The Sun Also Rises:
How Batteries are Reshaping the Effects of Renewables

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Abstract. Policies supporting investment in renewable electricity have been a cornerstone of climate policy for over a decade, and a growing literature has documented their short- and medium-run effects on wholesale power markets. Bushnell and Novan (2021) showed that, from 2014 through 2017, California's utility-scale solar expansion depressed mid-day prices while *raising* prices in the shoulder hours, a pattern implying that short-term markets were rewarding flexible conventional generation even as they undermined traditional baseload. In the years since, a second capacity boom has occurred: grid-scale battery storage has grown from essentially nothing to roughly 16 GW in California, approaching two-thirds of installed utility-scale solar capacity. We revisit the earlier analysis on a sample running from 2014 through May 2026 and ask whether the price patterns that motivated it still hold. They do not. In the most recent period, the reduction in mid-day prices caused by increaseing solar supply is roughly one-fifth of its earlier magnitude, and no hour of the day exhibits the shoulder-hour price increase that previously characterised the evening. Examining the response of individual supply sources, we find that, on the margin, the amount of in-state thermal generation avoided by increased solar has halved, with reductions in imports and increases in solar curtailment absorbing a growing share of each incremental GWh of solar availability. The results suggest that the market signal that would have sustained flexible conventional generation is itself eroding as storage scales.

1. Motivation

The empirical literature on renewable expansions has largely focused on quantifying the displacement of conventional generation and the associated emissions savings (Cullen, 2013; Novan, 2015; Kaffine et al., 2013; Fell and Kaffine, 2018; Callaway et al., 2018), while a parallel strand has measured the wholesale price reductions caused by renewables – i.e. the 'merit-order' effect (Sensfuß et al., 2008; Würzburg et al., 2013; Woo et al., 2016; Gowrisankaran et al., 2016). Bushnell and Novan (2021) furthered our understanding of how renewables impact wholesale prices by studying how the full hourly profile of prices was altered by expansions in California's utility-scale solar capacity. The results revealed that the same solar expansion that reduced mid-day prices raised them in the shoulder hours, with opposite implications for baseload and peaking technologies.[1]

That result was estimated on data through May 2017, when California's battery storage capacity was negligible. It is no longer. Figure 1 displays the amount of utility-scale solar and battery storage capacity installed in the market overseen by the California Independent System Operator (CAISO) from 2014 through May, 2026. Since 2020, over 16 GW of utility-scale battery storage capacity has been introduced to the market, roughly equal to two-thirds of installed utility-scale solar capacity. Storage is precisely the technology whose economics depend on the mid-day-to-evening spread that the earlier work documented, and which, in operating against that spread, should compress it. Recent work has begun to take this seriously: Butters et al. (2025) estimate a dynamic equilibrium model of battery investment and find that the marginal value of storage declines sharply with penetration, Lamp and Samano (2022) document the arbitrage behavior of California's early fleet, and Kirkpatrick (2025) shows that a large share of battery value is locational. What has not been established is whether the *reduced-form price response to solar* — the object of the original paper — has changed with the introduction of substantial storage capacity. That is our question.

[1] Jha and Leslie (2025) document the same impacts of solar growth on spot market prices in Western Australia.

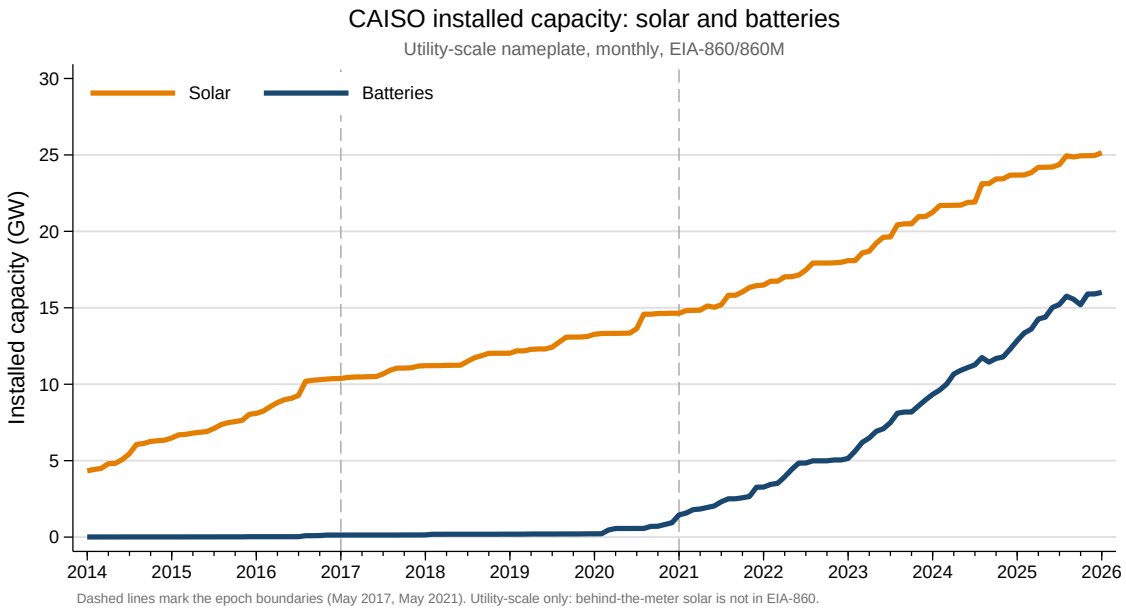


Figure 1: Installed CAISO capacity. Over the first epoch storage is negligible relative to solar (a ratio of 0.003); by the end of the sample it has reached 0.637.

2. Data and empirical approach

We assemble an hourly CAISO panel spanning May 2014 to May 2026 including real-time prices at the three investor-owned utility load aggregation points, hourly generation by source, hourly wind and solar curtailment, daily gas prices, quarterly California carbon allowance prices, and monthly installed capacity by technology from EIA Form 860.

To quantify the impact of expansions of solar expansions on wholesale prices, we make two changes to the original empirical specification. First, daily solar and wind enter as *potential* rather than realized generation — metered output plus curtailed output. Realized renewable output is mechanically censored by curtailment, which itself responds to price; by 2026 roughly eleven percent of an incremental GWh of potential solar is curtailed rather than delivered, so the distinction is no longer second-order. Second, we include installed battery capacity and the carbon allowance price as additional controls. For each hour of the day we estimate the following specification:

$$P_{h,d} = \alpha_m + \beta^s \text{SolarPot}_d + \beta^w \text{WindPot}_d + \beta^g \text{Spot}_d + \gamma \, \text{Load}_{h,d} + \delta \, \text{Hydro}_m + \beta^c \text{BattCap}_m + \beta^{co2} \text{Carbon}_q + \varepsilon_{h,d},$$

where $P_{h,d}$ represents the average real-time market price ($/MWh) during hour h of day d. Following Bushnell and Novan (2021), we include month-of-year fixed effects and Newey–West standard errors at a seven-day lag. We estimate the model separately within over three non-overlapping epochs: May 2014–April 2017, which corresponds to the original sample; May 2017–April 2021; and May 2021–May 2026. To further examine how the subsitution pattern between solar and other sources has changed over time, we also estimate the above model using the hourly aggregate output from various generation sources as the outcome variable of interest.

3. Results

Figure 2 displays the point estimates of β^s, the average change in the hourly real-time price in response to an additional GWh of daily potential solar, for each hour of the day across each of the three epochs.

The first epoch reproduces the familiar pattern uncovered in Bushnell and Novan (2021): a deep mid-day trough, reaching −1.34 $/MWh at hour-ending 15, with the profile recovering to positive values late in the day.[2]

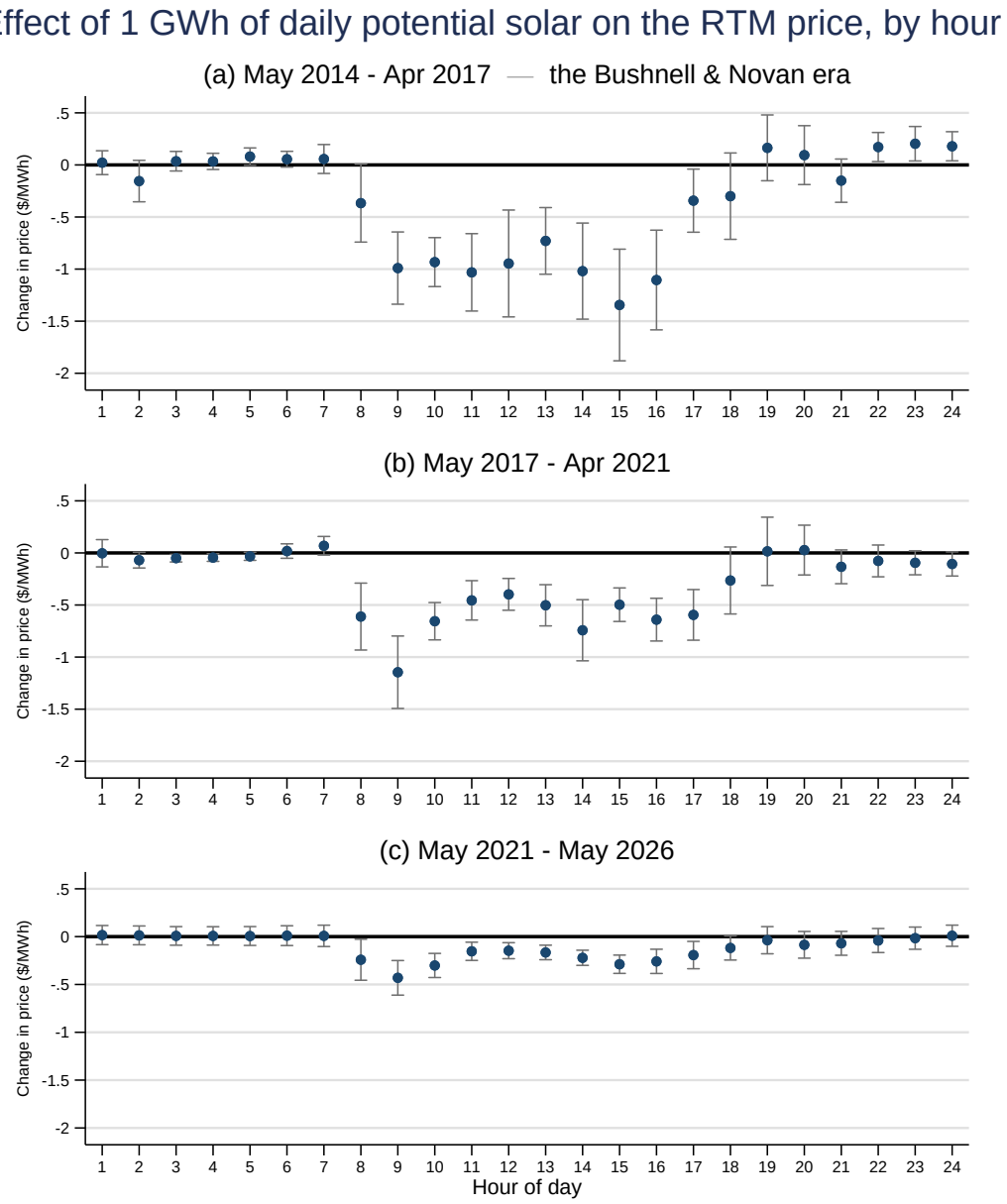


Figure 2: Hourly price response to daily potential solar, with 95% confidence intervals and a common vertical scale.

The contrast with the current epoch is the substance of the paper. Between May 2021 and May 2026 the mid-day effect is −0.22 $/MWh, roughly one-fifth of its earlier magnitude, and the profile is flat enough that no hour of the day carries a significantly positive coefficient. The evening mean is

[2]Our sample begins in May 2014 rather than January 2013, and the late-day coefficients in this epoch are less precisely estimated than in the original.

−0.07: an additional GWh of solar availability now depresses prices modestly in every part of the day rather than redistributing value across it. The within-day reallocation that characterised the earlier period has largely disappeared, and what remains is a smaller, more uniform reduction in the level of prices.[3]

Table 1 and Figure 3 examine the supply impacts. During the first epoch, effectively all of the daily output displaced by an increase in daily potential solar came from in-state thermal generation – an additional GWh of solar reduced in-state thermal by an average of 1,085 MWh. In the most recent epoch (2021-2026), this impact on CAISO thermal was halved – daily CAISO thermal fell by an average of 479 MWh per GWh of potential solar. Highlighting the extent to which California's solar growth is impacting the surrounding Western Interconnection, an additional GWh of daily potential solar offsets 357 MWh of output from out-of-state generation sources. The results also highlight the importance of no longer treating output from utility-scale solar sources as exogenously determined by nature. In the most recent epoch, the estimates reveal that over 11% of each additional GWh of daily solar goes towards increased solar curtailment. As a specification check we include nuclear output, which should not respond to a daily solar shock; its coefficient remains within ±30 MWh of zero throughout. With potential solar on the right-hand side the accounting identity requires the summed response across sources, net of curtailment, to equal −1000 MWh; the implied totals are −1001, −1026 and −975, omitting wind and other renewables.

Table 1: Daily change in output by source per GWh of daily potential solar (MWh).

Source	May 2014–Apr 2017	May 2017–Apr 2021	May 2021–May 2026
Thermal (gas and coal)	−1085.0	−751.6	−478.9
Net imports	−17.4	−272.0	−356.8
Solar curtailment	+20.7	+45.3	+112.5
Batteries	—	−0.9	+11.9
Nuclear	−8.7	+23.8	−22.2

Figure 3 displays the point estimates of the average change in generation by source across each of the day in response to an additional GWh of daily potential solar. Importantly, the bottom left panel highlights the important role batteries are now playing in the market. Battery capacity was effectively non-existent in the first two epochs, and thus, changes in daily solar did not alter charging or dischargin. In the most recent epoch, batteries are clearly absorbing a large share of each additional GWh of daily solar output supplied during the mid-day hours – output which is then resupplied in the evening and overnight hours when the sun is no longer shining.

4. Discussion

The pattern documented in Bushnell and Novan (2021) implied that power markets were, at least in the medium run, rewarding flexibility: solar depressed prices when it ran and raised them when it did not, improving the relative position of units able to follow the net load. In the current epoch that signal is no longer present. The mid-day merit-order effect survives in attenuated form, but the shoulder-hour premium that would compensate flexible capacity is not detectable in any hour, and the supply-side response has shifted markedly: in-state thermal units now absorb less than half of an incremental GWh of solar availability, with imports taking a comparable share and curtailment absorbing more than a tenth.

[3] A seasonal breakdown reinforces this. The attenuation holds within every calendar quarter, so it does not arise from a shift in which seasons dominate the sample. The mid-day effect in the current epoch ranges from −0.41 in the first quarter to −0.15 in the third, against −1.52 and −0.62 in the corresponding quarters of the first epoch.

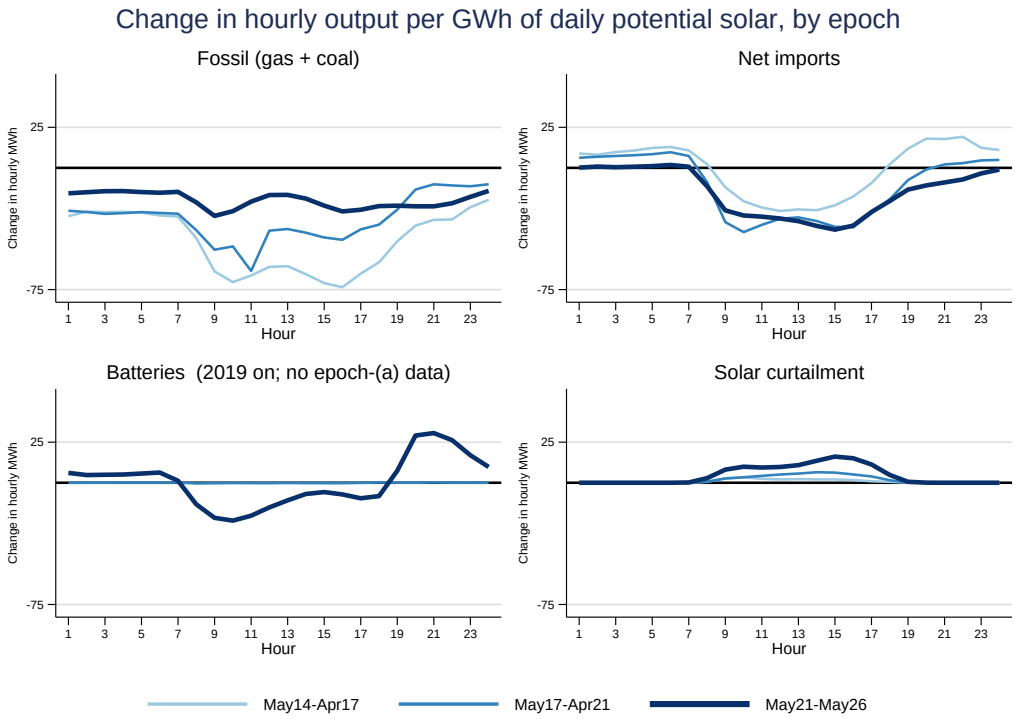


Figure 3: Change in hourly output per GWh of daily potential solar, by source and epoch.

We are cautious about attributing this to storage alone. Installed battery capacity is close to monotonic over our sample and is therefore hard to separate from other secular changes; we treat it as a control, not a causal estimate. What we can say is that the attenuation is concentrated in the hours in which the storage fleet operates, coincides with a sixfold increase in that fleet, and is accompanied by a reallocation of displaced generation away from in-state thermal units and toward imports and curtailment. If storage is compressing the spread, then the private returns to storage and the market's signal for flexible conventional capacity are being eroded by the same mechanism — a possibility with direct bearing on how both are compensated.

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