California Independent System Operator Corporation

California ISO

Demand Response Issues and Performance 2021

January 12, 2022

Department of Market Monitoring

1 Summary

1.1 Background

This report provides analysis of how demand response resources participated and performed in the ISO market on high load days in summer 2021. The Department of Market Monitoring (DMM) has provided similar analysis of the performance of demand response resources during summer 2020, when the ISO relied on demand response to curtail load more frequently and at much higher levels than in nearly two decades.[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 2021. 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 1,760 MW) in July, August, and September 2021. About 85 percent of this capacity is comprised of utility demand response programs, 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 the 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 nine days between June and September and issued system warnings on three days in July. Reliability demand response resources (RDRR) were also manually dispatched by the ISO on July 9 when the ISO declared an Emergency Energy Alert (EEA2).

[1] *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

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 were not available or directly accessible to the ISO in peak net load hours on days where 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.

- **One high load day in July fell on a weekend (Saturday), when a significant portion of demand response adequacy was not available.** The availability of utility and third-party demand response resources dropped significantly on weekends. When capacity was made available on weekends and holidays, this capacity was offered at higher prices than capacity offered on regular weekdays.

- **On high demand days in the summer, about 65 percent of the demand response capacity in real-time was reported to perform as scheduled**. Utility demand response reported higher performance than third-party demand response, consistent with historic trends. There were also significant differences in reported performance among different individual demand response providers.

- **Proxy demand response resources bid into ISO markets as supply resources generally did not face significant financial consequences for under-performance.** The majority of proxy demand response scheduled on high load days was scheduled in the day-ahead or 15- minute markets. When these resources under-perform, they are charged based on the 5-minute market price – which is generally lower than day-ahead and 15-minute market prices. Relatively low 5-minute market prices reflected the impact of several manual out of market actions that the ISO took to maintain system reliability. These low 5-minute market prices reduce incentives for demand response to perform.

- **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) represent 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.

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.[2] 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 to account for the variable nature of some demand response resources. However, DMM continues to recommend that the ISO consider other potential changes to enhance the reliability of demand response capacity. These include:

- ***Re-examine demand response counting methodologies.*** Utility demand response appeared to be over-counted in terms of these resources' contribution toward meeting resource adequacy requirements on high demand days in 2021. 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.[3] 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. In 2021, the CPUC also approved rules that would require demand response programs counted towards resource adequacy to be available on Saturdays, which DMM supported as high load days in recent years have not been limited to weekdays.[4]

- ***Adopt the ISO's recommendation to remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction.*** In the CPUC's resource adequacy rulemaking R.19-11-009, the ISO recommended that the CPUC discontinue applying a planning reserve margin adder to demand response capacity values.[5] Starting in 2022, the CPUC will remove 6 percent of the 15 percent planning reserve margin adder applied to demand response capacity credits, and the CEC will examine whether the remaining 9 percent of the adder should be retained.[6] While DMM supported this reduction of the planning reserve margin adder applied to demand response, 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.

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[2] *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

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

[4] *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. 9-10: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

[5] *California Independent System Operator Corporation Consolidated Comments on all Workshops and Proposals*, R.19-11-009, March 23, 2020, pp. 10-11: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M330/K052/330052136.PDF

[6] *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

- ***Consider removing the exemption for long-start proxy demand response to be available in the residual unit commitment process. This exemption does not exist for other types of long-start resources providing resource adequacy.*** The portion of supply plan proxy demand response considered long-start based on registered start-up times in the ISO's master file increased significantly in 2020. Long-start resources continue to make up a significant portion of the resource adequacy proxy demand response fleet. In September 2021, about 60 percent of supply plan demand response was registered with start-up times of 5 hours or more.[7] 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.

- ***Adopt a process to manually dispatch available demand response counted towards meeting resource adequacy requirements.*** DMM observed that on high demand days, including July 9, when the ISO declared an EEA2, that some demand response resource adequacy capacity bid into the day-ahead market was not scheduled economically in the integrated forward market. This capacity was not subsequently manually dispatched in the day-ahead timeframe and thus was not available in real-time. Furthermore, some demand response capacity that was available but was not economic in real-time was not manually dispatched by the ISO in peak net load hours.

- ***Continue to review why demand response resources in the same sub-lap continue to be sized less than 1 MW. Consider applying RAAIM to demand response resource adequacy capacity at the demand response provider and sub-lap level, rather than the resource level to ensure this capacity remains exposed to resource adequacy availability incentives.*** DMM has reported that supply plan demand response resources under the same scheduling coordinator in the same sub-lap continue to be sized at less than 1 MW—exempting this capacity from the ISO's resource adequacy availability incentive mechanism (RAAIM).[8] The ISO could develop rules so that resource adequacy availability incentive charges cannot be avoided simply by splitting demand response resources into smaller units.

- ***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 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 crediting 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.

- ***Consider developing a performance-based penalty or incentive structure for resource adequacy resources***. A performance-based penalty or incentive mechanism could be particularly relevant for demand response resources because of the difficulty of determining, in advance, whether or not a new demand response resource—or an existing provider that is selling additional new capacity—is

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

[8] *Q2 2020 Report on Market Issues and Performance*, Department of Market Monitoring, October 6, 2020, pp. 121-122: http://www.caiso.com/Documents/2020SecondQuarterReportonMarketIssuesandPerformance-Oct62020.pdf

capable of delivering load curtailment in critical hours equal to the quantity of resource adequacy capacity that the resource has been paid to provide.

- ***Develop guidelines for demand response commitment costs.*** In 2020, some demand response providers submitted very high commitment costs for capacity offered.[9] In 2021, while some demand response providers continued to submit startup and minimum load costs, these costs were significantly lower than costs observed last year. While commitment costs for demand response were significantly lower this year, the ISO should continue to consider what might constitute appropriate commitment costs for demand response resources. DMM understands that the ISO is currently working on this effort.

- ***Consider refinements to the demand response hourly dispatch model.*** In 2020, a combination of slow ramp rates and hourly block constraints limited the amount of proxy demand response capacity that the ISO could access in real-time on high load days.[10] Demand response resources appeared to increase ramp rates in 2021, and DMM did not observe the same availability limitations on hourly demand response resources as in 2020. However, should this issue arise again in the future, the ISO could consider modifying the hourly dispatch option so that the ISO could access more capacity from demand response resources that may be slow-ramping. This might be done by lifting or making the block schedule requirement optional for hourly demand response resources.

[9] *Report on demand response issues and performance*, DMM, February 25, 2021, pp. 12-14: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

[10] *Ibid*., pp. 14-15.

2 Analysis of demand response market participation

This section provides a summary of findings on demand response resource adequacy capacity participating in the ISO market on high load days in summer 2021.

2.1 Demand response as resource adequacy

Similar to last summer, demand response accounted for about 3 to 4 percent of total system resource adequacy capacity in July, August, and September 2021. Demand response counted towards meeting an average of 1,760 MW of system resource adequacy requirements during each month of this timeframe.

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 85 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 15 percent of demand response used to meet resource adequacy requirements.

Utility demand response

Utility demand response represents programs 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, August, and September, this type of demand response capacity accounted for about 1,500 MW of resource adequacy credits each month.[11]

Almost all of utility demand response capacity (94 percent) is 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 15 percent above the reported capacity of these demand response resources.

The majority of this IOU capacity (79 percent) consists of reliability demand response resources (RDRR), which are only called upon under emergency conditions after the ISO issues a system warning.[12] 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 availability incentive mechanism (RAAIM).

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

[12] Reliability demand response resource programs are primarily comprised of Base Interruptible Program (BIP) customers and agricultural and pumping loads.

In addition to CPUC-jurisdictional demand response credits, other non-CPUC jurisdictional regulatory authority load-serving entities (such as municipal utilities) accounted for about 100 MW of demand response resource adequacy credits in July, 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 is generally subject to ISO must-offer-obligations and the ISO's resource adequacy availability incentive mechanism (RAAIM).[13]

The majority of supply plan demand response capacity is contracted through the CPUC's Demand Response Auction Mechanism, although an increasing amount of supply plan demand response is being contracted bilaterally between third-party providers and load-serving entities. All supply plan demand response resources registered in 2021 were proxy demand response resources. In July, August, and September supply plan demand response capacity accounted for about 260 MW of resource adequacy capacity.

Table 2.1 below summarizes the breakdown between credited and supply plan demand response capacity counted towards resource adequacy requirements in July, August, and September 2021. 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 Summer 2021 demand response resource adequacy capacity (MW)

Month	Credited demand response (CPUC LRA)	Credited demand response (Other LRA)	Supply plan demand response	Total MW
July	1,351	125	263	1,739
August	1,400	97	260	1,757
September	1,428	96	262	1,786

[13] RAAIM is a financial incentive mechanism applied to resource adequacy capacity where suppliers could be penalized for not being available (bid) into the ISO market in Availability Assessment Hours that are currently peak net load hours (4:00 to 9:00 pm) on non-holiday weekdays. Resources with a Pmax less than 1 MW are exempt from RAAIM under the ISO Tariff, Section 40.9.2(a)(1). In September 2021, 44 percent of supply plan demand response capacity was associated with resources sized less than 1 MW and thus were exempt from RAAIM.

2.2 Availability of demand response resource adequacy capacity

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

Utility demand response availability

In peak net load hours on high load days in the summer, about 560 MW or about 39 percent of utility demand response resource adequacy capacity across all local regulatory authority jurisdictions, was not available or directly accessible to the ISO.

CPUC-jurisdictional credited demand response availability fell short of resource adequacy credits by an average of 450 MW, or 34 percent, of total resource adequacy credits (including the 15 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. 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.

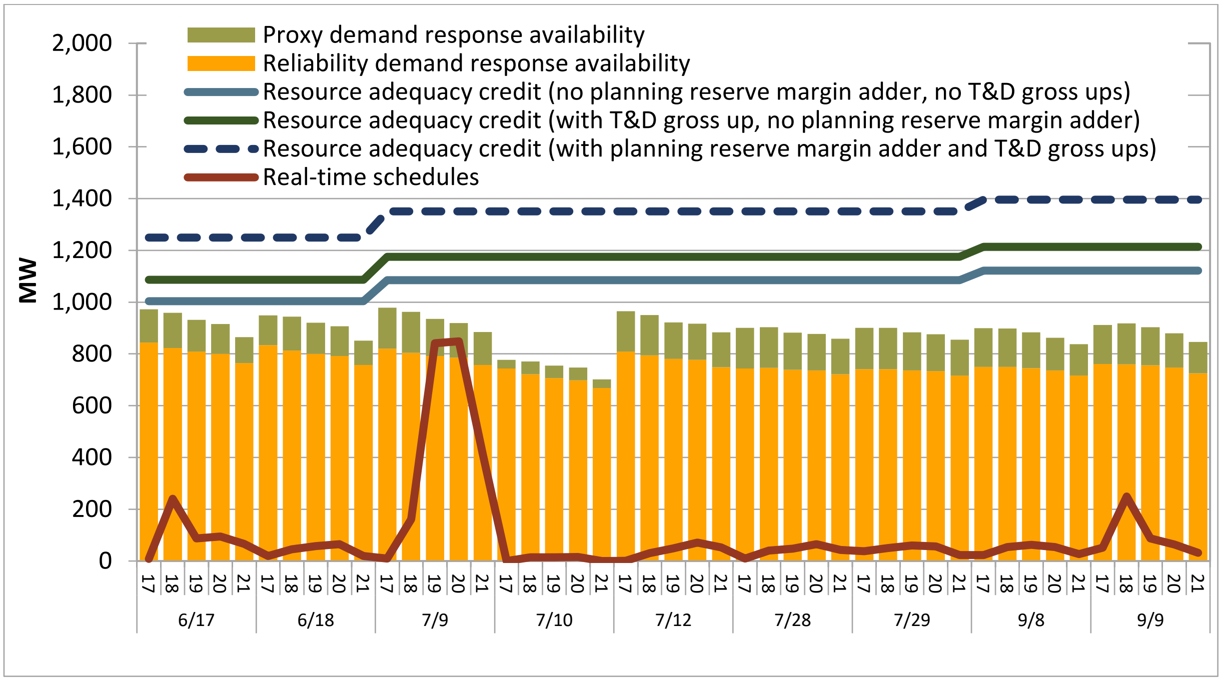
3) CPUC-jurisdictional demand response credits include a 15% planning reserve margin adder and gross ups for avoided transmission and distribution losses.

In addition, non-CPUC jurisdictional load-serving entities claimed 125 MW of demand response resource adequacy credits in July, and 96 MW of credits in August and September, which reduce 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, nor did the ISO have a process to be informed of program availability on a daily basis as it does with CPUC-jurisdictional demand response programs.

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 demand response resource bids into the ISO markets.

While utility demand response was not available up to resource adequacy credits, the capacity that was available was nearly fully utilized by the ISO via manual dispatch on July 9. The majority of utility demand response dispatches were associated with manual dispatches of reliability demand response resources after the ISO issued system warnings.

Figure 2.1 CPUC-jurisdictional utility demand response availability and resource adequacy credits



Supply plan demand response availability

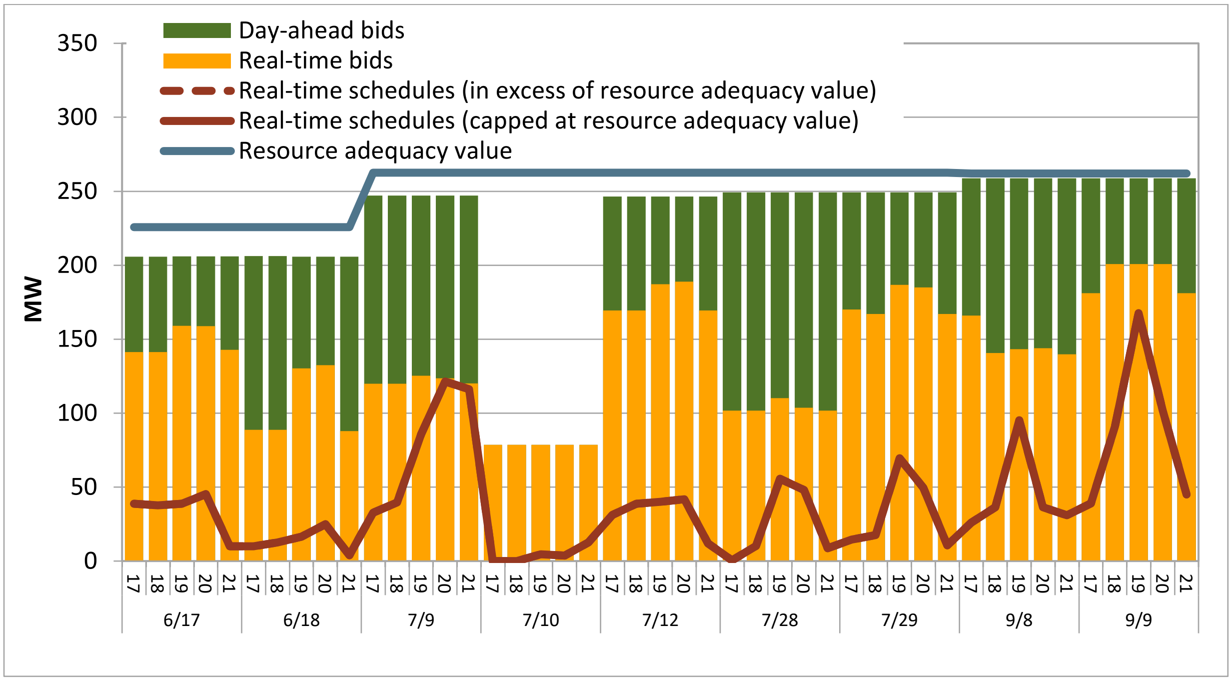
Supply plan demand response capacity was largely offered up to resource adequacy values in the day-ahead market, except on Saturday, July 10. However, given a large portion of the supply plan demand response fleet is long-start, if these resources are not scheduled economically in the day-ahead market, then a portion of these resources are not available in real-time. On average, about 115 MW or about 45 percent of supply plan demand response resource adequacy capacity was not available to the ISO in real-time 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). Across these days, supply plan demand response was not offered or scheduled above shown resource adequacy values.

The majority of the capacity not bid into the day-ahead market on high load weekdays was associated with resources sized less than 1 MW and thus were exempt from RAAIM. The majority of underbid capacity from resources sized less than 1 MW was associated with resources under the same scheduling coordinator, where more than one resource sized less than 1 MW existed in the same sub-lap. In September 2021, 44 percent of supply plan demand response was associated with resources sized less than 1 MW under the same scheduling coordinator, where more than one resource sized less than 1 MW existed in the same sub-lap.

A portion of available supply plan demand response was economically committed and dispatched in the day-ahead market on high load days. However, some supply plan demand response capacity did not economically clear the day-ahead market on these days, and was not subsequently available in real-time. 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. Many of these resources are uneconomic in the day-ahead market, and if not scheduled in the day-ahead market, are not available in RUC or in real-time. There were also no manual dispatches of third-party proxy demand response resources in this timeframe.

Figure 2.2 Day-ahead and real-time availability of supply plan demand response



2.3 Demand response bidding

Figure 2.3 shows day-ahead bid prices of proxy demand response and reliability demand response counted towards resource adequacy requirements across peak net load hours (utility and third-party demand response). Figure 2.3 shows that about 39 percent of the utility proxy demand response that was bid into the day-ahead market on high load days between 4-9 pm in July and September was scheduled in the day-ahead market. About 14 percent of third-party demand response was that was bid into the day-ahead market on these same days was scheduled in the day-ahead market. Additionally, while the majority of reliability demand response resources (RDRR) in this timeframe were scheduled in the real-time market on July 9, RDRR capacity was bid into and scheduled in the day-ahead market on some days this summer.

Figure 2.3 Demand response resource adequacy day-ahead bids

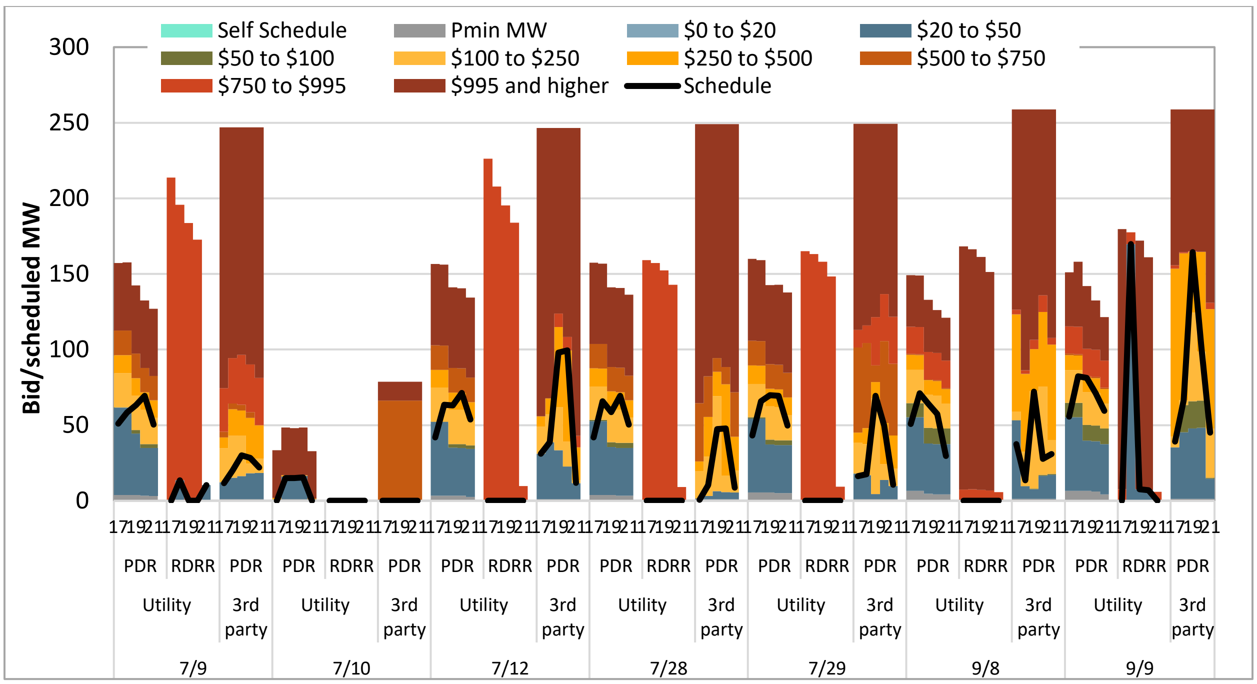
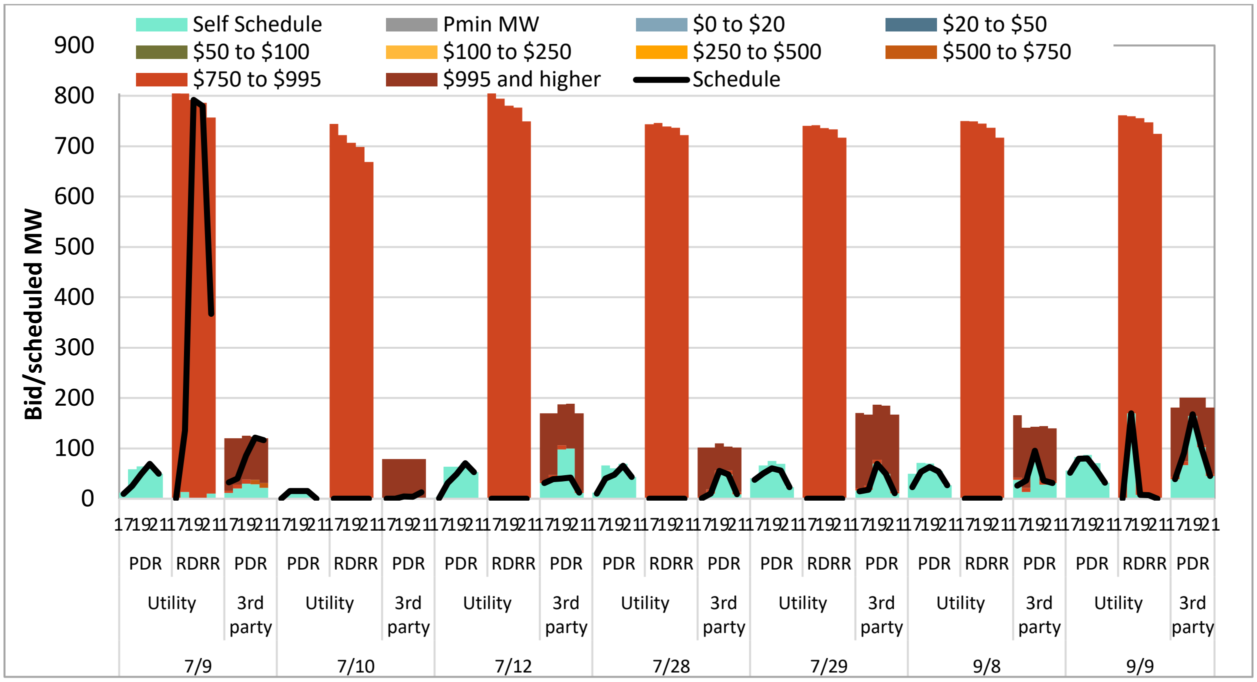


Figure 2.4 shows real-time bids of proxy demand response and reliability demand response counted towards resource adequacy requirements across peak net load hours. Figure 2.4 shows that demand response capacity that was scheduled in the day-ahead market was generally self-scheduled into real-time, and capacity incremental to day-ahead awards was largely offered at or near the $1,000/MWh bid cap. Incremental reliability demand response capacity offered into real-time must be offered at bid price of at least 95% of the ISO's soft energy bid cap, currently set at $1,000/MWh.[14]

[14] ISO Tariff Sections 30.6.2.1.2.1 and 30.6.2.1.2.2

Figure 2.4 Demand response resource adequacy real-time bids



2.4 Demand response performance

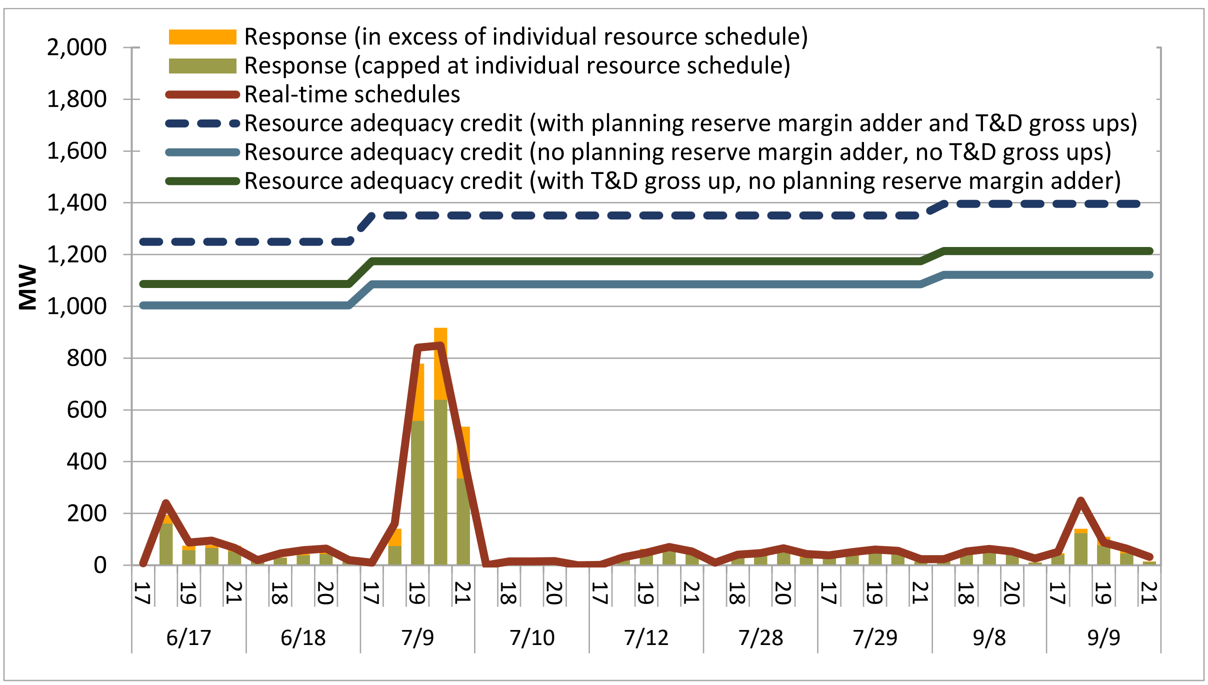
This section details the self-reported performance of both utility demand response and supply plan demand response resources on high load days in the summer. Performance defined here is the self-reported response of demand response resources compared to their real-time schedules.

Utility demand response performance

Figure 2.5 shows real-time dispatches and self-reported response of CPUC-jurisdictional utility demand response capacity on high load days. Figure 2.5 reflects both proxy demand response and reliability demand response resource 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 2.5.

Figure 2.5 shows 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. In aggregate, however, the total CPUC-jurisdictional utility demand response fleet reported to perform well compared to ISO dispatch instructions in peak net load hours.

Figure 2.5 CPUC-jurisdictional utility demand response performance



The largest amount of utility demand response was dispatched on July 9, with over 800 MW during hours ending 19 and 20. Resources reported to curtail almost 800 MW in hour ending 19 and over 900 MW in hour ending 20. These reported curtailments include load curtailment in excess of individual resource dispatches and suggest a performance of 93 percent and 108 percent in hours ending 19 and 20 respectively. Limiting performance to individual resources' dispatch instructions, utility demand performance was about 66 percent and 75 percent in hours ending 19 and 20 on July 9.

Figure 2.6 and Figure 2.7 show CPUC-jurisdictional demand response performance, split between proxy and reliability demand response resource capacity.

Figure 2.6 CPUC-jurisdictional utility proxy demand response performance

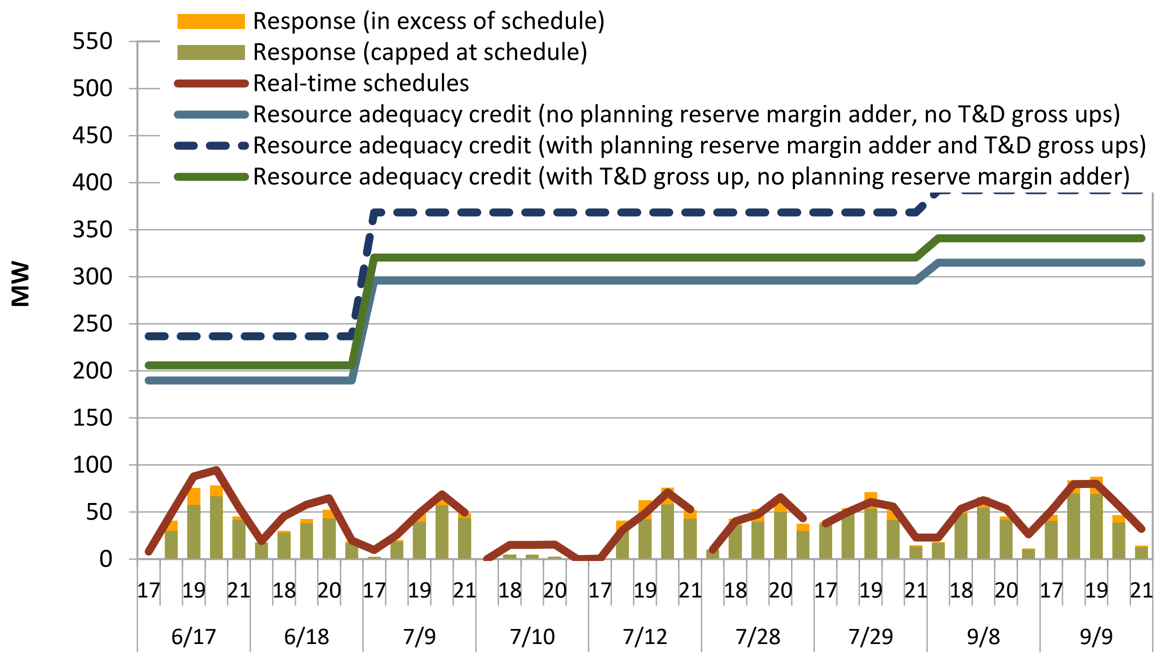
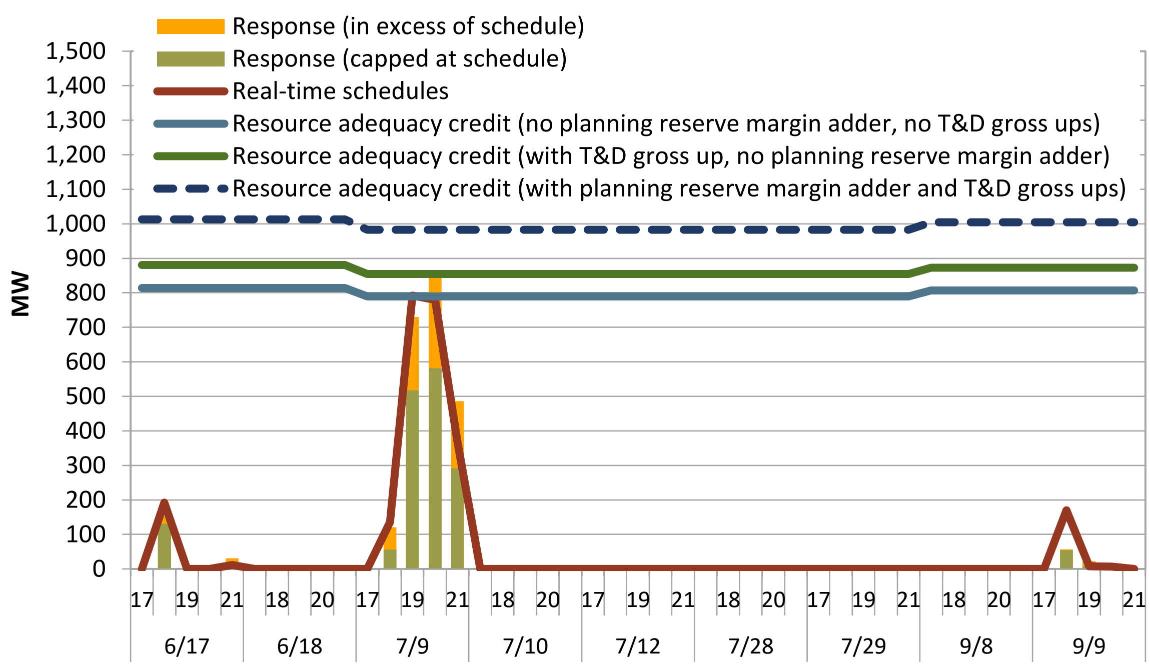


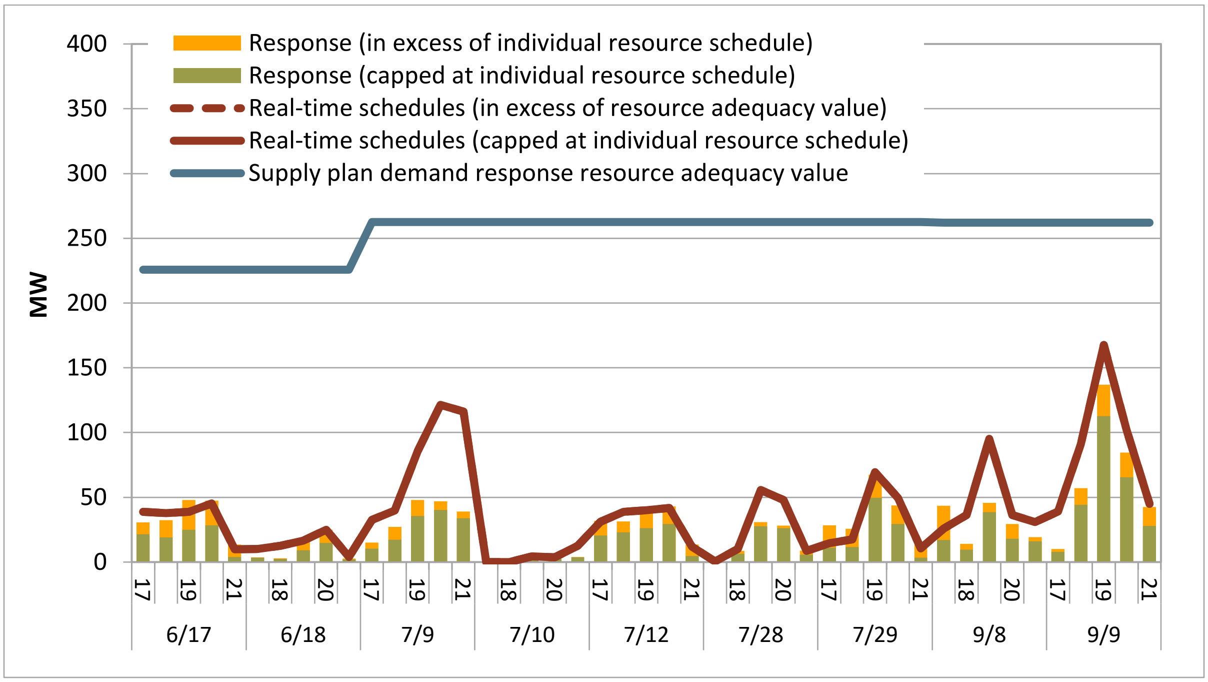
Figure 2.7 CPUC-jurisdictional utility reliability demand response resource (RDRR) performance



Supply plan demand response performance

Figure 2.8 shows the self-reported response of demand response resources shown on resource adequacy supply plans. Figure 2.8 shows both self-reported response capped at individual resources' resource adequacy values (green bar) and self-reported response in excess of resource adequacy values (yellow bar). In aggregate, the total third-party demand response fleet shown as resource adequacy reported to under-perform compared to ISO dispatch instructions on high load days, particularly on July 9, while performance appeared to improve on high load days later in the month.

Figure 2.8 Supply plan demand response performance



2.5 Demand response aggregate summary of availability, dispatch and performance

Figure 2.9 shows the availability, dispatch, and self-reported response of *all* demand response capacity (proxy demand response and reliability demand response) counted towards resource adequacy obligations on high load days across the summer. Figure 2.9 includes both credited utility and supply plan demand response capacity.

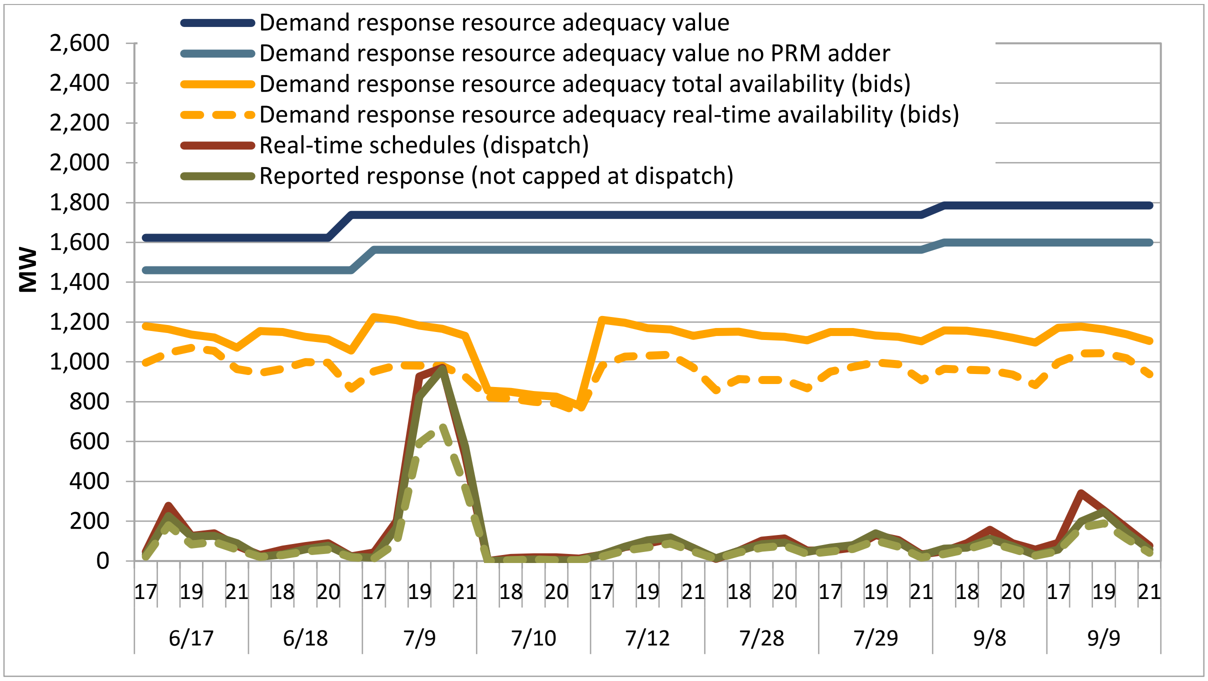
Figure 2.9 shows that demand response resource adequacy availability, as reflected through market bids and, fell short of resource adequacy values on high load days. On average across peak net load hours on high load days, about 64 percent of the resource adequacy requirement met by demand response capacity was available and accessible to the ISO in the market.

Further, some demand response resource adequacy, particularly supply plan proxy demand response resources were not fully dispatched up to available bid values on these days. Of the demand response capacity that was dispatched, a portion of demand response resource adequacy capacity that was dispatched, responded. Compared to high load days in 2020, demand response resource adequacy resources performance improved in the summer of 2021.

Limiting dispatches and response to individual resources' schedules or resource adequacy values, total demand response averaged 65 percent of real-time dispatches across peak net load hours on high load days in summer of 2021. This is an increase from the average reported performance of 53 percent from high load days in August and September of 2020.[15] This improved reported performance may be due in part to the difference in load conditions on high load days analyzed in 2021 versus 2020. Among the 2021 and 2020 data, reported demand response performance tends to be better on days where load levels do not lead to more extreme system conditions which warrant system warnings or emergency declarations. The 2021 data analyzed in this report include more days on which system warnings and emergencies were not declared, compared to the data analyzed in the 2020 report.

[15] *Report on Demand Response Issues and Performance*, DMM, February 25, 2021, p. 21: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

Figure 2.9 Aggregate demand response resource adequacy



2.6 Metered demand trends and baseline adjustments

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.[16] 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.[17]

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 from last summer that baselines were limited by capped baseline adjustment factors, thus under-representing demand response performance, 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.[18] Four scheduling coordinators applied to use alternate adjustment factors (AAF) in summer months. A combination of proxy demand response and reliability demand response resources on day-matching baseline types were eligible to use alternate adjustment factors.

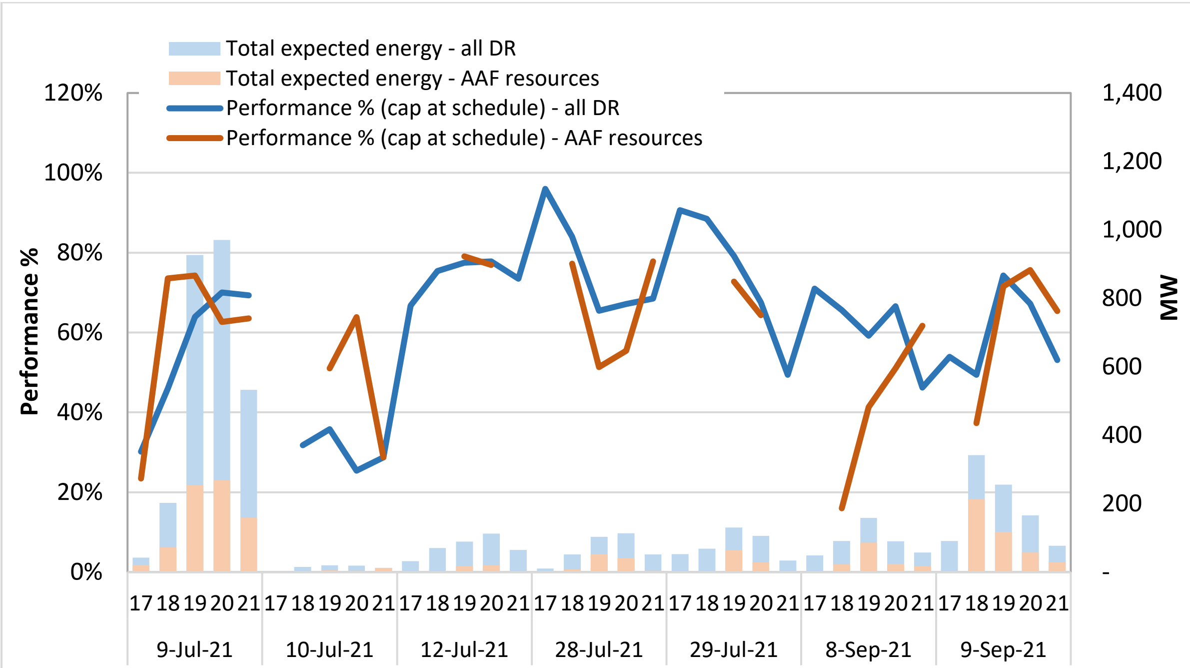
Based on high level load trends between intra-day and historic load, it appears that uncapped adjustment factors could have helped demand response providers reflect more accurate, higher performance values on some high demand days in July and September, particularly July 9. However, while alternate adjustment factors could have increased performance values, resources eligible to use alternate baselines still appeared to underperform compared to ISO dispatch instructions high demand days in July and September 2021. Figure 2.10 shows the performance of demand response resources using alternate adjustment factors compared to all demand response resources.

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

[17] ISO Tariff Section 4.13.4

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

Figure 2.10 Performance of demand response resources with alternate adjustment factors



3 Demand response compensation and incentives

This section provides of summary of findings concerning demand response compensation and incentives for demand response resources to perform and be available in ISO markets.

3.1 Energy market prices and compensation

On many high load days in summer 2021, 5-minute market (RTD) prices were generally lower than day-ahead and 15-minute market prices. Therefore, when demand response resources scheduled in the day-ahead and 15-minute markets did not perform, the prices that demand response resources faced to buy out of prior market (day-ahead or 15-minute market) positions were often relatively low. Because 5-minute market prices were often very low relative to day-ahead and 15-minute market prices, demand response resources may face little financial incentive to deliver expected load curtailment, and little financial consequence for not delivering expected load reductions.

Figure 3.1 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.[19] Proxy demand response resource adequacy resources were often scheduled in the day-ahead and 15-minute markets, rather than being dispatched in the 5-minute market.[20] Therefore, the majority of scheduled proxy demand response was first settled (paid) at day-ahead or 15-minute prices; to the extent that resources did not perform, deviations were settled at 5-minute market prices.

For example, in Figure 3.1 on September 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 so resources were primarily exposed to (paid) the day-ahead price. However, in aggregate, proxy demand resource adequacy resources reported to under-perform on September 8. Resources would be charged for uninstructed imbalance energy at 5-minute market prices which were generally lower than day-ahead and 15-minute market prices. In contrast, on July 9, real-time prices were generally higher than day-ahead prices and remained high between 15 and 5-minutes markets – therefore, proxy demand response capacity scheduled in the day-ahead market on July 9 would have had greater incentives to deliver load reduction in real-time.

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[19] In 2020 and on July 9 the majority of reliability demand response resources (RDRR) were dispatched in the 5-minute market but were not seen by the 15-minute market. This means that the majority of RDRR that was dispatched was exposed to 5-minute market prices as opposed to 15-minute market or day-ahead prices. Figure 3.1 and **Error! Reference source not found.**15 therefore focus on proxy demand response resources. In August, the ISO implemented market changes so that RDRR dispatch can be dispatched in the 15-minute market, however the ISO did not call on RDRR after July 9. See *Market Enhancements for Summer 2021 Readiness Final Proposal*, California ISO, March 19, 2021. p. 33: http://www.caiso.com/InitiativeDocuments/FinalProposal-MarketEnhancements-Summer2021Readiness.pdf

[20] 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 2020, 90 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.

Figure 3.2 shows the average nodal locational marginal prices for proxy demand response resource adequacy resources. In many of the hours where proxy demand response was scheduled the most in the real-time market, 5-minute market prices were low relative to day-ahead and 15-minute market prices.

Figure 3.1 Proxy demand response resource adequacy market schedules

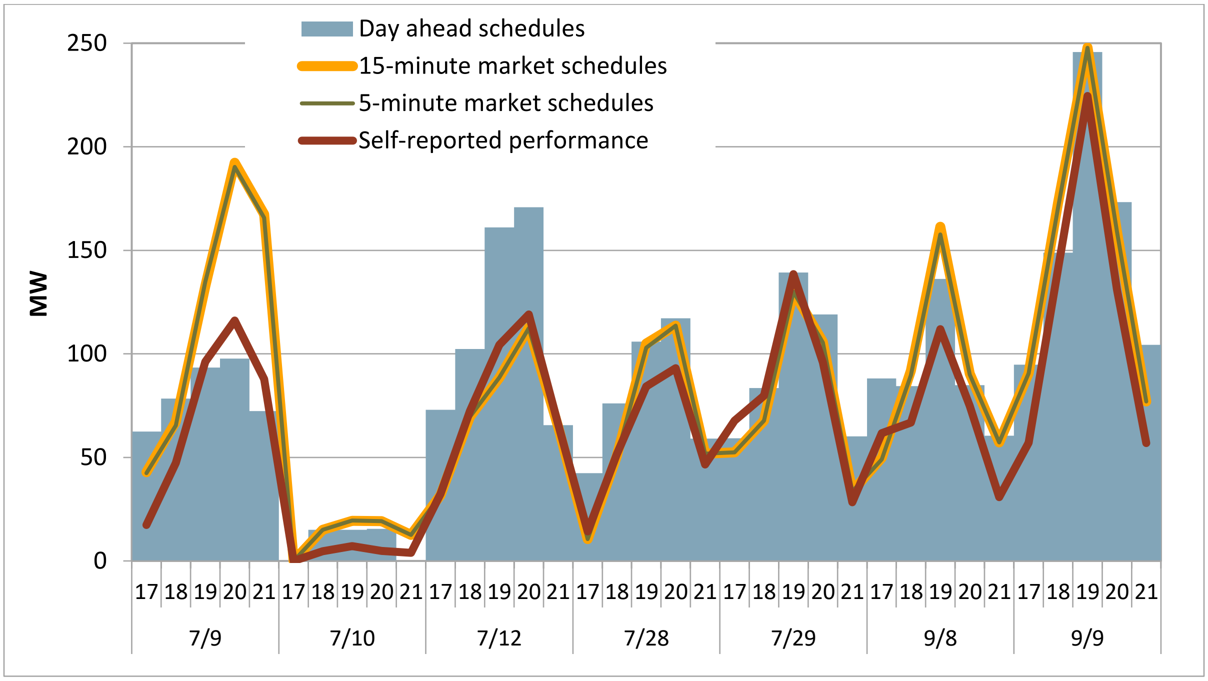

Figure 3.2 Proxy demand response resource adequacy nodal prices

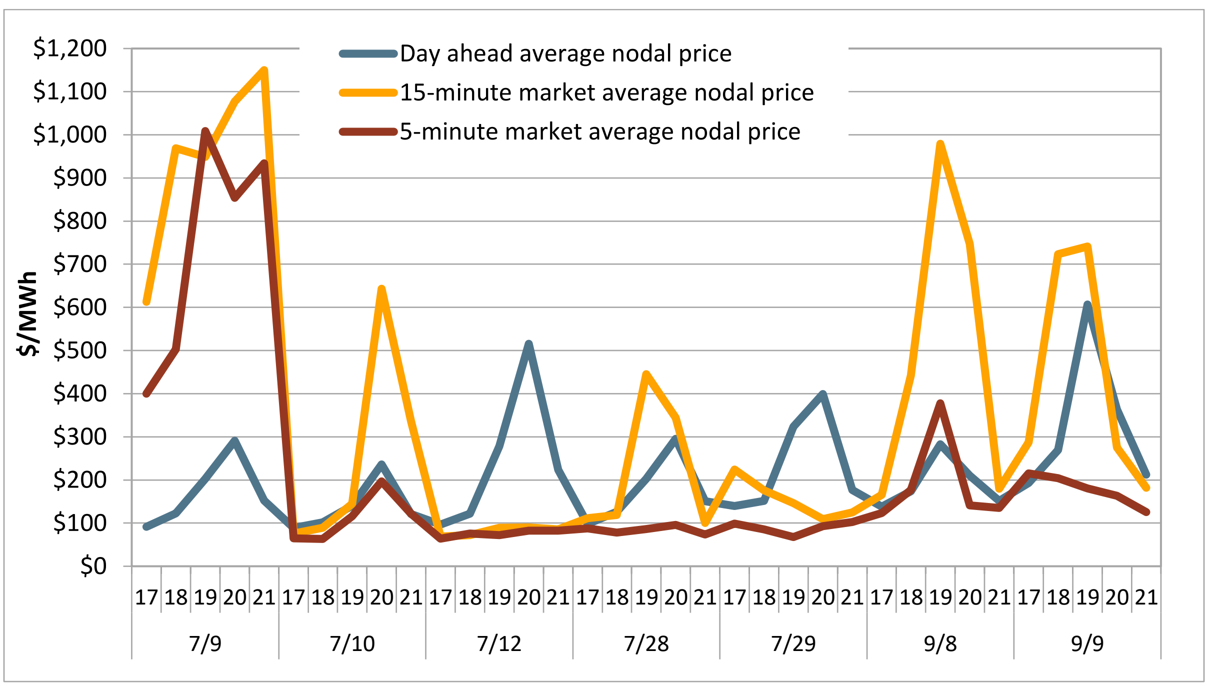

Figure 3.3 shows that demand response often did not face negative financial consequences for non-performance since 5-minute market prices were frequently lower than day-ahead and 15-minute market prices when load curtailment was under delivered, except on July 9. Figure 3.3 shows total under-delivered energy on high load days across the summer. Figure 3.3 also shows average day-ahead and 15-minute market nodal prices versus 5-minute market nodal prices, weighted by undelivered energy.

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