

Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 E. William Street
Carson City, NV 89701-3109

Re: Docket No. 20-08014

Dear Ms. Osborne,

Please accept for filing comments on behalf of the California Independent System Operator Corporation (CAISO) in the above-referenced docket. The purpose of CAISO's filing is to provide the Commission with two reports regarding the August 14 and 15, 2020 heat wave event. Specifically, these comments provide (1) the Preliminary Root Cause Analysis of the rotating outages in the CAISO footprint on August 14 and 15, 2020 (Preliminary Root Cause Analysis), and (2) the CAISO Department of Market Monitoring Report on System and Market Conditions, Issues and Performance for August and September 2020 (DMM Report). The CAISO provides these reports as Attachments A and B, respectively.

The CAISO, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC) jointly prepared the Preliminary Root Cause Analysis. The Preliminary Root Cause Analysis provides an overview of the system conditions and operator actions on August 14 and 15. The analysis also provides a preliminary understanding of factors that contributed to rotating outages. In addition, the Preliminary Root Cause Analysis provides recommendations and next steps to avoid similar conditions in the future. The CAISO, CPUC, and CEC are currently working to issue their final Root Cause Analysis, which is expected to be available prior to the end of 2020. The CAISO will seek to provide that Root Cause Analysis to this Commission when finalized.

The DMM Report reviews system conditions and performance of the CAISO's day-ahead and real-time markets from mid-August to September 7, 2020. The report was prepared by the CAISO's Department of Market Monitoring (DMM), which serves as the independent market monitor for the CAISO and Western Energy Imbalance markets. The DMM Report provides analysis that supports the finding in the Preliminary Root Cause Analysis and provides recommendations based on DMM's own independent analysis.

The CAISO acknowledges that the comment period established in the Commission's September 25, 2020 Procedural Order has closed, but believes that the Preliminary Root Cause

Trisha Osborne
Assistant Commission Secretary
December 9, 2020
Page 2

California Independent System Operator Corporation

Analysis and the DMM Report can inform the Commission's investigation in this proceeding. As a result, the CAISO asks that the Commission accept these late-filed comments into the record in Docket No. 20-08014 as public comment pursuant to Nevada Administrative Code section 703.491.

Respectfully submitted

By: /s/ Jordan Pinjuv

Roger Collanton
General Counsel
Anthony Ivancovich
Deputy General Counsel
Jordan Pinjuv
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
T: (916) 351-4429
F: (916) 608-7222
Email: jpjuv@caiso.com

Attorneys for the California Independent
System Operator Corporation

Attachment A

*Preliminary Root Cause Analysis
Mid-August Heat Storm*

Preliminary Root Cause Analysis

Mid-August 2020 Heat Storm

October 6, 2020



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

This page intentionally left blank



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

Table of Contents

Executive Summary	1
ES.1 Roles of the Entities Delivering This Report.....	1
ES.2 Summary of Conditions and Events of August 14 and 15, 2020.....	2
ES.3 Preliminary Understanding of Various Factors That Contributed to Rotating Outages on August 14 and 15, 2020.....	3
ES.4 Actions Taken to Mitigate Projected Supply Shortfalls During August	14
ES.5 Preliminary Recommendations	14
ES.6 Next Steps.....	15
1 Introduction	16
2 Background	17
2.1 Resource Adequacy Process in the CAISO BAA.....	17
2.2 CEC’s Role in Forecasting and Allocating Resource Adequacy Obligations 19	
2.3 CPUC’s Role in Allocating RA Obligations to Jurisdictional LSEs.....	21
2.3.1 Timeline for RA Process, Obligations, and Penalties	22
2.4 CAISO’s Role in Ensuring RA Capacity is Operational.....	24
3 Mid-August Event Overview	26
3.1 Weather and Demand Conditions During Mid-August	26
3.2 CAISO Reliability Requirements and Communications During mid-August Event	29
3.3 Sequence of Events of CAISO Actions	33
3.3.1 Prior to August 14.....	33
3.3.2 August 14	33
3.3.3 August 15	36
3.3.4 August 16 through 19.....	38
3.4 Number of Customers Impacted by Rotating Outages.....	41
4 Preliminary Understanding of Various Factors That Contributed to Rotating Outages on August 14 and 15	43
4.1 Existing Resource Planning Processes are Not Designed to Fully Address an Extreme Heat Storm.....	43

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	45
4.2.1	Planning Reserve Margin Was Exceeded on August 14	46
4.2.2	Critical Grid Needs Extend Beyond the Peak Hour	47
4.2.3	Supply, Market Awards, and Actual Energy Production by Resource Type 49	
4.2.3.1	Natural Gas Fleet	50
4.2.3.2	Imports	51
4.2.3.3	Hydro.....	51
4.2.3.4	Solar and Wind	52
4.2.3.5	Demand response.....	52
4.2.3.6	Combined Resources.....	55
4.3	Some Practices in the Day-Ahead Energy Market Exacerbated the Supply Challenges Under Highly Stressed Conditions	56
4.3.1	Demand Should Be Appropriately Scheduled in the Day-Ahead Timeframe	56
4.3.2	Convergence Bidding Masked Tight Supply Conditions	57
4.3.3	Residual Unit Commitment Process Changes Were Needed.....	57
5	Actions Taken During August 16 Through 19 to Mitigate Projected Supply Shortfalls	59
5.1	Detailed Description of Actions Taken	60
6	Preliminary Recommendations	64
7	Next Steps	70
	Appendix A: CEC Load Forecasts for Summer 2020	71
	Appendix B: Technical Discussion on Supply Conditions Based on Current Resource Planning Targets and Energy Market Practices	75
B.2	Detailed Analysis on Supply Conditions Based on Current Resource Planning Targets.....	76
B.2.1	Planning Reserve Margin.....	77
B.2.2	Critical Grid Needs Extend Beyond the Peak Hour	78
B.2.3	RA Resources Were Challenged to Provide Energy Up to the Full RA Value Shown to the CAISO	80
B.2.3.1	Supply-Side RA Shown Capacity, Bids, Awards, and Energy Production	84

B.2.3.2	Preliminary Demand Response Analysis for Credits and Shown RA	94
B.2.3.3	Combined Resources	96
B.3	Energy Market Practices Exacerbated the Supply Challenges Under Highly Stressed Conditions.....	97
B.3.1	Demand Should Be Appropriately Scheduled in the Day-Ahead Timeframe	97
B.3.2	Convergence Bidding Masked Tight Supply Conditions	101
B.3.3	Residual Unit Commitment Process Changes	104
B.3.4	Energy Imbalance Market	107

List of Tables

Table 2.1: RA 2020 LSE Forecast Timeline.....	21
Table 3.1: Customers Affected by August 14 Rotating Outages.....	42
Table 3.2: Customers Affected by August 16 Rotating Outages.....	42
Table 4.1: August 2020 RA Obligation, Shown RA, RMR, and Credits	45
Table 5.1: Day-Ahead Peak Forecast vs. Actual Peak During Heat Event.....	60

List of Figures

Figure ES.1: August Temperatures 1985 - 2020.....	5
Figure ES.2: Demand and Net Demand for August 14 and 15	7
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	8
Figure ES.4: Credited IOU Demand Response: Preliminary Estimated RDRR Response and PDR Dispatch vs. CPUC August 2020 DR Credit	10
Figure ES.5: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available).....	11
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)	12
Figure ES.7: Comparison of Actual, CAISO Forecast, and Bid-in Demand	13
Figure 3.1: National Weather Service Sacramento Graphic for August 14.....	26
Figure 3.2: National Weather Service Weather Prediction Center Graphic for August 15	27
Figure 3.3: National Weather Service Weather Prediction Center Graphic for August 18	28
Figure 3.4: 2017 -2019 Summer Net Imports at Time of Daily Peaks Above 41,000 MW	29
Figure 3.5: Wind and Solar Generation Profiles for August 14 and 15.....	38
Figure 3.6: Comparison of Day-Ahead Forecast and Actual Demand for August 17	39
Figure 3.7: Comparison of Day-Ahead Forecast and Actual Demand for August 18	40
Figure 3.8: Comparison of Day-Ahead Forecast and Actual Demand for August 19	40
Figure 4.1: August Temperatures 1985 - 2020.....	44
Figure 4.2: August 2020 PRM and Actual Operational Need During Peak	47
Figure 4.3: Demand and Net Demand for August 14 and 15	49
Figure 4.4: August 14 Net Demand Peak (6:51 pm) August 2020 Shown RA and RMR, Real-time Awards, and Actual Energy Production.....	50
Figure 4.5: Credited IOU Demand Response: Preliminary Estimated RDRR Response and PDR Dispatch vs. CPUC August 2020 DR Credit	54
Figure 4.6: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available)	54
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)	55
Figure 4.8: Comparison of Actual, CAISO Forecast, and Bid-in Demand	57

Figure B.1: August 2020 PRM and Actual Operational Need During Peak	78
Figure B.2: Demand and Net Demand for August 14 and 15	80
Figure B.3: RA Outage Snapshot for August 14 and 15	81
Figure B.4: August 14 Peak (4:56 pm) Unused RA Capacity by Resource Type	83
Figure B.5: August 14 Net Demand Peak (6:51 pm) Unused RA Capacity by Resource Type	83
Figure B.6: August 15 Peak (5:37 pm) Unused RA Capacity by Resource Type	84
Figure B.7: August 15 Net Demand Peak (6:26 pm) Unused RA Capacity by Resource Type	84
Figure B.8: August 14 Peak (4:56 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR.....	86
Figure B.9: August 14 Net Load Peak (6:51 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR	86
Figure B.10: August 15 Peak (5:37 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR.....	87
Figure B.11: August 15 Net Demand Peak (6:26 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR.....	88
Figure B.12: August 14 Peak (4:56 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR	89
Figure B.13: August 14 Net Demand Peak (6:51 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR.....	89
Figure B.14: August 15 Peak (5:37 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR	90
Figure B.15: August 15 Net Demand Peak (6:26 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR.....	90
Figure B.16: August 14 Peak (4:56 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR	92
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	92
Figure B.18: August 15 Peak (5:37 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR	93
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	93
Figure B.20: Credited IOU Demand Response: Preliminary Estimated RDRR Response and PDR Dispatch vs. CPUC August 2020 DR Credit	95
Figure B.21: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available)	95
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)	96
Figure B.23: Comparison of Actual, CAISO Forecasted, and Bid-in Demand	98
Figure B.24: Comparison of Non-RA Cleared Supply vs. Total Exports	100
Figure B.25: Total Exports by Category	100

Figure B.26: Illustrative Example of Impact of Under-Scheduled Load Under Supply Scarcity	102
Figure B.27: Illustrative Example of Impact of Under-Scheduled Load Under Supply Sufficiency	103
Figure B.28: Illustrative Example of Impact of Convergence Bidding.....	104
Figure B.29: CAISO EIM Real-Time Transfers as Compared to Flexible Ramping Sufficiency Cap.....	108

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.

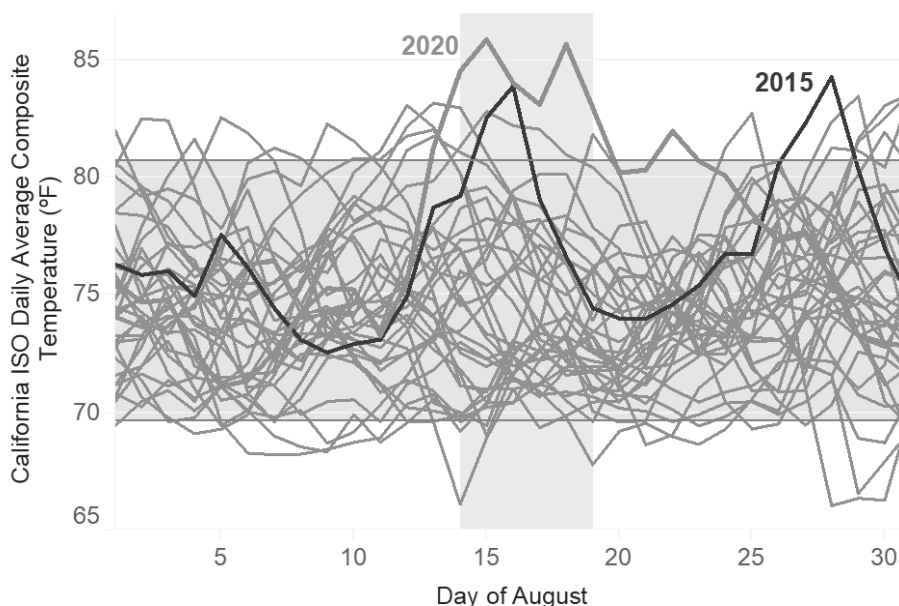
- In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified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

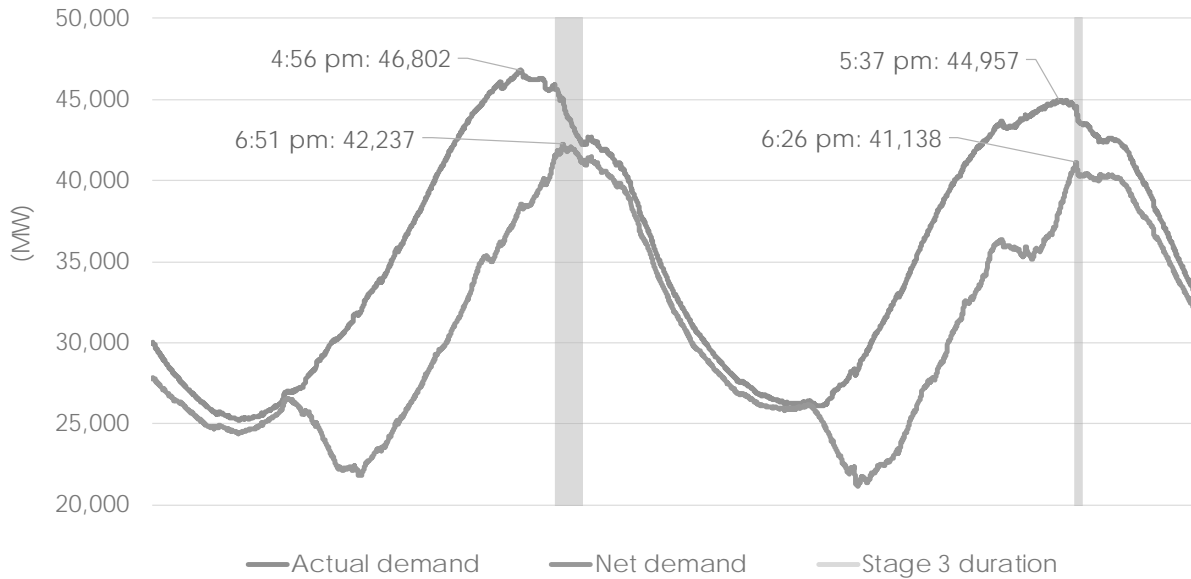
¹ Currently the RA obligation is planned for a 1-in-2 weather and adds a 15% PRM, in part to act as buffer for deviations from the 1-in-2 weather event.

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 pm 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



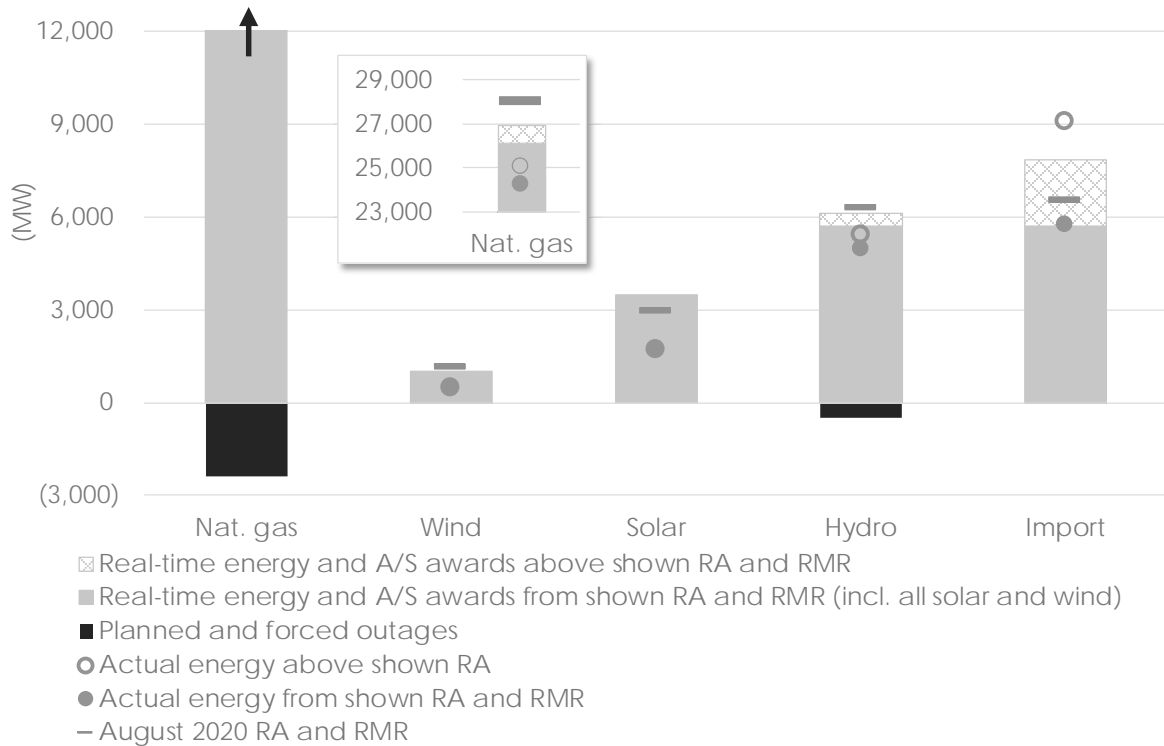
On August 14 the Stage 3 Emergency was declared at 6:38 pm, right before the net demand peak at 6:51 pm. Similarly, on August 15 the Stage 3 Emergency was called at 6:28 pm, just after the net demand peak at 6:26 pm.

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

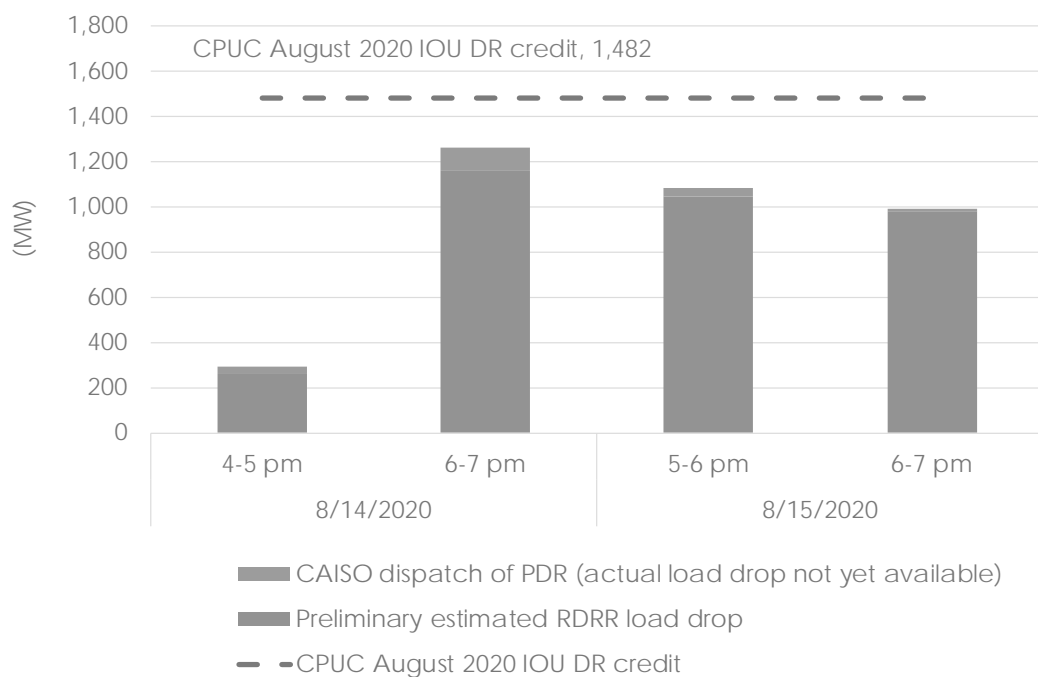
Demand response programs are designed to reduce demand at peak times. They take on many forms. Some programs bid into the CAISO's wholesale markets and are then dispatched similar to a power plant. A full analysis of how demand response performed cannot be completed in time to inform this analysis but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

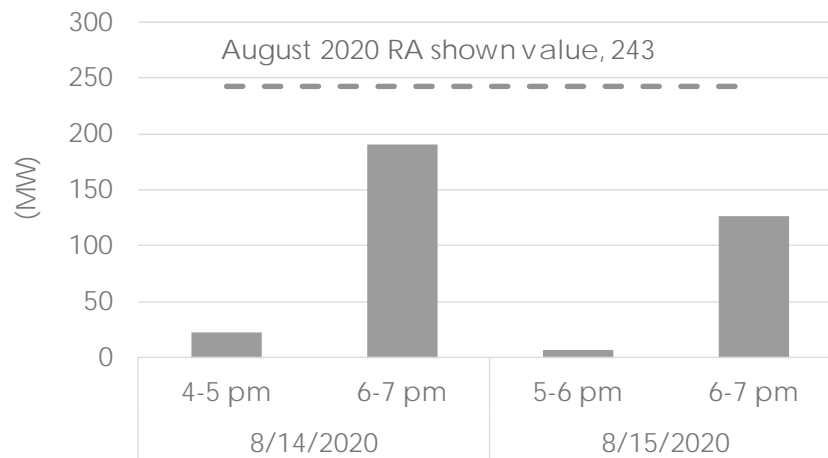


Aside from the IOUs, there is also economic demand response (PDR) from CPUC-jurisdictional third parties. As noted above, settlement quality data was not available

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.

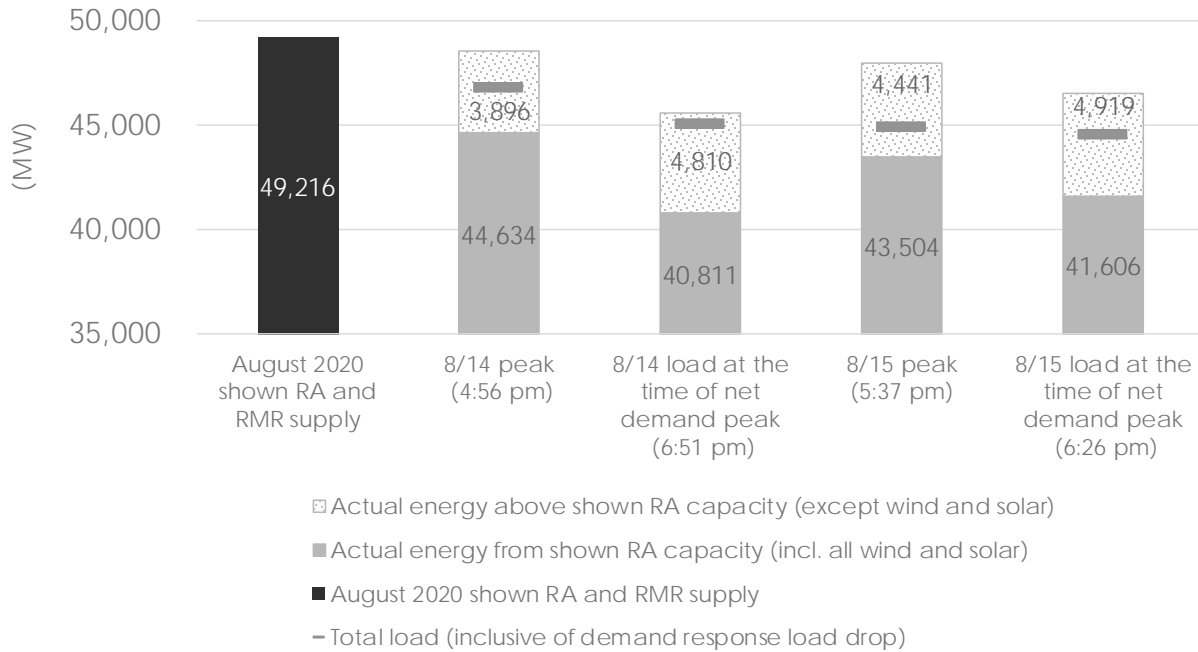
Figure ES.5: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available)



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

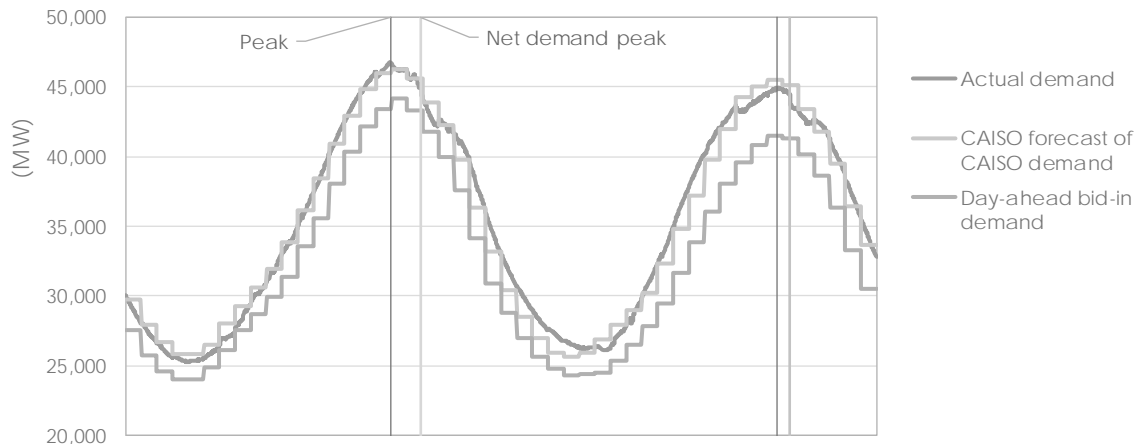
Certain energy market practices appear to have contributed to the inability to obtain additional energy that could have alleviated the strained conditions on the CAISO grid August 14 and 15. The contributing causes identified at this stage include: under-scheduling of demand in the day-ahead market by 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](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](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.

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.

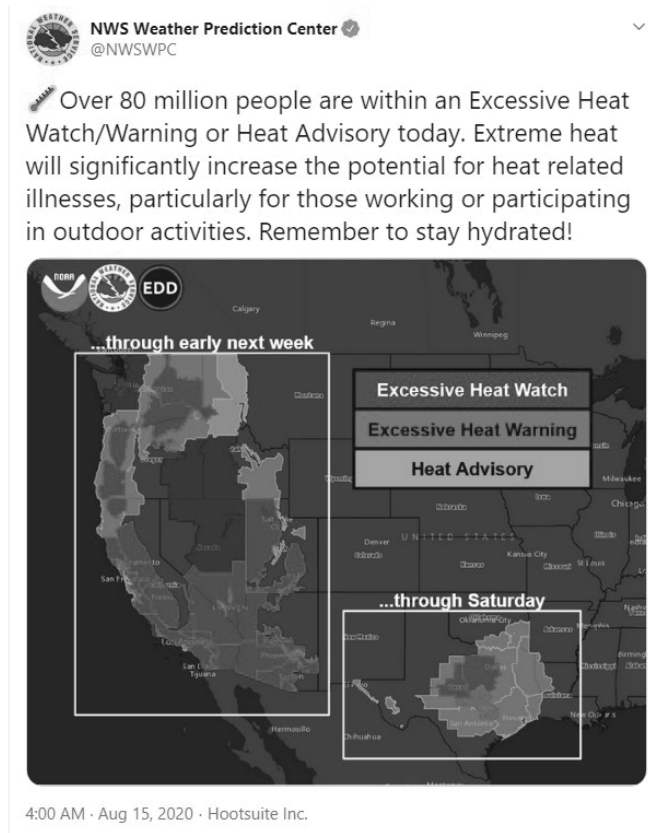
Figure 3.1: National Weather Service Sacramento Graphic for August 14



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).

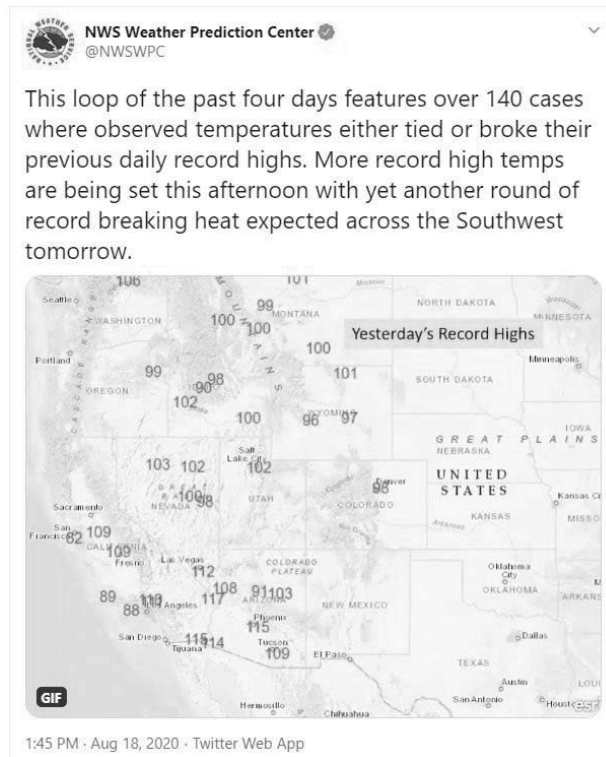
Figure 3.2: National Weather Service Weather Prediction Center Graphic for August 15



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>

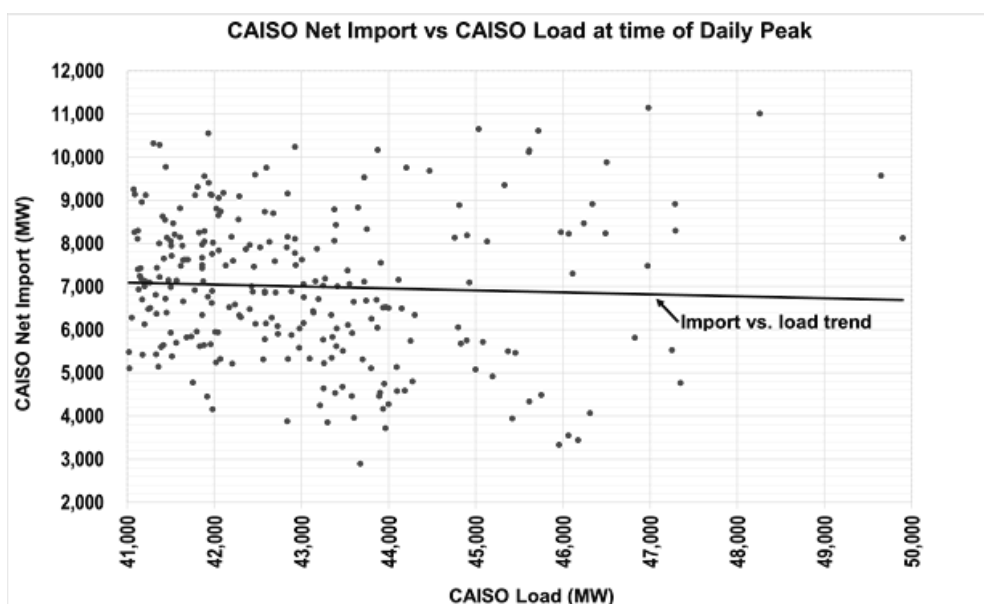
This rare West-wide heat storm affected both demand for and supply of generation. Typically, high day-time temperatures are offset by cool and dry evening conditions. However, the multi-day heat storm meant that there was limited overnight cooling, so air conditioners continued to run well into the evening 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.

Corporation¹⁵ (NERC) and the Western Electricity Coordinating Council¹⁶ (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-002-3¹⁸ (NERC requirement) and BAL-002-WECC-2a¹⁹ (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

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

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 canvassed 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 canvassed 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.

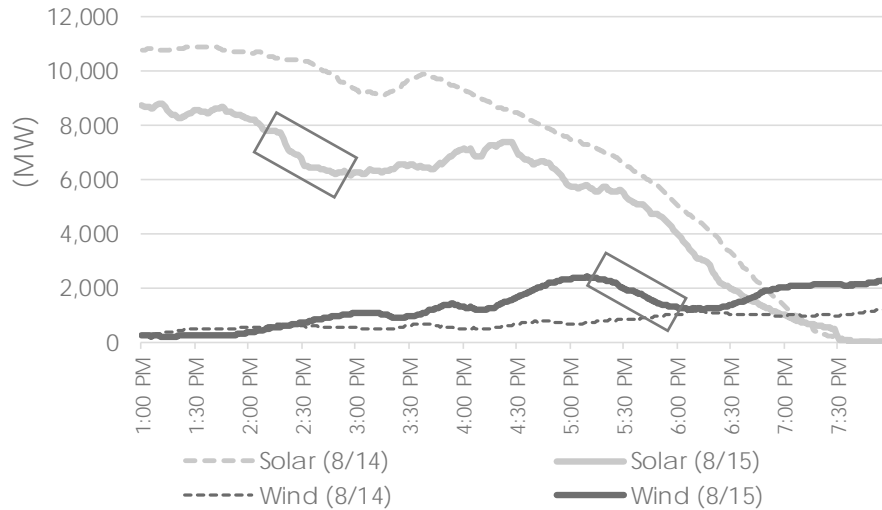
At 6:28 pm, the CAISO declared a Stage 3 Emergency because it was deficient in meeting its reserves requirement. The CAISO was not able to cure the deficiency with generation, because all generation was already online, and solar was rapidly declining while demand remained high. Because the CAISO was 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.

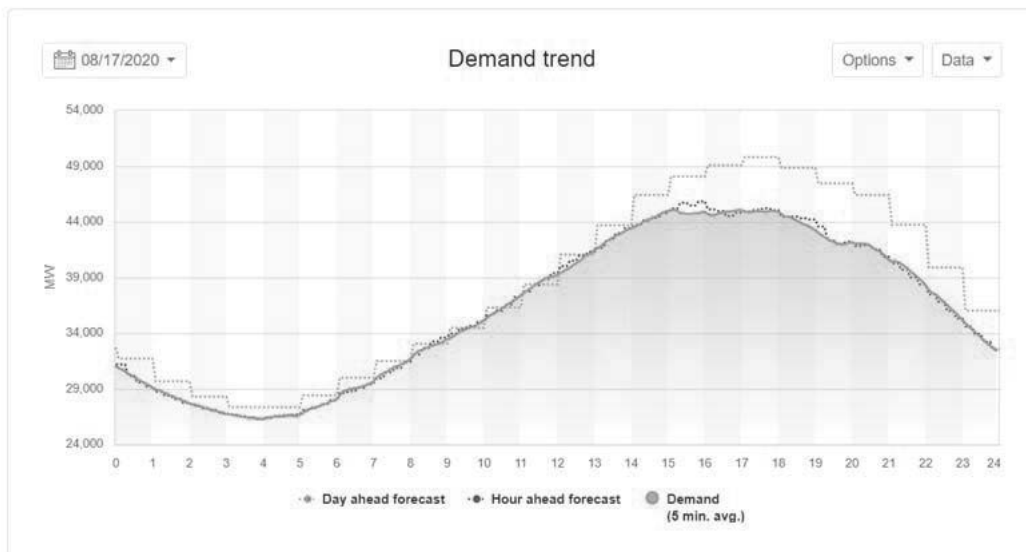
On August 16, Governor Newsom declared a State of Emergency³⁴ due to the significant heat storm in California and surrounding Western states. The proclamation

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-74-20³⁵, 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

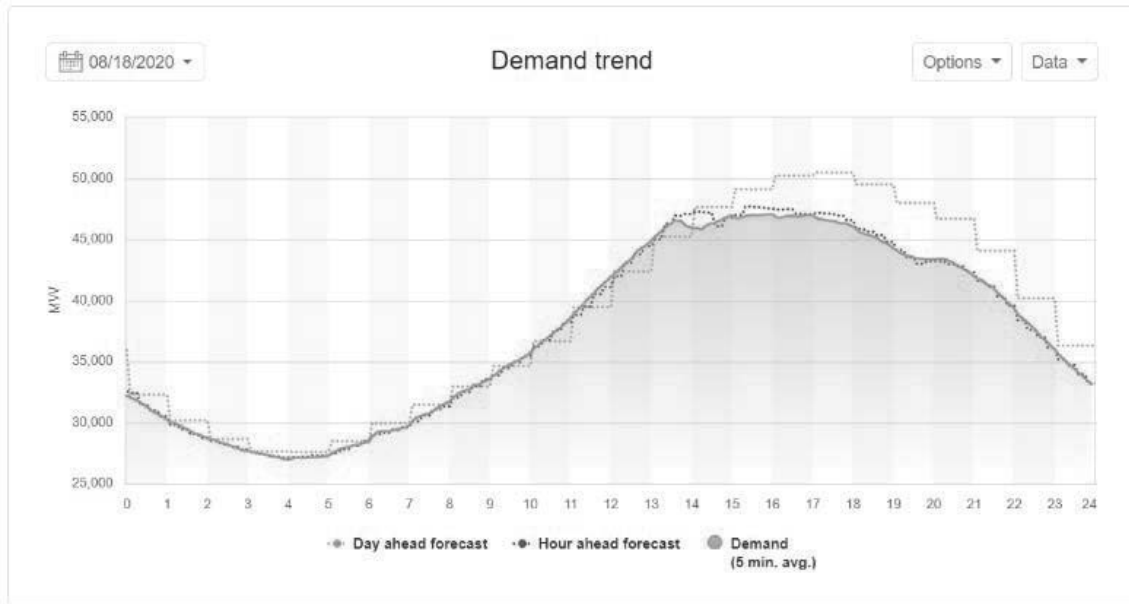
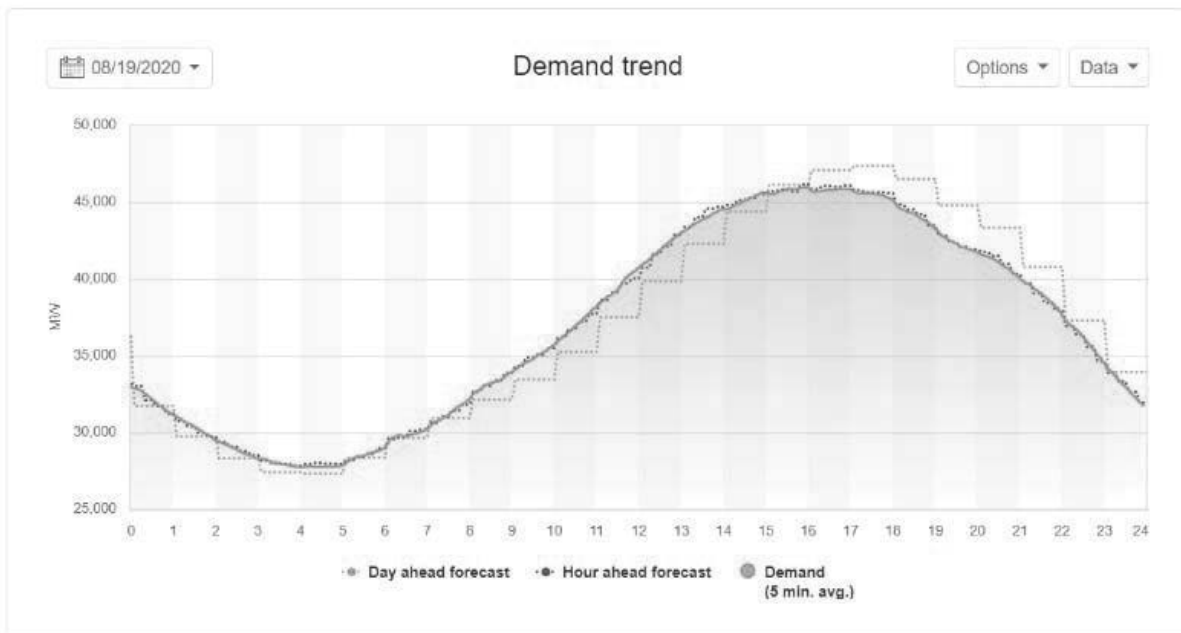


Figure 3.8: Comparison of Day-Ahead Forecast and Actual Demand for August 19



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.

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.

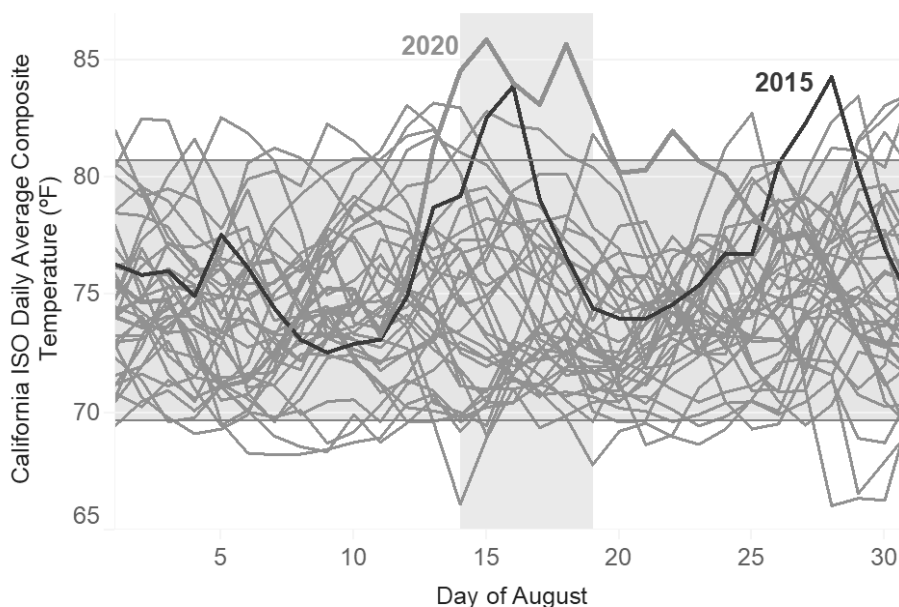
4.1 Existing Resource Planning Processes are Not Designed to Fully Address an Extreme Heat Storm

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

<u>CPUC</u>	<u>Non-CPUC</u>	<u>Total</u>	
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
<hr/>	<hr/>	<hr/>	<hr/>
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
<hr/>	<hr/>	<hr/>	<hr/>
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

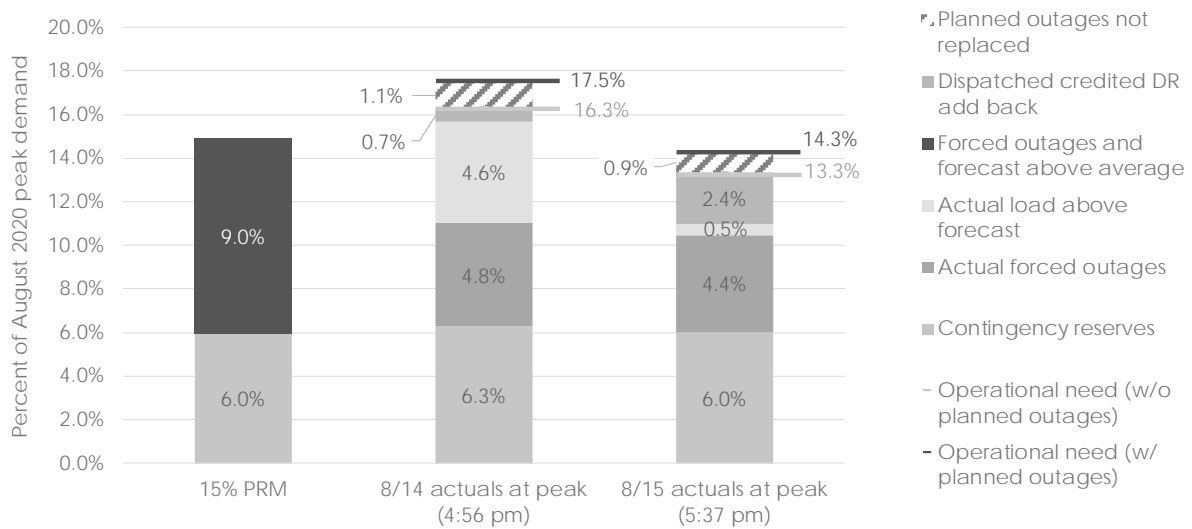
³⁹ Because of this ambiguity, the CAISO has taken action recently to stop the practice of crediting and to require all RA resources to be explicitly shown on the RA supply plans. See Business Practice Manual Proposed Revision Request 1280:

<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 NOC values. This means, for example, that solar is typically under-valued during the peak but over-valued later in the evening after sunset.

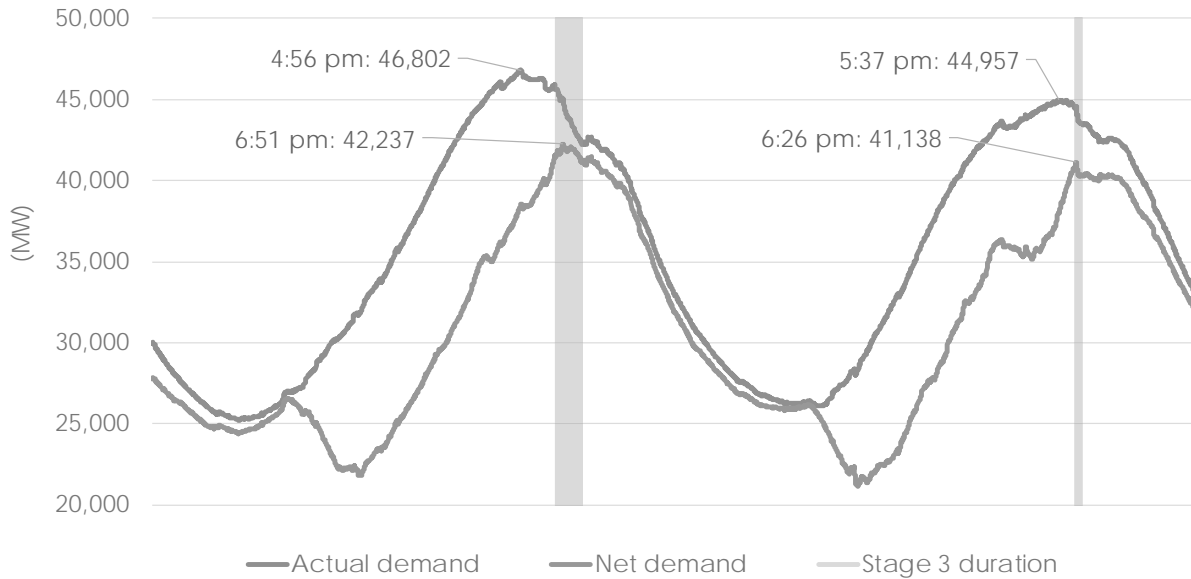
Since 2016, the CAISO, CEC, and the CPUC have worked to examine the impacts of significant renewable penetration on the grid. Solar generation in particular shifts “utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by solar generation, with 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



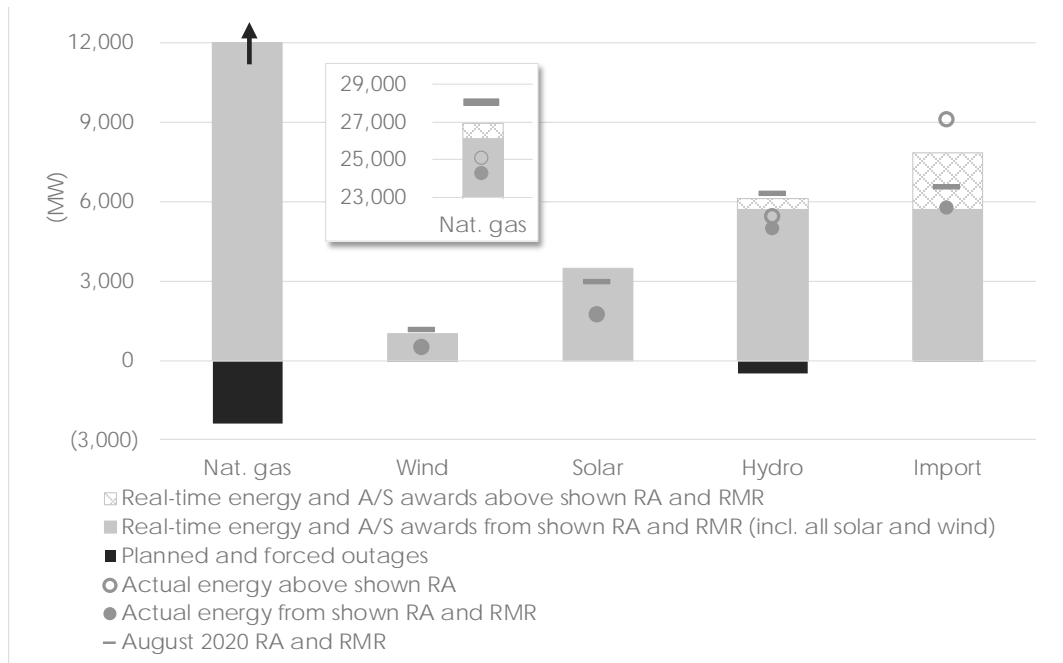
On August 14 the Stage 3 Emergency was declared at 6:38 pm, right before the net demand peak at 6:51 pm. Similarly, on August 15 the Stage 3 Emergency was called at 6:28 pm, just after the net demand peak at 6:26 pm.

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

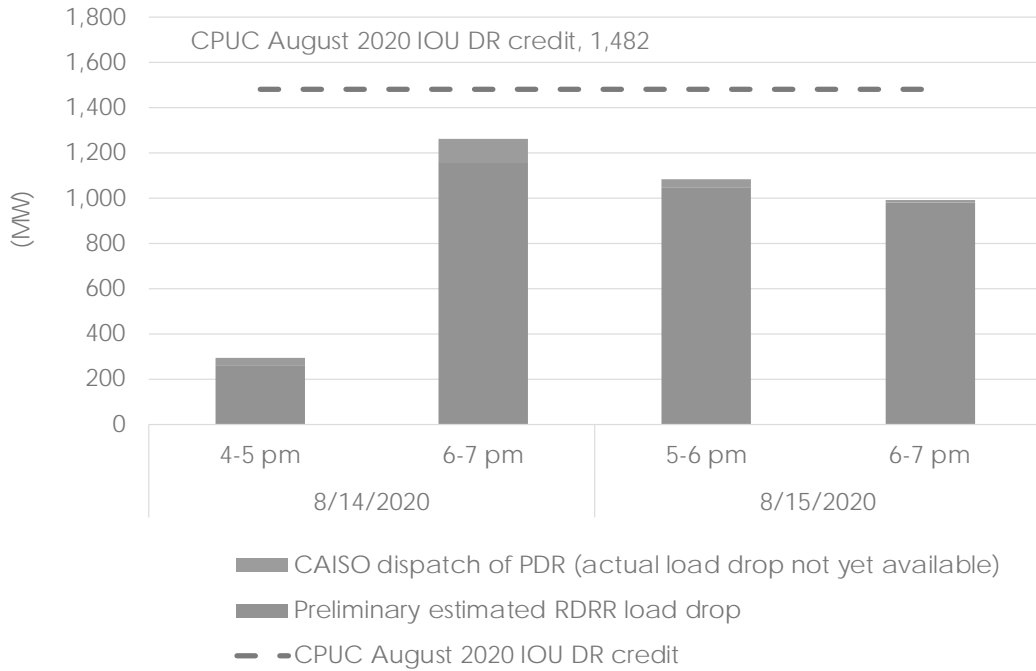
There are three distinct categories used to meet the total obligation: resource adequacy resources “shown” to the CAISO, RMR allocations from the CAISO, and the “credits” reported to the CAISO. The composition of credited amounts are generally not visible to the CAISO and do not submit bids consistent with a must offer obligation and are not subject to RAIM 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.aiso.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.

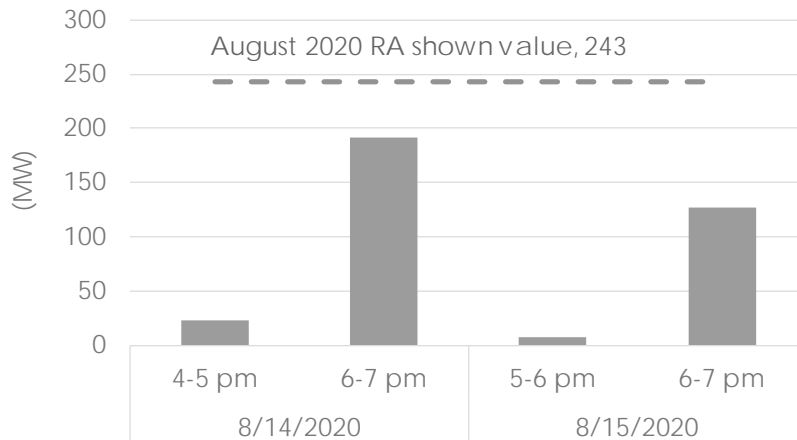
While the CAISO generally does not have visibility into credited amounts, the CPUC has clarified that the credits it includes in RA showings are IOU demand response programs. They include both emergency demand response RDRR and economically bid demand response (Proxy Demand Response or PDR). Per current 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)

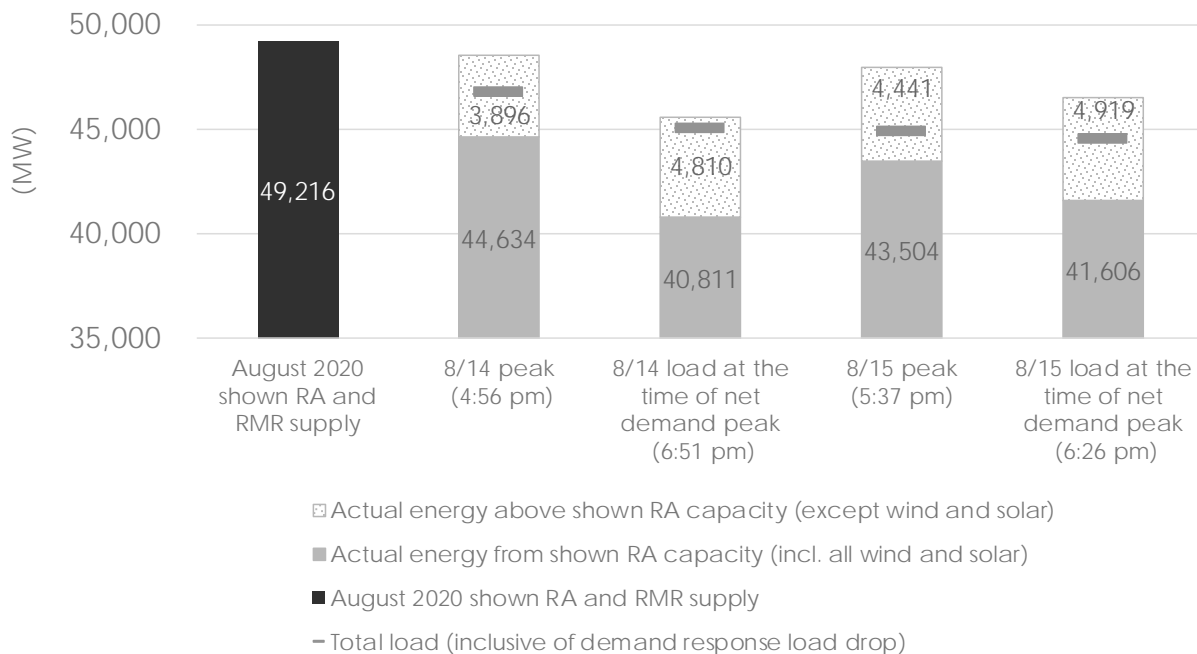


4.2.3.6 Combined Resources

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)



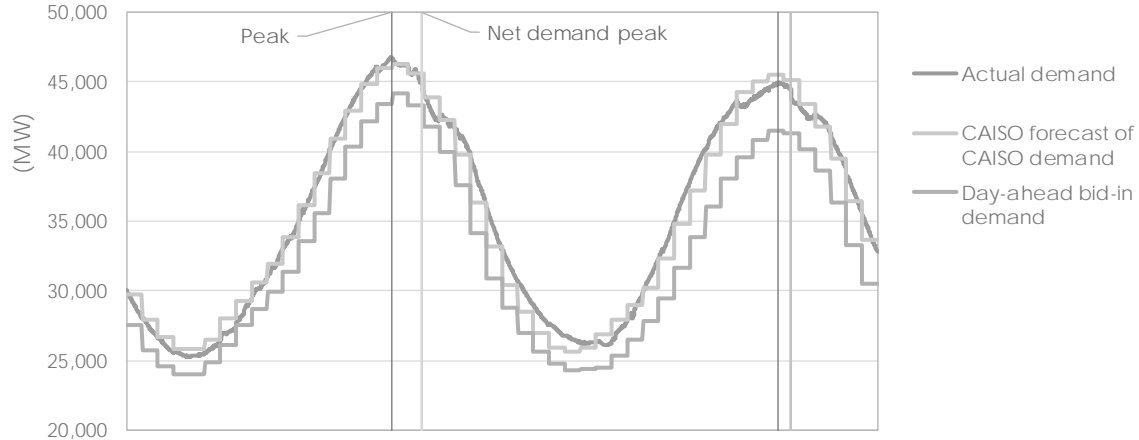
4.3 Some Practices in the Day-Ahead Energy Market Exacerbated the Supply Challenges Under Highly Stressed Conditions

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:

	<u>8/14</u>	<u>8/15</u>
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 Emergency⁴⁴, and on August 17 he signed Executive Order N-74-20⁴⁵, 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>

- o 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 inertia 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 market⁴⁹; 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.aiso.com/Documents/CaliforniaSOMarketParticipantsHeatWavePreparation-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 POU, 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.

⁵⁰Most 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

<u>CPUC</u>	<u>Non-CPUC</u>	<u>Total</u>	
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
<hr/> 46,656	<hr/> 4,758	<hr/> 51,413	<hr/> 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
<hr/> 46,656	<hr/> 4,758	<hr/> 51,413	<hr/> 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

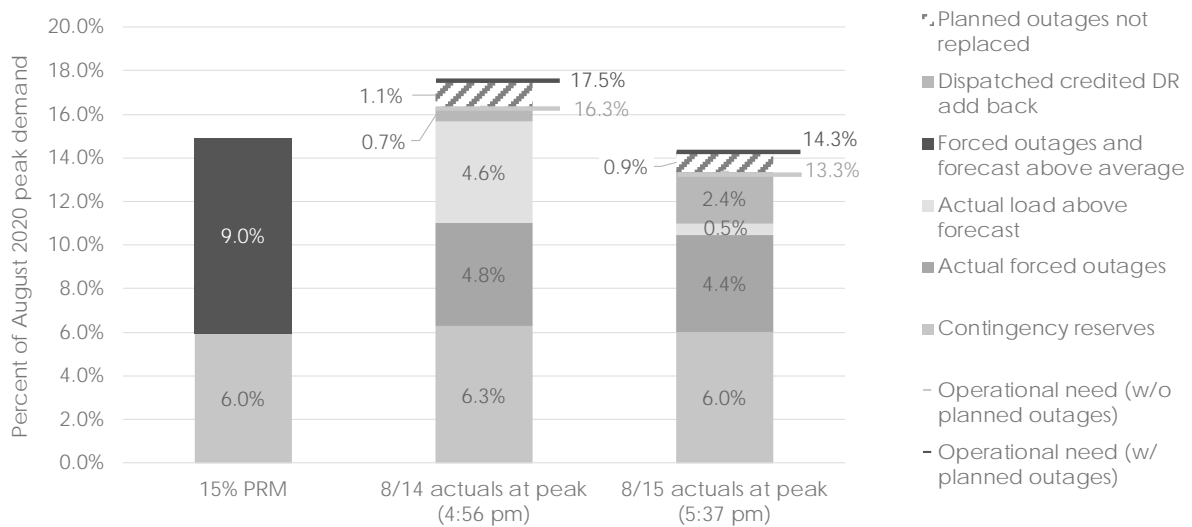
⁵¹ Because of this ambiguity, the CAISO has taken action recently to stop the practice of crediting and to require all RA resources to be explicitly shown on the RA supply plans. See Business Practice Manual Proposed Revision Request 1280:

<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.

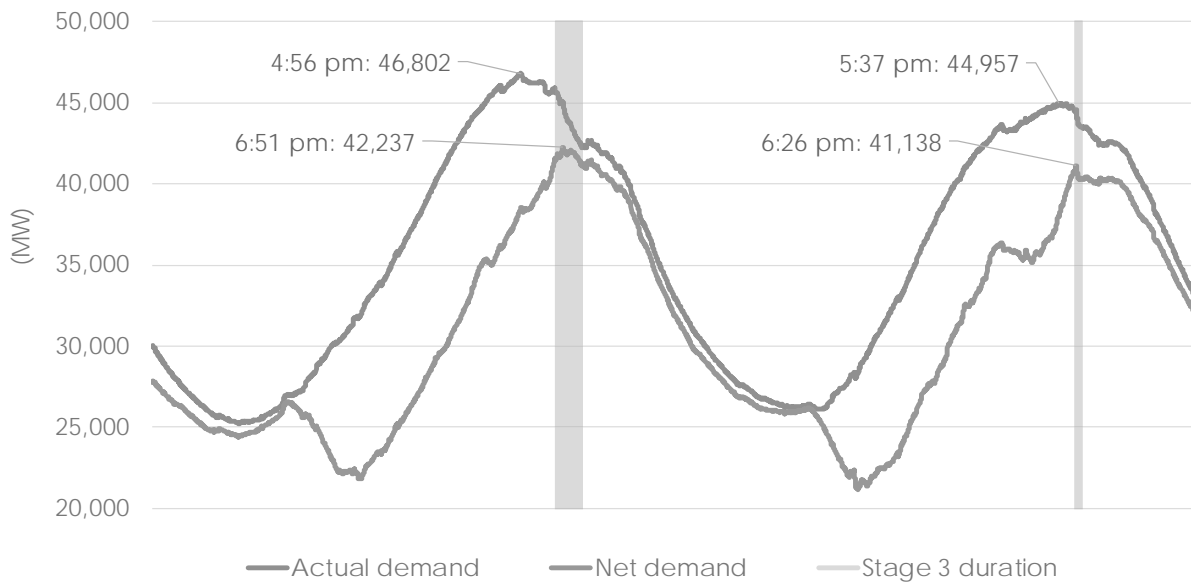
Since 2016, the CAISO has worked with the CEC and the CPUC to examine the impacts of significant renewable penetration on the grid and found that solar generation in particular shifts the peak load to later in the day around 7 pm.⁵³ This is because solar generation “may shift utility peaks to a later 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



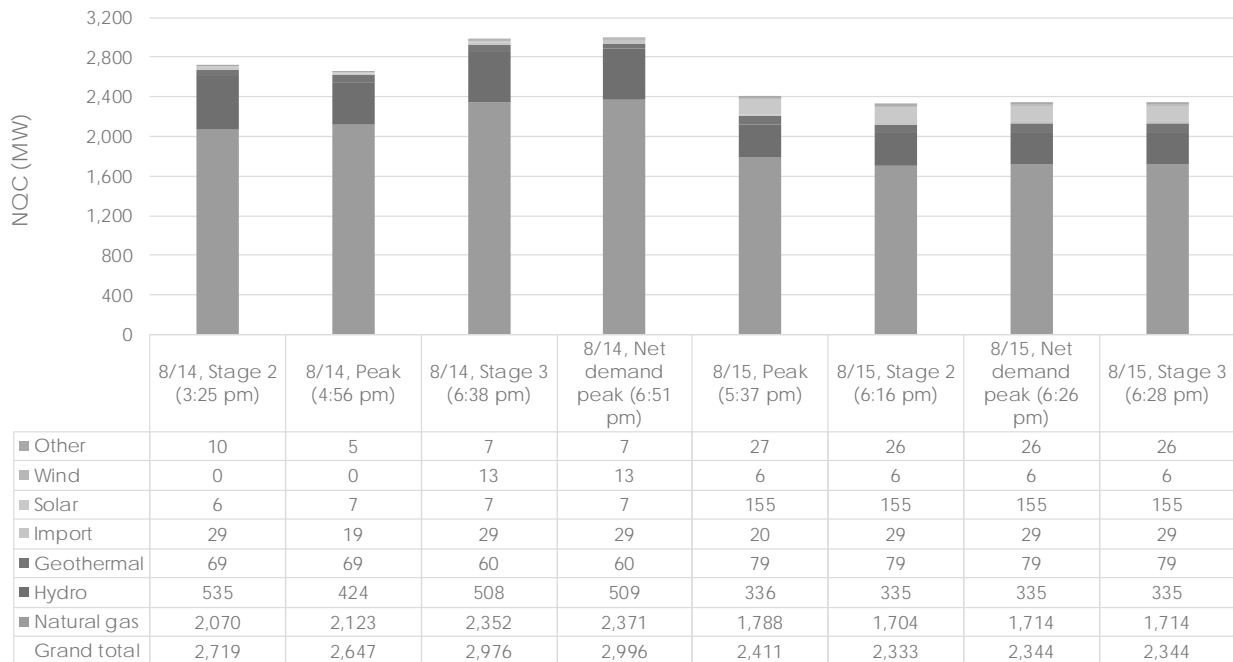
On August 14 the Stage 3 Emergency was declared at 6:38 pm, right before the net demand peak at 6:51 pm. Similarly, on August 15 the Stage 3 Emergency was called at 6:28 pm, just after the net demand peak at 6:26 pm. Given the importance of both the peak demand and net demand peak hours, this analysis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



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

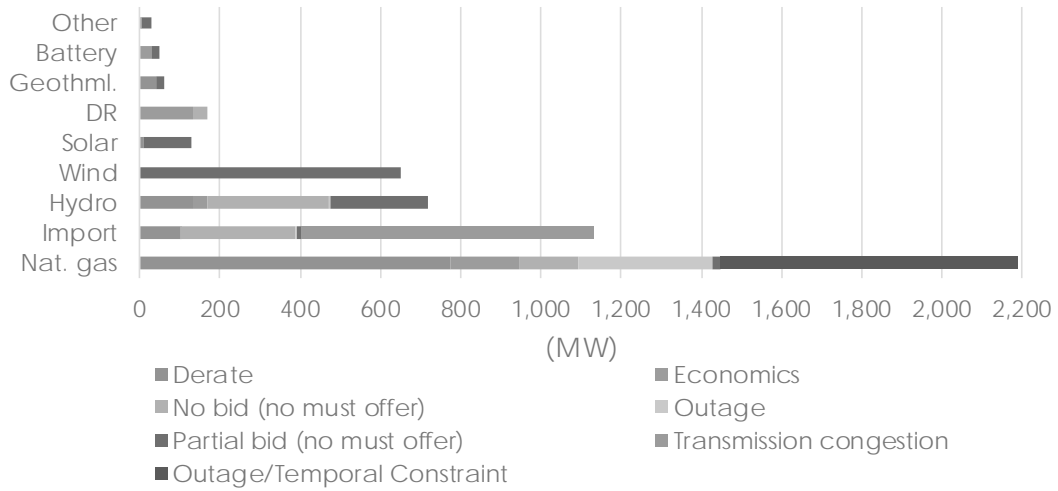


Figure B.5: August 14 Net Demand Peak (6:51 pm) Unused RA Capacity by Resource Type

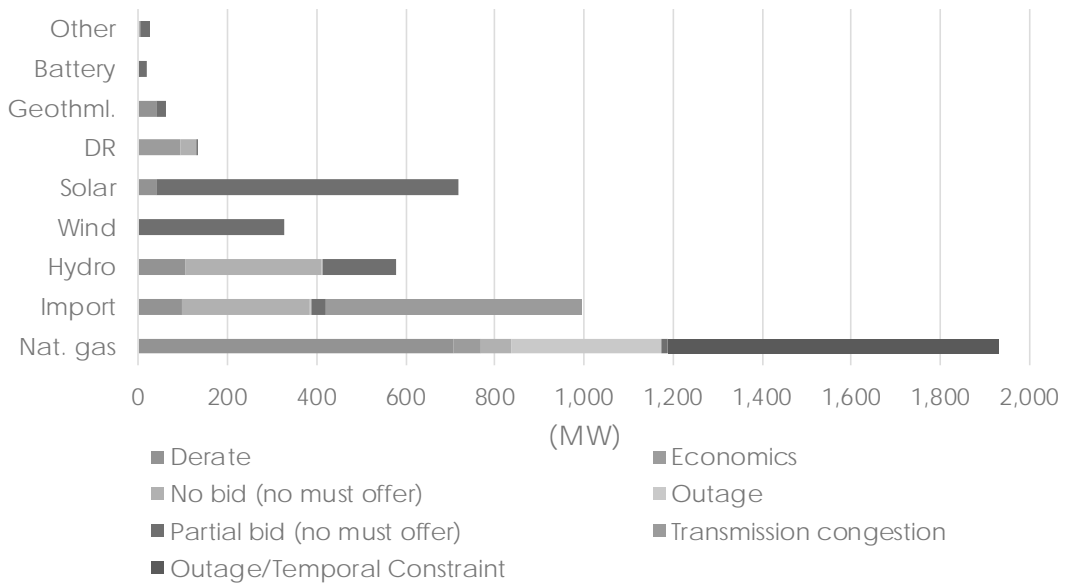


Figure B.6: August 15 Peak (5:37 pm) Unused RA Capacity by Resource Type

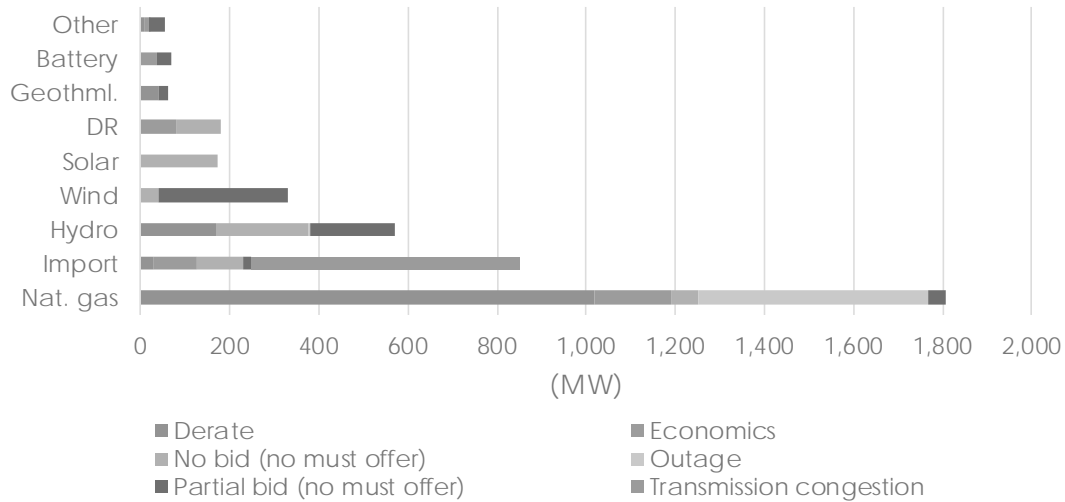
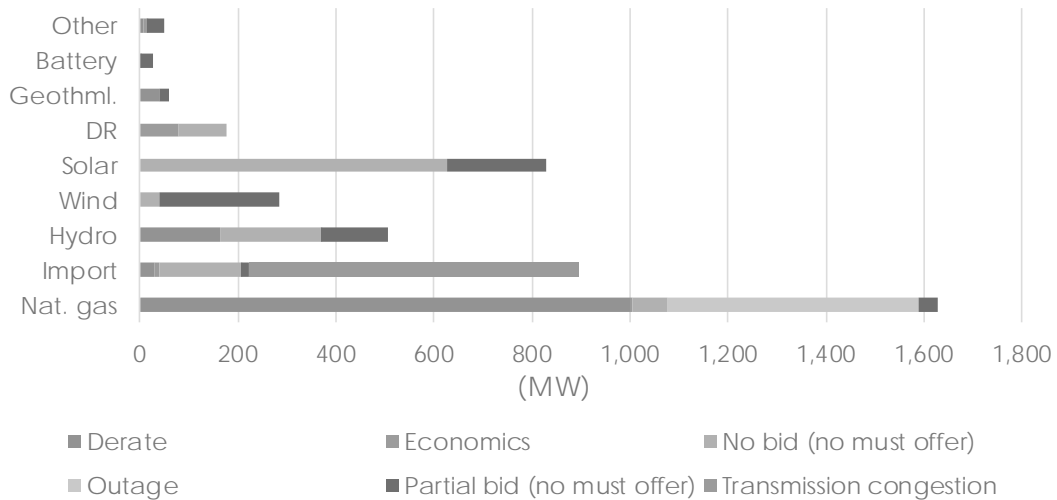


Figure B.7: August 15 Net Demand Peak (6:26 pm) Unused RA Capacity by Resource Type



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

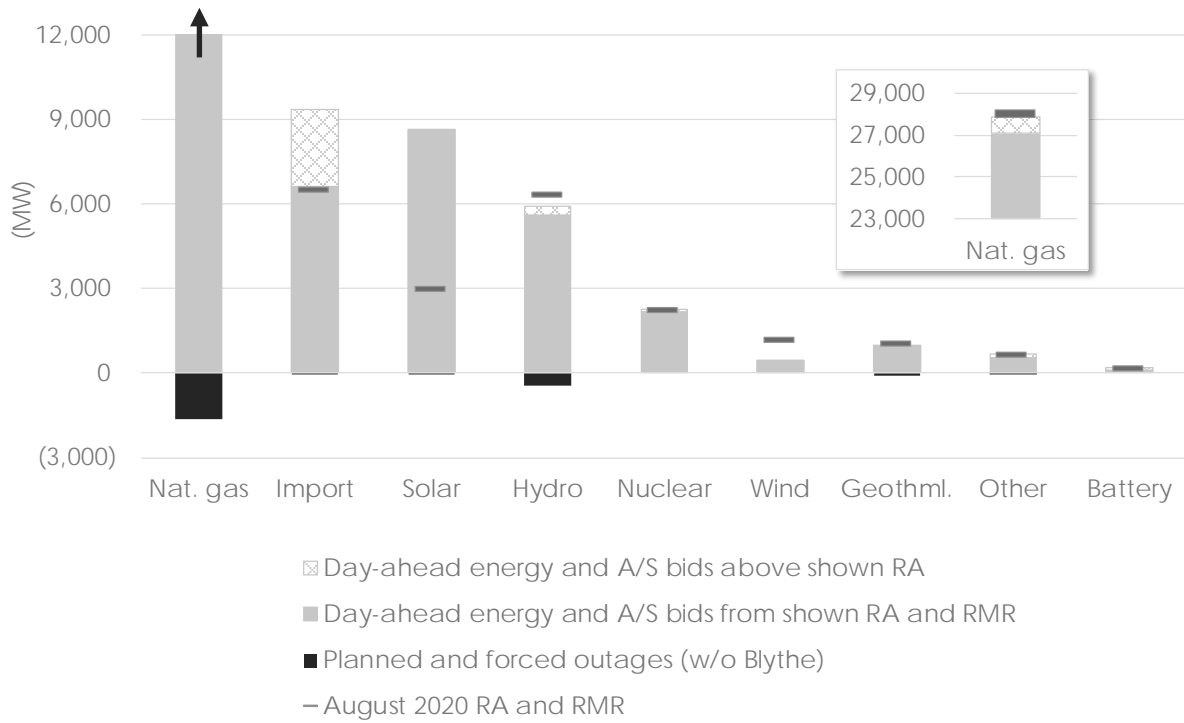


Figure B.9: August 14 Net Load Peak (6:51 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

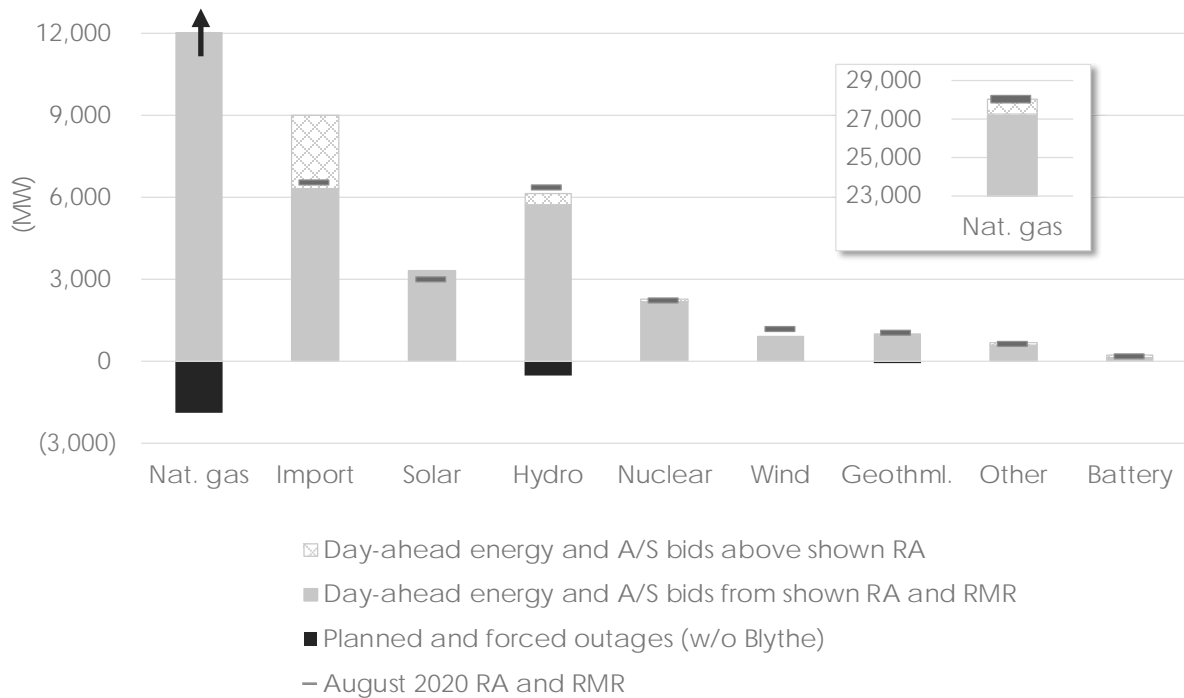


Figure B.10: August 15 Peak (5:37 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR

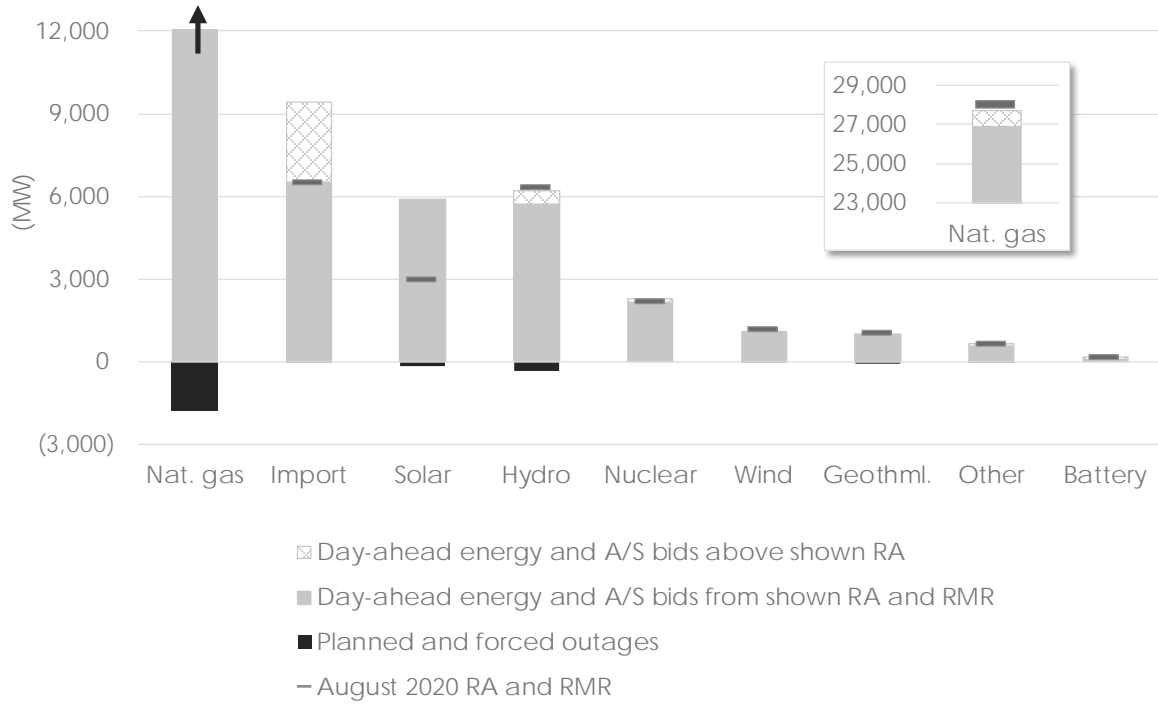


Figure B.11: August 15 Net Demand Peak (6:26 pm) – Day-Ahead Bids vs. August 2020 Shown RA and RMR



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

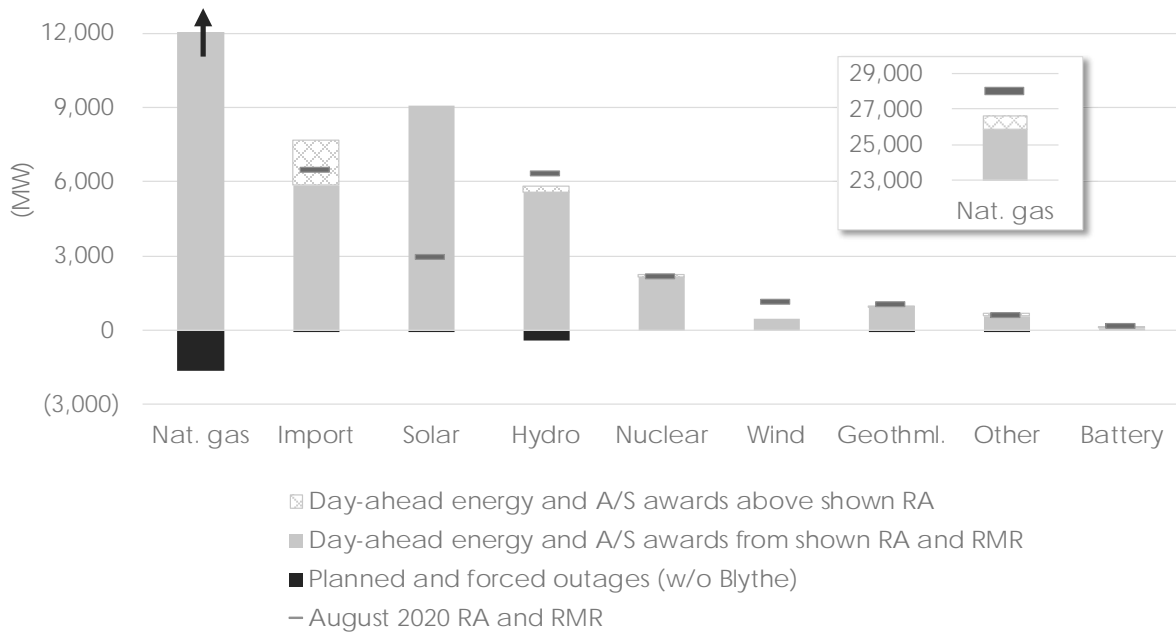


Figure B.13: August 14 Net Demand Peak (6:51 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

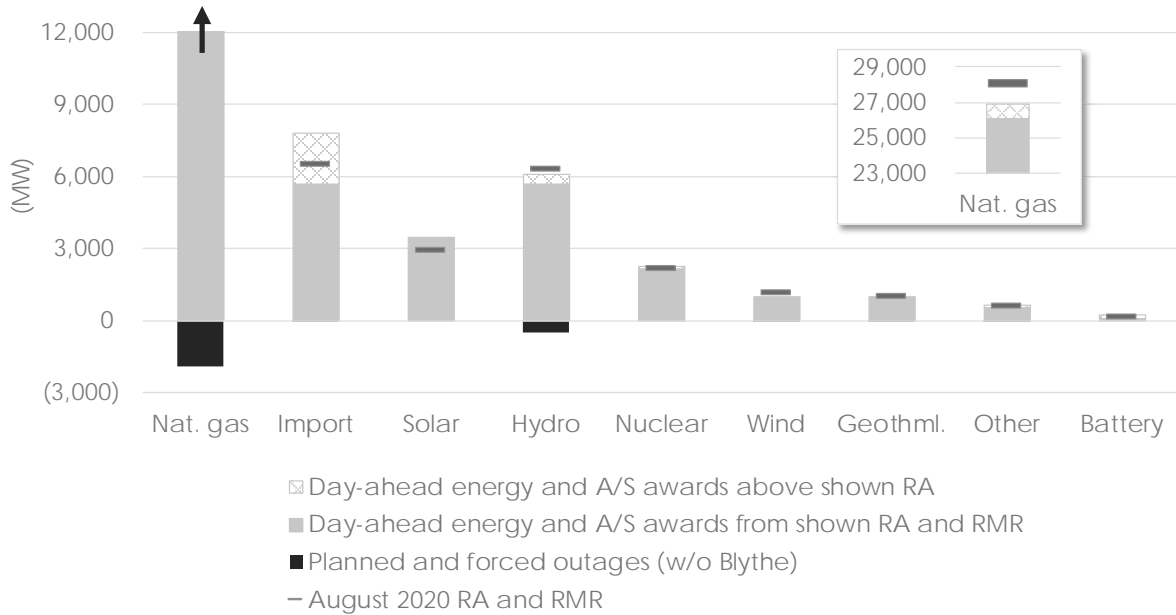


Figure B.14: August 15 Peak (5:37 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

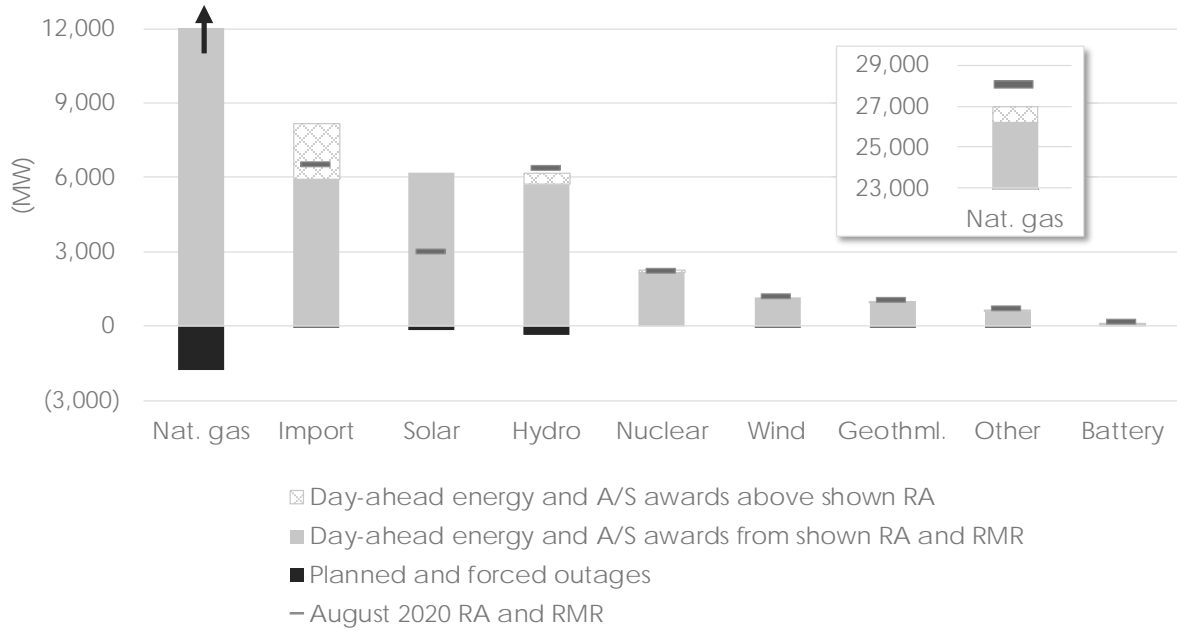


Figure B.15: August 15 Net Demand Peak (6:26 pm) – Day-Ahead Awards vs. August 2020 Shown RA and RMR

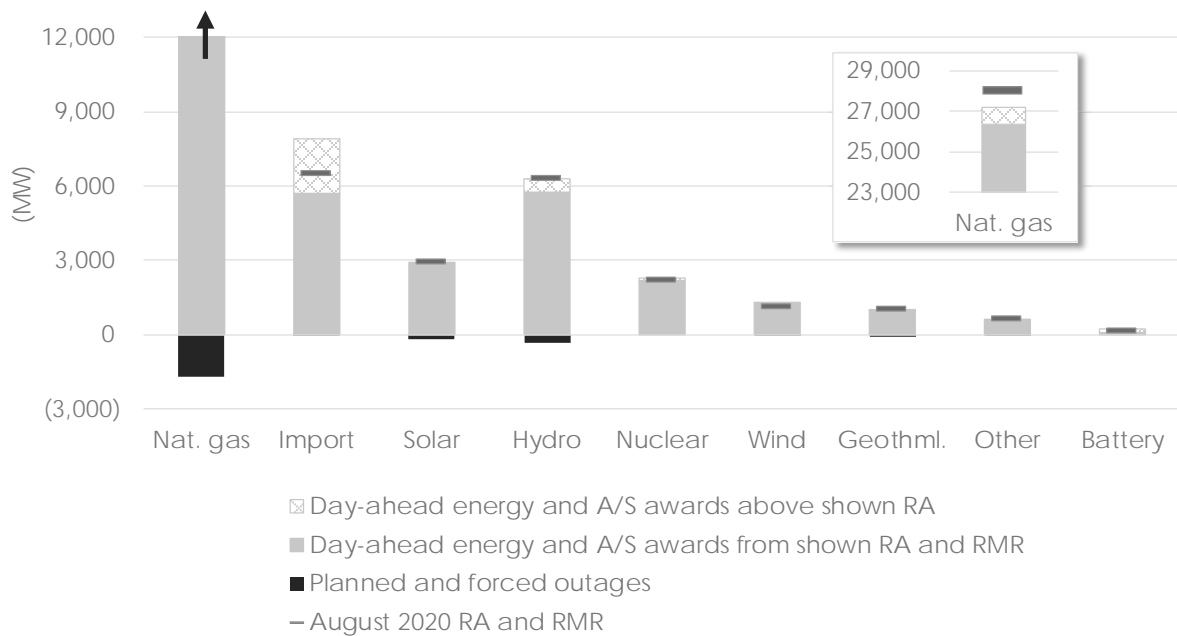


Figure B.16 through Figure B.19 below overlay three different timeframes. The first, as with the previous figures, includes the total shown RA supply plus RMR allocations (blue markers). The second timeframe is the real-time energy and ancillary service awards

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

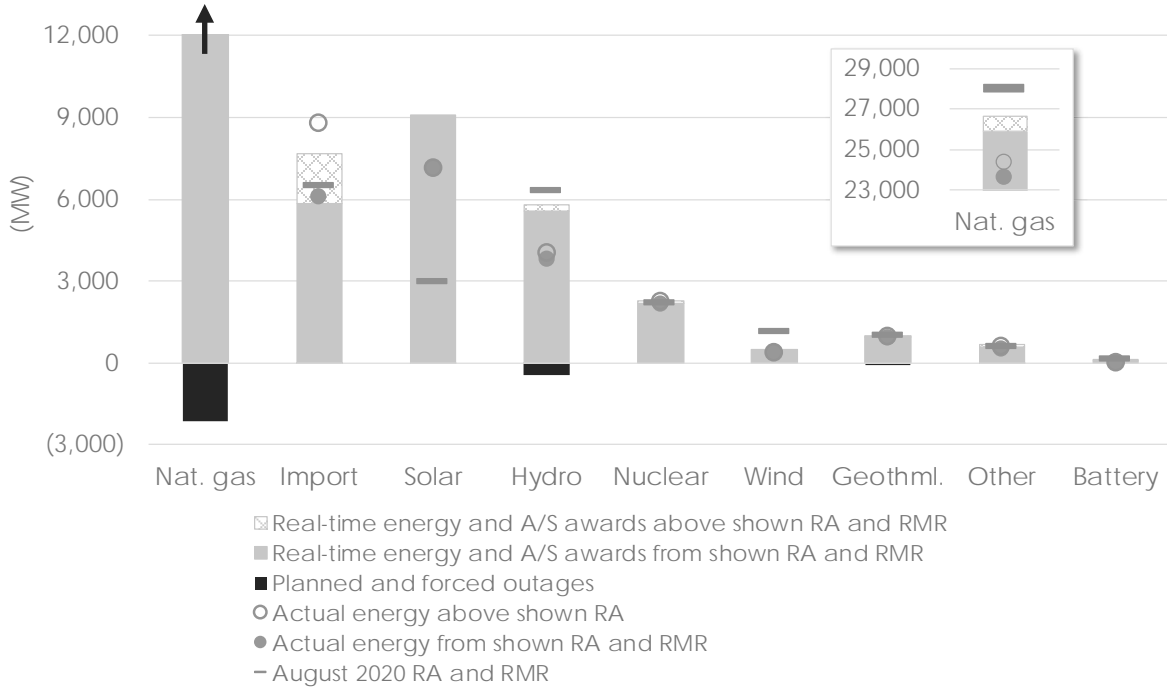


Figure B.17: August 14 Net Demand Peak (6:51 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR

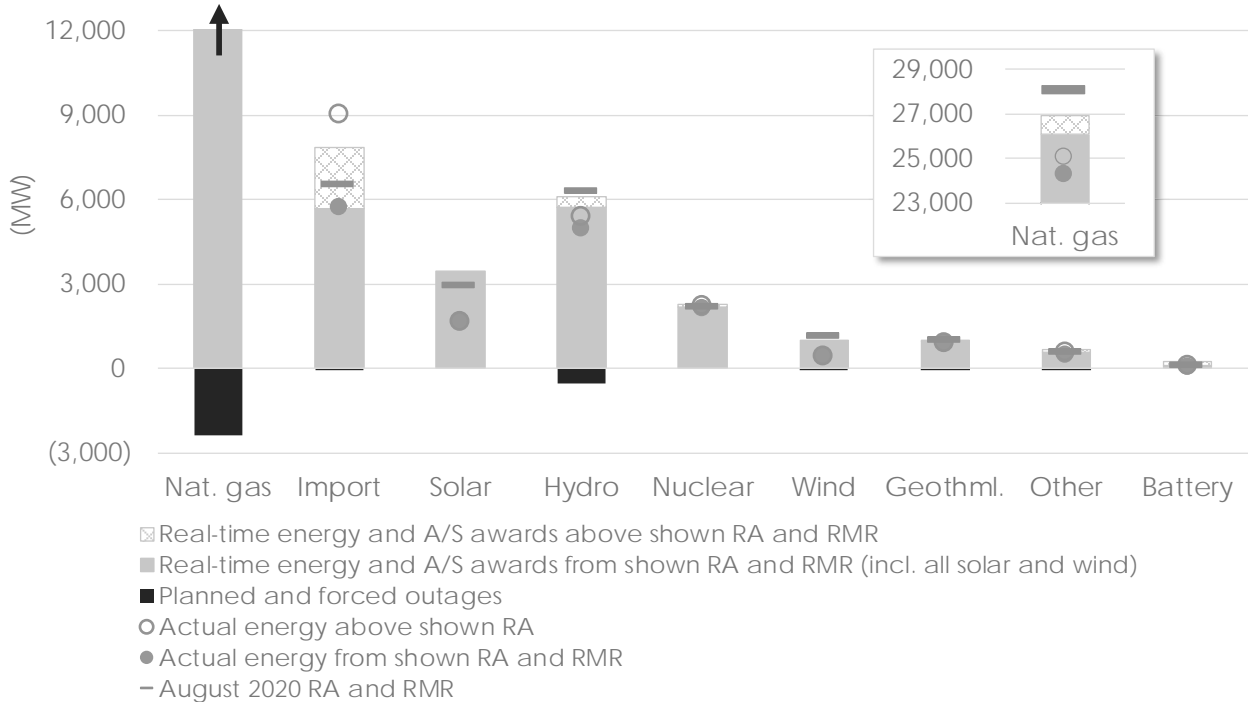


Figure B.18: August 15 Peak (5:37 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR

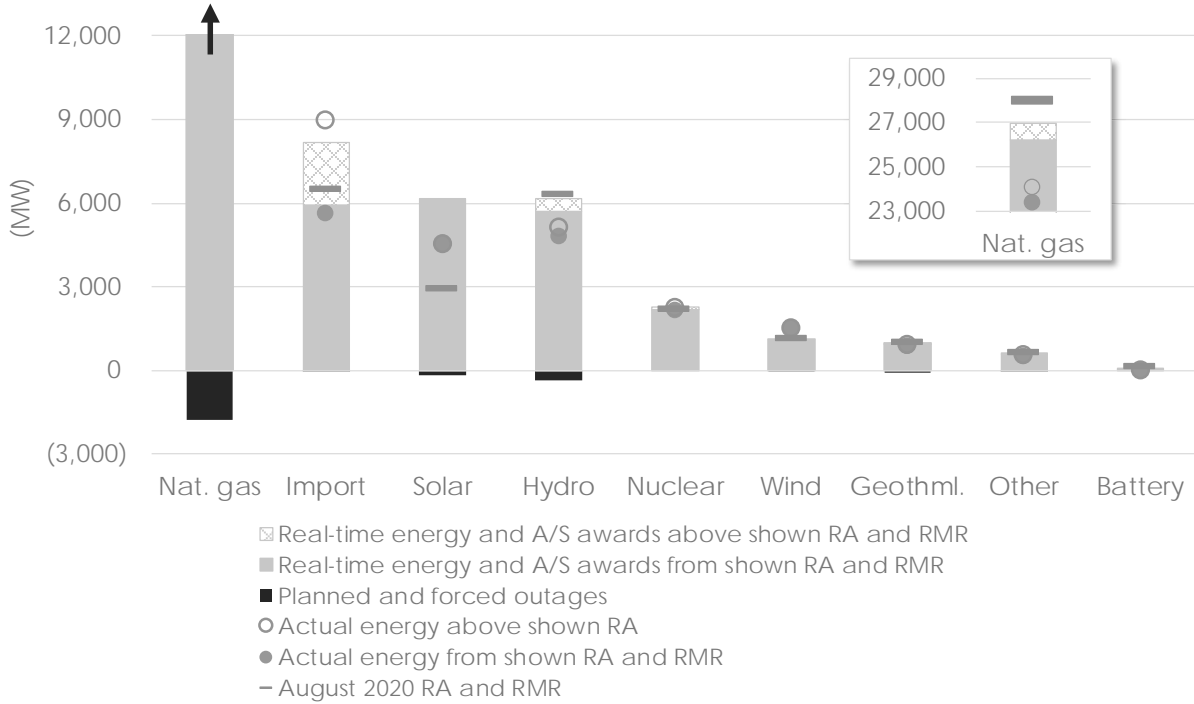
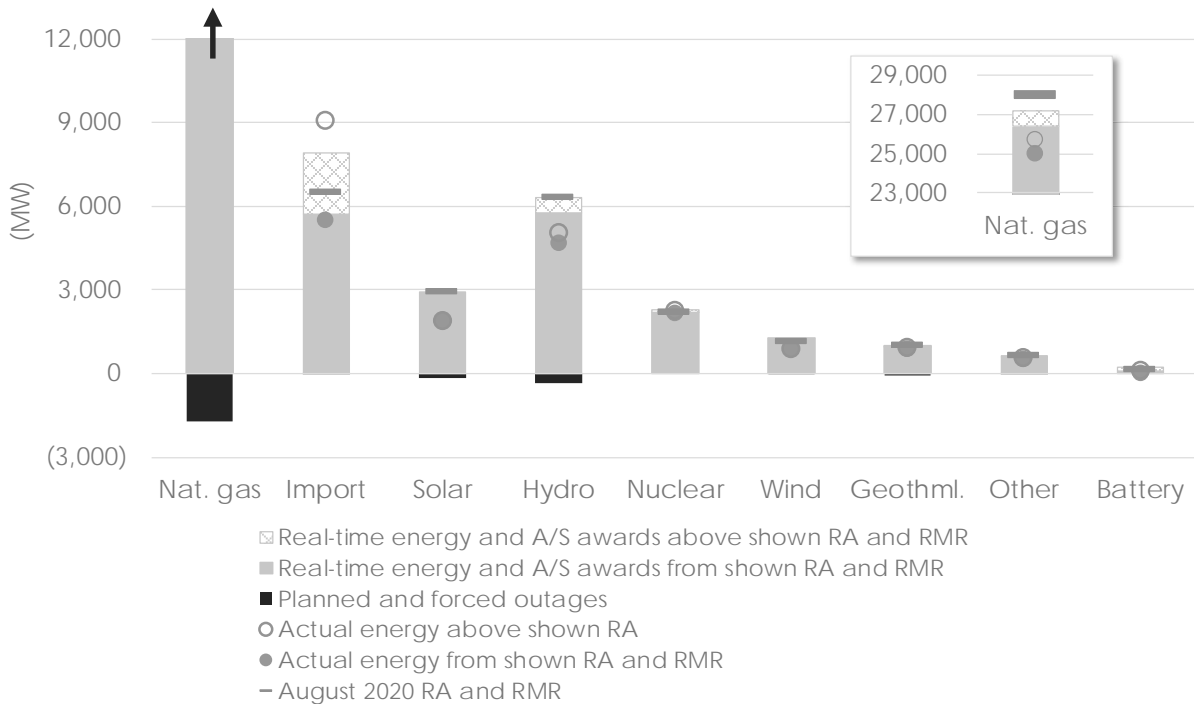


Figure B.19: August 15 Net Demand Peak (6:26 pm) – Real-Time Awards and Actual Energy Production vs. August 2020 Shown RA and RMR



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

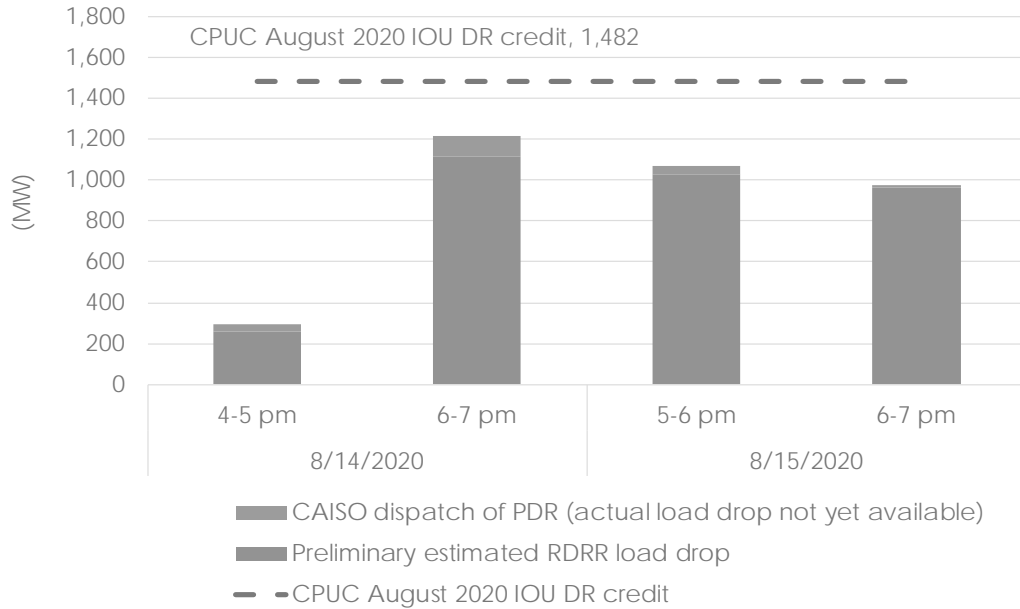
Demand response programs are designed to reduce demand at peak times. They take on many forms. Some programs bid into the CAISO's wholesale markets and are dispatched similar to a power plant. This Preliminary Analysis focuses on the largest portion of the demand response programs, which are the programs 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).

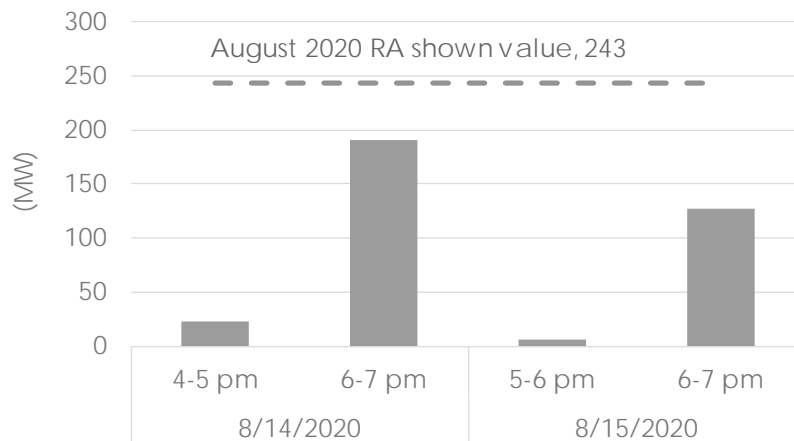
⁵⁸ Non-CPUC jurisdictional LSEs' credits were 565 MW, representing 11.9% of their total obligations.

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.

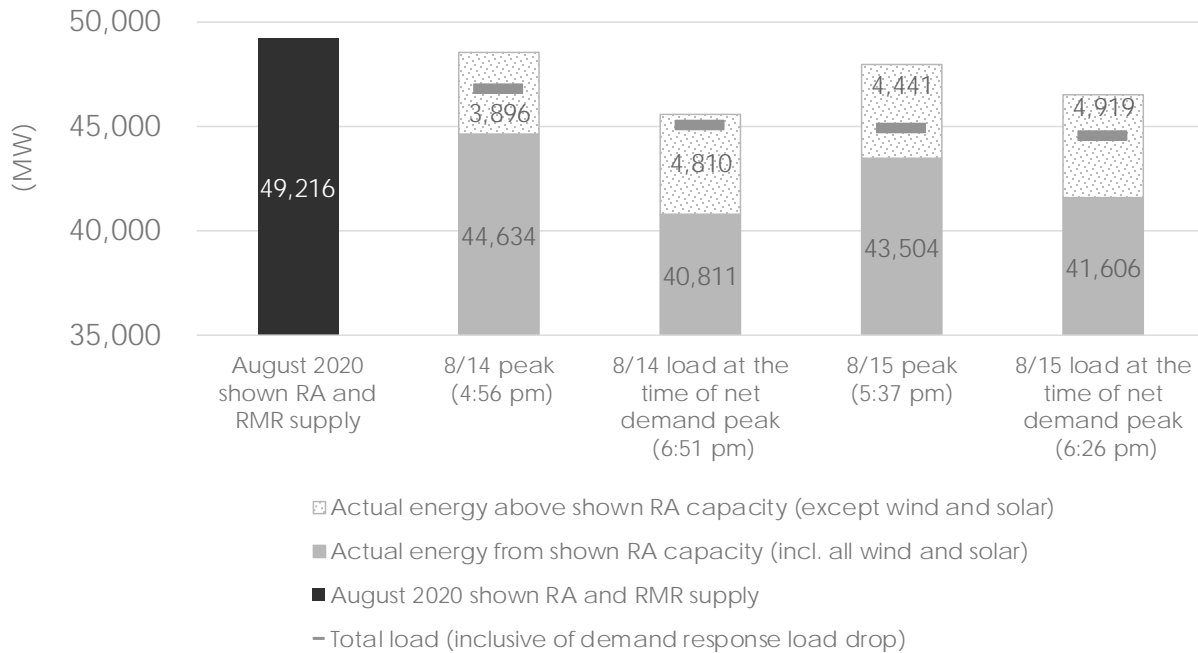
Figure B.21: CAISO Dispatch of Non-IOU PDR (Actual Load Drop Not Yet Available)



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.

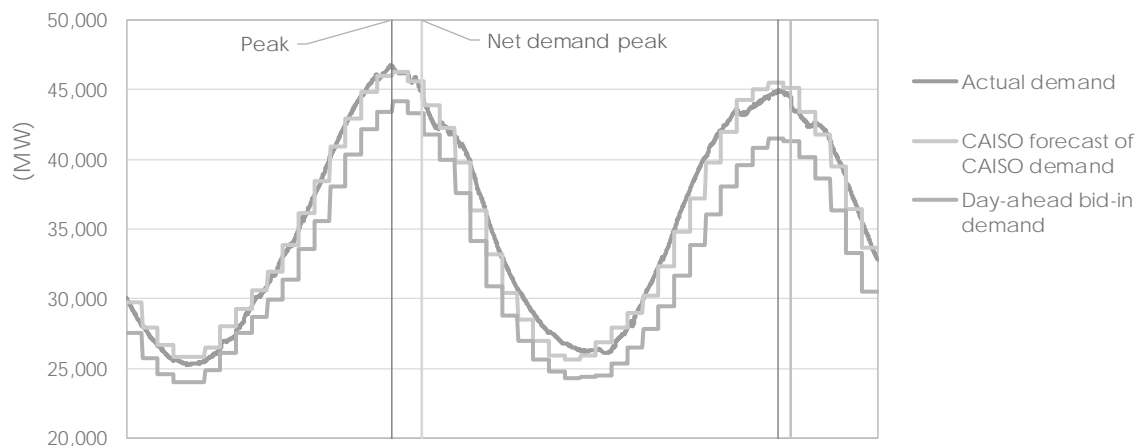
B.3.1 Demand Should Be Appropriately Scheduled in the Day-Ahead Timeframe

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:

	<u>8/14</u>	<u>8/15</u>
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 exports⁶² 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

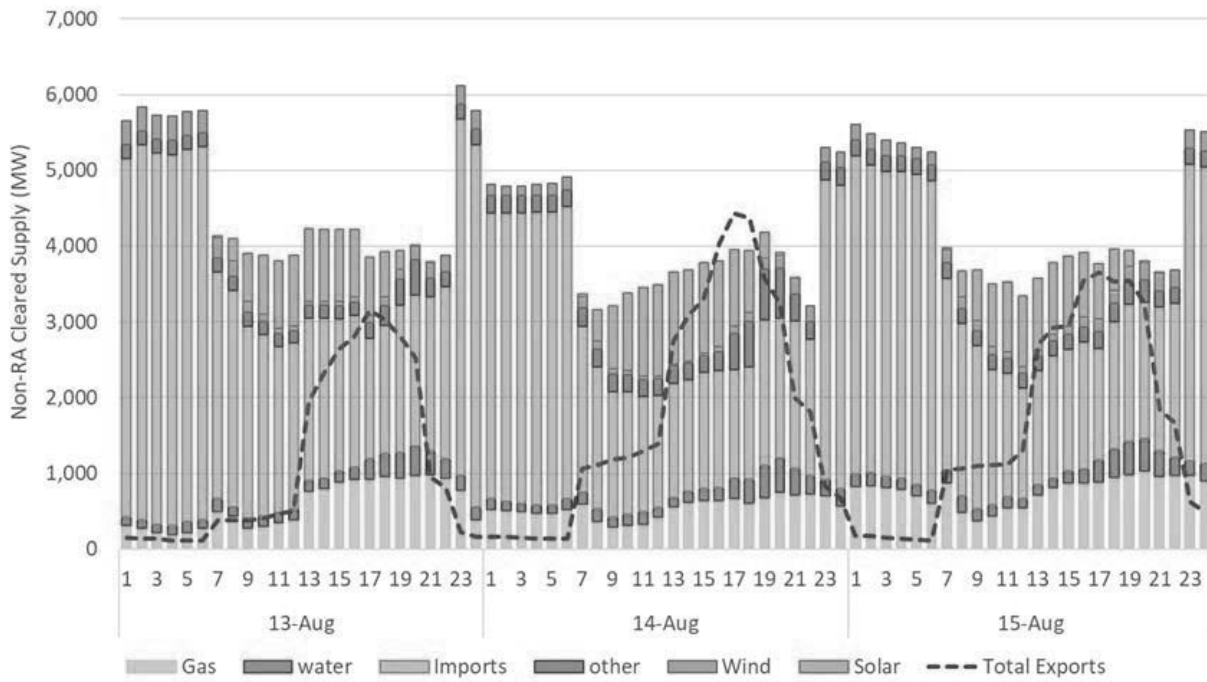
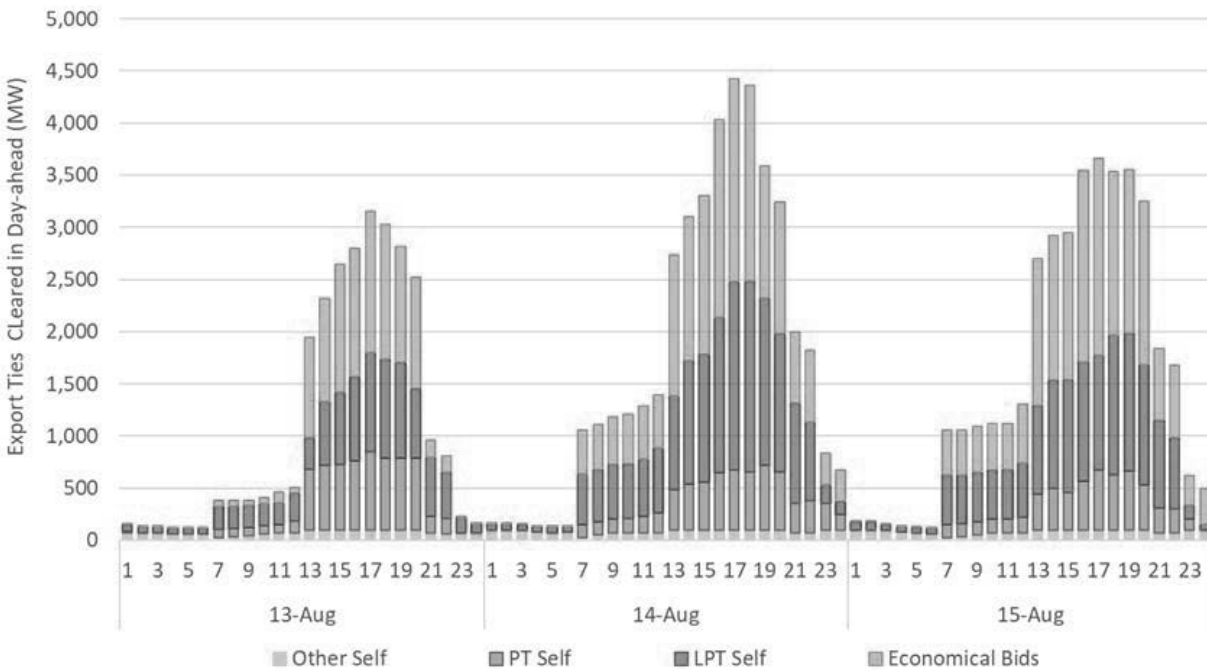


Figure B.25 below shows the breakdown of export types (reflected as the dotted line in the prior figure) from: economical bids, priority (PT), lower priority (LPT) and other self-schedule types.

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

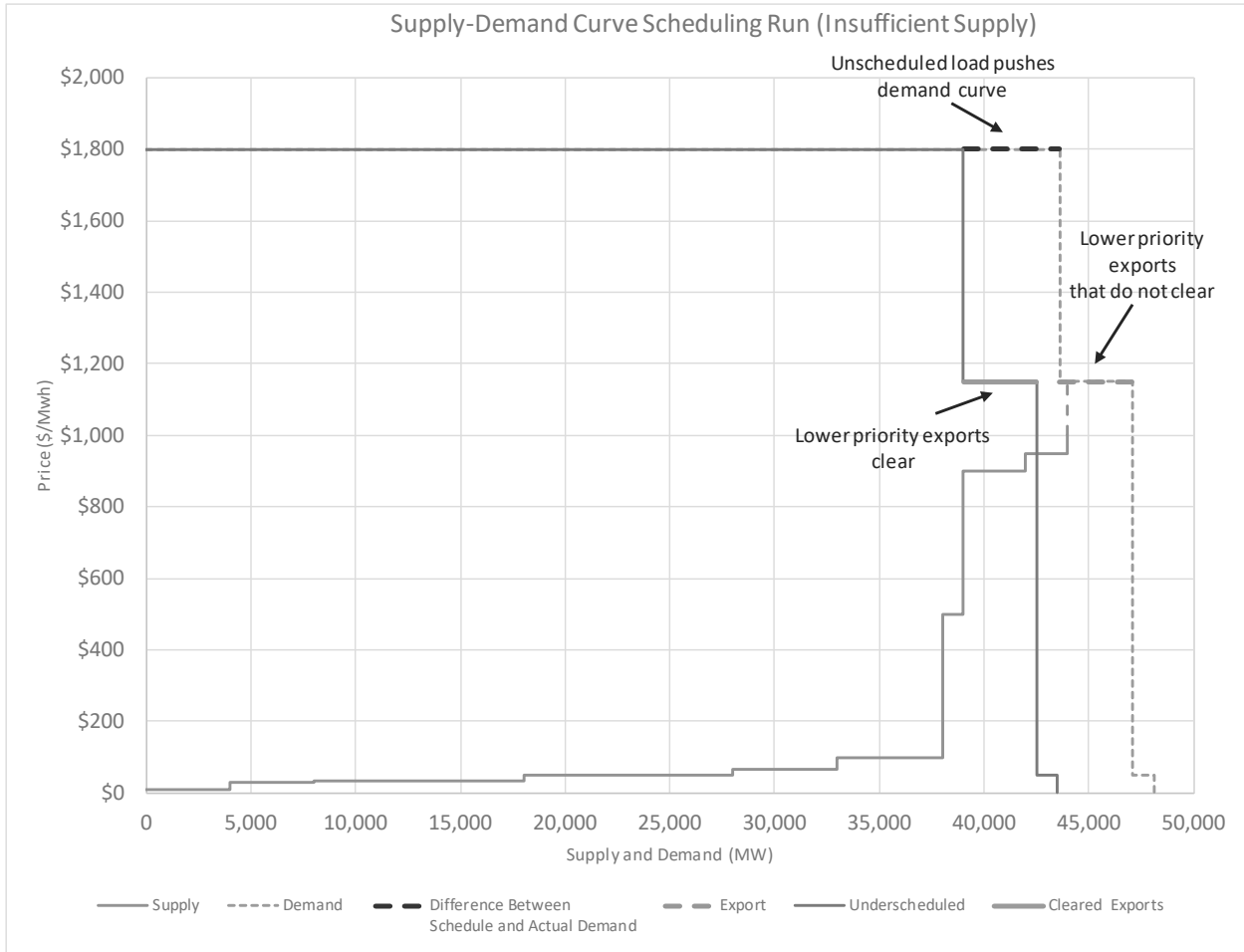
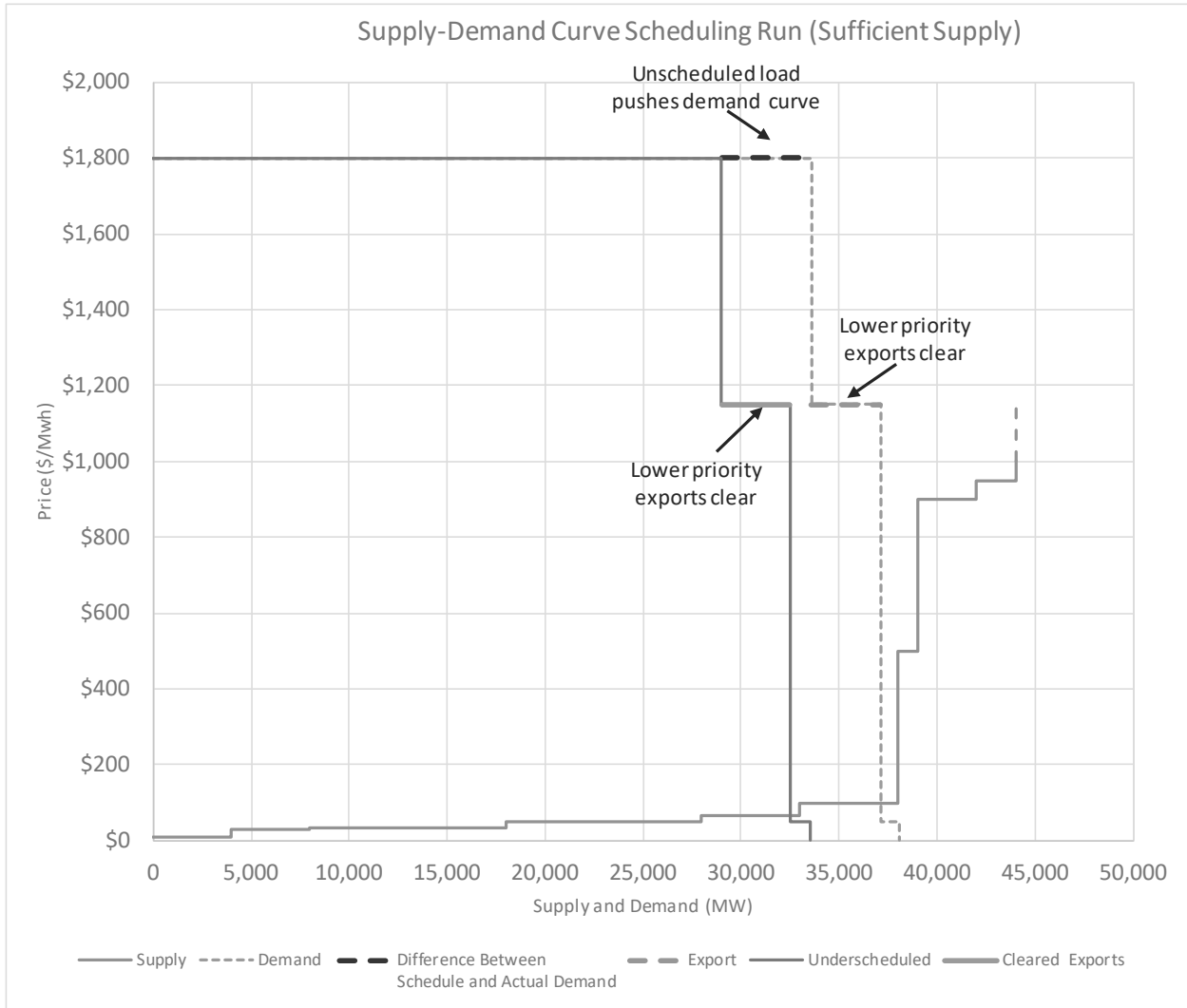
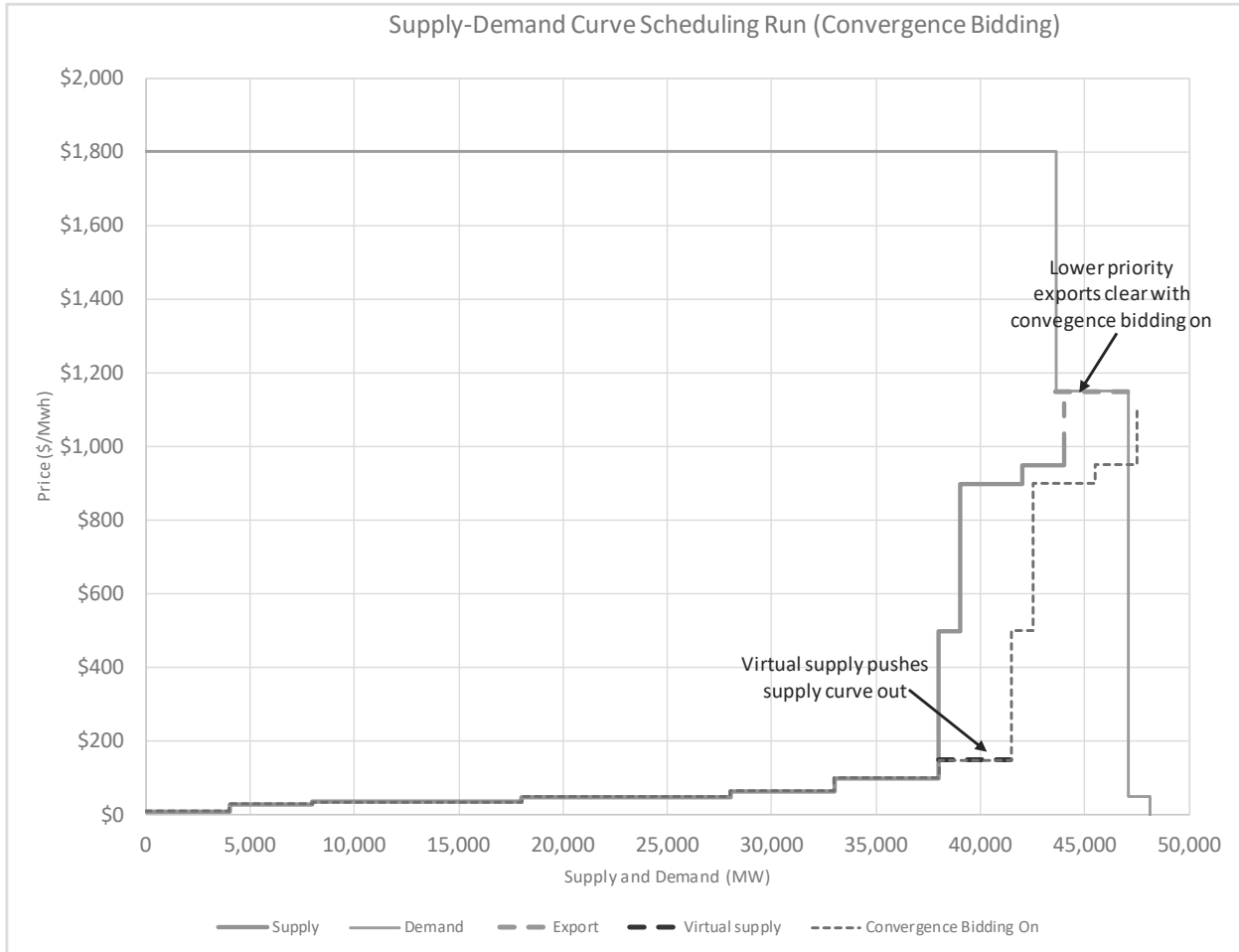


Figure B.27: Illustrative Example of Impact of Under-Scheduled Load Under Supply Sufficiency



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 All 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

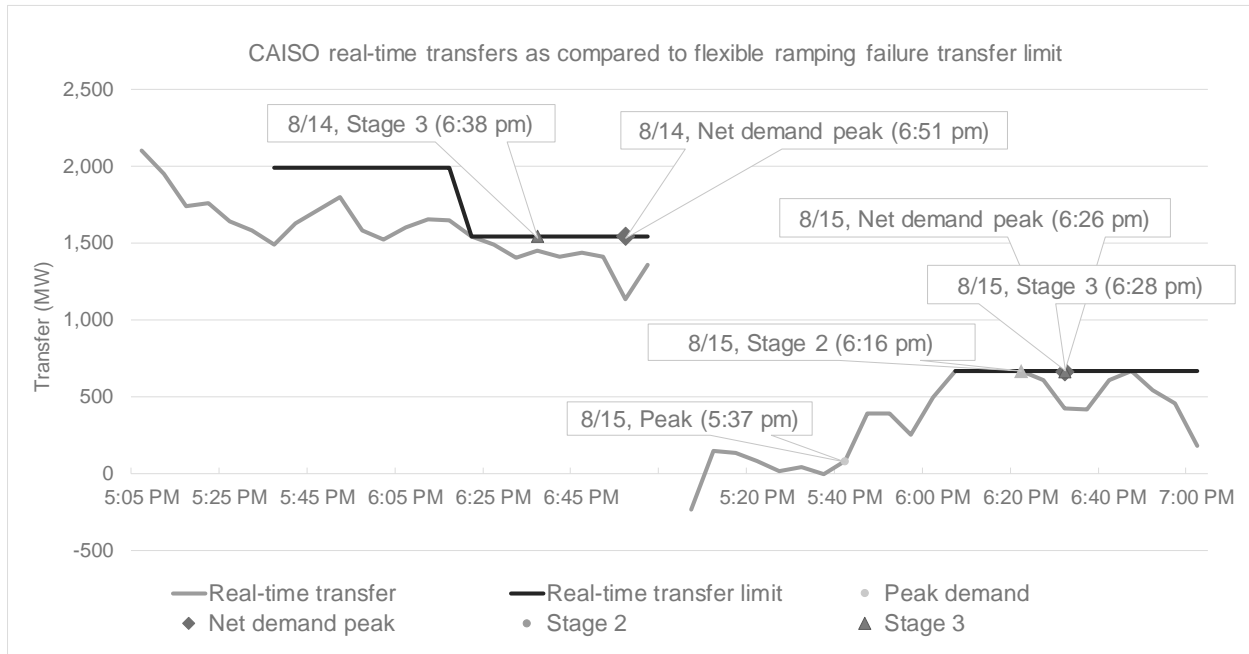
⁶⁵ Until September 5, 2020, the CAISO was protecting the full day-ahead schedule as cleared through the day-ahead IFM process. The CAISO modified its process to now only protect what is determined to be physically feasible through the day-ahead RUC process. See discussion of Business Practice Manual 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.

Attachment B

*Department of Market Monitoring
Report on system and market conditions, issues and performance:
August and September 2020*

California ISO

**Report on system and market conditions,
issues and performance:**

August and September 2020

November 24, 2020

Department of Market Monitoring

1 Summary

1.1 Background

This report reviews system conditions and performance of the CAISO's day-ahead and real-time markets from mid-August to September 7, 2020. During this period, regional high temperatures led to a high demand heat wave across the entire western region. On August 14 and 15, CAISO grid operators called upon load serving entities to curtail load due to system-wide conditions for the first time since 2001. In the following days and weeks, CAISO loads remained high but were well below forecasted levels, due largely to voluntary conservation efforts. Prices in the CAISO, Western Energy Imbalance Market and bilateral markets reached record levels on August 17-19, but no further load curtailments occurred.

This report was prepared by the CAISO's Department of Market Monitoring (DMM) which serves as the independent market monitor for the CAISO and Western Energy Imbalance markets. A prior report, prepared by the CAISO, CPUC and CEC, focuses on the root causes of the load shedding events occurring on August 14-15.¹ The CAISO/CPUC/CEC report includes more detailed background information on issues such as the state's resource adequacy program, CAISO market rules and operational practices, and weather and system conditions during this period.

DMM has reviewed the CAISO/CPUC/CEC report and has worked with the CAISO to understand and resolve differences in key metrics appearing in that report and analysis in DMM's report. DMM concurs with many of the key findings and recommendations in the CAISO/CPUC/CEC report, including the reports main conclusion that "there was no single root cause of the outages, but rather, a series of factors that all contributed to the emergency."²

This report provides additional analysis and some recommendations based on DMM's own independent analysis. This report also covers periods through September 7, during which CAISO energy demand was forecast to be higher than August 14 and 15, but further load curtailments were avoided due to a combination of different market conditions and steps taken by the CAISO and other entities.

1.2 Key findings

Key findings in this report are consistent with findings in the joint CAISO/CPUC/CEC report, which found that there was no single root cause of the load shedding events occurring on August 14-15. These load outages resulted from the combined effect of a series of factors, which include the following:

- **Extreme temperatures and energy demand** across the entire western region, which resulted in demand for electricity well in excess of current resource planning targets.

¹ *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*, October 6, 2020, prepared by the California Independent system Operator, California Public Utilities Commission and California Energy Commission. <http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf>. CAISO/CPUC/CEC report

² CAISO/CPUC/CEC report, cover letter, p. 1 of 3.

- **California state resource adequacy requirements** based on 1-in-2 year loads plus a 15 percent planning reserve margin, which are insufficient to reflect actual system conditions during this period.
- **Counting rules for resource adequacy capacity** which overestimate the actual capacity that is available from many resources during the early evening hours, when solar production is very low and demand is still very high.
- **Residual unit commitment (RUC) process and related real-time bid processing design.** The CAISO/CPUC/CEC report explains that “a prior market enhancement was unintentionally causing the CAISO’s RUC process to mask the load under-scheduling and convergence bidding supply effects, reinforcing the signal that more exports were supportable.”³ This report provides a detailed discussion of this issue, along with changes that were subsequently made to address this issue.
- **Transmission capacity from the Pacific Northwest was de-rated by about 650 MW** as a result of a weather-related forced outage which prevented additional available supply – including some resource adequacy imports -- from being imported into the CAISO.
- **The sudden loss of several large gas fired units** contributed to triggering the load curtailment events on both August 14 and 15. Although the overall level of gas capacity on outage was not unusually high on these days, this sudden loss of a significant amount of gas capacity came at a time when the amount of excess supply was very low due to a combination of other factors.
- **Self-scheduling of relatively large volumes of exports** in the day-ahead market that were not backed by imports being wheeled through or contracts with capacity within the CAISO. This increased the overall demand that had to be met in both the CAISO day-ahead and real-time markets because exports not supported by physical supply were passed from the residual unit commitment process into the real-time market at this time. These export schedules were not subsequently curtailed in real-time during hours when the CAISO was curtailed.

The most significant and actionable of these factors involve California’s resource adequacy program. To limit the potential for similar conditions in future years, system level resource adequacy requirements should be modified to ensure more capacity is available during net load peak hours. In addition, capacity counting rules for different resource types should be modified to more accurately reflect the actual availability of these resources during the net load peak hours. These recommendations are discussed in more detail in this report.

Additional findings highlighted in this report include the following:

- **The overall availability of resource adequacy capacity shown on supply plans during the most critical days and hours from mid-August to early September was not unusually low.** Of the 51,000 MW of capacity counted towards August resource adequacy requirements, about 6,100 to 8,200 MW (or 10 to 15 percent) was not bid or self-scheduled in the real-time market during the peak net load hours.
- **Solar and wind resources accounted for a significant portion of resource adequacy capacity that was not available in the real-time market during hours of load curtailments.** For August, solar and wind resources, including pseudo-tie resources, had a combined resource adequacy rating of 4,300 MW. Output from these resources averaged about 2,490 MW (57 percent) below this resource

³ CAISO/CPUC/CEC report, pp. 13-14.

adequacy rating during hours 19-20 on August 14-15. The output from these resources is predictably lower in these evening hours when net loads are highest, compared to the output of these resources in hours with highest gross load which are used to determine their resource adequacy rating.

- **Gas units accounted for about 1,870 MW of resource adequacy capacity unavailable in real-time during hours of load curtailments.** This represented about 6.7 percent of the 27,743 MW of gas-fired resource adequacy capacity. Almost half of this unavailable capacity (or about 3 percent of total resource adequacy capacity from gas units) was due to ambient de-rates which occur in very hot weather – when the total output from gas units falls below their normal rated capacity due to ambient temperature. This is an example of one of the types of factors that should be factored in resource adequacy counting rules.
- **Demand response resources accounted for about 650 MW of resource adequacy capacity that was unavailable in real-time during hours of load curtailment on August 14. Demand response accounted for about 820 MW of resource adequacy was unavailable in real-time during hours of load curtailment on August 15.** This represents over one-third of the 1,847 MW of resource adequacy capacity requirement that was met by demand response in August. The actual performance of demand response resources that were dispatched has not yet been fully evaluated.
- **Imports and hydro units combined account for about 1,436 MW of resource adequacy capacity that was unavailable in real-time during hours of curtailment.** About 9 percent of non-resource specific resource adequacy imports was unavailable (664 MW), with much of this capacity being unavailable due to transmission limitations. About 9 percent of resource adequacy capacity from hydro was unavailable (572 MW).
- **The Western energy imbalance market functioned well and helped facilitate transfers of available capacity in real-time across the west.** The CAISO was the largest net importer in the energy imbalance market during the most critical evening ramping hours of the summer 2020 heat wave. During curtailment intervals on August 14-15, the energy imbalance market provided an average of 1,346 MW and 530 MW respectively into the CAISO system.
- **The CAISO market was structurally uncompetitive during the high load days in August.** Although prices were very high during the high load days in August, analysis using the CAISO's day-ahead market software indicates that system wide mitigation of imports and gas-fired resources during this period would not have lowered prices. This reflects the fact that gas-fired and other resources that may be subject to mitigation were generally infra-marginal in re-runs of the day-ahead market using cost-based bids, and that high prices were set by demand response and other resources not subject to mitigation.
- **DMM has carefully reviewed major outages which occurred on August 14-15.** Based on its data analysis and conversations with plant operators, DMM has found no indication that outages were falsely declared at strategic times in order to allow generation owners to profit from higher prices (e.g. from output of other generating units under their control or virtual demand positions taken in the day-ahead market).
- **DMM closely monitored and reviewed market behavior during the August 14-15 heatwave.** Contrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation.

1.3 Recommendations

DMM agrees with many of the key recommendations related to resource adequacy in the CAISO/CPUC/CEC report and supports the coordinated efforts by the CAISO, CPUC and stakeholders to make the various planning, market design and operational enhancements identified in that report. The most significant and actionable of these recommendations involve California's resource adequacy program. To limit the potential for similar resource shortages in future years, a high priority should be placed on the following two recommendations:

- ***Increase resource adequacy requirements to more accurately reflect increasing risk of extreme weather events*** (e.g. beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system resource adequacy targets). Prior to this summer, CAISO peak load fell under the 1-in-2 years forecast four of the last five years.⁴ However, summer 2020 illustrates that higher reliability will require that resource adequacy requirements be based on load forecasts which reflect the high likelihood of much higher load conditions than are reflected in the 1-in-2 year forecast.
- ***Continue to work with stakeholders to clarify and revise the resource adequacy capacity counting rules***, especially as they apply to hydro resources, demand response resources, renewable resources, imports and other use limited resources. Counting rules should specifically take into account the availability of different resource types during the net load peak. Beginning in 2019, DMM has provided analysis and expressed concern in reports and CPUC filings about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements.⁵ This report includes additional analysis of the availability of different resource types during the peak net load hour in which load was curtailed in August, and highlights a variety of specific factors which could be incorporated into the resource adequacy ratings of these resources to better reflect their actual availability during the most critical net load peak hours.

In addition, DMM provides the following recommendation regarding the issue of exports.

- ***DMM recommends that further changes and clarifications in the rules and processes for limiting or curtailing exports be discussed and pursued by the CAISO in conjunction with other balancing areas.***

The CAISO/CPUC/CEC report includes the following recommendation regarding curtailment of exports:

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.⁶

⁴ 2019 Annual Report on Market Issues and Performance, Department of Market Monitoring, June 2020, pp.34-35. <http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf>

⁵ 2019 Annual Report on Market Issues and Performance, pp. 26-27, 299-302.

Reply Comments of the Department of Market Monitoring, Rulemaking 16-02-007, August 12, 2019, <http://www.caiso.com/Documents/CPUC->

[DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf](http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf)

⁶ CAISO/CPUC/CEC Report, p. 66.

Just prior to the Labor Day weekend heatwave, the ISO made important enhancements to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards. DMM supported these changes and believes that these changes played a key role in helping to improve real-time supply conditions on September 5 to 7.

DMM's understanding is that CAISO's current policy is still to prioritize exports that receive RUC awards over native CAISO balancing area load in real-time. DMM appreciates that curtailment of exports should be avoided when possible, given the potentially detrimental direct and indirect impacts of export curtailment on other balancing areas and the CAISO itself, as discussed in the CAISO/CPUC/CEC report.⁷ However, DMM believes that additional changes and clarifications to the residual unit commitment rules and other market processes are needed to address the issue of exports.

The rules and processes for limiting or curtailing exports used by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas. CAISO and other WECC balancing areas' ultimate policy on the priority of exports relative to native load will be a critical factor in CPUC resource adequacy reforms and many major CAISO market design initiatives. These include the extended day-ahead market, day-ahead market enhancements, system market power mitigation phase 2, resource adequacy enhancements, scarcity pricing, and refinements to export bidding rules. Further discussion of the need to clarify and potentially refine how CAISO and other balancing areas treat exports is provided in the final section of this report.

Finally, DMM provides the following recommendation regarding the demand response.

- ***DMM recommends that steps be taken to ensure a higher portion of demand response used to meet resource adequacy requirements is available during critical net load hours.***

Analysis in this report indicates that less than two thirds of the 1,847 MW of resource adequacy capacity requirements that were met by demand response were available for dispatch in real-time during the hours of load curtailment on August 14 and August 15. The actual performance of demand response resources that were dispatched has not yet been fully evaluated based on retail customer meter data. However, even if performance of demand response is high relative to the amount dispatched in the CAISO market, the amount of demand response that was available relative to the amount of resource adequacy capacity requirements met by demand response was relatively low.

DMM recommends that steps be taken to ensure the availability of these resources. These steps include (1) re-examining demand response counting methodologies, (2) adopting the ISO's recommendation to remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction, and (3) adopting a process to manually dispatch available demand response shown on resource adequacy supply plans before issuing exceptional dispatches to non-resource adequacy capacity and curtailing firm load. DMM recommends that these steps be taken before expanding reliance on demand response capacity.

A more detailed discussion of recommendations relating to demand response is provided in Section 3.13 of this report.

⁷ CAISO/CPUC/CEC Report, pp. 106-107.

2 Chronological summary

This section provides a short chronological summary of key events, conditions and findings for three distinct periods from mid-August to early September 2020. As summarized below, these three periods represent a series of different heat waves marked by different system and market conditions. In addition, a variety of different actions were taken by the CAISO, state agencies, market participants, and end use consumers which had a significant impact on system and market outcomes in these different periods.

August 14 and 15

- On Friday August 14, peak load was forecasted to be just over 45,750 MW in the day-ahead market, close to the one-in-two year peak used in setting resource adequacy requirements. Actual system loads on August 14 reached about 46,750 MW, about 1,000 more than the day-ahead forecast. Peak load on Saturday August 15 reached about 45,000 MW, similar to the day-ahead forecast.
- Regionally, the heat wave led to record levels of load across the EIM and the WECC.
- Load serving entities within the CAISO continued to submit self-schedules or very high bids to purchase energy in the day-ahead market on these days. Total physical load clearing the day-ahead market on these two days during hours 16 to 21 averaged about 95 percent of forecasted load.
- DMM’s analysis indicates that the amount of resource adequacy capacity scheduled or offered in the day-ahead market was slightly above the day-ahead load forecast on August 14 and 15.
- On these days additional demand was placed on the CAISO system by exports that were purchased in the day-ahead market. Most of these exports were self-scheduled (indicating a willingness to export at any market clearing price), with some additional exports clearing at very high bid prices to buy energy.
- The CAISO curtailed a very limited amount of export energy after the day-ahead energy market or in real-time, about 90 MW on August 14 and 30 MW on August 15. Thus, the remaining cleared exports added thousands of MW of additional demand to total CAISO area demand in both the day-ahead and real-time markets.
- On these two days, virtual supply bids clearing the day-ahead market at relatively high prices allowed additional export schedules and bids to clear the day-ahead market. About 2,900 MW of exports were scheduled out of the day-ahead market on interties connecting the CAISO with adjacent balancing areas in the southwest (NEVP, APS, SRP).⁸
- Most of the 4,500 MW of non-resource specific resource adequacy import capacity bid into the day-ahead market cleared (85 percent). Almost all of the capacity which did not clear (99 percent) was bid on interties from the Pacific Northwest, where congestion lowered prices below bids and limited the quantity available to import.

⁸ Exports cited here are the average during hours 17-22 on August 14 and 15 on ITCs in the southwest, including: CFE_ITC, NORTHGILA500_ITC, PALOVRDE_ITC, ELDORADO_ITC, MEAD_ITC, IPPUTAH_ITC, ADLANTO-SP_ITC, ADLANTOVICTVL-SP_ITC, WSTWGMED_ITC, VICTVL_ITC, and LAUGHLIN_ITC.

- With the exception of a single gas resource which was returning from an outage, all available gas-fired capacity was committed to be in operation through the day-ahead residual unit commitment process or exceptional dispatch commitments.
- The overall amount of capacity on outage on these days was not abnormally high, but a few large gas-fired units had sudden outages. These created sudden changes in available generation and appear to have increased uncertainty about real-time supply at critical times.
- On August 14, the ISO manually dispatched about 800 MW of utility reliability demand response (RDRR) to reduce load during net peak load hours. On August 15, the ISO manually dispatched almost 900 MW of utility reliability demand response to reduce load during net peak load hours.
- Operating reserve levels were short of requirements for multiple intervals during peak hours in both the day-ahead and real-time markets and during load shedding.
- Both load shed events on August 14 and August 15 began in hour ending 19 when CAISO grid operators called upon all utility distribution companies within the CAISO system to curtail a total of about 1,000 MW and 500 MW of load respectively.⁹ The August 14 event began load restoration in about an hour while on August 15 this process began after approximately 20 minutes.
- Actual load curtailments were implemented by utility distribution companies. The actual amount of load curtailed cannot be precisely quantified, but may be higher than called upon by CAISO operators.
- During the peak ramping hours, net transfers into the CAISO system from the rest of the energy imbalance market averaged about 1,500 MW on August 14 and 550 MW on August 15. Most of these transfers were from adjacent balancing areas in the southwest (NEVP, APS, SRP). Thus, these transfers offset a significant portion of the additional CAISO area demand that was created by exports to these balancing areas made through the day-ahead markets.
- During a few 15-minute intervals on these two days, the CAISO balancing area failed the resource sufficiency test applied to all balancing areas in the Western energy imbalance market. Balancing areas failing this test have their net import limit capped for subsequent 15-minute intervals. This limitation is designed to deter balancing areas from leaning excessively or systematically on the energy imbalance market to meet their resource and ramping energy requirements. However, DMM's analysis indicates that this limitation had little or no impact on net transfers from the energy imbalance market into the ISO during these intervals. EIM transfers were, however, limited by the total available greenhouse gas import supply in some intervals on both of these days.

August 17 to August 19

- During this three day period, CAISO system loads were projected to reach record levels. However, actual demand during these days was significantly lower than the day-ahead forecast. The lower-than-expected loads on these days appear to be due in large part to an extraordinary response by

⁹ CAISO/CPUC/CEC Report, pp. 41-42.

consumers to efforts by the Governor’s office, state agencies and CAISO to promote reduced energy usage during the peak afternoon and early evening hours.

- Regionally, the RC West reported historical peak load levels reaching 127,631 MW on August 17, 2020 in the 6 pm hour.¹⁰
- On the evening of August 16, the ISO announced the suspension of virtual bidding effective in the day-ahead market occurring on August 17 for operating day August 18. The ISO also informed scheduling coordinators with scheduled day-ahead exports for August 17 that if conditions warranted curtailing load, export schedules could be curtailed as well.
- This suspension was designed in part to prevent virtual supply bids from allowing additional exports from being scheduled in the day-ahead market which would ultimately need to be met by physical supply from within the CAISO system. At this time, RUC was not identifying exports with IFM schedules that could not be supported by physical supply capacity. Analysis by DMM suggests that, given this RUC implementation issue, the suspension of virtual bidding did have a significant impact on reducing exports from the CAISO system scheduled in the day-ahead market.
- On these days, DMM’s analysis indicates available resource adequacy capacity would not have been sufficient to meet the day-ahead load forecast of system loads during the peak ramping hours.
- On these days, the state of California and other entities took a variety of actions to allow additional supplies of energy to be made available to the CAISO grid and to reduce behind-the-meter loads.¹¹
- On August 17 to 19, load within the CAISO system was not curtailed and, on August 18, the ISO market curtailed exports from the CAISO system.
- The ISO reinstated virtual bidding in the day ahead market for August 22. Despite the ISO not having yet fixed the underlying RUC export and real-time schedule processing issue, by this time system and market conditions had changed so that virtual bidding was again viewed as providing market benefits without presenting a risk to system reliability. DMM concurred with the decision to reinstate virtual bidding based on its analysis of the change in market and system conditions which had occurred by that time.
- As discussed below, the CAISO took other actions prior to the next heat wave in early September to help mitigate the risk to real-time system reliability that could be created by a high level of exports from the CAISO’s day-ahead market.

¹⁰ September 24, 2020. California ISO: Board of Governors Memorandum <http://www.aiso.com/Documents/CEOReport-Sep2020.pdf>.

¹¹ CAISO/CPUC/CEC Report, pp. 38 - 40.

September 5 to 7 (Labor Day weekend).

- CAISO system loads were again projected to exceed the 1-in-10 year peak forecast on September 6. Real-time load on these days was high, but lower than forecast, exceeding the 1-in-2 forecast and reaching levels close to August 14 and 18.¹²
- The ISO announced a year-to-date peak load record of 47,236 MW on Sunday, September 6, 2020.¹³
- On these days, DMM's analysis indicates available resource adequacy capacity would not have been sufficient to meet either day-ahead load forecast or actual real-time system loads during the peak ramping hours.
- Beginning with the day-ahead market for September 5, the ISO implemented several software modifications designed to reduce exports from being scheduled in the day-ahead market which could not be supported by available physical supply in the CAISO system.
- These changes resulted in a significant reduction in exports from the CAISO system.
- On September 5 to 7, no load within the CAISO system was shed.

¹² Actual load measures are not adjusted for dispatched demand response, which may have reduced load on these days.

¹³ All other sources of data available to DMM indicate that load on August 18 exceeded load on September 6. These sources include real-time telemetry, the real-time market requirement and settlement data. See California ISO, Board of Governors Memorandum, September 24, 2020 <http://www.caiso.com/Documents/CEOReport-Sep2020.pdf>.

3 Analysis of key market Issues

This section provides a summary of findings concerning specific key market issues examined in this report.

3.1 Demand conditions

During the 2020 heat wave, actual peak load exceeded the 1-in-2 year peak forecast on August 14, 18, and 19, as well as on September 5 and 6. Figure 3.1 and Figure 3.2 show the actual system load peak in the ISO by day compared to the 2020 1-in-2 and 1-in-10 year peak forecasts during the time frames of August 13-21 and September 5-7, respectively.¹⁴ The day-ahead load forecast peak in the CAISO system surpassed the 1-in-10 year peak forecast on August 17, 18, and September 6.

As discussed in the CAISO/CPUC/CEC report, the high CAISO loads on these days resulted from record-high temperatures, and coincided with extremely high loads across the entire west.¹⁵ As shown in Figure 3.1, actual peak loads exceeded the day-ahead load forecast by about 1,000 MW on August 14. Additionally, Figure 3.2 shows that actual peak load also exceeded the day-ahead load forecast on September 5 by about 1,500 MW.

Actual peak load also exceeded the CEC's adjusted August 2020 1-in-2 peak forecast used to set resource adequacy requirements (44,740 MW) on August 14, 15, 18, and 19.¹⁶ The adjusted August 2020 1-in-2 forecast is over 1000 MW less than the CAISO 1-in-2 year peak forecast, as shown in Figure 3.1.

Both load shed events on August 14 and August 15 began in hour ending 19 when CAISO grid operators called upon all utility distribution companies within the CAISO system to curtail a total of about 1,000 MW and 500 MW of load respectively. The August 14 event began load restoration in about an hour while on August 15 this process began after approximately 20 minutes. Actual load curtailments were implemented by utility distribution companies. The actual amount and timing of load curtailed by the individual utility distribution companies cannot be precisely quantified, but is reported to have been higher and longer in duration than called upon by CAISO operators.¹⁷

Figure 3.3 compares the CAISO's day-ahead forecast to the actual market requirement for energy used by the real-time market software over the August heat wave. As shown in Figure 3.3, loads were forecasted to reach above 49,000 MW on Monday August 17 and were forecasted to exceed 50,000 MW on Tuesday August 18. Although the CAISO real-time requirement for energy reached almost 49,000 on August 18, it remained well below the day-ahead demand forecast on August 17 and 19.

The difference between the forecasted load peaks and the actual load peaks on August 17 to 19 appears to be due in large part to both the conservation efforts of Californians and out of market production in

¹⁴ The 1-in-2 year and 1-in-10 year peak forecasts are estimated by CAISO and reported annually in the Summer Loads and Resource Assessment report. The 2020 peak forecasts used for this analysis may be found on the CAISO website: <http://www.caiso.com/Documents/2020SummerLoadsandResourcesAssessment.pdf>

¹⁵ CAISO/CPUC/CEC Report, pp. 27-28.

¹⁶ CAISO/CPUC/CEC Report, pp. 45.

¹⁷ CAISO/CPUC/CEC Report, pp. 41-42.

response to the efforts of the Governor’s office, state agencies and CAISO to promote reduced energy usage during the peak afternoon and early evening hours. The combination of voluntary load reductions and emergency assistance from surrounding balancing authority areas helped avoid the need for any further load curtailments.

Figure 3.1 Actual peak load in the ISO compared to day-ahead forecast peaks (August 13 – 21)

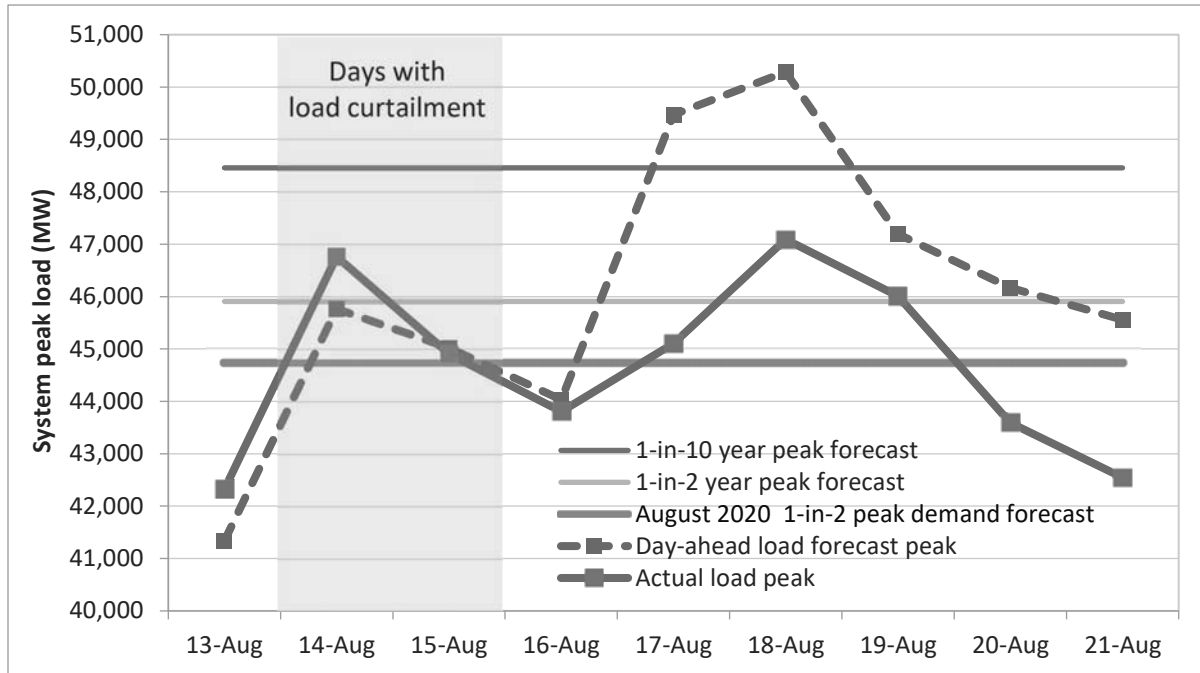


Figure 3.2 Actual ISO peak load compared to day-ahead load forecast peaks (September 5 – 7)

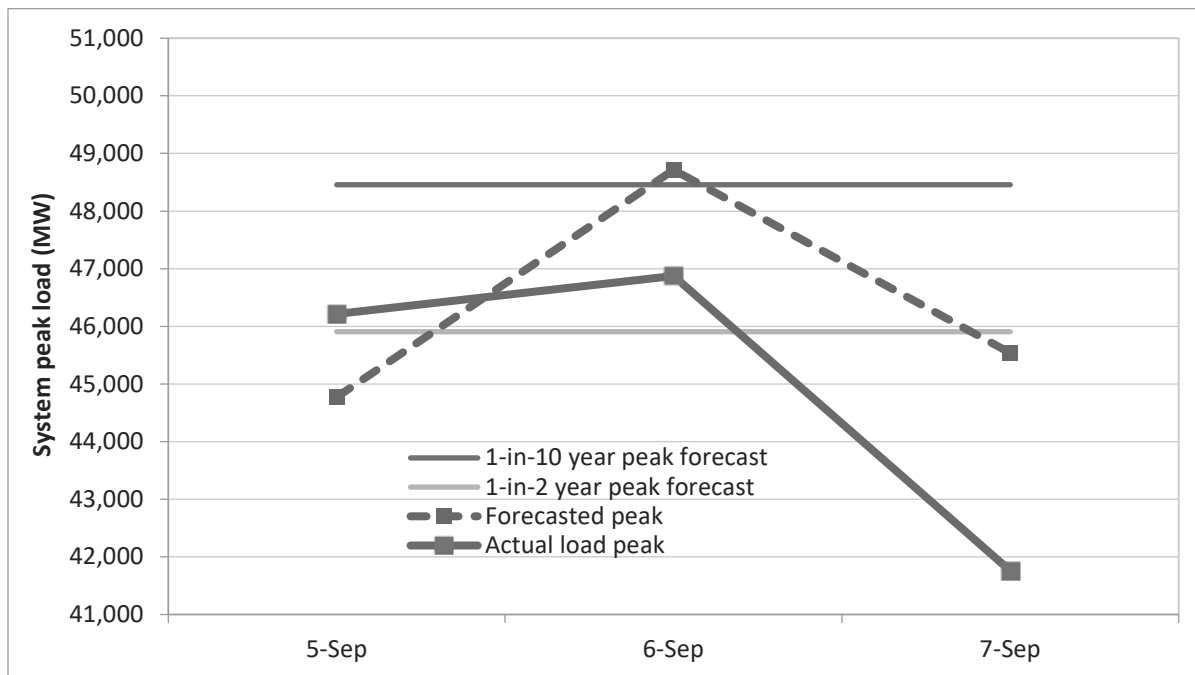


Figure 3.3 CAISO day-ahead load forecast vs real-time load (August 13 – August 19)

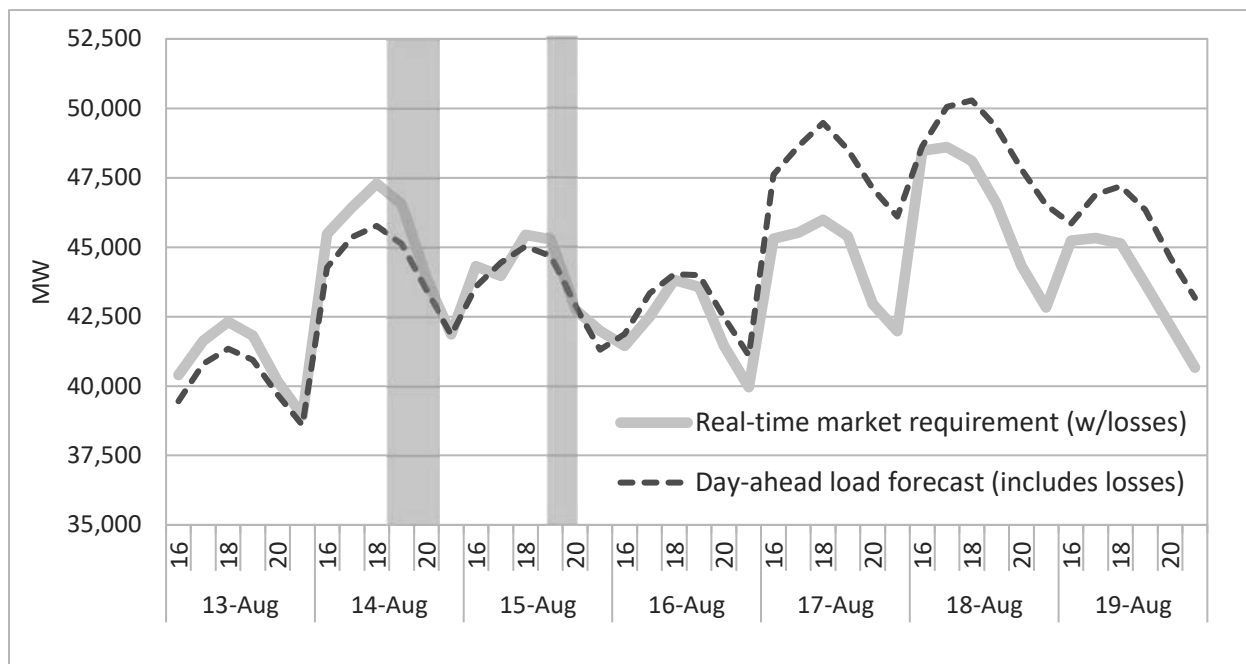
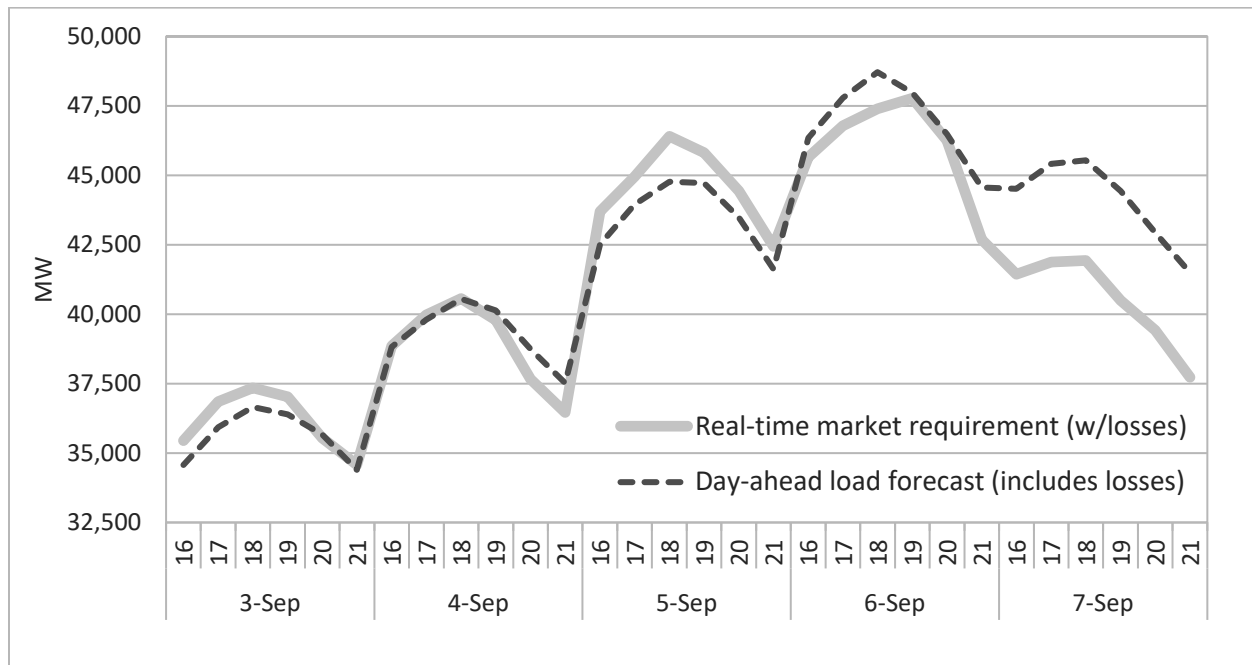


Figure 3.4 CAISO day-ahead load forecast vs real-time load (September 3 – September 7)



3.2 Energy market prices

Figure 3.5 shows hourly prices in the CAISO day-ahead and real-time market from August 13 to 21, with the hours in which curtailments occurred highlighted.

As shown in Figure 3.5, day-ahead and real-time prices spiked sharply on August 14 and 15 during some of the early evening hours. Prices reached the cap in at least one of the PG&E, SCE or SDG&E areas in 2 day ahead intervals, 4 intervals in the 15-minute market and 15 intervals in the 5-minute market on August 14. On August 15, prices hit the \$1,000/MW price cap in at least one area for 3 intervals in the 15-minute market and for 12 intervals in the 5-minute market.

Day-ahead prices rose sharply on August 17 and 18, with system marginal energy costs (SMEC) reaching the \$1,000/MW bid cap numerous hours, while prices for southern California (SP15) being driven well above the \$1,000/MW by north-to-south congestion within the CAISO system. On these days, real-time prices remained high but were well below day-ahead prices. On these days, actual loads in real-time were well below the day-ahead forecast, as previously shown in Figure 3.1 and Figure 3.2.

Figure 3.5 CAISO day-ahead and real time peak hour prices (August 14-21)

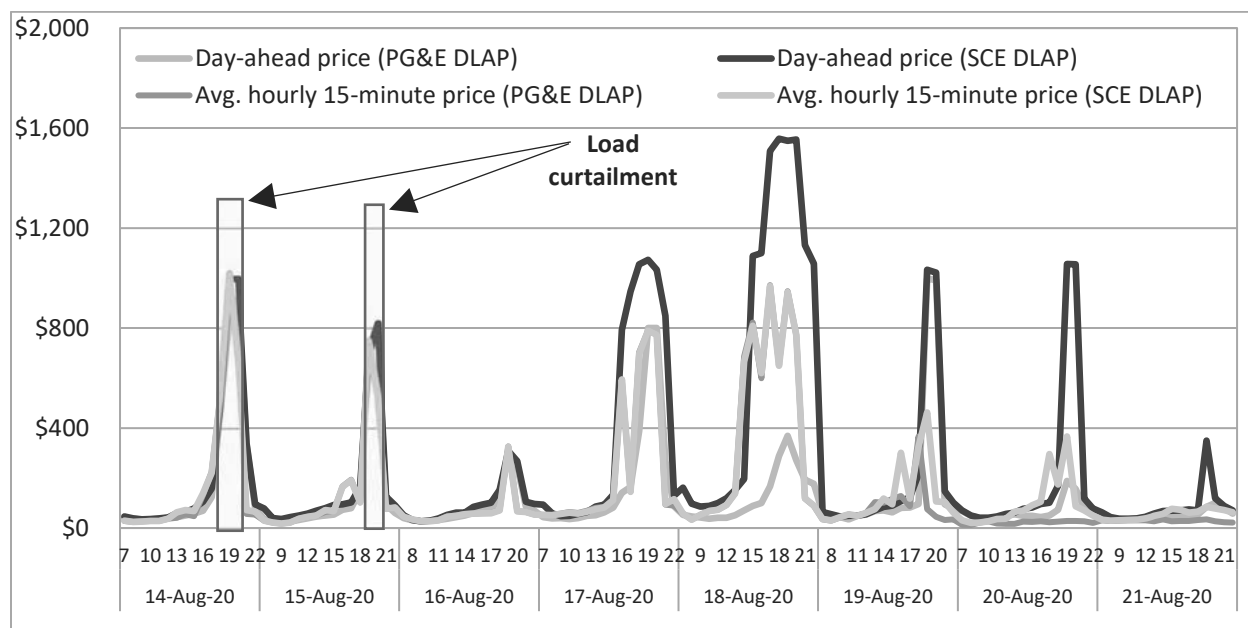
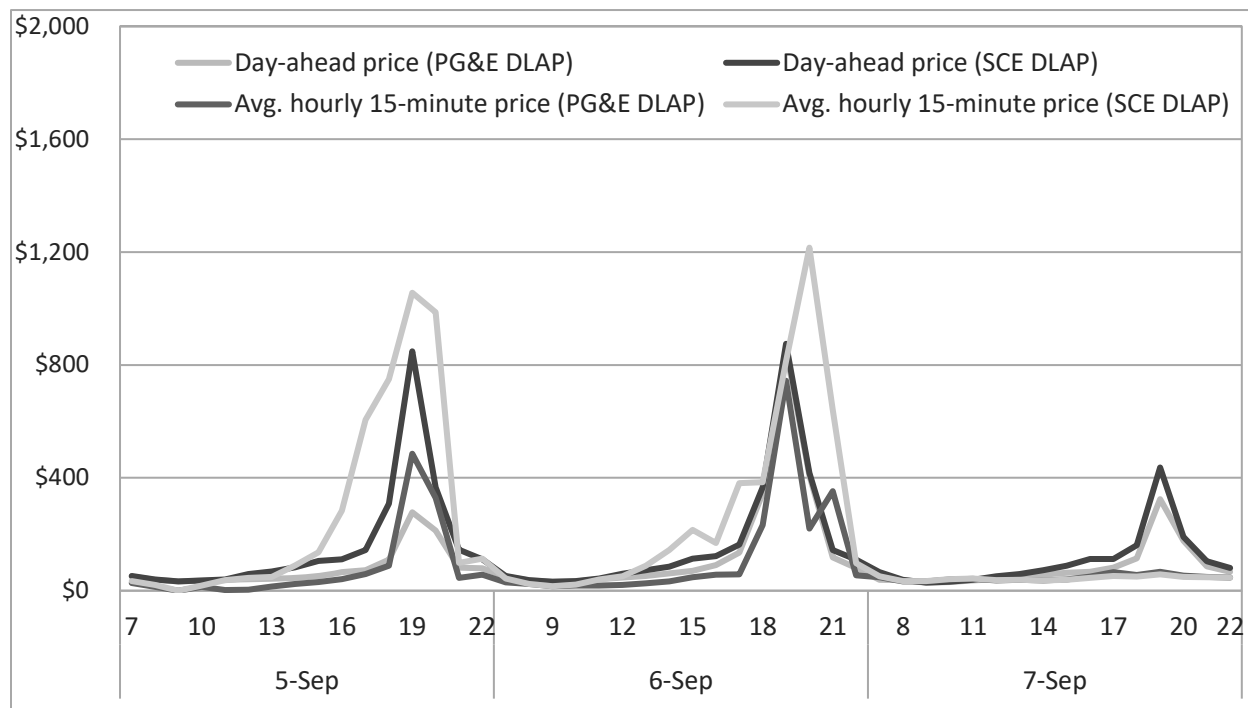


Figure 3.6 CAISO day-ahead and real time peak hour prices (September 5-7)



3.3 Load bidding and scheduling

The CAISO/CPUC/CEC report and CAISO presentations have emphasized under-scheduling of load in the day-ahead market as a major root cause of the load curtailments and stressed real-time market conditions during the summer 2020 heat waves.

Analysis in this section shows that load serving entities within the CAISO submitted self-schedules or demand bids equal to a relatively high percentage of the energy needed to meet their load forecast in the day-ahead market during the high load hours of mid-August to early September. However, under these high load conditions, under-scheduling of even a small percentage of total load had a significant impact on the volume of demand that needed to be met in the real-time market.

Figure 3.7 through Figure 3.11 compare the amount of load bid and scheduled in the day-ahead market with the CAISO day-ahead forecast. These figures also compare aggregate day-ahead load schedules to DMM's calculation of the energy requirement used by the real-time market software.¹⁸

As shown in Figure 3.7, Figure 3.8 and Figure 3.9 total physical load clearing the day-ahead market on August 14 during hours 16 to 21 averaged about 97 percent of forecasted load and 95 percent of the real-time market software requirement. On August 15, physical load clearing the day-ahead market in these hours averaged about 94 percent of forecasted load and 93 percent of the real-time requirement during hours 16 to 21.

While load under-scheduling in these hours was relatively small as a percentage of the total load forecast, the amount of unscheduled load that needed to be met by additional supply in the real-time market was still significant. For example:

- On August 14, during the net load peak (hour ending 19), while load scheduled in the day-ahead market totaled 97 percent of the day-ahead forecast, this equated to 1,527 MW of unscheduled load that needed to be met in the real-time market.
- On August 15, during hour ending 19 load scheduled in the day-ahead market totaled 94 percent of the day-ahead forecast, which equated to 2,866 MW of unscheduled load in the real-time market.

As shown in Figure 3.7, beginning on Monday August 17, load serving entities increased the portion of load self-scheduled in the day-ahead market significantly, but had fewer price sensitive load bids offered and accepted in the market. Total physical load clearing the day-ahead market on August 17 to 19 during hours 16 to 21 averaged about 93 percent of day-ahead load forecast. Since real-time loads were well below day-ahead forecast on these days, physical load schedules averaged about 99 percent of the real-time market requirement during the evening hours of August 17 to 19.

¹⁸ This is the measure of real-time demand produced by the market software. It includes biasing of 5-minute real-time load forecast by operators, which often exceeded 1,000 MW in the hours covered in this report. This measure is different than the measure of load from the PI system used by CAISO.

Figure 3.7 Physical load scheduled in day-ahead market (August 13 – August 19)

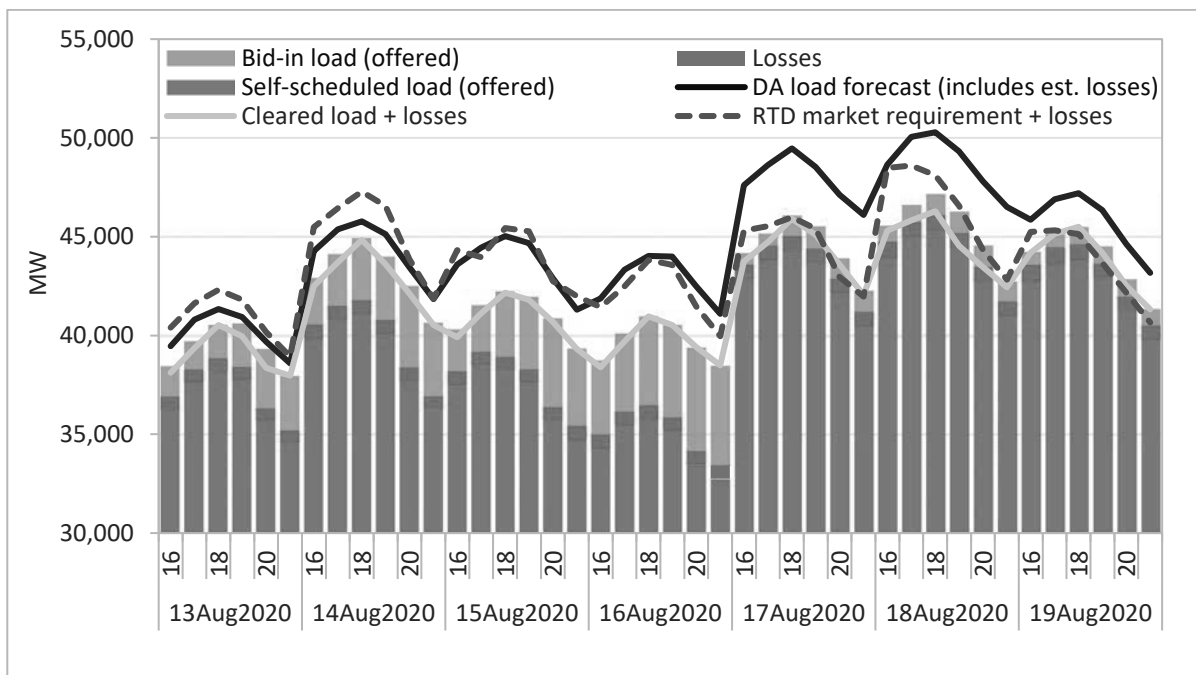


Figure 3.8 Physical load scheduled in day-ahead market (August 13 – August 19) (as a percentage of forecast and real-time load)

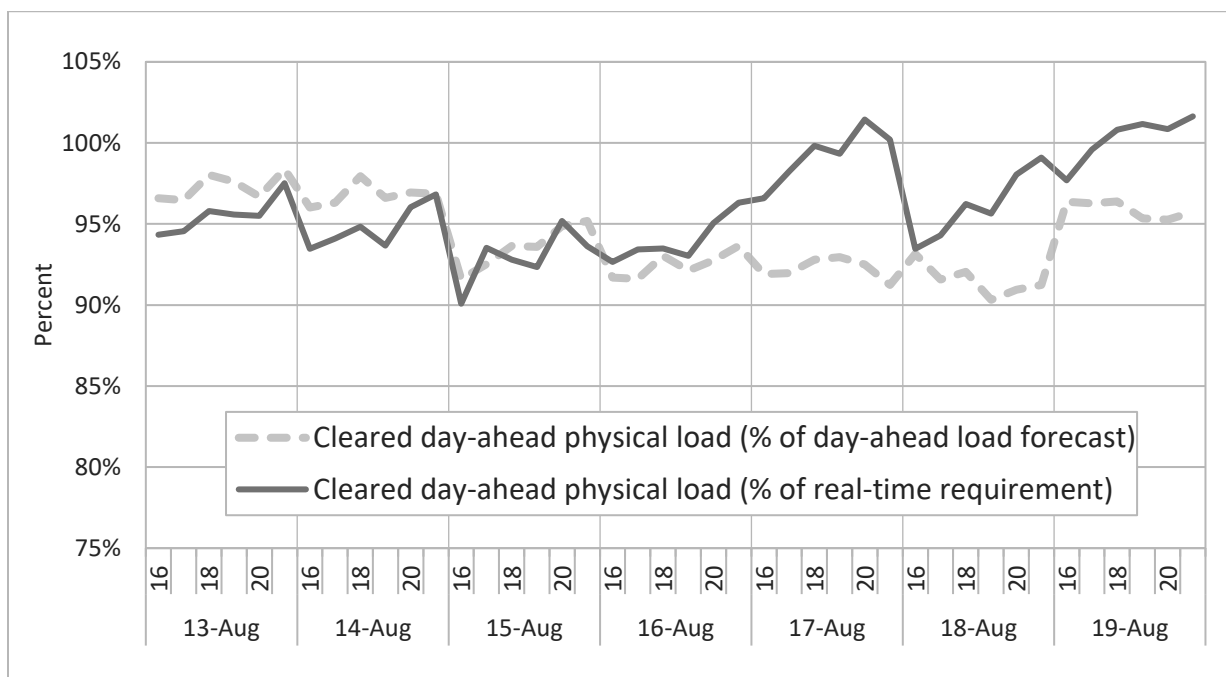


Figure 3.9 Under-scheduled load based on day-ahead forecast and real-time market requirement

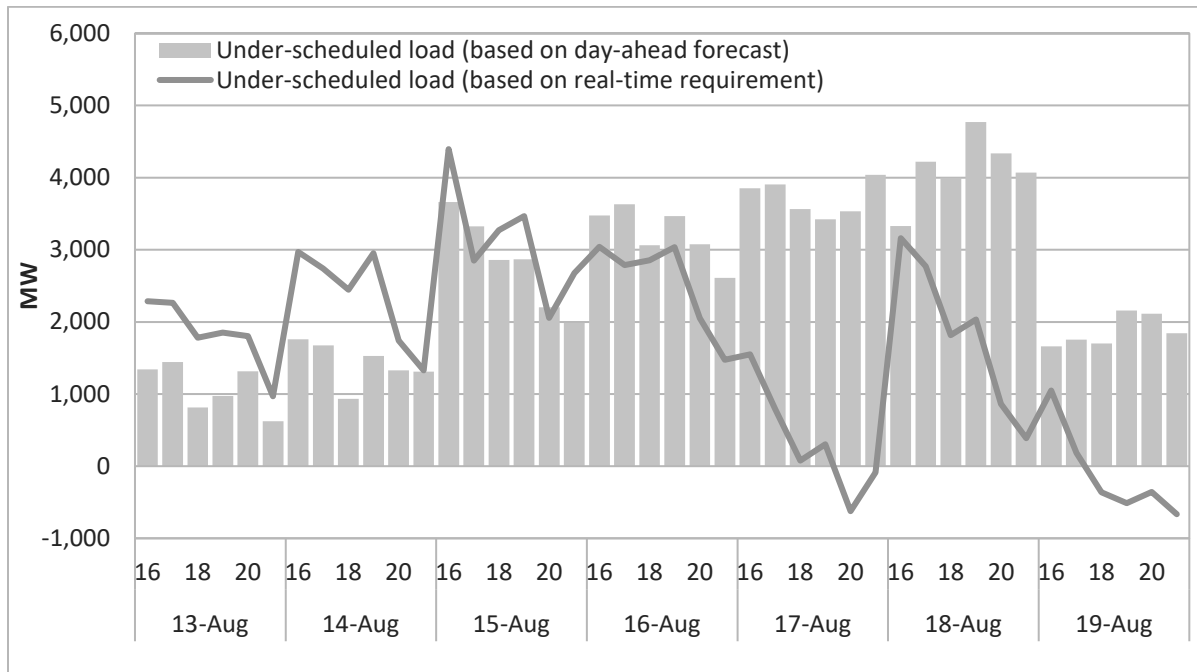


Figure 3.10 Physical load scheduled in day-ahead market (September 3 – September 7)

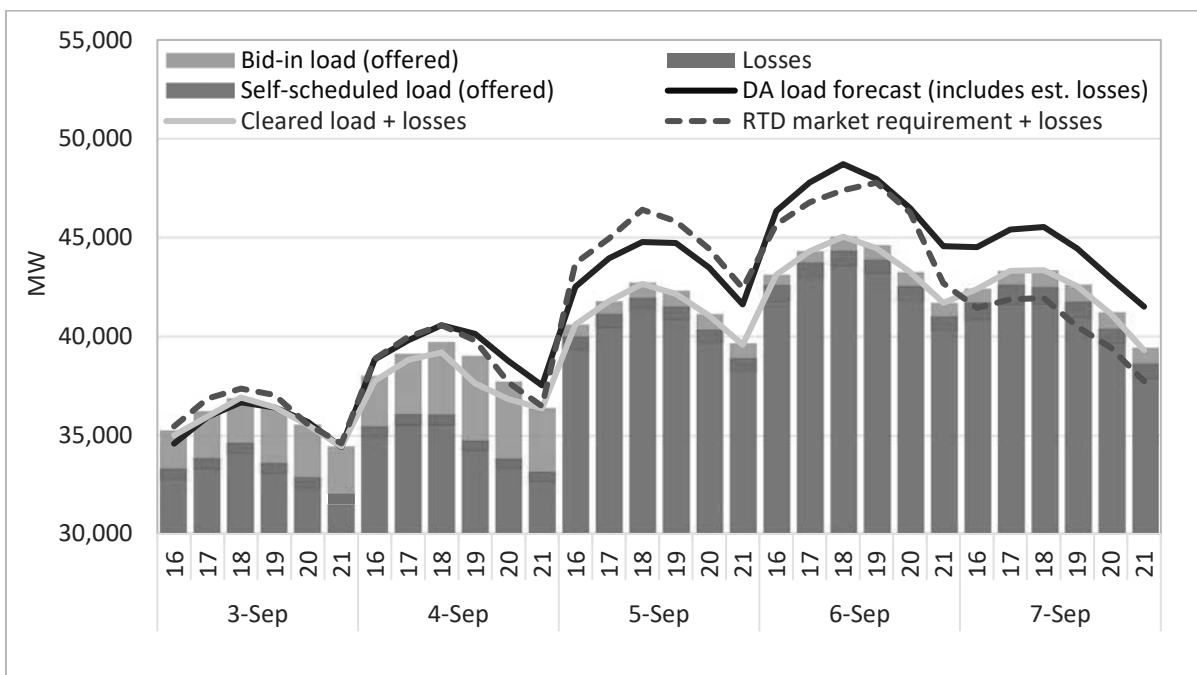
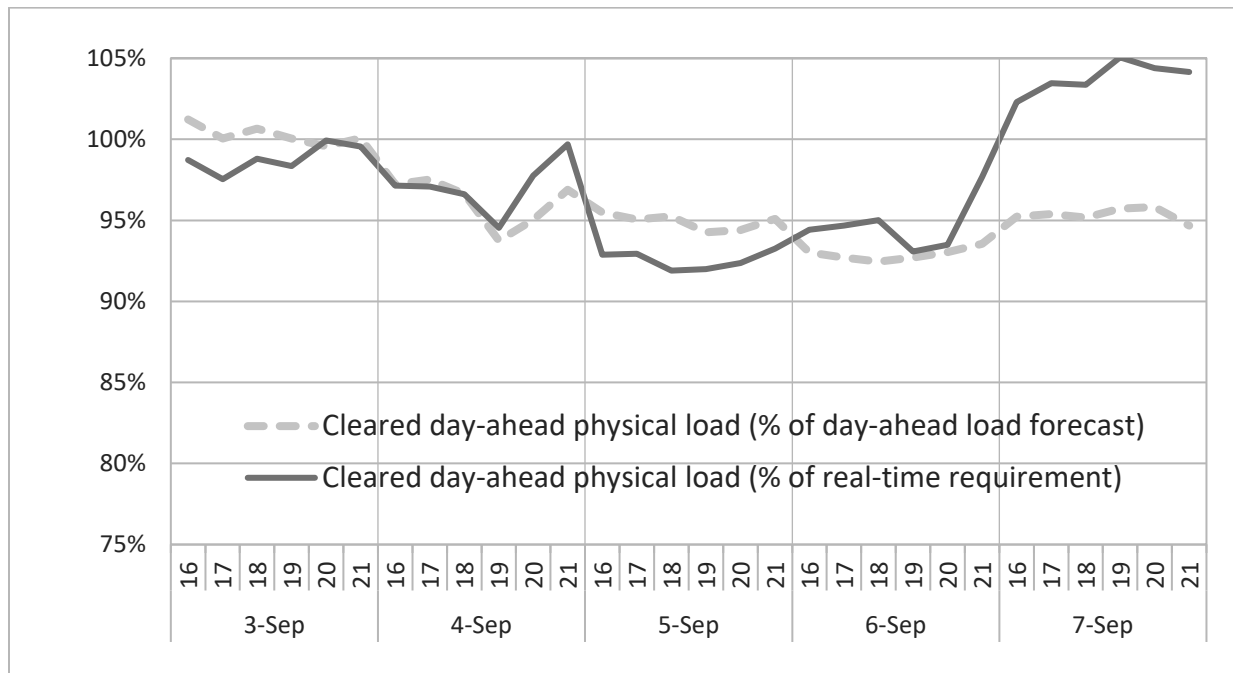


Figure 3.11 Physical load scheduled in day-ahead market (September 3 – September 7) (as a percentage of forecast and real-time market requirement)



3.4 Ancillary service requirements

This section provides a summary of ancillary service requirements, procurement and scarcities during the August heat wave.

Figure 3.12 and Figure 3.13 compare real-time upward ancillary service requirements (dotted lines) with the amount of ancillary service capacity procured (bars) for the expanded CAISO system region during the peak load hours. The dotted lines distinguish the ancillary service requirements for regulation up (dark green), regulation up and spin combined (light gray), and all upward ancillary services (dark gray). The cumulative requirements for these different ancillary service types reflect how higher quality ancillary services can be substituted for lower quality ancillary services. The white space below the total upward ancillary service requirement and the amount procured reflects ancillary service scarcities.

Figure 3.12 shows this information for August 14 and August 15, the days in which the ISO curtailed load. During the hours when the ISO curtailed load, the market procured around 2,800 MW of upward ancillary services. As shown in the figure, there was multiple 15-minute market intervals with scarcity of non-spinning reserve during these days, ranging from 133 MW to 505 MW.

Figure 3.13 shows the same information for August 17 and August 18, the days in which load was forecasted to be the highest. On August 18 hour 19, non-spinning reserve scarcity at the expanded system region level averaged around 940 MW. There was also some scarcity of regulation up on this day, ranging from 1 to 12 MW. The market run failed to publish for August 18 hour 18, interval 3 or 4. Prices are filled according to administrative pricing rules in these intervals.

Figure 3.12 Ancillary service requirements, procurement, and scarcity (August 14-15, 2020)

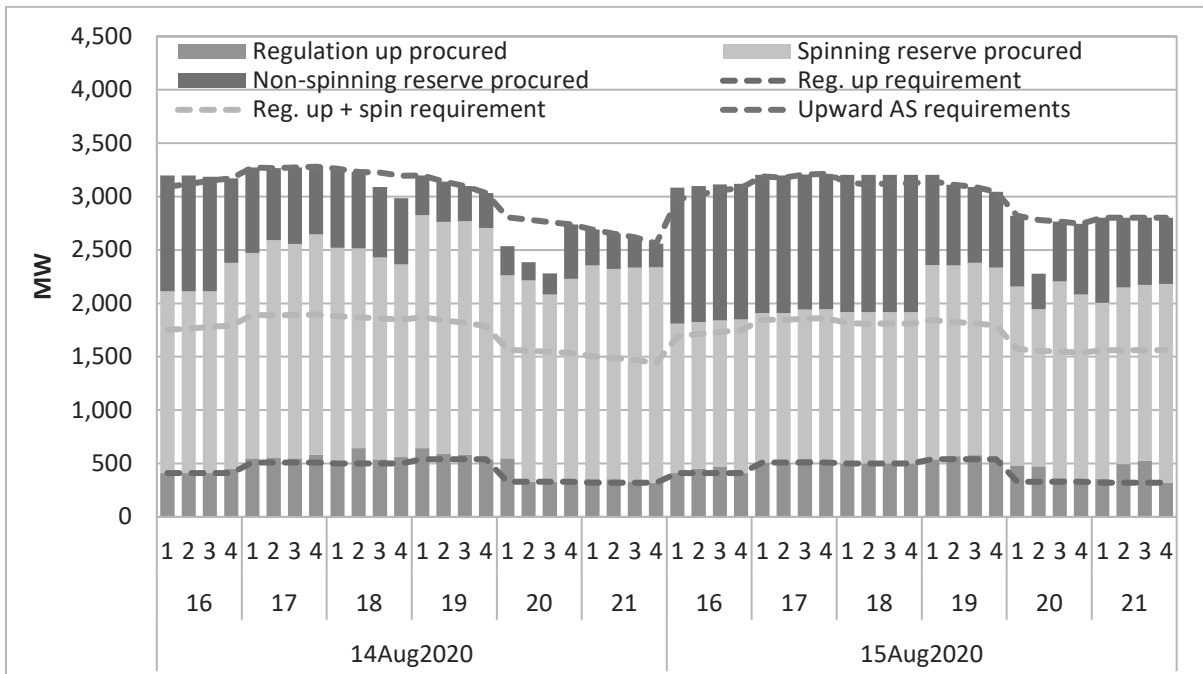
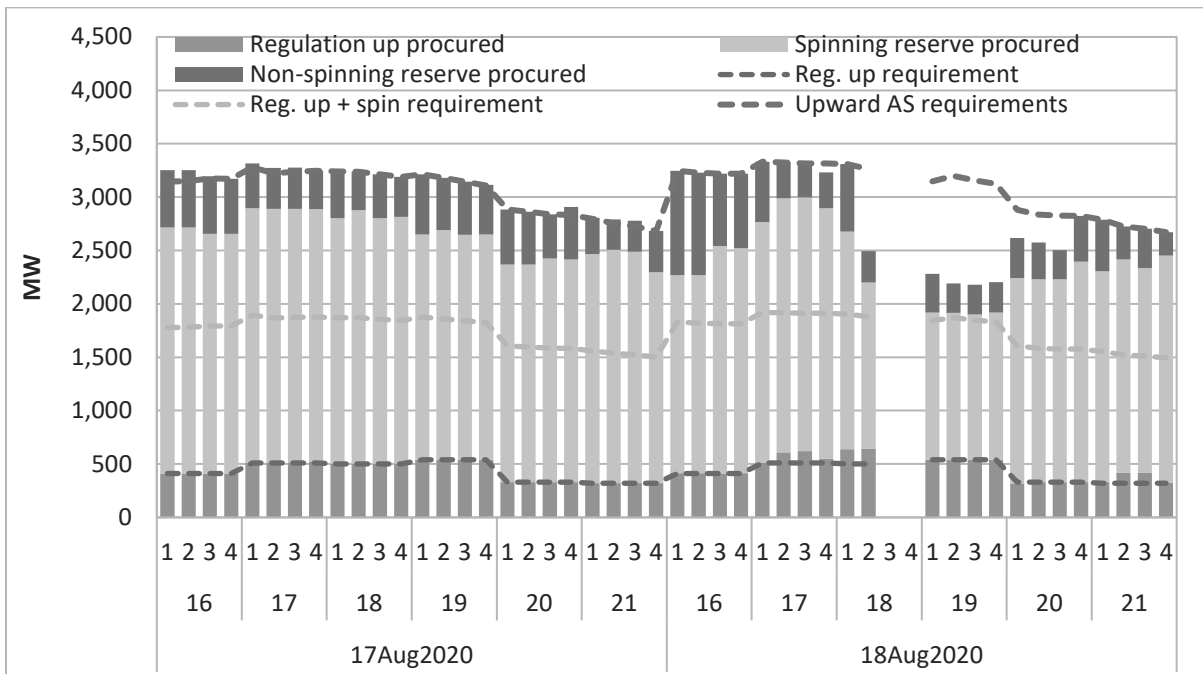


Figure 3.13 Ancillary service requirements, procurement, and scarcity (August 17-18, 2020)

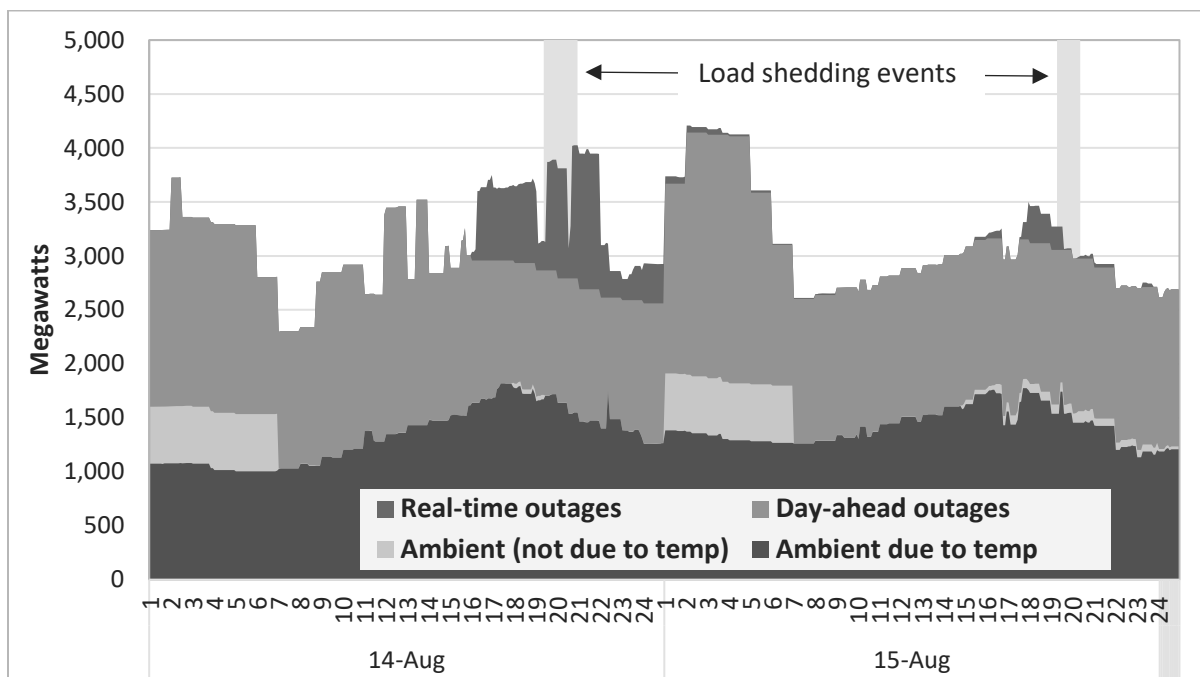


3.5 Generation outages

One of the key factors cited for triggering the load curtailment events on August 14 and 15 were sudden forced outages of several large gas-fired units in real-time. Figure 3.14 shows the gas-fired capacity (including resource adequacy and non-resource adequacy capacity) on outage during August 14 and 15.

On August 14, there was a large spike in outages in the hours leading up to load curtailment. On August 15, there was also a significant increase in the amount of capacity on outage in the hours leading up to load curtailment. Although the overall level of gas capacity on outage was not unusually high on these days, this sudden loss of a significant amount of gas capacity came at a time when the amount of available supply was very low due to a combination of other factors, as explained in other sections of this report.

Figure 3.14 Gas unit outages and load shedding events (August 14-15)



As shown in Figure 3.14, about half of the gas-fired capacity unavailable was due to ambient de-rates which occur in very hot weather – when the total output from gas units falls below their normal rated capacity due to ambient temperature. During the hours of load curtailment on August 14, about 12 percent of total gas-fired capacity was on outage, with about 5.3 percent of total gas-capacity reporting ambient de-rates due to high temperatures. On August 15, just over 10 percent of total gas-fired capacity was on outage during hours of load curtailment, with about 5 percent of total gas-capacity reporting ambient de-rates due to high temperatures.

As described in section 3.6 of this report, about 1,870 MW of resource adequacy capacity from gas units was unavailable in real-time during hours of load curtailments. This represents about 6.7 percent of the 27,743 MW of gas-fired resource adequacy capacity on these days. Almost half of this unavailable capacity (or about 3 percent of total resource adequacy capacity from gas units) was unavailable due to

ambient de-rates due to very hot weather. This is an example of one of the types of factors that should be factored in resource adequacy counting rules.

DMM has reviewed major outages which occurred on August 14 and 15. Based on data available to DMM at this time, there is no indication that on these days any outages were falsely declared at strategic times in order to allow generation owners to profit from higher prices (e.g. from output of other generating units under their control or virtual demand positions taken in the day-ahead market).

3.6 Resource adequacy capacity

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the CPUC to provide sufficient capacity to ensure reliability. The following analysis shows the availability of capacity that was used to meet system resource adequacy requirements as measured by bids into the day-ahead and real-time markets. This analysis does not include bids and transfers from EIM entities.

Resource adequacy capacity in this analysis reflects the capacity that is shown to the ISO on resource adequacy supply plans and also includes CPM capacity, RMR resources, and investor-owned utility demand response.¹⁹ The CAISO/CPUC/CEC report includes two additional categories of resource adequacy capacity in some metrics: (1) capacity above resource adequacy showings from resources that are shown for part of their total operating range and (2) capacity from resources not shown as resource adequacy. These two additional categories are included in the analysis below as separate categories, where appropriate.

Day-ahead market bids include energy bids and non-overlapping ancillary service bids; real-time market bids include energy bids only.²⁰ Bids are capped at the resource adequacy capacity values shown for individual resources to measure the availability of capacity that was secured in the planning timeframe. Bids are also capped according to individual resource outages and derates. This analysis also compares aggregated bids from resource adequacy capacity to actual load levels to measure how forward resource adequacy planning requirements compared to actual peak loads. While the analysis below includes all available resource adequacy bids at the system level, congestion and operating constraints may prevent the market from actually utilizing all of the bid capacity in this analysis.

Available resource adequacy vs loads

Day-ahead resource adequacy bids were sufficient to meet forecast load during peak hours on August 13 – 16, but not during the second half of the August heatwave (August 17 – 20), when loads were forecast to be above 46 GW on each day. However, resource adequacy bids were insufficient to meet forecast load plus ancillary service requirements during peak net load hours on each day from August 14 – 20. On these days, resource adequacy bids were also insufficient to meet the sum of forecast load, ancillary service requirements, and self-scheduled exports.

¹⁹ Other than investor-owned utility demand response, Figures 3.13-3.16 do not include the potential availability of resource adequacy supply that is reflected to the ISO as credits to overall resource adequacy obligations. As discussed in this section of the report, a portion of credited resource adequacy capacity cannot be tied to specific resources in the ISO market. CAM resources shown on investor-owned utility supply plans are included in relevant fuel categories.

²⁰ To calculate hourly real-time bid amounts, bids from variable energy resources were averaged over the hour. Bids from non-VER resources reflect the maximum hourly bid in the HASP, RTPD, and RTD markets adjusted for derates, due to data issues.

Figure 3.15 and Figure 3.16 show the hourly bids for resource adequacy resources by fuel type in the day-ahead market for August 13 – 20. Energy and non-overlapping ancillary service bids from resources shown to meet system resource adequacy requirements were sufficient to meet peak day-ahead load forecast (solid black line) on August 13 – 16, but not in several peak net load hours on August 17 - 20. Bids from these resources were not sufficient to meet the load forecast after the addition of non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast for most hours from August 14 – 20.

Figure 3.15 Day-ahead market hourly resource adequacy bids by fuel type (August 13 - 16, 2020)

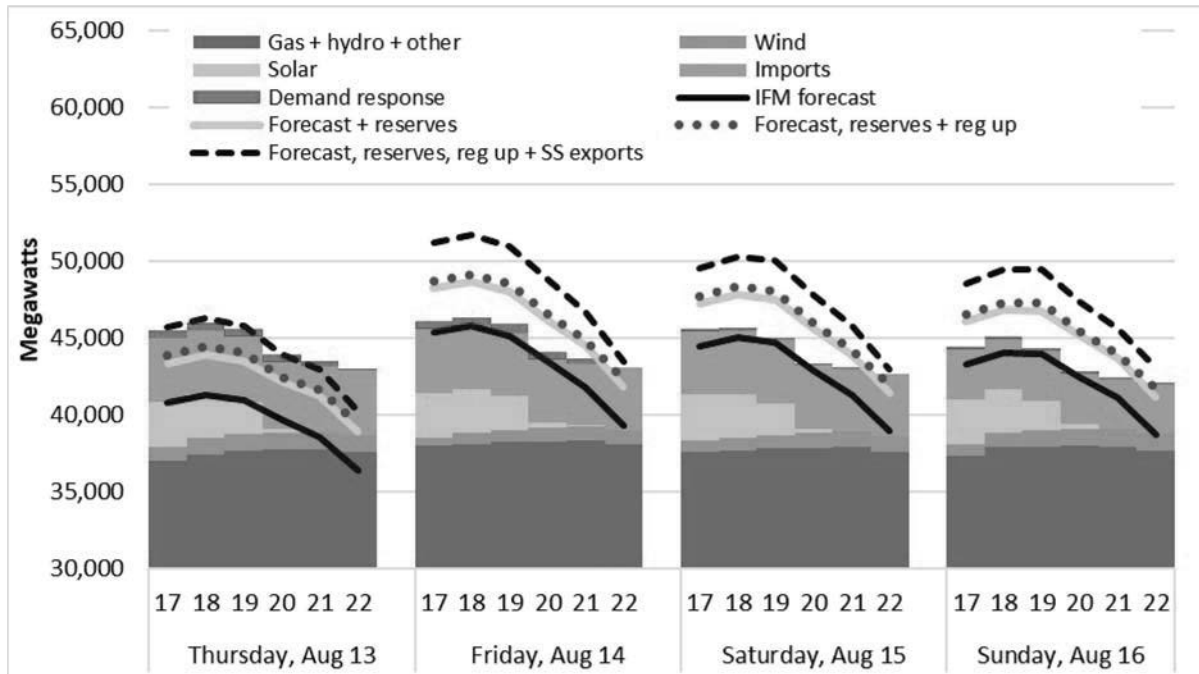
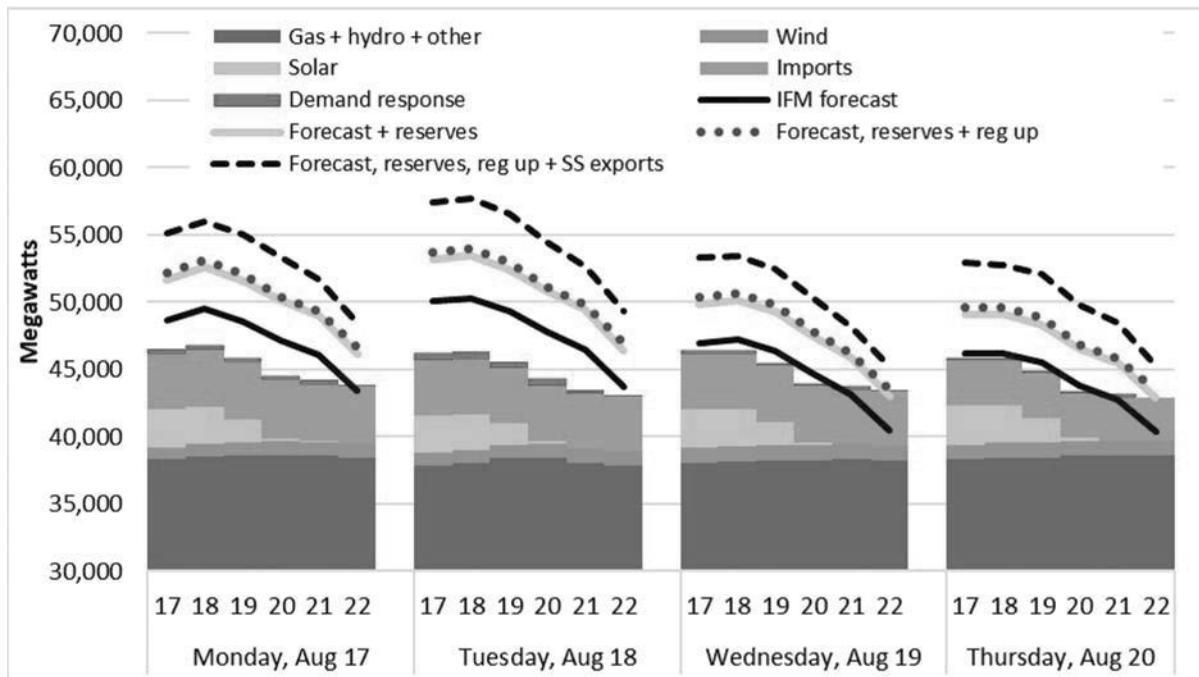


Figure 3.16 Day-ahead market hourly resource adequacy bids by fuel type (August 17 - 20, 2020)



Real-time resource adequacy bids were sufficient to meet the real-time market requirement in most peak load hours on August 13 – 20, with the exception of August 14 and 18. However, resource adequacy bids were not sufficient to meet the real-time market requirement and ancillary service requirements during most peak net load hours. The real-time market requirement can exceed actual load as it includes upward biasing of the real-time imbalance forecast by grid operators, which is often ranges from 1,000 to 2,000 MW during the early evening hours, as was the case over this time period.

Figure 3.17 and Figure 3.18 show the hourly average resource adequacy bids by fuel type in the real-time market for August 13-20, 2020. Energy bids from these resources were sufficient to meet the real-time market requirements and losses (solid black line) for most hours during these days. Similar to the results from the day-ahead market, these bids were not sufficient to meet the added spin and non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast in most hours depicted.

Availability by resource type

Table 3.1 lists the average hourly availability of resource adequacy capacity in the day-ahead and real-time markets during the hours when load was curtailed on August 14 and 15. This table shows resource adequacy capacity bids compared to the amount of capacity that was shown or credited towards resource adequacy obligations, by resource type. Bids and self-schedule megawatt totals for the day-ahead and real-time markets are derived by adjusting the bids and self-schedules of individual resources for outages and derates and aggregating by fuel type.

As shown in the bottom rows of Table 3.1, a total of 51,373 megawatts of capacity was shown on resource adequacy supply plans on August 14 and 51,333 megawatts was shown on August 15, 2020. A small amount of this capacity (between 3 to 4 percent) was on outage in the day-ahead market. During

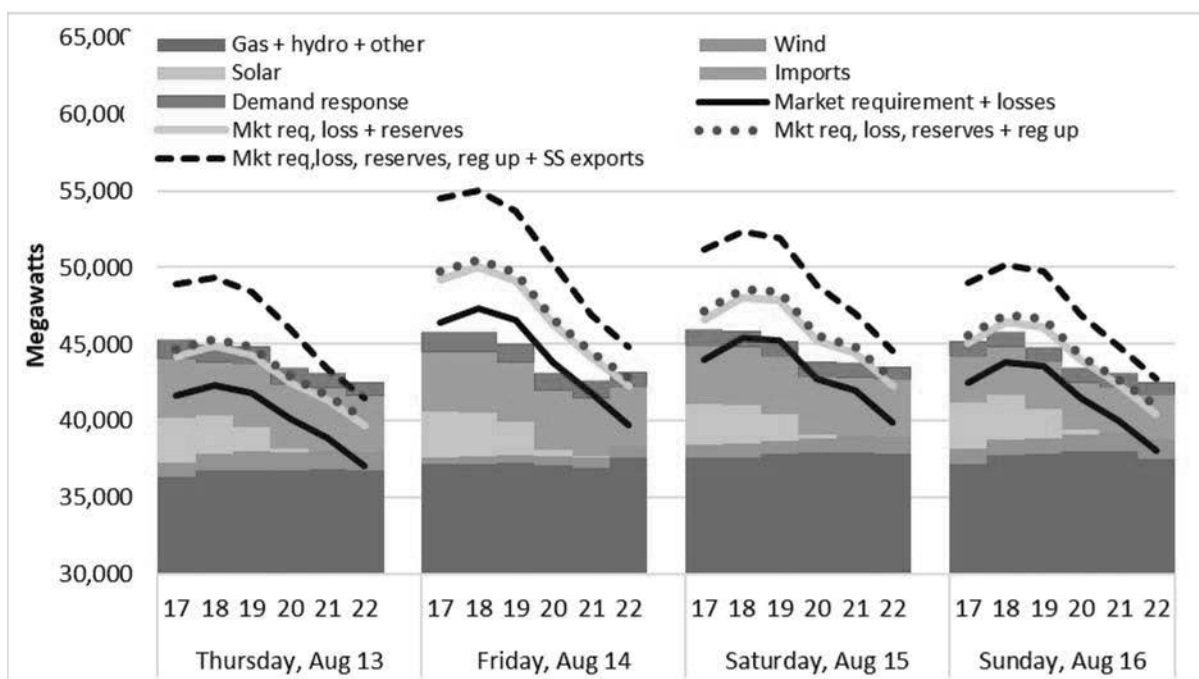
the hours in which load was curtailed on August 14 and 15, about 84 to 89 percent of this capacity was bid or self-scheduled in the day-ahead and real-time markets. A total of about 6,100 to 8,200 MW of resource adequacy capacity was not bid or self-scheduled into the real-time market during these hours.

Solar and wind

Solar and wind resources accounted for about 4,300 MW of shown resource adequacy capacity in August. The net qualified capacity of solar resources for the month of August equaled about 27 percent of solar resources’ maximum generating capacity. The resource adequacy rating of wind resources for the month of August equaled about 21 percent of wind resource’s maximum generating capacity.²¹

However, during the evening ramping period when net loads are highest, the actual output of solar and wind resources was lower than the net qualified capacity and shown resource adequacy values of these resources. During the hours when load curtailments occurred, the amount of solar and wind that was bid or self-scheduled into the real-time market equaled about 43 percent of the shown resource adequacy capacity of these resources.

Figure 3.17 Real-time market hourly resource adequacy bids by fuel type (August 13 - 16, 2020)



²¹ Though these values include resources contracted with both CPUC-jurisdictional and non-CPUC jurisdictional load serving entities, solar and wind, overall these resource adequacy ratings are consistent with the CPUC’s effective load carrying capacity values for wind and solar adopted under D.19-06-026: *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program*, CPUC, June 27, 2019: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K463/309463502.PDF>

Figure 3.18 Real-time market hourly resource adequacy bids by fuel type (August 17 - 20, 2020)

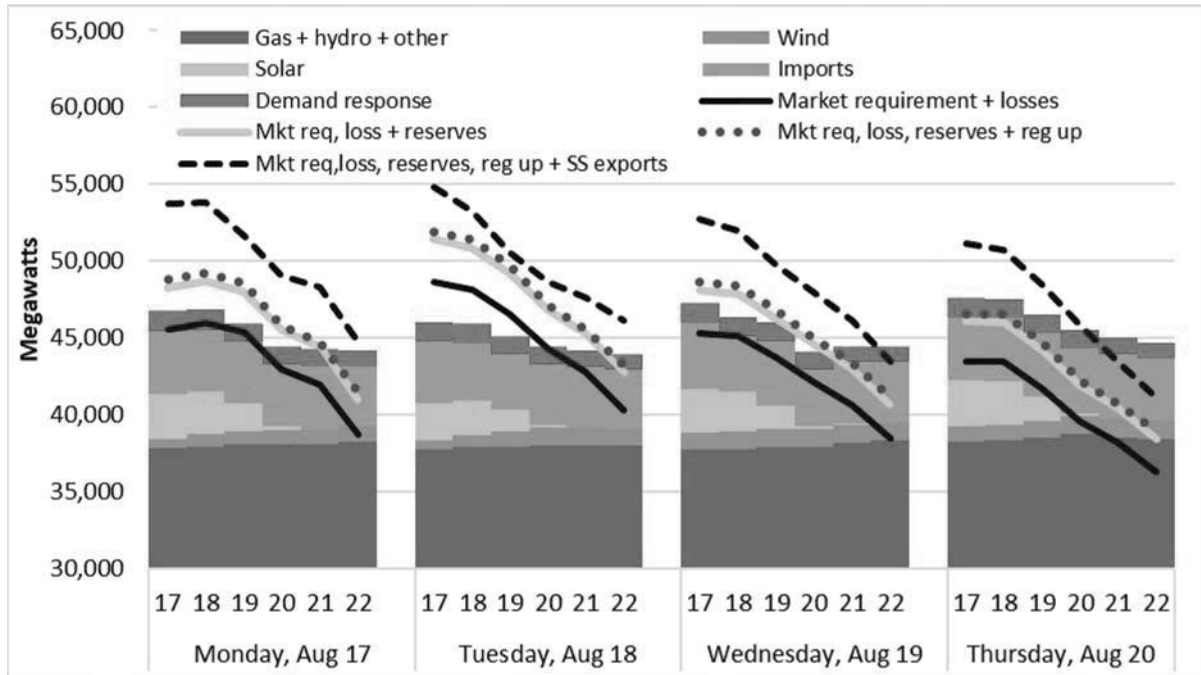


Table 3.1 Average resource adequacy capacity and availability by fuel type²²

Resource type	Date	Hour ending	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
				Adjusted for outages		Bids and self-schedules		Bids and self-schedules		Bids and self-schedules below cap	
				MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW	
Gas	8/14/2020	19	27,743	26,668	96%	26,629	96%	25,710	93%	2,033	
		20	27,743	26,727	96%	26,687	96%	25,441	92%	2,302	
	8/15/2020	19	27,716	26,197	95%	26,159	94%	26,062	94%	1,654	
		20	27,716	26,258	95%	26,220	95%	26,234	95%	1,482	
Solar	8/14/2020	19	3,077	3,071	100%	2,202	72%	2,197	71%	880	
		20	3,077	3,071	100%	330	11%	427	14%	2,650	
	8/15/2020	19	3,079	3,073	100%	2,072	67%	1,729	56%	1,350	
		20	3,079	3,073	100%	268	9%	202	7%	2,877	
Wind	8/14/2020	19	1,253	1,253	100%	824	66%	483	39%	770	
		20	1,253	1,253	100%	886	71%	538	43%	715	
	8/15/2020	19	1,253	1,253	100%	895	71%	864	69%	389	
		20	1,253	1,253	100%	959	77%	935	75%	318	
Hydro	8/14/2020	19	6,663	6,250	94%	6,074	91%	5,955	89%	708	
		20	6,663	6,250	94%	6,075	91%	6,090	91%	573	
	8/15/2020	19	6,661	6,253	94%	6,144	92%	6,155	92%	506	
		20	6,661	6,253	94%	6,144	92%	6,160	92%	501	
Utility demand response	8/14/2020	19	1,604	1,604	100%	315	20%	1,040	65%	564	
		20	1,604	1,604	100%	288	18%	1,022	64%	582	
	8/15/2020	19	1,604	1,604	100%	8	1%	931	58%	673	
		20	1,604	1,604	100%	0	0%	917	57%	687	
Supply plan demand response	8/14/2020	19	243	243	100%	195	80%	142	58%	101	
		20	243	243	100%	195	80%	142	58%	101	
	8/15/2020	19	243	243	100%	130	53%	100	41%	143	
		20	243	243	100%	130	53%	100	41%	143	
Imports	8/14/2020	19	4,171	4,100	98%	4,100	98%	3,834	92%	337	
		20	4,171	4,100	98%	4,100	98%	3,833	92%	338	
	8/15/2020	19	4,131	4,126	100%	4,098	99%	3,739	91%	392	
		20	4,131	4,126	100%	4,098	99%	3,743	91%	388	
Metered subsystem imports	8/14/2020	19	327	327	100%	26	8%	26	8%	301	
		20	327	327	100%	27	8%	27	8%	300	
	8/15/2020	19	327	327	100%	27	8%	27	8%	300	
		20	327	327	100%	27	8%	27	8%	300	
Other	8/14/2020	19	1,936	1,877	97%	1,837	95%	1,827	94%	109	
		20	1,936	1,878	97%	1,829	94%	1,825	94%	111	
	8/15/2020	19	1,936	1,871	97%	1,824	94%	1,808	93%	128	
		20	1,936	1,871	97%	1,829	94%	1,813	94%	123	
Qualifying facilities	8/14/2020	19	960	959	100%	890	93%	892	93%	68	
		20	960	959	100%	876	91%	886	92%	74	
	8/15/2020	19	987	986	100%	890	90%	876	89%	111	
		20	987	986	100%	893	90%	878	89%	109	
Legacy RMR	8/14/2020	19	165	164	99%	0	0%	100	61%	65	
		20	165	164	99%	0	0%	100	61%	65	
	8/15/2020	19	165	164	99%	0	0%	133	81%	32	
		20	165	164	99%	0	0%	73	44%	92	
Nuclear	8/14/2020	19	2,797	2,797	100%	2,797	100%	2,797	100%	0	
		20	2,797	2,797	100%	2,797	100%	2,797	100%	0	
	8/15/2020	19	2,797	2,797	100%	2,797	100%	2,797	100%	0	
		20	2,797	2,797	100%	2,797	100%	2,797	100%	0	
Total	8/14/2020	19	51,373	49,313	96%	45,889	89%	45,003	88%	6,370	
		20	51,373	49,373	96%	44,090	86%	43,128	84%	8,245	
	8/15/2020	19	51,333	48,894	95%	45,044	88%	45,221	88%	6,112	
		20	51,333	48,955	95%	43,365	84%	43,879	85%	7,454	

Solar and wind (continued)

Solar and wind resources accounted for most of the resource adequacy capacity that was not available in the real-time market during these hours. The availability of solar resources was about 2,800 MW below the shown resource adequacy capacity of these resources during hour ending 20 on these days. This represents the largest amount of unavailable resource adequacy capacity of any fuel category.

Natural gas

Natural gas resources accounted for over half of shown resource adequacy capacity on August 14 and August 15 (27,730 MW). About 5 percent of this capacity was unavailable in the day-ahead market due to outages and derates, and about 6.7 percent was unavailable in real-time. Almost half of this unavailable capacity (or just over 3 percent of total resource adequacy capacity from gas units) was unavailable due to ambient de-rates due to very hot weather. This is an example of one of the types of factors that should be factored in resource adequacy counting rules.

As a proportion of overall procured capacity, the availability of capacity from natural gas resources was relatively high compared to other resource types with over 92 percent of gas-fired resource adequacy capacity available in the real-time market during hours of load curtailment. However, because gas resources account for such a large portion of resource adequacy capacity, this fuel-type accounted for the second highest amount of resource adequacy capacity that was not available in the real-time market. About 1,500-2,300 MW of this capacity was not bid into the real-time market during these hours.

Hydro

Hydro resources accounted for the second highest amount of resource adequacy capacity on August 14 and August 15 (6,700 MW). The net qualifying capacity of hydro resources for the month of August equaled about 72 percent of their maximum generating capacity. About six percent of shown hydro resource adequacy capacity was unavailable to the day-ahead market due to outages and derates. About 500 to 700 MW (or 8 to 11 percent) of resource adequacy capacity from hydro resources was not bid into the real-time market during these hours.

Demand response

Demand response that was shown on resource adequacy supply plans as well as utility demand response that is credited towards resource adequacy obligations accounted for about 1,850 MW of resource adequacy capacity in August. On August 14 in hours 19 and 20, about 64 percent of utility demand response and 58 percent of demand response shown on resource adequacy supply plans was bid into the real-time market.

In the same hours on August 15, about 58 percent of utility demand response and 41 percent of demand response shown on supply plans was bid into the real-time market. Demand response availability dropped between August 14 and August 15 because several demand response programs are unavailable on weekends and holidays. Section 3.13 of this report provides additional discussion on demand response resources used to meet resource adequacy requirements.

Imports

Non-resource specific import capacity accounted for almost 4,500 MW of shown resource adequacy capacity in August.²³ This figure includes non-resource-specific imports shown by load-following metered sub-system entities. About 330 to 370 MW (8 percent) of import resource adequacy capacity was not bid into the day-ahead market on August 14 and August 15.

The majority (300 MW) of the import resource adequacy capacity not available in the day-ahead market was capacity shown and scheduled by load-following metered sub-system entities. This capacity is not subject to must-offer obligations or bid insertion. The remaining import resource adequacy capacity not bid into the day-ahead market on August 14 was declared on outage. About 28 MW of import resource adequacy capacity that was not bid into the day-ahead market on August 15 was not declared on outage but was not subject to bid insertion because August 15 was a weekend and thus fell outside of ISO availability assessment hours.

Most of the non-resource specific resource adequacy import capacity bid into the day-ahead market cleared (85 percent). Almost all of the capacity which did not clear (99 percent) was bid on interties from the Pacific Northwest, where congestion lowered prices below bids and limited the quantity available to import. On these congested paths, non-resource adequacy imports bid at a lower price could therefore clear, utilizing limited transmission capacity and replacing resource adequacy imports. The RUC process cleared an additional 1 percent on August 14, but no additional capacity on August 15. The additional capacity cleared on August 14 was on the same congested interties from the Pacific Northwest.

Most of the import resource adequacy capacity bid into the real-time market cleared, as in the day-ahead market (92 percent). Congestion on interties from the Pacific Northwest again lowered prices below bids and limited the total quantity of imports on these paths. High price bids from some resource adequacy import capacity on these paths (about 6 percent of all import resource adequacy bids) did not clear, allowing lower priced non-resource adequacy import capacity to clear on these congested paths. These imports were essentially replaced by non-resource adequacy imports that were bid at a lower price than these resource adequacy imports, and therefore cleared the market and utilized transmission capacity that could otherwise be utilized for higher priced resource adequacy imports. Congestion on interties from the Southwest also limited imports in the real-time market.

Revised CPUC import resource adequacy rules taking effect next year will require non-resource specific resource adequacy imports to be bid at \$0 or lower in the day-ahead and real-time markets during the availability assessment hours.²⁴ Although these requirements are not applicable on weekends and holidays, these new rules should help ensure that resource adequacy imports procured by CPUC-jurisdictional entities are available and delivered in the day-ahead and real-time markets. DMM continues to recommend that the ISO work with the CPUC to develop alternative approaches that would ensure that resource adequacy

²³ Pseudo-tie resources are not included under the import category in this analysis. Pseudo-tie resource adequacy capacity is included under the relevant fuel type category.

²⁴ *Decision Adopting Resource Adequacy Import Requirements* (D.20-06-028), CPUC, 6/25/2020: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF>

imports are available in the day-ahead and real-time markets when needed, but could provide more flexibility to submit price-responsive bids in some or most hours.²⁵

Non-resource adequacy capacity

The analysis in the CAISO/CPUC/CEC report includes three categories of supply that were not included in DMM's analysis of resource adequacy capacity shown in Figure 3.16 through Figure 3.19 and Table 3.1. These three other categories of supply include:

- (1) capacity above resource adequacy showings from resources within the CAISO that are shown for part of their total operating range;
- (2) capacity from resources within the CAISO not shown as resource adequacy and
- (3) bids from non-resource adequacy import resources.

Figure 3.19 through Figure 3.22 show analysis which includes these three other categories of capacity that were included in the CAISO/CPUC/CEC report.

As shown in Figure 3.19 and Figure 3.20, day-ahead bids from resource adequacy resources (including bid quantities above resource adequacy showings), were not sufficient to meet load forecast plus ancillary service requirements during multiple hours on August 17 and 18. However, day-ahead bids from these resources were sufficient to meet forecast load plus ancillary service requirements on other days during the August heat wave.

In Figure 3.19 and Figure 3.20, bids for energy and ancillary services from resources shown to meet system resource adequacy requirements are shown in blue. Extra capacity bid from wind and solar resources in excess of resource adequacy showings from these resources is shown in yellow. Additional bids from other resource adequacy units in excess of their resource adequacy capacity showing is shown in green.

As shown in Figure 3.19 and Figure 3.20, during most days and hours these bids from all these resources exceeded the peak day-ahead load forecast (solid black line), as well as the load forecast plus various ancillary service requirements (solid light blue and dotted purple lines).

The dashed black line in Figure 3.19 and Figure 3.20 shows the additional demand created by exports that are self-scheduled in the day-ahead market. As shown in these figures, day-ahead bids from resource adequacy resources (including bid quantities above resource adequacy showings), were not sufficient to meet additional load from self-scheduled exports during peak hours on any day during the August heat wave period. However, bids from non-resource adequacy resources, shown in grey (imports) and orange (other fuels), were sufficient to support self-scheduled exports in the day-ahead market during almost all hours except August 17 and 18.

²⁵ *Comments on Proposed Decision Adopting Resource Adequacy Import Requirements (17-09-020)*, June 8, 2020, Department of Market Monitoring. <http://www.caiso.com/Documents/CPUC-CommentsonProposedDecisionAdoptingResourceAdequacyImportRequirements-R17-09-020-Jun82020.pdf>

Figure 3.19 Day-ahead market hourly bids by resource adequacy status (August 13 - 16, 2020)

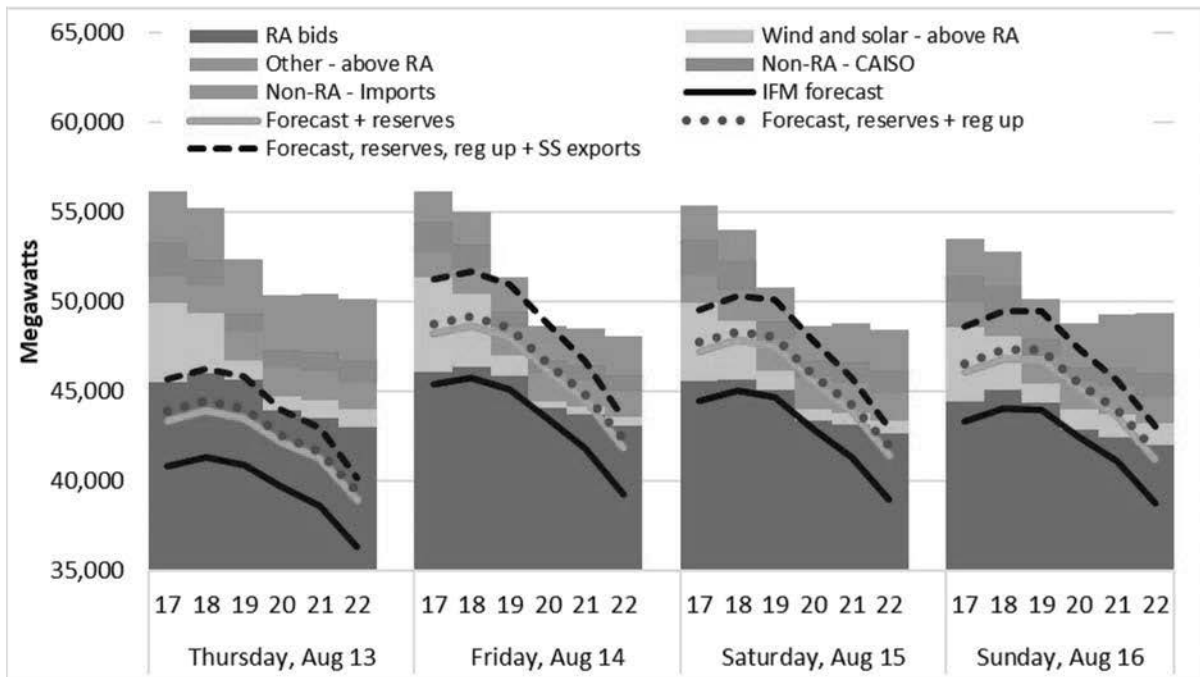


Figure 3.20 Day-ahead market hourly bids by resource adequacy status (August 17 - 20, 2020)

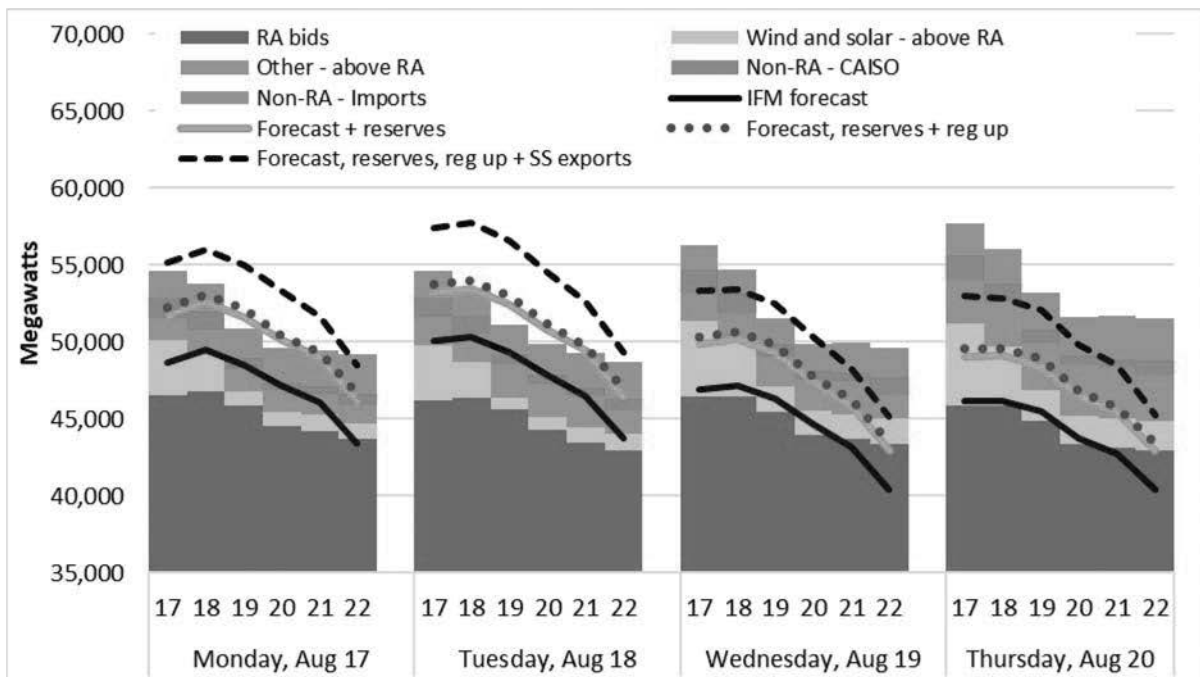


Figure 3.21 Real-time market hourly bids by resource adequacy status (August 13 - 16, 2020)

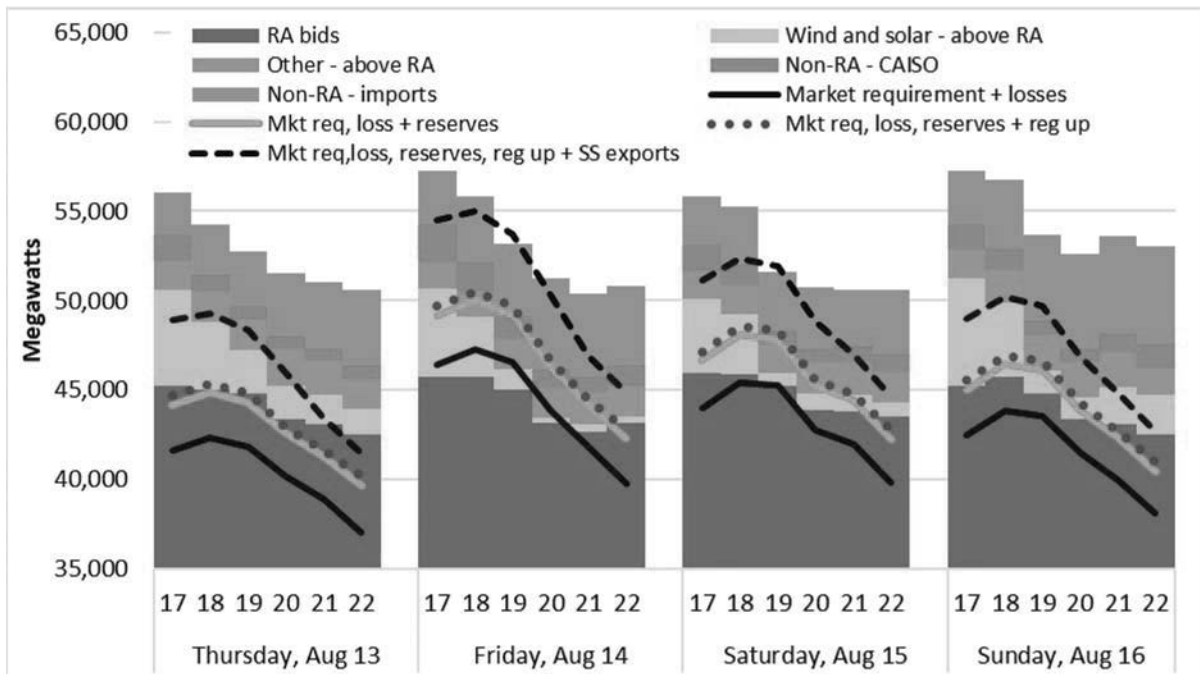
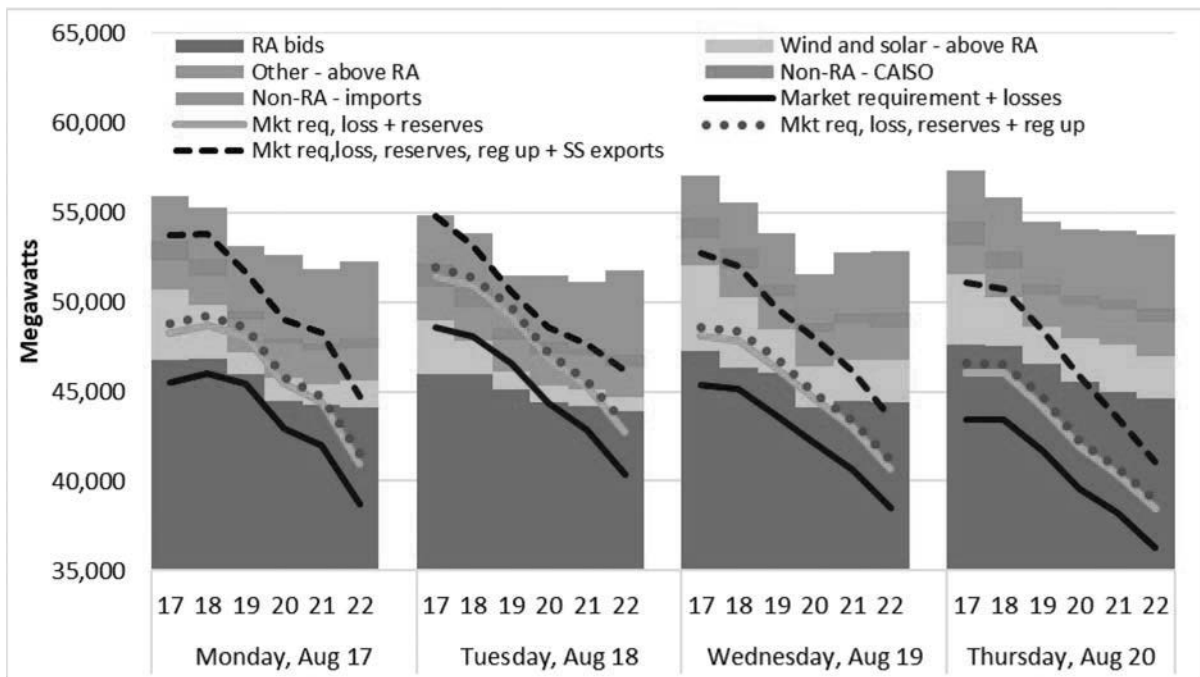


Figure 3.22 Real-time market hourly bids by resource adequacy status (August 17 - 20, 2020)



Real-time bids from resource adequacy units (including bid quantities above these units' resource adequacy showings), were sufficient to meet the real-time market requirement plus ancillary service requirements in most peak hours on August 13 – 20, with the exception of several hours on August 14 and August 18.²⁶ Additional bid capacity from non-resource adequacy resources (shown in orange and grey) was necessary to meet the additional demand of self-scheduled exports during peak hours on all days during the August heat wave period, as shown in Figure 3.22 and Figure 3.23.²⁷

Resource adequacy credits

The ISO's resource adequacy obligations are met with capacity which is reflected on supplier and load serving entity supply plans and capacity that is credited against load serving entity total resource adequacy obligations. Credited capacity consists primarily of utility demand response programs and liquidated damages credits. While the majority of monthly system resource adequacy obligations are met by capacity reflected on supply plans, the ISO also relies on credited capacity to be available. Credited capacity is not subject to the same must-offer obligations, bid insertion rules, and resource adequacy availability incentives as resources reflected on supply plans.

DMM estimates that 970 to 1,100 MW of capacity counted as resource adequacy credits was either unavailable or not directly accessible to the ISO in peak net load hours on August 14 and August 15. As discussed further in Section 3.13, on August 14, about 540 to 560 MW of utility demand response credits were unavailable in hours 19 and 20. On August 15, about 670 to 690 of utility demand response credits were unavailable in hours 19 and 20. These figures include the CPUC's planning reserve margin adder applied to demand response program capacity and non-CPUC local regulatory authority demand response program credits.

Additionally, 434 MW of liquidated damages credits were counted towards August resource adequacy requirements by non-CPUC-jurisdictional LSEs but cannot be tied to specific resources in the ISO market. While the capacity underlying liquidated damages credits may be reflected in the ISO in the form of imports or a combination of imports and inter-SC trades, these contracts are not associated with specific resource IDs in the ISO market. This capacity is also not subject to must-offer obligations, bid insertion or RAAIM like resource adequacy capacity on supply plans. The ISO does not have clear insight into these resources from an operational or market perspective.

Based on observations in August and September, there are improvements that the ISO and local regulatory authorities could consider to enhance the reliability of credited resource adequacy capacity. In its report, the ISO notes that it has taken action to eliminate the practice of resource adequacy crediting through a Business Practice Manual revision.²⁸ However, the ISO's proposed revisions are in the process of being reviewed and discussed with stakeholders.

Resource adequacy in September

System conditions on September 5 – 7 were similar to those experienced during the August heat wave, but the ISO did not need to shed load over this time period. Day-ahead resource adequacy bids were sufficient to meet most, but not all, forecast load during peak hours on September 5 – 7. However, resource adequacy bids were insufficient to meet forecast load plus ancillary service requirements

²⁶ The real-time market requirement can exceed actual load as it includes ISO operator imbalance conformance.

²⁷ Bid totals exclude bids from Western energy imbalance market resources.

²⁸ CAISO/CPUC/CEC report, pp. 10, 46, 52, 77.

during most peak net load hours, and were also insufficient to meet the sum of forecast load, ancillary service requirements, and self-scheduled exports during most hours on these dates.

Figure 3.23 shows the hourly bids for resource adequacy resources by fuel type in the day-ahead market for September 5 – 7. Energy and non-overlapping ancillary service bids from resources shown to meet system resource adequacy requirements were sufficient to meet peak day-ahead load forecast (solid black line) during most hours. However, bids from these resources were not sufficient to meet the added spin and non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast for most hours.

Real-time resource adequacy bids were sufficient to meet the real-time market requirement in most peak load hours on September 5 – 7, with the exception of September 6. However, resource adequacy bids were not sufficient to meet the real-time market requirement and ancillary service requirements during most peak net load hours. These conditions were similar to those experienced in August, but the ISO did not need to curtail internal load over these dates.

Figure 3.24 shows the hourly average resource adequacy bids by fuel type in the real-time market for September 5 – 7, 2020. Energy bids from these resources were sufficient to meet the real-time market requirements and losses (solid black line) for most hours during these days. Similar to the results from the day-ahead market, these bids were not sufficient to meet the added spin and non-spin reserve requirements (solid orange line), regulation up requirements (dotted purple line), and the amount of self-scheduled exports (dashed black line) above the load forecast in most hours in this time period.

Figure 3.23 Day-ahead market hourly resource adequacy bids by fuel type (September 5 - 7, 2020)

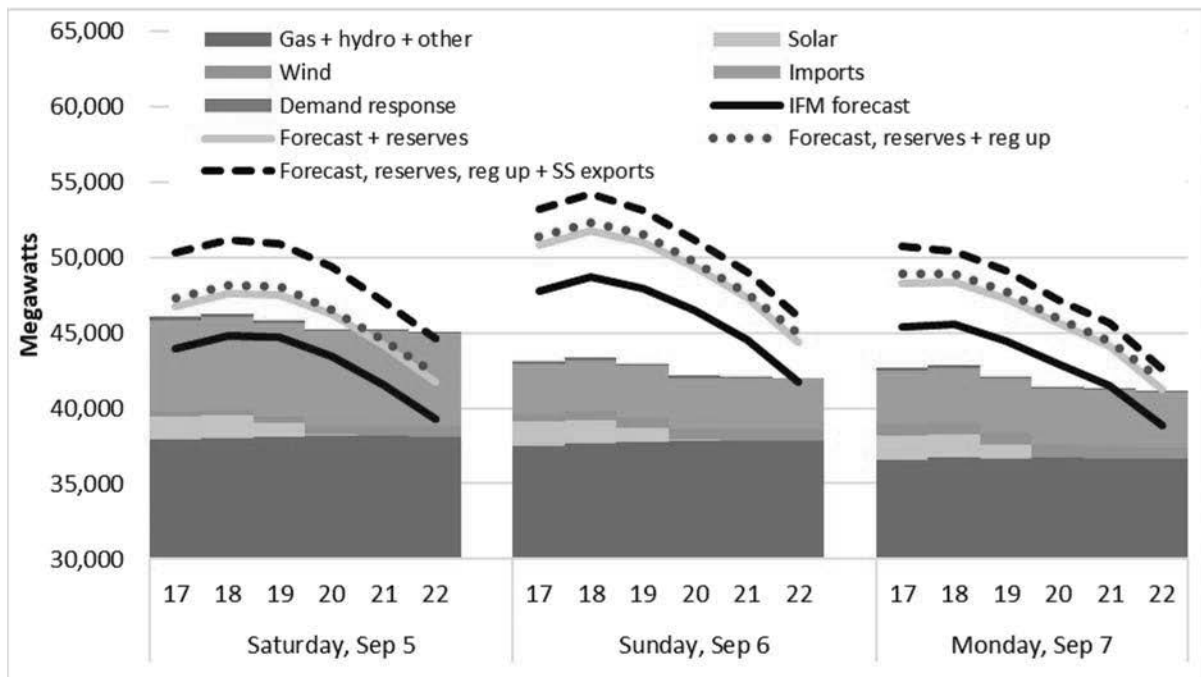
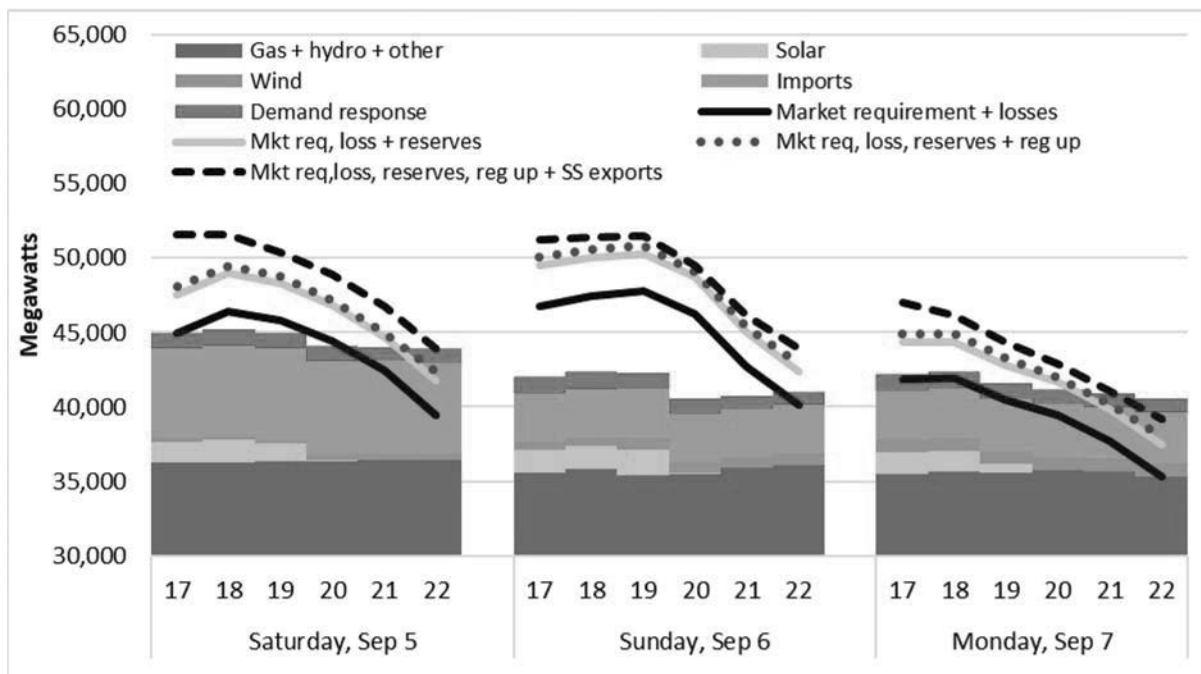


Figure 3.24 Real-time market hourly resource adequacy bids by fuel type (September 5 - 7, 2020)²⁹



²⁹ Wind and solar actual schedules are depicted in place of bids for solar and wind for hour-ending 19 on Sunday, September 6 due to data issues

3.7 Import and exports

This section provides a graphical summary of total CAISO system import and exports on the highest load days from mid-August to the September 7, 2020 during the key evening ramping hours (17-22). This summary highlights important trends and changes in CAISO system import and exports which reflect different market conditions and actions taken by the CAISO over this time period.³⁰

Figure 3.25 shows total gross and net imports to and exports from the CAISO system during hours 17-22 on August 13 to 16. Figure 3.26 shows the same data for August 17 to 20. The shaded area of these figures shows total resource adequacy imports delivered to the CAISO system. Most imports on these days were from the Pacific Northwest, while most exports were to the southwest.

As shown in

Figure 3.25 and Figure 3.26, total net imports during these days increased significantly after the day-ahead market (dotted red lines) due to increased imports in the CAISO's 15-minute market (dashed red line) and also through the energy imbalance market (solid red line). During many hours on these days, total net imports (solid red line) exceeded the amount of resource adequacy imports scheduled in the day ahead market (shaded gray area).

Figure 3.26 also highlights how exports scheduled in the day-ahead market dropped on August 18 – the first day on which virtual bidding was suspended. This is discussed in more detail in Section 3.9 of this chapter.

Figure 3.27 shows the same data for September 4 to 7. As shown in these charts, exports scheduled in the day-ahead market were extremely high on September 4, but declined over this period. This decline in exports reflects the changes in the residual unit commitment process discussed in Section 3.10 of this chapter.

³⁰ As elsewhere in this report, imports exclude tie-generators. Although physically located outside of the ISO, these resources are treated as internal generators by the market. Analysis in this report includes these generators with internal generation of the same fuel type. Tie-generators can add up to 2 GW to net interchange figures and appear to be included in the net interchange values publicly posted by the ISO (<http://www.caiso.com/TodaysOutlook/Pages/supply.aspx>).

Figure 3.25 Total CAISO system imports and exports (August 13-16, 2020)

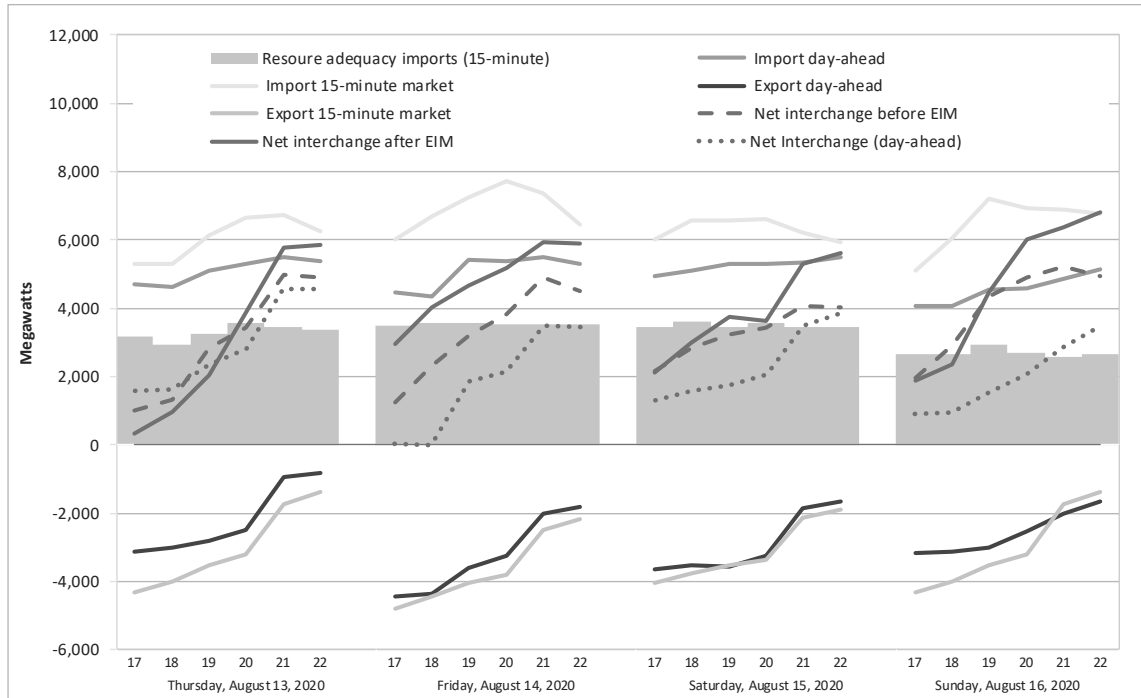


Figure 3.26 Total CAISO system imports and exports (August 17-20, 2020)

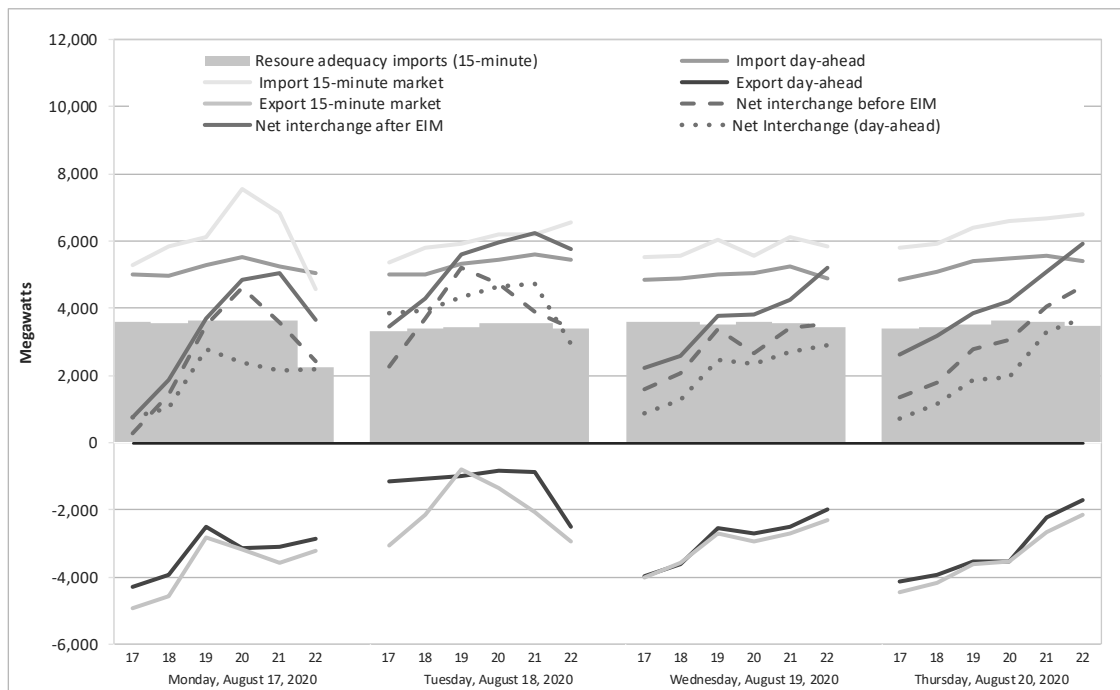
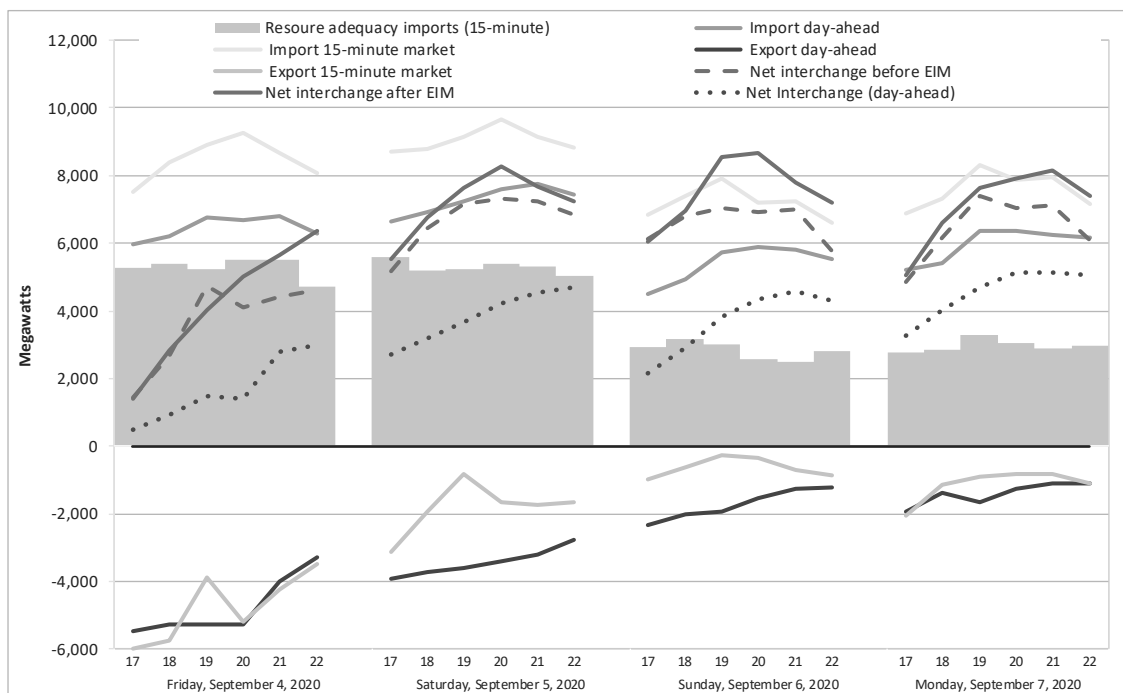


Figure 3.27 Total CAISO system imports and exports (September 4-7, 2020)



3.7.1 Out-of-market imports and export curtailments

Exceptional dispatches on the interties are instructions issued by ISO operators when the market optimization is not able to address a particular reliability requirement or constraint. Energy dispatches issued by ISO operators are sometimes referred to as *manual* or *out-of-market* dispatches. When conditions are tight, the ISO may call upon neighboring balancing authority areas to request imported energy on the interties in the real-time markets. ISO operators also may curtail self-scheduled exports to external balancing authority areas to prevent potential load shed and maintain system reliability.

Figure 3.28 shows the average hourly megawatts from all out-of-market actions taken by the ISO operators during peak net load hours (17-22). These include exceptional dispatches of internal generation within the ISO as well as manually dispatched imports, imports from emergency assistance by other balancing areas, and export curtailments determined by the market.

Imports coming from emergency assistance reflect energy imported from balancing authority areas with whom the ISO has contractual agreements during emergency conditions. All other manual dispatches reflect energy from offers made by ISO operators for imports from neighboring balancing areas for imports in the real-time market. These types of imports are often paid a negotiated price, typically for ‘bid or better’.³¹

Figure 3.29 shows the volume of out-of-market energy dispatches on the interties and curtailments of self-scheduled exports by the ISO operators from mid-August through September 6 during peak net load hours (17-22). In this figure, out-of-market import energy dispatches are shown for different scheduling

³¹ DMM’s 2017 annual report (pp. 206-207) provides more detail on manual dispatch types and prices paid for out-of-market imports, <http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf>

points into the ISO. Export curtailments show all self-scheduled exports leaving the ISO to outside balancing authority areas that were curtailed in the real-time market.

Figure 3.28 Average hourly out-of-market energy and market export curtailments (hours 17-22)

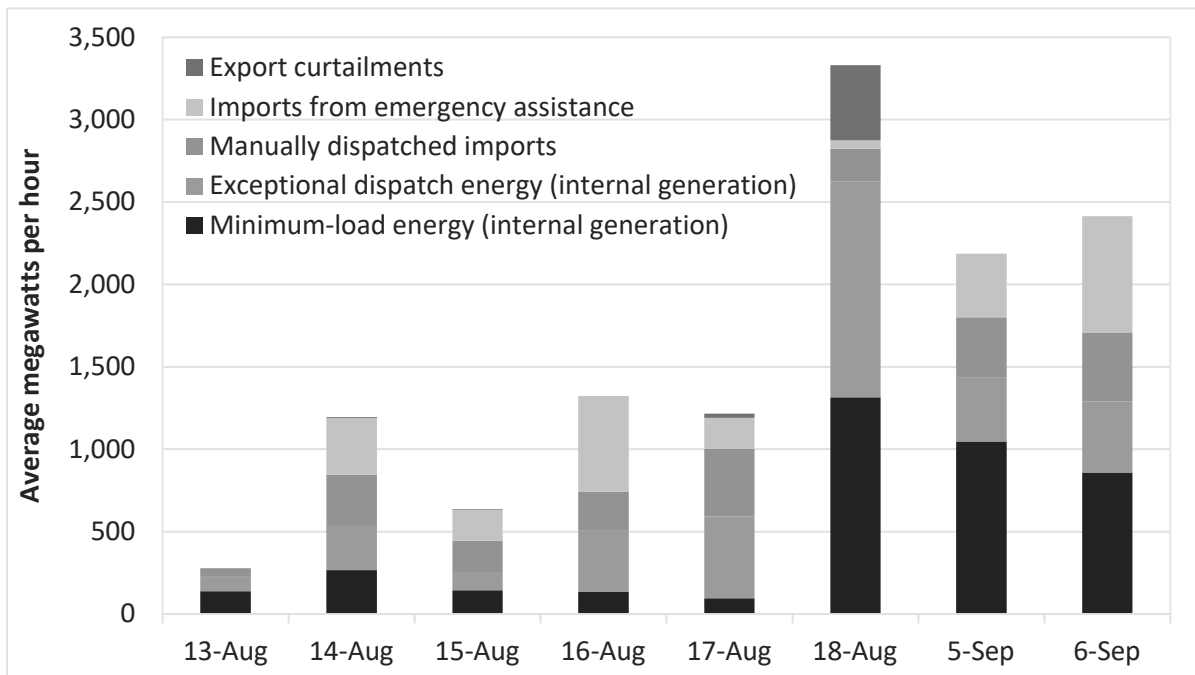
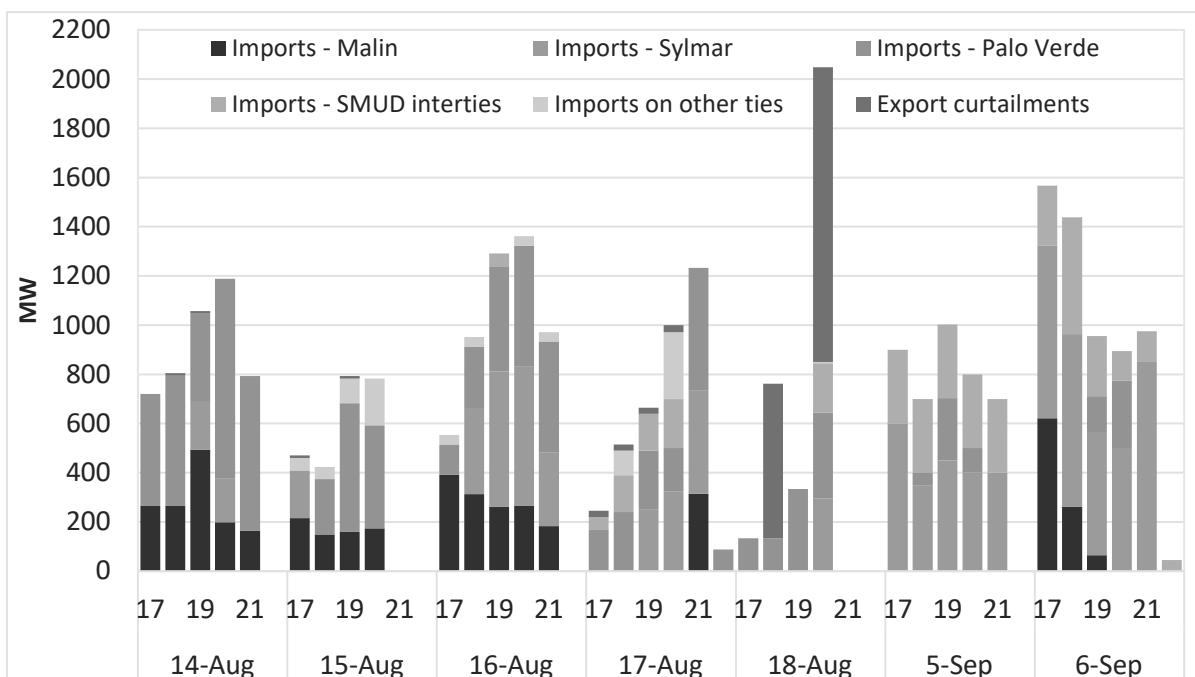


Figure 3.29 Hourly out-of-market imports and market export curtailments (hours 17-22)



3.8 Energy imbalance market performance

One of the key benefits of the Western energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. During the heat wave periods, the energy imbalance market functioned well under tight conditions, facilitating transfers from areas with surplus to areas with tighter supply conditions.

The CAISO was a net importer in the energy imbalance market during the most critical evening ramping hours of the summer 2020 heat wave. During curtailment intervals on August 14-15, the energy imbalance market provided an average of 1,346 MW and 530 MW respectively into the CAISO system.

3.8.1 Energy imbalance market transfers and congestion

Figure 3.30 and Figure 3.31 show average hourly transfers in and out of each energy imbalance market area for hours ending 19 and 20 on August 14 and August 15.³² These figures cover the four hours in which the ISO curtailed load on these days.

- As shown in Figure 3.30, the CAISO was the only major net importer in the energy imbalance market during these hours on August 14, with the NV Energy and Portland Gas & Electric areas also importing relatively small quantities.
- As shown in Figure 3.31, the CAISO was also the largest net importer in the energy imbalance market during these hours on August 15, with the other areas being a mix of net importers and exporters during different hours.

Energy imbalance market transfers are a function of both regional supply conditions and transfer limitations. Figure 3.32 and Figure 3.33 summarize which areas were export constrained, import constrained, or part of the greater CAISO/EIM system during the peak hours on August 14 and August 15.³³ Each of these categories is described in further detail below.

- **Export Constrained.** The green space indicates that the area was export constrained relative to the greater CAISO/EIM system. Combined export flows out of these areas generally helped conditions in the greater system, but only to the extent of export limits out of this region. In particular, the Northwest region, which includes PacifiCorp West, Portland General Electric, Seattle City Light, Puget Sound Energy, were mostly export constrained in hours-ending 19 and 20 on August 14.³⁴
- **Import Constrained.** The red space indicates that the area was import constrained relative to the greater CAISO/EIM system. On August 14 and August 15, NV Energy regularly failed the upward sufficiency test and was constrained by net import limits imposed as a result of failing the test. Here, the constraint limited the ability for energy outside of NV Energy to serve its load.

³² EIM transfers in these figures are net of all base schedules and therefore reflect dynamic market flows from the market optimization. Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

³³ This is calculated from the shadow price on an area's transfer constraint relative to prevailing system prices. When prices are lower relative to the system, this indicates congestion out of an area and limited export capability. The reverse is true when prices are higher relative to the system.

³⁴ Export capability from the Powerex area was set to 0 MW both days, so Powerex is excluded from this figure.

Figure 3.30 Average hourly 5-minute market energy imbalance market transfers (Hours ending 19-20, August 14, 2020)

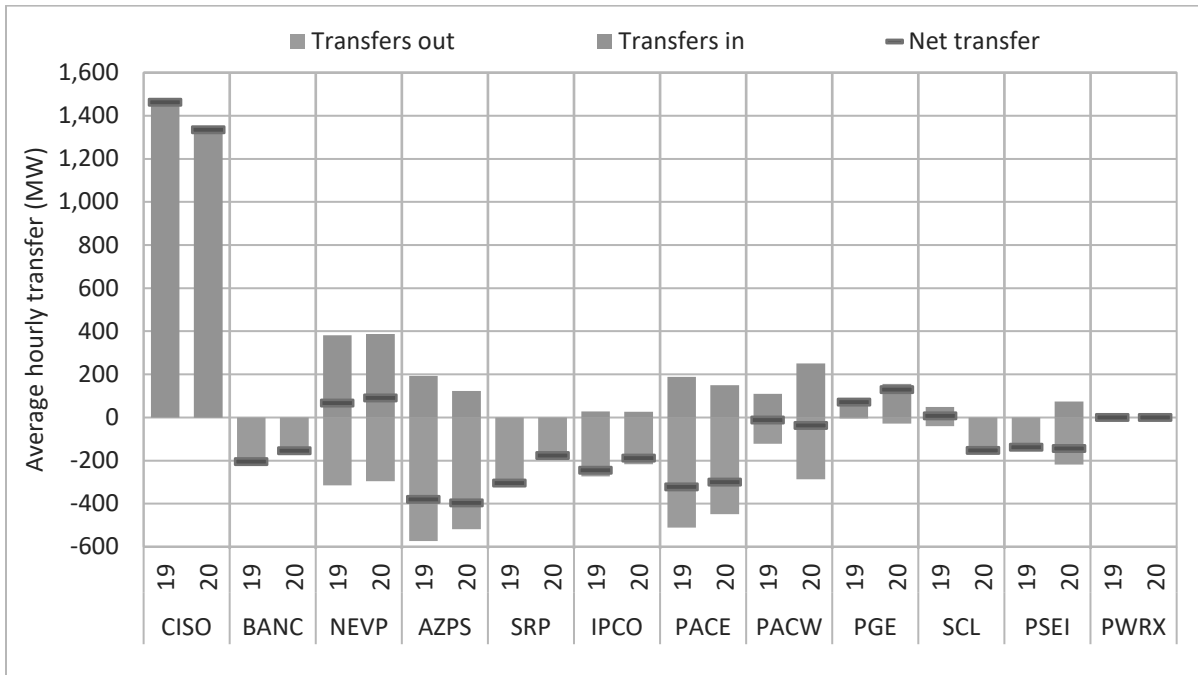


Figure 3.31 Average hourly 5-minute market energy imbalance market transfers (Hours ending 19-20, August 15, 2020)

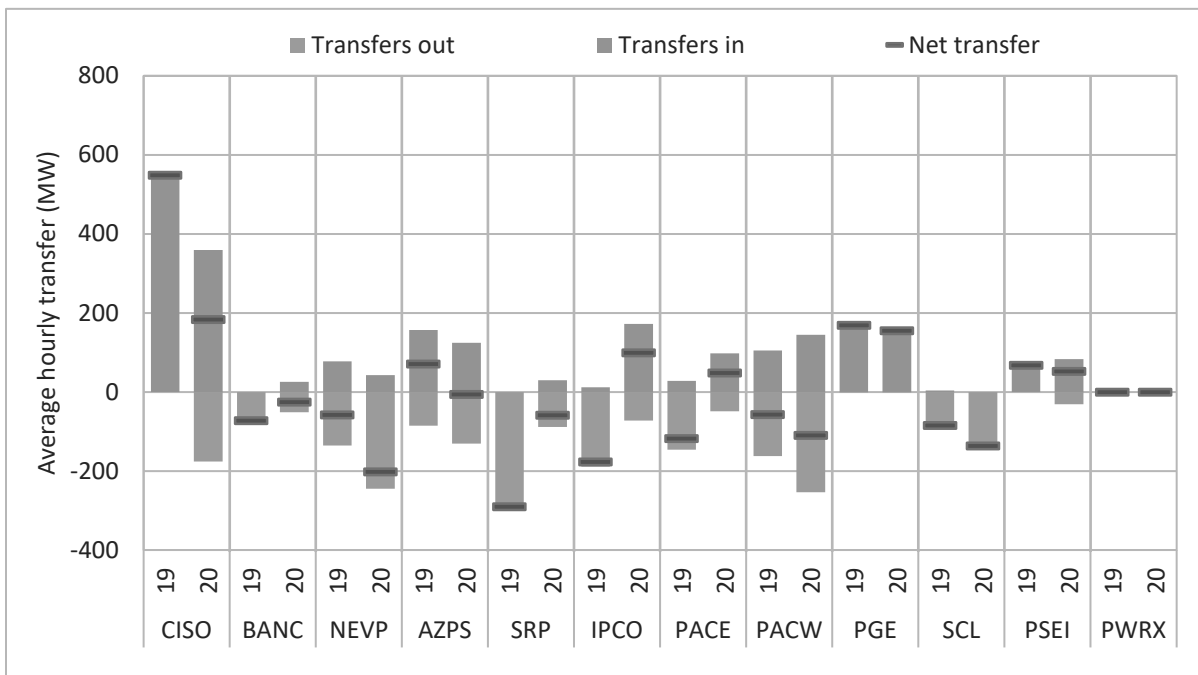


Figure 3.32 5-minute market congestion on energy imbalance market transfer constraints (August 14, 2020)

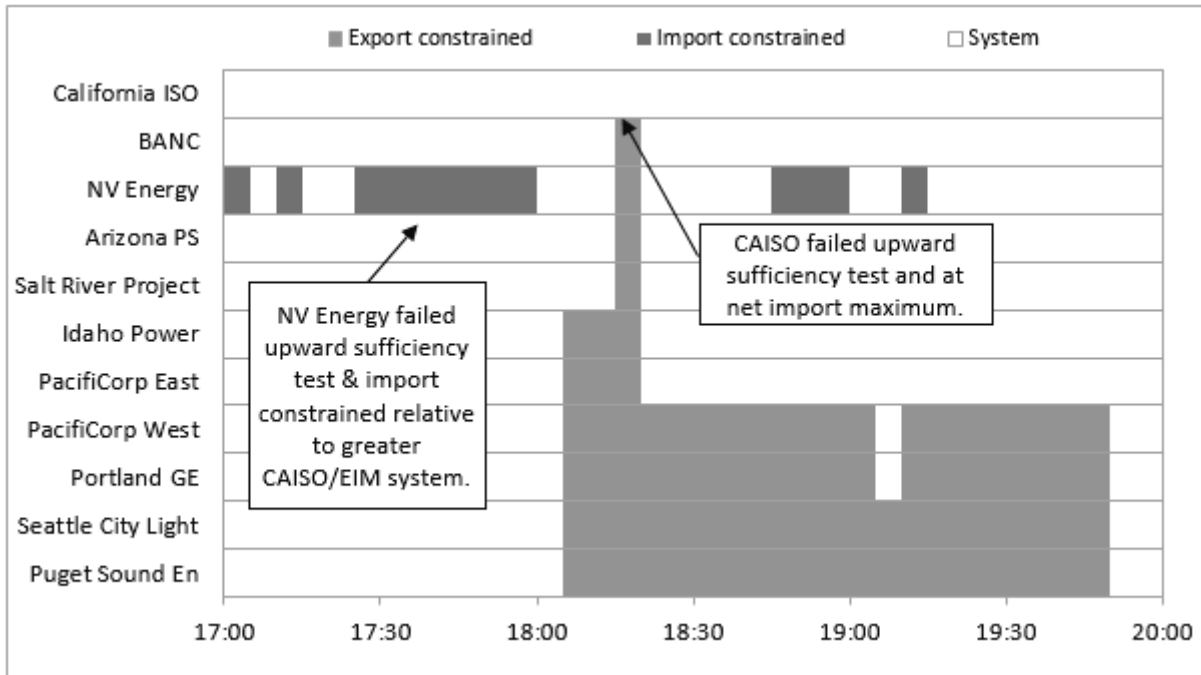
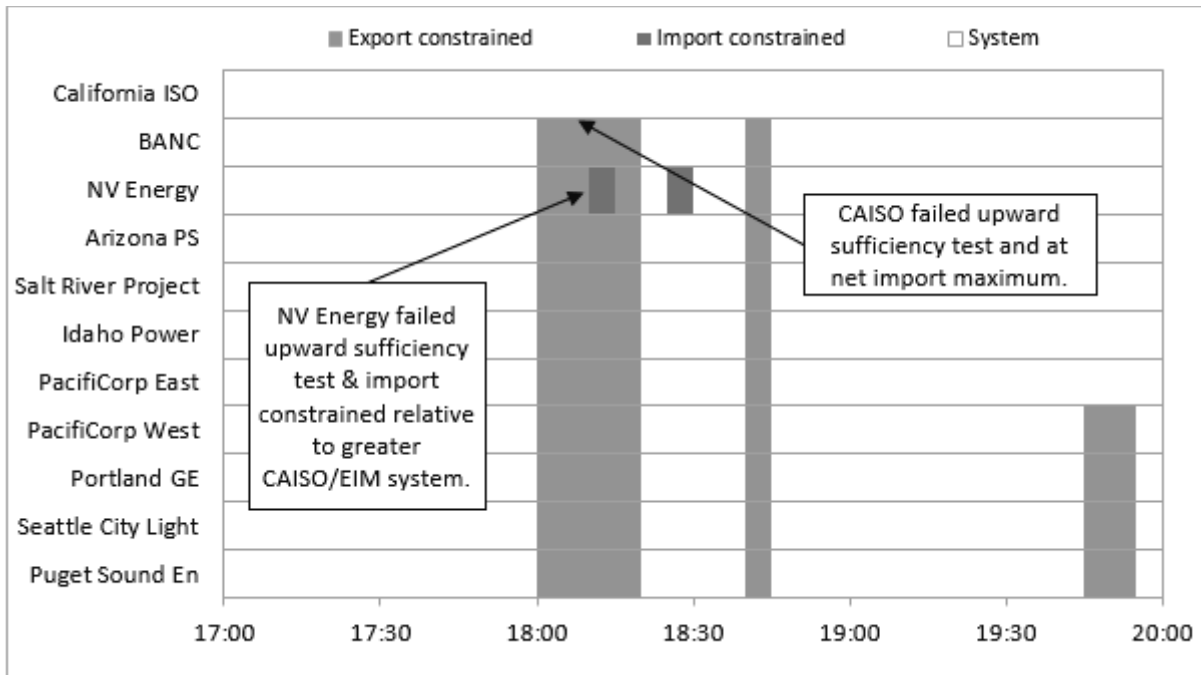


Figure 3.33 5-minute market congestion on energy imbalance market transfer constraints (August 15, 2020)



- **System.** The white space in Figure 3.33 and Figure 3.33 indicates that the area was part of the greater CAISO/EIM system. In these intervals, the market optimization freely facilitated transfers to support regional demand conditions, limited only by the amount of surplus supply available within in each balancing area.

3.8.2 Flexible ramping sufficiency test impact

The flexible ramping sufficiency test is applied to all balancing areas in the Western energy imbalance market. If an area fails the upward sufficiency test, net energy imbalance market transfers into that area are capped for the corresponding intervals in the 15-minute and 5-minute markets. This limitation is designed to deter balancing areas from leaning excessively or systematically of the energy imbalance market to meet their resource and ramping energy requirements.

The CAISO balancing area failed the upward flexible ramping sufficiency test on both days with load shedding events (August 14 and August 15). Figure 3.34 and Figure 3.35 show net EIM imports in the 15-minute and 5-minute markets, as well as the net import limit imposed as a result of failing the upward sufficiency test. The net import limit imposed is the same in both markets, and is set by the previous 15-minute market net import.

To the extent that the net EIM imports in the 5-minute market (blue bars) are below the sufficiency test import limit, the sufficiency test did not have an impact on CAISO's ability to access generation from the energy imbalance market. For August 14, the net EIM import was set at around 1,500 MW in hour-ending 19, intervals 2-4. The only RTD interval which was at the sufficiency test imposed import limit for this hour was interval 4, which was prior to the declaration of the Stage 3 Emergencies.

On August 15, the failure of the sufficiency test imposed an import limit of around 670 MW during all of hour-ending 19. For this hour, the 5-minute market net EIM import was at the imposed import limit for intervals 1 through 4 and 9. For each of these intervals, prices in the surrounding energy imbalance market areas with export capability to the ISO were also at extremely high levels. This signals that limited energy would have been available for the ISO had the net EIM import cap not been imposed. The failing of the flexible ramping sufficiency test had little or no impact on net transfers from the energy imbalance market into the ISO on August 14 and August 15.

Figure 3.34 Limit on EIM imports to CAISO due to resource sufficiency test failures (August 14)

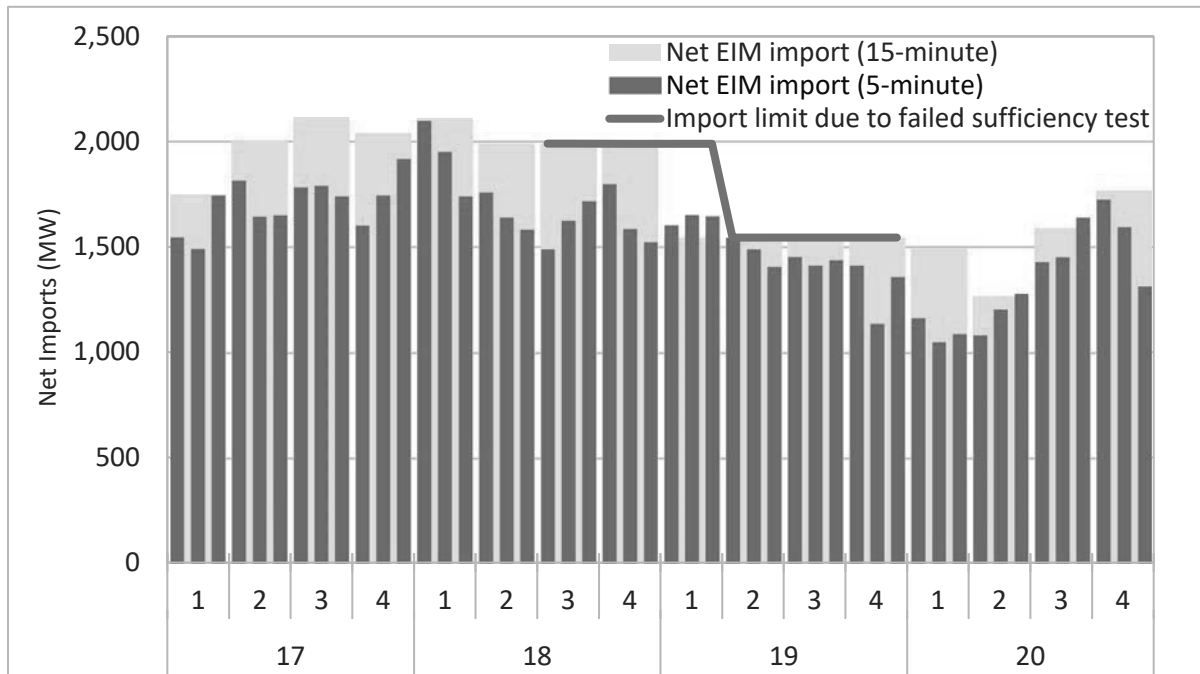
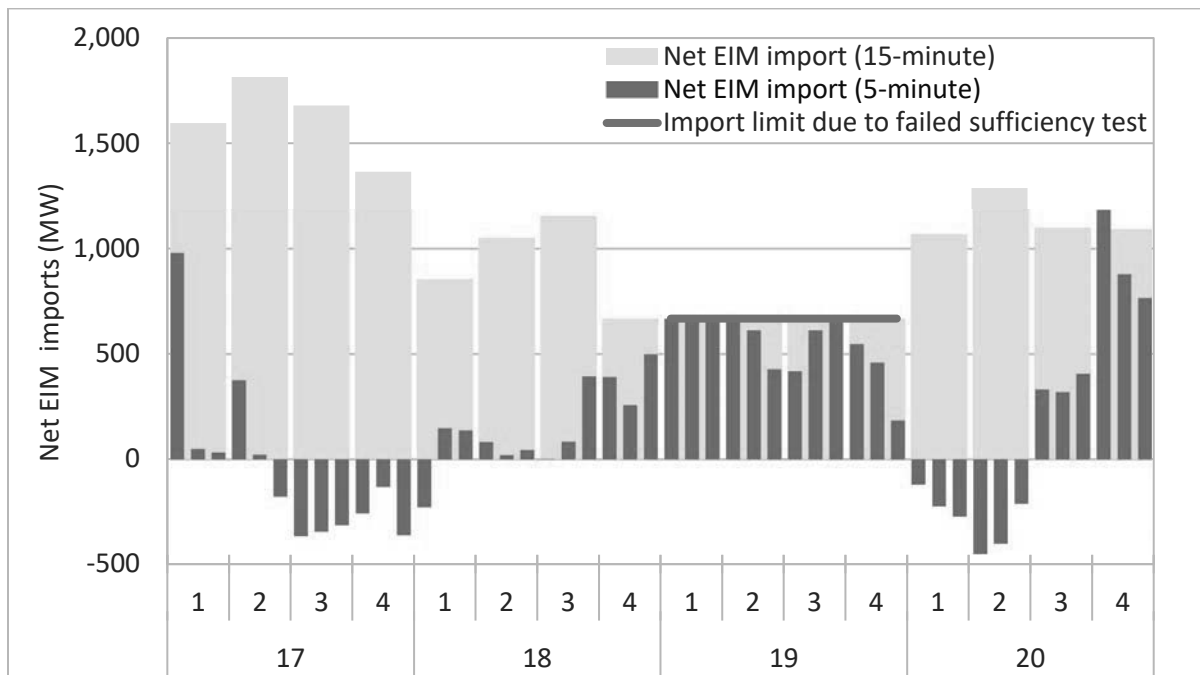


Figure 3.35 Limit on EIM imports CAISO due to resource sufficiency test failures (August 15)



3.9 Limited greenhouse gas imports in the Western energy imbalance market

Imports for the energy imbalance market into California are limited by total supply bid into the energy imbalance market as being willing to be transferred into California and made subject to California’s greenhouse gas cap-and-trade program. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. EIM greenhouse gas supply was very limited on both days with load shedding events (August 14 – August 15).

Figure 3.36 and Figure 3.37 show available EIM greenhouse gas supply above net EIM imports into California, that is additional available EIM imports into California, in both the 15-minute market (yellow bars) and the 5-minute market (blue bars). As shown in these figures, additional available capacity was zero in several intervals in both markets on both days in hour 19 when load was shed (although never simultaneously in both the 15-minute and 5-minute markets). EIM imports were capped at transfer levels shown above during intervals when no additional EIM greenhouse gas supply was available.

Figure 3.36 Additional available energy imbalance market greenhouse gas capacity (August 14)

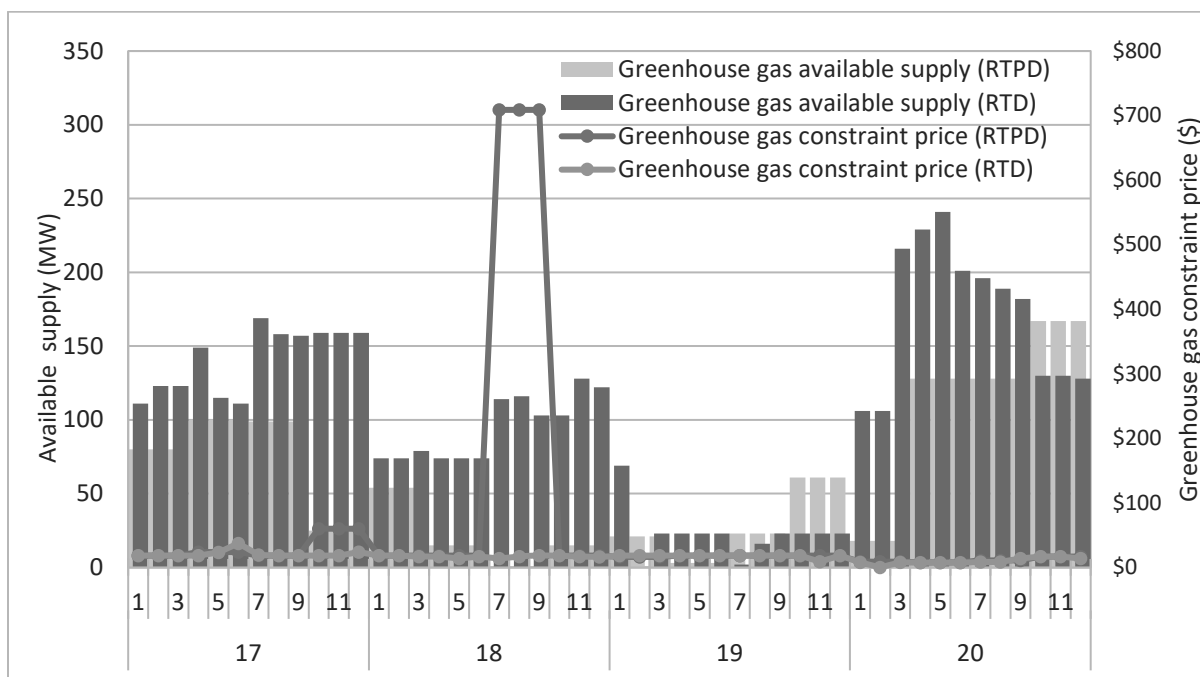
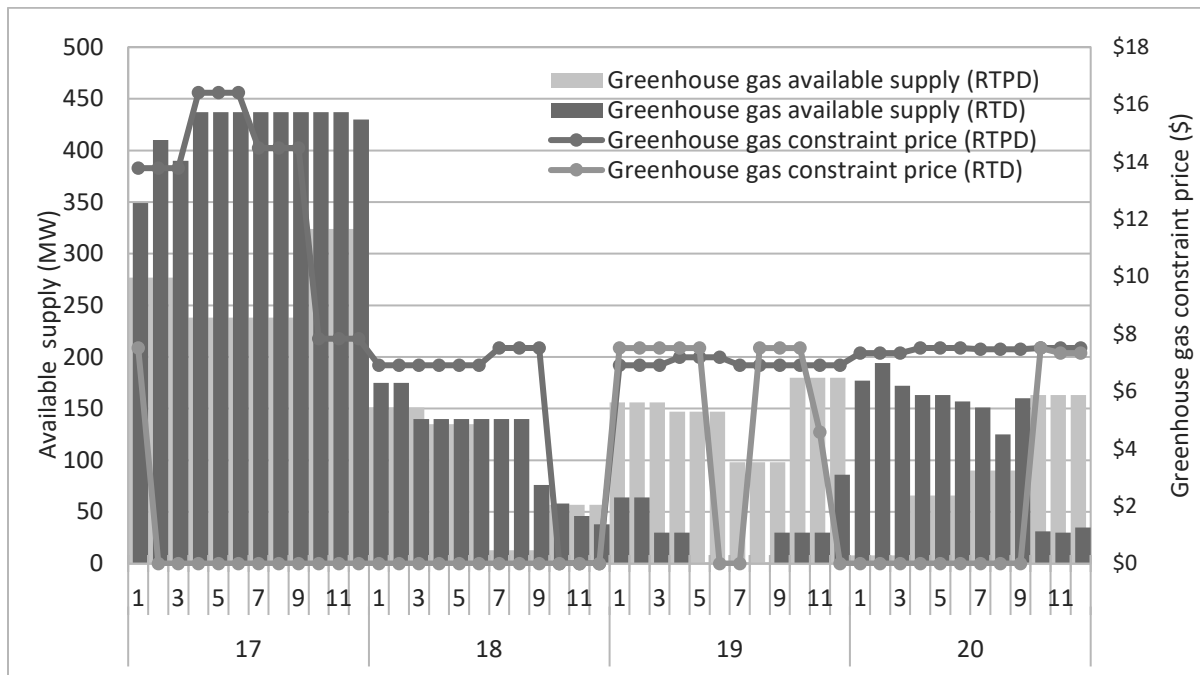


Figure 3.37 Additional available energy imbalance market greenhouse gas capacity (August 15)



3.10 Day-ahead exports in real-time

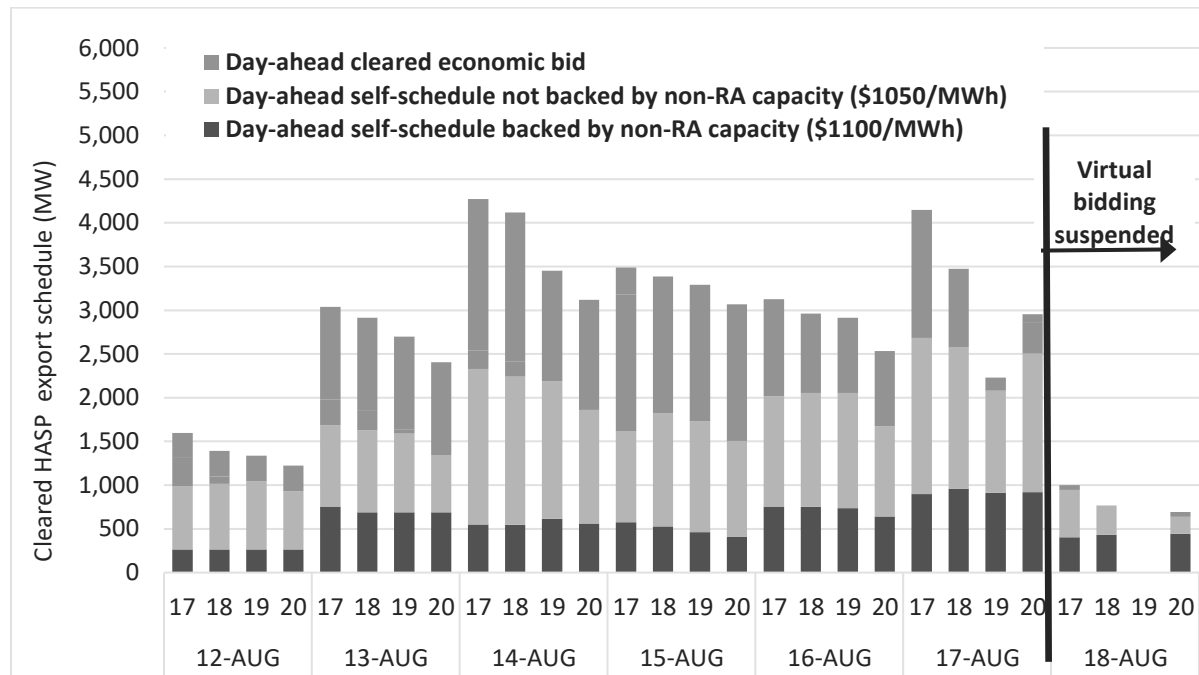
In the days leading up to August 14 and 15, market participants offered increasing volumes of exports in the day-ahead market at very high prices or as self-schedules.³⁵ The quantity of exports clearing the IFM over this period also increased, as shown in Figure 3.38. Both self-scheduled and economically bid exports cleared the day-ahead market on both the August 14 and 15, with over 3,000 MW clearing during the hours when load was shed.

Prior to September 5, 2020, all export schedules that cleared the day-ahead market’s integrated forward market (IFM) automatically received among the highest real-time self-schedule priorities for demand, unless rebid in real-time. This real-time scheduling priority is independent of day-ahead scheduling priority, and exceeds that of all real-time submitted export self-schedules, as well as the real-time market energy balance priority established to meet CAISO balancing area forecast load.

As shown in Figure 3.38, in each of the three hours when load was shed, there was close to 3,000 MW of HASP export schedules that were not backed by capacity contracts but that received a real-time scheduling priority above that of native CAISO balancing area load because the exports had cleared the IFM.

³⁵ Market participants submitting export self-schedules have the option of specifying non-RA capacity to support the export. Exports that are backed by specified non-RA capacity receive a “price-taker” scheduling priority. Export schedules that are not identified as backed by non-RA capacity receive a lower scheduling priority as “less-than price taker” self-schedules, with a corresponding lower penalty price. This “less-than price taker” scheduling priority is below that of self-scheduled exports backed by non-RA and self-schedules of CAISO demand.

Figure 3.38 Day-ahead export schedules cleared in HASP with real-time scheduling priority above real-time load curtailment (by HASP scheduling priority penalty price)³⁶



ISO operators can manually curtail exports for reliability reasons. However, as noted in that report, this is not a common practice because of concerns about potential detrimental direct and indirect reliability impacts on the CAISO and other balancing areas:

... 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 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.³⁷

³⁶ HASP data are missing for hour 19 on August 18.

³⁷ CAISO/CPUC/CEC report, pp. 106-107

The ISO took measures to limit exports entering the real-time market with scheduling priority above real-time load following the load shed event. First, as an interim measure, the ISO suspended virtual bidding effective August 18. Second, on September 5, the ISO implemented a change to the treatment of export schedules in RUC and real-time which limits the real-time self-scheduled quantities associated with day-ahead cleared schedules to quantities cleared in the RUC process. These measures are discussed in detail below.

3.11 Virtual bidding

To assess the impact of virtual bidding during mid-August leading up to the suspension of virtual bidding on August 18, DMM re-ran the day-ahead market software *without* virtual bids during this period. The change in the amount of different resources clearing the day-ahead market when the software is re-run without virtual bids shows the impact of the virtual bids that actually cleared the market.

Figure 3.39 shows the amount of virtual supply bids (green bars) and virtual demand bids (blue bars) that actually cleared in the market in hours 16 to 21 from August 14 to August 17, when virtual bidding was still in effect. As shown in Figure 3.39, the net impact of these virtual bids was to provide over 1,000 MW of net virtual supply in the peak ramping hours of 18 to 20 on Friday August 14 and Monday August 17. On the weekend of August 15 – 16, virtual bidding resulted in net virtual demand of 1,000 MW to 3,000 MW in hours 16 to 21.

Figure 3.40 shows the impact of removing virtuals on net supply in hours 16 to 21 from August 14 to August 17. This change is quantified based on the difference in bids clearing in the market software with and without virtual bids. The charts show the net supply impact of removing virtuals, so that a reduction in generation with the removal of virtuals is shown as a negative supply impact and a reduction in exports will appear as a positive supply impact.

As shown in Figure 3.40, when net virtual demand cleared the market, removing these virtual bids reduces the amount of generation that clears the day-ahead market by almost an equal amount (shown in the dark blue bars in Figure 3.40). This indicates that the primary impact of virtual bidding in hours when net virtual supply clears is to increase the physical generation within the CAISO system that receives day-ahead energy market awards.

As shown by the yellow bars in Figure 3.40, the net virtual supply which cleared the day-ahead market on August 14 had the effect of increasing the amount of physical load clearing the day-ahead market on this day during hours 19 and 20. However, as shown by the red bars in Figure 3.40, the net virtual supply which cleared the day-ahead market on August 17 had the effect of increasing the amount of exports clearing the day-ahead market on this day during hours 17 to 21.

When additional exports clear due to net virtual supply, additional physical supply is needed in real-time to meet the increased demand created by these exports. If RUC and related real-time bid processing is not functioning as intended under tight supply conditions, this scenario could create significant reliability risks in the real-time market. Concern about the potential reliability risk created by this situation was a major consideration in the CAISO's decision to suspend virtual bidding beginning with the day-ahead market for Tuesday August 18 – a day on which CAISO system load was expected to exceed 50,000 MW.

Figure 3.41 and Figure 3.42 below illustrate trends in day-ahead export bidding and awards in the days surrounding the CAISO's suspension of virtual bidding on August 18.

Figure 3.41 shows that although August 18 had the highest volume of submitted export bids and self-schedules in the day-ahead market, the volume of cleared exports on this day was considerably less than surrounding days. This also resulted in a lower volume of cleared real-time export schedules. Because many day-ahead export bids and self-schedules did not clear the day-ahead market, these quantities did not enter real-time market as self-schedules at the priority of a cleared day-ahead export schedule.

Figure 3.42 shows the quantities of exports clearing in the HASP in the real-time market that are associated with schedules cleared in the day-ahead market by scheduling priority. These are schedules that received a real-time self-scheduling priority exceeding that of real-time market energy balance, and any export self-schedules first submitted in real-time, regardless of IFM scheduling priority.

In the day-ahead market, self-scheduled exports not backed by non-RA capacity, and economic schedules each have a day-ahead scheduling priority below that of self-scheduled CAISO demand. When these schedules are submitted in the real-time market, they are prioritized similarly, with a scheduling priority below that of real-time market energy balance. However, by clearing first in the day-ahead market, these schedules receive a higher real-time scheduling priority above real-time market energy balance.

Figure 3.42 highlights the quantity of exports clearing HASP which received a higher real-time scheduling priority as a result of first clearing in the day-ahead market, and the drop in these quantities on August 18 that occurred with the suspension of virtual bidding.

Figure 3.39 Total virtual supply and demand bids cleared in day-ahead market (August 14 to 17)

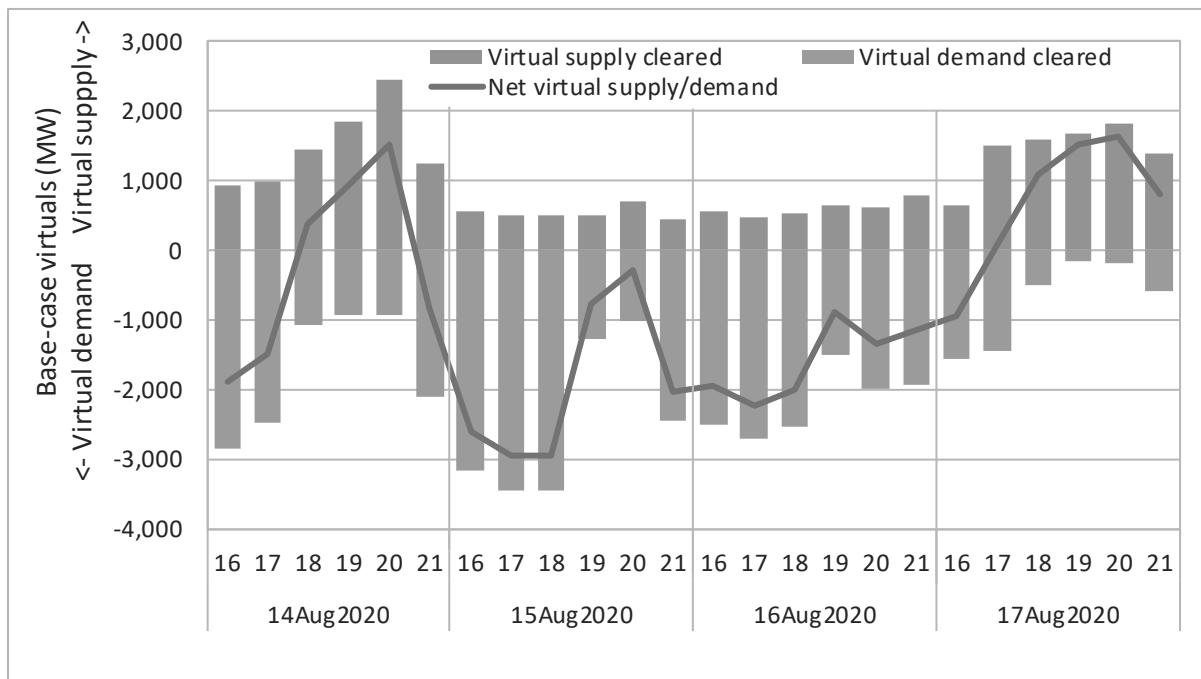


Figure 3.40 Impact of virtual bidding on resources clearing day-ahead market (August 14 to 17)

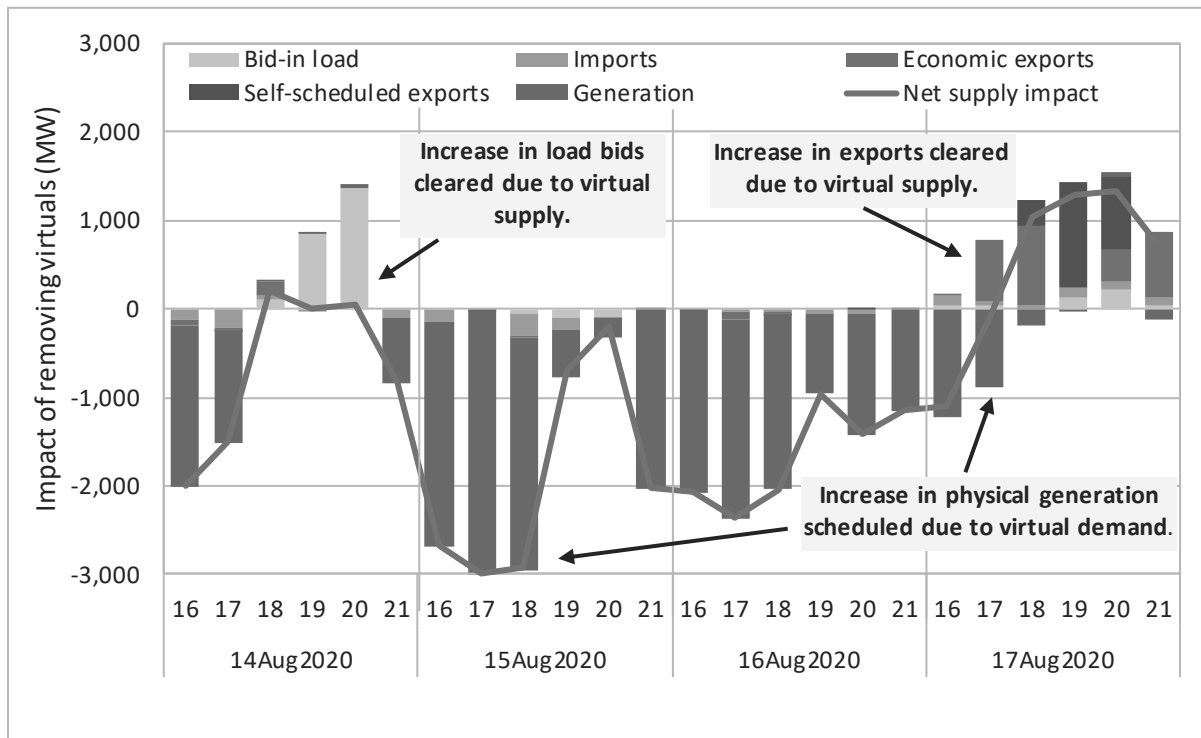


Figure 3.41 Exports before and after suspension of virtual bidding

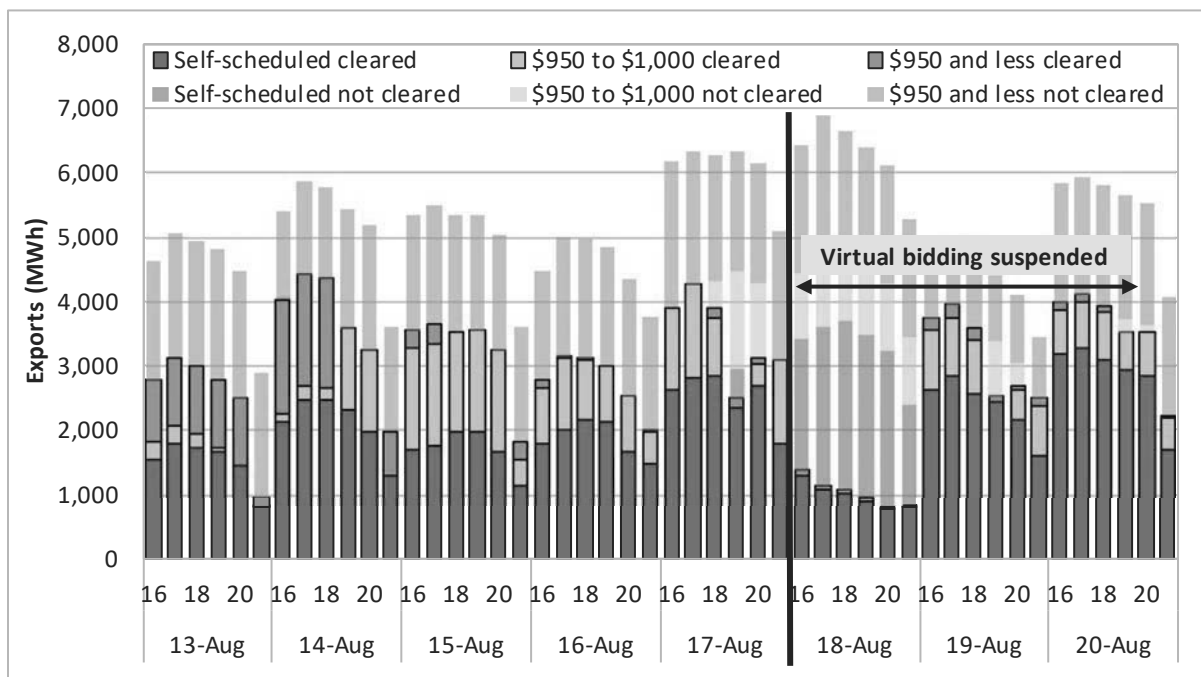


Figure 3.42 Day-ahead export schedules cleared in HASP with real-time scheduling priority above real-time load curtailment (by HASP scheduling priority penalty price)³⁸

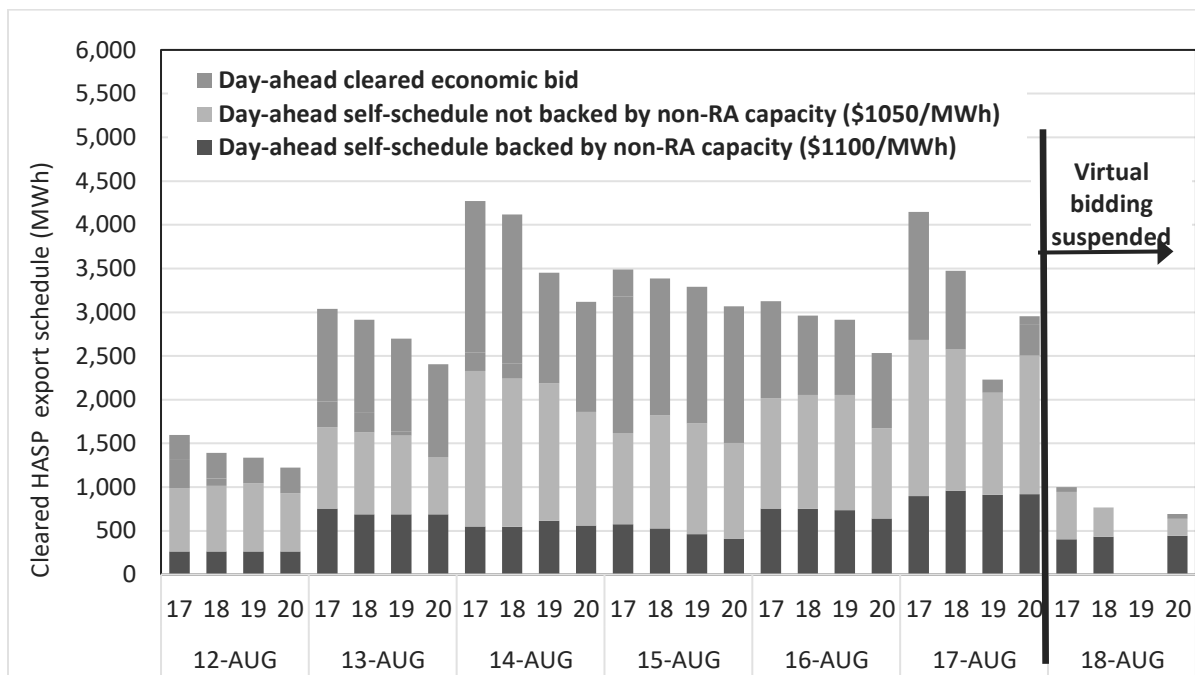
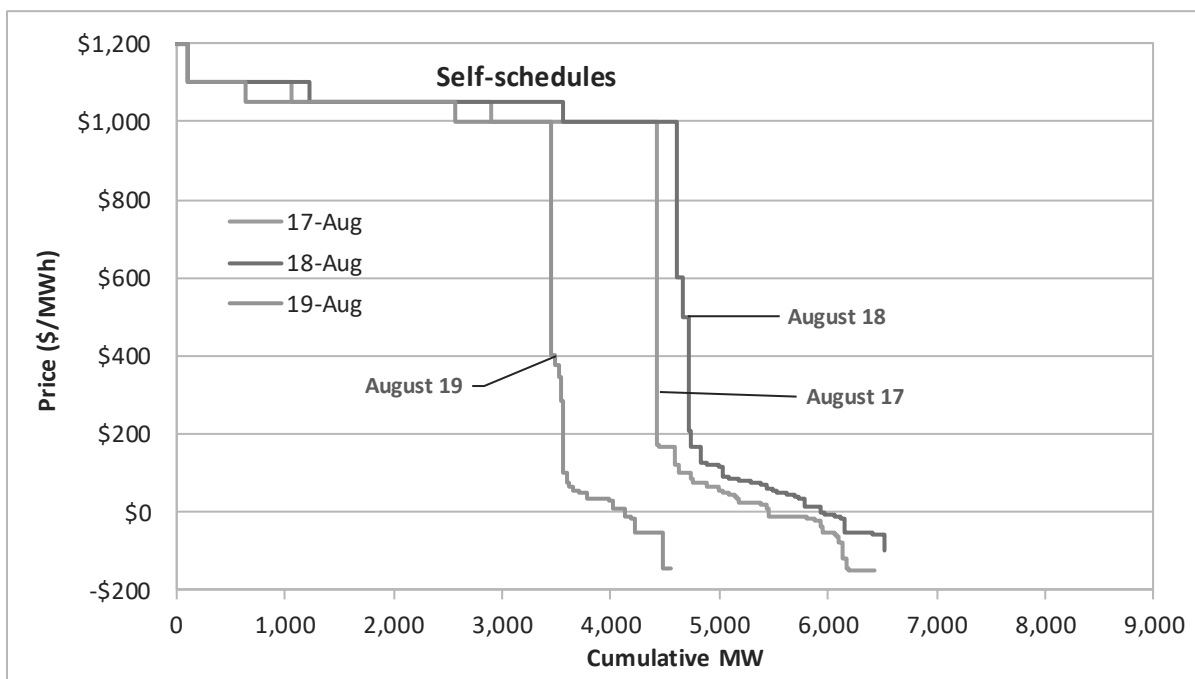
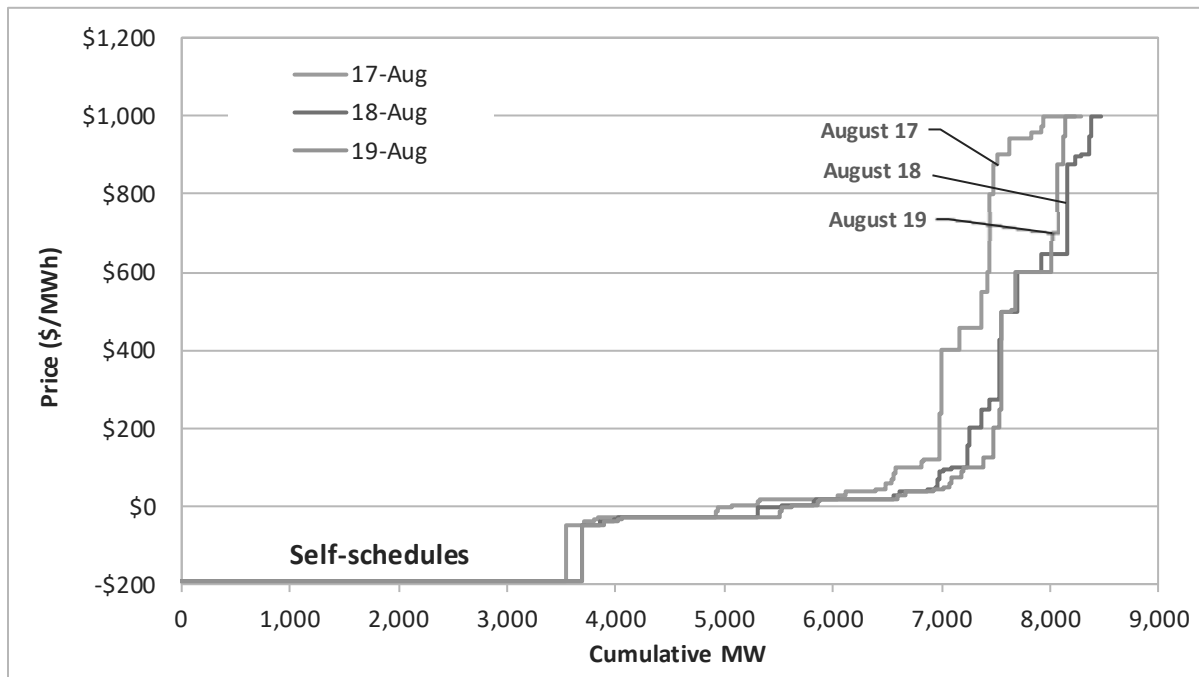


Figure 3.43 Day-ahead market export bids (August 17-19, Hour 19)



³⁸ HASP data are missing for hour 19 on August 18.

Figure 3.44 Day-ahead market import bids (August 17-19, Hour 19)

3.12 Residual unit commitment process

The ability of load serving entities to submit demand bids into the day-ahead market is a standard component of all ISO/RTO markets. Demand bidding allows load serving entities to manage their exposure to day-ahead and real-time prices.

Because the results of clearing all generation, load and other financial bids in the day-ahead market are not guaranteed to create resource commitments that can feasibly meet real-time load forecasts, ISOs/RTOs run supplementary reliability processes. In the California ISO this reliability process is called the Residual Unit Commitment (RUC). The RUC process should ensure that meeting the load forecast is feasible if it has sufficient resources to select from.

California's resource adequacy program is meant to ensure sufficient resources to meet load under most circumstances. If both the resource adequacy program and RUC process function to procure sufficient capacity, then meeting the real-time load forecast will be feasible regardless of how the day-ahead market clears bids.

Prior to September 5, 2020, RUC was allowing exports that were not supported by physical supply to receive RUC awards. Also, prior to September 5 all day-ahead cleared export schedules from the IFM that did not submit revised economic bids in real-time received the highest real-time export self-scheduling priority as a result of receiving a day-ahead market award. This real-time scheduling priority was assigned independent of whether the export was identified as backed by non-RA capacity or not. This real-time scheduling priority exceeds the real-time scheduling priorities for all real-time submitted self-schedules, as well as that for CAISO native load, whose priority is represented by the real-time market energy power balance penalty price.

On September 5, the ISO adjusted the RUC process. The change ensured that IFM exports not backed by capacity contracts would not receive RUC awards if there was insufficient physical supply in RUC to support them. On September 5, the ISO also adjusted the real-time market export scheduling priorities. With this change, exports that clear the integrated forward market, but subsequently receive a reduced RUC award in the RUC process, no longer receive a real-time scheduling priority that exceeds real-time ISO load. If a scheduling coordinator wishes for these schedules to be reinstated in real-time, the schedules must be re-bid in real-time or resubmitted as self-schedules in real-time.³⁹ This results in the scheduling priority below real-time ISO load.

The change implemented on September 5 appears to have had at least two notable impacts. First, as shown in Figure 3.45, the volume of exports offered into and clearing the IFM fell steadily over the period September 5-7 as RUC curtailments occurred each day over the high-load period. Second, the volume of exports ultimately scheduled in real-time was significantly below the quantities cleared in IFM over the same period. On these days, in the majority of hours 17-20, IFM export schedules were almost entirely eliminated by RUC curtailment.

Although more than half of these RUC curtailed schedules were resubmitted and cleared in HASP as real-time self-schedules or economic bids, the quantity of HASP cleared exports was still reduced by as much as 1,500 MW over IFM cleared values that may have been physically infeasible in real-time. As shown in Figure 3.47, the schedules that did ultimately clear HASP did so based on real-time market conditions, and at real-time scheduling priorities below that of real-time self-schedules associated with day-ahead awards.

These changes improved the alignment of export self-schedules with real-time system conditions, and may have led to a reduced need for manual intervention by operators.

³⁹ The ISO provided details and examples of this change in the Market Performance and Planning Forum meeting on September 9, 2020: <http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum>

Figure 3.45 RUC under-supply infeasibilities and cleared exports (Aug 14 – 20 and Sep 5 - 6)

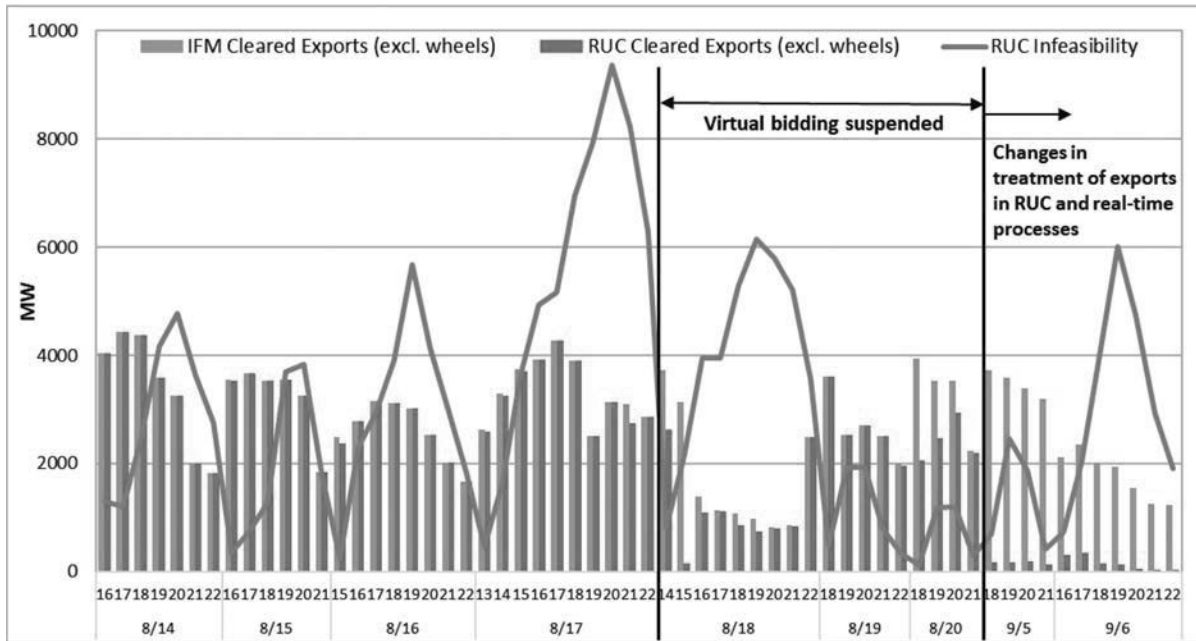


Figure 3.46 Exports bid and scheduled in day-ahead market (September 3-7)

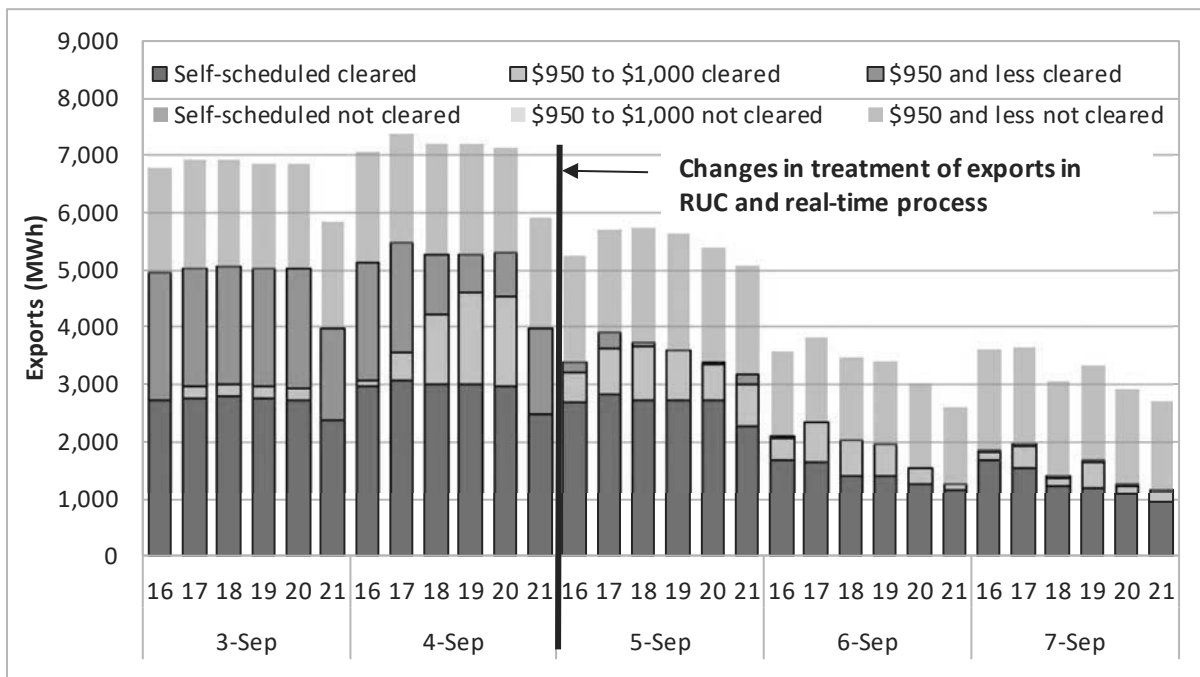
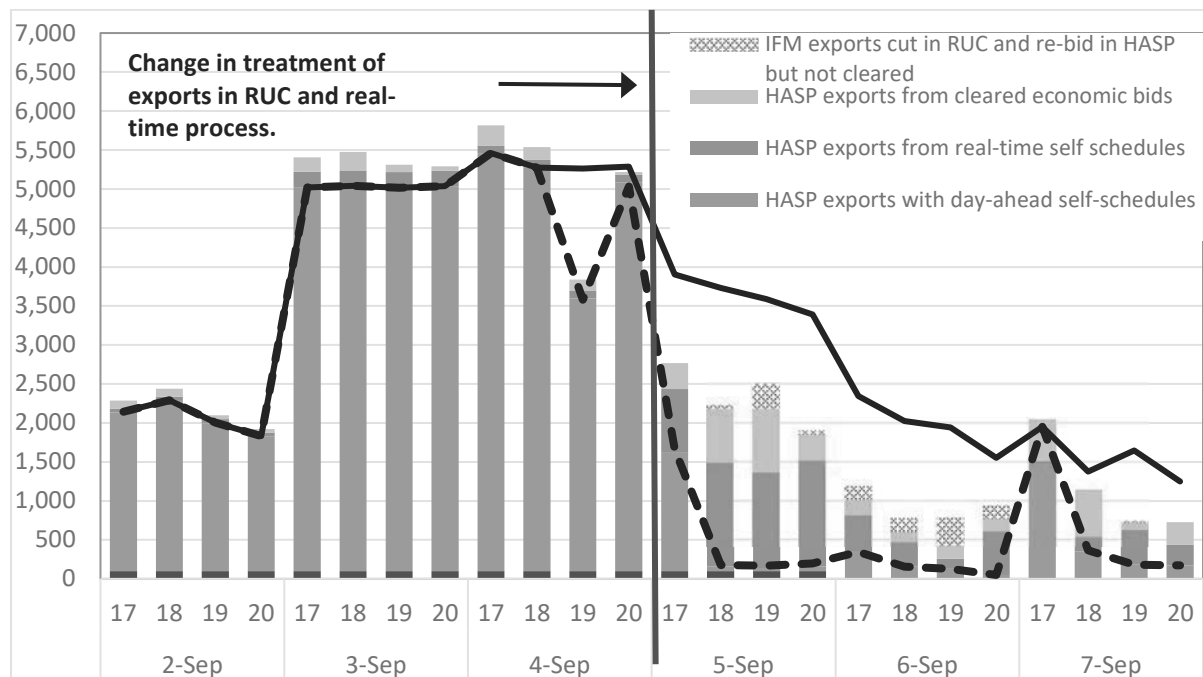


Figure 3.47 Reduction in exports due to changes in RUC and real-time process (September 2-7)



3.13 Demand response

Demand response programs counted for 1,847 MW of resource adequacy capacity in August and 1,769 MW of resource adequacy capacity in September. This capacity was comprised of both utility demand response programs which are credited against resource adequacy requirements across all local regulatory authorities, and third-party demand response programs which are contracted with load serving entities and shown on resource adequacy supply plans.

Demand response shown on resource adequacy supply plans

Demand response capacity shown on resource adequacy supply plans currently represents demand response programs scheduled by third party non-utility providers. This capacity is primarily contracted with load serving entities through the CPUC’s Demand Response Auction Mechanism (DRAM), but also includes third party demand response contracted with load serving entities and vetted through the CPUC’s Load Impact Protocol (LIP) process. This capacity is generally subject to must-offer obligations and the ISO’s resource adequacy availability incentive mechanism (RAAIM).

In August, supply plan demand response counted for 244 MW of resource adequacy capacity. In September, supply plan demand response counted for 237 MW of resource adequacy capacity.

Figure 3.48 shows the availability of supply plan demand response capacity as reflected by day-ahead and real-time bids, where bids are capped at individual resource shown resource adequacy values. Figure 3.48 also shows real-time dispatches of supply plan demand response. On August 14, 48 MW of supply plan demand response capacity was not bid into peak net load hours in the day-ahead market. Of the capacity not bid into the day-ahead market on August 14 through August 18, 23 MW was associated

with resources sized less than 1 MW and thus was exempt from RAAIM. On September 5 and 6, 25 MW of supply plan demand response capacity not bid into the day-ahead market was associated with resources sized less than 1 MW. The majority of underbid capacity from resources sized less than 1 MW was associated with resources under the same scheduling coordinator, where more than one resource sized less than 1 MW existed in the same sub-lap.

On August 15, 113 MW of supply plan demand response was not bid into the day-ahead market. Supply plan demand response capacity bids are generally concentrated in availability assessment hours (hours ending 17 through 21 on non-holiday weekdays), indicating that several underlying programs are defined around the ISO's availability assessment hours. Thus only about 53 percent of supply plan demand response resource adequacy capacity was available to the ISO on August 15.

Figure 3.48 also shows that real-time availability of supply plan demand response consistently drops off from day-ahead availability. On August 14, there was 53 MW less capacity available in real-time compared to day-ahead and on August 15 there was 30 MW less available in real-time compared to day-ahead. The additional capacity not available in real-time is associated with long-start proxy demand response resources which have no obligation to be available to the ISO's residual unit commitment (RUC) or real-time markets if not scheduled in the integrated forward market.⁴⁰ These underlying resources have start-up times of 5 hours or greater. Most of this underlying capacity was offered in the day-ahead market at the \$1,000/MWh bid cap while also submitting high startup and minimum load costs, resulting in resources being uneconomic to commit in the day-ahead market.

On August 14 in hours 19 and 20, about 50 percent of demand response capacity shown on resource adequacy supply plans was dispatched by the ISO. On August 15 in hours 19 and 20, only about 25 percent of supply plan demand response capacity was dispatched by the ISO.⁴¹ There were no manual dispatches of supply plan demand response resources on August 14 or August 15.

⁴⁰ ISO Tariff, Section 40.6.4.4.

⁴¹ In the CAISO/CPUC/CEC report (Figure ES.5), the ISO also reports on supply plan proxy demand response dispatches in select peak hours. The ISO's figures show dispatches on supply plan demand response resources in excess of shown resource adequacy values. Figure 3.48 shows demand response dispatches capped at individual resources' shown resource adequacy values (red line) and dispatches on supply demand response resources in excess of shown resource adequacy values (dashed red line). Of note, 99 percent of supply plan demand response dispatches in excess of shown resource adequacy in this timeframe were associated with a single demand response provider.

Figure 3.48 Day-ahead and real-time availability of supply plan demand response

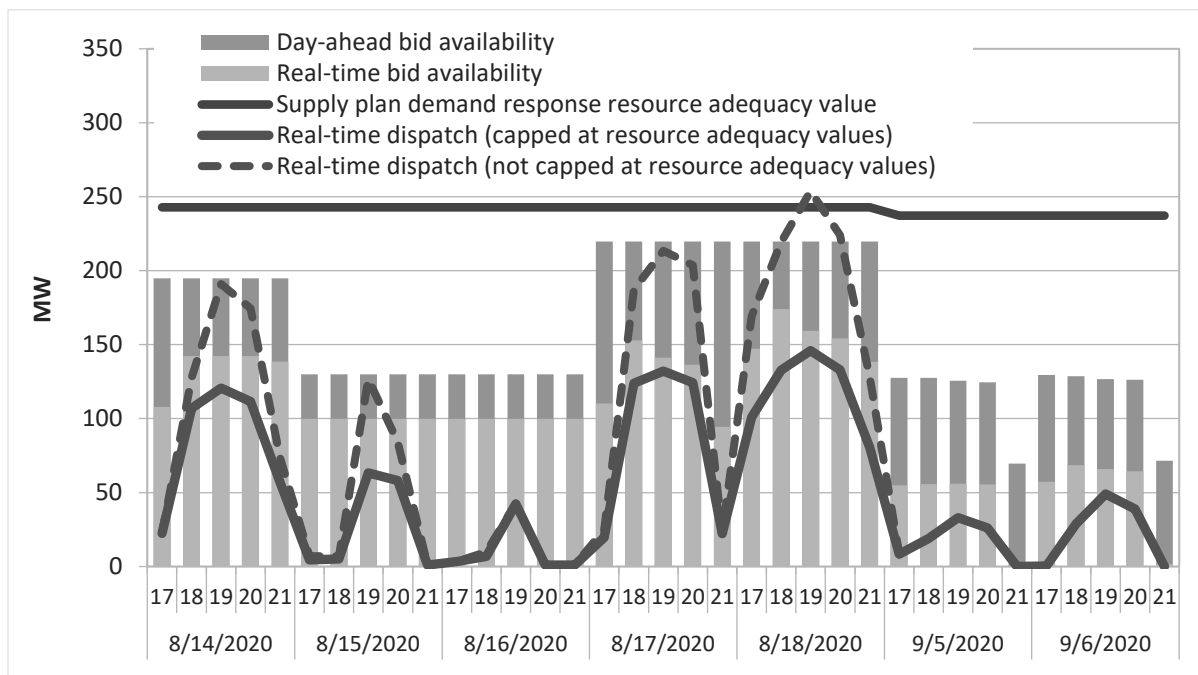


Figure 3.52 only reflects the aggregated dispatch of supply plan demand response, or *expected* load curtailment from supply plan demand response resources. DMM is continuing to review the self-reported performance, or self-reported load curtailment, of demand response resources in this timeframe.

Utility demand response programs

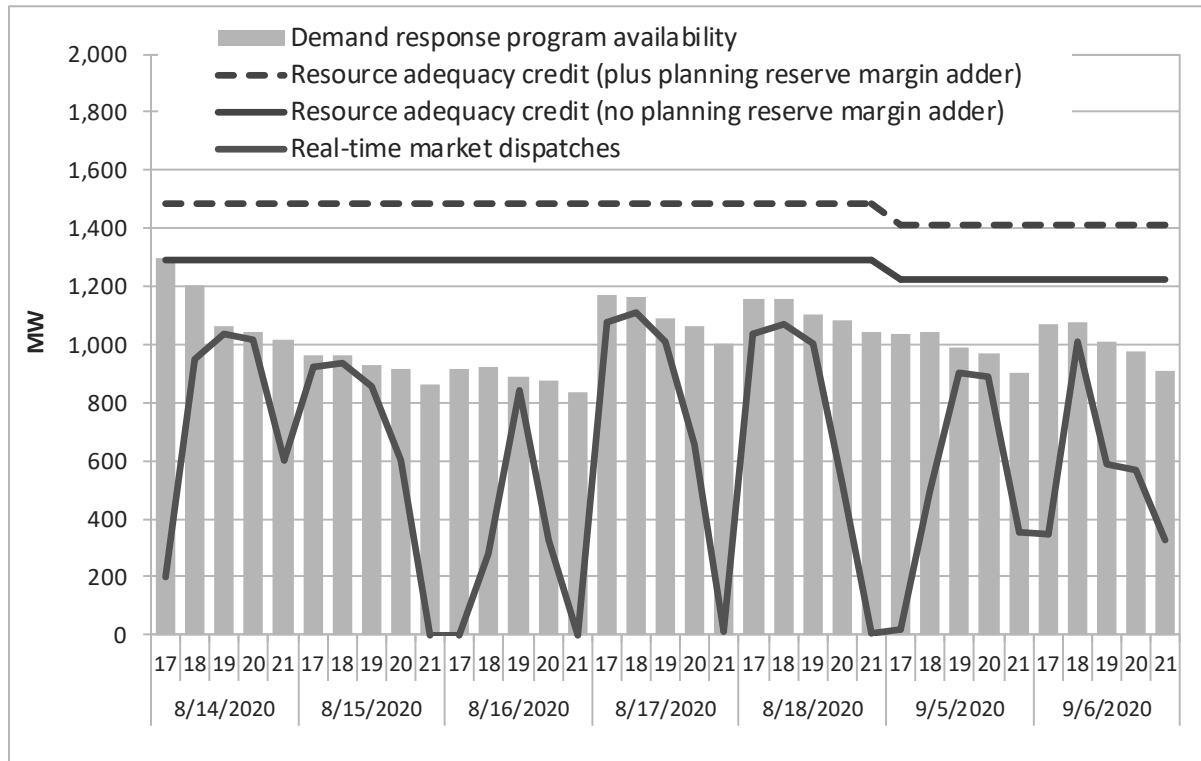
Demand response programs administered by load serving entities also count towards meeting resource adequacy requirements. These utility demand response programs count as credits against load serving entity resource adequacy obligations. While many of these demand response programs are also registered as resources in the ISO market, this capacity is not subject to the ISO’s must-offer obligations and resource adequacy availability incentive mechanism (RAAIM).

Utility demand response programs counted for 1,604 MW of resource adequacy credits in August. Of these utility demand response credits, demand response programs under the CPUC local regulatory authority (LRA) accounted for 1,482 MW. System resource adequacy demand response credits under the CPUC local regulatory authority also include a 15 percent planning reserve margin adder. In August, the CPUC planning reserve margin adder represented 193 MW.

Investor-owned utilities serve as scheduling coordinators for the demand response programs counted towards resource adequacy obligations under the CPUC local regulatory authority. The majority of this capacity is reliability demand response, or RDRR, which can only be called by the ISO under emergency conditions. The ISO relied on RDRR capacity between August 14 and August 18, and again on September 5 and September 6. The ISO communicates with IOU schedulers to activate their demand response programs when needed by the ISO.

Figure 3.49 shows the availability of CPUC-jurisdictional utility demand response capacity from August 14 to August 18, and September 5 to September 6, compared to total resource adequacy credits in respective months. Figure 3.49 also shows the real-time schedules of ISO-integrated utility demand response capacity (both proxy demand response and reliability demand response). Program availability is based on daily reports submitted by utilities to the ISO and demand response programs bid into the ISO markets. The higher of availability reflected in daily operational reports and bid capacity is reflected in Figure 3.49 to account for some demand response capacity that may not be integrated into the ISO market but can be activated by IOUs at the direction of the ISO.⁴²

Figure 3.49 CPUC-jurisdictional demand response availability and resource adequacy credits



The demand response credits under CPUC-jurisdictional IOUs that represent the CPUC’s 15 percent planning reserve margin (193 MW in August) is never physically available to the ISO. Even after accounting for the planning reserve margin adder, the availability of CPUC-jurisdictional utility demand response capacity fell short of the amount of system resource adequacy capacity credits that these programs were counted for. This shortfall was particularly significant in hours ending 19 and 20 when net loads were the highest on the ISO system. This trend appears to reflect that the underlying load profiles of these demand programs tend to drop off in peak net load hours. Some utility demand response programs are also unavailable on weekends and holidays, which accounted for the drop in utility demand response capacity available on August 15 and August 16.

⁴² Bid capacity includes real-time bids, plus any capacity bid into the day-ahead market which was not scheduled or not re-bid into real-time. While available capacity may include some demand response capacity that is not integrated in the ISO market, real-time schedules shown in Figure 3.49 are limited to demand response resources which are integrated in the ISO market.

On August 14, available CPUC-jurisdictional utility demand response fell short of resource adequacy credits (without the planning reserve margin adder) by 230 to 240 MW in hours 19 and 20. On August 15, available CPUC-jurisdictional utility demand response fell short of resource adequacy credits (without the planning reserve margin adder) by 350 to 370 MW in hours ending 19 and 20.

While utility demand response programs were not available up to credited capacity, nearly all available IOU demand response capacity was dispatched by the ISO either by the market or by manual dispatch across peak net load hours on August 14 and 15. DMM is continuing to review the self-reported performance, or self-reported load curtailment, of demand response resources in this timeframe.

Demand response capacity under the jurisdiction of non-CPUC local regulatory authorities also accounted for an additional 122 MW of demand response system resource adequacy credits in August. These programs are not directly integrated in the ISO market, nor does the ISO have a process to be informed of the availability of these demand response programs as they do with CPUC-jurisdictional utility programs. DMM understands that the ISO is working with these local regulatory authorities to develop processes similar to those that exist with CPUC-jurisdictional utilities in order to be able to call on these demand response programs when needed.

Non-resource adequacy demand response programs

Some third-party demand response programs that do not provide resource adequacy also participate in the ISO market. These programs do not receive capacity payments or count towards resource adequacy credits. However, participation from these types of programs was limited on high load days in August and September. These programs were dispatched to deliver less than 1 MW of load reduction across peak net load hours on these days.

Reliability demand response resources

From August 14 to August 18, ISO operators activated between 820 and 975 megawatts of reliability demand response resources (RDRR) during peak net load hours. In several hours, the ISO operators activated available RDRR out-of-market similar to exceptional dispatch instructions. RDRR resources represent CPUC-jurisdictional demand response programs that can be called by the ISO under emergency conditions.

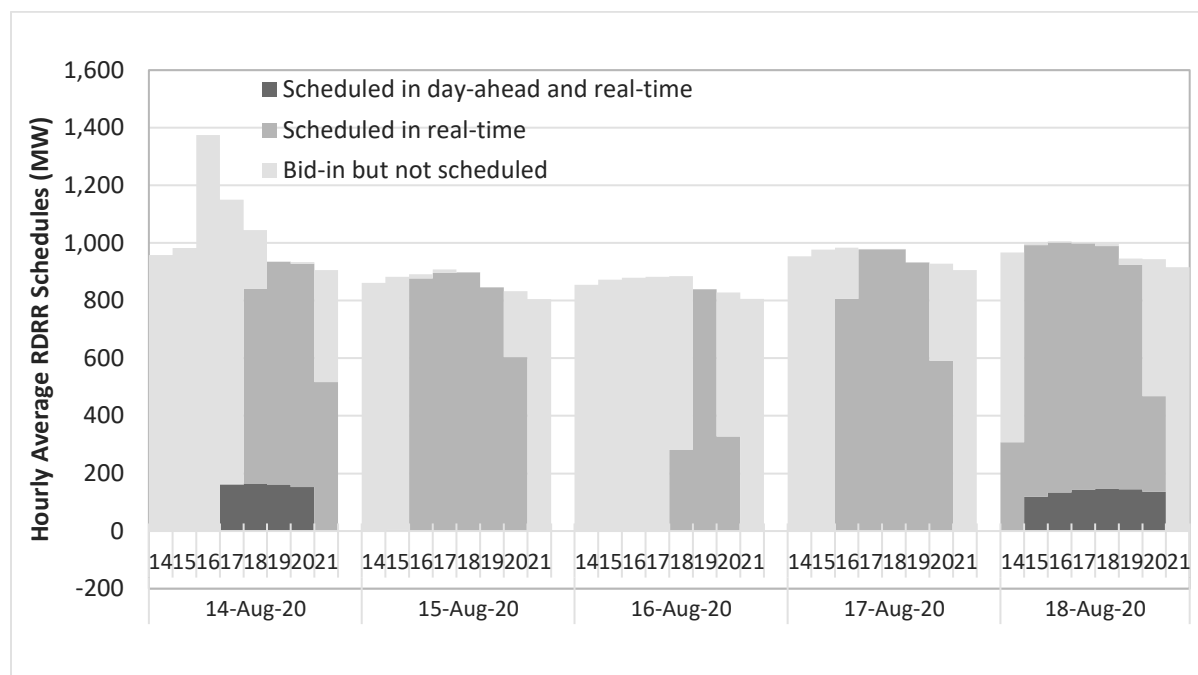
The bulk of the RDRR was dispatched in real-time.⁴³ RDRR resources have minimum bids of \$950 per megawatt hour. Because RDRRs were manually dispatched in many hours, they were often dispatched when prices were well below \$950 and RDRRs received significant bid cost recovery payments. Of the total \$8.6 million in real-time bid cost recovery payments between August 14 and August 18, \$4.8 million was paid to RDRRs.^{44, 45}

⁴³ The ISO is looking into why the real-time dispatch recognized the RDRR instructions but the fifteen-minute market did not.

⁴⁴ Day-ahead bid cost recovery payments during this period were negligible at less than \$100,000.

⁴⁵ Most of the rest of the real-time payments went to: resources exceptionally dispatched before the start of their day-ahead schedules such that commitment costs were incurred in real-time but most of the revenues from higher priced hours were from the day-ahead market; and to a lesser extent resources with real-time schedules below their day-ahead while prices exceeded offer prices.

Figure 3.50 Hourly average reliability demand response resource schedules by market



Recommendations for enhancing the treatment of demand response as capacity

There are several enhancements that the ISO and local regulatory authorities could consider to enhance the reliability of both demand response resources shown on resource adequacy supply plans and utility demand response programs. Demand response programs which are either compensated for or credited towards meeting resource adequacy requirements should be expected to curtail load before firm load is curtailed.

DMM recommends that the ISO and CPUC consider the following enhancements for supply plan demand response resources:

1. The ISO should be able to manually dispatch supply plan demand response before needing to resort to exceptional dispatch of non-resource adequacy capacity and firm load curtailment. The ISO has the ability to manually dispatch utility demand response and did so on high load days in August and September. However, there were no exceptional dispatches issued to supply plan demand response on these days.
2. Consider removing the exemption for long-start proxy demand response to be available in the residual unit commitment process. This exemption does not exist for other types of long-start resources providing resource adequacy.
3. Continue to review why demand response resources in the same sub-lap continue to be sized less than 1 MW. Consider applying RAAIM to demand response resource adequacy capacity at the demand response provider and sub-lap level rather than the resource level to ensure this capacity remains exposed to resource adequacy availability incentives.

4. Consider revising DRAM contract provisions to ensure that demand response that is available and receiving capacity payments can be activated before firm load is curtailed even if this is outside of availability assessment hours.

DMM recommends that the ISO and local regulatory authorities consider the following enhancements for utility demand response programs:

1. Continue efforts between the ISO and CPUC to better reflect the availability of demand response programs with variable load in capacity values.
2. Adopt the ISO's recommendation to remove the 15 percent planning reserve margin adder applied to utility demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction. In CPUC's recent Track 2 resource adequacy proceeding, the ISO recommended that the planning reserve margin adder applied to demand response capacity which is credited toward system resource adequacy supply obligations be removed.⁴⁶ Though this provision was not adopted, DMM supports the ISO's recommendation. The capacity reflected by the planning reserve margin adder cannot be utilized by the ISO, yet counts as supply towards meeting system resource adequacy obligations.
3. Ensure that non-CPUC jurisdictional load serving entities that schedule for demand response programs used to meet resource adequacy requirements communicate the capacity available from these programs to the ISO on a daily basis so that this capacity can be considered and called by the ISO when needed.

3.14 Competitiveness

3.14.1 Structural measures of market power

Market structure refers to the ownership of available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the *pivotal supplier test* and the *residual supply index*. Both of these measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test.** If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.
- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand. A residual supply index less than 1.0 indicates an uncompetitive level of supply.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. The potential for such behavior is high in the

⁴⁶ *California Independent System Operator Corporation Consolidated Comments on all Workshops and Proposals*, R.19-11-009, March 23, 2020, pp. 10-11: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M330/K052/330052136.PDF>

electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI1. With the two or three largest suppliers excluded, we refer to these results as RSI2 and RSI3, respectively. The residual supply index analysis includes the following elements for accounting for supply and demand:

- Day-ahead market bids for physical generating resources (adjusted for outages and de-rates).
- Using the day-ahead load forecast as demand in combination with upward ancillary service requirements and self-scheduled exports.
- Transmission losses were not explicitly added to demand. The day-ahead load forecast already factors in losses. This reflects a change from prior DMM analyses.
- Including ancillary services bids in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market.
- Exclusion of CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers.
- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- As in prior DMM analyses, virtual bids are excluded.

Results of this analysis for August and September are shown in Figure 3.51 and Figure 3.52. The assumptions listed above represent what DMM believes are the most appropriate supply and demand inputs. As shown in these figures, there were many hours with RSI1, RSI2, and RSI3 less than 1 during the heatwaves. For August and September alone, the residual supply index with the three largest suppliers removed (RSI3) was less than one during 256 hours. In comparison, there were 111 hours with RSI3 less than one during all of 2019, and 269 hours with RSI3 less than one during all of 2018.

With the largest two suppliers removed (RSI2), the residual supply index for August and September was less than one in 185 hours. With the largest supplier removed (RSI1), it was less than one in 88 hours.

Figure 3.53 shows the lowest 300 RSI values during August and September. Extremely low RSI values (at the bottom of the curve) can instead indicate scarcity conditions. During this period, calculated supply was less than demand in 22 hours. However, other hours shown in this figure with RSI less than one reflects potentially non-competitive conditions. With the three largest suppliers removed, the RSI was less than 0.9 in 136 hours, and less than 0.8 in 43 hours.

Figure 3.51 Hours with residual supply index less than one by day (August)

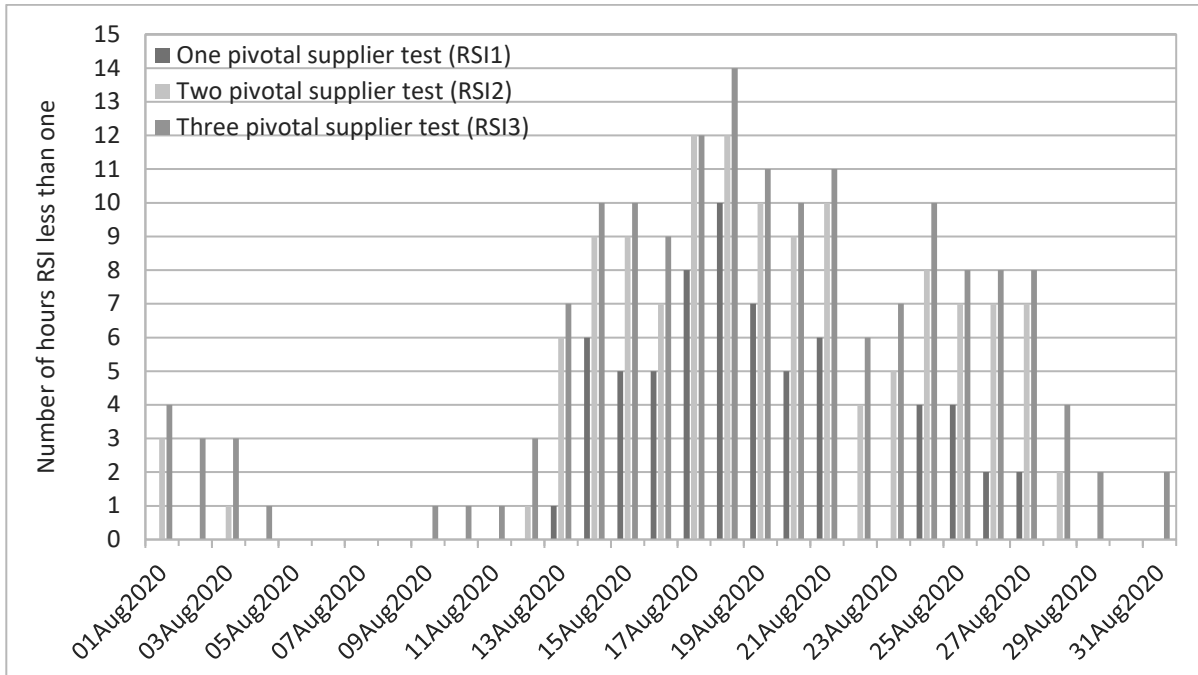


Figure 3.52 Hours with Residual supply index less than one by day (September)

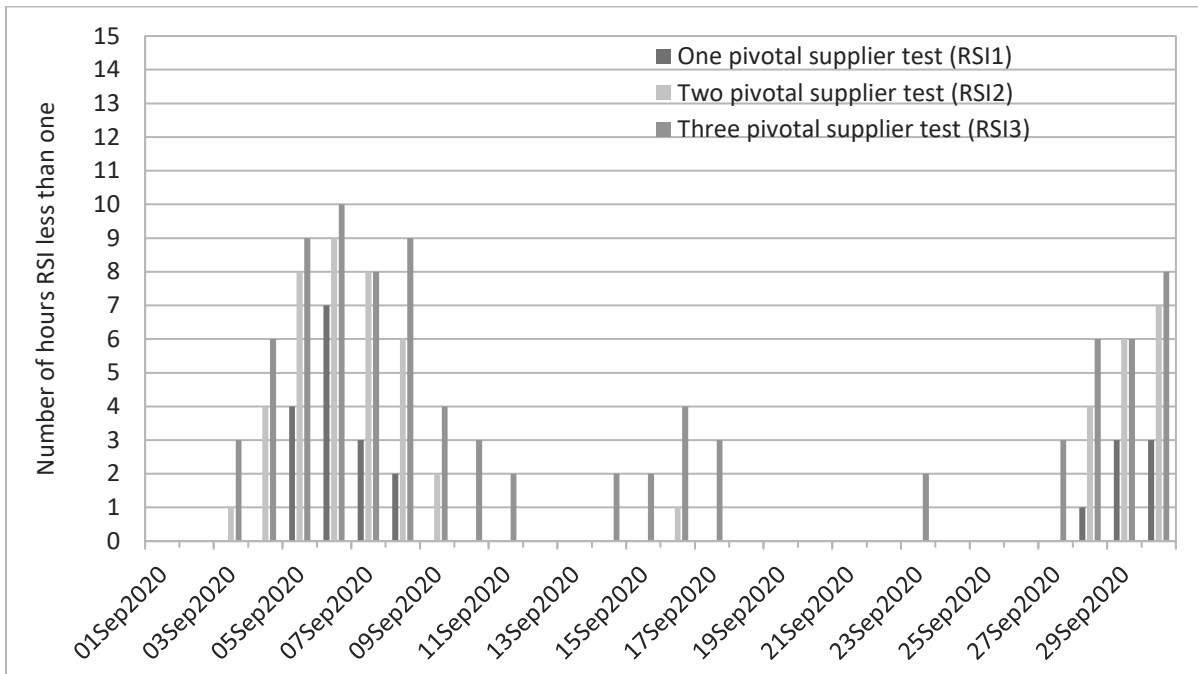
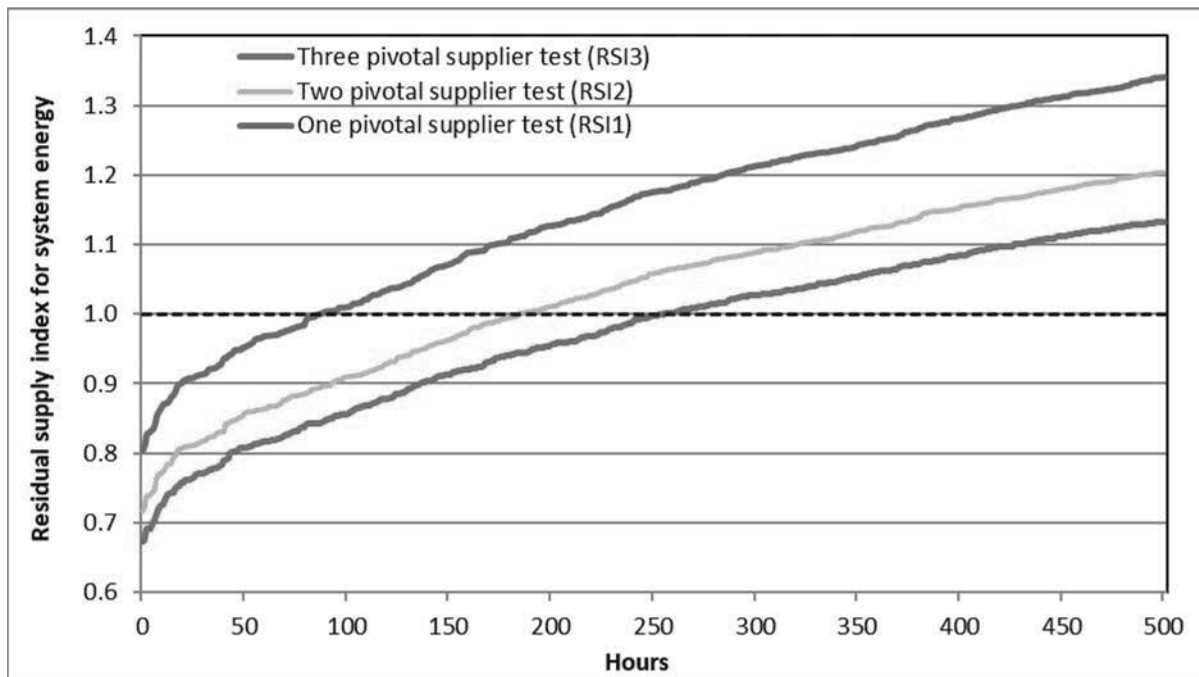


Figure 3.53 Lowest 300 residual supply index with largest one, two, or three suppliers excluded (August – September 2020)



3.14.2 Competitiveness of day-ahead market prices

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to *competitive benchmark prices* we estimate would result under highly competitive conditions. DMM estimates competitive benchmark prices by re-simulating the market after replacing bids or other market inputs using DMM’s version of the actual market software.

Day-ahead market simulation results show that market prices generally did not exceed these competitive benchmark prices during the heat wave period of August 14 to 19. Replacing high priced energy bids with cost-based bids did not result in lower prices since these high priced bids were often infra-marginal in high price hours, so system wide mitigation of imports and gas-fired resources during this period would not have lowered prices. This reflects the fact that gas-fired and other resources that may be subject to mitigation were generally infra-marginal in re-runs of the day-ahead market using cost-based bids, and that high prices were set by demand response and other resources not subject to mitigation.

The competitive benchmark prices were calculated by rerunning day-ahead market simulations under the following scenarios:

1. **Scenario 1:** Replace market bids of gas-fired units with the lower of their submitted bids or their default energy bids (DEBs), to capture the effect of competitive bidding of energy by gas resources
2. **Scenario 2:** In addition to inputs for Scenario 1, replace bid-in commitment costs (start-up, transition, and minimum load) of gas-fired units with the lower of their submitted bids or 110

percent of their proxy cost, to capture the effect of competitive bidding of commitment costs by gas resources

3. **Scenario 3:** In addition to inputs for Scenario 1, replace bids for import resources with the lower of their submitted bids or an estimated default energy bid based on a generous opportunity cost default energy bid option offered by the ISO (the hydro DEB), to capture the potential effect of uncompetitive bidding of imports

Each market simulation run is preceded by a base case rerun with all of the same inputs as the original market run before completing the benchmark simulation, to screen for accuracy. The price-cost markup is calculated as the difference between load-weighted average scenario prices compared to load-weighted average prices from this base case rerun.

As shown in Table 3.2, average hourly scenario prices are very similar to actual market results when comparing with the scenarios where bids for gas-fired resources are set to the minimum of the submitted bid or the default energy bid, bids for gas-fired resources’ commitment costs are set to the minimum of the bid or 110 percent of proxy cost, and import bids are set to the minimum of the bid or an estimated hydro default energy bid.

As shown in Figure 3.54, on average, prices in the combined competitive scenario (blue line) were higher than the average base case price (green line) in peak hours in SCE and SDG&E where average prices were close to \$1,000/MWh. Competitive scenario prices were lower in PG&E in peak hours, with competitive scenario prices over \$100/MWh less in hours 19 and 20 when base case and market prices were over \$600/MWh. On a load-weighted average basis the price cost markup across all hours and areas was low (3 percent or \$5.67).

Figure 3.54 Average hourly price results for day-ahead market re-run with cost-based bids for gas resources and opportunity cost-based bids for imports (Aug 14-19)

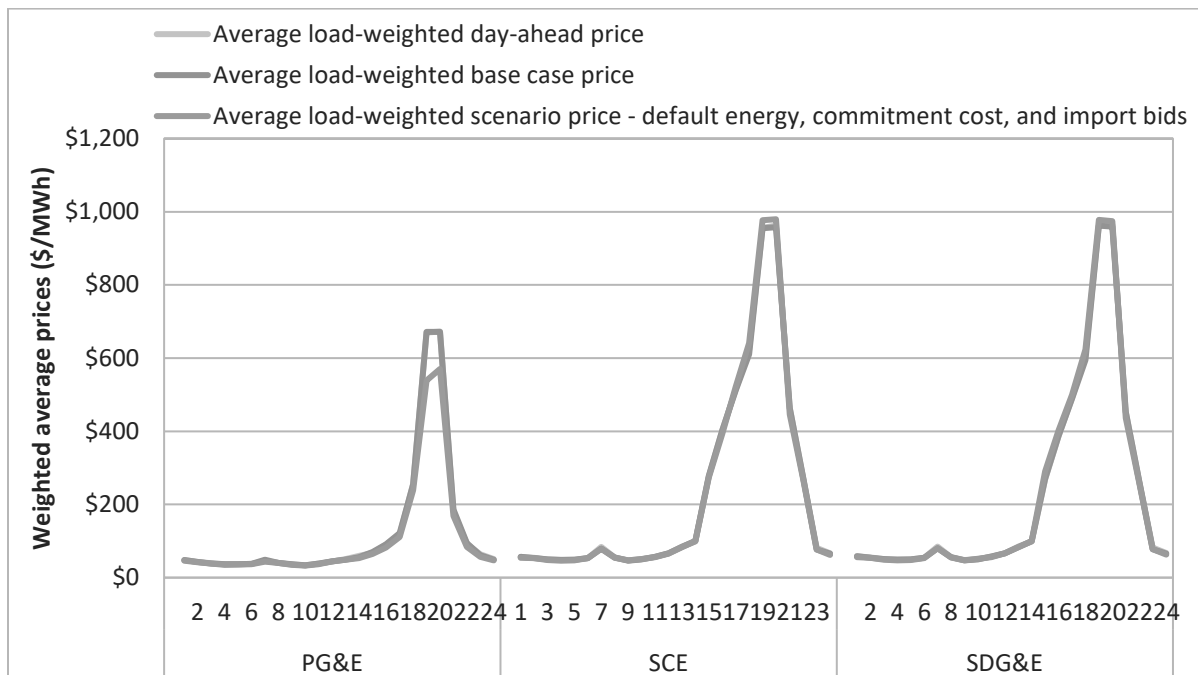


Table 3.2 Price-cost markup by scenario (Aug 14 – Aug 19)

Scenario	Load-wtd avg day-ahead prices	Load-wtd avg base case prices	Load-wtd avg scenario prices	Price-cost markup (\$/MWh)	Price-cost markup (%)
Gas resources at min(bid,DEB)	\$217	\$216	\$214	\$2.32	1%
Commitment costs for gas resources at min(bid,110% proxy)	\$217	\$216	\$218	-\$1.17	-1%
Import bids at min(bid,hydro DEB)	\$217	\$216	\$217	-\$0.58	0%
Energy and commitment cost bids capped for gas resources, imports capped	\$217	\$216	\$211	\$5.67	3%

4 Recommendations

DMM agrees with many of the key recommendations related to resource adequacy in the joint CAISO/CPUC/CEC report and supports the coordinated efforts by the CAISO, CPUC and stakeholders to make the planning, market design and operational enhancements identified in that report. The most significant and actionable of these recommendations involve California's resource adequacy program. To limit the potential for similar conditions in future years, a high priority should be placed on the following two recommendations:

- **Increase resource adequacy requirements to more accurately reflect increasing risk of extreme weather events** (e.g. beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system resource adequacy targets). Prior to this summer, CAISO peak load fell under the 1-in-2 years forecast four of the last five years.⁴⁷ However, summer 2020 illustrates that higher reliability will require that resource adequacy requirements be based on load forecasts which reflect the high likelihood of much higher load conditions than are reflected in the 1-in-2 year forecast.
- **Continue to work with stakeholders to clarify and revise the resource adequacy capacity counting rules**, especially as they apply to hydro resources, demand response resources, renewable resources, imports and other use limited resources. Counting rules should specifically take into account the availability of different resource types during the net load peak. Beginning in 2019, DMM has provided analysis and expressed concern in reports and CPUC filings about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements.⁴⁸ This report includes additional analysis of the availability of different resource types during the peak net load hour in which load was curtailed in August, and highlights a variety of specific factors which could be incorporated into the resource adequacy ratings of these resources to better reflect their actual availability during the most critical net load peak hours.

In addition, DMM provides a third major recommendation regarding the issue of how exports are treated in the day-ahead real-time markets.

DMM recommends that further changes and clarifications in the rules and processes for limiting or curtailing exports be discussed and pursued by the CAISO in conjunction with other balancing areas.

The CAISO/CPUC/CEC report includes the following recommendation regarding curtailment of exports:

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.⁴⁹

⁴⁷ 2019 Annual Report on Market Issues and Performance, Department of Market Monitoring, June 2020, pp.34-35. <http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf>

⁴⁸ 2019 Annual Report on Market Issues and Performance, pp. 26-27, 299-302.

Reply Comments of the Department of Market Monitoring, Rulemaking 16-02-007, August 12, 2019, [http://www.caiso.com/Documents/CPUC-](http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf)

[DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf](http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf)

⁴⁹ CAISO/CPUC/CEC Report, p. 66.

During the mid-August and Labor Day weekend heatwaves, the ISO made important enhancements to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards. DMM supported these changes and believes that these changes played a key role in helping to improve real-time supply conditions on September 5 to 7.

DMM's understanding is that CAISO's current policy is still to prioritize exports that receive RUC awards over native CAISO balancing area load in real-time. DMM appreciates that curtailment of exports should be avoided when possible, given the potentially detrimental direct and indirect impacts of export curtailment on other balancing areas and the CAISO itself, as discussed in the CAISO/CPUC/CEC report.⁵⁰ However, DMM believes that additional changes and clarifications to the residual unit commitment rules and other market processes are needed to address the issue of exports.

The rules and processes for curtailment of exports by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas. CAISO and other WECC balancing areas' ultimate policy on how they will prioritize exports relative to native load will be a critical factor in CPUC resource adequacy reforms and many major CAISO market design initiatives such as the extended day-ahead market, day-ahead market enhancements, system market power mitigation phase 2, resource adequacy enhancements, scarcity pricing, and refinements to export bidding rules.

More discussion of residual unit commitment enhancements and the need to clarify, and potentially refine, how CAISO and other balancing areas treat exports is provided below.

Residual unit commitment process

DMM supports the changes made to the residual unit commitment process which limit export schedules clearing the day-ahead energy market that are passed into the real-time market based on the quantity of exports supported by physical capacity.

Because the results of clearing all generation, load and other financial bids in the day-ahead market are not guaranteed to create resource commitments that can feasibly meet real-time load forecasts, ISOs/RTOs run supplementary reliability processes. In the California ISO this reliability process is called the Residual Unit Commitment (RUC). The RUC process should ensure that meeting the load forecast is feasible if it has sufficient resources to select from.

California's resource adequacy program is meant to ensure sufficient resources to meet load under most circumstances. If both the resource adequacy program and RUC process function as intended – to procure sufficient capacity – then meeting the real-time load forecast will be feasible regardless of how much load underschedules relative to its forecast, and regardless of how much virtual supply or exports clear in the integrated forward energy market. During the August heat waves, the ISO discovered that the RUC implementation was causing this critical backup reliability process to not function as intended.

Prior to September 5, RUC was implemented to allow exports that had received energy market awards to still receive RUC awards even when there was not enough supply to meet the CAISO balancing area load forecast. DMM's understanding is that CAISO's policy was to prioritize exports that receive RUC awards over native CAISO balancing area load in real-time. Therefore, this RUC implementation issue contributed to decreasing the reliability of CAISO balancing area native load.

⁵⁰ CAISO/CPUC/CEC Report, pp. 106-107.

Prior to September 5, any export that cleared the day-ahead market, such as the almost 3,000 MWs of exports that cleared during hour ending 19 on August 14 that were not wheels and not contracted to non-RA CAISO generation, was also given a higher scheduling priority than CAISO balancing area load by the real-time market. This could also have impacted reliability because cuts to export schedules in advisory runs of the real-time market could give CAISO operators advance warning to begin working with other balancing areas on whether or not CAISO native load or exports out of CAISO may need to be cut.

On September 5, the ISO made important enhancements to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards. RUC was adjusted to consistently reduce the RUC awards of exports not backed by contracts with specific generators when there was not enough physical supply to meet the CAISO load forecast. Export scheduling priorities were enhanced to only give exports that received RUC awards a higher scheduling priority than CAISO native load in the real-time markets.

DMM supports the enhancements to the residual unit commitment process and the real-time scheduling priority of day-ahead energy market exports made by the ISO on September 5. However, DMM's understanding is that CAISO's current policy is still for both operators and the real-time market to prioritize exports that receive RUC awards over native CAISO balancing area load. As explained in the following recommendation in this report, DMM recommends CAISO review the prioritization that other WECC balancing areas give to exports that marketers schedule out of their areas in the day-ahead time frame and that CAISO work with these balancing areas and other stakeholders to clarify and potentially refine how CAISO prioritizes exports. As part of this process, the ISO should consider potential changes to export bidding rules and scheduling priorities in both the day-ahead market and RUC process.

Export scheduling and prioritization relative to CAISO balancing area native load

The rules and process for curtailment of exports by the CAISO and other balancing areas should be reviewed, clarified, and potentially modified -- with a goal of establishing equal treatment and expectations of exports by all balancing areas.

As highlighted in this report, exports scheduled in the day-ahead market can significantly increase the overall demand that must be met by available supply in the CAISO day-ahead and real-time markets. DMM understands that limiting exports in the day-ahead market or curtailment of exports after the day-ahead market involves a wide range of operational and market considerations. Due to the interdependence of different control areas, curtailment of exports can have potential adverse impacts to other balancing areas as well the balancing area from which exports may be curtailed.

However, DMM believes that experience during the summer 2020 heatwave highlights the need to review and potentially modify rules and processes for curtailment of exports by the CAISO, as well as other balancing areas in the west. DMM recommends a much more detailed discussion of this very important issue which includes balancing areas across the west, with a goal of establishing equal treatment and expectations of exports by all balancing areas. DMM believes this discussion is particularly relevant to efforts to design a regional extended day-ahead market and discussions of developing more formal resource adequacy programs in other balancing areas across the west.

The sections below provide some initial discussion and recommendations on this issue.

Exports backed by specific resources

The CAISO already offers a scheduling feature which allows scheduling coordinators to explicitly link specific exports to energy from non-resource adequacy capacity in the CAISO. These exports are afforded a very high scheduling priority, equivalent to internal CAISO load. As discussed in this report, only a very small volume of exports are explicitly supported by non-resource adequacy capacity.

DMM has been recommending that exports from other balancing areas supporting resource adequacy imports into the CAISO be afforded this same scheduling priority. Specifically, DMM has recommended that “to ensure that external supply is truly dedicated to the ISO, particularly when other BAAs also face supply shortages, the ISO should ensure that BAAs cannot recall or curtail energy backing resource adequacy imports ...”⁵¹ Based on a benchmark with other RTOs, DMM understands that this is how all other RTO markets with resource adequacy or capacity markets work.⁵² To date, the CAISO has not adopted this recommendation, although CAISO has stated that it “seeks to adopt similar types of requirements for RA imports to the CAISO *to the extent practicable*” (emphasis added).⁵³

Adopting DMM’s recommendation for resource adequacy imports would still not provide totally uniform rules across the CAISO and other balancing areas. If adopted, the requirement suggested by DMM would only be applicable to exports from other balancing areas which are specifically identified in advance as being responsible for supporting resource adequacy imports. Meanwhile, current CAISO rules allow scheduling coordinators to schedule exports which are backed by any non-resource adequacy capacity on a daily and even hourly basis without any other advance notice or contractual agreement.

Exports not backed by specific resources

As explained in the residual unit commitment section above, on September 5 the ISO made important enhancements to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards.

However, DMM’s understanding is that CAISO’s current policy is still for both operators and the real-time market to prioritize exports not backed by specific resources, but that receive RUC awards, over native CAISO balancing area load. It is also DMM’s understanding that CAISO’s approach differs from how exports are treated in other RTO markets, and it is unclear how the CAISO’s rules and procedures compare to those of other balancing areas in the west.

There could still be uncertainty in generation availability and inflexible load between the day-ahead processes and real-time. That is why other RTOs and other balancing areas in the west may have emergency procedures to curtail some scheduled exports that clear their day-ahead processes before curtailing their native load.

CAISO’s policy exposes its balancing area to the risk of cutting native load when conditions change between the day-ahead time frame and real-time, and when there would have been sufficient resource adequacy capacity to avoid cutting CAISO native load if CAISO hadn’t committed capacity to exporters in

⁵¹ *Comments on Resource Adequacy Enhancements Working Group on September 15 and 17, October 1, 2020*, p. 4. <http://www.caiso.com/Documents/DMMComments-ResourceAdequacyEnhancementsWorkingGroupSept15and17-Oct12020.pdf>

⁵² *Comments on Resource Adequacy Enhancements Revised Straw Proposal, July 24, 2019* pp 5-9. <http://www.caiso.com/Documents/DMMComments-ResourceAdequacyEnhancements-RevisedStrawProposal.pdf>

⁵³ *Resource Adequacy Enhancements Fifth Revised Straw Proposal, CAISO, July 7, 2020*, p. 70. <http://www.caiso.com/InitiativeDocuments/FifthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf>

the day-ahead market time-frame. As described above, DMM understands that curtailment of exports after the day-ahead market involves a wide range of operational and market considerations. So any policy of curtailing exports with RUC awards not backed by specific capacity should obviously only be implemented after working carefully through all the issues with the western reliability coordinators, balancing areas, and other stakeholders and ensuring that the policy aligns with the export curtailment policies of other western balancing areas.

Prior to the August heat wave, the CAISO tariff and business practice manuals described day-ahead market exports not supported by specific generation being clearly prioritized below CAISO load in real-time.⁵⁴ Therefore, it was DMM's understanding that CAISO already had such a carefully defined process in place. Now, it is DMM's understanding that CAISO may not have such a procedure and that its policy may not be aligned with export curtailment policies of other western balancing areas. As a result, DMM recommends a much more detailed discussion of this very important issue which includes balancing areas across the west, with a goal of establishing equal treatment and expectations of exports by all balancing areas.

The CAISO and other WECC balancing areas' ultimate policy on how they will prioritize exports relative to native load will be a critical factor in CPUC resource adequacy reforms and many major CAISO market design initiatives such as the extended day-ahead market, day-ahead market enhancements, system market power mitigation phase 2, resource adequacy enhancements, scarcity pricing, and refinements to export bidding rules.

Finally, DMM provides the following recommendation regarding demand response.

DMM recommends that steps be taken to ensure a higher portion of demand response used to meet resource adequacy requirements is available and utilized during critical net load hours.

Analysis in this report indicates that less than two thirds of the 1,847 MW of resource adequacy capacity requirements that were met by demand response were available for dispatch in real-time during the hours of load curtailment on August 14 and August 15. The actual performance of demand response that was dispatched has not yet been fully evaluated based on retail customer meter data. However, even if performance of demand response is high relative to the amount dispatched in the CAISO market, the amount of demand response that was available relative to the amount of resource adequacy capacity requirements met by demand response was relatively low.

DMM recommends that steps be taken to ensure the availability of these resources. These steps include (1) re-examining demand response counting methodologies, (2) adopting the ISO's recommendation to remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction, and (3) adopting a process to manually dispatch available demand response shown on resource adequacy supply plans before issuing exceptional dispatches to non-resource adequacy capacity and curtailing firm load. DMM recommends that these steps be taken before expanding reliance on demand response capacity.

⁵⁴ *California Independent System Operator Corporation Fifth Replacement Electronic Tariff*, November 13, 2019, Section 34.12.1 – Increasing Supply: <http://www.caiso.com/Documents/Section34-Real-TimeMarket-asof-Nov13-2019.pdf>
BPM_for_Market Operations_V65_clean, pp. 233-5:
<https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations>