Title

Utility-Scale Solar, 2023 Edition: Empirical Trends in Deployment, Technology, Cost, Performance, PPA Pricing, and Value in the United States

Authors
Bolinger, Mark
Seel, Joachim
Kemp, Julie Mulvaney
et al.

Publication Date
2023-10-04

Utility-Scale Solar, 2023 Edition

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

Mark Bolinger[1], Joachim Seel[1],
Julie Mulvaney Kemp, Cody Warner, Anjali Katta, and Dana Robson

Lawrence Berkeley National Laboratory
[1]Corresponding authors

October 2023

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

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Utility-Scale Solar, 2023 Edition

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Acknowledgements

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

Photo credit:
Terra Gen's Edward's Sanborn Solar and Energy Storage Project
with 718MWdc solar and 424MW/1057MWh storage as of the end of 2022

Utility-Scale Solar, 2023 Edition

Purpose and Scope:

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

Data and Methods:

- See summary at end of PowerPoint deck

Funding:

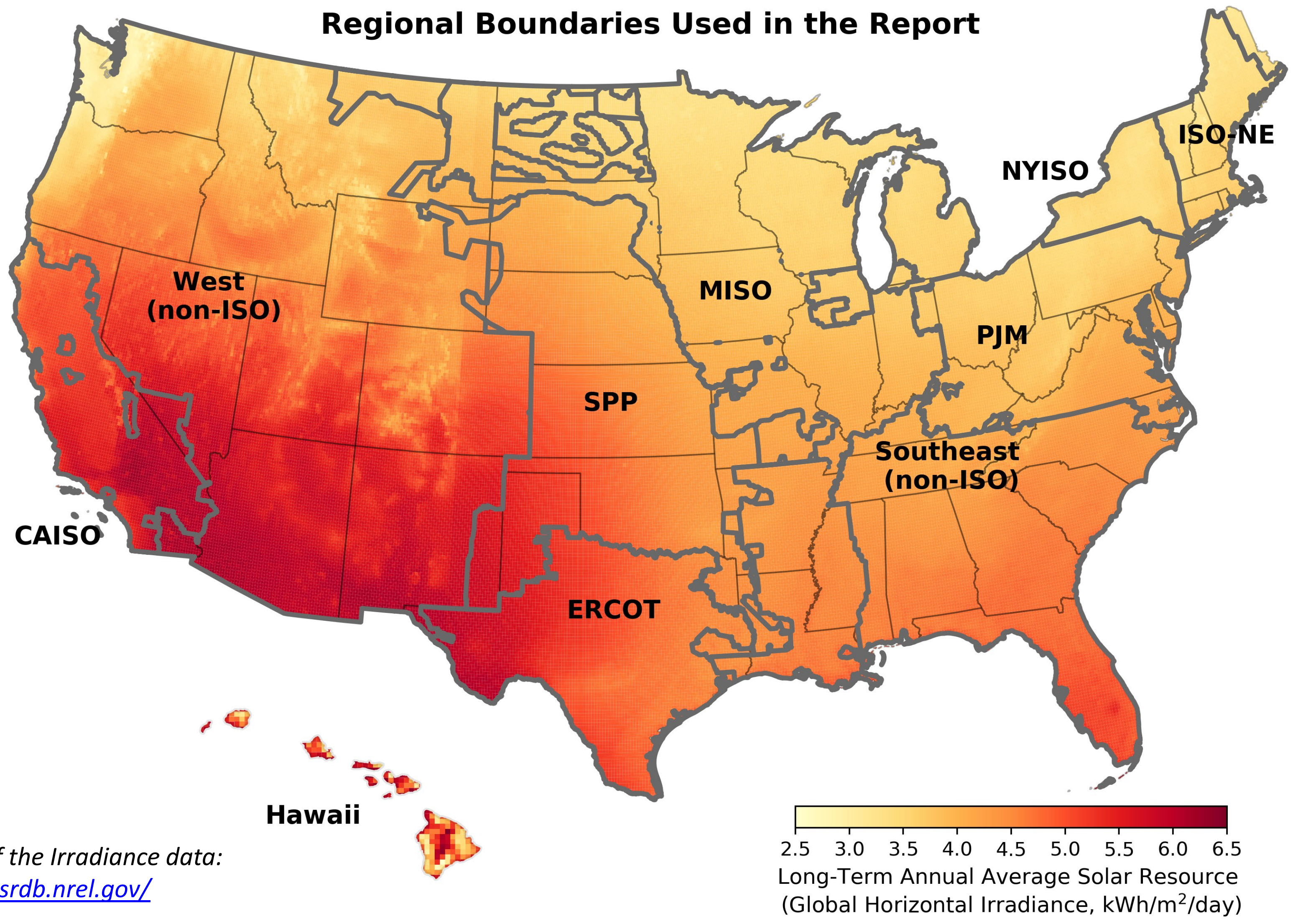
- U.S. Department of Energy’s Solar Energy Technologies Office

Products and Availability:

- This report deck is complemented by an Excel data file, a written executive summary, and interactive visualizations
- All products are available at: utilityscalesolar.lbl.gov

Report Contents

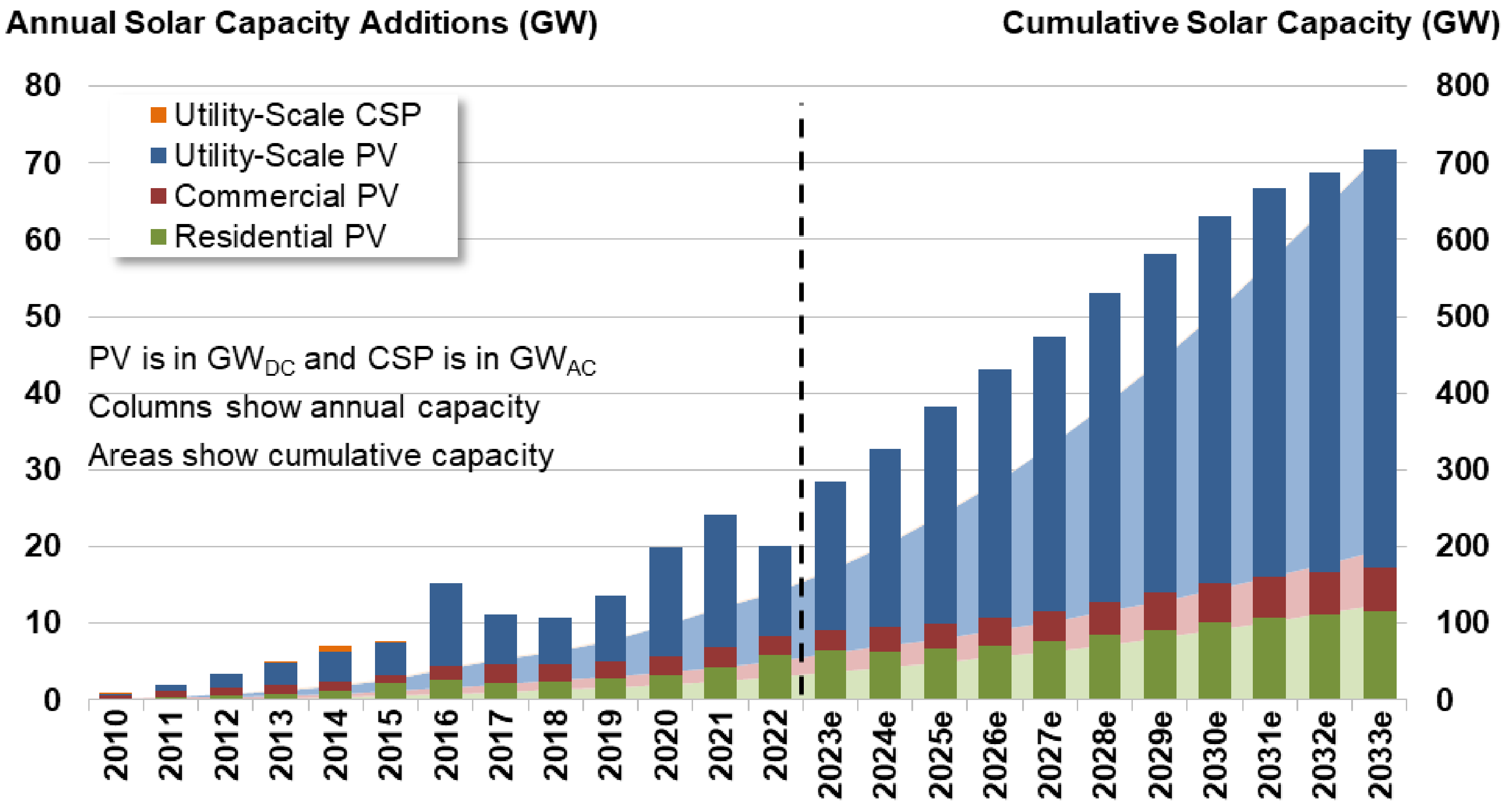
Regional boundaries applied in this analysis include the seven independent system operators (ISO) and two non-ISO regions



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

Deployment and Technology Trends

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



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

Wood Mackenzie and SEIA report that the utility-scale sector added 12 GW_{DC} of new solar capacity in 2022, accounting for **59% of all new solar** capacity. Annual growth declined by 32% compared to the record year 2021.

Utility-scale solar contributed **63% of cumulative solar** capacity (and 72% of solar generation) in 2022; this share is projected to rise above 67% by 2025 and 73% by 2033.

Our data analysis focuses on a subset of this sample—all projects larger than 5 MW_{AC} that were completed by the end of 2022:

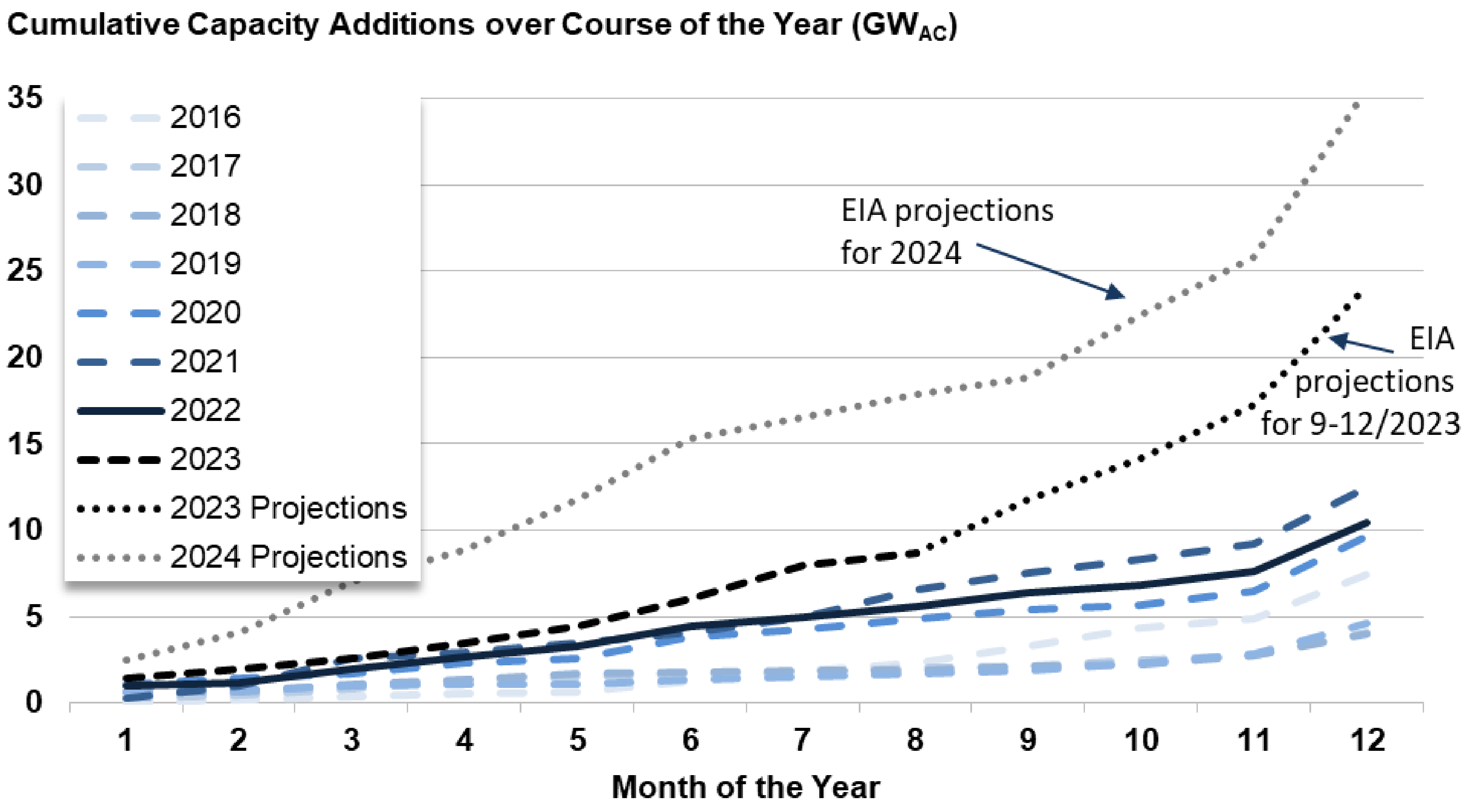
- **2021**: 155 new projects totaling 16.6 GW_{DC} or 12.5 GW_{AC}
- **2022**: 147 new projects totaling 13.2 GW_{DC} or 10.4 GW_{AC}

We define "utility-scale" as any ground-mounted project that is larger than 5 MW_{AC}

Smaller systems are analyzed in LBNL's *"Tracking the Sun"* series (trackingthesun.lbl.gov)

Note: Wood Mackenzie/SEIA's graph above defines utility-scale solar as >1 MW_{DC} while this report uses a definition of >5 MW_{AC}.

Utility-scale solar capacity additions on track for record year in 2023



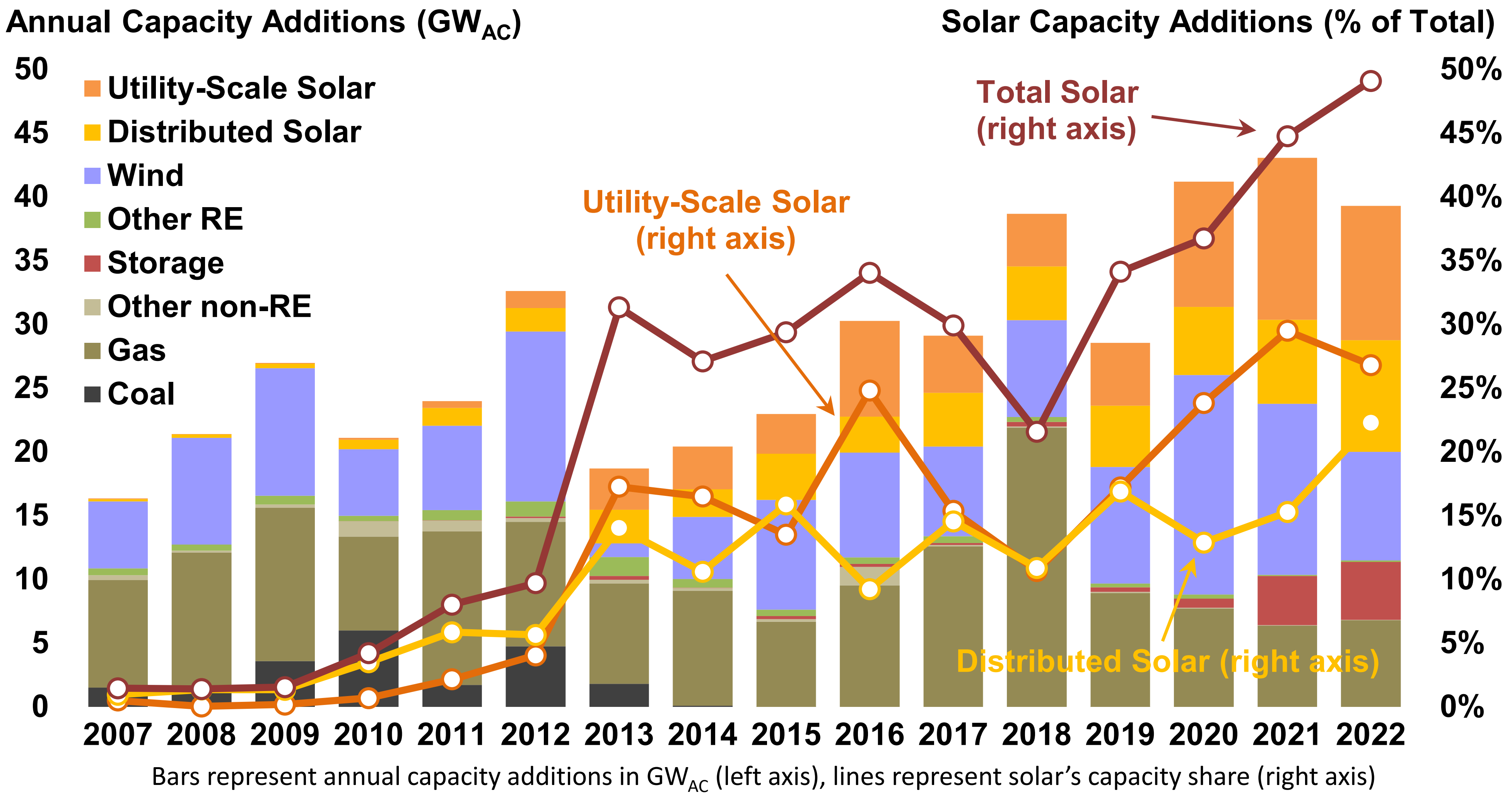
Utility-scale additions in 2022 did not reach 2021 levels as less capacity came online over the summer, in part due to temporary anti-dumping/circumvention tariffs and supply chain inspections related to Uyghur Forced Labor Prevention Act.

December had the most capacity growth in 2022, like past years. This does *not* point to a strategic withholding of capacity to benefit from more lucrative ITC/PTC benefits that took effect in January 2023.

2023 shapes up to be a record year, with 50% more capacity installed so far compared to the same month in 2022. Based on EIA estimated “Planned Capacity” more than $24GW_{AC}$ may get installed in 2023.

Note: This graph defines utility-scale solar as larger than 5 MW_{AC}.

Solar was the largest source of capacity added to U.S. grids in 2022



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

Utility-scale (27%) and distributed (22%) solar accounted for a combined 49% of all capacity added to U.S. grids in 2022 (ahead of wind's 22%).

Solar has contributed >40% of all new capacity for the past 2 years, >30% in 6 of the last 7 years, and >20% in each of the last 10 years.

Storage continues to expand: 4.5 GW of storage were added to U.S. grids in 2022, up from 3.9 GW in 2021 and 0.7 GW in 2020.

Sources: *EIA, Berkeley Lab*

Note: This graph follows the EIA's split between distributed (<1 MW_{AC}) and utility-scale (≥1 MW_{AC}) solar, rather than our 5 MW_{AC} threshold.

Solar generation's market share was 4.7% across the U.S. in 2022, but reached 27% in California and exceeded 15% in four other states

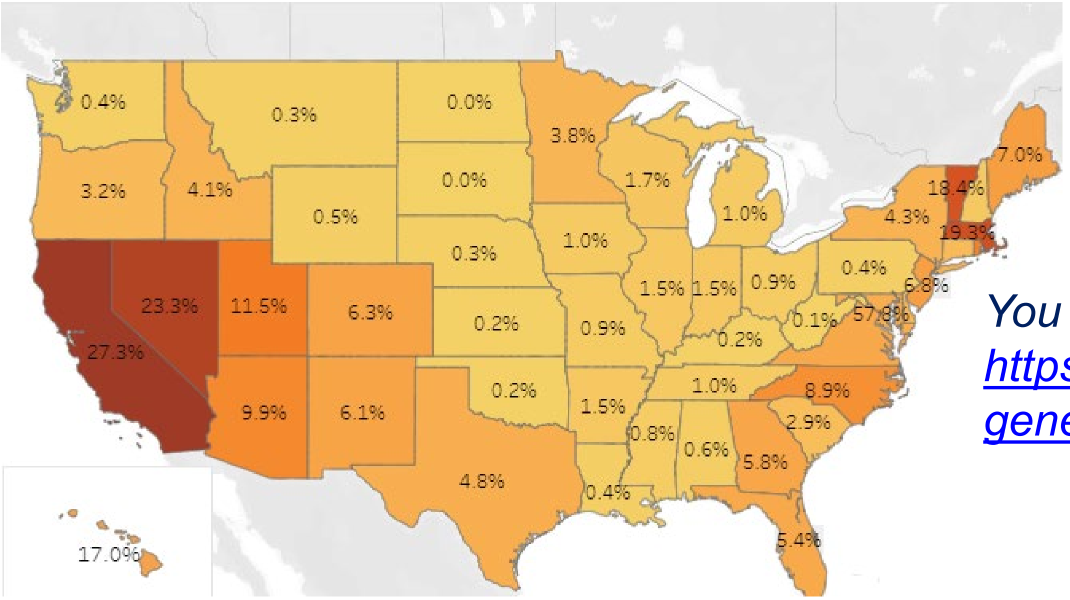
State	Solar generation as a % of in-state generation		Solar generation as a % of in-state load	
	All Solar	Utility-Scale Solar Only	All Solar	Utility-Scale Solar Only
California	27.3%	17.2%	24.8%	15.6%
Nevada	23.3%	20.4%	25.7%	22.4%
Massachusetts	19.3%	8.5%	9.2%	4.0%
Vermont	18.4%	9.4%	7.6%	3.9%
Hawaii	17.0%	5.3%	20.4%	6.3%
Utah	11.5%	9.6%	14.0%	11.6%
Rhode Island	11.0%	4.9%	12.5%	5.7%
Arizona	9.9%	6.5%	12.8%	8.5%
North Carolina	8.9%	8.5%	8.6%	8.2%
Maine	7.0%	4.2%	7.2%	4.3%
New Jersey	6.8%	2.4%	6.3%	2.2%
Colorado	6.3%	4.1%	6.6%	4.3%
New Mexico	6.1%	4.8%	9.2%	7.2%
Georgia	5.8%	5.4%	5.1%	4.8%
Virginia	5.6%	5.1%	3.9%	3.6%
Florida	5.4%	4.3%	5.4%	4.4%
Maryland	4.9%	2.0%	3.1%	1.3%
Texas	4.8%	4.2%	5.6%	4.9%
New York	4.3%	1.6%	3.8%	1.5%
Idaho	4.1%	3.1%	2.7%	2.1%
Rest of U.S.	*1.0%*	*0.7%*	*1.3%*	*0.9%*
TOTAL U.S.	**4.7%**	**3.4%**	**5.2%**	**3.7%**

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

As a percentage of in-state generation, California's solar market share reached 27% in 2022, while Nevada, Massachusetts, Vermont, and Hawaii all surpassed 15%

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

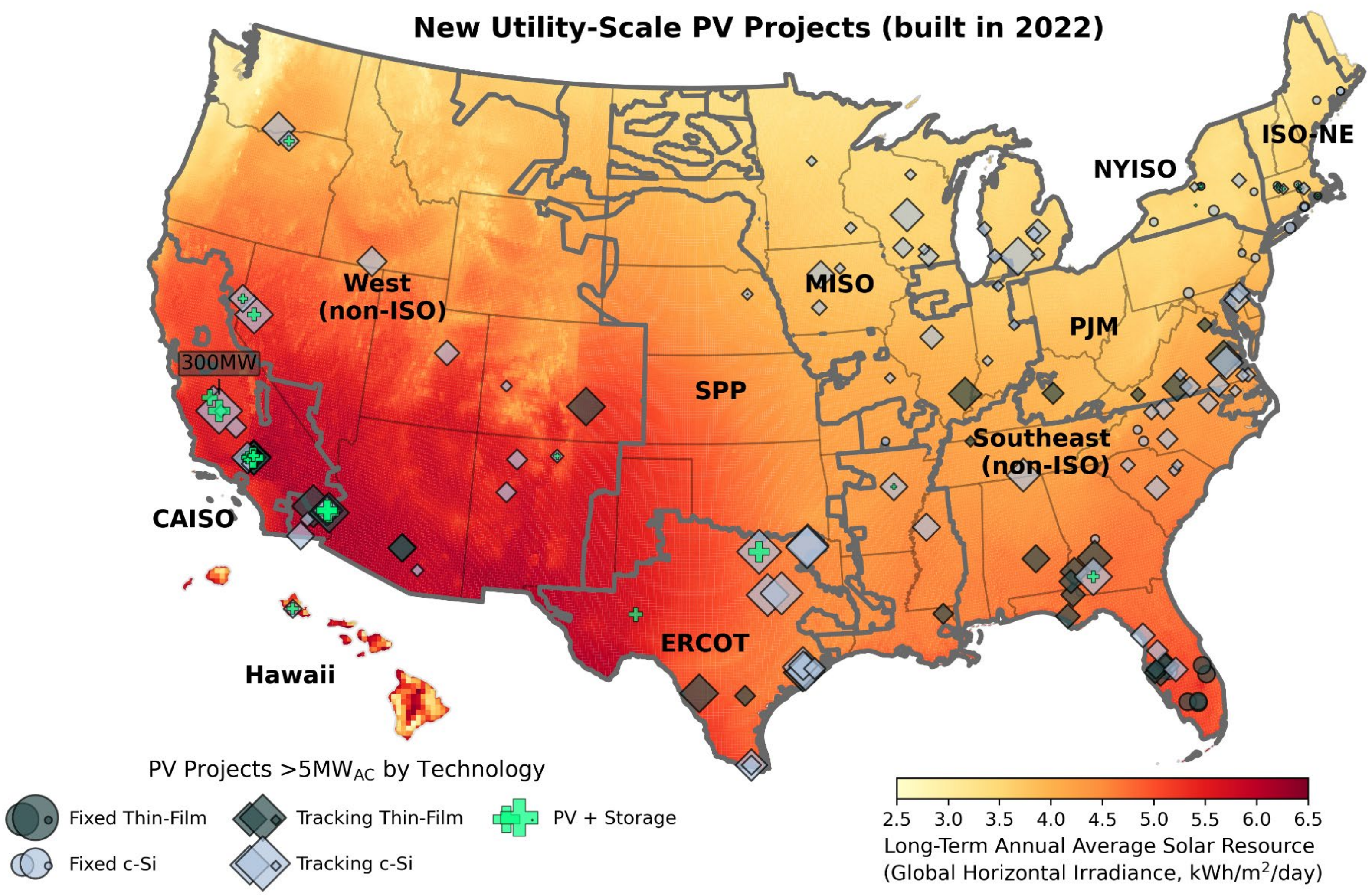
Percentage of In-State Electricity Sales and Generation from Solar PV, as of **2022**



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

Note: In this table, "utility-scale" refers to projects ≥ 1 MW_{AC}, rather than our typical 5 MW_{AC} threshold.

Texas continued to lead in new utility-scale solar deployment



Texas continues to add the most capacity in the nation, although less than in 2021. New projects shifted away from the northwest and closer to load centers.

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

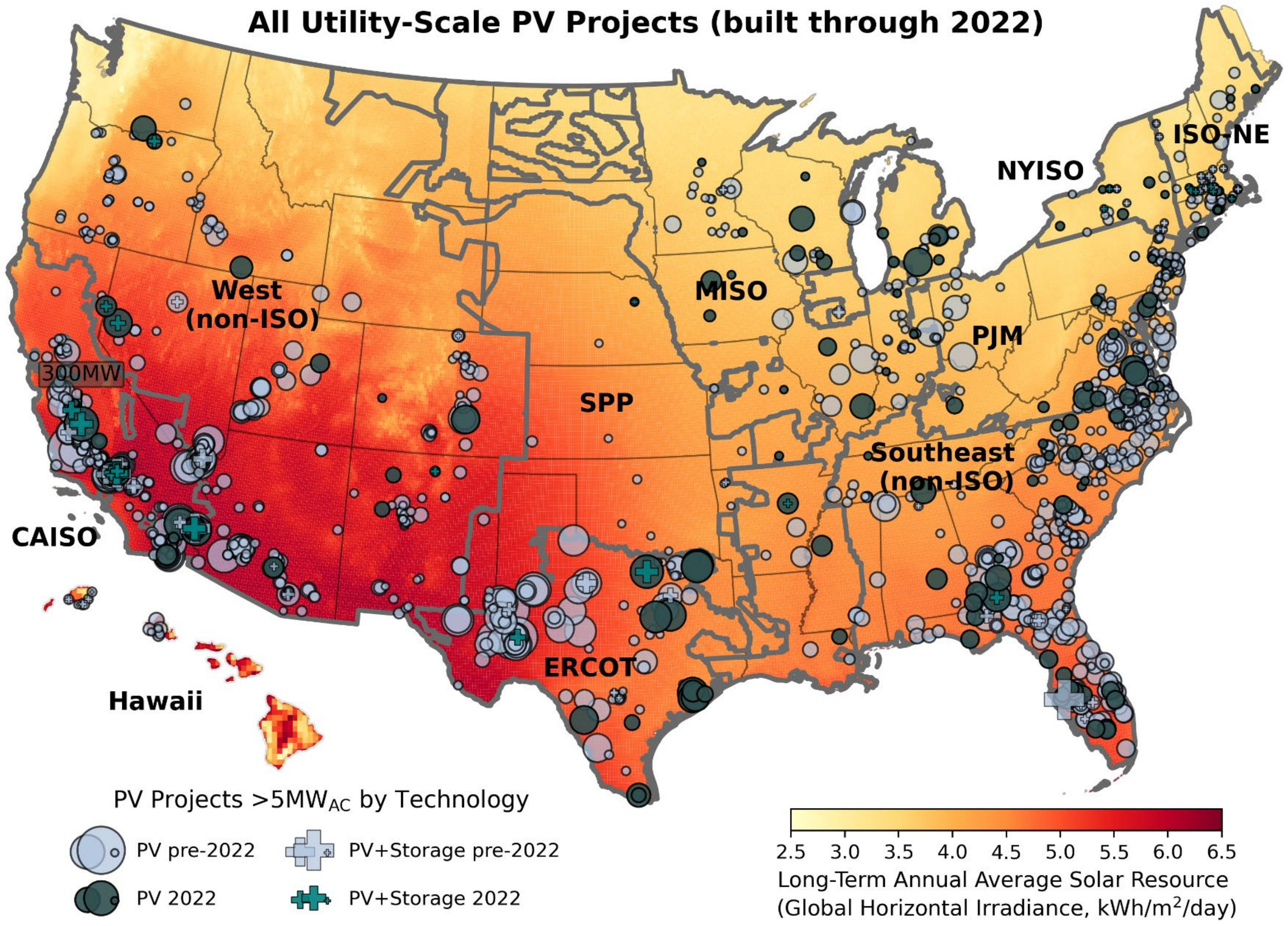
Other high-latitude states such as Oregon, Minnesota, Wisconsin, and Michigan, added predominantly **tracking** projects in 2022 ( ).

In 2022, storage ( ) hybrid projects hit the ground in record numbers. Batteries were added to already existing (4) and new (26) PV projects. Solar-rich CA added the most storage capacity (960 MW), while MA deployed several (6) small-sized battery projects.

2022 was the first time in 15 years that no new state joined the utility-scale solar market.

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

Utility-scale solar has become a growing source of electricity in all regions of the United States



Utility-scale PV is well-represented throughout the nation, with the exception of upper-Midwestern states in the "wind belt".

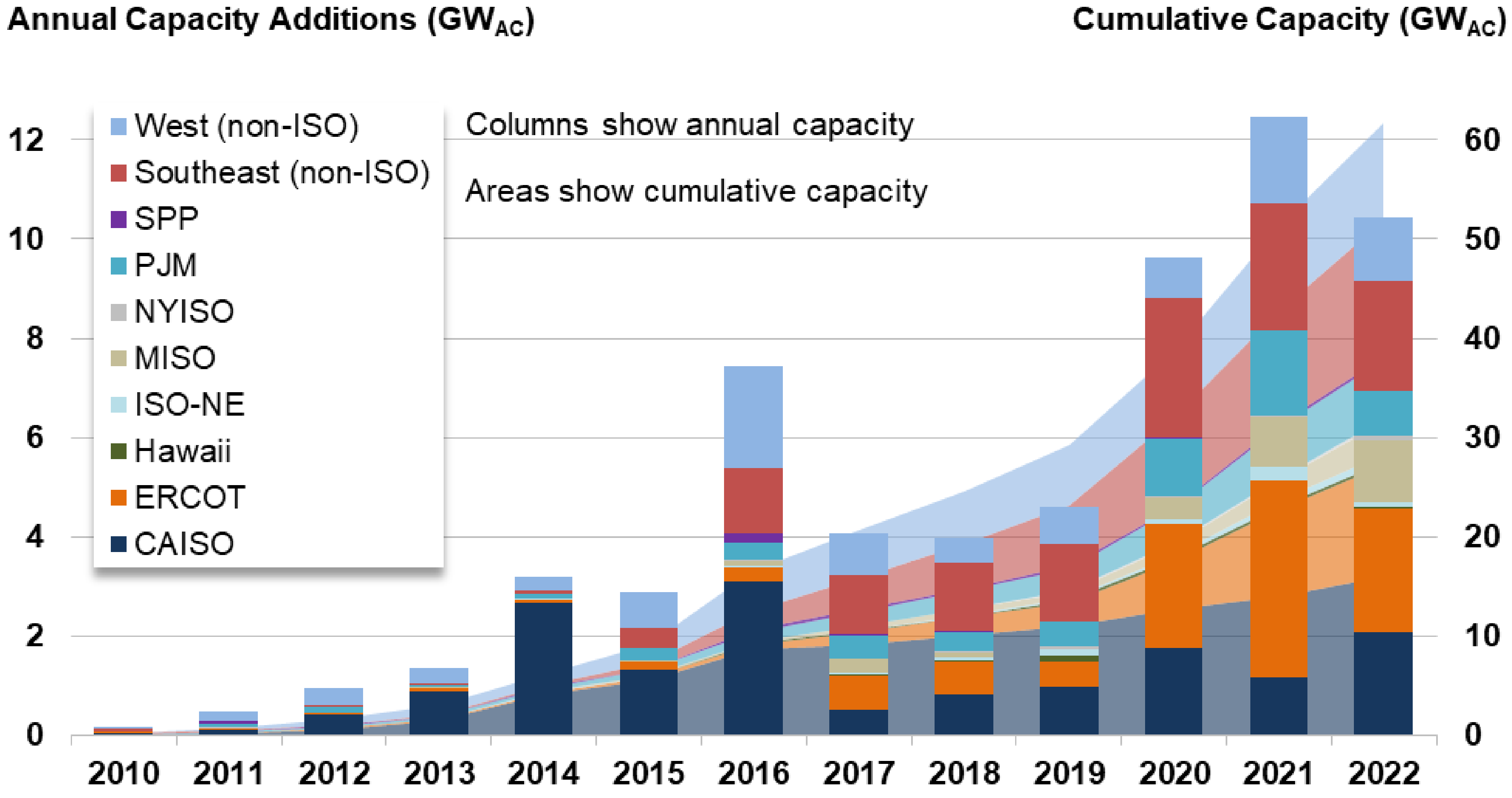
Large solar projects (>100 MW) are now being built in northern MISO, while Texas solar increasingly expands beyond the panhandle.

Montana, the Dakotas, New Hampshire, and West Virginia still await their first utility-scale solar projects in our sample.

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

Texas and California added the most utility-scale solar capacity in 2022

PV project population: 1,277 projects totaling 61.7 GW_{AC}



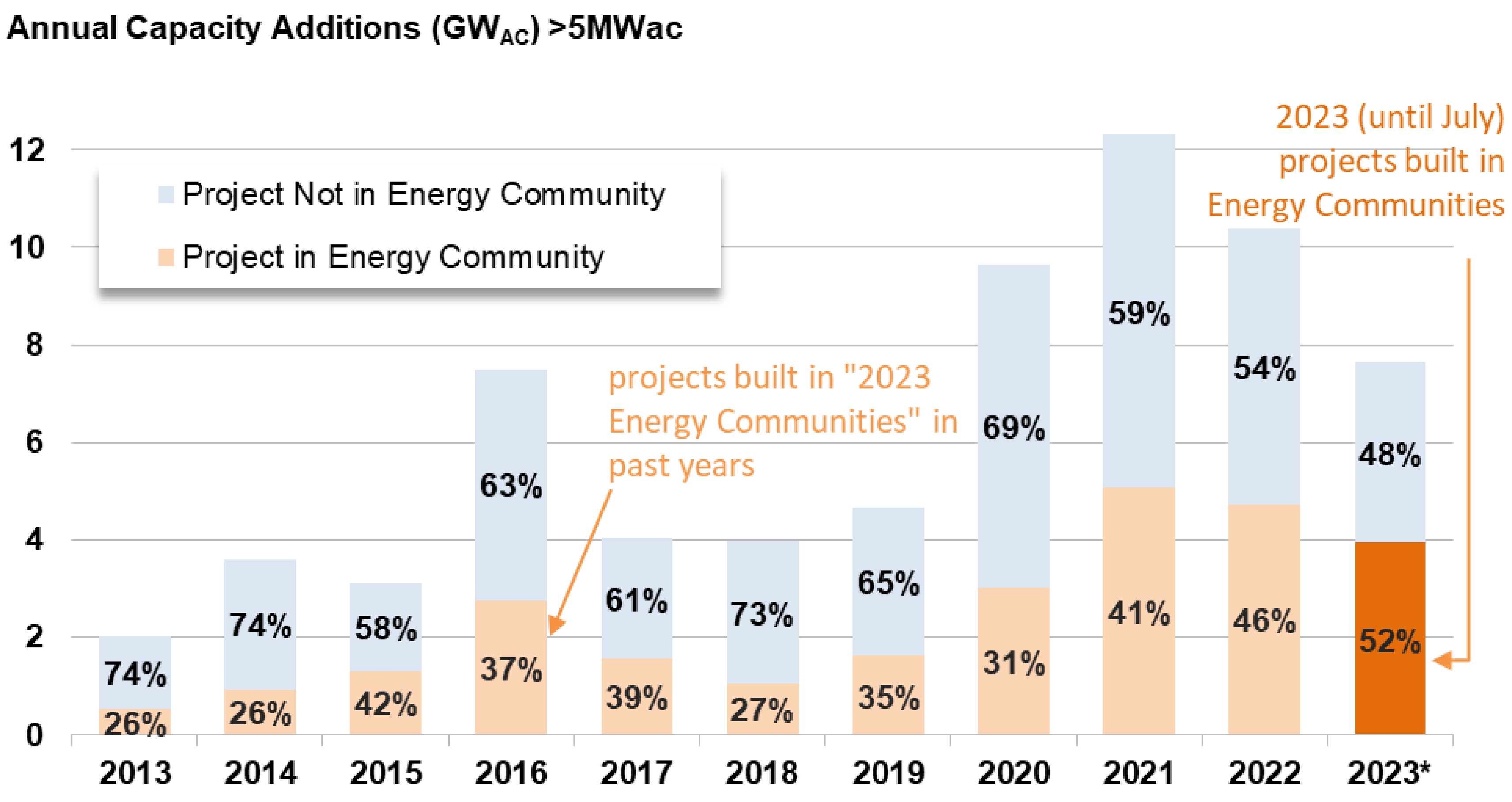
2022 utility-scale solar additions decreased compared to 2021 both across the nation and in many regions.

Texas (ERCOT) remains the strongest market, having added 2.5 GW_{AC} or 24% of all utility-scale solar capacity in 2022. In cumulative deployment, Texas is still lagging California (CAISO) with 11 GW_{AC} vs. 16 GW_{AC}, although the gap is narrowing.

California's USS growth accelerated in 2022 to 2.1 GW_{AC}—its greatest deployment since 2016. **Florida** (1.1 GW_{AC}), **Virginia** (0.6 GW_{AC}), and **Georgia** (0.5 GW_{AC}) continued to lead solar growth in the Southeast in 2022.

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

Half of 2023-to-date solar capacity is in Energy Communities



The Inflation Reduction Act offers a tax credit adder (10% for PTC and 10 percentage points for ITC) for solar projects located in "Energy Communities," starting in 2023.

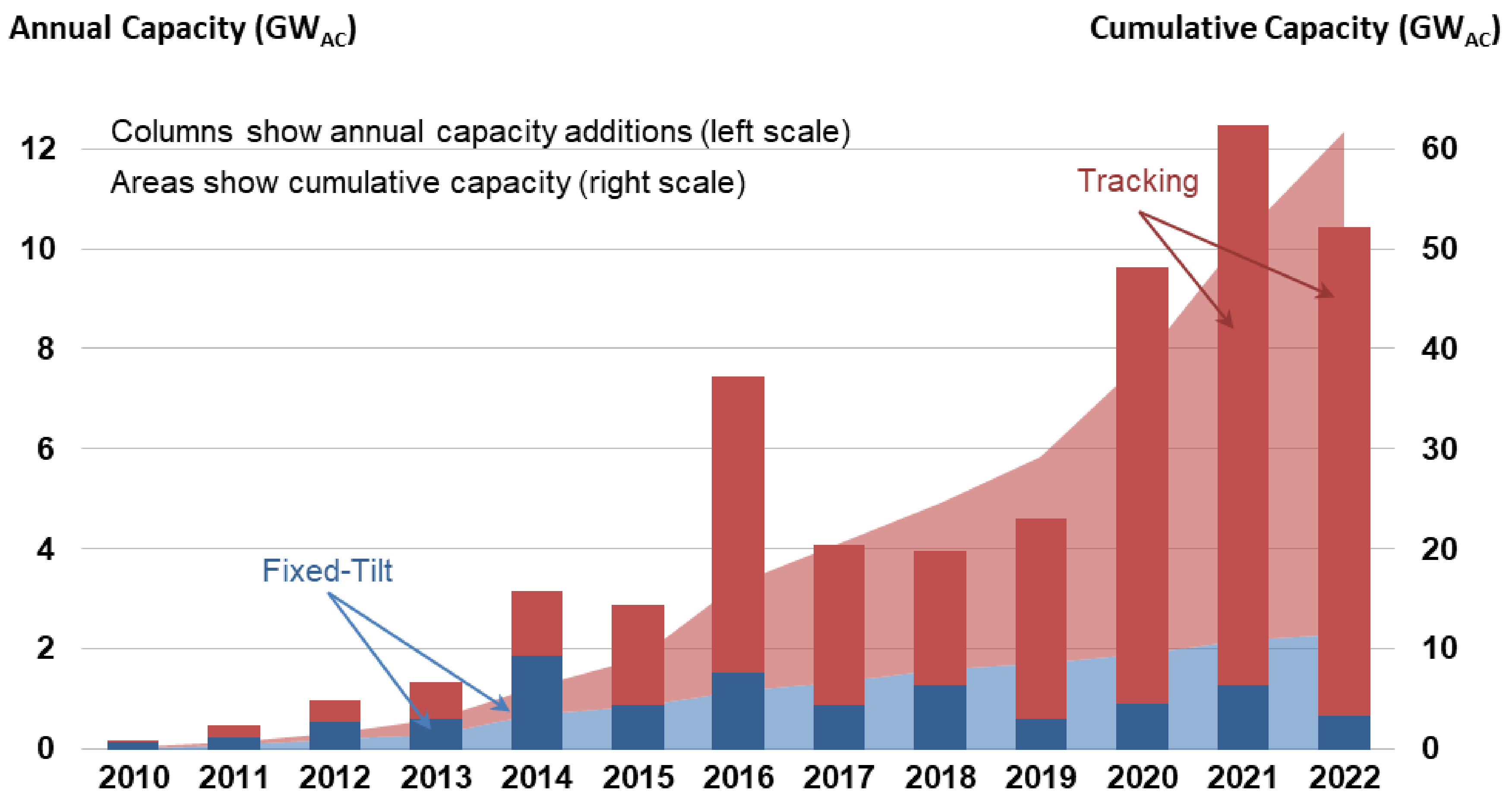
While relatively few projects were built in such communities a decade ago (e.g., 26% of capacity in 2013 and 2014), the share has trended upwards over the past five years.

Even though 2023 projects are unlikely to have been intentionally sited in such communities in order to capture the bonus credit (given that the interconnection process takes several years), more than half of the solar capacity built through July 2023 should qualify for the Energy Community tax credit adder.

Note: These data do not yet include solar projects built at brownfield sites as being part of an Energy Community and thus eligible for the added incentives.

Projects with tracking technology dominated 2021 additions

PV project population: 1,275 projects totaling 61.7 GW_{AC}



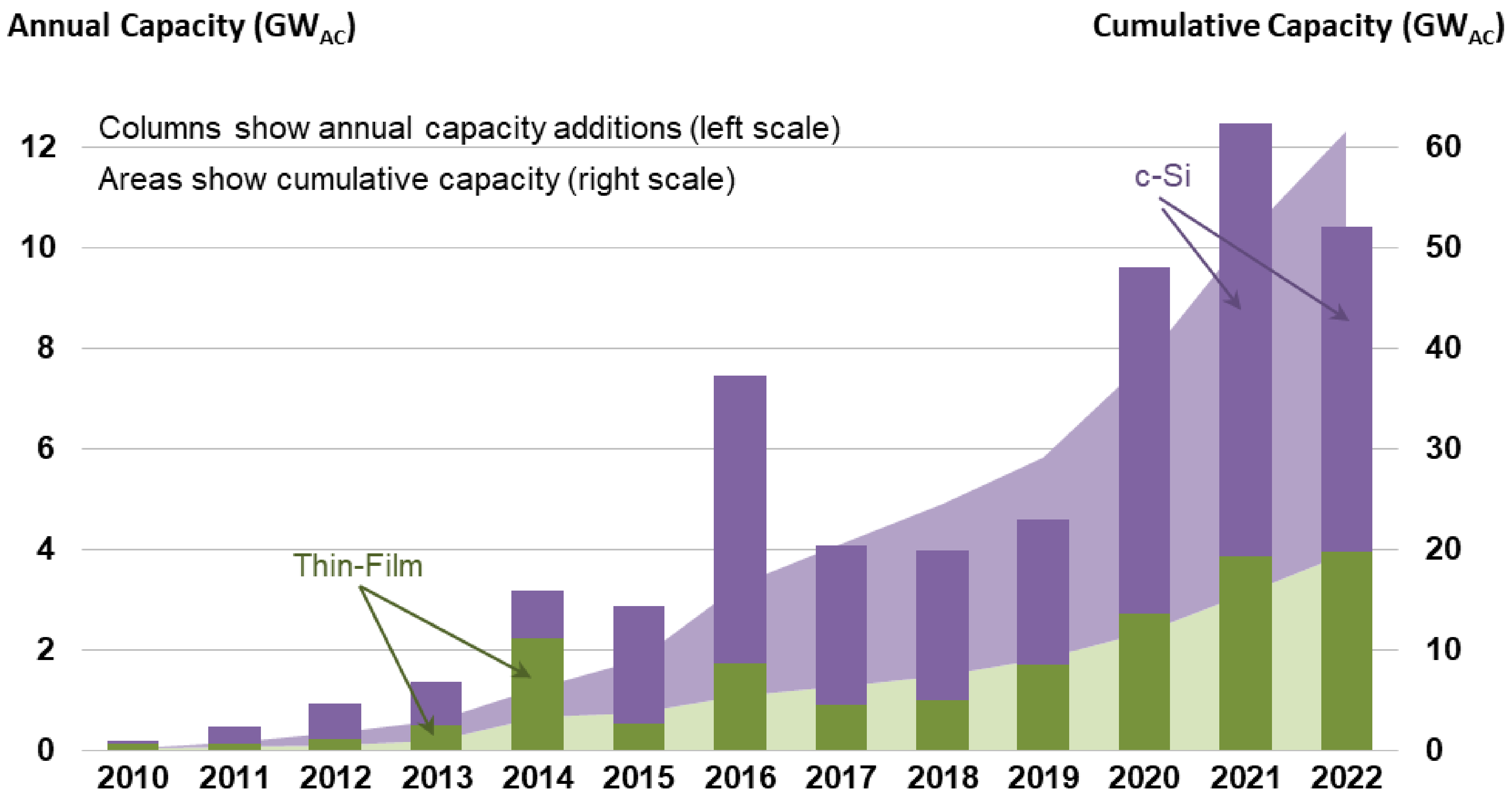
Projects using single-axis **tracking** have consistently exceeded **fixed-tilt** installations since 2015, and dominated again in 2022, with 94% of all new capacity using tracking- the greatest ever.

Upfront cost premiums for trackers have generally fallen over the years, resulting in favorable economics in most of the United States thanks to increased generation (though 2022 saw again an uptick in cost premiums—discussed later).

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

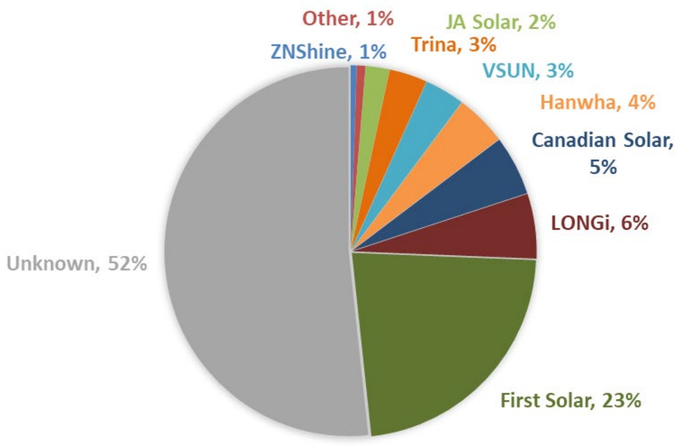
Thin-film modules became more popular in 2022, but c-Si modules still dominate

PV project population: 1,271 projects totaling 61.7 GW_{AC}



c-Si modules continued their clear lead (62% of newly installed capacity) relative to **thin-film** modules, though the latter have steadily become more popular since 2018 as they were not subject to Section 201 import tariffs.

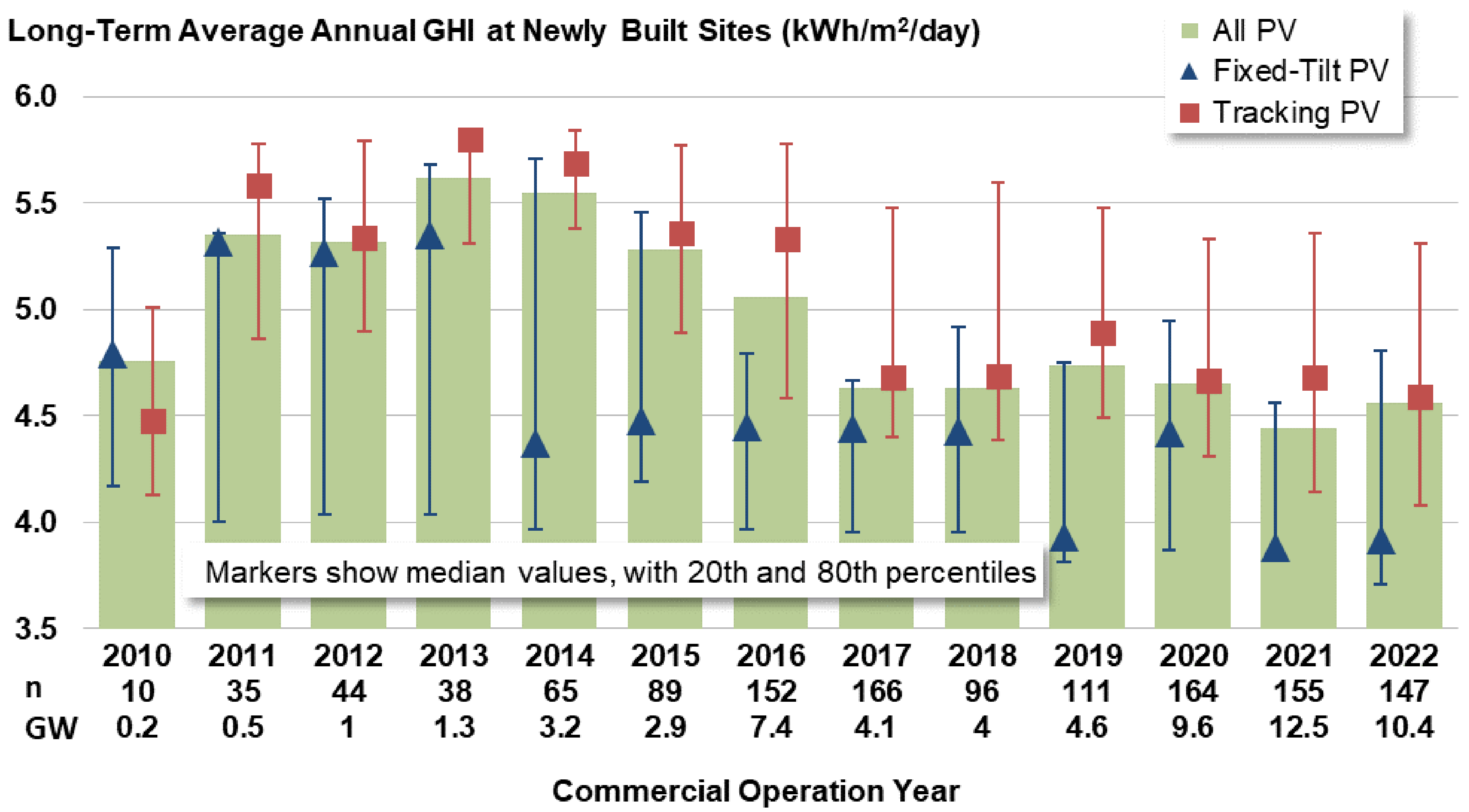
LONGi had the highest market share among known c-Si modules in our sample, followed by Canadian Solar and Hanwha. All thin-film modules in our 2022 sample were made by First Solar.



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

The median global horizontal irradiance (GHI) at utility-scale solar sites has trended sideways since 2017, after falling from 2013's peak

PV project population: 1,277 projects totaling 61.7 GW_{AC}



The decline in the average long-term global horizontal irradiance (**GHI**) at newly built sites from 2013 through 2017 represents the market expanding to less-sunny states. This metric rebounded slightly to 4.56 kWh/m²/day in 2022.

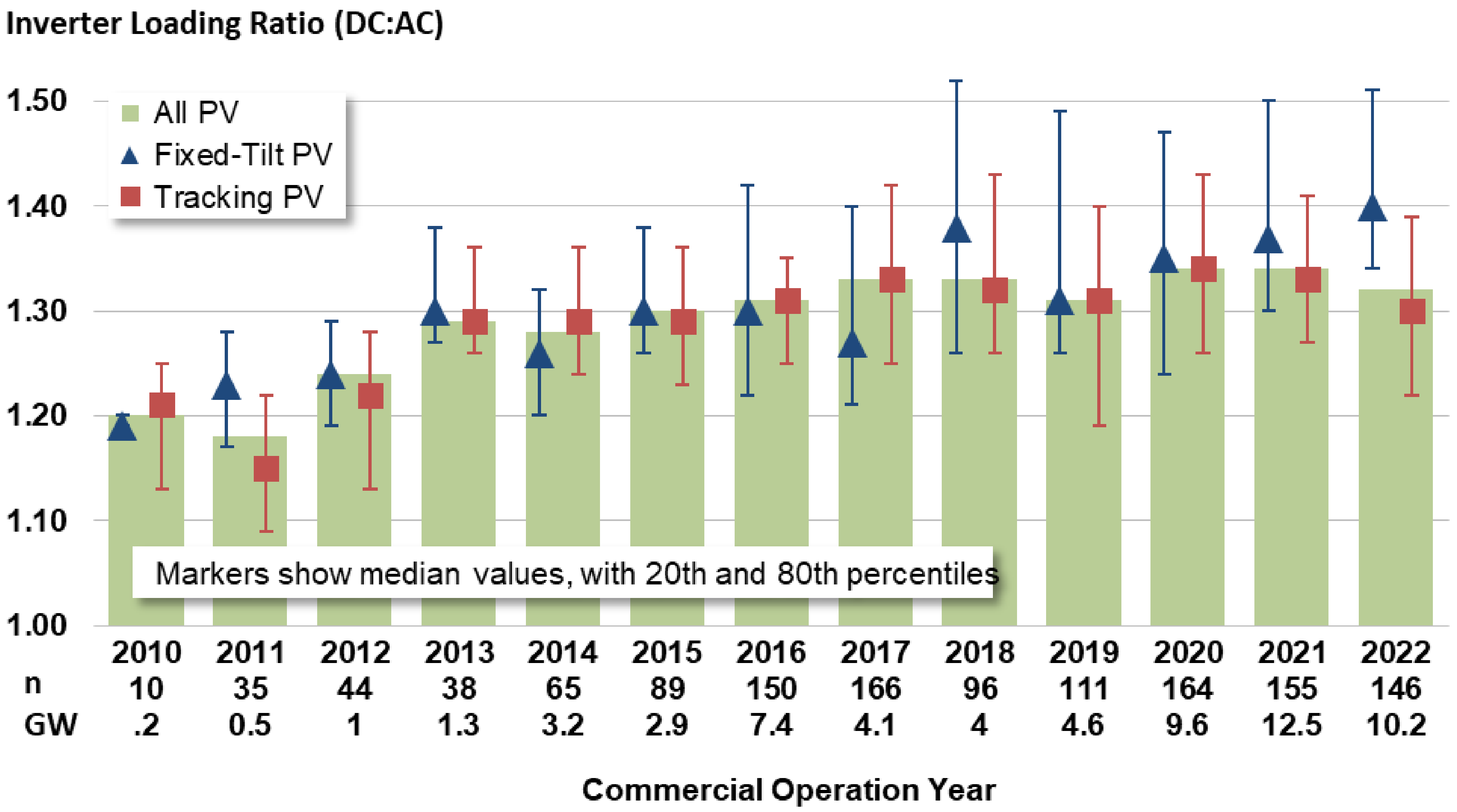
Fixed-tilt PV is increasingly relegated to lower-insolation sites, while tracking PV is increasingly pushing into those same areas (note the decline in its **20th percentile**).

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

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

The median inverter loading ratio (ILR) has decreased recently for tracking projects but continues to grow for fixed-tilt projects

PV project population: 1,274 projects totaling 61.5 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.

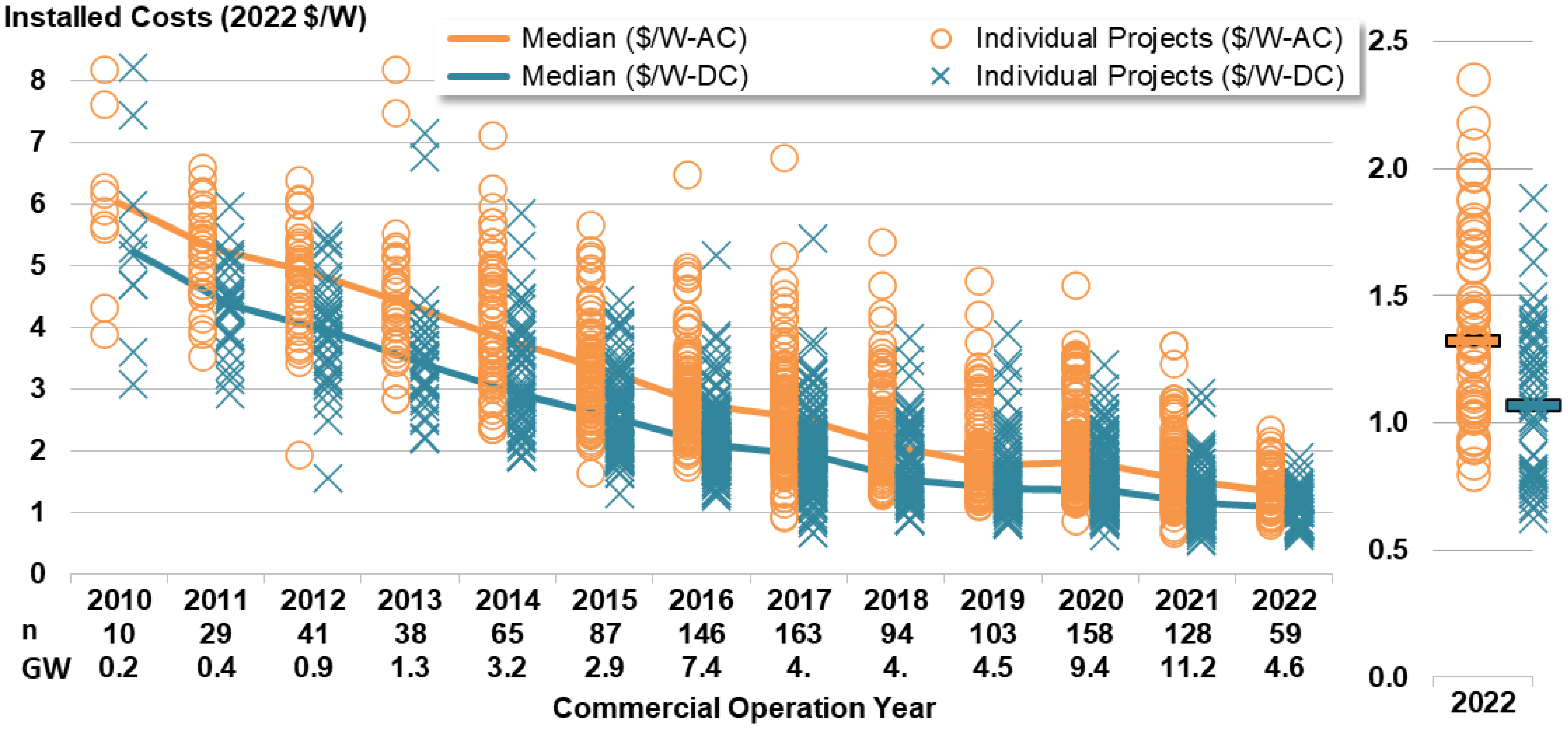
In 2022, the median inverter loading ratio (**ILR** or DC:AC ratio) was 1.32, and was higher for fixed-tilt installations (1.40) than for tracking projects (1.30).

All else equal, a higher ILR should boost capacity factors (reported later).

Capital Costs (CapEx) and O&M Costs

Median installed costs of PV have fallen by 78% (or 10% annually) since 2010, to $1.32/W$_{AC}$ ($1.07/W$_{DC}$) in 2022

Sample: 1,126 projects totaling 54.2 GW$_{AC}$



Despite inflationary pressures, utility-scale solar costs continued to decrease from $1.5/W$_{AC}$ in 2021 to $1.3/W$_{AC}$ in 2022.

The lowest 20th percentile of project costs fell in real terms from $1.2/W$_{AC}$ ($0.9/W$_{DC}$) in 2021 to $1.1/W$_{AC}$ ($0.8/W$_{DC}$) in 2022.

The lowest-cost projects among the 59 data points in 2022 are now around $0.9/W$_{AC}$.

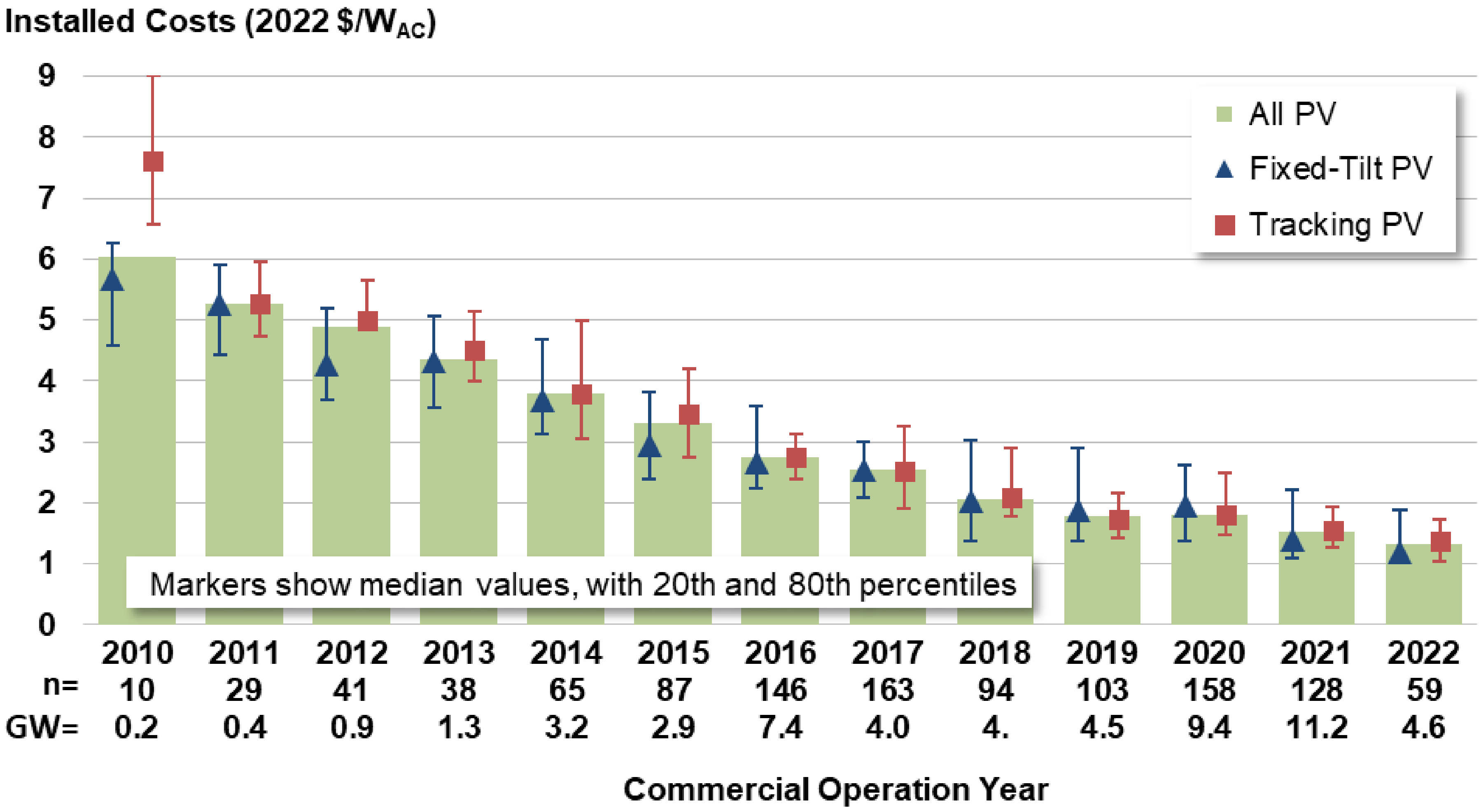
Historical sample is robust (covering 97% of installed capacity through 2021). 2022 data covers 40% of new projects or 44% of new capacity.

This sample is backward-looking and does not reflect the costs of projects built in 2023/2024.

Note on solar costs and inflation: We adjust costs to account for general inflation using BEA's implicit price deflators. As a result, costs for past years are 7% higher when expressed in $2022 compared to last year's report. Conversely, decreasing solar costs in real terms indicate that solar projects find at least some savings relative to the wider economy, even if prices may rise in nominal terms. Compared to the previous year, $/W$_{AC}$ costs fell both in real (-13%) and nominal (-8%) terms in 2022 in our sample. $/W$_{DC}$ costs decreased by 8% in real and 6% in nominal terms.

The cost premium for tracking projects relative to fixed-tilt has diminished over time

Sample: 1,126 projects totaling 54.2 GW_{AC}



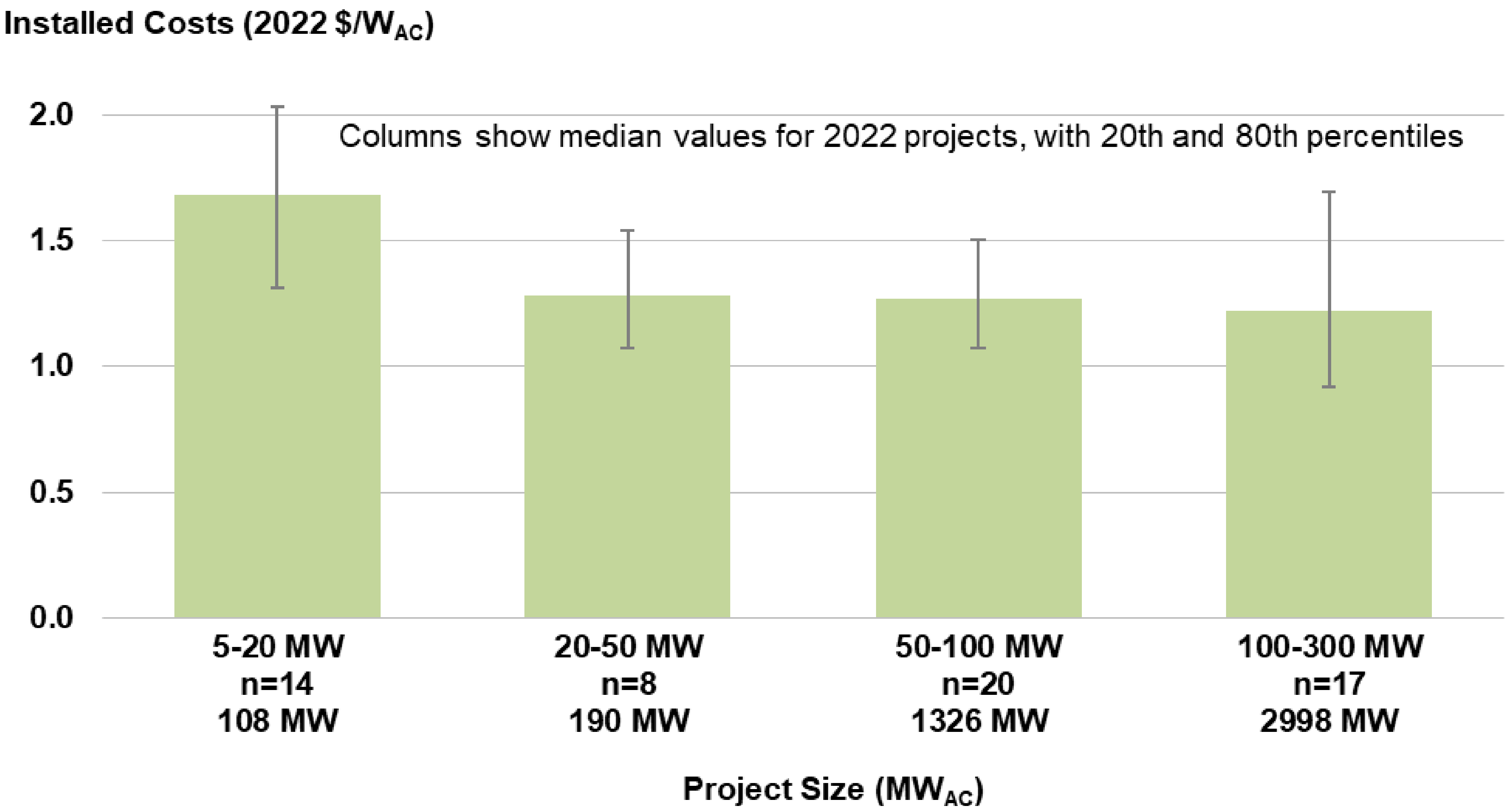
Through 2018, tracking projects in our sample were, on average, regularly more expensive (though by varying amounts) than fixed-tilt projects. In 2020, tracking projects ($1.8/W$_{AC}$ or $1.4/W$_{DC}$) appeared to be cheaper than fixed-tilt projects ($2.0/W$_{AC}$ or $1.5/W$_{DC}$).

This apparent reversal may be driven by challenging construction environments for fixed-tilt projects (e.g., high wind loads, sensitive brown-field sites) as well as sampling issues. However, for any ***individual*** project, using trackers presumably has a higher CapEx than mounting at a fixed-tilt.

In our 2022 sample, trackers ($1.4/W$_{AC}$ or $1.1/W$_{DC}$) once again exhibit a premium over fixed-tilt plants ($1.2/W$_{AC}$ or $0.9/W$_{DC}$). Trackers can sustain some amount of higher upfront costs because they deliver more kWh per kW.

Larger utility-scale solar projects cost 26% less than smaller projects (5-20 MW) per MW of installed capacity in 2022

Sample in 2022: 59 projects totaling 4.6 GW_{AC}



Differences in project size could potentially explain cost variation—we focus only on 2022 for this slide.

Cost savings seem to occur especially in projects larger than 20 MW_{AC} at ~$1.25/$W_{AC}$ vs. $1.68/$W_{AC}$ for smaller projects.

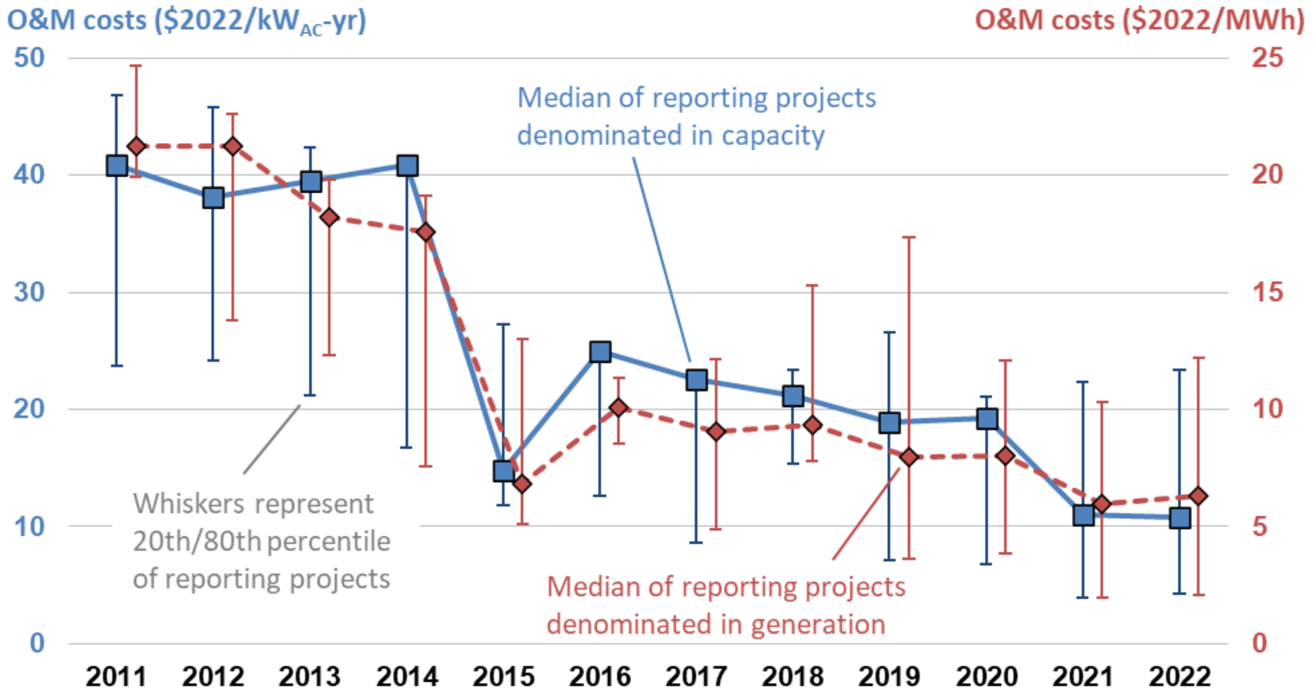
In $/$W_{DC}$ terms, prices seem to decline especially among the largest projects:

- $1.26/$W_{DC}$ for 5-20MW
- $1.02/$W_{DC}$ for 20-50MW
- $1.20/$W_{DC}$ for 50-100MW
- $0.82/$W_{DC}$ for 100-400MW

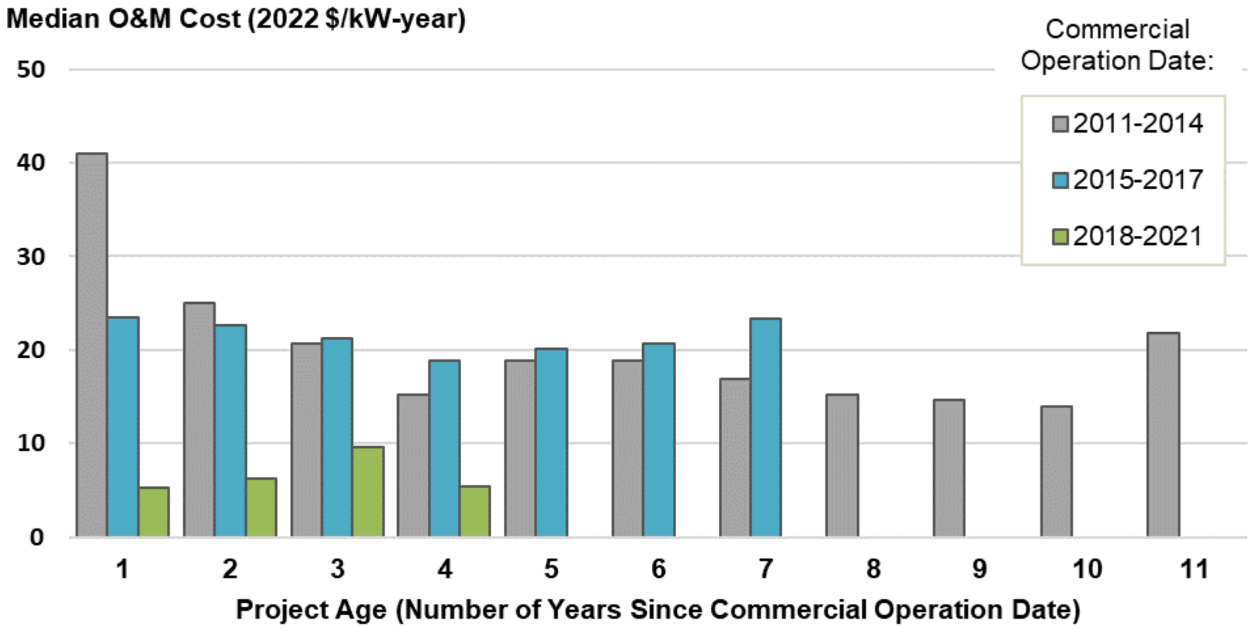
Operation and maintenance (O&M) costs decreased by 74% since 2011 as project portfolios grow and projects become established

PV project population: 122 projects totaling 6.4 GW_{AC}

Regulated utilities report solar O&M costs for plants that they own, representing a mix of technologies and at least one full operational year. These O&M costs are only one part of total operating expenses:	**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



Median O&M costs for the cumulative sample have declined from about $41/kW_{AC}$-year or $21/MWh in 2011 to about **$11/kW$_{AC}$-year or $6/MWh in 2022**.

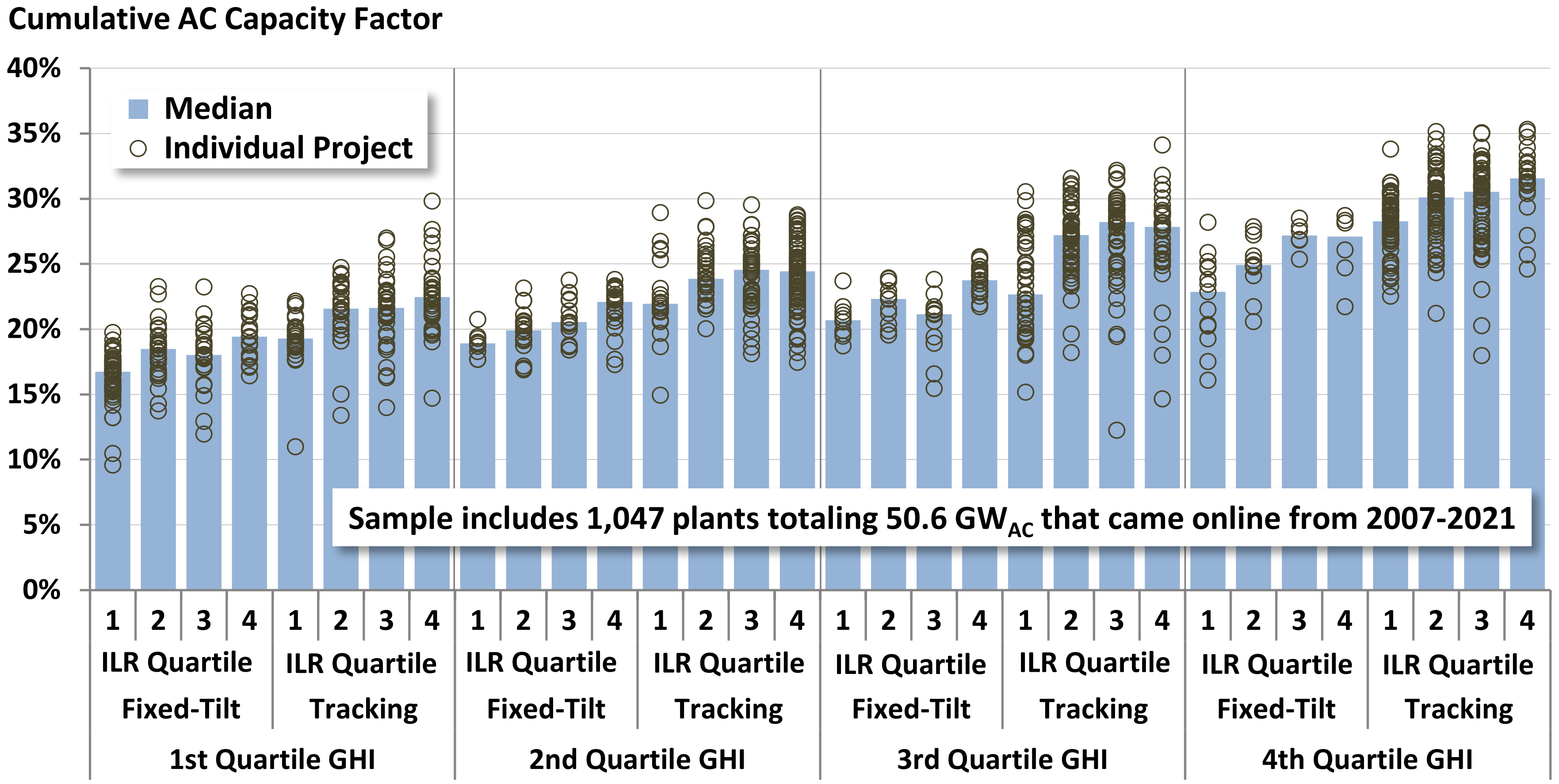


Projects built since 2018 report much lower O&M costs compared to older ones, potentially due to a narrower service scope of agreements. Costs seem to decline over the first 4 years across project vintages as projects become established. Among a very small sample of projects costs increase after 10 years.

Performance (Capacity Factors)

24% median PV net capacity factor (cumulative, sample-wide), but with large plant-level range from 9%-35%

PV performance sample: 1,047 plants totaling 50.6 GW_{AC}



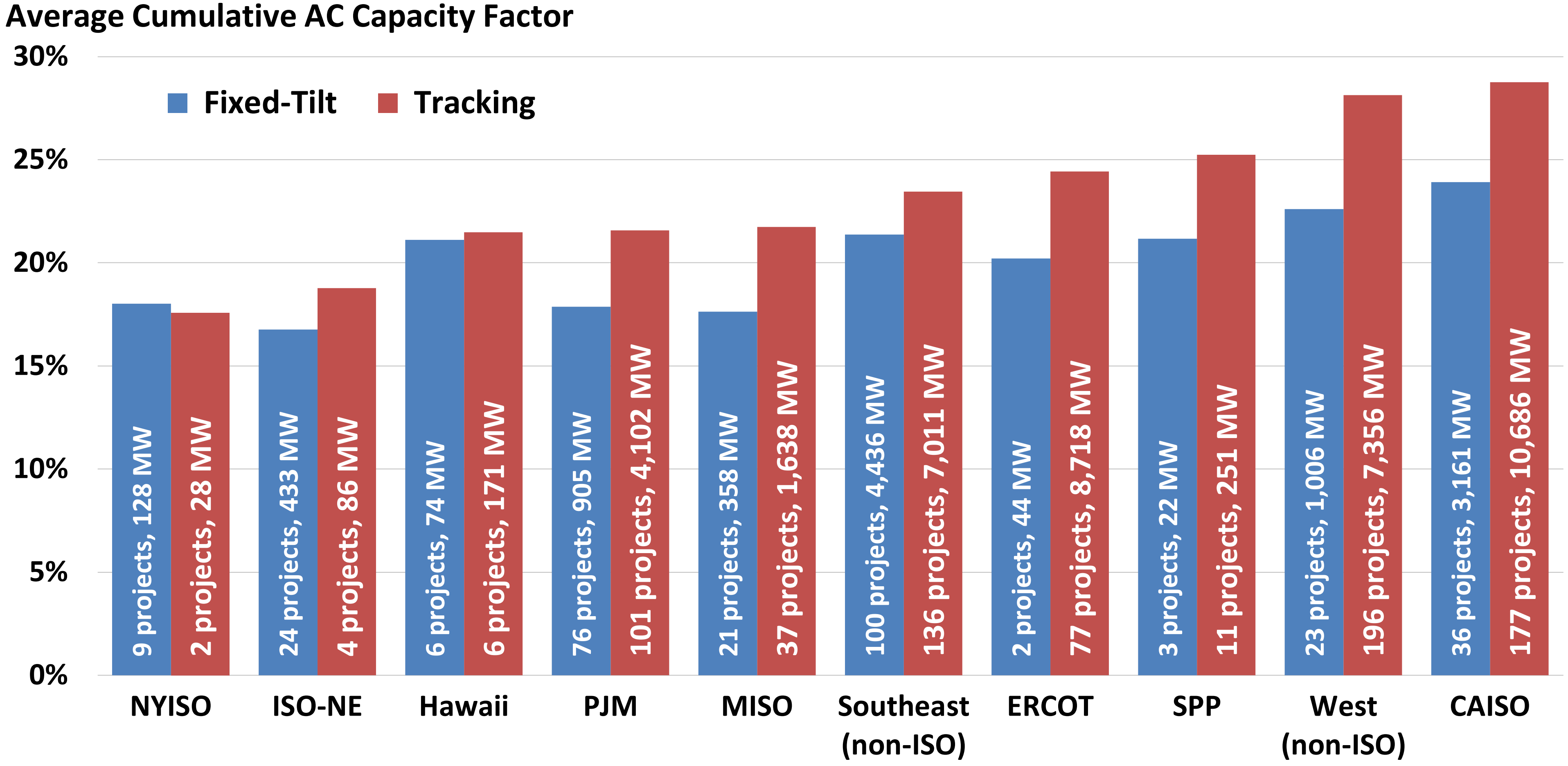
Project-level variation in PV capacity factor driven by:

- **Solar Resource (GHI)**: Strongest solar resource quartile has a ~8 percentage point higher capacity factor than lowest resource quartile
- **Tracking**: Adds ~4 percentage points to capacity factor on average, depending on solar resource quartile
- **Inverter Loading Ratio (ILR)**: Highest ILR quartiles have on average ~3 percentage point higher capacity factors than lowest ILR quartiles

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

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

Sample: 1,047 plants totaling 50.6 GW_{AC}



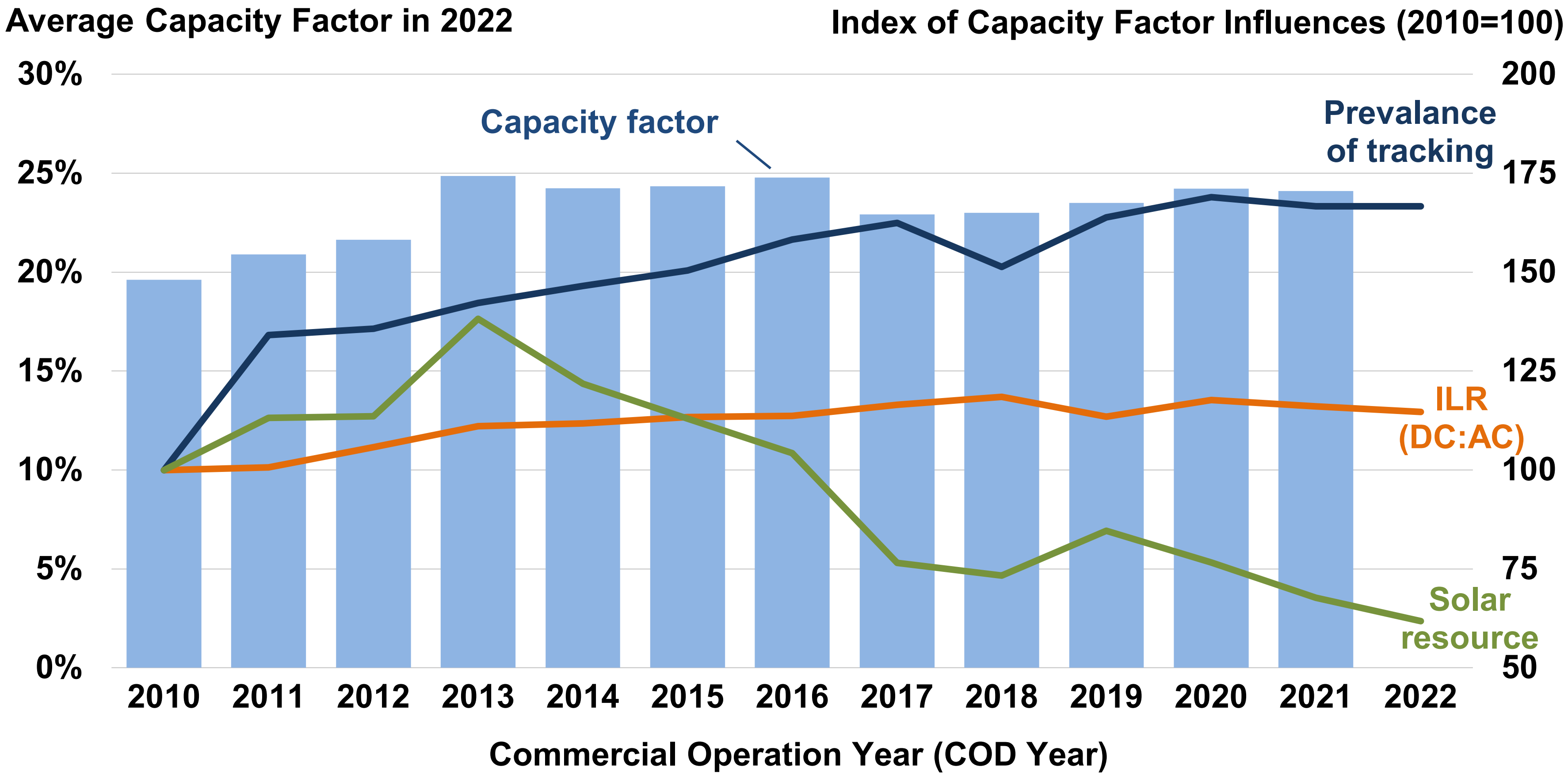
Not surprisingly, capacity factors are highest in California and the non-ISO West, and lowest in the Northeast (ISO-NE and NYISO).

Tracking provides more benefit in high-insolation regions, leading to a greater proportion of tracking projects in those regions.

Note: The regions are defined in the earlier slides with a map of the United States

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

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



The columns represent the capacity factor (left axis), the lines show changes in major drivers (right axis)

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

Average capacity factors increased from 2010- to 2013-vintage projects, due to a sample-wide increase in:

- ILR (from 1.17 to 1.28)
- tracking (from 14% to 57% of projects)
- average site-level GHI (from 4.97 to 5.35 kWh/m^2/day)

Since 2013, however, opposing forces have resulted in capacity factor stagnation (on average):

- ILR has increased (from 1.28 to 1.35)
- tracking has increased (from 57% to >80% of plants)
- average site-level GHI has declined (from 5.35 to 4.65 kWh/m^2/day) as the market has expanded to less-sunny parts of the country

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

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

LCOE and PPA price analysis: data sets and methodology

Project-level LCOE is based on empirical CapEx and capacity factor data presented earlier, as well as:

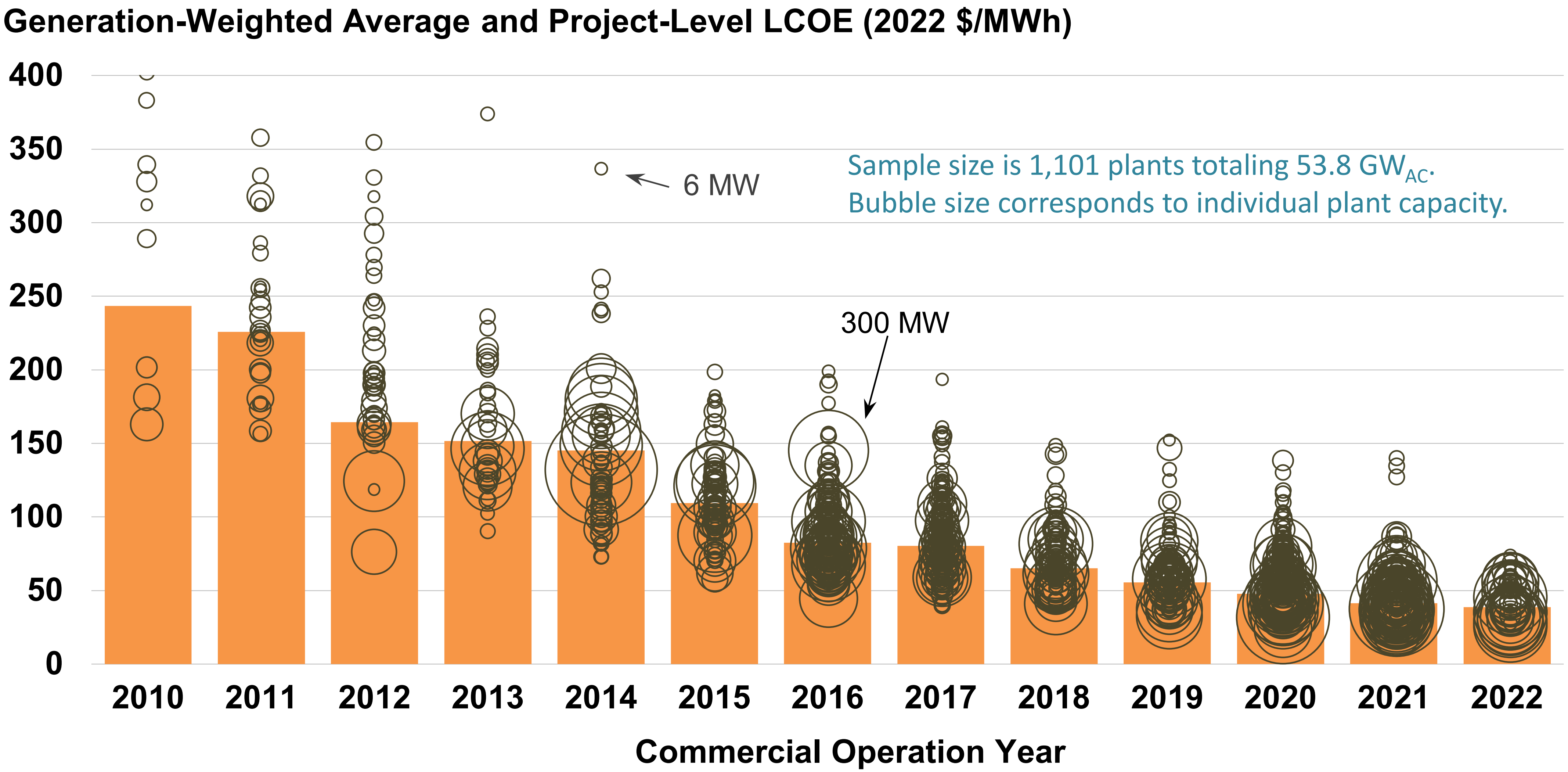
- OpEx and project life that change with vintage: OpEx declines from \$40/kW$_{DC}$-yr in 2007 to \$14/kW$_{DC}$-yr in 2022 (levelized, in 2022\$); project life increases from 21.5 years in 2007 to 35 years in 2021 and thereafter (both based on prior LBNL research)
- Weighted average cost of capital (WACC) based on a constant 70%/30% debt/equity ratio and time-varying market rates
- Combined income tax rate of 38% pre-2018 and 25% post-2017; 5-yr MACRS; inflation expectations ranging from 1.9%-2.6%

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

- 422 PV-only contracts totaling 30.6 GW$_{AC}$
- 81 PV+battery contracts totaling 9.9 GW$_{AC}$ of PV capacity and 5.5 GW$_{AC}$ / 21.8 GWh of battery capacity (presented in a later section)
- 5 concentrating solar thermal power (CSP) contracts totaling 1.2 GW$_{AC}$ (presented in a later section)

- PPA prices reflect the bundled price of electricity and RECs as sold by the project owner under the PPA
  - Dataset excludes merchant plants, projects that sell renewable energy certificates (RECs) separately, and most direct retail sales
  - Prices reflect receipt of state and federal incentives (e.g., the ITC), and as a result do not reflect solar generation *costs*
- We also present LevelTen Energy data on PPA offers; these are often for shorter contract durations and targeted at corporate offtakers

LCOE has fallen by 84% (or 14% annually) since 2010, to $39/MWh (without the ITC)

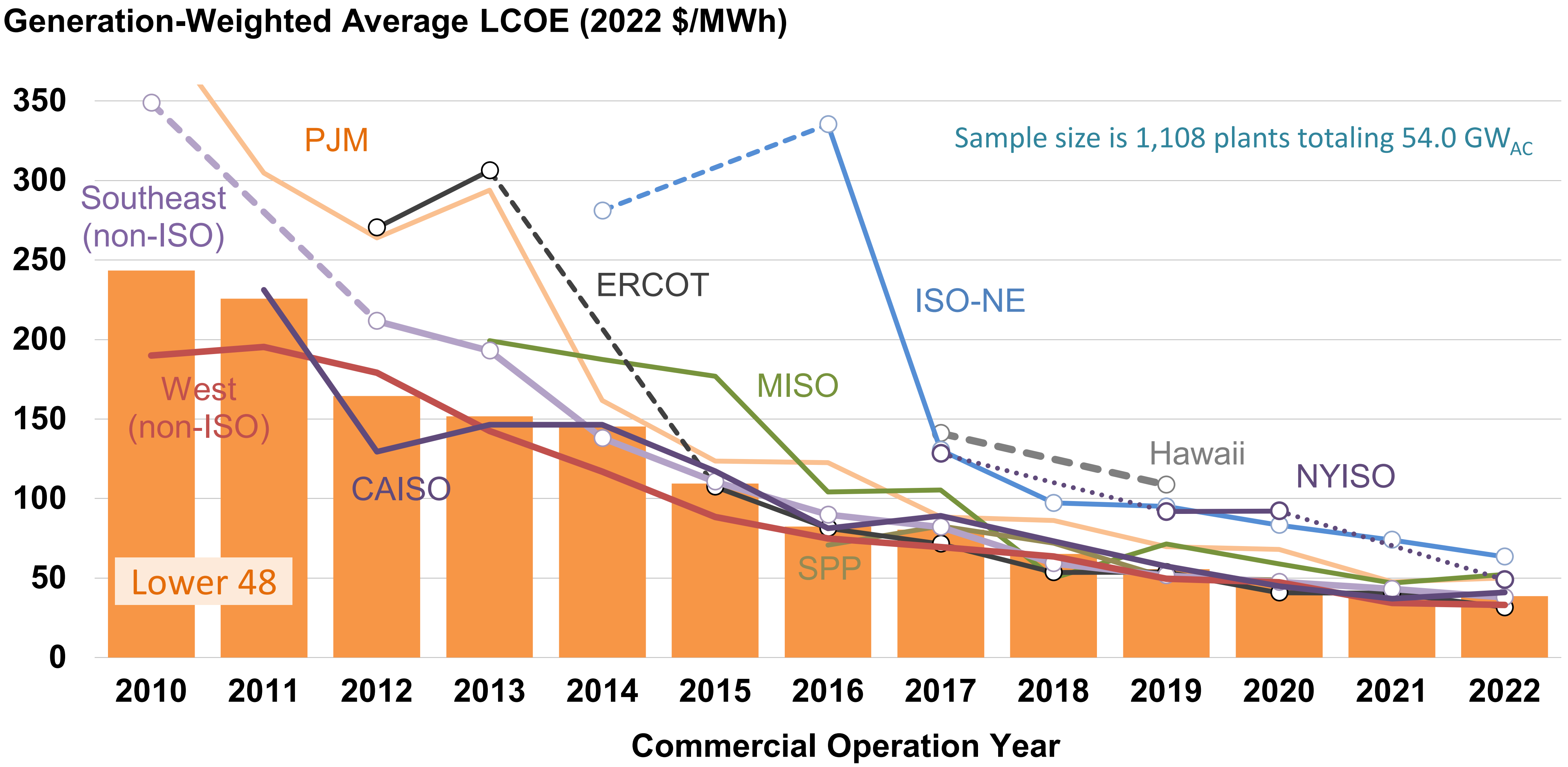


Driven by lower capital costs costs and, at least through 2013, higher capacity factors (as well as lower operating expenses, longer design life, and improved financing terms), utility-scale PV's average LCOE has fallen by about 84% since 2010, to $39/MWh in 2022 (not including the ITC)—down slightly from $41/MWh in 2021.

The standard deviation of project-level LCOEs has declined sharply among recent vintages (though the coefficient of variation has been more stable).

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

Utility-Scale PV's LCOE has been slowly converging across regions



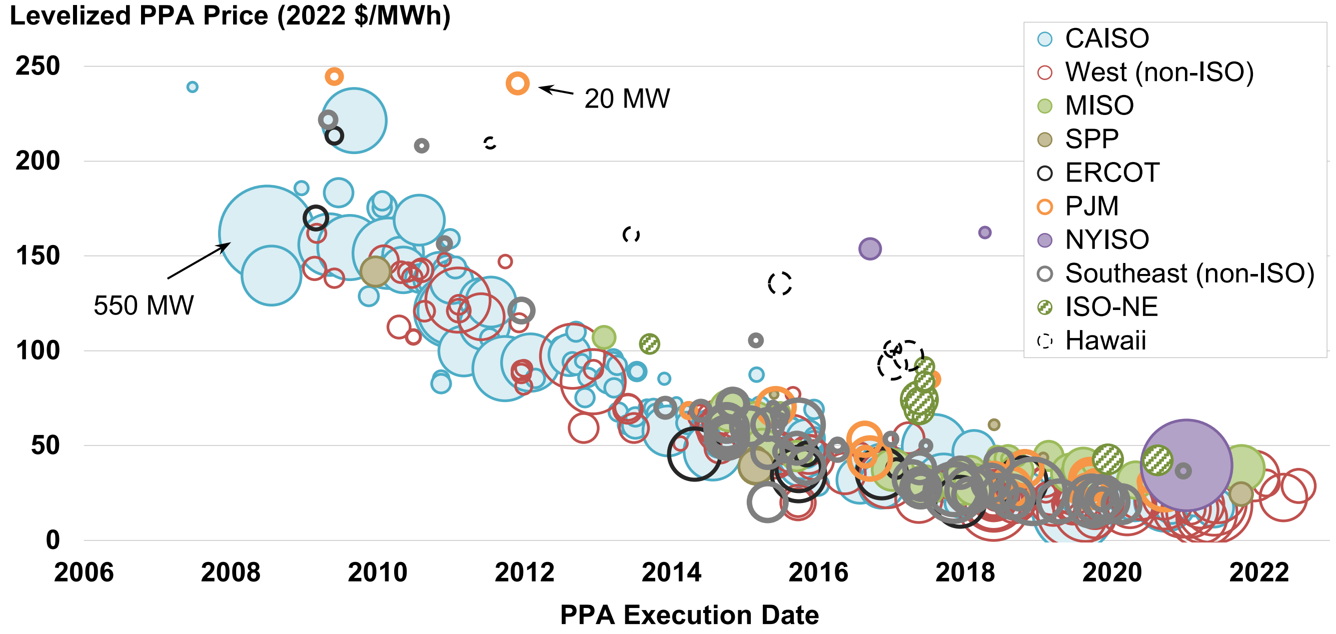
Lower-insolation regions (ISO-NE, NYISO, PJM, MISO) will always have higher LCOEs than higher-insolation regions (ERCOT, CAISO, the non-ISO West and Southeast), but the difference has narrowed over time.

Dashed segments of lines indicate no data (i.e., <2 projects) for that particular region-year combination.

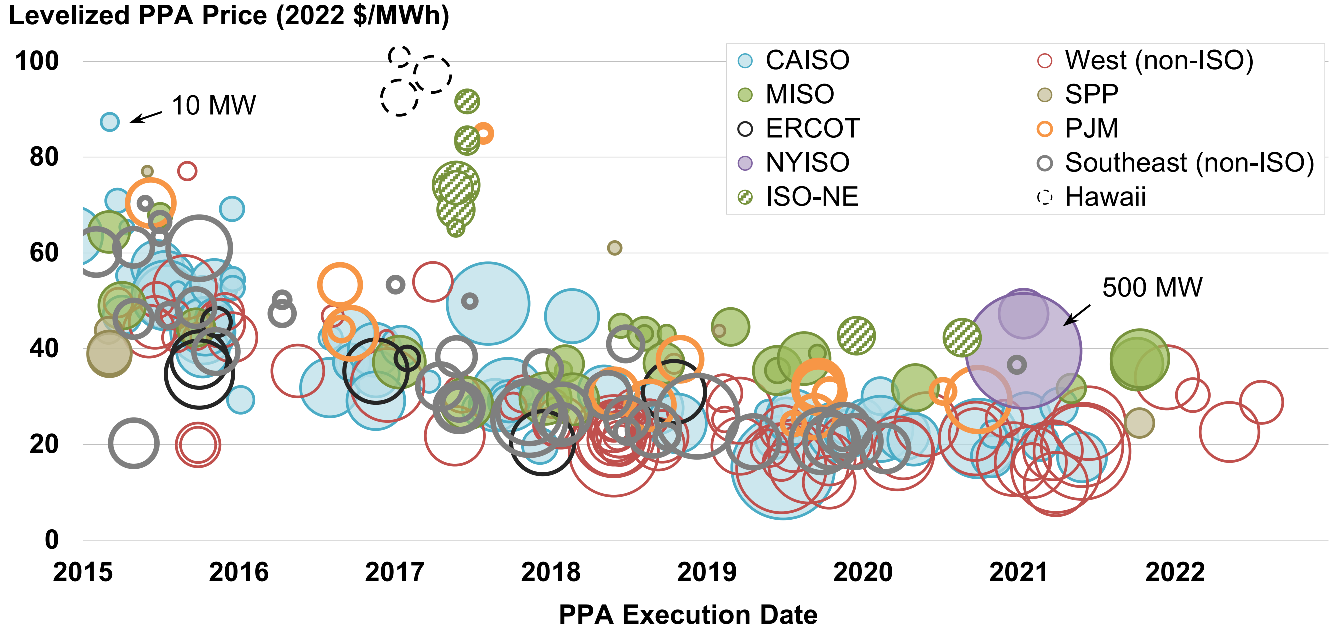
See interactive visualization at https://emp.lbl.gov/capex-lcoe-and-ppa-prices-region

Levelized PPA prices have followed LCOE lower in all regions, but have stagnated since 2019

Full sample: 422 PPAs, 30.6 GW_{AC}



Post-2014 sample: 263 PPAs, 21.1 GW_{AC}

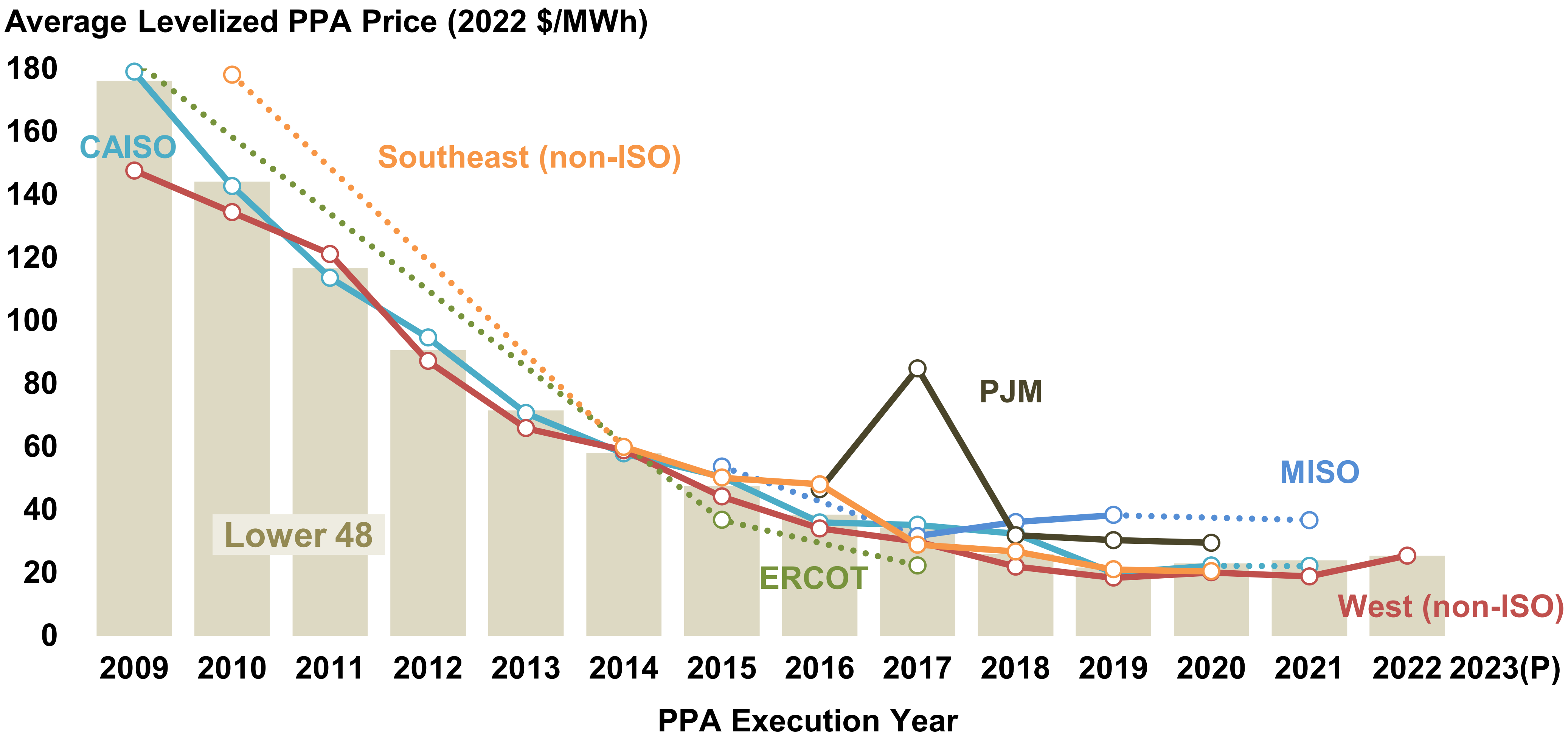


- Power Purchase Agreement (PPA) prices are levelized over the full term of each contract, after accounting for any escalation rates and/or time-of-delivery factors, and are shown in real 2022 dollars
- Aided by the 30% ITC, most recent PPAs in our sample are priced around $20-$30/MWh for projects in CAISO and the non-ISO West, and $30-$40/MWh for projects elsewhere in the continental United States
- Hawaiian PPAs are often higher-priced (and most include battery storage, and so are not shown here—see later section)
- >95% of the sample is currently operational

BERKELEY LAB

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

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



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

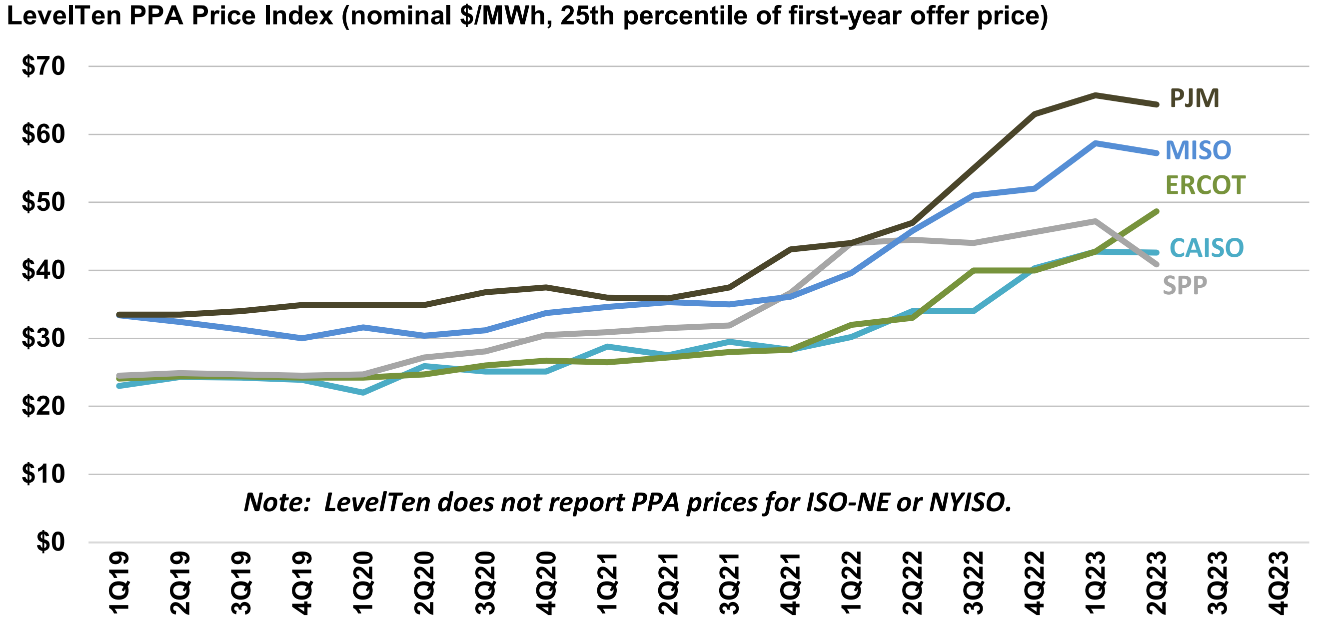
The national average was $25/MWh in 2022 (based on a small sample), up slightly from 2019's low of $22/MWh.

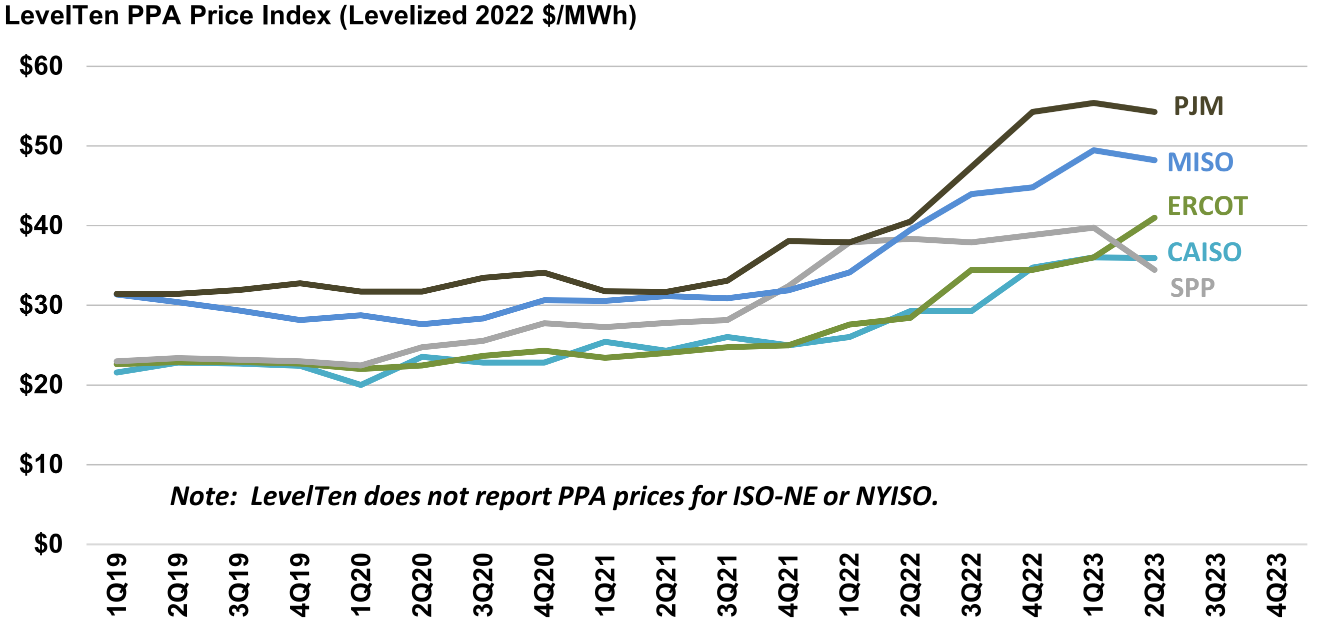
Year-Region combinations with fewer than 2 PPAs are excluded from the graph (dashed line segments indicate that the line is skipping over such years).

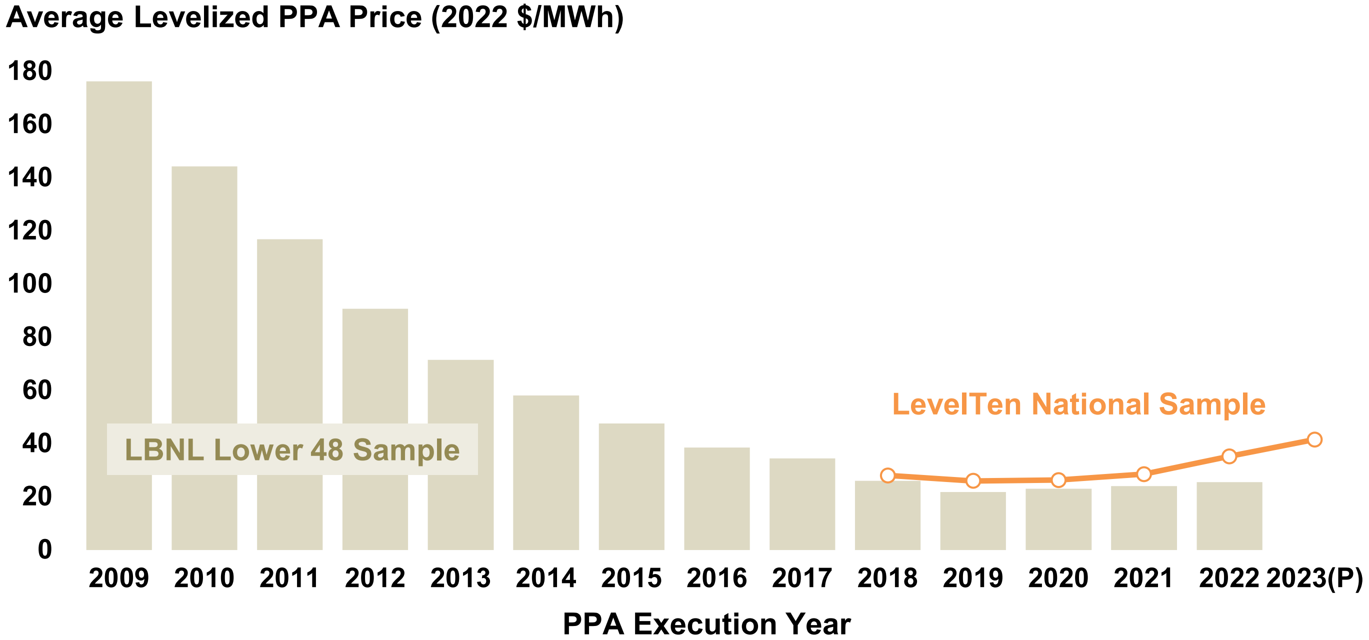
The graph reflects PV-only pricing, not PV+battery (PV+battery PPA prices are presented separately, in a later section).

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

Converted to real dollar terms, LevelTen Energy's utility-scale PV PPA price indices match trends seen in the LBNL sample





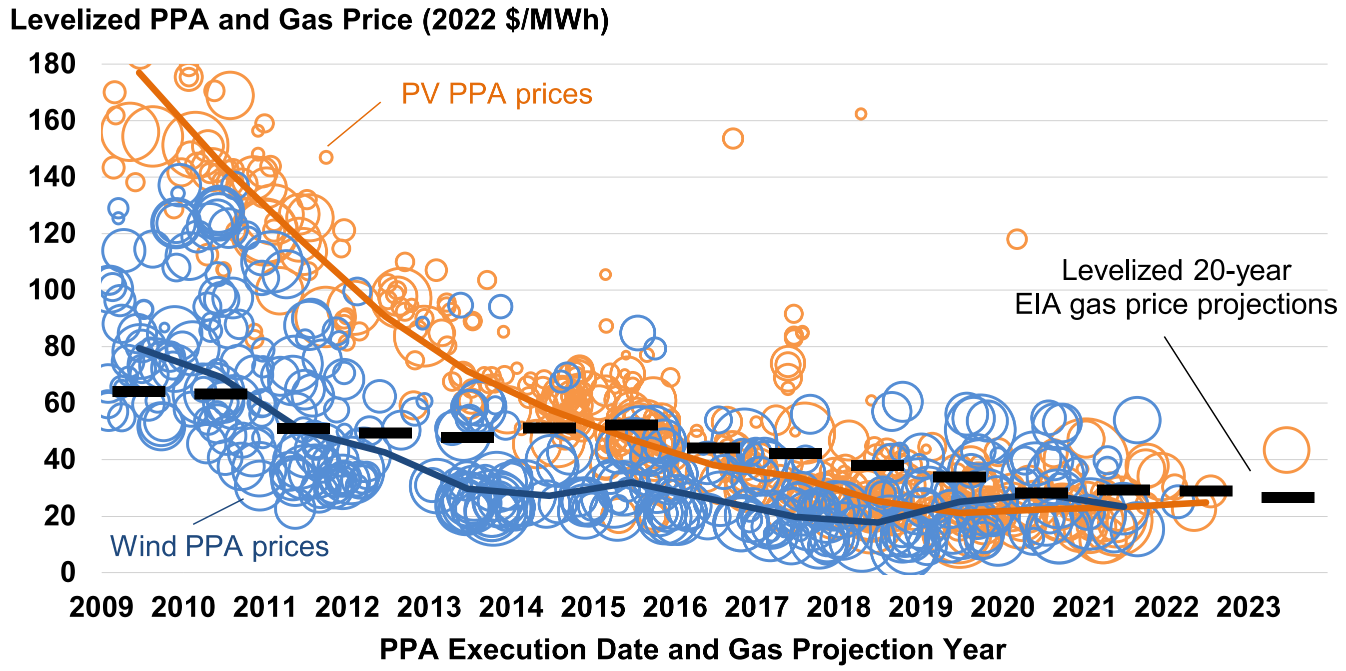


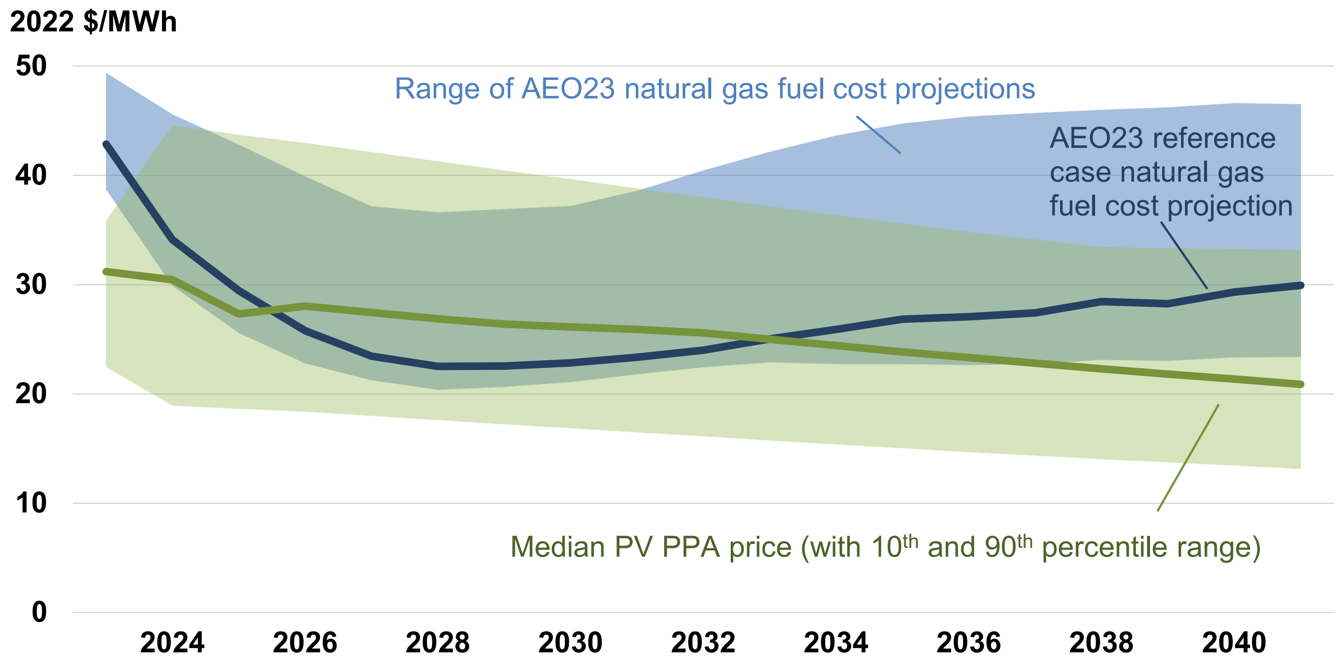
To augment our PPA price sample, and to gain visibility into corporate PPA pricing (which is not well-represented within our sample), we present LevelTen Energy's PPA Price Index.

LevelTen reports the 25th percentile of first-year offer prices in nominal dollar terms (upper left graph); in the upper right graph, we have converted the data to levelized real dollar terms (see the data workbook for notes on conversion methodology).

The bottom left graph shows consistency in national time trends between the two data sets, with the LevelTen data foreshadowing continued price increases in 2023.

Solar PPA prices are now often competitive with wind PPA prices, as well as the cost of burning fuel in *existing* gas-fired generators



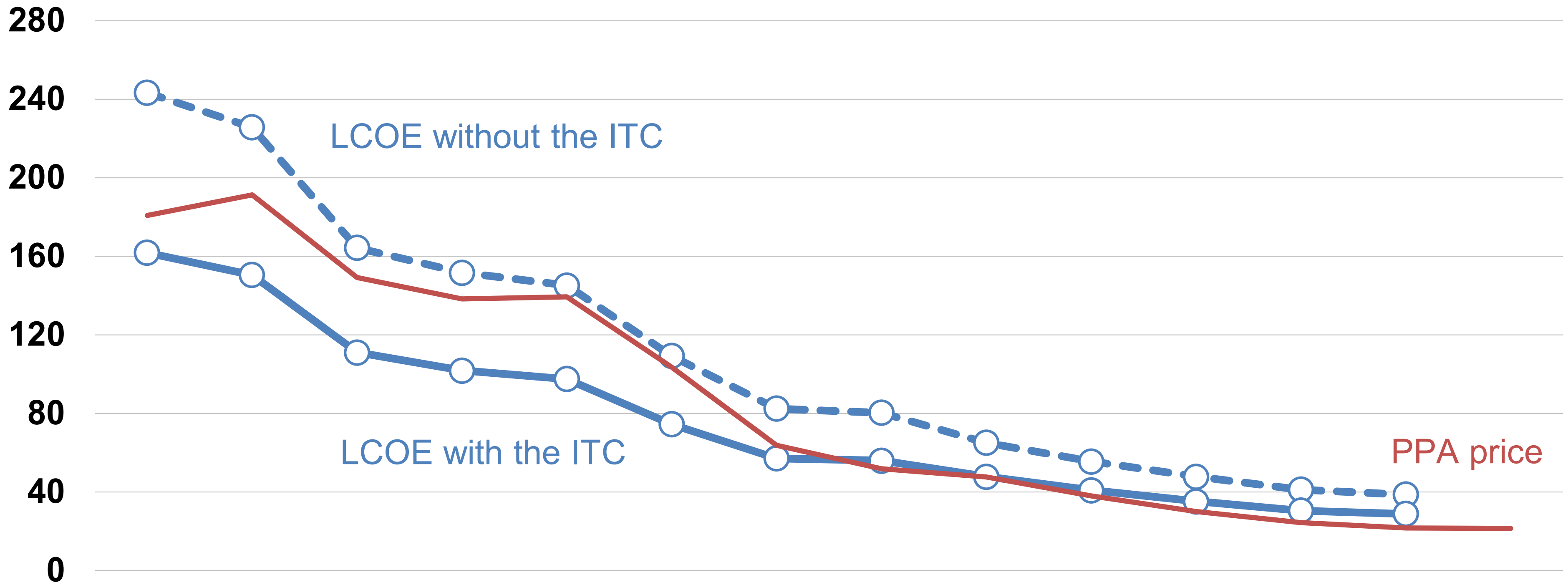


- The left graph shows that solar PPA prices have largely closed the gap with wind, and both are competitive with levelized gas price projections.
- The right graph compares recent solar PPA prices (extending out over their contract terms through 2040) to the range of gas price projections from the EIA's Annual Energy Outlook 2023 (AEO 2023). The median price from solar PPAs signed post-2020 is competitive with the projected AEO 2023 reference case cost of burning fuel in an ***existing*** combined-cycle natural gas unit (NGCC). The widening gap over the longer term suggests how PV can help protect against fuel price risk.
- Note that PV PPAs are priced to recover *both* capital *and* other ongoing operational costs—for an NGCC, this would add another ~$18-$77/MWh (per *Lazard* data) to the projected fuel costs shown in the graphs.

Levelized PPA prices track the LCOE of utility-scale PV

LCOE Sample: 1,101 plants totaling 53.8 GW_{AC}

Generation-Weighted Average LCOE and Levelized PPA Price (2022 $/MWh)



COD:	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plants:	10	28	39	38	63	85	145	160	93	99	159	123	59	TBD
MW-AC:	175	423	894	1,344	3,166	2,840	7,377	3,996	3,929	4,401	9,481	11,203	4,622	TBD

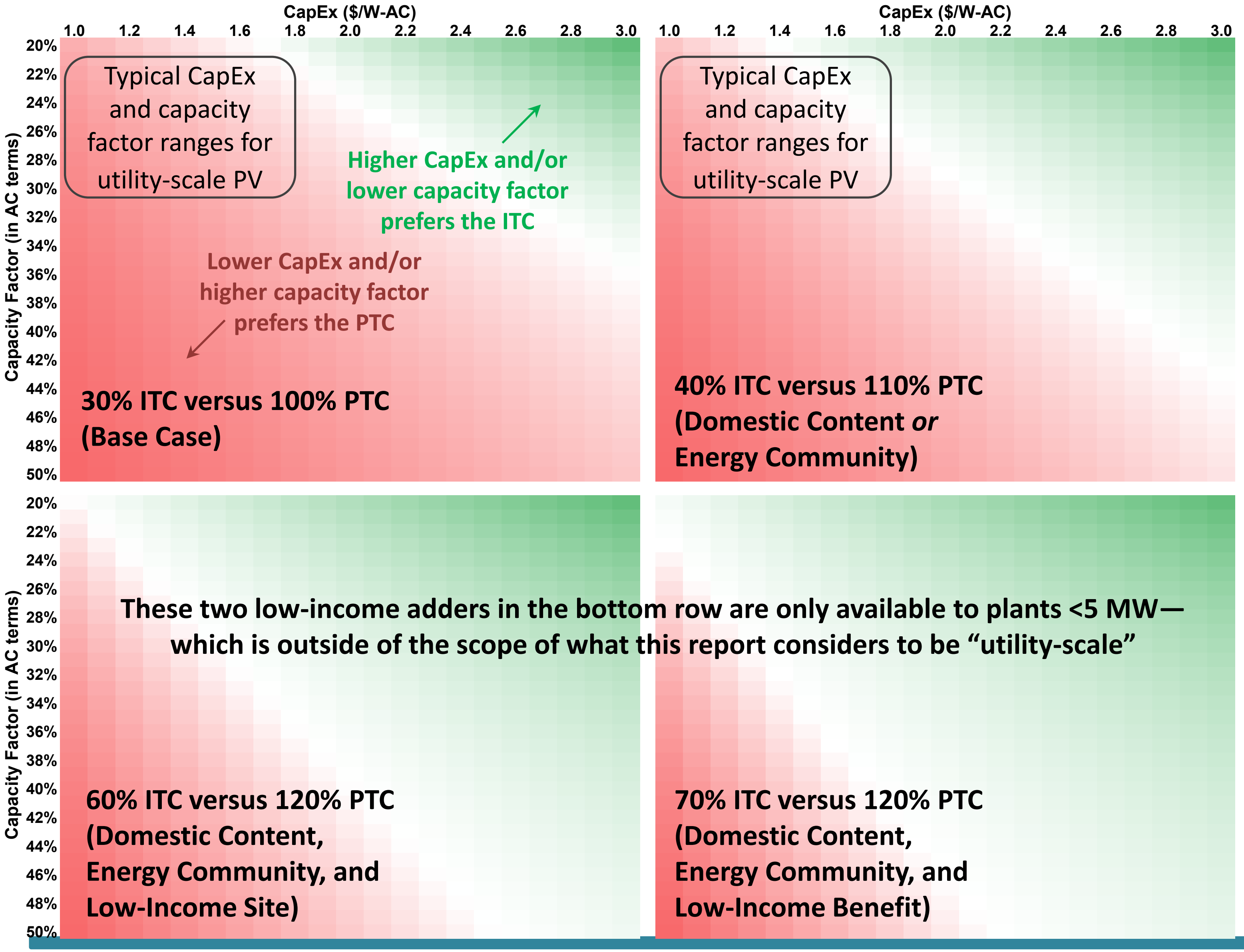
Commercial Operation Year

Prior LCOE graphs exclude the ITC, but here we graph LCOE both with and without the ITC, plotted against PPA prices by COD year (rather than by PPA execution date).

Levelized PPA prices fall within the range of the two LCOE curves over time, and since 2016 have closely tracked LCOE with the ITC, suggesting full pass-through of the credit and a competitive PPA market.

Also notable is the declining value of the ITC in $/MWh terms: while the credit has remained constant over time in percentage terms (at 30%), it has shrunk in $/MWh terms along with the CapEx to which it is applied.

Starting in 2023, PPA prices could benefit from solar now having access to the PTC under the Inflation Reducation Act (IRA)



All else equal, many utility-scale PV plants will find the **production tax credit (PTC)** to be more valuable than the **investment tax credit (ITC)**…but the PTC's advantage fades somewhat with the addition of bonus credits.

- X-axis: CapEx ranging from \$1/W-\$3/W_{AC}
- Y-axis: Capacity factor from 20%-50% (in AC terms)
- **Green-shaded combinations prefer the ITC**
- **Red-shaded combinations prefer the PTC**
- ITC adders (i.e., bonus credits) are worth more than PTC adders
  - A "10 percentage point" ITC adder is more than a "10%" PTC adder (moving from 30% to 40% ITC is a 33% increase)
  - The PTC caps out at 120%—the two low-income adders are ITC-only (and <5 MW, and must be allocated)

Wholesale Market Value

Wholesale market value analysis: data sets and methodology

We estimate the wholesale market value for each utility-scale PV project larger than 1 MW (as reported on Form EIA-860). We then aggregate the project-level data as generation-weighted averages for all seven ISOs and ten additional balancing authorities.

We draw from project-level modeled hourly solar generation (using NREL's System Advisor Model and site- and year-specific insolation data from NREL's National Solar Radiation Database and NOAA's High Resolution Rapid Refresh Model) and de-bias the generation by leveraging ISO-reported aggregate solar generation and plant-level reported generation by Form EIA-923.

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

- Plant-level debiased hourly solar generation
- Real-time energy price from nearest pricing node
- Focus on annual value of solar from all sectors

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

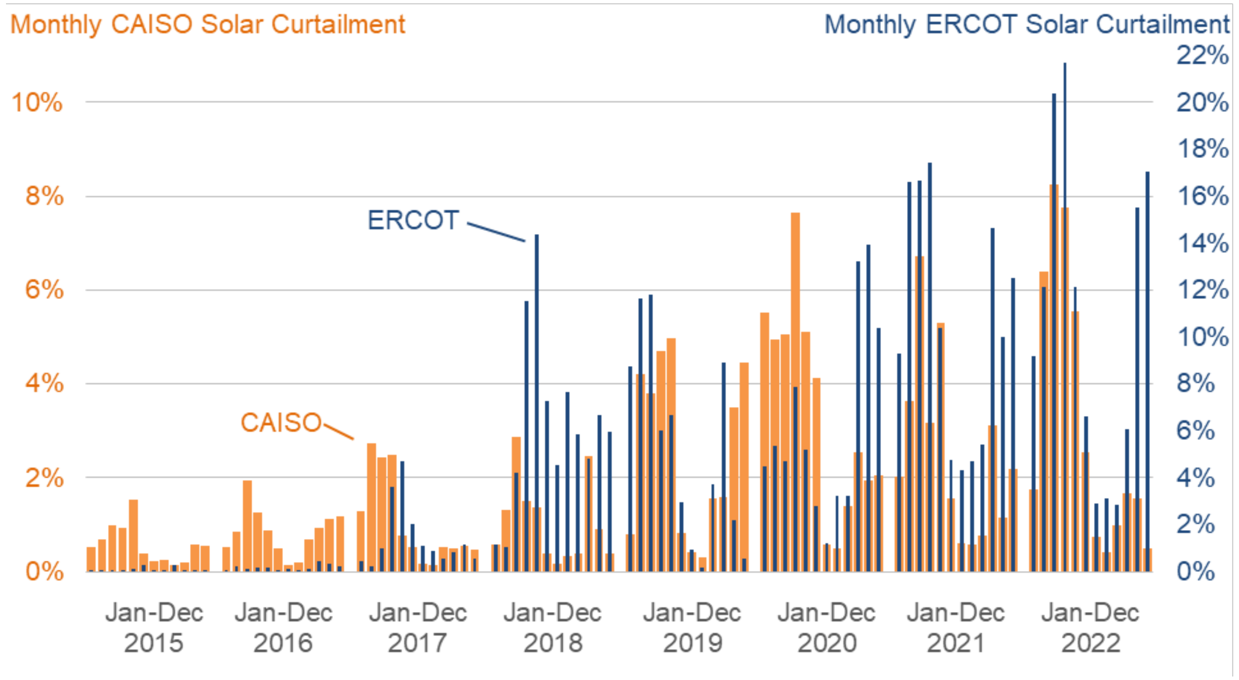
Capacity value is the product of a plant's or county's capacity credit and capacity prices

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

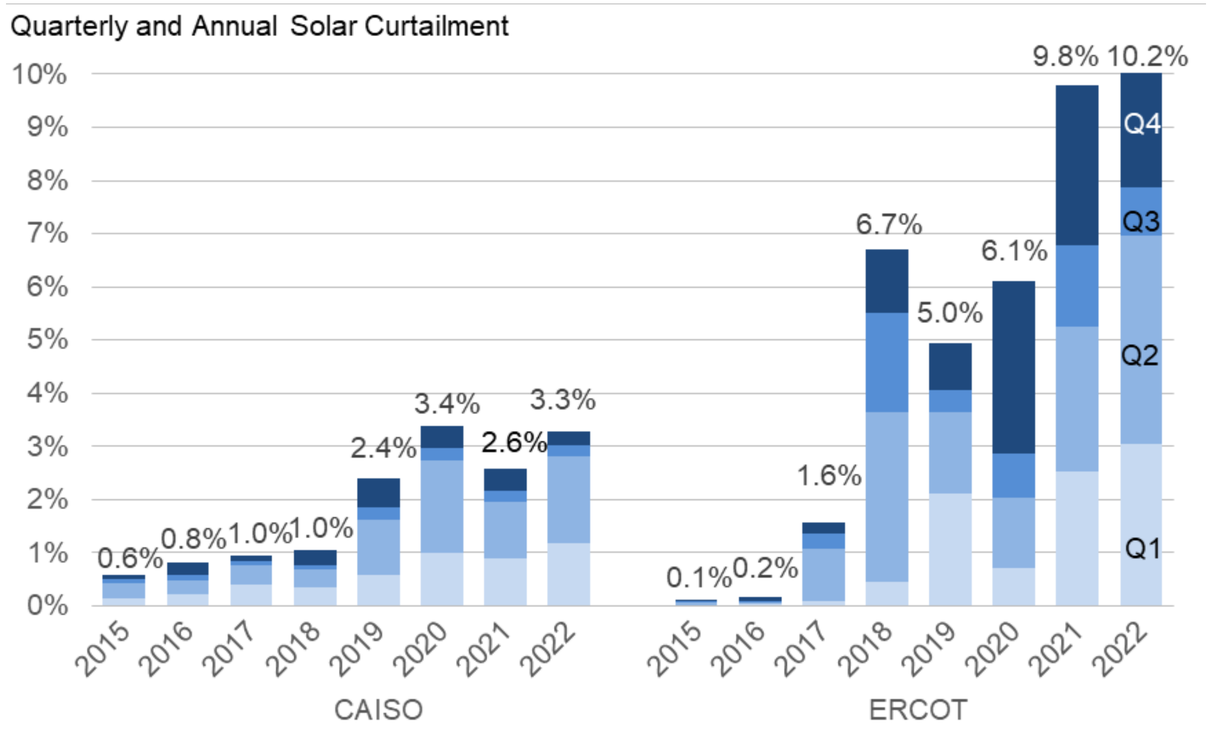
$$Capacity\ Value = \frac{\sum Capacity\ Credit_T * Nameplate * Capacity\ Price_T}{\sum Precurtailment\ Generation_T}$$

Total market value is simply the sum of energy and capacity value and does not include any potential additional revenue streams (ancillary service revenues, renewable energy credits, infrastructure deferral, resilience, energy security, or any other environmental or social values that are not already internalized in wholesale energy and capacity markets).

Only two of the seven ISOs currently report solar curtailment: CAISO and ERCOT



The orange columns represent curtailment in CAISO (left axis), the blue ones in ERCOT (right axis)

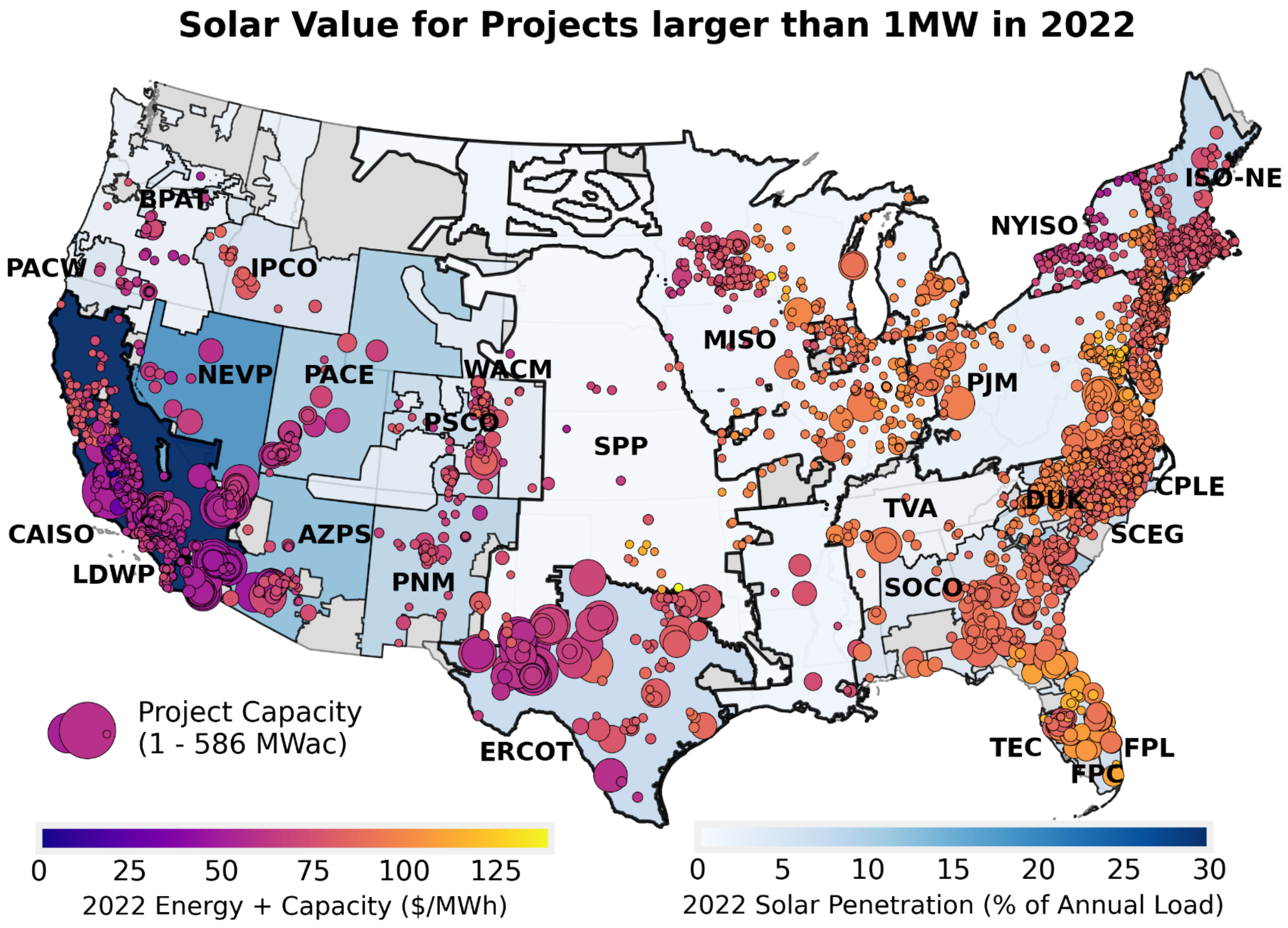


CAISO: 2,057 GWh of solar curtailed in 2022, equivalent to the annual output of a hypothetical 815 MW_{AC} tracking PV project operating at an average CA capacity factor of 28.8% (which would have been 29.8% if not for curtailment).

ERCOT: 2,797 GWh of solar curtailed in 2022, equivalent to the annual output of a hypothetical 1309 MW_{AC} tracking PV project operating at an average TX capacity factor of 24.4% (which would have been 27.2% if not for curtailment).

Much higher *rate of curtailment* in ERCOT (10.2%) than in CAISO (3.3%) in 2022, even though solar's penetration rate is far lower in ERCOT (6.5%) than CAISO (26%). While CAISO's curtailment is usually focused in the spring time, curtailment in ERCOT also occurs in the winter.

Solar's energy and capacity value varied by location



Solar's energy and capacity value varies from one wholesale market to another: It is lower in CAISO at $51/MWh, but high in many southeastern regions ($84-108/MWh), PJM ($85/MWh), Indiana ($81/MWh), or ISO-NE ($77/MWh.

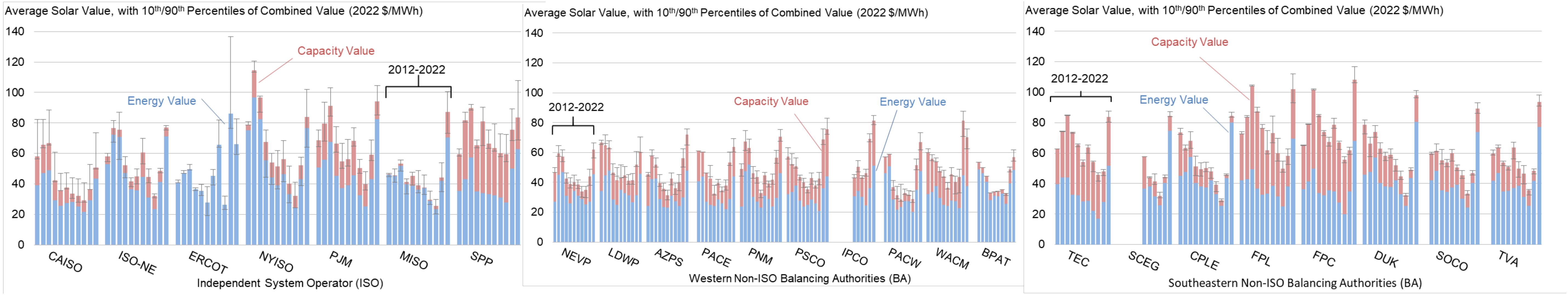
But value also varies within regions, driven by transmission congestion, solar resource quality or differing use of technology like trackers.

For example, in ERCOT, the western zone typically has lower solar values than the eastern zone. Solar in southern SPP and NYISO was nearly $40/MWh more valuable than solar in the north of the ISOs.

Other markets like PACE or BPAT show value variation of under $10/MWh.

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

Very high electricity prices lifted solar's energy value in 2022, bringing total energy and capacity value to record $71/MWh (40% above 2021 levels)



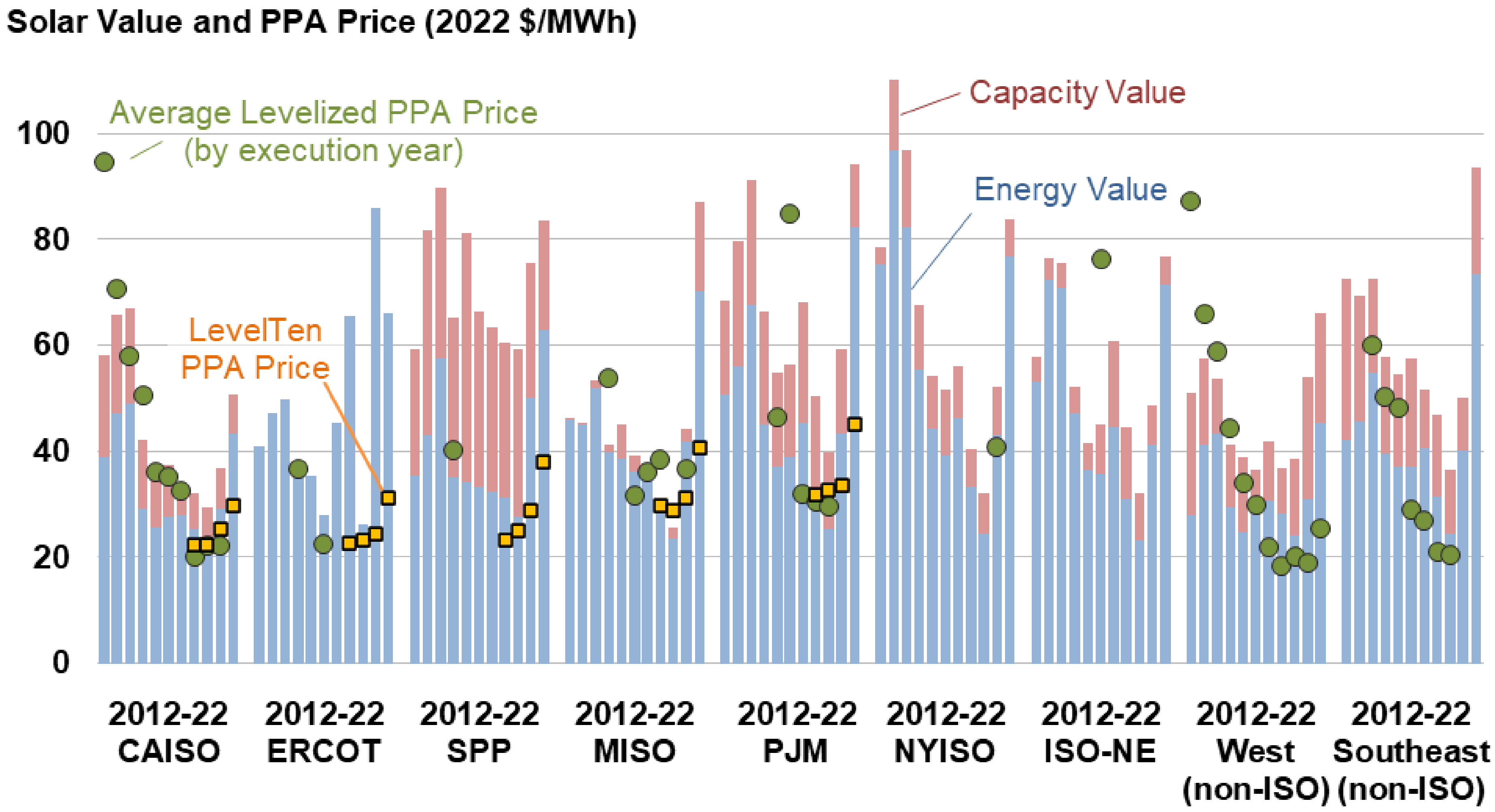
The regional solar value is the generation-weighted average value of all large-scale (1 MW+) solar generation in a given balancing authority.

The energy value typically makes up the bulk of total market value. High natural gas prices in 2022 lifted solar's average energy value to $60/MWh – 250% of what it was in 2020. Capacity value is more significant in the non-ISO regions and can add $30-40/MWh in some BAs.

Variation across years mostly reflect fluctuations in wholesale power prices, but also reflects increasing solar penetration that dampens solar's value (CAISO).

In 2022, market value was lowest in CAISO ($51/MWh) and highest in Duke Energy Florida (FPC - $108/MWh).

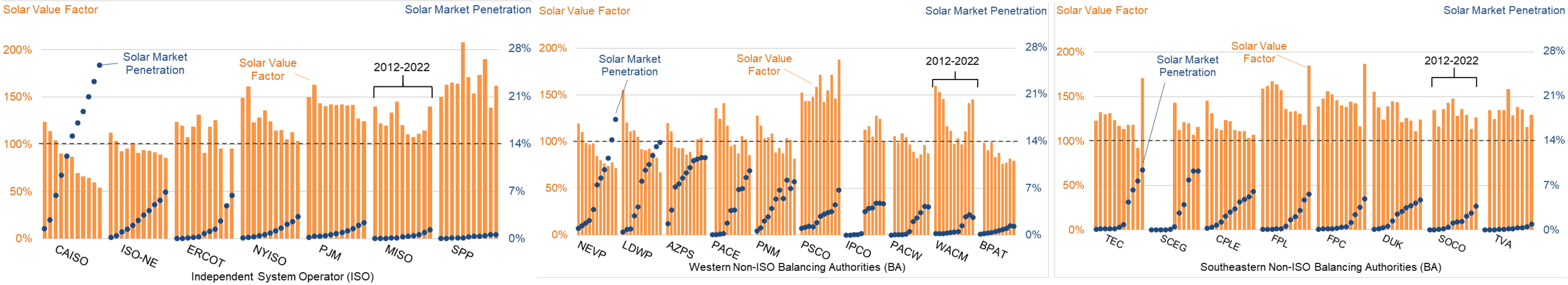
Solar's wholesale market value has been greater than PPA costs in recent years, despite rising PPA levels



The green dots show the average levelized solar PPA price within each region among new contracts signed in each year as reported by Berkeley Lab, the yellow squares represent PPA price estimates by LevelTen. We do not have sufficient PPA data to present robust trends for each balancing authority.

While solar's market value within several of these regions has declined over time, falling PPA prices have largely kept pace. Since 2020, rising wholesale energy prices more than compensated for moderate PPA price increases, making solar more competitive than it has ever been across the nation.

Solar provides below-average value in some regions with high solar penetration rates



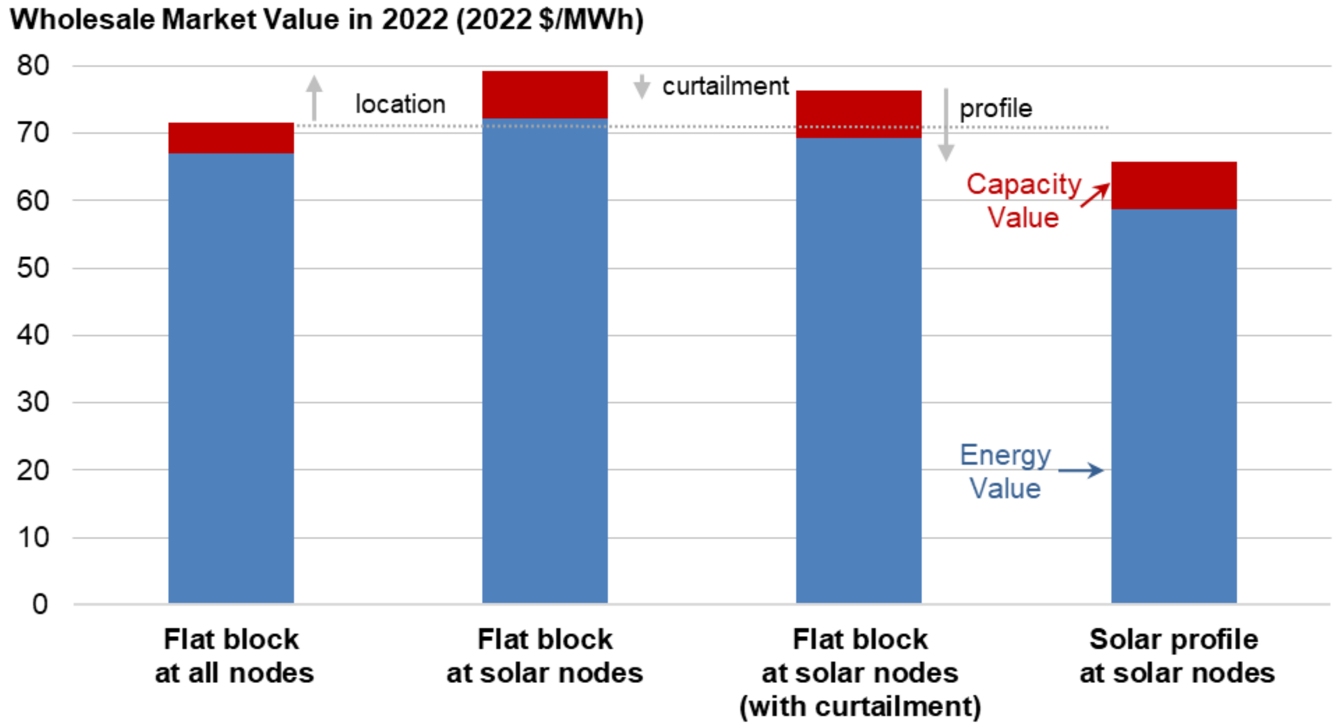
The columns represent the solar value factor (left axis), the dots show growth in solar market penetration (right axis)

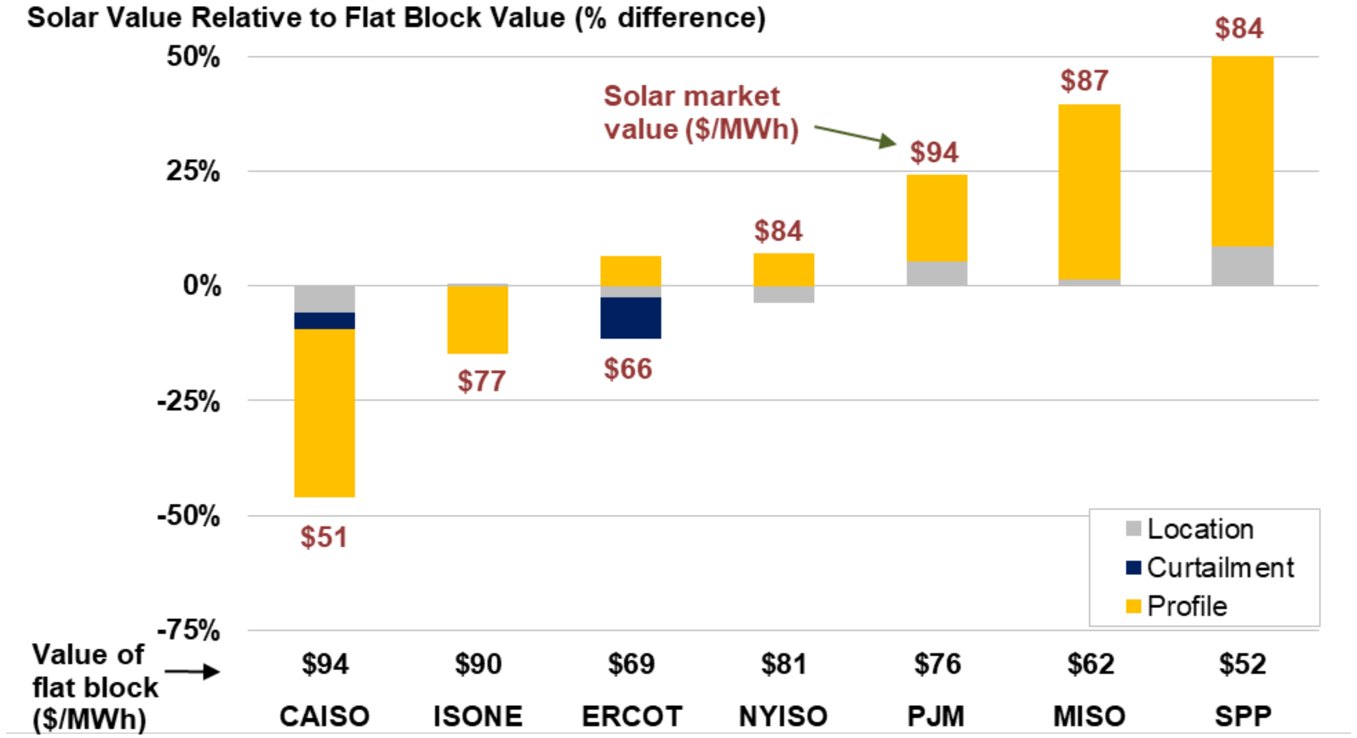
The “Value Factor” is defined as the ratio of solar’s total market value (both energy and capacity) to the market value of a “flat block” (i.e., a 24x7 block) of power. It indicates whether the total revenue captured by solar is higher (>100%) or lower (<100%) than the average wholesale price across all hours.

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

Most regions with the highest solar penetration rates show Value Factors less than 100%, even just 54% in CAISO. However, in many southeastern BAs solar still provides above-average value despite approaching 10% penetration.

Solar's generation profile was the largest source of value differences between solar and a flat block in 2022





Across the seven ISOs, solar projects are usually sited at locations with above average energy values. The large amount of solar deployed in areas with lower relative value (CAISO, ERCOT, ISONE) yields a value factor of 92% across all solar projects in the ISOs.

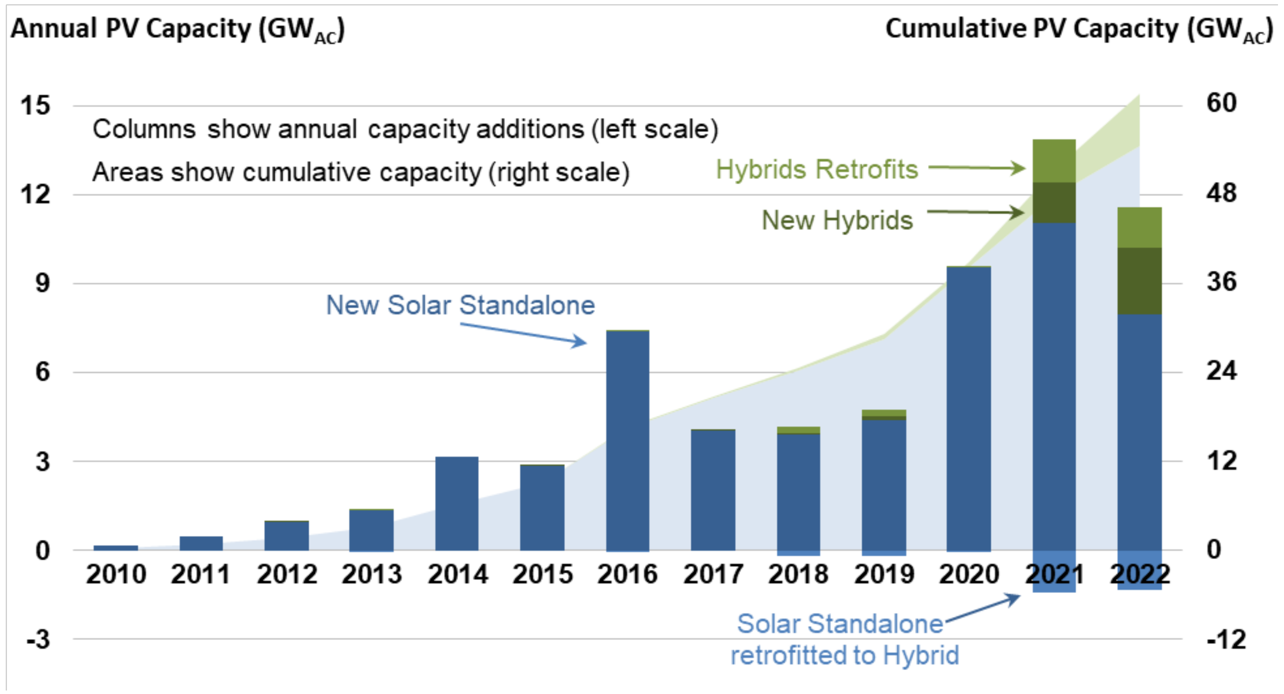
Solar's generation profile has the largest impact and either hurts (in CAISO and ISO-NE) or helps (in ERCOT, NYISO, MISO, PJM, and SPP) solar's value relative to a flat block. Curtailment is becoming a growing issue for solar in ERCOT.

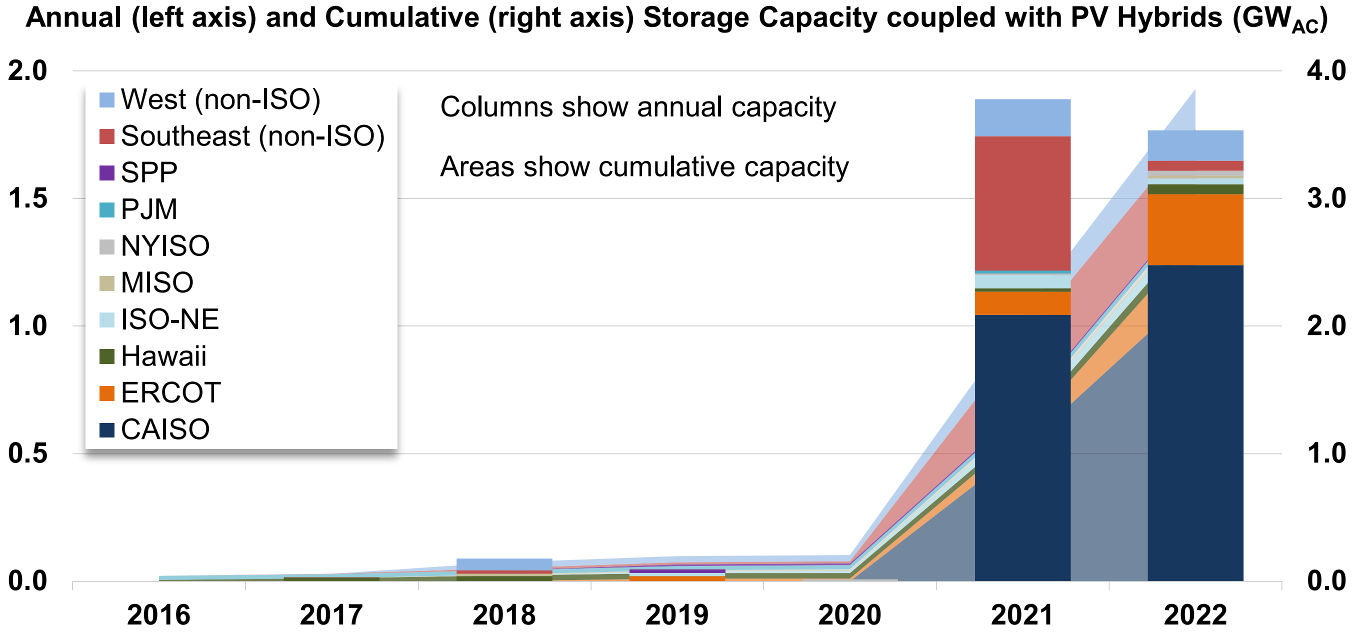
PV+Battery Hybrid Plants

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

Deployment of PV-battery hybrid plants was largely stable in 2022 after a surge in 2021

Sample: 100 projects totaling 7.1 GW_{AC} of PV, 3.9 GW_{AC} of battery capacity, and 12.1 GWh of battery energy



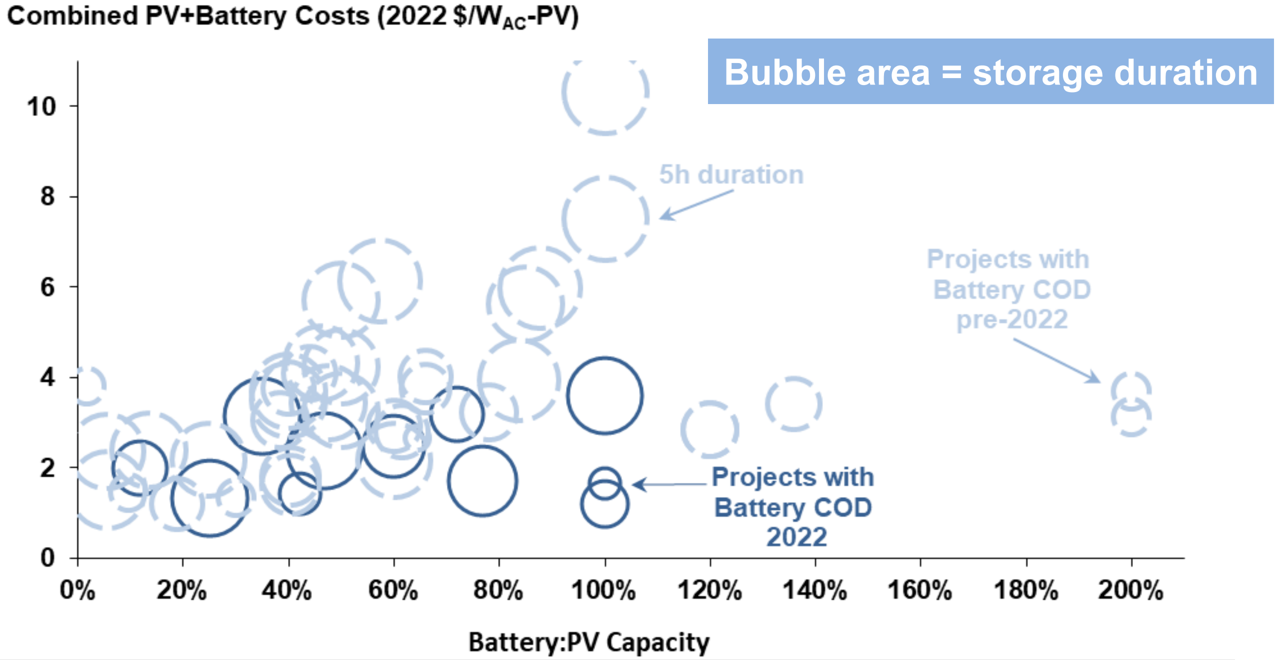


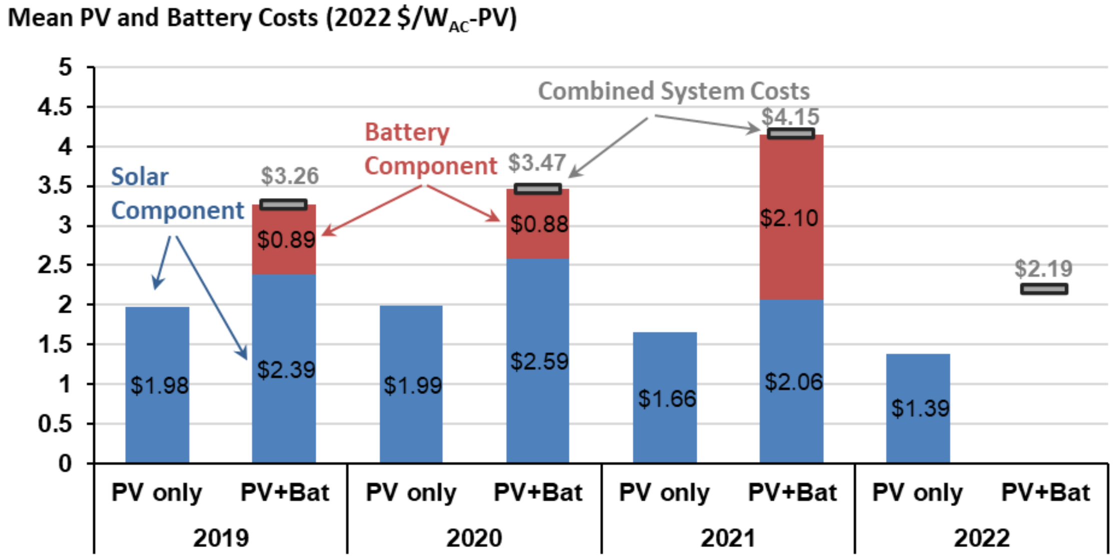
The large-scale PV+battery hybrid build-out started slowly in 2016, with just 1-11 plants/year built through 2020. The market started in earnest in 2021 with 39 hybrid installations. While growth slowed a bit in 2022 among retrofits to existing PV plants (9 plants, 1.4 GW_{AC}-PV), new greenfield hybrids installed record capacity (26 plants, 2.2 GW_{AC}-PV).

Most of the new hybrid storage was built in CAISO (13 plants, 1.2 GW storage capacity with ~3.5h storage energy), and ERCOT (3 plants, 0.3 GW storage capacity with ~1h energy). Massachusetts built smaller plants via the MA Smart program (6 plants, 24 MW capacity with ~2h energy)

For PV+battery hybrid plants, the battery cost adder scales with increased storage capacity and duration

Sample: 63 plants totaling 5,317 MW_{AC} of PV and 3,029 MW/ 9,979 MWh of batteries with CODs from 2018-2022





Combined PV+battery costs generally scale with increased battery capacity (relative to the PV capacity) and storage duration.

In our hybrid cost sample, average combined costs decreased from \$4.15/W_{AC}-PV in 2021 (n=21) to \$2.19/W_{AC}-PV in 2022 (n=11). In 2021, half of the hybrids were retrofits to older PV projects, whereas our 2022 cost sample contains primarily new builds. Average storage duration in our cost sample decreased from 3.2h in 2021 to 2.7h in 2022

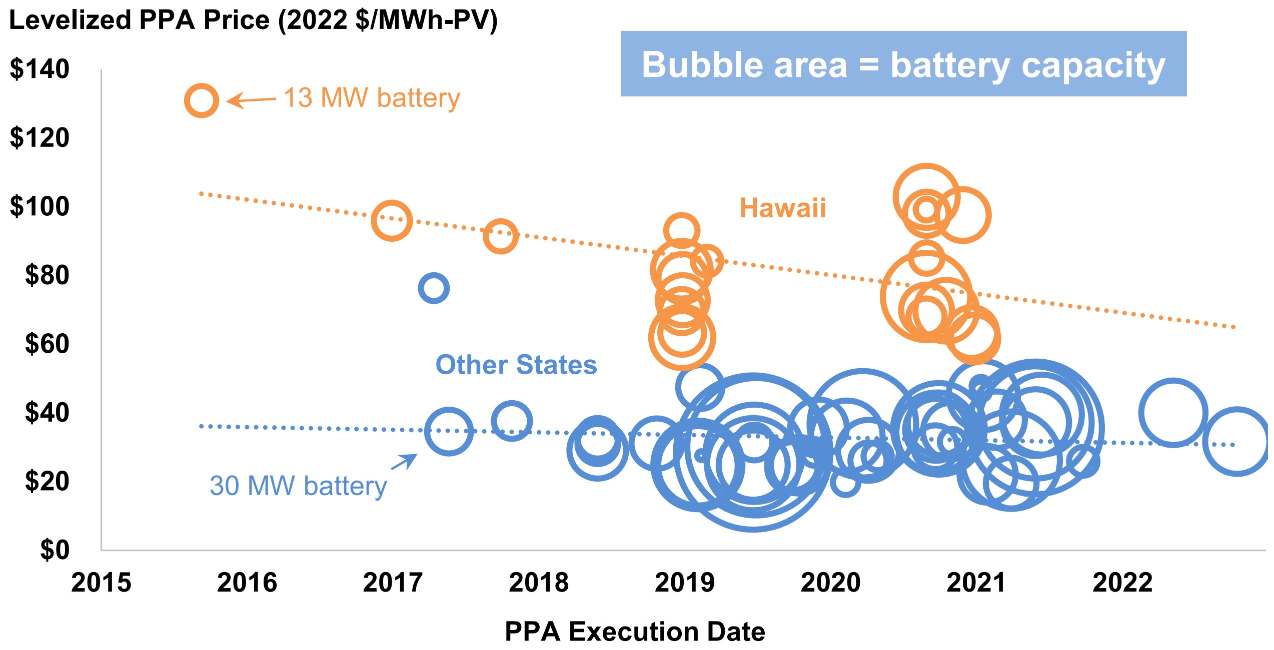
Not enough projects reported component costs in 2022 for a credible analysis, but we now have a robust cost sample for the year 2021. Back then, batteries cost \$709/kWh, representing a cost adder of \$2.1/W_{AC}-PV, or 51% of overall hybrid plant installed costs.

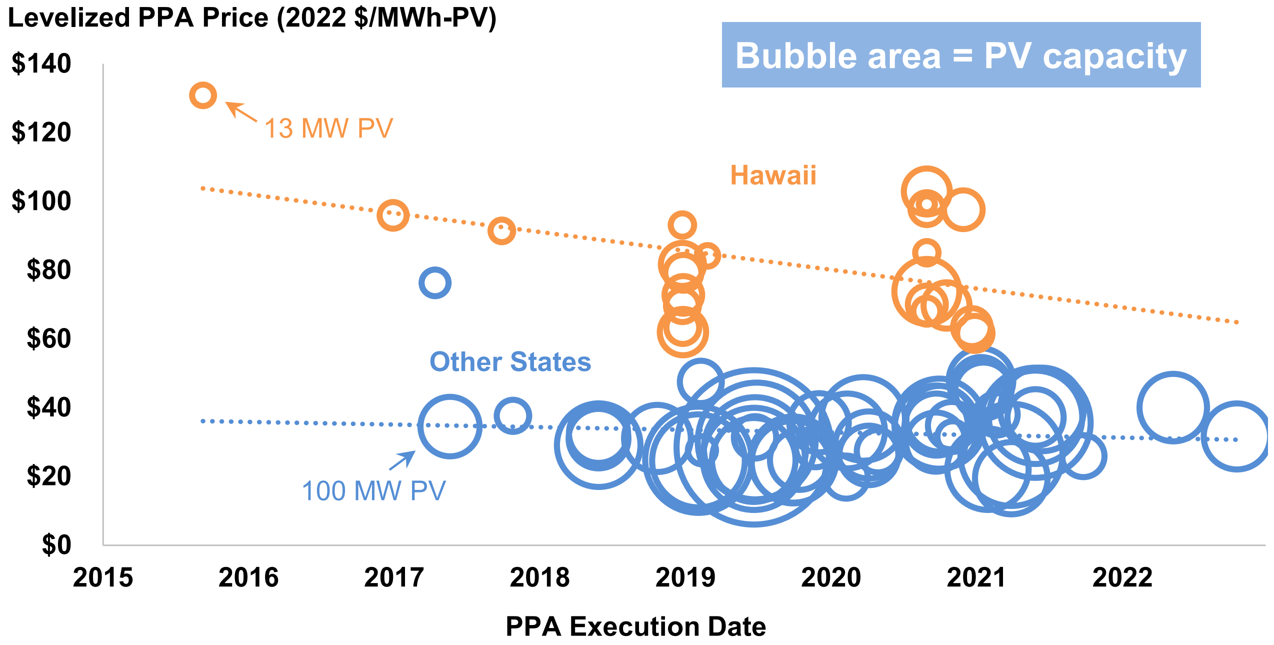
Solar components of hybrids may be more costly than standalone PV due to:

- a greater inverter loading ratio (overbuilt module arrays),
- retrofits to older PV projects when solar was more expensive,
- an uneven accounting of costs between the PV and battery components.

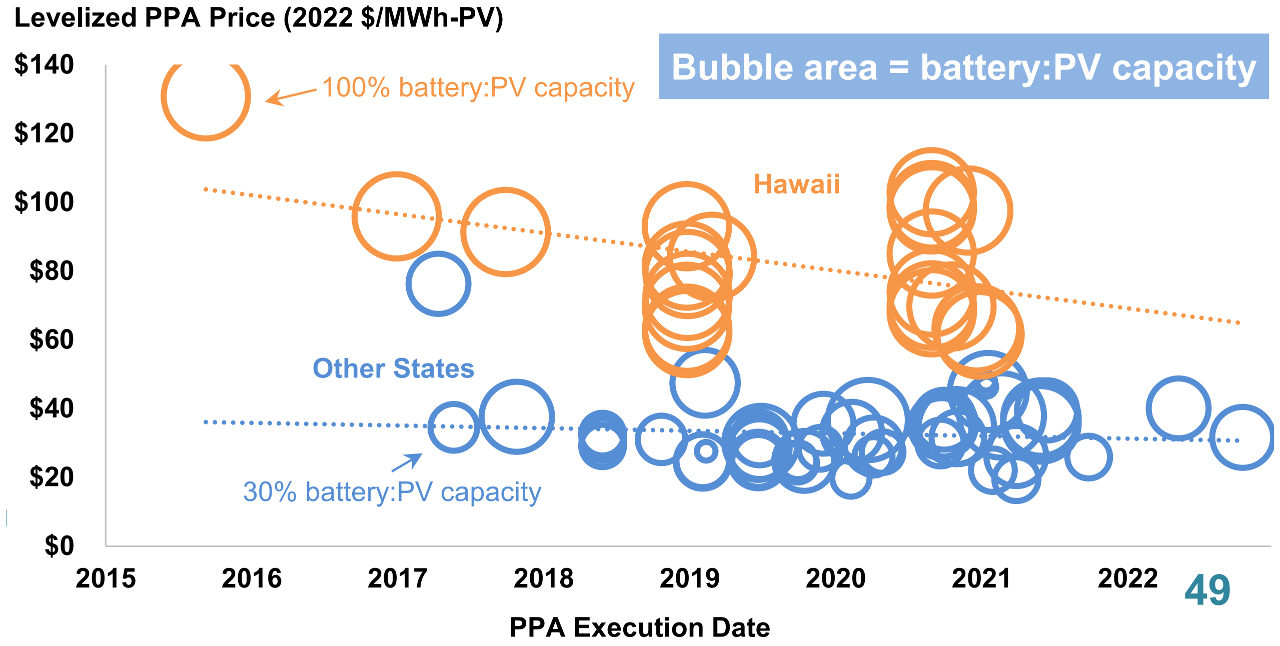
Note: We use means for the component cost analysis as medians (that we use for PV standalone cost analysis) do not sum neatly.

PPA prices for PV+battery hybrids have declined over time; Hawaii priced at a premium



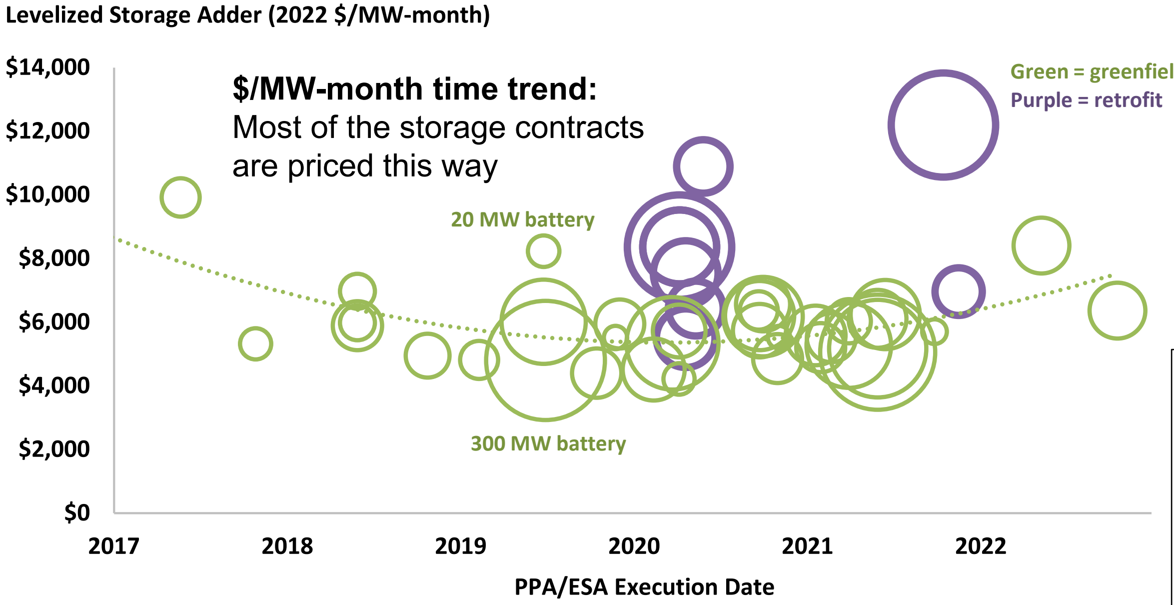


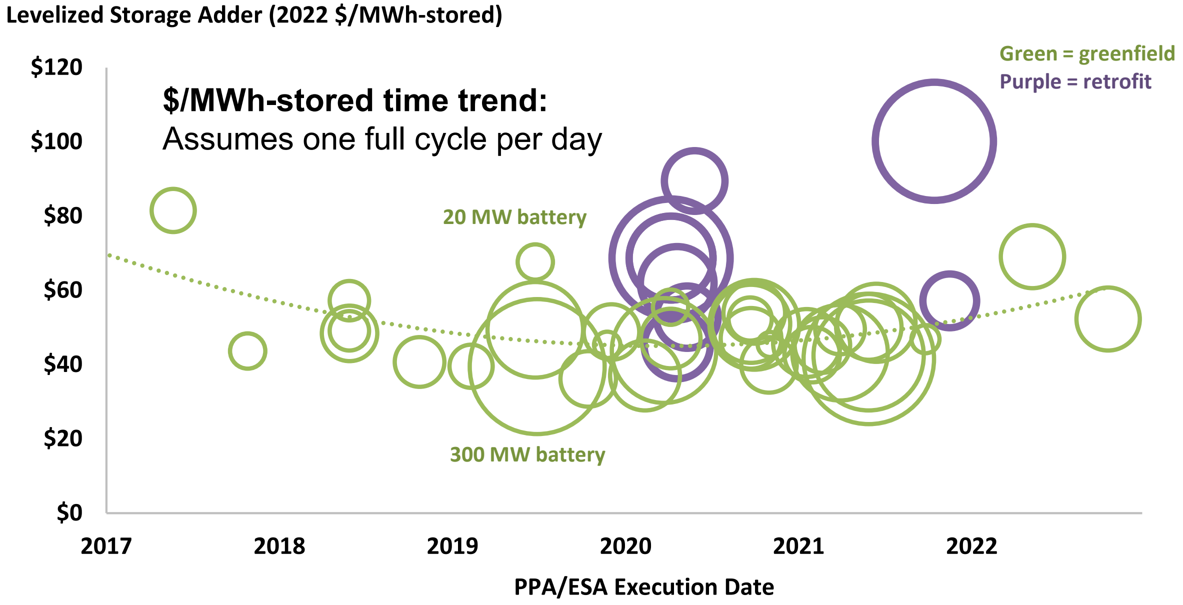
- All 3 graphs show same data from sub-sample of 71 plants (retrofits not included); the only difference is what the bubble size represents
  - Hawaii (orange): 22 plants, 0.8 GW_{AC} PV, 0.8 GW_{AC} battery
  - Other States (blue): 49 plants, 7.6 GW_{AC} PV, 3.7 GW_{AC} battery
- Downward trend over time, particularly in HI, but refinement is complicated by multi-dimensionality of these plants; other states are more heterogenous than HI in terms of solar resource
- Battery:PV capacity ratio always at 100% in HI; lower on the mainland (but increasing over time—see bottom right graph)
- Storage duration ranges from 2-8 hours; 59 of the 71 plants have 4-hour duration (other 12 are 5x2 hour, 1x2.5 hr, 1x3.7 hr, 4x5 hr, and 1x8 hr)



PPAs that price the PV and storage separately enable us to calculate a "levelized storage adder," shown here 4 different ways

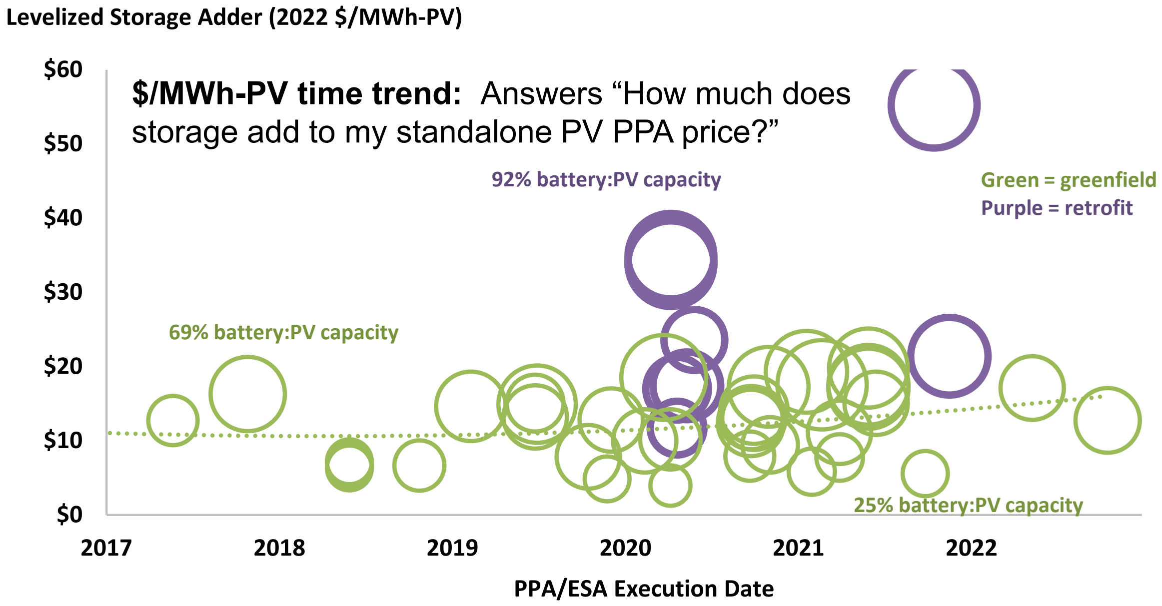
Graphs show adders from 44 PV hybrids in CA (25), NM (9), NV (6), AZ (3) and OR (1) totaling >3.7 GW_{AC} of batteries, all with 4-hour duration

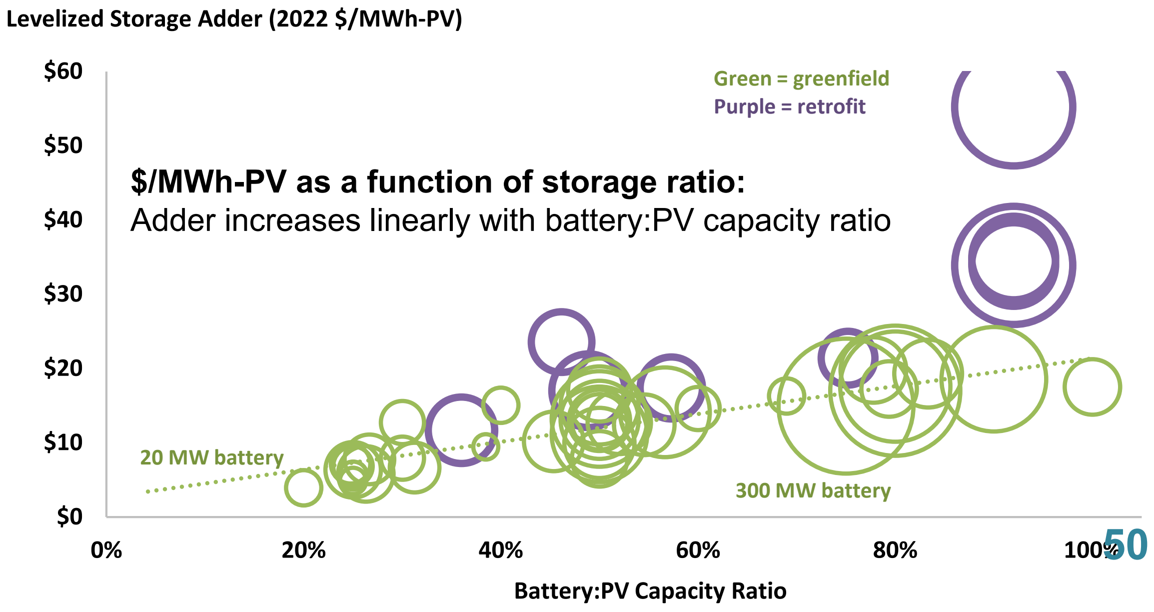




Green = greenfield
Purple = battery retrofit

Trend lines represent greenfield plants only. Bubble size corresponds to battery capacity except in bottom-left graph, where it corresponds to battery:PV capacity.

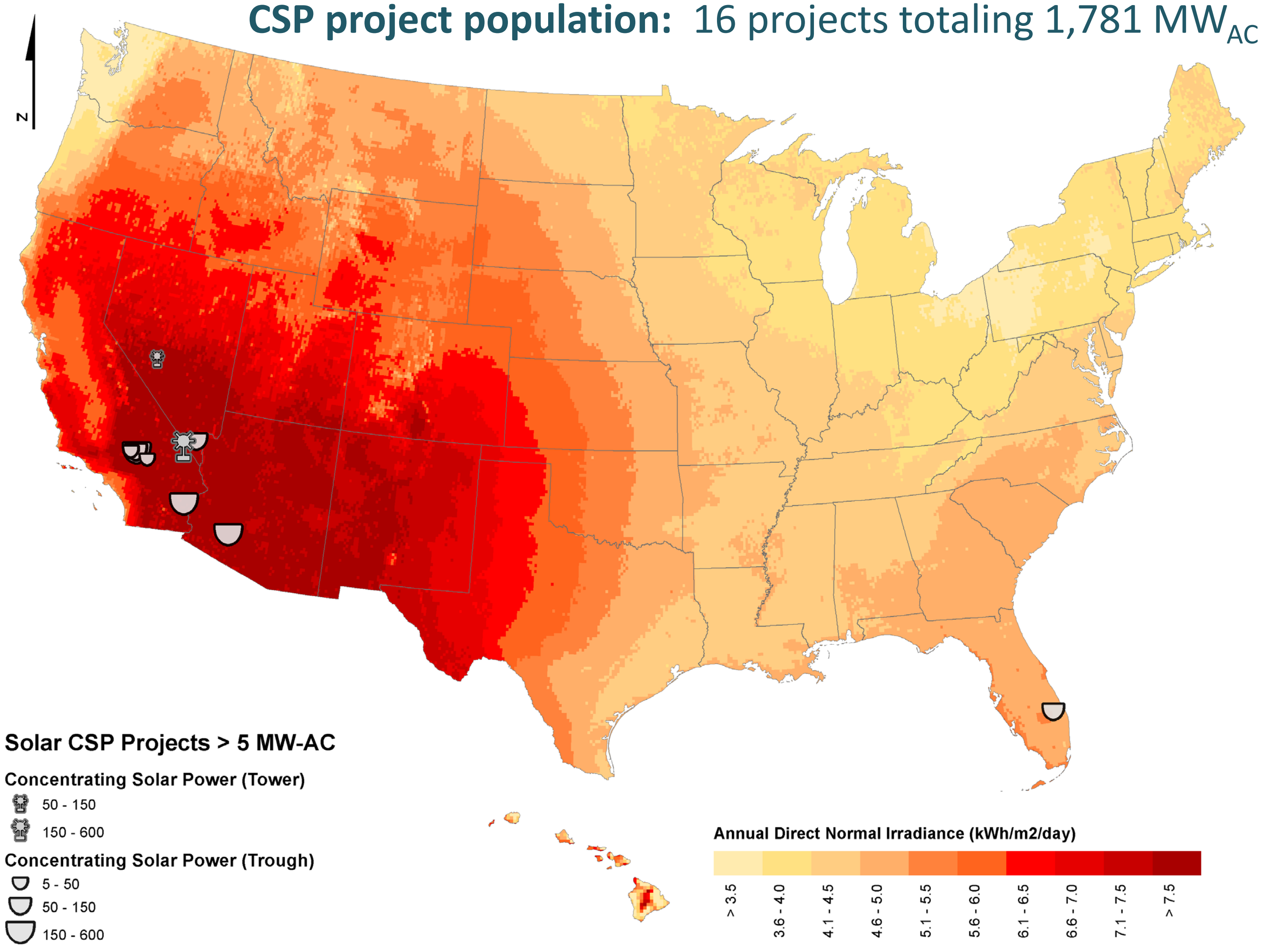




Concentrating Solar Thermal Power (CSP) Plants

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.

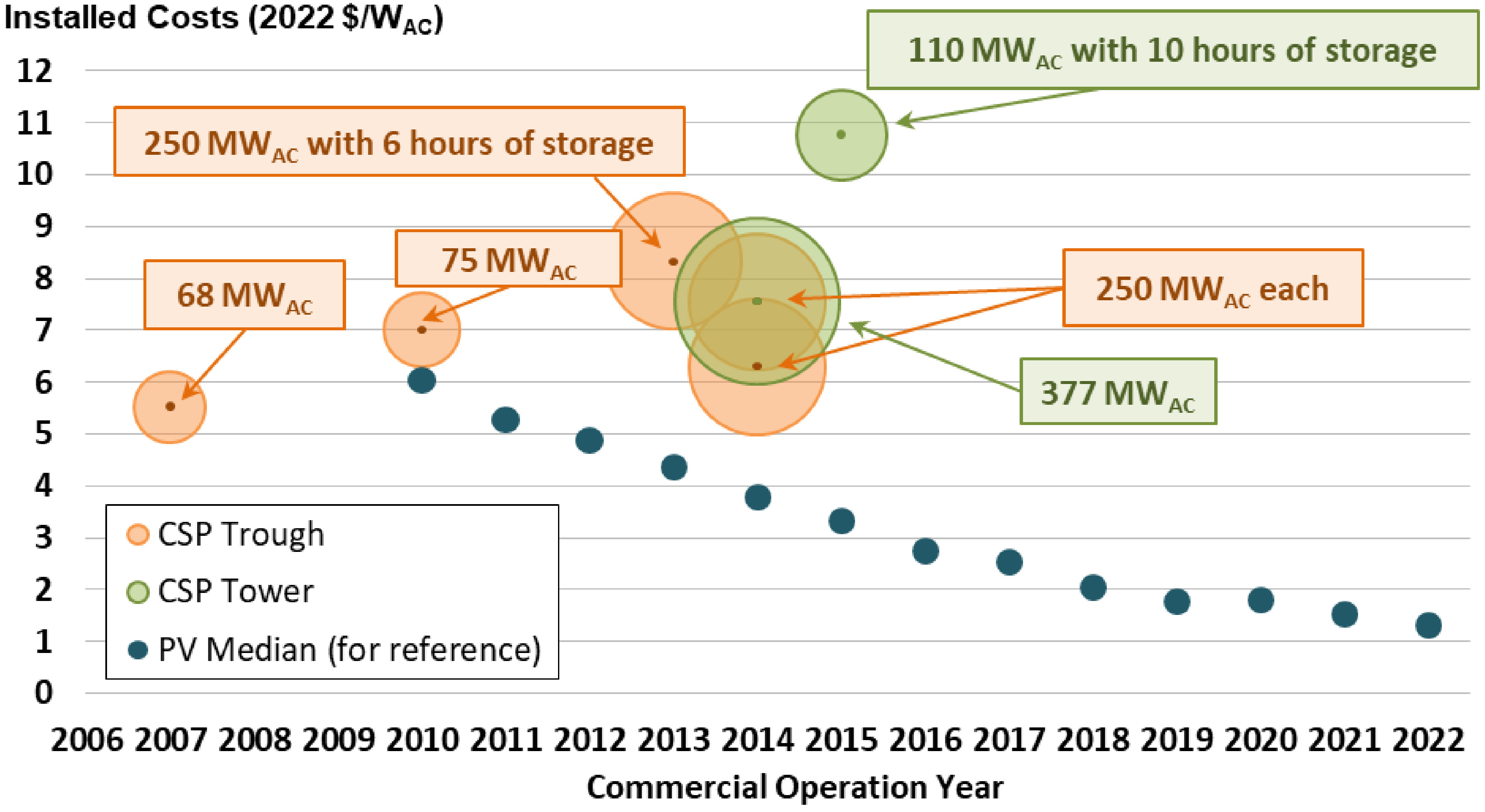
The five 2013-2015 projects include:

– 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).

Not much movement in the installed costs of CSP

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

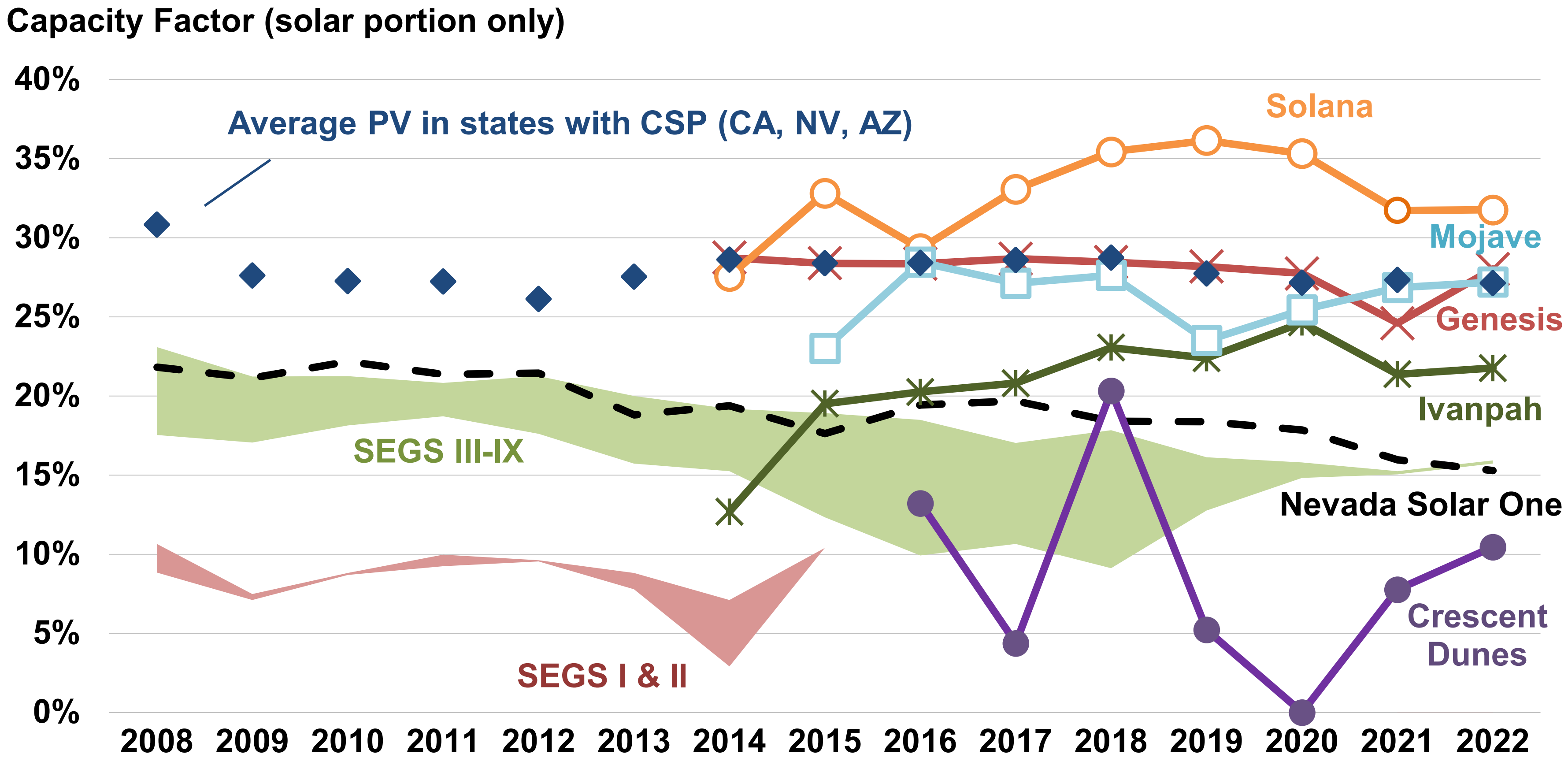


Small sample of 7 projects using different technologies makes it hard to identify trends. Newer projects (5 built in 2013-15) did not show cost declines, though some included storage or used new technology (power tower).

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

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

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



Power Towers: Ivanpah's (377 MW) capacity factor held steady in 2022, but is still below long-term expectations of ~27%, while Crescent Dunes (110 MW with 10 hours of storage) returned to service in the second half of 2021 after not operating for >2 years, but only managed 10% in 2022.

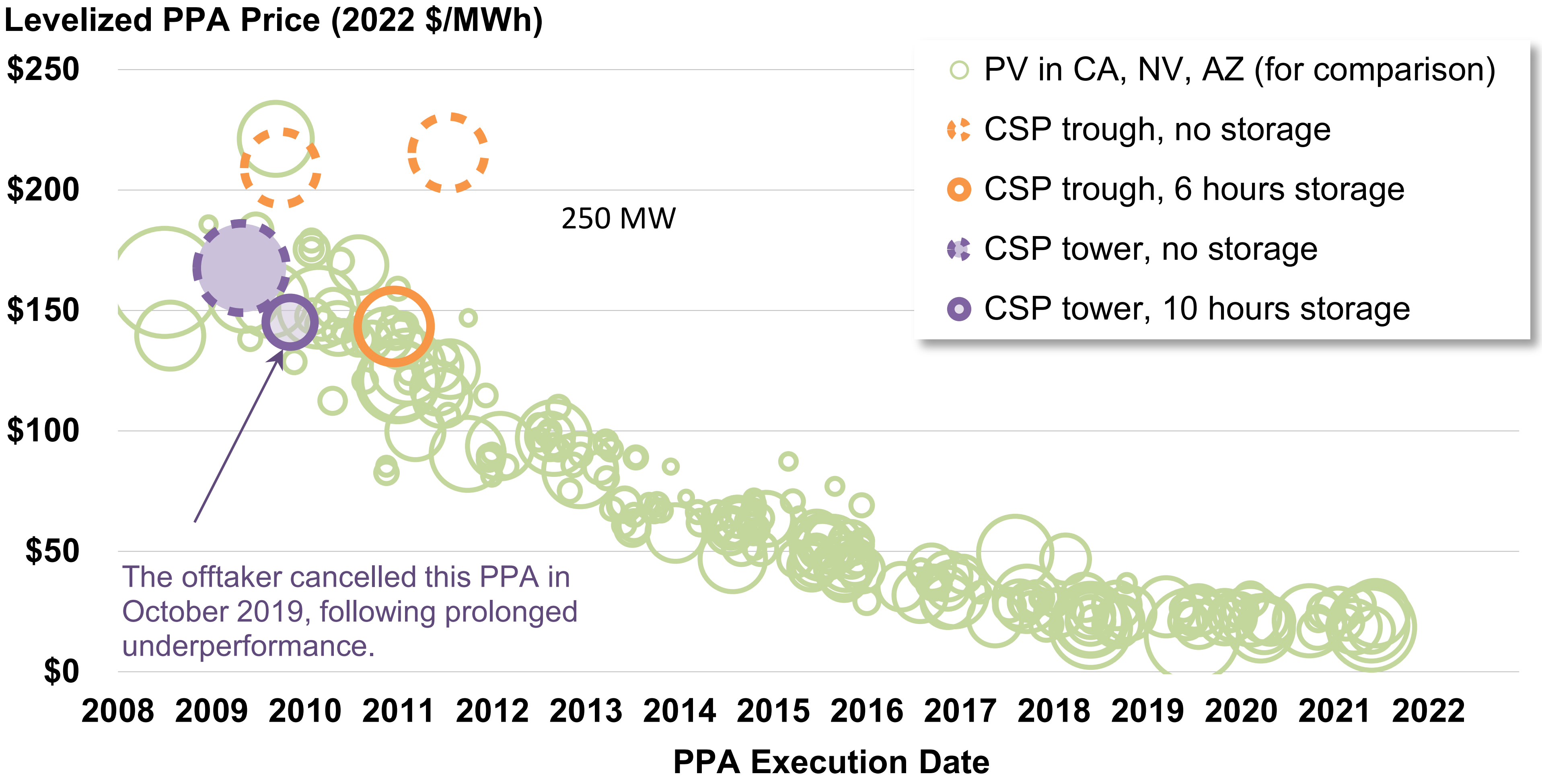
Trough with storage: Solana's (250 MW trough project with 6 hours of storage) capacity factor held steady at 32% in 2022, below long-term expectations of >40%.

Troughs without storage: Mojave and Genesis (both 250 MW net) were at 27-28% in 2022. Both have performed better than the old SEGS projects (now mostly decommissioned and being 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 once competitive, CSP PPA prices have failed to keep pace with PV's PPA price decline

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



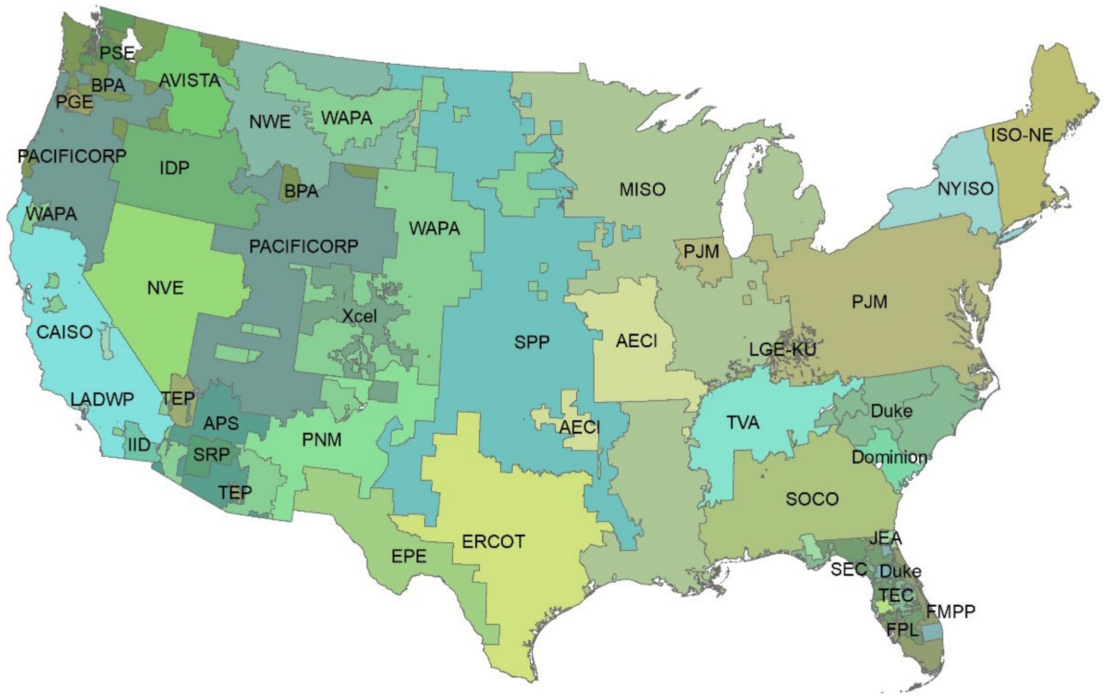
When PPAs for the most recent batch of CSP projects (with CODs of 2013-15) were signed back in 2009-2011, they were still mostly competitive with PV.

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

Capacity in Interconnection Queues

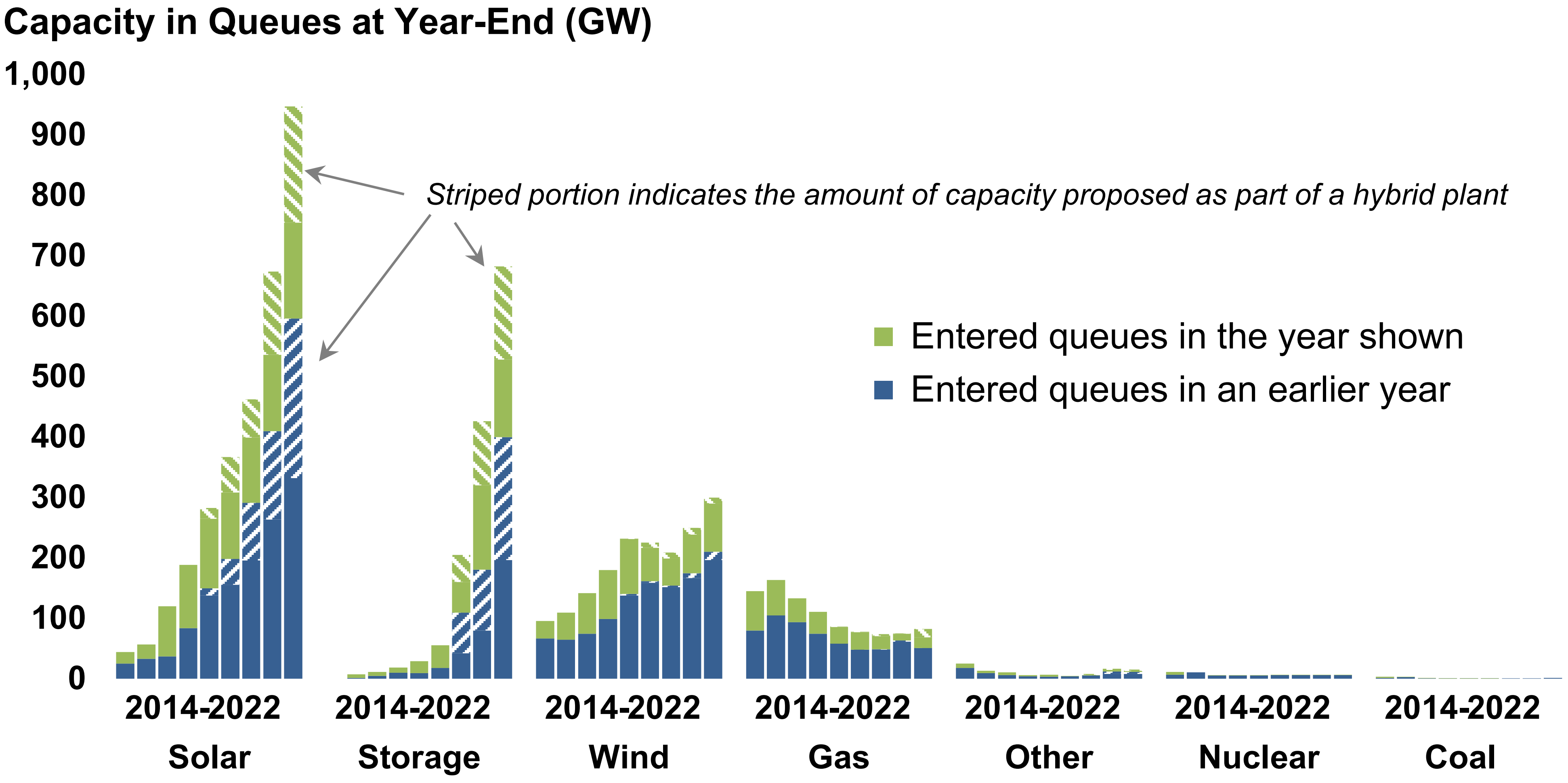
Scope of generator interconnection queue data

- Data compiled from **interconnection queues** for 7 ISOs and 35 utilities, representing ~85% of all U.S. electricity load
  - Projects that connect to the bulk power system: not behind-the-meter
  - Includes all projects in queues through the end of 2022
  - Filtered to include only “active” projects: removed those listed as “online,” “withdrawn,” or “suspended”
- Hybrid / co-located projects were identified and categorized
  - Storage capacity for hybrids (i.e., broken out from generator capacity) was not available in all queues
- Note that being in an interconnection queue does not guarantee ultimate construction: majority of plants are not subsequently built
- More queue data and analysis are available at: *https://emp.lbl.gov/queues*



Coverage area of entities for which data was collected
Data source: Homeland Infrastructure Foundation-Level Data (HIFLD)

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



947 GW of solar was in the queues at the end of 2022—351 GW of this total entered the queues in 2022 (the remainder entered in earlier years, and remain active)

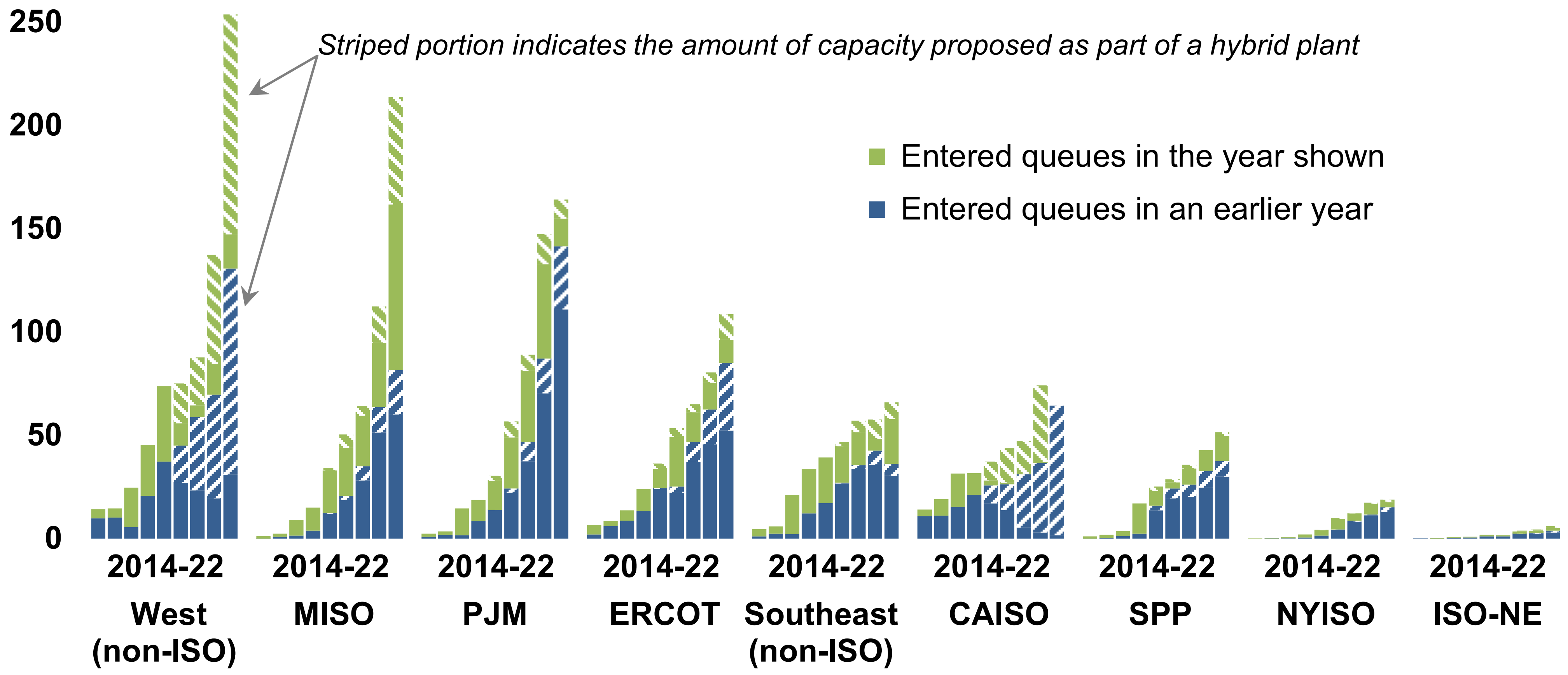
457 GW of the 947 GW of solar in the queues (i.e., 48%) includes a battery in a PV hybrid configuration

Solar (both standalone and in hybrid form) is by far the largest resource within these queues, followed by storage, wind, and natural gas (all other resources are negligible in comparison)

Graph shows solar and other capacity in 42 interconnection queues across the US:
Not all of these projects will ultimately be built!

Looking ahead: Continued broadening of the market

Solar Capacity in Queues at Year-End (GW)



The growth of solar within these queues is widely distributed across most regions of the country, with the non-ISO West, MISO, and PJM leading the way

97% of the solar capacity in CAISO's queue at the end of 2022 was paired with a battery; in the non-ISO West, that number was also high, at 81%

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

Graph shows solar capacity in 42 interconnection queues across the US:
Not all of these projects will ultimately be built!

Summary

Data Summary

- Utility-scale PV continued to lead solar deployment in 2022, with Texas adding the most new capacity. 81% of new projects and 94% of new capacity feature single-axis tracking.
- The median installed cost of projects that came online in 2022 fell to $1.3/W$_{AC}$ ($1.1 /W$_{DC}$), down 13% from 2021 and 78% from 2010.
- Average capacity factors range from 17% in the least-sunny regions to 32% where it is sunniest. Single-axis tracking adds nearly five percentage points to capacity factor in the regions with the strongest solar resource.
- Not including the ITC, the median LCOE from utility-scale PV has declined by 84% since 2010, to $39/MWh in 2022. Levelized PPA prices have kept pace, and—with the benefit of the ITC—currently range from $20-30/MWh in CAISO and the non-ISO West to $30-$40/MWh elsewhere.
- The market value of solar has increased with rising energy prices in 2022 to $71/MWh on average, more than compensating for modest PPA increases and making solar more competitive than it has ever been across the nation.
- Interest in hybridization (pairing PV with batteries) continued to surge in 2022. Some of these PV+battery hybrid plants have inked PPAs in the mid-$30/MWh-PV range. It remains to be seen if this trend towards hybridization will continue in the wake of the IRA's new standalone storage ITC.
- Across all 7 ISOs and 35 additional utilities, there were 947 GW of solar in interconnection queues at the end of 2022. Nearly half of this proposed solar capacity is paired with battery storage, with the highest concentration of these PV+battery hybrid plants in CAISO (97%) and the non-ISO West (81%).

Data and Methods

Summary of Data and Methods (1)

Much of the analysis in this report is based on primary data, the sources of which are listed below (along with some general secondary sources) by data set. We collect data from a variety of unaffiliated and incongruous sources, often resulting in data of varying quality that must be synthesized and cleaned in multiple steps before becoming useful for analytic purposes. In some cases, we essentially create new and useful data by piecing together various snippets of information that are of less consequence on their own.

Technology Trends: Project-level metadata are sourced from a combination of Form EIA-860, FERC Form 556, state regulatory filings, interviews with project developers and owners, and trade press articles. We independently verify much of the metadata—such as project location, fixed-tilt vs. tracking, azimuth, module type—via satellite imagery. Other metadata are indirectly confirmed (or flagged, as the case may be) by examining project performance—e.g., if a project's capacity factor appears to be an outlier given what we think we know about its characteristics, then we dig deeper to revisit the veracity of the metadata.

Installed Costs: Project-level CapEx estimates are sourced from a combination of Form EIA-860, Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, trade press articles, and data previously gathered by NREL. CapEx estimates for projects built from 2013-2021 have been cross-checked against confidential EIA-860 data obtained under a non-disclosure agreement (and we expect to receive similar data for 2022 projects and successive years going forward). The close agreement between the confidential EIA data and our other sources in most cases provides comfort that our normal data collection process (i.e., the process that we go through prior to receiving the confidential EIA data with a one-year lag) does, in fact, yield reputable CapEx estimates. That said, we do caution readers to focus more on the overall trends rather than on individual project-level data points.

Capacity Factors: We calculate project-level capacity factors using net generation data sourced from a combination of FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings. Because many projects file data with several of these sources, we are often able to cross-reference (and correct, if needed) odd-looking data across several sources, thereby providing higher confidence in the veracity of the data.

Summary of Data and Methods (2)

PPA Prices: We gather PPA price data from a combination of FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, and trade press articles. We 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. By this process of exclusion, there is very little chance for erroneous PPA price data to enter our sample. Instead, this winnowing process results in our PPA price sample being somewhat smaller than it might otherwise be—though we are typically able to add back in any “incomplete” PPAs in subsequent years, once more data have become available with the passage of time.

LCOE: Our project-level LCOE calculations draw upon the empirical project-level data presented throughout this report, including CapEx and capacity factors, and are supplemented with assumptions about financing and other items, as described in more detail in earlier slides.

Market Value: We draw from project-level modeled hourly solar generation (using NREL’s *System Advisor Model* and site- and year-specific insolation data from NREL’s *National Solar Radiation Database and NOAA’s High Resolution Rapid Refresh Model)* and de-bias the generation leveraging ISO-reported aggregate solar generation and plant-level reported generation by EIA 923.

Energy value is the product of hourly solar generation by plant (utility-scale) and the wholesale hourly real-time energy prices of the nearest node (for ISOs and most BAs) or the system-wide energy price (a few BAs that can only be approximated with gateway LMP nodes or FERC system lambdas).

Capacity value relies on the same reported and constructed generation profiles as does energy value to assess the “capacity credit” of solar according to each ISO’s rules in place at the time (for BAs we examine the historical plant-level performance over the top 100 load hours over the past 3 years). We then multiply the resulting capacity credit by historical zonal capacity prices to arrive at capacity value.

For more information, see Berkeley Lab’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/renewable-grid-insights*

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

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Contact the corresponding authors:

Mark Bolinger (MABolinger@lbl.gov)

Joachim Seel (JSeel@lbl.gov)

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

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