SUMMER MARKET PERFORMANCE REPORT

July 2023

Sept. 18, 2023

The following staff from the California ISO contributed to this report:

Jennie Araj

Gary Delsohn

Kevin Head

Abhishek Hundiwale

Scott Lehman

Zhu Liang

Haifeng Liu

Nick Messner

Amber Motley

Monique Royal

Cristy Sanada

John Rudolph

Jessica Stewart

Auswin Thomas

Katie Wikler

Kun Zhao

Guillermo Bautista Alderete

Content

List of Figures

Acronyms

AET	Assistance Energy Transfer
AZPS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
ISO	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
DSW	Desert Southwest
ED	Exceptional Dispatch
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capacity
ELRP	Emergency Load Reduction Program
EPE	El Paso Electric
ESP	Energy Service Provider
ETC	Existing Transmission Contract
F	Fahrenheit
FMM	Fifteen Minute Market
GIA	Generator Interconnection Agreement
GNRC	Generic non-generating resources
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IID	Imperial Irrigation District
IOU	Investor-Owned Utility

IPCO	Idaho Power Company
LADWP	Los Angeles Department of Water and Power
LESR	Limited Energy Storage Resource
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
MAPE	Mean Absolute Percentage Error
MNS	Market Notification System
MNW	Mountain Northwest
MSG	Multi-Stage Generator
MW	Megawatt
MWh	Megawatt-hour
NEVP or NVE	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
PNW	Pacific Northwest
PRM	Planning Reserve Margin
PSEI	Puget Sound Energy
PST	Pacific Standard Time
PTO	Participating Transmission Owner

PTK	High priority assigned to a schedule. Exports are assigned this priority when they can have a non-RA resource supporting its export.
QC	Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RMO	Restricted Maintenance Operations
RSE/RSEE	Resource Sufficiency Evaluation Enhancements
RTM	Real-Time Market
RTPR	Real-Time Price Taker
RUC	Residual Unit Commitment
SCL	Seattle City Light
SMEC	System Marginal Energy Component
SOC	State of Charge
SRP	Salt River Project
STUC	Short-Term Unit Commitment
TIDC	Turlock Irrigation District
TOR	Transmission Ownership Right
WECC	Western Electricity Coordinating Council

1 Executive Summary

Introduction

Operational conditions so far this summer have been significantly less strained than a year ago when California experienced a record heat wave in September that drove unprecedented demand for electricity. In the summer of 2023, temperatures have been less extreme and the state has been better positioned from a resource adequacy perspective due to strong hydro production resulting from record snowpack and significant amounts of generating and storage resources that have been added to the system. In the Summer of 2023 thus far, demand for electricity in California has been relatively moderate in contrast to the high levels of demand in other parts of the Western Electricity Coordinating Council (WECC) where demand was at 94 percent of its all-time peak in July, with particular strain seen in the Desert Southwest driven by sustained record-setting heat and below-average Pacific Northwest hydro conditions.

In many ways, conditions this July were the mirror image of last September when California experienced extreme heat and demand and other regions were able to supply California with power to help maintain reliability in the state. Nevertheless, there were several days in July when conditions required issuing Energy Emergency Alerts that enabled the use of additional tools and resources to balance supply and demand on the ISO-managed grid. On July 20, 25 and 26, 2023, the California Independent System Operator (ISO) issued Energy Emergency Alerts during late evening peak hours that reached Energy Emergency Alert Level 1 (EEA 1) and EEA Watch levels. Despite the rapidly evolving and challenging system conditions, through prompt actions of ISO operators and its effective coordination with market participants and neighboring balancing areas, the ISO operated the grid reliably without escalating to higher emergency stages or implementing rotating outages.

This Summer Monthly Performance Report for July 2023 details the ISO's analysis of factors contributing to the aforementioned events and reports on measures taken to preserve system reliability. This report also describes lessons learned and the procedural and system enhancements to avoid similar conditions in the future. These include: managing the reduction of exports, enhancements to market participant practices, and development of procedures and mechanisms to more effectively position resources within real-time operations. Finally, in addition to a review of specific July events, this report includes an assessment of broader market performance for the month of July.

July 2023 Events

The ISO balancing area reached an instantaneous gross peak of 43,545 MW on July 25 at 18:27 hrs, marking the highest peak demand of the year thus far. However, this peak fell significantly below the record peak demand of 52,061 MW recorded in September 2022. During the grid events of both 2022 and 2023, the ISO faced its most challenging system conditions during the net load peak, which is the period when solar production drops to zero as the sun sets and demand remains.

Still, resource adequacy supply in July was deemed adequate to meet projected load obligations, and the July events were not the result of a shortage of forward capacity to meet peak demands. Instead, the emergency alerts were driven by a confluence of rapidly emerging intra-hour conditions in real time that could not be anticipated far in advance, resulting from a combination of moderate internal and higher external demand during net peak hours, when ramping capability needs to offset the loss of solar production are highest.

The real-time market uses the flexible ramping product to secure ramp capability and respond to a prescribed level of uncertainty during the time horizon of the real-time market, with the amount of prescribed uncertainty based on estimated variation of load and renewable resources. However, the flexible ramping product does not procure capacity to respond to other types of supply changes, such as unexpected outages and loss of imports. Because the rapidly emerging intra-hour conditions observed in July were not the type of events the flexible ramping product is designed to capture, the flexible ramping product had limited success addressing emerging uncertainty issues.

July 20, 2023

On July 20, the ISO issued an EEA1, the first occurrence of an Energy Emergency Alert this summer. This was prompted by rapidly evolving grid conditions observed during real-time operations and, unlike grid events in 2020 and 2022, these evolving grid conditions were not projected far in advance. Two days before July 20 and in the day-ahead market results for that day, the market showed adequate supply to meet the projected demand but with thinning capacity margins to absorb changes in supply or demand. The reliability run of the day-ahead market (*i.e.,* the Residual Unit Commitment or RUC), included an adjustment to the procurement target of 4,000 MW to account for renewable and load uncertainties. This resulted in the determination that 900 MW of economic and low-priority exports cleared in the day-ahead energy market could not be supported for hour ending 20, *i.e.* 20:00 hrs. This adjustment was in line with others made in the immediate preceding days with similar conditions forecasted in the day-ahead timeframe. By reducing 900 MWs of low-priority exports, operators mitigated upward pressure on supply and there was no indication further actions were required in the day-ahead timeframe.

In the real-time, the combination of moderate loads but a substantial volume of exports cleared in the market driven by elevated demand in the West, mainly from the Desert Southwest, resulted in diminished net imports during the net load peak. The results of the Hour-Ahead Scheduling Process (HASP) for HE20 first saw sufficient bids to meet demand, including load conformance and exports, and did not indicate supply shortages. Based on submitted supply bids and forecasted demand, including supply bids and demand in the Western Energy Imbalance Market (WEIM), HASP cleared approximately 1,600 MW of advisory import transfers, anticipating that these transfers into the ISO would be available in the fifteen-minute market (FMM) and five-minute market (RTD). After the HASP cleared, the ISO found itself operating during real time with narrower supply margins than expected, compounded by load changes within both the ISO and other areas of the WEIM. As the system approached net load peak, the anticipated supply did not fully materialize. The reasons for the unrealized supply include lower forecast of renewable resources, import reductions due to potential fire impacts, resources deviating from instructions, resources not dispatched up due to congestion, management of storage resources providing other services, and resource outages and derates.

Starting at 19:00 hrs, the real-time market began seeing supply infeasibilities, thereby diminishing the market's effectiveness in balancing the system in real time. Regulation capacity was being depleted and operating reserves were reducing rapidly. In response, operators manually dispatched supplementary operating reserves to balance supply and demand. At nearly the same time, operators requested the declaration of an EEA1 and activated dispatch of 850 MW of reliability demand response resources (RDRR), which started at 19:30 hrs. An EEA1 indicates that ISO analysis shows available resources are in use or committed for use, and energy deficiencies are expected. Emergency Load Reduction Program (ELRP) resources were deployed pursuant to the EEA1. With these actions, the ISO was able to return to normal operations by approximately 20:30 hrs.

A complicating factor to the July 20 operational challenges was that while the market optimization appeared to accurately assess available dispatch capability as supply conditions changed and indicated infeasibility to meet demand for balancing energy, operators had contradictory information regarding the amount of dispatchable capacity available. This was due to a display of resource availability, which overestimated the amount of resource dispatch capability available mainly on storage resources that were providing multiple services. The available dispatchable capacity is one of several data points of information that operators use in real time to assess the state of the grid. This inconsistent information may have impacted operators' ability to take proactive actions sooner.

The loss of anticipated supply after HASP ran also contributed to operational issues. The HASP and FMM are the last opportunities to clear additional intertie capacity and one of the final chances to commit short-start units. Consequently, the HASP and FMM did not commit additional resources or position online resources in high operating ranges, and cleared low-priority exports in anticipation of the WEIM transfers projected to be available. Also, emerging supply and demand fluctuations in other regions as HASP, FMM and RTD market runs cycled through, resulted in a change in the WEIM import transfers that had been anticipated by the preceding market runs, ultimately seeing significant reductions in transfers in the real-time 5-minute RTD interval.

Lessons learned from July 20 led the ISO to re-evaluate load conformance practices for the HASP and FMM markets and implemented higher levels of load conformance in subsequent days. This was a partial solution because even with the load conformance, the HASP process could still clear additional advisory transfers to accommodate the increased load conformance. Based on events July 25, the ISO re-evaluated the use of WEIM transfers in HASP, which together with the load conformance was more effective in clearing supply in HASP and minimizing unsupportable low-priority exports starting July 26.

July 25, 2023

On July 25, with the ISO observing sustained high external demand, the loss of approximately 2,000 MW of California resources due to outages between the day-ahead and real-time markets, transmission congestion, challenges with reductions in export schedules and the potential threat of fires impacting transmission lines, an EEA Watch notification was called effective at 19:30. An EEA Watch indicates energy deficiencies are expected based on the ISO's analysis of available resources committed or forecasted to be in use. The EEA Watch declaration provided access to additional resources, including ELRP and state Strategic Reliability Reserve Resources. Reliability was maintained with no interruptions of service and no activation of RDRR.

July 25 saw some of the same load, supply, and transfers dynamics as July 20, in addition to two additional challenges. The first was significant congestion within the ISO area at times triggering prices at the $1,000/ megawatt hour (MWh) bid cap price and limiting the ability to move supply from north to south. The second challenge concerned scheduling coordinator intertie tags not adhering to reductions of economical and low-priority exports triggered in HASP.

During peak hours ending 19 through 22, congestion observed on Path 26 was significant due to underlying rating conditions, operational adjustments to align market flows with actual conditions, and a difference between the ISO market model and existing practices of certain neighboring areas. This congestion limited the ability to commit or dispatch supply in the northern part of the system to meet increasing supply needs in Southern California, where temperatures were still high.

The HASP assesses the feasible and reliable level of exports that can be scheduled and supported for the upcoming hour. Exports can economically participate in the market by submitting a bid specifying both a price and MWh quantity, or by submitting low or high-priority self-schedule specifying only a MW quantity indicating a willingness to pay any market-clearing price. During peak hours ending 19 through 22, up to 4,800 MW of economically bid and low-priority self-schedule exports did not clear in the HASP. Approximately 2,300 MW of these export reductions were not ultimately reflected in the scheduling coordinators' tagged schedules. These unmaterialized reductions in export schedules for the hour further strained the grid and prolonged challenging operating conditions, which contributed to the reduction of operating reserves and the ultimate need to declare the EEA Watch.

Because a significant portion of these export reductions were concentrated in the southern part of the system and were initially factored into the HASP process, the lack of export reductions in the 5-minute RTD market also exacerbated the observed congestion along Path 26 and stranded supply available in the northern part of the system.

July 26, 2023

On July 26, considering ongoing concerns regarding high demand in external balancing areas, continuing resource outages, and the uncertainties experienced in preceding days, the ISO took proactive measures early in the day to ensure market participants and neighboring balancing areas had adequate notice of potential system constraints, issuing an EEA Watch to be in effect between 18:00 hrs and 22:00 hrs. This allowed access to Strategic Reliability Reserve Resources, a portion of ELRP and some Demand Side Grid Support Resources.

Because of the level of unrealized imports seen in previous days, the ISO limited the level of advisory WEIM import transfers into the ISO balancing area in both HASP and FMM markets on July 26 for hours of the gross and net load peak. This adjustment, combined with load conformance, provided the HASP and FMM processes an opportunity to utilize internal resources and intertie transactions to meet projected ISO load and export schedules.

Market Performance

ISO markets' prices reflected system supply and demand conditions during the July events. Day-ahead prices averaged $66.5/MWh, up from $29 in June. The real-time ISO's daily average prices rose from $28 in June to $68/MWh in July, with maximum prices exceeding $1,000/MWh on July 25. Given the impacts of the July events, the average daily market costs were $52.4 million for the month, with daily market costs reaching a notable spike nearing $100 million on July 25. This is still lower than daily costs observed during the heat wave of September 2022.

The ISO area's average prices were generally lower than external bilateral prices, potentially creating incentives to clear exports in the ISO's market. ISO prices and the peak blocks of external bilateral prices are inherently different in their formation. ISO prices reflect marginal values across the day. For the majority of daylight hours, marginal prices are relatively low due to the abundance of solar production, offsetting higher peak-hour prices. When necessary to ensure internal load is served by available resource adequacy resources, the markets will reduce lower-priority exports such as observed on July 25 and 26 when the HASP market reduced exports by up to 4,800 MW and 2,500 MW, respectively.

Load levels encountered during the emergency alerts conditions did not surpass the available resource adequacy capacity available for the month. Throughout the July events, available resource adequacy capacity alone was sufficient to cover both the gross peak and the subsequent net load peak. With the ISO BAA now holding historic amounts of new battery storage and other clean energy resources, storage resources in July consistently bid for energy at levels exceeding 4,000 MW and continue to play a significant role in serving gross and net peak load, as well as providing regulation services.

With last winter's strong precipitation and the second largest snowfall on record, storage in major reservoirs statewide was 118 percent of average for this time of year, with reservoir capacity at 86 percent. This marked improvement in storage levels led to a substantial 56 percent increase in hydro production during July 2023 compared to July 2022.

There was a noticeable decrease in net imports, primarily due to an increase in export activity, reaching up to 9,000 MW in cleared transactions within ISO markets. Over recent years, there has also been a declining trend of imports. The shift to the ISO being a net-exporter can be attributed to distinct regional dynamics this year, characterized by below-average water levels in the Pacific Northwest and unprecedented demand in the Desert Southwest because of persistent extremely high temperatures. The ISO's market consistently managed to clear substantial volumes of exports during daylight hours when solar power generation is abundant. During sunset's peak hours, the ISO's reliance on imports increased. Nevertheless, because of demands on the system by neighboring areas, on July 20 the ISO still sustained 7,700 MWhs of exports during the critical net peak hour. Actions taken as of July 26 avoided continued low-priority exports during the critical hours to prevent further stressing already constrained system conditions.

The market upheld all high-priority wheeling-through market transactions, which facilitate the transmission of electricity through the ISO that is not designated for ISO load. A significant portion, reaching up to 948 MW out of the total registered wheel-through capacity of 1,820 MW, was actively utilized through the ISO's market. As an import-dependent system, it is imperative for the ISO to support and treat exports equitably, as cooperation in both directions is essential for maintaining reliability across the Western Interconnection. On July 25, some low-priority wheels were reduced while enabling high-priority wheels for external load and imports destined to serve ISO load.

The real-time market saw up to 2,500 MW of WEIM import transfers coming into the ISO. The allocation of imports, exports, and WEIM transfers within the market require continuous and careful balancing of a comprehensive range of system conditions affecting both the ISO and the broader Western region. Curbing exports can have disruptive effects on various balancing areas. As part of the communication and coordination strategy, the ISO is committed to furnishing as much advance notice as possible to entities affected by such reductions. The ISO is also taking steps to support liquidity in the hourly and real-time markets during times when the day-ahead market faces physical limitations on the amount of low priority exports that can be supported.

Opportunities for Improvement

During the emergency alerts, the ISO's market systems and processes largely responded in accordance with their intended design. The presence of scarcity conditions prompted an increase in prices, serving as a signal for the need for additional supply in the market. However, despite this overall good performance, several factors had adversely affected certain aspects of market functionality, causing unintended consequences. Below are the main improvements the ISO is considering in light of July's experiences:

1. Ensuring that exports are scheduled at a level that can be reliably supported by available supply while accounting for broader sources and magnitude of uncertainties. In the ISO market clearing process, dispatching supply to meet ISO load using resource adequacy and non-resource adequacy resources is assessed together with the level of exports demanded that could be reliably scheduled. Exports are assigned different priorities based on whether they are potentially served by resource adequacy resources. In situations where the ISO market must reduce exports, such reductions are guided by these scheduling priorities. Exports that are not explicitly linked to a non-resource adequacy resource have the lowest priority. It is also crucial that scheduling coordinators reflect any export reductions during tagging by adhering to their awarded schedules from the HASP, without exceeding them.

   On July 25, the ISO observed instances where multiple export reductions facilitated by the market result were not reflected in the ultimate tagging of schedules, thereby exacerbating tight system conditions. In light of this, the ISO reached out to scheduling coordinators to reiterate and clarify expectations about scheduling and tagging, and also posted reference material for guidance on scheduling priorities. The ISO is also evaluating changes and clarifications to the existing scheduling and tagging protocols for both imports and exports that will be implemented through a Business Practice Manual change. The goal is to ensure the system attains the anticipated export reductions to minimize undue strain on the grid that must then be managed manually by operators.

2. Harmonizing the accounting procedures for intertie transactions between the ISO and neighboring balancing areas is of paramount importance. Discrepancies in the treatment of ISO intertie transactions between the ISO area and some neighboring balancing areas resulted in an inaccurate

assessment of flow contributions along Path 26. This discrepancy notably compounded the challenges on July 25. Recognizing the critical nature of this issue, the ISO and its partner balancing areas are collaboratively engaged in evaluating a shared, enduring model solution, which the ISO anticipates adopting in the coming weeks.

3. Improving operator visibility regarding the real-time availability of dispatchable capacity is critical. During emergency alert conditions, there were two challenges. First, the accuracy of dispatchable capability in the system was hindered by imprecise calculations in the display provided to operators about resources' ramp capability. Second, this imprecise calculation limited operators' visibility of the actual dispatchable capability available in the system. The ISO implemented an enhancement to the display of dispatchable generation on September 13.

2 Background

In mid-August 2020, a historical heat wave affected the Western United States, resulting in energy supply shortages that required two brief and limited 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 California ISO initiated an analysis of the causes for the rotating outages. The findings were documented in the Final Root Cause Analysis report[1], which 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 resource adequacy and planning targets. This weather event extended across the Western United States, impacting loads in other balancing areas 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. 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 real-time market for exports being self-scheduled. Prior to this change, any export cleared in the IFM market received a day-ahead priority in the real-time market up to the cleared IFM schedule. With the change, exports cleared in the day-ahead market 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, discuss with market participants, and propose enhancements across different areas of the market practices. This effort was initiated with educational workshops to level the 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].

Enhancements implemented throughout summer 2021 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 EIM 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

For summer 2023, 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. New displays in Today's outlook for projected supply and demand 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, ISO has completed the policy effort of 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, ISO filed and FERC approved to extend the scheduling priorities phase 1 policy for 2022 and 2023 while working on finalizing the second phase of the policy initiative. FERC is currently considering the ISO's proposal for a more durable framework, which is expected to be in effect spring 2024[4].

---

[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

[4] *See* http://www.caiso.com/Documents/Jul28-2023-TariffAmendment-WheelingThrough-ER23-2510.PDF.

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

1. Enhancements to the resource sufficiency test. These include changes to the capacity test logic to improve the accounting of the supply available in real-time. This also include the consideration of the supply infeasibilities projected in the real-time market 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, high priority exports need 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 HASP markets.

The ISO also filed an extension continue to use the minimum state of charge for the summer 2023 and is currently in place. The ISO completed enhancements of the energy storage resources rules to require resources to bid in a real-time energy bid in the opposite direction to cover at least 50 percent of their ancillary service awards. Finally, the ISO implemented some enhancement to the resource sufficiency evaluation process, including

- The Assistance Energy Transfer process that allows entities in the WEIM to opt in for energy transfers during test failures at a charge.
- Exclusion of the low priority exports from the ISO area obligation in the resource sufficiency evaluation process, and
- Rules for low priority exports to be tagged as Firm Provisional Energy (G-FP).

These items were effective as of July 1.

3 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.

3.1 Temperature

Above average, much above average, and record warmest mean temperatures were observed across the western United States throughout July. This is shown in Figure 1[5].

Figure 1: Mean temperature percentiles for July 2023

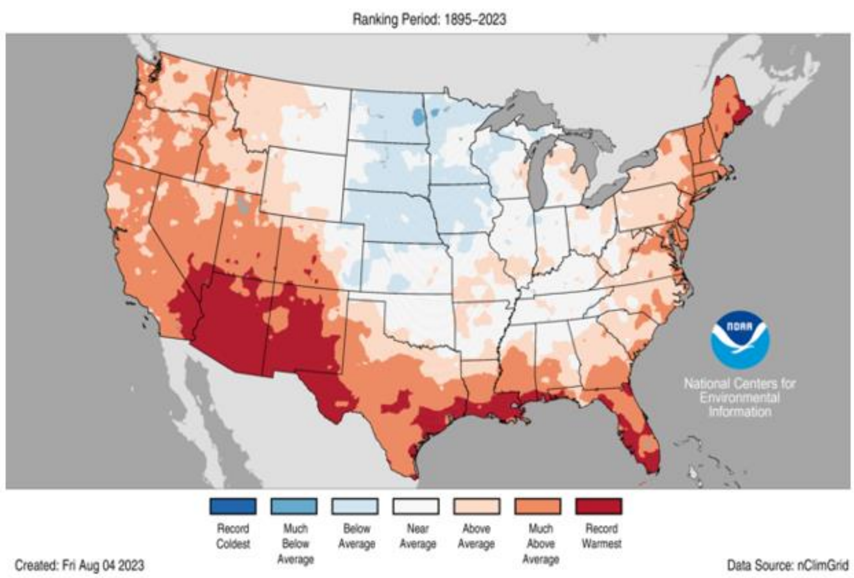
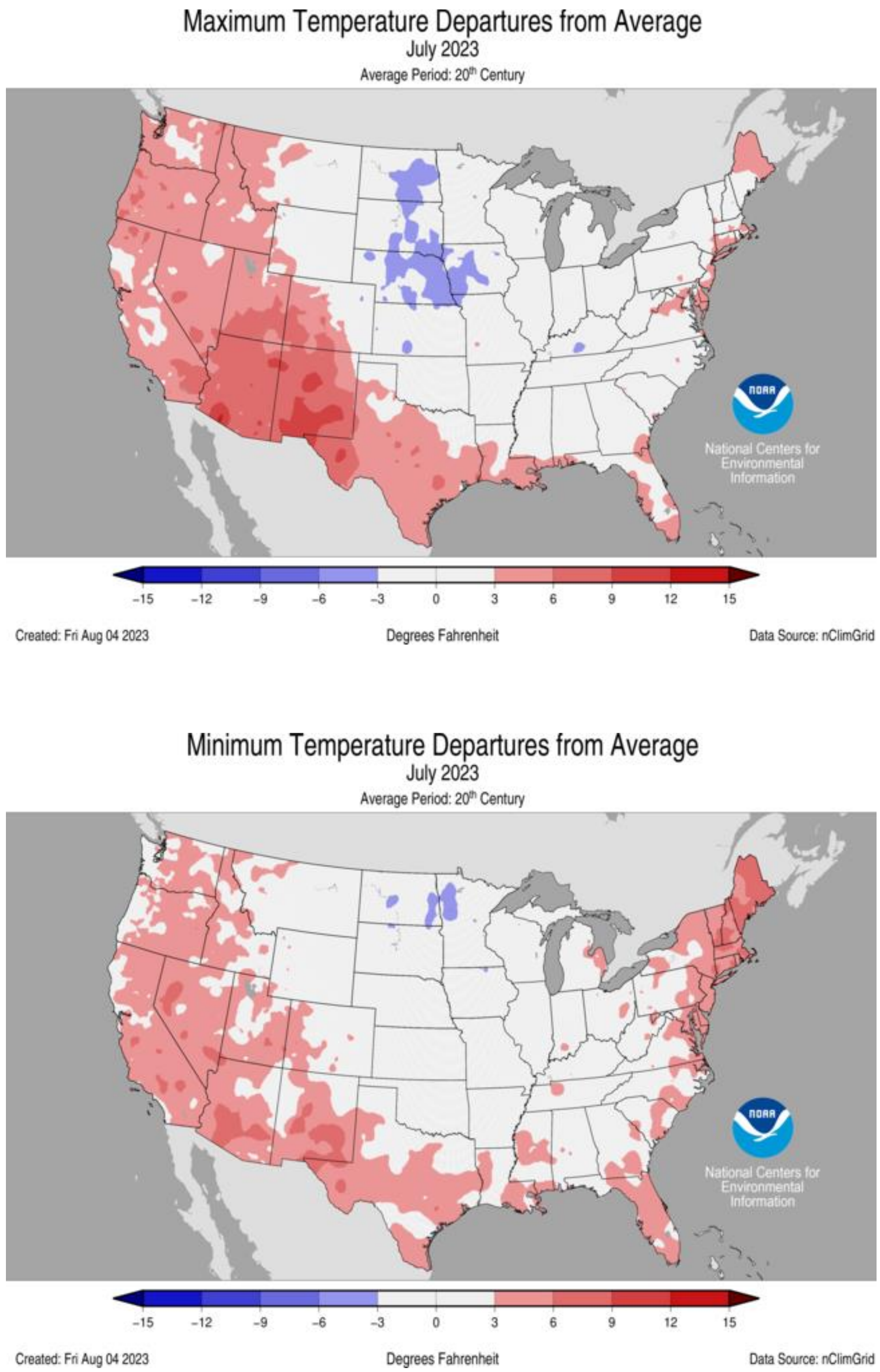


Figure 2[6] shows that both the maximum temperatures and minimum temperatures were above the July average across most of the West, with the warmer maximum temperatures being more widespread and larger in magnitude. The Desert Southwest, including the California desert, saw the more extreme temperature departures, with some areas having the July mean maximum temperature 9-12° above average. Many coastal areas did not see as large an impact to overnight temperatures as the interior locations.

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

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

Figure 2: Maximum and minimum CONUS temperature departures from normal for July 2023



Looking at the Desert Southwest WEIMs more closely in Figure 3, the maximum temperature anomalies varied across the region. Arizona Public Service (AZPS) in the Desert Southwest had above normal temperatures every day of the month except the last day. Phoenix, AZ had their hottest July on record with an average high temperature of 114.7°, shattering the previous warmest average high temperature record for July of 109.8° set in 2020. There were also 12 daily record high temperatures reached between July 13-29 in Phoenix and on July 19th, the all-time record warmest overnight of 97° was set[7]. New Mexico had similar heat extremes, with Albuquerque setting the record for the July warmest minimum temperature of 78° on July 10, 11 and 15 before finally tying the all-time record high minimum temperature of 79°, set back in 1892.[8] July 17th had Albuquerque's second hottest July day on record, reaching 104°, which prior to 2023 had not been reached since 2003[9].

Figure 3: High temperature departure from normal for select Desert SW WEIMs

Arizona Public Service (AZPS)
High temperature departure from normal

July 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
						1 5
2 8	3 8	4 5	5 2	6 5	7 3	8 4
9 3	10 1	11 2	12 3	13 7	14 8	15 10
16 7	17 7	18 10	19 11	20 12	21 8	22 10
23 6	24 7	25 10	26 9	27 8	28 7	29 6
30 2	31 -0.4			days < normal 1	days > normal 30	Deg +/- normal + 6.3

above normal | below normal | Normals: 1990-2020

Public Service Company of New Mexico (PNM)
High temperature departure from normal

July 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
						1 -1
2 0.2	3 2	4 3	5 5	6 6	7 3	8 2
9 7	10 4	11 5	12 6	13 4	14 8	15 5
16 7	17 11	18 9	19 8	20 9	21 5	22 3
23 4	24 7	25 8	26 10	27 7	28 8	29 4
30 2	31 1			days < normal 1	days > normal 30	Deg +/- normal + 5.2

above normal | below normal | Normals: 1990-2020

As shown in Figure 4, high temperatures throughout ISO fluctuated from below normal at the beginning of the month to mostly above normal for the remainder of July. The period of July 11-27 had above normal temperatures for most interior locations, such as the Valley, deserts and Inland Empire, and some desert locations had over 14 continuous days of excessive heat warnings in effect as a result of the heat. Palm Springs had 18 days of July with a high temperature 115° or greater.

[7] https://weather.gov/media/psr/Climate/July2023Climate.pdf
[8] https://forecast.weather.gov/product.php?site=ABQ&issuedby=ABQ&product=RER&format=CI&version=5&glossary=0
[9] http://xmacis.rcc-acis.org/

Figure 4: ISO high temperature departure from normal

California ISO (CAISO)

High temperature departure from normal

July 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
						1 6
2 5	3 0.3	4 -4	5 -5	6 -7	7 -8	8 -8
9 -9	10 -3	11 1	12 1	13 1	14 5	15 4
16 5	17 5	18 2	19 2	20 5	21 4	22 5
23 1	24 0.6	25 4	26 4	27 2	28 -0.3	29 2
30 2	31 -0.1			days < normal 9	days > normal 22	Deg +/- normal + 0.7

above normal | below normal | Normals: 1990-2020

In the Pacific Northwest, while there were some hot days, there were also periods of the month where maximum temperatures were below normal. Early July was the hottest period, with July 5th setting a daily high temperature record for Seattle and many locations around and Oregon. While Idaho Power Company did not have as extreme heat as Seattle City Light, there were more days with the high temperature above normal, and ultimate led them to have the average high temperature for July more above normal.

Figure 5 High temperature departure from normal for select Northwestern WEIMs

Seattle City Light (SCL)

High temperature departure from normal

July 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
						1 5
2 4	3 6	4 12	5 16	6 6	7 -3	8 -3
9 0.6	10 -5	11 -0.8	12 -2	13 2	14 9	15 12
16 4	17 -2	18 2	19 10	20 4	21 -2	22 2
23 4	24 -10	25 -5	26 -4	27 -0.8	28 -1	29 -3
30 -3	31 -2			days < normal 15	days > normal 16	Deg +/- normal + 1.7

above normal | below normal | Normals: 1990-2020

Idaho Power Company (IPCO)

High temperature departure from normal

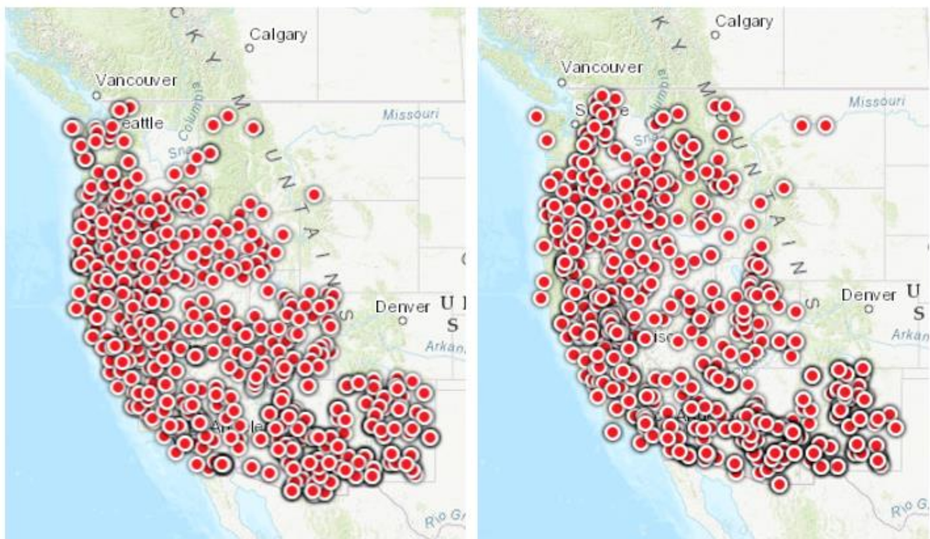
July 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
						1 9
2 7	3 3	4 -3	5 -1	6 4	7 1	8 1
9 8	10 4	11 0.1	12 3	13 -0.2	14 -0.7	15 4
16 9	17 2	18 0.4	19 3	20 5	21 7	22 8
23 4	24 -1	25 -2	26 0.4	27 -0.3	28 2	29 2
30 3	31 1			days < normal 7	days > normal 24	Deg +/- normal + 2.6

above normal | below normal | Normals: 1990-2020

Looking at the western United States temperature records in Figure 6[10], there were 1861 daily maximum temperature records which were tied or broken during the month of July and 1761 daily warmest minimum temperature records which were tied or broken. The number of daily maximum temperature records tied or broken in July is over 21 times higher than the number of daily maximum temperature records tied or broken in June. The number of daily maximum temperature records tied or broken is only 100 more than the number of daily minimum records tied or broken, showing how hot overnight temperatures were throughout the west in July and how limited the overnight relief from the daytime heat was.

Figure 6: Highest temperature records for maximum temperatures and minimum temperature

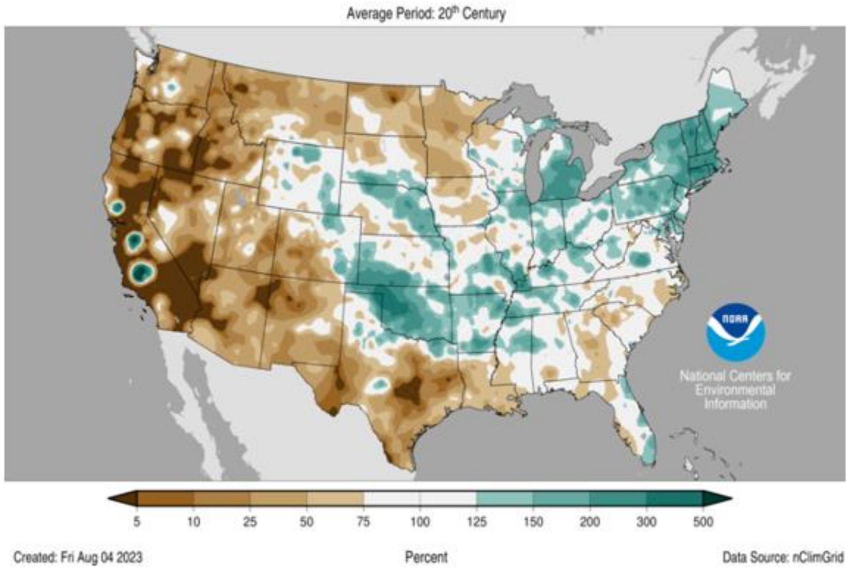


3.2 Hydro conditions

Nearly all of the western United States experienced below normal rainfall in July. This is shown in Figure 7[11]. A lack of monsoon storms across Arizona, New Mexico and the deserts of California led to these areas only seeing 25 percent or less of their average July rainfall, with most areas of the Desert Southwest totaling 1" or less and almost all of California totaling .1" or less. There were some areas of California that saw rainfall on/around July 18-19, but because typically no precipitation is observed in these areas, they show on the map as 500 percent of normal July precipitation.

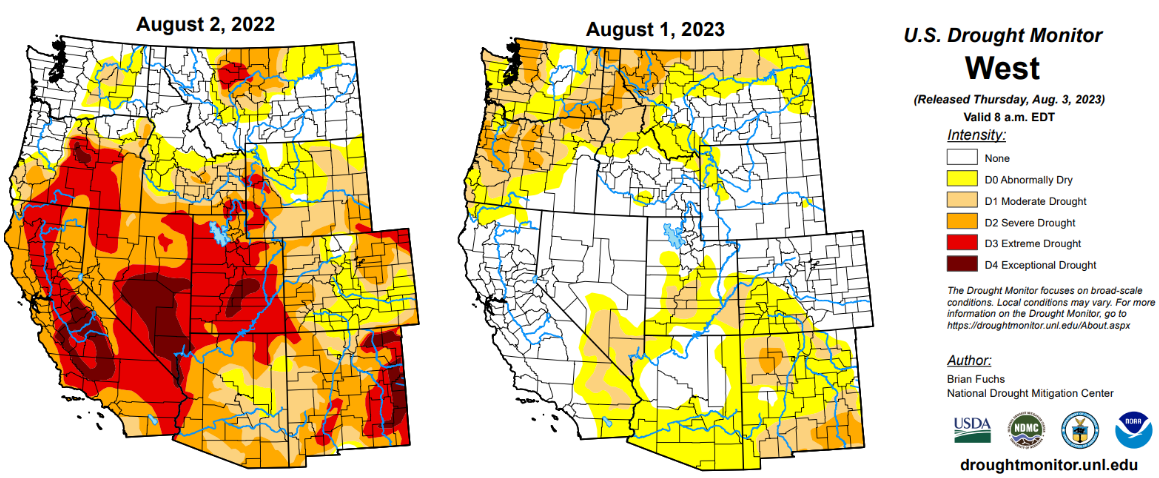
[10] https://www.ncdc.noaa.gov/cdo-web/datatools/records
[11] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Figure 7: The United States precipitation percent of normal for July 2023



As shown in Figure 8[12], the above normal winter rain and snowfall caused the Sierra's to see their 2nd largest snowfall on record, and has also lead to drought diminishing significantly compared to this time last year[13]. No state in the West, including California, has any areas that are in extreme or exceptional drought.

Figure 8: The Western United States drought monitor for August 2, 2022 and August 1, 2023



A large improvement compared to 2022. Drought worsened between June 2023 and July 2023 due to a lack of rainfall across the Pacific Northwest and below average monsoon storms for the Desert Southwest.

---

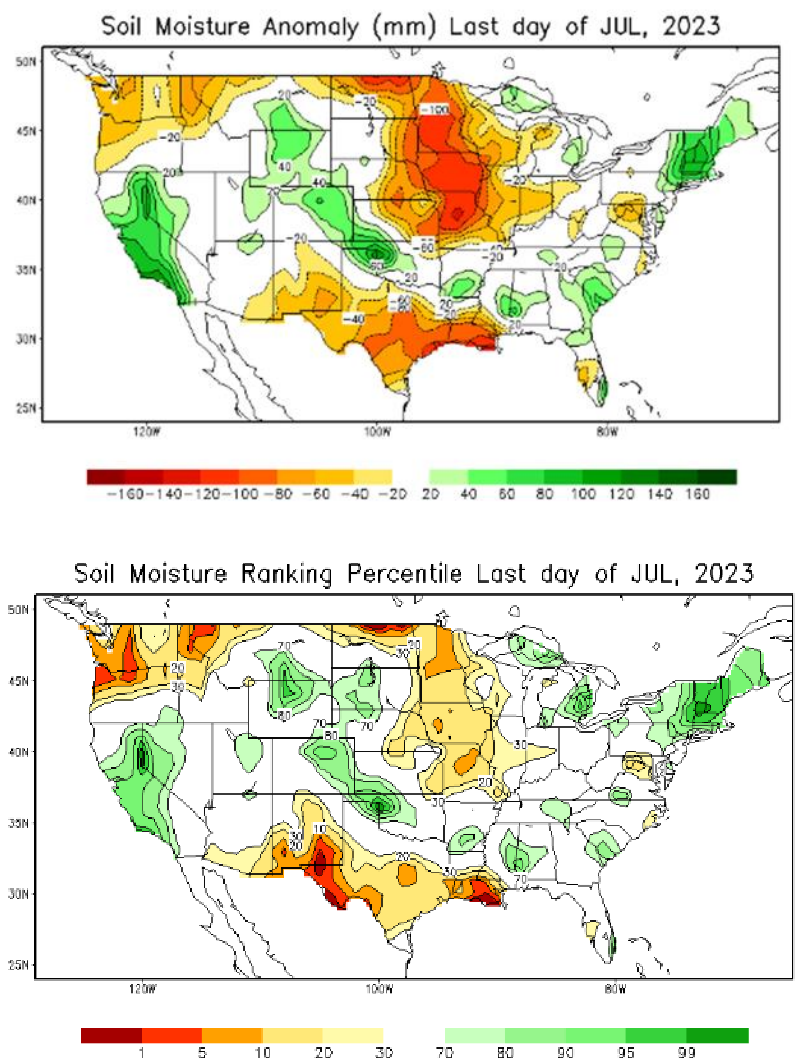
[12] https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?West

[13] https://www.forbes.com/sites/brianbushard/2023/03/29/700-inches-of-snow-sierra-nevadas-face-2nd-snowiest-season-on-record-stemming-brutal-california-drought/?sh=1a88ef4bcc0b

The abnormally dry, moderate drought and severe drought increased by 13.79 percent, 6.31 percent and 3.67 percent respectively across the area below in July.

The top of the image in Figure 9[14] shows that soil moisture is still above average for this time of year across almost all of California. During the summer months little-to-no precipitation is typically received, but due to the well above normal snowpack left in the mountains and continued snowmelt and runoff, this has led to above normal soil moisture in July. For the higher terrain, particularly the Sierras, this will likely lead to a later start to the fire season. At the end of July 2022, soil moisture percentiles were within the bottom 1-10% state-wide, so this is a large improvement compared to last summer.

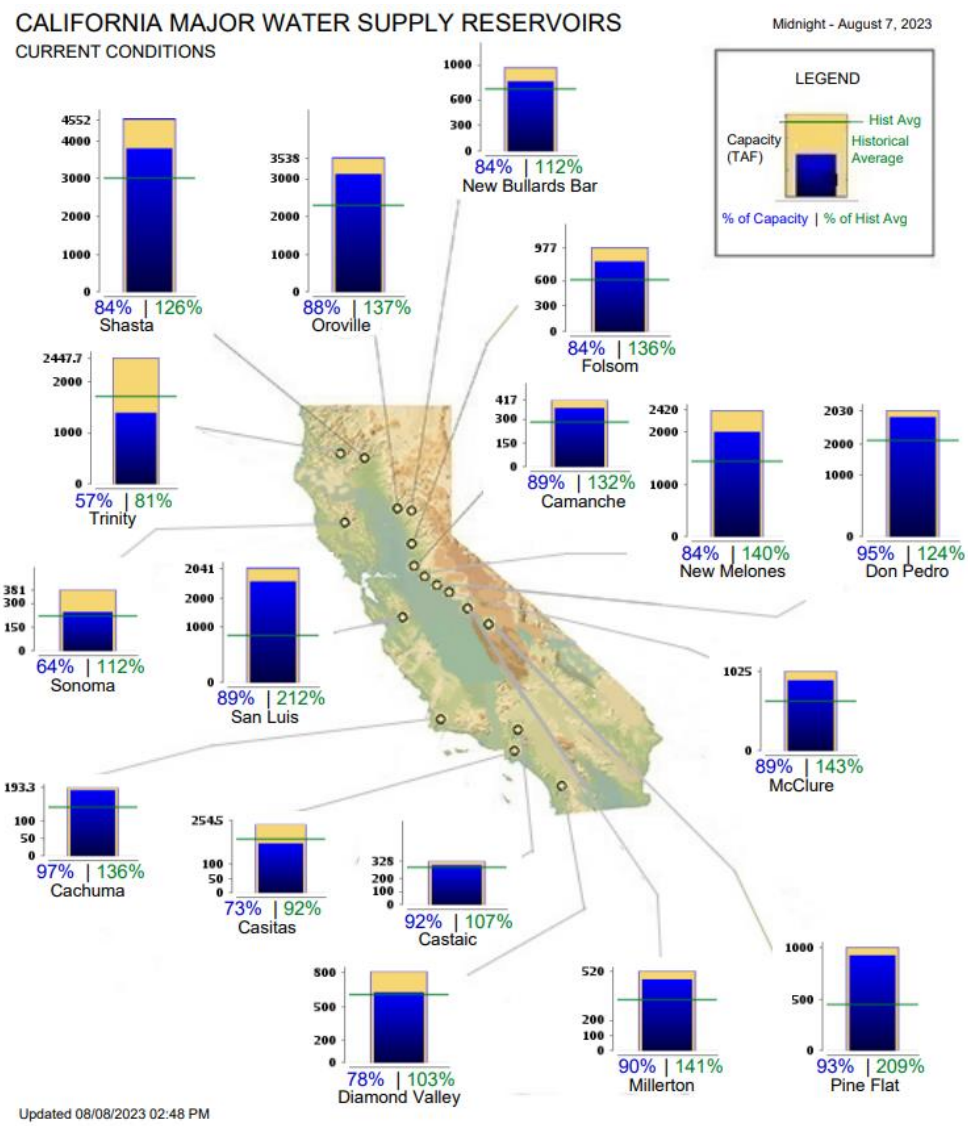
Figure 9: The United States soil moisture for July 2023 (top) and the soil moisture rank (bottom)



[14]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 above normal, as shown in Figure 10[15]. Reservoir levels across the state are at or above historical averages for end of June, including 15 of 17 that are above their historical average for this time of year. The statewide storage in major reservoirs is currently 87 percent of average and 57 percent of capacity[16]. This is compared to 55 percent of average and 36 percent of capacity at the end of July 2022.

Figure 10: California's reservoir conditions as of August 7, 2023



The ISO's electrical system utilizes hydro production throughout the year to meet the grid's demand. Figure 11 below shows the historical trend of total energy produced from hydro resources, as well as renewable resources, in which hydro production for 2023 so far has been relatively higher than in 2022.

---

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

[16] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM

Hydro production in July 2023 was about 56 percent higher than the production observed in July 2022. Figure 12 below shows the hourly profile of the average energy produced from hydro resources as well as renewable (solar and wind) resources for the month of July 2023.

Figure 11: Historical trend of hydro and renewable production

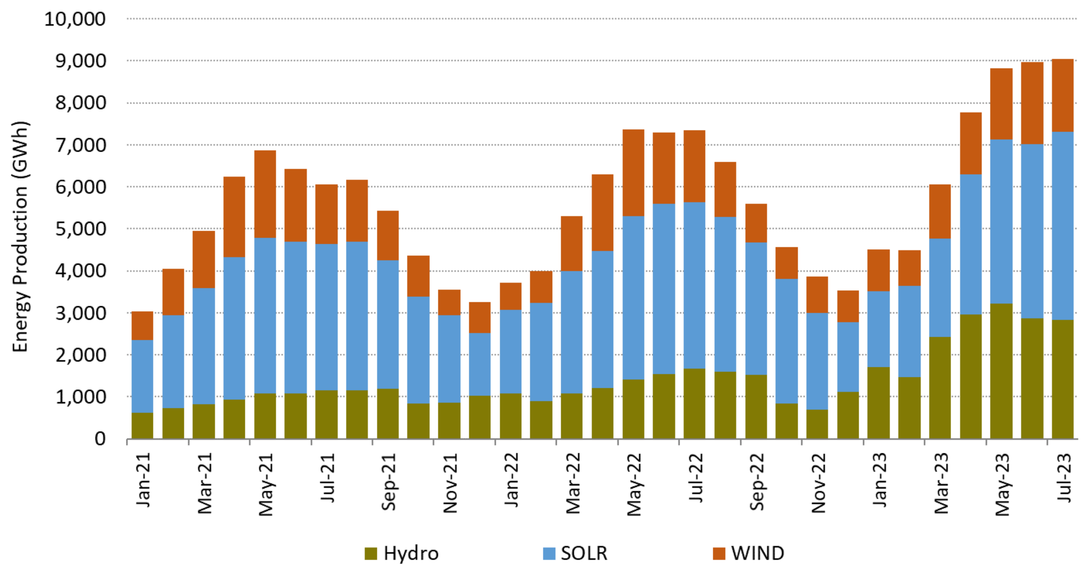
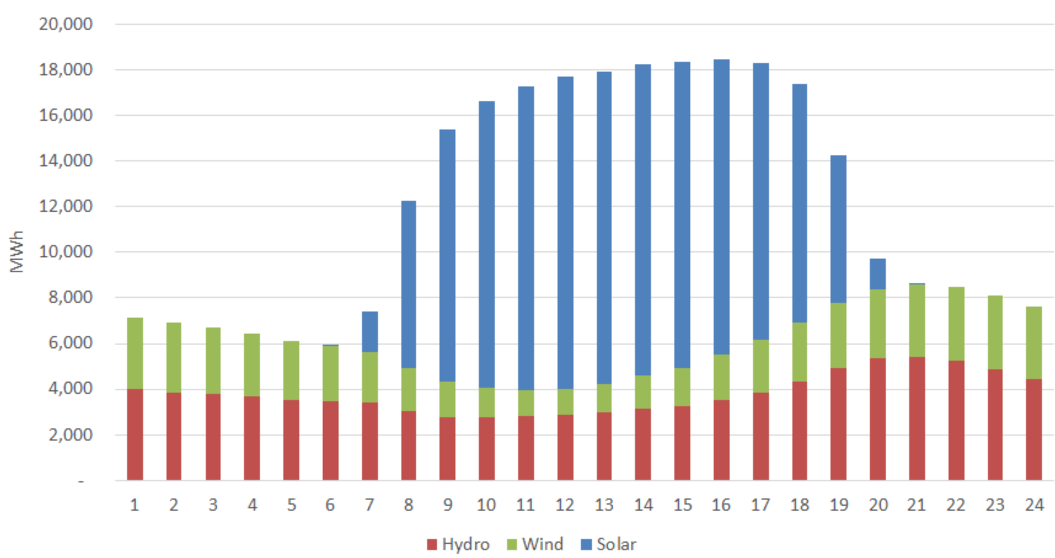


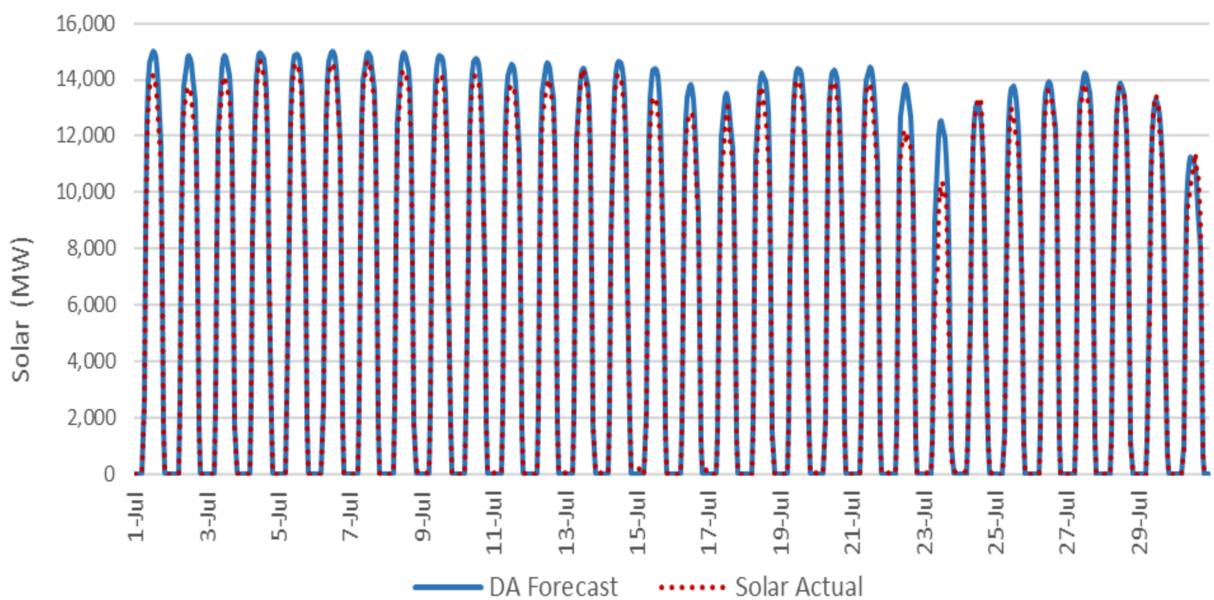
Figure 12: Hourly profile of wind, solar and hydro production for July



3.3 Renewable forecasts

Figures 13 and 14 below show the solar and wind day-ahead renewable forecasts compared to actual plus supplemental dispatch. Supplemental dispatch reflects the market's downward dispatch relative to the resource's forecast based on their bids. This allows the ISO to measure the performance of the full-fuel forecast that is utilized in RUC and the real-time market optimization.

Figure 13: Day-ahead solar forecasts for ISO's area



While much of July was sunny, there were some periods of passing clouds mid-month and eventually some more substantial cloud cover with areas of showers/storms the moved through around the 22-25. This caused some over-forecasting of solar in the day-ahead during this period. The average error[17] for the day-ahead solar forecast in July 2023 was 2.66 percent. The average error observed in July 2023 is lower than the day-ahead solar forecast error observed for July 2022 and July 2021[18].

[17] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[18] http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun29-2023.pdf

Figure 14: Day-ahead wind forecasts for ISO's area

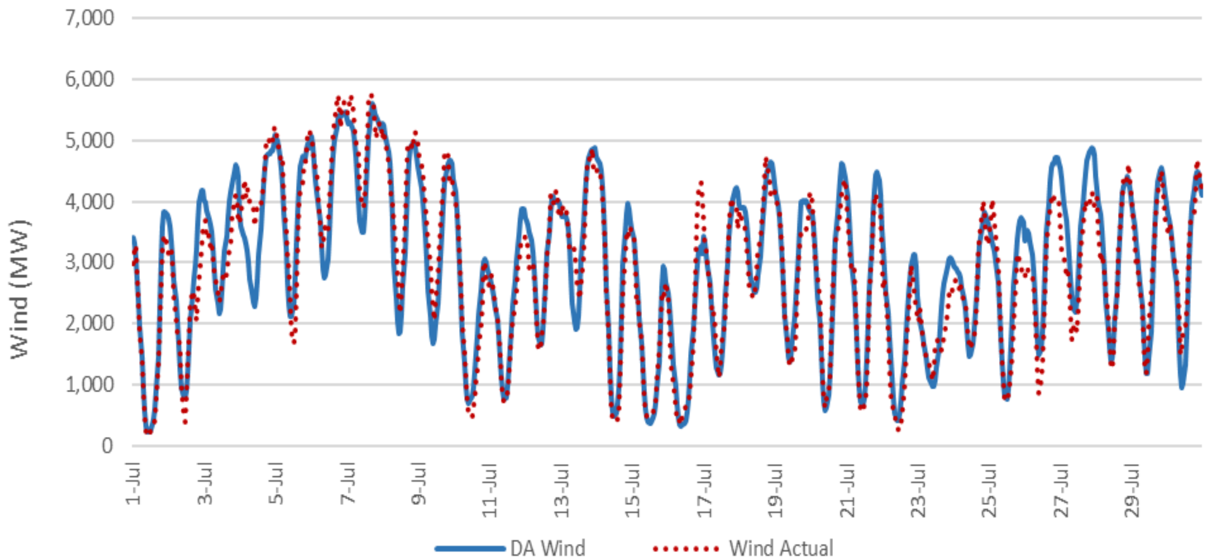


Figure 14 shows the day-ahead wind forecast compared to the actuals plus curtailments throughout the month of July for wind in the ISO's system. The average error[19] for the day-ahead wind forecast in July was 3.92 percent. The average error observed in July 2023 is lower to the day-ahead wind forecast error observed for July 2022 and July 2021[20].

3.4 Demand forecasts

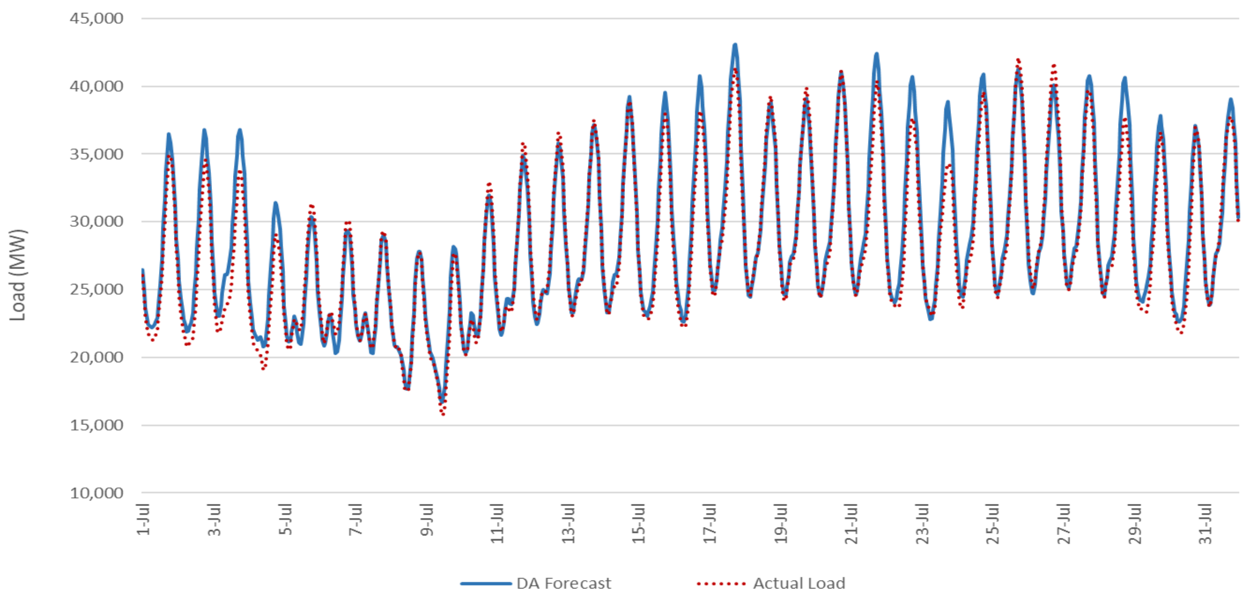
The ISO produces load forecasts for the day-ahead and real-time markets for all areas participating in the ISO markets.

3.4.1 ISO's demand forecast

ISO demand during the month of July 2023 continued to be fairly responsive to the temperature changes observed throughout the month. Figure 15 shows the trend of the ISO's load without pump loads included to examine forecast error. The highest hourly average July load of 43,237 MW was observed on July 25, 2023 when the ISO footprint maximum temperatures were 4 degrees F above normal.

[19] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[20] http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun29-2023.pdf

Figure 15: Day-ahead demand forecast for ISO's area



Some of the larger errors seen in July were observed in the days leading into the Independence Day holiday and days where temperatures were forecast to be above normal but due to cloud cover, came in cooler than expected. For example, the periods of July 15-17 and 21-24 saw high temperatures up to 5 degrees above normal, but cloud cover impacts, especially across southern California, led to temperatures coming in cooler than anticipated in the day-ahead timeframe, and lower loads as a result.

The average accuracy error for the day-ahead demand forecast in July was 3.07 percent, while the error for peak hours was 3.73 percent. The average error observed in July 2023 was moderately higher than the error observed in July 2021 and 2022 which was 2 and 1.98 percent.

3.5 Energy Conservation

During the month of July the ISO did not issue any Flex Alerts to assist in meeting the net load peak on tight supply conditions. Consequently, there are no energy conservation estimates to report for July.

3.6 Demand Response

3.6.1 Market demand response

The ISO markets consider demand response programs designed to reduce demand based on system needs, and trigger demand response programs through market dispatches. In the ISO's markets, there are two main market programs for demand response: economic (proxy demand response or PDRs) and reliability demand response resources (RDRRs). These programs use supply-type resources that can be dispatched similar to conventional generating resources.

Figure 16 shows the dispatch for PDRs in both the day-ahead and real-time markets. PDRs are dispatched economically in either market based on their bid-in prices. During the month of July, PDR resources were consistently dispatched in both the day-ahead and real-time markets. The largest volume of PDR dispatches in day –ahead occurred on July 20 at about 248 MW whereas in real time market, it was a maximum of 140 MW of PDR dispatches on July 25

Figure 16: PDR Dispatches in day-ahead and real-time markets in July 2023

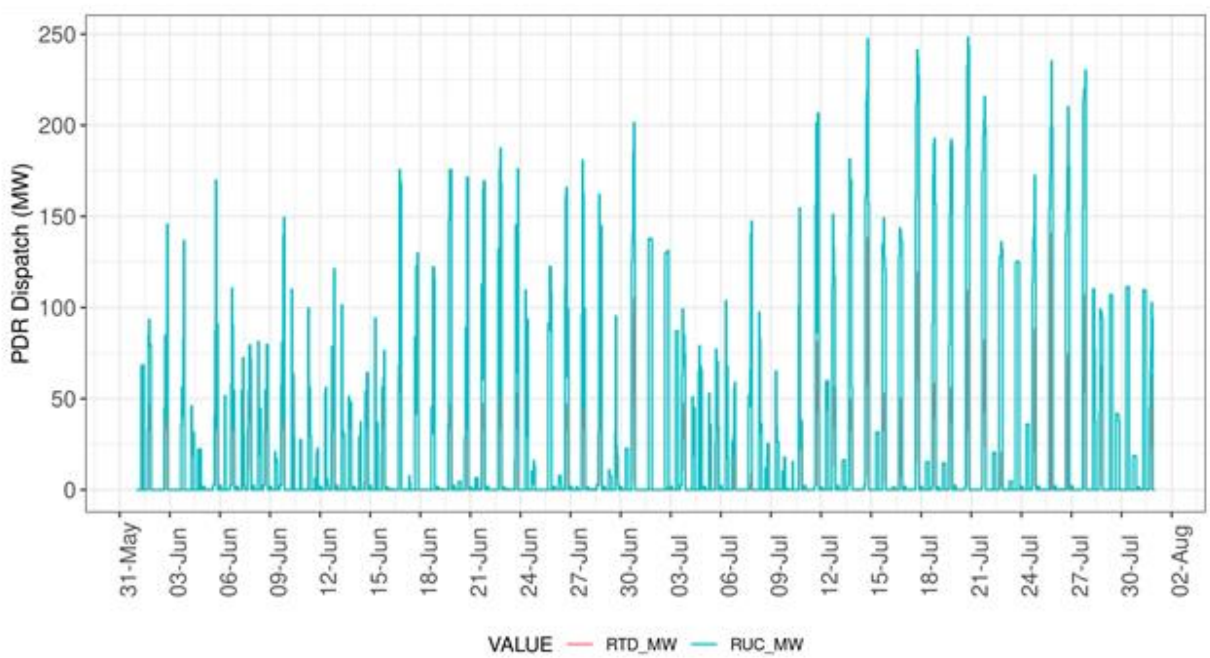
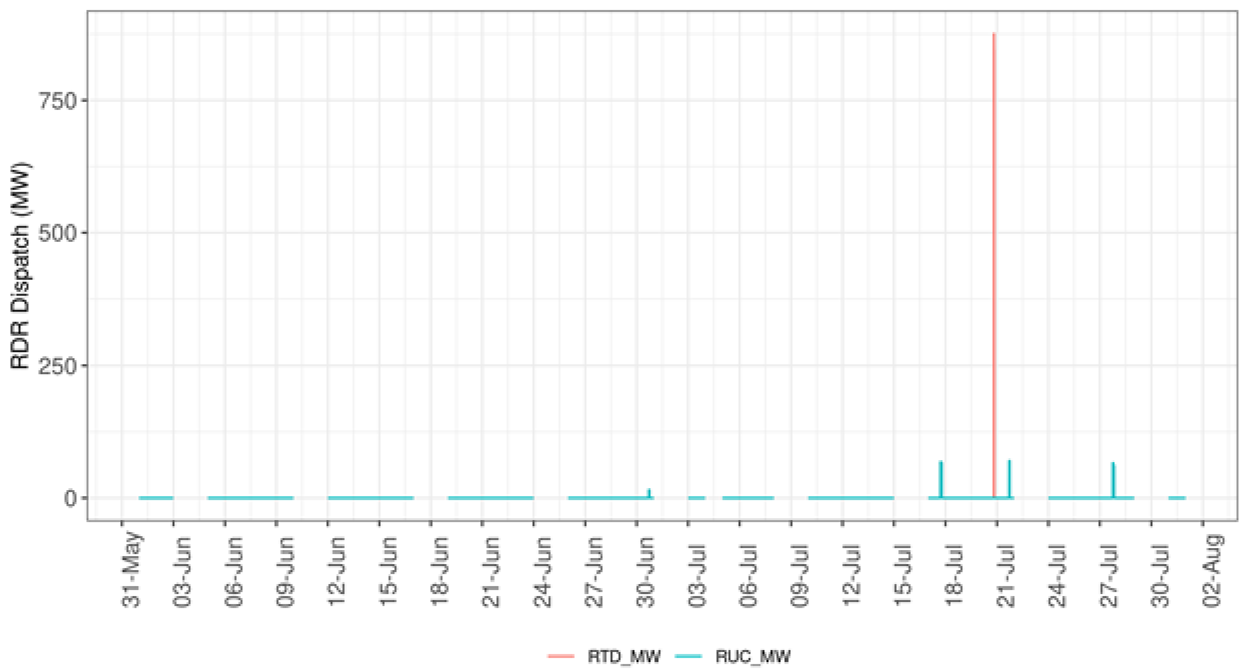


Figure 17 shows the dispatches for reliability demand response resources (RDRRs) in both the day-ahead and real-time markets for the month of June and July. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these day-ahead market dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market 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 EEA Watch, some RDRRs may bid-in economically into the ISO day-ahead market, in which case, any cleared RDRRs will come into the real-time market as a self-schedule and be dispatched generally at the same level of the day-ahead market award. RDRRs were dispatched in the in real time market on July 20 during the emergency event to about 875 MW for HE 20 – 21.

Figure 17: RDRR dispatches in day-ahead and real-time markets for July 2023



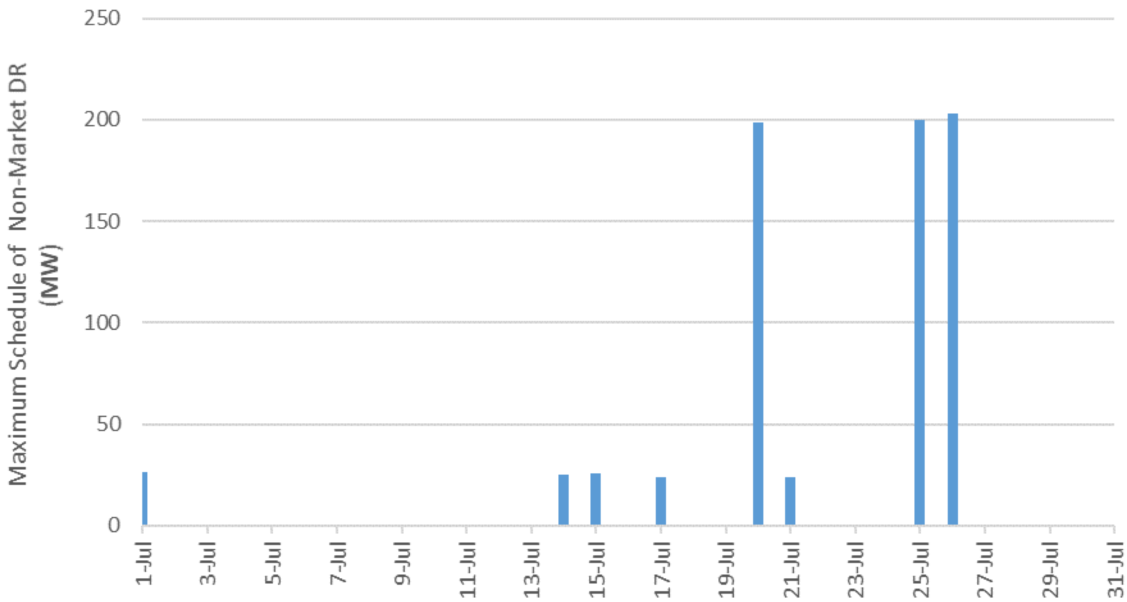
At the time this report was prepared, there were no estimates yet of the demand response performance. Estimates become available about three months after the trade date based on settlement data submitted by the scheduling coordinators and are used to measure the performance of demand response resources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

3.6.2 Non-market resources

In recent years, various state programs have been established to provide grid support during stressed grid conditions or extreme events. These out of market programs may trigger based on conditions on the ISO BA system. These resources include demand-side programs not integrated into the ISO market, coordinated conservation efforts, and non-market generation authorized by California legislation. Although some programs can be triggered by conditions such as Flex Alerts and EEA categories, some IOU demand-side programs can also be scheduled outside of these conditions.

Non-market resources were deployed a total of 8 days in July 2023, with a maximum schedule of 202.8 MW occurring on 7/26/2023. On days where an EEA Watch or EEA 1 was declared, these resources were scheduled for approximately 200 MW. Four days exhibited significantly smaller schedules of approximately 25 MW. There were no other scheduled non-market resource events in July 2023.

Figure 18: Non-Market Demand Responses for July 2023



4 Demand and Supply

4.1 Resource adequacy

The ISO manages the resource adequacy (RA) program established by the CPUC for its jurisdictional load serving entities (LSEs), which include Investor Owned Utilities (IOUs), Community Choice Aggregators (CCAs) and Energy Service Providers (ESPs). Collectively, these LSEs cover about 90 percent of ISO's load. The ISO also manages the RA program for several other Local Regulatory Authorities (LRAs) in the ISO's footprint. The RA program ensures through contractual obligations that there is sufficient supply capacity to meet the system's needs and to operate the grid reliably. The CPUC and respective LRAs set and enforce RA program rules for LSEs within their jurisdictional footprint. This includes setting monthly obligations based on an electric load forecast and planning reserve margin (PRM), and resource counting rules. The California Energy Commission (CEC) estimates the electric load forecast used by the CPUC and other LRAs in respective RA programs. 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. During the events of September 2022, there were days with insufficient system RA capacity 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 PRM[21]. This PRM is to cover the 6 percent of operating reserves plus a contingent headroom to account for higher-than-expected load forecast and resource outages.

The monthly RA showing for July 2023 was 51,144 MW, which is 157 MWs higher than July 2022's monthly showing of 50,988 MW[22]. Figure 18 compares the total monthly RA capacity in July 2022 and July 2023 by fuel type. In general, total RA capacity increased across fuel types between years with some exceptions. RA capacity for storage resources increased by 1,584 MW and also increased by 410 MW for static imports. Hydro RA saw an increase of 668 MW and gas-fired RA saw an increase of 786 MW.

Static RA imports increased from 2,223 MW in July 2022 to 2,634 MW in July 2023[23]. The composition by intertie varied between years as shown in Figure 19. RA imports through Malin increased by 92 MW between July 2022 and July 2023; imports through NOB also increased by 71 MW across the same timeframe. Monthly RA capacity tends to increase as the summer progresses and were generally on par

---

[21] The planning reserve margin is 16 percent for the CPUC jurisdictional entities in 2023 and will increase to 17 percent in 2024. Other LRAs may set their own respective PRMs. Per Decision 21-12-015, the CPUC increased the "effective" planning reserve margin to 20-22.5 percent for 2022 and 2023 which may be met with both RA and non-RA resources that may not be in the wholesale market.

[22] 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.

[23] 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.

with quantities from 2022. Monthly static RA imports also increases as the summer progresses, with July 2023 static imports at a higher quantity than July 2022 static imports. These trends are shown in Figure 20 and Figure 21.

Figure 18: RA capacity organized by fuel type

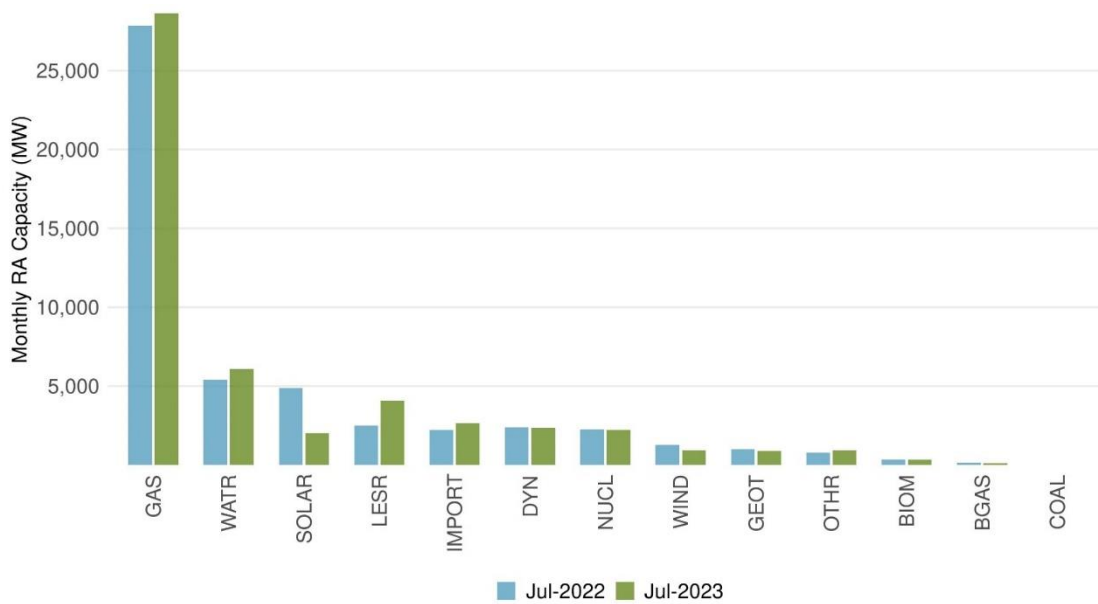


Figure 19: Monthly RA imports organized by tie

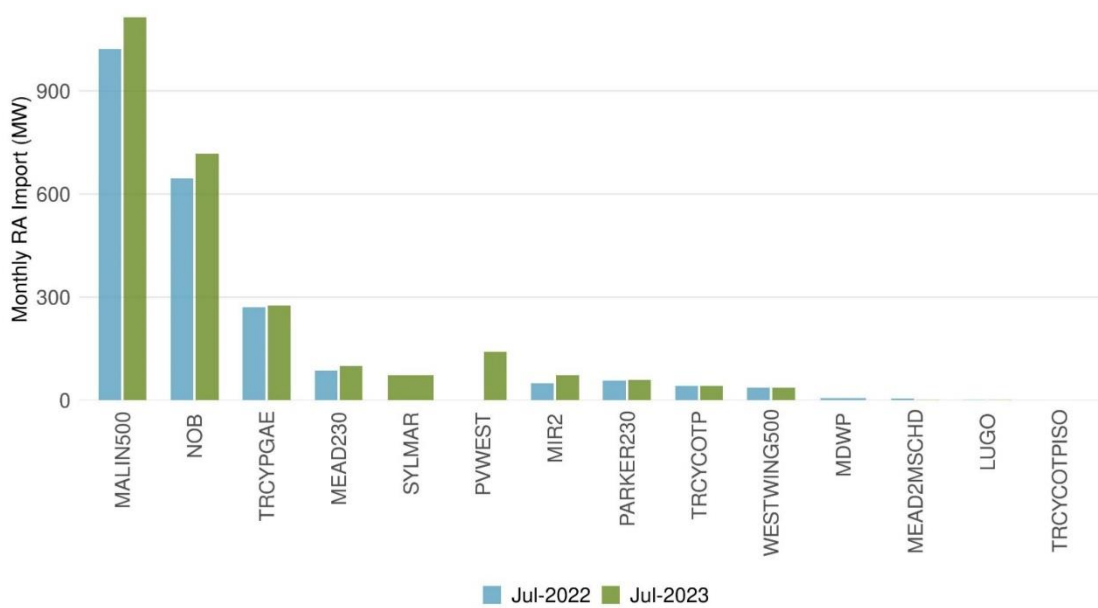


Figure 20: Monthly RA showings, three month trend

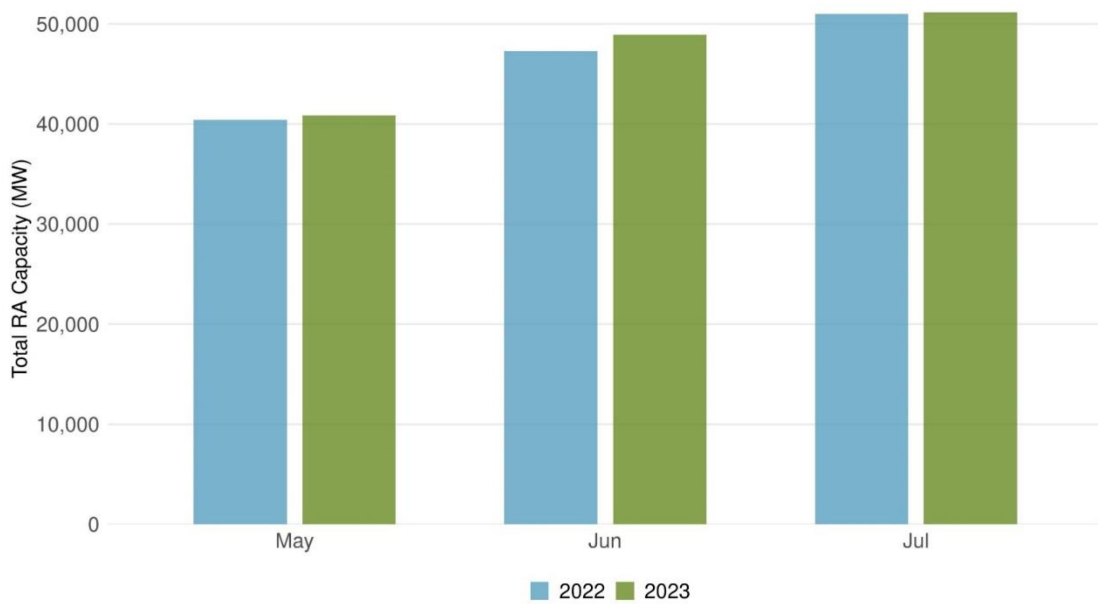
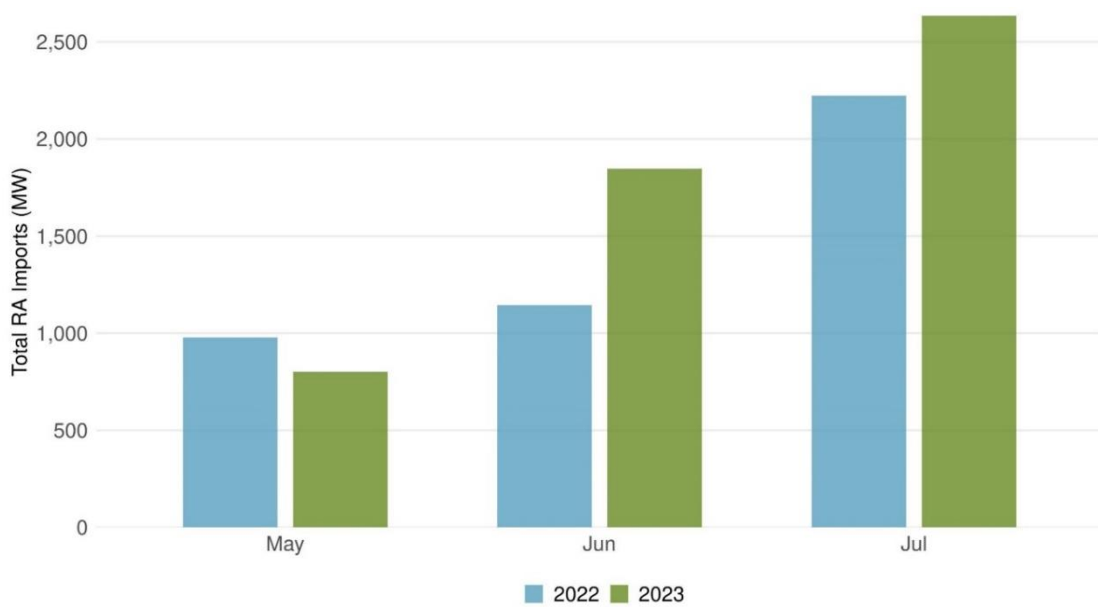


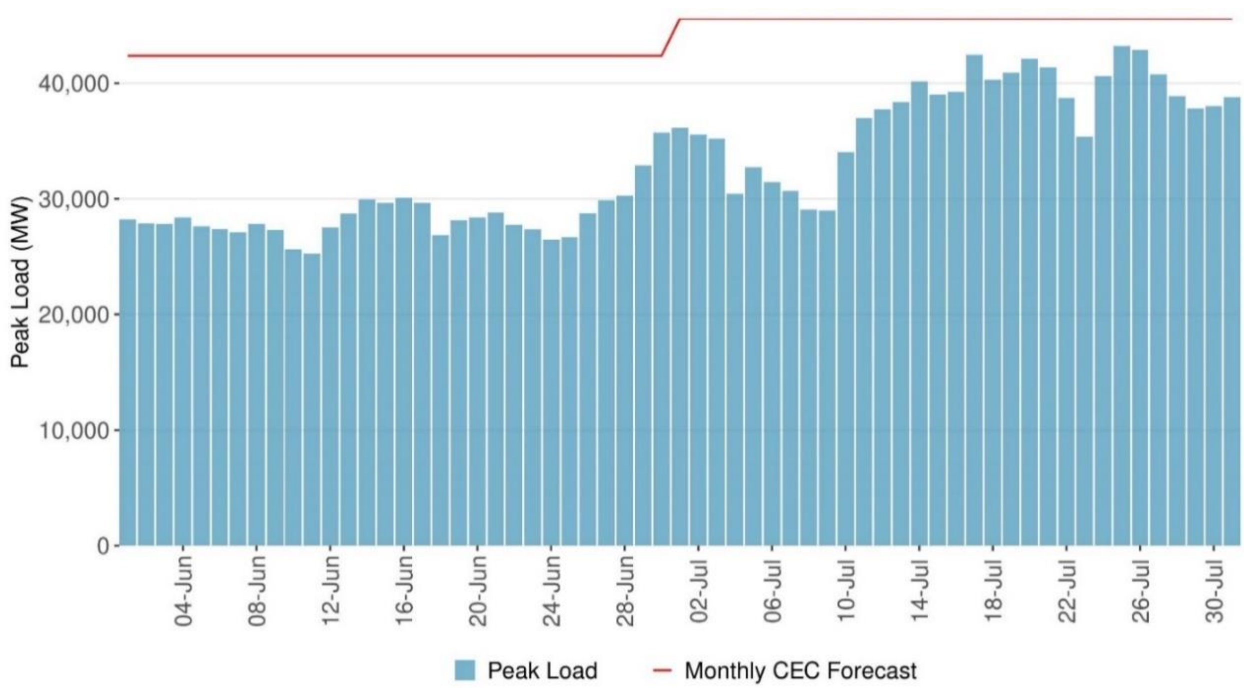
Figure 21: Monthly trend of static RA Imports, three month trend



4.2 Peak loads

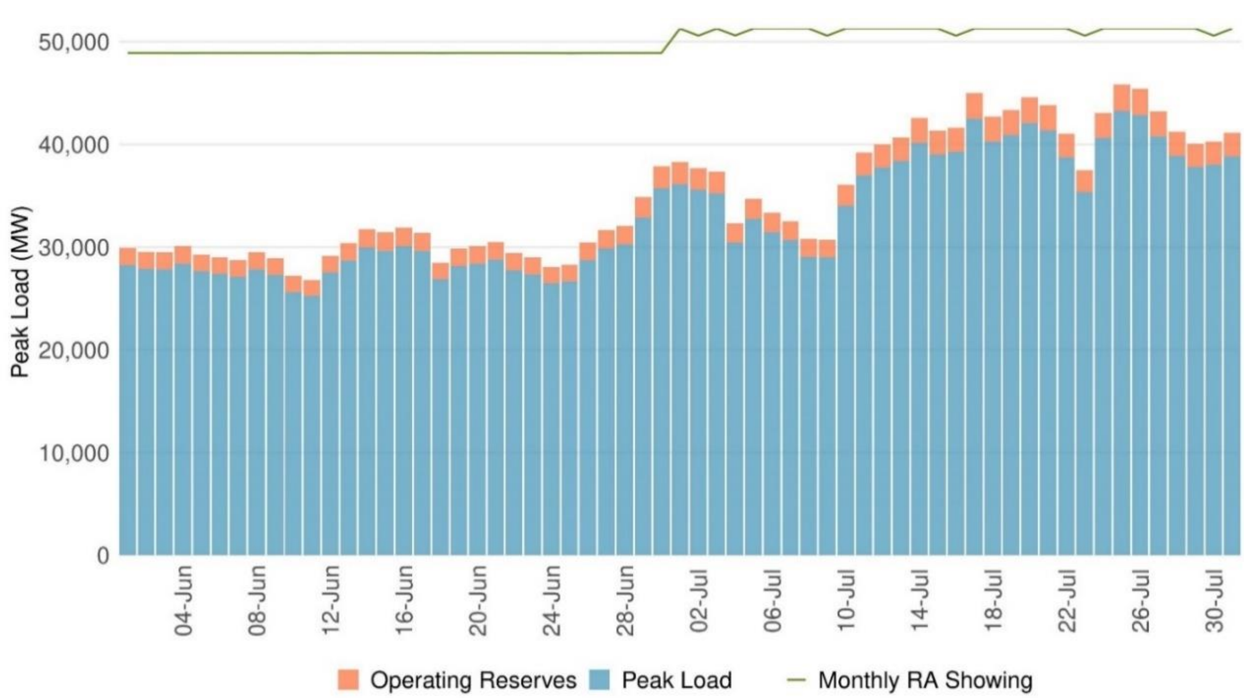
Peak loads in July 2023 were elevated from the previous month, generally coming in above 30,000 MW and at times exceeding 40,000 MW. The average daily peak load in July 2023 was approximately 37,351 MW which was higher than the average daily peak load in July 2022 of 36,443 MW. Figure 22 shows the 5-minute average daily load for June and July 2023 relative to the June and July 2023 CEC month-ahead forecast used to assess the resource adequacy requirements. The highest instantaneous load peak in July was 43,545 MW, which occurred on July 25, and was below the CEC month-ahead forecast of 45,588 MW.

Figure 22: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings for July 2023 as illustrated in Figure 23. 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.

Figure 23: Daily peak load, operating reserves and RA capacity

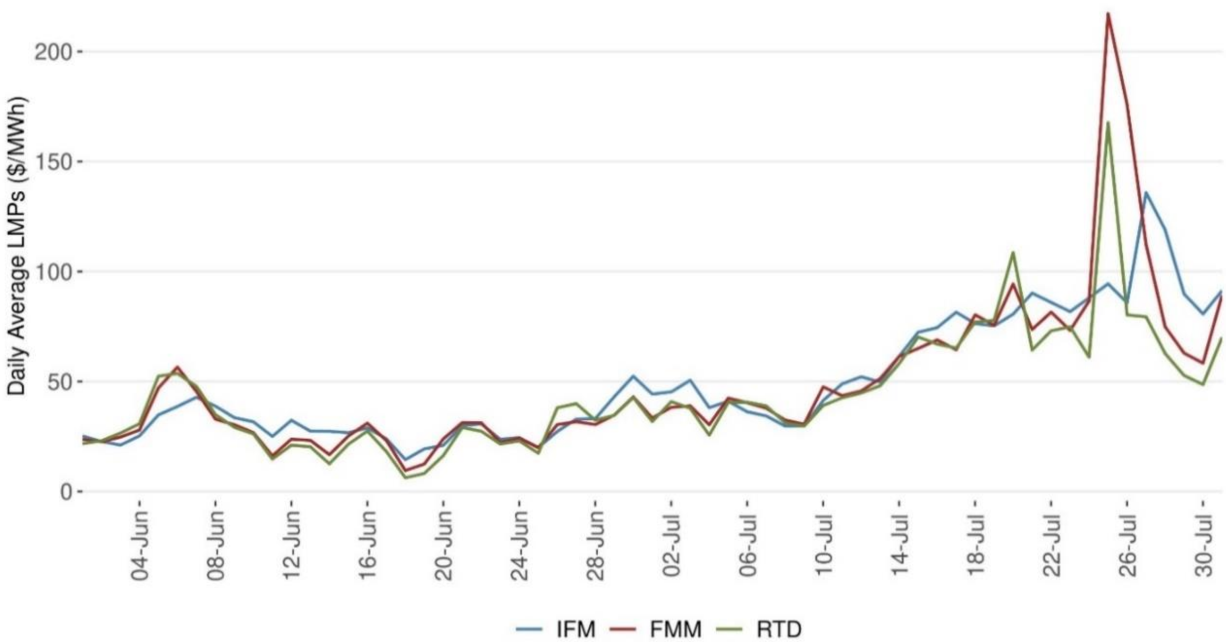


In subsequent sections, the actual RA capacity made available in the market is represented as a trend over for the month on an hourly basis, which more accurately represents RA capacity available to meet demand.

4.3 Market prices

Market prices reflect supply and demand conditions; as the market supply tightens, prices rise. Locational marginal prices 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 24 compares the daily average prices across ISO's markets[24]. Figure 25 shows average daily prices across ISO's markets for June and July 2023.

Figure 24: Average daily prices across markets



[24] Default Load Aggregation Point (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 25: Average hourly prices across markets

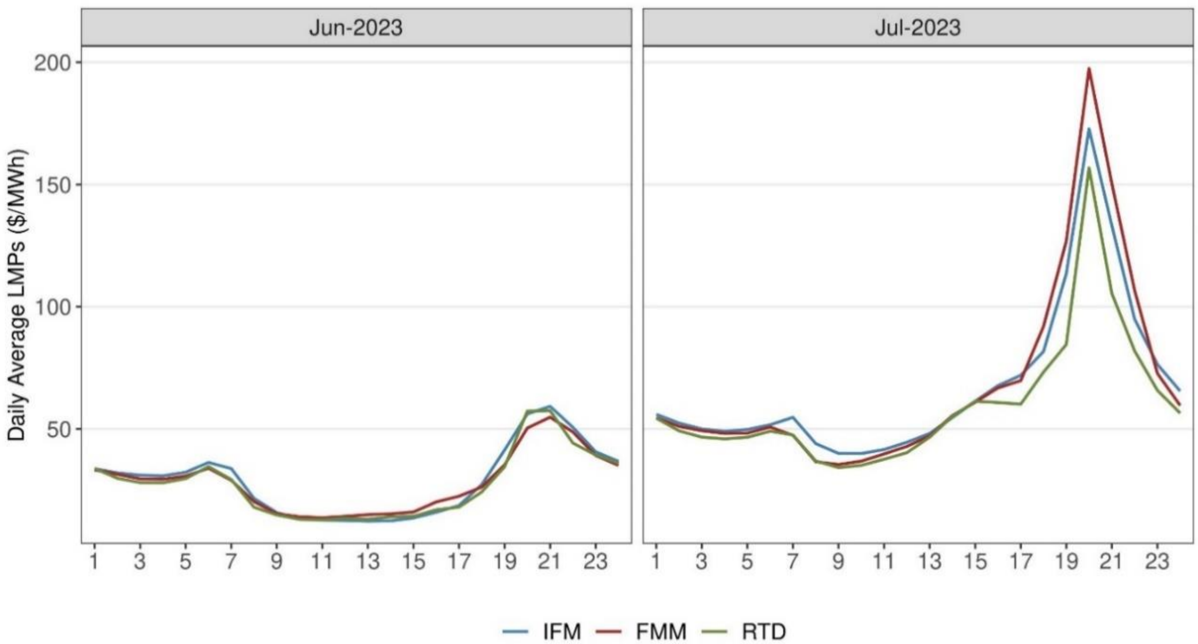


Figure 26 and Figure 27 show the daily and hourly distribution of day-ahead prices with box-whisker plots. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for the day or hour. These plots illustrate the full distribution of prices observed throughout the days and hours of the month. The average day-ahead LMP in July 2023 was $66.53/MWh and the maximum LMP of $535.33/MWh occurred on July 27, 2023.

Figure 26: Daily distribution of IFM prices

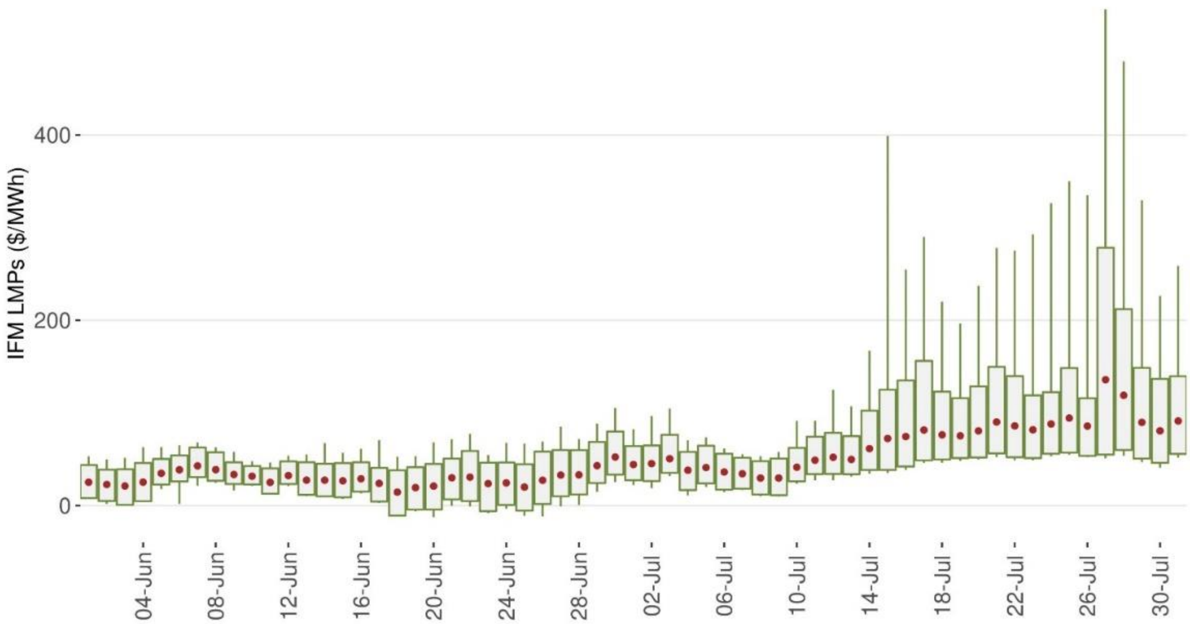


Figure 27: Hourly distribution of IFM prices

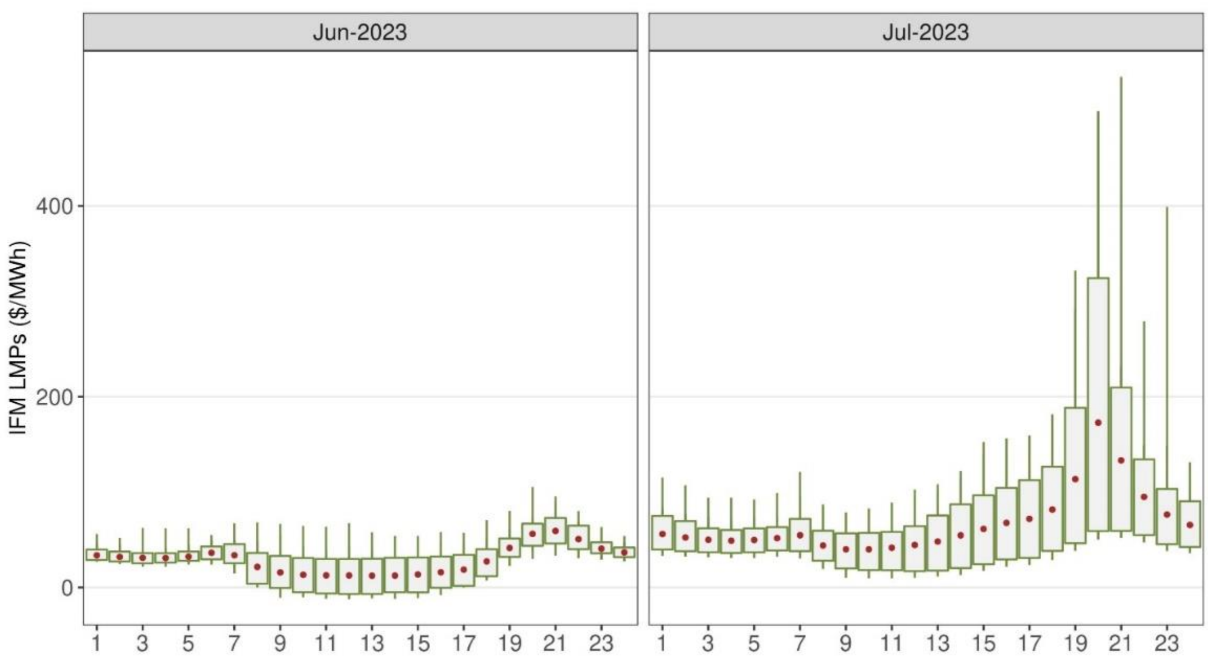


Figure 28 and Figure 29 show daily and hourly distributions of fifteen-minute market (FMM) prices throughout the month. The average FMM LMP in July 2023 was $67.95/MWh and the maximum LMP of $1,111.19/MWh occurred on July 25, 2023. The July 2023 FMM prices exhibited a larger spread than corresponding IFM prices, in part due to the events that unfolded until the real-time market.

Figure 28: Daily distribution of FMM prices

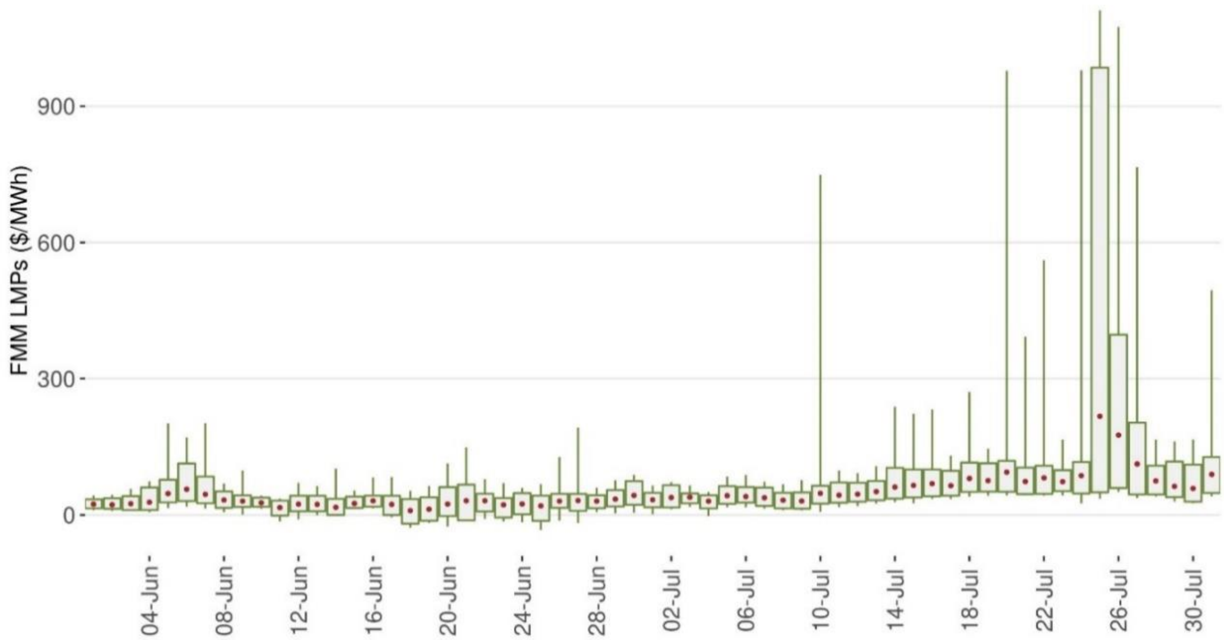
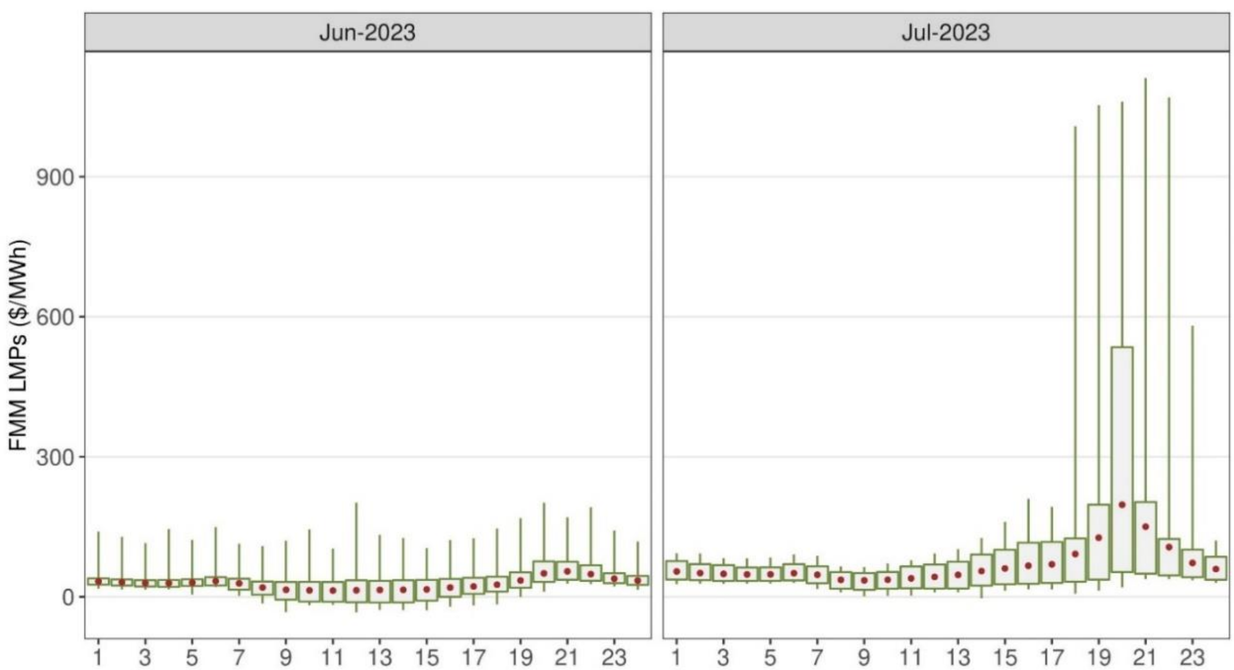


Figure 29: Hourly distribution of FMM prices



4.4 Index prices

With a meaningful share of the ISO's generation fleet consisting of gas resources, gas market and system conditions can have an impact on the electric market. Electricity prices generally track gas prices. Figure 30 shows the average prices (bars in red and blue), and the maximum and minimum prices (whiskers in black), for the two main gas hubs in California, PG&E Citygate and SoCal Citygate. For July 2023, next-day gas prices averaged $4.56/MMBtu and $5.51/MMBtu for PG&E Citygate and SoCal Citygate, respectively. The maximum next-day gas prices were $5.6/MMBtu and $12.3/MMBtu for PG&E Citygate and SoCal Citygate, respectively.

Figure 30: Gas prices at the two main California hubs

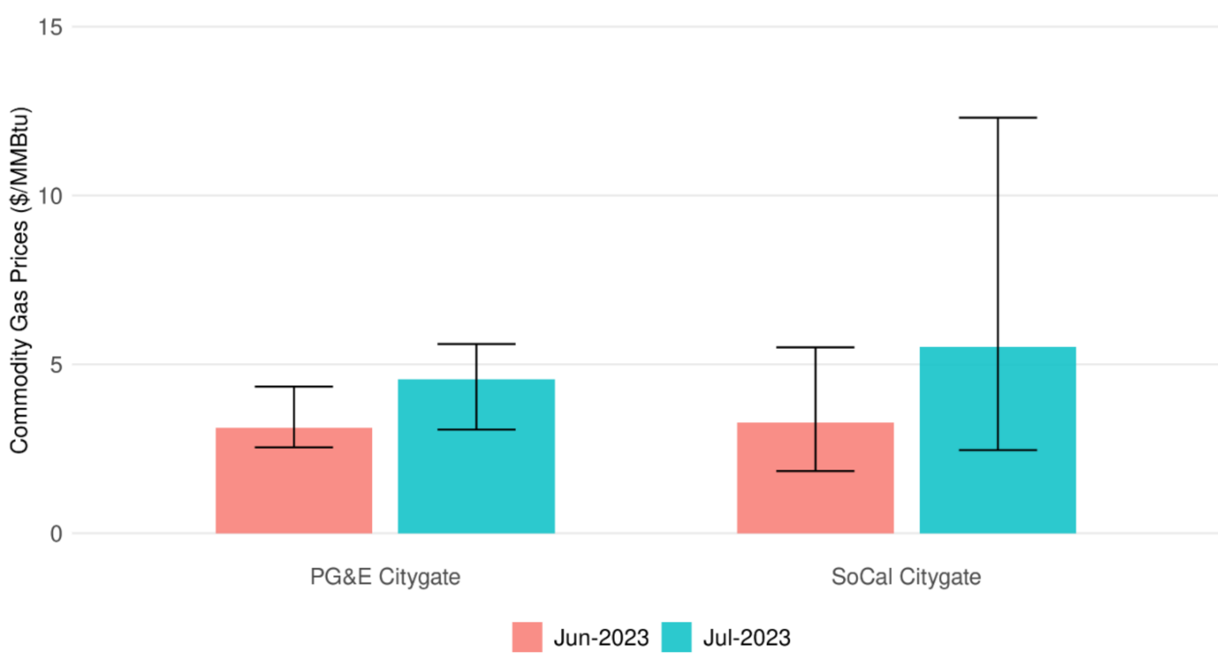


Figure 31 shows daily average electricity prices from the ISO day-ahead market (y-axis) relative to next-day gas prices at SoCal Citygate (x-axis) and the peak load (color gradient from blue to red) on a daily basis. The dashed red line shows a simple linear regression applied to the dataset. Figure 32 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 31: Correlation between electricity prices, SoCal Citygate gas prices and peak load level

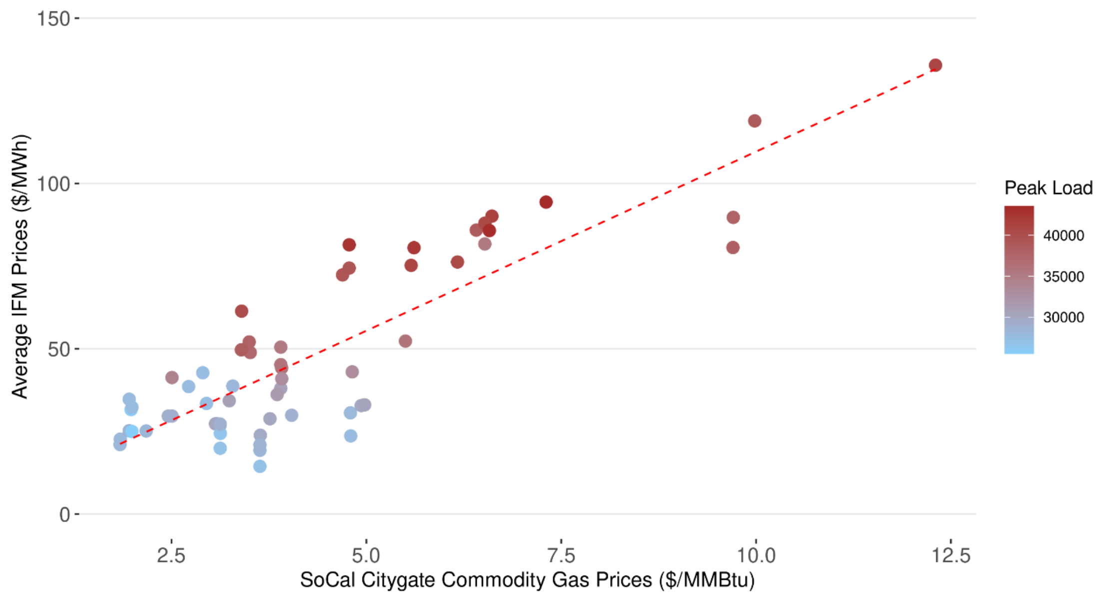
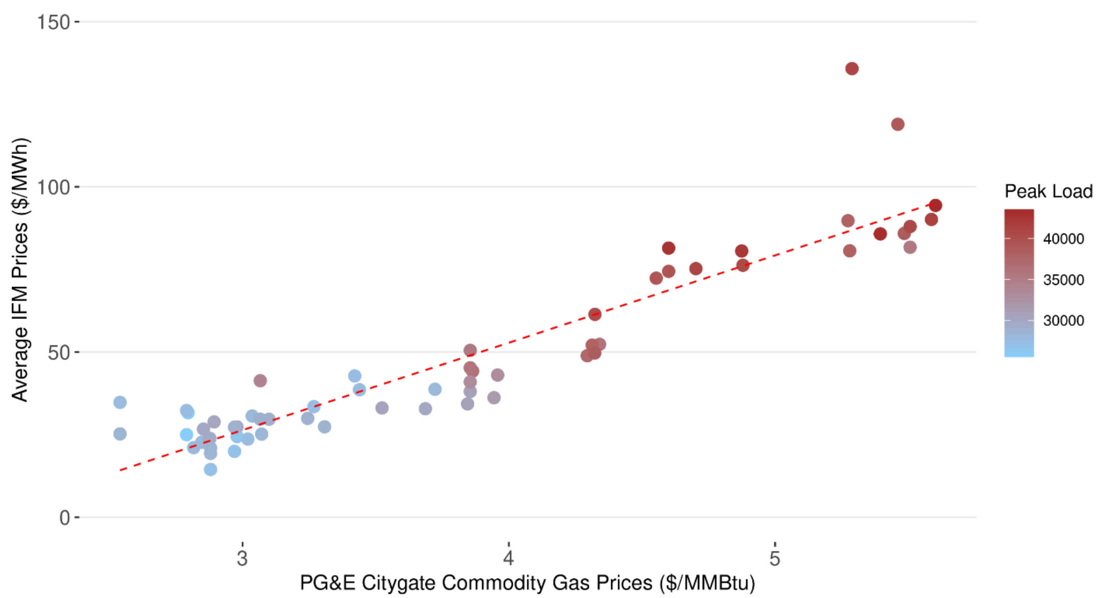


Figure 32: Correlation between electricity prices, PG&E Citygate gas prices and peak load level



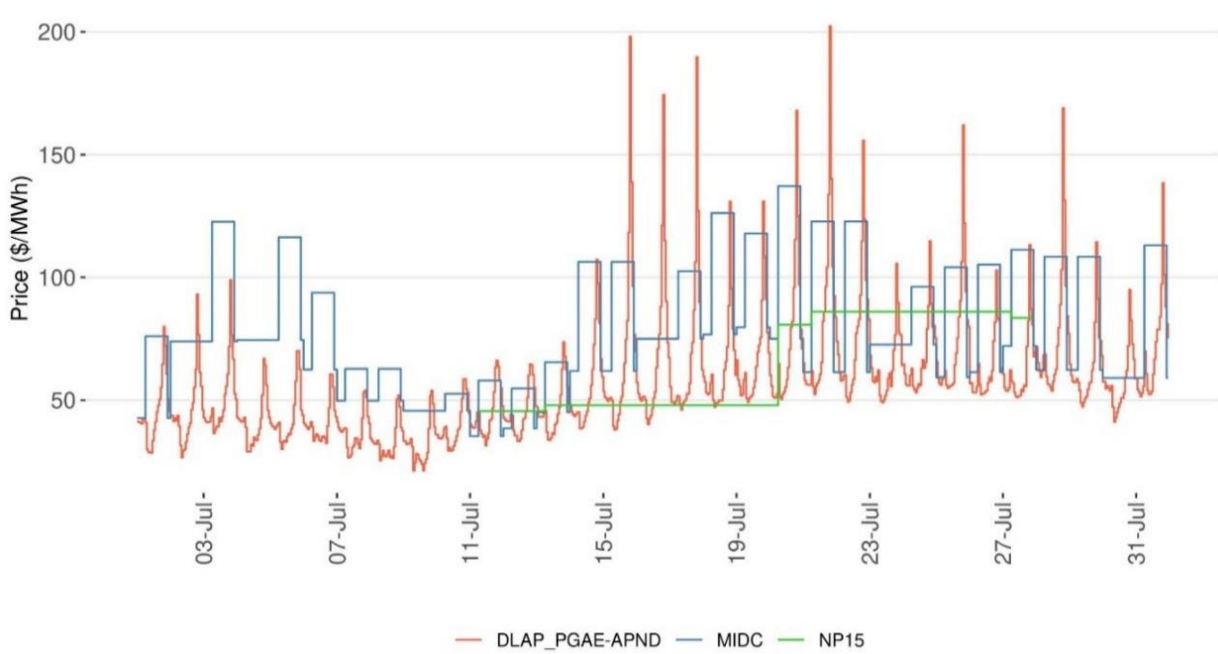
Energy trading outside the ISO's footprint on the bilateral power market provides a useful indication of broader price trends and conditions in the West. Prices at liquid hubs like Mid-Columbia (Mid-C) in the north and Palo Verde (PV) in the south may reflect ISO system conditions or vice versa. Power trades bilaterally on both a spot market for physical next-day delivery and on a forward basis for future months.

Next-day power trades in blocks for on-peak and off-peak periods[25]. Trading is conducted for next-day delivery and typically concludes prior to 10:00 AM PST. The figures below show a comparison between northern and southern hubs and their corresponding IFM LMP for the PG&E DLAP. In Figure 33 for the northern region, the Mid-C on-peak bilateral price traded lower than the highest hourly IFM LMP for the corresponding trading day throughout July, with some exceptions in the beginning of the month. However, due to the block nature of the bilateral power trades, the block price for Mid-C was generally higher than IFM LMPs for hours outside the evening ramp period. The NP15 bilateral price traded more infrequently throughout the month, hence the sporadic availability of data in the trend.

Figure 34 for the southern region shows a similar pattern of bilateral on-peak prices at Mead, PV, and SP15 trading lower than the highest hourly IFM LMP for the SCE DLAP. Towards the later part of July, the SCE IFM LMPs spike to exceed on-peak bilateral prices, though prices tracked more closely in the beginning of the month. Mead and PV prices traded closely while SP15 prices tended to trade lower, for both on-peak and off-peak periods.

Because bilateral prices trade in block intervals, Figure 35 and Figure 36 below show a similar trend with the corresponding ISO IFM LMP averaged over the on-peak or off-peak block interval. This trend attempts to smooth out the highest peak prices and provide a similar comparison to the block nature of the bilateral prices. Once averaged, the ISO IFM LMPs are generally lower than the corresponding bilateral prices throughout the month.

Figure 33: PG&E IFM LMP compared to bilateral northern prices



[25] Peak is typically defined as hours-ending 7-22 on weekdays and Saturdays; off-peak is typically defined as hours-ending 1-6 and 23-24 on weekdays and Saturdays, and hours-ending 1-24 on Sundays and holidays.

Figure 34: SCE IFM LMP compared to bilateral southern prices

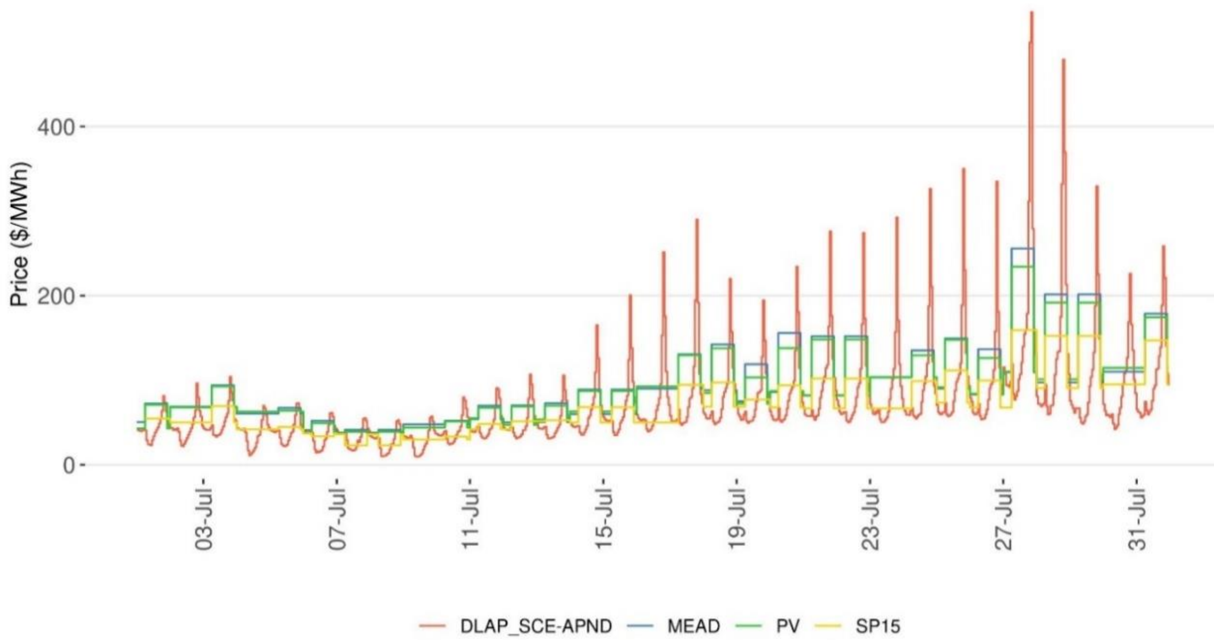


Figure 35: Northern hub prices and PG&E IFM LMP (block average), July 2023

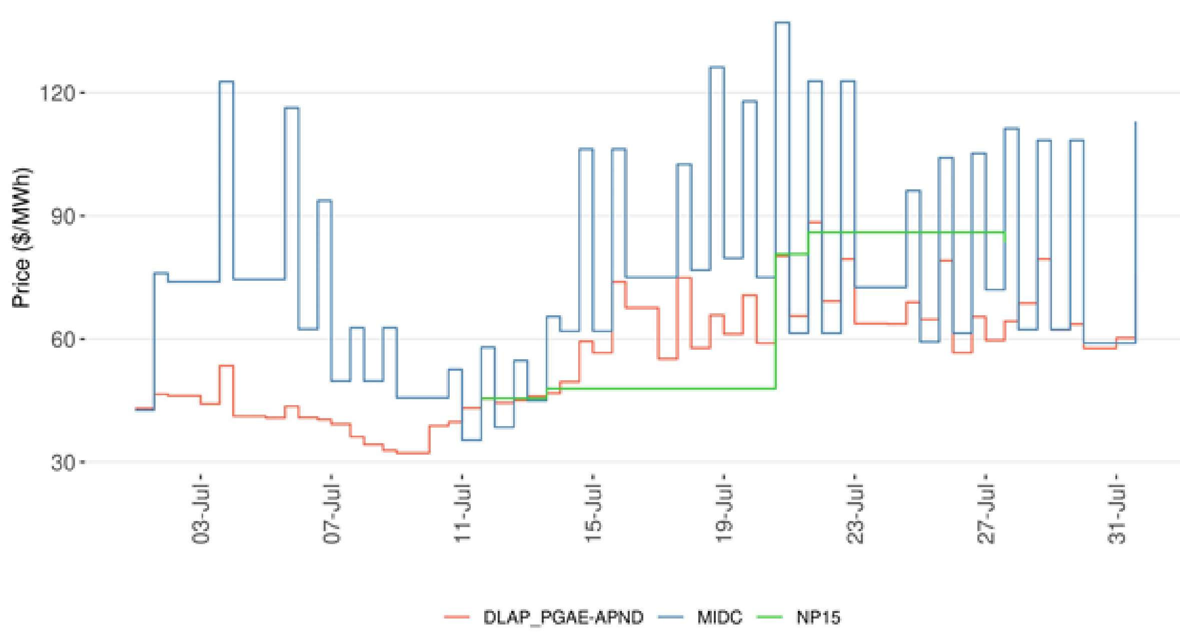


Figure 36: Southern hub prices and SCE IFM LMP (block average), July 2023

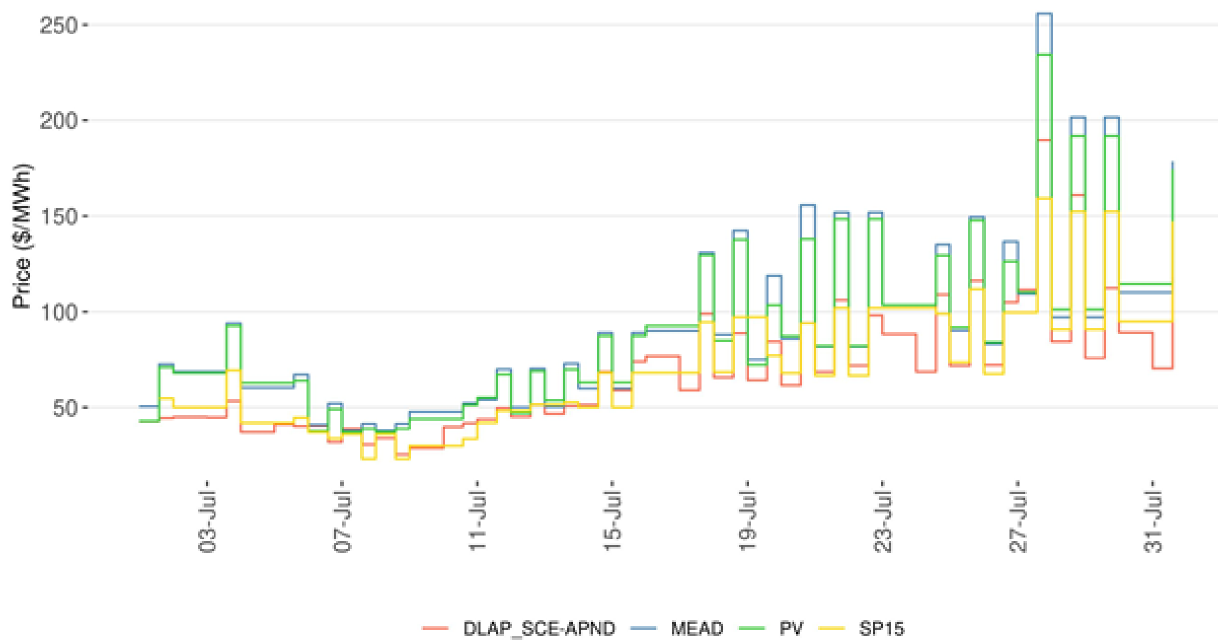
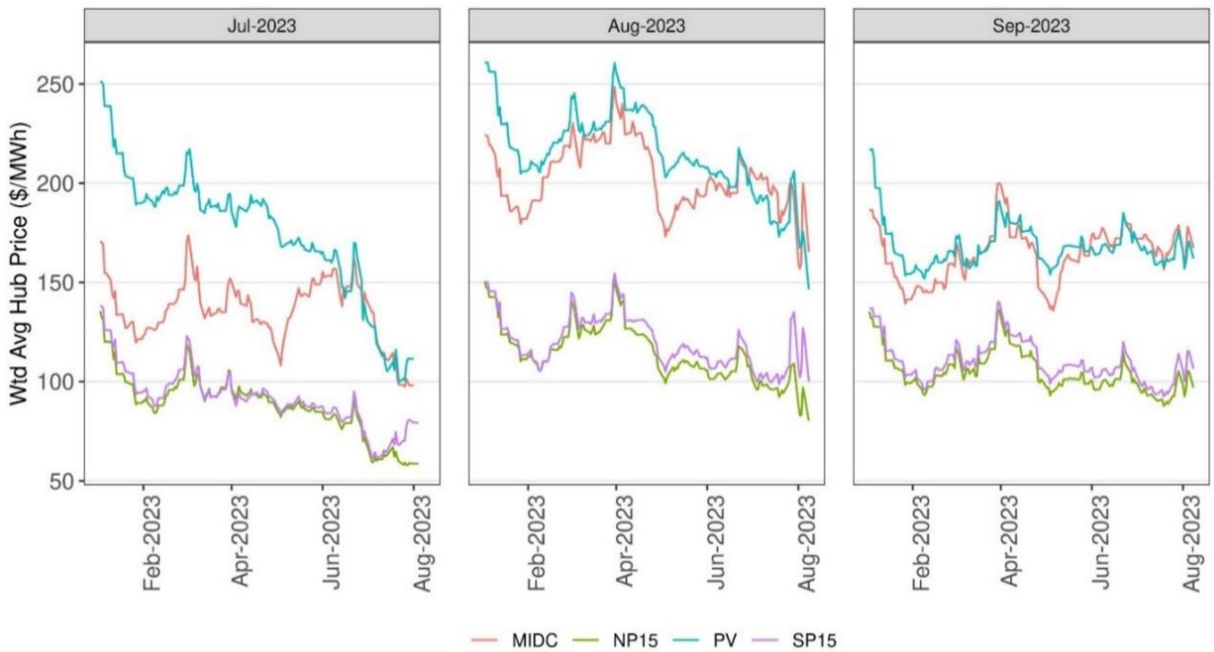


Figure 37 found below shows a year-to-date trend of on-peak future power prices traded for the 2023 summer months of July, August, and September. Price trends are captured for Mid-C and PV, as well as the NP15 and SP15 options that trade bilaterally. Figure 146 in the Appendix shows a similar trend for off-peak future power prices. On-peak future prices have traded dynamically for summer months, spiking in early January 2023 following the December gas price volatility. Price separation can be observed between the two groups of hubs, with Mid-C and PV generally trading higher than SP15 and NP15. Prices across all hubs track more closely for the off-peak future products.

Figure 37: On-peak future power prices for summer 2023



5 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 and other LRAs establish Qualifying Capacity (QC) calculations, which are generally 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.

5.1 Supply and RA capacity

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 according 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 day-ahead market 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 as above RA.

Figure 38 shows the breakdown of the day-ahead supply capacity[26] 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

[26] 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.

in the day-ahead market has the same capacity breakdown but the comparison is relative to the net load (gross load minus VER forecast).

Figure 38: Supply capacity available relative to load forecast in the day-ahead market

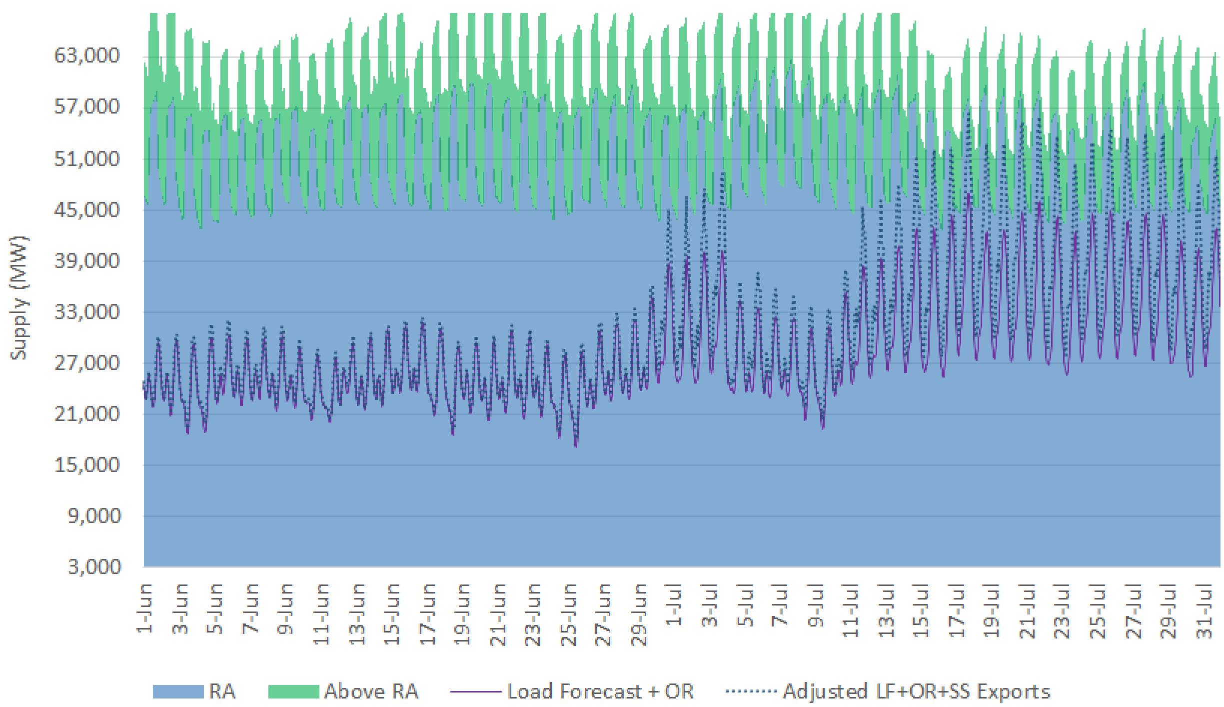
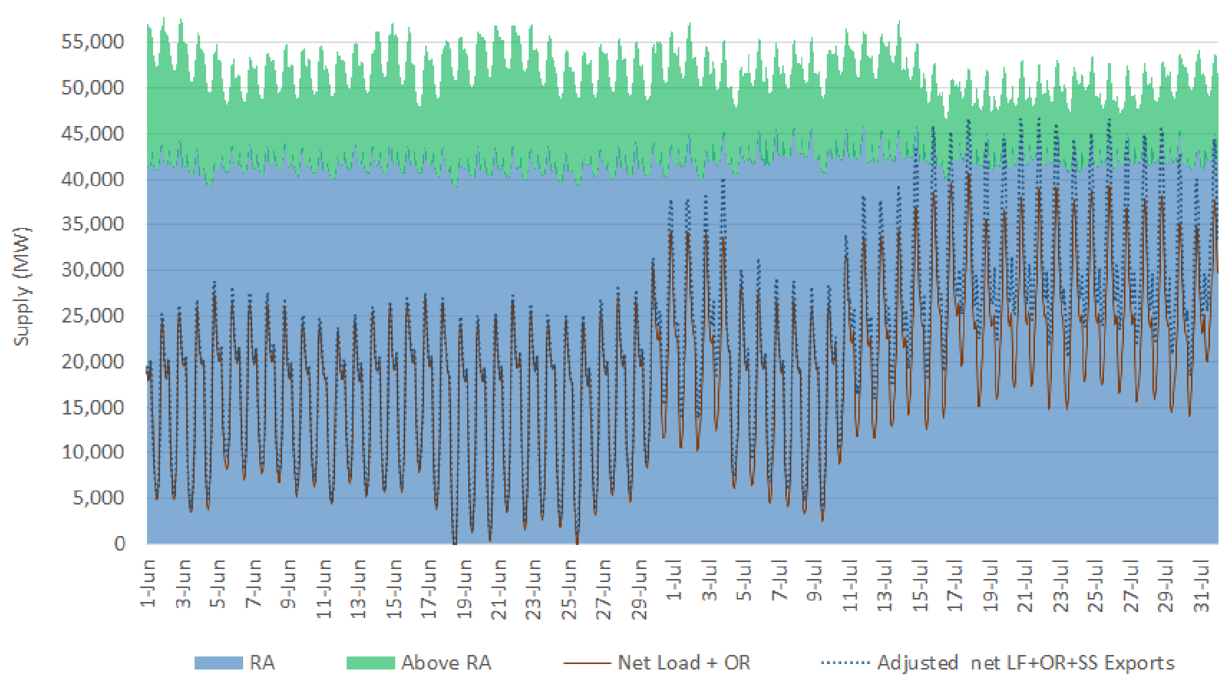


Figure 39: Supply capacity available relative to net load forecast in the day-ahead market

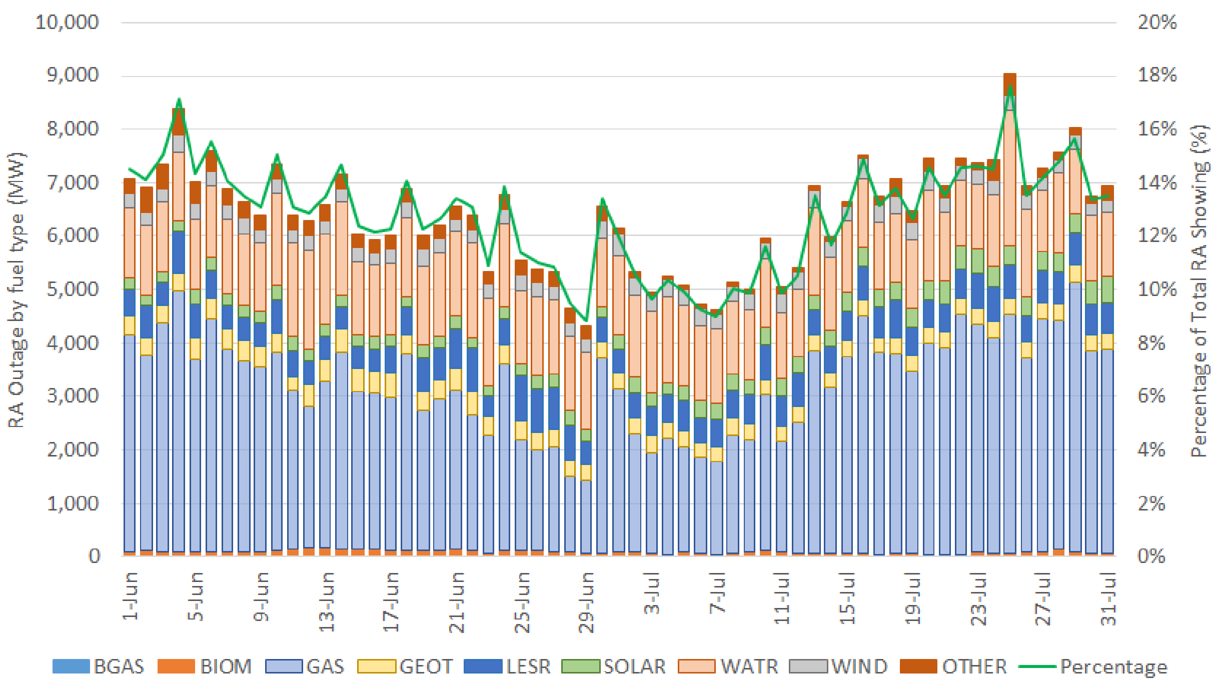


Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour. In gross load trend, the load peaked on July 17 whereas net load peaked on July 21 in the day market. For instances in which the load needs exceed the available RA capacity, the market will utilize any other above RA available capacity. For the month of July, above-RA capacity was consistently available into the market.

5.2 Unavailable RA capacity

Generating units can face operating conditions that required them to be derated or be offline. ISO tracks these outages through the outage system and these outages are reflected in the capacity made available in the market. The market consumes the outage information and imposes these limitations on the units when clearing, making them unavailable or derating their capacity accordingly. Some outages may be planned while others may be forced. Figure 40 provides the trend of RA capacity by fuel type on outage during the month of June and July. It shows that the capacity on outage decreased over the month. On average, the average daily capacity on outage is about 6,429 MW.

Figure 40: Volume of RA capacity by fuel type on outage in July



5.3 Demand and supply cleared in the markets

The day-ahead market is composed of three different passes: local market power mitigation (LMPM), IFM and RUC. Each of these market runs has a purpose and each of them is solved based on a cost-minimization optimization problem. The first pass of the day-ahead market, 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. The IFM clears both physical and convergence bid supply against bid-in demand, convergence bid demand and exports, and produces awards and 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 and renewable uncertainty. The RUC process will clear supply against the final adjusted load forecast. Figure 41 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, as compared to mild load days through the month to high load day on July 17.

Figure 41: Day-ahead demand trend in July

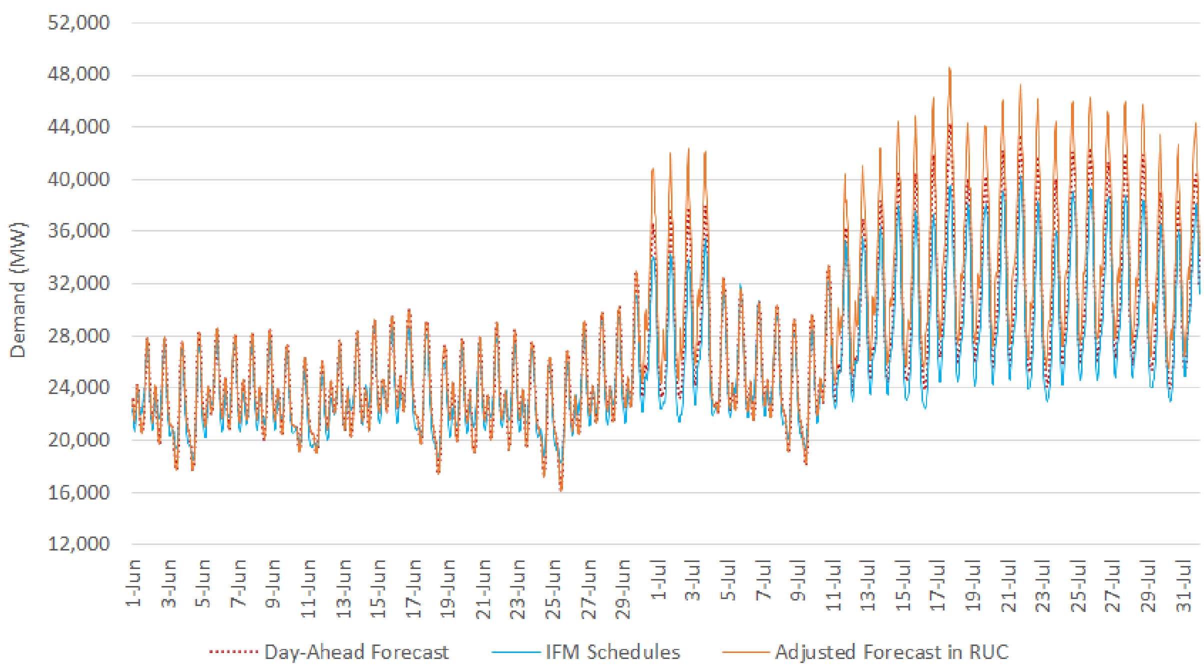
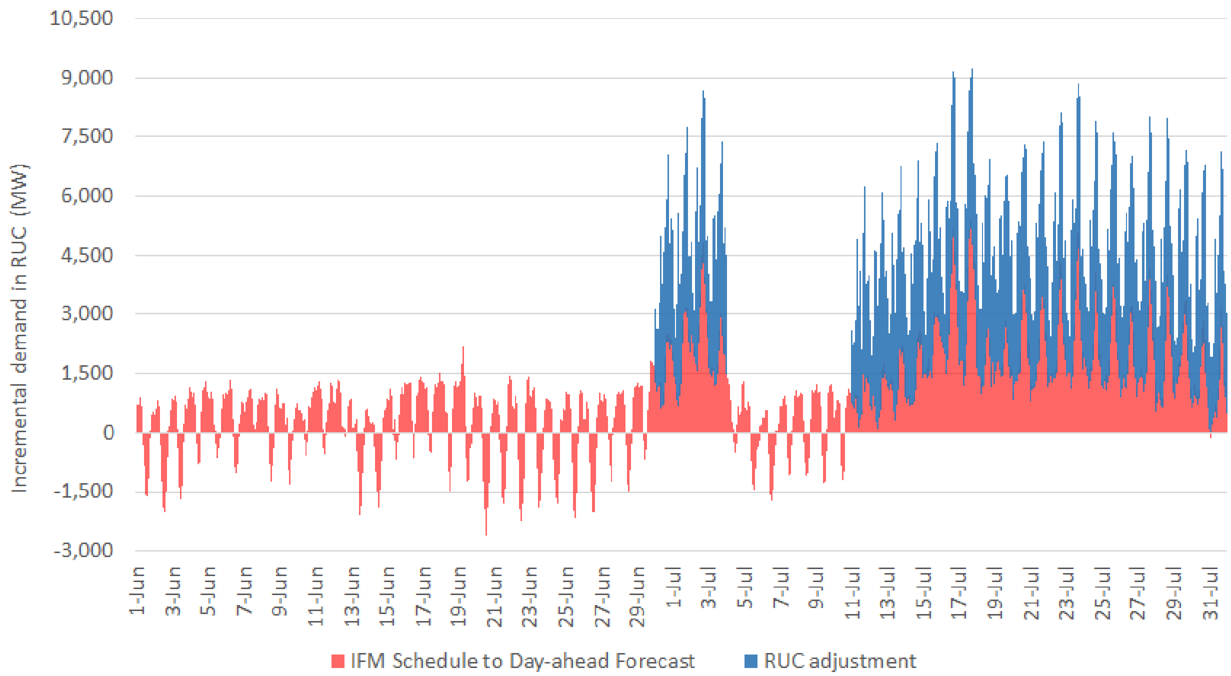


Figure 37 shows the differences between the IFM schedules for physical resources versus the nominal day-ahead load forecast. This is the additional capacity relative to the IFM solution that RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus 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. 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 add to this requirement.

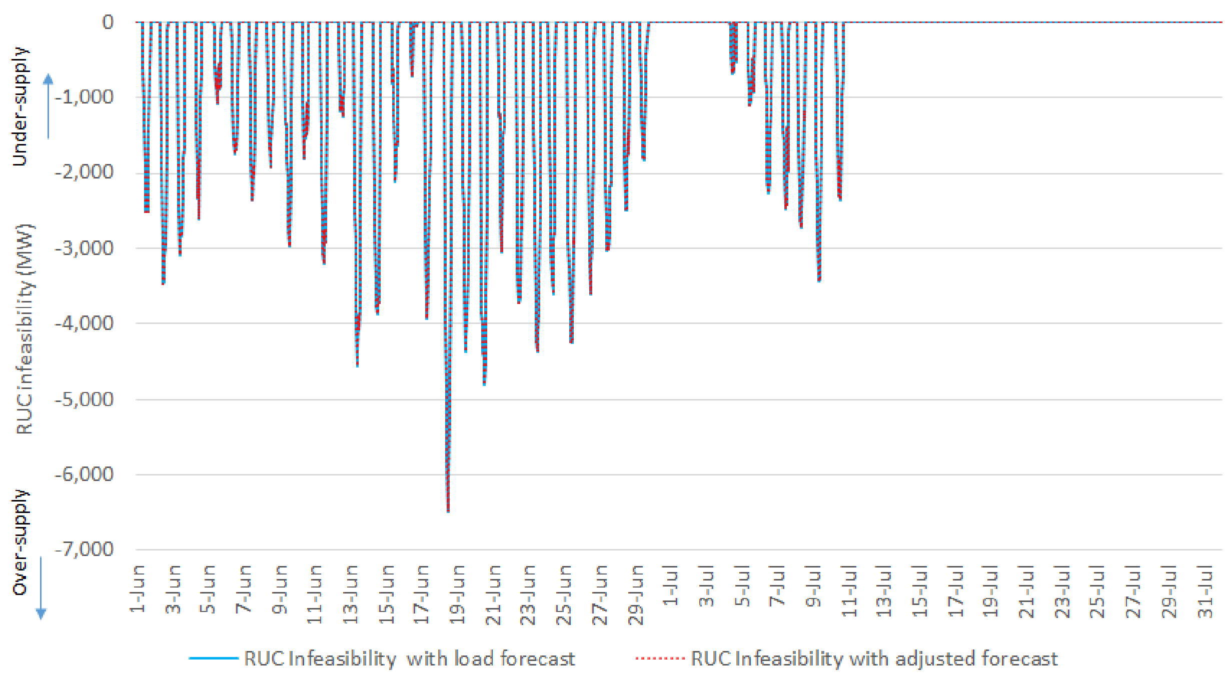
Figure 42: Incremental demand required in RUC in June and July 2023



The RUC forecast adjustment is guided by historical uncertainty of load, wind, and solar from the day-ahead to the real time market. In some cases, there may be other factors to consider by operators to determine the final adjustments. For the month of June there was no RUC adjustment with the exception of June 30. However, RUC adjustments were used throughout July once demand levels exceeded the 35,000 MW threshold. This minimum use of RUC adjustment for the month of June is part of a pilot program for ISO to assess the use of RUC adjustments. Under the pilot program, no RUC adjustments were used when demand was projected to be under 35,000 MW. ISO continues to assess the conditions and the need for RUC adjustments and in July ISO started using a methodology similar to the imbalance reserves proposed for the day-ahead market enhancement to use as a guidance for RUC adjustments.

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 reduced all the economic and LPT exports[27], which leaves just the power balance constraint to be relaxed and reducing PTK (high priority) exports, to allow RUC to clear. Figure 43 shows 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. There were no RUC under-supply infeasibilities for the month of June and July. There were over-supply infeasibilities for few days of July once demand levels started to increase.

Figure 43: RUC infeasibilities in June and July 2023



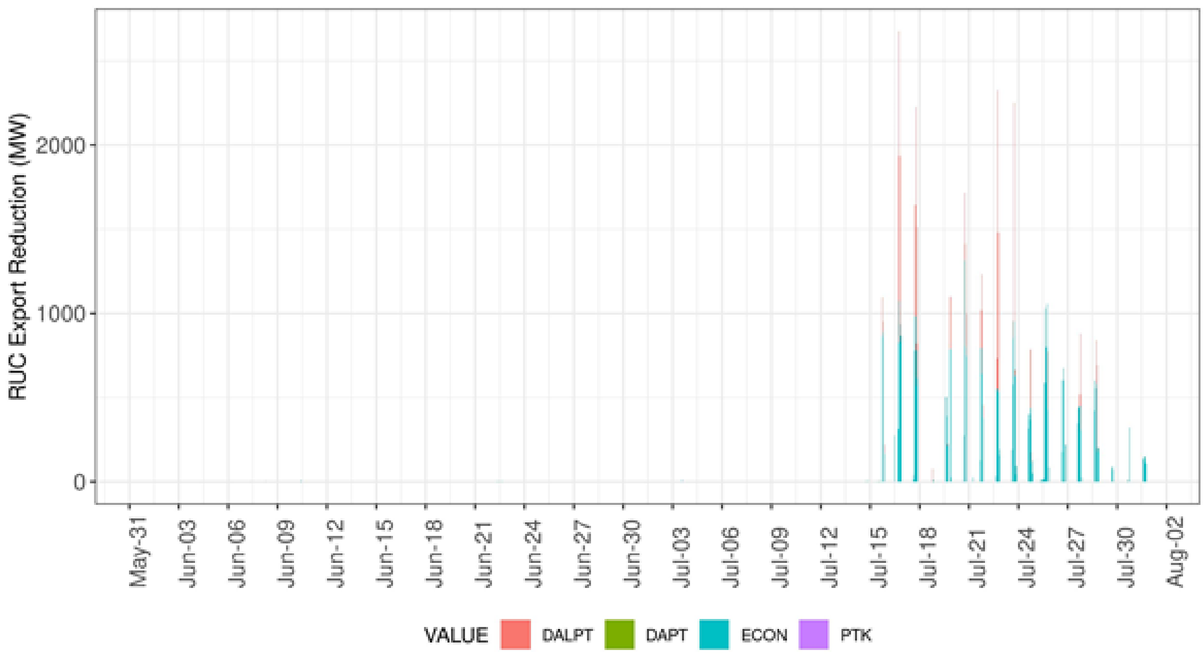
In addition to relaxing the power balance constraint, the RUC process utilized other scheduling priorities to enforce the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and 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[28].

[27] 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 PTK (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 reduced LPT exports before relaxing the power balance constraint.

[28] 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 reductions 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.

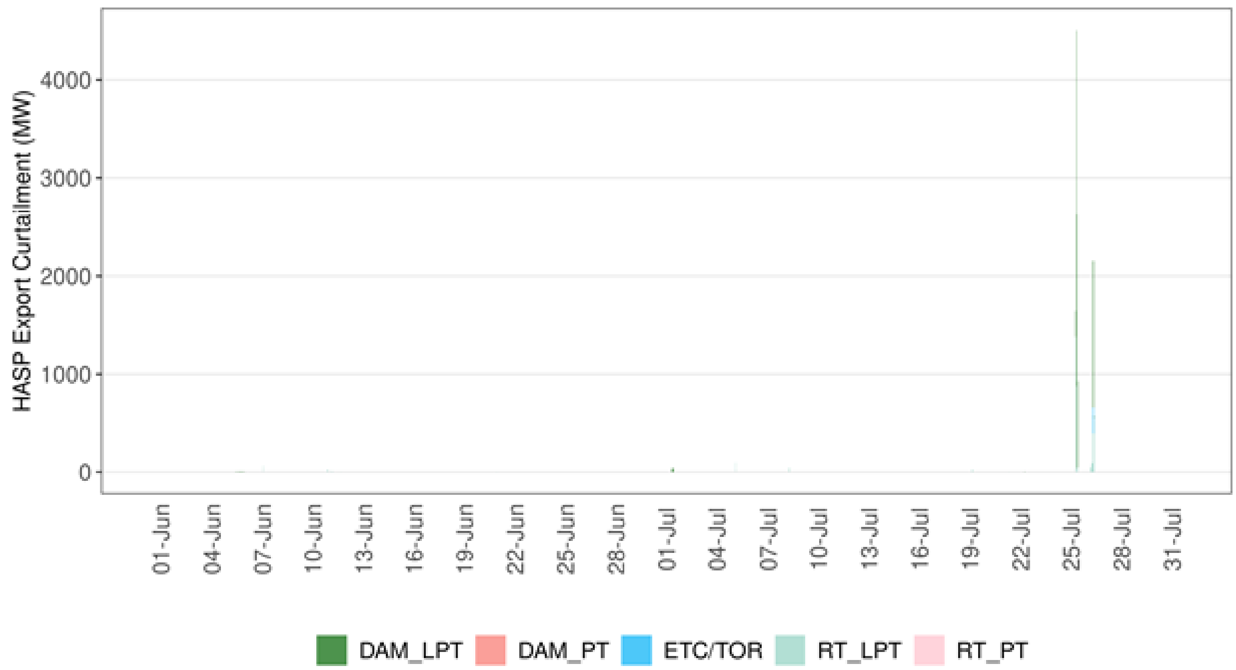
Figure 44: shows the volume of hourly export reduction in the RUC process, which happened only for economic exports and low priority exports across the month.

Figure 44: Exports reduction in RUC



Exports can still participate in the real-time market by rebidding relative to the DAM solution, or directly into real-time market 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 real-time market. The schedules cleared from the RUC process are treated in the real-time market as having a day-ahead priority, which is above the corresponding priority of LPT exports submitted directly 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 LPT self-schedules in the real-time market, which are more at risk of reductions in the hour-ahead scheduling process (HASP) process. The PTK or high-priority exports can be bid in either the day-ahead or real-time market and will have the same priority to ISO load, which is higher than the low-priority exports. The real-time market issued reductions during July 25 and July 26 mainly for low priority exports and economical exports. Appendix B of this report provides a detailed explanation of scheduling priorities in ISO's markets

Figure 45: Exports reductions in HASP



6 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 real-time markets 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 high priority (PTK) and low priority exports (LPT).

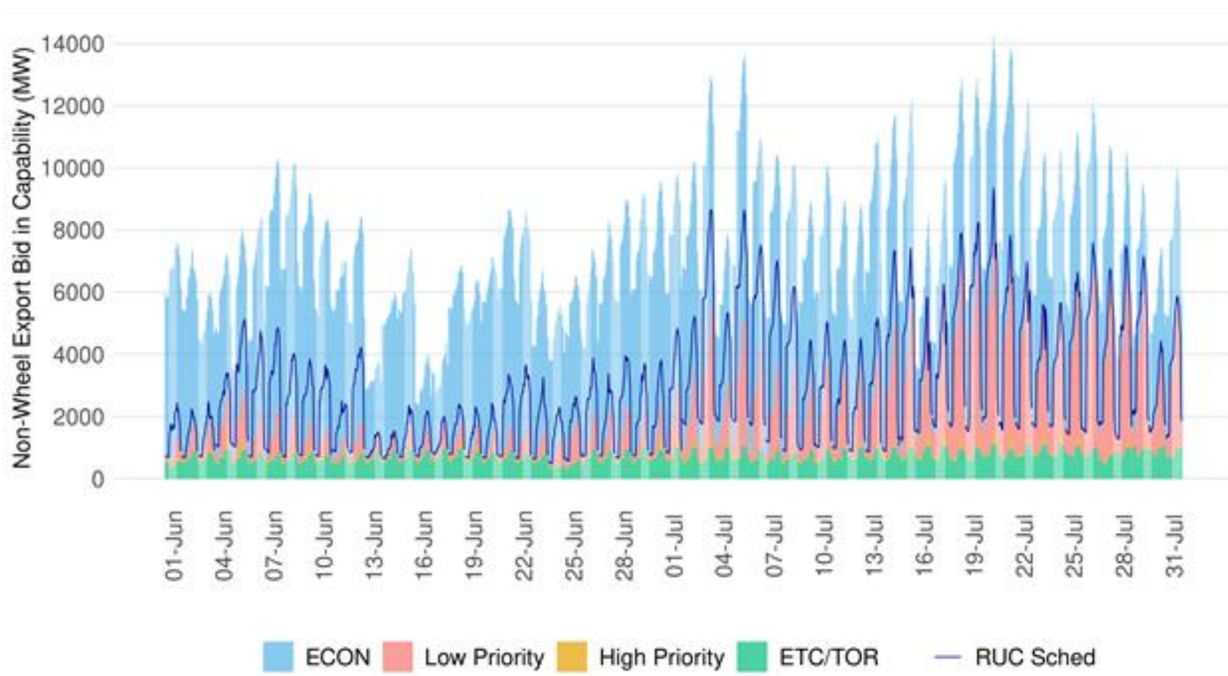
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into account. 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.

6.1 Intertie supply

Figure 46 shows the capacity from static export-based transactions in the day-ahead market for the month June and July 2023 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 day-ahead market. As defined in Section 31.8 of the ISO tariff, in the day-ahead market, 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 day-ahead market. This is to ensure that intertie schedules cleared in the day-ahead market 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 46: Day-ahead Bid-in capacity and RUC cleared export



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 adjusted by the ISO. This applies to all dynamic and static intertie schedules.

Export bid capacity in the day-ahead market varies by hour and typically follows a daily profile. About 62 percent, 27 percent, 9 percent and 1 percent of the export capacity were for economic bids, ETC/TOR, LPT and PTK, respectively. Due to mild load conditions and robust level of supply in the day ahead conditions in June and July, there was high volume of exports except for the heat wave events.

Figure 47: Day-ahead bid-in capacity and RUC-cleared imports

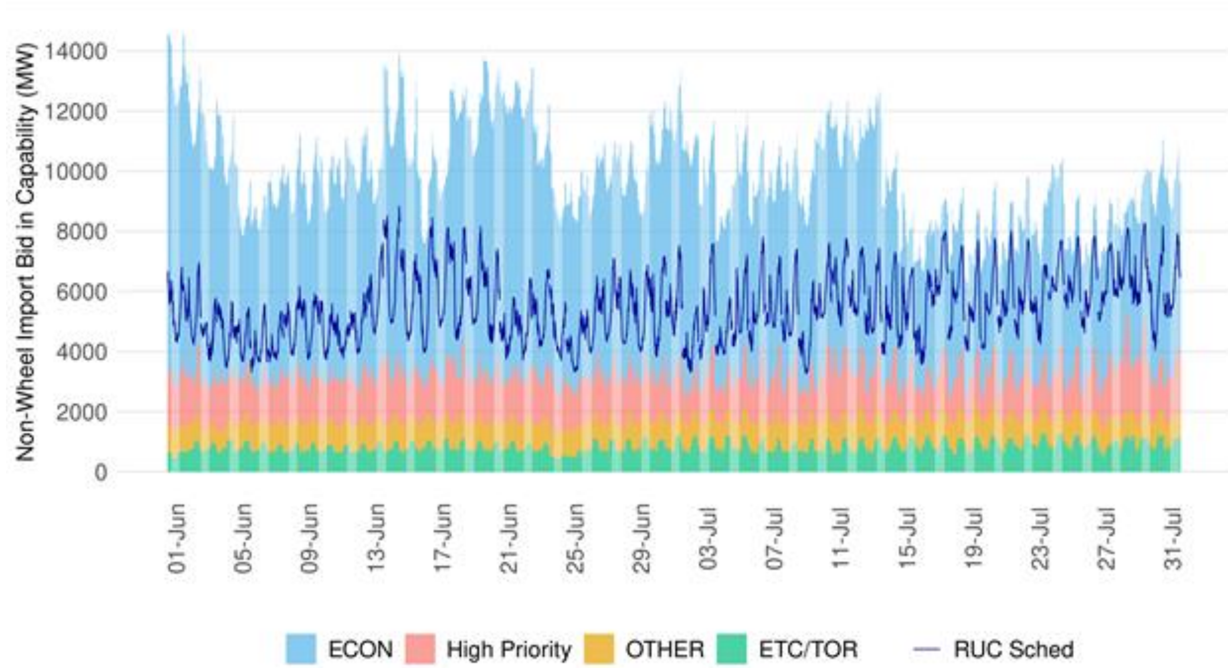


Figure 47 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the month, while hourly economic imports continued to see a high volume over 5,000 MW. The "Other" group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

Figure 48 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 levels on July 20 in HE 16 at about 2800 MW due to the higher level of exports cleared.

Figure 48: Breakdown of RUC cleared schedules

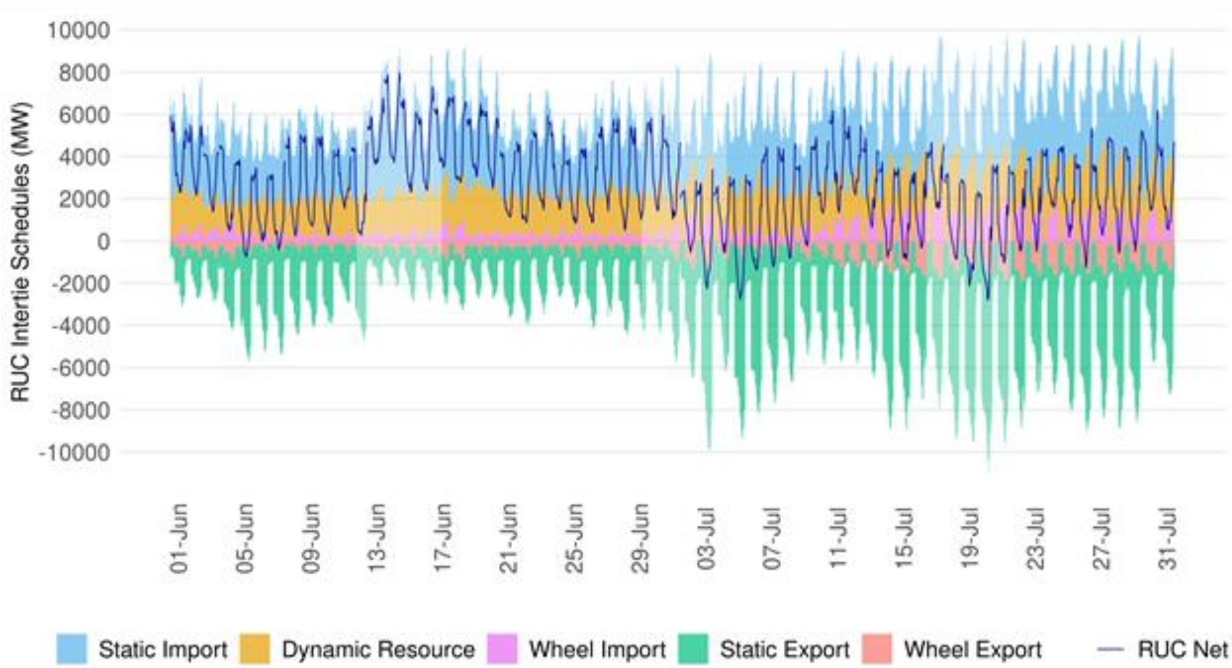
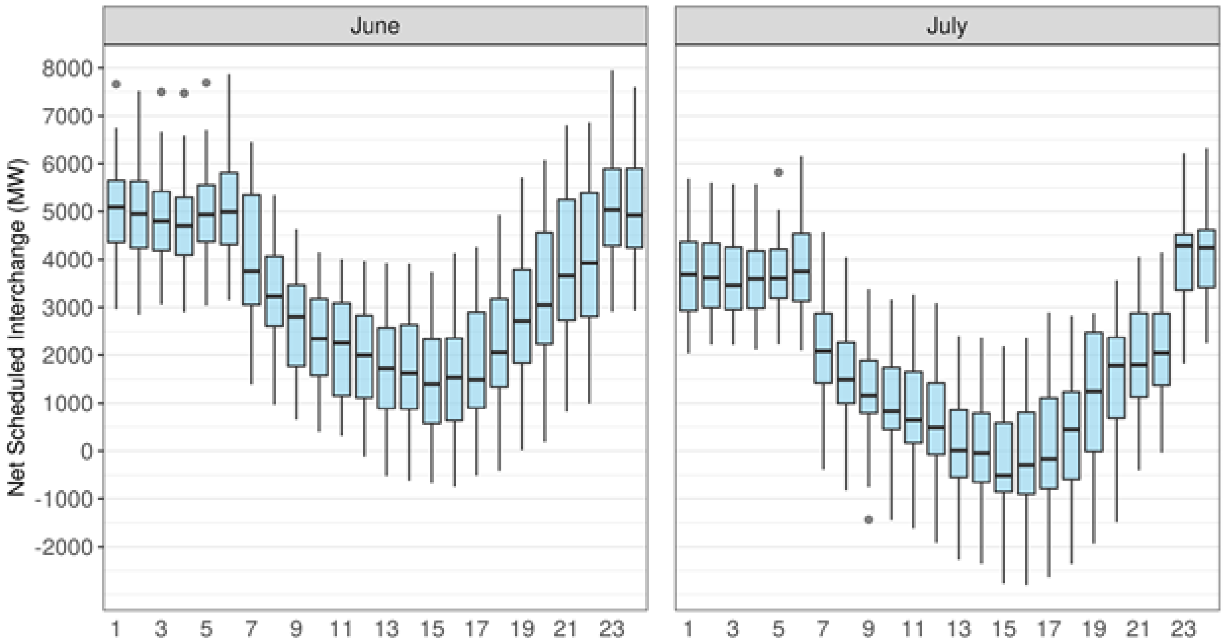


Figure 48 illustrates the hourly net schedule interchange distribution by hour for the month of June and July. This trend is useful to visualize the hourly profile of schedules and shows that net schedules reduce in midday hours when solar production comes in and start to increase as the solar production drops off 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 mid-day hours prior to the gross peak when solar supply is still plentiful.

Figure 44: Hourly RUC net schedule interchange



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 45 illustrates the hourly distribution of RUC schedules for exports, and that the highest volume occurred during midday hours when ISO's system has excess solar supply; exports were in high demand during the afternoon hours for the month of July.

Figure 49: Hourly RUC exports

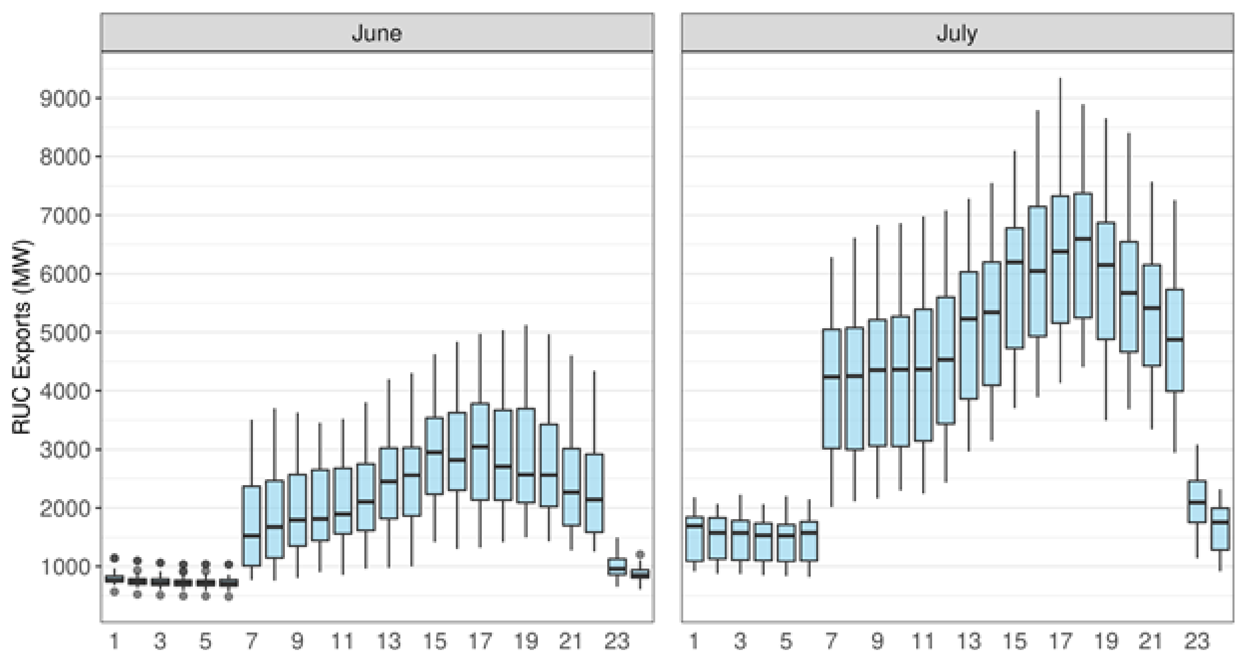
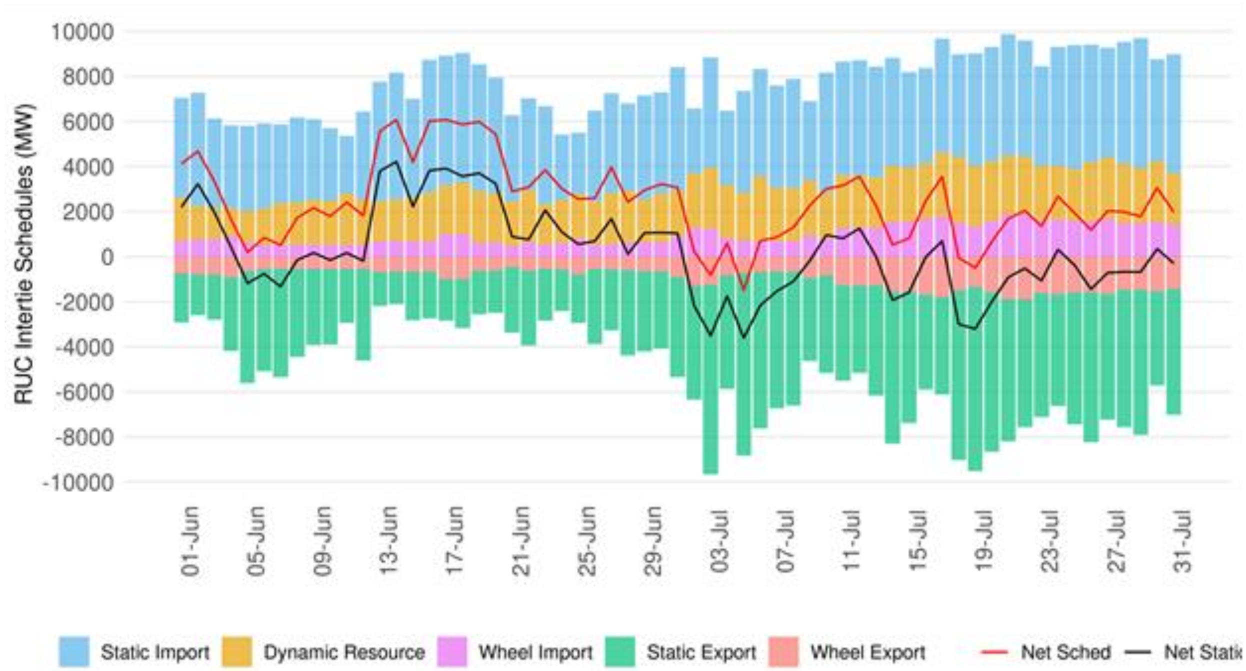


Figure 50 shows the intertie capacity available in the day-ahead market for hour ending 20 to highlight the conditions around peak time, when the ISO's system faces the highest supply needs.

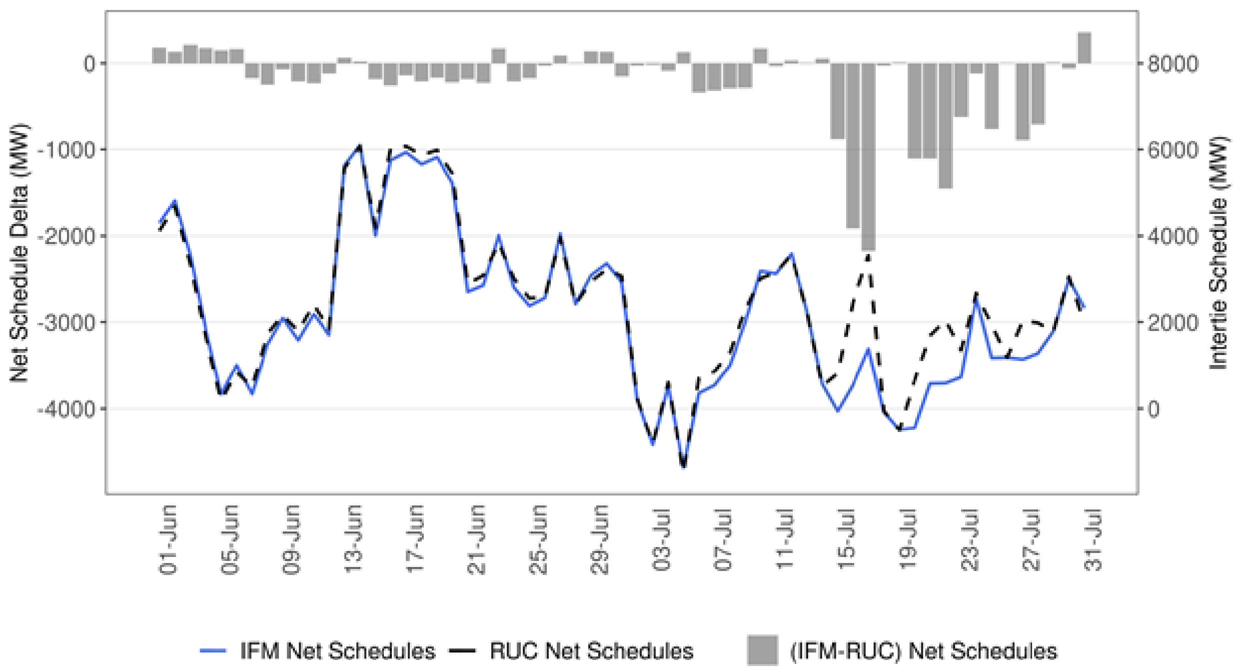
Figure 50: RUC schedules for interties for hour ending 20



The net balance between imports and exports does not include 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 blue 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 their 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 51 compares the net schedule cleared in both IFM and RUC for hour ending 20, and provides the relative change of schedules between the two processes as shown with the bars in green. These changes can happen for any type of resources and are not always limited to a reduction of exports. IFM schedules for exports were reduced in the RUC process for few days in the month of July.

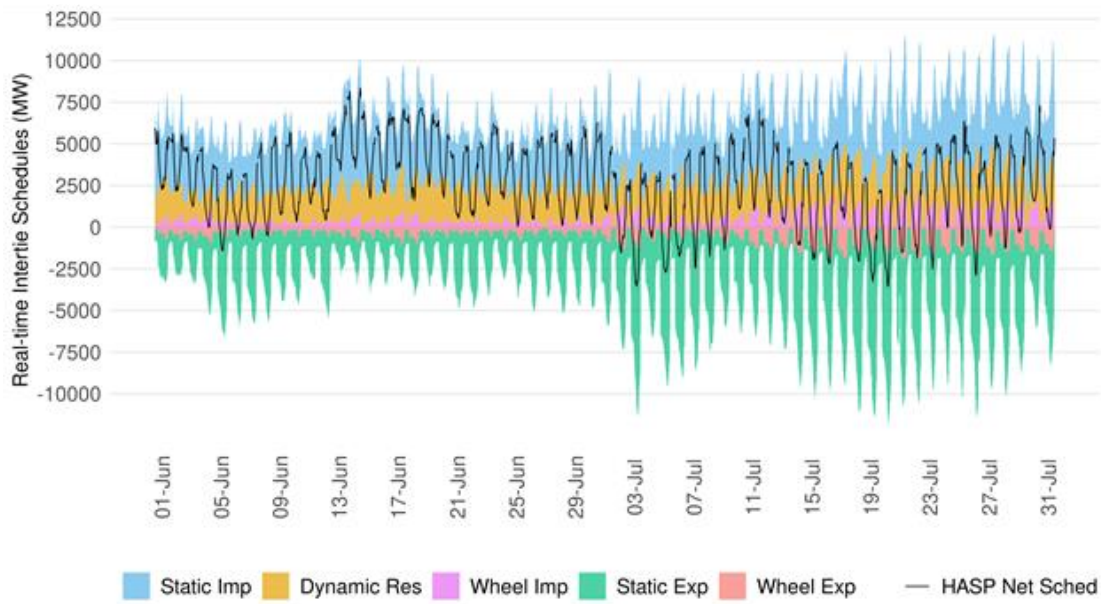
Figure 51: IFM and RUC schedule interchange for hour ending 20



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

Figure 47: shows the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred to as Net Schedule Interchange or NSI. The NSI is at its lowest value in July 5 due to the highest level of exports cleared on that day prior to the evening peak. The real-time market largely follows the trend observed in the day-ahead market. On average, for July the NSI in HASP was about 1,909 MW across all the hours of the month and about 740 MW for peak hours.

Figure 47: HASP cleared schedules for interties in July



The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Interties cleared in DAM can submit self-schedules into real-time. Clearing the RUC in the DAM process indicates that these exports were feasible to flow based on the projected system conditions in RUC[29]. Additionally, exports can participate directly into the real-time market with either self-schedules or economic bids.

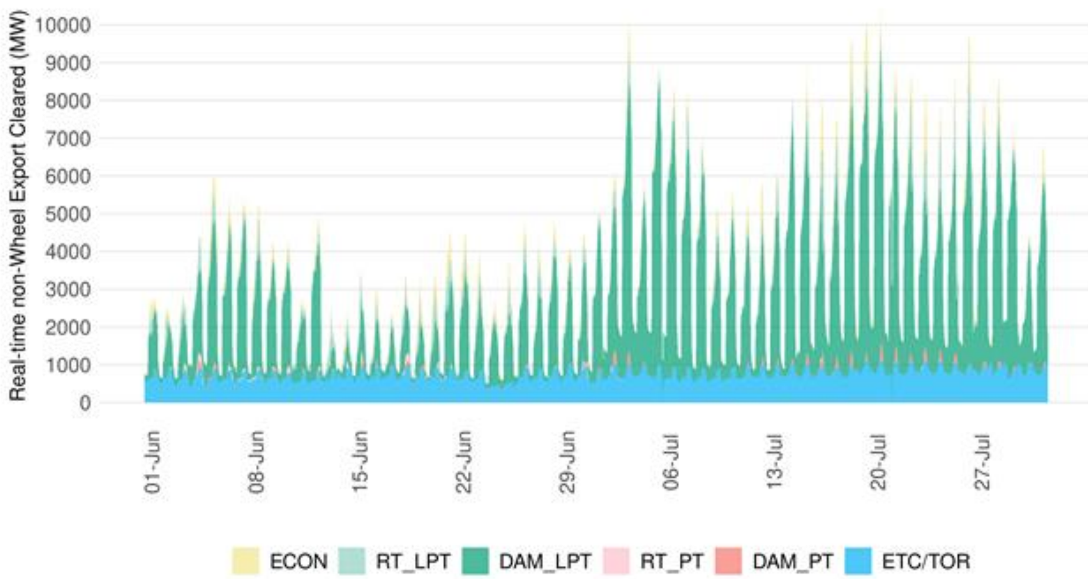
Both RUC and HASP, assess the ability to support exports based on the overall system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority but they are able to be rebid into the real-time market and be fully assessed based on real-time conditions. 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 52 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_PTK and RT_LPT). ECON stands for economic exports. The group of wheels stands for all type of wheels observed in the real-time market (low- or high-priority). Given the many different groups for exports, wheels are 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.

[29] Based on these rules implemented on August 4, 2021, 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

The volume of exports cleared in real time follows the pattern of loads with a fair increase in early July, peaking over 10,419 MW on July 20. In July a significant portion of cleared exports were those with low priority and economical bids.

Figure 52: Exports schedules in HASP



Imports and exports were scheduled over multiple intertie scheduling points in July, with Malin, Paloverde and NOB seeing the highest volume of transactions. Figure 53 through Figure 55 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[30]. For trade dates in early July and mid-July, exports on Malin were higher than imports so that the net flows on the intertie were in the export direction.

[30] 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 53 HASP schedules at Malin intertie

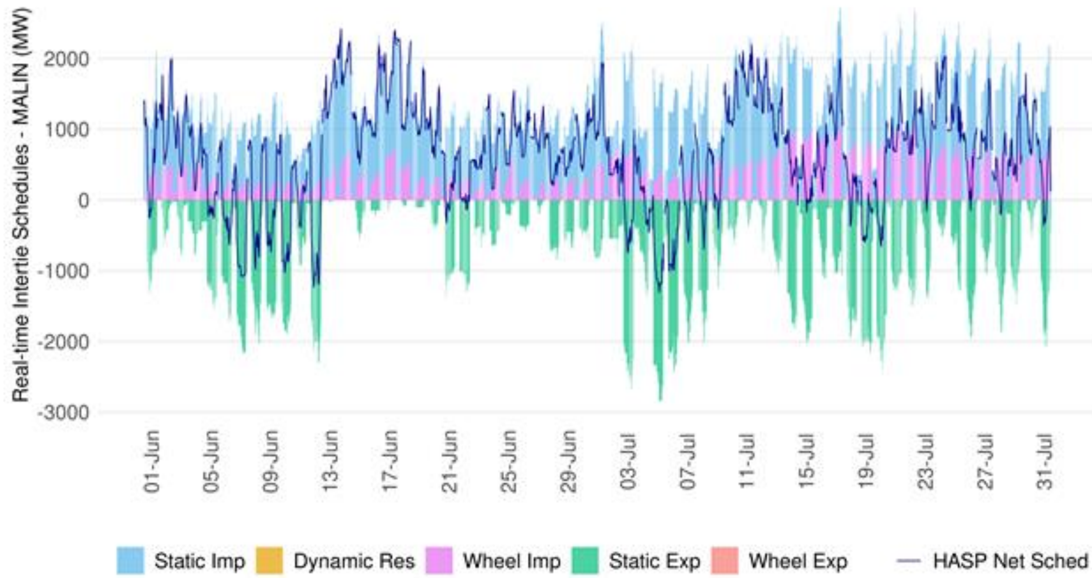


Figure 54: HASP schedules at PaloVerde intertie

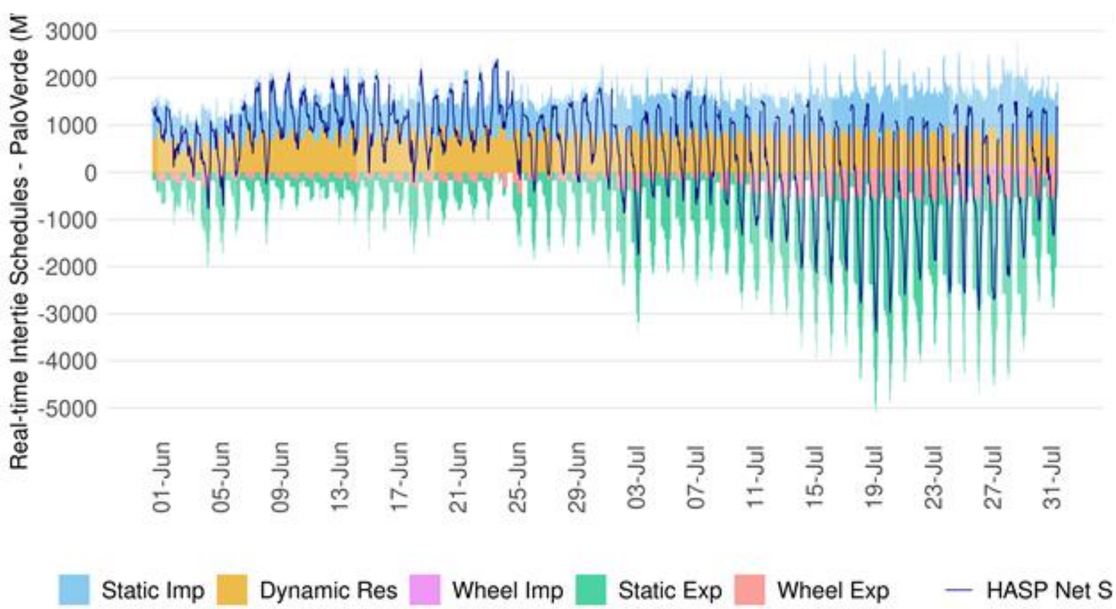
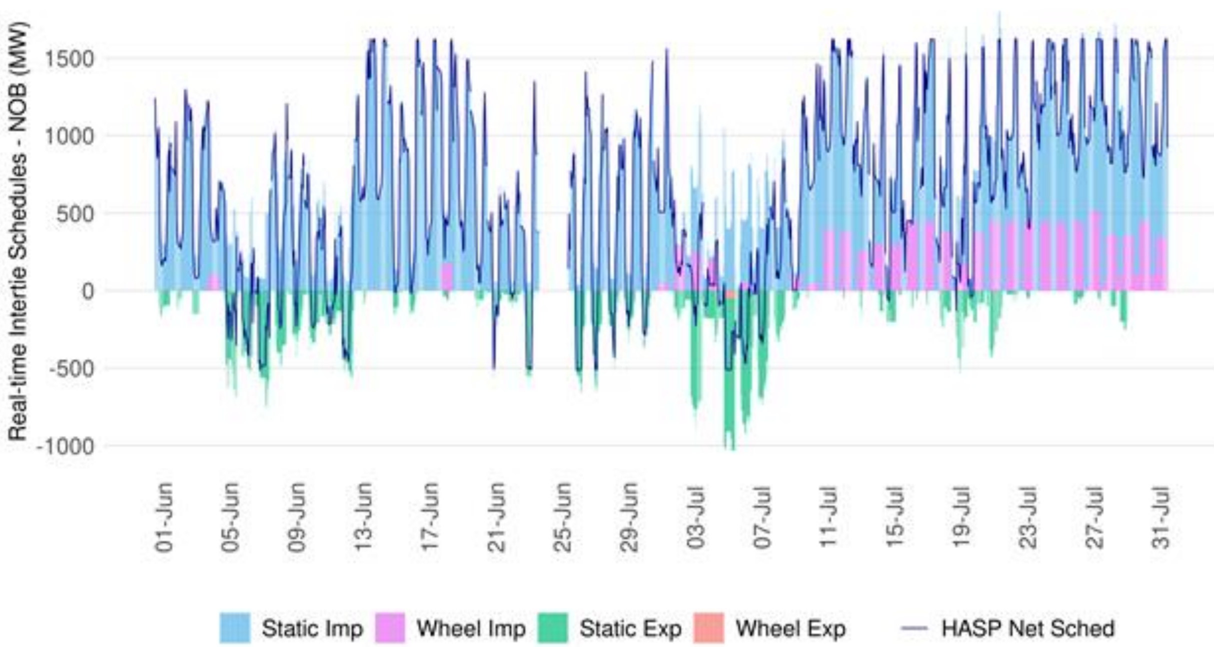


Figure 55: HASP schedules at NOB intertie



6.2 Resource adequacy imports

Imports can be used to meet Resource Adequacy (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. The total amount of RA supported by static imports in July was about 2,082 MW related to LSEs under CPUC jurisdiction.

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 56 is an approximation of the supply bid in the day-ahead market 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 also differentiates between RA capacity and above RA capacity. Based on this subset, about 97 of all RA import capacity bid with either self-schedules or economic bid at or below $0/MWh in the day ahead for July. This plot also shows the cleared imports, which largely utilized all the bid-in volume for RA and Above RA.

Figure 56: Day-Ahead RA import for hour endings 17 through 21 in July

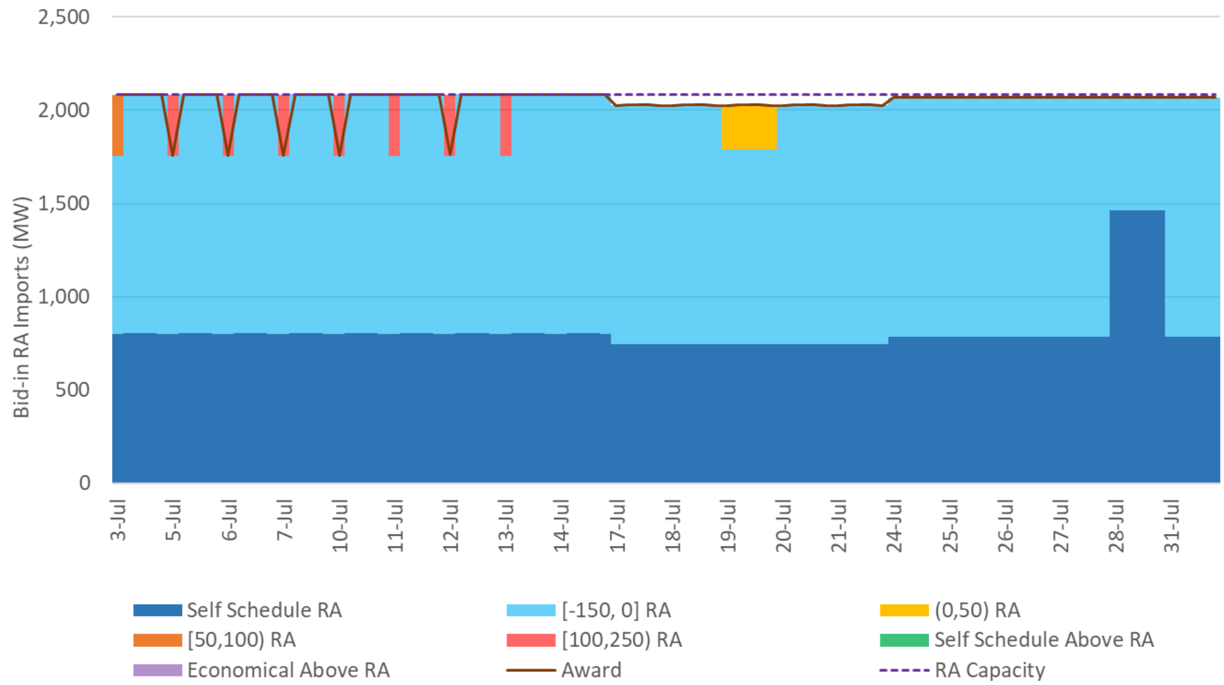
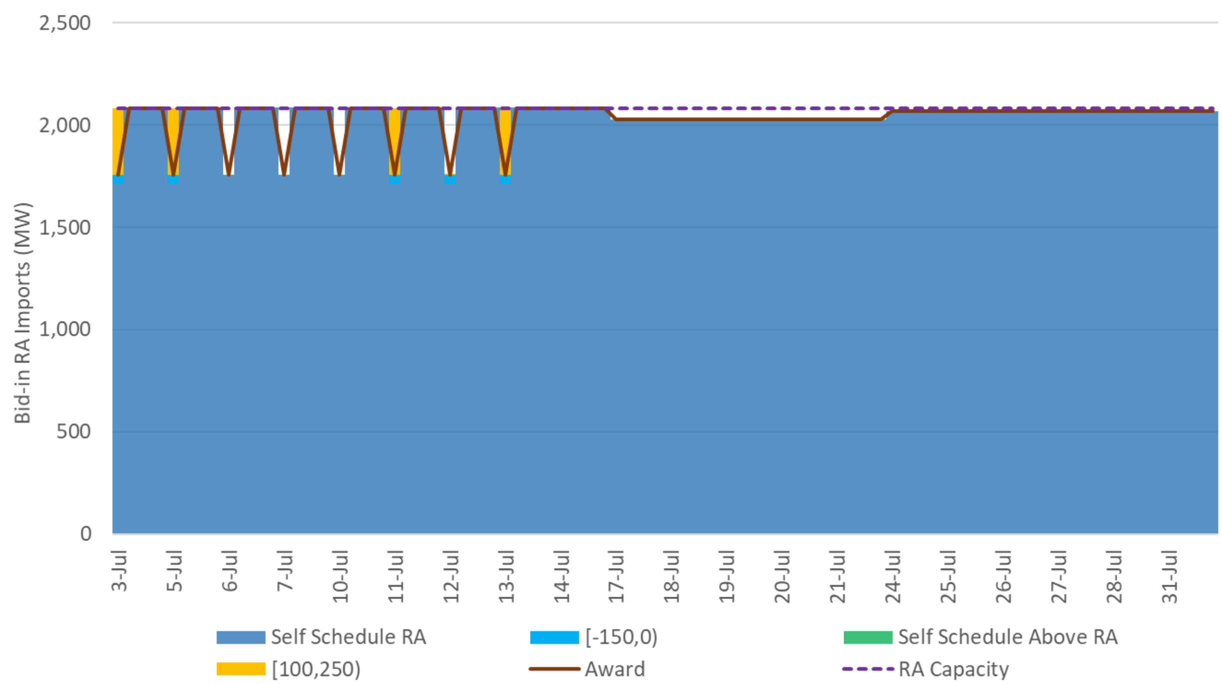


Figure 54 shows the same information for the real-time market using the HASP bids. About 97.7 percent of the RA imports submitted in the real-time market were with self-schedules or bids at or below $0. Small volumes of bids associated with RA imports bid in above their RA level with self-schedules.

Figure 54: HASP RA import for hour endings 17 through 21 for weekdays



6.3 Wheel transactions

With the enhancements for exports, loads and wheeling scheduling priorities extended for summer 2023, wheels seeking a high scheduling priority in the market equal to ISO load are required to register their wheel transactions up to 45 days prior to the start of month and meet specific requirements[31]. If the requirements are not met and the wheel transaction is not registered, the transaction receives a low scheduling priority. For the month of July 2023, the ISO received registration requests for a total of 1,820 MW from nine different scheduling coordinators. Table 1 shows all the wheel-through paths registered by scheduling coordinators[32].

Table 1. Wheel-through quantities registered for July 2023

Source	Sink	MW
CFEROA	PVWEST	50
CFETIJ	MEAD230	75
CTW230	LLL115	105
MALIN500	MEAD230	425
MALIN500	MCCULLOUG500	100
MALIN500	PVWEST	400
MIR2	RANCHOSECO	30
NOB	MEAD230	287
NOB	MCCULLOUG500	150
NOB	PVWEST	198
	Total:	1820

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

Figure 57 shows the hourly wheels cleared in the RUC process throughout the month. Wheels participating in the day-ahead market in the month of July were ETC/TOR, high- and low-scheduling priority, peaking at about 950 MW for high priority, with 700 MW of TORs, 375 MW of low priority wheels. There was only one economical bid with 50 MW for wheels on July 5. The volume of explicit wheels associated with ETC/TOR was stable throughout the month with higher values in peak hours.

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

[32] Some request for wheels provided both Malin and NOB as possible sources. For simplicity in the aggregation, half of the split MWs were assigned to Malin and half were assigned to NOB to split the MW quantity evenly between the two potential sources.

Figure 57: Hourly volume of day-ahead wheel transactions by type of self-schedule

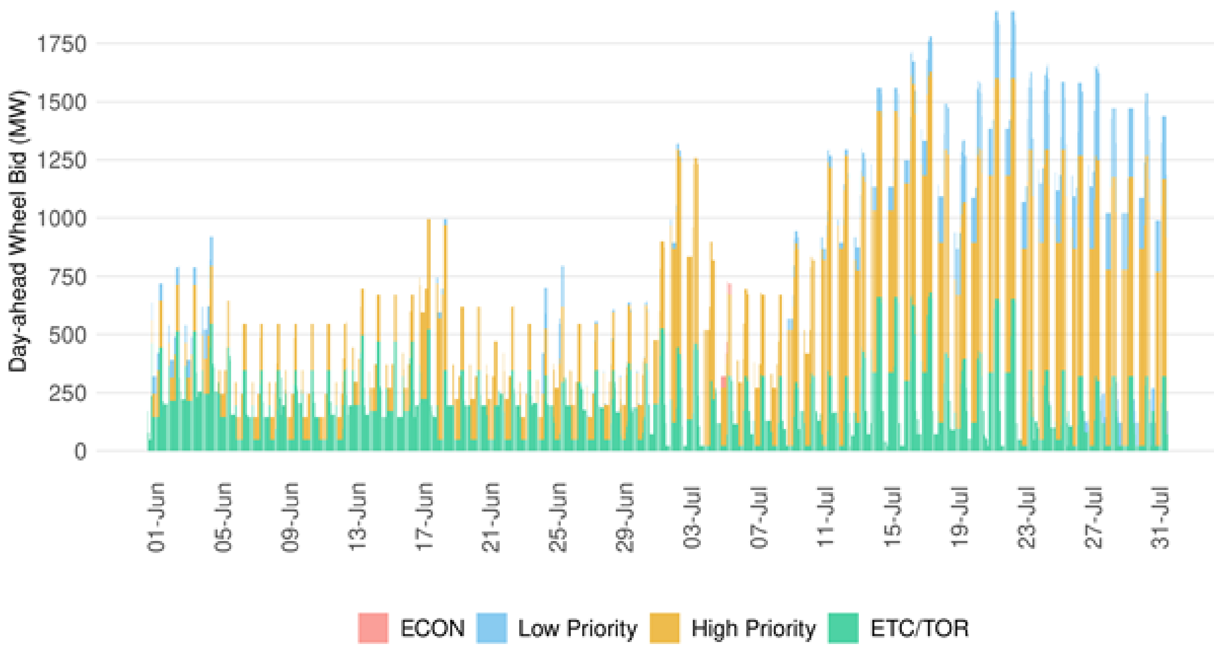


Figure 58: Hourly volume high- and low-priority wheels cleared in RUC

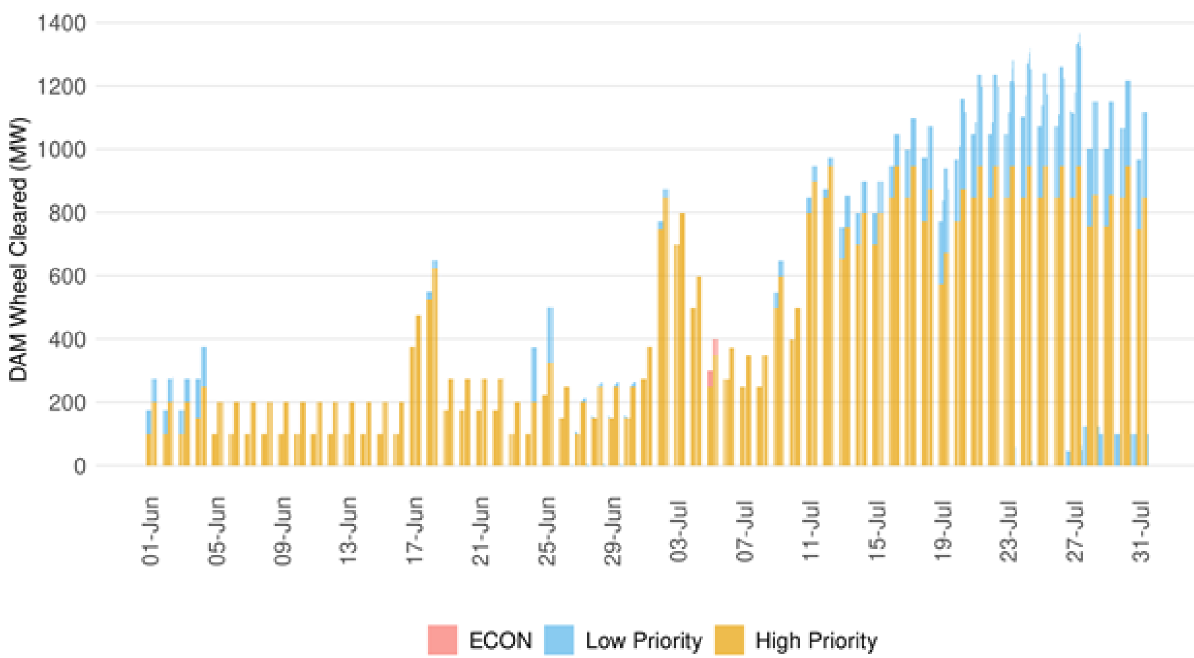
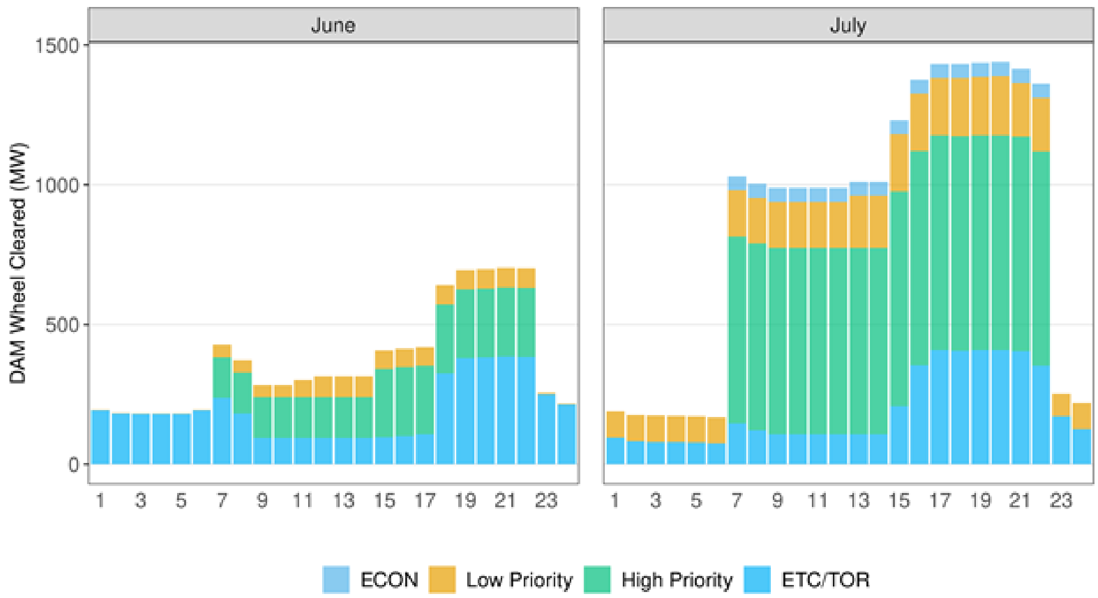


Figure 59 provides an hourly breakdown of high- and low-priority wheels, with the maximum hourly cleared RUC volumes of wheels occurring during the gross and net load peaks hours.

Figure 59: Day-ahead hourly profile of wheels in June and July



For July, high priority 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 58 ; *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 (hours ending 7 through hour ending 22).

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 60 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 June. Source refers to the import scheduling point while sink refers to the export scheduling point. The path with the largest volume of wheels in June in the day-ahead market was from Malin to PVWEST.

Figure 60 Hourly average volume (MWh) of wheels by path in July

		SINK			
TYPE	**SOURCE**	**MCCULLOUG500**	**MEAD230**	**MIR2**	**PVWEST**
LPT	MALIN500		14.5		7.4
	NOB		1.1		48
	PVWEST			26.7	
PT	MALIN500	16.7	126.9		183.3
	NOB	64.5	35.9		51.1

Figure 61 summarizes the maximum hourly wheels cleared in any hour in June in the day-ahead market by source-to-sink combination. The maximum volume of wheels in a given path occurred from Malin to Mead230.

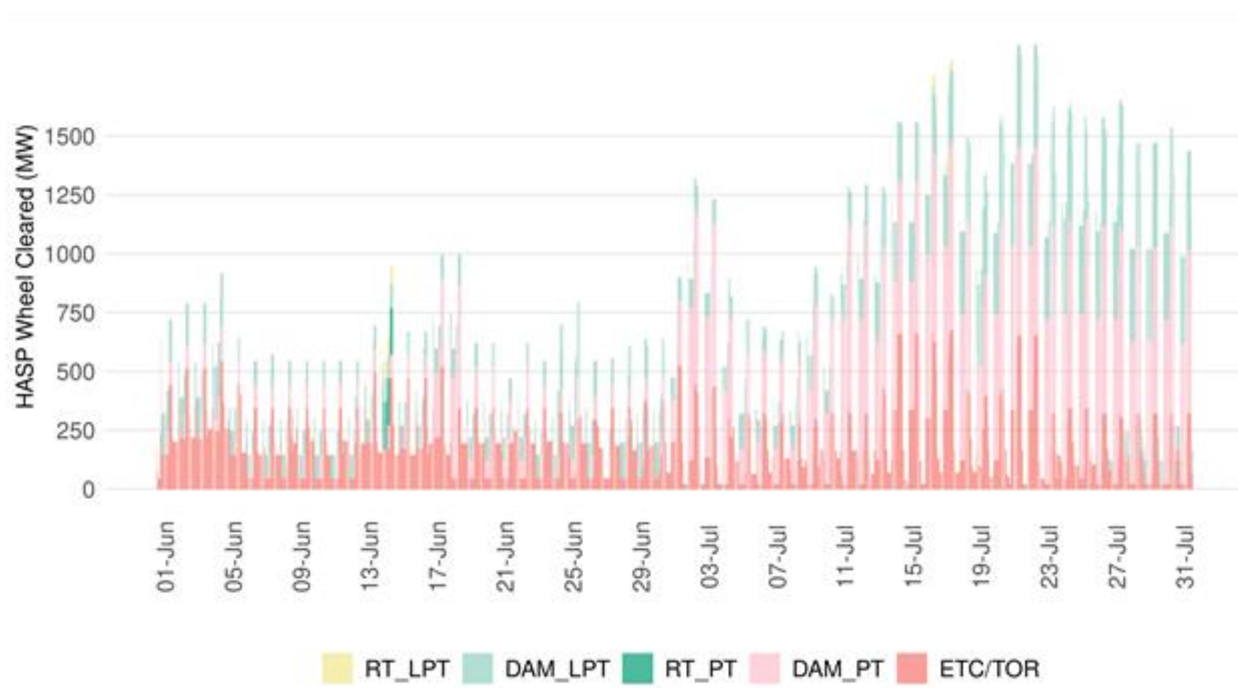
Figure 61: Maximum hourly volume (MW) of wheels by path in July

		SINK			
TYPE	SOURCE	MCCULLOUG500	MEAD230	MIR2	PVWEST
LPT	MALIN500		50		75
	NOB		50		176
	PVWEST			200	
PT	MALIN500	50	200		350
	NOB	150	100		98

Although wheels do not add or subtract energy to the overall power balance of the ISO market, they compete for limited scheduling and transmission capacity. Because self-schedules wheels have higher priority than stand-alone imports or exports, when there is no power balance infeasibility (i.e., no supply shortage) concurrent with limited intertie capacity (such that imports are competing for intertie capacity with wheels), wheels can clear before other imports.

Wheels cleared in the day-ahead market can be carried over into the real-time market with a day-ahead priority or be directly self-scheduled in HASP process. Figure 62 shows the volume of wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 62 Wheels cleared in real-time market



The ETC/TOR groups represent the wheels associated with either existing or owner transmission rights. The majority of ETC/TOR wheels scheduled in the day-ahead market carried over to real-time.

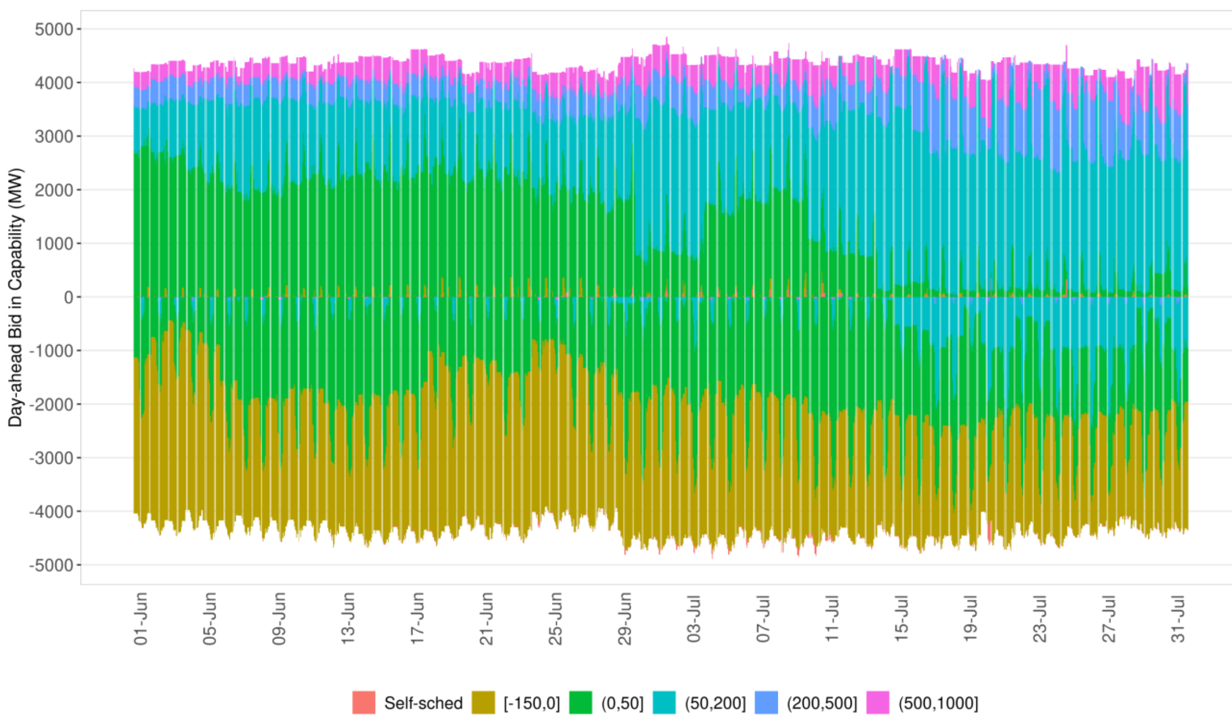
The *DAM*_PT is for wheel-through transactions with high priority that cleared in the day-ahead market and they rebid into real-time. RT_PT is high priority that came in directly into real-time market. DAM_LPT is for wheels with low priority cleared in day-ahead and rebid into real-time. Similarly. RT_LPT is for wheels bid in directly into real time. Econ is for economical wheels.

7 Storage and Hybrid Resources

The ISO's markets use the Non-Generating Resource (NGR) model to accommodate energy constrained storage resources that can consume and produce energy. The NGR model allows storage resources to participate in the regulation market only, or participate in both energy and ancillary service markets. In July 2023, there were 82 storage resources actively participating in the ISO markets. Most storage resources participated in both the energy and ancillary service market. Storage resources can arbitrage the energy price by consuming energy (storing charge) when prices are low, then subsequently delivering energy (discharging) during market intervals with high prices. Each storage resource has a maximum storage capability that reflects the physical ability of the resource to store energy.

The total storage from all the active resources participating in the market was 16,778 MWh. In terms of the capacity made available to the markets, Figure 63 shows the bid-in capacity for storage resources in the day-ahead market.

Figure 63: Bid-in capacity for batteries in the day-ahead market



The negative area represents charging while the positive area represents discharging. The overall capacity in the market was roughly consistent between July and June. The bid-in capacity is organized by $/MWh price ranges. There were consistent patterns of batteries bidding to charge at negative prices, and to discharge at prices above $50/MWh. In July, some were willing to charge when prices were $50 to $200. Conversely, they were almost always willing to discharge at higher prices. The bright pink shows bids close to or at the soft energy bid cap of $1000/MWh and shows that there was a certain volume of storage capacity expecting to discharge only at these high prices.

Figure 64 shows the bid-in capacity for the real-time market. The majority of bids were $50/MWh or above on the discharging side, and $0/MWh or below on the charging side. In the late morning to early afternoon hours before the evening peak, batteries were willing to charge even at prices higher than $200/MWh.

Figure 64: Bid-in capacity for batteries in the real-time market

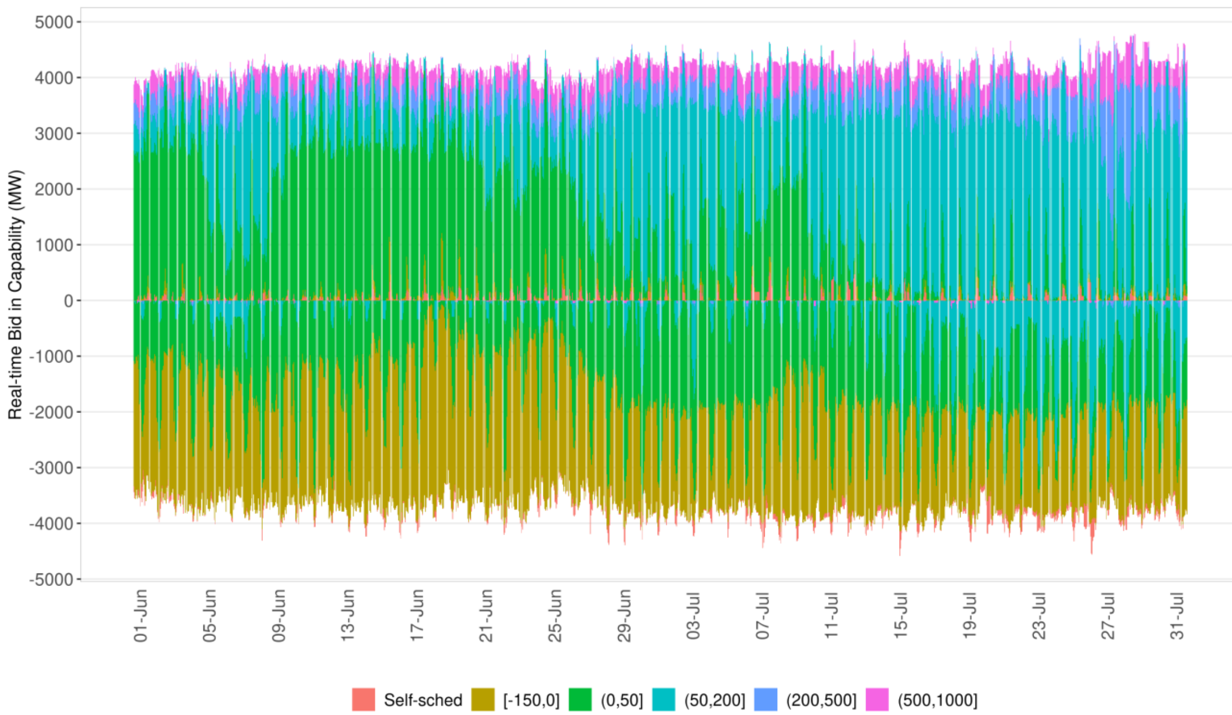


Figure 65 IFM distribution of state of charge for June and July 2023

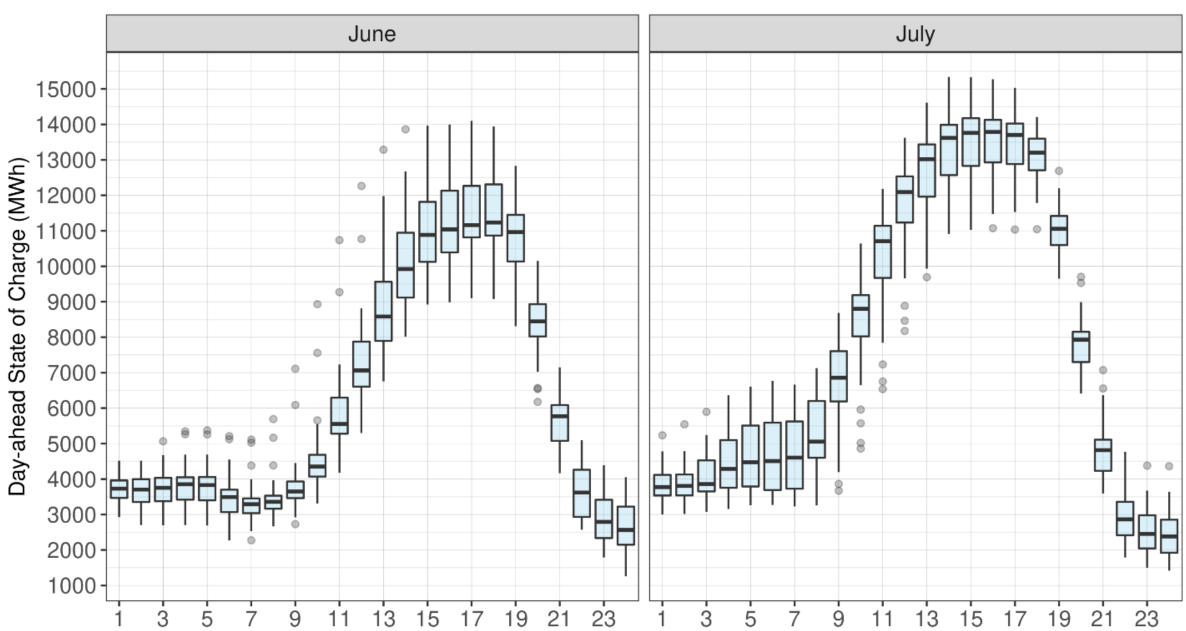
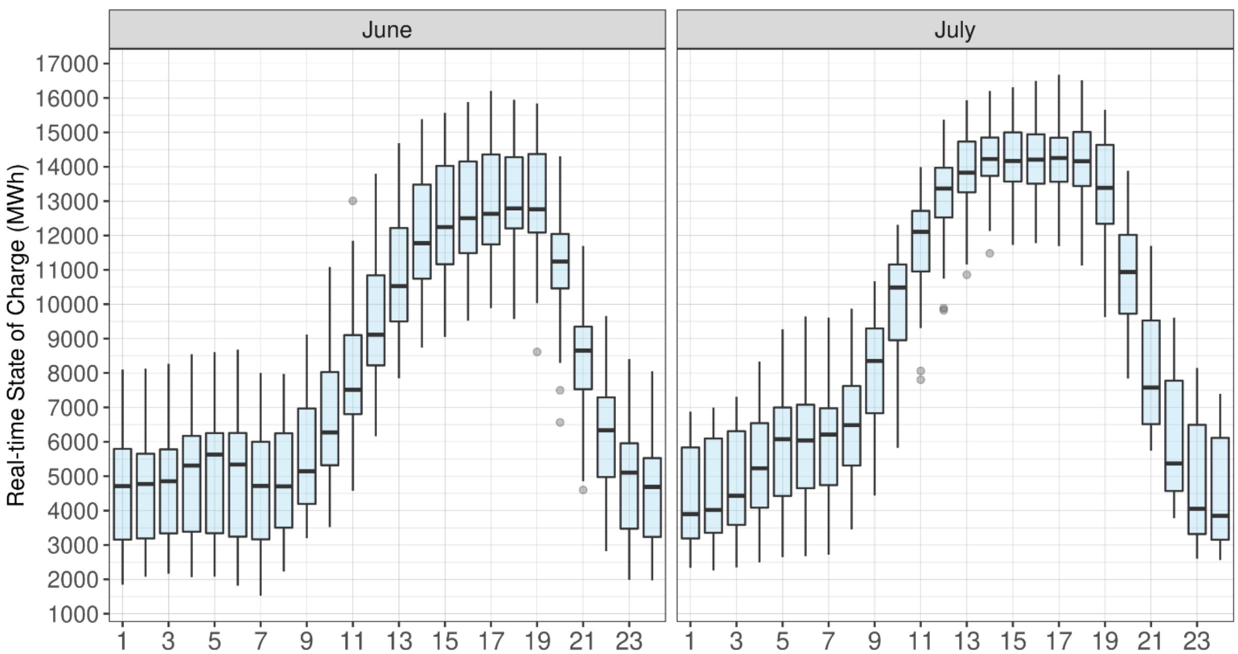


Figure 65 shows the hourly distribution of the storage capacity of resources participating in IFM for June and July 2023. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge in IFM. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime, between hour ending 9 and 18. The system reached maximum stored energy by hour ending 16, followed by a period of steady discharge from hours ending 18 through 24. In July, the highest median system state of charge was around 15,300 MWh, which occurred in the hour ending 14.

Figure 66 shows the distribution of state of charge for the real-time market for June and July 2023. The peak hourly state of charge in the real-time market was higher than the day-ahead peak state of change. The highest median system state of charge in July was higher than the median system state of charge in June. Also of note is the much wider spread of the state of charge in the real-time market compared to the day-ahead market.

Figure 66: Real-time market distribution of state of charge for June and July 2023



Most of the storage resources in the ISO market are four-hour batteries, which implies that if a resource is fully charged, it will take four hours to discharge this resource completely. To arbitrage prices, it is expected that the resource would be charged to full capacity just prior to the hours with high energy prices. With the need for more supply as solar production diminishes, it is expected that storage resources would be discharging during net load peak hours. Figure 64 shows the average hourly system marginal energy component (SMEC) of the locational marginal price in IFM for July 2023. Figure 65 shows the distributions of energy awards in IFM, and shows the hourly distribution of real – time dispatch for batteries in June and July 2023.

Figure 67: Hourly distribution of IFM energy awards for batteries in June and July 2023

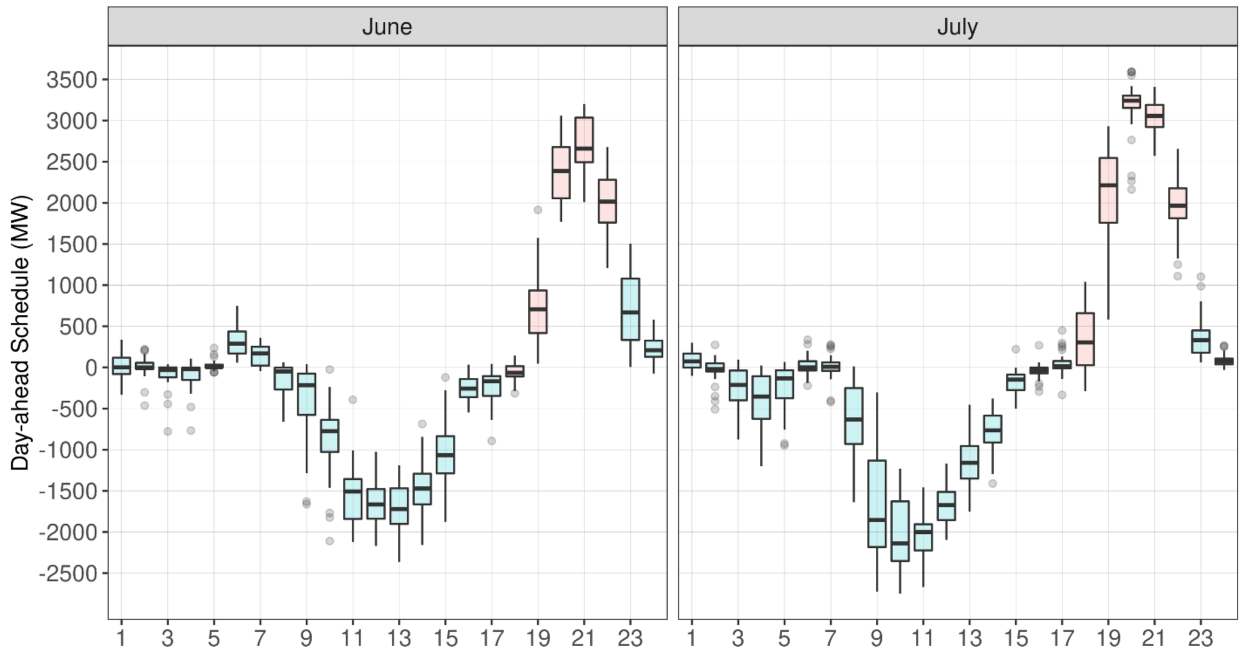


Figure 68: IFM hourly average system marginal energy price in July 2023

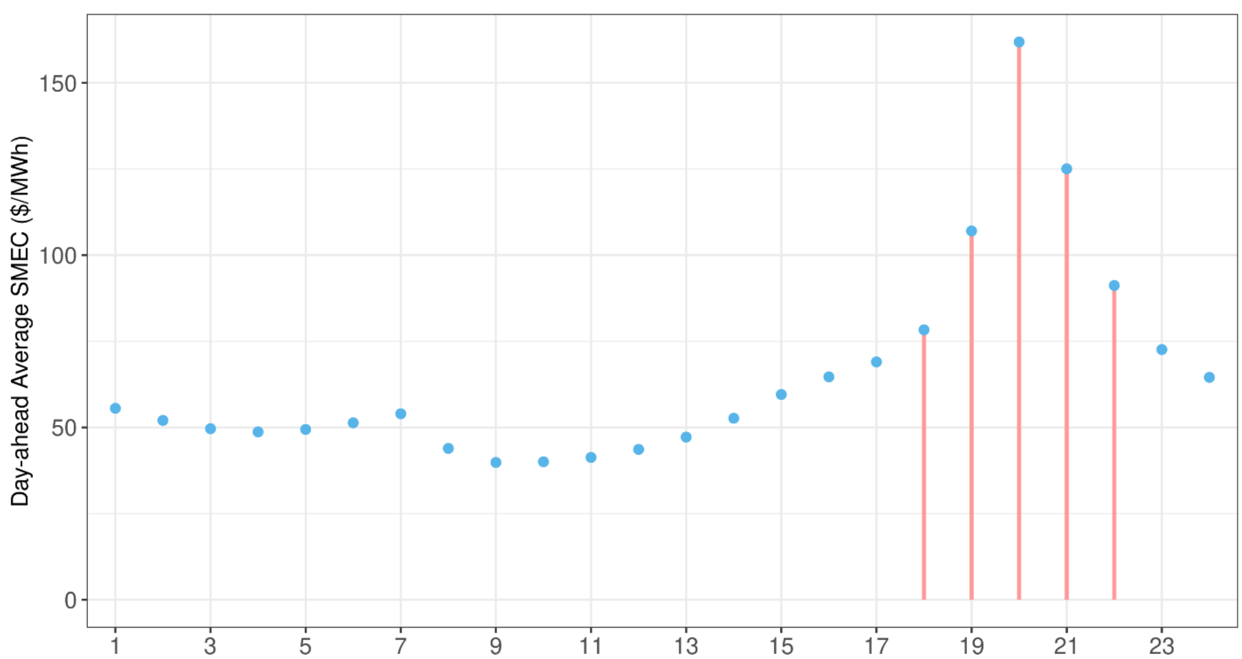
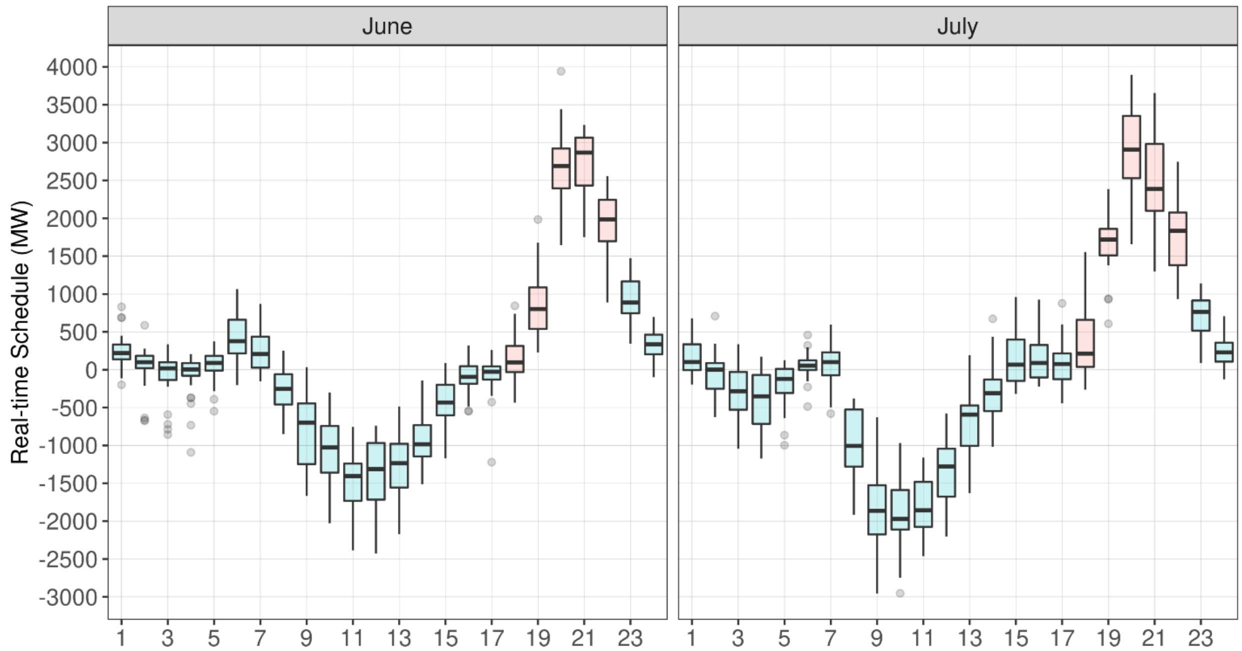


Figure 69 highlight hours ending 18 through 22 in a different color than the other hours, to show that the storage resources are being discharged in intervals with the highest energy prices.

Figure 69: Hourly distribution of real-time dispatch for batteries in June and July 2023



The storage resources continue to provide ancillary services to the market for the following products: regulation up, regulation down, and spinning reserve. Figure 70 shows the average hourly AS awards in day-ahead, and Figure 71 shows the average hourly AS awards in real-time, for June and July 2023.

Figure 70 Hourly average day-ahead storage AS awards in June and July 2023

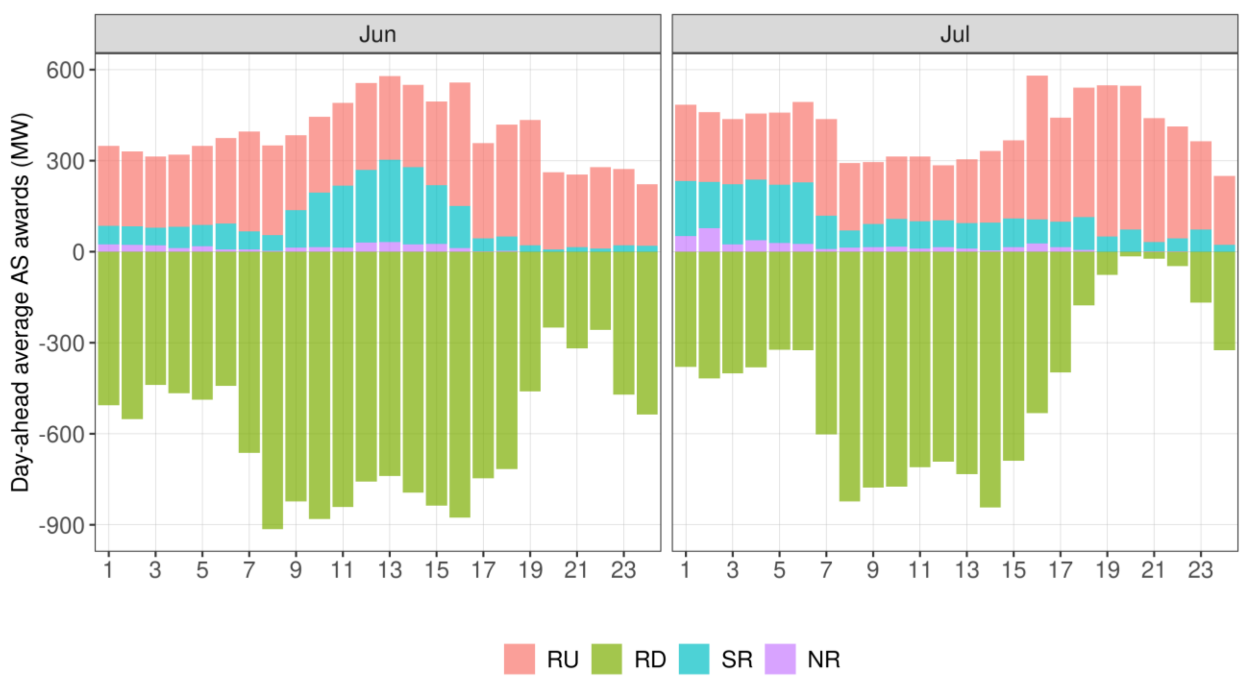
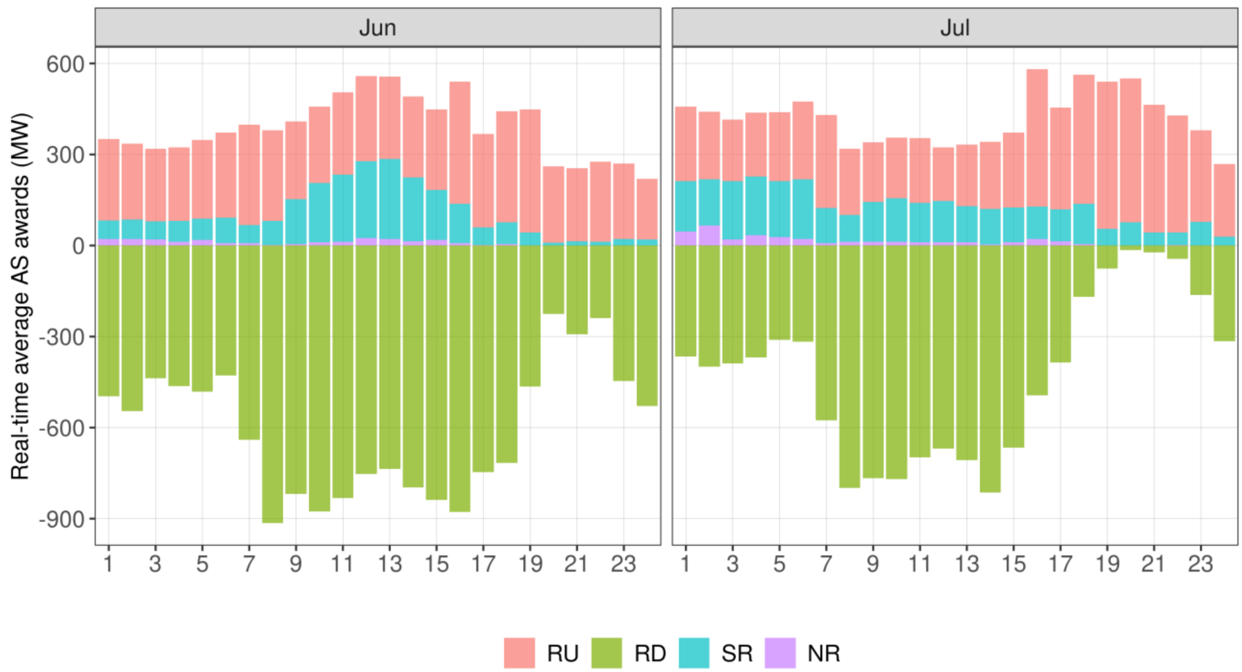


Figure 71 Hourly average real-time storage AS awards in June and July 2023



Beginning with the implementation of the Hybrid Resources Phase 2B project in February 2023, ISO began tracking more formally the market performance of hybrid resources. Hybrid resources are two different resource types that sit behind a single point of interconnection – typically a solar resource paired with a storage resource.

Figure 72 and Figure 73 show the IFM and real-time energy awards for hybrid resources, respectively. The pattern is markedly different than energy storage resources and instead matches more closely the dispatch patterns of solar resources with some differences. An important difference with solar energy dispatch is that the energy awards dip in the middle of the day when solar resources typically reach peak output. This is likely due to the energy storage component of the resource charging off of the solar component of the resource, thus resulting in a lower energy award. Another notable difference is that the evening ramp down as the sun sets is less steep compared to solar resources. This pattern can be attributed to the storage component of the resource discharging in these evening hours thus offsetting the decreased production of the solar component, resulting in flatter decline in output.

Figure 72: Hourly distribution of IFM energy awards for hybrid resources in June and July 2023

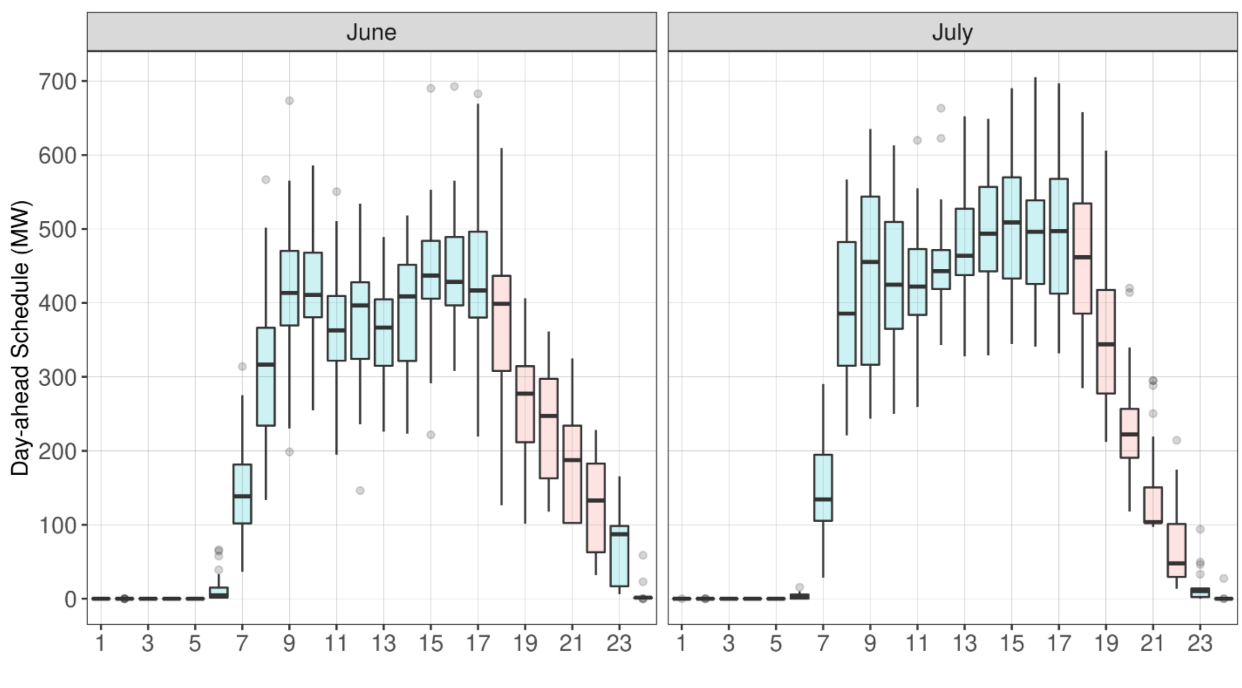
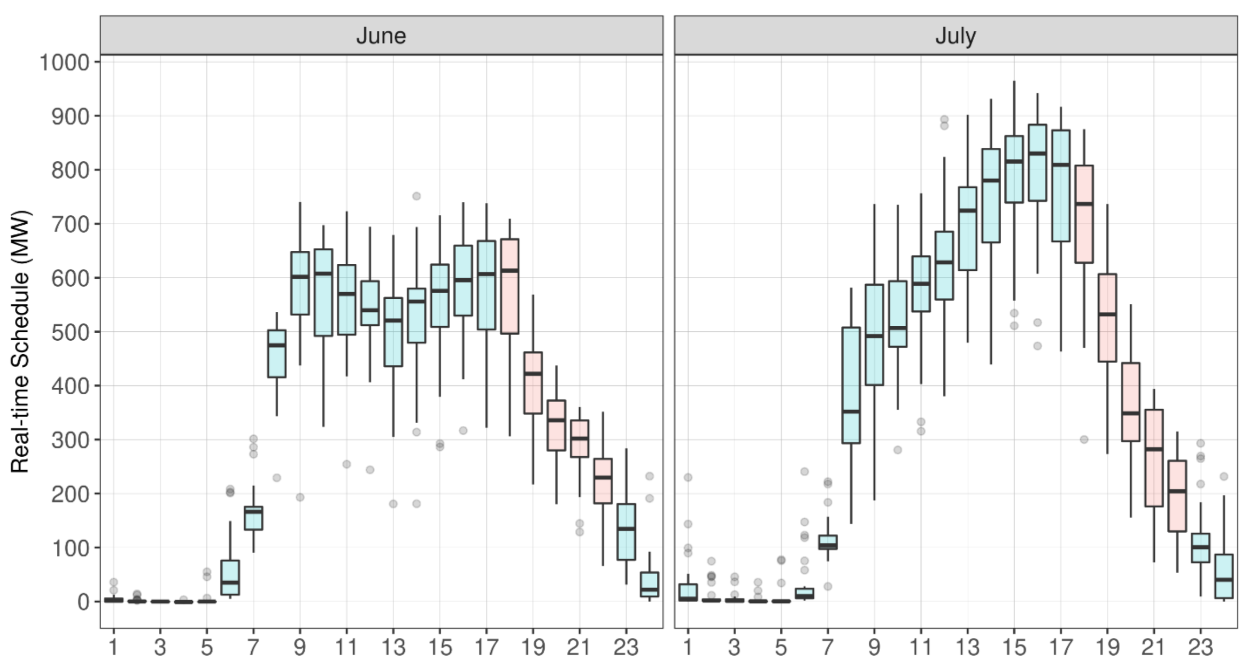


Figure 73: Hourly distribution of real-time dispatch for hybrid resources in June and July 2023



Similar to storage resources, hybrid resources can also provide ancillary services to the market for the following products: regulation up, regulation down, and spinning reserve. Figure 74 shows the average hourly AS awards in day-ahead, and Figure 75 shows the average hourly AS awards in real-time, for June and July 2023.

Figure 74: Hourly average day-ahead hybrid AS awards in June and July 2023

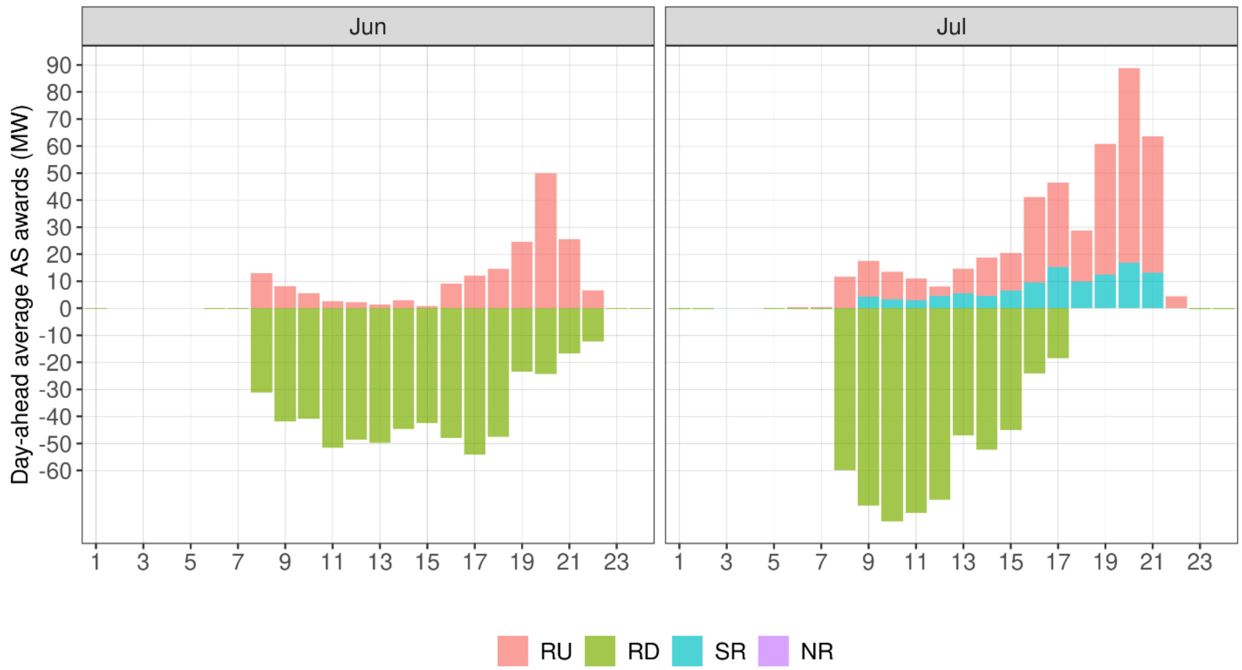
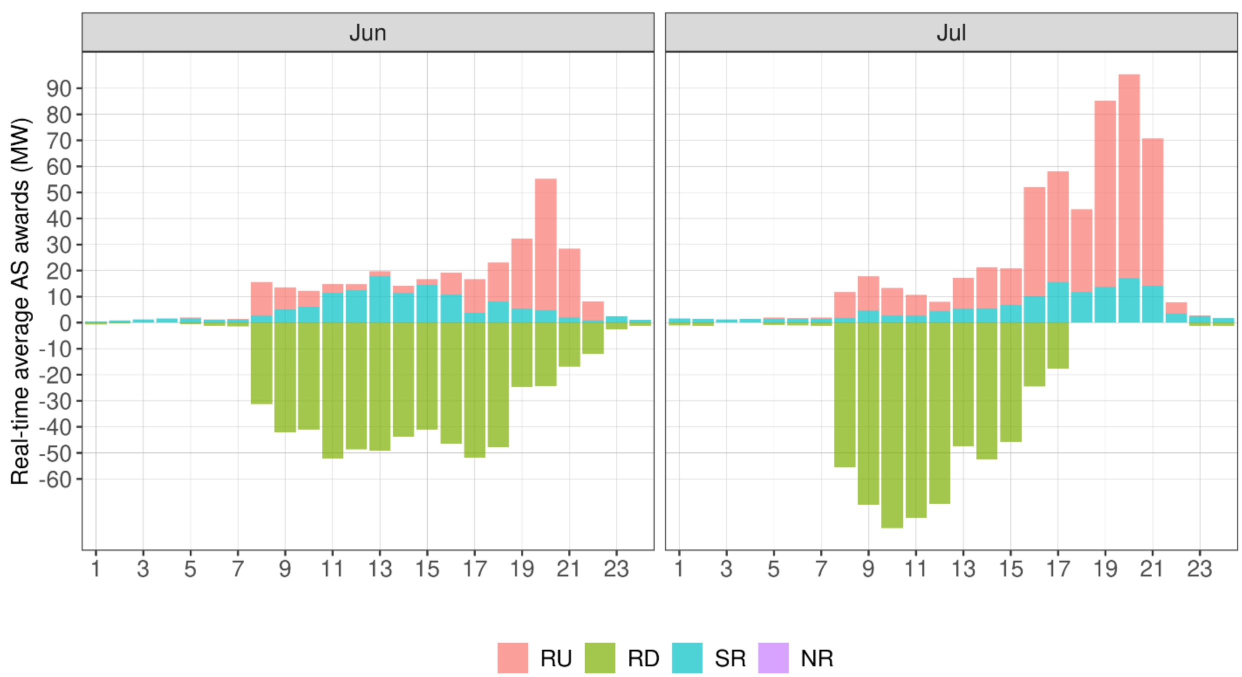


Figure 75: Hourly average real-time hybrid AS awards in June and July 2023



8 Western Energy Imbalance Market

The Western Energy Imbalance Market, or WEIM, provides an opportunity for participating balancing authority areas to serve their load while realizing the benefits of increased resource diversity. The ISO estimates WEIM's gross economic benefits on a quarterly basis[33]. 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 more expensive generation 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 76 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 76: Daily distribution of EIM transfers for ISO area

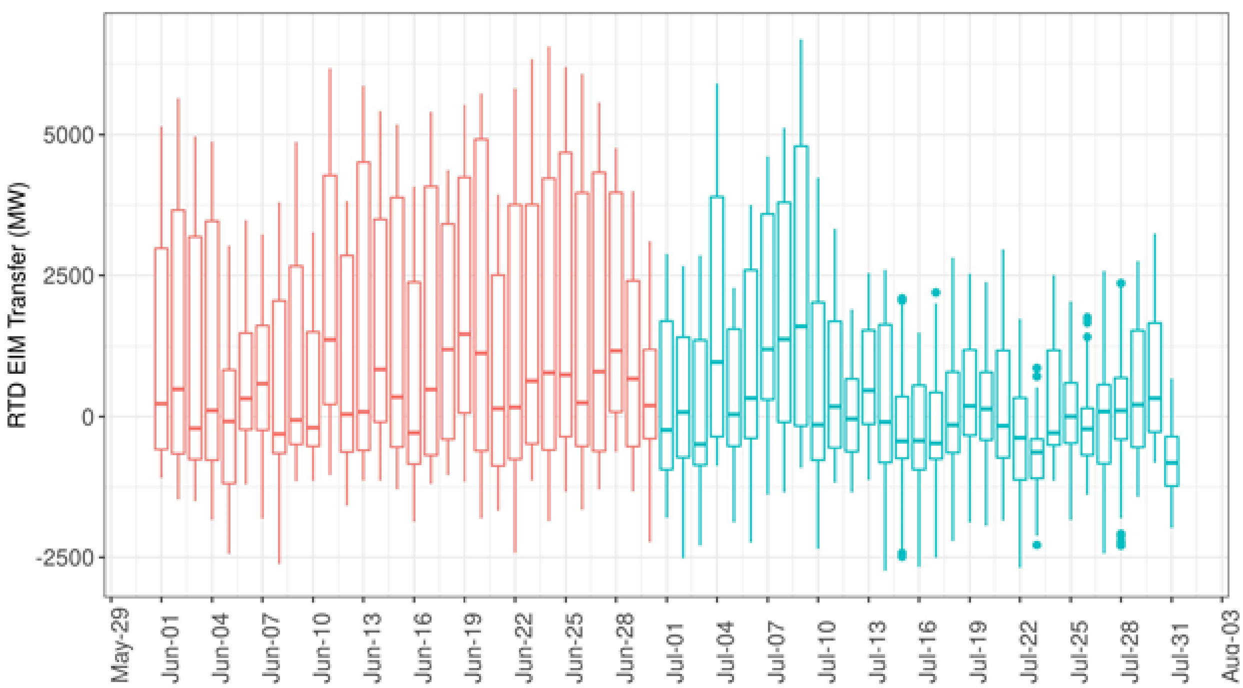
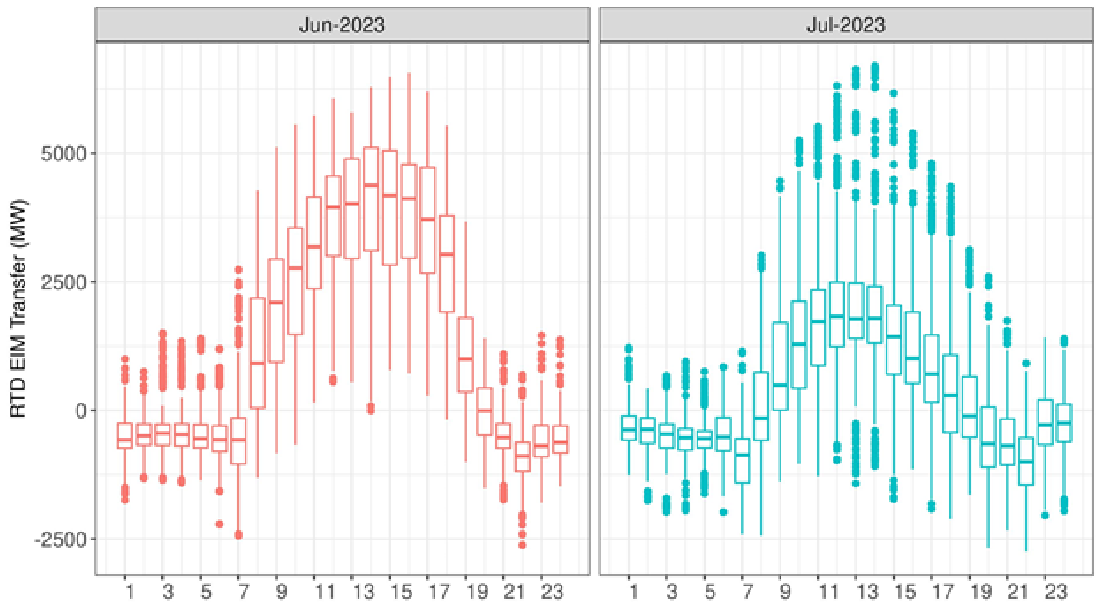


Figure 75 shows the WEIM transfers in an hourly distribution, which highlights the typical profile of the ISO transfers which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the ISO area. This trend is typical across summer months.

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

Figure 77: Hourly distribution of 5-minute EIM transfers for ISO area



9 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 78 shows the daily overall settlements costs for the ISO balancing area; this does not include WEIM settlements. As demand and prices rise, the overall cost settled are expected to increase. The dotted red line provides a reference of an average cost per MWh based on the overall costs relative to the volume of demand transacted. The average daily cost in July was $52.4 million, representing an average daily price of $74.91/MWh. The maximum daily cost of $105.6 million occurred on July 27.

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 daily trend is shown below in

Figure *79*. The high offset costs for July 25 and July 26 was primarily due to the congestion on Path26 (Midway – Vincent and Midway – Whirlwind flowgates).

Figure 78: ISO's daily total and average market costs

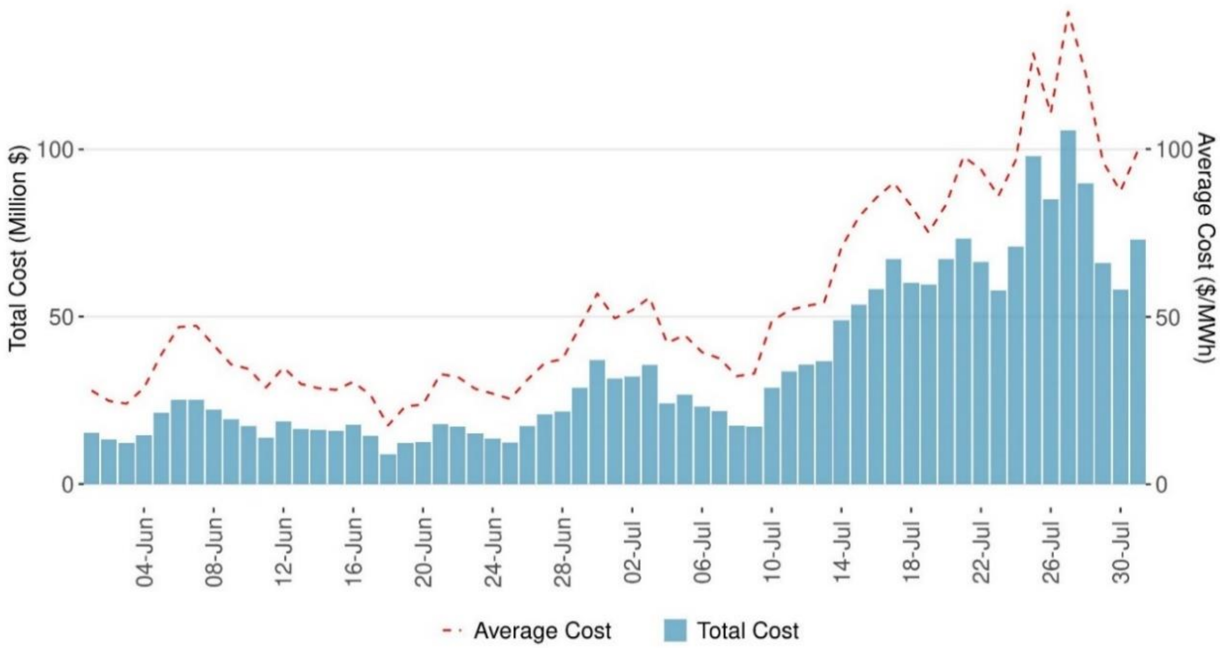
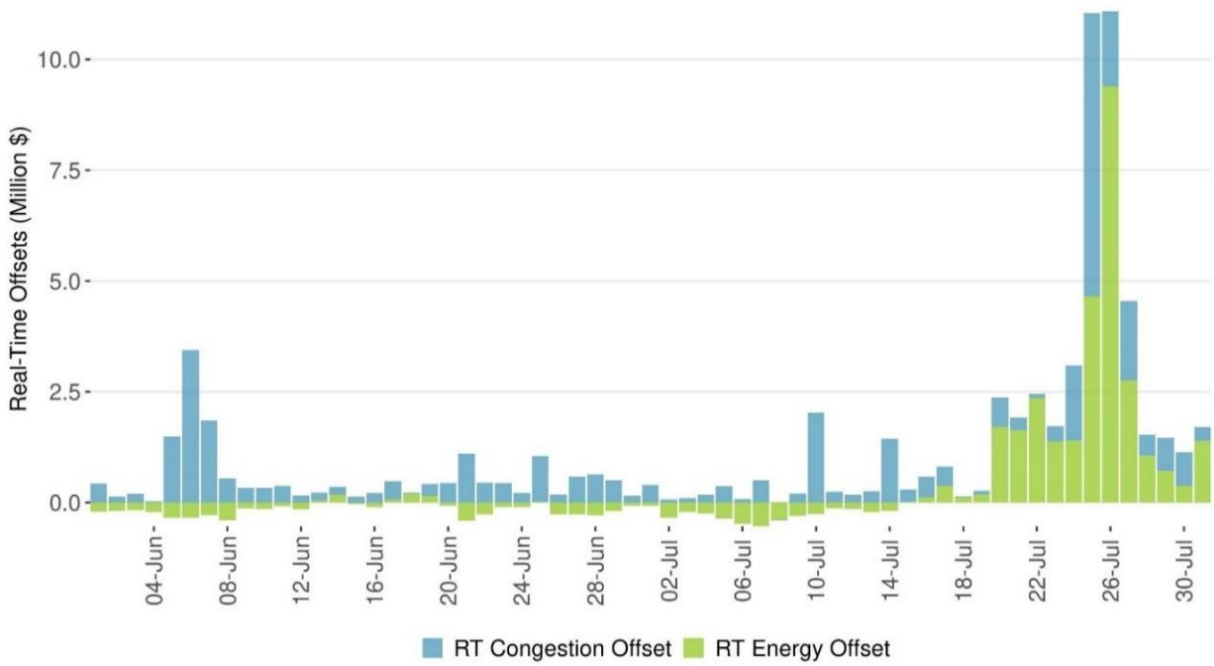


Figure 79: Real-time energy and congestion offsets



10 Import Market Incentives during Tight System Conditions

On June, 15, 2021, the ISO implemented an enhancement that improves incentives for imports to be available during tight system conditions. The prior settlement rules may have paid imports less than they bid, which could exacerbate conditions when supplies are tight. During very tight system conditions (*i.e.,* when ISO has issued an alert by 15:00 hrs PST, or a warning or emergency notice), the ISO will provide bid cost make-whole payments for real-time hourly block economic imports, rather than simply settling the imports at the FMM price. This feature was implemented as part of the summer readiness in 2021.

This feature was not triggered for the month of July 2023, even though the ISO had EEA1 and EEA Watch. This was due to a missing step in the process to enable the feature in the markets once the EEAs were declared. The ISO is revising its internal procedures to ensure this step is taken properly once an EEA is issued.

11 Minimum-State-of-Charge Constraint

The minimum State-Of-Charge (SOC) requirement is a tool to ensure that Limited Energy Storage (LES) resources with RA capacity obligations maintain sufficient SOC to provide energy during tight system conditions. This requirement was implemented as part of the market enhancements for the summer readiness 2021 stakeholder initiative and originally had a two-year sunset provision. After the summer of 2022, the ISO determined that the tool was important for maintaining reliability and requested an extension until September 30, 2023, or until another SOC management tool could be put in place. This extension was approved and the tool is available for summer 2023.

The minimum SOC constraint is only applied on days when system needs are critical. The constraint is activated when there are one or more hours with under-gen infeasibilities in RUC, which occurs infrequently but indicates tight system conditions. When activated, the constraint ensures that all LES resources with an RA obligation maintain sufficient SOC to cover energy schedules cleared in RUC over a set of critical hours. These critical hours are defined by the operators prior to running RUC, and remain consistent from RUC into the real-time markets.

The goal of the constraint is to ensure that each LES resource with an RA obligation will have enough SOC to meet its positive RUC schedules in the real-time markets in each critical hour. This means each resource needs to have enough SOC at the beginning of each critical hour to meet the RUC schedules in that hour plus all future critical hours, taking into account the resource's charging efficiency and operating limits. The minimum SOC constraint is defined as an end-of-hour constraint. In practice, this often means the minimum SOC will build up in the hours preceding the critical hours, and peak at the sum of the positive RUC schedules in the hour preceding the start of the critical hours.

There were no RUC infeasibilities in July 2023 and the minimum SOC constraint was not enforced.

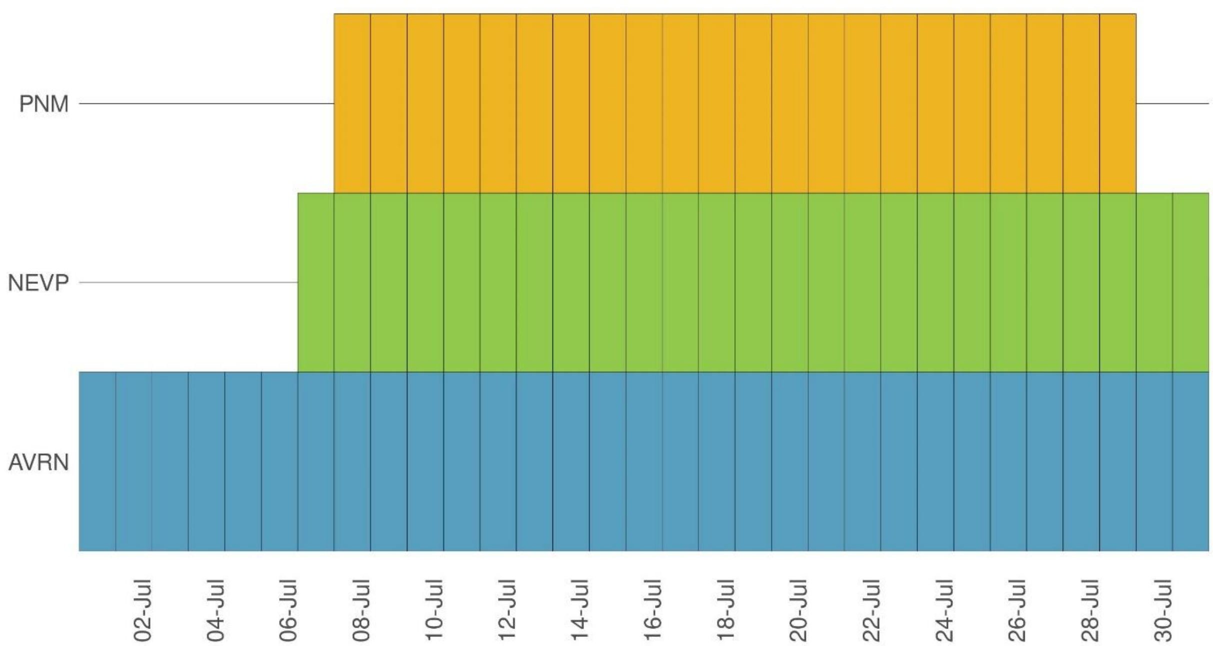
12 Assistance Energy Transfer

Assistance Energy Transfer (AET) was implemented with the Resource Sufficiency Evaluation Enhancements Phase 2, Track 1 effort which went live on July 1, 2023. The purpose of AET is to leverage the Western Energy Imbalance Market (WEIM) for energy assistance during under-supply conditions by optionally allowing incremental transfers at pre-set financial consequence following the failure of the WEIM Resource Sufficiency Evaluation (RSE). Assistance energy transfers are sourced from supply offers that are made voluntarily into the WEIM. Each WEIM BAA may voluntarily opt in to utilize assistance energy by notifying the ISO five business days in advance for a forward requested timeframe.

When a BAA that is not opted into AET fails the RSE, the market limits its WEIM energy transfers to the greater of the transfer amount from the last passed run's interval or the base scheduled transfer amount. If a BAA is opted into AET and fails the RSE in the upward direction, the BAA will still be allowed to receive WEIM energy transfers and pay an after-the-fact surcharge that is calculated based on the energy bid cap of $1,000/MWh or $2,000/MWh. The surcharge is only applied to net-import WEIM BAAs and is limited to the lower of the quantity of the upward RSE insufficiency amount or the tagged dynamic transfers.

During the month of July 2023, three WEIM BAAs opted into AET for some duration of the month. Figure 80 below shows the number of BAAs opted in for each trade date during the month. The ISO BAA did not opt into AET during July 2023 because the requirements for ISO BAA opt-in were not met[34].

Figure 80: Count of BAAs opted into Assistance Energy Transfers, July 2023



[34] See the Business Practice Manual (BPM) for Energy Imbalance Market section 11.3.2 for more details.

The total amount of AET surcharge assessed during the month of July 2023 was approximately $42,510 across three WEIM BAAs. Figure 81 below shows the breakdown of total AET surcharge assessed per day. By the nature of its design, AET is only assessed for WEIM BAAs that fail the RSE *and* are opted in ahead of time. Thus, the AET surcharge was only assessed for a total of six trading days during the month of July 2023. During those trading days, the energy bid cap remained at $1,000/MWh. Figure 82 shows total AET surcharge assessed per hour.

Figure 81: Total daily AET surcharge assessed, July 2023

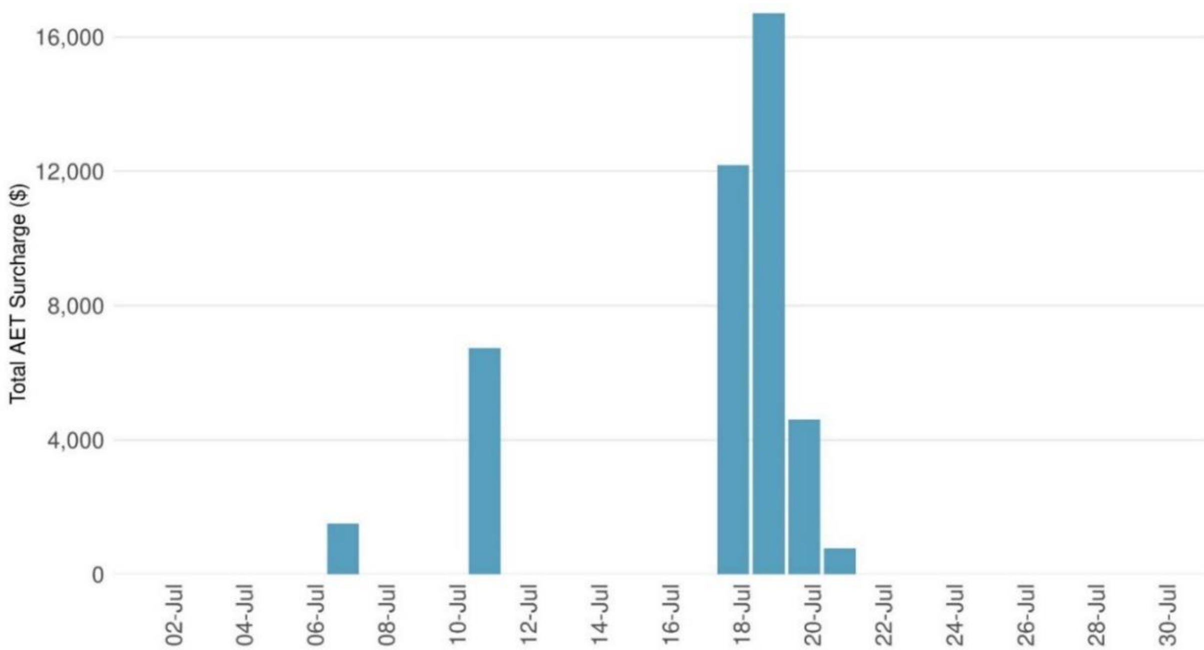
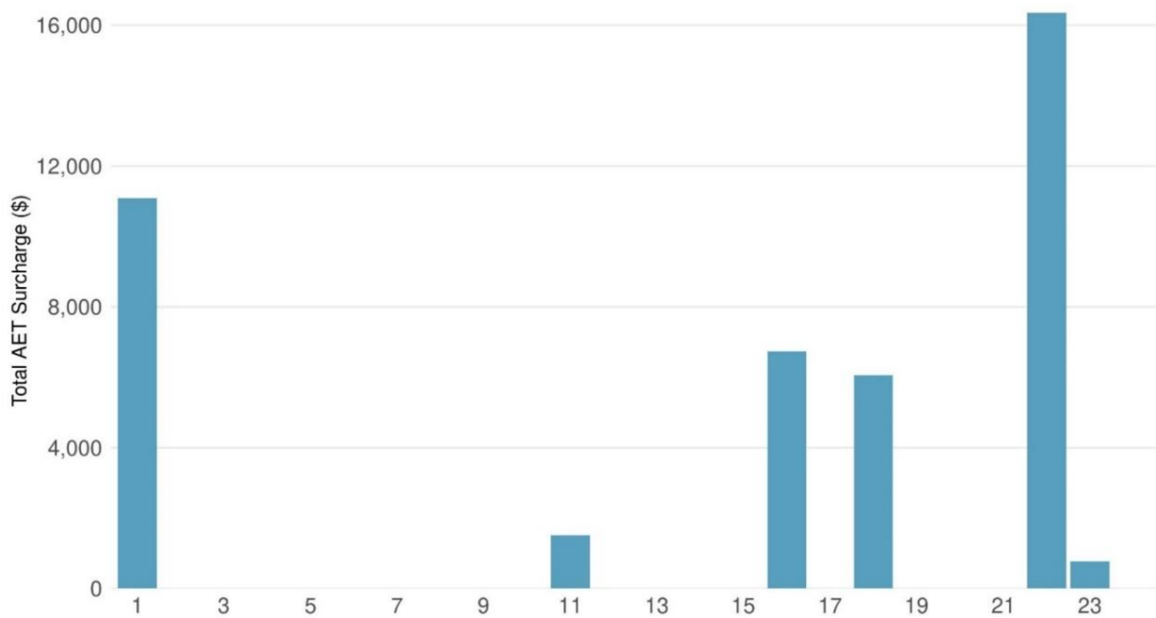


Figure 82: Total hourly AET surcharge assessed, July 2023



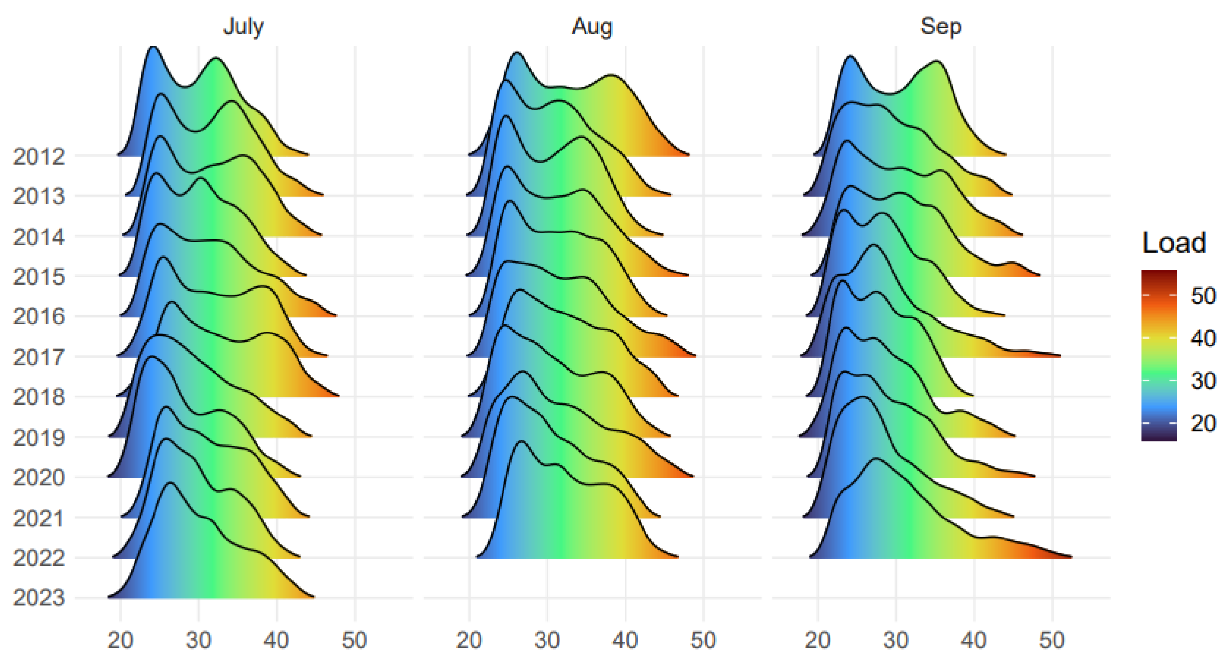
13 Emergency Alerts in July

13.1 Load conditions

ISO's demand remained within typical levels in July. Notably, the peak load recorded on July 25 was approximately 43,500 MW, a decrease compared to the peak load observed in July 2022.

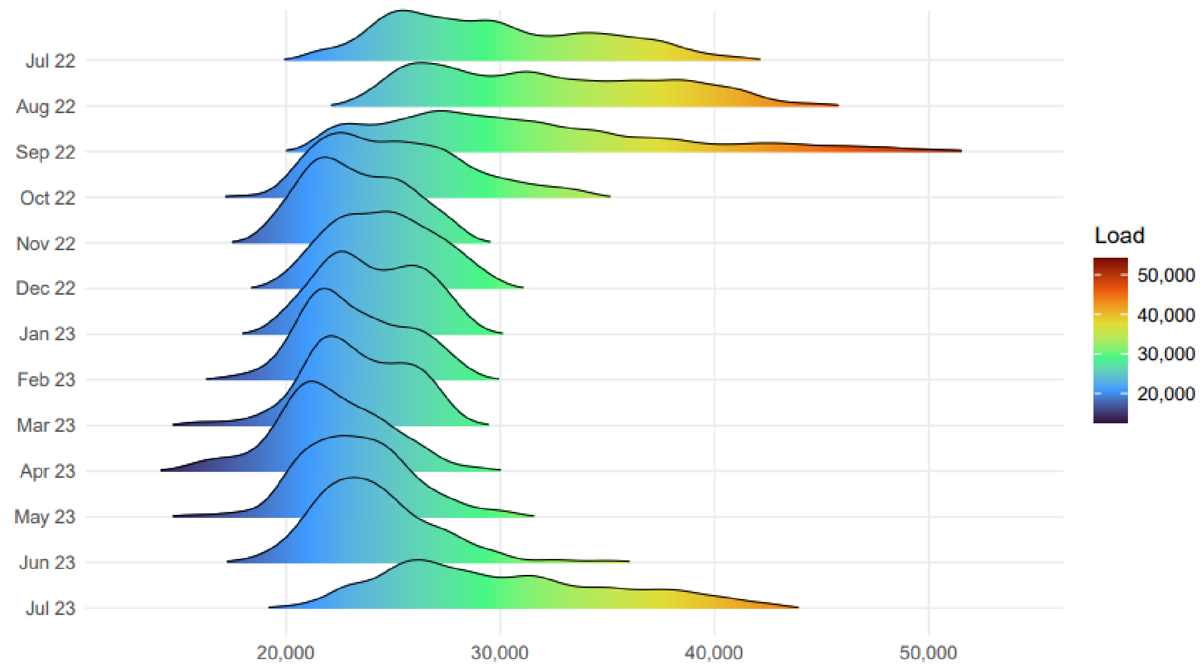
Figure 83 illustrates the historical distribution of load levels. The area's highest loads usually occur in September. While July 2023 surpassed the load levels of July 2022, the July peaks remain relatively consistent with recent years, though they do not reach the same magnitude as the peak loads observed during the period 2016-2018.

Figure 83: Historical distribution of summer loads (in GW)



To put July 2023 load levels in context, Figure 84 depicts a distribution comparison spanning the past 12 months. The figure illustrates the gradual escalation of load during the transition to summer months, with July displaying a notable increase in load levels compared to June.

Figure 84: Historical distribution of load levels in 2023



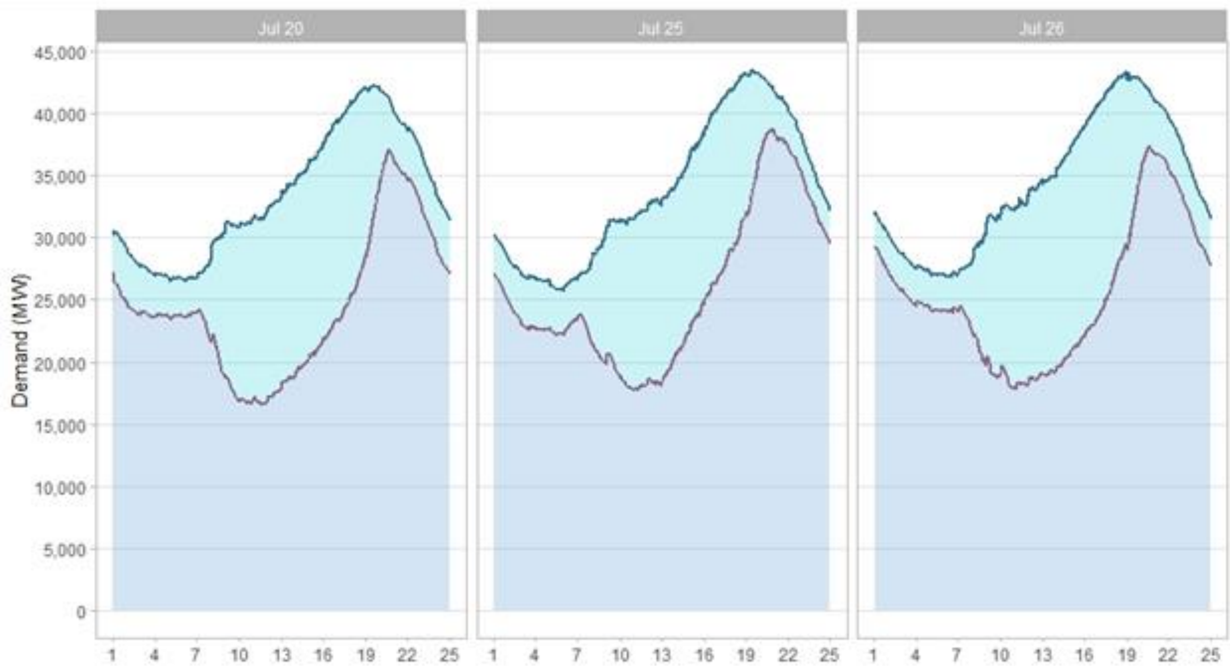
The system's peak load during summer typically occurs in the afternoon, usually before 19:00 hrs. However, grid conditions can become more challenging as sunset approaches and the system approaches the net load peak. As solar generation decreases, the difference between the gross demand and net demand curves diminishes, which requires rapidly ramping up additional supply resources to meet demand. The RA program does not explicitly reflect this dynamic currently, but rather relies on static solar generation values throughout the month. Moreover, after sunset, demand that was previously met by behind-the-meter solar generation returns to the ISO system, while the ISO system load remains high. Consequently, demand diminishes at a slower rate than the increase in net demand. This circumstance heightens the risk of shortages around 20:00 hrs, coinciding with the net demand's peak (net load peak). The incorporation of demand response also influences the magnitude and timing of these observed peaks. Table 2 below provides gross and net load peak figures for each day of the heat wave.

Table 2: Summary of demand peaks during the July energy emergency alerts

	Gross Peak		Net Peak	
Date	**Time**	**MW**	**Time**	**MW**
20-Jul	6:35pm	42,275	7:42pm	37,005
25-Jul	6:27pm	43,545	7:54pm	38,750
26-Jul	5:58pm	43,349	7:34pm	37,333

Figure 85 below illustrates the gross and net demand trends for days in July the ISO issued emergency alerts. The graph reveals that while gross demand surged beyond 43 GW, net demand peaked at just under 39 GW. The emergency alerts coincided with the timeframes of net load peaks.

Figure 85: Gross and net load for days with emergency alerts in July 2023



13.2 Communications and coordination

As part of the enhancements and lessons learned from the summer of 2020, the ISO has established a process to increase situational awareness, coordination, and communication during summer conditions. If the ISO anticipates a potential shortfall between two to eight days in advance, it will initiate the following communications and actions before and during a heat event:

- **Four to seven days out:**
  - Operational assessments:
    - The ISO monitors demand forecasts seven days out, operational resource adequacy, system conditions, weather, and other potential grid impacts, and plans for next possible steps.
    - Each calendar day, the ISO will look multiple calendar days ahead and has the authority, subject to input from ISO operations based on system conditions and operator experience, to submit an Assistance Energy Transfer (AET) designation request per Operating Procedure (OP) 4420.
  - Operational coordination with external entities:
    - Depending on actual and potential system conditions, the ISO conducts outreach and coordination of a possible extreme event with the Governor's Office and long-start strategic reserve resource scheduling coordinators (LS-SRR SCs).
    - The ISO considers the potential need for Department of Energy (DOE) 202c Orders and whether other government agency assistance may be needed.

- Public and customer communications:
  - The ISO may issue high temperature heads up via the ISO website and social media channels, communicating the ISO is forecasting high temperature in upcoming days.

- **<u>One to four days out</u>:**
  - Operational assessments:
    - The ISO reviews and validates most current information on actual and potential system conditions, operational resource adequacy, weather, and other potential factors impacting the grid.
  - Operational coordination with external entities:
    - To prepare entities for possible conservation efforts and potentially free up additional supply, the ISO may initiate communication to water agencies, neighboring balancing areas, the Emergency Load Reduction Program (ELRP) Board, utilities, Reliability Coordinator West (RC West) and regulatory agencies.
    - The ISO may also coordinate resource owners and regulatory agencies to determine whether the ISO may be able to access emergency supply above approved permit and/or Generator Interconnection Agreement (GIA).
    - If necessary, the ISO may coordinate with the Governor's Office for an Executive Order and the US Department of Energy for a 202c Order.
  - Public and customer communications:
    - The ISO may issue a Heat Bulletin via a news release, the ISO website, daily briefings, and social media channels, communicating details on forecasted high temperatures, and the possibility for the ISO to issue a Flex Alert in coming days.
    - The ISO may issue Restricted Maintenance Operations (RMO) notifications via the ISO Today mobile app, Today's Outlook, the ISO's Market Notification System (MNS), and to entities signed up for ISO emergency notifications e-mails. 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.
- **<u>One day out</u>:**
  - Operational assessments:
    - The ISO reviews and validates day-ahead market results and most current information on actual and potential system conditions, operational resource adequacy, weather, and other potential factors impacting the grid.
    - If day-ahead market results indicate potential energy shortfalls, the ISO may issue a Flex Alert notice for the next day. A Flex Alert is a call to consumers to voluntarily conserve electricity when the ISO anticipates energy shortfalls. Reducing energy use during a Flex Alert can prevent more dire measures, such as moving into emergency energy alert (EEA) notifications, emergency procedures, and even rotating power outages.
    - If day-ahead analysis indicates energy shortfalls in any hours, the ISO may issue an EEA Watch.

        - Note: The ISO may also issue Flex Alerts and/or EEA Watch either day-of or earlier than one day out depending on system conditions.
    - Operational coordination with external entities:
        - The ISO engages in operational coordination with utilities, neighboring balancing areas, the ELRP Board, and RC West to prepare for the operating day.
    - Public and customer communications:
        - The ISO may issue Flex Alert and/or Energy Emergency Alert (EEA) Watch notices via Emergency notifications e-mails, ISO Today app, Today's Outlook, MNS, news releases, daily briefings, emergency notifications e-mails, and social media channels.
        - Flex Alerts will also be communicated through FlexAlert.org, Flex Alert subscription lists, and Flex Alert and ISO social media channels.
- **Operating day:**
    - Operational assessments:
        - The ISO reviews actual and potential system conditions and takes actions in accordance with OP 4420.
        - 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 RC West to issue EEAs[35].
    - Operational Coordination with External Entities:
        - The ISO continues operational coordination with utilities, neighboring balancing areas, the ELRP Board, and RC West.
    - Public and customer communications:
        - The ISO may issue EEA notices as needed based on system conditions and communicates these alerts via Emergency notifications e-mails, ISO Today app, Today's Outlook, MNS, social media channels, and news releases
        - The ISO will issue "de-escalate" and "all clear" notices via emergency notifications e-mails, ISO today app, Today's Outlook, MNS, and social media channels.

On an ongoing basis, coordination between ISO and external partners continues each day, for current and future days, until the event ends.

13.3 Events overview and operational conditions

Throughout the events in July, the protocol detailed in the preceding section remained in effect. However, despite our process of looking out eight days in advance, there were no indications of supply shortages in that timeframe. Subtle indications of potentially thinner supply margins emerged only one, two, or three days out. Notably, these events only manifested during real-time operations due to the rapidly changing conditions. As discussed below, the events did not stem from projected insufficient supply to meet demand. The overall supply levels were sufficient to accommodate the relatively moderate demand

[35] Summary descriptions of EEAs are available here: http://www.CAcaiso.com/Documents/Emergency-Notifications-FactSheet.pdf

observed in July. Because of that the procedures looking multiple days out did not reveal problematic indicators; rather, these events resulted from rapidly changing real-time conditions.

13.4 Operational conditions

The ISO issued Energy Emergency Alerts (EEAs) on three days in July, as indicated in Table 3. These alerts were either Alert Level 1 or a Watch.

Table 3: Summary of emergency alerts in July

Date	Alert level	Timeframe	Definition
20-Jul	EEA1	7:30—8:30pm	All resources in use or committed for use, and energy deficiencies are expected.
25-Jul	EEA Watch	7:26—10:00pm	All available resources committed or forecasted to be in use, and energy deficiencies are expected.
26-Jul	EEA Watch	6:00—10:00pm	

As discussed below, although certain shared concerns existed across these days, there were also distinct nuances affecting each of them.

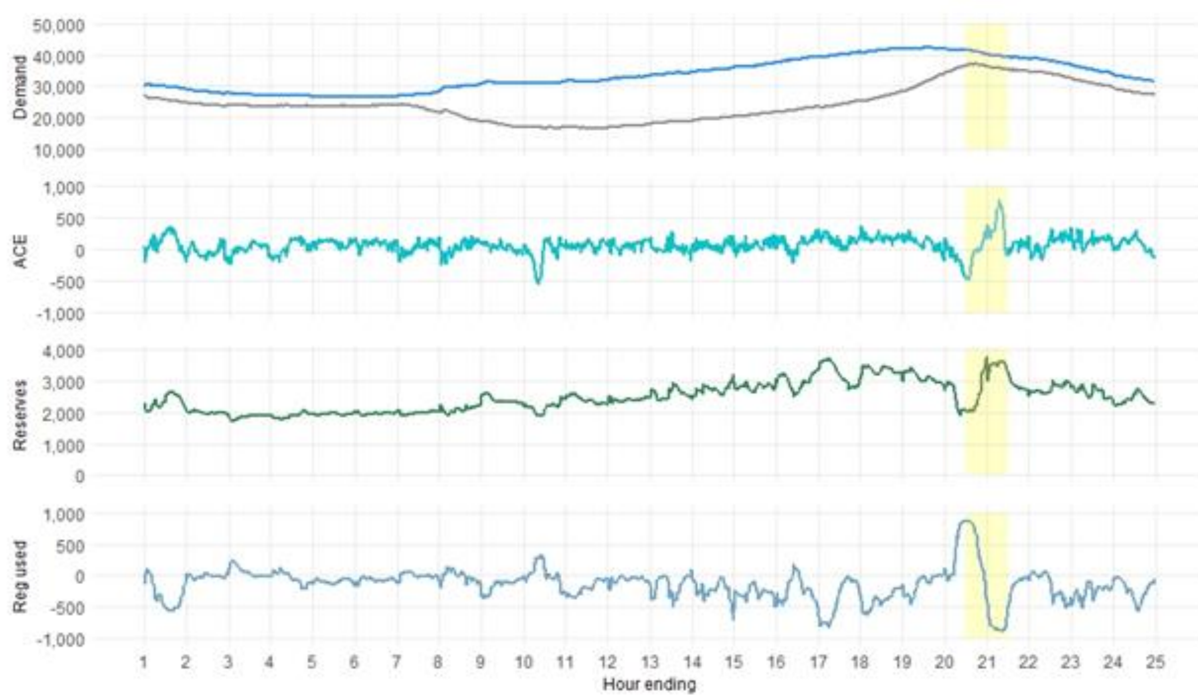
July 20th

On July 20th, ISO issued an EEA1, marking the first instance this summer of such an alert due to rapidly changing conditions during real-time operations. This occurred after the gross peak and coincided with the significant decline in solar production at sunset, leading to the net load peak. Figure 86 below illustrates the trend of key variables during real-time operations, including gross and net load, regulation usage, Area Control Error (ACE), and available operating reserves. The emergency period is highlighted in yellow in each subplot. Although this emergency was short-lived, it developed swiftly. Notable items from the emergency timeline include:

- Eight days prior, there were no projected conditions indicating a supply shortfall for July 20 in meeting the forecasted demand. This projection remained constant as the days progressed until one day before.
- On July 19, ISO projected thinning margins of supply capacity to meet all load obligation for July 20 during peak hours. The Day Ahead Market results published on July 19th for the trade date of July 20th indicated sufficient supply to fulfill the projected demand including up to 4,000 MW of additional RUC requirements to cover for renewable and load uncertainty. The RUC process reduced about 900 MW of economical and low-priority exports in HE20, and there were no supply shortfalls. No specific actions were taken one day prior.
- On July 20, by 18:00 hrs, the market results from the Hour-Ahead Scheduling Process (HASP) did not predict any supply shortfall. Supply remained sufficient to cover the forecasted demand along with HASP load conformance and exports.
- None of the FMM runs for HE20, including the FMM published at 18:30 hrs, 18:45 hrs, 19:00 hrs, and 19:15 hrs, indicated any supply issues. These runs successfully met the projected demand along with FMM load conformance and scheduled exports.

- By 19:00 hrs on July 20, approximately 1,115 MW of conventional capacity had been lost, with the majority of this capacity originally scheduled in the day-ahead market
- Suddenly, around 19:00 hrs, Real-Time Dispatch (RTD) started experiencing supply infeasibilities. These infeasibilities progressively intensified in subsequent RTD market runs. When the RTD market becomes infeasible, the effectiveness of RTD load conformance in helping to maintain Area Control Error (ACE) diminishes. As a result, this situation drove higher regulation usage, subsequently reducing Operating Reserve margins.
- Operators manually assigned around 150 MW of Operating Reserves out of market to offset the market's infeasibilities.
- Around 19:30 hrs, operators dispatched around 850 MW of RDRR in the market and requested that RC West declare an EEA1.
- Around 20:30 hrs, operators requested RC West to conclude the EEA1.

Figure 86: System conditions on July 20



July 25th

Similar to July 20, there were minimal signs in advance that the system would have tight supply conditions. Figure 87 shows the trend of the key metrics of real-time conditions that precipitated the call for an EEA watch.

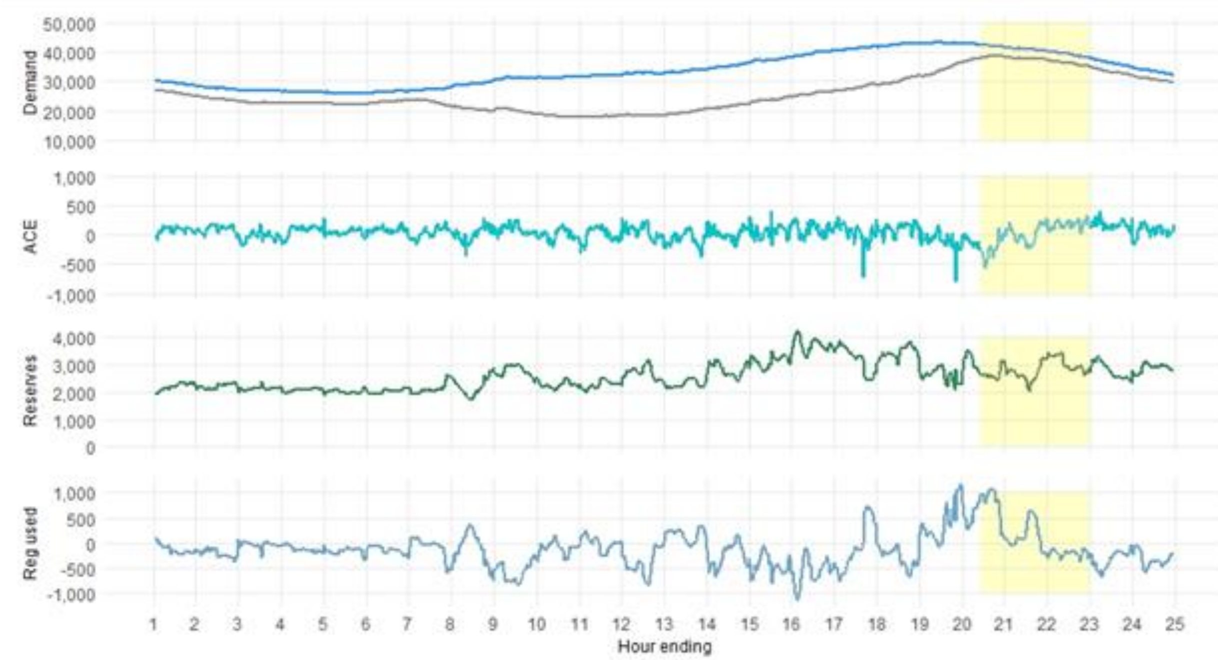
- Eight days prior, there were no indications of a supply shortfall for July 25 in meeting the forecasted demand. This projection remained constant as the day's progressed leading up to three days in advance.

- On July 22 ISO projected thinner supply margins to meet expected demand for the peak hours of July 25 as supply and load forecast conditions continue to be updated. This projection continued in the days leading up to July 25.
- On July 24, ISO projected thinning margins of supply capacity to meet all load obligation for July 25 during peak hours. The Day Ahead Market results published on July 24th for the trade date of July 25th indicated sufficient supply to fulfill the projected demand including up to 3,900 MW of additional RUC requirements to cover for renewable and load uncertainty. The RUC process reduced about 750 MW of economical and low-priority exports in HE20, and there were no supply shortfalls. No specific actions were taken one day prior.
- At 16:48 hrs and again at 17:45 hrs, ISO applied post-market pro-rata curtailments to schedules on NOB intertie because the path was over its limit caused by a schedule that was tagged above its HASP award.
- At 16:39 hrs about 700 MW of supply were lost due to the Victor Fire in Southern California.
- Between 18:00 hrs and -21:00 hrs on July 25, there were 1,576 MW of capacity on outage, of which about 1,368 MW had been already scheduled in the day-ahead market.
- Shortly after 18:00 hrs, ISO granted over 100 MW of Emergency Assistance for HE19 to another BA due to forced loss of generation, and expected to provide up to 175 MW for HE20.
- Although completion of the HASP for HE20 was anticipated by 18:00 hrs, this run experienced delays in finalization and publication of market results. The scheduling system also encountered delays in processing the large volume of export reductions. Consequently, the first interval of the hour could not incorporate the reduced schedules.
- HASP for HE20 issued about 4,800 MW of reductions for economical and low-priority exports, alongside 300 MW of low-priority wheels.
    - Around 340 MW of the export reductions were not accepted by their scheduling coordinators, who rather partially accepted a higher export schedule than what cleared in HASP.
    - In total, approximately 2,400 MW of the exports reductions directed by HASP were not upheld by their holders, either through retagging the already adjusted tag or by denying the adjustment that ISO issued to reduce the tagged energy. This further contributed to last-minute supply limitations within the ISO area, as the market had foreseen these exports being reduced to manage tight supply conditions. Consequently, this extended the supply infeasibilities within the RTD market.
- During HE19, due to the loss of approximately 350 MW of supply, which already projected to be available in the real-time market. This loss of supply prompted the utilization of Regulation to maintain system balance in the initial segment of the hour, leading to some Operating Reserve deficits in the early part of the hour.
- During both HE19 and HE20, congestion on Path 26 elements exhibited notable volatility and, at times, intensified to severe levels. This congestion had several implications:
    - Southbound congestion on Path 26 limited generation from the north to meet demand needs.
    - In the latter part of HE19 and given the complex problem to solve with all congestion and stressed conditions, RTD market faced challenges in executing successful runs on time and relied on advisory solutions produced in a the preceding run. Some RTD solutions resulted in

substantial WEIM transfer changes for one specific balancing area due to extreme congestion on elements of Path 26. These sizable transfers stemmed from the reduction of intertie-related schedules in RTD aimed at mitigating congestion. In some instances, the real-time schedules were infeasible on Path 26 constraints.
    - A share of export reductions that were not followed though were for exports sourcing in the southern part of the system. Therefore, they exacerbated congestion on Path 26, reducing the ability of the ISO to meet SP 15 load with generation in the north.
    - Throughout this period, the Path 26 limit was dynamically managed to true up market flows with actual conditions and flows.
- At 19:26 hrs ISO requested RC West to declare an EEA Watch.
- ISO Operators manually assigned about 500 MW of Operating Reserve out of market to compensate for upcoming market infeasibilities.
- At 19:37 hrs ISO recalls the Emergency Assistance that was being provided to other BAA to self-preserve capacity.
- The RTD Infeasibilities caused additional usage of Regulation, leading to more intermittent Operating Reserve deficiencies.
- Toward the end of HE20, the ISO manually curtailed around 600 MW of low priority exports for the reminder of HE20 and for HE21.
- During HE21, operators manually assigned an additional 100 MW of Operating Reserves out of market.
- Toward the end of HE21 the MW capacity lost from the Victor fire returned to service.
- The ISO ends EEA Watch at 22:00

Figure 87 shows a few quick metrics for real-time operations. The first subplot shows both the gross (blue) and net (grey) demand. The second subplot shows the trend of the area control error, while the third subplot sows the trend of reserves available in the system; the last subplot shows the level of regulation available.

Figure 87: System conditions on July 25

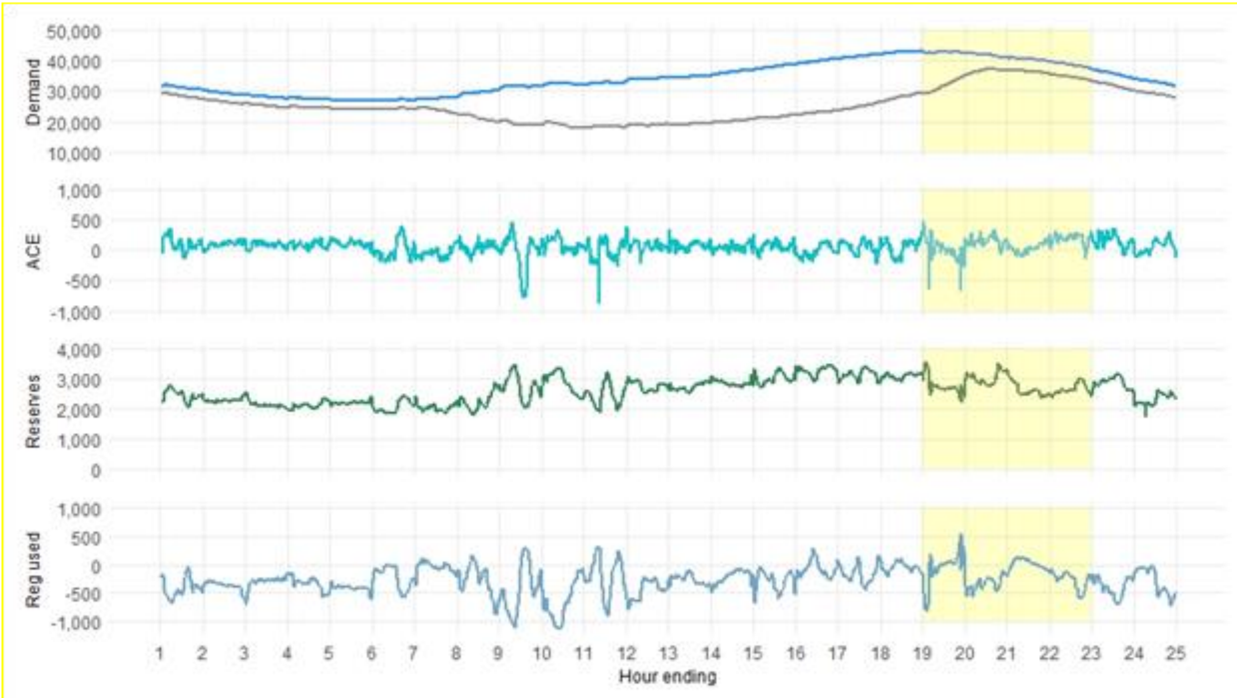


July 26th

Following the events of July 25, ISO issued an EEA watch for July 26. Ultimately, the conditions on July 26th were less severe compared to those experienced on July 20th and 25th.

- Eight days prior, there were no projected conditions indicating a supply shortfall for July 26 in meeting the forecasted demand. This projection remained constant as the day's progressed leading up to the day-ahead timeframe.
- The Day Ahead Market results published on July 25th for the trade date of July 26th indicated sufficient supply to fulfill the projected demand including up to 4,100 MW of additional RUC requirements to cover for renewable and load uncertainty. The RUC process did not result in significant reductions of economical and low-priority exports in HE20, and there were no supply shortfalls. No specific actions were taken one day prior.
- At around 12:00 the ISO declares EEA Watch between 18:00 and 22:00 hrs.
- Commencing with STUC around 17:00 hrs, and subsequently during FMM and the HASP, ISO restricted all dynamic transfers exclusively in the import direction for ISO area. This action was taken based on the observation since July 20th, that when WEIM advisory transfers were utilized to meet demand conditions in both HASP and FMM markets, these transfers were not fully available in the RTD market, necessitating last-minute adjustments to address the shortfall in available supply.
- During HE19, the Operating Reserve requirements were increased in the market by around 200 MW.
- At around 20:00 hrs the ISO unblocked all import transfers in STUC.
- At around 21:00 hrs the ISO unblocked all import transfers in FMM.
- At 22:00 hrs the ISO requests RC West to end EEA Watch.

Figure 88: System conditions on July 26



13.5 Market conditions

The events on July 20, 25, and 26 did not arise from insufficient capacity to meet demand, as supply was adequate. The swiftly shifting conditions described in the preceding section during these days revealed possible real-time market dynamics and highlighting the need to ensure resources are positioned in advance of the RTD.

The July events were not attributable to only a single issue, but rather arose from the convergence of various market dynamics and conditions. This section examines each facet of market operations, elucidating how these elements, along with their interplay, culminated in the observed tight supply conditions during those days that led to the emergency alerts.

13.5.1 Supply conditions

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 89 illustrates a comparison of the supply-side fleet, encompassing both Resource Adequacy (RA) and non-RA elements, available within the day-ahead window. This is based on the actual bids in the day-ahead market reflecting all supply available. This supply depiction is then juxtaposed with the load obligation, referencing three distinct points.

One of the reference points is to the total load obligation, accounting for the conventional load forecast combined with the need for operating reserves, as depicted by the purple line. Another reference point is the modified load forecast, which takes into account Reliability Unit Commitment (RUC) adjustments alongside the requirements for operating reserves. The third reference point adds the requirement that considers the clearing of the high priority (PT) exports, which are already supported by non-RA capacity. For the peak hours of July 20, 25 and 26, the available RA capacity was sufficient to meet the ISO load obligation relative to the standard load forecast and the load forecast plus RUC adjustments.

RA supply was adequate to meet ISO load during these three days of emergency alerts. Similarly, the same supply-demand comparison is done for the net load and supply, once the renewable resources are not factored in the capacity as shown in Figure 90. The RA capacity was sufficient to meet also the net load peak.

Figure 89: Day-ahead available supply and load forecast –July 20, 25-26

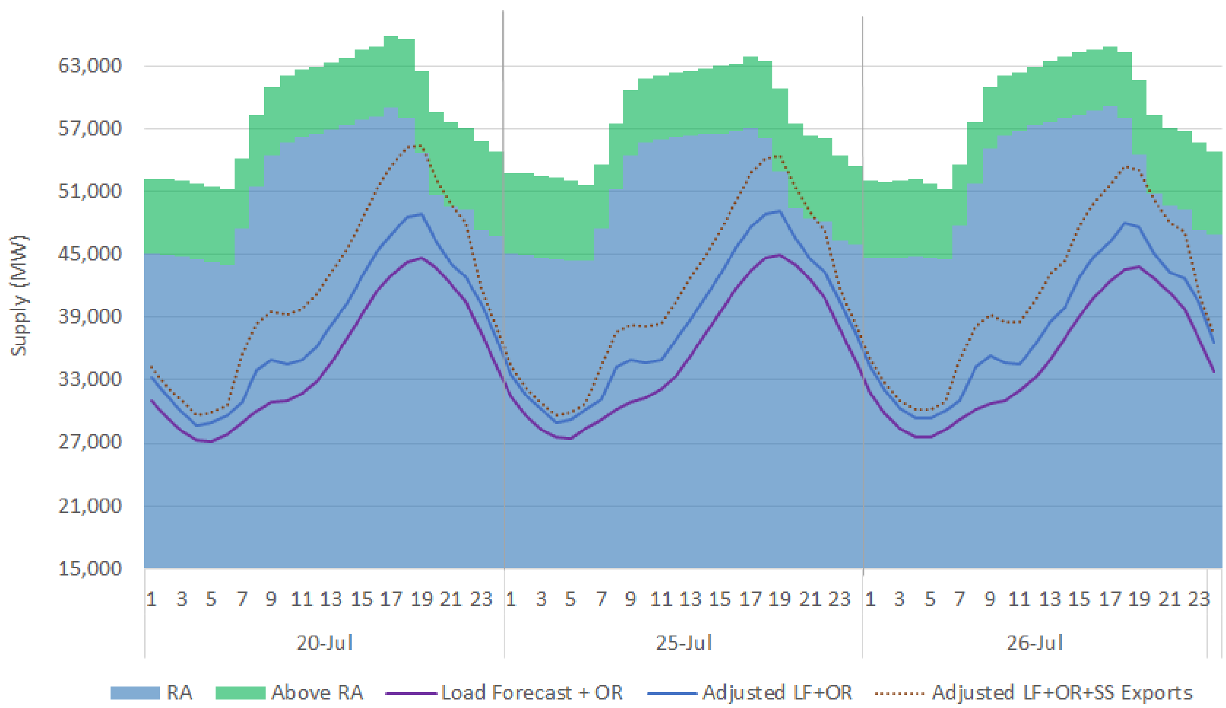


Figure 90: Day-ahead available supply and net load forecast – July 20, 25-26

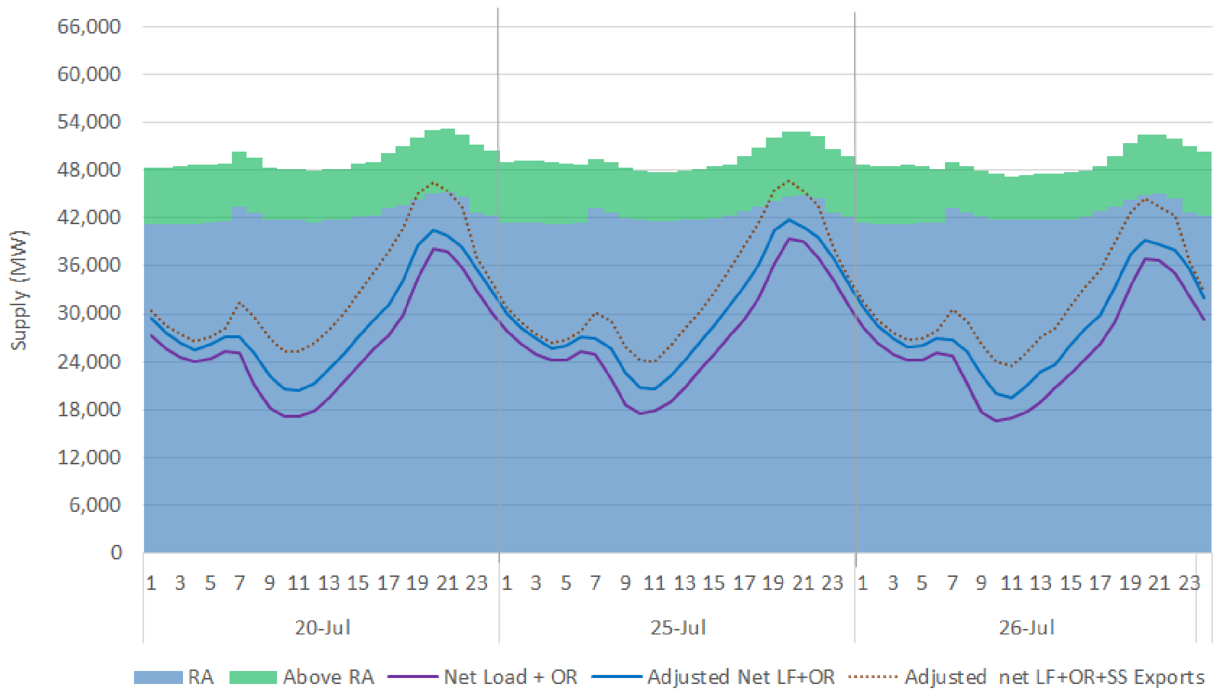
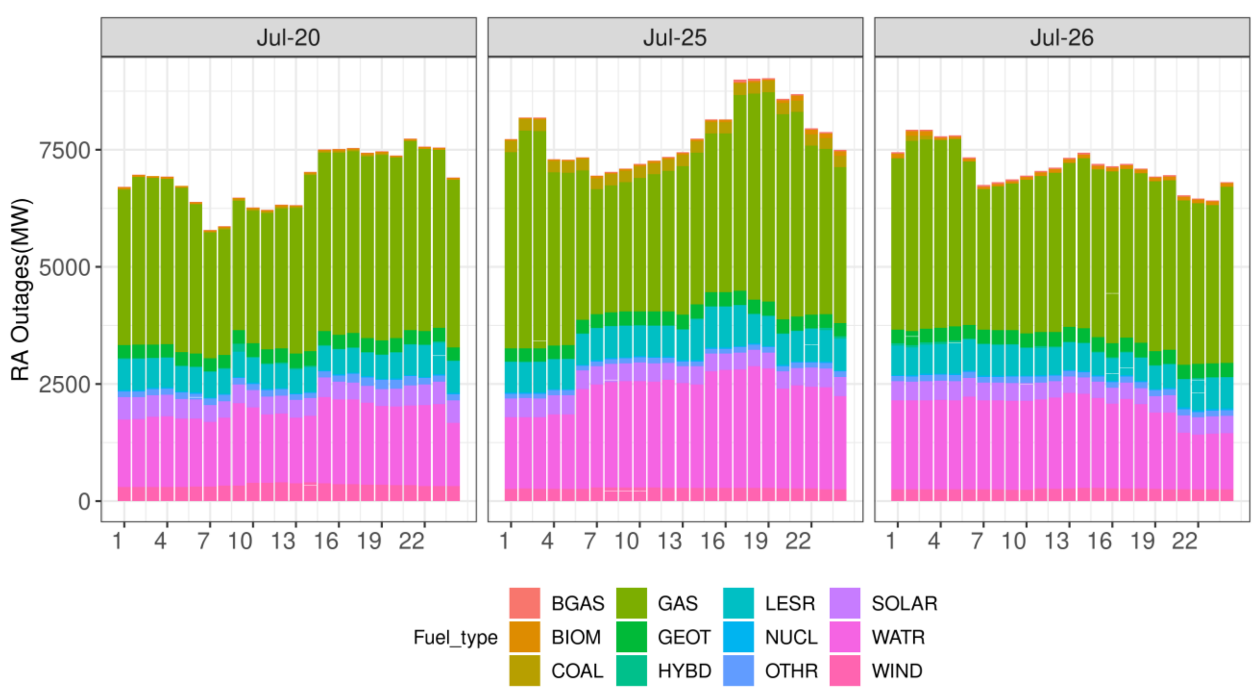


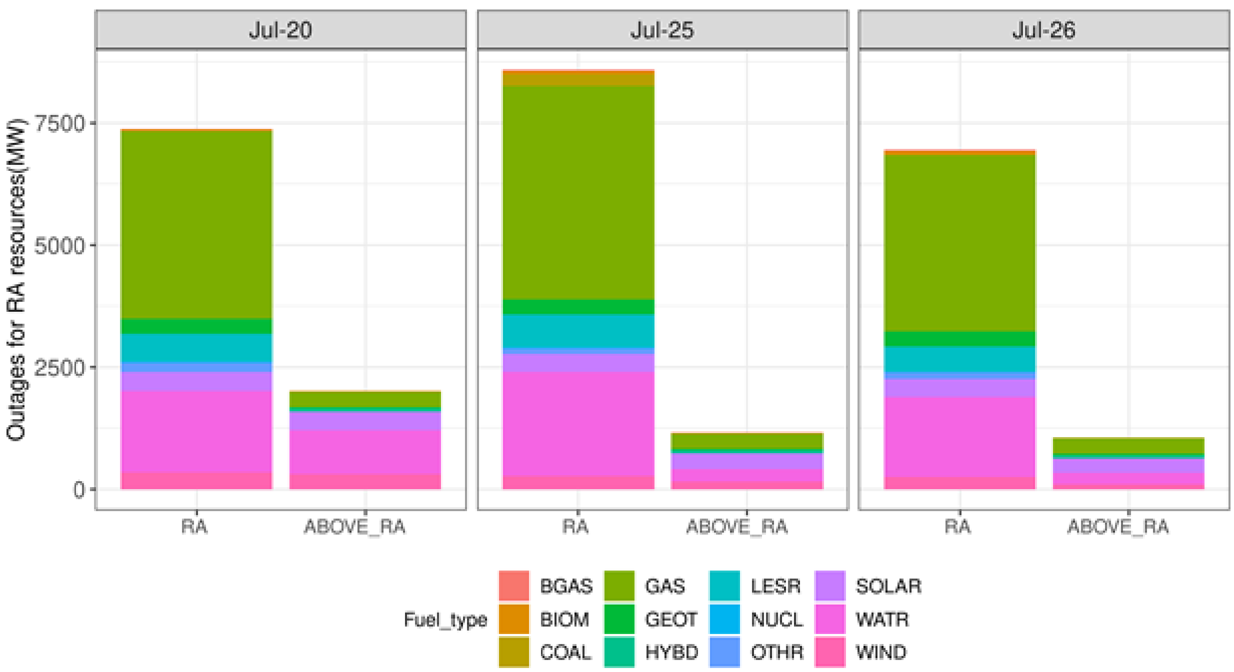
Figure 91 shows the hourly profile of outages and de-rates for resources that are designated as RA. Figure 92 shows the specific profile of all resources outages into two main groups, RA and non-RA as well as organized by technology type.

Figure 91 Hourly Profile of RA outages



For this metric, only resources that have RA designation are considered as RA capacity. There are two assumptions made for this analysis. One for wind and solar resources: if any amount of RA is associated with the resource, the entire capacity of these resources is considered as RA capacity. Any capacity above the established RA threshold for all other resource technologies is classified as "Above RA." The chart below shows the capacity that was on outage for resources that are designated as RA. Any capacity derate for an RA resource above the RA level is classified as an above-RA outage. Although there was a significant capacity that was derated above the RA levels for resources that have RA designation, it is within the ranges typically observed in July. The chart below shows the comparison for HE20 by technology type.

Figure 92 Outages for July 20, 25 and 26 for HE20



Conditions are bound to change from the day-ahead market to the real-time. Changes in outages, the demand forecast, VER uncertainty, and other elements may create a different supply profile to what was originally projected in the day-ahead market. 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 contributions from each of these resource types can fluctuate based on both seasonal changes and the time of day. The configuration of supply composition for the days marked by emergency alerts is illustrated in Figure 93 below. During the net demand peak, the supply breakdown reveals that slightly over half of the demand was met by gas resources, followed by hydro resources contributing 11 percent, imports covering 10 percent, and storage resources contributing around 6 percent.

Figure 93: Supply composition by type of resource

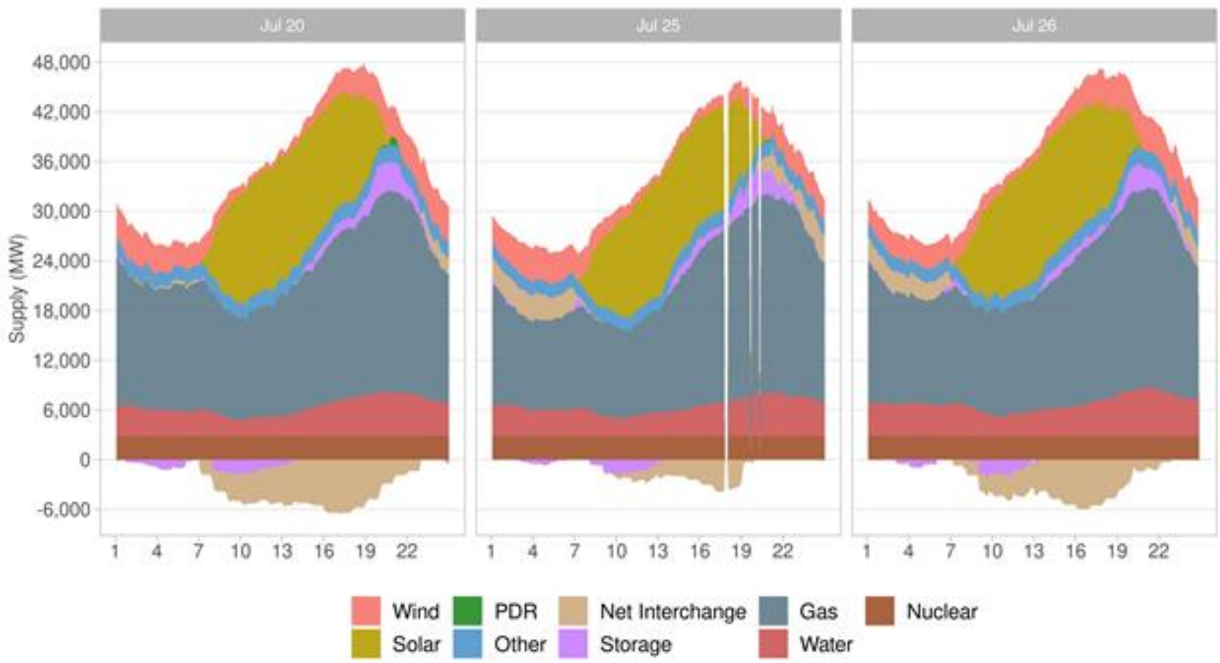


Figure 94 illustrates the volume of Exceptional Dispatches (EDs) during the period of the emergency alerts. Overall, the volume for July 20, 25 and 26 remained within similar levels of adjacent days. The main reason for these exceptional dispatches was for positioning resources for ramp capability.

Figure 94: Exceptional Dispatch Volume with the reason for July

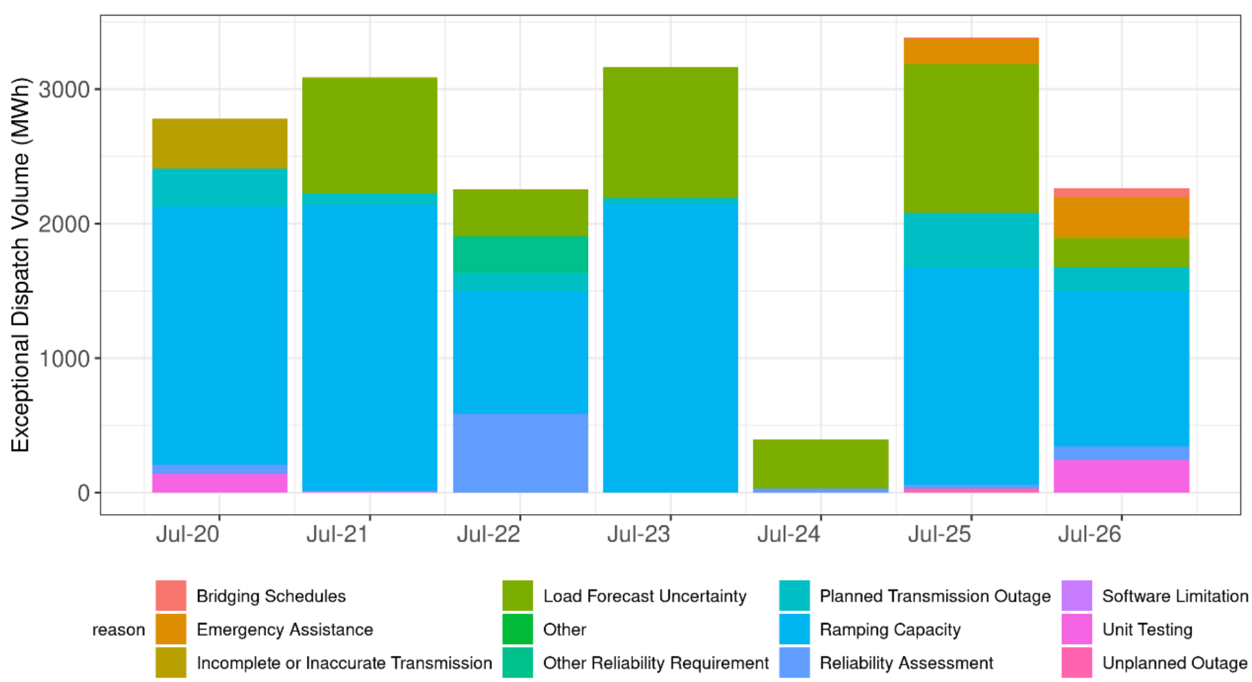
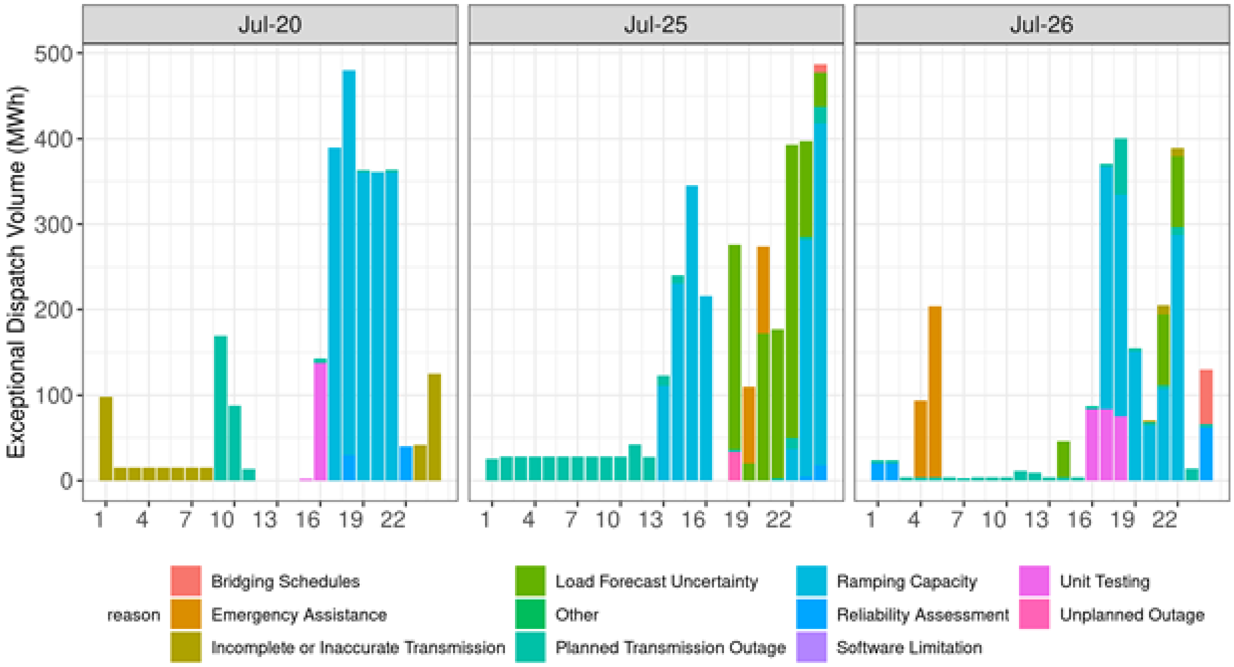


Figure 95 provides an hourly profile and shows that the largest volume of EDs on these days happened during the peak hours.

Figure 95: Hourly Profile of Exceptional Dispatch Volume with the reasons



13.5.2 Dispatchable supply

The measure of dispatchable megawatts (MW) within the market solution denotes the unloaded capacity ready for deployment in FMM and RTD markets. Figure 96 and Figure 97 show an approximation of the dispatchable capacity within both markets during the event days. This capacity is grouped to reflect the northern and southern regions of the system; a division that naturally emerges and becomes relevant when Path 26 experiences congestion. This distinction was particularly notable on July 25 when there was pronounced congestion along this path[36].

This metric represents just one of the numerous measures that operators must assess to gauge real-time conditions on the grid. However, certain issues arose with the display of this metric that gave a false sense of available capacity to operators. Although this inaccuracy involved the overestimation of capacity over different types of resources, one area was related to the accounting of dispatchable supply available from Limited Energy Storage (LES) resources, which possess unique operational characteristics. Consequently, the charts below do not incorporate LES resources.

Because it covers a longer time horizon, the FMM generally presents a larger amount of capacity available for dispatch than RTD. It's important to note that the count of dispatchable MW does not consider

---

[36] This is supply dispatched in the market, which will reflect any influence to clear for additional supply to meet load conformance used in real time. The same metric is organized by technology type in plots presented in the Appendix.

congestion, and as a result, this count can remain non-zero even in cases of supply shortfalls. This scenario may arise when available generation is impeded by a transmission constraints, such as on July 25 with Path 26 congestion.

Figure 96 Dispatchable supply in FMM organized by area

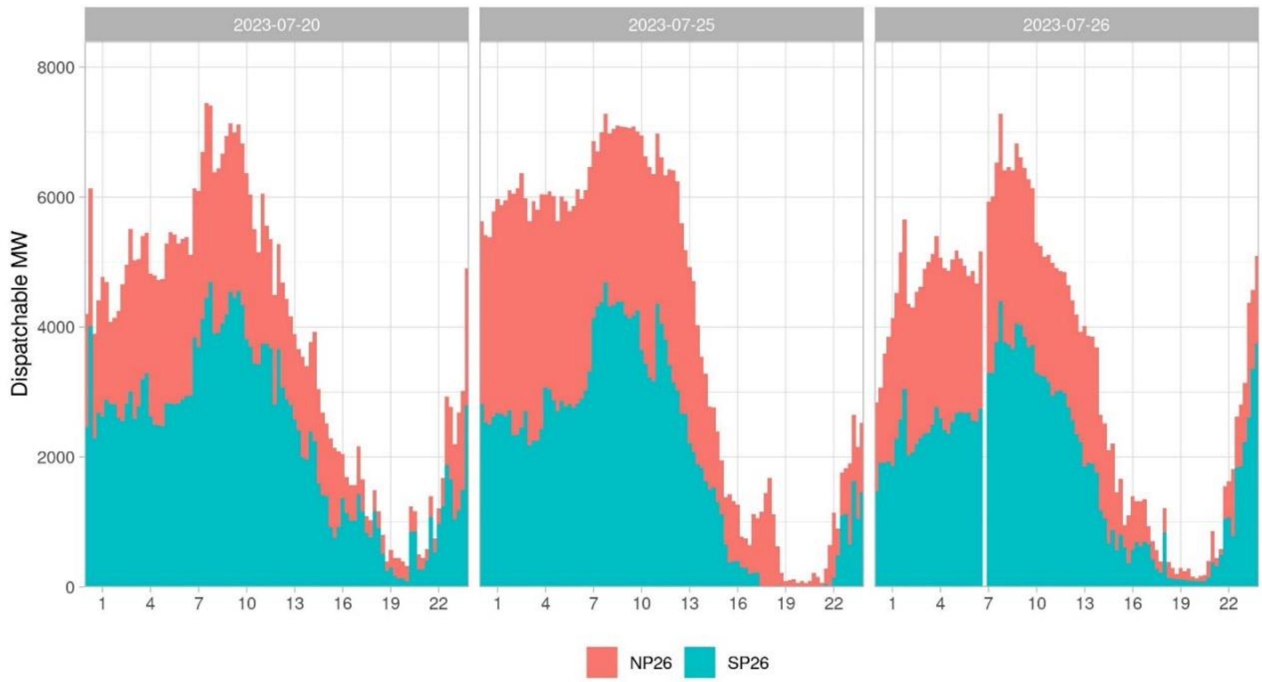
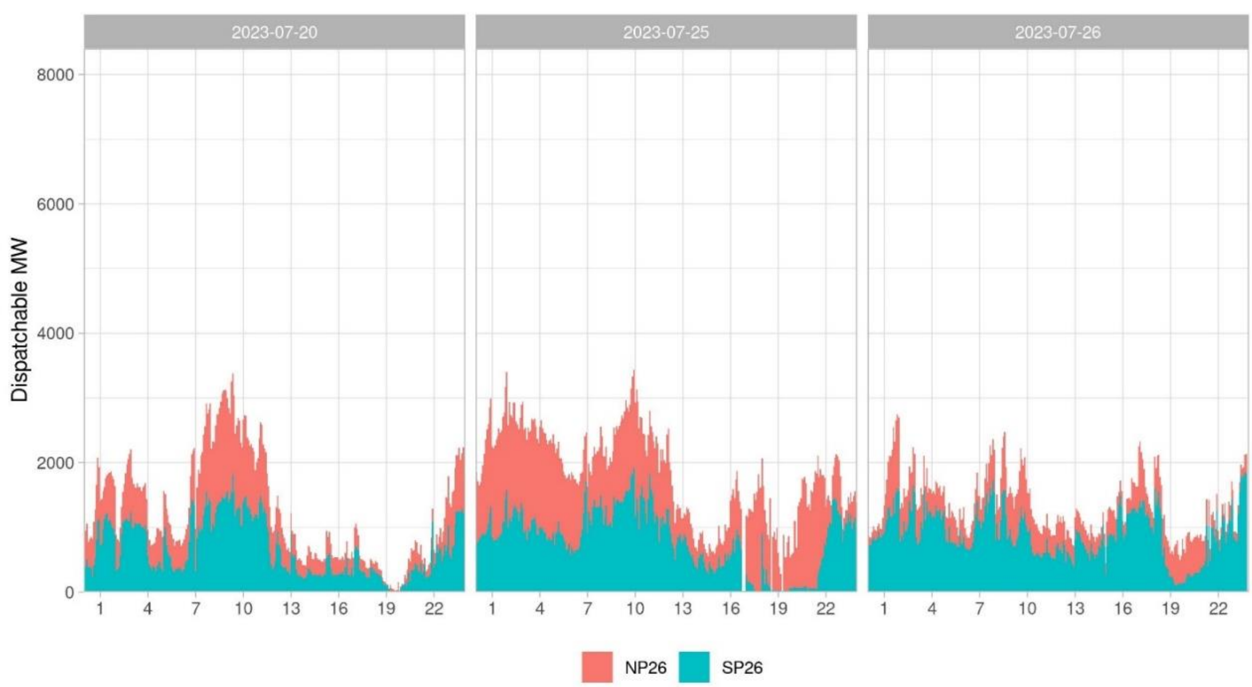


Figure 97 Dispatchable supply in RTD organized by area



During the emergency alert periods, the majority of available dispatchable capability depicted was located in the northern area of the system. However, this capability could not be deployed due to congestion along Path 26.

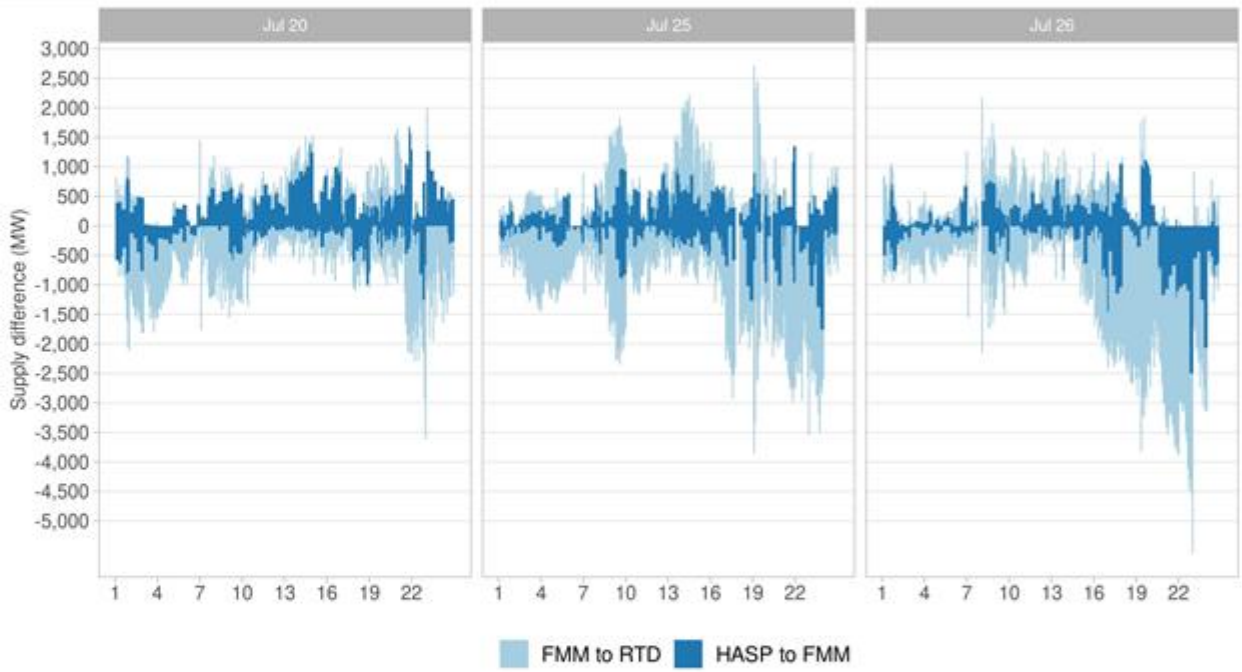
As the system demand increases towards the daily peak, supply will ramp up accordingly. This results in an anticipated reduction of available dispatchable capacity progressing toward the net peak demand. During the early hours of the day when demand is lower, supply tends to be more abundant, naturally tapering off during the evening ramp as solar declines. The FMM, with more time available to ramp resources, projected sufficient ramp capability to balance supply and demand over these days. However, during the emergency alert periods, there was a dramatic shift in the available supply within the RTD timeframe. As the net peak time neared, the market encountered a depletion of dispatchable supply.

The HASP and FMM markets did not forecast any instances of limited ramp capability, as evidenced by the absence of power balance infeasibilities. These markets are essential for securing additional intertie capacity or committing supplementary resources if necessary. However, during these events, the RTD market encountered supply infeasibilities that signaled system conditions that were materially different from the earlier projections.

Figure 98 shows changes in supply from the HASP market to the FMM market, as well as from the FMM market to the RTD market. Negative values denote unrealized supply within the subsequent market (e.g., the light blue negative values indicate RTD dispatch is less than FMM dispatch). These unrealized supply instances require the market to dispatch additional resources to offset the loss, subsequently diminishing the available dispatchable capability in the RTD market. The most significant share of supply changes transpired from the FMM to the RTD market[37].

[37] This compares supply dispatches, which in turn will reflect any load conformance used in each applicable market.

Figure 98 Supply changes in the real-time market



The loss of supply between FMM and RTD is due to a variety of reasons, including:

- Economics changing over the market horizon that led to different dispatch solutions,
- Management of state of charge to avoid depletion or reach the minimum state of charge
- Derates on resource capacity after the FMM run completed
- Changes in the available supply in the WEIM footprint resulting in a change of WEIM transfers
- Updates in VER forecast from FMM to RTD

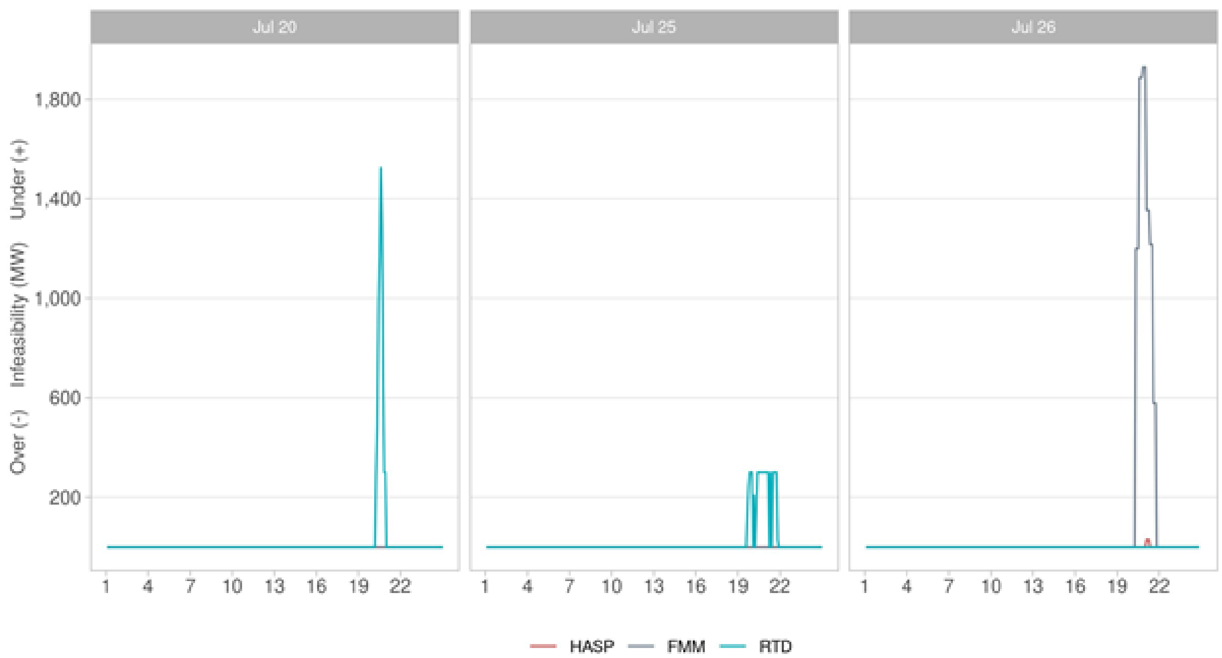
13.5.3 Market supply shortfalls

As part of the real-time market clearing process, supply is dispatched to meet the load forecast; this is commonly referred to as power balance. When supply is insufficient to meet demand because there is not sufficient capacity online or the available supply cannot ramp fast enough to meet the demand, the market observes a condition of power balance infeasibility (undersupply). This condition provides a first glimpse of tight supply conditions ahead of time from either the HASP, FMM or RTD market and can be an early signal for operators of projected infeasibilities that may realize in actual operations.

Figure 99 shows the trend of undersupply infeasibilities. The trend is markedly different for each of the three days under assessment. On July 20, there were no undersupply infeasibilities projected in HASP or FMM markets; infeasibilities of up to 1,500 MW appeared in the RTD timeframe when there was very limited ability to commit additional resources. On July 25, a similar pattern was observed when infeasibilities of about 300 MW were observed in RTD. Both HASP and FMM markets projected sufficient capacity to meet the load forecast plus the additional load conformance applied of up to 4,000 MW in the most critical hour.

Based on July 20 events, higher conformance was applied on both July 25 and 26 with the expectation that it would better position resources with ramp capability to meet the uncertain conditions later in the RTD market. On July 26, only FMM observed infeasibilities after ISO implemented the limitation of dynamic[38] import transfers for the ISO area. This reduced the reliance on transfers to meet the additional load requirement imposed by the load conformance and consequently required the demand to be met with internal supply and additional intertie resources. The profile of load conformance across the real-time market is shown in Figure 100.

Figure 99: Power balance infeasibilities in real-time markets



[38] WEIM transfers can be base, static or dynamic; for the change implemented on July 26, only the dynamic transfers were limited.

Figure 100: Load conformance applied in the real-time markets

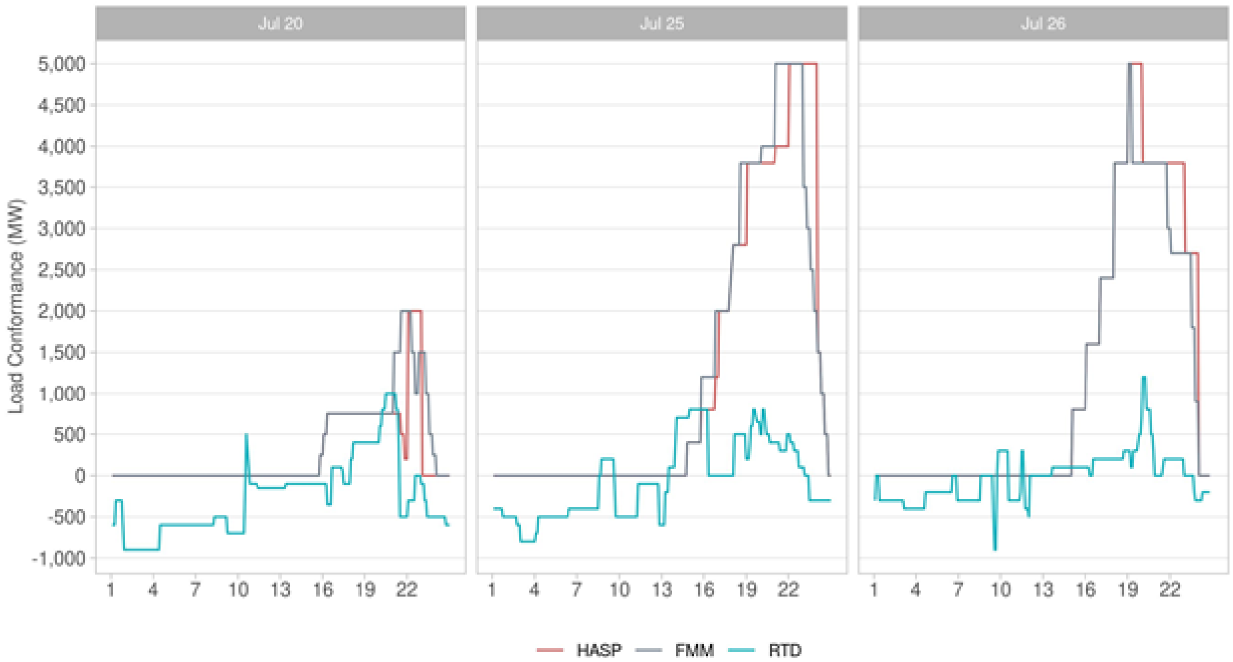


Figure 101 shows the progression of the tight supply conditions during the most critical time of the emergency on July 20. Each column corresponds to a RTD market run, with the initial entry (at the top of each column) indicating the binding interval of that market run. Each row denotes an interval forming the market horizon. The length of this horizon varies depending on the hourly run and can span up to ten intervals. The largest infeasibility of 1,524 MW observed in the real-time market was for the interval starting at 19:30 hrs. The earliest RTD run that encompassed this timeframe within its horizon was the RTD market for the binding interval at 18:50 hrs. This particular RTD market run did not forecast any supply infeasibilities. Subsequent RTD runs up to 19:05 hrs similarly projected no infeasibilities. However, the RTD market run for 19:10 hrs marked the initiation of moderate infeasibilities, amounting to 300 MW for the binding interval. In successive RTD market runs up to 19:30 hrs, the projections were continually updated with progressively larger infeasibilities. This scenario underscores the dynamic nature of conditions within both the system and the market. The transition from no infeasibilities to large infeasibilities occurred within just 20 minutes, resulting in the eventual declaration of an energy emergency.

Figure 101: Evolution of RTD supply infeasibilities (in MW) over time –July 20, 2023

	Binding Time Interval														
Horizon	18:45	18:50	18:55	19:00	19:05	19:10	19:15	19:20	19:25	19:30	19:35	19:40	19:45	19:50	19:55
18:45	-														
18:50	-	-													
18:55	-	-	-												
19:00	-	-	-	-											
19:05	-	-	-	-	-										
19:10	-	-	-	-	183	300									
19:15	-	-	-	-	50	300	491								
19:20	-	-	-	-	100	315	805	981							
19:25	-	-	-	-	155	300	898	1,043	1,176						
19:30	**-**	**-**	**-**	**-**	**277**	**300**	**638**	**919**	**1,189**	**1,524**					
19:35		-	-	-	229	300	564	813	1,127	1,228	1,296				
19:40			-	-	114	300	524	774	1,147	1,132	1,044	659			
19:45				-	-	96	300	385	821	988	991	300	300		
19:50								300	557	739	588	300	300	300	
19:55								300	423	597	579	300	-	42	-
20:00								223	300	382	579	251	-	-	-
20:05								-	137	256	300	-	-	-	-
20:10									-	146	265	-	-	-	-
20:15										271	300	-	-	-	-
20:20											141	-	-	-	-
20:25												-	-	-	-
20:30													-	-	-
20:35														-	-
20:40															-

A comparable matrix is shown in Figure 102 for July 25 peak conditions. In contrast to the abrupt trend shift witnessed on July 20, the evolution of supply conditions within the Real-Time Dispatch (RTD) market on July 25 did not exhibit a parallel rapid change. Instead, it indicates that the infeasibilities were of smaller magnitude but exhibited greater persistence throughout the period leading up to HE20.

However, owing to other dynamics within the system, the RTD market was unable to address the infeasibilities on an interval-by-interval basis. The reason for this is explained in subsequent sections as it has to do with congestion on Path 26 and export reductions not being tagged properly. Conversely, for July 26, no infeasibilities were recorded within the RTD market during the peak period.

Figure 102: Evolution of RTD supply infeasibilities (in MW) over time –July 25, 2023

Binding Time Interval

Horizon	18:20	18:25	18:30	18:35	18:40	18:45	18:50	18:55	19:00	19:05	19:10	19:15	19:20	19:25	19:30	19:35	19:40	19:45	19:50	19:55
18:20	0																			
18:25	0	0																		
18:30	0	0	0																	
18:35	0	0	0																	
18:40	0	0	0		244															
18:45	300	300	0		300	300														
18:50	0	10	0		300	300	300													
18:55	0	0	0		300	300	300	300												
19:00	0	0	0		0	0	2	149	0											
19:05	0	0	0		0	0	0	0	0	206										
19:10		0	0		0	0	0	0	0	0	0									
19:15			0			0	0	0	0	300	300									
19:20							86	0	0	300	300		300							
19:25				No run				0	0	300	300		300	300						
19:30									0	300	300		0	300	300					
19:35										300	300		300	0	300	300				
19:40											300		300	0	0	300	300			
19:45													300	300	0	300	300	300		
19:50													300	300	300	300	300	300	300	
19:55														0	300	0	300	300	300	300
20:00												No run			0	247	300	300	300	0
20:05																0	0	97	300	300
20:10																	0	0	86	300
20:15																		0	0	223
20:20																			0	0
20:25																				0

The volume of transfers is another critical element in maintaining system balance. Figure 103 visually outlines the sequence of WEIM import transfers directed into the ISO area on July 20. Notably, during the interval of the most significant supply infeasibility, import transfers diminished to 741 MW from an initial projection of 1,456 MW within the earlier RTD market run at 19:00 hrs.

It is important to recognize that these changes in transfer volumes, as observed within the RTD markets, contributed to a more constrained supply landscape within the ISO area. However, these variations were reflective of broader shifts occurring within the WEIM footprint, underscoring their interconnected nature and their repercussions on overall supply conditions.

Figure 103: Evolution of RTD imports transfers (in MW) –July 20, 2023

	Binding Time Interval														
horizon	18:45	18:50	18:55	19:00	19:05	19:10	19:15	19:20	19:25	19:30	19:35	19:40	19:45	19:50	19:55
18:45	1,039														
18:50	1,159	1,053													
18:55	995	1,004	907												
19:00	756	777	836	963											
19:05	618	582	646	1,004	764										
19:10	616	568	615	967	711	734									
19:15	749	666	793	1,166	907	950	653								
19:20	761	701	873	1,237	1,027	1,042	634	554							
19:25	842	805	952	1,325	1,111	1,170	679	566	756						
19:30	**968**	**944**	**1,069**	**1,456**	**1,220**	**1,433**	**902**	**713**	**710**	**741**					
19:35		1,043	1,196	1,565	1,337	1,596	1,074	881	857	866	1,060				
19:40			1,166	1,703	1,476	1,686	1,159	1,005	947	1,000	1,146	1,280			
19:45				1,758	1,476	1,761	1,282	1,246	1,222	1,381	1,365	1,578	1,517		
19:50								1,319	1,273	1,448	1,478	1,605	1,510	1,464	
19:55								1,216	1,103	1,324	1,319	1,397	1,448	1,326	1,463
20:00								438	636	1,136	1,028	1,203	898	1,000	1,112
20:05								394	494	964	997	1,203	686	794	1,139
20:10									475	917	884	1,009	654	762	917
20:15										900	904	944	641	802	922
20:20											1,058	951	697	781	882
20:25												1,034	692	853	813
20:30													825	927	977
20:35														906	954
20:40															988

Figure 104 shows the progression of WEIM transfers for ISO area for July 25; opposite to July 20, on this day the transfers were exporting (shown as negative values) from the ISO area and those exports gradually decreased over time, which helped reduce the upward pressure for ISO area supply.

Figure 104: Evolution of RTD imports transfers (in MW) –July 25, 2023

	Binding Time Interval																			
Horizon	18:20	18:25	18:30	18:35	18:40	18:45	18:50	18:55	19:00	19:05	19:10	19:15	19:20	19:25	19:30	19:35	19:40	19:45	19:50	19:55
18:20	-1,537																			
18:25	-1,190	-1,129																		
18:30	-1,023	-949	-1,178																	
18:35	-672	-796	-682																	
18:40	-483	-197	33		-739															
18:45	-380	-353	432		-614	-501														
18:50	-187	-127	499		-569	-463	-518													
18:55	-136	-43	86		-625	-548	-565	-610												
19:00	-1,130	-910	-668		-67	1	-83	-335	-766											
19:05	-1,688	-1,536	-546		-309	-16	-60	-181	-772	-567										
19:10		-1,780	-497		-235	-73	-31	-272	-768	-645	-758									
19:15			-765			-13	166	3	-397	-402	-472									
19:20							262	127	-260	-311	-453		-334							
19:25								272	-203	-208	-316		-313	-429						
19:30				No run					-123	-67	-206		-558	-422	-429					
19:35										-53	-265		-389	-665	-422	-468				
19:40											7		-351	-654	-665	-491	-341			
19:45													-362	-370	-654	-458	-333	-274		
19:50													-119	-312	-370	-425	-397	-358	-179	
19:55														-15	-312	-791	-348	-369	-448	-475
20:00												No run			-15	-316	-88	-23	-505	-611
20:05																-288	-29	0	-384	-529
20:10																	48	82	-195	-363
20:15																		250	-2	-212
20:20																			170	-29
20:25																				162

Changes in internal supply were one of the main contributors to the rapid change of conditions. The swift loss of ramp capability was not solely attributed to a single resource or specific technology experiencing significant changes in unrealized supply. Instead, these supply changes resulted from relatively modest changes across multiple resources. In the California region, the unrealized supply amounted to approximately 900 MW, while the rest of the WEIM footprint experienced an unrealized supply of 850 MW.

Figure 105 offers a comparison of the supply projection changes for 19:30 hrs derived from the 19:05 hrs market run (advisory generation) and the supply actually dispatched at 19:30 hrs (binding generation). This analysis is organized by supply technology and also encompasses the key regions within the WEIM. The "CAL" category incorporates the ISO, LADWP, and BANC areas, while the other regions group the balancing areas of the Desert Southwest (DSW), Pacific Northwest (PNW), and Mountain Northwest (MNW).

Figure 105: Unrealized supply from advisory 19:05 hrs to binding 19:30 hrs for July 20

Region	CC	E	Hy	I	LES	MSG	ST	VER	CT	In	Other
CAL	-7	-73	-35	-70	-244	-31	-16	-342		-92	-67
DSW				-3	-4	-122	-15	-258			-10
MNW						-121		-151			
PNW				-59		-35		-71	-4		

This matrix displays solely negative values, indicating less supply in the binding interval compared to projections in the 19:05 hrs market run. At the same time, other resources were dispatched higher during the binding interval to counterbalance the unrealized supply from some resources in the binding interval, thereby diminishing available ramp capability for ensuing intervals. Reduced supply was primarily from VER resources, MSG and storage resources being dispatched at lower levels than initially anticipated. Supply adjustments impacted numerous resources across the entire WEIM footprint area. The leading causes for the significant supply deviations between projections and actual RTD dispatch on July 20 include:

- Storage resources had to be charged or maintained at a state of charge to fulfill regulation obligations. In certain cases, regulation usage from storage necessitated additional charging to maintain resources' state of charge.
- Resources were not dispatched because their offers exceeded LMPs at their locations. These prices remained low amid tight supply conditions because of congestion effects, indicating that the resources could not be dispatched higher without overloading transmission constraints.
- The market issued instructions to multi-stage generating (MSG) units to transition to higher configurations to provide the market access to extra capacity. However, the transition either did not occur as instructed, resulting in the projected capacity not being available in RTD, or the resource experienced a delay beyond its standard transition time in completing the transition.
- Updates to base-schedule imports within the hour reduced supply available to certain entities in the Northwest, requiring the market to dispatch other resources to offset that supply loss for their region. The Rocky Reach-Columbia #2-230kV line was forced out of service due to a fire, affecting the Pacific Northwest and hydro deliveries in the area, possibly contributing to the import reduction.
- Storage resources experienced low state of charge, with the market optimization reserving the limited charge for use in future intervals.
- During the period of market infeasibilities, outages or Pmax derates affected some resources, worsening the situation. This occurred across various technology types, including MSGs and storage units.
- Import tags for ISO imports from the Northwest were curtailed by other transmission service providers due to transmission constraints caused by wildfire impacts.
- Lower limits were bid in for some hybrid resources compared to limits bid in earlier FMM or RTD runs.
- Reduced VER production resulted due to changing wind and solar conditions.

Likewise, Figure 106 illustrates the unrealized supply from the last interval without any supply infeasibility to the initial interval where infeasibilities emerged on July 25. In the California region, the aggregate unrealized supply exceeded 800 MW, primarily originating from storage resources, VER variability, and intertie schedule changes. The collective unrealized supply for the rest of the WEIM footprint exceeded 700 MW.

Figure 106: Unrealized supply from advisory 19:00 hrs to binding 19:05 hrs for July 25

	CT	E	Hy	I	LES	MSG	ST	VER	Other
CAL	-2	-102		-148	-395	-17	-12	-172	-41
DSW		-43		-32	-20	-17	-9	-133	-2
PNW		0	-12	-133		-59	-5	-107	-33
MNW		0				-64	-20	-69	

Figure 107 depicts a comparison of unrealized supply later in the night, during the persistence of RTD infeasibilities. The most notable unrealized supply originated from storage resources, followed by MSG resources and VER variability.

Figure 107: Unrealized supply from advisory 19:10 hrs to binding 19:40 hrs for July 25

	CT	Hy	I	LES	MSG	ST	VER	CT	In	Other
CAL	-40	-18	-22	-774	-321	-1	-232	-142	-103	-107
DSW	0		-132	-3	-502		-148			-2
MNW	0		-42		-113	-24	-168			-24
PNW	0	-226	-53			0	-348	-3		

As with the occurrences on July 20, the accumulation of unrealized supply spanned numerous resources across the broader footprint. The drivers for the largest changes of supply on July 25 include:

- Storage resources had to be charged or maintained at a state of charge to fulfill regulation obligations in future intervals. In some cases, storage resources changed to the maximum regulation limit which impacts the amount of regulation to be available.
- Manual dispatches fixed resources' output at a given MW level.
- Updates to based-schedule imports within the hour reduced supply provided by certain entities, representing a loss of supply that had to be offset with increased supply from other resources in the market software.
- Resources weren't dispatched due to economic factors, as their locational marginal prices didn't exceed their bid-in prices. These prices remained low amid tight supply conditions because of congestion effects, signaling resources need to be dispatched down to not further exacerbate congestion. Based on counterfactual analysis, congestion on Path 26 constraints prevented up to 700 MW of supply in the north from being dispatched higher.
- Outages or Pmax derates placed on resources reduced their supply.
- The market issued instructions to MSG units to transition to higher configurations to provide the market access to extra capacity. However, the transitions either did not occur as planned, resulting in the projected capacity not being available in RTD, or the resources experienced a delay, in some cases of over 30 minutes, in completing the transition.

Figure 108 illustrates the progression of the storage resource dispatches on July 20. The black dots on the graph represent the dispatches at the binding interval of each RTD market run. From each black dot, a line emerges, illustrating the trajectory of dispatches projected for the subsequent advisory intervals of each RTD market run. These trajectories are determined as part of the multi-interval optimization used in the ISO markets. This optimization process not only balances supply and demand for the first binding interval of each market run but also for the subsequent intervals. With every RTD market run, the optimization recalculates the subsequent advisory intervals, leading to distinct dispatch trajectories based on the most up-to-date system conditions.

Figure 108: Progression of Storage resources during the peak hours of July 20

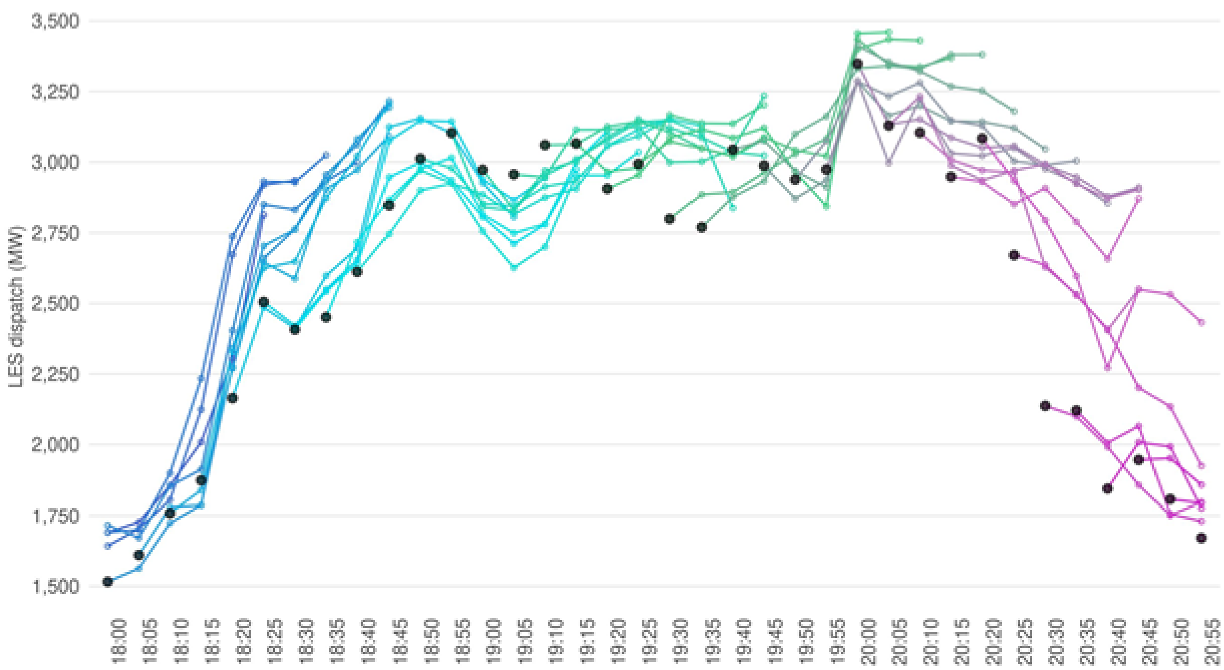


Figure 109 illustrates the divergence of these trajectories of dispatches in July 25 as each market run took place. For storage resources in general, the projected level of dispatch typically came in lower in subsequent market runs, resulting in unrealized supply, which has to be balanced with incremental dispatch of other supply.

Figure 109: Progression of Storage resources during the peak hours of July 25

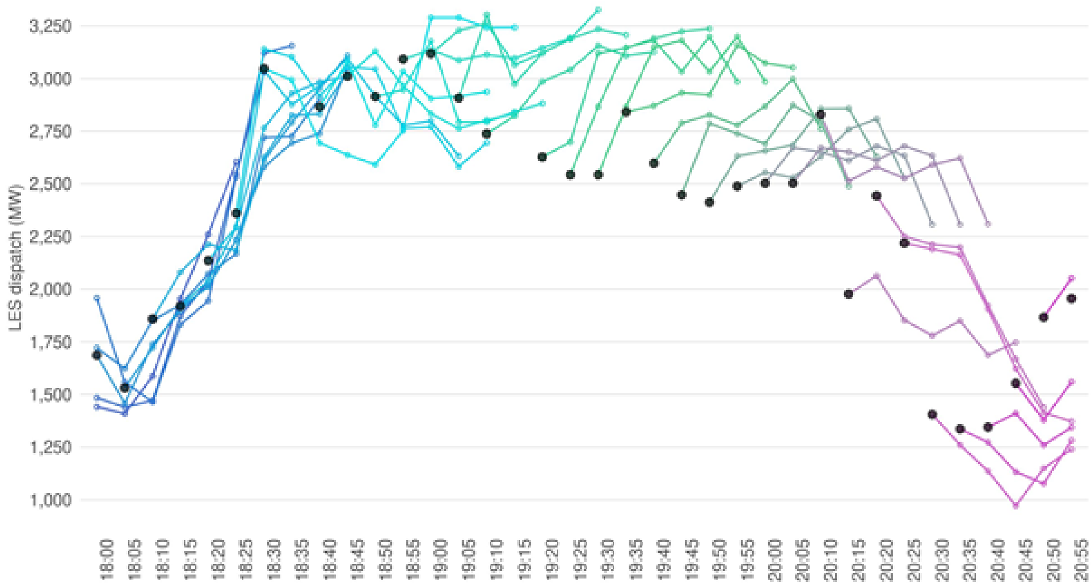
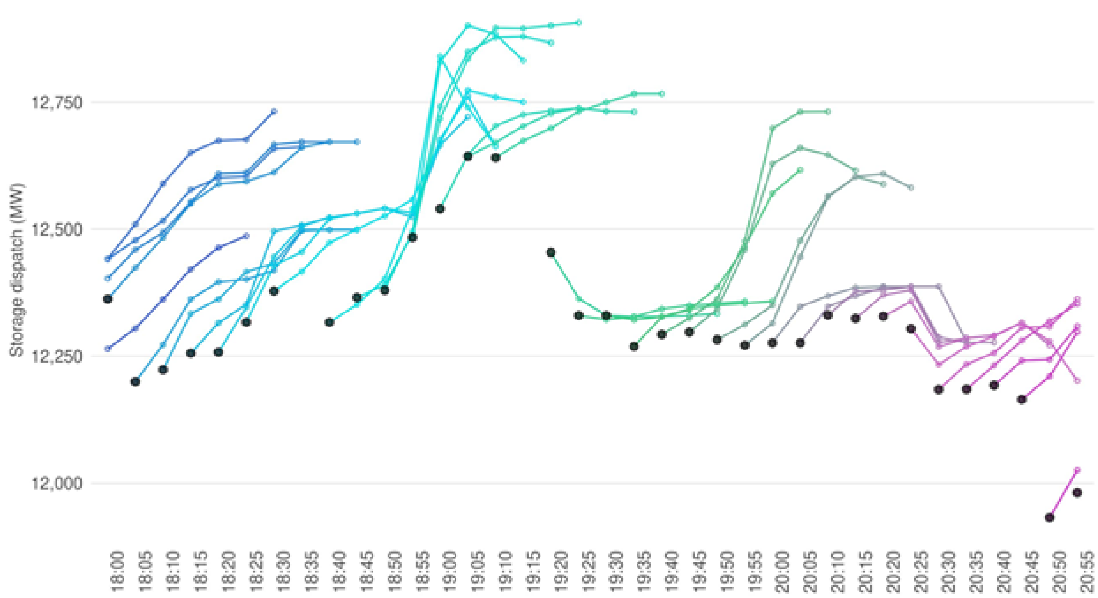


Figure 110 illustrates a similar trend for MSG units in the southwest region. Notably, a substantial discrepancy emerged between the projected dispatches and the actual dispatches realized in the binding intervals. Unrealized dispatches exceeded 1,000 MW in some market runs.

Figure 110: Progression of MSG dispatches in DSW during the peak hours of July 25



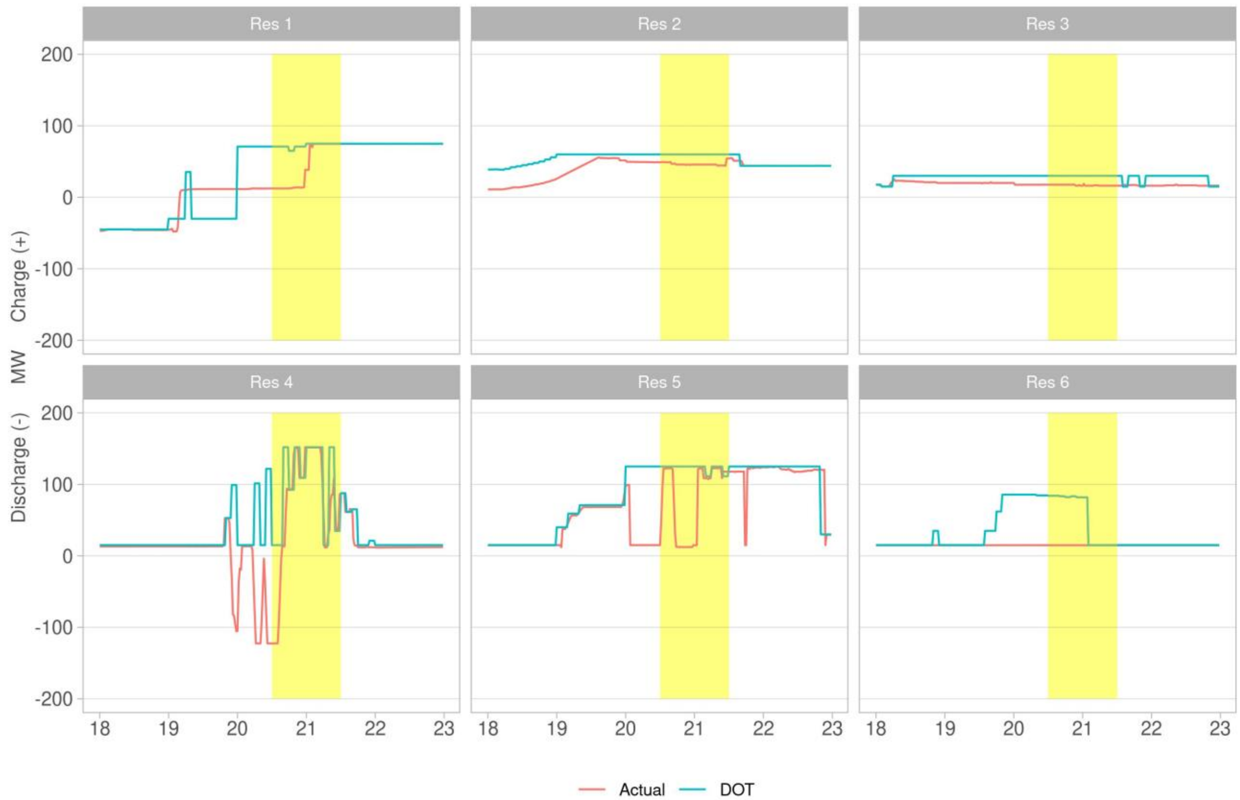
13.5.4 Resource performance

There are different ways to estimate resource performance. Historically one way has been to measure the RA shown versus the capacity made available to the market. As described in previous sections, the July events were not primarily driven by inadequate supply, but rather by rapid changing conditions within the real-time. In cases like July 25, congestion played a role in how these resources were positioned for the peak conditions.

For this reason, the resource performance described in this section is based on how resources actually followed ISO's instructions as measured by the difference between ISO instruction and actual production. For July 20 at the critical time of HE20, there were resource deviations that further contributed to the conditions leading to the EEA1. There was over 300 MW of conventional generation producing below their market instructions. There was also over 300 MW of renewable resources producing less than the market instruction (which is based on the latest RTD VER forecast). However, this was largely offset by another set of VERs producing above the forecasts in the market run. There was also over 300 MW of storage resources not producing at the level of their dispatch instruction. Figure 111 illustrates the profile of output and dispatch instructions during the EAA1 time frame of six different storage resources and it shows the difference in the deviation between dispatch instructions and performance, in some cases involving charging rather than discharging and vice versa[39].

[39] The depicted resources did not carry regulation and thus the comparison of their actuals with the instructions reflect deviations.

Figure 111: Resource deviation on July 20 during peak conditions



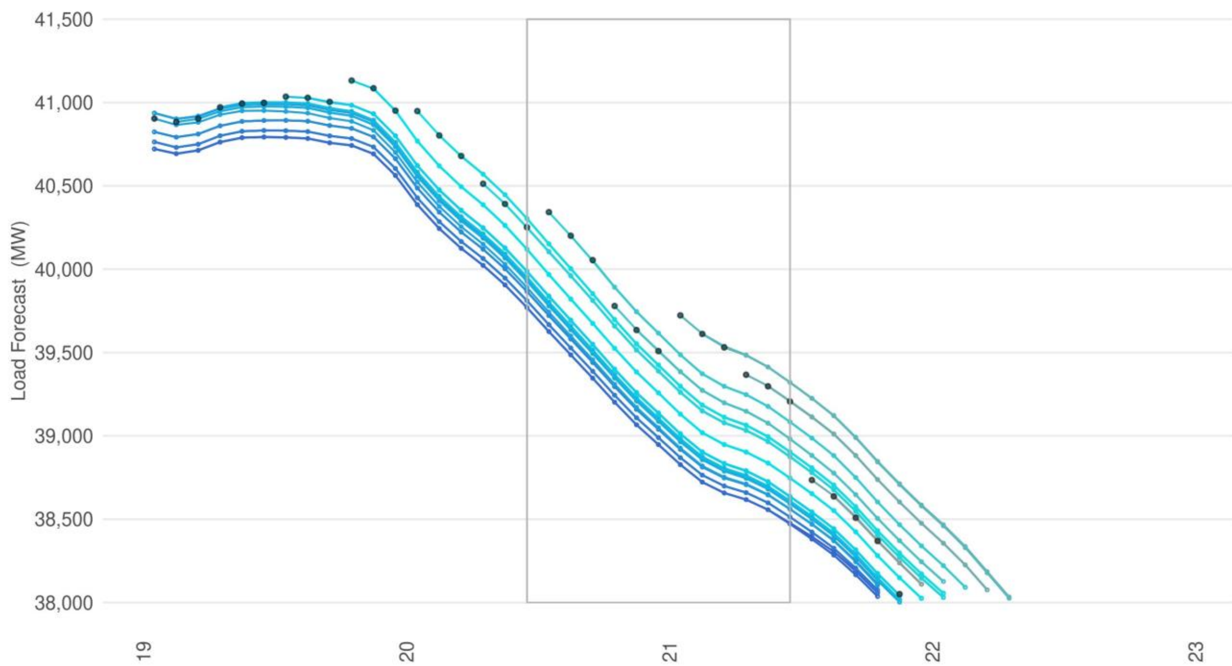
Given the complexities of storage resources, ISO continues to explore enhancements for more efficient and feasible dispatches. The ISO is also continuing to investigate the causes of resource deviations to understand the challenges and consider ways of addressing these issues.

13.5.5 Demand conditions

Demand is the other component of the power balance. Demand requirements can also change across the real-time markets, from HASP to FMM and from FMM to RTD, and as the load forecast updates. Supply must meet load forecast, load conformance input by operators in each balancing area, and for ISO area the exports that are cleared through the HASP and FMM markets. All these factors lead to changes in the total demand obligation.

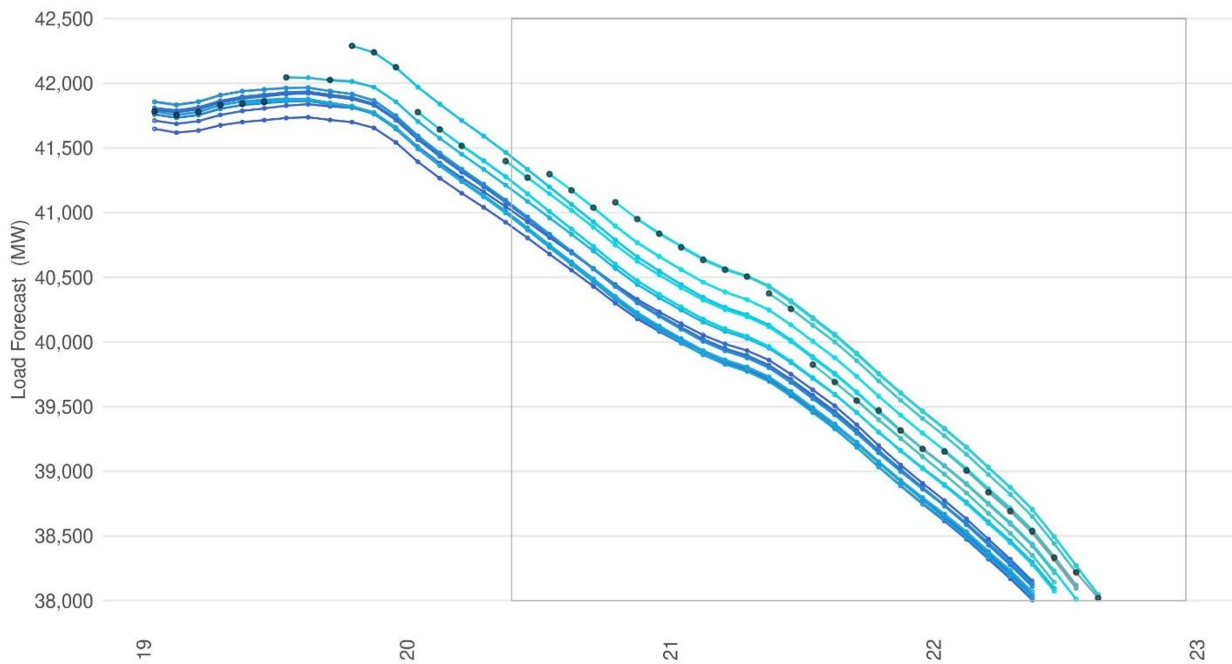
Figure 112 and Figure 113 show the evolution of the RTD load forecast for the ISO area on July 20 and 25, respectively. Each line shows one trajectory of load forecast starting with a black dot representing the RTD binding interval while the lines that continues from that point represents the forecast values for future advisory intervals. The square in grey capsules the timeframe of the EEAs. The RTD market clearing process balances supply and demand up to nine advisory intervals in the horizon.

Figure 112: RTD load forecast evolution during peak hours of July 20



There are similarities between both days for the evolution of the load forecast over time. As the market progressed over time, the load forecast was updated. For HE20, the period preceding the alerts and the start of the alerts, the updates came in with higher load forecast than previously projected in earlier updates. This required the RTD market to re-optimize the supply to be able to meet the additional demand that was not accounted for in prior RTD runs, which added to the strained condition of limited dispatchable supply. The magnitude of the load forecast changes were relatively modest in comparison to the supply changes described in previous sections.

Figure 113: RTD load forecast evolution during peak hours of July 20



13.6 Intertie transactions

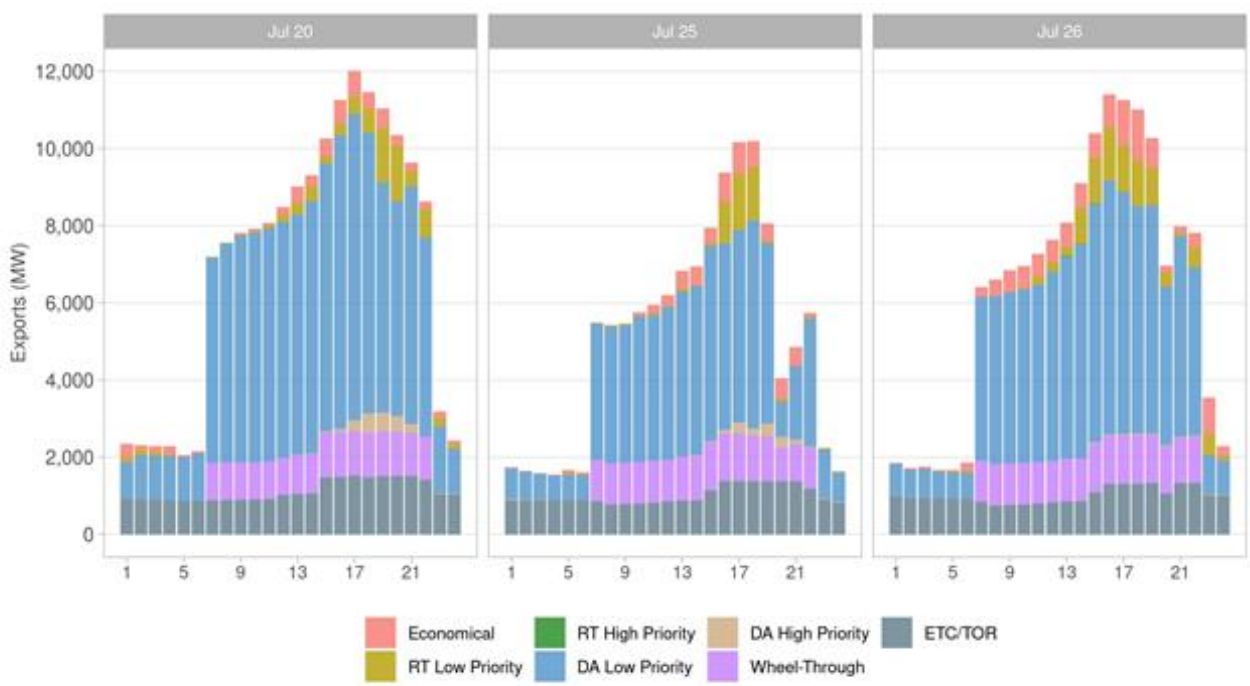
A pivotal aspect of the supply and demand mix within the ISO system is intertie transactions, encompassing static non-resource-specific imports, dynamic schedules on the supply side, and exports on the demand side. The net outcome of these three components yields the net schedule interchange. Figure 114 illustrates these intertie elements with different bars, while the blue line traces the net interchange according to the HASP solution. This representation also encompasses the volume linked to wheel transactions, which denote imports and exports. Nevertheless, wheel transactions do not contribute additional supply or demand to the ISO system wheel transactions balance out, thus exerting no impact on the net schedule interchange.

For the days of July 20, 25 and 26 export volumes were significant, offsetting much of the imports for midday hours, resulting in negative interchange (net export position), then shifting to low net import positions for peak hours.

Figure 114: Intertie transactions cleared in real-time organized by type of transaction

Figure 115 shows a more granular composition of the exports, classified by the type of participation and priority. For completeness, all types of exports are shown, however, ETC/TOR, high priority and wheel-through transactions do not add any additional load obligation for the ISO area.

Figure 115: Export schedules in real time organized by type of priority

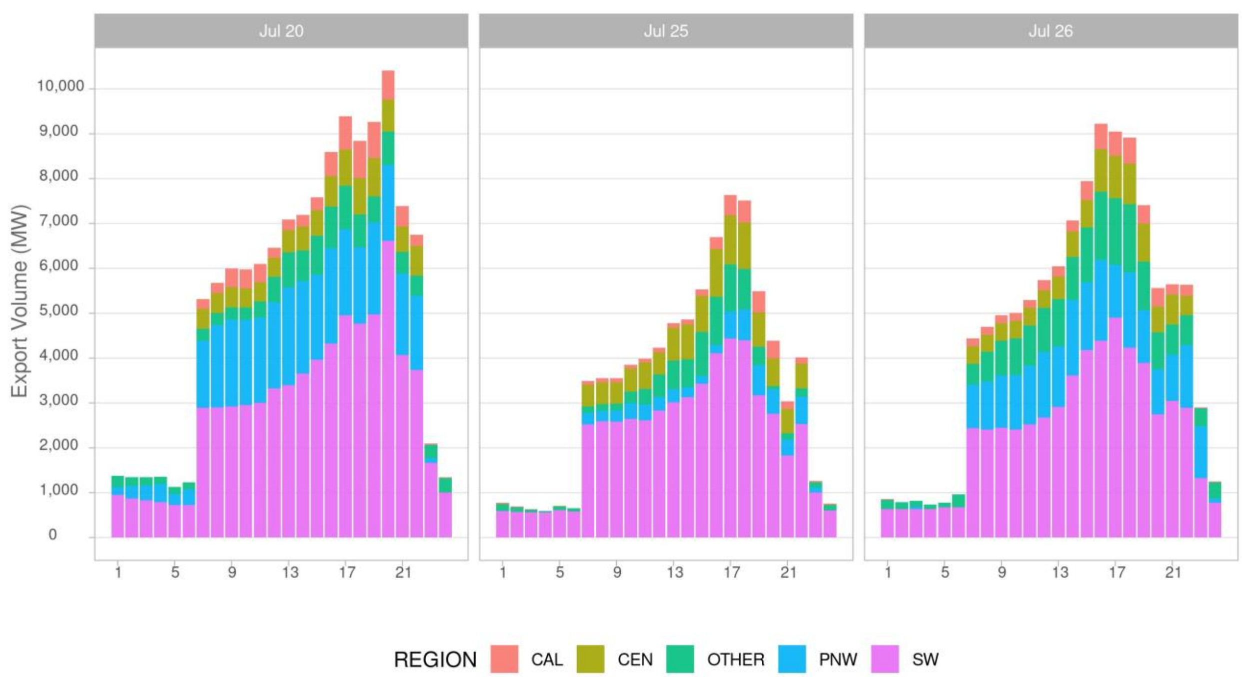


Exports categorized as ETC/TORs do not support load outside ISO area; rather, they pertain to exports tied to pre-existing transmission rights. Their volume remains consistent, hovering around 1,500 MW across the event days. Exports stemming from wheel-through transactions are in balance between their import and export side, thereby not adding any load obligation to the ISO. Meanwhile, high-priority exports rely on non-RA resources previously secured through exports. Deducting these three export types from the total export volume provides an accurate picture of exports cleared in the ISO market to serve other areas' load.

The maximum export levels reached approximately 9,300 MW on July 20; 7,500 MW on July 25, and 8,600 MW on July 26. During the hour 17, when the highest export level was observed, low-priority exports from the day-ahead market constituted about 75 percent, while real-time low-priority and economical exports comprising around 12 and 10 percent respectively.

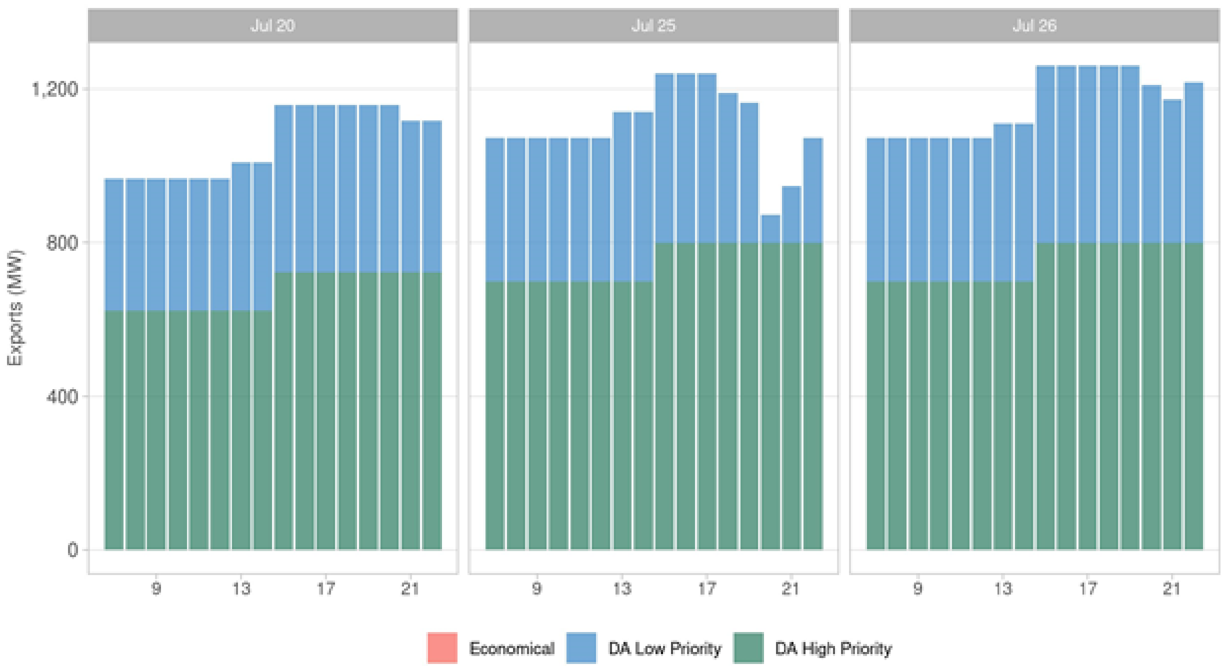
For the critical hour 20, about 70 percent of the volume was from day-ahead low priority exports, while real-time low priority and economical exports represented about 12 and five percent, respectively. Figure 116 illustrates the regions of withdrawals that exports being sourced at the ISO area. These exports are supporting many areas across the west. The sinking BAAs are grouped into the main regions, including CAL for areas in California, Cen for areas in central US, PWN for areas in the Pacific Northwest, SW for areas in the Southwest; all those captured areas that are part of the WEIM market; The group of OTHER is for any other areas that are not part of the WEIM market.

Figure 116: Breakdown of ISO exports by sinking BAA



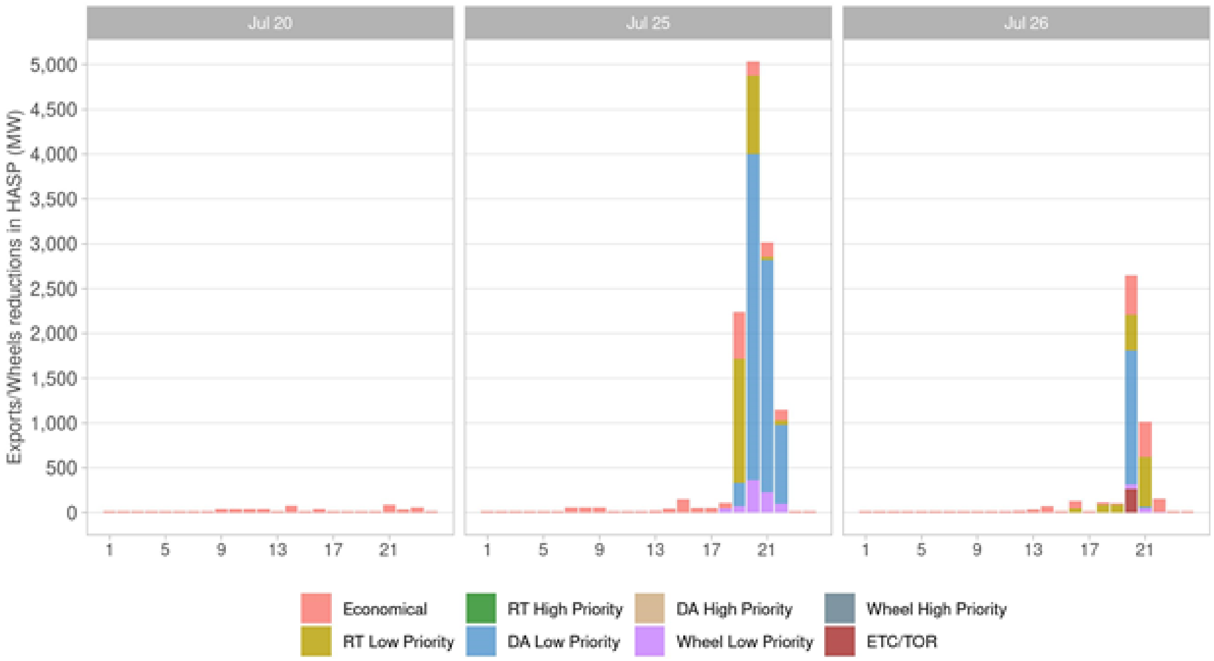
Wheel-through transactions do not directly influence the power balance of the ISO area, but they can wield a secondary influence when congestion materializes. In Figure 117 shows the quantity of wheel-through transactions cleared in the real-time market, categorized by participation type – high-priority, lower priority, or economical transactions. Across these three days, hardly any economical wheels were observed, whereas the peak volume for high- and low-priority wheels reached around 800 MW and 436 MW, respectively. However, registered high-priority wheels exceeded the actual bidding in the market. Moreover, through the analysis conducted on these wheels, it became evident that certain scheduling coordinators did not properly bid in wheels to utilize the high-priority designation, instead scheduling coordinators selected the low-priority classification. Consequently, the market treated them accordingly with lower priority.

Figure 117: Wheel-through transactions cleared in the real-time market



As part of the process to balance supply and demand, the market relies on the scheduling priorities for exports and wheels concurrent with the consideration of power balance infeasibilities. When tight supply conditions exist in the HASP process and HASP does not clear, the market will reduce exports following predefined priorities, starting by not awarding economical exports, followed by reducing low-priority exports, and if needed, reducing high-priority exports.

Figure 118: Exports not cleared in the HASP process



On July 20, only a minor portion of economical exports were not scheduled in HASP. On July 25, a total of 5,000 MW of exports were reduced in HASP, which included up to 367 MW attributed to low-priority wheels. High-priority exports and wheels remained unaffected. The breakdown of the export reductions is illustrated in Figure 118.

The majority of the reductions were applied to the day-ahead low-priority exports since this is the type of exports that cleared the most in the day-ahead. Interestingly, on July 25 there were also reductions of low-priority wheel-through transactions. These wheels were reduced because they were low priority, as explicitly bid-in by their scheduling coordinators, and the reduction was driven by the congestion on constraints related to Path 26. On this day, the pro-rata logic to proportionally reduce high priority wheels and imports self-schedules was not triggered because the congestion on Path 26 did not require any reductions of high-priority wheels[40].

Additionally, notably certain economical and low-priority exports managed to clear in the HASP market for HE20 on July 25. Multiple exports that were cleared at the Malin scheduling point were to mitigate congestion on Path 26 by providing counter-flow relief. While the scheduling priority is consistent for all exports and wheels of the same priority category (high or low), location-based differentiation impacts the order in which exports of the same priority level will be subjected to reductions.

After the HASP results were published, which included export reductions, it was anticipated that the 4,827 MW of export reductions in the HE20 HASP would alleviate the strain in the ISO grid in the subsequent fifteen-minute and five-minute market runs. Nevertheless, approximately 2,300 MW of export reductions

[40] Although some wheel-through exports were properly registered in advanced for high priority, these wheel-through transactions were bid in the market with low priority and, thus, the market treated accordingly, by reducing when needed.

did not materialize in those subsequent markets. There were two primary issues that affected the subsequent real-time market runs

1) The ISO's systems (market and E-tagging) experienced delays in identifying an optimal solution and in processing the extensive volume of export reductions made in the HASP. The E-tag system is responsible for adjusting the energy E-tags for the export resource schedules that were reduced in the HASP. However, the E-tagging system did not have enough time to cut all energy E-tags. This enabled certain export transactions that should have been reduced to deliver the exported energy in the initial fifteen-minute market run for HE 20.
   The completion of the HE20 HASP market run was delayed, and the results were communicated to market participants at 18:07. The ISO's E-tagging system received these HASP results and attempted to process them from 18:20 to 18:22. However, during this process, the E-tagging system faced difficulties in managing the high volume of export cuts. Consequently, the first fifteen-minute market run for HE20 was initiated at 18:22, and 2,243 MW of the export resources that were supposed to have HE20 HASP export cuts still retained their E-tags due to the E-tagging system's challenges processing the significant number of cuts.

2) Scheduling coordinators reinstated the E-tags that were adjusted by the HE20 HASP after the ISO adjusted those exports in the E-tagging system[41].
   After the ISO’s E-tagging system cut the remaining E-tags, Scheduling Coordinators for approximately 30 resources modified their the E-tag back to the HASP self-schedule amount so that their export could flow. Some scheduling coordinators have informed the ISO that it was not clear that low-priority exports can be reduced by the HASP when those low-priority exports cleared the day-ahead and Residual Unit Commitment markets. Therefore, the scheduling coordinators restored their E-tag to the amount that cleared in the Residual Unit Commitment market.

These two issues concerning the HASP HE20 export reductions exacerbated and prolonged the emergency alert conditions.

With more than half of the HE20 HASP export cuts still not materializing in the fifteen-minute and five-minute markets for HE 20, at 19:26 the ISO declared an EEA Watch. At 19:47 in the five-minute market, the ISO curtailed the E-tags for 610 MW of low-priority exports that were still delivering the export amount that was reduced by the HE20 HASP. Furthermore, the exports reductions that were not tagged where mostly at locations in the southern part of the system and, consequently, exacerbated congestion on Path 26. The ISO has followed with Scheduling Coordinators to clarify low-priority dispatch and tagging rules[42].

[41] There was a third minor issue impacting intertie resource awards. Due to congestion on multiple constraints, including 30060_MIDWAY _500_24156_VINCENT, 6410_CP1_NG and OMS OUTAGE JHINDS-MIRAGE_NG, the intertie was overloaded in the import direction so excess import schedules were awarded. ISO Operators had to take manual actions to pro-rata cut import schedules at the NOB intertie. Some of the NOB intertie resources that were cut were import wheeling resources and the export wheel counter-part also was cut so that the wheel pair was balanced.

[42] Additionally, ISO posted basic description of how scheduling priorities work in ISO’s market and the details of the market clearing process for participants to better understand their intertie awards. The document can be found at

Another challenge arose during the period of the emergency alerts. The NOB intertie had a 1,622 MW import limit for HE 20 and the HASP issued schedules to enforce the 1,622 MW limit. A resource that received a 0 MW HE20 HASP import schedule still created an E-Tag for 50 MW of import that was received by the real-time market and overloaded the intertie by 50 MW in the fifteen-minute market. When an intertie is overloaded, the real-time market system pro-rata cuts all import resources so that the sum of schedules is equal to the intertie limit. On July 25 given the combination of prices and congestion on Path 26, these reductions were not realized through the market and instead operators had to manually curtailed schedules.

13.7 Reliability demand response

Figure 119 shows the trend of RDRR dispatches for the five-minute market. RDRR were dispatched only in two days of July. On July 20, RDRR were dispatched up to 875.6 MW in the last 15 minutes of HE 20 and 844.7 MW in the first 15 minutes of HE21. This makes a total period of 30 minutes of RDRR dispatches.

Figure 119: RDRR dispatch in the real-time interval market

There are several factors to determine the period for which resources receive a dispatch, including intertemporal constraints and minimum up time. Many of these resources have a minimum load point of 0 MW, thus the market may still have considered them when at 0 MW. Dispatches on July 21 were associated with day-ahead awards, which for RDRR automatically convert to self-schedule in real-time.

The RDRR dispatches issued on July 20 were forced by operators, rather than driven by economics, given the sudden onset emergency conditions and the need to deploy additional capacity expeditiously to avoid

and is also provided in an appendix of this document. Also, a companion FAQ was posted at [FAQs-on-Export-Schedules-and-Scheduling-Priorities.pdf (caiso.com)] escalating to more severe grid conditions. At this time, intra-hour supply infeasibilities were worsening and ISO operators had manually deployed reserves to alleviate supply infeasibilities.

On August 1, the ISO published updates to Operating Procedure (OP) 4420[43], specifying that RDRR can be either enabled in the market (dispatched by economics) or "forced" in the market (forced into next market run regardless of economics) based on reliability-based triggers for a Transmission Emergency or EEA Watch or higher. These updates were based on a California Public Utilities Commission (CPUC) decision, effective June 29, 2023[44]. Prior to the CPUC decision, dispatch of RDRR would prompt the ISO to request an EEA 2. On July 20, although updates to OP 4420 were in draft form, operators issued such "forced" dispatches of RDRR at an EEA 1, but did not require to wait for the escalation to an EEA 2, pursuant to direction provided under the CPUC decision, effective June 29, 2023.

13.8 Western Energy Imbalance Market transfers

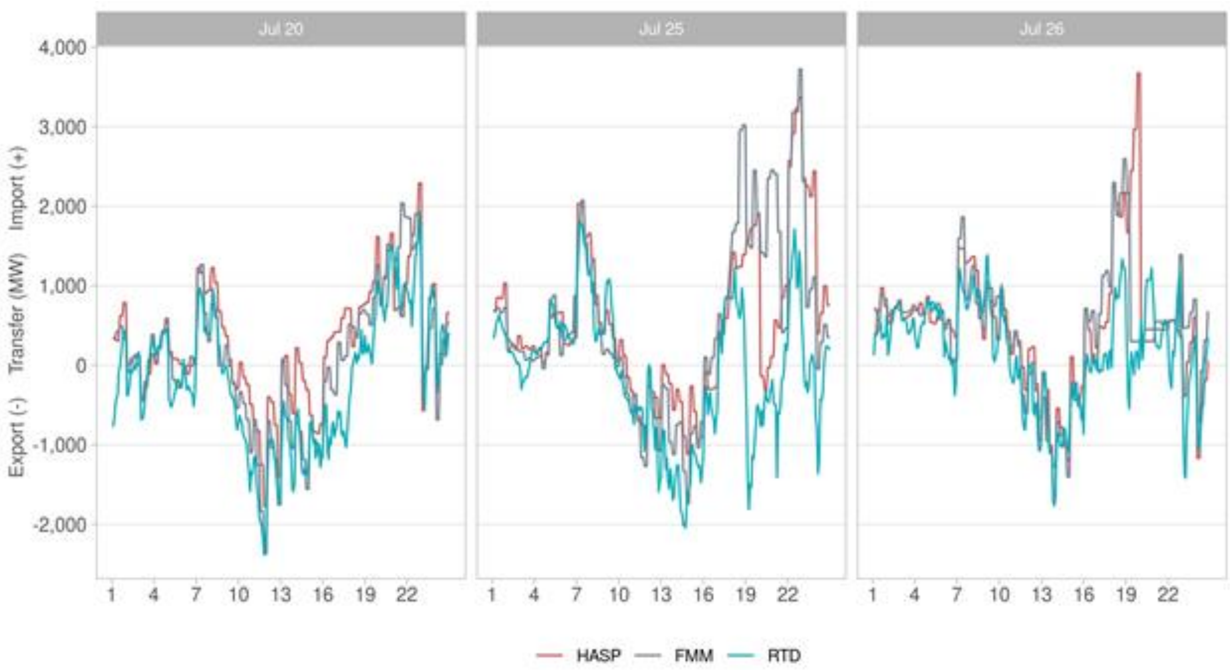
Figure 120 illustrates the profile of WEIM transfers for the ISO's BAA. A positive value represents an import transfer while a negative value represents an export transfer. Across all real-time submarkets, WEIM transfers imports to the ISO BAA were robust during peak hours. During the critical peak hours of July the emergency alerts, WEIM import transfers into the ISO area were about 1,000 MW.

While the level of WEIM transfers varies considerably throughout the day, for the July event days, the actual RTD transfers frequently remained below the WEIM transfers cleared in both the HASP and FMM markets. This pattern was more pronounced during peak hours, as depicted in Figure 120. The differences between FMM and RTD transfers of WEIM imports into the ISO BAA can stem from various factors, including the influence of load conformance in ISO or any other WEIM area. This dynamic is not new and was discussed at length in the analysis conducted for the RSE phase 2 initiative, which showed that the load conformance effects in both the HASP and FMM markets contribute to scheduling additional import transfers into the ISO BAA in HASP and FMM. These transfers, however, are advisory and are reevaluated in subsequent RTD market in which they become binding.

[43] CAISO, Operating Procedure 4420: http://www.caiso.com/Documents/4420.pdf

[44] CPUC Decision (D.)23-06-029 - Decision Adopting Local Capacity Obligations For 2024-2026, Flexible Capacity Obligations For 2024, and Program Refinements, June 29, 2023.

Figure 120: Transfer pattern for ISO area across markets



With the typically lower level of conformance present in RTD than in FMM and HASP, the need to meet the ISO load requirement in RTD will not require the same levels of WEIM transfers as scheduled in HASP and FMM. This will tend to result in lower level of WEIM import transfers in RTD than scheduled in HASP and FMM. It's also possible that in the RTD time frame, conditions in other BAAs may be different than in HASP and FMM, altering the originally available supply for supporting transfers, making the WEIM transfers scheduled in HASP and FMM unavailable in real-time

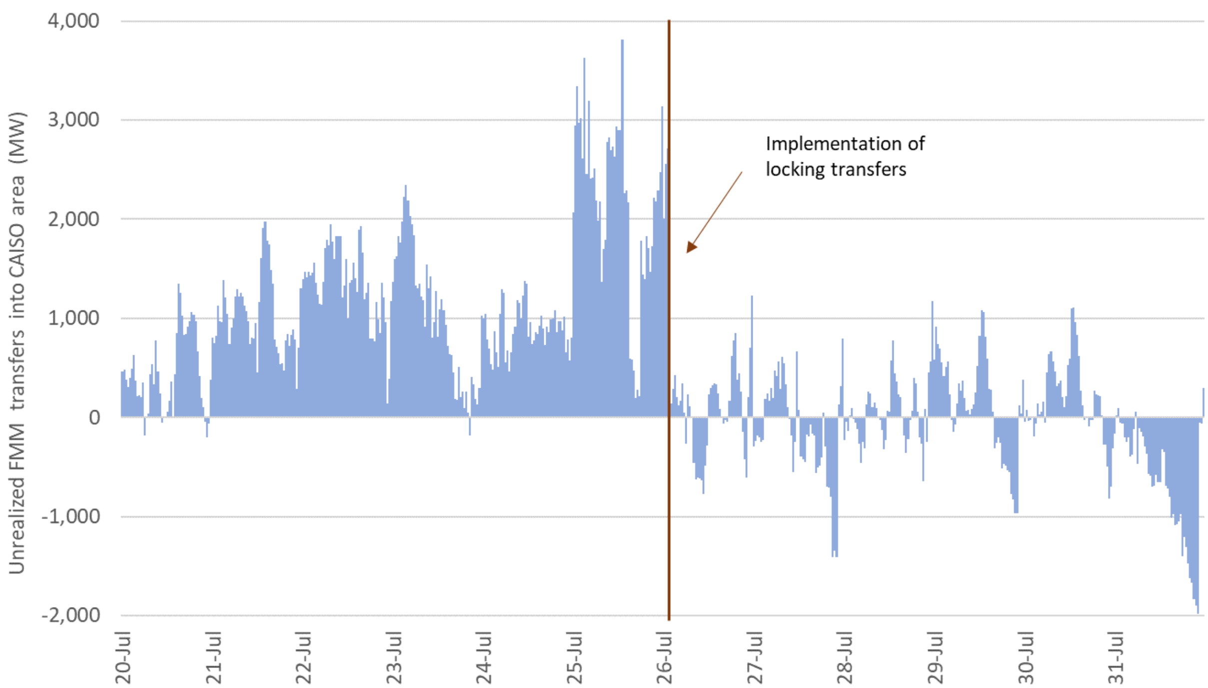
This happened during several evening peak hours over the July days, resulting in Western EIM transfers that had been scheduled in HASP and FMM not being available at any price, resulting in power balance violations.

This scenario in which substantial amounts of Western EIM transfers scheduled in HASP and FMM are not available in RTD can present a serious operational challenge, as the ISO resources were committed and intertie transactions cleared in the HASP and FMM, taking into consideration the availability of these advisory Western EIM import transfers. However, these transfers are subject to last-minute adjustments, potentially leading to a loss of projected supply that the RTD market, due to its brief timeframe, might not be able to compensate for with other internal supply. This dynamic can culminate in both insufficient capacity and limited ramp capability. During the evening ramp hours of the three days with emergency alerts, the unrealized WEIM transfers were significant, with over 3,000 MW of unrealized transfers on July 25 as shown in Figure 121. The figure illustrates the disparity in transfers between the FMM and RTD markets; a positive value signifies that RTD transfers fell below FMM transfers.

Because of the consequences of these dynamics and evaluating the impact of HASP load conformance to gain additional supply internal to ISO versus additional transfers, effective July 26 ISO implemented a change in the HASP and FMM markets where the dynamic transfers[45] were limited for hour ending 19 through 22 only for the import transfers coming to ISO area. Static transfers or transfers for exports continue to be open during these hours.

By locking import WEIM transfers, the market seeks to more reliable clearing of ISO's load obligation and exports using internal resources or supplementary hourly intertie transactions, thereby reducing reliance on advisory import WEIM transfers. This adjustment offers a more pragmatic allocation of ISO's resources to fulfill the regional load obligation, commencing from the HASP and FMM stages. Furthermore, this design allows for earlier detection of supply or ramp capability constraints. Figure 121 shows the steep change of advisory transfers into the ISO before and after the implementation of the transfer limitation. There are still some volume of transfers a after the change due to the clearing of static transfers.

Figure 121: FMM transfers not realized in the RTD market



This limitation on import transfers to the ISO area will also result in higher prices, both in the HASP (advisory) and FMM (binding) clearing prices for the ISO area, which in turn may lead to a price divergence within the broader WEIM area, characterized by higher prices in the ISO area and lower prices in other regions.

[45] Dynamic transfers are different than dynamic intertie resources. Dynamic transfers refers to WEIM transfers that can be optimized in RTD markets.

13.9 Congestion on Path 26

A central element of the locational marginal pricing in the ISO markets is the congestion management process, which ensures that we consider transmission constraints while finding a least-cost solution to serve load. Depending on the effectiveness of resources to a transmission constraint, resources can be dispatched up or down. Resources that contribute to flows in the prevailing direction exacerbate congestion and the market, based on economics, will dispatch them down. Conversely, resources that provide counter-flows will be dispatched up. The ISO market uses three main types of constraints to manage flow-based constraints: flowgates, nomograms and contingencies.

During the days of emergency alerts in July, ISO managed three constraints related to Path 26. One is the nomogram 6410_CP1_NG, and the other two are the Midway-Vincent and Midway-Whirlwind flowgates. The nomogram monitors the flows on Midway-Whirlwind 500 kV Line for the loss of two Midway-Vincent lines.

On July 20, 2023, the standard limit of the nomogram was 3,158 MW and it reduced to 1,569 MW with the conformance applied. The real-time market saw some congestion on these Path 26 related constraints. The market congestion on flowgate 30060_MIDWAY_500_24156_VINCENT_500_BR_2_3 for the contingency of SC1 MIDWAY-VINCNT_1 500 lined up well with actual flows. The flowgate for the Midway-Whirlwind 500 kV line had a transmission conformance that was not timely update for the market congestion seen for flowgate 30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_1 for the contingency of SC1 MIDWAY-VINCNT_1 500 did not align with actual flows. The Path 26 market nomogram had a conservative transmission conformance to compensate for modeling issues which misaligned market flows from the physical concern the congestion protects. These modeling issues were categorized as part of this analysis and ISO is reviewing its processes to mitigate these issues moving forward.

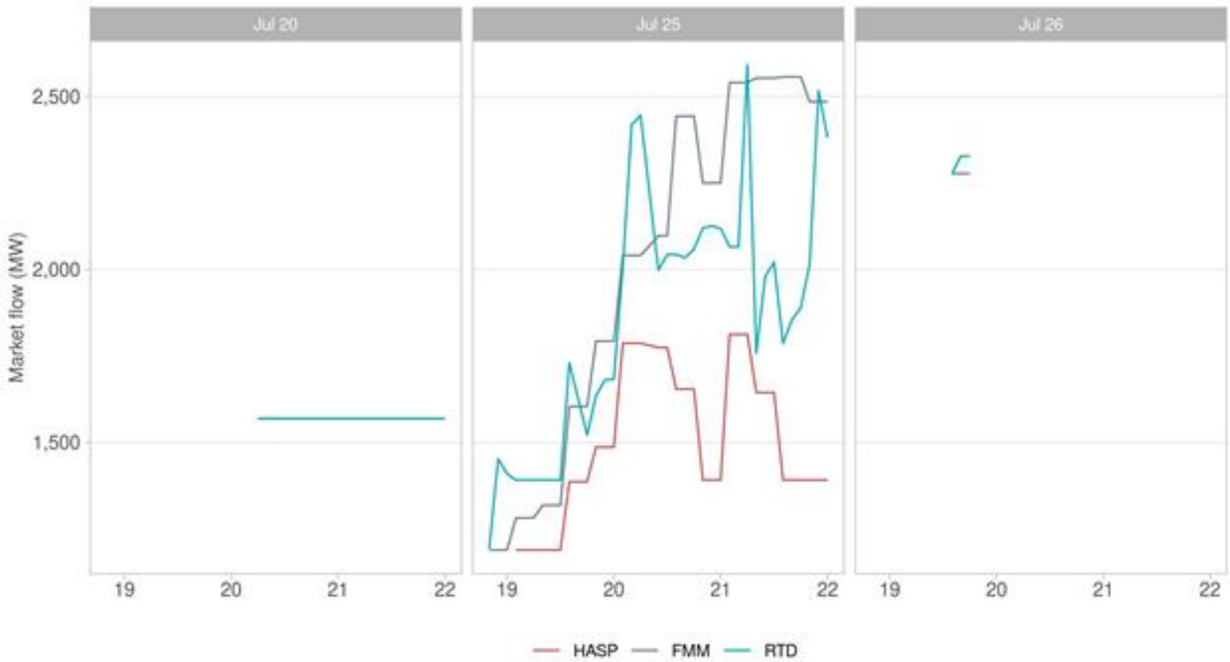
The market saw congestion on July 25, 2023, as well for these constraints. There was an outage scheduled for a portion of the Path 26 remedial action scheme (RAS) but that outage returned to service at 14:37 hrs so that was not a factor for the congestion seen starting HE 18 and beyond. The market congestion on flowgate 30060_MIDWAY_500_24156_VINCENT_500_BR_2_3 for the contingency of SC1 MIDWAY-VINCNT_1 500 lined up well with actual flows. The flowgate for the Midway-Whirlwind 500 kV line also had transmission conformance that was not timely update for the market congestion seen for flowgate 30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_1 for the contingency of SC1 MIDWAY-VINCNT_1 500 did not align with actual flows. The Path 26 nomogram limit was reduced from 3,158 MW to 2, 530 MW. The market congestion seen for nomogram 6410_CP1_NG aligned well with actual flows based on the new equipment derate.

The market limit on the nomogram was also adjusted as needed on this day when the nomogram could not be solved through redispatch in the market. Some of the modeling issues that impacted July 20 market congestion still existed on July 25. There were also HASP interchange export reductions in SP-26 that did not occur in real-time. When these export reductions did not materialize, the market solution to manage the Path 26 flows was not effective, requiring additional mitigation into the real-time market and limited the ramping and capacity available in real-time. The equipment derate on Midway-Whirlwind 500 kV transmission line was due to an update of rating methodology evaluation that went into effect on July

25th. At that time, there were RAS setting changes on July 25 to help mitigate potential overloads on the Midway-Whirlwind 500 kV nomogram due to the derate.

Figure 122 shows the market flow across HASP, FMM and RTD markets for the nomogram related to Path 26[46]. Figure 149 and Figure 150 show similar trend for flowgates also related to Path 26 constraint.

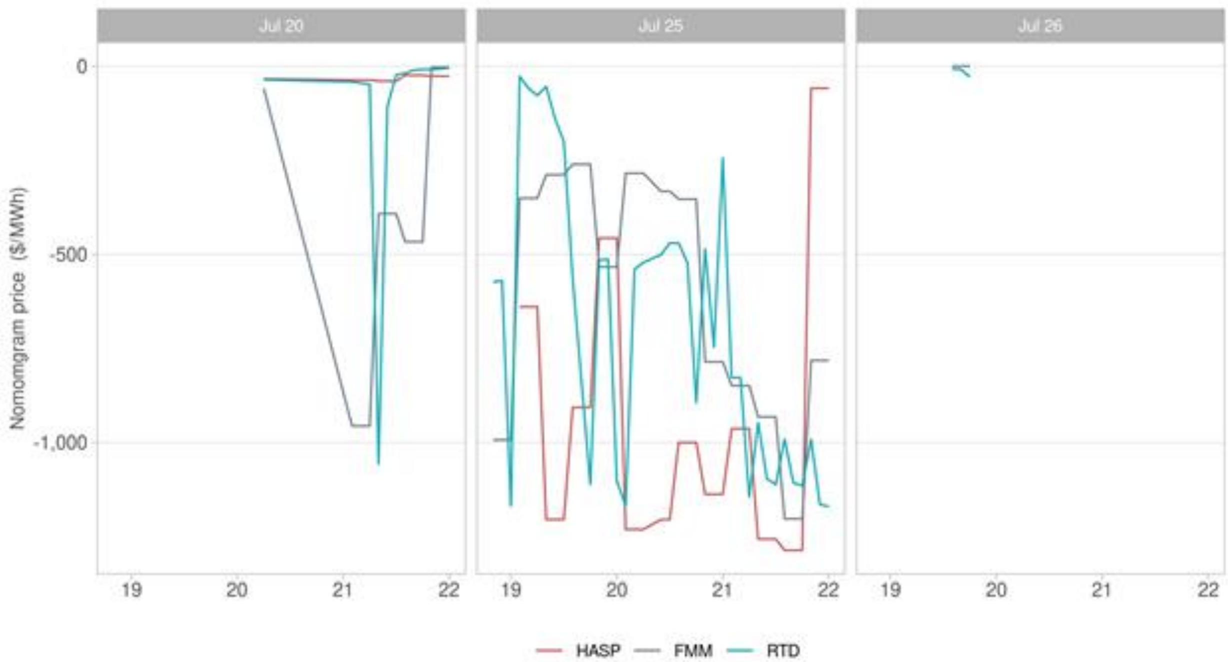
Figure 122: Market flows on Path26 nomogram



Congestion on constraints related to Path 26 positioned resources in the system accordingly. Resources in the southern part of the system will tend to be dispatched up to mitigate for southbound congestion, while resources in the norther part of the system will tend to be dispatched down to not further exacerbate congestion. When the Path 26 constraints are binding, it effectively limit resources from the north to be dispatched up more, even if these resources have headroom available to meet increasing demand needs. This congestion-induced limitation led to a complex trade-off within the market solution. On one hand, there was a need to augment generation in the north to meet escalating demand. On the other hand, it was essential to dispatch generation downward to adhere to the transmission constraint. Therefore, this congestion created a condition of scarce supply as available supply in the north could not further be dispatched to meet demand. Figure 123 shows the shadow prices of the nomogram across markets; it showed the volatile condition of Path 26 as reflected in congestion prices. These shadow prices directly influenced how resources were dispatched in the real-time market.

46 The plot only displays data when the constraint was binding.

Figure 123: Congestion price on Path26 nomogram

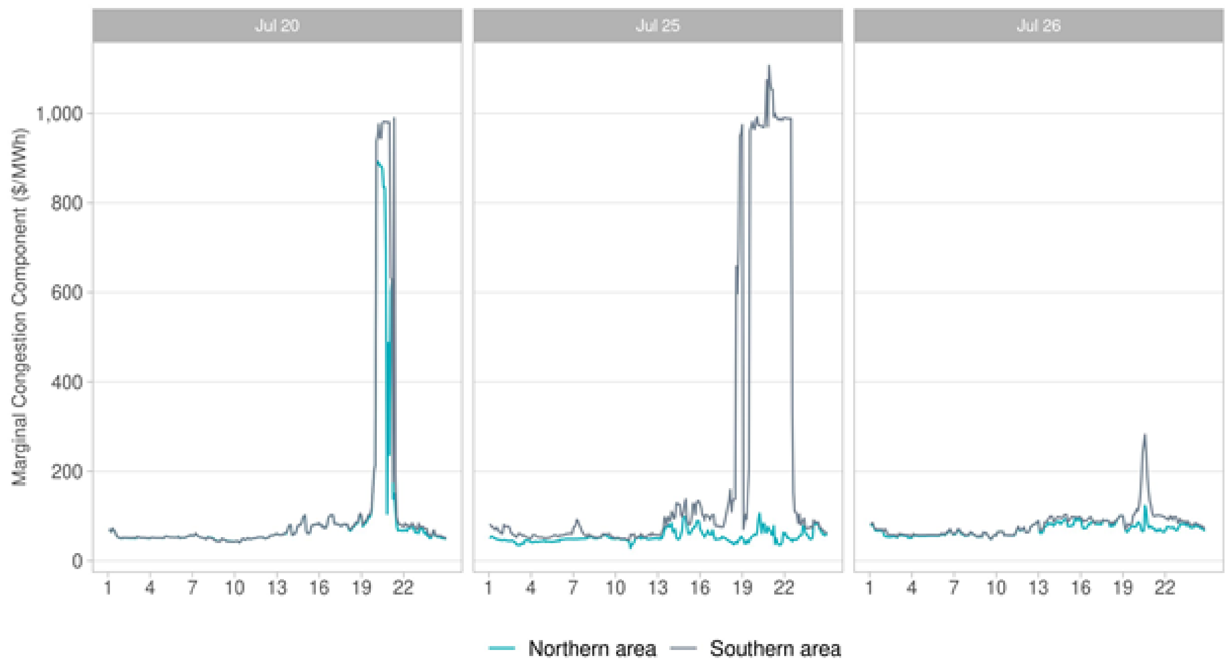


The extent to which generation could be dispatched upward hinged not only on the bid-in price of the resource but also on the intensity of congestion, as indicated by its corresponding price. The severity of congestion directly impacted the marginal congestion components, which could restrain a greater portion of generation from being dispatched upward.

Path 26 congestion effectively divided the system into two primary regions, leading to a notable price differential. Illustrated in Figure 124, this price separation between the northern and southern regions of the ISO area primarily emerged as a consequence of congestion on Path 26. As a result, resources located north of the constraint experienced lower Locational Marginal Prices (LMP) due to the negative marginal congestion component, while resources located in the southern region encountered higher LMP due to the addition of positive marginal congestion prices to the system energy marginal price.

The price spread was notably significant during the critical hours of the emergency alerts on both July 20 and 25, and to a lesser extent on July 26.

Figure 124: Price separation in ISO area driven by congestion



The complex congestion management challenges of Path 26 were exacerbated by an unintended discrepancy between the ISO market model and the practices of neighboring areas to account for the interties schedules of ISO within the energy imbalance market model. The conflicting consideration of the ISO's shares of schedules on the direct-current (DC) line among areas led to a double counting of certain ISO-related intertie transactions. As a result, there were inaccuracies and additional market flow contributions on Path 26, sometimes exceeding 500 MW. This situation necessitated active management of the Path 26 constraints. This congestion issue further reduced the ability of northern generation resources to be dispatched upward to meet rising demand. ISO and its partner balancing areas are jointly working on developing a solution to harmonize the models.

13.10 Flexible ramping product

The Flexible Ramping Product (FRP) Refinements were launched in February 2023, incorporating nodal procurement. This section provides an evaluation of the FRP's performance during the July events, with specific emphasis on the upward FRP, which is especially relevant in situations where the system operates under conditions of limited supply.

BAAs passing the capacity and flexible ramping tests collectively benefit from a passing group to procure FRP, leveraging BAA diversity. Those failing must individually fulfill their own requirements. The enhanced framework includes real-time uncertainty realization as one deployment scenario per direction. Nodal procurement of FRP accounts for both transmission and WEIM transfer constraints, thereby guaranteeing feasible FRP allocations at the nodal level, resulting in nodal pricing for FRP.

Figure 125 through Figure 127 contrast the estimated uncertainty requirement, indicated by the light blue envelope, with the actual realized uncertainty represented by the dark blue bars. These realized uncertainty values are computed for all participating BAAs in the passing group during each real-time market interval.

Figure 125 Comparison of actual uncertainty against Flex Ramp requirement for July 20

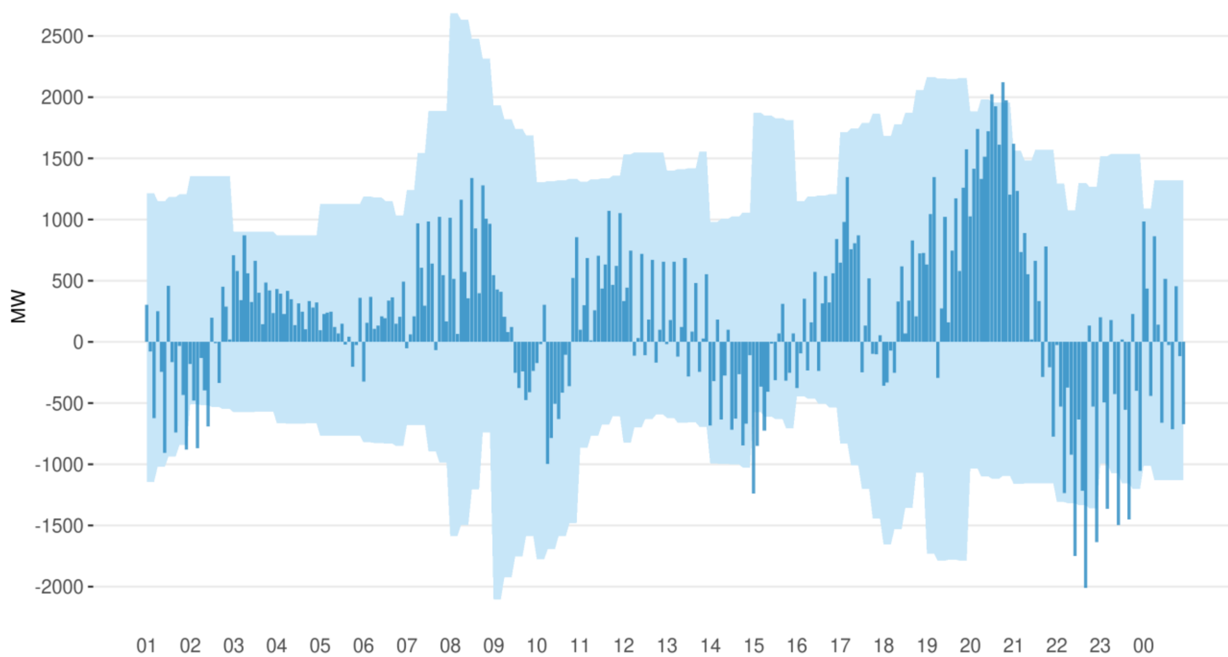
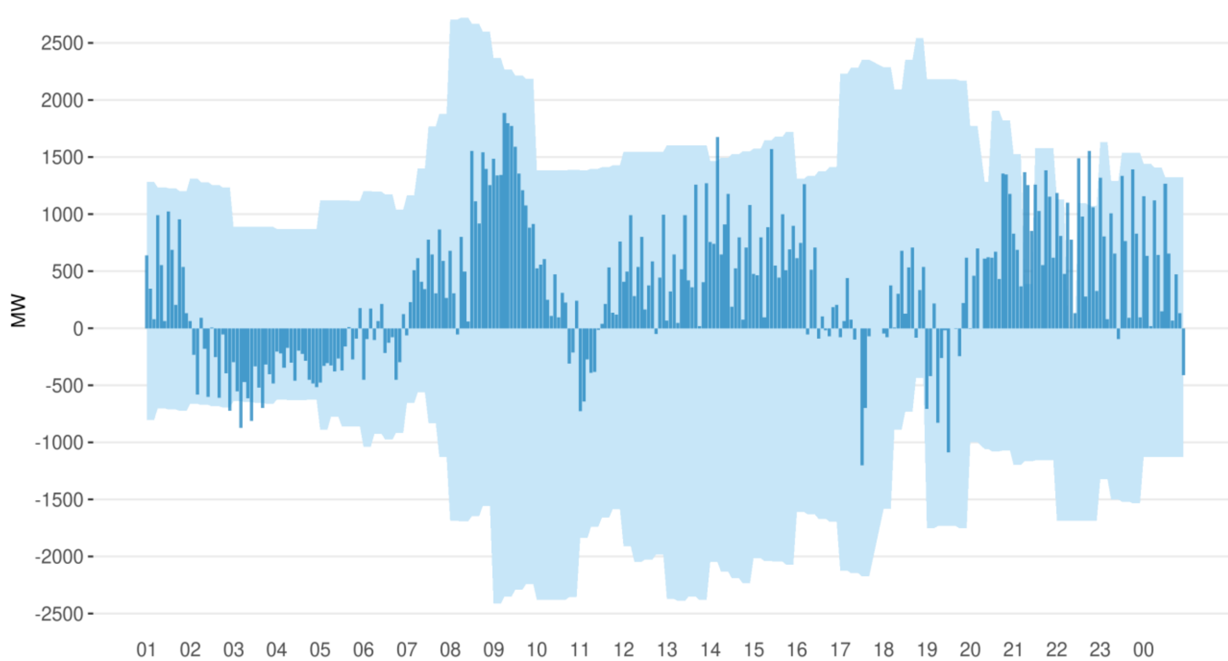


Figure 126 Comparison of actual uncertainty against Flex Ramp requirement for July 25



This analysis reveals that, for the majority of instances, the realized uncertainty for wind, solar and load remained within the bounds of the projected FRP requirements. Notably, during the timeframe of the emergency on July 20 the realized uncertainty of 2,024 MW was slightly higher than the upward uncertainty requirement of 1957 MW. For July 25, the actual uncertainty was much less at 617 MW than the 1905 MW of upward requirement. This dynamic is key for the effectiveness of the FRP, as it sets a reference how adequate the FRP requirement was to meet the ramping needs to accommodate realized uncertainties. This is then complemented, as discussed below, with how well that FRP capacity was utilized.

Figure 127 Comparison of actual uncertainty against Flex Ramp requirement for July 26

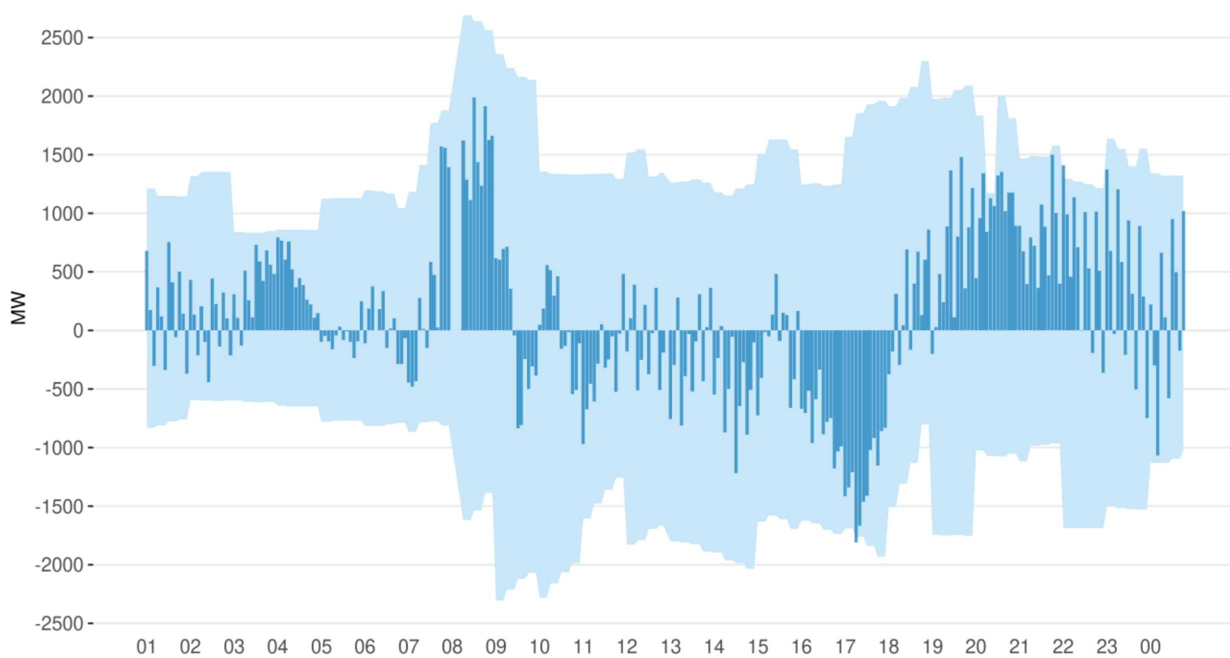


Figure 128 illustrates FMM FRU procurement across the wide WEIM area, encompassing both passing and failed BAAs, categorized by region. At the peak time, the FRU procurement reached approximately 2,400 MW, gradually decreasing as solar production waned toward the net load peak. Procurement was wide spread across the WEIM footprint. Predominantly, FRU awards were sourced from the Pacific Northwest region throughout the day, while peak-hour FRP procurement was also sourced from the California region.

Figure 128 FMM FRU procurement by region, WEIM

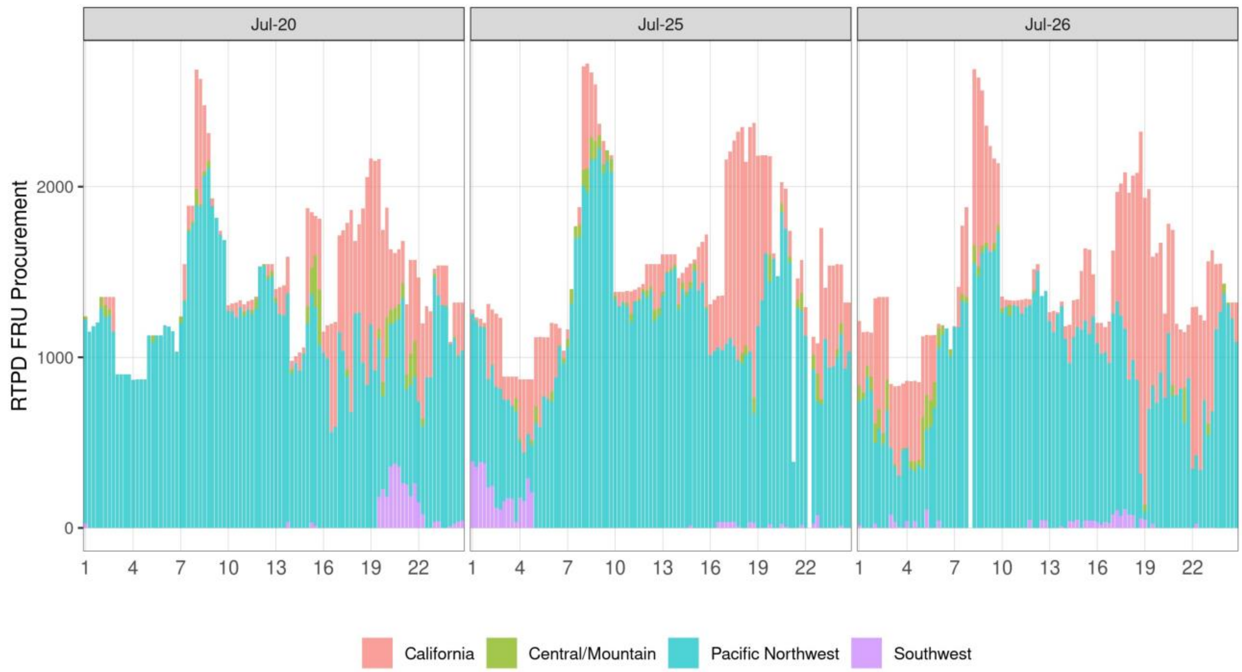
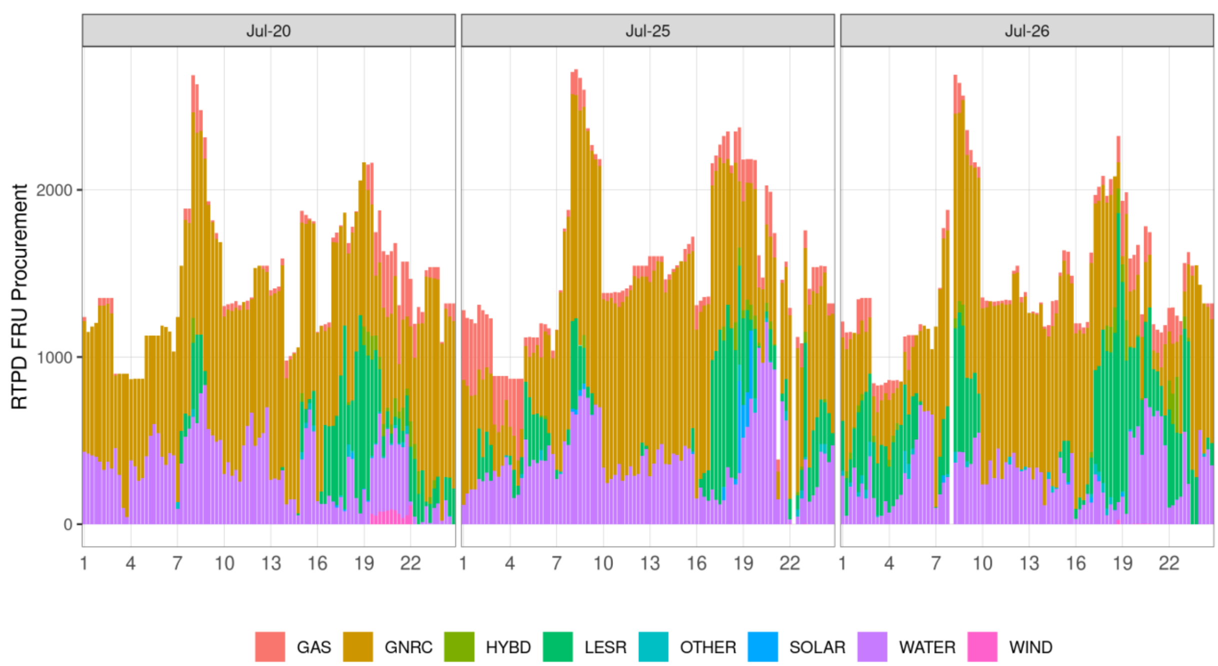


Figure 129 shows the composition of the FRP procurement in the WEIM footprint by resource types. Generic non-generating resources (GNRC), water, and storage resource (LESR) are the main resource types getting FRU awards.

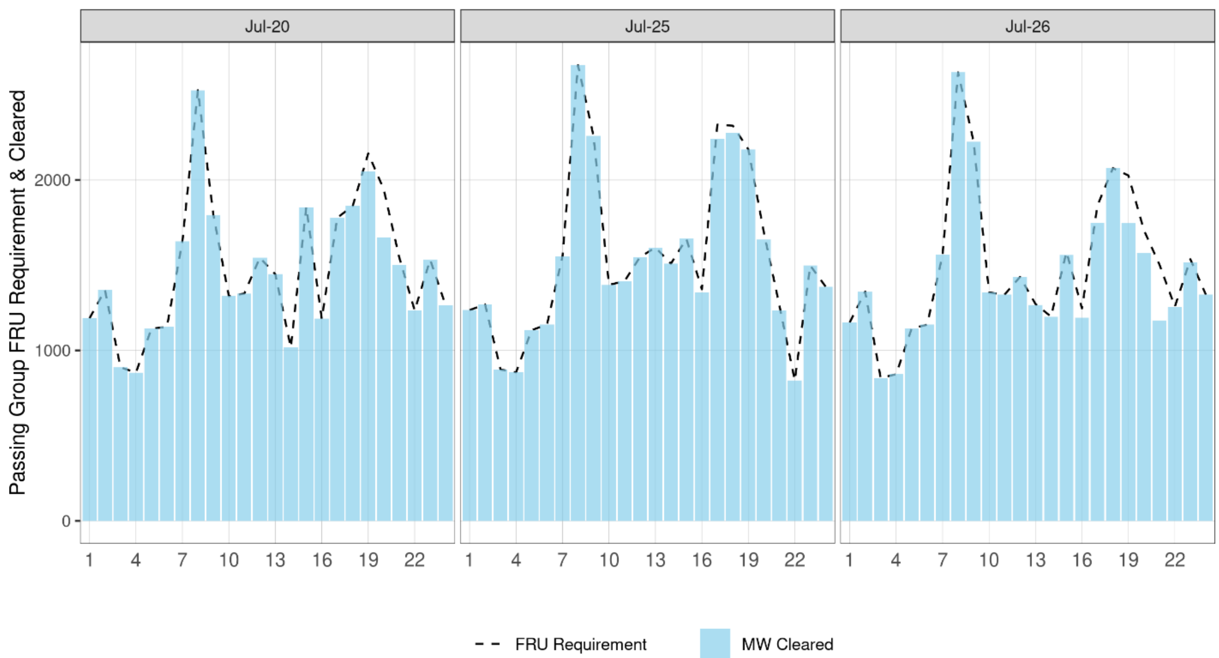
Figure 129 FMM FRU procurement by resource type, WEIM



The majority of the FRP was procured from storage resources (LESR) and hydro resources, which includes the generic non-generating resources (GNRC). Hydro and GNRC are used throughout the day while storage resources are mainly used to support FRP for evening peak hours.

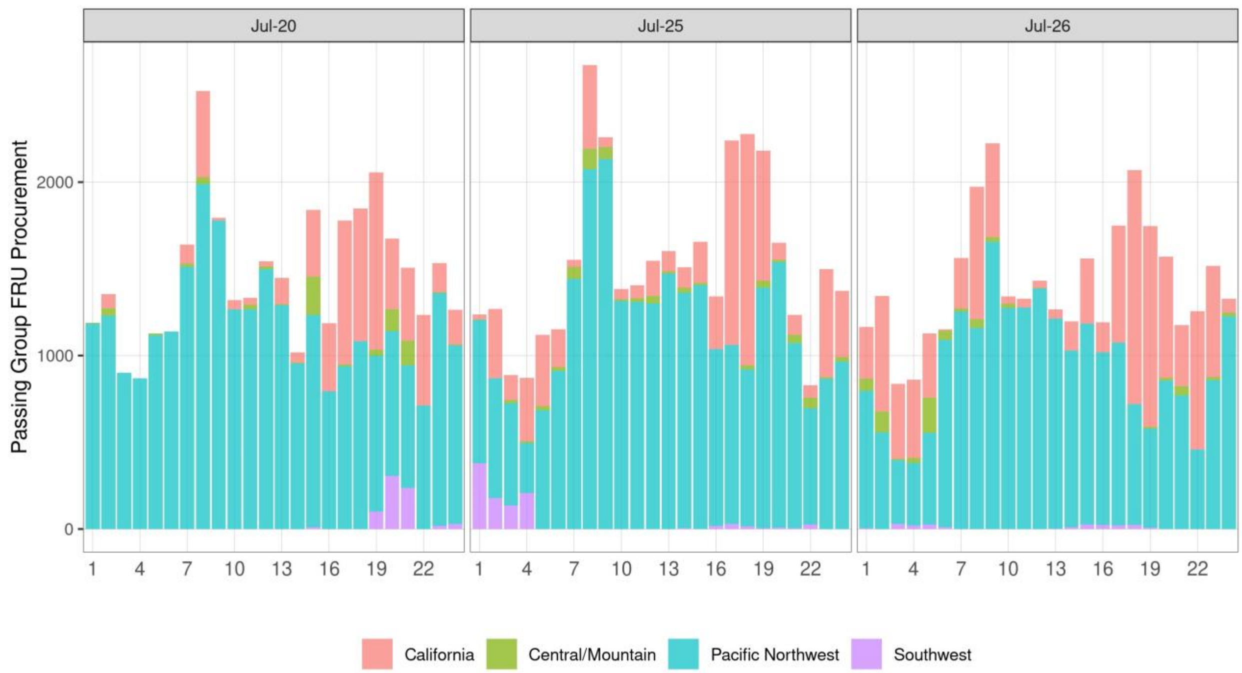
Figure 130 shows the hourly average requirements versus procurements in the passing group. The market will procure uncertainty requirements at that group level while respecting the transmission and WEIM transfer constraints. Requirements can be relaxed, based on price, when it is not economical to fulfill it. Some noticeable amount of violations, up to 24% of requirements, occurred in a few intervals in the afternoon peak hours. Figure 131 illustrates the breakdown of the FRU procurement by region[47] within the passing group. The passing group generally consists of most of the WEIM areas, so the composition of the procurements also follows a similar pattern.

Figure 130 FRU requirement & procurement in the passing group



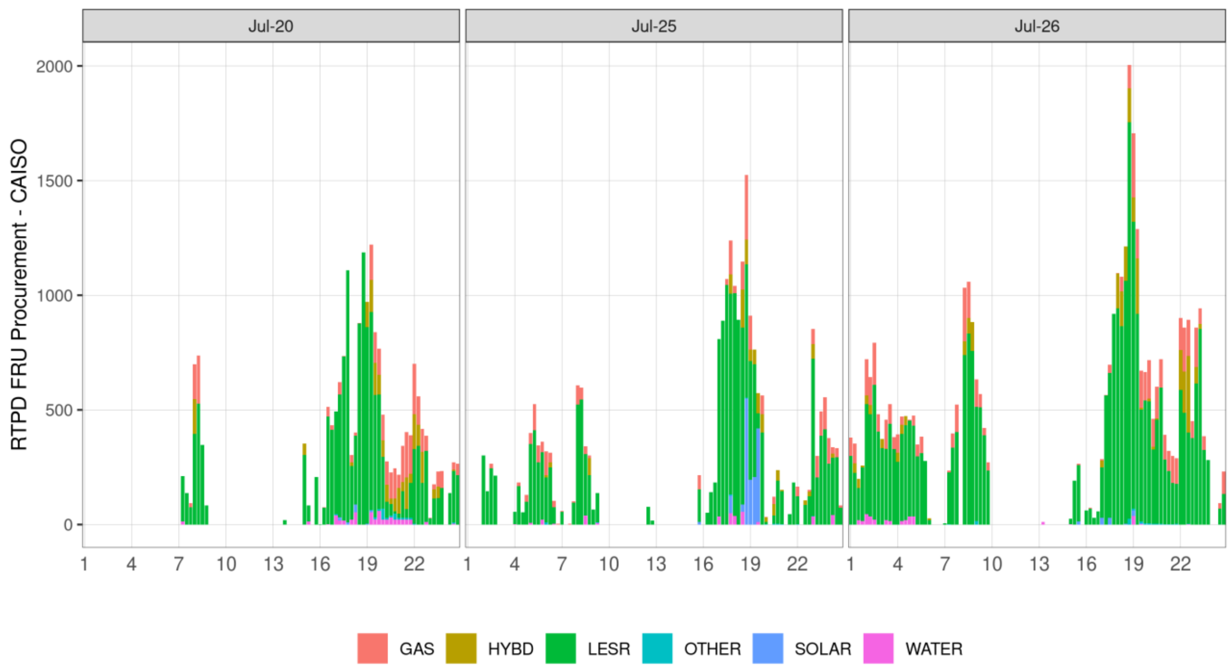
[47] The concept of region in this metric is only to ease the illustration of the FRP procurement by summing up all FRP procurement from the areas within each region. California region, for instance, includes ISO, LADWP, BANC and IID areas. The market clearing process, however, does not use region definitions in any form.

Figure 131 Passing group FRU procurement by region



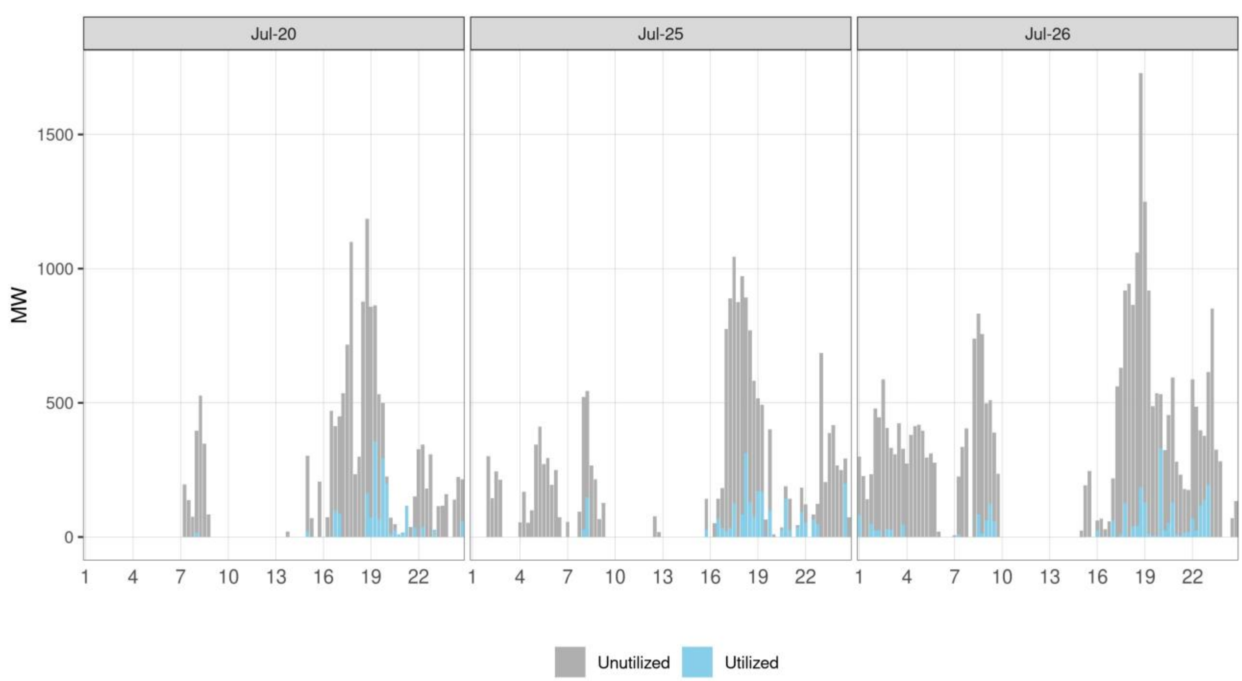
Generally, ISO was part of the passing group during the July events. The source of FRP procurement was dictated by the overall economics and the system constraints. Figure 132 illustrates the ISO FRU procurement by resource type. The majority of the FRU procurement comes from 72 different storage resources in the afternoon to evening peak hours while gas resources provided very little capability. Further analysis of some instances reveals that the ability of storage resources to supply FRP may be limited by consideration of other factors in subsequent RTD markets. The procurement of FRP does not factor in the impact of FRP schedules on the state of charge and, thus, FRP awards will not take into account the depletion of SOC if FRP is deployed. For instance, if a storage resource is schedule to provide upward FRP only for multiple intervals and that capacity is deployed in any of these intervals, its state of charge will be reduced, jeopardizing the ability to support FRP capacity scheduled in FMM for subsequent intervals.

Figure 132 FRU procurement by resource type, ISO area



One method to evaluate the efficacy of the FRP involves assessing the capacity utilization. This utilization is quantified by comparing the capacity deployed from FMM to RTD against the FRU procurement. Figure 133 shows the FRU utilization by storage resources (LESR) in the ISO area.

Figure 133 FRU utilization from storage resources, ISO area



The quantities utilized, at the base of each bar, represent a low portion of the overall procurement. Different factors contribute to this limited utilization. In the subsequent part of this section, two instances are examined further to provide detailed insights.

By incorporating the deployment scenarios, FRP is priced at the nodal level. Figure 134 and Figure 135 show the scatter plots of the FRU nodal prices at locations having nonzero FRU awards, for all WEIM areas and within the passing groups, respectively. The FRU prices are zeros most of the time. For all hours of the day, 19.3 percent of all nodal prices are non-zero in the WEIM footprint, and 17.4 percent in the passing group. The non-zero prices are mostly concentrated during the afternoon peak hours. For the peak hours, there are 42.1 percent non-zero nodal price points in the WEIM areas, and 40.8 percent in the passing group. The highest FRU prices in all WEIM areas were over $100/MWh, coming from the failed BAAs. The highest prices within the passing groups were less than $50/MWh.

Figure 134 FRU nodal price distributions, all WEIM areas

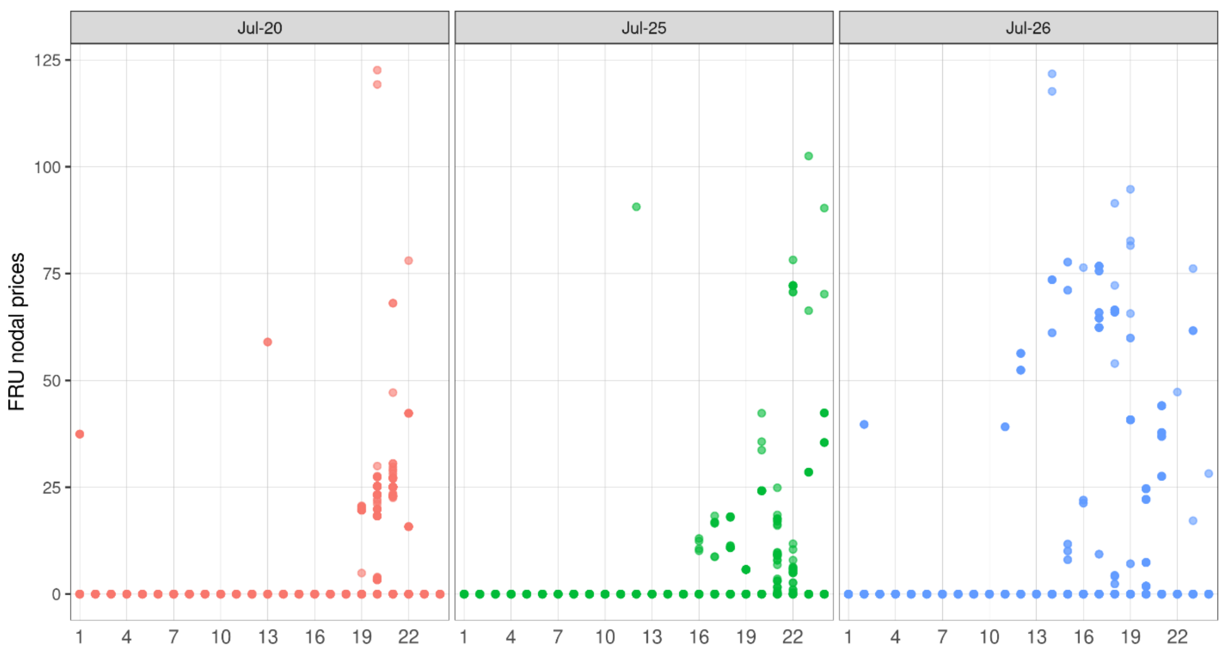
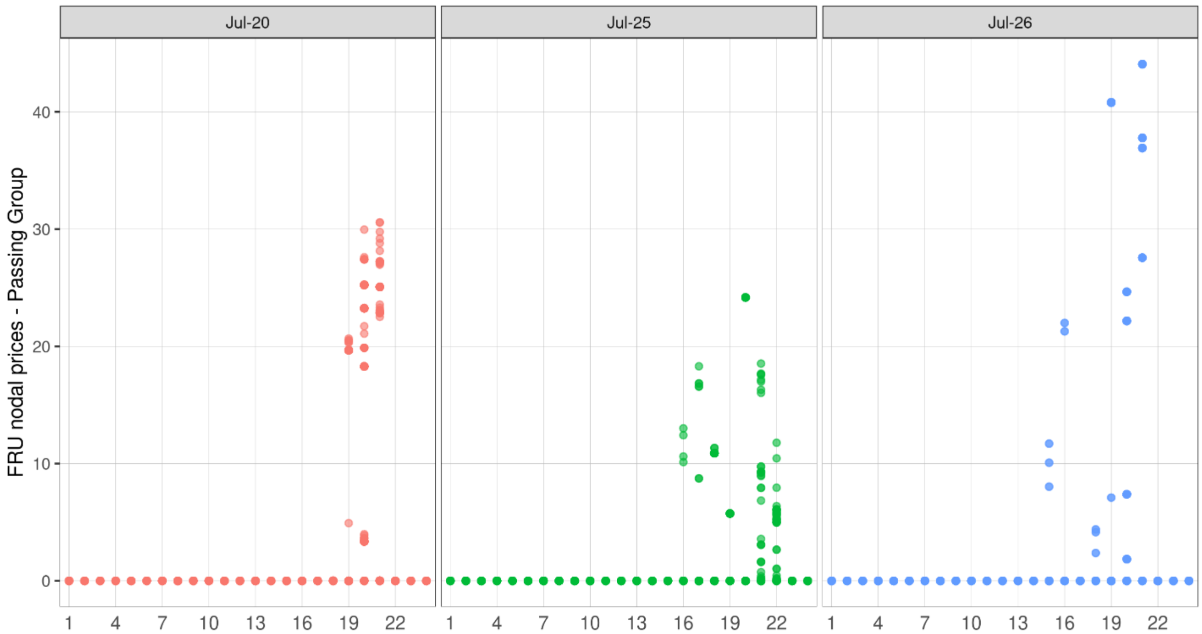


Figure 135 FRU nodal price distributions, passing group



As described in previous sections, a significant driver for the July events was the rapidly changing system conditions in real time. The FRP is a market product introduced in the real-time market to account for load, wind and solar uncertainty and ensure resources are properly positioned in advance to absorb realized uncertainty. The rapid changes of system conditions in the July events were not exclusively attributable to renewable resources and load variations as it also encompassed other resource changes, including MSGs, storage resources, and interties. However, it's important to underscore that the design of the FRP product doesn't encompass these distinct resource changes. Should changes occur within the supply mix and sufficient ramping capacity is procured, the market will indeed utilize it. Nevertheless, in terms of magnitude, the FRP is not tailored to comprehensively address all realized changes across the spectrum of resources.

In order to assess the performance of FRP during the July events, there are two snapshots assessed in more detail for the most critical time of 19:30 hrs on both July 20 and 25. The market procures FRP in FMM markets to cover the uncertainties from FMM to RTD markets, and subsequently between RTD markets to cover the uncertainties in RTD.

July 20

All WEIM BAAs passed both capacity and flex ramp tests in the upward direction for interval 19:30 on July 20th. Therefore, the passing group included all BAAs. The group-level FRU requirement was 1957.46 MW. To fulfill the group requirement, FMM procured 1597.35 MW FRU from all BAAs, with 360.11 MW of requirements not met (relaxation), resulting in a group-level FRP price of $23.25/MWh. Figure 136 shows the FMM FRU procurement and relaxation by BAA. Within the passing group, the distributions and locations of FRU procurement and requirement relaxation are results from optimization model.

Figure 136 FMM FRU procurement and shortfall by BAA, 07/20 19:30

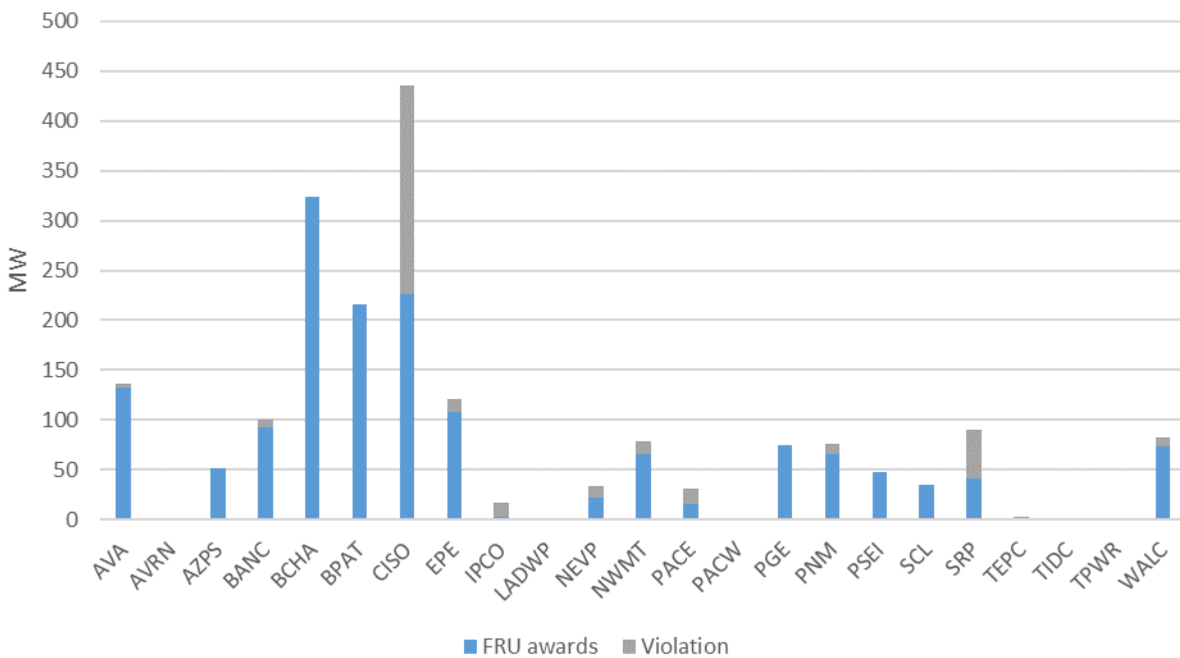
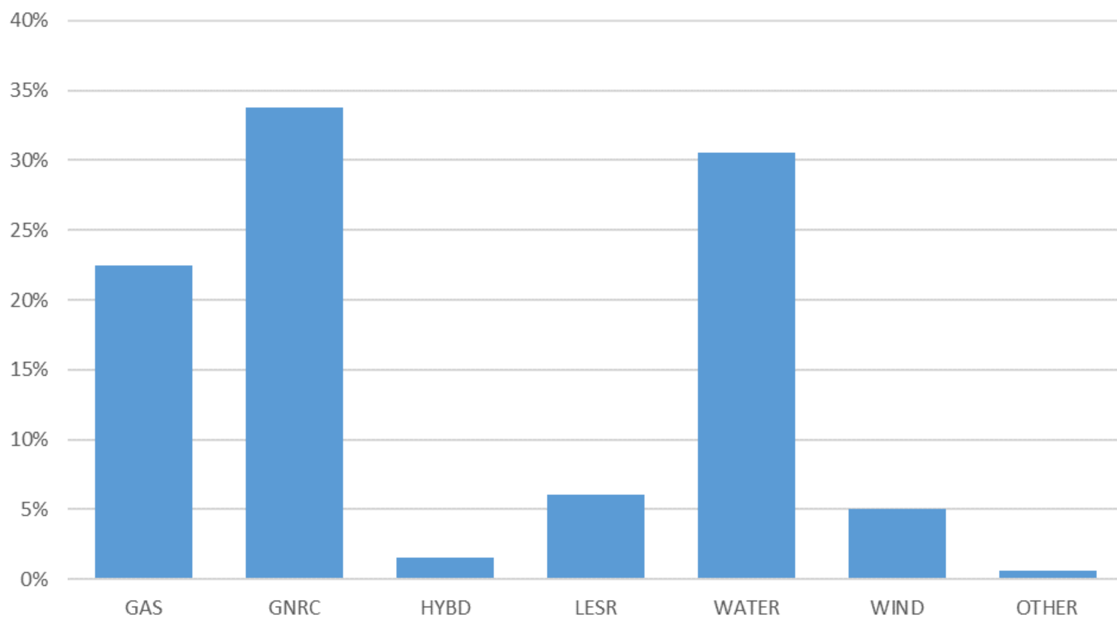


Figure 137 shows the FMM FRU procurement percentage by resource type. Generic NGR (GNRC), water, and gas resources are the major contributors in the FRU procurement.

Figure 137 FMM FRU procurement by resource type



Within the passing group, approximately 81 percent of the total FRU procurement, amounting to 1296.63 MW, was effectively utilized in RTD. This was a reasonable performance during the most critical time. Figure 138 and Figure 139 show the utilization breakdown by BAA and by resource types. The proportion of unutilized FRP primarily accrued within the gas, storage, and hydro resources.

Figure 138 FRU utilization by BAA

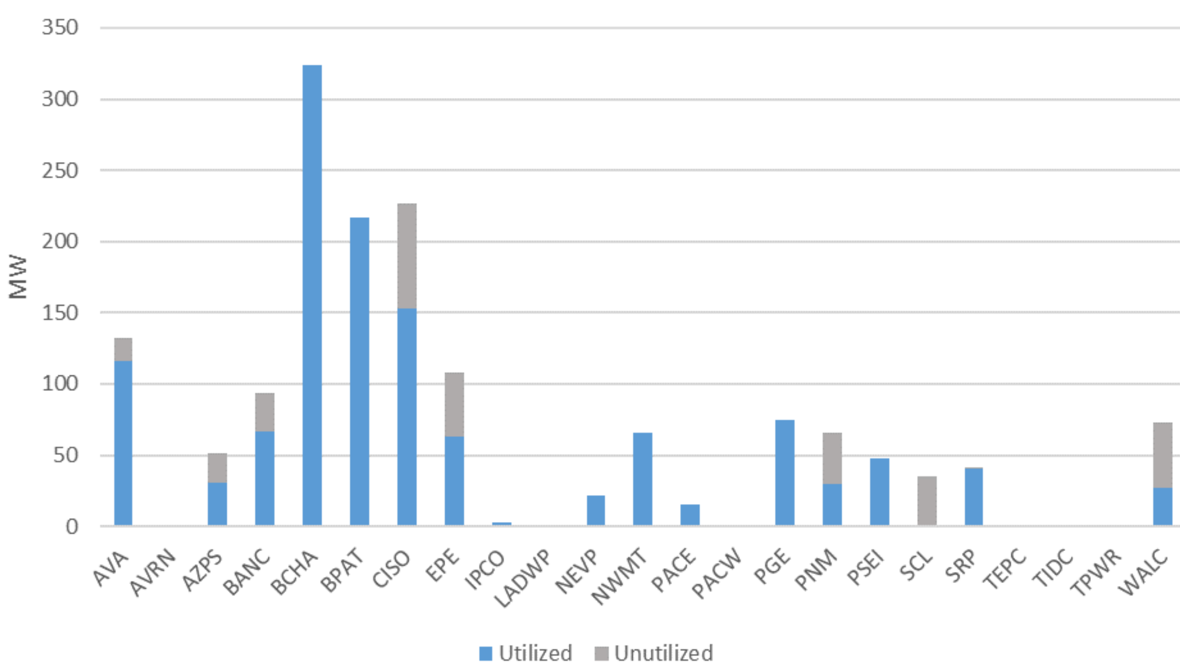
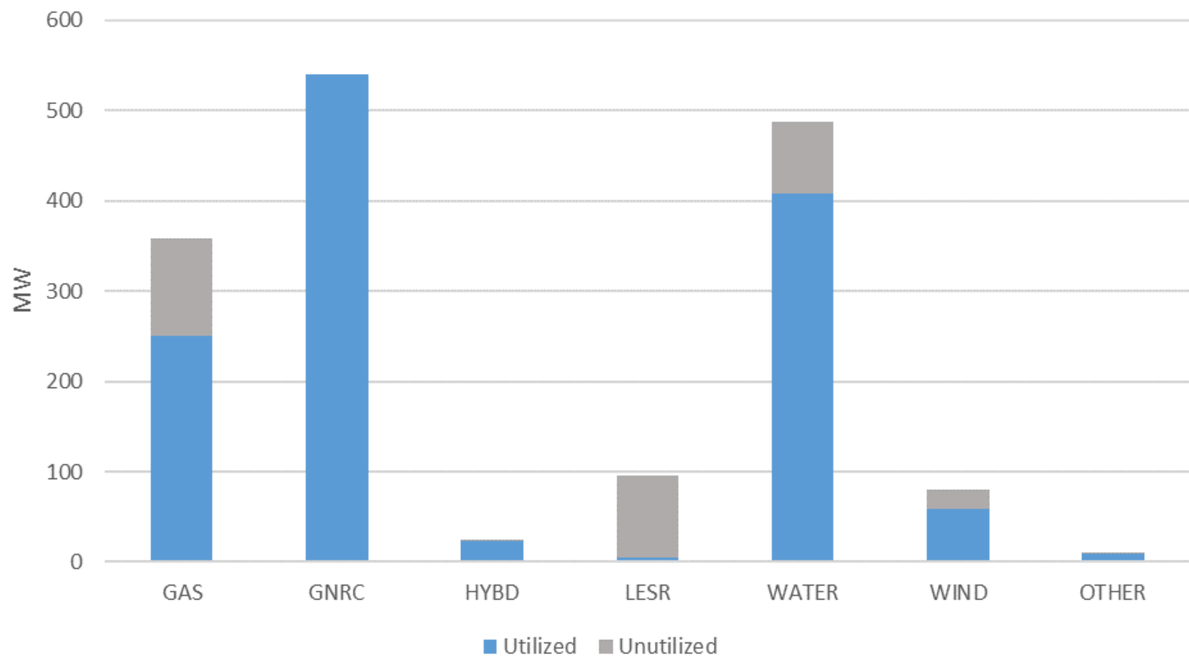


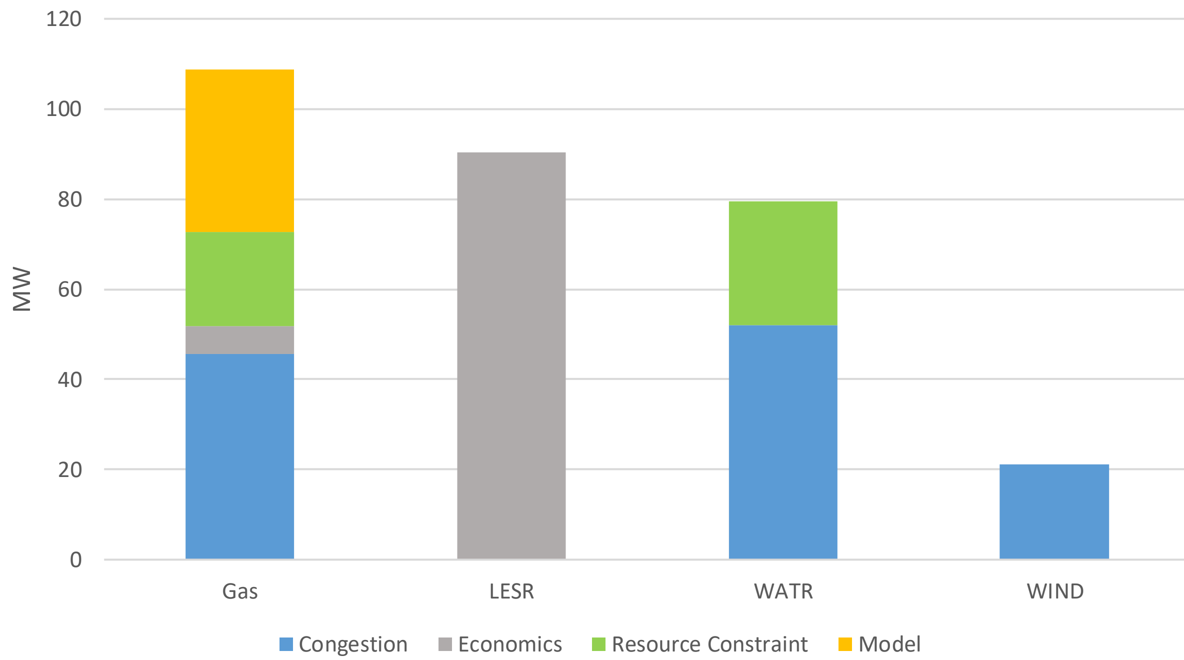
Figure 139 FRU utilization by resource type



There was still about 19 percent of FRP capacity procured that was not utilized due to several reasons. Figure 140 shows the breakdown of the unutilized FRU procurement by categories of different reasons. There are four primary drivers:

- Congestion. Congestion is when a resource is awarded FRU in FMM but cannot be deployed in RTD due to congestion. A known limitation with the current implementation is that nomograms and contingencies are not considered in the deployment scenarios. Also with the deployment scenarios already considered in FMM, in some cases, the congestion showing up in RTD market was not projected in the FMM when FRU was procured.
- Economics. Economics is when FRU award is not utilized because the LMP is not high enough compared to the resource bid price. Thus, it is not economical to schedule more energy (resulting in deploying FRP capacity) from this resource even though it still has capacity available.
- Resource constraints. Certain resource limitations may prevent the realization of the FRU awards, including derates and outages, MSG in transition or on a lower configuration, and energy limits.
- A model limitation. There is a model issue that the maximum-level manual dispatch was not respected in FRU procurement. The FRU awards from three resources were not available in the real time due to this limitation. The ISO is working on an enhancement to address this issue.

Figure 140 Unutilized FRU, 7/20 19:30



July 25

Similar assessment was performed for FRP performance on July 25 for the snapshot of 19:30 hrs. All BAAs except for BPA passed the tests. The FRU requirement for the passing group was 1905.83 MW. A total of 1894.5MW FRU was procured from all passing BAAs, with 11.32 MW relaxation, resulting in a price of $24.17. Figure 141 and Figure 142 show the passing group FRU procurement by BAA and by resource types, respectively. Hydro, generic NGR (GNRC) and gas were also the main contributors to FRP procurement in this case.

Figure 141 FRU procurement and violation

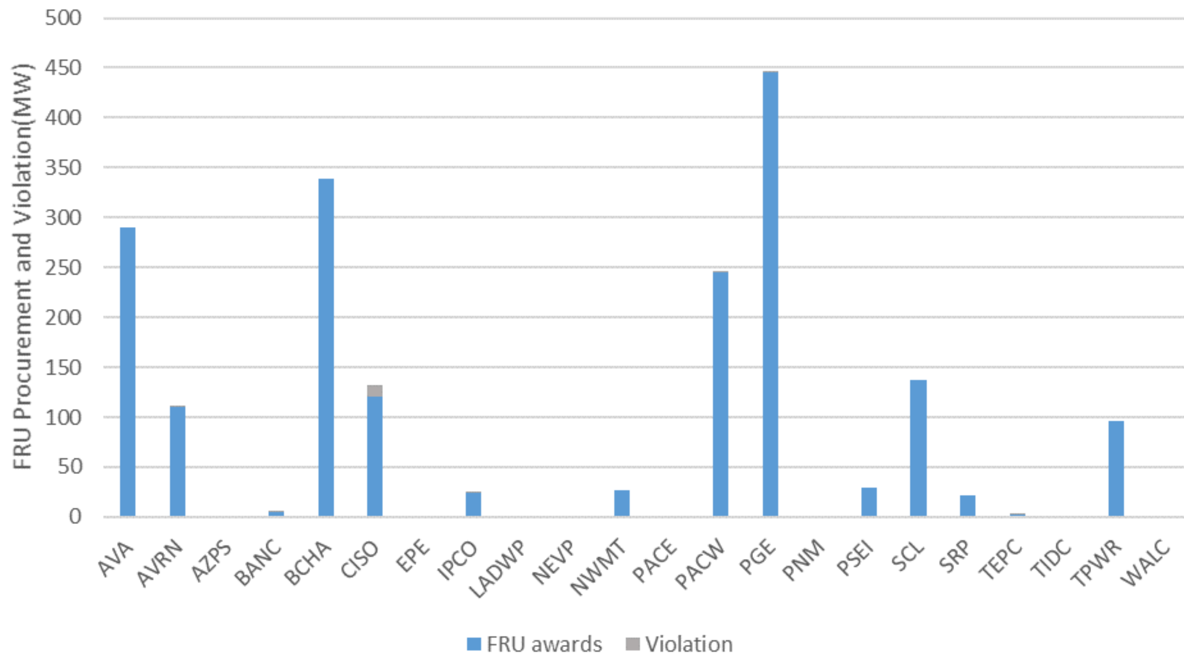
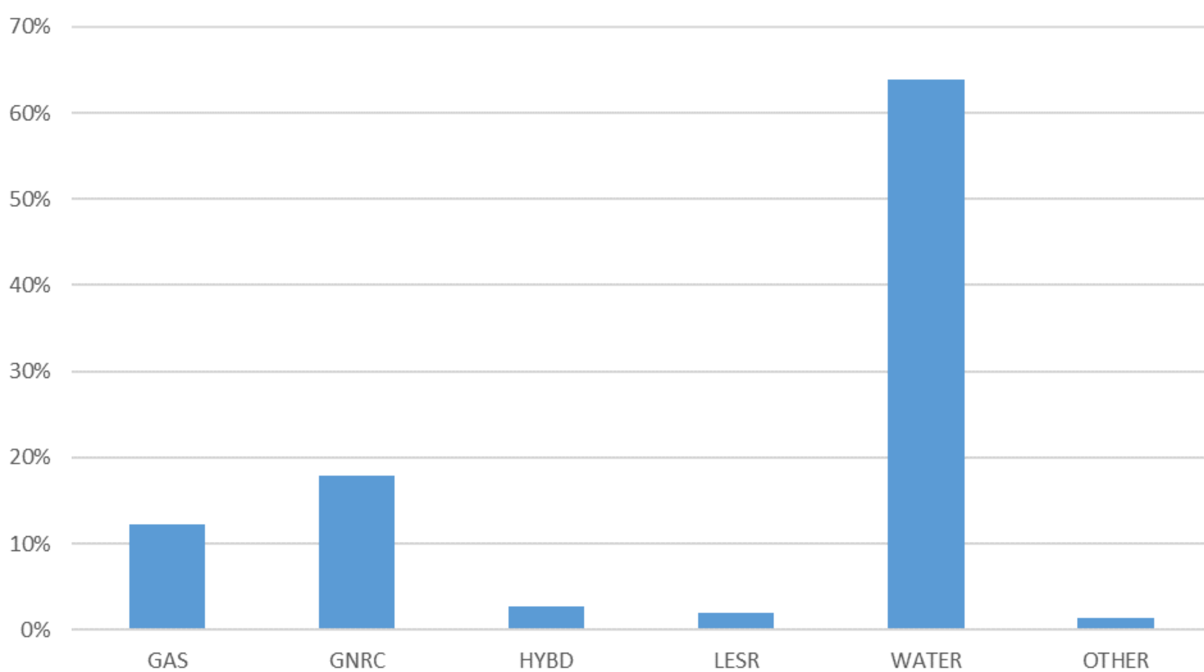


Figure 142 FRU procurement percentage by resource type



The overall FRU utilization in the passing group was just about 38 percent. Figure 143 and Figure 144 show the utilization breakdown by BAA and by resource types. The unutilized FRP was spread across the WEIM footprint, while it was mainly concentrated in hydro and GNRC resources.

Figure 143 FRU utilization by BAA

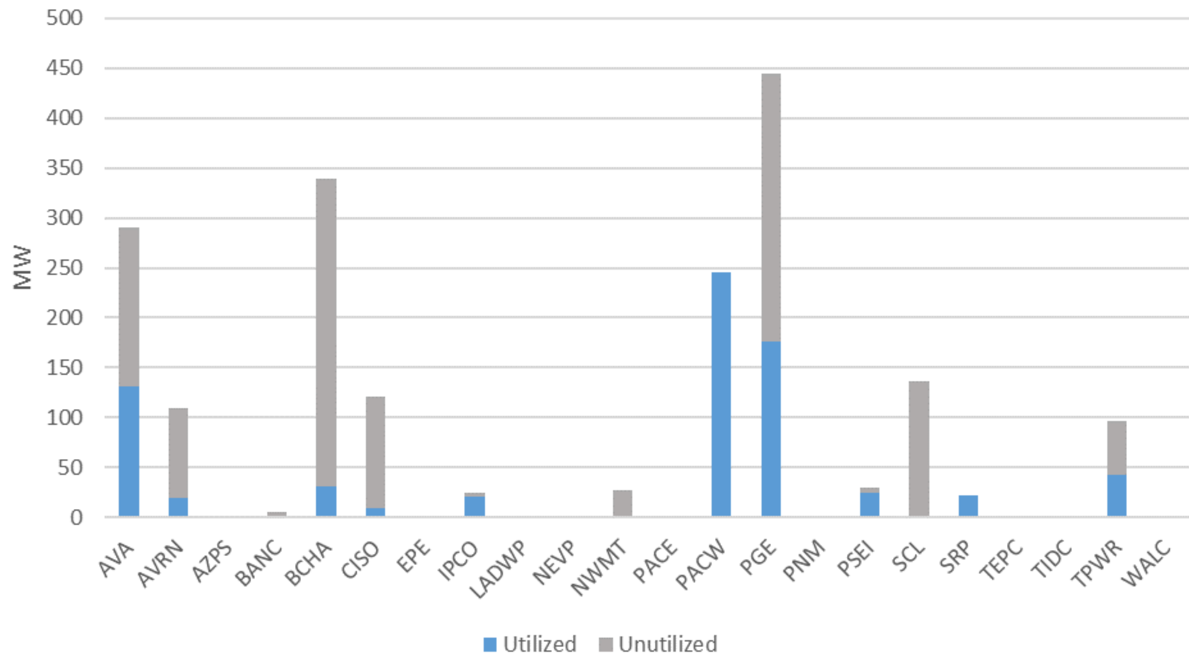


Figure 144 FRU utilization by resource type

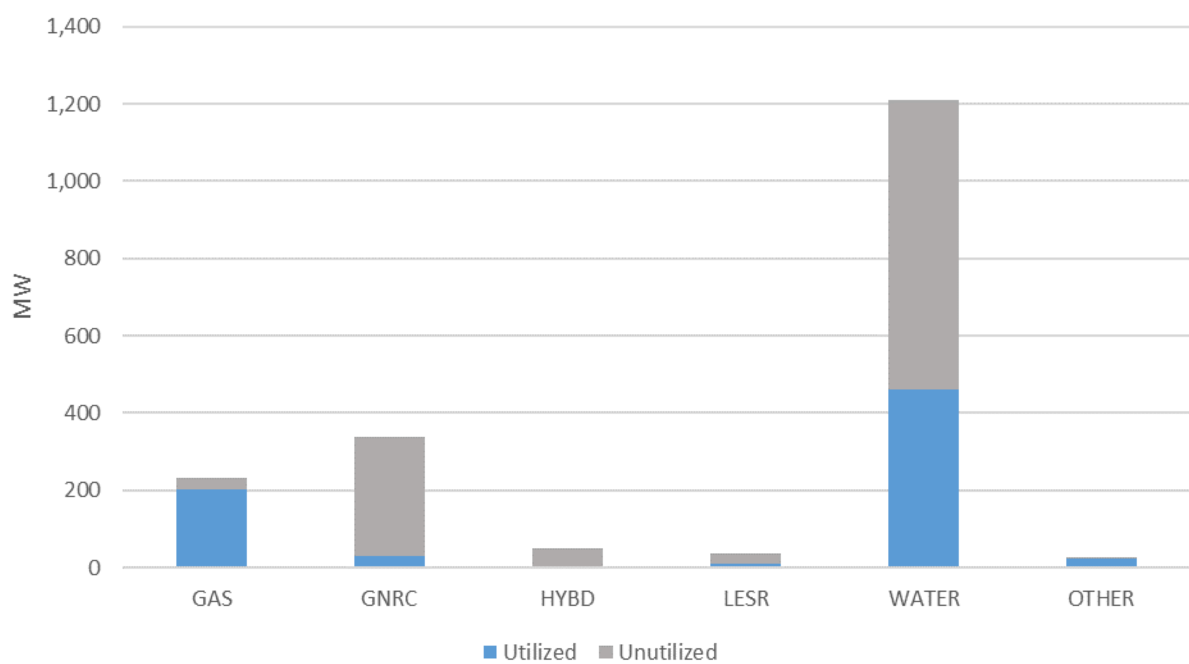
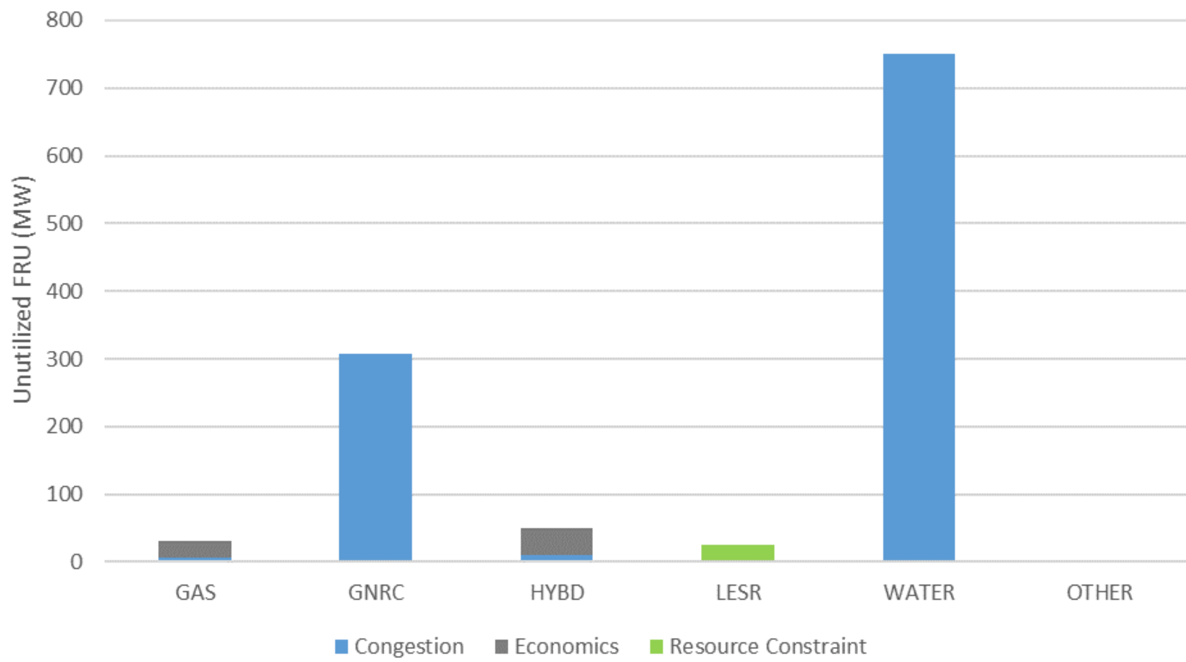


Figure 145 shows the breakdown of the unutilized FRU procurement by reason. Within the unutilized FRU procurements, 1075 MW was not deliverable due to congestion. Two primary causes of the congestion are the nomogram 6410_CP1_NG, and flowgate Midway-Vincent and Midway-Whirlwind contingencies. These are constraints related to Path 26. By not having these constraints enforced for FRP procurement, FRP was procured behind transmission constraints and, therefore, could not be delivered. Enforcing these transmission constraints for FRP, however, would have resulted simply in relaxing the FRP requirement by about the same amount since there was no more capacity available and deliverable. For energy storage resources, the primary issue was the need to manage the state of charge, so it could not support the extra energy dispatched when FRP capacity needed to be deployed.

Figure 145 Unutilized FRU for July 25



14 Areas for Improvement

Through the analysis of the market outcomes and performance, the following some items the ISO has identified during the month of July 2023; these include:

1. Ensuring that exports are scheduled to the level that can be reliably supported by the system. On July 25, ISO observed instances where multiple exports reductions were not reflected in the tagging schedules, thereby exacerbating the grid conditions. ISO is presently evaluating potential changes and clarifications to the existing scheduling and tagging protocols for both imports and exports. The forthcoming adjustments and enhancements will be implemented through a Business Manual Practice change.

2. Harmonizing the accounting procedures for intertie transactions between ISO and neighboring balancing areas. Discrepancies in the treatment of ISO intertie transactions between ISO and its neighboring balancing areas resulted in an inaccurate assessment of flow contributions along Path 26. This discrepancy notably compounded the challenges during the July 25 EEA Watch periods. Recognizing the critical nature of this issue, the ISO and its partner balancing areas are collaboratively engaged in evaluating a shared, enduring model solution.

4. Improving operator visibility of the real-time availability of dispatchable capability. During emergency conditions, the accuracy of dispatchable capability in the system was hindered by imprecise calculations mainly related to available storage resources' supply, limiting operators' visibility of actual dispatchable capability. The ISO implemented an enhancement to the display of dispatchable generation on September 13.

3. Revising and updating procedures regarding Path 26 management. The Path 26 constraint management is complex given the nuances related to the rating, remedial action schemes and model of the constraints. The events of July 25 further emphasized the need to improve its management. Revision and updates to the ISO's procedures, including operator training, are underway.

4. Reviewing procedures to enable the feature of import bid incentives in the market when an EEA1 is issued. This is a change implemented as part of the summer 2021 enhancements. This was not activated in the July events. The ISO is reviewing its procedure number 4420B and training to emphasize the need to take this step during an EEA event.

5. Including nomograms and contingency flowgates in the nodal procurement logic. When FRP was implemented in February 2023, only flowgate constraints were enforced for FRP scenarios. ISO continued to work on expanding the logic to include nomogram constraints, which had been tested and were ready for implementation in early August. However, this was not activated because of concerns with introducing the change while the ISO is contending with summer conditions. With summer conditions subsided, the ISO has activated the nomograms for FRP scenarios on September

7, 2023. The ISO will continue to assess the need and feasibility to enforce contingency-based constraints for FRP scenarios. Furthermore, the ISO has been evaluating the performance of this new design and will continue to assess and report on its performance, in particular the level of utilization of FRP among the different resource technologies like storage resources. There are other aspects that require fine tuning of the market logic, like enhanced functionality to consider maximum exceptional dispatch within the market clearing process to ensure FRP awards are supported and feasible.

6. As part of the recent policy effort for the resource sufficiency evaluation, the ISO analyzed the interactions among advisory WEIM transfers, load conformance and clearing of hourly exports. In 2023, the ISO has taken an effort to further assess the need and use of load conformance in both the day-ahead and real-time markets, which have been discussed in previous market performance forum analysis. The ISO has been running a pilot program to better understand the implications of the use of load conformance. The July events highlight the complex interactions of these market components and warrant further assessment.

15 Additional Metrics

This section provides additional metrics to the areas presented in previous sections.

Figure 146: Off-peak future power prices for summer 2023

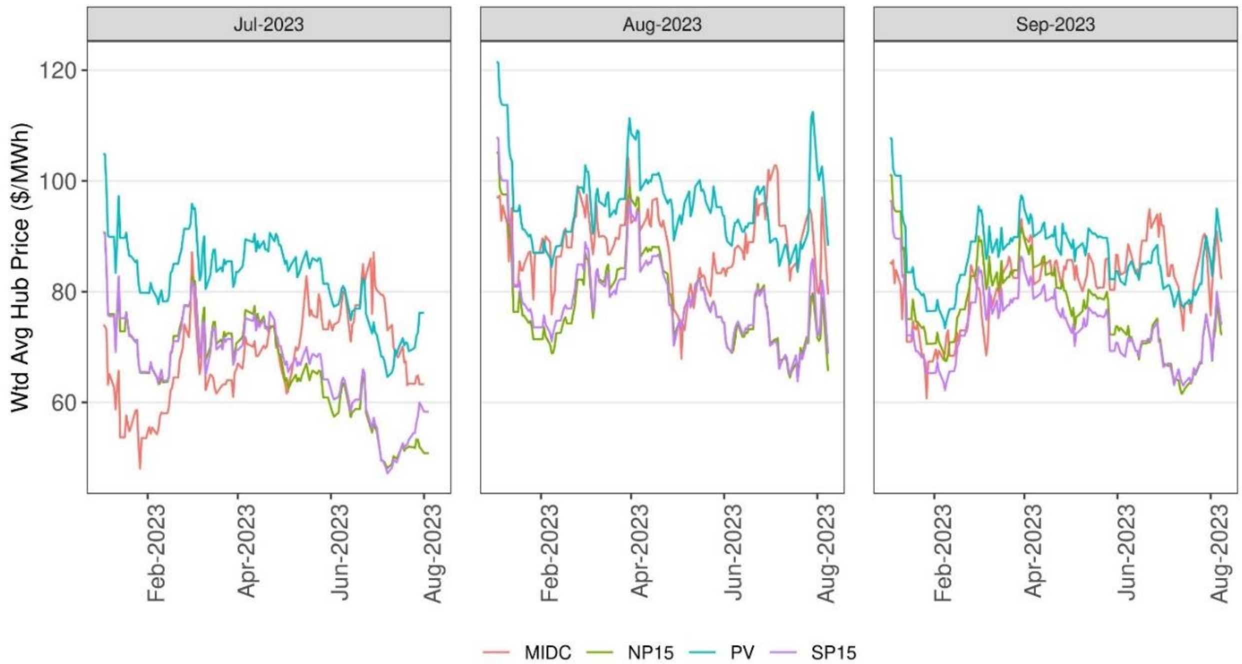


Figure 147 Dispatchable supply in FMM organized by technology

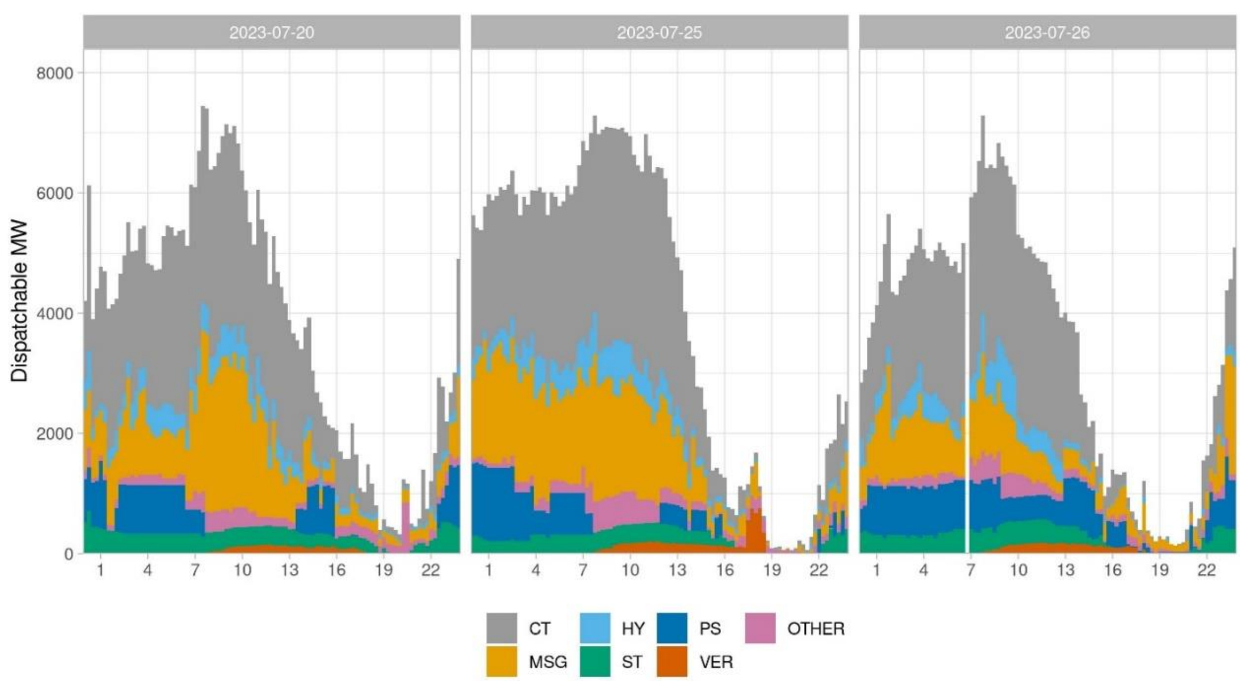


Figure 148 Dispatchable supply in RTD organized by technology

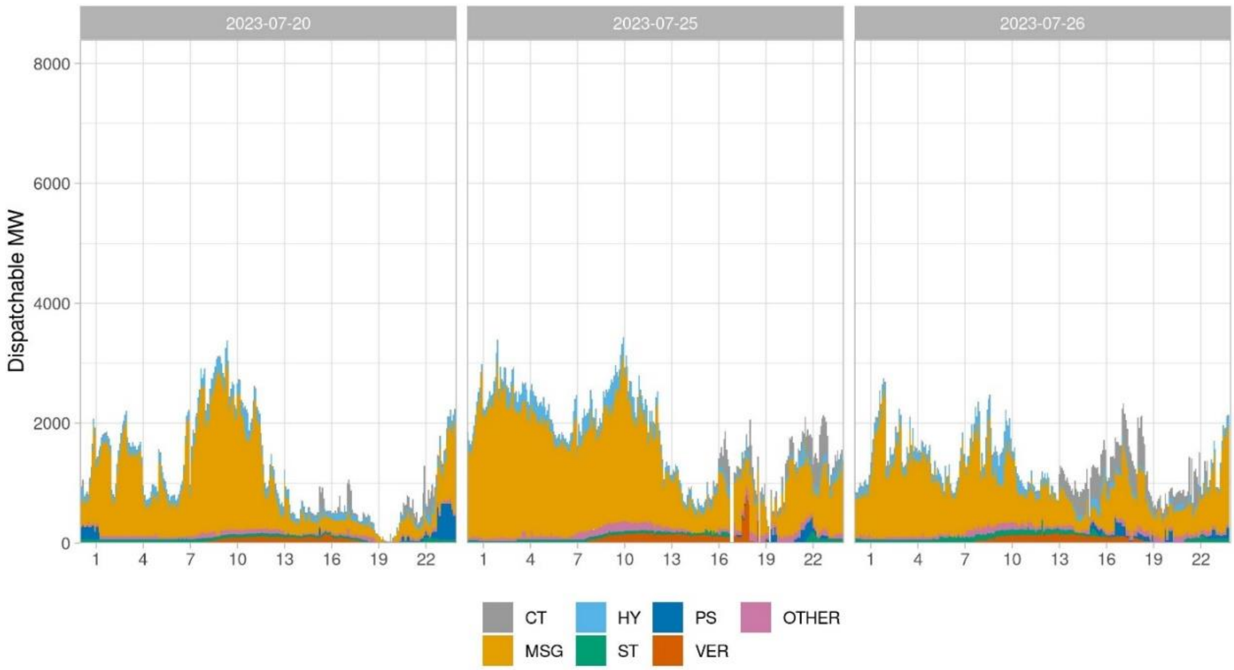


Figure 149: Market flows on Midway-Vincent flowgate

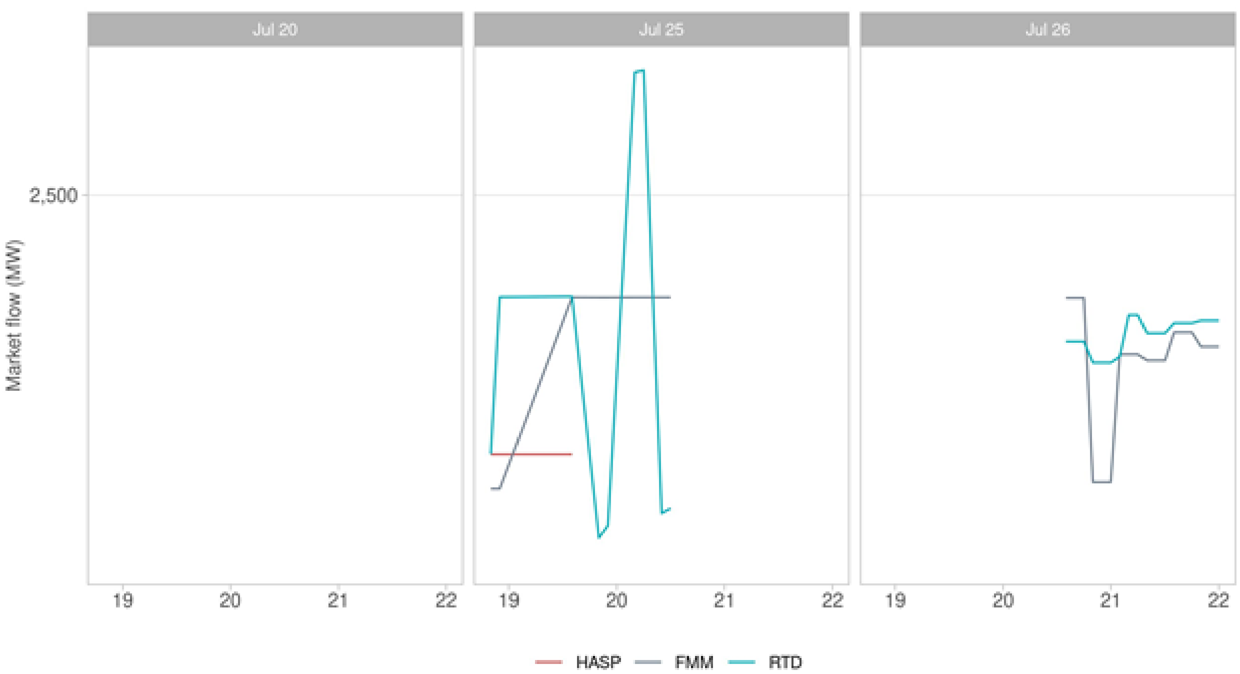


Figure 150: Market flows on Midway-Whirlwind flowgate

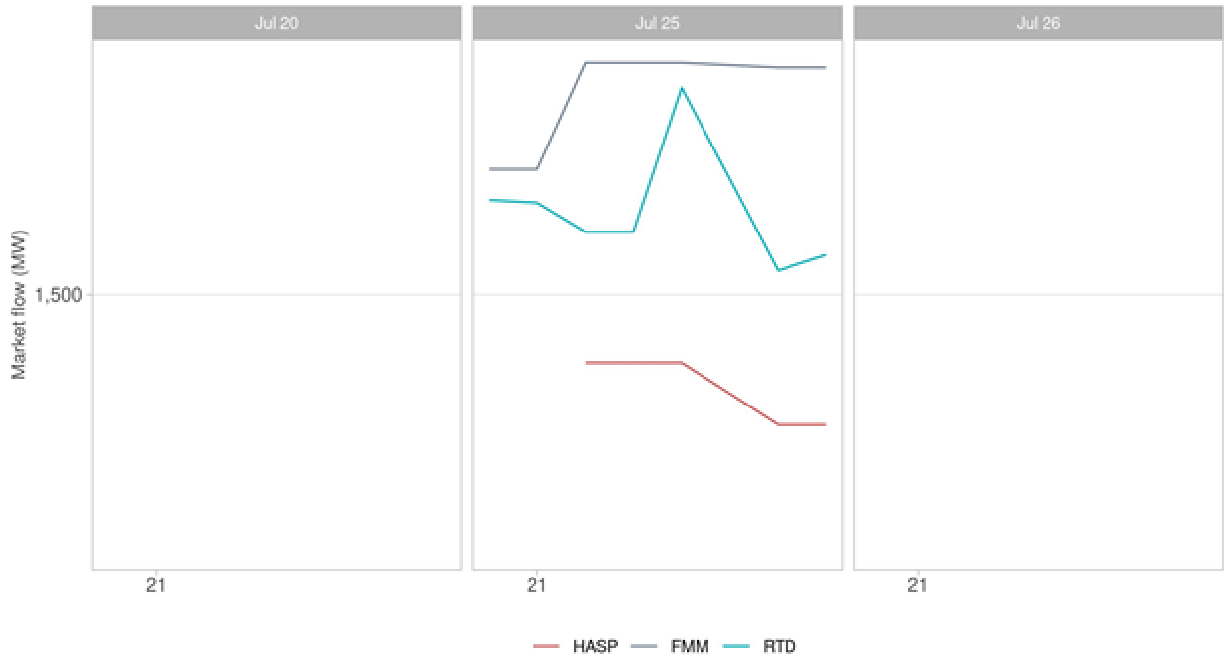


Figure 151 FMM FRD procurement by BAA

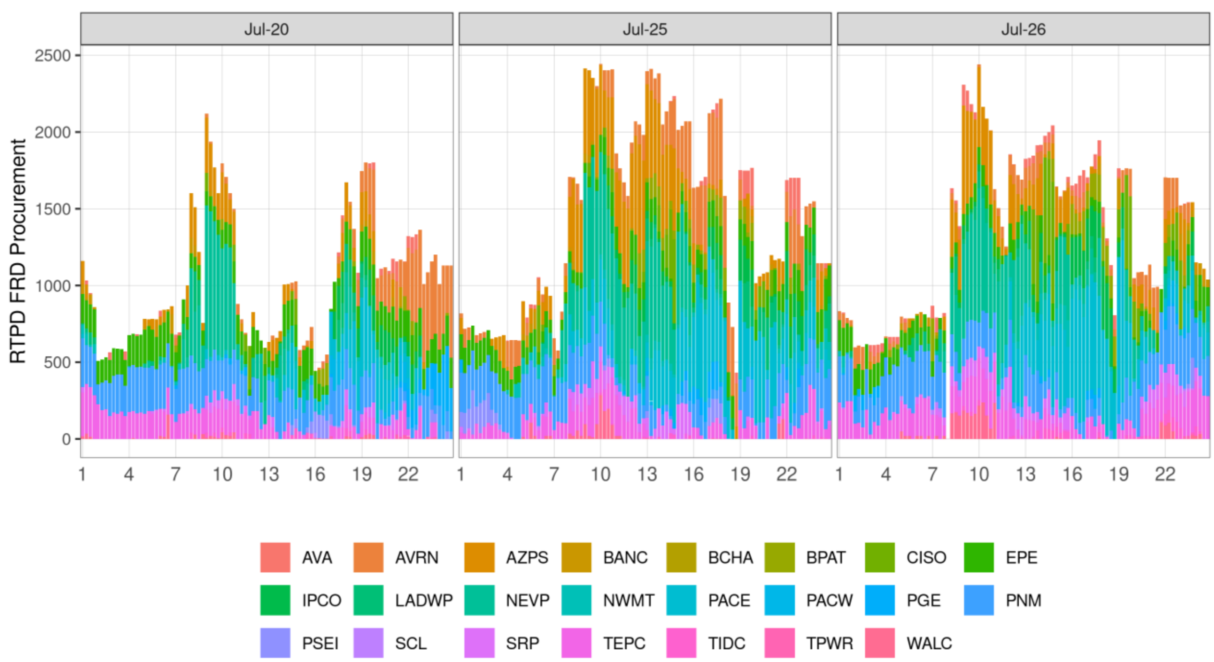


Figure 152 FMM FRD procurement by resource type

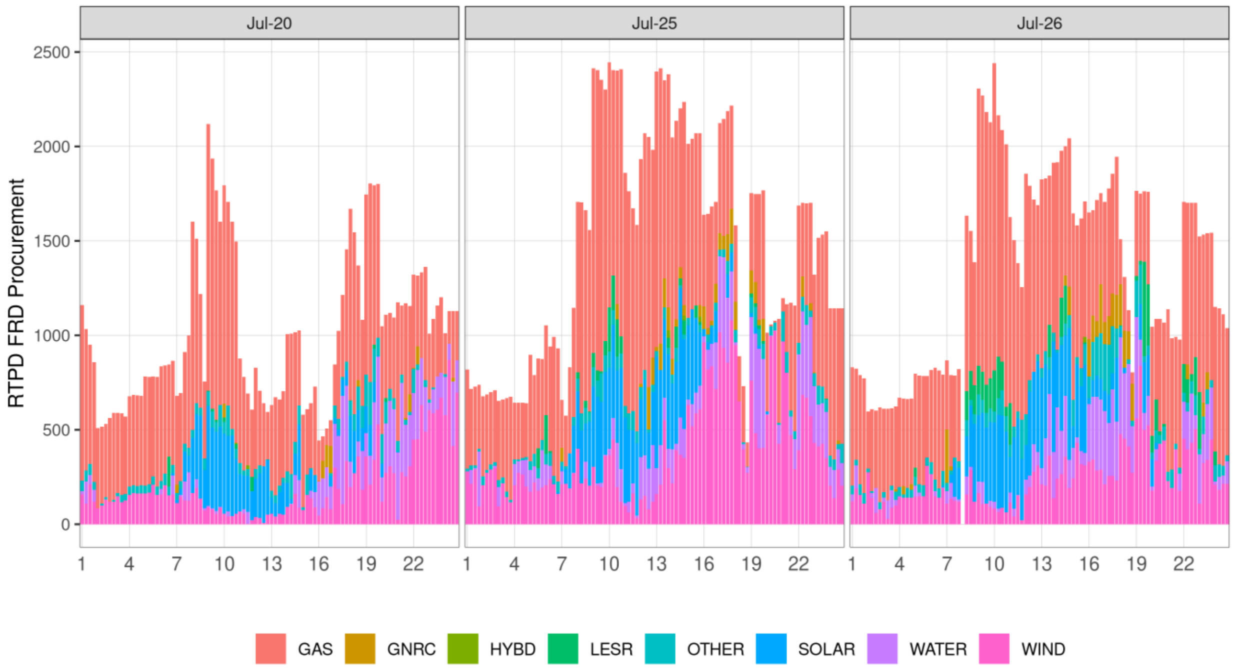


Figure 153 shows the ISO FRD procurement breakdown by resource type.

Figure 153 ISO FRD procurement by resource type

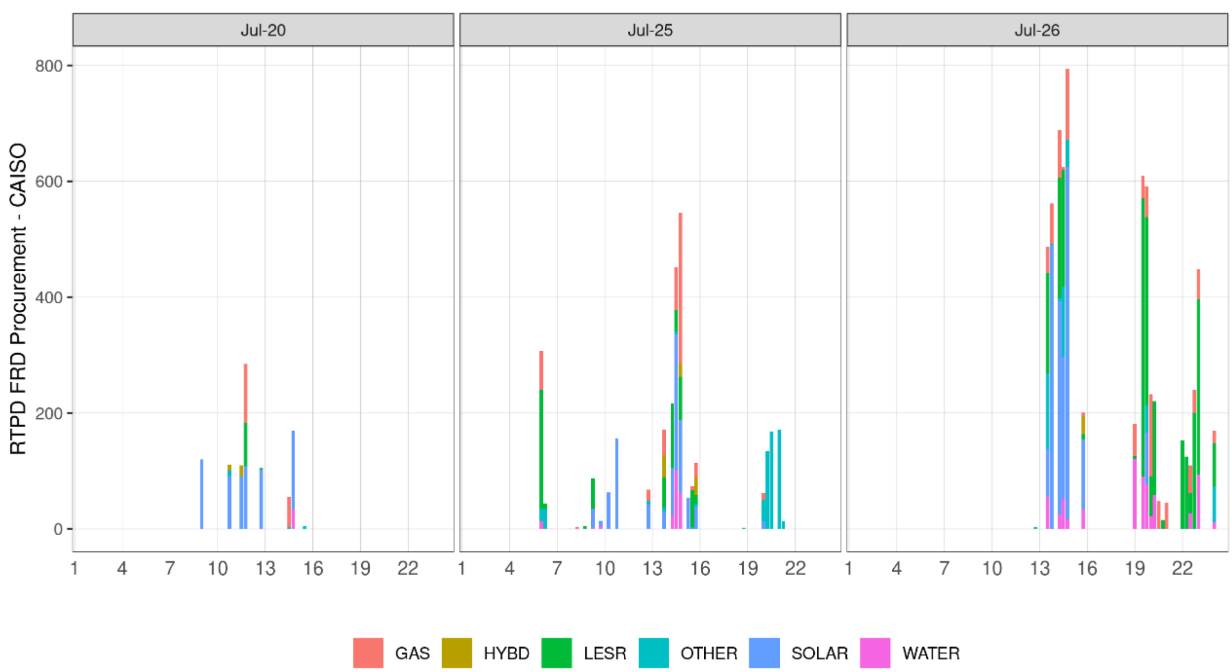


Figure 154 shows the passing group FRD requirement versus procurement. Within the three days, FRD group requirements are all met except for one RTPD interval having a violation of less than 1MW. Figure 155 shows the passing group procurement breakdown by BAA. There are minimal failed BAAs in the downward direction.

Figure 154 Passing group FRD requirement & procurement

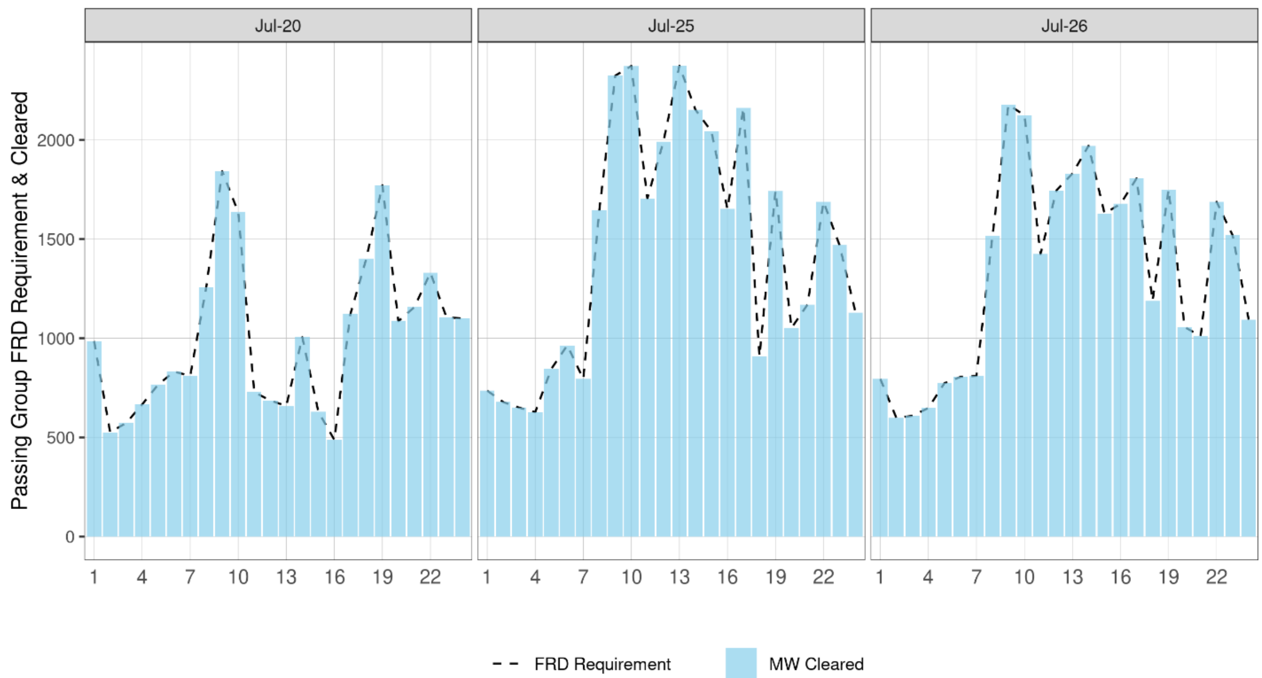


Figure 155 Passing group FRD procurement by BAA

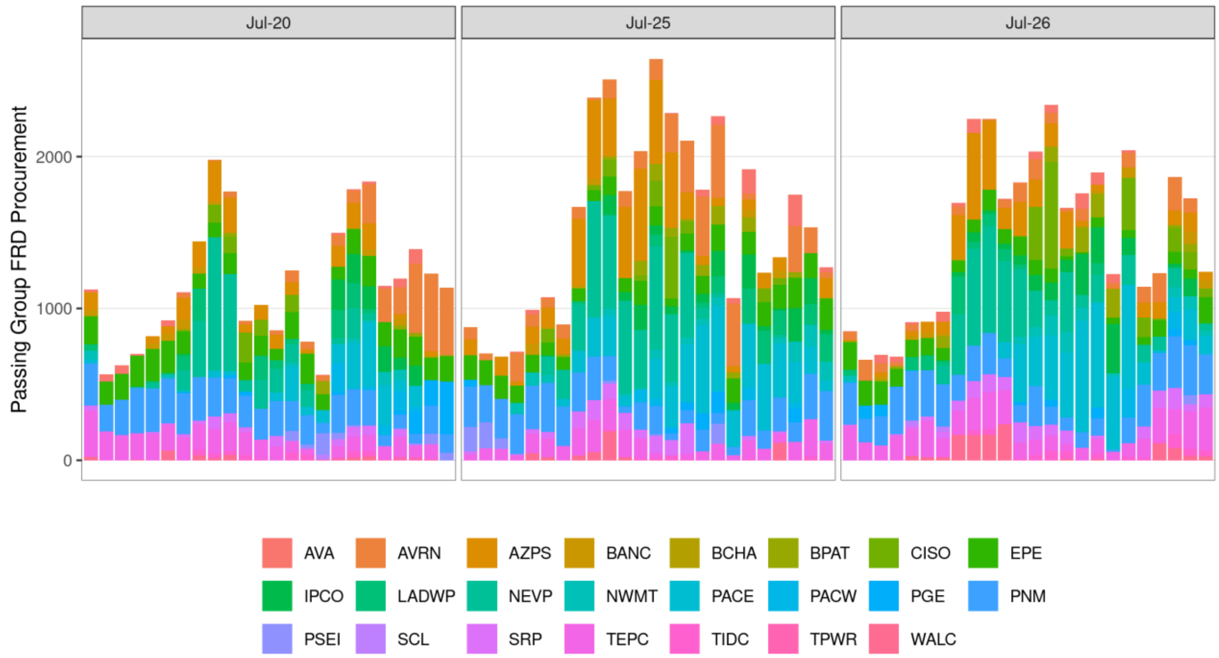


Figure 156 and Figure 157 show the FRD price distributions within all WEIM areas, and the passing groups. Majority of the FRD prices are zeros, with only a few positive prices. The pricing outcomes of the passing groups are almost the same as the WEIM areas.

Figure 156 FRD nodal price distributions, all WEIM areas

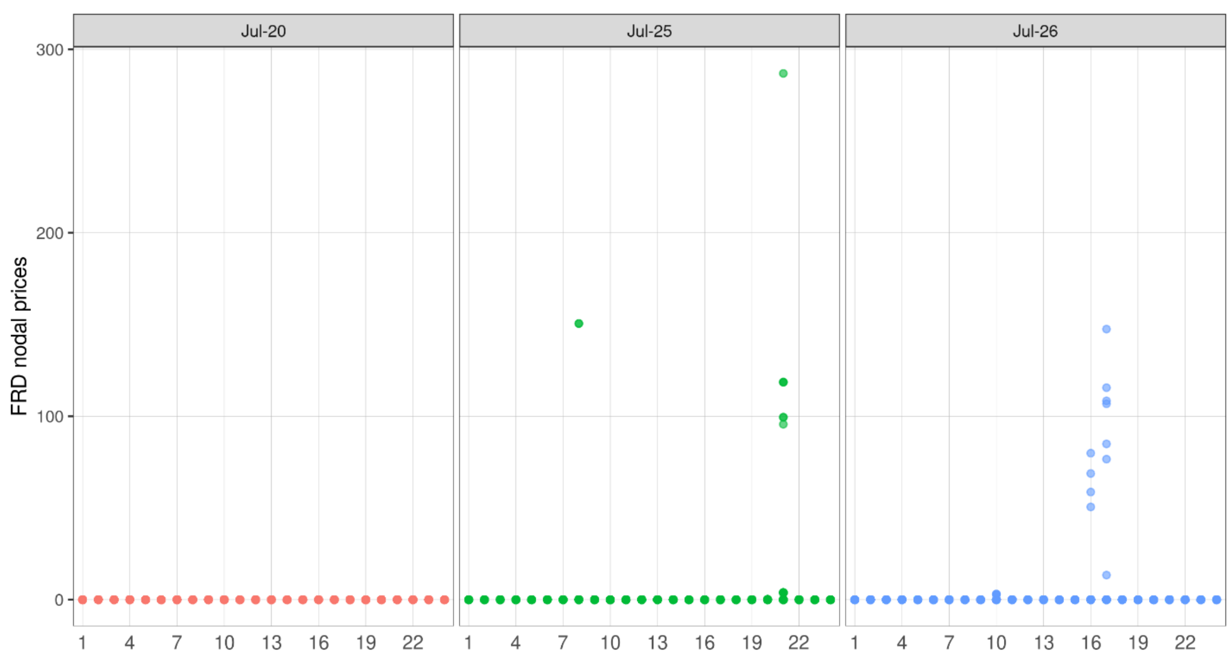
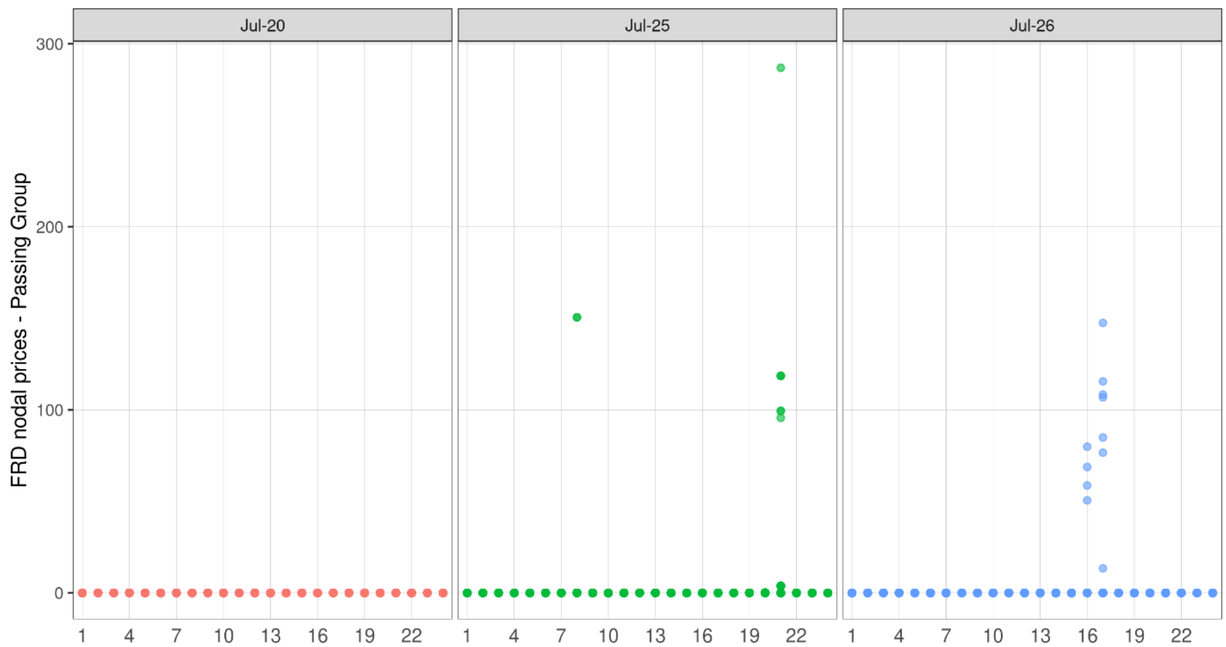


Figure 157 FRD nodal price distributions, passing group



16 Scheduling Priorities

16.1 Types of exports in ISO Markets

The ISO markets use defined market-scheduling priorities, as prescribed in the ISO tariff, to determine the amount and sequence of exports the market must reduce in the day-ahead and real-time markets. This allows the ISO to balance supply and demand while considering underlying transmission capabilities of the system. The principles for scheduling priorities are largely the same between the day-ahead and real-time markets.

16.2 Day-Ahead Market

The day-ahead market optimally schedules exports in both the Integrated Forward Market (IFM) and the Reliability Unit Commitment (RUC) processes. Each of these two processes apply the same priorities. If RUC reduces an export previously cleared in the IFM process, the RUC schedule is now the reference quantity for tagging if tags are submitted before the HASP clears and real-time participation. Table 1 (below) lists the applicable scheduling priorities for the day-ahead market (both IFM and RUC) for all exports *and* the export leg of wheel transactions.

Table 4: Scheduling priorities for the day-ahead processes

#	Type	Requirement	Label/Identifier
D1	Economical	Bid with a specified price and quantity	ECON
D2	Low priority	Bid with quantity only -no price-	DALPT
D3	High priority	Bid with quantity only -no price- identifying a non-RA supporting resource or a resource on a RA plan to serve external load. For Exports of a wheel, transaction approved and registered 45 days in advance. Selection of self-schedule type SS in the bid to have high priority	DAPT
D4	ETC/TOR	Bid with quantity -no price- under registered legacy contract or transmission ownership rights	ETC/TOR

Higher priority

16.3 Real-Time Market

In the context of the real-time market, scheduling priorities apply to the sub-market clearing interties. The Hour-Ahead Scheduling Process (HASP) clears all hourly interties on an hourly basis, whereas the Fifteen-Minute Market (FMM) clears 15-minute resources. The FMM and/or Real-Time Dispatch (RTD) markets do not use scheduling priorities for hourly transactions because these transactions have already cleared HASP. Table 2 (below) lists all scheduling priorities used in the real-time market, which are largely the same as those of the day-ahead market—with some minor differences.

Table 5: Scheduling priorities for the real-time processes

#	Type	Requirement	Label
R1	Economical	Bid with a specified price and quantity	ECON
R2	Low priority	Bid with quantity only -no price-	RTLPT
R3	Low priority	Bid with MW quantity only -no price- up to cleared MW in RUC	DALPT
R4	High priority	Bid with quantity only -no price- identifying a non-RA supporting resource or a resource on a RA plan to serve external load. For Exports of a wheel, transaction approved and registered 45 days in advance. Selection of self schedule type SS in the bid to have high priority.	DAPT/RTPT
R5	ETC/TOR	Bid MW quantity -no price- under registered legacy contract or transmission ownership rights	ETC/TOR

Higher priority

The main difference between day-ahead and real-time scheduling priorities is that for the real-time market, there are *two* groups of low priority exports. The lowest priority is assigned to price takers participating only in the real-time market (R2). A slightly higher priority is given to price takers or economical exports already cleared in the day-ahead market who roll their RUC schedules into the real-time market (R3). For any self-schedules above RUC schedules, the market assigns a lower priority (R2).

High priority exports also encompass two internally categorized groups. The first groups involves direct bidders for high priority exports in real-time (RTPT), while the second group includes those cleared in the day-ahead market and then roll their RUC schedules into real-time. Both groups share an identical high priority status. For any self-schedules above the RUC schedule—or above its high priority quantity—the market assigns it the lowest priority (R2).

16.4 Market clearing process and export/wheel reductions

Market scheduling priorities are operationalized via distinct scheduling parameters (parameter prices), which are prescribed in the Tariff and the BPM for Market Operations. These parameter prices are greater than the bid cap to ensure they get used only until all economical bids are considered. Within the internal market clearing process and treatment of exports, several factors play a pivotal role in determining optimal schedules for exports and wheels.

16.4.1 Balance between supply and demand

Reductions in exports or wheel-through transactions are only necessary when there is a lack of sufficient supply to meet ISO demand and exports—i.e., the balance between supply and demand will not be met with increasing demand and thus exports and demand need to be reduced. The clearing process begins by not clearing economical bids, then reduces low-priority exports, and then potentially high-priority exports. Strict adherence to scheduling priorities, from lowest to highest, only becomes relevant in power balance conditions when supply cannot meet all demand and exports.

Even when reductions are necessary to maintain power balance, the market uses the full functionality of locational marginal prices. Therefore, when the optimal solution requires reducing only a *portion* of a group of exports, the clearing process will take into account the locations of these exports (scheduling points) to differentiate which reductions produce the least-cost solution. In the absence of congestion, marginal losses—which are location specific—will be the main factor in determining which exports are reduced first among those of the same priority.

16.4.2 Congestion management

As an integral element within the locational marginal pricing framework, congestion management plays a crucial role in shaping the optimal schedules of all resources, including exports, in the ISO markets. In addressing congestion, resources are dispatched incrementally to alleviate congestion, while other resources are dispatched decrementally to not exacerbate congestion. This congestion management approach leads to out-of-merit dispatches, prioritizing the dispatch of relatively more expensive resources before cheaper ones. This principle extends to exports with scheduling priorities as well. Export resources may also be reduced to manage congestion, even when supply is adequate to meet both demand and exports.

More significantly, export reductions prompted by congestion may not strictly adhere to scheduling priorities as their determination is predominantly influenced by the export's relative location to the congested constraint. It is conceivable that low priority exports could be reduced prior to utilizing all economical bids or that certain high priority exports might be reduced ahead of low priority ones due to congestion.

Conversely, certain low-priority—or even economical—exports could receive full awards while other exports of higher priority are reduced. This out-of-sequence reduction can be caused by exports creating counter-flows that alleviate congested constraints, which in some cases can allow more imports to flow into the ISO area. These schedules are not driven by limited supply conditions.

16.4.3 Wheel reductions

Wheel transactions are bid and cleared in balance, thus not introducing additional supply or demand on the system. Consequently, when the market clearing process schedules resources (including exports) for the specific conditions of limited supply, wheel transactions will not be subject to reductions. Wheel transactions come into play when supply constraints arise due to congestion on the interties they are scheduled on or if internal congestion is exacerbated by wheel-through transactions.

ISO incorporates specific functionality to proportionally allocate restricted intertie capacity in situations where both the intertie capacity is limited and the ISO has a supply infeasibility. Similar to exports, severe congestion on internal constraints can prompt the market clearing process to reduce wheel-through transactions, deviating from the standard priority sequence. This divergence is solely driven by their location and impact on the constraint.

16.4.4 Post-market process

After the completion of the HASP market, the final schedules are transmitted via the Automatic Dispatch System (ADS). These schedules encompass any export reductions, which participants can accept or decline.

Upon receipt of an ISO real-time market award for an intertie, the Scheduling Coordinator must submit an e-Tag to formalize the scheduling of the award. Notably, with the introduction of new provisions in July 2023 as part of the Resource Sufficiency Evaluation (RSEE) Phase 2 Track 1, all economical and low-priority exports are required to be e-tagged as firm provisional energy (G-FP). This classification aims to provide the proper identification to involved parties with visibility of the provisional nature of economical or low-priority exports.