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Utility-Scale Solar, 2021 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) systems in the United States (where "utility-scale" is defined as any ground-mounted project larger than 5 MW_{AC}). This summary briefing highlights key trends from the latest edition of the report, covering data on projects built through year-end 2020. 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 2020, there were 969 utility-scale PV (and in some cases, PV plus battery) projects totaling 38,745 MW_{AC} operating across 43 of the 50 United States (Figure 1).

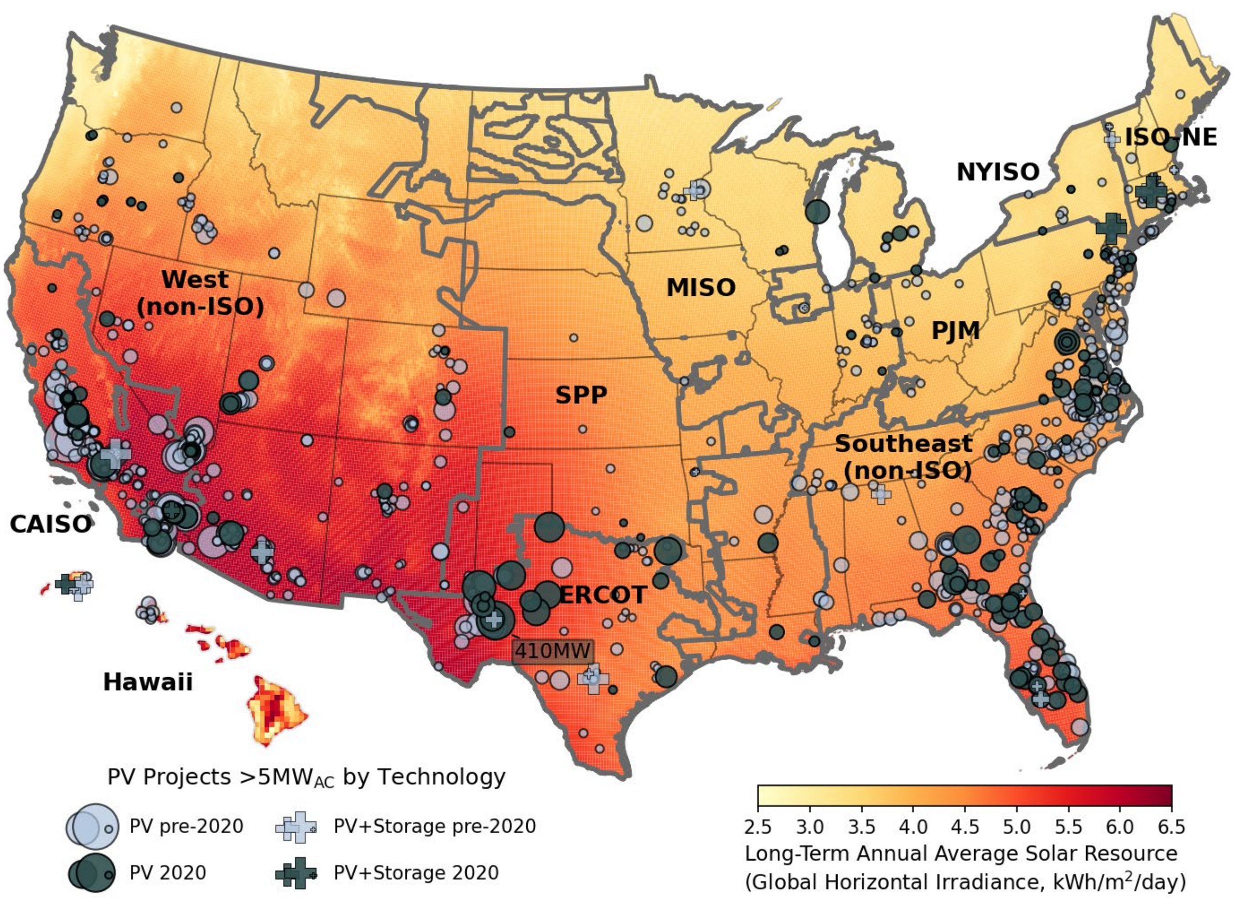

Figure 1. Utility-Scale PV Projects (> 5 MW_{AC}) in the United States, through 2020

Notes: Marker size corresponds to PV capacity.

Nearly 9.6 GW_{AC} of the 38.7 GW_{AC} total achieved commercial operations in 2020 (Figure 2)—a record deployment year for the utility-scale sector, which accounted for more than 60% of all new PV capacity added in the United States in 2020.[1] 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.

Some of these more-recent northerly projects 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 nearly 90% of all new capacity added in 2020 (Figure 2). Fixed-tilt projects 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).

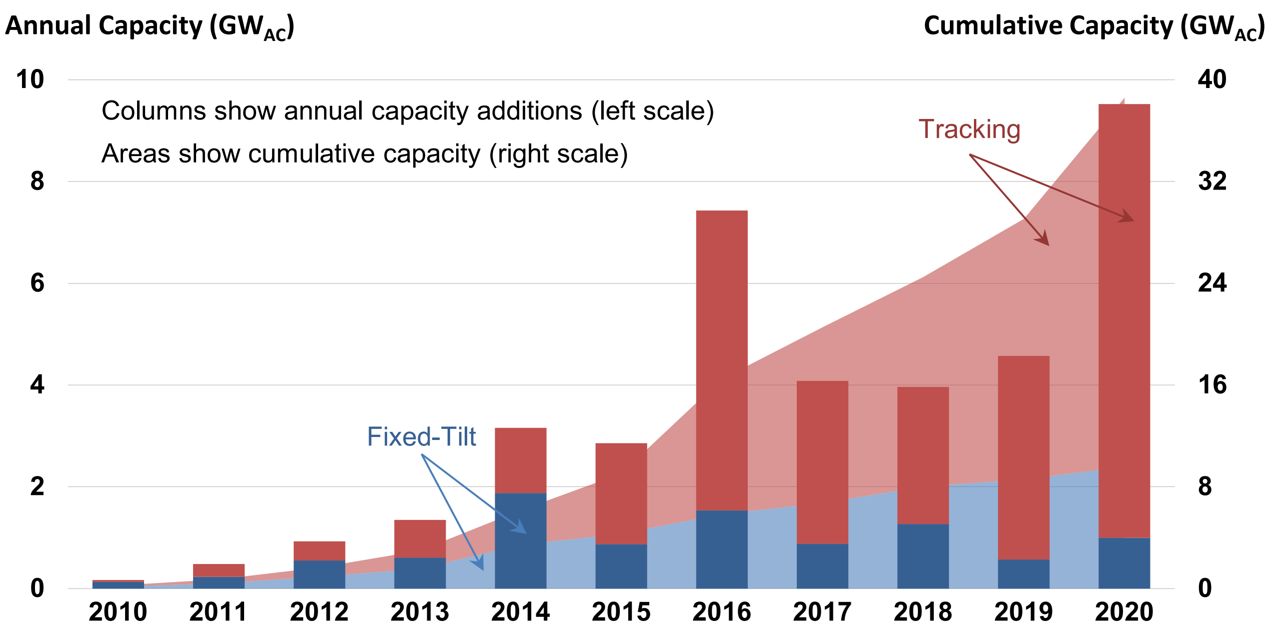

Figure 2. Annual and Cumulative Utility-Scale PV Capacity by Mounting Type

Falling costs are a big reason for the strong deployment trend seen in Figure 2. Median installed project costs have steadily fallen by nearly 75% (averaging 12% annually) since 2010, to $1.4/$W_{AC}$ ($1.1/$W_{DC}$) among 68 utility-scale PV plants (totaling 5.1 GW_{AC}) completed in 2020 (Figure 3). Costs were lowest in the Southeast ($1.2/$W_{AC}$ or $0.9/$W_{DC}$) and highest in CAISO. Projects that use single-axis tracking have slightly higher up-front costs than fixed-tilt projects, but the difference has narrowed over time, particularly since 2015.

[1] The remaining 40% 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.

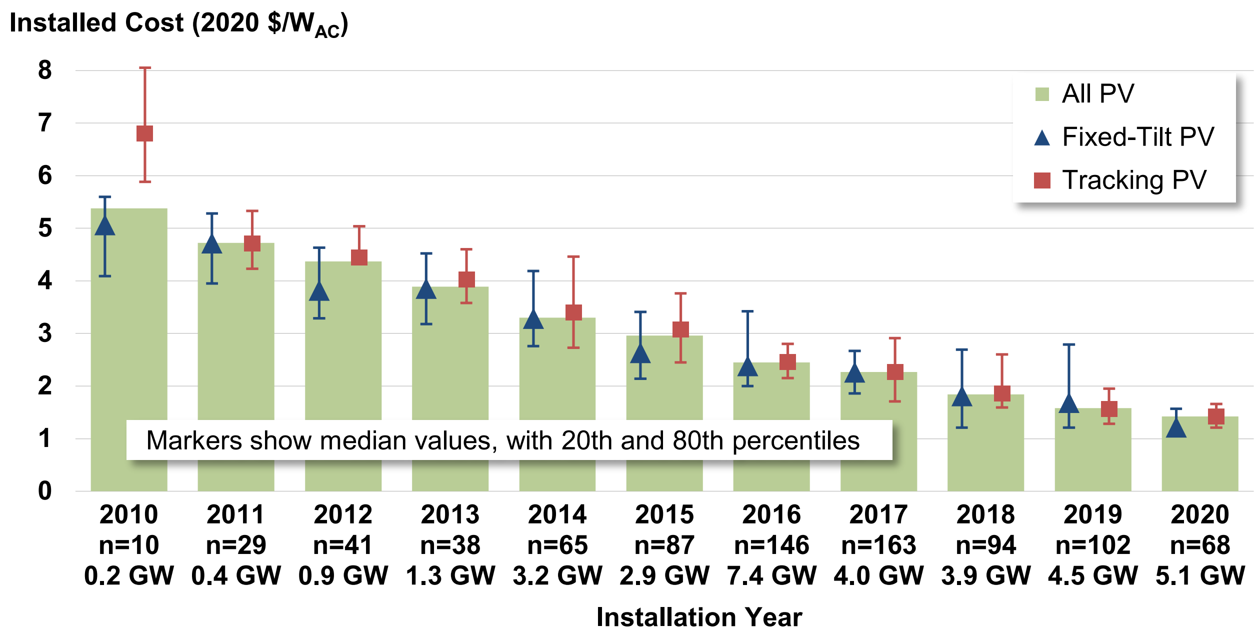

Figure 3. Installed Price of Utility-Scale PV Projects by Installation Year and Mounting Type

To assess how these projects 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 projects in our sample vary widely, from 9% to 36% (in AC terms), with a sample median of 24% (or, ranging from 8%-29% in DC terms, with a median of 18%). Much of this project-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 project tracks the sun or is mounted at a fixed-tilt, and the DC:AC ratio or inverter loading ratio (ILR) —i.e., the ratio of a project'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 project 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.

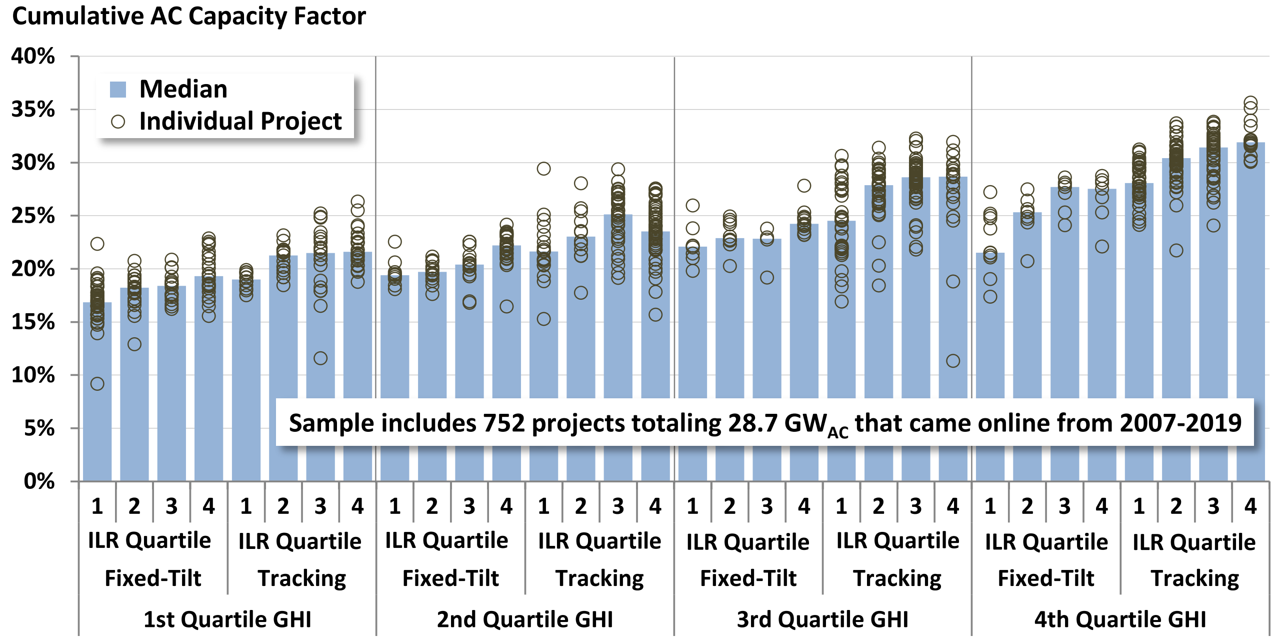

Figure 4. Cumulative Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio

Figure 5 plots average capacity factor by project 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 projects was driven by increases in all three of these drivers.[3] Since 2013, though, average ILRs have held fairly steady around 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 project 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 4.97 kWh/m^2/day among 2010-vintage projects to 5.37 kWh/m^2/day among 2013-vintage projects, while tracking increased from 14% to 59% of projects and the average ILR rose from 1.17 to 1.28, respectively.
[4] Among 2020-vintage projects, the median long-term average GHI is 4.65 kWh/m^2/day, 89% of projects employ tracking, and the median ILR is 1.34.

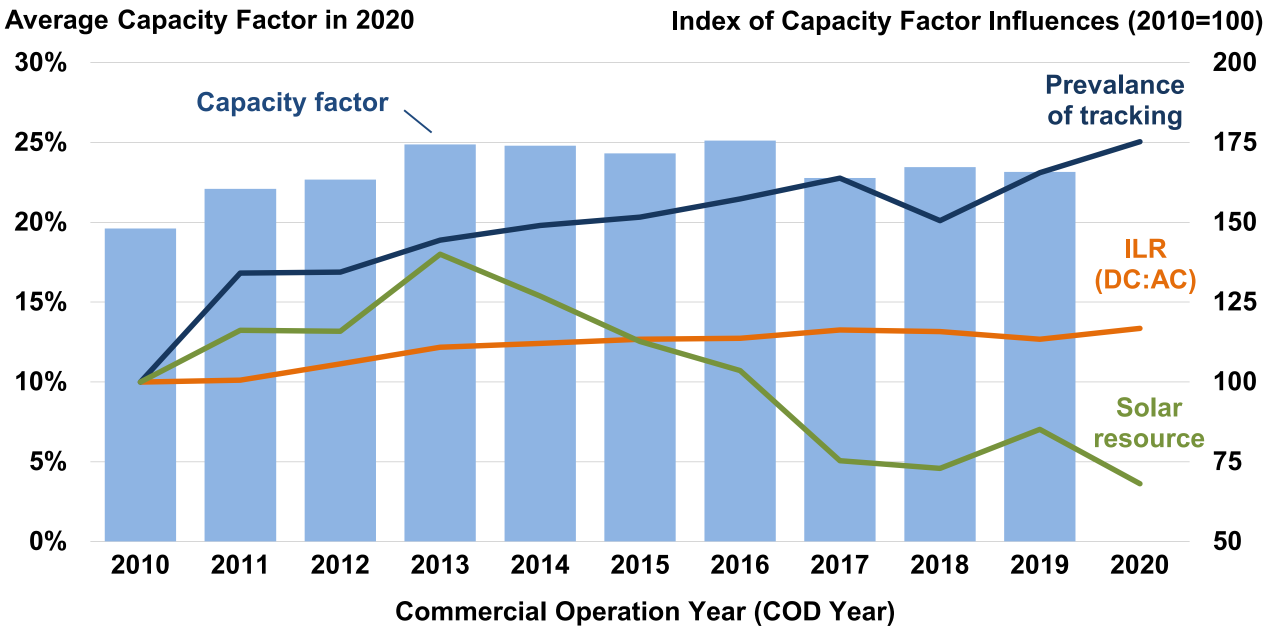

Figure 5. Average Capacity Factor in 2020 by Project Vintage

In addition to analyzing capacity factors by plant characteristics (Figure 4) and over time by COD (Figure 5), we also look at how the performance of each individual plant has changed with age. Figure 6 graphs the median "irradiance-normalized" (i.e., to correct for inter-annual variability in the strength of the solar resource) capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values). The dashed black line approximates the slope of the median, and depicts a straight-line degradation rate of -1.2%/year—i.e., worse than the -0.5%/year to -0.8%/year range that often serves as conventional wisdom. It is important to recognize, however, that Figure 6 captures plant-level performance decline from all possible degradation pathways—both recoverable and unrecoverable—including (but not limited to) module degradation, balance of plant degradation (e.g., from trackers), soiling, and downtime (e.g., due to outages, scheduled maintenance, or curtailment)—and so should not be confused with the more-commonly measured (and typically more modest) module degradation rate.

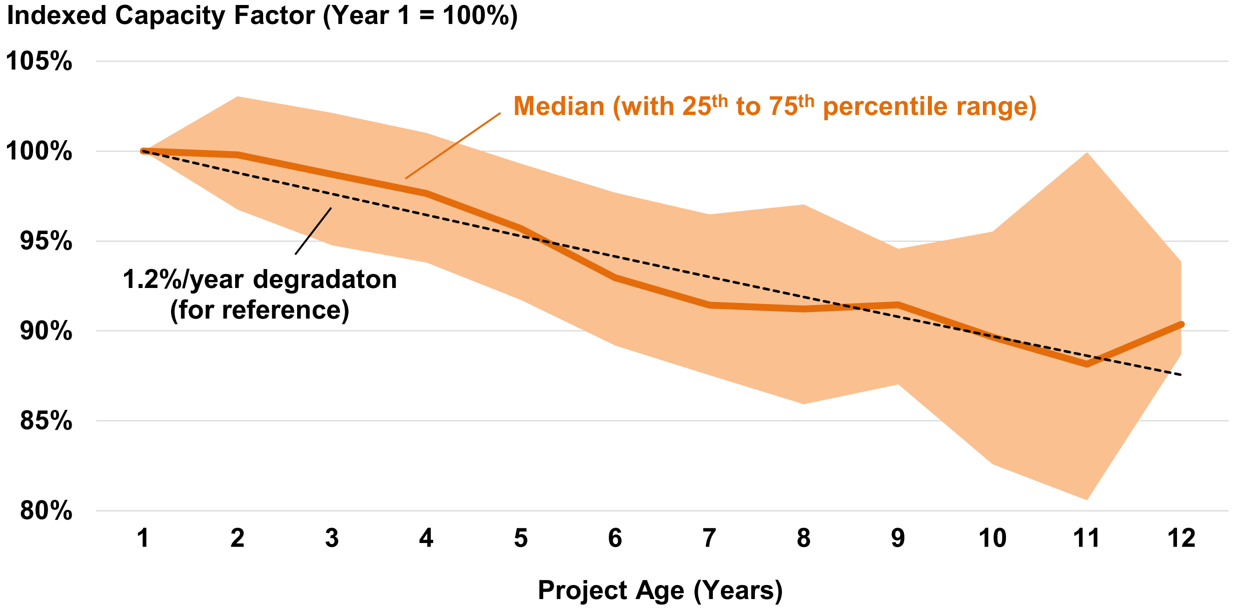

Figure 6. Fleet-Wide Performance Decline as Projects Age

Driven by lower installed project 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 17% annually) since 2010, to $34/MWh in 2020 (Figure 7). Figure 7 does not include the impact of the 30% federal investment tax credit (ITC); if the ITC is factored in, the average LCOE in 2020 drops from $34/MWh to $28/MWh.

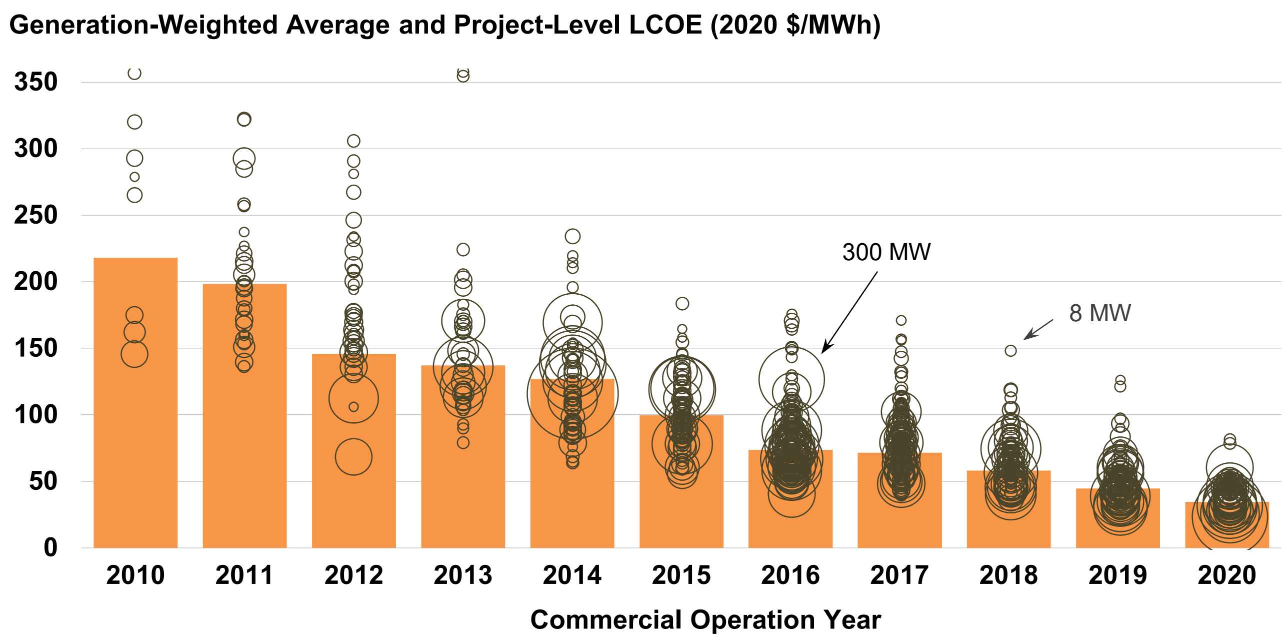

Figure 7. Levelized Cost of Energy (LCOE) by Project Capacity and Commercial Operation Year

Note: Sample size is 817 projects totaling 33.6 GW_{AC} of capacity. Bubble size corresponds to individual project capacity. ITC not included.

Power purchase agreement (PPA) prices for utility-scale PV plants have largely followed the decline in solar's LCOE, also falling by roughly 85% on average (or 15% annually) over the past decade, though the pace of decline has recently stagnated (Figures 8 and 9). Aided by the ITC, most recent PPAs in our sample are priced around $20/MWh or less (on a levelized basis, expressed in real 2020 dollars, and including bundled energy, capacity, and RECs) for projects located in the West, and $30-$40/MWh for projects elsewhere in the continental United States. Hawaiian PPAs are often higher-priced (and many include battery storage—see later). Across much of the United States, solar PPAs are now cheaper than wind PPAs.

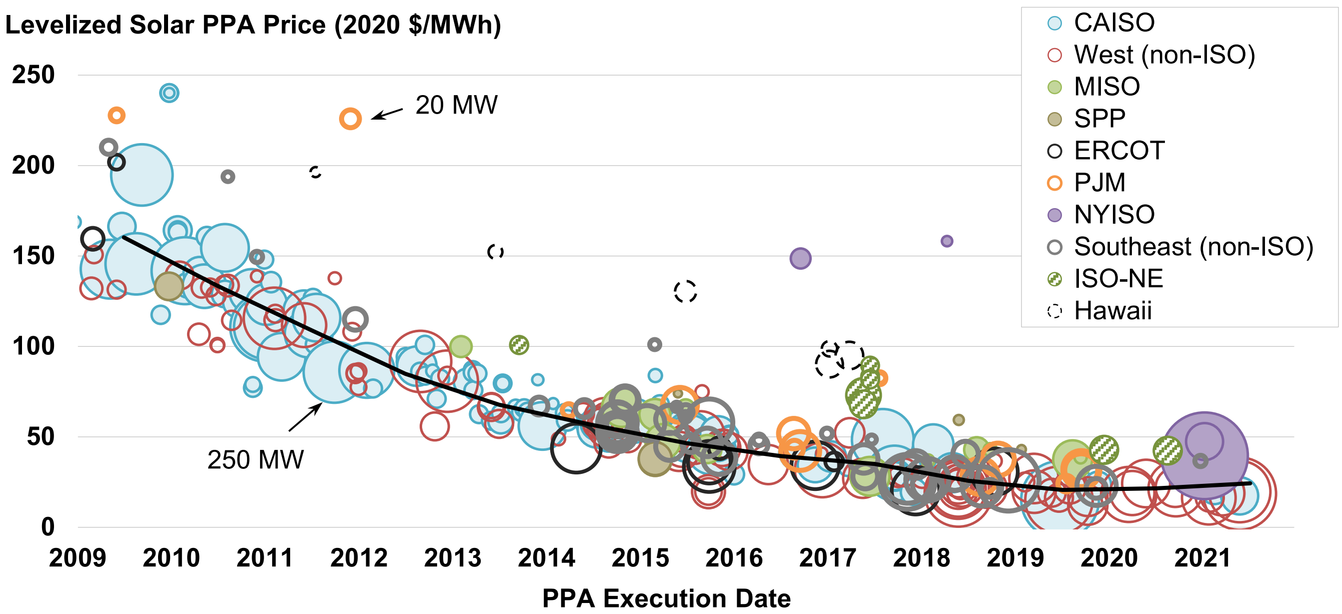

Figure 8. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date

Note: Sample size is 333 projects totaling 22.8 GW_{AC} of capacity. Bubble size corresponds to individual project capacity. The line shows the generation-weighted average price by year.

Figure 9 brings together utility-scale PV's nationwide average LCOE (with and without the ITC) and levelized PPA price by commercial operation year for easier comparison. The fact that levelized PPA prices have tracked LCOE over time suggests full pass-through of the credit and a competitive market for PPAs.

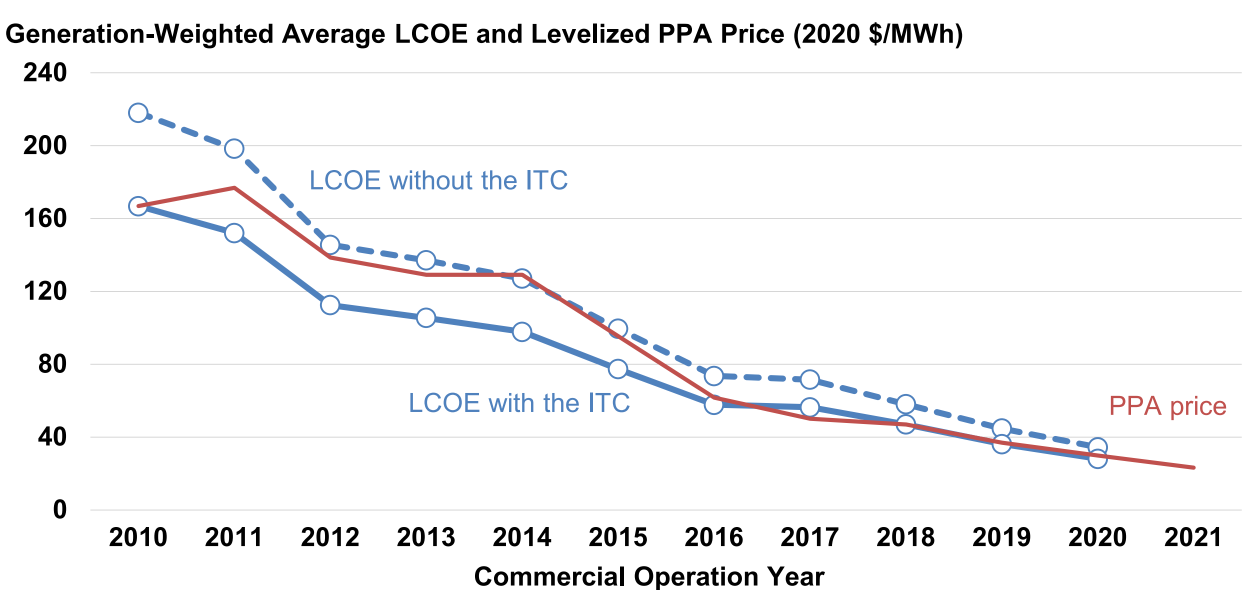

Figure 9. Levelized PPA Prices versus LCOE by Plant Vintage

While Figures 7-9 show what utility-scale PV has cost and how it has been priced, Figure 10 shows what that solar energy has been worth (in terms of energy and capacity value) within six of the seven wholesale power markets operated by independent system operators (ISOs) across the United States (the New York ISO—NYISO—is not shown, due to lack of PPA sample), plus the aggregate non-ISO West and Southeast regions. In all eight regions, the wholesale market value of solar energy has declined considerably since 2014, due in large part to declining wholesale power prices more broadly (but also impacted by solar-specific factors such as project location, generation profile, and curtailment). In general, however, the falling PPA prices shown above in Figure 8 and transferred (along with LevelTen Energy PPA price index data) to Figure 10 have largely kept pace with the declining market values, thereby more or less maintaining solar's competitiveness over time. In other words, an offtaker purchasing solar power in these regions through a PPA signed in 2020 would have generally paid about the same as it otherwise would have to purchase the same amount of energy (delivered at the same time and location as solar) and capacity from the spot wholesale market.

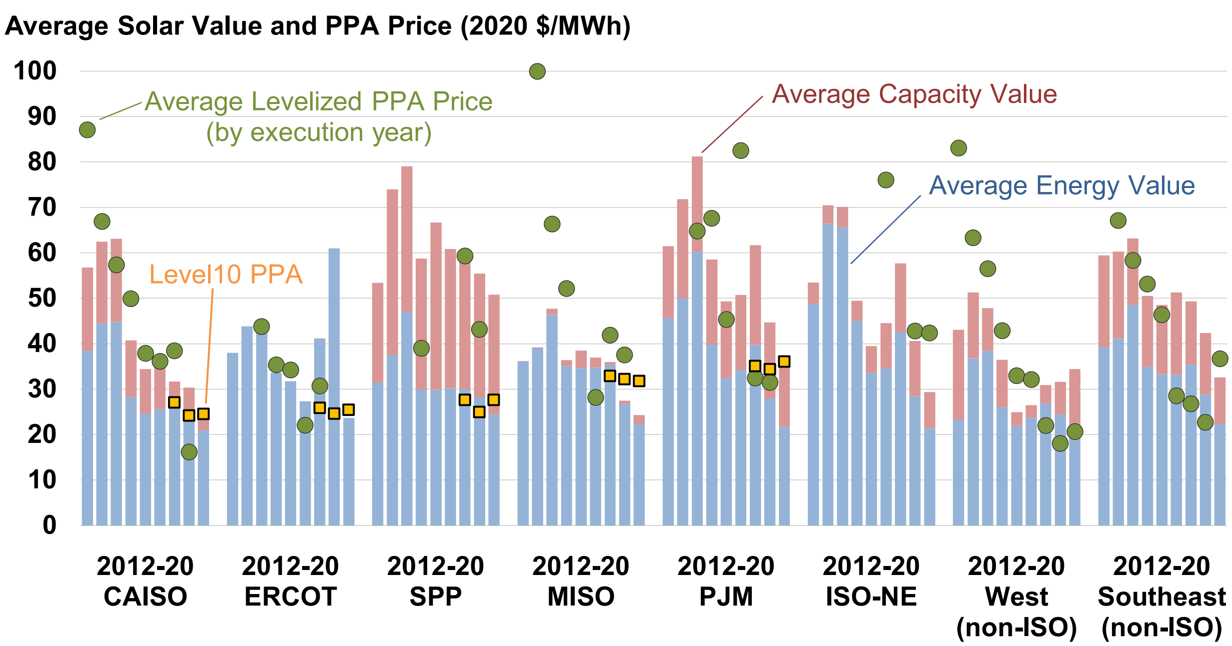

Figure 10. Solar's Average Energy and Capacity Value versus Average PPA Price by Region

While Figure 10 shows the *absolute* value of PV in wholesale markets, Figure 11 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 11—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 11, the ISOs are sorted from left right in order of highest-to-lowest solar market penetration; those with the highest solar penetrations generally have the lowest value factor, and vice versa. For example, solar's 2020 penetration rate in the California ISO (CAISO) was 21%, while its value factor was

70%—meaning that solar's $25/MWh average wholesale market value in CAISO (per Figure 10, above) was 70% of CAISO's average wholesale price in 2020 (Figure 11). In contrast, solar's 2020 penetration rate in the Southwest Power Pool (SPP) was less than 1%, while its average market value of $51/MWh (per Figure 10) resulted in a value factor of 188% (Figure 11). In other words, solar energy sold on a merchant basis into these two wholesale power markets in 2020 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 2020.

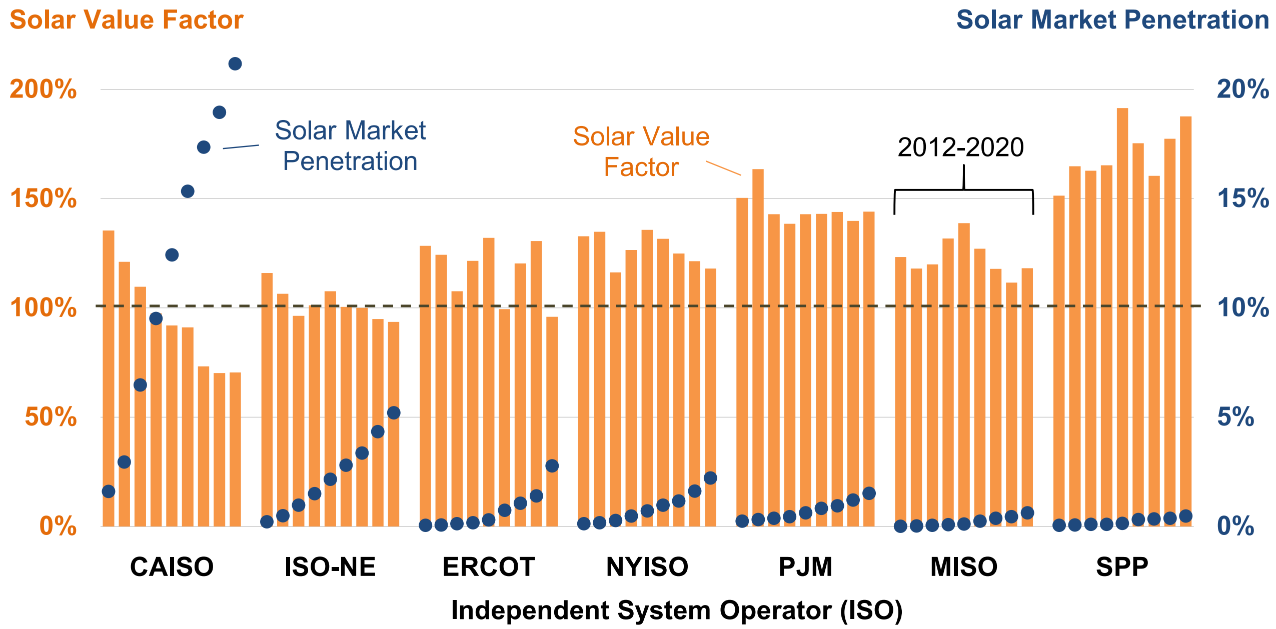

Figure 11. Solar's "Value Factor" and Market Penetration by Independent System Operator (ISO)

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 11), solar benefited from higher capacity prices in 2020, gaining 5-20% 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. Due in part to batteries being eligible for the ITC if paired with solar, PV+battery hybrid plants are becoming increasingly popular, both as greenfield projects and as battery retrofits to existing PV plants. Though relatively few of these utility-scale PV+battery hybrids had reached commercial operations prior to the end of 2020, many such projects have signed PPAs, providing an early glimpse into the relative competitiveness of these hybrids.

[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.

Figure 12 shows levelized PPA prices from 47 PV+battery hybrids, 20 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), the battery-to-PV capacity ratio has historically been less than 100% (with some as low as 5%), but seems to be increasing over time. Perhaps because of this relative increase in battery size over time (which adds costs—see Figure 13), 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).

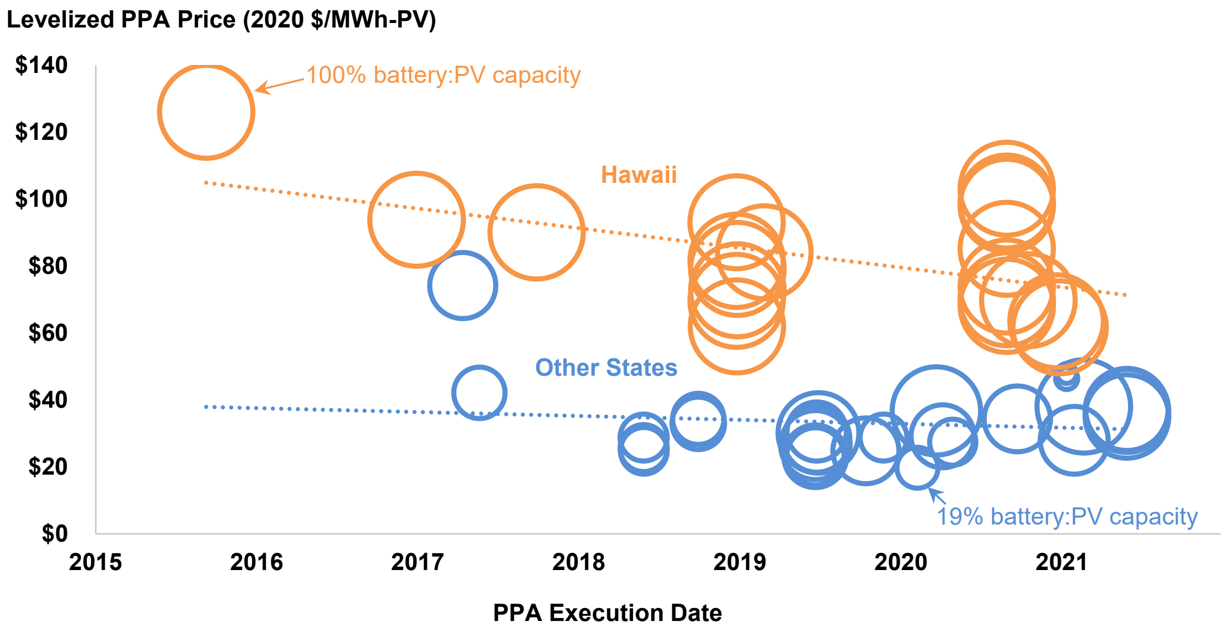

Figure 12. Levelized PPA Prices for PV+Battery Projects by PPA Execution Date

Note: Sample size is 47 projects totaling 5.4 GW_{AC} of PV capacity and 3.1 GW_{AC} of battery capacity. Bubble size corresponds to the battery-to-PV capacity ratio of each individual plant. Two plants—one in Hawaii, one on the mainland—feature 2-hour storage duration, while all other plants have at least 4-hour durations (with four at 5 hours and one at 8 hours—most of these on Hawaii).

Seventeen of these 47 PV+battery hybrid PPAs (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) increases linearly with the battery-to-PV capacity ratio, doubling from ~$5/MWh-PV when the battery is sized at just 25%-30% of the PV capacity to ~$10/MWh at 50%, and then doubling again to ~$20/MWh once the battery approaches parity with the PV capacity. Figure 13 also attempts to tease out a time trend in the levelized storage adder: within each battery-to-PV capacity ratio bin, the adder appears to be trending largely sideways or perhaps slightly downward. The trend towards larger batteries (relative to PV capacity) is also evident, as the earliest PPAs fall into the smallest size bin while the most recent fall into the largest size bin.

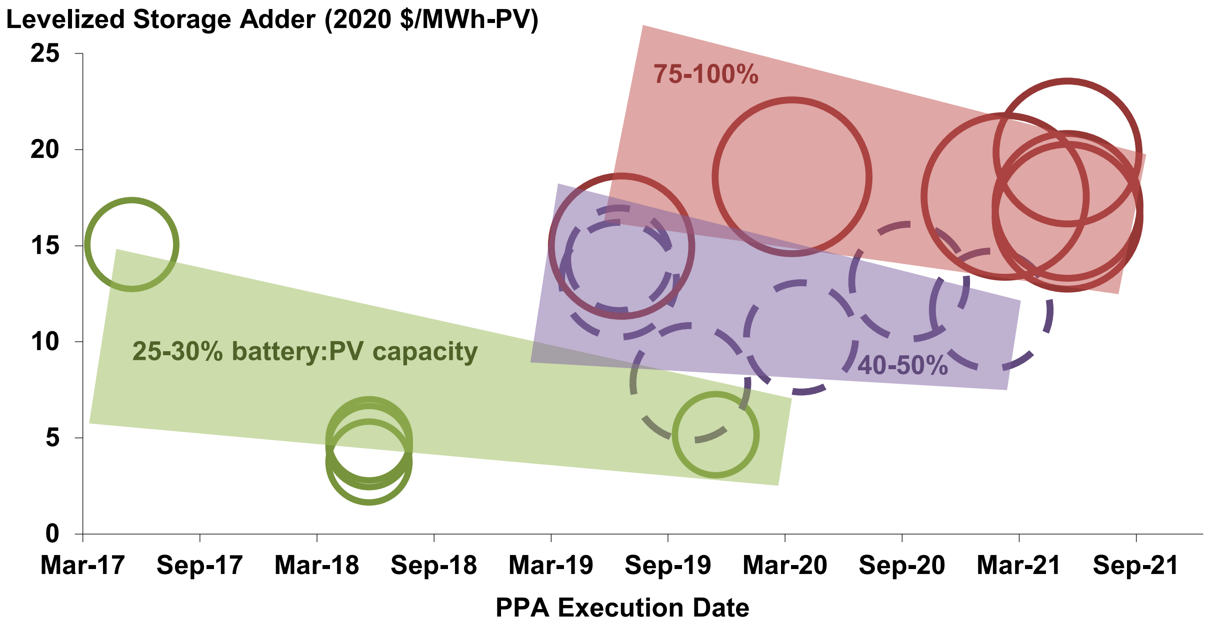

Figure 13. Levelized Storage Adder for PV+Battery Projects by Battery-to-PV Capacity Ratio and PPA Execution Date

Note: Sample size is 17 projects totaling 2.9 GW_{AC} of PV capacity and 1.7 GW_{AC} of battery capacity (all on the mainland). Bubble size corresponds to the battery-to-PV capacity ratio of each individual plant. 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 2020, there were at least 460 GW of utility-scale solar power capacity within the interconnection queues across the nation, 170 GW of which first entered the queues in 2020. Nearly 160 GW of the 460 GW total (i.e., 34% of all solar in the queues) include batteries. Solar (both standalone and in hybrid form, including batteries) is by far the largest resource within these queues, roughly equal to the amount of wind, storage, and natural gas combined.

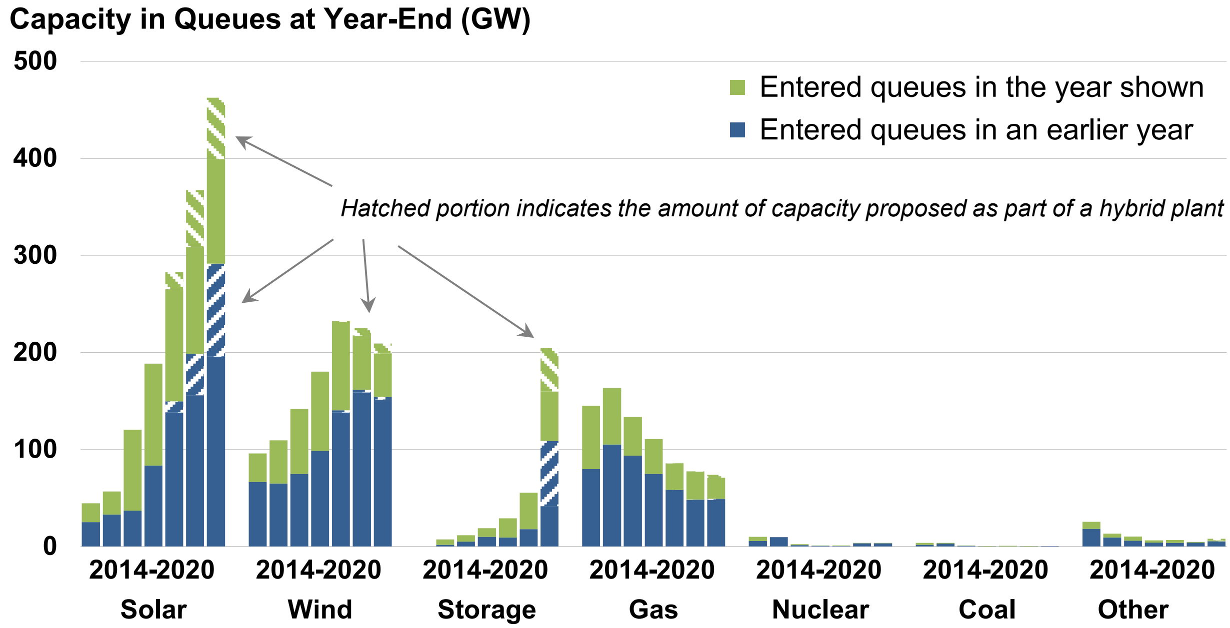

Figure 14. Solar and Other Resource Capacity in 42 Interconnection Queues across the U.S.

The growth of solar within these queues is widely distributed across almost all regions of the country (Figure 15), with PJM 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%. Though not all of these projects will ultimately be built as planned (i.e., entering the queues is a necessary but not a sufficient condition for development success), the ongoing influx and widening geographic distribution of both standalone solar and solar+storage projects 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.

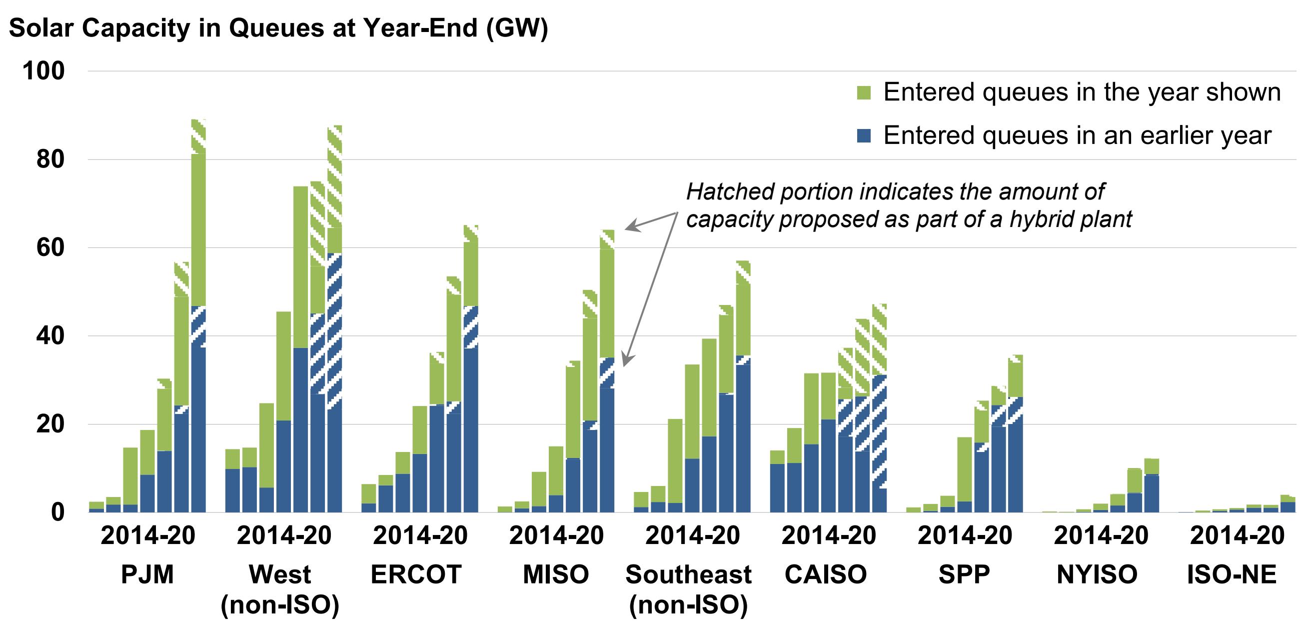

Figure 15. Solar Capacity in 42 Interconnection Queues by Region

Acknowledgements

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