California Independent System Operator Corporation

California ISO

Demand response issues and performance 2023

March 6, 2024

Department of Market Monitoring

1 Summary

This report provides analysis of how demand response resources participated and performed in the California ISO market on high load days during summer 2023. The Department of Market Monitoring (DMM) has provided similar analysis of the performance of demand response resources during summers 2020 through 2022.[1] While a larger portion of demand response resource adequacy capacity was available for dispatch in summer 2023 compared to previous years, demand response resources continued to perform below dispatched levels during key peak net load hours. 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

Demand response accounted for roughly 3 percent of total system resource adequacy capacity (about 1,680 MW) in July and August 2023. About 80 percent of this capacity is comprised of utility demand response programs. This capacity is subtracted from the resource adequacy requirements of the load serving entities. The remaining 20 percent 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 it is explicitly shown on monthly resource adequacy plans as supply providing resource adequacy capacity.

This report focuses on the availability, schedules, and performance of demand response resources counted towards resource adequacy requirements on days when the ISO issued a Restricted Maintenance Operations (RMO) notice or an Energy Emergency Alert (EEA). The ISO declared an EEA 1 on July 20, two EEA Watches on July 25-26, and issued RMO notices on August 15-17 and August 28-30. Previous reports have focused specifically on days when the ISO called Flex Alerts, but there were no Flex Alerts declared in summer 2023.

1.2 Key findings

Key findings in this report include the following:

- **About 85 percent of demand response capacity used to meet resource adequacy requirements was available to be dispatched in peak net load hours on days where the ISO issued system warnings or restricted maintenance operations.** This is an improvement from the previous two years when about two thirds of resource adequacy demand response was unavailable. This improvement is due in part to high load days in 2023 not falling on any holidays or weekends, when availability of demand response resources tends to be lower.

[1] *Report on demand response, issues and performance*, February 25, 2021: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

Report on demand response, issues and performance, January 12, 2022: http://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf

Report on demand response, issues and performance, February 14, 2023: https://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf

- **On high demand days in the summer, about 76 percent of the demand response capacity dispatched in real-time was reported to have performed as scheduled.** Utility demand response reported substantially higher performance than third party demand response. Utility demand response reported to curtail about 88 percent of scheduled load reductions, while performance of supply plan demand response averaged 46 percent of scheduled load reductions.

- **The resource adequacy capacity of proxy demand resources on high load days is likely overstated, as evidenced by low availability from utility proxy demand response and poor performance of supply plan proxy demand.** Only 41 percent of utility proxy demand response resource adequacy capacity was bid into market on high load days in summer 2023. While almost 100 percent of supply plan resource adequacy capacity bid into the markets on high load days, performance only averaged 46 percent of scheduled load curtailments. The poor performance of third party demand response and the low availability of utility proxy demand response suggests the resource adequacy values of proxy demand resources may not accurately reflect these programs' ability to curtail load during peak hours of high load days.

- **In July 2023, the California Public Utilities Commission clarified that the ISO should be able to dispatch reliability demand response in the real-time upon the declaration of an Energy Emergency Alert (EEA) Watch.** Previously, reliability demand response could only be dispatched in the real-time if the ISO was under EEA 2 or higher. On July 20, 2023, the ISO was in EEA 1 and reliability demand response was dispatched in the real-time. All other times that reliability demand response was dispatched in summer 2023 resulted from these resources being economically scheduled in the day-ahead market.

- **The primary revenue sources for demand response resources come from capacity payments (or the value of reduced resource adequacy requirements) rather than from energy market revenues.** Even for demand response resources that 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.[2] This current market framework does not provide a strong financial incentive for most demand response resources to perform when needed, and may incentivize providers to sell and offer more capacity than they can realistically deliver, if there are not adequate non-performance penalties.

1.3 Policy changes and recommendations

In prior reports, DMM has highlighted some recommendations that the ISO and California Public Utilities Commission (CPUC) could consider to enhance the availability and performance of demand response resources.[3] The CPUC recently made a number of changes to the treatment of demand response resources that count towards resource adequacy requirements. In July 2023, the CPUC clarified that reliability demand response could be dispatched in the real-time if the ISO was in EEA Watch or higher, a change from previous summers when the ISO had to be in EEA 2 or higher. In addition, starting in 2024:

- **Transmission gross-ups and the planning reserve margin adder will be removed from credited utility demand response resource adequacy values.** DMM previously

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[2] *Report on demand response, issues and performance,* February 14, 2023, pp 23-25: https://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf

[3] *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

recommended the CPUC reconsider the transmission and distribution gross-ups and the planning reserve margin (PRM) adder because evidence suggested the resource adequacy values of utility demand response was over-estimated. During high load days the past two summers, only about 65 percent credited utility demand response capacity was bid into the market on average. DMM stated this might be due in part to the CPUC-jurisdictional demand response gross-ups and PRM adder. Starting in 2024, the CPUC will not apply the transmission gross-up or the planning reserve margin to demand response capacity.

- **Demand response resource adequacy capacity must be available during all days during which the ISO calls a Flex Alert, issues a Grid Warning, or the Governor's Office has issued an emergency notice.** In addition, the CPUC now requires all demand response capacity to be available a minimum of three days per week for at least four hours per day. The CPUC's Energy Division proposed these changes following the 10-day heat wave in September 2022. DMM supported this proposal to incentivize resource adequacy demand response resources to bid in whatever capacity they have available during hours with tight system conditions.

- **Capacity awarded to demand response resources under the load impact protocol (LIP) process will be de-rated based on performance during test events.** The average performance results of each quarter will be used in determining the capacity awarded through the LIPs for the respective sub-load aggregation point. DMM supported this proposal to incorporate the test results in capacity awards because it may incentivize resources to provide accurate capacity estimates and to perform better when dispatched, which could lead to improved reliability.

- **Proxy demand response bids will be capped at $949/MWh** to ensure proxy demand resources are dispatched before reliability demand response resources.[4] DMM supported this proposal and agrees the proxy demand resources should be used prior to emergency reliability demand response.

DMM recognizes that the ISO, CPUC, and California Energy Commission (CEC) are continuing to work on addressing some important issues pertaining to demand response. This includes enhancing resource adequacy counting methodologies to account for the variable nature of some demand response resources. DMM continues to recommend that the ISO consider other potential changes to enhance the reliability of demand response capacity, which include the following:

- ***Re-examine demand response counting methodologies*.** Demand response appeared to be over-counted in terms of the contribution by these resources toward meeting resource adequacy requirements and their reported load curtailments. DMM supports efforts to better capture the capacity contribution of demand response with load reduction capabilities that vary across the day or that may have limited output in general. The CPUC and CEC are currently working to develop an incentive-based qualifying capacity valuation for supply-side demand response resources.[5] DMM has recommended considering a performance-based penalty or incentive structure for resource adequacy resources. An incentive-based methodology for awarding qualifying capacity to resource adequacy demand response may improve the trend in recent years where availability and

[4] The $949/MWh bid cap will not apply for resources contracted through the demand response auction mechanism (DRAM) for 2024. CPUC Decision (D.) 21-10-002, June 29, 2023, p 144: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF

[5] Ibid, pp 79-81:

performance of proxy demand response resource fall below resource adequacy capacity. The CPUC and CEC will submit a joint proposal in December 2024.

- ***Consider removing the exemption for long-start proxy demand response to be available in the residual unit commitment (RUC) process.*** This exemption does not exist for other types of long-start resources providing resource adequacy. Long-start resources continue to make up a significant portion of the resource adequacy proxy demand response fleet. In July and August of 2023, about 50 percent of supply plan demand response was registered with start-up times of over 255 minutes.[6] If this capacity is not scheduled economically in the integrated forward market, then per the ISO tariff, this capacity has no obligation to be available in RUC.

- ***Consider tariff changes to better define deadlines and penalties on data submission as well as continue outreach to demand response providers to ensure all necessary historical data is available for DMM to assess the validity of baseline submissions.*** Under many of the most frequently used baseline calculation methodologies, demand response providers are required to submit hourly data on their metered load and baseline for the 90 days prior to an event when the resource was scheduled to curtail load. This historical data allows monitoring of the baselines submitted by demand response providers. However, due to lack of a clear timeline and penalties for failing to submit data, DMM has observed significant and ongoing problems with some demand response providers submitting this data. DMM supports the ISO addressing this issue in the upcoming Penalty Enhancements initiative, which is focused in part on defining the penalty structure of demand response monitoring data.[7]
- ***Ensure non-CPUC jurisdictional load serving entities that are using demand response to meet resource adequacy requirements communicate the available capacity to the ISO on a daily basis, so that the ISO is aware of and can call this capacity when needed.*** DMM understands that the ISO has reached out to non-CPUC jurisdictional load serving entities using demand response, to better ensure that the ISO has insight into these demand response programs. It will be important that the ISO have the same insight into other local regulatory authority demand response programs which are counted towards meeting resource adequacy, as the ISO does with CPUC-jurisdictional load serving entity demand response programs.

[6] Long-start resources have a cycle time greater than 240 minutes, where cycle time is a resource's startup time plus minimum run time.

[7] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Penalty-enhancements-demand-response-investigation-tolling

2 Analysis of demand response market participation

This section provides a summary of findings on demand response resource adequacy capacity participating in the California ISO market on high load days in summer 2023.[8]

2.1 Demand response as resource adequacy

Similar to the last three summers, demand response accounted for about 3 to 4 percent of total system resource adequacy capacity in July and August 2023, meeting almost 1,700 MW of system resource adequacy requirements. 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 80 percent of demand response capacity 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 20 percent of demand response capacity used to meet resource adequacy requirements.

Table 2.1 below summarizes the breakdown between credited utility and supply plan demand response capacity counted toward resource adequacy requirements in July and August 2023. In 2023, credited demand response values under the CPUC local regulatory authority (LRA) include transmission and distribution loss factors and planning reserve margin gross-ups.

Table 2.1 July and August demand response resource adequacy capacity (megawatts)

Month	Credited demand response (CPUC LRA)	Credited demand response (Other LRA)	Supply plan demand response	Total MW
July	1,280	49	334	1,663
August	1,324	43	332	1,699

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 and August 2023, this type of demand response capacity accounted for about 1,350 MW of resource adequacy credits.[9]

[8] Defined in this report as days where the ISO issued an Energy Emergency Alert or a Restricted Maintenance Operations notice.

[9] Credited values in 2023 include transmission and distribution loss factors, and planning reserve margin gross-ups.

Almost all of utility demand response capacity (96 percent) are 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. This percentage is comprised of transmission and distribution gross-ups and a planning reserve margin (PRM) adder.

Recently, the CPUC decided to remove the transmission gross-ups and the PRM adder, starting in 2024.[10] In 2022, the PRM adder decreased from 15 percent to 9 percent, and starting in 2024 the CPUC will no longer apply any PRM adder to demand response capacity. The transmission gross-ups average around 3 percent and will also be removed in 2024. The distribution gross-ups average roughly 6.5 percent and will continue to be applied moving forward.

The majority of this IOU capacity (around 70 percent) consists of reliability demand response resources (RDRR), which are primarily called upon under emergency conditions after the ISO issues a system warning.[11] This year, 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.[12]

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 incentive mechanism (RAAIM). Pursuant to D.12-06-029, once the CPUC confirms that the ISO has implemented a 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.[13]

In addition to CPUC-jurisdictional demand response credits, other non-CPUC jurisdictional regulatory authority load serving entities (such as municipal utilities) accounted for about 50 MW of demand response resource adequacy credits in both July and August. 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.

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

[10] CPUC Decision (D.) 21-10-002, June 29, 2023.

[11] Reliability demand response programs are primarily comprised of Base Interruptible Program (BIP) 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.

[12] In 2022, the ISO switched from the Alerts Warnings and Emergencies (AWE) notification system to the North American Electric Reliability Corporation (NERC) Energy Emergency Alerts (EEA) notification system. Under these protocols, the ISO'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.

[13] 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

resources only include proxy demand response resources and are generally subject to the ISO's resource adequacy incentive mechanism (RAAIM).[14]

Supply plan demand response capacity averaged 333 MW in July and August 2023, a 20 percent reduction compared to summer 2022. Supply plan demand response capacity is contracted either through the CPUC's Demand Response Auction Mechanism (DRAM) or bilaterally between third party providers and load serving entities. Previously, most third party demand response was contracted through DRAM but increasingly, more capacity is being contracted bilaterally.

2.2 Availability of demand response resource adequacy capacity

On days when the ISO issued an Energy Emergency Alert (EEA) or a Restricted Maintenance Operations (RMO) notice, about 85 percent of resource adequacy demand response capacity was bid into the ISO market across peak net load hours. This is a substantial increase in the availability of resource adequacy demand response capacity compared to summer 2022.

In summer 2023, the bid-in capacity of utility demand response averaged about 81 percent of resource adequacy credits, compared to 67 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.

In 2023, third party demand response was available up to 96 percent of their resource adequacy capacity in the day-ahead market and 69 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 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

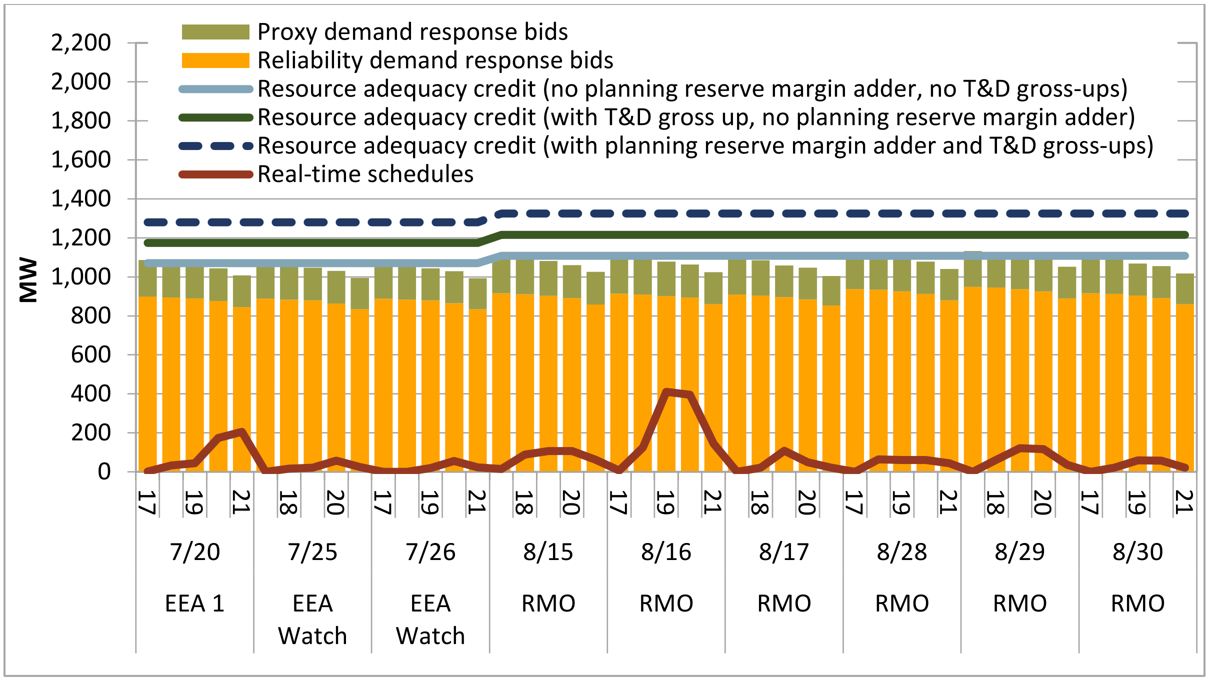
Figure 2.1 shows the availability of CPUC-jurisdictional credited demand response capacity on high load days, compared to total resource adequacy credits in respective months. Figure 2.1 also shows the real-time schedules of ISO-integrated CPUC-jurisdictional utility demand response capacity (both proxy demand response and reliability demand response). Program availability is based on demand response resource bids into the ISO markets. On average, utility demand response resources bid in about 81 percent of the amount of demand response capacity used to meet resource adequacy requirements (after inclusion of the 9 percent planning reserve margin adder, and the transmission and distribution gross-ups).

This is a substantial increase in availability compared to 2021 and 2022, when utility demand response bids fell short of resource adequacy credits by 34 and 33 percent, respectively. The shortfall of bid-in capacity compared to resource adequacy credits was primarily associated with proxy demand response. Since credited demand response resources are not included in resource adequacy supply plans, there is

[14] 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 (4:00 to 9:00 pm) 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 July and August 2023, 18% of supply plan demand response capacity was associated with resources sized less than 1 megawatt and thus were exempt from RAAIM.

limited visibility into which resources were failing to bid in adequate capacity. However, availability was much lower for proxy demand response resources compared to reliability demand response resources.

Figure 2.1 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 2.2 and Figure 2.3 show the bid-in capacity for reliability demand response resources and proxy demand response resources separately.[15] As seen in Figure 2.2, bids from reliability demand response resources met or exceeded the CPUC-jurisdictional credited resource adequacy values for reliability demand response programs.

The percentage of credited utility proxy demand response that bid in during these tight system days was substantially lower, averaging 41 percent of resource adequacy values (including the PRM adder and T&D gross-ups). 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 explain why such a large portion of this capacity was unavailable to the ISO during peak hours on high load days in summer 2023.

In addition, non-CPUC jurisdictional load serving entities claimed an average of 46 MW of demand response resource adequacy credits in July and August, which reduced system resource adequacy obligations for these entities. The ISO did not have insight into the availability of non-CPUC-jurisdictional utility demand response programs as this capacity is not integrated in the ISO market.

[15] The aggregate resource adequacy values in Figures 2.2 and 2.3 vary slightly from Figure 2.1. This is due to Figure 2.1 using data from the CPUC's CIRA Generic Obligations Report, which has total RA Obligations met by DR, while 2.2 and 2.3 use the individual LSE reports that breakdown DR capacity between PDR and RDRR. There are some slight data discrepancies between these two sources.

Figure 2.2 Utility reliability demand response availability and resource adequacy credits

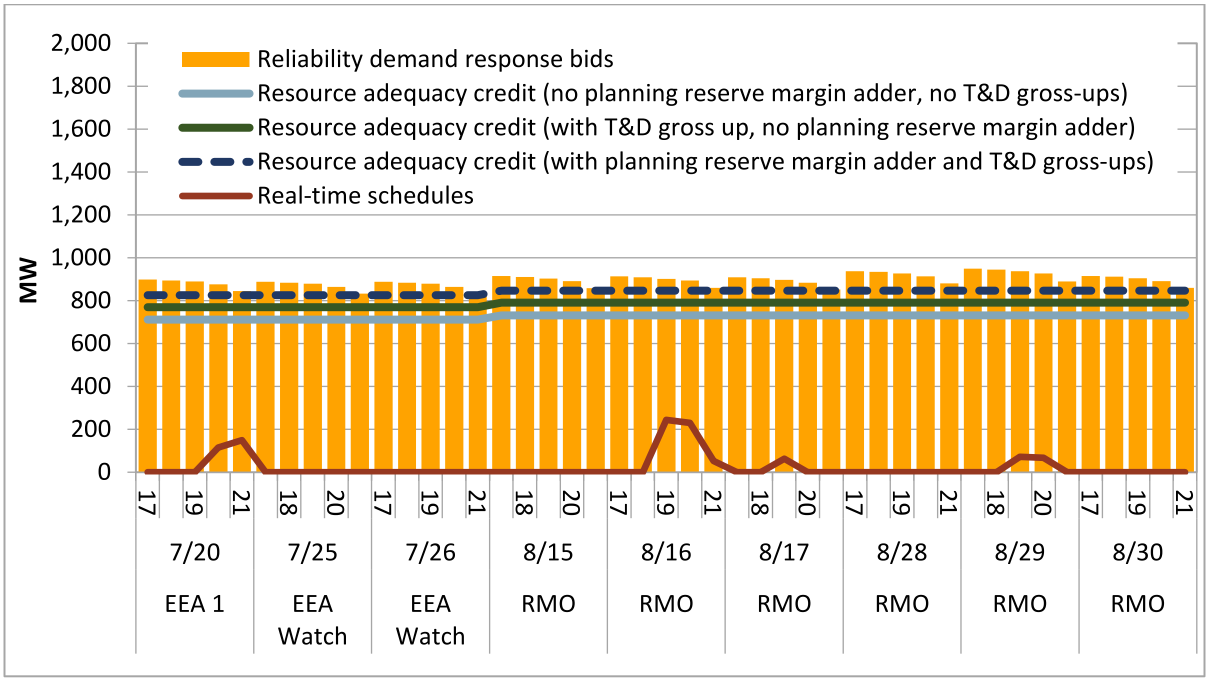
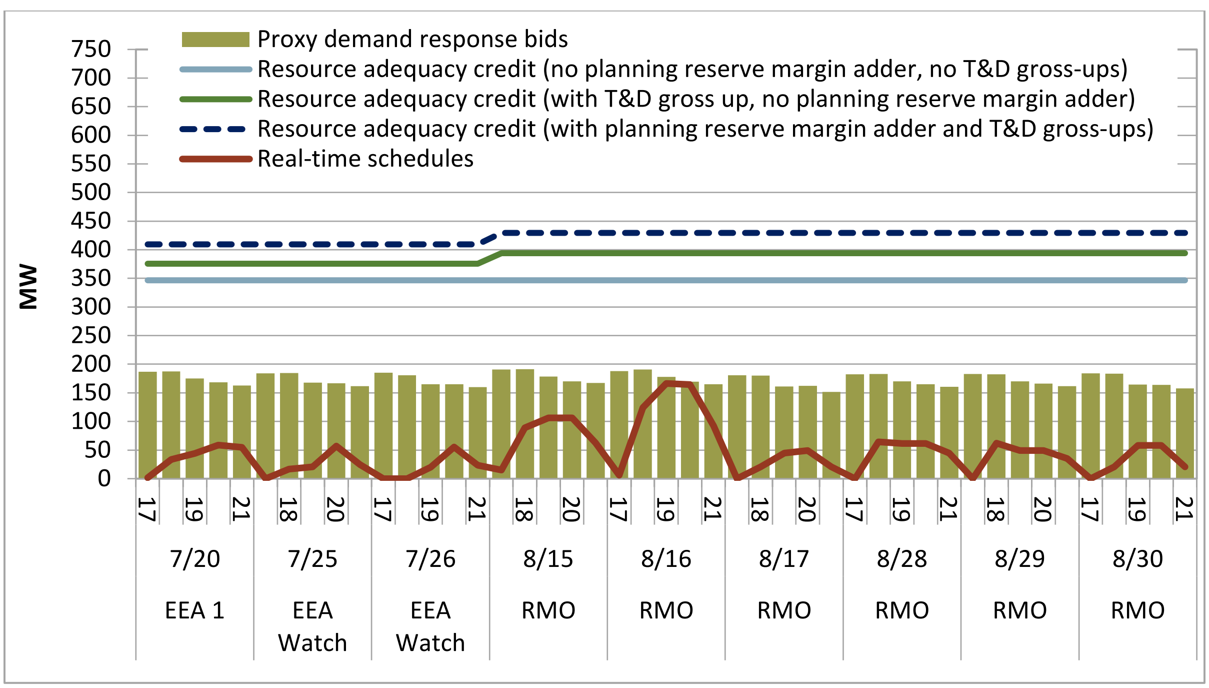


Figure 2.3 Utility proxy demand response availability and resource adequacy credits

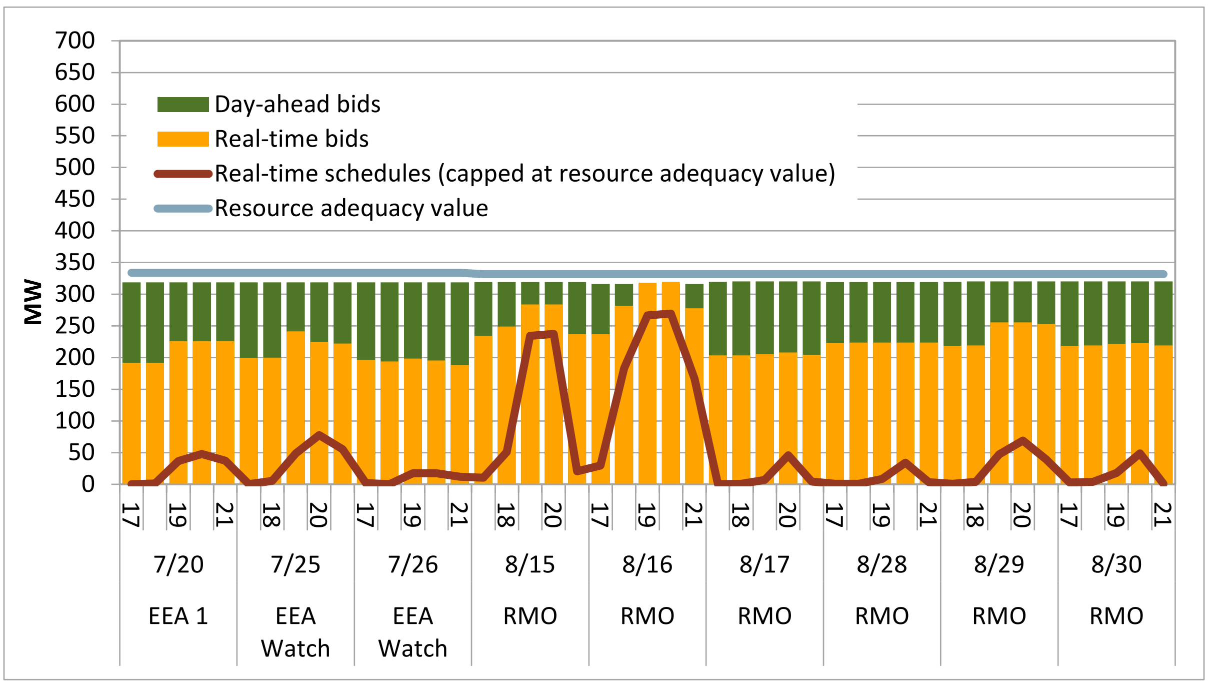


Supply plan demand response availability

Supply plan demand response was largely offered up close to resource adequacy values in the day-ahead market, although a smaller percentage was available in real-time. 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 net peak hours.

Figure 2.4 shows the availability of supply plan demand response capacity as reflected by day-ahead and real-time bids, where bids are capped at individual resource adequacy values. Bids from supply plan demand response resources averaged 96 percent of resource adequacy capacity during high load days in summer 2023. This is an increase from summer 2022, when bid-in capacity in the day-ahead market averaged 75 percent of resource adequacy values. The increase in availability is due in part to high load days not falling on weekends or holidays in summer 2023. In summer 2022, the availability of supply plan demand response averaged 90 percent on non-holiday weekdays but only 35 percent on holidays or weekends.

Figure 2.4 Day-ahead and real-time availability of supply plan demand response



While bid-in capacity from supply plan demand response averaged close to its resource adequacy value in the day-ahead market, only about 70 percent was bid in the real-time market. 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 and therefore are not penalized for being unavailable in the real-time if they are not scheduled economically in the day-ahead market. In July and August of 2023, around 52 percent of supply plan demand resource adequacy capacity was associated with long-start resources.

2.3 Demand response bidding

Figure 2.5 shows day-ahead bid prices and day-ahead schedules across peak net load hours (hours ending 17 through 21) of proxy demand response resources (utility and third party) counted toward resource adequacy requirements.

Figure 2.5 Proxy demand response resource adequacy day-ahead bids

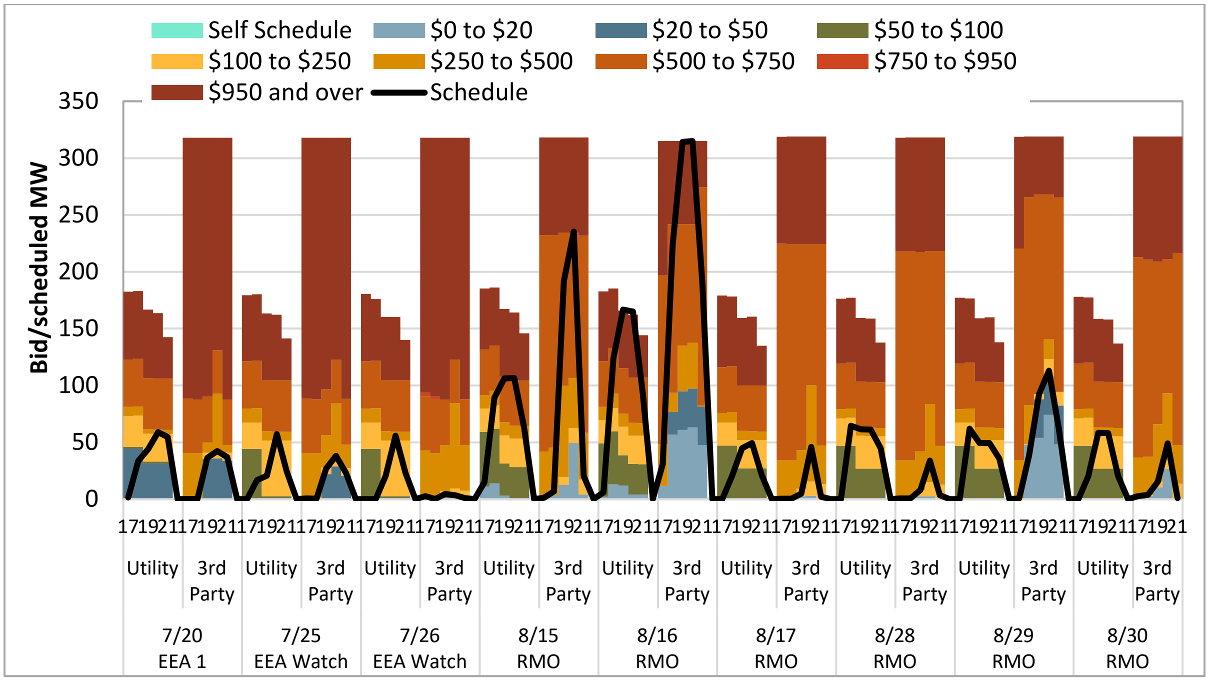
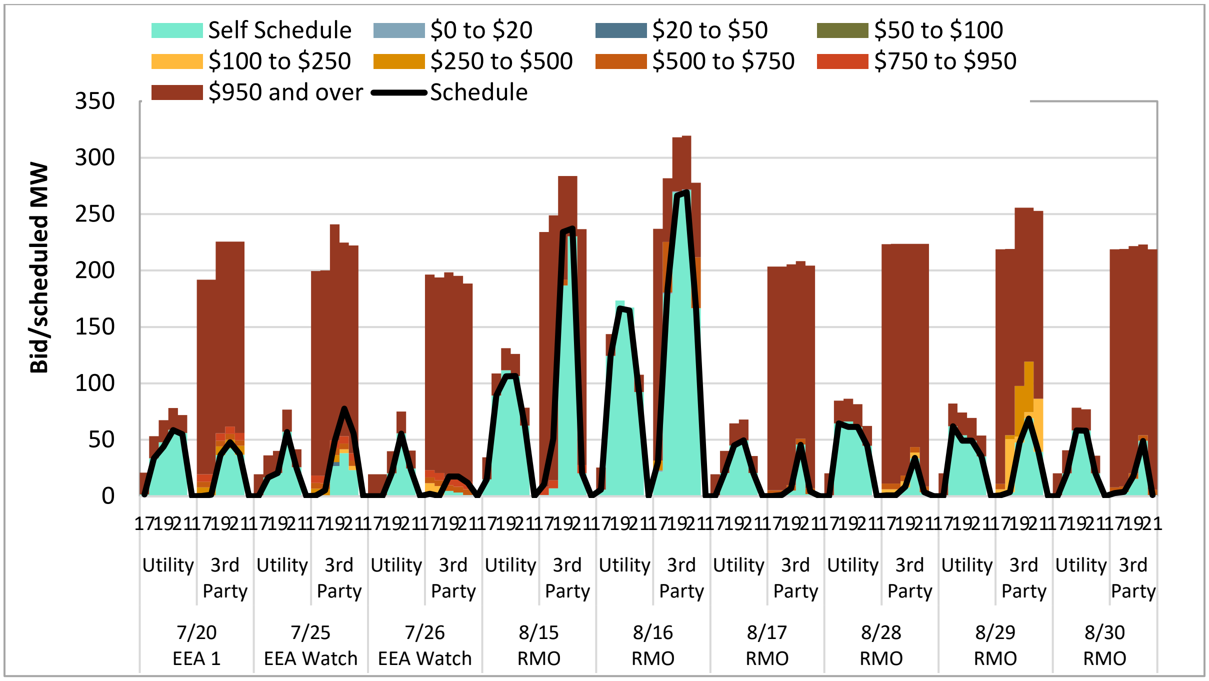


Figure 2.5 highlights the pattern of proxy demand response bids in the day-ahead market. Across high load days in summer 2023, around half of utility demand response bids and 80 percent of third party demand response bids exceeded $500/MWh. These high bid prices led to a small percentage of demand response capacity being scheduled in the day-ahead market. Over this period, about 30 percent of the utility proxy demand response that bid into the day-ahead market was scheduled, while about 16 percent of bid-in third party demand response was scheduled.

Figure 2.6 shows real-time bids of proxy demand response (utility and third party) counted towards resource adequacy requirements across peak net load hours. Figure 2.6 highlights that proxy demand response capacity incremental to day-ahead awards was largely offered at or near the $1,000/MWh soft 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. Although the hard bid cap of $2,000/MWh was in effect during various hours on August 15 and 16, no proxy demand response resources submitted a reference level change request and thus were unable to bid over $1,000/MWh.[16]

[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 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 2.6 Proxy demand response resource adequacy real-time bids



Beginning in 2024, resource adequacy proxy demand response resources will be 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. As a reference, in high load days in 2023, 41 percent of third party demand response and 31 percent of utility proxy demand response bid in at $950 or above in the day-ahead market. In the real-time market these percentages are even higher, averaging 43 percent for utility demand response and 78 percent for third party demand response.

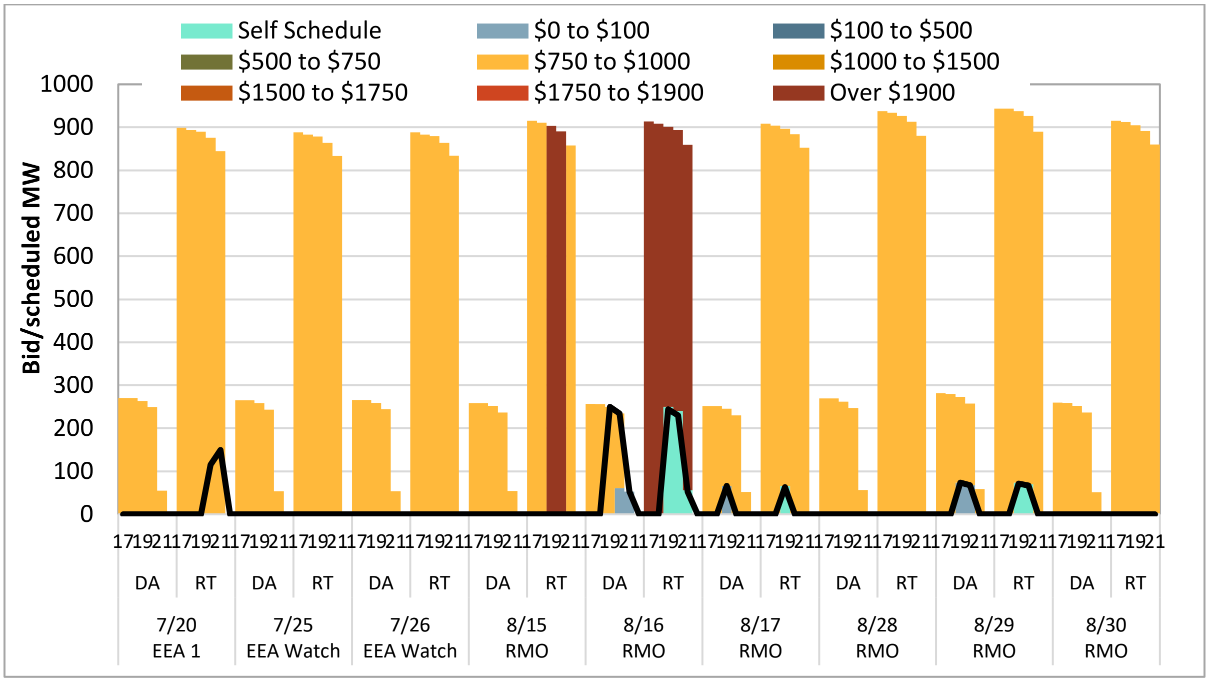
Figure 2.7 shows day-ahead and real-time bids for reliability demand response counted towards resource adequacy requirements. Reliability demand response resources may bid economically in the day-ahead market; however, incremental reliability demand response capacity offered into real-time must submit 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 is a change from previous years where 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]

Figure 2.7 also shows that reliability demand response resources were scheduled on four days in summer 2023. On August 16, 17, and 29, reliability demand response resources were scheduled economically in the day-ahead market. On July 20, the reliability demand response was dispatched in real-time. These resources were forced into the market by operators, therefore their bids were unable to set market prices.

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

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. Under stressed system conditions, the bid cap is raised to $2,000/MWh.[18] During several peak hours on August 15 and 16, the bid cap in the market was $2,000/MWh and thus reliability demand response resources were required to bid in at least $1,900/MWh.

Figure 2.7 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 high load days in the summer. The aggregate performance of utility demand response, both proxy demand response and reliability demand response, averaged about 89 percent of their scheduled load curtailment during high load days, similar to summer 2022. The performance of third party demand response averaged substantially lower at 46 percent of their scheduled curtailments, similar to the previous summers.[19]

Utility demand response performance

Figure 2.8 shows real-time dispatches and self-reported response of CPUC-jurisdictional utility demand response capacity on high load days. Figure 2.8 reflects both proxy demand response and reliability demand response capacity scheduled by CPUC-jurisdictional investor-owned utilities. Non-CPUC-

[18] FERC Order 831. See additional information on conditions in DMM's 2021 Q1 Market Issues and Performance Report, 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.

jurisdictional demand response programs are not currently tied to specific resources in the ISO market and thus are not included in Figure 2.8.

Figure 2.8 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. The performance of CPUC-jurisdictional demand response resources, capped at individual resource schedules, averaged 75 percent of their real-time schedules during high load days this summer. In aggregate, the total CPUC-jurisdictional utility demand response fleet, including excess curtailed load, averaged 89 percent of their real-time schedules. Overall, this is very similar to performance during high load days in summer 2022.

The largest amount of utility demand response was dispatched on August 16, with about 400 MW scheduled during hours-ending 19 and 20. Resources reported to curtail about 343 MW in hour-ending 19 and 260 MW in hour-ending 20. These reported curtailments include load curtailment in excess of individual resource dispatches and suggest a performance of 84 percent and 66 percent in hours-ending 19 and 20, respectively.

Figure 2.8 CPUC-jurisdictional utility demand response performance

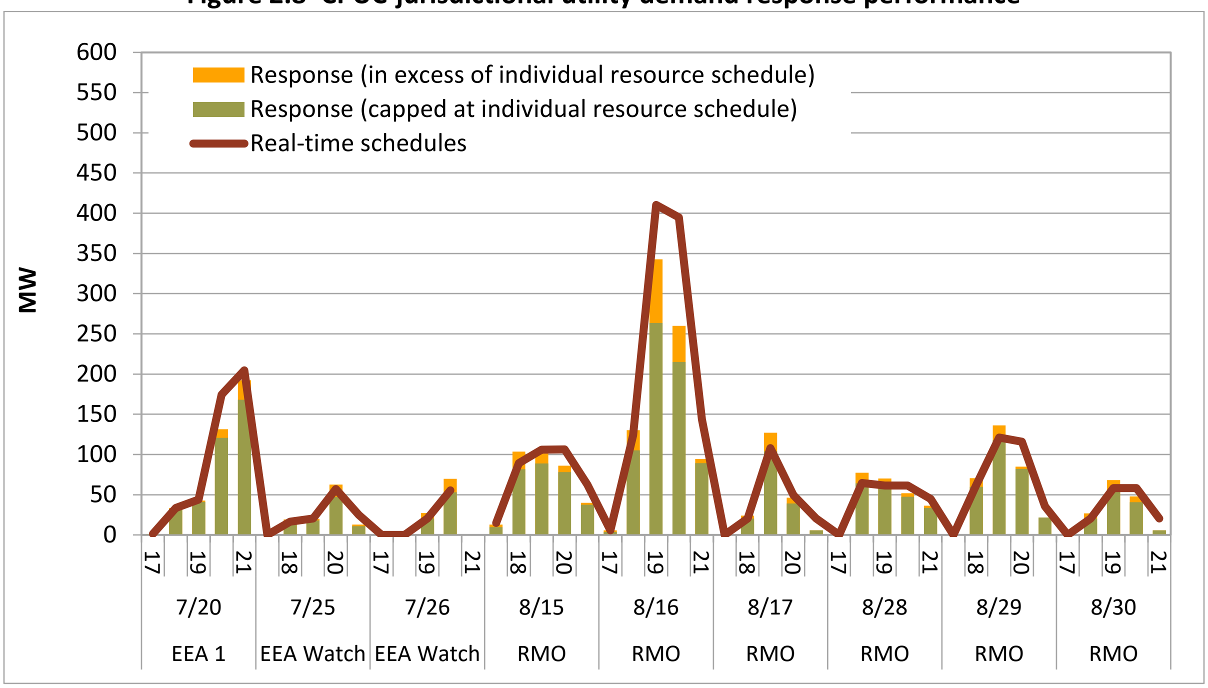


Figure 2.9 and Figure 2.10 show CPUC-jurisdictional demand response performance, split between proxy and reliability demand response capacity. Including curtailments above individual resources' schedules, the performance of proxy demand resources averaged 97 percent of their scheduled curtailments and reliability demand response resources averaged 71 percent during the high load days of this summer. Compared to summer 2022, proxy demand response resources performed better while reliability demand response resources performed worse on average during high load days in summer 2023.

Figure 2.9 CPUC-jurisdictional utility proxy demand response performance

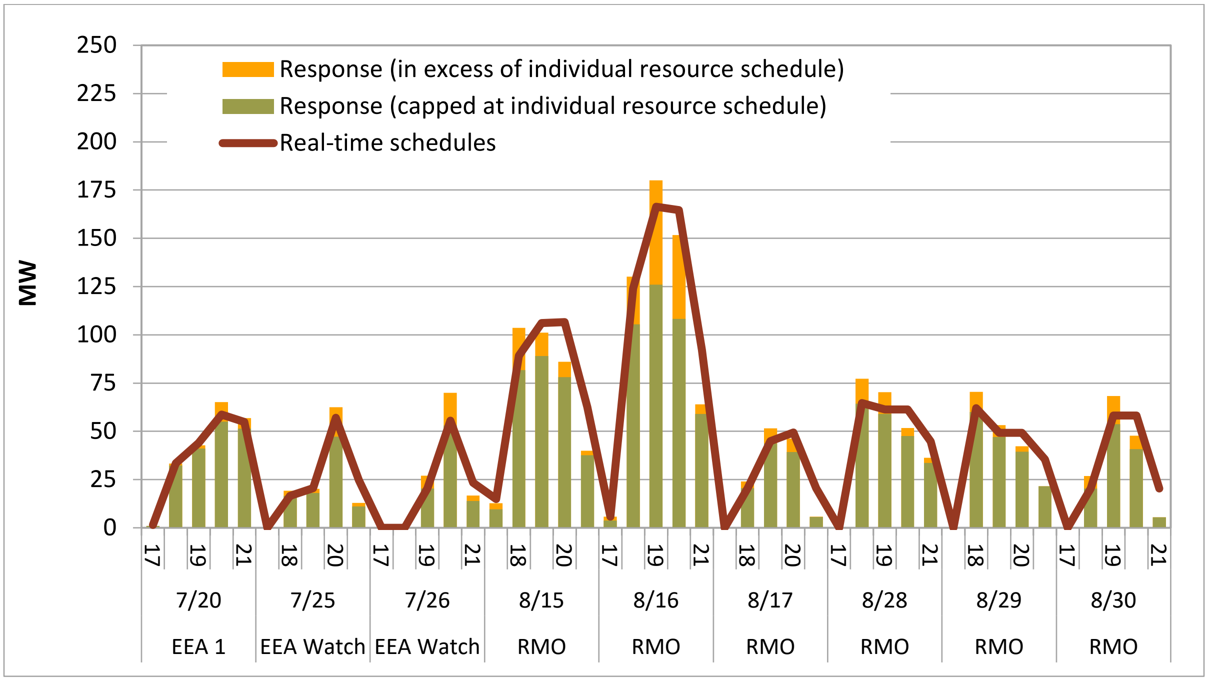
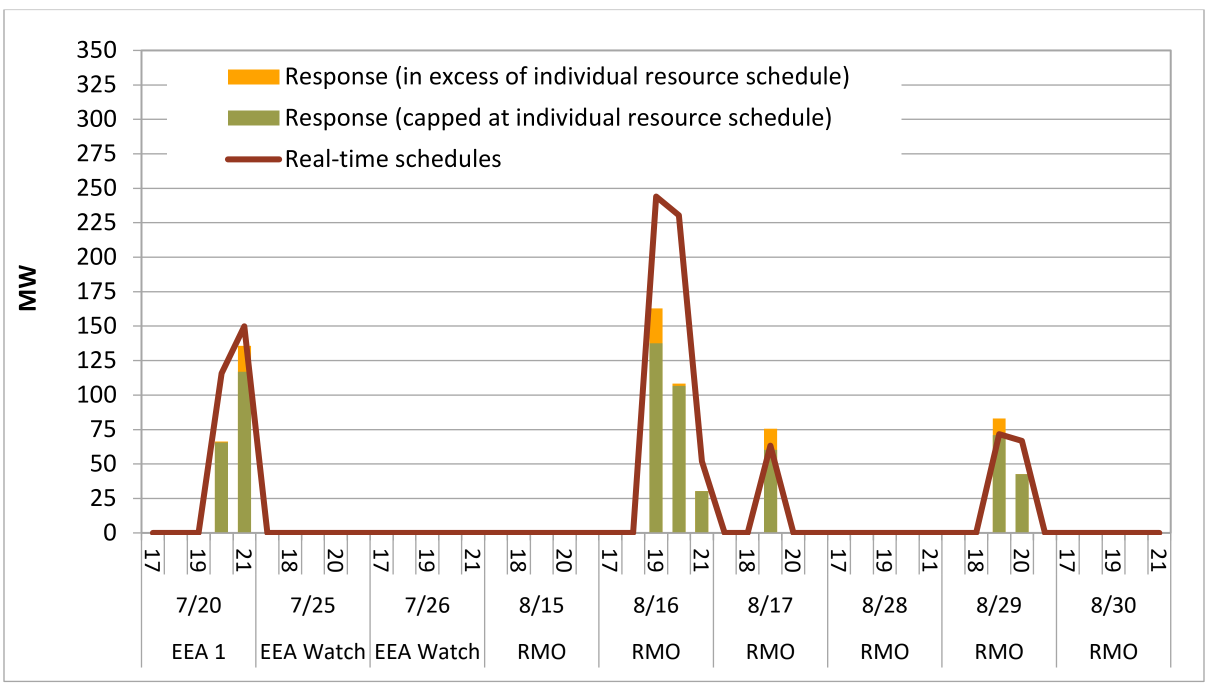


Figure 2.10 CPUC-jurisdictional utility reliability demand response performance

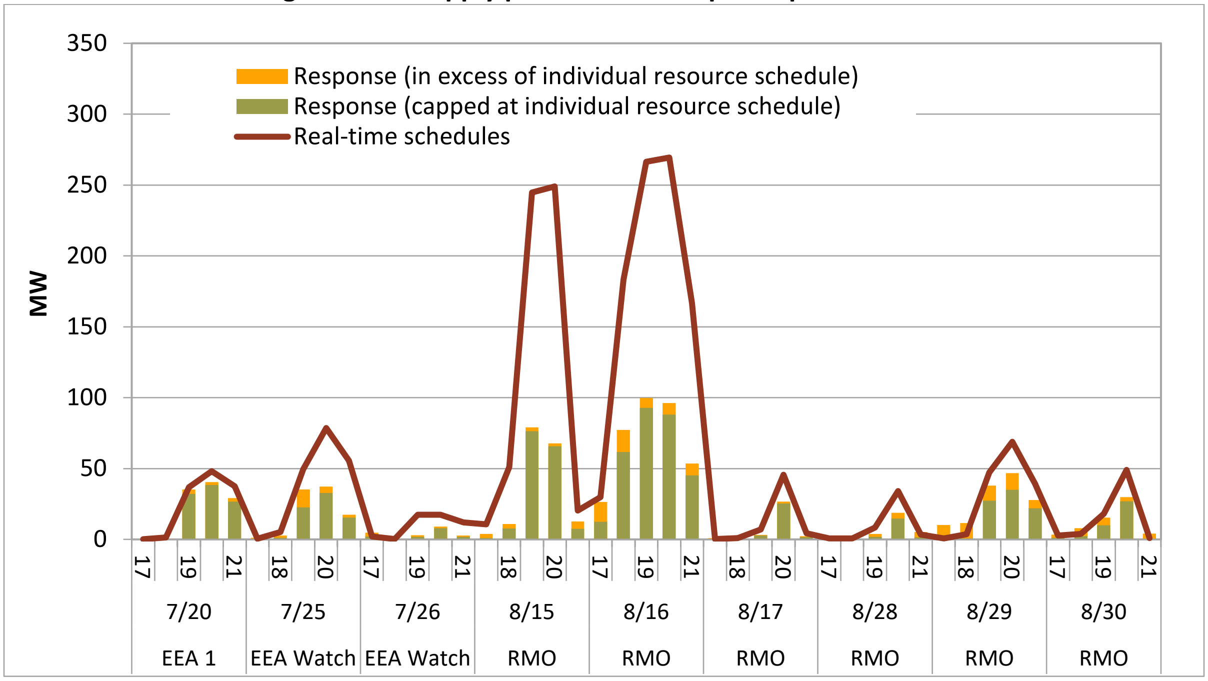


Supply plan demand response performance

Figure 2.11 shows the self-reported response of third party demand response resources shown on resource adequacy supply plans. Figure 2.11 depicts both self-reported response capped at individual resources' schedules (green bar) and self-reported response in excess of resource schedules (yellow bar). Overall on high load days in summer 2023, supply plan demand response resources under-performed compared to dispatch instructions. Performance capped at individual resource schedules averaged 37 percent on high load days in summer 2023. When considering load curtailments in excess of individual resource schedules, performance of supply plan demand response resources averaged 46 percent. These average performances are very similar to high load days in summer 2022.

The largest quantity of third party demand response was dispatched on August 15 and 16 during hours-ending 19 and 20. On average during these hours, roughly 260 MW were dispatched, while reported uncapped performance averaged 86 MW. This implies an average performance of 33 percent. While supply plan demand response tends to bid in close to their resource adequacy values, their performance compared to their schedules suggests this available capacity may be inaccurate during high load days. As mentioned previously, supply plan demand response resources face consequences for not bidding their resource adequacy capacity in peak hours and thus may have the incentive to submit bids above their actual curtailment capabilities. Utility proxy demand response resources do not have the same bidding incentives, and their bid-in capacity averaged only 41 percent of their resource adequacy capacity. Therefore, it is possible that third party and utility proxy demand resources have similar curtailment ability compared to their resource adequacy capacity, but third party resources may bid more capacity even when this curtailment amount may not be feasible.

Figure 2.11 Supply plan demand response performance



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

Figure 2.12 shows the availability, dispatch, and self-reported response of *all* demand response capacity (credited utility and supply plan demand response) counted toward resource adequacy obligations on high load days across the summer. Figure 2.12 includes both credited utility and supply plan demand response capacity.

Figure 2.12 Aggregate demand response resource adequacy

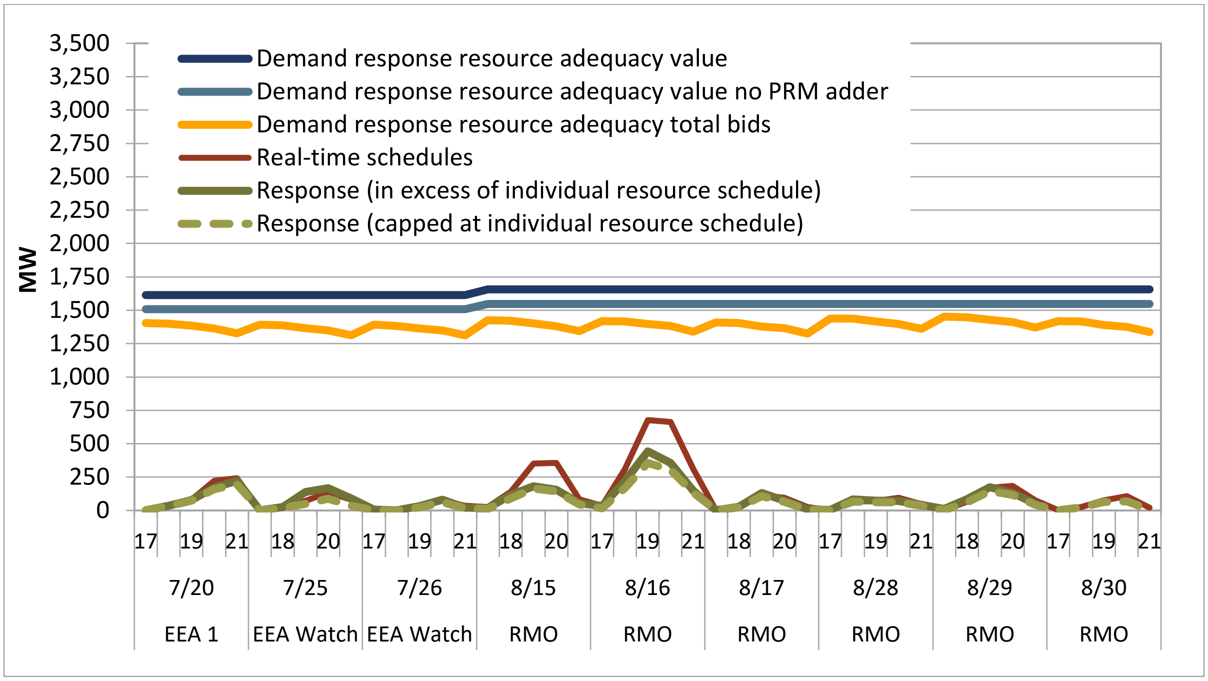


Figure 2.12 shows that demand response availability, as reflected through market bids, averaged about 85 percent of resource adequacy values. This is substantially higher than 2021 and 2022 when availability of resource adequacy demand response averaged about 65 percent during high load days in the summer. Availability was higher for both utility and supply plan demand response, in part due to high load days in summer 2023 not falling on holidays or weekends, when availability tends to be lower.

Figure 2.12 also depicts the real-time schedule of demand response resource adequacy (red line), along with their reported performance capped at individual resources' schedules (dashed green line) and reported performance in excess of schedules (solid green line). Including load curtailment in excess of individual resources' schedules, total demand response performance averaged 76 percent of real-time dispatches across peak net load hours on high load days. This is an increase from 67 percent in the summer of 2022.

3 Special Issues

This section discusses a variety of issues related to demand response participation in the California ISO market.

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 intra-day load deviations from historical levels. However, the ISO has developed tariff-defined caps on the amount that intra-day baselines can be adjusted, based on different baseline methodologies.[21]

In 2020, based on supplier-submitted baseline and meter data and historic load trends, there was evidence that baseline adjustments could have been limited in the upward direction by tariff-defined baseline adjustment caps. Based on self-reported meter data and system load trends, certain customer loads on high load days may have deviated from load on previous days 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 2023, 62 percent of all demand response capacity used alternative adjustment factors in summer months, the same percentage as the previous year. A combination of proxy demand response and reliability demand response resources using day-matching baseline types were eligible to use alternate adjustment factors.

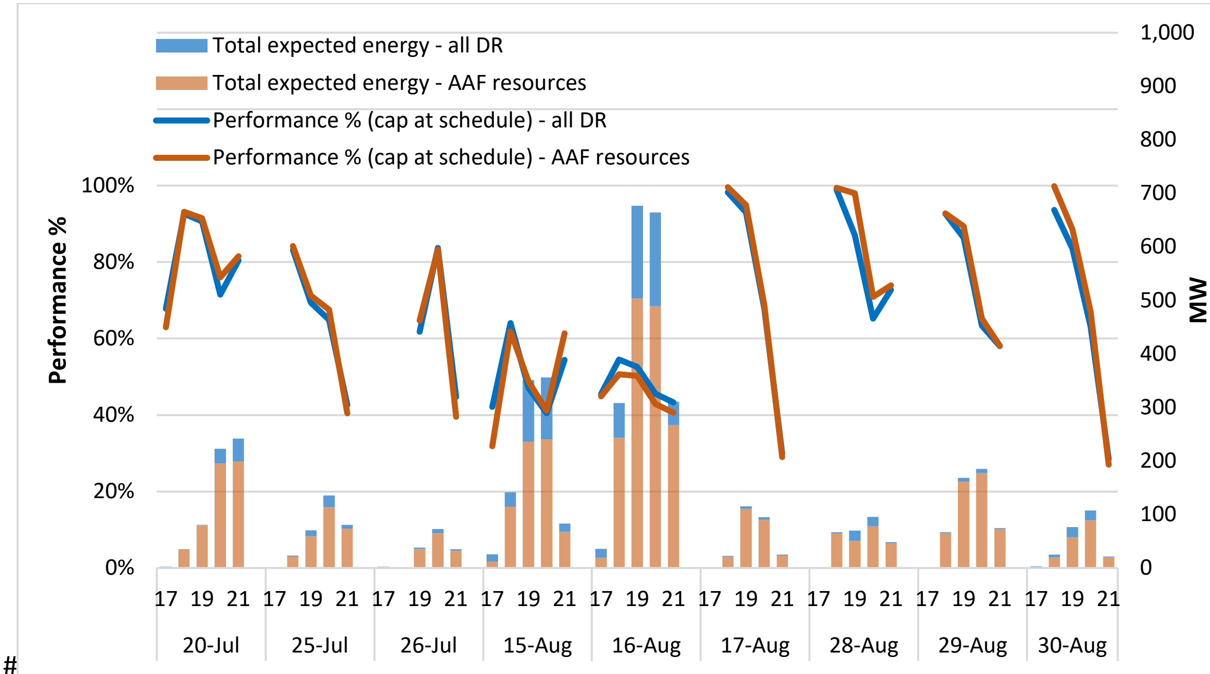
Figure 3.1 shows the performance of demand response (DR) resources using alternate adjustment factors (AAF) compared to all demand response resources. Overall performance is very similar for resources who utilize the alternative adjustment factors compared to the entire demand response fleet. Average performance on high load days for resources using the alternative adjustment factors averaged 67 percent while resources without averaged 56 percent. This indicates that the uncapped adjustment factors may help demand response resource achieve 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] 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 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 toward resourced 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 varies significantly among demand response resource types. In 2023, utility proxy demand response (PDR) resources earned about $117/MWh while third party demand response resources earned about $303/MWh of energy delivered. Third party demand response was scheduled less frequently than utility proxy demand response, and was primarily scheduled when prices were very high. Reliability demand response resources (RDRR) earned the highest value of about $512/MWh, due to these resources only being scheduled during emergency events or very tight conditions when prices are highest.

Table 3.1 Demand response resource adequacy net market revenues - 2023

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	28,949	23,152	$184	$67	$0	$117
Utility RDRR	1,496	1,200	$751	$266	$27	$512
3rd party PDR	7,356	5,148	$504	$205	$5	$303

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 2022 and 2023.

The capacity values shown in Table 3.2 are based on the 85th percentile of resource adequacy prices, as reported in the CPUC's 2021 Resource Adequacy report.[23] Annualized capacity prices are based on the 2022 and 2023 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 (2022-2023)

Year	Demand response type	Net energy market revenues ($/kW-year)	Capacity price - system RA 85th percentile ($/kW-year)	Capacity price - DRAM auction ($/kW-year)
2022	Utility PDR	$26.97	$96	$120
	Utility RDRR	$3.42	$96	$120
	3rd party PDR	$15.18	$96	$120
2023	Utility PDR	$8.22	$96	$157
	Utility RDRR	$0.75	$96	$157
	3rd party PDR	$7.30	$96	$157

[23] 2021 Resource Adequacy Report, CPUC Energy Division, April 2023, p 24: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021-ra-report---update-011624.pdf

Table 3.2 shows that in 2023, the primary revenue stream for demand response resource adequacy resources continue to be the capacity payments they receive. Net energy market revenues for all three types of demand response decreased compared to 2022, and remains much lower than the estimated capacity prices for resource adequacy. This does not provide a strong incentive 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.