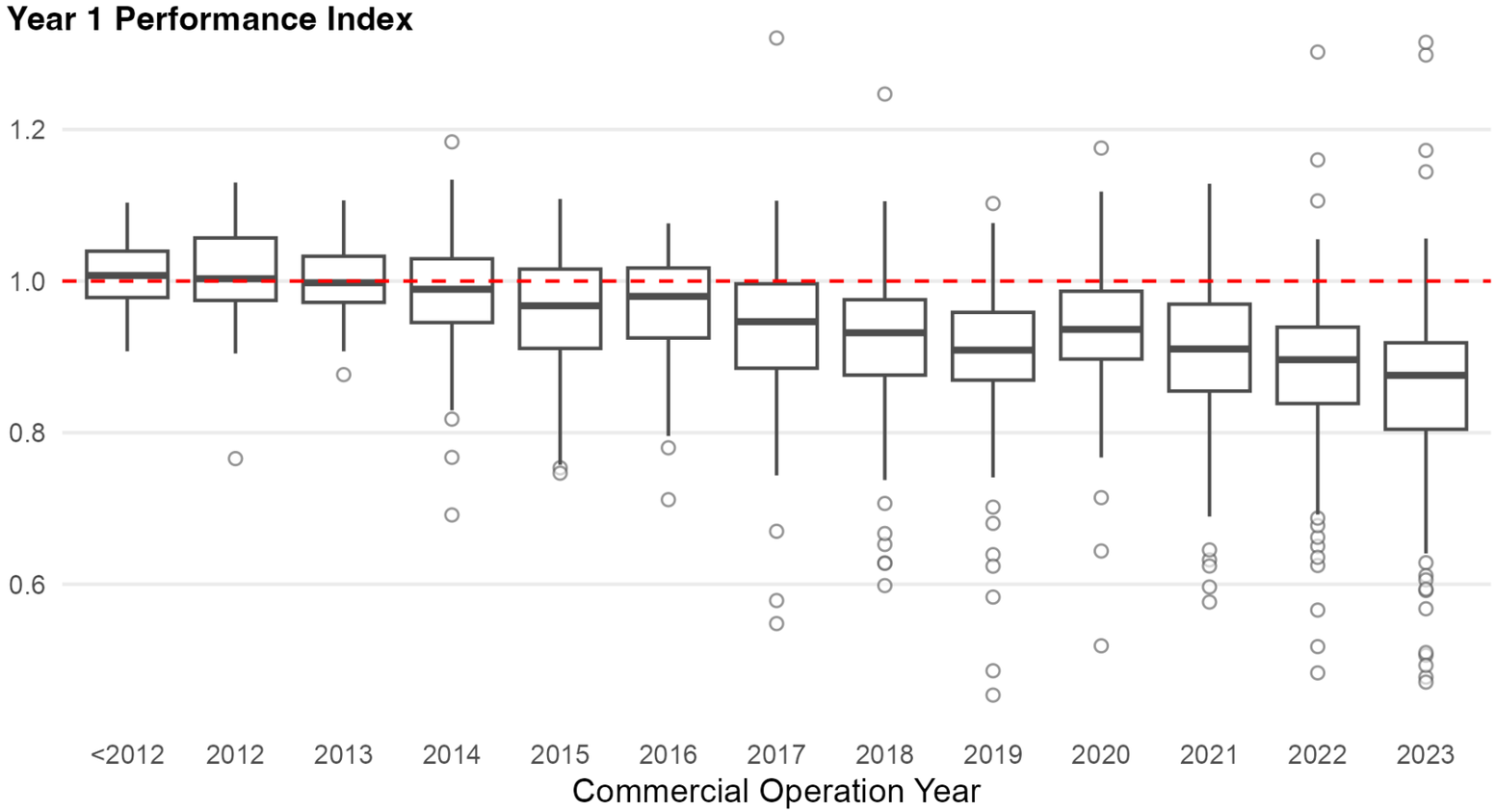
Cumulative capacity-weighted capacity factors increased from 2010 to 2013 due to greater DC-oversizing relative to the AC-inverter capacity (ILR), adoption of single-axis tracking, and better solar resource sites.

Since 2013, capacity factors have declined and stagnated due to mixed factors: while tracking has become widespread (53% to 96% of capacity in 2025) and ILR has seen minor growth, new projects have expanded into less sunny regions (average capacity-weighted site GHI decreased from 5.55 to 4.70 kWh/m²/day between 2013 and 2025).

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: 1,349 projects totaling 78 GW_{AC}



Notes: We use site-level weather data from NLR's National Solar Radiation Database (NSRDB) and plant-specific characteristics to model plant output using NLR's System Advisor Model (SAM). SAM and NSRDB are models and may have biases. Sample includes plants built through 2023 due to availability of NSRDB data (through 2024).

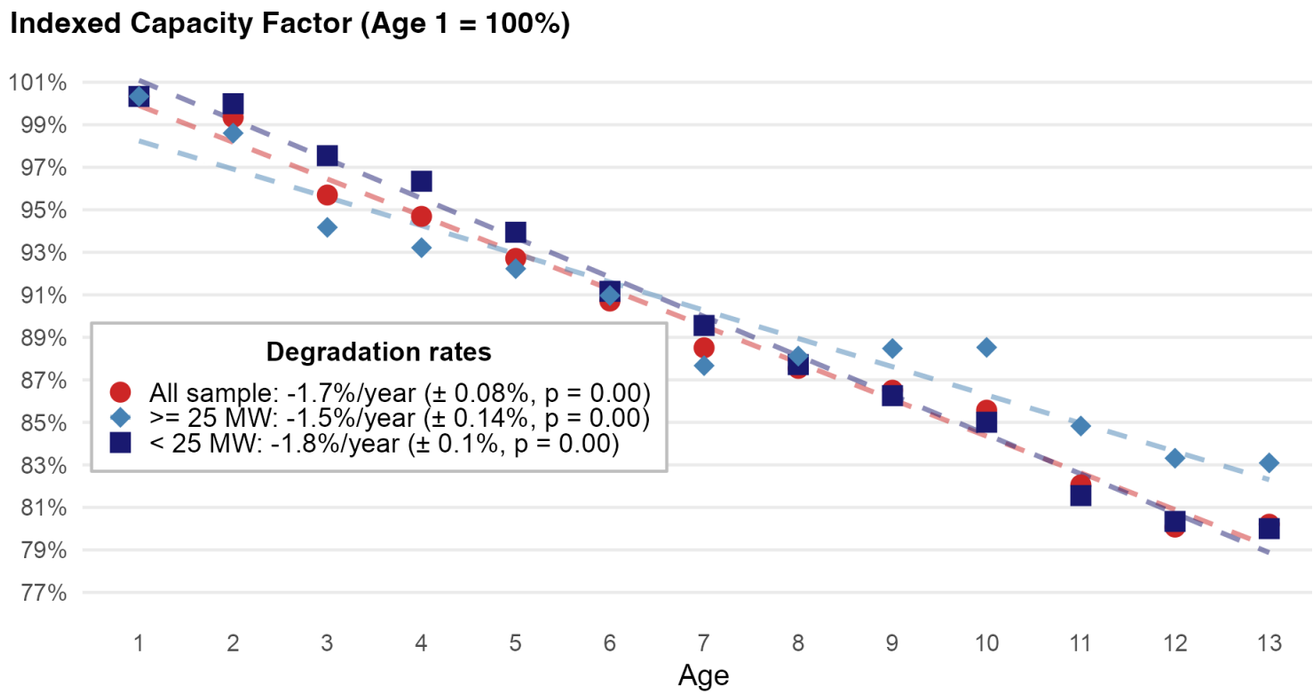
The Performance Index (PI) compares real-world operations of a PV project to simulated generation using location- and year-specific weather data. A PI below 1.0 means the plant produced less than the model predicted. We focus on the first operational year after COD to sidestep early teething issues and long-term degradation effects. For projects in CAISO, ERCOT, and SPP, we adjust for curtailment effects.

More recent vintages have lower year-one PIs than older ones: the median 2023 project has a PI of 88%. This could reflect genuine underperformance, worsening model accuracy, or both. On the modeling side, hourly modeling underestimates sub-hourly clipping in projects with high DC/AC ratios, leading to overestimates of expected generation.[1] On the empirical side, factors that have become more common over time may be leading to reduced output, including weather impacts (such as wildfire smoke, hailstorms, or hurricanes) or curtailment in regions outside of CAISO, ERCOT, or SPP (we adjust for curtailment in these three regions only).

[1]M. J. Prilliman, J. M. F. Keith and W. B. Hobbs, "Side-by-Side Comparison of Subhourly Clipping Models," *2024 IEEE 52nd Photovoltaic Specialist Conference (PVSC)*, Seattle, WA, USA, 2024, pp. 0697-0702, doi: 10.1109/PVSC57443.2024.10748694.

Project output declines with age at an average annual degradation rate of 1.7%, but larger projects degrade more slowly

PV project sample: 1,199 projects totaling 61 GW_{AC}



Note: Sample includes plants built through 2022 with performance data through 2024 (model requires two years of performance and weather data, and public weather data from NSRDB is only available through 2024 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 1.7%, with variation by project size: larger projects (≥25 MW_{AC}) average 1.5%, while smaller projects (<25 MW_{AC}) average 1.8%. While we attempt to correct for curtailment in CAISO, ERCOT, and SPP, 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:

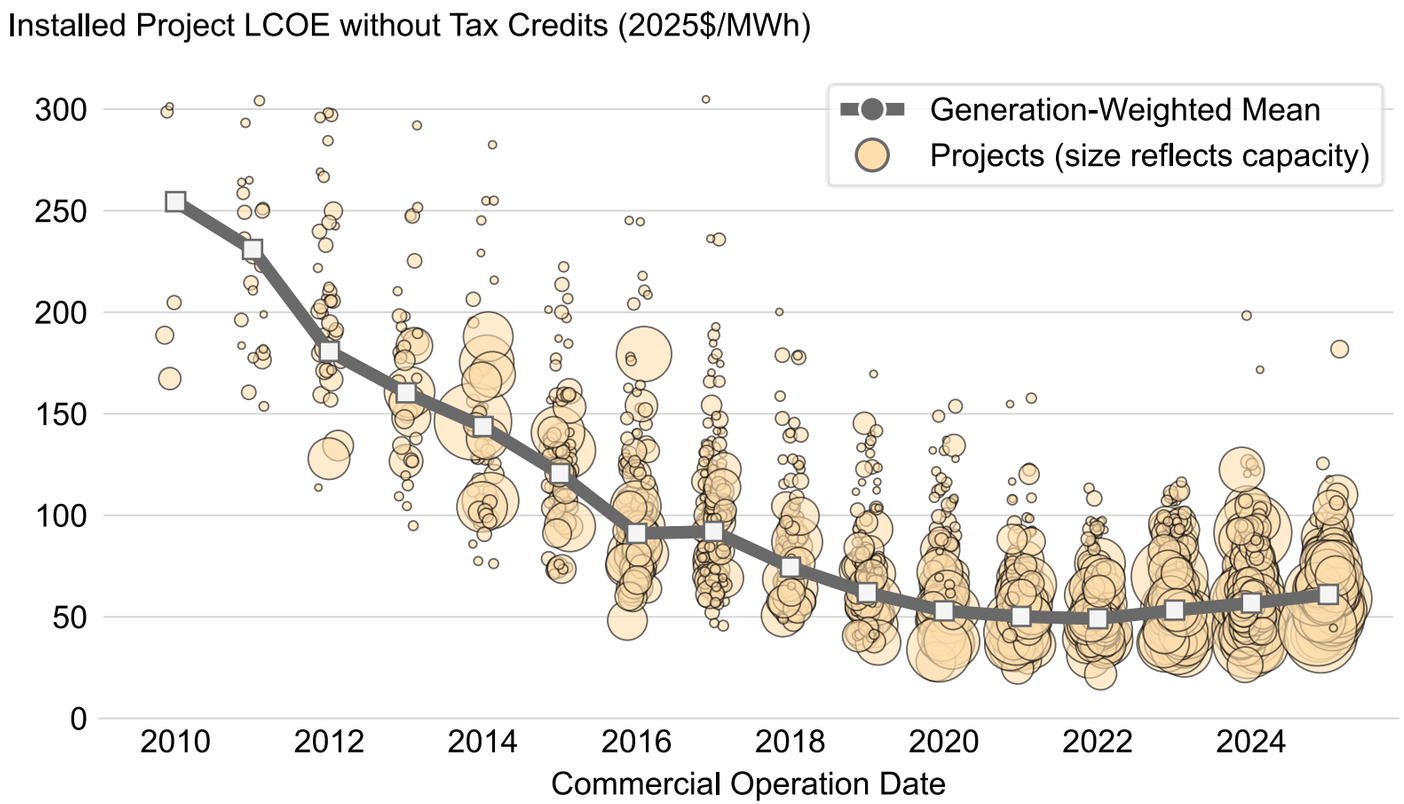
- For our project-level LCOE estimates of solar projects we follow the formula published in NLR's Annual Technology Baseline, describing the average costs to generate a MWh over the lifetime of a project.
- We use LCOE as proxy for direct generation costs in later parts of this publication. It is important 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, representing energy delivered to the grid after curtailment. For missing and future years we assume annual degradation rates ranging between 1.74% (projects <25MW) and 1.28% (projects >=25MW) based on last year's analysis. Using results from this year's analysis (1.8% and 1.5%) would result in slightly higher LCOE than what is presented on the following slides. 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 (shown later) 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 \$52/kW_{DC}-yr in 2007 to \$26/kW_{DC}-yr in 2025 (in 2025\$, based on prior LBNL and NLR Benchmarks). For hybrid projects we assume a battery replacement after 15 years with replacement costs derived from NLR 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 long-term annual inflation expectations are 2.40% for 2025 COD projects.
    - Real WACC for 2025 COD projects is 3.33%.

Average LCOE (without the ITC/PTC) has increased 24% since 2022 to $61/MWh

Sample: 1,812 projects totaling 126.8 GW_{AC}



Utility-scale PV's average LCOE fell by 81% between 2010 and 2022 to $49/MWh, driven by lower capital costs and operating expenses, as well as increased project design life.

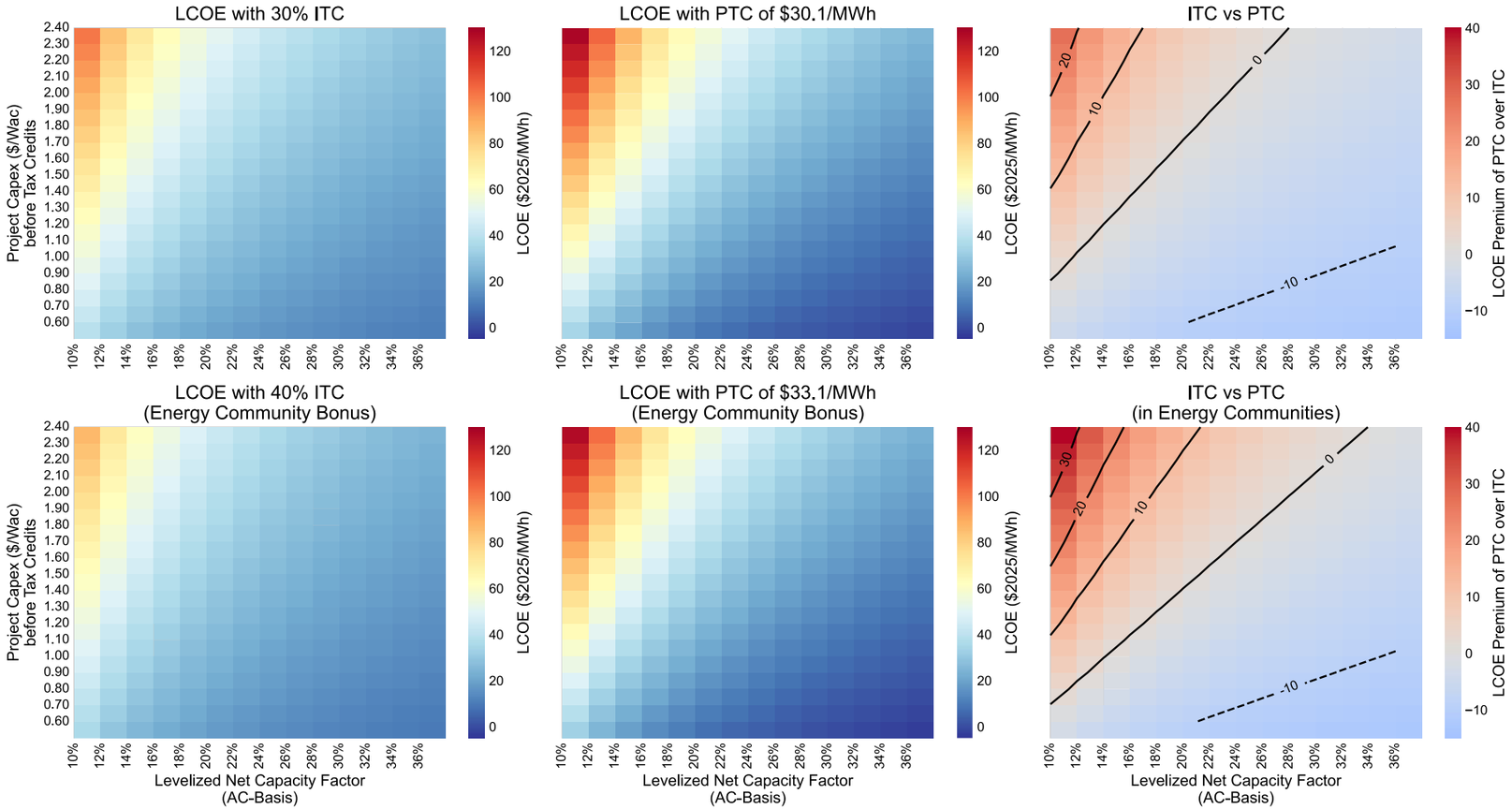
Counteracting these longer-term trends were falling average capacity factors since 2016 as PV was built increasingly in less sunny regions, much higher financing costs since 2020, and increasing CapEx since 2023.

As a result, average LCOE (not including any tax credits) increased by 24% since 2022 to $61/MWh in 2025.

Note: LCOE estimates depicted here do not include tax credit benefits.
Only preliminary data is available for new solar projects coming online in 2024 and 2025.
Findings may shift as more final EIA Capex and project-specific performance data become available.

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

The Production Tax Credit lowered post-credit LCOE more than the Investment Tax Credit for 40% of projects since 2023



Available federal tax credits reduce the LCOE shown on the previous slide. The graphs show post-incentive LCOE by project CapEx and performance under the Investment Tax Credit (ITC, left) and Production Tax Credit (PTC, center). The PTC is paid for 10 years ($30.1/MWh in 2025, adjusted for inflation); levelized over a 35-year project life, it reduces 2025 project LCOE by about $16.4/MWh.

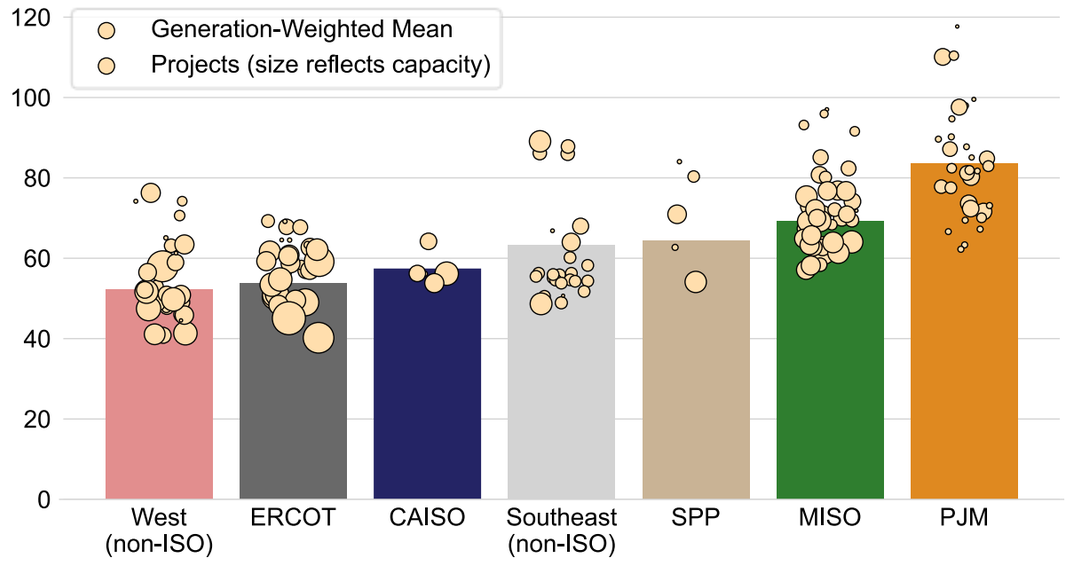
The right column compares the two credits: red squares indicate where the ITC produces a lower LCOE (higher-cost, lower-performing projects), while blue squares favor the PTC (lower-cost, higher-performing projects). The isoline of 0 shows the transition between ITC and PTC superiority. The bottom row includes the Energy Community bonus. Preliminary data suggest that about 40% of projects entering operation since 2023 (246 of 607) would benefit more from the PTC than the ITC.

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

Sample: 181 projects totaling 23.4 GW_{AC}

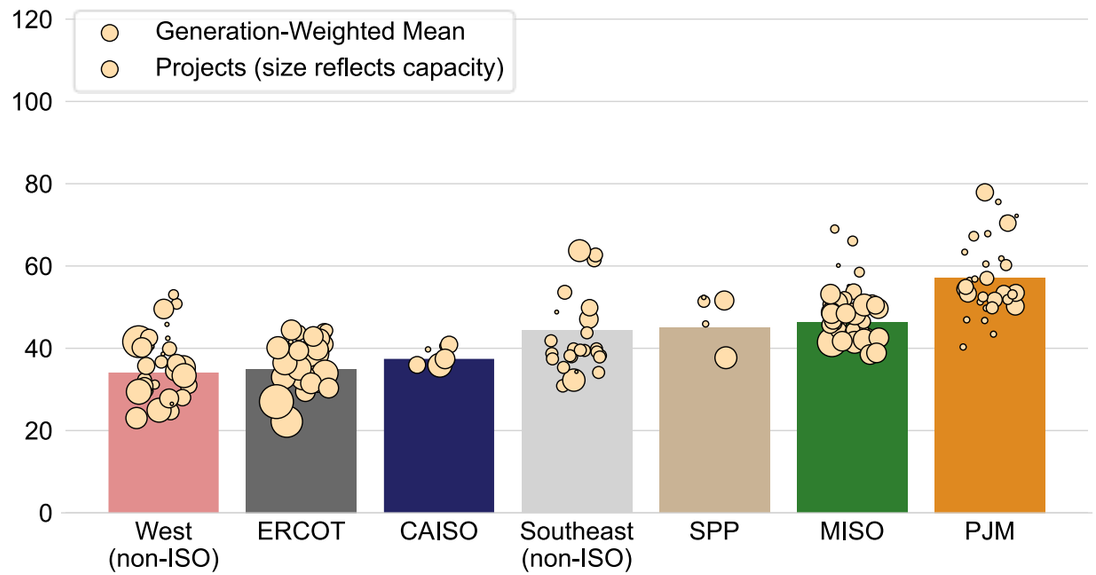
See interactive visualization at https://emp.lbl.gov/capex-lcoe-and-ppa-prices-region

LCOE of 2025 Projects without Tax Credits (2025$/MWh)



Higher insolation regions will generally have lower LCOEs compared to less sunny parts of the country. Among projects coming online in 2025, projects in the non-ISO West ($52/MWh), ERCOT and CAISO had the lowest cost, while projects in PJM had the highest cost ($84/MWh).

LCOE of 2025 Projects with Tax Credits (2025$/MWh)



Accounting for either the ITC or PTC (whichever results in lower costs), post-incentive LCOE of 2025 projects are near $35/MWh in the non-ISO West, ERCOT, and CAISO, near $45/MWh in the Southeast, SPP, and MISO, and $57/MWh in PJM.

Note: Only preliminary data is available for new solar projects coming online in 2025. 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:

- 636 PV-only contracts totaling 54.2 $GW_{AC.}$
- 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 (25^{th} 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.

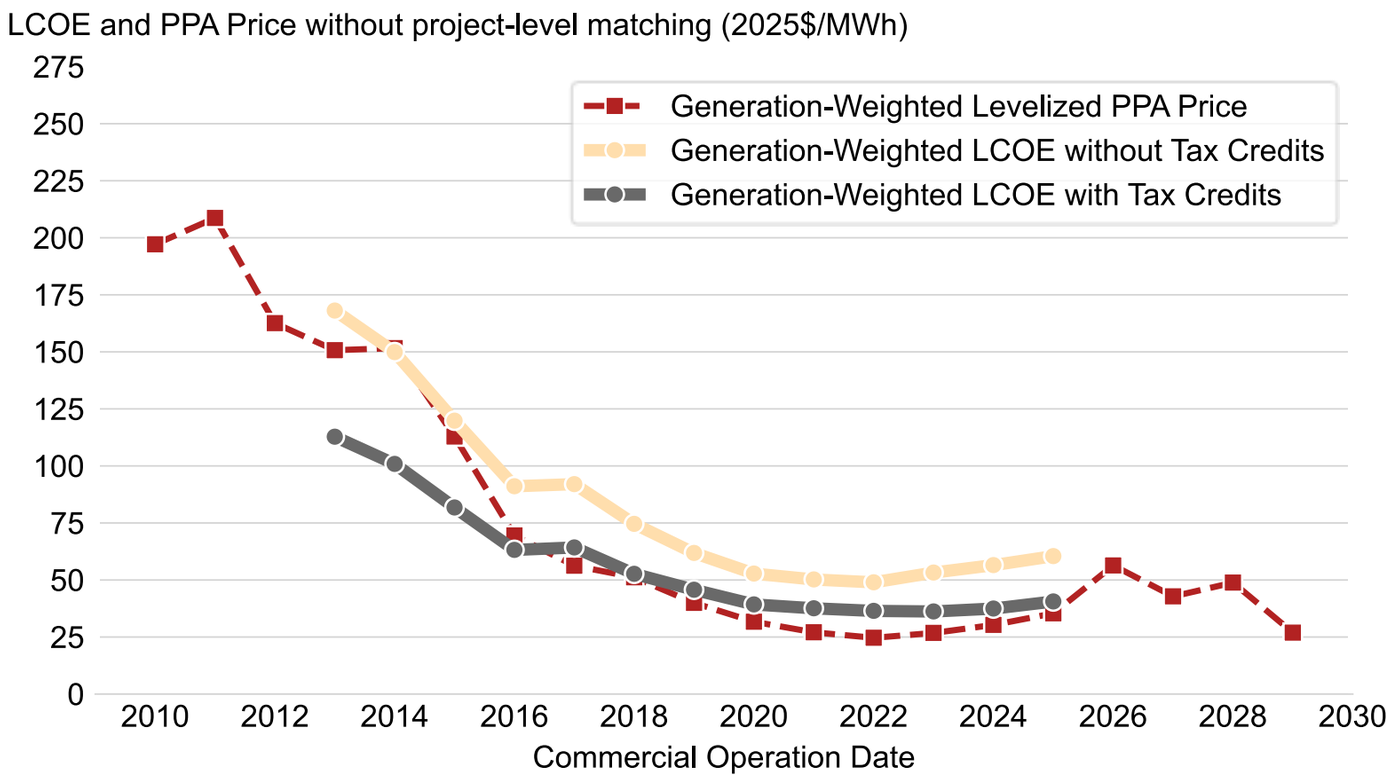
Levelization methodology

- We deflate the nominal dollar price series to 2025 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: 1,662 projects totaling 121 GW_{AC}



This graph compares 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).

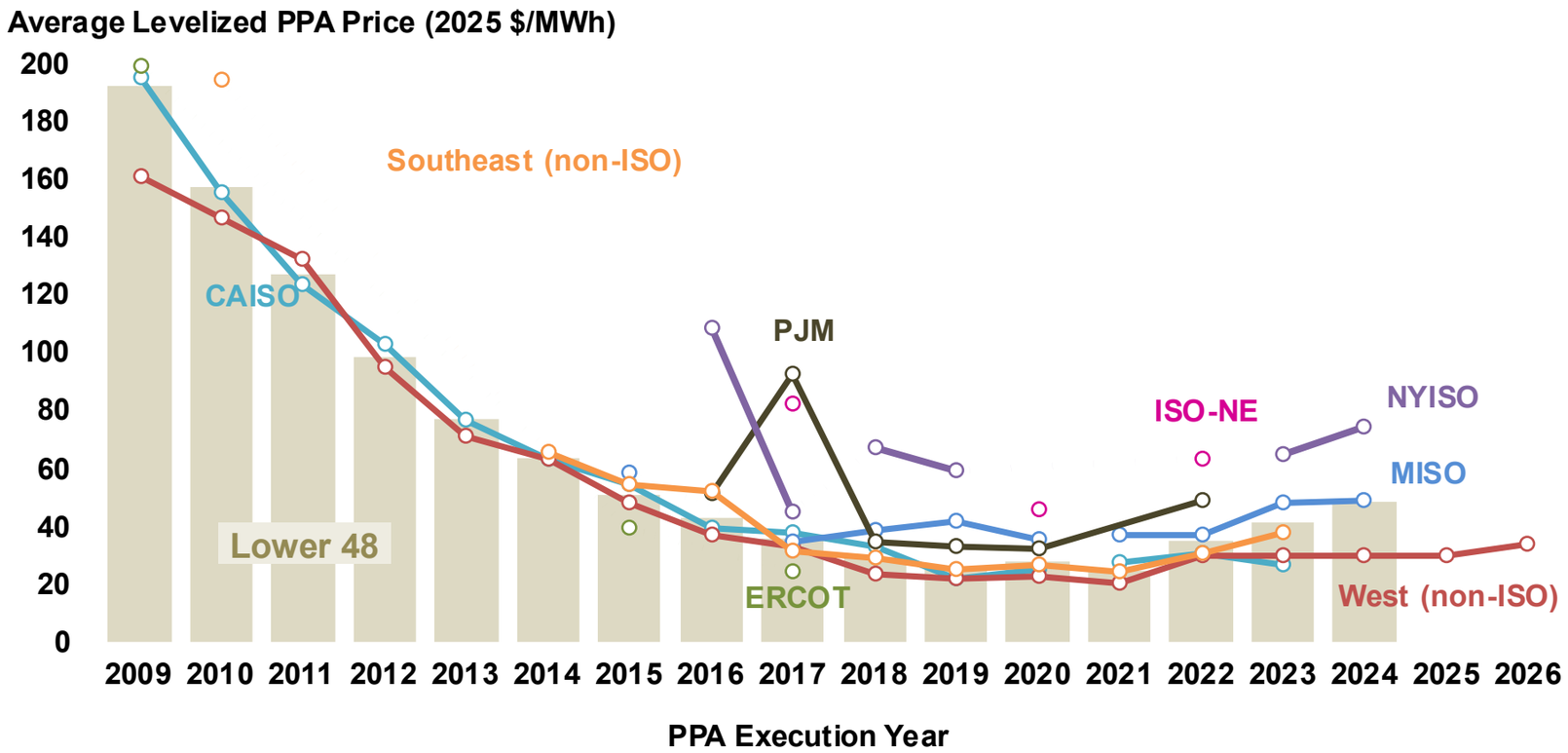
Generation-weighted average LCOE increased since 2022 both before the application of tax credits ($61/MWh in 2025 vs. $49 in 2022) and after ($41/MWh vs. $37/MWh).

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 2025. 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 PPA prices by contract execution date, depicting regional and national averages, 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.

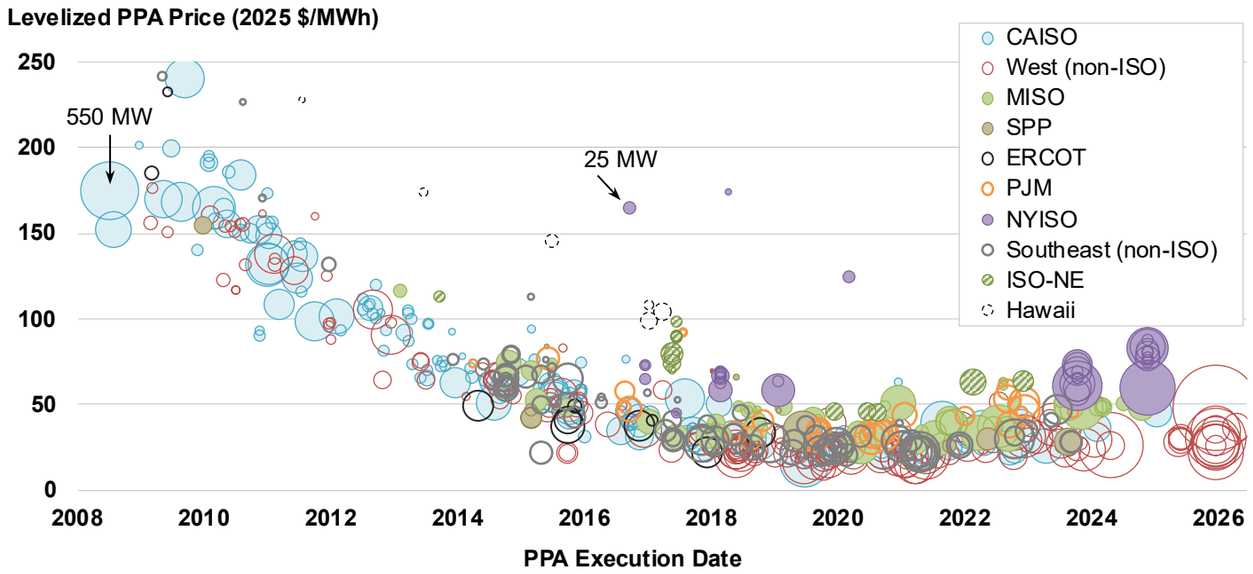
Year-Region combinations with fewer than 2 PPAs are excluded from the graph (dashed line segments indicate that the line is skipping over such years).

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: 636 PPAs, 54.2 GW_{AC}



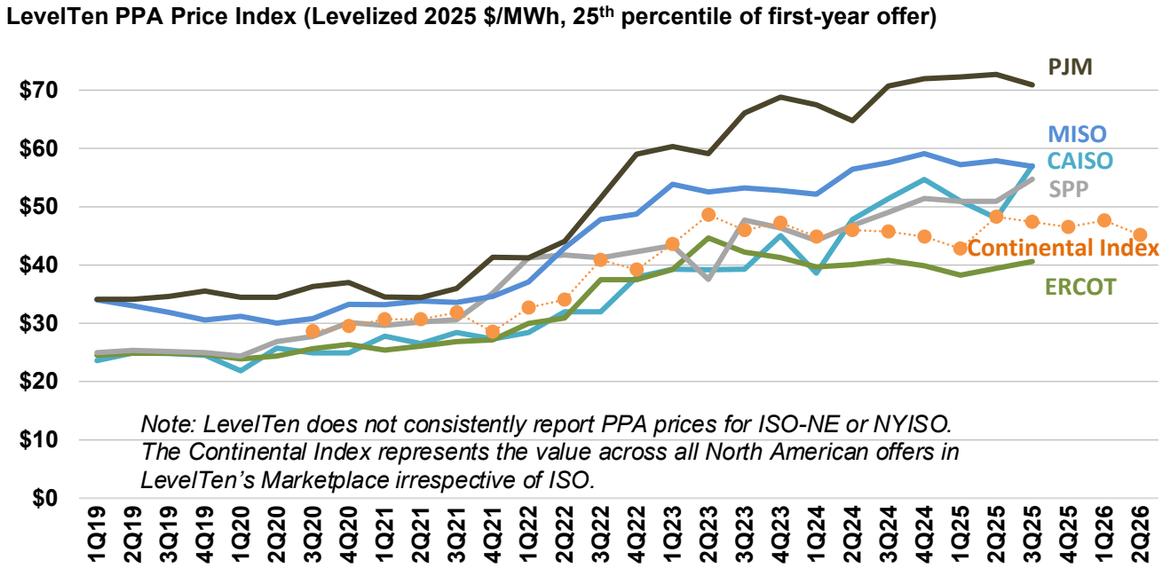
2024-present sample: 48 PPAs, 5.0 GW_{AC}

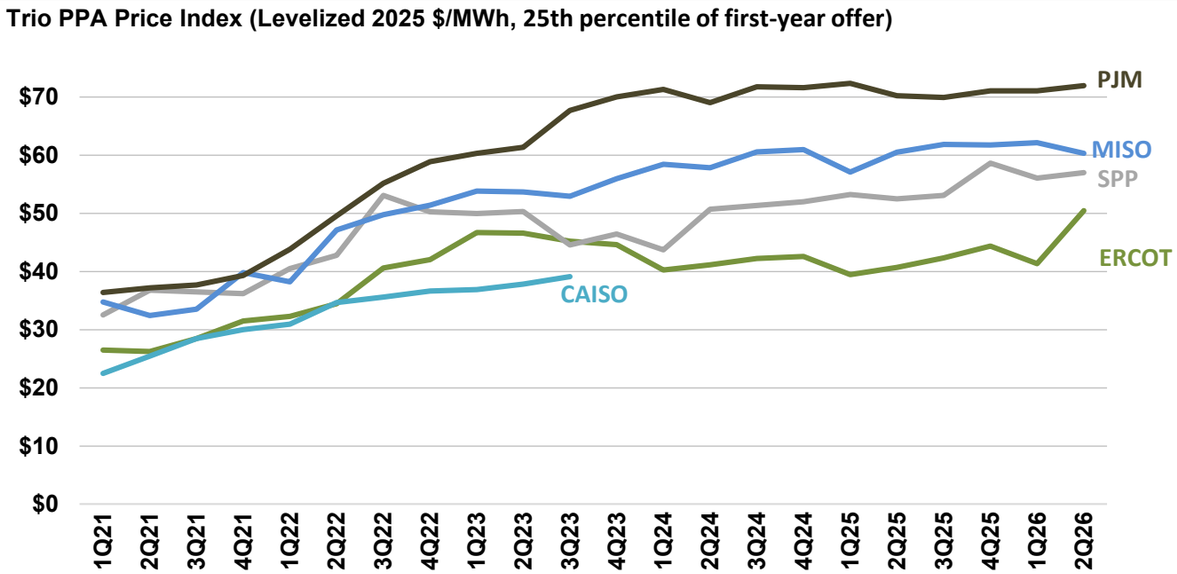
- Characteristics of PPAs in the full sample:
  - Contract term is between 20 and 25 years (inclusive) for 75% of PPAs
  - >90% of the sample is currently operational
  - PPAs are typically executed 1.5-3 years before a project's commercial operation date

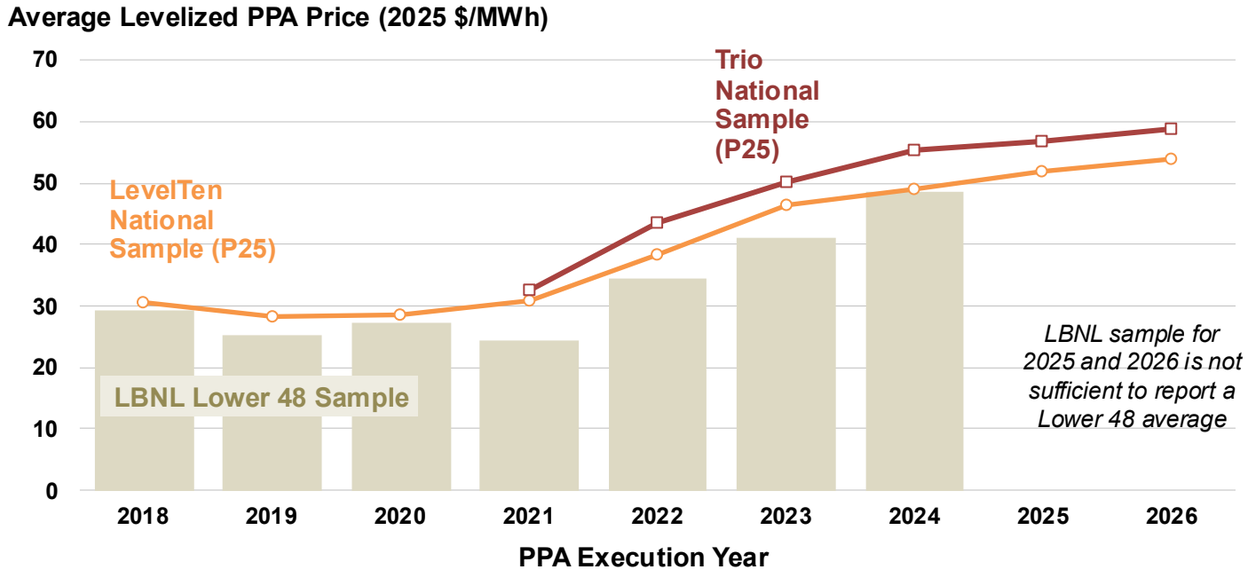
- Characteristics of PPAs in sample signed since 2024:
  - Majority of contracts are with NV Energy or Public Service Company of New Mexico as offtakers (West) or reflect NYSERDA REC strike prices (NYISO)
  - Most projects are not yet operational

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

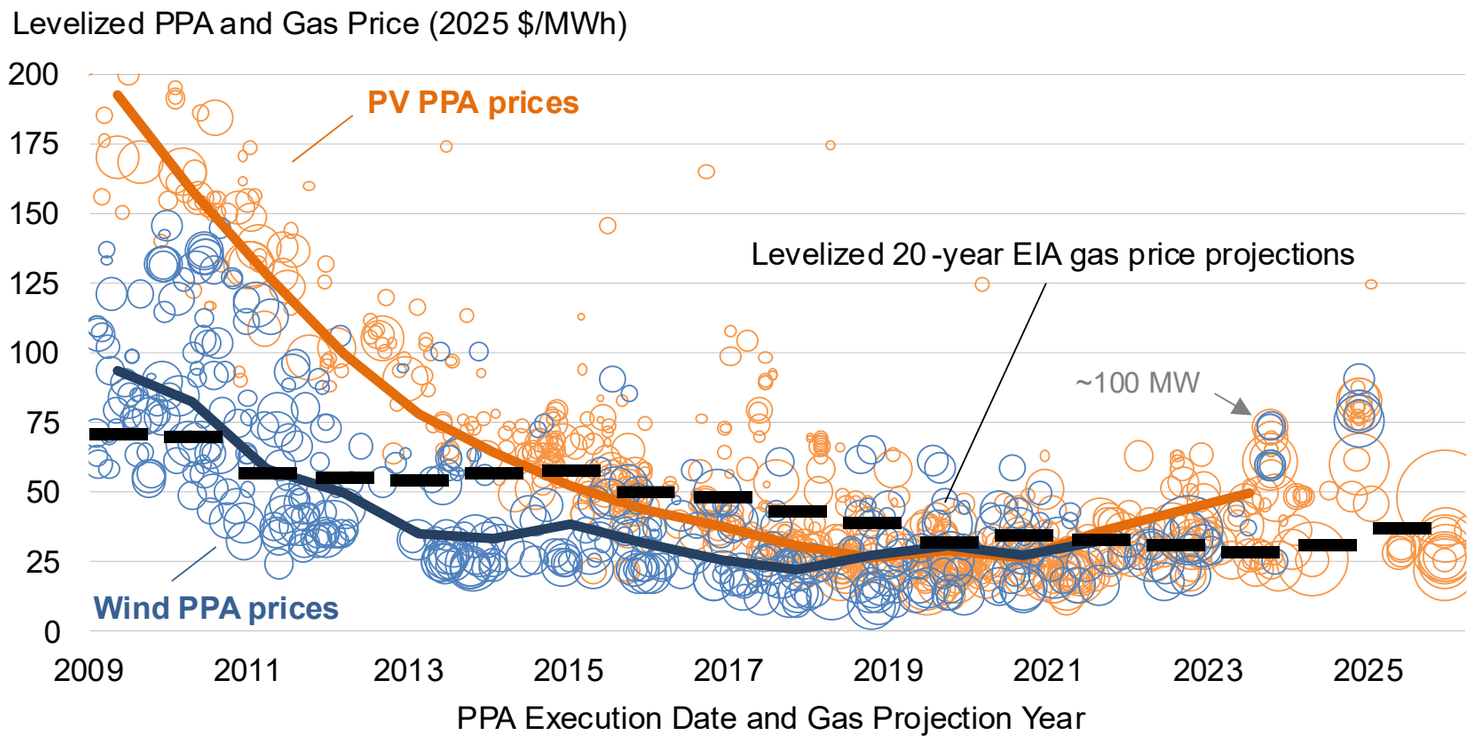






To augment our PPA price sample, and to gain visibility into corporate PPA pricing (which is not well-represented within our sample), we present LevelTen Energy and Trio's PPA price indices.

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 NLR's System Advisor Model and site- and year-specific insolation data from NLR'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 de-biased 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 imbalance markets

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

Capacity value is the product of a plant 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

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

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

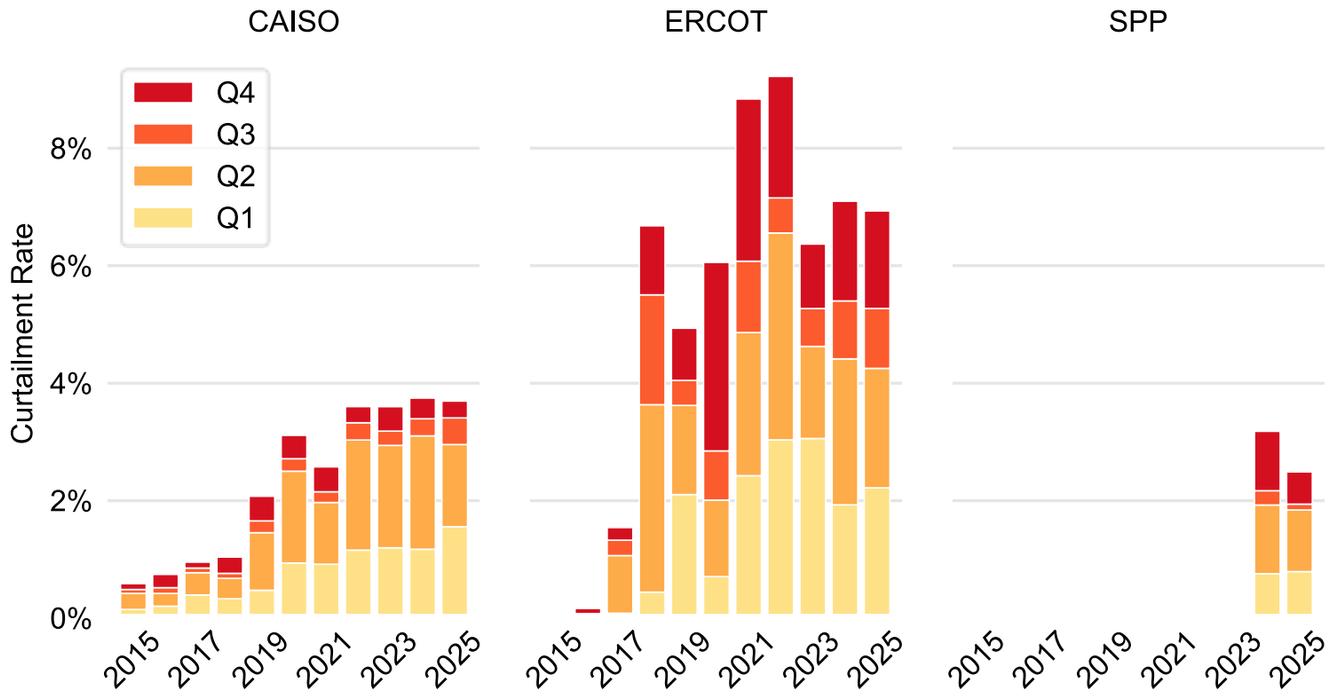
Wholesale market value analysis: data sets and methodology (II of II)

- **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 derivative penetration and congestion analyses.

Solar curtailment varied by region in 2025. Most ISOs and regions do not yet report curtailment

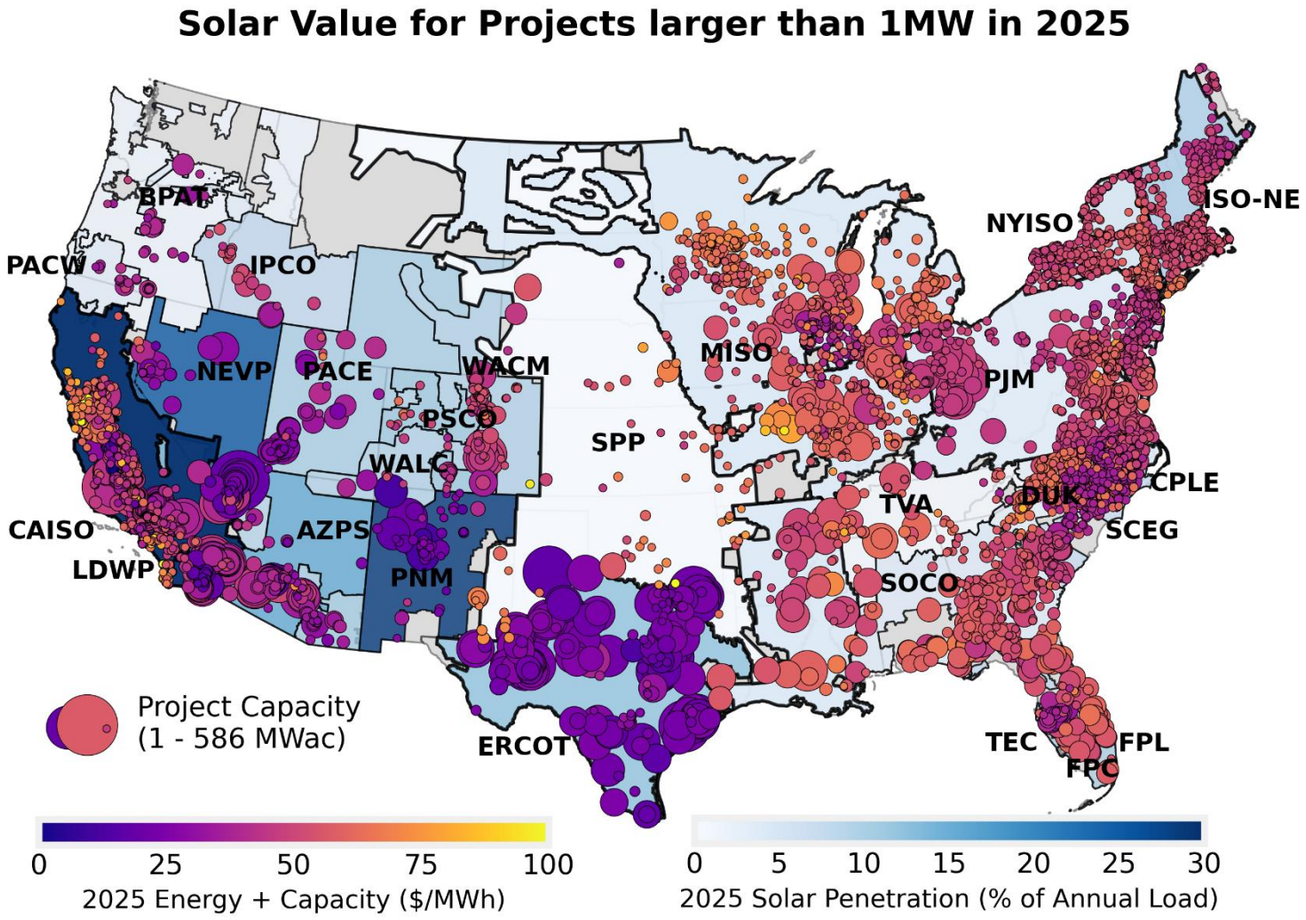


Despite large solar generation growth, the *rate of solar curtailment* stayed mostly stable in 2025 and is highest in ERCOT (6.9%) compared with CAISO (3.8%) and SPP (2.8%), even though solar's penetration rate is far lower in ERCOT (13%) than in CAISO (33%).

West Texas accounted for approximately half of modeled plant-level curtailed energy in 2025, down from about two-thirds in 2024 as curtailment became more geographically dispersed across the South and North zones. Within West Texas, the export-constrained Panhandle and other renewable-rich areas experience low or negative local prices.

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



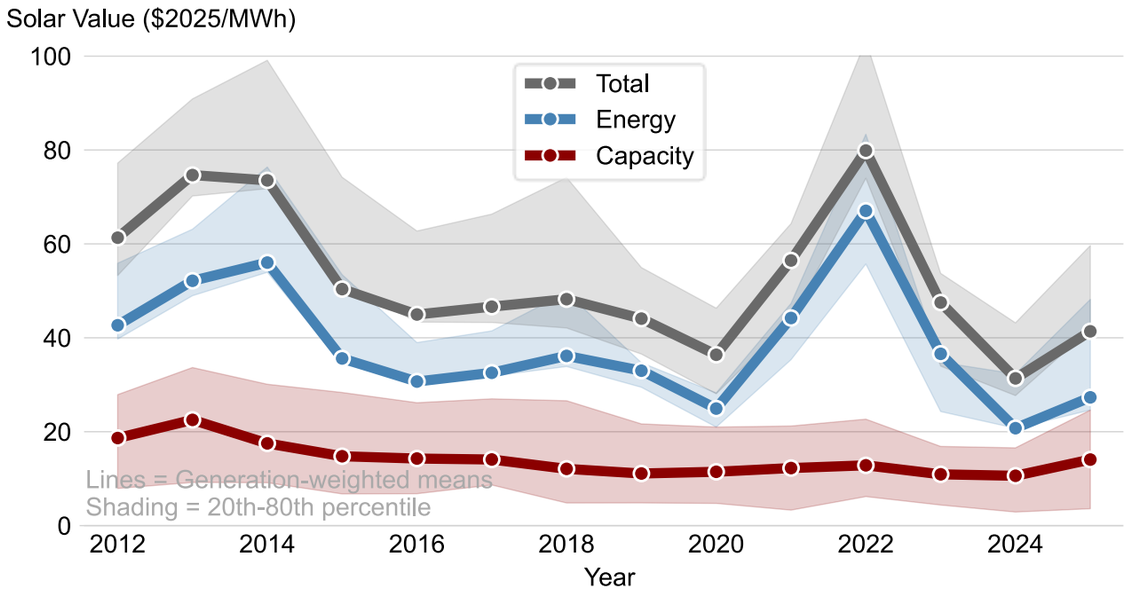
We estimate solar wholesale market value for 6,391 projects in 30 balancing authorities (subset shown on the left map).

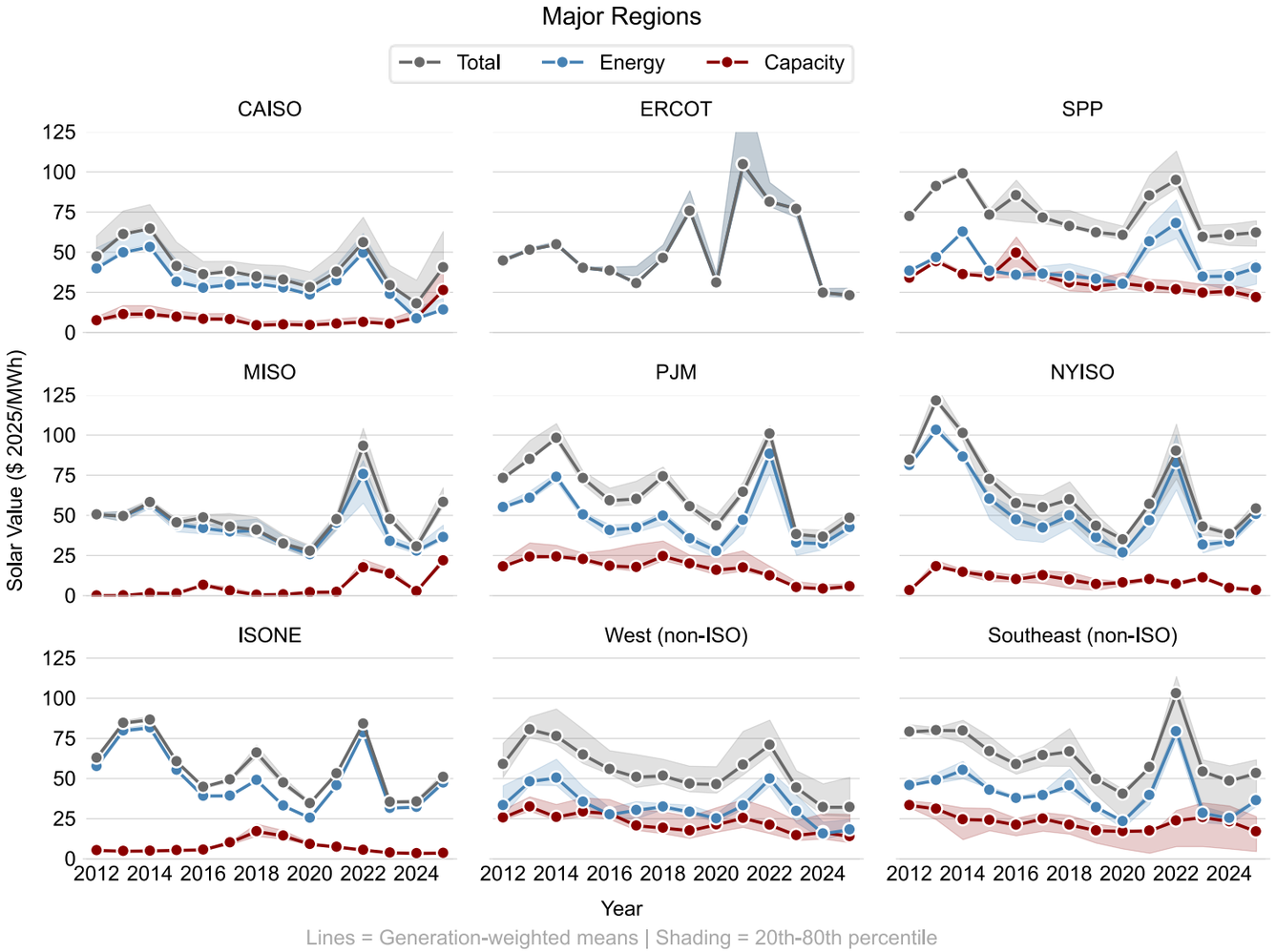
Value varies both between and within regions, driven by generator supply curves, transmission congestion, solar resource quality or differing use of technology like trackers.

For example, in CAISO, the northern zone typically has higher average values than the southern zone. 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.

Solar's energy plus capacity value increased to a national average of $41/MWh in 2025



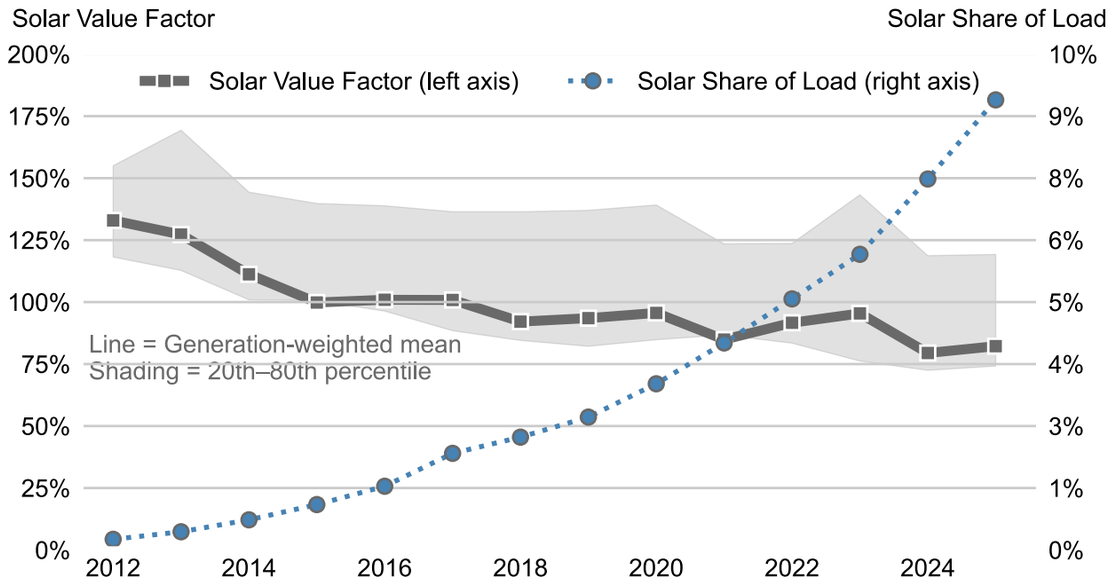


Driven by rising natural gas prices, strong storage deployment, and greater capacity value, PV's average market value increased from $31/MWh in 2024 to $41/MWh in 2025.

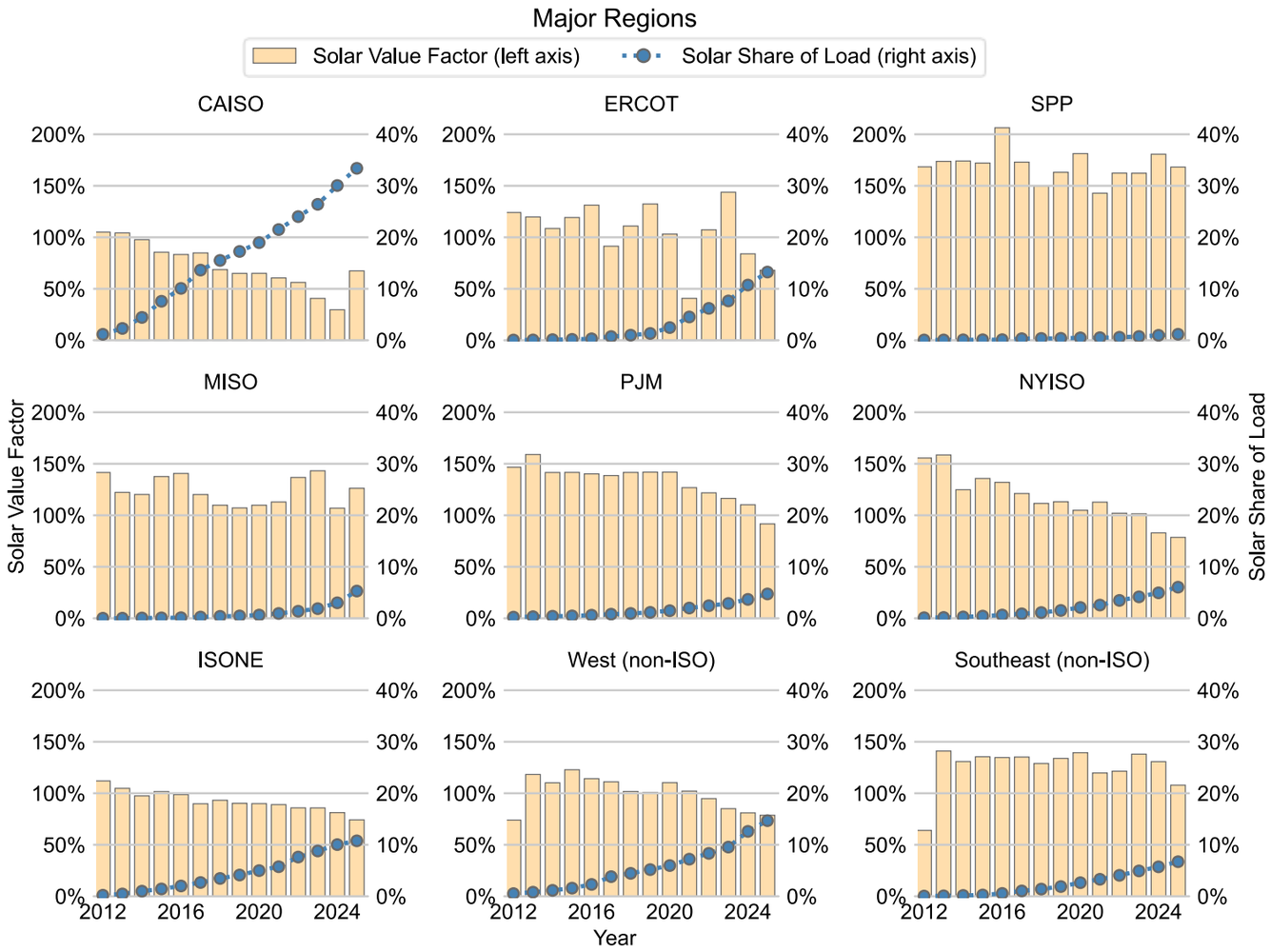
ERCOT had the lowest standalone solar value at $23/MWh, while SPP ($62/MWh), MISO, NYISO, ISONE, and many southeastern BAs exceed $50/MWh.

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; the national average was 82% in 2025

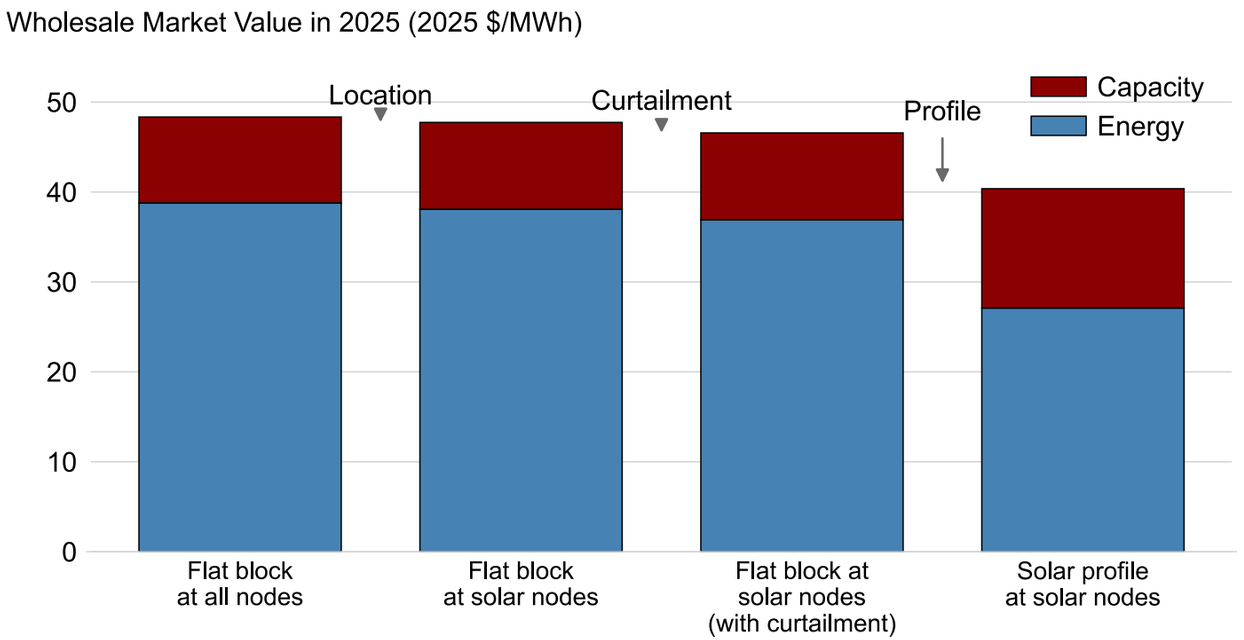


Without flexibility investments, solar's value factor tends to fall as it serves a greater share of load, reaching 82% in 2025 at a national penetration of 9%. It is lowest in western BAs like the Imperial Irrigation District (value factor of 39% at 37% penetration) or Public Service New Mexico (value factor of 43% at 35% penetration). It is highest at 168% in SPP (at 1% penetration) and is still above 100% in MISO and most southeastern BAs. Large-scale storage additions and accreditation changes in CAISO improved solar's value factor again.



Note: 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 2025

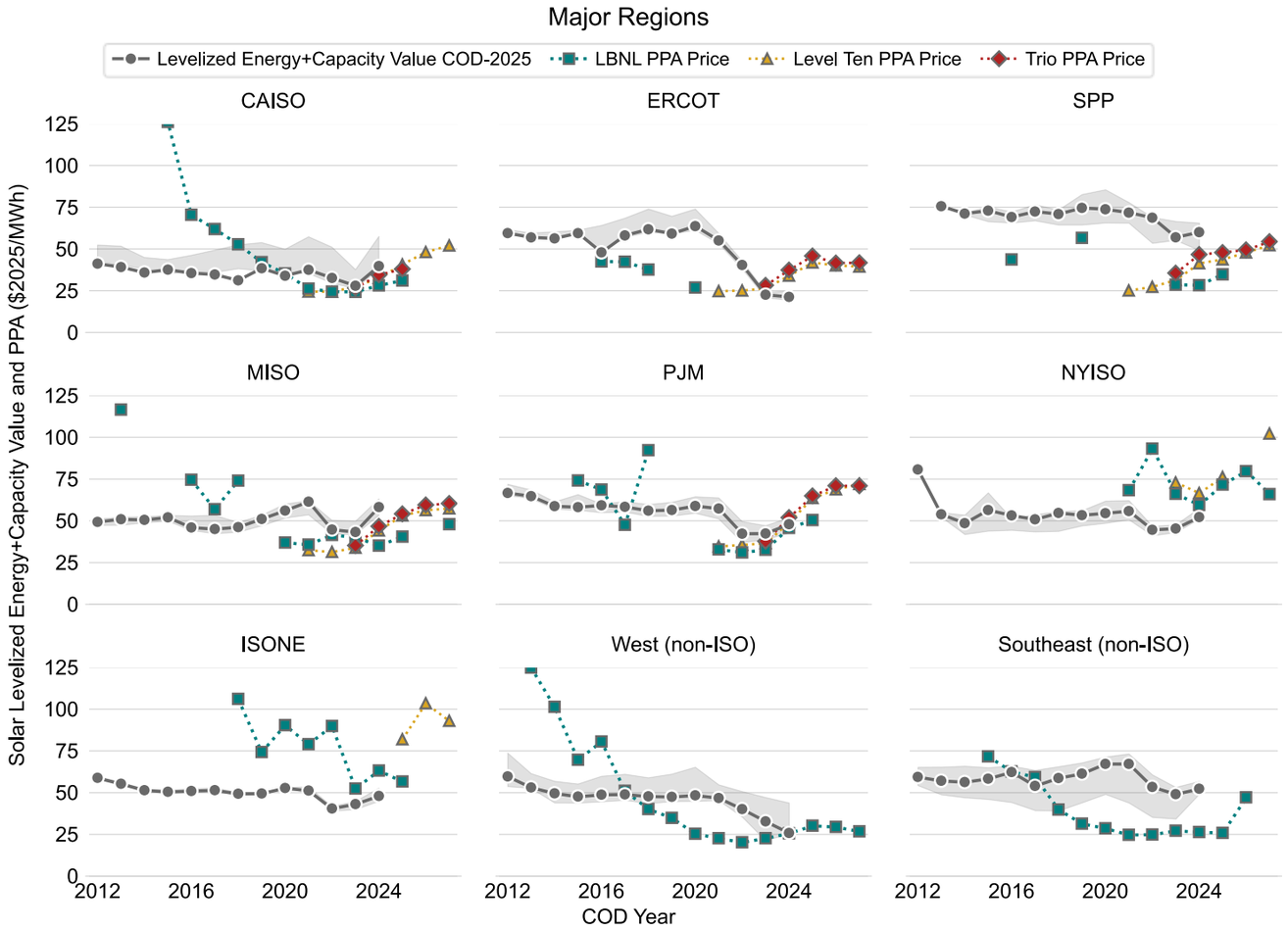


Across the seven ISOs, solar projects were usually sited at locations with slightly lower than average energy and capacity values. Curtailment did not affect value strongly. Mismatches between solar's output profile and high-priced hours matter most, yielding a value factor of 84% across all solar projects in the ISOs.

Solar's generation profile has the largest impact and either helps (in SPP and MISO) or hurts (all other ISOs) 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 2025 in the seven ISOs and do not include data from other years or non-ISO regions.

Market Value vs. PPAs: Increasing market value in 2025 kept pace with rising prices for new PPAs in most regions



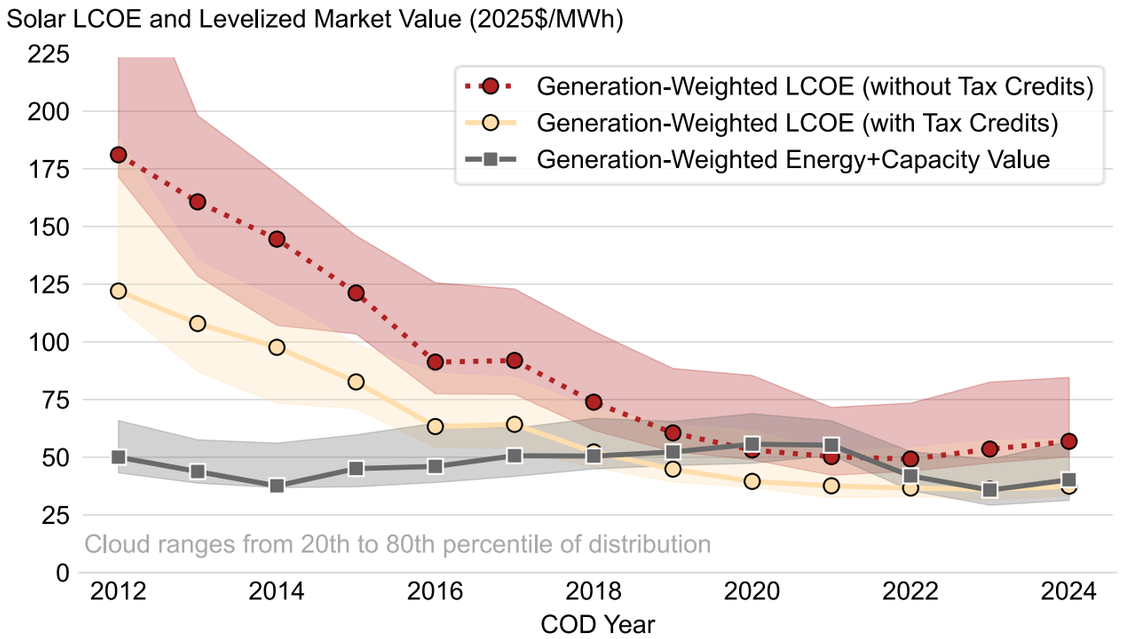
Value Line = Generation-weighted mean | Value Shading = 20th–80th percentile
For Trio and LevelTen we assume a delay of 2 years between PPA execution and project COD

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 value (which will change with solar penetration, load growth and natural gas prices) and simply levelize wholesale market value between COD and 2025 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.

Solar standalone PPAs started rising in 2021. Lower energy prices in 2023 and 2024 decreased market value in some regions, while 2025 price increases provided some uplift. Our levelized wholesale energy and capacity value of recent projects exceeded PPA prices in CAISO, SPP, MISO, PJM, and the non-ISO Southeast. In contrast, PPA prices are higher than market value in ERCOT, NYISO and ISO-NE.

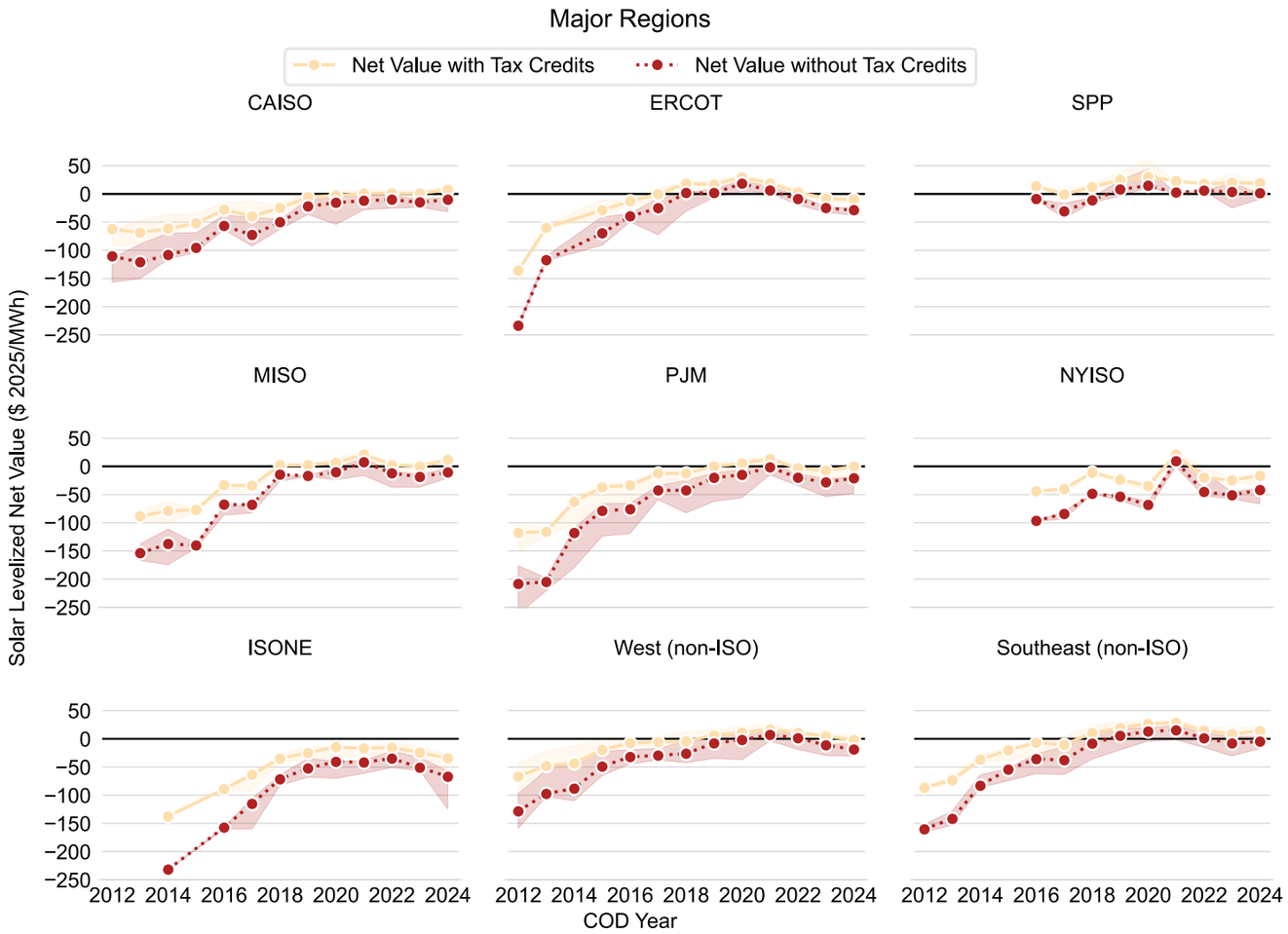
Note: We do not have sufficient PPA data to present robust trends for every balancing authority. PPAs are indexed here by Commercial Operation Date and span a longer time than the wholesale market estimates.

Solar's average market value has mostly been greater than generation costs (after tax credits) since 2018, but recent margins have been compressed



National average net value (energy+capacity value minus LCOE) for 2024 COD solar standalone projects is positive ($3/MWh) after accounting for tax credits.

Net value of these recent projects vary by region from -$34/MWh in ISONE to $19/MWh in SPP. 13 out of 25 BAs have positive net values in 2025.



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.

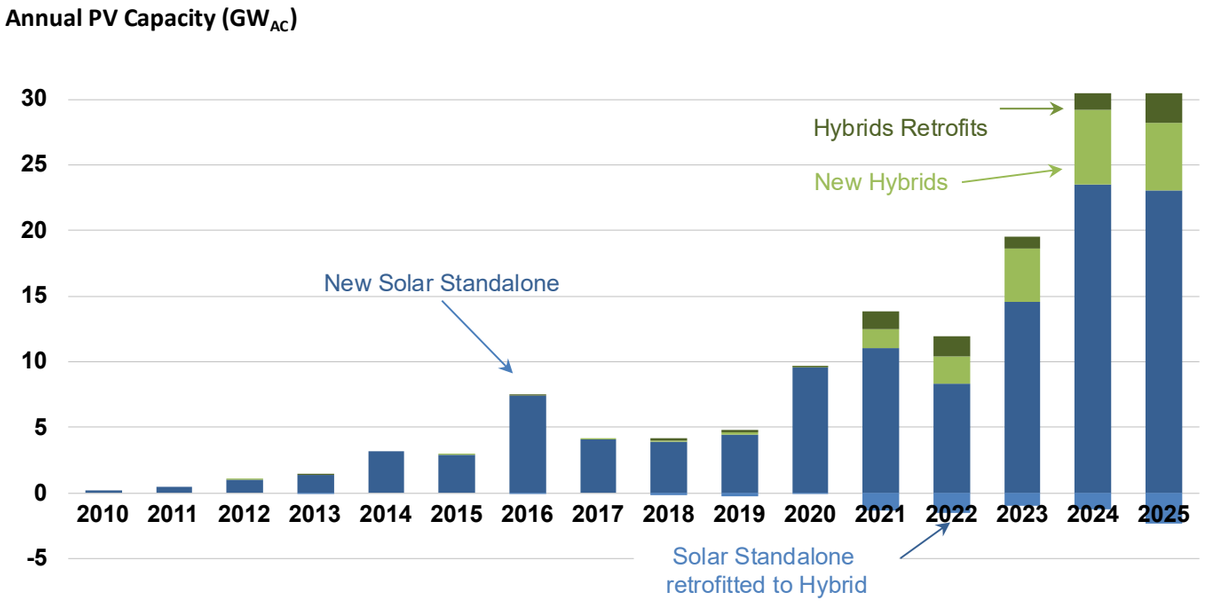
PV+Battery Hybrid Plants

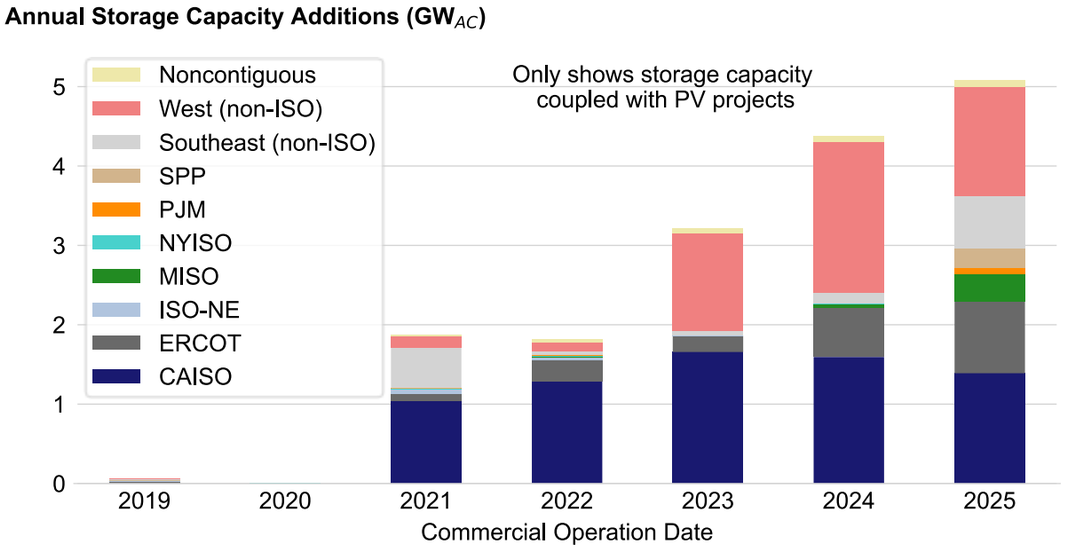
For more of Berkeley Lab's analysis of hybrid power plants, see:

- **Hybrid Tracker** (Deployment trends and interconnection queues, costs and PPAs for multiple fuel types): https://emp.lbl.gov/hybrid
- **Hybrid Operations** (valuation of modeled and empirical PV+battery operations, comparison with generation costs) https://emp.lbl.gov/utility-scale-storage

PV+battery hybrid plants added 7 $GW_{AC\text{-}PV}$ and 5 $GW_{Storage}$ capacity in 2025 (both greenfield and retrofit)

Sample: 248 projects totaling 26.6 GW_{AC} of PV, 16.6 GW_{AC} of battery capacity, and 54.8 GWh of battery energy



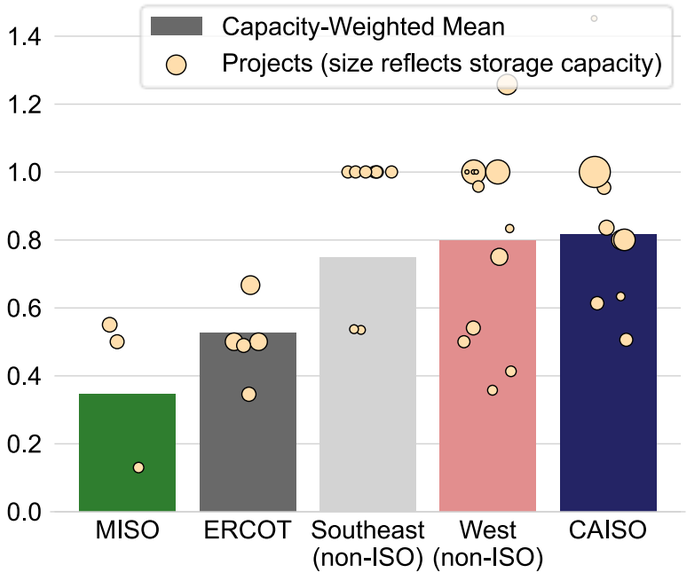


The large-scale PV+battery hybrid market started in earnest in 2021. 2025 added 32 newly built hybrids (5.1 $GW_{AC\text{-}PV}$) and 12 storage retrofits to existing stand-alone solar projects with record capacity of 2.3 $GW_{AC\text{-}PV}$.

Most of the new hybrid storage was built in the solar-rich non-ISO West (13 plants, 1.4 $GW_{storage}$) followed by CAISO (10 plants, 1.4 $GW_{storage}$). ERCOT (6 plants, 0.9 $GW_{storage}$), the non-ISO Southeast (10 plants, 0.7 $GW_{storage}$) and MISO (4 plants, 0.3 $GW_{storage}$) continued to expand.

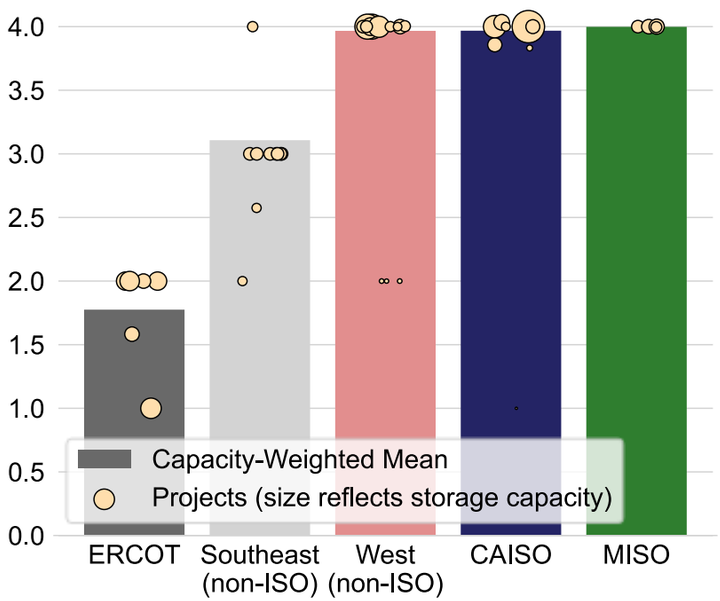
The average storage:PV capacity ratio was 0.67 with 3.4 hours of duration in 2025

Storage Capacity Ratio
(Storage Capacity [MW] / PV Capacity [MW_{AC}])
of Projects Hybridizing in 2025



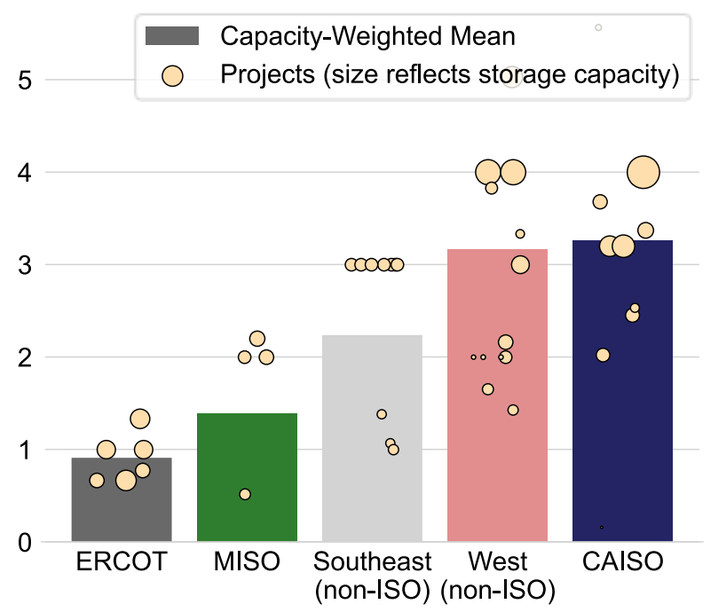
Storage capacity ratio (SCR) describes the battery capacity relative to solar capacity (MW_{AC}). In 2025 it was greatest in CAISO and non-ISO West and lowest in MISO.

Storage Duration [Hours]
(Storage Energy [MWh] / Storage Capacity [MW])
of Projects Hybridizing in 2025



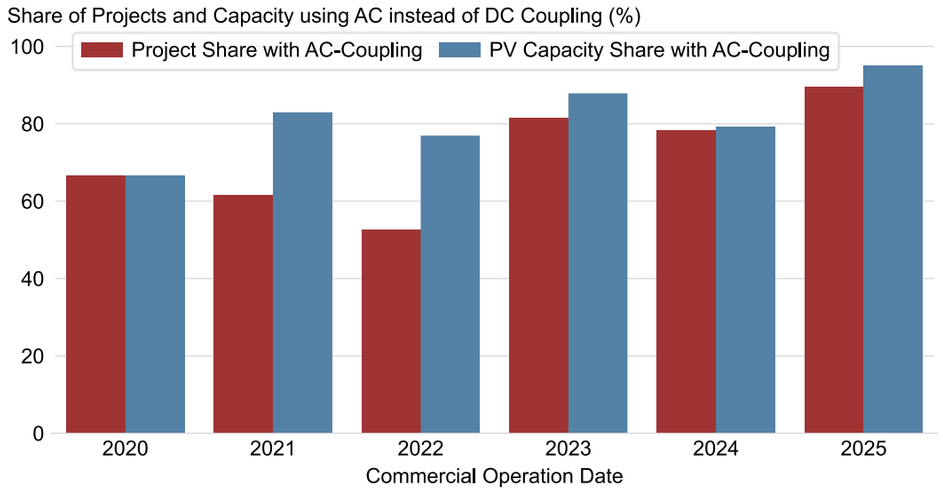
Storage duration at full rated battery capacity was shortest in ERCOT and often at 4h in the rest of the country.

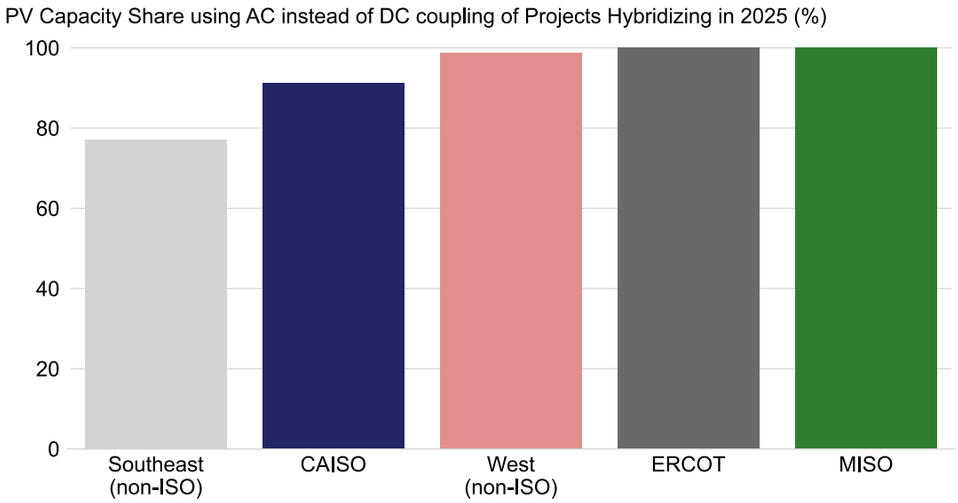
PV-Equivalent Duration [Hours]
(Storage Energy [MWh] / PV Capacity [MW_{AC}])
of Projects Hybridizing in 2025



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.

95% of new PV+battery projects used AC-coupling in 2025





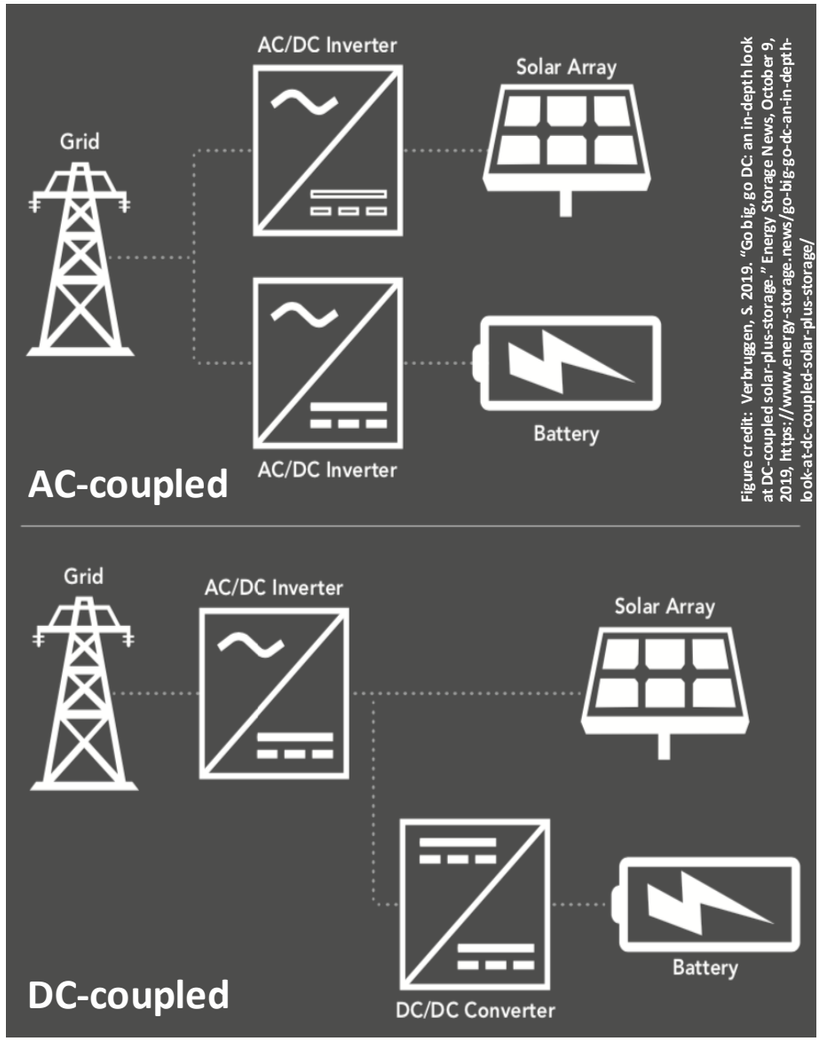
PV and batteries can be **AC-coupled**

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

or **DC-coupled**

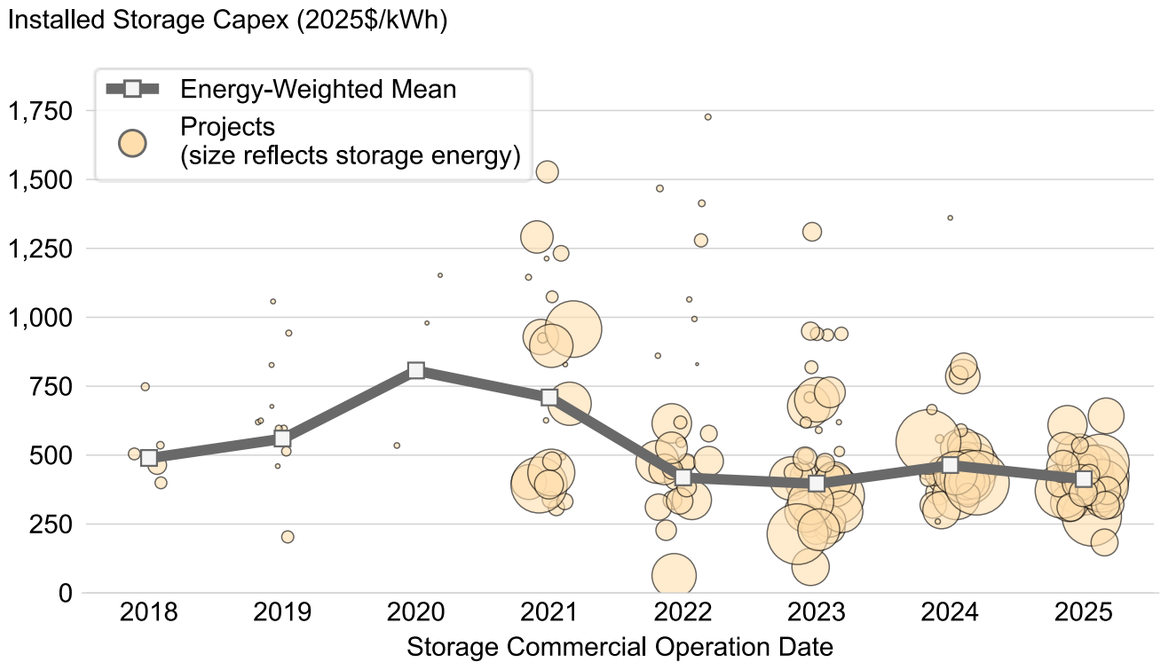
- only using one inverter setup but a separate DC/DC converter
- often having higher ILR as battery can capture clipped energy

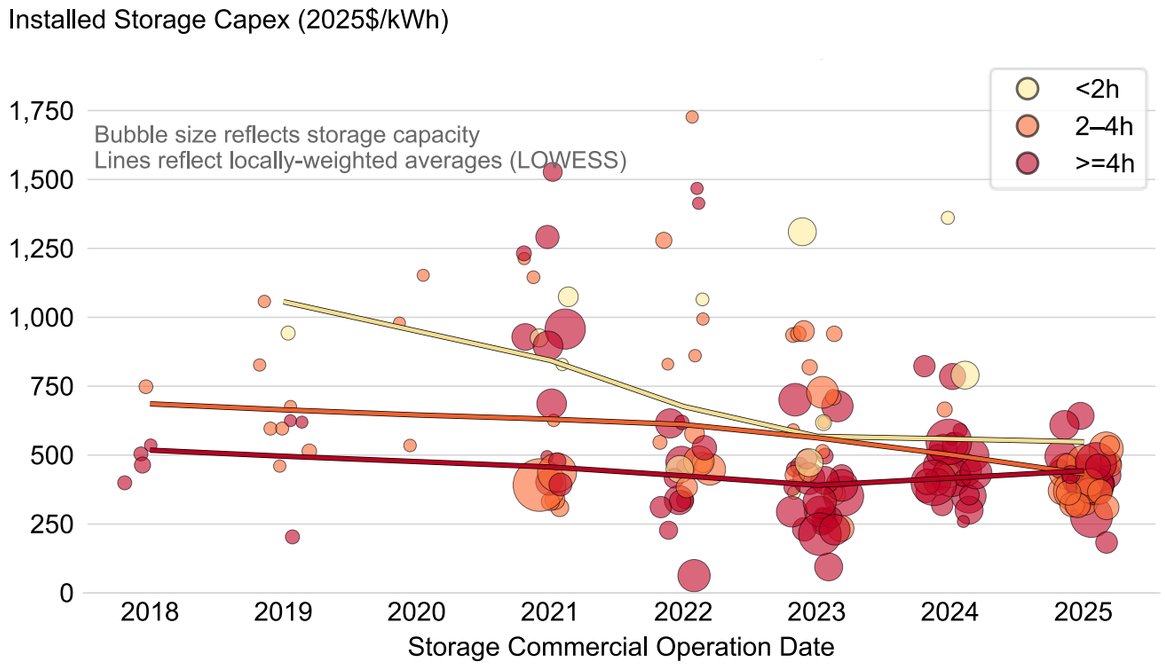
Despite theoretical cost savings of DC-coupling, most of the recent projects use AC-coupling (except in Florida).



Costs of co-located batteries decreased to $412/kWh in 2025

Sample: 178 projects totaling 12.7 GW and 44.1 GWh of batteries





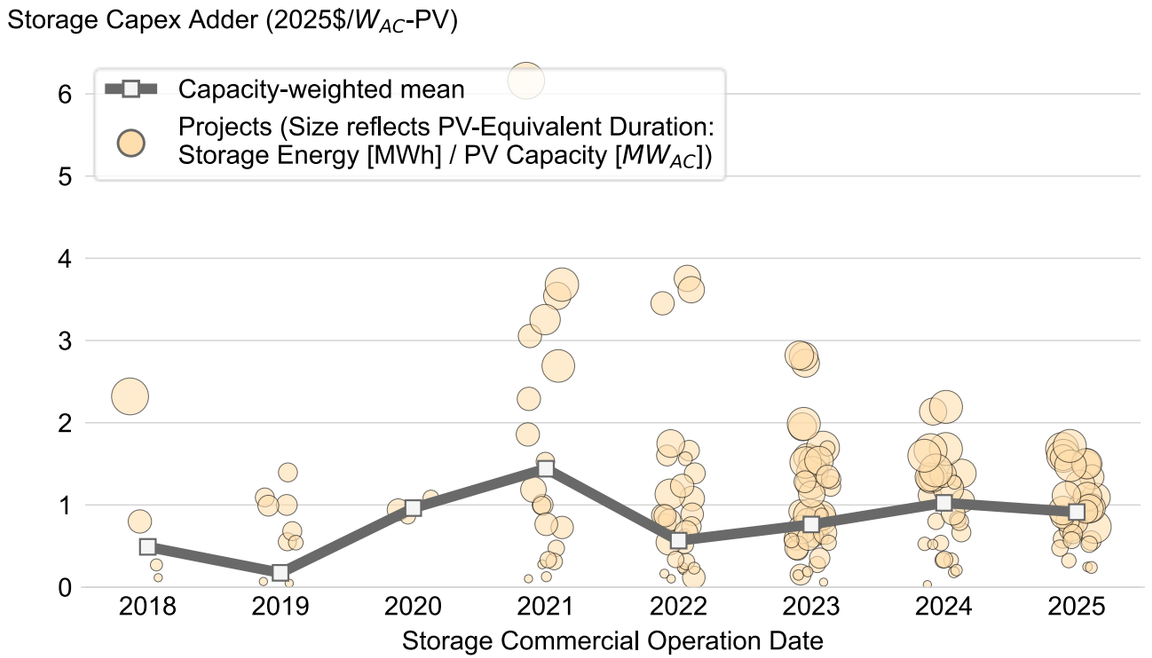
Energy-weighted average costs decreased from $463/kWh in 2024 to $412/kWh in 2025. Costs are lowest in the non-ISO Southeast ($356/kWh) and greatest in MISO ($499/kWh) .

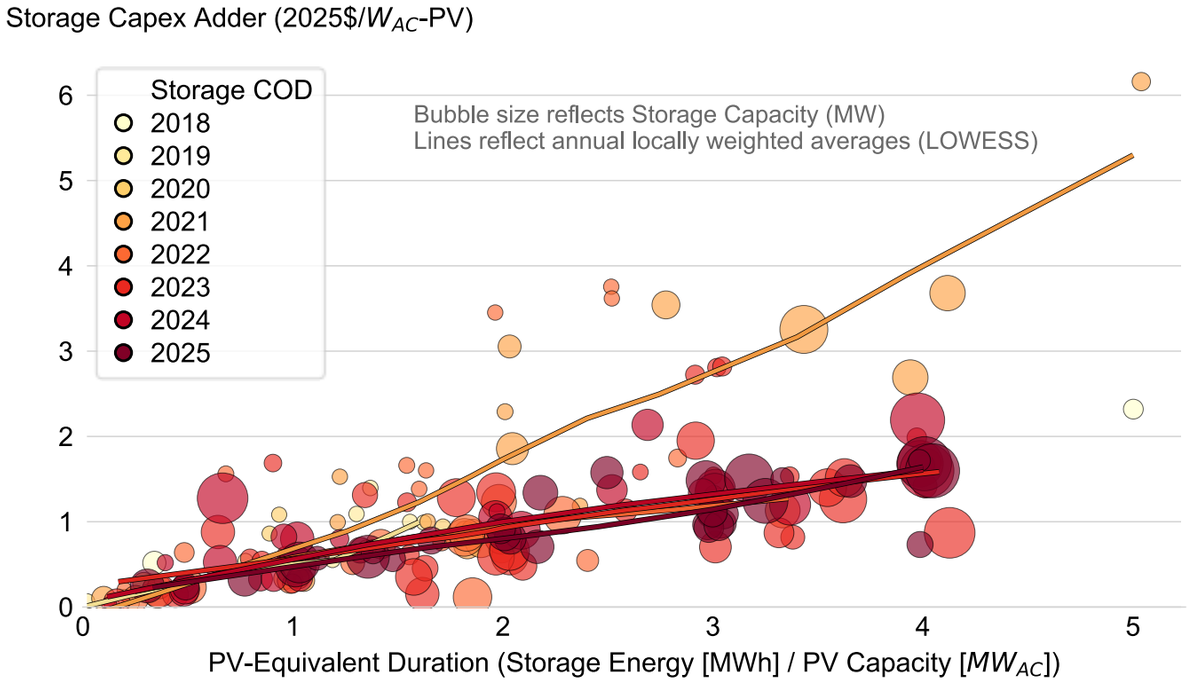
Longer duration storage is cheaper on a per kWh basis than shorter duration storage, indicating economies of scale.

Note: Estimates for projects with 2024 and 2025 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: 167 projects totaling 11.5 GW and 39.3 GWh of batteries





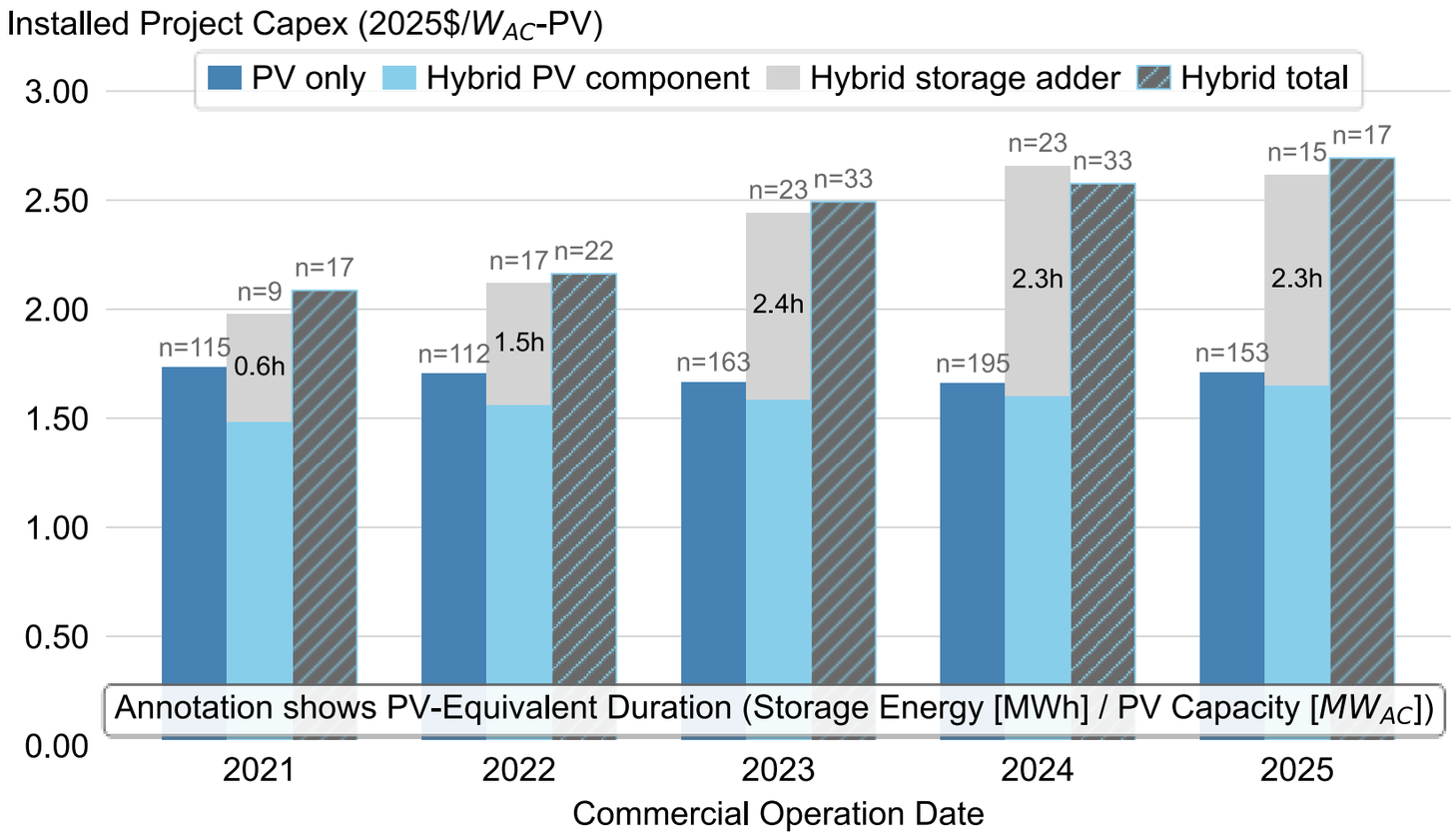
Storage sizes increased by nearly 60% since 2022, explaining, in part, the growth of the storage cost adder since then to \$0.9/$W_{AC\text{-}PV}$ in 2025.

Accounting for storage size variations, storage CapEx adders in 2025 (**dark red line**) were slightly smaller than over the past three years.

Note: Estimates for projects with 2024 and 2025 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 increased to $2.69/$W_{AC\text{-}PV}$ in 2025

Sample: 122 greenfield plants totaling 15.6 GW_{AC} of PV and 8.7 GW / 32.5 GWh of batteries



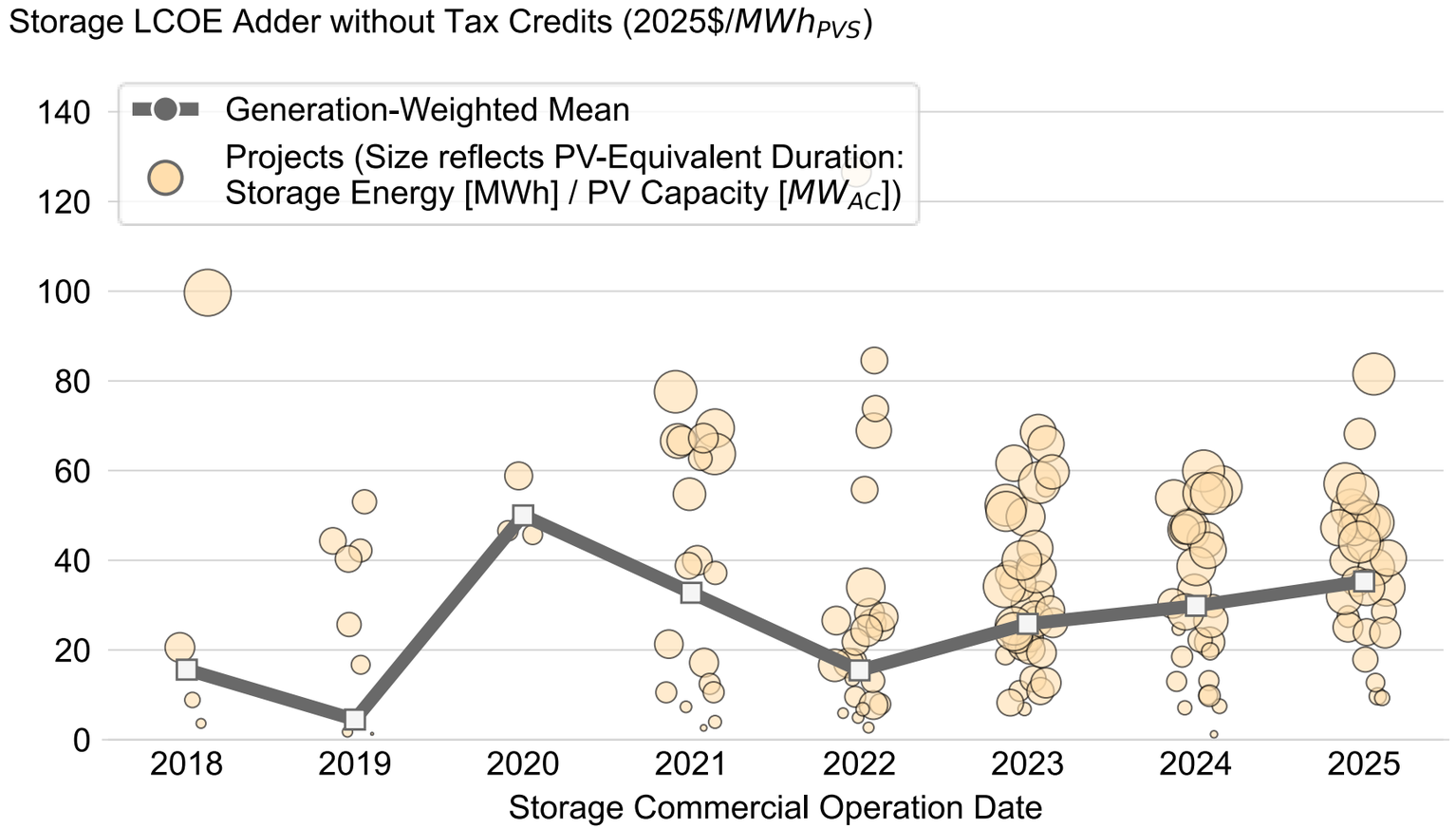
Focusing only on greenfield hybrid developments (i.e., excluding retrofits), the average cost of PV components of a co-located project are slightly lower than for a PV-standalone project (driven by project size, geographics or shared infrastructure with storage components like inverters for DC-coupled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

For some hybrid projects, we lack component-level costs and can only report total system costs (hatched) – these were thus excluded from previous slides. These sample differences explain slightly diverging trends (cost decreases in center bars vs. increase in right-most bars for the years 2024 vs. 2025).

Note: Estimates for projects with 2024 and 2025 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

Sample: 155 projects totaling 10.5 GW and 37.8 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.

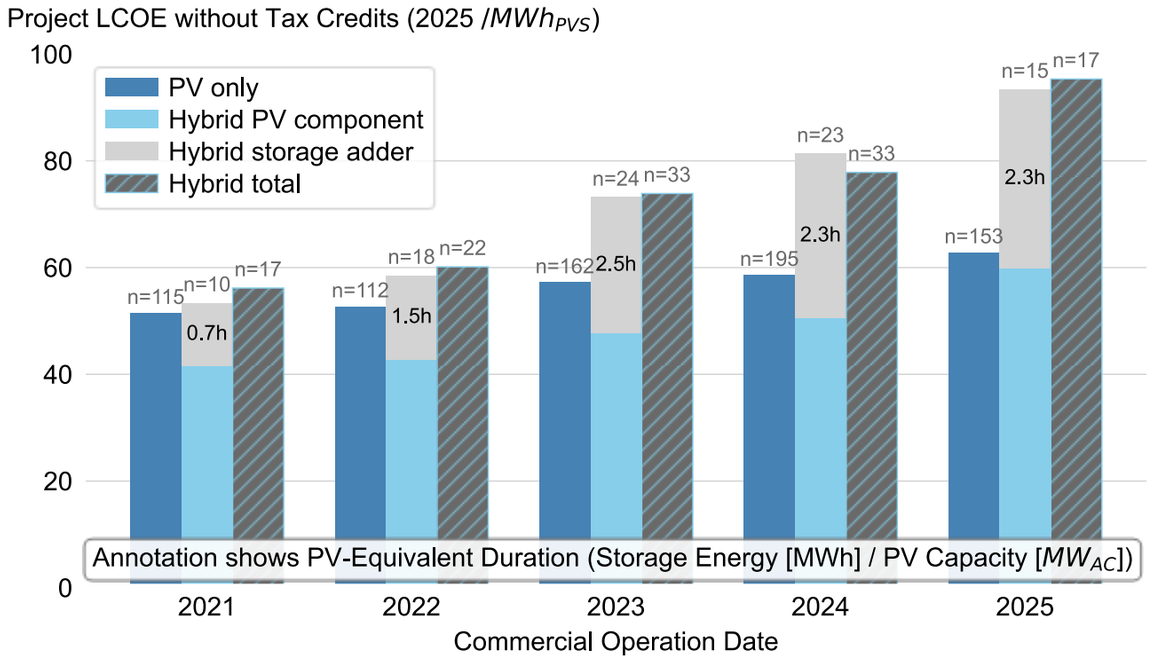
Estimated life-time generation costs are denominated in energy delivered to the grid and account for storage efficiency losses (MWh_{PVS}).

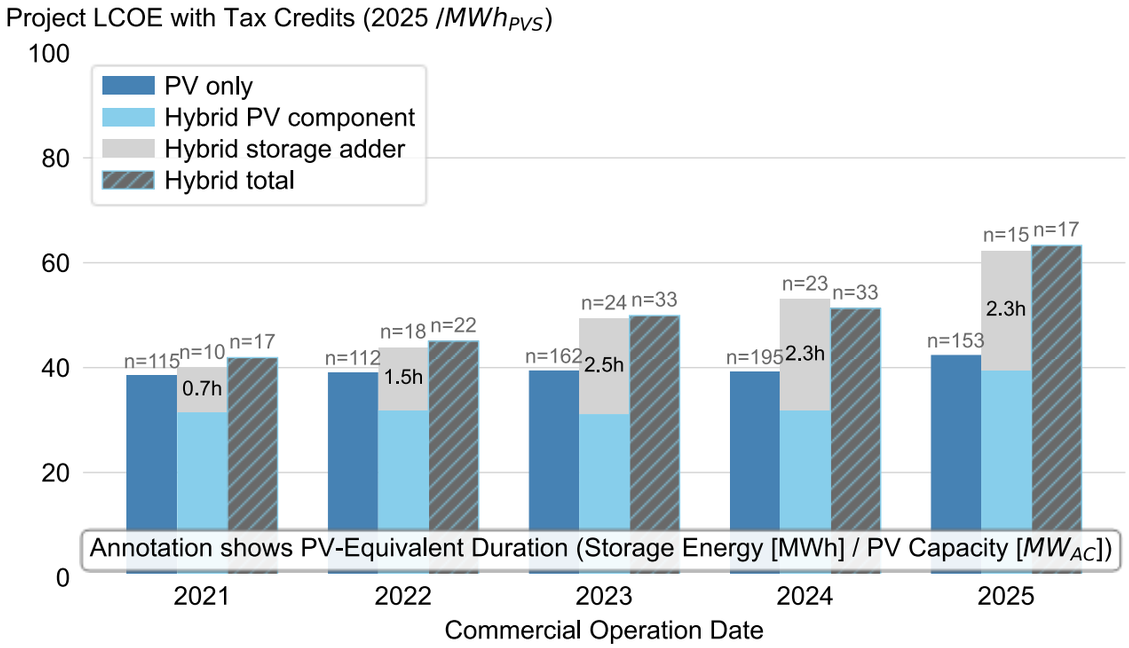
In 2025, the adder was \$35/MWh_{PVS} before tax credits (shown in graph) and \$24/MWh_{PVS} after tax credits.

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

PV+battery projects had an LCOE of $95/MWh without and $63/MWh with tax credits

Sample: 122 greenfield plants totaling 15.6 GW_{AC} of PV and 8.7 GW / 32.5 GWh of batteries (excluding retrofits)



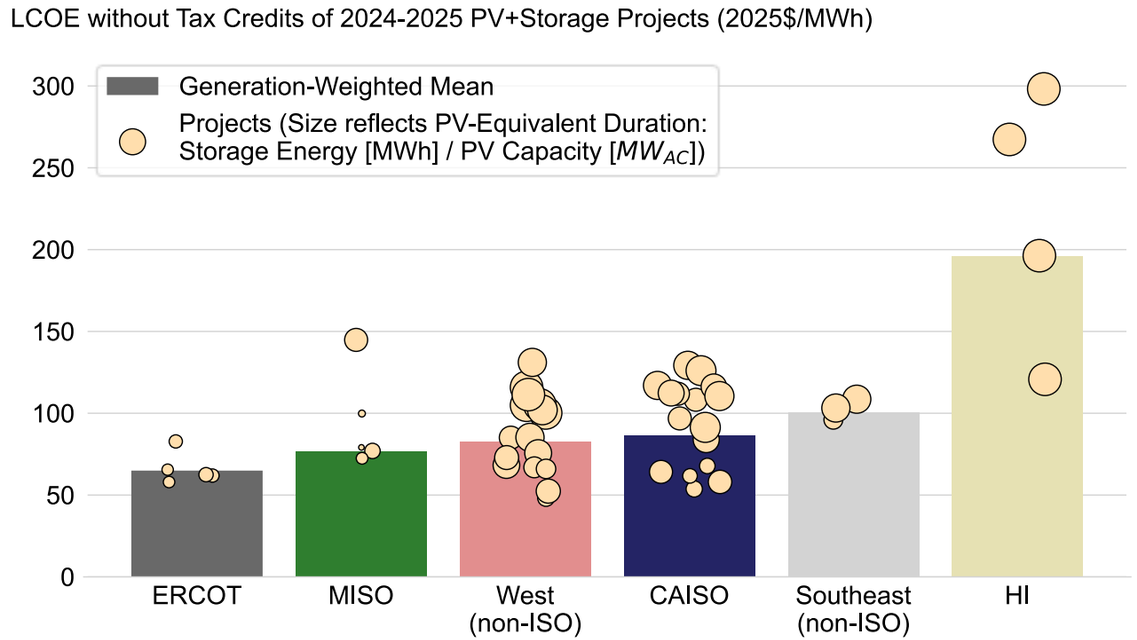


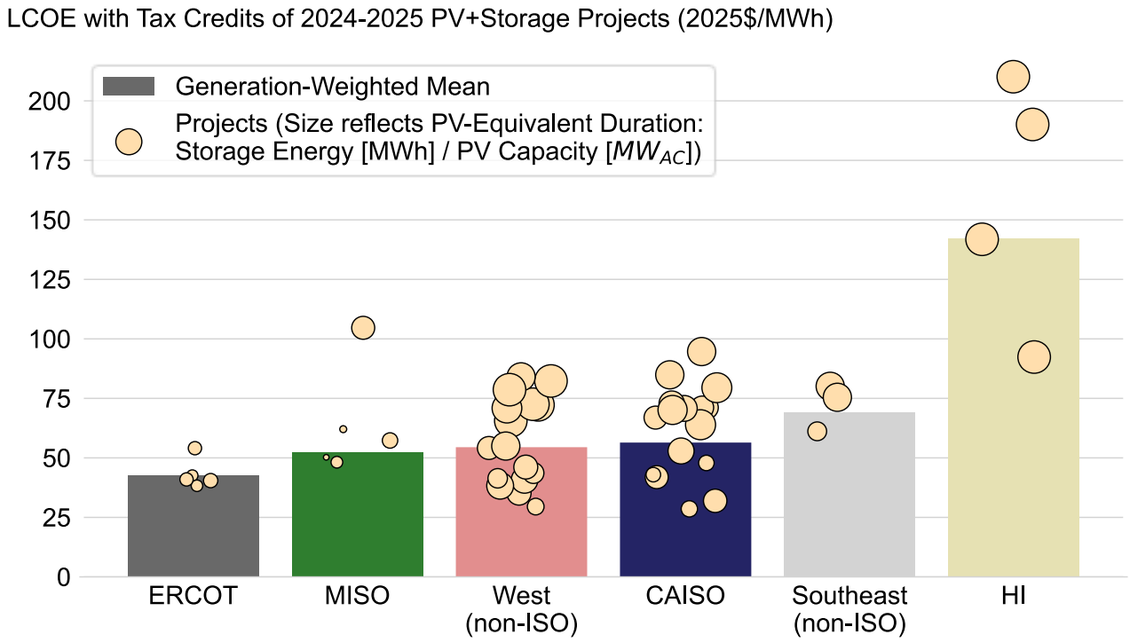
This sample excludes projects with storage retrofits (unlike previous slide). The PV component of LCOE in a co-located project is lower than PV only as hybrids are usually in sunnier regions.

The battery LCOE adder has grown to $33/MWh before tax credits (left graph) and $23/MWh after tax credits (right graph) in 2025.

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

Sample: 49 greenfield plants totaling 8.6 GW_{AC} of PV and 5.1 GW / 19.2 GWh of batteries (excluding retrofits)





Average PV+battery LCOE in ERCOT was $65/MWh compared to $196/MWh in Hawaii in 2024/2025 (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 of $43/MWh to $142/MWh.

Wholesale market value analysis for PV+batteries: methodology

Estimating the wholesale market value of PV+battery projects requires assumptions about how storage is operated. Because empirical operating data are rarely available, we present their value potential – an upper bound associated with idealized operations in hindsight. Actual wholesale market revenue is likely lower than our modeled estimates because operators lack perfect information, often under-participate in still-lucrative ancillary services (AS) markets, and use less flexible dispatch strategies than we assume. Our value estimates do not include additional potential revenue streams from DA-RT arbitrage, renewable energy certificates, tolling agreements, or state incentive programs that may support PV+battery projects.

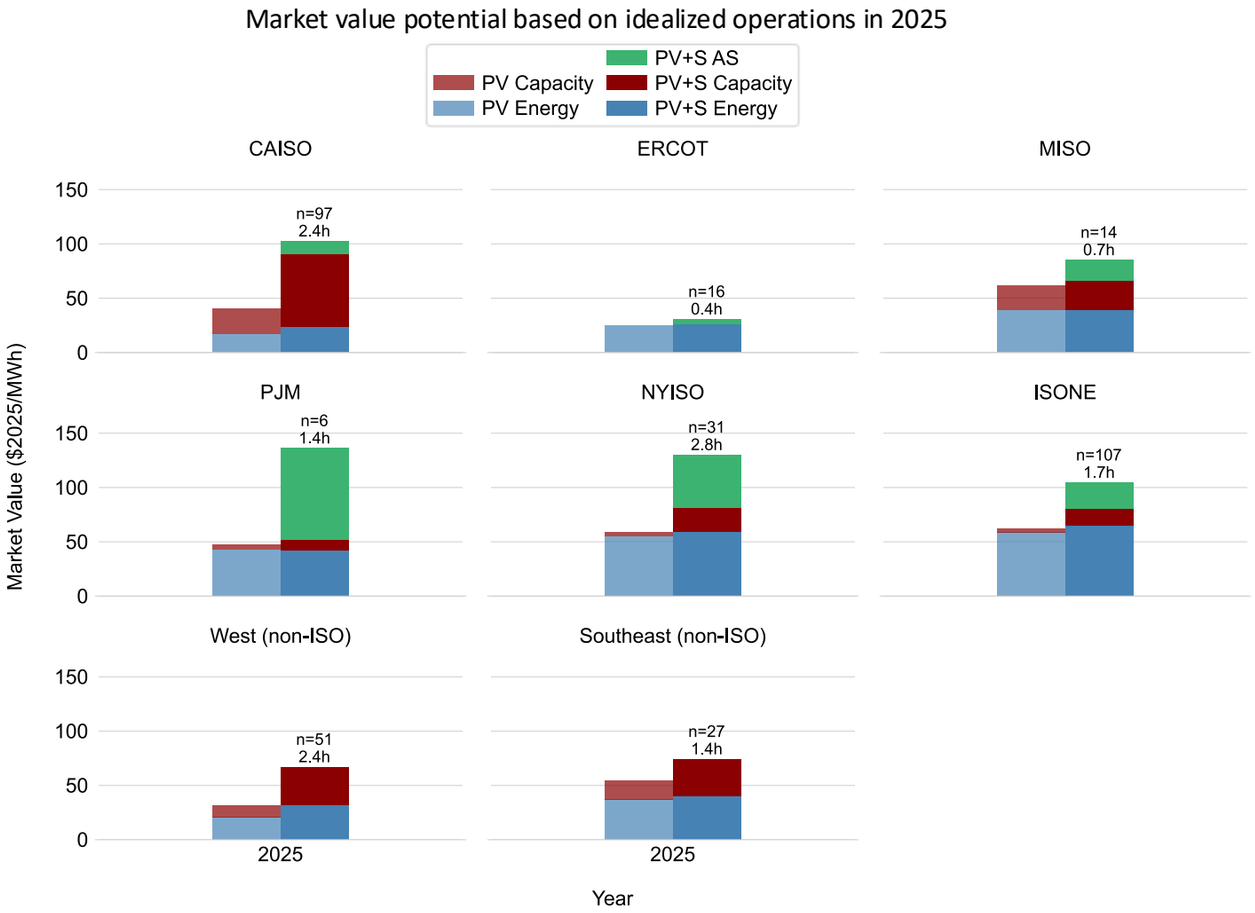
Model assumptions:

- We model battery dispatch to **maximize energy, capacity, and ancillary services (AS) market value** as a price-taker, while accounting for battery degradation through a linear throughput-cost proxy of $10/MWh. The model operates at hourly resolution and assumes participation in day-ahead energy markets where available. Where possible, we use project-specific technical characteristics, including the modeled PV input profile, DC- or AC-coupling configuration, battery power and energy capacity, and point-of-interconnection limit. We assume instantaneous ramping and constant battery and inverter efficiencies of 90%. Modeled PV curtailment during negative-price periods may exceed real-world practices because we do not account for PTC incentives, PPA provisions, or RPS obligations. Batteries may charge from the grid if they came online after 2022 or after five years of operation.
- Market value is expressed in $/MWh using pre-curtailment PV production as the denominator. For each project, we compare the hypothetical value of standalone PV—which is assumed to be ineligible for AS revenue—with the idealized value of PV+battery systems, including AS revenue in ISO regions. AS value is dominated by award payments. Deployment is compensated at real-time energy prices, assuming deployment-to-award ratios of 30% for regulation and 2% for non-regulation products.

Note: For more method details see Seel et al 2026 “Identifying Barriers to Solar and Storage Hybrids” https://emp.lbl.gov/utility-scale-storage

With idealized operations, battery additions could double the national average market value of co-located solar projects

Sample: 349 projects totaling 20.1 GW_{PV} , 11.5 GW_{Bat} / 38.7GWh

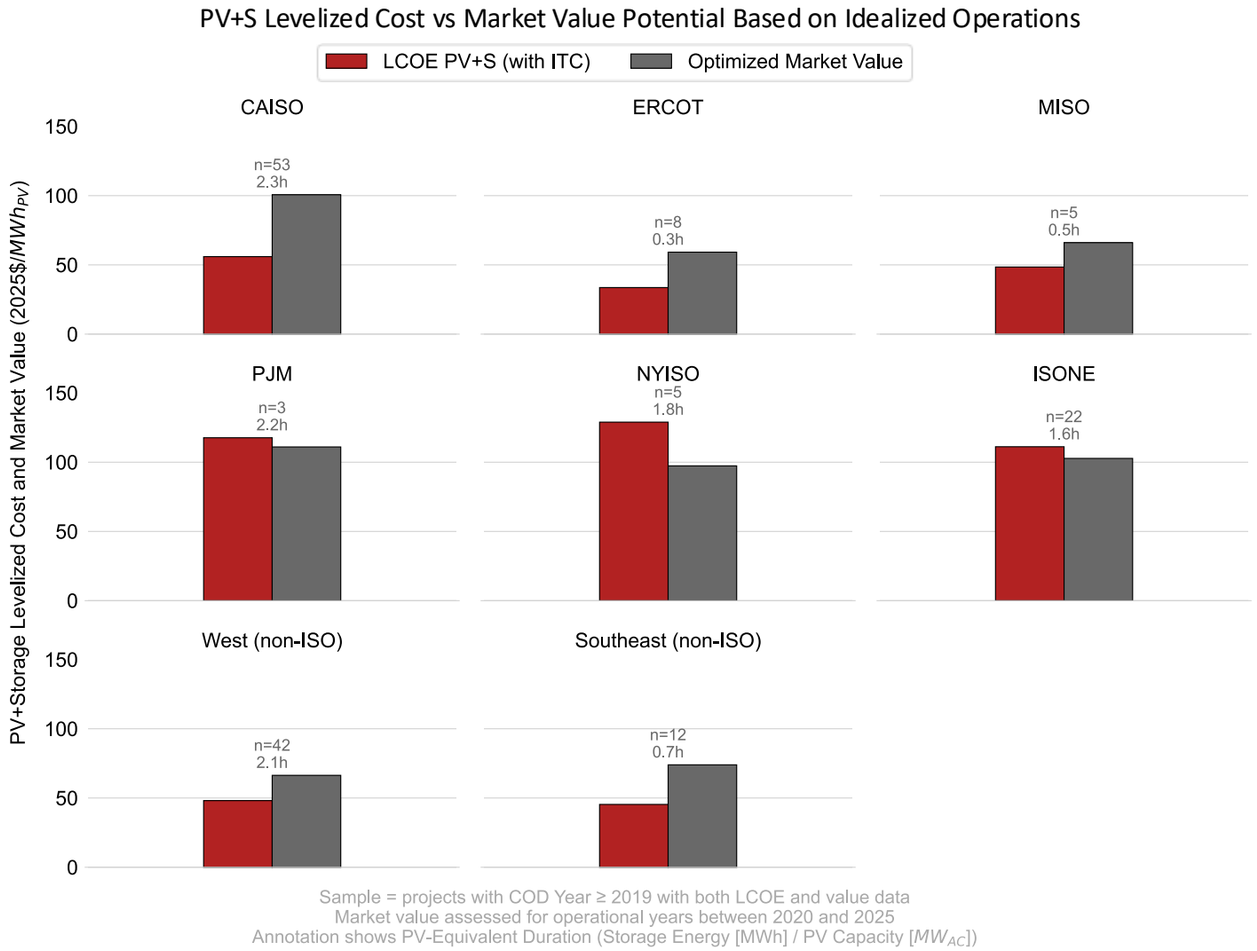


In 2025, idealized operation of installed co-located batteries could increase the national generation-weighted average wholesale market value from $37/MWh for standalone solar to $79/MWh for PV+battery projects. This increase was driven primarily by capacity value ($43/MWh, or 2.8 times that of standalone solar), followed by energy value ($28/MWh, or 1.3 times standalone solar value) and ancillary services value ($7/MWh).

The incremental value varies with battery sizing and market conditions. Gains are greatest where the marginal value of standalone solar is low, such as in the Southwest, where high solar penetration depresses solar energy and capacity value. Batteries can also unlock additional ancillary services (AS) revenue, particularly in markets with relatively limited existing battery participation, including PJM, NYISO, and ISO-NE.

On a national average basis, idealized PV+storage market value between 2020 and 2025 exceeded LCOE

Sample: 150 projects, 16.6 GW_{PV} , 9.1 GW_{Bat} / 32.4GWh (including retrofits)



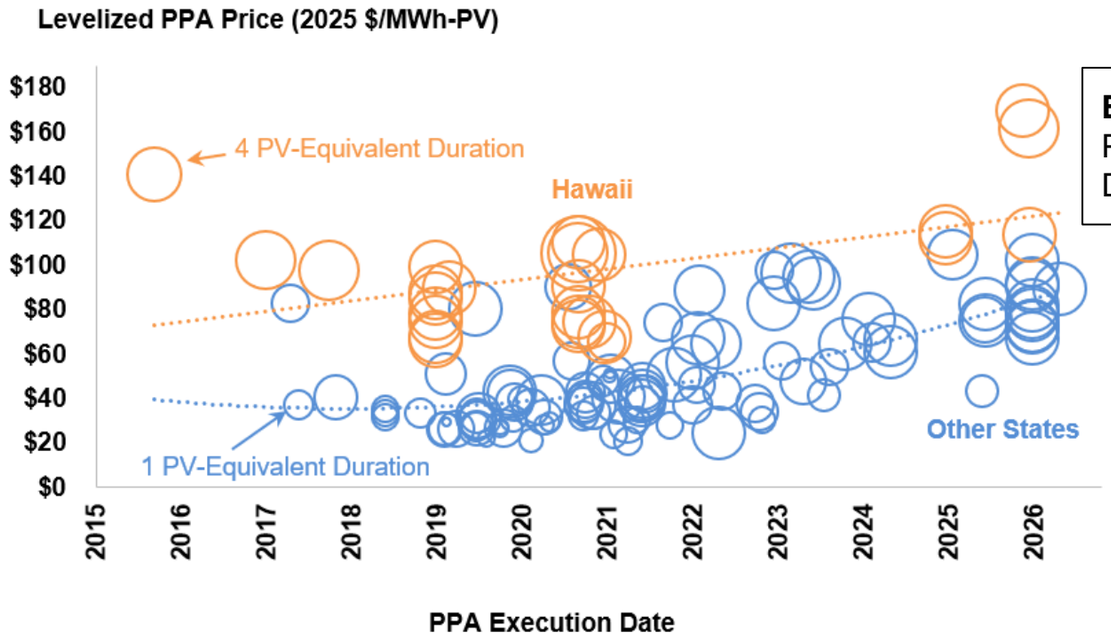
Sample = projects with COD Year ≥ 2019 with both LCOE and value data
Market value assessed for operational years between 2020 and 2025
Annotation shows PV-Equivalent Duration (Storage Energy [MWh] / PV Capacity [MW_{AC}])

From 2020 to 2025, the national average idealized wholesale market value exceeded LCOE both with investment tax credits (net value of $32/MWh) and without them (net value of $12/MWh).

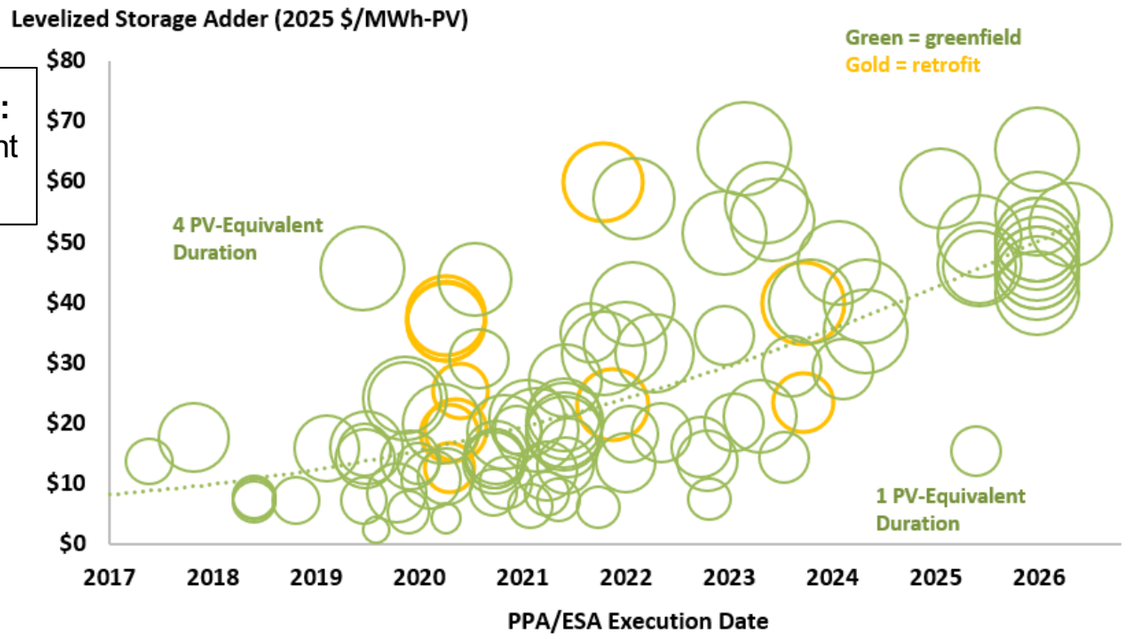
The net value proposition varied by region. It remained strong in the established CAISO market. Early ERCOT projects benefited from several years of high prices that have now decreased. In the non-ISO West, projects with storage retrofits often had costs above their potential market value, but a growing fleet of greenfield projects typically had positive net value.

In regions with lower solar resources, such as ISO-NE and NYISO, PV+storage generation costs exceeded optimized wholesale market value as modeled.

PPA prices for PV+battery projects have increased significantly from 2019/2020 lows



Bubble area: PV-Equivalent Duration



Left graph is sub-sample of 130 plants (retrofits not included)

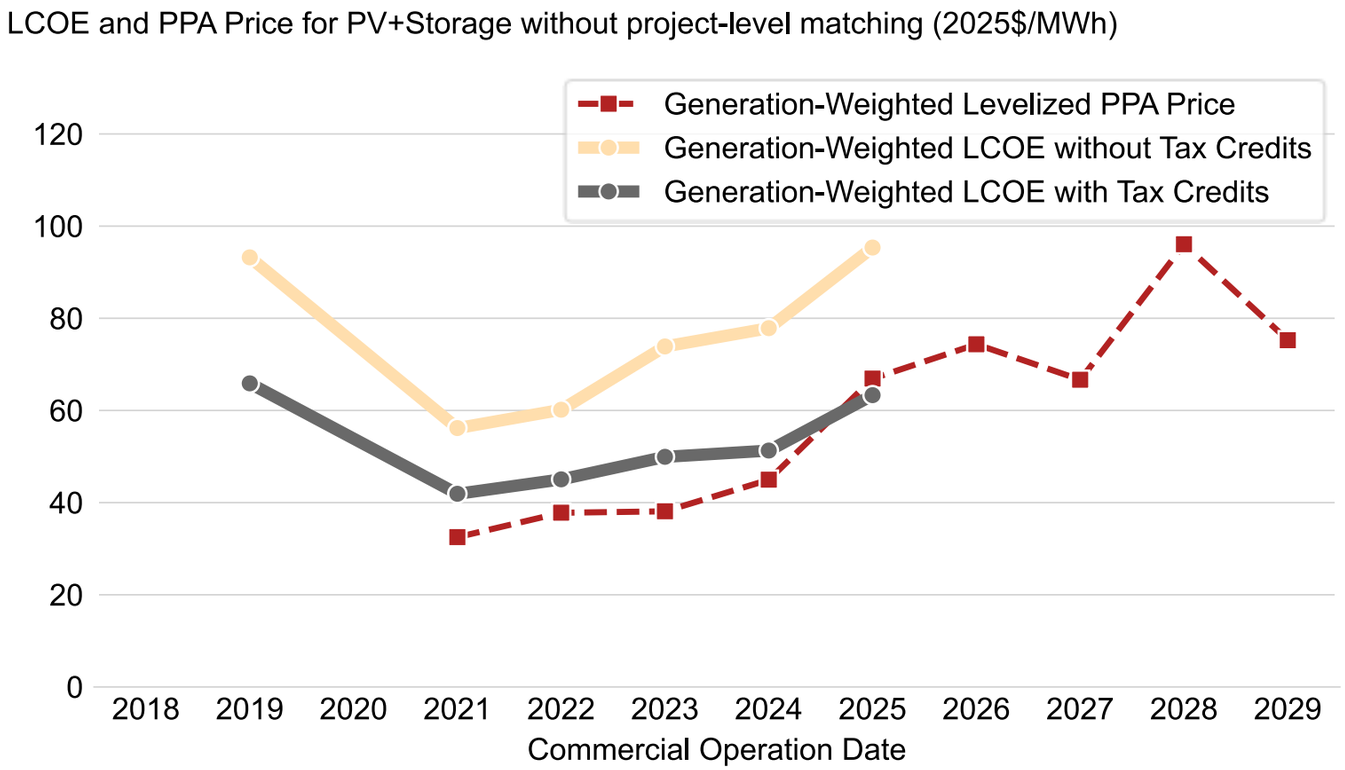
- Hawaii (orange): 27 plants, 1 GW_{AC} PV, 1 GW_{AC} battery
- Other States (blue): 103 plants, 18 GW_{AC} PV, 12.6 GW_{AC} battery
- Storage duration ranges from 2-8 hours

Right graph is sub-sample of 99 plants (12.8 GW_{AC}) that provide enough information to calculate a levelized storage adder

- CA: 42 plants; NV 25 plants; NM 17 plants; AZ 10 plants; MS 2 plants; OR, OK, TX all 1 plant

Levelized PPA prices of PV+battery projects tracked LCOE after accounting for tax credits

Sample: 129 projects totaling 15.7 GW_{AC}



This graph contrasts PV+battery LCOE with PPA prices. We show LCOE both with and without tax credits – modeling ITC for the battery and either PTC or ITC for solar, whatever results in lowest cost (including the Energy Community but excluding the Domestic Content adder).

As discussed before, generation-weighted average LCOE increased since 2021 both before the application of tax credits ($95/MWh in 2025 vs. $56 in 2021) and after ($63/MWh vs. $42/MWh). Levelized PPA prices charted by plant COD have roughly tracked the LCOE with tax credits. This suggests a pass-through of these tax credits and a competitive PPA market.

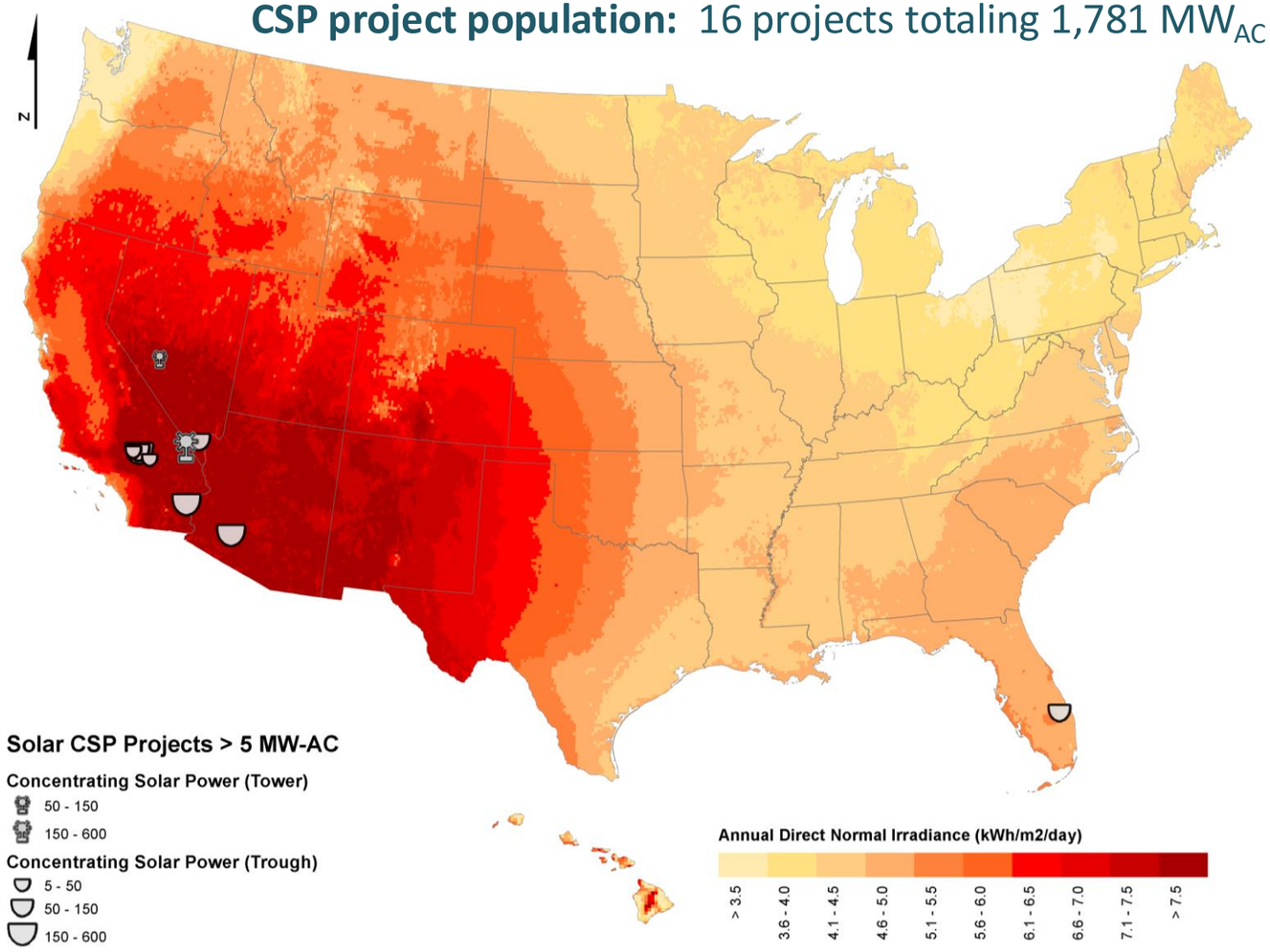
The depicted PPA sample is smaller than the shown LCOE sample. When performing a project-level match the gap between PPA and LCOE is roughly similar, though at times reversed (see accompanying workbook).

Note: Only preliminary data is available for new solar projects coming online in 2025. Findings may shift as more final EIA Capex and project-specific performance data become available.

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}).

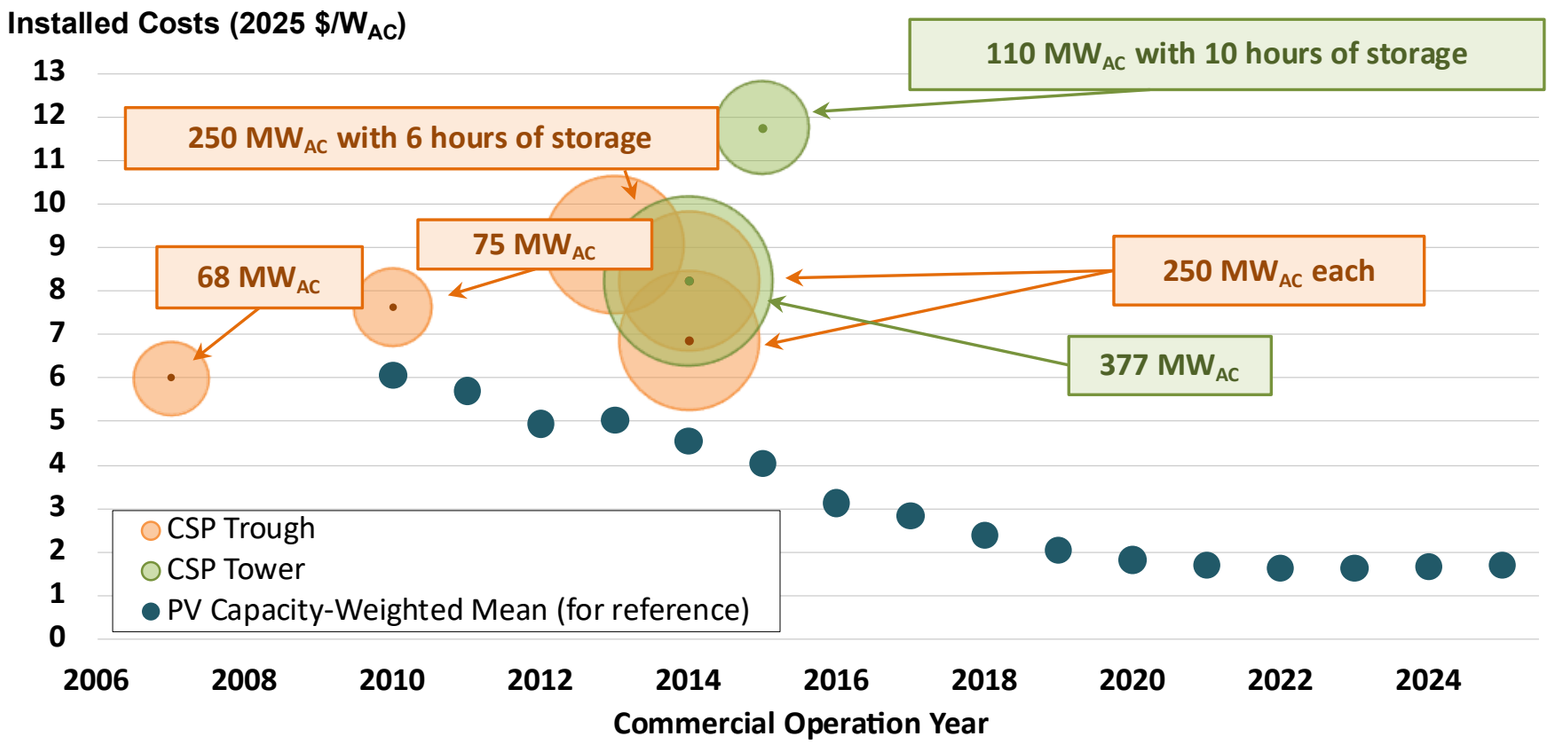
Prior to the large 2013-15 build-out, all utility-scale CSP projects in the U.S. used parabolic trough collectors.

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}

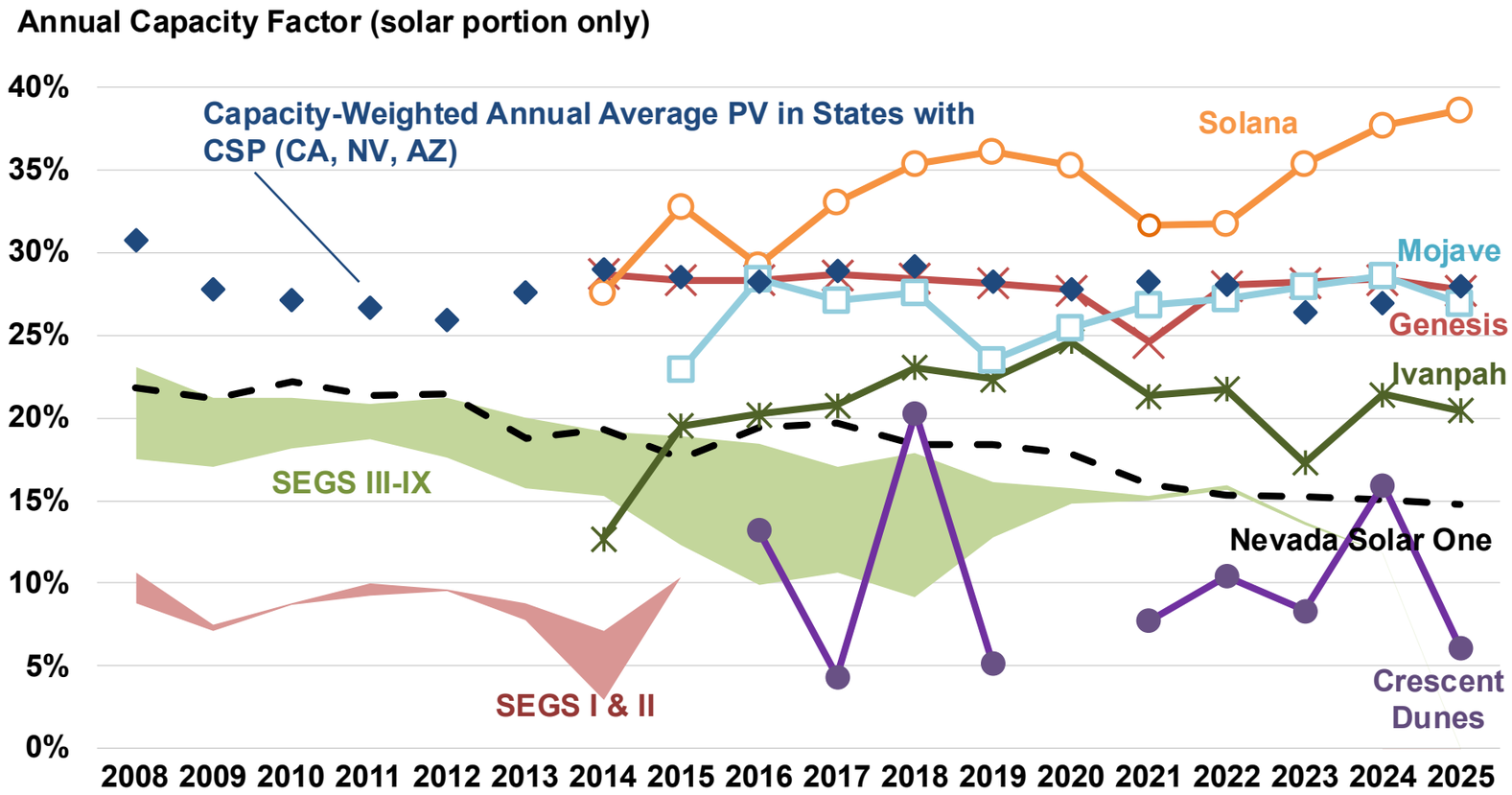


Small sample of 7 projects using different technologies makes it hard to identify trends. Newer projects (5 built in 2013-15) did not show cost declines, though some included storage or used new technology (power tower).

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.

Most CSP projects underperform expectations, yet California regulators rejected decommissioning of Ivanpah

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



Power Towers: Ivanpah's (370 MW) capacity factor remained steady in 2025 at 20.4%. California regulators rejected PG&E's proposal to terminate its contract with Ivanpah's owners, citing reliability issues, meaning the projects will stay online for the foreseeable future. Crescent Dunes (110 MW with 10 hours of storage) performed at just 6.1% capacity factor in 2025, down from 16.0% in 2024.

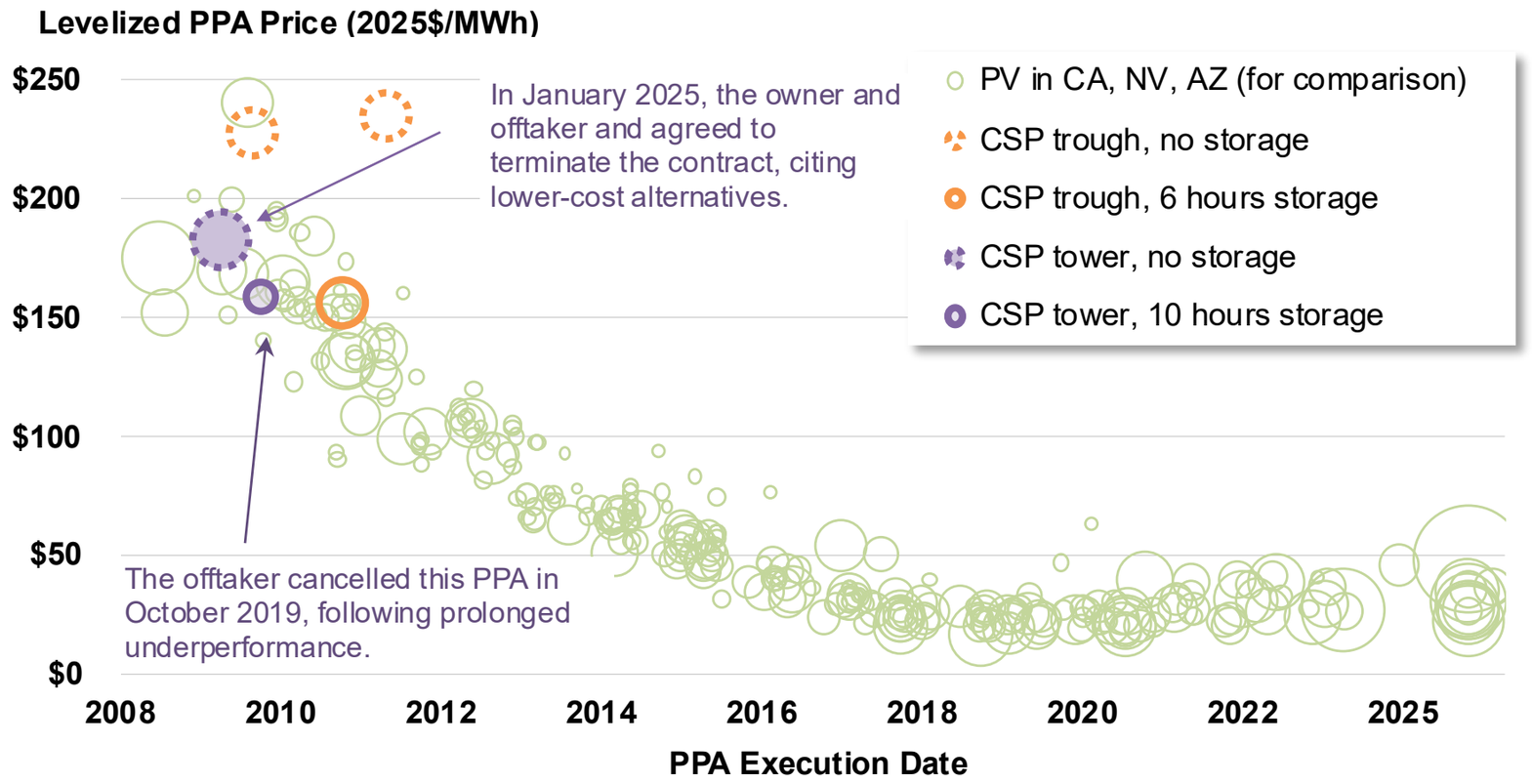
Trough with storage: Solana (250 MW trough project with 6 hours of storage) performed at 38.6% capacity factor in 2025, inching closer to expectations of >40%.

Troughs without storage: Mojave and Genesis (both 250 MW net) were at 27-28% capacity factor in 2025. 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.

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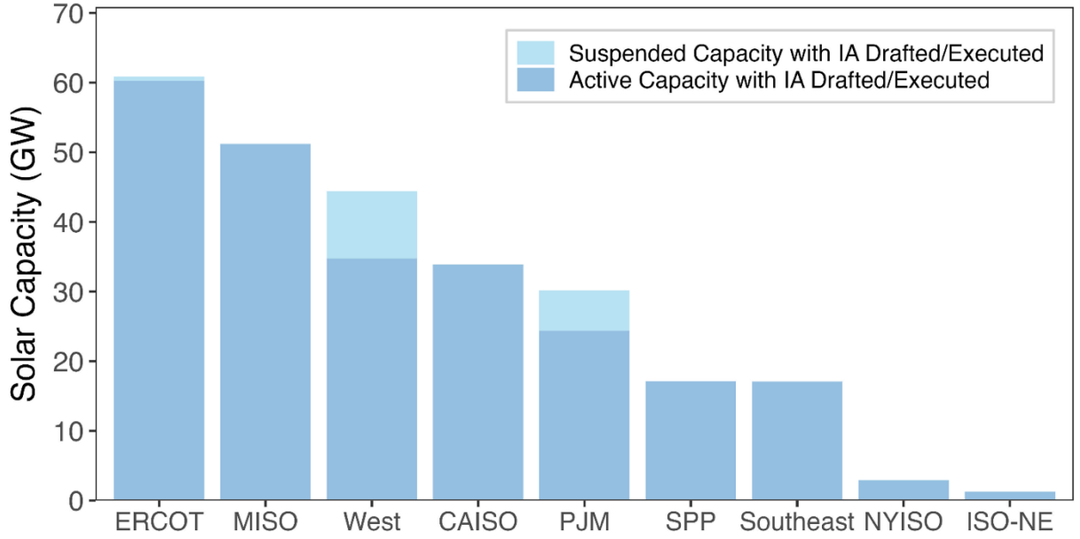
Solar Capacity in Interconnection Queues

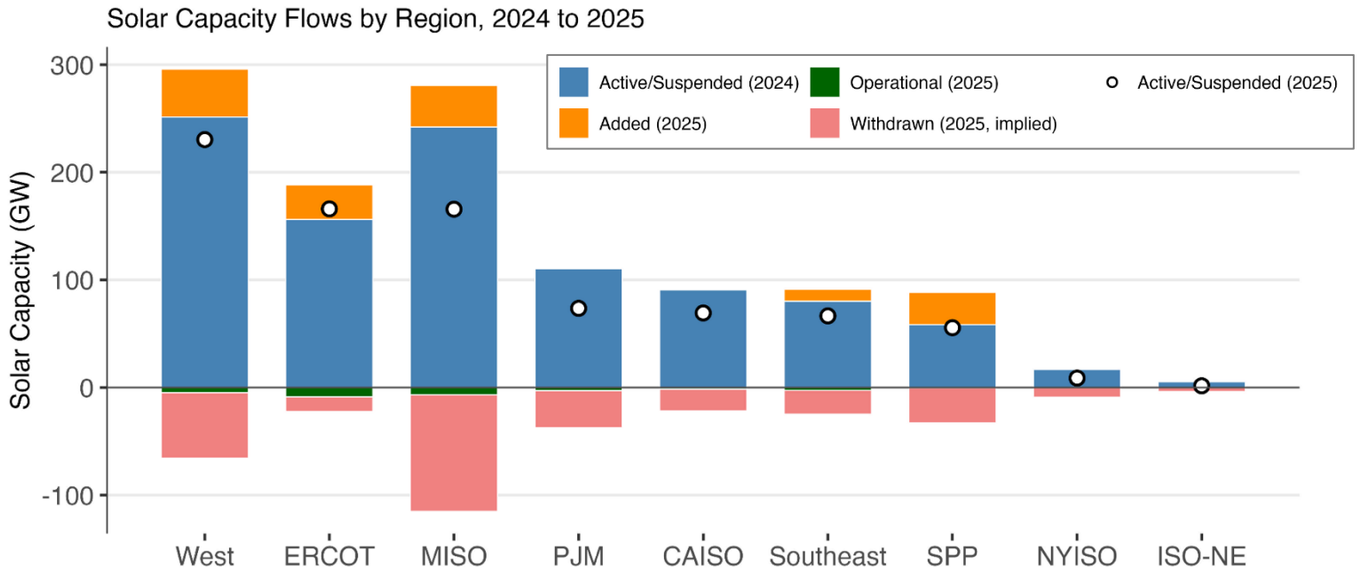
"Queued Up: 2026 Edition Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2025" is LBNL's resource for transmission interconnection data and data visualizations. It covers all types of power plants. The two figures below utilize the Queued Up data to highlight important trends in queued solar capacity.

243 GW of solar have a draft or executed interconnection agreement



While an interconnection agreement does not guarantee that a project will be built – many still withdraw after IA execution – these are the most likely queued projects to be completed.

Withdrawals have driven year-over-year declines in active solar capacity in most regions



***Notes**: Withdrawn capacity in 2025 is estimated as follows: [Active (2024) + Suspended (2024) + Annual Additions (2025) – Operational (2025) – Suspended (2025) – Active (2025)]. "Operational" reflects installed capacity only for the regions for which we collect interconnection data.*

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For more information

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

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