Utility-Scale Solar, 2021 Edition

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

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Photo: *Enel Green Power*

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Photo credit:
Enel's 497 MW_{DC} Roadrunner Solar Project with bifacial modules

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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
- 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

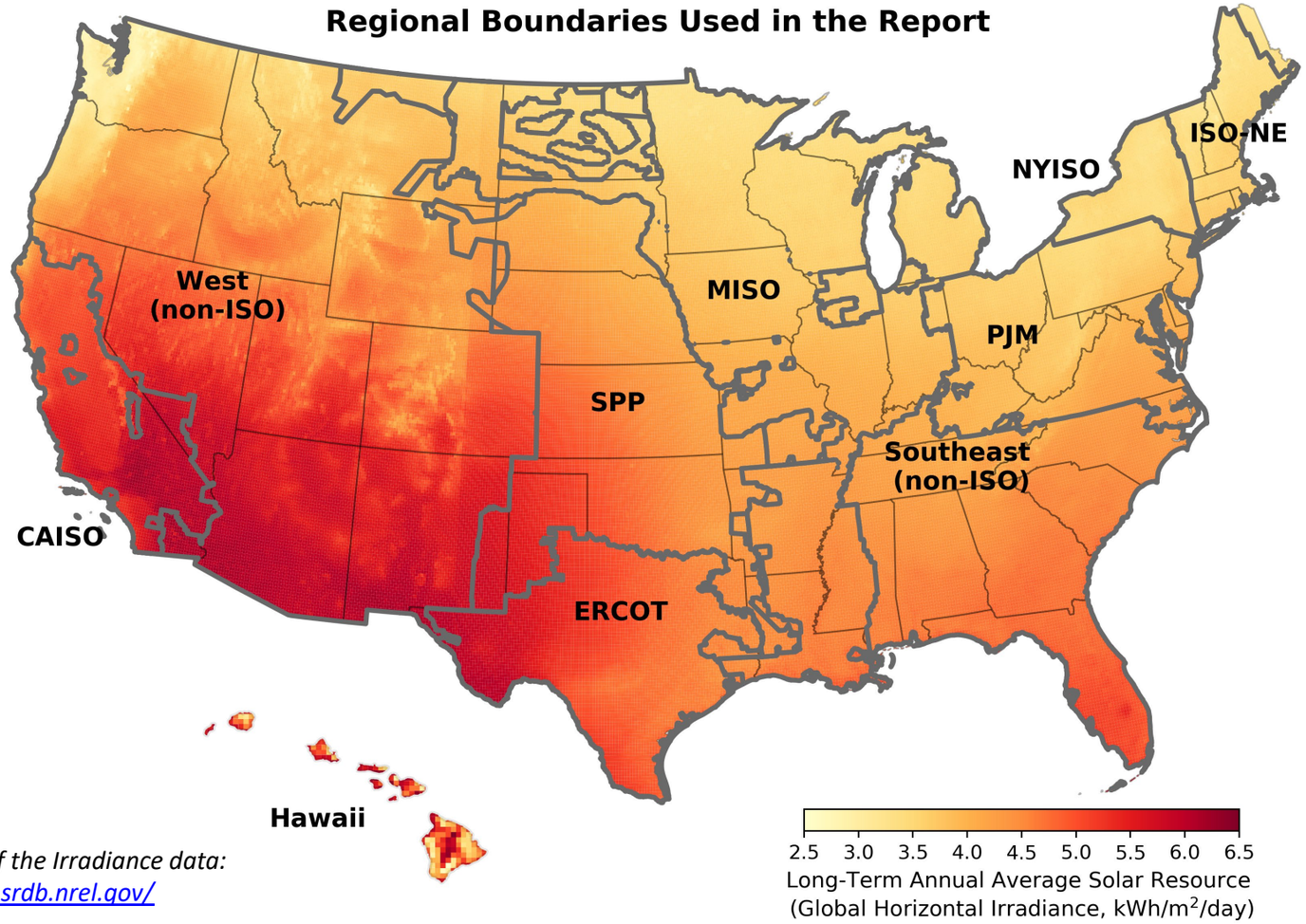
Products and Availability:

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

Report Contents

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

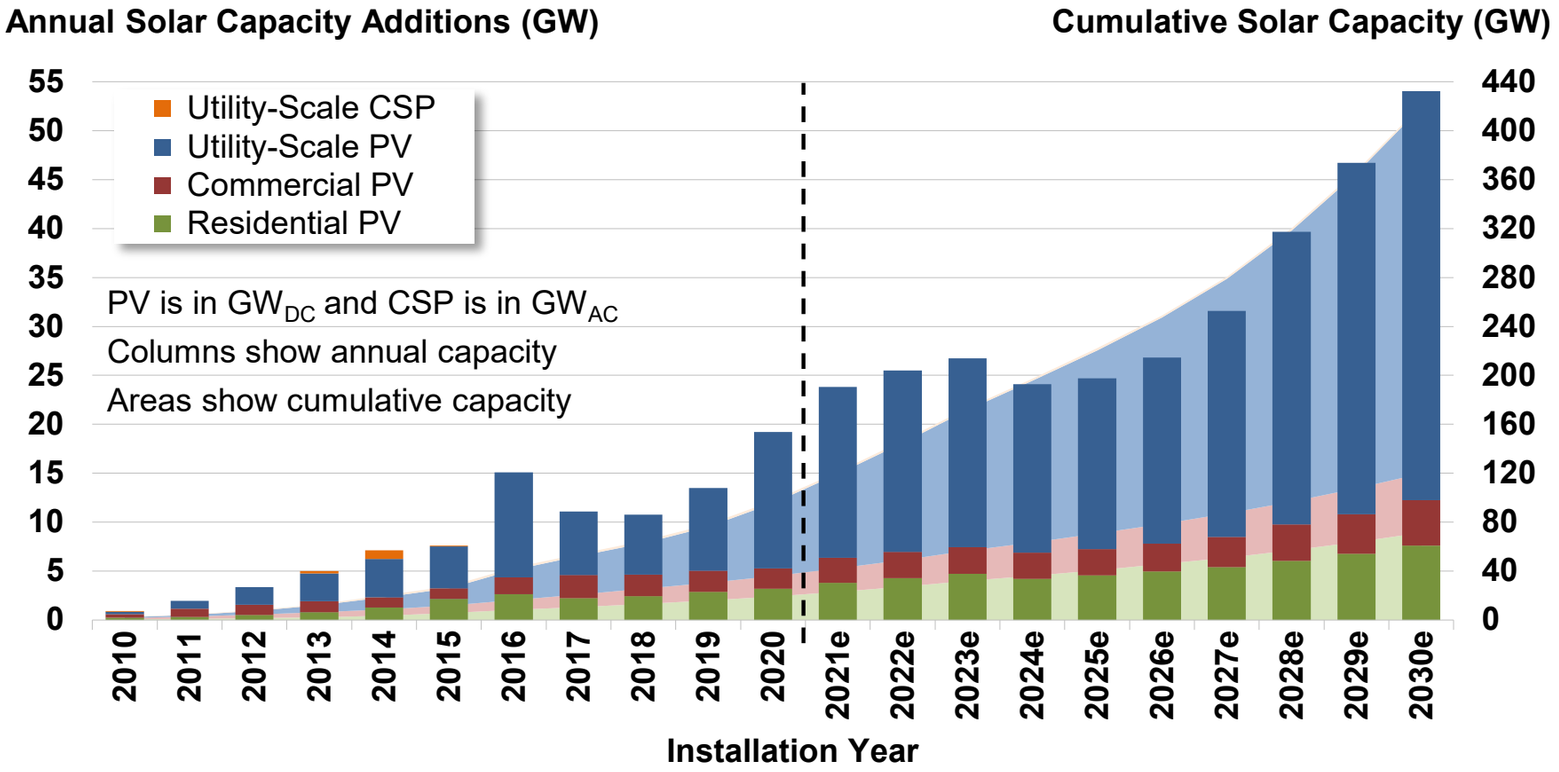
Regional boundaries applied in this analysis include the seven independent system operators (ISO) and two non-ISO regions



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

Deployment and Technology Trends

Utility-scale projects have the greatest capacity share in the U.S. solar market



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

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)

Wood Mackenzie and SEIA report that the utility-scale sector added 14 GW_{DC} or **73% of all new solar** capacity of 2020. It was the year with the greatest utility-scale solar capacity expansion in the United States so far, representing a year-over-year growth of 65%.

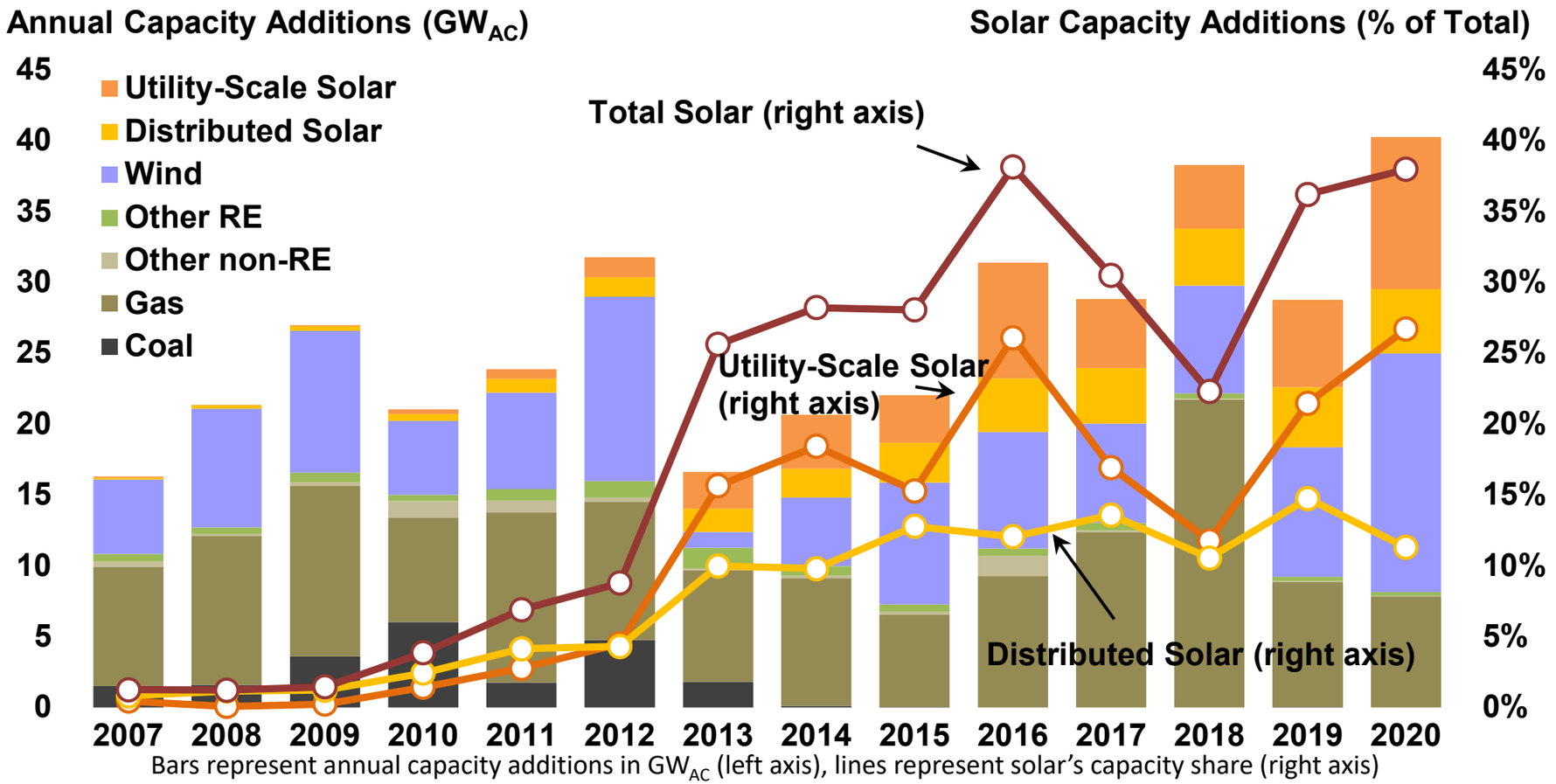
Utility-scale solar accounts for **61% of cumulative solar** capacity.

Our data analysis focuses on a subset of this sample—all projects larger than 5MW_{AC} that were completed by the end of 2020:

- **2019**: 108 new projects totaling 6.1 GW_{DC} or 4.6 GW_{AC}
- **2020**: 161 new projects totaling 12.8 GW_{DC} or 9.6 GW_{AC}

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}.

Solar power was the second largest source of U.S. electricity-generating capacity additions in 2020



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

Led by the utility-scale sector, solar power has comprised >20% of all generating capacity additions in the United States in each of the past eight years.

In 2020, solar made up 38% of all U.S. capacity additions (with utility-scale accounting for 27%), behind wind (42%) but ahead of natural gas (19%).

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

Note: This graph follows Wood Mackenzie/SEIA split between distributed and utility-scale solar, rather than our 5 MW_{AC} threshold.

Solar penetration rates topped 22% in California and exceeded 10% in four other states

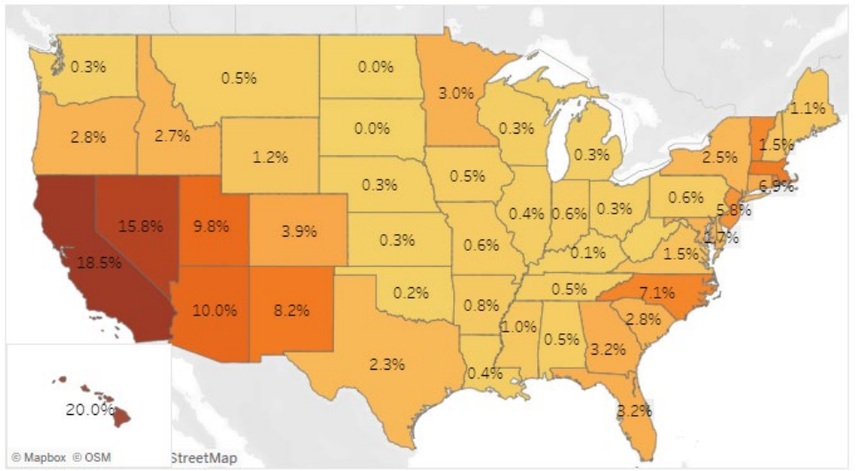
State	Solar generation as a % of in-state generation		Solar generation as a % of in-state load	
	All Solar	Utility-Scale Solar Only	All Solar	Utility-Scale Solar Only
California	22.7%	14.4%	19.4%	12.3%
Massachusetts	18.9%	7.6%	7.9%	3.2%
Hawaii	16.5%	5.0%	20.0%	6.1%
Nevada	14.8%	12.7%	16.1%	13.8%
Vermont	14.3%	7.4%	6.9%	3.6%
Utah	8.1%	6.6%	9.8%	8.0%
Arizona	7.9%	5.3%	10.9%	7.4%
North Carolina	7.5%	7.2%	7.1%	6.9%
New Jersey	6.4%	2.5%	5.8%	2.2%
Rhode Island	6.1%	2.5%	6.9%	2.8%
New Mexico	5.9%	4.9%	8.2%	6.7%
Maryland	4.4%	1.6%	2.8%	1.0%
Colorado	4.0%	2.8%	3.9%	2.7%
Delaware	3.6%	1.2%	1.7%	0.6%
Georgia	3.5%	3.3%	3.2%	2.9%
Idaho	3.4%	2.9%	2.7%	2.3%
Minnesota	3.3%	3.1%	3.0%	2.8%
Florida	3.1%	2.6%	3.2%	2.8%
New York	2.5%	0.8%	2.5%	0.8%
Connecticut	2.3%	0.5%	3.6%	0.8%
Rest of U.S.	*0.8%*	*0.6%*	*1.0%*	*0.7%*
TOTAL U.S.	**3.3%**	**2.2%**	**3.6%**	**2.5%**

Solar penetration rates vary considerably depending on whether they are calculated as a percentage of generation or load (e.g., see Vermont).

In 2020, California exceeded 20% of solar penetration levels based on generation share while four other states surpassed 10%. Four states had >10% based on load share.

Contribution of utility-scale also varies (a minority in Northeast states and Hawaii, a majority in Southwest states and overall U.S.).

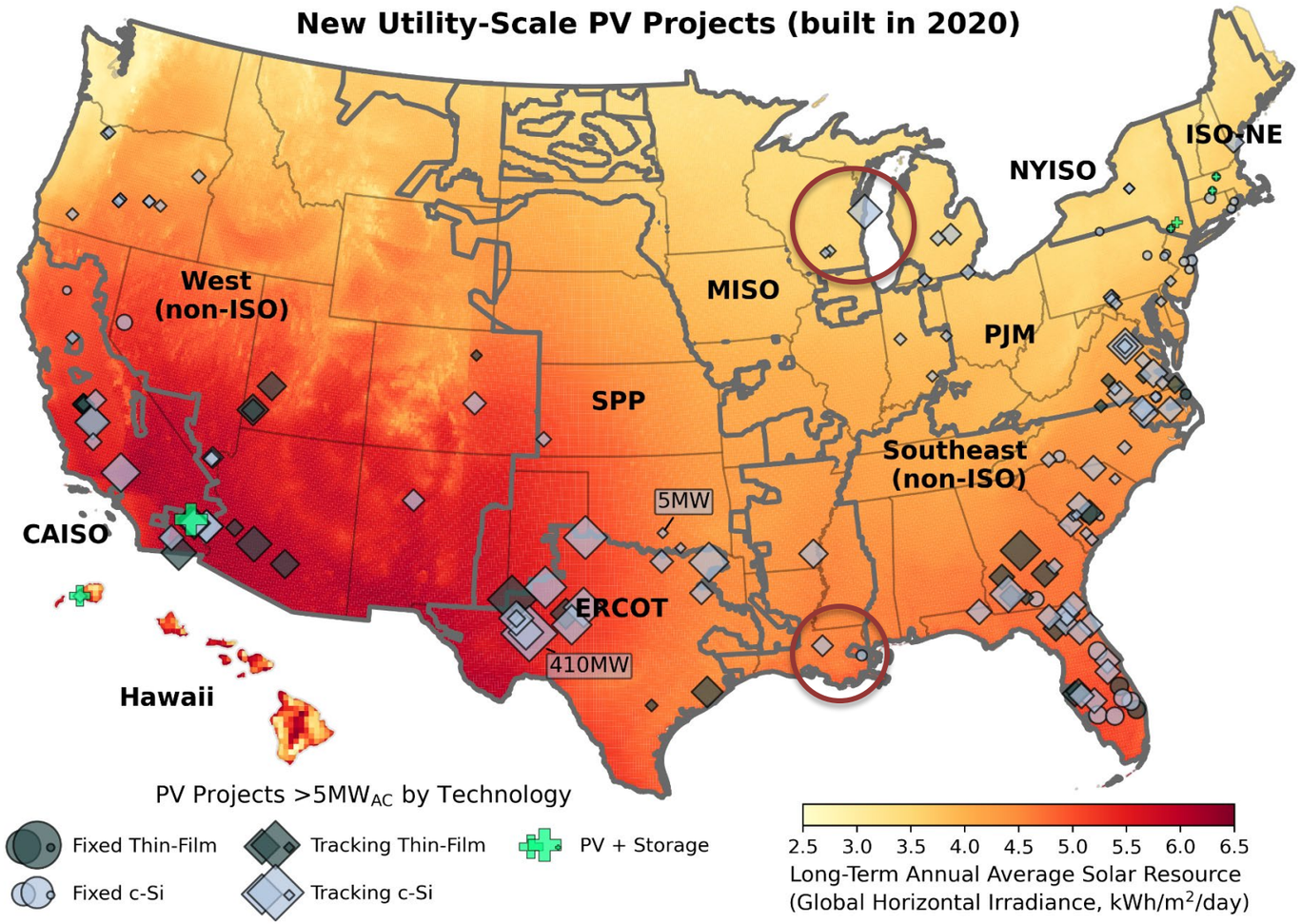
Percentage of In-State Electricity Sales and Generation from Solar PV, as of 2020



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.

In 2020, Texas led the nation in utility-scale solar deployment



Texas completed some of the largest projects we have seen in the US (up to 410 MW_{AC}).

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.

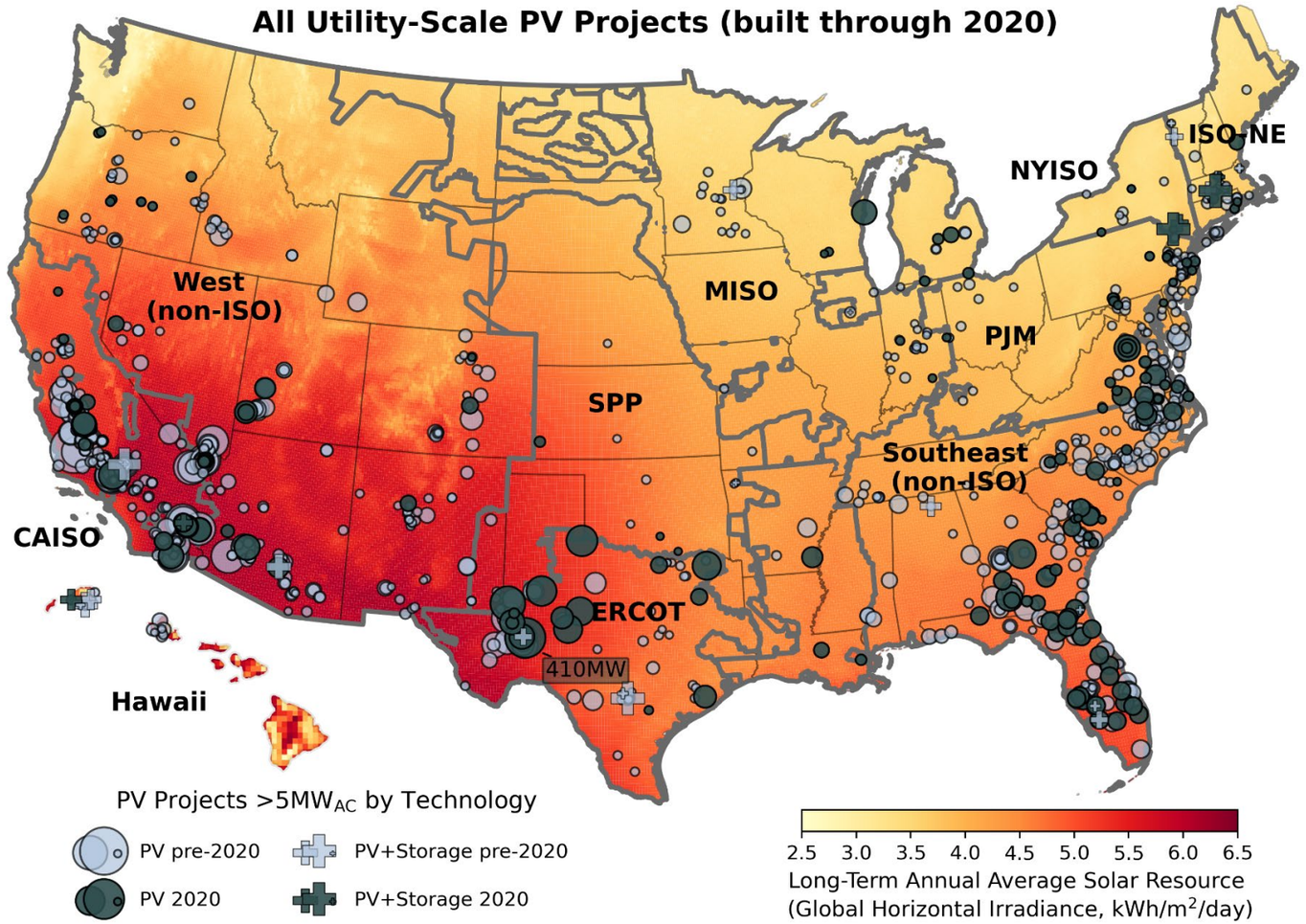
Other high-latitude states such as Oregon, Wisconsin, Michigan, New York and Maine added predominantly **tracking** projects in 2020 ( ).

In 2020, storage ( ) was added to already existing (1) and new (5) PV projects. 4 of these were built in the northeast, while high penetration regions in HI and CA added one each.

2 new states added their first utility-scale PV projects: **Wisconsin** and **Louisiana.**

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



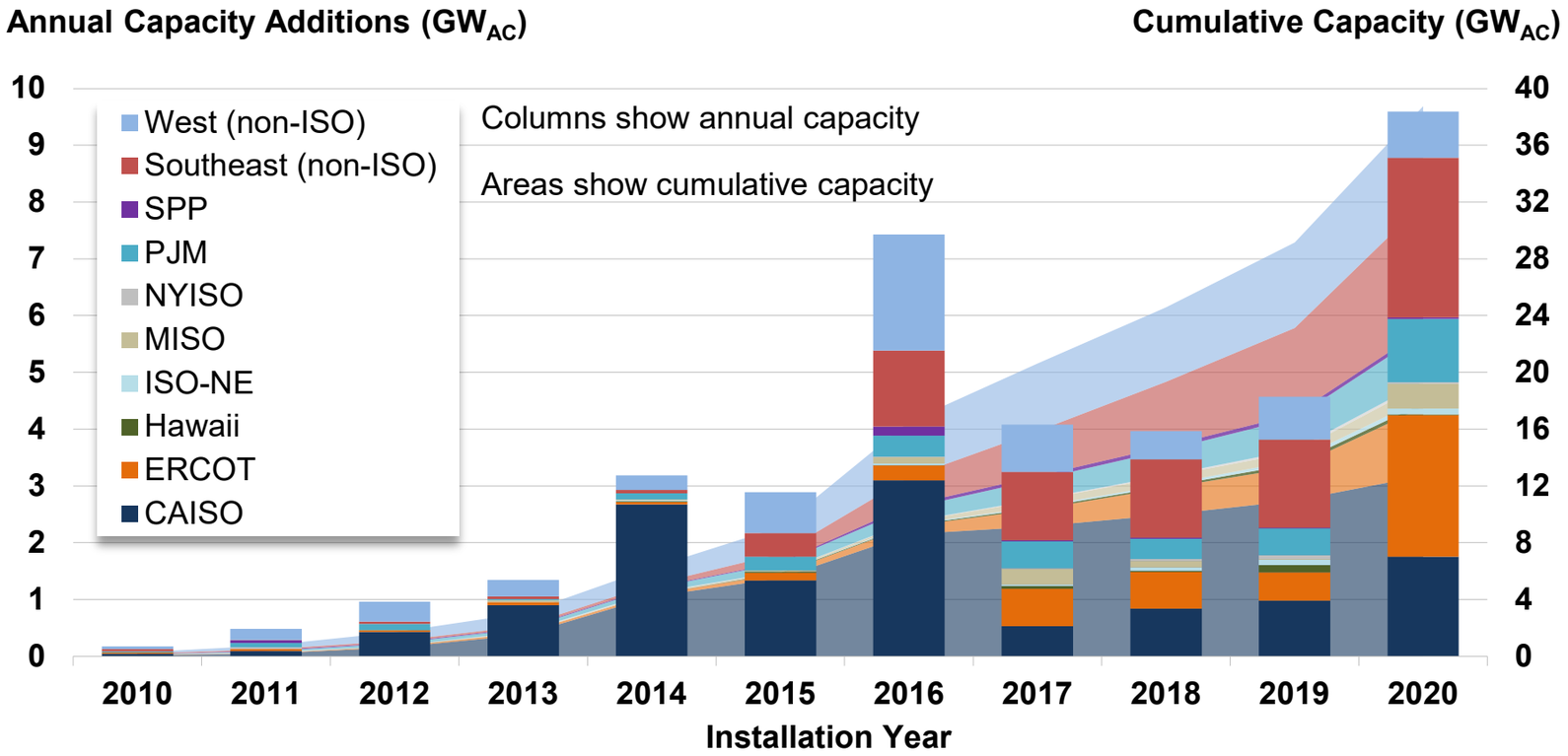
Utility-scale PV is well-represented throughout the nation, with the exception of upper-Midwestern states in the “wind belt”.

Recent recipients of new utility-scale solar projects in the north (Idaho, Minnesota) did not add new capacity in 2020, while Montana, the Dakotas, Iowa, 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 the Southeast added the most utility-scale solar capacity in 2020

PV project population: 969 projects totaling 38,745 MW_{AC}

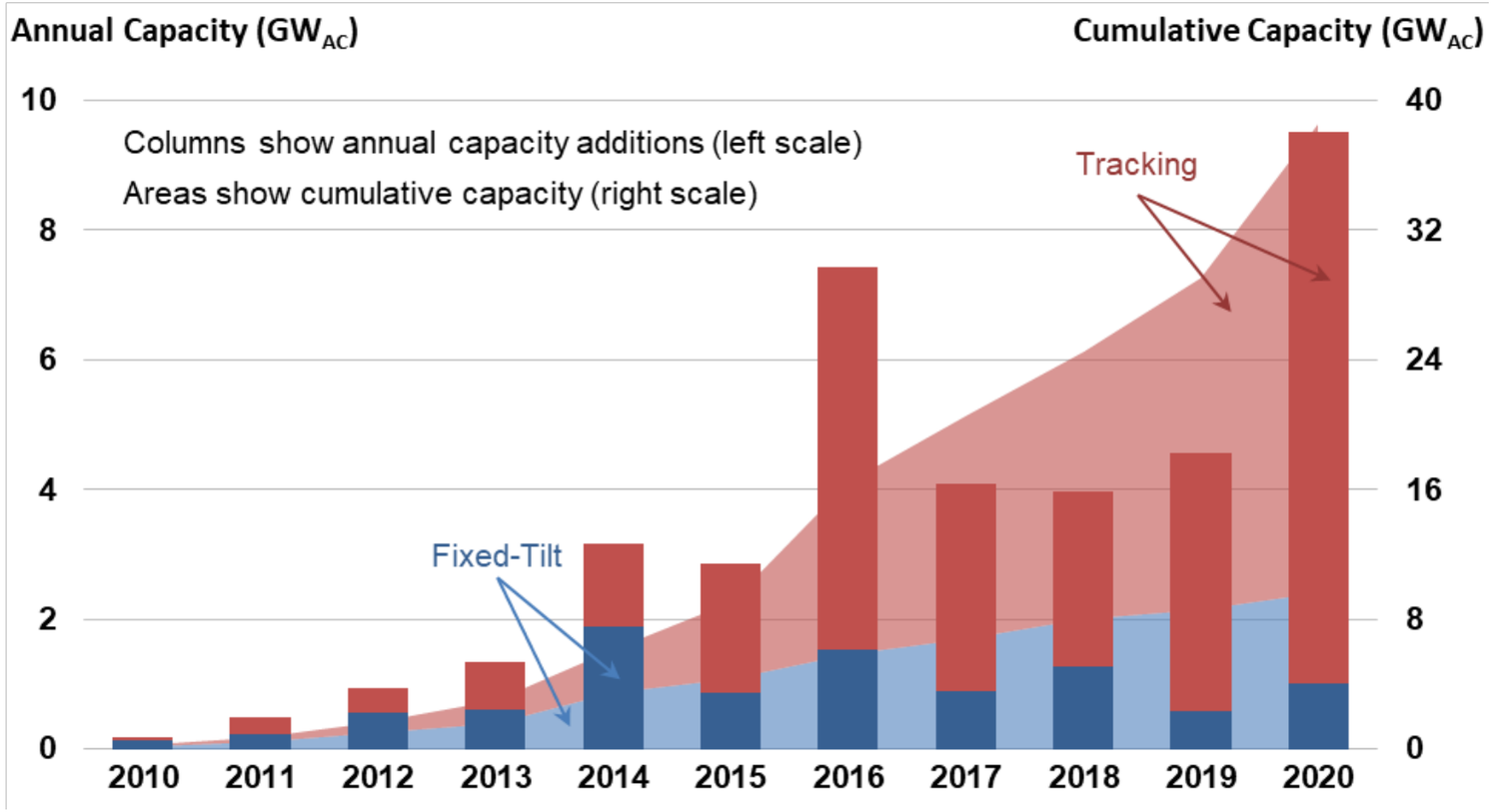


Texas (ERCOT) surpassed California as the leader of utility-scale solar growth in 2020, adding 2.5 GW_{AC} or 26% of total U.S. additions.

Florida (1.6 GW_{AC}), **Georgia**, and **Virginia** (both 0.7 GW_{AC}) led solar growth in the Southeast in 2020. **California**, which added 1.6 GW_{AC} in 2020, still accounts for the most installed capacity on a cumulative basis (32% of the U.S. total).

Projects with tracking technology dominated 2020 additions

PV project population: 969 projects totaling 38,745 MW_{AC}

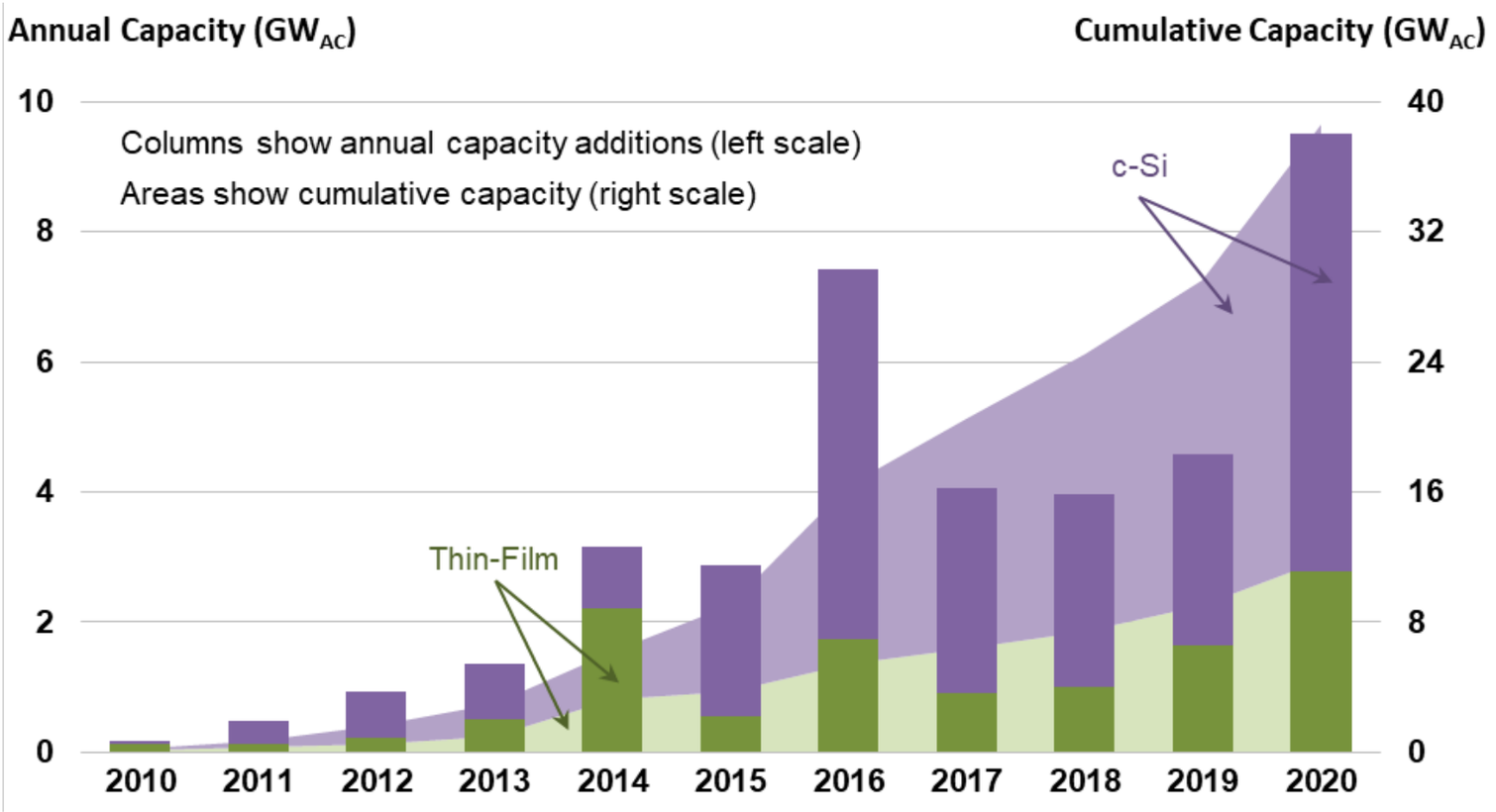


Projects using single-axis **tracking** have consistently exceeded **fixed-tilt** installations since 2015, but achieved a new level of dominance in 2020, with 89% of all new capacity using tracking.

Upfront cost premiums for trackers have fallen over the years, resulting in favorable economics in most of the United States thanks to increased generation.

Projects with c-Si modules led thin-film additions in 2020

PV project population: 969 projects totaling 38,745 MW_{AC}

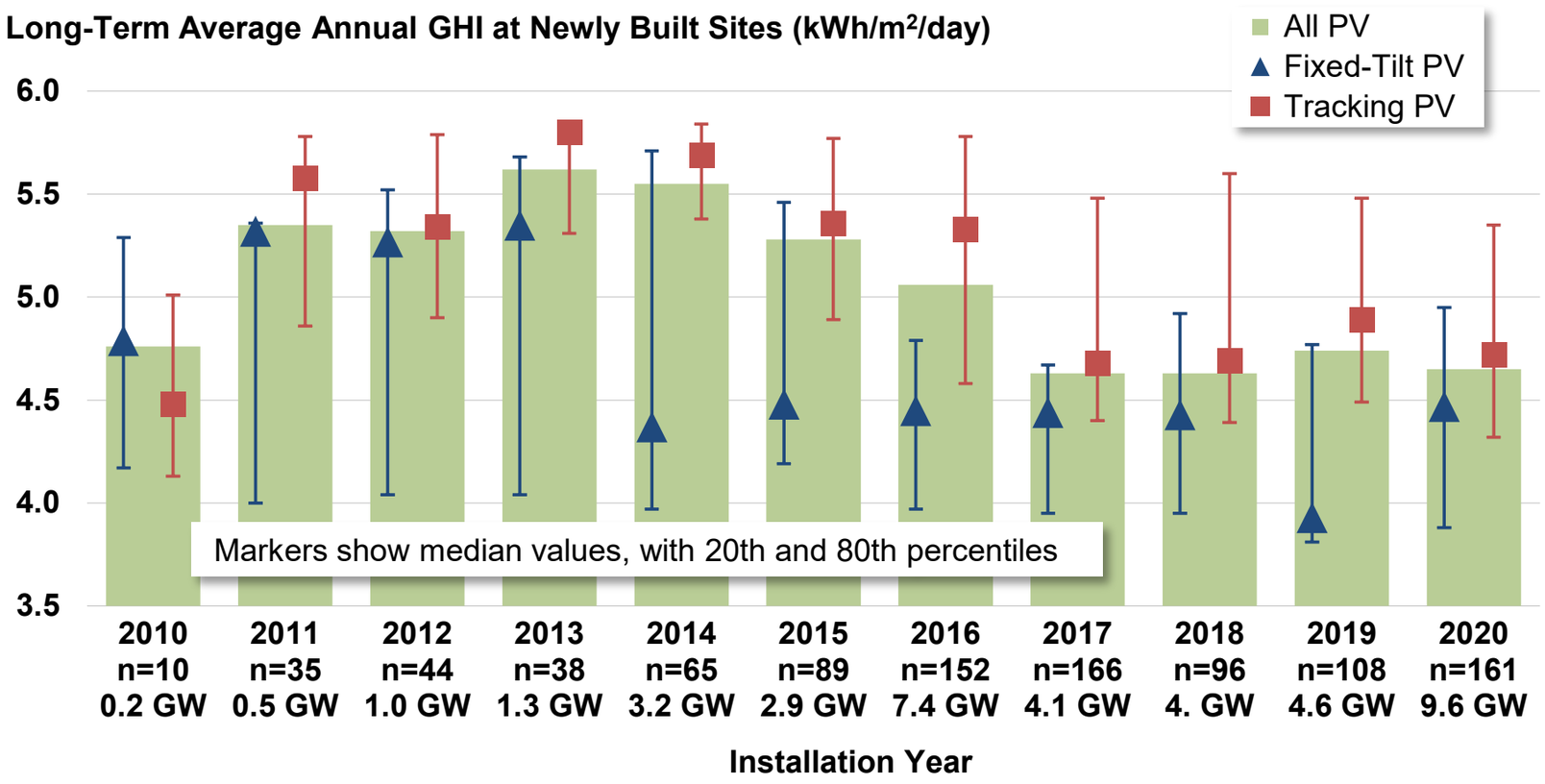


c-Si modules continued their clear lead (71% of newly installed capacity) relative to **thin-film** modules (29%), though the latter have become more popular since 2018 as they were not subject to Section 201 import tariffs.

Hanwha had the highest market share among c-Si modules in our sample, followed by Jinko and Trina. All thin-film modules in our 2020 sample were made by First Solar.

The median global horizontal irradiance (GHI) at utility-scale solar project sites has stabilized since 2017

PV project population: 969 projects totaling 38,745 MW_{AC}



The median solar resource (measured in long-term global horizontal irradiance—**GHI**) at new project sites has declined since development began expanding to less-sunny states post-2013, but has largely stabilized since 2017.

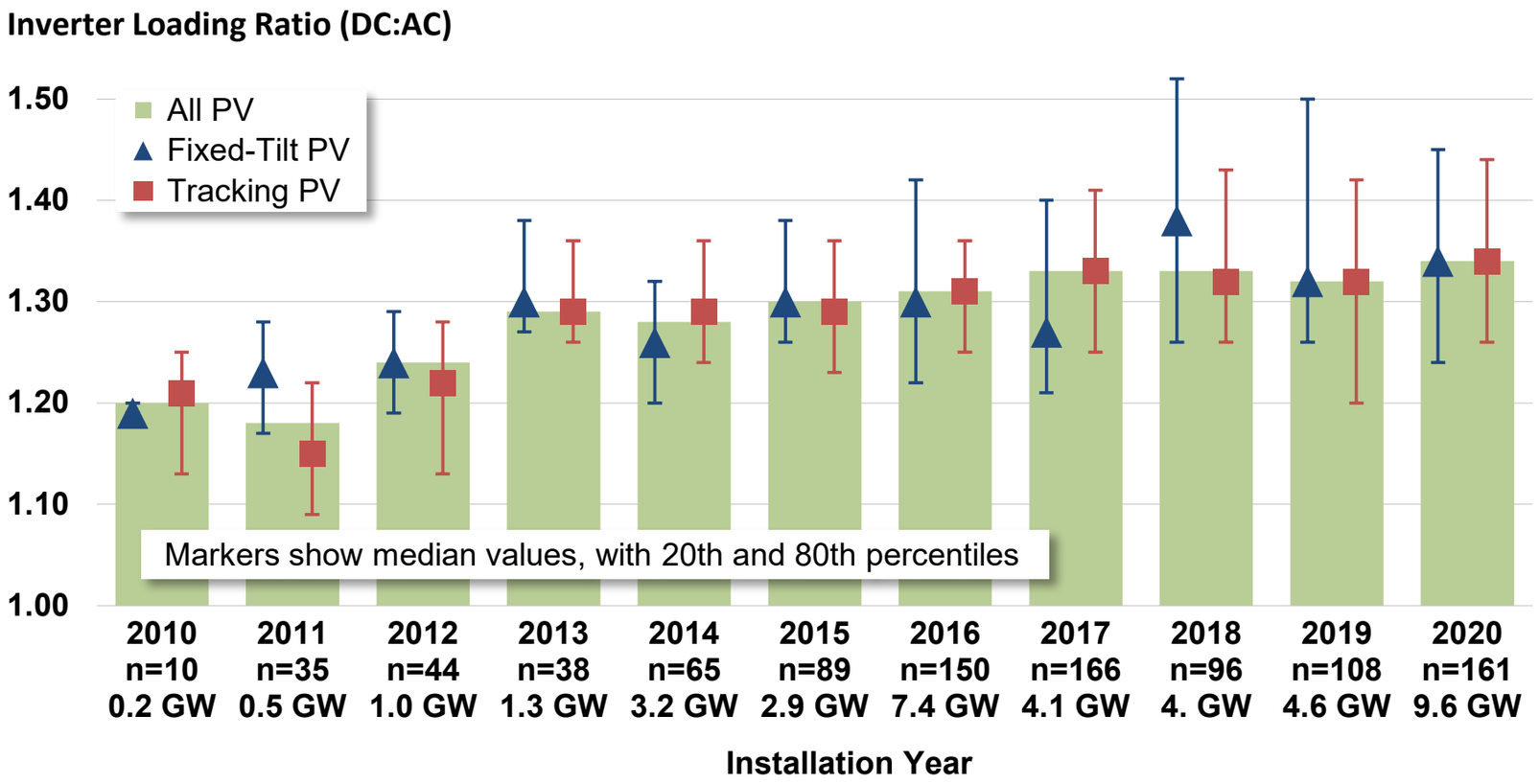
Fixed-tilt PV is increasingly relegated to lower-insolation sites, while tracking PV is pushing into those same areas (note the decline in its **20th percentile**).

Exceptions are fixed-tilt installations in windy regions (Florida), on brownfields and landfill sites, and on particularly challenging terrain.

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

The median inverter loading ratio (ILR) continued to gradually climb

PV project population: 969 projects totaling 38,745 MW_{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.

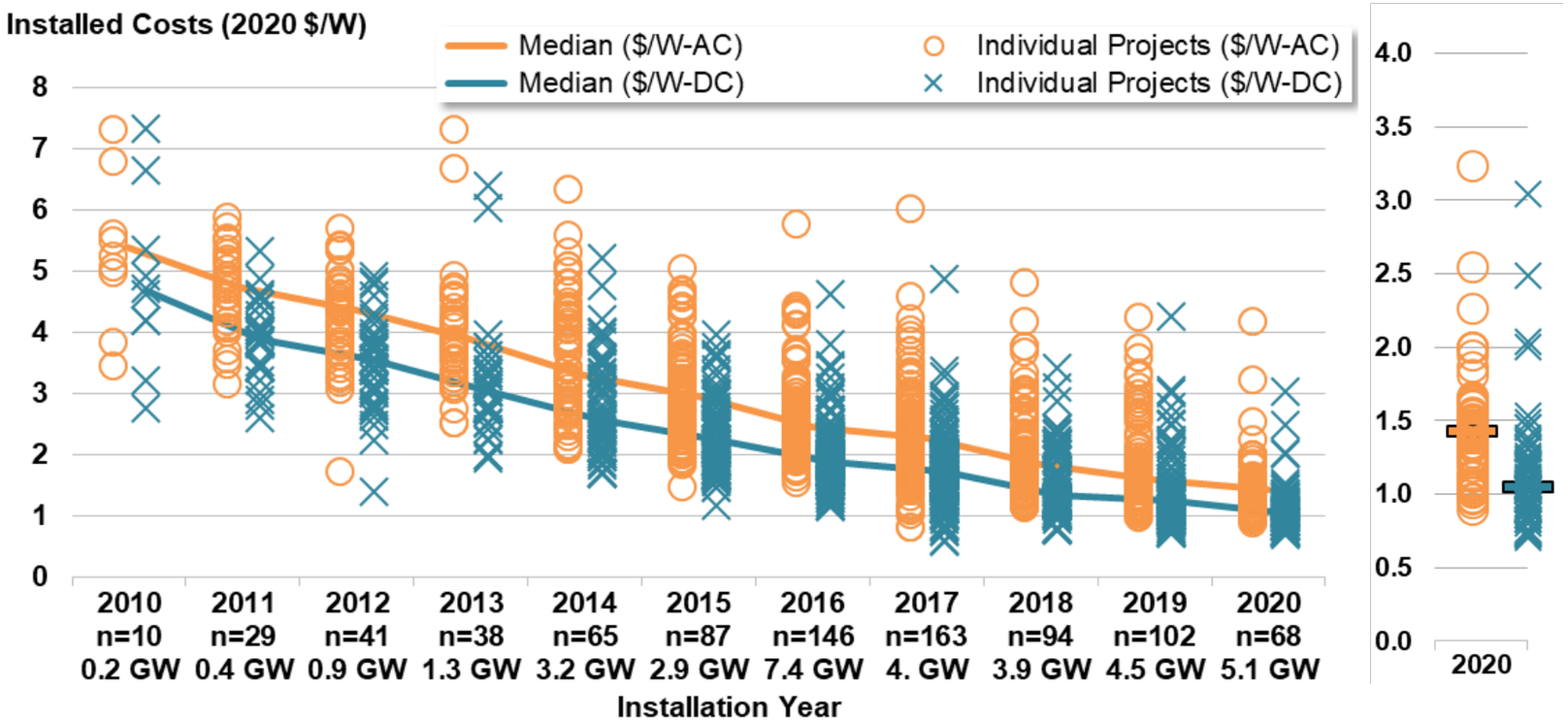
The median inverter loading ratio (**ILR** or DC:AC ratio) increased slightly to 1.34 in 2020, compared with 1.32 in 2019.

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 74% (or 12% annually) since 2010, to $1.42/W$_{AC}$ ($1.05/W$_{DC}$) in 2020

Sample: 848 projects totaling 34,020 MW$_{AC}$



The lowest 20th percentile of project costs fell from $1.3/W$_{AC}$ ($1.0/W$_{DC}$) in 2019 to $1.1/W$_{AC}$ ($0.9/W$_{DC}$) in 2020.

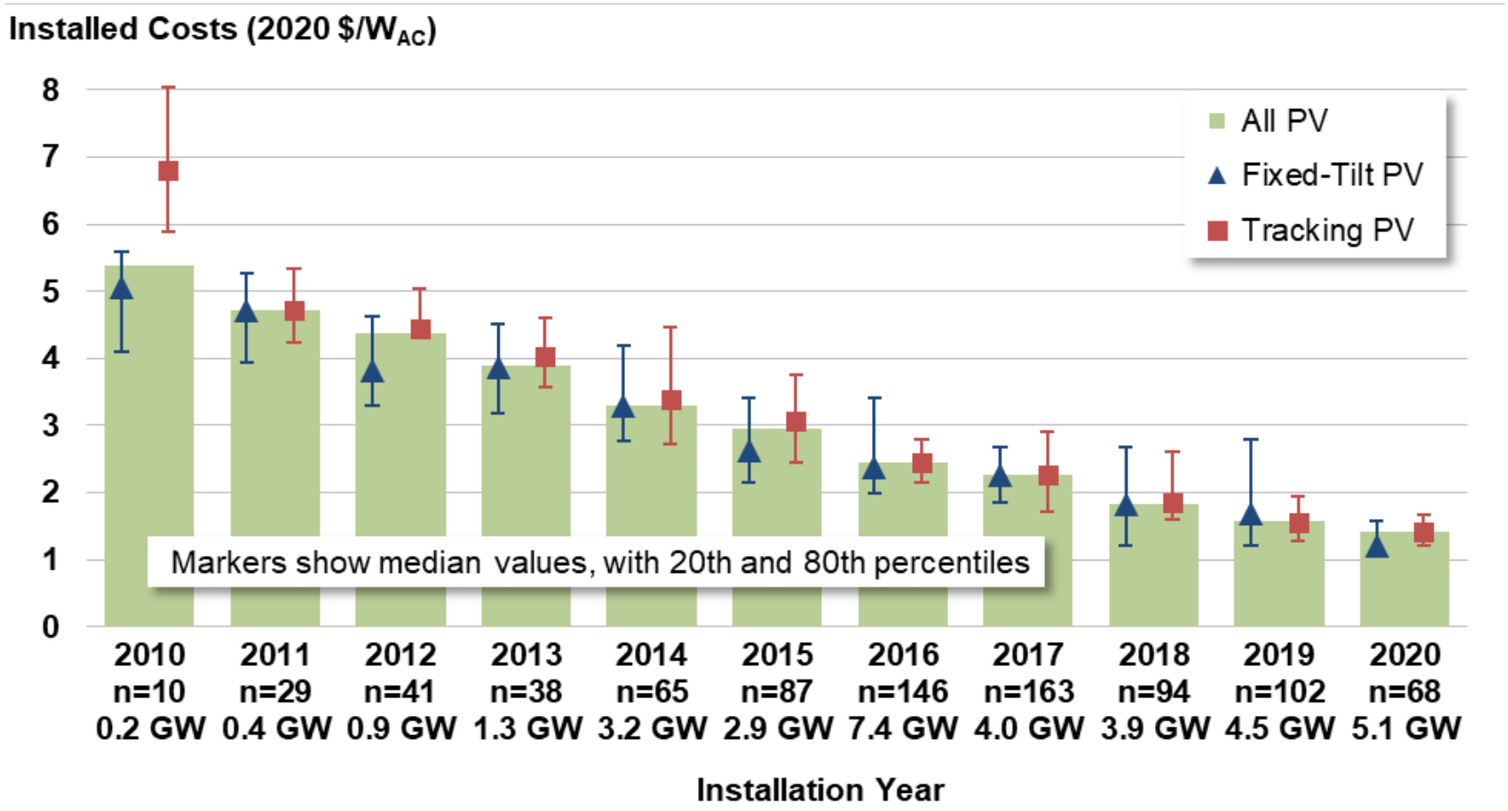
The lowest-cost project among the 68 data points in 2020 was $0.9/W$_{AC}$ ($0.7/W$_{DC}$).

Historical sample is robust (covering 99% of installed capacity through 2019). 2020 data covers 41% of new projects or 63% of new capacity.

This sample is backward-looking and does not reflect the costs of projects built in 2021/2022.

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

Sample: 848 projects totaling 34,020 MW_{AC}



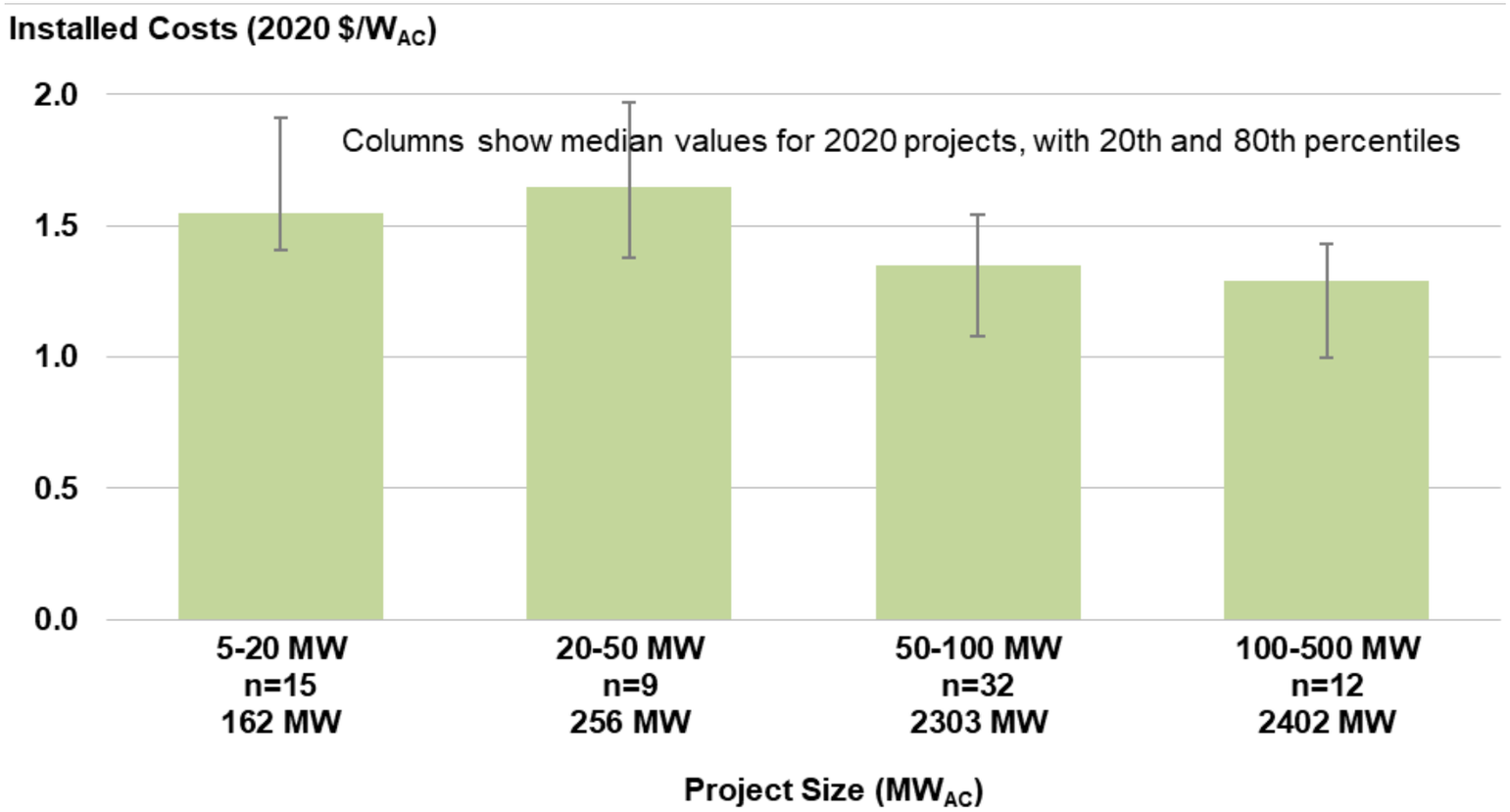
Through 2016, tracking projects in our sample were, on average, regularly more expensive (though by varying amounts) than fixed-tilt projects. This relationship became more nuanced starting in 2017, and in 2019, tracking projects ($1.6/$W_{AC}$ or $1.2/$W_{DC}$) appeared to be cheaper than fixed-tilt projects ($1.7/$W_{AC}$ or $1.3/$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 2020 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 (100-500 MW) cost 17% less than smaller projects (5-20 MW) per MW of installed capacity in 2020

Sample in 2020: 68 projects totaling 5,123 MW_{AC}



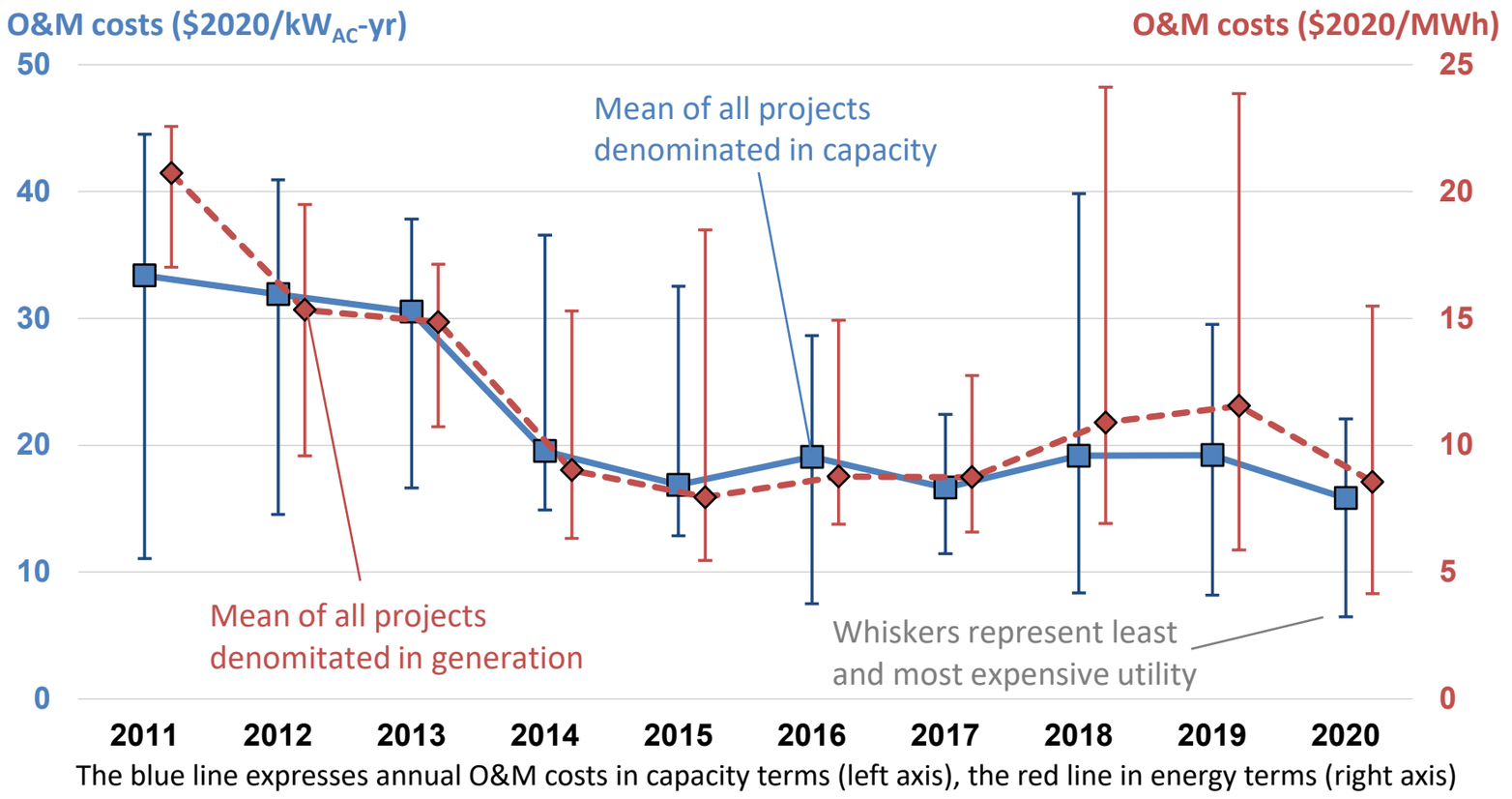
Differences in project size could potentially explain cost variation—we focus only on 2020 for this slide.

Cost savings seem to occur especially in the third size bin (50-100 MW_{AC}) and fourth size bin (100-500 MW_{AC})—at \$1.35/W_{AC} and \$1.29/W_{AC}.

In \$/W_{DC} terms, price decline is even more obvious over the first three bins:

- \$1.23/W_{DC} for 5-20MW
- \$1.05/W_{DC} for 20-50MW
- \$0.95/W_{DC} for 50-100MW
- \$0.98/W_{DC} for 100-500MW

Improvements in operation and maintenance (O&M) costs have plateaued in recent years



The blue line expresses annual O&M costs in capacity terms (left axis), the red line in energy terms (right axis)

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

13 utilities report solar O&M costs for plants that they own, representing a mix of technologies and at least one full operational year (at least 2020).

Average O&M costs for the cumulative sample have declined from about $32/kW$_{AC}$-year in 2011 to about $16/kW$_{AC}$-year 2020.

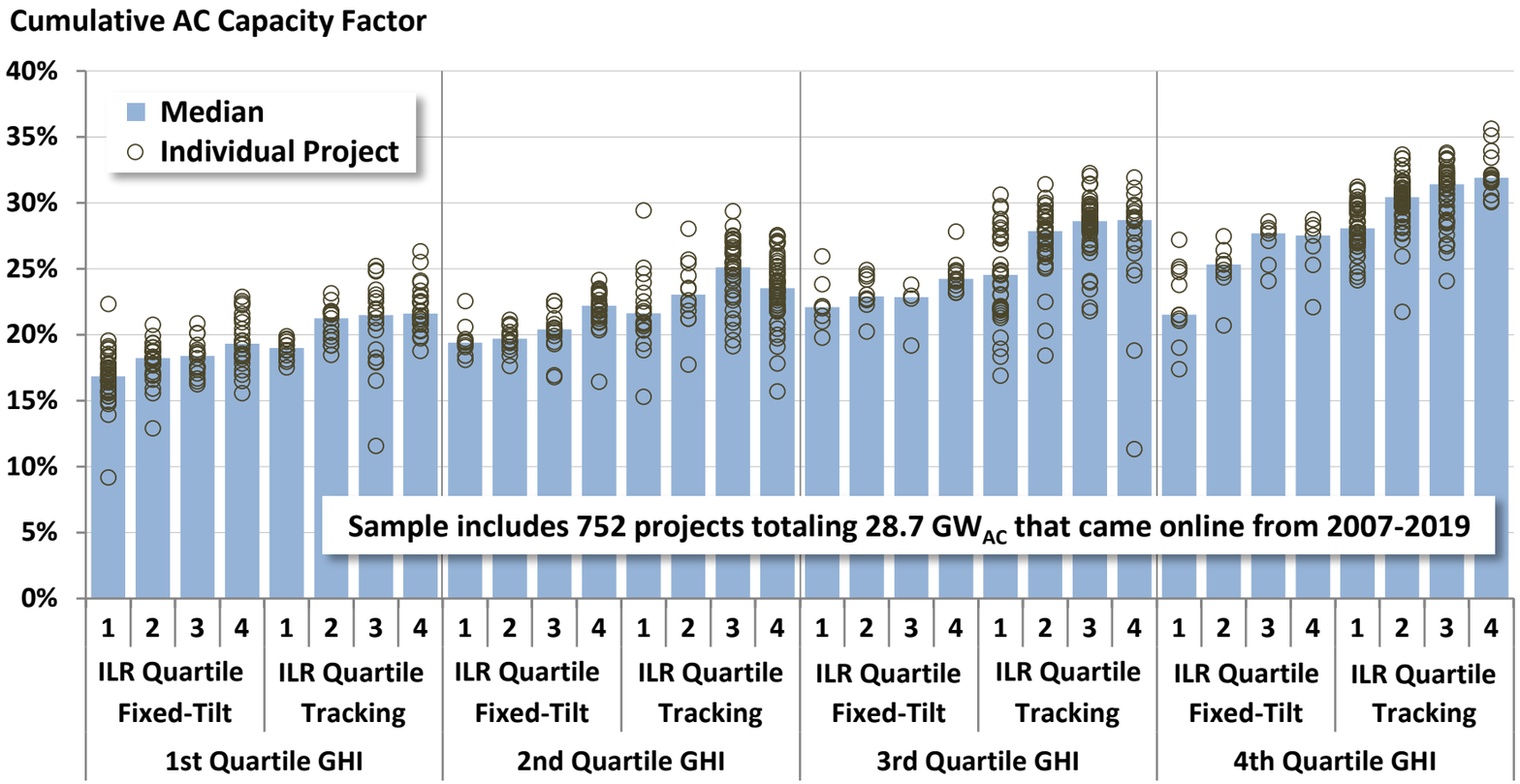
The overall cost range among utilities narrowed in 2020 relative to 2018 and 2019.

These O&M costs are only one part of total operating expenses (OpEx)—see Cost Scope in box to the left.

Performance (Capacity Factors)

24% median PV net capacity factor (cumulative, sample-wide), but with large project-level range from 9%-36%

PV performance sample: 752 projects totaling 28,652 MW_{AC}



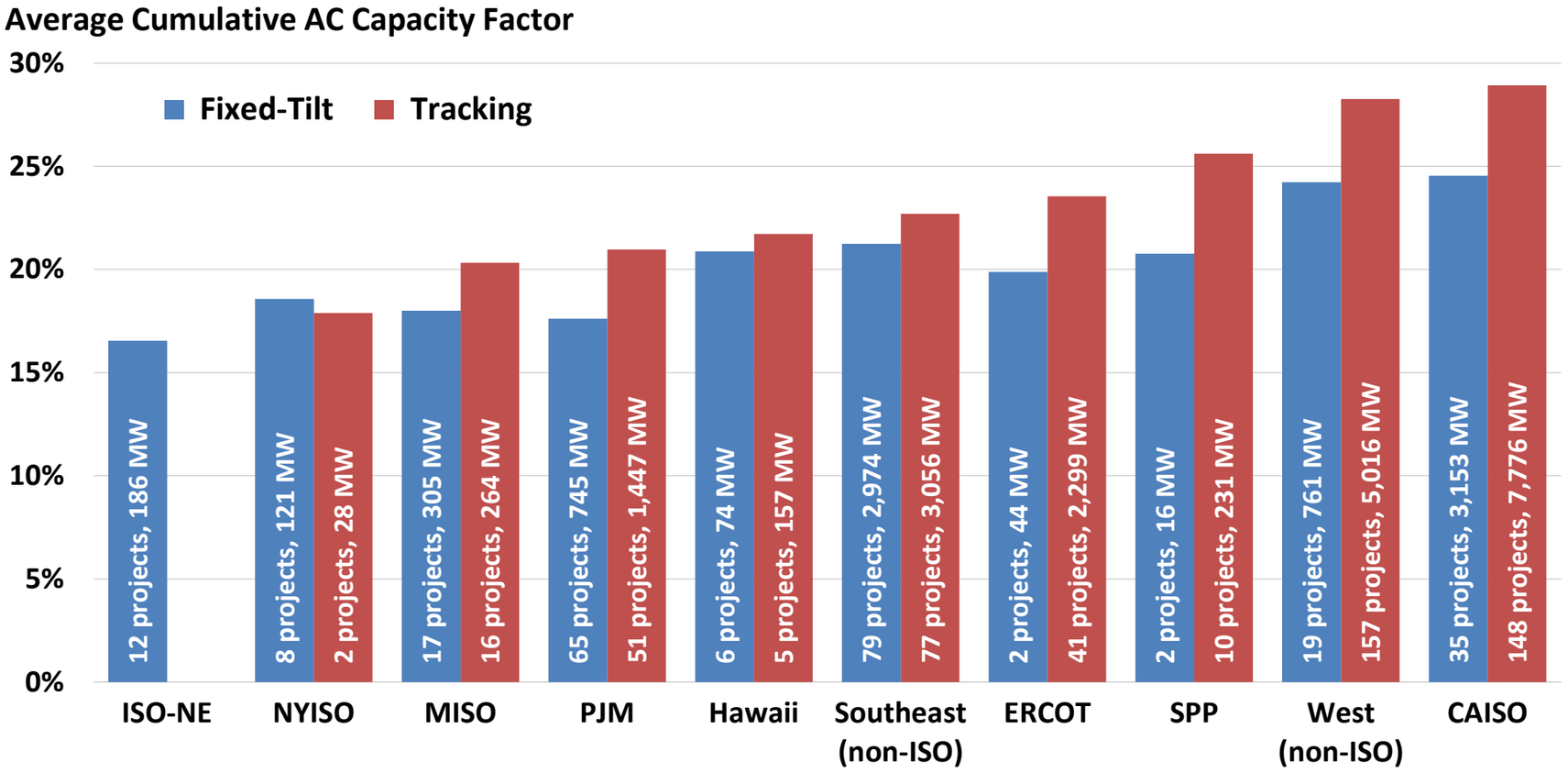
Project-level variation in PV capacity factor driven by:

- **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 up to 5 percentage points in high-insolation regions

Sample: 752 projects totaling 28,652 MW_{AC}

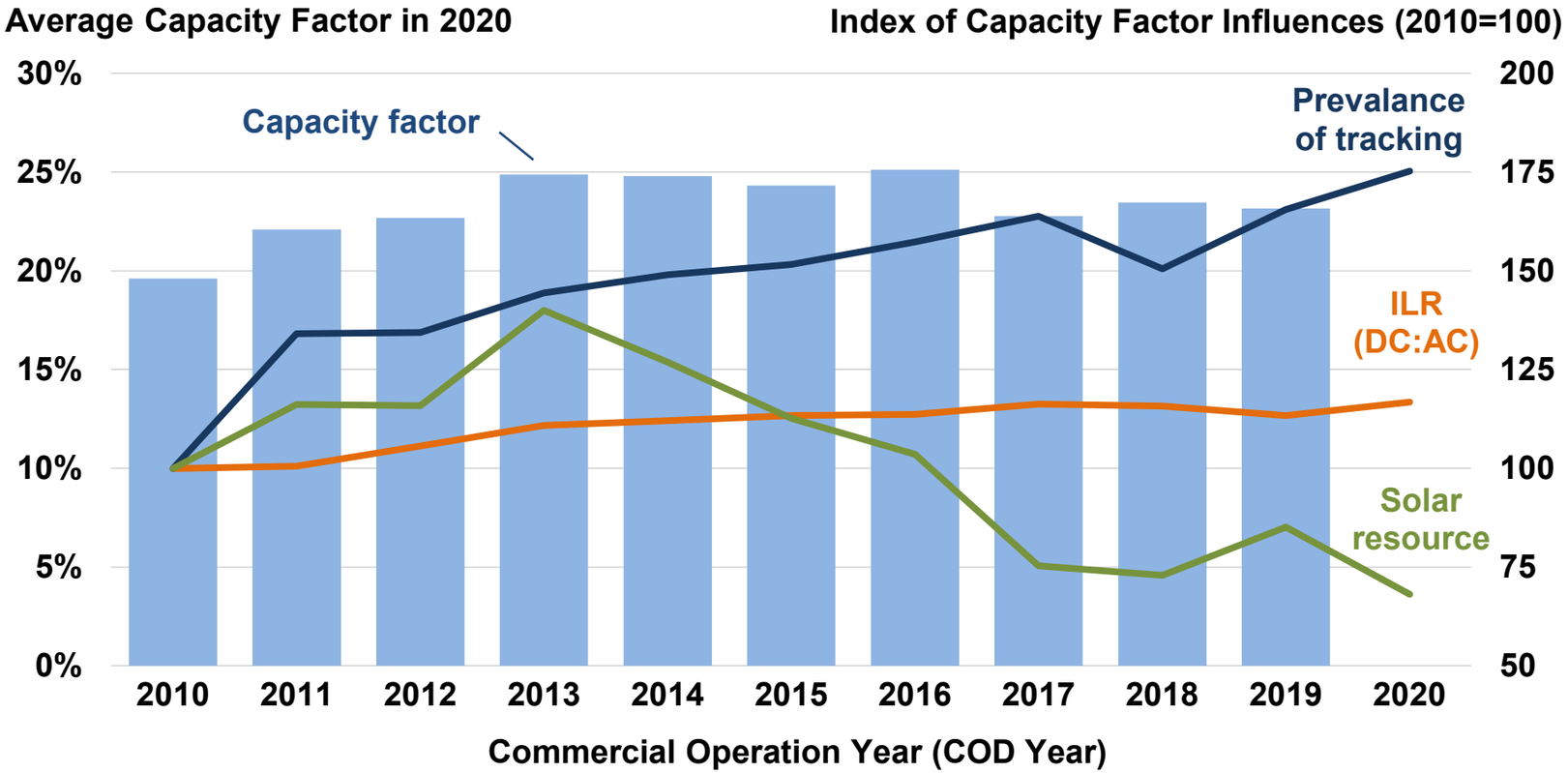


Not surprisingly, capacity factors are highest in California and the non-ISO West, and lowest in the Northeast (ISO-NE and NYISO).

Tracking 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

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



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

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

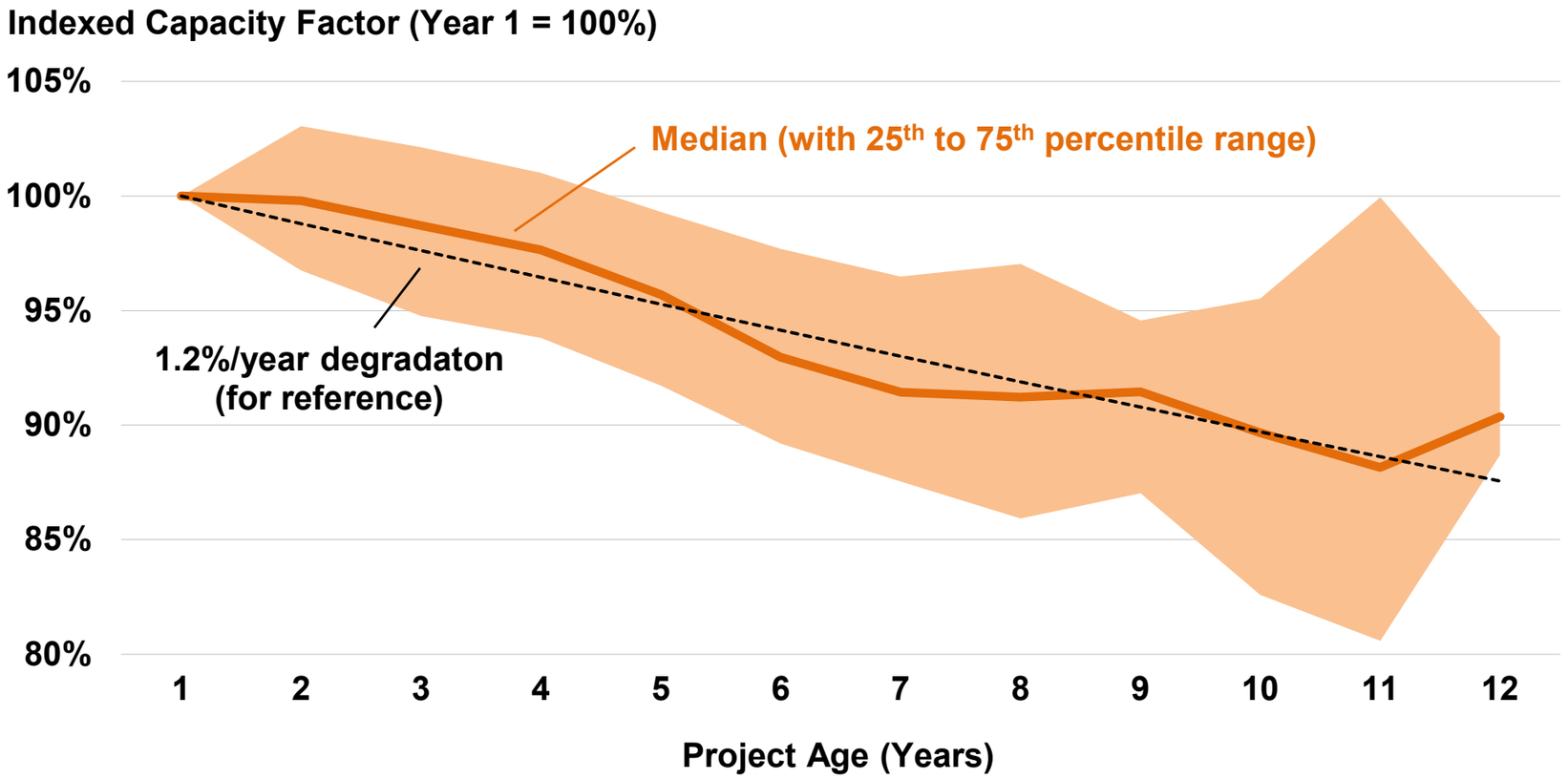
- ILR (from 1.17 to 1.28)
- tracking (from 14% to 59% of projects)
- average site-level GHI (from 4.97 to 5.37 kWh/m^2/day)

Since 2013, however, ILRs have moved only slightly higher (to 1.31 in 2019), while tracking (80% in 2019) and GHI (4.82 kWh/m2/day) have moved in opposite directions, resulting in capacity factor stagnation (on average)

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

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

Fleet-wide performance has declined as projects age, but is difficult to assess and attribute at the project level



Graph shows indexed capacity factors in each full calendar year following COD. Capacity factors have been normalized to correct for inter-year resource variation.

Graph shows plant-level performance decline from all possible degradation pathways—both recoverable and unrecoverable—including:

- ❑ Module degradation
- ❑ BOP degradation
- ❑ Soiling
- ❑ Downtime (unplanned outages, scheduled maintenance, curtailment)

Weather-normalized fleet-wide performance decline appears to be running at ~1.2%/year on average

- ❑ Should not be confused with often-cited lesser rates that pertain solely to module degradation

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:

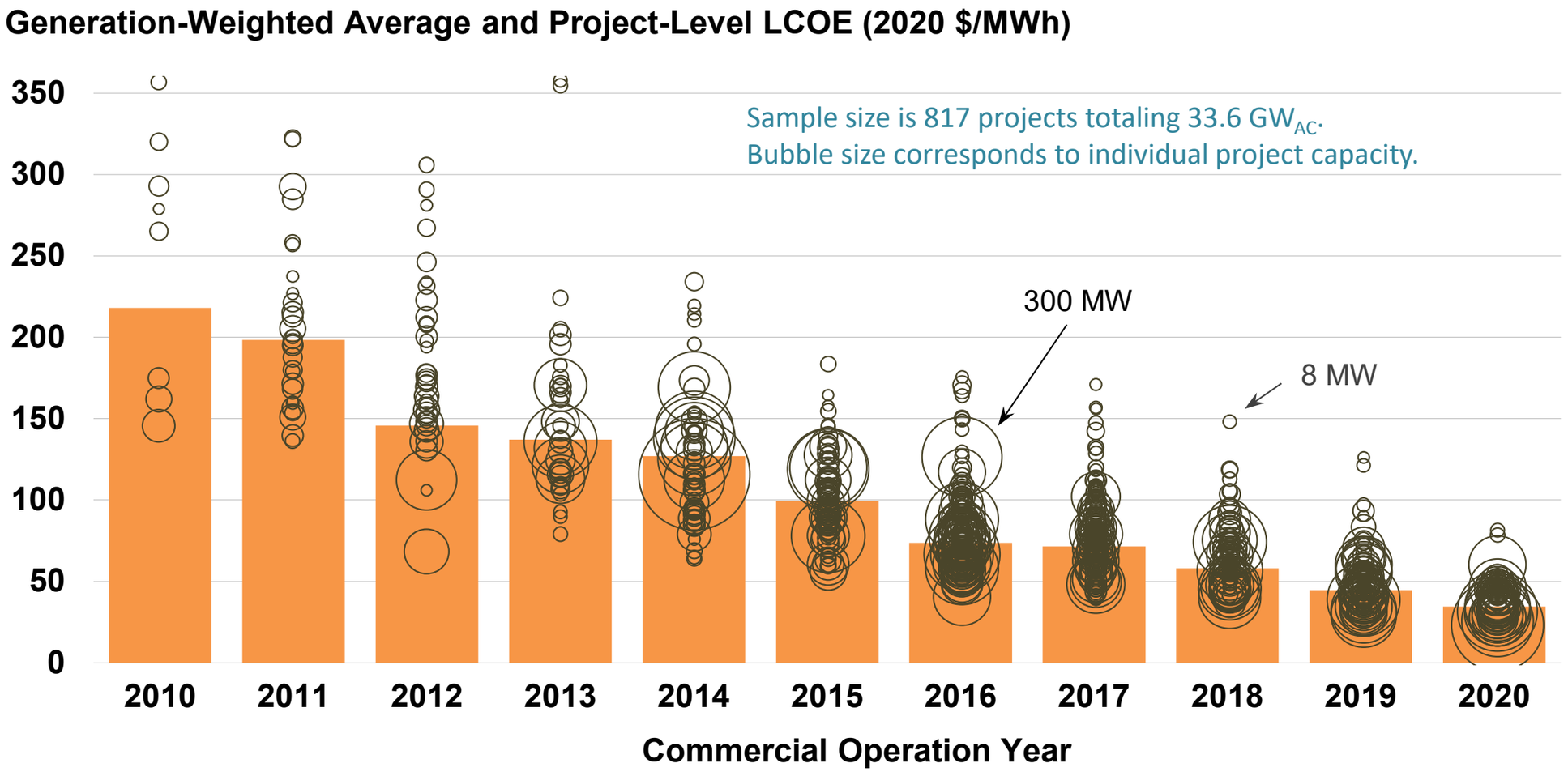
- OpEx and project life that change with vintage: OpEx declines from \$35/kW$_{DC}$-yr in 2007 to \$15/kW$_{DC}$-yr in 2020 (levelized, in 2020\$); project life increases from 21.5 years in 2007 to 33.7 years in 2020 (both based on prior LBNL research)
- Weighted average cost of capital (WACC) based 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:

- 333 PV-only contracts totaling 22.8 GW$_{AC}$
- 47 PV+battery contracts totaling 5.4 GW$_{AC}$ of PV capacity and 3.1 GW$_{AC}$ 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 levelization details are unclear

LCOE has fallen by 85% (or 17% annually) since 2010, to $34/MWh (without the ITC)

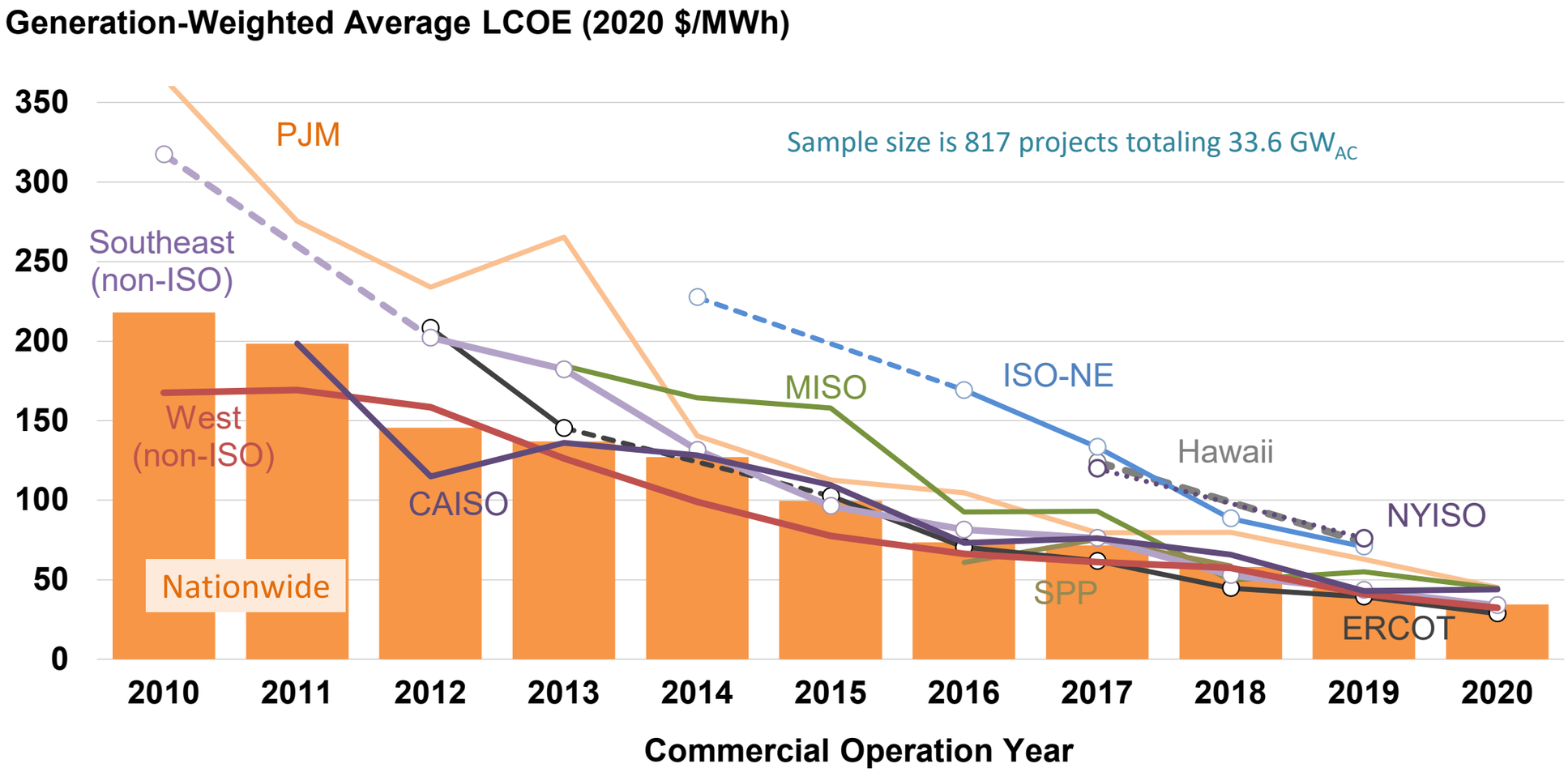


Driven by lower capital costs costs and, at least through 2013, higher capacity factors (as well as lower operating expenses, longer design life, and improved financing terms), utility-scale PV's average LCOE has fallen by about 85% since 2010, to $34/MWh in 2020 (not including the ITC).

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 gradually converged across regions



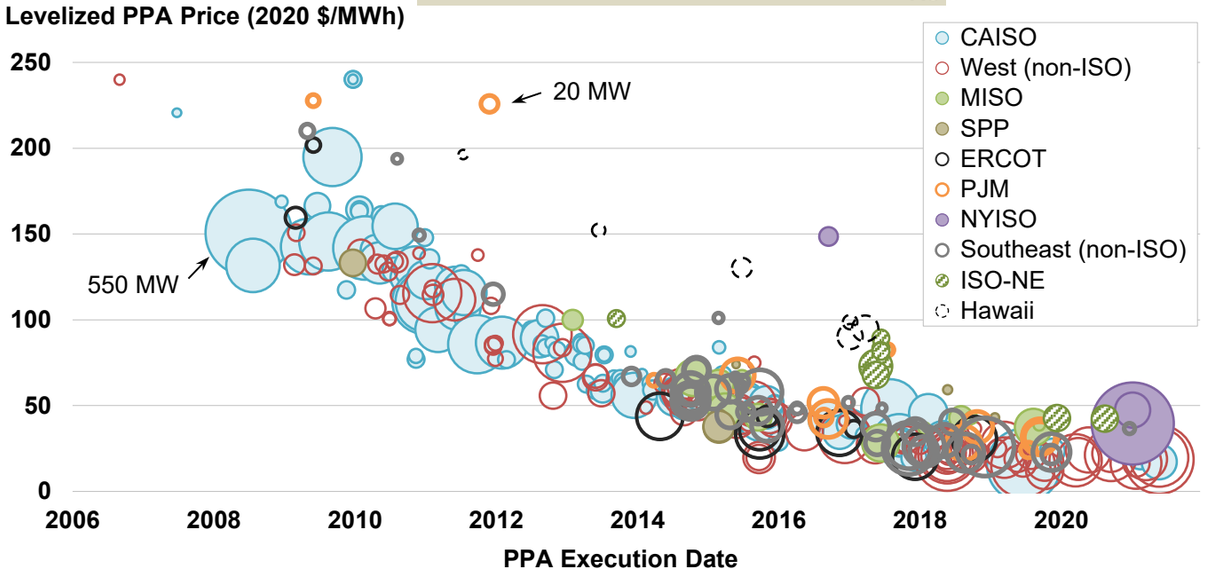
Lower-insolation regions (ISO-NE, NYISO, PJM, MISO) will always have higher LCOEs than higher-insolation regions (ERCOT, the non-ISO West and Southeast), but the difference has been narrowing (the regional standard deviation declines on average by 23% per year).

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

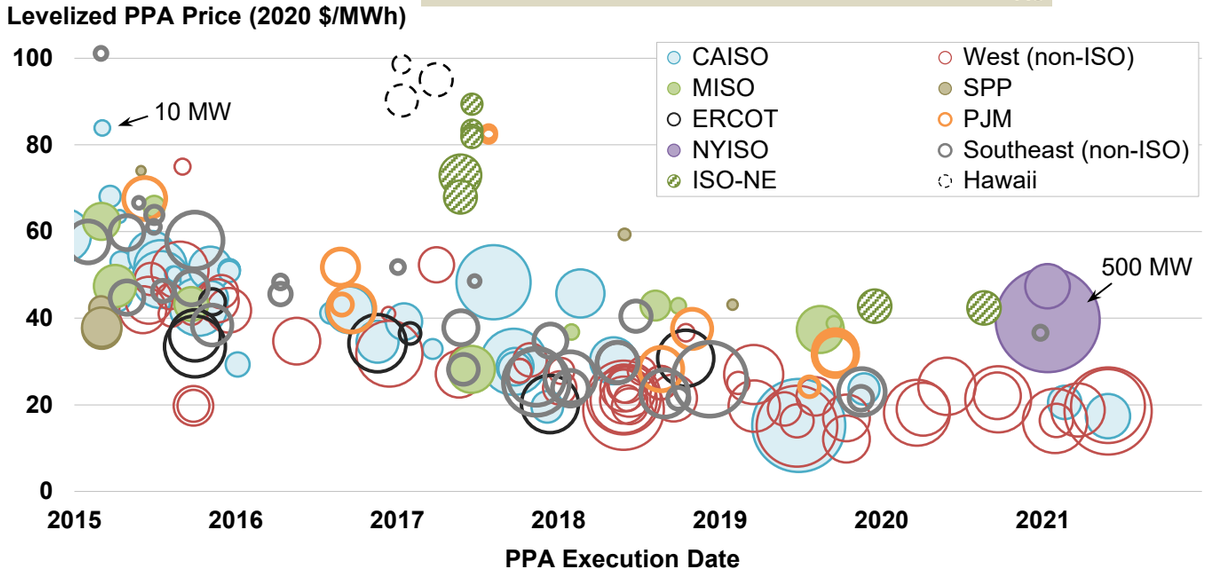
See interactive visualization at https://emp.lbl.gov/capex-lcoe-and-ppa-prices-region

Levelized PPA prices have followed LCOE lower in all regions, though the pace of decline has recently stagnated

Full sample: 333 PPAs, 22.8 GW_{AC}

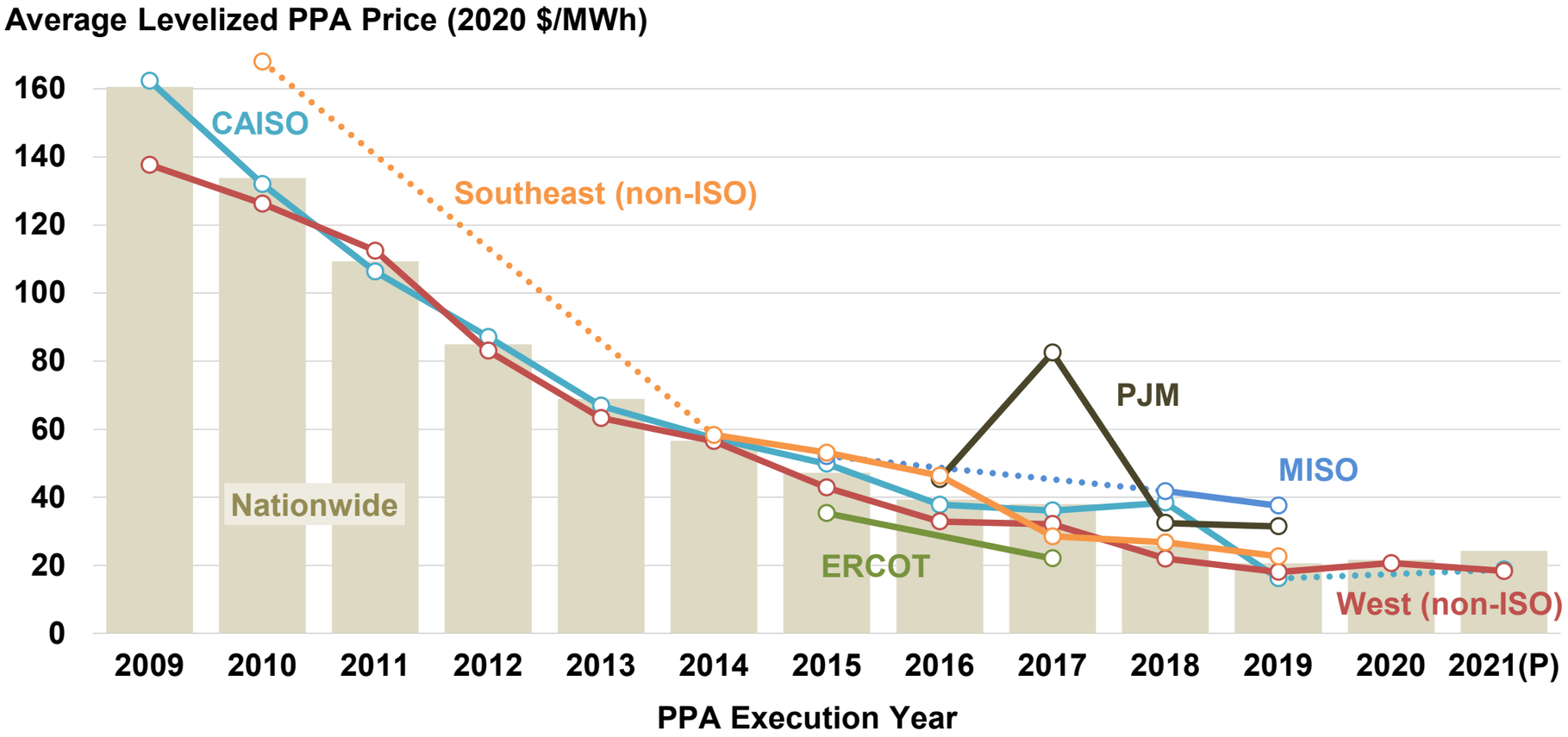


Post-2014 sample: 176 PPAs, 13.6 GW_{AC}



- 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 2020 dollars
- Aided by the 30% ITC, most recent PPAs in our sample are priced around $20/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

Nationwide, average PPA prices have fallen by ~85% (or 15% per year) since 2009, though the pace of decline has recently stagnated



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

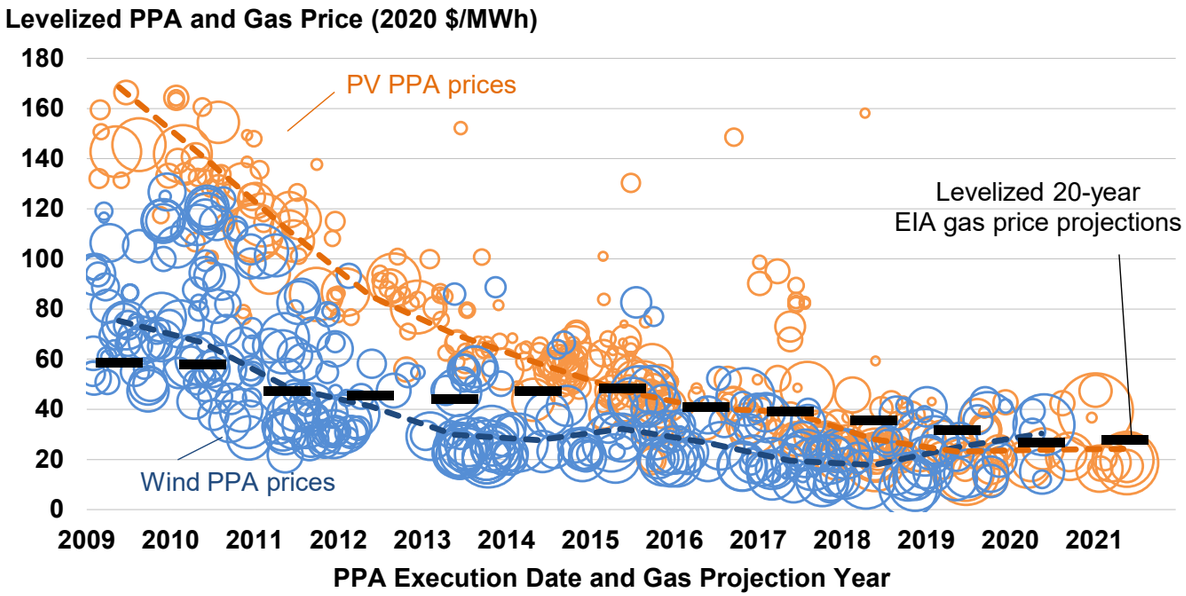
Note a slight uptick in the national average since 2019.

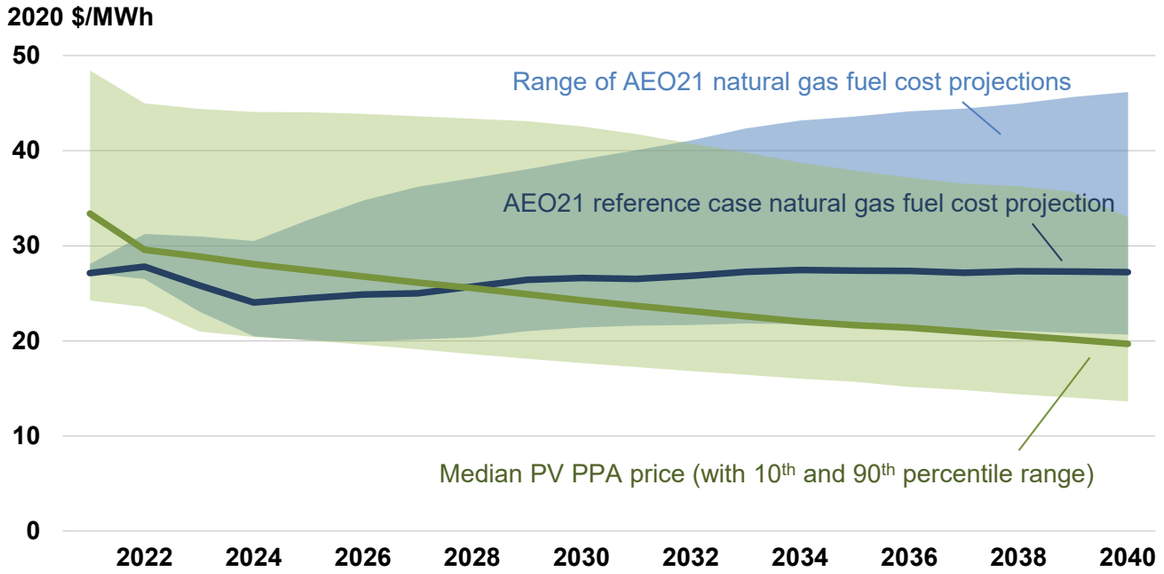
Year-Region combinations with fewer than 2 PPAs are excluded from the graph (dashed line segments indicate that the line is skipping over such years).

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

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

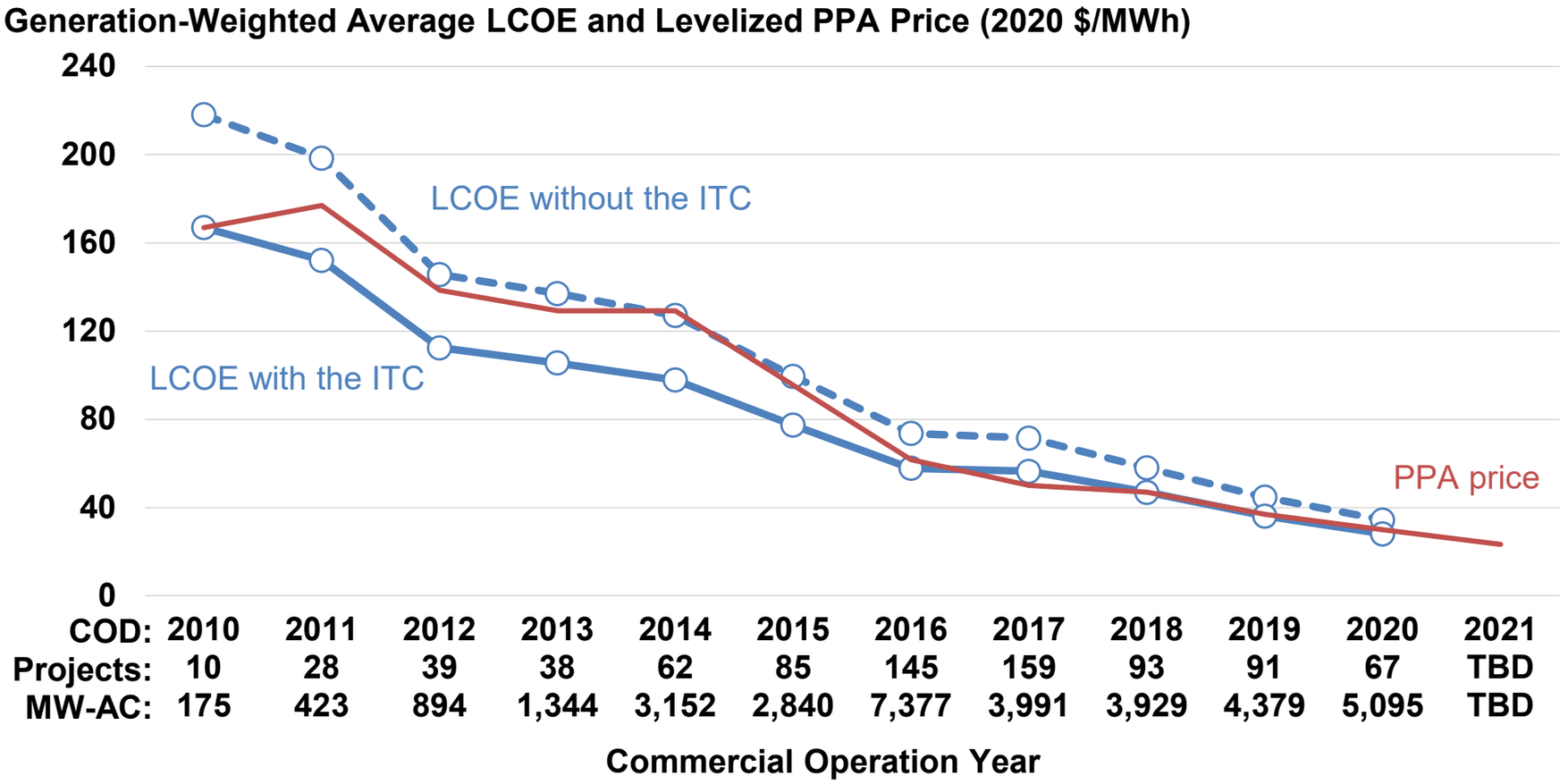




- Left graph shows that solar PPA prices have largely closed the gap with wind, and both are competitive with levelized gas price projections.
- Right graph compares recent solar PPA prices to range of gas price projections from AEO 2021. Although solar PPAs signed post-2017 are initially priced higher than the cost of burning fuel in an ***existing*** combined-cycle natural gas unit (NGCC), over longer terms PV is potentially more competitive (depending on what happens to the price of natural gas), and can help protect against fuel price risk.
- PV PPAs are priced to recover *both* capital *and* other ongoing operational costs—for an NGCC, this would add another ~$23-$49/MWh to fuel costs.

Levelized PPA prices track the LCOE of utility-scale PV

Sample: 817 projects totaling 33,599 MW_{AC}

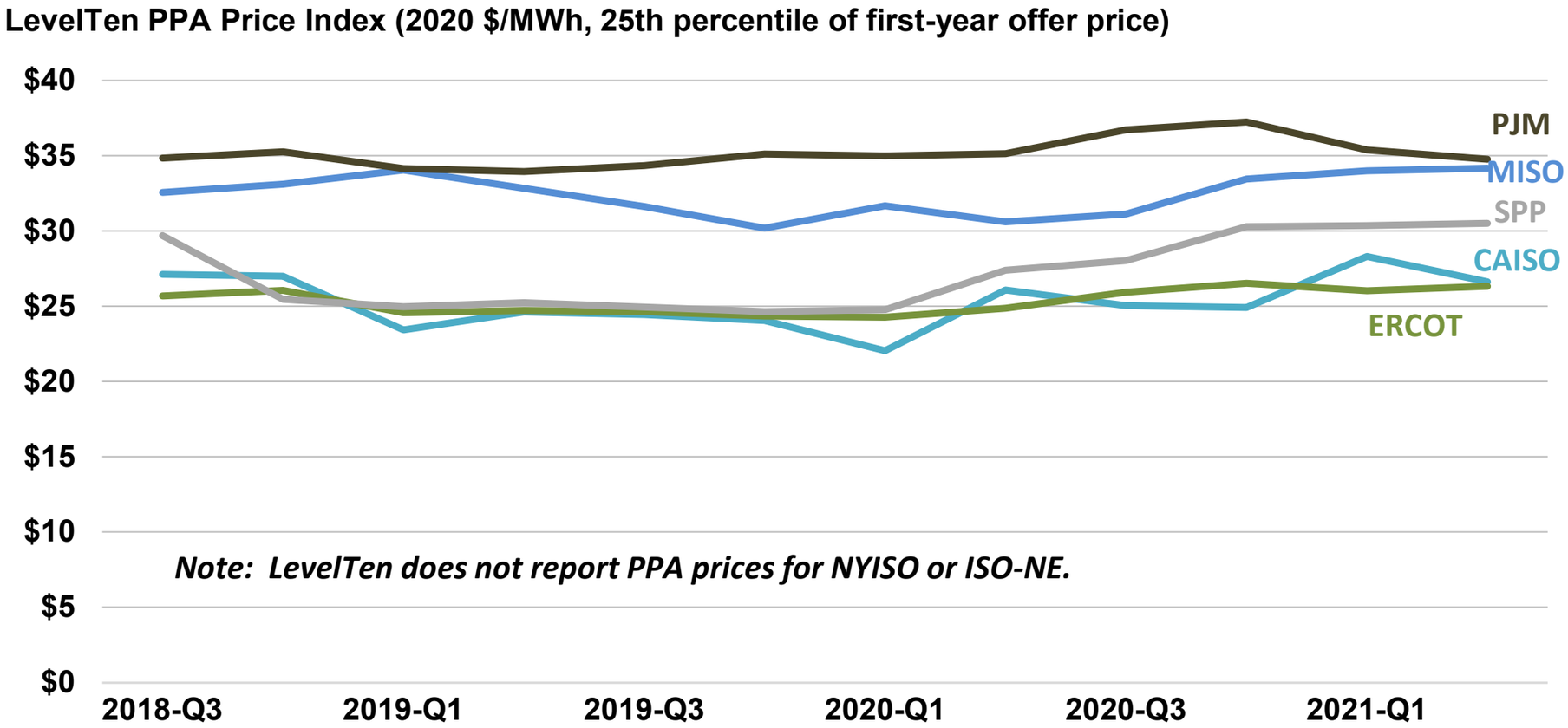


Prior LCOE graphs exclude the ITC, but here we graph LCOE both with and without the ITC, plotted against PPA prices by COD year (rather than by PPA execution date).

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.

LevelTen Energy utility-scale PV PPA price indices



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

LevelTen pricing represents the 25th percentile of offers (levelization details unclear), rather than pricing from executed contracts.

In the five ISOs that LevelTen tracks, offer prices rose gradually throughout 2020, but have mostly stabilized so far in 2021.

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) and for distributed PV (DPV) capacity for each county (as reported on Form EIA-861). 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 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

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

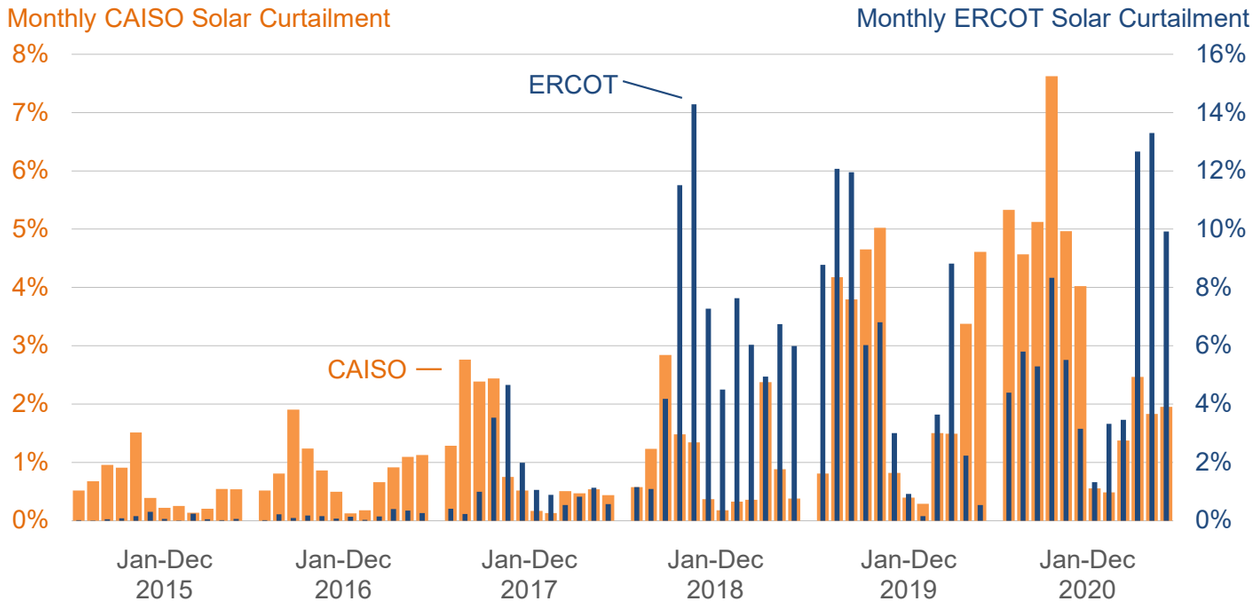
Capacity value is the product of a plant's or county's capacity credit and capacity prices

- 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 from all sectors
- Calculate capacity value for all solar, even if some solar does not participate in capacity markets

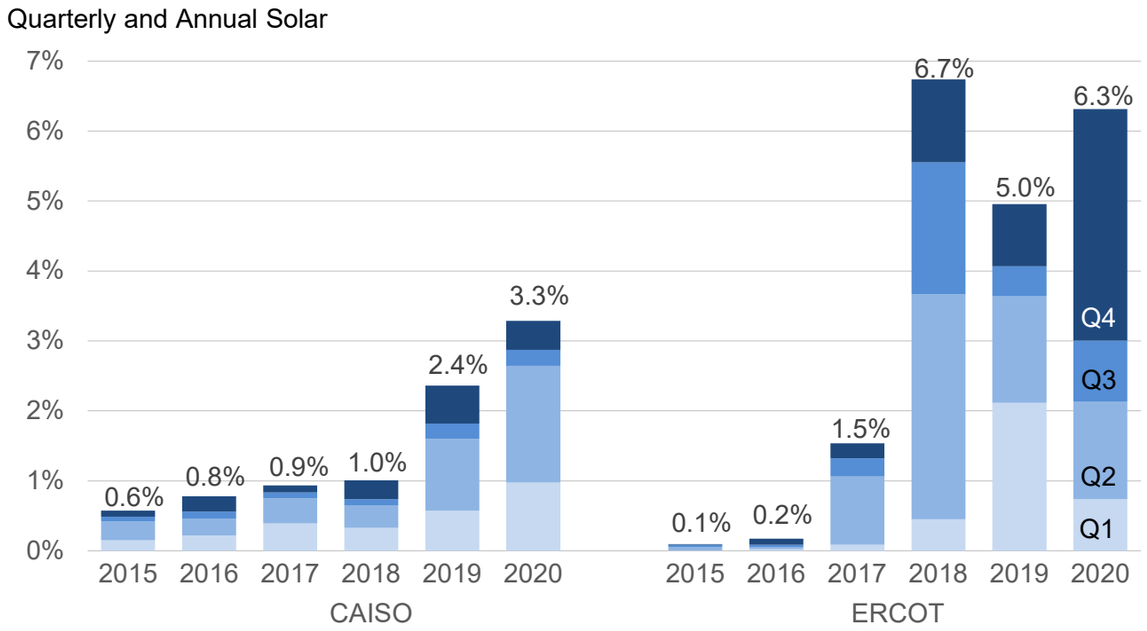
$$Capacity\ Value = \frac{\sum Capacity\ Credit_T * Nameplate * Capacity\ Price_T}{\sum Precurtailment\ Generation_T}$$

Total market value is simply the sum of energy and capacity value and does not include any potential additional revenue streams (ancillary market 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)

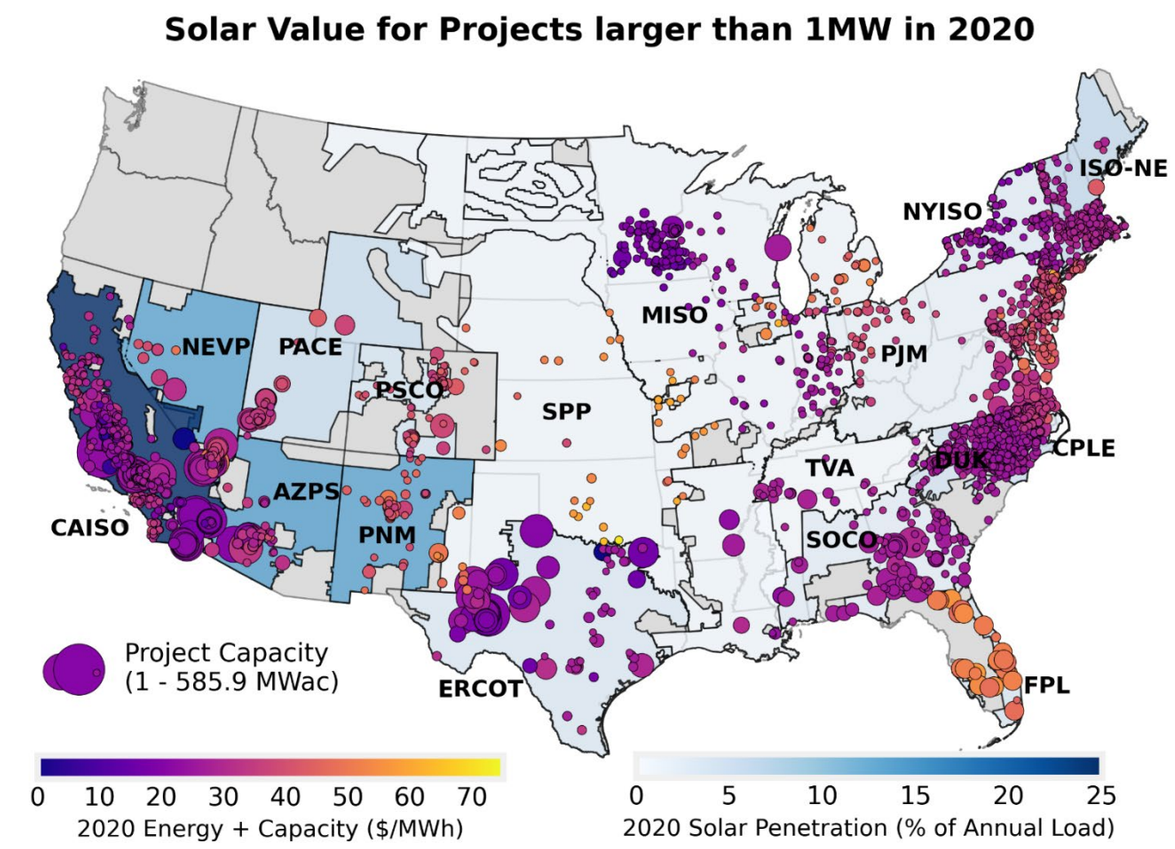


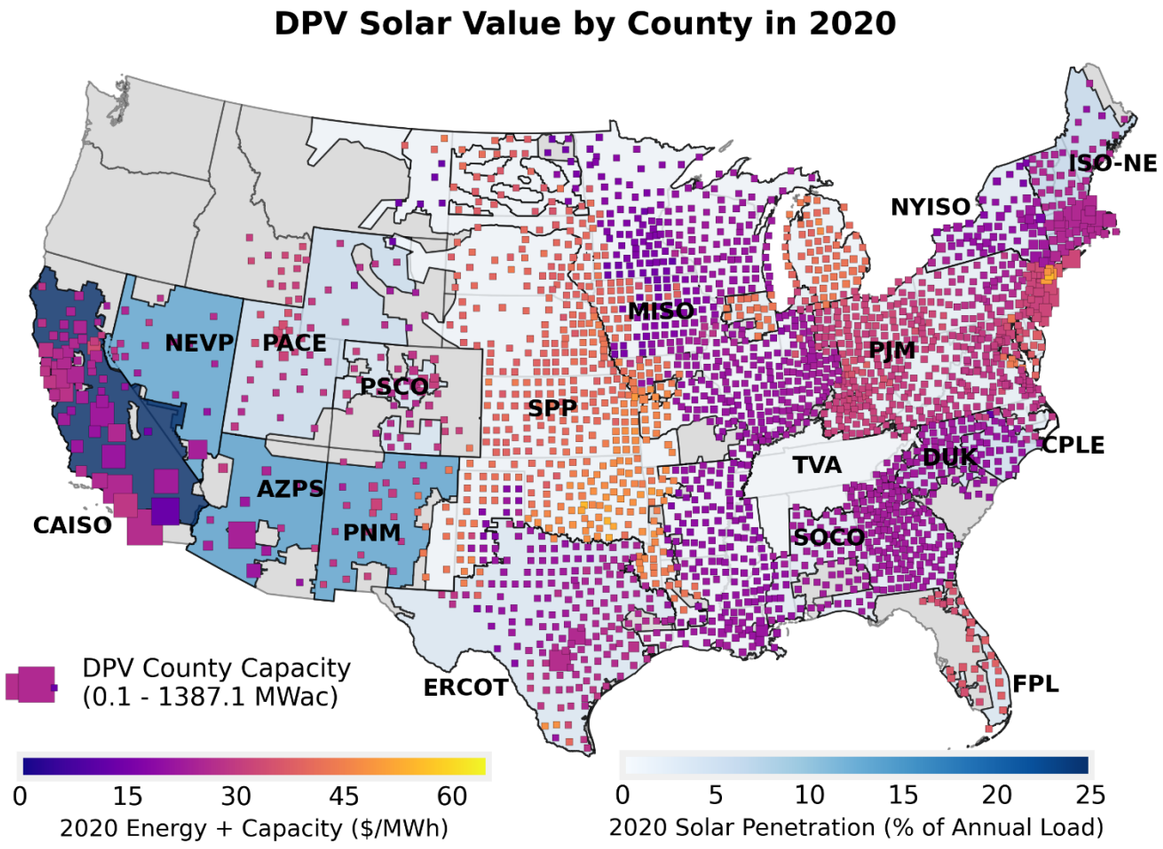
CAISO: 1,659 GWh of solar curtailed in 2020, equivalent to the annual output of a hypothetical 725 MW_{AC} PV project operating at an average CA capacity factor of 26.1% (which would have been 27.5% if not for curtailment).

ERCOT: 671 GWh of solar curtailed in 2020, equivalent to the annual output of a hypothetical 385 MW_{AC} PV project operating at an average TX capacity factor of 19.9% (which would have been 21.5% if not for curtailment).

Much higher *rate of curtailment* in ERCOT (6.3%) than in CAISO (3.3%) in 2020, even though solar's penetration rate is far lower in ERCOT (3%) than CAISO (~23%).

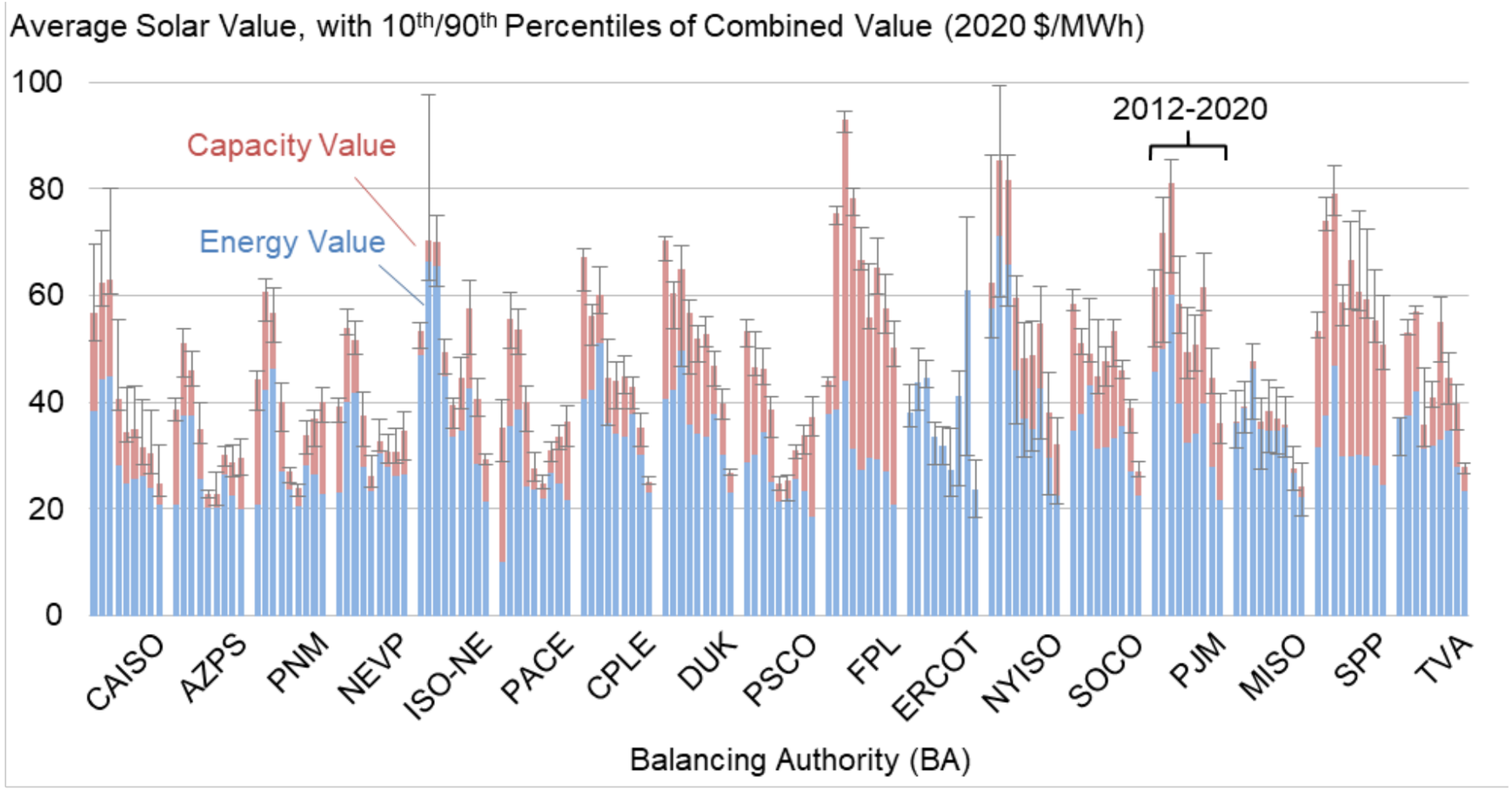
Solar's energy and capacity value varied by location





Solar's value varies between regions (low in CAISO and MISO and high in SPP and FPL) and within regions (for example, western ERCOT has lower solar values than eastern ERCOT). Some markets showed very little variation in solar value in 2020 (value across ISO-NE differed by only 7%) while others had large discrepancies (values varied by up to 50% in ERCOT and NYISO).

Here we roll up the plant- and county-level estimates from the previous slide to regional averages (and also separate energy and capacity value)



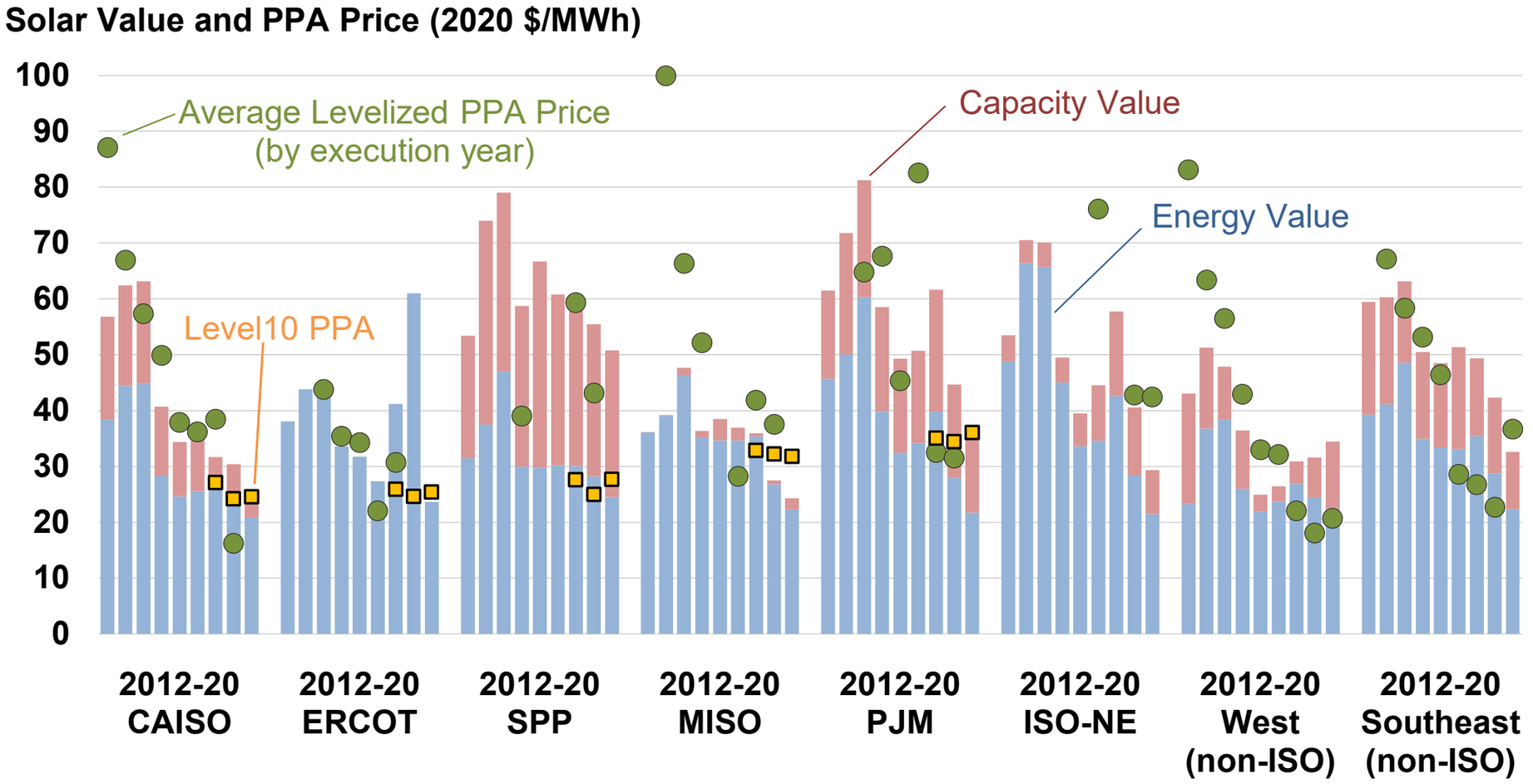
In 2020, market value was lowest in ERCOT ($23.7/MWh) and highest in SPP ($50.8/MWh).

The regional solar value is the generation-weighted average value of all distributed and utility-scale solar generation in a given balancing authority.

The energy value makes up the bulk of total market value, but capacity value is significant in eastern markets in particular.

Fluctuations across years mostly reflect fluctuations in wholesale power prices, but in CAISO, the visible decline in value over time also reflects increasing solar penetration.

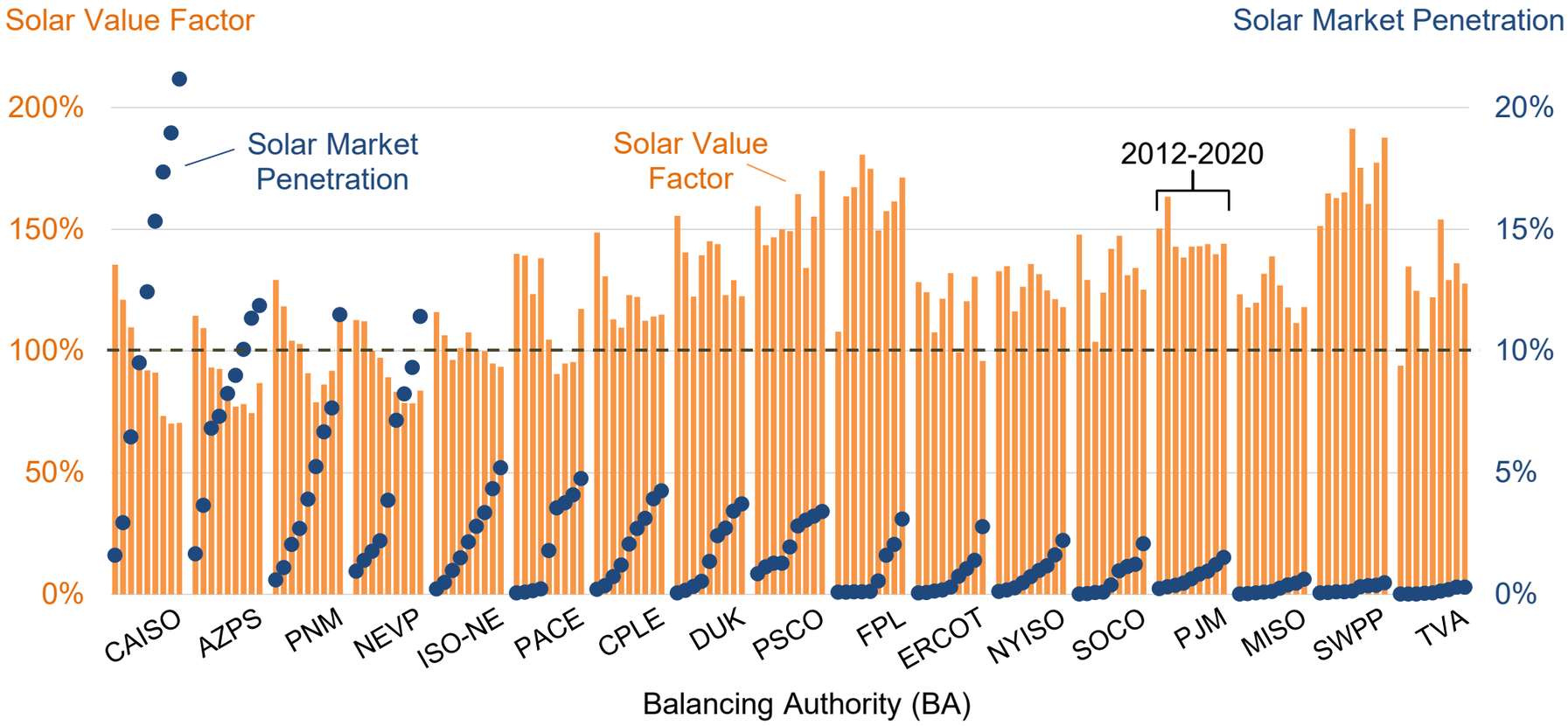
In a subset of regions for which we have sufficient PPA sample, falling PPA prices have largely kept pace with declining solar value



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, more or less maintaining solar's competitiveness.

Solar provides below-average value in 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)

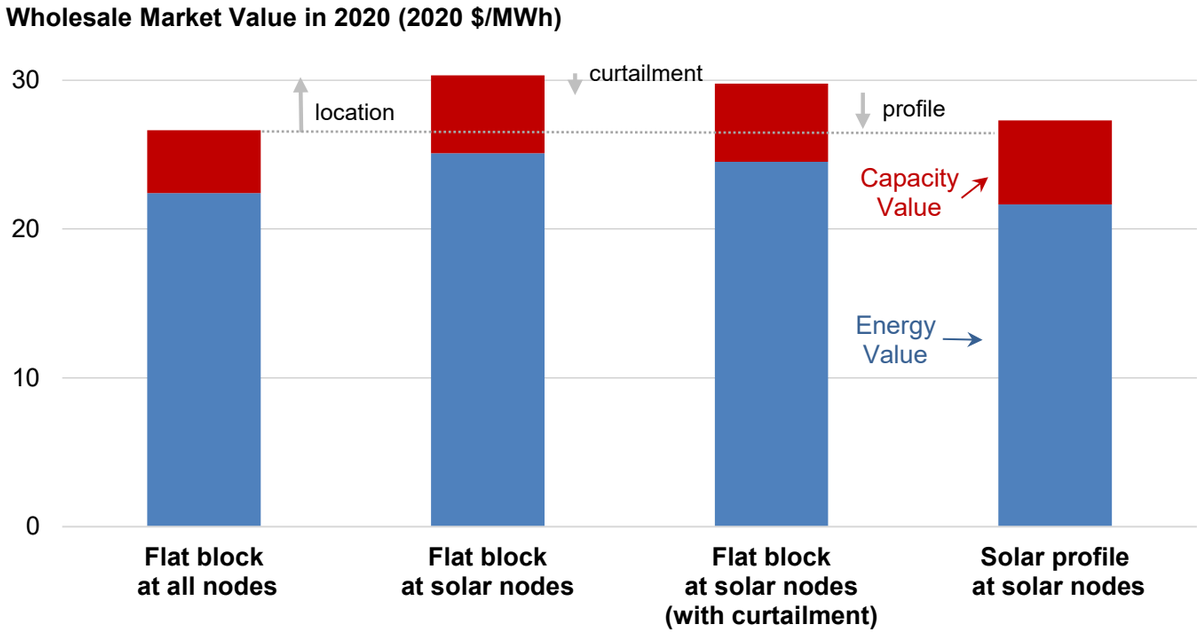
The "Value Factor" is defined as the ratio of solar's total market value (both energy and capacity) to the market value of a "flat block" (i.e., a 24x7 block) of power.

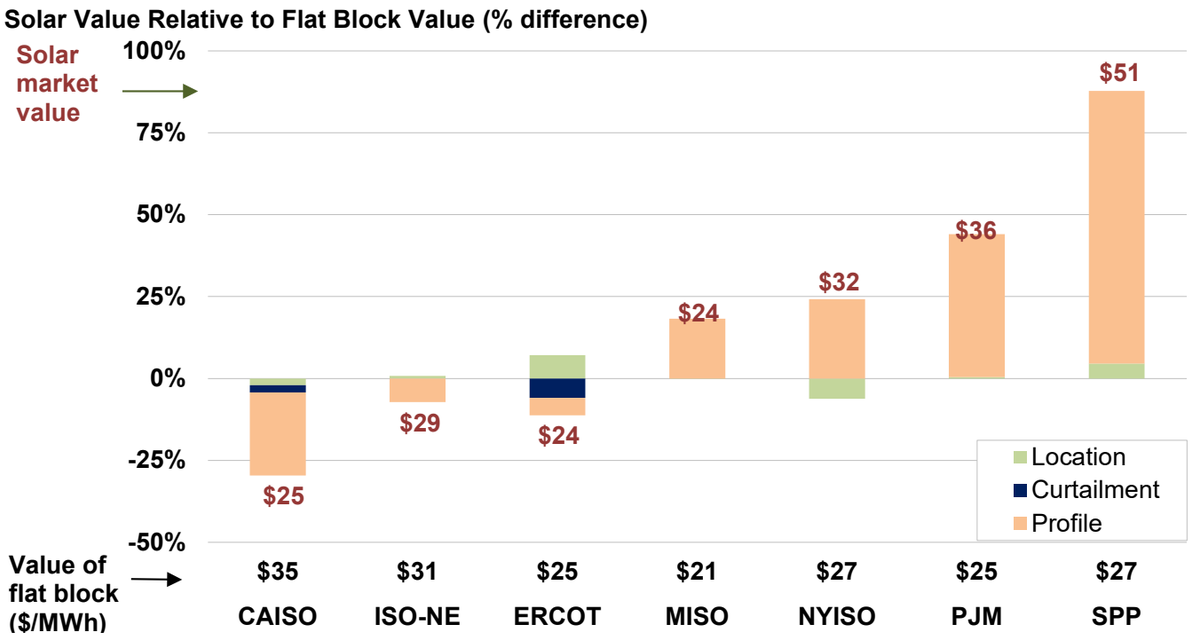
It indicates whether the total revenue captured by solar is higher (>100%) or lower (<100%) than the average wholesale price across all hours.

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.

Regions with the highest solar penetration rates (CAISO, AZPS, PNM, NEVP, and ISO-NE) all show Value Factors less than 100% (except PNM).

Solar's generation profile is the largest source of value differences between solar and flat block in 2020





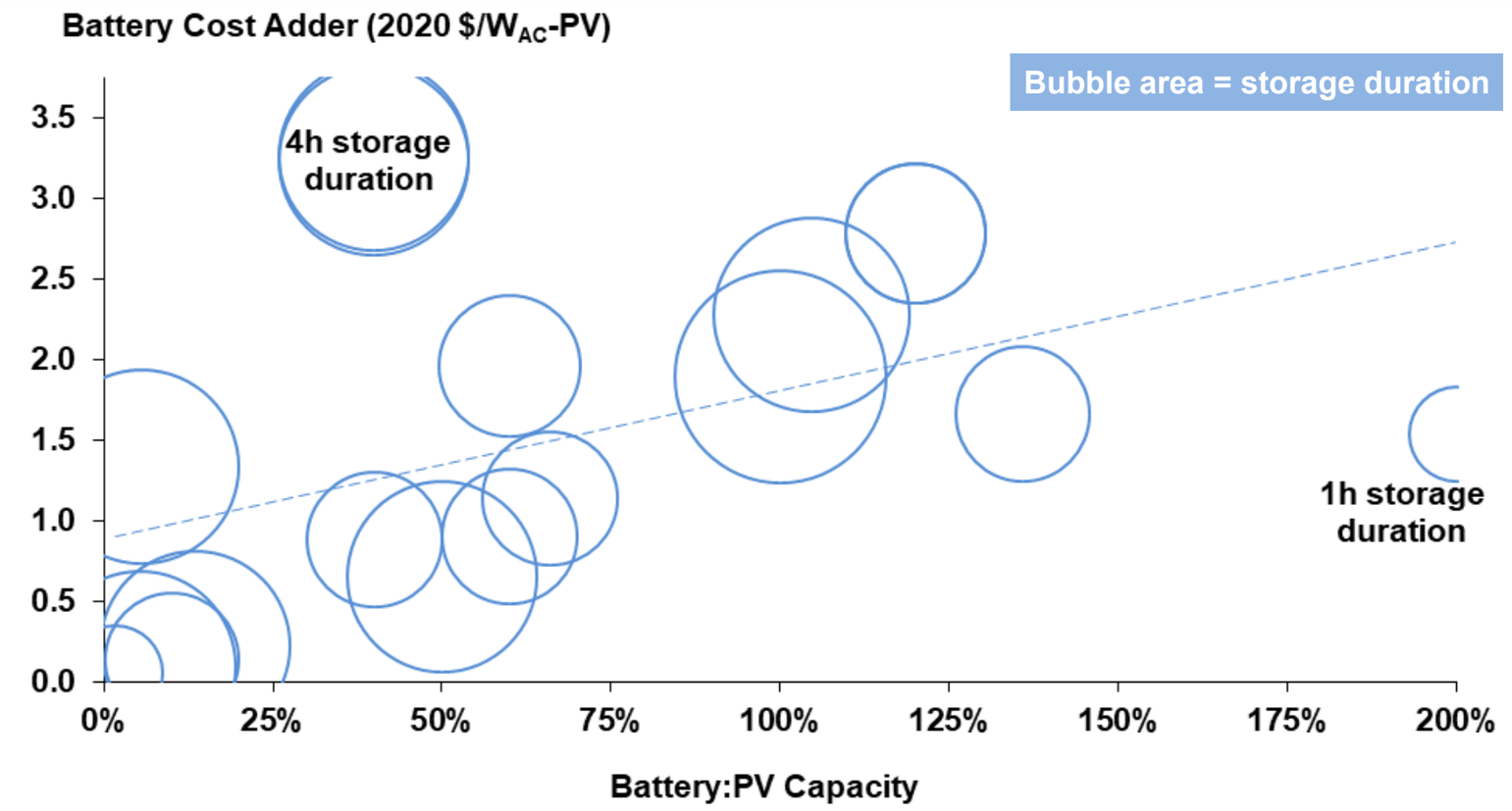
On a national average basis, solar's relative value is enhanced by project location but hurt by solar's generation profile (and, to a lesser extent, by curtailment).

With the exception of ERCOT (where the location of solar plants is the largest driver of relative value), solar's generation profile either hurts (in CAISO and ISO-NE) or helps (in MISO, NYISO, PJM, and SPP) solar's value the most (relative to a flat block).

PV+Battery Hybrid Plants

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

Sample: 18 projects totaling 180 MW_{AC} of PV, 116 MW_{AC} of battery capacity, and 392 MWh of battery energy, with CODs from 2017-2019

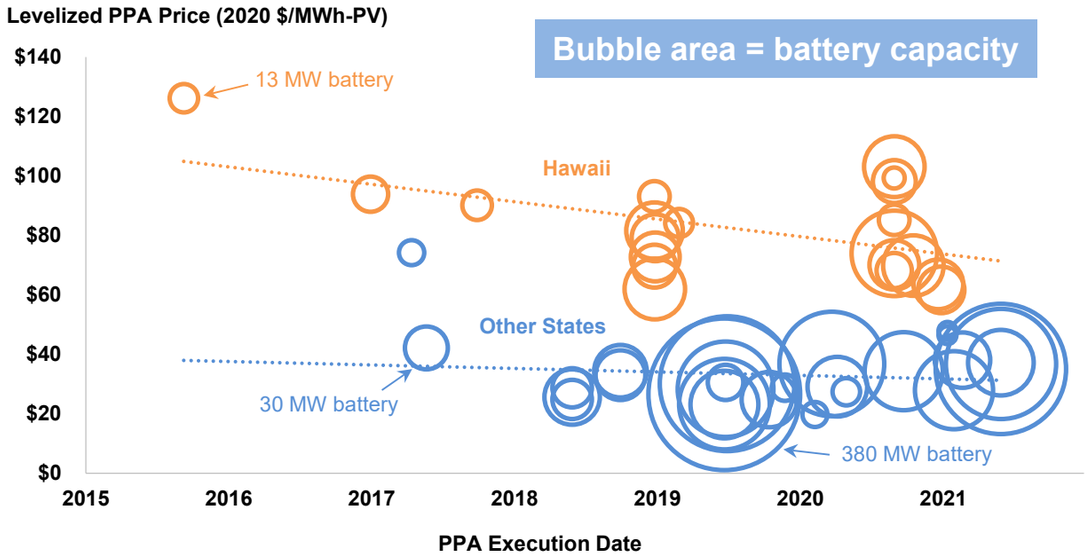


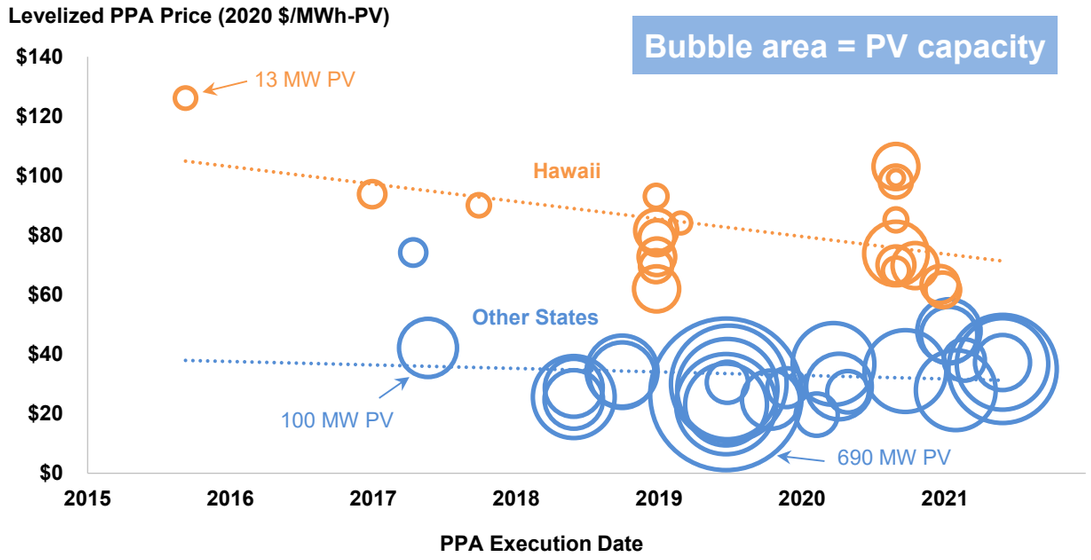
Empirical cost sample for utility-scale PV+battery hybrid projects is still very thin, and does not include 2020.

The median reported battery costs among 11 projects with a 2019 COD was $1,100/kWh, representing a median cost adder of $1.54/$W_{AC}$-PV, or 48% of overall hybrid project installed costs.

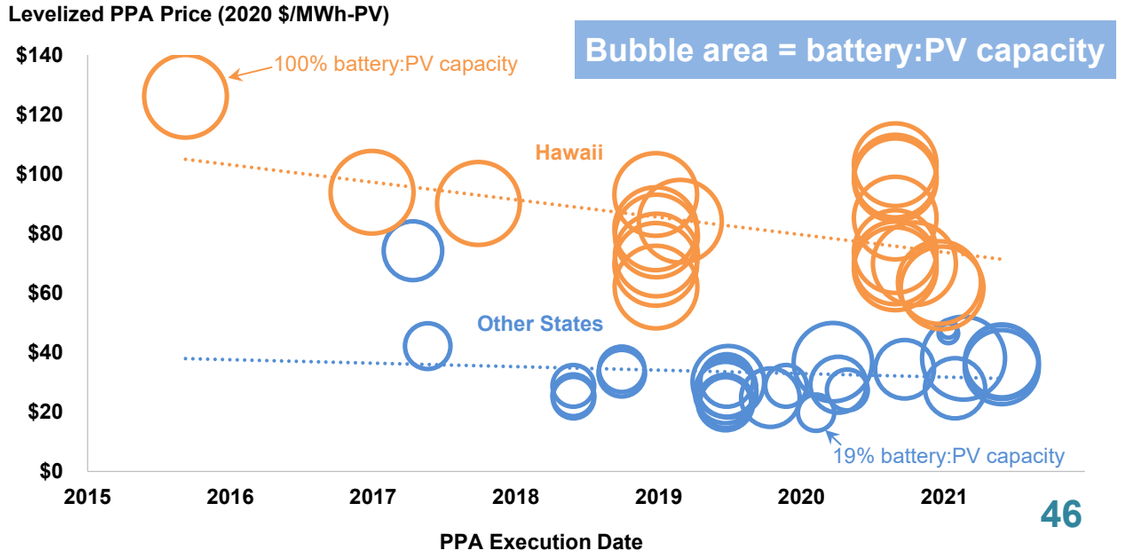
Within this 2019 COD sample, the median battery capacity is 60% of the PV capacity and can release energy at rated power for a little more than 2 hours.

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



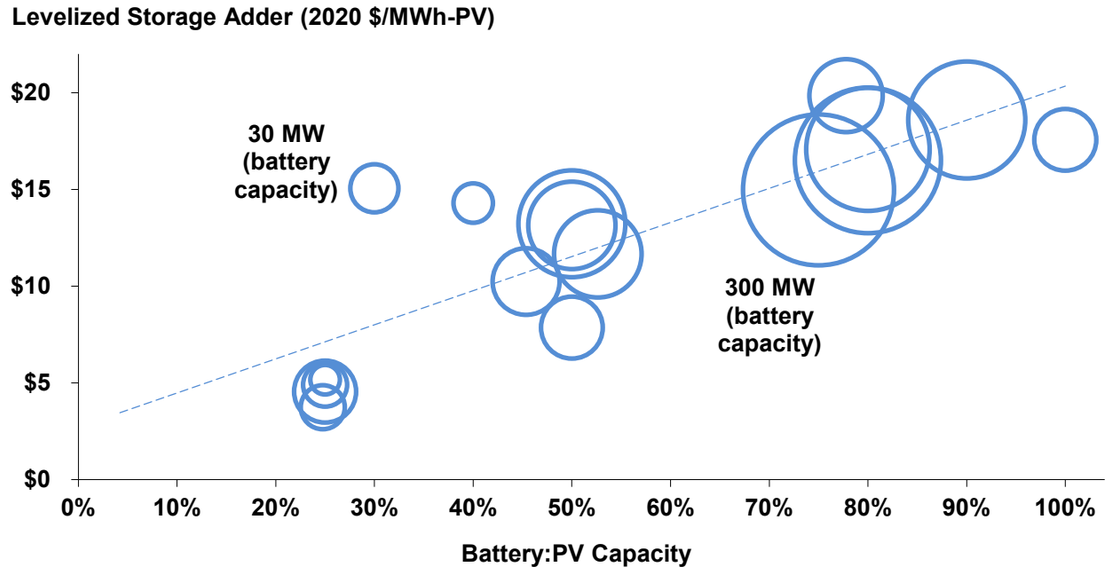


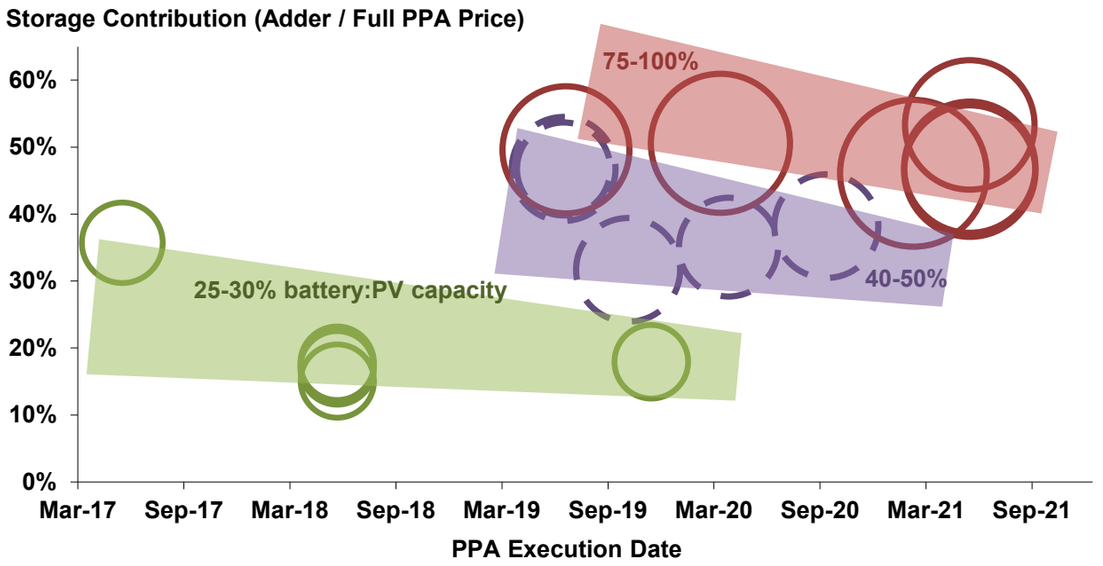
- All three graphs show the same data from a sample of 47 PPAs (totaling 5.4 GW_{AC} of PV and 3.1 GW_{AC} of battery); the only difference is what the bubble size represents
- Downward trend over time, particularly in HI, but refinement is complicated by multi-dimensionality of these plants; "Other States" (in blue) are more heterogeneous than HI in terms of solar resource
- Battery:PV capacity ratio always at 100% in HI; lower on the mainland
- Battery duration ranges from 2-8 hours; 44 of the 47 plants shown have durations ≥4 hours (other three are 3.8, 2, and 2 hours)

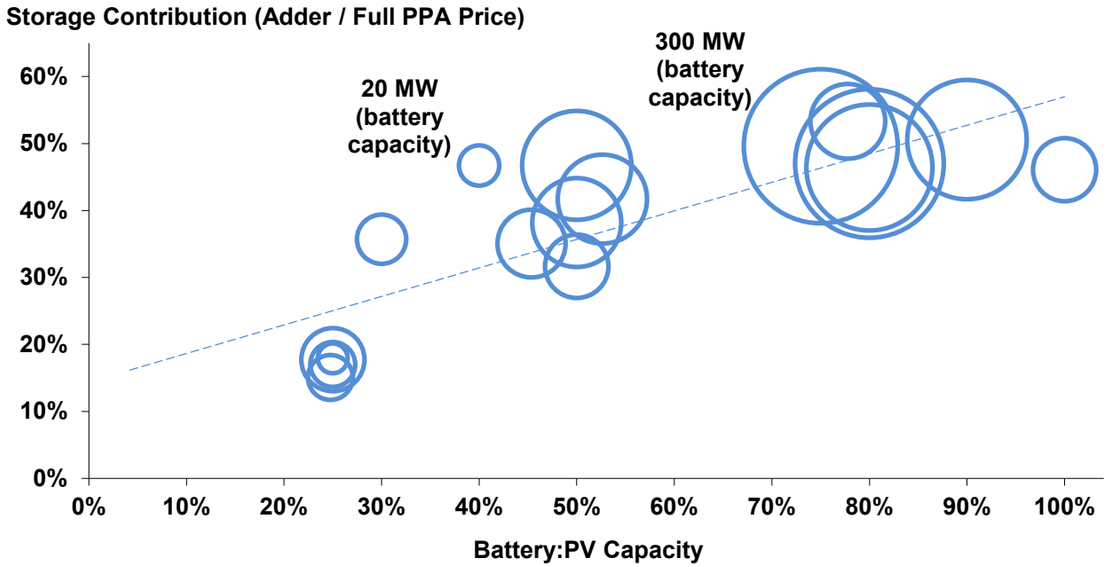


BERKELEY LAB

PPAs that price the PV and storage separately enable us to calculate a "levelized storage adder"—which depends on the battery:PV capacity ratio





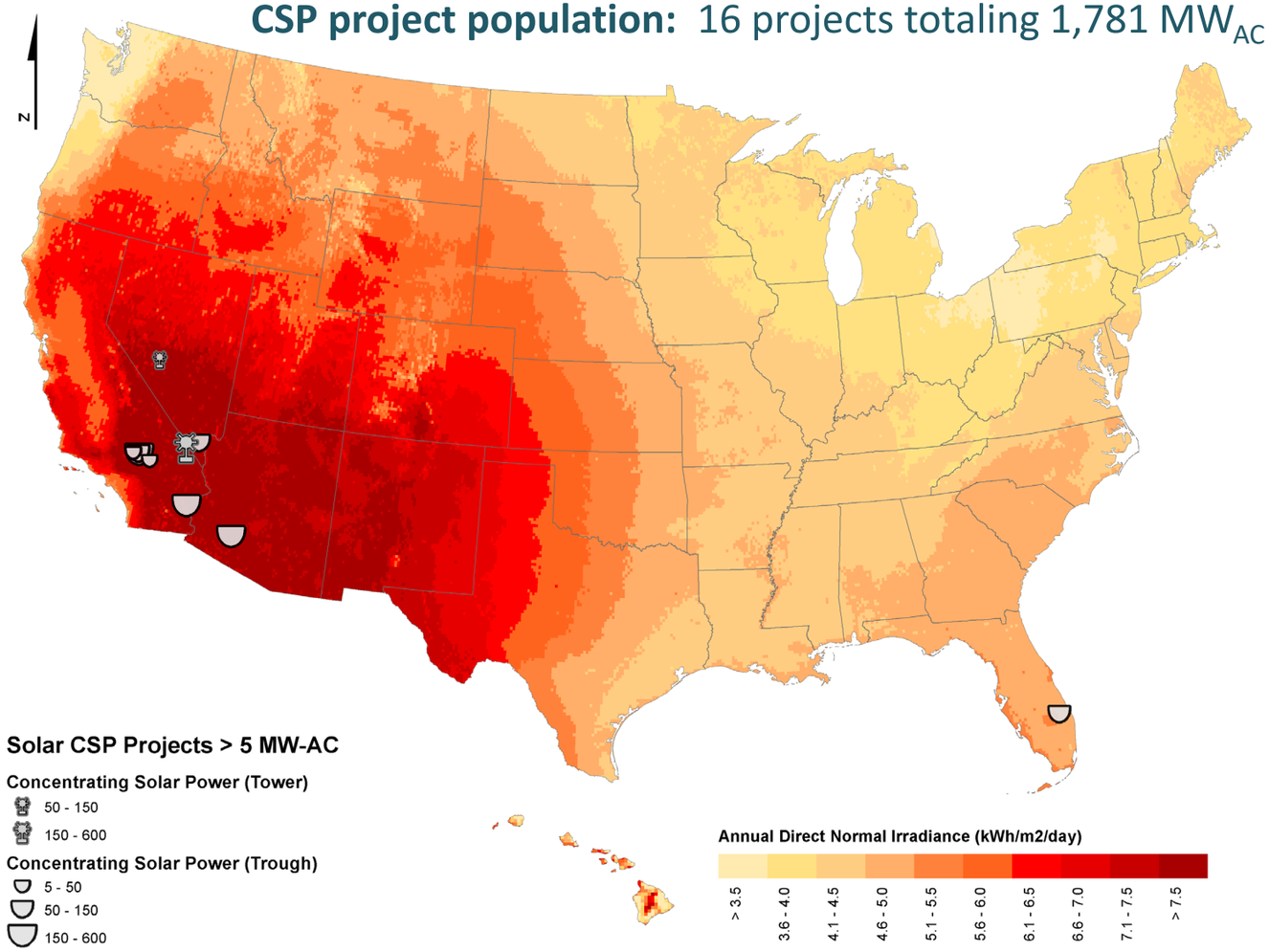


- The "levelized storage adder"—*expressed in the top-left graph in $/MWh-PV, not $/MWh-stored*—increases linearly with the battery:PV capacity ratio: ~$5/MWh-PV at 25% battery:PV capacity, ~$10/MWh at 50%, ~$20/MWh at 100%
- Bottom-left graph presents the storage adder as a percentage of the full PPA price (i.e., storage's contribution to the overall price)
- Top-right graph shows storage's contribution holding fairly steady, and a trend toward larger battery:PV capacity, over time
- All batteries depicted on this slide have a 4-hour storage duration

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}).

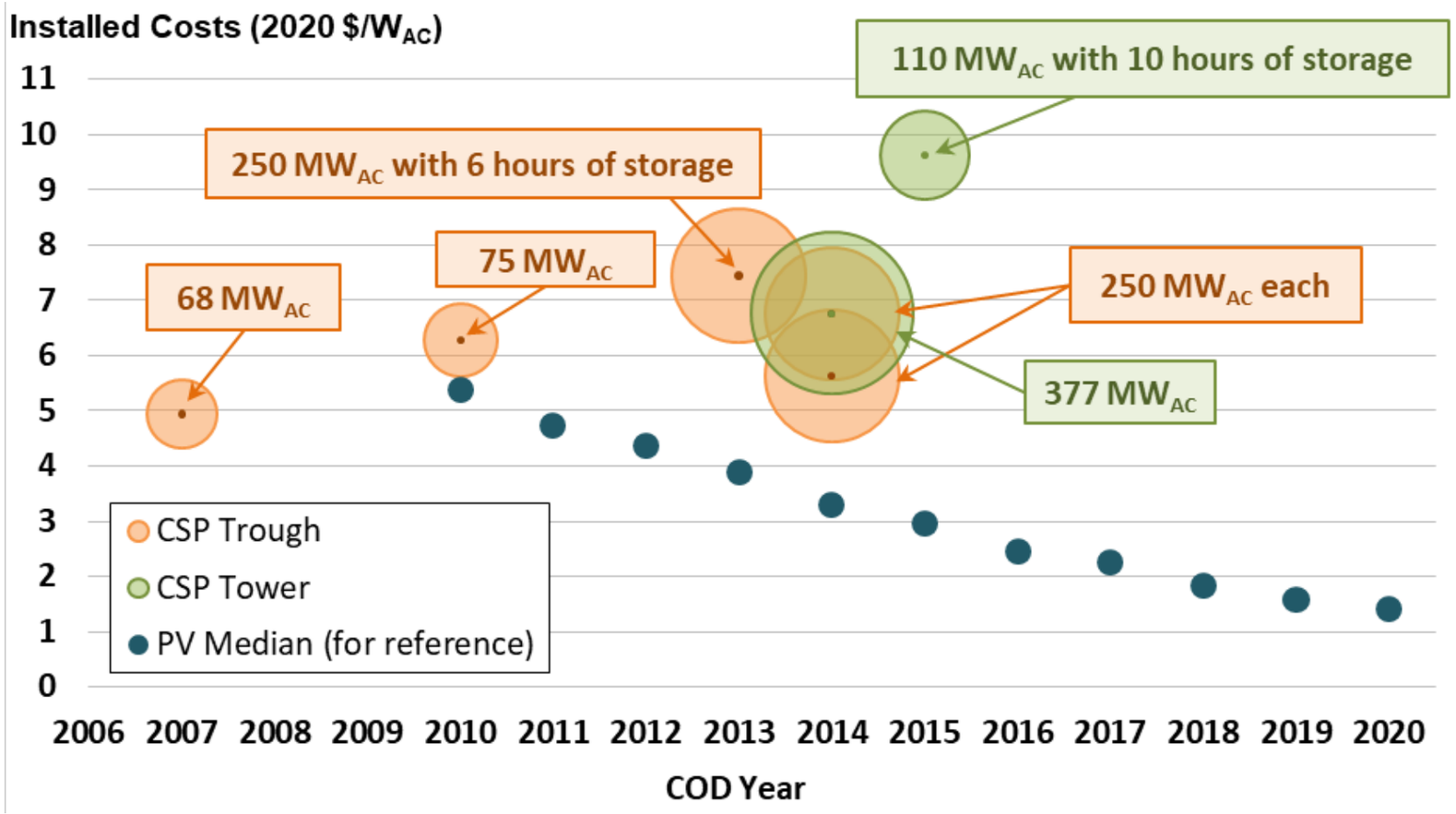
Prior to the large 2013-15 build-out, all utility-scale CSP projects in the U.S. used parabolic trough collectors.

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}

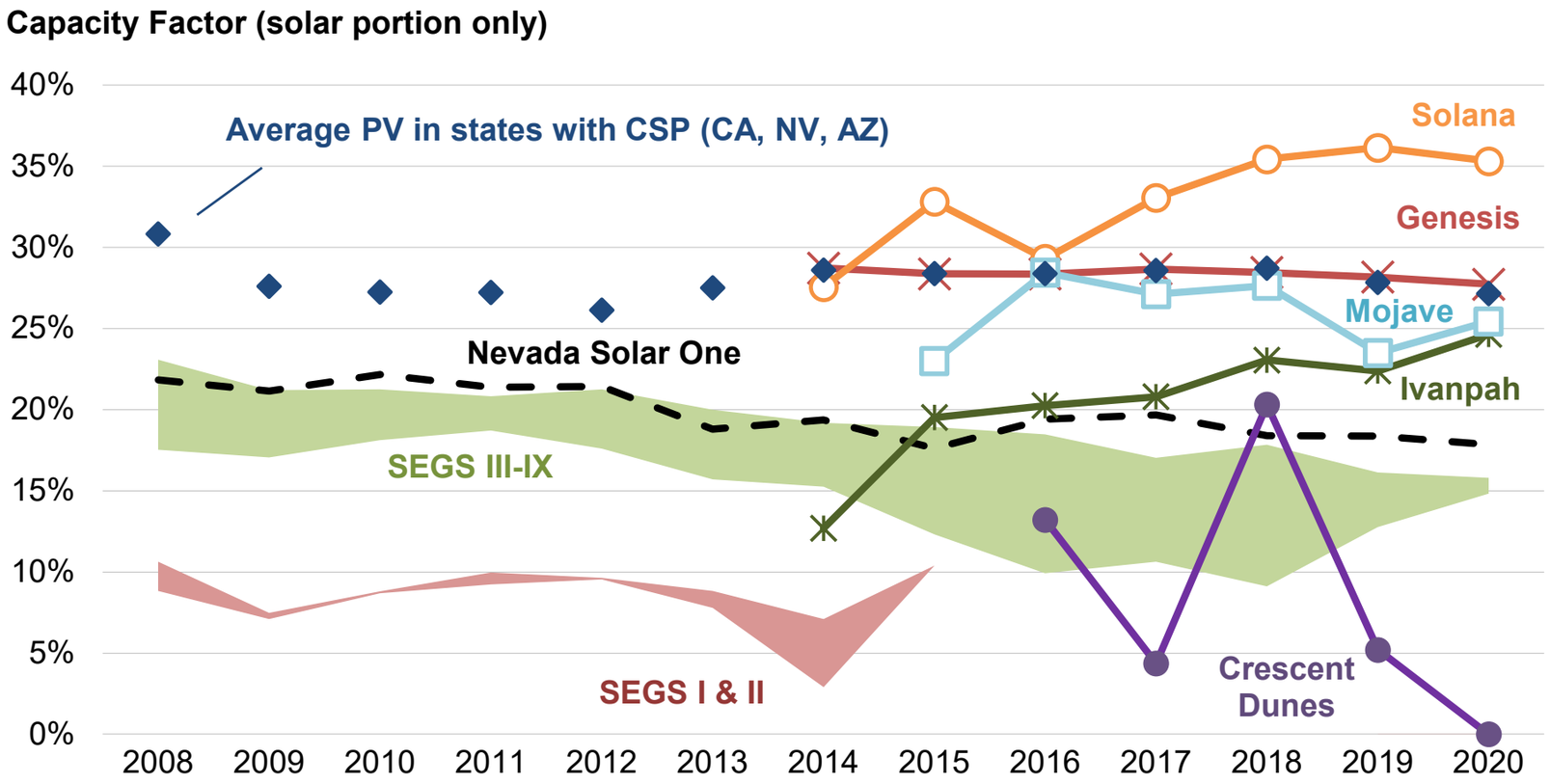


Small sample of 7 projects using different technologies makes it hard to identify trends. Newer projects (5 built in 2013-15) did not show cost declines, though some included storage or used new technology (power tower).

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.

Despite improvements, most newer CSP projects continue to underperform relative to long-term expectations

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



Power Towers: Ivanpah (377 MW) had its best year yet in 2020 (though still below long-term expectations of ~27%), while Crescent Dunes (110 MW with 10 hours of storage) ceased to operate following a late-2019 PPA cancellation and subsequent bankruptcy.

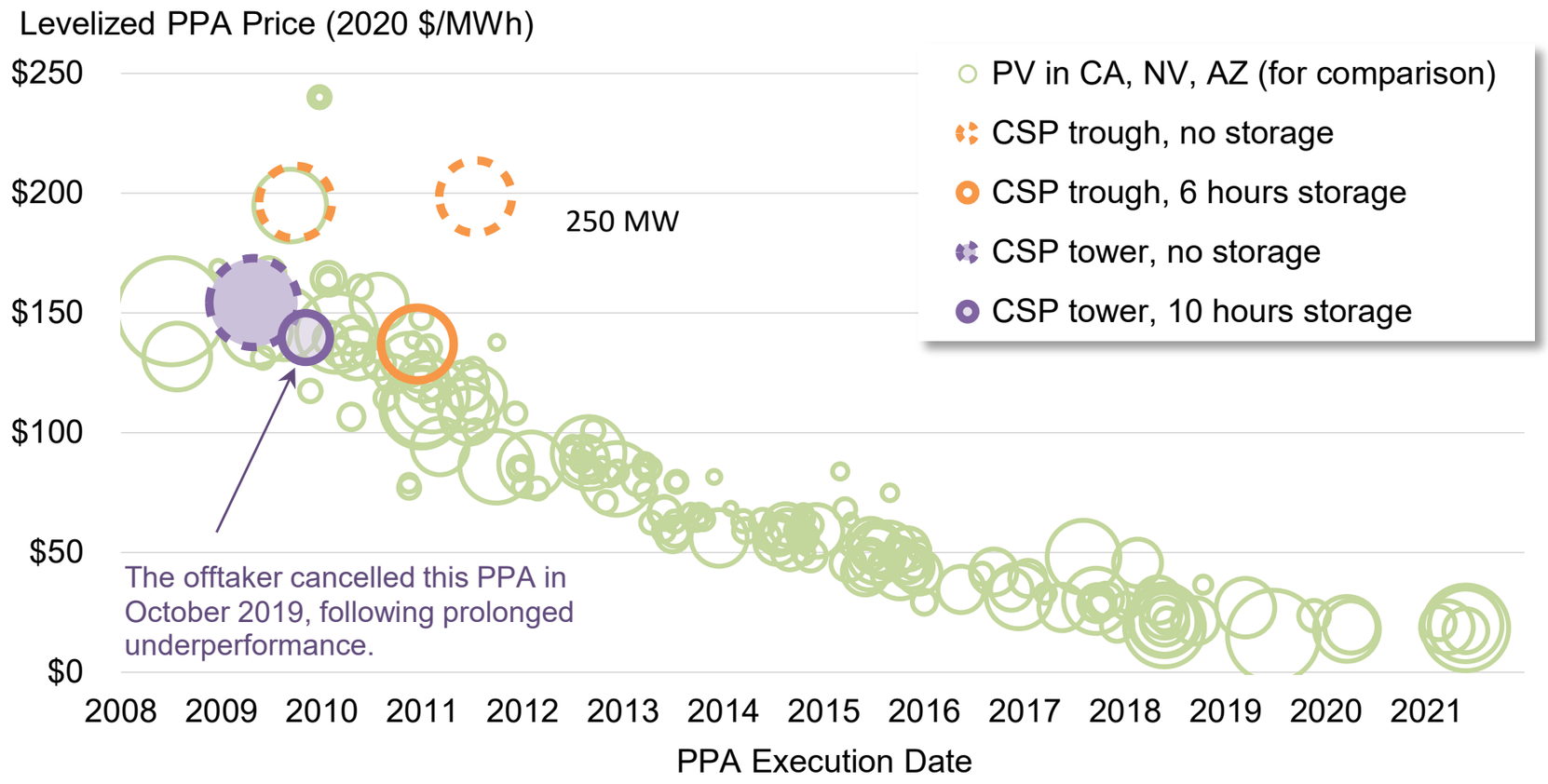
Trough with storage: Solana (250 MW trough project with 6 hours of storage) seems to have leveled off around 35%, below long-term expectations of >40%.

Troughs without storage: Genesis continued to match expectations in 2020, while Mojave has been more variable. Both have performed better than the old SEGS projects (now decommissioned and being partially repowered with PV), and the 2007 Nevada Solar One project.

Only Solana and Genesis 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 price sample: 7 projects totaling 1,381 MW_{AC}



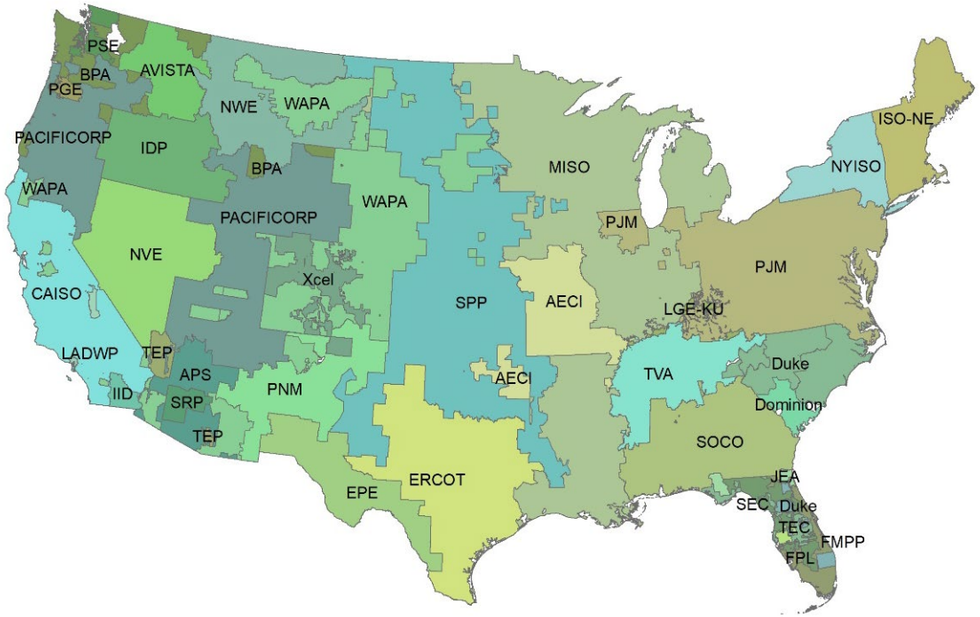
When PPAs for the most recent batch of CSP projects (with CODs of 2013-15) were signed back in 2009-2011, they were still mostly competitive with PV.

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

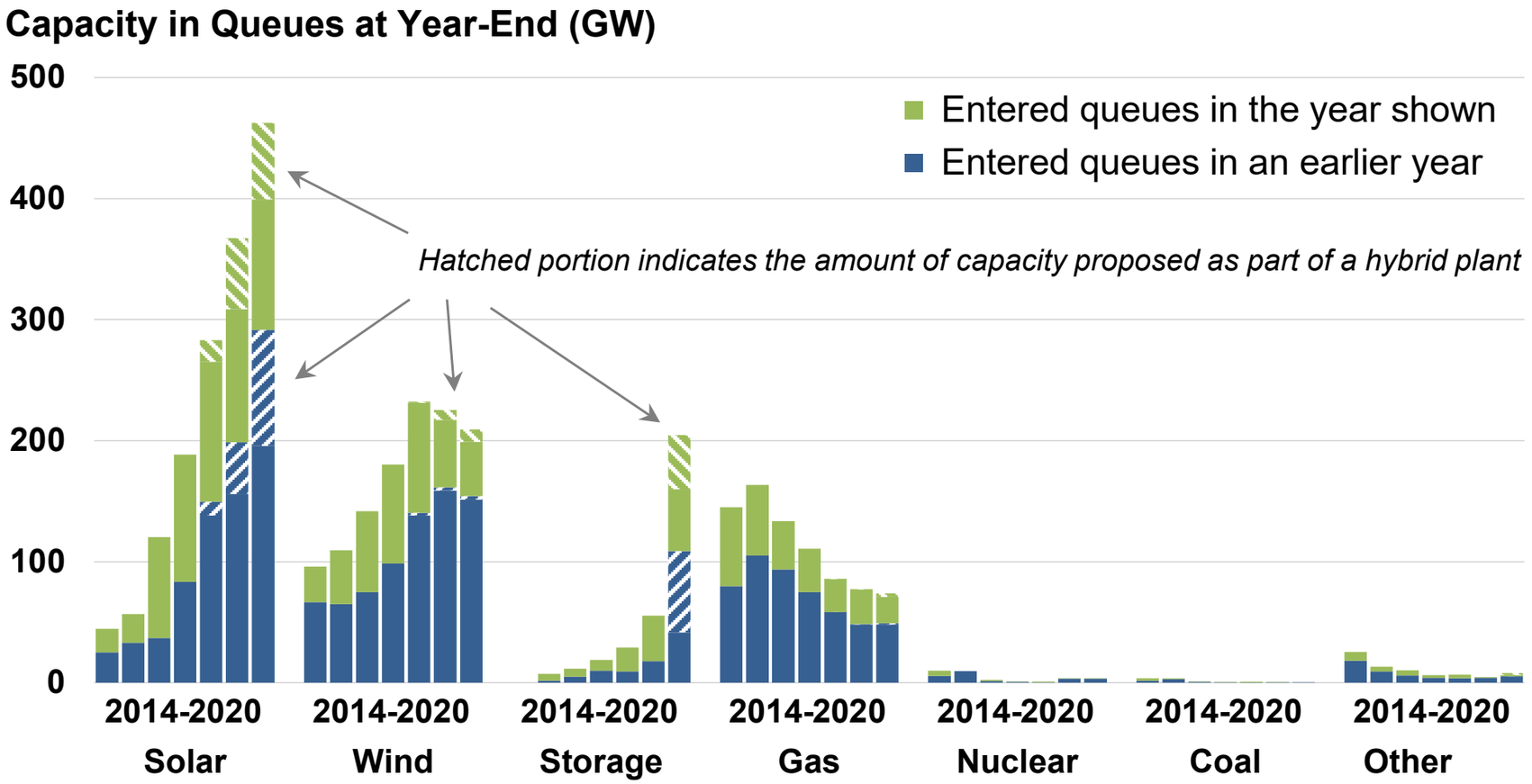
Scope of generator interconnection queue data

- 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 2020
  - 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/publications/queued-characteristics-power-plants*



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



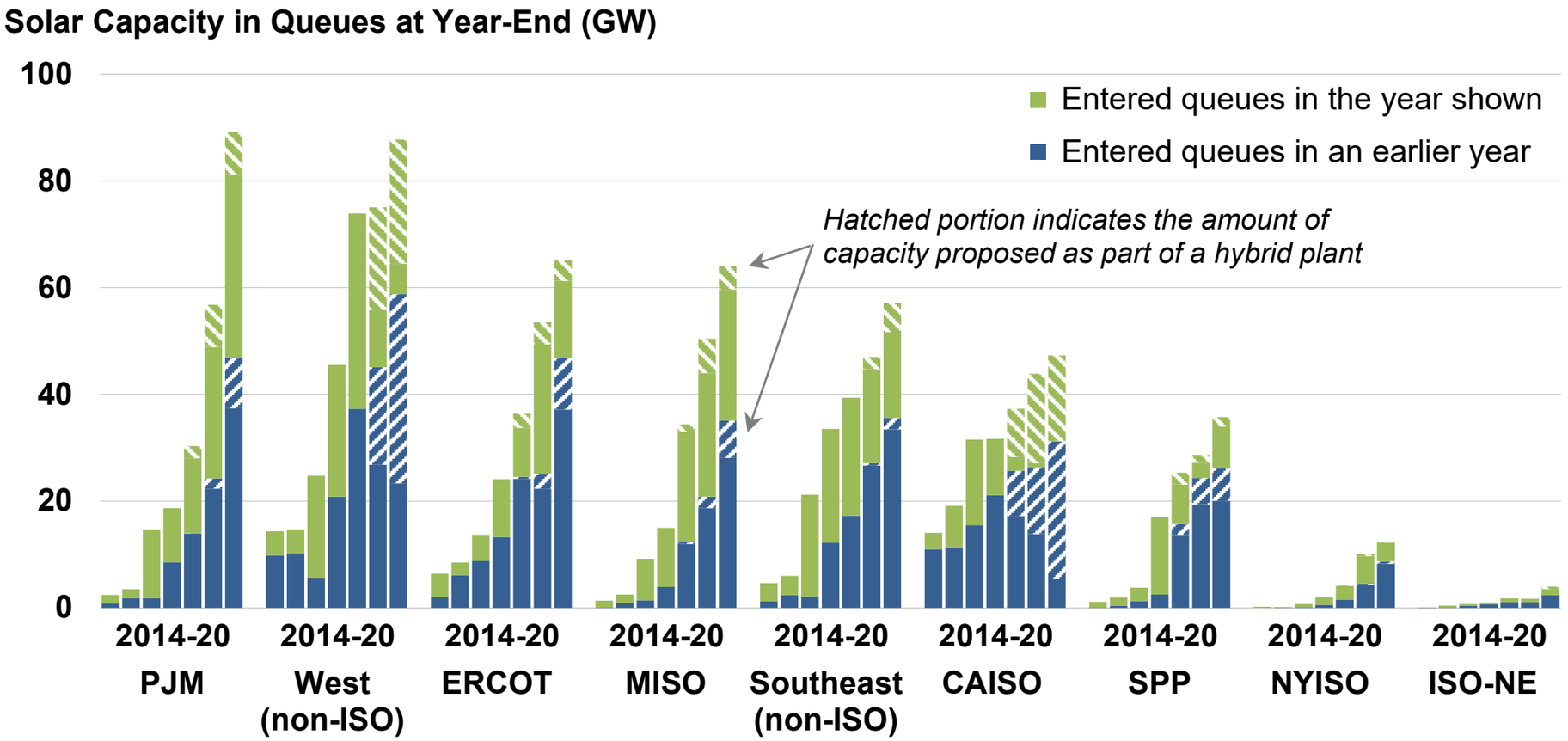
460 GW of solar was in the queues at the end of 2020—170 GW of this total entered the queues in 2020 (the remainder entered in earlier years, and remain active)

Nearly 160 GW of the 460 GW of solar in the queues (i.e., 34%) includes a battery in a PV hybrid configuration

Solar (both standalone and in hybrid form) is by far the largest resource within these queues, roughly equal to the amount of wind, storage, and natural gas combined

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



The growth of solar within these queues is widely distributed across almost all regions of the country, with PJM and the non-ISO West leading the way with nearly 90 GW_{AC} each, followed by ERCOT, MISO, and the non-ISO Southeast, each with ~60 GW_{AC}

Nearly 90% of the solar capacity in CAISO's queue at the end of 2020 was paired with a battery; in the non-ISO West, that number is also relatively high, at 67%

- 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 2020, with Texas adding the most new capacity. 81% of new projects and 89% of new capacity feature single-axis tracking.
- The median installed cost of projects that came online in 2020 fell to \$1.4/W_{AC} (\$1.1/W_{DC}), down 10% from 2019 and 75% from 2010.
- Average capacity factors range from 19% in the least-sunny regions to 30% where it is sunniest. Single-axis tracking adds roughly five percentage points to capacity factor in the regions with the strongest solar resource. Fleet-wide performance has declined at ~1.2%/year.
- Not including the ITC, the median LCOE from utility-scale PV has declined by 85% since 2010, to \$34/MWh in 2020. Levelized PPA prices have kept pace, and—with the benefit of the ITC—currently range from \$20/MWh in CAISO and the non-ISO West to \$30-\$40/MWh elsewhere.
- In higher-penetration markets like CAISO, the market value of solar has been declining, but falling PPA prices have largely kept pace, preserving solar's net value.
- There has been much interest in hybridization (pairing PV with batteries). Our public data file includes metadata on >150 PV+battery projects that are operating or planned in 23 states. Some of these PV+battery hybrid projects have inked PPAs in the mid-\$20/MWh range.
- Across all 7 ISOs and 35 additional utilities, there were 460 GW of solar in interconnection queues at the end of 2020. More than a third of this proposed solar capacity is paired with battery storage, with the highest concentration of these PV+battery hybrid plants in CAISO and non-ISO West.

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 2013-2019 have been cross-checked against confidential EIA-860 data obtained under a non-disclosure agreement (and we expect to receive similar data for 2020 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 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) or county (distributed PV) and the wholesale hourly real-time energy prices of the nearest node (for ISOs) or the system-wide energy price (other Balancing Authorities).

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 Balancing Authorities 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 forthcoming 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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