California Independent System Operator Corporation

California ISO

Demand response issues and performance 2025

September 21, 2026

Department of Market Monitoring

ISO Public

1 Summary

This report summarizes market participation models and nonmarket load adjustments representing demand response in Western Energy Imbalance Market (WEIM) entities. This report also provides analysis of how demand response resources participated and performed in the California ISO (CAISO) balancing area on high load days in summer 2025.

The Department of Market Monitoring (DMM) has provided similar analysis of the performance of demand response resources during summers 2020 through 2024.[1] This report also follows up on prior recommendations made by DMM for improving the availability and performance of demand response resources used to meet resource adequacy requirements.

1.1 Background

This report summarizes demand response activity among Western Energy Imbalance Market (WEIM) entities. Out-of-market demand response is reported on an hourly basis as a load adjustment to the forecasted demand used in either the market optimization or, in the summer months, the resource sufficiency evaluation. In 2025, WEIM entities submitted load adjustments through both mechanisms in 81 distinct hours. These load adjustments accounted for a total of -20,070 MWh throughout the year, which represents an average load adjustment of -250 MW during hours in which a load adjustment was submitted. This also represents an average hourly load adjustment of about -2 MW across all hours of the year, accounting for about 0.003 percent relative to the WEIM average system load of 78.3 GW in 2025.[2]

In addition, this report provides an overview of the non-generator resource – dispatchable demand response (NGR-DDR) participation model, under which WEIM entities can bid in demand response as pseudo-generation.

Finally, this report analyzes the availability, schedules, and performance of demand response resources counted towards CAISO balancing area resource adequacy requirements on nine days in summer 2025. In this report, we refer to this sample of nine days as *analysis days*. Analysis in the report focuses on the peak net load hours (17 to 22) on these high load days.

Demand response accounted for roughly 3.1 percent of total system CAISO balancing area resource adequacy capacity (or about 1,330 MW) in the summer of 2025. About 87 percent of this capacity is comprised of utility demand response programs, which is subtracted from the resource adequacy requirements of the load serving entities. Of this utility demand response, about 40 percent was California Public Utilities Commission (CPUC) jurisdictional proxy demand response, about 50 percent was CPUC jurisdictional reliability demand response and the final 10 percent was non-CPUC jurisdictional demand response. The remaining 13 percent of total demand response capacity is bid and scheduled by third party non-utility demand response providers, who contract to sell resource adequacy capacity to load serving entities. This capacity is often referred to as *supply plan demand response* since

[1] Prior reports are available on DMM's website under Special Reports and Presentations at: https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations

[2] This data includes adjustments made by the CAISO balancing area.

it is explicitly shown on monthly resource adequacy plans as supply providing resource adequacy capacity.

1.2 Key findings

Key findings in this report include the following:

- **WEIM entities submit load forecast adjustments to reflect increased demand response activity during the summer months.** WEIM entities may submit load adjustments to be incorporated into the demand forecast used in the ISO real-time market optimization. These load adjustments are intended to reflect nonmarket demand response activities and other forms of load flexibility. Most of these load adjustments are submitted during the summer months.

- **WEIM entities may also bid in demand response under the non-generator resource – dispatchable demand response (NGR-DDR) participation model.** This allows WEIM entities to bid demand response as pseudo-generation.

- **About 76 percent of CAISO resource adequacy requirements met by demand response capacity was available through bids into the ISO market during peak net load hours on days when the CAISO balancing area issued system warnings or restricted maintenance operations.** This is slightly lower than 2024 and 2023 (with 85 percent and 81 percent, respectively), but an improvement from the previous two years when almost two thirds of resource adequacy demand response was unavailable. This increase in availability is due in part to removing the planning reserve margin and transmission adders previously applied to demand response resource capacity used to meet resource adequacy requirements in 2024.

- **On days with strained grid conditions in the summer, about 77 percent of the CAISO balancing area demand response capacity in real-time reported performing as scheduled.**[3] Utility demand response reported substantially higher reported performance than third party demand response, though schedules were lower than previous years. Utility demand response reported to curtail about 80 percent of scheduled load reductions, while reported performance of supply plan demand response averaged 65 percent of scheduled load reductions.[4]

[3] Performance of demand response dispatched in the ISO is based on data self-reported by demand response scheduling coordinators. These data include the aggregate metered loads of demand response resources, and a counterfactual baseline of estimated load that would have occurred if the demand response had not been dispatched.

[4] The reported performance of utility and supply plan demand response is calculated after applying a cap at each individual resource's scheduled load curtailment. The uncapped performance was 84 percent for utility demand response, 134 percent for supply plan demand response, and 90 percent overall.

- **The availability and performance of proxy demand resources providing resource adequacy capacity was relatively low on days with strained grid conditions.** Only 26 percent of utility proxy demand response resource adequacy capacity bid into the market on strained system days in summer 2025. Bids for non-utility (or supply plan) demand response resources was very close to resource adequacy values, but the aggregate reported performance of these resources averaged only 65 percent of their scheduled load curtailments as measured by capping individual resource performance at each resources' schedule.[5] These results suggest that resource adequacy values of proxy demand response resources may overstate the ability of these programs to curtail load during peak net load hours on days where grid conditions may be strained.

- **On days with strained grid conditions in 2025, supply plan demand response was scheduled in real-time far less often than in previous years.** In 2025, an average of 2.5 MW was scheduled in each hour of the analysis days, compared to 11 MW in 2024.

- **In July 2023, the California Public Utilities Commission (CPUC) clarified that the CAISO balancing area should be able to dispatch reliability demand response in the real-time upon the declaration of an Energy Emergency Alert (EEA) Watch.** During 2025, CAISO was never declared to be under an EEA Watch. Though the ISO was under Restricted Maintenance Operations notice for about forty hours during January 20-21, 2025, no reliability demand response was dispatched during those intervals. Reliability demand response was dispatched during a single hour on a single day, July 1, 2025.

- **Resource adequacy payments, or the value of reduced resource adequacy requirements for load serving entities, are the primary revenue source for demand response resources.** Even when demand response resources are frequently dispatched, the energy market revenues from actually performing (or charges for failing to perform) have represented a relatively small portion of the overall compensation or value of these resources.[6] This current market framework does not provide a strong financial incentive for most demand response resources to perform when needed most under critical system conditions.

1.3 Policy changes and recommendations

In prior reports, DMM has highlighted some recommendations that the CAISO balancing area and California Public Utilities Commission (CPUC) could consider to enhance the availability and performance of demand response resources in California.[7] Over the last few years, the CPUC has made a number of changes to the treatment of demand response resources that count towards resource adequacy

[5] Without capping reported performance at the resource adequacy ratings of each individual resource, supply plan proxy demand response performed at 134 percent of their schedules. However, aggregate performance measured this way varied widely by day and hour, exceeding scheduled load reductions significantly during some hours and falling well short of scheduled reductions in other hours.

[6] *Demand response issues and performance 2022,* Department of Market Monitoring, February 14, 2023, pp 23-25: https://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf

[7] *2022 Annual report on market issues and performance,* July 11, 2023, pp 21-22: https://www.caiso.com/documents/2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf

requirements. In July 2023, the CPUC announced several significant changes and clarifications regarding treatment of reliability demand response, which took effect in 2024.[8]

DMM continues to recommend additional enhancements to the demand response model, including models for Western Energy Market participation, improved baseline methodologies, real-time load bidding, modeling demand response as participating load, and improving resource adequacy accounting methodologies.

- **Western Energy Market participation**. DMM supports expanding the demand response participation options available to participants in the Western Energy Imbalance Market or the Extended Day Ahead Market (jointly "western markets"). Currently western market demand response outside of the CAISO balancing authority area is used as a load modifier, or in the resource sufficiency evaluation test. DMM recommends the ISO work with stakeholders to develop resource-level participation pathways suited to demand response types that may be more prevalent in the broader western markets. However, DMM cautions against any model to allow double compensation by allowing resources to continue to participate as they do currently, and the resource-level pathway.

- **Baseline methodologies**. DMM recommends the ISO facilitate wider adoption of the "control group" baseline methodology. The wider adoption of the control group methodology will improve the precision and accuracy of the empirically estimated counterfactual used to determine a response of the resource. The improvement will ensure higher quality estimates of demand response resource availability and performance, and reduce the potential for baseline manipulation.

- **Modeling demand response resources as participating load**. DMM recommends the ISO incrementally work to evolve demand response to a demand-side resource from the current supply side model. Further, DMM recommends the ISO consider the interactions of this change to long-term planning for resource adequacy obligations, and methods to value the resource adequacy of demand-side resources if they are treated as load.

- **Real-time load bidding**. DMM supports enhancements to real-time load bidding for resources that are able to respond to real-time economic signals to increase market reliability and efficiency.

- **Re-examine demand response counting methodologies.** Demand response appears to be over-counted in terms of these resources' contribution towards meeting resource adequacy requirements and their reported load curtailments. DMM supports efforts to better capture the capacity contribution of demand response whose load reduction capabilities vary across the day, and who may have limited output in general. In addition to DMM's recommendation to increase adoption of the control group methodology, DMM also recommends the ISO consider development of a performance-based penalty or incentive structure for resource adequacy resources to disincentivize misrepresentation.

[8] CPUC Decision (D.) 23-06-029, July 5, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

2 Analysis of demand response market participation in CAISO balancing area

This section provides a summary of findings on CAISO balancing area demand response resource adequacy capacity participating in the ISO's markets for the highest load, price, and tightest resource adequacy margins during Summer 2025. The sample of days in summer 2025 are July 1, August 21, August 22, September 1-3, September 7, September 16, and September 20. The analysis focuses on the availability, schedules, and performance of demand response resources counted towards resource adequacy requirements on those nine days, referred to as *analysis days* in this report.

Methodology for selecting analysis days

In previous years, DMM reported on demand response performance for days when the CAISO balancing area issued a Restricted Maintenance Operations (RMO) notice or Energy Emergency Alert (EEA). Because the ISO issued no RMO notices or EEAs in summer 2025, the analysis of demand response in this report focuses on selected analysis days when grid conditions were the most extreme. The summer 2025 extremes were chosen as the days with the highest load forecast, highest day-ahead price, and greatest resource adequacy scarcity. Table 2.1 shows the days that meet each of the three criteria, and total eight of the nine days that are used as ***analysis days***.

Table 2.1 Analysis days and criteria

Date	Highest load forecast	Highest day-ahead price	Greatest resource adequacy scarcity
August 21, 2025	x	x	
August 22, 2025	x	x	
September 1, 2025	x		x
September 2, 2025	x	x	x
September 3, 2025	x	x	x
September 7, 2025			x
September 16, 2025		x	
September 20, 2025			x

The analysis day descriptions and selection criteria are given below:

- **Highest load forecast** days are determined using the five-minute market load forecasts. All five-minute load forecast market intervals from May through September of 2025 were arranged in order of highest to lowest, and the first five unique days are selected. The top five load forecast days are in the first column of Table 2.1.
- **Highest day-ahead price** days are determined on day-ahead price. All day-ahead prices in May through September of 2025 were arranged in order of highest to lowest system marginal energy cost, and the first five unique days were selected. The top five day-ahead priced days are in the second column of Table 2.1.
- **Greatest resource adequacy scarcity** days occur when the margin between real-time resource adequacy bid availability and load requirement is the lowest. These days are determined using

the following methodology: for each hour in May through September of 2025, the difference between real-time bids from resource adequacy resources and load requirements was computed, and then arranged in order of smallest to largest difference. The first five unique days were selected and are presented in the third column of Table 2.1.

Reliability Demand Response Dispatch Day

Throughout summer 2025, reliability demand response was dispatched in only a single one-hour interval: hour-ending 16 on July 1, 2025. Though not a peak-hour interval, this interval is included in the analysis because it offers an opportunity to assess reliability demand response performance in 2025. July 1, 2025 is included among the other analysis days, yielding a total of nine analysis days.

2.1 Demand response as resource adequacy

Demand response accounted for about 2.9 percent of total system resource adequacy capacity in July through September 2025, meeting an average of 1,327 MW of system resource adequacy requirements. This is a modest increase compared to 2.6 percent of total system resource adequacy in the summer of 2024 but remains below 3 to 4 percent recorded in earlier summers. The reduction in 2024 relative to previous summers are partially a result of the CPUC excluding the planning reserve margin (PRM) and transmission loss adders for utility demand response.

This capacity is comprised of two types of demand response resources:

- **Utility demand response programs.** These resources are operated and scheduled by utilities, and the capacity from these resources is subtracted from the resource adequacy obligation of these load serving entities. These resources account for about 87 percent of demand response used to meet resource adequacy requirements.
- **Supply plan (third party) demand response.** These resources are developed, bid and scheduled by non-utility (or third party) providers under contract to supply resource adequacy capacity for utilities. This capacity is often referred to as *supply plan demand response* since it is explicitly shown on monthly resource adequacy plans as supply that is providing resource adequacy capacity. These providers account for about 13 percent of demand response used to meet resource adequacy requirements.

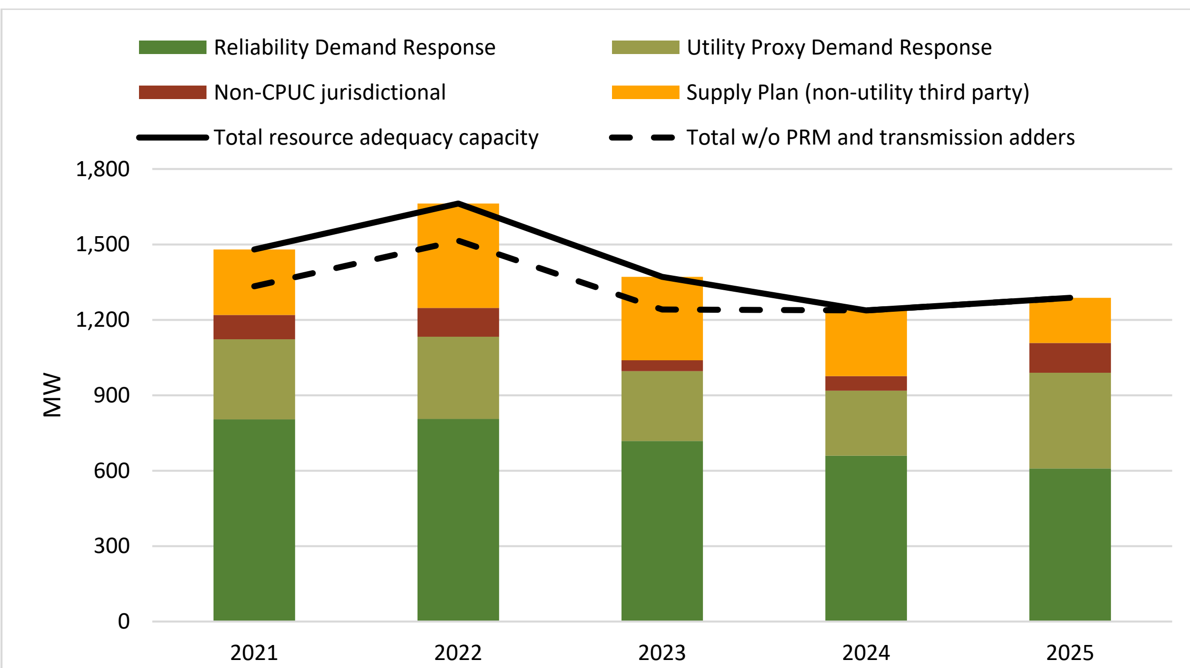
Table 2.2 below summarizes the breakdown between credited utility and supply plan demand response capacity counted towards resource adequacy requirements in July through September 2025. Capacity values for demand response under the CPUC-jurisdictional load serving entities local regulatory include distribution loss factors.

Table 2.2 Demand response resource adequacy capacity in 2025 (megawatts)

Month	Credited demand response (CPUC LRA)	Credited demand response (Other LRA)	Supply plan demand response	Total MW
July	919	103	172	1,194
August	1,047	119	179	1,345
September	1,106	158	178	1,442

Figure 2.1 below shows a decline in average resource adequacy demand response capacity in August, from 2021 to 2025. Over this period, total resource adequacy capacity met by demand response has dropped from 1,757 MW to 1,345 MW, or about 23 percent. The trend is similar in the surrounding summer months. There was a 61 MW increase in resource adequacy demand response for non-CPUC jurisdictional entities in 2025 relative to 2024.

Figure 2.1 Resource adequacy demand response in August (2021–2025)



Utility demand response

Utility demand response represents programs that are operated by load serving entities in various local regulatory authority jurisdictions. This capacity is credited toward meeting resource adequacy requirements by being subtracted from the resource adequacy requirements of each load serving entity. In July through September 2025, this type of demand response capacity accounted for about 1,150 MW of resource adequacy credits.[9]

The largest share of utility demand response capacity (89 percent) is from programs run by investor-owned utility (IOU) programs under the jurisdiction of the CPUC. Historically, the CPUC has allowed these entities to reduce their resource adequacy requirements by an additional percent above the reported capacity of their demand response resources. Prior to 2024, utility demand response resources included adders for the planning reserve margin, and transmission and distribution losses. In 2024 and 2025, only distribution loss adders are included.

The majority of this IOU capacity (62 percent) consists of reliability demand response resources (RDRR), which are primarily called upon under emergency conditions after the CAISO balancing area issues a system warning.[10] In 2023, the CPUC clarified that the ISO should be able to dispatch RDRR in the real-time, for economic or exceptional dispatch, upon the declaration of an Energy Emergency Alert (EEA) Watch, rather than an EEA 2.[11] RDRR resources are also able to economically bid into the CAISO day-ahead market.

Capacity from IOU demand response programs are bid and scheduled as supply in the ISO market, but is not shown on resource adequacy supply plans and therefore is not subject to ISO must-offer-obligations or the ISO's resource adequacy availability incentive mechanism (RAAIM). Pursuant to D.21-06-029, once the CPUC confirms that the ISO has implemented a Federal Energy Regulatory Commission (FERC)-approved exemption to the RAAIM penalty for demand response resources, each investor-owned utility will be directed to move their demand response portfolios onto supply plans.[12]

In addition to CPUC-jurisdictional demand response credits, other non-CPUC jurisdictional regulatory authority load serving entities (such as municipal utilities) accounted for about 125 MW of demand response resource adequacy credits in July through September. This capacity was not bid or scheduled into the ISO market, and the ISO did not have operational insight into this capacity. However, DMM understands that the ISO is working with these local regulatory authorities to develop processes similar to those that exist with CPUC-jurisdictional utilities in order to be able to call on these demand response programs when needed.

[9] Credited values include distribution loss factor gross-ups.

[10] Reliability demand response programs are primarily comprised of Base Interruptible Program customers and agricultural and pumping loads. While reliability demand response can only be dispatched in the real-time if the ISO is in an EEA Watch, it may be economically scheduled in the day-ahead market.

[11] Under these protocols, the CAISO balancing area's interpretation was that RDRR could only be dispatched in the real-time if the system was in an EEA 2 or higher. The CPUC clarified that the ISO should be able to use resource-adequacy qualifying resources prior to an emergency in decision (D.) 21-10-002 on June 29, 2023.

[12] *2022 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings*, R.19-11-009, California Public Utilities Commission, October 18, 2021: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/final-2022-ra-guide-clean-101821.pdf

Supply plan (third party) demand response

Demand response that is shown on monthly resource adequacy supply plans (referred to as *supply plan demand response*) currently represents capacity that is scheduled by third party non-utility demand response providers who contract to sell capacity to load serving entities. Supply plan demand response resources only include proxy demand response resources and are generally subject to CAISO must-offer obligations and the CAISO's resource adequacy availability incentive mechanism (RAAIM).[13]

Supply plan demand response capacity averaged 175 MW during July through September 2025, a 31 percent reduction compared to summer 2024. In previous years, supply plan demand response capacity was contracted either through the CPUC's demand response auction mechanism (DRAM) or bilaterally between third party providers and load serving entities. Beginning in 2025, DRAM has been discontinued, and third party demand response capacity is being contracted entirely through bilateral agreements.

2.2 Availability of demand response resource adequacy capacity

During the nine analysis days in summer 2025, about 76 percent of resource adequacy capacity from demand response was bid into the ISO market across peak net load hours. This is a modest decrease in the availability of resource adequacy demand response capacity compared to summer 2024. This is partially because three of the eight days in summer 2025 were holidays or weekends, when there may have been reduced bidding requirements for demand response.

In summer 2025, the bid-in capacity of utility demand response averaged about 80 percent of resource adequacy credits, compared to 85 percent last year. While supply bid in from reliability demand response met or exceeded resource adequacy capacity for reliability demand response, proxy demand response fell substantially short of resource adequacy credits, at 26 percent availability. Third party demand response was available on average to 80 percent of their resource adequacy capacity in the day-ahead market and 44 percent in the real-time market. Greater availability of supply plan demand response, compared to utility proxy demand response, is likely due to supply plan resources being subject to potential penalties for failing to bid in up to their resource adequacy capacity, while utility demand response resources do not face the same penalties.

Utility demand response availability

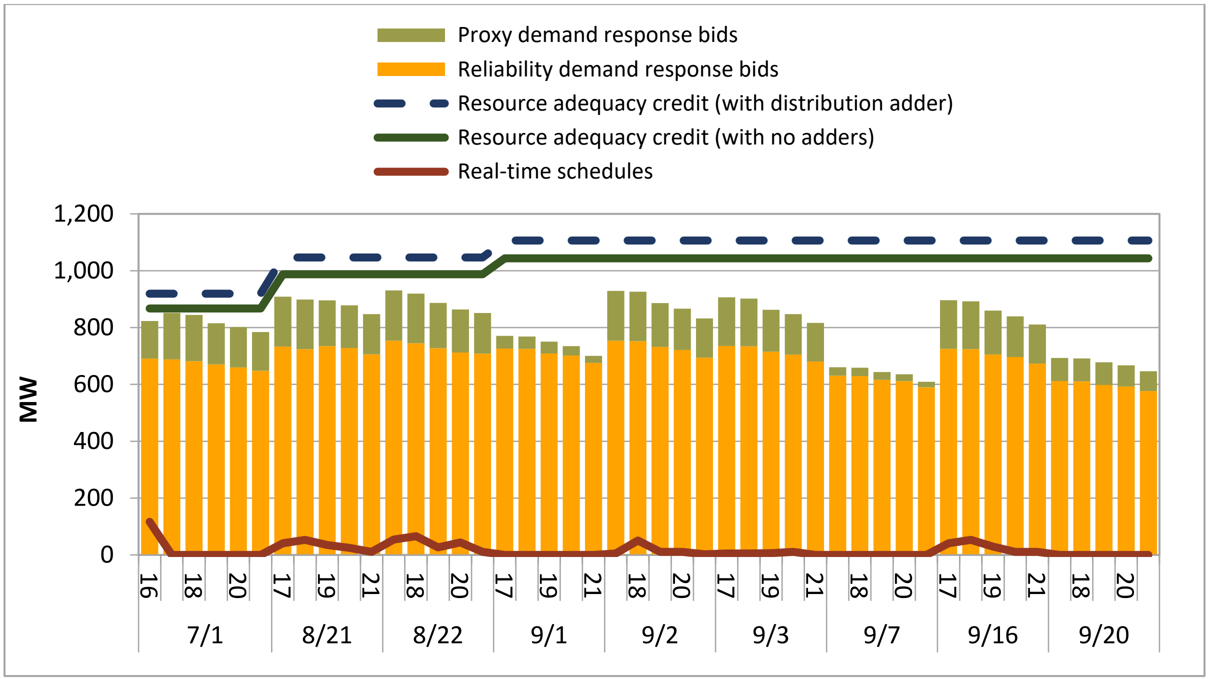
Figure 2.2 shows the availability of CPUC-jurisdictional credited demand response capacity on analysis days, compared to total resource adequacy credits in respective months. Figure 2.2 also shows the real-time schedules of ISO-integrated CPUC-jurisdictional utility demand response capacity (both proxy demand response and reliability demand response).[14] Program availability is based on demand response resource bids into the ISO markets. On average, utility demand response bid in about 80 percent of

[13] RAAIM is a financial incentive mechanism applied to resource adequacy capacity where suppliers could be penalized for not being available (bid) into the ISO market in Availability Assessment Hours, which are currently peak net load hours (4:00pm to 9:00pm) on non-holiday weekdays. Resources with a Pmax less than 1 megawatt are exempt from RAAIM under the ISO Tariff, Section 40.9.2(a)(1). In August 2024, 15 percent of supply plan demand response capacity was associated with resources sized less than 1 megawatt and thus were exempt from RAAIM.

[14] For all days but 7/1, analysis is provided for hours-ending 17 through 21. For 7/1, demand response market participation is additionally provided for hour-ending 16 as reliability demand response was only dispatched during this particular interval in 2025. To maintain consistent analysis hours across the CAISO section, hour-ending 16 on 7/1 is included in all CAISO demand response analyses.

resource adequacy credits on analysis days in 2025. This is a modest decrease in availability compared to 2024, when utility demand response bids fell short of resource adequacy credits by 15 percent. The shortfall of bid-in capacity compared to resource adequacy credits was almost entirely associated with proxy demand response.

Figure 2.2 CPUC-jurisdictional utility demand response availability and resource adequacy credits



The availability of credited utility demand response varied significantly between reliability demand response resources and proxy demand response resources. Figure 2.3 and Figure 2.4 show the bid-in capacity for reliability demand response resources and proxy demand response resources separately.[15]

As seen in Figure 2.3, bids from reliability demand response resources met or exceeded the CPUC-jurisdictional credited resource adequacy values for reliability demand response programs. The only days the RDRR did not bid in their full resource adequacy value were weekend days, but overall averaged 121 percent of resource adequacy.

The percentage of credited utility proxy demand response capacity that bid in during these days of tight system conditions was substantially lower, averaging only 26 percent of resource adequacy values (including distribution gross-ups). This is a significant decrease from 44 percent availability in summer 2024. Because credited utility demand response is not shown on supply plans, utility proxy demand resources are not subject to RAAIM if they fail to bid in their resource adequacy capacity. This may

[15] The aggregate resource adequacy values in Figures 2.3 and 2.4 vary slightly from Figure 2.2. This is due to Figure 2.2 using data from the CPUC's CIRA Generic Obligations Report which has total RA Obligations met by demand response, while Figures 2.3 and 2.4 use the individual load serving entities reports that break down demand response capacity between proxy demand response (PDR) and RDRR, and there may be some slight data discrepancies between these two sources.

explain why such a large portion of this capacity was unavailable to the ISO during peak hours on analysis days in summer 2025.

In addition, non-CPUC jurisdictional load serving entities claimed an average of 125 MW of demand response resource adequacy credits in July and August, which reduced these entities' system resource adequacy obligations. The ISO does not have insight into the availability of non-CPUC jurisdictional utility demand response programs as this capacity is not integrated in the ISO market.

Figure 2.3 Utility reliability demand response availability and resource adequacy credits

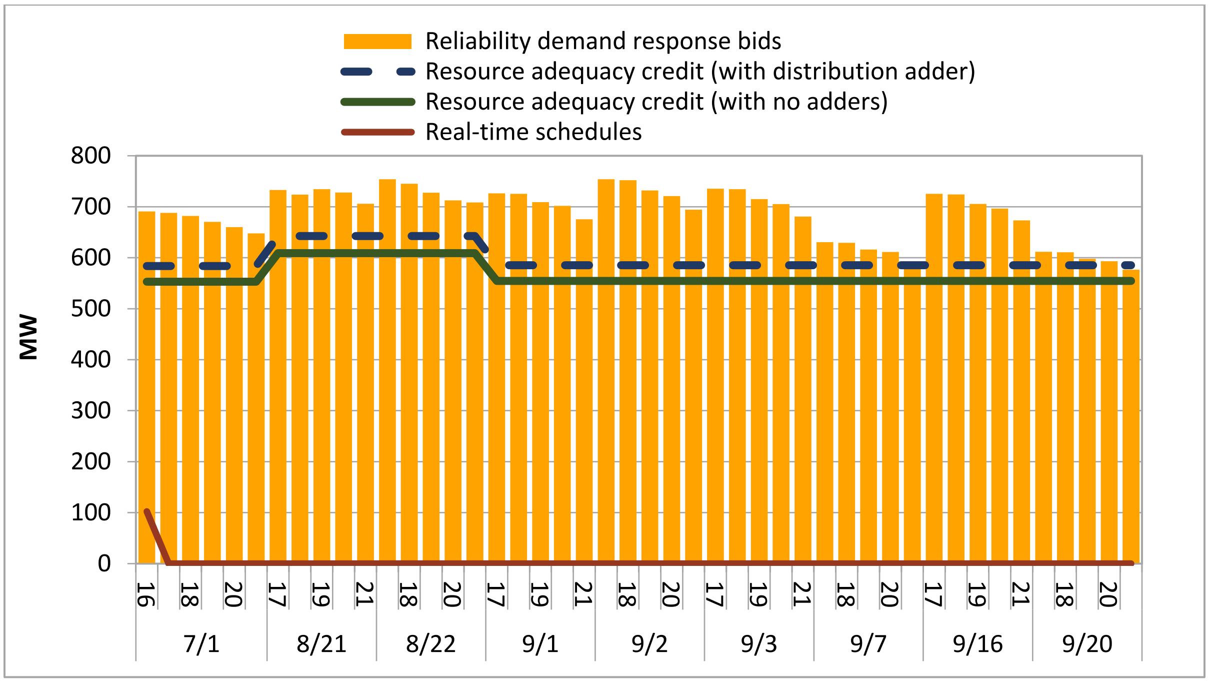
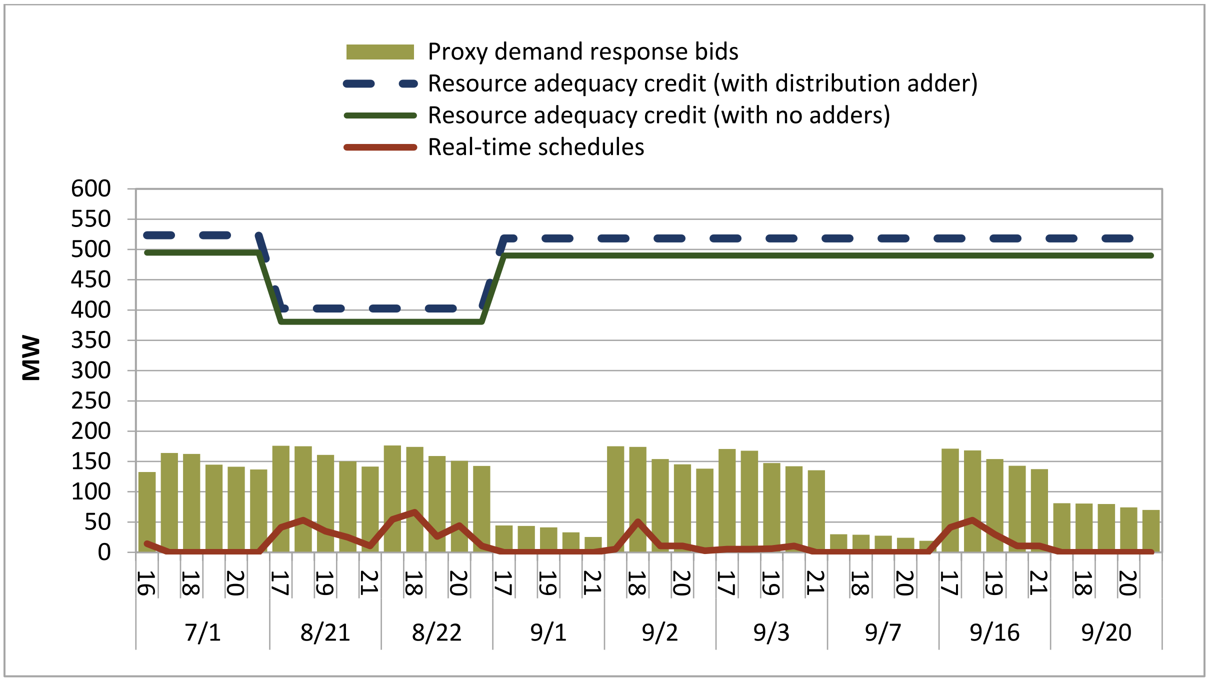


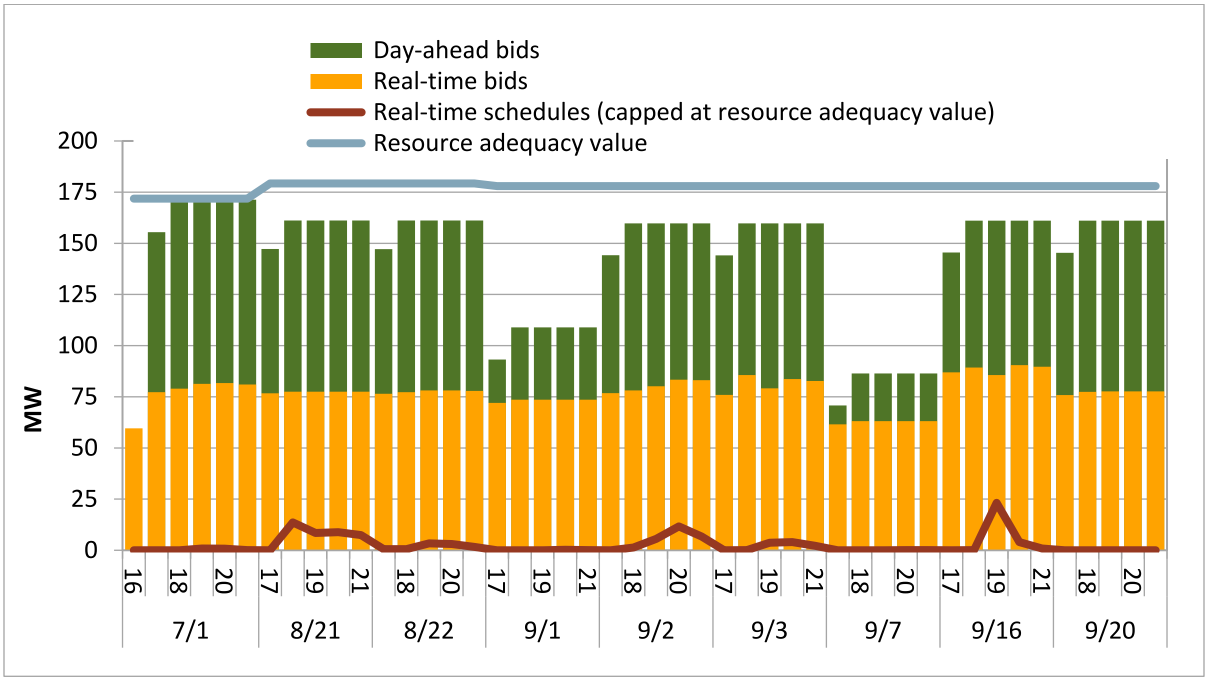
Figure 2.4 Utility proxy demand response availability and resource adequacy credits



Supply plan demand response availability

Figure 2.5 shows the availability of supply plan demand response capacity as reflected by day-ahead and real-time bids, where bids are capped at individual resources' shown resource adequacy values. The high availability of supply plan demand response resources in the day-ahead market is due in part to these resources being subjected to resource adequacy availability incentive mechanism (RAAIM) penalties for failing to bid in resource adequacy values during peak net load hours. The lower availability of bids in real-time can primarily be attributed to demand response programs with start-up times more than 255 minutes, which are not subject to RAAIM and therefore are not penalized for being unavailable in real-time.

Figure 2.5 Day-ahead and real-time availability of supply plan demand response



Day-ahead bids from supply plan demand response resources averaged 80 percent of resource adequacy capacity during analysis days this summer. This is a decrease from summer 2024, when bid-in capacity in the day-ahead market averaged 86 percent of resource adequacy values. Analysis days in summer 2025 included a holiday and weekends, which reduced bidding requirements. Comparing weekdays between 2025 and 2024, the decrease was similar, with 87 and 94 percent bid in, respectively.

In the real-time market, only about 44 percent was bid in. Limited availability of demand response capacity in real-time can primarily be attributed to demand response programs with start-up times more than 255 minutes, which qualify these resources as long-start. Long-start resources are not subject to RAAIM in the real-time if they are not scheduled economically in the day-ahead market, and therefore are not penalized for being unavailable. In July through September of 2025, around 55 percent of supply plan demand resource adequacy capacity was associated with long-start resources.

2.3 Demand response bidding

Figure 2.6 shows day-ahead bid prices and day-ahead schedules of utility and third party proxy demand response resources counted towards resource adequacy requirements across peak net load hours. For each date, there are two columns of data. Each column includes data for hours-ending 17 through 21, except for July 1, which includes hour-ending 16. The left column is for utility resources, while the right column is for third party resources. The presentation of the data is the same for Figure 2.6 and Figure 2.7.

Figure 2.6 Proxy demand response resource adequacy day-ahead bids

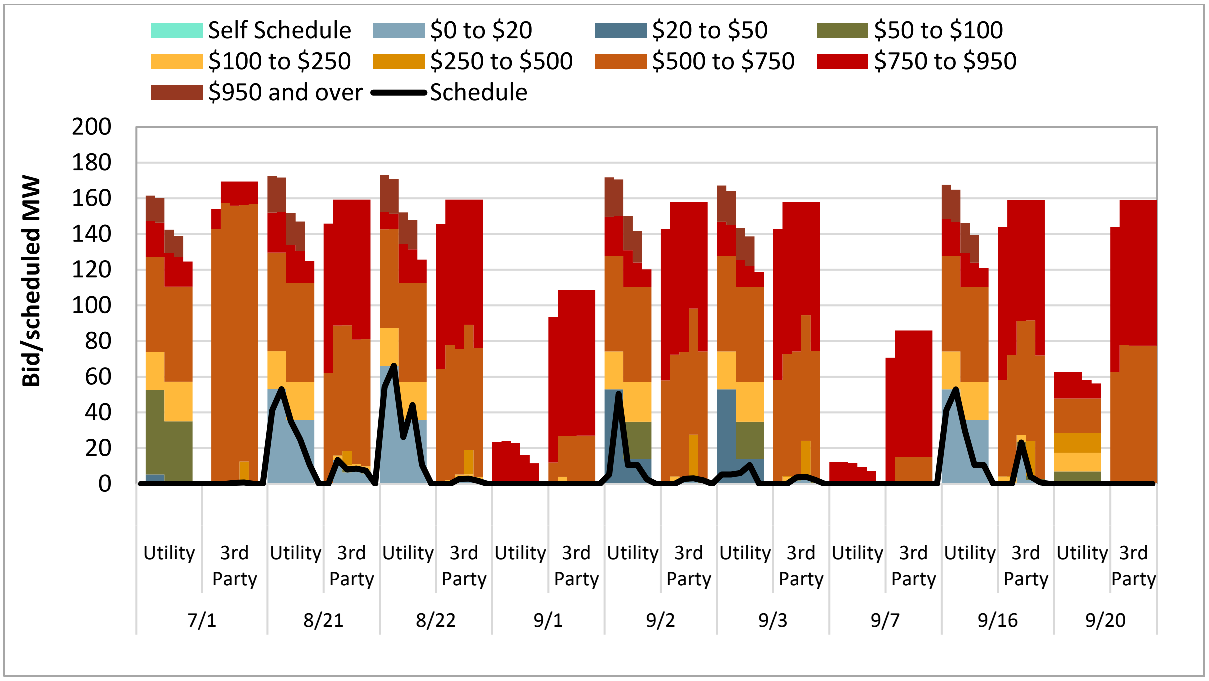
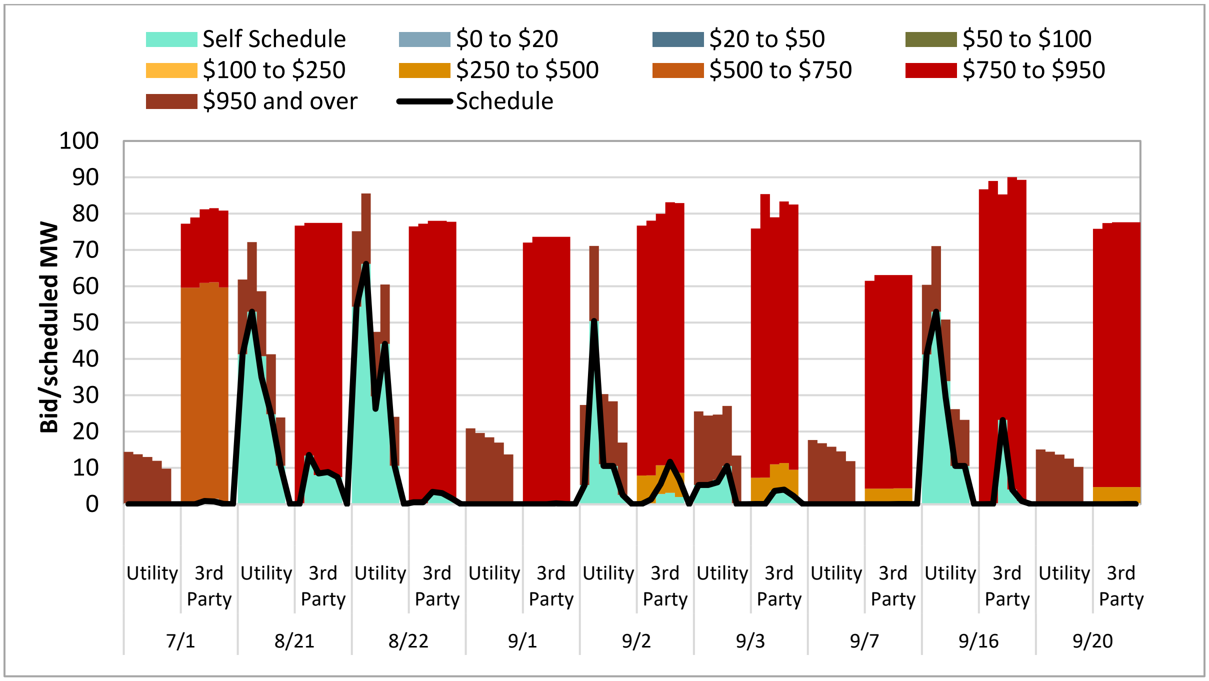


Figure 2.6 highlights the pattern of proxy demand response bids in the day-ahead market. Across analysis days in summer 2025, around 66 percent of utility demand response bids and 96 percent of third party demand response bids exceeded $500/MWh. These high bid prices led to a small percentage of demand response capacity being scheduled in the day-ahead market. Over this period, about 10 percent of the utility proxy demand response that bid into the day-ahead market was scheduled, while about one percent of bid-in third party demand response was scheduled.

Figure 2.7 shows real-time bids of proxy demand response (utility and third party) counted towards resource adequacy requirements across peak net load hours. Figure 2.7 highlights that utility proxy demand response capacity incremental to day-ahead awards was largely offered at or near the $1,000/MWh soft offer bid cap. Under certain conditions, the bid cap can be increased from $1,000/MWh to $2,000/MWh, however proxy demand response, as with all internal resources, must submit reference level change requests to bid over $1,000/MWh.[16] No proxy demand response bid over $1,000/MWh in summer 2025.

[16] It is not clear to DMM if proxy demand response resources can submit reference level change requests and whether the ISO would be able to validate these requests. DMM has recommended the ISO open a policy initiative to consider improvements to the reference level change request process to ensure non-gas resources are able to submit requests to accurately reflect their costs. See *Comments on Policy Initiatives Catalog and Roadmap Process 2024*, Department of Market Monitoring, Feb 29, 2024: https://www.caiso.com/Documents/DMM-Comments-on-2024-Policy-Roadmap-Feb-29-2024.pdf

Figure 2.7 Proxy demand response resource adequacy real-time bids



Beginning in 2024, non-DRAM resource adequacy proxy demand response resources contracted with load serving entities (LSEs) under the CPUC jurisdiction are subject to a bid cap of $949/MWh. This change was implemented by the CPUC in order to ensure that proxy demand response resources are dispatched prior to reliability demand response resources who are required to bid in at 95 percent of the current market bid cap. Since DRAM was discontinued beginning in 2025, all third party proxy demand response resources were subject to the $949/MWh bid cap.

On the analysis days in summer 2025, six percent of utility proxy demand response bid in at $950 or above in the day-ahead market. In the real-time market, this percentage increased to 73 percent. As a reference, on high load days in 2024, 20 percent of third party demand response and nine percent of utility proxy demand response bid in at $950 or above in the day-ahead market. In the real-time market, these percentages for 2024 averaged 41 percent for utility demand response and 61 percent for third party demand response.

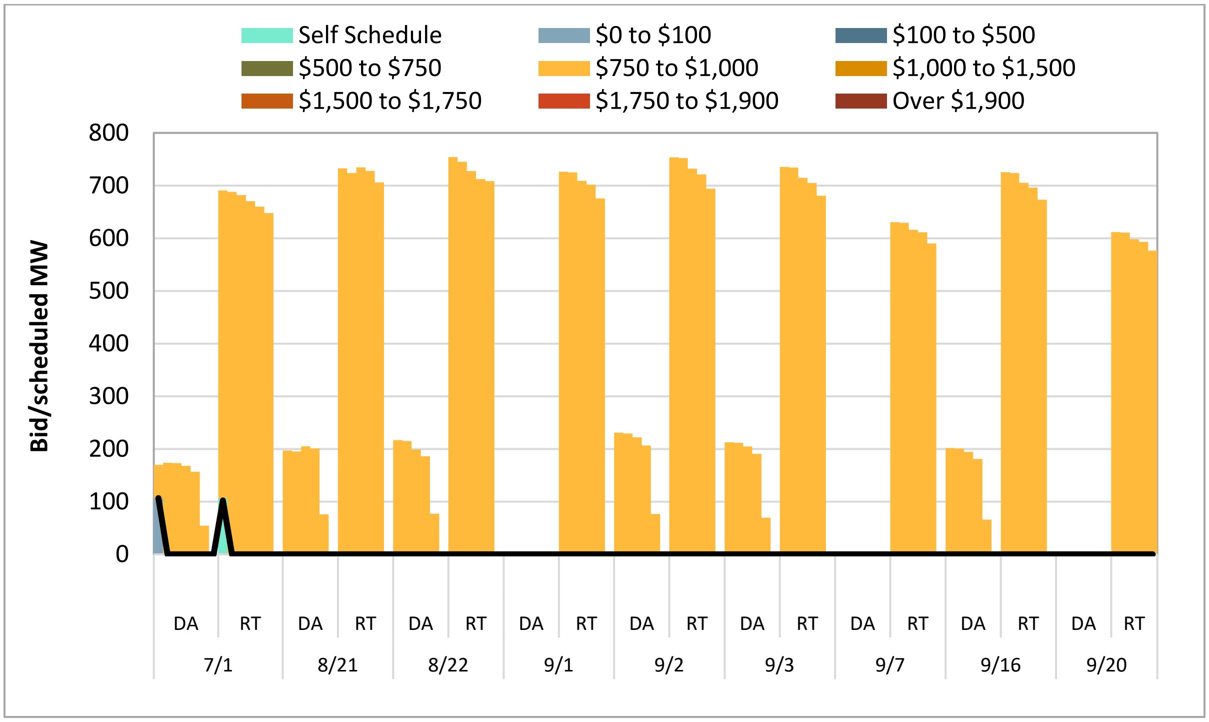
Figure 2.8 shows day-ahead and real-time bids for reliability demand response counted towards resource adequacy requirements. Reliability demand response resources (RDRRs) may bid economically in the day-ahead market, however incremental reliability demand response capacity offered into real-time must submit bids at or above 95 percent of the ISO's current energy bid cap, and can only be dispatched under an Energy Emergency Alert (EEA) Watch or greater. This change was implemented in summer 2023. Prior to this change, reliability demand response could only be dispatched in the real-time if the ISO was in an EEA 2 or greater. In July 2023, the CPUC clarified reliability demand response should be available prior to an emergency, and instructed the ISO to allow operators to dispatch RDRR in an EEA Watch.[17]

[17] Following this CPUC decision, the ISO updated their operating procedures: https://www.caiso.com/Documents/4420.pdf

Figure 2.8 also shows that reliability demand response resources were scheduled on exactly one day in summer 2025.

Bids from reliability demand response resources must be at least 95 percent of the bid cap in the real-time market. Under normal conditions, the bid cap is $1,000/MWh but under stressed system conditions, the bid cap is raised to $2,000/MWh.[18] Due to no such conditions in summer 2025, RDRR was bid under $1,000 on all analysis days. RDRR did not bid in the day-ahead markets on September 1, a holiday, and September 7 and 20, weekends.

Figure 2.8 Reliability demand response resource adequacy bids



2.4 Demand response performance

This section details the self-reported performance of both utility demand response and supply plan demand response resources on analysis days in summer 2025. The aggregate performance of utility demand response, both proxy demand response and reliability demand response, averaged about 84 percent of their scheduled load curtailment during analysis days, similar to summer 2024. The performance of third party demand response averaged 134 percent of their scheduled curtailments, considerably higher than the previous summers.[19] The high performance of third party demand response appears to be due to the lower level of resources that were scheduled compared to previous

[18] FERC Order 831. See additional information on conditions in DMM's *Q1 2021 Market Issues and Performance* report, June 9, 2021, pp 93-96: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

[19] Performance here refers to uncapped performance where responses are not capped at each resource's scheduled load curtailment. The performance of third party demand response where responses are capped at each individual resource's scheduled load curtailment is much lower, at 65 percent.

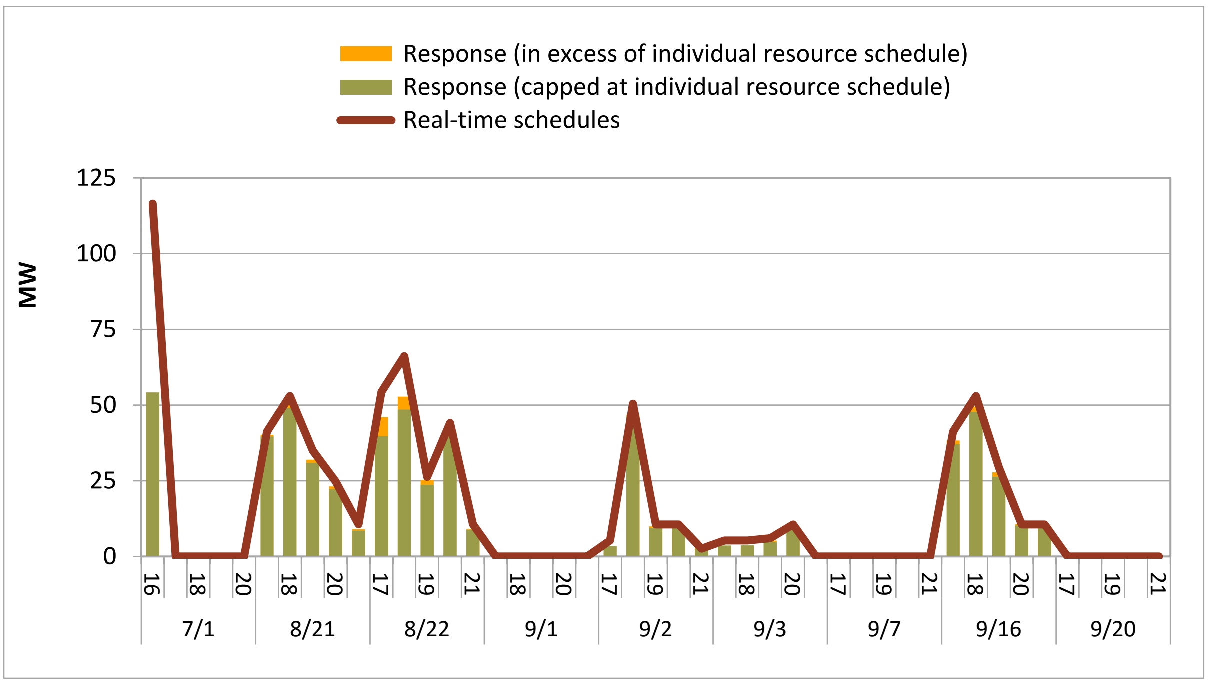
years. Reviewing performance data across years, performance appears to be higher at lower levels of dispatch.

Utility demand response performance

Figure 2.9 shows real-time dispatches and self-reported response of CPUC-jurisdictional utility demand response capacity on analysis days. Figure 2.9 reflects both proxy demand response and reliability demand response capacity scheduled by CPUC-jurisdictional investor-owned utilities. Non-CPUC jurisdictional demand response programs are not currently tied to specific resources in the ISO market and thus are not included in Figure 2.9.

Figure 2.9 depicts self-reported response capped at individual resources' dispatch instructions (green bar), and self-reported response in excess of individual resource dispatches (yellow bar). These metrics indicate that some individual resources under-performed while other resources reported to curtail load in excess of dispatch instructions.

Figure 2.9 CPUC-jurisdictional utility demand response performance



The performance of CPUC-jurisdictional demand response resources, capped at individual resource schedules, averaged 80 percent of their real-time schedules during analysis days this summer. In aggregate, the total CPUC-jurisdictional utility demand response fleet, including excess curtailed load, averaged 84 percent of their real-time schedules. Overall, this is a decrease in performance relative to high load days in summer 2024.

The largest amount of utility demand response was dispatched on July 1, with about 115 MW scheduled during hour-ending 16. This is the only hour in 2025 when reliability demand response was scheduled. Resources reported to curtail about 55 MW in hour-ending 18. These reported curtailments include load curtailment in excess of individual resource dispatches and suggest a performance of 47 percent. Proxy demand response performance on this day was worse than the average performance across all nine analysis days in summer 2025, explained in detail below.

Figure 2.10 and Figure 2.11 show CPUC-jurisdictional demand response performance, split between proxy and reliability demand response capacity. Including curtailments above individual resources' schedules, the performance of proxy demand resources averaged 89 percent of their scheduled curtailments and reliability demand response resources averaged 50 percent during the high load days of this summer when the resources were dispatched. Compared to summer 2024, proxy demand response resources recorded similar performance while reliability demand response resources recorded much lower performance when dispatched.

Figure 2.10 CPUC-jurisdictional utility proxy demand response performance

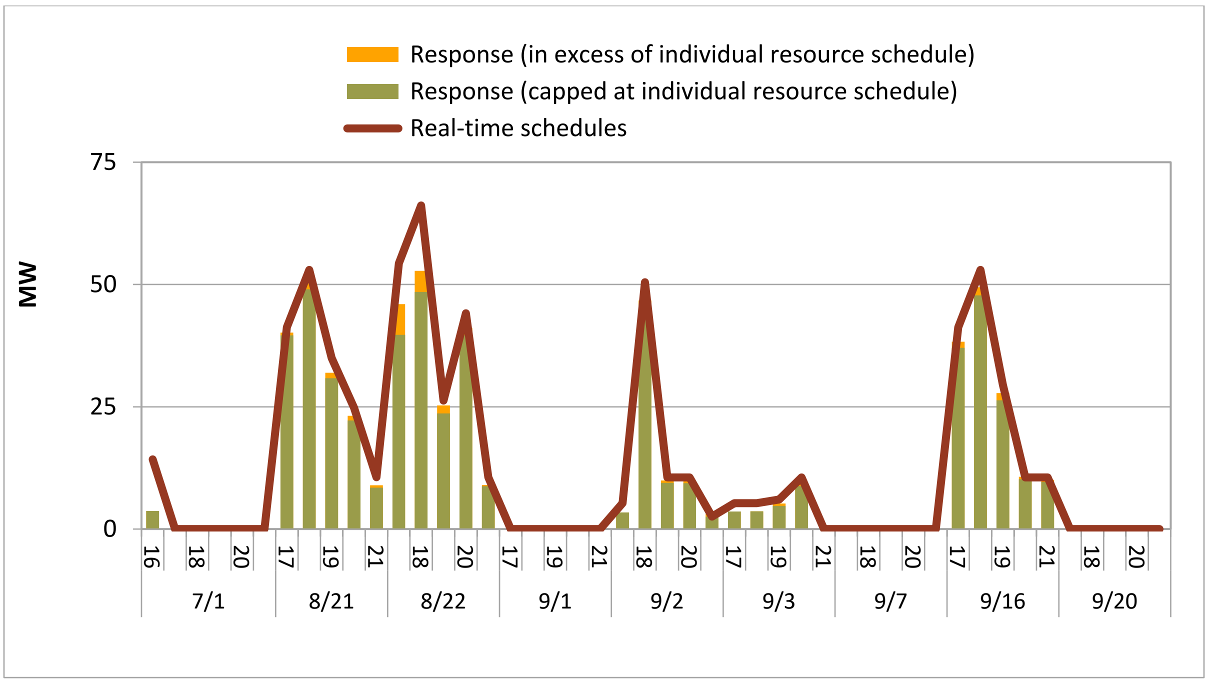
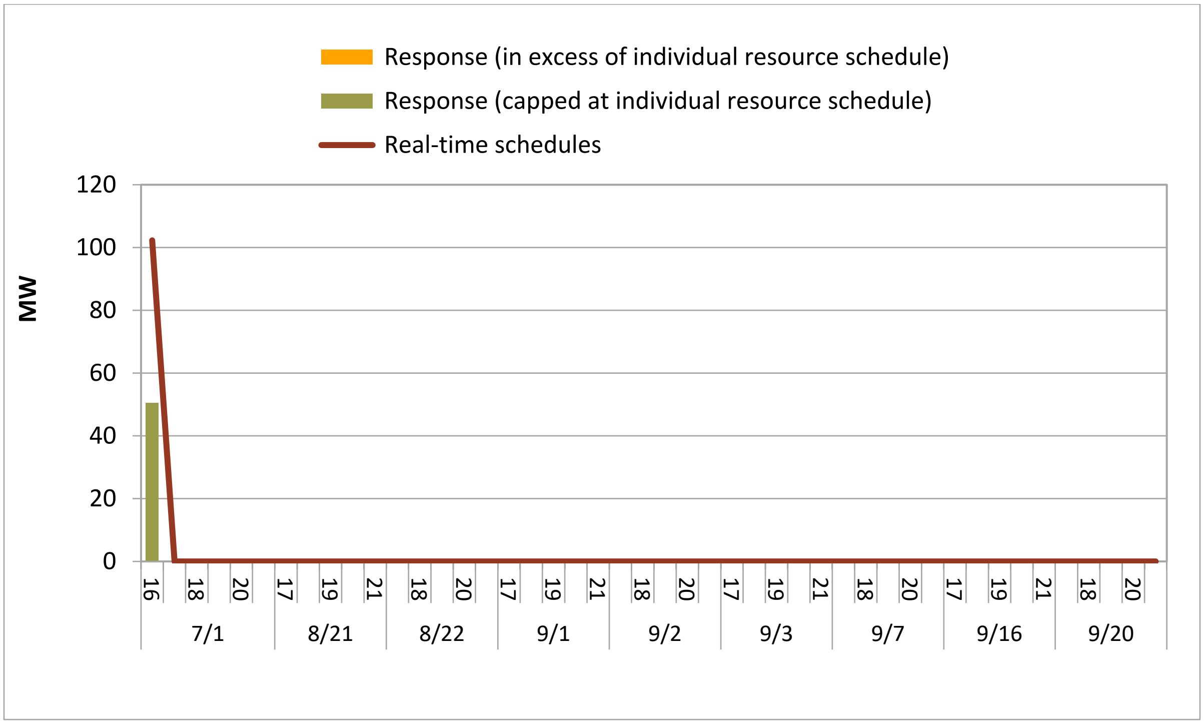


Figure 2.11 CPUC-jurisdictional utility reliability demand response performance



Supply plan demand response performance

Figure 2.12 shows the self-reported response of third party demand response resources shown on resource adequacy supply plans. The aggregated self-reported response of all third party demand response resources can be measured in two ways. First, aggregated performance can be measured with the response of each individual resource capped at the scheduled load reduction for each resource. Second, aggregated performance can be measured without capping the response of each individual resource capped at the scheduled load reduction for each resource. These two measures can vary significantly when the reported load reductions are well below scheduled reductions for some resources, while reported reductions for other resources are well above scheduled levels.

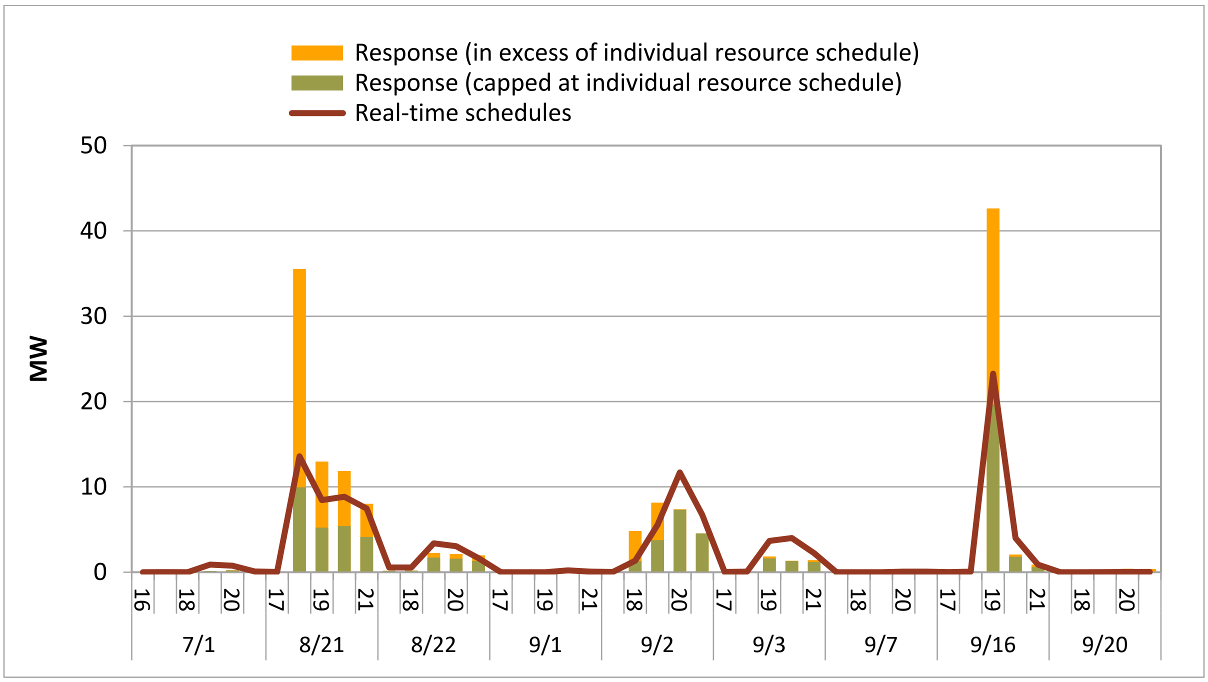
Figure 2.12 shows self-reported response capped at individual resources' scheduled level (green bars) and self-reported response in excess of scheduled reductions for individual resource schedules (yellow bar). When reported demand reductions are capped at the scheduled reductions for individual resources, aggregate reductions averaged 65 percent of total scheduled reductions during analysis days in summer 2025. When adding in load curtailments in excess of individual resource schedules, aggregate performance of supply plan demand response resources averaged 134 percent.

While some difference can be expected between these two measures of overall demand response performance, the large difference between these measures in summer 2025 raises some concern over the performance of this type of demand response and the way this performance is measured. To the extent some resources underperform while others overperform during the same time interval, aggregate performance may still be close to scheduled levels.

However, as shown in Figure 2.12, the aggregate performance of these demand response resources tended to vary significantly from scheduled load reductions during many high load hours. While supply plan demand response tends to bid in close to their resource adequacy values, their average performance compared to their schedules suggests this available capacity may be inaccurate when individual resource schedules are high.

Notably, supply plan demand response was scheduled in real-time far less often than in previous years. In 2025, an average of 2.5 MW was scheduled in each hour of the analysis days, compared to 11 MW in 2024.

Figure 2.12 Supply plan demand response performance

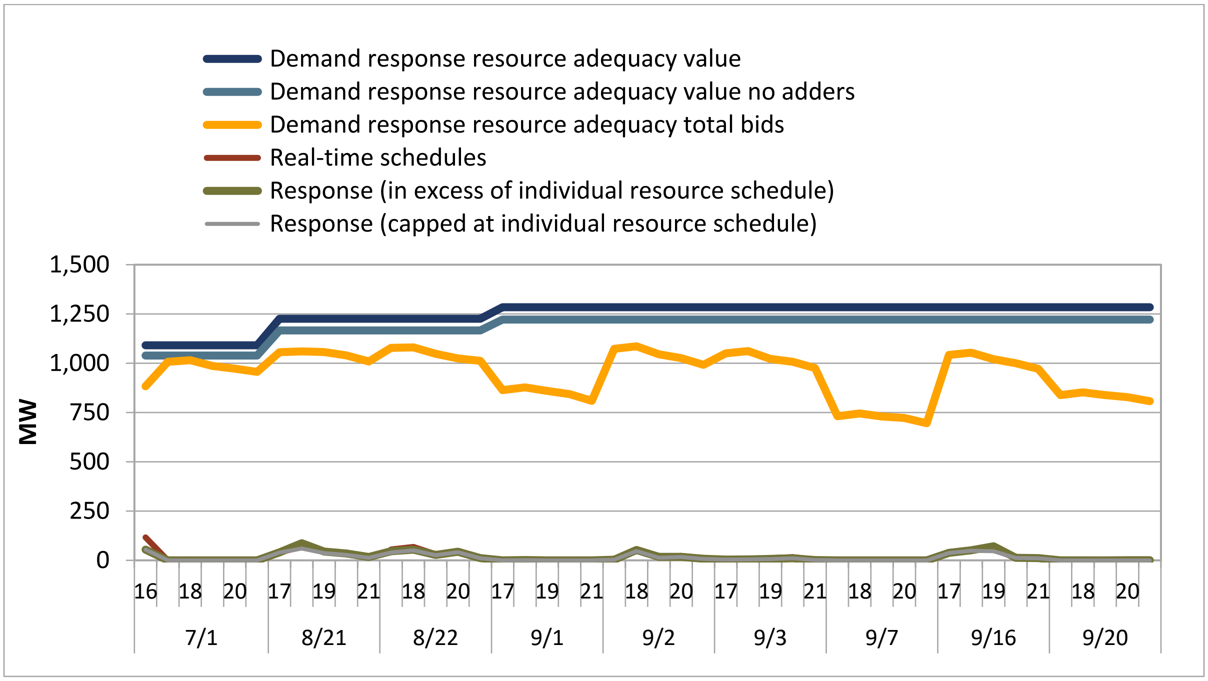


2.5 Demand response aggregate summary of availability, dispatch, and performance

Figure 2.13 shows the availability, dispatch, and self-reported response of *all* demand response capacity (credited utility and supply plan demand response) counted towards resource adequacy obligations on high load days across the summer. Figure 2.13 includes both credited utility and supply plan demand response capacity. Figure 2.13 shows that demand response availability, as reflected through market bids, averaged about 75 percent of resource adequacy values. This is a reduction from summer of 2024, when availability of resource adequacy demand response averaged about 80 percent during high load, and even lower than in summer of 2023, when availability averaged 85 percent. Availability was lower for both utility and supply plan demand response, in part due to some analysis days in summer 2025 falling on holidays or weekends, when availability tends to be lower.

Figure 2.13 also depicts the real-time schedule of demand response resource adequacy (red line) along with their reported performance capped at individual resources' schedules (grey line) and reported performance in excess of schedules (solid green line). Including load curtailment in excess of individual resources' schedules, total demand response averaged 90 percent of real-time dispatches across peak net load hours on high load days. This is a modest decrease from 91 percent in the summer of 2024.

Figure 2.13 Aggregate demand response resource adequacy



3 Special issues in CAISO balancing area

This section discusses a variety of issues related to demand response participation in the CAISO balancing area.

3.1 Baseline adjustment factors

Demand response baseline calculations generally rely on historical like-day metered load to establish the day-of counterfactual load baselines from which demand response performance is measured.[20] The ISO allows for baseline calculations to be adjusted upward and downward to capture intraday load deviations from historical levels. However, the ISO has developed tariff-defined caps on the amount that intraday baselines can be adjusted, with caps specified for each baseline methodology.[21]

In 2020, supplier-submitted baseline and meter data and historic load trends suggested that there was evidence that baseline adjustments could have been limited in the upward direction by tariff-defined baseline adjustment caps. Self-reported meter data and system load trends indicated that, on high-load days, certain customer loads may have deviated from historic days' load by factors greater than the ISO's baseline adjustments allowed. This could have resulted in self-reported performance values that were lower than actual load reduction, if baselines could not be adjusted sufficiently upward.

Given concerns that demand response performance could be under-represented due to the capped baseline adjustment factor, the ISO began to allow demand response providers to apply adjustment factors to baselines in excess of tariff-defined caps for certain baseline methodologies in summer months (May to October), should event day load exceed historic load by more than the ISO's capped ratios.[22] In the summer of 2025, 57 percent of all demand response capacity used alternative adjustment factors (AAF) in summer months, about the same as in 2024. A combination of proxy demand response and reliability demand response resources using day-matching baseline types were eligible to use alternative adjustment factors.

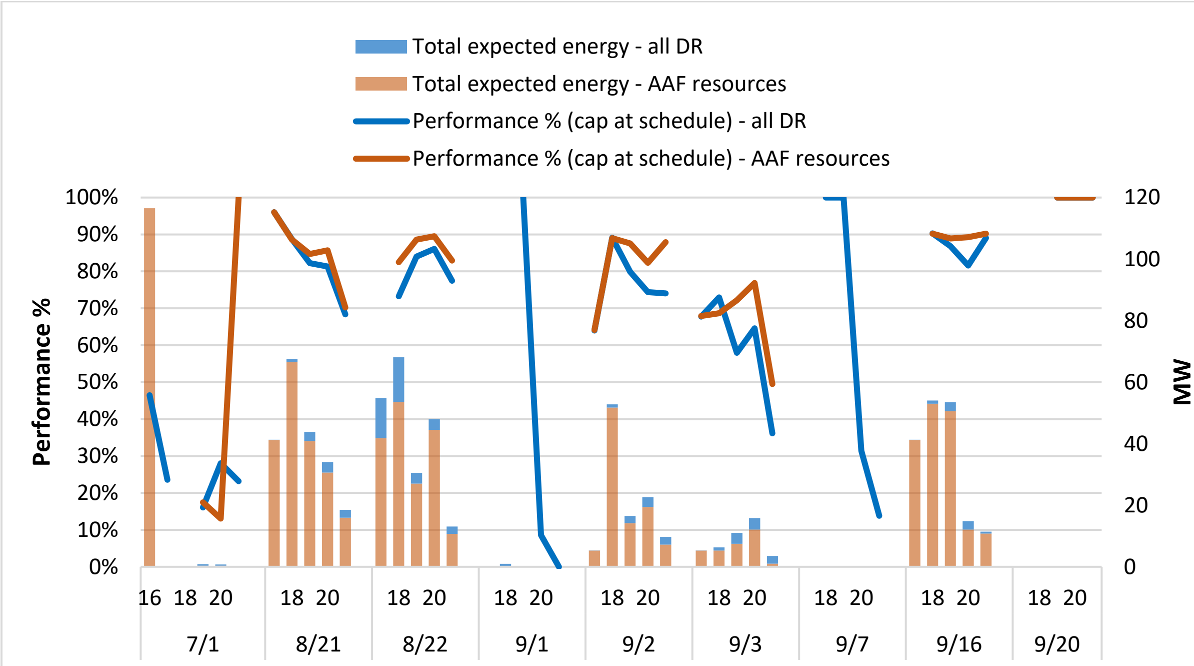
Figure 3.1 shows the performance of demand response resources using alternate adjustment factors compared to all demand response resources. Overall performance is very similar for resources who utilize the alternative adjustment factors compared to the entire demand response fleet. Average performance on high load days for resources using the alternative adjustment factors averaged 84 percent while resources without averaged 73 percent, indicating the uncapped adjustment factors may help demand response resources report slightly higher performance values.

[20] These baseline methodologies include the ISO's Day Matching baseline methodologies which are currently the most commonly used baseline methodologies for demand response resources.

[21] ISO Tariff Section 4.13.4

[22] *Demand Response Customer Partnership Working Group*, California ISO, April 22, 2021: http://www.caiso.com/Documents/Presentation-DemandResponseCustomerPartnershipGroup-Apr22-2021.pdf

Figure 3.1 Performance of demand response resources with alternative adjustment factors



3.2 Resource adequacy demand response compensation

This section examines the revenue streams for demand response providing resource adequacy. Capacity payments (or value of avoided capacity procurement for utilities) for demand response resources can be much higher than potential net market revenues earned in the energy market. High capacity payments relative to potential market revenues can limit the incentive for demand response resources to participate in the energy market and earn additional market rents on a regular basis. Additionally, while the ISO's resource adequacy availability incentive mechanism (RAAIM) provides some incentives for supply plan demand response resources to remain available, RAAIM does not provide incentives for resources to actually deliver scheduled load curtailment.

Demand response market revenues

Table 3.1 shows net market revenues (market revenues, less bid costs, plus bid cost recovery) of demand response resources counted towards resource adequacy requirements, by resource type. Net market revenues are reflected in dollars per megawatt-hour of energy delivered.

Net market revenue per megawatt-hour of energy delivered varied significantly among demand response resource types. In 2025, utility proxy demand response resources earned about $46/MWh while third party demand response resources earned about $60/MWh of energy delivered. Reliability demand response resources earned the highest value of about $79/MWh.

Table 3.1 Demand response resource adequacy net market revenues – 2025

Demand response type	MWh scheduled	Energy delivered (MWh)	Energy market revenues ($/MWh delivered)	Bid costs ($/MWh delivered)	Bid cost recovery ($/MWh delivered)	Net energy market revenues ($/MWh delivered)
Utility PDR	34,981	32,522	$54	$8	$0	$46
Utility RDRR	102	50	$78	$0.12	$1.42	$79
3rd party PDR	2,136	3,032	$55	-$4	$0	$60

Demand response net market revenues and capacity value

Table 3.2 shows net market revenues accrued by demand response resources counted towards meeting resource adequacy requirements compared to potential capacity values for demand response resources in 2023, 2024, and 2025.

The capacity values shown in Table 3.2 are based on the 85th percentile of resource adequacy prices as reported in the CPUC's 2023 Resource Adequacy report.[23] Annualized capacity prices are based on the 2023-2024 budgets for the CPUC's Demand Response Auction Mechanism (DRAM) and DRAM capacity shown on resource adequacy supply plans.

Table 3.2 Demand response resource adequacy net market revenues and capacity costs (2023–2025)

Year	Demand response type	Net energy market revenues ($/kW-year)	Capacity price - system RA 85th percentile ($/kW-year)	Capacity price - DRAM auction ($/kW-year)
2023	Utility PDR	$8.22	$20.00	$157.07
	Utility RDRR	$0.75		
	3rd party PDR	$7.30		
2024	Utility PDR	$1.59	$30.00	$206.42
	Utility RDRR	$0.41		
	3rd party PDR	$2.67		
2025	Utility PDR	$7.48	$25.00	NA[24]
	Utility RDRR	$0.01		
	3rd party PDR	$1.78		

Table 3.2 shows that in 2025, the primary revenue stream for demand response resource adequacy resources continued to be the capacity payments they received. Net energy market revenues increased for utility PDR, but decreased for utility RDRR and third party PDR compared to 2024, but remained lower than the estimated capacity prices for resource adequacy. This does not provide a strong incentive

[23] *2023 Resource Adequacy Report*, CPUC Energy Division, August 2025: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-resource-adequacy-reportv2.pdf

[24] The Demand Response Auction Mechanism was discontinued by the CPUC in 2025.

for resources to deliver load curtailments. To strengthen incentives to be available and perform, DMM has recommended the ISO consider developing a performance penalty or incentive structure for resource adequacy resources, particularly for demand response resources.

4 Demand response in WEIM entities

This section provides a summary of demand response participation from the Western Energy Imbalance Market (WEIM) entities. Primarily, WEIM entities report out-of-market demand response activities as projected adjustments to their load forecasts, generally referred to as load adjustments. Load adjustments can be made to the overall load forecast used in the market optimization, or separately to the load forecast to be considered for the WEIM resource sufficiency evaluation. In 2025, WEIM entities submitted load adjustments through both of these mechanisms during 81 distinct hours. Collectively, these adjustments totaled -20,070 MWh over the year, corresponding to an average adjustment of -250 MW in hours when a load adjustment was submitted. Averaged across all hours of the year, load adjustments amounted to approximately -2 MW per hour, representing about 0.003 percent of the WEIM's average system load of 78.3 GW in 2025.

Alternatively, demand response in WEIM entities can participate in the California ISO market as pseudo-generation under the non-generator resource – dispatchable demand response (NGR-DDR) participation model.

4.1 Non-generator resource dispatchable demand response

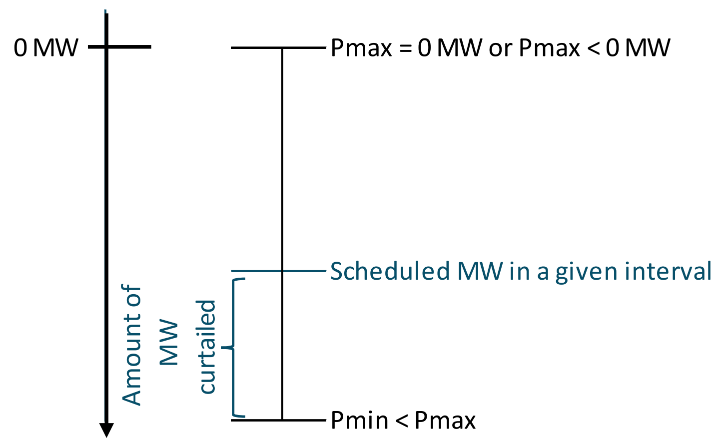
Non-generator resource dispatchable demand response (NGR-DDR) represents a resource that is capable of curtailing load in response to ISO market signals, similar to a participating load. This model allows industrial loads or aggregated loads to participate in the ISO markets as though they are generators, treating these loads as dispatchable grid assets. The operation range of NGR-DDR resources are in the non-positive range and ramp continuously. The ISO market dispatches NGR-DDR resources in the positive direction, from a negative level of generation upwards toward zero as these loads curtail. Unlike the proxy demand response and reliability demand response models. NGR-DDR resources can provide regulation. However, ancillary services are not optimized in the WEIM. NGR-DDR resources require telemetry at the level of resource aggregation separate from any other load at the aggregation point.

Each NGR-DDR must schedule load with a single scheduling coordinator in the market. The key Masterfile characteristics of NGR-DDR resources are:

(1) The minimum generating capability, or Pmin, represents the load curtailment when the resource has not been dispatched, or directed to curtail load. The Pmin is a negative value.
(2) The maximum generating capability, or Pmax, represents the load curtailment when the resource has been dispatched to curtail load to its full curtailment capability. In many cases, this value is exactly zero MW. In some cases, NGR-DDR resources may be characterized by a negative Pmax value.
(3) The curtailment energy limit, in megawatt-hours, is the maximum amount of load that an NGR-DDR can curtail in a given period.
(4) The ancillary service certifications, including certified spin/non-spin/regulation amount.

A typical bid for an NGR-DDR resource includes bid curves for energy, regulation, and spin. There are no startup or minimum load costs. Table 4.1 provides an illustration of the operating range of an NGR-DDR resource, as well as how to interpret the amount of curtailment in megawatts.

Table 4.1 Non-generator resource-dispatchable demand response – operating range



4.2 Demand response load adjustments

WEIM entities can submit load adjustments to reflect demand response programs and other forms of load flexibility that may not otherwise be captured in market forecasts or the resource sufficiency evaluation. These adjustments may be positive or negative, representing expected load reductions, additional demand, or post-event load recovery, and can affect both resource sufficiency requirements and real-time market optimization forecasts.

Demand response-based load adjustments in the resource sufficiency evaluation

WEIM entities may submit load forecast adjustments in the resource sufficiency evaluation to reflect demand response programs which could not be otherwise accounted for in the real-time market. This adjustment is included in both the capacity and flexibility tests, and impacts the load used in the requirements of both tests.

Load adjustments can be either positive or negative. A negative adjustment reflects a lower load forecast, such as load reductions from a demand response program. This will decrease the requirement for the upward capacity and flexibility tests, but increase the requirement for the downward tests. A positive load adjustment increases requirements and reflects additional demand because of expected pre-cooling or post-demand-response event increases (sometimes referred to as “snapback”). The feature to adjust the load forecast in the tests based on a demand response program was used by five balancing areas during the third quarter: BANC, Idaho Power, NV Energy, PacifiCorp East, and PacifiCorp West.

For ease of visual interpretation, all instances of demand response-based load adjustments are separated into two charts: (1) long durations—when a balancing area submitted demand response-based load adjustments for periods of 12 or more consecutive hours; and (2) short durations—when a balancing area submitted such an adjustment for less than 12 hours at a time. Figure 4.1 reports all instances where any balancing area submitted demand response-based load adjustments for long durations. Idaho Power, PacifiCorp East, and PacifiCorp West submitted negative load forecast adjustments for such extended periods during the quarter. Figure 4.2 shows the same information for short durations of demand response-based load adjustments. PacifiCorp East submitted large positive load adjustments on July 15, July 17, and August 5.

During the quarter, these adjustments had no impact on any balancing area passing or failing the resource sufficiency evaluation.

Figure 4.1 Demand response-based load adjustments included in the resource sufficiency evaluation – Load adjustment durations of 12 or more hours (July–September 2025)

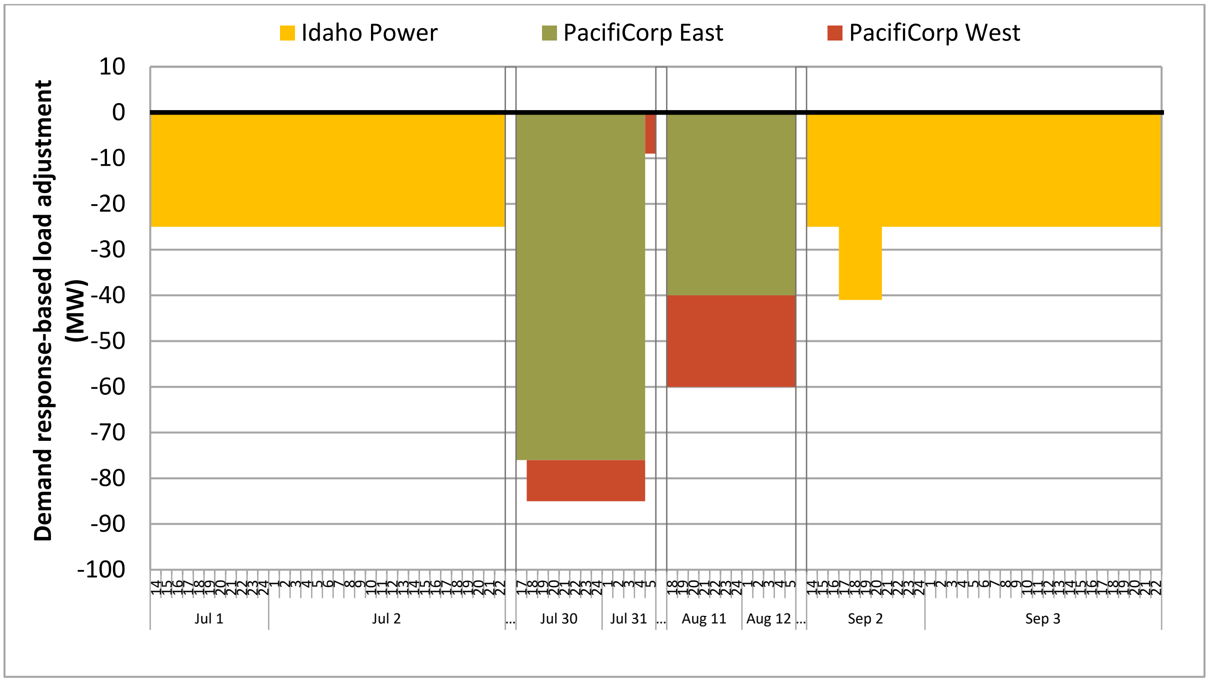
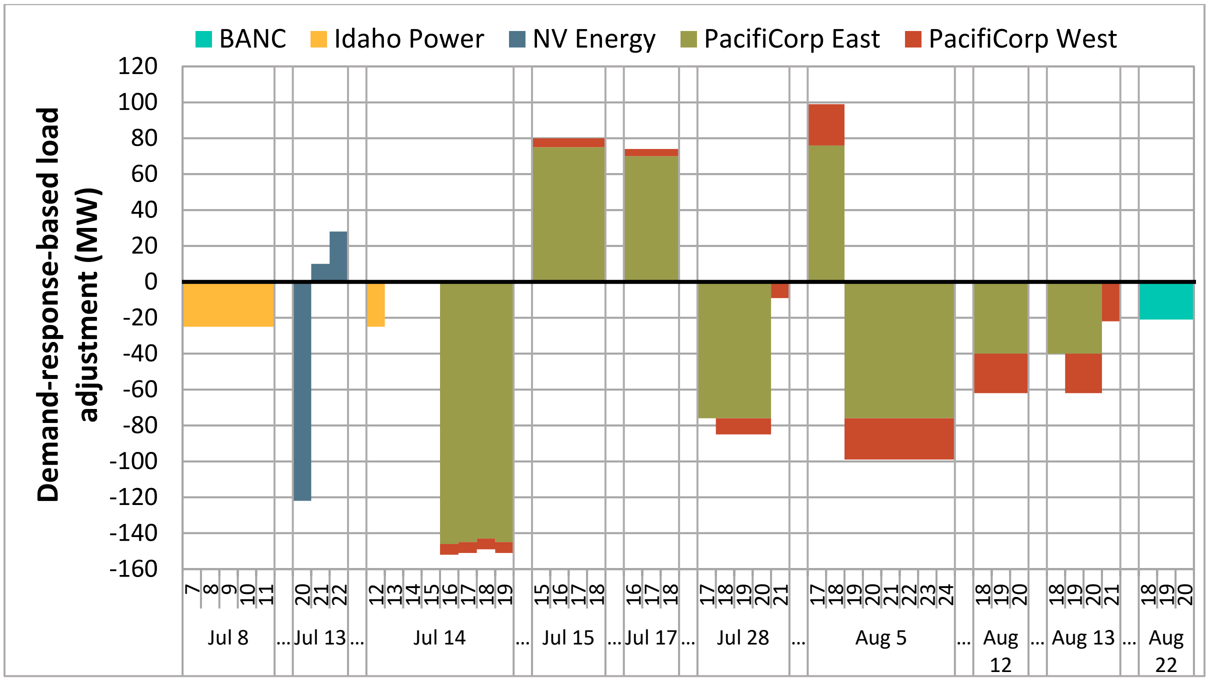


Figure 4.2 Demand-response-based load adjustments included in the resource sufficiency evaluation – Load adjustment durations shorter than 12 hours (July–September 2025)



Load adjustments submitted to short-term forecasting

WEIM entities may submit load adjustments to be incorporated into the demand forecast used in the ISO real-time market optimization. These load adjustments are intended to reflect nonmarket demand response activities and other forms of load flexibility. Load adjustments can be positive or negative. Positive adjustments often occur in the hours immediately preceding or following negative load adjustments. During 2024 through 2025, this option was used by eight balancing areas: Portland General Electric, California ISO, BANC, NV Energy, Arizona Public Service, Salt River Project, LADWP, and Idaho Power.

Figure 4.3 provides a summary of the load adjustments submitted to short-term forecasting by balancing area. Within each stacked bar, an individual color represents average hourly load adjustments submitted during a given month for a specific balancing area. Load adjustments are not uniformly submitted for each hour of the month but only for hours when the load adjustments are non-zero. Thus, only non-zero load adjustment values are considered for the average calculations given in Figure 4.3. The number of hours represented in each month's average load adjustment calculation is indicated at the top of the chart in grey. Figure 4.4 provides a detailed summary of the underlying frequency of load adjustment submissions by balancing area. Within each stacked bar, an individual color represents the total number of hours during a given month for which a balancing area submitted a load adjustment.

Figure 4.5 provides a distribution of load adjustments by hour of day for each balancing area. In this chart, a line indicating a value of 0 MW indicates that *no* load adjustments were submitted by a given balancing area during that hour. All nonzero values represented by the lines in the chart represent the average value of nonzero load adjustments submitted by a given balancing area for a particular hour.

Figure 4.3 Load adjustments submitted to short-term forecasting (2024–2025)

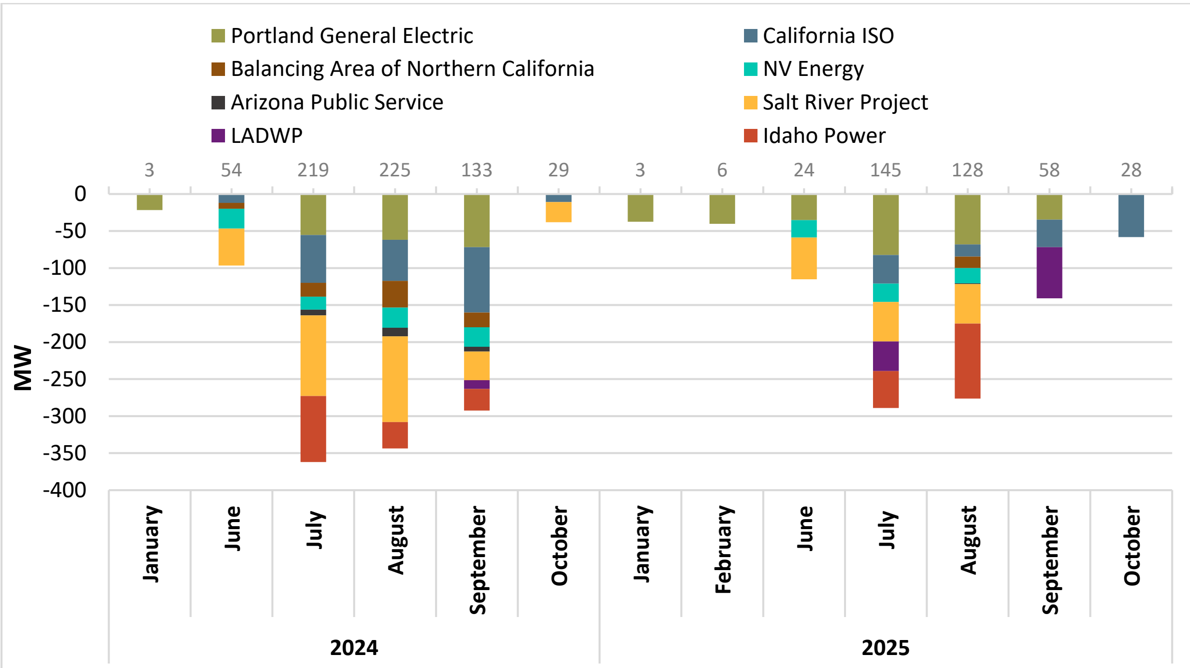


Figure 4.4 Load adjustment-hours submitted to short-term forecasting (2024–2025)

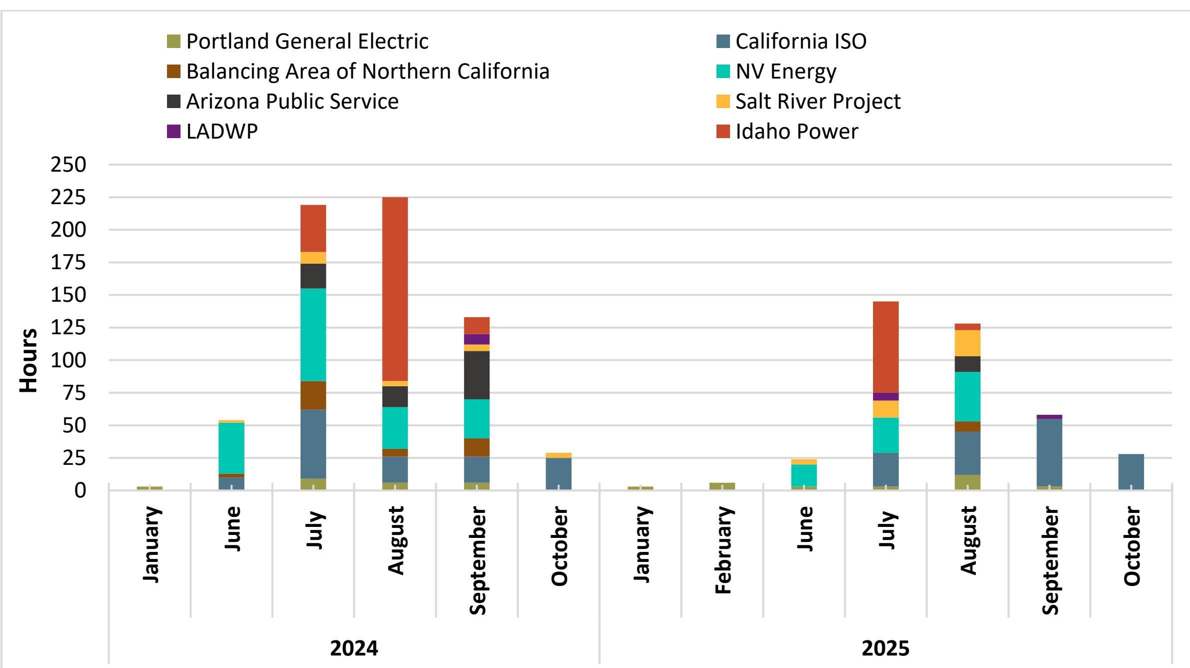


Figure 4.5 Load adjustments submitted to short-term forecasting by hour of day (2024–2025)