California Independent System Operator Corporation

# California ISO

# Demand response issues and performance

February 25, 2021

Department of Market Monitoring

# 1 Summary

## 1.1 Background

In August and September 2020, the ISO relied on demand response to curtail load more frequently and at much higher levels than in nearly two decades. Demand response resources were dispatched based on economic bids and reliability demand response was also manually dispatched by the ISO. As summarized in recent Department of Market Monitoring (DMM) reports, a large portion of demand response resource adequacy capacity was not available for dispatch. In addition, the reported performance of a large portion of demand response resources that were dispatched was significantly below dispatched levels during peak net load hours in summer 2020.[1]

Demand response resources met about 4 percent of total system resource adequacy capacity requirements in August and September. This capacity is comprised of utility demand response programs that are credited towards reducing resource adequacy requirements, along with demand response capacity that is scheduled by third-parties and shown on resource adequacy supply plans as contributing to meeting requirements. While demand response currently comprises a relatively small portion of the resource adequacy fleet, discussions are taking place at the CPUC and the CAISO which will consider steps to increase supply on the system by summer of 2021, including additional capacity from demand response resources.

This report provides further analysis of how demand response resources, both utility and supply plan capacity, participated and performed in the CAISO market in August and September 2020.[2] This report also discusses demand response compensation and assesses the incentives for demand response resources providing resource adequacy to participate and perform in the ISO market. Finally, this report includes a list of recommendations to be considered for improving the availability and performance of demand response resources used to meet resource adequacy requirements.

[1] *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, pp. 5, 60, 71: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

*Quarterly Report on system and market conditions, issues and performance: Q3 2020,* January 2021, pp. 121-125: http://www.caiso.com/Documents/2020ThirdQuarterReportonMarketIssuesandPerformance-Feb4-2021.pdf

[2] This report does not cover the activity of load-modifying demand response programs.

## 1.2 Key findings

Key findings on demand response in this report include the following:

- **About one-third of the 1,847 MW of resource adequacy capacity requirement met by demand response in August was not available or directly accessible to the ISO in real-time during periods of firm load curtailment**. Utility demand response resource adequacy appeared to be over-counted compared to its actual contribution, particularly in peak net load hours. Additionally, in 2020, the percentage of supply plan demand response with long-start operating characteristics more than doubled from 2019. 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.

- **Some high load days in August and September (August 15 and Labor Day weekend) coincided with weekends and holidays, where a significant portion of demand response adequacy was not available.** Both utility and supply plan demand response availability dropped significantly on weekends and holidays. When capacity was made available on weekends and holidays, this capacity was offered at higher prices than capacity offered on non-holiday weekdays.

- **Low ramp rates and hourly block scheduling restricted access to demand response capacity bid into the real-time markets.** Some supply plan demand response that was bid in real-time appeared economic but was not feasibly accessible because of resource ramping limitations. The majority of this slow-ramping capacity was also registered on the ISO's hourly dispatch option which requires that a resource have flat schedule across the hour. Hourly scheduling further limits accessible capacity by reducing allowable ramp times to 15-minutes for each hour.

- **On August 14 and 15 in hours ending 19 and 20 (6:00-8:00 pm), about 73 to 77 percent of the demand response capacity in real-time reported to perform as scheduled**. Utility demand response reported higher performance than supply plan demand response which is consistent with historic trends. There was also significant disparity in reported performance among demand response providers. For some providers, based on submitted baseline and meter data, there was also evidence that baseline adjustment caps could have limited reported performance.

- **Proxy demand response resources 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. The current rules do not provide a strong financial incentive for most demand response resources to perform when needed most under critical system conditions.

## 1.3 Recommendations

DMM highlighted some recommendations that the ISO and CPUC could consider to enhance the availability and performance of demand response resources in its August and September 2020 report.[3] DMM suggested that the ISO and CPUC consider these recommendations before increasing reliance on demand response towards meeting resource adequacy requirements. DMM includes these recommendations here with additional details as well as provides additional recommendations based on further analysis:

- ***Re-examine demand response counting methodologies.*** Utility demand response in particular appeared to be over-counted in terms of these resources' contribution toward meeting resource adequacy requirements. The ISO is currently examining different counting methodologies for demand response including methodologies which would better capture the variable nature of demand response availability.[4] DMM continues to support efforts to better capture the capacity contribution of demand response whose load reduction capabilities vary across the day, depending on load profiles.

- ***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 Track 2 resource adequacy proceeding, the ISO recommended that the CPUC discontinue including a planning reserve margin adder in demand response capacity values.[5] The ISO and Energy Division have also raised this issue for consideration in the CPUC's resource adequacy Track 4 proceeding (R.19-11-009).[6] The capacity reflected by the planning reserve margin adder cannot be utilized by the ISO, yet counts as supply towards reducing system resource adequacy obligations. DMM supports the ISO's recommendation that the planning reserve margin adder associated with utility demand response not be credited for reducing resource adequacy requirements.

- ***Adopt a process to manually dispatch available demand response counted towards meeting resource adequacy requirements before issuing exceptional dispatches to non-resource adequacy capacity and curtailing firm load.*** DMM observed that some demand response resource adequacy capacity bid into the day-ahead market that was not scheduled economically in the integrated forward market, 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 (and was not ramp limited) was not manually dispatched by the ISO in peak net load hours on high load days in August and September.

- ***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***

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[3] *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, pp. 60-61: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

[4] *Track 3B.1 proposals of the California Independent System Operator Corporation*, R.19-11-009, January 28, 2021, pp. 18-22: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M362/K887/362887738.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] *Track 4 proposals of the California Independent System Operator Corporation*, R.19-11-009, January 28, 2021, pp. 9-10: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M362/K898/362898648.PDF

*Energy Division Proposals for Proceeding R.19-11-009*, CPUC, January 28, 2021, p. 5: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M362/K898/362898786.PDF

***long-start resources providing resource adequacy.*** The percentage of supply plan proxy demand response considered long-start based on registered start-up times in the ISO's master file increased from 38 percent in August 2019 to 71 percent in August 2020. If this capacity is not scheduled economically in the integrated forward market, per the ISO tariff, this capacity has no obligation to be available in RUC.

- ***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 megawatt—exempting this capacity from the ISO's resource adequacy availability incentive mechanism (RAAIM).[7] The ISO could develop rules so that resource adequacy availability incentive charges cannot be avoided simply by splitting demand response resources into smaller units.

- ***Develop guidelines for demand response commitment costs.*** The ISO should consider what may constitute appropriate commitment costs for demand response resources. First, submitting high commitment costs for the amount of capacity offered could cause resources to be uneconomic to commit in the day-ahead market even on days with sustained high prices. But if the ISO were to manually dispatch these resources, resources could recover bid costs in excess of market revenues through bid cost recovery payments. The ISO should consider what may constitute appropriate commitment costs for demand response resources so that potential bid cost recovery payments are also reasonable. DMM understands that the ISO is currently working on this effort.

- ***Consider refinements to the demand response hourly dispatch model.*** DMM observed that 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. DMM understands that the ISO is taking steps to review and validate resource ramp rates. DMM suggests that the ISO could also consider modifying the hourly dispatch option by lifting or making the block schedule requirement optional under the hourly dispatch option, so that the ISO could access more capacity from slow-ramping demand response resources.

- ***Ensure that non-CPUC jurisdictional load serving entities that manage utility demand response programs credited against 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

[7] *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

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

# 2 Analysis of demand response market participation

This section provides of summary of findings on demand response resource adequacy capacity participating in the ISO market on high load days in August and September 2020.

## 2.1 Demand response as resource adequacy

Demand response accounted for about 4 percent of total system resource adequacy capacity in August and September 2020. In August, demand response counted towards meeting 1,847 MW of system resource adequacy requirements. In September, demand response counted towards meeting 1,769 MW of system resource adequacy requirements.

This capacity is comprised of two types of demand response resources: (1) utility demand response capacity that is credited against overall resource adequacy requirements and are scheduled by utilities, and (2) supply plan demand response resources that are shown on monthly resource adequacy supply plans and are the bid and scheduled by third party providers. In August and September about 86% of demand response resource adequacy capacity came from utility demand response.

### Utility demand response

Utility demand response represents programs that are operated by load serving entities in various local regulatory authority jurisdictions. This capacity is credited toward meeting resource adequacy requirements by being subtracted from the resource adequacy requirements of each load serving entity. In August, credited demand response capacity accounted for 1,604 MW of resource adequacy credits.[8] In September, credited demand response capacity accounted for 1,531 MW of resource adequacy.

The majority (about 92 percent) of credited demand response capacity represents investor-owned utility 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 including transmission and distribution loss factor gross ups, which represents the CPUC local regulatory authority planning reserve margin. The majority of these IOU programs are reliability demand response resources (RDRR), which are only called upon under emergency conditions, and can be called after the ISO issues a system warning.[9] Most available capacity from utility 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).

In addition to CPUC-jurisdictional demand response credits, other non-CPUC jurisdictional regulatory authority load-serving entities accounted for about 122 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

[8] Credited values includes transmission and distribution loss factors and planning reserve margin gross-ups. About 10 MW of non-utility demand response credits are reflected in this figure, which represents transmission and distribution loss factors and a planning reserve margin gross up for non-utility, non-DRAM, demand response resource adequacy capacity under the CPUC jurisdiction.

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

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 incentive mechanism (RAAIM).[10]

The majority of supply plan demand response capacity is contracted through the CPUC's Demand Response Auction Mechanism (DRAM). All supply plan demand response resources registered in 2020 were proxy demand response resources. In August, supply plan demand response capacity accounted for 243 MW of resource adequacy capacity. In September, supply plan demand response capacity accounted for 237 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 August and September 2020. 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 2020 demand response resource adequacy capacity (megawatts)**

| Month | Credited demand response (CPUC LRA) | Credited demand response (Other LRA) | Supply plan demand response | Total MW |
|---|---|---|---|---|
| August | 1,482 | 122 | 243 | 1,847 |
| September | 1,409 | 122 | 237 | 1,769 |

## 2.2 Availability of demand response resource adequacy capacity

As detailed in DMM's August and September report, about one third of demand response that was counted towards meeting resource adequacy requirements was not available or accessible to the ISO in real-time on high load days in August and September across peak net load hours.[11]

[10] 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 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 2020, 49 percent of supply plan demand response capacity was associated with resources sized less than 1 megawatt and thus were exempt from RAAIM.

[11] *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp. 55-59: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

### Utility demand response availability

In hours when firm load was curtailed on August 14, about 550 megawatts or about 34 percent of utility demand response resource adequacy capacity across all local regulatory authority jurisdictions, was not available or directly accessible to the ISO. In hours when firm load was curtailed on August 15, about 680 MW or about 42 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 495 megawatts, or 33 percent of total resource adequacy credits (including the 15 percent planning reserve margin adder) in hours where firm load was curtailed on August 14 and 15. 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. The 15% planning reserve margin adder does not represent physical capacity.

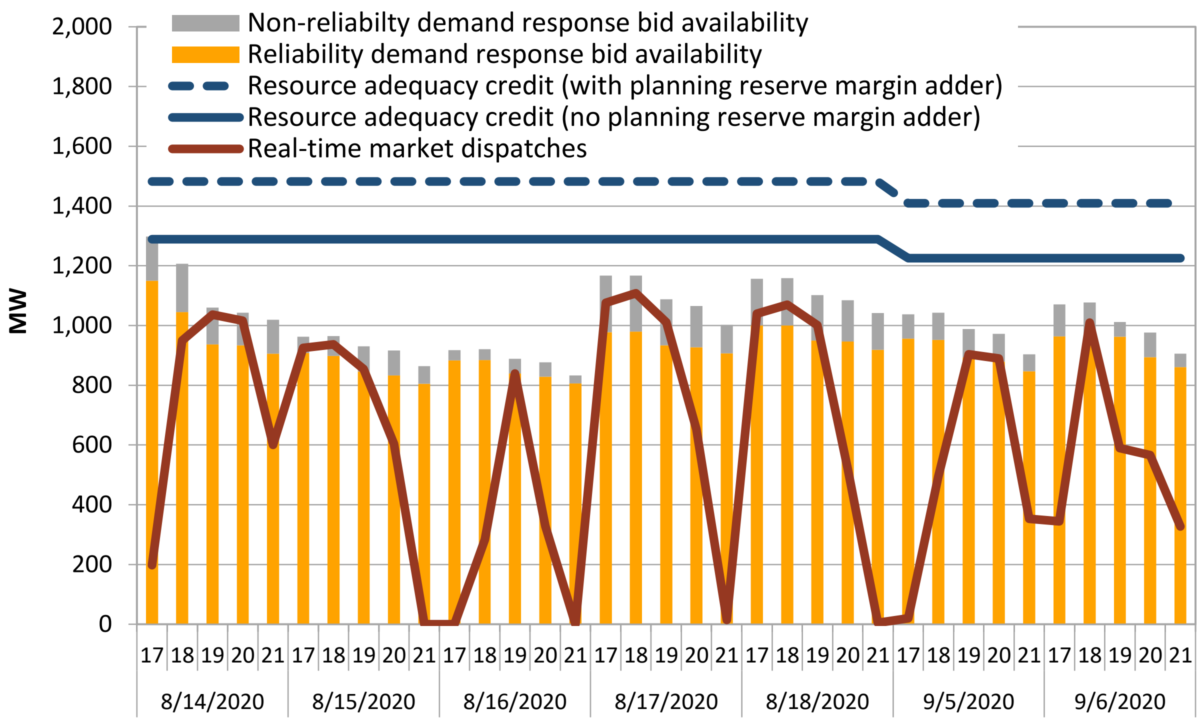
In addition, non-CPUC jurisdictional load serving entities claimed 122 megawatts of demand response resource adequacy credits in August and September which reduce these entities' system resource adequacy obligations. The ISO did not have insight into the availability of non-CPUC jurisdictional utility 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 from August 14 to August 18, and September 5 to September 6, compared to total resource adequacy credits in respective months.[12] 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 daily reports submitted by utilities to the ISO and demand response programs bid into the ISO markets. The higher of availability reflected in daily operational reports and bid capacity is reflected in Figure 2.1 to account for some demand response capacity that may not be integrated into the ISO market but can be activated by investor owned utilities under the CPUC jurisdiction at the direction of the ISO.[13]

[12] Resource adequacy credit values include transmission and distribution loss factors. About 10 megawatts of non-utility demand response credits are reflected in the resource adequacy credit value (with planning reserve margin adder), which represents transmission and distribution loss factors and a planning reserve margin gross up for non-utility, non-DRAM, demand response resource adequacy capacity contracted with CPUC-jurisdictional load serving entities.

[13] Bid capacity includes real-time bids, plus any capacity bid into the day-ahead market which was not scheduled or not re-bid into real-time. While available capacity may include some demand response capacity that is not integrated in the ISO market, real-time schedules shown in Figure 2.1 are limited to demand response resources which are integrated in the ISO market.

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




### Supply plan demand response availability

Supply plan demand response availability in real-time also fell short of resource adequacy values in hours where firm load was curtailed on August 14 and 15. In hours when firm load was curtailed on August 14, about 100 megawatts or about 41 percent of supply plan demand response resource adequacy capacity was not available to the ISO in real-time. In hours when firm load was curtailed on August 15, about 143 megawatts or about 59 percent of supply plan demand response resource adequacy capacity was not available to the ISO. The main drivers of this unavailability appeared to be:

1) Some demand response programs appeared to be unavailable on weekends and holidays.

2) Some demand response resources were not available (bid) up to shown resource adequacy values in the day-ahead market. DMM presumes these resources did not have load to support resource adequacy values in these hours.[14]

3) In August, 172 megawatts, or 71 percent of supply plan demand response resource adequacy was associated with long-start resources. Long-start proxy demand response resources are not required to participate in RUC or real-time if not cleared in the integrated forward market.[15] Several long start resources did not clear the integrated forward market in this timeframe and

[14] Some supply plan demand response resources that were not available (bid) up to resource adequacy values, were partially bid into the market. There were no outages submitted for supply plan demand response resources on August 14 and August 15. However, under current ISO practices, demand response resources cannot take partial outages (BPM for Demand Response, Section 15).

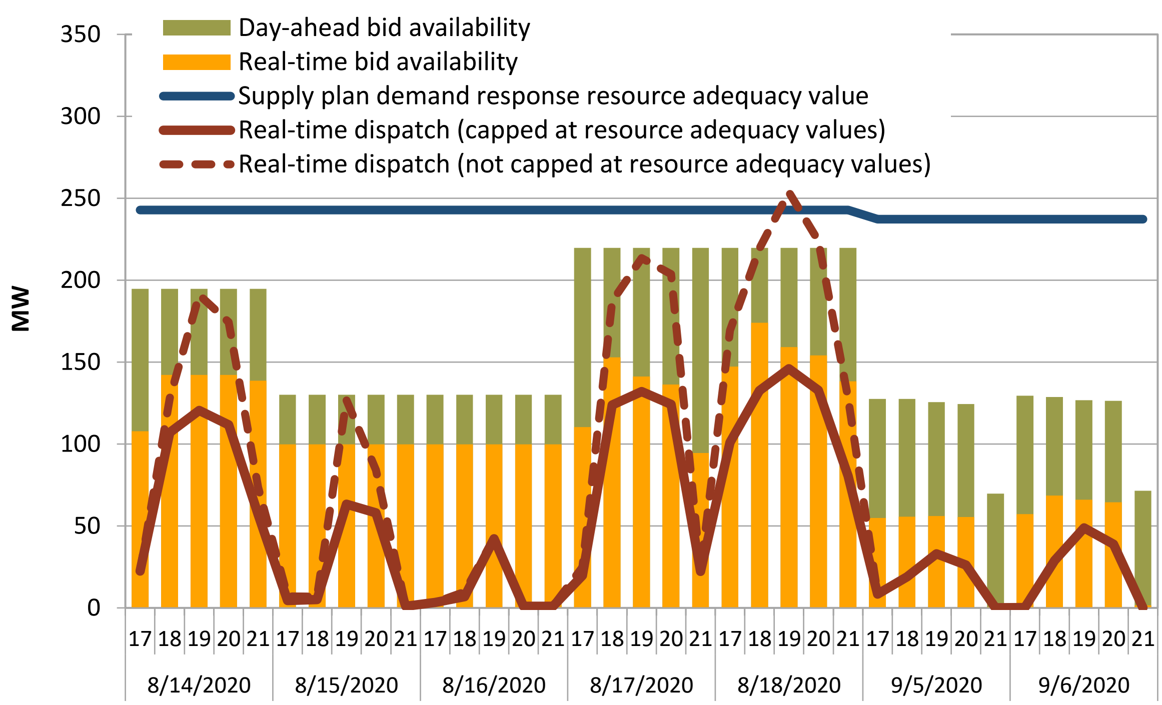
[15] ISO Tariff, Section 40.6.4.4.

were not subsequently manually dispatched by the ISO. Thus this capacity was not available in real-time.

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, 99 percent of supply plan demand response dispatches in excess of shown resource adequacy in this timeframe were associated with a single demand response provider.

On August 14, 48 megawatts of supply plan demand response capacity was not bid into peak net load hours in the day-ahead market. Of the capacity not bid into the day-ahead market on August 14 through August 18, 23 megawatts were associated with resources sized less than 1 megawatt and thus were exempt from RAAIM. The majority of underbid capacity from resources sized less than 1 megawatt was associated with resources under the same scheduling coordinator, where more than one resource sized less than 1 megawatt existed in the same sub-lap. In August 2020, 47 percent of supply plan demand response was associated with resources sized less than 1 megawatt under the same scheduling coordinator, where more than one resource sized less than 1 megawatt existed in the same sub-lap.

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



## 2.3 Dispatch of demand response resource adequacy capacity

As detailed in DMM's August and September report[16] and as shown in Figure 2.1 and Figure 2.2 above, the proportion of available demand response that was dispatched by the ISO varied between utility and supply plan demand response in August and September.

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 most high load days between August 14 and August 18 and on September 5 and 6. The majority of utility demand response dispatches were associated with manual dispatches of reliability demand response after the ISO issued system warnings.

In contrast, a significant portion of available supply plan demand response was not fully scheduled or manually dispatched by the ISO. A portion of available supply plan demand response was economically committed and dispatched in the day-ahead market. However, some supply plan demand response capacity did not economically clear the day-ahead market, and was not subsequently manually dispatched by the ISO so that it could be available in real-time. As shown in Figure 2.2 above, there was also some supply plan demand response capacity that was available (bid) in real-time that was not dispatched in real-time.

### Demand response not scheduled in the day-ahead market and not available in real-time

Capacity that was available in the day-ahead market but was not scheduled, and was not available in real-time was primarily associated with long-start proxy demand response that was not committed economically in the day-ahead market. This capacity includes supply plan and some utility proxy demand response capacity. Figure 2.3 shows long-start proxy demand response capacity that was offered but not committed in the day-ahead market on high load days in August and September 2020.[17]

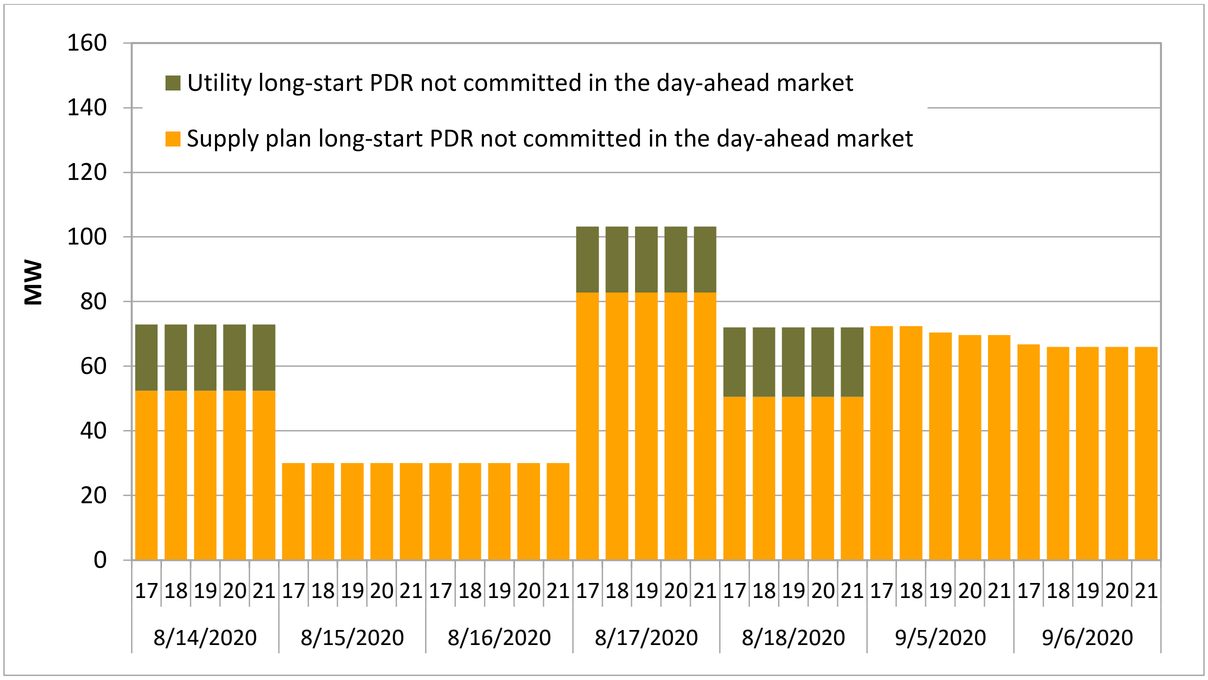
DMM has recommended that the ISO adopt a process to manually dispatch available demand response shown on resource adequacy supply plans before issuing exceptional dispatches to non-resource adequacy capacity and curtailing firm load.[18] The ISO should also consider including utility proxy demand response credited towards resource adequacy requirements in any manual dispatch process for proxy demand response resources.

[16] *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp. 55-59: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

[17] Figure 2.3 does not include capacity from resources that were committed in the day-ahead market but were not fully dispatched.

[18] *Ibid*, p. 5.

**Figure 2.3 Long-start proxy demand response not committed in the day-ahead market and not available in real-time**




### Long-start demand response capacity

As noted above and in DMM's August and September report, several long-start proxy demand response resources did not clear the integrated forward market on high load days in August and September. Proxy demand response resources that do not clear the integrated forward market have no further obligation to be available to the ISO's residual unit commitment (RUC) or real-time markets.[19] In August, 172 megawatts (or 71 percent) of the total 243 megawatts of supply plan demand response had start up times of five hours or greater which would qualify this capacity to be considered long-start.[20] In August, 44 megawatts (or 19 percent) of utility proxy demand response was also registered with start-up times greater than or equal to five hours and thus would be considered long-start resources.

The percentage of demand response capacity considered long-start increased from 2019, particularly for third party demand response capacity. In August 2019, 38 percent of total supply plan proxy demand response capacity had start up times of five hours or greater (compared to 71 percent in 2020). In August 2019, 15 percent of total utility proxy demand response capacity had start up times of five hours or greater (compared to 19 percent in 2020).

Despite day-ahead system energy prices reaching $1,000/MWh in peak net load hours between August 14 and September 6, some long-start demand response resources were not scheduled economically in the day-ahead market. This is because in addition to bidding energy at the $1,000/MWh bid cap, many long-start supply plan demand response resources also bid non-zero commitment costs (start-up costs and minimum load costs). In total, these bid costs caused these resources to be very expensive for the

[19] ISO Tariff, Section 40.6.4.4.

[20] Long-start resources cannot be committed in the ISO's real-time short term unit commitment process (STUC) which has a 4 and a half hour look ahead horizon.

amount of capacity offered. DMM observed that many long-start supply plan demand response resources submitted resource parameters and bids similar to the following:

**Table 2.2 Example demand response bid parameters with commitment costs**

| Pmin (MW) | Resource adequacy (MW) | Minimum load cost ($/hr) | Start-up cost ($/start) | Energy cost ($/MWh) |
|---|---|---|---|---|
| .01 | .5 | $12.50 | $1,000 | $1,000 |

Some demand response resources also limit bids to availability assessment hours (4:00 to 9:00 pm on non-holiday weekdays). Despite prices reaching over $1,000/MWh in the integrated forward market at several nodes in August and September for a number of hours, a resource with bid parameters similar to those in, Table 2.2 could still be uneconomic to commit in the integrated forward market. Consider the example below:

Suppose prices in hours 17-21 (4:00 to 9:00 pm) were sustained at $1,000/MWh. If the resource was committed at its resource adequacy value for 5 hours it would earn:

Market revenues = $1,000/MWh*5 hours* 0.5 MW = **$2,500**

The resource's commitment and variable costs would be as follows:

Minimum load cost = $12.50/hr * 5 hours = $62.50

Startup cost = $1,000

Incremental energy cost = 0.49 MW * $1,000/MWh * 5 hours = $2,450

Total costs = **$3,513**

If this resource was committed at its resource adequacy value for the five hours it was bid into the market, the resource would not recover its operating costs across the day, even if prices were sustained at $1,000/MWh across a five hour period. To fully recover its operating costs over the 5 hour period, the resource would require day-ahead prices in this period to average **$1,405/MWh**. Considering commitment costs in addition to energy bid costs, some resources with high commitment costs for the amount of energy offered appeared uneconomic to commit in the integrated forward market in August and September 2020 despite often high day-ahead nodal prices.

DMM recommended that the ISO take steps to develop a process to be able to manually dispatch proxy demand response resources since some available demand response providing resource adequacy was not utilized on high load days in August and September.[21] However, the ISO should also consider what may constitute appropriate commitment costs for demand response resources.

First, submitting high commitment costs for the amount of capacity offered could cause resources to be uneconomic to commit in the day-ahead market even on days with sustained high prices. But if the ISO were to manually dispatch these resources, resources could recover bid costs in excess of market

[21] *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp. 5, 60, 71: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

revenues through bid cost recovery payments. The ISO should consider what may constitute appropriate commitment costs for demand response resources so that potential bid cost recovery payments are also reasonable.

### Demand response available in real-time but not scheduled in real-time

As shown in Figure 2.2, there was also some supply plan demand response capacity that was made available in real-time that was not dispatched in real-time. The majority of this unscheduled capacity was offered at the $1,000/MWh bid cap and was registered under the hourly dispatch option. Some of this capacity did not appear to be economic in the HASP where hourly proxy demand response resources are evaluated.[22] Demand response resources on the hourly dispatch option also require a flat schedule across the hour – therefore to be scheduled, an hourly resource must be economic across the hour at a flat megawatt value.

While some capacity available in real-time did not appear economic across several hours, average hourly prices did exceed $1,000/MWh in some hours in HASP where some available hourly proxy demand response was not scheduled. This hourly demand response capacity appeared not to be scheduled in the HASP market due to resources' ramp limitations. Though capacity was made available, not all capacity could feasibly be accessed by the ISO across some hours due to resources' ramp rates. Many of these resources had bid-in ramp rates as low as 0.01 megawatts per minute.[23]

Figure 2.4 shows HASP bids and schedules of proxy demand response resource adequacy resources (utility and third party resources) on the hourly dispatch option on August 14 and August 15.[24] Figure 2.4 shows that while some capacity offered from hourly demand response resources in real-time appeared otherwise economic, some of this capacity was inaccessible to the ISO due to resources' slow bid-in ramp rates. Because demand response resources under the hourly dispatch option by design require a flat or block schedule across the hour, these resources' HASP schedules across an hour are limited by the amount that a resource can ramp between hours. In other words, hourly demand response schedules are limited by the highest possible operating point the resource can reach ramping from one hour to the next. In Figure 2.4, hourly resources' maximum feasible schedules based on ramp rates is shown by the dotted gray line.

Schedules between hours in HASP depend on how much a resource can ramp across a 15 minute timeframe. Therefore, an hourly demand response resource with a 0.01 megawatt per minute ramp rate, at most, could be awarded an incremental 0.15 megawatts (0.01 MW/min * 15 minutes) from one hour to the next.

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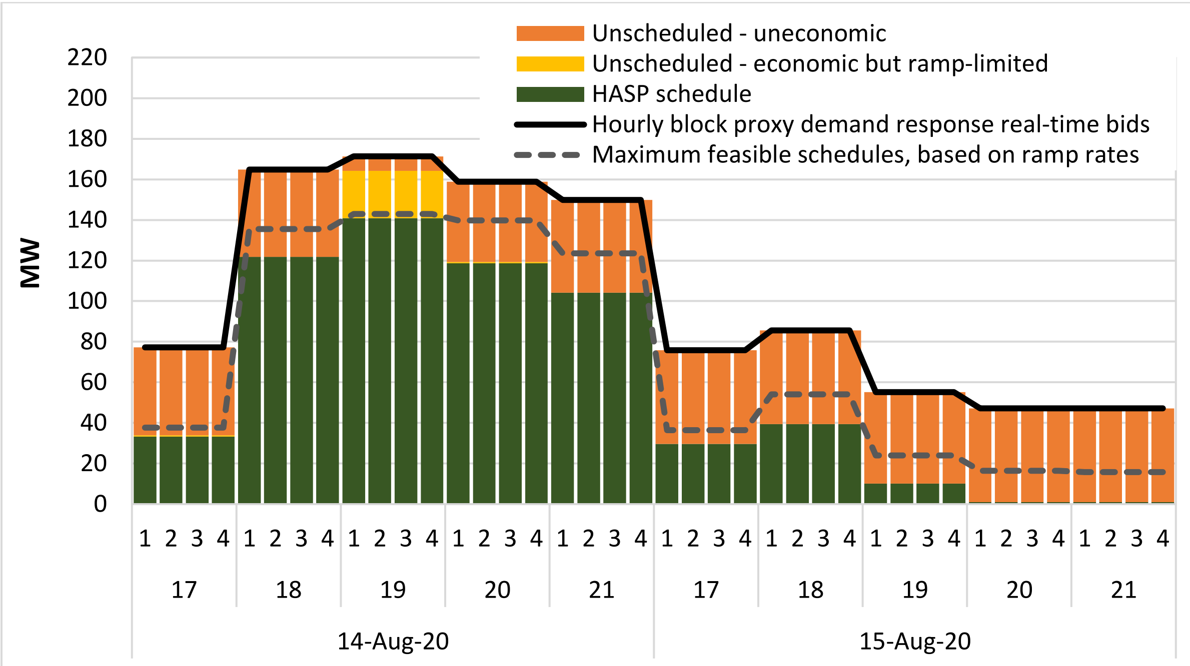
[22] In this analysis, DMM compares average nodal HASP prices to resource bids in each hour as a proxy for assessing whether an hourly resource appeared economic to dispatch in an hour.

[23] Per ISO Tariff Section 30.7.7, a supplier may submit an operational ramp rate in SIBR each trading day which would take precedence over ramp rates reflected in master file. These SIBR-submitted operational ramp rates are also referred to as "bid-in" ramp rates

[24] HASP schedules and real-time bids in this chart for supply plan demand response resources are not capped at shown resource adequacy values.

**Figure 2.4 Hourly block proxy demand response HASP schedules (August 14 and 15)**




It will be important for the ISO to assess the validity of some resources' bid-in ramp rates which were often much lower than ramp rates submitted in master file. DMM understands that the ISO has already reached out to demand response providers to better understand suppliers' bid-in ramp rates.

If demand response capacity is truly slow-ramping, however, DMM suggests that the ISO and stakeholders could consider whether hourly demand response resources should be allowed to ramp across a longer time horizon or whether the flat schedule constraint could be lifted or made optional. As DMM understands, one of the main drivers behind demand response providers' use of the hourly dispatch option was to allow for a longer notification time to position resources to curtail load. A longer ramping horizon would allow slow-ramping demand response resources to ramp to higher operating points within an hour, allowing the ISO to access a greater portion of hourly demand response capacity. While a flat schedule across the hour would not be guaranteed, demand response providers could still be made aware of real-time schedules almost an hour in advance.

## 2.4 Demand response bidding

On high load days in August and September, proxy demand response resources were largely scheduled in the day-ahead market. Almost 200 MW of reliability demand response (RDRR) was also scheduled in the day-ahead market across peak net load hours on August 14 and August 18.

Figure 2.5 shows day-ahead bids of proxy demand response and reliability demand response counted towards resource adequacy requirements across peak net load hours (capped at individual resources' resource adequacy values for supply plan demand response). While the majority of reliability demand response (RDRR) in this timeframe was scheduled in the real-time market, there was RDRR capacity bid into the day-ahead market on some days in August. Figure 2.5 shows that the majority of RDRR that was bid into the day-ahead market on August 14 and August 18, was bid at prices below $250/MWh and was scheduled economically in the day-ahead market. Additionally, most of the utility proxy demand response that was bid into the day-ahead market at prices below $500/MWh on August 14 and 15 and on August 17 and 18, was scheduled. Day-ahead demand response bids also dropped off on weekends, but capacity that was bid into the day-ahead market on weekends was typically bid in at higher prices than on weekdays.

Figure 2.5 also shows that more than half the third party proxy demand response capacity was bid at or near the $1,000/MWh bid cap in the day-ahead market most high load days in August and September 2020. While some of this capacity was economically scheduled in the day-ahead particularly on August 17 and August 18 when day-ahead prices were very high, most of the third party demand response capacity bid near the $1,000/MWh bid cap was still not scheduled. As discussed in the previous section, this outcome was also impacted by some resources bidding high commitment costs in addition to energy bids at the bid cap on these days.

**Figure 2.5 Demand response resource adequacy day-ahead bids in August and September**

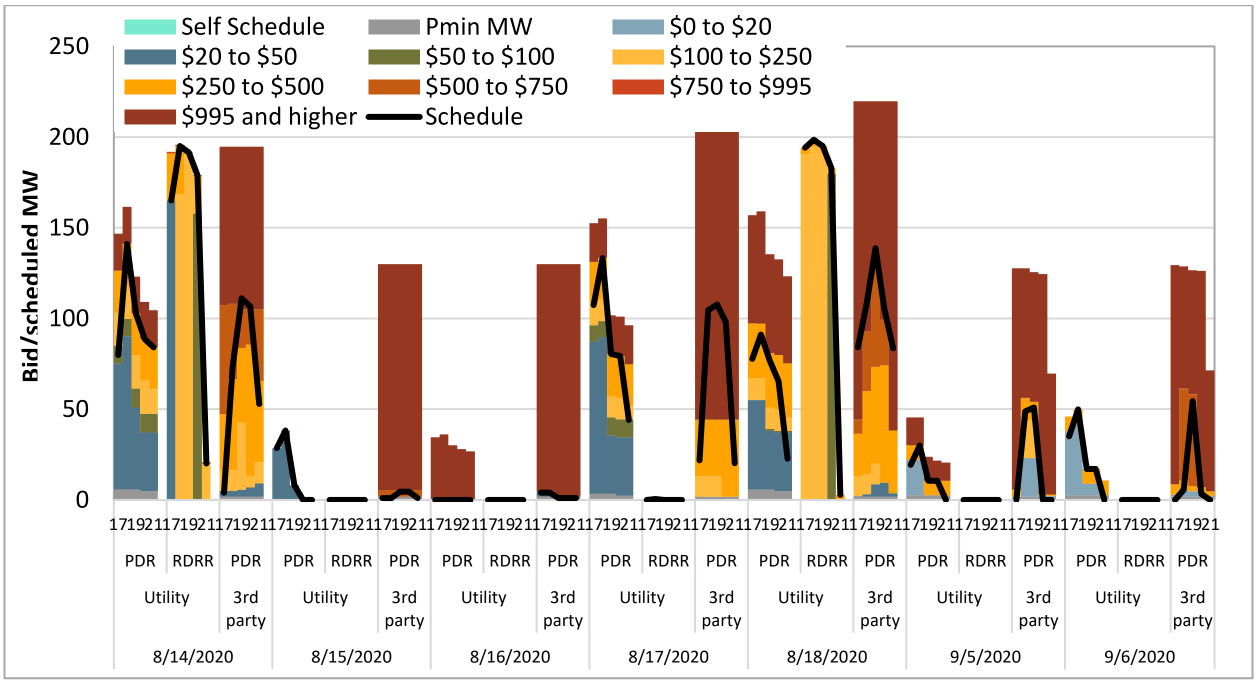
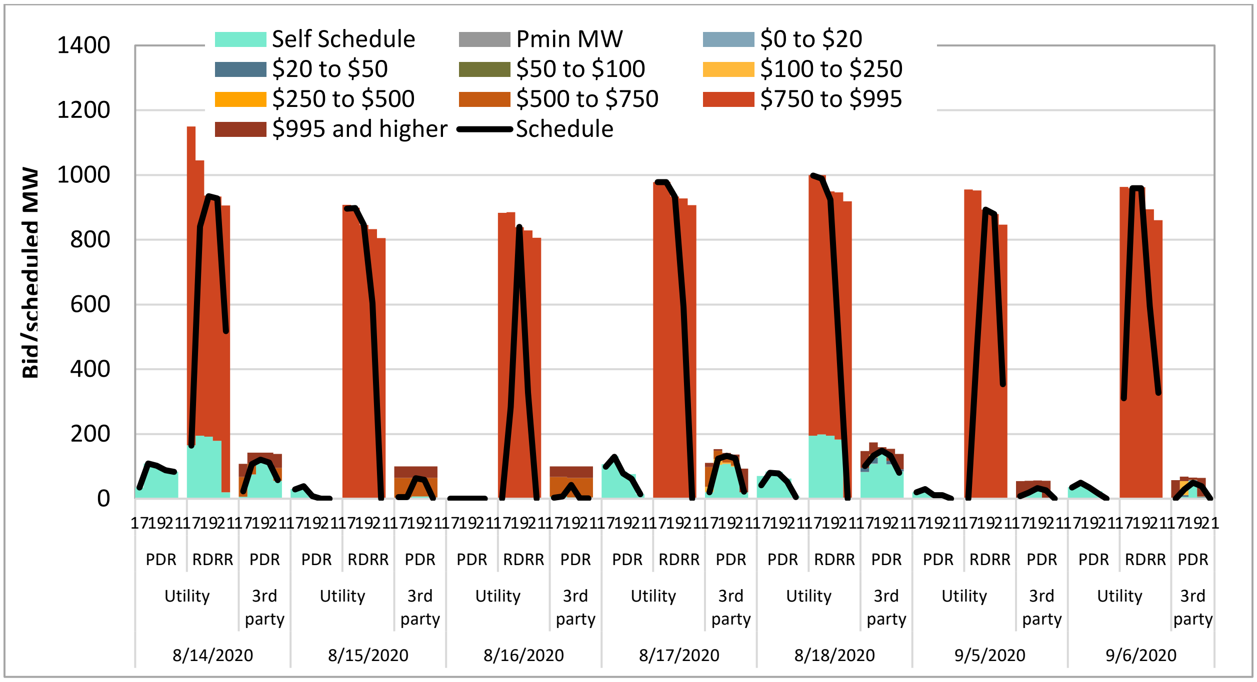



Figure 2.6 shows real-time bids of proxy demand response and reliability demand response counted towards resource adequacy requirements across peak net load hours (capped at individual resources' resource adequacy values for supply plan demand response resources). Figure 2.6 shows that demand response capacity that was scheduled in the day-ahead market was generally self-scheduled into real-time. Incremental reliability demand response capacity offered into real-time must be offered at bid price between 95% of the ISO energy bid cap and the ISO energy bid cap, currently set at $1,000/MWh.[25]

[25] ISO Tariff Section 30.6.2.1.2.1

**Figure 2.6 Demand response resource adequacy real-time bids in August and September**




## 2.5 Demand response performance

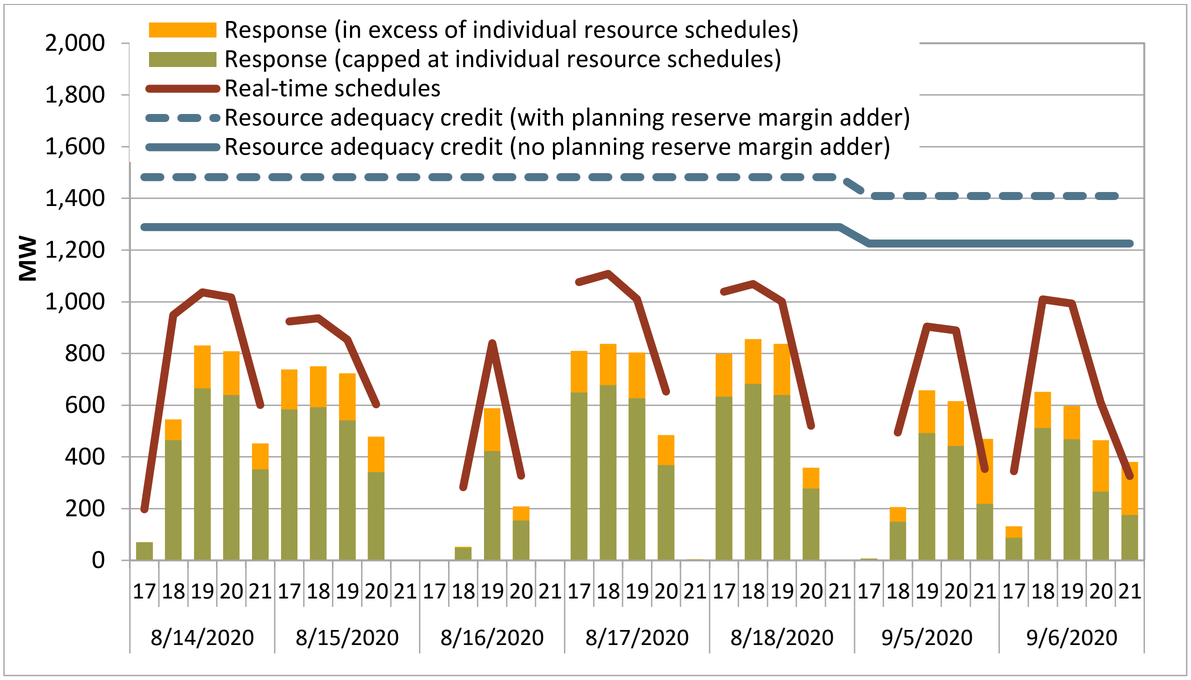
This section details the self-reported performance of both utility demand response and supply plan demand response resources on high load days in August and September.

### Utility demand response performance

Figure 2.7 shows the real-time dispatches and self-reported response of CPUC-jurisdictional utility demand response capacity on high load days in August and September 2020. Figure 2.7 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 2.7.

Figure 2.7 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 under-perform compared to ISO dispatch instructions in peak net load hours.

**Figure 2.7 CPUC-jurisdictional utility demand response performance in August and September**




While just over 1,000 megawatts of available CPUC-jurisdictional utility demand response was dispatched in both hours ending 19 and 20 (6:00-8:00 pm) on August 14, resources reported to curtail about 820 megawatts of load, or about 80 percent, of total expected load curtailment each hour (including load curtailment in excess of individual resource dispatches). Limiting performance to individual resources' dispatch instructions, utility demand response performance was about 64 percent in hours ending 19 and 20 on August 14.

On August 15 in hours ending 19 and 20, CPUC-jurisdictional utility demand response reported to curtail about 740 megawatts of load, which was about 82 percent of total expected load curtailment each hour. Limiting performance to individual resources' dispatch instructions, utility demand response performance was about 63 percent in hours ending 19 and 20 on August 15.

Figure 2.8 and Figure 2.9 show CPUC-jurisdictional demand response performance, split between proxy and reliability demand response capacity.

**Figure 2.8 CPUC-jurisdictional utility proxy demand response performance**

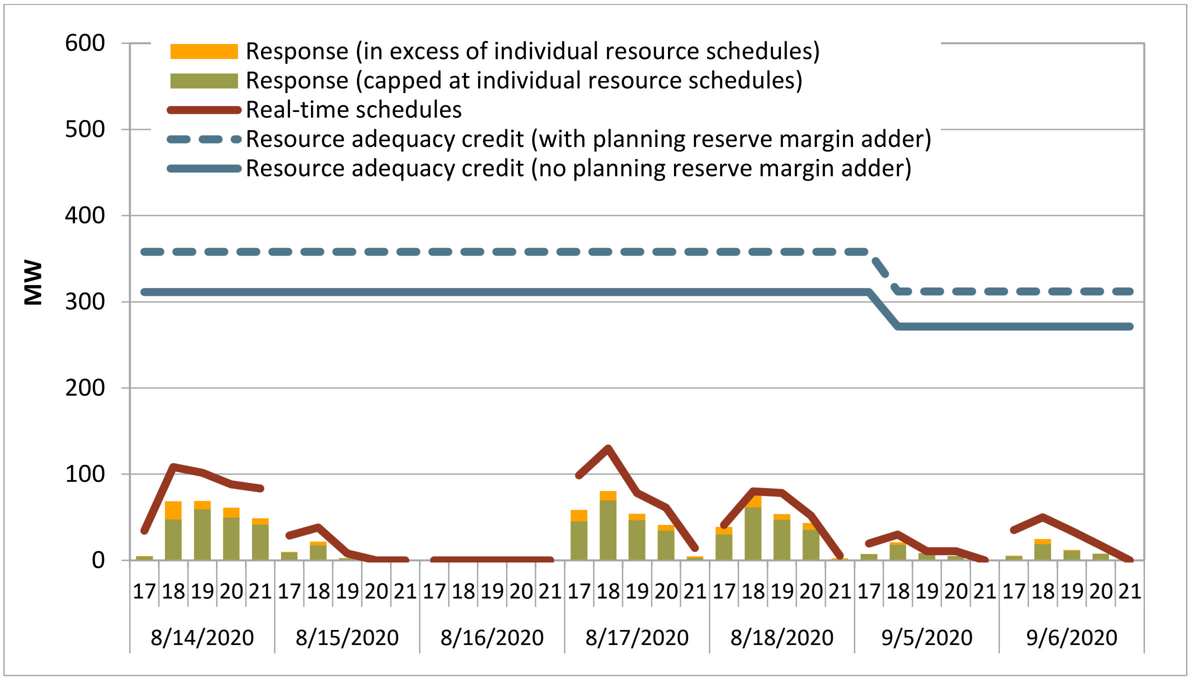
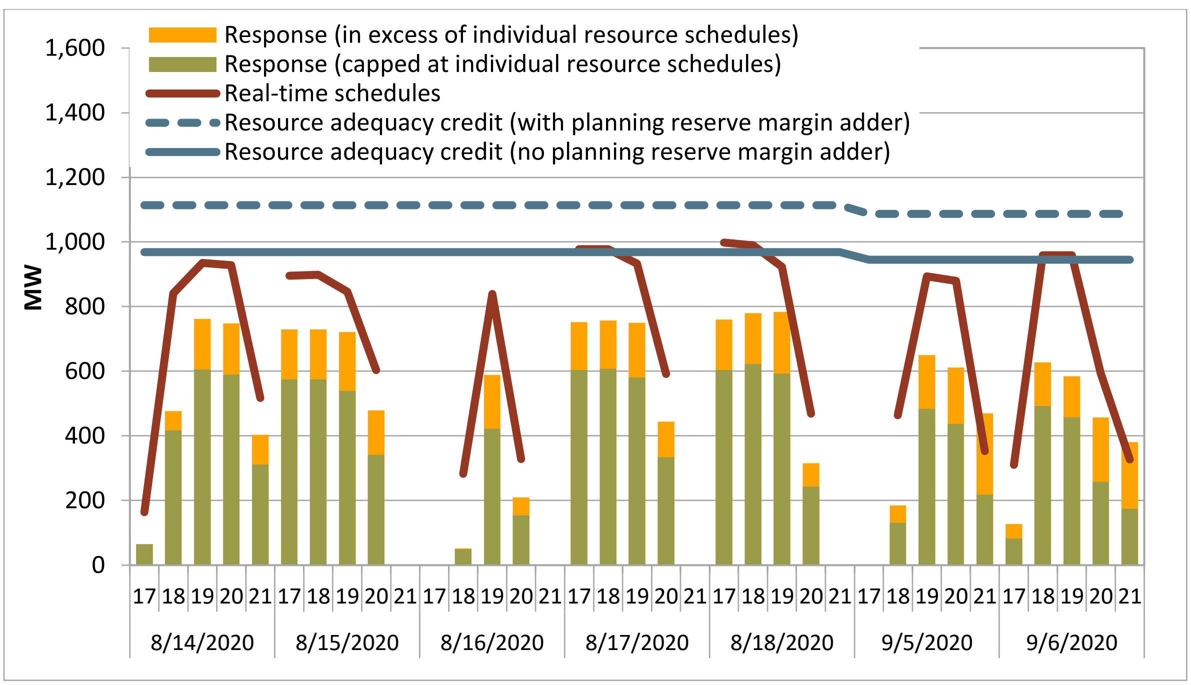



**Figure 2.9 CPUC-jurisdictional utility reliability demand response (RDRR) performance**



### Supply plan demand response performance

As detailed in DMM's August and September report, on August 14 in hours ending 19 and 20 (6:00 to 8:00 pm), about 45 to 50 percent of total demand response capacity shown on resource adequacy supply plans was dispatched by the ISO.[26] On August 15 in hours ending 19 and 20, only about 25% of supply plan demand response capacity was dispatched by the ISO. There were no manual dispatches of supply plan demand response resources on high load days in August and September.

Figure 2.10 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). Of note, 99 percent of supply plan demand response dispatches in excess of shown resource adequacy in this timeframe were associated with a single demand response provider.

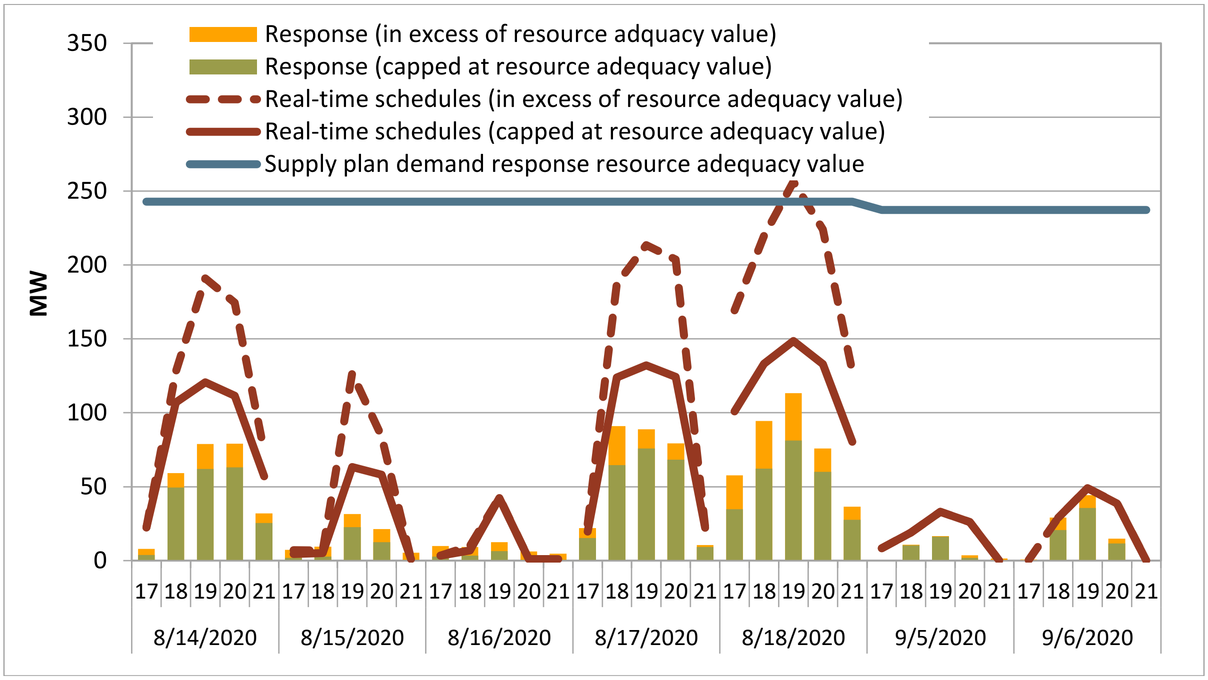
Figure 2.10 also shows the self-reported response of demand response resources shown on resource adequacy supply plans. Figure 2.10 shows both self-reported response capped at individual resources' resource adequacy values (green bar) and self-reported response in excess of resource adequacy values (yellow bar). In aggregate, the total demand response fleet reflected on resource adequacy supply plans reported to under-perform compared to ISO dispatch instructions in high load hours in August and September.

In aggregate on August 14 in hours ending 19 and 20, the supply plan demand response fleet reported to curtail about 79 megawatts of load in each hour, which was 41 to 45 percent of total megawatts dispatched in each hour. Limiting dispatches and response to individual resources' resource adequacy values, total response was 51 to 57 percent of real-time dispatches on August 14 in hours ending 19 and 20.

In aggregate on August 15 in hours ending 19 and 20, the supply plan demand response fleet reported to curtail about 20 to 30 megawatts of load in each hour, which was 25 percent of total capacity dispatched in each hour. Limiting dispatches and response to individual resources' resource adequacy values, total response was 22 to 36 percent of real-time dispatches on August 15 in hours ending 19 and 20.

[26] *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp. 55-57: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

**Figure 2.10 Third-party demand response performance in August and September**



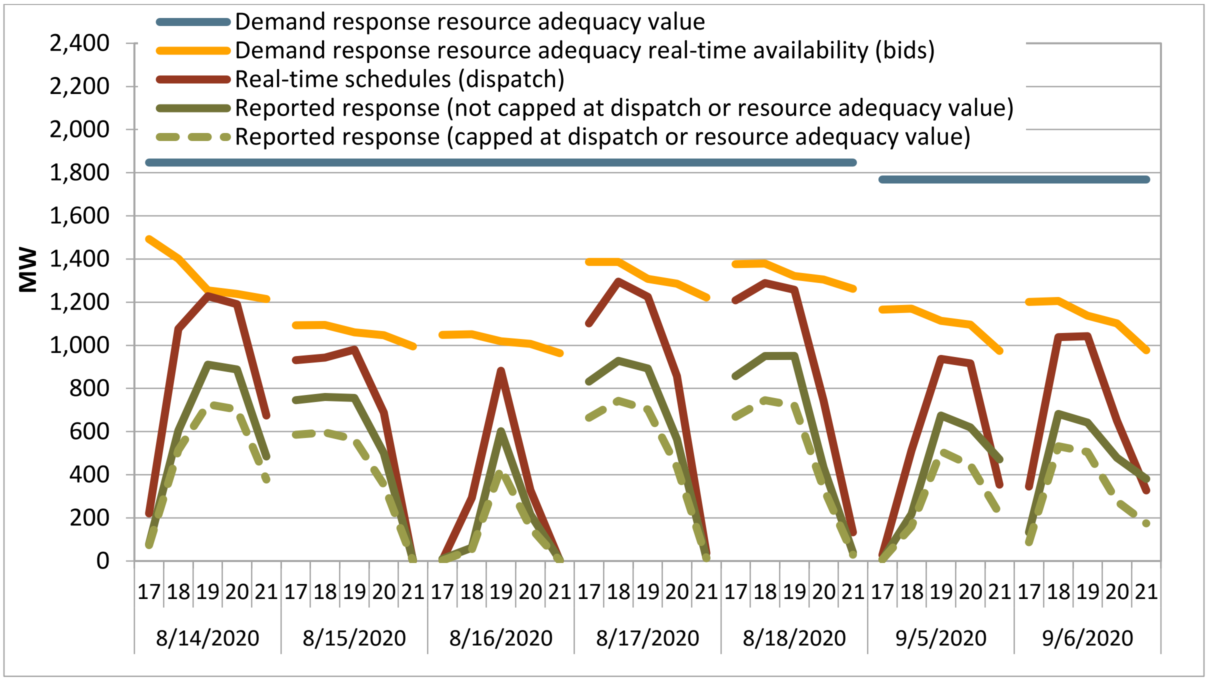

## 2.6 Demand response aggregate summary of availability, dispatch and performance

Figure 2.11 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 in August and September. Figure 2.11 includes both credited utility and supply plan demand response capacity.

Figure 2.11 shows that demand response resource adequacy availability, as reflected through real-time bids and daily reports sent from CPUC-jurisdictional investor-owned utilities to the ISO, fell short of resource adequacy values on high load days. On average across peak net load hours on high load days in August and September, about 65 percent of demand response resource adequacy capacity was available and accessible to the ISO in real-time.

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 on August 14 in hours ending 19 and 20, about 900 megawatts, or about 74 percent, responded each hour (reported performance not capped at schedule or resource adequacy values). On August 15 in hour ending 19, about 756 megawatts, or about 77 percent of demand response resource adequacy capacity that was dispatched, responded (reported performance not capped at schedule or resource adequacy values). On August 15 in hour ending 20, about 500 megawatts, or about 73 percent of demand response resource adequacy capacity that was dispatched, reported to respond. On average across peak net load hours on high load days in August and September, about 70 percent of demand response resource adequacy capacity that was dispatched, reported to respond each hour. Limiting dispatches and response to individual resources' schedules or resource adequacy values, total response averaged 53 percent of real-time dispatches across peak net load hours on high load days in August and September.

**Figure 2.11 Aggregate demand response resource adequacy in August and September**




## 2.7 Metered demand trends and baseline adjustments

Demand response baseline calculations generally rely on historical lookbacks of like-day metered load to establish the day-of counterfactual load baselines from which demand response performance is measured.[27] 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.[28]

Based on supplier-submitted baseline and meter data, there is some evidence that baseline adjustments could have been limited in the upward direction by defined baseline adjustment caps. Based on self-reported meter data, 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. However, DMM estimates that even if higher baseline adjustments were permitted, many demand response resources would still have shown to under-deliver compared to expected load curtailment in high load days in August and September 2020.

Figure 2.12 and Figure 2.13 show an example of the baseline adjustment issue based on supplier-submitted meter and baseline data for a sample set of resources.

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

[28] ISO Tariff Section 4.13.4

**Figure 2.12 Demand response baseline example with baseline adjustment caps**

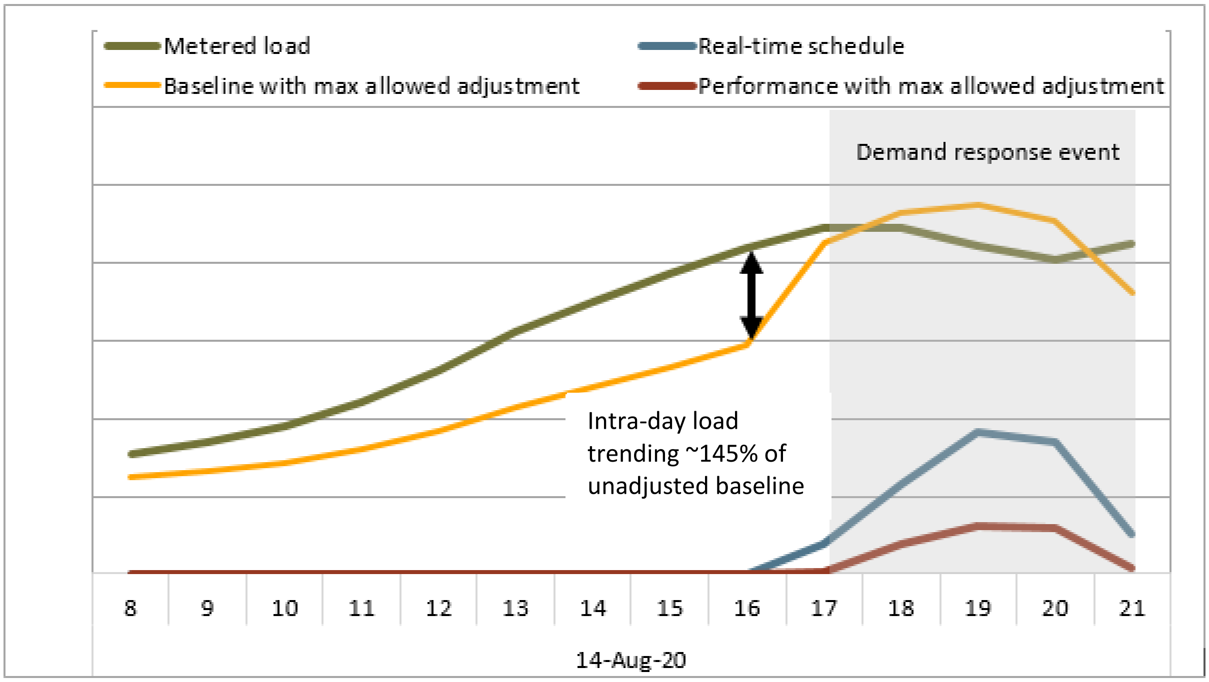



**Figure 2.13 Demand response baseline example with no baseline adjustment caps**

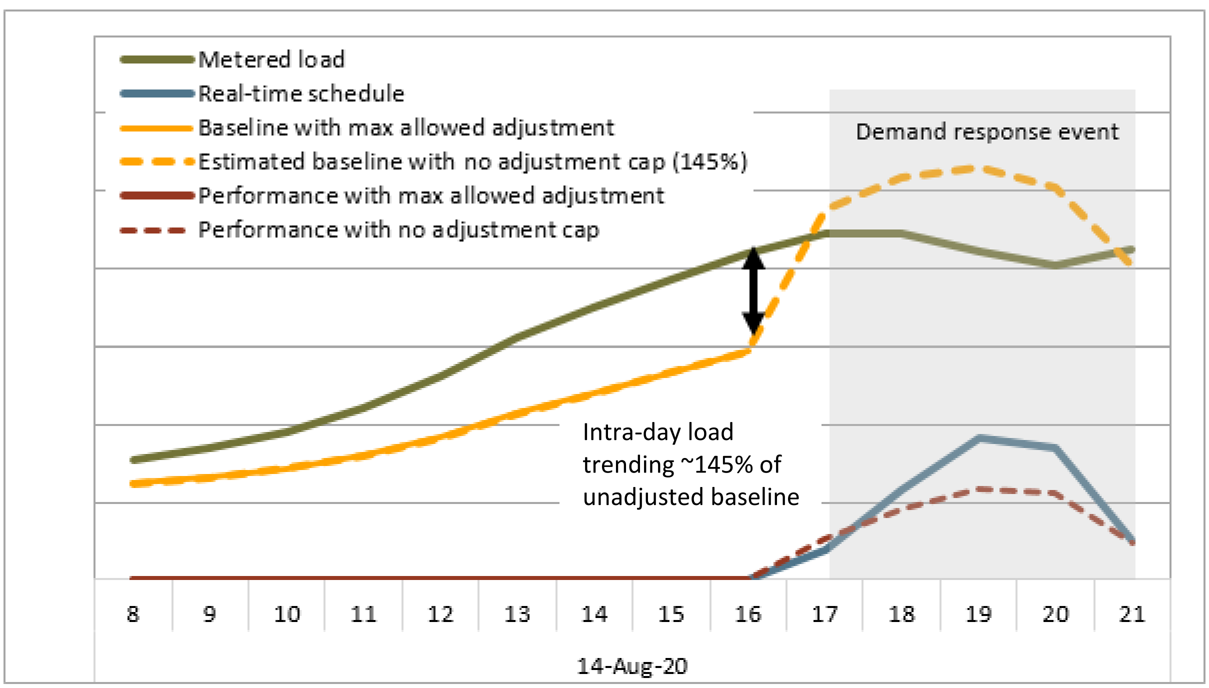


Figure 2.12 shows supplier-submitted metered demand (green line) and baseline values (yellow line) for a sample group of resources scheduled only across peak net load hours (4:00 to 9:00 pm) on August 14. Baseline data submitted to the ISO should reflect unadjusted baselines in non-event intervals and adjusted baselines in event intervals.[29]

Figure 2.12 shows that there is evidence that adjusted baselines (with maximum allowable adjustments) did not sufficiently capture the ratio between intra-day metered demand and historic demand for these resources. For this sample group of resources, intra-day load appeared to trend about 145 percent of unadjusted baselines (comprised of historic metered demand) in hours leading up to the demand response event. Since this group of resources was under the day matching combined baseline methodology, these resources' baseline adjustments would have been capped between 120 percent and 140 percent, depending on underlying resources' split between residential and non-residential load. Since the ratio of intra-day demand to historic demand appeared to be around 145 percent, baseline adjustments could have been limited in the upward direction by baseline adjustment caps, thus impacting reported performance.

Figure 2.13 shows for the same sample group of resources, adjusted baselines based on the 145 percent ratio between intra-day and historic load observed in hours before the demand response event.[30] Figure 2.13 shows that the adjusted baseline with a 145 percent adjustment better captures the shape of intra-day load. Applying a 145 percent adjustment to the baseline also results in higher performance values. However, DMM estimates that for this group of resources, while performance would have shown to be higher with uncapped baseline adjustments, these resources would still have shown to under-deliver.

[29] *Business Practice Manual for Demand Response*, California ISO, Appendix B: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Demand%20Response

[30] DMM does not have details on the split between residential and non-residential load for individual demand response resources. For this analysis, DMM assumes that the adjusted baseline was adjusted by 130 percent (between the 120 and 140 percent adjustment cap for load associated with resources on the day matching combined baseline), in order to derive a non-adjusted baseline to which the uncapped adjustment is applied.

# 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 most high load days in August and September 2020, 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 have faced little financial incentive to deliver expected load curtailment, and little financial consequence for not delivering expected load reductions.

Figure 3.14 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.[31] Proxy demand response resource adequacy resources were generally scheduled in the day-ahead and 15-minute markets, rather than being dispatched in the 5-minute market.[32] Therefore the majority of proxy demand response that was scheduled 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 3.14 on August 14, 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 August 14. 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.

Figure 3.2 shows the average nodal locational marginal prices for proxy demand response resource adequacy resources. Day-ahead and 15-minute market prices were often significantly higher than 5-minute market prices in peak net load hours. This trend is particularly significant on August 14 and August 15 in hour ending 20, and across peak net load hours on August 17 and August 18. 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.

[31] As discussed in DMM's August and September report (pp. 59-60), the majority of reliability demand response (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 3.14 and Figure 3. therefore focus on proxy demand response resources.

[32] 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 August 2020, 85 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 3.14 Proxy demand response resource adequacy market schedules**

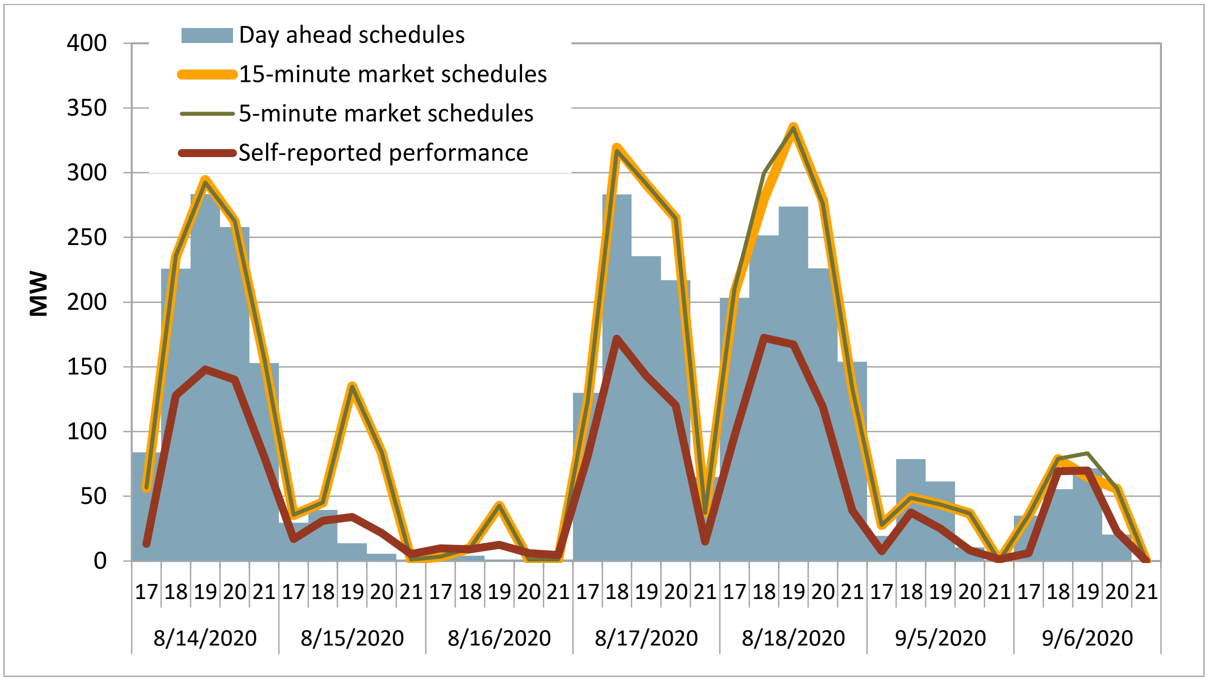



**Figure 3.2 Proxy demand response resource adequacy nodal prices**

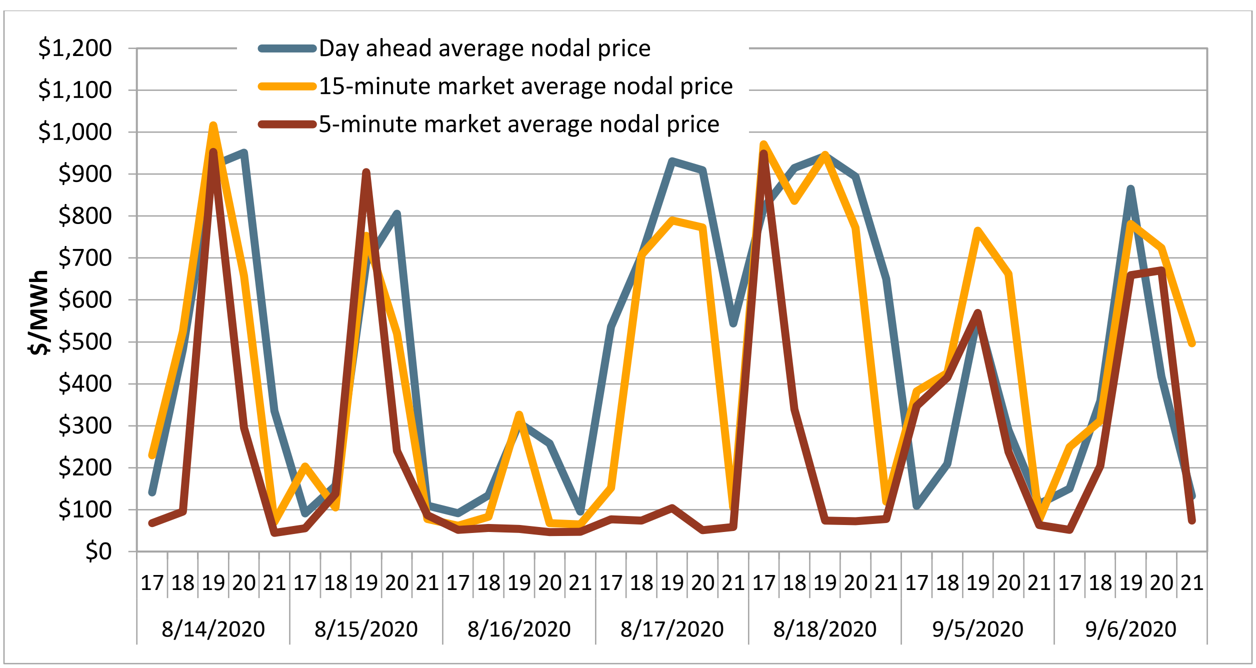
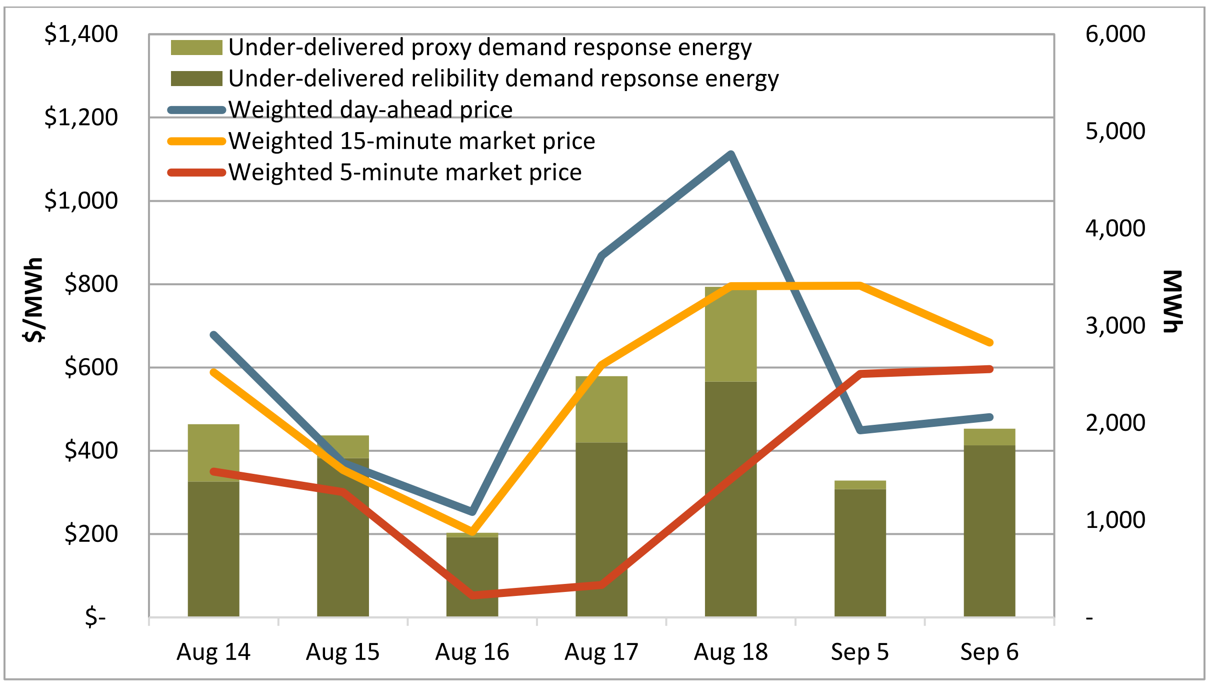


Figure 3.15 shows that demand response generally did not face negative financial consequences for non-performance since 5-minute market prices were frequently lower than day-ahead and 15-minute market prices when load curtailment was under delivered. Figure 3.15 shows total under-delivered energy on high load days in August and September. Figure 3.15 also shows average day-ahead and fifteen minute market nodal prices versus 5-minute market nodal prices, weighted by undelivered energy.

In periods where demand response under-performed, the day-ahead and fifteen minute market prices on average were much higher than 5-minute market prices. The difference between day-ahead and fifteen minute market prices and 5-minute market prices were highest on August 17 and 18 where under-delivery was also the highest. On September 5 and 6, 5-minute market prices trended higher than day-ahead prices in periods where demand response under-delivered. However, on these days, under-delivery was primarily associated with reliability demand response resources which were dispatched in the 5-minute market and thus were not exposed to day-ahead or 15-minute market prices.

**Figure 3.15 Demand response resource adequacy under-delivery and weighted nodal prices**




## 3.2 Resource adequacy demand response compensation

This section examines the revenues streams for demand response providing resource adequacy.

### Demand response market revenues

Historically, demand response resources counted towards resource adequacy have been dispatched relatively infrequently and thus have earned limited energy market revenues. In August and September 2020, however, demand response resources accrued significant energy market revenues compared to prior years. In 2020, 87 percent of total net market revenues accrued by demand response counted towards resource adequacy requirements was accrued in August and September.

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

Table 3.1 shows that net market revenues per megawatt-hour of energy delivered varies significantly among demand response resource types. In 2020, utility proxy demand resources earned about $113/MWh of energy delivered while third party demand response resources earned about $365/MWh of energy delivered. This difference can be explained by much higher energy market revenues per megawatt-hour of energy delivered for third party demand response.

The revenue figure for third party demand response appears high because total revenues for third party demand response are high compared to the energy delivered by these resources. Third party demand response was also scheduled less frequently than utility proxy demand response but schedules primarily coincided with periods where prices were very high. Additionally, the majority of third party demand response is scheduled in the day-ahead and 15-minute market. As shown in Figure 3.15, prices have generally been higher than 5-minute market prices at which under-delivery would be charged (i.e. a portion of day-ahead and 15-minute market revenues are generally preserved despite under-performance). While bid costs per megawatt-hour of energy delivered are also higher for third party demand response, overall, net revenues per megawatt-hour of energy delivered for third party demand response far exceeded that of utility proxy demand response.[33]

Reliability demand response (RDRR) resources accrued significant bid cost recovery in August and September for capacity that was manually dispatched across several high load hours in the 5-minute market. However, RDRR also accrued significant infra-marginal revenues in the day-ahead market in August and September. As shown in Figure 2.5, reliability demand response capacity was bid and scheduled at prices less than $250/MWh in the day-ahead market in August while day-ahead prices exceeded these bid prices in several hours. Economic bidding of RDRR in the day-ahead market also accounts for RDRR bid costs for energy delivered being lower than $950/MWh of energy delivered which is the bid floor for incremental RDRR capacity bid into real-time.

**Table 3.1 Demand response resource adequacy net market revenues – 2020**

| Demand response type | 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 | 21,717 | $166 | $55 | $2 | **$113** |
| Utility RDRR | 18,342 | $525 | $484 | $291 | **$333** |
| 3rd party PDR | 4,864 | $1,091 | $730 | $4 | **$365** |

[33] Bid costs are adjusted based on real-time performance. If a resource does not deliver or curtail load, then the resource does not incur its bid costs and thus bid costs would be set to zero.

### Demand response net market revenues and capacity value

Table 4.2 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 2019 and 2020.

The capacity values shown in Table 4.2 are based on the 85 percentile of 2019 system resource adequacy prices as reported in the CPUC's 2018 Resource Adequacy report[34], and annualized capacity prices based on 2019 and 2020 budgets for the CPUC's Demand Response Auction Mechanism (DRAM)[35] and DRAM capacity shown on resource adequacy supply plans throughout each year.

**Table 4.2 Demand response resource adequacy net market revenues and capacity costs (2019-2020)**

| Year | Demand response type | Net energy market revenues ($/kW-year) | Capacity price - 2019 system RA 85th percentile ($/kW-year) | Capacity price - DRAM auction ($/kW-year) |
|---|---|---|---|---|
| 2019 | Utility PDR | $2.36 | $51.00 | $102.39 |
| | Utility RDRR | $0.50 | $51.00 | $102.39 |
| | 3rd party PDR | $4.59 | $51.00 | $102.39 |
| 2020 | Utility PDR | $15.44 | $51.00 | $78.68 |
| | Utility RDRR | $5.91 | $51.00 | $78.68 |
| | 3rd party PDR | $13.60 | $51.00 | $78.68 |

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

While total dispatch of demand response did increase in 2020, many demand response resources continue to be bid into the market at high prices and were infrequently scheduled outside of August and September high load days. Additionally, in 2020, many demand response resources became more expensive to dispatch (started bidding commitment costs) and became less likely to be available in real-time due to slower ramp rates and increased start-up times (resulting in more capacity being considered long-start and thus only available in the day-ahead timeframe).

While incentives to participate in the energy market and earn market rents may be limited for many demand response providers relative to potential capacity payments, as discussed in Section 3.1, even if a demand response resource is scheduled in the day-ahead or 15-minute market and does not deliver,

[34] *2018 Resource Adequacy Report*, CPUC Energy Division, August 2019, pp. 22-23: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report.pdf

[35] *Energy Division's Evaluation of the Demand Response Auction Mechanism*, CPUC, January 4, 2019, p. 13: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442460092

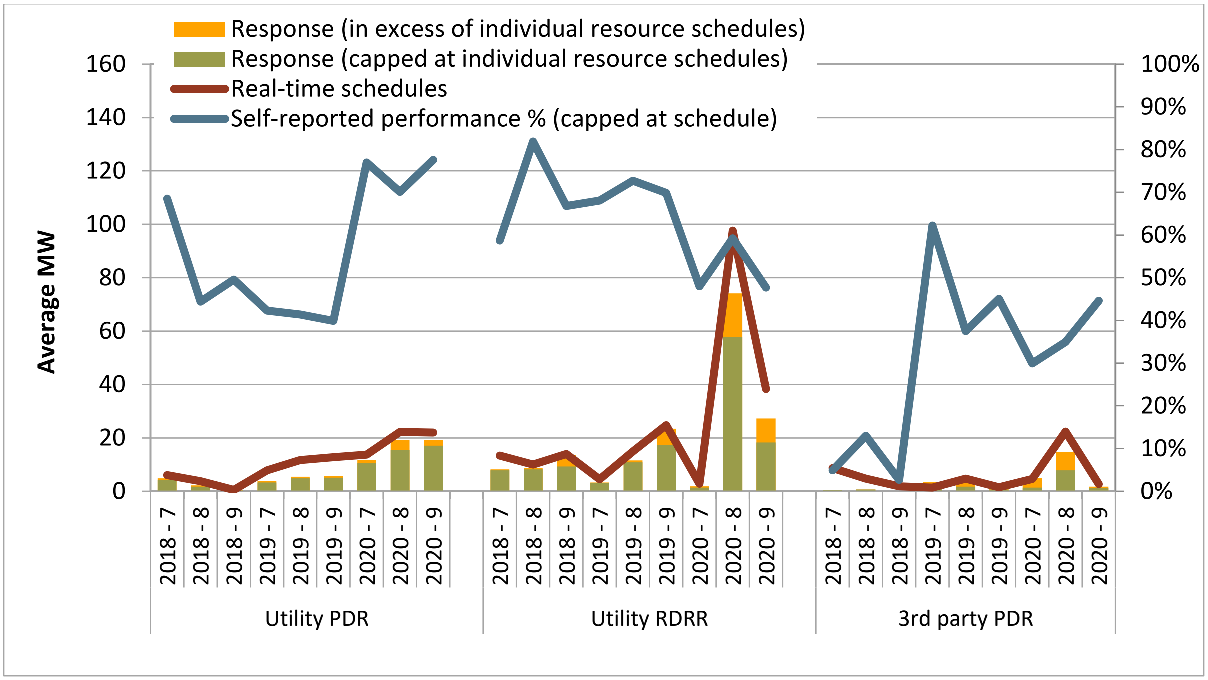
resources generally face little financial risk for non-delivery. Resources may often even retain net positive market revenues due to often low 5-minute market prices relative to day-ahead and 15-minute market prices.

With limited incentives to deliver scheduled load curtailment and high capacity value relative to potential net energy market revenues, demand response resources may continue to have limited incentives to be available and perform in the energy market. To strengthen incentives to be available and perform, DMM has recommended that the ISO consider developing a performance penalty or incentive structure for resource adequacy resources.[36] 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 capable of delivering load curtailment in critical hours equal to the quantity of resource adequacy capacity that the resource has been paid to provide.

[36] *Comments on Reliability Service Initiative – Phase 2 Second Revised Draft Final Proposal*, DMM, October 4, 2016, p. 2: http://www.caiso.com/Documents/DMMComments-ReliabilityServicesInitiativePhase2- SecondRevisedDraftFinalProposal.pdf

# 4 Appendix

**Demand response resource adequacy performance – Averages 2018-2020 (Hours ending 17-21)[37]**




[37] Real-time schedules are not capped at resource adequacy values. Of note, 2019 third party demand response average performance has decreased compared to July/August performance reported in DMM's 2019 Annual Report on Market Issues and Performance (pp. 55-56): http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf)

This change is due to some scheduling coordinators submitting updated performance data which was picked up in settlement recalculations issued 9 months (T+9M) after relevant 2019 market dates.

**Demand response resource adequacy performance – Averages 2018-2020 (all hours)**