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Utility-Scale Solar, 2022 Edition

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Berkeley Lab's annual *Utility-Scale Solar* report presents trends in deployment, technology, capital expenditures (CapEx), operating expenses (OpEx), capacity factors, the levelized cost of solar energy (LCOE), power purchase agreement (PPA) prices, and wholesale market value among the fleet of utility-scale photovoltaic (PV) and PV+storage plants in the United States (where "utility-scale" is defined as any ground-mounted plant larger than 5 MW_{AC}). This summary briefing highlights select key trends from the latest edition of the report, covering data on plants built through year-end 2021. For additional data, graphs, and analysis, see the full report (in slide deck form), the accompanying Excel data workbook with linked graphics, and interactive data visualizations, all available at http://utilityscalesolar.lbl.gov.

At the end of 2021, there were 1,131 utility-scale PV (and in some cases, PV plus battery) plants totaling 51,346 MW_{AC} operating across 44 of the 50 United States (Figure 1).

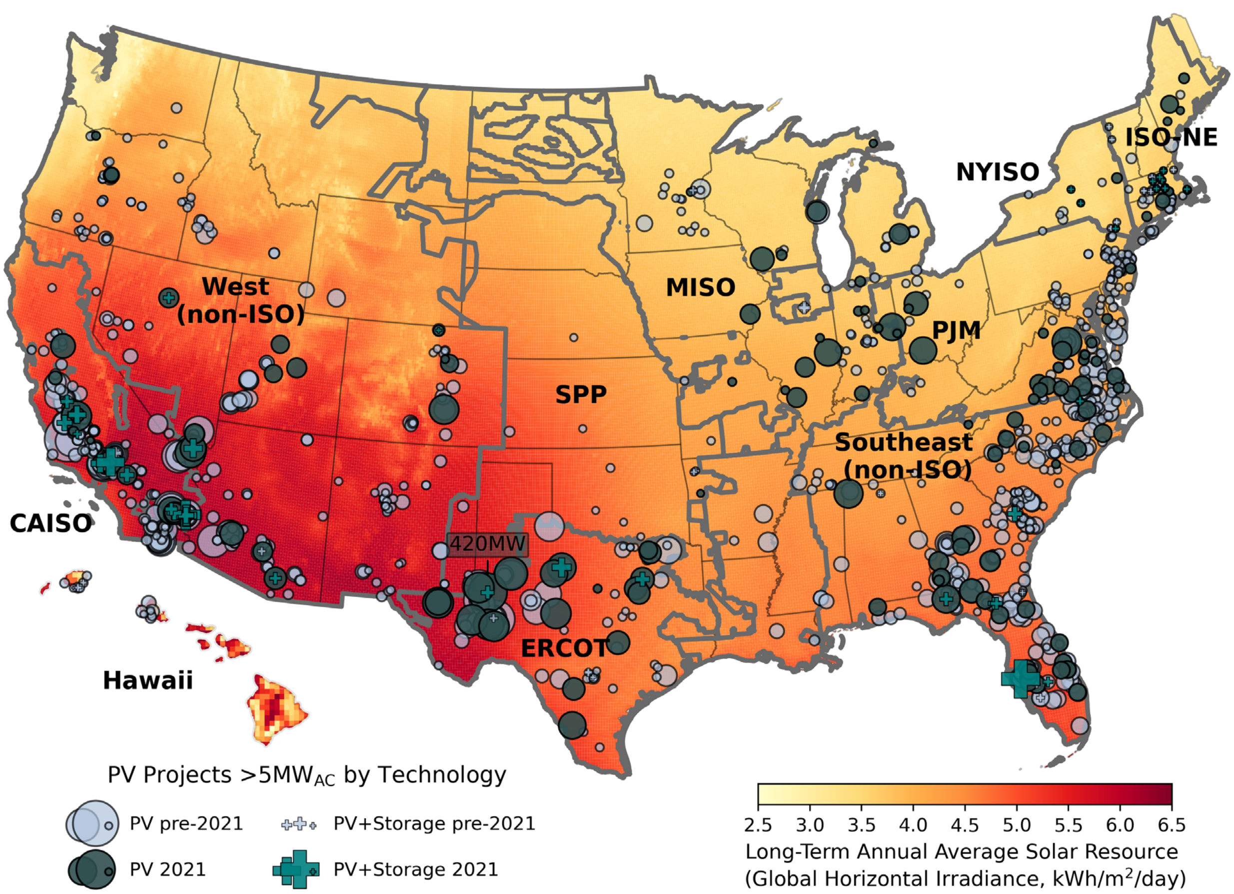

Figure 1. Utility-Scale PV and PV+Storage Plants (> 5 MW_{AC}) in the United States, through 2021

Notes: Marker size corresponds to PV capacity.

More than 12.5 GW_{AC} of the 51.3 GW_{AC} total achieved commercial operations in 2021 (Figure 2)—a record deployment year for the utility-scale sector, which accounted for 66% of all new PV capacity added in the United States in 2021,[1] and 29% of *all* capacity added to U.S. grids. While utility-scale PV dates back to the late-2000s in the sunny Southwest, declining installed costs have since enabled it to expand to less-sunny regions of the country—initially into the Southeast and along the East Coast, but more recently including numerous northerly states along the border with Canada as well.

Many of these more-recent northerly plants are even using single-axis tracking, which in earlier years had been reserved primarily for the sunniest sites (i.e., where the solar resource was strong enough to justify the expense of tracking it). Since 2015, though, single-axis tracking has become the dominant mount type in most parts of the country, and was deployed with 90% of all new capacity added in 2021 (Figure 2). Fixed-tilt plants are increasingly only being built on challenging sites (e.g., with difficult terrain or high wind loading) or in less-sunny regions, even while single-axis tracking continues to penetrate those same regions as its incremental up-front cost has diminished (Figure 3).

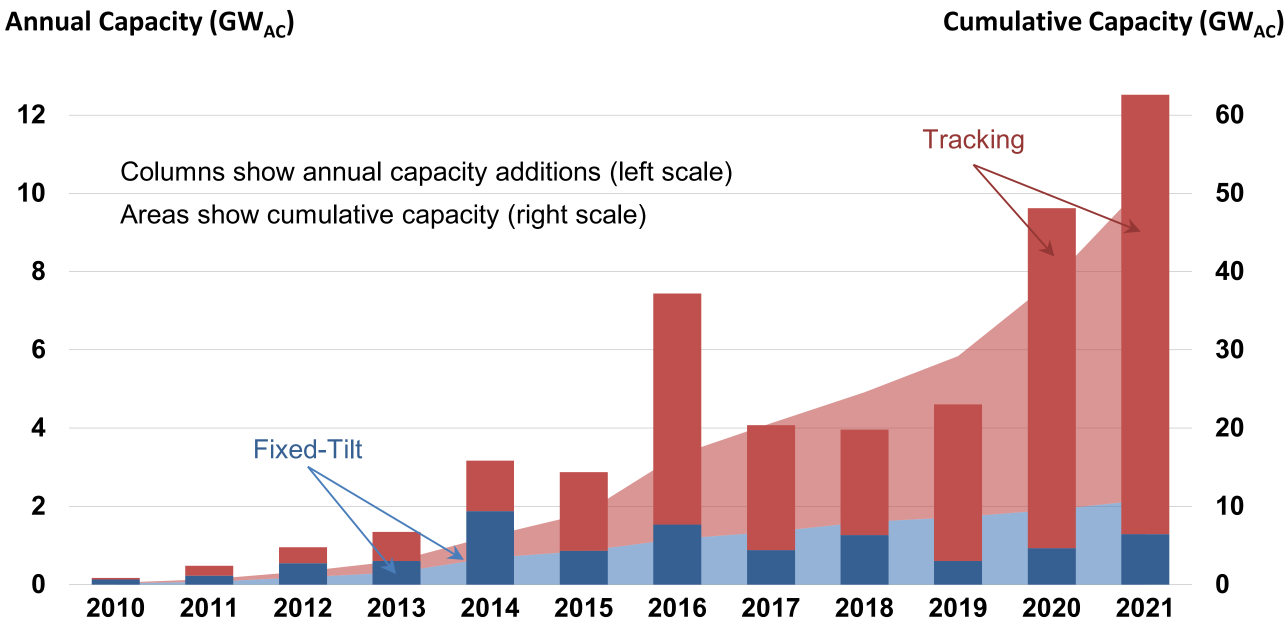

Figure 2. Annual and Cumulative Utility-Scale PV Capacity by Mounting Type

Falling costs are a big reason for the strong deployment trend seen in Figure 2. Median installed costs for standalone utility-scale PV plants have steadily fallen by more than 75% (averaging 10% annually) since 2010, to \$1.35/W_{AC} (\$1.0/W_{DC}) among 62 plants (totaling 5.4 GW_{AC}) completed in 2021 (Figure 3). Plants that use single-axis tracking have slightly higher up-front costs than fixed-tilt plants, but the difference has narrowed over time, particularly since 2015. Coupling PV plants with batteries adds to overall costs, depending on the size of the battery. The median installed cost among 20 PV+battery hybrid plants installed in 2021 was \$3.46/W_{AC}-PV.

[1] The remaining 34% was contributed by the residential and commercial sectors, which are covered separately in Berkeley Lab's annual *Tracking the Sun* report series, available at https://trackingthesun.lbl.gov.

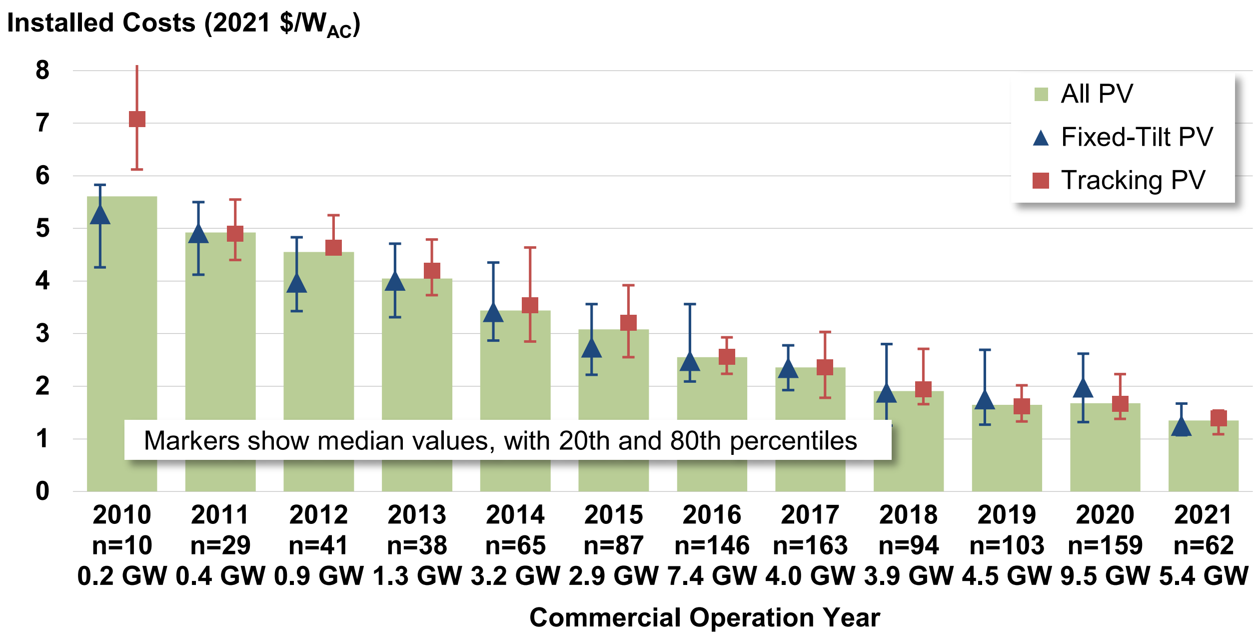

Figure 3. Installed Price of Utility-Scale PV Plants by Installation Year and Mounting Type

To assess how these plants have performed, we rely on capacity factors—a measure of the amount of electricity generated in a given period relative to how much electricity could have been generated if the plant was operating at full capacity for the entire period. Because solar generation varies seasonally, capacity factor calculations for solar are typically performed in full-year increments. Figure 4 shows that the capacity factors of individual plants in our sample vary widely, from 9% to 35% (in AC terms), with a sample median of 24% (or, ranging from 7%-28% in DC terms, with a median of 18%). Much of this plant-level variation can be explained by the three primary drivers of capacity factor that parse the data in Figure 4: the quality of the solar resource at the site (broken out into quartiles), whether the modules track the sun or are mounted at a fixed-tilt, and the DC:AC ratio or inverter loading ratio (ILR) —i.e., the ratio of a plant's DC module array nameplate rating to its AC inverter nameplate rating (also divided into quartiles).[2] Curtailment and degradation—both of which are baked into the capacity factors shown in Figure 4—can also play a role, and may be partly responsible for some of the apparent outliers.

[2] Solar resource is defined here in terms of the long-term average global horizontal irradiance (GHI) at each plant site, expressed in kWh/m^2/day. Higher DC:AC ratios, or ILRs, allow inverters to operate closer to (or at) full capacity for more of the day, but as the ILR increases, the extra generation during the morning and evening "shoulder hours" must be balanced against any mid-day power clipping that occurs to ensure that there is a net gain in production (and/or a net gain in the market value of the solar generation). See the public data file for the quartile thresholds for GHI and ILR in Figure 4.

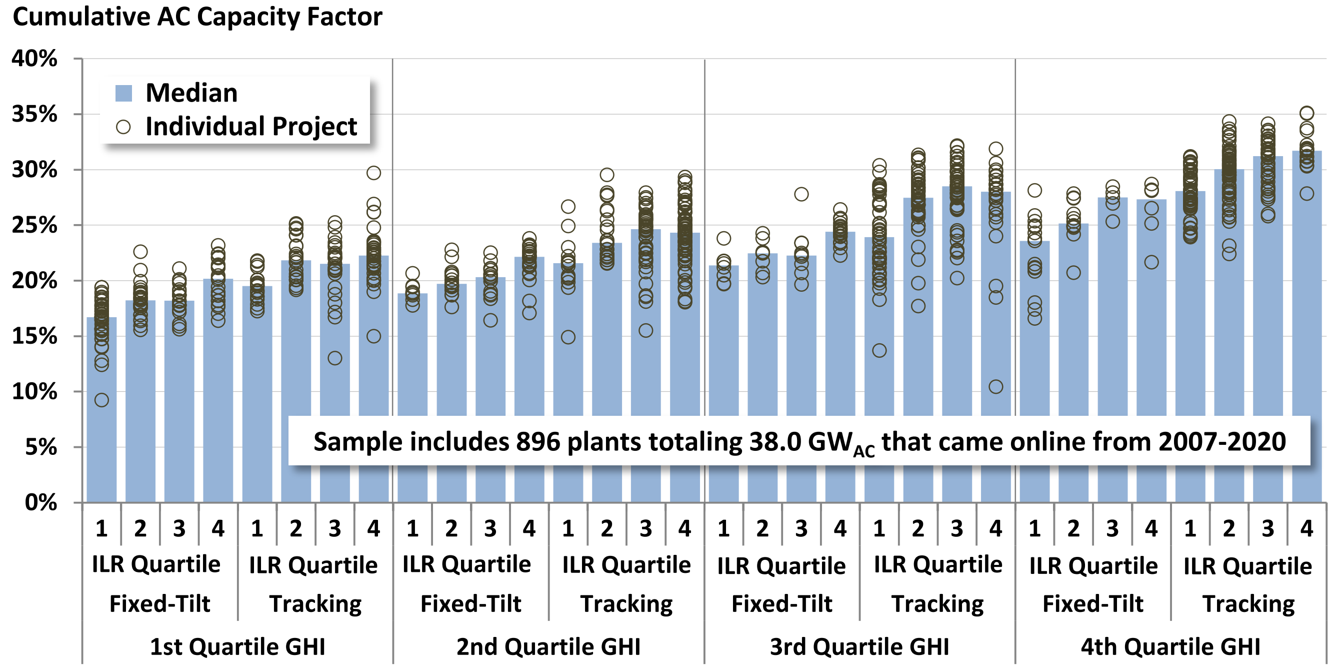

Figure 4. Cumulative Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio

Figure 5 plots average capacity factor by plant vintage (based on commercial operation date, or COD) against the same three fundamental drivers broken out in Figure 4: long-term average global horizontal irradiance (GHI) at each site, the prevalence of tracking, and the average ILR. The steady improvement in average capacity factor from 2010-vintage through 2013-vintage plants was driven by increases in all three of these drivers.[3] Since 2013, though, average ILRs have drifted only slightly higher, to just above 1.3, while the two other drivers—prevalence of tracking and long-term average GHI—have moved in opposite directions, largely canceling each other out and resulting in stagnant capacity factors among more-recent plant vintages.[4] The lower long-term average GHI since 2013 reflects the geographic expansion of the market from California and the Southwest into less-sunny regions of the United States—this is a positive trend, despite having a negative impact on average fleet-wide capacity factor.

[3] The average long-term average GHI increased from 4.90 kWh/m^2/day among 2010-vintage plants to 5.36 kWh/m^2/day among 2013-vintage plants, while tracking increased from 0% to 56% of plants and the average ILR rose from 1.19 to 1.29, respectively.

[4] Among 2021-vintage plants, the average long-term average GHI is 4.56 kWh/m^2/day, 75% of plants employ tracking, and the average ILR is 1.35.

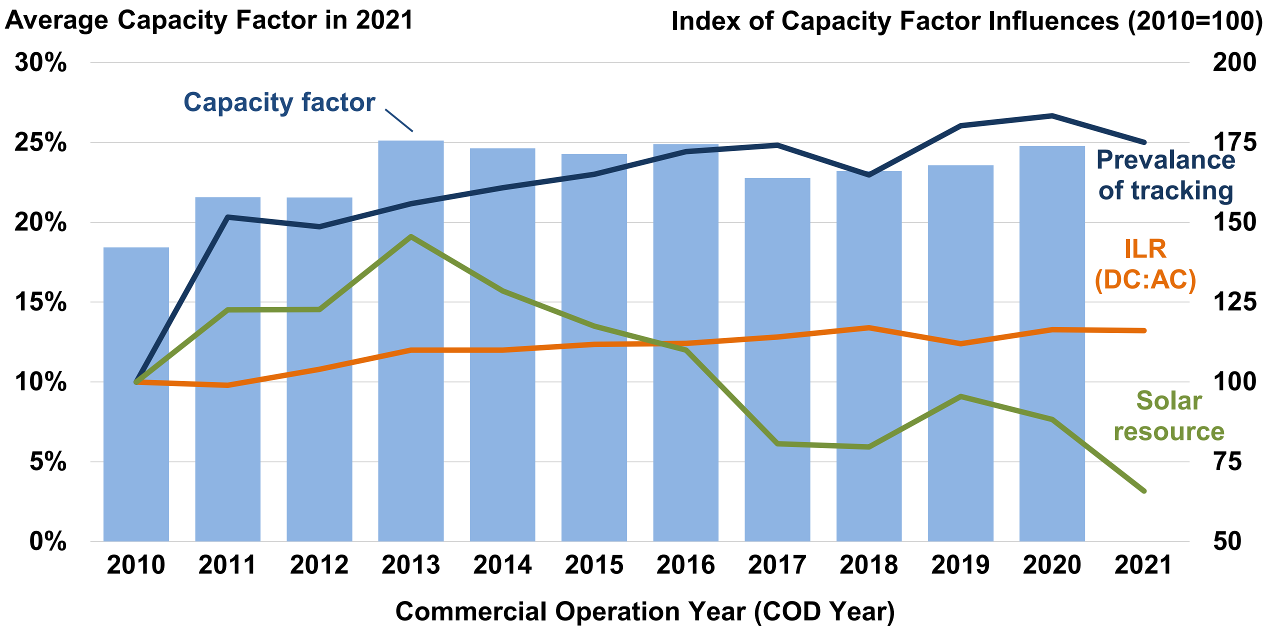

Figure 5. Average Capacity Factor in 2021 by Plant Vintage

Driven by lower installed plant costs and, at least through 2013, improving capacity factors (as well as lower operating expenses and longer design life—neither shown here), utility-scale PV's average levelized cost of energy (LCOE) has fallen by about 85% (averaging 16% annually) since 2010, to $33/MWh in 2021 (Figure 6). Figure 6 does not include the impact of the 30% federal investment tax credit (ITC); if the ITC is factored in, the average LCOE in 2021 drops from $33/MWh to $27/MWh.

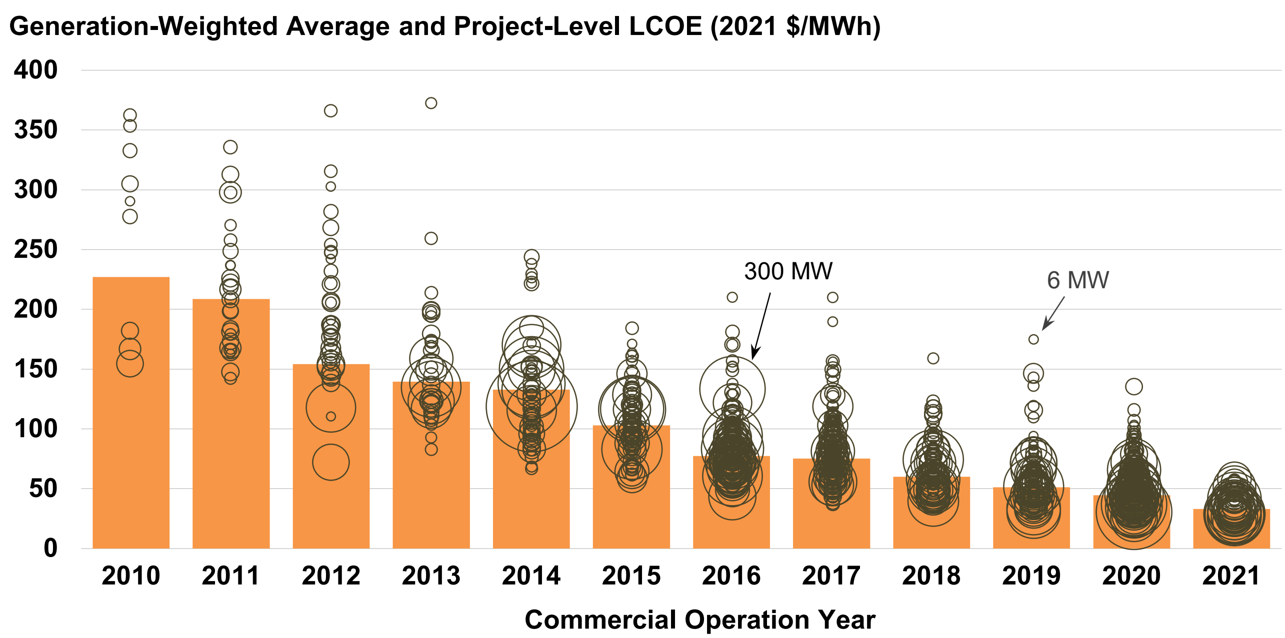

Figure 6. Levelized Cost of Energy (LCOE) by Plant Capacity and Commercial Operation Year

Note: Sample size is 981 plants totaling 43.4 GW_{AC} of capacity. Bubble size corresponds to individual plant capacity. ITC not included.

Power purchase agreement (PPA) prices for utility-scale PV plants have largely followed the decline in solar's LCOE over time, also falling by roughly 85% on average (or 15% annually) since 2009/2010

(Figures 7 and 8). That said, the pace of decline has slowed in recent years, and average PPA prices—which we track by contract signing date, typically preceding the COD by a year or more—have even drifted slightly higher since 2019, consistent with the trend in the 25th percentile offer prices published by LevelTen Energy (Figure 8). Aided by the ITC, most recent PPAs in our sample are priced around \$20/MWh (on a levelized basis, expressed in real 2021 dollars, and including bundled energy, capacity, and RECs) for plants located in the West, and \$30-\$40/MWh for plants elsewhere in the continental United States. Hawaiian PPAs are often higher-priced (and most include battery storage—see later).

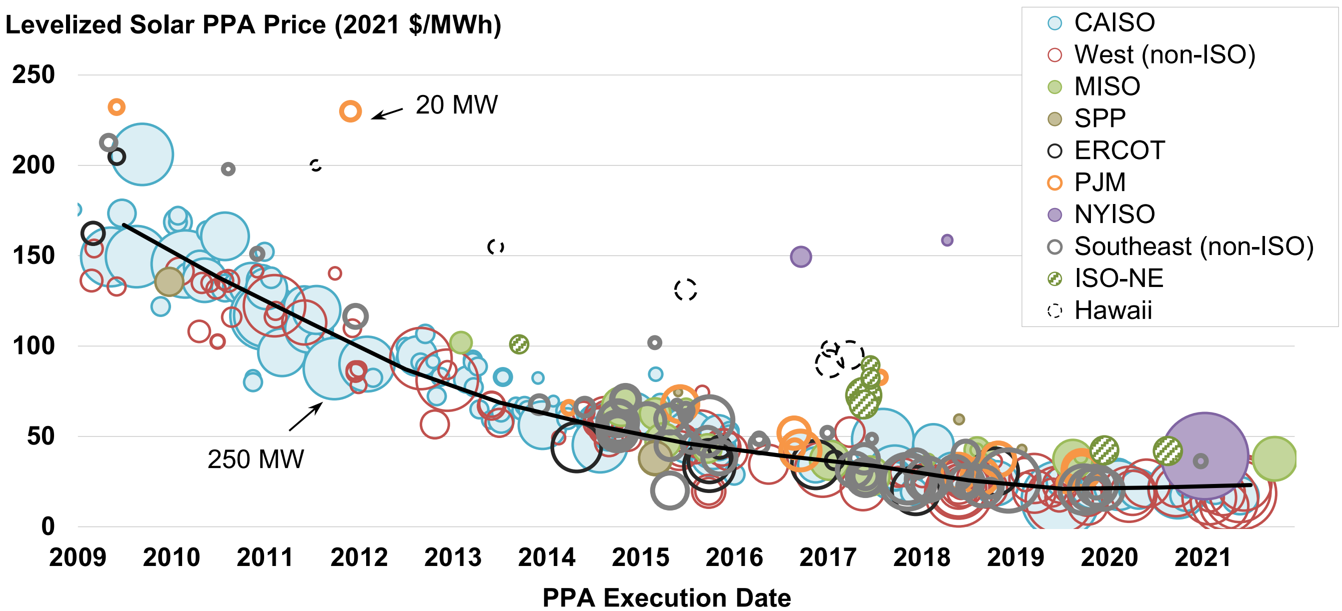

Figure 7. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date

Note: Sample size is 372 PV plants totaling 26.85 GW_{AC} of capacity. Bubble size corresponds to individual PPA capacity. The line shows the generation-weighted average price by year for the "Lower 48" states (i.e., the trend line excludes Hawaii and Alaska).

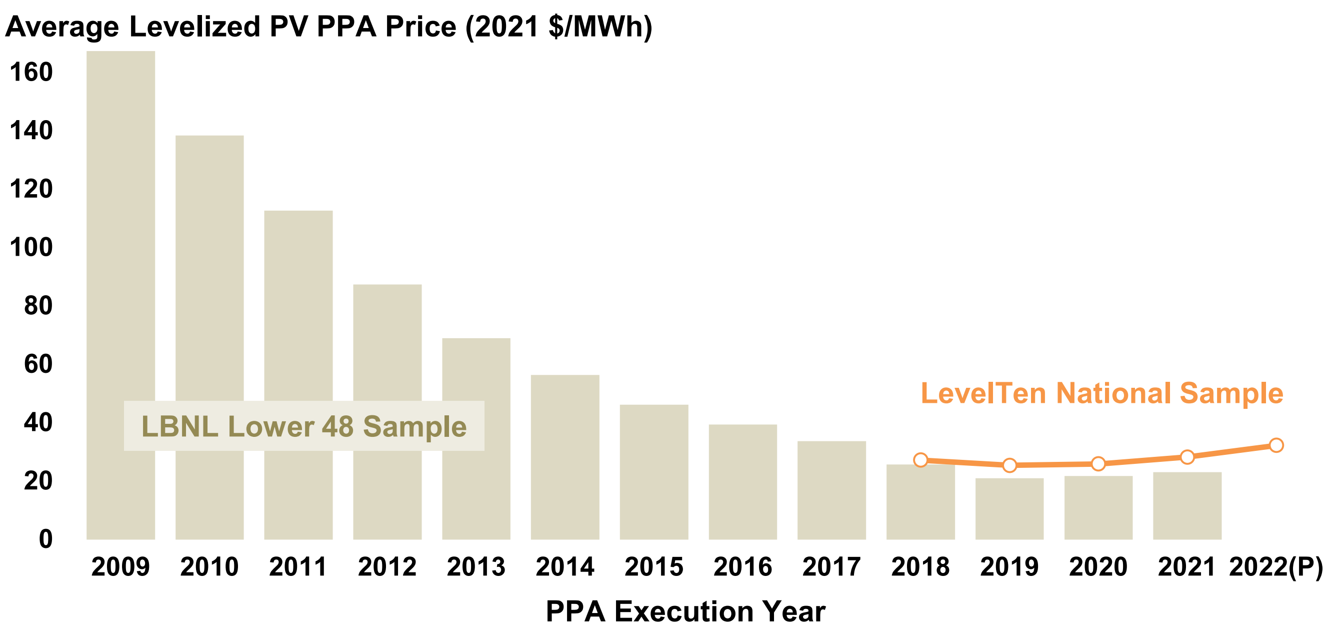

Figure 8. Average Levelized PV PPA Prices: Comparison of LBNL and LevelTen Energy National Samples

While Figures 6-8 show what utility-scale PV has cost and how it has been priced, Figure 9 shows what that solar energy has been worth (in terms of energy and capacity value) within the seven wholesale power markets operated by independent system operators (ISOs) across the United States, plus the aggregate non-ISO West and Southeast regions. In all nine regions, the wholesale market value of solar energy declined considerably from 2014 through 2020, due in large part to declining wholesale power prices more broadly (but also impacted by solar-specific factors such as plant location, generation profile, and curtailment). In general, however, the falling PPA prices shown above in Figure 7 and transferred (along with LevelTen Energy PPA price index data) to Figure 9 have largely kept pace with declining market values over time, thereby more or less maintaining solar's competitiveness. More recently, rising wholesale power prices in 2021 provided a significant boost to solar's wholesale market value in all nine regions (and this trend has continued to date into 2022), pushing solar PPA prices into the money.

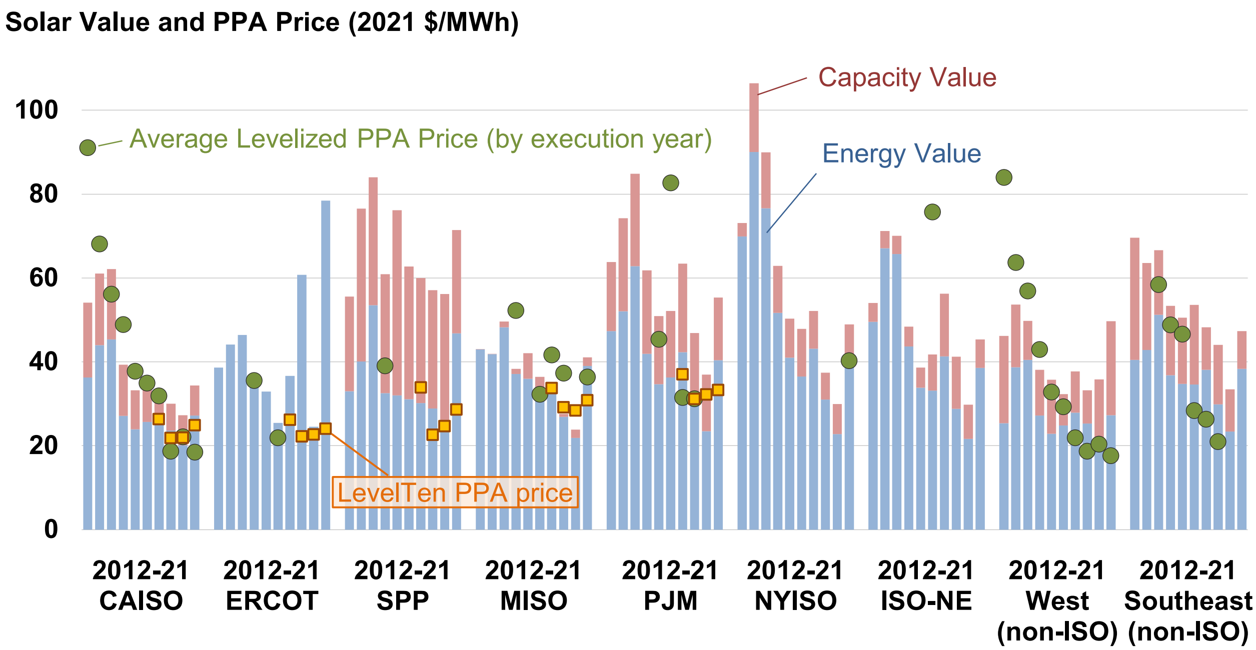

Figure 9. Solar's Average Energy and Capacity Value versus Average PPA Price by Region

While Figure 9 shows the *absolute* value of PV in wholesale markets, Figure 10 teases out its *relative* value compared to a simple average of wholesale energy and capacity prices across all hours and pricing nodes. The relative value of PV in wholesale power markets depends primarily on PV's hourly generation profile, but also on the location of the PV plants and the extent to which they are curtailed—and how those three characteristics correlate with real-time nodal electricity prices and capacity markets. The "solar value factors" in Figure 10—which show solar's average value as a percentage of a flat block of power (i.e., the average wholesale price across all hours and locations)—reflect these influences while controlling for differences in average wholesale power prices across years and ISOs.

In Figure 10, the ISOs are sorted from left right in order of highest-to-lowest solar market penetration; those with the highest solar penetrations generally (but not always) have the lowest value factor, and vice versa. For example, solar's 2021 penetration rate in the California ISO (CAISO) was 23%, while its value factor was 61%—meaning that solar's $34/MWh average wholesale market value in CAISO (per Figure 9, above) was 61% of CAISO's average wholesale price in 2021 (Figure 10). In contrast, solar's 2021 penetration rate in the Southwest Power Pool (SPP) was less than 1%, while its average market value of $71/MWh resulted in a value factor of 141%. In other words, solar energy sold on a merchant basis into these two wholesale power markets in 2021 would have earned below-average pricing in CAISO and above-average pricing in SPP, on average. Solar value factors in the other five ISOs were closer to parity (100%) in 2021, with the notable exception of ERCOT, where solar was unable to take advantage of extremely high overnight power prices during Winter Storm Uri, resulting in a value factor of just 36%.

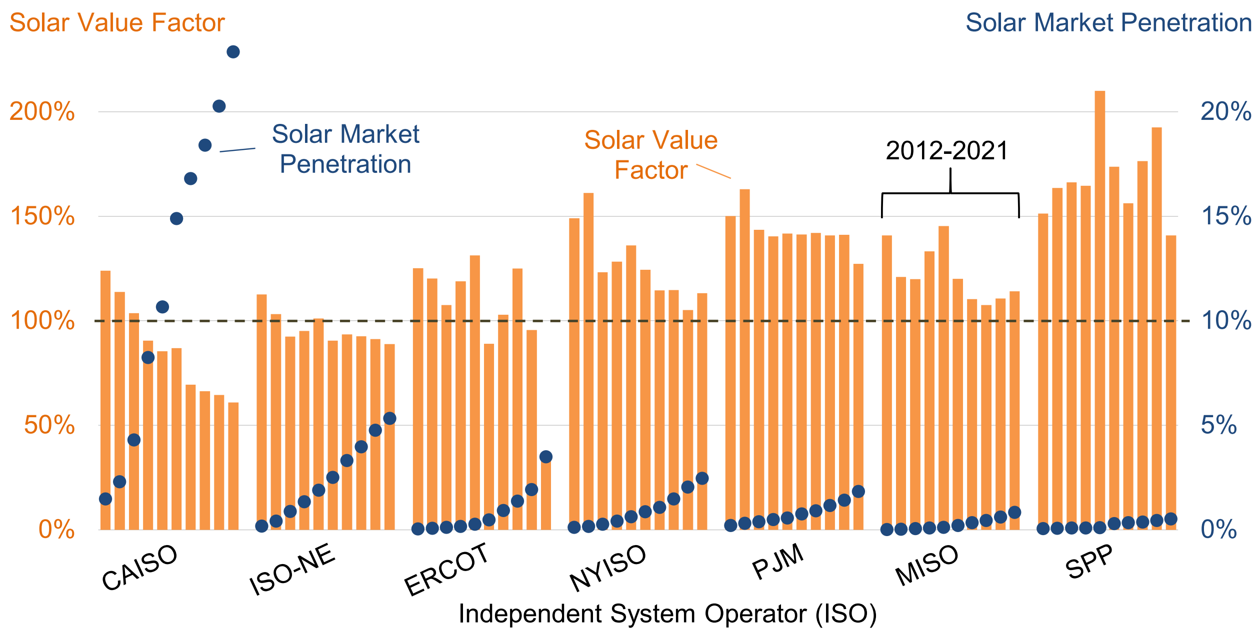

Figure 10. Solar's "Value Factor" and Market Penetration by Independent System Operator (ISO)

This inverse relationship between market penetration and value factor makes intuitive sense: at higher market shares, increasing amounts of solar flow onto the grid at sunny times, depressing wholesale power prices and thereby reducing the marginal value of additional solar. It is not, however, a foregone conclusion that solar's relative value will *always* decline with increasing penetration; for example, among several Southwestern balancing authorities (not shown in Figure 10), solar benefited from higher capacity prices in 2020 and 2021, gaining in relative value despite substantial increases in market share.[5]

One way to increase the market value of solar is to add batteries that can store PV generation when wholesale prices are low and dispatch that stored solar energy when prices are higher. Prior to the *Inflation Reduction Act of 2022*, batteries were only eligible for the ITC if paired with solar, driving the popularity of PV+battery hybrid plants.[6] In fact, 2021 was a breakout year for hybrids, with 47 plants totaling 3.5 GW_{AC} of PV and 2.2 GW / 6.9 GWh of battery storage achieving commercial operations (Figure 11). The vast majority of battery storage coupled with utility-scale PV was added in CAISO (1.2 GW in 2021), followed by Florida Power & Light (0.5 GW) and ERCOT (0.2 GW). Many additional hybrids have announced the execution of PPAs (Figures 12 and 13) and/or entered the development pipeline (Figures 14 and 15).

[5] For more information on solar's value in non-ISO regions (the balancing authorities of AZPS, PNM, NEVP, PACE, CPLE, DUK, PSCO, FPL, SOCO, and TVA) see the public data file.
[6] For more of Berkeley Lab's research on hybrid plants, see https://emp.lbl.gov/hybrid.

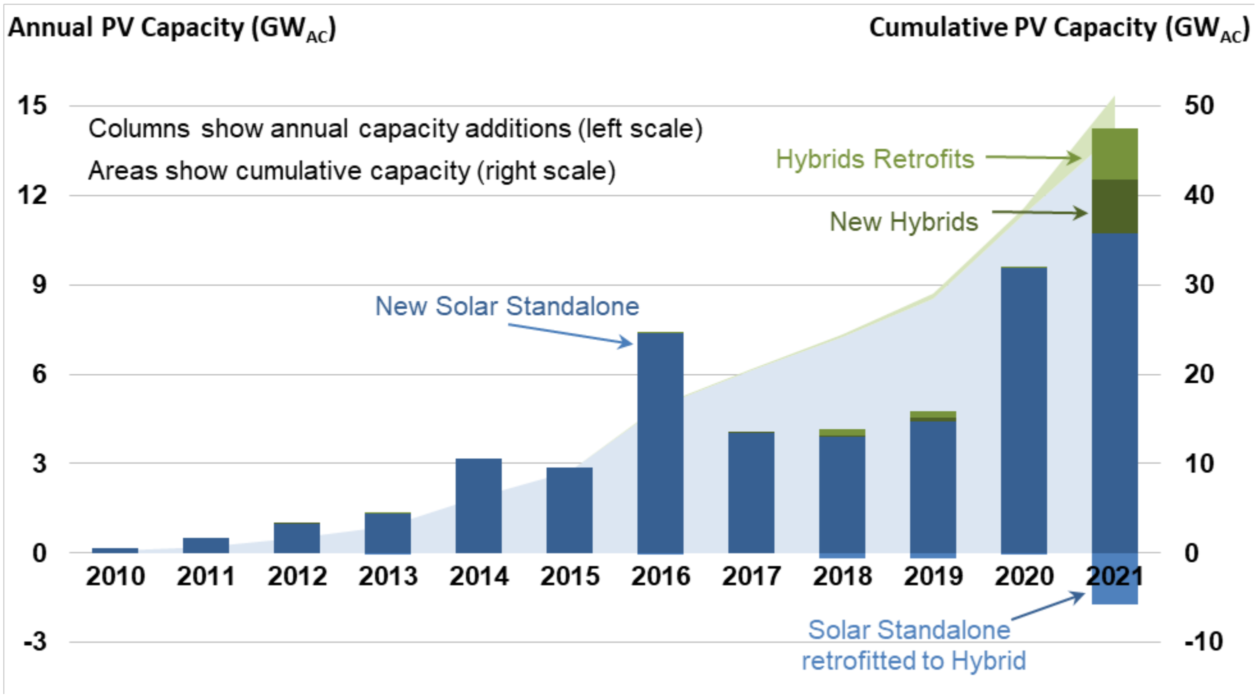

Figure 11. Deployment of standalone PV and PV-battery hybrids by COD

Note: The 47 hybrid plants that became operational in 2021 include 29 greenfield plants totaling 1.8 GW_{AC} of PV as well as battery retrofits to 18 pre-existing PV plants totaling 1.7 GW_{AC} of PV.

Figure 12 shows levelized PPA prices from 61 PV+battery hybrids (all greenfield plants; no battery retrofits), 22 of which are in Hawaii (orange bubbles). The bubble size corresponds to the battery-to-PV capacity ratio, which in Hawaii is always at 100% to ensure that all mid-day solar generation from these utility-scale plants can be stored rather than flowing onto a grid that is already contending with high levels of residential and commercial solar in those hours. On the mainland (shown in blue), battery-to-PV capacity ratios have historically been less than 100% (with some as low as 5%), but have generally been increasing over time. Perhaps because of this relative increase in battery size over time (which adds costs[7]), the PPA price trend on the mainland has been relatively flat, compared to the downward trend in Hawaii (where the battery-to-PV capacity ratio has remained constant over time). Recent PV+battery PPA prices on the mainland have been in the $20-$40/MWh-PV range, while Hawaii is priced at a premium due to a combination of higher costs related to its remote island status, its 100% battery-to-PV capacity ratios, and perhaps also a touch of value-based pricing given relatively high-cost competition (e.g., oil-fired generation).

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[7] See Figure 13 and the "PV+Storage CapEx" tab in the public data file.

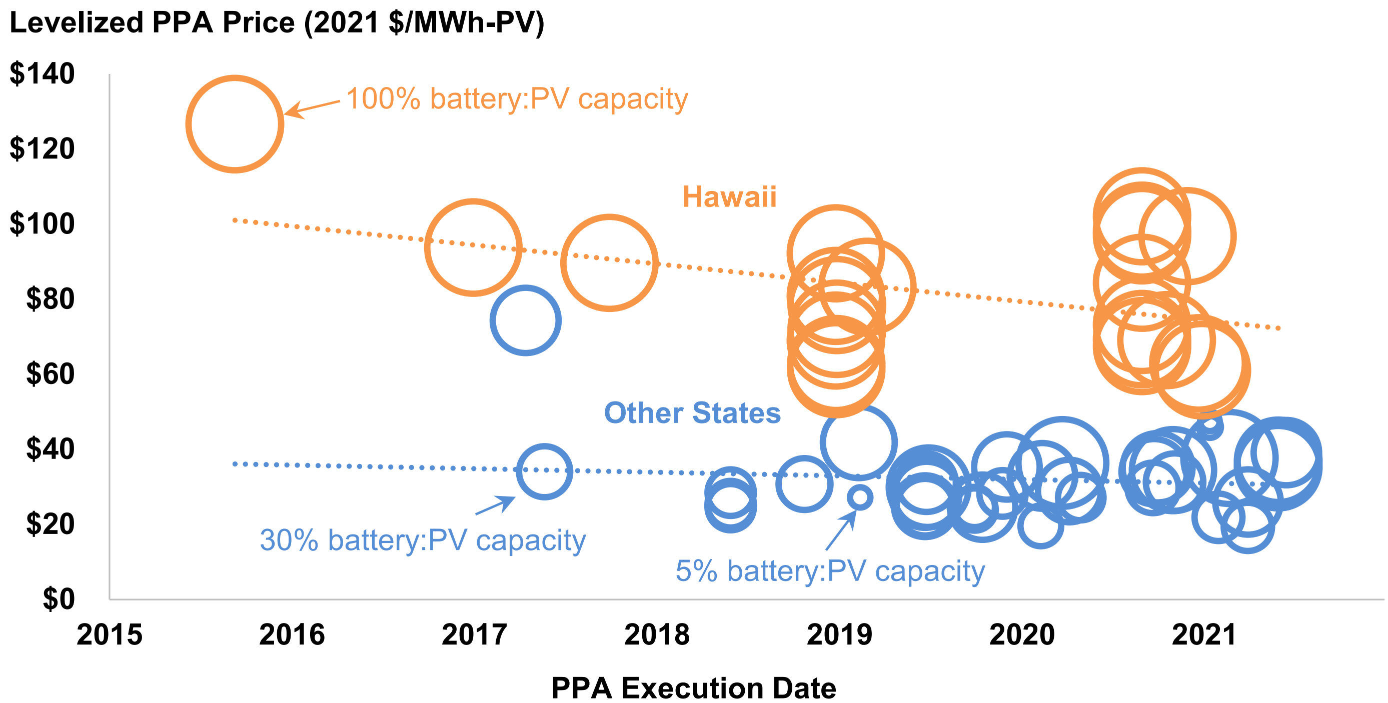

Figure 12. Levelized PPA Prices for PV+Battery Plants by PPA Execution Date

Note: Sample size is 61 greenfield plants totaling 7.1 GW_{AC} of PV capacity and 3.9 GW_{AC} / 15.3 GWh of battery capacity. Bubble size corresponds to the battery-to-PV capacity ratio of each individual plant. Fifty of the 61 plants have 4-hour durations (the other 11 are 5x2 hours, 1x3.7 hours, 4x5 hours, and 1x8 hours).

Twenty-eight of these 61 PV+battery hybrid PPAs (all greenfield, all on the mainland, none in Hawaii) break out the PV pricing from the storage pricing, providing a sense for how much the battery increases the overall PPA price. Figure 13 shows that the "levelized storage adder" (expressed in $/MWh-PV rather than $/MWh-stored) has increased over the past few years (left graph), in part due to higher battery-to-PV capacity ratios (i.e., larger batteries), which add costs (right graph), but also presumably due to the well-publicized inflationary pressures and supply chain challenges facing the industry. In general, Figure 13 suggests that adding a battery will increase a standalone PV PPA price by anywhere from $5-$20/MWh-PV, depending on the capacity of the battery relative to the PV capacity.

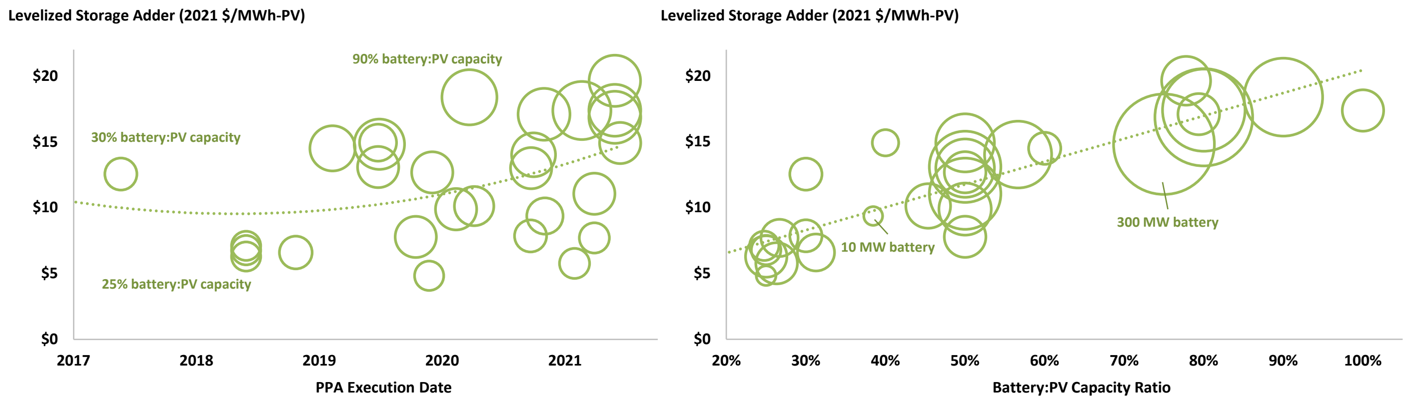

Figure 13. Levelized Storage Adder for PV+Battery Plants by PPA Execution Date and Battery-to-PV Capacity Ratio

Note: Sample size is 28 plants totaling 4.4 GW_{AC} of PV capacity and 2.4 GW_{AC} / 9.4 GWh of battery capacity (all on the mainland). Bubble size corresponds to the battery-to-PV capacity ratio (left graph) or battery capacity (right graph). Storage duration is 4 hours in all cases.

Looking ahead, the amount of utility-scale solar—and solar+storage—capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years (Figure 14). At the end of 2021—i.e., prior to the passage of the *Inflation Reduction Act of 2022*, which is likely to stimulate significant additional deployment—there were at least 674 GW of utility-scale solar power capacity within the interconnection queues across the nation, 265 GW of which first entered the queues in 2021. Some 284 GW of the 674 GW total (i.e., 42% of all solar capacity in the queues) include batteries. Solar (both standalone and in hybrid form, including batteries) is by far the largest resource within these queues, followed by storage, wind, and natural gas; all other resources are marginal contributors.

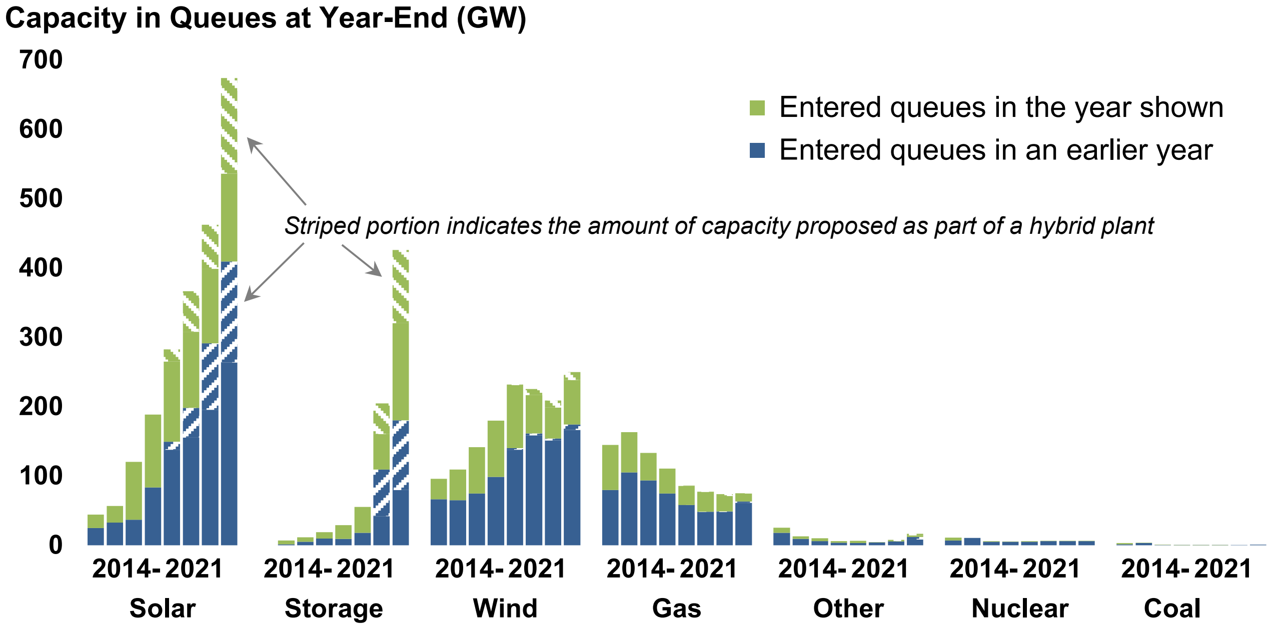

Figure 14. Solar and Other Resource Capacity in 42 Interconnection Queues across the U.S.

The growth of solar within these queues is widely distributed across almost all regions of the country (Figure 15), with PJM, the non-ISO West, and MISO leading the way. Roughly 95% 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 is also relatively high, at 75%. Though not all of these plants will ultimately be built as planned (i.e., entering the queues is a necessary step in the development process, but by no means assures eventual success), the ongoing influx and widening geographic distribution of both standalone solar and solar+storage plants within these queues is as clear of an indication as any of the accelerating energy transition and the major role that the utility-scale PV sector will continue to play in the years to come.[8]

[8] For more of Berkeley Lab's research on interconnection queues, see https://emp.lbl.gov/queues.

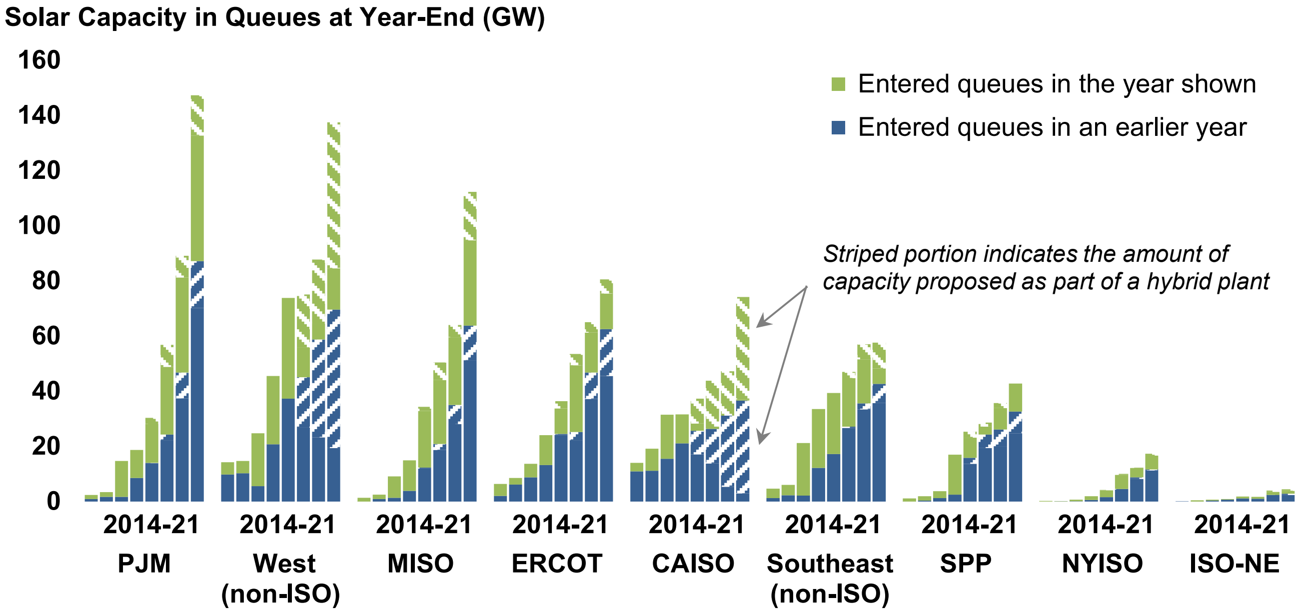

Figure 15. Solar Capacity in 42 Interconnection Queues by Region

Finally, we reiterate that all of the data and analysis in this 2022 edition of *Utility-Scale Solar* preceded the passage of the *Inflation Reduction Act of 2022*. This new law, with its many incentives aimed at stimulating clean energy deployment, is likely to have a significant impact on the utility-scale solar market in future years, potentially accelerating some trends and slowing others, while also creating new developments altogether. We look forward to tracking the industry's progress in future editions of *Utility-Scale Solar*.

Acknowledgements

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