SUMMER MARKET PERFORMANCE REPORT

SEPT 2022

California ISO

November 2, 2022

The following ISO staff contributed to the analysis presented in this report

Jennie Araj

Kevin Head

Delphine Hou

Abhishek Hundiwale

Tricia Johnstone

Scott Lehman

Zhu Liang

Haifeng Liu

Amber Motley

Monique Royal

John Rudolph

Tobiah Steckel

Jessica Stewart

Michael Stewart

Rebecca Webb

Katie Wikler

Kun Zhao

Guillermo Bautista Alderete

Contents

List of Tables

List of Figures

Acronyms

AGC	Automatic Generation Control
AZPS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
Cal OES	California Office of Emergency Services
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CMRI	Customer Market Results Interface
CPUC	California Public Utilities Commission
DAM	Day ahead market
DLAP	Default Load Aggregated Point
DR	Demand Response
EEA	Energy Emergency Alert
ED	Exceptional Dispatch
EIM	Energy Imbalance Market
ELAP	EIM Load Aggregation Point
ELCC	Effective Load Carrying Capacity
EOH	End of Hour
ESP	Energy Service Provider
ETC	Existing Transmission Contract
F	Fahrenheit
FMM	Fifteen Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor-Owned Utility
IPCO	Idaho Power Company
LADWP	Los Angeles Department of Water and Power
LMP	Locational Marginal Price
LMPM	Local Market Power Mitigation
LPT	Low priority export. This is a scheduling priority assigned to price-taker exports that do not have a non-RA supporting resource
LSE	Load Serving Entity
MIBP	Maximum Import Bid Price
MSG	Multi-Stage Generator
MW	Megawatt
MWh	Megawatt-hour
NEVP	NV Energy
NGR	Non-Generating Resource
NOB	Nevada-Oregon Border
NSI	Net Scheduled Interchange
NWMT	Northwestern Energy

OASIS	Open Access Same-Time Information System
OR	Operating Reserves
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PRM	Planning Reserve Margin
PSEI	Puget Sound Energy
PST	Pacific Standard Time
PTO	Participating Transmission Owner
PT	High priority assigned to a schedule. Exports are assigned this priority when they can have a non-RA resource supporting its export
PV West	Palo Verde West
QC	Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RMO	Restricted Maintenance Operation
RSE	Resource Sufficiency Evaluation
RTM	Real-Time Market
RUC	Residual Unit Commitment
RTPT	Real-Time Price Taker
SC	Scheduling Coordinator
SCL	Seattle City Light
SIBR	Scheduling Infrastructure and Business Rules
SMEC	System Marginal Energy Component
SOC	State of Charge
SRP	Salt River Project
TIDC	Turlock Irrigation District
TOR	Transmission Ownership Right
UDC	Utility Distribution Company

Executive Summary

Introduction

From August 31 through September 9, 2022, California and much of the Western United States experienced record-setting heat resulting in all-time high demand for electricity across the region (September 2022 heat wave). The prolonged heat event precipitated an unprecedented number of calls for consumer conservation. This included 10 consecutive days of voluntary Flex Alerts and new state programs that provided non-market resources to address extreme events culminating on September 6, the only day when the ISO system reached its highest emergency alert level.

Despite the sustained heat wave and unprecedented load levels, the California Independent System Operator (ISO) did not order rotating outages and maintained reliable system operations at all times. This would not have been possible without the significant mobilization of new generating resources and the enhanced communication and coordination between the ISO, state and federal agencies, and industry that have occurred over the past two years. At the same time, the ISO's analysis of the event reveals several issues that led to unintended consequences that impacted specific components of the market. The ISO is addressing those issues in a transparent and rigorous fashion and they are discussed in detail later in this report.

The ISO has been publishing its monthly Summer Market Performance Reports since June 2021 and this final publication for summer 2022 includes an in-depth analysis of the September 2022 heat wave, with particular focus on September 5 through 8, which were some of the most challenging days in the history of the ISO's electrical grid. In this analysis, the ISO focuses on factors that enabled it to maintain reliability throughout the event, including an unprecedented level of coordination and public conservation. At the same time, the report identifies additional software improvements that are needed, especially for the clearing of exports and the resource sufficiency test used in the Western Energy Imbalance Market (WEIM). Lastly, the report covers a wide range of topics regarding resource and market performance during the extreme heat event and throughout the month of September.

The Heat Wave and Its Impacts

There have been other extreme heat events in recent years that caused stressed conditions for the ISO grid, but the grid has never faced anything like the September 2022 heat wave. With historic high maximum and minimum temperatures in many parts of California, demand on the ISO grid reached a new instantaneous gross peak record load of 52,061 megawatts (MW) on September 6 at 4:58 p.m. System demand had exceeded 50,000 MW on the ISO grid only twice before—on July 24, 2006 and September 7, 2017. The ISO observed the highest ever hourly average load of 51,479 MW on September 6, 2022, and demand within the Reliability Coordinator footprint in the West also saw record load that day of 130,920 MW.

After the gross peak, the ISO faces its period of maximum stress on the grid because the sun is setting, reducing solar production to zero, even as demand remains high, largely due to air conditioning use. This period is known as the net load peak. Although the ISO regularly operates successfully through the net load peak, the intense heat wave meant that temperatures did not cool down overnight as they usually do and air conditioning load was abnormally high. On September 6, the ISO's net load peak was 45,141 MW at 6:58 p.m.

Although there are several ways to contextualize how the severity of the 10-day heat wave drove this record level of demand, nothing illustrates it better than some of the record high temperatures seen around California and the West. On September 6, Downtown Sacramento reached 116° Fahrenheit (F), an all-time high; Livermore hit 116° F on September 5 and 6, the hottest temperature ever recorded there. Riverside had its warmest 5-day and 10-day mean maximum temperatures for the period ending September 5 and 6, respectively. From August 31 through September 9, 2022, the ISO's system saw maximum daily temperatures 5-15° F above normal, with some cities experiencing maximum temperatures of up to 30° F above normal. In addition to the maximum temperature records broken, 17 all-time minimum high temperature records, 134 September monthly minimum high temperature records and 773 daily minimum high temperature records were tied or broken. More detailed weather data is highlighted in Section 2 and Appendix A.

Maintaining Reliability through an Unprecedented Heat Wave

Despite the sustained heat wave and record-breaking load levels, the ISO never ordered rotating outages. It maintained system reliability throughout the 10-day event due to multiple factors:

1. **Increased capacity through resource adequacy procurement** since summer 2020, including more than 3,500 MW of lithium-ion battery storage (Section 9);
2. **Enhanced coordination, awareness, and communications** internally, and with neighboring balancing authority areas, including those participating in the WEIM, external stakeholders such as business and customer groups, investor-owned and publicly-owned utilities, state agencies including the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC), and the Governor's Office (Section 9.2);
3. **Market enhancements developed and implemented over the past two years**, including clarification of scheduling priorities, enhancements to resource sufficiency evaluations and electricity market pricing designed to incentivize generation during periods of high demand. (Section 9);
4. **The use of new state programs to provide non-market resources to address extreme events**, as well as the California Governor's Office of Emergency Services (Cal OES) Wireless Emergency Alert urging consumers to reduce non-essential electricity use if it was safe to do so the evening of September 6. (Section 2.5 and Section 2.6);
5. **Close coordination with load-serving entities during the ISO's highest emergency alert level, an Energy Emergency Alert 3,** the afternoon of September 6 that allowed utilities to arm firm load after being notified by the ISO of the need to prepare for rotating outages, which were ultimately avoided. (Section 2.5 and Section 2.6);
6. **Geographic diversity of extreme heat across the West**, which, because the heat was not as intense or prolonged throughout the Desert Southwest or Pacific Northwest compared to California, better positioned the ISO to import power when it was most needed. This included net imports of more

than 6,500 MW during net peak on September 6 as well as an additional 1,000 MW from WEIM transfers (Section 2 and Appendix A); and

7. **The ISO both received emergency assistance energy and provided it** to other balancing authority areas experiencing stressed system conditions (Section 9.3).

Market and Resource Performance

Since 2020, efforts have been made to improve the performance of the aging thermal generation fleet. These resources were critical during the most stressed part of the heat wave; however, some of these resources still experienced high levels of unavailability during other times of the event.

As noted above, recent improvements to the ISO market positively contributed to reliability by ensuring appropriate market incentives. During the heat wave event, the ISO's daily average prices rose to $600/megawatt-hour (MWh) with maximum prices reaching $2,000/MWh in the real-time market. Day-ahead average prices reached $300/MWh. Given the impacts of the September 2022 heat wave, the average daily market costs were $100 million for the month, materially higher than the daily average market price of $84 million in August. These prices and costs were influenced by higher natural gas prices (trending up to $15/MMBTU) and higher demand levels settling at higher energy prices. Bilateral prices outside of the ISO market also increased during the heat wave. Further, these bilateral prices triggered an increase in the bid cap in the ISO's market from $1,000/MWh to $2,000/MWh during certain hours. This increase allowed for the ISO market to more accurately reflect the scarcity conditions experienced in the system and attract imports. (See Section 3.4 and Section 9.8.)

The high loads experienced during the September 2022 heat wave far exceeded the 49,748 MW of resource adequacy capacity shown to the ISO. During the September 2022 heat wave, resource adequacy capacity alone was insufficient to cover both the gross peak and the net load peak later in the day. On average, resource adequacy resources performed to their expected output, including new resources on the grid such as battery storage. The ISO market also called upon (*i.e.*, dispatched) up 1,300 MW of demand response on September 6, comprised of 500 MW of voluntary demand response bid in the market and 800 MW of emergency demand response. Actual performance based on meter data is not available until the end of the year. It is important to note that extreme heat is a challenge to resource availability. For example, thermal resources often cannot run at their maximum output, and the record dry conditions limit hydroelectric production in California and the West. Reservoir levels for California and the West are significantly below normal, with storage in major reservoirs statewide only at 54 percent of average and 32 percent of total capacity. (See Section 2, Section 3.1, and Section 9.6.)

New state programs providing non-market resources to address extreme events and conservation efforts also played a key role in supplementing the resource adequacy program to provide relief during the most critical times. Market-integrated resources are visible to the ISO optimization and can be dispatched when and where needed to reduce load on the system. On the other hand, non-market resources and conservation efforts are not visible to nor controlled by the ISO. The heat-related stress on the grid triggered 10 consecutive days of Flex Alerts, calling on consumers voluntarily to conserve their electricity usage during the evening hours. In addition, other conservation efforts were deployed this summer outside of the core resource adequacy program. Because voluntary conservation efforts and non-market resources are not visible to the ISO, the ISO can provide only an estimate of their impact on load.

Organized, programmatic efforts from a diverse set of entities including customer and business groups, local regulatory authorities, the state Legislature, and the California Governor's office, provided more than 1,200 MW of potential load reduction. Perhaps most significantly, immediately following the Cal OES Wireless Emergency Alert on September 6 at 5:45 p.m., there was a steep decline in the ISO's load. Based on the ISO's best estimates of response to the Cal OES alert, voluntary response to the Flex Alert, and other non-programmatic conservation efforts, there was approximately 1,510 MW of conservation between 6:00 p.m. and 7:00 p.m. (See Section 2.5.)

Both resource adequacy and non-resource adequacy imports were critical in providing 6,300 MW of net imports to the ISO during the net load peak on September 6. At the same time, there were about 1,000 MW of WEIM transfers into the ISO. Despite the stressed system conditions during the heat wave, the market honored all wheeling-through market transactions that enable electricity to flow through the ISO but do not serve ISO load. As an import-dependent system, it is critical that the ISO support and equitably treat exports necessary to maintain other systems' reliability. The market's awards of imports, exports, and WEIM transfers reflects a careful balance and optimization based on all the system conditions affecting the ISO and the West. (See Section 5.3 and Section 9.5.)

Areas for Improvement

Throughout most of the heat wave, the ISO's market systems and processes largely responded as designed. Scarcity conditions led to higher prices, which in turn brought additional supply into the market. Because of greater regional coordination, reciprocity, and cooperation within the market, significant amounts of imported energy were available during the most stressed grid conditions. Despite this, several factors adversely affected specific components of market functionality and led to unintended outcomes. As discussed in this report, the ISO has already addressed these issues or is in the process of addressing them. These issues include:

1. **Ensuring storage resources are appropriately charged and accounted for in ISO systems to avoid manual corrective action.** California leads the world in grid-scale battery integration and continues to evolve market rules and advanced algorithms for shaping the most efficient use of energy storage over each operating day. We continue to learn how best to integrate storage into the market, and the high prices experienced during the heat wave presented new scenarios for the ISO to learn about the complexities and challenges of managing battery state of charge. The ISO identified a software issue that resulted in storage resources not charging sufficiently early in the day. Specifically, storage resources that bid above $150/MWh to charge were not charged by the market. Despite this, ISO operators were able to position storage resources during the September 2022 heat event to meet net peak requirements by leveraging minimum state of charge market functionality that was implemented as part of a package of 2021 summer readiness enhancements. The ISO has now fixed the software issue. (See Section 9.8.)

2. **Ensuring exports are awarded based on their intended priorities.** Exports in the ISO market have different priorities ranging from those supported by economic bids to those supported by non-ISO resource adequacy resources. When the ISO market must curtail exports to ensure it can

serve ISO load, it will do so based on these priorities. During the extreme conditions of the Summer 2022 heat wave, the software unintentionally curtailed higher-priority exports (*i.e.*, those supported by non-resource adequacy resources) while allowing lower-priority exports to flow. Although the ISO largely caught and reversed the error in high-priority curtailments, it deployed a software upgrade on October 13, 2022 to ensure the appropriate export curtailment order is followed going forward. (See Section 9.5 and Section 10.); and

3. **Over and under-counting of capacity available to the ISO in the WEIM resource sufficiency evaluation.** The WEIM allows for the beneficial, economic, and efficient transfer of energy between balancing authority areas. The WEIM resource sufficiency evaluation ensures each participating balancing authority area has sufficient capacity and flexibility to serve its load needs prior to participating in the real time market. If a balancing authority fails the resource sufficiency evaluation, transfers into it from other WEIM participants are limited until the insufficiency is resolved. On September 6, the ISO failed the resource sufficiency evaluation in two instances, and transfers into the ISO were limited, but not material. This is because the transfer limits were well above the actual available transfers of 1,000 MW from the WEIM, so transfers into the ISO were not restricted. Upon further investigation, the ISO found that there was both over- and under-counting of capacity, the net impact of which would have potentially led the ISO to fail the resource sufficiency evaluation up to an additional four instances. Some over-counting resulted from the export priority issues noted above and also from the incorrect accounting of capacity of storage resources procured to meet ancillary services. The ISO has already addressed some of these issues, such as the export priority issue and over-accounting of ancillary service capacity, and it is evaluating fixes or potential enhancements for the others (See Section 9.4, Section 9.6, and Section 10.)

Conclusion

The ISO recognizes there are areas of improvement and enhancement that demand attention going forward and is addressing them as quickly and as thoroughly as possible. At the same time, it's important to focus on everything that worked well during one of the most extreme and prolonged heat events in California memory. Reliable delivery of electricity was maintained throughout the event due to unprecedented levels of regional, state and federal, coordination; robust advance planning; utilization of both market and non-market resources; integration of new capacity, including the highly effective use of recently added lithium-ion batteries; and conservation. As we continue to integrate new resources onto the grid and make other necessary adjustments, our experience and lessons learned during the September 2022 heat wave will help us navigate the next climate-driven challenge.

1 Background

In mid-August 2020, a historical heat wave affected the western United States, resulting in energy supply shortages that required two rotating power outages in the ISO balancing authority area (BAA) on August 14 and 15, 2020. The heat wave extended through August 19. ISO declared Stage emergencies for August 17 and 18 but avoided rotating outages. Over the 2020 Labor Day weekend, California experienced another heat wave and again the ISO avoided rotating outages.

In a joint effort, the California Public Utilities Commission, the California Energy Commission and the ISO initiated an analysis of the causes for the rotating outages. The findings were documented in the Final Root Cause Analysis report.[1]

That analysis found three major causal factors contributing to the rotating outages of August 14 and 15, 2020,

1. The extreme heat wave experienced in mid-August 2020 was a 1-in-30 year weather event in California and resulted in higher loads that exceeded RA and planning targets. This weather event extended across the Western United States, impacting loads in other balancing authority areas (BAA) and straining supply across the West.

2. In transitioning to a reliable, clean, and affordable resource mix, resource-planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand for both the gross and net load (gross peak of demand less solar and wind production) peaks.

3. Some existing practices in the day-ahead energy market at that time exacerbated the supply challenges under highly stressed conditions.

Effective September 5, 2020, while still facing high-load conditions, the ISO identified one area of improvement to existing market practices regarding the treatment of export priorities. The ISO made an emergency business practice manual change to address this issue. The first part of the change was to use the intertie schedules derived from the scheduling run, instead of the pricing run, in the reliability unit commitment (RUC) process to more accurately reflect the feasible export schedules coming from the day-ahead market (DAM). These schedules serve as a reference for E-tagging. The second part of the change was to use the RUC schedules, instead of the integrated forward market (IFM) schedules, in determining the day-ahead priority utilized in the RTM for exports being self-scheduled. Prior to this change, any export cleared in the IFM market received a day-ahead priority in the RTM up to the cleared IFM schedule. With the change, exports cleared in the DAM receive a day-ahead priority up to the cleared schedule in the RUC process. After the implementation of the export priorities in August 2021, the practice of using RUC schedules as the reference for feasible export schedules remains in place.

[1] California Independent System Operator, California Public Utilities Commission, and California Energy Commission. Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave. January 13, 2021. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

Following the publication of the Final Joint Root Cause Analysis, the ISO initiated an effort to identify issues, discuss them with market participants, and propose enhancements across different areas of the market practices. This effort was initiated with educational workshops to give everyone the same level of understanding of existing market practices and their implications. This was followed by the formal launch of the Market Enhancements for summer 2021 Readiness initiative[2].

The summer 2021 enhancements included:

1. Load, export and wheeling priorities
2. Import market incentives during tight system conditions
3. Real-time scarcity pricing enhancements
4. Reliability demand response dispatch and real-time price impacts
5. Additional publication of intertie schedules
6. Addition of uncertainty component to the WEIM resource capacity test
7. Management of storage resources during tight system conditions
8. Interconnection process enhancements
9. New displays in Today's outlook for projected conditions seven days in advance

These enhancements were implemented at different times during summer 2021. For the summer 2022, the following enhancements continue to be in place:

1. Import market incentives during tight system conditions
2. Real-time scarcity pricing enhancements
3. Reliability demand response dispatch and real-time price impacts
4. Additional publication of intertie schedules
5. Management of storage resources during tight system conditions
6. Interconnection process enhancements
7. New displays in Today's outlook for projected conditions seven days in advance

After the assessment of the performance of the capacity test, the enhancement to include the uncertainty requirement in the capacity test was disabled from the production system effective February 15, 2022[3].

Furthermore, as early as July 2021 ISO started the second phase of the Transmission service and market scheduling priorities with the aim at developing a long-term, holistic, framework for establishing scheduling priorities in the ISO market. Given the limited time available to develop this policy and how soon it could be implemented to be ready for summer 2022, ISO filed at FERC to extend the scheduling priorities phase 1 policy until 2024 while still working on finalizing the second phase of the policy initiative.

Finally, ISO implemented several additional enhancements in preparation for summer 2022; these include:

[2] The policy initiative material can be found at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness

[3] Market notice about the suspension of the net load uncertainty adder can be found at http://www.caiso.com/Documents/Update-WEIM-Resource-Sufficiency-Evaluation-Suspension-Net-Load-Uncertainty-Adder-from-Capacity-Test-Effect-021522.html

1. Enhancements to the WEIM resource sufficiency test. These include changes to the logic of the capacity test to improve the accounting of the supply available in real-time. This also include the consideration of the supply infeasibilities projected in the RTM into the flexible ramping test.
2. Further visibility to non-RA capacity for resources supporting exports. This includes notifications when high priority exports schedule exceeds the non-RA capacity of the supporting resource.
3. Enhancements to ensure variable energy resources (VER) supporting high-priority exports are based on the most recent forecast ahead of the real-time. Therefore, when the forecast changes, the exports needs to bid accordingly.
4. There were also additional transparency improvements to post on OASIS data related to load forecast adjustments across the applicable markets, as well as export reductions in the RUC and Hour Ahead Scheduling Process (HASP) markets.

Table 1 summarizes the different enhancements in place in summer 2022.

Table 1: Summary of enhancements in place for summer 2022

Summer enhancement	Date Implemented	Trigger	Dates Triggered
WEIM resource sufficiency test	1-Jun-2022	Permanent feature	Continuous
Import market incentives during tight supply conditions	15-Jun-2021	Warning or Emergency	September 5-9
Intertie schedules information on OASIS	26-Jul-2021	Permanent feature	Continuous
Enhanced real-time pricing signals during tight supply conditions	15-Jun-2021	Warning or Emergency	September 6-7
Management of storage resources during tight system conditions	30-Jun-2021	RUC undersupply	September 1-9
Reliability demand response dispatch and real-time price impacts	4-Aug-2021	Activation of RDRR	September 5-7
Load, export and wheeling priorities	4-Aug-2021	Permanent feature[4]	Continuous
ISO's public communication protocols	29-May-2021	System Event driven	September 1 -9
Today's Outlook displays	Aug 18-2021	Permanent feature	Continuous
Resource sufficiency test	Jun 1, 2022	Permanent feature	Continuous
Enhancements to supporting resources for exports	June, 2022	Permanent feature	Continuous
Further visibility for supporting resources	June, 2022	Permanent feature	Continuous
Additional transparency for load conformance	June, 2022	Permanent feature	Continuous

[4] The wheeling through priorities the ISO placed into effect are interim with an original sunset date of May 31, 2022. ISO filed at FERC to extend these provision from June 1, 2022 through May 31, 2024 while it develops a long term policy for reserving higher priority wheel through scheduling rights.

2 Weather and Demand Conditions

Weather, such as temperatures and hydro conditions, play a key role in the variables affecting the market and system operations, including hydro production, renewable production and load levels.

2.1 Temperature

Nearly all of the Western United States had temperatures significantly above records for warmest September conditions for the mean daily temperature. This is shown in Figure 1. The areas that experienced the record warmest September were widespread, covering much of Nevada and Utah, as well as parts of California.

Figure 1: Mean temperature percentiles for September 2022[5]

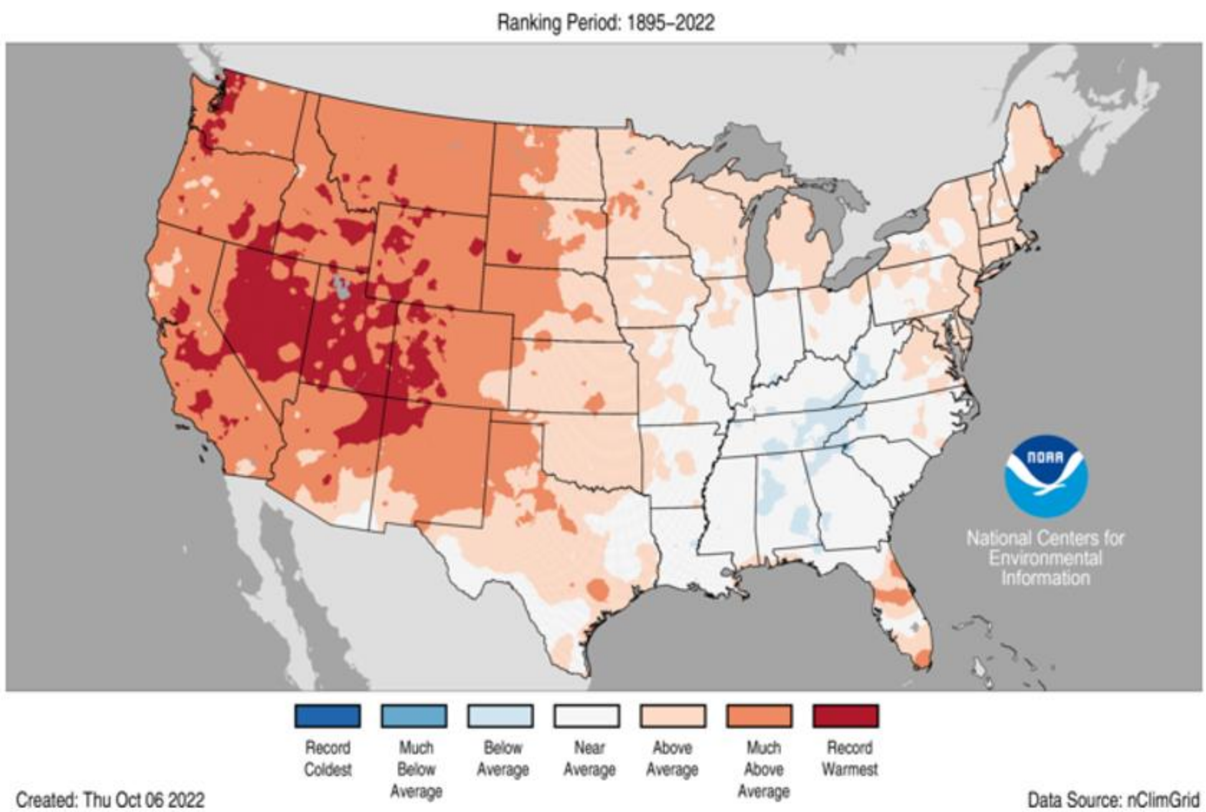
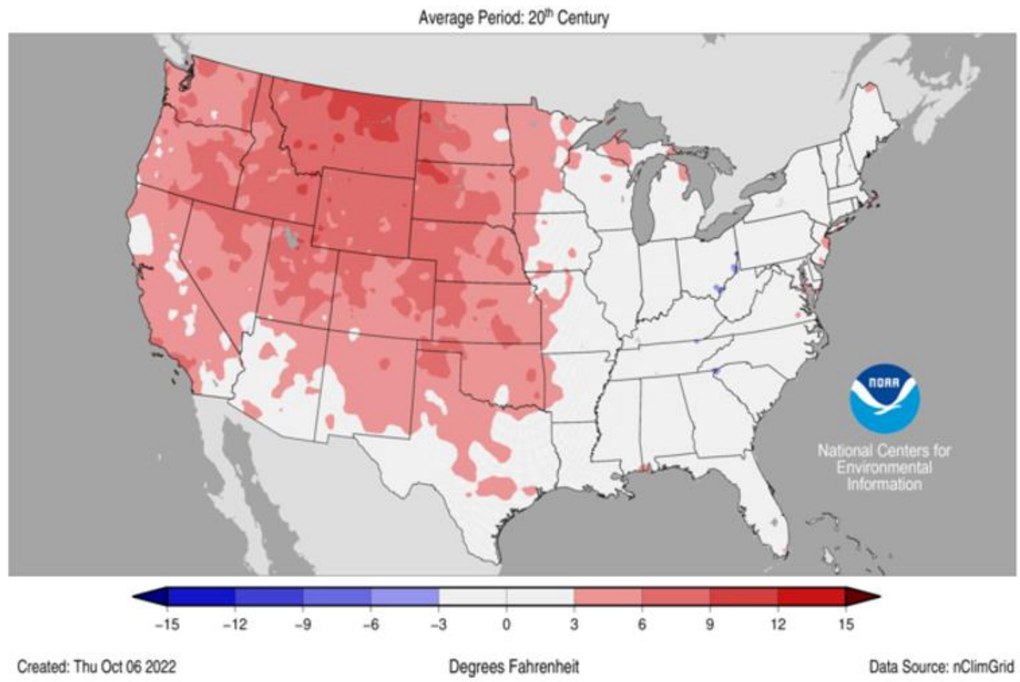
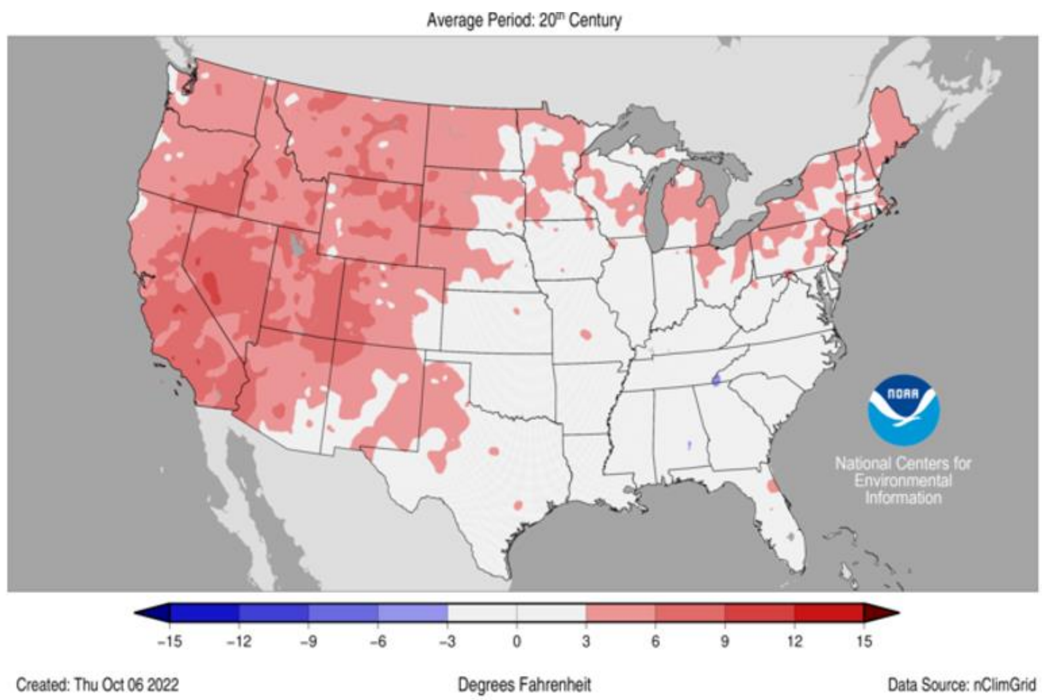


Figure 2 shows the spatial extent of how much above the maximum and minimum temperatures were from average in September. Most of the western half of the US had both maximum and minimum temperatures at least 3 degrees above normal for September, with a large area of minimum temperatures being 6 or more degrees above normal. There were slightly more widespread minimum departures from normal across Arizona and parts of California due to the middle of the month featuring below normal maximum temperatures, but above normal minimum temperatures.

[5] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Figure 2: Maximum and minimum CONUS temperature departures from normal[6]





[6] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Figure 3: Maximum and minimum temperature departure from normal for ISO

California ISO (CAISO)
High temperature departure from normal

September 2022

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 9	2 7	3 8
4 11	5 14	6 15	7 11	8 12	9 5	10 -7
11 -0.8	12 -3	13 -6	14 -7	15 -8	16 -5	17 -8
18 -11	19 -9	20 -7	21 -6	22 -1	23 3	24 6
25 5	26 5	27 4	28 4	29 2	30 2	
				days < normal 13	days > normal 17	Deg +/- normal + 1.4

above normal	below normal	Normals: 1990-2020

California ISO (CAISO)
Low temperature departure from normal

September 2022

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 8	2 9	3 10
4 12	5 12	6 13	7 13	8 12	9 13	10 10
11 11	12 10	13 6	14 3	15 2	16 0.1	17 2
18 4	19 1	20 1	21 2	22 -0.3	23 2	24 5
25 6	26 7	27 6	28 7	29 6	30 4	
				days < normal 13	days > normal 17	Deg +/- normal + 6.6

above normal	below normal	Normals: 1990-2020

As shown in Figure 3, the first nine days of the month were not only the hottest throughout California in September, but they were hottest for the entire summer. Across California from September 1 to 10, there were 41 tied or broken records for all-time hottest temperatures, 174 tied or broken monthly hottest September records and 697 tied or broken daily hottest temperatures recorded.[7] Downtown Sacramento reached its all-time hottest temperature of 116° on September 6, with records dating back to 1877.[8] Livermore also reached 116 on September 5 and 6, which set its record of hottest temperature ever recorded since records began in 1903.[9] In addition to the maximum temperature records broken, there were also 17 all-time warm minimum temperature records tied or broken, 134 tied or broken record warm September monthly minimums and 773 daily warm minimum records tied or broken. The ISO-weighted overnight minimum temperature was on average 6.6°F above normal for September, much more above normal compared to the daytime highs, as well as the rest of the summer's overnight monthly averaged minimums.

Sacramento and Livermore each had 6 days of high temperatures above 105°F, tying the longest streak for Sacramento and breaking the record for Livermore. Sacramento also set records for the warmest 5-day, 7-day and 10-day average maximum temperature for the period ending on September 9. Riverside in southern California also had their warmest 5-day and 10-day mean maximum temperatures for the period ending September 5 and September 8, respectively.[10] On September 6, the hottest day of the event for California, there were over 58.7 million people in the US under a heat alert, many of those in California or in the West.[11] This includes an excessive heat watch, heat advisory or excessive heat warning.

Comparing 2022 to previous extreme temperature years such as 2020, 2017 and 2006 in Table 2, the hottest 3-day period of the 2022 heat wave ranks 4th; however, it is the hottest ranking weekday.

---

7 https://www.ncdc.noaa.gov/cdo-web/datatools/records
8 https://twitter.com/NWSSacramento/status/1568438344836874240
9 https://www.ncdc.noaa.gov/cdo-web/datatools/records
10 http://xmacis.rcc-acis.org/
11 https://www.heat.gov/

Table 2: The top 20 hottest ISO three-day weighted temperature days

Rank	Year	Month	Day	3-day weighted 70 percent max/30 percent min[12]	Annual Peak	Weekday	Weekend/ Holiday
1	2006	7	23	99.10		Sun	Weekend
2	2020	9	6	98.67		Sun	Weekend
3	2006	7	22	98.38		Sat	Weekend
4	**2022**	**9**	**6**	**97.99**	**X**	**Tue**	
5	2006	7	24	97.7	X	Mon	
6	**2022**	**9**	**5**	**97.14**		**Mon**	**Holiday**
7	**2022**	**9**	**7**	**97.09**		**Wed**	
8	2017	9	2	96.93		Sat	Weekend
9	2017	9	1	96.02	X	Fri	
10	2006	7	25	95.89		Tue	
11	**2022**	**9**	**8**	**95.76**		**Thu**	
12	2020	8	18	95.67	X	Tue	
13	2020	8	15	95.59		Sat	Weekend
14	**2022**	**9**	**4**	**95.52**		**Sun**	**Weekend**
15	2020	8	16	95.51		Sun	Weekend
16	2020	8	19	95.16		Wed	
17	2017	9	3	95.01		Sun	Weekend
18	2020	9	7	94.73		Mon	Holiday
19	2020	8	17	94.48		Mon	
20	**2022**	**9**	**3**	**94.18**		**Sat**	**Weekend**

Comparing the length of the 2017, 2020 and 2022 heat events in Figure 4, this year's heat wave had the longest period of temperatures 10 or more degrees above normal for the given date. While Table 2 above only takes into consideration a 3-day temperature ranking, Figure 4 below shows the full duration of the heat events, showing that the 2022 heat wave was also the most extreme of the 3 events, with 10 consecutive days with temperatures 5 or more degrees above daily normal. The other more recent heat event and second hottest 3-day period for ISO was Labor Day weekend 2020. The period of September 5-7, 2020 the ISO had a weighted maximum temperature up to 18 degrees above normal. Although more extreme in magnitude than the 2022 event, it was much shorter in duration and the hottest day was on Sunday, September 6, versus a weekday, which is shown as the 2nd hottest ISO day in Table 2 above.

[12] 3-day weighted temperature is calculated using 70 percent of the maximum heat index of the last 3 days with a 60 percent weighting on the day displayed, 30 percent on day -1, and 10 percent on day -2 and a 30 percent weighting of the daily minimum temperature. Note that the weather stations and weightings utilized in this table differ slightly from those used in Figures 3 and 4, but both are representative of the ISO area.

Figure 4: Comparing the duration and magnitude of the 2017, 2020 and 2022 heat events

California ISO (CAISO)
High temperature departure from normal

August/September 2017

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
20 -5	21 -6	22 -2	23 -4	24 -5	25 -2	26 5
27 5	28 8	29 5	30 5	31 8	1 14	2 13
3 6	4 -4	5 -0.3	6 -1	7 -4	8 -4	9 -2
10 4	11 4	12 -0.3	13 -8	14 -11	15 -8	16 -6
17 -7	18 -7	19 -8	20 -9	21 -14	22 -12	23 -9
24 -4	25 -0.5	26 1	27 3	28 4	29 1	30 -1

California ISO (CAISO)
High temperature departure from normal

August/September 2020

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
2 0.3	3 0.8	4 -4	5 -8	6 -7	7 -4	8 -2
9 0	10 -0.8	11 -4	12 0.9	13 5	14 10	15 10
16 10	17 7	18 9	19 8	20 3	21 2	22 4
23 2	24 0	25 -0.3	26 -0.7	27 -0.2	28 -1	29 -3
30 -3	31 -4	1 -5	2 -5	3 -2	4 4	5 13
6 18	7 8	8 -2	9 -8	10 -8	11 -3	12 -1

California ISO (CAISO)
High temperature departure from normal

August/September 2022

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
28 -5	29 -3	30 2	31 6	1 9	2 7	3 8
4 11	5 14	6 15	7 11	8 12	9 5	10 -7
11 -0.8	12 -3	13 -6	14 -7	15 -8	16 -5	17 -8
18 -11	19 -9	20 -7	21 -6	22 -1	23 3	24 6
25 5	26 5	27 4	28 4	29 2	30 2	

above normal	below normal	*Normals: 1990-2020*

Regarding the frequency of this type of weather event, by calculating an ISO weighted weather index using 20 years' worth of weather data, the hottest 3-day weighted temperature of the September 2022 heat wave had a weather index of 97.99°F and was a 1-in-11 year event. A 1-in-11 year event means that in a given year the event has a 9% chance of occurring. Using 28 years' worth of weather data, the ISO weighted 3-day temperature through September 6 was a 1-25 year event. A 1-in-25 year event means that in a given year the event has a 4% chance of occurring. These two values are shown below in Table 3. The reason the weather index rankings are different using different data sets is the additional 8 years of data in the bottom table represent a frequency of lower temperatures than what is projected to be normal. By having more periods of below normal temperatures in the set, that brought down the 28-year observed temperature across the ISO's BAA, making this year's heat event relatively more extreme, and thus more unusual. More information regarding why the 20-year and 28-year data sets are used can be found in the 2022 Summer Loads and Resources Assessment.[13]

[13] See the Probabilistic Study Key Parameters, beginning on page 4 and the Annual Peak and Energy Forecast beginning on page 26 of the assessment. The ISO has worked closely with California Energy Commission (CEC) staff who have a similar methodology but use slightly different weights. The CEC staff results are within a close range of the ISO's analysis.

Table 3: 2022 20-year peak 3-day weighted weather ranking (top) and 2022 28-year peak weather ranking (bottom)[14]

2022 Summer Peak Load and Peak Day Weather Ranking Across the CAISO
(based on 20 years of historical weighted average of 24 weather stations data across the ISO)

Area Load	Time	Actual Peak (MW)	Weather Index (deg. F)	Percentile	Weather Event
ISO Load	9/6/22 17:00	51,479	97.99	91%	1-in-11

Notes:
1. The weather data is based on a weighted average of the 24 weather stations across the ISO that the ISO uses for day ahead and summer assessment load forecasts.
2. This weather event analysis is based on 20 years of weather data from 2003 to 2022.
3. Loads are based on hourly average load data. Hourly average load figures are what are reported to FERC in the Form 714 report and to WECC/NERC.

2022 Summer Peak Load and Peak Day Weather Ranking Across the CAISO
(based on 28 years of historical weighted average of 24 weather stations data across the ISO)

Area Load	Time	Actual Peak (MW)	Weather Index (deg. F)	Percentile	Weather Event
ISO Load	9/6/22 17:00	51,479	97.99	96%	1-in-25

Notes:
1. The weather data is based on a weighted average of the 24 weather stations across the ISO that the ISO uses for day ahead and summer assessment load forecasts.
2. This weather event analysis is based on 28 years of weather data from 1995 to 2022.
3. Loads are based on hourly average load data. Hourly average load figures are what are reported to FERC in the Form 714 report and to WECC/NERC.

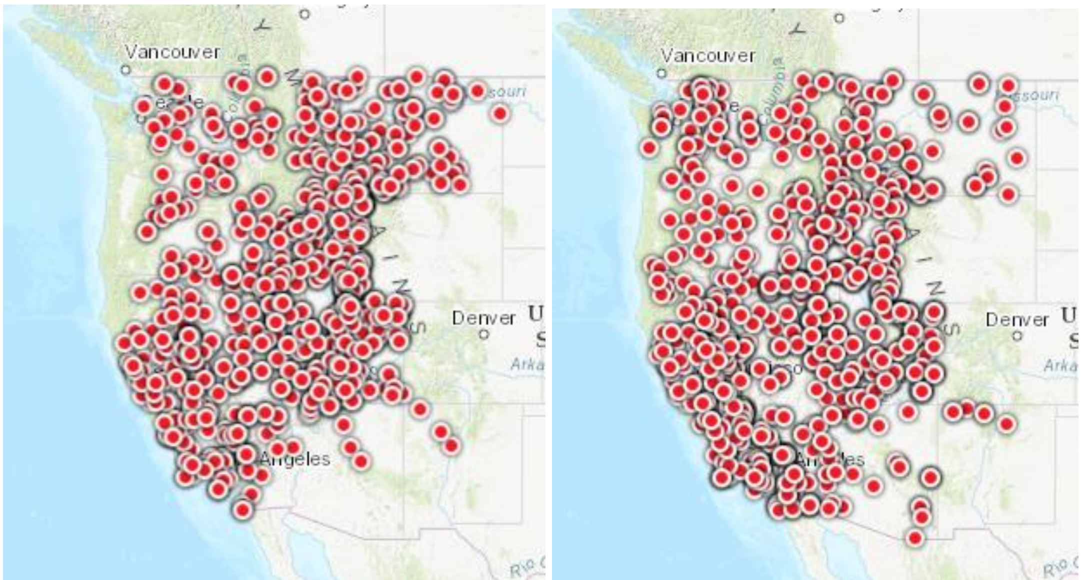
Following the record-breaking heat wave, a prolonged period of below normal temperatures was observed from September 10-22, the start of which was assisted by the arrival of Hurricane Kay off the coast of Baja. This led to the heat finally breaking down, as well as some much-needed rainfall across Southern California. Once the moisture from Hurricane Kay subsided, it was followed by a robust feature of upper-level cool air that not only brought temperatures that were up to 20 degrees below normal, but also an early season rainfall to much of northern California. With the arrival of cooler air, the maximum temperature in Thermal went from 104°F on September 8 to 88°F on September 9th, an abrupt end to the heat. This larger drop off in temperatures for interior Southern California on the 9th signaled the beginning of the end of the heat wave, as the rest of the state saw large temperature improvements on September 10th and 11th as seen in Figure 5.

Looking at the Western United States temperature records in Figure 5, there were 3,306 daily highest maximum temperature records tied or broken and 3,065 daily highest minimums tied or broken. Of these, 2,864 (86 percent) of the maximum records and 2,074 (67 percent) of the minimum records occurred between September 1-10. There were 44 all-time hottest temperatures tied or broken across the west in

[14] Load values displayed below are hourly averaged.

September 41 of which occurred in California, and 26 all-time hottest overnight low temperatures tied or broken, 17 of which occurred in California.

Figure 5: Highest maximum (left) and highest minimum temperature (right) in September[15]



Excessive heat, depending on the day of week, has the potential to bring load to the electrical system that may be higher than demand anticipated during long-term planning and forecasts about the supply that is anticipated to be necessary to meet demand. In addition, during excessive heat events, supply resources (thermal and renewable) typically operate less efficiently, creating de-rates on the maximum energy that can be produced depending on the temperature and other characteristics, such as airflow.

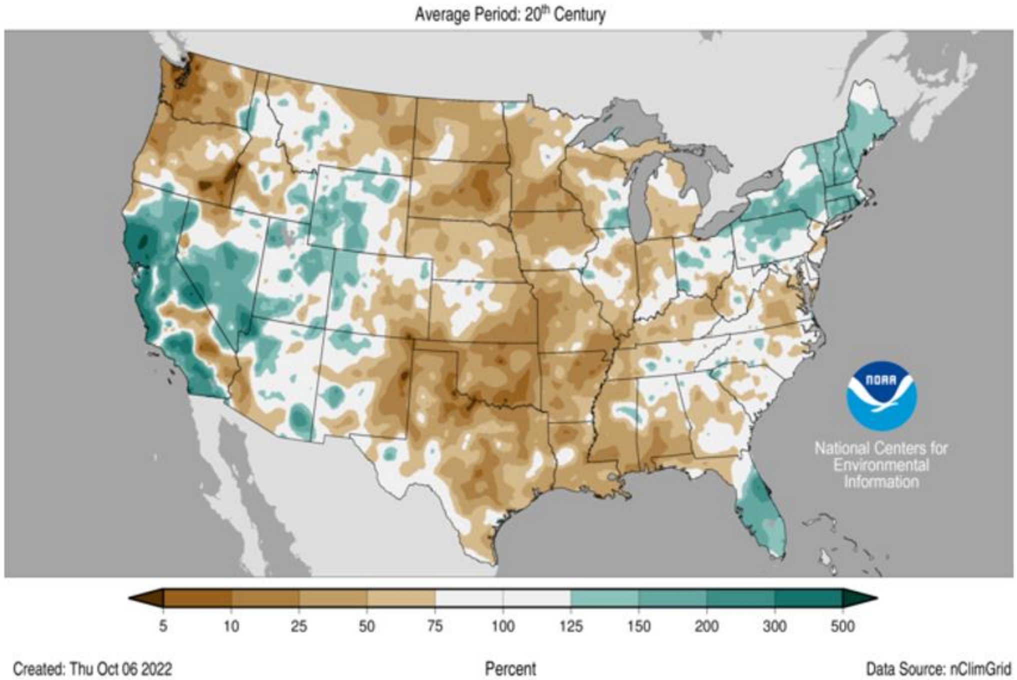
2.2 Hydro conditions

The Southwestern US and most of California experienced near-to-above normal precipitation conditions in September while the Pacific Northwest mostly saw below-average precipitation.[16] This is shown in Figure 6. With the arrival of clouds and rainfall associated with Hurricane Kay between September 9-11, Ramona received 0.94” of rainfall, which is approximately 680 percent of its normal September precipitation. Downtown LA received 260 percent of its usual September rainfall on just the 9th and 10th.

With the mid-September system that brought rain to Northern California, Napa received 1080 percent of its normal September rainfall in just one day on the 18th and Sacramento Received 250 percent from September 18 and 19. Between these two systems, this led to most of the state of California seeing above normal precipitation for the month of September, as shown in Figure 6. However, despite this, there was no improvement in the state’s drought.

[15] https://www.ncdc.noaa.gov/cdo-web/datatools/records
[16] https://www.ncei.noaa.gov/access/monitoring/us-maps/

Figure 6: The United States precipitation percent of normal for September 2022 [17]



Due to the lack of total precipitation throughout this last water year for California and the Desert Southwest, the majority of the Western United States remains in drought conditions, extending from abnormally dry to exceptionally dry. The extent of the drought coverage is shown in Figure 7 below. Comparing the beginning of September to the end, despite increased rainfall across California, there has been little-to-no improvement in the drought across the state. Throughout the West, there was an increase in the total drought area by 6.46 percent, primarily due to a lack of precipitation across the Pacific Northwest, which is also shown in Figure 7.

Figure 8 below, shows the soil moisture ranking across nearly all of California and the West has improved in 2022 compared to the same time in 2021. Increased monsoonal coverage for the deserts and early season rainfall for both the northern and southern portions of the state have assisted in this improvement and should assist going into the fall months with keeping fire risk lower than it was last year, but still elevated.

[17] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Figure 7: The Western United States drought monitor as of October 4, 2022 [18]

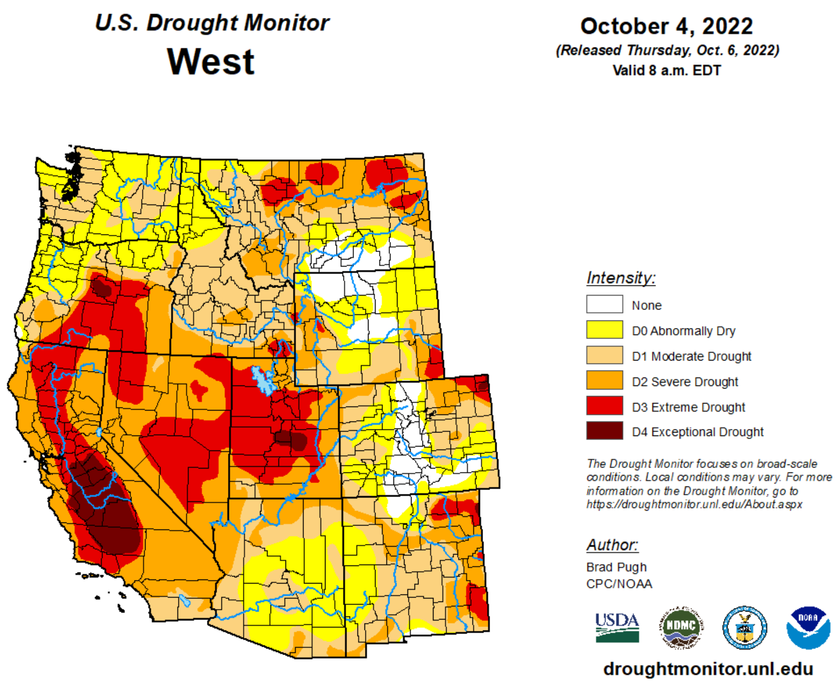
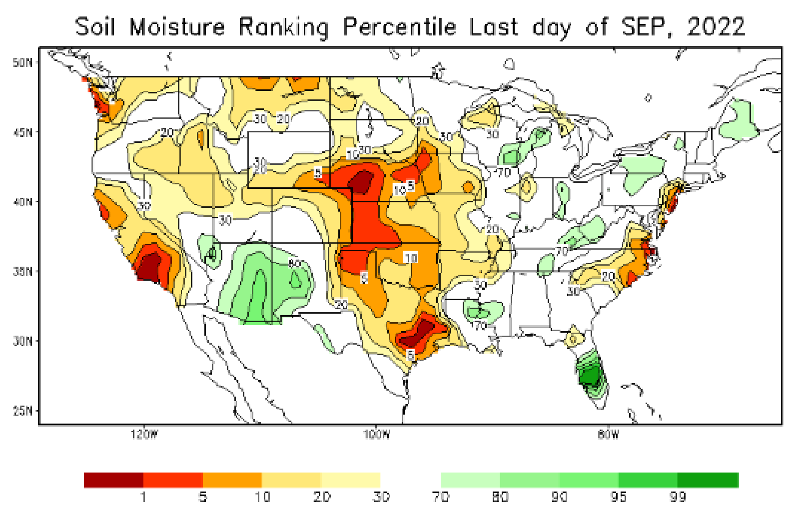
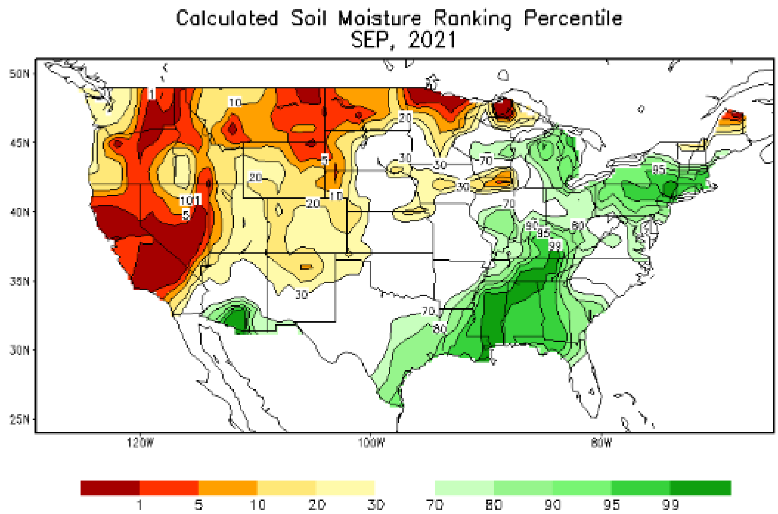


Figure 8: The United States soil moisture for September 2022 (top) and September 2021 (bottom) [19]



[18] https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?West

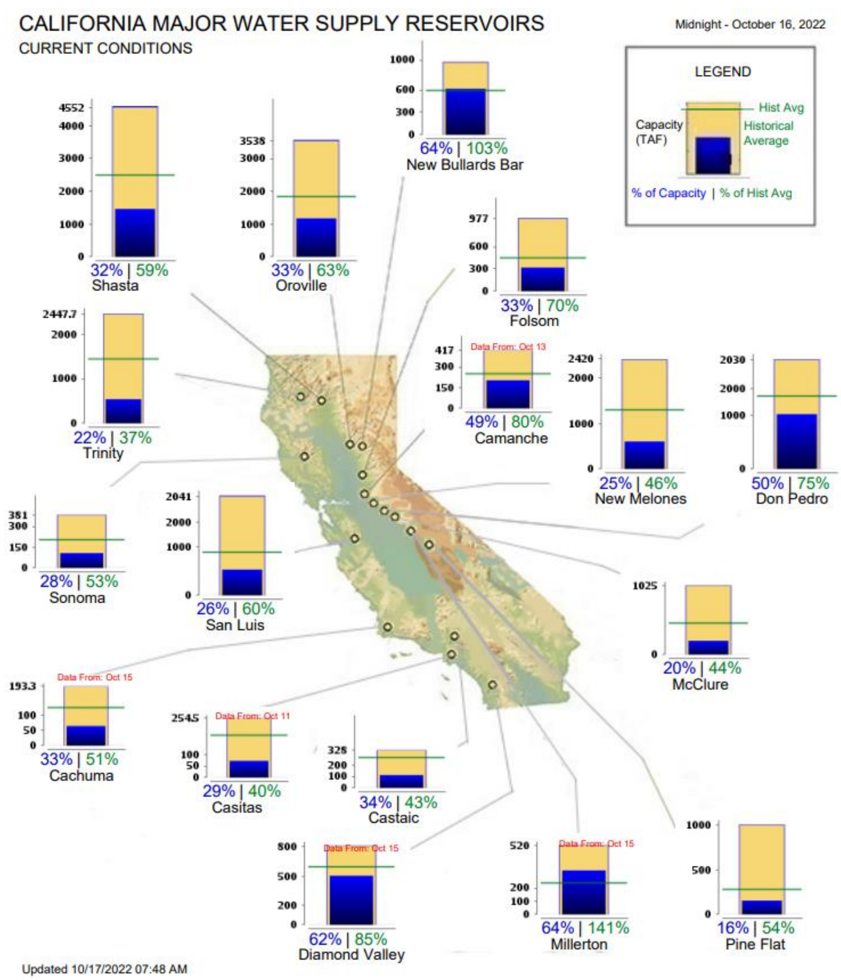
[19] https://www.cpc.ncep.noaa.gov/products/Soilmst_Monitoring/US/Soilmst/Soilmst.shtml#



Because of all the factors discussed above related to temperatures, precipitation, drought conditions, and soil moisture levels, many reservoir conditions for California and the West are significantly below normal, as shown in Figure 9. The statewide storage in major reservoirs is currently 54 percent of average and at 32 percent of capacity.[20] This is compared to 58 percent of average and 33 percent of capacity at the end of September 2021. Lake Mead in Nevada had a water level of 1,045 feet at the end of September, below the average September elevation of 1,152 ft. and the lowest level recorded for the end of September since 1936, the year after the level tracking began.[21] [22]

[20] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM
[21] https://www.usbr.gov/lc/region/g4000/hourly/mead-elv.html
[22] http://lakemead.water-data.com/

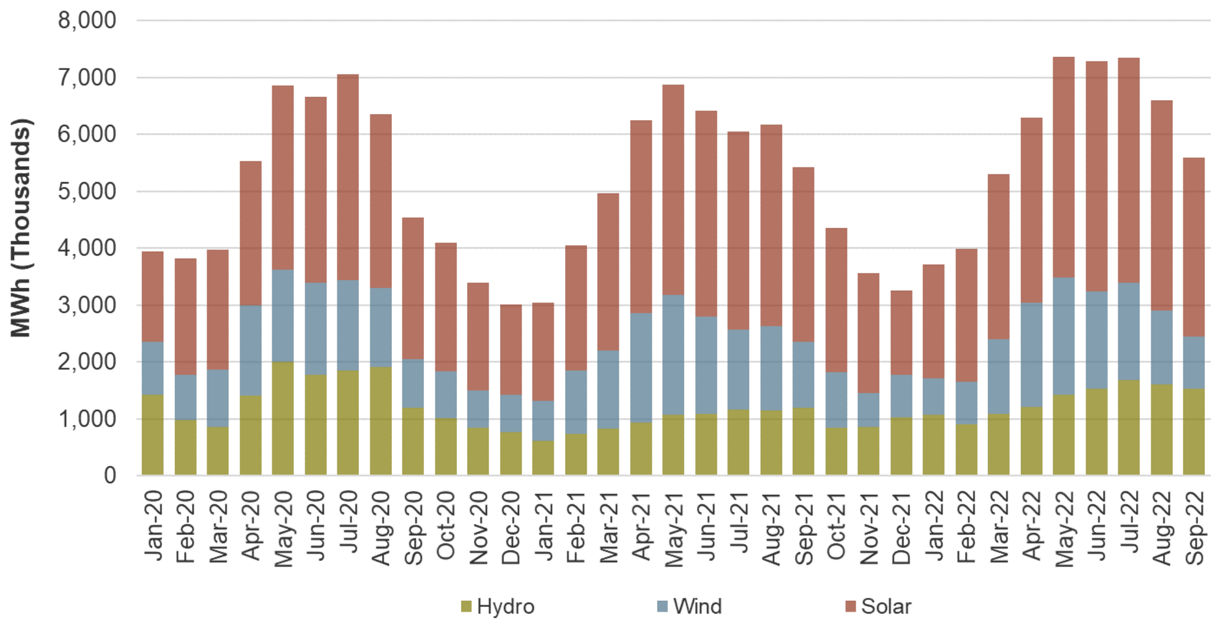
Figure 9: California's reservoir conditions as of October 1, 2022[23]



The ISO's electrical system utilizes hydro production throughout the year to meet ISO demand. Due to the significant reduction in available water capacity currently observed in the reservoirs, the ISO continues to see reduced capacity in hydro production this year. Figure 10 below shows the historical trend of total energy produced from hydro resources, as well as renewable resources, in which hydro production for 2022 so far has been relatively higher than in 2021. Hydro production in September 2022 was about the same compared to September 2021. Although drought conditions continue to reduce the overall available energy available over the summer, hydro resource operators typically strive to conserve their more limited water to provide peaking energy, which helps mitigate the adverse impact of limited hydro.

[23] https://cdec.water.ca.gov/resapp/RescondMain

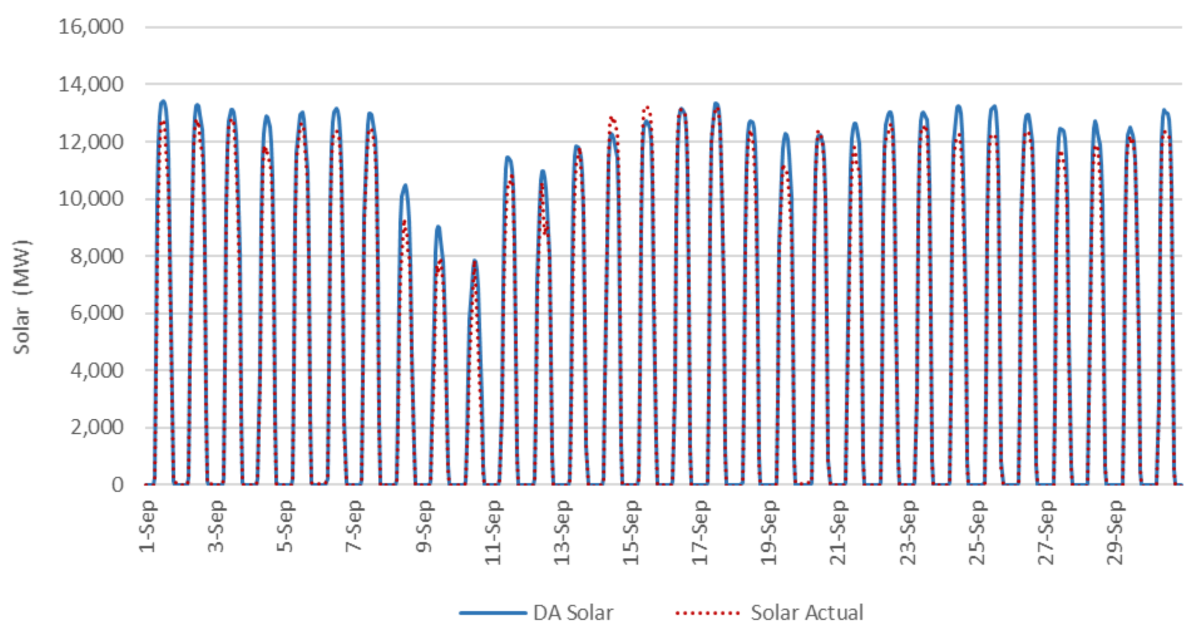
Figure 10: Historical trend of hydro and renewable production



2.3 Renewable forecasts

Figure 11 and Figure 12: below show the solar and wind day-ahead renewable forecasts compared to actual plus supplemental dispatch.

Figure 11: Day-ahead solar forecasts for ISO's area



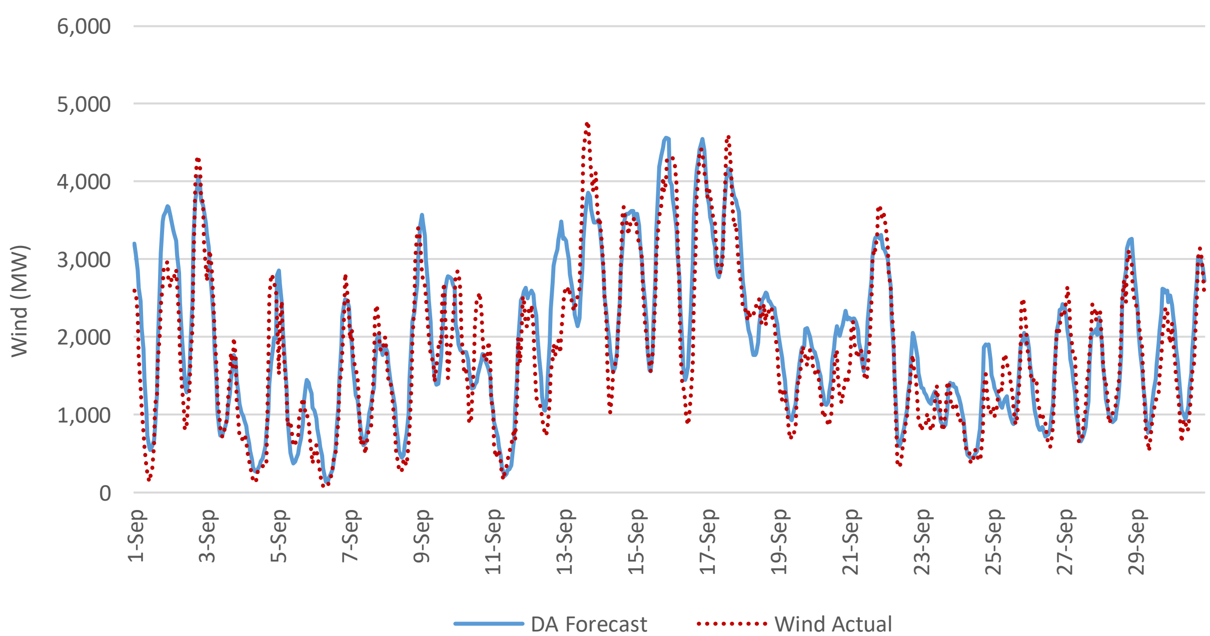
Supplemental dispatch reflects the market's downward dispatch relative to the resource's forecast based on their bids. Adding supplemental dispatch back into the actuals allows the ISO to measure the performance of the full-fuel forecast that is utilized in RUC and the RTM optimization.

The high bias to the day-ahead solar forecast for September 1 to 7 is likely due to the reduction in efficiency of the solar sites in extreme temperatures, as observed during this period. September 8 to 10 saw decreased solar production, as Hurricane Kay brought cloud cover and rain to Southern California. Compared to September 7, which saw nearly cloud-free skies, solar generation was reduced by 39.5 percent on September 8 and by 51.5 percent on September 9 due to the large spatial extent and heavy thickness of the clouds associated with Hurricane Kay. The average day-ahead solar absolute error for the September 5 to 8 heat wave event is shown in Table 4, along with the MW bias from the peak and net load peak hours. [24] [25]

Table 4: Day-ahead solar accuracy September 5 to 8

Date	Daily Average Percent Error	Load Peak Hour MW Error	Net Load Peak Hour MW Error
5-Sep	2.3	+490	-7
6-Sep	3.3	+596	+31
7-Sep	2.7	+510	+440
8-Sep	7.3	+826	+178

Figure 12: Day-ahead wind forecasts for ISO's area



The average error for the day-ahead solar forecast in September was 3.57 percent. The average error observed in September 2022 is lower than the day-ahead solar forecast error observed for September

[24] Percent error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[25] Peak hour MW error = forecast – actual. Positive values represent forecast coming in over actuals, and negative values represent forecast coming in under actuals.

2020 and 2021.[26] This is likely due to the impact on solar generation from smoke in September 2021, while 2022 had minimal smoke impacts to grid-scale solar.

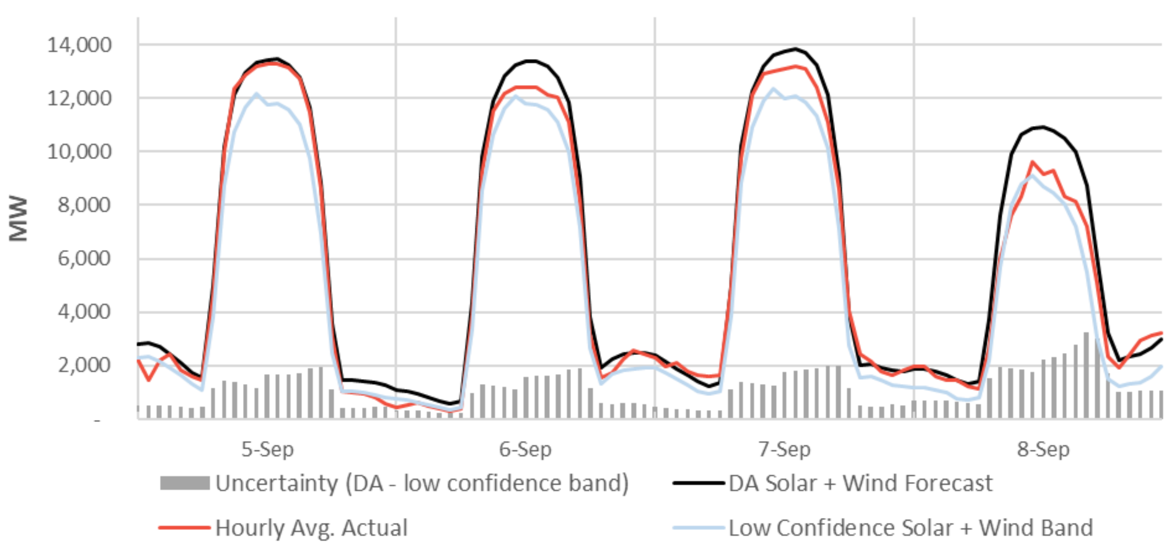
Figure 12: shows the day-ahead wind forecast compared to the actuals plus curtailments throughout the month of September for wind in the ISO's system. The average day ahead wind accuracy error for the September 5-8 heat wave event is shown in Table 5, along with the MW bias from the peak and net load peak hours.[27]

Table 5: Day-ahead wind accuracy September 5 to 8

Date	Daily Average percent Error	Load Peak Hour MW Error	Net Load Peak Hour MW Error
5-Sep	4.2	-321	+377
6-Sep	3.2	+169	+319
7-Sep	2.7	+117	-684
8-Sep	2.8	+385	+579

The average error for the day-ahead wind forecast in August was 4.12 percent.[28] The average error observed in September 2022 is comparable to the day-ahead wind forecast error observed for the month of September in 2020 and 2021.[29]

Figure 13: Solar + wind day-ahead forecast and uncertainty compared to actual



[26] http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun162022.pdf
[27] Peak hour MW error = forecast – actual. Positive values represent forecast coming in over actuals, and negative values represent forecast coming in under actuals.
[28] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[29] http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun162022.pdf

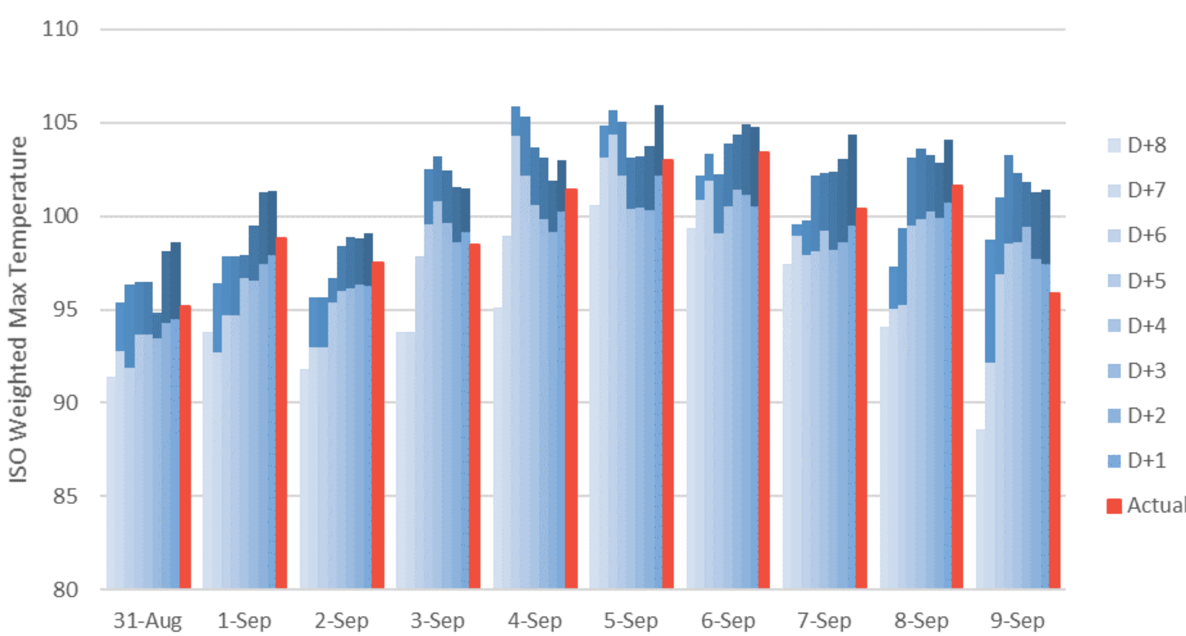
In Figure 13 above, the solar and wind day-ahead forecasts are shown compared to the actuals. The low confidence solar and wind band was formed using meteorological information regarding the uncertainties with the day-ahead forecast due to weather. The low confidence band is provided to the operations team in the day-ahead for awareness of these uncertainties and to assist if further actions are needed to cover these uncertainties. During the peak of the heat on September 6, the actual solar and wind ended up coming in closer to the low-end of the confidence band instead of the day-ahead, likely due to the impacts from the extreme temperatures on resource efficiencies. On September 8, the large reduction in the daytime renewable generation was due to the increase in cloud cover across Southern California associated with Hurricane Kay. This also resulted in the renewable production coming in below the day-ahead and closer to the low confidence ban during the daylight hours.

2.4 Demand forecasts

The ISO produces load forecasts for the day-ahead and real time markets for all areas participating in the ISO markets, including WEIM entities. With historic heat in many parts of California, electricity use on the ISO grid hit a peak of 52,061 megawatts (MW), breaking previous load records by almost 2,000 MW. Previous peak loads on the system reached 50,270 MW in 2006 and 50,116 MW in 2017.[30]

The CEC month ahead forecast for September's Peak was 44,578 MW. The highest hourly average September load of 51,479 MW was observed on September 6, 2022 when the ISO footprint was running 15 degrees F above normal for maximum temperatures, coming in 6,900 MW above the CEC forecast. The instantaneous peak load of 52,061 MW was 7,483 MW above the CEC forecast.

Figure 14: Preliminary temperature forecasts for ISO's area



[30] http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf

Figure 14 shows the progression of the ISO weighted max temperature forecast for each trade date of the heat event. The light blue bars represent the discrete temperature forecast, while the dark blue lines represent the maximum forecast observed from various weather models. The maximum forecast assisted in determining risk for temperatures and load to come in higher than anticipated.

As the heat approached in early September, preliminary load forecasts were completed as far as eight days in advance to assist in analyzing potential demand. Figure 15 shows the trend of peak forecasts updated eight days prior to the trade date up through the day ahead forecast. As the hottest temperatures moved from September 4 to 6 with each forecast update, the load forecast for September 4 gradually decreased while the load forecast for September 6 gradually increased with each update. The load and temperature forecasts for September 8 and 9 following the heat event had high levels of uncertainty due to the impact on Southern California temperatures with Hurricane Kay.

Figure 15: Progression of the peak load forecast for ISO BAA

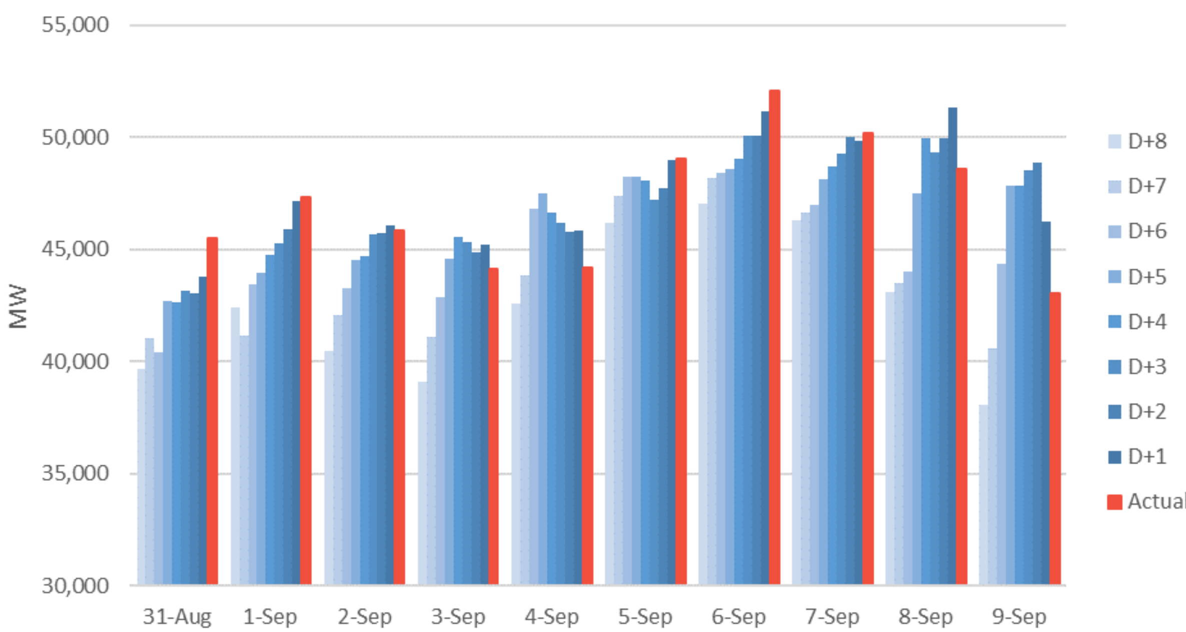
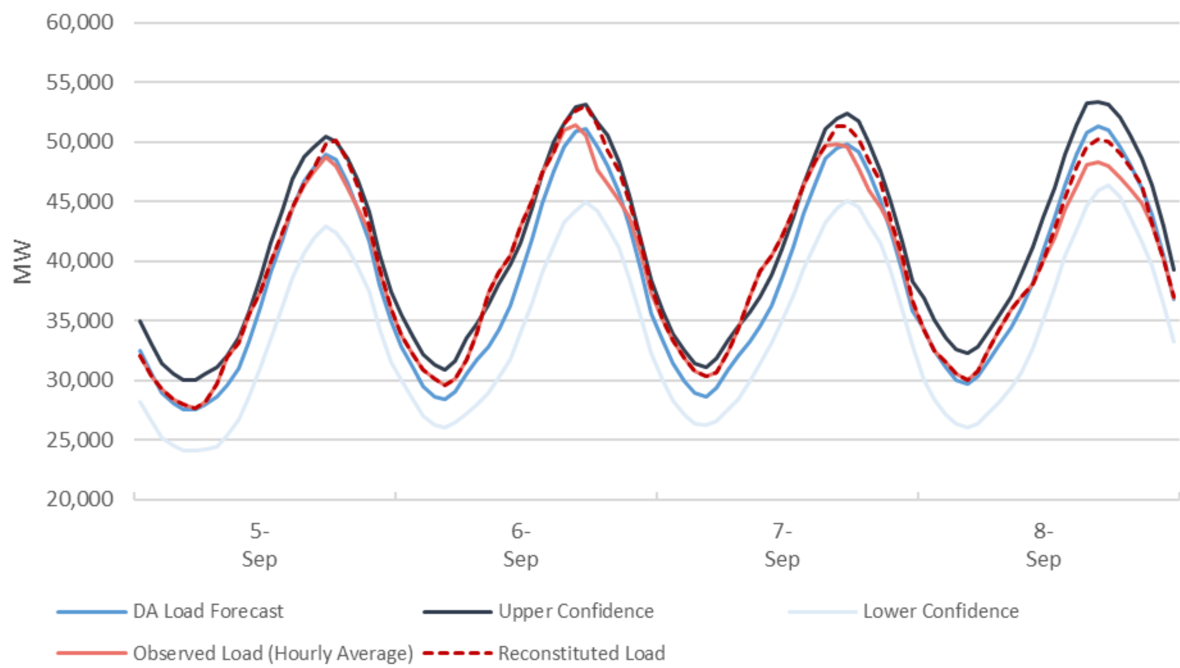


Figure 16 below shows the load day-ahead forecasts compared to the actuals and confidence bands. The load confidence bands are formed by referencing days with similar weather as well as historical error patterns, and provided to operations in the day-ahead for awareness of uncertainties in the load forecast.

Figure 16: Day-ahead load confidence bands September 5 to 8



The peak accuracy error[31] for September 5 to 8 is shown in Table 6, comparing day-ahead peak load forecast to the instantaneous peak load observed each day. Note that the instantaneous load values are observed and do not incorporate impact from energy conservation.

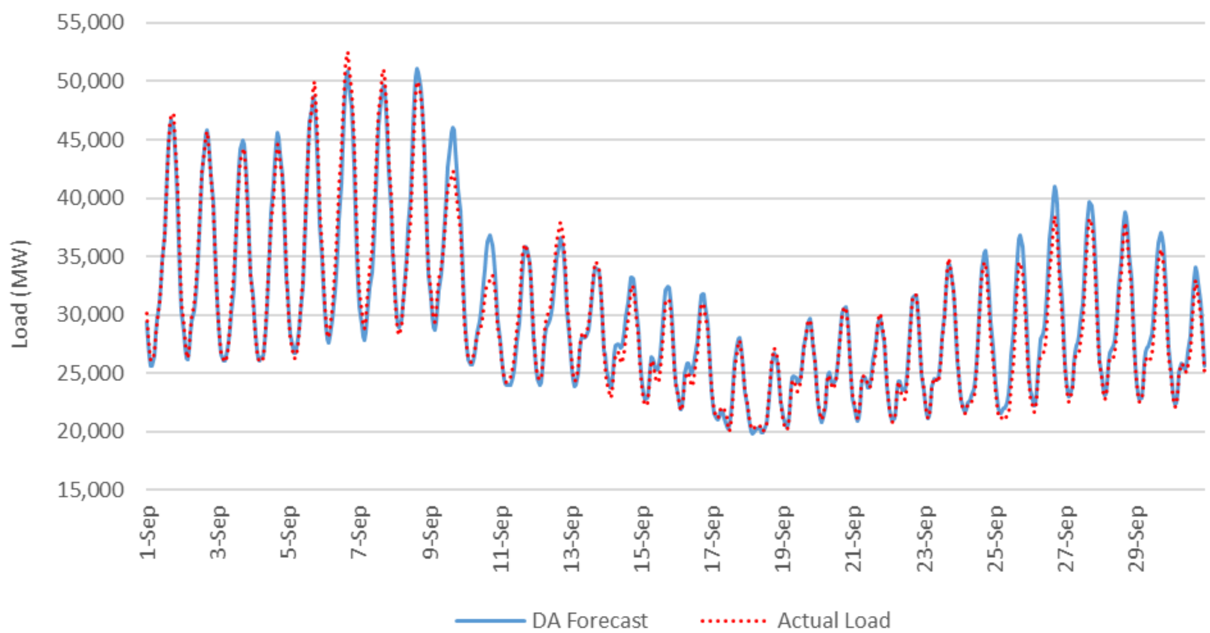
Table 6: Day-ahead peak load forecast error

Date	Peak percent Error	Peak MW Bias
5-Sep	0.1	-53
6-Sep	1.8	-917
7-Sep	0.6	-316
8-Sep	5.6	+2703

Figure 17: shows the monthly trend of the ISO's forecasted load versus actual demand.[32] The ISO called on a Flex Alert for September 1 through September 9.[33] In order to compare the day-ahead forecast to estimated demand, the scheduled Demand Response MW as well as the estimated response from energy conservation are accounted for in the actuals shown in Figure 17:, these are referred to as the reconstituted actuals. Further details on the energy conservation analysis is described below in the section on Impact of Energy Conservation.

[31] MW Bias = forecast – actual. Positive values represent forecast coming in over actuals, and negative values represent forecast coming in under actuals.
[32] Demand trend data used to examine forecast error does not include pump loads and battery storage that is charging on the system.
[33] The Flex Alerts for September 1 through September 9 were effective from 4pm to 9pm.

Figure 17: Day-ahead demand forecast for ISO's area



Some of the larger errors seen in September were observed in the days following the heat wave. September 9 and 10 resulted in large over-forecasting due to Hurricane Kay's impact in Southern California and temperatures cooling more than anticipated.

The average accuracy error[34] for the day-ahead demand forecast in September was 2.4 percent, while the error for peak hours was 2.7 percent. The average error observed in 2022 is lower than the day-ahead demand forecast error observed for September 2020 and higher than the day-ahead demand forecast error observed in 2021.

2.5 Demand response and non-market resources

During the September heat wave, there were both market-integrated demand response programs as well as non-market resources, including state programs to address extreme events, played a key role in providing relief. Under tight supply conditions, demand response is a critical tool to balance the ISO system. The goal of the demand response programs is to reduce demand based on system needs. Demand response programs have differing trigger criteria, but all were utilized throughout the heat wave to reduce demand. In addition, there were several non-market resources that supplemented the resource adequacy program to address extreme events. As described below, these ranged from non-market demand response, to behind-the-meter backup diesel generators, and temporary grid-side natural gas-fired resources that were deployed by utilities and state agencies with coordination from a wide variety of government, utility, and customer and business groups. The sections below summarize how both market-

[34] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Actual).

integrated demand response and non-market resources were used in the ISO footprint throughout the September heat wave, with a focus on the more stressed days of September 5 through September 8.

The timing and magnitude of market-integrated demand response and non-market resource utilization coincided with the severity of the heat wave. At the start of the heat wave from August 31 to September 4, daily market demand response schedules ranged between 34 MW and 344 MW while non-market resources ranged from 174 MW to 902 MW. The latter half of the heat wave saw larger amounts of resources being called upon with September 6 having the largest amount of market demand response and non-market resources called at 1,267 MW and 1,216 MW, respectively at HE 18. Over the heat wave, the largest amounts of these resources were typically called between HE 18 and HE 20. The timing and magnitude of demand response utilization coincided with the severity of the heat wave. At the start of the heat wave from Aug 31 to Sep 4, daily market demand response schedules ranged between 34 MW and 344 MW while non-market resources ranged from 174 MW to 902 MW. The latter half of the heat wave saw larger amounts of demand response with September 6 having the largest amount of market and non-market demand response called at 1,267 MW and 1,216 MW respectively at hour ending (HE) 18. Over the heat wave, the largest amounts of demand response were typically called between HE 18 and HE 20.

Market demand response

In the ISO's markets, there are two main programs for market demand response: economic and emergency demand response. These programs are modeled in the ISO markets as supply-type resources that can be dispatched similar to conventional generating resources.

Figure 18: PDR Dispatches in DAM and RTM in September

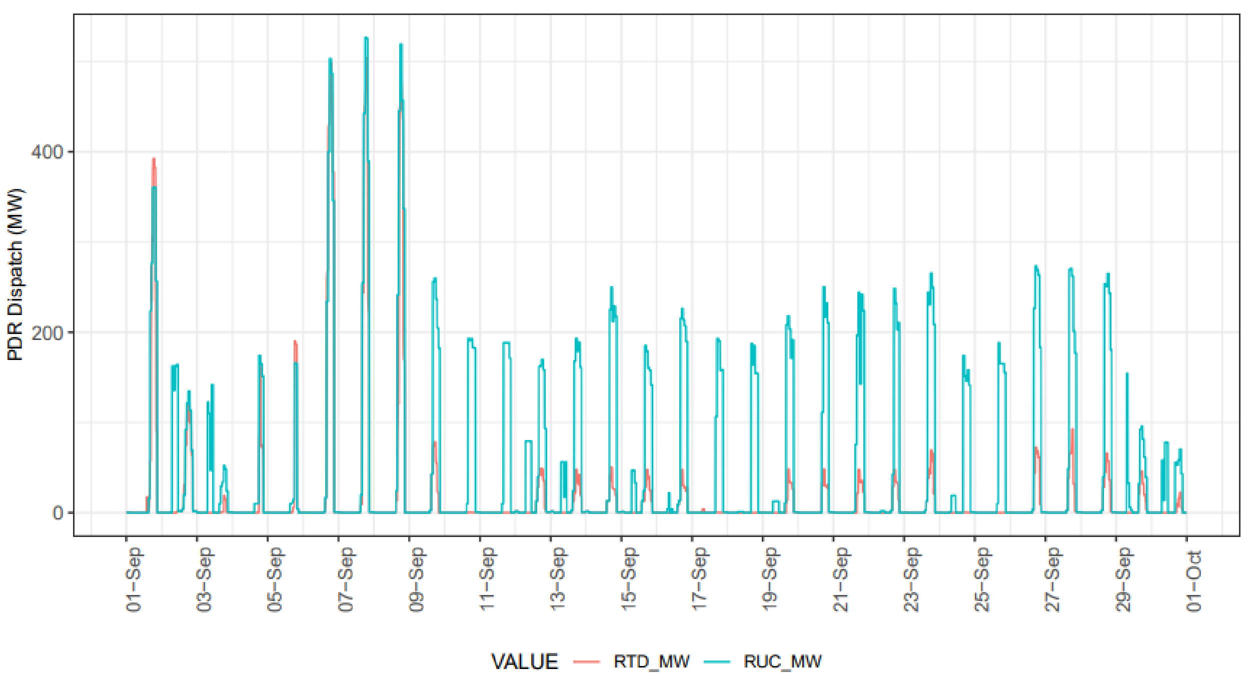
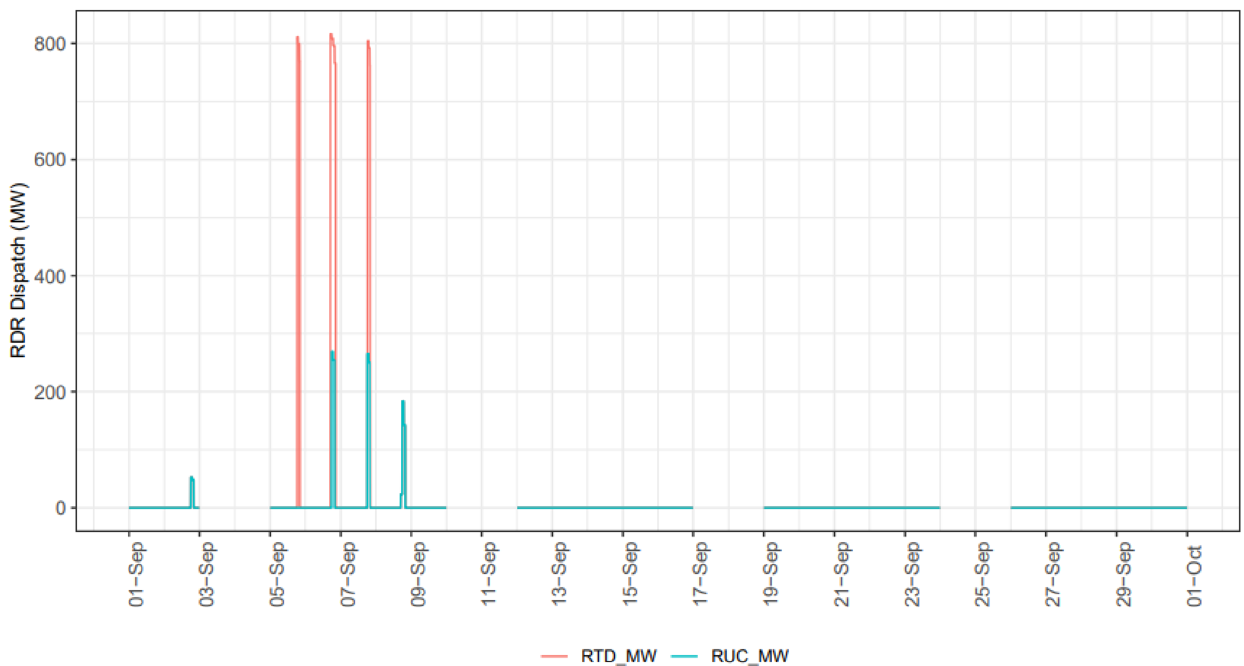


Figure 61 shows the dispatch for economic demand response, known as proxy demand resources (PDR), in both the day-ahead and RTMs. PDRs are dispatched economically in either market based on their bid-in prices. During the month of September, PDRs were consistently dispatched in both the DAM and RTM. The largest volume of PDR dispatches in real-time occurred on September 7 at about 504 MW.

Figure 19 shows the dispatches for emergency demand response, known as reliability demand response resources (RDRRs), in both the day-ahead and RTMs. In the DAM, these types of resources can be dispatched based on economics. The RTM will consider these DAM schedules dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the RTM even when there is no Energy Emergency Alert declaration. Although most RDRRs are only deployed in the real-time when the ISO has declared at least an Energy Emergency Alert 2, some RDRRs may bid-in economically into the ISO DAM. In that case, any cleared RDRRs will come into the RTM as a self-schedule and be dispatched generally at the same level of the DAM award. RDRRs were dispatched in the RTM only on September 5 through 8 up to 816 MW.

Figure 19: RDRR dispatches in DAM and RTM for September



At the time this report was prepared, there were no estimates yet of demand response performance. Estimates become available about two months after the trade date based on settlement data submitted by the scheduling coordinators and are used to measure the performance of demand response resources relative to a baseline. The ISO will report on their performance when the data become available.

Non-market resources

This section will focus on various non-market resources, many of them new state programs to address extreme events, which are triggered through differing conditions on the BAA's system. These resources include formalized demand-side programs not integrated into the ISO market, coordinated conservation efforts during the heat wave, and non-market generation authorized by California legislation. In addition, some of the non-market resources were provided by back-up diesel generation if authorized under the local regulatory authority's program design or permissible pursuant to California Governor Gavin Newsom's Proclamation of a State of Emergency issued on August 31[35] and extended through to September 9.[36] For the ISO, some of these programs can be triggered by conditions such as Flex Alerts and EEA categories.

The ISO footprint has had some level of non-market response, most visibly through the Flex Alert system, a voluntary call for consumers to conserve electricity, initiated in 2000. In addition, the investor-owned utilities in the ISO footprint also have load reduction programs that are not integrated into the ISO market. These are generally referred to as load modifying demand response (LMDR). Overall, the response from these programs collectively has resulted in hundreds of MWs in conservation during critical hours.

Since 2020, there has been an increased effort by local regulatory authorities and the state of California to increase the level of demand-side response and load reduction capabilities, though due to time constraints and cost concerns the vast majority are not integrated into the ISO market. Consequently, the ISO market optimization cannot directly reflect the level or timing of any conservation from these new programs. In 2021, the California Public Utilities Commission created the Emergency Load Reduction Program (ELRP) for its jurisdictional investor-owned utilities to incentivize demand-side load reduction from residential, commercial, and industrial customers.[37] Funded through 2025 and expanded in 2022, ELRP is a pay-for-performance program, rather than RA capacity, where participants may be paid up to $2,000/MWh for successful responses. The ELRP is dispatched by the investor-owned utilities but may use ISO warning levels (such as a Flex Alert or any of the Energy Emergency Alerts) as the trigger. Unlike RA demand response, backup diesel generators may participate in ELRP.

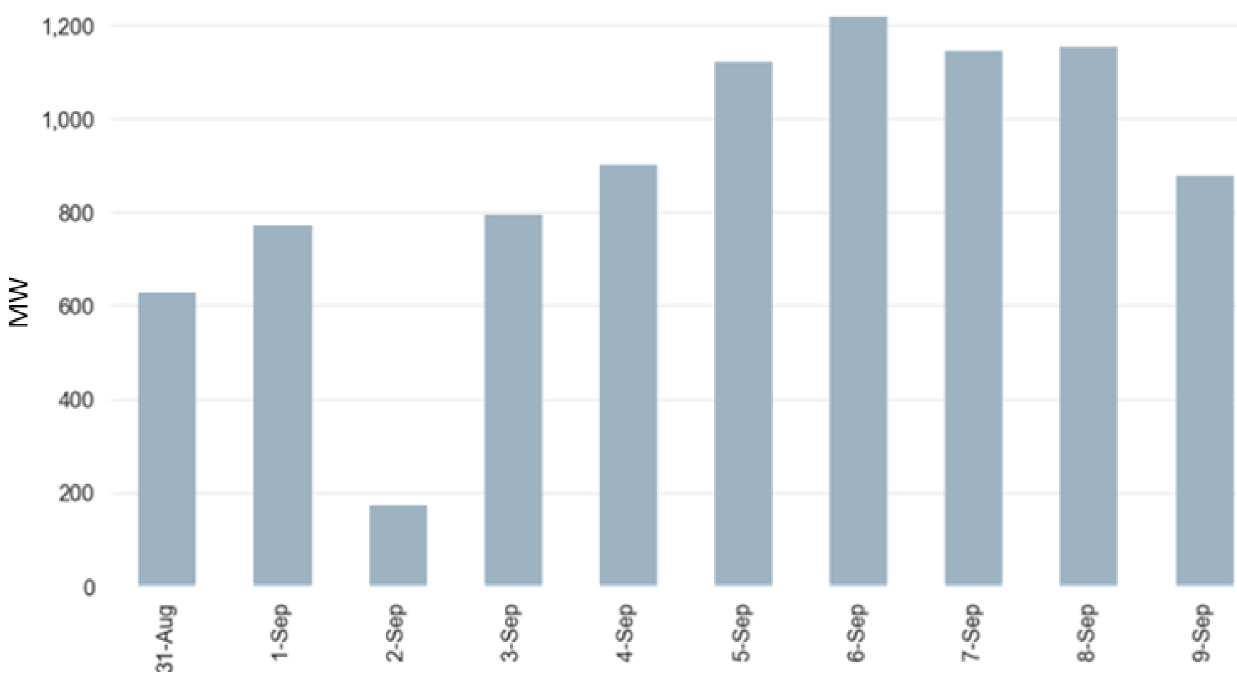
In 2021, Governor Newsom authorized the use of temporary generation to address extreme heat.[38] Consequently, the State Power Augmentation Power (SPAP) resources were secured to provide out-of-market generation to be deployed during a grid emergency due to a sudden energy supply shortage in California resulting from an extreme heat wave or wildfire event, as designated and directed by the ISO. Lastly, Assembly Bill (AB) 205,[39] approved in June 2022, created a statewide Electricity Supply Strategic Reliability Reserve Program (Strategic Reserve) and the Demand-Side Grid Support (DSGS) program to bolster system reliability under extreme events. Under the Strategic Reserve, the state deployed temporary out-of-market generation, similar to the SPAP resources, during ISO system emergencies. Similar to ELRP, the DSGS program was focused on out-of-market demand-side response, which included both traditional load drop as well as generation from backup diesel generators. Overseen by the California Energy Commission, the DSGS program was originally meant to focus on load within the state of California, which was not eligible to participate in ELRP. It was expanded during the 2022 early September heat wave to overlap with some ELRP territory. The DSGS has both out-of-market and in-market options, but only the out-of-market option was in effect during early September. Like ELRP, participants may be paid up to $2,000/MWh for successful performance. Lastly, there were numerous organized and coordinated efforts to reduce energy demand from state agencies such as the Department of General Services, military

[35] https://www.gov.ca.gov/wp-content/uploads/2022/08/8.31.22-Heat-Proclamation.pdf?emrc=78e3fc
[36] https://www.gov.ca.gov/2022/09/06/as-record-heat-wave-intensifies-governor-newsom-extends-emergency-response-to-increase-energy-supplies-and-reduce-demand/
[37] https://www.cpuc.ca.gov/elrp/
[38] https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf
[39] California State Legislature. 2022. Bill Text – Assembly Bill 205. Sacramento, CA: California Legislative Information.

installations, businesses, water districts, and others. Some of these efforts were captured in ELRP and DSGS participation. As out-of-market resources, the ISO cannot assess participant response for either ELRP or DSGS.

Figure 20 below provides a breakdown of the major categories of non-market resources for each day of the event including load modifying demand response (LMDR), Emergency Load Reduction Program (ELRP), State Power Augmentation Power and Strategic Reserve (SPAP and Strategic Reserve); Demand-Side Grid Support (DSGS), and Other. As noted, the ISO cannot assess actual participant response but provides an estimate below of the overall potential that could have been used in the ISO grid.

Figure 20: Estimated non-market resource impact-side activity



At the time this report was prepared, there were no estimates yet of any market-integrated demand response or non-market resource participant performance. Estimates may become available after the fact. The ISO will report on any performance data for market-integrated demand response once the meter-based settlement data becomes available towards the end of the year.

2.6 Energy Conservation

The ISO issued Flex Alerts[23] on September 1 through 9 to assist in meeting system and net load peak time periods. The estimated response to Flex Alerts looks at the back-casted model results, taking actual weather and behind the meter (BTM) solar conditions into account. In addition, the ISO also estimates the hourly model error that exists by reviewing similar-day model performance.[24] The reconstituted peak on September 6, 2022 at HE 18 is at 52,350 MWs. This is an estimate of what energy demand would have been after taking into consideration demand response and energy conservation.

The conservation estimates highlighted in Table 7 summarizes the estimated range of conservation, which fluctuates based on hourly impacts during the declared Flex Alert. The conservation values are the remaining customer response after adding back in the scheduled demand response and non-market resource estimated response; these additive values include programs such as ELRP, LMDR, DSGS, and the resources from the SPAP and Strategic Reserve.

Table 7: Estimated Conservation impact

Date	Conservation (MW)
September 1	0-500
September 2	230-795
September 3	0-550
September 4	0-540
September 5	0-245
September 6	560-1,510
September 7	None Observed
September 8	320-720
September 9	85-1,410

On September 7, 2022, the Flex Alert had limited impact on the overall energy demand. On September 1, 3, 4, 5, and 9, the hourly conservation impacts from the Flex Alerts ranged from 0 MW to 550 MW. On September 2, 6, and 8, hourly conservation impacts from the Flex Alerts ranged from 230 MW to 1510 MW; the largest conservation impacts occurred between HE 19 and HE 21.

Figure 21 shows the estimated load reduction for September 6, the peak day of the heat wave. During this day, you can see large participation on ISO demand response reflected in the difference between the Observed Load (red) and the Observed Load + DR (dashed yellow).[40] In addition, conservation savings were observed, especially during HE 19. The conservation savings can be seen looking at the difference between the Reconstituted Load Actuals (Blue) and Observed Load + DR.

[40] The Observed Load and the Observed Load + DR does not include pump loads and battery storage that is charging on the system.

Figure 21: Estimated load reduction for September 6

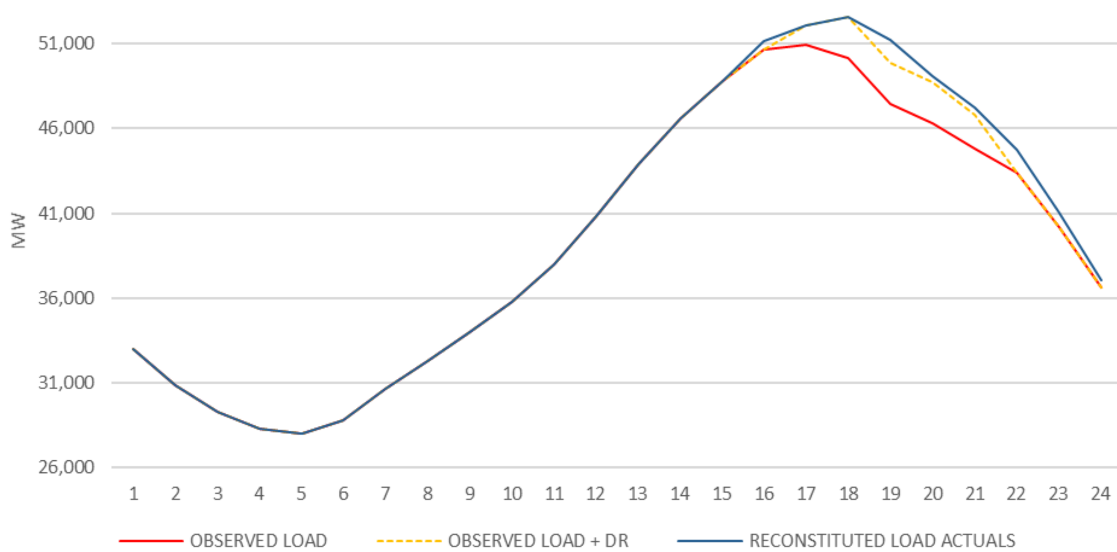
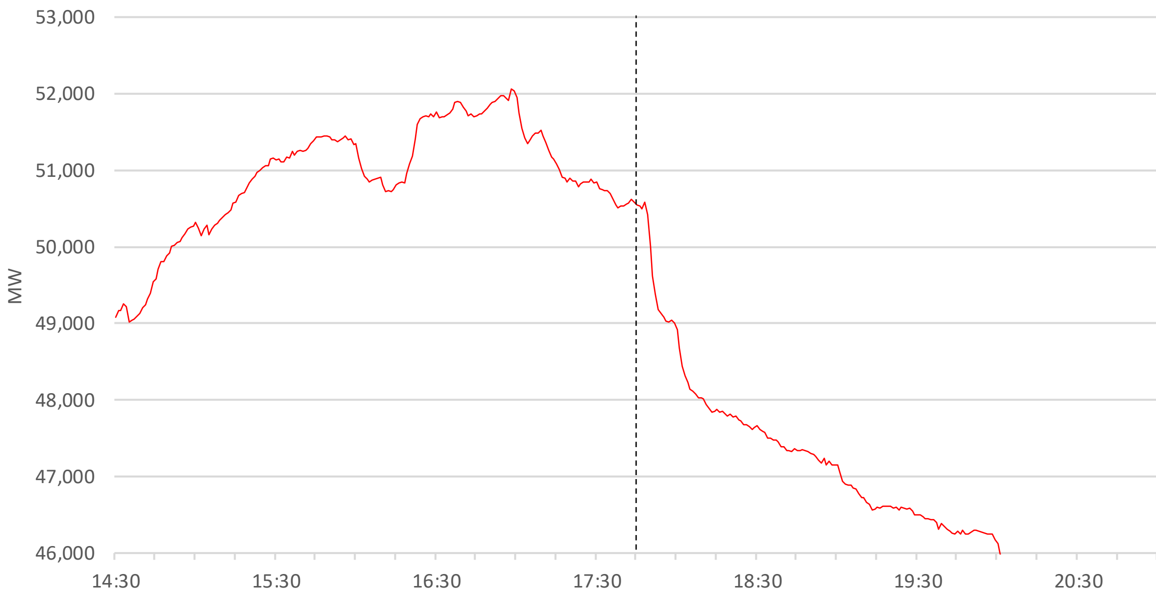


Figure 22: Load profile following the Cal OES emergency call



On the peak load day, September 6, the largest of load reductions came at HE 19 in response to the California Governor's Office of Emergency Services (Cal OES) issuing an emergency alert in the forms of a phone call and text message to California residents at 5:45 PM, consumers to reduce non-essential electricity use if it was safe to do so.[41] Figure 21 depicts the estimated savings for September 6, while Figure 22 illustrates the real-time reduction in demand that ISO operators saw in response to the Cal OES

[41] https://news.caloes.ca.gov/state-officials-sent-cell-phone-alerts-to-protect-public-safety-amidst-ongoing-record-heat-energy-grid-shortfalls/

text message. As seen in Figure 22, a significant amount of demand reduction was observed when the grid needed it the most from 17:48 to 18:04 on September 6 following the Cal OES alert. During this time, the ISO observed a load drop from 50,409 MWs to 48,024 MWs. Of this reduction, approximately 1,510 MW during HE 19 is attributed to energy conservation brought about by the Flex Alert, the Cal OES alert and other factors impacting the energy demand. Due to a lack of meter data, the precise impact of the Cal OES message is unable to be determined.

Lastly, on September 9, savings from HE 21 could have been caused by in-day cancellation of ELRP. This day the grid was impacted by Hurricane Kay, and lower temperatures were observed, while load came in in lower than what was anticipated during the day-ahead time period. Due to this there was an in day change of EEA status. At this time, it is unknown whether cancellation of EEA-1 and EEA Watch on September 9, 2022 at 6:00 PM were executed in time to affect customers' participation.[42] Thus, the conservation effort observed in the Flex Alert analysis could be an over-estimation of approximately 800 MW.

[42] http://www.caiso.com/Documents/Grid-Emergencies-History-Report-1998-Present.pdf, page 42-43

3 Demand and Supply

3.1 Resource adequacy

The ISO manages a RA program under its tariff that operationalizes the RA requirements established by the local regulatory authorities in its balancing authority area, including that established by the CPUC for its jurisdictional load-serving entities (LSEs). The CPUC program applies to the Investor-Owned Utilities (IOUs), Community Choice Aggregators (CCAs), Energy Service Providers (ESPs) and Direct Access (DA) customers, which collectively covers about 90 percent of the ISO's load. This construct ensures through contractual obligations that there is sufficient supply capacity to meet the system's needs and to operate the grid reliably.

The CPUC RA program includes setting the monthly obligations based on an electric load forecast and planning reserve margin (PRM). The California Energy Commission estimates the electric load forecast used by the CPUC in its RA program. Non-CPUC jurisdictional LSEs can set their own RA program. RA capacity from both CPUC and non-CPUC jurisdictional LSEs is shown to the ISO annually and monthly following a process established by the ISO.

Through the RA program, there are three types of capacity: System, Local and Flexible. All three products serve a purpose in ensuring a reliable operation of the system. The events of September 2022 were primarily a result of insufficient system supply to meet the overall system demand. For system capacity, the RA requirement ensures the contracted capacity is sufficient to cover the 1-in-2-year (average) peak load plus a 15 percent PRM.[43] This PRM is to cover the 6 percent of operating reserves, while the rest is a contingent headroom to account for higher-than-expected load forecast and resource outages.

The monthly RA showing for September 2022 was 49,748 MW, which is higher than September's 2021 monthly showing of 48,623 MW.[44] Figure 23 compares the total monthly RA capacity in September between 2021 and 2022 by fuel type. Although the total RA capacity in September's 2022 is about 1,125 MW higher than that of 2021, there are some marked variations in the RA composition. RA capacity increased by 1,210 MW in storage resource, which fully offsets the reduction of 587 MW of static imports along with a reduction in hydro RA of about 443 MW whereas gas-fired RA saw an increase of 63 MW.

Static RA import showings decreased from 4,259 MW in September 2021 to 3,671 MW in September 2022.[45] The composition by intertie varied between years as shown in Figure 24. RA imports through Malin decreased from 2,162 MW to 1,634 MW from September 2021 to September 2022, while imports through

---

[43] The official planning reserve margin is 15 percent for the CPUC jurisdictional entities. Per Decision 21-03-056, the CPUC increased the "effective" planning reserve margin to 17.5 percent for 2021 and 2022 but this is met with both RA and above RA resources that may also not be in the wholesale market.

[44] These values are based on the monthly showings estimates available at the time of preparing this report. These monthly showings are provided through the supply plans to meet the final RA obligation. The final RA obligation is composed of the forecast plus PRM and then all credits, including DR, are deducted. The total RA values can change through the month, with weekend showing typically a significant reduction. For simplicity in the reporting and comparison, the simple average through the month is used as a reference in this report. Also, the total RA values represented in this report include any CPM and RMR capacity.

[45] Dynamic and pseudo tie resources are grouped into the corresponding fuel type instead of the generic import group. Generic imports are referred as Static imports in this report.

NOB decreased from 1,046 MW to 997 MW across the same timeframe. Imports on Malin and NOB account for about 70 percent of all static RA imports both September 2021 and September 2022.

Figure 23: September's 2022 RA organized by fuel type

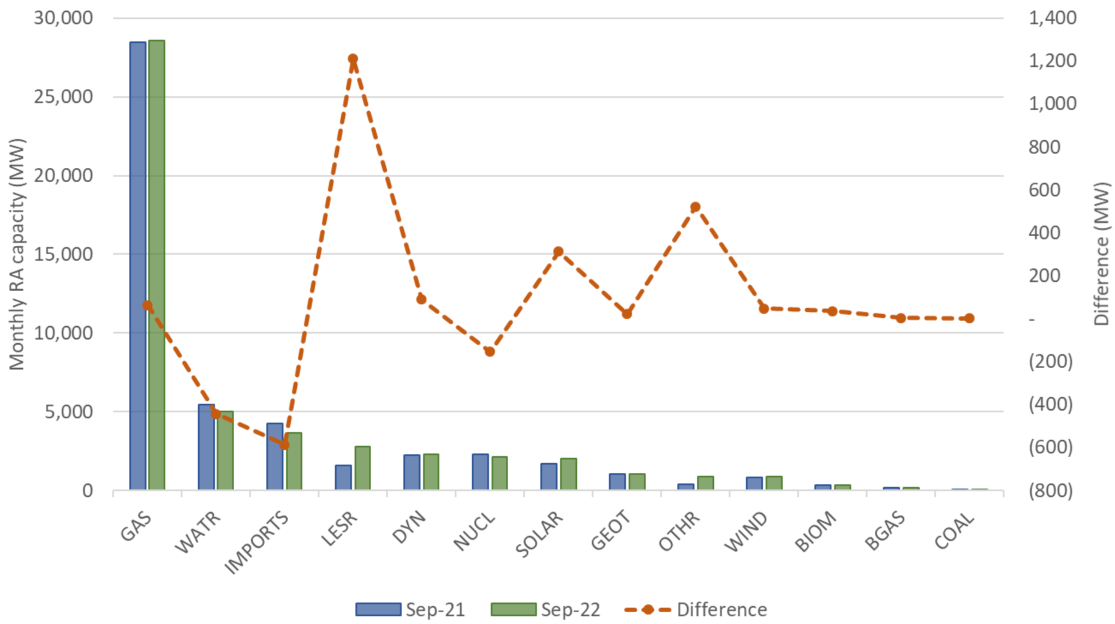
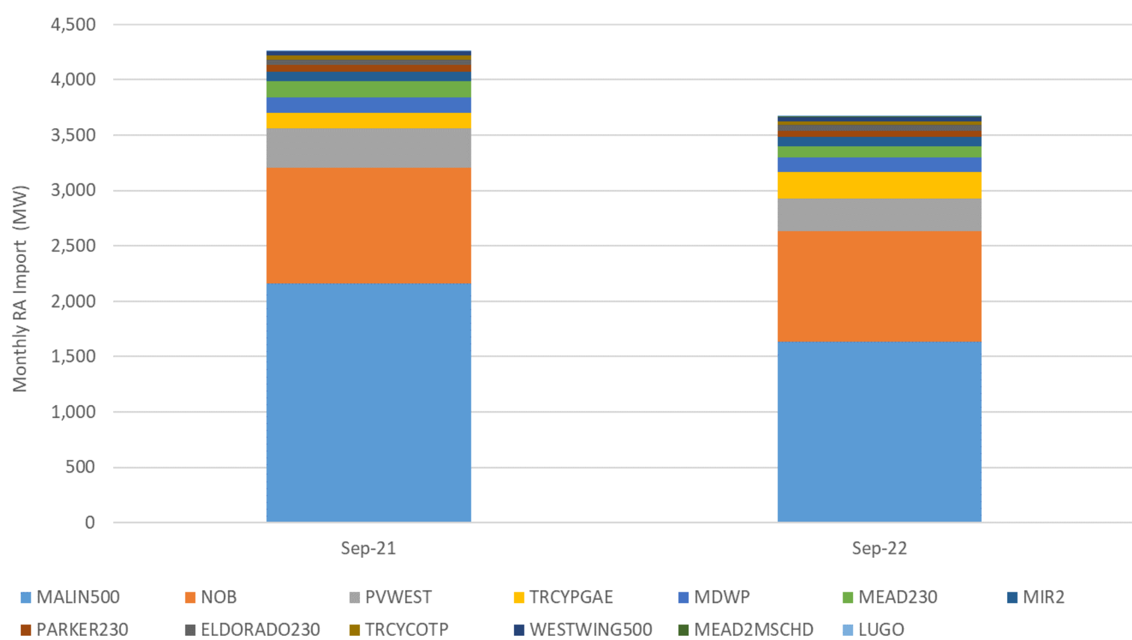


Figure 24: Monthly RA organized by tie



RA static import showings (without pseudo-ties and dynamic resources) declined in September 2022 to 3,671 MW relative to 4,259 MW in September 2021. Overall, RA and RA imports tend to increase through summer. These trends are shown in Figure 25: and Figure 26.

Figure 25: Monthly RA showings

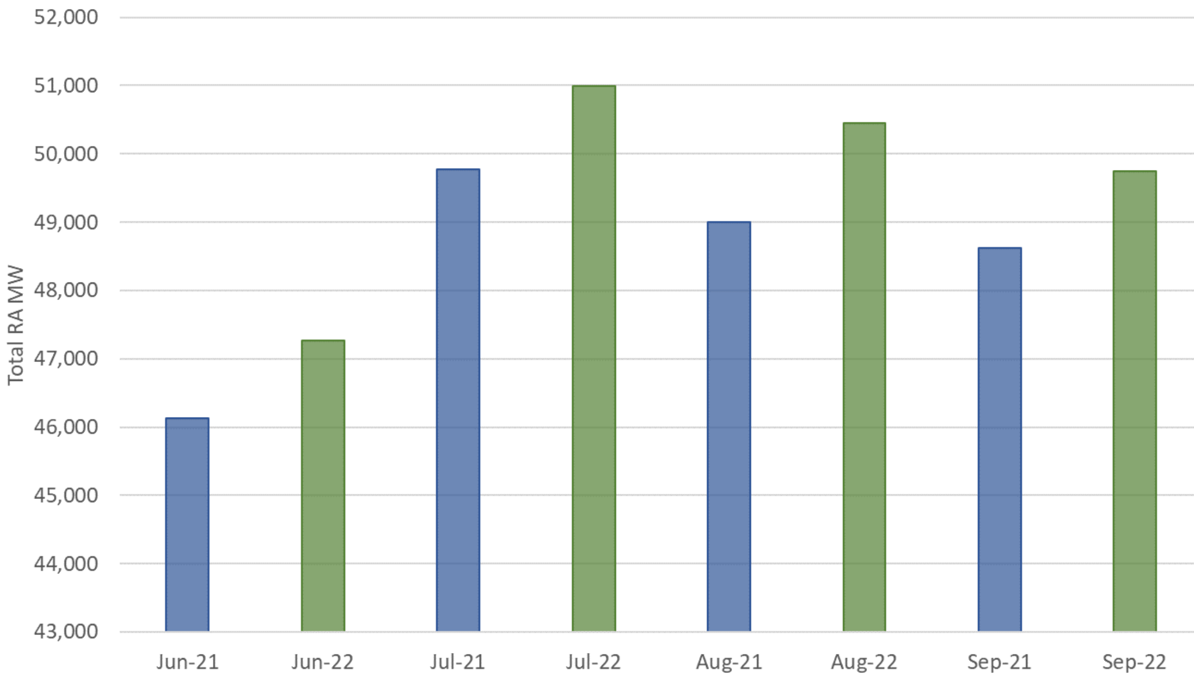
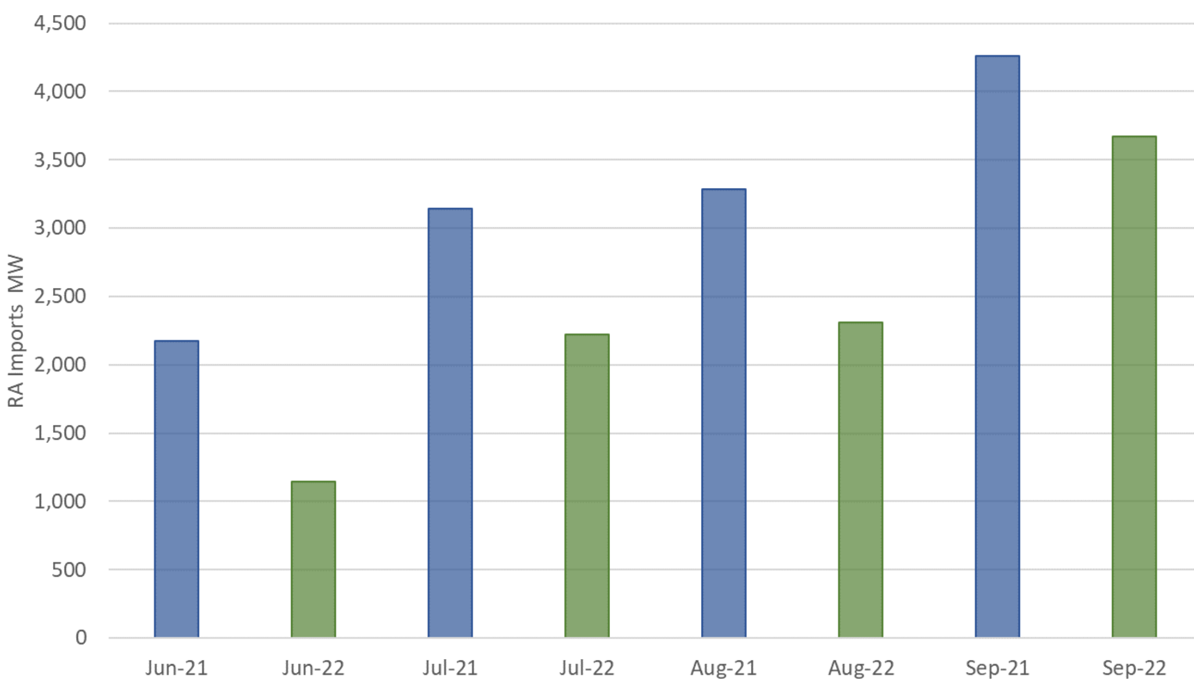


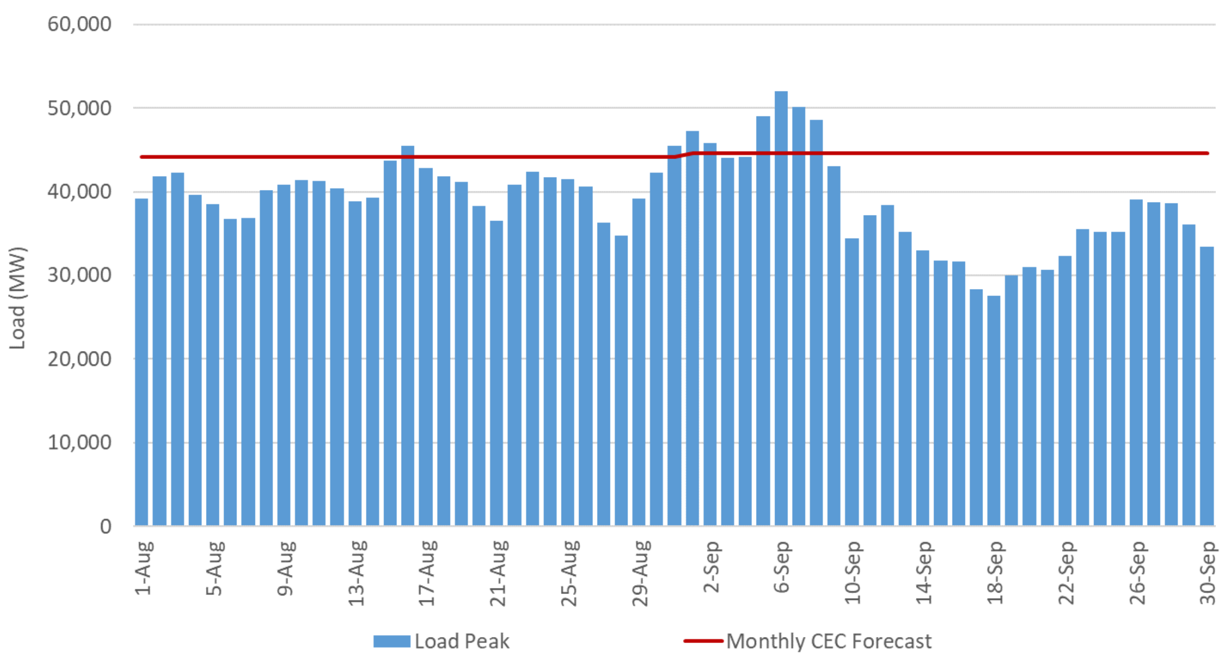
Figure 26: Monthly trend of static RA Imports



3.2 Peak loads

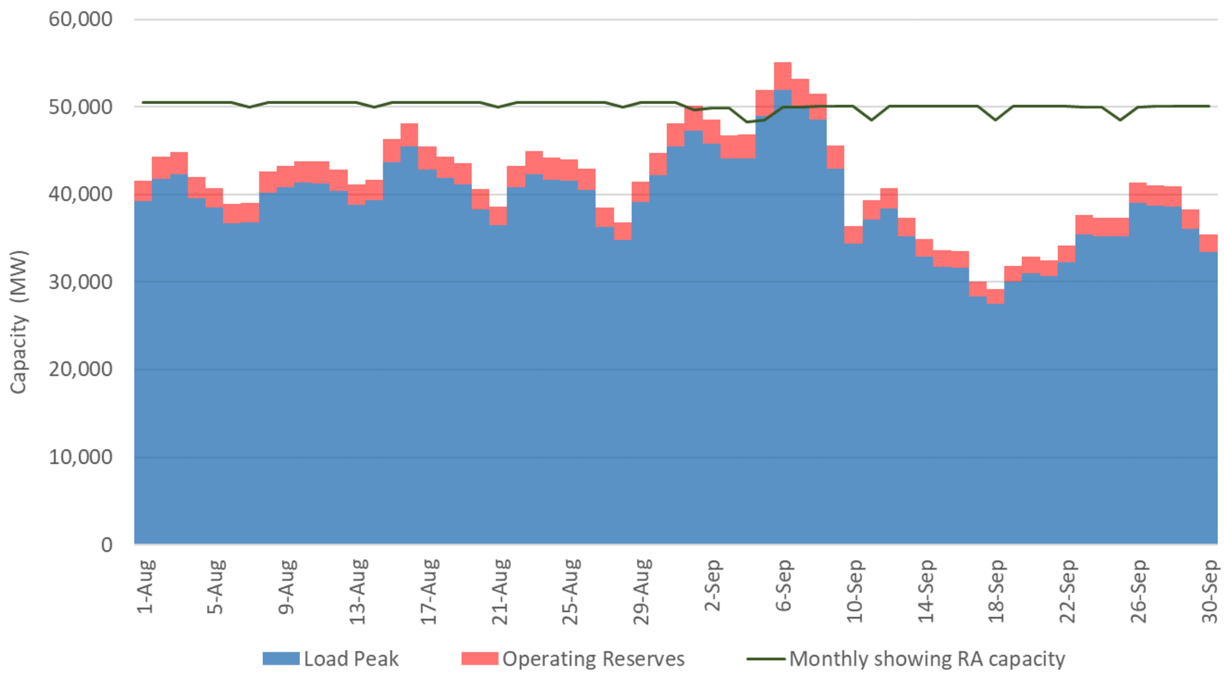
Peak loads in September 2022 exceeded 40,000 MW on multiple days and indeed exceeded the 50,000 MW mark. The average peak load in September was about 37,705 MW, lower than the average peak load of August 2022 of 40,148 MW mainly due to the lower demands observed in the second part of September. Figure 27 shows the 5-minute daily load peak for the June to September relative to the CEC month ahead forecast used to assess the RA requirements. The highest instantaneous peak load in the month happened on September 6 at 52,061 MW and was above the CEC month-ahead forecast of 44,578 MW.

Figure 27: Daily peaks of actual load from August to September 2022



The actual load did exceed the monthly RA showings for the month of September 2022 during the period of September 5 to 8, as illustrated in Figure 28. The green line indicates nominal monthly RA showings. As discussed later in this report, the actual capacity made available into the ISO's market (accounting for outages and other factors) can vary from day-to-day. In subsequent sections, the actual RA capacity made available in the market is represented as a trend over for the month on an hourly basis, which more accurately represents RA capacity available to meet demand.

Figure 28: Daily peaks and RA capacity for August and September 2022



3.3 Demand scheduling

In the ISO balancing authority area, the IFM in the DAM uses bids for energy and ancillary services for supply and demand. The IFM allows the demand to bid into the market and clears based on the bid-in demand and supply. The IFM bid-in demand for the same trading day and hour was below the day-ahead demand forecast during the heat wave from September 1 to 8, whereas following the heat-event, bid-in demand came in over the day-ahead demand forecast. Figure 29 below shows the difference between IFM bid-in demand and day-ahead forecasted demand. The positive number indicates bid-in demand was over the day-ahead forecast. Figure 30 shows the hourly averages for the difference between IFM bid-in demand and day-ahead forecasted demand for the month of September 2022. On average, the bid-in demand was higher than the load forecast from 9 to 15 hours, whereas the bid-in demand was below the load forecast during the peak hours.

Figure 31 below shows the average difference between the bid-in demand for the metered load for the month of September 2022 organized by load-serving area. In addition, Figure 32 shows the hourly profile of the load differences by area for the month of September 2022. Based on the lessons learned during the summer of , this analysis may suggest that load-serving entities continue to experience challenges in coming to the market with accurate load forecast to construct their bid-in demand. The load forecast for the extreme heat wave posed a challenge since it reached levels not seen before and there were not many historical data points to rely on.

Figure 29: Difference between IFM bid-in demand and DA forecast for September 2022

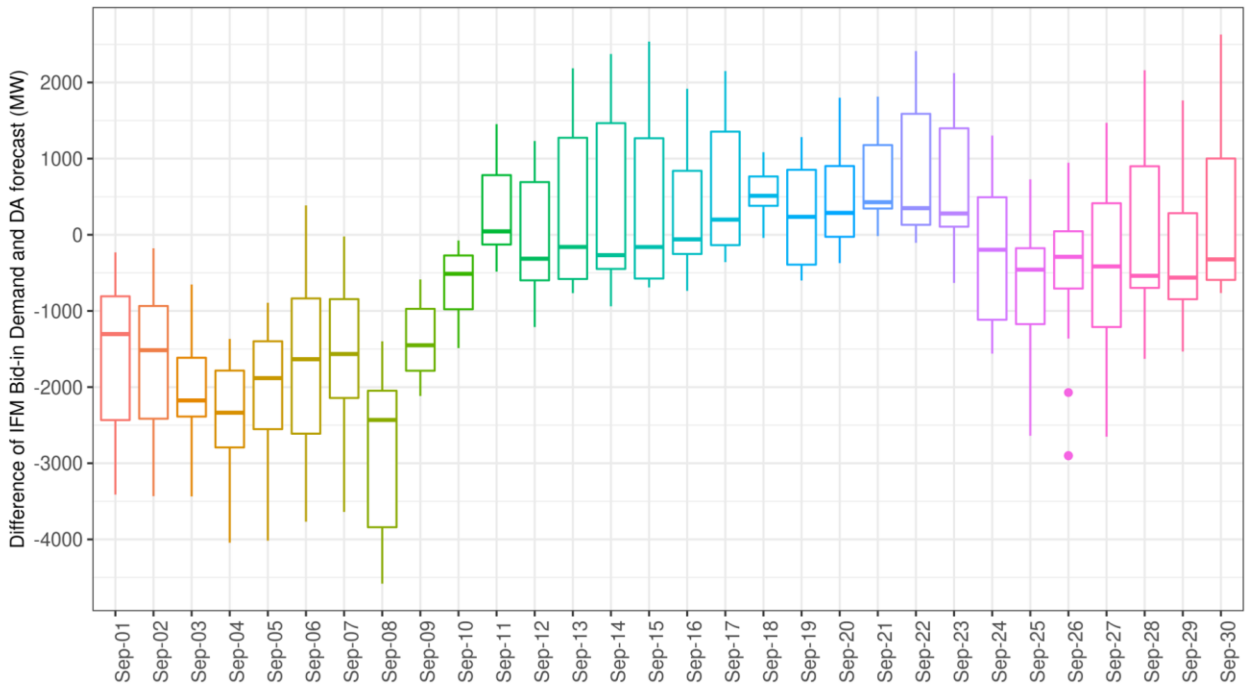


Figure 30: Hourly averages of the difference between bid-in demand and DA forecast for September

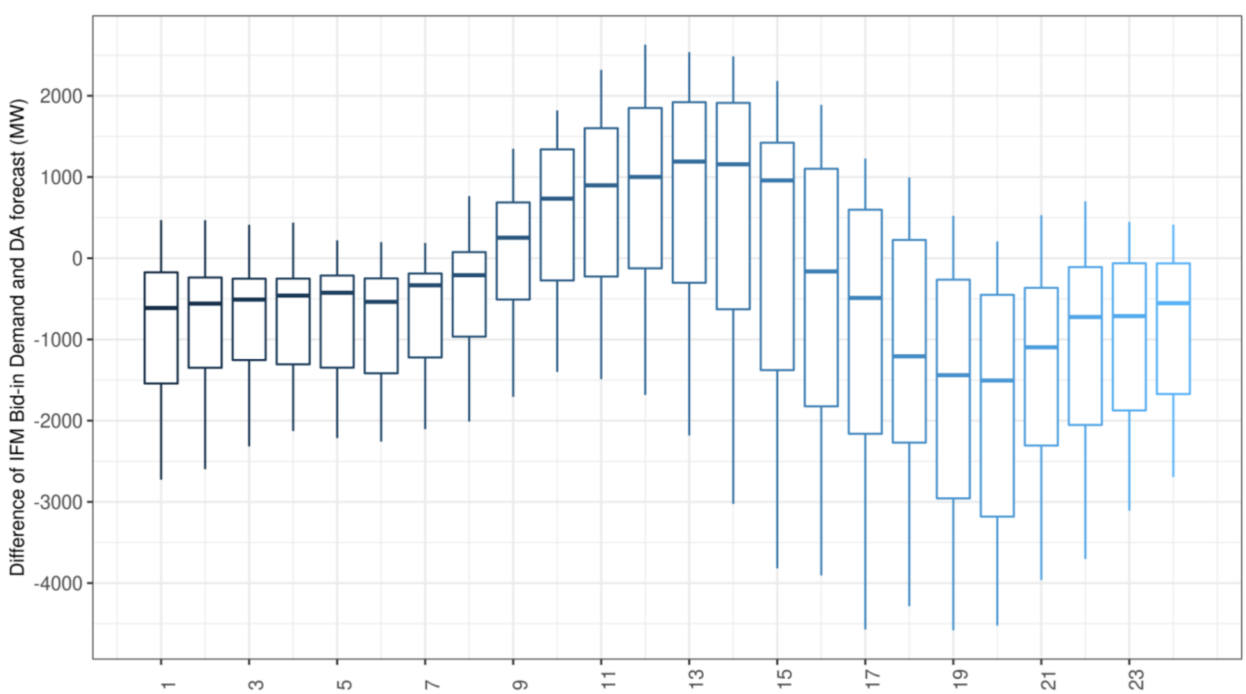


Figure 31: Average difference between bid-in demand and metered load (MW)

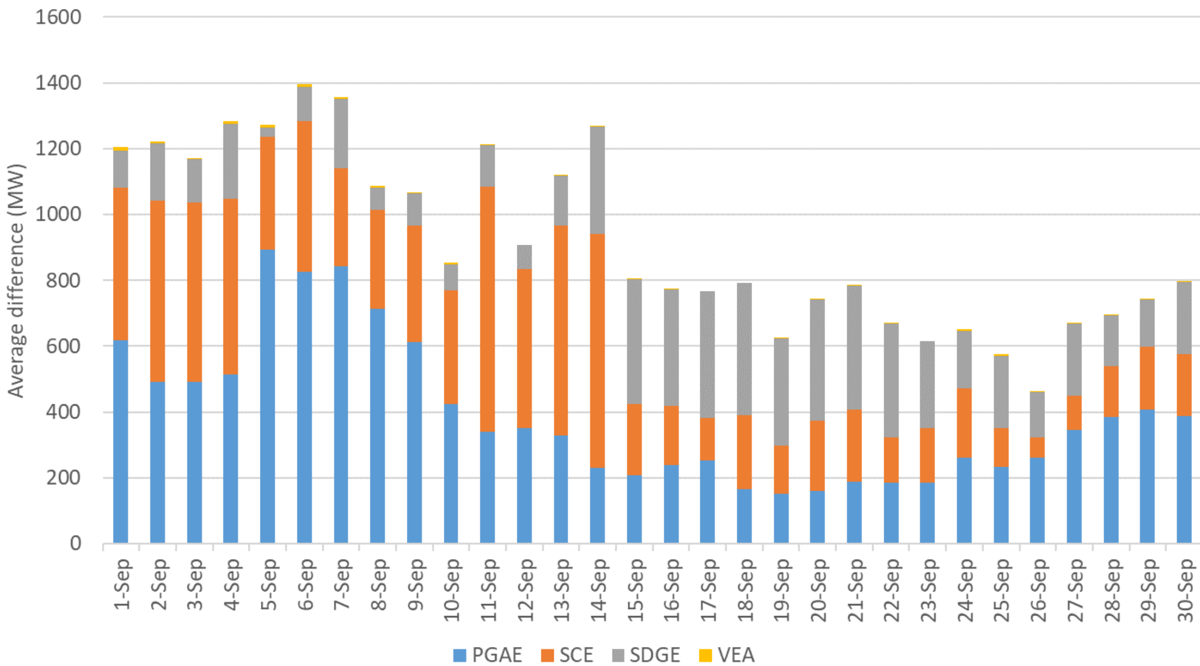
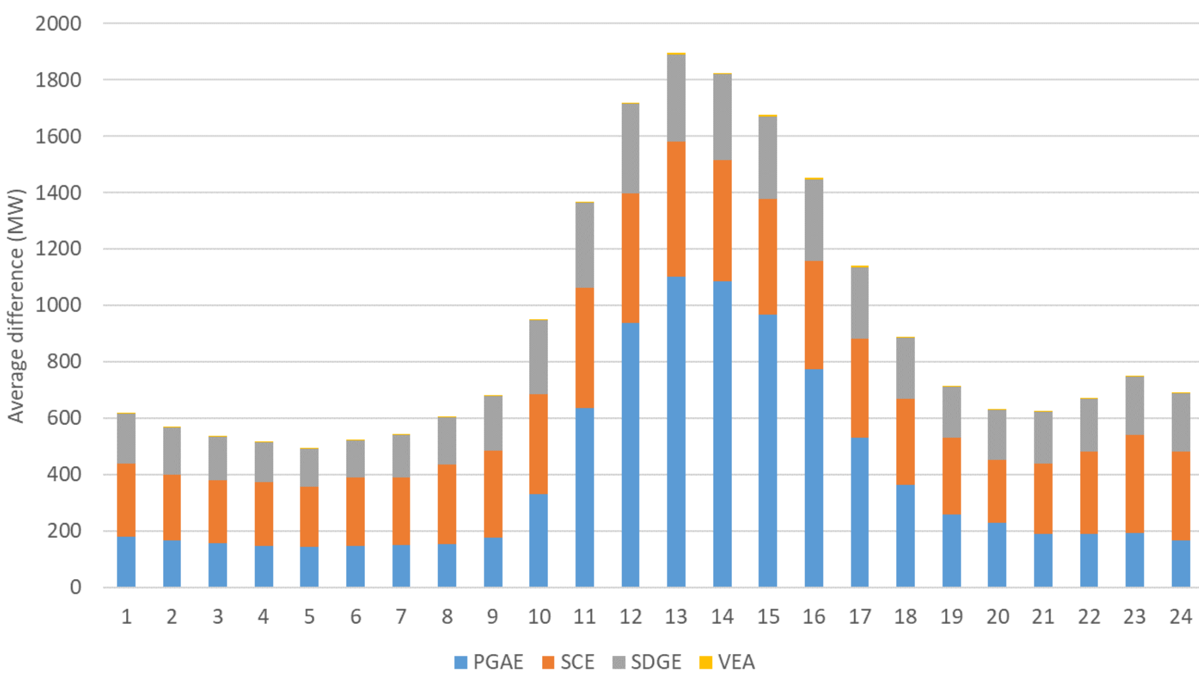


Figure 32: Average Hourly difference between bid-in demand and metered load (MW)



3.4 Market prices

Market prices naturally reflect supply and demand conditions; as the market supply tightens, prices rise. Locations marginal prices (LMPs) have three components: the marginal cost of energy on the system, the marginal cost of congestion reflecting constraints, and the marginal cost of losses. The marginal energy component reflects the impact of supply and demand conditions. Congestion conditions may also create local or regional price separations.

Figure 33 compares the average daily LMPs across ISO's markets for the months of August and September 2022.[46] Pricing trends for June and July 2022 can be referenced in the previously published summer 2022 reports on the ISO website. Prices spiked in the first week of September corresponding to the heat event. On average, prices throughout the month of September were higher than previous summer months, though monthly averages were heavily influenced by the high prices at the beginning of September. For the last two weeks of September, prices were lower and generally consistent with pricing trends from previous summer months.

Figure 33: Average daily prices across markets

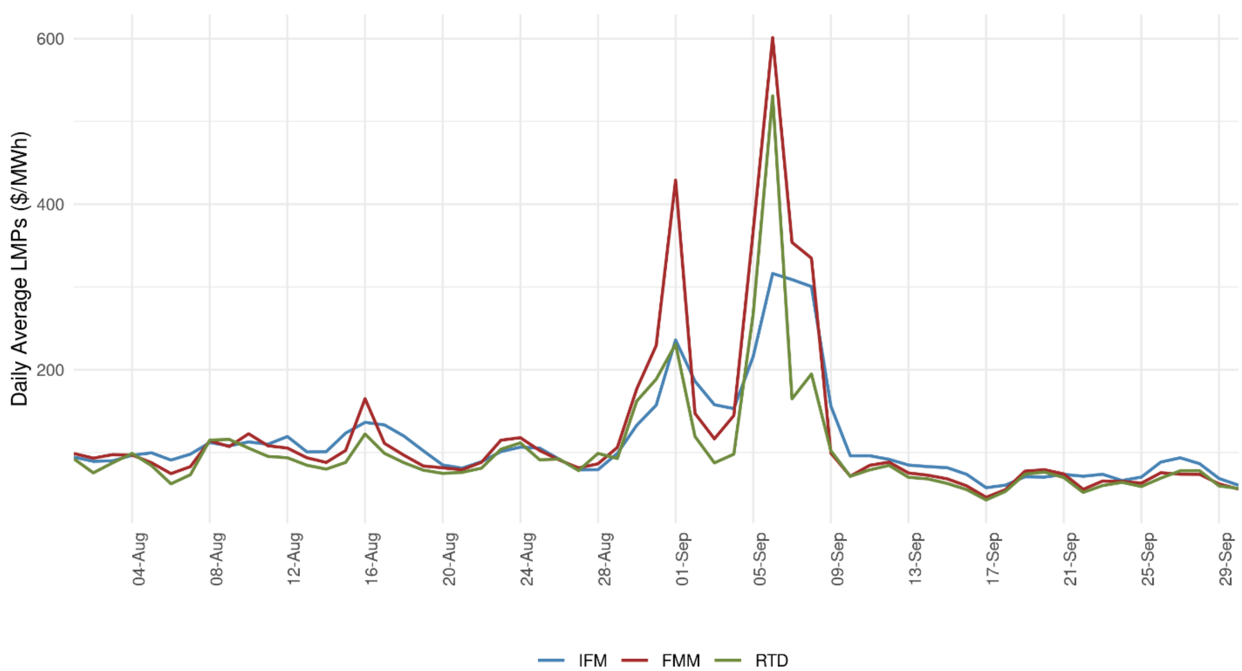


Figure 34 shows average hourly LMPs across the ISO's markets; price divergence is most significant in the peak hours, specifically between 15-minute market (FMM) and IFM/RTD between hours 16 through 22, however price divergence occurs at varying degrees for all hours. Please refer to the section titled "September 5-8 Heat Wave" for more details on prices during the specific days of the September heat event.

[46] DLAP prices are a good indicator of overall prices. However, congestion may create price separation among DLAPs. The metrics presented here are based on a weighted average price of the DLAPs within the ISO area.

Figure 34: Average hourly LMPs across markets

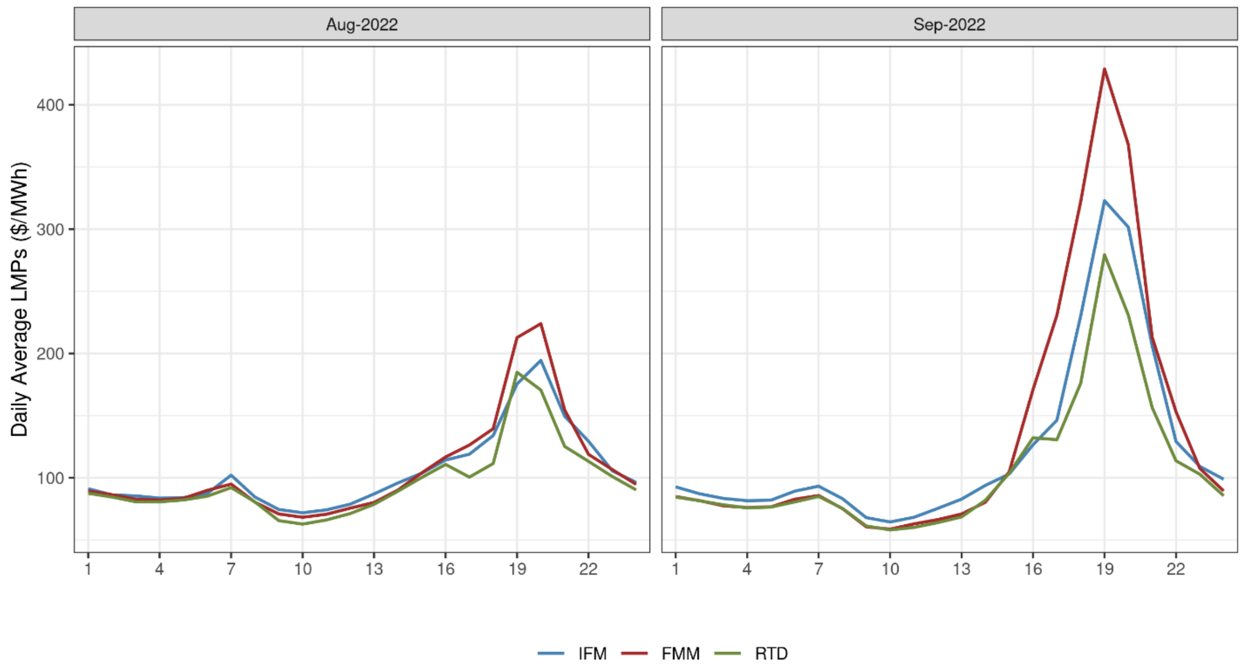
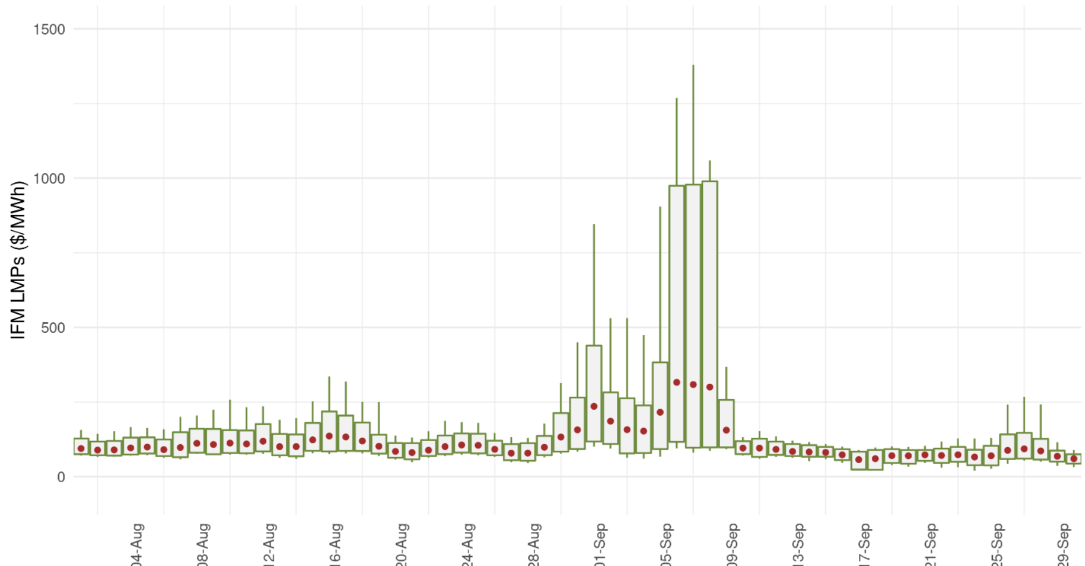


Figure 35 and Figure 36 show the daily and hourly distribution of day-ahead prices with box-whisker plots for the months of August and September 2022. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for the day or hour.

Figure 35: Daily distribution of IFM LMPs



These plots better illustrate the full distribution of prices observed throughout the days and hours of the month. As previously discussed, day-ahead prices in September were much higher on average than past summer months, including August, due to the heat event at the beginning of the month. The average IFM LMP value was $104.53/MWh for the month of September and the maximum price of $1,379.32/MWh occurred on September 7.

Figure 36: Hourly distribution of IFM LMPs

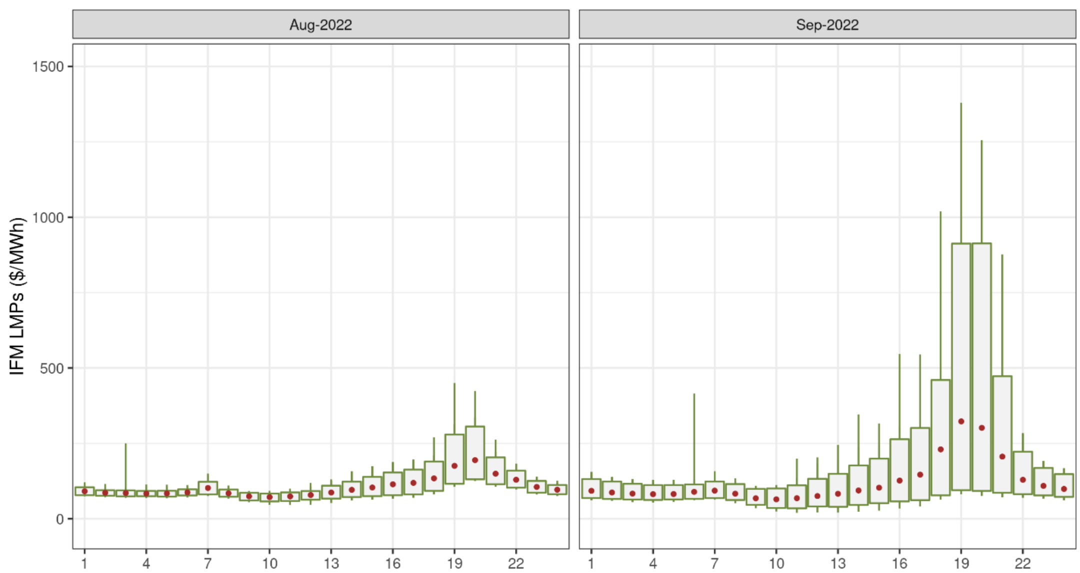


Figure 37: Daily distribution of FMM LMPs

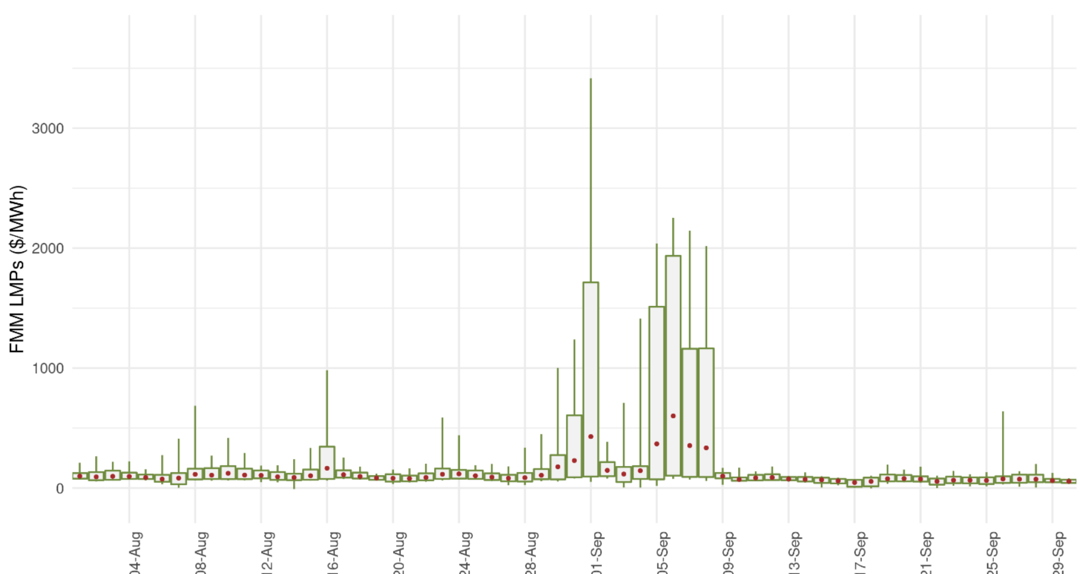


Figure 37 and Figure 38 show daily and hourly distributions of FMM prices throughout the month. Consistent with trends displayed above for IFM, FMM LMPs at the beginning of September exhibited a larger spread driven by the heat event. The average FMM LMP value was $134.54/MWh for the month of September and the maximum price of $3,416.18/MWh occurred on September 1.

Figure 38: Hourly distribution of FMM LMPs

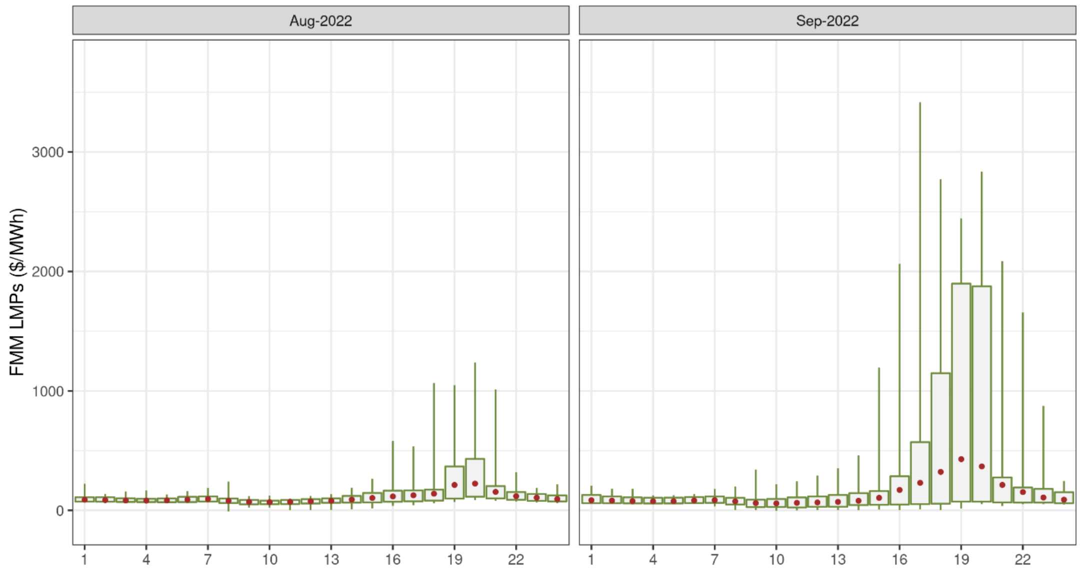


Figure 39 and Figure 40 show the daily and hourly distribution of real-time dispatch (RTD) prices throughout August and September 2022. Consistent with trends displayed above for IFM and FMM, RTD LMPs at the beginning of September exhibited a larger spread driven by the heat event. The average RTD LMP value was $106/MWh for the month of September and the maximum price of $2,035/MWh occurred on September 1. There were also some negative prices observed during the heatwave period driven by congestion on the California-Oregon Intertie (COI) constraint.

Figure 39: Daily distribution of RTD LMPs

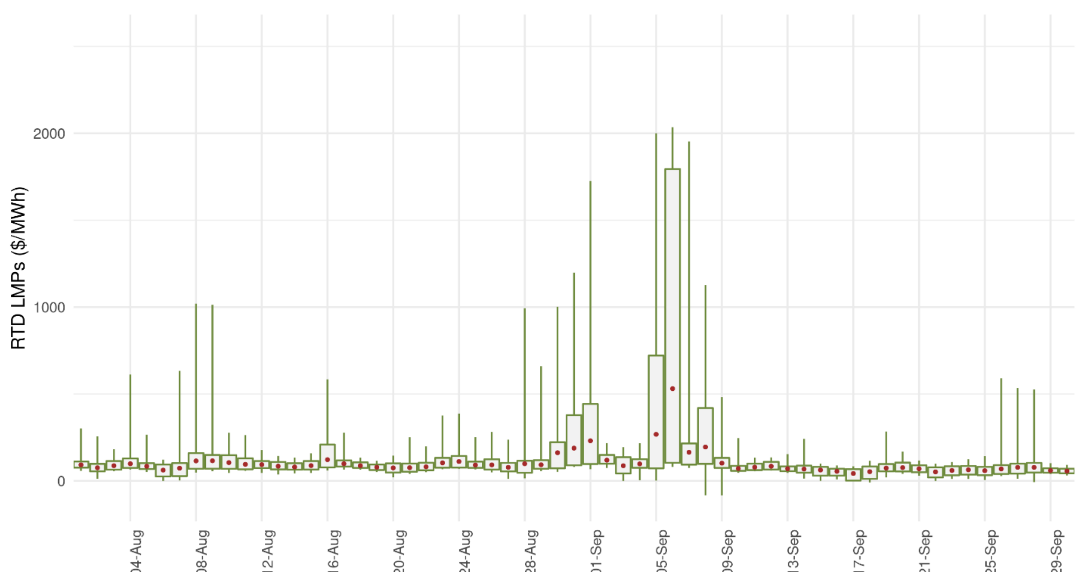
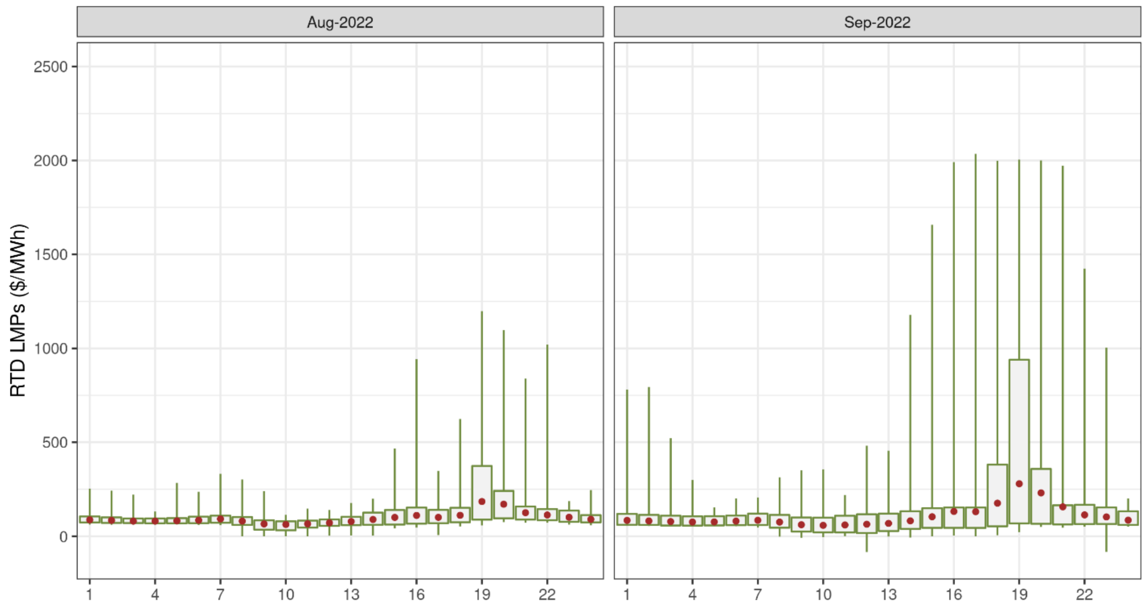
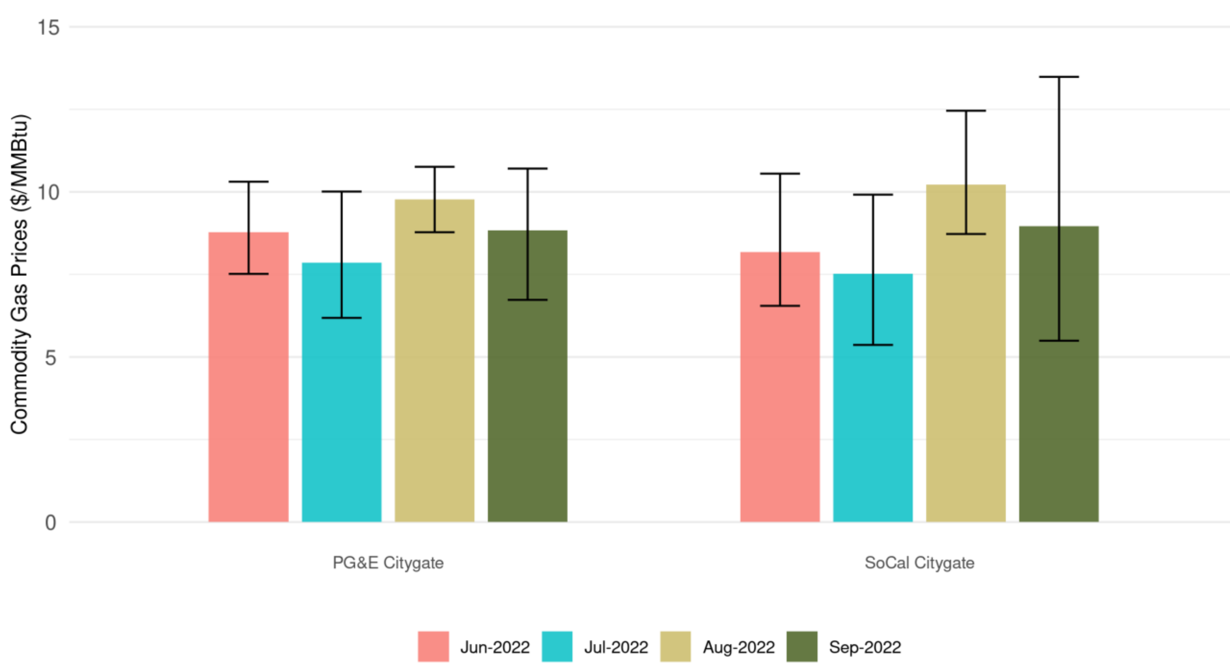


Figure 40: Hourly distribution of RTD LMPs



Because the ISO's generation fleet consists of a meaningful amount of gas resources, the gas market and system dynamics typically have an impact on the electric market and consequently electricity prices generally track gas prices. Figure 41 shows the average prices (bars in red, blue yellow, and green), and the maximum and minimum prices (whiskers in black), for the two main gas hubs in California.

Figure 41: Gas prices at the two main California hubs



On average, gas prices were lower in September 2022 as compared to August, but higher than both June and July. However, gas prices traded higher during the first week of September as the heat event unfolded. SoCal Citygate saw some of its highest-traded prices of the summer so far, reaching a maximum value of almost $16/MMBtu on September 1. For the month of September, next-day gas prices averaged $8.83/MMBtu and $9.41/MMBtu for PG&E Citygate and SoCal Citygate, respectively.

Figure 42 shows daily average electricity prices from the ISO DAM (y-axis) relative to next-day gas prices at SoCal Citygate (x-axis) and the peak load (color gradient from blue to pink) on a daily basis for the months of August and September 2022. The light blue line shows a simple linear regression applied to the dataset. Figure 43 shows the same metric using next-day gas prices at PG&E Citygate. Peak loads ranged widely and this comparison exhibits a good degree of correlation between electricity and gas prices. In addition, it can be observed that electricity prices generally rise when load levels are higher.

Figure 42: Correlation between electricity prices, SoCal Citygate gas prices and peak load level

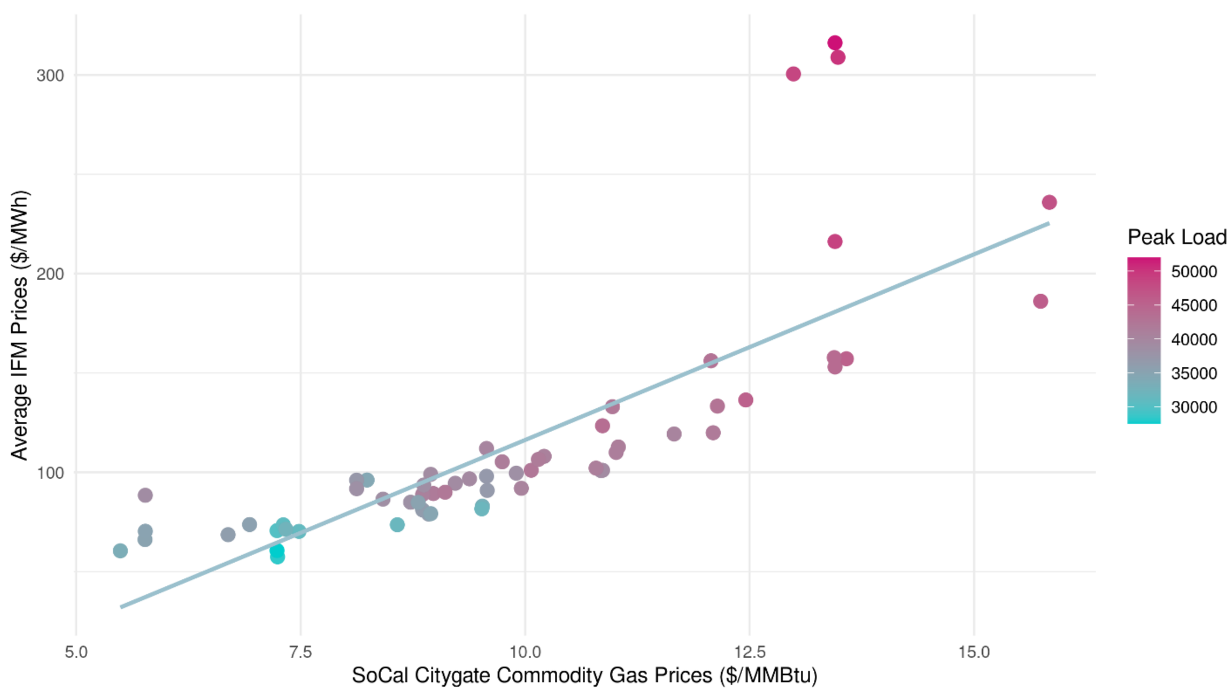
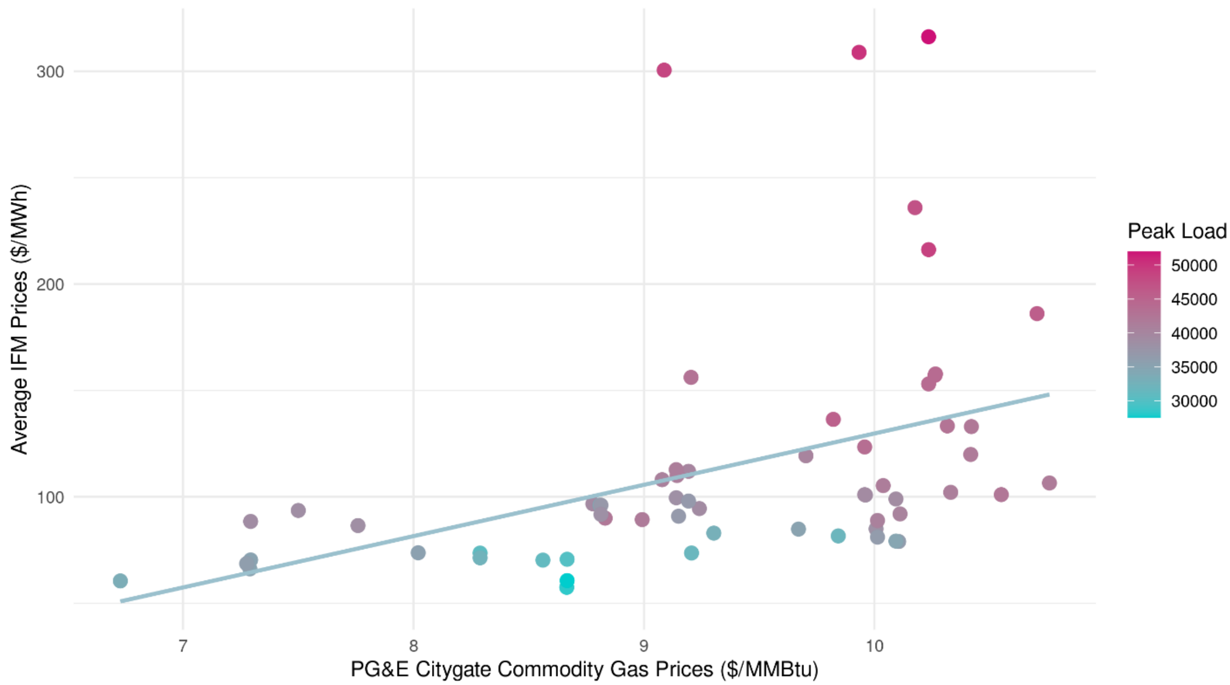


Figure 43: Correlation between electricity prices, PG&E Citygate gas prices and peak load level



4 Bid-In Supply

The ISO's markets rely on supply made available from different resources, including internal supply of various technologies and imports. Supply capacity is bid into the market with three components: startup costs, minimum load costs and incremental energy costs. The bid-in capacity is adjusted for any outages and derates on an hourly basis to reflect the actual available supply. That available bid-in capacity is then considered in the market optimization along with the resource's characteristics and system constraints. In addition to supply capacity from RA resources, the market also considers bid-in supply from above RA resources. This supply does not have an RA obligation but economically and voluntarily participates in the ISO's markets. Based on the submitted bids, the market will optimally determine the least-cost dispatch of all resources to meet the bid-in demand in IFM or the load forecast in RUC. It is not unusual that above RA capacity be dispatched before all the RA capacity is exhausted since resource dispatches are based entirely on prices and resource characteristics and system conditions, and there is no merit order based on whether they are RA or not.

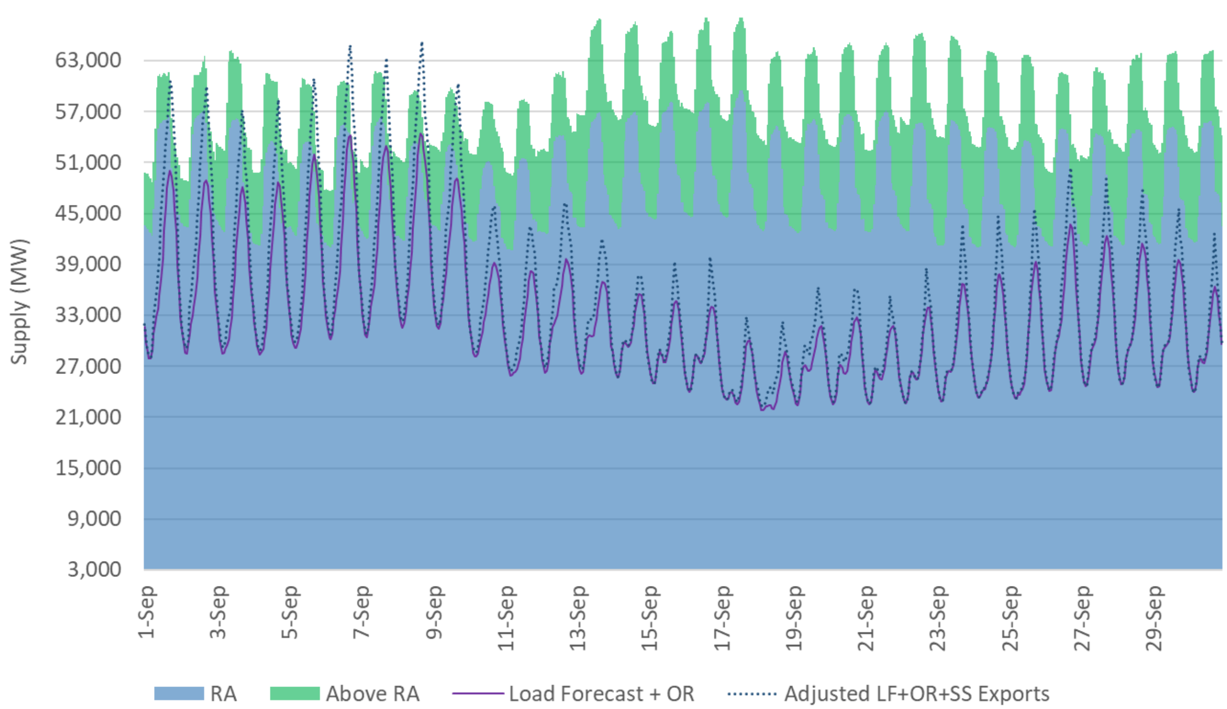
In the RA program, there are certain qualifiers for a resource's capacity to be eligible to count towards meeting the RA requirements. The CPUC developed a Qualifying Capacity (QC) requirement based on what a resource can produce during peak load hours. For conventional resources such as gas and hydro, the QC value is based on maximum output of the resource. For wind and solar resources, the QC values are based on a statistical methodology known as effective load carrying capability (ELCC). This approach will estimate QC values for wind and solar significantly below their maximum output. Resources are then assessed for deliverability to determine their net qualifying capacity, which is ultimately, what is used to determine their RA capacity.

4.1 RA capacity and supply

Since the summer 2020 events, the ISO has been tracking whether RA capacity available in the ISO's markets could be sufficient to meet the needs of both load and operating reserves. To assess this condition, all supply capacity is classified accordingly relative to its monthly RA value. For any wind or solar resource that has any RA capacity assigned in the month, the entire supply available in the market from that resource is considered RA. For instance, if a solar or wind resource has a supply available in the DAM for 100 MW in a given hour and its RA capacity is 30 MW, the full 100 MW are considered RA capacity. For any other type of resource such as gas, hydro or imports, RA capacity is determined up to the RA monthly value; any capacity above the RA value is considered "above" RA.

Figure 44 shows the breakdown of the day-ahead supply capacity[47] as RA capacity and above RA capacity. The purple line represents the day-ahead load forecast plus the capacity required to meet operating reserves (OR), which is typically about 6 percent of the load value. The dashed line represents the adjusted load forecast plus OR plus high-priority export self-schedules, which represents the overall need to be met in the DAM.

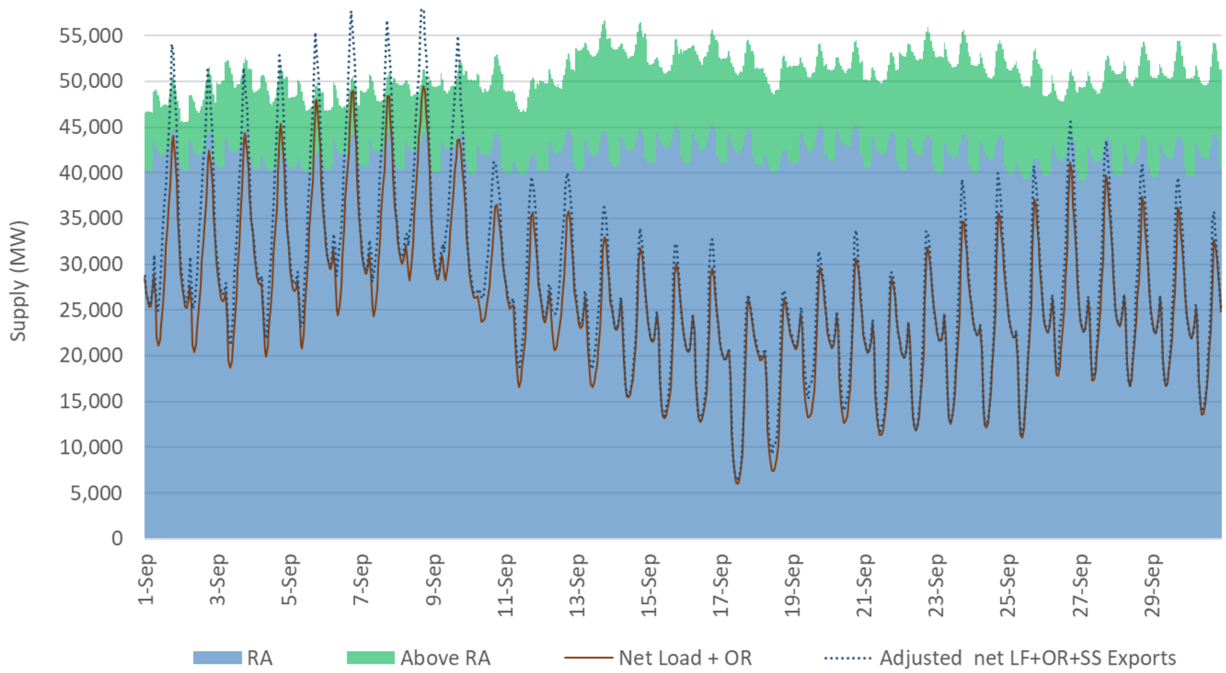
Figure 44: Supply capacity available relative to load forecast in the DAM



[47] This capacity is assessed based on the supply bid in the market and reflects any outages or derates of resources as long as they are known and recorded before the market is run.

Figure 45 has the same capacity breakdown but the comparison is relative to the net load, which is calculated as gross load minus VER forecast. Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

Figure 45: Supply capacity available relative to net load forecast in the DAM



In both trends, the load peaked on September 6. A more granular view of the supply-demand conditions are provided in the September 5 – 8 Heat Wave section below. The RA capacity was sufficient relative to the standard day-ahead load forecast as well as for the adjusted load forecast during the gross and net load peak.

For instances in which demand exceeds the available RA capacity, the market will utilize any other above RA available capacity. For the month of September, above RA capacity was consistently bid into the market.

4.2 Market clearing process

The DAM is composed of three different passes: local market power mitigation (LMPM), IFM and RUC. Each of these market runs has a purpose and each is solved based on a cost-minimization optimization problem. The first pass of the DAM, LMPM identifies structural conditions for the potential exercise of local market power enabled by transmission constraints. The outcome is the identification of uncompetitive constraints and potentially results in the mitigation of specific resource bids. These mitigated bids are then used, together with the rest of non-mitigated bids, in the IFM process to solve the financially binding market where bid-in demand is cleared against bid-in supply. This IFM clears both physical and convergence bid supply against bid-in demand, convergence bid demand and exports, and produces awards and day-ahead prices that are financially binding for all resources. The RUC process uses the IFM solution as a starting point to further refine the supply schedules that can meet the day-ahead load forecast. Operators may adjust the day-ahead forecast to factor in other foreseeable conditions such as load uncertainty. The RUC process will clear supply against the final adjusted load forecast. Figure 46 compares the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast eventually used in the RUC process. Day-ahead load forecast varied through the month, going from high-load days on September 1 to 8 and September 26 to other days with very mild loads.

Figure 46: Day-ahead demand forecast trend in September

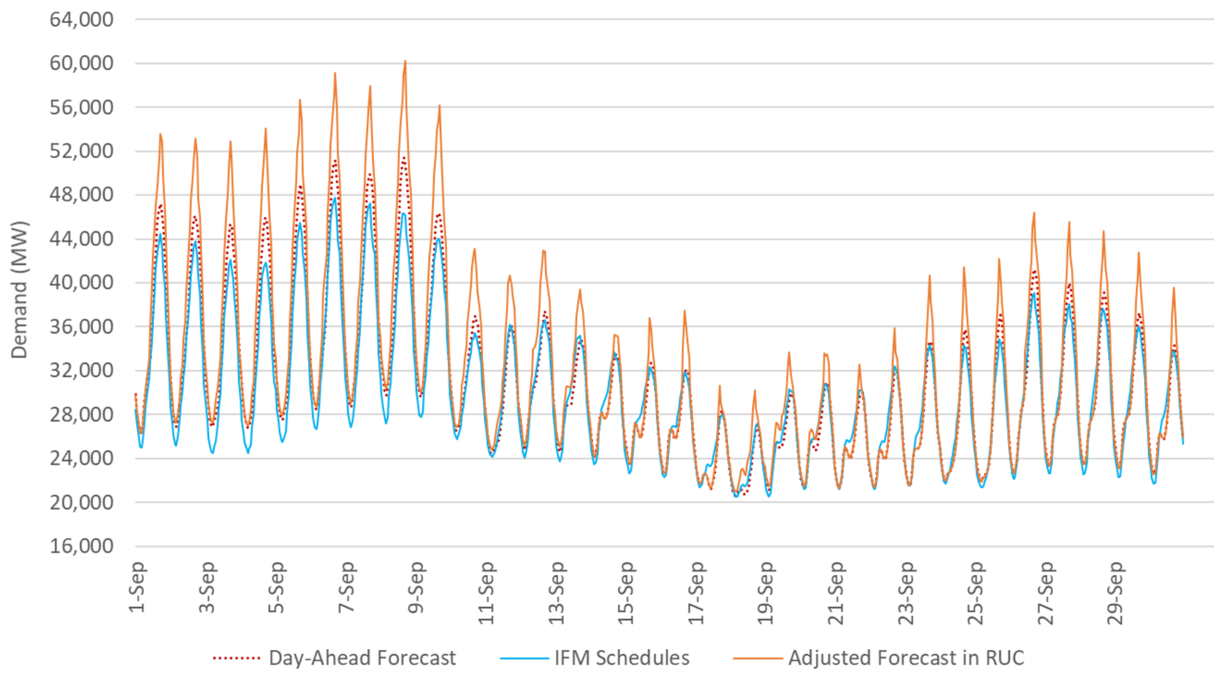
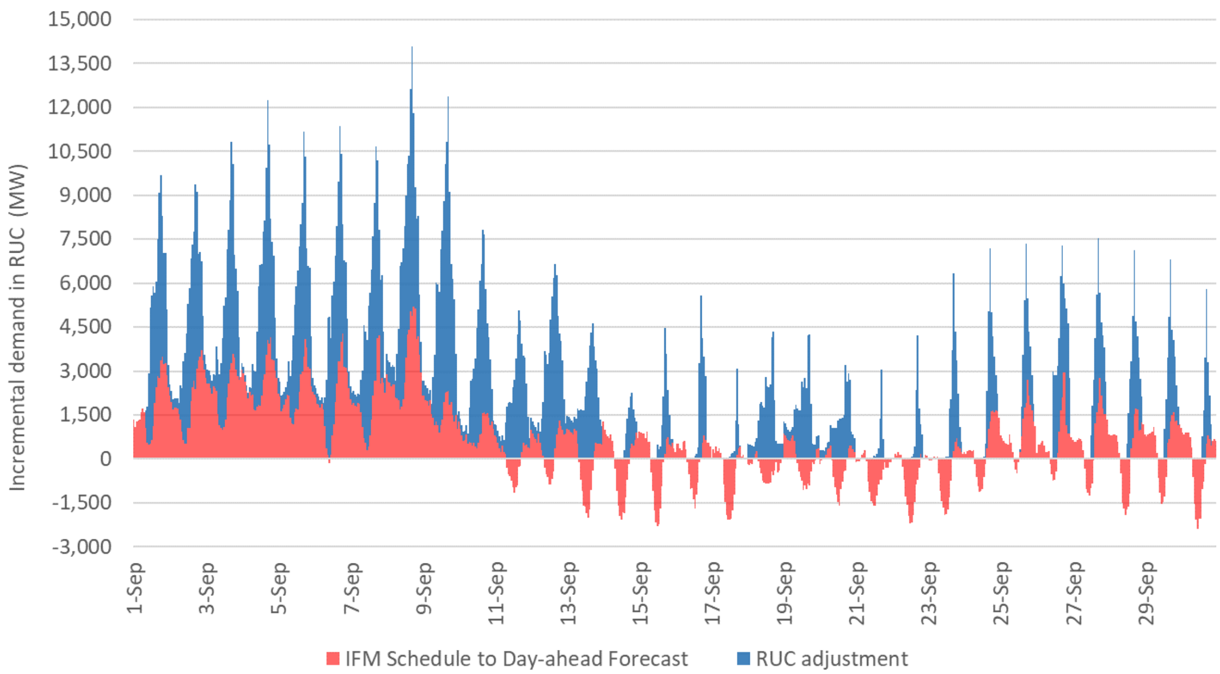


Figure 47 shows the differences between the IFM schedules for physical resources versus the nominal day-ahead load forecast. This is the additional capacity relative to the IFM solution that RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus capacity from IFM that RUC has to meet. The delta is driven by the difference between cleared bid-in demand and the load forecast, as well as any displacement driven by convergence bids. The area in blue is the RUC adjustment to the day-ahead load forecast. In cases when RUC is infeasible, some of this additional capacity will not be met. For most of the first seven days of the month and with milder loads, IFM was already clearing naturally above the day-ahead forecast. As loads increase towards the end of the month, RUC has to clear additional supply to meet the day-ahead forecast, while RUC adjustments done by operators were adding to this requirement.

Figure 47: Incremental demand required in RUC in September



The RUC forecast adjustment is typically guided by a reference of an upper confidence bound and is estimated by the ISO with consideration to weather and load model and renewables uncertainty. In some cases, there may be other factors to consider by operators to determine the final adjustments. With summer conditions from September 1 to 8, IFM schedules and RUC adjustments were predominantly positive, meaning that RUC had to clear higher physical supply than IFM.

Since RUC clears against a load forecast which is not price sensitive, under certain conditions RUC may relax the power balance constraint due to a surplus or shortfall of supply capacity. A relaxation signals that there is an imbalance between the load requirements and the supply available. An infeasible power balance can be in either direction. In hours with low levels of load and minimum downward capability, RUC may observe an oversupply condition, resulting in a negative infeasibility. Conversely, in hours where there is insufficient supply to meet the load requirement, RUC may have an undersupply condition, resulting in a positive infeasibility. Negative RUC infeasibilities occur because RUC can only dispatch a resource down to its minimum load and cannot actually de-commit a resource or set up additional exports. Conversely, positive RUC infeasibilities occur because all incremental RUC bids have been exhausted and RUC has curtailed all the economic and LPT exports,[48] which leaves just the power balance constraint to be relaxed and reducing high priority (PT) exports, to allow RUC to clear. Figure 48 shows

[48] There are different type of exports participation. They can be based on economic bids with prices between the bid floor and the bid cap; they can be price takers, also referred to as low priority exports and labeled as LPT. Exports can also be high priority self-schedule labeled as PT (i.e., not backed by capacity that may be committed to ISO load under its resource adequacy program). If the market clearing process encounters constraints, the ISO will treat PTK exports similar to internal loads, but treats LPT exports as recallable and the market will curtail LPT exports before relaxing the power balance constraint.

the RUC infeasibility against two reference points: one infeasibility is relative to the final adjusted forecast in RUC, while the other is relative to the raw day-ahead forecast. For the month of September, there were RUC under-supply infeasibilities relative to the standard load forecast from September 1 to 8. There were some over-supply infeasibilities especially on September 17. The marked over-supply in September occurred during mid-September when loads came in significantly low in comparison to adjacent days.

Figure 48: RUC infeasibilities in September

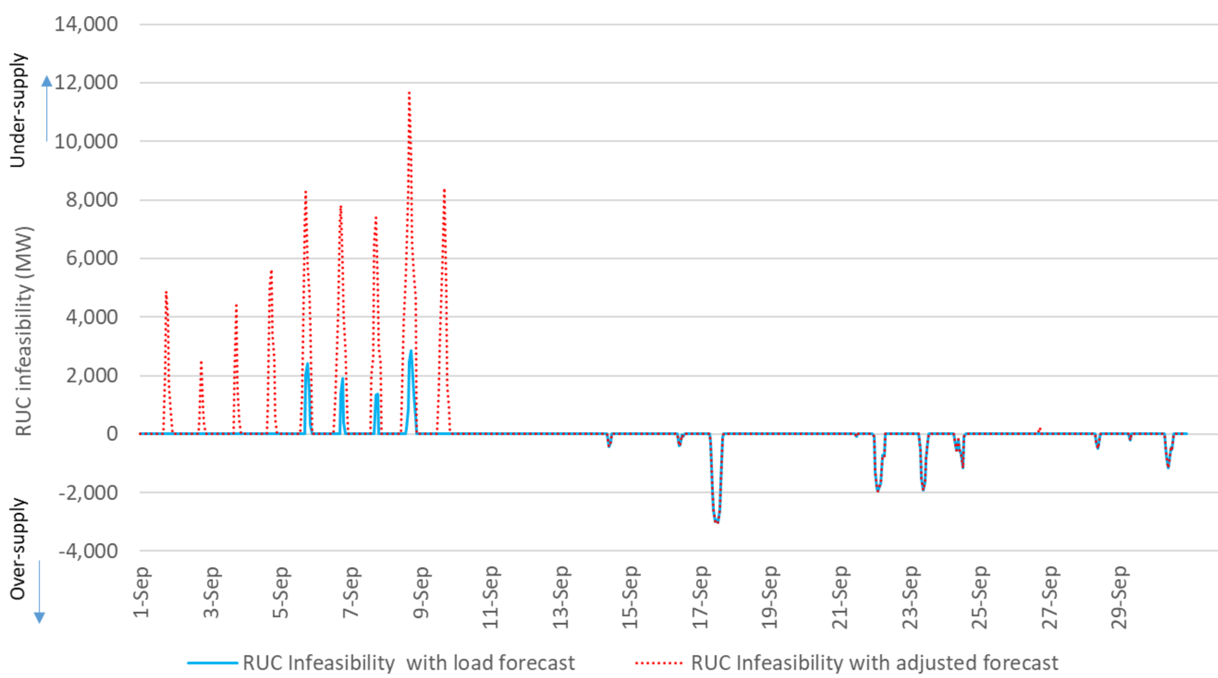
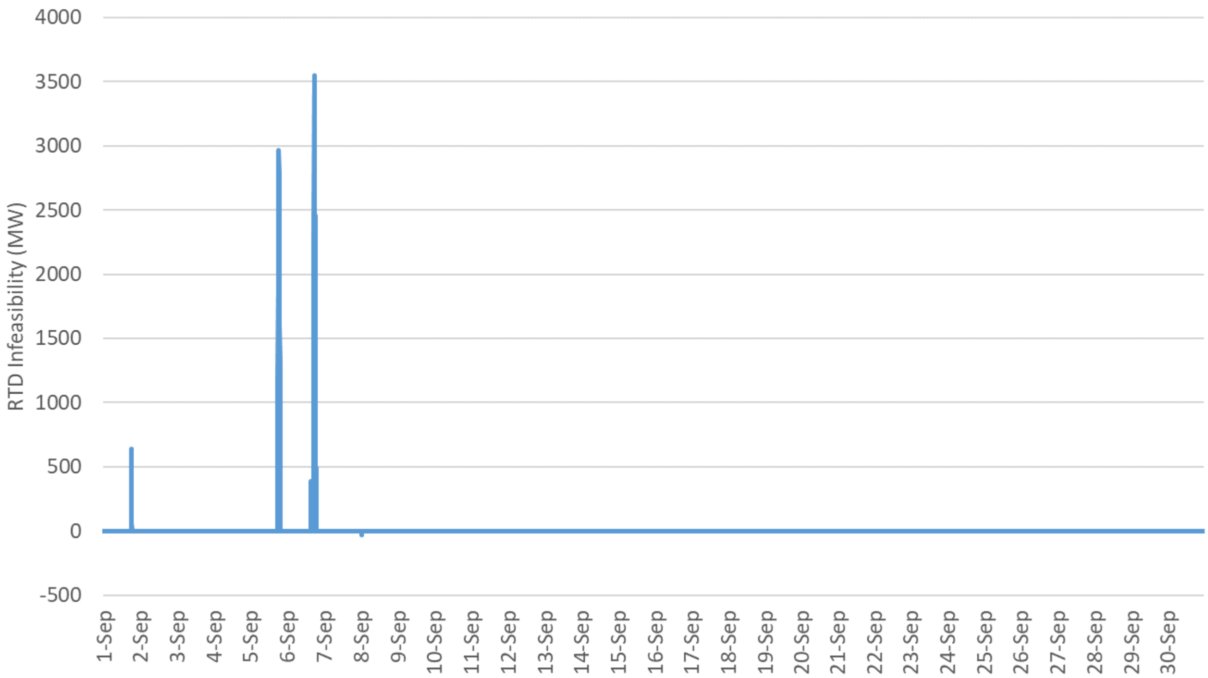


Figure 49 shows the corresponding RTD power balance infeasibilities observed in September; they reached 3,500 MW during the heatwave event signaling the supply shortfall, which were comparable to the extent of infeasibilities observed in RUC when measured against the standard load forecast.

Figure 49: RTD infeasibilities in September

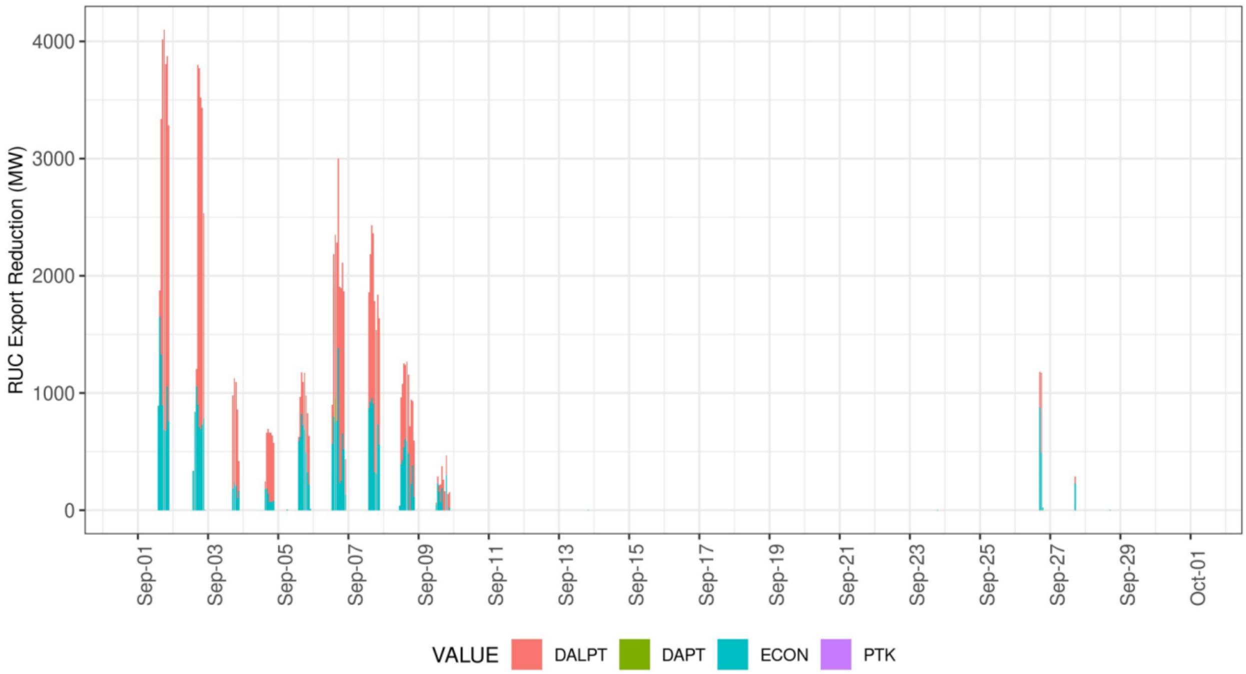


In addition to relaxing the power balance constraint, the RUC process utilized other scheduling priorities to enforce the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and lower priority price-taker exports. Only when RUC has exhausted these LPT exports, PT exports may be reduced concurrently to relaxing the power balance constraint.[49]

Figure 50: shows the volume of hourly export reduction in the RUC process, which only happened on September 1 - 8 and 26 and 27 for volumes of up to 4,000 MW of economical bids and low-priority exports.

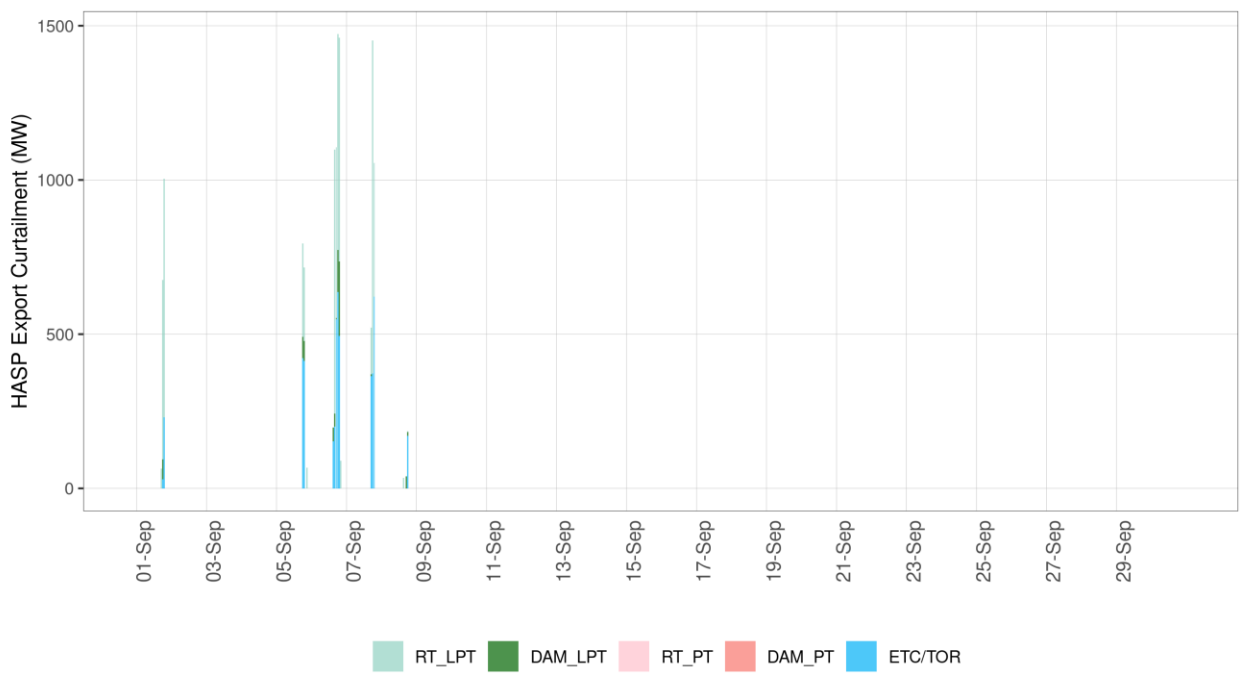
[49] Under the current setup of scheduling priorities, PT exports and the RUC power balance constraint have the same priority reflected with the same penalty price utilized in the market optimization. What level of curtailment relative to the level of power balance relaxation is achieved will depend on many other conditions in the optimization process, such as the location of the exports that may look more or less attractive for reduction in comparison to the power balance. Thus, typically, both export reduction and power balance infeasibilities can be observed in an RUC solution under tight supply conditions.

Figure 50: Exports reduction in RUC



Exports can still participate in the RTM by rebidding relative to the DAM solution, or directly into RTM with either high or low priority, as well as with economical bids. Market participants can self-schedule exports cleared in the day-ahead into the RTM. Under the new market rules and scheduling priorities post August 4, these cleared day-ahead schedules are treated in the RTM as having a day-ahead priority, which is above the priority of exports submitted in the real-time. Thus, exports cleared in the day-ahead are less likely to be cut in the real-time. Participants can also submit self-schedules in the RTM, which are more at risk of curtailments in the hour-ahead scheduling process (HASP) process. In September, the RTM saw curtailments for various trade dates with maximum curtailment on September 6 and 7.

Figure 51: Exports reductions in HASP



5 Intertie Transactions

The ISO's system relies on imports that arrive into the balancing authority area through various interties, including Malin and NOB from the Northwest and Paloverde and Mead from the Southwest, among others. Interties are generally grouped into static imports and exports, or dynamic and pseudo tie resources, which are generally resource-specific. Similar to internal supply resources, interties can participate in both the day-ahead and RTMs through bids and self-schedules. Additionally, the ISO's markets offer the flexibility to organize pair-wise imports and export to define a wheel. This transaction defines a static import and export at given intertie scheduling points which are paired into the system to ensure both parts of the transaction will always clear at the same level. Wheel transactions must be balanced, thus, do not add or subtract supply to the overall ISO system, regardless of the cleared level. However, they utilize scheduling capacity on interties and transmission capacity on ISO's internal transmission system. All intertie transactions will compete for scheduling and transmission capacity via scheduling priority and economic bids to utilize the scarce capacity on the transmission system.

Economic bids for imports are treated similarly to internal supply bids, while exports are treated similarly to demand bids, or fixed load through the load forecast feeds. These bids are bounded between the bid floor (-$150/MWh) and bid cap ($1,000/MWh or $2,000/MWh). Each part of a wheel is also treated accordingly as supply or demand but its net bid position is defined as the spread between its import and export legs.

Intertie transactions also have the flexibility to self-schedule. The ISO's market utilizes a series of self-schedules which define higher priorities than economic bids based on the attributes applicable to such resources. Participants with such entitlements can submit intertie self-schedules using transmission ownership rights (TORs) or Existing Transmission Contracts (ETCs), as well as PTK and LPT.

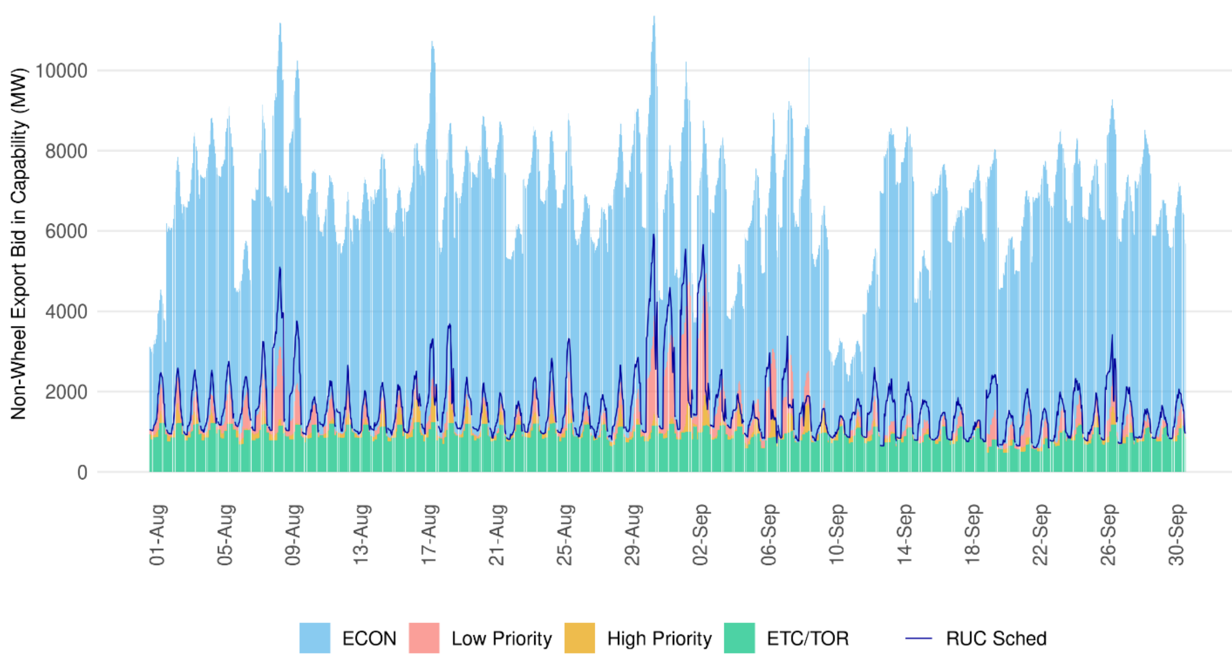
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics – and system conditions – are taken into account. In the upward direction, when supply capacity is limited, imports with self-schedules clear first, followed by economic bids from cheapest to most expensive, up to the level of the market clearing price. Conversely, exports will clear first for ETC/TORs, then PTK exports, followed by LPT exports and lastly economic bids from most expensive to cheapest. Wheel transactions have a higher priority in the clearing process defined as the relative spread of penalty prices between the import and export sides.

5.1 Intertie imports and exports

Figure 52 shows the capacity from static export-based transactions in the DAM for the month August and September 2022 organized by the various types of exports. This capacity does not include export capacity associated with wheel transactions of any type because wheels are in balance on a net basis and, thus, the export side of wheels does not reduce supply to the ISO supply stack.

This figure also illustrates the clearing schedules from the RUC process with the line in purple. The RUC schedules are used as reference, instead of the IFM schedules, because they are the relevant schedules for clearing interties in the DAM. As defined in Section 31.8 of the ISO tariff, in DAM, the ISO enforces a net physical intertie scheduling limit in the RUC process and enforces a net physical and virtual intertie schedules limit in the IFM process of the DAM. This is to ensure that intertie schedules cleared in the DAM are physically feasible and not encumbered by virtual intertie schedules. Prior to May 1, 2014, the ISO enforced a net physical intertie scheduling limit in the IFM. As a result of this change where physical-based flows from the RUC process are the most reliable reference of feasible schedules on interties, the ISO operators use the RUC schedules to evaluate E-tags submitted in the pre-scheduling timeframe.

Figure 52: Bid-in and RUC cleared export capacity



The RUC schedule represents the expected delivery and E-tags that market participants should submit in the pre-scheduling timeframe, and not the IFM schedule. While not required to submit their E-tags in the day-ahead timeframe, market participants are encouraged to do so and in such cases should base their E-tag on the RUC schedule. If not, E-tags greater than RUC schedules may be curtailed by the ISO. This applies to all dynamic and static intertie schedules.

Export bid capacity in the DAM varies by hour and typically follows a daily profile. About 78 percent, 12 percent, 9 percent and 1 percent of the export capacity were for economic bids, ETC/TOR, LPT and PTK, respectively. The volume of exports reduced slightly due to the heat wave conditions in September.

Figure 53: Bid-in and RUC cleared import capacity

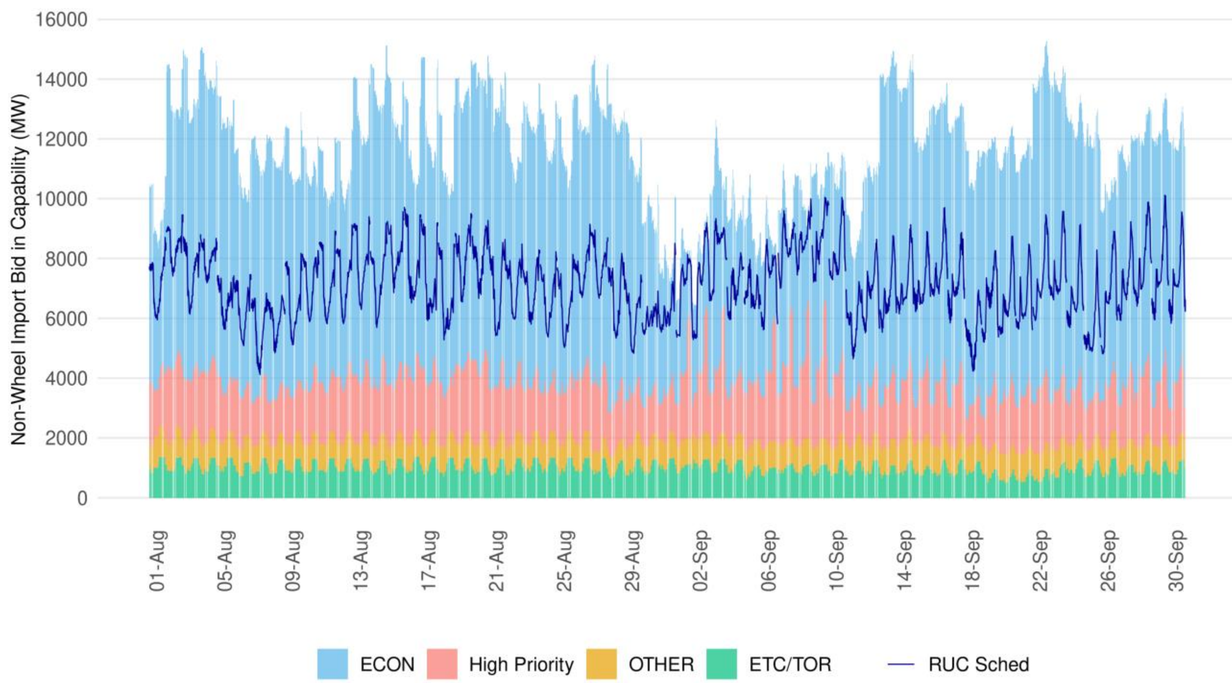


Figure 53 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the month, while hourly economic imports continued to see a high volume over 5,000 MW. The “Other” group includes regulatory must run priority capacity and the portion of minimum load for dynamic resources with a Pmin above 0 MW.

Figure 54: Breakdown of RUC cleared schedules

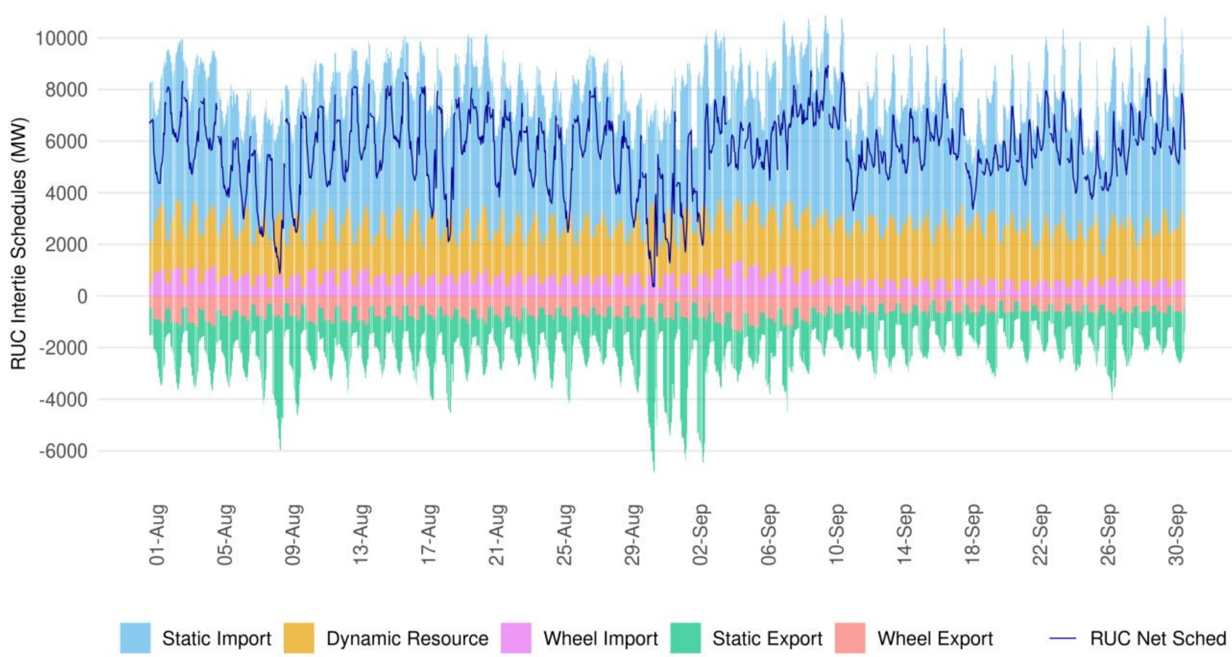


Figure 54 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution. The net interchange projected in the RUC process reached its lowest level on September 1 at about 1700 MW due to the higher level of exports cleared, and highest level of 8930 MW on September 9.

Figure 55: shows the hourly self-schedule curtailment of non-wheel exports in RUC. In September, the export curtailments were mostly observed during the heat wave event, from September 1 through the 9, in the afternoon peak hours. Majority of the curtailment was on low priority schedules.

Figure 55: RUC export curtailment

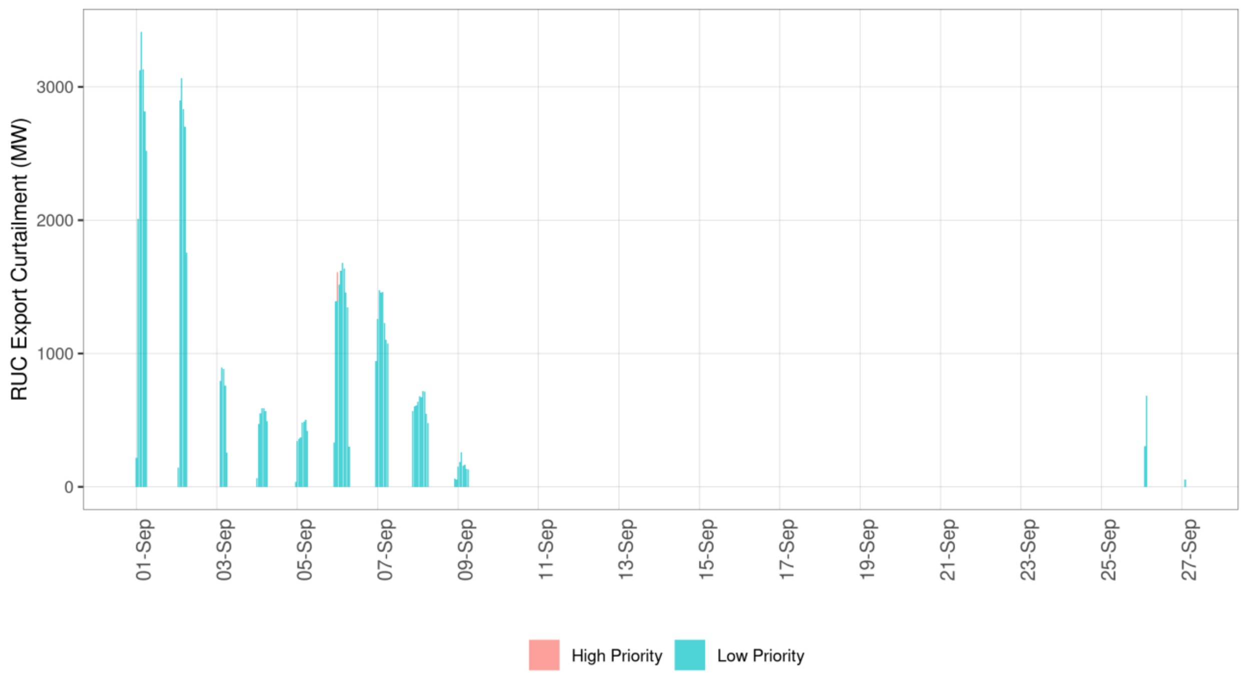
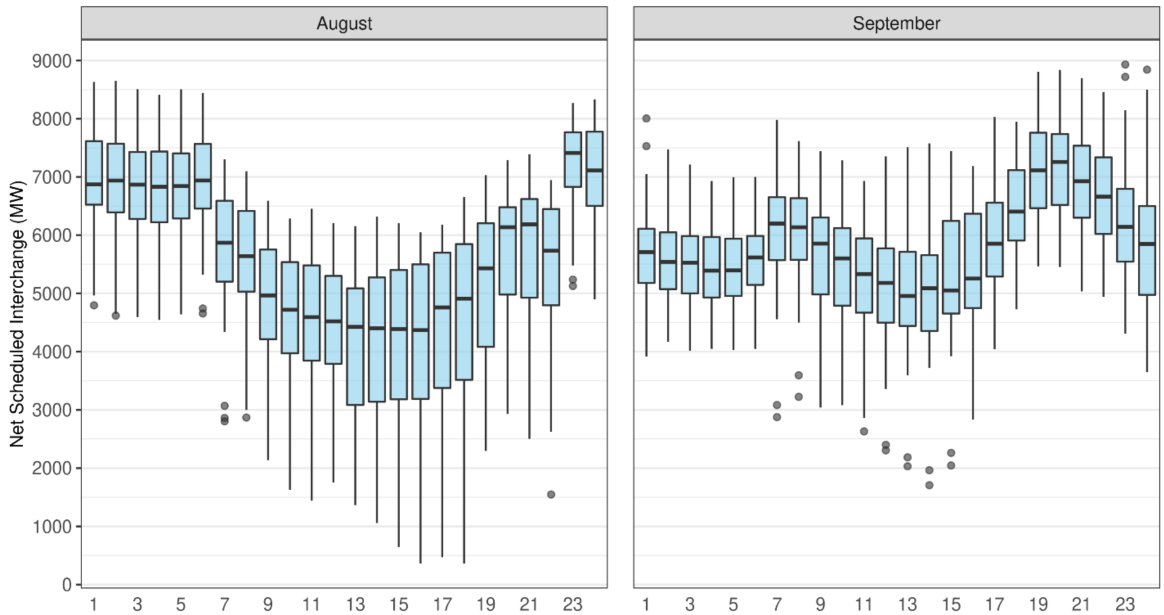


Figure 56 illustrates the hourly net schedule interchange distribution by hour in the summer months. This trend is useful to visualize the hourly profile of schedules and shows that net schedules reduce in midday hours when solar production comes in and start to increase as the solar production fades away in the evening hours. It also shows two well-defined blocks of On and Off-peak schedules. The lowest net interchange values are attained in hours prior to the gross peak when solar supply is still plentiful.

Figure 56: Hourly RUC net schedule interchange



An area of interest since summer 2020 is the trend of exports in the ISO's system. Export levels were generally low in June with milder loads but increased significantly in the second half of July, and decreased on average in August. In September 2022, export levels were further decreased compared to August 2022.

Figure 57: Hourly RUC exports

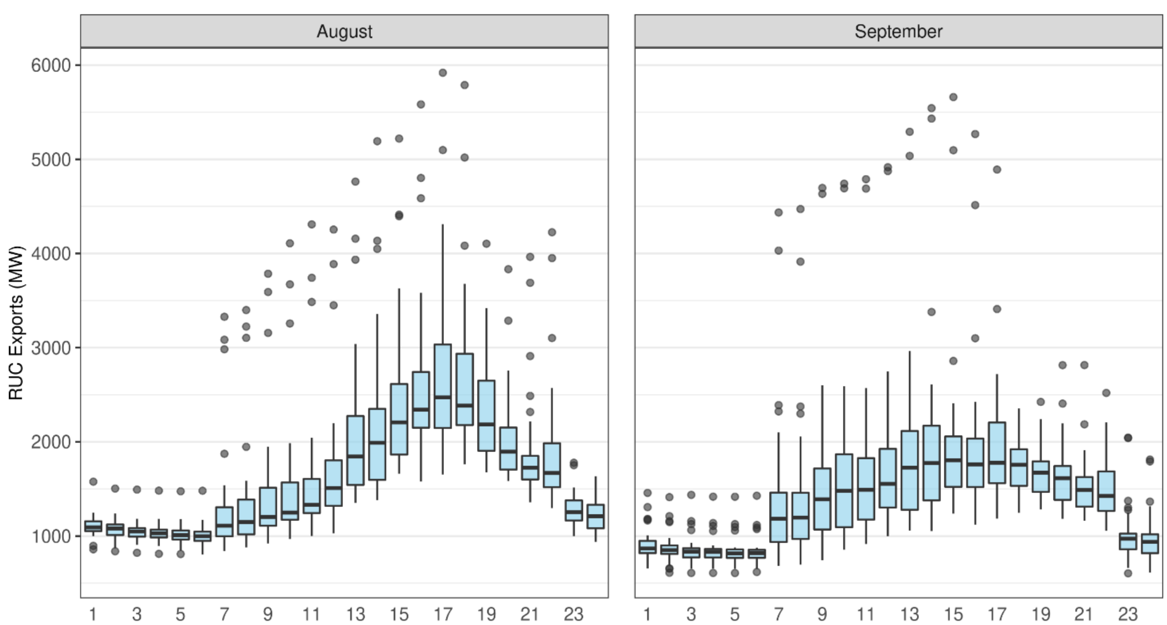
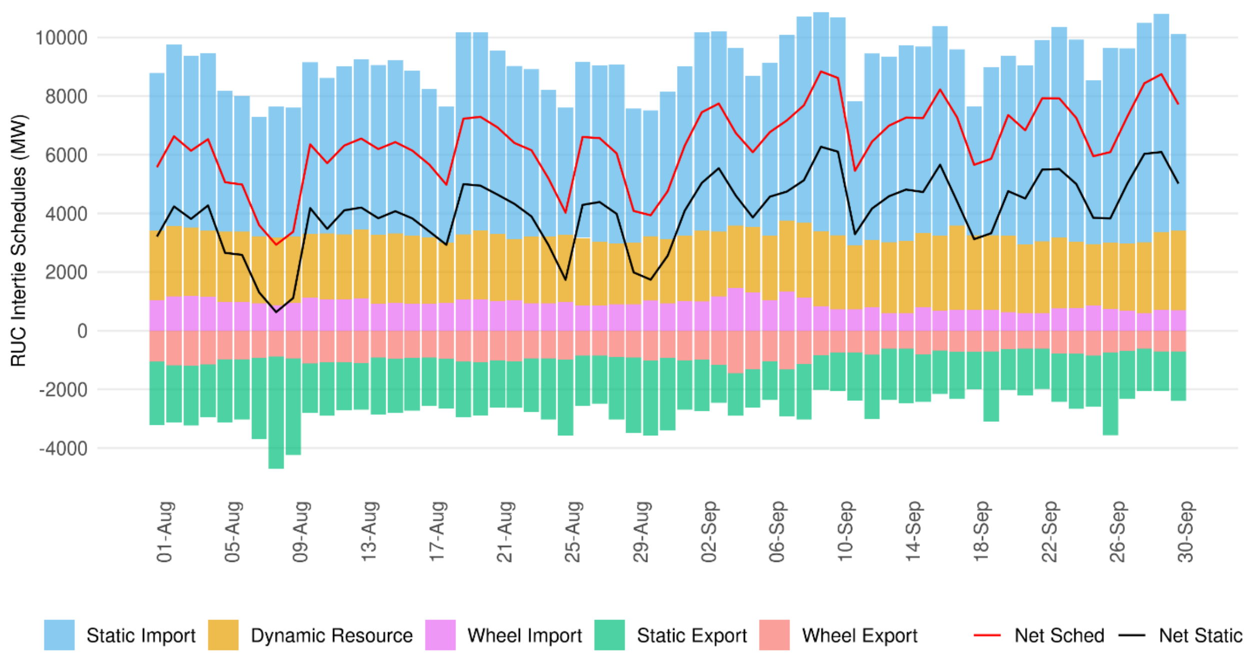


Figure 57 illustrates the hourly distribution of RUC schedules for exports, and shows that the highest volume occurred during midday hours when the ISO's system has excess solar supply; exports were in high demand during the afternoon hours at the end of September.

Figure 58 shows the intertie capacity available in the DAM for HE 20 to highlight the conditions around peak time, when the ISO's system faces the highest supply needs.

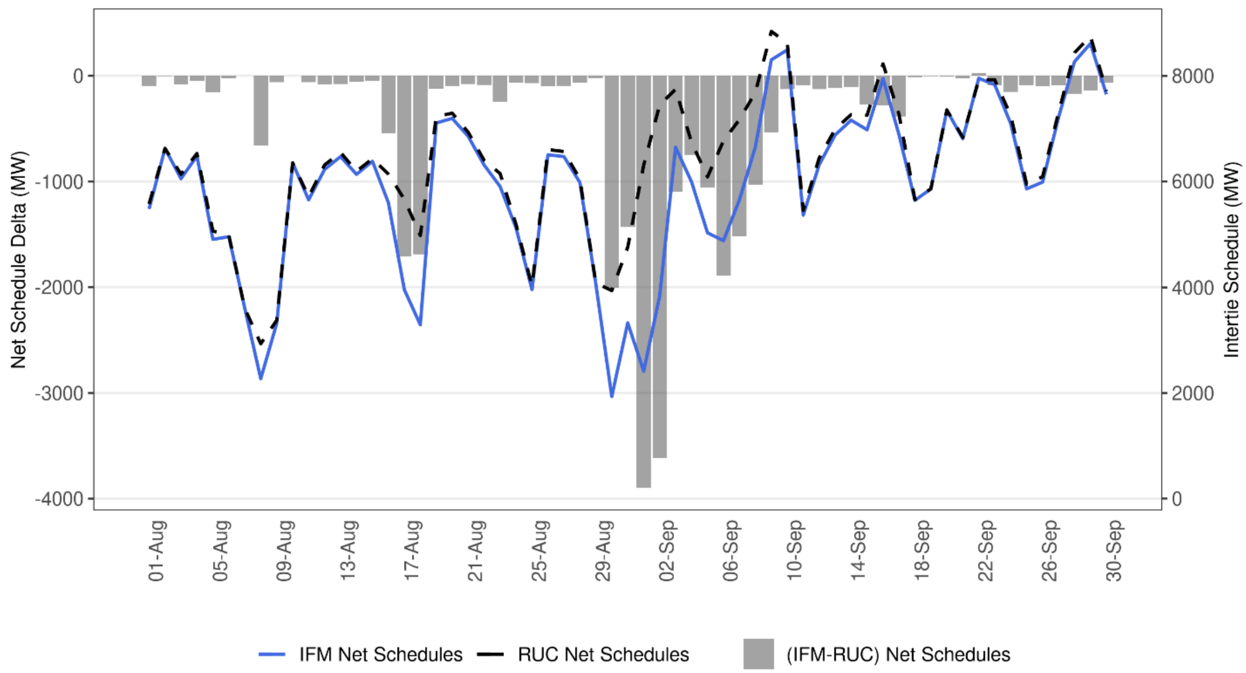
Figure 58: RUC schedules for interties for HE 20



This figure includes any imports or exports associated with explicit wheeling transactions. Including wheels will increase the volume of imports and exports by the same amount such that the net schedule remains the same. The red line represents the net schedules cleared in RUC (imports plus dynamics less exports), while the black line represents the net schedule in RUC when considering only static imports and exports.

The RUC process may schedule additional supply to meet the load forecast, above what was scheduled in the IFM. Under tight supply conditions, the RUC process may also identify that export schedules cleared in the IFM process are not feasible, and signals to the participant that its exports are not feasible in the real-time. Therefore, for interties, the RUC schedules are the relevant schedules for assessing what is feasible to flow into real-time, and they are what should be tagged if participants submit a day-ahead tag for their export. IFM schedules are still financially binding. Figure 59 compares the net schedule cleared in both IFM and RUC for HE 20, and provides the relative change of schedules between the two processes as shown with the bars in gray. These changes can happen for any type of resources and it is not always limited to a reduction of exports. IFM schedules for exports were reduced in the RUC process mainly for September 1 to 9.

Figure 59: IFM and RUC schedule interchange for HE 20



Intertie positions are largely set from the DAM. Imports or exports cleared in the day-ahead may tend to self-schedule into the real-time to preserve the DAM award. There may still be incremental participation in the RTM through the HASP process, which allows resources to bid-in economically to buy back their day-ahead position, or also enables the procurement or clearing of additional capacity in the RTM.

Figure 60: HASP cleared schedules for interties in –August - September

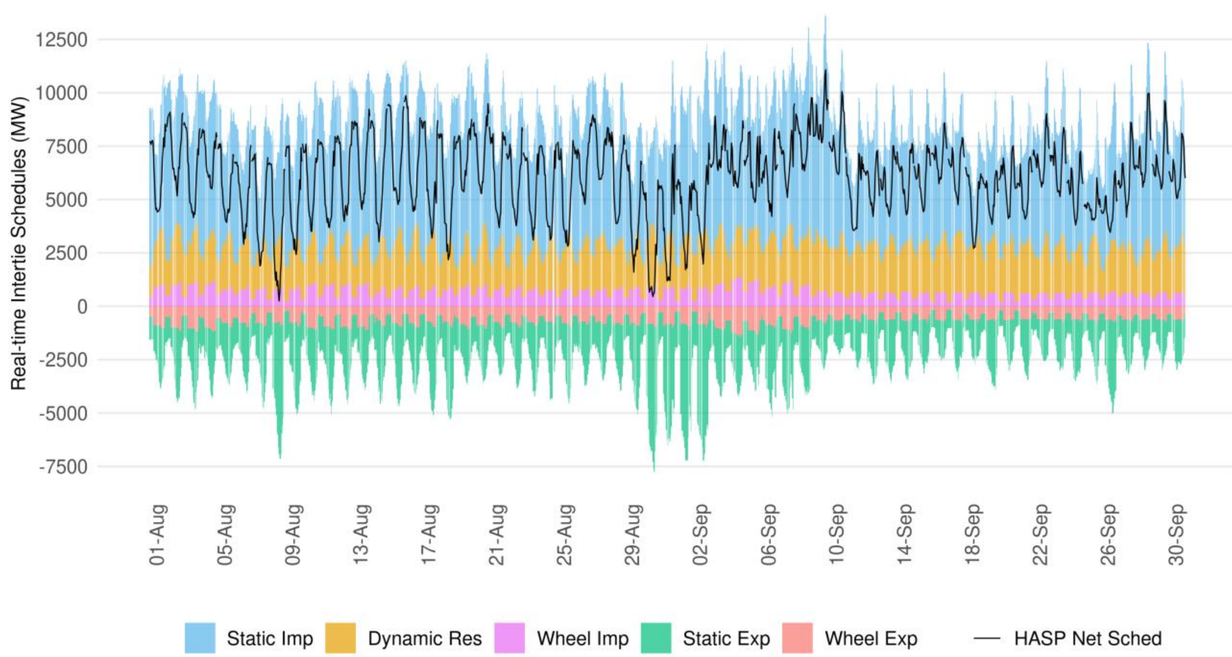


Figure 60 shows the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred as Net Schedule Interchange. The net schedule interchange is at its lowest value on September 1 due to the highest level of exports cleared on that day prior to the evening peak. The RTM largely follows the trend observed in the DAM. On average, for September the net schedule interchange in HASP was about 7,248 MW for peak hours (17 through 22).

The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Interties cleared in the DAM can submit self-schedules into the RTM. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC.[50] Additionally, exports can participate directly into the RTM with either self-schedules or economic bids.

Each market, RUC or HASP, can assess reduction of exports based on the overall system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority but they are able to rebid into the RTM and be fully assessed based on real-time conditions. LPT or economic exports cuts in the RUC process are most likely to be cut again in HASP since they will have the lowest priority in the presence of tight supply conditions. Figure 61 shows all the exports cleared in the HASP process and identifies the nature of such exports. TOR is for export with scheduling priorities associated with transmission rights. The groups of DA_PTK or DA_LPT stand for day-ahead exports coming into real-time as self-schedules with high or low priorities. Similar classification is followed for those high and low priority exports coming into real-time directly (RT_PT and RT_LPT). ECON stands for economic exports. The group of wheels stands for all type of wheels observed in the RTM (low- or high-priority. Given the many different groups for exports, wheels are not shown in this metric explicitly. These exports are only for non-wheel transactions. A granular breakdown of wheels is provided in a subsequent section of wheels.

The volume of exports cleared in real time follows the pattern of loads with a slight decrease in September, peaking over 6,000 MW on September 1. In September a significant portion of cleared exports were those with low priority and economical bids.

[50] Based on these rules implemented on August 4, through the summer enhancements described earlier and now in place, the ISO will no longer provide exports a higher priority than load in the real-time, and will only provide them equal in priority to load if the participant demonstrates that they continue to be supported by resources contracted to serve external load.
Details are available at http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

Figure 61: Exports schedules in HASP

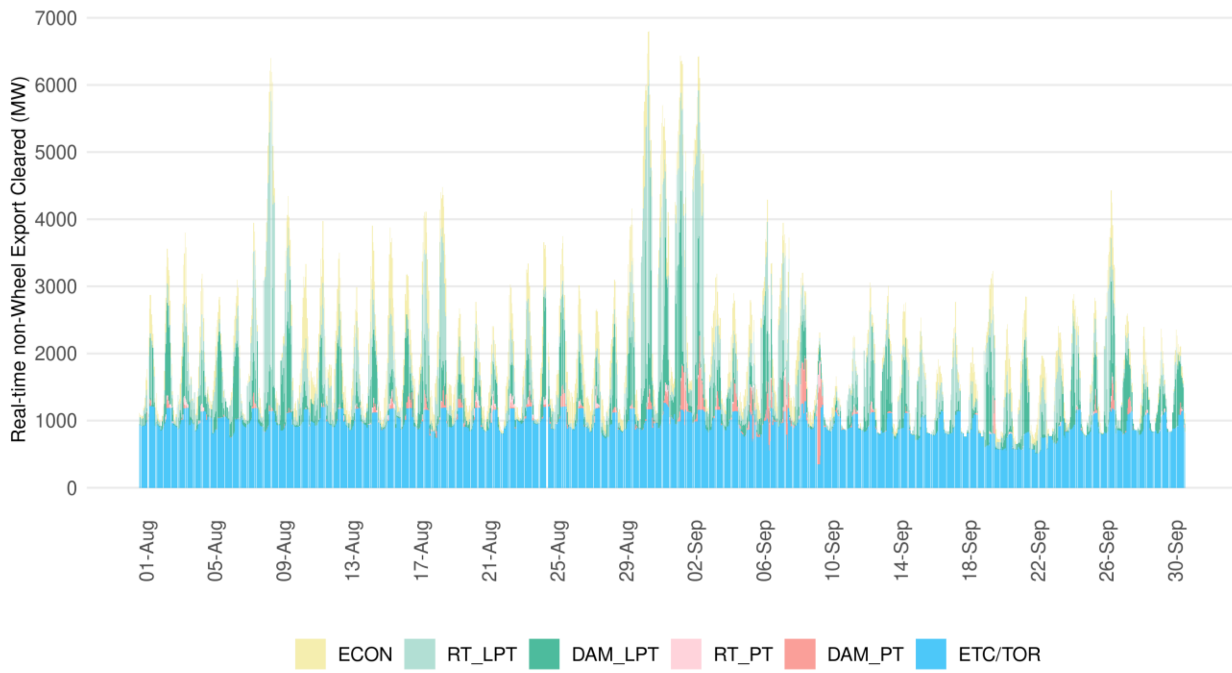
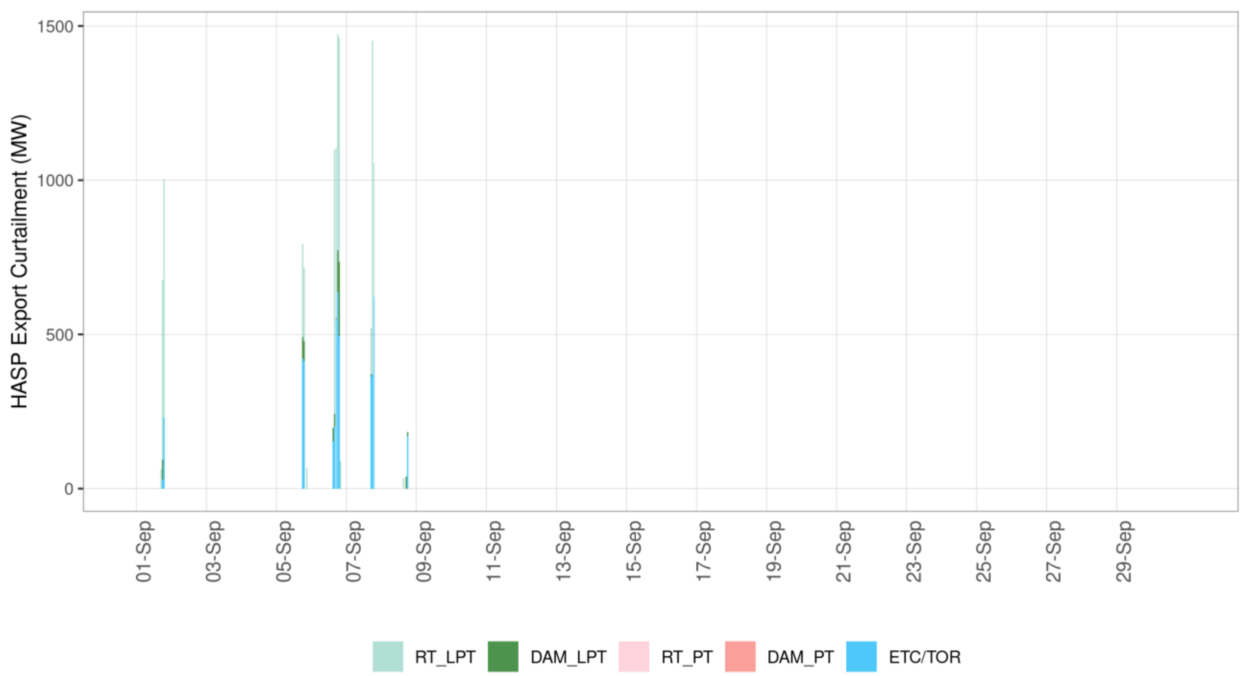


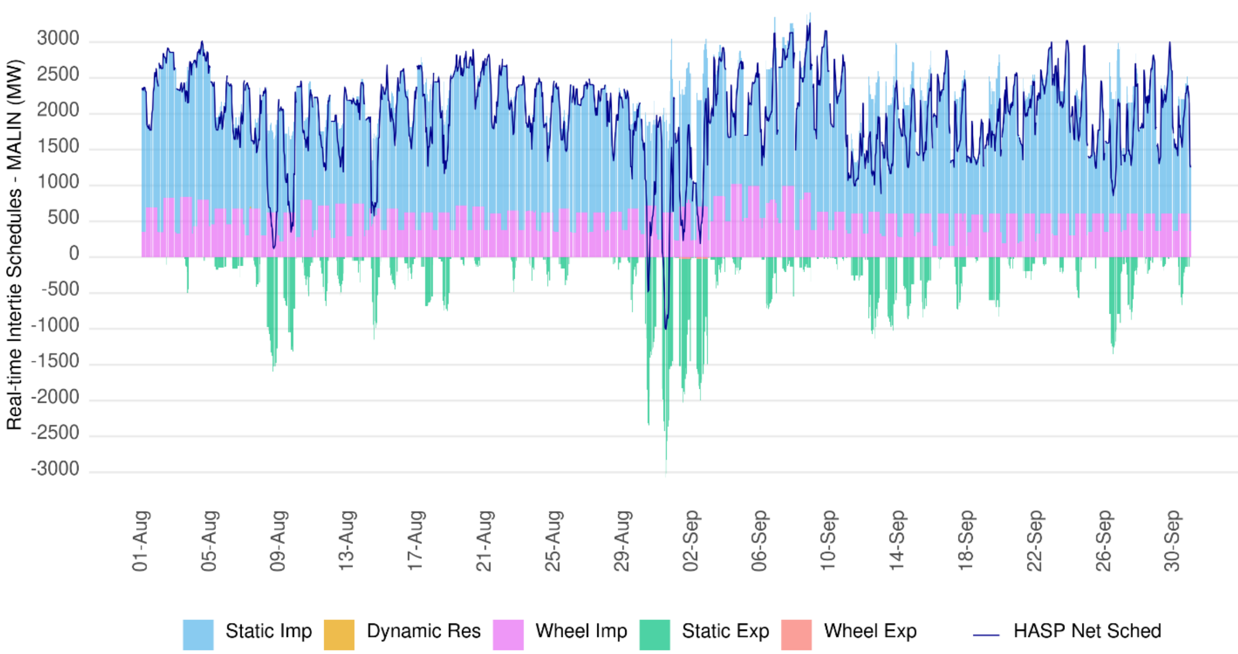
Figure 62 shows the export self-schedule reduced in HASP. The export curtailments happened on September 1, and 5 through 9.

Figure 62. HASP export reductions



Imports and exports were scheduled over multiple intertie scheduling points in September, with Malin, Paloverde and NOB seeing the highest volume of transactions. Figure 63 through Figure 65 illustrate the trend of import and export schedules cleared in HASP for the top three intertie points. Although schedules in the import direction are the predominant schedules, exports cleared at different levels on these major interties when supply was tight.[51] Exports on Malin and Palo Verde were higher on July in multiple days of July; in some days, the exports were higher than imports so that the net flow on these interties were in the export direction.

Figure 63: HASP schedules at Malin intertie



[51] The breakdown of imports and exports at the system or tie level may be subject to different levels of aggregation. For instance, wheels are in balance and the import side of a wheel nets out with the export side of the wheel. There are some transactions like TORs that behave like wheels although they are not explicit wheels in the market clearing process; *i.e.,* the market can clear the import at a value different than the export's value. Generally they may clear in balance and thus the export side may not add demand needs to the system, like stand-alone exports, even though it is counted in the total volume of exports for a specific tie.

Figure 64: HASP schedules at PaloVerde intertie

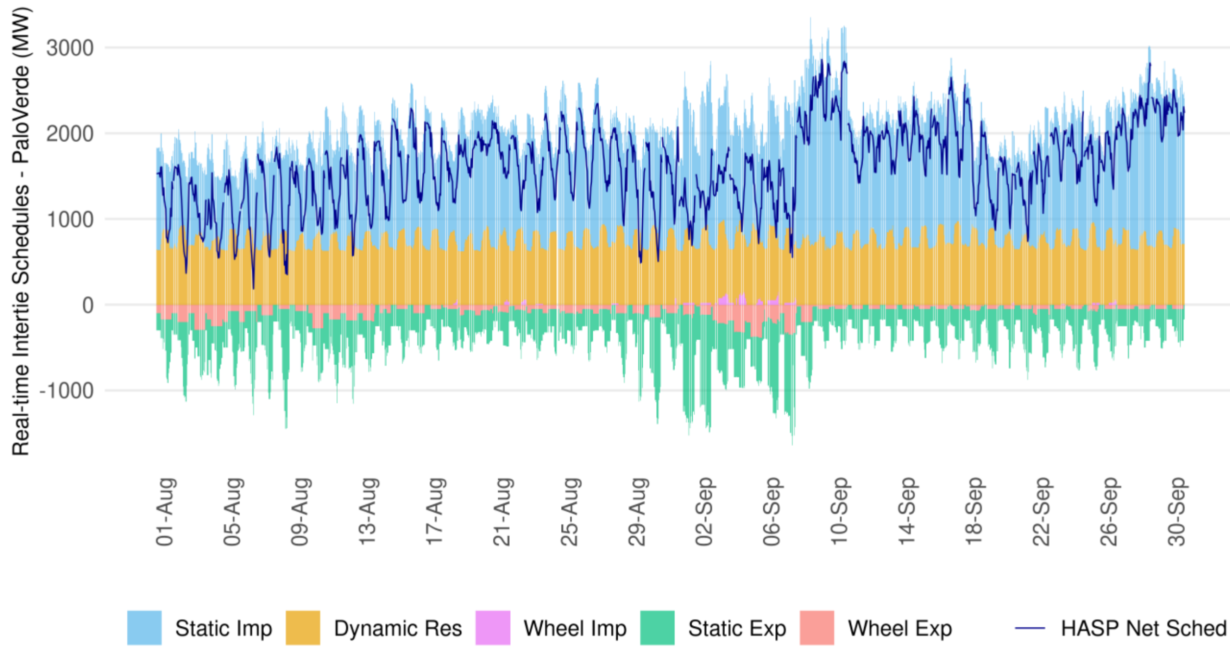
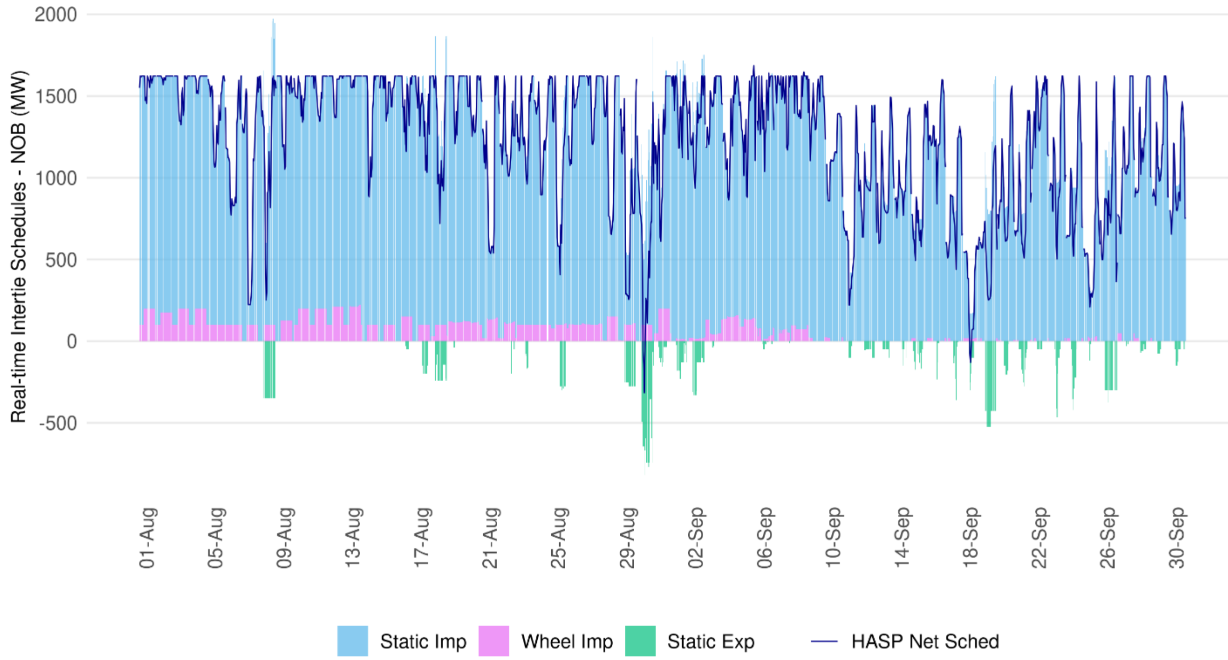


Figure 65: HASP schedules at NOB intertie



5.2 Resource adequacy imports

Imports can be used to meet RA requirements and they can be resource-specific or non-resource specific. For simplicity, this analysis relies on static imports as a proxy for non-specific resources. The other type of imports are dynamic or pseudo tie resources, which typically will be resource-specific.

Under RA rules, non-resource specific RA imports for LSEs under CPUC jurisdiction must self-schedule or bid with economics bids between -$150/MWH and $0/MWh at least for the availability assessment hours. Figure 66 is an approximation of the supply bid in the DAM by static RA imports associated with LSEs under CPUC jurisdiction and for hours ending 17 through 21 of weekdays only. This supply is organized by price range, including self-schedules and differentiates between RA capacity and above RA capacity. Based on this subset, about 99.96 percent of all RA static import capacity bid with either self-schedules or economic bids at or below $0/MWh in September. Very small and scattered instances of bids associated with RA imports bid in above their RA level with economical bids. This plot also shows the cleared imports, which largely utilized all the bid-in volume for RA and Above RA.

Figure 66: Day-Ahead RA import for hours ending 17 through 21 for weekdays

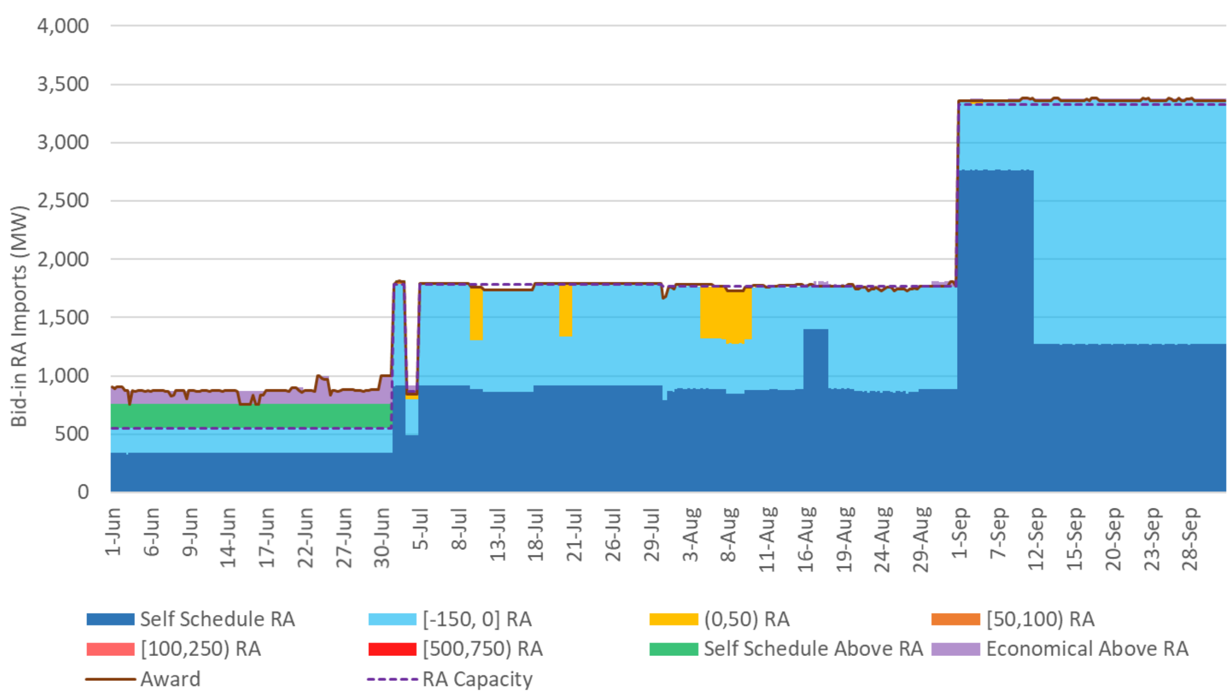
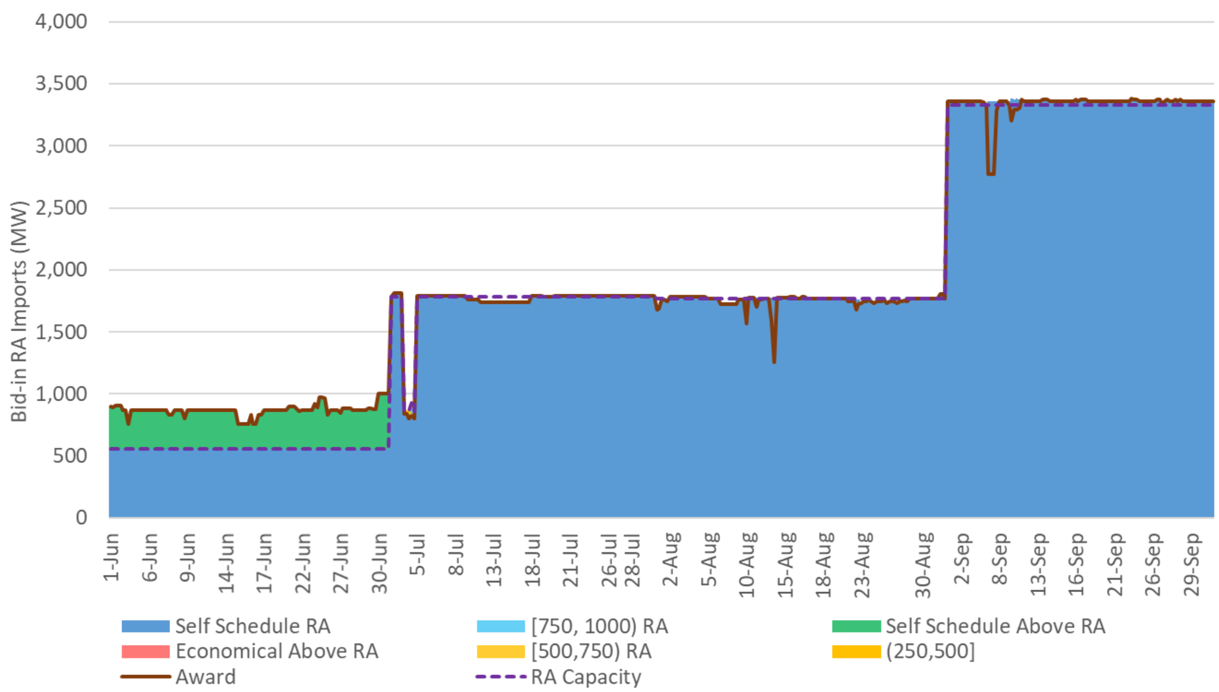


Figure 67 shows the same information for the RTM using the HASP bids. The majority of RA imports come in as self-schedules in the RTM, with only a small fraction of imports coming with an economic bid.

Figure 67: HASP RA import for hours ending 17 through 21 for weekdays



5.3 Wheel-through transactions

With the extension of the interim high-priority wheel through measures extended to May 2024, they were still at play in summer 2022 and therefore scheduling coordinators seeking high scheduling priority in the market equal to ISO load were required to register in advance their wheel transactions and had to meet specific requirements up to 45 days prior to the start of month.[52] If the requirements are not met and the wheel transaction is not registered, the transaction receives low scheduling priority. For the month of September, the ISO accepted a total of 861 MW of PT wheels from nine different scheduling coordinators. Table 8 shows all the wheel-through paths registered by all scheduling coordinators.[53]

[52] Market Operations Business Practice Manual, section 2.5.5 (2021).

[53] Some request for wheels provided both Malin and NOB as possible sources. For simplicity in the aggregation, some sources were assigned to Malin and others to NOB trying to assign the wheels evenly between the two potential sources.

Table 8: Wheel-through transaction registered for September 2022

Source	Sink	MW
CFEROA	MEAD230	50
CFETIJ	MEAD230	75
CTW230	LLL115	105
MALIN500	ELDORADO	12.5
MALIN500	MCCULLOUG500	100
MALIN500	MEAD230	200
MALIN500	PVWEST	162.5
MIR2	RANCHOSECO	30
NOB	MEAD230	51
NOB	PVWEST	62.5
NOB	ELDORADO	12.5
	Total	861

Once these transactions are registered, they can be scheduled in the ISO's markets and receive a high scheduling priority. Scheduling coordinators can opt to utilize these wheels on an hourly basis through the month.

Figure 68 shows the hourly wheels cleared in the RUC process throughout the month. Wheels participating in the day-ahead market in the month of September were ETC/TOR, high- and low-scheduling priority, peaking at 1,447 MW on September 4th, with 405 of ETC/TOR, 476MW of PT and 566 of low priority wheels. This is a slightly higher profile than the one observed for the maximum level of August. There were no wheels with economic bids. The volume of explicit wheels associated with ETC/TOR was stable throughout the month with higher values in peak hours.

Figure 69 provides an hourly breakdown of high- and low-priority wheels, with the maximum hourly cleared RUC volumes of 476 MW of PT wheels in some hours on September 3-7; this is about a 55 percent utilization of the volume of high-priority wheels registered for September.

For September, PT wheels exhibit an on-peak block with largely the same MW value across the block. Low-priority wheels were in the market all hours of the day but exhibited a pattern for the off- and on-peak blocks as shown in Figure 70; *i.e.,* the submitted self-schedules were at the same MW value for blocks of multiple hours that define off-peak (hours ending 1 through 6 and hours ending 23 through 24) and on-peak hours (HE 7 through HE ending 22).

Figure 68: Hourly volume of wheel transactions used in the day-ahead market by type of self-schedule

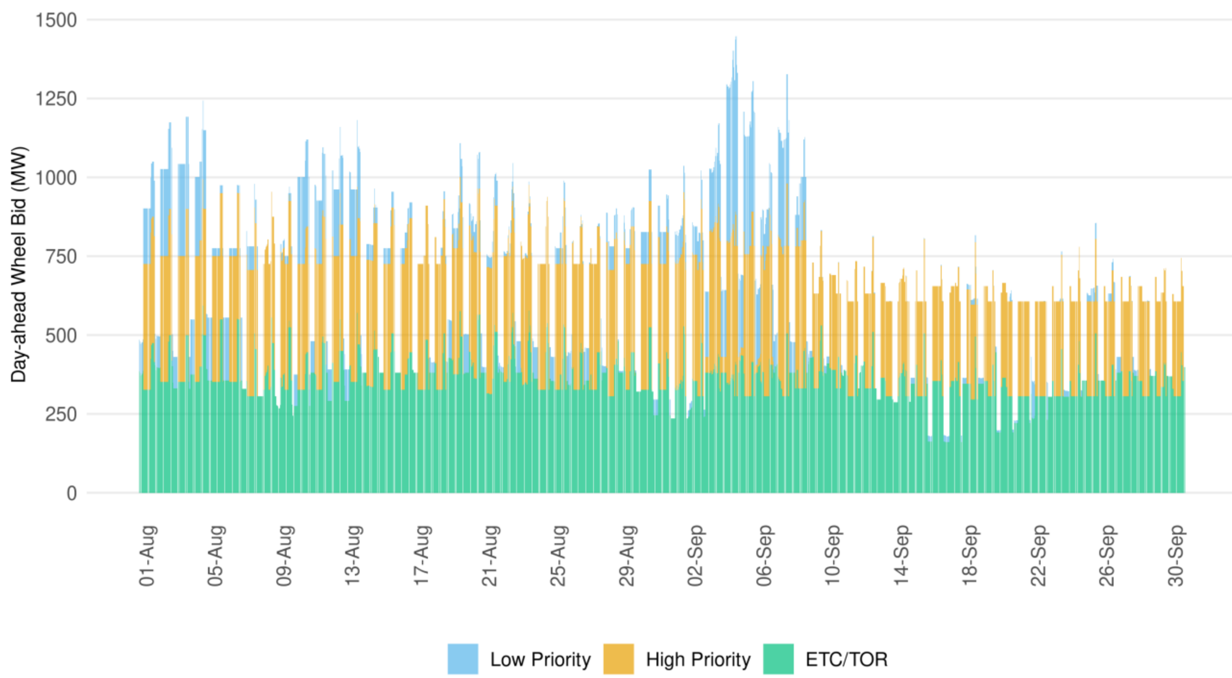


Figure 69: Hourly volume high- and low-priority wheels cleared in RUC

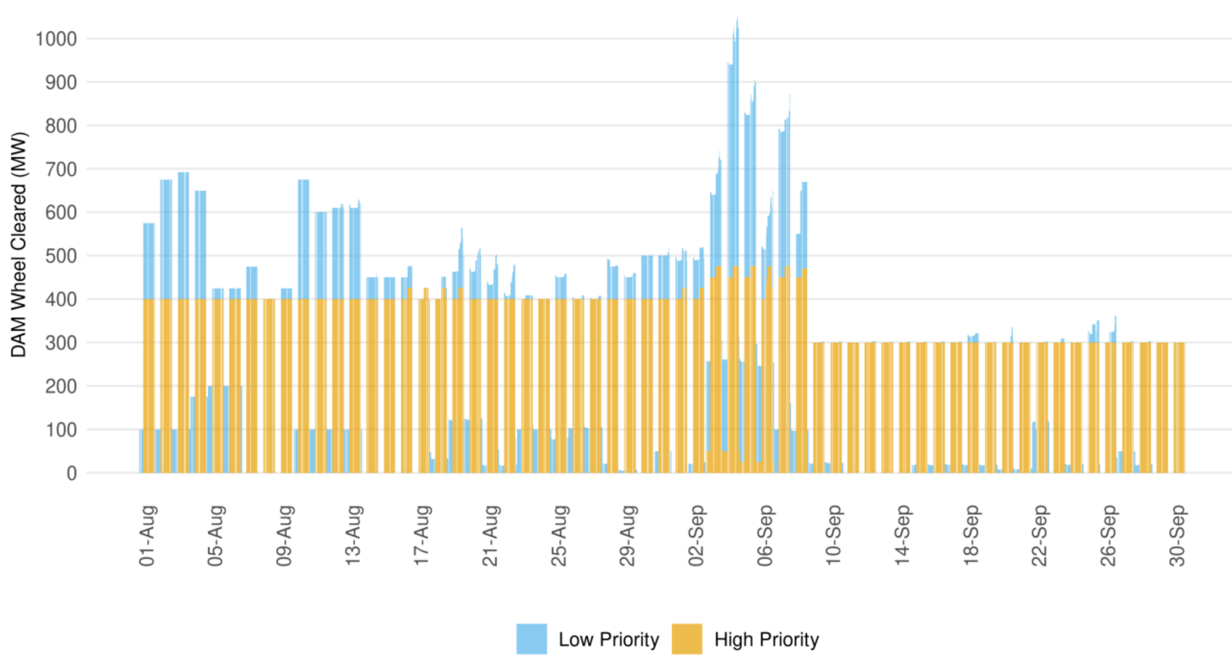


Figure 70: Day-ahead hourly profile of wheels in August and September

Wheels are defined with a source and sink location in the ISO's markets to factor in their contribution to the flows on either intertie constraints or internal transmission constraints. Figure 71 summarizes the hourly average of wheels organized by source and sink combinations. An empty entry reflects that no wheels were present for that given source-to-sink combination in September. *Source* refers to the import scheduling point while *sink* refers to the export scheduling point. The path with the largest volume of wheels in September in the day-ahead market was from Malin to MEAD230, followed by wheels from Malin to PVWEST.

Figure 71: Hourly average volume (MWh) of wheels by path in September

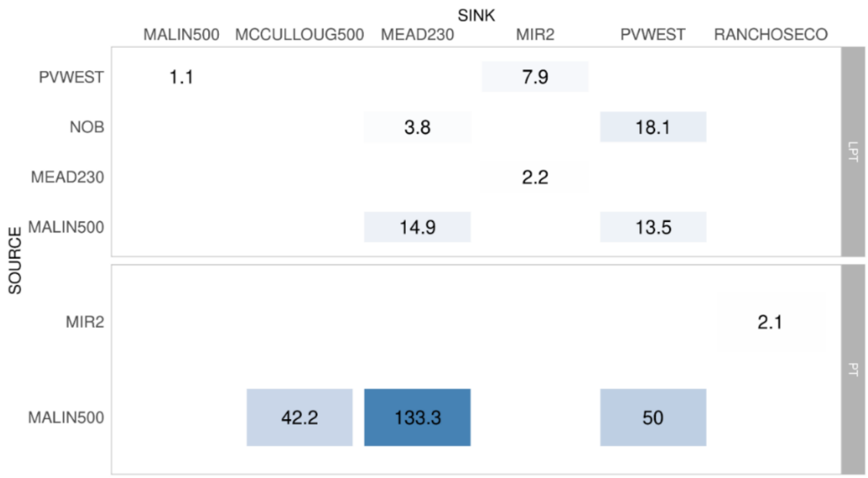
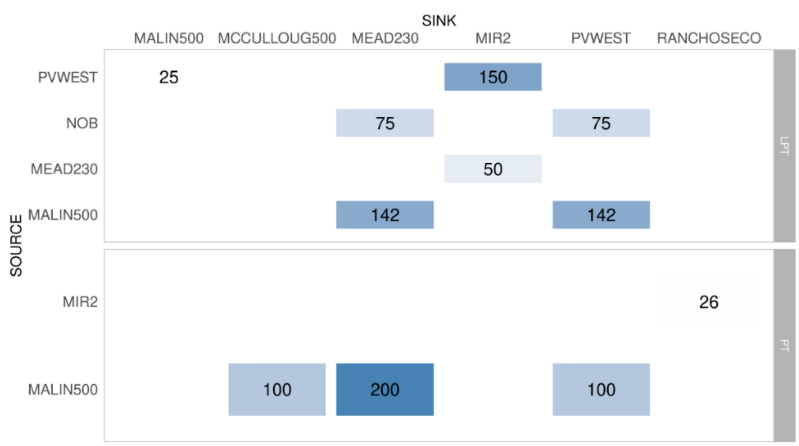


Figure 72 summarizes the maximum hourly wheels cleared in any hour in September in the day-ahead market by source-to-sink combination. The maximum volume of wheels in a given path occurred from Malin to MEAD230.

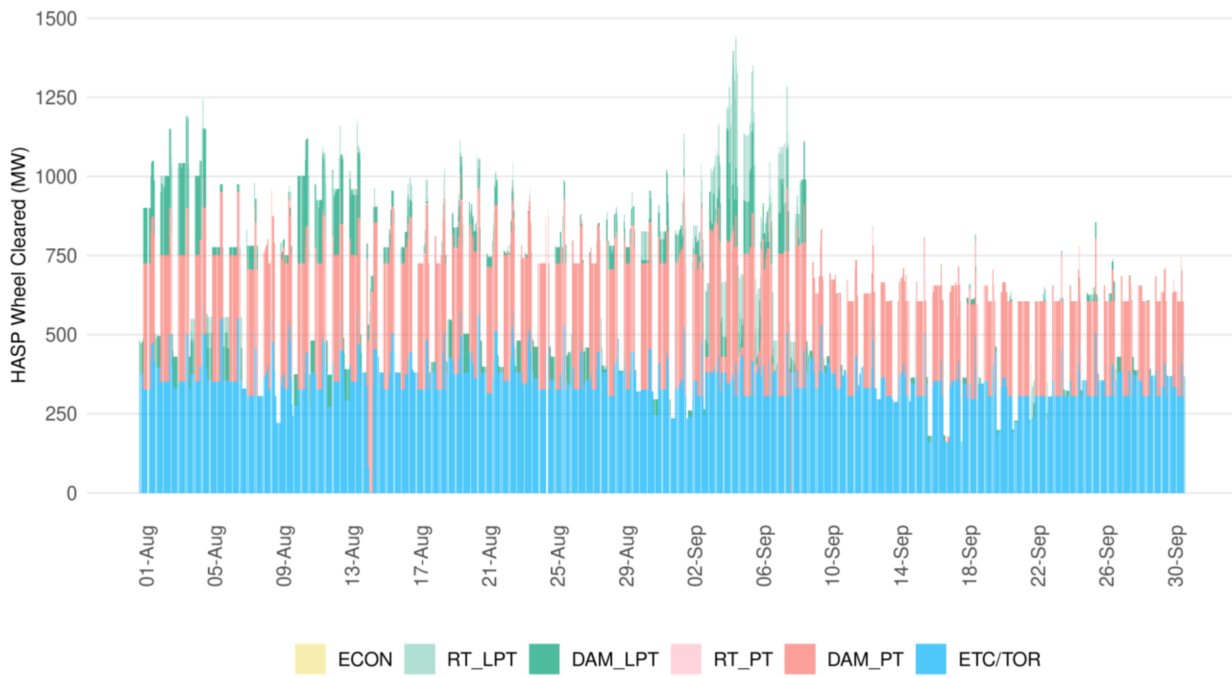
Figure 72: Maximum hourly volume (MW) of wheels by path in September



Although wheels do not add or subtract capacity to the overall power balance of the ISO market, they compete for limited scheduling and transmission capacity. With self-schedule wheels having higher priority than stand-alone imports or exports; wheels can clear before other imports on paths with limited capacity available.

Wheels cleared in the day-ahead market can be carried over into the RTM with a day-ahead priority or be directly self-scheduled in HASP process. Figure 73 shows the volume of wheels cleared eventually in the RTM, organized by the various types of priority and relative changes.

Figure 73: Wheels cleared in RTM



The ETC/*TOR* group represent the wheels with priority of transmission rights. These groups include those wheels that explicitly bid as wheels in either day-ahead. The majority of TOR wheels scheduled in the day-ahead market carried over to real-time.

The DAM_PT is for wheels with PT that cleared in the day-ahead market and they rebid into real-time. RT_PT is PT that came in directly into RTM. DAM_LPT is for wheels with low priority cleared in day-ahead and rebid into real-time. Similarly. RT_LPT is for wheels bid in directly into real time. Econ is for economical wheels. Figure 74 and Figure 75 summarize the average and maximum hourly wheels cleared in September in HASP by source-to-sink combination. On average, the maximum volume of wheels in a given path observed was from Malin to MEAD230, followed by Malin to PVWEST. 133.3 MW of PT wheels from Malin to MEAD230 was all cleared day-ahead market (DAM_PT). Out of 50 MW of PT wheels from Malin to PVWEST, 49.9MW was from day-ahead market (DAM_PT) and 0.1 MW was directly into the RTM (RT_PT).

Figure 74: HASP average hourly volume (MW) of wheels by path in September

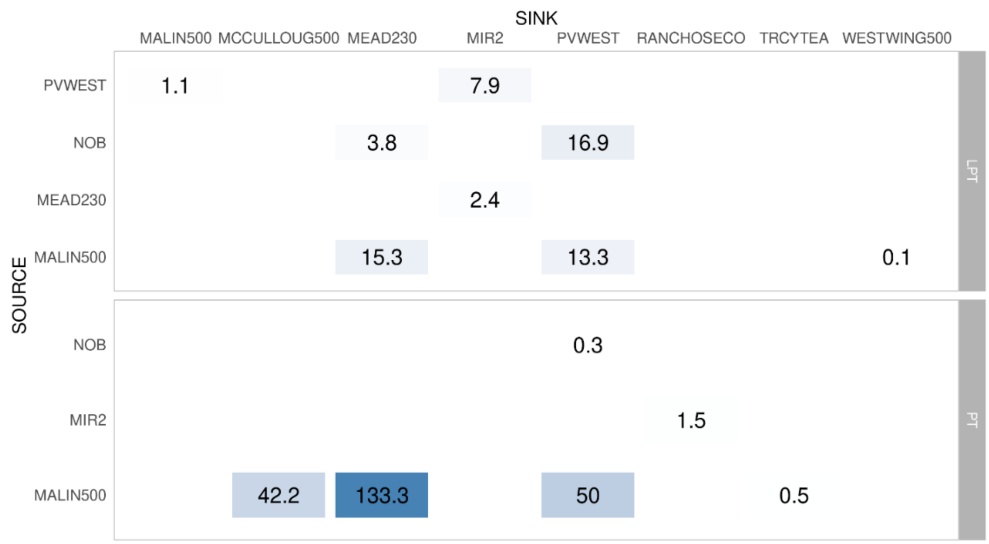
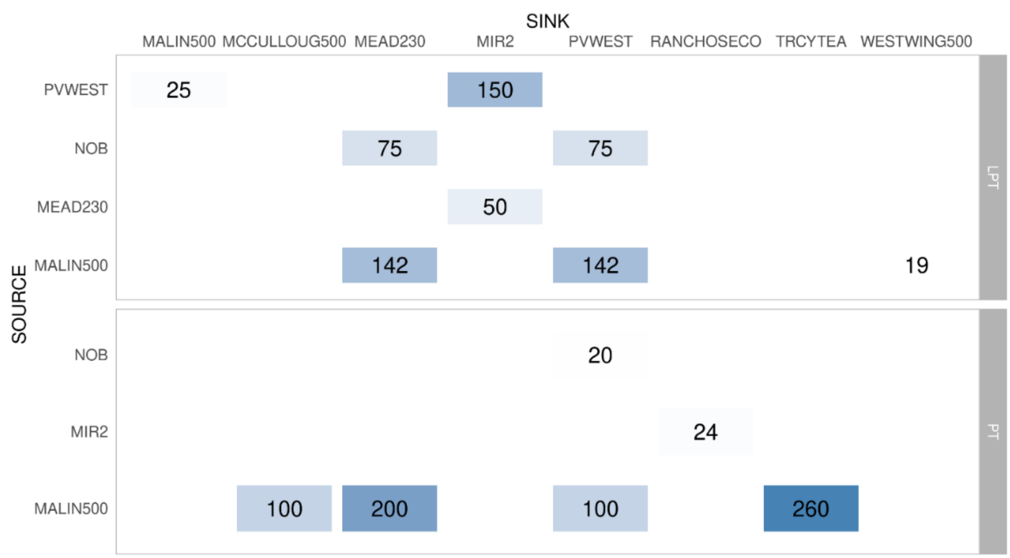


Figure 75: HASP maximum hourly volume (MW) of wheels by path in September

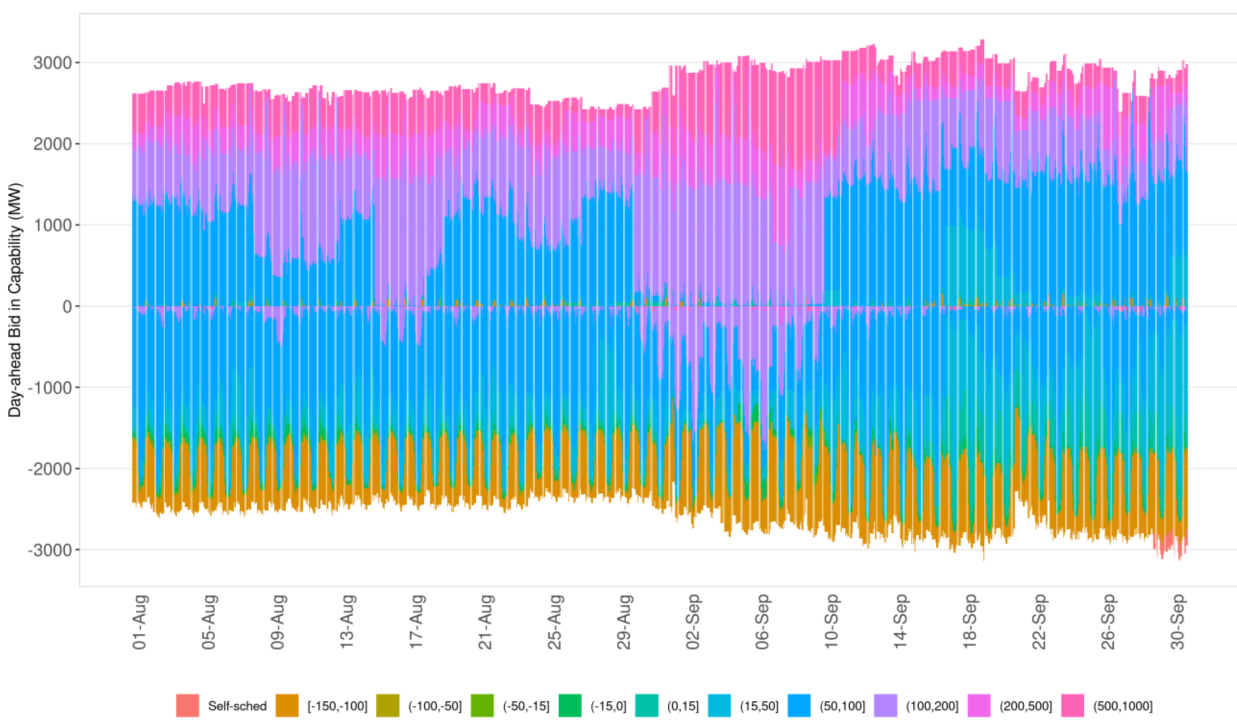


6 Storage Resources

The ISO markets use the Non-Generating Resource (NGR) model to accommodate energy constrained storage resources. This model accommodates capabilities to both consume (charge) and produce (discharge) energy. In September 2022, there were more than 4,000 MW of storage capacity with 15,000 MWh of storage of energy storage capability from 60 storage resources actively participating in the ISO markets. All storage resources participated in both the energy and ancillary service markets. Storage resources can arbitrage the energy price by charging when prices are low, and discharging when prices are high. The ISO models minimum and maximum storage capability in addition to the upper and lower operating limits for each storage resource, which reflects the physical operational capabilities of the resources.

Figure 76 shows the bids-in for all capacity storage resources, with color coding reflecting prices, in the day-ahead market during each day in August and September.

Figure 76: Storage bids in the day-ahead market



The negative area on the y-axis represents charging while the positive area represents discharging. The overall capacity in the market increased from August to September. The bids are organized by $/MWh ranges. There were consistent patterns of significant amounts of bids to charge at negative prices during both months. Some capacity was willing to charge when prices were lower than $50/MWh, and in September some were willing to charge when prices were $50/MWh to $100/MWh or higher. Most storage was willing to discharge at prices above $200/MWh, with some bidding to discharge only when prices exceeded $500/MWh.

Figure 77 shows bids for storage resources in the RTM. The majority of bids were to discharge at prices above $50/MWh, and to charge at prices below $50/MWh.

Figure 77: Storage bids in the RTM

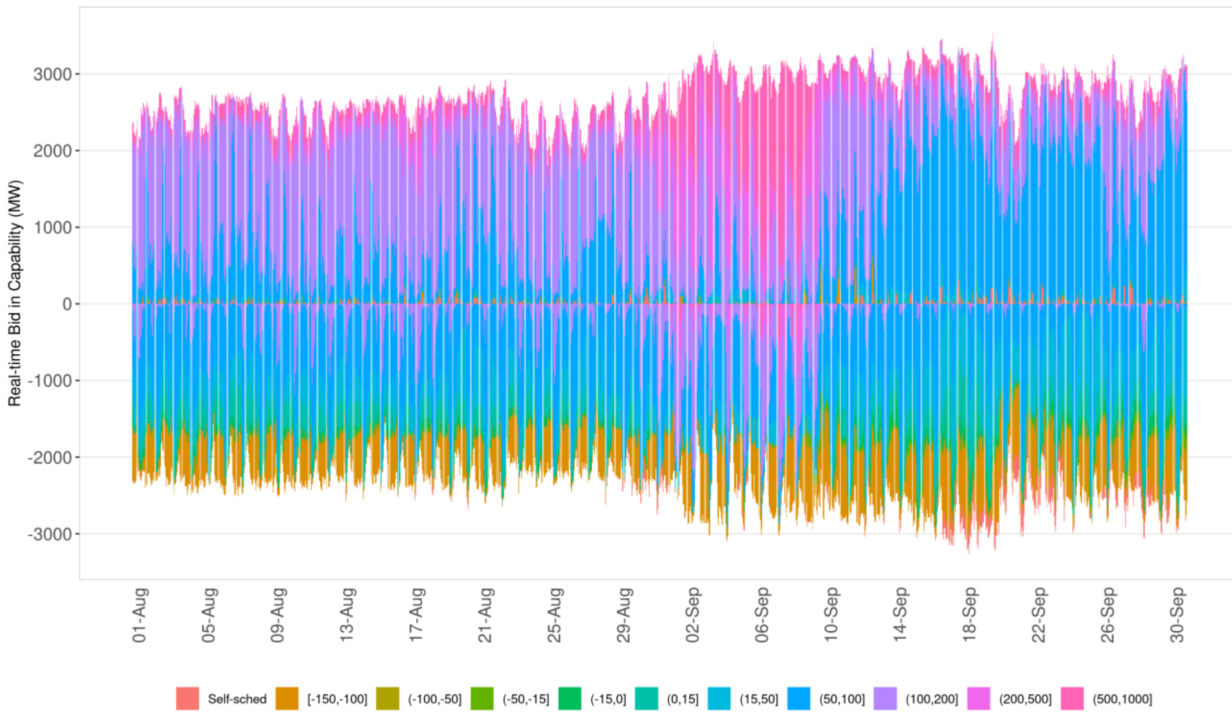


Figure 78 Aggregate day-ahead state of charge for storage in August and September 2022

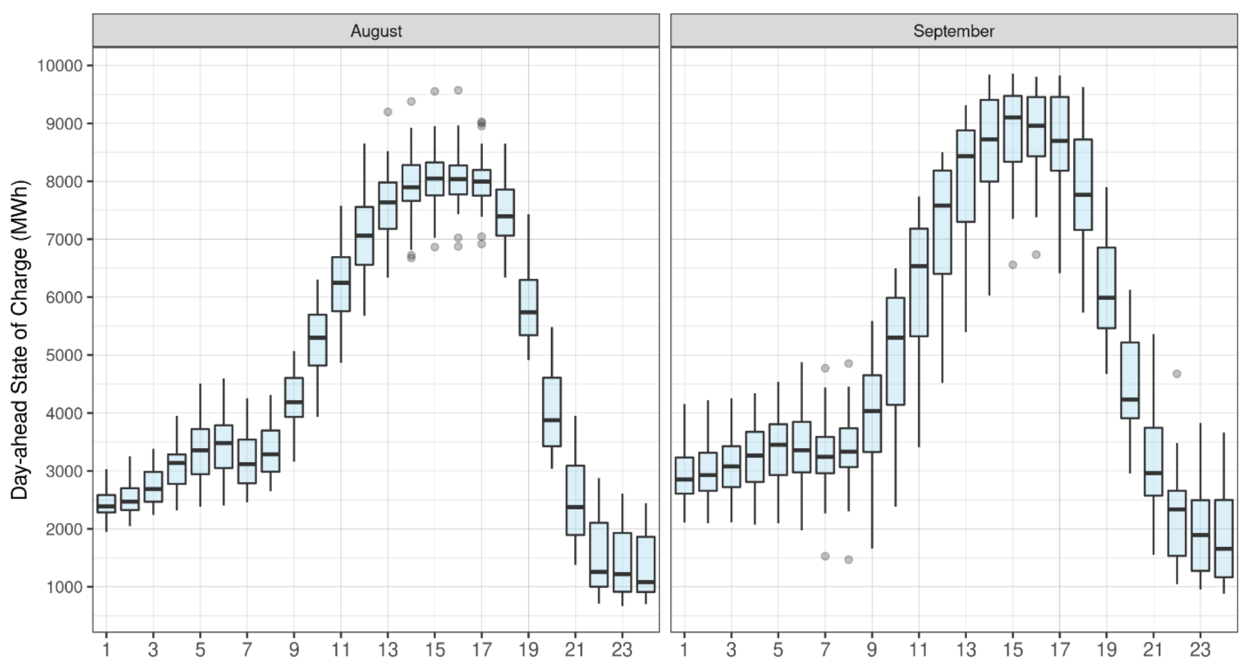
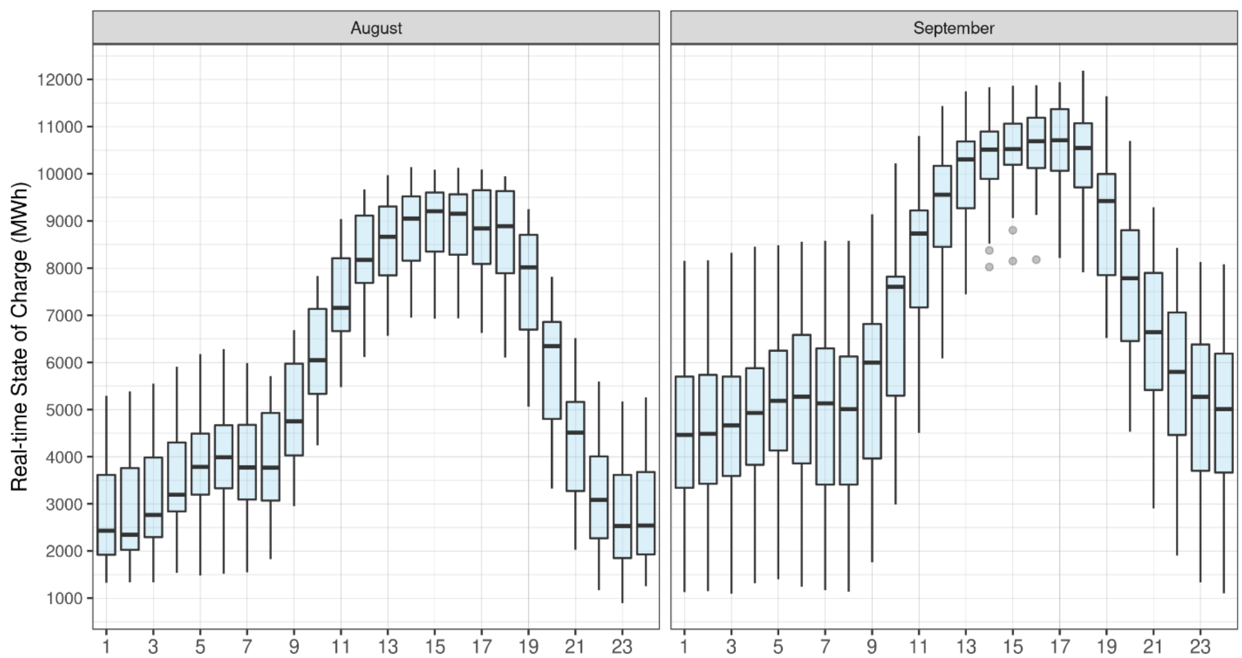


Figure 79 shows the hourly distribution of the aggregate state of charge for the storage fleet participating in day-ahead market in August and September 2022. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge in the day-ahead market. This figure shows that storage resources charge in hours when energy is inexpensive, typically during late morning hours when solar generation is abundant. The maximum aggregate state of charge was typically in the evening hours, followed by a period of steady discharge when prices are highest. This graph shows that a significant amount of storage capacity is arbitraging energy prices across the day.

Figure 79 shows the distribution of state of charge for the RTM for August and September 2022. This figure shows the same pattern in the RTM and that the peak hourly state of charge in the RTM tended to be higher.

Figure 79: Aggregate real-time state of charge for storage in August and September 2022



Most of the storage resources in the ISO market are four-hour batteries, which means that it takes most fully charged resources four hours to discharge completely. To maximize revenue from arbitraging prices, resources charge to full capacity prior to the hours with the highest energy prices, when they discharge. Figure 80 shows the distributions of energy awards in IFM, and Figure 81 shows the distributions of energy awards in real-time, for August and September 2022. These figures highlight hours ending 18 through 22 in a different color than the other hours, to show that the storage resources are being discharged in intervals with the highest energy prices.

Figure 80: Hourly distribution of IFM energy awards for batteries in August and September 2022

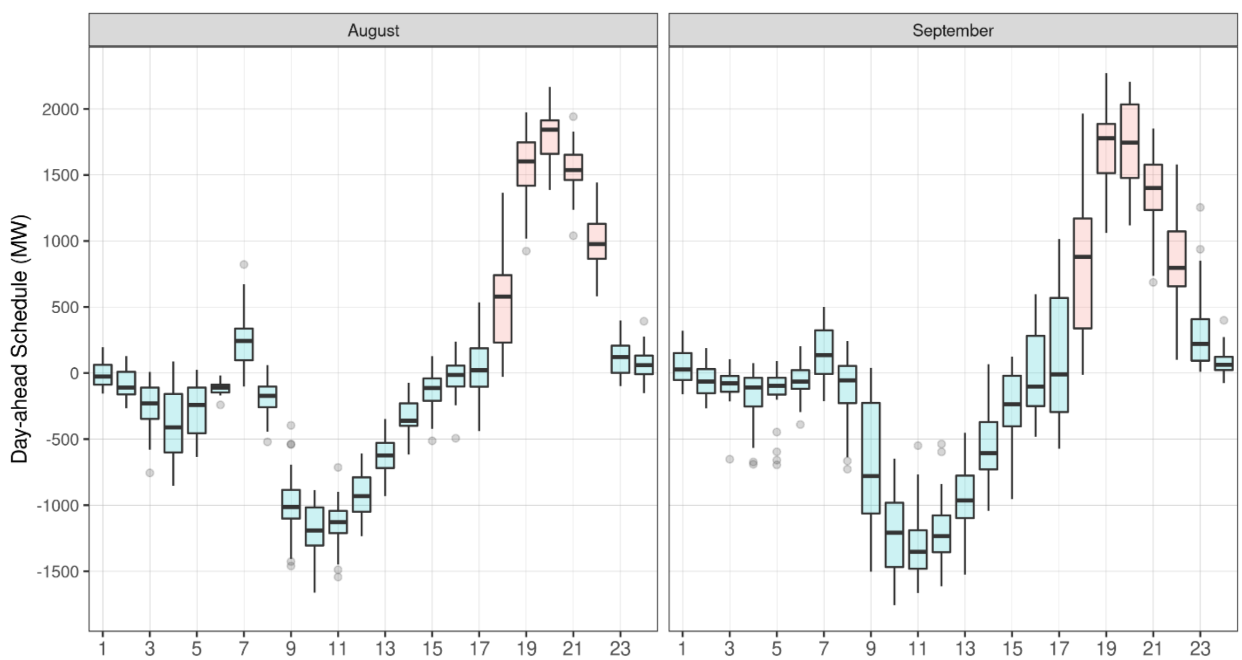
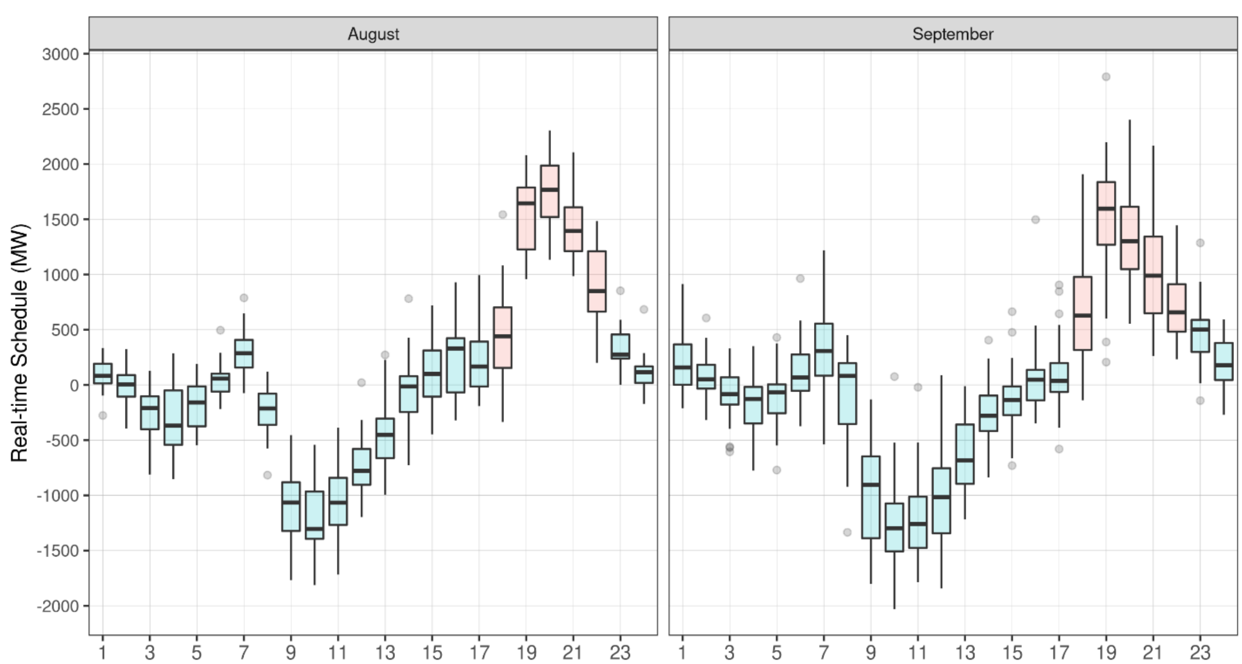


Figure 81: Hourly Distribution of RTD for batteries in August and September 2022



The storage resources continue to provide ancillary services to the market, regulation up, regulation down, and spin. Figure 82 shows the average hourly AS awards in day-ahead, and Figure 83 shows the average hourly AS awards in real-time, for August and September 2022.

Figure 82 Hourly average day-ahead AS awards for storage in August and September 2022

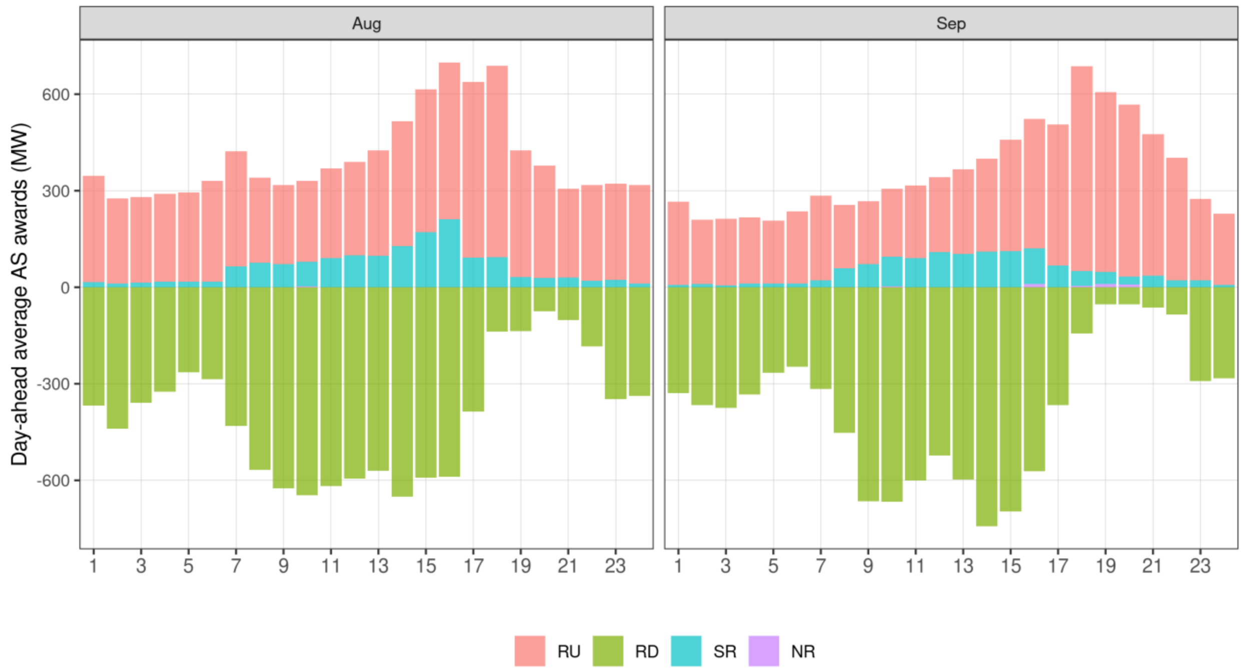
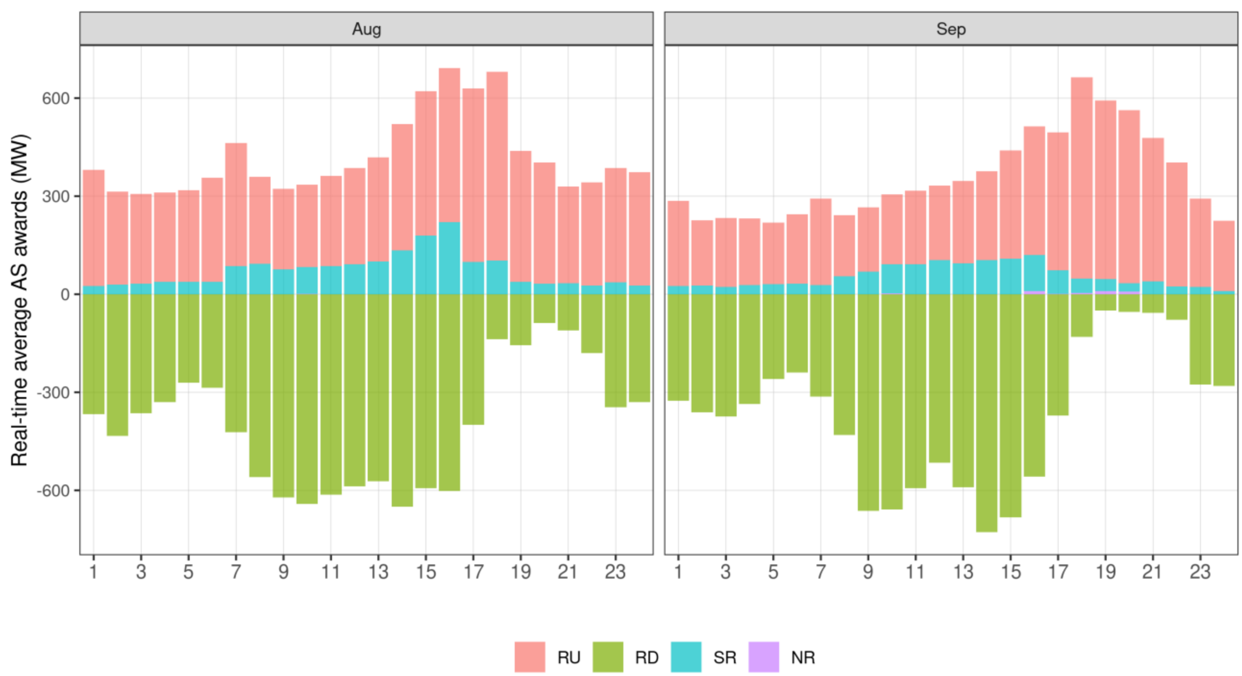


Figure 83 Hourly average real-time AS awards for storage in August and September 2022



7 Western Energy Imbalance Market

The WEIM provides an opportunity for participating balancing authority areas to serve their load while realizing the benefits of increased resource diversity. The ISO estimates the WEIM's gross economic benefits on a quarterly basis.[54] One main benefit of the WEIM is the realized economic transfers among areas. These transfers are the realization of a least-cost dispatch by reducing generation that is more expensive in an area and replacing it with cheaper generation from other areas. In a given interval, one area may have an import transfer with another area while concurrently having an export transfer with another area. Figure 84 shows the distribution of five-minute WEIM transfers for the ISO area. A negative value represents an import into the ISO area from other WEIM areas.

Figure 84: Daily distribution of WEIM transfers for ISO area

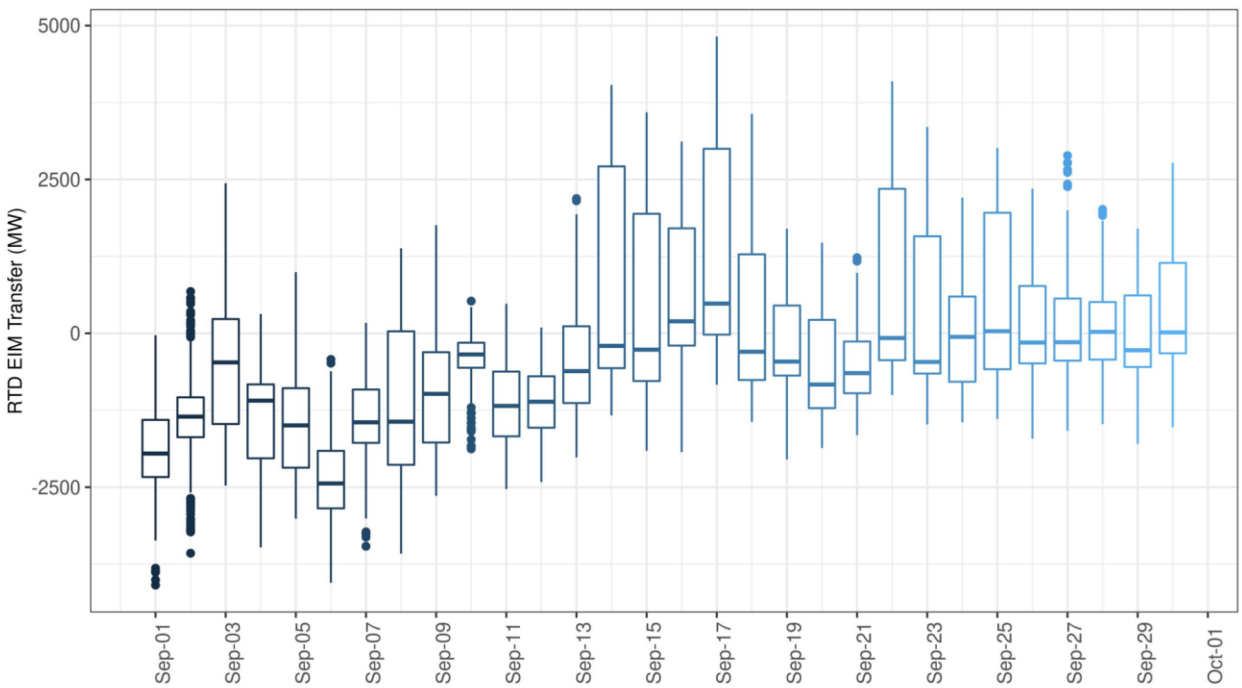
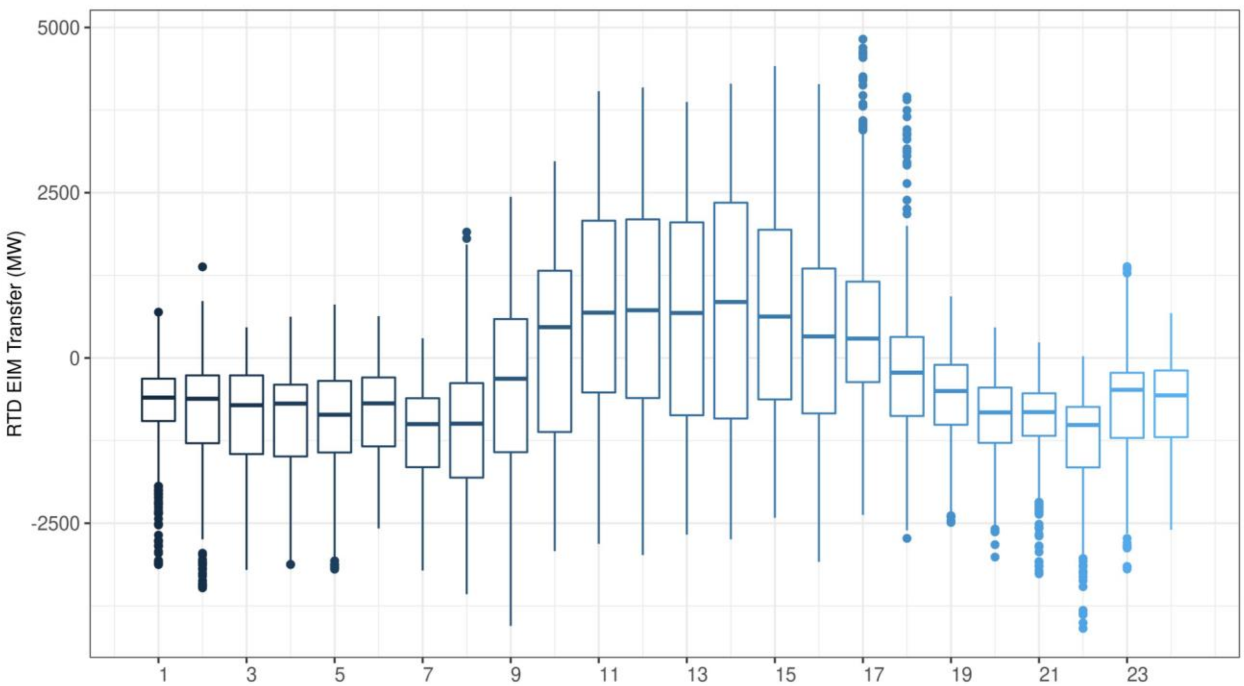


Figure 85 shows the WEIM transfers in an hourly distribution, which highlights the typical profile of the ISO transfers, which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the ISO area. This trend is typical across summer months.

[54] The WEIM quarterly reports are available at https://www.westerneim.com/pages/default.aspx

Figure 85: Hourly distribution of 5-minute WEIM transfers for ISO area

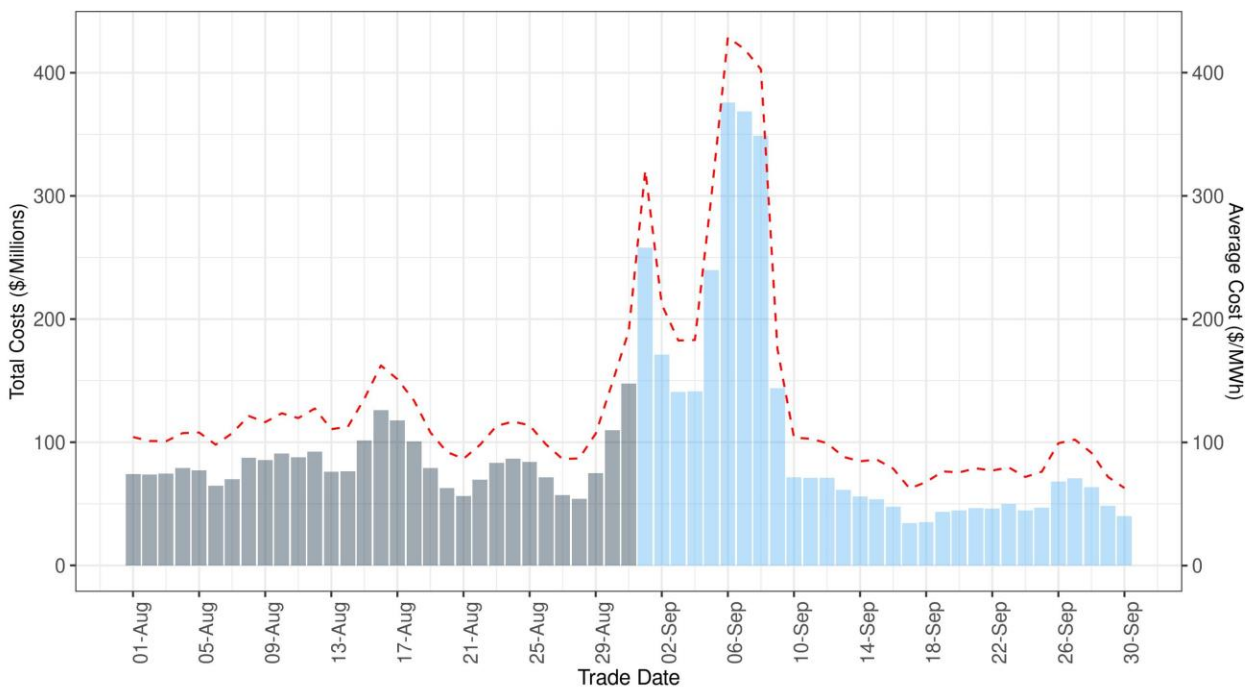


8 Market Costs

The ISO markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy, and ancillary services, among others. The majority of the overall costs accrue on the day-ahead settlements.

Figure 86 shows the daily overall settlements costs for the ISO BAA; this does not include WEIM settlements. As demand and prices rise, the overall settlements are also expected to increase. This trend shows the increase in the overall costs in September, reaching a maximum daily value of about $375 million on September 6. When considering the overall costs relative to the volume of demand transacted, the dotted red line provides a reference of an average cost per MWh.

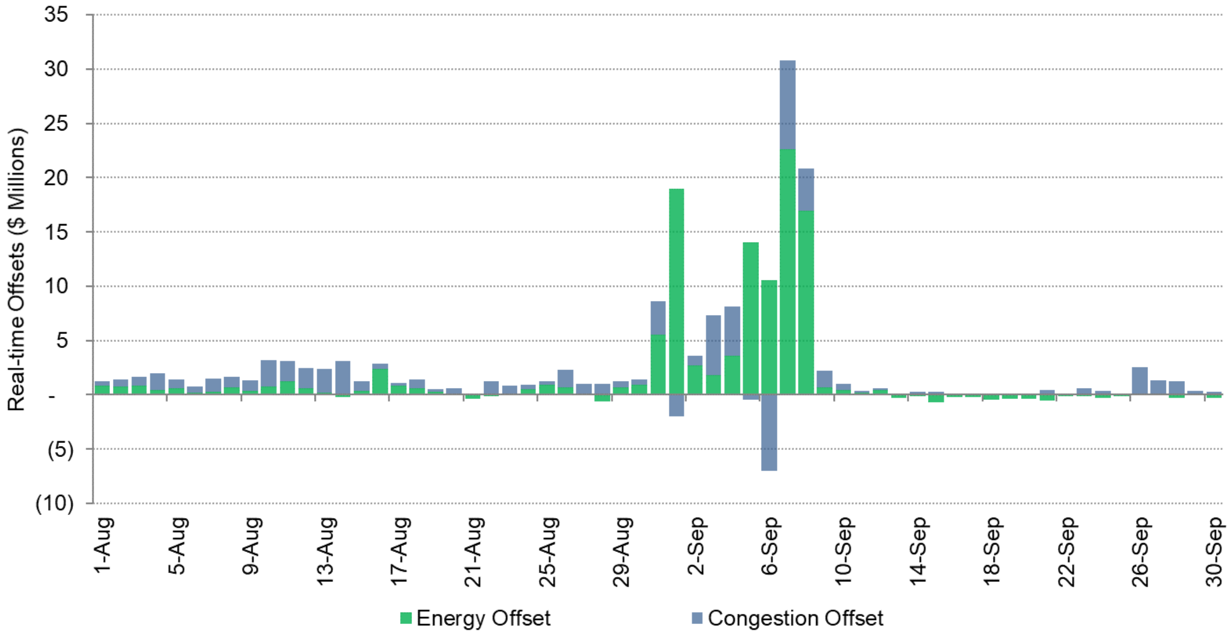
Figure 86: ISO's market costs in summer months of 2022



The average daily cost in September was $110 million (or an average daily price of $145.32/MWh).

Two components of this overall cost are the real-time energy and congestion offsets. These costs reflect the settlements of differences between the day ahead and real-time markets for energy and congestion. These costs typically track system conditions. The congestion offset was about 22 percent of the overall real-time offset totaling about 24 million; however, the energy offset was about 78 percent totaling to about 88 million, which was driven by the significant heat wave observed in first week of September. The real time offset amount was significantly higher for September 5-8, when the highest temperatures occurred. The daily trend is shown in Figure 87.

Figure 87: Real-time energy and congestion offsets in August through September



9 September 5-8 Heat Wave

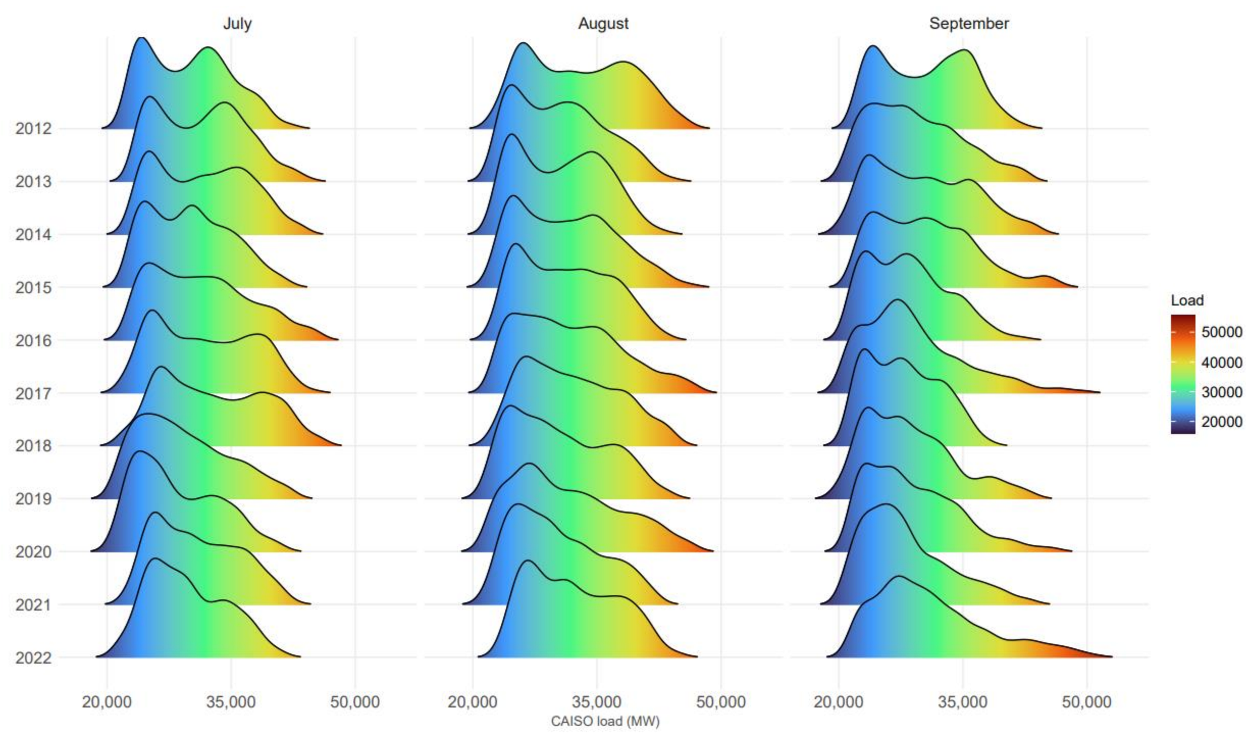
This sections provides more detailed analysis for the period of September 5-8, when the ISO's grid experienced the most critical conditions of the heat wave.

9.1 Load conditions

During the period of September 5 – 8, 2022, as the ISO system was experiencing an historic multi-day heat wave, a new all-time high for peak load was reached at 52,061 MW on September 6. As described in the weather section above, this was due to unprecedented hot weather persisting for 10 days. These high temperature days broke records in many California regions, some of which dated back to 1877.

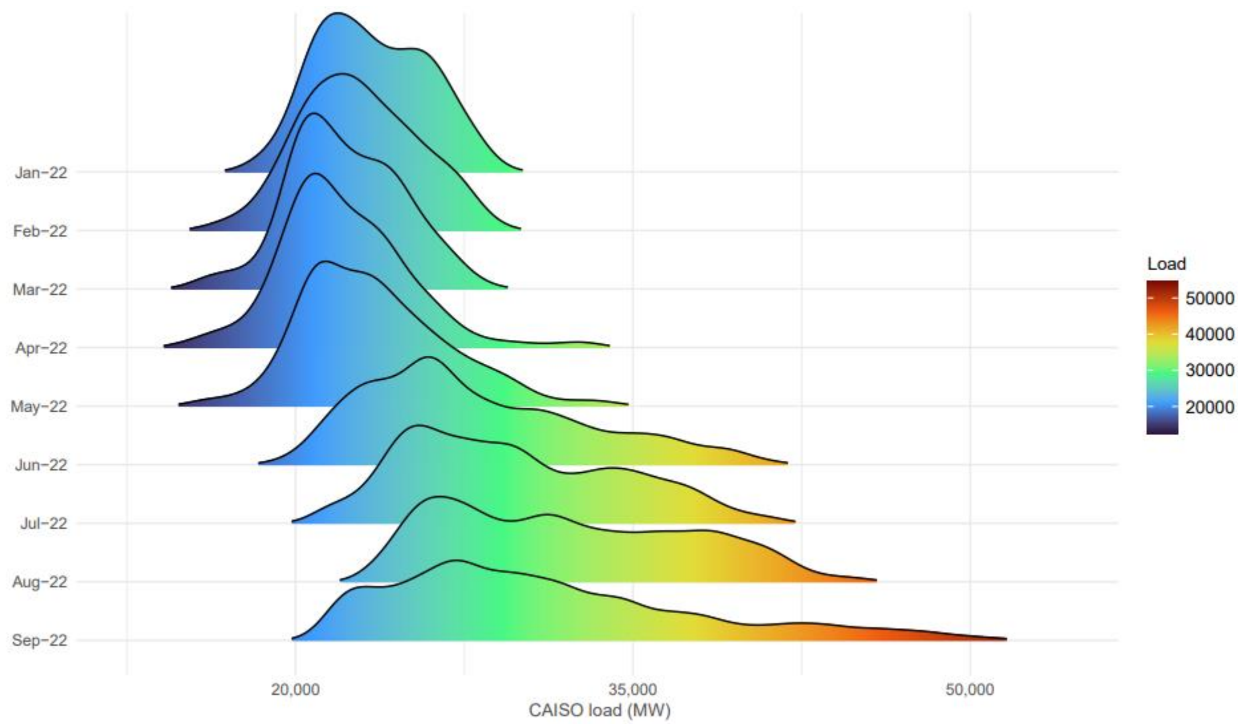
Figure 88 shows the distribution of these historic load levels. The ISO's load has exceeded the 50,000 MW mark only twice before: once in September 7, 2017 and again in 2006. For September 2022, the higher distribution on the right-hand side (in red) demonstrates not only the high loads that materialized but also the higher number of hours these high loads were sustained in the first 9 days of September. However, the multi-day extreme heat wave meant that there was limited overnight cooling, so air conditioners continued to run well into the evening and the next day.

Figure 88: Historical distribution of ISO's load levels in summer months



The ISO's system is summer peaking and largely driven by temperatures across the state. Figure 89 shows the load distribution for all months of 2022. The elongated right hand side of the distribution in the figure shows how much more extreme the load levels in September were relative to August. In fact, with the second part of September cooling down, the minimum load levels were actually also lower overall in September compared to those observed in August. The figure also shows how different the load distribution is once entering the summer timeframe in June relative to the winter and spring months of May and earlier when loads are milder.

Figure 89: Distribution of ISO's load levels in 2022



The system peak load in summer is typically observed in the afternoon hours before 6 pm. However, as the sun sets, the difference between the gross demand and the net demand curves narrow, reflecting mainly in a reduction of solar generation that the RA program does not account for due to the static values used for solar generation across the month.[55] Furthermore, as the sun sets, demand previously served by behind-the-meter solar generation is coming back to the ISO system while ISO system load remains high. This means demand is decreasing at a slower rate than the net demand is increasing. This creates a higher risk of shortages around 7 pm, when the net demand reaches its peak (net load peak). The deployment of demand response also plays a role for the level and timing of when these peaks were observed Figure 90 below shows gross and net load peak figures for each day of the heat wave.

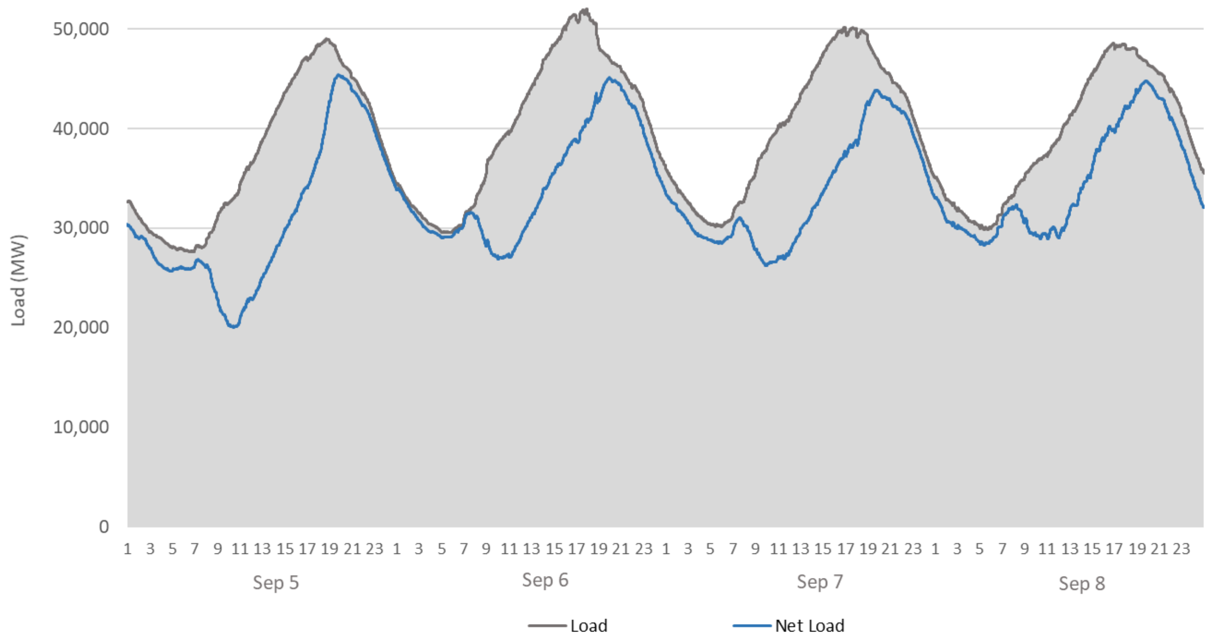
Table 9: Summary of peak times and values during the heat wave

	Gross Load Peak		Net Load Peak	
Date	**Time**	**MW**	**Time**	**MW**
Sept. 5	5:45pm	49,020	6:48pm	45,394
Sept. 6	4:58pm	52,061	6:58pm	45,141
Sept. 7	3:55pm	50,184	6:50pm	43,897
Sept. 8	3:56pm	48,613	6:48pm	44,826

[55] Unlike solar which diminishes as the sun sets, the profile for wind does not necessary follow the pattern defined by the sunset.

Figure 90 below depicts both the gross and net demand trends for the heat wave period. The figure shows that while gross demand exceeded 50,000 MW on September 6 and 7, net demand only peaked at approximately 45,000MW. Note that the peak and net demand peak shown in Figure 90 are based on actual demand levels, which already reflect the impact of any demand response that reduced load.

Figure 90: Gross and net demands for September 5 through 8



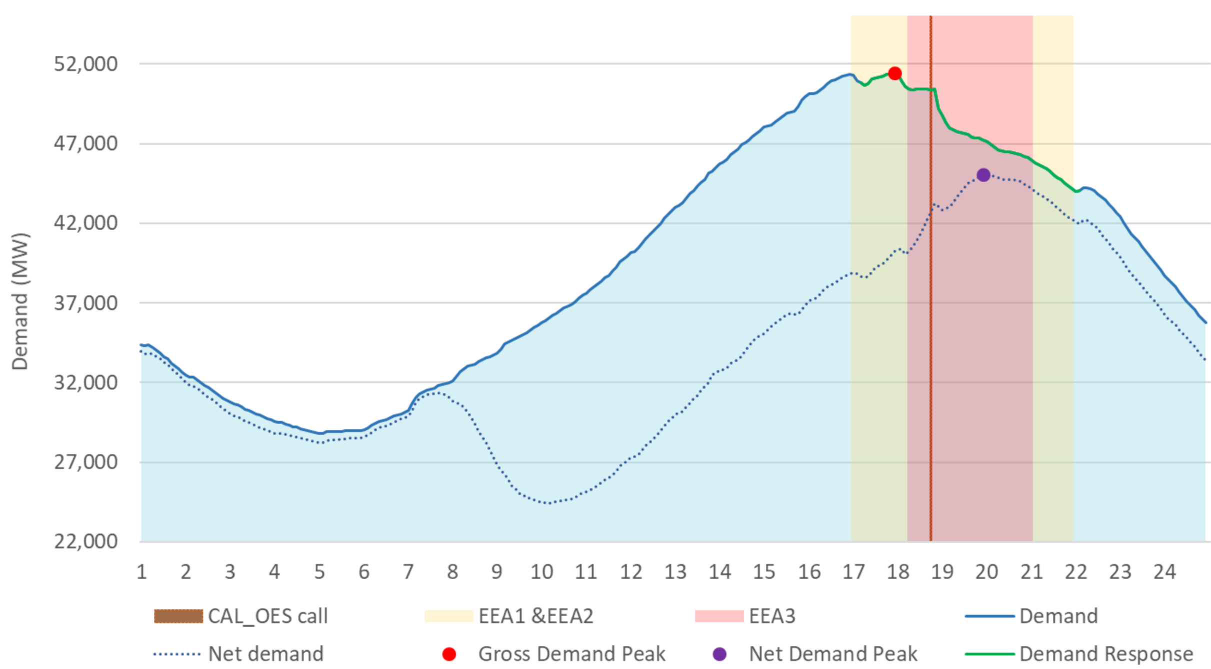
September 6 was the most critical day of the heat wave period. Despite reaching a new peak load record, the confluence of many factors resulted in no ISO system-level load shedding events. The factors that led to this remarkable outcome include the enhanced processes and market functionality, additional demand response, and exogenous conditions:

1. Increased capacity through resource adequacy procurement since summer 2020, including more than 3,500 MW of lithium-ion battery storage;
2. Enhanced coordination, awareness, and communications internally, and with neighboring balancing authority areas, including those participating in the WEIM, external stakeholders such as business and customer groups, investor-owned and publicly-owned utilities, state agencies including the CPUC and the CEC, and the Governor's Office;
3. Market enhancements developed and implemented over the past two years, including clarification of scheduling priorities, enhancements to resource sufficiency evaluations and electricity market pricing designed to incentivize generation during periods of high demand;
4. The use of new state programs to provide non-market resources to address extreme events, as well as the California Governor's Office of Emergency Services (Cal OES) Wireless Emergency Alert urging consumers to reduce non-essential electricity use if it was safe to do so the evening of September 6;

5. Close coordination with load-serving entities during the ISO's highest emergency alert level, an Energy Emergency Alert 3, the afternoon of September 6 that allowed utilities to arm firm load after being notified by the ISO of the need to prepare for rotating outages, which were ultimately avoided;
6. Geographic diversity of extreme heat across the West, which, because the heat was not as intense or prolonged throughout the Desert Southwest or Pacific Northwest compared to California, better positioned the ISO to import power when it was most needed. This included net imports of more than 6,500 MW during net peak on September 6 as well as an additional 1,000 MW from WEIM transfers; and
7. The ISO both received emergency assistance energy and provided it to other balancing authority areas experiencing stressed system conditions.

Figure 91: depicts both the gross and net demand for September 6 with certain events and conditions highlighted. Specifically, the figure highlights the period of the energy emergencies and when demand response events were triggered. It also shows the time when the Cal OES call came in and the immediate effect it had on the demand. These events are described further throughout the report.

Figure 91: September 6 demand profile



9.2 Communications and coordination

If the ISO forecasts a potential shortfall two to eight days in advance, the ISO will initiate the following communications and actions:

- *Two to eight days out* – ISO initiates communications with utilities, the Governor's Office, state agencies, key legislative consultants, and the media.

- *One to four days out* – ISO issues a Restricted Maintenance Operations (RMO) notice for one or more days. An RMO indicates that ISO participants and transmission entities should avoid taking grid assets offline for routine maintenance to assure that all generators and transmission lines are in-service and available. At this time, the ISO also initiates communications with California water agencies and adjacent Balancing Authorities to review their anticipated operating conditions to determine whether the ISO can anticipate any potential relief or assistance from these entities during the forecasted shortfall period. Throughout this period, the ISO continues to communicate with utilities, the Governor's Office, state agencies, key legislative consultants, and the media. If shortfalls are anticipated over consecutive days, the ISO also considers if additional resources will be needed to provide energy to the grid and/or to reduce demand on the grid. If necessary, the ISO coordinates with the Governor's Office for an Executive Order and the US Department of Energy for a 202c Order.
- *One day out* – As a part of the ISO's internal processes, the day-ahead market solution is carefully validated and assessed every day. During summer conditions, this process is expanded to track supply conditions and shortfalls; this includes the posting of a daily report. In the day-ahead timeframe, the daily Day-ahead Summer Report[56] will indicate if the market produces a solution that will be infeasible to meet demand with supply. If these forecasts indicate potential energy shortages, variable or uncertain load or temperature forecasts, gas curtailments, or other grid issues (e.g., wildfires, natural disasters), the ISO then typically issues a Flex Alert notice for the applicable trade date and timeframe following the Day Ahead Market publication. A Flex Alert is a call to consumers to voluntarily conserve electricity when the ISO anticipates using nearly all available resources to meet demand. Reducing energy use during a Flex Alert can prevent more dire measures, such as moving into EEA notifications, emergency procedures, and even rotating power outages. The ISO may also issue an EEA Watch notice if analysis shows all available resources are committed or forecasted to be in use, and thus shortfalls are expected. Throughout this period, the ISO continues to communicate with utilities, the Governor's Office, state agencies, key legislative consultants, and the media. With a Flex Alert and EEA Watch, ISO will also initiate discussions with the Emergency Load Reduction Program (ELRP) Board to determine how much demand response may be activated during the stressed timeframe.
- *On the operating day* (a.k.a. trade date, 'day of') – The data and information ISO uses to analyze the forecasted conditions continues to be reviewed and adjusted throughout the day. As needed, ISO will work with its Reliability Coordinator – RC West – to issue Energy Emergency Alerts (EEAs)[57] to indicate current and anticipated conditions to the public, market participants, utilities and neighboring entities.
- *Ongoing* – Communications and coordination continue each day, for current and future days, as indicated above until the forecasted extreme conditions end.

[56] The Day-Ahead daily market watch and summer reports are posted here: http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx. A description of the data included in the posted reports is here: http://www.caiso.com/Documents/ExplanationofDataIncludedintheDay-AheadSummerReports.pdf

[57] Summary descriptions of the EEAs are available here: http://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf

9.3 Events overview and operational conditions

With the planned communication and coordination procedures described above, this section will discuss how the ISO went about executing these procedures during the heat wave.

Days prior to August 31:

Wednesday, August 24 was the first day the ISO's analysis flagged a temperature alert for the period of August 31 through September 2. This flag only covered through September 2 since the look-ahead window is nine days. On Sunday, August 28, the ISO analysis of the look-ahead window started to highlight the severity and length of the upcoming heat wave. This analysis provided the warning of extreme heat and high loads for August 31 and the potential for a RA shortfall starting on September 1. At this point, the ISO initiated communications with utilities, the Governor's Office, state agencies, key legislative consultants, and the media. As August 31 approached, the ISO continued to update the forecasts and other relevant data. On August 29, the ISO analysis continued to indicate extreme heat and high loads starting August 31, so the ISO issued RMO Notices for August 31 through September 6, each day for the time period 12:00 – 22:00. The days with Flex alerts or EEAs are summarized in Table 10 below.[58]

Table 10: Summary of alerts related to extreme heat and high loads

Trade Date	RMO	Flex Alert	EEA Watch	EEA 1	EEA 2	EEA 3
31-Aug	Yes	Yes	Yes	Yes		
1-Sep	Yes	Yes	Yes			
2-Sep	Yes	Yes				
3-Sep	Yes	Yes	Yes			
4-Sep	Yes	Yes	Yes			
5-Sep	Yes	Yes	Yes	Yes	Yes	
6-Sep	Yes	Yes	Yes	Yes	Yes	Yes
7-Sep	Yes	Yes	Yes	Yes	Yes	
8-Sep	Yes	Yes	Yes	Yes	Yes	
9-Sep	Yes	Yes	Yes	Yes		

August 31:

The Day Ahead Market results published on August 30 for trade date August 31 indicated that supply would be sufficient for that day. However, several resources became unavailable overnight, and on the morning of August 31, the actual load was trending higher than the day-ahead forecast. As it was not likely that the resources would be online prior to or during peak hours, the ISO issued a Flex Alert for August 31 16:00 – 21:00 and an EEA Watch for August 31 17:00 – 20:00. By declaring these notices, ISO was able to initiate discussions with the ELRP Board to see if some ELRP-registered demand response could be activated, even though the amount of reductions would be lower than if the Flex Alert had been declared in the day-ahead timeframe. Another factor impacting operating conditions on August 31 was two new fires (Route Fire and Boarder Fire) reported in the afternoon with actual and potential impacts to ISO

58 Detailed report posted on ISO's website at: http://www.caiso.com/Documents/Grid-Emergencies-History-Report-1998-Present.pdf

generation and transmission availability in southern California. ISO coordinated with RC West to issue an EEA 1 notice at 15:10 indicating that all available resources would be in use for the time period 17:00 – 20:00. A portion of the resources impacted by the Route Fire were able to return to service, the ISO was able to procure additional energy, and additional EEA notices were not needed.

On August 31, California Governor Gavin Newsom declared a State of Emergency[59] to temporarily increase energy production and reduce demand beginning August 31 through September 6. Throughout this period, new and existing state programs providing non-market resources to address extreme events were also deployed.

September 1 through 4:

The ISO analysis of Day-Ahead Market results, potential system conditions and criteria for each of the trade dates September 1 through September 4 indicated extreme heat and high loads; therefore, the ISO issued Flex Alerts after the Day Ahead Market published each day. Additionally, because the analysis also indicated potential supply shortfalls, the ISO issued EEA Watch notices for applicable days (all except September 2). Although there were challenging operational conditions each day due to unplanned outages and wildfires, it was apparent that the additional energy and demand reductions related to the Governor's proclamation provided relief through this period. Because the ISO analysis of potential system conditions and criteria indicated extreme heat and high loads continuing through the later part of the week, the ISO extended the RMO notices for trade dates September 7 through September 9, each day for the time period 12:00 – 22:00.

September 5:

On September 5, the ISO area experienced unplanned resource de-rates and outages throughout the day and, in some cases, it was not clear whether the estimated time needed by these resources to return would be sufficient to meet the high load peak hours. Then ISO coordinated with RC West to issue an EEA 1 indicating that all available resources would be in use for the time period 17:00 – 21:00. Later, the ISO coordinated with RC West to issue an EEA 2 due to forecasted supply shortages. This allowed for the activation of emergency demand response (i.e. Reliability Demand Response Resources or RDRR) to meet the forecasted load if needed. The ISO was able to procure additional energy and additional EEA notices were not needed. Unrelated to the system extreme conditions, the ISO also issued a Transmission Emergency notice to help mitigate local overloads in the Palermo area.

September 6:

Similar to September 5, on September 6 the ISO area experienced unplanned resource de-rates and outages throughout the day. The ISO coordinated with RC West to issue an EEA 1 indicating that all available resources would be in use for the time period 16:00 – 21:00. Later, the ISO coordinated with RC West to issue an EEA 2 due to forecasted supply shortages. This allowed the activation emergency demand response to meet the forecasted load if needed. The ISO also coordinated with RC West to issue an EEA 3 in anticipation of ISO arming 2000 MW of firm load which could be counted as contingency reserves. The

[59] https://www.gov.ca.gov/2022/08/31/as-heat-wave-grips-western-u-s-governor-newsom-takes-action-to-increase-energy-supplies-and-reduce-demand/

Cal OES Wireless Emergency Alert came in at 5:45 p.m. and provided additional energy conservation on top of existing responses to Flex Alert and non-programmatic conservation efforts. The ISO was able to procure additional energy and firm load shedding was not needed. Unrelated to the system extreme conditions, the ISO also issued a Transmission Emergency notice to help mitigate local overloads in the Palermo area.

On September 6, Governor Newsom issued an executive order[60] extending the provisions of the earlier emergency proclamation and executive order through September 9.

On September 7:

The ISO area experienced unplanned resource de-rates and outages throughout the day, and in some cases, it was not clear if the estimated times for resources to return would be on time for peak hours. The ISO coordinated with RC West to issue an EEA 1, which indicated that all available resources would be in use for the time period 16:00 – 21:00. Later, ISO coordinated with RC West to issue an EEA 2 due to forecasted supply shortages, and the need to activate emergency demand response (RDRR) to meet the forecasted load. The ISO was able to procure additional energy and additional EEA notices were not needed. Unrelated to the system extreme conditions, the ISO also issued a Transmission Emergency notice to help mitigate local overloads in the Palermo area.

On September 8:

The ISO area experienced unplanned resource de-rates and outages throughout the day, and in some cases, it was not clear if the estimated times for resources to return would be on time for peak hours. The ISO coordinated with RC West to issue an EEA 1, which indicated that all available resources would be in use for the time period 15:00 – 21:00. Later the ISO coordinated with RC West to issue an EEA 2 due to forecasted supply shortages, and the need to activate emergency demand response (RDRR) to meet the forecasted load. The ISO was able to procure additional energy and additional EEA notices were not needed. Unrelated to the system extreme conditions, the ISO also issued a Transmission Emergency notice to help mitigate local overloads in the Palermo area.

[60] https://www.gov.ca.gov/2022/09/06/as-record-heat-wave-intensifies-governor-newsom-extends-emergency-response-to-increase-energy-supplies-and-reduce-demand/

9.4 Resource sufficiency evaluation

The design of the WEIM includes a resource sufficiency evaluation process, with the purpose of ensuring each participating BAA has sufficient resources, capacity and flexibility to serve its load needs prior to participating in the real time market. The final and binding pass runs at forty minutes prior to the upcoming hour of the RTM. The RSE includes:

1. Balancing test,
2. Capacity (bid range) test,
3. Feasibility evaluation, and
4. Flexible ramping test

The ISO area is assessed for the bid range capacity test and the flexible ramp sufficiency test. The objective of the capacity test is to assess whether participating BAAs have sufficient bid-range capacity in their corresponding control area to meet the imbalance requirements for each 15-minute interval within the upcoming hour. The goal of the flexible ramp sufficiency test is to assess whether participating areas have sufficient ramping capability among all areas' resources to meet the forecasted demand changes across intervals plus the uncertainty estimated on historical uncertainty. The RSE consists of three passes at 75 minutes prior to the assessed hour (T-75), at T-55 and at T-40. The first two passes are advisory and enable BAAS to adjust their schedules to pass the last pass at T-40. A BAA fails the test if it failed either the bid-range capacity or flexibility ramping sufficiency test at T-40. For the ISO BAA, there is no expectation of making adjustments in the first two passes since the ISO area relies on the capacity made available through the RA program and the day-ahead market solution. As a practice, ISO BAA operators do not actively take actions on resources to change the outcome of the test process.

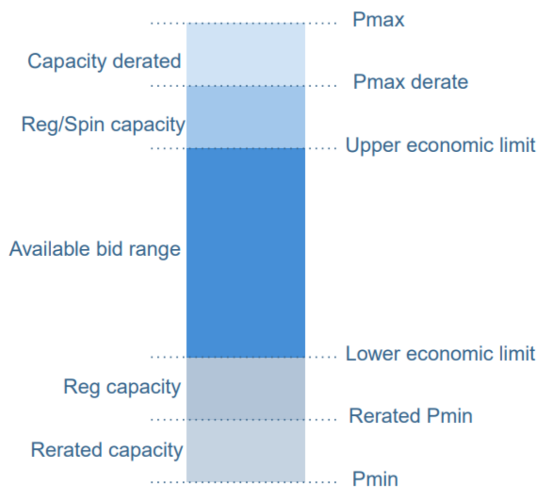
The capacity test assesses if there is sufficient capacity to meet the forecast obligation. The inputs for the capacity test include:

1. Fifteen-minute load forecast
2. Imports and exports; for the ISO's test at T-40, only the fifteen-minute imports and exports bids are considered because they can be optimized in the FMM market and consequently can provide bid-range capacity
3. Hourly next schedule interchange schedules; for the ISO, these are the inter-tie schedules cleared in the RTM
4. Bids for all internal resources
5. Resources de-rates and re-rates

The bid range capacity is the summation of the individual bid range capacity of resources that are online or otherwise were made available to and could have been committed by the RTM. This design was changed during the RSE enhancements for summer 2022.

The bid range capacity test is a capacity test, which means that the overall capacity of a resource is counted regardless of its current operating point or ramp capability. The flexible ramping capacity test complements the capacity test with a more stringent assessment of ramp capability. Under this construct, the resource's individual capacity range is based on the available capacity once derates/rerates, outages, spin and regulation capacity are discounted since these use up a certain range of the resource capacity, as illustrated in Figure 92. The range in dark blue titled Available bid range is the bid range effectively utilized in the capacity test.

Figure 92: Resource capacity breakdown



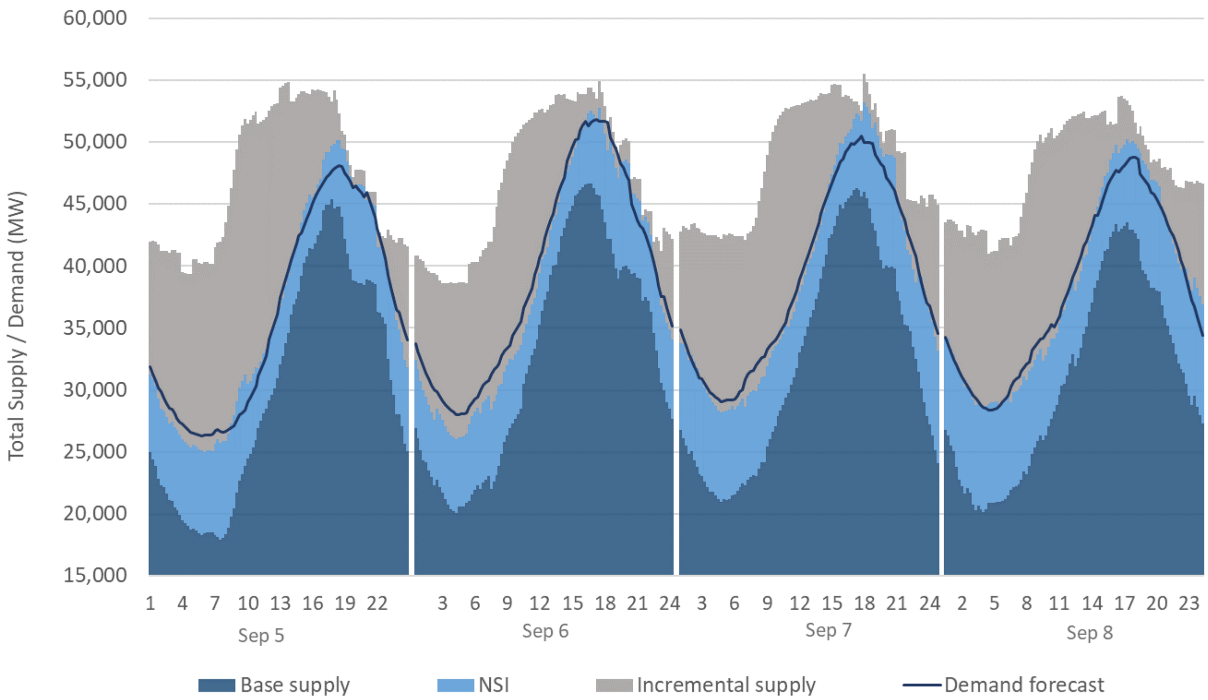
During the heat event of early September, demand in the different WEIM BAAs trended higher and the ISO BAA set a new record of peak demand. Under these high load conditions, available capacity counted in the test becomes limited and scarce, thus there may be more conditions that would cause BAAs to fail the capacity test. Table 11 provides the list of all intervals with a capacity test failure in any of the BAAs participating in the WEIM. Capacity test failures only occurred on September 5 and 6 across different BAAs. ISO BAA (shown as CISO below) had one failure on September 5 and two failures on September 6 during peak hours.

Table 11: Capacity test failures across BAAs during the heat wave

Date	Hour	Interval	BAA	MW Failure
5-Sep	18	1	SRP	338.6
5-Sep	18	2	SRP	308.2
5-Sep	18	3	SRP	251.8
5-Sep	18	4	SRP	185.8
5-Sep	19	1	SRP	159.1
5-Sep	19	2	SRP	72.4
5-Sep	21	1	PACW	3.8
5-Sep	22	1	CISO	335.4
6-Sep	1	1	SCL	17.2
6-Sep	1	2	SCL	5.6
6-Sep	2	1	SCL	8.0
6-Sep	2	2	SCL	0.6
6-Sep	3	1	SCL	5.5
6-Sep	3	2	SCL	2.4
6-Sep	15	1	BANC	35.3
6-Sep	15	2	BANC	82.3
6-Sep	15	3	BANC	122.8
6-Sep	15	4	BANC	153.4
6-Sep	16	1	NW	59.0
6-Sep	16	2	NW	65.1
6-Sep	16	3	NW	65.9
6-Sep	16	4	NW	66.9
6-Sep	17	3	IPCO	5.2
6-Sep	18	1	BANC	456.8
6-Sep	18	1	IPCO	63.8
6-Sep	18	2	BANC	437.9
6-Sep	18	2	IPCO	51.6
6-Sep	18	3	BANC	424.7
6-Sep	18	3	IPCO	39.3
6-Sep	18	4	BANC	399.4
6-Sep	18	4	CISO	27.6
6-Sep	18	4	IPCO	24.3
6-Sep	19	1	PACE	182.9
6-Sep	19	2	PACE	64.2
6-Sep	19	4	CISO	61.2

Figure 93 shows the overall comparison between available supply and demand requirements of the capacity test during the heat event for the ISO area. The overall available supply consists of the base supply (*i.e.*, generation) and net schedule interchange, both obtained from the most recent FMM solution prior to the run of the capacity test; the incremental capacity is the unloaded capacity above the FMM schedules. As long as the available supply was greater than the demand requirement, ISO BAA passed the capacity test. The margin between available supply and demand was reduced across the peak hours of the day as an increasing amount of supply was utilized to meet the increasing demand needs. This margin became negative in only those three 15-minute intervals mentioned above, as shown by the demand forecast line being above the total available supply.

Figure 93: Total supply-demand condition in the capacity test, ISO area



The capacity test can also be evaluated through an incremental approach where the unloaded capacity from available supply is compared against the incremental demand requirement. This incremental demand requirement is derived as the difference between demand requirement and the total supply (generation and net schedule interchange, or NSI) already scheduled in the last FMM market. The difference between these incremental supply and demand figures is the imbalance that determines the outcome of the capacity test, passing when incremental supply is greater than demand (*i.e.*, a positive imbalance). Figure 94 shows the imbalance in the capacity test for ISO BAA across peak hours and the intervals with failures showing a small negative imbalance. For all other intervals, the imbalance is positive and ISO BAA passed the test, indicating that there was sufficient supply to meet the forecasted demand obligation.

Figure 94: Incremental supply-demand in the capacity test

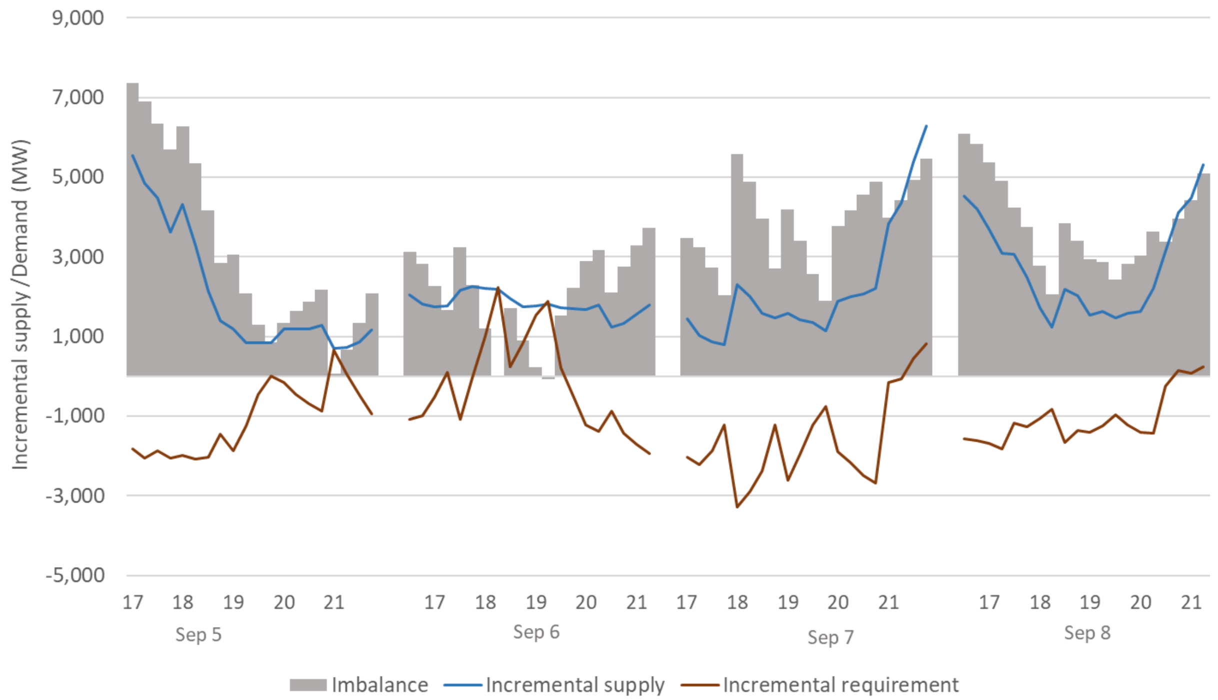
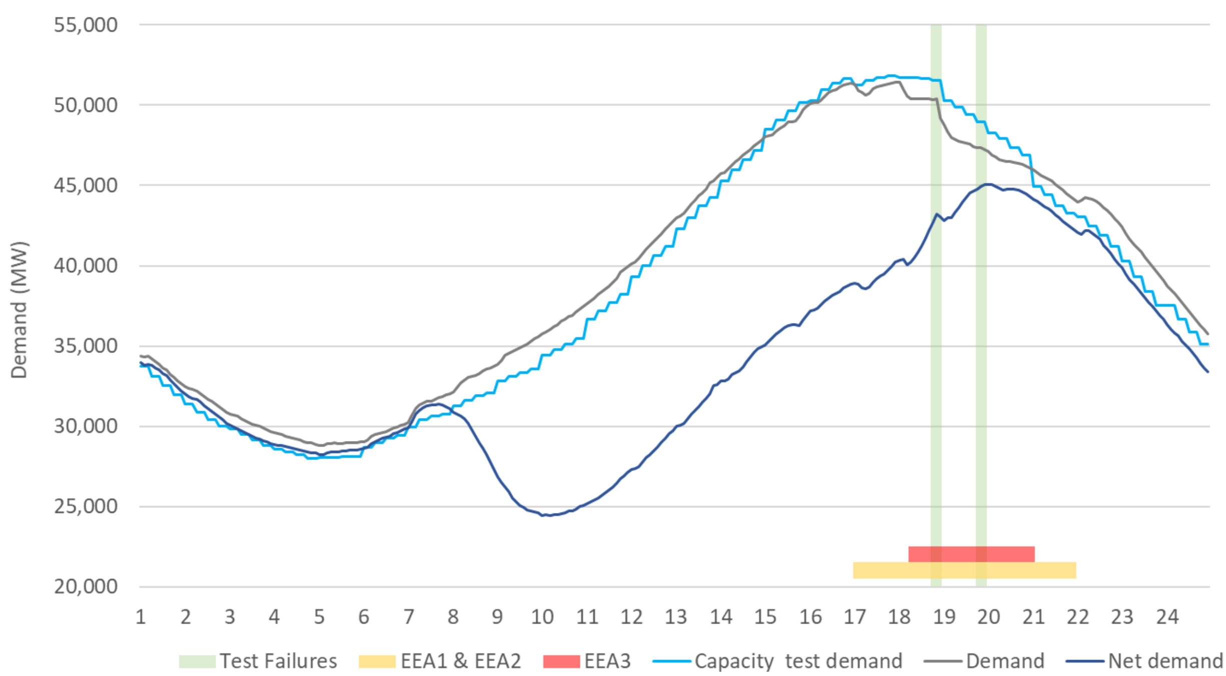


Figure 95 illustrates the timing of the capacity test failures relative to the tight supply conditions on September 6 when the ISO area called an Energy Emergency Alert (EEA) 1, and subsequently an EEA2 and EEA3.

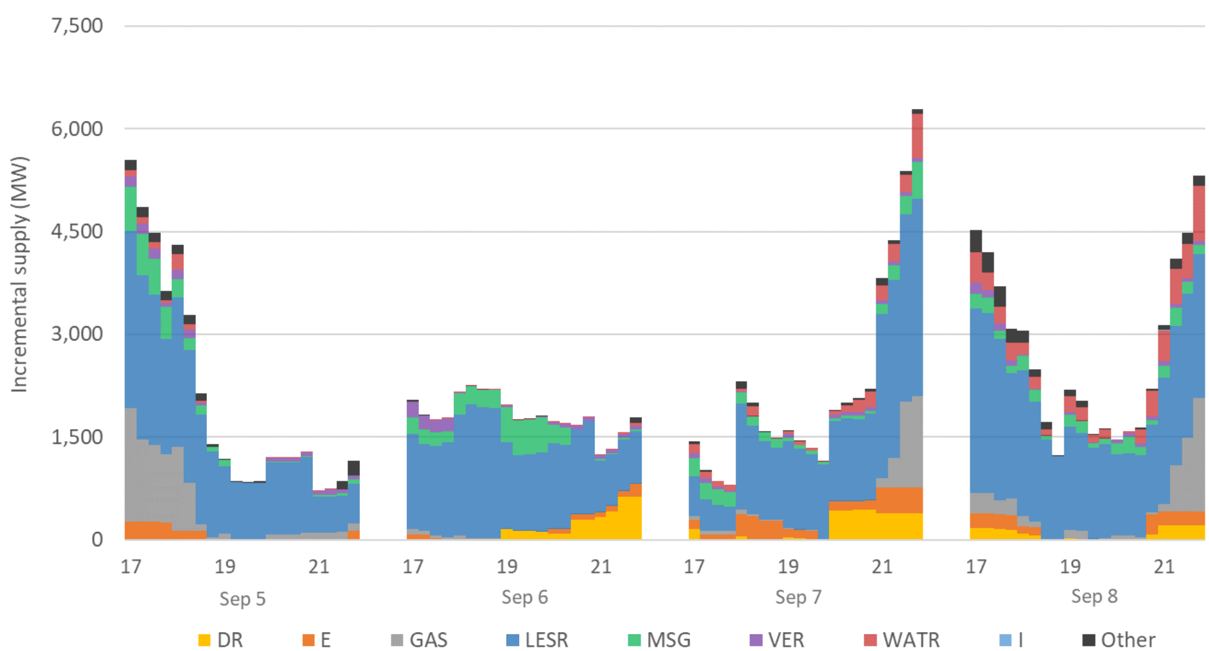
Figure 95: Demand used in capacity test relative to actual demand on September 6



The capacity test failures were within the duration of the EEA3. This duration also corresponded to the time when demand peaked. The demand used in the capacity test tracked relatively close to the actual demand for most of the hours. However, as demand response programs and the Cal OES wireless emergency alert notification resulted in demand reductions, the actual demand came in lower than the forecasted demand used in the test. The capacity test failures occurred after the gross load peak, closer to the net load peak.

Figure 96 shows the types of resources that contributed to the available incremental supply counted in the capacity test for the ISO area. For the peak hours of September 6, the majority of incremental capacity that aided in passing the test was supported by storage resources (LESR) followed by modest contributions from multi-stage generator (MSG) and market demand response (DR) resources. These market DR resources included both proxy and reliability demand response resources (PDR and RDRR). There are also contributions from Exports (E) and Imports (I).

Figure 96: Incremental capacity breakdown by resource type estimated in the capacity test



The capacity test projects the supply capacity that is expected to be available in real time, based on conditions at the time the test is run. However, since real-time conditions are inherently dynamic, there is a time window between when the test is run and the actual real-time operation where supply capacity can change.

In previous efforts to assess the performance of the capacity test, the ISO has provided extensive analysis of the mis-accounting supply during this time window to identify potential further enhancements to the RSE. These assessments have relied on both the incremental capacity estimated in the capacity test as well as the construct of the gross capacity available in the test and in the RTM. Figure 97 through Figure 103 show the capacity available in the test and in the RTM by resource type. These figures illustrate any differences between capacity used in the capacity test and capacity that was actually available in real-time. The green line highlights the actual RTD of these resources to have a reference of how much they were actually utilized in real time. As tight supply conditions evolved through the peak hours, the expectation is that these resources were fully or nearly fully utilized, shown by the green line approaching the blue line.

Figure 97: Supply capacity comparison test vs. RTM for Gas MSG resources

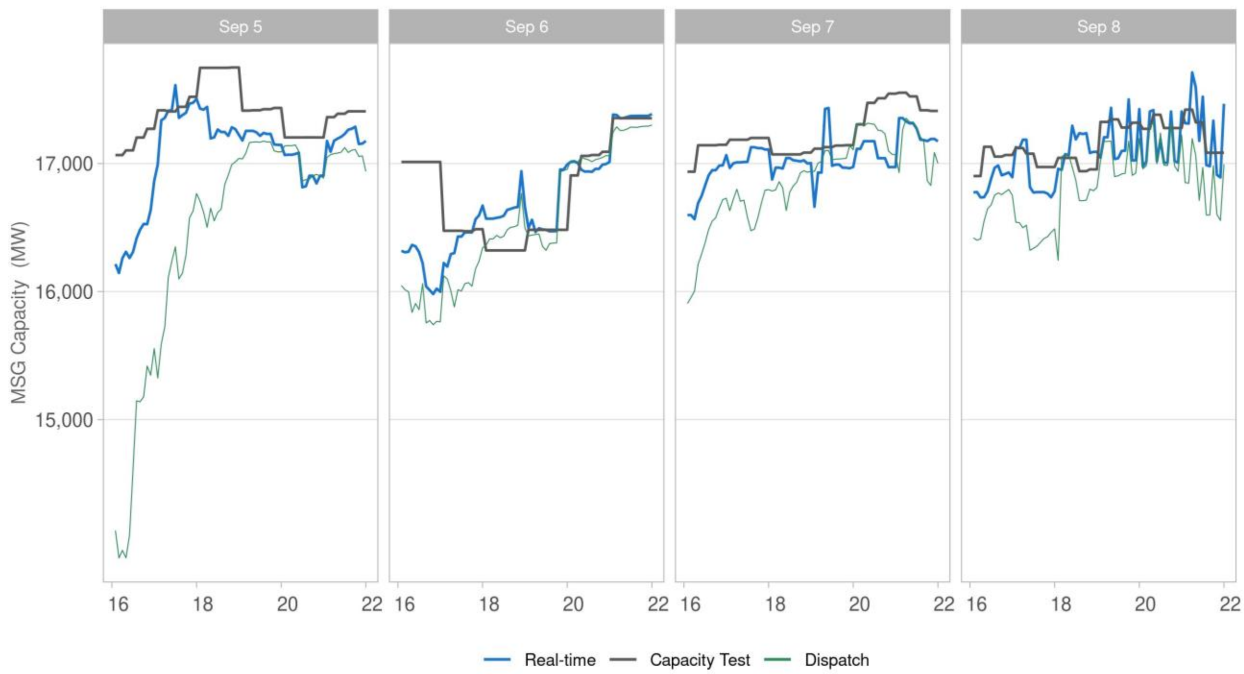


Figure 98: Supply capacity comparison test vs. RTM for Imports

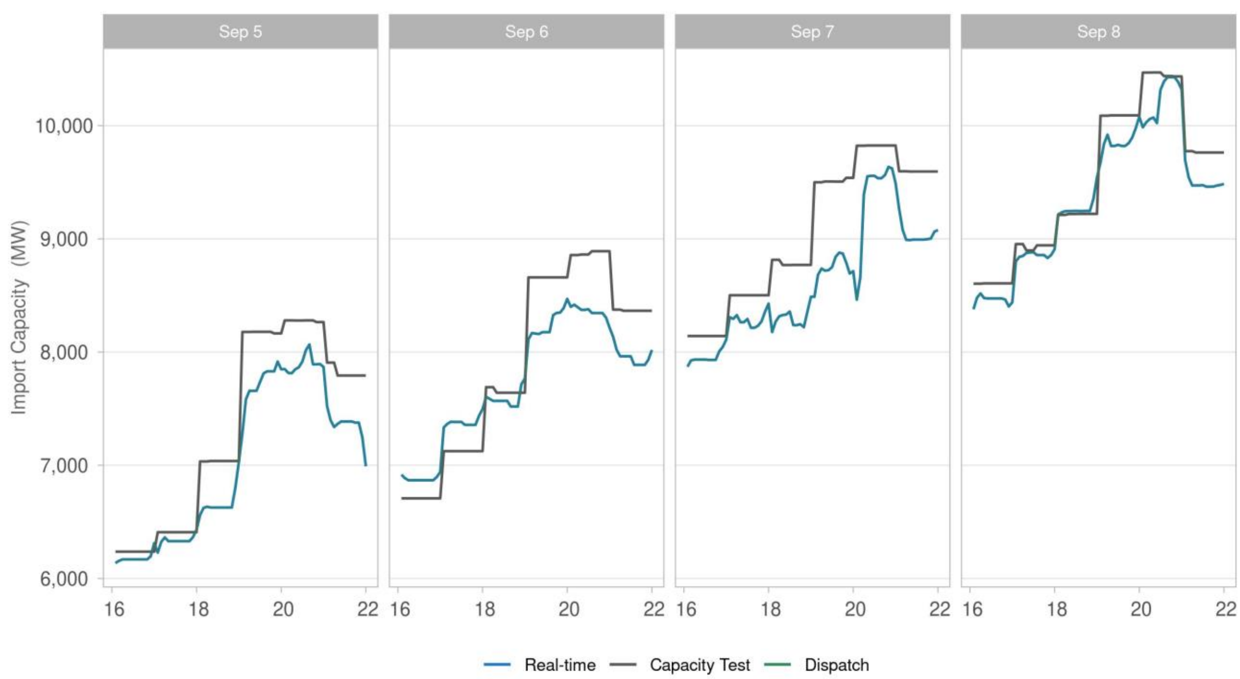


Figure 99: Supply capacity comparison test vs. RTM for VER

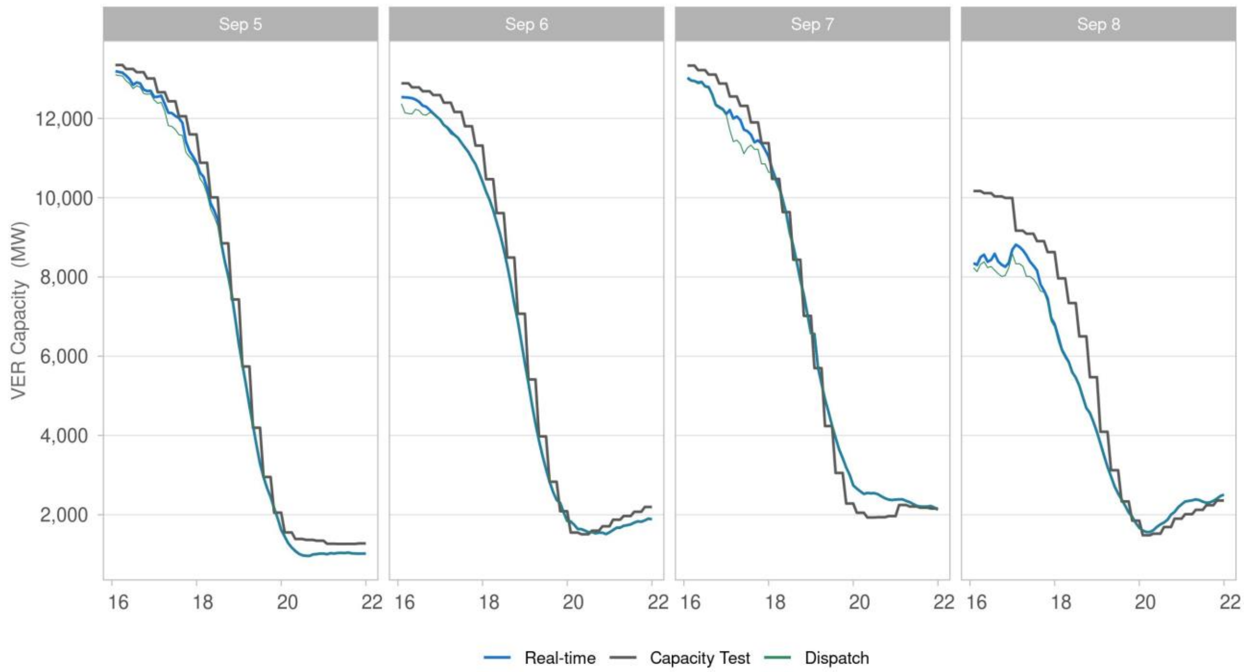


Figure 100: Supply capacity comparison test vs. RTM Storage

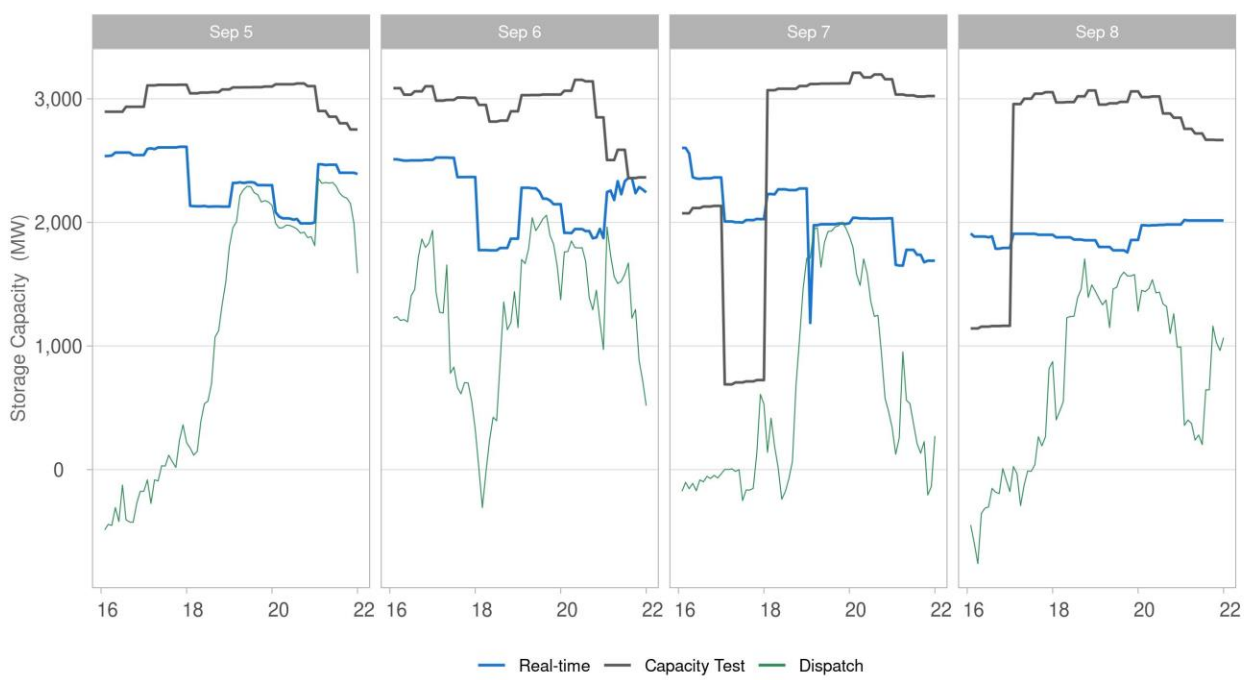


Figure 101: Supply capacity comparison test vs. RTM for Export

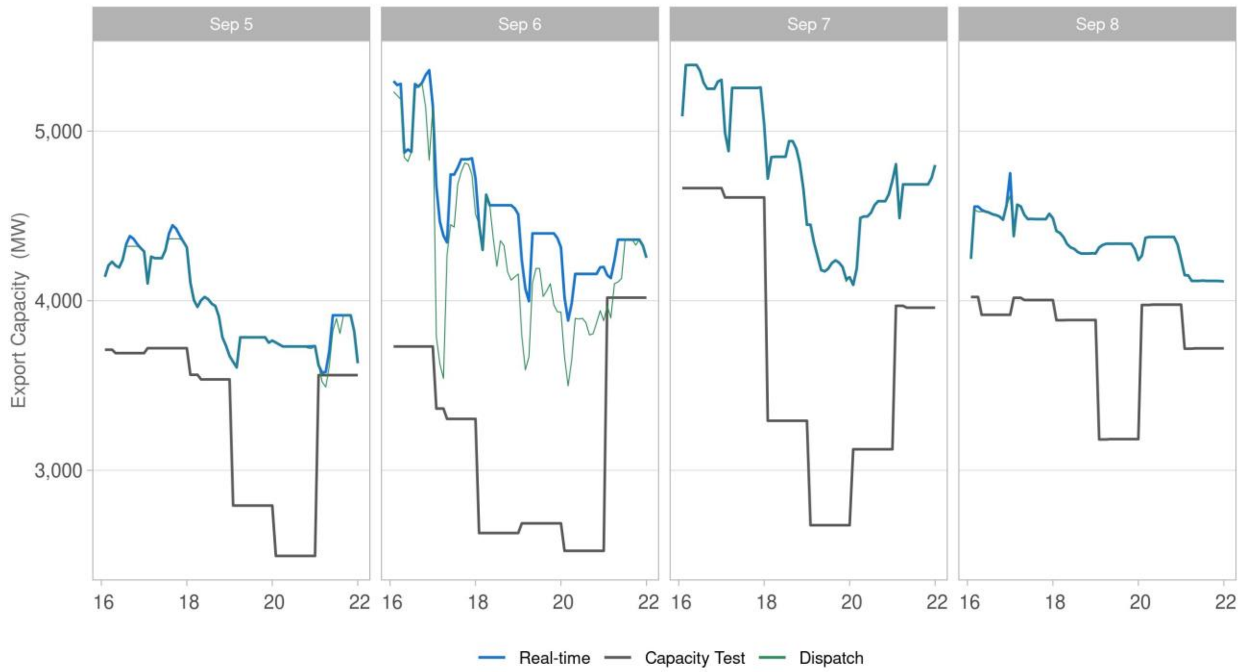


Figure 102: Supply capacity comparison test vs. RTM for Hydro

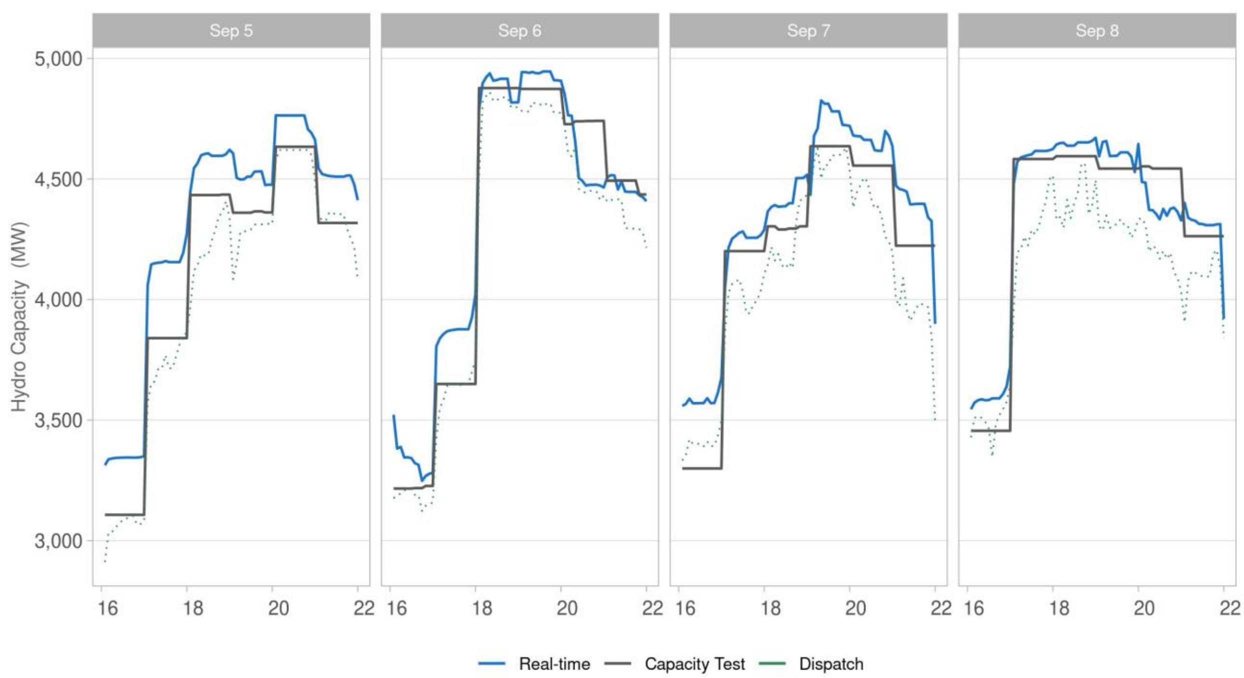


Figure 103: Supply capacity comparison test vs. RTM for Gas non-MSG resources

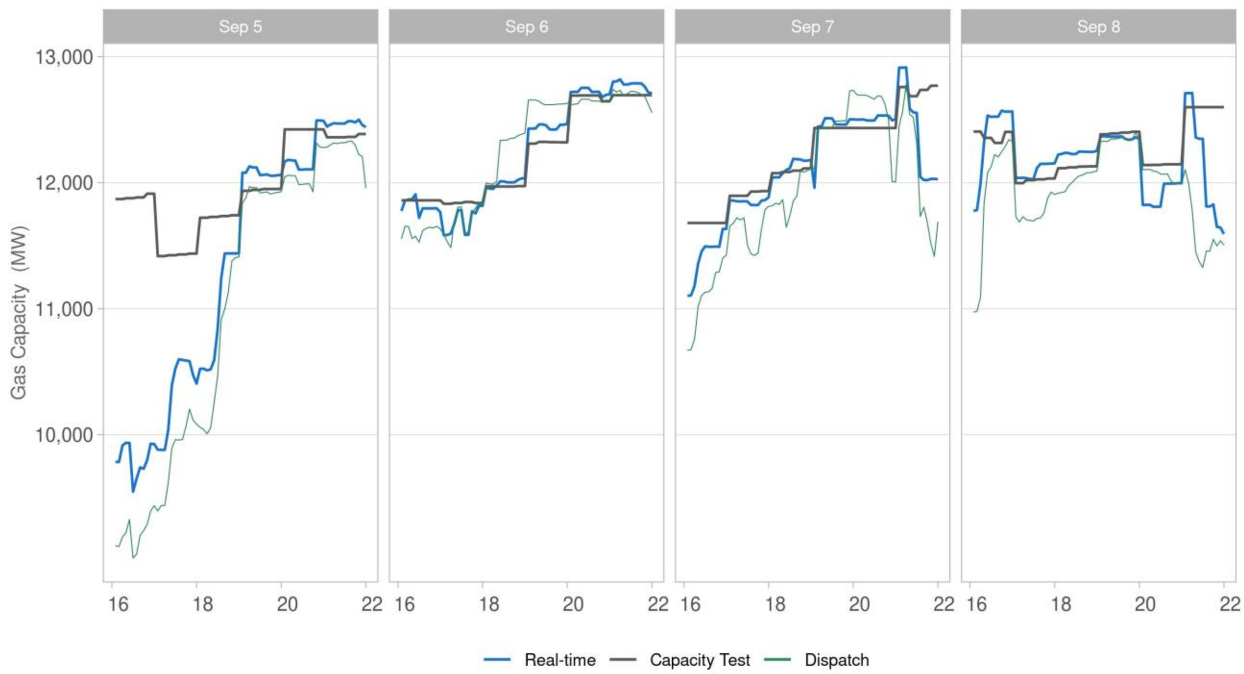
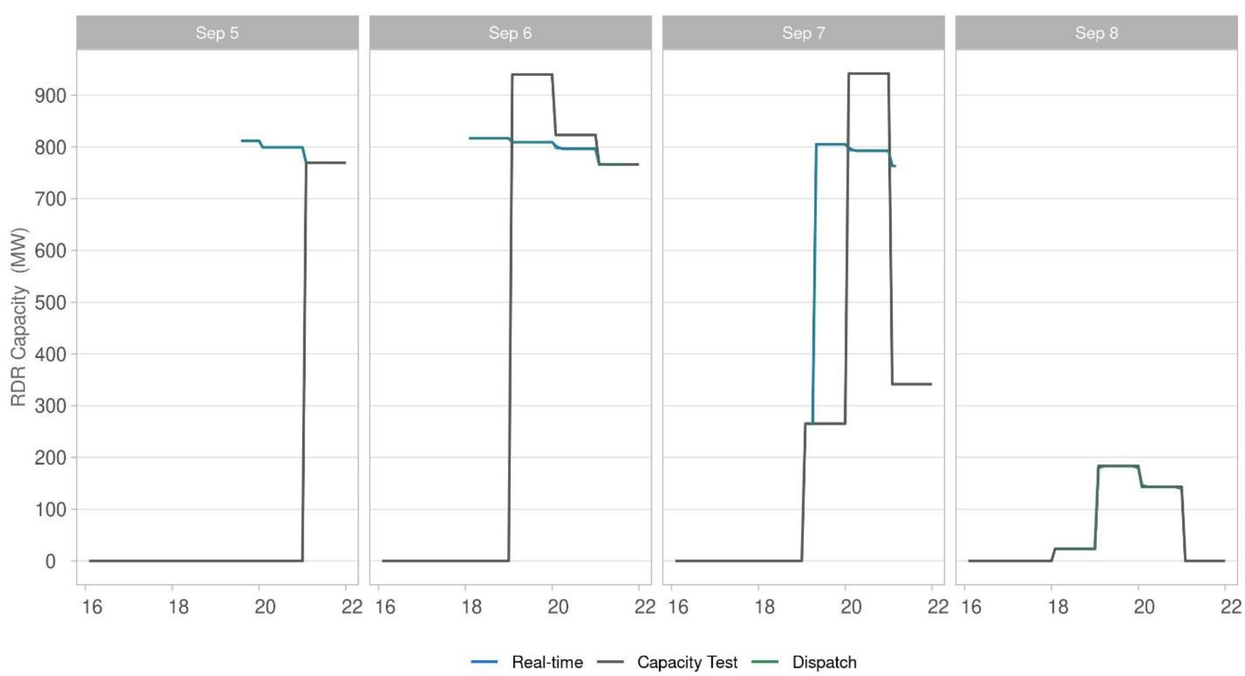


Figure 104: Supply capacity comparison test vs. RTM for RDRR



During the ISO's detailed analysis of the RSE results during the heat wave, the ISO identified discrepancies between the capacity counted in the test and the capacity eventually available in the RTM. These discrepancies account for either over- or under-counting upward capacity in the test. The following items summarize the discrepancies identified during the September 6 HE19:

1. *MSG units*. The capacity test considered some MSG capacity still available from two units that were coming back from an outage. The incremental upward capacity assessed in the test assumed that these units could be online and producing if needed based on the logic implemented as part of summer 2022 enhancements. This logic requires both the startup time and the minimum up time to be less than 255 minutes to be treated as short start, and this assessment is based on the resource characteristics defined at plant level instead of the configuration level. The root cause for the wrongful inclusion of these units in the supply available in the capacity test, was due to a stale value for the startup time of the resource used in the system running the test. The inclusion of these units in the available supply impacted the resource sufficiency evaluation in different hours. The inclusion of one unit impacted HE19 on September 6 by about 260MW, while the other unit impacted the supply in earlier hours by about 240 MW.

2. *Exports*. In the HASP process, self-schedules for exports of both low and high priority were reduced. As discussed below, the reduction of the high priority exports was erroneous, while other low priority exports should have been reduced. After the HASP solution completed, there is a post-process to assess if these high-priority reductions are sent downstream. Based on real-time conditions, operators assess whether the high-priority exports could be reinstated. These revised schedules are then sent to downstream systems, including to the application that runs the RSE. The exports and imports schedules are used in the capacity test as the reference to calculate the net schedule interchange (NSI) value which contributes to the overall supply (if net import) or overall demand (if net export). The PT exports were curtailed in HASP but then the curtailment instructions were blocked, and thus these exports were expected to flow. After the fact, these exports eventually flowed. However, the capacity test used the curtailed values for high-priority exports as if they did not flow. This resulted in the capacity test accounting for fewer exports than what flowed in real time, increasing the NSI. The RSE effectively included capacity that was designated to support high priority exports as available in the test assessment. For the applicable hours, these issues resulted in about 400 MW of exports not being included in the capacity test. However, had HASP operated as intended, about 400 MW of additional lower priority exports would have been curtailed.

3. *Curtailment of imports*. HASP cleared a given level of import schedules that was then used in the capacity test. After the T-40 deadline and after the capacity test run, there were about 459 MW of imports curtailed by other BAAs. As a result, the ISO area did not have as much imports supply available during the operating hour as the capacity test projected it to have. The capacity test functioned properly and used the latest information available. The reduction of supply that eventually materialized in real-time was due to post-market external curtailments. This accounted for over 500 MW supply in the capacity test that eventually did not realize in real time.
   There is a second type of capacity discrepancy related to the imports used by the capacity test. This difference was driven by a timing issue whereby the data of the T-40 transmission profile was not available in time to be accounted for in the capacity test. This amounted to over 200 MW in the capacity test that did not realize in real time.
4. *Emergency imports and exports*. In addition to intertie schedules awarded in HASP, the ISO used emergency energy from and supplied emergency energy to other BAAs. Depending on the timing of when these schedules happened, the capacity test may or may not have included the additional

exports or imports in the calculation of the NSI, which could result in more or less capacity counted to what eventually flowed in real time. There were about 400 MW of emergency exports not seen in the capacity test, and a net of about 120 MW of imports not accounted for in the capacity test. This resulted in a net of about 280 MW of emergency exports flowing into real time and not accounted for in the capacity test. The capacity test worked properly and this outcome was a consequence of the timing of the emergency energy flowing into the systems, which is based on a process outside the market. Emergency energy happens dynamically in the real time and thus it is not expected to be counted the test.

5. *DC losses*. The ISO has a mechanism to account for losses in the DC elements of the system, which are effectively modeled as exports. These exports are not actual resources; these are placeholders to model the DC losses. These losses are not modelled in the day-ahead market or the HASP market since they are not based on bidding resources and they are not known in advance but instead are considered directly in the 15- and 5-minute market. Therefore, they will not be considered in the capacity test data but will be considered in the RTM. These DC losses modeled as exports will add load obligation to the ISO area that is not counted in the capacity test. This added about 130 MW to the load obligation in real time. [61]

6. *Storage resources*. The capacity test estimates the up capacity for all resources as the headroom available after discounting the obligation for upward ancillary services (see Figure 92 above) and starting from the base schedule. A software issue was identified that incorrectly did not set aside the capacity from ancillary service (AS) awards in the Up capacity calculation. In addition, in some cases the maximum economic was also not reflected properly in the capacity test. These two issues resulted in overly estimating the up capacity available from storage resources in the test in some intervals by over 1,000 MW.

7. *RDR resources*. The capacity accounted for reliability demand response (RDR) resources in the test was higher than what effectively was made available in the real-time by about 130 MW. This may be related to how FMM and RTD handle the triggering of RDRRs and is being further investigated.

8. *Export cuts for ETC/TOR wheels*. Certain wheels are used to exercise ETC/TORs; these are set up with an import and export leg paired together to create a wheel. Participants are required to fully set up the wheel transaction in the bidding system so that the market can consider it as a wheel. There were two issues impacting these type of wheels. First, these transactions were not properly submitted as wheels but rather as individual imports and exports. Second, due to the issue described in item 2 above, the HASP market curtailed only the export leg of the transaction. This curtailed value was then used in the capacity test. Since these were ETC/TOR transactions, they were not actually cut in real-time. Wheels counted in the capacity test do not impact the supply or demand available but when the export leg was reduced, the wheel was counted in the test with an imbalance that effectively reduced the export amount, resulting in higher NSI and increasing the supply available for the capacity test (less restrictive). This error resulted in about 630 MW of

[61] This was identified as one of the factors impacting divergence between markets in the price formation effort of 2019. Page 122. Price formation report is available at http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

exports not being counted in the capacity test and erroneously reducing the load requirement for ISO's BAA in the capacity evaluation.

9. *MSG transitions.* There were some MSG resources that had a limited capacity counted in the test based on the current configurations reflected in the base schedules; however, given their respective transition times, these resources could, and some of them indeed did, transition into a higher configuration in the real-time. Consequently, the capacity test accounted for less capacity than actually available. The logic in the capacity test is limited in its ability to model capturing all the possible permutations of transitions that could eventually realize in real-time.

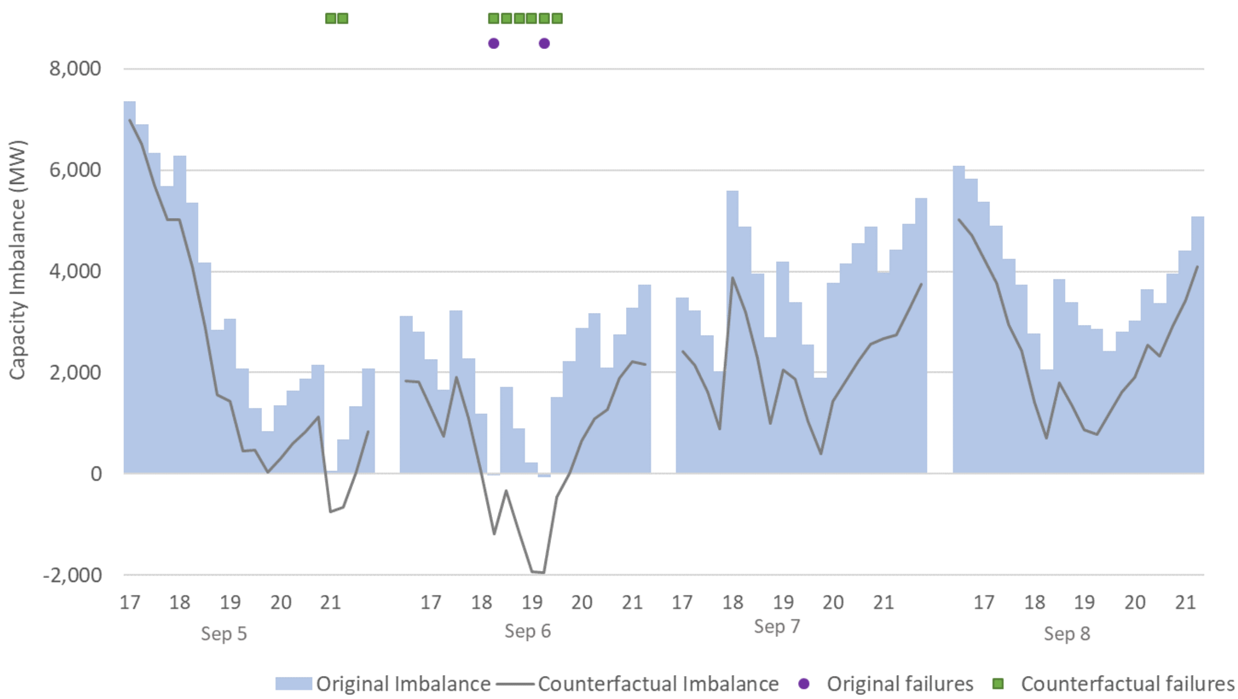
10. *Load arming in EEA3.* As part of the emergency process, ISO armed up to 2,000 MW of load during the EEA3 timeframe, which effectively released the contingency reserves to meet energy needs. During the stage 3 of the emergency up to 900MW of contingency reserves were released into the energy stack. This resulted in more supply being made available for energy in real-time. This capacity was not counted towards the Up capacity in the test as it was still set aside to meet ancillary service awards despite having been replaced by armed load. This applies to the different resource technologies based on what resources carried the released reserves. This meant that up to 900MW of supply made available in the real-time when arming load was not counted in the capacity test.

The description of these 10 different drivers shows the complexity of an ideal representation of the capacity actually available and counted in the test. These issues showed that there was an under but also an over-accounting of capacity in the test. Some of these are simple issues in the calculation that are being corrected. However, other drivers are more nuanced and go to the core of the accounting complexity and highlight the inherent challenges of the capacity test to reflect actual real-time conditions 40 minutes in advance of the actual operation when conditions may be inherently bounded to change.

A counterfactual estimate was assessed by considering specifically four of the issues listed above: i) AS capacity not set aside, ii) MSG units while on outage, iii) export and ETC/TOR reductions, as well as iv) the delta of RDR dispatches. Figure 105 illustrates the counterfactual imbalance for up capacity in the test by taking the original capacity imbalance and subtracting or adding the deltas identified for each of the four reasons described above. The errors identified by specifically analyzing the HE 19 in September 6 were extrapolated and assumed to remain valid for the period under analysis. This is a simplification in lieu of attempting to analyze each interval for the entire period.

Any interval with a resulting negative counterfactual imbalance reflect a capacity test failure. Naturally after adjusting for the identified deltas, the ISO BAA fails more intervals in the critical period of September 6, as well as a couple of interval on September 5. This is not precise analysis and is aimed at providing a rough assessment of the extent of the issues impacting the capacity test.

Figure 105: Original failures compared to a counterfactual scenario



9.5 Load conformance

In all ISO markets, except the IFM where demand is bid in, system operators can adjust either demand (through conformance) or supply (through Exceptional Dispatches, or EDs) based on expected system conditions. Changes to market inputs can influence market-clearing prices. The adjustment to the load forecast in the day-ahead timeframe is referred to as RUC net short, while in the RTM, it is referred to as load conformance. These load conformances can effectively increase or decrease the overall demand requirements that the market optimization uses to clear against supply. Operators may use load adjustments to true up the market (RUC, HASP, FMM or RTD) to the real-time system based on projected or observed system conditions. Figure 106 and Figure 107 show the daily distribution of RUC and HASP adjustments, respectively. As the heat wave began, the adjustments started to increase as early as August 31, reaching their highest levels during the critical period of September 5 through 8. Figure 108 shows the same load adjustments in an hourly profile to help ease the understanding of when in the day these adjustments are apply to.

Figure 106: Daily distribution of RUC adjustments in August and September

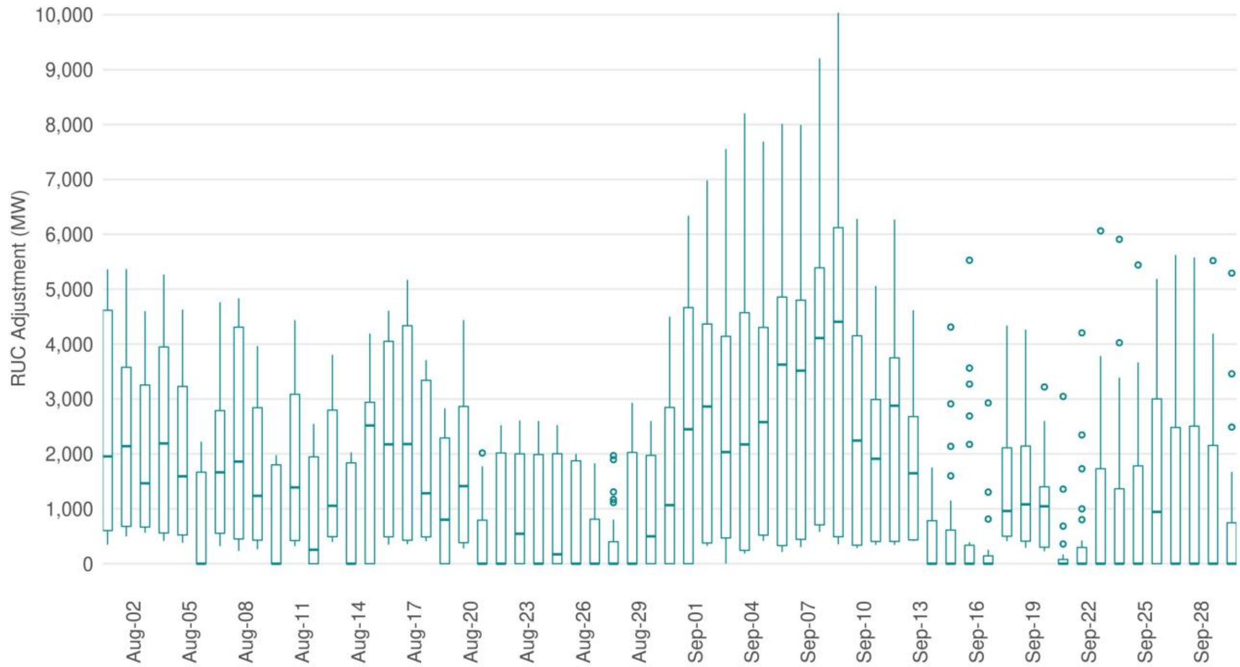


Figure 107: Daily distribution of load conformance in HASP in August and September

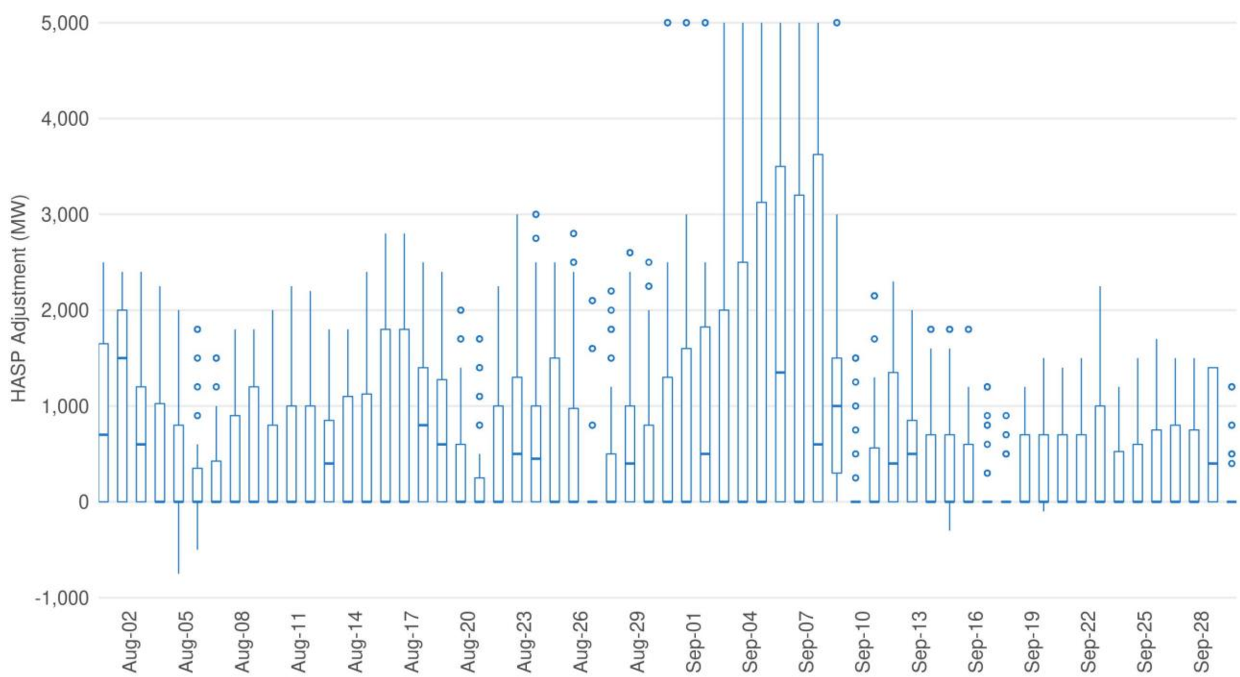
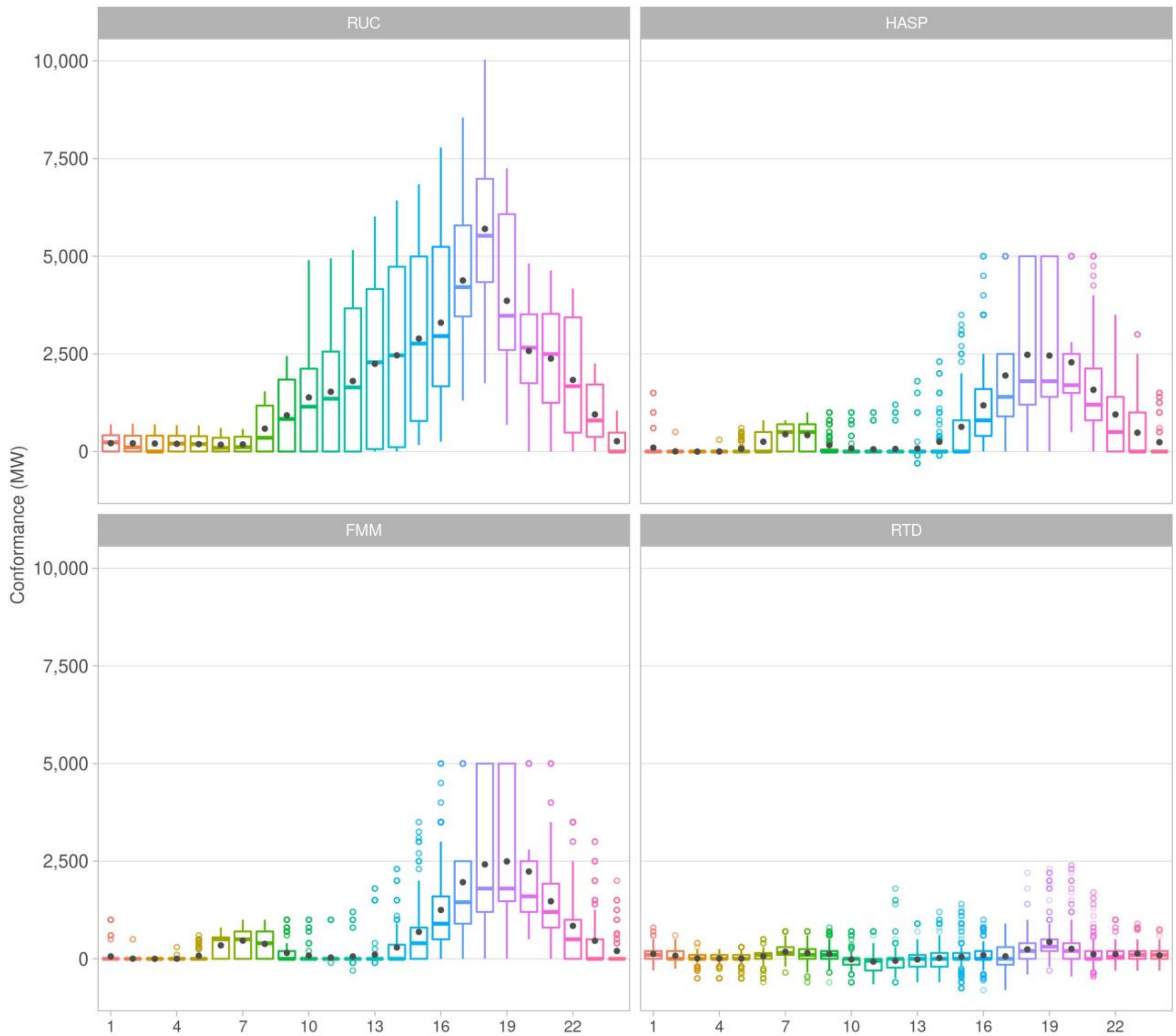
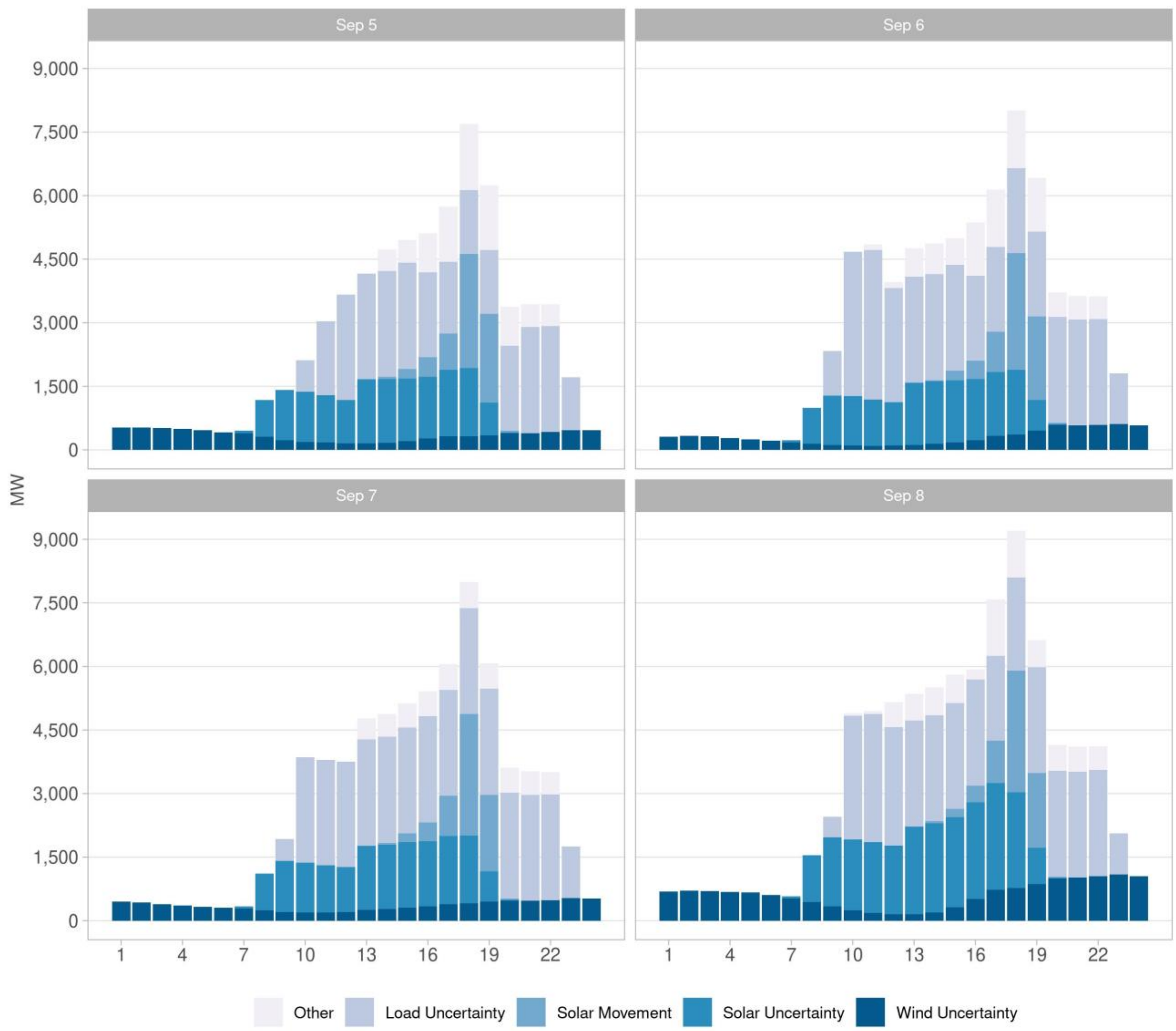


Figure 108: Hourly distribution of load conformance across markets in September



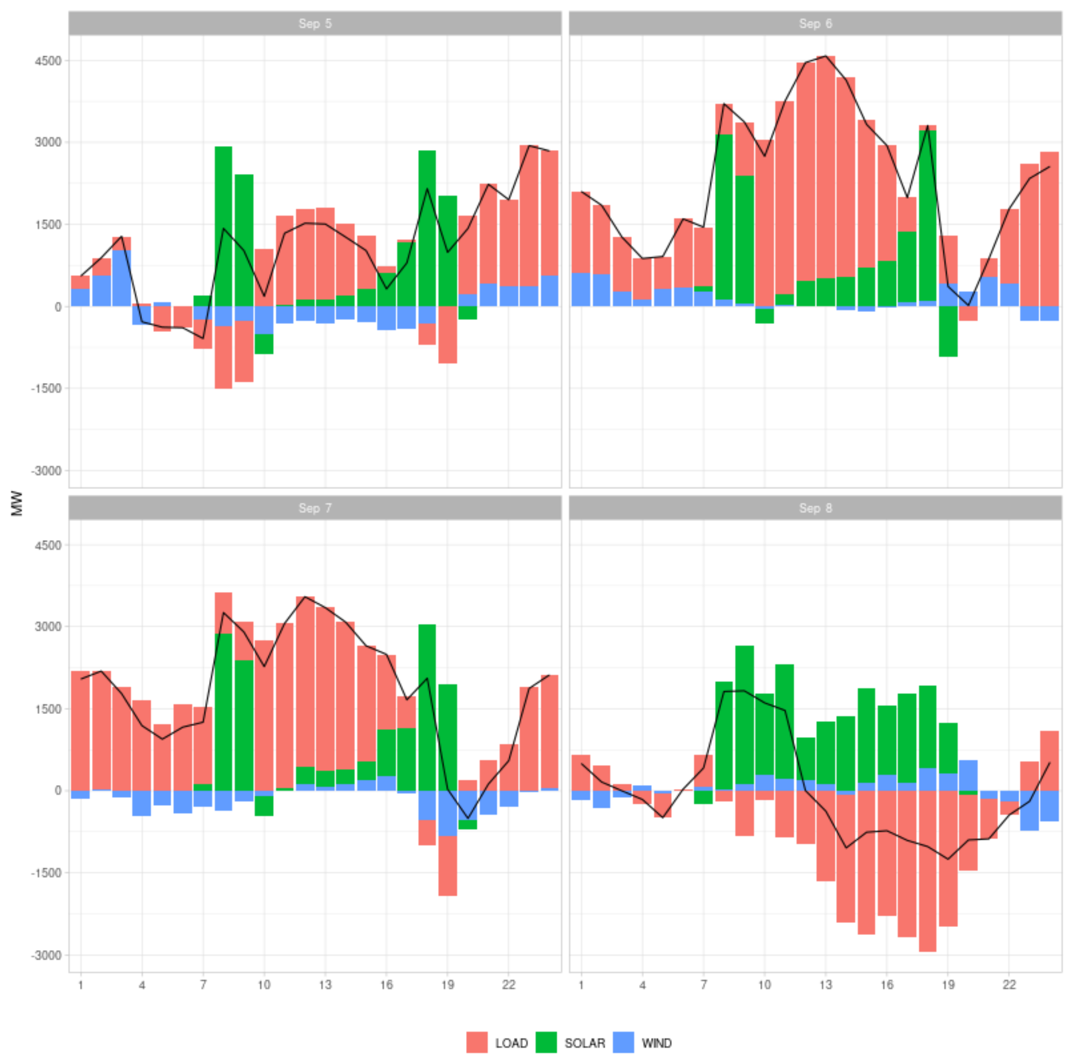
The RUC process schedules supply against the day-ahead load forecast for the ISO area. In order to factor in uncertainties between the day-ahead and real time, including load uncertainties, operators have the flexibility to apply adjustments to the day-ahead load forecast in either the upward or the downward direction. This is a practice that has been in place for several years but, over time, the logic used to determine the magnitude of the adjustments has been enhanced. Historically, RUC adjustments have applied mainly to peak hours during summer months, when the system faces higher demands and there are tighter supply conditions while weather variations can lead to significant variations. As the logic to determine the RUC adjustments evolved over time, they have more recently been guided by an upper confidence band for the day-ahead gross load forecast. This confidence band is a proxy that uses historical days to assess the maximum load forecast that could be exhibited under similar weather conditions. Operators may consider this upper confidence bound plus other operational conditions, such as risk of fires, to determine the final RUC adjustments. More recently, a similar approach has been developed to factor in renewable uncertainties, which may result in adjustment to any hours of the day. In addition, since the day-ahead market is at an hourly granularity and the decrease of solar production is very steep during the downward ramp hours, there is another component to account for the intra-hour ramp, referred as the solar net movement. This factor is mainly included as part of the RUC adjustment during the ramp-down hours. These three components – load uncertainty, renewables uncertainty, and solar net movement – guide the operators' determination of the level of RUC adjustments. Figure 109 shows the different components of the RUC adjustments utilized in the day-ahead market. For September 5 to 8, the RUC adjustments are relatively higher compared to their typical level.

Figure 109: Hourly profile of the RUC adjustment components



As the heat wave conditions quickly reached extreme levels, there were concerns that the high load and renewable output uncertainties could pose significant variability and uncertainty for real-time operations. These projected uncertainties became larger towards the end of the heat wave with the arrival of Hurricane Kay into the southern part of the system, impacting not only demand but also renewable production. In the context of the demand levels observed and the available supply available, it was not possible to schedule enough supply to cover these large RUC adjustments. In multiple hours, the RUC process was infeasible to meet the adjusted load forecast with available supply capacity. However, the supply scheduled by the RUC adjustments was less than the additional supply that ultimately was available in the real-time market, while real-time net load was lower than RUC adjusted net load forecast. Figure 110 below shows the realized uncertainty for load, wind and solar during the heatwave days. The bar represent the different uncertainty components while the line in black stand for the net uncertainty. Uncertainty was significant but not as high as the projected RUC adjustments. As the ISO continues to evolve the assessment of uncertainty and how it could guide the RUC adjustments, ISO is currently assessing and expecting to start using the imbalance reserve derived from net load error between day ahead and real time as a more accurate estimate of the uncertainty between DAM and RTM. This would rely on the proposed methodology to derive the imbalance reserves within the day-ahead market enhancement initiative.

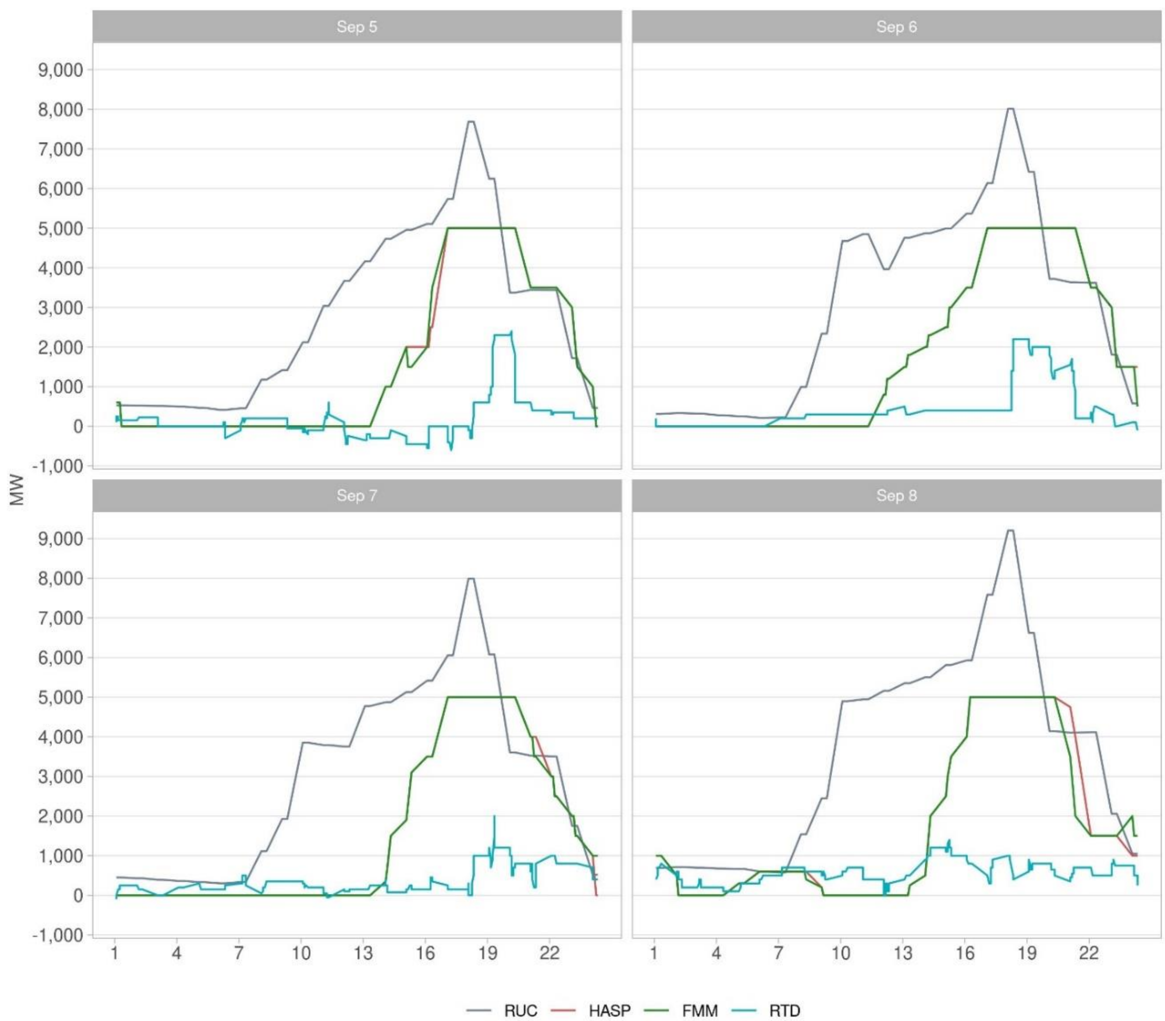
Figure 110: Components of realized uncertainty from day-ahead to real-time.



Furthermore, at the beginning of the heat wave period, operators observed tight supply conditions that realized until the operation of the five-minute market. This was largely driven by changing conditions from the HASP process towards the RTD market at which time system conditions changed primarily due to additional procurement of ancillary services, outages, and realization of VER uncertainty. Some of these changes happened not only in the ISO area but also in other WEIM BAAs. They resulted in significantly lower transfers levels realized in RTD than the projected advisory transfers cleared in HASP and FMM.

Given these factors and the need to ensure that the HASP process positions resources for the ramping and peaking conditions, as well as securing sufficient supply over the interties through the market, both the HASP and FMM process also used higher-than-usual load adjustments.

Figure 111: Hourly profile of load adjustment across markets during the September heat wave



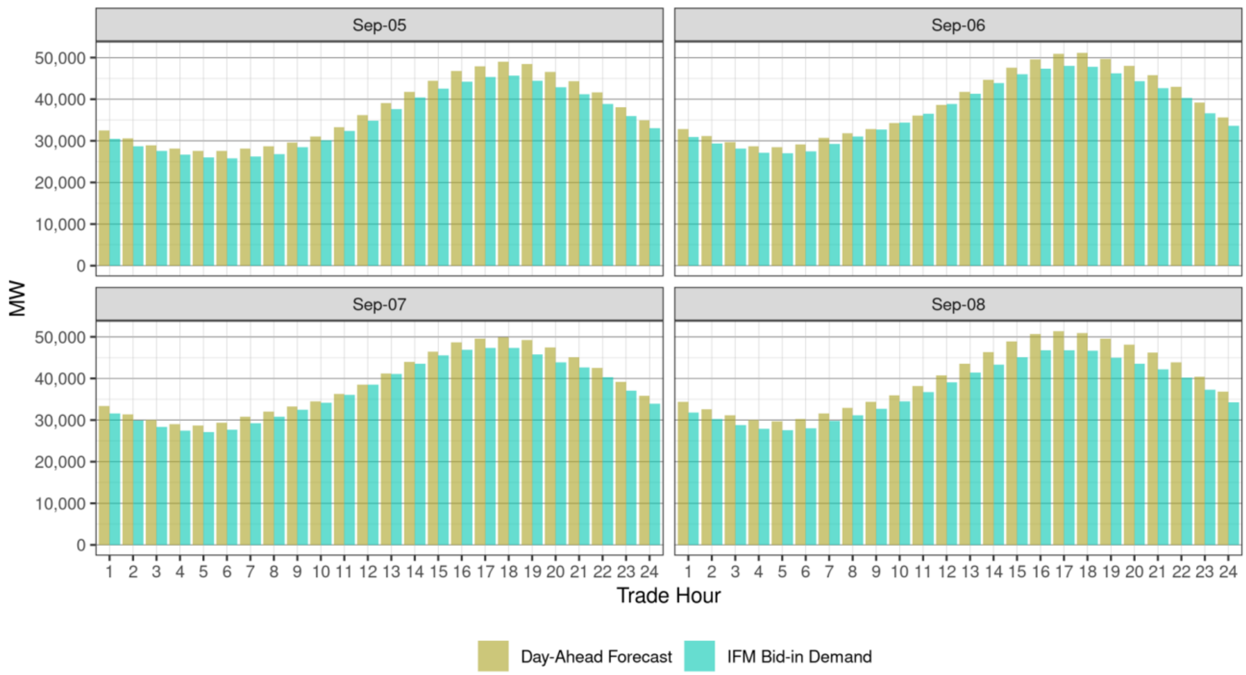
As explained in the analysis provided to support the policy development of the RSE enhancement initiative,[62] load conformance may result in a variety of different outcomes. These outcomes include commitment and ramping of internal ISO resources, clearing more hourly intertie imports in HASP, clearing less hourly intertie exports in HASP, increasing WEIM import transfers, and power balance infeasibilities. Of these outcomes, only additional ISO commitments or clearing of hourly interties

[62] See http://www.caiso.com/InitiativeDocuments/Analysis-LoadConformanceImpactonResourceSufficiencyEvaluation.pdf

represent additional firm supply for the ISO BAA. Any additional WEIM import transfers are advisory and they are not held firm because they are re-optimized based on RTD conditions, while infeasibilities do not increase supply. Figure 111 shows the overall trend of load adjustments across the markets for the heat wave days.

Figure 112 below shows the comparison of IFM bid-in demand and DA forecast for the September 5 to 8 heat wave events. It shows the demand scheduled in the day-ahead market was below the ISO's load forecast during those heat wave event days (this does not include any RUC adjustments).

Figure 112 Comparison of IFM bid-in demand and DA forecast



9.6 Intertie schedules and WEIM transfers

This section illustrates the intertie supply and demand conditions during the September heat event. Figure 113 shows the hourly bid-in capacity from static exports by types of transaction in the Day Ahead Market for September 5 – 8. This capacity does not include the volume associated with wheel transactions because the export legs of a wheel do not represent additional load obligation on the ISO area. It also illustrates the market schedules from the IFM and RUC solutions. When there are no export reductions in the RUC process relative to the scheduled awards in IFM, both markets will overlap. During this period, RUC had export reduction during the evening peak hours. RUC schedules become the reference for both pre-day tagging and the RTM to assign day-ahead priority. The portion of exports labeled as ETC/TORs are not exports to support load outside the ISO system; rather, they are exports associated with existing transmission rights. They exhibit a stable level through the days at about 600 to 1000 MW. About 76 percent of the bid-in exports were economical, and the majority of the self-schedule exports were of lower priority. Any export resource can bid in as a self-schedule which gives it higher priority than economical exports. During critical periods such as the peak hours of September 6, the RUC process cleared no economical exports and less than 50 MW low-priority exports; instead, it was almost only PT exports cleared, in amounts up to 554 MW. These PT exports are backed by non-RA resources and thus are not supported by the ISO's area RA capacity.

Figure 113 Day ahead non-wheel export bid-in capacity

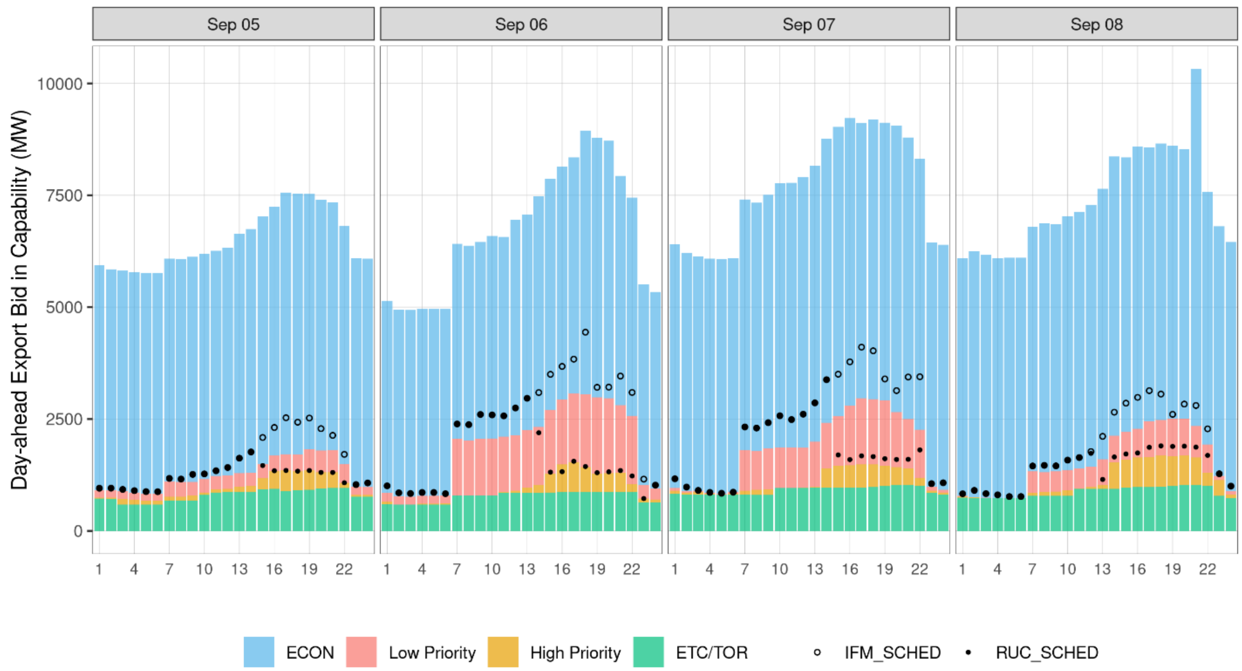


Figure 114 shows the volume of hourly self-scheduled export reduction in RUC relative to IFM by transaction type. The majority of the exports curtailed in RUC was on the curtailment of economical exports and low-priority exports. The highest level of export reductions was at 1,680 MW of low-priority exports in HE 19 on September 6, the most critical day of the heat wave. In HE 16 on the same day, there was 215 MW reductions of high-priority exports which occurred after all the low-priority schedules were reduced to 0 MW. This additional reduction in high priority exports is an expected outcome of the RUC scheduling priorities because, if low-priority export curtailments are exhausted and there is still a power balance infeasibility, high-priority exports with the same priority as the power balance (*i.e.*, ISO's load) can also be curtailed.

Similarly, Figure 115 shows the hourly bid-in capacity by type of transactions from static import in the day ahead market for the same period. The capacity does not include the wheel transactions. It also illustrates the market schedules from IFM and RUC. RUC schedules are mostly close to or slightly higher than IFM schedules. Under tight supply conditions, there is no expectation of imports curtailments unless RUC needs to address congestion condition not projected in the IFM process. In the RUC process, a robust level of imports cleared, with cleared MW being consistently over 6,459 MW during peak hours.

Figure 114: RUC export reduction relative to IFM schedules

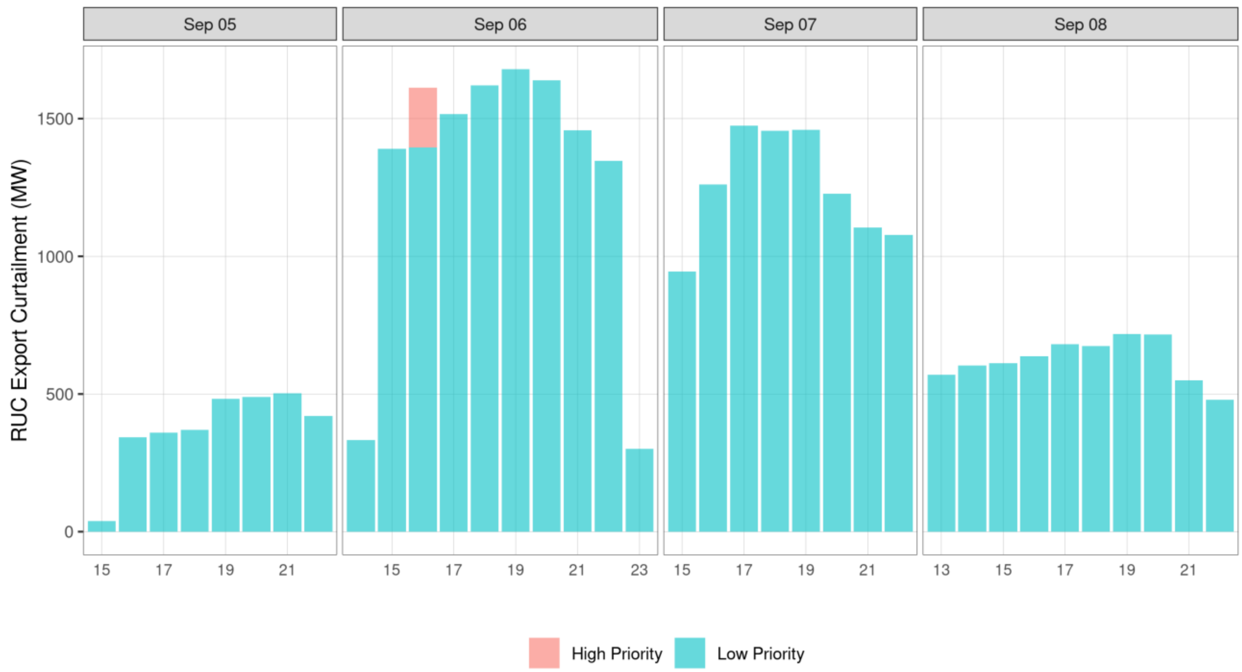


Figure 115: Day-ahead (IFM) non-wheel import bid-in capability

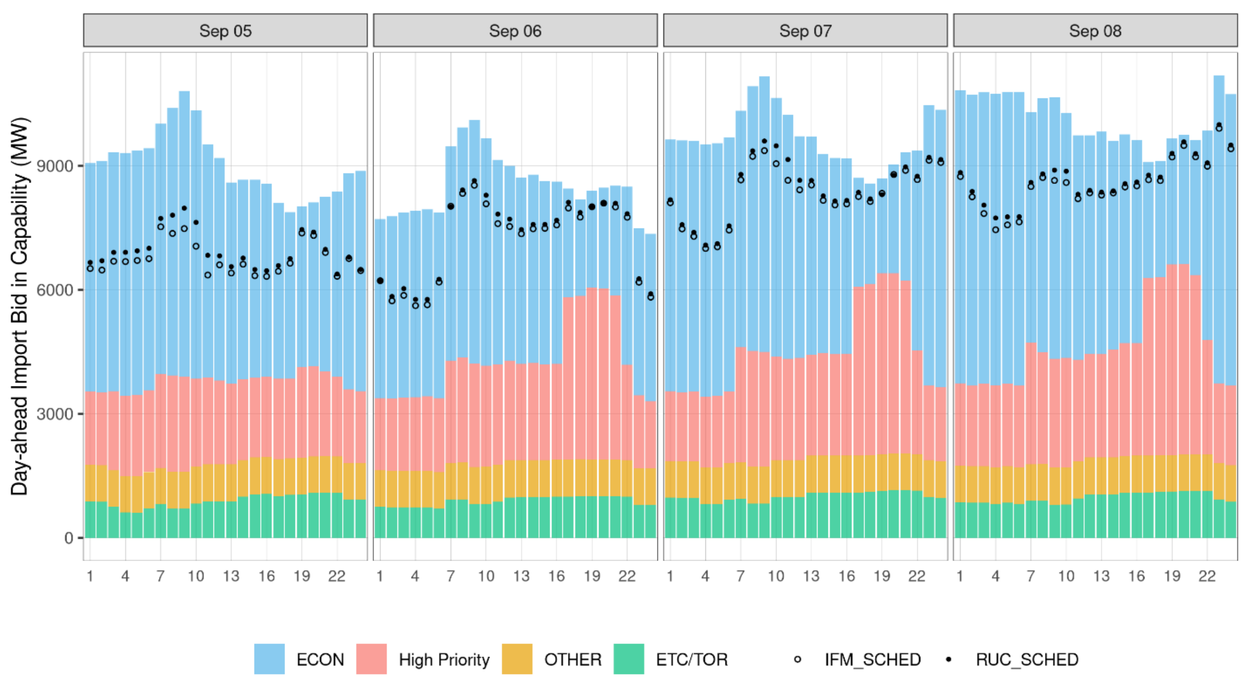


Figure 116: shows the RUC intertie schedules by schedule type. It also shows the overall net schedules as indicated by a solid black line. The net intertie schedules provide a more holistic reference of the supply available to the system once exports are balanced out with imports. The net intertie schedules reached their lowest levels in the early afternoon due to the large export volume cleared. The net intertie imports

then trend up during evening peak hours with RUC export reductions. This is a typical pattern since exports tend to be higher during the midday hours when large amounts of solar supply is available. For the critical peak hours, the net interchange was a robust ranging from 5,116 to 7,686 MW in the import direction.

Figure 116: RUC schedule breakdown

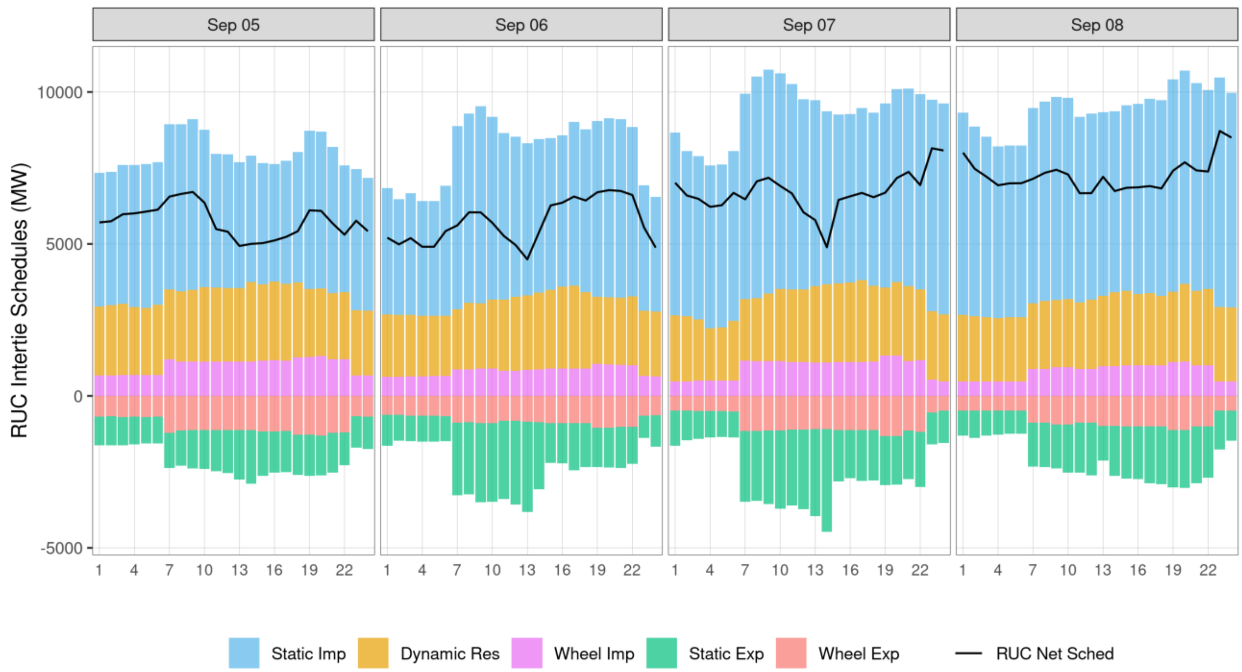


Figure 117 shows the net interchange from the IFM and RUC solutions. The net schedule differences in the afternoon hours between IFM and RUC largely came from export reduction of economic bids and low-priority schedules. By reducing exports, the net schedule interchange is higher since there are fewer exports to offset the imports.

Similar to the day-ahead market, ISO's RTM runs the HASP to adjust the intertie hourly schedules. The HASP is the last opportunity to rebalance these intertie hourly schedules. Participants can bid economically into HASP or they can self-schedule both imports and exports with either low- or high-priority bids. For those interties that cleared in RUC, the RUC schedule becomes a reference for the quantity of exports assigned a day-ahead priority. In the RTM, in addition to low and high priorities, there is also a subgrouping between day-ahead and real-time self-schedules.

Figure 117: Day-ahead net inter tie schedules

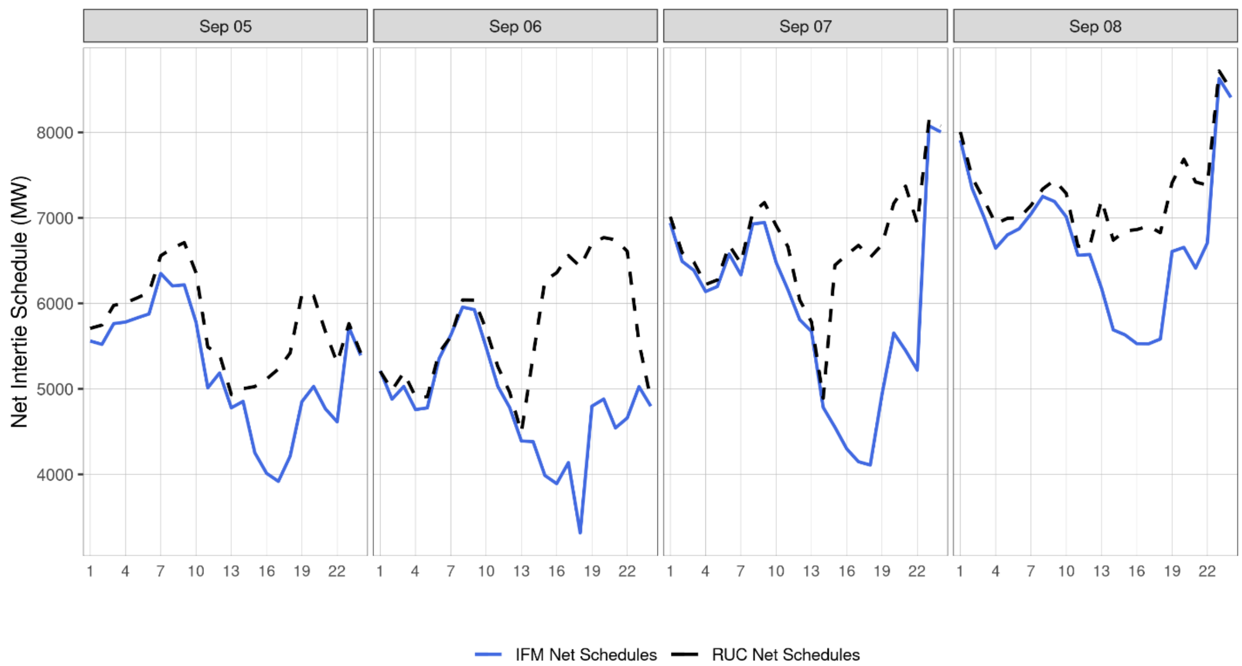
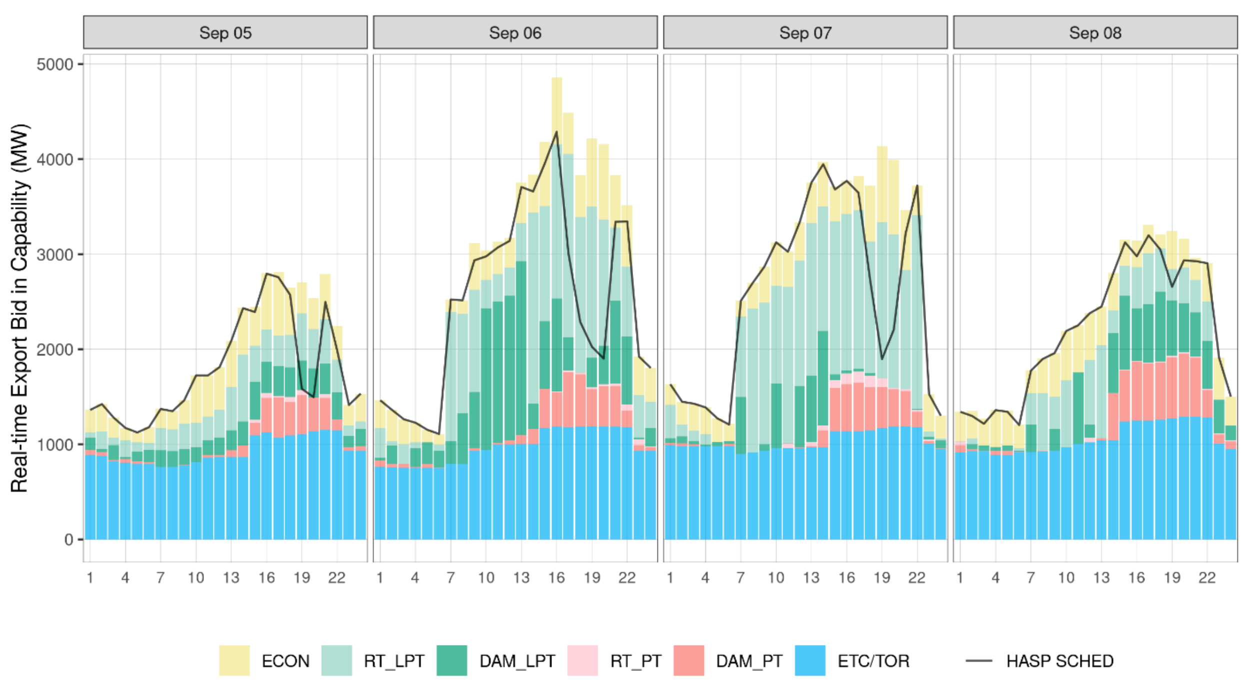


Figure 118: shows the non-wheel export bid-in capacity in HASP and the volume of these transactions that HASP ultimately scheduled. Import or exports cleared in the day-ahead tend to self-schedule into the real-time to preserve the day-ahead priority. They may also participate incrementally in the RTM through the HASP process, including the option to or even buy back their day-ahead position at the real-time prices.

Figure 118: HASP export bid in capacity



The majority of the PT export transactions were from day-ahead schedules. During the heat wave, there was a significant amount of real-time self-schedule exports submitted into the market. HASP drastically reduced the amount of low-priority exports scheduled (in addition to not clearing economical exports) during the afternoon peak hours, as shown by the steep drop of the black trend in Figure 118. The HASP awards are organized by type of exports in Figure 119.

Figure 119: HASP export schedule breakdown

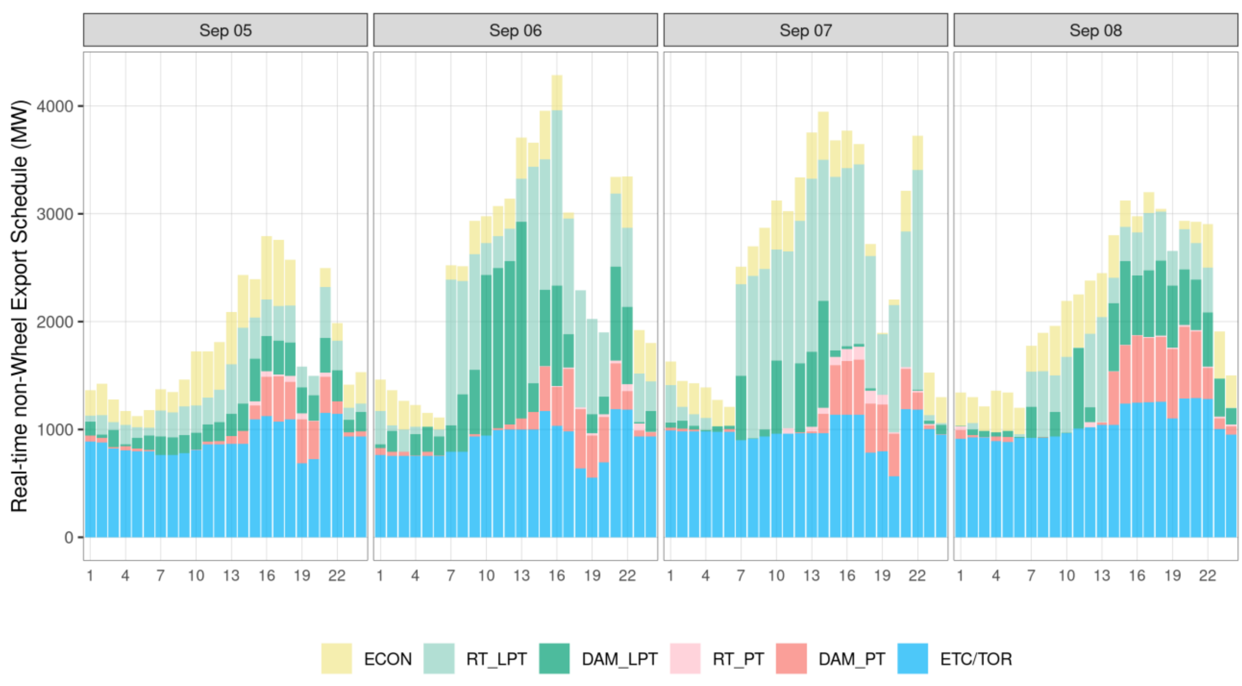


Figure 120 shows the export self-schedule curtailment by transaction type projected in HASP. The largest volume of export reductions was 1,336 MW in HE 19 on September 6. The majority of the export reductions were on low priority exports from both day-ahead and real-time. There was also some ETC/TOR reductions that were erroneously issued as part of the original HASP solution as discussed elsewhere in this report. However, after the fact, these ETC/TORs reductions were eventually reversed and the exports flowed in FMM and RTD. This means effectively only the reductions associated with low-priority exports were in effect. Figure 121 presents the same data in a different breakdown. It maps the HASP export reductions to the original reductions assessed in the RUC process, and arranges them into three main groups. The first group in blue represents HASP reductions for exports bid in the RTM. The second group in green represents HASP reductions that are the same of those assessed in the RUC process. The third group in pink represents HASP reductions that were less than the reductions in RUC. About 30 percent of HASP cuts were projected in the RUC reductions, in pink and green areas combined. Again, the total reflects the ETC/TOR reductions that were eventually reverted after HASP cleared, and these ETC/TOR reductions were all in the "HASP reductions only" category.

Figure 120: Export reductions projected by the HASP solution by transaction type

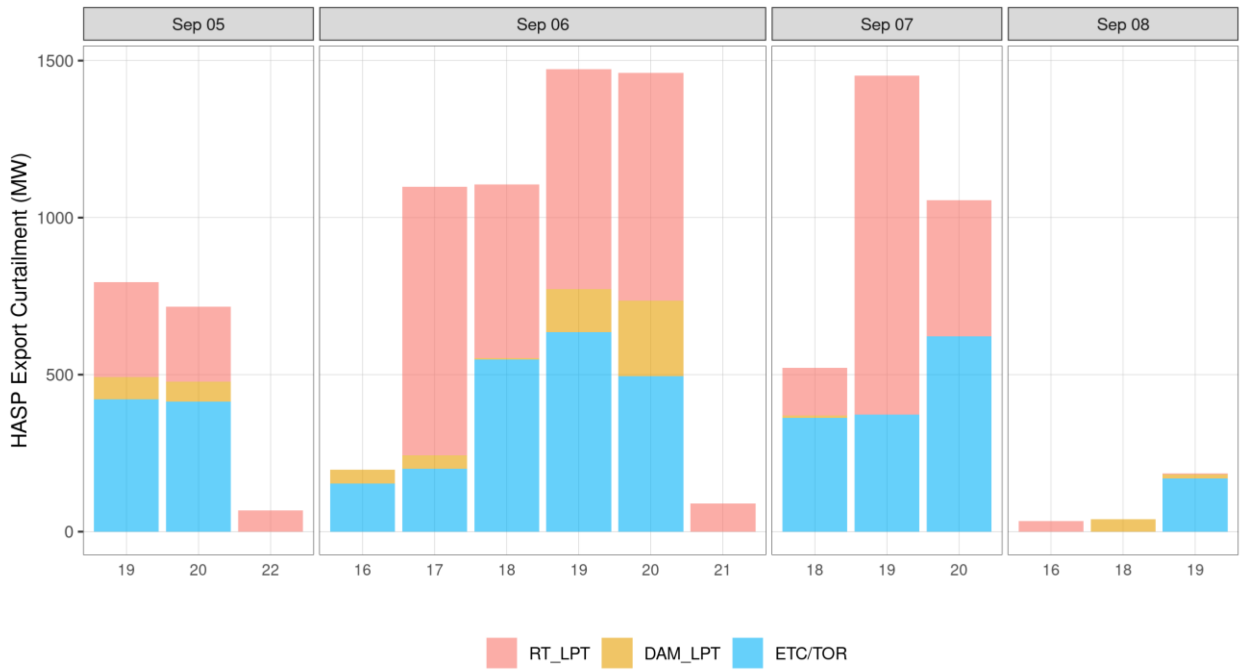
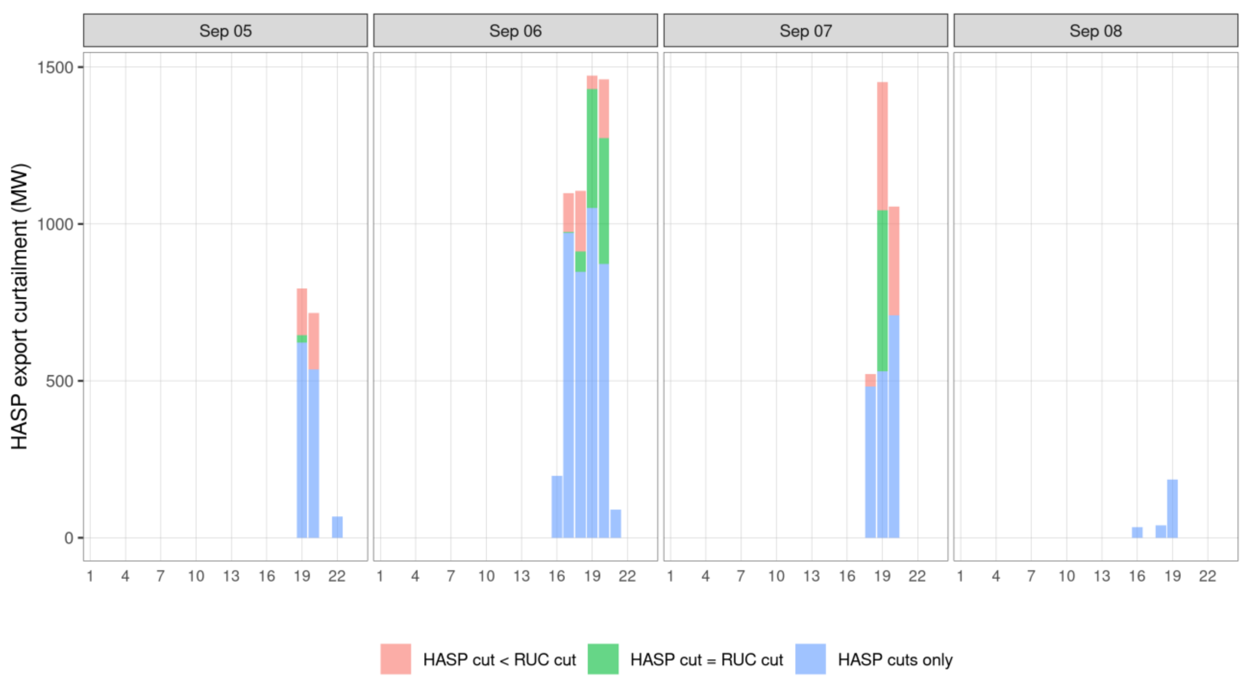


Figure 121: Export reductions projected by the HASP solution



Analysis of the HASP solution during the critical hours of September 6 exposed two areas for improvement. The first relates to the different priorities applied in the scheduling run and the pricing run. The peak hours had high loads with additional load conformance on top of actual loads. This resulted in HASP being unable to meet the combined adjusted load and exports. Under these conditions, the provisions for relative scheduling priorities play a key role in determining the sequencing of export reductions in coordination with power balance infeasibilities. Under a condition of only supply shortfalls (*i.e.*, no congestion), the expected priority is to not award economical exports followed by the reductions of low-priority exports. If the undersupply condition still exists, then the market will either reduce PT exports or relax the power balance constraint in combination. Since ETC/TORs have the highest priorities, it is not expected they will experienced any reductions.

The logic described in the previous paragraph applies in the scheduling run step. However, this is followed by a second iteration known as the pricing run. In the pricing run, all the relative priorities are no longer in place because all penalty prices are set to the bid cap or bid floor. The pricing run is set up such that the pricing run is expected to clear close to the scheduling run solution. Since the implementation of the price inconsistency market enhancements, the binding results from the HASP solution utilizes the schedules from the pricing run. Prices obtained in the HASP pricing run are not financially binding but do drive the optimal solution and schedules.

During the peak hours of September 6, the scheduling run projected certain level of export reductions for low priority exports, but these reductions were not implemented in the pricing run. These low priority exports that were curtailed in the scheduling run, but erroneously cleared in the pricing run, were issued as the final HASP solution and this resulted in the clearing of low priority exports. Conversely, some high priority exports and some ETC/TOR exports that cleared in the scheduling run were erroneously curtailed in the pricing run and these curtailments were also issued as part of the final solution. This outcome in which the pricing run reversed the scheduling priorities in the scheduling run was not the intended outcome.

This difference between the scheduling run and pricing run had an interplay with the issue described in a subsequent section on storage resources in which the bid prices below the bid floor were not considered in merit for storage resources. The ISO has fixed the logic impacting storage resources and is assessing an enhancement to ensure the pricing run produces interties schedules consistent with the schedules cleared in the scheduling run. As part of the HASP results review process, there is a time window for operators to assess the HASP solution prior to sending the results downstream and to scheduling coordinators for review and approval. There is also a safeguard logic that any high-priority export reductions are blocked for operators in their determination of whether or not these exports reductions will be eventually sent out. The reductions for high-priority exports were left as blocked and therefore the expectation was that the projected reductions from HASP would not be issued; *i.e.,* the high-priority exports would still flow.

The second area of improvement in this area is that the blocked reductions in high priority export schedules that had been blocked by operators were nevertheless sent out to the system that manages the tags but not to other downstream systems. Once operators saw the export reductions for PT exports realized in the tagging system, they manually reversed the curtailments and reinstated the original self-scheduled transactions. The root cause of this issue is due to the lack of active approval by scheduling coordinators of their awards. When they actively approve, the system uses the curtailments; but if active action is not taken then the export reductions do not occur. The ISO is exploring an enhanced logic to ensure that, when instructions are not actively approved but instead are let expire, the reductions originally blocked are not realized in downstream systems.

Figure 122 shows bid-in capacity in HASP for non-wheel static imports and dynamic resources. The “other” category includes regulatory must run priority, hourly tie generator (energy) priority, the Pmin for dynamic resources with a Pmin above 0 MW. The capacity from ETC/TOR and 'other' categories were relatively consistent at about 1,722 to 2,298 MW. The majority of the import capacity bid in was from day ahead schedules. In HASP there was also a volume of bid-in real-time imports, which, given the tight supply conditions and high prices in HASP, were cleared in HASP. Overall, these imports reached up to 10,000 MW during peak hours, which was relatively higher than what cleared in the RUC process

Figure 122: HASP static import & dynamic resources bid in capacity

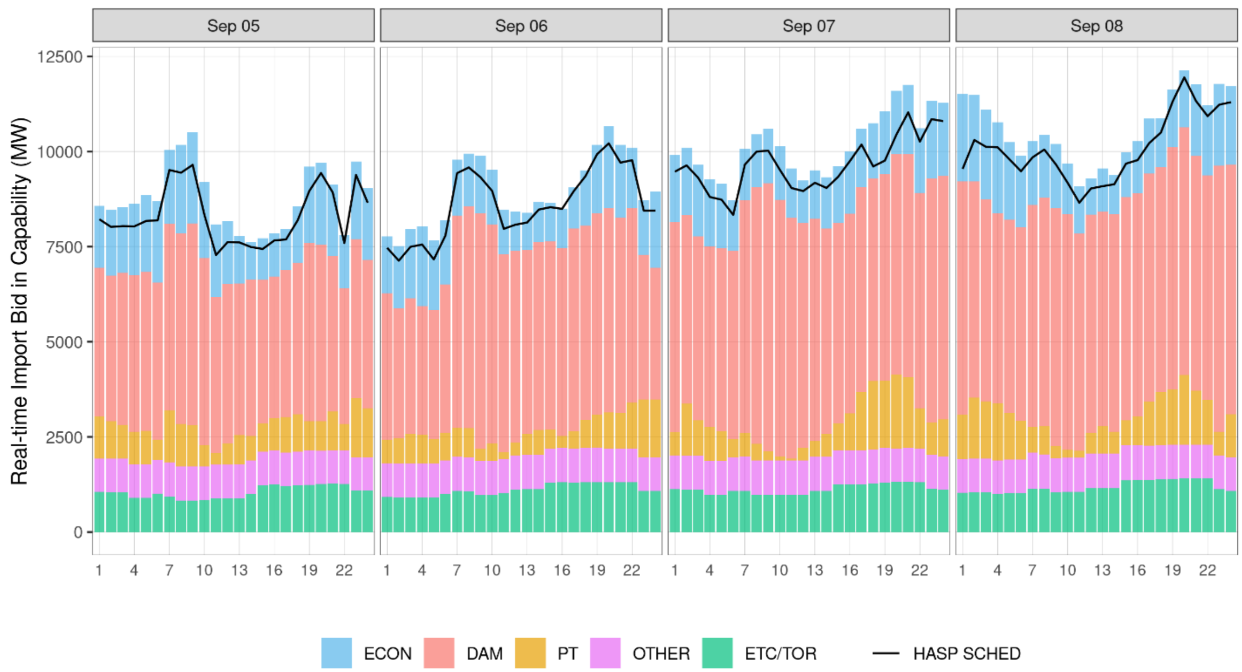


Figure 123 shows the cleared schedules of different groups on interties, with the net intertie schedules in HASP.

The net schedule interchange is at its lowest value on September 6 HE 16, due to the high level of exports cleared. The net import schedule increases for peak hours later in the day, reaching up to 8,312 MW in HE20.

In addition to imports and exports, ISO's market cleared wheel-through transactions. These are a pair of an import matched to an export; they reflect a transaction to inject at a given scheduling point and to withdraw that same power at another different scheduling point. The market sees these paired interties schedules as one transaction, which remain in balance. With this, wheel through transactions do not add load obligation nor supply capacity to the ISO power balance; rather, these transactions result in energy flowing through the ISO system. However, these flows transmission capacity on any transmission constraint they impact, including potential constraints at the intertie points for the source and sink of the transactions. Figure 124 shows the hourly bid-in volume of wheel transactions in day-ahead, with IFM and RUC schedules shown by market. There were no wheel reductions in either IFM or RUC. The maximum overall volume of wheels cleared was 1,323MW on September 7 hours ending 19 and 20. That consisted of 505 of ETC/TORs, 476 MW of high-priority wheels and 346 MW of low-priority wheels. There were no economical wheels bid in the day-ahead market. Figure 125 presents the same information for real-time.

Figure 123: HASP schedule breakdown

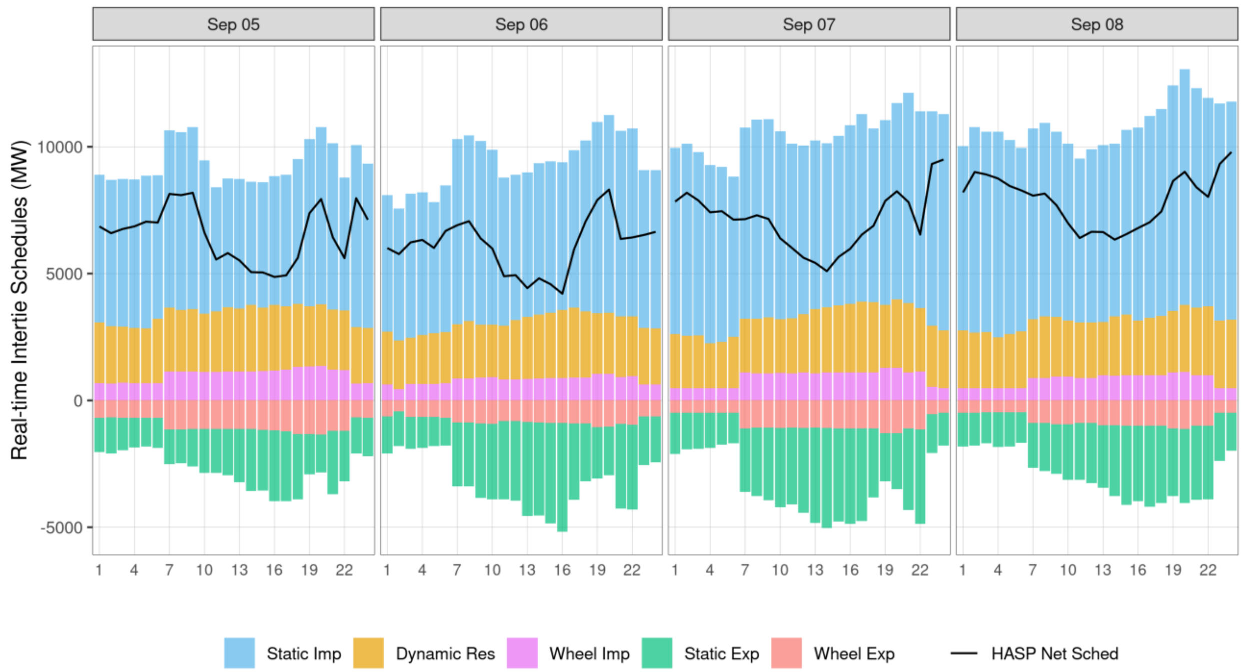


Figure 124: Day ahead wheel bid volume

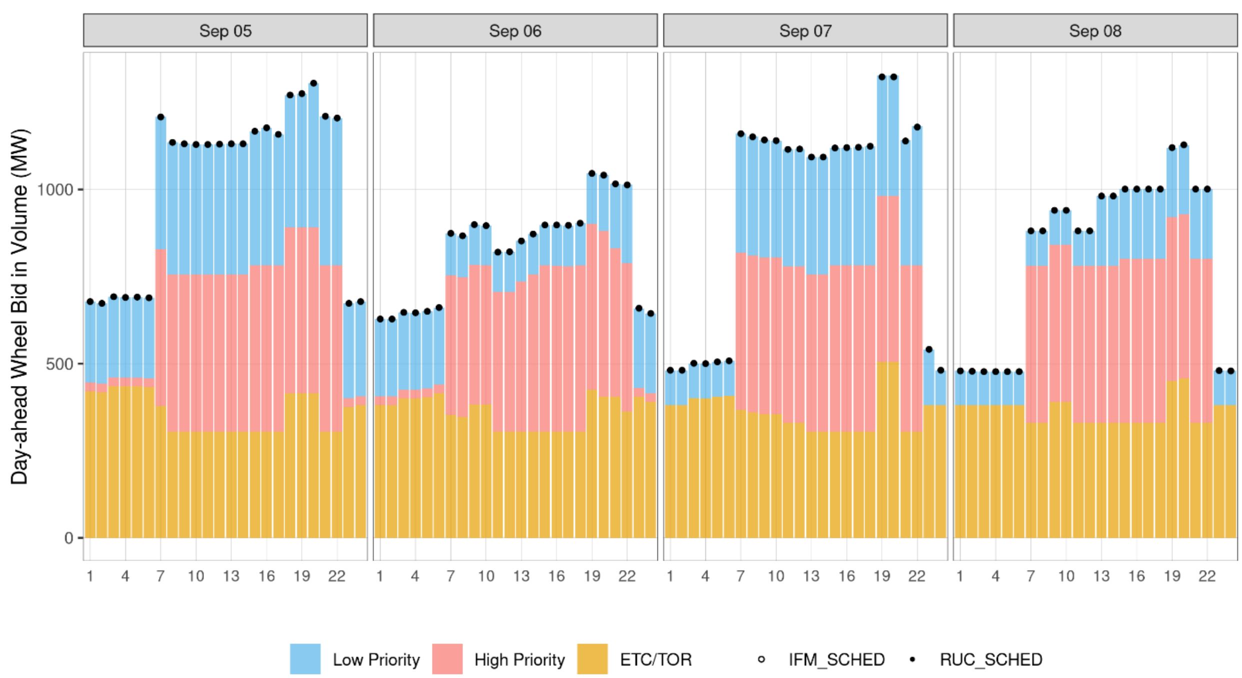


Figure 125: HASP wheel bid volume

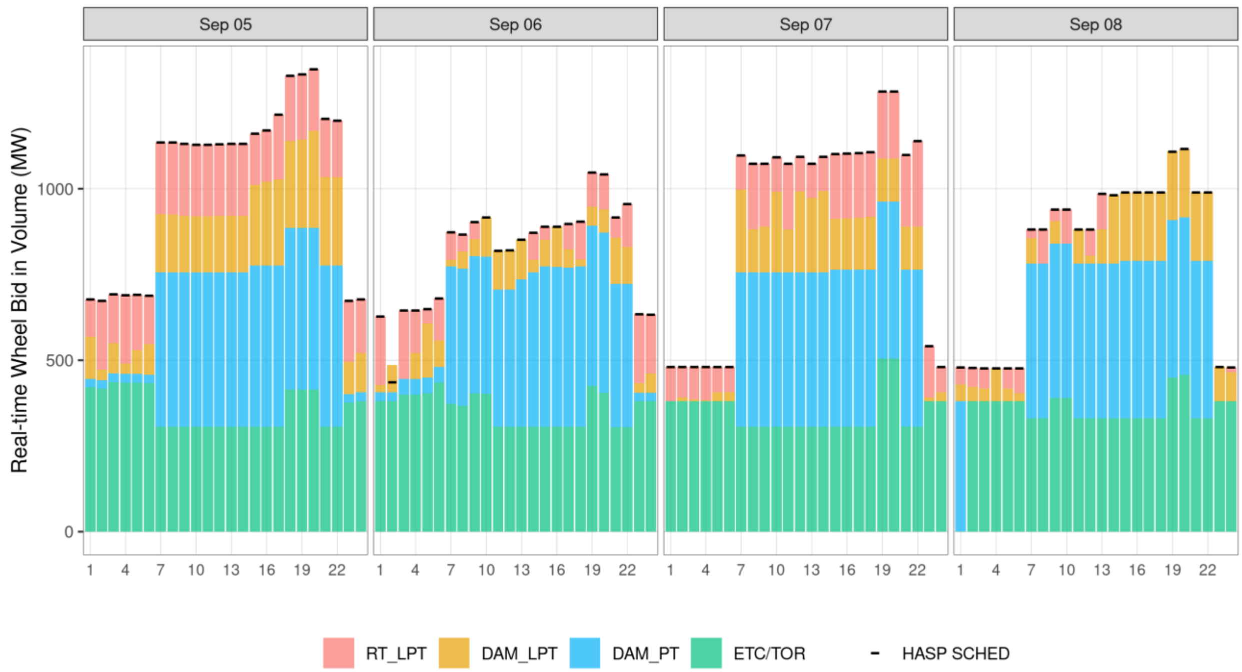


Figure 126 shows the profile of WEIM transfers for the ISO's BAA. A positive value represents an import transfer while a negative value represents an export transfer. Across all real-time submarkets, WEIM transfers imports for the ISO BAA were robust during the critical days of the heat wave, reaching levels of up to 3,000 MW imports in the RTD market. During the critical peak hours of September 6, WEIM import transfers into the ISO area were about 1,000 MW.

These plots show the trends of WEIM transfers for the ISO area across the various RTMs. Although the trends are very dynamic throughout the day, most of the time for these selected days, the actual RTD transfers were consistently below the WEIM transfers cleared in both the HASP and FMM markets. This pattern is more pronounced during the peak hours when larger differences between FMM schedules and RTD flows can be seen in Figure 126.

The changes observed on WEIM transfers for the ISO BAA between FMM and RTD can be driven by a variety of conditions, including the effect of load conformance. As explained in the previously mentioned analysis to support the RSE phase 2 initiative, the load conformance induced in both the HASP and FMM markets drive some level of additional import transfers into the ISO BAA in the HASP and FMM markets. Once that level of conformance is no longer present in RTD, the need for meeting the additional load requirement is no longer inducing the same levels of WEIM transfers and will tend to result in lower level of WEIM import transfers. These reductions will tend to be concentrated in EIM transfers in RTD as hourly import schedules are fixed. There is also the possibility that, in RTD, conditions in other BAAs change such that the original supply available to support transfers is no longer available and RTD transfers will be lower as a result.

Figure 126: ISO's WEIM transfers across market

Figure 127 shows the composition of the ISO WEIM transfers by BAA. Positive values represent an import into ISO's BAA. This is based on the RTD transfers. The pattern is quite dynamic and consists of both imports and exports, even though the majority of the transfers during the critical days of the heatwave are import transfers into the ISO's area. Prior to the peak hours, there were robust import transfers coming to ISO area reaching up to 4,000 MW, which gradually reduced during the peak time to under 1,000 MW. Figure 128 shows the composition of the import transfers coming into ISO's area from the different BAAs. This is a very dynamic composition since transfers are optimally determined on the prevailing real time conditions, and highlights the reduction of import transfers from the gross peak to the net peak.

Figure 127: ISO's WEIM transfers organized by BAA

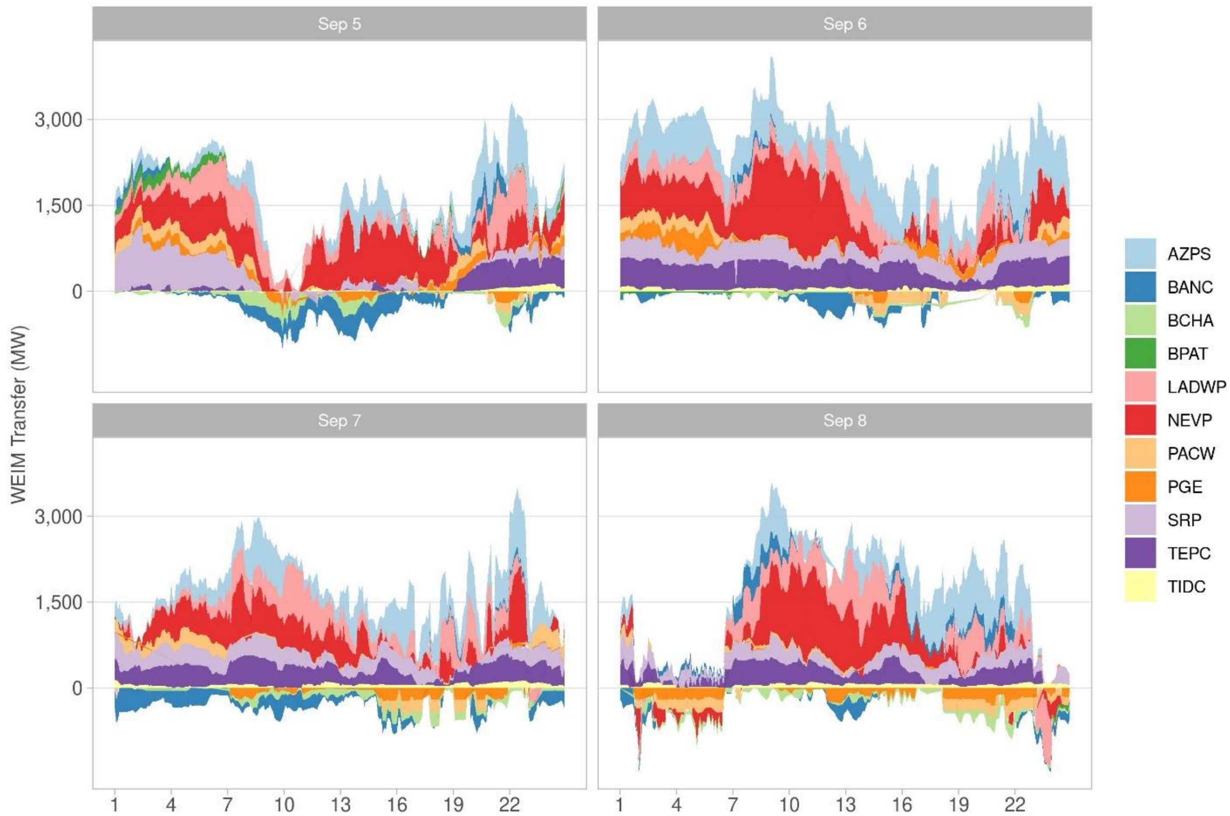


Figure 128: ISO's WEIM transfers imports by BAA during peak times

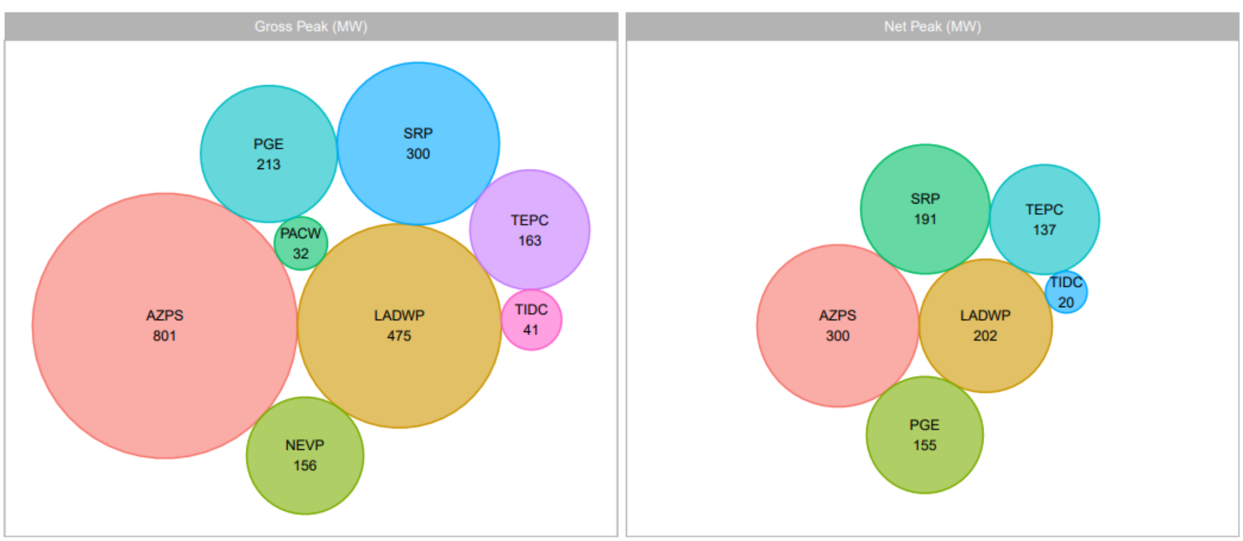
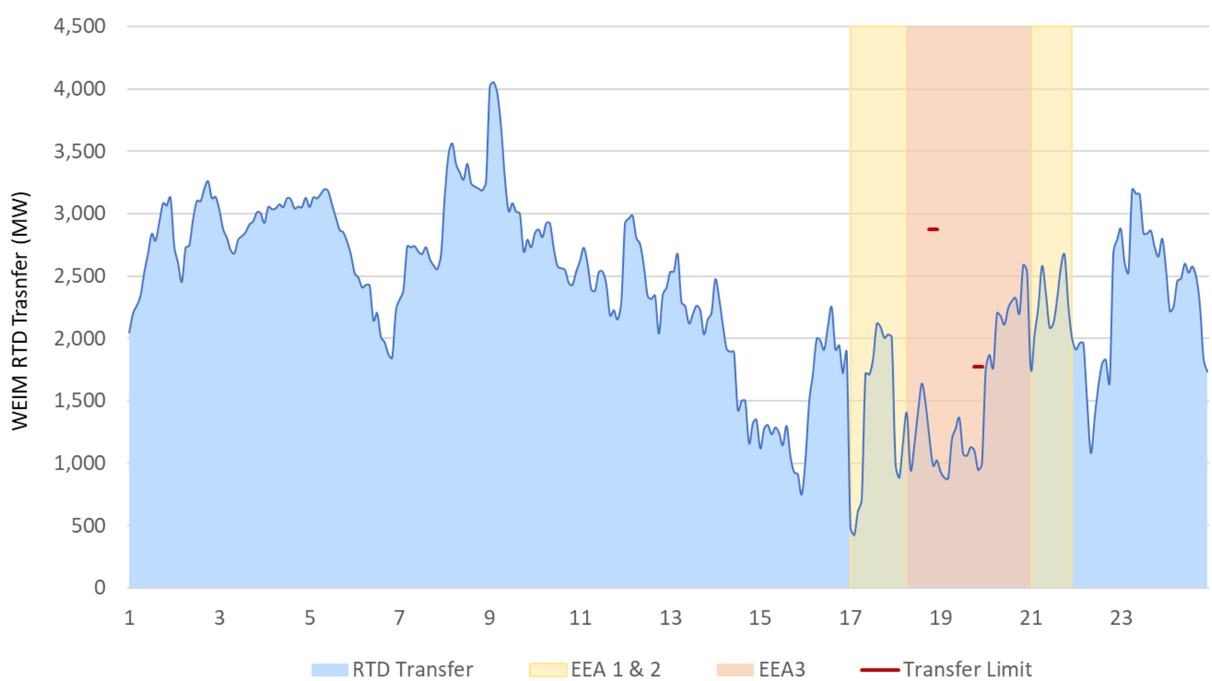


Figure 129 shows the critical day of September 6 when the ISO faced an EEA3. The WEIM transfers were in the import direction throughout the day. In the intervals that the ISO BAA failed the capacity test, the WEIM transfers were limited to the value shown with the line in red. The natural trend of the WEIM transfers show that the limit imposed on the transfers had no effect on the optimal transfers cleared in RTD because they were naturally well below the limit. The limits imposed by the failures did not bound the amount of transfer imports coming into the ISO BAA. For instance, the limit imposed due to the capacity failure in HE 19 was about 2,878 MW while the optimal and natural transfer cleared in RTD was just 1,070 MW. The transfer limits were set by the FMM transfers in the prior binding FMM interval.

Figure 129: ISO's WEIM transfers during intervals with capacity test failures



The imports and exports scheduled over the various through the different interties provide the standard net schedule interchange, which is then complemented with more granular WEIM transfers in the FMM and RTD. Similar to intertie transactions, WEIM transfers can represent either an import or export. Both intertie schedules and WEIM transfers represent the overall net schedule interchange, with a positive value representing net supply provided to ISO area. Figure 130 shows the contribution of the WEIM transfers to the overall net interchange schedule and how WEIM transfers contributed on a net basis with additional supply during peak hours. Net schedule interchange tends to reach its lowest levels during the midday hours when plenty of renewable production is available to meet ISO's needs and any surplus supply can be economic to export. As the system reaches the net load peak and solar production decreases, net schedule interchange tends to increase.

Figure 130: Net schedule interchange observed during the heat wave period

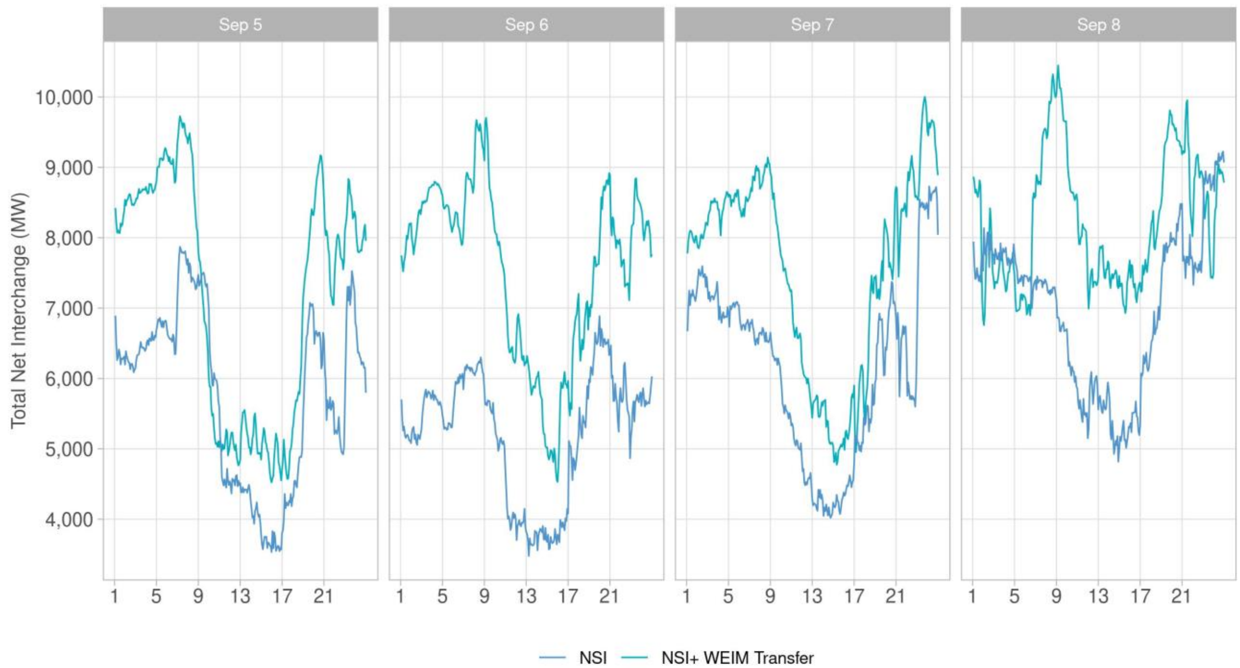
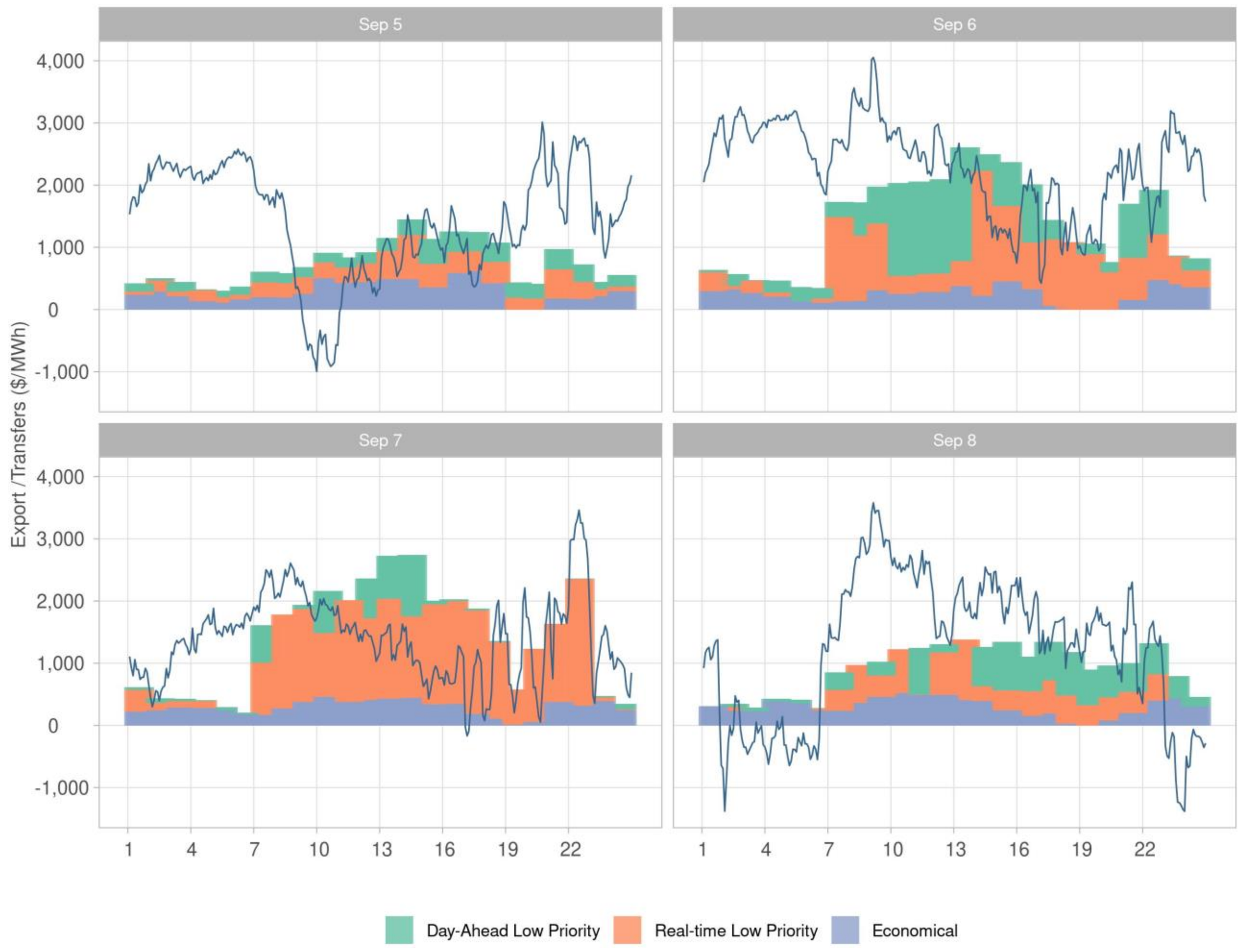


Figure 131 compares the volume of economical and low-priority exports cleared in the RTM against the WEIM import transfers cleared in the RTD market. For completeness, the low-priority exports that were cleared and rebid in the RTM are included. These exports are shown with the stacked bars while the RTD WEIM transfers are shown with the blue line. Real-time exports represent additional demand obligation, while WEIM import transfers represent additional supply. Once some exports are cleared in the HASP process, they may be utilized to meet demand in other BAAs. This may result in less upward pressure on the supply outside ISO area, which in turn may result in available supply that manifests as WEIM transfers coming into the ISO area. As the trend shows, during peak hours the WEIM import transfers coming into the ISO's BAA partially offset the exports cleared in the HASP process. In the end, whether they are hourly intertie imports/exports or five-minute import/exports transfers, they equally contribute to additional demand or supply for the ISO area.

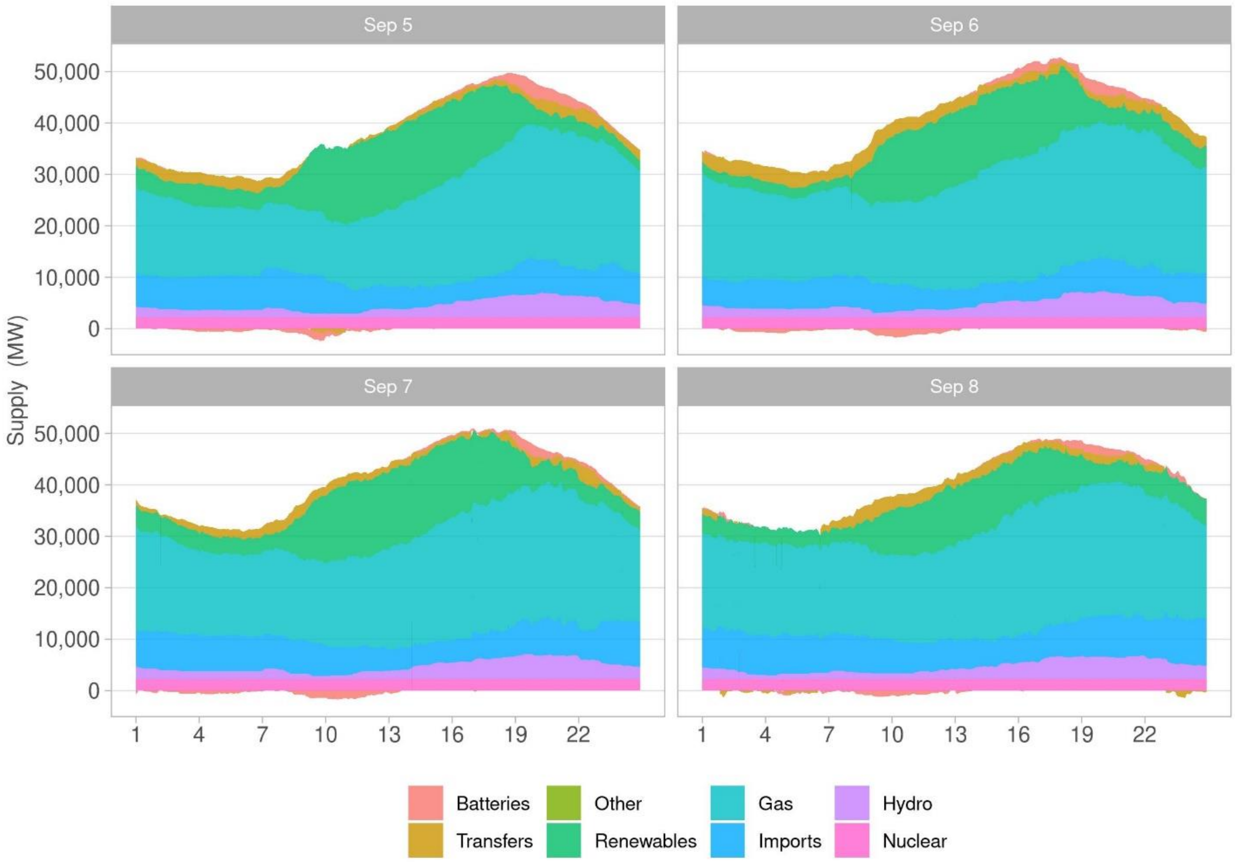
Figure 131: Cleared economical and low priority wheels compared to WEIM impor transfers



9.7 Resource performance

The ISO's demand and exports are met with supply available in the system from different types of resources and technologies including gas, hydro, nuclear, wind, solar, storage, imports and WEIM transfers. Many of these resources support California's RA program. The contribution of each of these types of resources may vary seasonally and on the time of day. The profile of the supply composition is illustrated in Figure 132 below.

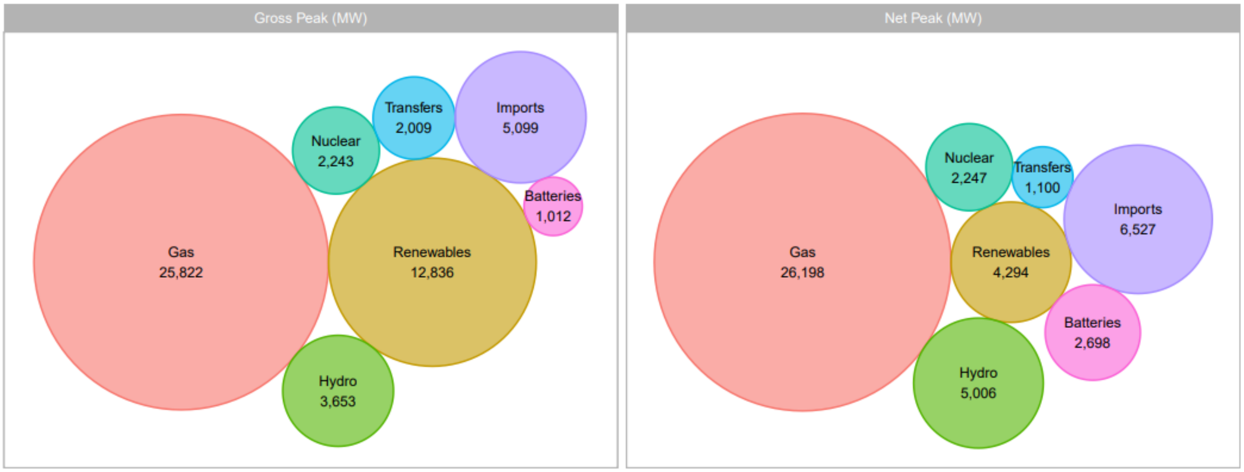
Figure 132: Supply composition by type of resource



During the gross demand peak, gas supplied about half of the demand followed by 24 percent supplied by renewables and 10 percent supplied by imports. In the net load peak and with lower gross demand level to meet, renewables reduced significantly with the decline of solar production to about 8 percent share. To make up for this gas supported about 50 percent of demand followed by 12 percent of imports and 10 percent of hydro. The relative contribution of each type of supply is illustrated in Figure 133.

Supply-side resources are evaluated in the operational time frame. Specifically, the resource adequacy (RA) capacity shown to the ISO for September 2022 is compared to all resources that bid and were awarded in the RTMs, and their actual performance, for September 5 through 8 when ISO experienced the most challenging system conditions of the heat wave. Actual performance of demand response resources cannot be assessed at this time since the data of their utilization is received approximately 60 days after the operating date. This analysis was conducted for both peak and net peak periods.

Figure 133: Relative contribution to meet load by type of resource



Overall, supply from all resources was over 90 percent of the shown RA plus RMR allocation for the period of analysis during the peak, mainly because of the additional solar production. During the net demand peak, this decreased between 85 and 90 percent. This assumes that a wind or solar resource with any level of RA has all capacity considered as RA.

The ISO evaluates the supply conditions for both gross demand and net demand. The net demand is the demand that remains after discounting the supply provided by wind and solar generation. In Figure 134 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 a.m. until 4 p.m.) when renewables, especially solar, are generating at the highest levels and serving a significant amount of ISO load.

The ISO clears most of supply to meet demand in the day-ahead market in hourly blocks, which includes both energy and ancillary services (A/S). Ancillary services are reliability services that the ISO co-optimizes and clears with energy needs and includes both contingency reserves and regulation up and down capability. Figure 134 compares the supply-side fleet including both RA and non-RA as available in the day-ahead timeframe. This is based on the actual bids in the day-ahead market reflecting all supply available. The supply is organized between RA resources and non-RA resources. This supply is then compared to the load obligation with three different references. One reference uses the total load obligation consisting of the standard load forecast plus the requirement for operating reserves as shown with the line in purple. A second reference is the adjusted load forecast; this includes the RUC adjustments plus the operating reserve requirements. The third reference as an additional requirement that considers the clearing of the high priority (PT) exports which already supported by non-RA capacity. For the peak hours of September 5 and 8, the available RA capacity was not sufficient to meet the ISO load obligation relative to the standard load forecast. This required ISO to rely on additional non-RA capacity. This reliance was more pronounced during the net load peak hours as observed in Figure 135 where the net load peaks are above the RA supply.

Figure 134: Supply available in the day-ahead timeframe to meet gross peak demand

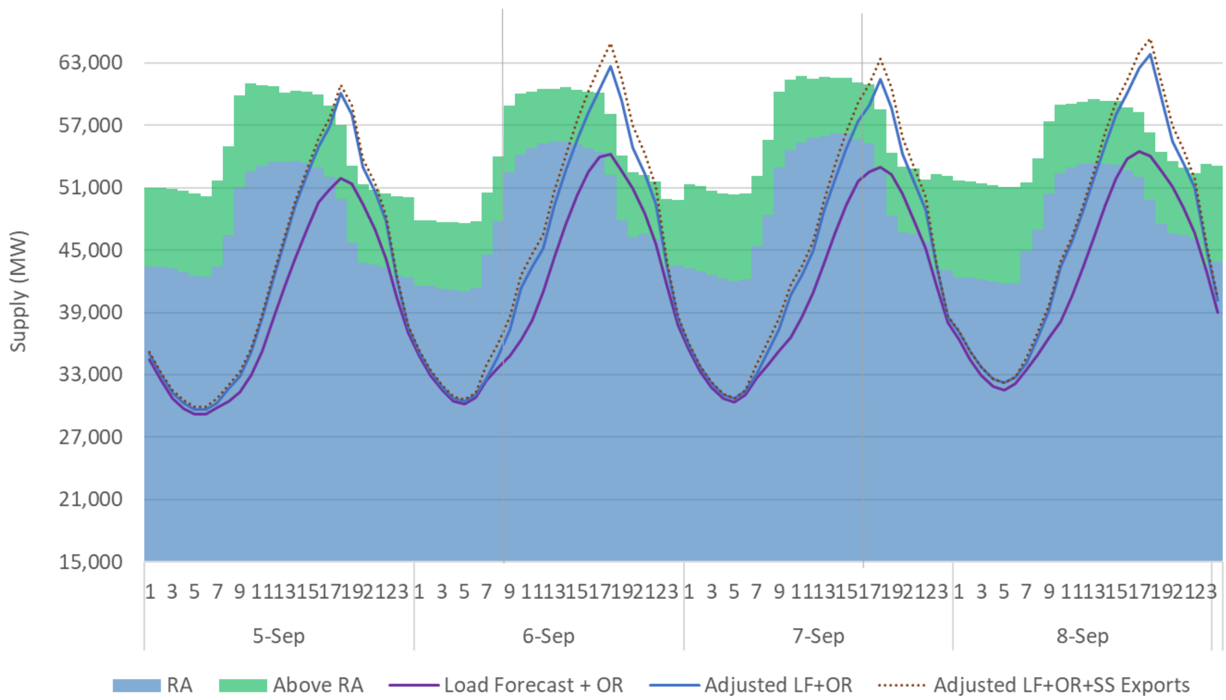
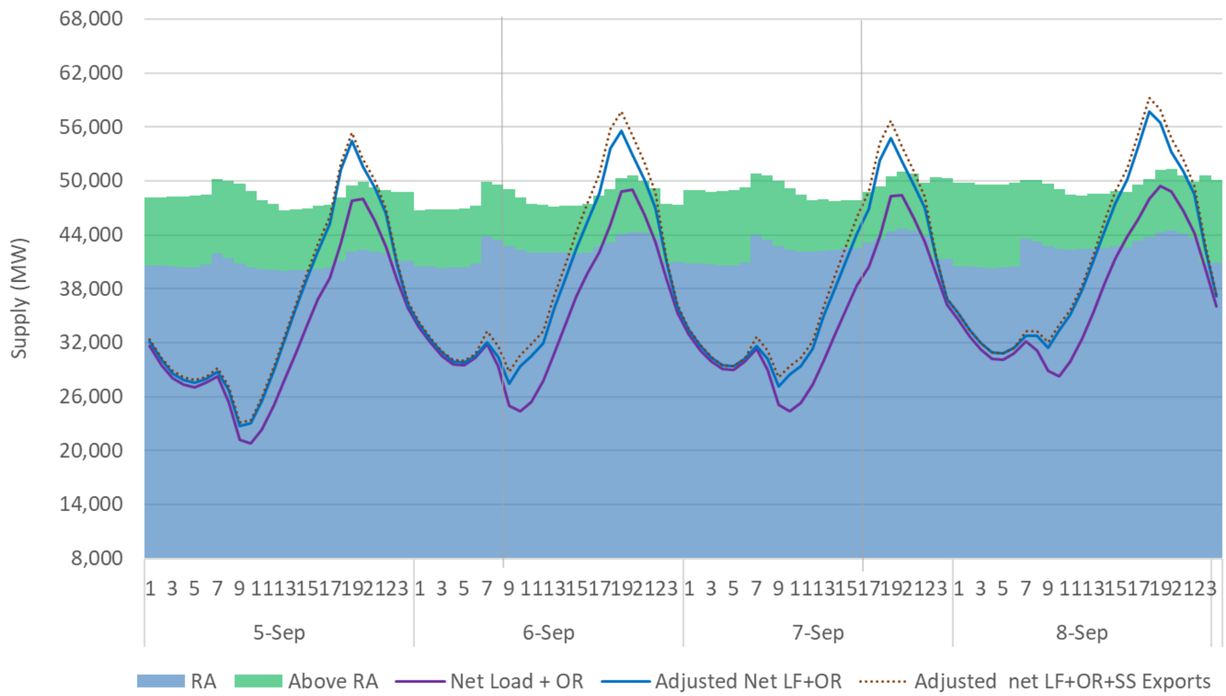


Figure 135: Supply available in the day-ahead timeframe to meet net peak demand



Since conditions may change in the RTM, the RA supply performance is also analyzed for this market. Based on ISO rules, only resources shown to the ISO as RA are considered to be RA capacity. Both RA resources that generate above their shown amounts and resources with RA long-term contracts that are not shown to the ISO are not considered RA resources under ISO rules. Two simplifying assumptions were made for the analyses. First, if a wind or solar carries any amount of RA then the analysis assumed all of its capacity to count as RA. Second, capacity above the RA level for any other type of resource technology is classified as Above RA. For completeness of the overall supply conditions, capacity from any resource with no RA attribution is explicitly identified as Non-RA capacity.

Figure 136 shows the outages or de-rates for resources that are designated as RA. Any capacity derates above the RA level is classified as above RA outage and any capacity outages that are not attributed to RA capacity are classified as non-RA outage.

Figure 136 Outages for September 5 - 8 for HE 19

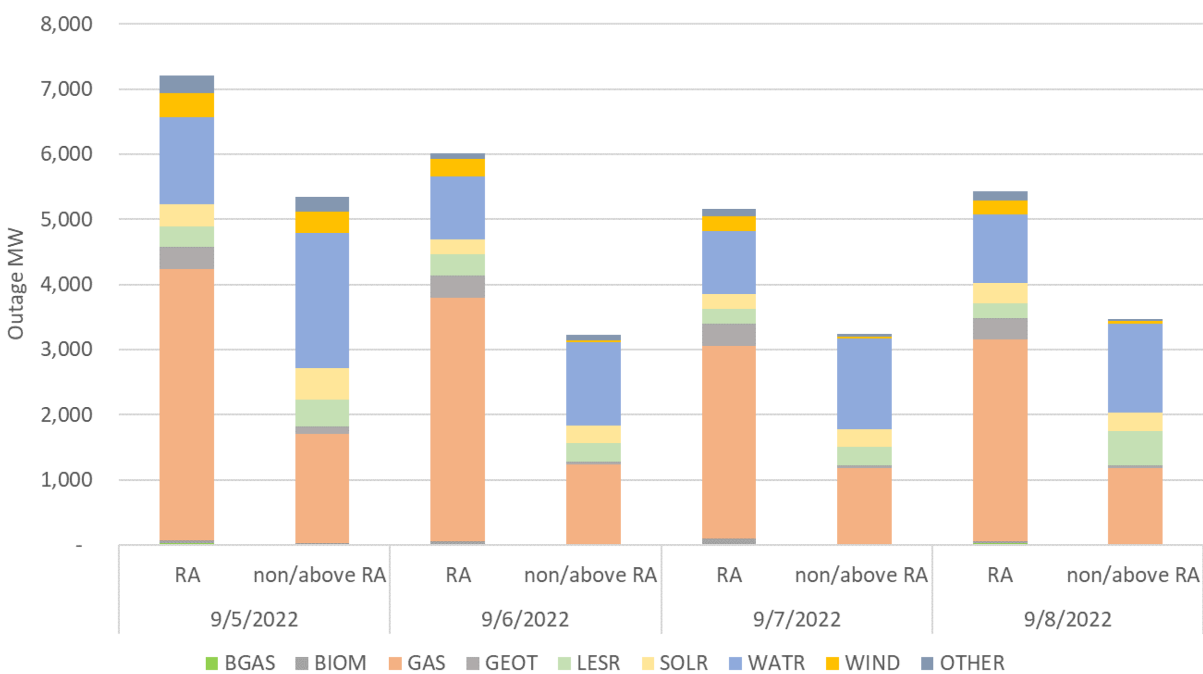


Figure 137 through Figure 140 show the comparison between RA capacities relative to two different real-time references. The first reference is the RTD for supply consisting of both energy dispatches and upward ancillary service awards (regulation up, spinning and non-spinning reserves). This reference is based on the real-time interval dispatch for energy and the FMM awards for AS. The analysis considers this reference because it is the capacity that the market utilizes to balance the load forecast conditions and meet the reliability obligation of AS. That supply is then organized in the groups described in the previous paragraph (RA, Above RA, and Non-RA) and depicted in the plots with stacked bars. The second reference is the actual production of resources. This is based on the telemetry of each resource and reflects the final state of resource outputs. If a resource is dispatched for energy only, that actual value will reflect the production for energy. If the resource is scheduled for regulation, the actual telemetry value will also reflect any production due to following the regulation signal. One element to consider when comparing against actual production is that some resources may still have headroom. This headroom can arise for two reasons: the resource is carrying operating reserves (*i.e.,* capacity that can be deployed into energy if a contingency event occurs) or the resource has regulation capacity which is not fully utilized based on overall AGC system. Actuals will also reflect any upward or downward resource deviations from market dispatches. The Actuals are represented with empty circles markets for RA-only supply, while the filled circles reflect the total actual telemetry values (RA plus Above RA plus Non-RA).

The performance of resources against their shown RA values are as follows:

- ***Natural gas***: Collectively, the RA natural gas fleet generated approximately between 85 and 90 percent of its shown RA value during the net load peaks. The difference between real-time awards and actual generation can likely be attributed to forced outages and de-rates due to the extreme heat.
- ***Hydro***: Actual energy generation from the hydro generation fleet may seem low – 73 percent, on average, of the shown RA value across both days and time periods – but this does not include the provision of necessary ancillary services. Although actual generation production and ancillary service awards are not additive, analyzing both provides a fuller picture of the hydro fleet performance.
- ***Solar:*** Real-time solar production also varied from its RA value. Although generation during the gross peaks remained largely above the shown RA values, it was between 15 percent and 25 percent of the RA shown during the net demand peak hours on both days. Solar generators collectively produced 6,000 to 8,000 MW more than the shown RA values at peak, but 1,600 MW to 1,800 MW less than the shown RA values at the net demand peak. This highlights the known difference in RA value at the gross and net load peak given the current resource mix.
- ***Wind:*** With a less certain profile over time, wind generators had the opposite pattern as solar. Wind generation during the gross demand peak was below shown RA by 67 percent (or 360 MW) on September 6 and by 71 percent (or 314 MW) on September 7. Conversely, during the net demand peak, wind production was 22 percent (or 247 MW) and 103 percent (1100 MW) higher than the total shown RA values for September 6 and 7, respectively.
- ***RA Imports:*** RA imports shown in this section only include transactions that are non-resource specific, whereas any resource-specific imports are grouped into the corresponding fuel/technology type. Overall, RA imports tracked below the RA shown values for four main reasons. First, under-performance occurred when RA imports bid in the day-ahead market but they reported an outage for the amount they did not offer in real-time. The second type of under-performance occurred when some non-CPUC RA imports did not bid in to the market to cover for their expected obligation; this represented over 200 MW. The final type of under-performance was RA imports that offered into the markets and cleared as expected but then they were subject to curtailments by other BAAs after the fact due to transmission or scheduling constraints. In some hours these curtailments were over 400 MW. This underperformance was not under the Scheduling Coordinators control. Critically, non-RA imports filled in much of these gaps by providing additional supply of up to about 1,700 MW and 2,700 MW during the gross peaks, while they provided additional supply of about 2,500 MW and 2,900 MW during the net peak on September 6 and 7, respectively.
- ***Storage:*** Storage resource generation was also in lower than RA shown values during both gross and net peaks, though the generation was very close to the RA value on the net peak of September 7. The reason for this outcome is rooted in the complexities of how the market dispatches these type of resources when considering their limited energy (*i.e.*, state of charge). The utilization of storage resources and the complexities to maximize the dispatches during peak times is analyzed in more detail below in the section on storage resources.

Figure 137: September 6 Gross peak (4:58pm). Real-time supply and actual production vs RA capacity

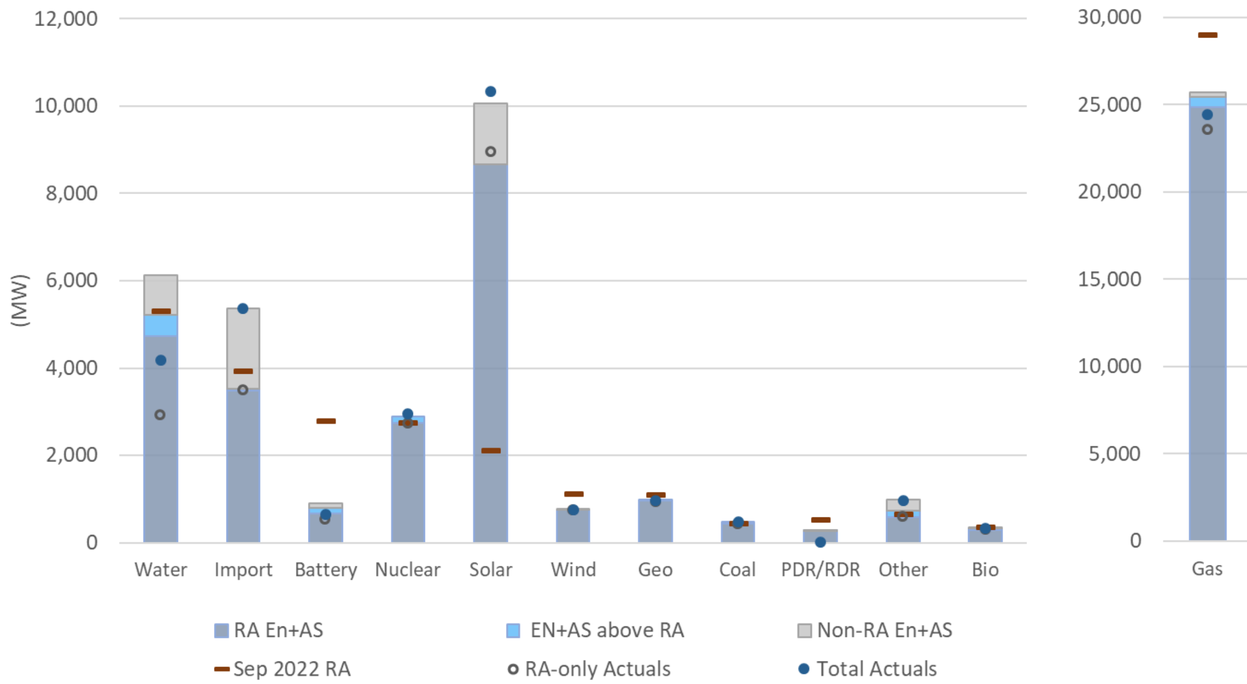


Figure 138: September 6 Net peak (6:58pm). Real-time supply and actual production vs RA capacity

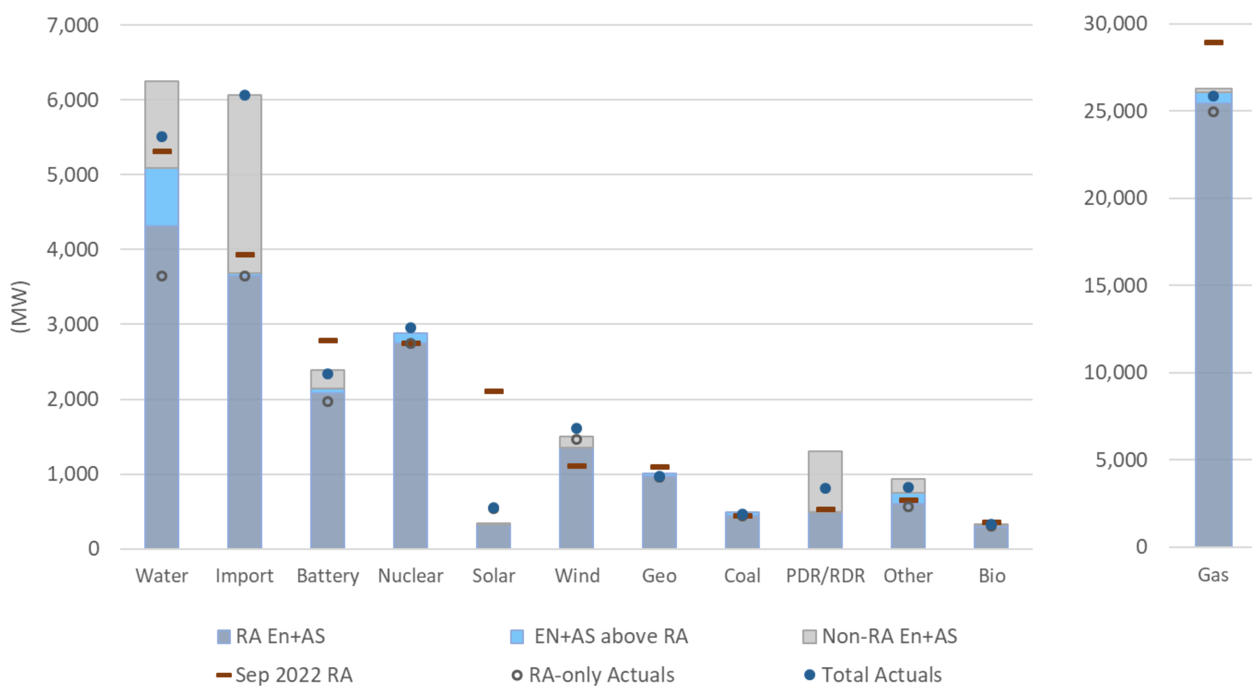


Figure 139: September 7 Gross peak (3:55pm). Real-time supply and actual production vs RA capacity

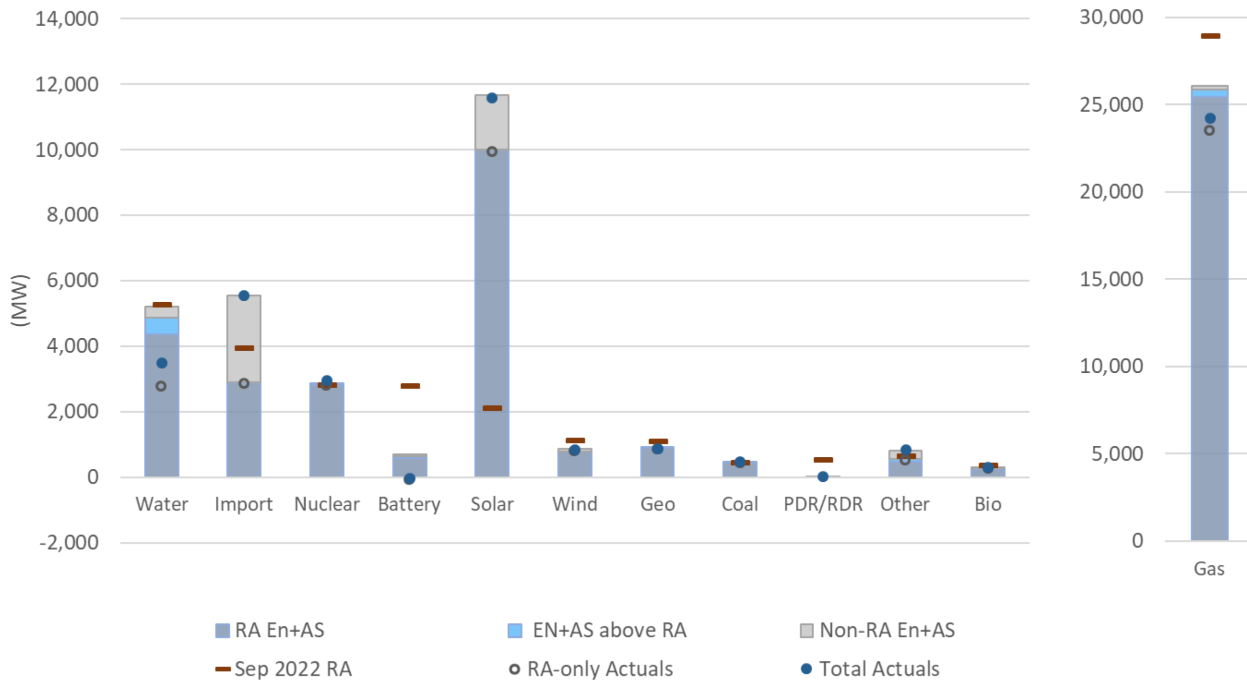
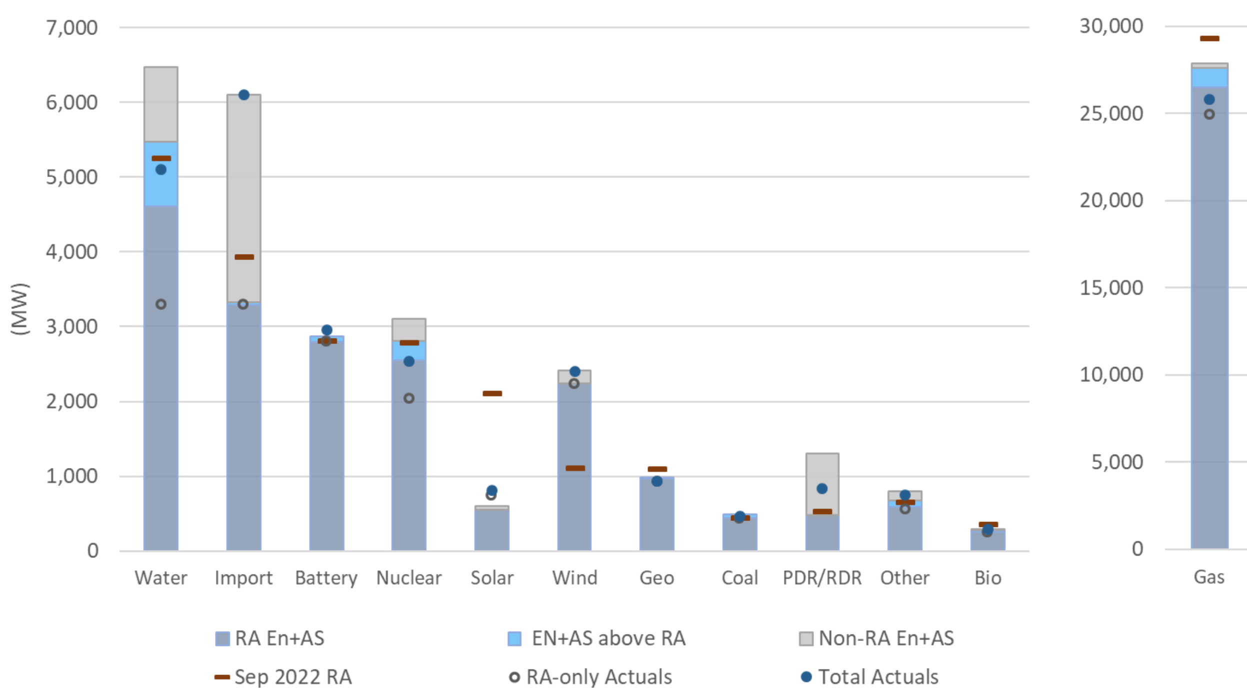


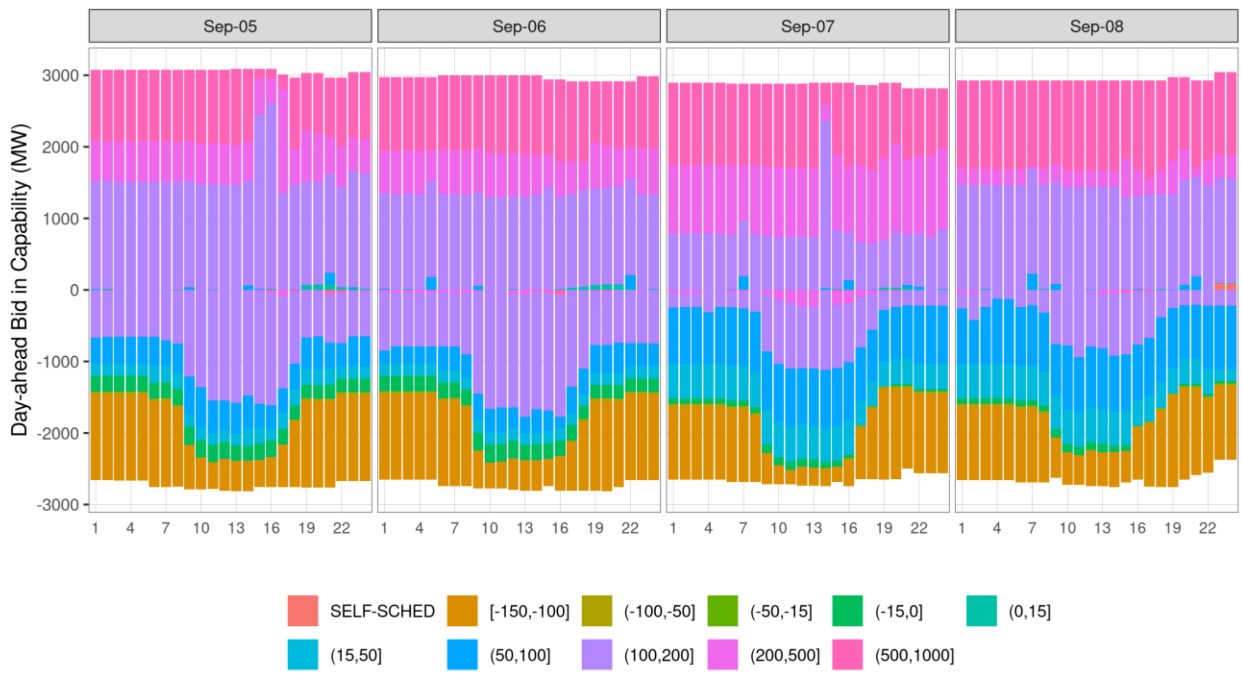
Figure 140: September 7 net peak (6:50pm). Real-time supply and actual production vs RA capacity



9.8 Storage resources

This section presents the performance of the energy storage resources on the tight days of the early September heat event. The bids for storage capacity are shown in Figure 141:. This figure shows that bids were relatively consistent across this period and that storage was willing to charge at higher than normal prices, between $100 to $200/MWh, in morning and early afternoon hours.

Figure 141: Day-ahead storage bids



Correspondingly, Figure 142 shows the bids for storage resources in the RTM. The bids in real-time were more dynamic, potentially due to anticipated system and pricing conditions. In hours ending 8 to 16, storage resources bid to charge at prices higher than $200/MWh, and the majority of discharge bids were above $500/MWh. During the evening peak hours, storage bid to discharge between $50 and $100/MWh, or even lower.

Figure 142: Real-time storage bids

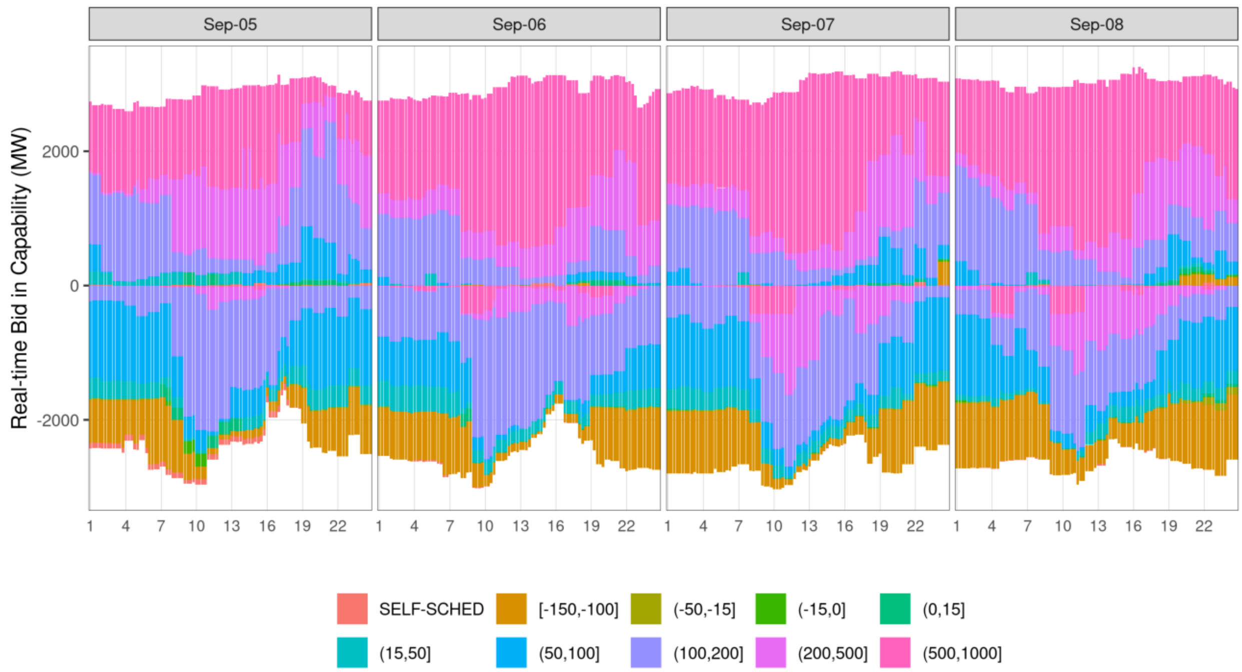
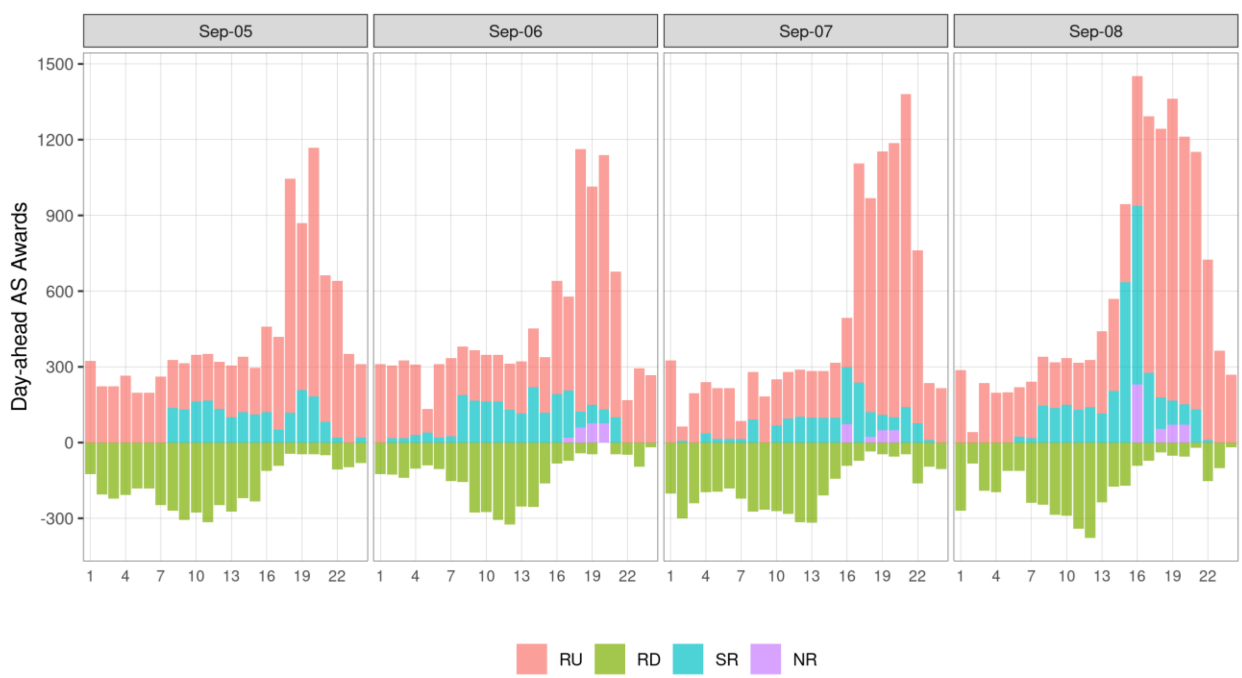


Figure 143 shows the hourly AS awards for storage resources in the day-ahead market. Regulation down awards (RD) peaked during the solar hours and regulation up, spinning reserves and non-spinning reserves (upward ancillary services: RU, SR, NR) reached peaked during evening peak hours.

Figure 143: Day-ahead (IFM) AS awards



In addition to regulation up and down, storage was awarded some spinning reserves and small amounts of non-spinning reserves in certain hours. Storage resources contributed a significant share of total regulation. In fact, storage provided all of the regulation during some hours.

Although the objective is to procure all the AS requirements through the day-ahead market, given changing conditions inherent to real-time operation, the RTM is the last opportunity to re-procure or procure incremental AS. Figure 144 presents the total ancillary service awards in the real-time for storage resources, which shows a similar pattern to the day-ahead.

Figure 144 Real-time (RTPD) AS awards

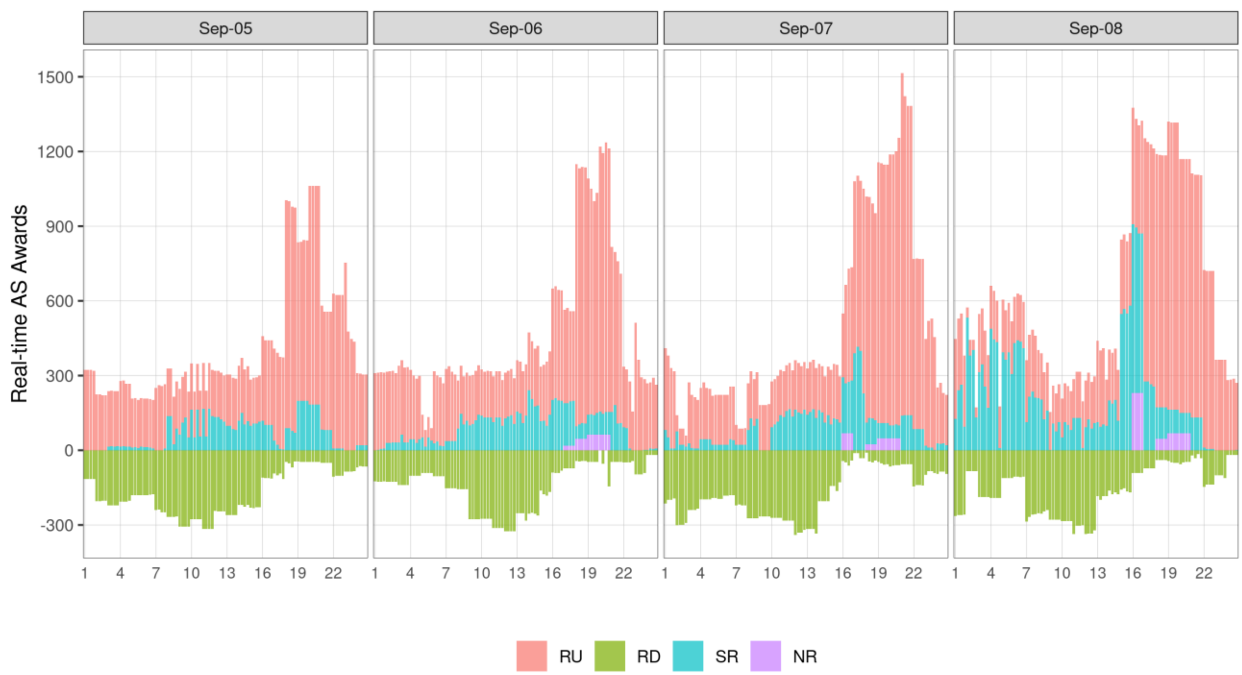


Figure 145 presents the aggregate state of charge across the fleet of storage resources in the RUC process (day-ahead) and RTD (real-time) market. The state of charge was similar to the typical patterns observed for storage resources though the summer, where state of charge peaked in the afternoon hours. State of charge was generally higher in the RTM compared to the day-ahead market. Peak state of charge in the RTM was about 11,700 MWh on September 7 during HE 15.

Predicting, modeling and knowing state of charge for short-duration storage resources is incredibly important for reliable grid operations. Without accurate information about state of charge the ISO is unable to assess if the system will have enough energy to serve load on peak days through the most challenging operational hours of the day. There are some challenges to estimating what state of charge is going to be. First, the ISO's day-ahead market uses a biddable parameter as a starting point for the state of charge in the market. Figure 145 shows that during these four days, sometimes the state of charge in the day-ahead market was significantly higher than actual state of charge in the RTM, and sometimes it was accurate. Second, ancillary service awards for storage resources do not impact the ISO's model for state of charge. When a resource is providing either regulation up or regulation down it will respond to 4-second automatic generator control (AGC) instructions, which impacts state of charge. This potentially results in instances where the ISO must take out-of-market action in real time to charge or discharge storage resources so that they are able to support regulation awards.

Figure 145 State of charge, RUC vs. RTD

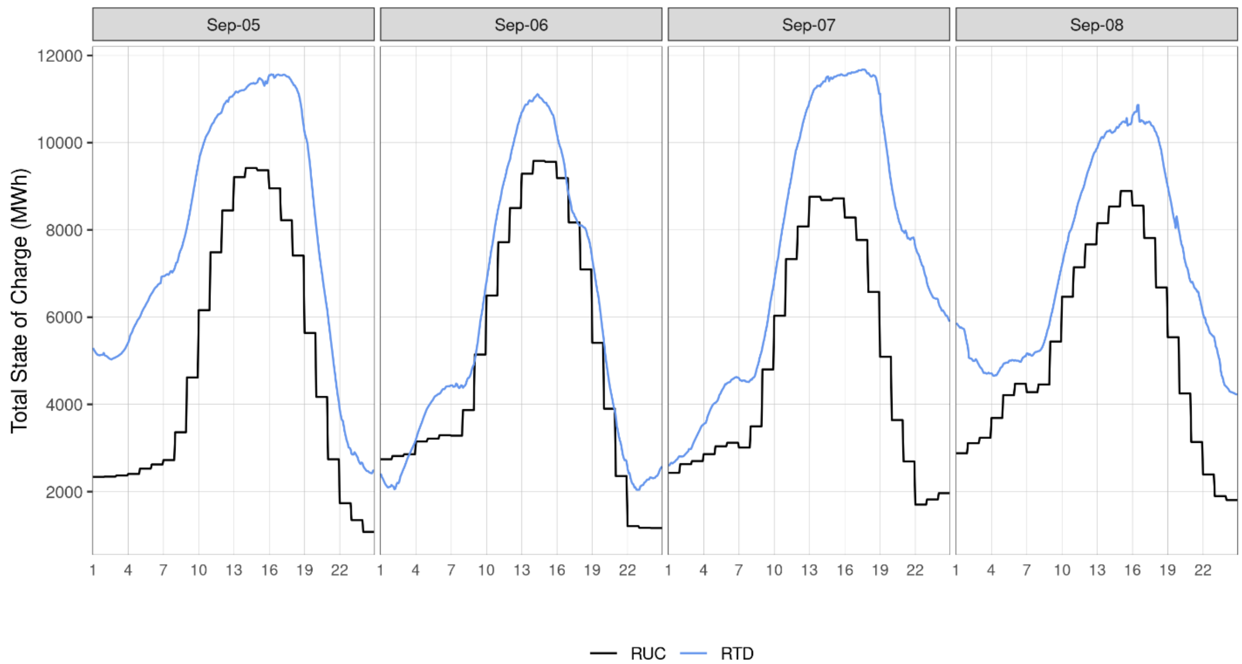


Figure 146 compares the energy schedules for storage resources in the day-ahead and RTMs. In both markets, the storage resources primarily charged during peak solar hours of the day, and discharged in the evening peak net-load hours. As the most stressed system conditions from the heat wave materialized on September 5, storage charged early in the day to support peak conditions. Later in the day, those resources were dispatched for over 2,000 MW for energy.[63]

On September 6, the most critical day of the heat wave, challenging market conditions arose for storage resource operations. Several factors made storage more challenging to operate, including:

1. Some resources were not charged early in the day due to high energy bids combined with a software issue. Specifically, resources with bids to charge above $150/MWh were not considered even when they had economic merit. This prevented these resources from charging to increase their state of charge (SOC) in the early hours of the day.

2. The RTM issued instructions to discharge to some resources significantly earlier than the evening peak. Some storage resources were discharged economically as early as HE 13 because of prices that were higher than expected. Other resources were impacted by congestion and subject to local market power mitigation, which resulted in economic bids. As time progressed prices continued increasing, which exacerbated both issues. Figure 147 illustrates the energy awards for storage with prices in the RTM.

[63] The 2,000 MW does not include additional energy that can be released when units follow regulation instructions.

Storage resource are energy limited and thus, inter-temporal conditions need to be factored in. The expectation is that storage resources will charge at times of lowest prices and discharge at times of highest prices to maximize their value. As the RTM progresses five minutes at a time, it is of paramount importance for the market to be able to look ahead for evolving conditions. This is possible to some extent by the use of multi-interval optimization where in addition to considering conditions for the next immediate five minute interval, it also considers the next 45 minutes ahead in order to determine the most optimal trade-off between discharging resources for the next interval or saving that SOC for more valuable conditions in future intervals. The conditions experienced during the heat wave highlights the importance of relying on a multi-interval optimization to better position storage resources to discharge when most valuable and minimize the premature depletion of their state of charge. However, as noted above, the RTD look-ahead is not long enough to identify the need to conserve state of charge for periods more than an hour in the future.

3. By HE 16, storage dispatches for discharge were significantly higher than day-ahead market outcomes and state of charge was at or lower than day-ahead market outcomes. This lead the ISO to employ two tools that reduced storage dispatch:
    a. Exceptional Dispatch: Operators issued exceptional dispatches (EDs) to force resources to charge or to preserve state of charge for the peak hours. Figure 148 shows exceptional dispatch to four resources on September 6.[64]
    b. Minimum State-of-Charge Constraint: The minimum state-of-charge constraint activated and forced storage resources to maintain the state of charge modeled in the day-ahead market at the same time. This resulted in reduced instructions for discharge or even instructions to charge for some resources. Figure 145 shows that in hours 17 through 21 aggregate real-time state of charge values were approaching to the day-ahead state of charge values.[65]

Figure 147 also shows that real-time prices were negative during a few intervals in the evening on September 7 and 8. These prices were not in the day-ahead market, and were the result of severe congestion in real-time only regarding the COI nomogram. The negative prices in real-time were the result of the interplay with congestion. However, LMPs for storage and other generators were generally still positive, resulting in economic energy dispatches in real-time.

[64] Exceptional dispatches to help manage state of charge were issued to more resources on September 7 and 8.

[65] The reduction in output and occasional charging from storage resources occurred during high priced periods when prices reached $1,000/MWh.

Figure 146: RUC and RTD Energy Schedules for Storage

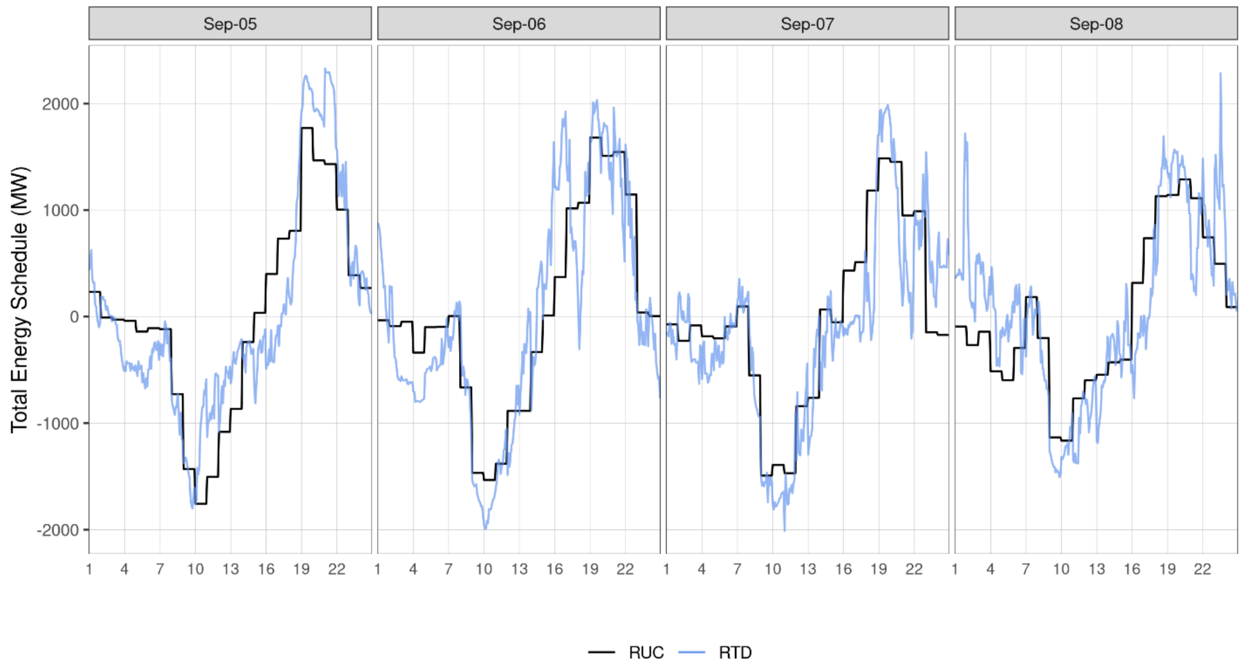


Figure 147: RTD Energy Awards for Storage and SMEC

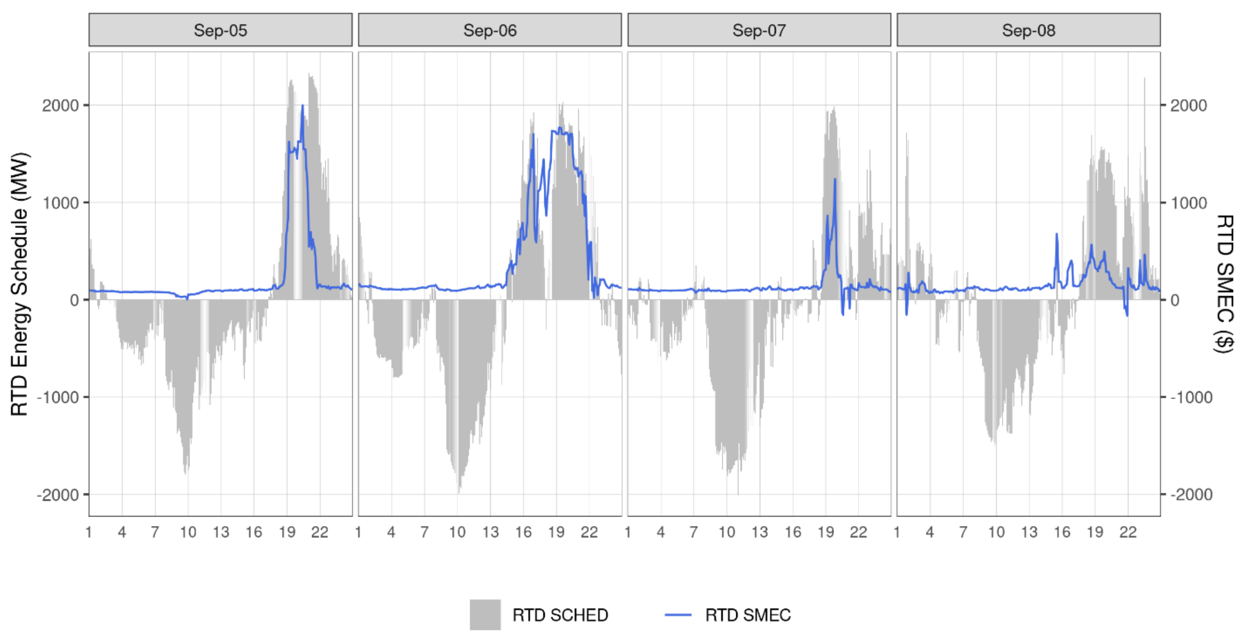
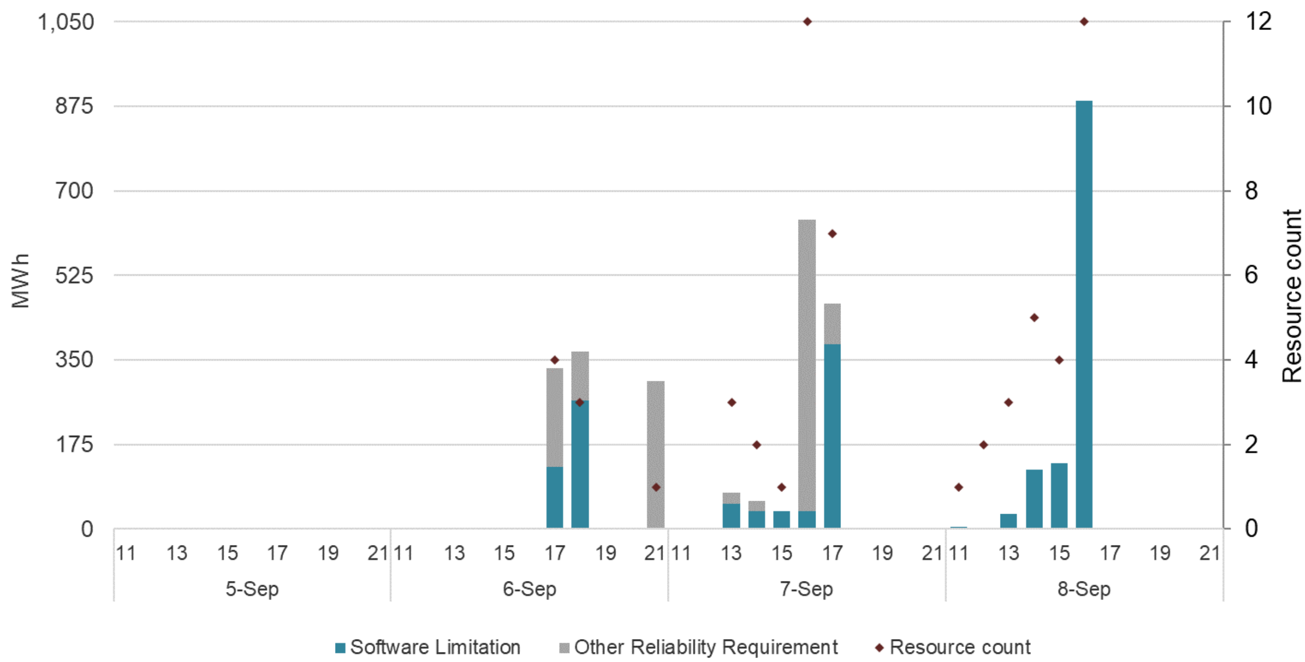


Figure 148: Volume of Exceptional Dispatches issued to storage resources



The minimum state-of-charge requirement is a tool introduced as part of the market enhancements for summer 2021 readiness initiative[66] to ensure that storage resources shown for RA maintain sufficient state of charge to provide energy during tight system conditions. This provision was added to the market with a two-year sunset provision.

The minimum state-of-charge requirement is only applied on days when system needs are critical. The constraint is activated when there are one or more hours with infeasibilities in the residual unit commitment process, where supply cannot satisfy demand, which occurs infrequently and indicates very tight system conditions. When activated, the requirement ensures that all storage resources shown for RA maintain sufficient state of charge in the RTM to cover discharge energy schedules from the day-ahead market during a set of critical hours. These critical hours are defined by the operators prior to running the day-ahead market. The requirement ensures that each resource has enough state of charge at the beginning of each critical hour to meet the day-ahead schedules in that hour plus all future critical hours, taking into account the resource's charging efficiency and operating limits.

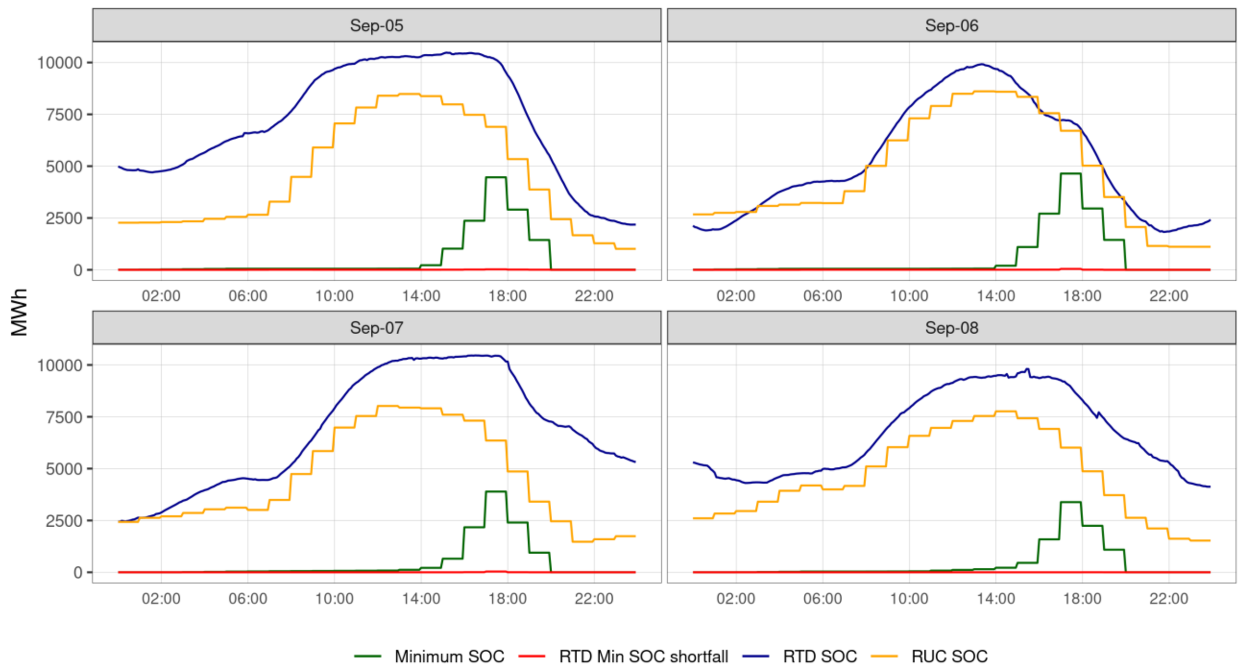
The minimum state-of-charge requirement was activated nine days in September 2022, including September 5 through September 8. During this period, the critical hours were defined as HE 19 to 21.

During the critical hours across the heat wave, the minimum state of charge was maintained across the storage fleet, with minimal individual resource shortfalls. The fleet was able to provide energy at or greater than day-ahead awards during almost every interval when prices were sufficient for economic dispatch.

[66] Material on the initiative can be found at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness

Towards the end of hour-ending 19 and 20 on September 6, the RTD energy awards drop below the RUC energy awards, despite very high RTD prices. This was due to a confluence of factors, including additional ancillary service awards being procured in the RTM and resources using up SOC while providing regulation, which was then bought back at the end of the hour to satisfy the minimum SOC constraint.

Figure 149: State-of-Charge for RA resources



Over the critical peak hours, the total real-time SOC of the resources subject to this constraint was near the RUC level SOC, and significantly above the minimum SOC constraints, as seen in Figure 149. The RTD EOH Min SOC Shortfall represents the total amount of shortfall between the minimum SOC requirement and the actual SOC in RTD at the end of the hour.

Figure 150: Enforced end-of-hour RTD minimum SOC constraints

To illustrate the impact that the minimum state of charge requirement had in real-time, Figure 150 shows the total number that the requirement applied to during specific real-time hours. The teal bars indicate resources that the requirement is applied to but did not bind, and the salmon bars reflect the resources that the requirement applied to and the requirement did bind. The figure indicates that the greatest number of resources in the intervals where the requirement was in place were the hours leading up to the critical hours, which is expected. For most of the storage resources economic bids kept them above the minimum state of charge imposed by the requirement and, in many hours, the real-time pricing did not warrant dispatch at the day-ahead schedules for the full hour. During HE 18 on September 6 40 percent of the resources with a minimum state of charge requirement enforced bound. Overall, the minimum state of charge constraint worked as designed and ensured that storage resources shown for RA maintained minimum state of charge levels during critical hours.

9.9 Market prices

The following market pricing metrics reflect the data reported in the section titled “Market prices” of this report but with a focus on the specific days of the September heat event in order to assess pricing dynamics during this time period in a more targeted manner.

Figure 151 below shows the Locational Marginal Prices (LMPs) for each market averaged across the four DLAPs within the ISO area for market interval. In general, price separation across markets is most prominent during the peak hours, especially between hours 16 through 22 between DAM and RTM. FMM LMPs were higher than other market LMPs during the four days of the heat event. During September 7 and 8, there was noticeable price separation between the FMM and RTD markets especially in the peak hours, even though in several other intervals prices tracked closely. Higher FMM prices relative to RTD prices could be mainly driven by the additional load conformance applied in FMM. The higher load conformance drive higher dispatches and transfers requiring higher-price bids to clear. Then in RTD, any additional imports or commitment achieved through the HASP/FMM conformance are binding in RTD and provide additional supply. With RTD clearing at lower load levels, prices in RTD may tend to be lower.

Figure 151: DLAP-average LMPs across markets by interval

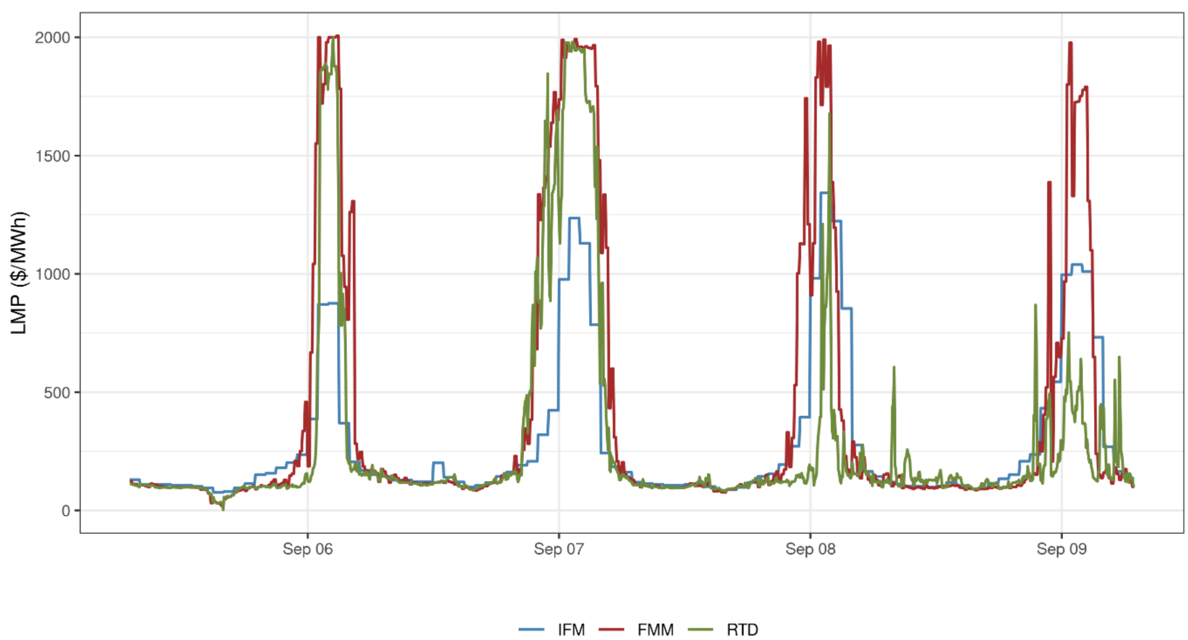
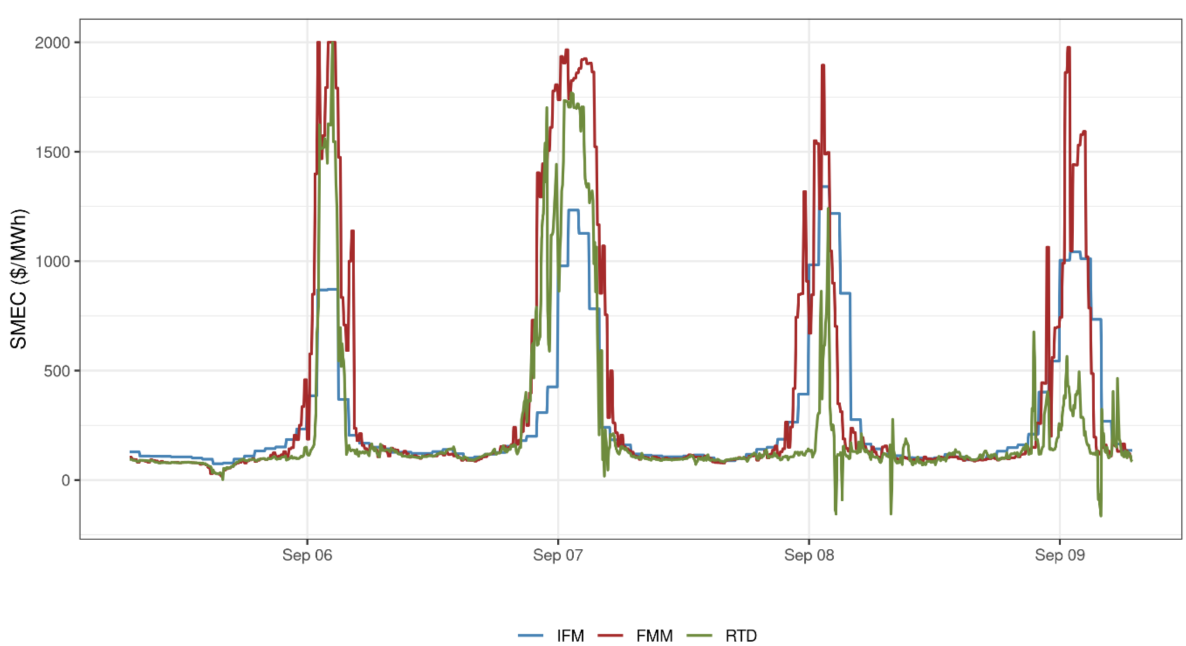


Figure 152 below shows a similar metric but for the System Marginal Energy Cost (SMEC) only, across the IFM, FMM, and RTD markets at an hourly average.

Figure 152: Interval-based SMEC across markets



SMEC values tracked overall LMPs relatively closely; however, the congestion component of FMM LMPs drove the overall LMPs higher on September 7. Prices in the RTM reached the bid cap level of $2000/MWh.

BY looking at the interval level SMEC prices, one can observe some RTD intervals in the hours after the peak time when the SMEC was negative. The SMEC reflects on the supply-demand balance in the area but will be an incomplete reflection of the system conditions when other factors, like congestion, are at play. Looking at only SMEC prices may result in less intuitive observations when there are negative prices during peak conditions. The comparison of the full LMPs in Figure 151 helps better explain such conditions. Although there were some RTD intervals in which there were negative SMECs, the full LMPs still resulted in positive and higher LMPs in the ISO area. High congestion on the COI RTD constraint drove such a result. From a transmission reference, ISO's locations are south of the constraint and when congestion occurred the congestion management required ISO resources to increase to provide counter flow congestion, and increasing generation will be reflected as excess of supply for power balance. Overall, the full LMPs still reflect the value of supply in the system and the negative SMEC is only a component that cannot be looked in isolation in an LMP-based market.

The hourly averages of the LMPs and SMEC prices across markets are also provided in the Appendix. Hourly averages show a smoother trend of prices.

The following figures show hourly IFM ISO intertie prices overlaid with bilateral market prices from the hub or hubs in close geographical proximity. Figure 152 shows the hourly trend of the Palo Verde and Mead ISO intertie prices, plotted against the Mead and Palo Verde hub prices traded on the bilateral market. Figure 153 shows the hourly trend of the Malin and NOB ISO intertie prices plotted against the Mid-C and NOB bilateral hub prices.

The bilateral prices tracked relatively closely for both on- and off-peak periods, with the exception of Mead and PV during the on-peak hours of September 7. The NOB hub did not trade an off-peak product during this period. The Mead on-peak price exceeded $1,000/MWh for September 6, but the on-peak prices for the rest of the bilateral hubs traded at or below $1,000/MWh. In general, bilateral hub prices remained below ISO intertie prices during peak hours; however, the Mead bilateral price on September 6 traded as high as the highest price realized on the Palo Verde and Mead ISO interties.

Figure 153: Hourly IFM intertie prices vs bilateral market prices, southern region

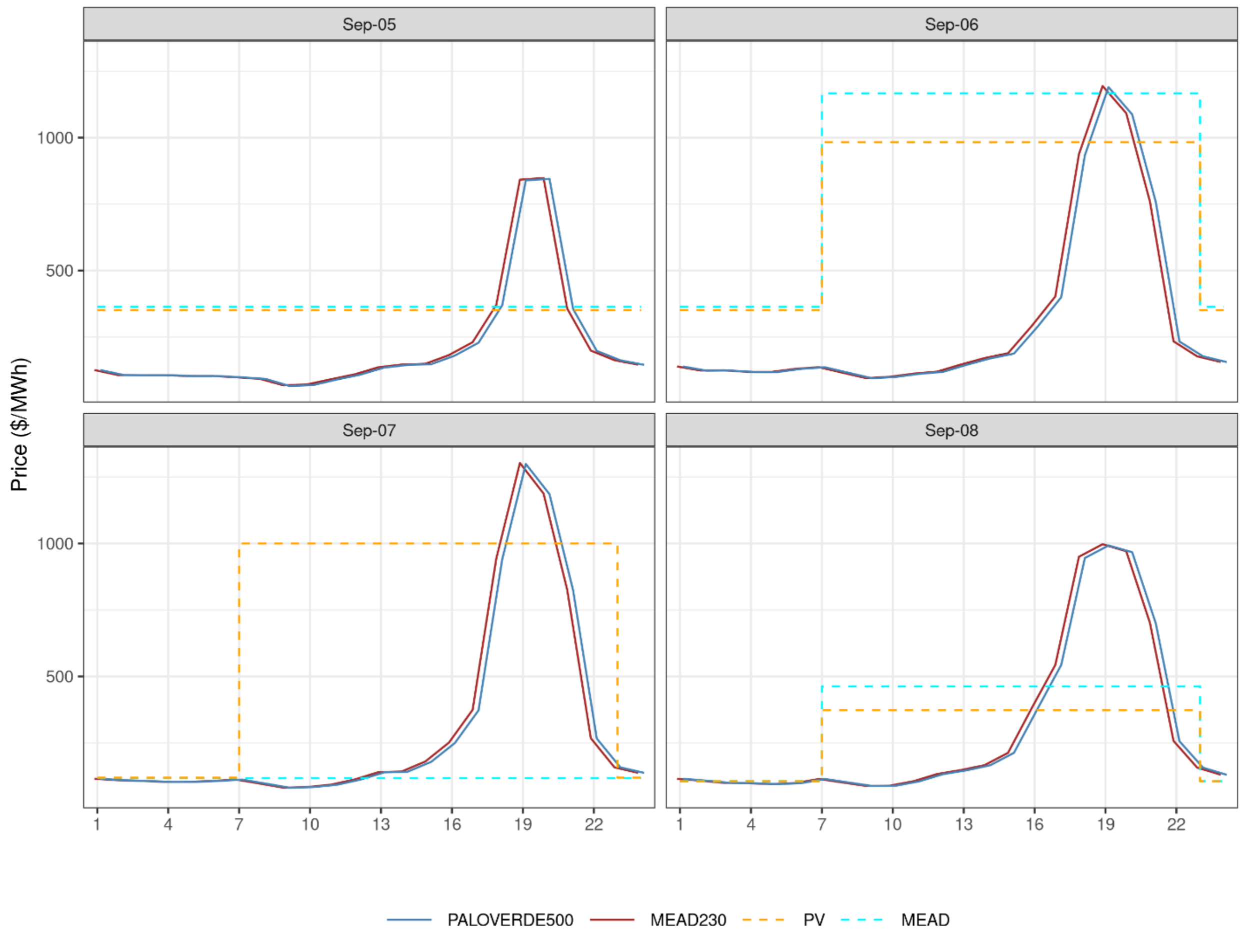
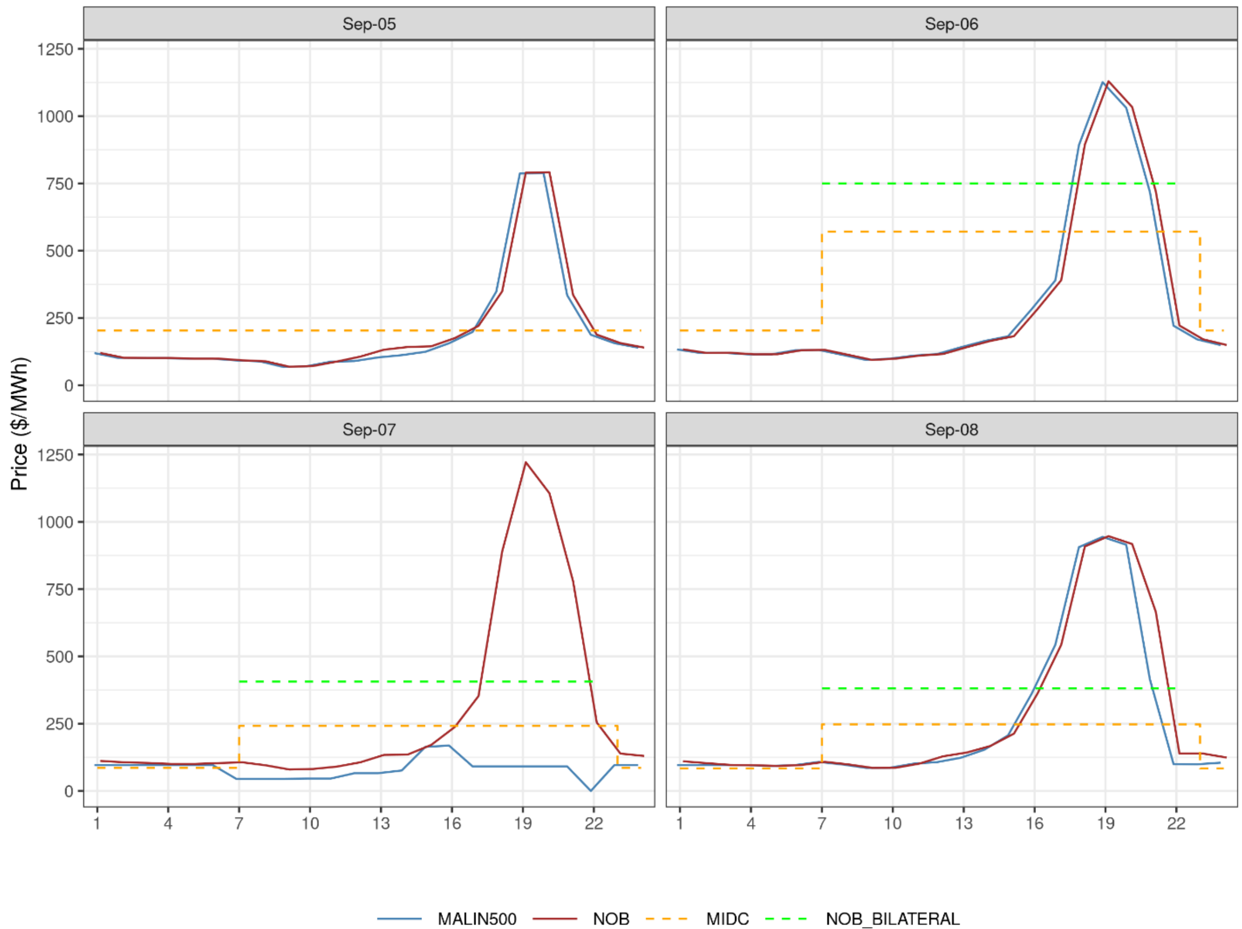


Figure 154: Hourly IFM intertie prices vs bilateral market prices, northern region



The figures below show the daily LMPs across the four DLAPs within the ISO area for each hour plotted separately instead of on average. This helps show whether there were any significant variations between DLAPs during the heat event. The black dashed line shows the average LMP across each hour. Note that the number of observations increases for each subsequent market due to the number of intervals within each hour. Specifically, there are four observations per hour for the IFM chart because there is only one IFM price per hour for each DLAP, however there are 48 observations per hour for the RTD chart because there are 12 RTD prices per hour for each DLAP.

Figure 155 shows that IFM LMPs for the four DLAPs track relatively closely to the average with some exceptions in the later afternoon and evening peak hours. Figure 155 shows more variability across FMM LMPs for the four DLAPs in the peak hours with outliers primarily materializing at the PG&E and SCE DLAPs. Figure 156 shows the most variability across RTD LMPs for the DLAPs, again in the peak hours but also in the morning hours on September 8. Some instances of low or negative RTD LMPs in the evening hours on September 8 drove the average RTD price down as compared to the same hours in other markets.

Figure 155 Daily LMPs across DLAPs, IFM

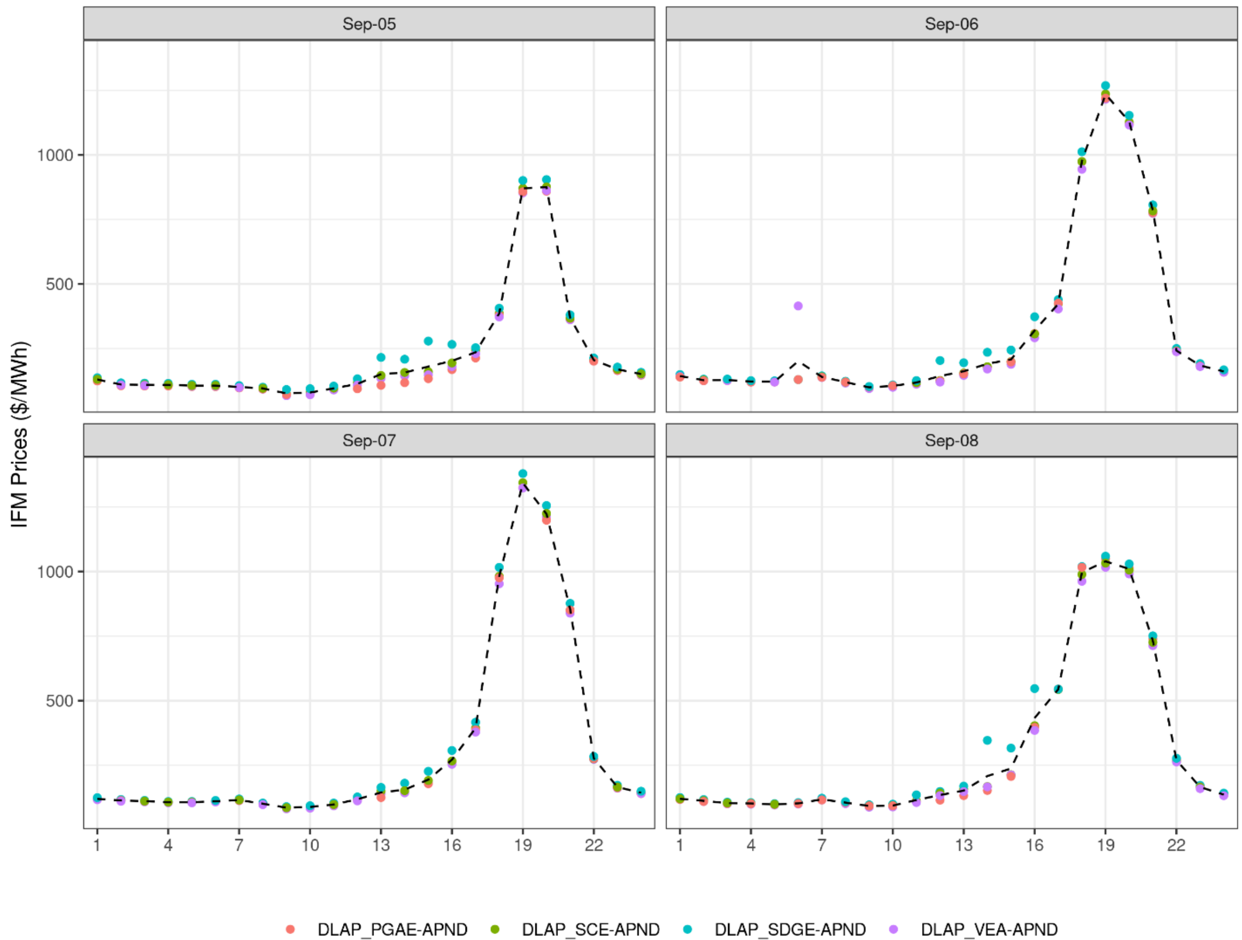


Figure 156: Daily LMPs across DLAPs, FMM

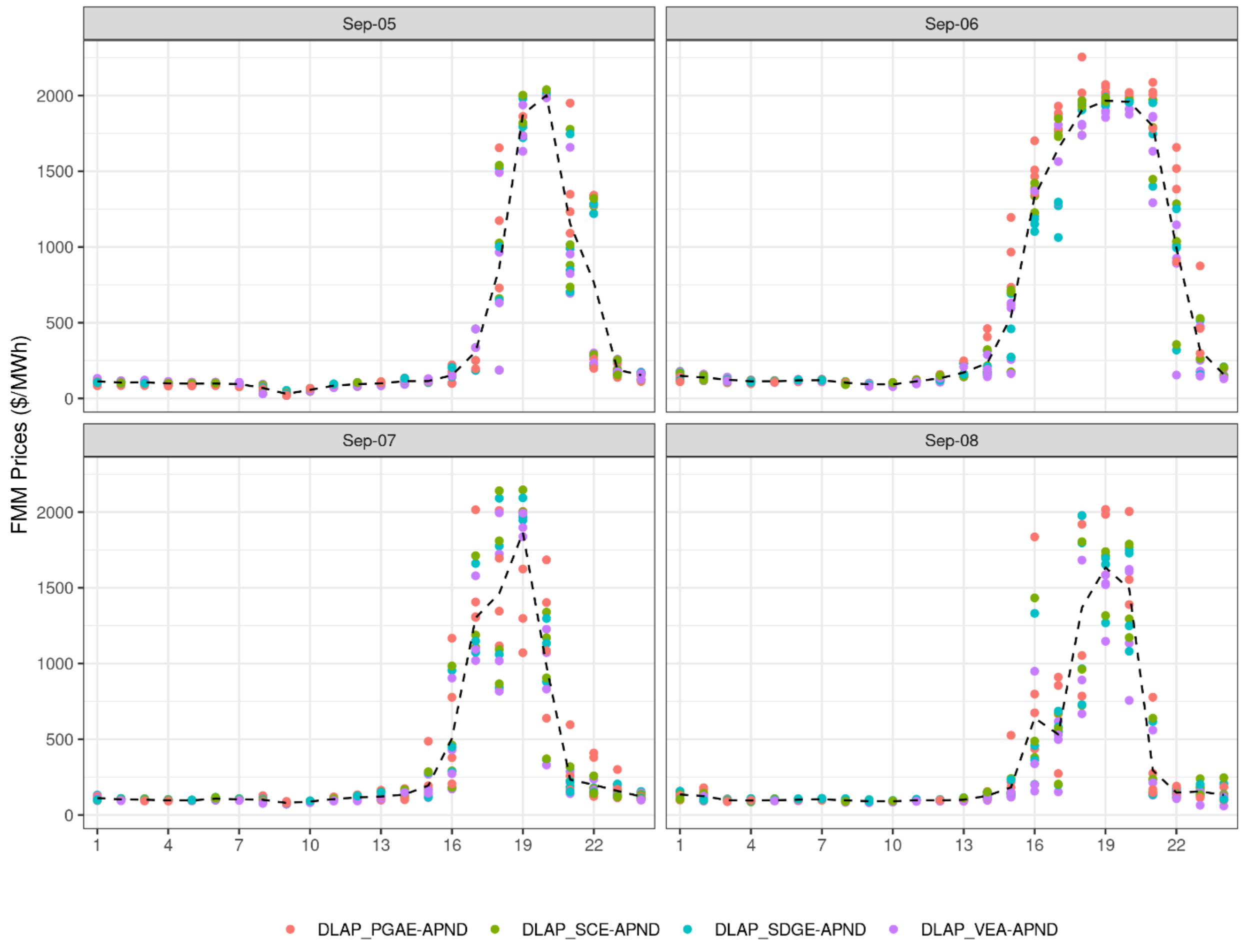
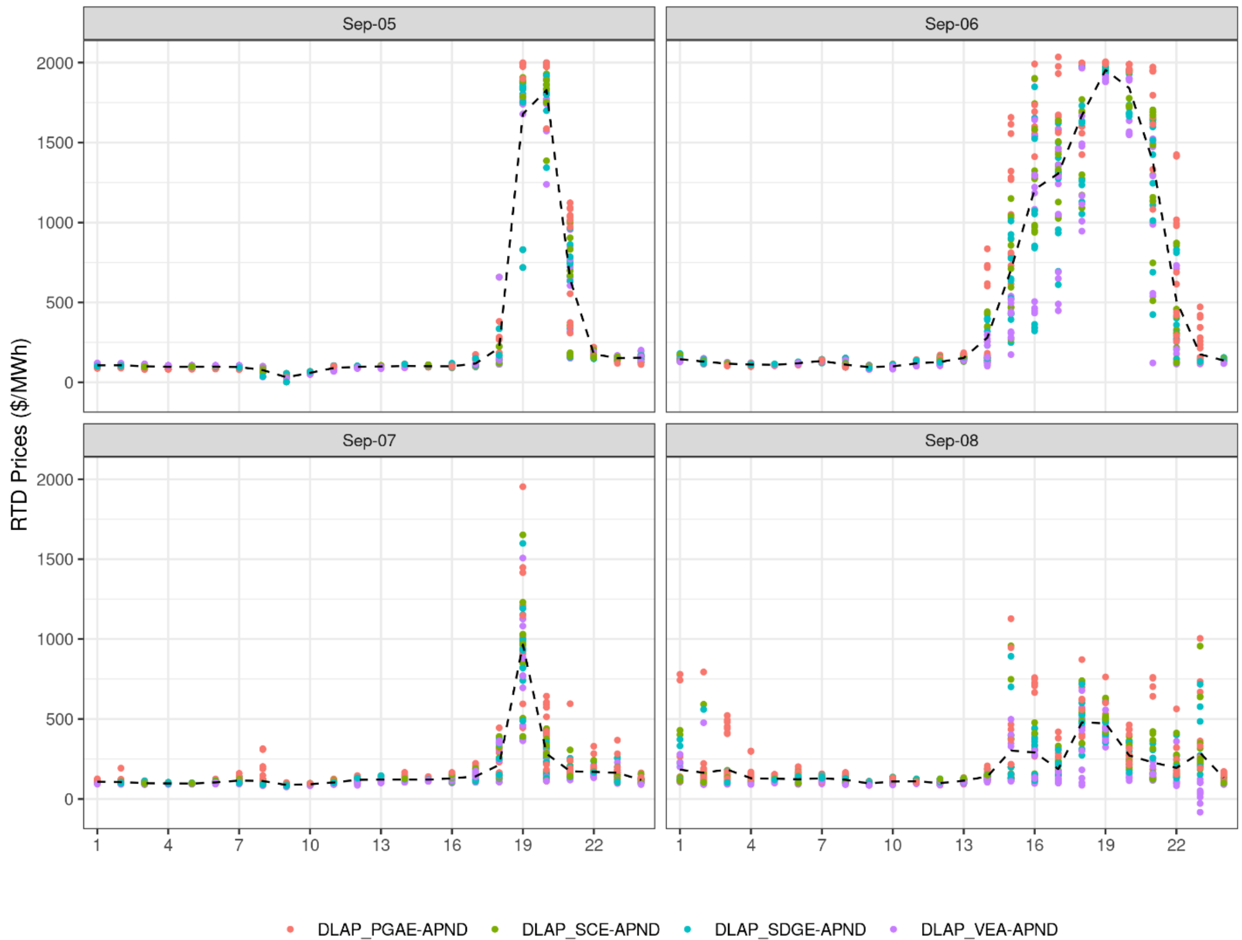


Figure 157: Daily LMPs across DLAPs, RTD



9.10 Bid caps and maximum import bid prices

During the heat event in early September 2022, the energy bid cap increased above $1,000/MWh for multiple days. While this has differing impacts depending on the type of resources, it did have wider impacts on the market. For example, it allowed for the SMEC in the DAM to increase above $1,000/MWh for the first time since August 2020. This section discusses some background about how the energy bid cap can be increased above $1,000/MWh, how the energy bid caps were set during the heat event, and how bids for various resource types materialized.

Background

In most ISO market runs, the energy bid cap is $1,000/MWh. However, the energy bid cap can be raised above $1,000/MWh and up to $2,000/MWh if the following conditions are met:

1. The ISO-calculated Maximum Import Bid Price (MIBP) exceeds $1,000/MWh or,
2. A scheduling coordinator submits a cost-verified energy bid above $1,000/MWh.

Operational experience over the past two summers has shown that it is more likely for the bid cap to be raised due to the MIBP exceeding $1,000/MWh, so this condition will be discussed in further detail.

When the MIBP exceeds $1,000/MWh, there are effectively three bid caps that are enforced within ISO's bidding platform – SIBR – depending on the type of resource for which bids are being submitted:

- $2,000/MWh: non-RA-backed import bids, reliability demand response resources (RDRRs) in the RTM, non-participating load, exports, and virtual bids,
- MIBP amount (ranges between $1,000-2,000/MWh): RA-backed import bids, or
- $1,000/MWh: resource-specific resources including generators, participating load, reliability demand response resources (RDRRs) in the DAM, tie-gens, non-generator resources (NGRs), and proxy demand response (PDR) resources.

Resource-specific resources can submit energy bids above $1,000/MWh (and up to $2,000/MWh) if they have the ability to prove that they have costs above $1,000/MWh, *i.e.*, cost-verify their bids.[67]

The MIBP is intended to approximate the prevailing bilateral energy prices outside the ISO's BAA on an hourly basis and is used to screen bids from specific resource types that are submitted in excess of the soft energy bid cap of $1,000/MWh. As discussed above, the MIBP being calculated above $1,000/MWh is one of two triggers to raise the energy bid cap to $2,000/MWh and to scale penalty prices in the market.

The MIBP is calculated at an hourly granularity and is comprised of three primary components: the bilateral electric price, the hourly energy price shaping factor, and a multiplier of 1.1. The bilateral electric price is set as the maximum of either the Palo Verde or Mid-Columbia next-day bilateral price as traded on the Intercontinental Exchange (ICE) for the applicable on-peak or off-peak hours. The hourly energy price-shaping factor is calculated as a ratio of the ISO hourly day-ahead SMEC to the ISO average day-ahead SMEC for a recent high-priced day.[68]

Whether or not the MIBP exceeds $1,000/MWh depends on high prices in the bilateral energy market, a high hourly energy price shaping factor due to elevated day-ahead SMEC, or some combination of the two.

SIBR functionality

During the heat event in early September, some questions were raised about how and when the energy bid caps change. While the ISO did provide training on the functionality during the implementation of FERC Order 831[69] and has the technical details described in its BPM and SIBR User Guide[70], the ISO believes that the number of questions received regarding this topic warrants additional discussion.

---

[67] Details on cost-verified bids can be found in the BPM for Market Instruments Attachments O and P
[68] Details on the Max Import Bid Price (MIBP) calculation can be found in the BPM for Market Instruments, Attachment P.2
[69] http://www.caiso.com/Documents/Presentation-FERC-Order-831-Import-Bidding-Market-Parameters-Training-Apr-28-2021.pdf
[70] http://www.caiso.com/Documents/SIBR-Scheduling-Coordinator-User-Guide.pdf

The effective bid cap is communicated in SIBR on the Messages tab and is an hourly value. When the Messages tab displays a value of $1,000/MWh, a $1,000/MWh energy bid cap is enforced for all resources. When the Messages tab displays a value of $2,000/MWh, the energy bid caps described previously above apply.

In theory, the energy bid cap can change at any point during an open market bidding window if a cost-verified energy bid is successfully submitted above $1,000/MWh. However, as mentioned above, experience shows that the MIBP is more likely to be the factor that increases the bid cap above $1,000/MWh. The MIBP has a pre-defined calculation timeline whereby the DAM MIBP is calculated twice (once around 2:00AM PST and again around 9:00AM PST) and the RTM MIBP is calculated once (around 10:00PM PST). These timelines are based around the availability of the bilateral electricity price indices from ISO's vendors.

Once a new MIBP is received, SIBR will perform an automated revalidation of submitted bids. This revalidation has the potential to invalidate previously accepted bids above $1,000/MWh if the effective bid cap decreases down to $1,000/MWh. ISO observed several such instances during the heat event, particularly when the bid cap was calculated around 2:00AM was above $1,000/MWh but decreased to below $1,000/MWh was re-calculated around 9:00AM. These changes occurred due to more up-to-date bilateral electricity price indices received from the ISO's vendors.

Other repercussions of raising the energy bid cap

In addition to the ability for scheduling coordinators to submit higher bids, the increase of the energy bid cap above $1,000/MWh triggers other events:

- Scaling market penalty parameters: the increased bid cap automatically triggers the various penalty parameters in the market to be scaled based on $2,000/MWh. This functionality has been in place the implementation of FERC Order 831 in 2021.[71]
- Changes to allowable RDRR bid price range in the RTM: The increased bid cap also causes adjustments to the RDRR bid price range in the RTM. When the bid cap is $1,000/MWh, RDRR resources' bids must be between $950-1,000/MWh. This range doubles to $1,900-$2,000/MWh when the bid cap increases above $1,000/MWh. This functionality is only effective in the RTM.[72]

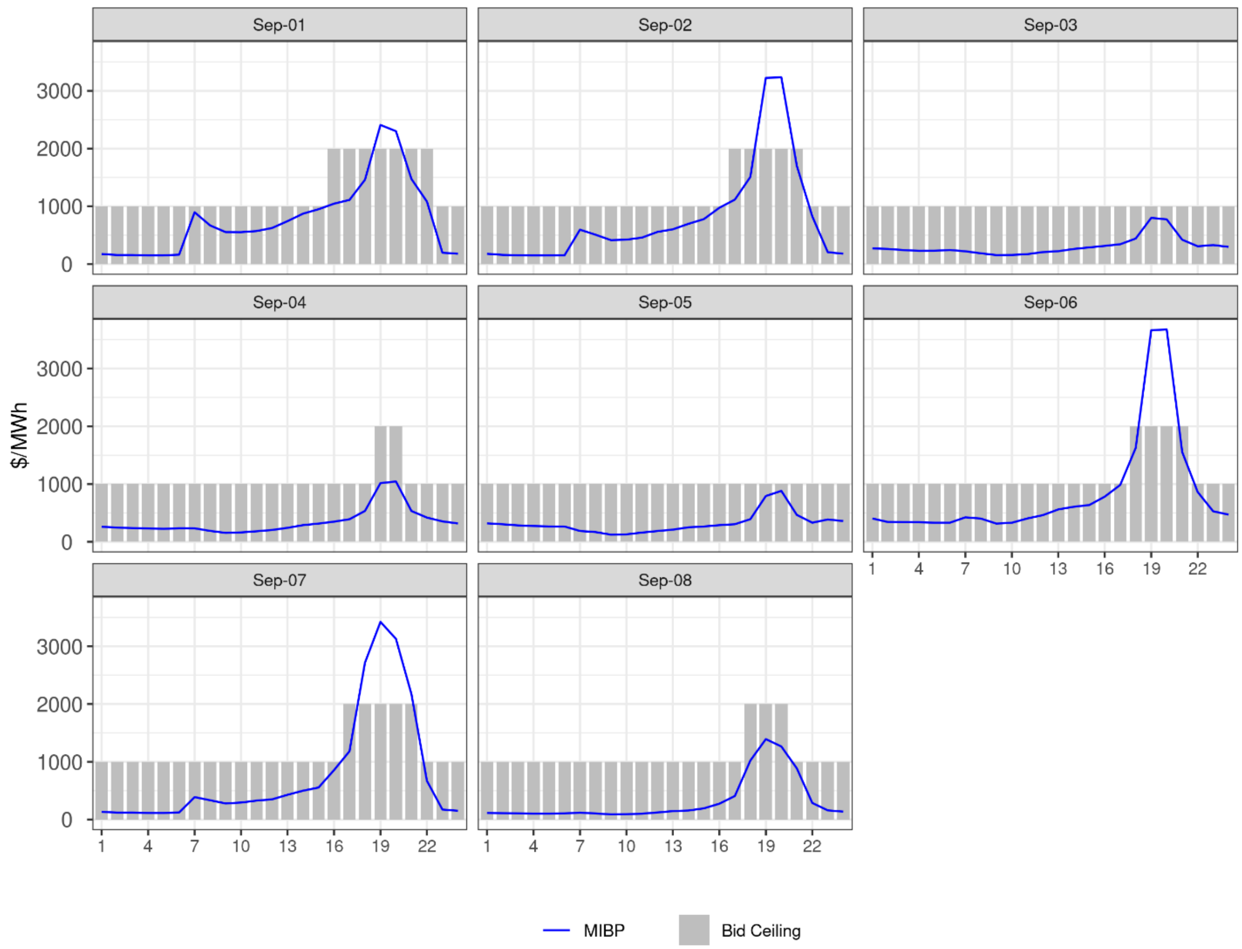
Performance of the maximum import bid price

As discussed above, one of the main drivers of the calculated MIBP value in the day-ahead market is day-ahead 16 hour block bilateral energy prices from the Palo Verde and Mid-Columbia hubs as sourced from the Intercontinental Exchange (ICE). Similarly, the MIBP value for real-time is calculated when system conditions began to tighten starting in the beginning of September, bilateral energy prices rose. Figure 158: shows the MIBP compared to the effective bid cap for the period of September 1-8 for the day-ahead market, and Figure 159. shows the same information for the RTM. In both figures, the MIBP values are shown over a longer timeframe beyond just September 5-8 to illustrate the dynamics for each day and

[71] More information about the penalty parameters can be found in Section 6.6.5 of the BPM for Market Operations.
[72] This functionality has been in place since the implementation of the RDRR Bidding Enhancements Phase 1 initiative in Spring 2022. More information about this functionality can be found in BPM for Market Instruments Attachment P.

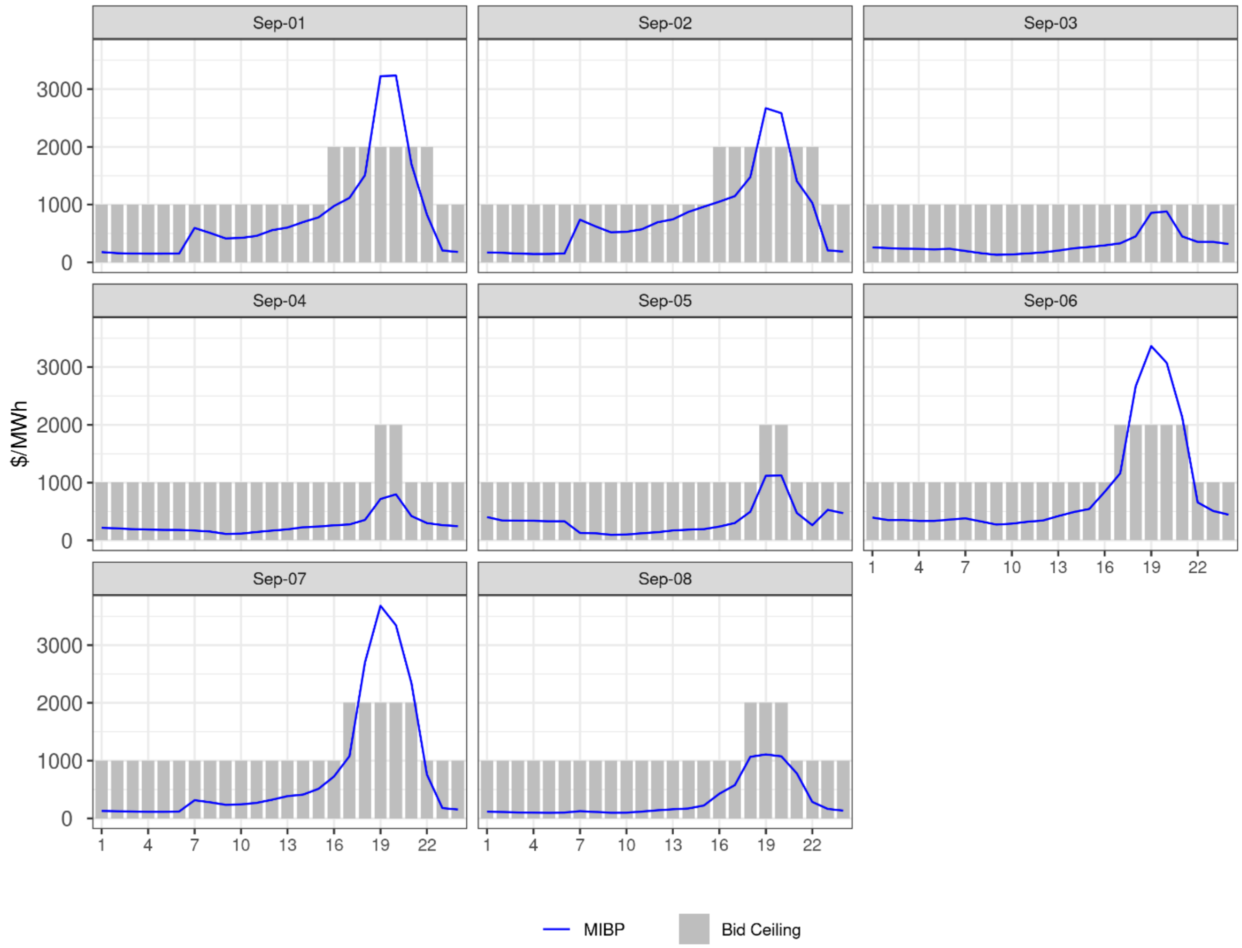
market that the bid cap was raised to $2,000/MWh. The bid cap was raised to $2,000/MWh for 26 hours in the day-ahead market and 31 hours in the RTM.

Figure 158: Day-Ahead MIBP and energy bid caps, September 1 to 8



In general, during the heat event, the Palo Verde bilateral hub price traded higher than the Mid-Columbia price for on and off-peak strips and was typically the bilateral hub price used to set the MIBP. Note that although the MIBP values may rise above $2,000/MWh in the figures below, the market still enforces a $2,000/MWh hard energy bid cap, so in circumstances where the actual numerical value of the MIBP is important (*i.e.*, setting the bid ceiling for RA-backed imports), a cap of $2,000/MWh is still imposed. However, it is helpful to see how high the MIBP was calculated above $2,000/MWh to illustrate how elevated the bilateral hub prices were during this period. A high MIBP value is influenced by a combination of high bilateral hub prices and a high hourly price-shaping factor, set based on day-ahead prices. For each day and market during the heat event, both factors influenced the MIBP to varying degrees.

Figure 159. Real-Time MIBP and energy bid caps, September 1 to 8



Resource Bidding

In order for the higher bid caps to have a market impact, market participants must react to the adjusted bid caps by offering supply at prices above the lower bid cap. Offering supply that has costs above the lower bid cap level increases supply and helps ensure the locational marginal prices are indicative of the scarcity of supply. This price signal in turn incents more high cost supply to offer into the market. This section will discuss how market participants adjusted their bidding behavior in reaction to the adjusted bid caps.

As discussed in the previous section, there were 26 hours in the DAM and 31 hours in the RTM in which the bid caps were increased above $1,000/MWh between September 1 and September 8. In each of these intervals, at least one market participant offered supply at prices exceeding $1,000/MWh. However, energy bids above $1,000/MWh were only submitted for non-RA backed imports at ISO interties and for RDRRs. No generating resources or NGRs submitted bids above $1,000/MWh because, in order to do so, these resources must cost-verify their bids with the ISO. It is also notable that no RA-backed imports submitted bids above $1,000/MWh.

Figure 160 shows a representative hour for DAM September 6 during which the energy bid cap was increased above $1,000/MWh. The different colored bars represent the various resource types for which bids were submitted. Only the highest 10,000 MW of bids are shown to give a better view of the highest end of the bid stack. Note that this figure only displays economic bids, so many of the imports that were self-scheduled into ISO's BAA are not shown.

In the example below, the bids above $1,000/MWh in the DAM are dominated by virtual supply, *i.e.*, convergence bids that do not represent physical supply, with the remainder of the bids above $1,000/MWh being non-RA imports and non-participating load. Other resource-specific resources like generating resources and NGRs bid at or just below $1,000/MWh. For resource-specific resources, the submitted bids may not be what the market optimization will use to create resource schedules if the submitted bids are mitigated during ISO's local market power mitigation process. Additionally, there was also a meaningful volume of virtual demand at bid prices above $1,000/MWh.

Figure 160: Bid stack for DAM September 6, hour-ending 19

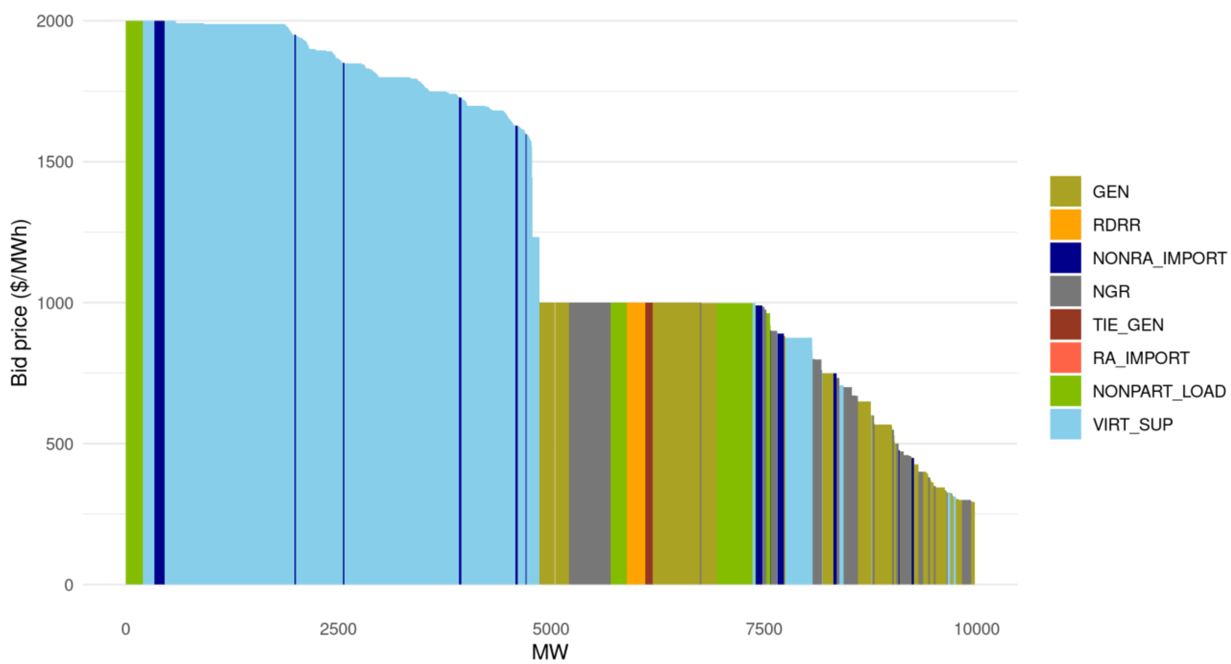


Figure 161 shows the same metric as displayed above but for RTM. This representative example gives a better perspective of the capacity available in real-time and shows a markedly different picture than the DAM. First, all of the virtual supply is gone as virtual bidding does not occur in the RTM. Second, a substantial amount of capacity of RDRR bids are submitted at the high-end of the bid stack. Finally, it is clear that there was very little import capacity bidding economically in the constrained hours of the heat event. This is likely due to many imports being self-scheduled into the ISO's BAA. It is noteworthy that many NGR resources offered supply at the $1000 offer cap, which would result in them being dispatched any time the price exceeded $1000 rather than preserving state of charge for hours when prices were even higher.

Figure 161: Bid stack for RTM on September 6, hour-ending 19

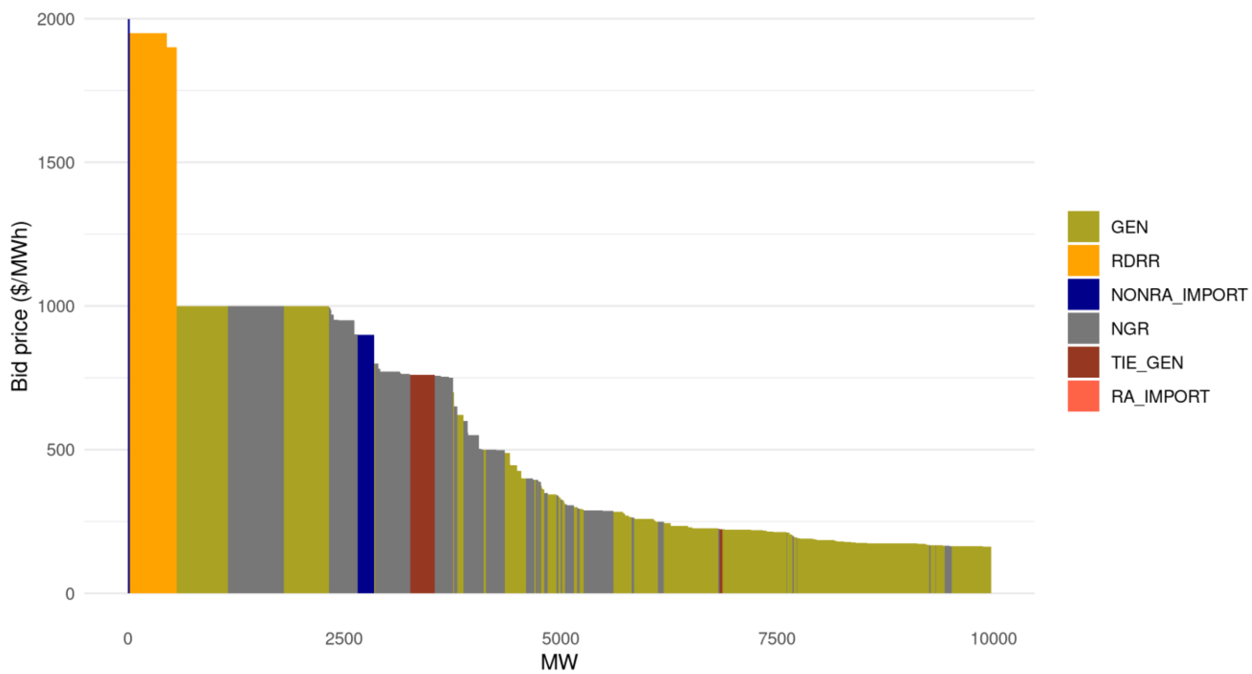


Figure 162 below shows the percentage of non-RA imports that submitted DAM bids above $1,000/MWh during the hours in which the bid cap was increased for the period of September 1 through September 8. For example, if, for DAM September 4, there were 1000 MW of bids submitted for non-RA imports but only 68 MW of bids were submitted above $1,000/MWh, the figure would show 6.8 percent. If a value is missing, this indicates that the bid cap did not exceed $1,000/MWh for that hour (e.g. all values are missing for September 3 because the bid cap was set at $1,000/MWh for all hours during that day). Self-schedules are not included in the MW figures for this figure. Figure 163 shows the same percentages but for RTM bids.

One observation is that the higher bid caps were more fully utilized in the DAM compared to the RTM. This is likely due to more certainty in real time and SCs' ability to adjust their bids as conditions progressed. There were also no intervals in which the bidding headroom was fully utilized by non-RA imports. This could be due to scheduling coordinator expectations of what prices would materialize and calibrating their bids to be high but not so high that the offers would price their supply out of the market. It could also be due to some scheduling coordinators not being aware that the bid cap exceeded $1,000/MWh in the impacted hours.

The ISO does not show similar figures for generating resources, NGRs, or RA-backed imports because none of these resource types submitted bids above $1,000/MWh so the figure would show only zeroes. Conversely, in the RTM hours in which the bid cap was increased, RDRRs must bid between $1,900-2,000/MWh so the figure would show only 100 percent amounts.

Figure 162: Percent of eligible DAM bids above $1000/MWh for non-RA import resources

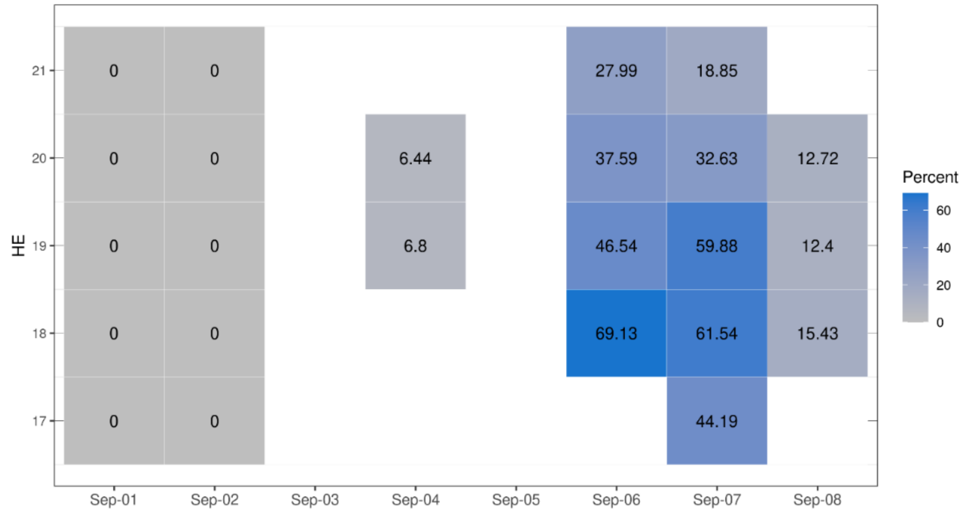
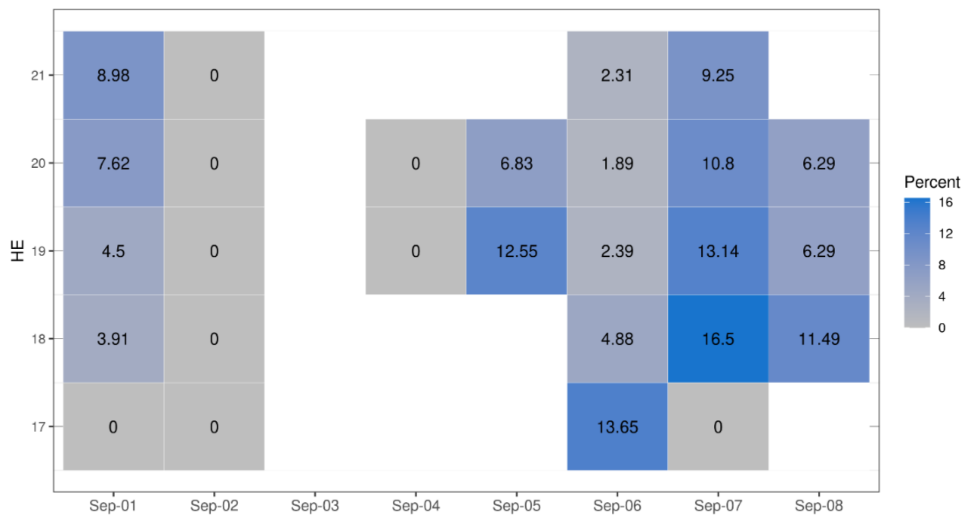


Figure 163 Percent of eligible RTM bids above $1000/MWh for non-RA import resources



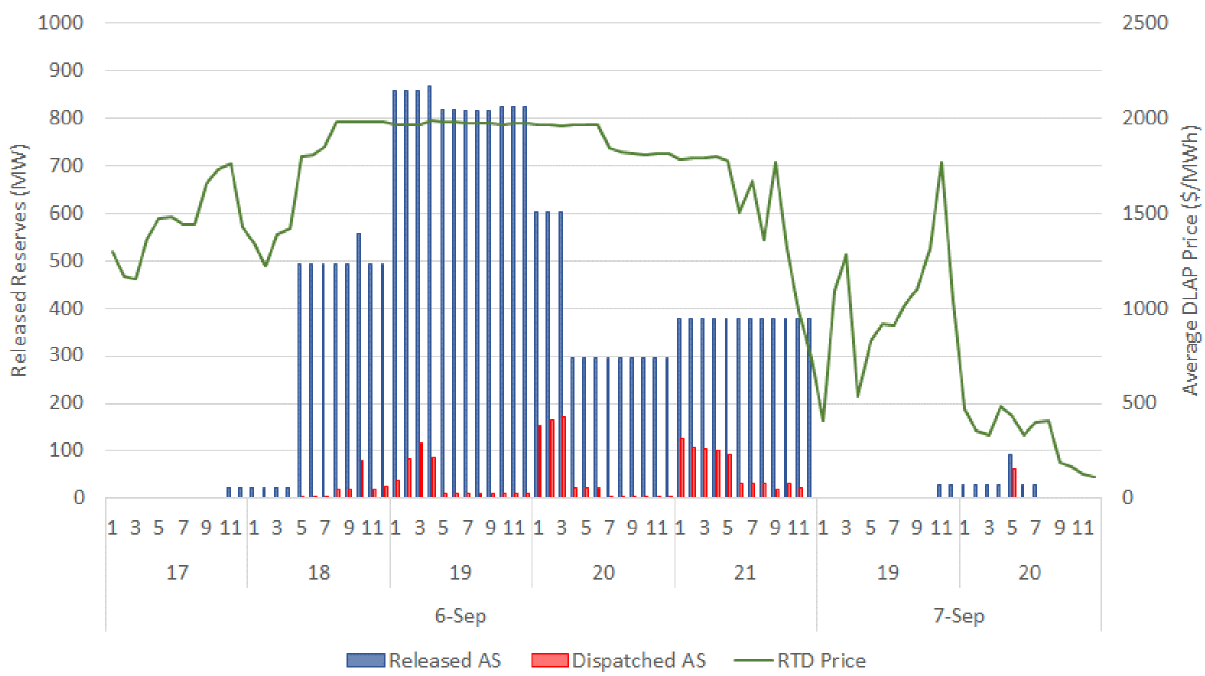
9.11 Scarcity pricing

On June 15, 2021 the ISO implemented a new pricing measure that during intervals in which the ISO is arming load to meet contingency reserve requirements, the ISO will release both the contingency and non-contingency operating reserves at the bid cap price. This will set prices at the applicable bid cap when there is insufficient generation supply to meet both energy and contingency reserve requirements and the released operating reserves are dispatched for energy. When the ISO is in an Energy Emergency Alert 3 it is allowed to use generators providing contingency reserves to serve demand and meet its contingency reserve requirement by arming load. ISO generally enters into Energy Emergency Alert 3 with the intent to begin "arming load" to meet reserve requirements. "Arming load" is a process where the ISO system operators inform load-serving entities to make all preparations necessary to be able to drop load in a controlled manner, but is not actually instructing dropping load.

Figure 164 shows the total ancillary service released in the market and the total ancillary services dispatched in the five-minute market. During HE 17 through 21 on September 6 and HE 19 and 20 on September 7, operating reserves capacity from multiple resources were released from the energy market at the energy bid cap. Once this energy is available in the energy bid stack, these resources were considered in the market clearing process in economic merit order to be dispatched for energy.

The green line shows the average default load aggregation point (DLAP) price observed during these intervals and they are generally in the range of the bid cap such that the capacity coming from the released operating reserves cleared economically. There were several intervals within the timeframe mentioned, in which capacity from these resources were still dispatched for ancillary services as seen from the red bars in the figure below.

Figure 164: Release of contingency reserves and volume cleared in the market



10 Market Issues

Through the analysis of the market outcomes and performance during the month of September 2022, a number of market and software issues were identified. These issues either have already been addressed or are being addressed. The issues are summarized here but have been discussed in more detail in the relevant sections of this report.

1. A software issue prevented storage resources from bidding to charge at a price higher than $150/MWh. This resulted in those resources not being able to charge more even when in merit. This issue was fixed on September 9, 2022. Furthermore, the current construct contributed to premature discharge and required recurrent use of exceptional dispatch to maintain adequate state of charge to meet demand at the net load peak.

2. A software issue resulted in incorrectly accounting for the resource awards to provide ancillary services in applying the capacity test. This resulted in over-counting the available up capacity in the test calculation and, therefore, increased the likelihood that the ISO would pass the resource sufficiency. This issue was fixed on September 9, 2022. The ISO is also evaluating software enhancements to better reflect the initial state of charge and its use in the base schedule when calculating the upward capacity on storage resources.

3. A software issue in the treatment of blocked curtailments for exports resulted in two incorrect results. First, it considered some of the curtailed export in real-time even though the intent was to allow the high-priority export to flow. This was mitigated partially by operators reinstating the original exports. Second, the original curtailments were consumed in the capacity test even though they were indeed blocked in the market and flowing in the system. This resulted in the capacity test to under-count export obligation in up capacity and, therefore, resulted in a more optimistic capacity test for ISO. This fix is still under assessment.

4. Unintended interplay between scheduling priority logic with pricing enhancement logic. The scheduling priorities are set up as intended for the scheduling run; however, in the pricing run all priorities are limited by the bid cap and floor. During the heat wave, some export curtailments in the scheduling run were not realized in the pricing run. This resulted in low priority exports being awarded but also PT exports being curtailed. However, as described earlier, reductions of PT exports are by default blocked from transmitting unless operator approves to transmit reduced PT exports. This issue interacted with the issue described in item 1 above in this list. This issue resulted in low priority exports not being curtailed as they should have been, increasing the likelihood that the ISO would fail the resource sufficiency capacity evaluation. ISO is implementing an enhancement to the pricing run logic to preserve more closely the schedule solution in the pricing run. This enhancement was put in the market on October 13, 2022.

5. The logic to calculate the up capacity for resources coming back from outages did not correctly capture the conditions of two MSG units. They could not come back online within the timeframe of the resource sufficiency capacity evaluation but the test nevertheless included their up capacity in the evaluation. On the other hand, there was also a different logic issue in which an MSG unit's configuration status was not correctly accounted for in applying the resource sufficiency capacity evaluation, resulting in an under-counting of its up Capacity.

6. The unloaded capacity made available by arming load and dispatching contingency reserves was not included in the resource sufficiency capacity evaluation, therefore increasing the likelihood that the ISO would fail the resource sufficiency capacity and flexibility evaluations.

Appendix A: WEIM Weather Conditions

Temperature Conditions

Beginning with to the desert southwest WEIM entities in Figure 165, there was a trend similar to the ISO with above normal temperatures at the beginning of the month, then a shift to below normal for the middle, before ending the month above normal. While there were periods of above normal temperatures, there were not as extreme as California and parts of the Pacific Northwest experienced.

Figure 165: Maximum temperature departure from normal for select desert southwest WEIMs

Arizona Public Service (APS)

High temperature departure from normal

September 2022

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 3	2 4	3 3
4 5	5 7	6 7	7 3	8 1	9 -3	10 -10
11 -0.7	12 -6	13 -7	14 -6	15 -4	16 -4	17 -1
18 0.8	19 2	20 -3	21 -12	22 -6	23 0.7	24 3
25 5	26 7	27 5	28 4	29 4	30 2	
				days < normal 12	days > normal 18	Deg +/- normal + 0.1

above normal	below normal	Normals: 1990-2020

Public Service Company of New Mexico (PNM)

High temperature departure from normal

September 2022

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 -0.9	2 3	3 -0.7
4 0	5 3	6 3	7 5	8 3	9 1	10 -0.2
11 -6	12 -2	13 -2	14 -6	15 -2	16 2	17 4
18 4	19 3	20 2	21 2	22 2	23 2	24 2
25 -0.1	26 -0.2	27 0.7	28 1	29 -1	30 -0.3	
				days < normal 13	days > normal 17	Deg +/- normal + 0.8

above normal	below normal	Normals: 1990-2020

Like CISO*, the Pacific Northwest entities also have periods of extreme temperatures in September, largely located at the beginning of the month. This is shown in* Figure 165 and due to the same weather feature bringing the heat for CA also impacting the Pacific NW. During the period of September 1-7, Idaho had 121 locations that tied or broke the record for warmest temperature recorded during the month of September. Glenns Ferry, ID reached 109°F on September 1, breaking the previous hottest September temperature record of 107 set in 1905.

Figure 166 High temperature departure from normal for select Northwestern WEIMs

Portland Gas and Electric (PGE)

High temperature departure from normal

September 2022

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 10	2 8	3 -2
4 6	5 2	6 13	7 5	8 2	9 10	10 9
11 0.4	12 -3	13 -5	14 -3	15 -2	16 -7	17 -5
18 2	19 8	20 9	21 2	22 -1	23 0.7	24 6
25 14	26 15	27 9	28 -2	29 -3	30 -0.1	
				days < normal 11	days > normal 19	Deg +/- normal + 3.3

above normal	below normal	Normals: 1990-2020

Idaho Power Company (IPCO)

High temperature departure from normal

September 2022

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 11	2 11	3 16
4 12	5 11	6 16	7 17	8 2	9 -6	10 -0.8
11 5	12 4	13 -7	14 -1	15 -3	16 -3	17 -3
18 0.9	19 5	20 8	21 -1	22 -8	23 -2	24 4
25 7	26 11	27 16	28 15	29 0.1	30 -5	
				days < normal 11	days > normal 19	Deg +/- normal + 4.4

above normal	below normal	Normals: 1990-2020

ISO's hourly average prices

Figure 167: DLAP-average daily LMPs across markets

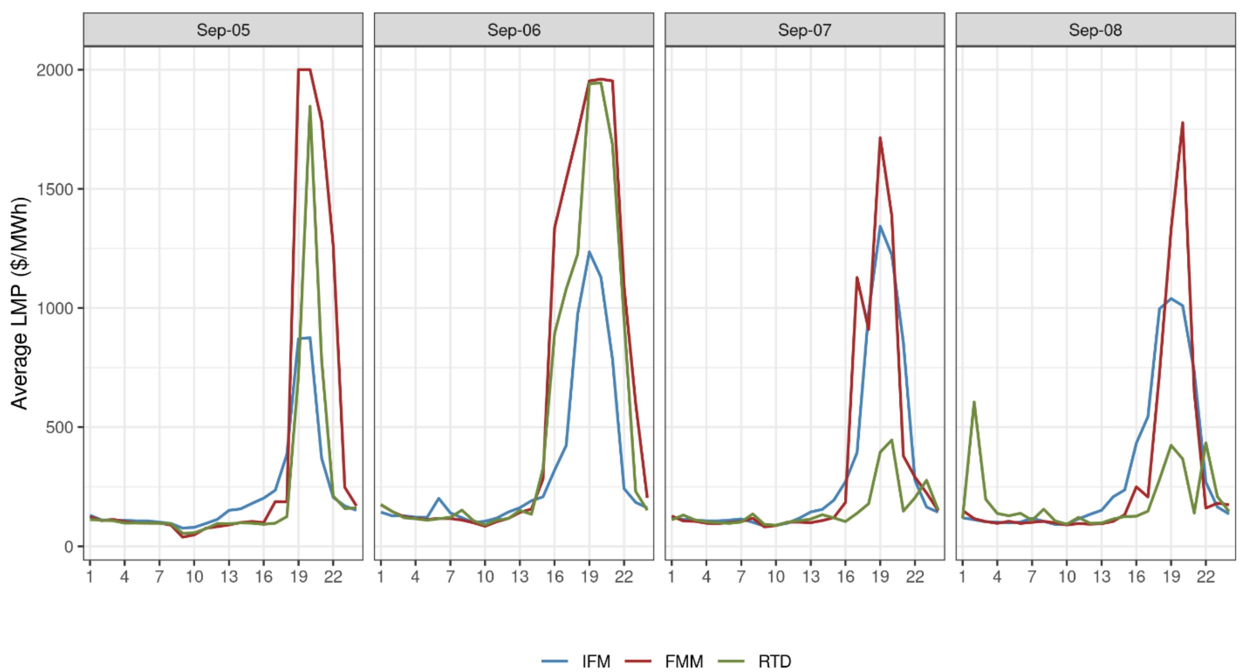


Figure 168: Hourly averages of SMEC across markets