



2025 Special Report on Battery Storage

October 28, 2026

ISO Public

Prepared by: Department of Market Monitoring

California Independent System Operator

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1 Summary

1.1 Background

As energy systems evolve from fossil fuels to renewable resources, battery storage is playing an increasingly important role in maintaining the flexibility and resilience of the power grid. This is especially true in the Western U.S., where ambitious decarbonization goals and widespread solar energy development are helping drive the growth of battery storage.

Most large-scale storage systems in operation have a maximum duration of 4 hours and use lithium-ion technology, which provides fast response times and high-cycle efficiency (low energy loss between charging and discharging), while still being cost-effective. These 4-hour resources primarily operate through intra-day arbitrage, buying power during mid-day hours when solar is plentiful and system prices are lowest, then selling it back to the grid in the evening when power is in high demand, solar output is low, and prices are much higher.

Because of their fast response times, batteries are ideal for providing services used to balance very short-term differences in supply and demand, such as frequency regulation and flexible ramping product. In addition, battery charging now represents a significant amount of energy demand, especially in the afternoon.

This report provides a description by the Department of Market Monitoring (DMM) of the state of battery storage resources in the California ISO market footprint, including the California ISO (CAISO) balancing area and all other balancing areas in the Western Energy Imbalance Market. The report includes analysis of the performance of batteries using several key metrics, and assesses the recent market enhancements for battery resources.

1.2 Key findings

- **Battery storage capacity in the ISO market footprint reached 25,700 MW at year-end 2025, a 42 percent increase from year-end 2024.** This growth was most concentrated in California and the Desert Southwest region.
- **Batteries account for a significant amount of energy supply during the evening when net loads are highest.** During hours-ending 18 to 22, batteries supplied an average of 15 percent of California balancing areas' load, 11 percent for the Desert Southwest, 3 percent for the Intermountain West, and 1 percent for the Pacific Northwest.
- **Batteries account for a significant portion of load during peak solar hours.** From hours-ending 10 to 13, battery charging represented around 10 percent of load in the ISO market footprint in 2025.
- **Batteries provided 85 percent of the CAISO balancing area's regulation up and regulation down requirements in 2025.** However, as the amount of battery capacity has increased in recent years, the percentage of total battery storage capacity being scheduled for ancillary services has decreased, with batteries providing more energy during the peak net load hours.

- **Net market revenue for batteries in the CAISO balancing area decreased from an average of about \$53/kW-yr in 2024 to \$45/kW-yr in 2025.** This decrease was driven largely by lower peak energy prices compared to 2024.
- **Batteries received \$6.3 million of real-time bid cost recovery payments in 2025, representing 5 percent of total bid cost recovery to generators.** These payments represented around 1 percent of batteries' total net market revenues. In comparison, battery resources received 13 percent of all bid cost recovery paid to resources in 2024. DMM continues to recommend enhancements to the market design of bid cost recovery for batteries.
- **Local market power mitigation has had minimal impact on the dispatch of batteries.** An average of about 296 MW of battery capacity per hour had bids lowered under local market power mitigation procedures in 2025. Mitigation of bids potentially increased battery dispatch by an average of about 29 MW per hour.
- **DMM continues to find that battery resources used to meet resource adequacy requirements, primarily 4-hour batteries, are partially unavailable to the market during consecutive hours with tight system conditions.** There is a combination of factors which prevent batteries from being fully charged and then discharging up to their nameplate capacity during some peak net load hours. These factors include short discharging durations, modeling limitations, and bidding behavior.

2 Battery storage market participation

2.1 Battery resource modeling

In the ISO market, storage resources participate under the non-generator resource (NGR) model. NGRs are resources that operate as either generation or load (demand) and bid into the market using a single supply curve with prices for negative capacity (charging) and positive capacity (discharging).

NGRs are constrained by an energy limit to generate or consume energy on a continuous basis. They can produce at any point in their operating range and can switch immediately between generating and consuming energy. To reflect the physical operational capabilities of batteries, the ISO models minimum and maximum storage capability, upper and lower operating limits, and round-trip efficiency for each storage resource.

For their day-to-day operations, NGRs have the option to use several biddable parameters to manage their state-of-charge. They can submit upper and lower charge limits for each trading day, which represent the highest and lowest stored energy values (in MWh) that must be maintained in the resource. For greater control in how their state-of-charge changes throughout the day, resources may use the end-of-hour state-of-charge parameter, described in more detail below in Section 2.2.

NGRs can also submit an initial state-of-charge value as part of their day-ahead market bid to indicate the expected available energy on the first market interval of the following day. This initial state-of-charge value should be a forecast based on anticipated real-time battery operations, including ancillary service delivery.

Batteries require constraints in the day-ahead and real-time markets to manage state-of-charge to ensure the deliverability of the awarded ancillary services for the duration required by the ISO tariff. These constraints are referred to as the ancillary services state-of-charge constraints (ASSOC). When a resource is providing either regulation up or regulation down, it will respond to four-second automatic generator control (AGC) instructions, which impact the battery's state-of-charge. Real-time regulation delivery can result in discrepancies between day-ahead and real-time state-of-charge and can cause the ASSOC to bind in real-time to charge or discharge storage resources so that they are able to fulfill regulation awards. Starting May 1, 2026, the ASSOC was updated to include the impact of imbalance reserve up and imbalance reserve down, two new products added as part of the Extended Day-Ahead Market initiative, on state-of-charge.

In November 2023, the ISO implemented market design changes to model the impact of batteries providing ancillary services on their state-of-charge. For this implementation, the ISO kept the original calculation for battery state-of-charge the same—in that it only accounts for the impact of energy schedules—and introduced a new market constraint for batteries which accounts for the impact of regulation and energy schedules. The new state-of-charge constraint works by using multipliers for regulation up and regulation down MW—called attenuation factors—which model the state-of-charge as being depleted or increased by a certain percentage of the regulation schedule. The ISO chooses multipliers based on historical usage of regulation and updates the multipliers on a quarterly basis to account for seasonality of regulation usage.

Starting May 1, 2026, the ISO introduced new constraints consisting of an upper and lower boundary, or “envelope,” that maintains the feasibility of batteries' imbalance reserve awards in the day-ahead

market. Like operating reserves, imbalance reserve awards may be converted to energy in the real-time market and therefore require this constraint to ensure real-time deliverability. Also, like with the ASSOC, the envelope constraints include configurable attenuation factors that model the expected proportion of the imbalance reserve award that will be delivered in real-time.

Currently, there are two modeling options that allow resources to combine batteries with other generation technologies in their operations: the *hybrid* and *co-located* models. However, many resources operate as *stand-alone* batteries, which do not share a point of interconnection with other resources and do not use multiple generation technologies.

Batteries across the ISO footprint share most operational characteristics. However, batteries that participate in the day-ahead market (limited to those in the CAISO BA in 2025) differ from those that participate in only the real-time market in several respects related to scheduling, bidding, and settlements. Throughout this report, these real-time-only batteries are referred to interchangeably as WEIM batteries or non-CAISO BA batteries.

2.2 Multi-interval optimization

The California ISO uses a multi-settlement market design where bidding and dispatch are managed in a set of successive market runs—first in the day-ahead market, then in the real-time market. Each of these markets uses a multi-interval optimization to effectively dispatch resources such that they are positioned to anticipate future conditions. The day-ahead market optimizes over a 24-hour horizon to determine the least costly way of dispatching resources to meet load.

As part of the ISO’s real-time processes, the 15-minute market generates optimal dispatch solutions for up to two hours into the future. The 5-minute market develops solutions for 65 minutes, or up to 13 5-minute intervals. Because of the computational complexity inherent with a large optimization, the length of these time horizons is limited. The ISO real-time market design includes the settlement of one financially binding interval in the time horizon, with the schedules for the remaining intervals being advisory.

Given that storage resources are energy limited, the multi-interval optimization is essential to ensuring that inter-temporal conditions are factored into battery schedules. For example, the multi-interval optimization allows the market to hold state-of-charge, or even dispatch batteries to charge uneconomically in a given interval, in anticipation of higher future prices—so long as those high prices occur within the optimization horizon of its respective market.

One challenge of the limited optimization horizon in the real-time market is that the software may dispatch batteries to discharge earlier than desired when high real-time prices materialize early in the day. This can result in batteries entering peak net load hours with a diminished state-of-charge. During the summer of 2022, the ISO used a newly-implemented market constraint called the minimum state-of-charge (MSOC) requirement, which was designed to address this issue.¹ The constraint was activated on days when there was a shortfall between supply and forecasted demand in the day-ahead market, causing a residual unit commitment (RUC) infeasibility.

¹ 2022 Special Report on Battery Storage, Department of Market Monitoring, July 7, 2023, p 32: <https://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf>

Before the MSOC was activated in the real-time market, market operators would decide on a series of “critical hours” which would represent the period where the system is most at risk of undersupply. The market software would then optimally dispatch batteries such that their states-of-charge would be preserved until the critical hours.

The MSOC was a temporary initiative which expired in September 2023. The functionality of the MSOC can be replicated if needed, using enhanced exceptional dispatch functionality for batteries. This functionality allows exceptional dispatch to hold state-of-charge, and considers forgone market opportunities in the exceptional dispatch settlement. Battery operators may also reflect intra-day opportunity costs in real-time energy bids to preserve limited stored energy for the highest-valued hours.

Another feature of the multi-interval optimization that presents challenges is that batteries may be dispatched to charge at prices above their bid prices to charge if high advisory prices in future intervals signal that the energy can be sold to the grid at a profit. However, advisory prices are not financially binding and are subject to change based on real-time conditions. The Department of Market Monitoring’s (DMM) analysis shows that, despite this limitation, batteries overwhelmingly benefit from the multi-interval optimization.²

In light of the challenges of having a limited optimization horizon, the ISO proposed measures to help prevent sub-optimal market outcomes as part of its Energy Storage and Distributed Energy Resources (ESDER) Phase 4 stakeholder initiative. One solution proposed in this initiative was the end-of-hour state-of-charge (EOH SOC) bid parameter, which was approved by the Federal Energy Regulatory Commission (FERC) in May 2021.

The EOH SOC bid parameter is an optional, real-time-only bid parameter for NGRs that scheduling coordinators submit hourly as a range with an upper and lower state-of-charge limit. The market dispatches resources such that their states-of-charge end the hour within the submitted range, while respecting minimum and maximum energy bid limits.

2.3 Installed battery capacity

Figure 2.1 shows the total capacity of participating battery storage in the ISO market footprint by balancing area as of December 2025. In total, 7,600 MW of additional storage capacity participated in the market compared to 2024. With an additional 4,100 MW, CAISO had the largest year-over-year addition of storage capacity of any balancing area.

In December 2025, active battery capacity across the ISO market footprint totaled about 25,700 MW—with 11,900 MW from stand-alone projects, 11,500 MW from co-located projects, and about 2,300 MW from the storage components of hybrid resources and co-located hybrids.³

² *Comments on Storage Design and Modeling Working Group Presentation on September 29, 2025*, Department of Market Monitoring, October 14, 2025: <https://www.caiso.com/documents/dmm-comments-on-storage-design-and-modeling-sep-29-2025-working-group-presentation-oct-14-2025.pdf>

³ For individual battery resources, the minimum power output (or potential demand to charge batteries) tends to be the negative value of its maximum power output.

Figure 2.2 shows aggregate maximum state-of-charge (SOC) by balancing area in December 2025. The aggregate maximum energy storage capacity across the entire market footprint reached nearly 93,000 MWh.

Figure 2.1 Active battery capacity by balancing area in 2025

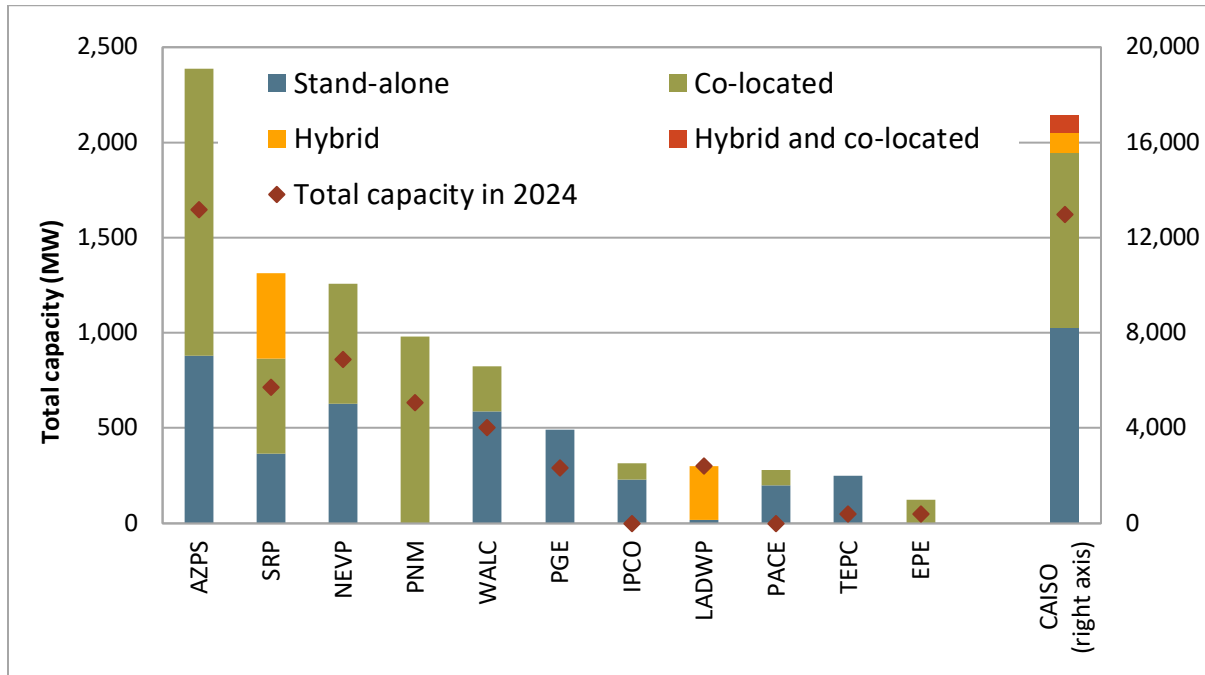
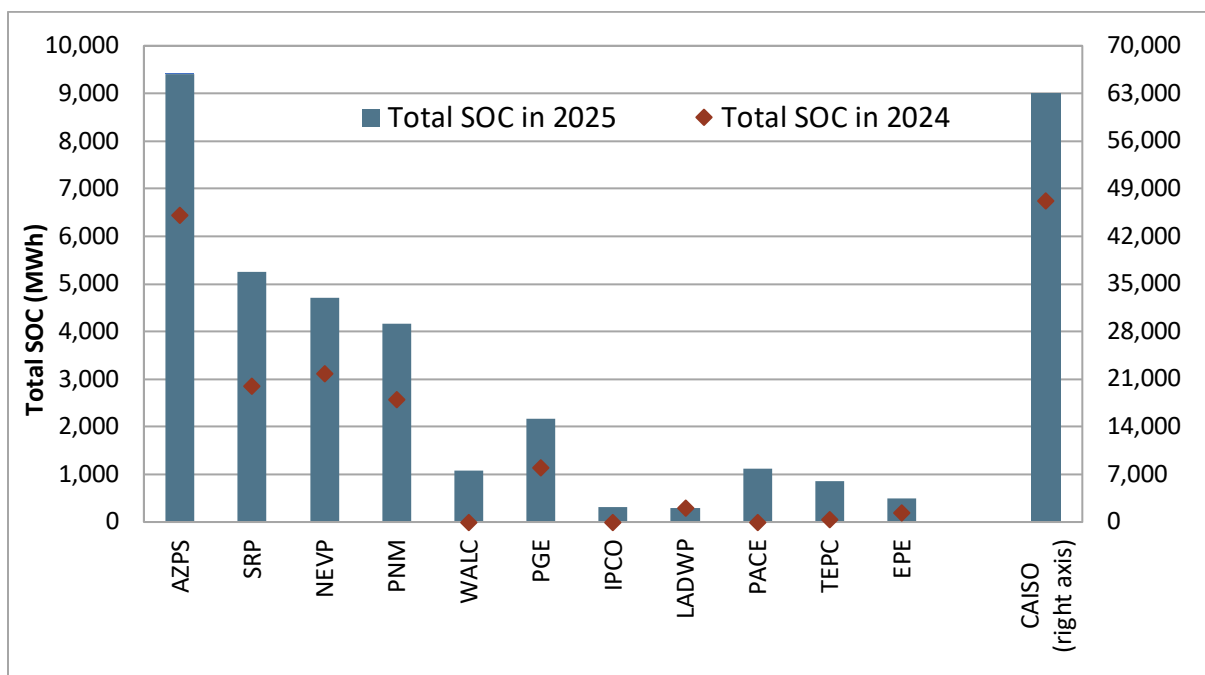


Figure 2.2 Active battery state-of-charge by balancing area in 2025

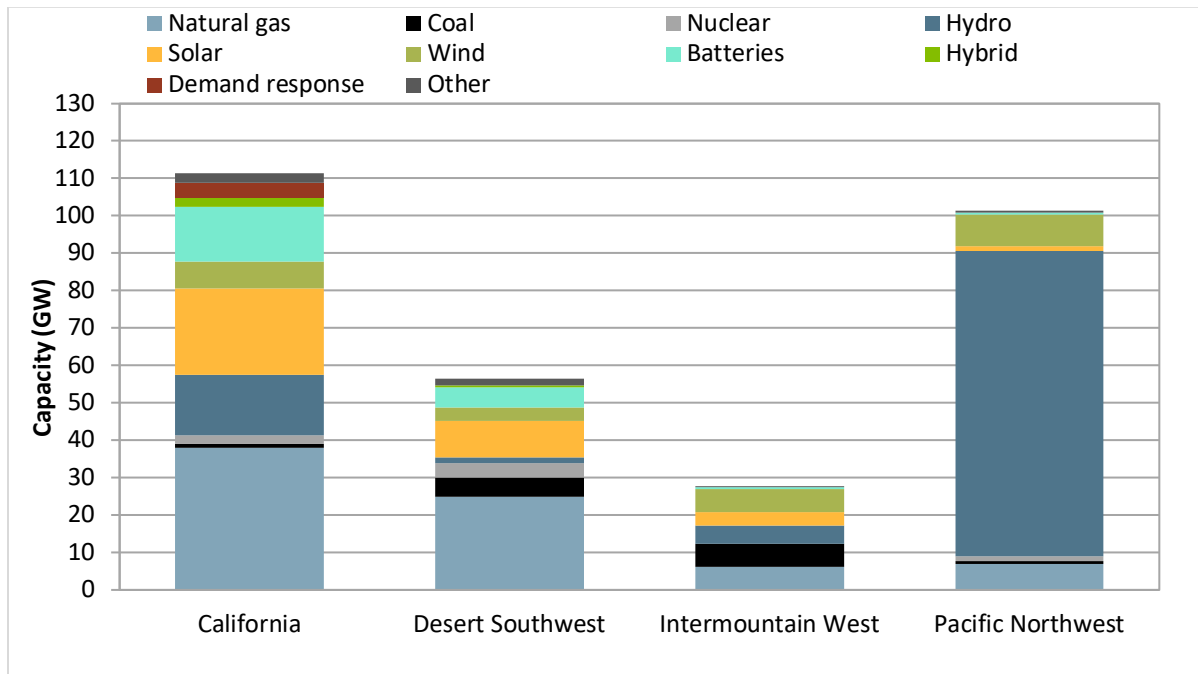
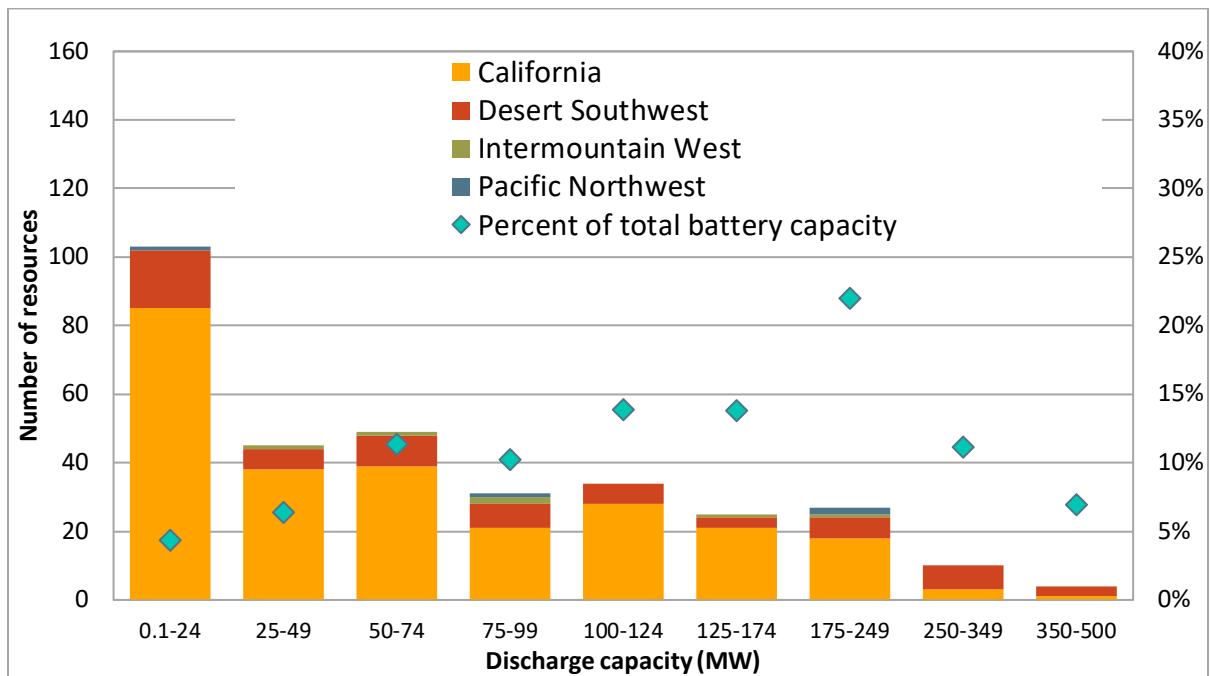


The share of batteries has increased relative to other generation resources in recent years in most areas of the ISO market footprint. Figure 2.3 shows the total nameplate capacity of all generation by region as of April 2026. The balancing areas are divided into four geographical regions:

- **California:** includes all balancing areas in California: California ISO (CAISO), the Balancing Authority of Northern California (BANC), Los Angeles Department of Water and Power (LADWP), and Turlock Irrigation District (TIDC).
- **Desert Southwest:** includes Arizona Public Service (AZPS), El Paso Electric (EPE), NV Energy (NEVP), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric (TEPC), and WAPA-Desert Southwest.
- **Intermountain West:** includes Avista Corporation (AVA), Idaho Power Company (IPCO), NorthWestern Energy (NWMt), and PacifiCorp East (PACE).
- **Pacific Northwest:** includes Avangrid Power (AVRN), Bonneville Power Administration (BPA), PacifiCorp West (PACW), Portland General Electric (PGE), Powerex, Puget Sound Energy (PSE), Seattle City Light (SCL), and Tacoma Power (TPWR).

In April 2026, the share of nameplate generation capacity belonging to batteries was 14 percent in the California region, 14 percent in the Desert Southwest, 5 percent in the Intermountain West, and 0.5 percent in the Pacific Northwest. In comparison, the share of battery capacity in 2025 was 13 percent for the California region, 10 percent for the Desert Southwest, 2 percent for the Intermountain West, and 0.5 percent in the Pacific Northwest.

The size of active batteries varies widely, ranging from 470 kW to 500 MW. Figure 2.4 shows the size distribution of active battery resources by region, along with the percentage of active battery capacity represented by each histogram bin. Most batteries in the ISO market footprint have a duration of around four hours.

Figure 2.3 Total nameplate capacity by region as of April 1, 2026⁴**Figure 2.4 Histogram of battery sizes**

⁴ Values for 2020 through 2024 show capacity as of June 1 of the respective year. The value for 2025 shows capacity as of January 1.

2.4 Energy bids and prices

With the ISO's non-generator resource model, batteries submit a single energy bid curve, which reflects both willingness to charge and discharge. Battery resources do not submit energy price bids solely based on the actual costs of providing energy. Rather, they also consider the *opportunity costs* of discharging or charging in one particular part of the day. For example, discharging energy during low-demand hours may preclude batteries from discharging during high-demand hours. The difference in market prices between low-demand and high-demand hours can represent an opportunity cost of discharging in lower priced hours.

Batteries participating in California's resource adequacy (RA) program are subject to must-offer obligations, meaning they are required to bid their entire upward RA capacity into the market. These resources tend to manage opportunity cost through their bid prices, rather than by limiting the quantity of their bids. For example, to avoid being dispatched when market prices are low, batteries may submit bid prices to discharge that greatly exceed the prices they paid to charge, especially in earlier hours of the day. Conversely, batteries may submit excessively low downward energy bids to avoid charging in certain hours.⁵

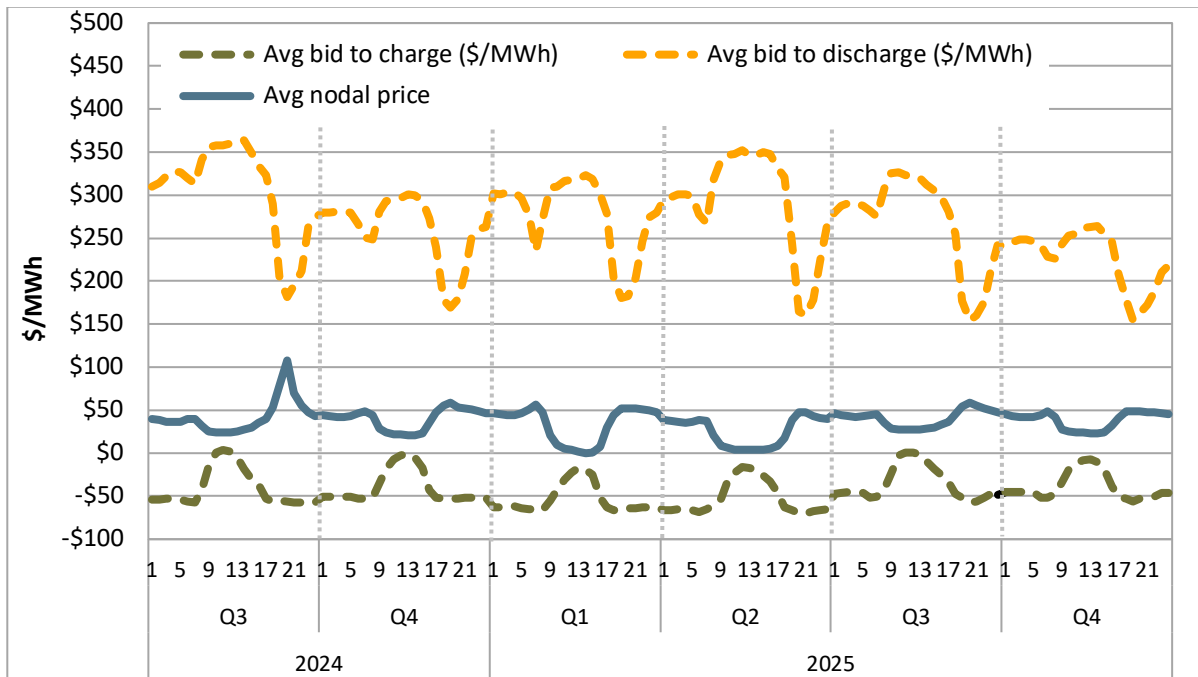
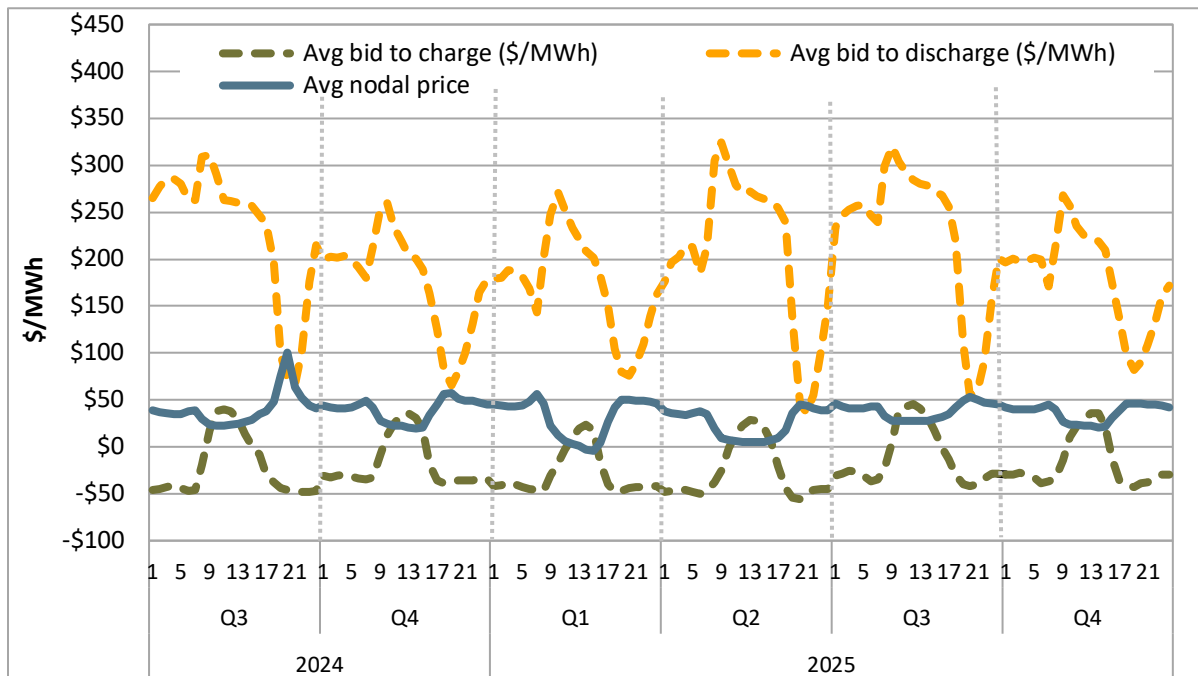
Figure 2.5 and Figure 2.6 show average energy bids of battery resources in the CAISO balancing area compared to average nodal prices by quarter in both the day-ahead and real-time markets, respectively.⁶ As shown in Figure 2.5, the spread of average energy bids remained high throughout 2025 in the day-ahead market. Average bid prices to charge were \$80 lower and bids to discharge were \$232 higher than the nodal price, with an average bid price spread of \$312.

Figure 2.6 shows average real-time bids of battery resources for the portion of a resource's dispatch range that is available to the real-time market (i.e., operating range that is not covered by real-time self-schedules or day-ahead ancillary service awards held in real-time). The average price spread in battery bids in the real-time market decreased from \$223/MWh in 2024 to \$219/MWh in 2025.

In both the real-time and day-ahead markets, batteries expressed their highest willingness to charge in the afternoon during peak solar production hours, when nodal prices are lowest on average. Batteries submitted their lowest discharging bids for peak demand hours, when their opportunity cost for discharging is lowest.

⁵ Currently, only batteries with flexible resource adequacy capacity are subject to must-offer requirements on their downward capacity (i.e., to charge).

⁶ Both bids and nodal prices are weighted average values, weighted by the bid quantity at each price and location.

Figure 2.5 Hourly average day-ahead bids and nodal prices (by quarter)**Figure 2.6** Hourly average real-time battery bids and nodal prices (by quarter)

Balancing areas strictly in the real-time market participate through a combination of base schedules (i.e., submitted generation quantities that are not moved by the market optimization) and real-time market bids. Figure 2.7 shows these WEIM batteries' average hourly 15-minute market bid quantities by price range, as well as base schedules submitted in excess of bid-in quantities (labeled "Base over bid") in Q3 2025. Batteries may base schedule capacity in larger quantities than they bid into the market, or participate solely through base schedules. However, this bidding strategy is uncommon, and therefore the "Base over bid" category in Figure 2.7 is negligible for Q3 2025. The black dotted line in Figure 2.7 represents average total battery capacity participating in the market, and the distance between the black dotted line and the top of the bars represents capacity neither bid into the market nor base scheduled in a given hour. Some of this excess capacity may be reserved to provide a balancing area's ancillary services or available balancing capacity.

Figure 2.8 shows the average of all batteries' submitted 15-minute market bids by price range in each hour in Q3 2025. Though some battery discharging capacity was bid in at the \$1,000/MWh price cap throughout the day, most was bid in at lower than \$100 across all hours, on average.

Figure 2.9 compares 15-minute market battery aggregated bids during the first interval of hour-ending 12 across several days. March 15, March 25, and August 21, respectively, represent the lowest, median, and highest fifteen-minute market evening load in 2025. Load statistics shown in Figure 2.9 and Figure 2.10 represent peak combined load in California and Desert Southwest balancing areas on the respective days. Similar to those in DMM's real-time market bid-cost markup analysis, these bid curves show all incremental energy bids, including charging bids.⁷ As such, they may be interpreted as battery resources' willingness to discharge energy or reduce charging.

Figure 2.10 shows 15-minute market battery aggregated bid curves during hour-ending 19 across the same days. Batteries across the ISO market footprint increased bids for their highest discharging levels to reflect expectations of high prices in hour-ending 19. In 2025, gas, coal, and storage resources provided most of the incremental bid-in supply in the range of \$0/MWh to \$100. DMM estimates storage and hybrid resources set market prices as the marginal resource in 37 percent of intervals.⁸

⁷ 2025 Annual Report on Market Issues and Performance, Department of Market Monitoring, June 26, 2026, pp 156–160: <https://www.caiso.com/documents/2025-annual-report-on-market-issues-and-performance.pdf>

⁸ Ibid., 159.

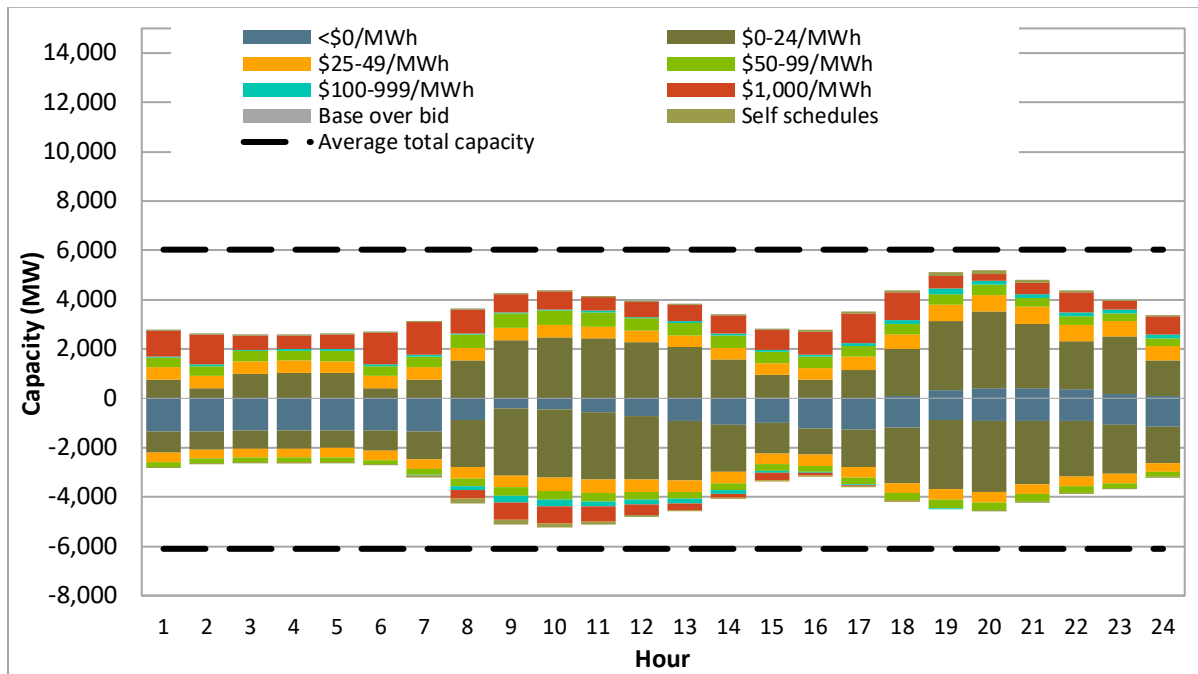
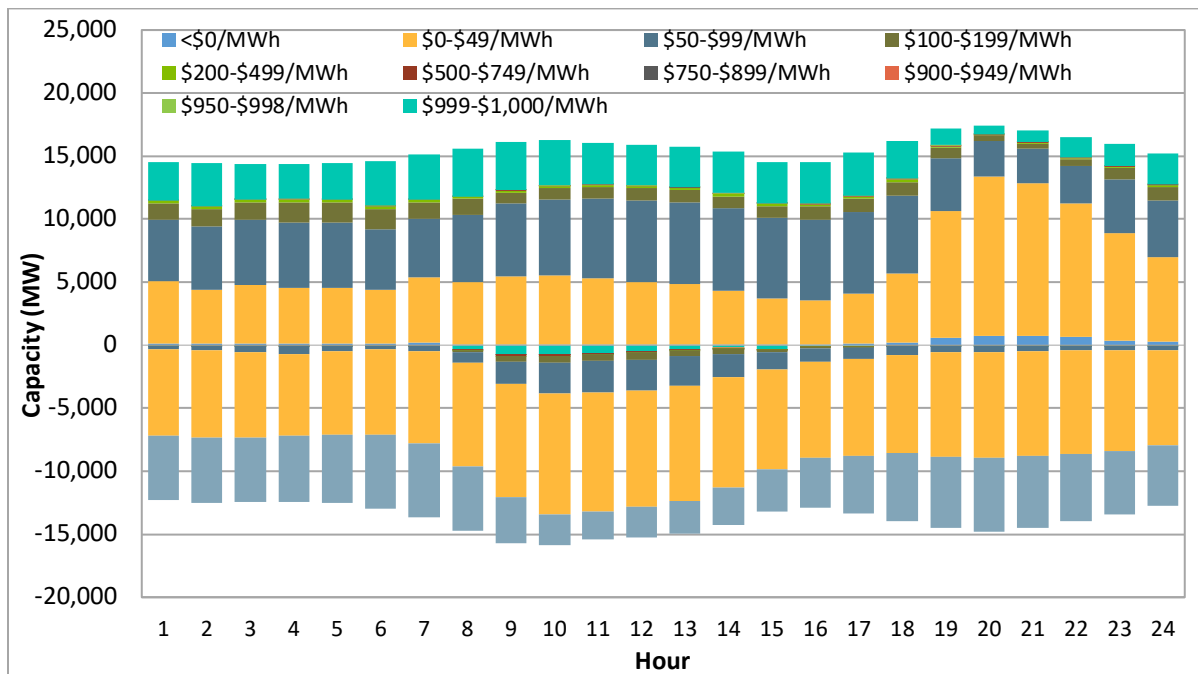
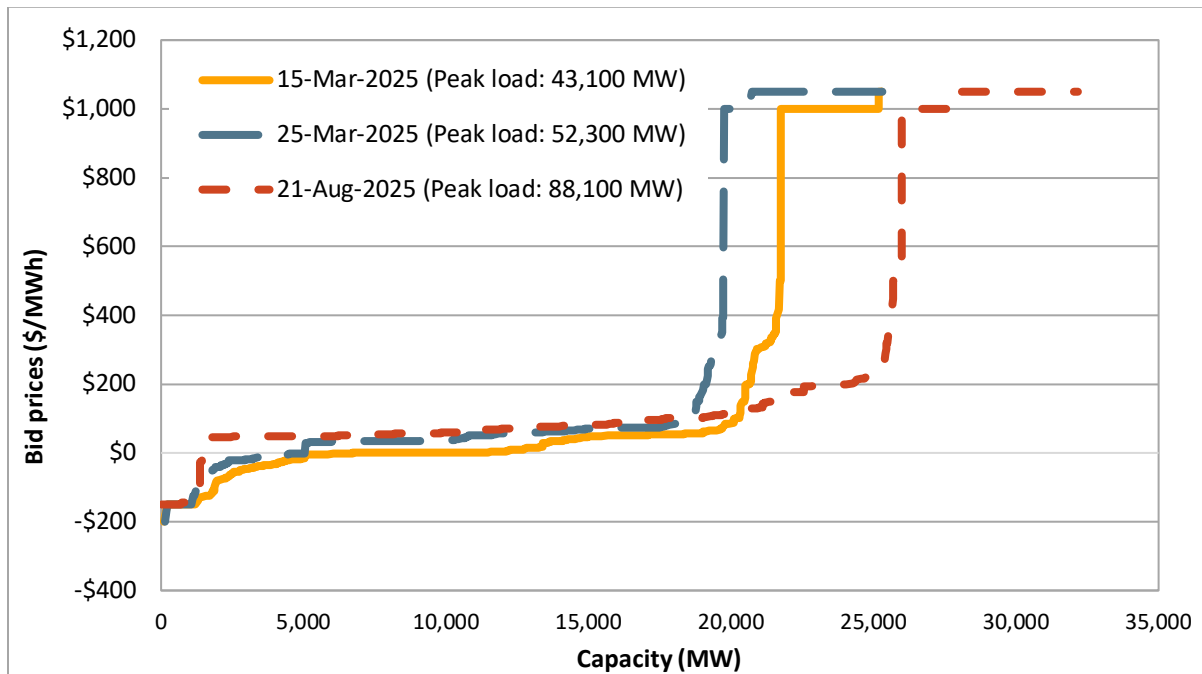
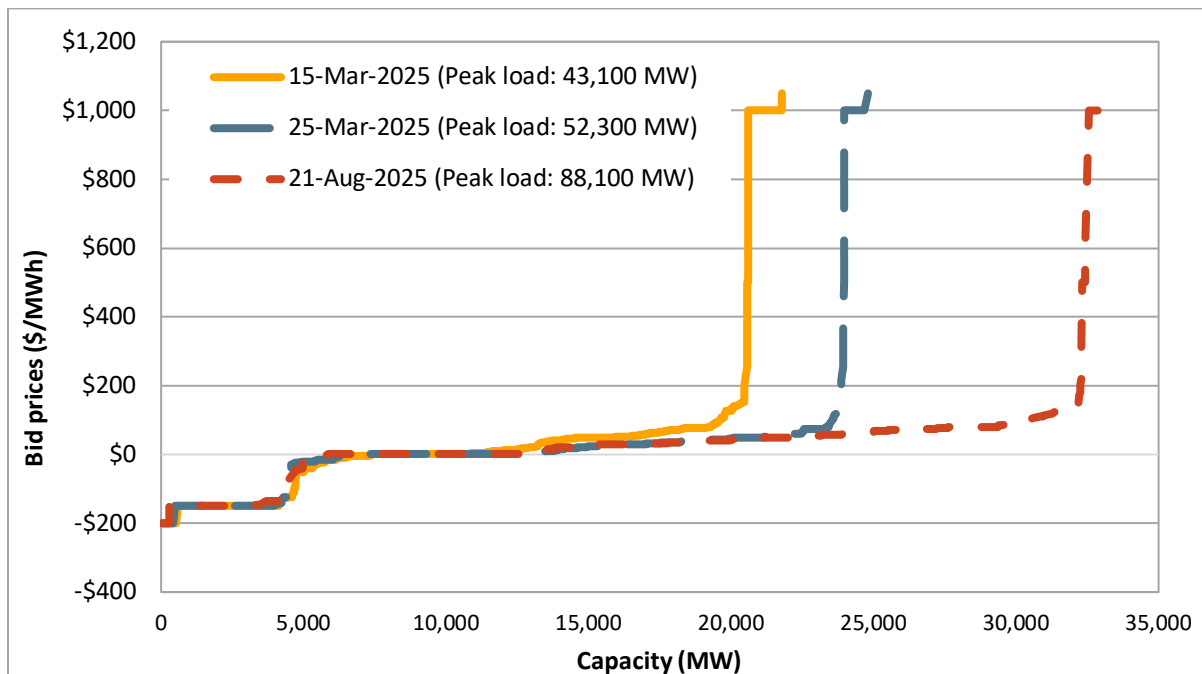
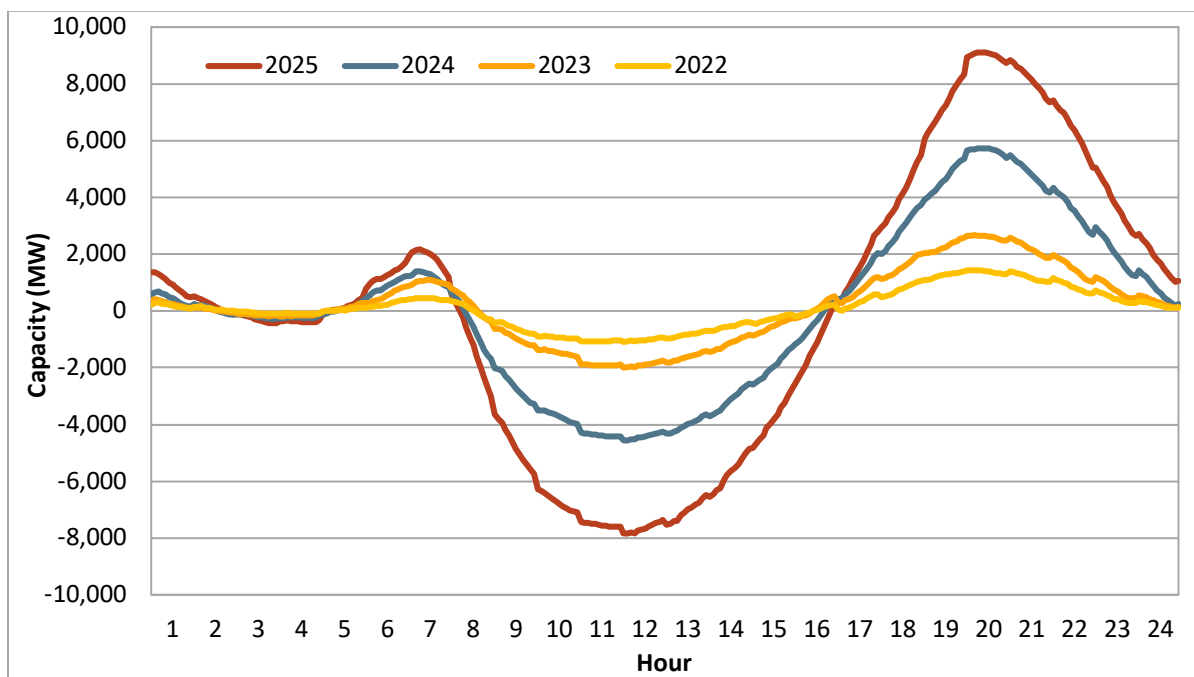
Figure 2.7 WEIM battery bid stack (Q3 2025)**Figure 2.8 15-minute market average bid stack in Q3**

Figure 2.9 15-minute market bid curve comparison for 11:00 AM**Figure 2.10 15-minute market bid curve comparison for 6:00 PM**

2.5 Battery schedules

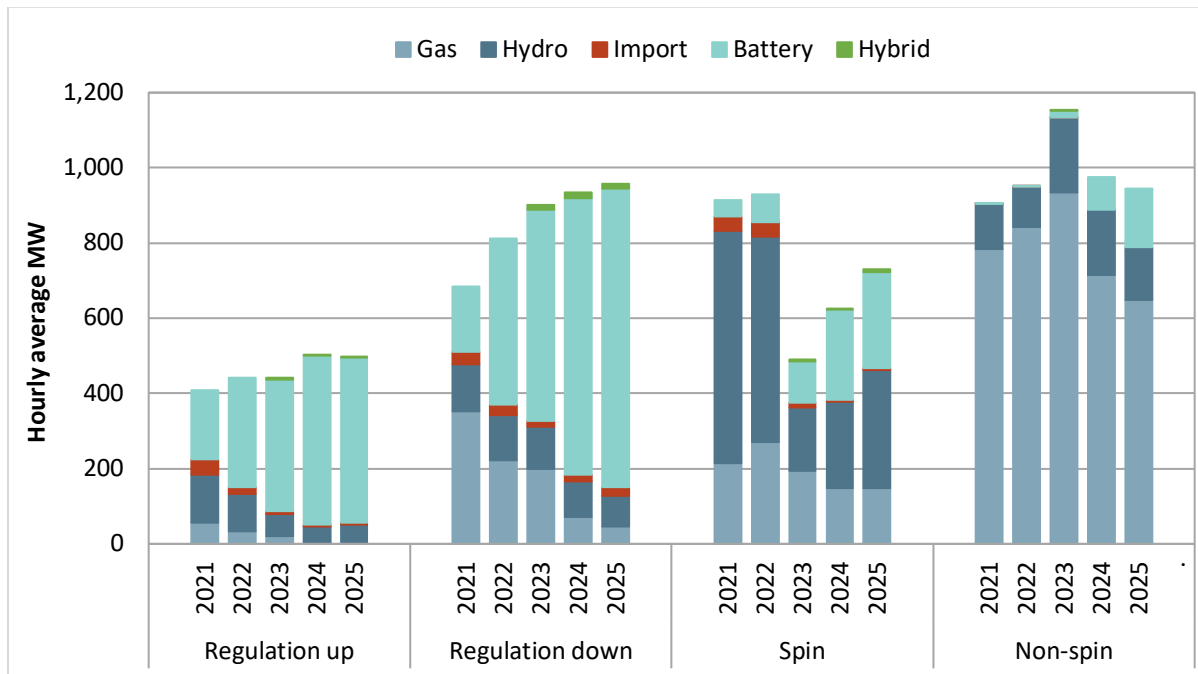
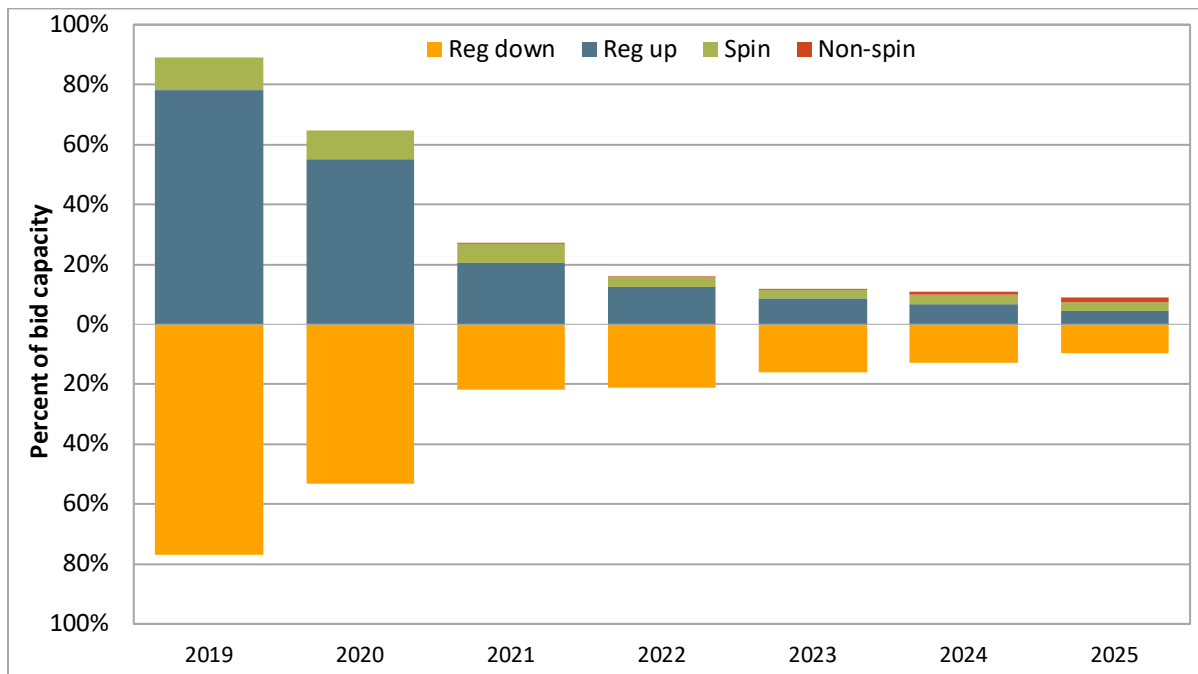
Figure 2.11 shows average battery energy schedules in the 5-minute market from 2022 to 2025, where points below the zero axis represent charging and points above represent discharging. The average energy output from batteries peaked at about 9,100 MW during hour-ending 19 in 2025, compared to a peak of 5,700 MW in 2024. During hours-ending 18 to 22, batteries supplied an average of 15 percent of California balancing area load, 11 percent for the Desert Southwest, 3 percent for the Intermountain West, and 1 percent for the Pacific Northwest.

Figure 2.11 Average 5-minute battery energy schedules



In addition to energy, batteries can provide all ancillary services. Initially, batteries favored providing ancillary services, especially frequency regulation, because it allows them to avoid deep charging and discharging cycles which cause rapid cell degradation. Batteries in the CAISO balancing area consistently offer many times more regulation than the market requires. The ISO market only procures ancillary services for the CAISO balancing area.

As shown in Figure 2.12, batteries provided most of the CAISO balancing area's regulation in 2025, at nearly 85 percent. In recent years, battery capacity has grown faster than ancillary service requirements. As a result, the portion of total battery capacity scheduled for ancillary services has declined. Figure 2.13 shows how the percentage of battery capacity scheduled for ancillary services has decreased as battery capacity has grown.

Figure 2.12 Average ancillary service procurement by resource type**Figure 2.13 Percent of CAISO battery capacity scheduled for ancillary services**

Battery resources are also frequently scheduled to provide flexible ramping capacity (FRP), a product designed to manage volatility and uncertainty of real-time imbalance demand. Figure 2.14 shows the percentage of upward and downward flexible ramping capacity procured by batteries by month in the 15-minute market.

Figure 2.14 15-minute flexible ramping product procured from batteries (2025)

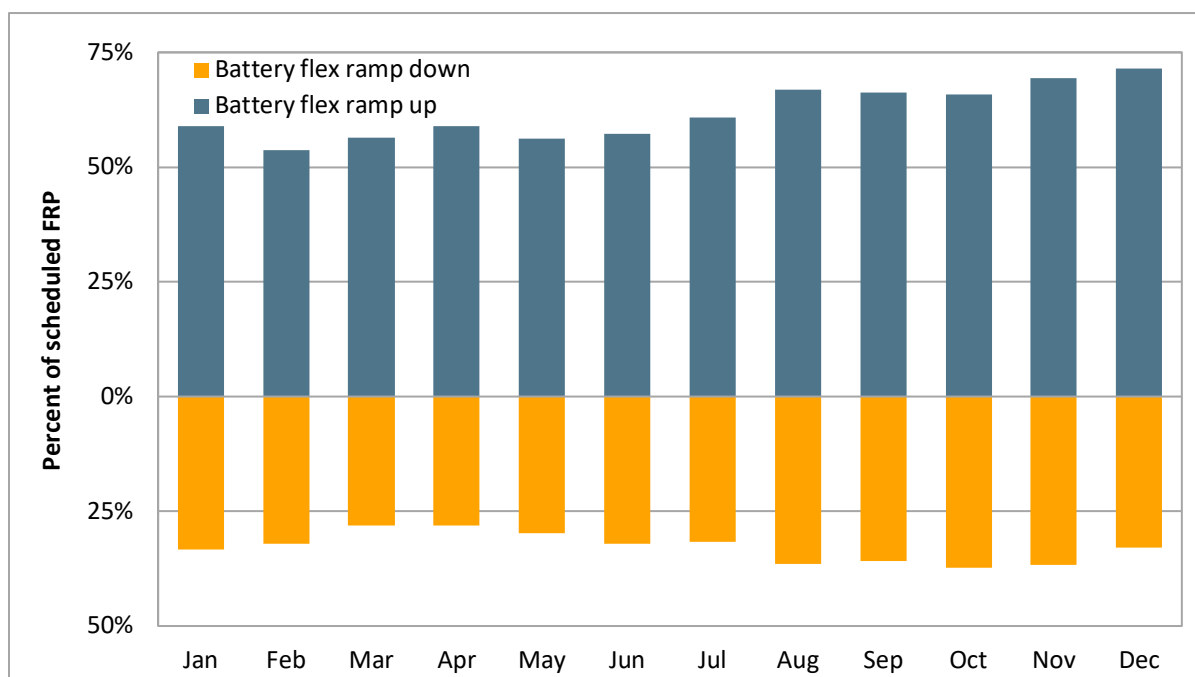


Figure 2.15 shows average hourly real-time (15-minute market) schedules of all battery storage resources in the CAISO balancing area in 2025. Batteries provide much of the CAISO balancing area's regulation down capacity when requirements are the highest during peak solar production hours of the afternoon. During these same periods, batteries represent a significant amount of the system's energy demand. Figure 2.16 compares battery charging in the 5-minute market with average 5-minute market load by region in 2025. From hours-ending 10 to 13 in 2025, battery charging represented around 10 percent of load in the ISO market footprint.

Figure 2.17 shows average 15-minute CAISO BA battery schedules as a percentage of participating capacity in each hour from 2024 to 2025. This figure highlights the continued shift from providing ancillary services towards arbitraging energy.

As shown in Figure 2.18, batteries participating in the WEIM have similar schedules to batteries in the CAISO balancing area (i.e., primarily charging in the morning and early afternoon hours, then discharging in the evening). However, WEIM batteries do not have ancillary service schedules, since ancillary services are not procured through the market in WEIM balancing areas.

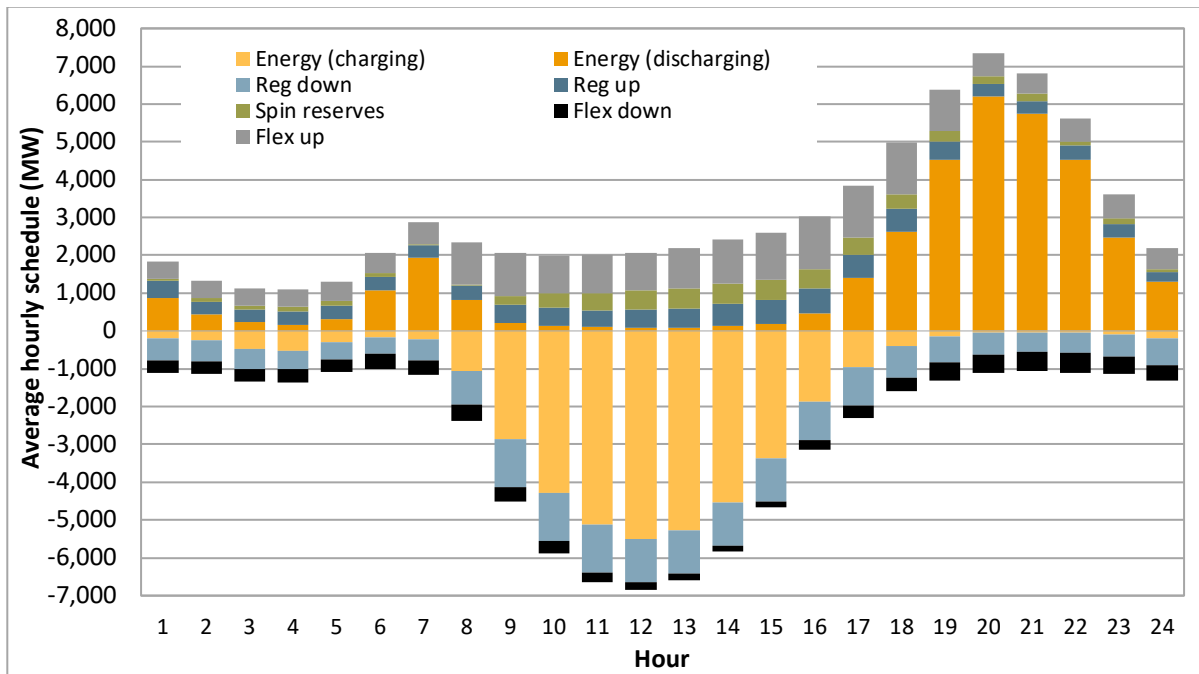
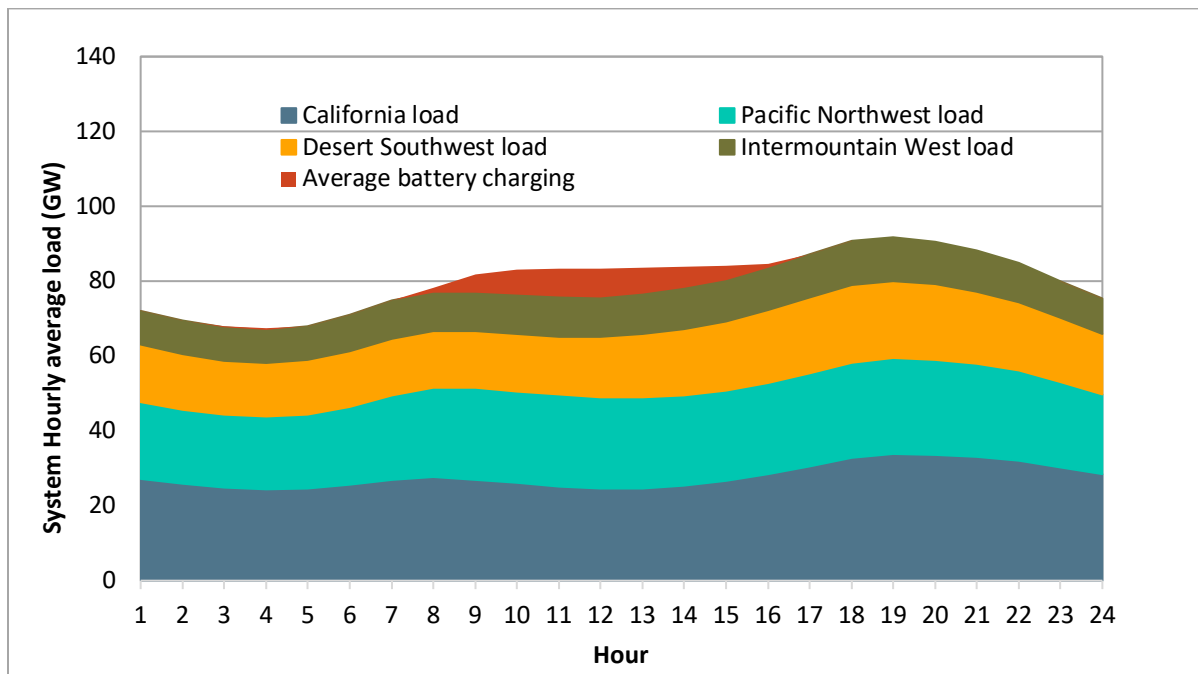
Figure 2.15 Average hourly CAISO battery schedules by product (2025)**Figure 2.16 5-minute market battery charging and average load by region (2025)**

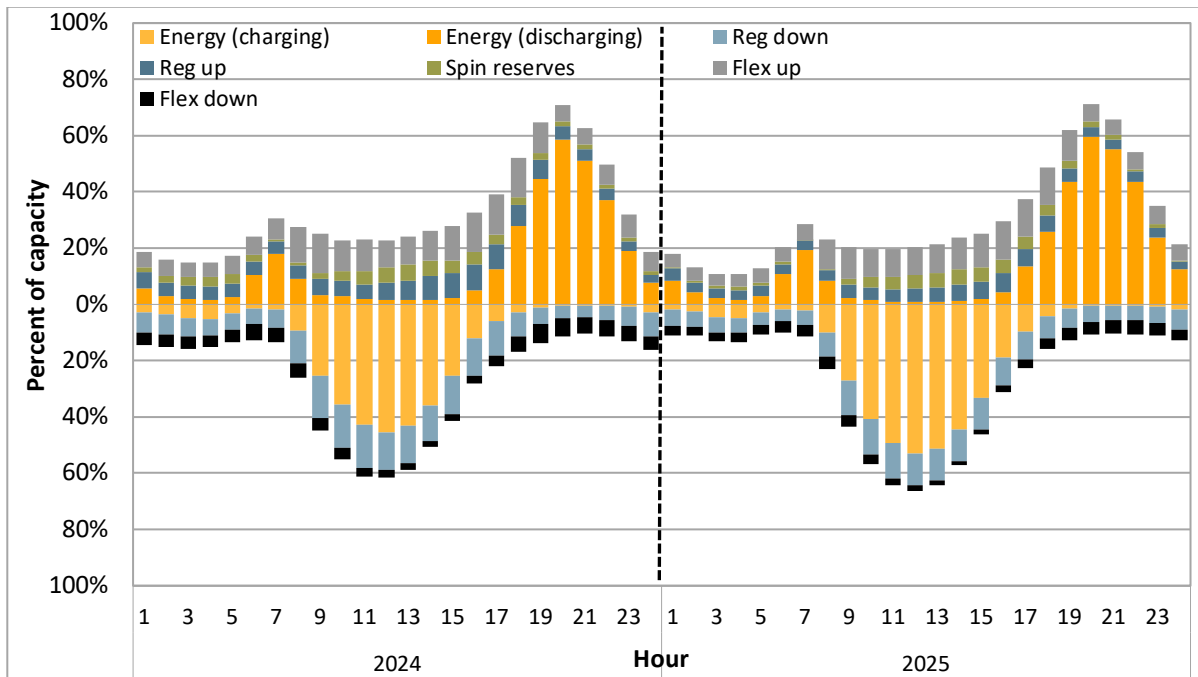
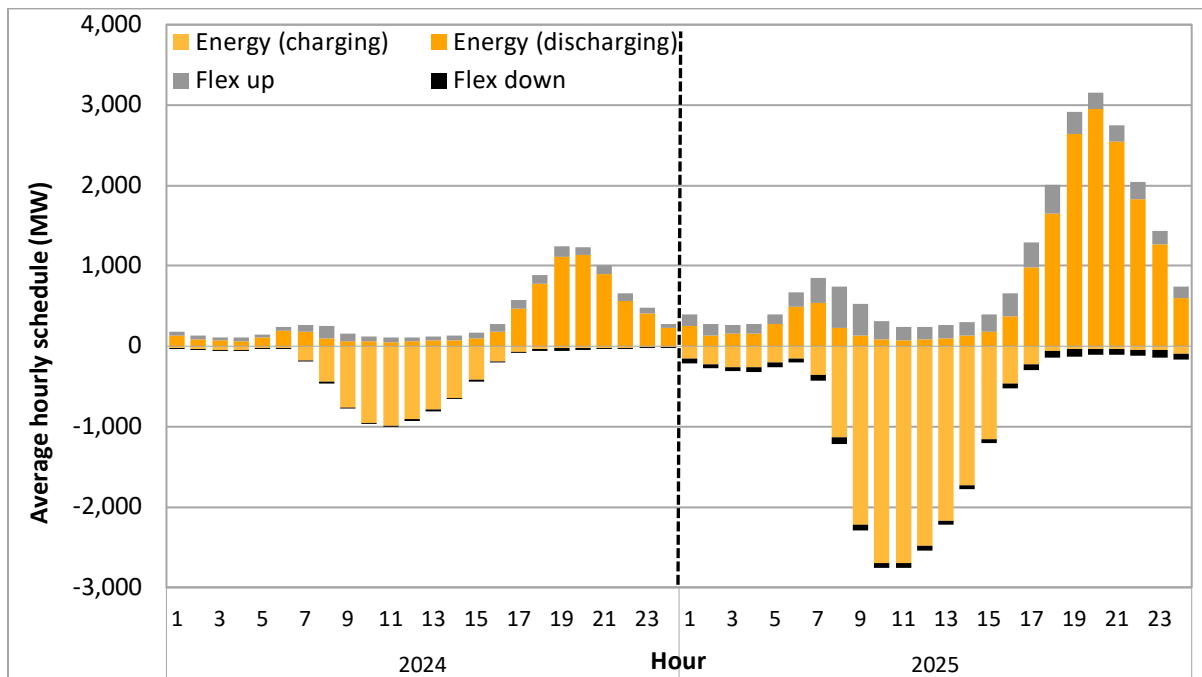
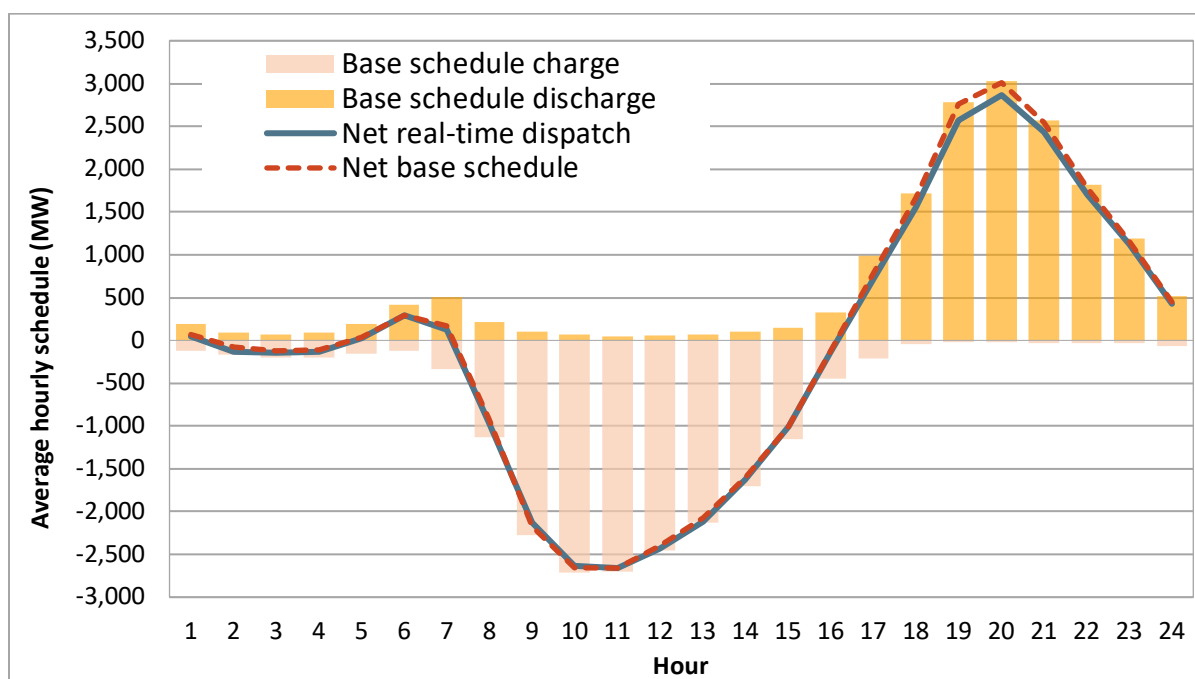
Figure 2.17 Scaled average 15-minute CAISO battery schedules (2024–2025)**Figure 2.18 Non-CAISO BA average hourly battery schedules (2024–2025)**

Figure 2.19 compares average base schedules and net 5-minute market schedules for batteries participating in the WEIM. Notably, the real-time dispatch of WEIM battery capacity was lower than base schedules in the evening, averaging about 130 MW less during hours-ending 19 through 22. As shown in Figure 2.7 WEIM batteries tend to increase discharge bid quantities in the evening and often bid at prices well above locational marginal prices (LMPs). As a result, more batteries were decremented below base schedules in these hours.

Figure 2.19 Average base schedules and real-time dispatch of participating batteries in 2025



2.6 Co-located battery resources

Co-location framework allows the ISO to model multiple resources participating at a single point of interconnection. Resources in co-located facilities submit separate energy bid curves, have separate metering arrangements, submit separate outages, receive separate dispatch instructions, and may be operated by different entities.

Though there are benefits for batteries co-locating with renewable resources, resources co-located together do not necessarily need to use different generation technologies. As of January 1, 2026, six out of all 87 sets of co-located resources have a single generation technology. Around 95 percent of co-located interconnections have at least one battery and batteries represent nearly 39 percent of total co-located capacity.

One benefit of the co-located model is that shared infrastructure between co-located facilities can reduce equipment, interconnection, and permitting costs. In 2022, the National Renewable Energy Laboratory (NREL) estimated that the cost of co-locating storage with photovoltaic solar systems is 7

percent lower than siting these units separately.⁹ In addition, co-located resources with renewable and storage components have historically been able to benefit from a federal investment tax credit, which could offset up to 30 percent of investment costs. The 2022 Inflation Reduction Act extended the investment tax credit for stand-alone energy storage.¹⁰ In California, some co-located storage and renewable resources also benefit from county property tax incentives.

Co-located batteries also differ from stand-alone batteries in that they are subject to several special market constraints. One of these is the aggregate capability constraint (ACC), which ensures that dispatch instructions to co-located resources behind a common point of interconnection do not exceed interconnection limits. The ACC can also restrict frequency regulation awards.

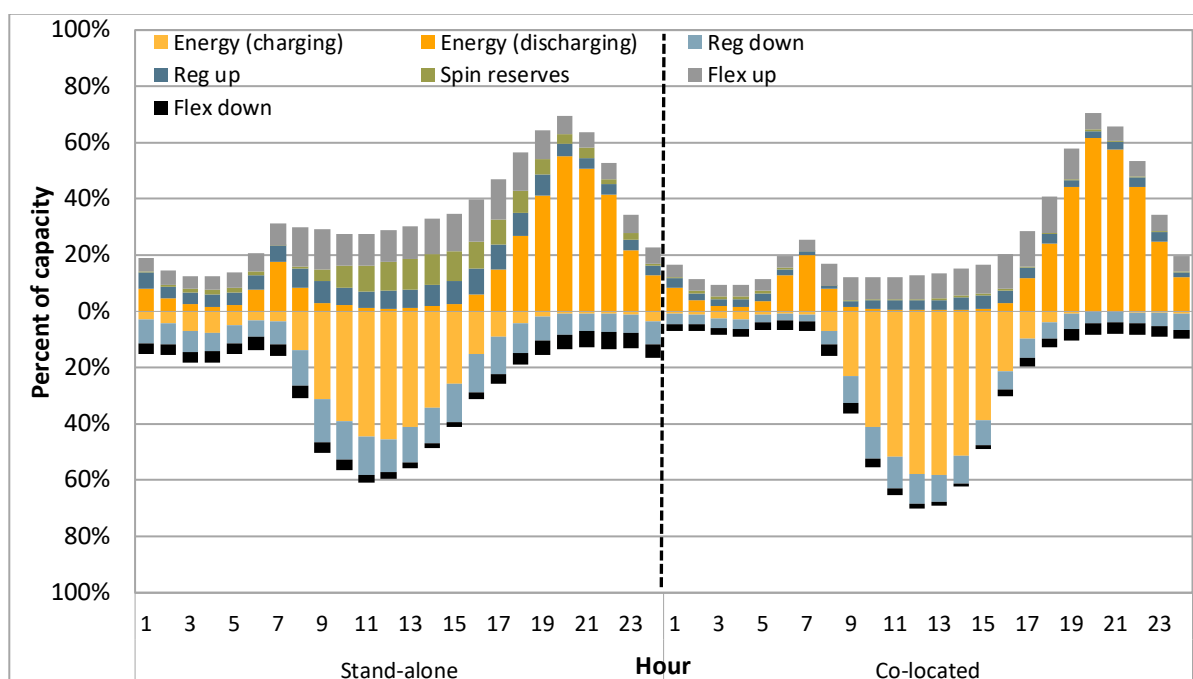
As of November 2023, co-located batteries have access to an hourly electable parameter that prevents them from grid charging. This new constraint was meant to help co-located batteries capture federal investment tax credits and local property tax benefits by allowing them to restrict charging when their renewable facilities weren't producing energy. The maximum observed hourly amount of co-located battery capacity that restricted grid charging was 872 MW in 2025.

Figure 2.20 shows average hourly real-time schedules for active co-located batteries (not including hybrids with battery components) compared to that of active stand-alone battery resources, scaled by total capacity from active batteries. On average, co-located batteries supply more energy and less ancillary services than stand-alone batteries per MW of capacity. Co-located batteries tend to profit more from energy arbitrage than stand-alone batteries due to lower afternoon prices driven by nearby solar generation.¹¹

⁹ *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, National Renewable Energy Laboratory, September 2022, p 50: <https://docs.nrel.gov/docs/fy22osti/83586.pdf>

¹⁰ Title 26—Internal Revenue Code Section 48E, *Clean electricity investment credit*, April 15, 2025: <https://uscode.house.gov/view.xhtml?req=granuleid:USC-prelim-title26-section48E&num=0&edition=prelim#sourcecredit>

¹¹ *2024 Special Report on Battery Storage*, Department of Market Monitoring, May 29, 2025, pp 22-23: <https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf>

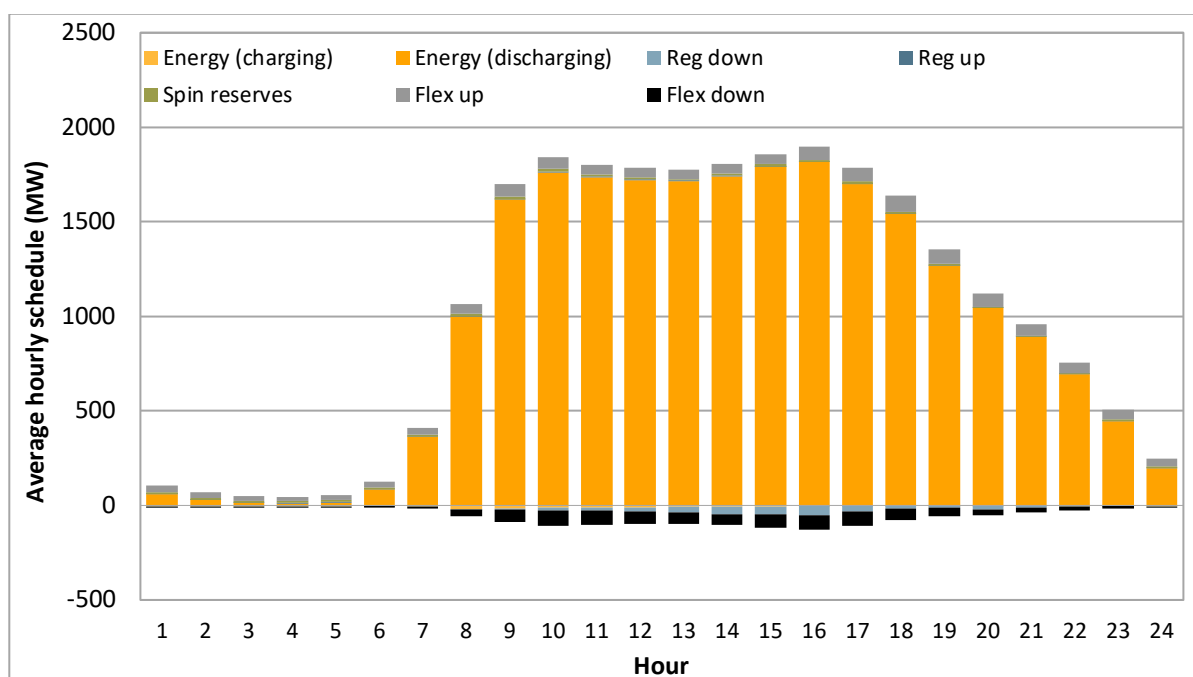
Figure 2.20 Average hourly schedules: co-located versus stand-alone batteries

2.7 Hybrid battery resources

Hybrid battery resources are batteries combined with a generation resource (usually solar) which choose to be modeled as single resource. Hybrid resources have a single bid curve that applies to all their component parts and receive one dispatch instruction from the ISO. The hybrid resource operator self-optimizes the components of its resource to meet that dispatch instruction. As of December 2025, there were 43 actively participating hybrid resources with battery technology in the ISO market footprint.

Figure 2.21 shows average hourly 15-minute market schedules of all active hybrid resources in 2025. Hybrids differ from battery-only resources in that most of their energy schedules occur during the afternoon when solar is abundant. Then, in the evening when solar is unavailable, hybrids can still discharge energy that they have stored in battery components during the day.

In 2025, 96 percent of registered hybrids participated as non-generating resources (NGRs). However, only around 42 percent of these resources had the operational capabilities which would make them eligible to charge from the grid. In 2025, hybrids received very few market awards to charge from the grid and mostly charged from on-site renewables.

Figure 2.21 Average hourly hybrid battery resource schedules

Whereas the ISO manages the efficient dispatch of individual co-located renewable and storage resources using tools such as renewable forecasts and state-of-charge tracking, hybrids self-optimize generation across their different components. Though hybrids have discretion in how they manage their generation, the resource operators are still required to respond to dispatch instructions from the ISO. Hybrid resources are required to manage their state-of-charge such that they have sufficient headroom (either upward or downward) to fulfill their ancillary service awards.

In February 2023, the ISO implemented dynamic limits, a tool for hybrids to communicate their operational capabilities in real time. The ISO requires hybrid operators to update their upper and lower dynamic limits—representing the minimum and maximum MW value they can operate at—for every 5-minute real-time market interval where they have an economic bid, for a rolling six-hour look-ahead period. The real-time market treats these inputs as constraints, such that the resource will not be dispatched outside of the dynamic limits.

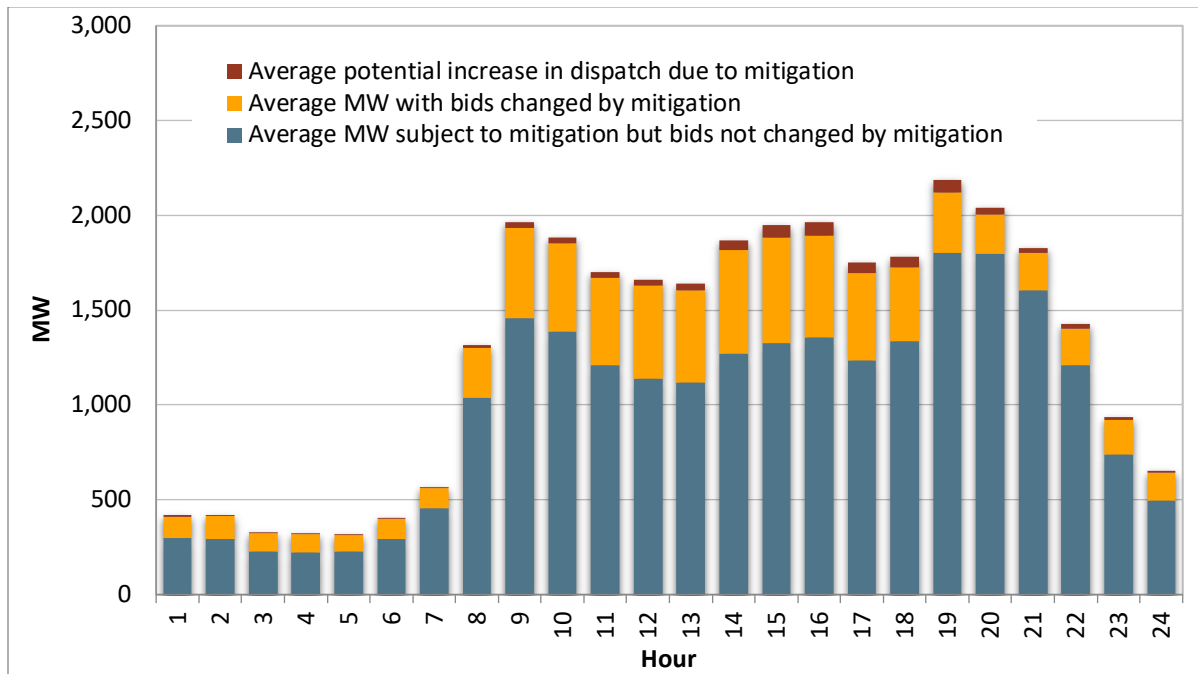
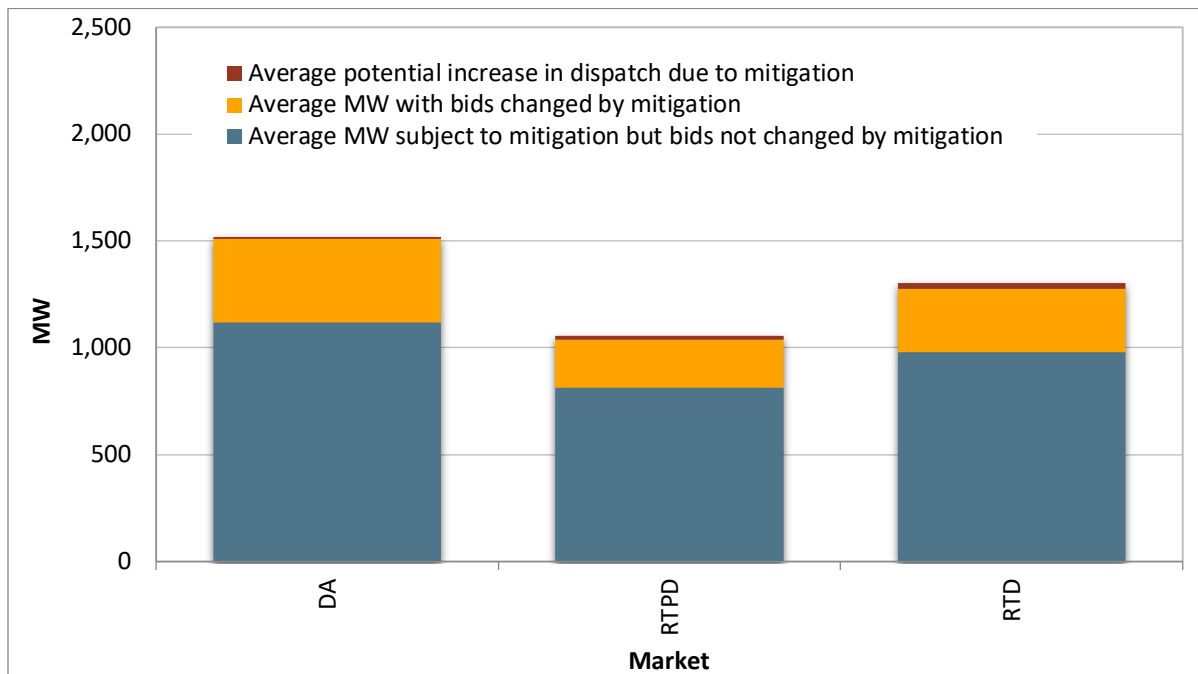
2.8 Local market power mitigation

As part of its day-ahead and real-time market processes, the ISO includes local market power mitigation (LMPM), an automated procedure meant to ensure that resources are providing energy at or near their cost of production. Beginning in November 2021, battery resources using the NGR model became subject to mitigation. Storage resources with 5 MW or less of capacity, and whose parent company is not a net-supplier in the ISO market, are exempt from mitigation. As with all resource types, batteries are subject to mitigation based on when they can provide counterflow to relieve congestion on a binding non-competitive transmission constraint.

Unlike other resource types, battery resources modeled as NGR may bid negative MW for charging, and are therefore subject to mitigation of both negative and positive bid segments. A resource can potentially withhold counterflow to a non-competitive constraint by submitting a high bid to charge when it may be uneconomic to do so. When the resource is mitigated, the charging bid can be lowered, resulting in the battery not receiving a market charging award. When charging is not awarded, flow on the non-competitive constraint is reduced.¹²

Figure 2.22 shows average hourly mitigated battery capacity in the 5-minute market in 2025 broken out into three categories: capacity subject to mitigation where bids were not changed, capacity with bids changed by mitigation, and the potential increase in dispatch due to mitigation. Average potential increase in dispatch due to mitigation peaked in hour 16 of the 5-minute market at 72 MW. Figure 2.23 shows average battery mitigation by market across all hours in 2025. Average capacity with bids changed by mitigation was 392 MW in the day-ahead market, 226 MW in the fifteen-minute market, and 296 MW in the 5-minute market. Average potential increase in dispatch due to mitigation across all hours in 2025 was 10 MW in the day-ahead market, 16 MW in the 15-minute market, and 29 MW in the 5-minute market.

¹² Battery storage resources could also potentially exercise market power in future intervals by submitting very low charging bids to prevent charging in the current interval. This could result in the battery being unable to discharge in a future interval when it has local market power in that interval. Mitigation of these bids would involve increasing charging bids to a level higher than submitted. This type of mitigation does not currently exist in the ISO market.

Figure 2.22 Hourly average 5-minute market battery mitigation (2025)**Figure 2.23 Average battery mitigation by market (2025)**

2.8.1 Default energy bid for CAISO balancing area batteries

As with other resource types, battery bids are only changed during the LMPM processes if a resource has bid higher than their default energy bid (DEB) and the competitive locational marginal price (LMP) at the resource's location. Batteries in the CAISO balancing area, or in any balancing area participating in the extended day-ahead market as of May 1, 2026, can choose a "storage option" for their DEB calculation.¹³ As of December 2025, around 91 percent of active CAISO balancing area batteries that are subject to LMPM had opted for the storage DEB. The day-ahead and real-time market storage DEBs are calculated using Equation 2.8.1.

Equation 2.8.1 Storage default energy bid formula

$$DEB = \text{Max} \left\{ \text{Max} \left(\frac{En_{\partial}}{\eta}, 0 \right) + \rho, OC_{\gamma} \right\} * 1.1$$

Where:

En:	Energy cost
∂ :	Energy charging duration
γ :	Energy discharge duration
η :	Round-trip efficiency
ρ :	Variable storage operation cost
OC:	Price-based opportunity cost

The energy cost component of the storage DEB is calculated under the assumption that the resource performs one cycle of charging and discharging per day, and that it will charge during the least expensive continuous block of time during the day. Resources may have individualized variable operation costs, which are validated by the ISO. These costs often reflect a conservative estimate of potential cell degradation costs that may be incurred should the battery cycle multiple times per day.

The storage DEB includes a priced-based opportunity cost parameter which is meant to prevent mitigated batteries from being dispatched at a time that is not profit-maximizing over the day. The opportunity cost component for a given resource is set to the Nth highest LMP for a trade date, where N equals the discharge duration of the resource in hours. For most storage resources (which have a four-hour discharge duration), the opportunity cost is based on the fourth highest day-ahead LMP. Whereas the real-time storage DEB uses day-ahead prices for the corresponding trade date to calculate the opportunity cost parameter, the day-ahead market uses advisory prices from the day-ahead LMPM process.

In 2024, the California ISO introduced a stakeholder initiative to consider changes to storage modeling, including the storage DEB. DMM has noted that the accuracy of the current real-time storage DEB as an estimate of opportunity cost is limited since it is a static value in each trade date based on day-ahead prices.

The current storage DEB design may both underestimate costs in pre-peak hours, allowing for potential inefficient dispatch due to mitigation, and overestimate costs during peak hours resulting in more

¹³ *Business Practice Manual Change Management, Market Instruments, Attachment D.9, Storage Default Energy Bid*, California ISO: <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments>

opportunities to exercise market power. In the case of inefficient underestimation of costs, real-time market power mitigation may cause upward dispatch during hours preceding the peak, and result in state-of-charge depletion during those peak-price hours. This effect can be compounded by the real-time market's limited optimization horizon, meaning that peak prices are not considered until one or two hours in advance. As shown by Figure 2.22 and previous analysis, this kind of inefficient mitigation occurs very infrequently.¹⁴ DMM has proposed allowing the storage DEB to vary by hour to better capture real-time conditions and get a more accurate estimate of opportunity cost.¹⁵

One potential enhancement to the current DEB would involve using different scalars in different multi-hour blocks to model changing opportunity costs throughout the day. Under current pricing trends, the DEB would be scaled up in the afternoon, e.g., in hours-ending 11 through 17, then scaled down for the rest of the day. DMM evaluated several such DEB formulations by analyzing the effect of counterfactual mitigation scenarios under the DEB on net market revenues for batteries.¹⁶ In this analysis, battery resources yielded higher net revenues in scenarios with higher scalars. The benefits of higher multipliers diminished after about 1.3 or 1.4. In the ISO's storage design and modeling stakeholder initiative, DMM proposed a storage DEB that includes a time-of-day multiplier equal to 1.4 during the morning and pre-peak hours and equal to 0.8 during and following the peak hours and provided analysis demonstrating this design would balance preventing early dispatch with still providing protection against local market power.¹⁷

2.8.2 Default energy bid for WEIM batteries

Since there are no day-ahead market prices for WEIM areas, DEBs for WEIM batteries must be established under the negotiated rate option of the ISO tariff. All real-time negotiated DEBs that have been implemented for WEIM batteries are based on the same framework as the standard opportunity cost DEB used for batteries in the ISO, but include two modifications:

- **Day-ahead price.** Instead of using each resource's hourly LMP in the day-ahead market, DEBs for WEIM batteries are based on day-ahead default generation aggregation point (DGAP) prices. These DGAP prices are a product of the full-network model and reflect prices for modeled aggregations of generating units (usually aggregated at a balancing area-wide level).
- **Upward adjustment based on recent real-time prices.** To account for any systematic differences between DGAP prices and real-time prices at each WEIM battery's location, DMM

¹⁴ *Analysis of battery bid cost recovery and bid mitigation issues*, Department of Market Monitoring, September 11, 2024: <https://www.caiso.com/documents/presentation-battery-bid-cost-recovery-and-mitigation-data-dmm-sep-11-2024.pdf>

¹⁵ *Comments on Storage Design and Modeling Working Group Session 2 and 3*, Department of Market Monitoring, March 7, 2025: <https://www.caiso.com/documents/dmm-comments-on-storage-design-and-modeling-working-group-sessions-2-and-3-mar-07-2025.pdf>

¹⁶ *Comments on Storage Design and Modeling Working Group Presentation on March 16, 2026*, Department of Market Monitoring, April 3, 2026: <https://www.caiso.com/documents/dmm-comments-on-storage-design-and-modeling-mar-16-2026-working-group-presentation-apr-03-2026.pdf>

¹⁷ *Supplemental Comments on Storage Design and Modeling: Straw Proposal on Default Energy Bids, Uplift, and State-of-Charge Management*, Department of Market Monitoring, August 17, 2026: <https://www.caiso.com/documents/dmm-supplemental-comments-on-the-storage-design-and-modeling-jul-15-2026-working-group-presentation-aug-17-2026.pdf>

includes an upward adjustment to the DGAP prices when calculating negotiated DEBs. This adjustment scales up hourly DGAP prices based on the ratio of (1) the average hourly 15-minute real-time price for the WEIM area over the past three days, and (2) the hourly DGAP price from the ISO's day-ahead model in the corresponding hours.

DMM's analysis of the WEIM storage DEB has shown that the DEB consistently provides enough headroom to prevent the market from inefficiently dispatching these resources such that they would be unable to discharge during high priced periods. In 2025, negotiated DEBs for batteries in WEIM areas were rarely less than the resources' LMPs for more than 4 hours per day.¹⁸ This was primarily a result of the fact that day-ahead DGAP prices were usually higher than WEIM battery LMPs. DMM continues to recommend that the ISO create a standardized DEB for WEIM storage resources that would not require negotiation. Such a DEB could be based largely on the current negotiated formula as recently discussed in the ISO stakeholder process.¹⁹

2.9 Market revenue

2.9.1 Total net market revenues

In 2025, total net market revenue for CAISO balancing area batteries increased by around 2 percent as the result of increases to the battery fleet. However, net annual revenues per kW of battery capacity decreased due to lower peak hour prices in 2025. Figure 2.24 shows weighted average revenue by category for batteries in the CAISO balancing area with a full year of operation. Net market revenue for these resources was \$45/kW-yr in 2025, compared to \$53/kW-yr in 2024, and \$78/kW-yr in 2023.

Figure 2.25 shows quarterly net market revenues for battery resources in the CAISO balancing area by category from January 2024 through December 2025.²⁰ Unlike previous years, total battery revenues were highest in the first and second quarters of 2025. This trend is largely a result of high renewable production driving down prices in the spring and an increase in generation capacity to meet demand and drive down peak prices in the summer.

Net real-time market revenues for batteries outside of the CAISO balancing area were negative overall in 2025, at -\$14.5 million.²¹ WEIM energy settlements are determined by the amount of energy imbalance, i.e., the difference between submitted base schedules and the market output, in the real-time market.

¹⁸ *Supplemental Comments on Storage Design and Modeling Working Group Presentation on March 16, 2026*, Department of Market Monitoring, April 14, 2026: <https://www.caiso.com/documents/dmm-supplemental-comments-on-storage-design-and-modeling-mar-16-2026-working-group-presentation-apr-14-2026.pdf>

¹⁹ *Storage Design and Modeling Revised Straw Proposal on Default Energy Bids*, California ISO, September 17, 2026: <https://stakeholdercenter.caiso.com/StakeholderInitiatives/Storage-design-modeling>

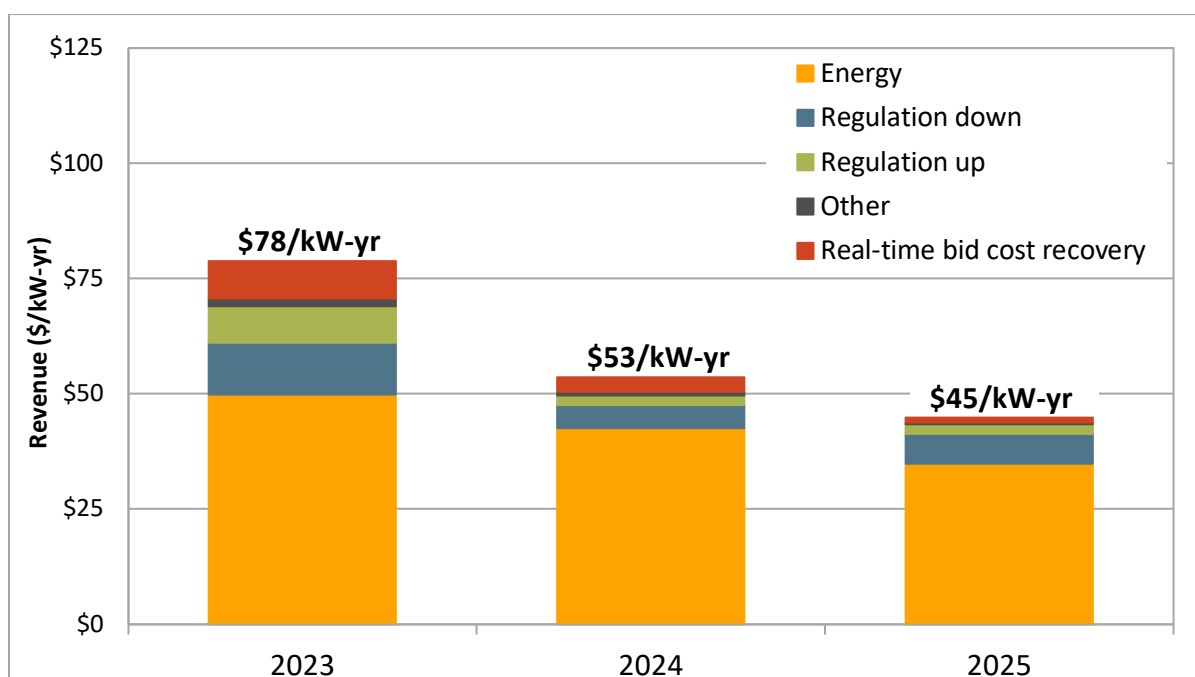
²⁰ The regulation down category contains payments and charges from settlements codes 6600, 6624, 6670, and 7261. Regulation up includes 6500, 6524, 6570, and 7251. Energy includes 6011, 6800, 6824, 6460, 6470, and 6475. Real-time bid cost recovery includes 6620. Other includes codes 6100, 6124, 6170, 7071, 6200, 6224, 6270, 6482, 6488, 7081, 7070, and 6630. More details can be found on the CAISO settlements page: <https://www.caiso.com/market/Pages/Settlements/Default.aspx>

²¹ This figure accounts for invoices related to instructed imbalance energy, uninstructed imbalance energy, bid cost recovery, flexible ramping product, and greenhouse gas emission settlements.

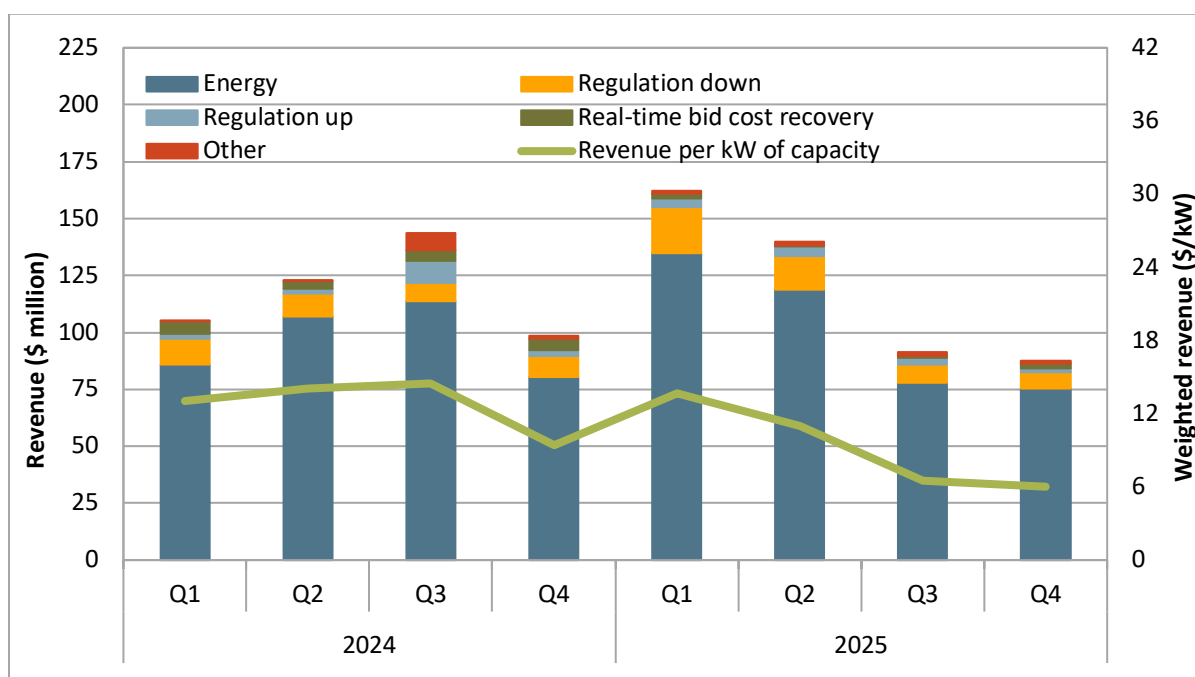
As shown in Figure 2.19 in Section 2.5 of this report, WEIM batteries were often dispatched below base scheduled discharging in the evening when prices are typically highest, leading to significant charges for real-time instructed imbalance energy.

Although settled payments for CAISO and non-CAISO balancing area batteries are not directly comparable, some non-CAISO batteries are well-situated to profit from energy arbitrage. DMM's 2025 market revenue optimization analysis found that hypothetical battery resources fully optimized in the real-time market were most profitable in certain non-CAISO balancing areas, especially those in the Desert Southwest.²² For example, a hypothetical battery with dispatch optimized using El Paso Electric prices earned \$50.2/kW-yr, compared to \$24.8/kW-yr for CAISO NP15 and \$27/kW-yr for CAISO SP15.

Figure 2.24 Average revenue for batteries with a full year of operation



²² 2025 Annual Report on Market Issues and Performance, Department of Market Monitoring, June 26, 2026, p 122: <https://www.caiso.com/documents/2025-annual-report-on-market-issues-and-performance.pdf>

Figure 2.25 Quarterly net market revenues for battery resources (2024–2025)

2.9.2 Bid cost recovery

Generating units are eligible to receive bid cost recovery (BCR) payments if total market revenues earned over the course of a day do not cover the sum of all the unit's eligible bid costs. The main purpose of bid cost recovery for gas and other thermal generators is to alleviate the risk that the net revenues from energy sales will provide insufficient revenue to cover the units' start-up and minimum load costs, incentivizing efficient three-part bidding.

Generating units may also be eligible to receive bid cost recovery if they are dispatched out of merit order (in the current settlement interval) due to the multi-interval optimization, and the associated excess bid costs are not recovered over the rest of the operating day. For example, slower ramping units whose bids are economic in future intervals may be ramped up during intervals when the market price is lower than their energy bid price.

Batteries lack all traditional drivers of bid cost recovery in that they are continuously dispatchable, and therefore do not have startup, shutdown, minimum load, or transition costs. Batteries also do not have most of the operational constraints that current bid cost recovery rules are designed to address (such as minimum on and off times, relatively slow ramp rates, etc.).

Bid cost recovery payments to batteries are extremely low in the day-ahead market. This reflects the fact that batteries have few operational limitations that create a need to schedule batteries out of merit order given the 24-hour optimization timeframe of the day-ahead market. All non-negligible instances of day-ahead bid cost recovery paid to batteries identified by DMM since 2022 have been the result of scheduling coordinator-submitted parameters interacting with the day-ahead optimization to cause uneconomic market dispatches.

Almost all bid cost recovery paid to batteries is in the real-time market. The main limitations on battery dispatch that lead to real-time bid cost recovery payments stem from state-of-charge constraints that limit charging and discharging. For example, when a battery does not have sufficient real-time state-of-charge to deliver a day-ahead market award, the real-time market software may force a battery to forgo charging or discharging out of merit order to “buy back” or “sell back” the day-ahead market award. Under the ISO’s settlement rules, this can lead to payment of real-time bid cost recovery due to the difference between the battery’s bid price and the real-time market clearing price.

DMM and the California ISO’s Market Surveillance Committee (MSC) have noted that the current real-time bid cost recovery design incentivizes inefficient battery bidding behavior by removing batteries’ exposure to real-time prices, and reduces the reliability benefits of these resources.^{23,24} In addition, the bid cost recovery design creates gaming opportunities, especially through manipulation of various biddable parameters used to manage state-of-charge. Gaming concerns are exacerbated by the fact that bid cost recovery payments are partly driven by submitted bid prices, meaning that inflated bids can cause bid cost recovery payments to drastically exceed any economic losses caused by reversal of day-ahead schedules.

In January 2025, FERC approved a new rule that energy real-time bid cost for batteries would reflect the lower of (1) the resource’s energy bid in the real-time market interval, or (2) the greater of the resource’s day-ahead locational marginal price (LMP), its real-time market default energy bid, or its real-time LMP for that interval.²⁵ These changes were focused on bid cost recovery deriving from real-time energy bid costs and largely address gaming concerns associated with battery bid cost recovery. However, DMM analysis prior to those market design changes showed that most of real-time bid cost recovery paid to batteries was the result of real-time revenue losses incurred by buying back infeasible day-ahead schedules at elevated real-time prices.²⁶ Therefore, lower overall prices and a decrease in extreme real-time price spikes contribute to lower bid cost recovery payments for batteries.

After accounting for resettlements since 2024, bid cost recovery payments to batteries represented 5 percent of all bid cost recovery in 2025, a decrease from 13 percent in 2024. Total bid cost recovery paid to batteries in 2025 was nearly \$6.3 million. DMM continues to recommend the ISO develop storage bid cost recovery rules that allow no eligibility for bid cost recovery by default, and only allow eligibility under certain situations where uplift to storage resources is deemed appropriate and necessary to support market efficiency.

²³ *Opinion on Storage Bid Cost Recovery*, James Bushnell, Scott M. Harvey, Benjamin F. Hobbs; Members of the Market Surveillance Committee, November 1, 2024: <https://www.caiso.com/documents/market-surveillance-committee-final-opinion-storage-bid-cost-recovery-nov-01-2024.pdf>

²⁴ *Comments of the Department of Market Monitoring of the California Independent System Operator Corporation*, Department of Market Monitoring, ER25-576-000, December 17, 2024: <https://www.caiso.com/documents/dmm-comments-on-er25-576-storage-bcr-dec-17-2024.pdf>

²⁵ FERC Docket No. ER25-576-000, *Order Accepting Tariff Revisions Bid Cost Recovery to Storage Resources*, January 24, 2025: <https://www.caiso.com/documents/jan-24-2025-order-accepting-tariff-revisions-bid-cost-recovery-to-storage-resources-er25-576.pdf>

²⁶ *Analysis of battery bid cost recovery and bid mitigation issues*, Department of Market Monitoring, September 11, 2024: <https://www.caiso.com/documents/presentation-battery-bid-cost-recovery-and-mitigation-data-dmm-sep-11-2024.pdf>

2.10 Resource adequacy

California’s resource adequacy (RA) program is designed to ensure the California ISO system has enough resources to operate the grid safely and reliably in real-time and to provide incentives for the siting and construction of new resources to operate the grid reliably in the future. All load serving entities within the California Public Utilities Commission’s (CPUC) jurisdiction are required to have enough capacity to meet peak demand and maintain a reserve margin, among other requirements.

2.10.1 Resource adequacy capacity from batteries

Starting in 2025, the CPUC implemented numerous reforms to the RA program. Notably, the CPUC’s “slice-of-day” enhancement requires load serving entities (LSEs) to demonstrate sufficient capacity to satisfy its specific gross load profile—including a planning reserve margin—in all 24 hours on the ISO’s “worst day” in each month.²⁷ In addition, under the slice-of-day approach, load serving entities’ capacity portfolios must include sufficient surplus energy from non-storage resources to ensure batteries can be fully charged over the four most critical net peak hours, accounting for efficiency losses—this is verified through the CPUC’s storage excess capacity test.²⁸ The CPUC recently approved new rules for counting long duration energy storage (LDES) resources—which they define as a storage resource capable of discharging at maximum capacity for at least eight hours—under the slice-of-day framework.²⁹ In effect, this new rule will allow LDES resources to satisfy slice-of-day charging requirements by spreading out charging over multiple days.

California’s resource adequacy program uses a metric called net qualifying capacity (NQC) to represent the maximum MW capacity that all resources—including batteries—can sell to an LSE to meet its resource adequacy obligations each hour. The CPUC determines the NQC of batteries based on testing of their sustained output over a four-hour period. Batteries with a longer discharge duration do not receive a different amount of credit for resource adequacy capacity than those that can only provide energy for four hours. Under slice-of-day, load serving entities must reflect daily resource capabilities (such as maximum daily run hours, maximum stored energy value, and storage efficiency) in their hourly capacity showing. Starting in the 2027 RA compliance year, the CPUC has modified the NQC methodology for batteries to account for foldback constraints, which limits maximum and minimum power capabilities near a resource’s state-of-charge limits.³⁰

The CPUC calculates NQC for hybrid and co-located batteries based on the NQC of the individual components at shared facilities, minus any physical limitations due to sharing a point of interconnection. In addition, for these “paired” storage resources, load serving entities must account for charging needs—either from the storage excess capacity test in the case of grid-charging enabled resources, or

²⁷ The “worst day” is defined as the day of the month that contains the hour with the highest coincident peak load forecast. The CPUC has acknowledged that this definition can evolve over time if some other attribute is found to better reflect reliability challenges.

²⁸ *Resource Adequacy Slice-of-Day Showing Template User’s Guide*, California Public Utilities Commission, July 2, 2024, p 25: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/rashowing_template_usersguide_rev30.docx

²⁹ *Decision Adopting Local Capacity Obligations for 2027-2029, Flexible Capacity Obligations for 2027, and Program Refinements*, California Public Utilities Commission, July 2, 2026, pp 39-48: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M610/K575/610575803.PDF>

³⁰ Ibid., 197.

from the paired generating capacity for non-grid-charging storage. For co-located grid-charging restricted storage, the charging capabilities of the paired generating resource will be applied to charging the storage regardless of whether the load serving entity has the off-take rights to the generation. In addition, the total capacity of any non-storage resource that could be used toward the storage excess capacity test is reduced by the total charging energy of any paired or co-located grid-restricted storage resource.³¹ As a result of modeled charging needs, hybrid and co-located battery components receive less qualifying capacity than identically sized stand-alone resources.

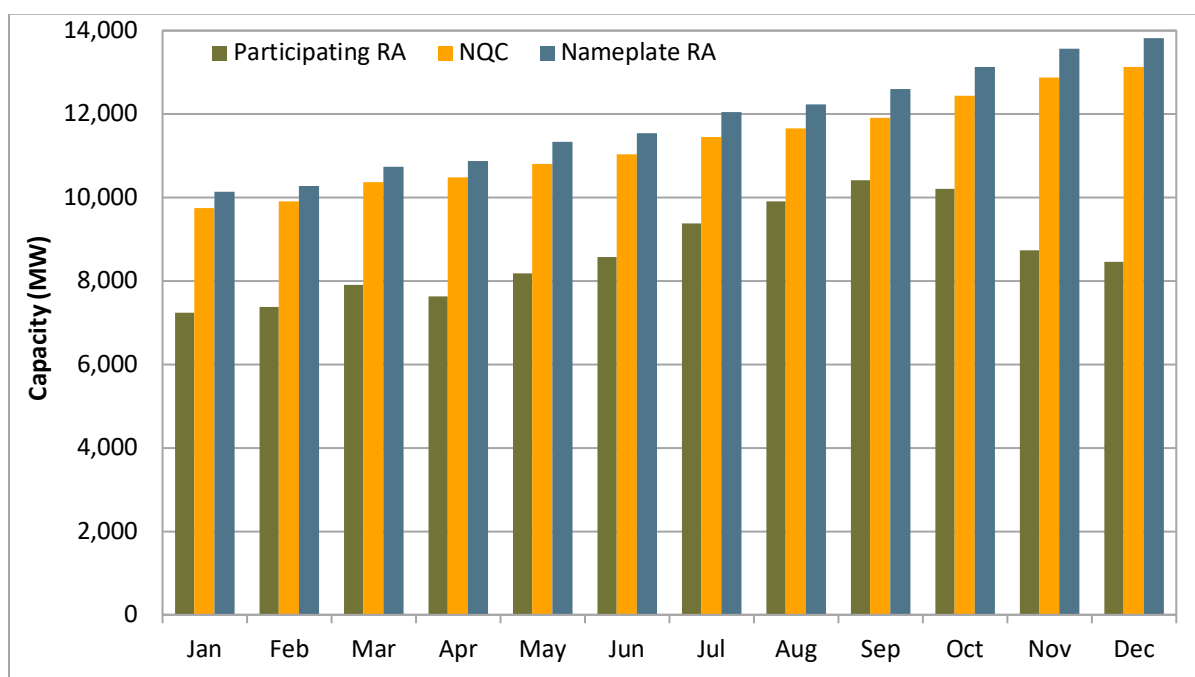
Resources benefit by participating in the resource adequacy program by getting capacity payments when they contract with load serving entities. However, resource adequacy resources are subject to numerous additional requirements when participating in the ISO market. For example, batteries and other resource types with flexible resource adequacy capacity are subject to must-offer obligations, meaning that they must submit economic bids for energy for the full amount of their flexible resource adequacy value during specified hours of the real-time and day-ahead markets.³²

Figure 2.26 shows month-end participating resource adequacy capacity, aggregate battery NQC, and total nameplate battery capacity for 2025.³³ In 2025, between 64 and 87 percent of the total available NQC from batteries was counted towards resource adequacy requirements, depending on the month. Battery RA participation tends to decrease outside of summer months because load serving entities' obligations are lower.

³¹ Ibid.

³² *Fifth Replacement Electronic Tariff, section 40.10.6 Flexible RA Capacity Must-Offer Obligation*, California ISO, February 11, 2023, p 102: <http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-asof-Feb11-2023.pdf>

³³ For battery nameplate capacity, we count Master File maximum power values for any battery which has a NQC rating from the CPUC.

Figure 2.26 Resource adequacy capacity from batteries (2025)

2.10.2 Availability of resource adequacy batteries

Battery capacity may become unavailable to the market due to a combination of factors. One cause is simply that on high-priced days, a portion of the battery fleet may begin to discharge early based on their bid prices, and do not have the opportunity to recharge prior to the most critical peak net load hours. In addition, batteries are subject to numerous special market constraints which ensure that a resource's state-of-charge does not fall outside its physical operating parameters or other important operational limits. These constraints include:

- **The ancillary services state-of-charge (ASSOC) constraint**, which can bind in the real-time market and cause batteries to either charge or discharge in order to give them sufficient headroom to fulfill their ancillary service awards.
- **The aggregate capability constraint**, which ensures that the combined generation of co-located resources does not exceed interconnection limits.
- **Upper and lower charge limits**, optional biddable parameters which represent the highest and lowest stored energy values (in MWh) that should be maintained in the resource in a trading day.
- **The end-of-hour state-of-charge (EOH SOC) bid parameter**, which is an optional real-time only parameter for use by NGR resources to manage their state-of-charge.
- **The attenuated state-of-charge constraint**, which models the impact of batteries' providing regulation on their state-of-charge, and can restrict provision of ancillary services from batteries until they have charged or discharged to provide sufficient headroom.

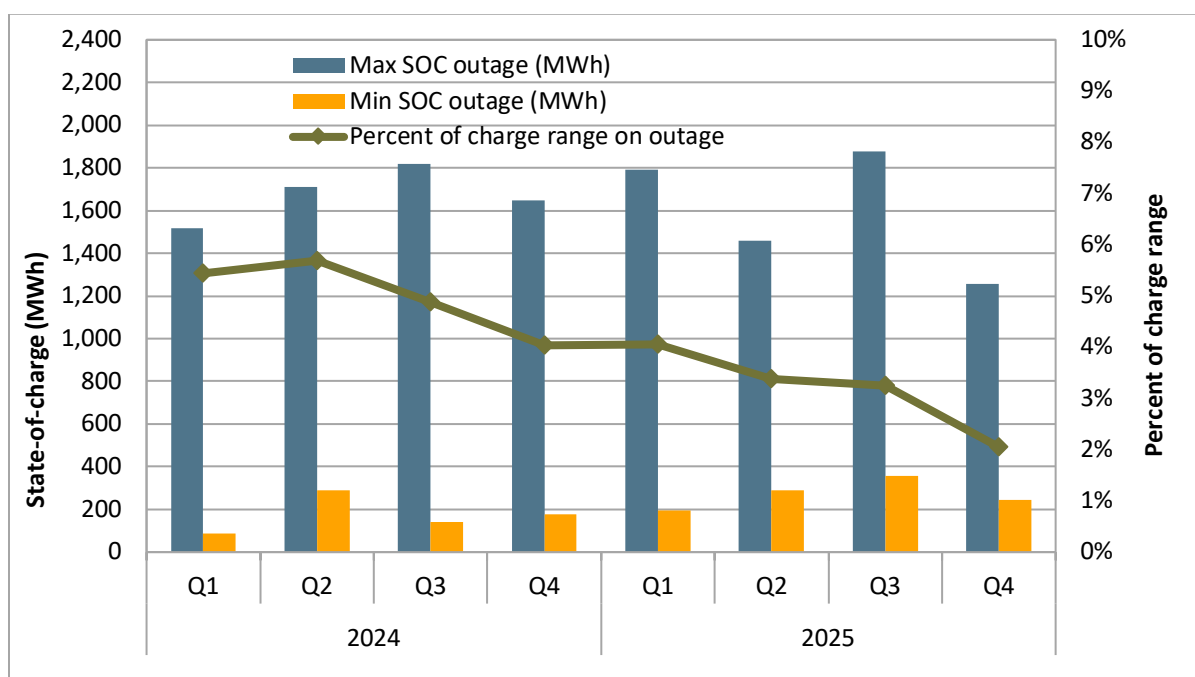
- **The off-grid charging indicator**, an optional biddable parameter which allows co-located batteries to restrict grid charging in specified intervals.

Batteries may use energy bids, as well as some of the biddable parameters described above, to signal when they do not want to be available to the market for charging or discharging. In general, batteries use their energy bids to signal a high willingness to discharge during peak net load hours, and a low willingness to discharge when prices are lower in the afternoon.

In addition, there are certain physical characteristics of batteries that the market does not currently account for, which may cause batteries to become unavailable. One such characteristic is called *foldback*, which is where maximum and minimum power levels can change when a battery is at the highest and lowest ends of its state-of-charge. Cell imbalance—which is caused by a variance in voltage across cells in a battery storage system—can also limit the maximum power of a battery resource.

Market participants tend to reflect these physical limitations through outages and de-rates. The ISO gives batteries the option to reflect limitations on lower and upper state-of-charge bounds through the Outage Management System (OMS). Batteries may set their minimum required charge above their lower energy limit in Master File, and set their maximum allowable charge below their maximum energy limit. For example, a typical 100 MW, 4-hour duration battery would have a lower charge limit of zero MWh and an upper limit of 400 MWh in Master File—but in OMS they could set these values to 50 MWh and 350 MWh, respectively. In effect, both actions restrict the amount of energy that can be made available to the market.

The blue bars in Figure 2.27 reflect the average quarterly decrease in the upper charge limit, and the yellow bars reflect the average increase in the lower charge limit, compared to batteries' Master File values. The green line in Figure 2.27 shows the average percentage of aggregate charging range that was made unavailable through these outages. On average, around 3 percent of batteries' nameplate charge range was on outage in the real-time market in 2025.

Figure 2.27 Quarterly average real-time state-of-charge outages

Finally, there are also limitations in the market software that can cause batteries to be unavailable when they are needed to meet demand. Because of the computational complexity inherent with a large optimization, the ISO's real-time market has a limited optimization horizon. This limited optimization horizon can cause batteries to discharge earlier than desired when high real-time prices materialize early in the day, and can result in batteries entering peak net load hours with a diminished state-of-charge.

In 2025, the CAISO balancing area did not experience an Energy Emergency Alert (EEA). Prior reporting has shown that RA battery performance on EEA days is similar to performance on high-load non-EEA days.³⁴ For this report, DMM evaluates RA battery performance based on the average status of the resource adequacy battery fleet during each of the peak net load hours (17 to 22) on the five days with the highest average daily load in the CAISO balancing area.³⁵ Results of this analysis are summarized in Figure 2.28.

The data in Figure 2.28 are shown in terms of the percentage of the total capacity of the battery fleet providing resource adequacy that falls into the following categories in the 15-minute market:

- The striped yellow and orange portion of each bar shows the portion of the battery fleet unavailable due to a reported outage or de-rate.

³⁴ 2024 Special Report on Battery Storage, Department of Market Monitoring, May 29, 2025, p 32: <https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf>

³⁵ In order from highest to lowest average load, the days are August 22, August 21, September 2, September 3, and August 25.

- The solid yellow bars show the average amount of undispached energy bids offered at prices below the resources' LMPs. Since this capacity was bid at prices below the LMP but not dispatched, it may have been unavailable due to some of the various resource constraints that can limit the actual availability of battery capacity described above.
- The solid orange bars show the average amount of undispached energy bids offered at prices greater than the resources' LMPs.³⁶ It is possible that some of this capacity also may not have been available due to state-of-charge and other constraints, but this cannot be determined.
- The dark green and light green bars show the average portion of battery capacity scheduled to provide spinning and non-spinning reserves and upward flexible ramping capacity, respectively.
- The dark blue and light blue bars show the average portion of battery capacity dispatched to provide energy and regulation up, respectively, during the peak net load on these five days.

The bars for each hour in Figure 2.28 are higher than the dotted black line showing the total aggregate resource adequacy capacity from batteries. This reflects the fact that batteries tend to contract less than their maximum power capacity for resource adequacy, and can therefore theoretically provide more power than their resource adequacy value.

Battery availability (in terms of capacity scheduled for energy, upward ancillary services, or flexible ramping product) peaked in hour-ending 19. In this hour, the average scheduled battery capacity in the 15-minute market represented 87 percent of total resource adequacy capacity. Around 41 percent of this capacity was unavailable in hour-ending 17 because it was bid at prices above the resources' LMPs. Since real-time prices tend to peak after hour-ending 17, batteries reflected a high opportunity cost to discharge in their bids in this hour. In hour-ending 22, 45 percent of battery capacity was unavailable to the market, not including outages or derates, of which 19 percentage points were bid in at a price less than the LMP. As previously noted, DMM cannot determine the extent to which some additional capacity providing operating reserves or bid at prices greater than the LMP may have been unavailable due to various constraints.

³⁶ This figure is most relevant as a metric for resource adequacy performance for units that are required to submit economic bids, e.g., units with flexible resource adequacy capacity.

Figure 2.28 Average 15-minute resource adequacy battery capacity during 5 highest load days