Summer Market Performance Report
August 2023

October 10, 2023

Prepared by

Market Performance and Advanced Analytics

Content

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Acronyms

AZPS or APS	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
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capacity
EPE	El Paso Electric
ESP	Energy Service Provider
ETC	Existing Transmission Contract
F	Fahrenheit
FMM	Fifteen Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor-Owned Utility
IPCO	Idaho Power Company
LADWP	Los Angeles Department of Water and Power
LMP	Locational Marginal Price
LMPM	Local Market Power Mitigation
LPT	Low priority export. This is a scheduling priority assigned to price-taker exports that do not have a non-RA supporting resource
LSE	Load Serving Entity
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
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
RTM	Real-Time Market
RUC	Residual Unit Commitment
SCL	Seattle City Light
SMEC	System Marginal Energy Component
SOC	State of Charge
SRP	Salt River Project
TIDC	Turlock Irrigation District
TOR	Transmission Ownership Right

1 Executive Summary

The California ISO regularly reports on the performance of its markets to provide timely and relevant information. This is the third in a series of customized monthly reports focusing on the ISO's market performance and system conditions during the 2023 summer months from June through September, when system conditions are particularly constrained in California and the Western Interconnection. These monthly reports also provide a performance assessment of specific market enhancements implemented as part of the ISO's summer readiness market rules changes.[1]

No emergency events nor flex alerts were called in August. The market and system operated well in ensuring demand and uncertainties were met.

August 2023 Highlights

Overall August 2023 temperatures were cooler than normal. Average peak loads in August 2023 were at 37,819 MW, which is lower than the 40,148 MW average in August 2022. The highest hourly average load in the month was observed on August 16 at 44,226 MW when the ISO area experienced temperatures 3 degrees F above normal. This load peak was lower than the peak in August 2022 of 45,520 MW or the all-time peak of 52,016 on September 6, 2022.

The system saw an increase in hydroelectric production. Reservoir conditions for California and the West were significantly above the historical average. Storage in major reservoirs statewide was 118 percent of average for this time of year and 86 percent of capacity overall.[2] Hydro production in August 2023 increased by 63 percent relative to the level observed in August 2022.

Monthly resource adequacy capacity was 51,685 MW and above the level of load needs, which includes demand, operating reserves and supply and demand uncertainties. Compared to 2022, resource adequacy capacity for storage resources increased by 2,097 MW and also increased by 228 MW for static imports. Hydro saw an increase of 729 MW and gas-fired supply saw an increase of 486 MW.

The ISO's average real-time prices were $16.43/MWh higher than real-time markets throughout the month of August, with the largest divergence occurring on August 15. The ISO area energy prices for August 2023 saw larger price spreads compared to prices of August 2022, primarily driven by the prices that materialized on August 15 and 16.

The residual unit commitment process, which determines supply needed to meet the day-ahead load forecast as compared to supply cleared in the integrated forward market, found there was sufficient supply to meet the adjusted California ISO load forecast in peak hours for all days in August. On August 15-16, this process identified the need to reduce economic and low priority self-scheduled exports for peak hours. These type of exports are not back up by any specific supply capacity.

[1] This report is targeted in providing timely information regarding the ISO's market's performance for the month of August. Several metrics provided in this report are preliminary and based on data still subject to change. It is also important to note that the data and analysis in this report are provided for informational purposes only and should not be considered or relied on as market advice or guidance on market participation.

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

Hourly average of net imports was 3,207 MW for peak hours from 17 through 21 in August. The ISO experienced the largest volume of exports on August 14. The larger volume of exports generally occurred prior to the peak hours and was driven by increasing demand in the West as temperatures increased.

Towards the end of the month, WEIM transfers turned to predominant imports for the ISO BAA mainly for on-peak hours. Overall, WEIM transfers reflect the economic and operational benefits that EIM offers to participating entities by maximizing supply diversity and transferring supply from where it was available to where it was needed in real-time.

About 99 percent of the resource adequacy imports to the ISO bid at $0/MWh or lower prices in both the day-ahead and real-time markets. This assessment is for static import related to CPUC-jurisdictional load serving entities.

Up to 1,602 MW of the 1,776 MW of registered high-priority wheel-through transactions for the month of August bid in and cleared in the day-ahead market. This represents a 90 percent utilization of the registered wheels. For low priority wheels, the maximum transaction was 110 MW from Palo Verde to Mirage locations. Ho high-priority wheels were reduced in the markets in August.

Reliability demand response resources were optimally dispatched at 270 MW in the real-time market on August 16 after they were bid and cleared in the day-ahead market economically. Proxy demand response was dispatched up to 461 MW in the day-ahead market and 420 MW in the real-time market for the same trade date.

Capacity offered to the ISO market by storage resources continues to increase. The bid-in capacity for energy was consistently over 4,000 MW for the month of August. The maximum state of charge in real time was about 16,500 MWh while real-time dispatches reached about 4,000 MW. This capacity helps to meet peak conditions. Storage resources continue to procure a significant portion of regulation capacity.

On average, the ISO's daily average market costs were $60.81 million in August, representing an average daily cost of $85.00/MWh. The highest daily cost accrued on August 16 at about $259.29 million. These cost levels are consistent with the overall price increases and conditions that materialized mid-month.

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. The ISO declared 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,[3] 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.

[3] 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 the Summer 2021 Readiness initiative[4].

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[5].

Furthermore, the 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 still 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[6].

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

[5] 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

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

The ISO implemented several additional enhancements in preparation for summer 2022.These include:

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

The ISO also filed an extension to continue to use the minimum state of charge for summer 2023, and it is currently in place. Finally, the ISO completed subsequent enhancements of the energy storage resources initiative to require resources to have bid in the opposite direction to cover at least 50 percent of their ancillary service awards in the real time. Also, effective July 1 the ISO implemented one more phase of the resource sufficiency evaluation process, including:

- Implementation of the Assistance Energy Transfer process that allows entities in the WEIM to OPT in for energy during test failures.
- 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).

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

Below average, near average, above average, much above average and record warmest mean temperatures were observed across the western United States throughout August. This is shown in Figure 1[7]. The last time California had near or below average August temperatures was in 2018; however there were areas of the Southwest with below or near average temperatures during August 2022 and parts of the north central U.S. with below or near average temperatures in August 2021.

Figure 1: Mean temperature percentiles for August 2023

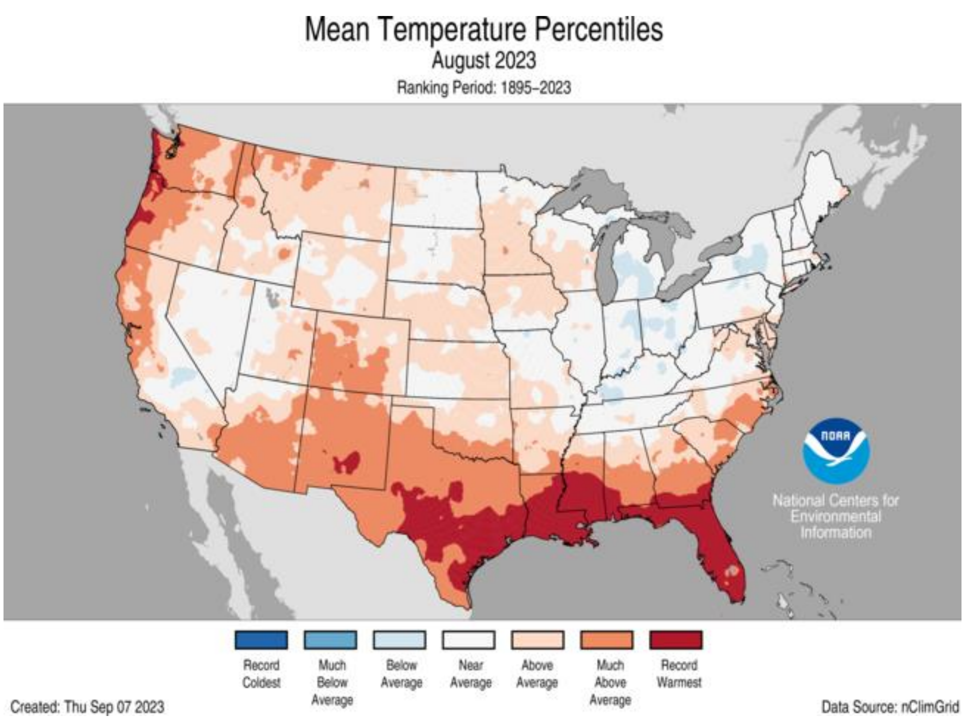
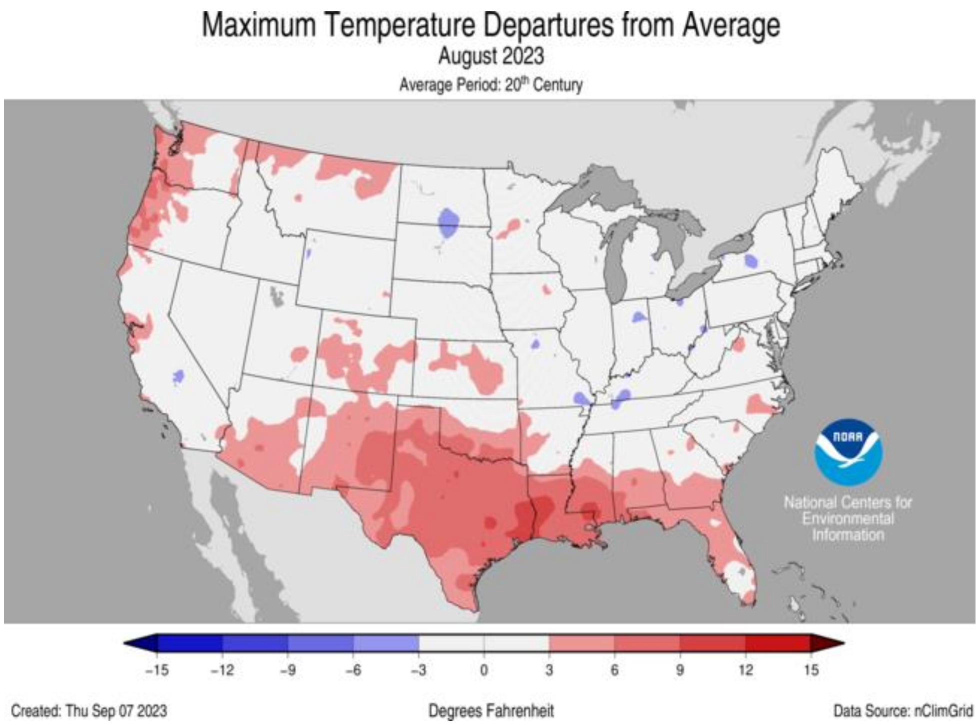


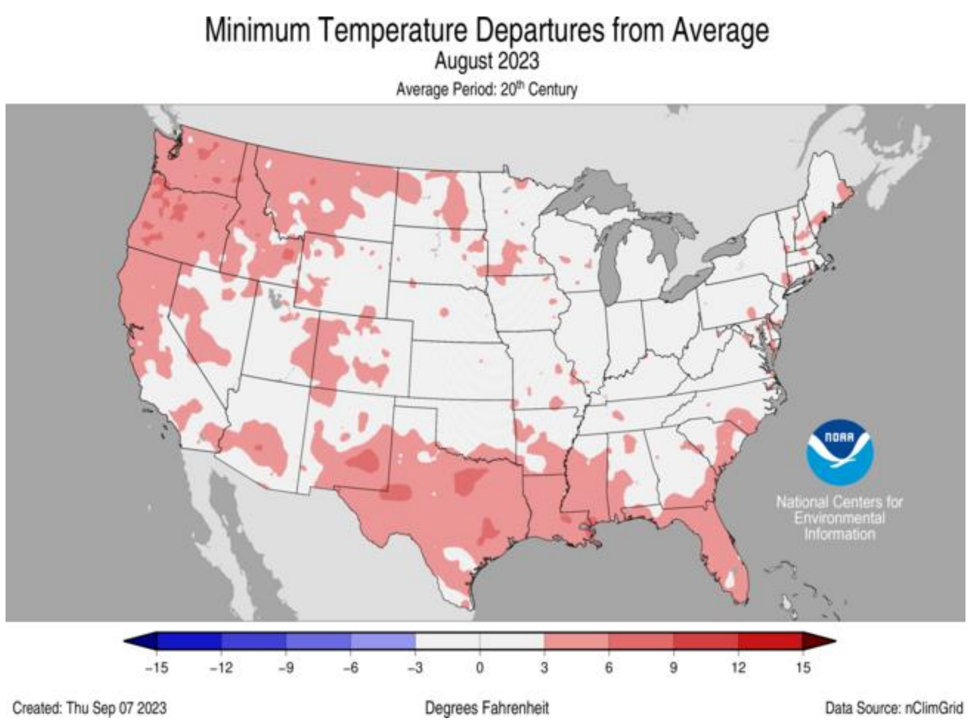
Figure 2[8] shows that warmer minimum temperatures were more widespread than maximum temperatures. There was even a small area of California where the average maximum temperature for August was below average. The Desert Southwest and Pacific Northwest saw the most widespread

7 https://www.ncdc.noaa.gov/temp-and-precip/us-maps/
8 https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

maximum and minimum temperature departures; in some areas the August mean maximum temperature was 6-9 degrees above average.

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





Looking at the areas of two Desert Southwest WEIM entities more closely in Figure 3, the maximum temperature anomalies varied across the region. Salt River Project (SRP) and El Paso Electric (EPE) had above normal temperatures 25 days of the month. For SRP and other Arizona entities, the hottest period of the month was the end, while El Paso had its hottest stretch at the beginning of August. Cloud cover and cooler air from hurricane Hilary led to a large drop in temperatures around August 19-21 for WEIM entities farther west while areas farther east saw impacts a few days later. Despite these few cool days, Phoenix, AZ had its hottest summer on record, with a mean daily average temperature from June 1-August 31 of 97 degrees F. That beat the previous record of 96.7 degrees set in 2020.

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

Salt River Project (SRP)

High temperature departure from normal

August 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
		1 3	2 4	3 4	4 7	5 11
6 6	7 6	8 5	9 4	10 0.7	11 -0.2	12 3
13 3	14 -1	15 5	16 9	17 9	18 0	19 -12
20 -3	21 -15	22 -1	23 2	24 0.3	25 4	26 6
27 7	28 13	29 10	30 6	31 4		
				days < normal 6	days > normal 25	Deg +/- normal + 3.2

above normal | below normal | *Normals: 1990-2020*

El Paso Electric (EPE)

High temperature departure from normal

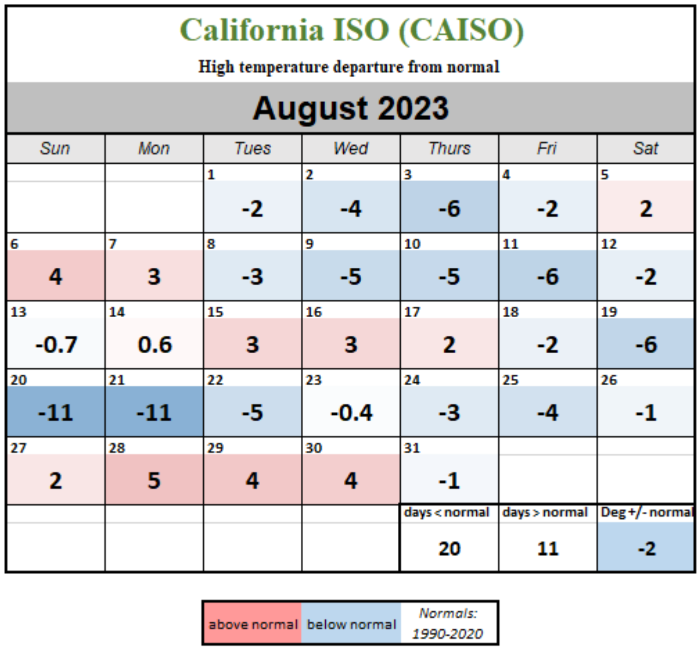
August 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
		1 5	2 7	3 6	4 11	5 13
6 16	7 13	8 7	9 7	10 7	11 4	12 4
13 3	14 -3	15 -0.5	16 4	17 8	18 7	19 5
20 5	21 4	22 1	23 -15	24 -0.4	25 -0.2	26 4
27 4	28 5	29 -2	30 2	31 5		
				days < normal 6	days > normal 25	Deg +/- normal + 4.5

above normal | below normal | *Normals: 1990-2020*

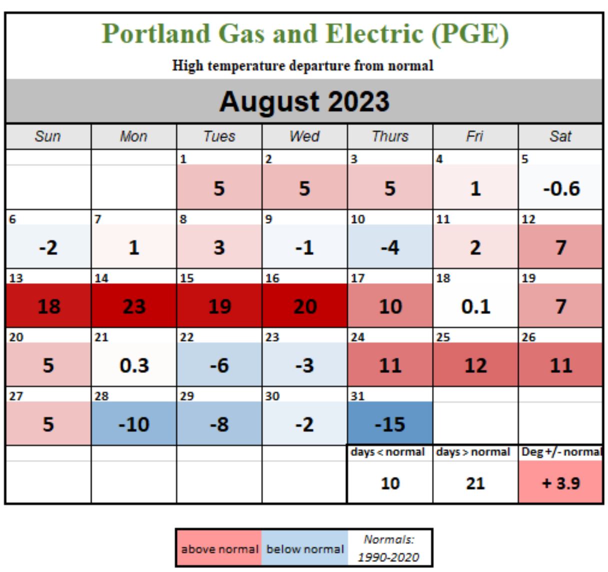
As shown in Figure 4, high temperatures throughout ISO fluctuated from below normal to above normal every few days throughout the month of August. The largest departures from normal was a stretch of below normal conditions from the 19th to the 21st due to the impacts from hurricane Hilary. During this time, some locations experienced high temperatures as much as 20 degrees below their normal mid-August values.

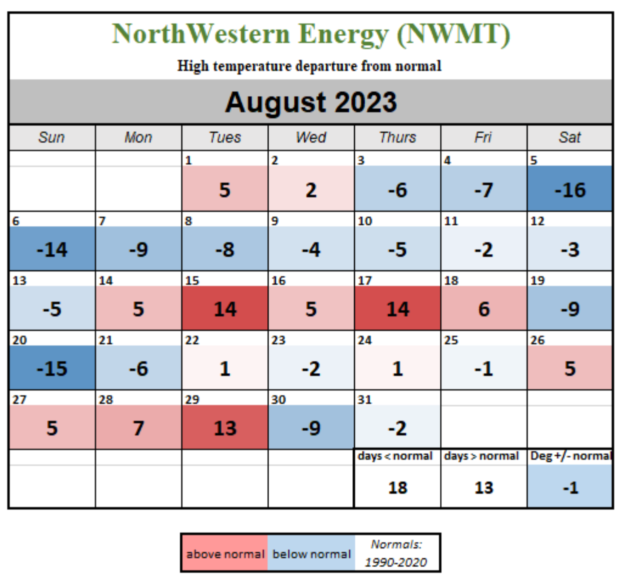
Figure 4: ISO high temperature departure from normal



In the Pacific Northwest, temperature departures for August varied for locations closer to the coast and areas farther inland. Portland Gas and Electric (PGE) and Seattle City Light (SCL), for example, saw well-above normal temperatures in their service territories from August 13-16. Record breaking temperatures across the area during this time included highs above 100 degrees in Portland and above 90 degrees in Seattle.

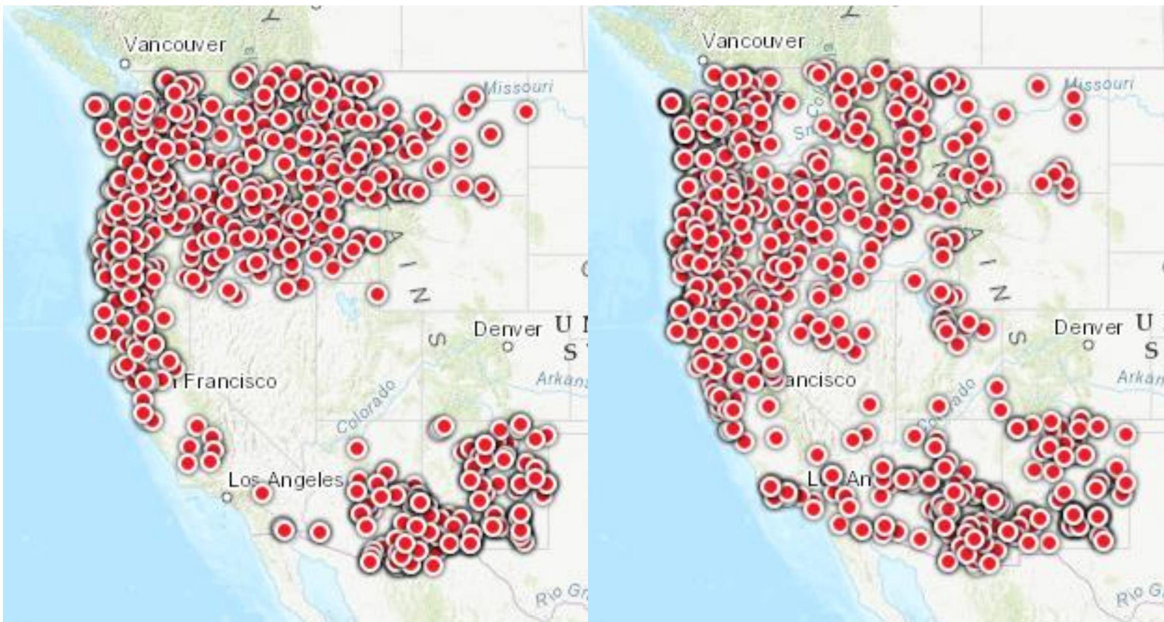
Figure 5 High temperature departure from normal for select Northwestern WEIMs





Looking at western U.S. temperature records in Figure 6[9], there were 1,314 daily warmest maximum temperature records that were tied or broken in August and 2,345 daily warmest minimum temperature records tied or broken. Compared to July, this is approximately 1,000 fewer daily maximum records tied or broken compared but 300 more daily minimum records tied or broken. There were also 1,011 daily coolest maximum temperature records set or broken, which speaks to the strength of both the hot and cool air that passed through the West during August at varying times.

Figure 6: Temperature records broken or tied for maximums (left) and minimums (right)



3.2 Hydro conditions

Nearly all of the western United States experienced above normal rainfall in August. This is shown in Figure 7[10]. Hurricane Hilary brought widespread heavy rain and flooding across California and Nevada August 19-21 with remnant moisture bringing rain to many other locations across the West. Many areas of Southern California broke daily rainfall records for August 20th and summertime daily record rainfall for June through August. Palmdale set an all-time daily rainfall record on August 20. Most parts of Southern California saw 2,000-5,000% of their average August rainfall with Sandberg, CA observing over 13,000% of average August rainfall[11]. Hurricane Hilary also brought the first-ever hurricane and tropical storm warnings issued for California, with the strongest wind gust of 84 mph observed at Big Black Mountain

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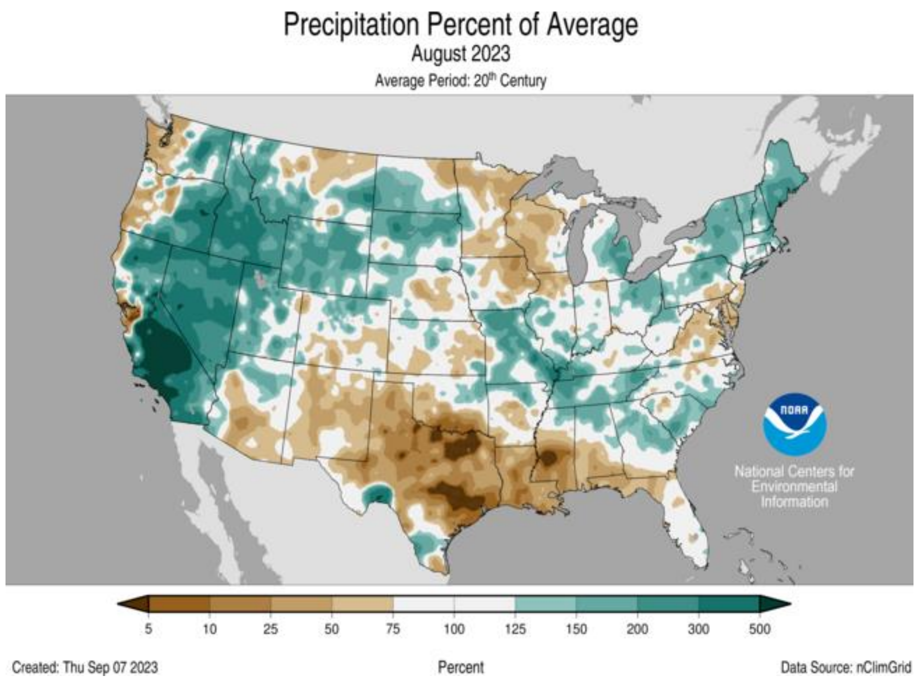
[9] https://www.ncdc.noaa.gov/cdo-web/datatools/records

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

[11] https://www.cnrfc.noaa.gov/?product=PNM&product2=QPEmonthlyPercentNormal&lat=34.425&lng=-113.494&PNGtypeID=QPEmonthlyPercentNormal

near San Diego. In contrast, areas not impacted by the hurricane or its remnants in California, Oregon, Washington, Arizona and much of New Mexico had below normal rainfall.

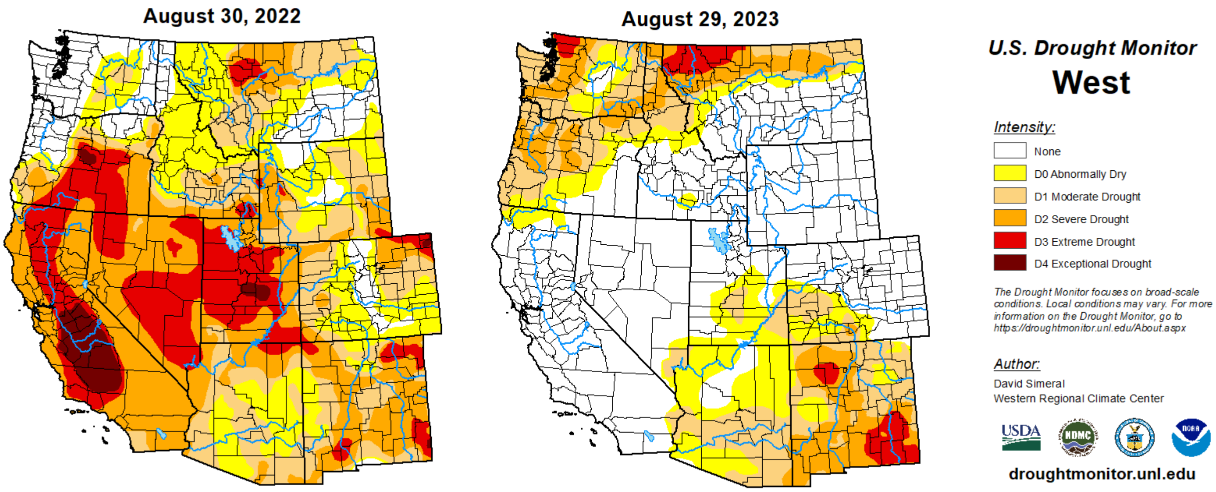
Figure 7: The United States precipitation percent of normal for August 2023



The above normal winter rain and snowfall caused the Sierra Nevada to see its second largest snowfall on record.[12] This helped to keep the drought index lower through the first half of summer, and the rainfall from Hurricane Hilary lead to an improvement in the drought between July and August. While the drought situation in California has improved since 2022, and the extent of extreme or exceptional drought in the West also has improved, there are portions of New Mexico, Washington, Montana and Oregon where the drought has worsened due to below-normal summer rainfall. This is shown in Figure 8[13]. During August, the abnormal and exceptional drought in these areas increased by 2.92 percent; however, the areas with no drought improved by 4.30 percent.

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

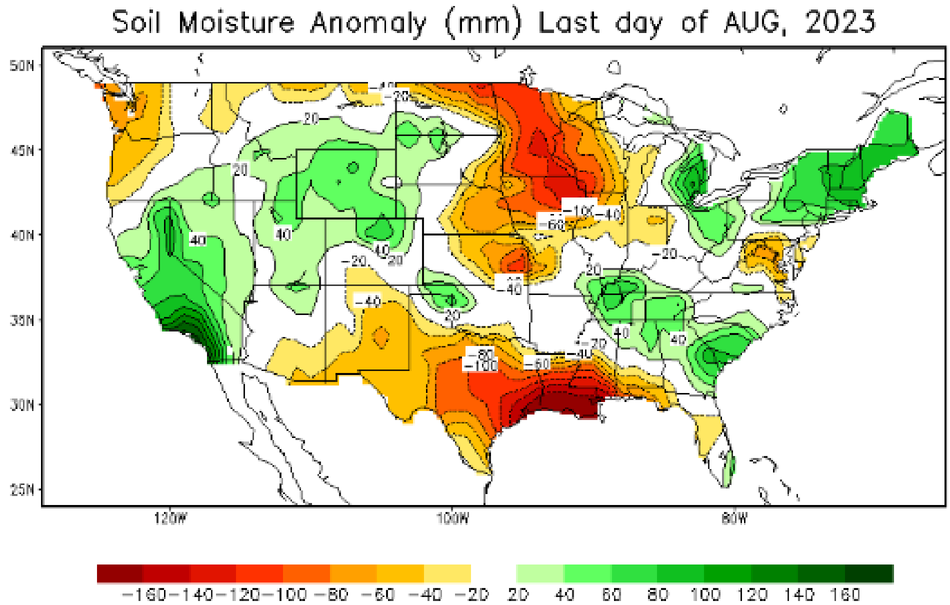
Figure 8: The Western United States drought monitor

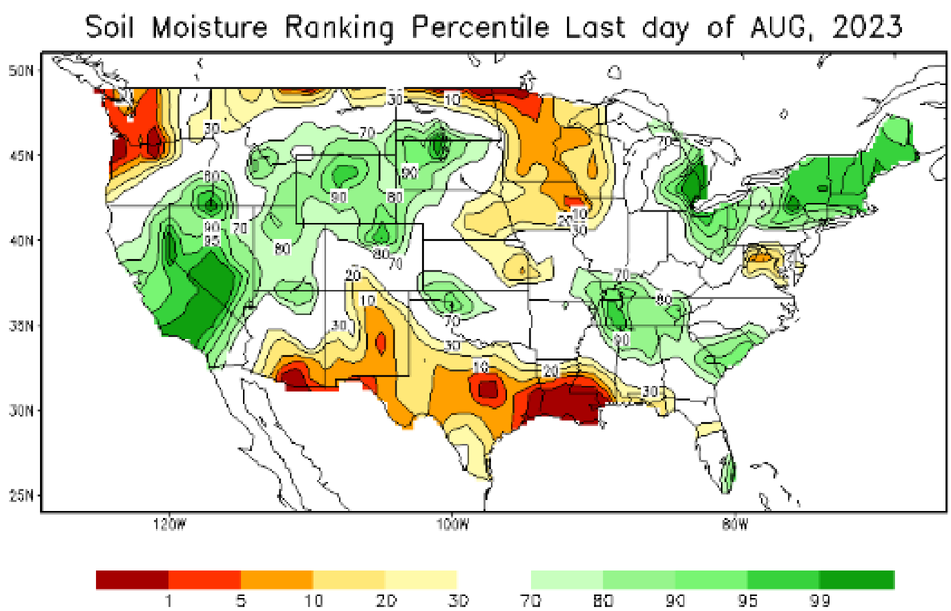


In Figure 9[14], below, the top image shows that soil moisture is still above average for this time of year across almost all of California, but especially in Southern California. During the summer months, the state typically receives little-to-no precipitation. But this year's above-normal snowpack, and its continuing snowmelt and runoff, led to above normal soil moisture in August. The rains from hurricane Hilary also contributed to unusually high soil moisture levels. At the end of August 2022 soil moisture percentiles were within the bottom 20 percent across almost all of California, so August 2023 having much of the state in the top 20% of soil moisture is a large improvement compared to last summer.

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

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



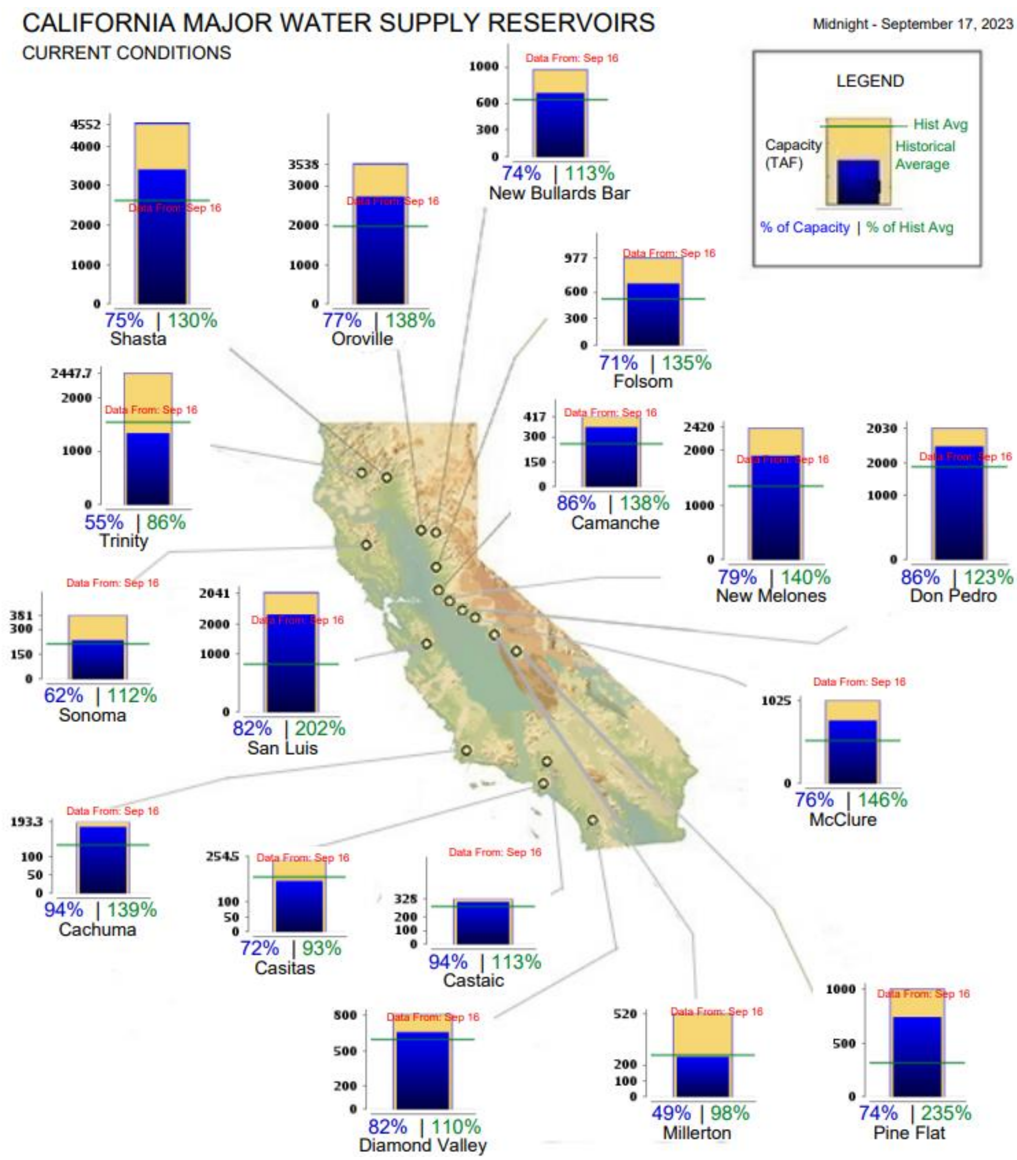


Based on all the factors discussed above related to temperatures, precipitation, drought conditions and soil moisture levels, many reservoir conditions in California and the West were significantly above normal in August, as shown in Figure 10[15]. Reservoir levels across the state are at or above historical averages for the end of August; including 14 of the 17 reservoirs are above their historical average for this time of year.

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

The statewide storage in major reservoirs is currently 87 percent of average and 54 percent of capacity[16]. This is compared to 55 percent of average and 34 percent of capacity at the end of August 2022.

Figure 10: California's reservoir conditions as of September 16, 2023



The ISO's electrical system utilizes hydro production throughout the year to meet demand needs. Figure 11 shows the historical trend of total energy produced from hydro and other renewable resources. Hydro production for 2023 so far has been significantly higher than in 2021 and 2022. Hydro production in August 2023 was about 63 percent higher than the production observed in August 2022. Figure 12 below shows

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

the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for August 2023.

Figure 11: Historical trend of hydro and renewable production

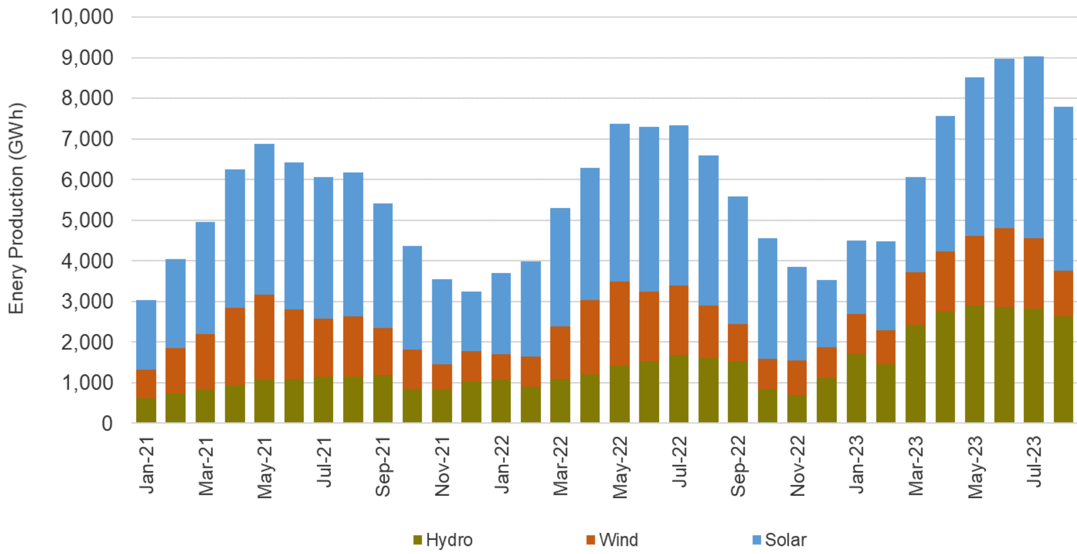
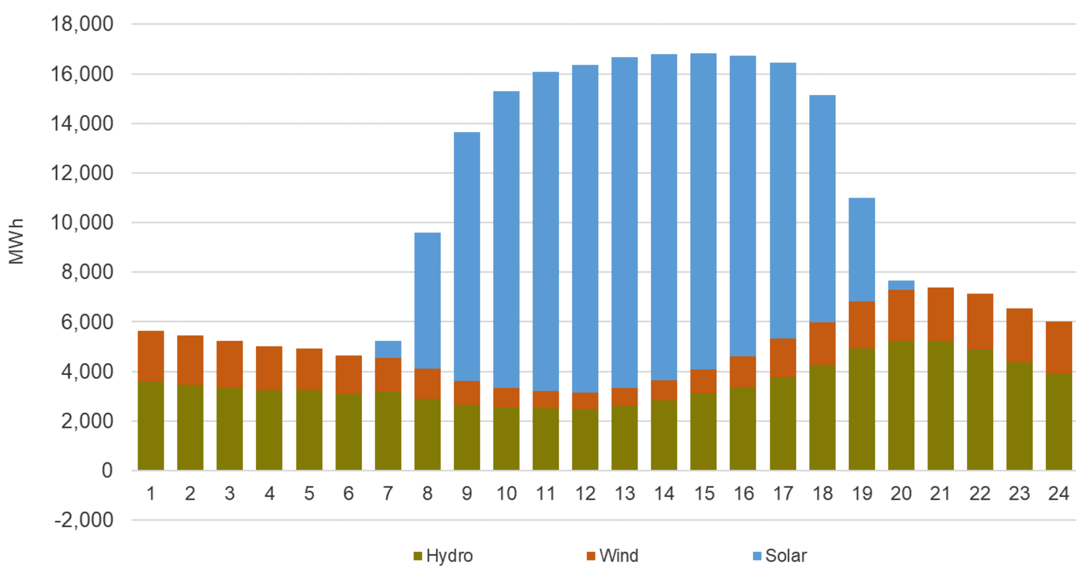


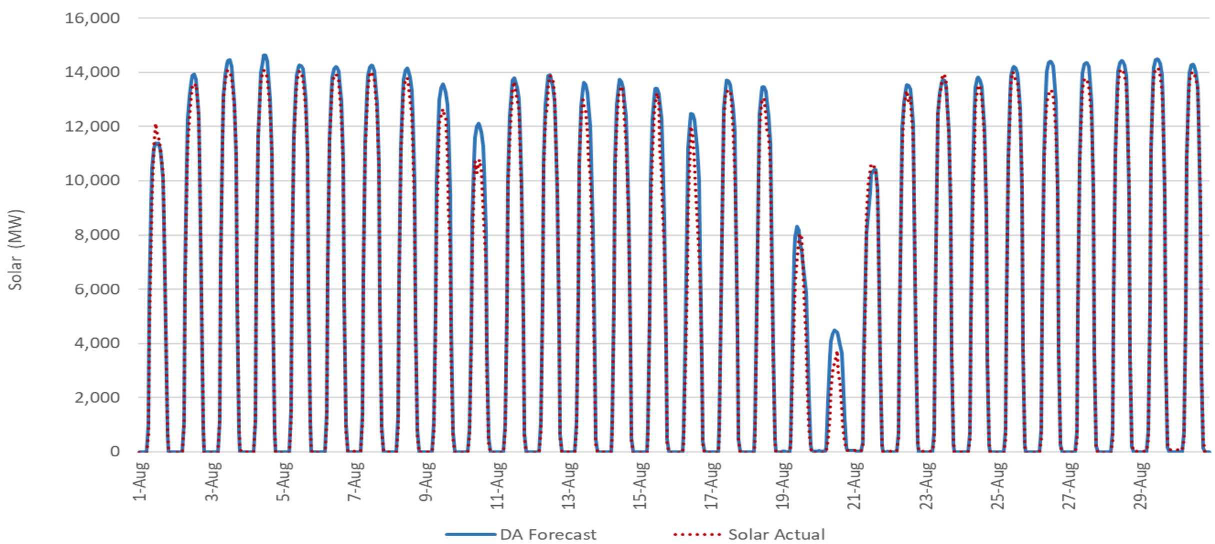
Figure 12: Hourly profile of wind, solar and hydro production for August



3.3 Renewable forecasts

Figures 13 and 14 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 a resource's forecast based on its 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 August was sunny, there were some periods of passing clouds and light showers in Southern California on August 9-10, which led to a reduction in solar output. The heavy cloud cover and rain caused by hurricane Hilary from the 19-21 lead to a very large reduction in solar output. The average error[17] for the day-ahead solar forecast in August 2023 was 2.87 percent. The average error observed in August 2023 is higher than the day-ahead solar forecast error observed for August 2022 but lower than in August 2021.[18]

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

[18] https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Sep27-2023.pdf

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

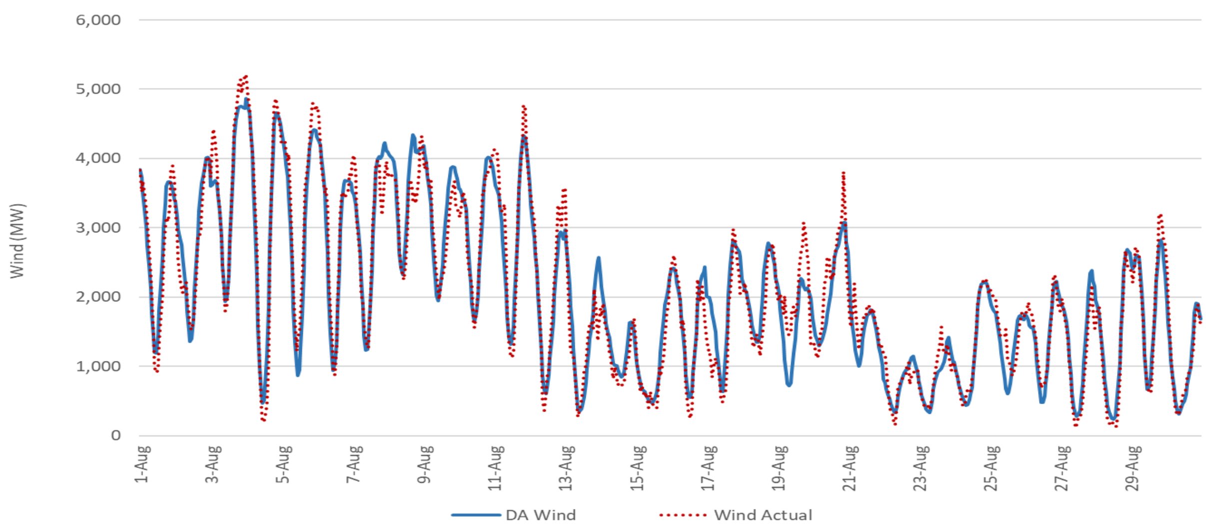

Figure 14 shows the day-ahead wind forecast compared to the actuals plus curtailments throughout the month of August for wind in the ISO's system. The average error[19] for the day-ahead wind forecast in August was 2.86 percent. The average error observed in August 2023 is lower than the day-ahead wind forecast error observed for August 2022 and August 2021.[20]

3.4 Demand forecasts

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 August 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 average hourly August load of 44,226 MW was observed on August 16, when the ISO footprint maximum temperatures were 3 degrees F above normal.

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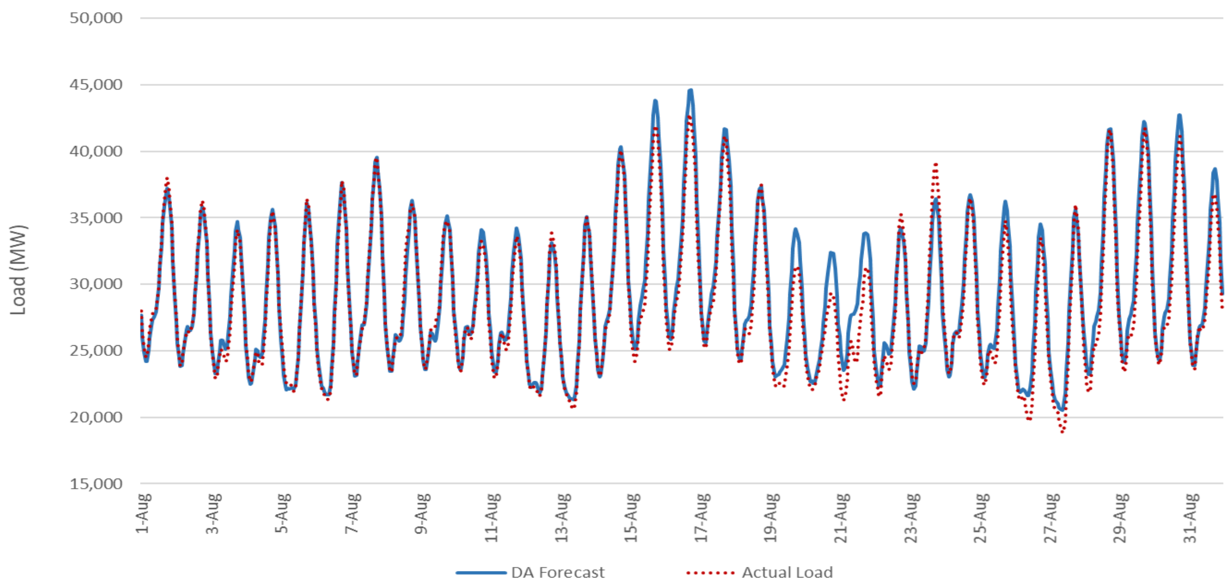
[19] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[20] https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Sep27-2023.pdf

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



Some of the larger errors in August were observed in the middle of the month when above-normal temperatures occurred followed by a large drop in temperatures due to Hurricane Hilary. In addition to the large temperature drop, cloud cover and rain associated with Hurricane Hilary also impacted loads and led to actual demand coming in lower than forecast for the period of August 19-21.

The average accuracy error for the day-ahead demand forecast in August was 2.87 percent, while the error for peak hours was 2.57 percent. The average error in August 2023 was higher than the errors observed in August 2021 and 2022, which were 1.85 and 1.97 percent respectively. Hurricane Hilary contributed to the error increased.

3.5 Energy Conservation

During the month of August 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 August.

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) and reliability demand response. These programs use supply-type participation models that can be dispatched similar to conventional generating resources.

Figure 16 shows the dispatch for proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in either market based on their bid-in prices. During the months of July and August, PDR resources were consistently dispatched in both the day-ahead and real-time markets. The largest volume of PDR dispatches in the day-ahead timeframe occurred on August 16 at about 461 MW, whereas in the real-time market, it was a maximum of 420 MW of PDR dispatches for the same trade date.

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

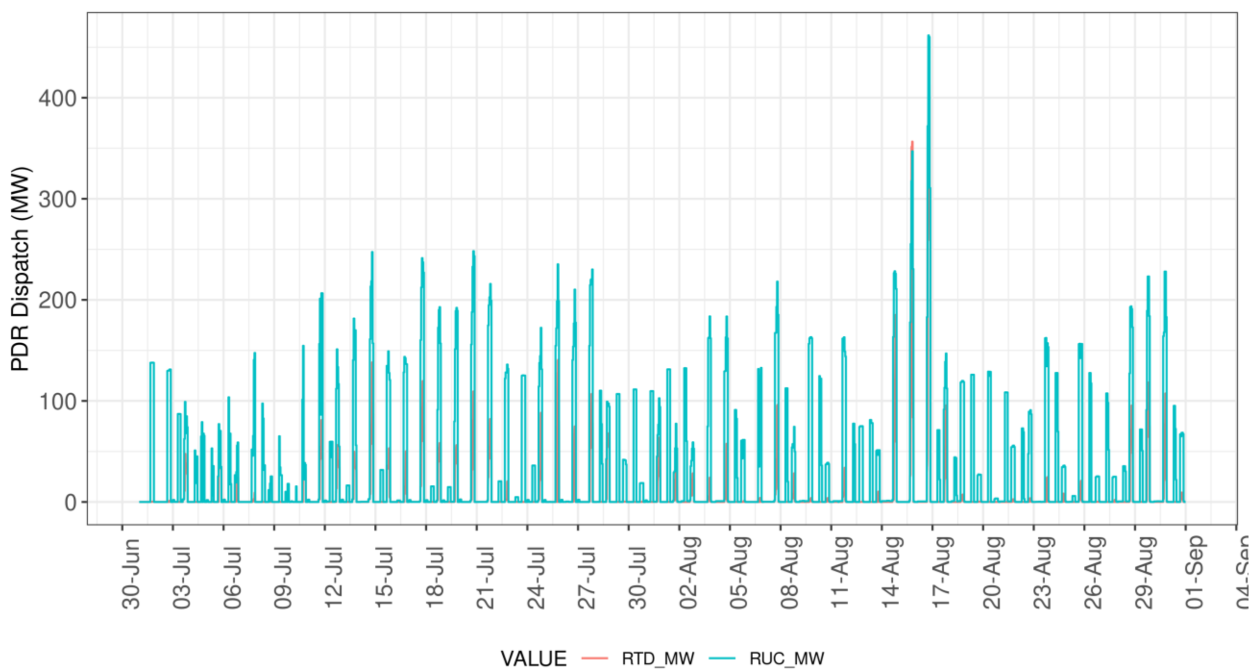
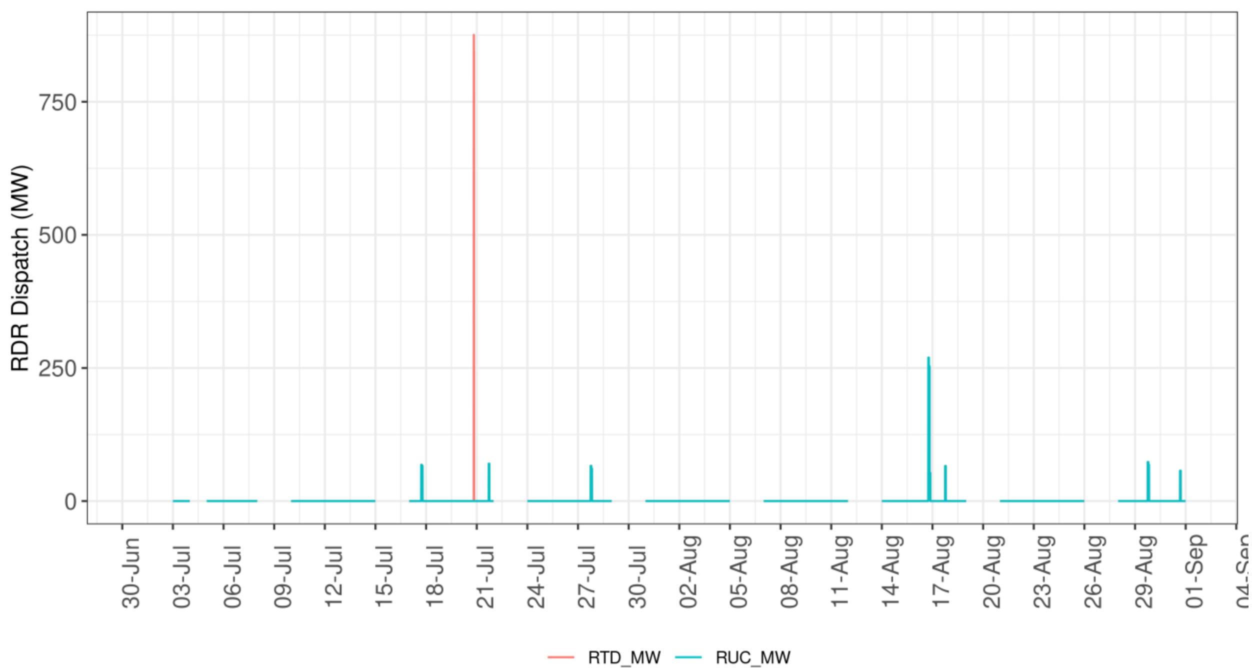


Figure 17 shows the dispatches for reliability demand response resources (RDRRs) in both the day-ahead and real-time markets for the month of July and August. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches 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 real time market on August 16 to about 270 MW for HE 19.

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



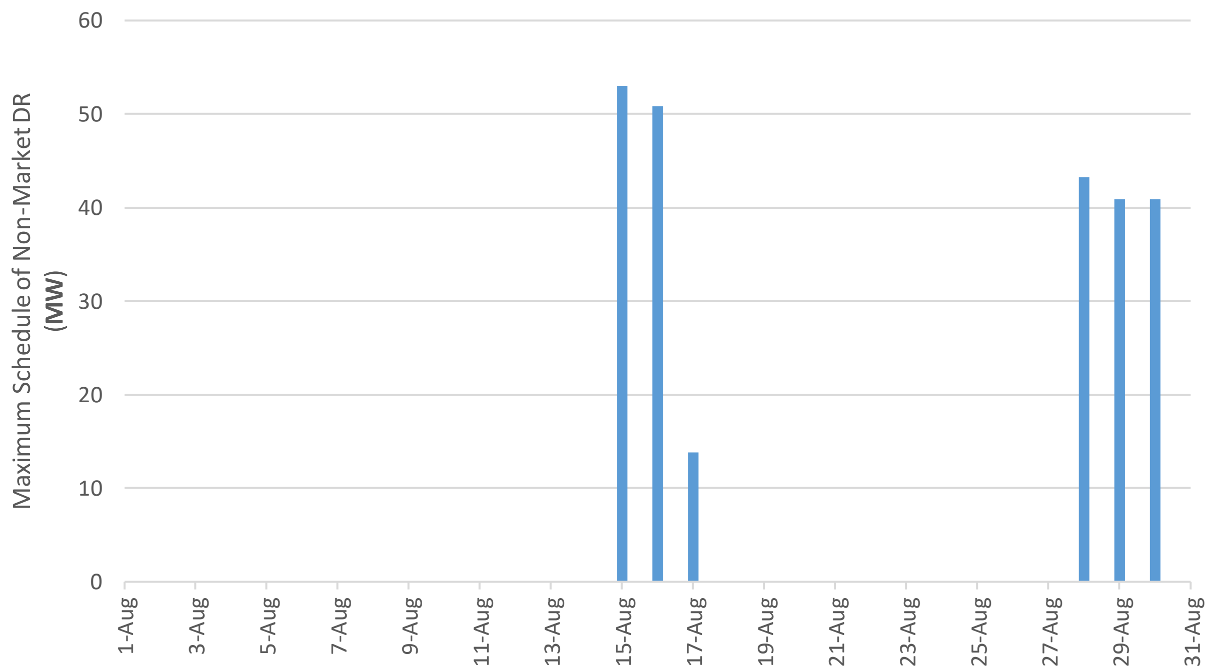
At the time this report was prepared, there were no estimates yet of the demand response performance. Estimates become available about three months after the trade date based on settlement data submitted by the scheduling coordinators and are used to measure the performance of demand response resources 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 be triggered 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 6 days in August 2023, with a maximum schedule of 53.0 MW occurring on August 15, 2023. Five of the six days when non-market DR was utilized scheduled resources between 40-53 MW. The remaining day scheduled approximately 14 MW of resources. There were no other scheduled non-market resource events in August 2023

Figure 18: Non-Market Demand Responses for August 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 August 2023 was 51,685 MW, which is higher than August 2022's monthly showing of 50,445 MW.[22] Figure 18 compares the total monthly RA capacity in August 2022 and August 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 2,097 MW and also increased by 228 MW for static imports. Hydro RA saw an increase of 729 MW and gas-fired RA saw an increase of 486 MW.

Static RA imports increased from 2,310 MW in August 2022 to 2,537 MW in August 2023.[23] The composition by intertie varied between years as shown in Figure 19. RA imports through Malin decreased by 5 MW between August 2022 and August 2023; imports through NOB increased by 63 MW across the same timeframe. Monthly RA capacity tends to increase as the summer progresses and was generally on

[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.

par with quantities from 2022. Monthly static RA imports also increase as the summer progresses, with more static imports in August 2023 than August 2022. These trends are shown in Figure 20 and Figure 21.

Figure 18: RA capacity organized by fuel type

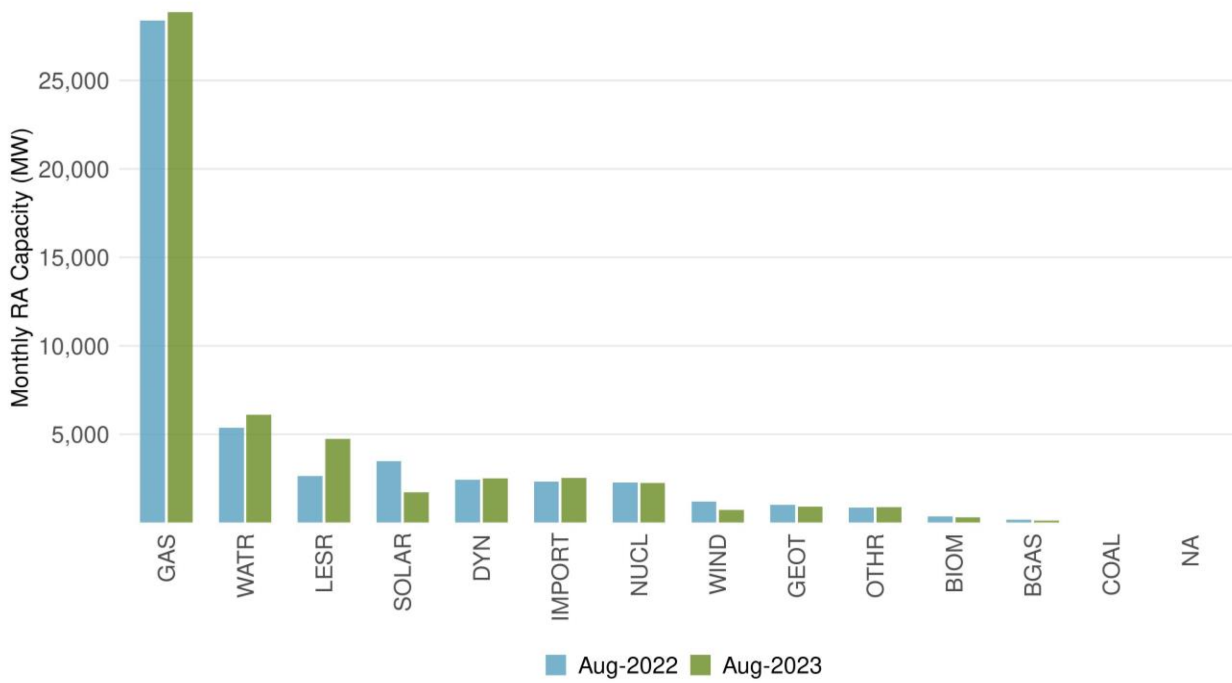


Figure 19: Monthly RA imports organized by tie

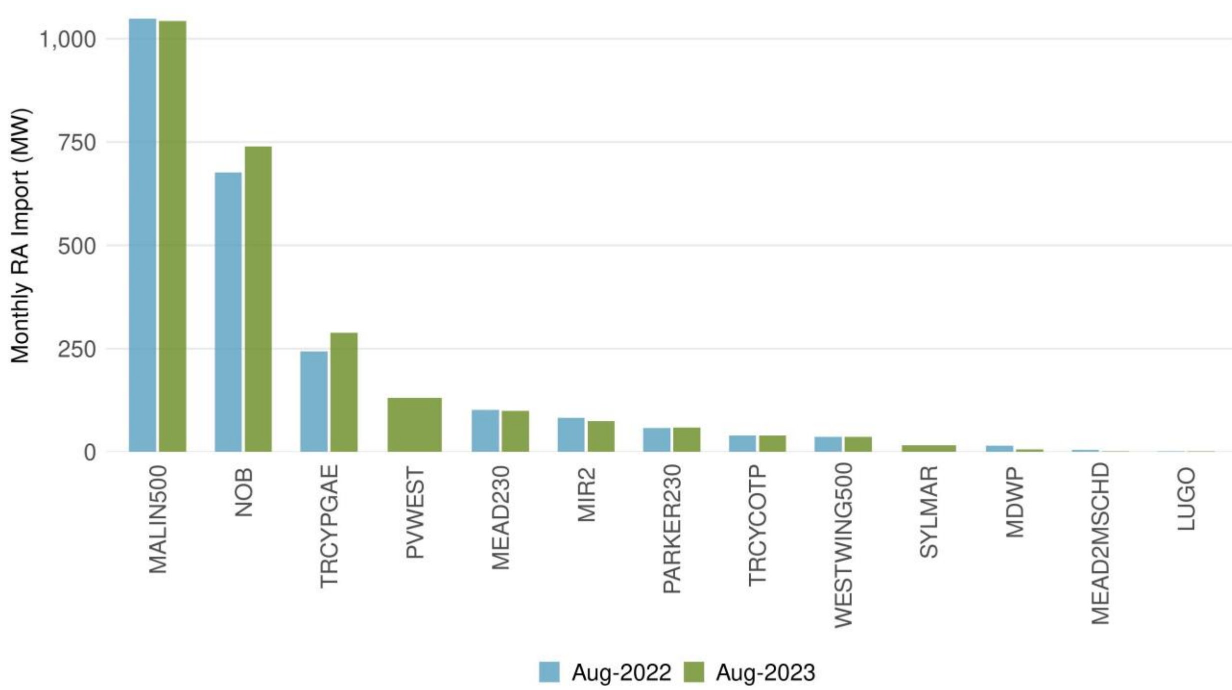


Figure 20: Monthly RA showings, two month trend

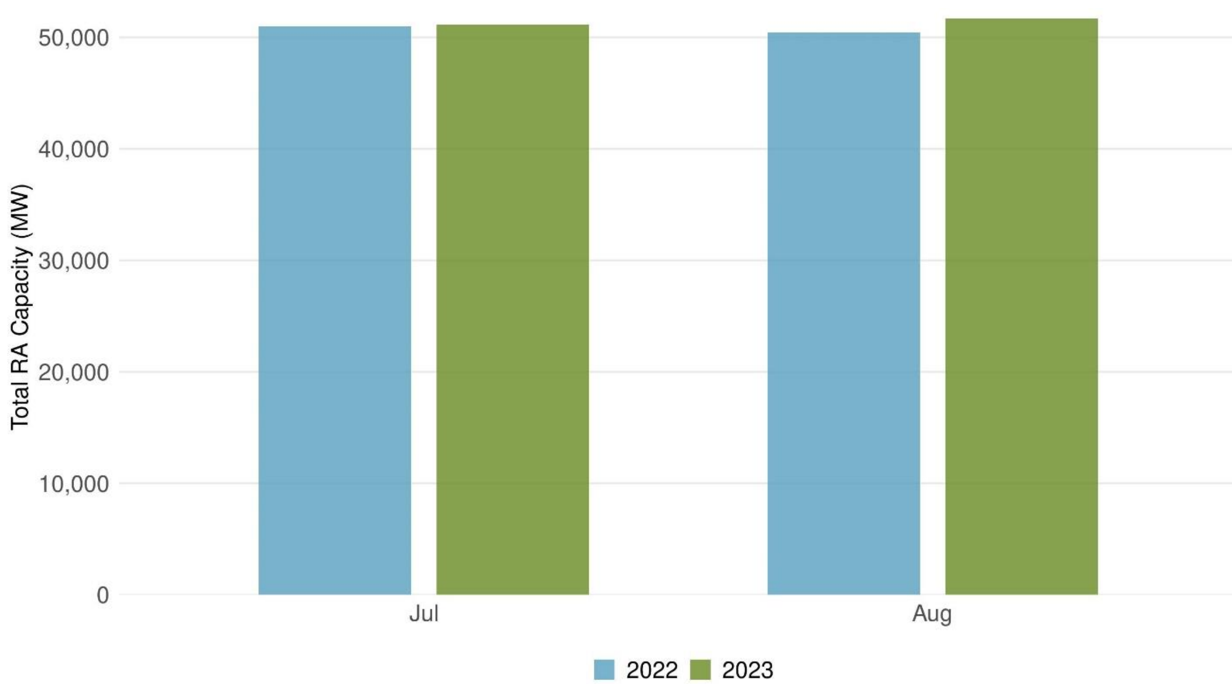
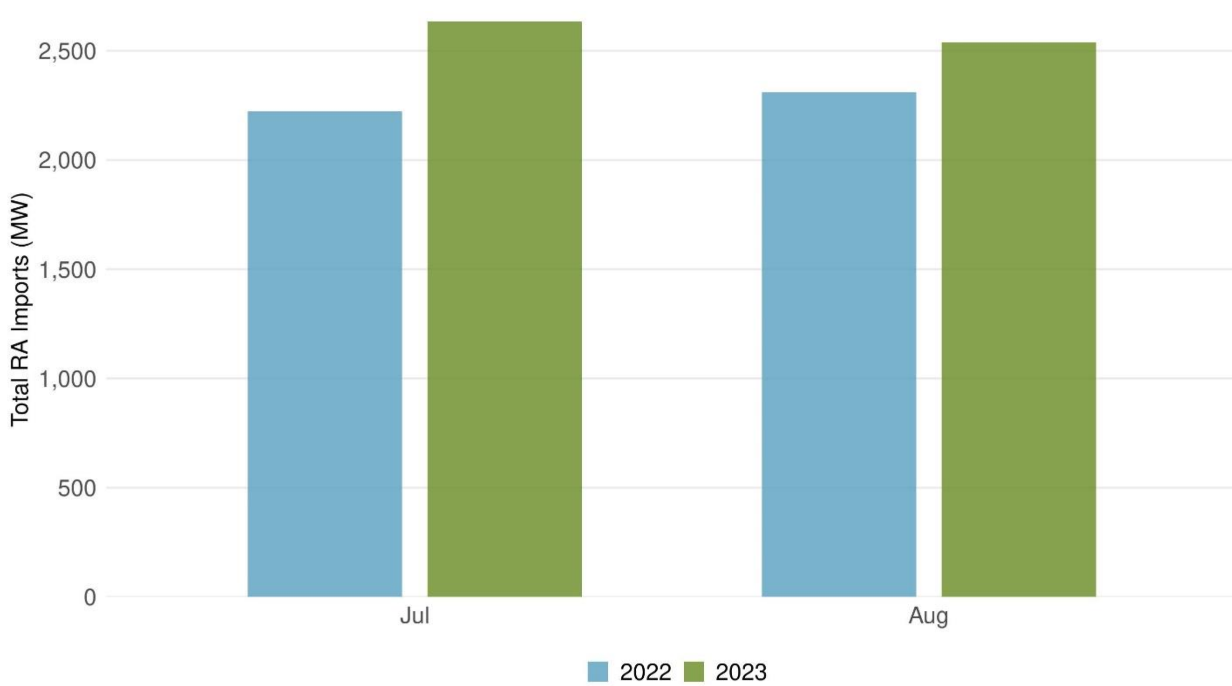


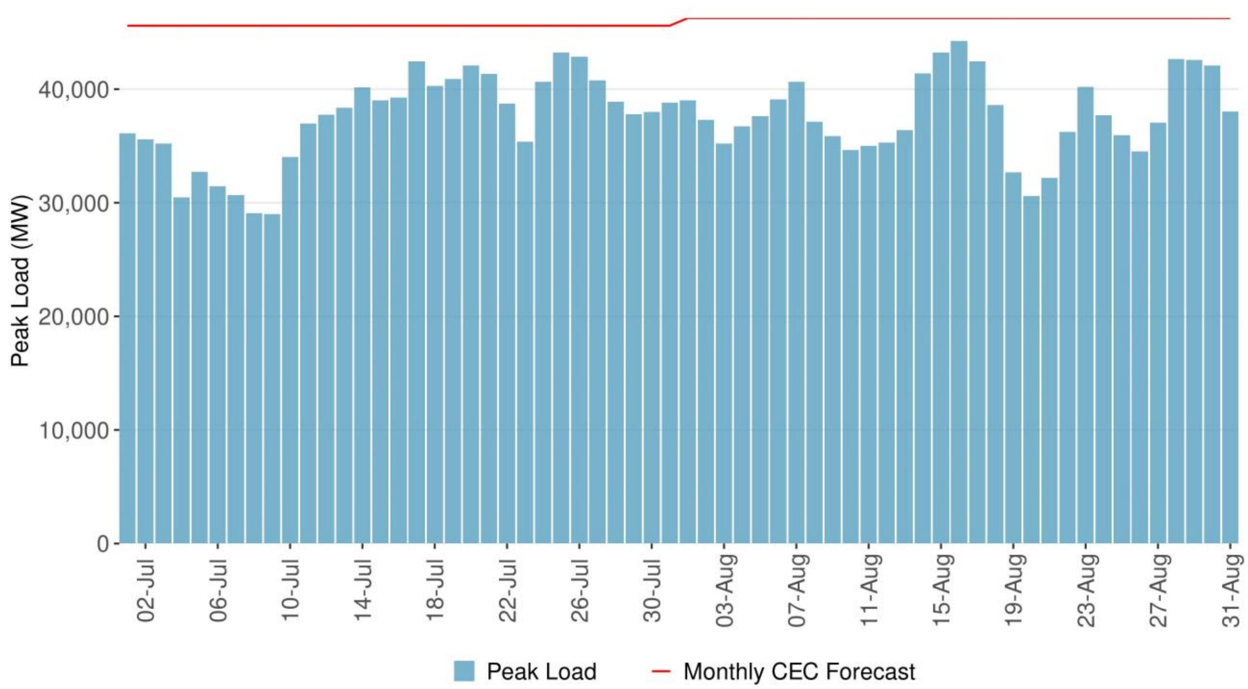
Figure 21: Monthly trend of static RA Imports, two month trend



4.2 Peak loads

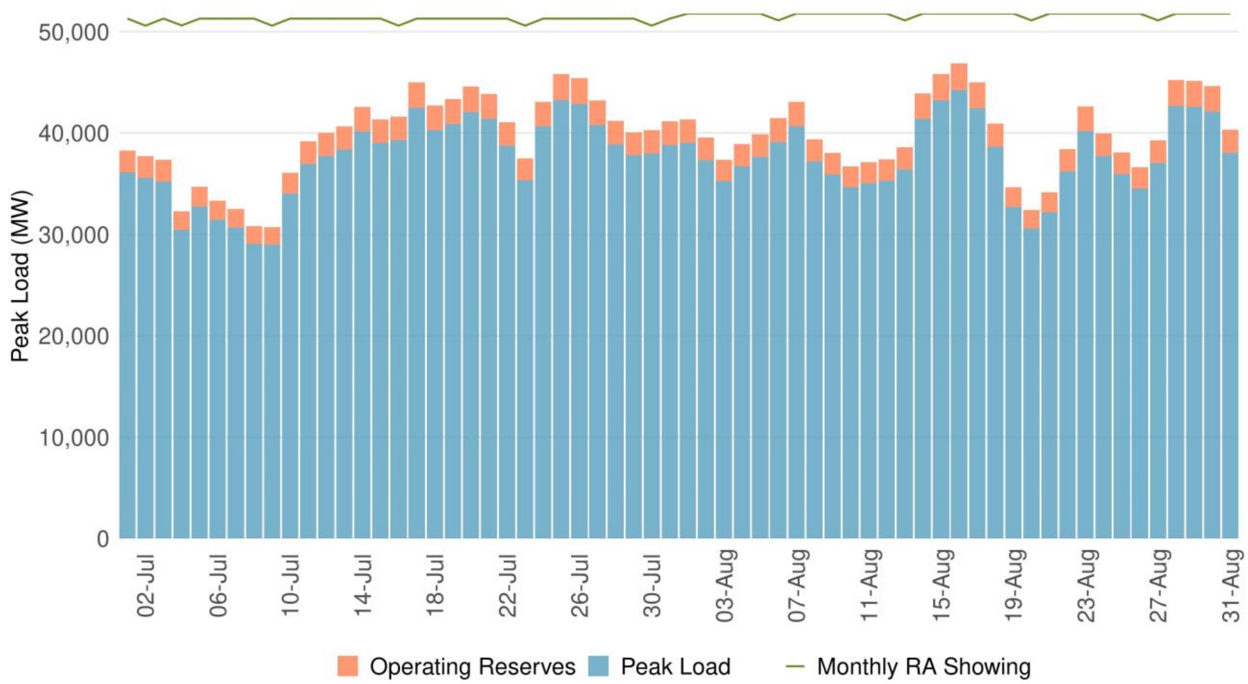
Peak loads in August 2023 were on par with levels from the previous month and at times exceeded 40,000 MW. The average daily peak load in August 2023 was 37,819 MW which was lower than the average daily peak load in August 2022 of 40,148 MW. Figure 22 shows the 5-minute average daily load for July and August relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The highest instantaneous load peak in August 2023 was 44,226 MW which occurred on August 16, and was below the CEC month-ahead forecast of 46,256 MW.

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



The actual load did not exceed the monthly RA showings for August 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. In subsequent sections, the actual RA capacity made available in the market is represented as a trend over for the month on an hourly basis, which more accurately represents RA capacity available to meet demand.

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



4.3 Market prices

Market prices naturally 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 July and August 2023.

[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 24: Average daily prices across markets

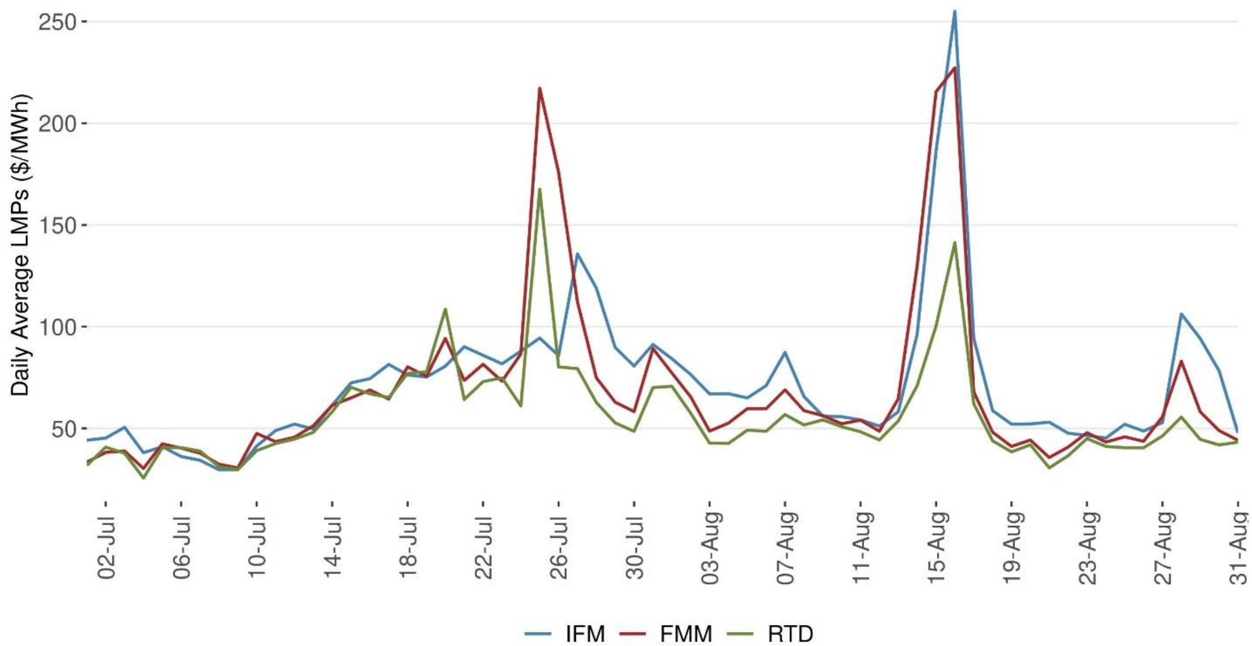


Figure 25: Average hourly prices across markets

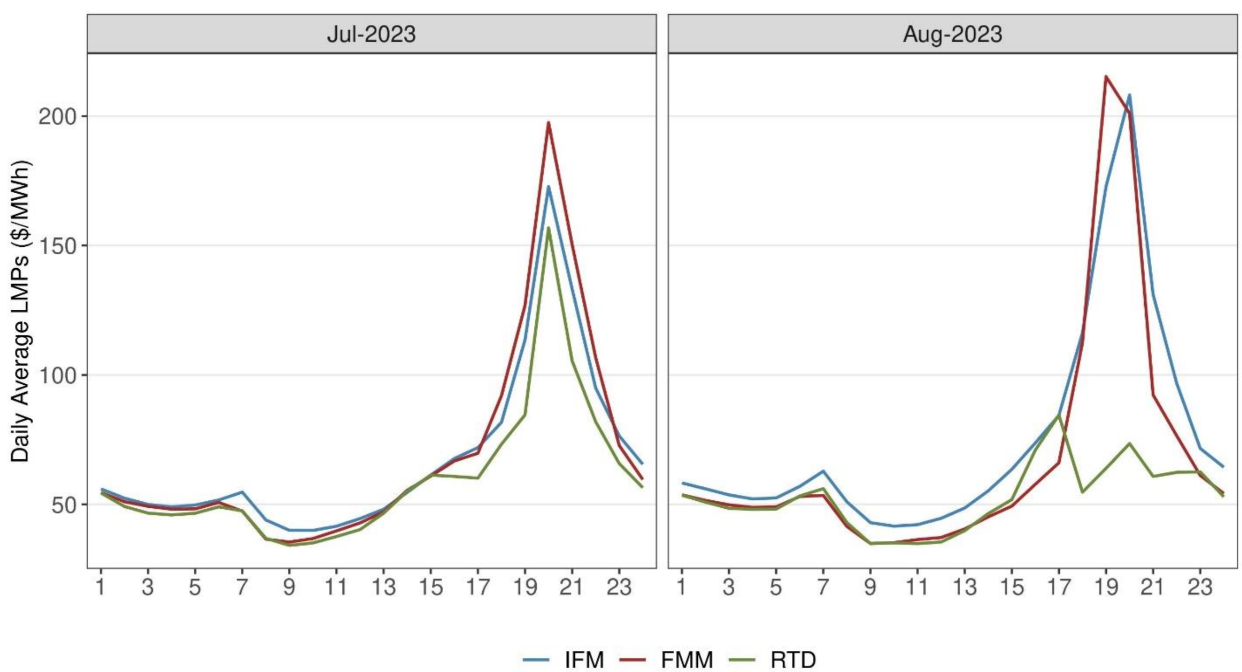


Figure 26 and Figure 27 show the daily and hourly distribution of day-ahead prices with box-whisker plots. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for the day or hour. These plots better illustrate the full distribution of prices observed throughout the days and hours of the month. The average day-ahead LMP in August 2023 was $75.04/MWh and the maximum LMP of $1,288.81/MWh occurred on August 16, 2023.

Figure 26: Daily distribution of IFM prices

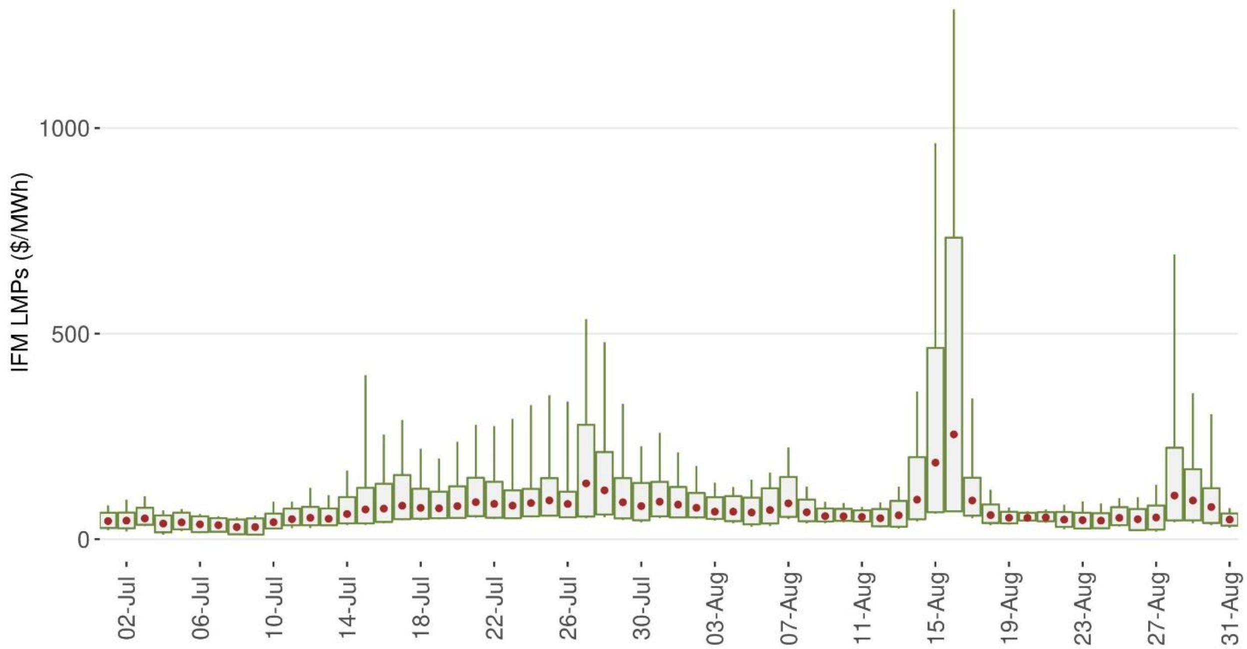


Figure 27: Hourly distribution of IFM prices

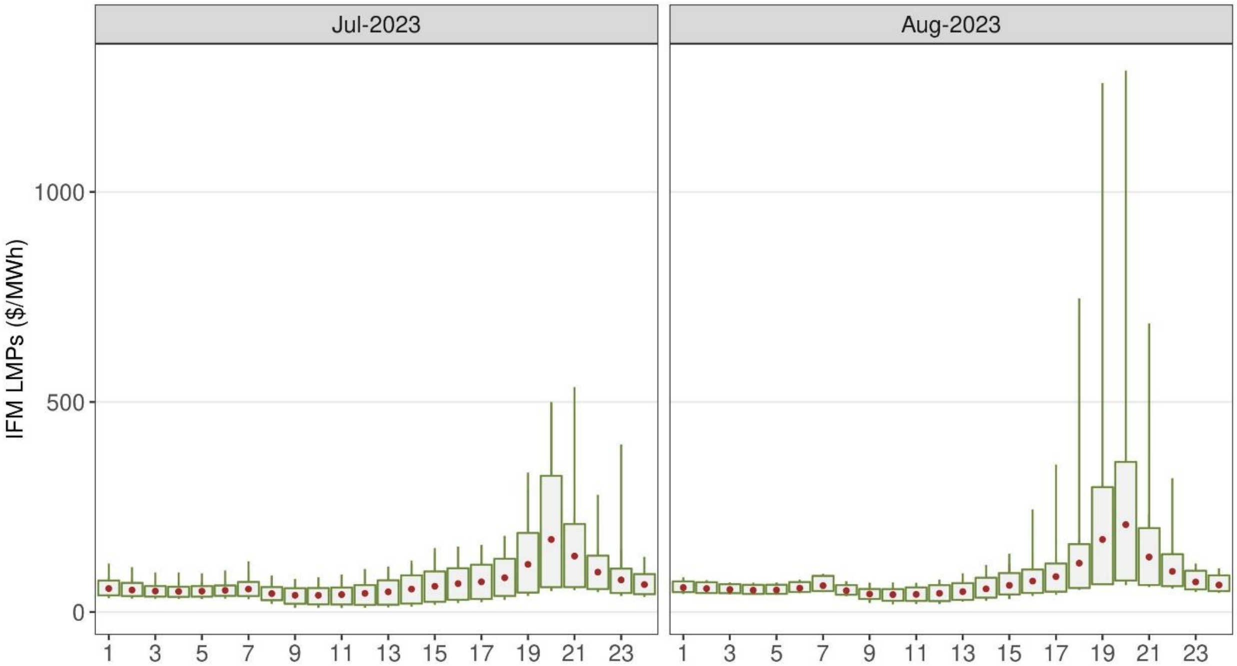


Figure 28 and Figure 29 show daily and hourly distributions of fifteen-minute market (FMM) prices throughout the month. The average FMM LMP in August 2023 was $67.35/MWh and the maximum LMP of $2,000/MWh occurred on August 16, 2023. Similar to July, the August 2023 FMM prices exhibited a larger spread than corresponding IFM prices, in part due to the events that unfolded until the real-time market.

Figure 28: Daily distribution of FMM prices

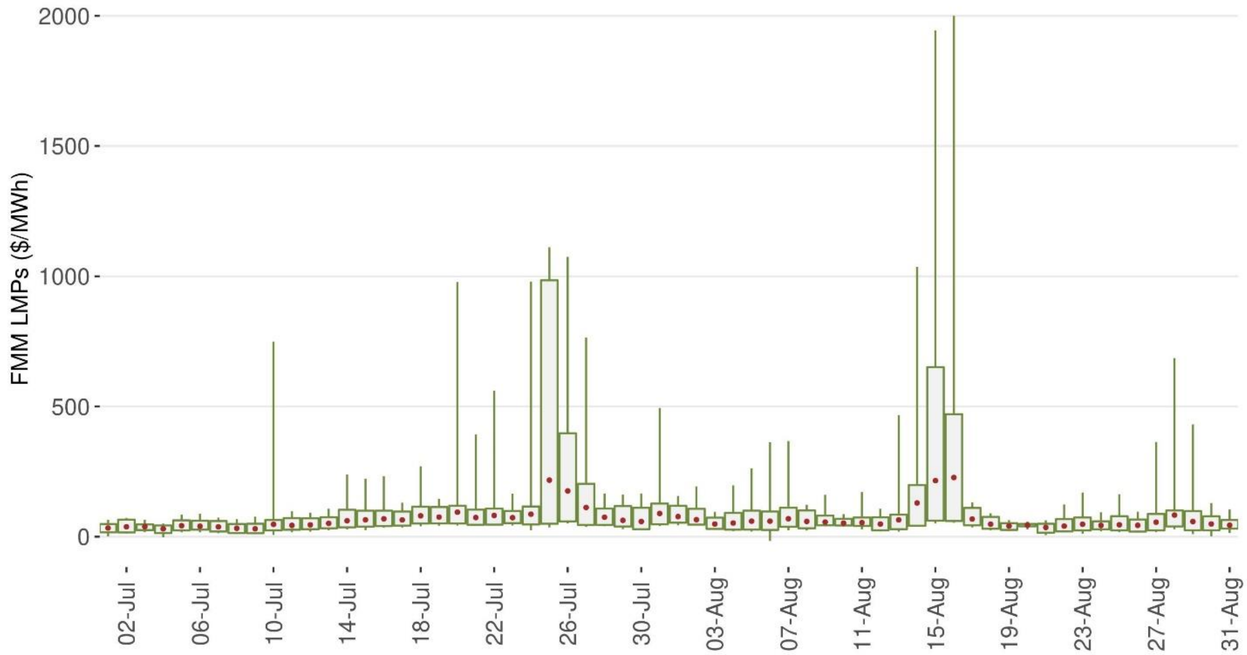
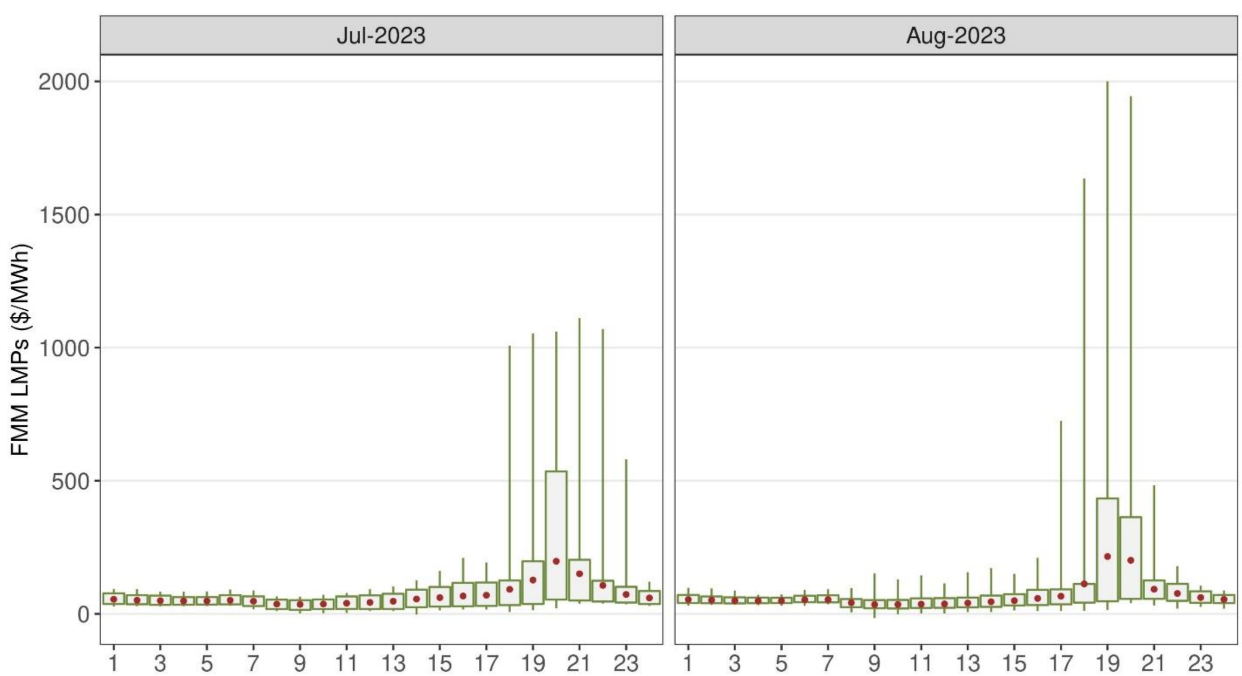


Figure 29: Hourly distribution of FMM prices



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 August 2023, next-day gas prices averaged $5.19/MMBtu and $6.14/MMBtu for PG&E Citygate and SoCal Citygate, respectively. The maximum next-day gas prices were $6.28/MMBtu and $10.11/MMBtu for PG&E Citygate and SoCal Citygate, respectively.

Figure 30: Gas prices at the two main California hubs

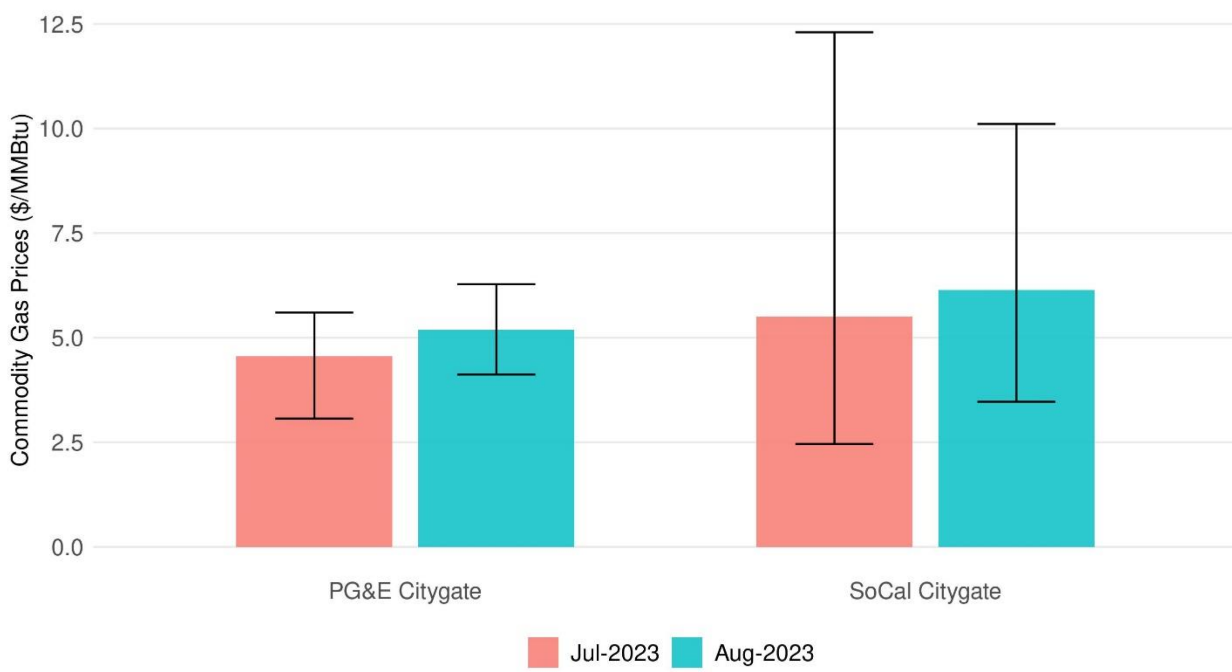


Figure 31 shows daily average electricity prices from the ISO day-ahead market (y-axis) relative to next-day gas prices at SoCal Citygate (x-axis) and the peak load (color gradient from blue to red) for each day in July and August 2023. The dashed red line shows a simple linear regression applied to 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

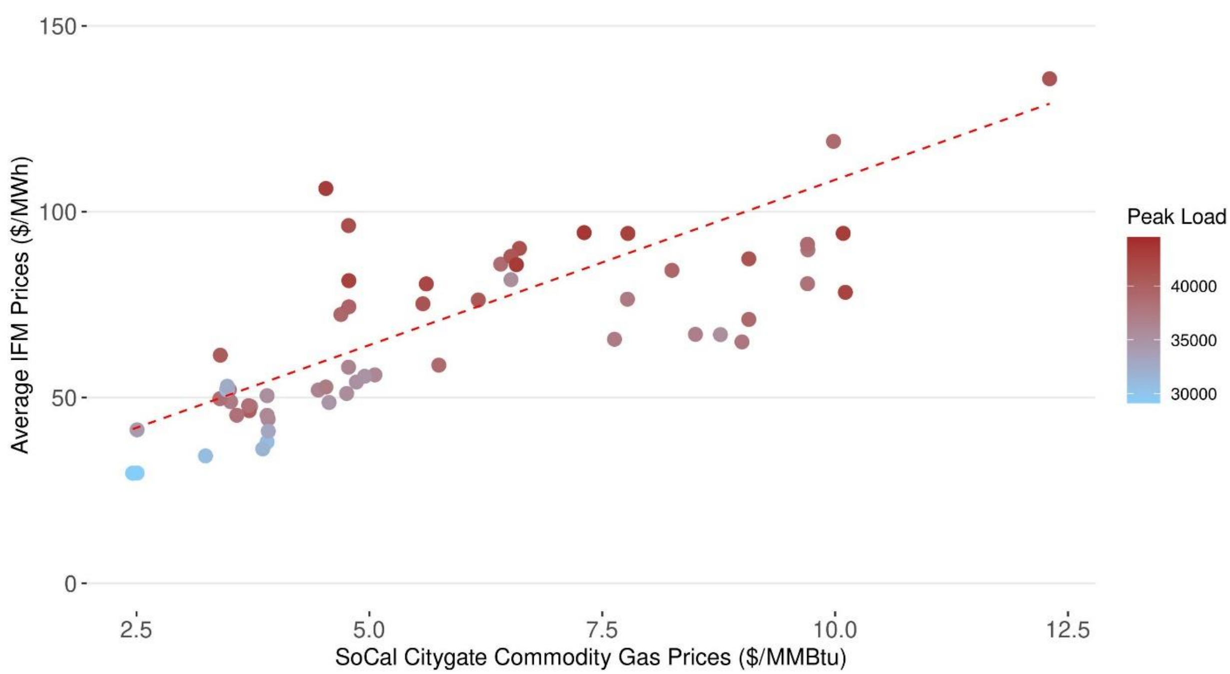
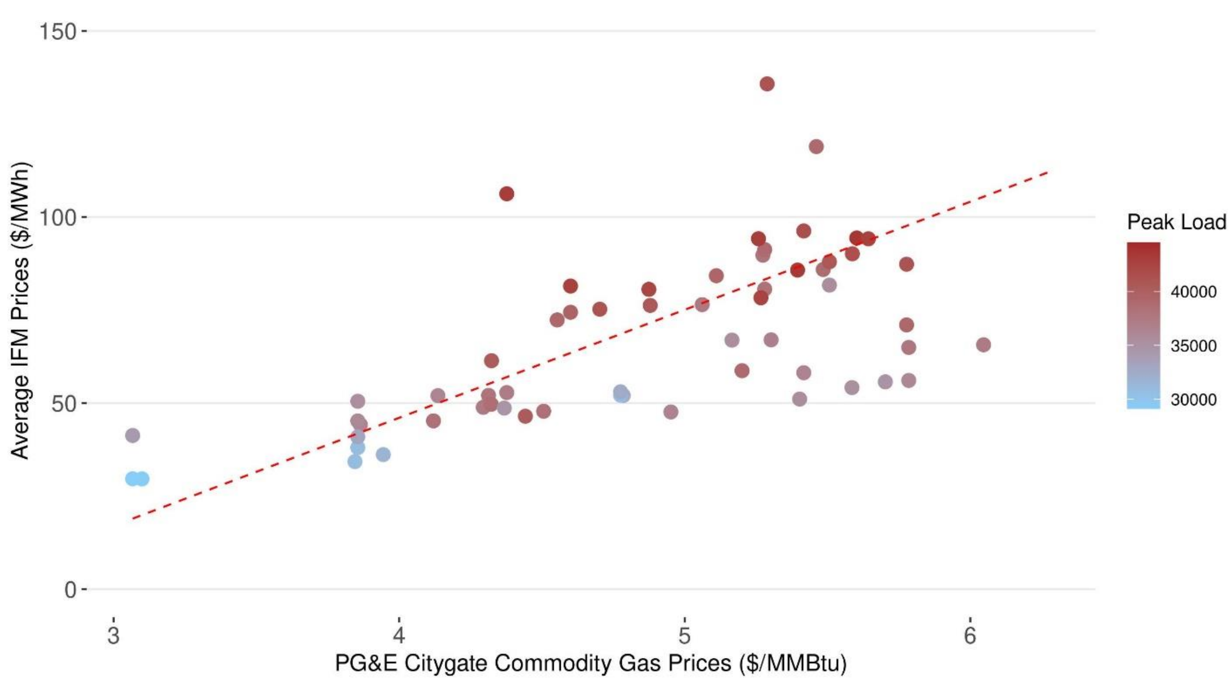


Figure 32: Correlation between electricity prices, PG&E Citygate gas prices and peak load level



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 generally traded lower than the highest hourly IFM LMP for the corresponding trading day in August. However, due to the block nature of the bilateral power prices, 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. In mid-August, the SCE IFM LMPs spike to exceed on-peak bilateral prices and were generally elevated above the bilateral prices throughout August. 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. This divergence is particularly noticeable in mid-August when bilateral prices in both regions traded around $1,000/MWh.

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

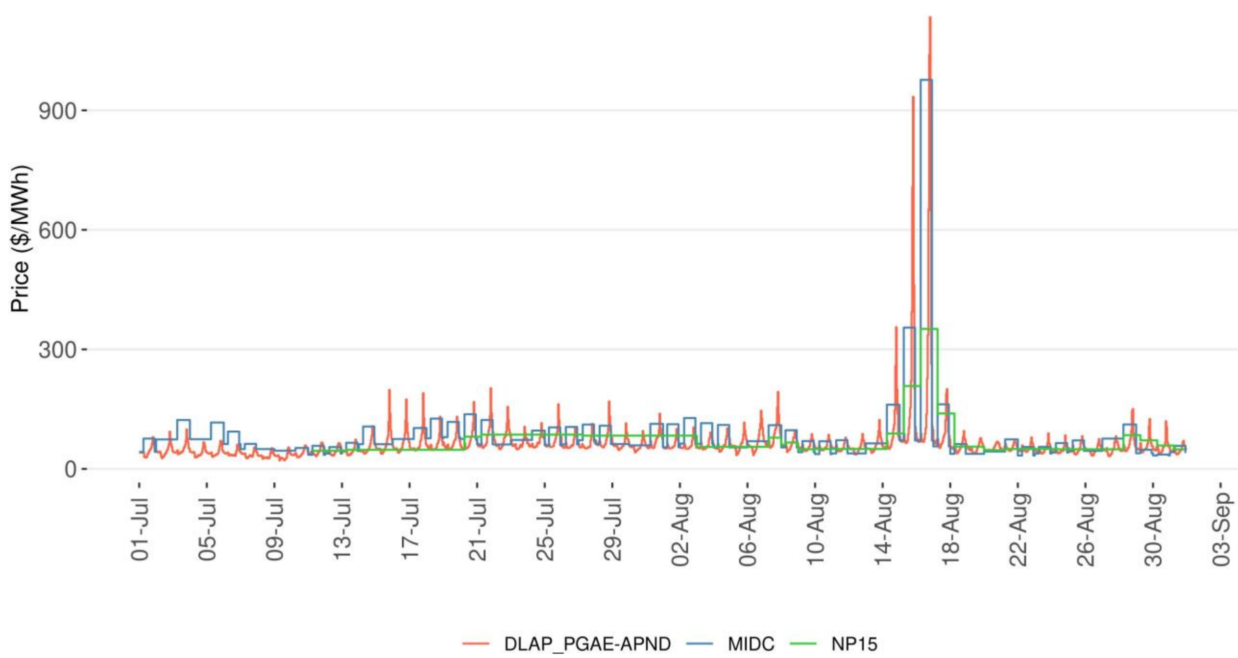


Figure 34: SCE IFM LMP compared to bilateral southern prices

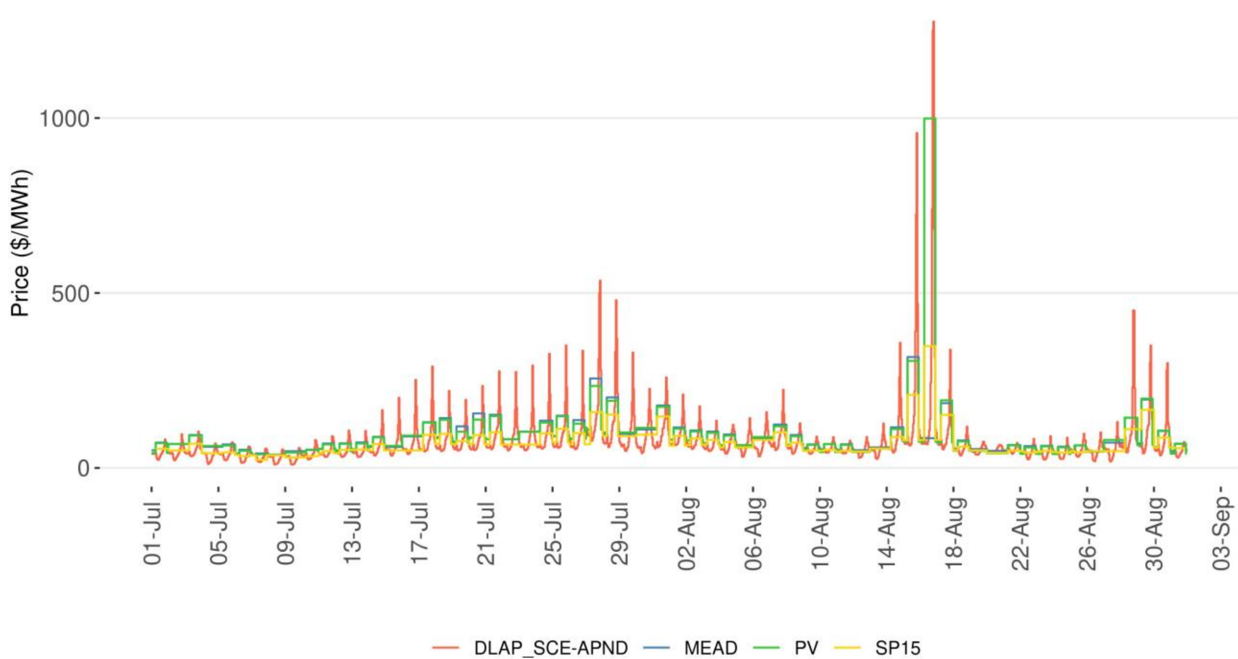


Figure 35: Northern hub prices and PG&E IFM LMP (block average)

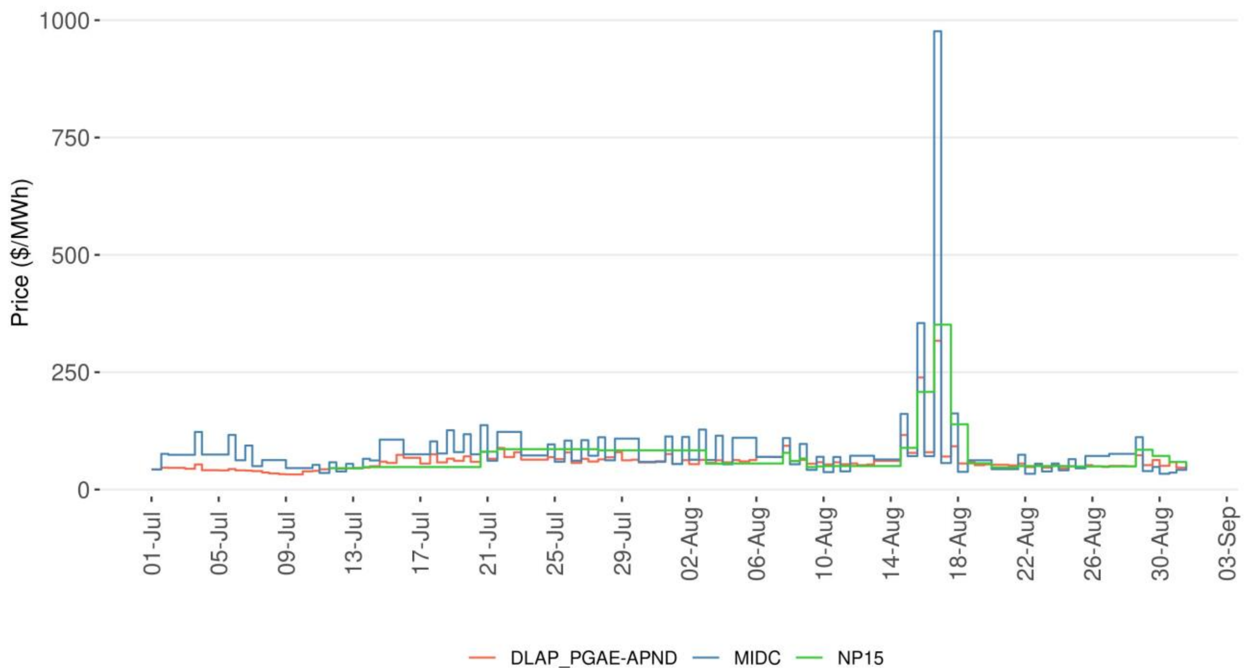


Figure 36: Southern hub prices and SCE IFM LMP (block average)

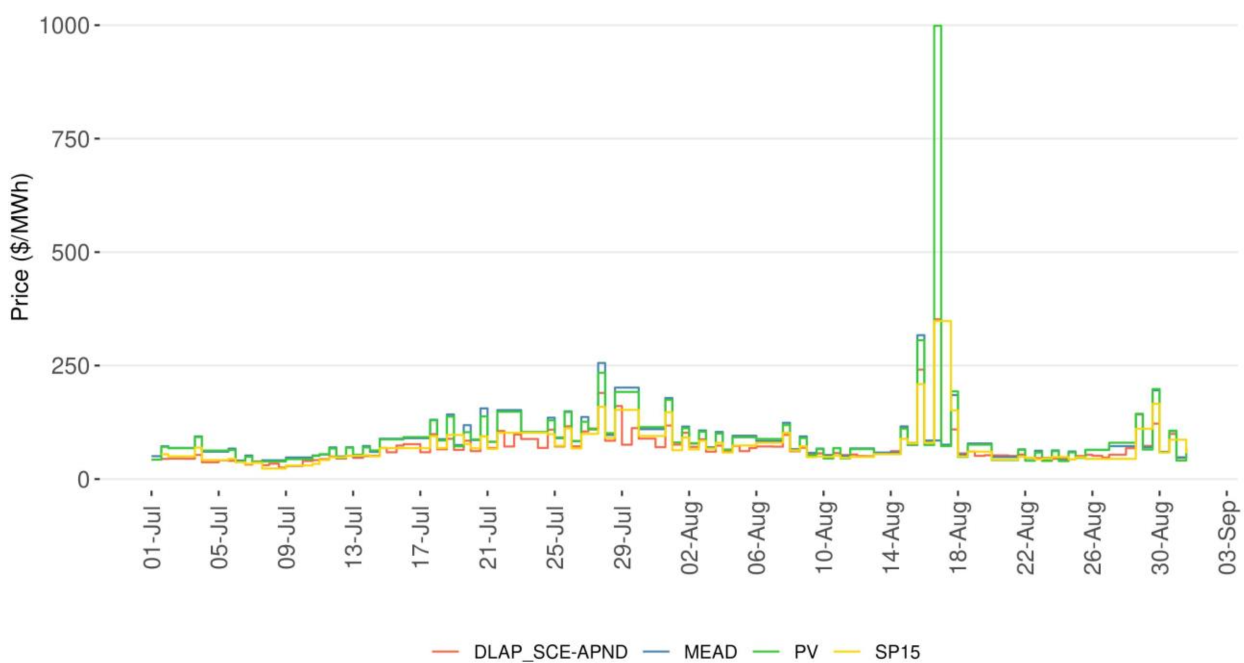
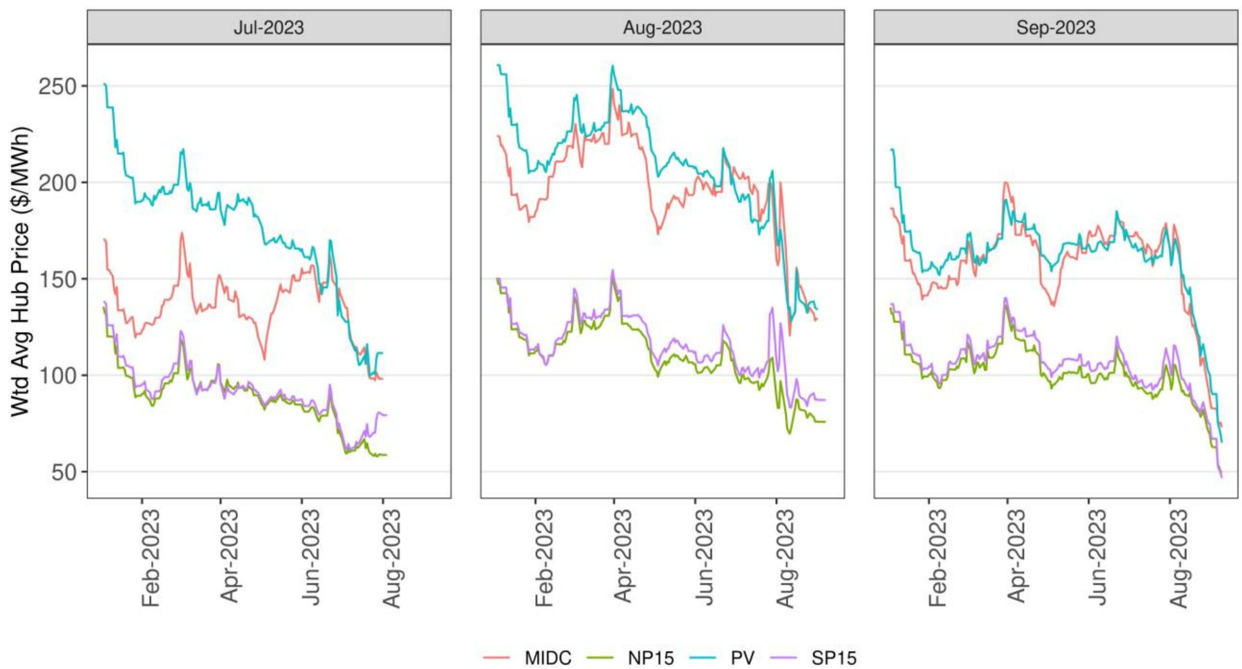


Figure 37 shows a year-to-date trend of on-peak future power prices traded for the 2023 summer months of July, August and September. Price trends are captured for Mid-C and PV, as well as the NP15 and SP15 options that trade bilaterally. On-peak future prices have traded dynamically for summer months, spiking in early January 2023 following the December gas price volatility and declining in recent months, particularly for September 2023 futures. Price separation can be observed between the two groups of hubs, with Mid-C and PV generally trading higher than SP15 and NP15.

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 for above RA capacity to 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 supply is 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 potential 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 accordingly relative to its monthly RA value. For any wind or solar resource that has any RA capacity assigned in the month, the entire supply available in the market from that resource is considered RA. For instance, if a solar or wind resource has a supply available in the 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 or 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 shows the adjusted

[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.

load forecast, plus OR, plus high-priority export self-schedules. It represents the overall need to be met in the day-ahead market.

Figure 39 has similar convention for the same capacity breakdown, but the comparison is relative to the net load (gross load minus VER forecast). Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

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

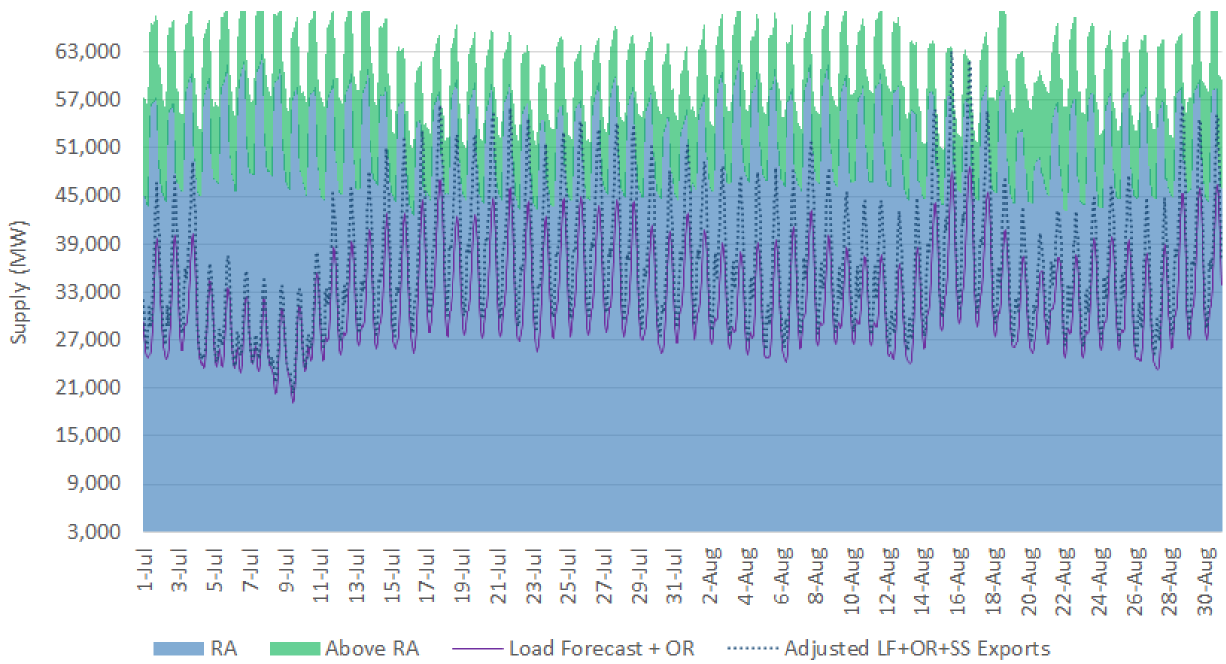
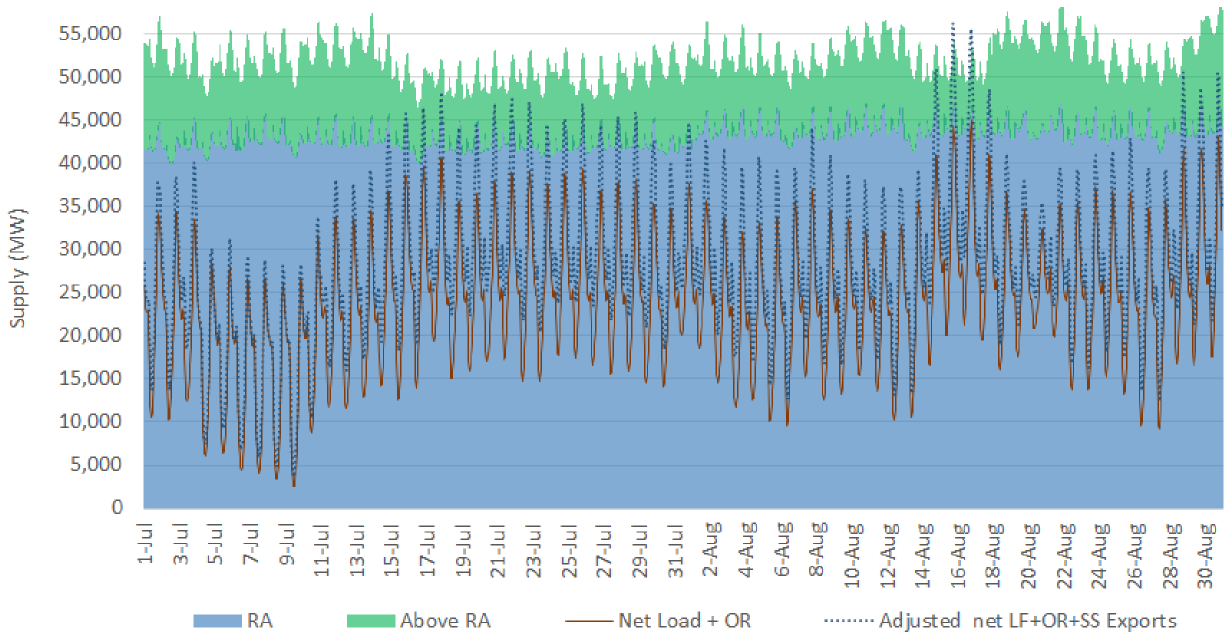


Figure 39: Supply capacity available relative to net load forecast in the day-ahead market



In August, both the gross load and the net load peaked on August 16 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 August, above-RA capacity was consistently available into the market. The supply available in the market was sufficient to cover the load forecast, and also the load forecast plus the RUC adjustments.

Figure 40 Day-ahead supply capacity available and load forecast for Aug 15 - 17

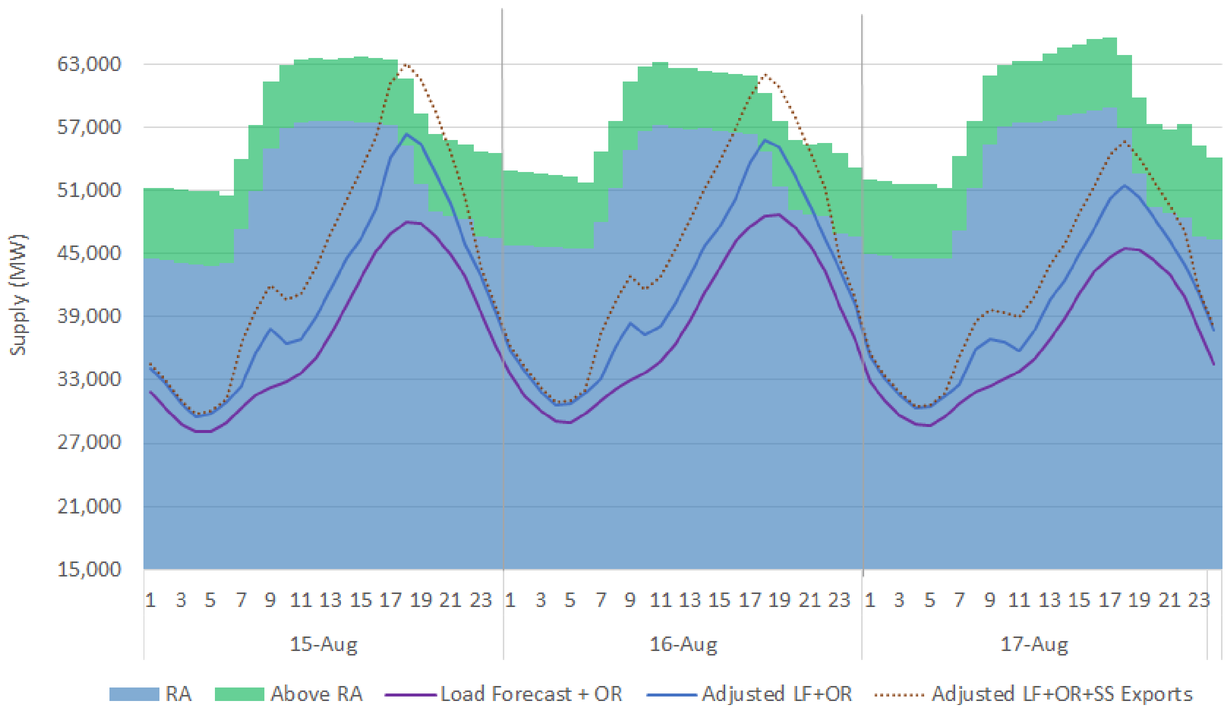
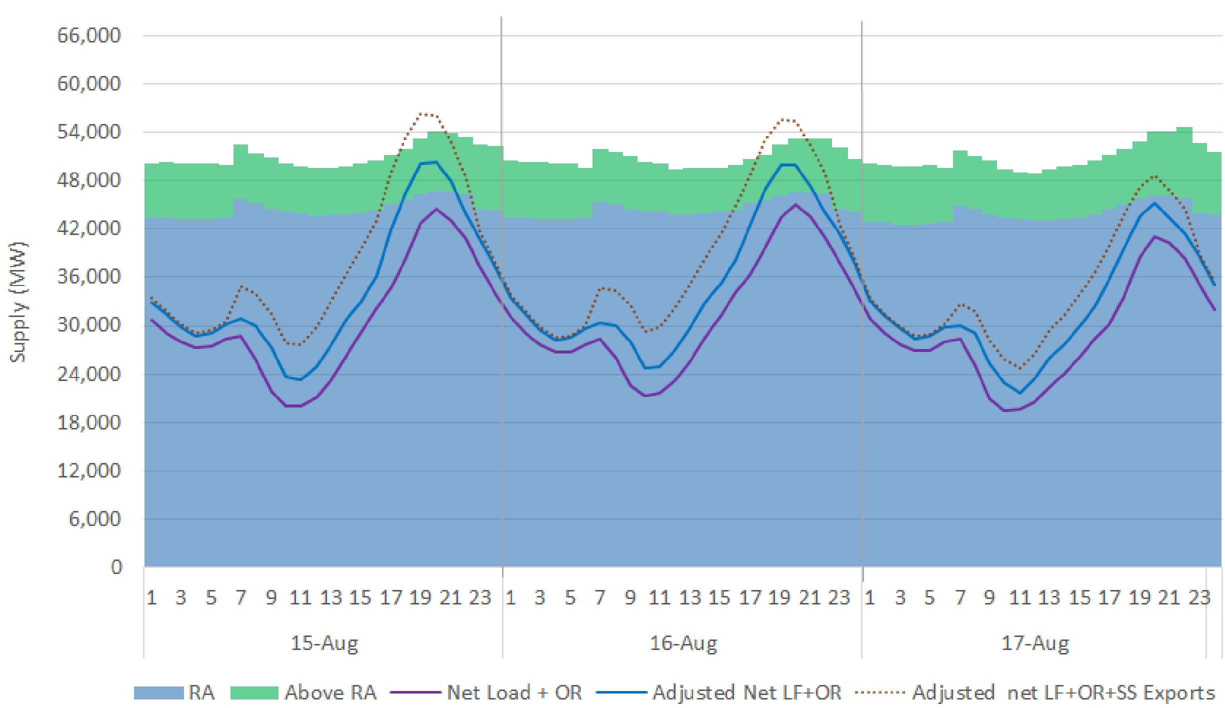


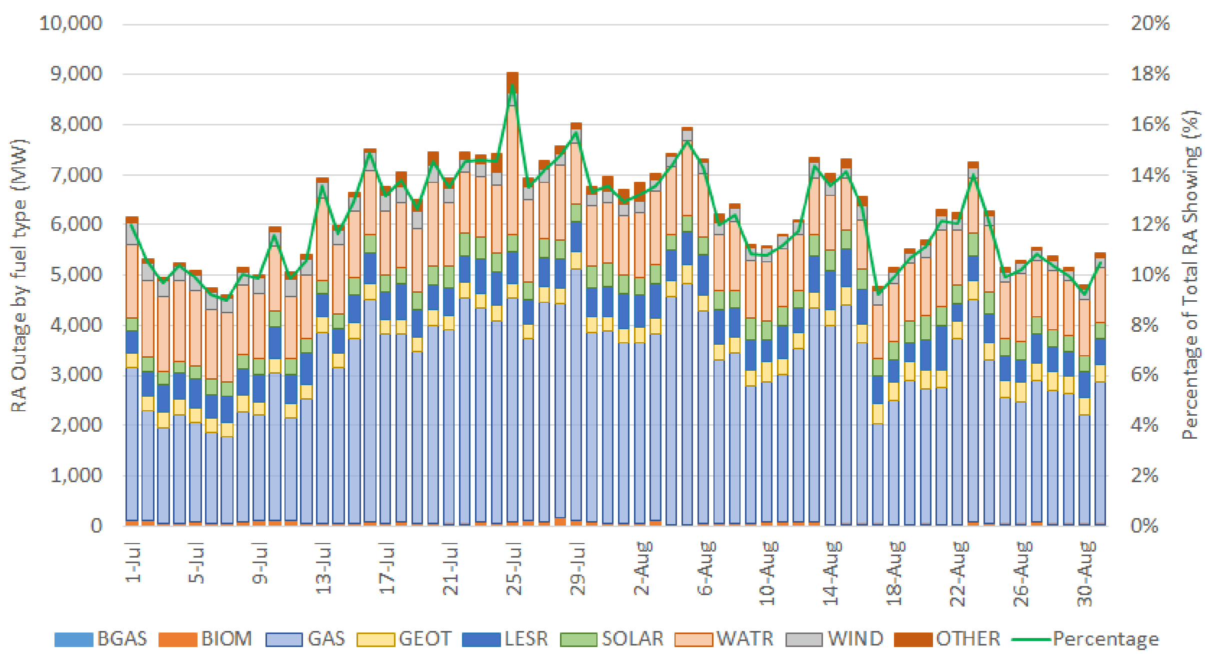
Figure 41 Day-ahead supply capacity available and net load forecast for August 15 - 17



5.2 Unavailable RA capacity

Generating units can face operating conditions that require them to be derated or to be offline. The ISO tracks these outages through the outage system and the outages are reflected in the resource capacity made available in the market. The market considers the outages and derates to impose these limitations on the units, making them unavailable or derating their capacity accordingly. Some outages may be planned while others may be forced. Figure 42 provides the trend of RA capacity by fuel type on outage during the month of July and August. It shows that the capacity on outage decreased over the month. On average, the average daily capacity on outage is about 6165 MW.

Figure 42: Volume of RA capacity by fuel type on outage in July and August



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. This 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 43 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 forecasts varied through the month with relatively mild levels, with the exception of the spike observed on August 16. Since RUC adjustments were used consistently, the adjusted load forecast used in the RUC process followed similar trend, spiking on August 16.

Figure 43: Day-ahead demand trend in July and August 2023

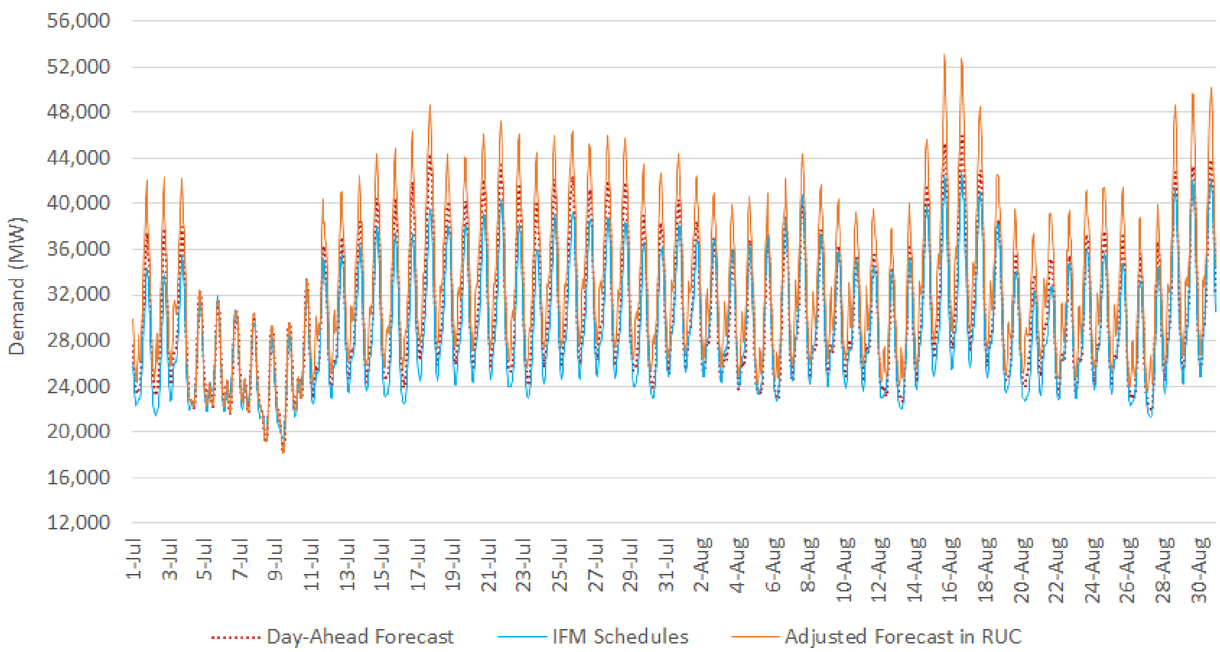
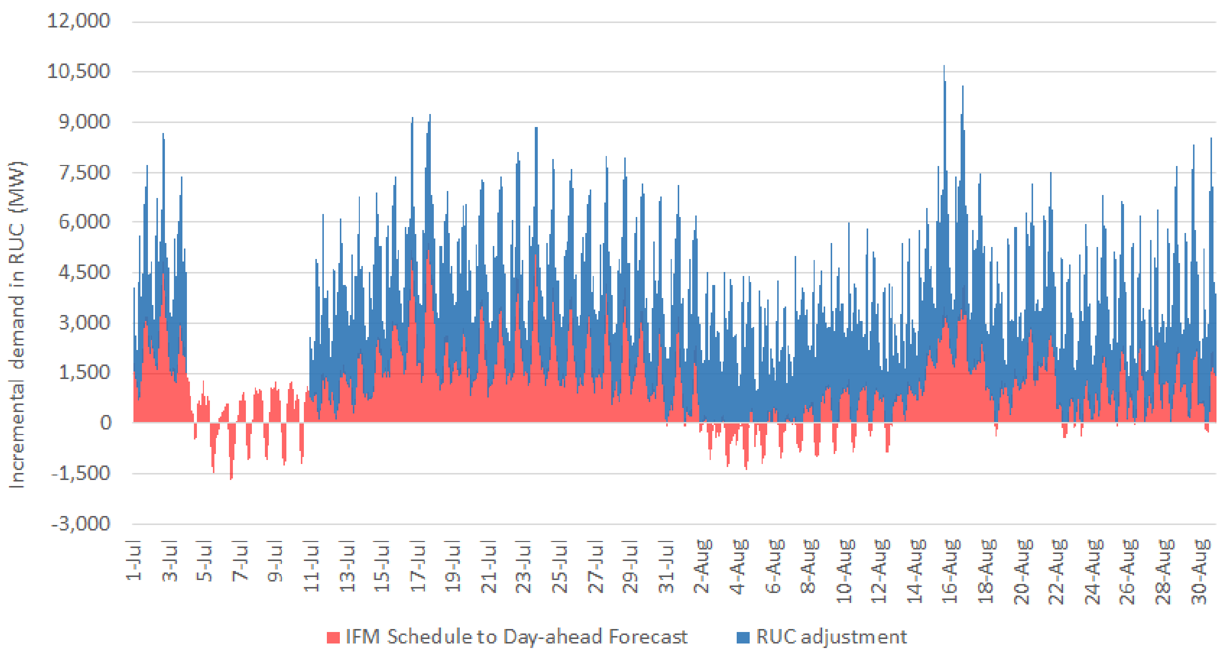


Figure 37 shows the differences between the IFM schedules for physical resources versus the nominal day-ahead load forecast. This is the additional capacity relative to the IFM solution that RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus 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 44: Incremental demand required in RUC in July and August 2023



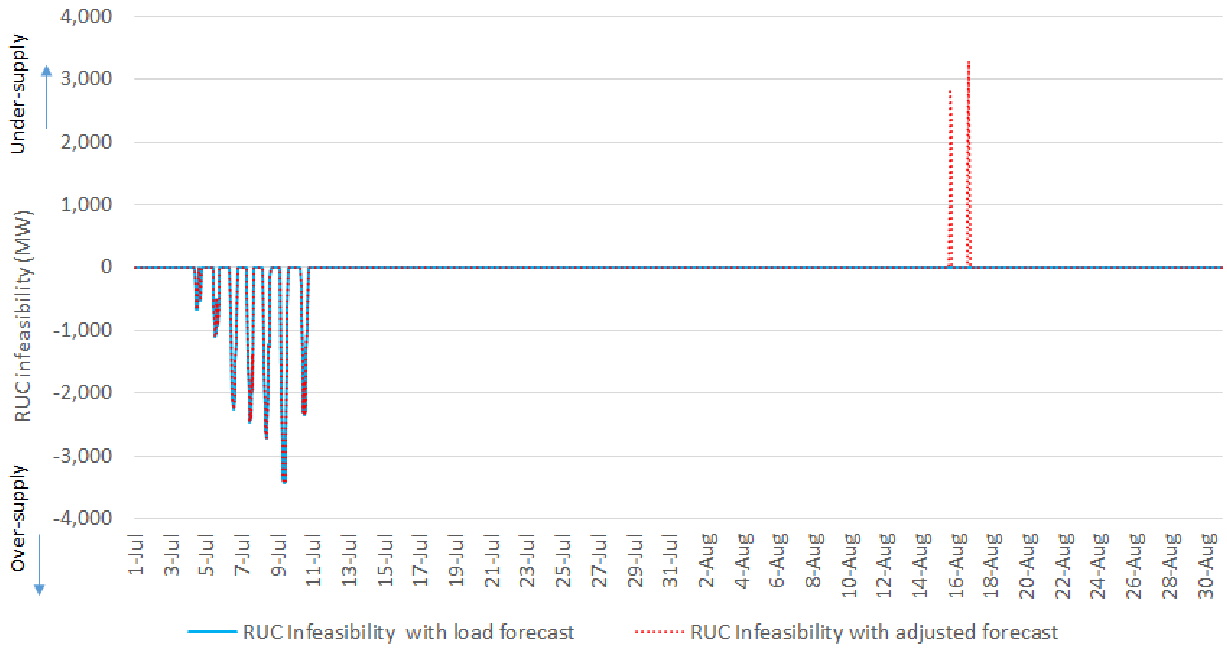
The RUC forecast adjustment is guided by historical uncertainty of load, wind and solar from the day-ahead to the real time market. In some cases, there may be other factors to consider by operators to determine the final adjustments. There were RUC adjustments for several days for the month of July and August. 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 as 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

[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

constraint to be relaxed and reducing PTK (high priority) exports to allow RUC to clear. Figure 45 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 was RUC under-supply infeasibilities for August 16-17. There were over-supply infeasibilities for few days for the month of July.

Figure 45: RUC infeasibilities in July and August 2023



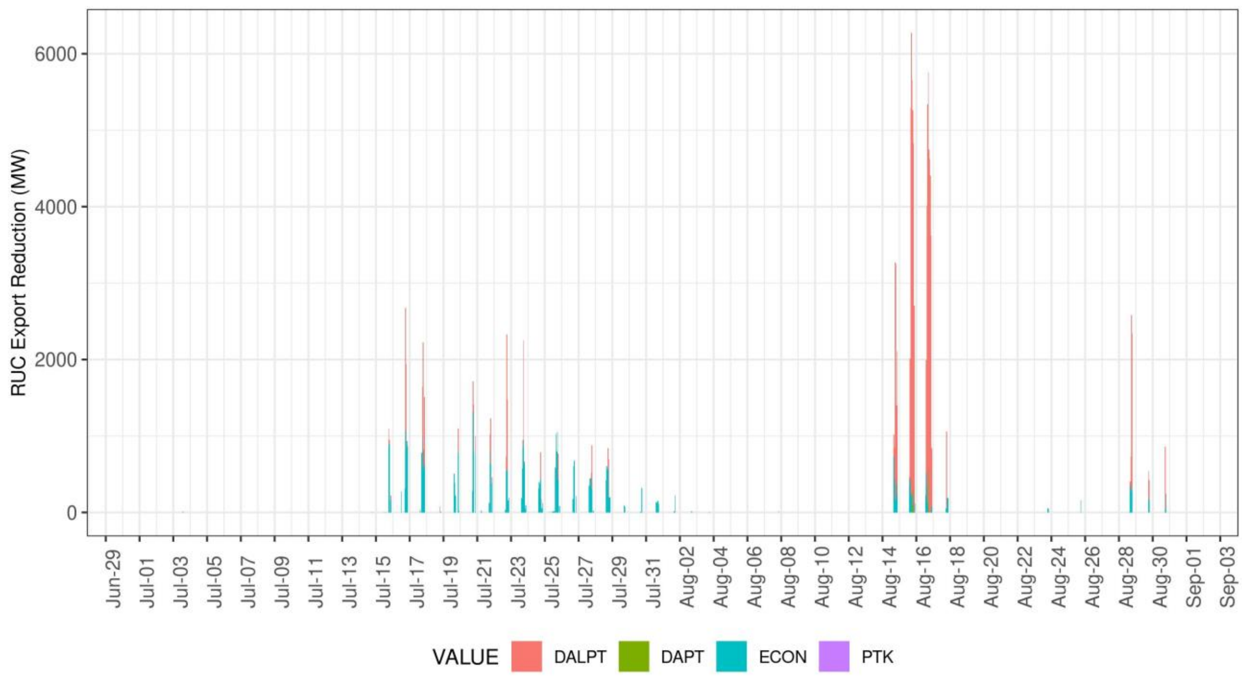
In addition to relaxing the power balance constraint, the RUC process utilized other scheduling priorities to enforce the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and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

Figure 46: shows the volume of hourly export reduction in the RUC process, which happened only for economic exports and low priority exports across the month.

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.

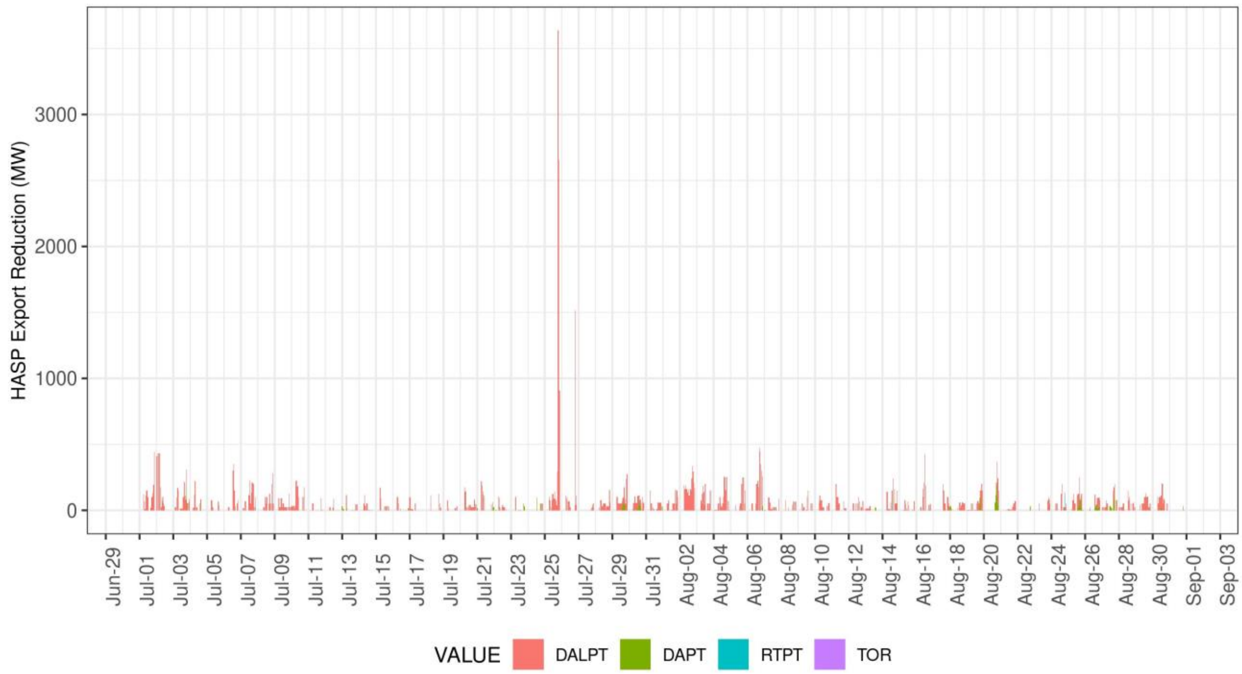
[28] Under the current setup of scheduling priorities, PT exports and the RUC power balance constraint have the same priority reflected with the same penalty price utilized in the market optimization. What level of reductions relative to the level of power balance relaxation is achieved will depend on 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 46: Exports reduction in RUC



Exports can still participate in the real-time market by rebidding relative to the DAM solution, or directly into the 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 market. 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, which is higher than the low-priority exports. In the chart below, the real-time market issued significant reductions during July 25 and July 26 mainly for low priority exports and economical exports.

Figure 47: 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 Palo Verde and Mead from the Southwest. 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 exports to define wheels. 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 transactions will always clear at the same level. Because wheel transactions must be balanced, they 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 resources. Participants with such entitlements can submit intertie self-schedules using transmission ownership rights (TORs) or Existing Transmission Contracts (ETCs), as well as PTK and LPT.

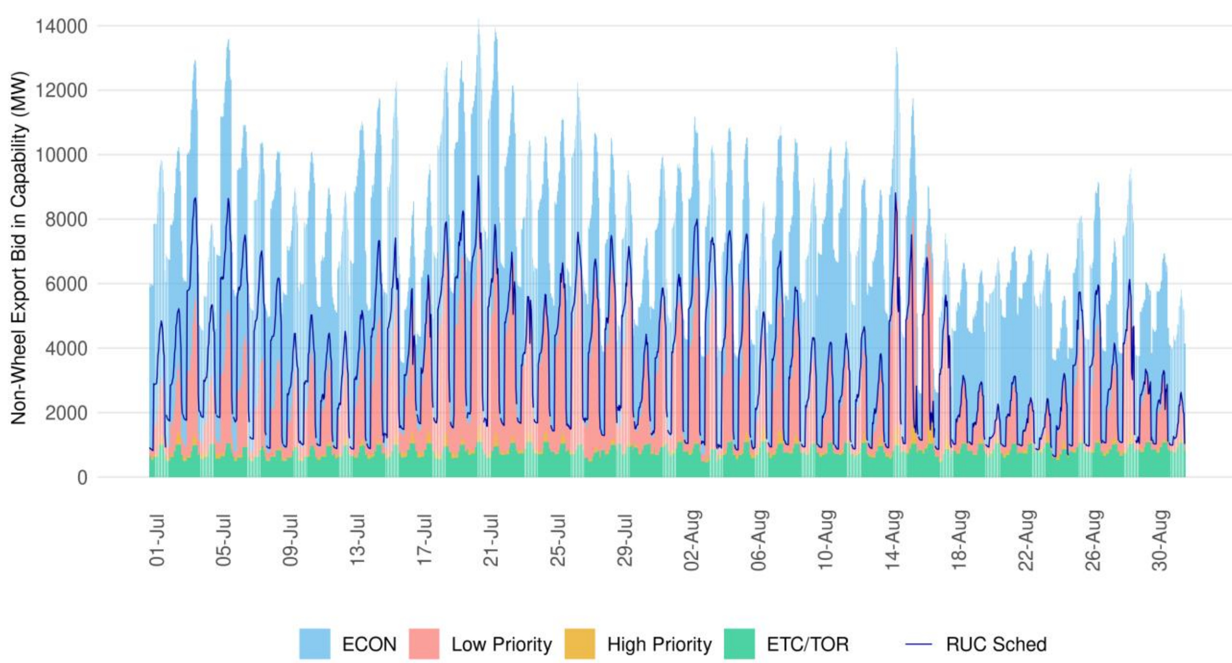
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into account.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

6.1 Intertie supply

Figure 48 shows the capacity from static export-based transactions in the day-ahead market for July and August 2023 organized by 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 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 48: 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 60 percent, 26 percent, 13 percent and 1 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. Due to mild load conditions and robust level of supply in the day ahead conditions in August, there was a high volume of exports except for the heat wave events.

Figure 49: Day-ahead bid-in capacity and RUC-cleared imports

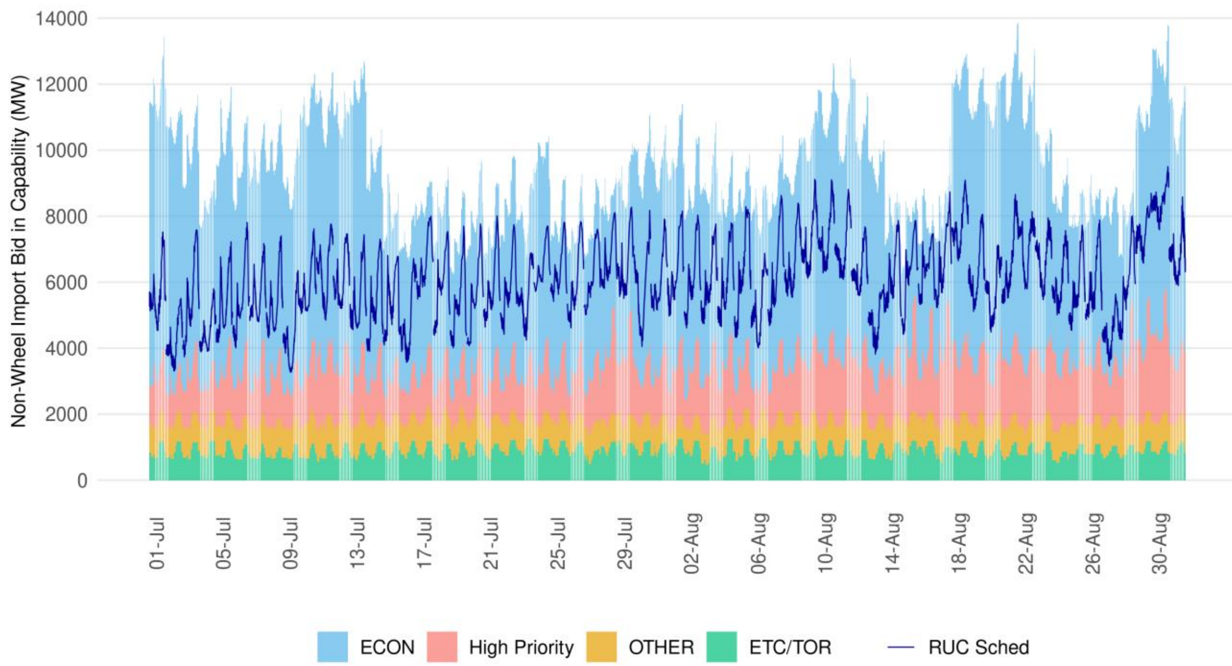


Figure 49 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the month, while hourly economic imports continued to see a high volume over 5,000 MW. The "other" group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

Figure 50 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution. The net interchange projected in the RUC process reached its lowest level on July 20 in HE 16 at about -2800 MW due to the higher level of exports cleared, followed by the a net interchange of -2,000 on August 14.

Figure 50: Breakdown of RUC cleared schedules

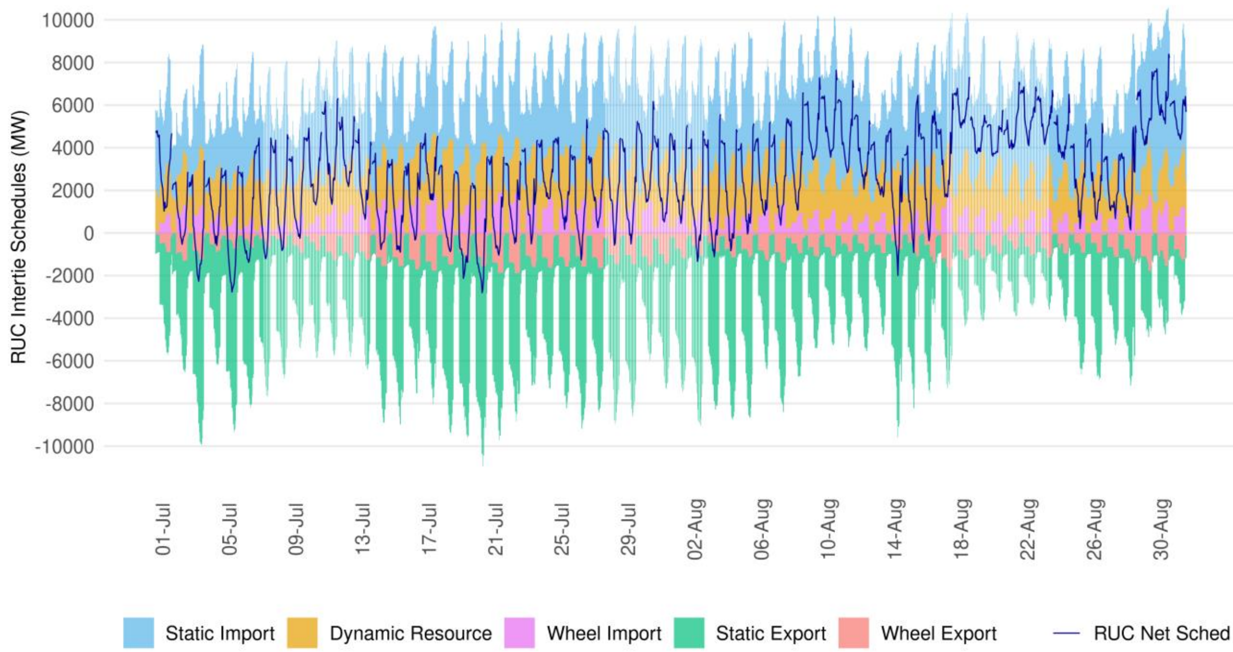
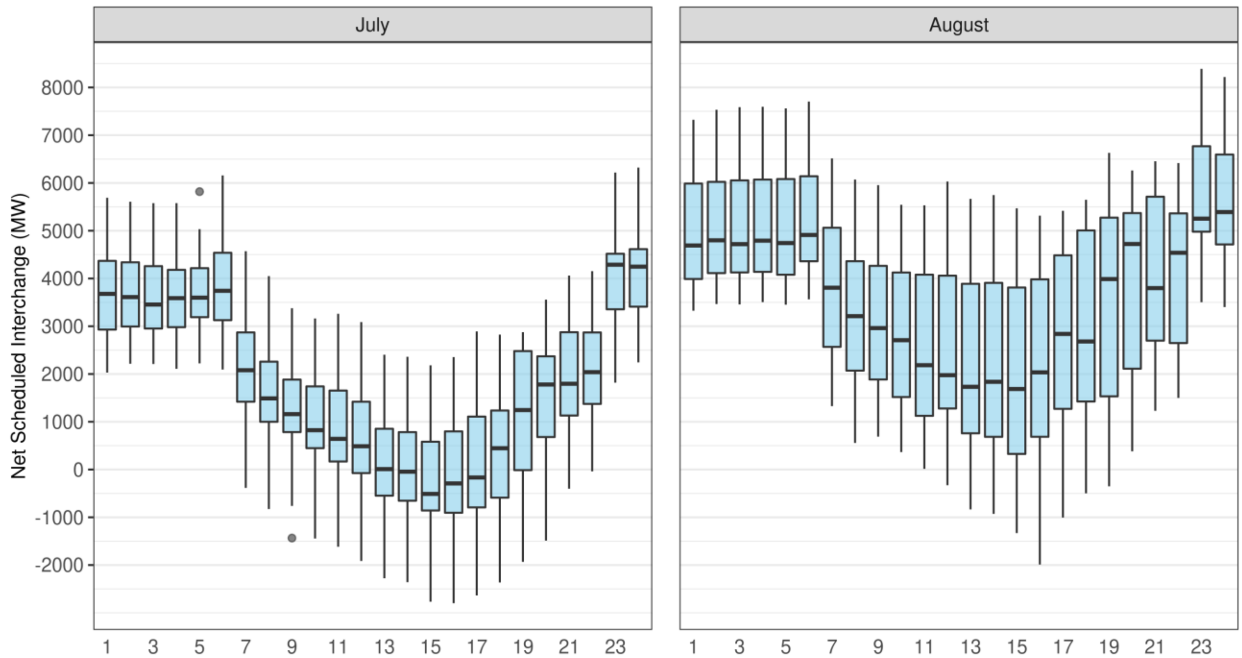


Figure 50 illustrates the hourly net schedule interchange distribution by hour for the month of July and August. This trend is useful to visualize the hourly profile of schedules and shows that net schedules reduce in midday hours when solar production comes in and start to increase as the solar production 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 the ISO's system has excess solar supply. Exports were in high demand during the afternoon hours for the month of July.

Figure 51: Hourly RUC exports

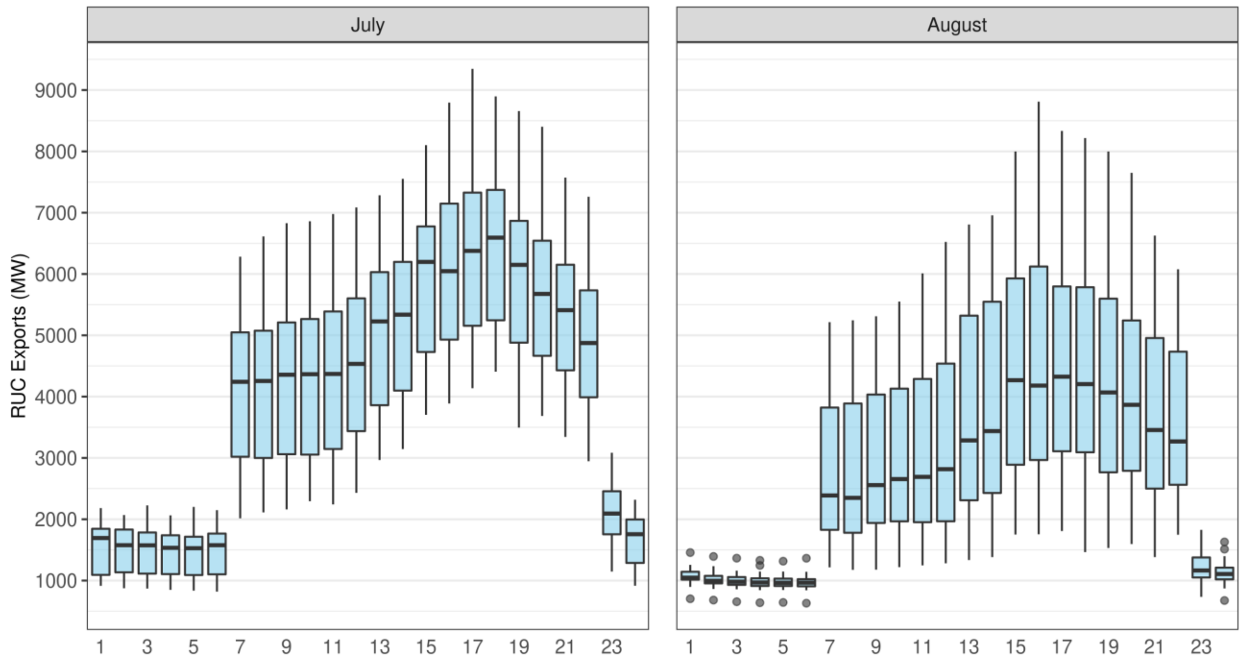
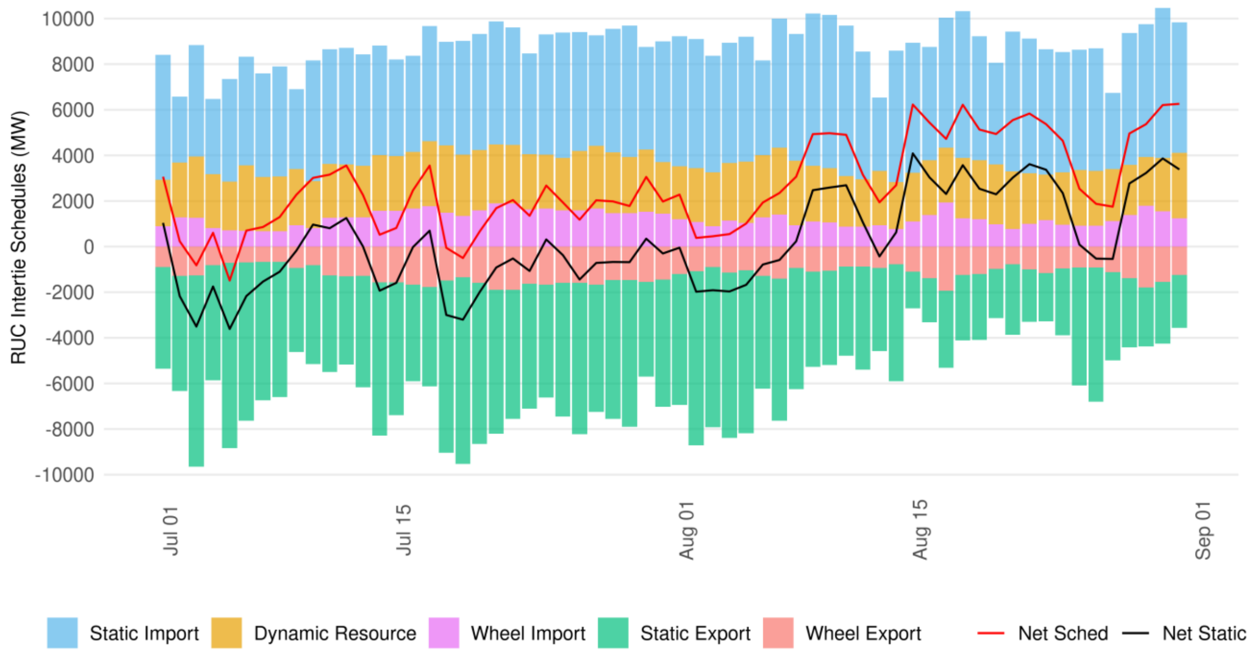


Figure 52 shows the intertie capacity available in the day-ahead market for the hours ending 20 to highlight the conditions around peak time, when the ISO's system faces the highest supply needs.

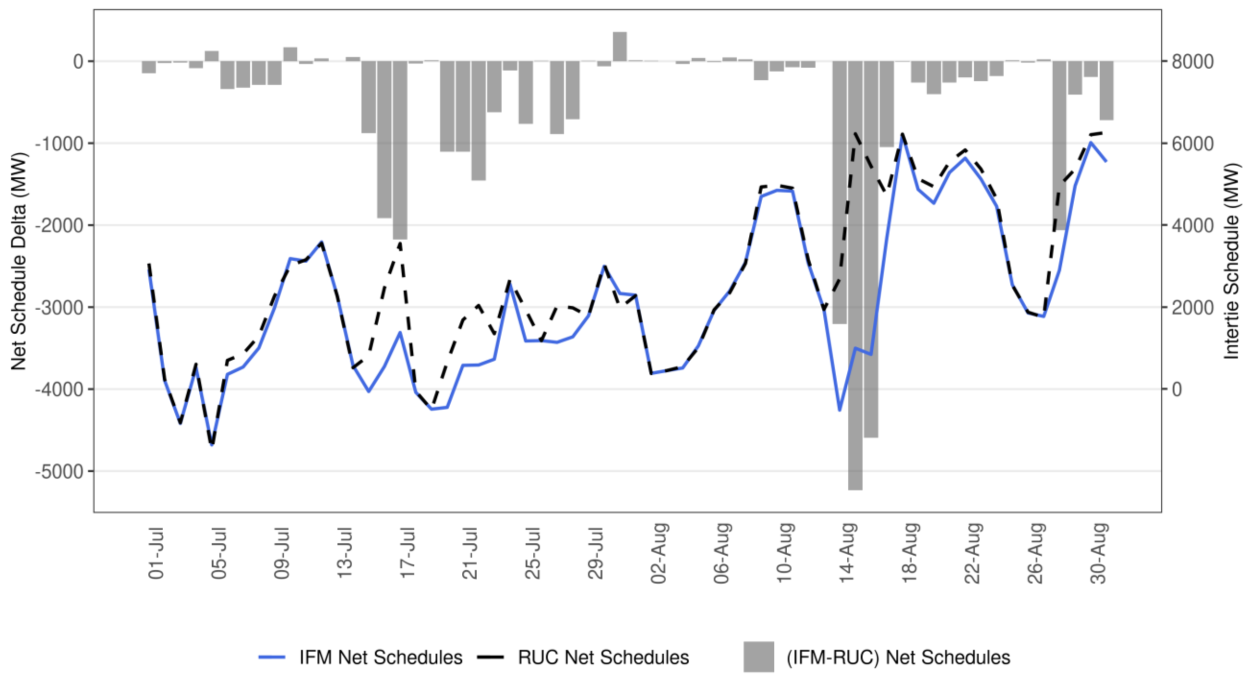
Figure 52: RUC schedules for interties for hour ending 20



This balance 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 53 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 by 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 months of July and August.

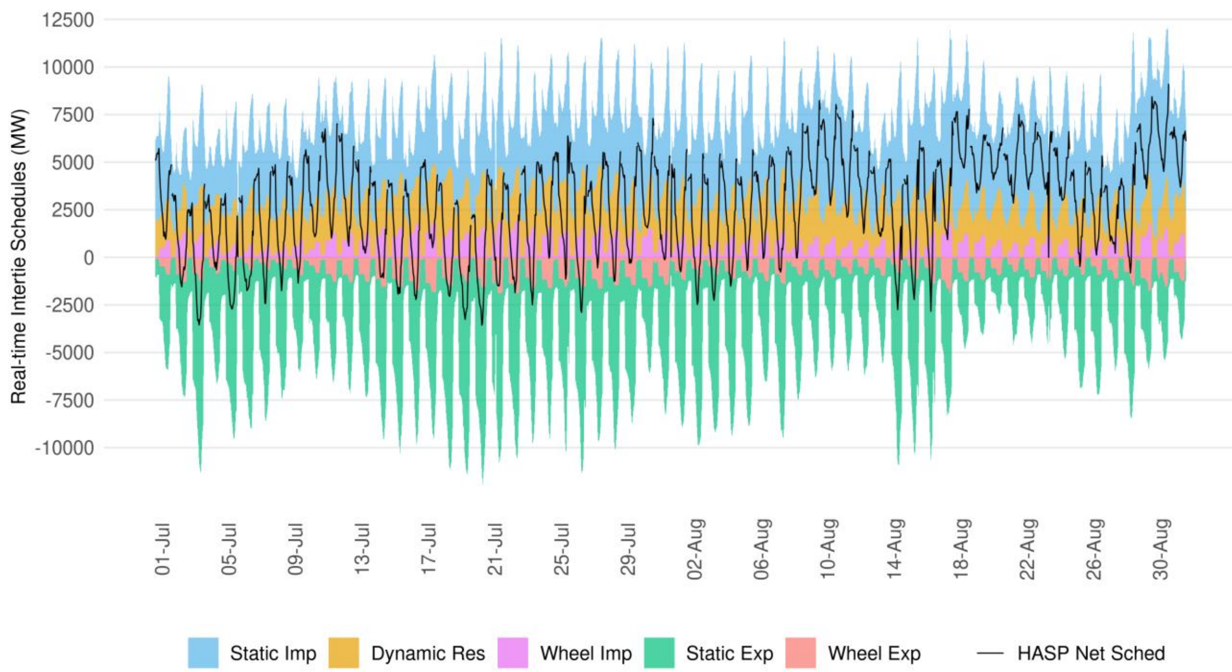
Figure 53: IFM and RUC schedule interchange for hour ending 20



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 to procure or clear additional capacity in the real-time market.

Figure 47: shows both the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred to as net schedule interchange. The net schedule interchange was at its lowest value on 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 and August, the net schedule in HASP was about 1909 MW and 3763 MW respectively across all the hours of the month and about 740 MW and 3,207 MW respectively for peak hours.

Figure 47: HASP cleared schedules for interties in July and August



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

Each market, RUC or HASP, can assess reduction of exports based on the overall system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority, but they are able to 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.

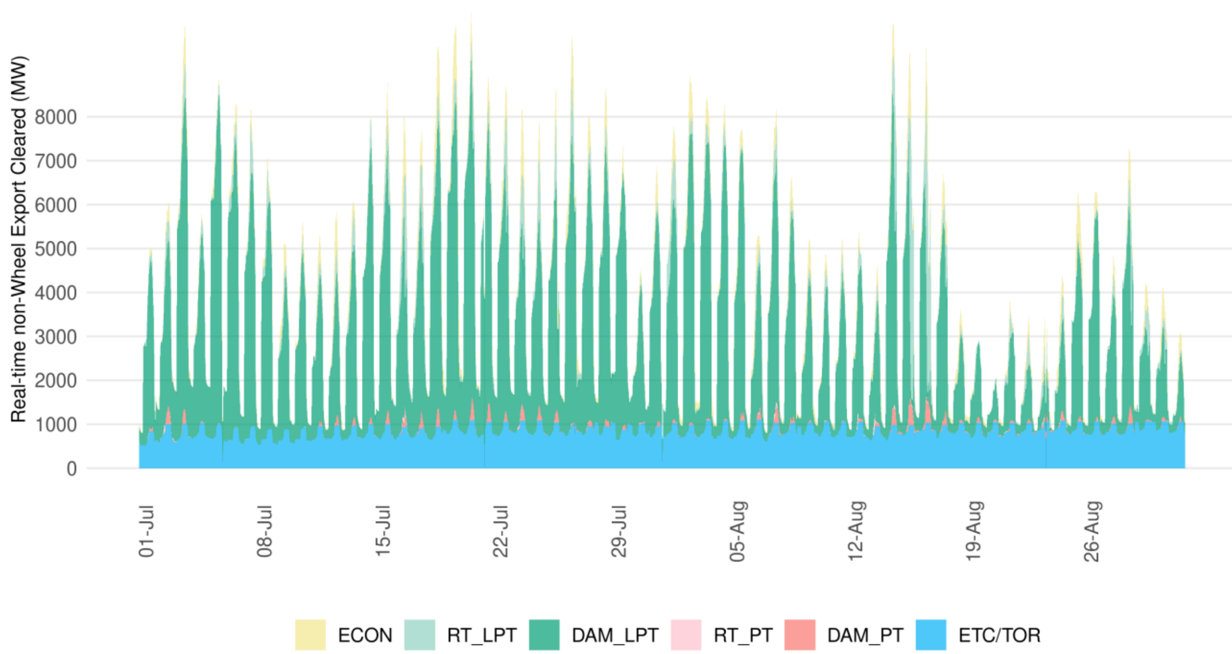
Figure 54 shows all the exports cleared in the HASP process and identifies the nature of such exports. TOR is for export with scheduling priorities associated with transmission rights. The groups of DA_PTK or DA_LPT stand for day-ahead exports coming into real-time market as self-schedules with high 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

[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

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.

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 and about 10,110 MW on August 14. In July and August, a significant portion of cleared exports were those with low priority and economical bids.

Figure 54: Exports schedules in HASP



Imports and exports were scheduled over multiple intertie scheduling points in July, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 55 through Figure 57 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] Throughout July and around August 16, 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 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 55 HASP schedules at Malin intertie

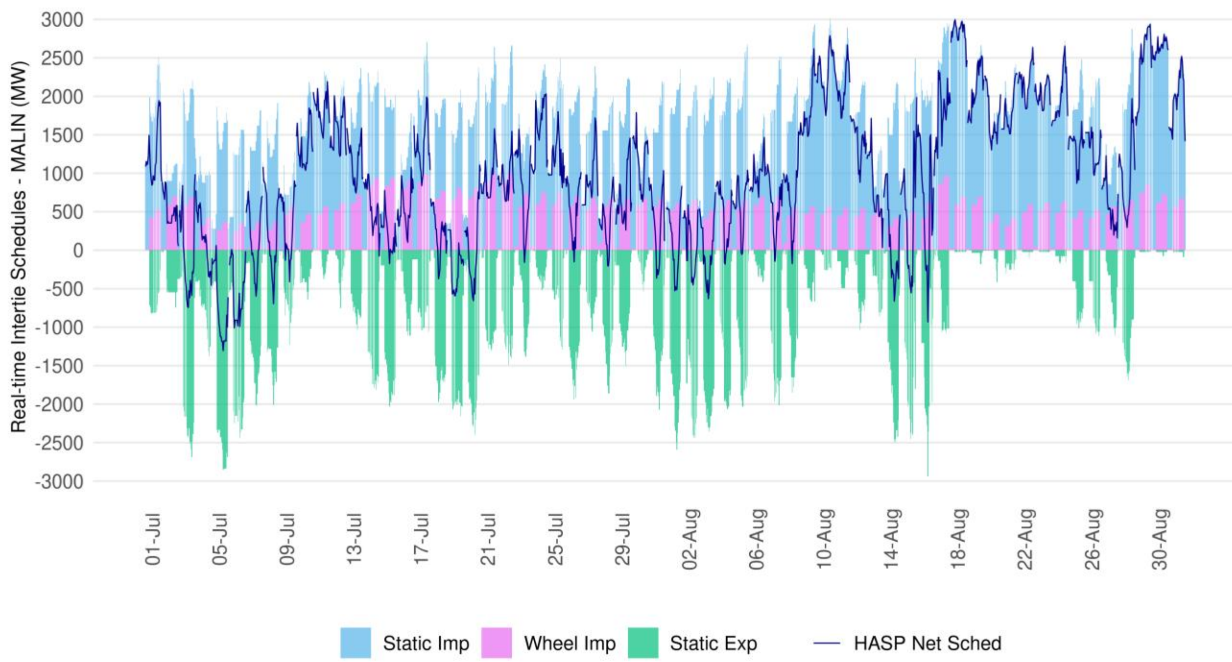


Figure 56: HASP schedules at Palo Verde intertie

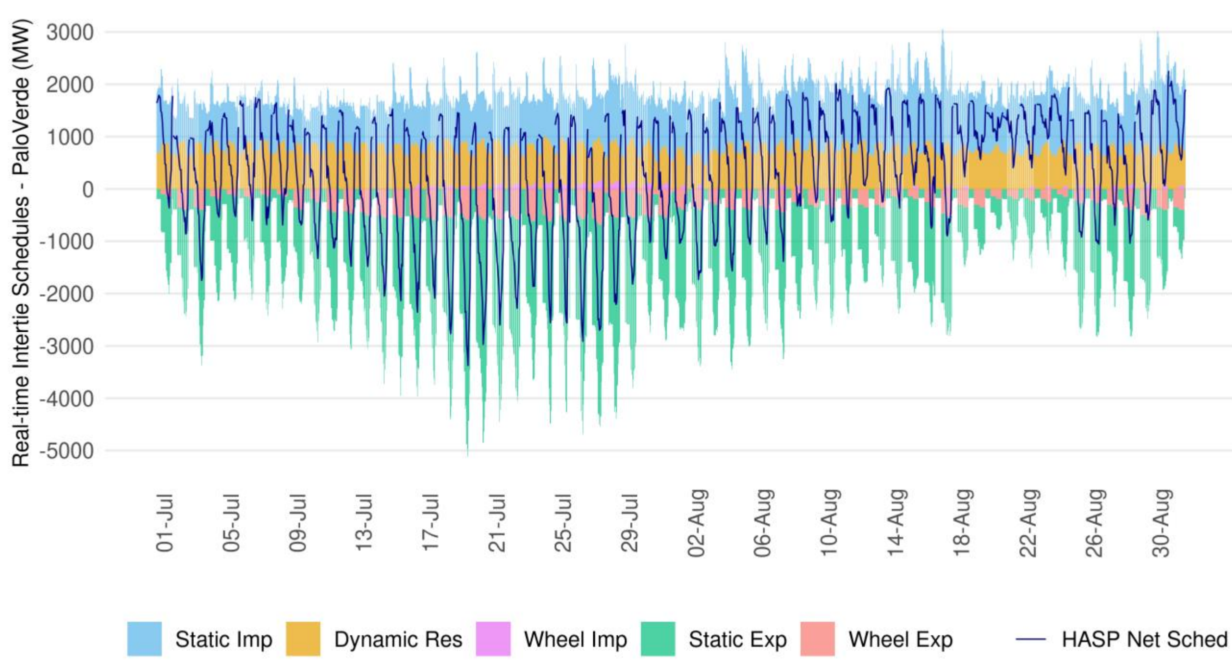
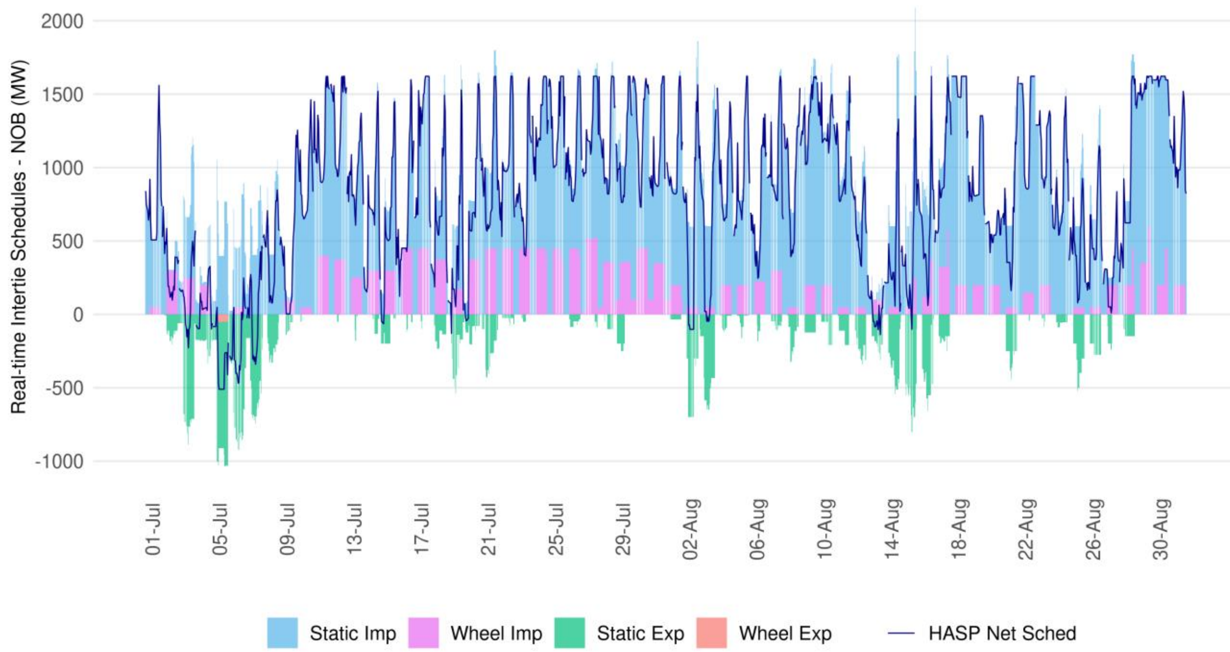


Figure 57: HASP schedules at NOB intertie



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 economically with prices between -$150/MWh and $0/MWh at least for the availability assessment hours. Figure 58 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 percent of all RA import capacity bid with either self-schedules or economic bids at or below $0/MWh in the day ahead for June. This plot also shows the cleared imports, which largely utilized all the bid-in volume for RA and above RA.

Figure 58: Day-Ahead RA import for hour endings 17 through 21 for weekdays

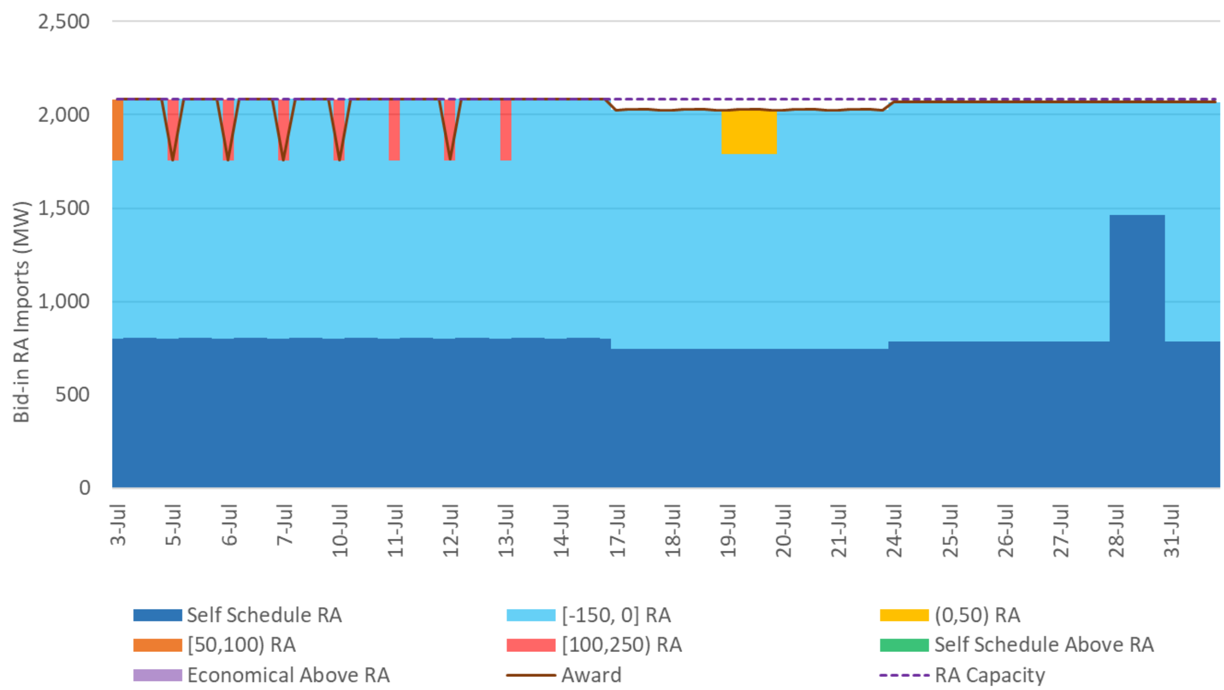
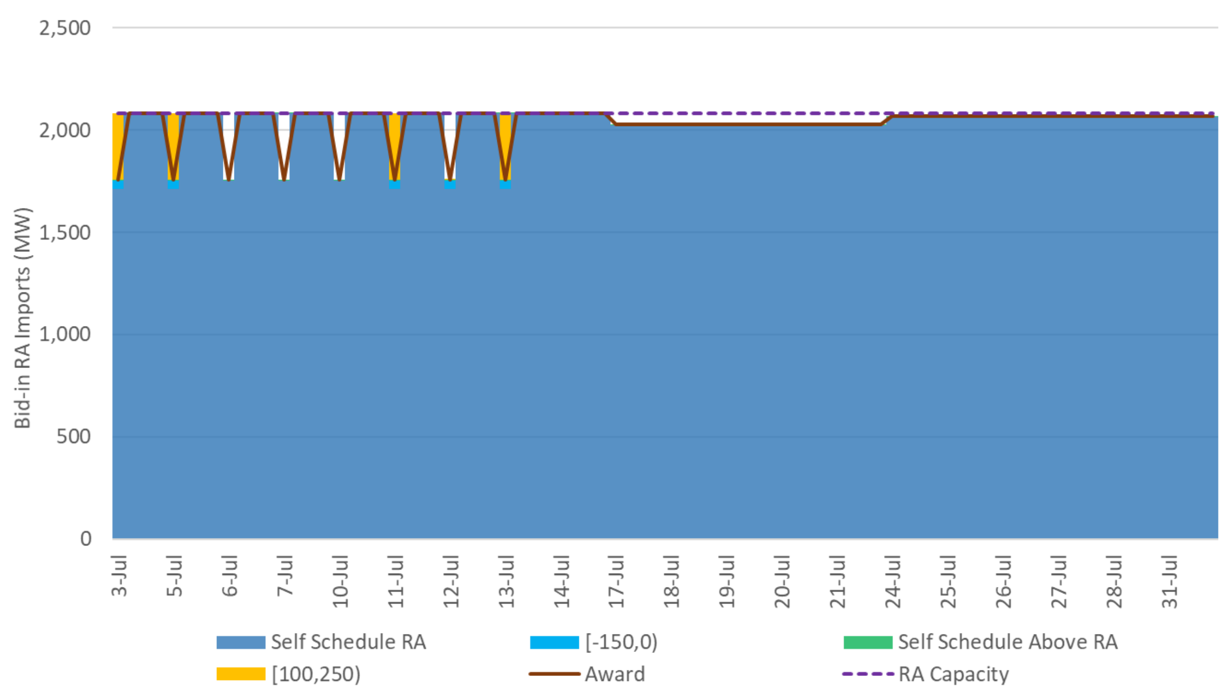


Figure 54 shows the same information for the real-time market using the HASP bids. About 97.7 percent of the RA imports submitted in the real-time market were with self-schedules or bids at or below $0. Small volumes of bids associated with RA imports bid in above their RA level with self-schedules.

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



6.3 Wheel transactions

With the summer 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 August 2023, the ISO received registration requests for a total of 1,776 MW from ten different scheduling coordinators. Table 2 shows all the wheel-through paths registered by scheduling coordinators.[32]

Table 1. Wheel-through quantities registered for August 2023

Source	Sink	MW
CFEROA	PVWEST	50
CFETIJ	MEAD230	75
CTW230	LLL115	105
IPP	SYLMAR	25
MALIN500	MEAD230	425
MALIN500	MCCULLOUG500	100
MALIN500	PVWEST	400
MIR2	RANCHOSECO	30
NOB	MEAD230	208
NOB	MCCULLOUG500	150
NOB	PVWEST	198
PVWEST	SYLMAR	10
	Total:	1776

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

Figure 59 shows the hourly wheels cleared in the RUC process throughout the month. Wheels participating in the day-ahead market in August were ETC/TOR, high- and low-scheduling priority, peaking at about 1931 MW on August 17, with 628 MW of ETC/TORs, 1223 MW of high priority and 80 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 requests 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 59: Hourly volume of day-ahead wheel transactions by type of self-schedule

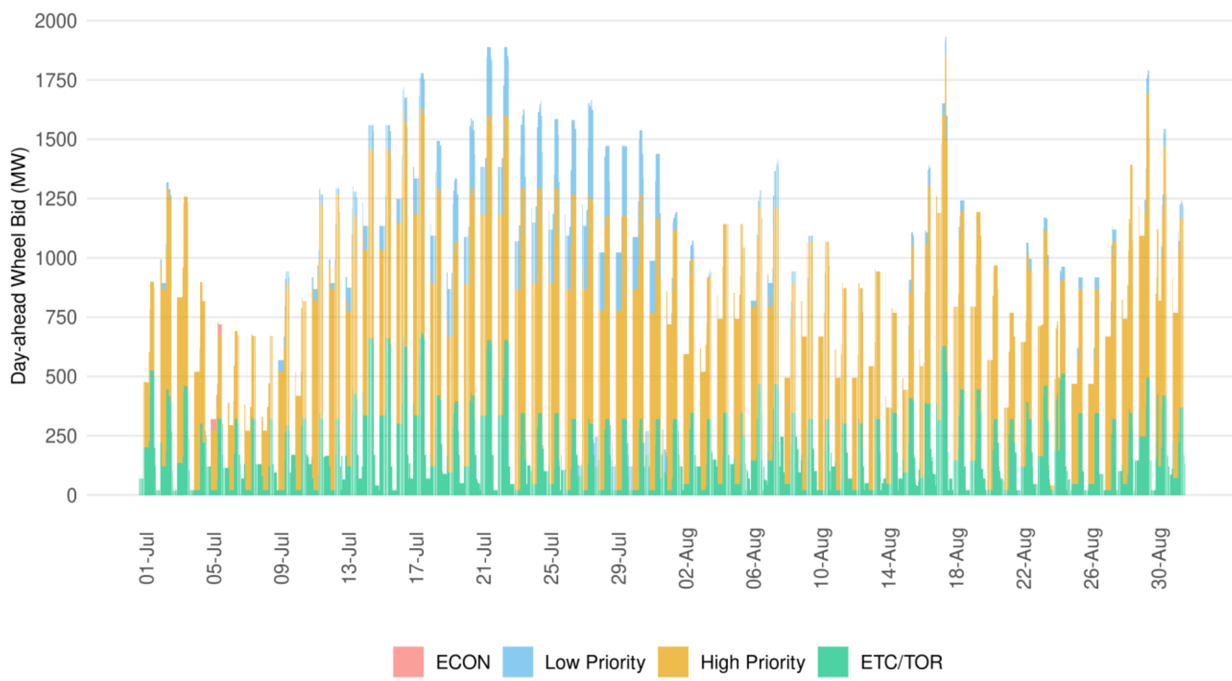


Figure 60: Hourly volume high- and low-priority wheels cleared in RUC

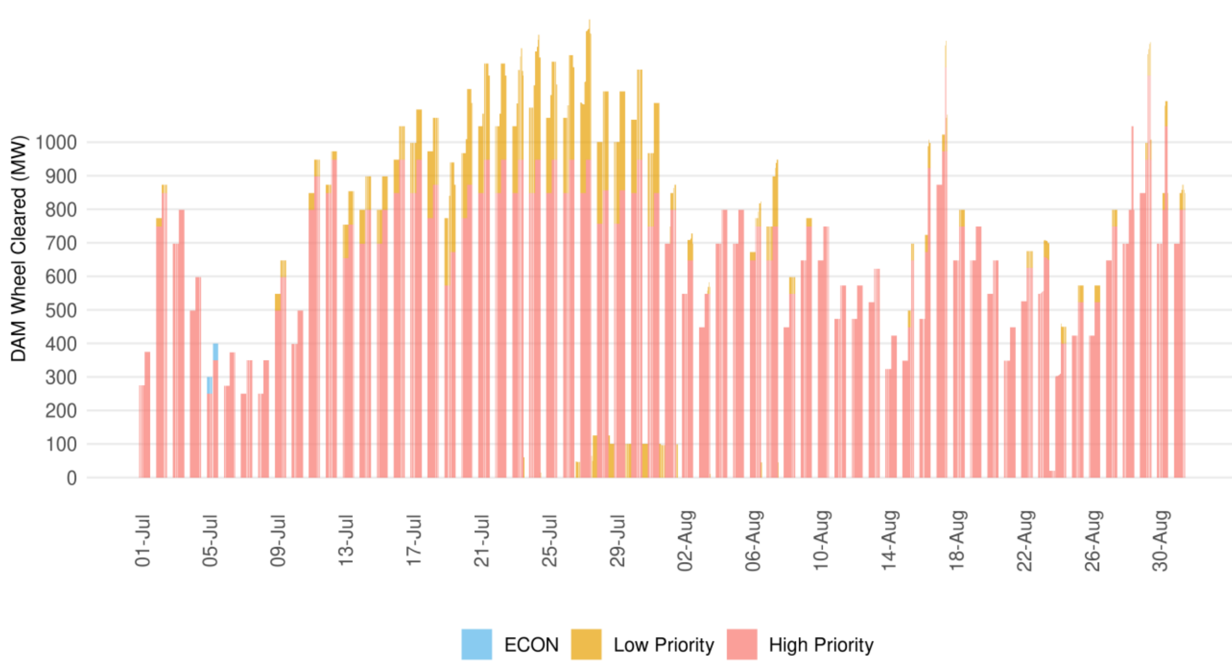
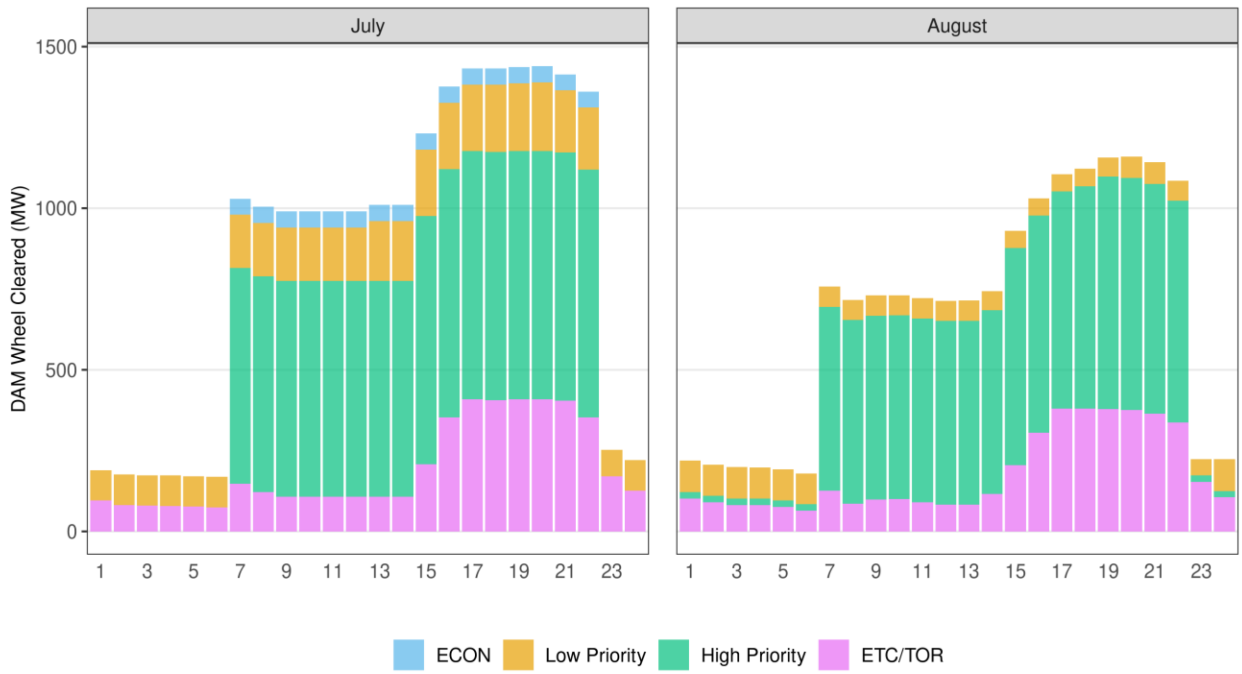


Figure 56 provides an hourly breakdown of high- and low-priority wheels, with the maximum hourly cleared RUC volumes about 1223 MW of high priority wheels on August 17.

Figure 61: Day-ahead hourly profile of wheels in July and August



For July and August, 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 57; *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 58 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 August. Source refers to the import scheduling point while sink refers to the export scheduling point. The path with the largest volume of wheels in August in the day-ahead market was from Malin to PVWEST.

Figure 62 Hourly average volume (MWh) of wheels by path in August

		SINK				
TYPE	**SOURCE**	**LLL115**	**MCCULLOUG500**	**MEAD230**	**MIR2**	**PVWEST**
LPT	NOB			47		60
	PVWEST				53	
PT	MALIN500		52	200		249
	NOB		145	165		59
	TRCYPGAE	9				

Figure 63 summarizes the maximum hourly wheels cleared in any hour in August in the day-ahead market by source-to-sink combination. The maximum volume of wheels in a given path occurred from Malin to PV West.

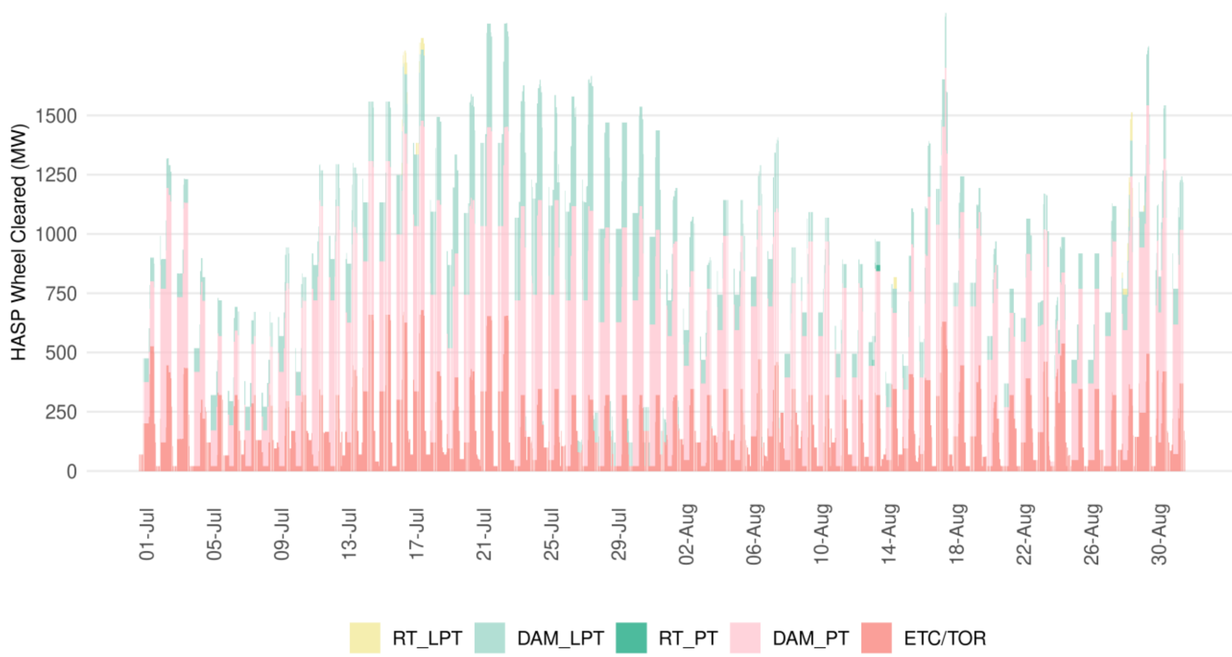
Figure 63: Maximum hourly volume (MW) of wheels by path in August

		SINK				
TYPE	**SOURCE**	**LLL115**	**MCCULLOUG500**	**MEAD230**	**MIR2**	**PVWEST**
LPT	NOB			49		100
	PVWEST				110	
PT	MALIN500		100	250		350
	NOB		150	275		198
	TRCYPGAE	20				

Although wheels do not add or subtract capacity to the overall power balance of the ISO market, they compete for limited scheduling and transmission capacity. Self-schedules wheels have higher priority than stand-alone imports or exports under the specific scenario when there is limited intertie capacity and there is no power balance infeasibility and. With limited intertie capacity imports will be competing with wheels for intertie capacity. Under this scenario, self-schedule wheels can clear before stand-alone 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 64 shows the volume of wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 64 Wheels cleared in real-time market



The *TOR* groups represent the wheels associated with either existing or owner transmission rights. The majority of 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 then 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 to participate in both energy and ancillary service markets. In August 2023, there were 86 storage resources actively participating in the ISO markets. Most storage resources participated in both the energy and ancillary service market. Batteries 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 19,199 MWh. In terms of the capacity made available to the markets, Figure 65 shows the bid-in capacity for storage resources in the day-ahead market.

Figure 65: 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 August and July. The bid-in capacity is organized by $/MWh price ranges. There were consistent patterns of batteries bidding to charge at negative prices though more batteries were willing to charge at positive prices compared to July. Most batteries were willing to discharge at prices above $50/MWh. In August, some were willing to charge when prices were $200 to $500. 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 66 shows the bid-in capacity for the real-time market. The majority of bids were $50/MWh or above on the discharging side, and $50/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 66: Bid-in capacity for batteries in the real-time market

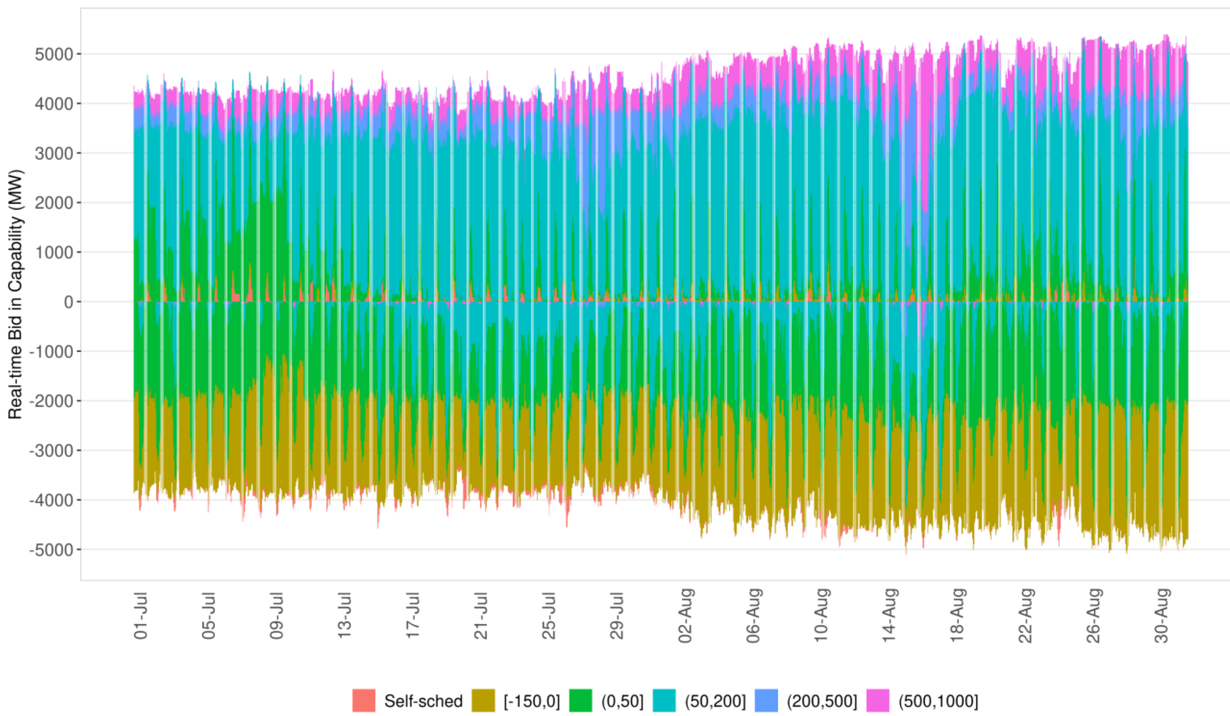


Figure 67 IFM distribution of state of charge for July and August 2023

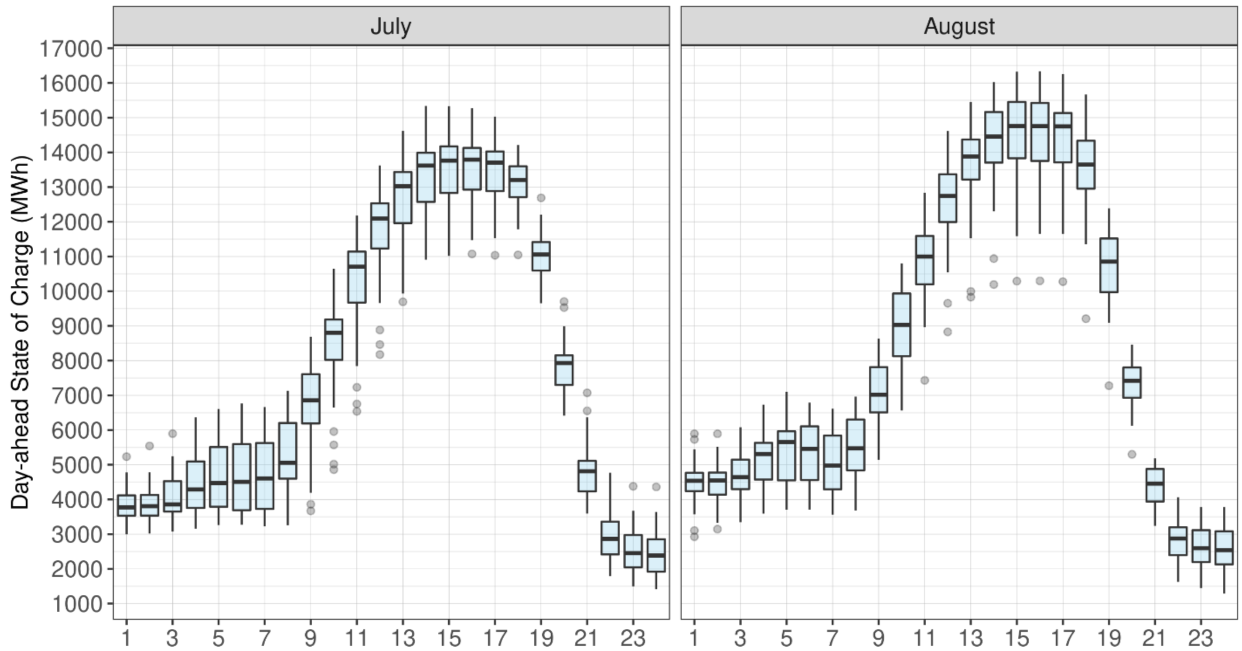
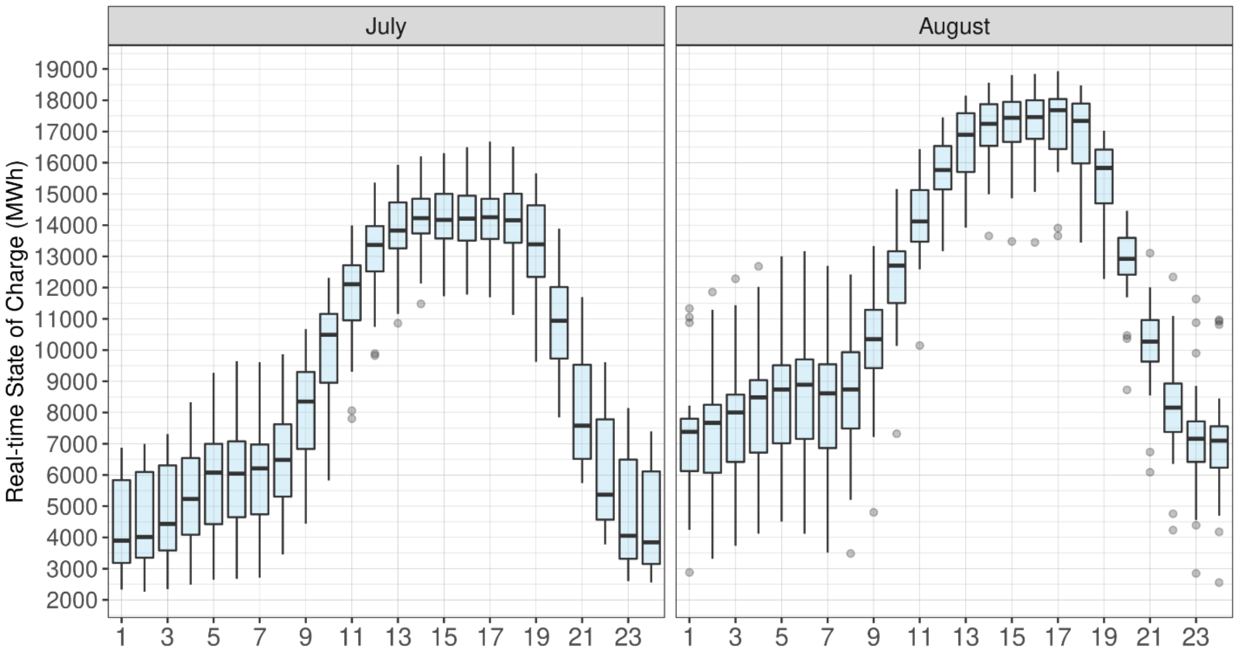


Figure 67 shows the hourly distribution of the storage capacity of resources participating in IFM for July and August 2023. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge in IFM. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime, between hours ending 9 to 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 August, the highest median system state of charge was around 16,300 MWh, which occurred in the hour ending 16.

Figure 68 shows the distribution of state of charge for the real-time market for July and August 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 August was higher than the median system state of charge in July, following additional capacity coming online. 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 68: Real-time market distribution of state of charge for July and August 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 made available for energy 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 69 shows the distributions of energy awards in IFM, and shows the hourly distribution of real-time dispatch for batteries in July and August 2023. The figure 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 70 shows the average hourly system marginal energy component (SMEC) of the locational marginal price in IFM for August 2023.

Figure 69: Hourly distribution of IFM energy awards for batteries in July and August 2023

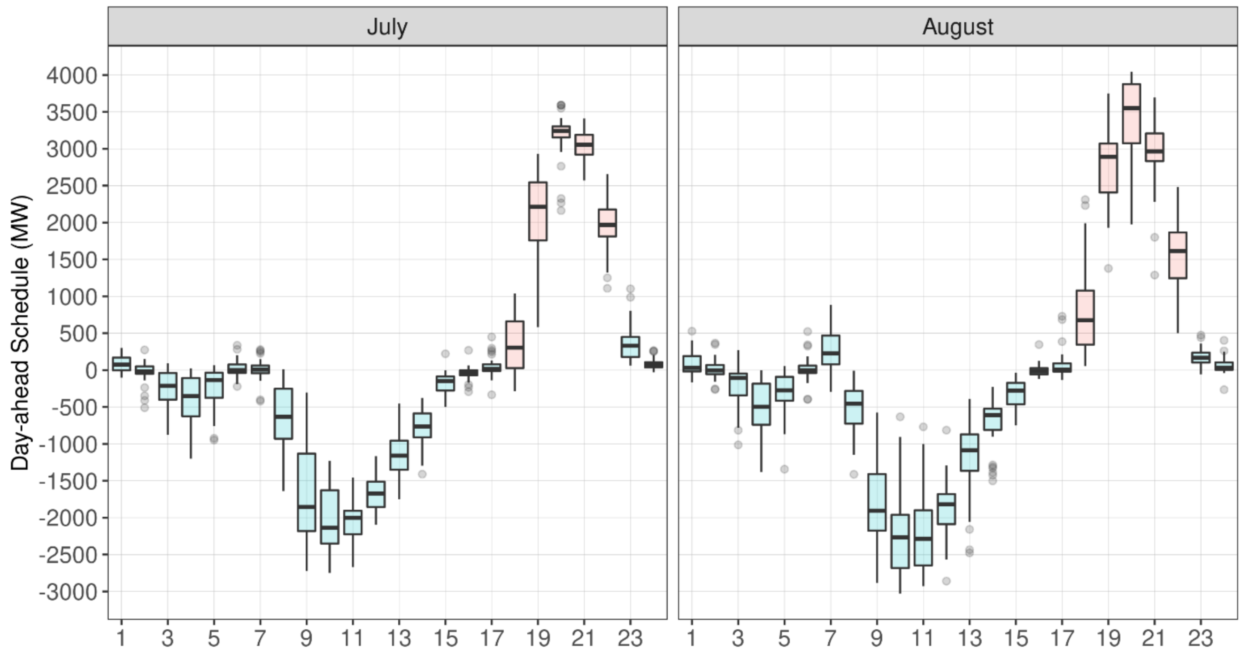


Figure 70: IFM hourly average system marginal energy price in August 2023

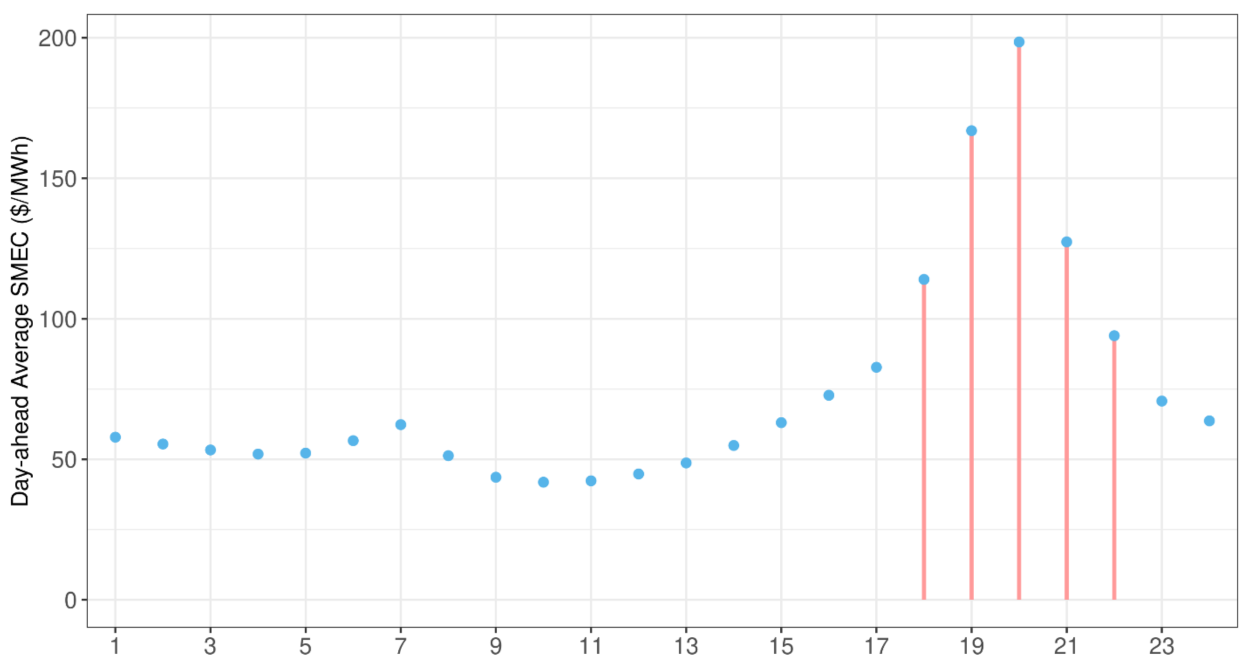
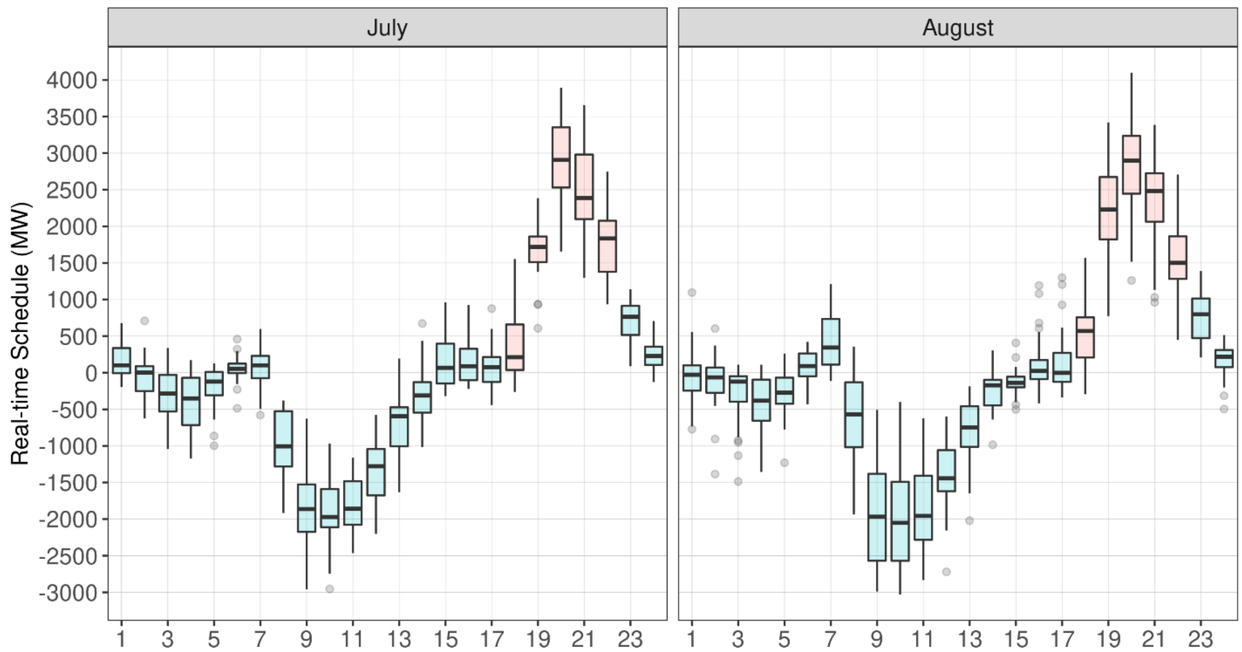


Figure 71 shows the distributions of energy awards in IFM, and shows the hourly distribution of real-time dispatch for batteries in July and August 2023. The figure highlight hours ending 18 through 22 in a different color than the other hours to show that the storage resources are being discharged in intervals with the highest energy prices.

Figure 71: Hourly distribution of real-time dispatch for batteries in July and August 2023



The storage resources continue to provide ancillary services to the market for the following products: regulation up, regulation down, and spinning reserve. Figure 72 shows the average hourly AS awards in day-ahead, and Figure 73 shows the average hourly AS awards in real-time, for July and August 2023.

Figure 72 Hourly average day-ahead storage AS awards in July and August 2023

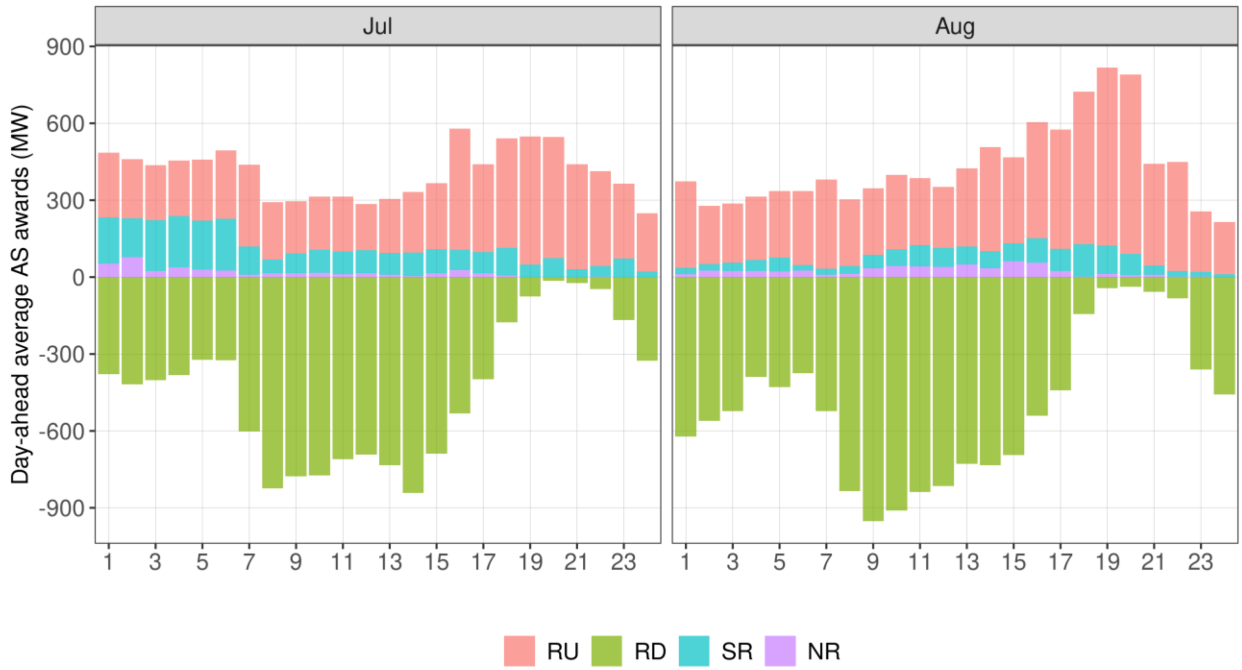
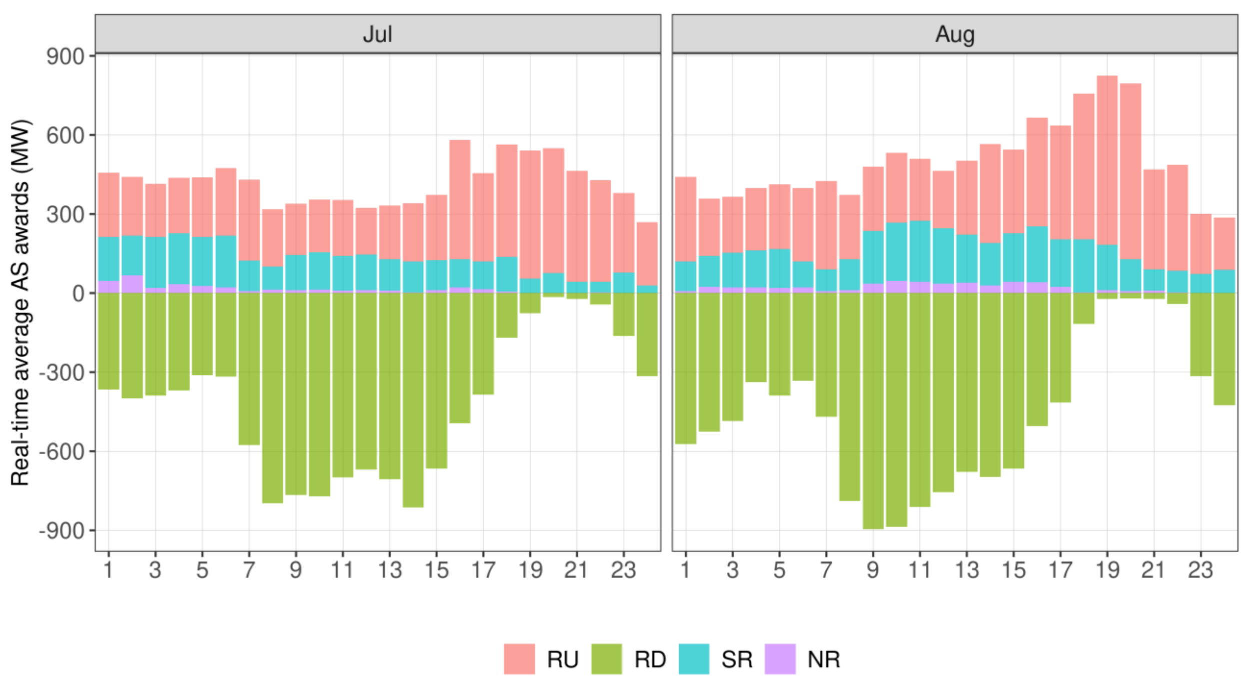


Figure 73 Hourly average real-time storage AS awards in July and August 2023



Beginning with the implementation of the Hybrid Resources Phase 2B project in February 2023, the 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 74 and Figure 75 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, 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, offsetting the decreased production of the solar component and resulting in a flatter decline in output.

Figure 74: Hourly distribution of IFM energy awards for hybrid resources in July and August 2023

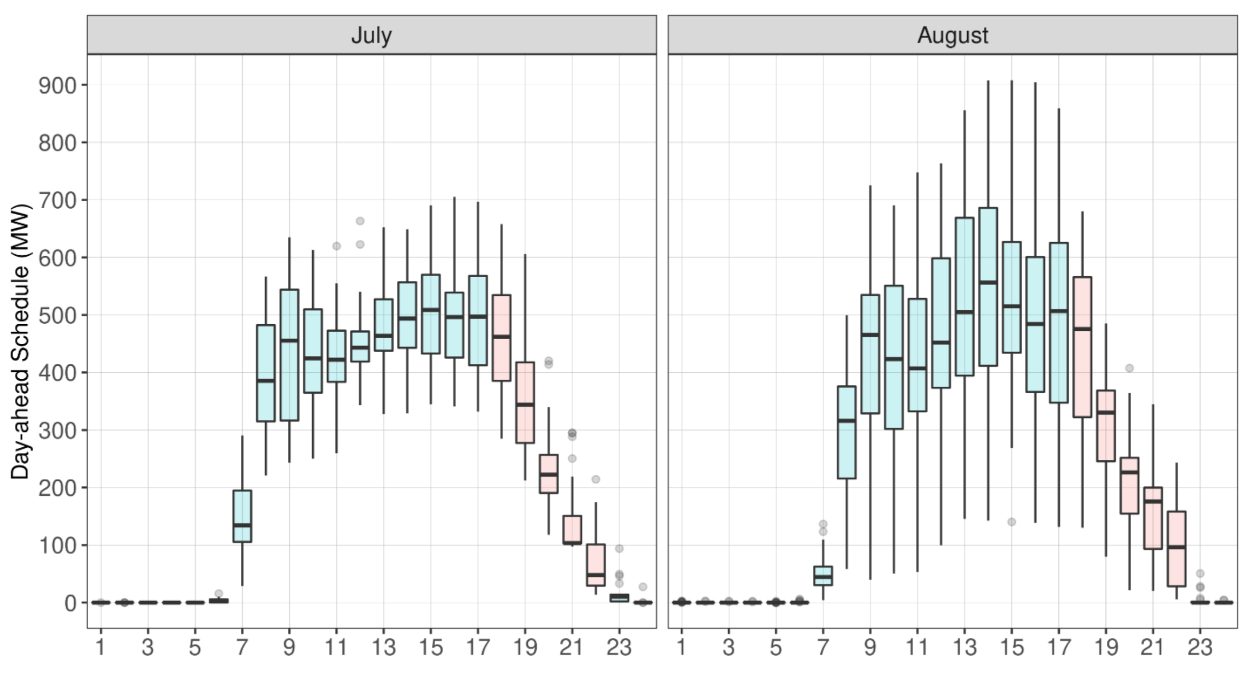
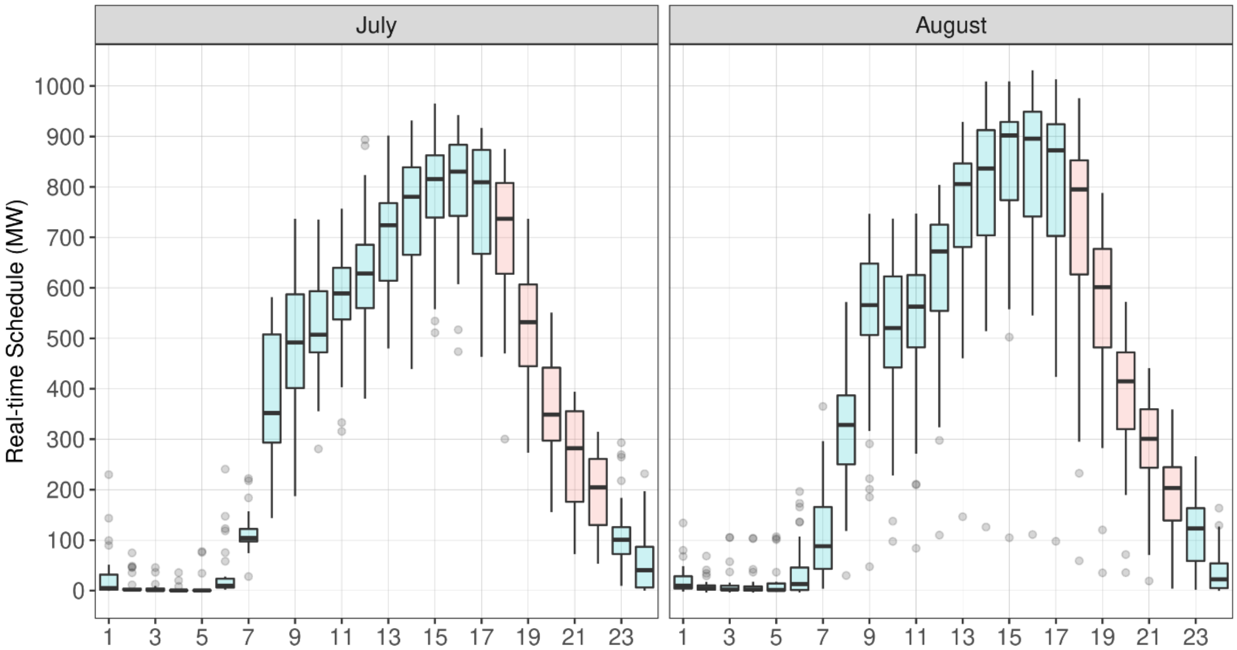


Figure 75: Hourly distribution of real-time dispatch for hybrid resources in July and August 2023



Similar to storage resources, hybrid resources can also provide ancillary services to the market for regulation up, regulation down and spinning reserve. Figure 76 shows the average hourly AS awards in day-ahead, and Figure 77 shows the average hourly AS awards in real-time, for July and August 2023.

Figure 76: Hourly average day-ahead hybrid AS awards in July and August 2023

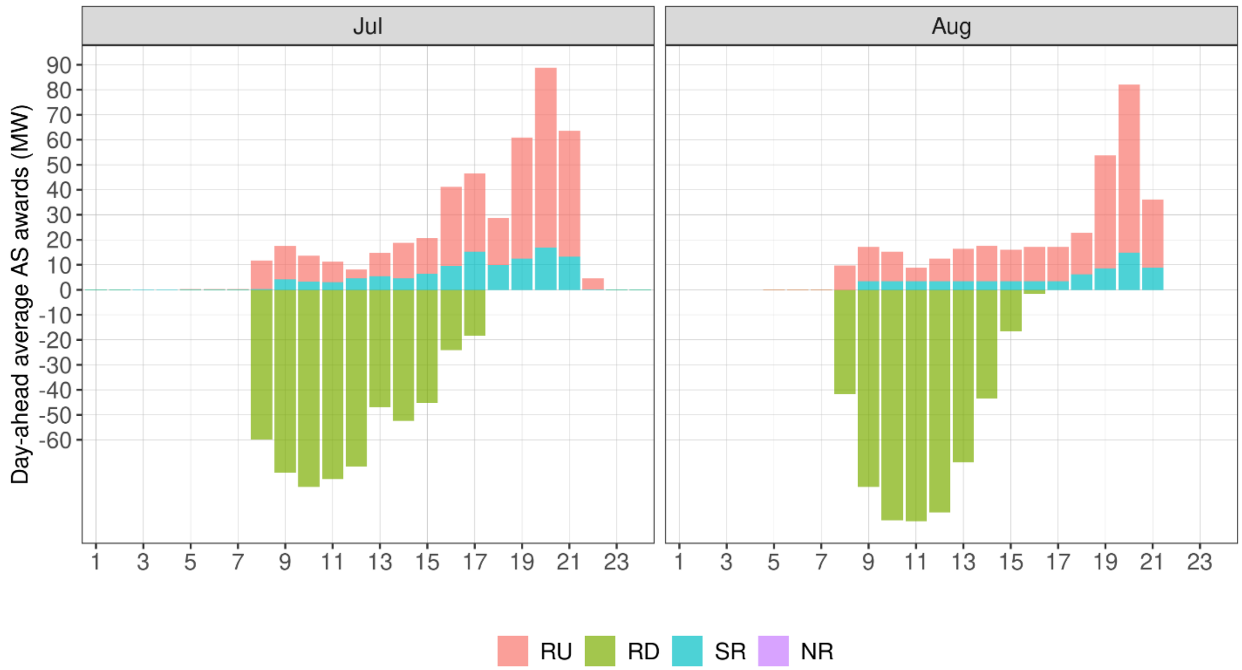
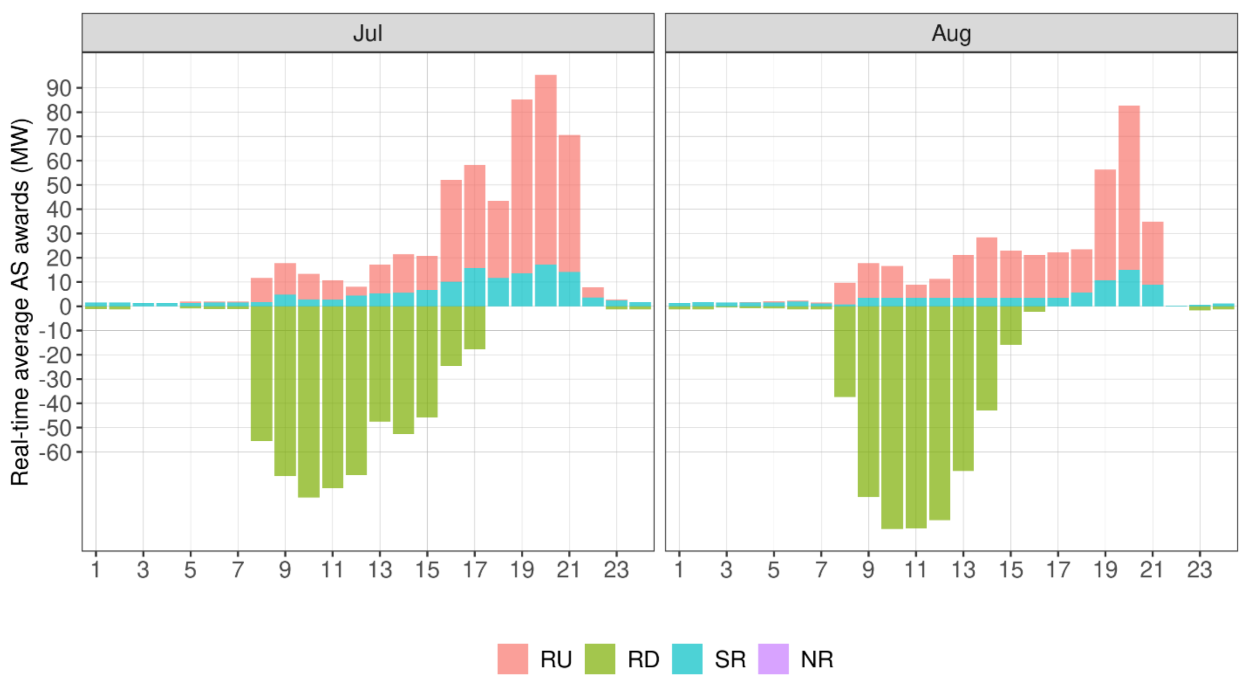


Figure 77: Hourly average real-time hybrid AS awards in July and August 2023



8 Western Energy Imbalance Market

8.1 WEIM transfers

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 one area and replacing it with cheaper generation from other area. In a given interval, import and export transfers can concurrently happen for one area.

Figure 78 shows the distribution of five-minute WEIM transfers for the ISO area. A negative value represents an import into the ISO from other WEIM entities.

Figure 78: Daily distribution of EIM transfers for ISO area

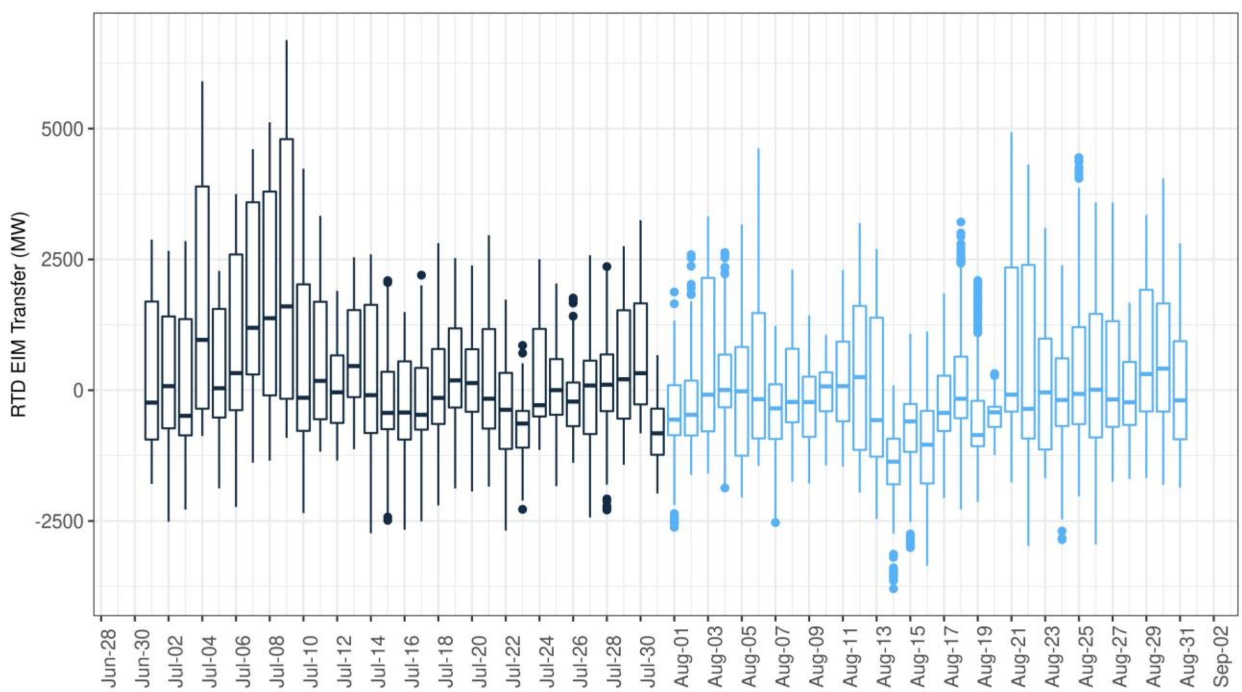
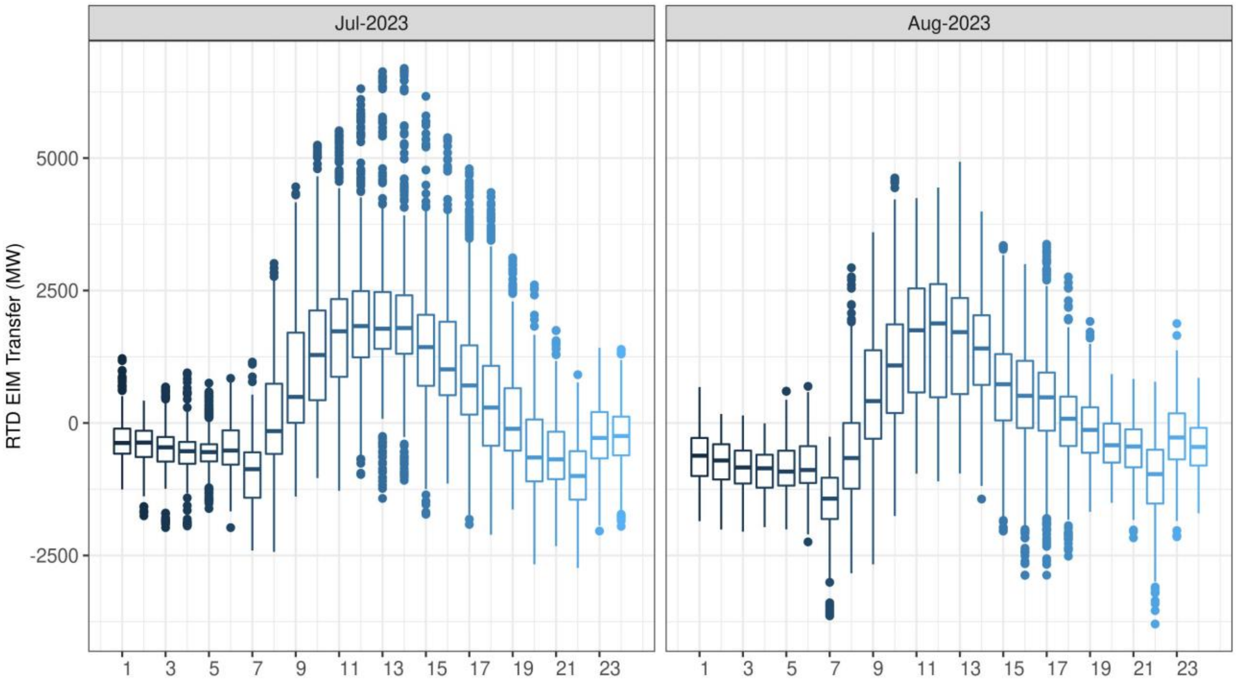


Figure 75 shows the WEIM transfers in an hourly distribution, which highlights the typical profile of the ISO transfers which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the ISO area. This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

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

Figure 79: 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 80 shows the daily overall settlements costs for the ISO balancing area; this does not include WEIM settlements. As demand and prices rise, the overall settlements are expected to increase. When considering the overall costs relative to the volume of demand transacted, the dotted red line provides a reference of an average cost per MWh. The average daily cost in August was $60.81 million, representing an average daily price of $85.00/MWh. The maximum daily cost of $259.29 million occurred on August 16.

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 81.

Figure 80: ISO's daily total and average market costs

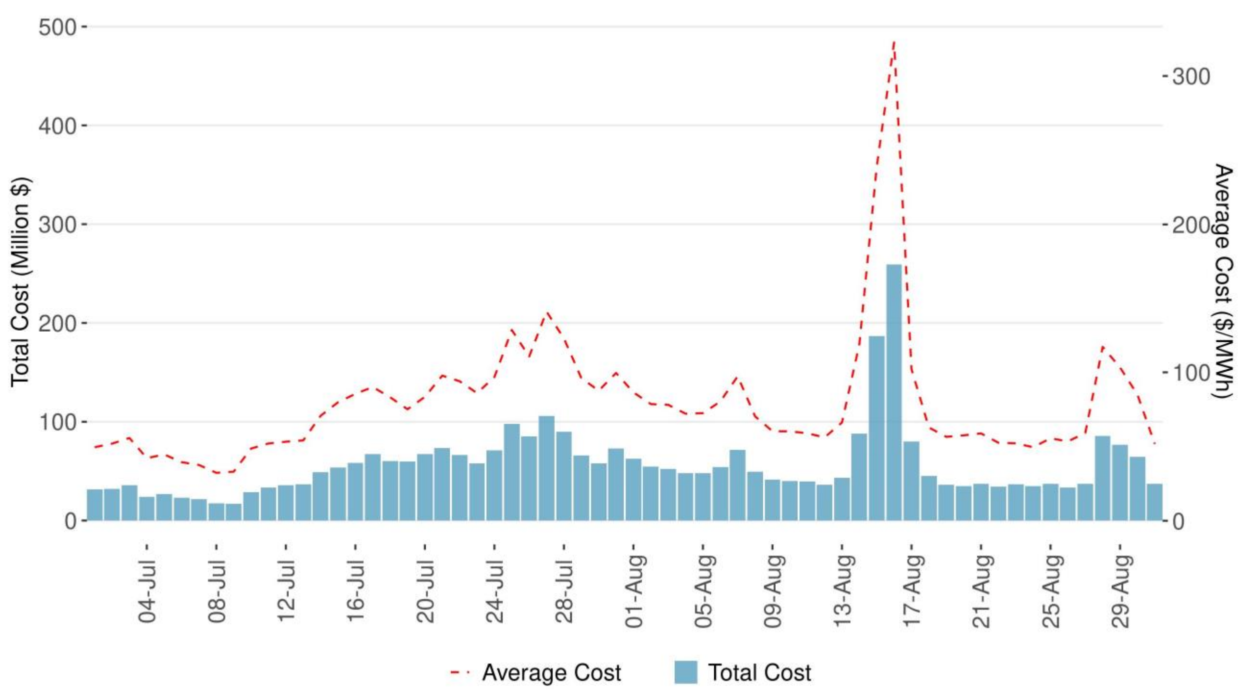
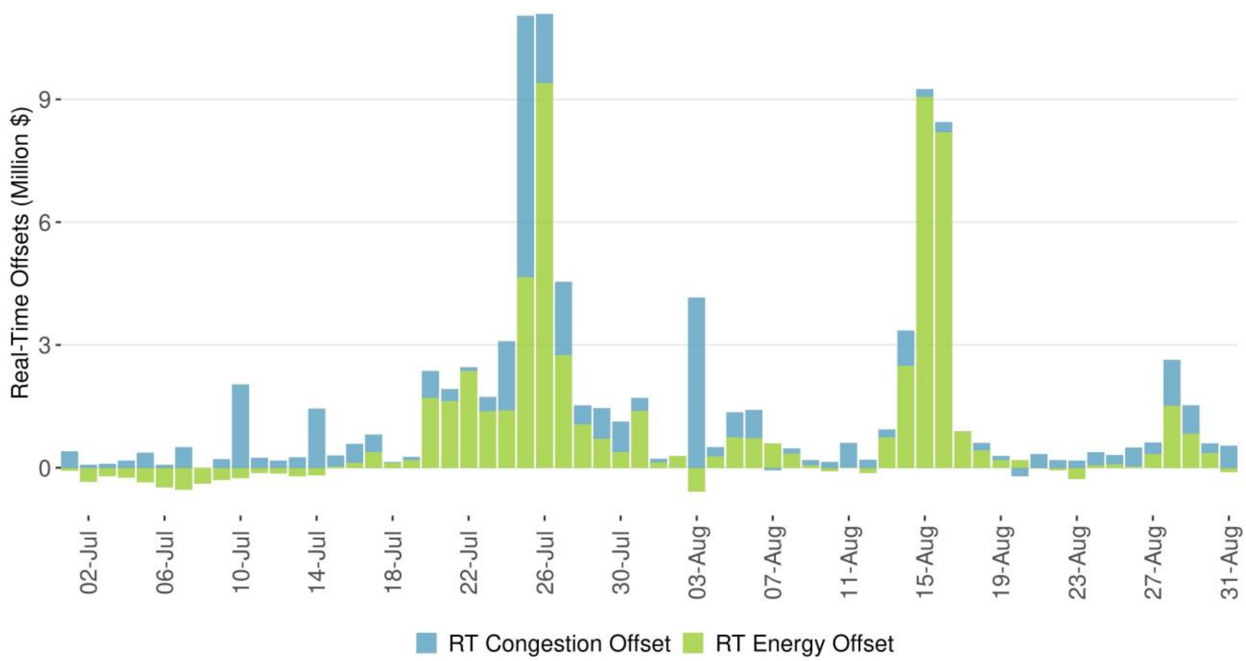


Figure 81: Real-time energy and congestion offsets



10 Import market incentives during tight system conditions

On June, 15, 2021, the ISO implemented an enhancement that provides improved incentives for import supplies to be available during tight system conditions because 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 the ISO has issued an alert by 3 PM 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 summer readiness in 2021.

This feature was not triggered for the month of August 2023.

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 in real-time 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.

The minimum SOC constraint was applied on August 15 and 16 in response to infeasibilities in RUC. The set of critical hours in August were defined as hours ending 18 through 21. The constraint effectively maintained sufficient SOC to provide energy during the critical hours, while still allowing the batteries to respond to periods of high prices in earlier hours. The impact of the constraint was most acute on August 16 towards the end of hour ending 17. Hours ending 16 and 17 on this day saw a period of high prices in RTD, which led to significant battery discharging awards immediately leading up to the start of the critical hours. Roughly one third of batteries subject to the minimum SOC constraint were limited by the constraint at the end of hour-ending 17, as seen in Figure 82.

The minimum SOC constraint was designed as a stop-gap measure to ensure that batteries with an RA obligation could be counted on to provide energy during the most critical times of day on the days with the most stressed system conditions. The constraint gave operators additional confidence that the battery fleet would not be depleted earlier in the day while still allowing for economic optimization. The minimum SOC constraint is to be retired at the end of September 2023, and more sophisticated operator tools for managing SOC on tight days will be put in its place.

Figure 82: Battery resources with RA obligations Real-Time market awards and pricing

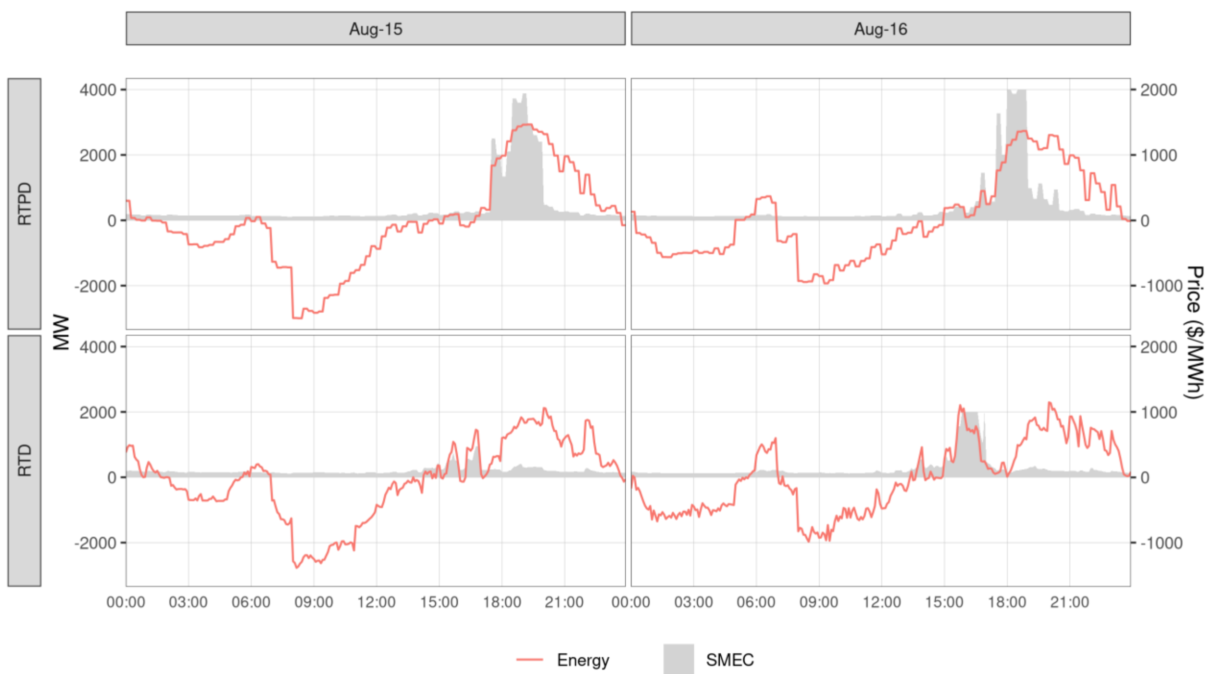


Figure 83: State of Charge and minimum SOC requirement for resources with an RA obligation

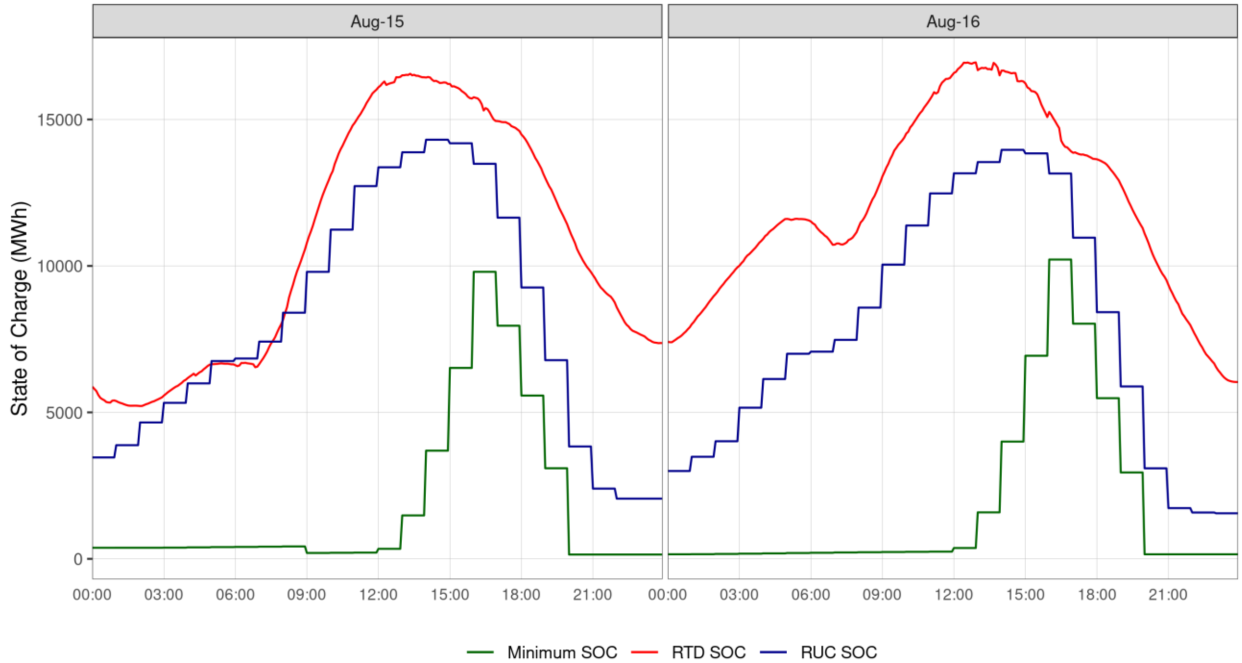


Figure 84: RTD end of hour binding minimum SOC constraints

12 Assistance Energy Transfer

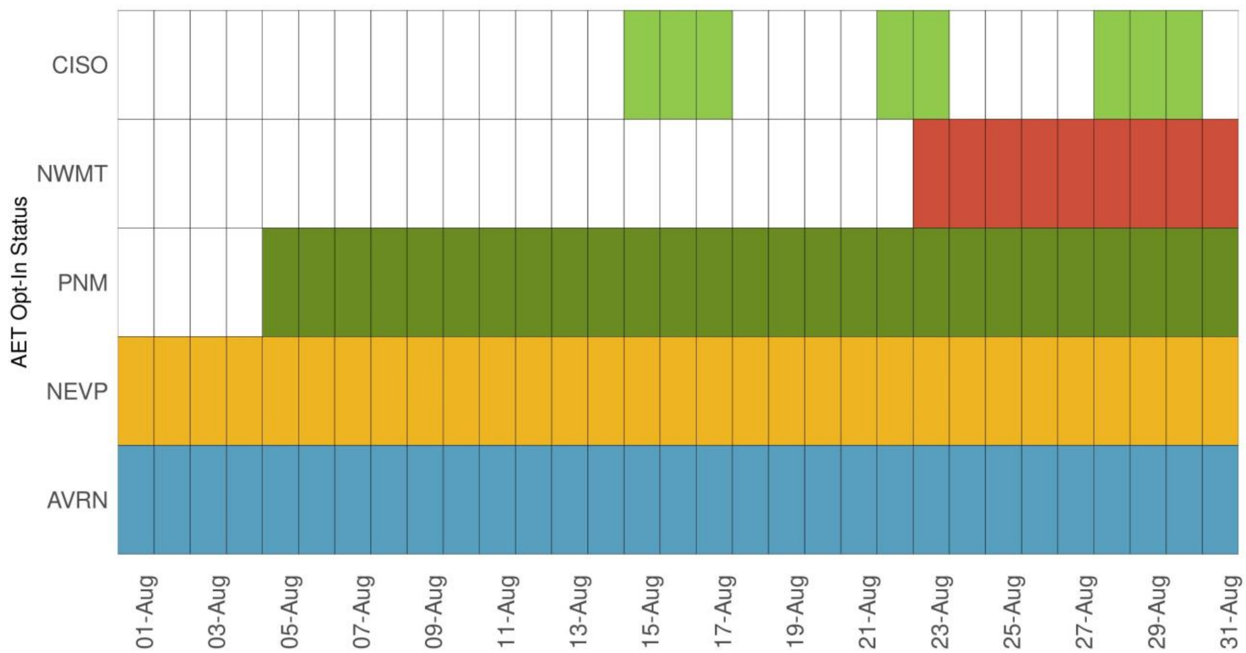
Assistance Energy Transfer (AET) was implemented with the Resource Sufficiency Evaluation Enhancements Phase 2, Track 1, effort which went live on July 1, 2023. The purpose of AET is to leverage the WEIM for energy assistance during under-supply conditions by optionally allowing incremental transfers 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, under current market rules, 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 applicable 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 August 2023, five BAAs opted into AET for some duration, including the ISO BAA. Figure 85 below shows the number of BAAs opted in for each trade date during the month. The ISO BAA opted into AET during the month of August when the requirements for the ISO BAA opt-in were met.[34]

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

Figure 85: BAAs opted into Assistance Energy Transfers, August 2023



The total amount of AET surcharge assessed during August was approximately $171,005 across the opted-in BAAs. Figure 86 shows the breakdown of total AET surcharge assessed per day for July and August 2023. 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 four trading days in August. Although the energy bid cap was raised to $2,000/MWh during some trading days in August, the cap was set at $1,000/MWh during all trading hours in which the opted-in BAAs were assessed for AET surcharge. In addition, although the ISO was opted-in for AET for a few trading days in August, no AET surcharge was assessed for the ISO because the conditions were not met to trigger AET for the BAA. Figure 87 shows a similar breakdown of total AET surcharge assessed by hour.

Figure 86: Total daily AET surcharge assessed, July and August 2023

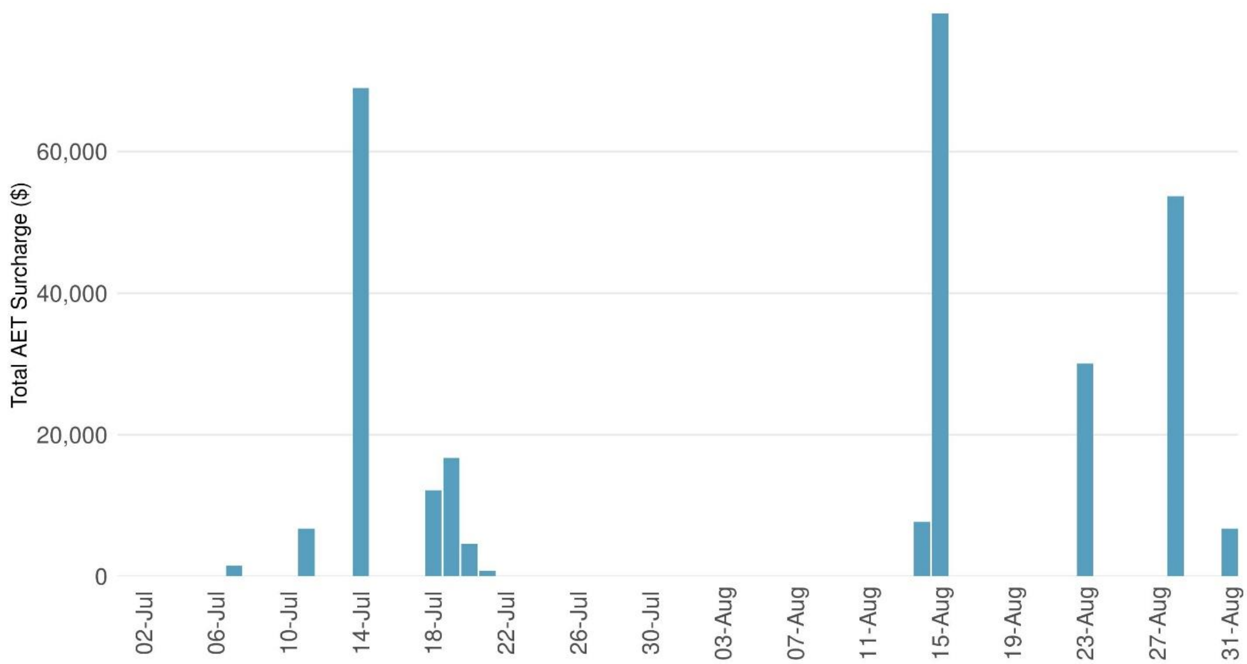
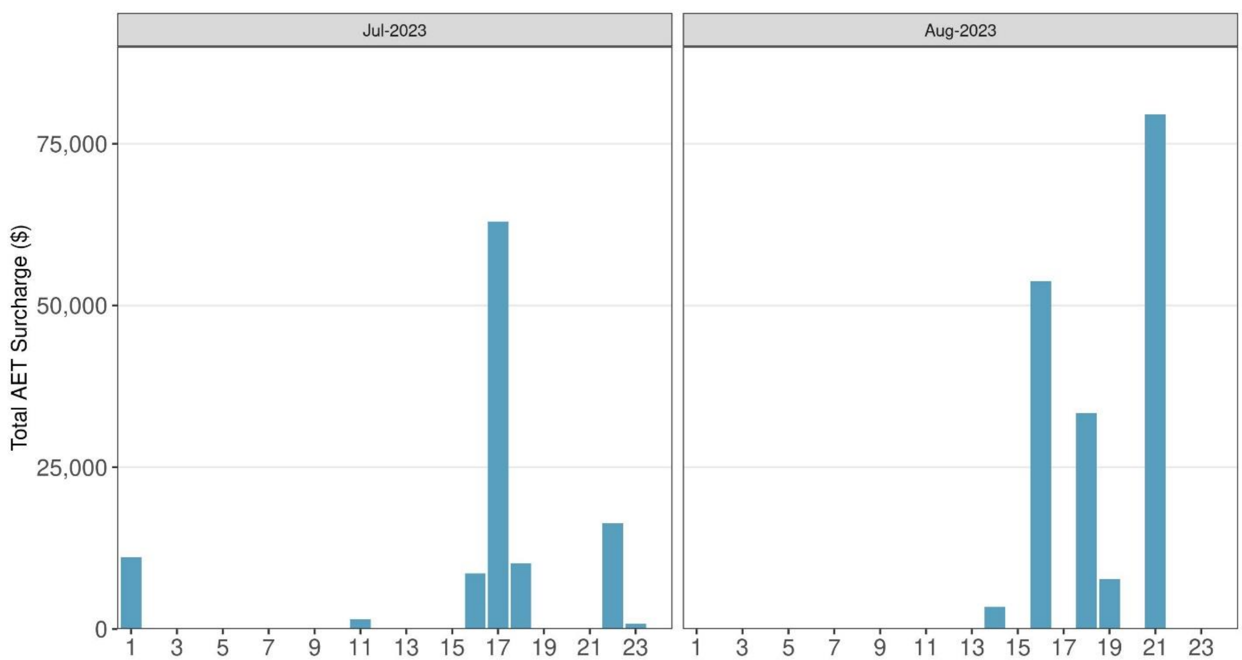


Figure 87: Total hourly AET surcharge assessed, July and August 2023



Areas for Improvement

Through the analysis of the market outcomes and performance, the ISO tracks any areas for improvements. For the month of August, there were no issues identified.