California Independent Sy stem Operator Corporation

California ISO

Demand response issues and performance 2022

February 14, 2023

Department of Market Monitoring

1 Summary

1.1 Background

This report provides analysis of how demand response resources participated and performed in the California ISO market on high load days in summer 2022. The Department of Market Monitoring (DMM) has provided similar analysis of demand response resources during summers 2020 and 2021.[1] As in these prior reports, this analysis shows that a large portion of demand response resource adequacy capacity was not available for dispatch or performed significantly below dispatched levels during key peak net load hours in summer 2022. 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.

Demand response counted for 3 to 4 percent of total system resource adequacy capacity (or about 1,875 MW) in August and September 2022. Utility demand response programs account for about 78 percent of this capacity, which is subtracted from the resource adequacy requirements of these load serving entities. The remaining portion of this 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 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 called Flex Alerts and/or issued system warnings or emergencies. The ISO issued Flex Alerts on eleven days between August and September and issued system warnings on six of those days. Reliability demand response (RDRR) was also manually dispatched by the ISO on September 5-7 when the ISO declared an Emergency Energy Alert (EEA) 2. Historically high loads led the ISO to declare an EEA3 on September 6.

During the September heatwave there was substantial relief from non-market resources that reduced demand, including state programs and an emergency alert from the Governor's Office to reduce electricity usage. DMM does not have insight into the performance of these resources and thus they are not included in this report, but the ISO has provided analysis on the estimated impacts of these resources during the September heatwave.[2]

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[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

[2] Summer Market Performance Report for September 2022: http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

1.2 Key findings

Key findings in this report include the following:

- **About one-third of the resource adequacy requirements met by demand response capacity was not available or directly accessible to the ISO in peak net load hours on days when the ISO issued Flex Alerts and/or system warnings.** Thus, demand response programs used to meet resource adequacy requirements are significantly over-counted compared to the actual availability of these resources, particularly in peak net load hours. Additionally, long start demand response capacity is not available to the ISO in the residual unit commitment process or in real-time unless committed in the day-ahead market. This further reduces the amount of demand response resource adequacy available in real-time.

- **On high demand days in the summer, about 67 percent of the demand response capacity in real-time reported to perform as scheduled.** Utility demand response reported substantially higher performance than third party demand response. Utility demand response reported meeting about 88 percent of scheduled load reductions, while performance of supply plan demand response averaged 45 percent. Supply plan demand response tends to perform worse on days with the tightest system conditions.

- **Three high load days fell on Labor Day weekend, when a significant portion of proxy demand response resource adequacy was not available.** The availability of utility and third party proxy demand response resources dropped significantly on holidays and weekends. The CPUC has adopted a new policy requiring demand response resources counted towards resource adequacy to be available on Saturdays. However, the ISO's resource adequacy incentive mechanism (RAAIM) penalty still only applies to peak net load hours on non-holiday weekends.[3]

- **Supply plan demand response resources bid into the day-ahead market at a high rate, but their performance suggests their ability to curtail load may be over-estimated.** Excluding holidays and Sundays, the availability of supply plan demand response averages 90 percent of resource adequacy capacity. Supply plan demand response resources face must-offer obligations and RAAIM penalties, which may explain the high percentage of available capacity. However, their performance compared to their schedules suggests this available capacity may be inaccurate.

- **Resource adequacy payments, or the value of reduced resource adequacy requirements, are the primary revenue sources 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. 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.

[3] Decision adopting local capacity obligations for 2022-2024, flexible capacity obligations for 2022, and refinements to the resource adequacy program (D.21-06-029), R.19-11-009, June 25, 2021, pp. 38-41: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

1.3 Recommendations

In prior reports, DMM has highlighted some recommendations that the ISO and CPUC could consider to enhance the availability and performance of demand response resources.[4] DMM suggested that the ISO and CPUC consider these recommendations before increasing reliance on demand response towards meeting resource adequacy requirements. DMM recognizes that the ISO, CPUC, and CEC are currently working on addressing some important issues pertaining to demand response. These include enhancing resource adequacy counting methodologies and several demand response related proposals made by the Energy Division.[5] However, DMM continues to recommend that the ISO and CPUC consider other potential changes to enhance the reliability of demand response capacity. These include:

- ***Re-examine demand response counting methodologies.*** Utility demand response capacity continues to appear to be over-counted in terms of these resources' contribution toward meeting resource adequacy requirements on high demand days. The ISO, CPUC, and CEC are currently examining different counting methodologies for demand response, including methodologies which would better capture the variable nature of demand response availability.[6] DMM continues to support 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.

- ***Adopt the ISO's recommendation to remove the remaining planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction.*** Beginning in 2022, the CPUC removed the 6 percent ancillary services and operating reserves component of the 15 percent planning reserve margin adder applied to demand response capacity credits. The CEC will examine whether the remaining 9 percent of the adder should be retained.[7] The ISO and DMM recommend that the CPUC consider removing the remaining 9 percent of the planning reserve margin adder, as this adder contributes to overestimating the actual resource adequacy value of utility demand response programs on high load days.

- ***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 September 2022, about 50 percent of supply plan demand response was registered with start-up times of 5 hours or more.[8] If this capacity is not scheduled economically in the integrated forward market, then this capacity has no obligation to be available in RUC under the ISO tariff.

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[4] *Report demand response, issues and performance*, February 25, 2021, pp. 3-4: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

2020 Annual report on market issues and performance, August 2021, pp. 21-22: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

[5] DMM will be providing comments on the proposals set forth by the Energy Division. *Energy Division Proposals for Proceeding R.21-10-002*, January 28, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M501/K407/501407493.PDF

[6] *CEC Docket Number 21-DR-01:* https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-DR-01

[7] *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, CPUC, June 25, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

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

- ***More specific timeline for submission of required historical data and meaningful financial penalties for demand response providers failing to submit required data to the ISO.*** Under many of the most frequently used baseline methodologies, demand response providers are required to submit hourly data on their metered load and baseline data for the 90 days prior to an event when the resource was scheduled to curtail load.[9] This historical data is necessary to monitor the baselines submitted by demand response providers.[10] DMM has observed that several demand response providers consistently fail to provide all required data.

- ***Consider developing a performance-based penalty or incentive structure for resource adequacy resources***. A performance-based penalty or incentive mechanism could be particularly appropriate for demand response resources because of the difficulty of determining in advance whether a demand response resource is capable of delivering its full resource adequacy rating for load curtailment in critical hours. While must-offer obligations and RAAIM penalties appear to incentivize supply plan demand response to bid into the market, the performance of these resources continues to fall below their scheduled dispatch.

- ***Ensure that non-CPUC jurisdictional load serving entities that manage utility demand response programs used to meet resource adequacy requirements communicate the available capacity to the ISO on a daily basis.*** DMM understands that the ISO has reached out to non-CPUC jurisdictional load serving entities using demand response to meet resource adequacy requirements to better ensure that the ISO is aware of all available capacity and can call on this when needed. The ISO should have the same insight into this demand response capacity as the ISO does with demand response capacity of CPUC-jurisdictional load-serving entities.

[9] BPM for Demand Response, Appendix B

[10] Tariff Section 11.6.1

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 2022.[11]

2.1 Demand response as resource adequacy

Similar to the last two summers, demand response accounted for about 3 to 4 percent of total system resource adequacy capacity in August and September 2022, meeting almost 1,900 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 78 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 22 percent of demand response used to meet resource adequacy requirements.

Table 2.1 below summarizes the breakdown between credited and supply plan demand response capacity counted towards resource adequacy requirements in August and September 2022. Credited demand response values under the CPUC local regulatory authority include transmission and distribution loss factors and planning reserve margin gross-ups.

Table 2.1 August and September 2022 demand response resource adequacy capacity (megawatts)

Month	Credited demand response (CPUC LRA)	Credited demand response (Other LRA)	Supply plan demand response	Total MW
August	1,339	115	415	1,869
September	1,348	116	418	1,882

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.

[11] High load days include days where Flex Alerts were issued.

In August and September, this type of demand response capacity accounted for about 1,460 MW of resource adequacy credits.[12]

Almost all of utility demand response capacity (94 percent) are from programs run by investor-owned utility (IOU) programs under the jurisdiction of the CPUC. The CPUC allows these entities to reduce their resource adequacy requirements by an additional percent above the reported capacity of these demand response resources. Previously this percentage was 15%, but starting in 2022, this percentage decreased to 9 percent. [13] This reduction in the planning reserve margin in part explains the reduction in credited utility demand response this year compared to summer 2021.

The majority of this IOU capacity (71 percent) consists of reliability demand response resources (RDRR), which are primarily called upon under emergency conditions after the ISO issues a system warning.[14] Capacity from IOU demand response programs are bid or 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 and 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.[15]

In addition to CPUC-jurisdictional demand response credits, other non-CPUC jurisdictional regulatory authority load-serving entities (such as municipal utilities) accounted for about 115 MW of demand response resource adequacy credits in both August and 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.

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 are proxy demand response resources and are generally subject to ISO must-offer-obligations and the ISO's resource adequacy incentive mechanism (RAAIM).[16]

[12] Credited values includes transmission and distribution loss factors and planning reserve margin gross-ups.

[13] This includes a 9% planning reserve margin (PRM) adder which accounts for forced outages and forecast error. Previously the PRM adder included an additional 6% component associated with ancillary services and operating reserves. This 6% component was removed starting in 2022.

[14] 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 2, it may be economically scheduled in the day-ahead market.

[15] 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

[16] 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 August 2022, 16% of supply plan demand response capacity was associated with resources sized less than 1 megawatt and thus were exempt from RAAIM.

Supply plan demand response capacity increased by 60 percent this summer compared to last. In August and September of 2022, supply plan demand response capacity accounted for about 415 MW of resource adequacy capacity. Supply plan demand response capacity can be contracted through the CPUC's Demand Response Auction Mechanism (DRAM) or bilaterally between third party providers and load serving entities. Previously the majority was contracted through DRAM, however an increasing amount of supply plan demand response is being contracted bilaterally.

2.2 Availability of demand response resource adequacy capacity

On high load days in the summer, about one third of resource adequacy requirements met by demand response capacity was not available or accessible to the ISO across peak net load hours.

Utility demand response availability

CPUC-jurisdictional credited demand response bids fell short of resource adequacy credits by an average of 440 megawatts, or about 33 percent of total resource adequacy credits (including the 9 percent planning reserve margin adder) in peak net load hours on high demand days. The shortfall of bid capacity compared to resource adequacy credits (without planning reserve margin or transmission and distribution loss adders), was primarily associated with proxy demand response. Since credited demand response resources are not included in resource adequacy supply plans, there is limited visibility into which resources were failing to bid in adequate capacity, however the main drivers of this unavailability appeared to be:

1) CPUC-jurisdictional utility demand response resource adequacy values appeared to be over-counted across peak net load hours compared to actual load curtailment available.

2) Some utility demand response programs are unavailable on weekends and holidays.

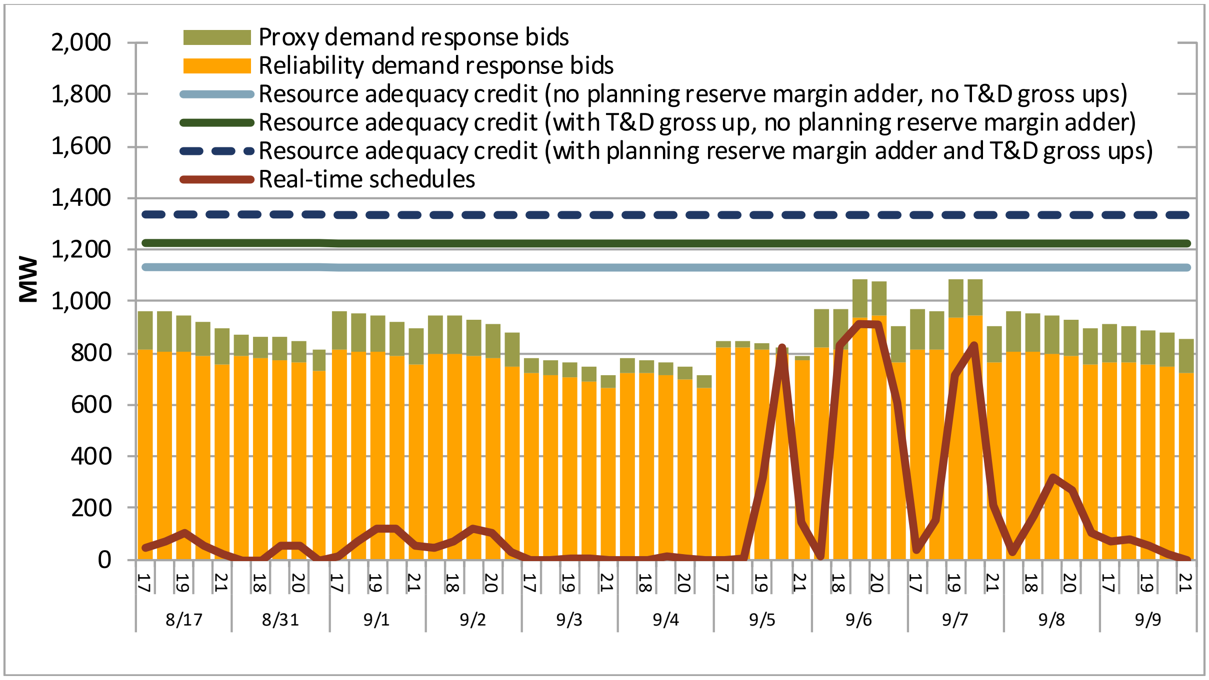
3) CPUC-jurisdictional demand response credits include a 9% planning reserve margin adder and gross ups for avoided transmission and distribution losses.

In addition, non-CPUC jurisdictional load serving entities claimed about 115 megawatts of demand response resource adequacy credits in August and September, which reduced these entities' system resource adequacy obligations. 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.

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.

While only 67 percent of demand response resource adequacy credits was available on average, the capacity that was available was nearly fully utilized by the ISO during certain hours on September 5-7. The majority of utility demand response dispatches were associated with the forced dispatch of reliability demand response after the ISO entered EEA 2.

Figure 2.1 CPUC-jurisdictional utility demand response bid quantities and resource adequacy credits[17]



Supply plan demand response availability

Supply plan demand response capacity offered in the day-ahead market averaged about 90% of resource adequacy values, except September 3-5, which was Labor Day Weekend.[18] In the real-time market, however, an average of 190 megawatts (46 percent) of supply plan demand response resource adequacy capacity was not available to the ISO in peak net load hours.

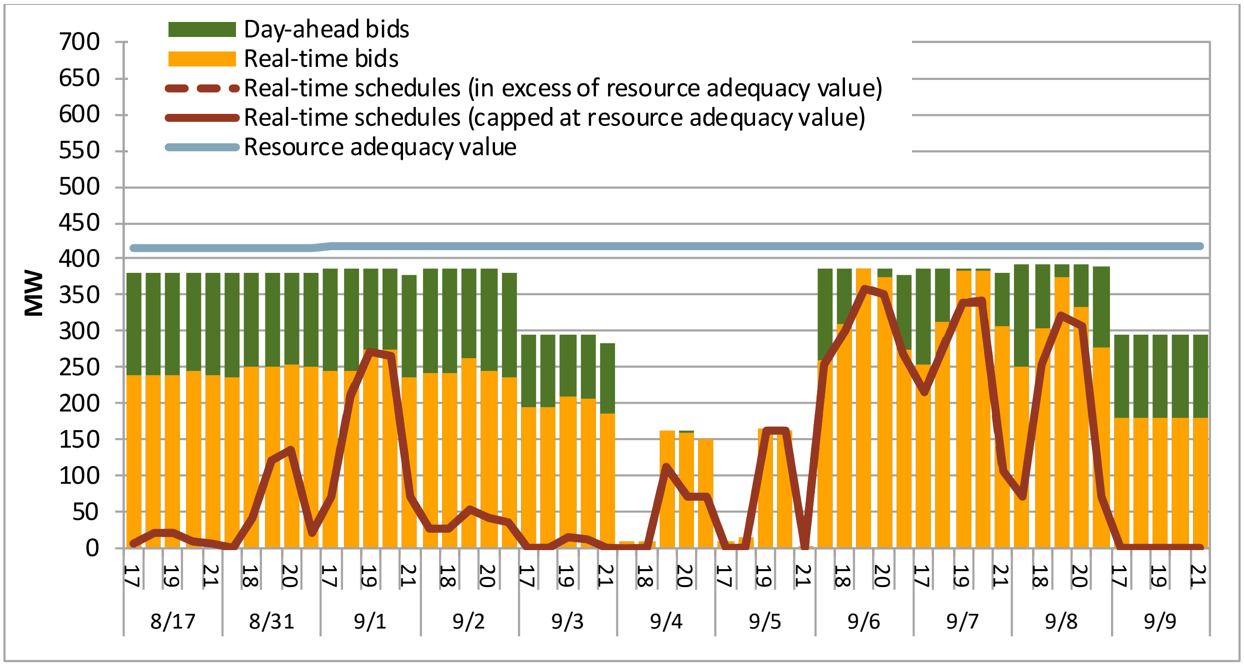
Figure 2.2 shows the availability of supply plan demand response capacity as reflected by day-ahead and real-time bids, where bids are capped at individual resource shown resource adequacy values. Figure 2.2 also shows demand response dispatches capped at individual resources' shown resource adequacy values (red line) and dispatches on supply demand response resources in excess of shown resource adequacy values (dashed red line), however on these high load days there no real-time schedules of supply plan demand response resources above their resource adequacy capacity.

[17] A small number of reliability demand response resources partially shut down over Labor Day weekend in coordination with the California ISO which may lead to under-estimation of availability on these days.

[18] Availability on Saturday September 3 was substantially higher (70%) than availability on Sunday and Monday (20%) of the holiday weekend. This could be due in part to the new CPUC requirement for demand response resources counted towards resource adequacy to be available on Saturday. It should be noted that although the CPUC has adopted this requirement the CAISO RAAIM penalty still only applies to peak net load hours on weekdays and thus the financial incentive to be available may be limited.

Decision adopting local capacity obligations for 2022-2024, flexible capacity obligations for 2022, and refinements to the resource adequacy program (D.21-06-029), R.19-11-009, June 25, 2021, pp. 20-22: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

Figure 2.2 Day-ahead and real-time bid quantities from supply plan demand response



Around 50 percent of the capacity not bid into the day-ahead market on high load weekdays was associated with resources sized less than 1 megawatt and thus were exempt from RAAIM. In general, about 12 percent of supply plan demand response resource adequacy capacity consisted of resources smaller than 1 megawatt. This is substantially lower than 40 percent last summer.

Limited availability of demand response capacity in real-time can primarily be attributed to demand response programs with start-up times of 5 hours or greater which qualify these resources as long-start. Long start resources are not subject to RAAIM and may be unavailable in the real-time if they are not scheduled economically in the day-ahead market. In August and September of 2022, around 48 percent of supply plan demand response resource adequacy capacity was associated with long-start resources, compared to 61 percent in 2021.

2.3 Demand response bidding

Figure 2.3 shows day-ahead bid prices of proxy demand response (utility and third party) counted towards resource adequacy requirements across peak net load hours as well as their day-ahead schedules.

Figure 2.3 Proxy demand response resource adequacy day-ahead bids

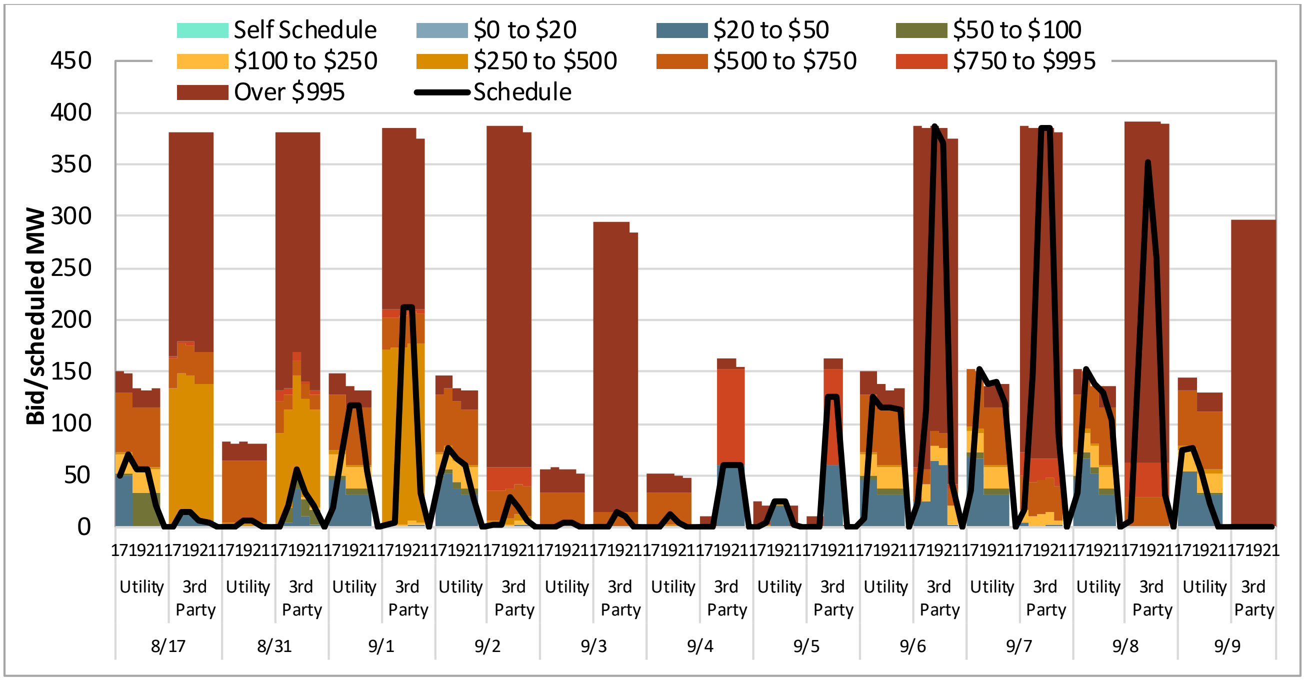


Figure 2.3 highlights the pattern of proxy demand response bids. From September 5 – 8, between 4-9 pm, around 21 percent of utility demand response bids and 87 percent of third party demand response bids exceeded $750/MWh. Over this period, about 68 percent of the utility proxy demand response that was bid into the day-ahead market was scheduled in the day-ahead market, while about 45 percent of bid-in third party demand response was scheduled. Long-start resources that are not scheduled in the day-ahead time period are unable to bid into the real-time.

Figure 2.4 shows real-time bids of proxy demand response (utility and third party) counted towards resource adequacy requirements across peak net load hours. Figure 2.4 shows that over the highest load days of the September heat wave (September 5-8) demand response capacity was primarily scheduled in the day-ahead market and thus self-scheduled into real-time. 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 of the September heat wave, no proxy demand response resources submitted a reference level change request and thus were unable to bid over $1,000/MWh.

Figure 2.4 Proxy demand response resource adequacy real-time bids

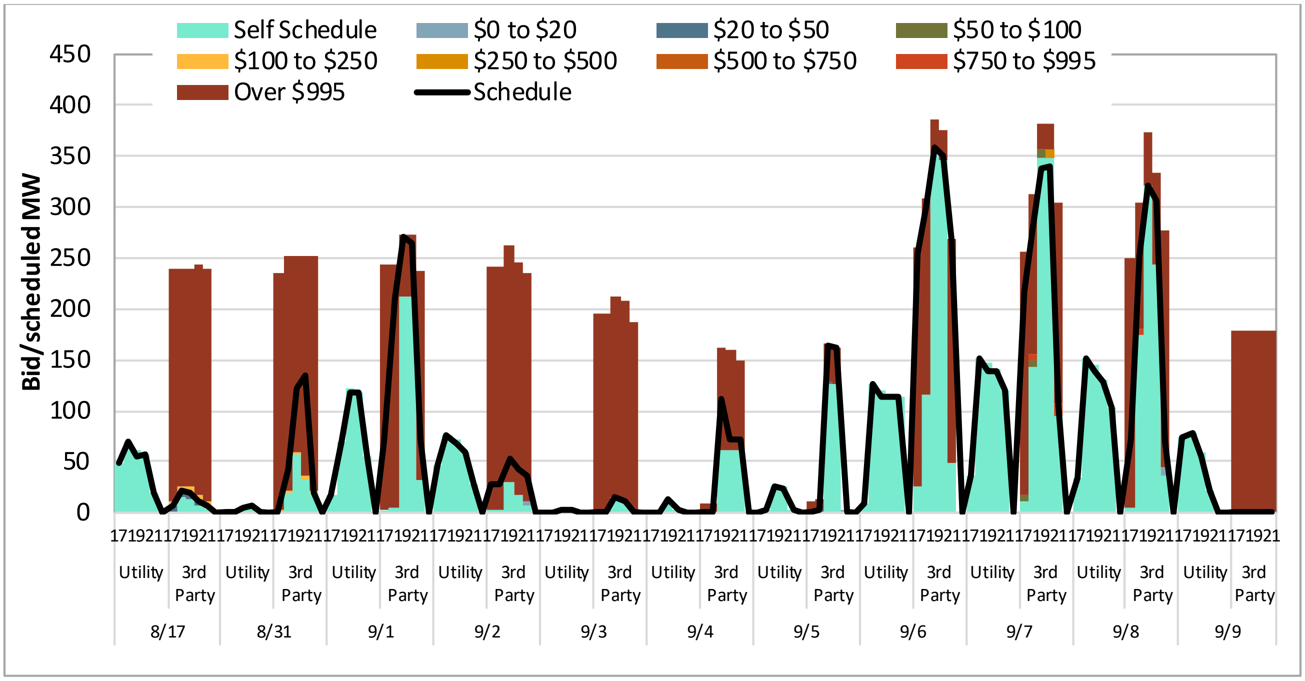


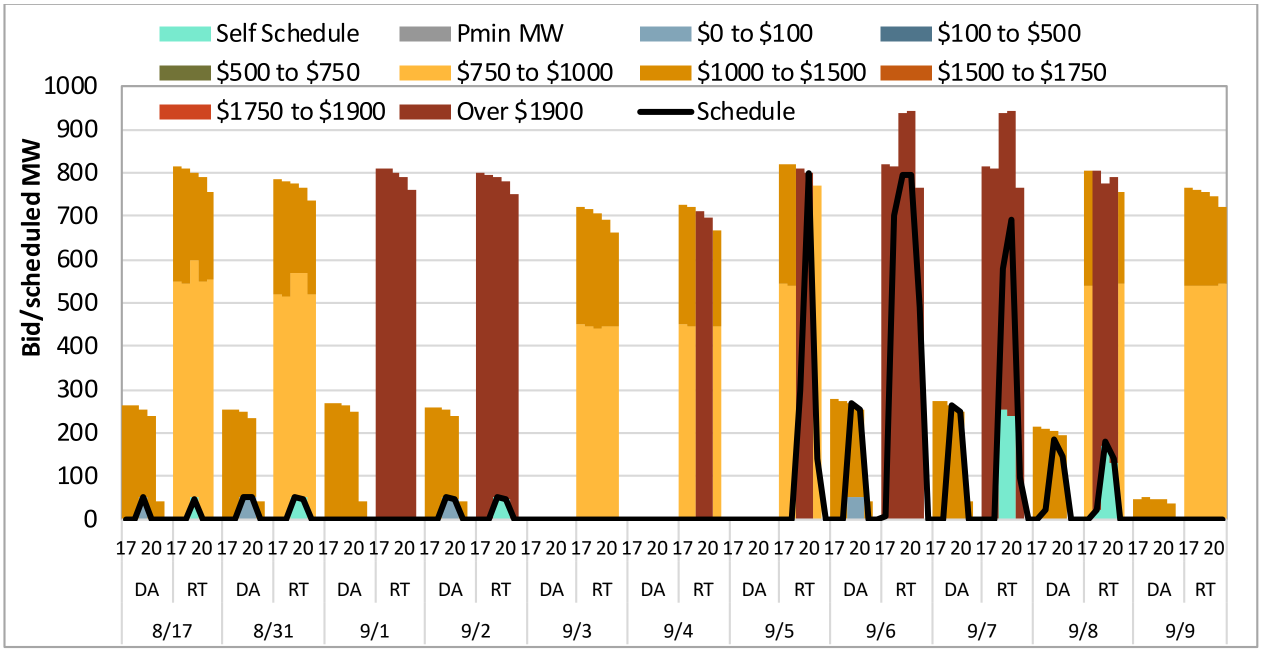
Figure 2.5 shows day-ahead and real-time bids for reliability demand response counted towards resource adequacy requirements. Reliability demand response resources may bid economically in the day-ahead market, however incremental reliability demand response capacity offered into real-time can only be dispatched under an EEA 2 and must be offered at a bid price of at least 95 percent of the ISO's current energy bid cap. Under normal conditions, the bid cap is $1,000/MWh but under stressed system conditions the bid cap is raised to $2,000/MWh.[19] During several peak hours on high load days, the bid cap in the market was $2,000/MWh and thus reliability demand response resources were required to bid at or above $1,900/MWh.

Figure 2.5 also shows that during the September heat wave reliability demand response resources were primarily dispatched in the real-time rather than being scheduled economically in the day-ahead market. In an EEA 2, reliability demand response can either be enabled and dispatched by the market, or forced into the market by operators. During September 5-7, all of the reliability demand response dispatched in the real-time was forced into the market by operators. When resources are forced into the market in this way, their bids may not be able to set market prices.[20]

[19] 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

[20] If operators force resources to be fixed at one position, the resource's bid cannot set price. If operators just force resource to be on, the bid can set price.

Figure 2.5 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. Performance is measured as resources' self-reported response in comparison to their real-time schedule. The performance of aggregate utility demand response, including both proxy demand response and reliability demand response, averaged about 88 percent during high load days, similar to summer 2021 and substantially higher than summer 2020. The performance of third party demand response, however, remained about the same as the last two years, averaging roughly 50 percent. [21]

Utility demand response performance

Figure 2.6 shows real-time dispatches and self-reported response of CPUC-jurisdictional utility demand response capacity on high load days. Figure 2.6 reflects both proxy demand response (PDR) and reliability demand response (RDRR) 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 2.6.

Figure 2.6 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 74 percent of their real-time schedules during high

[21] Performance here refers to uncapped performance where responses are not capped at each resource's scheduled load curtailment.

load days this summer. When including excess curtailed load, total CPUC-jurisdictional utility demand response fleet averaged 88 percent of real-time schedules.

The largest amount of utility demand response was dispatched on September 6, with about 910 MW scheduled during hours ending 19 and 20. Resources reported to curtail about 850 MW in hour ending 19 and 720 MW in hour ending 20. These reported curtailments include load curtailment in excess of individual resource dispatches and suggest a performance of 94 percent and 79 percent in hours ending 19 and 20, respectively.

Figure 2.6 CPUC-jurisdictional utility demand response performance

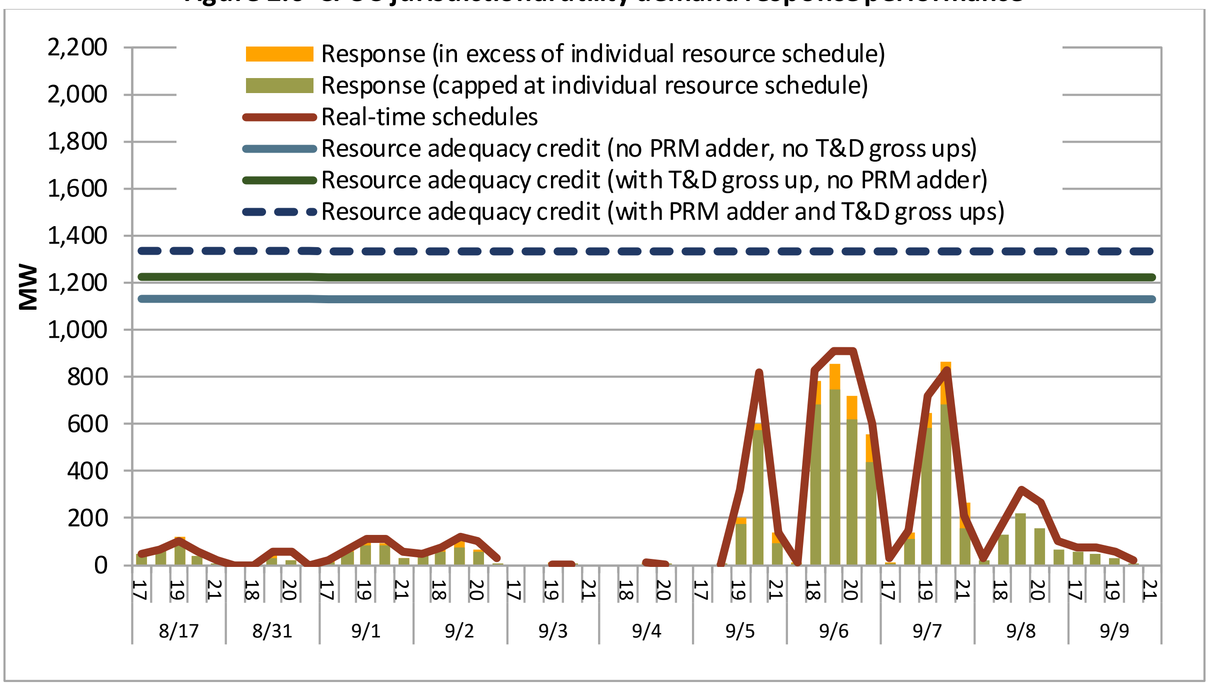


Figure 2.7 and Figure 2.8 show CPUC-jurisdictional demand response performance, split between proxy and reliability demand response capacity. Including curtailments above individual resources' schedules, the performance of proxy demand resources averaged 85 percent and reliability demand response resources averaged about 89 percent during the high load days of this summer.

Figure 2.7 CPUC-jurisdictional utility proxy demand response performance

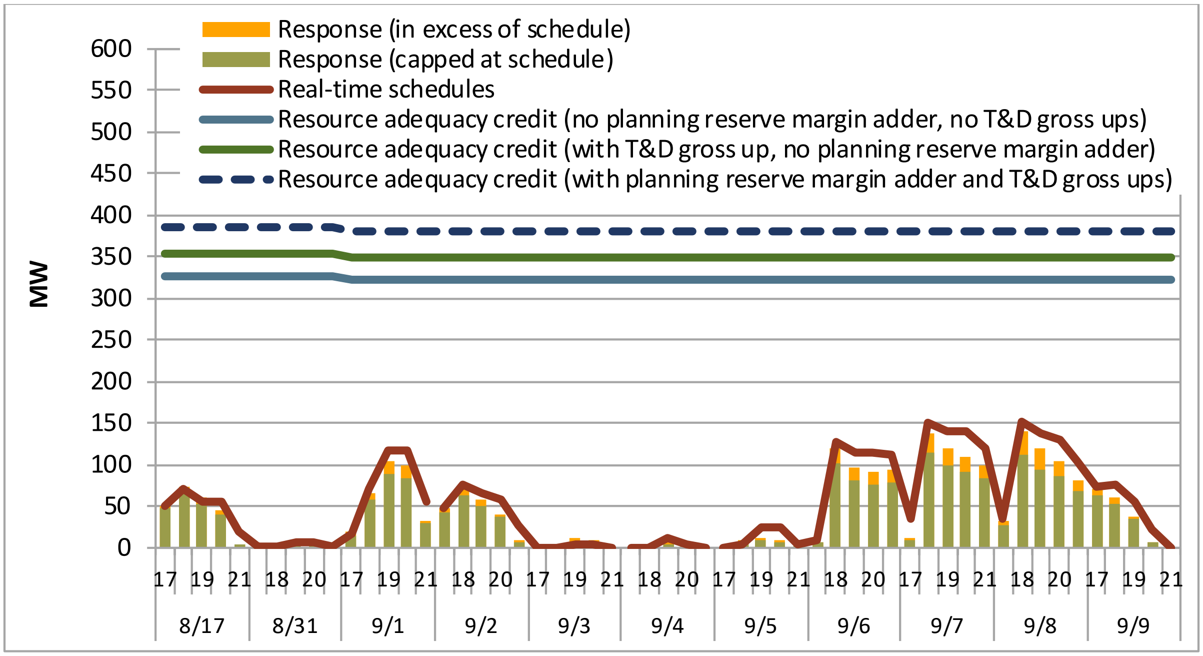
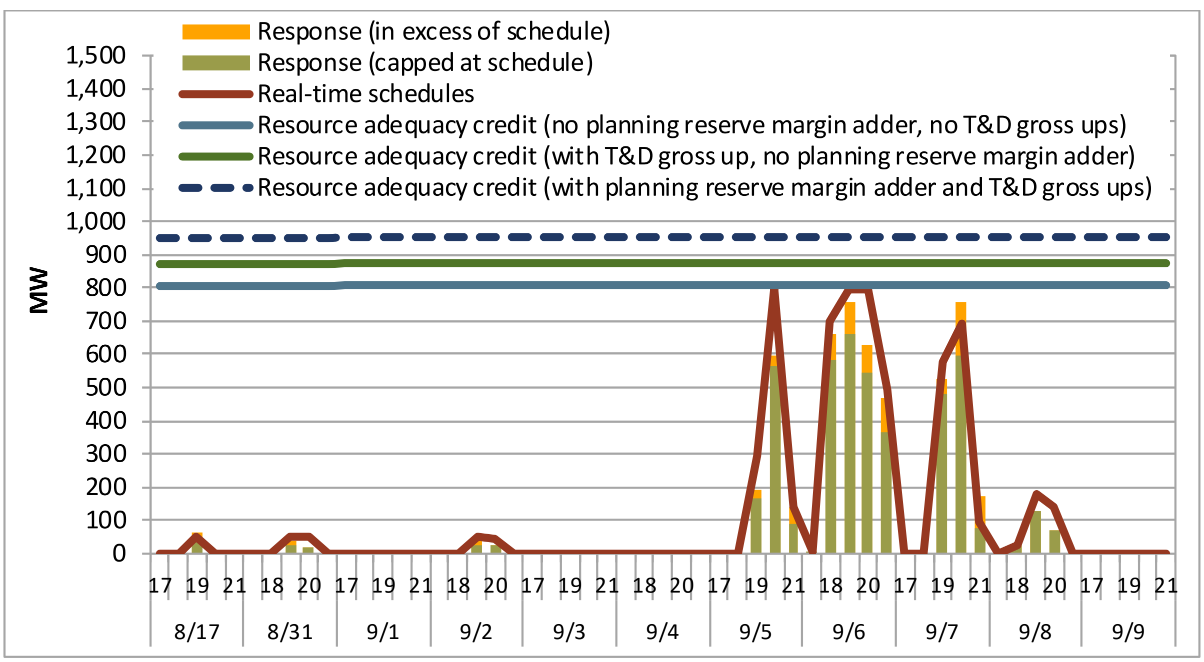


Figure 2.8 CPUC-jurisdictional utility reliability demand response (RDRR) performance[22]



[22] A small number of reliability demand response resources partially shut down on Labor Day weekend. Depending on their baseline calculation methodology, this may have impacted their baseline on days following the outage which could lead to underestimated performance of these resources.

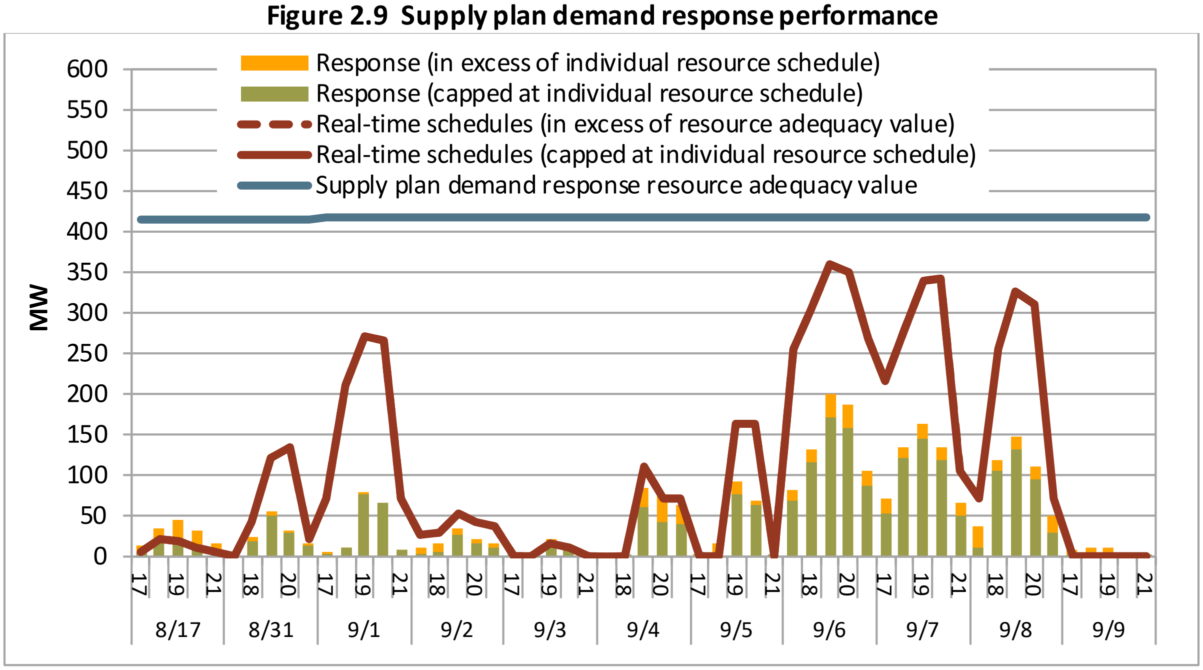
Supply plan demand response performance

Figure 2.9 shows the self-reported response of third party demand response resources shown on resource adequacy supply plans in comparison to their schedule capped at individual resources' shown resource adequacy values (red line) and their schedule in excess of shown resource adequacy values (dashed red line).[23] Figure 2.9 includes both self-reported response capped at individual resources' schedule (green bar) and self-reported response in excess of schedule (yellow bar).

Overall, supply plan demand response resources under-performed compared to dispatch instructions on high load days. Performance capped at individual resource schedules averaged 36 percent of real-time schedules during high load days this summer. When considering load curtailments in excess of individual resource schedules, performance of supply plan demand response averaged 45 percent.

The largest quantity of third party demand response was dispatched on September 6 during hours ending 19 and 20. While roughly 350 MW were dispatched, reported uncapped performance in these two hours only averaged 195 MW.

Figure 2.9 Supply plan demand response performance



2.5 Demand response aggregate summary of availability, dispatch and performance

Figure 2.10 shows the availability, dispatch, and self-reported response of *all* demand response capacity (proxy demand response and reliability demand response) counted towards resource adequacy

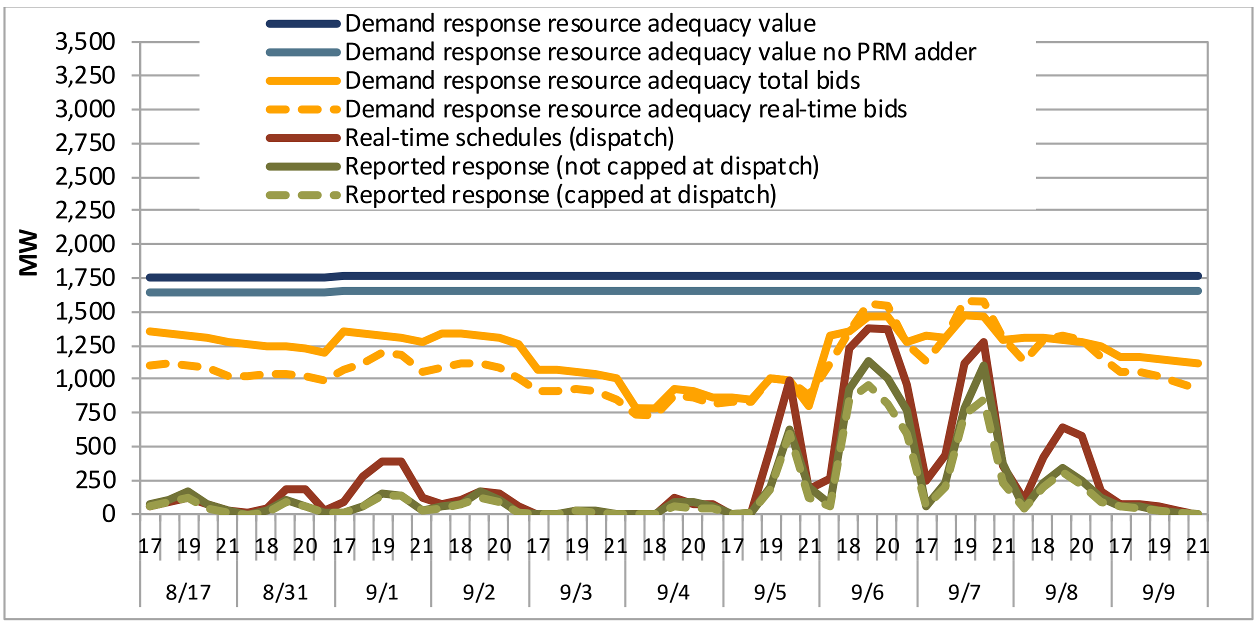
[23] On these high load days, there no real-time schedules of supply plan demand response resources above their resource adequacy capacity.

obligations on high load days across the summer. Figure 2.10 includes both credited utility and supply plan demand response capacity.

Figure 2.10 shows that demand response resource adequacy availability, as reflected through market bids, fell short of resource adequacy values on high load days. On average across peak net load hours on high load days, about 68 percent of the resource adequacy requirement met by demand response capacity, including the PRM adder, was available and accessible to the ISO in the market. However, only 62 percent of resource adequacy demand response capacity was available in the real-time.

Including load curtailment in excess of individual resources' schedules, total demand response performance averaged 67 percent of real-time dispatches across peak net load hours on high load days. This is a decline from 90 percent in the summer of 2021, but similar to the reported performance of 70 percent in August and September of 2020. The similar performance between summer 2020 and 2022 may be due to the similar load conditions in these two summers.

Figure 2.10 Aggregate demand response resource adequacy

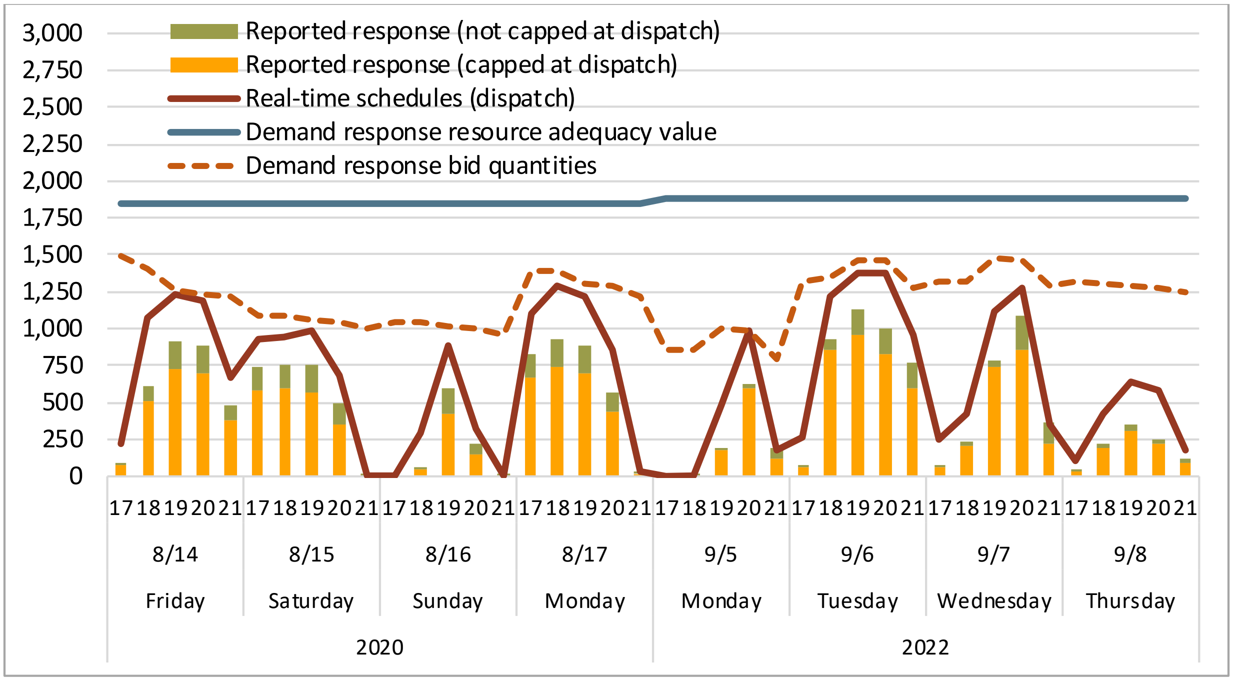


2.6 Comparison to 2020 heat wave

During August of 2020, the California ISO experienced extremely high temperatures that led to rotating electricity outages across the state of California on August 14 and 15. These few days of high load conditions are very similar to the heatwave in September of 2022 that led to an EEA 3 on September 6.

Figure 2.11 shows the aggregated availability and performance of demand response resource adequacy across the four days of the heatwaves of August of 2020 and September 2022. Overall, the availability and performance were similar across the two time periods. Around 65 percent of resource adequacy demand response was bid into the market during these tight conditions while uncapped performance averaged about 70 percent of the real-time schedule.

Figure 2.11 Aggregate demand response resource adequacy summer 2020 and 2022



One of the most prominent changes in demand response resource adequacy capacity from summer 2020 to summer 2022 was the composition of utility demand response versus third party. Compared to 2020, credited utility demand response resource adequacy decreased slightly while supply plan demand response almost doubled in magnitude. While performance of credited utility demand response increased from 74 percent the during the August 2020 time period to 90 percent in the September 2022 time period, performance of supply plan demand response has remained poor during hours on the highest demand days.[24]

Supply plan demand response resources tend to perform poorly on days when the system experiences the tightest system conditions. Supply plan demand response only reported to curtail around 45 percent of their scheduled load reductions on August 14-15 2020, July 9 2021, and September 6-7 2022, the most extreme days in the California ISO over the last three years.

[24] Charts with availability and performance by credited utility demand response versus supply plan demand response are provided in the appendix.

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.[25] 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.[26]

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 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.[27] In the summer of 2022, 62 percent of all demand response capacity used alternative adjustment factors in summer months. This is an increase from last summer when 48 percent of demand response capacity utilized alternative adjustment factors. A combination of proxy demand response and reliability demand response resources on day-matching baseline types were eligible to use alternate adjustment factors.

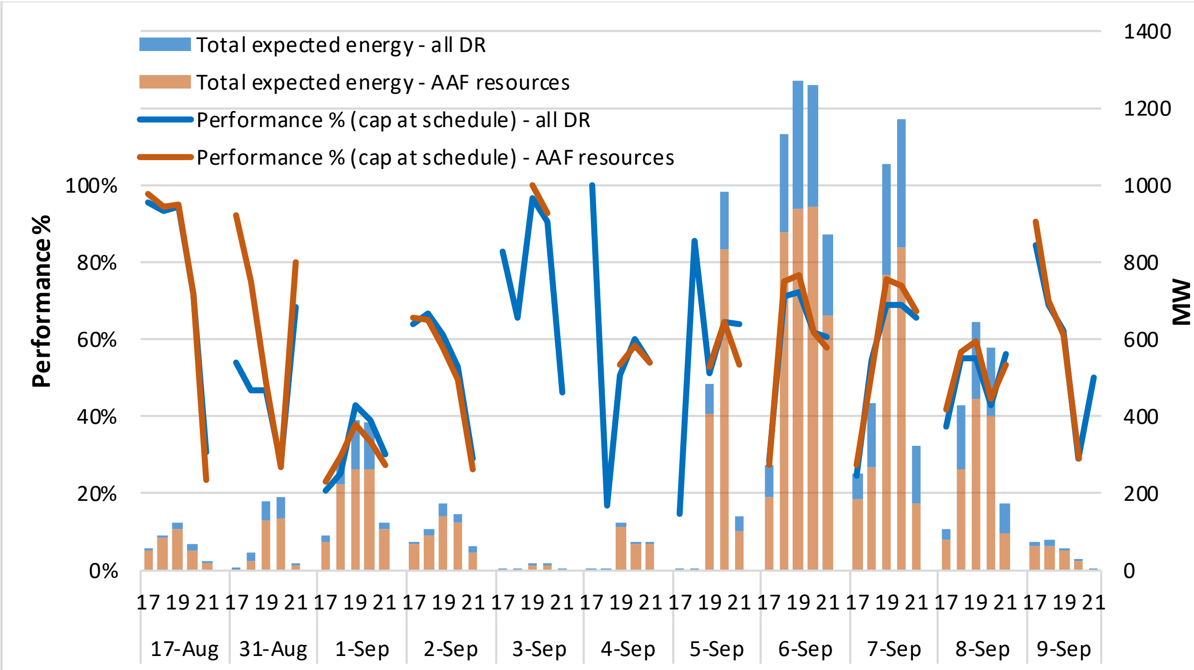
Figure 3.1 shows the performance of demand response resources using alternate adjustment factors compared to all demand response resources. Overall performance is similar for resources who utilize the alternative adjustment factors compared to the entire demand response fleet. Uncapped adjustment factors may have helped demand response providers achieve slightly higher performance values on September 6 and 7.

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

[26] ISO Tariff Section 4.13.4

[27] http://www.caiso.com/Documents/Presentation-DemandResponseCustomerPartnershipGroup-Apr22-2021.pdf

Figure 3.1 Performance of demand response resources with alternative adjustment factors



3.2 Energy market prices and incentives to deliver load reductions

Proxy demand response resource adequacy resources are often scheduled in the day-ahead and 15-minute markets, rather than being dispatched in the 5-minute market.[28] Therefore the majority of proxy demand response that was scheduled is first settled (paid) at day-ahead or 15-minute prices. To the extent that resources did not perform, deviations are settled at 5-minute market prices. Resources face greater financial consequences for failing to deliver expected load reductions when 5-minute market prices are high relative to day-ahead and 15-minute market prices.

Figure 3.2 shows the market schedules of the *proxy* demand response resource adequacy fleet (utility and supply plan resources) between day-ahead, 15-minute, and 5-minute markets.[29] During September 5 - 8, proxy demand resource adequacy was largely scheduled in the day-ahead market. Real-time schedules in 15 and 5-minute markets did not deviate significantly from day-ahead awards, implying proxy demand resources were primarily paid the day-ahead price and would be charged for undelivered energy at the 5-minute market price.

[28] Hourly and 15-minute dispatch options were made available for proxy demand response resources starting November 2019 as a result of the ISO's energy storage and distributed energy resources phase 3 (ESDER3) initiative. Most of the proxy demand response fleet has since switched from 5-minute dispatchable to hourly and 15-minute dispatch options. In September 2022, 92 percent of the proxy demand response fleet counted towards meeting resource adequacy requirements was registered under hourly or 15-minute dispatchable options. Therefore, only a small portion of the proxy demand response fleet can now be dispatched incrementally from HASP or 15-minute market schedules in the 5-minute market. The widespread adoption of hourly and 15-minute dispatch options by proxy demand response resources has resulted in minimal changes in schedules between 15 and 5-minute markets.

[29] The majority of RDRR was dispatched in the 5-minute market and therefore was only exposed to 5-minute market prices as opposed to 15-minute or day-ahead prices. Therefore Figure 3.2 and Figure 3.3 solely focus on proxy demand response resources.

Figure 3.2 Proxy demand response resource adequacy market schedules

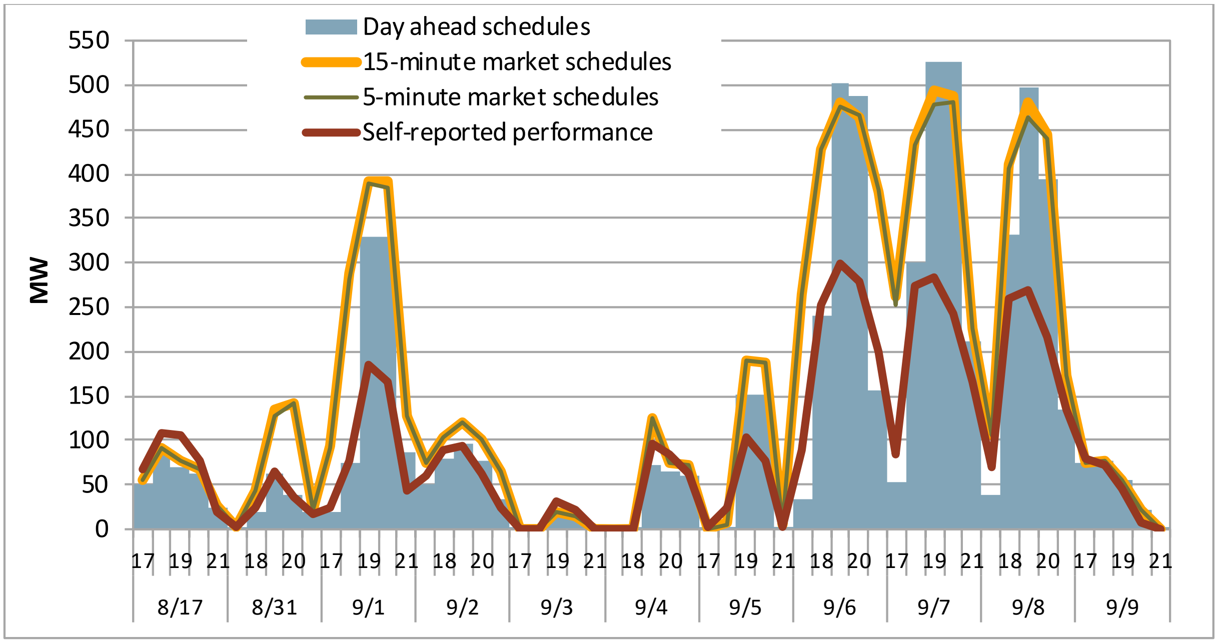
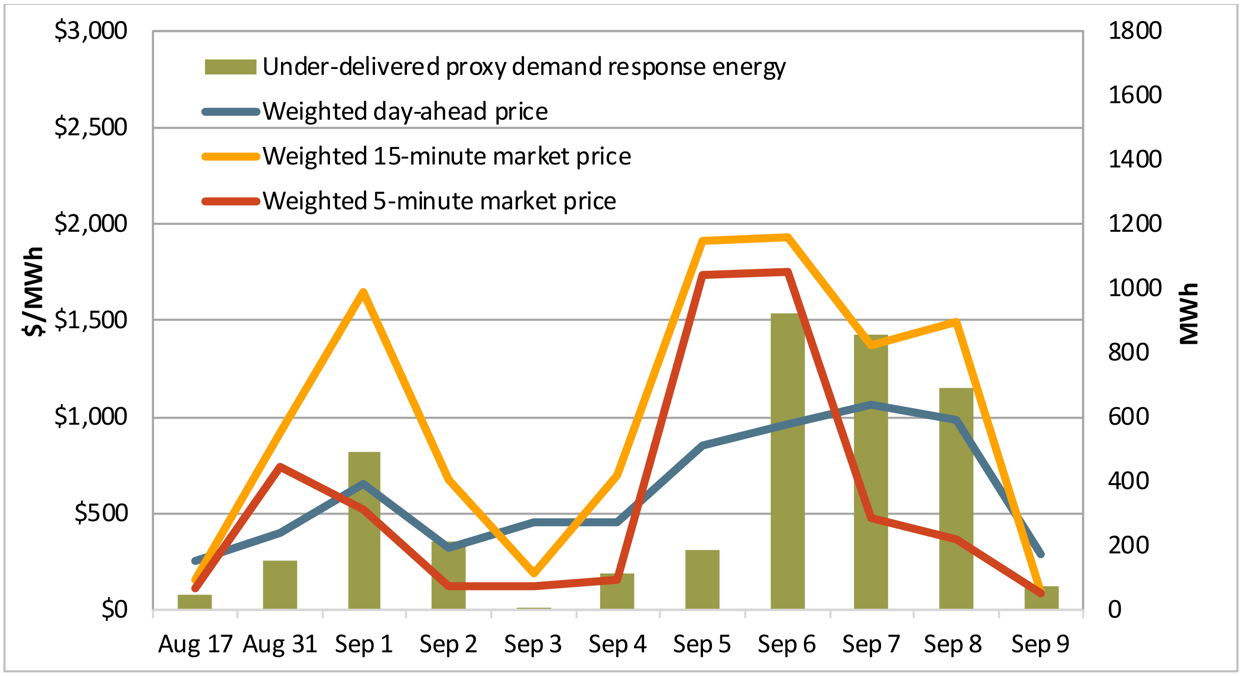


Figure 3.3 shows total undelivered energy from proxy demand resources on high load days across the summer, along with average day-ahead, 15-minute, and 5-minute prices. Undelivered proxy demand response was highest on September 6 - 8. On September 6, prices in the 5-minute market were higher than day-ahead prices and thus proxy demand response capacity scheduled in the day-ahead market would have had greater incentives to deliver load reductions in real-time. On September 7 and 8, prices in the 5-minute market were lower than day-ahead and 15-minute prices, and thus the financial consequences of undelivered energy would be lower.

Figure 3.3 shows total undelivered energy from proxy demand resources on high load days across the summer, along with average day-ahead, 15-minute, and 5-minute prices. Undelivered proxy demand response was highest on September 6 - 8. On September 6, prices in the 5-minute market were higher than day-ahead prices and thus proxy demand response capacity scheduled in the day-ahead market would have had greater incentives to deliver load reductions in real-time. On September 7 and 8, prices in the 5-minute market were lower than day-ahead and 15-minute prices, and thus the financial consequences of undelivered energy would be lower.

While there are instances of lower 5-minute market prices creating little financial incentive for resources to deliver, there are also days with higher 5-minute market prices where resources continue to have substantial volumes of undelivered energy. This may be due in part to resource adequacy payments being the primary revenue sources for demand response resources. Energy market revenues make up a smaller portion of the overall compensation for resource adequacy demand response resources compared to their capacity payments.

Figure 3.3 Demand response resource adequacy under-delivery and weighted nodal prices



3.3 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 towards resource adequacy requirements, by resource type.[30] 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 2022, utility proxy demand response resources earned about $118/MWh while third party demand response resources earned about $485/MWh of energy delivered. This difference can be explained by much higher energy market revenues per megawatt-hour of energy

[30] This analysis is based on settlements data, which is not finalized until T+70 business days. This implies the data for Oct – Dec is a preliminary estimate.

delivered for third party demand response. Third party demand response receive schedules less frequently than utility proxy demand response, and are primarily scheduled when prices are very high.

Table 3.1 Demand response resource adequacy net market revenues - 2022

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	42,241	35,810	$214	$96	$0	$118
Utility RDRR	6,731	5,985	$1,070	$554	$4	$519
3rd party PDR	12,244	7,638	$1,122	$646	$8	$485

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, 2021, and 2022.[31]

The capacity values shown in Table 3.2 are based on the 85 percentile of resource adequacy prices as reported in the CPUC's 2020 Resource Adequacy report.[32] Annualized capacity prices are based on the annual budgets for the CPUC's Demand Response Auction Mechanism (DRAM) and DRAM capacity shown on resource adequacy supply plans.

[31] This analysis is based on settlements data, which is not finalized until T+70 business days. This implies the net energy market revenue data for Oct – Dec 2022 is a preliminary estimate.

[32] 2020 Resource Adequacy Report, CPUC Energy Division, April 2022, p. 24:
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2020_ra_report-revised.pdf

Table 3.2 Demand response resource adequacy net market revenues and capacity costs (2020-2022)

Year	Demand response type	Net energy market revenues ($/kW-year)	Capacity price - system RA 85th percentile ($/kW-year)	Capacity price - DRAM auction ($/kW-year)
2020	Utility PDR	$15.45	$91.20	$78.68
	Utility RDRR	$5.91	$91.20	$78.68
	3rd party PDR	$13.52	$91.20	$78.68
2021	Utility PDR	$10.30	$96.00	$109.75
	Utility RDRR	$0.93	$96.00	$109.75
	3rd party PDR	$4.52	$96.00	$109.75
2022	Utility PDR	$26.97	$93.00	$120.20
	Utility RDRR	$3.42	$93.00	$120.20
	3rd party PDR	$15.10	$93.00	$120.20

While net market revenues for all three types of demand response increased in 2022 compared to 2021, Table 3.2 shows that the primary revenue stream for demand response resource adequacy resources continues to be the capacity payments they receive. 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.

4 Appendix

Figure 4.1 Utility demand response in August 2020 and September 2022

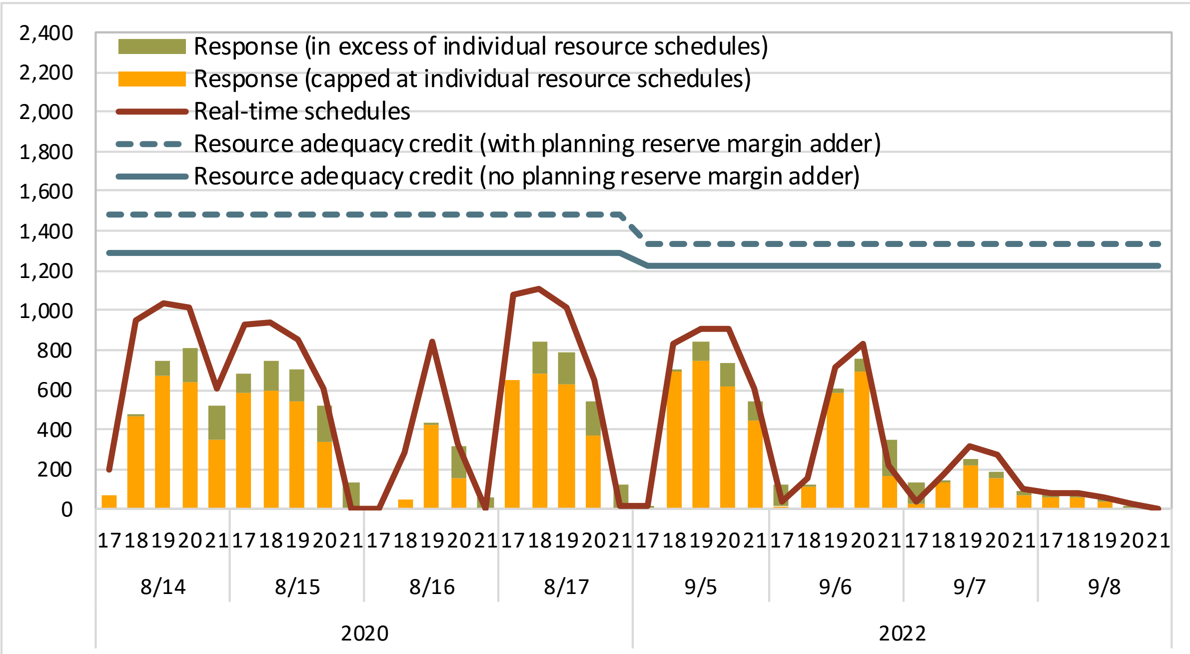


Figure 4.2 Third party demand response in August 2020 and September 2022