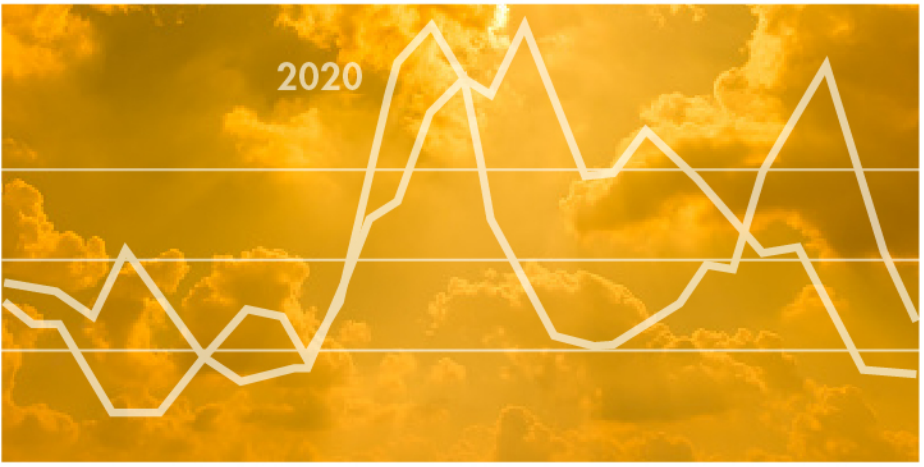
Preliminary Root Cause Analysis

Mid-August 2020 Heat Storm

October 6, 2020



California ISO

Prepared by:
California Independent System Operator
California Public Utilities Commission
California Energy Commission

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October 6, 2020

The Honorable Governor Gavin Newsom
State Capitol Building, 1st Floor
Sacramento, CA 95814

Dear Governor Newsom:

In response to your August 17, 2020 letter, the California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC) have jointly prepared the attached Preliminary Root Cause Analysis (Preliminary Analysis) of the two rotating outages in the CAISO footprint on August 14 and 15, 2020. In our response, we also recognized our shared responsibility for the power outages many Californians unnecessarily endured. The findings of the Preliminary Analysis underscore this shared responsibility and give greater definition to the actions that should have been taken to avoid or minimize the impacts to those we serve. The findings and recommendations of this Preliminary Analysis will guide our agencies to ensuring the events of August 14 and 15 do not reoccur.

We have identified several factors that, in combination, led to the need for the CAISO to direct utilities in the CAISO footprint to trigger rotating outages. There was no single root cause of the outages, but rather, a series of factors that all contributed to the emergency. The report finds that:

1) The climate change-induced extreme heat storm across the western United States resulted in the demand for electricity exceeding the existing electricity resource planning targets. The existing resource planning processes are not designed to fully address an extreme heat storm like the one experienced in mid-August.

2) In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.

3) Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

The combination of these factors was an extraordinary event. But it is our responsibility and intent to plan for such events, which are becoming increasingly common in a world rapidly being impacted by climate change.

After the rotating outages on August 14 and 15, your office led an effort to take immediate actions that minimized risks of further outages during the extended heatwaves in August and September. This Preliminary Analysis also reviews the impact of those actions.

The Preliminary Analysis provides recommendations for immediate, near and longer-term improvements to our resource planning, procurement, and market practices. These actions are intended to ensure that California's transition to a reliable, clean, and affordable energy system is sustained and accelerated. This is an imperative – for our citizens, communities, economy, and environment.

Most critical is that we take immediate action to prevent similar circumstances from threatening reliability in the near term. The joint entities and the State should take the following immediate actions to ensure reliability for 2021 and beyond:

1. Update the resource and reliability planning targets to better account for:

    a. Heat storms and other extreme events resulting from climate change like the ones encountered in both August and September;

    b. A transitioning electricity resource mix to meet the clean energy goals of the state during critical hours of grid need;

2. Ensure that the generation and storage projects that are currently under construction in California are completed by their targeted online dates;

3. Expedite the regulatory and procurement processes to develop additional resources that can be online by 2021. This will most likely focus on resources such as demand response and flexibility. This can complement the resources that are already under construction;

4. Coordinate additional procurement by non-CPUC jurisdictional entities; and

5. Enhance CAISO market practices to ensure they accurately reflect the actual balance of supply and demand during stressed operating conditions.

We also provide additional recommendations in the Preliminary Analysis for the near-, mid-, and long-term time horizons. Implementation of these recommendations will involve processes within State agencies and the CAISO, partnership with the

Legislature, and collaboration and input from stakeholders within California and across the Western United States.

This Preliminary Analysis has served as an important step in learning from the events of August 14-15, as well as a clear reminder of the importance of effective communication and coordination. We will continue our review of the root causes of the August events as more data becomes available and provide a final analysis by the end of the year.

We are unwavering in our commitment to meeting California's clean energy and climate goals. Thank you for your personal engagement on these issues and for your unequivocal commitment and leadership on addressing climate change.

Regards,

Elliot Mainzer
President and Chief Executive Officer
California Independent System Operator

Marybel Batjer
President
California Public Utilities Commission

David Hochschild
Chair
California Energy Commission

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GLOSSARY OF ACRONYMS

ACRONYM	DEFINITION
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
A/S	Ancillary Services
AWE	Alerts, Warnings, and Emergencies
BA	Balancing Authority
BAA	Balancing Authority Area
BPM	Business Practice Manual
CAISO	California Independent System Operator Corporation
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CDWR	California Department of Water and Power
CEC	California Energy Commission
CHP	Combined Heat and Power
COI	California Oregon Intertie
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
DMM	CAISO Department of Market Monitoring
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
ESP	Electric Service Provider
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
IERP	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor Owned Utility
IRP	Integrated Resource Planning
JASC	Joint Agency Steering Committee
LADWP	Los Angeles Department of Water and Power
LMS	Load Management Standards
LOLE	Loss of Load Expectation
LRA	Local Regulatory Authority
LSE	Load Serving Entity
MW	Megawatt
MWD	Metropolitan Water District
NCPA	Northern California Power Agency
NERC	North American Electric Reliability Corporation
NOB	Nevada Oregon Border

ACRONYM	DEFINITION
NQC	Net Qualifying Capacity
NWS	National Weather Service
PDCI	Pacific DC Intertie
PDR	Proxy Demand Resource
PGE	Portland General Electric
PG&E	Pacific Gas & Electric
PIME	Price Inconsistency Market Enhancements
POU	Publicly Owned Utility
PRM	Planning Reserve Margin
QC	Qualifying Capacity
RA	Resource Adequacy
RAAIM	Resource Adequacy Availability Incentive Mechanism
RDRR	Reliability Demand Response Resource
RMO	Restricted Maintenance Operations
RMR	Reliability Must Run
RUC	Residual Unit Commitment
SB	Senate Bill
SCE	Southern California Edison
SDGE	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
TAC	Transmission Access Charge
TOU	Time of Use
WAPA	Western Area Power Administration
WECC	Western Electric Coordinating Council

Executive Summary

On August 14 and 15, 2020, the California Independent System Operator (CAISO) was forced to institute rotating electricity outages in California in the midst of a West-wide heat storm. Following these emergency events on two consecutive days, Governor Newsom sent a letter to the CAISO, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC), requesting, after immediate actions to minimize further outages, a report identifying the root causes of the events leading to the outages.

This report serves as the preliminary root cause analysis. The report reflects the findings that no single factor caused the outages, rather it was a series of factors related to planning processes, weather conditions and market constructs. Additional data analysis is required to complete a final in-depth root cause analysis, which is expected to be completed by the end of the year.

ES.1 Roles of the Entities Delivering This Report

California's electricity market is complex and overseen by numerous entities with overlapping but distinct authority. The three entities sponsoring this report and their roles in electricity reliability relevant to the August outages are described briefly below.

CAISO

The CAISO is the Balancing Authority that oversees the reliability of approximately 80% of California's electricity demand and a small portion of Nevada. The remaining 20% is served by publicly-owned utilities such as the Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD), which operate separate transmission and distribution systems. However, there are some California publicly-owned utilities in the CAISO's Balancing Authority Area and some investor-owned utilities that are not. The CAISO manages the high-voltage transmission system and operates wholesale electricity markets for entities within its system and across a wider Western footprint via an Energy Imbalance Market (EIM). The CAISO performs its functions under a tariff approved by the Federal Energy Regulatory Commission (FERC) and reliability standards set by the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Corporation (NERC).

CEC

CEC has many electricity planning and policy functions including forecasting electricity and natural gas demand, investing in energy innovation, setting the state's appliance and building energy efficiency standards, and planning for and directing state

response to energy emergencies. This report focuses on the CEC's key responsibilities in the preparation and adoption of electricity demand forecasts for the CAISO BAA. As part of its Integrated Energy Policy Report process and in consultation with the joint entities, the CEC develops a set of forecasts to support the needs of CAISO transmission planning, CPUC Integrated Resources Planning, and CPUC and CAISO resource adequacy. For resource adequacy, the CPUC uses the monthly "1-in-2" peak demand forecast taken from the CEC's hourly forecast. This forecast is constructed to have a 50% probability that actual monthly peak will be either higher or lower than the forecast, given expected variation in temperatures.

CPUC

The CPUC also has many regulatory responsibilities for energy, telecommunications, water, transportation, and safety in California. Relevant to the outages described in this report, the CPUC sets reliability requirements for the electric investor-owned utilities that participate in the CAISO markets and comprise the majority of the CAISO footprint. Electricity utilities regulated by the CPUC represent approximately 80% of the electricity demand in California and 91% of the electricity demand in the CAISO system. The CPUC's reliability (termed resource adequacy) requirements are set based on the peak demand shown in the CEC's demand forecast, plus a planning reserve margin (PRM) of 15%. The PRM is comprised of a 6% requirement to meet grid operating contingency reserves, as required by the WECC reliability rules, and a 9% contingency to account for unplanned plant outages and higher-than-average peak electricity demand.

ES.2 Summary of Conditions and Events of August 14 and 15, 2020

From August 14 through 19, 2020, the Western United States as a whole experienced an extreme heat storm, with temperatures 10-20 degrees above normal. During this period, California experienced four out of the five hottest August days since 1985; August 15 was the hottest and August 14 was the third hottest. This heat event was the equivalent of the hottest year of 35. The only other period on record with a similar heat wave was July 21–25, 2006, which included three days above the highest temperature in August 2020.

Extreme heat affects both the demand for and the supply of electricity in several ways. In terms of electricity demand, during normal summer weather conditions in California, high daytime temperatures are offset by cool and dry evening conditions. However, during extreme heat events when hot temperatures persist into the evening and overnight hours, air conditioners continue to run and drive up electricity demand beyond normal levels.

In terms of electricity supply, conventional thermal generation (such as natural gas) operates less efficiently in extreme heat. California also typically relies on imported

power during peak demand times, but because the rest of the Western United States was also experiencing extreme heat, California could rely on fewer imports than usual. Also due to the effects of heat and drought over time, the availability of hydroelectric power in California in 2020 was below normal. In addition, high clouds from a storm were covering parts of California during the same period, reducing available generation from all types of solar generation facilities.

Further, throughout most of the day on both August 14 and 15, numerous fires were threatening the loss of major transmission lines.

After observing some of these trends earlier in the week, and seeing higher temperatures forecasted on August 12, the CAISO issued a restricted maintenance request for August 14 through 17. This was to caution generator and transmission operators to avoid actions that could jeopardize their resource availability. On August 13, the CAISO issued a Flex Alert for August 14, calling for voluntary energy conservation from 3:00 pm to 10:00 pm.

Despite taking pre-emptive actions designed to maintain electric system reliability, the CAISO declared a Stage 3 Emergency at 6:38 pm on August 14 because reserves had fallen below the minimum requirements. The requirements are set by NERC and WECC and are approximately equal to 6% of load. In order to remain compliant with these mandatory reliability standards, the CAISO initiated rotating outages (also called load-shedding) for about an hour. This affected approximately 492,000 customers for a duration of 15 minutes to 150 minutes. The net demand peak (demand minus available solar and wind resources) occurred at 6:51 pm.

Similarly, on August 15, a Stage 3 Emergency requiring rotating outages was declared at 6:28 pm for 20 minutes, just after the net demand peak at 6:26 pm. This ultimately affected 321,000 customers for 8 minutes to 90 minutes.

ES.3 Preliminary Understanding of Various Factors That Contributed to Rotating Outages on August 14 and 15, 2020

This Preliminary Analysis identifies several factors that, in combination, led to the need for the CAISO to direct utilities in the CAISO footprint to trigger rotating outages. There was no single root cause of the outages, but rather, a series of factors that all contributed to the emergency:

- The climate change-induced extreme heat storm across the western United States resulted in the demand for electricity exceeding the existing electricity resource planning targets. The existing resource planning processes are not

designed to fully address an extreme heat storm like the one experienced in mid-August.

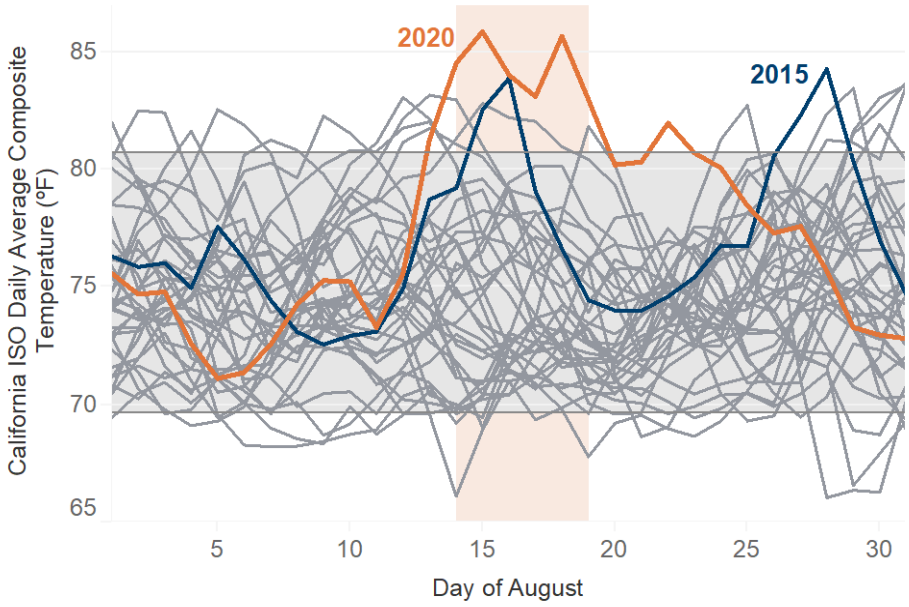
- In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.
- Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

Existing Resource Planning Processes are Not Designed to Fully Address an Extreme Heat Storm

As discussed above, California and the rest of the Western United States faced an extreme heat storm from August 14 through August 19. During this period, California experienced four out of the five hottest August days since 1985. August 14 was the third-hottest August day; August 15 was the hottest. The only other period on record with a similar heat wave was July 21–25, 2006, which included three days above the highest temperature in August 2020.

Figure ES.1 shows daily August temperatures for each year from 1985 to 2020. The middle 90% of temperatures contained in the shaded gray region and 2020's six-day heat storm shaded in light orange. August 2020 (orange) is distinguished from the year with the next-hottest days, 2015 (blue), by both the magnitude and duration of the heat storm. The hottest day in 2020 was a full degree and a half higher than that of 2015 – averaged over all hours of the day and across different parts of California – and 2020's six hottest days came in succession, compared with two distinct heat waves in 2015 that each lasted just a day or two. In addition, the heat storm spanned the American West, which California typically relies on for electricity imports.

Figure ES.1: August Temperatures 1985 - 2020



(Source: CEC Weather Data/CEC Analysis)

Based on CEC analysis, the heat storm experienced in August was a 1-in-35 year weather event.[1] Moreover, the rapidly evolving demand patterns induced by COVID-19 were not anticipated in the planning and resource procurement timeframe, which is necessarily an iterative, multi-year process. The energy markets can help fill the gap between planning and real-time conditions, but the West-wide nature of this heat storm limited the energy markets' ability to do so.

In Transitioning to a Reliable, Clean, and Affordable Resource Mix, Resource Planning Targets Have Not Kept Pace to Lead to Sufficient Resources That Can Be Relied Upon to Meet Demand in the Early Evening Hours, Which Were Amplified by the Extreme Heat

For August 2020, all LSEs met their resource adequacy (RA) obligations either with physical resources or demand response shown to the CAISO, allocations from resources backstopped under a Reliability Must Run (RMR) agreement, or through credits that are applied by the local regulatory authority (LRA) on behalf of a LSE. Collectively, the obligations include a 15% PRM added to the peak of the August forecasted 1-in-2 demand. However, on August 14, the operational need was 1.3 to 2.5% higher than the PRM driven by higher load and therefore higher contingency reserve requirements and reduced resource and transmission availability. On August 15 the operational need

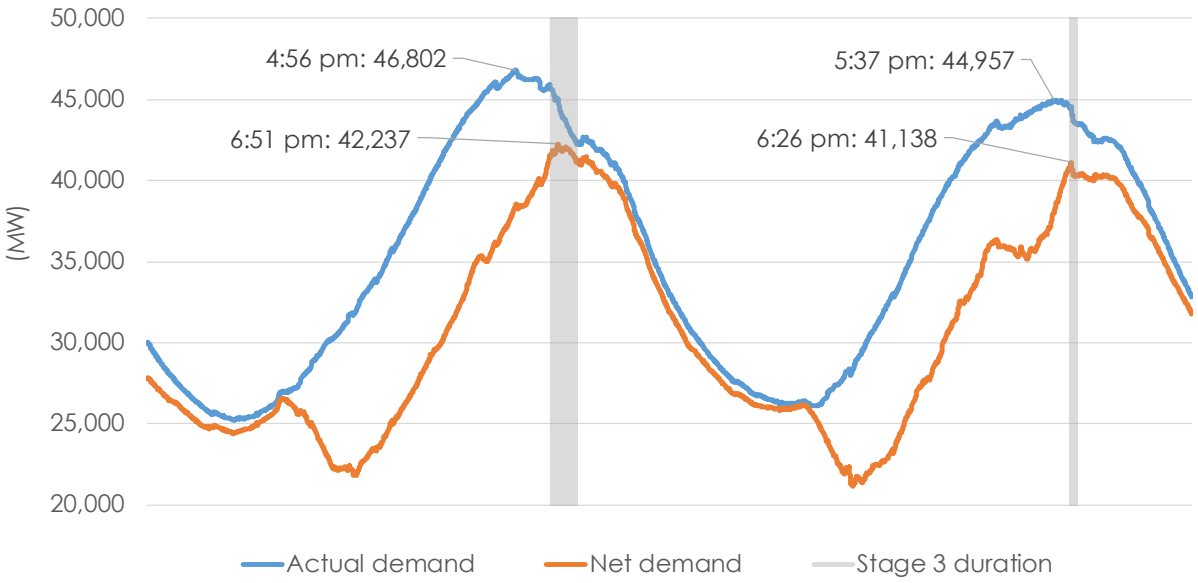
[1] Currently the RA obligation is planned for a 1-in-2 weather and adds a 15% PRM, in part to act as buffer for deviations from the 1-in-2 weather event.

was 0.7 to 1.7% lower than the PRM. While a PRM comparison is informative, the rotating outages both occurred after the peak hour, as explained below.

The construct for RA was developed around peak demand, which until recently has been the most challenging and highest cost moment to meet demand. The principle was that if enough capacity was available at peak demand there would be enough capacity at all other hours of the day as well since most resources could run 24/7 if needed. With the increase of solar penetration in recent years, however, this is no longer the case. The single critical period of peak demand is giving way to multiple critical periods during the day. A second critical period is the net demand peak, which is the peak of load net of solar and wind generation resources and occurs later in the day than the peak. While RA processes should meet load at all times throughout the day, the net demand peak is becoming the most challenging time period in which to meet demand. Over time, critical grid needs may manifest in other hours, seasons or conditions as the energy resource portfolio continues to evolve.

August 14 illustrates the challenges of with the net demand peak. Figure ES.2 shows the demand peak and net demand peak for August 14 and 15. On August 14, the net demand peak of 42,237 MW at 6:51 pw was 4,565 MW lower than the peak demand at 4:56 pm but wind and solar generation have decreased by 5,431 MW during the same time period. The net demand peak shown is already reduced by the impact of emergency demand response triggered by this time, as discussed further later. The difference between the demand curve (in blue) and the net demand curve (in orange) is largest in the middle of the day (approximately 10 am until 4 pm) when renewables are generating at the highest levels and serving significant CAISO load. Most important, the rotating outages coincide closely with the net demand peaks.

Figure ES.2: Demand and Net Demand for August 14 and 15



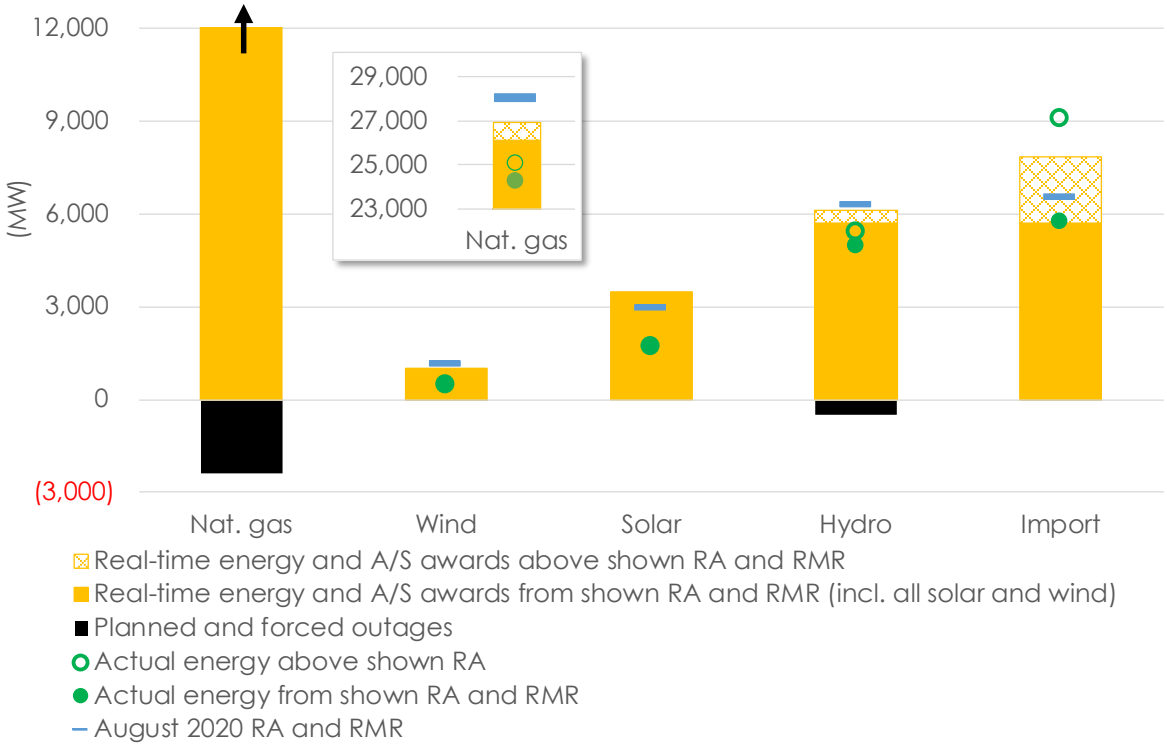
On August 14 the Stage 3 Emergency was declared at 6:38 pm, right before the net demand peak at 6:51 pm. Similarly, on August 15 the Stage 3 Emergency was called at 6:28 pm, just after the net demand peak at 6:26 pm.

Supply Side Resources Were Differently Impacted

In addition to the fact that California and the West were facing an extreme heat storm that pushed forecasted demand up to and beyond the limits that California's RA programs anticipate, many resources that were required to provide energy to the CAISO Balancing Authority Area (BAA) did not, or were not able to, deliver that energy during the hours of peak and net demand peak.

Figure ES.3 shows how selected resources performed during the net demand peak on August 14 across three different time periods. It shows: (1) the levels of shown RA and RMR for August 2020 (blue markers); (2) the real-time awards for energy and ancillary services from shown RA capacity and for amounts above the shown RA (solid yellow and yellow cross-hatched bars) net of planned and forced outages (black bars); and (3) the actual energy delivered (green circles). For real-time awards and actual energy, the amounts are divided between shown RA and RMR capacity and for the amounts above the shown RA. As a simplifying assumption, all wind and solar generation is assumed to count towards RA capacity. Each resource is discussed below.

Figure ES.3: August 14 Net Demand Peak (6:51 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR



The **natural gas fleet** collectively experienced 1,400 MW to 2,000 MW of forced outages (*i.e.*, derating or lowering the resource's available capacity) largely attributed to the extreme heat, and day-of outages. Additionally, almost 400 MW of planned outages had not been substituted.

Total **import** bids received in the day-ahead market were between 2,600 MW and 3,400 MW (40-50%) higher than the August shown RA requirements for imports. Of this total, imports required to provide energy to California under RA contracts collectively bid in approximately 330 MW less than their August shown RA obligation, though some import resources under RA contract may have bid above their shown RA obligations. The difference is likely attributed to transmission constraints from the Pacific Northwest, since through the month of August, a major transmission line in the Pacific Northwest upstream from the CAISO system was forced on outage due to weather and thus derated the California Oregon Intertie (COI). The derate reduced the CAISO's transfer capability by approximately 650 MW and congested the usual import transmission paths across both COI and Nevada-Oregon Border (NOB).[2] In other words, more

[2] See Grizzly-Portland General Electric (PGE) Round Butte No 1 500 kV Line at: https://transmission.bpa.gov/Business/Operations/Outages/OutagesCY2020.htm

imports were available than could be physically delivered based on the transfer capability and the total import level was less than the amount the CAISO typically receives.

Because of this congestion, lower-priced non-RA imports cleared the market in lieu of higher-priced RA imports. Consequently, the amount of energy production from RA imports can be lower than the level of RA imports shown to the CAISO on RA supply plans.

Note that the CAISO reached out to neighboring Balancing Authorities and was able to get a temporary emergency increase in transfer capability of approximately 200 MW on August 14 and 15.

Total **hydro** generation bids were equivalent to their August net qualifying capacity (NQC) value, with hydro generation resources under RA contract bid equivalent to 90% of the August RA requirements. However, real time energy production may be higher or lower than this amount. Therefore, actual energy production from shown RA capacity may vary from the amount reported to the CAISO.

For **solar and wind** generation, the August RA NQC values were set based on modeled assumptions and it is normal to see variations between this amount and the bid-in amount, which reflects forecasted conditions for the following day.

The total solar fleet collectively bid in approximately 370 MW (13%) more on August 14 but 160 MW (5%) less on August 15 than the August RA values at the net demand peak. Actual energy production during the net demand peak was 1,200 MW (40%) less and 1,000 MW (35%) less on August 14 and 15, respectively. The total wind fleet within the CAISO collectively bid in approximately 230 MW (20%) less on August 14 but 120 MW (10%) more on August 15 during the net demand peak. In contrast, actual energy production during the net demand peak was 640 MW (57%) less and 230 MW (20%) less on August 14 and 15, respectively. In addition, wind generation was impacted by storm patterns through the demand peak and net demand peak period on August 15. Between 5:12 pm and 6:12 pm, wind generation declined by 1,200 MW before increasing again closer to 7:00 pm.

Demand Response Resource Preliminary Performance and Dispatch

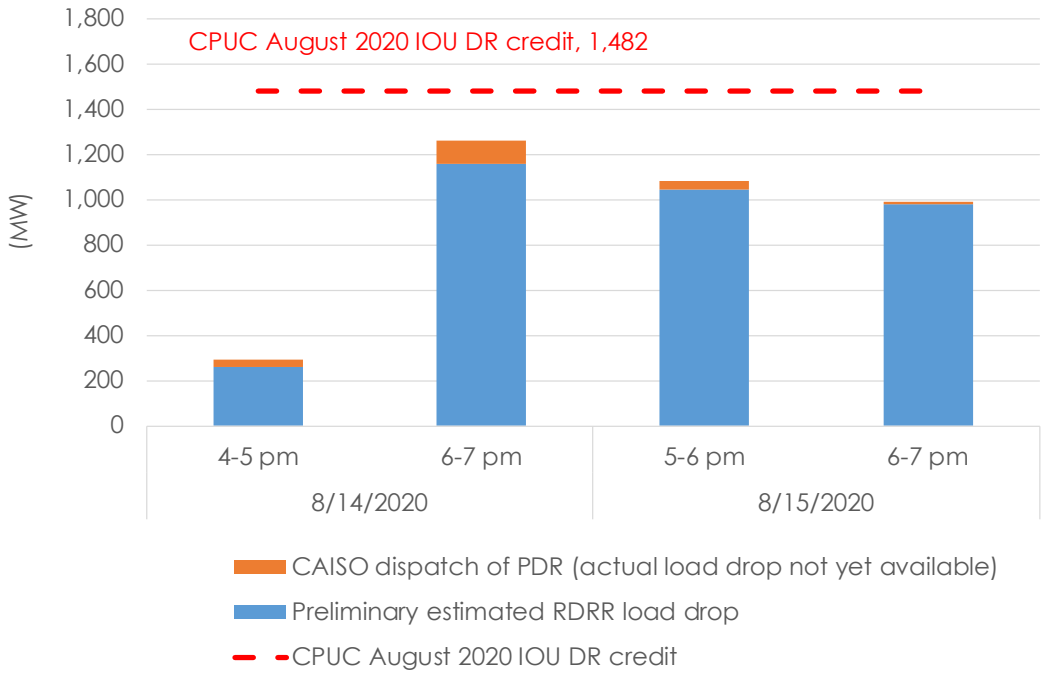
Demand response programs are designed to reduce demand at peak times. They take on many forms. Some programs bid into the CAISO's wholesale markets and are then dispatched similar to a power plant. A full analysis of how demand response performed cannot be completed in time to inform this analysis but will be presented in a future analysis. This Preliminary Analysis focuses on the largest portion of the demand response

programs, which are the programs that are credited by the CPUC toward the investor owned utilities' (IOUs') RA obligations.

CPUC jurisdictional LSEs' August 2020 credits were 1,632 MW representing 3.5% of their total obligations.[3] The vast majority of this amount is the emergency demand response programs (Reliability Demand Response Resource or RDRR) that are triggered by the CAISO's emergency protocols and the IOUs' economic demand response programs (Proxy Demand Response or PDR).

Figure ES.4 below compares the expected load drop from August 14 and 15 during the hours of the peak and net demand peak from the demand response programs. These four timeframes are compared to the August 2020 CPUC IOU demand response credit of 1,482 MW. The IOU demand response programs responded at approximately a maximum of 80% of the total credited amount (August 14 during the net demand peak).

Figure ES.4: Credited IOU Demand Response: Preliminary Estimated RDRR Response and PDR Dispatch vs. CPUC August 2020 DR Credit

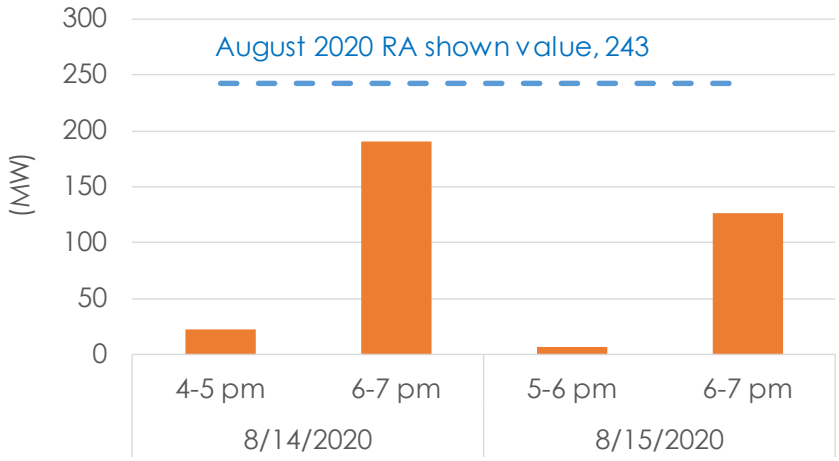


Aside from the IOUs, there is also economic demand response (PDR) from CPUC-jurisdictional third parties. As noted above, settlement quality data was not available

[3] Non-CPUC jurisdictional LSEs' credits were 565 MW, representing 11.9% of their total obligations.

at the time of the drafting of this report. Therefore, Figure ES.5 below shows the level of CAISO dispatch based on bids accepted into both the day-ahead and real-time energy markets. Dispatches were less than 10% of the RA shown values during peak on both days but increased to 80% and 50% during the net demand peak on August 14 and 15, respectively.

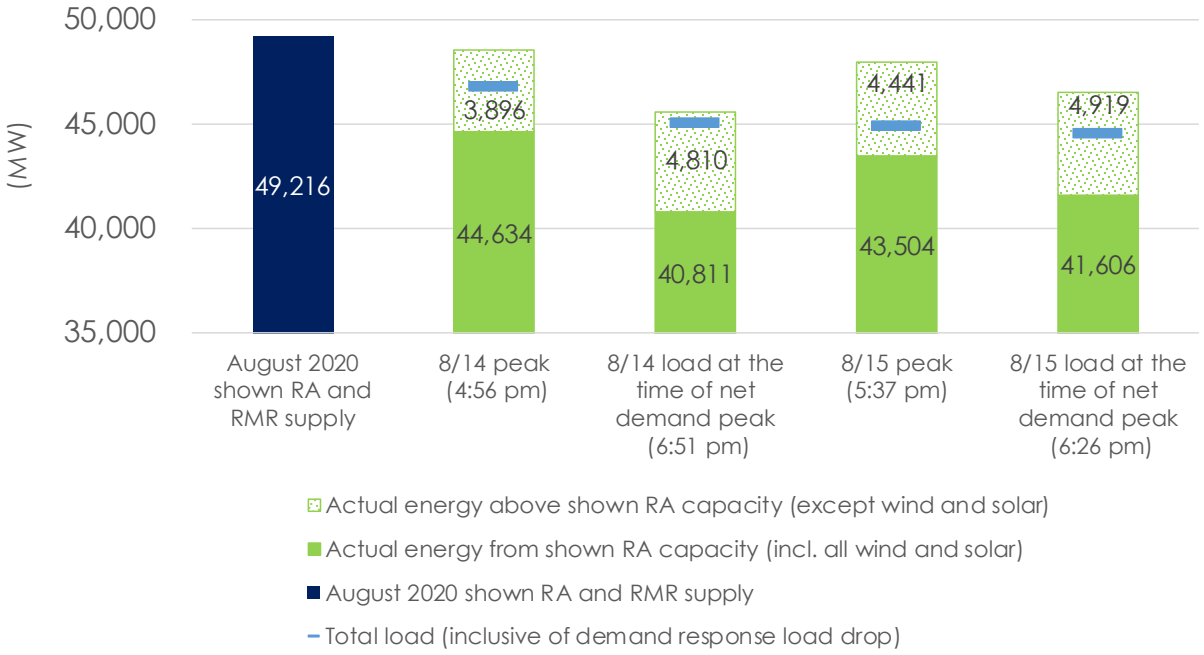
Figure ES.5: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available)



Combined Resources - Actual Energy Production

Figure ES.6 below compares the total August 2020 RA and Reliability Must Run (RMR) capacity versus actual energy production for both days during the peak and net demand peak times for total resources and the subset of these resources at their shown RA values. The August 2020 RA capacity in the first column reflects the qualifying capacity shown to the CAISO on RA supply plans. The second through fourth columns in the figure show the actual energy production from RA resources and energy produced above the shown RA amount. Any IOU emergency and economic demand response dispatched during these time periods is already reflected in the reduced load. The figure shows a decrease in generation known to be under RA contract between the peak and net demand peak periods, though as explained above some of capacity above shown RA is likely generated from resources under RA contract. The load markers show that a portion of load was served by energy produced above the shown RA amount for each time period. For simplicity, the figure does not include ancillary services awards.

Figure ES.6: August 2020 Shown RA and RMR Allocation vs. August 14 and 15 Actual Energy Production (Assumes All Wind and Solar Count as RA Capacity)



Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions

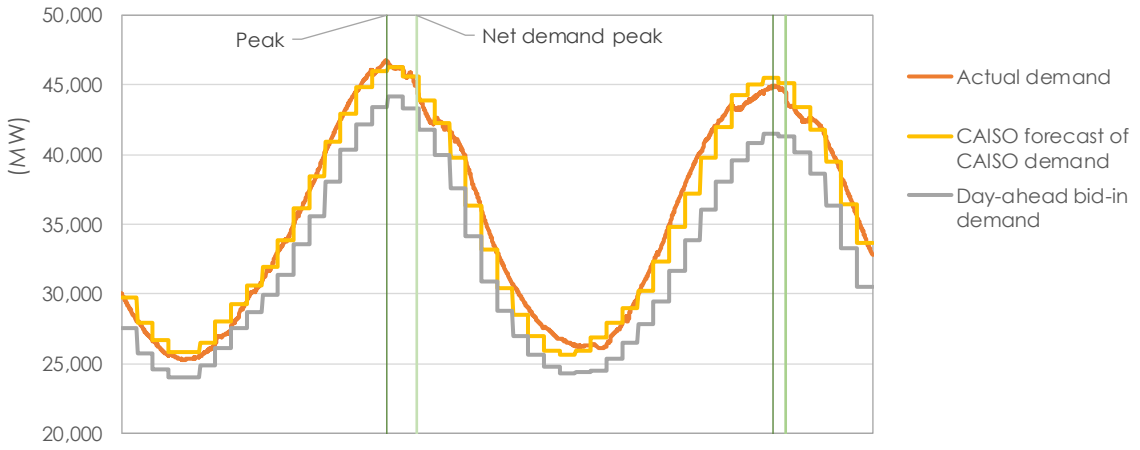
Certain energy market practices appear to have contributed to the inability to obtain additional energy that could have alleviated the strained conditions on the CAISO grid August 14 and 15. The contributing causes identified at this stage include: under-scheduling of demand in the day-ahead market by scheduling coordinators, convergence bidding masking the tight supply conditions, and the configuration of the residual unit commitment market process.

Demand Should Be Appropriately Scheduled in the Day-Ahead Timeframe

Scheduling coordinators representing LSEs collectively under-scheduled their demand for energy by 3,386 MW and 3,434 MW below the actual peak demand for August 14 and 15, respectively, as shown in Figure ES.7. During the net demand peak time, the under-scheduling was 1,792 MW and 3,219 MW for August 14 and 15, respectively. The under-scheduling of load by scheduling coordinators had the detrimental effect of not setting up the energy market appropriately to reflect the actual need on the system

and subsequently signaling that more exports were ultimately supportable from internal resources.

Figure ES.7: Comparison of Actual, CAISO Forecast, and Bid-in Demand



Day-ahead bid-in demand below actual:

	8/14	8/15
At peak:	3,386	3,434
Time of net demand peak:	1,792	3,219

Convergence Bidding Masked Tight Supply Conditions

During the mid-August events, it was difficult to pinpoint these contributing causes because processes that normally help set up the market were not performing as expected under the tight supply conditions. One such process was convergence bidding. As the name suggests, convergence bidding should allow bidders to converge or moderate prices between the day-ahead and real-time markets. Under normal conditions, when there is sufficient supply, convergence bidding plays an important role in aligning loads and resources for the next day. However, during August 14 and 15, under-scheduling of load and convergence bidding clearing net supply signaled that more exports were supportable. Once this interplay was identified on August 16 after observing the results for trade day August 17, convergence bidding was temporarily suspended for the August 18 trade date through the August 21 trade date.

Residual Unit Commitment Process Changes Were Needed

The CAISO has a residual unit commitment (RUC) process that provides additional reliability checks based on the CAISO's forecast of CAISO load after scheduling coordinators provide all of their schedules and bids for supply, demand, but excluding convergence bids. After a review of the August 14 event, it was discovered that a prior market enhancement was inadvertently causing the CAISO's RUC process to mask the

load under-scheduling and convergence bid supply effects, reinforcing the signal that more exports were supportable. While this market enhancement was a necessary functionality in other market processes, it was not required in the RUC reliability-based process. The CAISO therefore stopped applying the enhancement to the RUC process starting from the day-ahead market for September 5, 2020, which allowed it to conduct its reliability check appropriately by internalizing whether load was under-scheduled as compared to the CAISO's forecast of CAISO load and regardless of the influence of convergence bidding.

The CAISO's real-time market and operations helped to significantly reduce the effects of the interaction of load under-scheduling, convergence bidding, and the impact on the RUC process in the day-ahead market. The CAISO market attracted imports including market transactions, voluntary transfers from the Energy Imbalance Market (EIM), and emergency transfers from other Balancing Authorities to reduce the impacts of these challenges. However, actual supply and demand conditions continued to diverge from market and emergency so even with the additional real-time imports, the CAISO could not maintain required contingency reserves as the net demand peak approached on August 14 and 15.

ES.4 Actions Taken to Mitigate Projected Supply Shortfalls During August

While August 14 and 15 are the primary focus of this Preliminary Analysis due to the rotating outages that occurred during those days, August 17 through 19 were projected to have much higher supply shortfalls. If not for the leadership through the Governor's office to mobilize a state-wide effort to mitigate the situation, California was at risk of further rotating outages in August due to the unprecedented multi-day heat storm across the West. Specific actions taken are detailed in Section 5 of the report.

ES.5 Preliminary Recommendations

The Preliminary Analysis provides recommendations for immediate, near and longer-term improvements to resource planning, procurement, and market practices. These actions are intended to ensure that California's transition to a reliable, clean, and affordable energy system is sustained and accelerated.

Most critical are immediate actions to prevent similar circumstances from threatening reliability in the near term. The following immediate actions are recommended to ensure reliability for 2021 and beyond:

1. Update the resource and reliability planning targets to better account for:
    a. Heat storms and other extreme events resulting from climate change like the ones encountered in both August and September;

b. A transitioning electricity resource mix to meet the clean energy goals of the state during critical hours of grid need;

2. Ensure that the generation and storage projects that are currently under construction in California are completed by their targeted online dates;
3. Expedite the regulatory and procurement processes to develop additional resources that can be online by 2021. This will most likely focus on resources such as demand response and flexibility. This can complement the resources that are already under construction;
4. Coordinate additional procurement by non-CPUC jurisdictional entities; and
5. Enhance CAISO market practices to ensure they accurately reflect the actual balance of supply and demand during stressed operating conditions.

Implementation of these recommendations will involve processes within State agencies and the CAISO, partnership with the Legislature, and collaboration and input from stakeholders within California and across the Western United States.

ES.6 Next Steps

Additional analysis that will be performed for the final version of this report, includes, but is not limited to:

- Evaluate how credited resources performed across CPUC and non-CPUC jurisdictional footprints.
- Evaluate demand response performance based on settlement meter data.
- Analyze how different LSE scheduling coordinators scheduled load in the day-ahead market compared with their forecasted peak demand, and understand and address the underlying drivers.
- Improve communications to utility distribution companies to ensure appropriate response during future critical reliability events and grid needs.
- Review performance of specific resources during the heat storm.

1 Introduction

On August 17, 2020 Governor Gavin Newsom sent a letter to the California Independent System Operator (CAISO), the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC) after the CAISO footprint experienced two rotating outages on August 14 and 15 during a West-wide heat storm.[4] In the letter Governor Newsom requested immediate actions to minimize rotating outages as the heat storm continued, and a comprehensive review of existing forecasting methodologies and resource adequacy requirements. The Governor also requested that the CAISO complete an after-action report to identify root causes of the events.

In response to Governor Newsom, the CAISO, the CPUC, and the CEC responded in a letter on August 19, 2020 with immediate actions for the next five days and a commitment to an after-action report.[5] This Preliminary Root Cause Analysis (Preliminary Analysis) responds to that commitment and reflects the collective efforts of the CAISO, the CPUC, and the CEC.

This analysis is preliminary and will be updated as more data becomes available. For example, demand response resources are evaluated based on meter data, which is not available to the CAISO until almost two months after a demand response call, per existing practice. Therefore, load curtailed from demand response programs is estimated based on the best information or approximations as of the publishing of this Preliminary Analysis. Similarly, CAISO system data is large and complex, often tracking generation movement down to a four second interval. The aggregation, validation, and analysis of this significant quantity of data is labor intensive. The information provided in this report reflects the best available assessment at this time.

[4] *See* Office of the Governor, Letter from Gavin Newsom to Marybel Batjer, Stephen Berberich, and David Hochschild, August 17, 2020, https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-Letter-to-CAISO-PUC-and-CEC.pdf.

[5] *See* CPUC, CAISO, and CEC, Letter from Marybel Batjer, Stephen Berberich, and David Hochschild to Governor Gavin Newsom, August 19, 2020, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/Joint%20Response%20to%20Governor%20Newsom%20Letter%20August192020.pdf.

2 Background

The CAISO is the Balancing Authority that oversees the reliability of approximately 80% of California's electricity demand and a small portion of Nevada. The remaining 20% is served by publicly-owned utilities such as the Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD), which operate separate transmission and distribution systems. However, there are some California publicly-owned utilities in the CAISO's Balancing Authority Area (BAA) and some investor-owned utilities that are not. The CAISO manages the high-voltage transmission system and operates wholesale electricity markets for entities within its system and across a wider Western footprint via an Energy Imbalance Market (EIM). The CAISO performs its functions under a tariff approved by the Federal Energy Regulatory Commission (FERC) and reliability standards set by the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Corporation (NERC).

Utilities and other electric service providers operate within a hybrid retail market. Within the hybrid retail market there are a variety of utilities, some of which fall under the direct authority of the CPUC, others that are subject to some CPUC jurisdiction but also have statutory authority to control some procurement and rate setting decisions, and other public or tribal entities that operate wholly independently of the CPUC or other state regulatory bodies for the purposes of procurement and rate setting.

2.1 Resource Adequacy Process in the CAISO BAA

Following the California Electricity Crisis in 2000-2001, the Legislature enacted Assembly Bill (AB) 380 (Núñez, 2005), which required the CPUC, in consultation with the CAISO, to establish resource adequacy (RA) requirements for CPUC jurisdictional load serving entities (LSEs). The primary function of the RA program is to ensure there are enough resources with contractual obligations to ensure the safe and reliable operation of the grid in real-time providing sufficient resources to the CAISO when and where needed. The RA program also incentivizes the siting and construction of new resources needed for future grid reliability.

Broadly speaking, the CPUC sets and enforces the RA rules for its jurisdictional LSEs, including establishing the electricity demand forecast basis and planning reserve margin (PRM) that sets the monthly obligations. CPUC jurisdictional LSEs must procure sufficient resources to meet these obligations based on the resource counting rules established by the CPUC. The CEC develops the electricity demand forecasts used by the CPUC and provided to the CAISO. Non-CPUC jurisdictional LSEs in the CAISO footprint can set their own RA rules regarding resource procurement requirements including the PRM and capacity counting rules or default to the CAISO's requirements. RA capacity from both CPUC and non-CPUC jurisdictional LSEs are shown to the CAISO

every month and annually based on operational and market rules established by the CAISO. The CAISO enforces these rules to ensure it can reliably operate the wholesale electricity market.

The CPUC and the CAISO require LSEs to acquire three types of (RA) products: System, Local, and Flexible. Although Local and Flexible RA play important roles in assuring reliability, the August 14 through 19 events primarily implicated system resource needs, and therefore System RA requirements. This Preliminary Root Cause Analysis focuses on issues associated with System RA.

Separate from the RA programs, California has established a long-term planning process, now known as the Integrated Resource Planning (IRP) process, through statutes and CPUC decisions. Under IRP, the CPUC models what portfolio of electric resources are needed to meet California's Greenhouse Gas (GHG) reduction goals while maintaining reliability at the lowest reasonable costs. The IRP models for resource needs in the three- to ten-year time horizons. If the IRP identifies a need for new resources, the CPUC can direct LSEs to procure new resources to meet those needs.

The RA and IRP programs work in coordination. The RA program is designed to ensure that the resources needed to meet California's electricity demand are under contract and obligated to provide electricity when needed. The IRP program ensures that new resources are built and available to the shorter-term RA program when needed to meet demand and to ensure the total resource mix is optimum to meet the three goals of clean energy, reliability, and cost effectiveness.

The RA rules are set to ensure that LSEs have resources under contract to meet average peak demand (a "1-in-2 year" peak demand) plus a 15% planning reserve margin (PRM) to allow for 6% Western Electricity Coordinating Council (WECC)-required grid operating contingency reserves, and a 9% contingency to account for plant outages and higher than average peak demand. The demand forecasts are adopted by the CEC as part of its Integrated Energy Policy Report (IEPR) process. To develop CPUC RA obligations, the adopted IEPR forecast may be adjusted for load-modifying demand response, as determined by the CPUC.

Like RA, IRP modeling is also based on the CEC's adopted 1-in-2 demand forecast plus a 15% PRM. In addition, the CPUC conducts reliability modeling based on a 1-in-10 Loss of Load Expectation (LOLE) standard which is more conservative than the 1-in-2 demand forecast.

2.2 CEC's Role in Forecasting and Allocating Resource Adequacy Obligations

The CEC develops and adopts long-term electricity and natural gas demand forecasts every two years as part of the IEPR process. The CEC develops and adopts new forecasts in odd-numbered years, with updates in the intervening years. The inputs, assumptions and methods used to develop these forecasts are presented and discussed publicly at various IEPR workshops throughout each year.

Since 2013, the CEC, the CPUC, and the CAISO have engaged in collaborative discussions around the development of the IEPR demand forecast and its use in each organization's respective planning processes. Through the Joint Agency Steering Committee (JASC), the three organizations have agreed to use a "single forecast set" comprised of baseline forecasts of annual and hourly energy demand, specific weather variants of annual peak demand, and scenarios for additional achievable energy efficiency (AAEE).[6] For 2020, the CEC used the 1-in-2 Mid-Mid Managed Case Monthly Coincident Peak Demands (mid case sales and mid case AAEE), adopted in January 2019. This was the most recently adopted forecast at when the RA process for 2020 began in early 2019 and follows the single forecast set agreement.

Using the adopted CAISO transmission access charge (TAC) area forecast as a basis, the CEC then determines the individual LSE coincident peak forecasts which are the basis for each LSE's RA obligations. In California, each TAC area is the equivalent to the IOU footprint. Each LSE's load forecast is adjusted by the CEC for system coincidence by month. The RA system requirement is based on this coincident peak load.

This process is implemented differently for CPUC-jurisdictional LSEs (which include Investor-Owned Utilities (IOUs), Community Choice Aggregators (CCAs), and Electric Service Providers (ESPs) and non-CPUC-jurisdictional LSEs, which are primarily publicly owned utilities (POUs), but also include entities such as the California Department of Water Resources, the Western Area Power Administration (WAPA) and tribal utilities, each of whom is its own local regulatory authority (LRA).[7]

For CPUC jurisdictional LSEs, the CEC develops the reference total forecast and LSE-specific coincidence adjusted forecasts. To determine the reference forecast, CEC

[6] The 2018 single forecast set—which informed the determination of LSE requirements for 2020 system RA—also included additional achievable scenarios around PV adoption induced by the 2019 Title 24 building standards update. Following adoption of the standards in 2019, the impact from these systems has been embedded in the baseline demand forecasts.

[7] As of summer 2020, there are 70 LSEs in the CAISO, of which 33 are non-CPUC jurisdictional. In aggregate, the non-CPUC jurisdictional entities serve about 9% of CAISO load. See Appendix A, Table A2 for details.

staff disaggregates the Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) transmission area peaks to CPUC and non-CPUC jurisdictional load based on the CEC forecast of the annual IOU service area peak demand (CEC Form 1.5b) and analysis of LSE hourly loads and year-ahead forecasts. The CPUC-jurisdictional total, adjusted for load-modifying demand response programs, serves as the reference forecast for the CPUC RA forecast process. CEC staff then reviews and adjusts CPUC LSE submitted forecasts consistent with CPUC rules. The final step in this process is to apply a pro-rata adjustment to ensure the sum of the CPUC jurisdictional forecasts is within 1% of the reference forecast.

The CEC develops a preliminary year-ahead forecast for the aggregate of Non-CPUC jurisdictional entity load as part of developing the CPUC reference forecast. Non-CPUC jurisdictional entities then submit their own preliminary year-ahead forecasts of non-coincident monthly peak demands and hourly load data in April of each year. CEC staff determine the coincidence adjustment factors, and the resulting coincident peak forecast plus each non-CPUC jurisdictional entity's PRM (which most set equivalent to the CAISO's default 15% PRM) determines the entity's RA obligation. Non-CPUC jurisdictional entities, as their own LRA, may revise their non-coincident peak forecast before the final year-ahead or month-ahead RA showings to CAISO. The CEC-determined coincidence factors are applied to the new noncoincident peak forecast. For the final year-ahead RA showings to the CAISO, the non-CPUC jurisdictional collective August 2020 coincident peak load was 4,170 MW, 3.7% lower than the CEC's preliminary estimate of 4,330 MW. For the August 2020 month-ahead showing, non-CPUC jurisdictional forecasts increased to 4,169 MW. The CEC then transmits both non-coincident and coincident forecasts to the CAISO to ensure that congestion revenue rights allocations, based on non-coincident forecasts, are consistent with RA forecasts. The CEC transmits preliminary forecasts for all LSEs for the month of the annual peak (currently September) to CAISO by July 1. The load share ratios of the preliminary coincident forecasts are used to allocate local capacity requirements.

In August, CPUC LSEs may update their year-ahead forecast only for load migration. The CEC applies the same adjustment and pro-rata methodology to determine their final year-ahead forecasts. The CEC may also receive updated forecasts from POUs. The final coincident peak forecasts for all LSEs are transmitted to the CAISO in October to validate year-ahead RA compliance obligation showings. Throughout the year, LSEs may also update month-ahead forecasts. Both coincident and non-coincident forecasts are transmitted to the CAISO each month. Non-coincident forecasts are the basis for allocations of congestion revenue rights. Table 2.1 summarizes this process.

Table 2.1: RA 2020 LSE Forecast Timeline

January 2019	Adopted 2018 IEPR Update TAC Area Monthly peak demand forecast
February – May	All LSEs submit preliminary forecasts of 2021 monthly peak demand and 2018 hourly loads. CEC develops jurisdictional split.
July 2019	Preliminary forecasts to LSEs; September load ratio shares to CAISO for local capacity allocation
August 2019	CPUC LSEs submit revised forecasts, updated only for load migration.
September 2019	CEC issues adjusted CPUC LSE forecasts, which must sum to within 1% of reference forecast.
	POUs may update non-coincident peak forecasts
October 2019	Year-ahead showing to CAISO
November 2019 - November 2020	LSEs may submit revised non-coincident peak forecasts to CEC before the month-ahead showing.

2.3 CPUC's Role in Allocating RA Obligations to Jurisdictional LSEs

Under state and federal rules, the CPUC is empowered to set the RA requirements for its jurisdictional LSEs, which include the IOUs, CCAs, and ESPs. Collectively, these jurisdictional entities represent 90% of the load within the CAISO service territory.

Monthly and annual system RA requirements are derived from load forecasts that LSEs submit to the CPUC and CEC annually. Following the annual forecast submission, the CEC makes a series of adjustments to the LSE load forecasts to ensure that individual forecasts are reasonable, and aggregated to within one percent of the CEC forecast. These adjusted forecasts are the basis for year-ahead RA compliance obligations. Throughout the compliance year, LSEs must also submit monthly load forecasts to the CEC that account for load migration. These monthly forecasts are used to calculate monthly RA requirements.

In October of each year, CPUC jurisdictional LSEs must submit filings to the CPUC's Energy Division demonstrating that they have procured 90% of their system RA obligations for the five summer months (May – September) of the following year. Following this year-ahead showing, the RA program requires that LSEs demonstrate procurement of 100% of their system RA requirements on a month-ahead basis. To determine each resource's capacity eligible to be counted towards meeting the CPUC's RA requirement, the CPUC develops Qualifying Capacity (QC) values based on

what the resource can produce during periods of peak electricity demand. The CPUC-adopted QC counting conventions vary by resource type:

- The QC value of dispatchable resources, such as natural gas and hydroelectric (hydro) generators, are based on the generator's maximum output when operating at full capacity—known as its Pmax.
- Resources that must run based on external operating constraints, such as geothermal resources, receive QC values based on historical production.
- Combined heat and power (CHP) and biomass resources that can bid into the day-ahead market, but are not fully dispatchable, receive QC values based on historical MW amount bid or self-scheduled into the day-ahead market.
- Wind and solar QC values are based on a statistical model looking at the contribution of these resources to addressing loss of load events. This methodology is known as the effective load carrying capability (ELCC). This modeling has reduced the amount of qualifying capacity these resources receive by approximately 80% (that is, a solar or wind resource that can produce 100 MW at its maximum output level is assumed to produce only about 20 MW for the purpose of meeting the CPUC's RA program).[8]
- Demand Response QC values are set based on historical performance.

The resultant QC value does not take into account potential transmission system constraints that could limit the amount of generation that is deliverable to the grid to serve load. Consequently, the CAISO conducts a deliverability test to determine the Net Qualifying Capacity (NQC) value, which may be less than the QC value determined by the CPUC. RA resources must pass the deliverability test as the NQC value is what is ultimately used to determine RA capacity.

2.3.1 Timeline for RA Process, Obligations, and Penalties

System RA is based on a one-year cycle where procurement is set for one year forward.[9] In the year ahead (Y-1), the CEC adjusts each LSE's 1-in-2 demand forecast according to the process described above. The LSE's RA obligation is their forecast plus the PRM established by the CPUC or applicable LRA. Each CPUC jurisdictional LSE must then file an RA resource plan with the CPUC on October 31 of each year that shows the

[8] CPUC, D.19-06-026, Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program, June 27, 2019, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K463/309463502.PDF

[9] Local RA has a three year forward requirement.

LSE has at least 90% of its RA obligations under contract for the five summer months of the following year. If a jurisdictional LSE submits an RA plan with the CPUC that does not meet its full obligations, the LSE can be fined by the CPUC.

The CEC staff uploads into the CAISO RA capacity validation system all of the approved load forecasts for each CPUC-jurisdictional and non-jurisdictional LSE for each month of the year-ahead obligation. Credits to an LSE's obligation permitted by the LRA, may result in a lower amount of total RA shown by the LSE scheduling coordinator to the CAISO. Credits generally represent demand response programs and other programs that have the impact of reducing load at peak times. These credits are not included in the forecasts transmitted by the CEC. The composition of credited amounts are generally not visible to the CAISO and resources that are accounted for in the credits do not submit bids consistent with a must offer obligation and are not subject to availability penalties or incentives, or substitution requirements as described below.[10] Lastly, the CAISO will allocate the capacity of reliability must-run (RMR) backstop resources to offset LSE obligations, also described below.

Finally, RA submissions are provided to the CAISO as required for both CPUC and non-CPUC jurisdictional LSEs via a designated scheduling coordinator. To participate in the CAISO market, an entity (whether representing an LSE, generation supplier, or other) must be a certified scheduling coordinator or retain the services of a certified scheduling coordinator to act on their behalf.[11] For the year-ahead RA obligation, scheduling coordinators for suppliers of RA capacity are required to submit a matching supply plan to the CAISO. The CAISO then combines the supply plans to determine if there are sufficient resources under contract to meet the planning requirements.

All LSEs must also submit month-ahead RA plans 45 days prior to the start of each month showing that they have 100% of their system RA requirement under contract. The CPUC once again verifies the month-ahead supply plans and can fine LSEs that do not comply with its RA requirements. The CAISO also receives supply plans in the month-ahead timeframe from the designated scheduling coordinators similar to the year-ahead timeframe.

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[10] Because of this ambiguity, the CAISO has taken action recently to stop the practice of crediting and to require all RA resources to be explicitly shown on the RA supply plans. *See* Business Practice Manual Proposed Revision Request 1280: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1280&IsDlg=0

[11] Scheduling coordinators can directly bid or self-schedule resources as well as handle the settlements process. *See* http://www.caiso.com/participate/Pages/BecomeSchedulingCoordinator/Default.aspx

Under CAISO rules, if there are not sufficient resources on the supply plans, the CAISO can procure additional backstop capacity on its own to meet the planning requirements. To address supply plan deficiencies, the CAISO can procure additional resources through its Capacity Procurement Mechanism (CPM). The CAISO procures CPM capacity through a competitive solicitation process. The CPM allows the CAISO to procure backstop capacity if load serving entities are deficient in meeting their RA requirements or when RA capacity cannot meet an unforeseen, immediate, or impending reliability need.

In addition, the CAISO can procure backstop capacity through its Reliability Must Run (RMR) mechanism. The RMR mechanism authorizes the CAISO to procure retiring or mothballing generating units needed to ensure compliance with applicable reliability criteria. Once so designated, participation as an RMR unit is mandatory.

2.4 CAISO's Role in Ensuring RA Capacity is Operational

Resources providing system RA capacity generally have a "must-offer" obligation, which means they must submit either an economic bid or self-schedule to the CAISO day-ahead market for every hour of the day.[12] The CAISO tariff provides limited exceptions to this 24x7 obligation for resources that are registered with the CAISO as "Use-Limited Resources," "Conditionally Available Resources," and "Run-of-River Resources." Additionally, wind and solar resources providing RA capacity must bid consistent with their forecast because their variable nature would not reflect full availability 24x7.

Resources providing RA capacity whose registered start-up times allow them to be started within the real-time market time horizon, referred to in the CAISO tariff as "Short Start Units" and "Medium Start Units," have a must-offer obligation to the real-time market irrespective of their day-ahead market award. Resources with longer registered start times, referred to in the CAISO tariff as "Long Start Units" and "Extremely Long-Start Resources," have no real-time market bidding obligation if they did not receive a day-ahead market award for a given trading hour. This is because if they are not already online, the lead time for a dispatch from the real-time market is too short for these resources to respond.

The CAISO has two main mechanisms to ensure that resources providing RA capacity meet their must-offer obligation. First, the CAISO submits cost-based bids on behalf of resources providing generic RA capacity that do not meet their RA must-offer obligation. The generated bid helps ensure the CAISO market has access to energy from an RA resource even when that RA resource fails to bid as required. Second,

[12] Additional CAISO market rules exist for flexible RA capacity.

through the RA Availability Incentive Mechanism (RAAIM), the CAISO assesses non-availability charges and provides availability incentive payments to both generic and flexible RA resources based on whether their performance falls below or above, respectively, defined performance thresholds. The CAISO tariff exempts certain resource types from bid generation and RAAIM. The exemptions from bid generation, RAAIM, and the 24x7 generic RA must-offer obligation are not necessarily paired; a resource type can be exempt from one but still face the other two. Lastly, credited amounts do not have any RA market obligations because the underlying resources are not always visible to the CAISO and were not provided explicitly on the RA supply plans. Credited resources are accounted for as non-RA throughout this analysis.

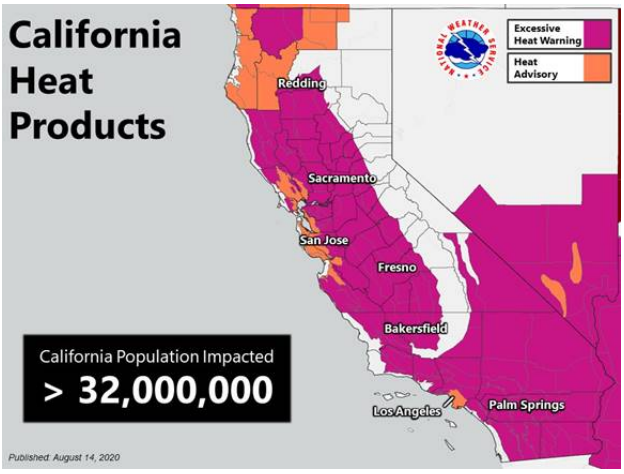
Pursuant to section 34.11 of its tariff, the CAISO may issue exceptional dispatches (*i.e.*, manual dispatches by CAISO operators outside of the CAISO's automated dispatch process) to resources to address reliability issues. The CAISO may issue a manual exceptional dispatch for resources in addition to or instead of resources with a day-ahead schedule during a System Emergency or to prevent a situation that threatens System Reliability and cannot otherwise be addressed.

3 Mid-August Event Overview

3.1 Weather and Demand Conditions During Mid-August

During August 14 through 19, California experienced state-wide extreme heat with temperatures 10-20 degrees above normal. As Figure 3.1 below shows, this impacted 32 million California residents.

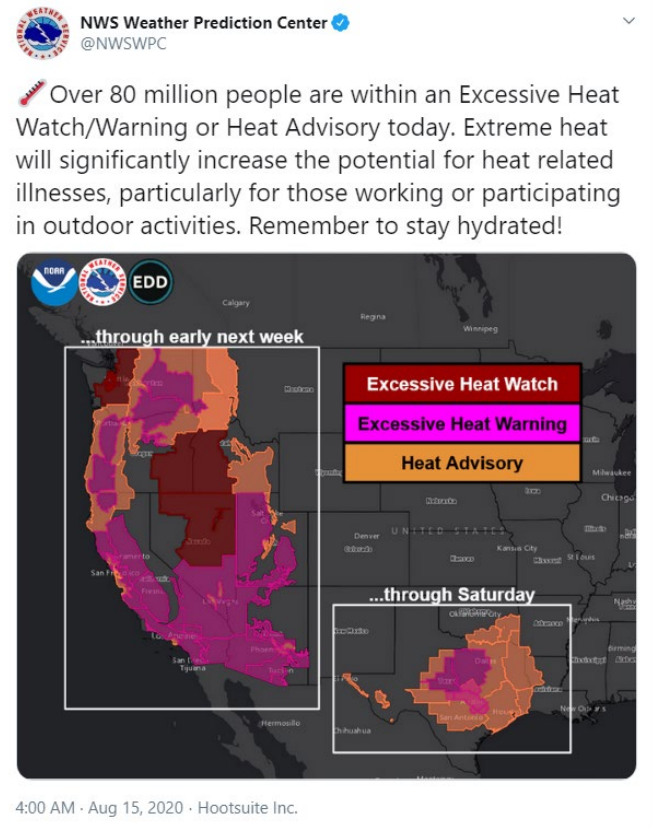
Figure 3.1: National Weather Service Sacramento Graphic for August 14



Source: https://twitter.com/NWSSacramento

In total, 80 million people fell within an excess heat watch or warning as shown in Figure 3.2 below from the National Weather Service (NWS).

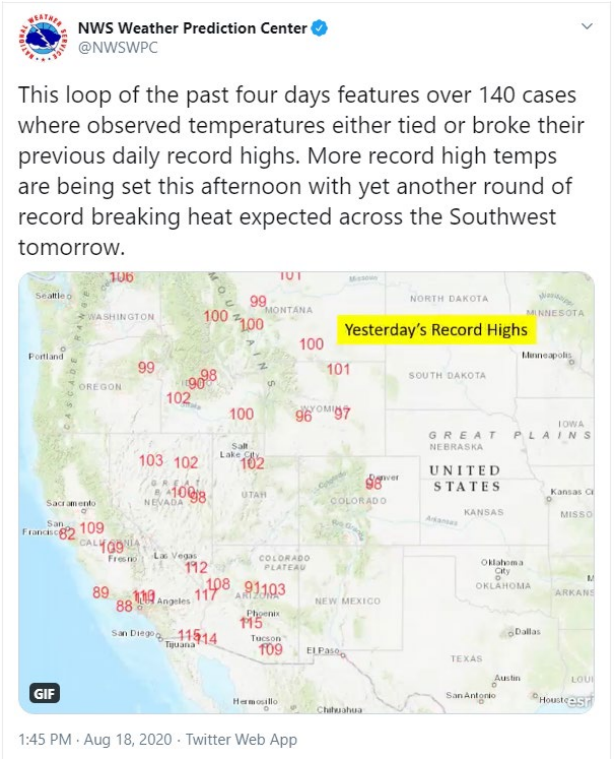
Figure 3.2: National Weather Service Weather Prediction Center Graphic for August 15



Source: https://twitter.com/NWSWPC/status/1294589703254167557

The rest of the West also experienced record or near-record highs with forecasts ranging between five and 20 degrees above normal, with the warmest temperatures in the Southwest (Las Vegas and Phoenix) as well as the Coastal Pacific Northwest (Portland and Seattle). Figure 3.3 below documents the continuing heat storm on August 18 into August 19.

Figure 3.3: National Weather Service Weather Prediction Center Graphic for August 18



Source: https://twitter.com/NWSWPC/status/1295824180638670848

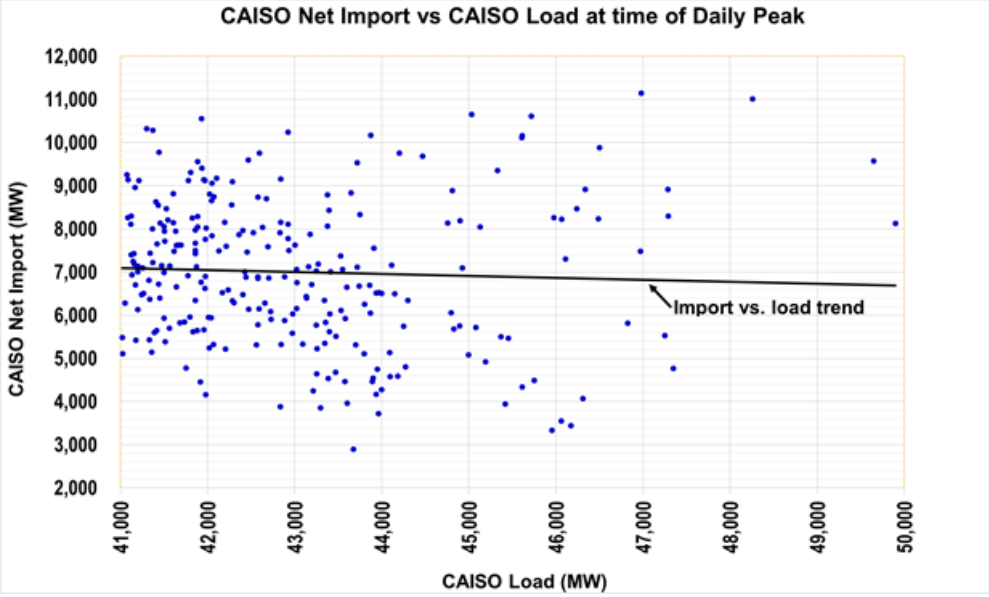
This rare West-wide heat storm affected both demand for and supply of generation. Typically, high day-time temperatures are offset by cool and dry evening conditions. However, the multi-day heat storm meant that there was limited overnight cooling, so air conditioners continued to run well into the evening and the next day. The CAISO also conducted a backcast analysis isolating the impacts of shelter-in-place and work from home conditions due to COVID-19.[13] The backcast analysis found that while load was lower in the spring months, during the month of July, as air conditioning use increased, the CAISO observed minimal to no load reductions compared to pre-COVID-19 conditions.

In terms of supply, the heat storm negatively impacted conventional generation such as thermal resources, which typically operate less efficiently during temperature extremes. Even for solar generation, high clouds reduced large-scale grid-connected solar and behind-the-meter solar generation on some days, leading to increased variability. Lastly, California hydro conditions for summer 2020 were below normal. The statewide snow water content for the California mountain regions peaked at 63% of average on April 7, 2020.

[13] See CAISO analysis: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf#search=covid

The CAISO footprint is traditionally a net importer of electricity on peak demand days, meaning that while trade of electricity occurs with the rest of the West, on net, the CAISO imports more than it exports. During the heat storm, given the similarly extreme conditions in some parts of the West, the usual flow of net imports into the CAISO was drastically reduced. Figure 3.4 below shows the historical trend of net imports into the CAISO footprint from 2017 through 2019 at the daily peak hour when demand is at or above 41,000 MW.[14] On average the import trend is about 6,000 MW to 7,000 MW of net imports, but this can vary widely and generally decreases as the CAISO load increases.

Figure 3.4: 2017 -2019 Summer Net Imports at Time of Daily Peaks Above 41,000 MW



3.2 CAISO Reliability Requirements and Communications During mid-August Event

This section provides an overview of relevant CAISO reliability requirements and related operations-based communications, as well as more general communications channels, used during the mid-August event.

The CAISO operates the wholesale electricity markets and is the Balancing Authority (BA) for 80% of California and a small portion of Nevada (CAISO Controlled Grid). The CAISO operates to standards set by the North American Electric Reliability

[14] 41,000 MW is 90 percent of the forecast of the CAISO 2020 1-in-2 peak demand of 45,907 MW.

Corporation[15] (NERC) and the Western Electricity Coordinating Council[16] (WECC) regional variations as approved by the Federal Energy Regulatory Commission (FERC). Violations of WECC and NERC standards can result in FERC fines of up to $1 million per day.[17]

Specifically, pursuant to standard BAL-002-3[18] (NERC requirement) and BAL-002-WECC-2a[19] (WECC regional variance), the CAISO as the BA is required to have contingency reserves.[20] Contingency reserves are designated resources that can be deployed to address unplanned and unexpected events on the system such as a loss of significant generation, sudden unplanned outage of a transmission facility, sudden loss of an import and other grid reliability balancing needs.[21] Contingency reserves are maintained to ensure the grid can respond quickly in case the CAISO loses a major element on the grid such as the Diablo Canyon Power Plant (Diablo Canyon) or the Pacific DC Intertie (PDCI) transmission line. The NERC and WECC standards specifically require the grid operators to identify the most severe single contingency that could potentially destabilize the Balancing Authority Area (BAA) and cause cascading outages throughout the Western interconnected grid if that resource is lost. For the CAISO this tends to be either Diablo Canyon or the PDCI.

Generally, the CAISO is required to carry reserves equal to 6% of the load, consistent with WECC contingency requirements that operating reserves be equal to the greater of: (1) the most severe single contingency, or (2) the sum of three percent of hourly integrated load plus three percent of hourly integrated generation.[22] Under normal conditions, the CAISO uses two types of generating resources to meet this requirement: spinning and non-spinning reserves. Spinning reserves are generating resources that are running (*i.e.*, "spinning") and can quickly and automatically provide energy in case of a contingency. Non-spinning reserves are resources, which may include demand response, that are available to respond within 10 minutes but are not running pre-contingency. Under extraordinary conditions, it is possible for the CAISO to designate

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[15] https://www.nerc.com

[16] https://www.wecc.org

[17] *See* https://www.ferc.gov/enforcement-legal/enforcement/civil-penalties

[18] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf

[19] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-002-WECC-2a&title=Contingency%20Reserve&jurisdiction=United%20States

[20] Also referred to as operating reserves or ancillary services. This discussion does not include regulation up and down services.

[21] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

[22] *See* https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-002-WECC-2a&title=Contingency%20Reserve&jurisdiction=United%20States

load that is not specifically designated as demand response resources and that can be curtailed within 10 minutes as non-spinning reserves, if the resources normally used are not available. Although the CAISO can utilize load curtailment to meet its reserve requirements, it can only do so for non-spinning reserves. Continuing to operate while lacking sufficient spinning reserves runs the risk that if an actual contingency were to occur, such as the loss of Diablo Canyon or PDCI, the CAISO BAA would lack the automatic response capability needed to stabilize the grid, leading to uncontrolled load shed that could potentially destabilize the greater Western grid.

The CAISO's operational actions are largely communicated through Restricted Maintenance Operations (RMO), and Alerts, Warnings, and Emergencies (AWE) per Operating Procedure 4420.[23] Each is explained briefly below:

- **Restricted Maintenance Operations** request generators and transmission operators to postpone any planned outages for routine equipment maintenance and avoid actions which may jeopardize generator and/or transmission availability, thereby ensuring all grid assets are available for use.
- **Alert** is issued by 3 p.m. the day before anticipated contingency reserve deficiencies. The CAISO may require additional resources to avoid an emergency the following day.
- **Warning** indicates that grid operators anticipate using contingency reserves. Activates demand response programs (voluntary load reduction) to decrease overall demand.
- **Stage 1 Emergency** is declared by the CAISO when contingency reserve shortfalls exist or are forecast to occur. Strong need for conservation.
- **Stage 2 Emergency** is declared by the CAISO when all mitigating actions have been taken and the CAISO is no longer able to provide for its expected energy requirements. Requires CAISO intervention in the market, such as ordering power plants online.
- **Stage 3 Emergency** is declared by the CAISO when unable to meet minimum contingency reserve requirements, and load interruption is imminent or in progress. Notice issued to utilities of potential electricity interruptions through firm load shedding.

In addition to these operational communication tools, the CAISO relies on Flex Alerts to broadly communicate with consumers to appeal for voluntarily energy conservation

[23] https://www.caiso.com/Documents/4420.pdf

when demand for power could outstrip supply. Starting in 2016, the administration of the Flex Alert program was entirely transferred from the IOUs to the CAISO without a paid media component.[24] However, between 2016 and 2019, the CPUC allocated up to $5 million per year to support paid Flex Alert advertising, as funded and administered by the Southern California Gas Company, due to the Aliso Canyon natural gas leak.[25] The funded Flex Alert advertising focused on customers in the Los Angeles area and eventually shifted to a focus on winter electricity conservation to reduce gas usage.[26] In February 2020 a new CPUC proceeding was opened to discuss Flex Alert funding in the Los Angeles area.[27]

During the mid-August event, the Flex Alert program was administered by the CAISO and is comprised of a website (www.flexalert.org), a Twitter account (https://twitter.com/flexalert, 8,000 followers), and placement of the Flex Alert logo and activation websites such as the home page of caiso.com. Additional communication of the Flex Alert status was sent by the CAISO on the CAISO's Twitter account (https://twitter.com/California_ISO, 28,000 followers), market notices, and via the alert function of the CAISO's app. The CAISO's webpage, Twitter account, and app were also used to communicate RMO and AWE notifications. All Flex Alerts, RMO, and AWE notifications called by the CAISO since 1998 are posted online.[28]

The CAISO also communicated with the load serving entities in the CAISO footprint, representatives of the market participants (*i.e.*, wholesale buyers and sellers of electricity), and with the BAs throughout the West on operational matters.

In addition, the CAISO actively used public facing communications tools such as Twitter (both Flex Alert and CAISO accounts), caiso.com website updates, notifications pushed through the CAISO app, market notices, and targeted outreach to the energy sector leadership in the state of California. More broadly, the CAISO provided media updates and interviews as early as August 13 and held a public Board of Governors meeting on August 17 with associated media calls.[29] The CAISO also added a section on its News page dedicated to the 2020 heat storm events.[30]

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[24] CPUC Decision 15-11-033, November 19, 2015.
[25] CPUC Decision 16-04-039, April 21, 2016.
[26] CPUC Decision 18-07-008, July 12, 2018.
[27] Scoping Memo was released for Application 19-11-018, Application of Southern California Gas Company for adoption of its 2020 Flex Alert Marketing Campaign, February 27, 2020.
[28] http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf
[29] *See* http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=E847D21D-54A0-4B54-9517-48B4EEA6DCED
[30] http://www.caiso.com/about/Pages/News/default.aspx#heatwave

3.3 Sequence of Events of CAISO Actions

This section provides an overview of events and CAISO actions taken to operate through and communicate the conditions during the days preceding and following the August 14 and 15 events.

3.3.1 Prior to August 14

Wednesday, August 12
Prior to August 14, the CAISO began to anticipate higher load and temperatures than average in California and across the West. On August 12, the CAISO issued its first RMO for August 14 through 17 in anticipation of high loads and temperatures. The RMO cautioned market participants and transmission operators to avoid actions that may jeopardize generator and/or transmission availability.

Thursday, August 13
The CAISO issued a Flex Alert for August 14 calling for voluntary conservation from 3:00 pm to 10:00 pm. The CAISO communicated the Flex Alert on Twitter (both Flex Alert and CAISO accounts), caiso.com website updates, notifications pushed through the CAISO app, market notices, and news releases. More broadly, the CAISO provided direct media updates to outlets such as: KCBS, KNX 1070 Los Angeles, KPIX/KBCW – TV San Francisco, KGO TV, KTVU Fox2, and KFSN-TV Fresno.

By 3:00 pm, the CAISO issued a grid-wide Alert effective August 14 5:00 pm through 9:00 pm, forecasting possible system reserve deficiency for those hours, requesting additional ancillary services and energy bids from market participants, and encouraging conservation efforts. In addition to broader coordination, the CAISO provided customized outreach to PG&E, SCE, and San Diego Gas and Electric (SDGE) and asked them to review the system outlook for August 14 through 17.

3.3.2 August 14

Friday's events
The CAISO began the day coordinating with the various affected entities to discuss the day's outlook, availability and activation of emergency demand response, and the possible need for emergency measures up to and including shedding load, due to the high load forecast and resource deficiencies.

At 11:51 am the CAISO re-issued a Warning notice effective August 14 5:00 pm through 9:00 pm, still forecasting possible reserve deficiencies for those times and requesting additional ancillary services and energy bids. The CAISO reached out to PG&E, SCE, and SDGE advising them that the CAISO anticipated the need to call on emergency

demand response (Reliability Demand Response Resources (RDRR)) later that day. The CAISO operators contacted other BAs for potential emergency assistance.

At 2:57 pm the Blythe Energy Center in Riverside County, a unit with full capacity of 494 MW, recorded a forced outage due to plant trouble. At the time it went out of service, it was generating 475 MW. The CAISO deployed its contingency reserves to replace the lost energy. As explained above, contingency reserves as required by the NERC and WECC are designed to protect against a sudden loss of generation, sudden unplanned outage of a transmission facility, or sudden loss of an import due to the loss of transmission.

Throughout this time, the CAISO operators continuously canvased for additional unloaded capacity and for potential emergency assistance from other BAs. CAISO operators requested neighboring BAs to increase the available transmission capacity to allow for increased import capability into the CAISO BAA. As a result, the capacity on CAISO's share of the California Oregon Intertie (COI) was increased between 6:00 pm to 11:59 pm by 189 MW.

At 3:20 pm the CAISO enabled the RDRR in the real-time market. Unlike other resources in the resource adequacy program or in the market, RDRR can only be accessed by the CAISO after, at minimum, a Warning notice is issued. The programs that comprise the RDRR can only be called a limited number of times and for specific maximum durations. Accordingly, the CAISO must position these resources to be used when the need is greatest.[31] By enabling this pool of demand response, the RDRR was positioned to respond.

At 3:25 pm, the CAISO declared a Stage 2 Emergency for the CAISO BAA from 3:20 pm to 11:59 pm.[32]

Throughout this time, consistent with WECC standards, the CAISO was having difficulty maintaining the 6% WECC reserve requirement with generating resources and began to rely on meeting part of its requirement with firm load available to be shed within 10 minutes, counting it as non-spinning contingency reserves. The CAISO worked directly

[31] For example, some programs are limited to one call per day, 10 calls per month, and a maximum of a six hour duration per call. Therefore, if the RDRR is called too early in the day, it may exhaust its response before the greatest need on the grid.

[32] The CAISO does not need to declare a Stage 1 before declaring either a Stage 2 or Stage 3 Emergency. Warning and Stage emergency declarations are based on operating conditions, which can change rapidly.

with PG&E, SCE, and SDGE to designate approximately 500 MW as non-spinning contingency reserves based on a pro rata share.

By 5:00 pm, conditions had not improved and the CAISO manually dispatched approximately 800 MW of RDRR. Per RDRR program requirements, the full response is required to be realized within 40 minutes following the dispatch, which is a request to respond.[33]

By approximately 6:30 pm, all demand response had been dispatched. The conditions still had not improved. Though the system peak load occurred at 4:56 pm, throughout this time demand remained high while solar generation was rapidly declining. The CAISO reached out to PG&E, SCE, and SDGE to secure an additional 500 MW of load to be counted toward non-spinning contingency reserves (for a total of 1,000 MW).

At 6:38 pm, the CAISO declared a Stage 3 Emergency because it was deficient in meeting its reserve requirement. The CAISO was not able to cure the deficiency with generation, because all generation was already online, and solar was rapidly declining while demand remained high. Because the CAISO was no longer able to maintain sufficient spinning reserves to address the loss of significant generation or transmission, the load shed was necessary to allow the CAISO to recover and maintain its reserves. If the CAISO continued to operate with the deficiency in spinning reserves, the CAISO risked causing uncontrolled load shed and destabilizing the rest of the Western grid if during this time it lost significant generation or transmission. Consequently, the CAISO ordered two phases of controlled load shed of 500 MW each, based on a pro-rata share across the CAISO footprint for distribution utility companies.

By 7:40 pm, the CAISO began restoring previously shed load as system conditions had improved so that resources were adequate to meet the CAISO load and contingency reserve obligations.

At 8:38 pm, the CAISO downgraded from a Stage 3 to Stage 2, and Stage 2 was cancelled at 9:00 pm. The Warning expired at 11:59 pm.

Other Circumstances and Actions Taken

Throughout most of the day numerous fires threatened the loss of major transmission lines. For example, the Lake Fire was threatening the PDCI and Path 26, the Poodle Fire was also burning close to PDCI, and the Grove Fire was also threatening transmission lines.

[33] At the time of the publication of this Preliminary Analysis, the CAISO has not received the actual response data based on settlement quality meter information.

Under CAISO Operating Procedure 4420, a declaration of a Stage 2 Emergency allows the CAISO to request emergency assistance from other BA.

In preparation for the next day, the CAISO issued an Alert notice at 2:24 pm because of possible reserve deficiencies due to resource shortages between 5:00 pm and 9:00 pm on August 15.

3.3.3 August 15

Saturday's Events
The CAISO began the day coordinating with the various affected entities to discuss the day's outlook as California and the Western region continued to experience extreme heat with high loads, availability and activation of their emergency demand response, and the possible need for emergency measures up to and including shedding load due to the high load forecast and resource deficiencies.

At 12:26 pm the CAISO issued a Warning notice effective 12:00 pm through 11:59 pm confirming the Alert notice issued the day before because conditions had not improved, and the forecasted load was trending higher. The CAISO noted possible reserve deficiencies due to resource shortages between 5:00 pm and 9:00 pm, requested additional ancillary services and energy bids, and requested voluntary conservation efforts.

Between 2:00 pm and 3:00 pm, solar declined by over 1,900 MW caused by storm clouds while loads were still increasing and contingency reserves were down to minimal WECC requirements. *See* Figure 3.5 below. At approximately 3:00 pm the CAISO manually dispatched 891 MW of RDRR in the real-time market. Note that this is different from the events of August 14, where RDRR was first accessed and then dispatched at a later time. Here, the rapidly evolving situation led the CAISO to immediately dispatch the RDRR. Per RDRR program requirements, the full load drop response is expected to be realized within 40 minutes after dispatch.

Between 3:00 pm and 5:00 pm CAISO operators continuously canvased for additional unloaded capacity and for potential emergency assistance from other BAs. CAISO operators requested neighboring BAs to increase the available transmission capacity to allow for increased import capability into the CAISO BAA. As a result, the California Oregon Intertie capacity was increased from 3:00 pm to 10:00 pm.

Between 5:12 pm and 6:12 pm, wind generation declined by 1,200 MW (*see* Figure 3.5 below). Like on August 14, the CAISO requested PG&E, SCE, and SDGE to designate

approximately 500 MW of 10-minute responsive load as non-spinning contingency reserve.

At 6:13 pm, the Panoche Energy Center in Fresno County unexpectedly ramped down its generation from about 394 MW to about 146 MW, resulting in a loss of about 248 MW. This was not an outage, but a ramp down from the CAISO dispatch, which the CAISO now understands to be due to an erroneous dispatch from the scheduling coordinator to the plant.

At 6:16 pm, the CAISO declared a Stage 2 Emergency because like the day before, consistent with WECC standards, the CAISO was having difficulty maintaining the 6% WECC reserve requirement with generating resources and began to rely on meeting part of its requirement with firm load available to be shed within 10 minutes, counting it as non-spinning contingency reserves.

Like on August 14, the CAISO requested additional load from PG&E, SCE, and SDGE to designate as non-spinning contingency reserve for a total of approximately 1,000 MW.

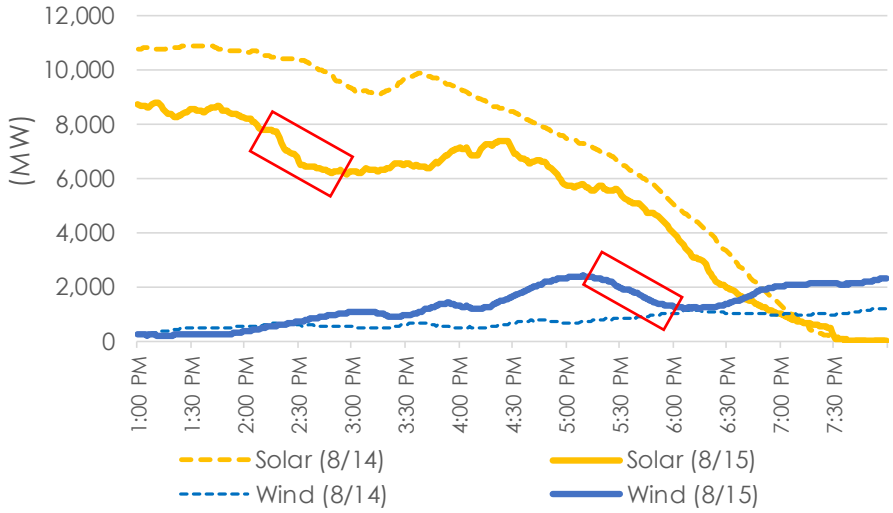
At 6:28 pm, the CAISO declared a Stage 3 Emergency because it was deficient in meeting its reserves requirement. The CAISO was not able to cure the deficiency with generation, because all generation was already online, and solar was rapidly declining while demand remained high. Because the CAISO was no longer able to maintain sufficient spinning reserves to address the loss of significant generation or transmission, the load shed was necessary to allow the CAISO to recover and maintain its reserves. If the CAISO continued to operate with the deficiency in spinning reserves the CAISO risked causing uncontrolled load shed and destabilizing the rest of the Western grid if during this time it lost significant generation or transmission. Consequently, the CAISO ordered approximately 500 MW of controlled load shed.

At 6:48 pm, the Stage 3 Emergency was cancelled because wind production had increased over 500 MW and the CAISO ordered all previously shed load to be restored. The duration of the controlled load shed was 20 minutes. The CAISO eventually downgraded to a Stage 2, and Stage 2 was cancelled at 8:00 pm. The Warning expired at 11:59 pm.

Other Circumstances and Actions Taken

Between 1:00 pm until 8:00 pm, there was more solar generation on August 14 than August 15, and production was more consistent as shown in Figure 3.5 below. On the other hand, wind generation was lower on August 14 but steadily increasing.

Figure 3.5: Wind and Solar Generation Profiles for August 14 and 15



Throughout most of the day, transmission lines were impacted because of thunderstorms across the PG&E service territory.

Under Operating Procedure 4420, declaration of a Stage 2 Emergency allows the CAISO to request emergency assistance from other BAs.

In preparation for the next day, the CAISO issued an Alert notice at 2:55 pm because of possible reserve deficiencies between 5:00 pm and 9:00 pm on August 16.

3.3.4 August 16 through 19

From August 16 through 19, excessive heat was forecasted consistently for California. Consequently, the CAISO issued RMO and Alert notices from August 16 through 19, as well as a Flex Alert for the same days from 3:00 pm to 10:00 pm. Warning notices were called and RDRR was dispatched from August 16 through 18. During this period various portions of the Western region began to cool off, which meant that imports increased on those days. As a result, the most critical days were concentrated on Monday, August 17 and Tuesday, August 18 and the CAISO declared Stage 2 Emergencies for both days. However, controlled load shed and thus rotating outages were avoided.

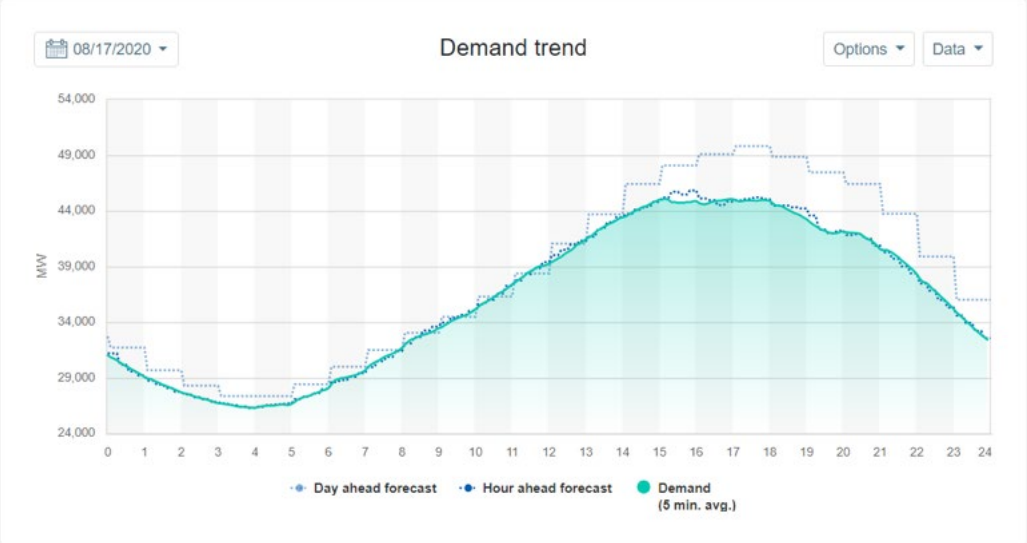
On August 16, Governor Newsom declared a State of Emergency[34] due to the significant heat storm in California and surrounding Western states. The proclamation

[34] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.16.20-Extreme-Heat-Event-proclamation-text.pdf

gave the California Air Resources Board maximum discretion to permit the use of stationary and portable generators, as well as auxiliary ship engines, to reduce load and increase generation through August 20. On August 17, Governor Newsom issued Executive Order N-74-20[35], which suspended restrictions on the amount of power facilities could generate, the amount of fuel they could use, and air quality requirements that prevented facilities from generating additional power during peak demand periods through August 20.

As a result of the conservation messaging and awareness created by the State of Emergency, the state was successful in significantly reducing peak demand by as much as 4,000 MW (compared to day-ahead forecasts) on August 17 through 19, as shown in Figure 3.6 through Figure 3.8 below.

Figure 3.6: Comparison of Day-Ahead Forecast and Actual Demand for August 17



[35] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-EO-N-74-20.pdf

Figure 3.7: Comparison of Day-Ahead Forecast and Actual Demand for August 18

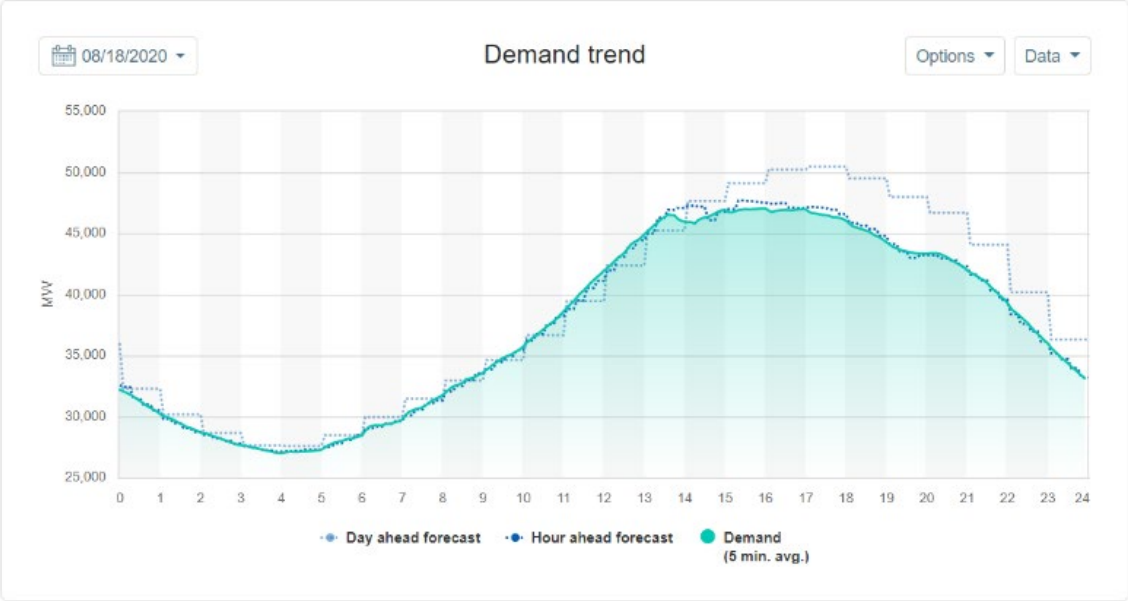
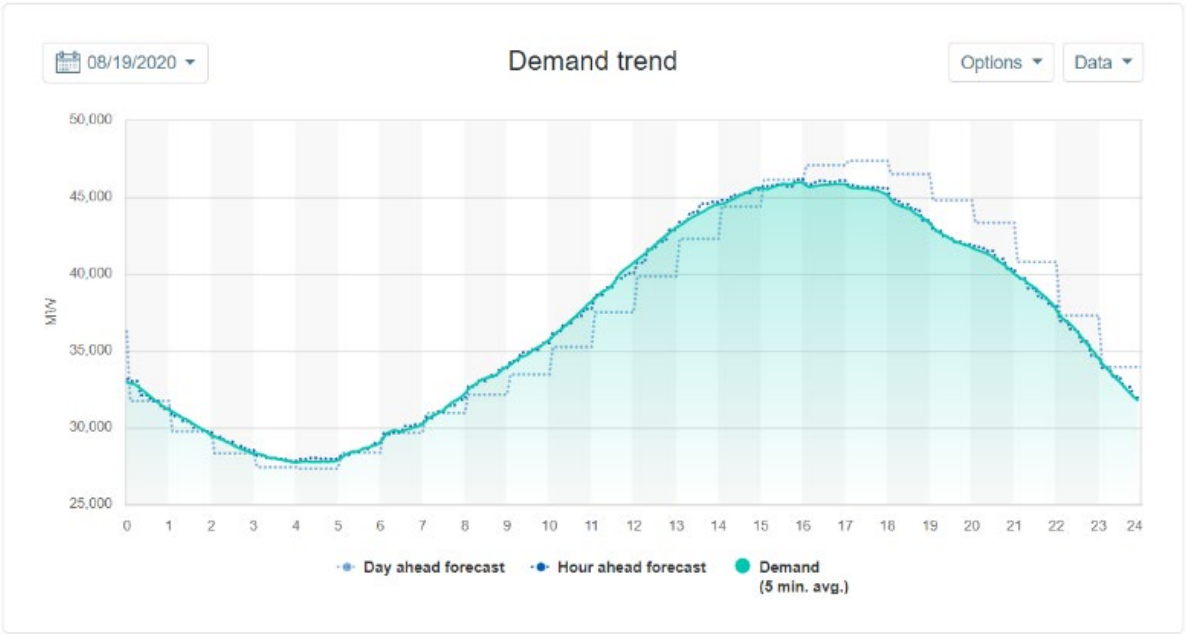


Figure 3.8: Comparison of Day-Ahead Forecast and Actual Demand for August 19



On August 17 the CAISO Board of Governors convened for a special session to provide an overview of system operations on August 14 and 15, followed by a question and

answer session from the public and CAISO responses to submitted comments.[36] Subsequently on August 21 and 27 the CAISO held two special sessions open to the public to address market-related questions.[37] Responses to questions were later posted online.[38]

See Section 5 for a discussion on capacity procurement mechanism procurement.

3.4 Number of Customers Impacted by Rotating Outages

As noted earlier, CAISO called two successive 500 MW blocks of controlled load shed on August 14 for a total of one hour and one 500 MW block of controlled load shed on August 15 for 20 minutes. The controlled load shed requests were implemented as rolling outages for customers. On August 14, the load shed requests went out to all LSEs in the BAA (both CPUC and non-CPUC jurisdictional), and on August 15 the requests only went out to CPUC-jurisdictional LSEs, as the event was over before the request was submitted to other entities in the CAISO footprint. Table 3.1 and Table 3.2 below depict the number of CPUC-jurisdictional customers impacted by the rotating outages, how much was shed, and for what duration in total and for each IOU. Neither the agencies, nor the CAISO, have visibility into the number of customers, amount of load shed, or duration for non-CPUC jurisdictional entities. Non-CPUC jurisdictional entities that were contacted prior to the issuance of this report that they did not shed load on either day.

Note that the duration of rotating outages experienced by PG&E customers on both days significantly exceeds the load shed duration called by the CAISO. Because PG&E received less than 10 minutes' warning to begin shedding load, it implemented its operating instructions protocol (covered in NERC standard COM-002-4) rather than its rotating outage protocol, for which more than 10 minutes' advance warning is required. PG&E's operating instructions protocol required the implementation of manual switching using field personnel, resulting in longer duration outages due to the need for manual restoration.

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[36] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=E847D21D-54A0-4B54-9517-48B4EEA6DCED

[37] http://www.caiso.com/Documents/SpecialSessionMarketUpdateQuestion-AnswerWebConference082120.html and http://www.caiso.com/Documents/UpdatedParticipationInformationMarketUpdateCall082720.html

[38] http://www.caiso.com/Documents/Aug14-15-StakeholderQandA.pdf

Table 3.1: Customers Affected by August 14 Rotating Outages

	Customers	MWs	Time (in mins)	Start	Finish
SCE	132,000	400	63	6:56 PM	7:59 PM
PG&E	300,600	588	~150	6:38 PM	~9:08 PM
SDGE	59,000	84	~15-60		
Total	**491,600**	**1,072**	**15 to 150 mins**		

Table 3.2: Customers Affected by August 16 Rotating Outages

	Customers	MWs	Time (in mins)	Start	Finish
SCE	70,000	200	8	6:43 PM	6:51 PM
PG&E	234,000	459	~90	6:25 PM	~7:55 PM
SDGE	17,000	39	~15-60		
Total	**321,000**	**698**	**8 to 90 mins**		

4 Preliminary Understanding of Various Factors That Contributed to Rotating Outages on August 14 and 15

This section provides the preliminary analysis of the root causes of the rotating outages that were called on August 14 and 15. A number of different factors appear to have contributed to the need for these emergency measures. Consequently, there is no single root cause identified in this report. Instead, this report identified the following challenges that all contributed to the emergency:

- The climate change-induced extreme heat storm across the western United States resulted in the demand for electricity exceeding the existing electricity resource planning targets. The existing resource planning processes are not designed to fully address an extreme heat storm like the one experienced in mid-August.
- In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.
- Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

Additional analyses and details are provided in Appendix B.

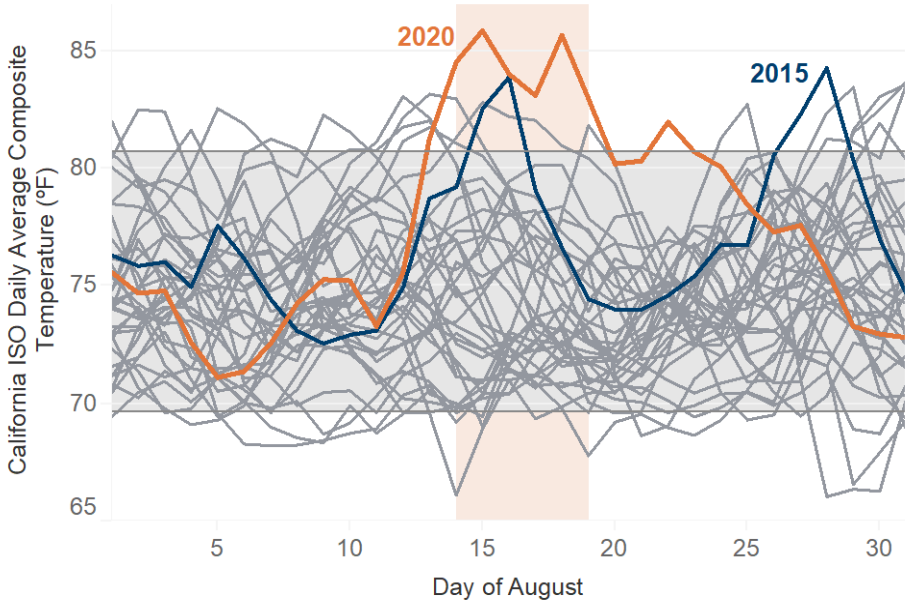
4.1 Existing Resource Planning Processes are Not Designed to Fully Address an Extreme Heat Storm

Between August 14 and August 19, 2020, the entire Western US experienced a heat storm. During this period, California experienced four out of the five hottest August days since the CAISO and the CEC began tracking this data in 1985, as measured by the daily average temperature composite used to predict electricity consumption across the California ISO region. August 14 was the third-hottest August day; August 15 was the hottest. The only other period on record with a similar heat wave was July 21–25, 2006, which included three days above the highest temperature in August 2020.

Figure 4.1 shows daily August temperatures for each year from 1985 to 2020. The middle 90% of temperatures is contained in the shaded gray region and 2020's six-day heat

storm is shaded in light orange. August 2020 (orange) is distinguished from the year with the next-hottest days, 2015 (blue), by both the magnitude and duration of the heat storm. The hottest day in 2020 was a full degree and a half higher than that of 2015 – averaged over all hours of the day and across different parts of California – and 2020's six hottest days came in succession, compared with two distinct heat waves in 2015 that each lasted just a day or two. In addition, as mentioned previously, the heat storm spanned the Wester U.S., which California typically relies on for electricity imports.

Figure 4.1: August Temperatures 1985 - 2020



(Source: CEC Weather Data/CEC Analysis)

The current resource adequacy planning standards are based on a 1-in-2 peak weather demand plus a 15% PRM to account for changing conditions. The August heat storm, which was a 1-in-35 year weather event in California and impacted the entire Western US for multiple days, combined with any energy demand impacts from COVID-19 were not anticipated in the planning and resource procurement timeframe, which is necessarily an iterative, multi-year process. The energy markets can help fill the gap between planning and real-time conditions, but the West-wide nature of this heat storm limited the energy markets' ability to do so. While this Preliminary Analysis suggests that the rotating outages on August 14 and August 15 may have been avoided if some of the root causes identified in the remainder of this section had not occurred, it is unlikely that current RA planning levels would have avoided rotating outages for the demand forecasted for August 17 through August 19 without the extraordinary measures described in Section 5.

4.2 In Transitioning to a Reliable, Clean, and Affordable Resource Mix, Resource Planning Targets Have Not Kept Pace to Lead to Sufficient Resources That Can Be Relied Upon to Meet Demand in the Early Evening Hours

As discussed in Section 2, all LSEs in the CAISO's BAA based their reliability planning on a 1-in-2 average weather forecast. The CPUC's RA program is based on a 1-in-2 average forecast plus a 15% planning reserve margin (PRM). The forecast used in the RA program is based the single forecast set developed by the CEC. The CEC sets the forecast for the CAISO footprint and works with load serving entities to set the individual coincident forecasts for RA purposes. Based on the established methodology and timelines, the August 2020 obligation was based on the August 2018 IEPR Update transmission area monthly peak demand forecast of 44,955 MW, adjusted down to 44,741 MW and entered into the CAISO system by CEC staff as 44,740 MW. Table 4.1 below shows the breakdown between CPUC jurisdictional LSEs and non-CPUC local regulatory authority (LRA) obligations and the resources and credits used to meet those obligations.

Table 4.1: August 2020 RA Obligation, Shown RA, RMR, and Credits

CPUC	Non-CPUC	**Total**	
40,570	4,169	**44,740**	CEC forecast for 1-in-2 August 2020 (adjusted)
6,086	588	**6,674**	Total 15% planning reserve margin
46,656	4,758	**51,413**	Total obligation
91%	9%	100%	
44,763	4,164	**48,926**	August 2020 system resource adequacy shown
261	29	**290**	Reliability Must Run (RMR) contracted resources
1,632	565	**2,197**	Credits provided by local regulatory authorities
46,656	4,758	**51,413**	Total resource adequacy, RMR, and credits

The CPUC jurisdictional LSEs comprise approximately 91% of the total load. Per the CPUC's RA program requirements, a 15% PRM is added to the peak of the 1-in-2 forecast for a total obligation of 46,656 MW. The non-CPUC local regulatory authorities vary slightly in their PRM requirements but collectively yield a 14% PRM for a total obligation of 4,758 MW. Approximately 500 MW or about 1% of the total load uses a PRM less than 15%. In total, across both CPUC jurisdictional and non-jurisdictional entities, the PRM is 14.9% and the obligation for August 2020 was 51,413 MW.

There are three distinct categories used to meet the total obligation. The most straightforward is the resource adequacy resources "shown" to the CAISO. This means the physical resource (either generation or demand response) is provided on a supply plan with the unique resource identification number (resource ID) to the CAISO system and noted as specifically meeting the August 2020 obligation. The second category of

resources is Reliability Must Run (RMR) allocations from the CAISO. RMR resources are contracted by the CAISO pursuant to a reliability need and the capacity from these resources are allocated to the appropriate load serving entities to offset their obligations. The last category is "credits" provided by the local regulatory authorities to the CAISO. A credit is essentially an adjustment the LRA has made to its resource adequacy obligation, which can be neutral or decrease the obligation. For example, the largest credited amount is from the CPUC at 1,482 MW which reflects the various demand response programs from the IOUs, including the emergency triggered RDRR. However, the composition of credited amounts is generally not visible to the CAISO and all credited amounts do not submit bids consistent with a must offer obligation and are not subject to CAISO resource adequacy market rules such as RAAIM or substitution.[39] Since credited resources are not shown directly on the resource adequacy supply plans, they are not considered RA supply and are reflected as non-RA capacity throughout this analysis.

4.2.1 Planning Reserve Margin Was Exceeded on August 14

As described in the background in Section 2, the 15% PRM in the RA program was finalized in 2004 to account for 6% contingency reserves needed by the grid operator with the remaining 9% intended to account for plant forced outages and higher than average demand. The PRM has not been revised since.[40]

Figure 4.2 below compares August 14 and 15 actual peak, outages, and 6% contingency reserve requirement against the total PRM for August 2020. For August 14, contingency reserves were actually 6.3%, which reflects the fact that the actual load was higher than the forecast. In other words, based on the forecasted load of 44,740 MW, 6% contingency reserves is 2,669 MW. However, on August 15, the actual peak was 46,802 MW and 6% is 2,808 MW. Compared to the original forecasted load, 2,808 MW is 6.3%.

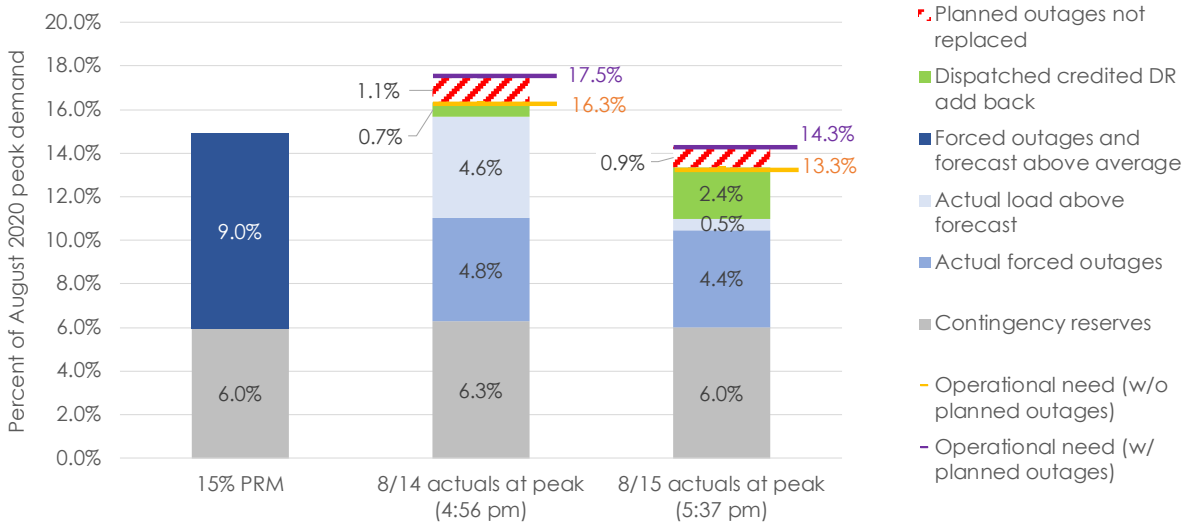
On August 14 the actual load was 4.6% above forecast but does not include another 0.7% of load that was potentially served by credited demand response. Adding back in the potential effects of demand response, load was 5.3% higher than forecasted. Total forced outages were 4.8%. Adding all of these elements, the operational need for

[39] Because of this ambiguity, the CAISO has taken action recently to stop the practice of crediting and to require all RA resources to be explicitly shown on the RA supply plans. *See* Business Practice Manual Proposed Revision Request 1280: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1280&IsDlg=0

[40] One difference from 2004 is the original PRM allocated 7% to contingency reserves. The CAISO does carry another 1% in regulation up requirements. However, for the purposes of this analysis and to simplify the discussion, the 6% WECC requirement is used throughout.

August 14 was 1.3% higher than the 15% PRM. In addition to forced outages, during the actual operating day the CAISO also had 514 MW and 421 MW of planned outages that were not replaced on August 14 and 15, respectively. The CPUC-approved PRM does not include planned outages under the assumption that planned outages will be replaced with substitute capacity or denied during summer months. Adding in the planned outages would increase the operational need to 2.5% higher than the PRM. On the other hand, the operational need for August 15 was below the 15% PRM by 1.7% including only forced outages and 0.7% with planned outages.

Figure 4.2: August 2020 PRM and Actual Operational Need During Peak



While a PRM comparison is informative, the rotating outages both occurred after the peak hour, as explained below.

4.2.2 Critical Grid Needs Extend Beyond the Peak Hour

The construct for RA was developed around peak demand, which until recently has been the most challenging and expensive moment to meet demand. The principle was that if enough capacity was available during peak demand there would be enough capacity at all other hours of the day as well, since most resources were capable of running 24/7 if needed. With the increase of use-limited resources such as solar generation in recent years, however, this is no longer the case. Today, the single critical period of peak demand is giving way to multiple critical periods during the day including the net demand peak, which is the peak of load net of solar and wind generation resources. The RA program has also tried to adjust for this change in resource mix by identifying reliability problems now seen later in the day by simulating each hour of the day, not just peak, and identifying the risk of lost firm load called Loss of Load Expectation (LOLE). The evaluation of wind and solar generation in particular are evaluated on its Effective Load Carrying Capability (ELCC), which reflects the ability

of generators to provide value at times when there is risk of lost firm load, now including later evening times. However, these ELCC values are still translated into static NQC values. This means, for example, that solar is typically under-valued during the peak but over-valued later in the evening after sunset.

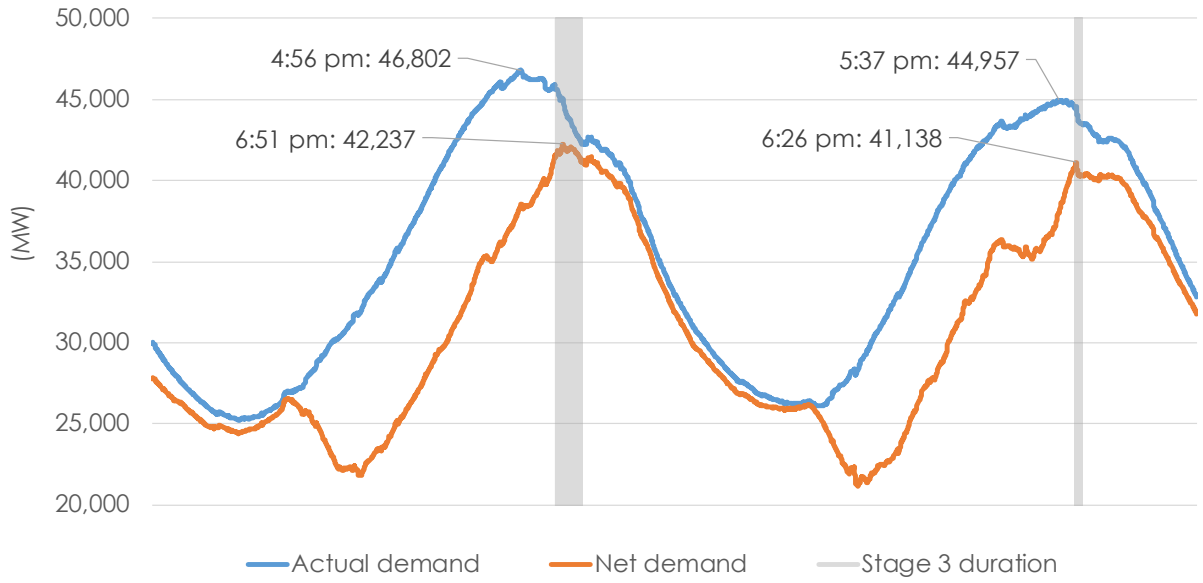
Since 2016, the CAISO, CEC, and the CPUC have worked to examine the impacts of significant renewable penetration on the grid. Solar generation in particular shifts "utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by solar generation, with generation dropping off quickly as the evening hours approach."[41] Furthermore, as the sun sets, demand previously served by behind-the-meter solar generation is coming back to the CAISO system while load remains high. Consequently, on hot days, load later in the day may still be high, after the gross peak has passed, because of air conditioning demand and other load that was being served by behind-the-meter solar coming back on the system. As a result of declining behind-the-meter and front-of-meter (utility scale) generation in the late afternoon, after the peak demand hour of the day, demand is decreasing at a slower rate than net demand is increasing, which creates higher risk of shortages around 7 pm, when the net demand reaches its peak (net demand peak).

Figure 4.3 shows on August 14, the net demand peak of 42,237 MW is 4,565 MW lower than the peak demand but wind and solar generation have decreased by 5,438 MW during the same time period. On August 15, the system peak is again before 6 pm and the net demand peak is slightly earlier at 6:26 pm. The net demand peak is 41,138 MW, 3,819 MW lower than the peak demand, while wind and solar generation have decreased by 3,450 MW during the same time period.

It is also important to note that the net demand peak shown is already reduced by the impact of emergency demand response that had been triggered by this time. The difference between the demand curve (in blue) and the net demand curve (in orange) is largest in the middle of the day (approximately 10 am until 4 pm) when renewables are generating at the highest levels and serving a significant amount of CAISO load. Most importantly, the rotating outages coincide closely with the net demand peaks.

[41] California Energy Commission Staff Report, California Energy Demand Updated Forecast, 2017-2027, January 2017, p. 51.

Figure 4.3: Demand and Net Demand for August 14 and 15



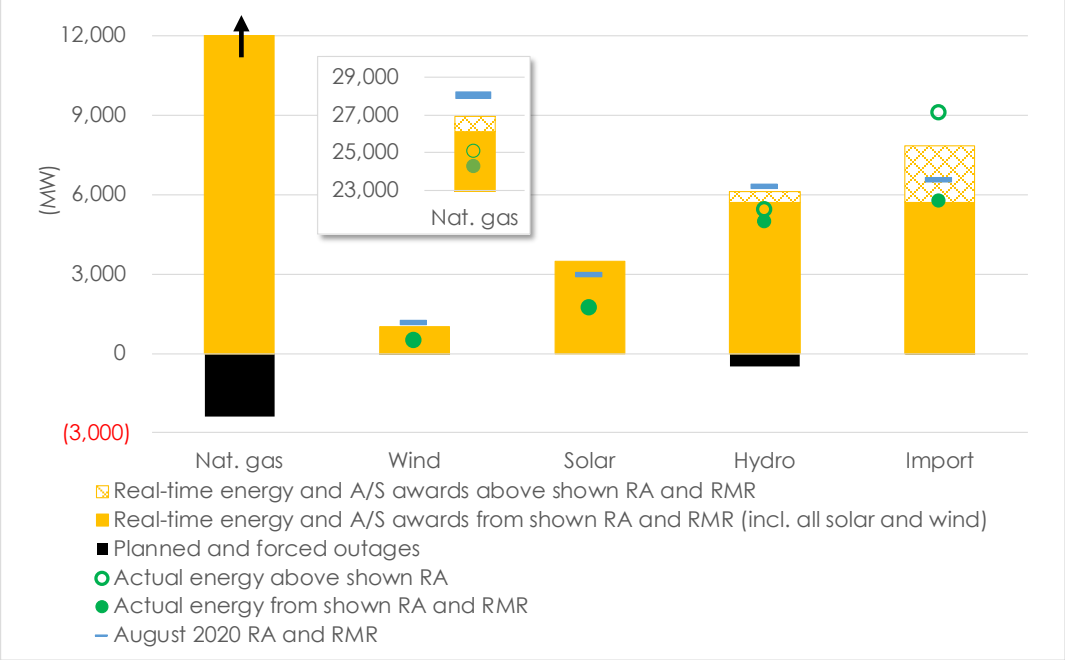
On August 14 the Stage 3 Emergency was declared at 6:38 pm, right before the net demand peak at 6:51 pm. Similarly, on August 15 the Stage 3 Emergency was called at 6:28 pm, just after the net demand peak at 6:26 pm.

4.2.3 Supply, Market Awards, and Actual Energy Production by Resource Type

This section discusses issues affecting planned RA versus actual energy supply resources that received awards in the day-ahead markets and ultimately provided energy on August 14 and 15. The focus is on the largest resource types: natural gas, imports, hydro, solar and wind generation. Resources totaling approximately 106% of the LSEs' total August RA obligations bid into the day-ahead market and resources equaling 101% of RA obligations received awards to provide energy or ancillary services in the day-ahead market, though not all of this capacity is under RA contract. Of these totals, approximately 90% of shown RA capacity received an award. Figure 4.4 overlays three different time periods for the net demand peak on August 14. It shows: (1) the levels of shown RA and RMR for August 2020; (2) the real-time awards for energy and ancillary services from shown RA capacity and for amounts above the shown RA; and (3) the actual energy delivered, and the portion of that energy bid into the market again divided between shown RA capacity and for the amounts above the shown RA. As explained in the individual resource discussions, a portion of the total energy delivered above the shown RA levels can be from resources under RA contract. Additional analysis is needed to identify these differences. As a simplifying assumption, all wind and solar generation is assumed to count towards RA capacity.

A detailed explanation on the interaction between RA capacity obligations, the day-ahead markets, real-time awards, and actual energy production dispatches can be found in Appendix B.

Figure 4.4: August 14 Net Demand Peak (6:51 pm) August 2020 Shown RA and RMR, Real-time Awards, and Actual Energy Production



4.2.3.1 Natural Gas Fleet

Natural gas resources bid in approximately 300 MW less than the gas fleet's collective contribution to RA requirements, though an additional 700 MW of bids came from resources that had no RA contract and/or RA resources that bid above their shown August RA requirements. The 1,000 MW difference between shown RA requirements and bid from RA resources is largely attributed to forced outages and derates due, at least in part, to the extreme heat. Plant derates (*i.e.*, a decrease in the resource's available capacity) due to extreme temperatures are not uncommon and in fact increase with the temperature. Even though the CAISO had issued a RMO notification for August 14 through 17 which should have limited planned outages, there were approximately 400 MW of planned outages that were not substituted. The largest planned outage had been approved for maintenance in June but had extended into peak summer months without providing replacement capacity.

In addition to the forced outages known to the CAISO at the beginning of the day, on August 14, at 2:57 pm, the Blythe Energy Center, a unit with full capacity of 494 MW, recorded a forced outage due to plant trouble. At the time it went out of service, it was generating 475 MW.

On August 15 at 6:13 pm, the Panoche Energy Center unexpectedly ramped down its generation from about 394 MW to about 146 MW, resulting in a loss of about 248 MW. This was not an outage, but a ramp down from the CAISO dispatch, which the CAISO now understands to be due to an erroneous dispatch from the scheduling coordinator to the plant.

4.2.3.2 Imports

The imports category includes both non-resource-specific resources as well as resource-specific imports like those from Hoover Dam and Palo Verde Nuclear Generating Station. Total import bids received in the day-ahead market were between 2,600 MW and 3,400 MW (40-50%) higher than the August shown RA requirements from imports. Of this total, imports required to provide energy to CAISO under RA contracts collectively bid in approximately 330 MW less than their shown August RA values. Despite this robust level of import bids, transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint. Through the month of August, a major transmission line in the Pacific Northwest upstream from the CAISO system was forced on outage due to weather and thus derated the California Oregon Intertie (COI). The derate reduced the CAISO's transfer capability by approximately 650 MW and caused congestion on usual import transmission paths across both COI and Nevada-Oregon Border (NOB).[42] In other words, more imports were available than could be physically delivered and the total import level was less than the amount the CAISO typically receives.

Because of this congestion, lower-priced non-RA imports may have cleared the market in lieu of higher-priced RA imports. Consequently, the amount of energy production from RA imports can be lower than the level of RA imports shown to the CAISO on RA supply plans.

Note that the CAISO was able to reach out to neighboring BAs to get a temporary emergency increase in transfer capability of approximately 200 MW on August 14 and 15.

4.2.3.3 Hydro

The hydro generation category includes a variety of hydro-based resource types such as run-of-river facilities, pumping loads, and pumped storage. While the August RA values are set almost a year ahead of time, bidding reflects the resources' capabilities

[42] *See* Grizzly-Portland General Electric (PGE) Round Butte No 1 500 kV Line at: https://transmission.bpa.gov/Business/Operations/Outages/OutagesCY2020.htm

for the next day. Across both days, total hydro generation bids were equivalent to the August NQC value. The portion of these bids from resources under RA contract was approximately 90% of the August NQC value. However, real-time energy production may be higher or lower than this amount. Therefore, actual energy production from these shown RA resources may vary from the amount reported to the CAISO. Additional analysis is needed to accurately characterize the level of generation from shown RA resources above the shown capacity level.

4.2.3.4 Solar and Wind

The total solar fleet within the CAISO collectively bid in approximately 370 MW (13%) more on August 14 but 160 MW (5%) less on August 15 than the August RA values at the net demand peak. In contrast, actual energy production during the net demand peak was 1,200 MW (40%) less and 1,000 MW (35%) less on August 14 and 15, respectively. The total wind fleet within the CAISO collectively bid in approximately 230 MW (20%) less on August 14 but 120 MW (10%) more on August 15 during the net demand peak. In contrast, actual energy production during the net demand peak was 640 MW (57%) less and 230 MW (20%) less on August 14 and 15, respectively.

For solar and wind, the August resource adequacy NQC values were set based on modeled assumptions and it is normal to see variations between this amount and the bid-in amount, which reflects forecasted conditions for the following day. The largest difference between August shown values and the bids is during the net demand peak hour where the combined solar and wind NQC values decline by 1,300 MW on both days. In addition, wind and solar generation were impacted by storm patterns on August 15. Between 5:12 pm and 6:12 pm, wind generation declined by 1,200 MW before increasing again closer to 7:00 pm.

4.2.3.5 Demand response

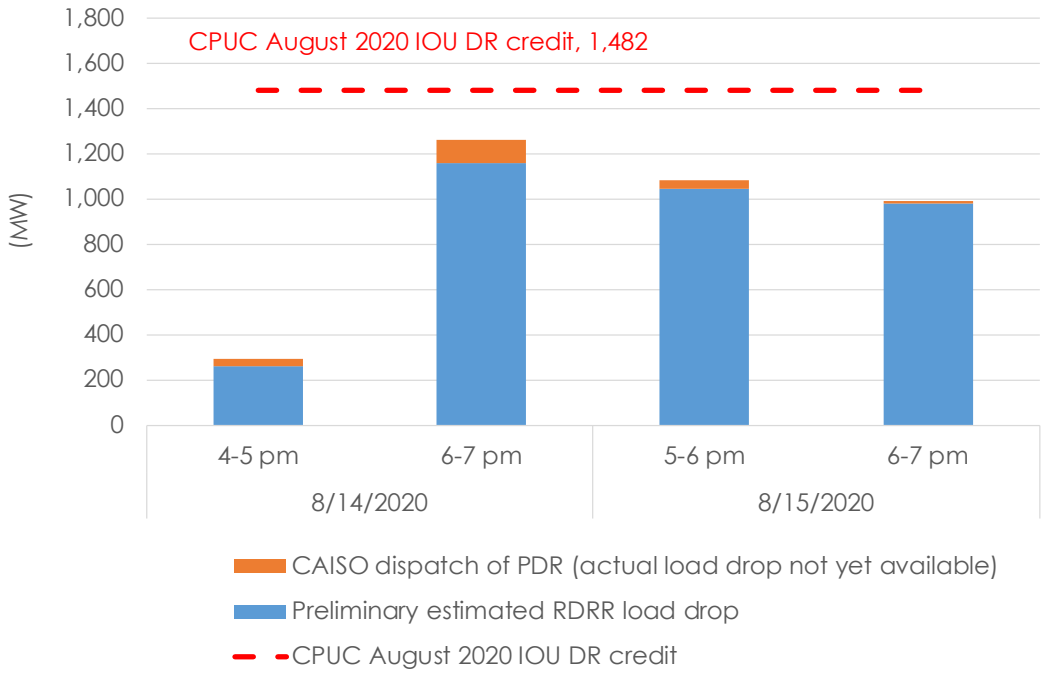
There are three distinct categories used to meet the total obligation: resource adequacy resources "shown" to the CAISO, RMR allocations from the CAISO, and the "credits" reported to the CAISO. The composition of credited amounts are generally not visible to the CAISO and do not submit bids consistent with a must offer obligation and are not subject to RAAIM penalties or incentives, or substitution requirements.[43]

[43] Because of this ambiguity, the CAISO has taken action recently to stop the practice of crediting and to require all RA resources to be explicitly shown on the RA supply plans. *See* Business Practice Manual Proposed Revision Request 1280: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1280&IsDlg=0

CPUC jurisdictional LSEs' August 2020 credits were 1,632 MW representing 3.5% of their total obligations. The vast majority of this amount is the emergency triggered RDRR, for which the CAISO receives daily emailed spreadsheets regarding their availability. In contrast, non-CPUC jurisdictional LSEs' credits were 565 MW, representing 11.9% of their total obligations. The vast majority of the non-CPUC jurisdictional LSEs' credits consisted of resources other than demand response not visible to the CAISO and may reflect contracts or behind-the-meter resources.

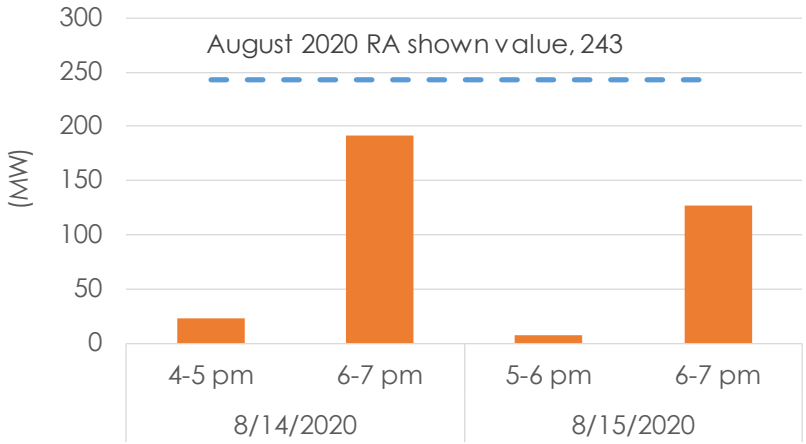
While the CAISO generally does not have visibility into credited amounts, the CPUC has clarified that the credits it includes in RA showings are IOU demand response programs. They include both emergency demand response RDRR and economically bid demand response (Proxy Demand Response or PDR). Per current practice, the CAISO does not receive settlement quality data until almost two months after each demand response event (i.e., each call). Therefore, all information here is preliminary. RDRR data was provided directly by the IOUs reflecting their preliminary estimates of load drop. PDR data is the CAISO expected load drop based on bids that were accepted into both the day-ahead and real-time energy markets. As a simplifying assumption, the PDR is shown as providing a full response to the CAISO expected load drop. Since the data blends preliminary reported response and expected but unconfirmed response, for lack of a better term they are collectively referred to as expected load drop, but these data do not reflect any actual load drop as this is unknown as this time. Figure 4.5 below compares the collective RDRR and PDR expected load drop from August 14 and 15 during the hours of the peak and net demand peak. These four timeframes are compared to the August 2020 CPUC demand response credit of 1,482 MW. The IOU demand response programs may have collectively provided a maximum response of approximately 80% of the total credited amount (August 14 during the net demand peak). This may also reflect the amount of demand response actually available for dispatch.

Figure 4.5: Credited IOU Demand Response: Preliminary Estimated RDRR Response and PDR Dispatch vs. CPUC August 2020 DR Credit



Aside from the IOUs, there is also economic demand response (PDR) from CPUC-jurisdictional third parties. As noted above, settlement quality data was not available at this time so Figure 4.6 below shows the level of CAISO dispatch based on bids that were accepted into both the day-ahead and real-time energy markets. During the peak hours, non-IOU PDR dispatch was less than 10% of the total shown RA capacity of 243 MW for both days. Over the net demand peak hours, the dispatch increased to approximately 80% and 50% on August 14 and 15, respectively.

Figure 4.6: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available)

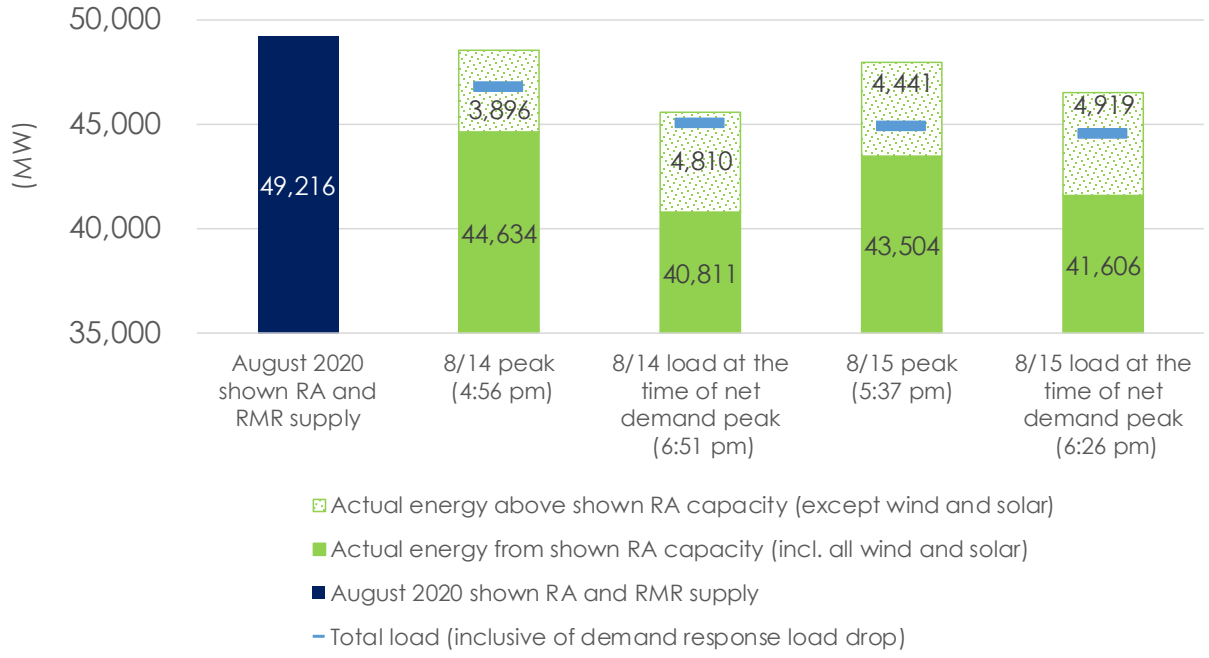


4.2.3.6 Combined Resources

Figure 4.7 below compares the total August 2020 RA and RMR capacity versus actual energy production for both days during the peak and net demand peak times. The August 2020 RA capacity reflects the qualifying capacity shown to the CAISO on RA supply plans. For example, solar resources are valued based on the effective load carrying capability (ELCC) methodology and may produce more or less energy throughout the day. The second through fourth columns in the figure show the actual energy production from RA resources and energy produced above the shown RA capacity.

As noted above, this may undercount the amount of generation from imports and hydro resources in particular that may be shown for RA but generating above the shown capacity level or providing ancillary services. While this is also true for solar and wind, as a conservative simplifying assumption for the analysis in Figure 4.7, all solar and wind resource generation in the CAISO footprint is categorized as RA though that has not been validated. Any IOU emergency and economic demand response dispatched during these time periods is already reflected in the reduced load. The figure shows a decrease in RA-based generation between the peak and net demand peak periods. The load markers show that a portion of load was served by energy produced above the shown RA amount for each time period. Also for simplicity, the figure does not include ancillary services awards.

Figure 4.7: August 2020 Shown RA and RMR Allocation vs. August 14 and 15 Actual Energy Production (Assumes All Wind and Solar Counts as RA Capacity)



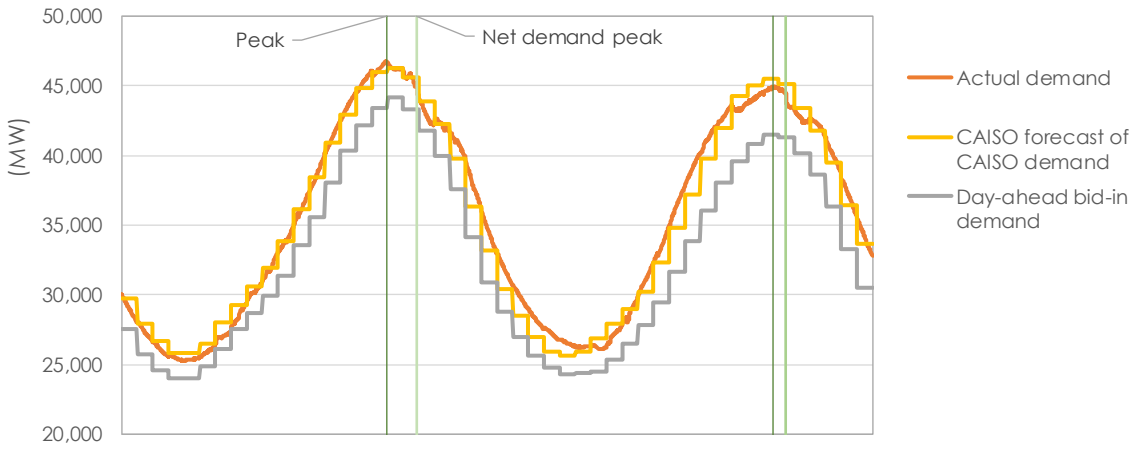
4.3 Some Practices in the Day-Ahead Energy Market Exacerbated the Supply Challenges Under Highly Stressed Conditions

Energy market practices encompass inputs into the energy market, how the energy market matched supply with demand, and ultimately whether the schedules from the market fully prepared the CAISO Operational staff to run the grid. Energy market practices appear to have contributed to the inability to obtain additional energy that could have alleviated the strained conditions on the CAISO grid on August 14 and 15. The contributing causes identified at this stage include: under-scheduling of demand in the day-ahead market by scheduling coordinators, convergence bidding masking the tight supply conditions, and the configuration of the residual unit commitment market process.

4.3.1 Demand Should Be Appropriately Scheduled in the Day-Ahead Timeframe

Scheduling coordinators representing LSEs collectively under-scheduled their demand for energy by 3,386 MW and 3,434 MW below the actual peak demand for August 14 and 15, respectively. During the net demand peak time, the under-scheduling was 1,792 MW and 3,219 MW for August 14 and 15, respectively. Figure 4.8 below also shows that the CAISO's own forecast for peak was 825 MW below and 559 MW above actual for August 14 and 15, respectively. The CAISO's own forecast for the net demand peak time was 511 MW and 632 MW above actual. The under-scheduling of load by scheduling coordinators had the detrimental effect of not setting up the energy market appropriately to reflect the actual need on the system and subsequently signaling that more exports were ultimately supportable from internal resources.

Figure 4.8: Comparison of Actual, CAISO Forecast, and Bid-in Demand



Day-ahead bid-in demand below actual:

	8/14	8/15
At peak:	3,386	3,434
Time of net demand peak:	1,792	3,219

4.3.2 Convergence Bidding Masked Tight Supply Conditions

During the mid-August event, it was difficult to pinpoint these contributing causes because processes that normally help set up the market masked the under-scheduling. One such process was convergence bidding. As the name suggests, convergence bidding is intended to allow bidders to converge or moderate prices between the day-ahead and real-time markets. Under normal conditions, when there is sufficient supply, convergence bidding plays an important role in aligning loads and resources for the next day. However, during August 14 and 15, under-scheduling of load and convergence bidding clearing net supply signaled that more exports were supportable. Once this interplay was identified on August 16 after observing the results for trade day August 17, convergence bidding was temporarily suspended for August 18 trade date through the August 21 trade date.

4.3.3 Residual Unit Commitment Process Changes Were Needed

The CAISO has a residual unit commitment (RUC) process that provides additional reliability checks based on the CAISO's forecast of CAISO load after scheduling coordinators provide all of their schedules and bids for supply and demand, excluding convergence bids. After a review of the August 14 event, it was discovered that a prior market enhancement was inadvertently causing the CAISO's RUC process to mask the load under-scheduling and convergence bid supply effects, reinforcing the signal that more exports were supportable. While this market enhancement was found to be a

necessary functionality in other market processes, it was not required in the RUC reliability-based process. The CAISO therefore stopped applying the enhancement to the RUC process starting from the day-ahead market for September 5, 2020. This enabled the CAISO to better evaluate the feasibility of the export schedules in the day-ahead market, regardless of the influence of convergence bidding.

The CAISO's real-time market and operations helped to significantly reduce the interaction of load under-scheduling, convergence bidding and the impact on the RUC process in the day-ahead market. The CAISO relied on the real-time market and operations to attract more imports including market transactions, voluntary transfers from the Energy Imbalance Market (EIM), and emergency transfers from other BAs. However actual supply and demand conditions continued to diverge from market and emergency plans such that even with the additional real-time imports, the CAISO could not maintain required operating reserves as the net load peak approached on August 14 and 15.

5 Actions Taken During August 16 Through 19 to Mitigate Projected Supply Shortfalls

While August 14 and August 15 are of primary focus due to the rotating outages that occurred during those days, August 16 through 19 were projected to have much higher supply shortfall. If not for the leadership through the Governor's Office to mobilize a statewide effort to mitigate the situation, California might have experienced further rotating outages in August due to the unprecedented multi-day heat storm across the West.

In preparation for continued challenging conditions on Monday, August 17, the CPUC and CEC worked closely with the Governor's Office to take immediate actions designed to reduce load and/or increase generating capacity within the state. The actions were taken with the goal of balancing factors such as how much the action would help address the deficit, the durability of the action over the week, the level of disruption to commercial and residential customers, impacts on air quality and water, and the potential for disproportionate effects on disadvantaged communities.

On August 16, Governor Newsom declared a State of Emergency[44], and on August 17 he signed Executive Order N-74-20[45], which allowed for temporarily easing of regulations on stationary generators, portable generators, and auxiliary engines by vessels berthed in California ports. This proclamation enhanced the response of the Governor's Office, CAISO, CEC, and CPUC as they worked collectively to create a statewide mobilization to:

- Conserve electricity
- Reduce demand on the grid by:
    - Moving onsite demand to backup / behind-the-meter generation
    - Deploying demand response programs
    - Initiating demand flexibility
- Increase access to supply-side resources by:
    - Maximization of output from generation resources
    - Additional procurement of resources

[44] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.16.20-Extreme-Heat-Event-proclamation-text.pdf

[45] https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-EO-N-74-20.pdf

- Resource support from other balancing areas

The efforts led to estimated reductions in peak demand on Monday (August 17) and Tuesday (August 18) by nearly 4,000 MW and added nearly 950 MW of available temporary generation to balance the grid. Table 5.1 below shows the difference between day-ahead-peak and the actual peak, which was largely realized due to the statewide efforts.

Table 5.1: Day-Ahead Peak Forecast vs. Actual Peak During Heat Event

	Day-Ahead Peak forecast (MW)	Actual Peak (MW)	Difference (MW)
8/14/2020	46,257	46,797	540
8/15/2020	45,514	44,947	(567)
8/16/2020	44,395	43,815	(580)
8/17/2020	49,825	45,152	(4,673)
8/18/2020	50,485	47,118	(3,367)
8/19/2020	47,382	46,023	(1,359)

5.1 Detailed Description of Actions Taken

Awareness Campaign and Appeal for Conservation

- The CAISO continued to issue Flex Alerts and warnings.
- The CAISO, CEC and CPUC supported the Governor's Office and the California Governor's Office of Emergency Services to publicly request electricity customers lower energy use during the most critical time of the day, 3:00 pm to 10:00 pm.
- The CPUC issued a letter to the investor-owned utilities on August 16 requesting that they aggressively pursue conservation messaging and advertising, and requested Community Choice Aggregators do the same.
- The CPUC redirected the Energy Upgrade California marketing campaign messaging and media outreach to focus on conservation messaging.
- The CEC, CPUC, and Governor's Office used a wide variety of media to ensure widespread awareness, including freeway signage, social media, website and app updates.

Demand Reduction Actions

Demand reduction efforts included transferring demand from the grid to on-site sources, deploying demand response programs, and initiating demand flexibility.

Transfer of Demand from Grid to On-site Sources

- The CAISO and CEC coordinated with data center customers of Silicon Valley Power to move approximately 100 MW of load to onsite backup generation facilities.
- The CEC coordinated with the US Navy and Marine Corps to disconnect 22 ships from shore power, move a submarine base to backup generators, and activate several microgrid facilities, resulting in approximately 23.5 MW of load reduction.
- The CEC coordinated with six Electric Program Investment Charge-funded microgrids to reduce load by approximately 1.2 MW each day.

Deployment of Demand Response Programs

- On August 17 the CPUC issued a letter clarifying the use of back-up generators in connection with specific demand response programs is allowable, which resulted in at least 50 MW of additional demand reduction each day.

- "The Los Angeles Department of Water and Power (LADWP) on Aug. 13 said that in addition to asking residential customers to save energy, LADWP was also implementing a Demand Response event with its commercial customers in response to a CAISO Flex Alert. The alert asked all power customers to save energy from 3:00 p.m. to 10:00 p.m. on Friday, August 14."[46]

Initiation of Demand Flexibility

- DWR and the US Bureau of Reclamation shifted on-peak pumping load that resulted in 72 MW of load flexibility.

[46] American Public Power Association, "Calif. grid operator initiates rotating power outages with extreme heat, high power demand", August 17, 2020. https://www.publicpower.org/periodical/article/calif-grid-operator-initiates-rotating-power-outages-with-extreme-heat-high

- The CEC contacted Tesla, which offered to reduce load at its factory between 3 and 8 pm.
- The Governor's Office contacted large industrial users to seek opportunities for load shifting away from peak hours. In response, Poseidon Water Desal Plant reduced its load by 24 MW; Dole Foods reduced its load by 3.3 MW, with support from SDG&E; California Steel Industries reduced its load by 35 MW on Monday through Wednesday (August 17 through 19) during the hours of 3 to 8 pm; and California Resources Corporation reduced its demand by about 100 MW during peak hours, shutting in 7% of oil production daily for 6-hour peak periods.

Increase Access to Supply-Side Resources

Actions taken to increase access to supply-side resources included maximizing output from generation resources, additional procurement of resources, and resource support from neighboring BAs.

Maximization of Output from Generation Resources

- The CEC led the effort for jurisdictional power plants to contribute an additional 147 MW of generation (60 MW from SEGS Solar Plant; 42 MW from Ivanpah Solar Power Plant; and 45 MW from the CPV Sentinel Energy Project.)
- The CEC contacted Watson Cogen and received a commitment for them to provide 20 to 30 MW of additional generation on August 17 and 18.
- The Governor's Office secured commitments from three refineries to increase their on-site generators. El Segundo Refinery cogeneration unit ramped up to export 10 MW to the grid. Richmond Refinery increased its onsite power production by 4 MW to reduce their imports. Bakersfield Refinery generated 22 MW for export to the grid for one day.
- The CEC worked with the City and County of San Francisco to maximize power output at Hetch Hetchy, which allowed for an additional 150 MW of generation during the peak load.
- DWR and the Metropolitan Water District (MWD) adjusted water operations to shift 80 MW of electricity generation to the peak period.
- PG&E deployed temporary generation (procured for Public Safety Power Shutoff purposes) across its service territory, totaling approximately 60 MW.

- SCE worked with generators to ensure that additional capacity was made available to the system from facilities with gas on site or through inverter changes.

Resource Support from Neighboring BAs

- LADWP helped bring additional generation from Haynes Unit 1 and Scattergood natural gas-fired plants, totaling 300 to 600 MW.
- SMUD issued a news release on August 16, calling for conservation.[47]
- The Western Area Power Administration (WAPA) offered 40 MW of its Hoover Dam allocation.

CAISO Market Actions

Prior to August 14, the CAISO had already begun to exceptionally dispatch long start units to ensure they would be available to provide energy. The CAISO exceptionally dispatched both RA and non-RA resources. As explained in Section 2, non-RA capacity is eligible for capacity payment under the CAISO's capacity procurement mechanism (CPM) authorization in return for a commitment to provide energy to the CAISO for a term of at least 30 days. However, no resources accepted such an offer because of prior contracting commitments to other BAs. However, many provided short-term energy as requested. Starting on August 16, the CAISO was successful in attracting non-RA capacity under the CPM authorization due to a system capacity shortage caused by the heat storm. In total, 477.45 MW of CPM capacity was procured.[48]

[47] American Public Power Association, "Calif. grid operator initiates rotating power outages with extreme heat, high power demand", August 17, 2020, https://www.publicpower.org/periodical/article/calif-grid-operator-initiates-rotating-power-outages-with-extreme-heat-high

[48] *See* http://www.caiso.com/Documents/CapacityProcurementMechanismDesignation-081620.html; http://www.caiso.com/Documents/SignificantEventCapacityProcurementMechanismDesignation-081720-081820.html; http://www.caiso.com/Documents/CapacityProcurementMechanismDesignation-081720.html; http://www.caiso.com/Documents/SignificantEventCapacityProcurementMechanismDesignation-081920.html; and http://www.caiso.com/Documents/RevisedSignificantEventCapacityProcurementMechanismDesignation-081720-081820.html

6 Preliminary Recommendations

This section identifies a preliminary set of recommendations and immediate steps that either have been or are in the process of being implemented or are recommended to reduce the likelihood of additional rotating outages during the remainder of this year or next year. The recommendations are organized into three timeframes: Near-term (2021), Mid-term (2022-25) and Longer-term (beyond 2025). Within each timeframe, the recommendations are grouped into categories to specifically address the contributing factors established in Section 4 and to systematize and expand on the mitigation activities undertaken to address the potential shortfall on August 16 through 19 as detailed in Section 5.

1) Near-term – by Summer 2021

a) Actions That Have Already Been Taken

- **Construction of new generation** - CPUC jurisdictional LSEs have already begun procurement of new capacity that will be online by summer 2021 derivative of prior CPUC authorizations. This includes NQC values of approximately 2,100 MW of storage and hybrid storage resources and approximately 300 MW solar and wind resources.
- Furthermore, the CPUC is already working with its jurisdictional LSEs to track the projects with 2021 online dates to reduce the risk of delays. When possible delays are identified, the CPUC, CEC, and CAISO will work with the developers, other relevant state agencies and local governments to ensure projects stay on track.
- **Adjustments to energy market processes** - Following the mid-August events, the CAISO took immediate actions to adjust market processes, which improved the CAISO's ability to limit market export schedules to what is physically feasible based on system conditions and intertie constraints. These measures alleviated pressures during the Labor Day weekend heat wave.

b) Resource Planning and Procurement

- **Increase RA requirements for LSEs to more accurately reflect increasing risk of extreme weather events -** The current planning targets were developed in 2004 and have not been updated since. The 1-in-2 load forecast plus a 15% reserve margin should be updated to better account for heat storms like the ones encountered in both August and September. The CPUC already has an open proceeding to consider changes in how the planning targets are set for the purposes of RA rules and this discussion should start before summer 2021. Once these changes are developed, the CPUC, CEC, and CAISO should

ensure they are used consistently across all long- and short-term planning programs.

- **Bring additional resources online** - The CPUC and CEC to expedite the regulatory and procurement processes to develop additional resources that can be online by 2021, including coordination with non-CPUC jurisdictional entities. This will most likely focus on "demand side" resources such as demand response and, as possible, the acceleration of online dates of resources under development but not scheduled to be online by summer 2021. This can complement the resources that are already under construction.
- **Modernize Flex Alert** - Flex Alert was designed as a voluntary conservation program during the 2000-2001 California Electricity Crisis. It is largely a media campaign asking the public to conserve electricity on peak demand days. The program design and targeting have not changed since its inception. The program should be redesigned to better target social media and to take advantage of home automation devices. The CEC, CAISO and CPUC should coordinate to add funding from all LSEs to better target conservation messaging and utilize automated devices.
- **Non-jurisdictional entity planning targets** - The CAISO and CEC should work with the non-CPUC jurisdictional entities to pursue consistency between CPUC and non-CPUC jurisdictional entity planning targets, including forecasting and PRM targets.
- **RA crediting counting requirements** - The CAISO to continue efforts to stipulate its expectations on credits applied by CPUC and non-CPUC jurisdictional entities.

c) Market Enhancements

Based on this Preliminary Analysis, the CAISO has identified possible improvements to its market practices to ensure they accurately reflect the actual balance of supply and demand during stressed operating conditions. Furthermore, market practices should ensure sufficient resources are available to serve load across all hours, including the peak and net demand peak.

- **Address under-scheduled CAISO load in the day-ahead market** – The CAISO, working with stakeholders, to develop and institute a procedure to adequately communicate to the market (including LSEs and their scheduling coordinators) the need to schedule load in the day-ahead market by:
    - Continuing its new practice of notifying the market of the degree of under-scheduled load based on prior day results of the day-ahead

market if load is under-scheduled, and request that LSE scheduling coordinators properly schedule their anticipated load in the day-ahead market[49]; and

- Increasing outreach to LSEs to discuss and resolve any issues with their ability to schedule the amount of load in the day-ahead market consistent with system conditions.

- **CAISO to pursue the following market rule enhancements through its stakeholder processes:**
  - Continue to review and clarify through changes to its tariffs and business practice manuals the existing rules for scheduling priorities and protection of internal and external schedules. Ensure that market processes appropriately curtail lower priority exports that are not supported by non-resource adequacy resources to minimize the export of capacity that could be related to RA resources during reliability events.
  - Through a stakeholder process, pursue redesign of CAISO RA market rules to ensure planned outages do not create unnecessary reliability risk and that performance penalties are sufficient to ensure compliance.
  - Through a stakeholder process, develop a process to evaluate monthly RA supply plans with backstop if necessary.
  - In coordination with the CPUC, continue to work with stakeholders to clarify and refine the counting rules as they apply to hydro resources, demand response resources, renewable, use limited resources, and imports.
  - Through a stakeholder process, continue to enhance the day-ahead market design to ensure reliable load and supply scheduling.

d) Improving Situational Awareness and Planning for Contingencies

- **State-Wide and WECC-Wide Resource Sufficiency Assessments** – The CEC, in coordination with CPUC, CAISO and other BAAs, will begin developing a statewide summer assessment to provide additional information to support RA proceedings beginning in 2021. The CEC will also engage in

[49] http://www.caiso.com/Documents/CaliforniaISOMarketParticipantsHeatWavePreparation-LoadScheduling.html

relevant WECC RA processes to maintain situational awareness of the WECC-wide summer assessments and publish information as appropriate.

- **Develop Communication Protocols to Trigger Statewide Coordination** - The CAISO, CEC, and CPUC will develop improved warning and trigger protocols to adequately forewarn the severity of an extreme event and initiate coordination with one another, with other State agencies and the Governor's Office, with the IOUs, municipal or POUs, and the CCAs.

- **Contingency Plan** – The CEC, in coordination with the Governor's Office, CPUC, CAISO and other appropriate state agencies and stakeholders, will systematize a Contingency Plan. This plan will draw from actions taken statewide under the leadership of the Governor's Office to mitigate the anticipated shortfall from August 17 through 19. It will be ready to be deployed in case of unanticipated stressed conditions. The Contingency Plan will lay out a process to sequence emergency measures in rank order to minimize environmental, equity, and safety impacts. The measures will include: load flexibility and conservation from large users, moving demand to microgrids and back-up generation (including emergency use of diesel generation that the three large electric IOUs own or have under contract for use in major emergencies such as wildfire prevention and wildfire or earthquake response), and temporarily increase capacity of existing generation resources.

2) Mid-Term (2022 through 2025) and Long-Term

a) Resource Planning and Development

- **Consider New Resources -** Consider whether new resources are needed to meet the mid- and longer-term timeframes reflective of the re-evaluation of the forecast basis and PRM noted above. Conduct a production cost analysis to ensure that additional resources will meet reliability needs during all hours of the year including the net demand period.

- **Accelerate Deployment of Demand Side Resources**

    - **Dynamic Rates –** Rate design can help reduce demand at net demand peak by creating financial incentives to shift demand to other times of the day. The CPUC is already implementing rate design changes by directing the three large IOUs in California to default all residential customers to Time of Use Rates (TOU).[50] SDG&E has already defaulted most of its customers to TOU rates.

[50]Most commercial and industrial customers are already on mandatory TOU rate plans.

PG&E and SCE will begin moving their customers to TOU plans in 2021.

- Beyond the move to TOU rates, other dynamic rate designs that more accurately reflect real-time market conditions (or GHG emissions) can be developed. These rate plans can be paired with low-cost hardware to enable automated demand flexibility. The CEC has already opened a proceeding on Load Management Standards (LMS) to 1) require the large electric utilities and CCAs to post their time-based rates in a public database in a standardized format, and 2) automate the publishing of those rates in real-time in machine-readable form. The CEC is also beginning the process to implement the load flexibility requirements laid out in Senate Bill (SB) 49 (Skinner, 2019) in conjunction with the State Water Board. The CPUC and CEC should open additional proceedings to expand dynamic rate plans and encourage the roll out of automated devices. The CPUC and CEC will need to coordinate with the smaller non-CPUC jurisdictional entities and CCAs to encourage these entities to implement similar rate plans and automate access to them.

- Building on the Senate Bill (SB) 100 (De León, 2018) scenarios, consider where diverse resources can be built and the transmission and land use considerations that must be taken into account. Establish a transmission technical working group (CAISO, BAs, CEC, CPUC) to evaluate the transmission options and constraints from the SB 100 scenarios.

b) Market Enhancements

- The CAISO to continue to engagement with stakeholders to develop market enhancements identified in the near-term.

c) Improving Situational Awareness and Plan for Contingencies

- **Statewide and WECC-Wide RA Assessments as Part of IEPR** Building on the statutory role of the CEC in reviewing POU IRPs, the CEC, in coordination with CPUC, CAISO and statewide LSEs, will develop necessary assessments as part of the Integrated Energy Policy Report (IEPR) to develop state-wide, and WECC-wide RA assessments.

- As part of IEPR, continue efforts to expand assessments to support mid- to long-term planning goals by including the following:
  - The CEC, CPUC, and CAISO continue mid-term efforts from SB 100, IRP, and the CAISO's transmission planning process to address electric

sector reliability and resiliency considering evolving policy goals of the state. May coordinate with the California Air Resources Board.

- Update (likely broaden) the range of climate scenarios to be considered in CEC forecasting (supply and demand).
- Consider developing formal crosswalks between the CEC forecast and emerging SB 100 scenarios to bridge gaps between planning considerations across various planning horizons.

7 Next Steps

Additional analysis that will be performed for the final version of this report, includes, but is not limited to:

- Evaluate how credited resources performed across CPUC and non-CPUC jurisdictional footprints.
- Evaluate demand response performance based on settlement meter data.
- Analyze how different LSE scheduling coordinators scheduled load in the day-ahead market compared with their forecasted peak demand, and understand and address the underlying drivers.
- Improve communications to utility distribution companies to ensure appropriate response during future critical reliability events and grid needs.
- Review performance of specific resources during the heat storm.

Appendix A: CEC Load Forecasts for Summer 2020

The following is a detailed discussion on the CEC's load forecast adjustment for June through September 2020. Table A.1 shows the allocation of the CEC forecast by jurisdiction type, and how those forecasts compare with both final year-ahead and month-ahead forecasts. Each element is discussed below.

Table A.1: Summary of 2020 LSE RA Forecasts

		Jun-20	Jul-20	Aug-20	Sep-20
1. 2018 IEPR Update 2020 CAISO Coincident Peak		41,220	44,650	44,955	45,277
	Adjustment for CPUC load-modifying demand response	(97)	(116)	(127)	(133)
	Adjusted CAISO Forecast	41,123	44,533	44,828	45,144
2. Disaggregation to Jurisdiction Type					
	CPUC Jurisdictional	37,138	40,170	40,495	40,779
	Non-CPUC Jurisdictional	3,984	4,363	4,333	4,365
	Adjusted CAISO Forecast	41,123	44,533	44,828	45,144
3. CPUC Reference Forecast		37,138	40,170	40,495	40,779
	Reference @ 99%	36,767	39,768	40,090	40,371
4. Final 2020 Year-Ahead Forecasts					
	CPUC Jurisdictional	36,766	40,036	40,415	40,371
	Non-CPUC Jurisdictional	3,623	3,980	4,022	3,948
	Total Forecast for Year-Ahead Showing	40,389	44,016	44,437	44,319
	Percent of Adjusted CAISO Forecast	98.2%	98.8%	99.1%	98.2%
5. June-August 2020 Month-Ahead Forecasts					
	CPUC Jurisdictional	36,914	40,132	40,571	40,758
	Non-CPUC Jurisdictional	3,782	4,086	4,169	4,041
	Total Forecast for August Month-Ahead Showing	40,696	44,218	44,741	44,798
	Percent of Adjusted CAISO Forecast	99.0%	99.3%	99.8%	99.2%

1. CEC adjusts the forecast for expected impacts of certain CPUC demand response programs, primarily critical peak pricing, which are not accounted for in the CEC

forecast but which CPUC determines may receive credit for reducing peak demand. CPUC provides the estimated load impacts.
2. CEC disaggregates the TAC area monthly peaks for PG&E and SCE to jurisdiction type. This is done using TAC area annual forecast peaks from CEC Form 1.5b, analysis of 2019 hourly loads for all individual LSEs and for the IOU service area, and preliminary forecasts submitted by LSEs in May. The JASC was briefed on the methodology and results for 2020 on June 4, 2019. For comparison, the load of the non-CPUC jurisdictional entities at the time of the 2019 system peak for POUs was 4,393 MW, and 2019 RA obligation for those POUs was 4,285 MW.

3. In determining CPUC-jurisdictional LSE forecasts, CEC applies a pro-rata adjustment to ensure that the aggregate forecasts in each TAC are within 1% of the reference forecast. For August 2020, pro-rata adjustments were only necessary in the PG&E area.

4. For the final year ahead-ahead forecasts, non-CPUC jurisdictional entities may submit updated forecasts to the CEC. Most revised forecasts are from LSEs whose load is related to water pumping and can vary significantly with hydrologic conditions. The decrease in non-CPUC jurisdictional load from the expected 4,333 MW in August to 4,022 MW reflects lower LSE forecasts of pumping load. CPUC-jurisdictional forecasts were 0.2% below the CPUC reference forecast. This left the total year-ahead forecast for August at 99.1% of the adjusted CAISO forecast total. In May and September, the year-ahead forecast total fell to 98.2%.

5. For the August month-ahead showing, LSE forecasts increased, with POU forecasts increasing to 4,169 MW. This brought the forecast total to 99.8% of CEC's adjusted CAISO forecast. In all summer months, aggregate month-ahead forecasts increased for both groups of LSEs compared to the year-ahead forecasts, and in total were within 1% of the CEC forecast.

Table A.2 lists all load serving entities (LSEs) in the CAISO footprint for summer 2020 by jurisdiction and type.

Table A.2: LSEs in the CAISO Footprint – Summer 2020

	Load Serving Entity	**Jurisdiction & Type**
1	Pacific Gas & Electric	CPUC - IOU
2	San Diego Gas & Electric	CPUC - IOU
3	Southern California Edison	CPUC - IOU
4	3 Phases Energy Services	CPUC - ESP
5	American PowerNet Management	CPUC - ESP
6	Calpine PowerAmerica-CA, L.L.C. (1362)	CPUC - ESP

	Load Serving Entity	Jurisdiction & Type
7	Commerce Energy, Inc. (1092)	CPUC - ESP
8	Commercial Energy of California	CPUC - ESP
9	Constellation New Energy, Inc.	CPUC - ESP
10	Direct Energy, L.L.C.	CPUC - ESP
11	EDF Industrial Power Services (CA), LLC	CPUC - ESP
12	Noble Americas Energy Solutions LLC	CPUC - ESP
13	Pilot Power Group, Inc.	CPUC - ESP
14	Shell Energy North America	CPUC - ESP
15	Tiger Natural Gas	CPUC - ESP
16	UC Office of the President	CPUC - ESP
17	Apple Valley Clean Energy	CPUC - CCA
18	City of Solana Beach	CPUC - CCA
19	Clean Power Alliance of Southern California	CPUC - CCA
20	Clean Power San Francisco	CPUC - CCA
21	Desert Community Energy	CPUC - CCA
22	East Bay Community Energy	CPUC - CCA
23	King City Community Power	CPUC - CCA
24	Lancaster Choice Energy	CPUC - CCA
25	Marin Energy Authority	CPUC - CCA
26	Monterey Bay Community Power Authority	CPUC - CCA
27	Peninsula Clean Energy Authority	CPUC - CCA
28	Pico Rivera Innovative Metropolitan Energy	CPUC - CCA
29	Pioneer Community Energy	CPUC - CCA
30	Rancho Mirage Energy Authority	CPUC - CCA
31	Redwood Coast Energy Authority	CPUC - CCA
32	San Jacinto Power	CPUC - CCA
33	San Jose Clean Energy	CPUC - CCA
34	Silicon Valley Clean Energy	CPUC - CCA
35	Sonoma Clean Power	CPUC - CCA
36	Valley Clean Energy Authority	CPUC - CCA
37	Western Community Energy	CPUC - CCA
38	Arizona Electric Power Cooperative, Inc.	Non-CPUC
39	Bay Area Rapid Transit	Non-CPUC
40	Bear Valley Electric Services	Non-CPUC
41	CDWR	Non-CPUC
42	City and County of San Francisco	Non-CPUC
43	City of Anaheim	Non-CPUC

	Load Serving Entity	Jurisdiction & Type
44	City of Azusa	Non-CPUC
45	City of Banning	Non-CPUC
46	City of Cerritos	Non-CPUC
47	City of Colton	Non-CPUC
48	City of Corona Department of Water & Power	Non-CPUC
49	City of Industry	Non-CPUC
50	City of Vernon	Non-CPUC
51	City of Victorville	Non-CPUC
52	Eastside Power Authority	Non-CPUC
53	Kirkwood Meadows	Non-CPUC
54	Lathrop Irrigation District	Non-CPUC
55	Metropolitan Water District	Non-CPUC
56	Moreno Valley	Non-CPUC
57	NCPA	Non-CPUC
58	Pasadena Water & Power	Non-CPUC
59	Pechanga Tribal Utility	Non-CPUC
60	Port of Stockton	Non-CPUC
61	Power and Water Resources Pooling Authority	Non-CPUC
62	Rancho Cucamonga Municipal Utility	Non-CPUC
63	Riverside Public Utility	Non-CPUC
64	Silicon Valley Power	Non-CPUC
65	Valley Electric Association	Non-CPUC
66	WAPA - WDOE	Non-CPUC
67	WAPA - WFLS	Non-CPUC
68	WAPA - WNAS	Non-CPUC
69	WAPA - WPUL	Non-CPUC
70	WAPA - WSLW	Non-CPUC

Appendix B: Technical Discussion on Supply Conditions Based on Current Resource Planning Targets and Energy Market Practices

Of the three challenges identified in this Preliminary Analysis, this appendix provides a more detailed, technical discussion on how the current resource planning targets have not kept pace to support the transition to a reliable, clean, and affordable resource mix and energy market practices in the day-ahead market that exacerbated the supply challenges under highly stressed conditions.

Supply-side resources are evaluated from the planning horizon into the operational timeframe. Specifically, the resource adequacy (RA) capacity shown to the CAISO for August 2020 is compared to all resources that bid and were awarded in the day-ahead and real-time markets, and actual performance for August 14 and 15 peak and net-load peak periods. A separate analysis is provided for preliminary information available on demand response resources. This analysis was conducted for both peak and net demand peak for August 14 and 15. Overall, actual generation from all resources was only 98% of the shown RA plus RMR allocation for August 2020 during the peak. During the net demand peak this decreases to 94%. When considering only shown RA resources (but assuming all wind and solar generation is RA capacity), this decreases to 90% during peak and 84% during the net demand peak. The resource-specific analysis did not attempt to quantify when RA resources may have provided above or below its shown amount so actual generation from the shown RA fleet may be higher or lower than provided in this Preliminary Analysis.

Appendix B also includes a detailed discussion on the relevant energy market practices that impacted exports during August 14 and 15 and includes a preliminary export analysis. Unlike the resource-specific analysis, the export analysis is a deeper dive and explicitly considers and differentiates between shown RA and non-RA resources. The analysis finds that during the Stage 3 Emergencies there were more non-RA resources than exports. Lastly, the appendix concludes with a brief analysis on Energy Imbalance Market transfers, showing that available real-time transfers were below the transfer cap during the Stage 3 Emergencies and that voluntary transfers helped the CAISO market on those challenging days.

The CAISO collaborates with its Department of Market Monitoring (DMM) on monitoring and investigating such issues. The DMM is the CAISO's independent market monitoring body that reports on market design, behavior, and performance issues. The DMM is independently responsible for conducting research and presents any findings

separately. The CEC and CPUC will continue reviewing market data from the August event and will share pertinent information with DMM if needed.

B.2 Detailed Analysis on Supply Conditions Based on Current Resource Planning Targets

As described in Section 2, all load serving entities (LSEs) in the CAISO's BAA based their reliability planning on a 1-in-2 average weather forecast. The CPUC's RA program is based on a 1-in-2 average forecast plus a 15% planning reserve margin (PRM). The forecast used in the RA program is based the single forecast set developed by the CEC. The CEC sets the forecast for the CAISO footprint and works with LSEs to set the individual coincident forecasts for RA purposes. Based on the established methodology and timelines, the August 2020 obligation was based on the August 2018 IEPR Update transmission area monthly peak demand forecast of 44,955 MW, adjusted down to 44,741 MW and entered into the CAISO system by CEC staff as 44,740 MW. Table B.1 below shows the breakdown between CPUC jurisdictional LSEs and non-CPUC local regulatory authority (LRA) obligations and the resources and credits used to meet those obligations.

Table B.1: August 2020 RA Obligation, Shown RA, RMR, and Credits

CPUC	Non-CPUC	**Total**	
40,570	4,169	**44,740**	CEC forecast for 1-in-2 August 2020 (adjusted)
6,086	588	**6,674**	Total 15% planning reserve margin
46,656	4,758	**51,413**	Total obligation
91%	9%	100%	
44,763	4,164	**48,926**	August 2020 system resource adequacy shown
261	29	**290**	Reliability Must Run (RMR) contracted resources
1,632	565	**2,197**	Credits provided by local regulatory authorities
46,656	4,758	**51,413**	Total resource adequacy, RMR, and credits

The CPUC jurisdictional LSEs comprise approximately 91% of the total load. Per the CPUC's RA program requirements, a 15% PRM is added to the peak of the 1-in-2 forecast for a total obligation of 46,656 MW. The non-CPUC local regulatory authorities vary slightly in their PRM requirements but collectively yield a 14% PRM for a total obligation of 4,758 MW. Approximately 500 MW or about 1% of the total load uses a PRM less than 15%. In total across both CPUC jurisdictional and non-jurisdictional entities, the PRM is 14.9% and the obligation for August 2020 was 51,413 MW.

There are three distinct categories used to meet the total obligation. The most straightforward is the RA capacity "shown" to the CAISO. This means the physical

resource (either generation or demand response) is provided on a supply plan with the unique resource identification number (resource ID) to the CAISO system and noted as specifically meeting the August 2020 obligation. The second category of resources is Reliability Must Run (RMR) allocations from the CAISO. RMR resources are contracted by the CAISO pursuant to a reliability need and the capacity from these resources are allocated to the appropriate load serving entities to offset their obligations. The last category is "credits" to an LSE's obligation permitted by the LRA. A credit may cause a lower amount of total RA shown by the LSE scheduling coordinator to the CAISO. The composition of credited amounts are generally not visible to the CAISO and resources that are accounted for in the credits do not submit bids consistent with a must offer obligation and are not subject to availability penalties or incentives, or substitution requirements.[51] The largest credited amount is from the CPUC at 1,482 MW which reflects the various demand response programs from the investor owned utilities (IOUs), including the emergency triggered Reliability Demand Response Resource (RDRR). Since credited resources are not shown directly on the RA supply plans, they are not considered RA supply and are reflected as non-RA capacity throughout this analysis.

B.2.1 Planning Reserve Margin

As described in the background in Section 2, the 15% PRM in the RA program was finalized in 2004 to account for 6% contingency reserves needed by the grid operator with the remaining 9% intended to account for plant forced outages and higher than average demand. The PRM has not been revised since.[52]

Table B.1 below compares August 14 and 15 actual peak, outages, and 6% contingency reserve requirement against the total PRM for August 2020. For August 14, contingency reserves were actually 6.3%, which reflects the fact that the actual load was higher than the forecast. In other words, based on the forecasted load of 44,740 MW, 6% contingency reserves is 2,669 MW. However on August 14, the actual peak was 46,802 MW and 6% is 2,808 MW. Compared to the original forecasted load, 2,808 MW is 6.3%.

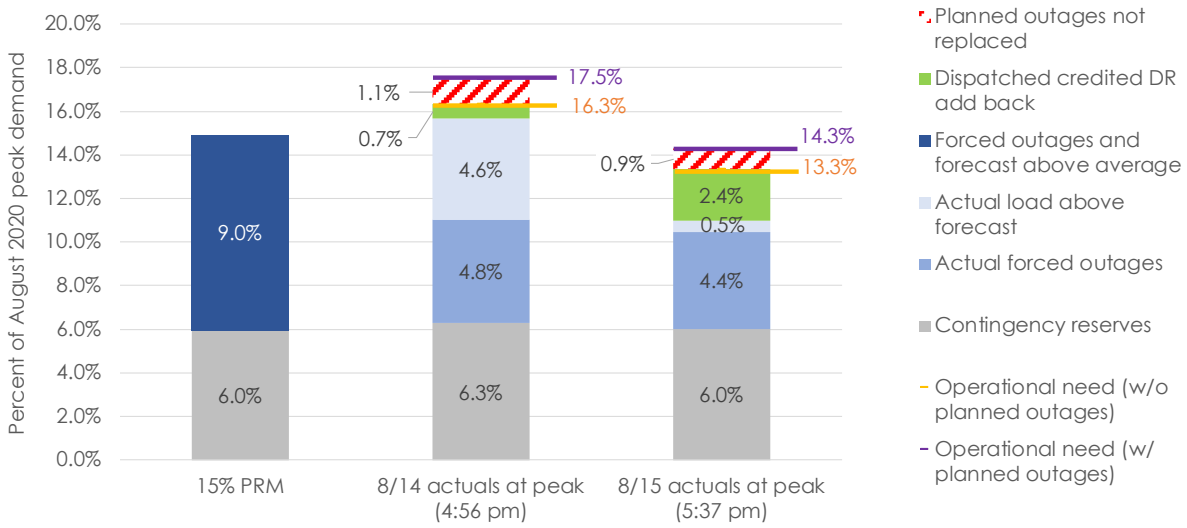
On August 14 the actual load was 4.6% above forecast but does not include another 0.7% of load that was potentially served by credited demand response. Adding back

[51] Because of this ambiguity, the CAISO has taken action recently to stop the practice of crediting and to require all RA resources to be explicitly shown on the RA supply plans. *See* Business Practice Manual Proposed Revision Request 1280: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1280&IsDlg=0

[52] One difference from 2004 is the original PRM allocated 7% to contingency reserves. The CAISO does carry another 1% in regulation up requirements. However, for the purposes of this analysis and to simplify the discussion, the 6% WECC requirement is used throughout.

in the potential effects of demand response, load was 5.3% higher than forecasted. Total forced outages were 4.8%. Adding all of these elements, the operational need for August 14 was 1.3% higher than the 15% PRM. In addition to forced outages, during the actual operating day the CAISO also had 514 MW and 421 MW of planned outages that were not replaced on August 14 and 15, respectively. The CPUC-approved PRM does not include planned outages under the assumption that planned outages will be replaced with substitute capacity or denied during summer months. Adding in the planned outages would increase the operational need to 2.5% higher than the PRM. On the other hand, the operational need for August 15 was below the 15% PRM at by 1.7% including only forced outages and 0.7% with planned outages.

Figure B.1: August 2020 PRM and Actual Operational Need During Peak



While a PRM comparison is informative, the rotating outages both occurred after the peak hour, as explained below.

B.2.2 Critical Grid Needs Extend Beyond the Peak Hour

The construct for RA was developed around peak demand, which until recently had been the most challenging and highest cost moment to meet demand. The principle was that if enough capacity was available at peak demand there would be enough capacity at all other hours of the day since most resources were capable of running 24/7 if needed. With the increase of solar penetration in recent years, however, this is no longer the case. The single critical period of peak demand is giving way to multiple critical periods during the day. A second critical period is the net demand peak, which is the peak of load net of solar and wind generation and occurs later in the day than the peak. While RA processes should be designed to meet load at all times throughout the day, the net demand peak is becoming the most challenging time period in which

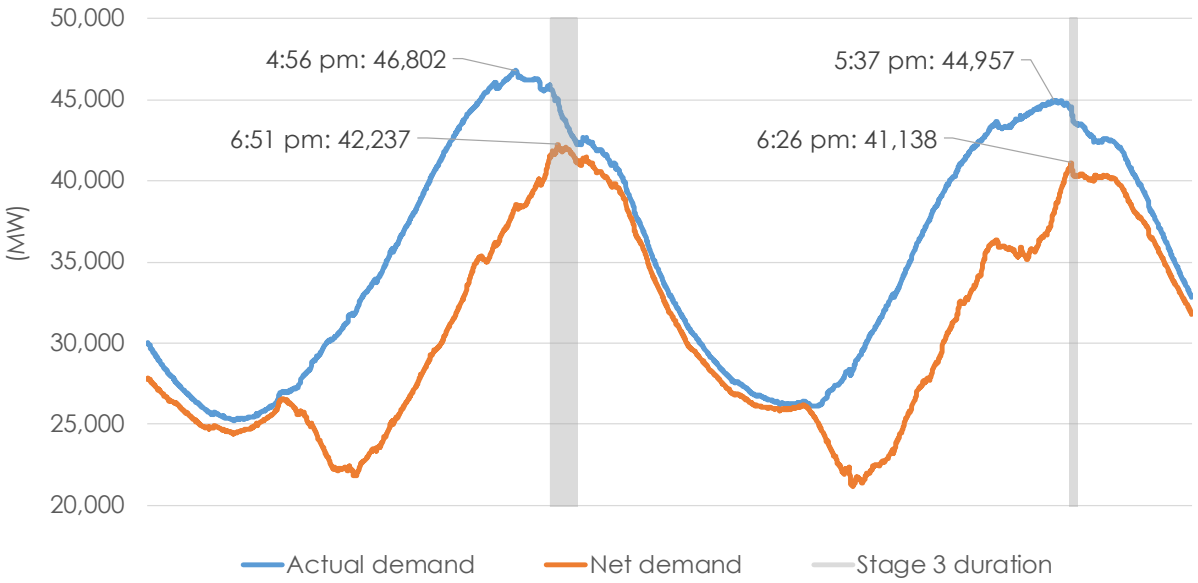
to meet demand at this time. As the grid transforms, other periods of grid needs may emerge in future.

Since 2016, the CAISO has worked with the CEC and the CPUC to examine the impacts of significant renewable penetration on the grid and found that solar generation in particular shifts the peak load to later in the day around 7 pm.[53] This is because solar generation "may shift utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by [solar generation], with generation dropping off quickly as the evening hours approach."[54] On hot days, load later in the day may still be high, after the gross peak has passed, because of air conditioning demand and other load that was being served by behind-the-meter solar comes back on the system.

The CAISO evaluates this period by examining the net demand. The net demand is the demand that remains after subtracting the demand that is served by wind and solar generation. In Figure B.2 below, the difference between the demand curve (in blue) and the net demand curve (in orange) is largest in the middle of the day (approximately 10 am until 4 pm) when renewables, especially solar, are generating at the highest levels and serving a significant amount of CAISO load. The system peak is before 6 pm. However, as the sun sets, the difference between the demand and the net demand curves narrow, reflecting a reduction in wind and solar generation that the RA program does not recognize. Furthermore, as the sun sets, demand previously served by behind-the-meter solar generation is coming back to the CAISO system while load remains high. This means demand is decreasing at a slower rate than the net demand is increasing which creates higher risk of shortages around 7 pm, when the net demand reaches its peak (net demand peak). In Figure B.2 below, the net demand peak on August 14 of 42,237 MW is 4,565 MW lower than the peak demand but wind and solar generation have decreased by 5,438 MW during the same time period. On August 15, the system peak is again close to 5 pm and the net demand peak is slightly earlier at 6:26 pm. The net demand peak is 41,138 MW, 3,819 MW lower than the peak demand, while wind and solar generation have decreased by 3,450 MW during the same time period. Note that the peak and net demand peak shown in Figure B.2 is already reduced by the impact of any demand response that dropped load.

[53] California Energy Commission Staff Report, California Energy Demand Updated Forecast, 2017-2027, January 2017. *See* Chapter 4: Peak-Shift Scenario Analysis.
[54] California Energy Commission Staff Report, California Energy Demand Updated Forecast, 2017-2027, January 2017, p. 51.

Figure B.2: Demand and Net Demand for August 14 and 15



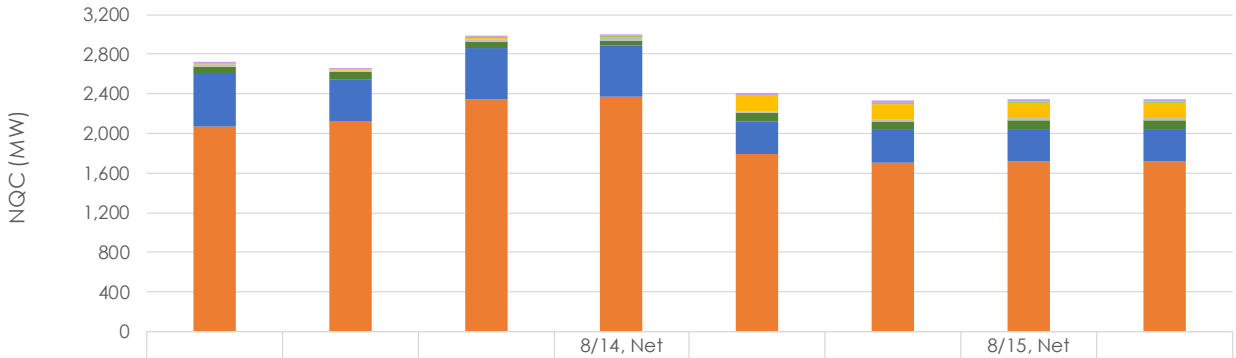
On August 14 the Stage 3 Emergency was declared at 6:38 pm, right before the net demand peak at 6:51 pm. Similarly, on August 15 the Stage 3 Emergency was called at 6:28 pm, just after the net demand peak at 6:26 pm. Given the importance of both the peak demand and net demand peak hours, this analysis will examine both as compared to the planning timeframe.

B.2.3 RA Resources Were Challenged to Provide Energy Up to the Full RA Value Shown to the CAISO

As described above, RA resources were challenged during mid-August to provide energy up to the full RA value shown to the CAISO for different reasons, both related and unrelated to the heat storm. This section provides an overview of supply, with a focus on the RA capacity shown to the CAISO as well as other related capacity and credits to meet RA requirements and their performance. The timeline traces the resources from the planning horizon into the operational (day-ahead and real-time markets) bidding, dispatch, and actual performance for August 14 and 15 peak and net demand peak periods. Note that this Preliminary Analysis uses available telemetry and does not have the benefit of using settlement quality meter data, which is typically provided to the CAISO approximately two months after the operating day. This directly impacts the CAISO's ability to provide demand response performance analysis for which direct real-time telemetry is not available. Conservative assumptions have been made in lieu of such data and noted accordingly.

Outage analysis is particularly complicated as the term "outage" can reflect a number of conditions why generators are not able to perform. For example, some outages may be temporal such as a noise limitation permit that restricts plant operations between certain hours of the day while other outages may be due to mechanical failure. In these two examples, if the outage capacity is added across the day, the noise limitation permit may artificially inflate the actual outage at the time of interest. If the noise permit only applies from midnight to 6:00 am, this outage would not be relevant to an analysis of the 7:00 pm net demand peak. Therefore, the RA plant outage information used in this analysis has been carefully analyzed for four snapshots relevant to the discussion. For each day on August 14 and 15, the outages are reported for the time of peak, net demand peak, and when the Stage 2 and 3 Emergencies were declared. Figure B.3 below provides the four snapshots based on the net qualifying capacity (NQC) capacity.

Figure B.3: RA Outage Snapshot for August 14 and 15



	8/14, Stage 2 (3:25 pm)	8/14, Peak (4:56 pm)	8/14, Stage 3 (6:38 pm)	8/14, Net demand peak (6:51 pm)	8/15, Peak (5:37 pm)	8/15, Stage 2 (6:16 pm)	8/15, Net demand peak (6:26 pm)	8/15, Stage 3 (6:28 pm)
Other	10	5	7	7	27	26	26	26
Wind	0	0	13	13	6	6	6	6
Solar	6	7	7	7	155	155	155	155
Import	29	19	29	29	20	29	29	29
Geothermal	69	69	60	60	79	79	79	79
Hydro	535	424	508	509	336	335	335	335
Natural gas	2,070	2,123	2,352	2,371	1,788	1,704	1,714	1,714
Grand total	2,719	2,647	2,976	2,996	2,411	2,333	2,344	2,344

The overall outage level may have been reduced by the CAISO's RMO issued for both days. The majority of the outages were comprised of the natural gas-fired fleet, which is largely driven by outage cards submitted because of high ambient temperatures, which impact a thermal resource's ability to produce generation.[55]

[55] Note that the Blythe Energy Center outage is reflected in the outage number and the outage was entered by the time a Stage 2 Emergency was declared. On the other hand, the Panoche Energy Center ramp down is not included in the above outage numbers because this was not

Beyond outages, a variety of factors impacted RA resources' ability to fully bid their capacity and ultimately provide energy. Figure B.4 through Figure B.7 below provide categories of unused RA capacity for each day and timeframe. As described above, plant forced outages and derates (*i.e.*, a reduction in the resource's capacity) largely affected the natural gas fleet.

The next largest category is congestion due to transmission constraints. This limits imports which is a category that includes both non-resource-specific resources as well as resource-specific imports like those from Hoover Dam and Palo Verde Nuclear Generating Station. Congestion is largely attributed to transmission constraints on imports from the Pacific Northwest. Through the month of August, a major transmission line in the Pacific Northwest upstream from the CAISO system was forced on outage due to weather and thus derated the California Oregon Intertie (COI). The derate on COI congested the usual import transmission paths across both COI and Nevada-Oregon Border (NOB).[56]

Hydro generation was affected by a variety of reasons such as derates but also a lack of day-ahead bids on RA capacity that did not have any or only had a must-offer obligation on a portion of its capacity.

Lastly, wind and solar unused RA capacity largely reflects the difference between the shown RA value and the actual production capability of these resources.

an actual plant outage and instead was a resource deviation, which the CAISO understands to be due to an erroneous instruction from the scheduling coordinator to the plant.

[56] *See* Grizzly-Portland General Electric (PGE) Round Butte No 1 500 kV Line at: https://transmission.bpa.gov/Business/Operations/Outages/OutagesCY2020.htm

Figure B.4: August 14 Peak (4:56 pm) Unused RA Capacity by Resource Type

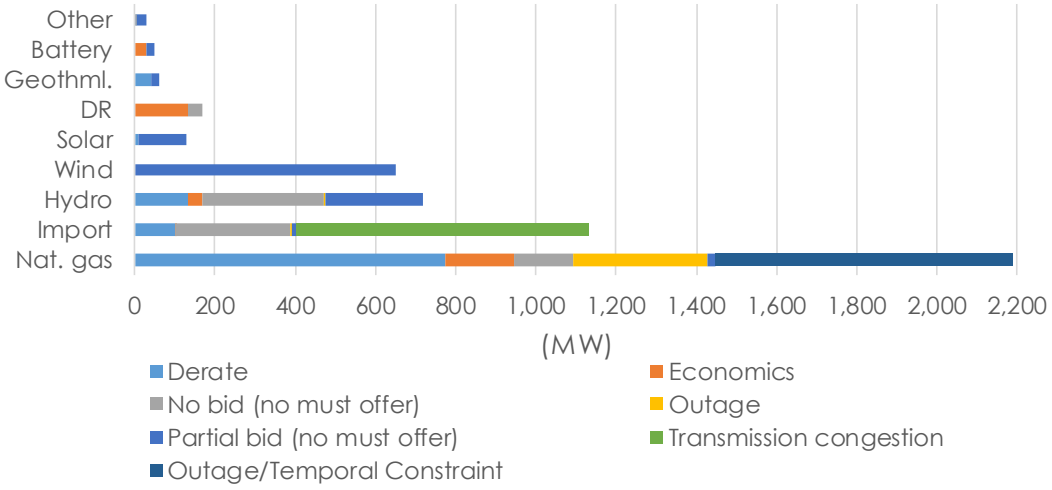


Figure B.5: August 14 Net Demand Peak (6:51 pm) Unused RA Capacity by Resource Type

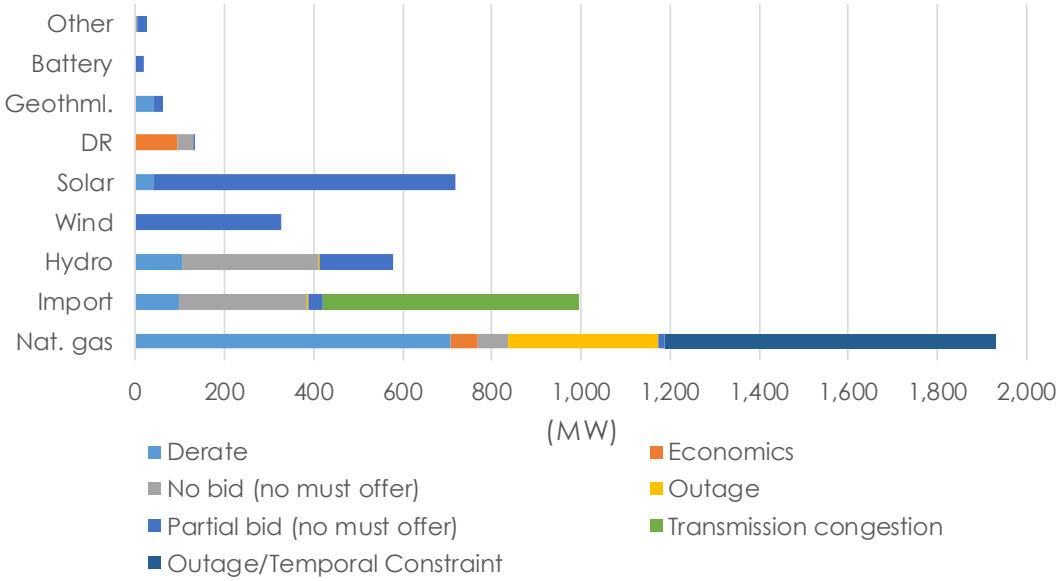


Figure B.6: August 15 Peak (5:37 pm) Unused RA Capacity by Resource Type

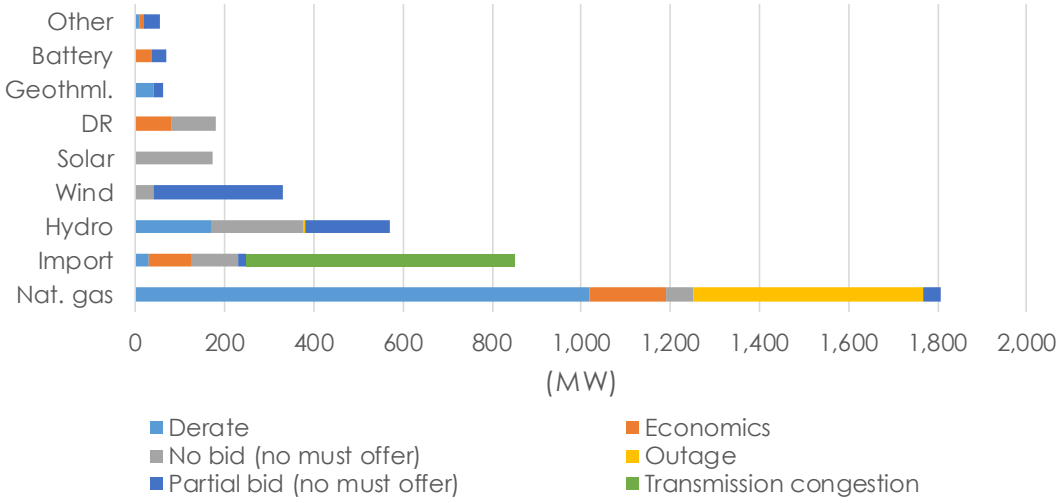
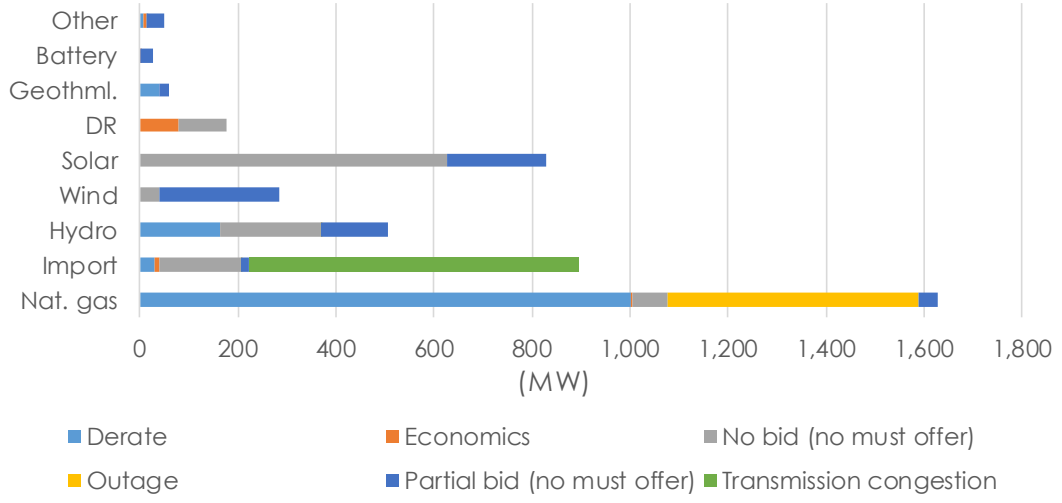


Figure B.7: August 15 Net Demand Peak (6:26 pm) Unused RA Capacity by Resource Type



B.2.3.1 Supply-Side RA Shown Capacity, Bids, Awards, and Energy Production

The CAISO clears most of its real-time need in the day-ahead market in hourly blocks, which includes both energy and ancillary services (A/S). Ancillary services are reliability services that the CAISO co-optimizes and clears with energy needs and includes both contingency reserves and regulation up and down capability. The following analysis compares the supply-side fleet from the planning horizon (August 2020 shown RA and RMR allocations), through day-ahead (bids and awards), and into real-time (real-time awards and actual energy production). As a simplifying assumption, all wind and solar

is assumed to count towards RA though that has not been validated. On the other hand, bids or generation from RA resources above the shown RA amount is categorized as "above RA," except for wind and solar generation. Similarly, if shown RA resources bid or generate below the amount shown to the CAISO, those bids or generation may be replaced by non-RA resources. Note that any credited resources that bid or are awarded are considered above the RA shown amounts. Demand response is addressed separately in the next subsection.

Figure B.8 through Figure B.11 below overlay the total shown RA supply plus RMR allocations (blue markers) on the amount of both RA and above RA day-ahead bids for peak and net demand peak on August 14 and 15, respectively.[57] Generally the shown RA resources bid 90% or more of their capacity for energy and ancillary services in the day-ahead market. In particular, natural gas and RA import bids were 95% or higher as compared to the shown RA. The main outliers are solar and wind generation as these resources produce as capable, which varies from the shown RA amounts. Especially during peak, solar day-ahead bids were up to three times as much as the shown capacity. Of note, there was also 2,500 to 3,500 MW of import bids above the shown RA amount.

[57] For ease of discussion, residual unit commitment is included in RA and above RA energy awards.

Figure B.8: August 14 Peak (4:56 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

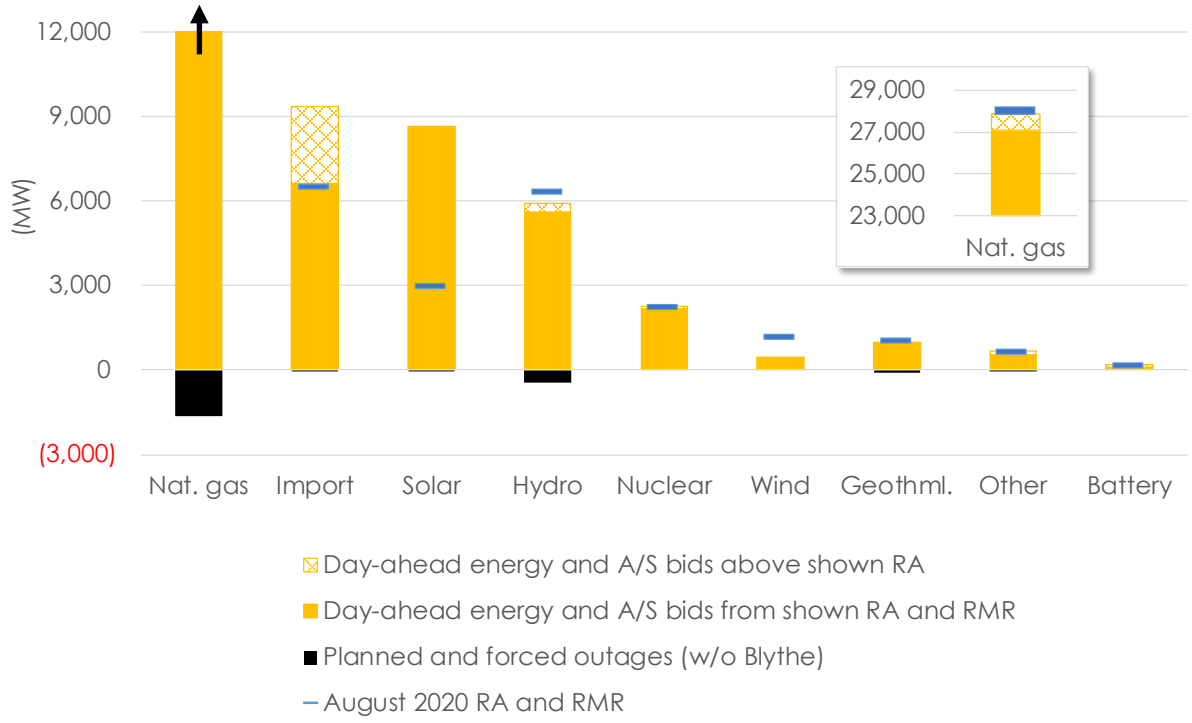


Figure B.9: August 14 Net Load Peak (6:51 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

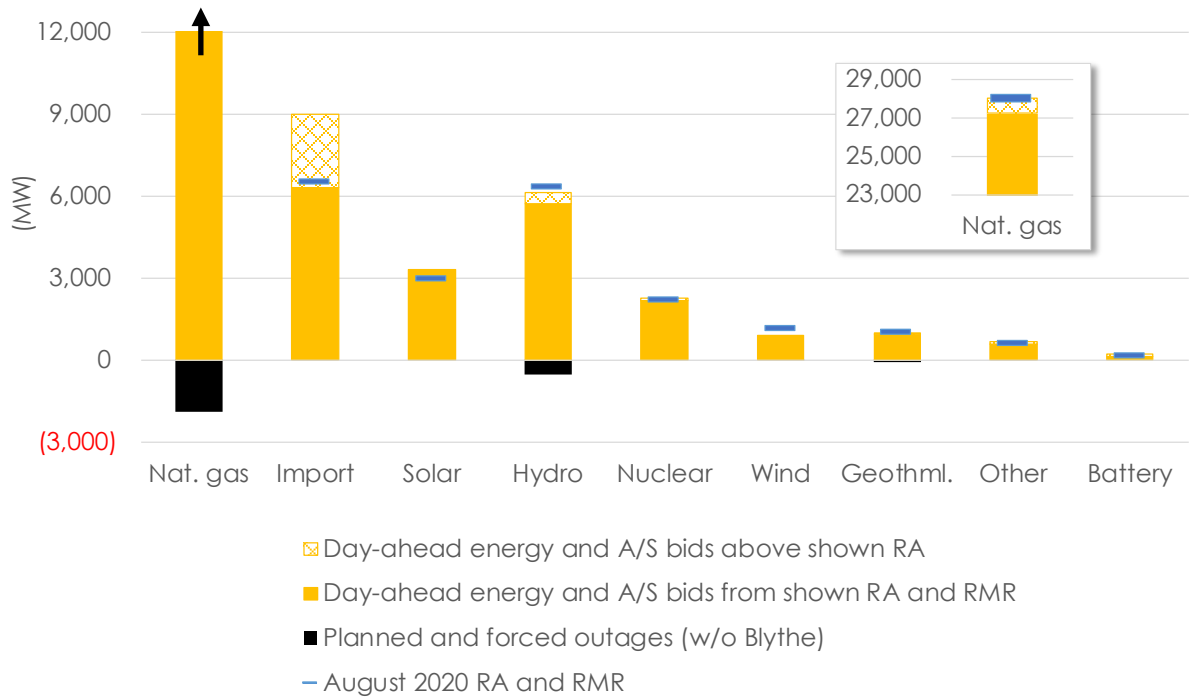


Figure B.10: August 15 Peak (5:37 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

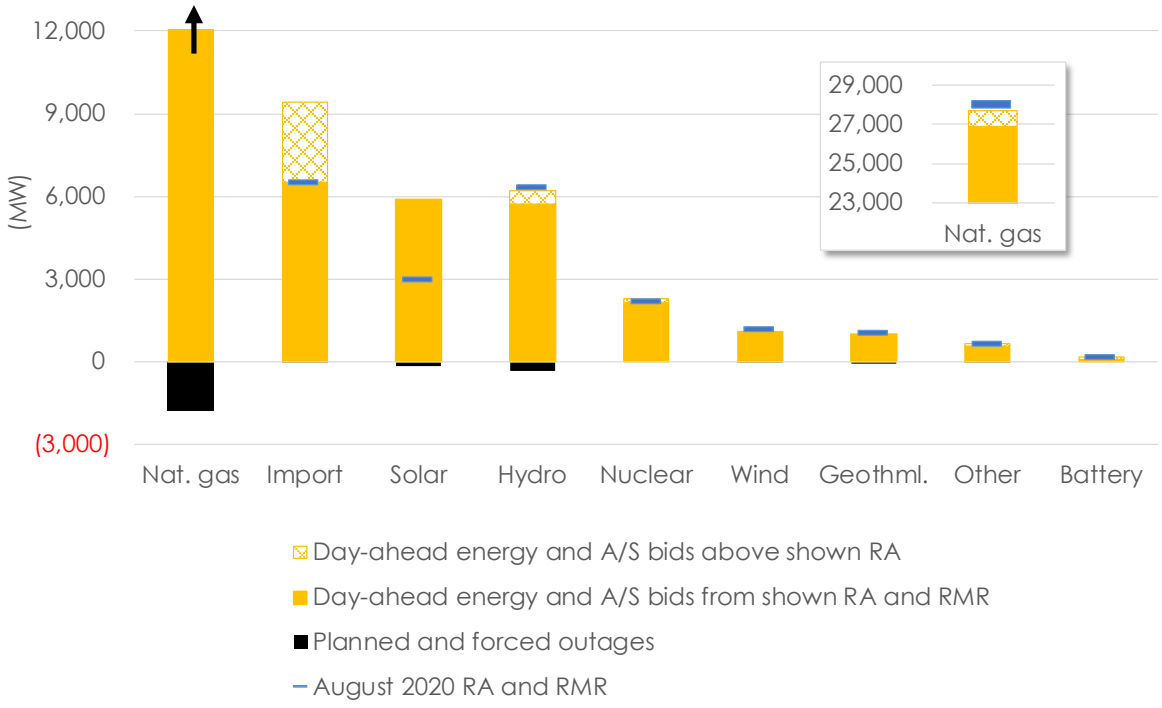


Figure B.11: August 15 Net Demand Peak (6:26 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

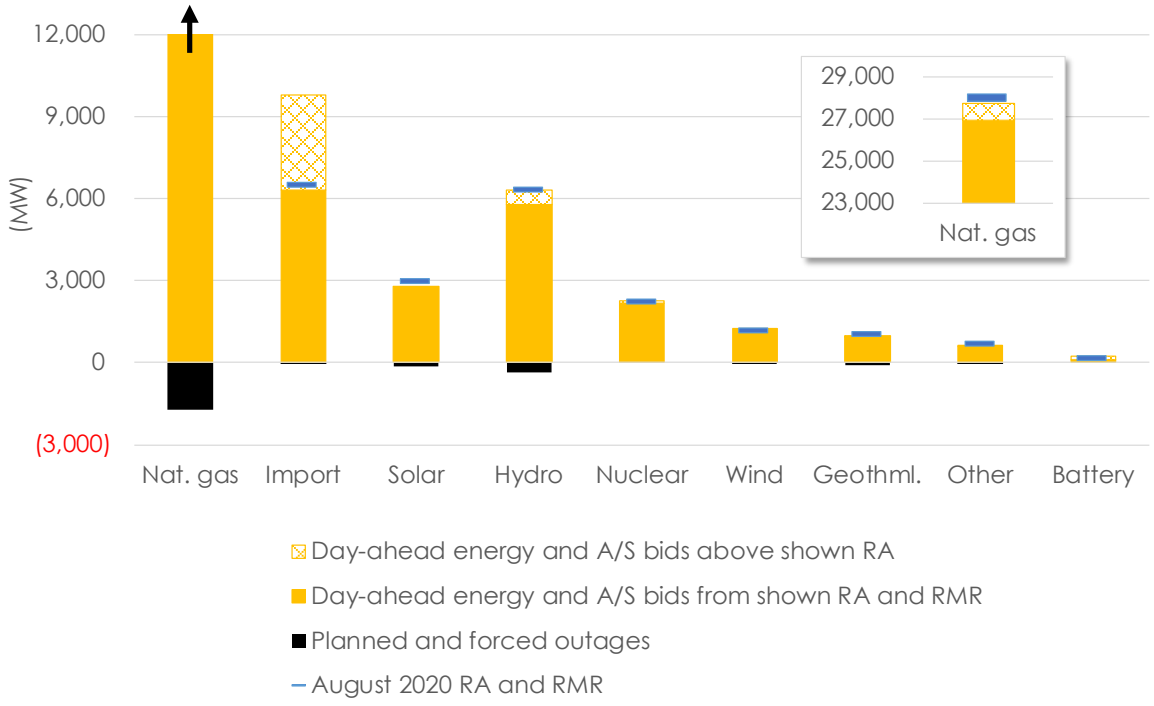


Figure B.12 through Figure B.15 below overlay the total shown RA supply plus RMR allocations (blue markers) as compared to the amount of both RA and above RA day-ahead awards for peak and net demand peak on August 14 and 15, respectively. As noted above, several factors impacted the resource fleet in different ways. Natural gas generators experienced a higher level of planned and forced outages and as such, RA natural gas resources were awarded on average only 93% of the shown capacity. The average for RA imports decreased to slightly below 90%. As discussed above, transmission congestion limited the physical import capability for RA imports. Because of this congestion, lower-priced non-RA imports cleared the market in lieu of higher-priced RA imports. Consequently, the amount of energy production from RA imports can be lower than the level of RA imports shown to the CAISO on RA supply plans. All other resources stayed relatively the same as compared to the day-ahead bid.

Figure B.12: August 14 Peak (4:56 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

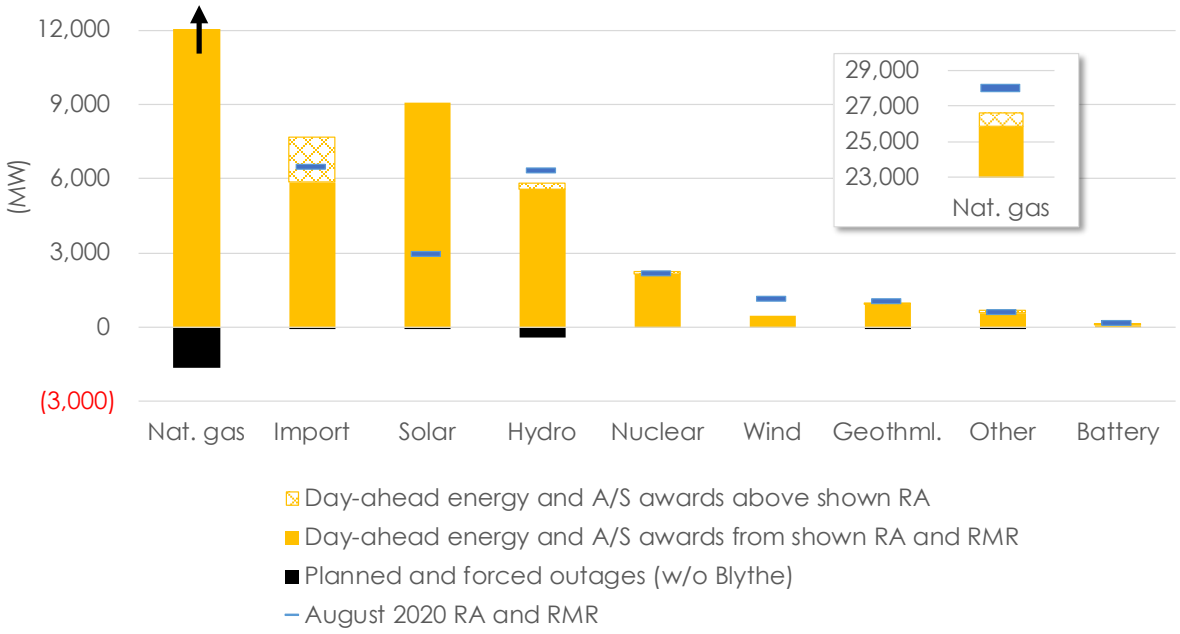


Figure B.13: August 14 Net Demand Peak (6:51 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

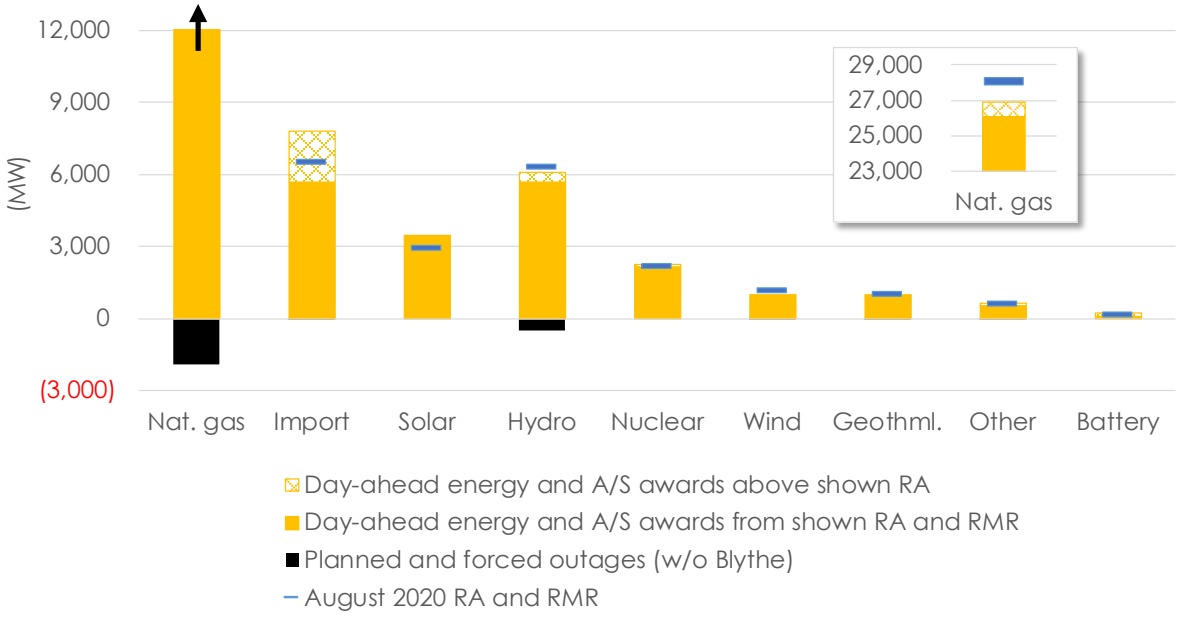


Figure B.14: August 15 Peak (5:37 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

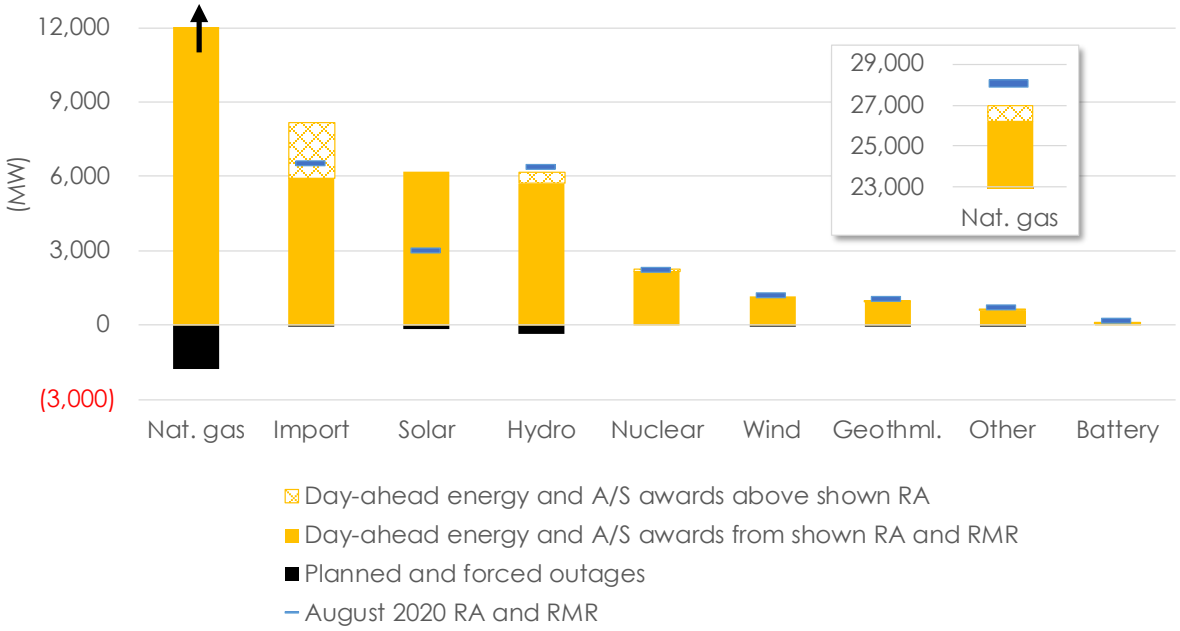


Figure B.15: August 15 Net Demand Peak (6:26 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

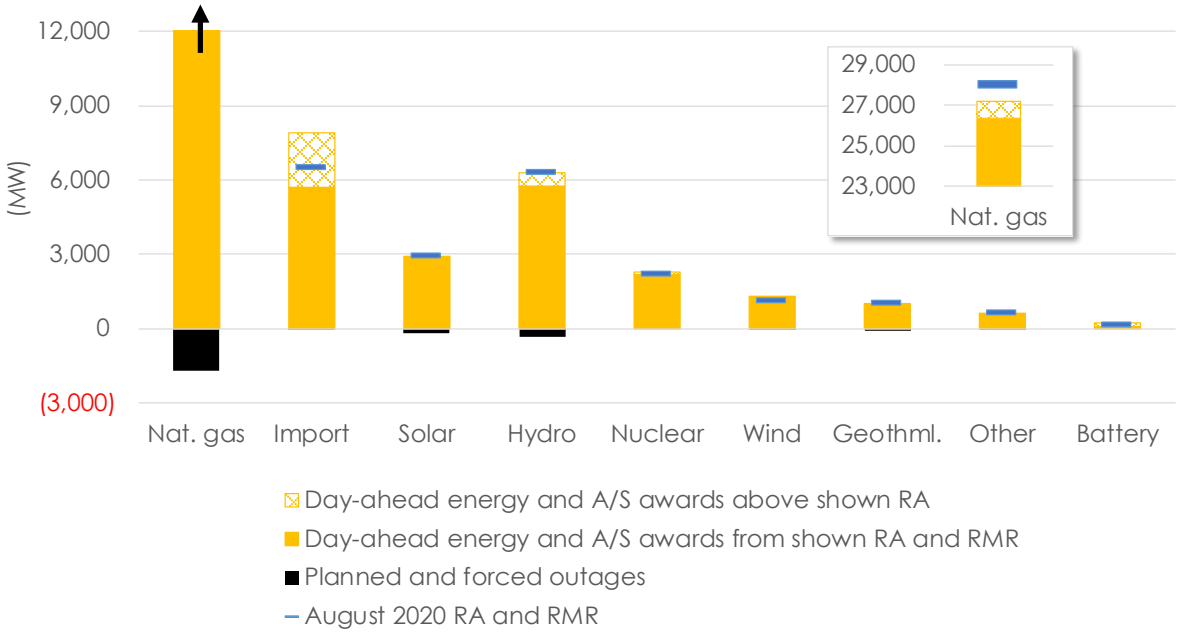


Figure B.16 through Figure B.19 below overlay three different timeframes. The first, as with the previous figures, includes the total shown RA supply plus RMR allocations (blue markers). The second timeframe is the real-time energy and ancillary service awards

and the third timeframe is the actual energy production for peak and net demand peak on August 14 and 15, respectively. Overall real-time awards were very similar to the day-ahead awards across all resources. However, energy production did vary for specific resources and that may be due to events happening in the moment or provision of ancillary services.

The RA natural gas fleet collectively generated approximately 85% of its shown RA value. The difference between real-time awards and actual generation is likely attributed to forced outages and derates due to the extreme heat. Even though the CAISO had issued an RMO notification for August 14 through 17, plants that were already on outage may not have been able to return to service safely within the timeframe and derates due to extreme temperatures are not uncommon. Furthermore, the forced outage of the Blythe Energy Center and the erroneous dispatch at the Panoche Energy Center contributed to this difference.

Actual energy generation from the hydro generation fleet may seem low, on average 73% of the shown RA value across both days and time periods, but this does not include the provision of necessary ancillary services. Real-time ancillary services awards for shown RA hydro range from 600 MW to a high of 1,500 MW during the August 14 peak demand. While actual generation production and ancillary service awards are not additive, analyzing both provides a fuller picture of the hydro fleet performance. Solar production also varied from the real-time awards. While generation during the peak remained above the shown RA values, it was half that during the net demand peak hours on both days. Solar generators collectively produced 1,600 to 4,200 MW more than the August RA values at peak but 1,000 to 1,200 MW less at the net demand peak.

Wind generators on the other hand did not have a consistent pattern with generation at only 30% (or 800 MW less) during the August 14 peak but almost 140% (or 400 MW more) during the August 15 peak. During the net demand peak, production was 40% (600 MW less) and 80% (200 MW less) of the total shown RA values for August 14 and 15, respectively.

Figure B.16: August 14 Peak (4:56 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR

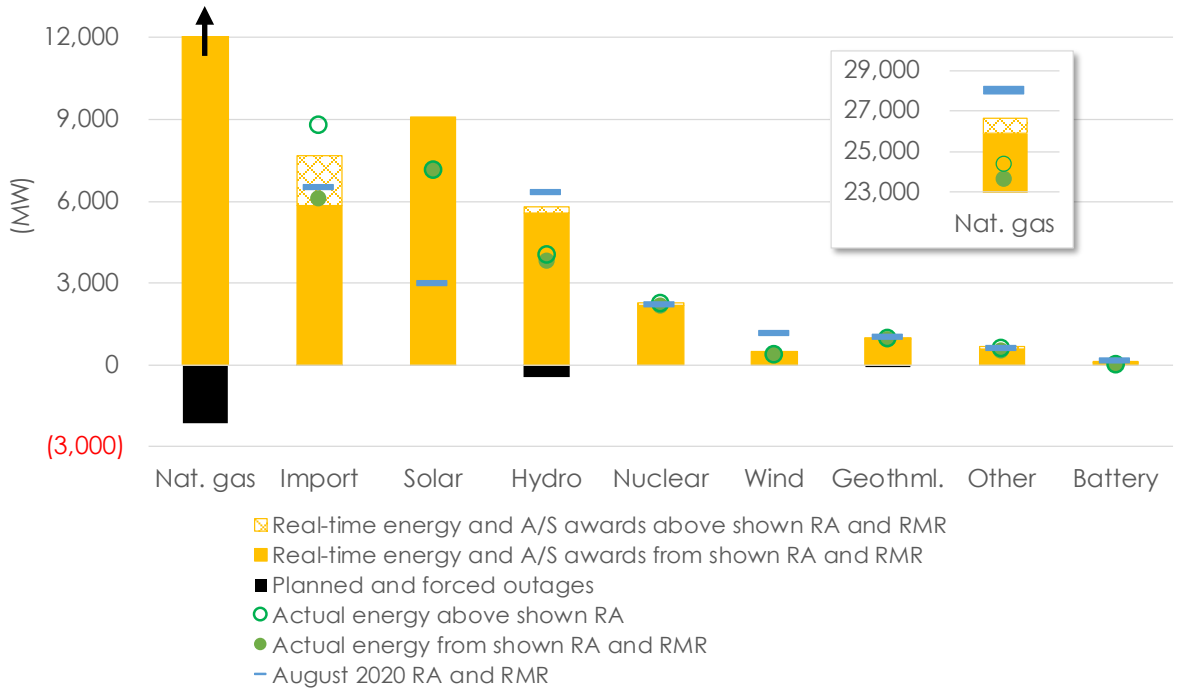


Figure B.17: August 14 Net Demand Peak (6:51 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR

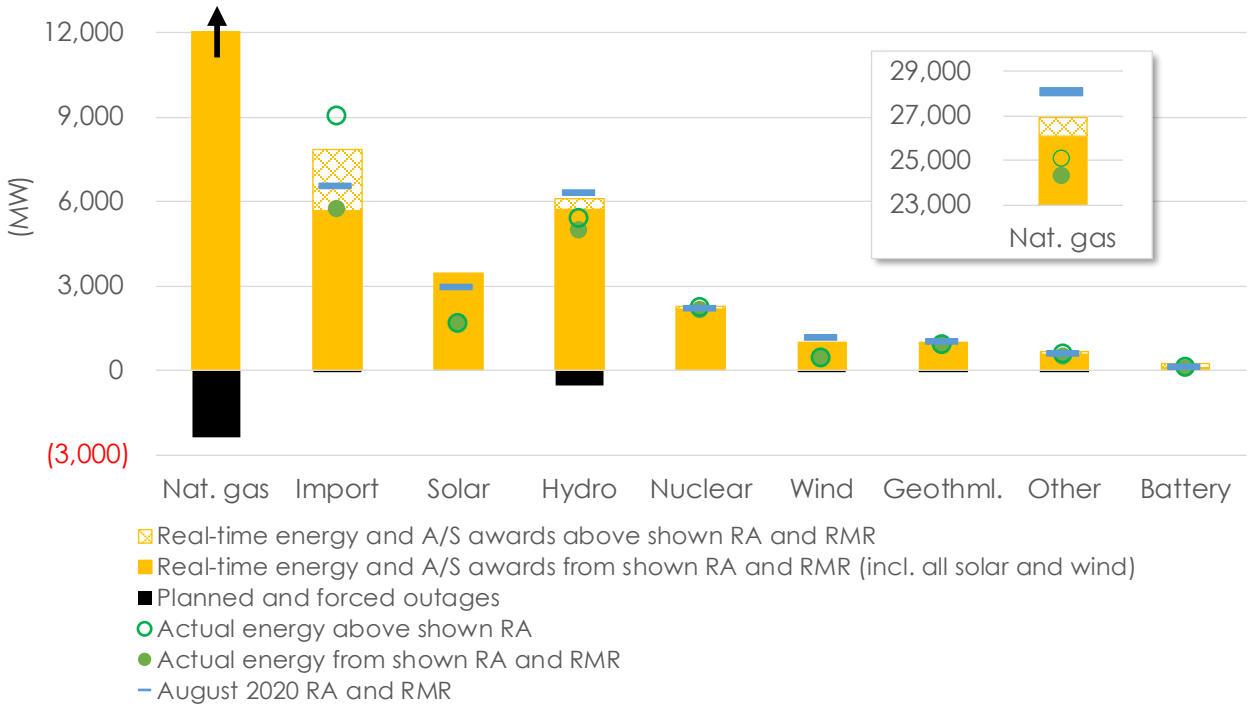


Figure B.18: August 15 Peak (5:37 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR

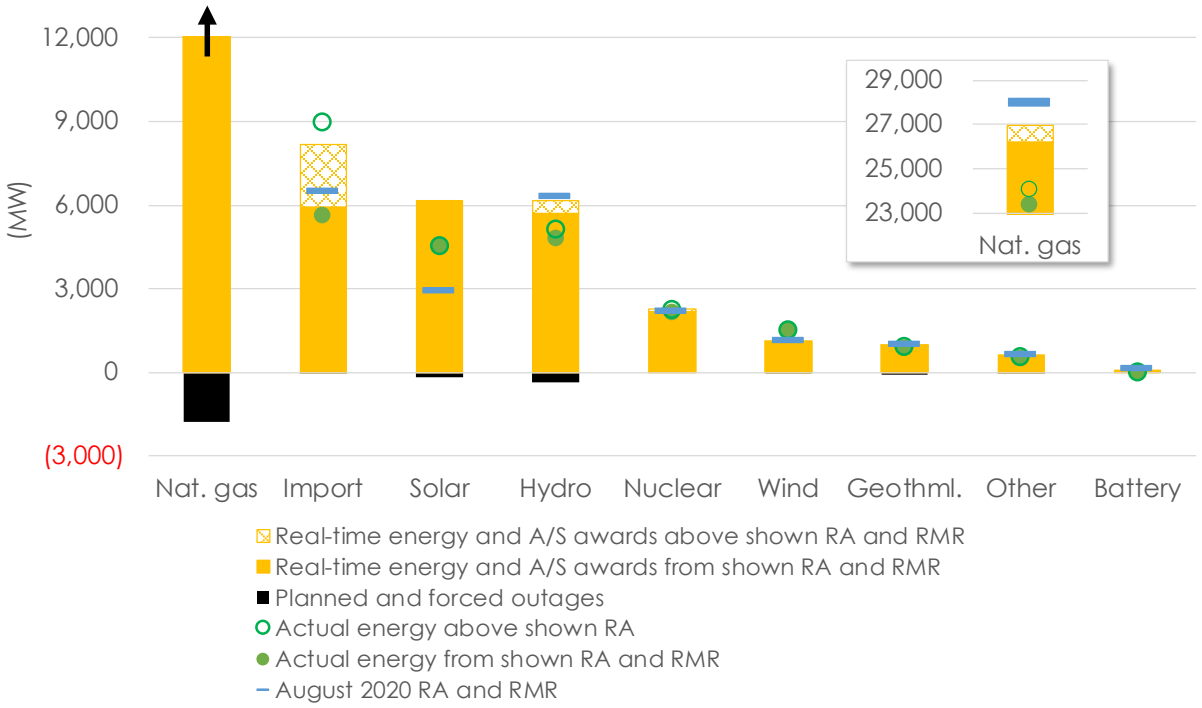
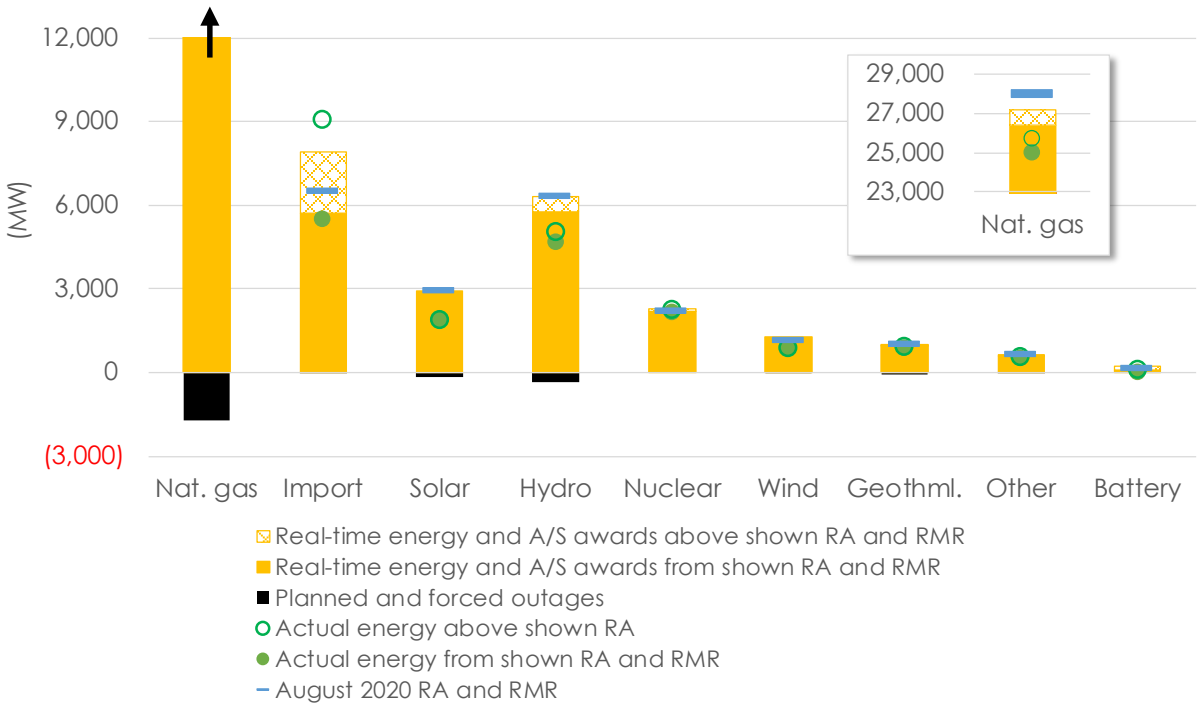


Figure B.19: August 15 Net Demand Peak (6:26 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR



B.2.3.2 Preliminary Demand Response Analysis for Credits and Shown RA

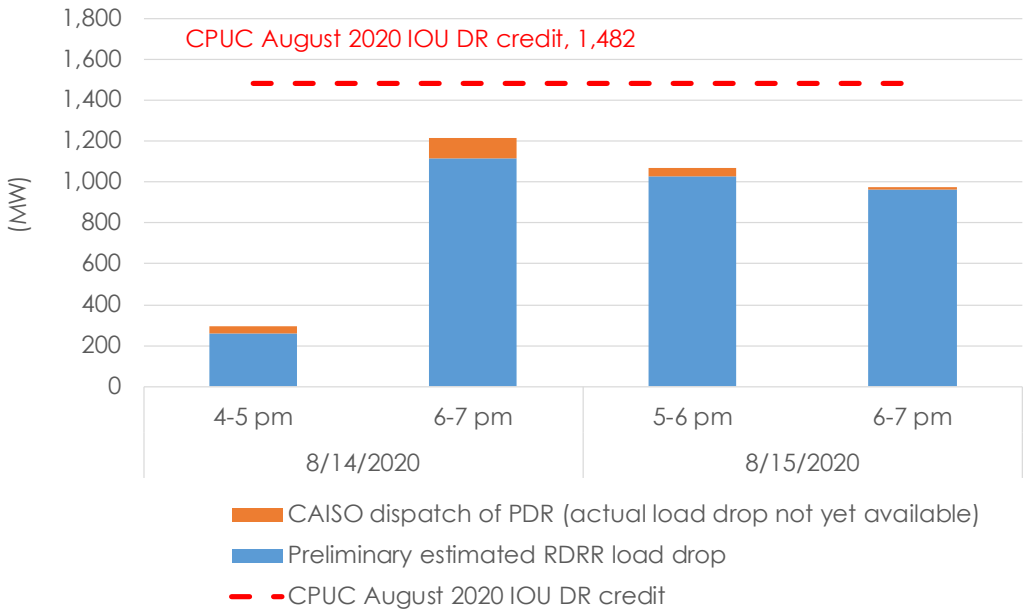
Demand response programs are designed to reduce demand at peak times. They take on many forms. Some programs bid into the CAISO's wholesale markets and are dispatched similar to a power plant. This Preliminary Analysis focuses on the largest portion of the demand response programs, which are the programs that are credited by the CPUC toward the investor owned utilities' (IOUs') RA obligations.

CPUC jurisdictional LSEs' August 2020 credits were 1,632 MW, representing 3.5% of their total obligations.[58] While the CAISO generally does not have visibility into credited amounts, the CPUC has clarified that 1,482 MW of the credit reflects IOU demand response programs and the vast majority of this amount is the RDDR emergency demand response programs that are triggered by the CAISO's emergency protocols. The 1,482 MW credit also includes the IOU's economically bid PDR demand response programs.

Per current practice, the CAISO does not receive settlement quality data until almost two months after each demand response event (*i.e.*, each call). Therefore, all information provided herein is preliminary. RDRR data was provided directly by the IOUs reflecting their preliminary estimates of load drop. PDR data is the CAISO expected load drop based on bids that were accepted into the both the day-ahead and real-time energy markets, referred to as CAISO dispatch. Figure B.20 below compares the collective RDRR preliminary estimated response and PDR dispatch from August 14 and 15 during the hours of the peak and net demand peak. These four timeframes are compared to the August 2020 CPUC demand response credit of 1,482 MW. As the figure shows these programs potentially provided a maximum response of approximately 80% of the total credited amount (August 14 during the net demand peak).

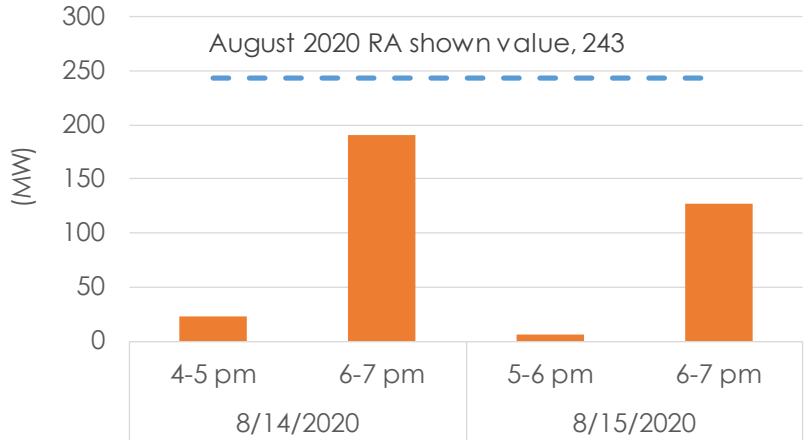
[58] Non-CPUC jurisdictional LSEs' credits were 565 MW, representing 11.9% of their total obligations.

Figure B.20: Credited IOU Demand Response: Preliminary Estimated RDRR Response and PDR Dispatch vs. CPUC August 2020 DR Credit



Aside from the IOUs, there is also economic demand response (PDR) from CPUC-jurisdictional third parties. As noted above, settlement quality data was not available at this time so Figure B.21 below shows the level of CAISO dispatch based on bids that were accepted into both the day-ahead and real-time energy markets. During the peak hours, non-IOU PDR dispatch was less than 10% of the total shown RA capacity of 243 MW for both days. Over the net demand peak hours, the dispatch increased to approximately 80% and 50% on August 14 and 15, respectively.

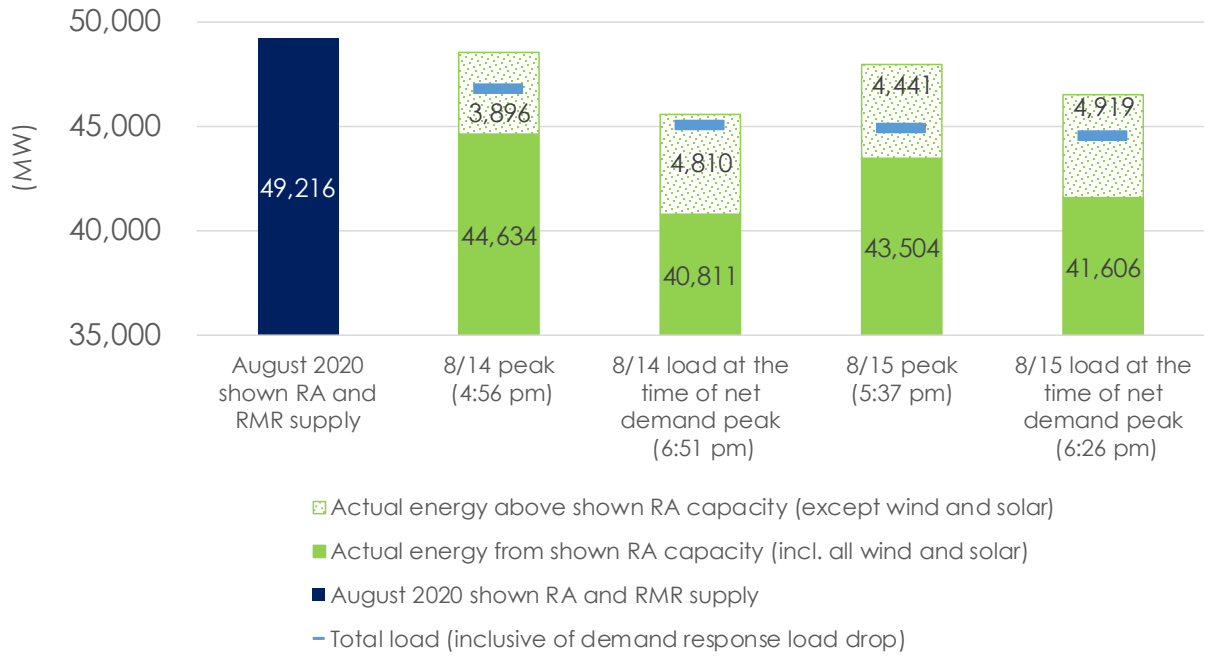
Figure B.21: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available)



B.2.3.3 Combined Resources

Figure B.22 below compares the total August 2020 RA and RMR capacity versus actual energy production for both days during the peak and net demand peak times. The August 2020 RA capacity reflects the value shown to the CAISO on RA supply plans. The second through fourth columns in the figure show the actual energy production from RA resources and energy produced above the shown RA amount. Any IOU emergency and economic demand response dispatched during these time periods is already reflected in the reduced load. The figure shows a decrease in RA-based generation between the peak and net demand peak periods. The load markers show that a portion of load was served by energy produced above the shown RA amount for each time period. Also for simplicity, the figure does not include ancillary services awards and some RA capacity, in particular hydro generation, were used to provide that service.

Figure B.22: August 2020 Shown RA and RMR Capacity vs. August 14 and 15 Actual Energy Production (Assumes all Wind and Solar Counts as RA Supply)



Overall, actual generation from all resources was only 98% of the shown RA plus RMR allocation for August 2020 during the peak. During the net demand peak this decreases to 94%. When considering only shown RA capacity (but assuming all wind and solar generation is RA capacity), this decreases to 90% during peak and 84% during the net demand peak. The resource-specific analysis did not attempt to quantify when RA resources may have provided above or below its shown amount so actual

generation from the shown RA fleet may be higher or lower than provided in this Preliminary Analysis.

B.3 Energy Market Practices Exacerbated the Supply Challenges Under Highly Stressed Conditions

Energy market practices encompass inputs into the energy market, how the energy market matched supply with demand, and ultimately whether the schedules from the market fully prepared the CAISO Operational staff to run the grid. Energy market rules as implemented at the time appear to have contributed to the inability to obtain additional energy that could have alleviated the strained conditions on the CAISO grid on August 14 and 15. The contributing causes identified at this stage include: under-scheduling of demand in the day-ahead market by scheduling coordinators, convergence bidding masking the tight supply conditions, and the configuration of the residual unit commitment market process.

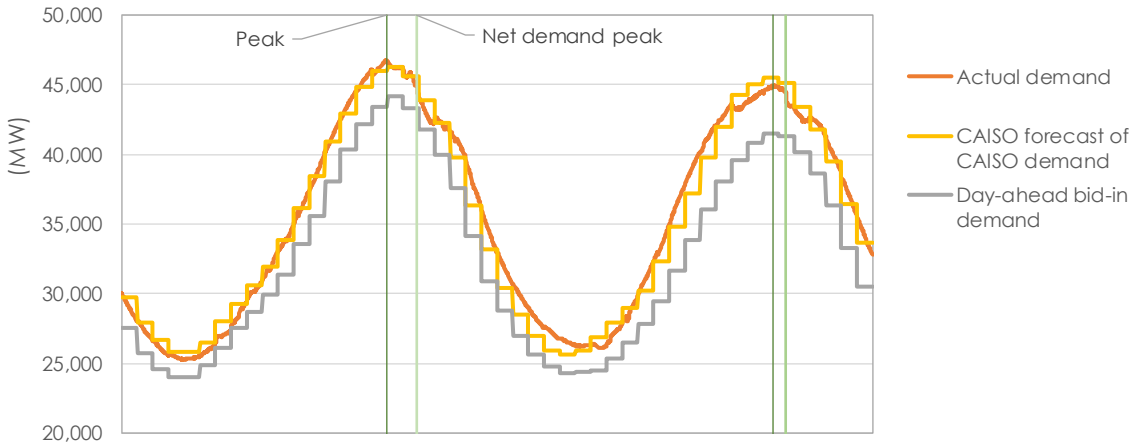
B.3.1 Demand Should Be Appropriately Scheduled in the Day-Ahead Timeframe

As explained in the background in Section 2, the CAISO operates both a market the day prior to operations (*i.e.*, the day-ahead market) and a market for the day of operations (*i.e.*, the real-time market). The day-ahead market is further split into two parts: an integrated forward market (IFM) and a residual unit commitment (RUC) process. In the IFM, scheduling coordinators can bid in their load and exports at a price they are willing to pay to have their demand served. Alternatively, they can submit self-schedule for their load and exports indicating they are a price-taker. Collectively this is referred to as bid-in demand. The CAISO BAA LSEs are not obligated to self-schedule or bid-in their load in the day-ahead market. However, there are reliability consequences as the CAISO uses the day-ahead market to firm-up demand and supply schedules that are served in the real-time. In other words, the bid-in demand is cleared against bid-in supply and the outcome of the IFM is used to set the schedules for the next operating day and will determine the level of imports needed to serve load. Therefore, to secure available capacity and transmission, a load serving entity should schedule or bid in their load. Because CAISO load and exports compete with each other for available supply, a scheduling coordinator is most likely to secure its day-ahead position through a price-taker self-schedule.

After the IFM, the RUC process starts and this is where the CAISO can commit incremental internal capacity if the CAISO forecast of CAISO demand exceeds the bid-in demand. On both August 14 and 15, the day-ahead bid-in demand fell significantly below both the CAISO forecast of CAISO demand for the next day as well as the actual demand realized in real-time. Figure B.23 below shows the August 14 and 15 actual demand (orange), CAISO forecast of CAISO demand (yellow), and bid-in demand

(grey), all of which include pumping load. The actual peak on August 14 occurred at 4:56 pm and was 46,802 MW.[59] The CAISO forecast of CAISO demand during this hour was 45,977 MW or 825 MW below actual. However, the bid-in demand was only 43,416 MW or 3,386 MW below actual. The actual peak on August 15 occurred at 5:37 pm and was 44,957 MW.[60] The CAISO forecast of CAISO demand was only 559 MW above this amount but the bid in demand was 3,434 MW below. During the net demand peak time, the under-scheduling was 1,792 MW and 3,219 MW.

Figure B.23: Comparison of Actual, CAISO Forecasted, and Bid-in Demand



Day-ahead bid-in demand below actual:

	8/14	8/15
At peak:	3,386	3,434
Time of net demand peak:	1,792	3,219

Under-scheduling the level of demand impacts the level of supply and demand, including imports and exports, cleared in the IFM and scheduled in the day-ahead timeframe. The CAISO honors self-schedules so long as there is sufficient generation and transmission capacity to support those schedules. Although this is done infrequently, if there is a shortage of supply, or transmission constraints are binding, the IFM will curtail self-schedules to clear the market. When such curtailments are necessary, the CAISO protects these load self-schedules with high priority.[61]

Scheduling coordinators may also self-schedule exports in the IFM. Export self-schedules will receive equal or lower priority than CAISO self-scheduled load depending whether

[59] This amount includes pumping load.
[60] This amount includes pumping load.
[61] Those using Existing Transmission Contract (ETC) and Transmission Ownership Rights (TOR) may also schedule balanced source (generation, imports) and sinks (load and exports) pursuant to their rights to receive higher self-schedule priority.

they are explicitly supported by capacity that has not been designated as RA capacity when scheduled into the day-ahead market. If the scheduling coordinator identifies in its export self-schedule that it is explicitly supported by capacity that is not designated as RA capacity, that export self-schedule will receive the same priority as internal self-scheduled load. All other self-scheduled exports, *i.e.*, any export self-schedules that do not identify capacity that has not been designated as RA capacity will have a lower priority than internal load. If there is a shortage of supply or transmission constraints are binding, these lower priority export self-schedules will only clear the IFM if sufficient supply is available after serving self-scheduled CAISO load and the higher priority exports.

In this way, even though entities scheduling exports cannot tie the export to RA capacity, the CAISO ensures the IFM curtails exports that may be served from RA resources first to the benefit of internal CAISO load.

CAISO load cannot benefit from the higher protection for their day-ahead schedules if scheduling coordinators do not actually submit self-schedules to the day-ahead market to cover their expected load. Therefore, if CAISO load under-schedules in the day-ahead market, that is, it does not submit sufficient self-schedules or bids in the day-ahead market to cover the amount of load that actually materializes in the real-time market, export schedules will be cleared and will secure a firmer position in the day-ahead market.

Figure B.24 below shows the amount of total exports[62] cleared for August 13 through 15 relative to the amount of capacity that was in the market but was not associated with capacity that was not shown to be RA capacity. Unlike the prior analyses, this export analysis is based on a deeper dive that specifically tracks resources shown for RA, rather than a simplifying assumption applied to wind and solar resources. For this export analysis, a resource with any amount of shown RA capacity is fully categorized as RA. The analysis finds that during the Stage 3 Emergencies there were more non-RA resources than exports.

[62] Net of energy wheeled through the CAISO system.

Figure B.24: Comparison of Non-RA Cleared Supply vs. Total Exports

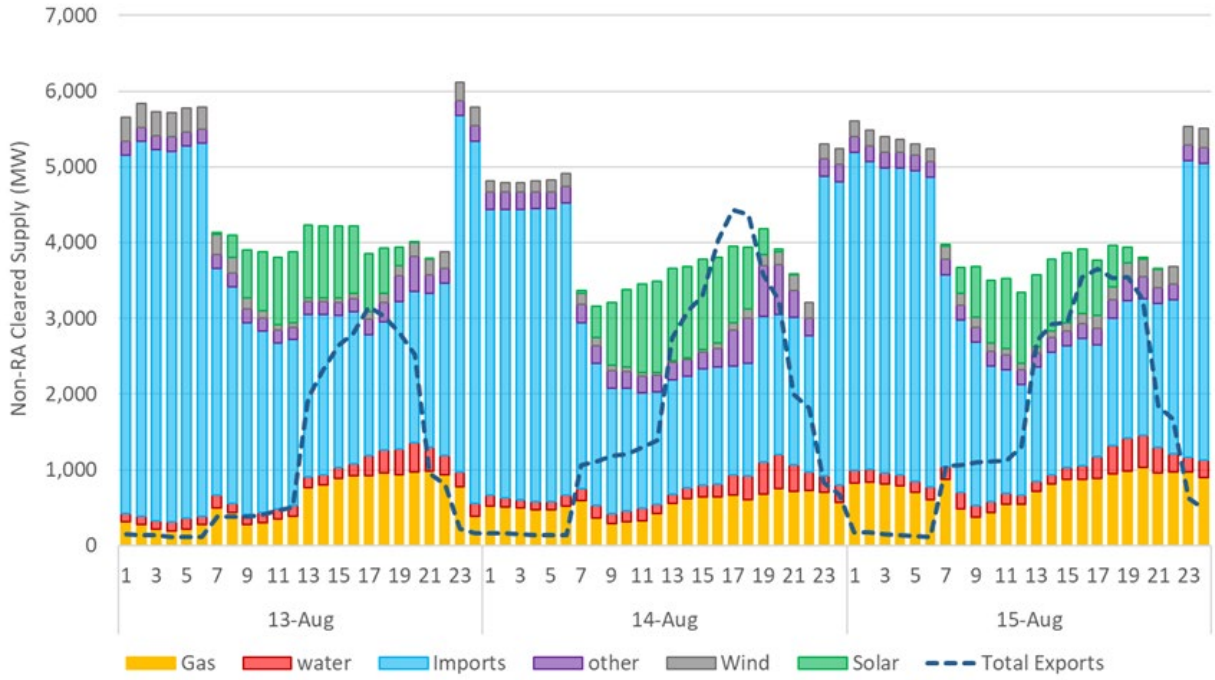
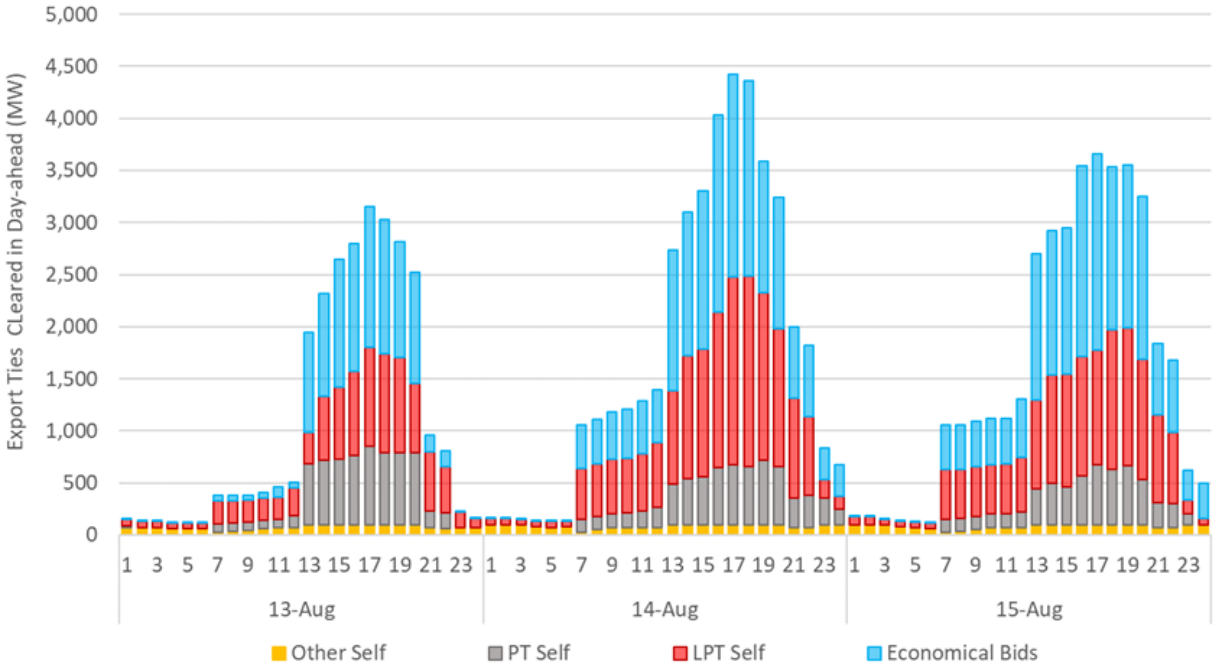


Figure B.25 below shows the breakdown of export types (reflected as the dotted line in the prior figure) from: economical bids, priority (PT), lower priority (LPT) and other self-schedule types.

Figure B.25: Total Exports by Category



B.3.2 Convergence Bidding Masked Tight Supply Conditions

Scheduling coordinators can also submit convergence bids for supply and demand at internal locations on the CAISO grid. Convergence bids are financial positions in the IFM that automatically liquidate at the real-time price.[63] As the name suggests, convergence bidding should allow bidders to converge or moderate prices between the day-ahead and real-time markets. Convergence bids cannot be price-takers and therefore they are only considered to the extent there are sufficient supply bids to clear the demand and are not protected from curtailment as are self-scheduled CAISO load and exports. However, if CAISO load does not submit sufficient bids or self-schedules in the day-ahead market, the convergence supply bids will influence how much load and exports are scheduled in the day-ahead market. Convergence supply bids may support bid-in load and exports and may avoid triggering the need to curtail self-schedules. In addition, convergence demand bids may clear supply schedules for load that actually materializes in the real-time. Convergence demand bids do not guarantee that the specific load schedule will be served in the real-time, but they may facilitate the scheduling of physical generation to serve actual demand in the real-time.

Figure B.26 illustrates how under-scheduling of CAISO load when there is a shortage of supply can result in lower-priority self-scheduled exports clearing the market compared to what would have cleared had load scheduled closer to the actual load level. In contrast, Figure B.27 illustrates how under-scheduled load has no impact on the amount of cleared self-scheduled exports when there is sufficient supply. While the cleared price could be lower with less load schedule the amount of self-scheduled exports that clear is the same.

[63] Convergence bidding is not permitted at the interties. Therefore, only physical export bids are permitted.

Figure B.26: Illustrative Example of Impact of Under-Scheduled Load Under Supply Scarcity

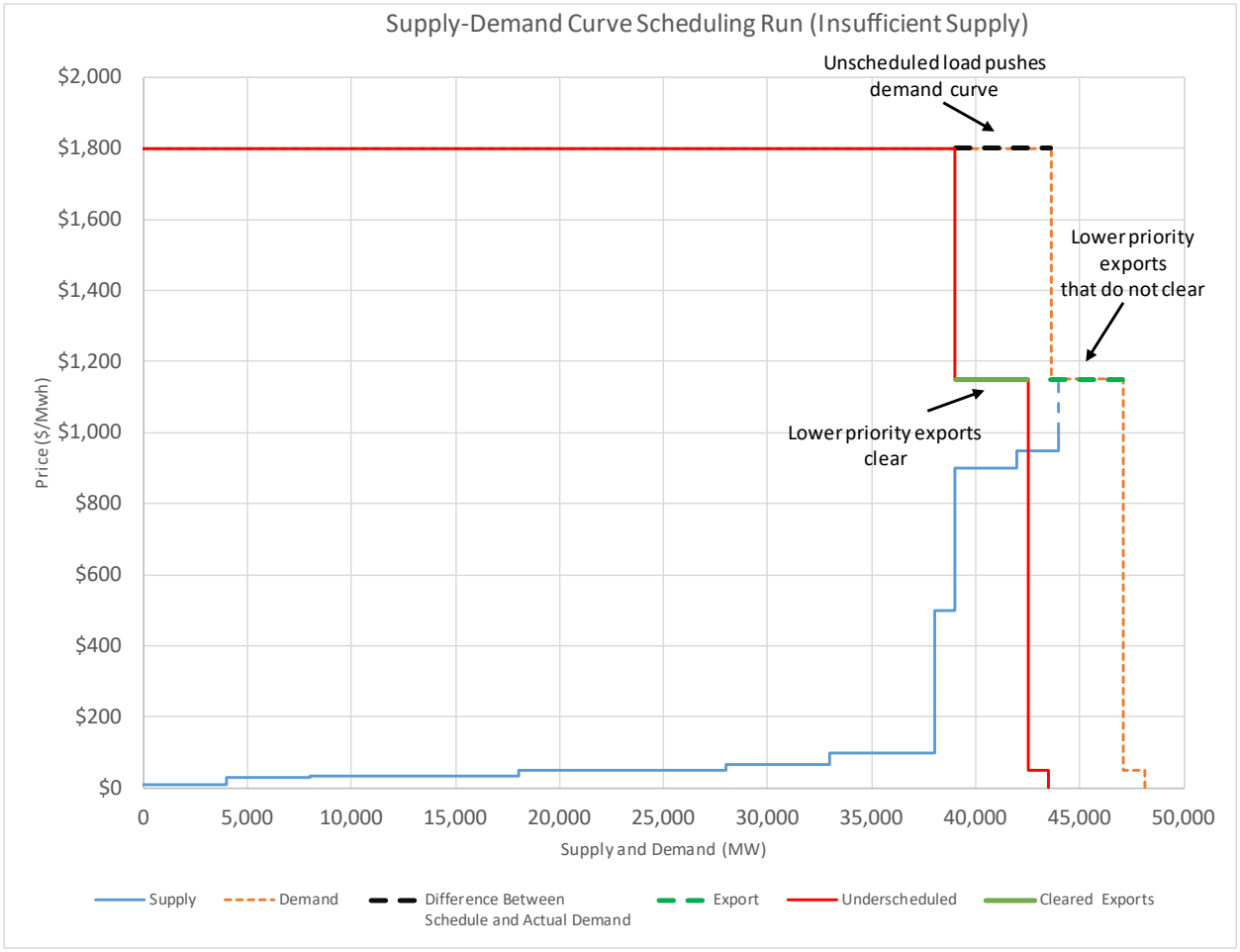
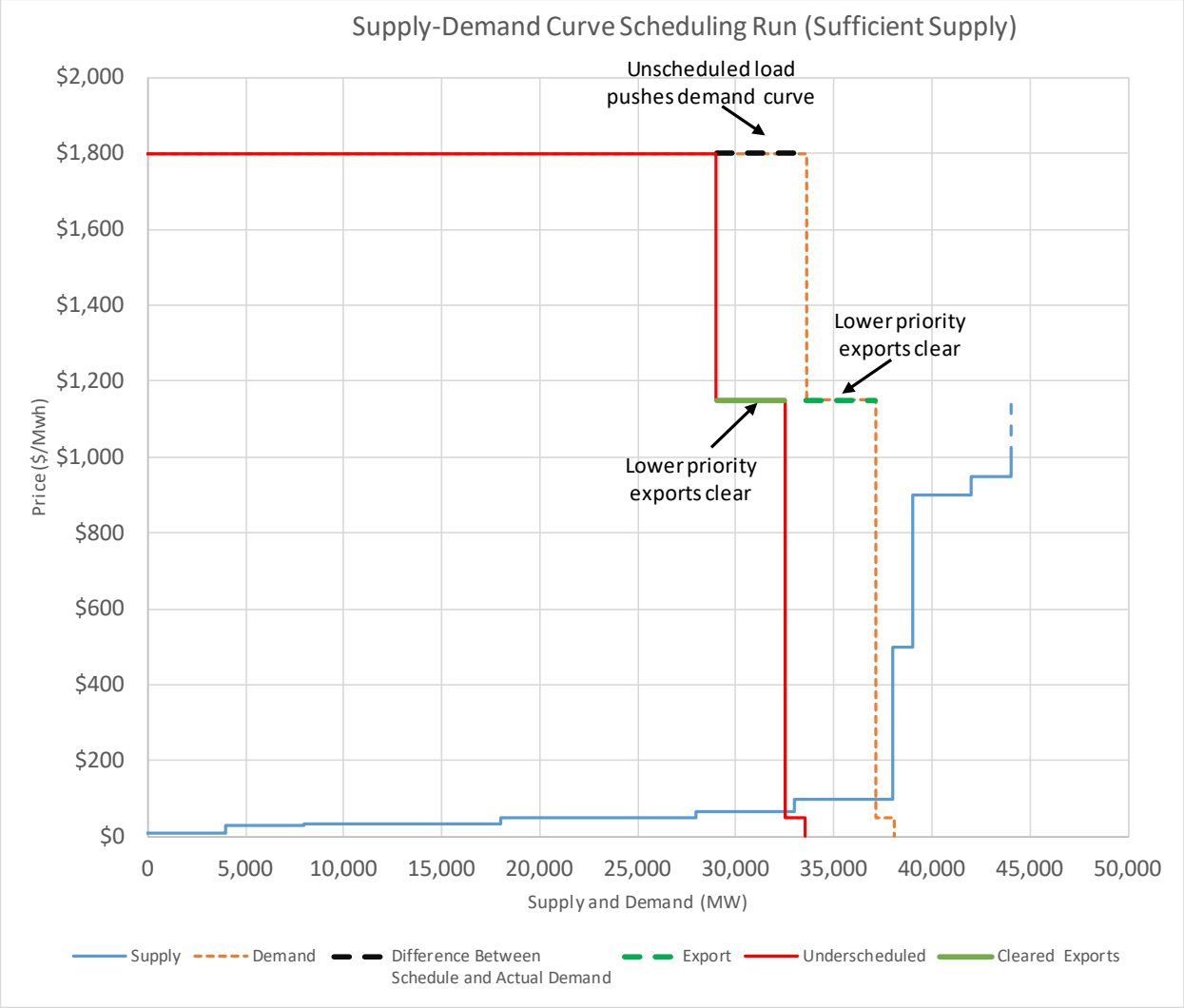
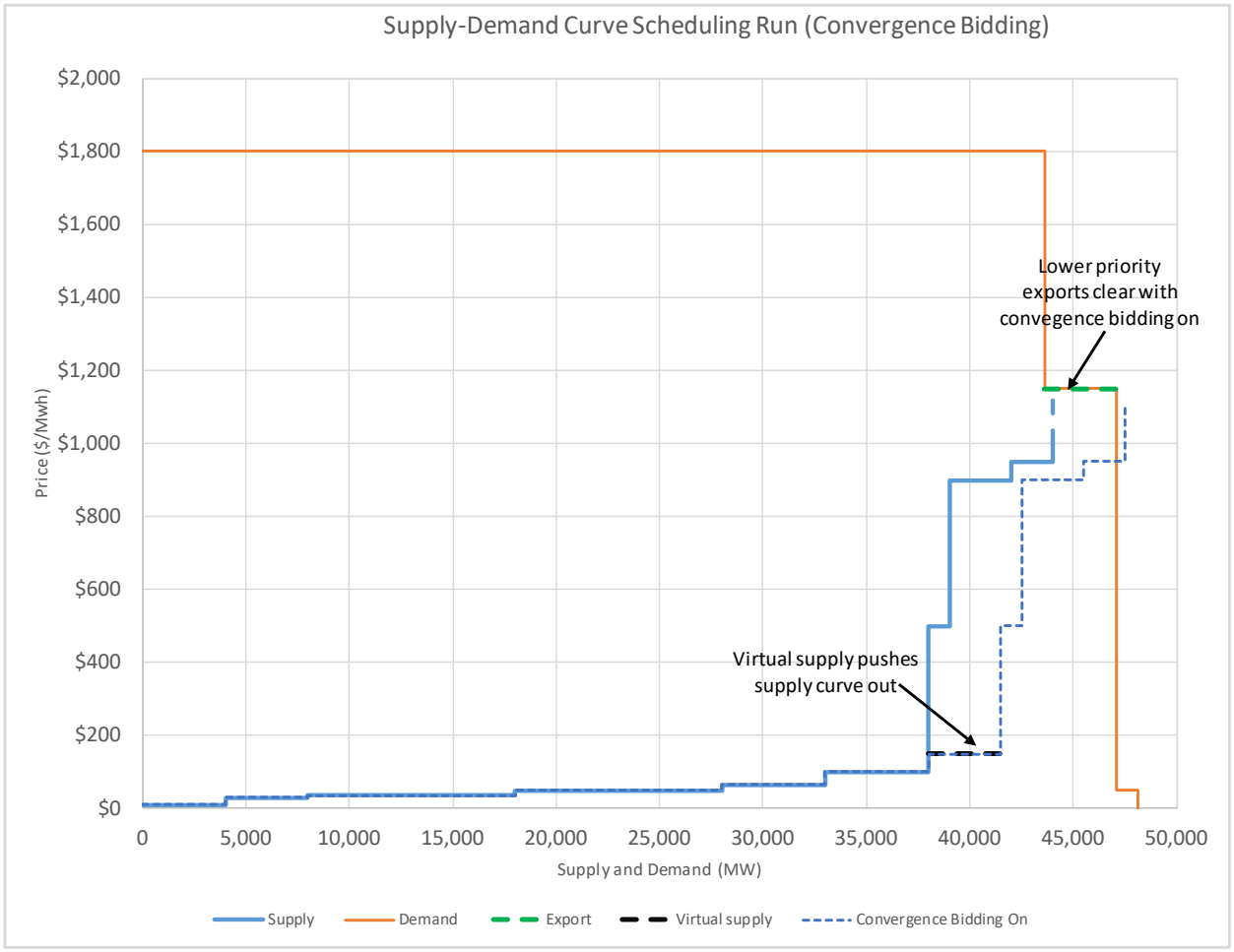


Figure B.27: Illustrative Example of Impact of Under-Scheduled Load Under Supply Sufficiency



Under normal conditions, when there is sufficient supply, convergence bidding plays an important role in converging or moderating prices between the day-ahead and real-time market conditions. Similar to under-scheduled load, during conditions in which physical supply is scarce, cleared virtual supply can mask physical supply shortages and allow more demand including low-priority exports to clear than what can be physically supported (refer to Figure B.28 illustration).

Figure B.28: Illustrative Example of Impact of Convergence Bidding



In the day-ahead IFM conducted for the August 14 and 15 trading days, the IFM solution was able to clear the CAISO load and self-scheduled exports self-schedules, regardless of their priorities. The IFM for those days cleared without having curtailments, in part because load under-scheduled based on the day-ahead forecast of demand, and in part because financial supply side positions taken by convergence bids facilitated the clearing of all demand and exports.

B.3.3 Residual Unit Commitment Process Changes

The day-ahead RUC process runs after the IFM and is also part of the day-ahead market. The RUC inputs differ from the output of the IFM in several key ways to ensure the CAISO can produce a reliable operating plan for the next operating day. First, the CAISO load cleared in the IFM is replaced by the CAISO forecast of CAISO demand, which does not include exports. Second, the wind and solar schedules cleared in the IFM are replaced by CAISO forecast production for wind and solar resources. Lastly, the

virtual supply and demand cleared in the IFM are removed. Under normal conditions when there is sufficient supply to commit, RUC will commit additional resource capacity to ensure forecast load can be served in the real-time. However, in rare circumstances that there is insufficient supply to commit, the RUC process has to address the supply insufficiency. There are two passes in the RUC process: a scheduling run pass and a pricing run pass. The RUC scheduling run pass is designed to address any unresolved constraint using an intricate but prescribed set of relative priorities for how to relax the constraint or curtail schedules previously determined in the IFM. Prior to the implementation of Pricing Inconsistency Market Enhancements (PIME), the scheduling run results were the source of final RUC awards and schedules. The pricing run was intended to produce prices that align both bid cap of $1,000 as well the scheduling run results.[64] However, after the implementation of PIME both IFM and RUC were redirected to use pricing run results for the source of both schedules and prices.

As discussed above, under normal supply and transmission conditions, the CAISO does not expect RUC to have to curtail day-ahead schedules cleared in the IFM. The RUC also does not dispatch down supply resources scheduled in the IFM. However, the CAISO enforces both power balance and intertie scheduling constraints in the RUC to ensure the schedules produced in the IFM are physically feasible. The power balance constraint ensures that forecast load can be met and the intertie constraint ensures that the net of physical imports and physical exports schedules on each intertie are less than or equal to the scheduling limit at the intertie, in the applicable direction. Through these RUC constraints the CAISO determines what portion of the day-ahead schedules are physically feasible, and which portion that market participants should tag when the E-Tag is submitted in the day-ahead.

After experiencing the August 14 and 15 events, the CAISO reviewed the results of the day-ahead market for those trading days more closely and observed that rather than reducing exports that cleared the IFM that were not feasible, the RUC pricing run solution relaxed the system power balance constraint. However, in the RUC scheduling run pass, IFM exports were relaxed based on their order of priority prior to relaxing the power balance constraint. The CAISO had previously applied the PIME to the RUC as a matter of applying PIME to all its markets. The PIME in the other markets is necessary because it is necessary to have consistency between energy schedules and prices. The lack of energy schedules in RUC obviates the need for PIME in the RUC process. As a result, starting from the day-ahead market for September 5, 2020, the CAISO stopped

[64] In 2014, the CAISO implemented pricing functionality enhancements to address observed inconsistencies between scheduling run schedules and pricing run prices. The enhancement is referred to as Pricing Inconsistency Market Enhancement (PIME). Among other things, PIME changed from using schedules from the scheduling run to using schedules produced by the pricing run.

applying the PIME functionality to RUC process, which enabled it to use the scheduling run results for RUC schedules and awards instead of the pricing run results.

After the day-ahead market and leading up to the real-time market, the CAISO protects the outcome of the schedules awarded in the day-ahead market as inputs into the real-time market so as to ensure that cleared day-ahead schedules are honored and treated as "firm" in the real-time. This is accomplished by providing these schedules a higher priority than new schedules that were not scheduled and cleared day-ahead market and now being considered for in the real-time market.[65] ll the cleared schedules that clear the day-ahead market are protected equally in the real-time market process, regardless of how they were submitted to the real-time market. In the real-time market, the CAISO again allows participants to submit export bids and supply bids. However, load cannot submit bids to the real-time market and the CAISO clears the market based on the CAISO forecast of CAISO demand, at the same time the market solution considers clears export schedules and bids. Like the day-ahead market, participants can submit export self-schedules and the priorities for export schedules are the same as the day-ahead market. That is, the newly submitted real-time export self-schedules that are supported by non-RA capacity will have the same priority as CAISO load. However, any new exports that did not clear day-ahead market and are not explicitly supported by non-RA capacity will have a lower priority as the CAISO relies on that generation to serve its load reliably.

In addition to potentially curtailing exports through the CAISO markets, the CAISO operators may curtail export or import schedules for purposes of reliable operations. However, there are significant operational matters that need careful consideration before curtailing cleared and tagged exports in real-time. In order for such curtailments to be even be implemented effectively, information about the individual exports and relative priorities would have to be readily available to the operators. Furthermore, those relying on such exports need to be made aware of the potential risk of such exports being curtailed in advance so that they can take measures to avoid being put into an emergency condition upon loss of such exports. Absent such operator information or neighboring BAAs being aware of curtailments in a timely manner, curtailing cleared and tagged exports during quickly emergent real-time conditions would not be consistent with coordinated and good utility practices. Furthermore, the curtailment of the export may not be effective in addressing the reliability issue. In other

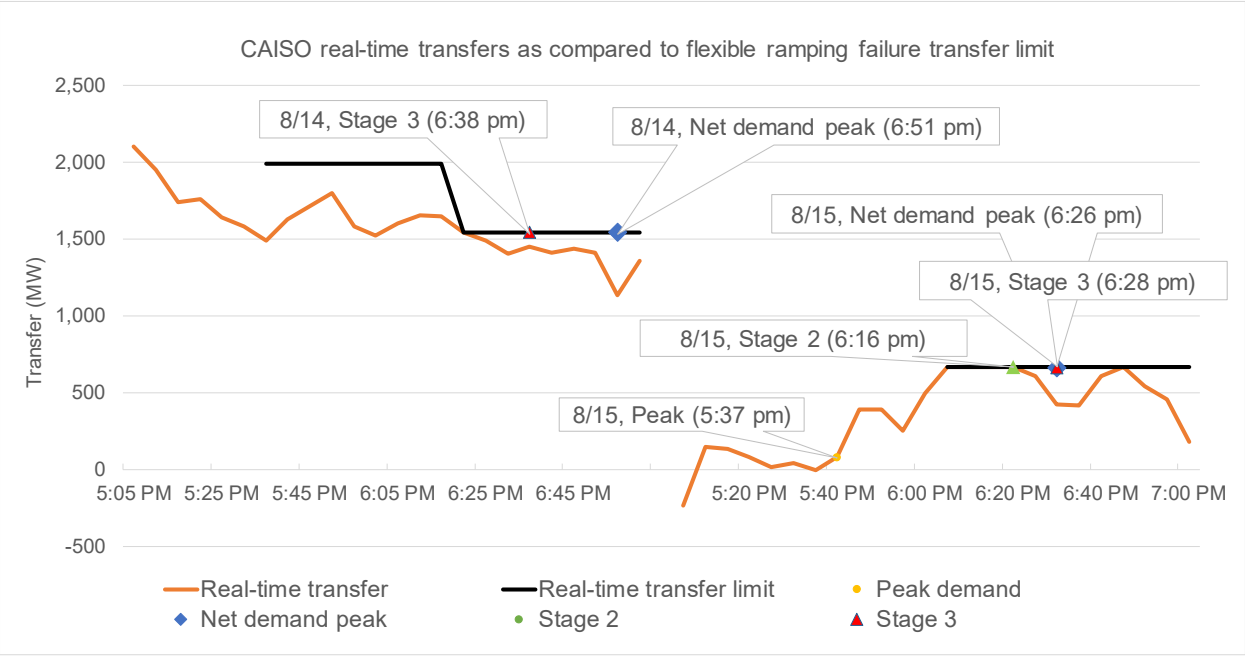
[65] Until September 5, 2020, the CAISO was protecting the full day-ahead schedule as cleared through the day-ahead IFM process. The CAISO modified its process to now only protect what is determined to be physically feasible through the day-ahead RUC process. See discussion of Business Practice Manual change (PRR 1282) in: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf

cases, cutting the exports may further exacerbate conditions as curtailment of an export may result in the cutting of an import at the applicable intertie because the interchange was permissible only due to counterflow provided by the export. Finally, when the CAISO is in the position of relying on emergency energy from its neighbors, the threat of an export curtailment to another BAAs when conditions are constrained throughout the system may prevent access to emergency energy either at that time or in the future.

B.3.4 Energy Imbalance Market

During August 14 and 15 the CAISO BAA failed the flexible ramping sufficiency test in some intervals during peak hours. This test is a feature of the Western Energy Imbalance Market (EIM) and was designed to ensure that each participating member procured enough resources to meet its own ramping needs. If a BAA participating in the EIM passes the resource sufficiency evaluation, it will have access to additional EIM transfers to meet its load for the next operating hour. If the EIM Entity fails the resource sufficiency evaluation for the next operating hour, then the BAA that failed the test will only be allowed transfers during that hour up to the amount transfers from the prior hour in the direction of the failure. The CAISO is subject to the flexible ramping sufficiency test like all other BAAs in the EIM. On August 14 and 15, the CAISO failed for less than two hours on each day and a cap was imposed on the transfer limit into the CAISO. Transfers are still allowed to occur up to the most recent transfer level but not beyond it. On those days the failure of the flexible ramping sufficiency test did not negatively impact the CAISO's ability to obtain EIM resources because the transfers were largely below the cap. Figure B.29 below shows that during critical times when the Stage 3 Emergencies were declared, the actual real-time transfers into the CAISO were below the cap imposed by the failures. This means that even with no failures there was already limited energy available for additional transfers. On August 15 there was a 20 minute period when the transfer limit was binding (*i.e.*, when the transfer of energy was at the cap), which overlapped with the declaration of a Stage 2 Emergency, but real-time transfers quickly fell after that and was below the cap when the Stage 3 Emergency was declared. The figure also shows that the CAISO did utilize and benefit from voluntary EIM transfers when available.

Figure B.29: CAISO EIM Real-Time Transfers as Compared to Flexible Ramping Sufficiency Cap



The CAISO's real-time market and operations helped to significantly reduce the interactive effects of load under-scheduling, convergence bidding, and the impact on the RUC process in the day-ahead market. The CAISO market and operations was able to attract imports including market transactions, voluntary transfers from the Energy Imbalance Market (EIM), and emergency transfers from other BAs to reduce the impact of these challenges. However, actual supply and demand conditions continued to diverge from market and emergency plans such that even with the additional real-time imports, the CAISO could not maintain required contingency reserves as the net demand peak approached on August 14 and 15.