Summer Market Performance Report

June 2023

July 28, 2023

Prepared by

Market Analysis and Short Term Forecasting

The following members of the CAISO contributed to the analysis of this report.

Kevin Head

Scott Lehman

Zhu Liang

Monique Royal

John Rudolph

Jessica Stewart

Katie Wikler

Hong Zhou

Abhishek Hundiwale

Amber Motley

Guillermo Bautista Alderete

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Acronyms

AZPS or APS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CMRI	Customer Market Results Interface
CPUC	California Public Utilities Commission
DAM	Day ahead market
DLAP	Default Load Aggregated Point
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 first in a series of customized monthly reports focusing on the CAISO'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 will also provide a performance assessment of specific market enhancements implemented as part of the CAISO's summer readiness market rules changes.[1]

June 2023 Highlights

The CAISO extended the summer readiness initiative for the period of June 1, 2023 through May 31, 2024. This allows for the continued use of functionality for scheduling priorities for load, exports, and wheel-through transactions. There are also a series of summer 2022 enhancements that remained in place, including enhanced real-time pricing signals, management of storage resources, and resource sufficiency evaluation enhancements.

Overall June 2023 temperatures came in cooler than normal. On average, the peak loads in June 2023 came at about 28,463 MW, which is lower than the 34,249 MW average observed in June 2022. The highest hourly average load in the month was observed on June 30 at 35,721 MW when CAISO area experienced temperatures 3° F above normal. The instantaneous load peak on June 30 was 36,111 MW.

System saw an increase in levels of 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 the year and 86 percent of capacity overall.[2] Hydro production in June 2023 increased by 86 percent relative to the level observed in June 2022.

The CAISO's hourly load peak in the month happened on June 30 at about 35,721 MW. This load level was below the June 2022 as well as below monthly showings forecast of 42,373 MW used in resource adequacy (RA) programs.

Monthly RA capacity was approximately 48,909 MW and above the level of load needs, which is demand plus operating reserves. Compared to 2022, RA capacity for storage resources increased by 1,555 MW and also increased by 701 MW for static imports. Hydro RA saw an increase of 564 MW and gas-fired RA saw an increase of 1,415 MW.

[1] This report is targeted in providing timely information regarding the CAISO's market's performance for the month of June. 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

CAISO's prices showed moderate convergence across markets during June, and peaked at the beginning and towards the end of the month. The CAISO energy prices have been generally lower than historical prices from the same time period due to milder summer conditions and lower gas prices.

The residual unit commitment (RUC) process was able to meet the adjusted load forecast in peak hours for all the days in the month of June. Small volume of export reductions were observed on few days for the month of June mostly for economical bid-in exports.

Hourly average of net imports was about 2,892 MW for peak hours (17-21) in June. Real-time net imports reached their minimum levels on June 5 when CAISO experienced the largest volume of exports from the system in the month. The larger volume of exports was generally observed prior to the peak hours.

Western EIM transfers into the CAISO area evolved more to imports towards the end of the month. Transfers into CAISO's were from multiple areas, including adjacent areas and also from farther reaching areas. Overall, EIM transfers reflect the economic and operational benefits that EIM offers to participating entities by maximizing supply diversity.

About 92 percent of the RA imports bid at $0/MWh or lower prices in both the day-ahead market and real-time markets. This is assessed for static RA imports related to CPUC-jurisdictional load serving entities and for hours ending 17 through 21 on weekdays.

Up to 550 MW out of the 1,412 MW of registered wheels in June were used in the market. This represents a 39 percent utilization of the registered wheels. A maximum of 200 MW of high priority self-schedule wheels in the day-ahead were scheduled from Malin to Mead230 locations. For low priority wheels, the maximum transaction was 174 MW from Malin to Paloverde locations.

Reliability demand response resources were not activated in the real-time market in the month of June, while proxy demand response was dispatched up to 201 MW in the day-ahead market , and reliability demand response was scheduled in the day-ahead market up to 15 MW.

Storage resources continue to increase the level of capacity provided to the market. The bid-in capacity for energy was consistently over 4,000 MW for the month of June. The maximum state of charge in real time was about 16,000 MWh while real-time dispatches reached about 3,500 MW. Storage resources continue to procure a significant portion of regulation capacity.

On average, the CAISO's daily average market costs were $16.8 million in June. The highest daily cost accrued on June 29 at about $28.1 million. These cost levels are consistent with milder summer conditions observed in June.

2 Background

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

The Final Root Cause Analysis found three major causal factors contributing to the rotating outages of August 14 and 15, 2020:

1. The extreme heat wave experienced in mid-August 2020 was a 1-in-30 year weather event in California and resulted in higher loads that exceeded 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 CAISO identified one area of improvement to existing market practices regarding the treatment of export priorities. The CAISO 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 CAISO initiated an effort to identify, discuss with market participants, and propose enhancements across different areas of the market practices. This effort was initiated with educational workshops to level the understanding of existing market practices and their implications. This was followed by the formal launch of the Market Enhancements for Summer 2021 Readiness initiative[4].

The summer 2021 enhancements included:

1. Load, Export and wheeling priorities
2. Import market incentives during tight system conditions
3. Real-time scarcity pricing enhancements
4. Reliability demand response dispatch and real-time price impacts
5. Additional publication of intertie schedules
6. Addition of uncertainty component to the 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

These enhancements were implemented at different times during summer 2021.

For the 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, CAISO 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 and how soon they could be implemented to be ready for summer 2022, CAISO filed at FERC to extend the

[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

scheduling priorities phase 1 policy for 2022 and 2023 while still working on finalizing the second phase of the policy initiative

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

1. Enhancements to the resource sufficiency test. These include changes to the logic of the capacity test to improve the accounting of the supply available in real-time. This also include the consideration of the supply infeasibilities projected in the real-time market into the flexible ramping test.
2. Further visibility to non-RA capacity for resources supporting exports. This includes notifications when high priority exports schedule exceeds the non-RA capacity of the supporting resource.
3. Enhancements to ensure variable energy resources (VER) supporting high-priority exports are based on the most recent forecast ahead of the real-time. Therefore, when the forecast changes, 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.

Finally, CAISO completed a subsequent phases of the resource sufficiency evaluation process and energy storage resources. These items were effective as of July 1 and therefore were not in place for the performance assessment of the month of June. CAISO also filed an extension continue to use the Minimum state of charge for the summer 2023 and is currently in place.

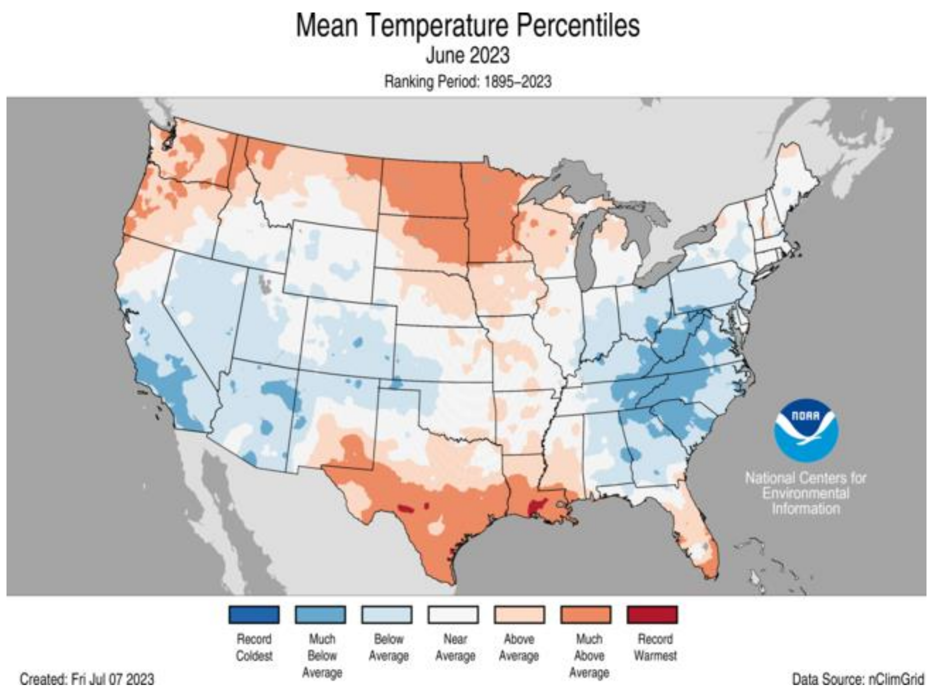
3 Weather and Demand Conditions

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

Much below average and below average mean temperatures were observed across most of California and the Southwest in June 2023 while the Pacific Northwest observed above and much above average mean temperatures. This is shown in Figure 1.

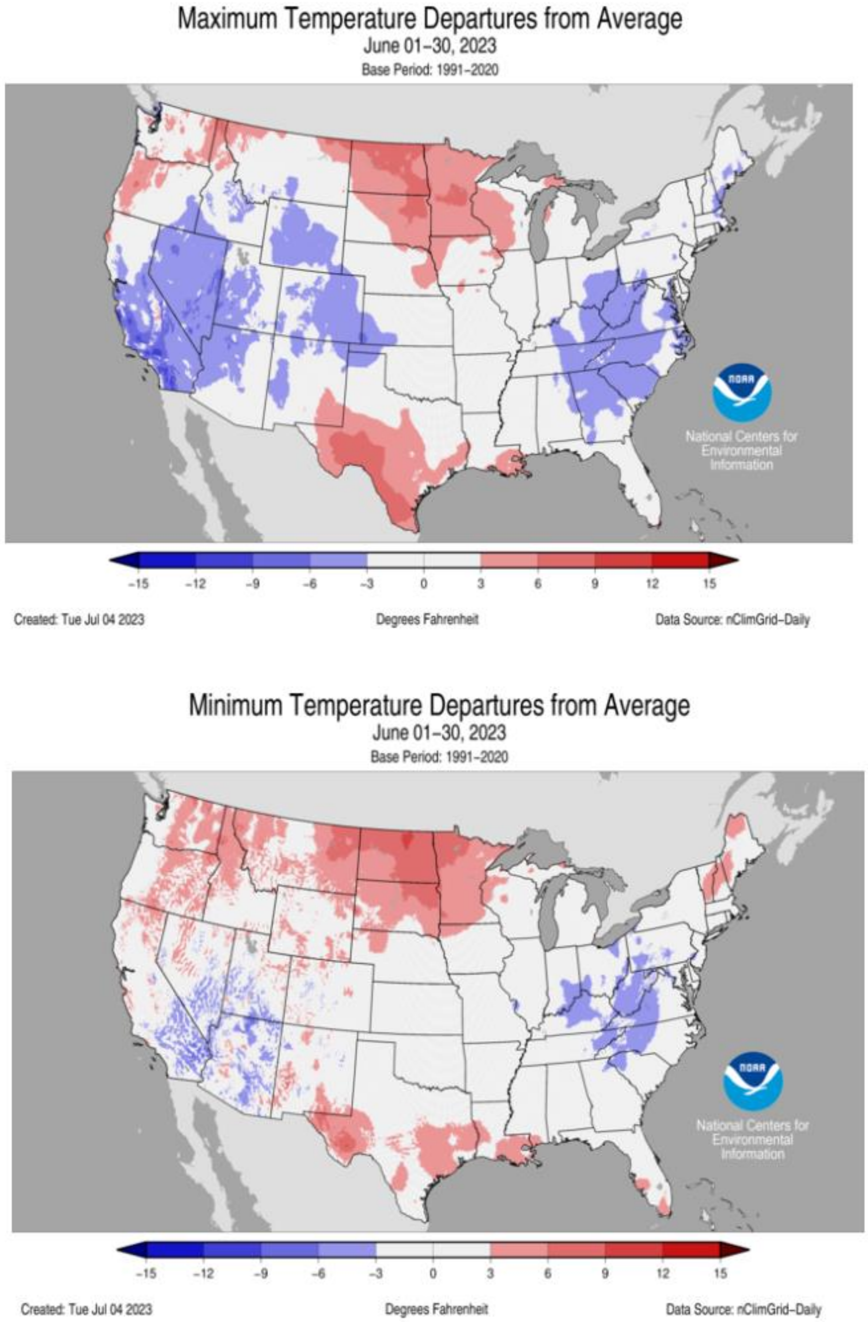
Figure 1: Mean temperature percentiles for June 2023[6]



In Figure 2 it is shown that there were more widespread maximum departures below normal versus above normal. Much of California, Utah, Arizona, Colorado and Wyoming ended June with an average maximum temperature at least 3 degrees below average while parts of Oregon, Washington, Idaho and Montana had some maximum temperature areas above average and some areas below average. Minimum departures from average across the west weren't as widespread, but many desert locations throughout the southwest had below average overnight temperatures while the Pacific Northwest has the largest concentration of above normal overnights.

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

Figure 2: Maximum and minimum CONUS temperature departures from normal for June 2023[7]



Looking at the Desert Southwest WEIMs more closely in Figure 3, the maximum temperature anomalies varied across the region. Entities further west within Nevada and Arizona saw below normal temperatures for most of the month but shifting further east into Texas, above normal temperatures were observed the second half of the month.

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

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

Arizona Public Service (APS)

High temperature departure from normal

June 2023

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

above normal	below normal	Normals: 1990-2020

El Paso Electric

High temperature departure from normal

June 2023

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1 -7	2 -6	3 -2
4 -3	5 -4	6 -3	7 -4	8 -2	9 -8	10 -3
11 1	12 -2	13 -4	14 -1	15 0.4	16 2	17 2
18 2	19 5	20 2	21 5	22 8	23 7	24 7
25 9	26 10	27 10	28 8	29 5	30 3	
				days < normal 13	days > normal 17	Deg +/- normal + 1.3

above normal	below normal	Normals: 1990-2020

As shown in Figure 4, throughout the CAISO temperatures were below normal almost every day of the month. Most days featured highs 5-15°F below average, but there were some days where highs dropped as low as 20-25°F below average in spots. On June 6 Sacramento only hit a high of 73°F, their coolest June high since 2017 and on June 12 Riverside only reached 65°F, their coolest June high since 1969.[8] The final day of June was the warmest for the state, ahead of the first warm up of the season with temperatures across the interior reaching 100°F+ on June 30.

Figure 4: CAISO high temperature departure from normal

California ISO (CAISO)

High temperature departure from normal

June 2023

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

above normal	below normal	Normals: 1990-2020

Unlike CAISO and most of the Desert Southwest, the Pacific Northwest ended June with an above average high temperature. There were many large temperatures swings, with highs dropping upwards of 20+

[8] http://xmacis.rcc-acis.org/

degrees in just 2 days for many cities across the Pacific Northwest, but ultimately the hotter days were a bit stronger and more frequent than the cooler days.

Figure 5 High temperature departure from normal for select Northwestern WEIMs

Portland Gas and Electric (PGE)
High temperature departure from normal
June 2023

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

above normal | below normal | Normals: 1990-2020

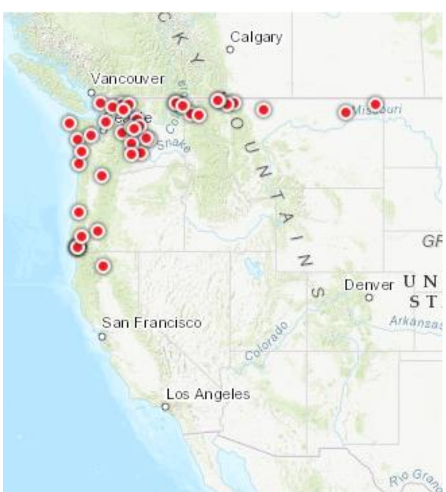
Seattle City Light (SCL)
High temperature departure from normal
June 2023

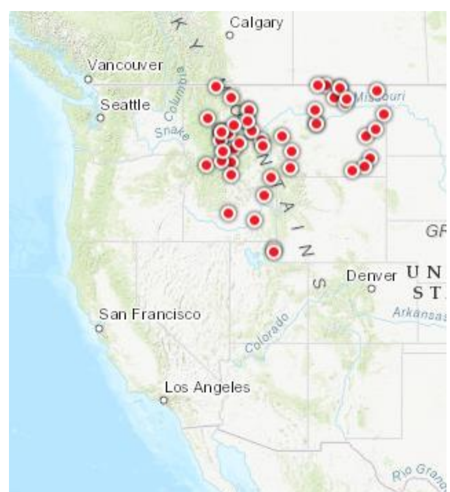
Sun	Mon	Tues	Wed	Thurs	Fri	Sat
				1: 0.3	2: 3	3: 4
4: -0.2	5: 2	6: 12	7: 15	8: 2	9: -11	10: -9
11: 0	12: 13	13: -4	14: -6	15: 0.3	16: 0	17: -12
18: -10	19: -9	20: -13	21: -2	22: 5	23: 8	24: -3
25: 5	26: 0	27: -1	28: 4	29: 6	30: 4	
				days < normal: 14	days > normal: 16	Deg +/- normal: + 0.1

above normal | below normal | Normals: 1990-2020

Looking at the western United States temperature records in Figure 6, there were only 83 daily maximum temperature records which were tied or broken during the month of June and 627 daily warmest minimum temperature records which were tied or broken. However, for the record lowest maximum temperatures, indicating that locations observed their record coolest high temperature for a given date, there were 690 daily lowest maximum temperature records tied broken for the west and 766 record lowest minimum temperature records tied or broken. This reiterates the strength and frequency of the cooler air that was observed across the west in June, both overnight and during the daytime.

Figure 6: Highest maximum temperature records broken or tied (left) and highest minimum temperature records tied or broken (right) in June 2023[9]



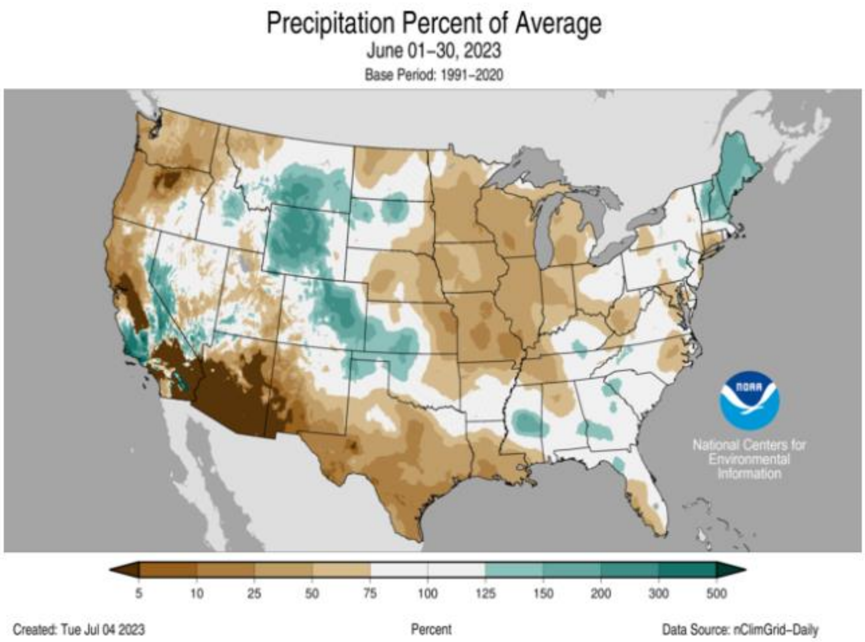


[9] https://www.ncdc.noaa.gov/cdo-web/datatools/records

3.2 Hydro conditions

The majority of the western United States experienced below normal rainfall in June. This is shown in Figure 7. A lack of monsoon storms across Arizona, New Mexico and the deserts of California led to these areas only seeing 5% or less of their average June rainfall, totaling .01" or less. Northern California and the Pacific Northwest also had below normal rainfall. Frequent afternoon showers and storms across the Sierra's lead to this region seeing above normal precipitation.

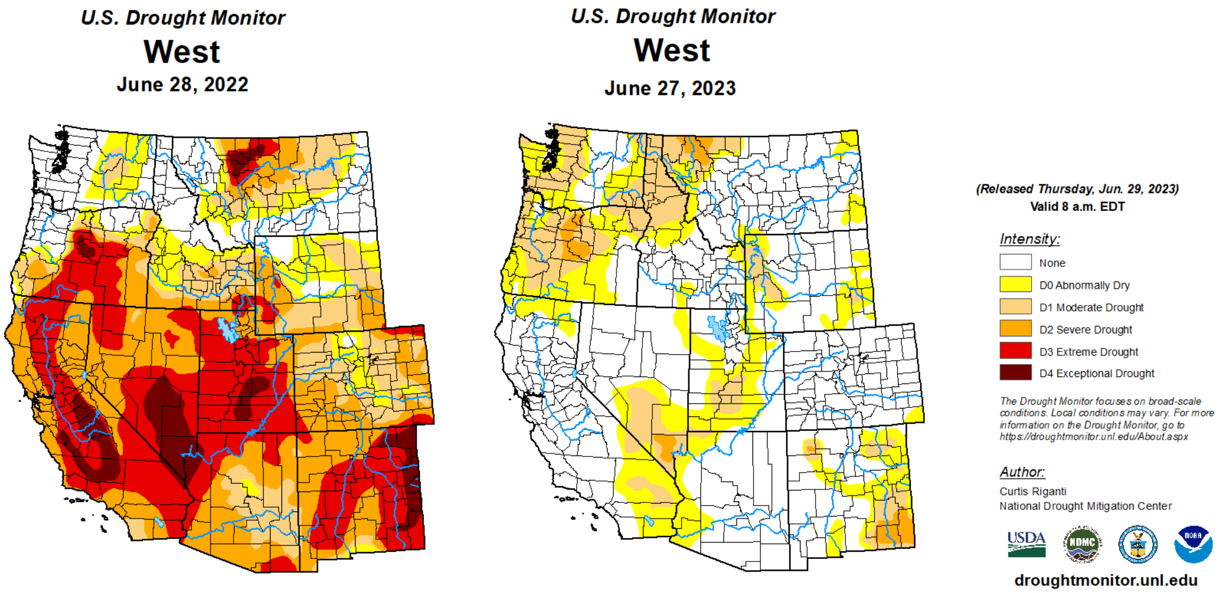
Figure 7: The United States precipitation percent of normal for June 2023 [10]



The above normal winter rain and snowfall caused the Sierra's to see their 2nd largest snowfall on record, and has also lead to drought diminishing significantly compared to this time last year.[11] This is shown in Figure 8. California nor any other state in the west has any areas that are in extreme or exceptional drought, a large improvement compared to 2022. In June 2022, extreme or exceptional drought covered 32% of the west. While this is great for reservoirs and water supply, excessive rainfall throughout the winter months can also aid in leading to longer, taller and more grasses to dry out and could lead to a more impactful fire season in the Summer and Fall for the lower elevations due to larger fuel availability.

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

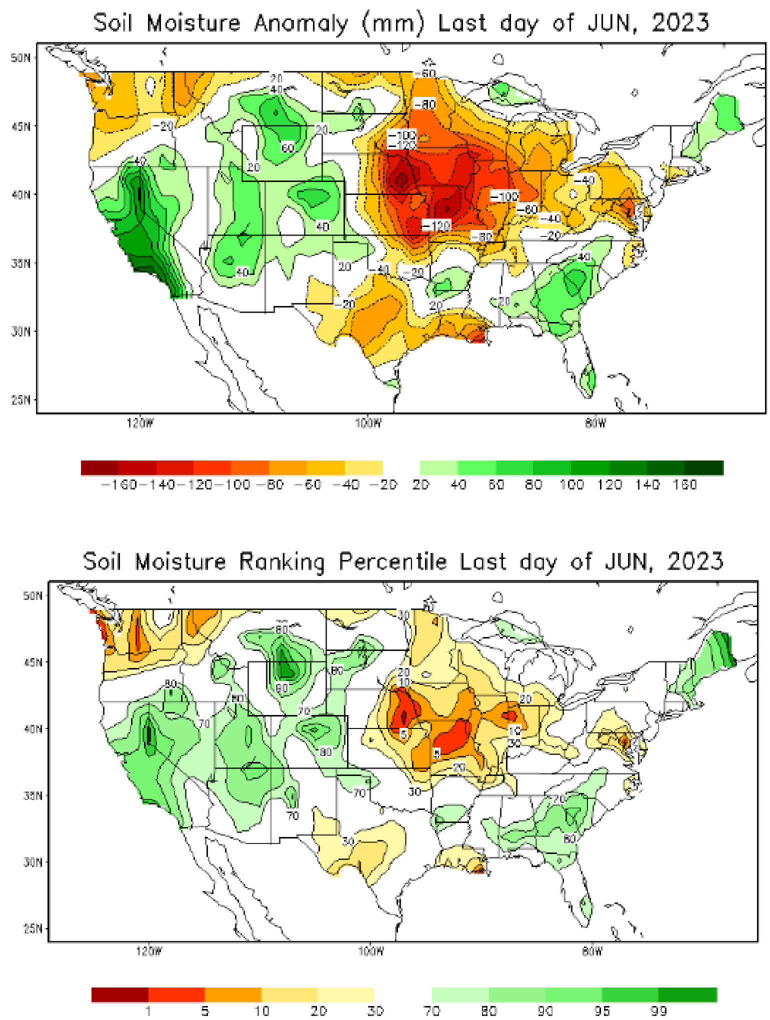
Figure 8: The Western United States drought monitor for June 28, 2022 (left), compared to June 27, 2023 [12]



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

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

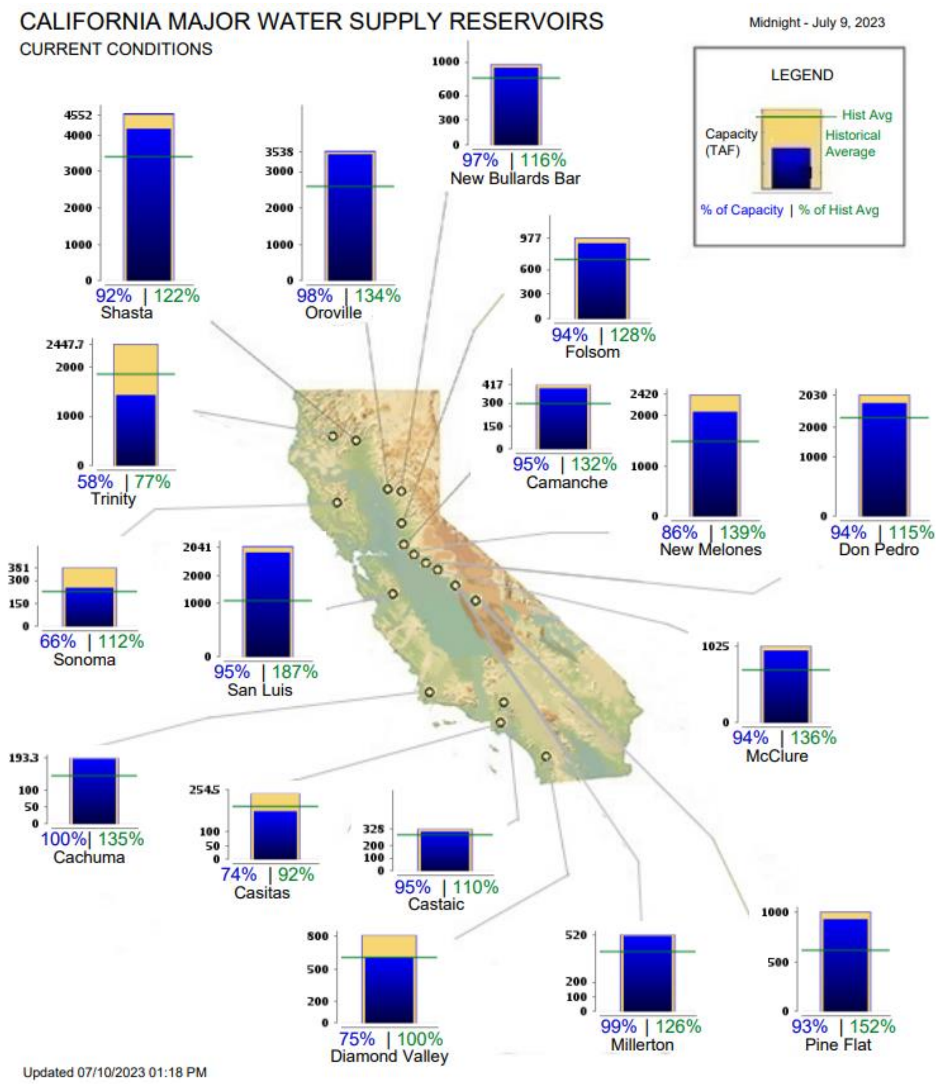
Figure 9: The United States soil moisture for June 2023 (top) and the soil moisture rank (bottom)[13]



Based on all the factors discussed above related to temperatures, precipitation, drought conditions, and soil moisture levels, many reservoir conditions for California and the west are significantly above normal, as shown in Figure 10. Reservoir levels across the state are at or above historical averages for end of June, including 12 of 17 that are at 90% or more of their capacity.[14] The statewide storage in major reservoirs is currently 80% of average and 54% of capacity[15]. This is compared to 57% of average and 39% of capacity at the end of June 2022. As of June 30, the states remaining snowpack contains 325% more water equivalent than average, which will assist in keeping more snowmelt and runoff later into the season.[16]

[13] https://www.cpc.ncep.noaa.gov/products/Soilmst_Monitoring/US/Soilmst/Soilmst.shtml#
[14] https://cdec.water.ca.gov/resapp/RescondMain
[15] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM
[16] https://cdec.water.ca.gov/snowapp/sweq.action

Figure 10: California's reservoir conditions as of July 9, 2023[17]



The CAISO's electrical system utilizes hydro production throughout the year to meet the CAISO demand needs. Due to the significant reduction in available water capacity currently observed in the reservoirs, the CAISO continues to see reduced capacity in hydro production this year. Figure 11 below shows the historical trend of total energy produced from hydro resources, as well as renewable resources, in which hydro production for 2022 so far has been relatively higher than in 2021. Hydro production in June 2023 was about 86 percent higher than the production observed in June 2022.

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

Figure 11: Historical trend of hydro and renewable production

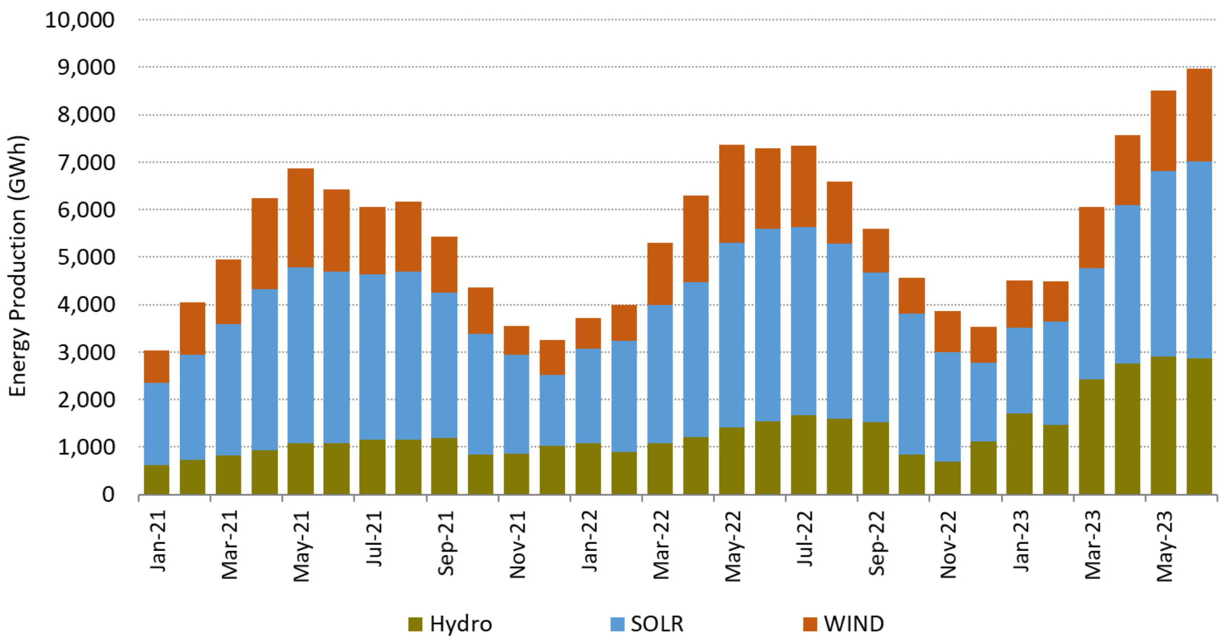
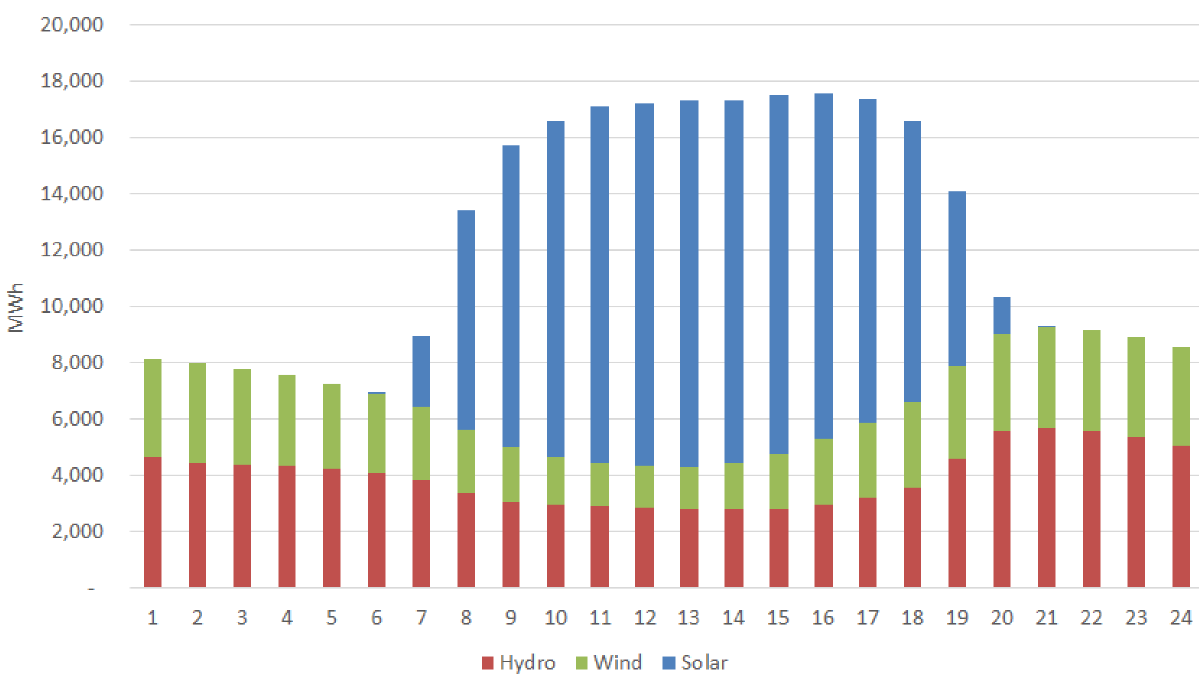


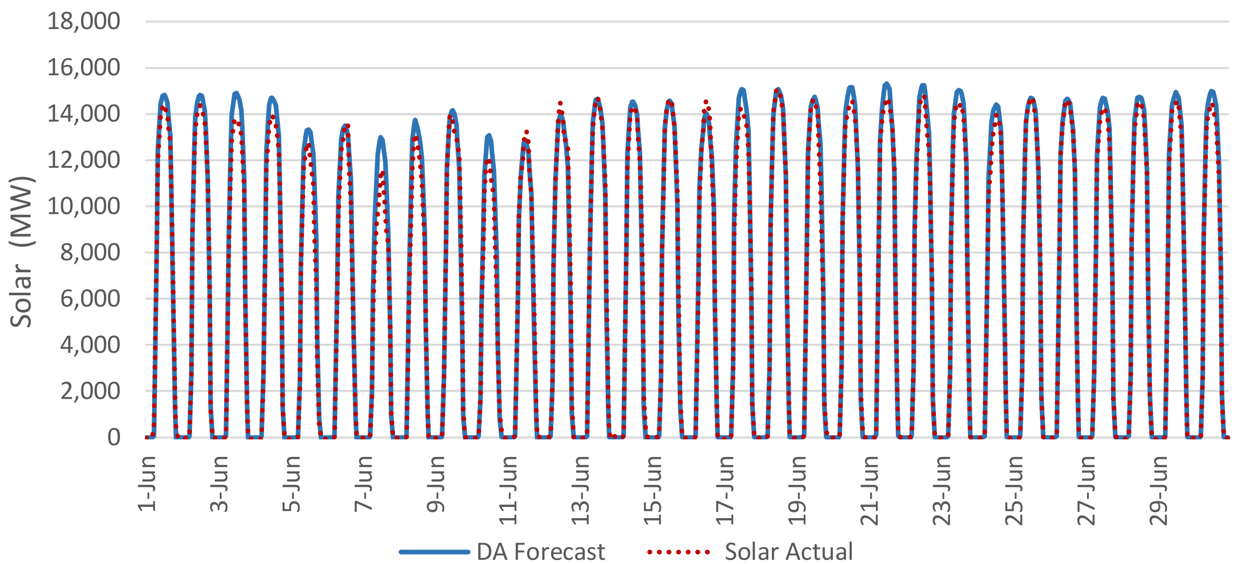
Figure 12: Hourly profile of wind, solar and hydro production for June



3.3 Renewable forecasts

Figures 12 and 13 below show the solar and wind day-ahead renewable forecasts compared to actual plus supplemental dispatch. Supplemental dispatch reflects the market's downward dispatch relative to the resource's forecast based on their bids. This allows the CAISO 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 CAISO's area



Unusual June showers for parts of the southern San Joaquin Valley and Sierra's, as well as increased periods of cloud cover for the deserts accompanied by the systems bringing the cooler June air led to an increase in cloud cover for the first couple weeks of the month. This caused some over-forecasting of solar in the day-ahead during this period. The average error[18] for the day-ahead solar forecast in June 2023 was 2.60 percent. The average error observed in June 2023 is slightly higher than the day-ahead solar forecast error observed for June 2022, but lower than the error observed in June 2021.[19]

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

[19] http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun29-2023.pdf

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

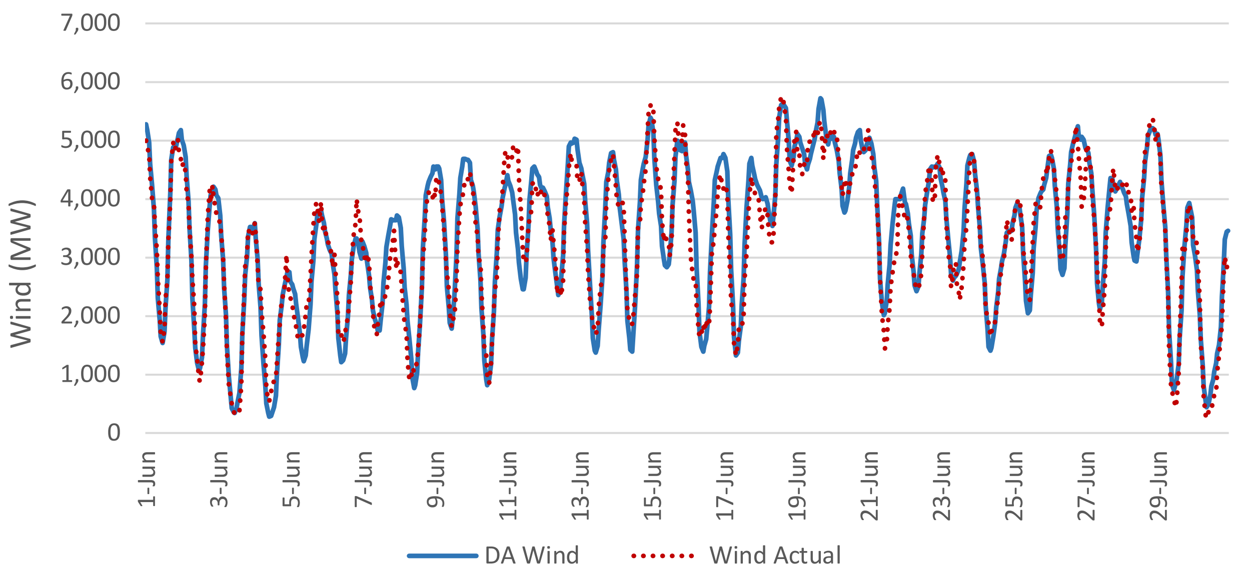


Figure 13 shows the day-ahead wind forecast compared to the actuals plus curtailments throughout the month of June for wind in the CAISO's system. The average error[20] for the day-ahead wind forecast in June was 3.55 percent. The average error observed in June 2023 is lower to the day-ahead wind forecast error observed for June 2022 and June 2021.[21]

3.4 Demand forecasts

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

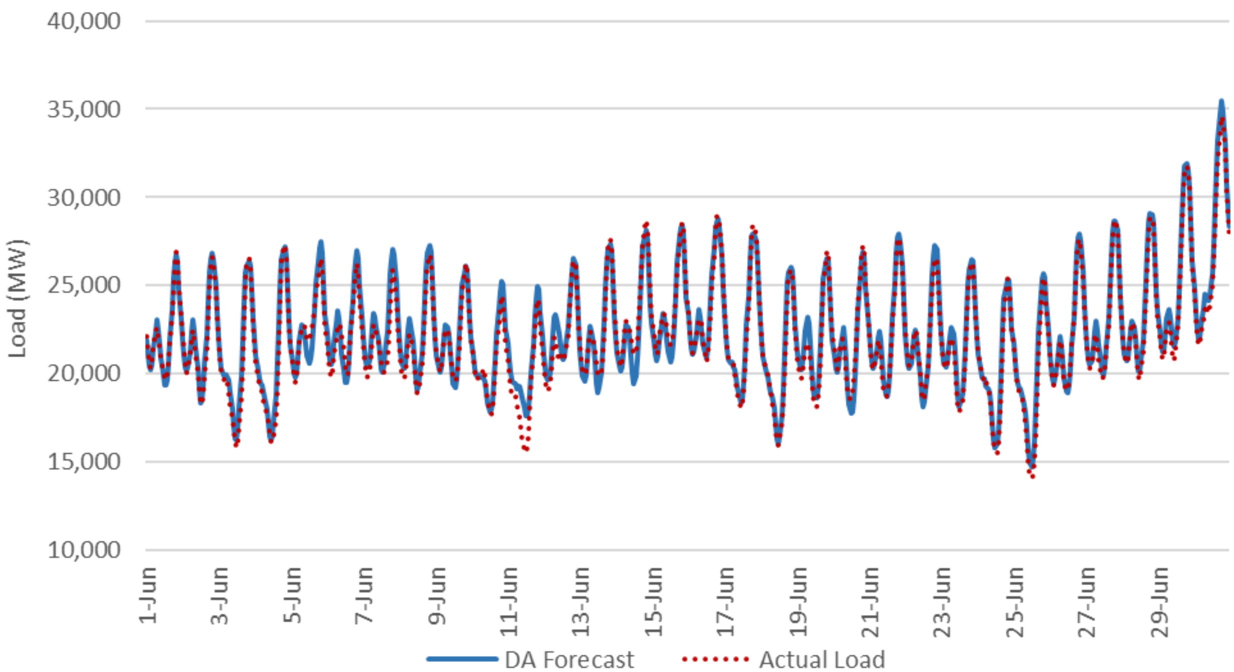
3.4.1 CAISO's demand forecasts

The CAISO demand during the month of June 2023 continued to be very responsive to the temperature changes observed throughout the month. Figure 14 shows the trend of the CAISO's load without pump loads included to examine forecast error. The highest hourly average June load of 35,721MW was observed on June 30, 2023 when the CAISO footprint was running 3 degrees F above normal for maximum temperatures.

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

[21] http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun29-2023.pdf

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



Some of the larger errors seen in June were observed in the days with cooler than normal temperatures and increased cloud cover. For example, the period of June 5 – 12 saw high temperatures up to 11 degrees below normal due to increased cloud cover. The significantly below normal temperatures in addition to the increased cloud cover results in the forecasted peak to come in higher than the actuals, in addition to more error during the day due to behind-the-meter solar variability.

The average accuracy error for the day-ahead demand forecast in June was 2.05 percent, while the error for peak hours was 1.39 percent. The average error observed in June 2023 was slightly higher than the error observed in June 2021 and 2022 which was 2.0 and 1.92 percent.

3.5 Energy Conservation

During the month of June the CAISO 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 June.

3.6 Demand Response

3.6.1 Market demand response

The CAISO markets consider demand response programs designed to reduce demand based on system needs, and trigger demand response programs through market dispatches. In the CAISO's markets, there are two main market programs for demand response: economic (proxy) and emergency demand response. These programs use supply-type resources 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 month of June, PDR resources were consistently dispatched in both the day-ahead and real-time markets. The largest volume of PDR dispatches in real-time occurred on June 30 at about 201 MW.

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

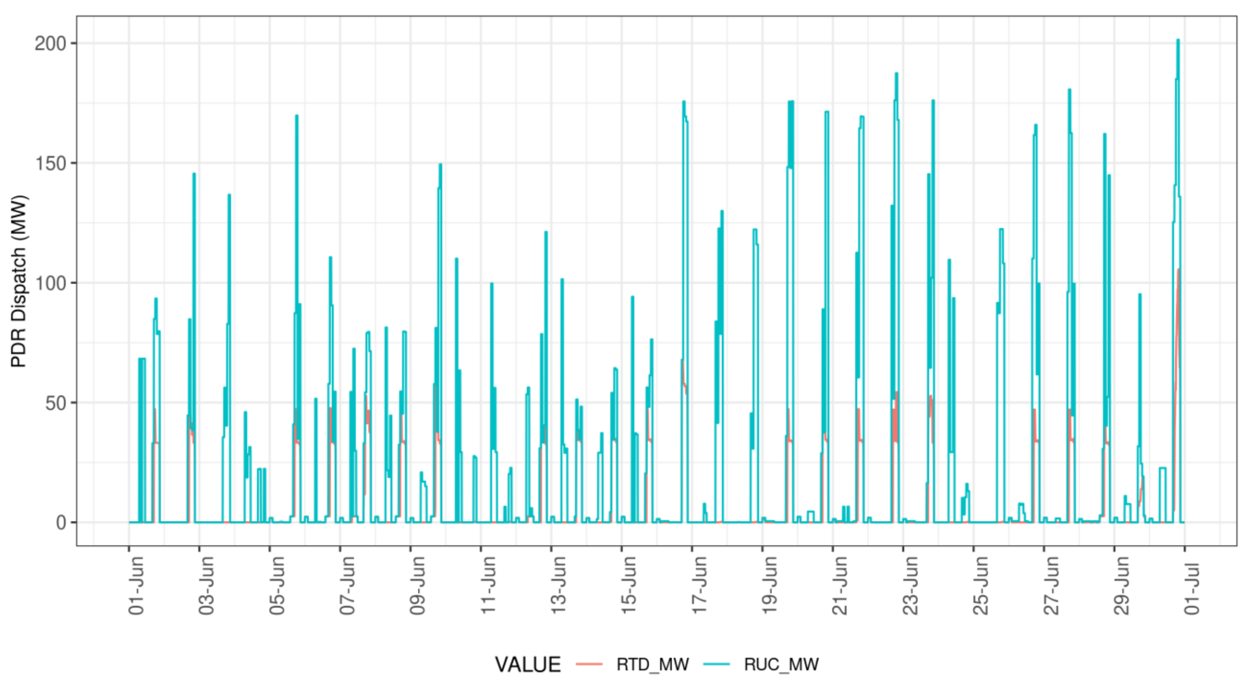
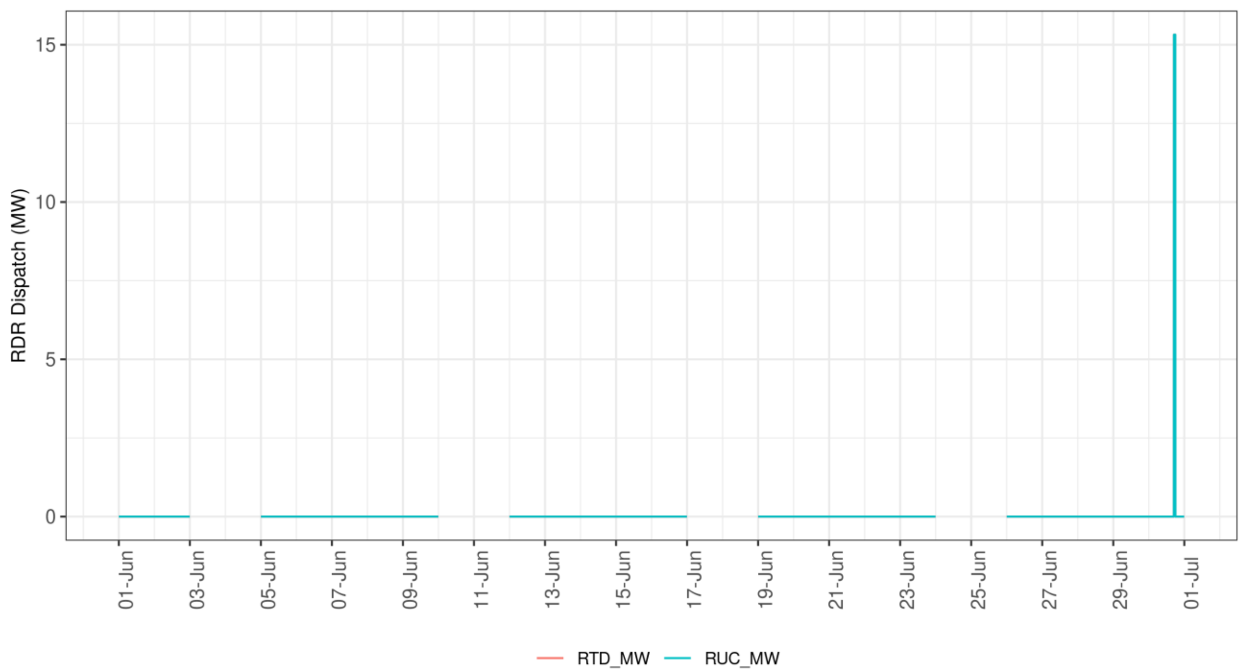


Figure 17 shows the dispatches for reliability demand response resources (RDRRs) in both the day-ahead and real-time markets. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market even when there is no energy emergency declaration. Although most RDRRs are only deployed in the real-time when the CAISO has declared at least a CAISO Warning, some RDRRs may bid-in economically into the CAISO day-ahead market. In that 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 day ahead market only on June 30 to about 15 MW.

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



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

3.6.2 Non-market resources

This section will focus on various non-market resources, many of them new state programs to address extreme events, which are triggered through differing conditions on the BAA's system. These resources can include formalized demand-side programs not integrated into the ISO market, coordinated conservation efforts, and non-market generation authorized by California legislation. For the ISO, some of these programs can be triggered by conditions such as Flex Alerts and EEA categories. For the IOU's some of these demand-side programs can be scheduled outside of Flex Alerts and EEA conditions.

On June 30th there was 25.1 MW of non-market resources scheduled for deployment. There were no other scheduled non-market resource events in June 2023.

4 Demand and Supply

4.1 Resource adequacy

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

Through the RA program, there are three types of capacity: System, Local and Flexible. All three products serve a purpose in ensuring a reliable operation of the system. The events of August 2020 were primarily a result of insufficient system RA since it was a condition of insufficient supply to meet the overall system demand. For system capacity, the RA requirement ensures the contracted capacity is sufficient to cover the 1-in-2-year (average) peak load plus a 15 percent PRM.[22] This PRM is to cover the 6 percent of operating reserves while the rest is a contingent headroom to account for higher-than-expected load forecast and resource outages.

The monthly RA showing for June 2023 was 48,909 MW, which is higher than June 2022's monthly showing of 47,266 MW.[23] Figure 18 compares the total monthly RA capacity in June 2022 and June 2023 by fuel type. The total RA capacity in June 2023 is about 1,643 MW higher than that of June 2022 and generally increased across fuel types with some exceptions. RA capacity for storage resources increased by 1,555 MW and also increased by 701 MW for static imports. Hydro RA saw an increase of 564 MW and gas-fired RA saw an increase of 1,415 MW.

Static RA imports increased from 1,144 MW in June 2022 to 1,845 MW in June 2023.[24] The composition by intertie varied between years as shown in *Figure* 19. RA imports through Malin increased by 512 MW between June 2022 and June 2023; imports through NOB also increased by 193 MW across the same

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

[23] 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.

[24] 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.

timeframe. Monthly RA capacity tends to increase as the summer progresses and were generally on par with quantities from 2022. Monthly static RA imports also increases as the summer progresses, with June 2023 static imports at a higher quantity than June 2022 static imports. These trends are shown in Figure 18 and Figure 19.

Figure 18: RA capacity organized by fuel type

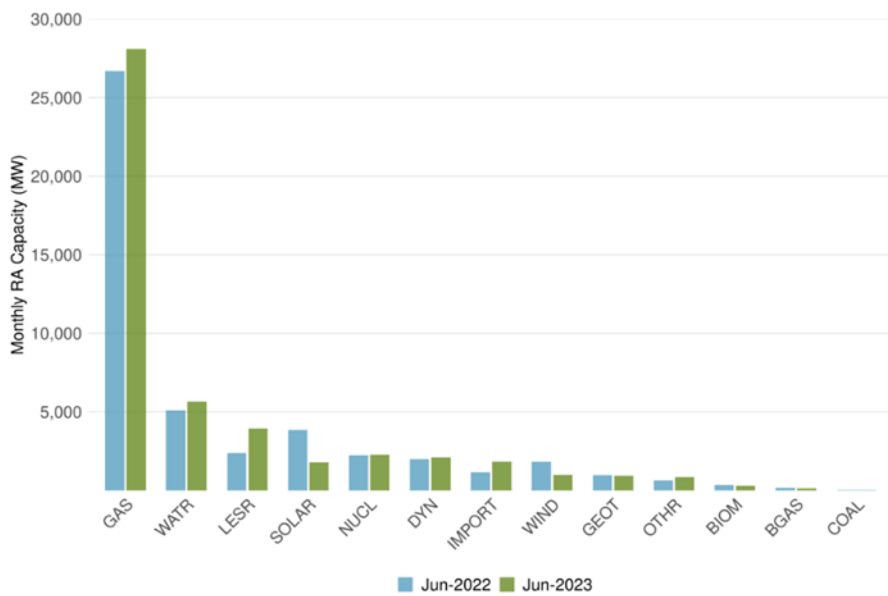


Figure 19: Monthly RA imports organized by tie

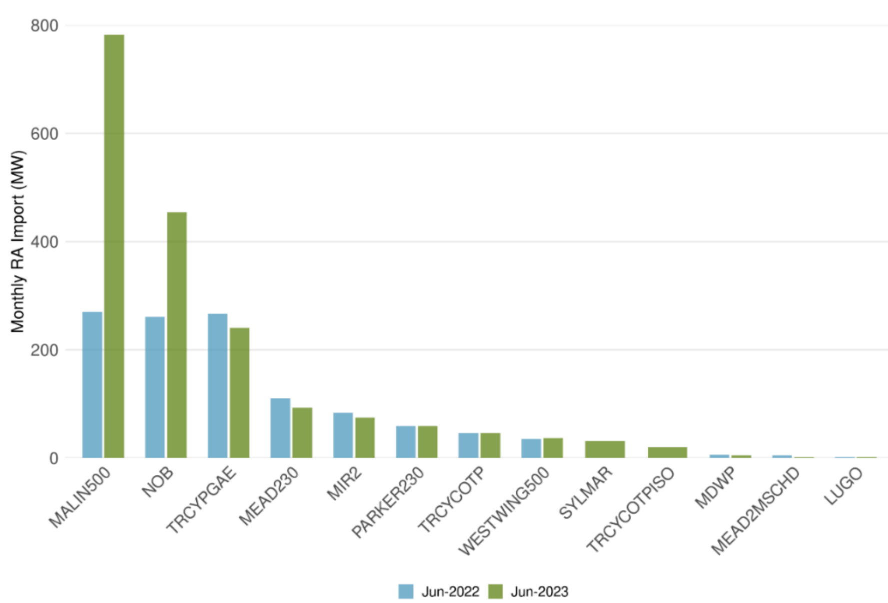


Figure 20: Monthly RA showings, three month trend

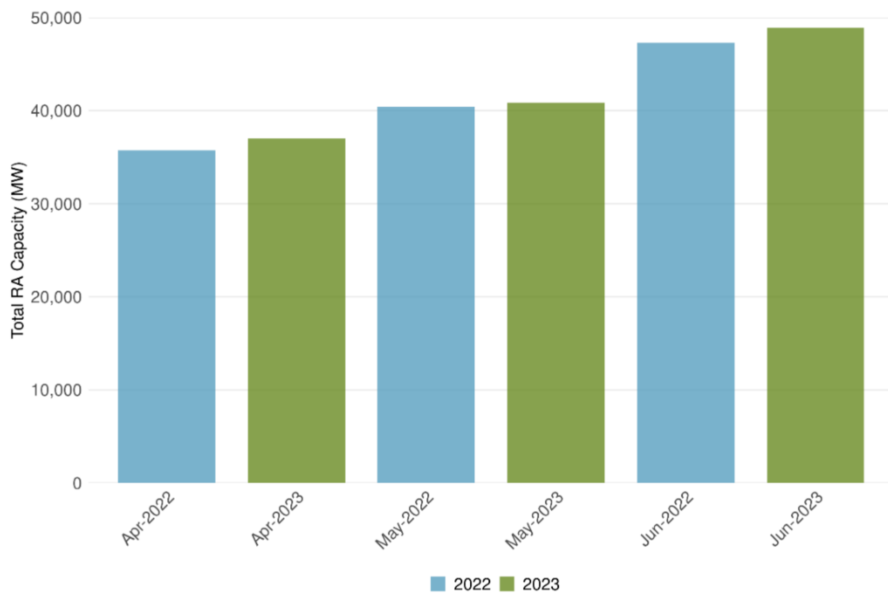
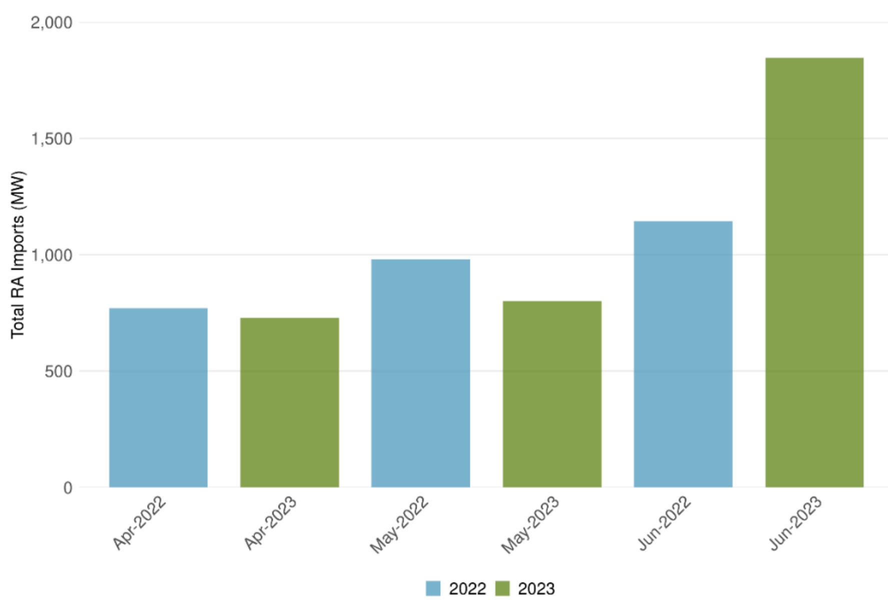


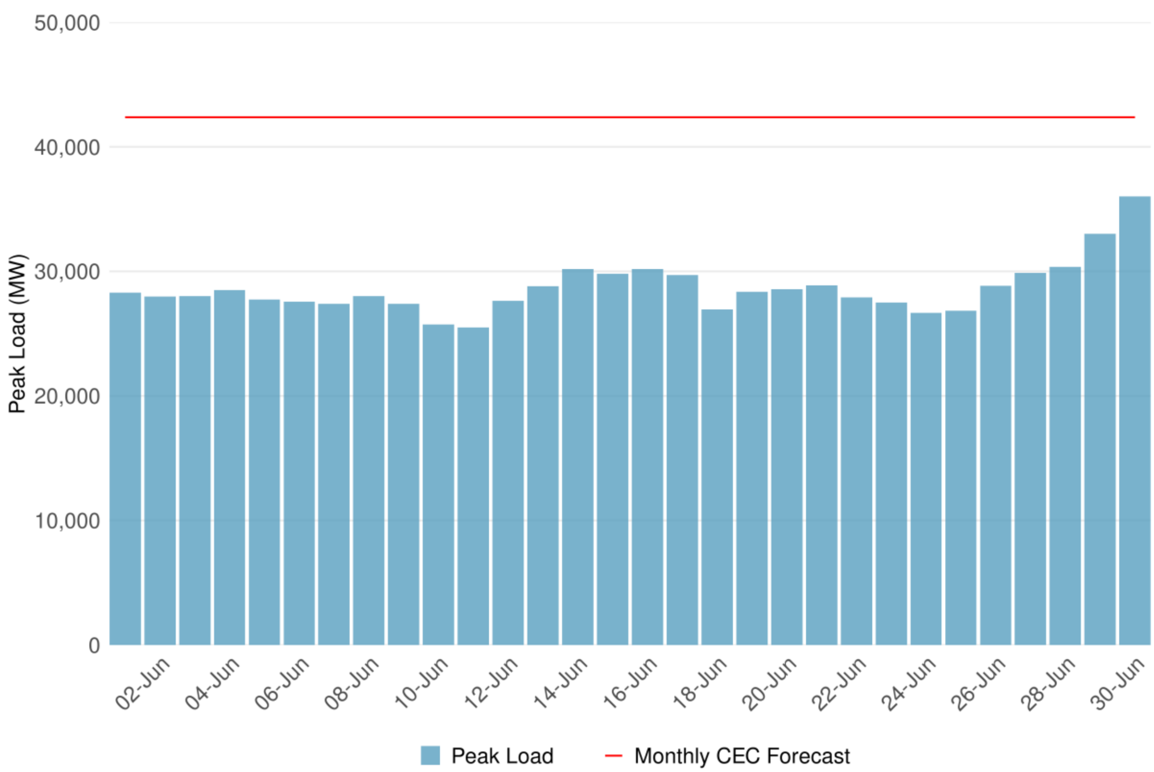
Figure 21: Monthly trend of static RA Imports, three month trend



4.2 Peak loads

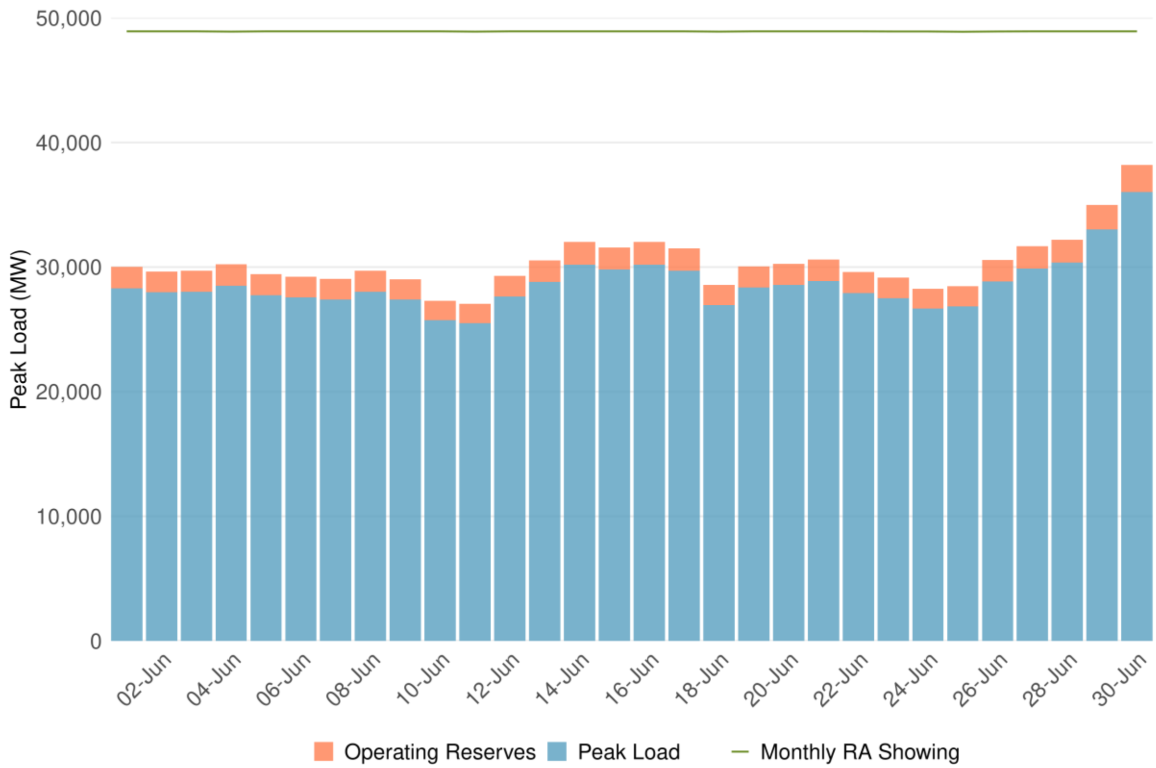
Peak loads in June 2023 generally remained below 30,000 MW with some exceptions throughout the month. The average daily peak load in June 2023 was approximately 28,608 MW which was lower than the average daily peak load in June 2022 of 34,445 MW. Figure 22 shows the 5-minute average daily load peak for June 2023 relative to the June 2023 CEC month-ahead forecast used to assess the resource adequacy requirements. The highest 5-minute average load of the month was 36,029 MW, occurred on June 30 and was below the CEC month-ahead forecast of 42,372 MW.

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



The actual load did not exceed the monthly RA showings for June 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 CAISO'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. Locations 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 CAISO's markets.[25] Figure 25 shows average daily prices across CAISO's markets for June 2023.

[25] 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 CAISO area.

Figure 24: Average daily prices across markets

Figure 25: Average hourly prices across markets, June 2023

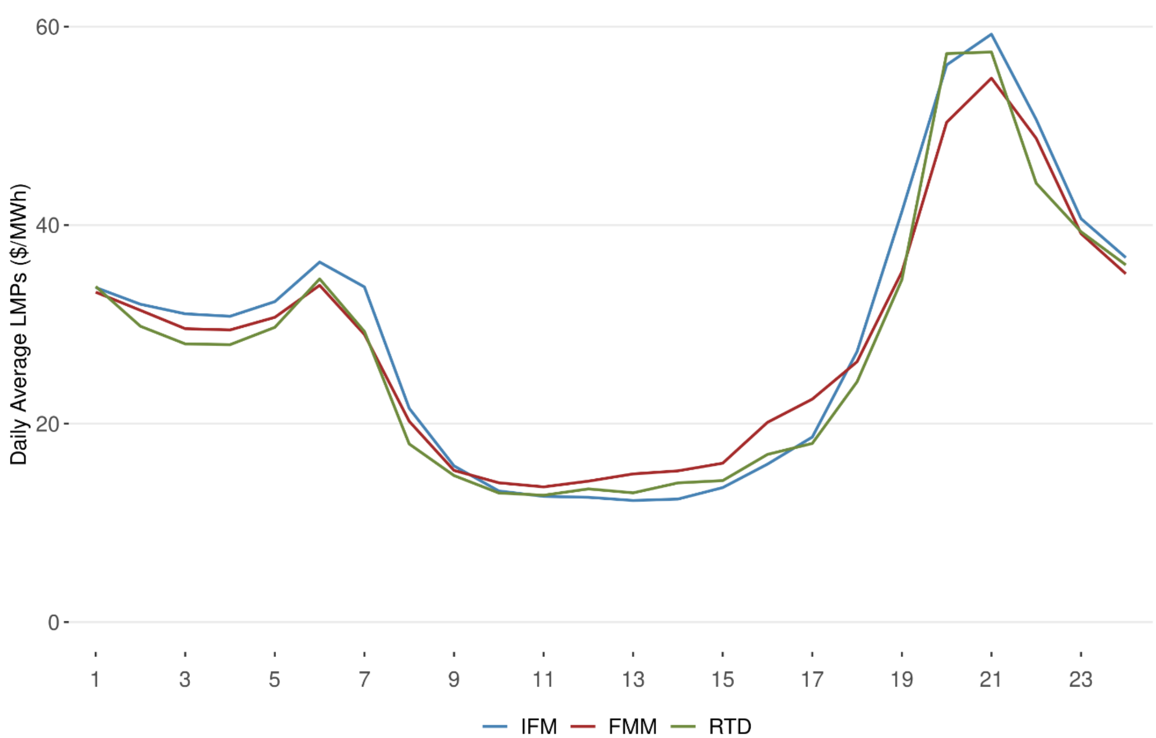


Figure 26 and Figure 27 show the daily and hourly distribution of day-ahead prices with box-whisker plots. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for 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 June 2023 was $28.77/MWh and the maximum LMP of $105.3/MWh occurred on June 30, 2023.

Figure 26: Daily distribution of IFM prices

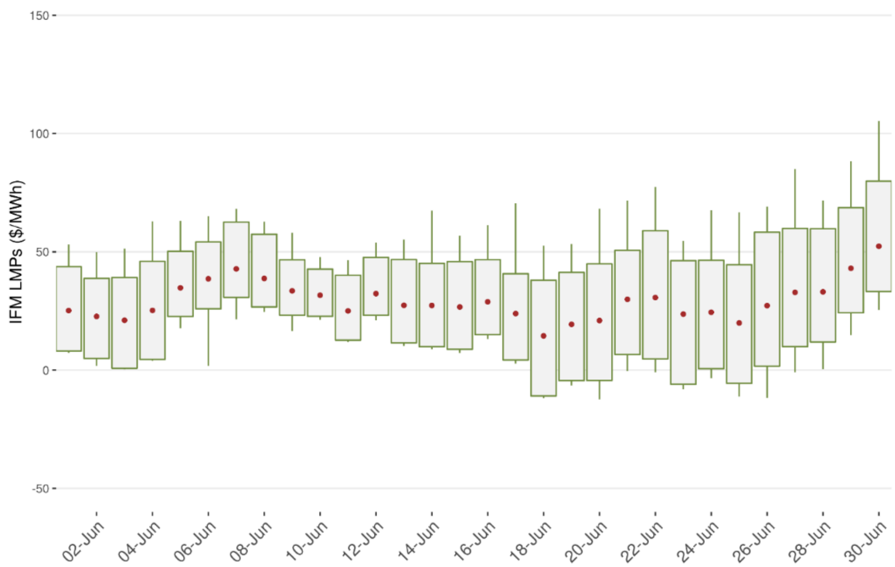


Figure 27: Hourly distribution of IFM prices, June 2023

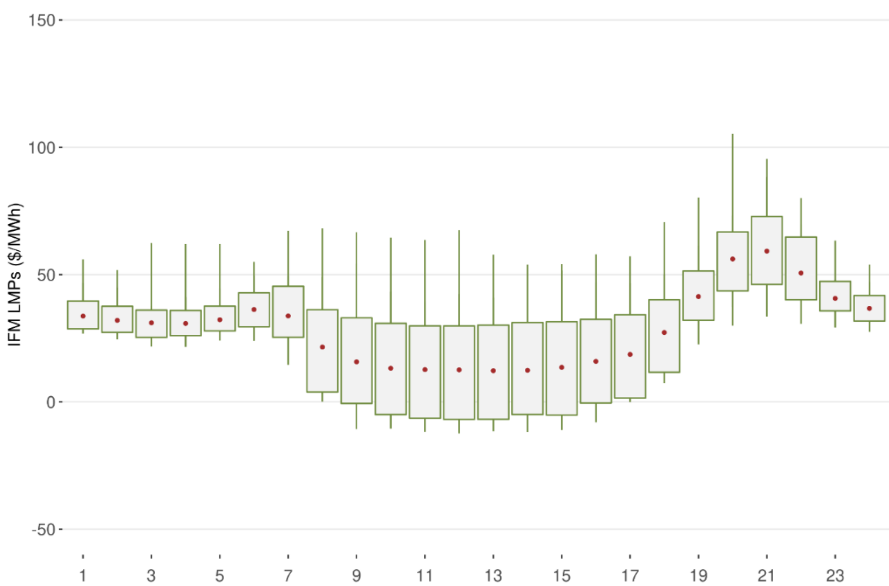


Figure 28 and Figure 29 show daily and hourly distributions of fifteen-minute market (FMM) prices throughout the month. The average FMM LMP in June 2023 was $28.05/MWh and the maximum LMP of $201.79/MWh occurred on June 7, 2023. The June 2023 FMM prices exhibited a larger spread than corresponding IFM prices, however given the dynamic conditions of real-time as compared to day-ahead, such price excursions are not unusual.

Figure 28: Daily distribution of FMM prices

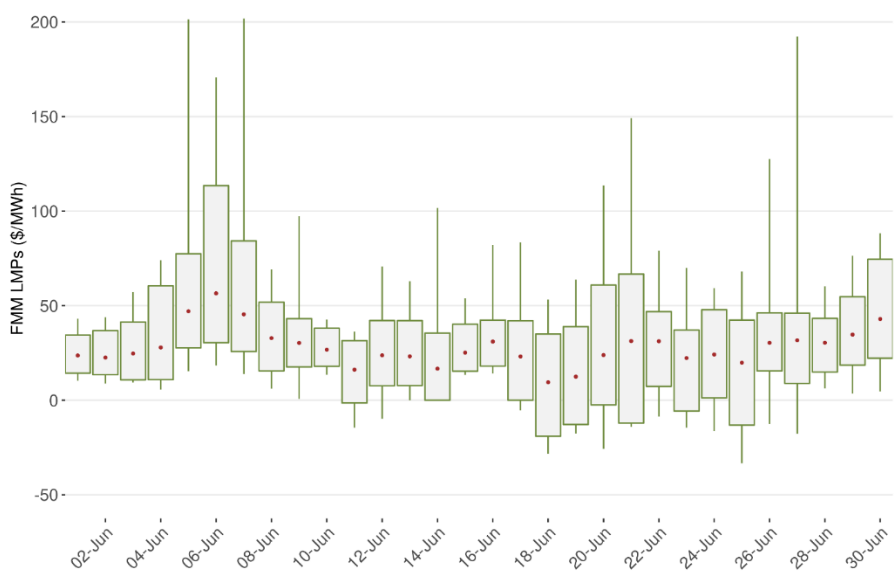
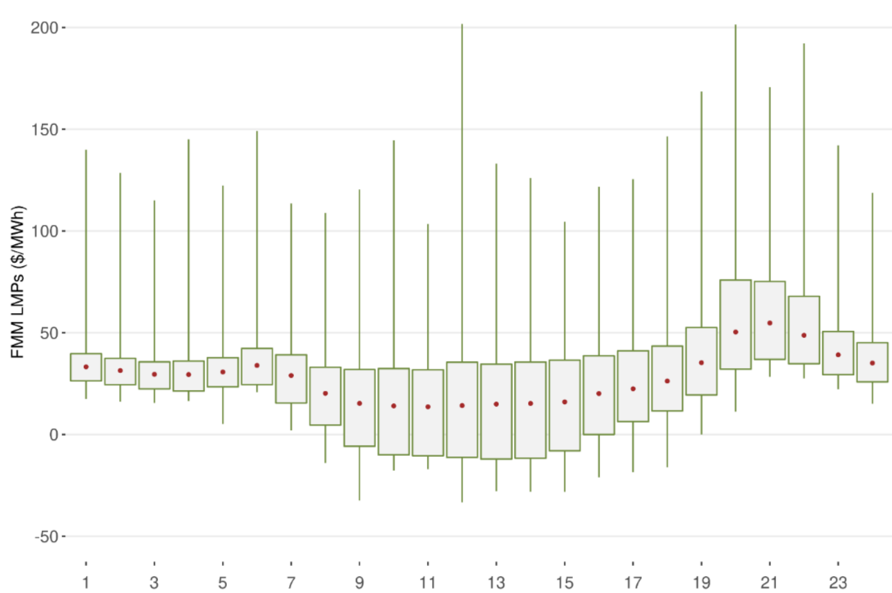


Figure 29: Hourly distribution of FMM prices, June 2023



With the CAISO's generation fleet consisting of a meaningful share of gas resources, dynamics from the gas market and system can typically have an impact on the electric market. Electricity prices generally track gas prices. Figure 30 shows the average prices (bars in red), and the maximum and minimum prices (whiskers in black), for the two main gas hubs in California, PG&E Citygate and SoCal Citygate. For June 2023, next-day gas prices averaged $3.11/MMBtu and $3.28/MMBtu for PG&E Citygate and SoCal Citygate, respectively. These gas prices are relatively lower than prices observed for the last two summer, which consequently may drive lower electric prices.

Figure 30: Gas prices at the two main California hubs

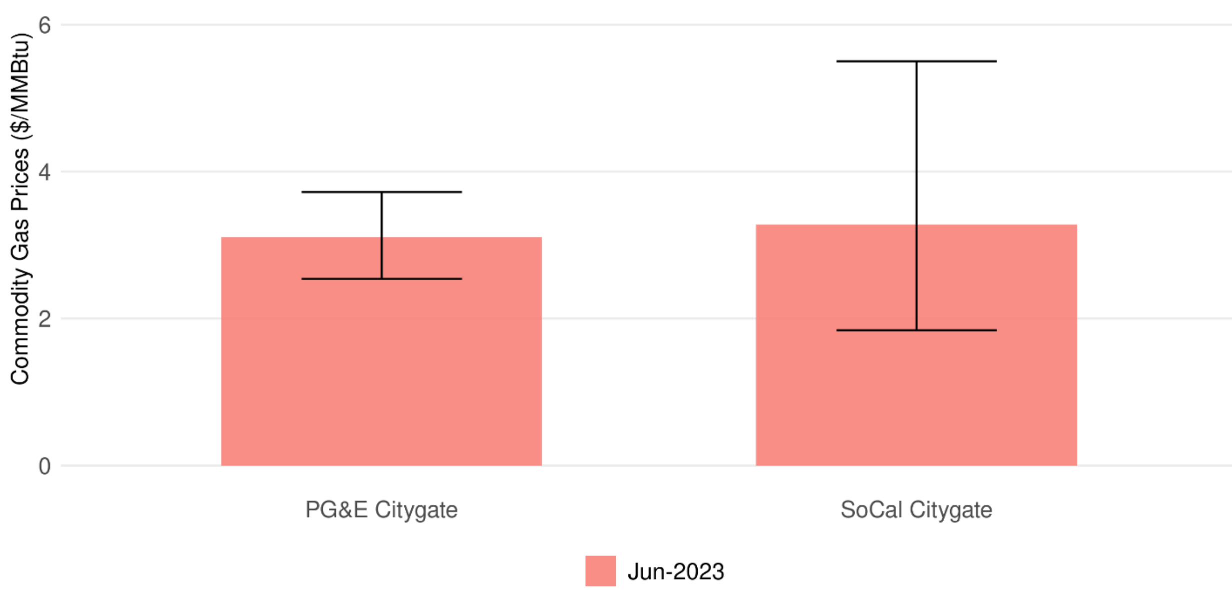


Figure 29 shows daily average electricity prices from the CAISO day-ahead market (y-axis) relative to next-day gas prices at SoCal Citygate (x-axis) and the peak load (color gradient from blue to red) on a daily basis. The dashed red line shows a simple linear regression applied to the dataset. Figure 32 shows the same metric using next-day gas prices at PG&E Citygate. Peak loads ranged widely and this comparison exhibits a good degree of correlation between electricity and gas prices. In addition, it can be observed that electricity prices generally rise when load levels are higher.

Figure 31: Correlation between electricity prices, SoCal Citygate gas prices and peak load level

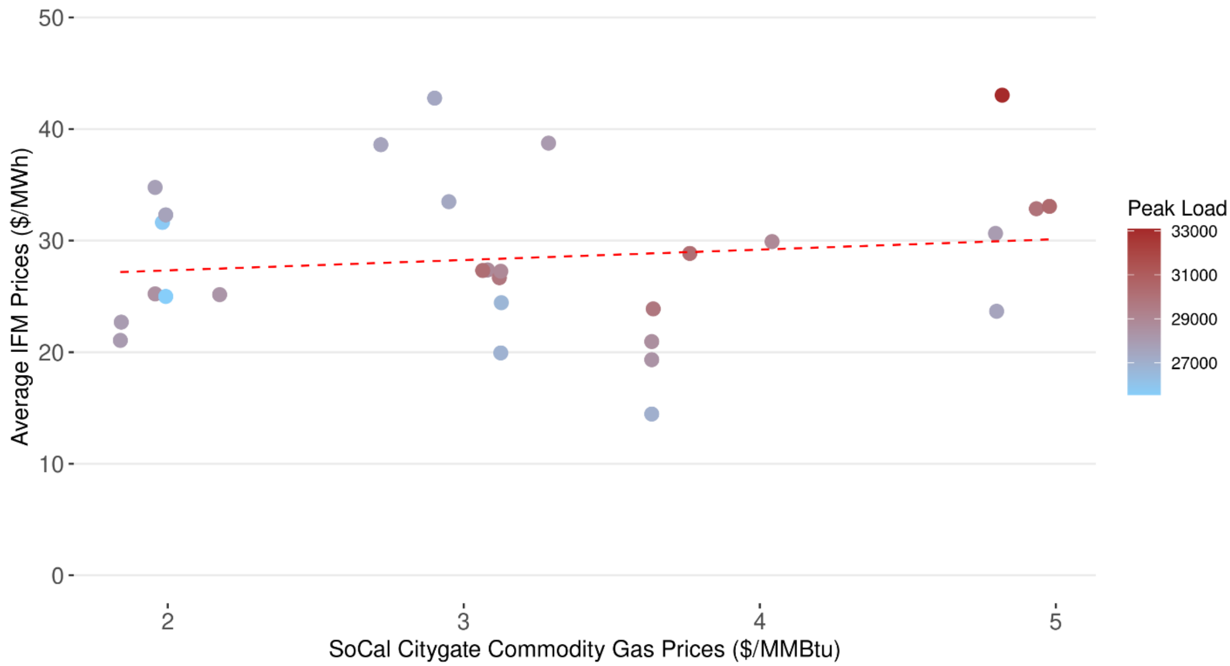
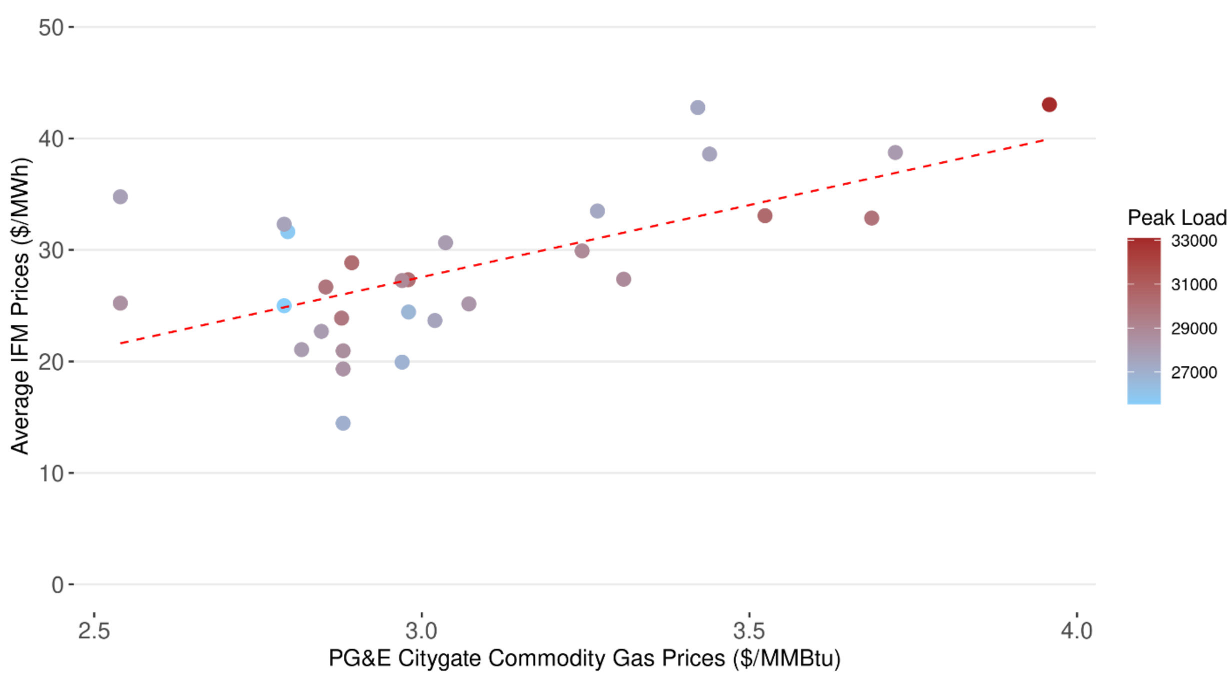


Figure 32: Correlation between electricity prices, PG&E Citygate gas prices and peak load level



5 Bid-In Supply

The CAISO'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 CAISO's markets. Based on the submitted bids, the market will optimally determine the least-cost dispatch of all resources to meet the bid-in demand in IFM or the load forecast in RUC. It is not unusual that above RA capacity be dispatched before all the RA capacity is exhausted since resource dispatches are based entirely on prices and resource characteristics and system conditions, and there is no merit order based on whether they are RA or not.

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

5.1 Supply and RA Capacity

Since the summer 2020 events, the CAISO has been tracking whether RA capacity available in the CAISO'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 33 shows the breakdown of the day-ahead supply capacity[26] as RA capacity and above RA capacity. The purple line represents the day-ahead load forecast plus the capacity required to meet operating reserves (OR), which is typically about 6 percent of the load value. The dashed line represents the adjusted load forecast plus OR plus high-priority export self-schedules, which represents the overall need to be met

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

in the day-ahead market has the same capacity breakdown but the comparison is relative to the net load (gross load minus VER forecast). 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 33: Supply capacity available relative to load forecast in the day-ahead market

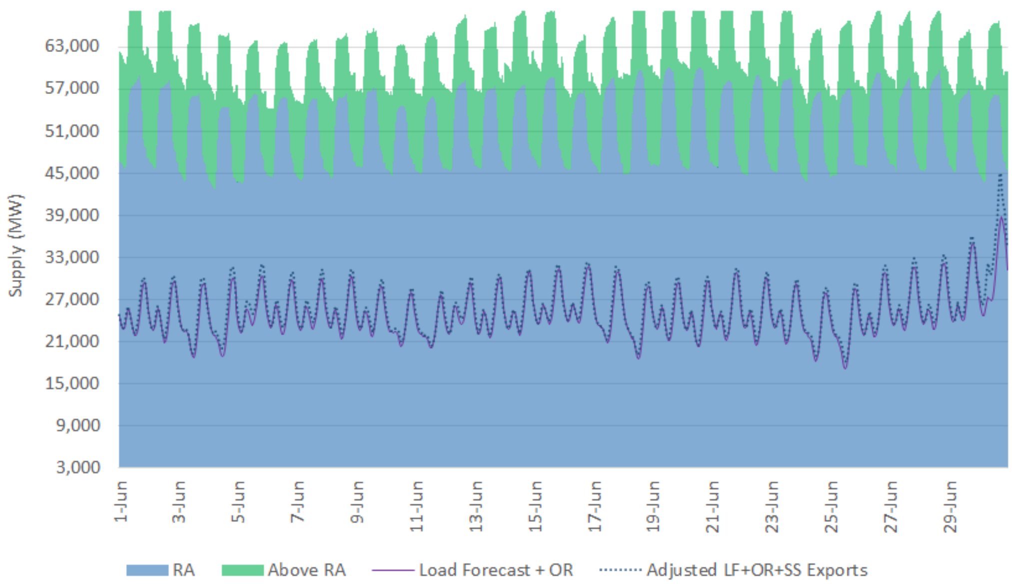
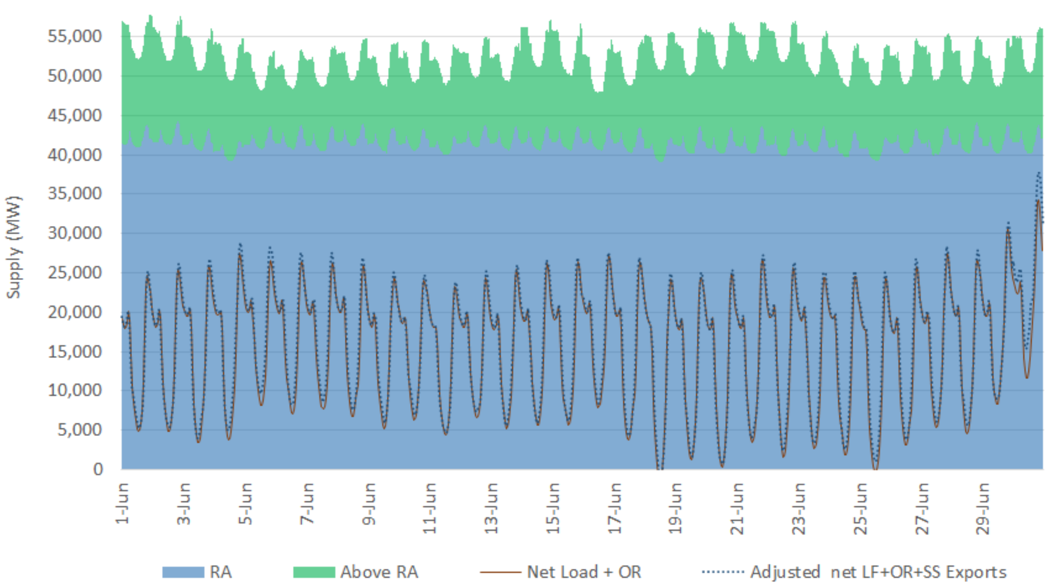


Figure 34: Supply capacity available relative to net load forecast in the day-ahead market



In both trends, the load peaked on June 30. A more granular view of the supply-demand conditions are provided for this period in Figure 33 and Figure 34. The RA capacity was sufficient relative to the standard day-ahead load forecast as well as for the adjusted load forecast during the gross and net load peak.

Figure 35: Supply capacity available relative to load forecast in the day-ahead market –June 28-30

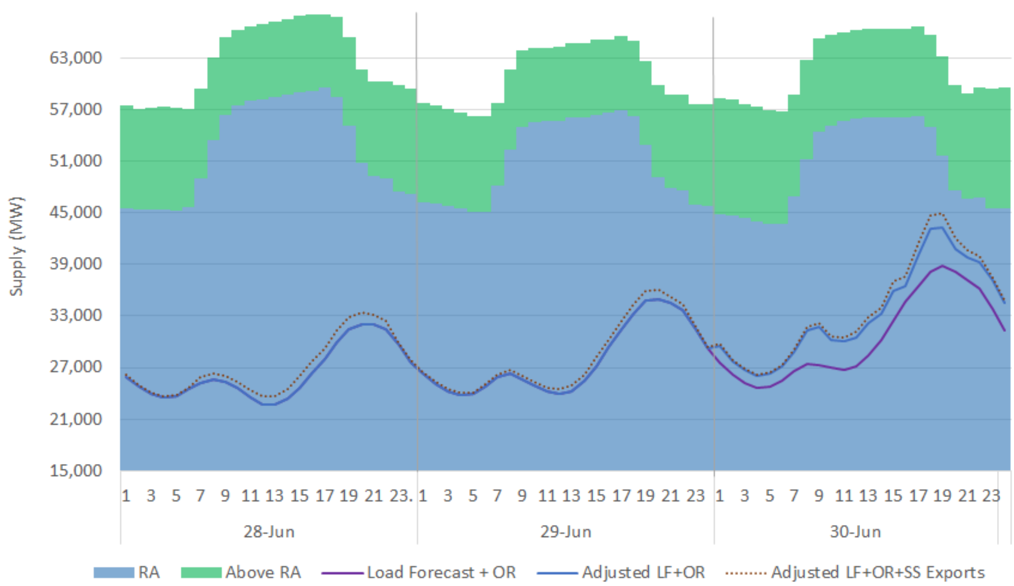
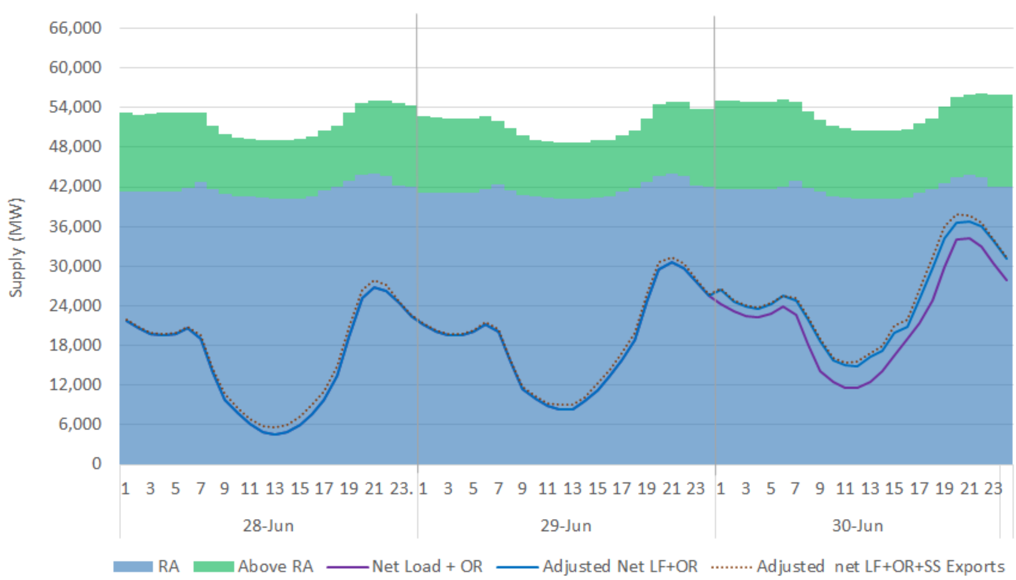


Figure 36: Supply capacity available relative to net load forecast in the day-ahead market – June 28-30

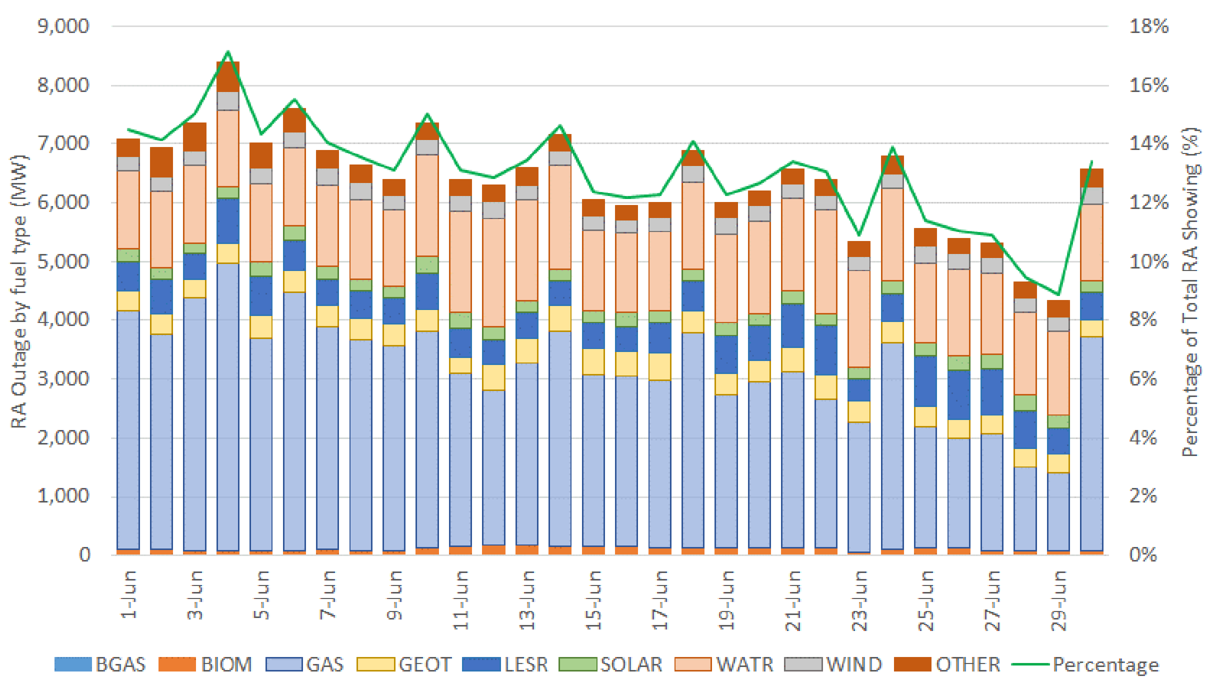


For instances in which the load needs exceed the available RA capacity, the market will utilize any other above RA available capacity. For the month of June, above-RA capacity was consistently available into the market.

5.2 Unavailable RA capacity

Generating units can face operating conditions that required them to be derated or be offline. CAISO tracks these outages through the outage system and these outages are reflected in the capacity made available in the market. The market consumes the outages and 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 37 provides the trend of RA capacity by fuel type on outage during the month of June. It shows that the capacity on outage decreased over the month as the month progressed. On average, the average daily capacity on outage is about 6,401 MW.

Figure 37: Volume of RA capacity by fuel type on outage in June



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 38 compares the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast eventually used in the RUC process. Day-ahead load forecast varied through the month, as compared to mild load days through the month to high load day on June 30.

Figure 38: Day-ahead demand trend in June

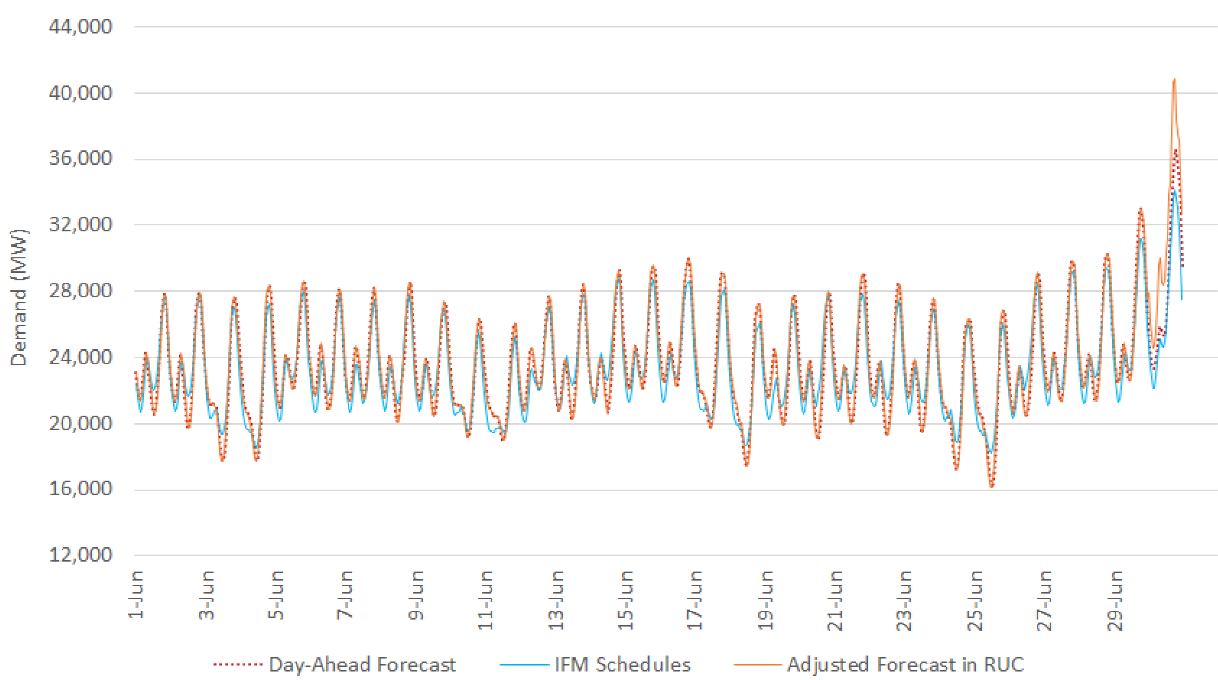
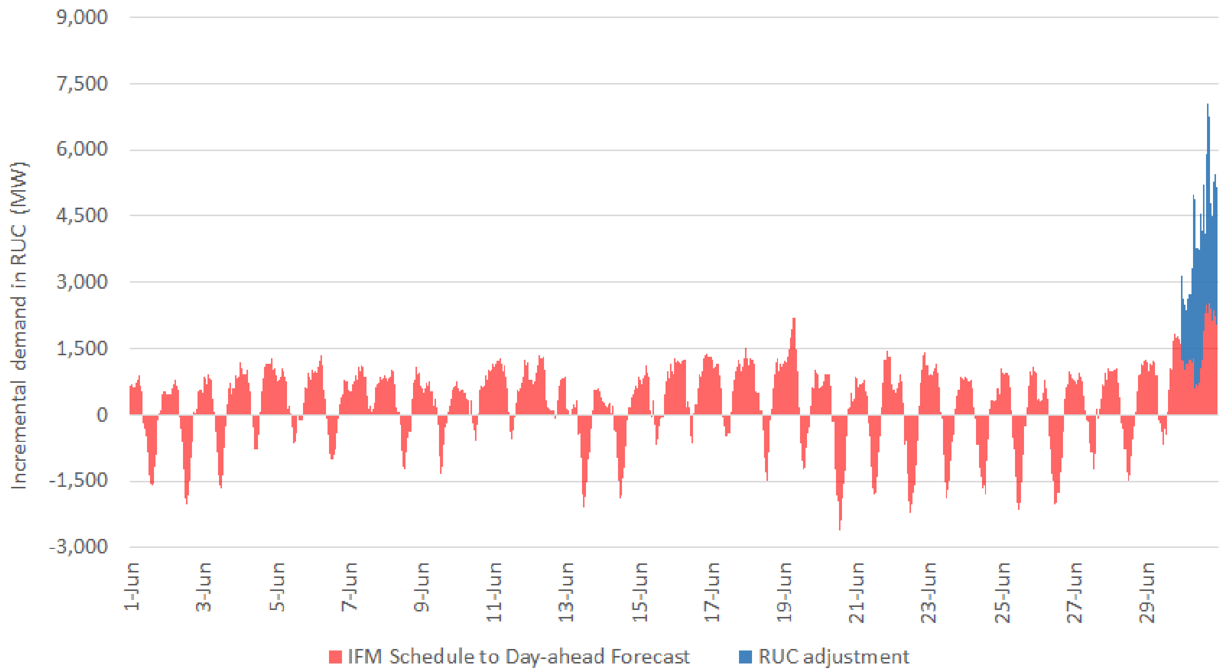


Figure 37 shows the differences between the IFM schedules for physical resources versus the nominal day-ahead load forecast. This is the additional capacity relative to the IFM solution that RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus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

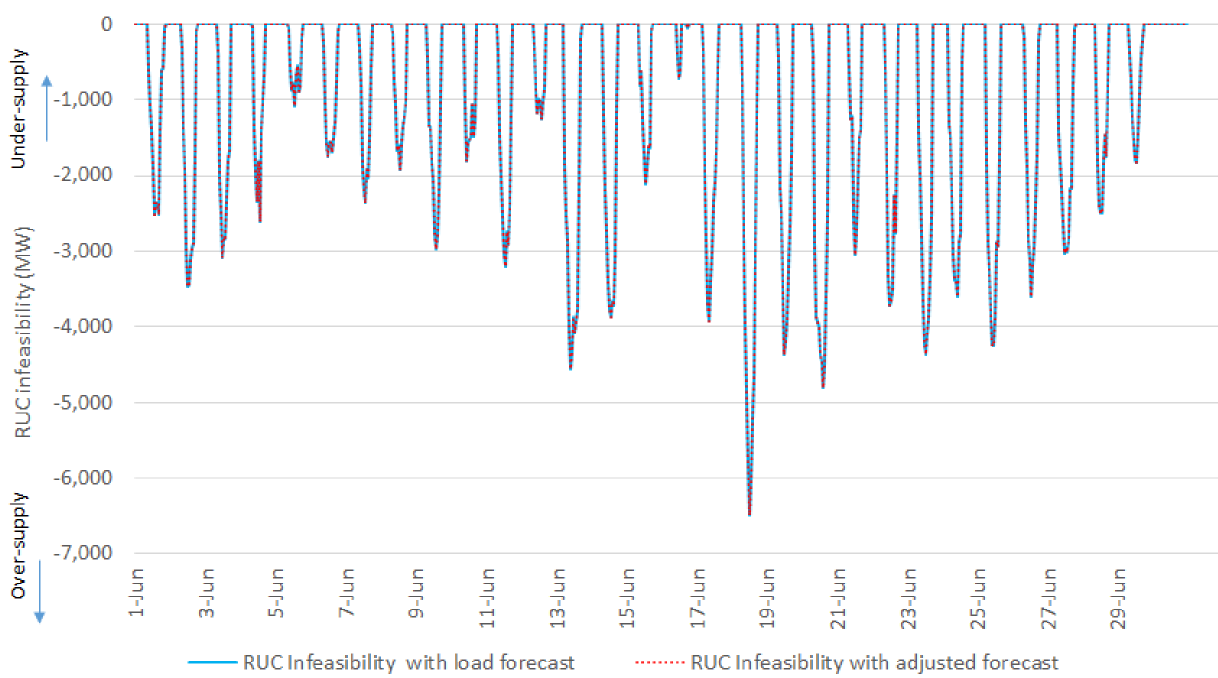
Figure 39: Incremental demand required in RUC in June



The RUC forecast adjustment is typically guided by a reference of an upper confidence bound and is estimated by the CAISO with consideration to weather and load model and renewables uncertainty. In some cases, there may be other factors to consider by operators to determine the final adjustments. For the month of June there was no RUC adjustment with the exception of June 30. This minimum use of RUC adjustment is part of a pilot program being run by CAISO to assess the use of RUC adjustments. As a partial enhancement to the day-ahead market operation, no RUC adjustments were used when demand was projected to be under 35,000MW. CAISO continues to assess the conditions and the need for RUC adjustments and in July CAISO started using a methodology similar to the imbalance reserves proposed for the day-ahead market enhancement to use as a guidance for RUC adjustments.

Since RUC clears against a load forecast which is not price sensitive, under certain conditions RUC may relax the power balance constraint due to a surplus or shortfall of supply capacity. A relaxation signals that there is an imbalance between the load requirements and the supply available. An infeasible power balance can be in either direction. In hours with low levels of load and minimum downward capability, RUC may observe an oversupply condition, resulting in a negative infeasibility. Conversely, in hours where there is insufficient supply to meet the load requirement, RUC may have an undersupply condition, resulting in a positive infeasibility. Negative RUC infeasibilities occur because RUC can only dispatch a resource down to its minimum load and cannot actually de-commit a resource or set up additional exports. Conversely, positive RUC infeasibilities occur because all incremental RUC bids have been exhausted and RUC has curtailed all the economic and LPT exports,[27] which leaves just the power balance constraint to be relaxed and reducing PTK (high priority) exports, to allow RUC to clear. Figure 40 shows the RUC infeasibility against two reference points: one infeasibility is relative to the final adjusted forecast in RUC, while the other is relative to the raw day-ahead forecast. There were no RUC under-supply infeasibilities for the month of June. There were over-supply infeasibilities for few days of the month too..

Figure 40: RUC infeasibilities in June



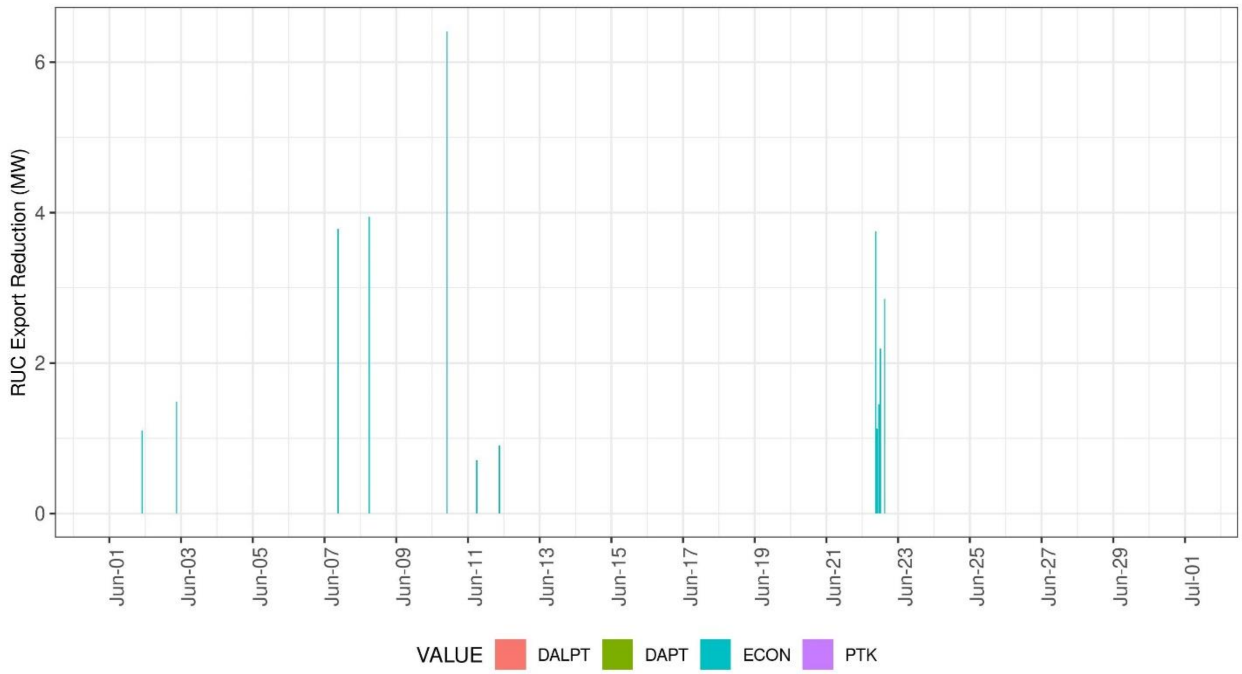
In addition to relaxing the power balance constraint, the RUC process utilized other scheduling priorities to enforce the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and lower priority price-taker exports. Only when RUC has exhausted these LPT exports, PT exports may be reduced concurrently to relaxing the power balance constraint.[28]

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

[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 curtailment relative to the level of power balance relaxation is achieved will depend on many other conditions in the optimization

Figure 41: shows the volume of hourly export reduction in the RUC process, which happened only for economic exports for small volumes across the month.

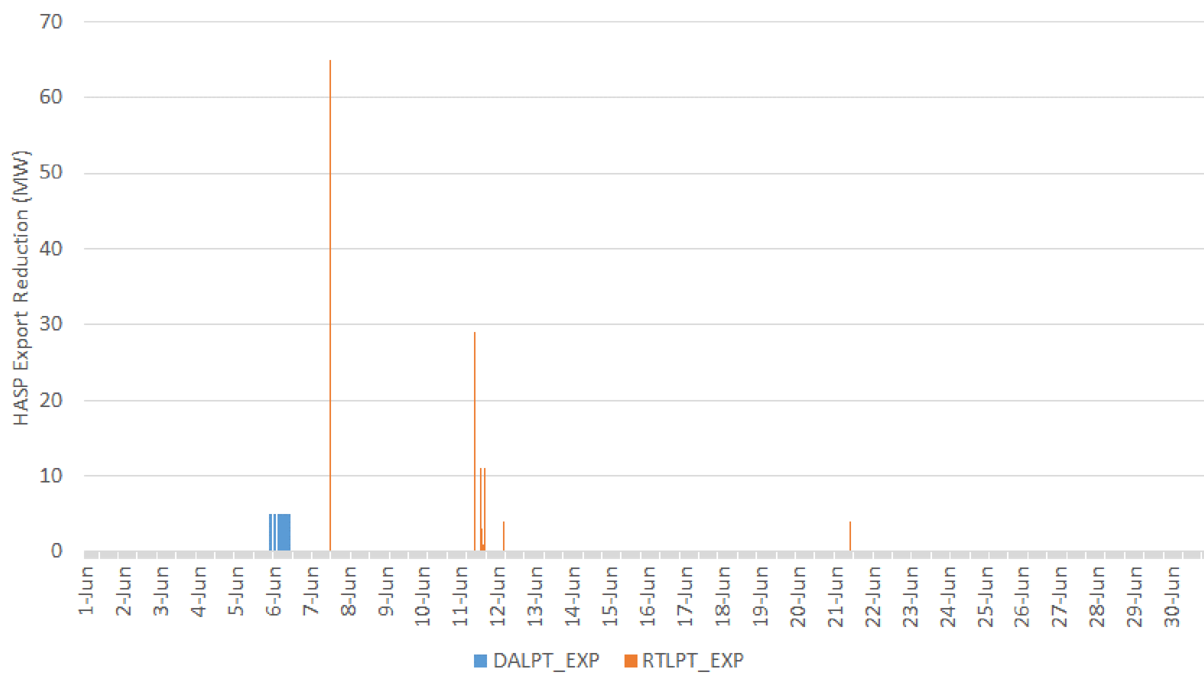
Figure 41: Exports reduction in RUC



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

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 42: Exports reductions in HASP



6 Intertie Transactions

The CAISO's system relies on imports that arrive into the balancing authority area through various interties, including Malin and NOB from the Northwest and Paloverde and Mead from the Southwest, among others. Interties are generally grouped into static imports and exports, or dynamic and pseudo tie resources, which are generally resource-specific. Similar to internal supply resources, interties can participate in both the day-ahead and real-time markets through bids and self-schedules. Additionally, the CAISO's markets offer the flexibility to organize pair-wise imports and export to define a wheel. This transaction defines a static import and export at given intertie scheduling points which are paired into the system to ensure both parts of the transaction will always clear at the same level. Wheel transactions must be balanced, thus, do not add or subtract supply to the overall CAISO system, regardless of the cleared level. However, they utilize scheduling capacity on interties and transmission capacity on CAISO'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 CAISO's market utilizes a series of self-schedules which define higher priorities than economic bids based on the attributes applicable to such resources. Participants with such entitlements can submit intertie self-schedules using transmission ownership rights (TORs) or Existing Transmission Contracts (ETCs), as well as PTK and LPT.

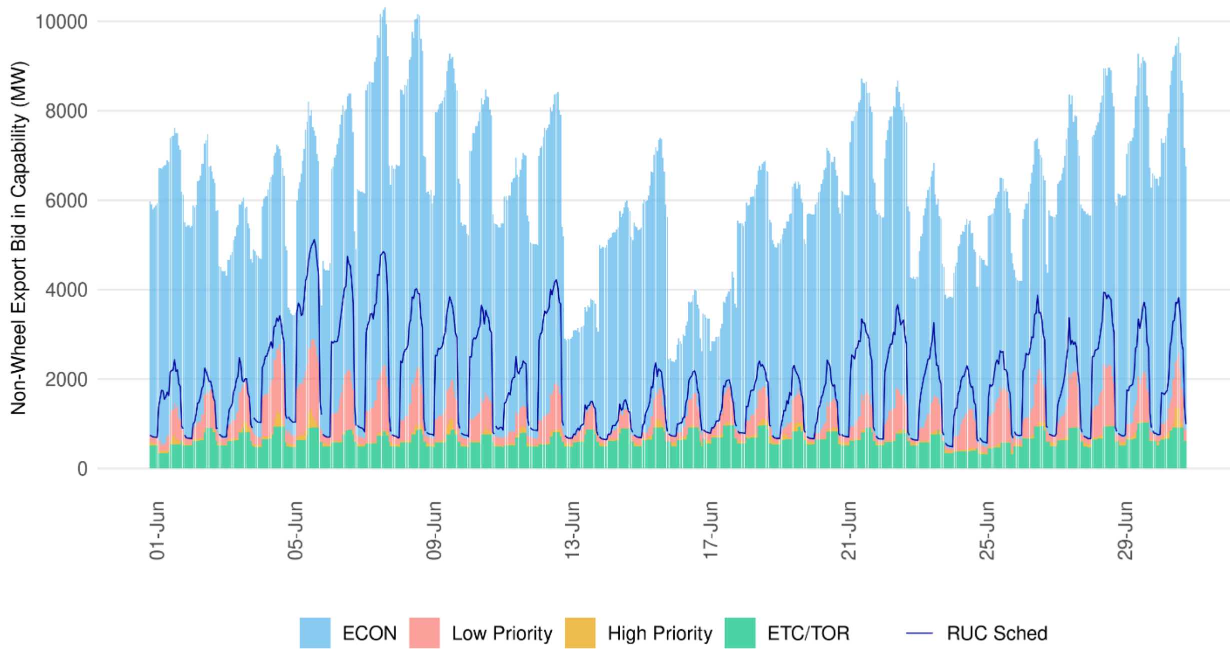
The CAISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into 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 43 shows the capacity from static export-based transactions in the day-ahead market for the month June 2023 organized by the various types of exports. This capacity does not include export capacity associated with wheel transactions of any type because wheels are in balance on a net basis and, thus, the export side of wheels does not reduce supply to the CAISO 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 CAISO tariff, in the day-ahead market, the CAISO 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 CAISO 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 CAISO operators use the RUC schedules to evaluate E-tags submitted in the pre-scheduling timeframe.

Figure 43: 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 curtailed by the CAISO. 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 78 percent, 12 percent, 9 percent and 1 percent of the export capacity were for economic bids, ETC/TOR, LPT and PTK, respectively. Due to mild load conditions and robust level of supply in June there was high volume of exports for the month of June.

Figure 44: Day-ahead bid-in capacity and RUC-cleared imports

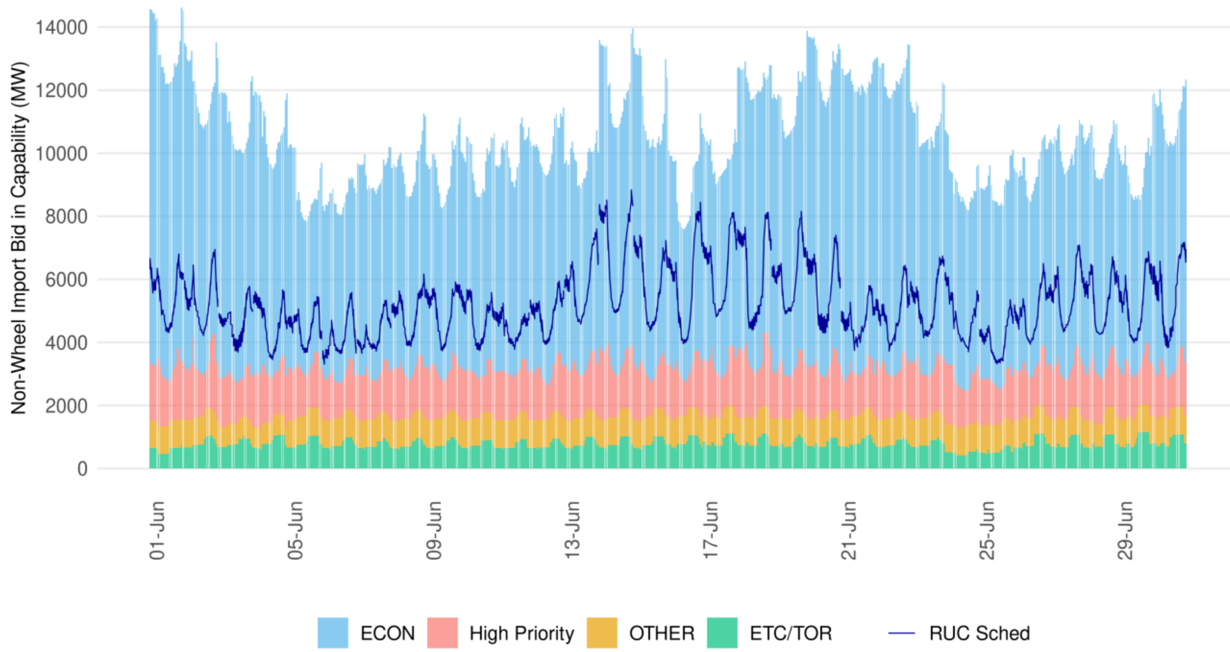


Figure 42 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the month, while hourly economic imports continued to see a high volume over 5,000 MW. The "Other" group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

Figure 43 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution. The net interchange projected in the RUC process reached its lowest levels in June 5 due to the higher level of exports cleared.

Figure 45: Breakdown of RUC cleared schedules

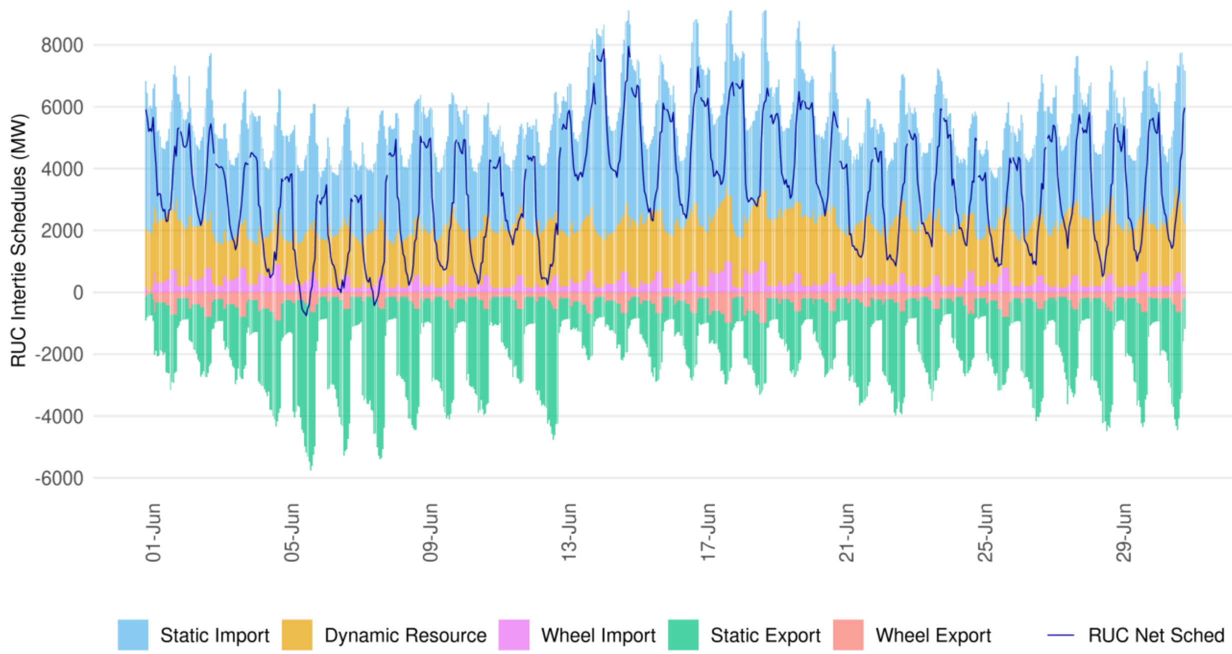
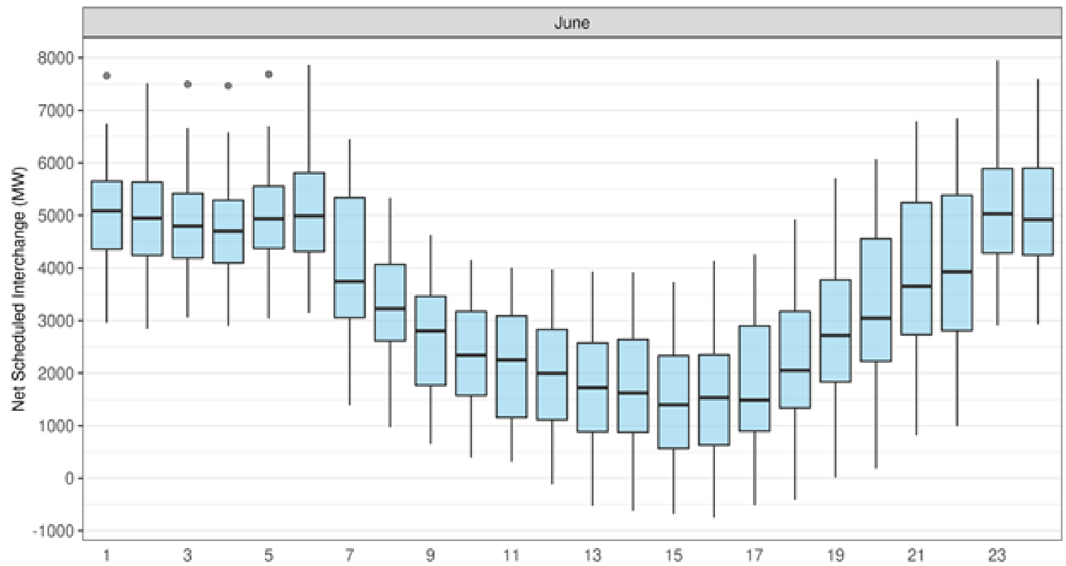


Figure 45 illustrates the hourly net schedule interchange distribution by hour for the month of June . This trend is useful to visualize the hourly profile of schedules and shows that net schedules reduce in midday hours when solar production comes in and start to increase as the solar production fades away in the evening hours. It also shows two well-defined blocks of On- and Off-peak schedules. The lowest net interchange values are attained in 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 CAISO's system. Export levels were generally low during the off-peak hours and high during the on-peak hours for the month of June .

Figure 45 illustrates the hourly distribution of RUC schedules for exports, and that the highest volume occurred during midday hours when CAISO's system has excess solar supply; exports were in high demand during the afternoon hours for the month of June.

Figure 46: Hourly RUC exports

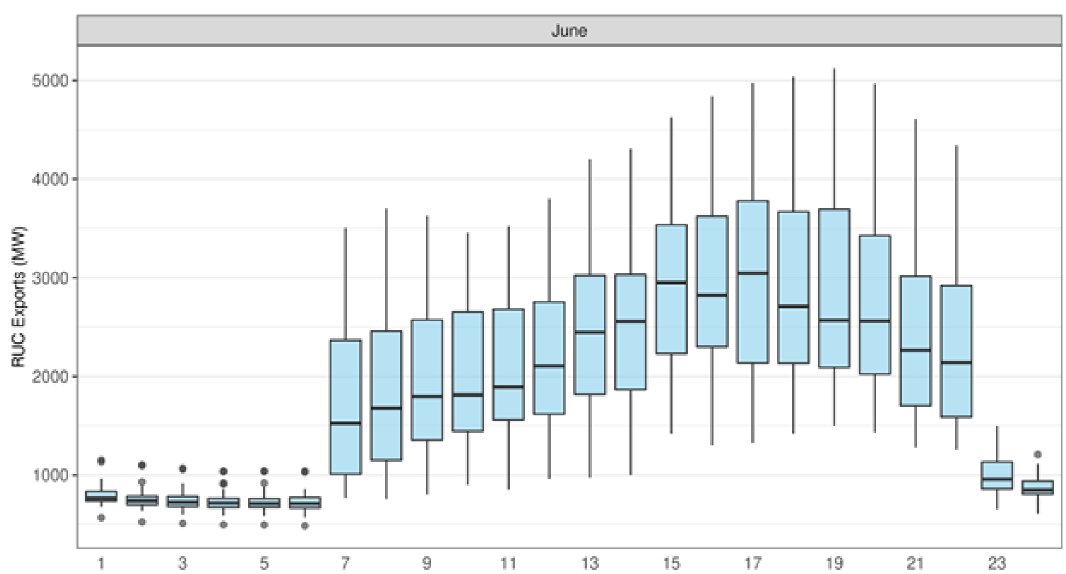
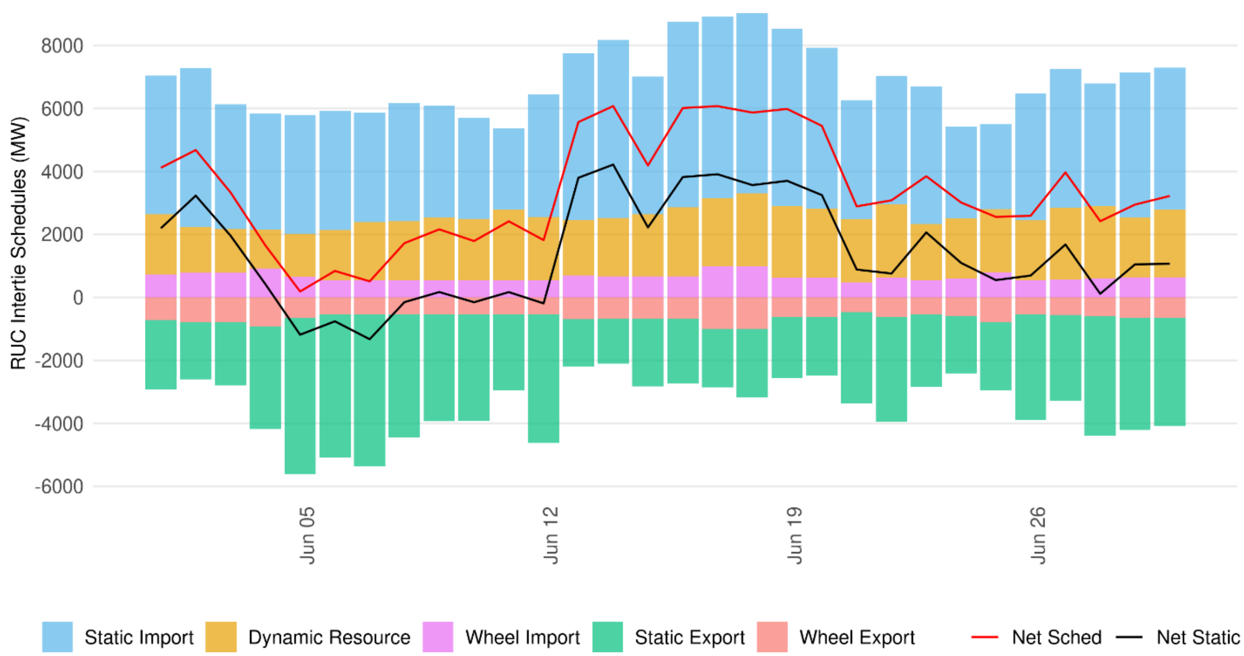


Figure 47 shows the intertie capacity available in the day-ahead market for hour ending 20 to highlight the conditions around peak time, when the CAISO's system faces the highest supply needs.

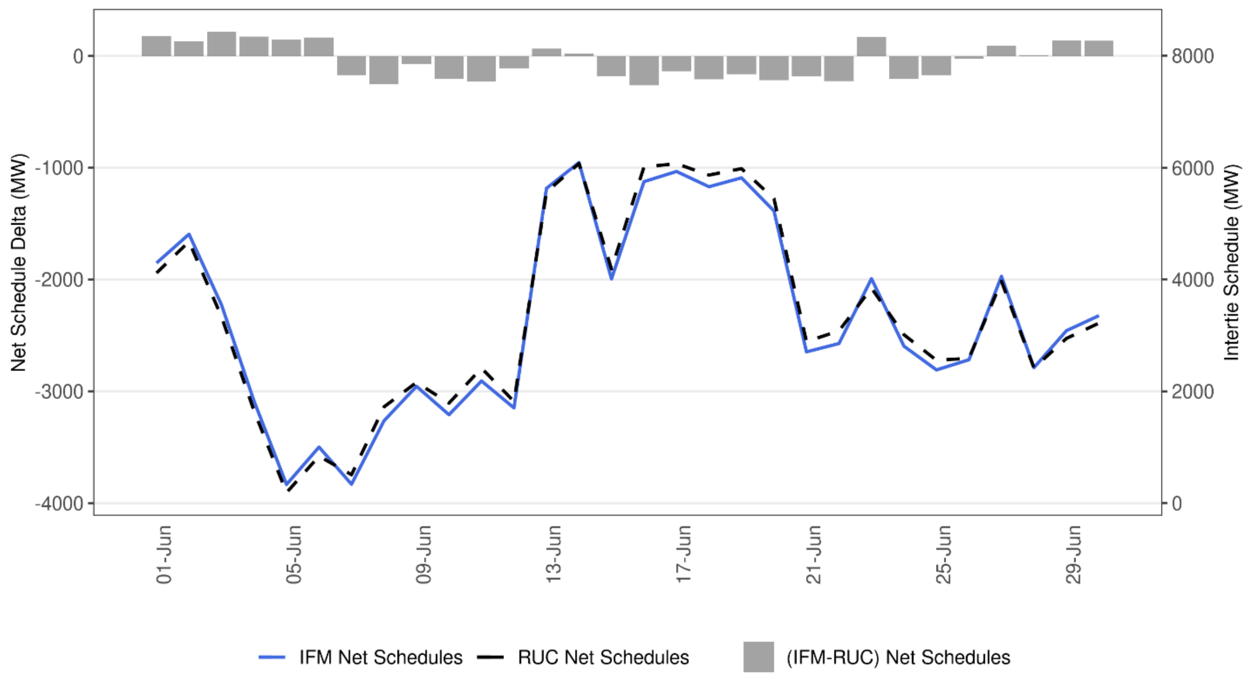
Figure 47: RUC schedules for interties for hour ending 20



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 is 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 48 compares the net schedule cleared in both IFM and RUC for hour ending 20, and provides the relative change of schedules between the two processes as shown with the bars in green. These changes can happen for any type of resources and it is not always limited to a reduction of exports. IFM schedules for exports were reduced in the RUC process for few days in the month of June.

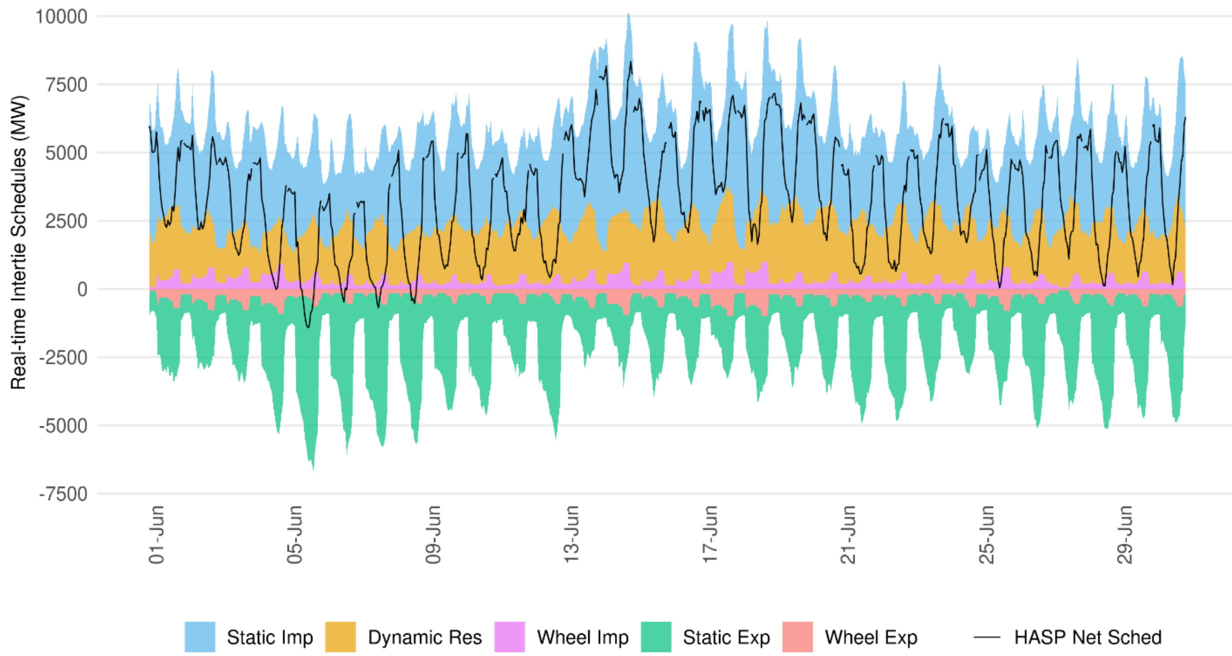
Figure 48: IFM and RUC schedule interchange for hour ending 20



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 also enables the procurement or clearing of additional capacity in the real-time market.

Figure 47: shows the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred as Net Schedule Interchange. The net schedule interchange is at its lowest value in June 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 June the net schedule in HASP was about 3,433 MW across all the hours of the of the month and about 2,568 MW for peak hours.

Figure 47: HASP cleared schedules for interties in June



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. 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 into 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.

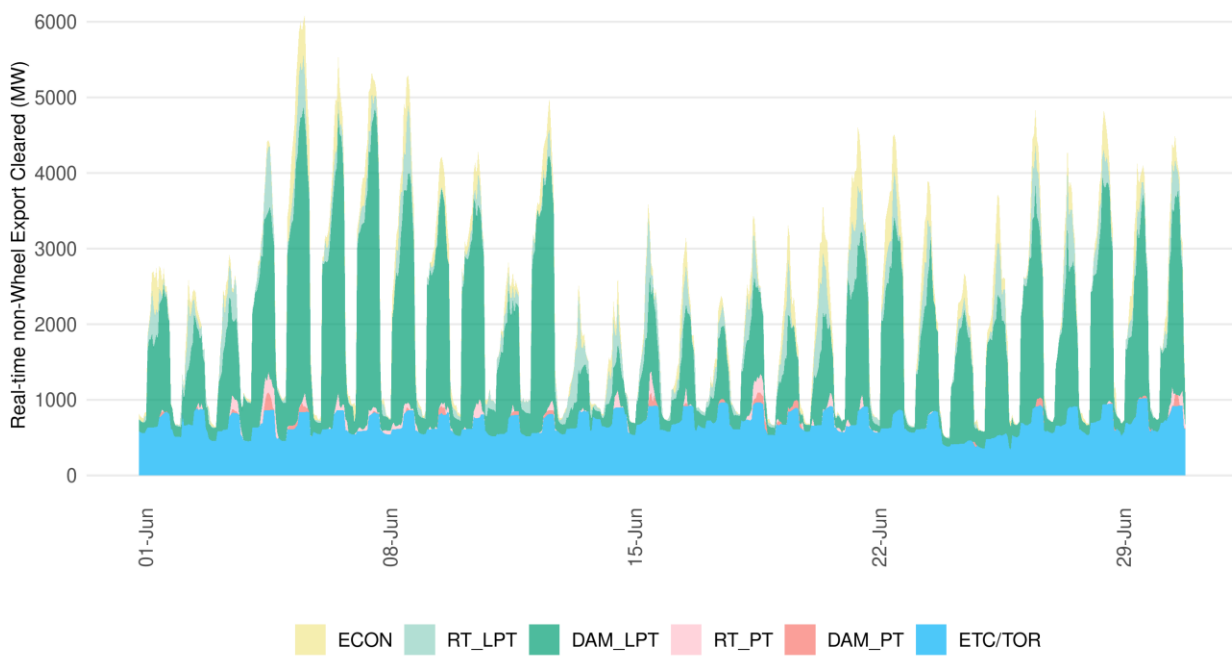
Figure 49 shows all the exports cleared in the HASP process and identifies the nature of such exports. TOR is for export with scheduling priorities associated with transmission rights. The groups of DA_PTK or DA_LPT stand for day-ahead exports coming into real-time as self-schedules with high or low priorities. Similar classification is followed for those high and low priority exports coming into real-time directly (RT_PTK and RT_LPT). ECON stands for economic exports. The group of wheels stands for all type of

[29] Based on these rules implemented on August 4, through the summer enhancements described earlier and now in place, the CAISO 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

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 June, peaking over 6,000 MW on June 5. In June a significant portion of cleared exports were those with low priority and economical bids.

Figure 49: Exports schedules in HASP



Imports and exports were scheduled over multiple intertie scheduling points in June, with Malin, Paloverde and NOB seeing the highest volume of transactions. Figure 50 through Figure 50 illustrate the trend of import and export schedules cleared in HASP for the top three intertie points. Although schedules in the import direction are the predominant schedules, exports cleared at different levels on these major interties when supply was tight.[30] For trade dates June 5 – June 12, exports on Malin were higher than imports so that the net flows on the intertie were in the export direction. On June 24 and 25 NOB was on outage and therefore it had no capacity available.

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

Figure 50 HASP schedules at Malin intertie

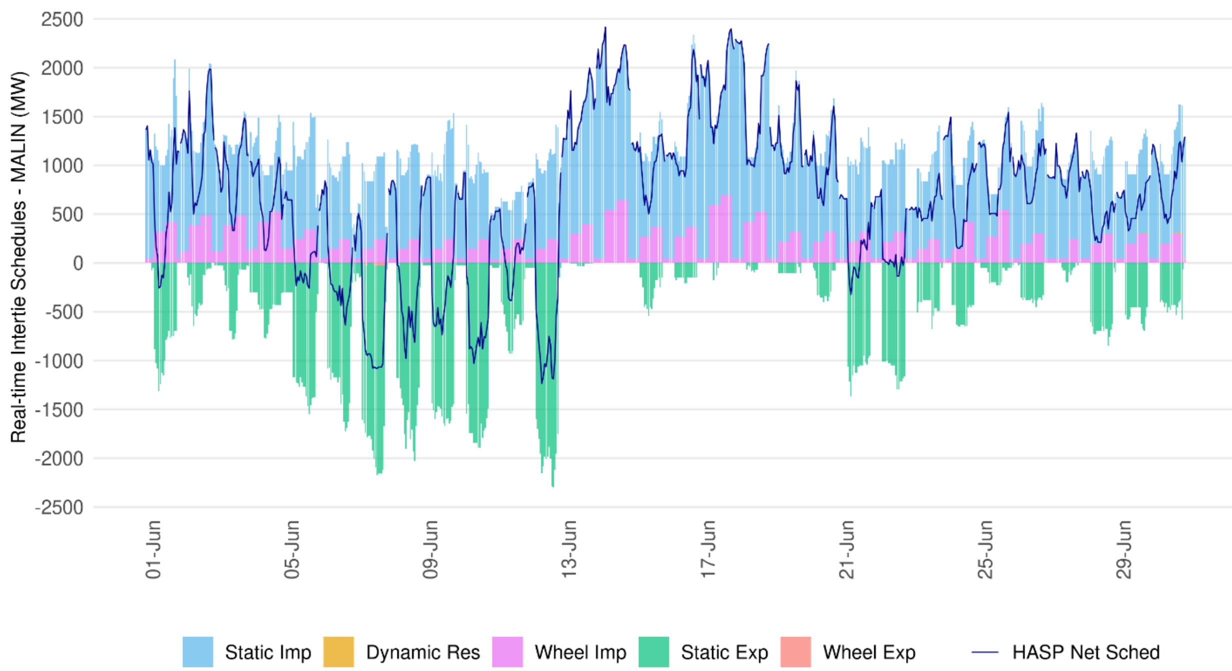


Figure 51: HASP schedules at PaloVerde intertie

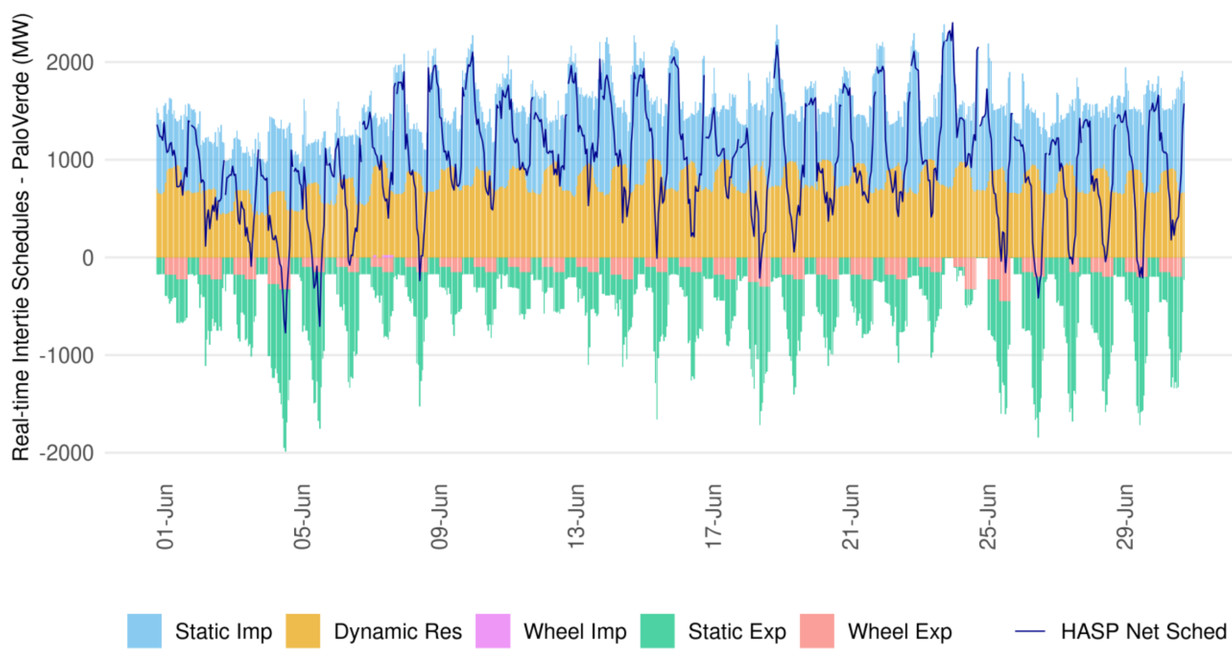
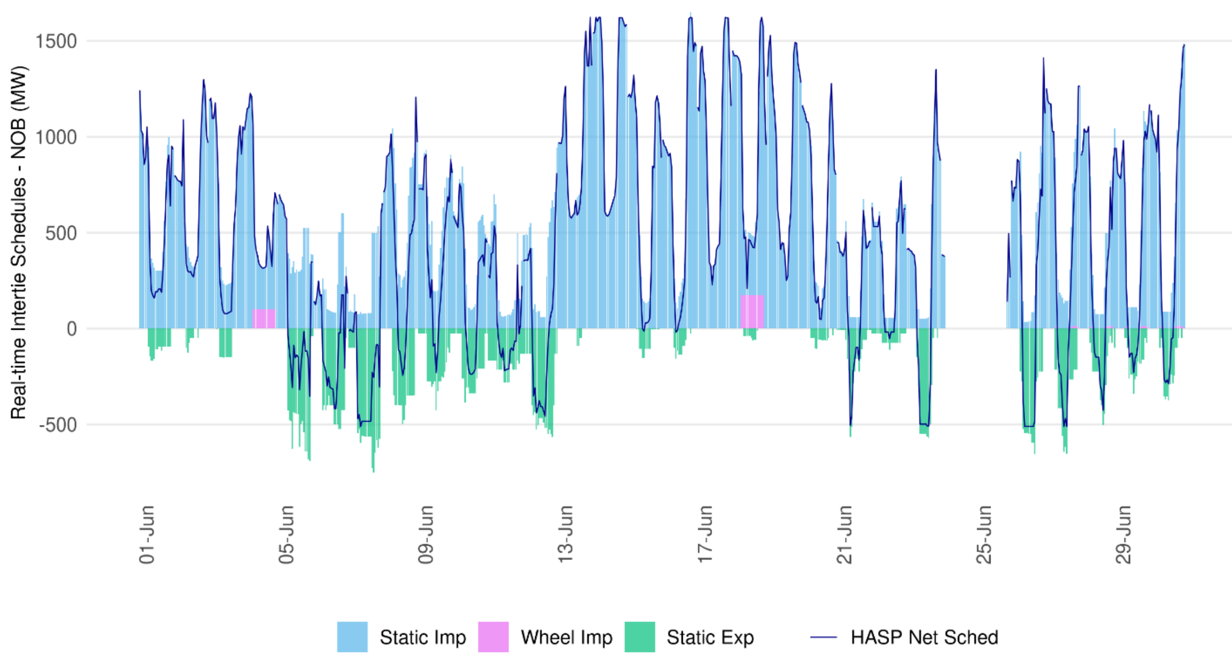


Figure 52: HASP schedules at NOB intertie



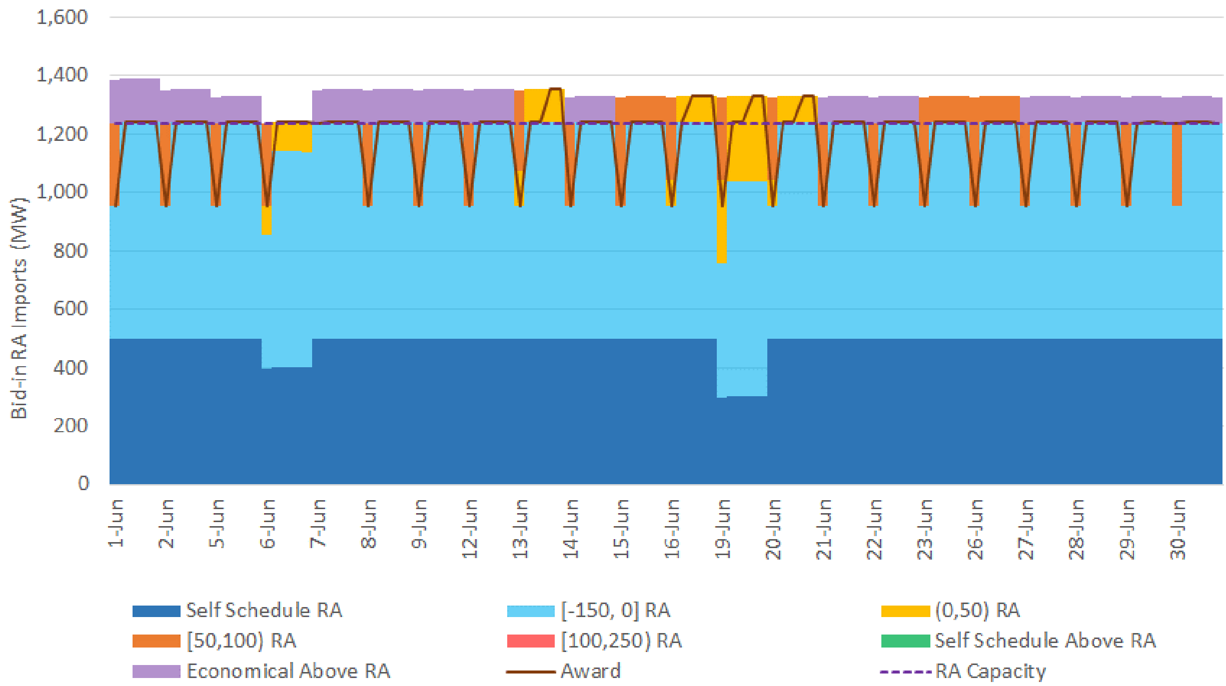
6.2 Resource adequacy imports

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 June was about 1325 MW related to LSEs under CPUC jurisdiction.

Under RA rules, non-resource specific RA imports for LSEs under CPUC jurisdiction must self-schedule or bid with economics bids between -$150/MWH and $0/MWh at least for the availability assessment hours.

Figure 53 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 92 of all RA import capacity bid with either self-schedules or economic bid 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.

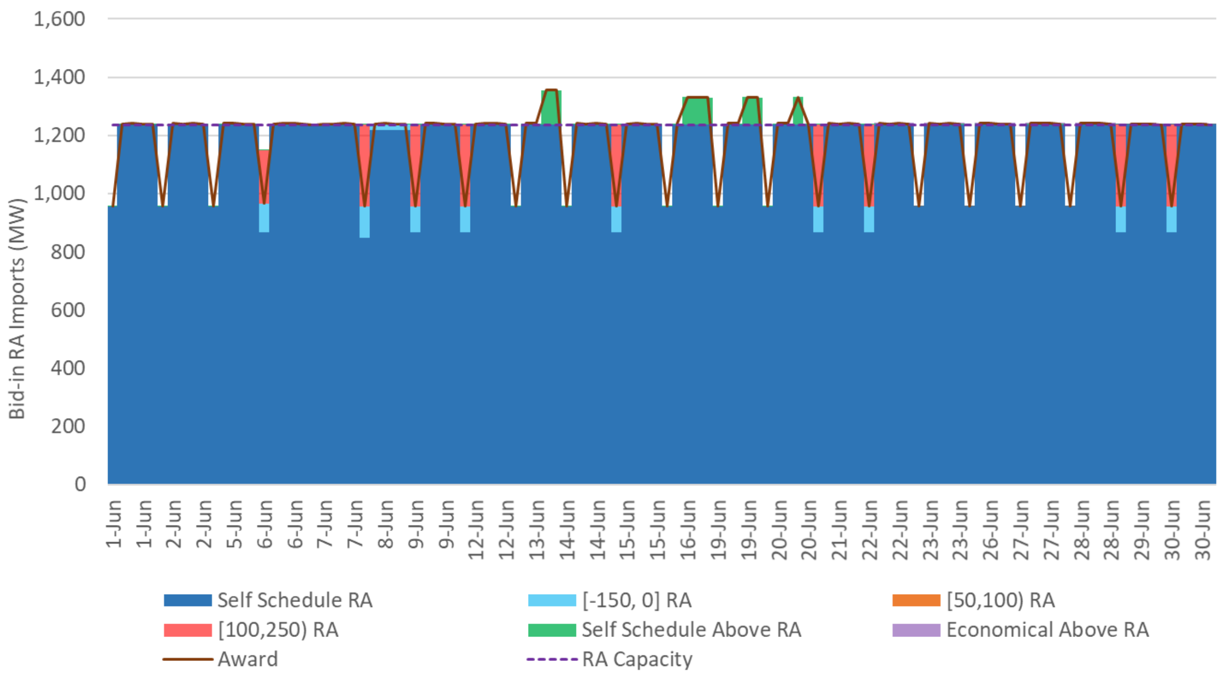
Figure 53: Day-Ahead RA import for hour endings 17 through 21 for weekdays



About 98 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. Also, about 5 percent of RA import capacity was not bid in the real-time market.

Figure 54 shows the same information for the real-time market using the HASP bids. About 98 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. Also, about 5 percent of RA import capacity was not bid in the real-time market.

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 June 2023, the CAISO received registration requests for a total of 1,412 MW from 10 different scheduling coordinators. Table 2 shows all the wheel-through paths registered by scheduling coordinators.[32]

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

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

Table 2: Wheel-through quantities registered for June 2023

Source	Sink	MW
CFEROA	PVWEST	50
CFETIJ	MEAD230	75
CTW230	LLL115	105
MALIN500	MEAD230	325
MALIN500	MCCULLOUG500	100
MALIN500	PVWEST	325
MIR2	RANCHOSECO	30
NOB	MEAD230	252
NOB	PVWEST	150
	Total:	1412

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

Figure 54 shows the hourly wheels cleared in the RUC process throughout the month. Wheels participating in the day-ahead market in the month of June were ETC/TOR, high- and low-scheduling priority, peaking at about 995 MW on June 17 and 18, with 520 MW of TORs, 375 MW of high priority and 100MW of low priority wheels. There were no wheels with economic bids. The volume of explicit wheels associated with ETC/TOR was stable throughout the month with higher values in peak hours.

Figure 54: Hourly volume of day-ahead wheel transactions by type of self-schedule

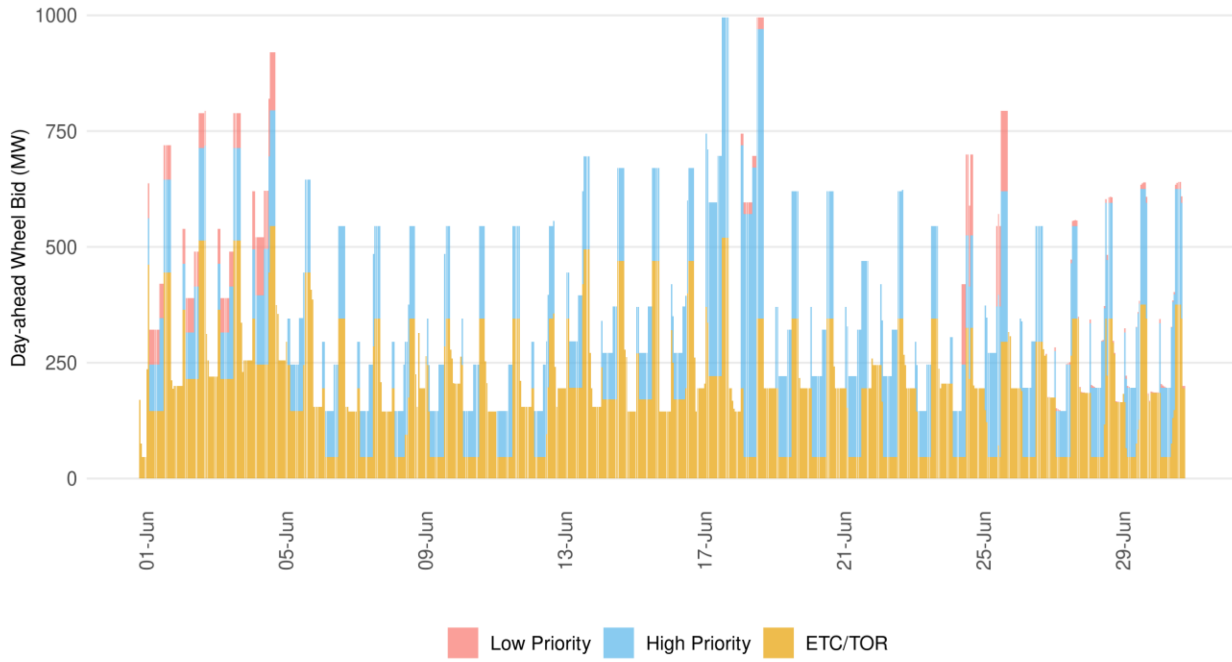


Figure 55: Hourly volume high- and low-priority wheels cleared in RUC

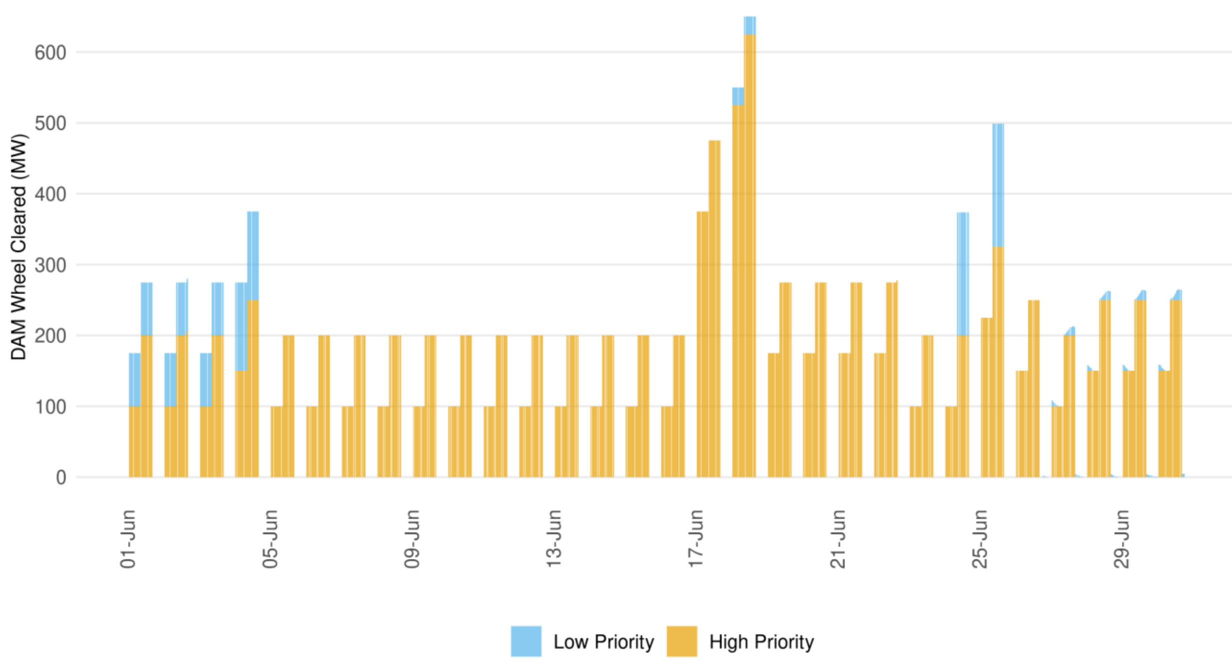
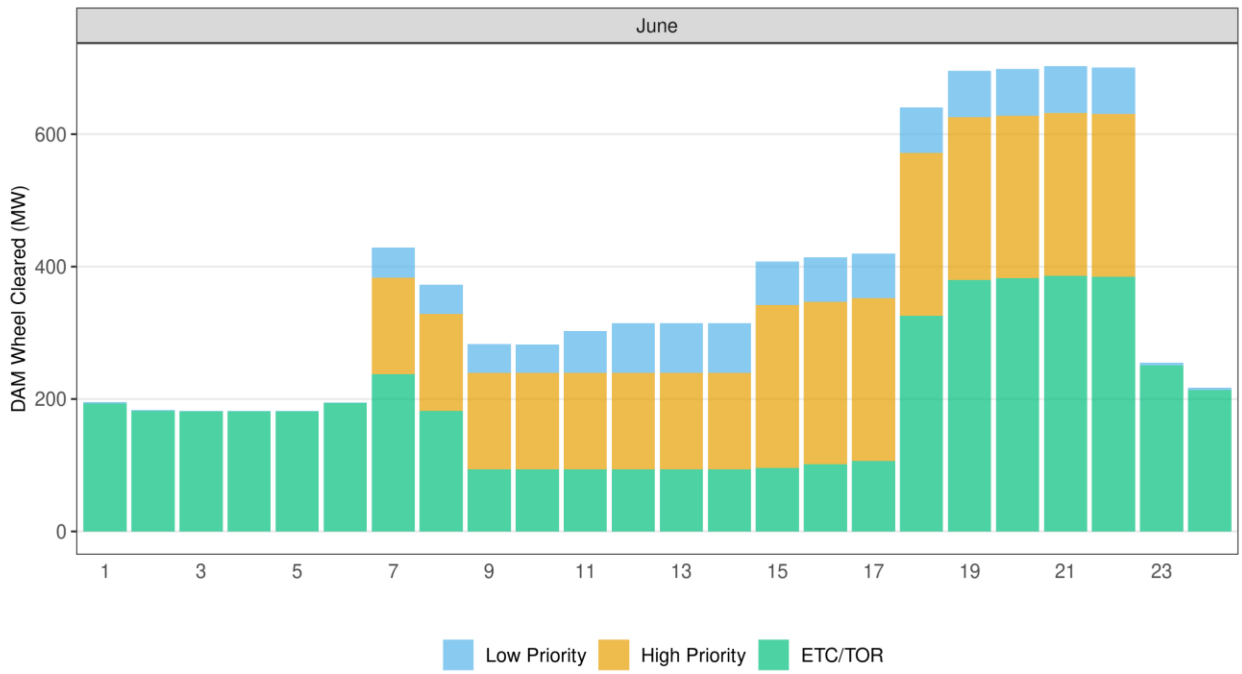


Figure 56 provides an hourly breakdown of high- and low-priority wheels, with the maximum hourly cleared RUC volumes about 600 MW of high priority wheels on June 18.

For June, 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).

Figure 56: Day-ahead hourly profile of wheels in June



Wheels are defined with a source and sink location in the CAISO'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 June. Source refers to the import scheduling point while sink refers to the export scheduling point. The path with the largest volume of wheels in June in the day-ahead market was from Malin to PVWEST.

Figure 57 Hourly average volume (MWh) of wheels by path in June

		SINK		
TYPE	**SOURCE**	**MCCULLOUG500**	**MEAD230**	**PVWEST**
LPT	MALIN500			10.5
	NOB		0.6	1.7
PT	MALIN500	16.7	8.9	100.6
	NOB		2.2	2.2

Figure 58 summarizes the maximum hourly wheels cleared in any hour in June in the day-ahead market by source-to-sink combination. The maximum volume of wheels in a given path occurred from Malin to Mead230.

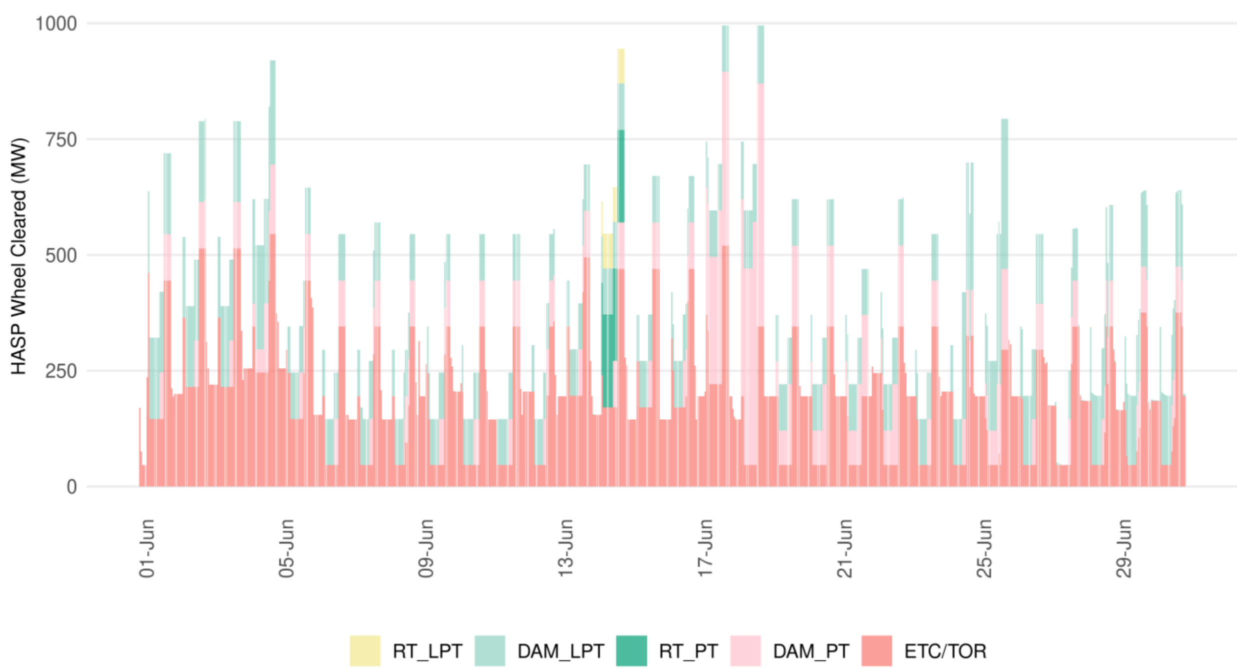
Figure 58: Maximum hourly volume (MW) of wheels by path in June

		SINK		
TYPE	SOURCE	MCCULLOUG500	MEAD230	PVWEST
LPT	MALIN500			174
	NOB		15	50
PT	MALIN500	50	200	150
	NOB		100	50

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

Wheels cleared in the day-ahead market can be carried over into the real-time market with a day-ahead priority or be directly self-scheduled in HASP process. Figure 59 shows the volume of wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 59 Wheels cleared in real-time market



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

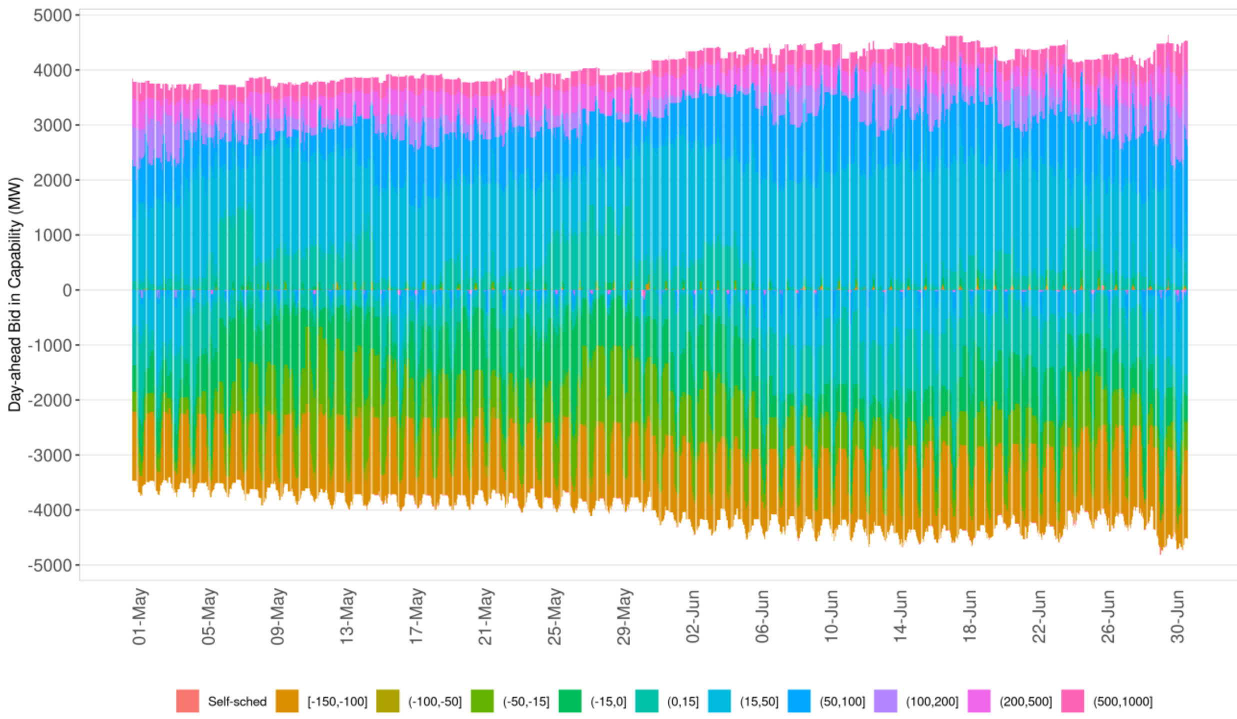
The *DAM*_PT is for wheels with high priority that cleared in the day-ahead market and they rebid into real-time. RT_PT is high priority that came in directly into real-time market. DAM_LPT is for wheels with low priority cleared in day-ahead and rebid into real-time. Similarly. RT_LPT is for wheels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

7 Storage and Hybrid Resources

The CAISO's markets use the Non-Generating Resource (NGR) model to accommodate energy constrained storage resources that can consume and produce energy. The NGR model allows storage resources to participate in the regulation market only, or participate in both energy and ancillary service markets. In June 2023, there were 74 storage resources actively participating in the CAISO markets. Most storage resources participated in both the energy and ancillary service market. Storage resources can arbitrage the energy price by consuming energy (storing charge) when prices are low, then subsequently delivering energy (discharging) during market intervals with high prices. Each storage resource has a maximum storage capability that reflects the physical ability of the resource to store energy.

The total storage from all the active resources participating in the market was 19,791 MWh. In terms of the capacity made available to the markets, Figure 60 shows the bid-in capacity for storage resources in the day-ahead market.

Figure 60: 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 increased in June compared to May due to capacity additions. The bid-in capacity is organized by $/MWh price ranges. There were consistent patterns of batteries bidding to charge at negative prices, and to discharge only at prices above $15/MWh. In June, some were willing to charge when prices were $50 to $100 or higher in some cases. 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 certain volume of storage capacity that is expecting to discharge only at these high prices.

Figure 61 shows the bid-in capacity for the real-time market. The majority of bids were $15/MWh or above on the discharging side, and $0/MWh or below on the charging side. In the late morning to early afternoon hours before the evening peak, batteries were willing to charge even at prices higher than $100/MWh

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Figure 61: Bid-in capacity for batteries in the real-time market

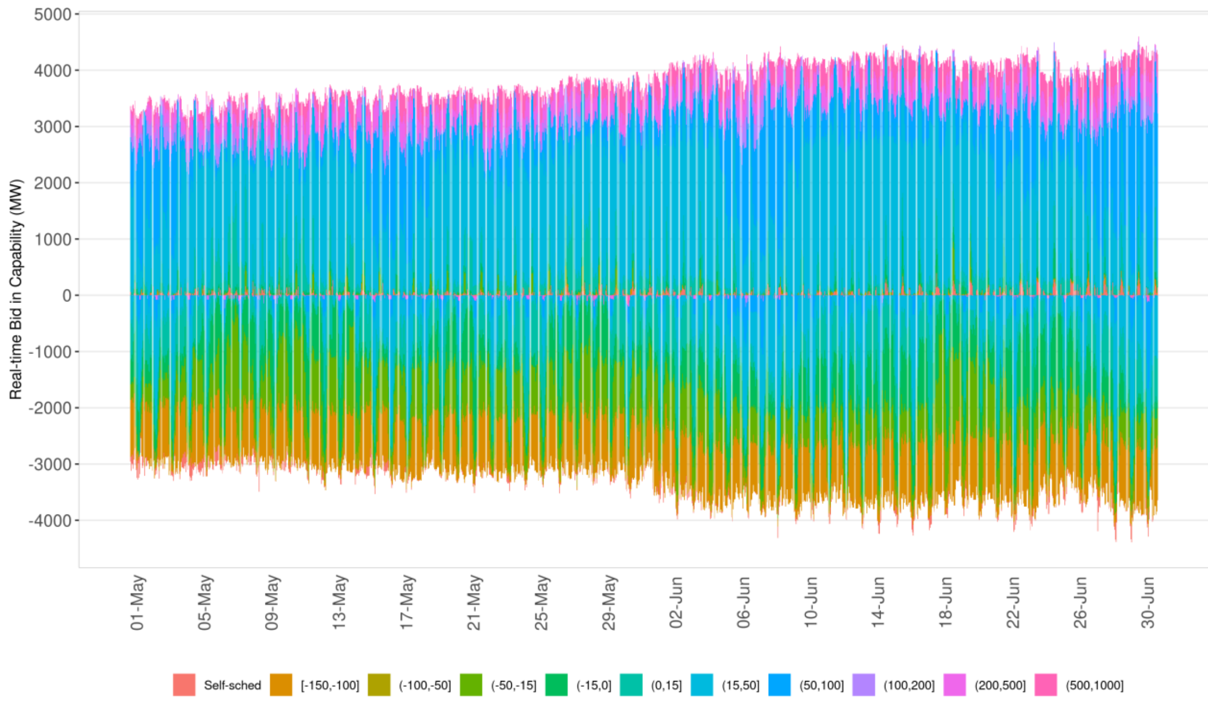


Figure 62 IFM distribution of state of charge for May and June 2023

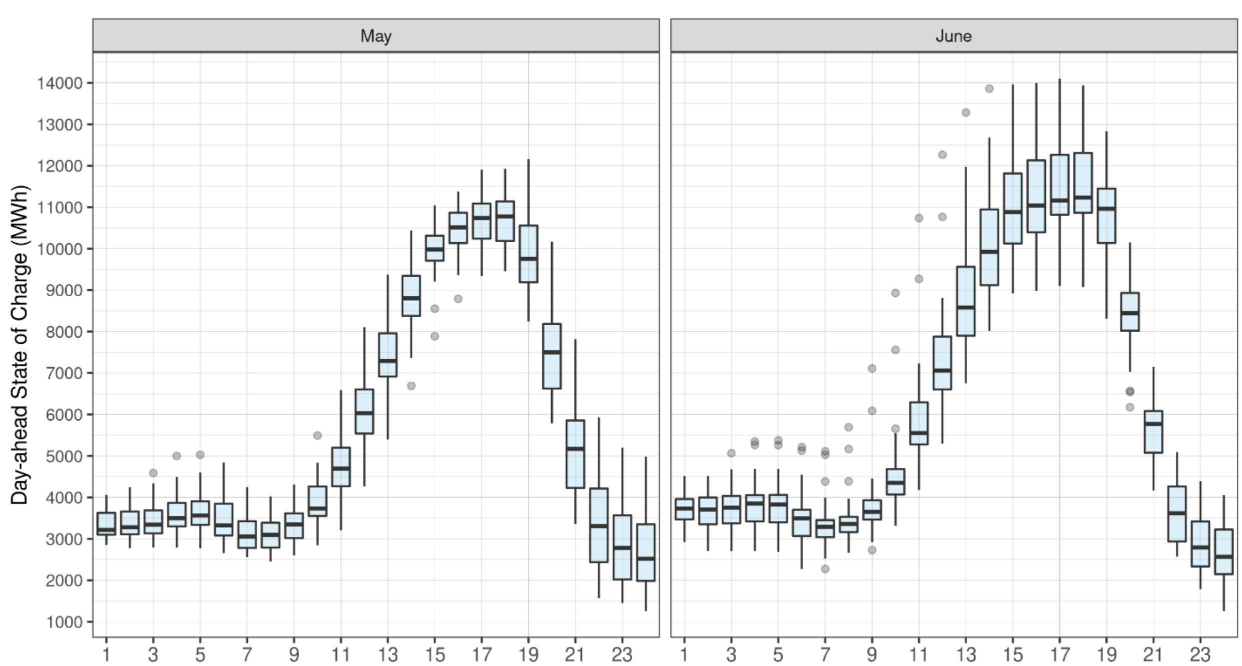
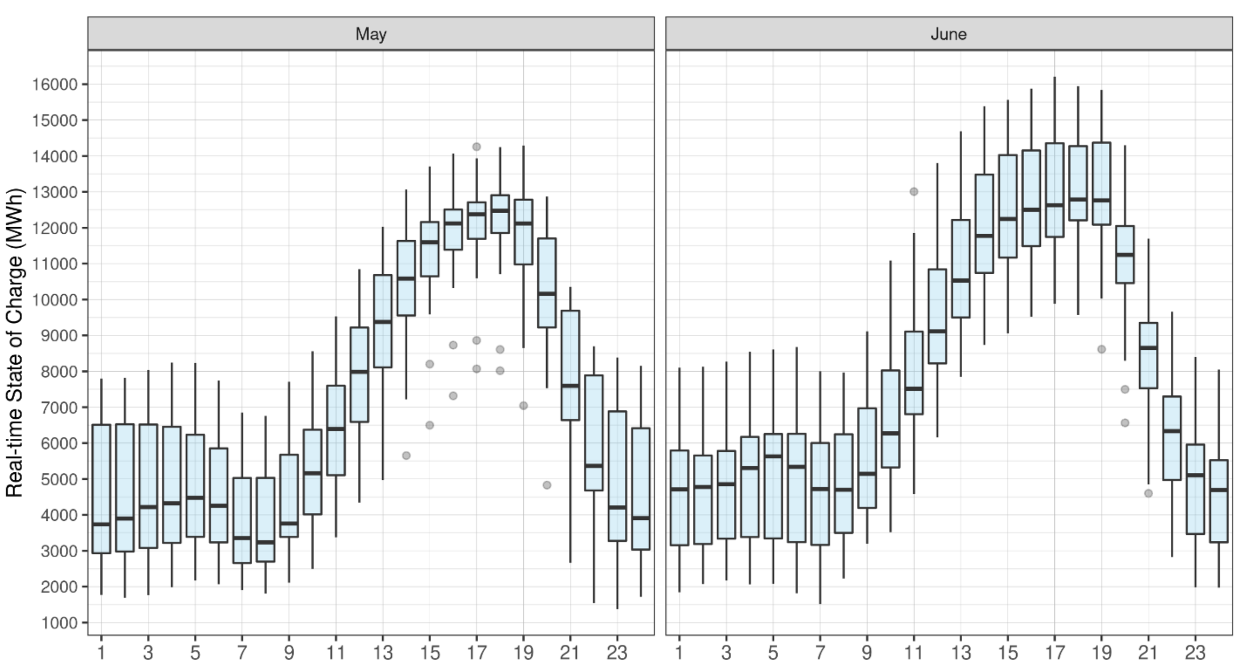


Figure *62* shows the hourly distribution of the storage capacity of resources participating in IFM for May and June 2023. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge in IFM. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime, between hour ending 9 and 18. The system reached maximum stored energy by hour ending 18, followed by a period of steady discharge from hours ending 19 through 24. In June, the highest median system state of charge was around 11,500 MWh, which occurred in the hour ending 18.

Figure 63 shows the distribution of state of charge for the real-time market for May and June 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 June was higher than the median system state of charge in May. 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 63: Real-time market distribution of state of charge for May and June 2023



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

Figure 66 shows the hourly distribution of real – time dispatch for batteries in May and June 2023. Figure 65 and

Figure 66 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 64: IFM hourly average system marginal energy price in May 2023

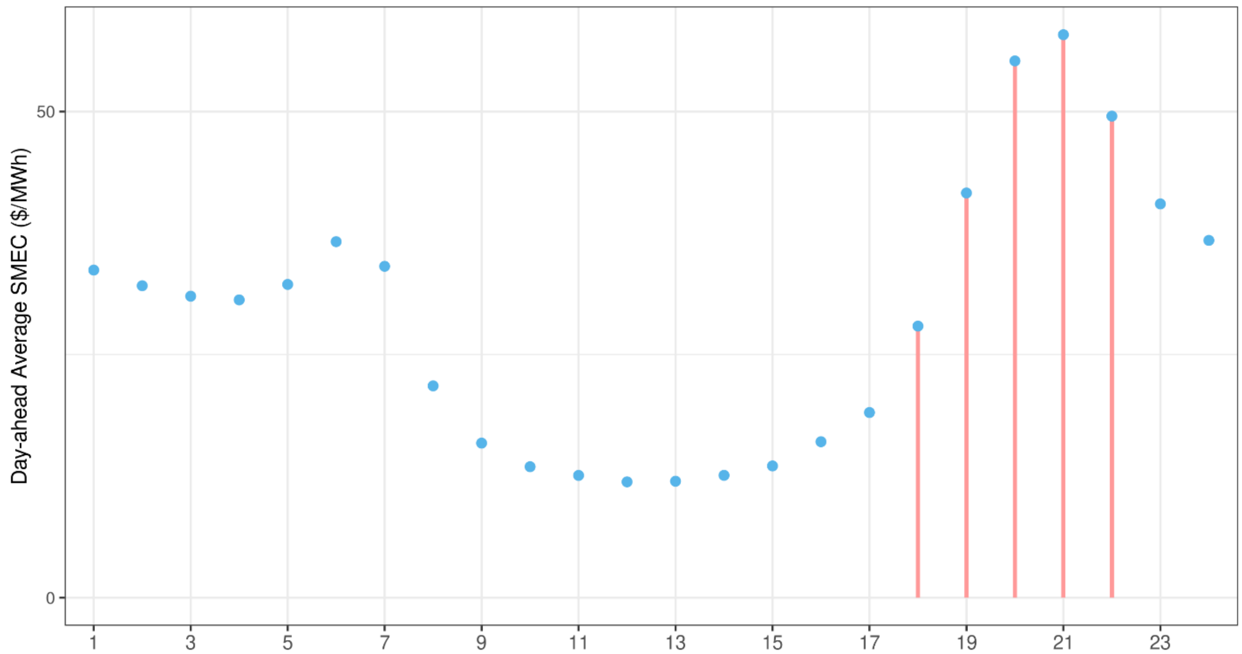


Figure 65: Hourly distribution of IFM energy awards for batteries in May and June 2023

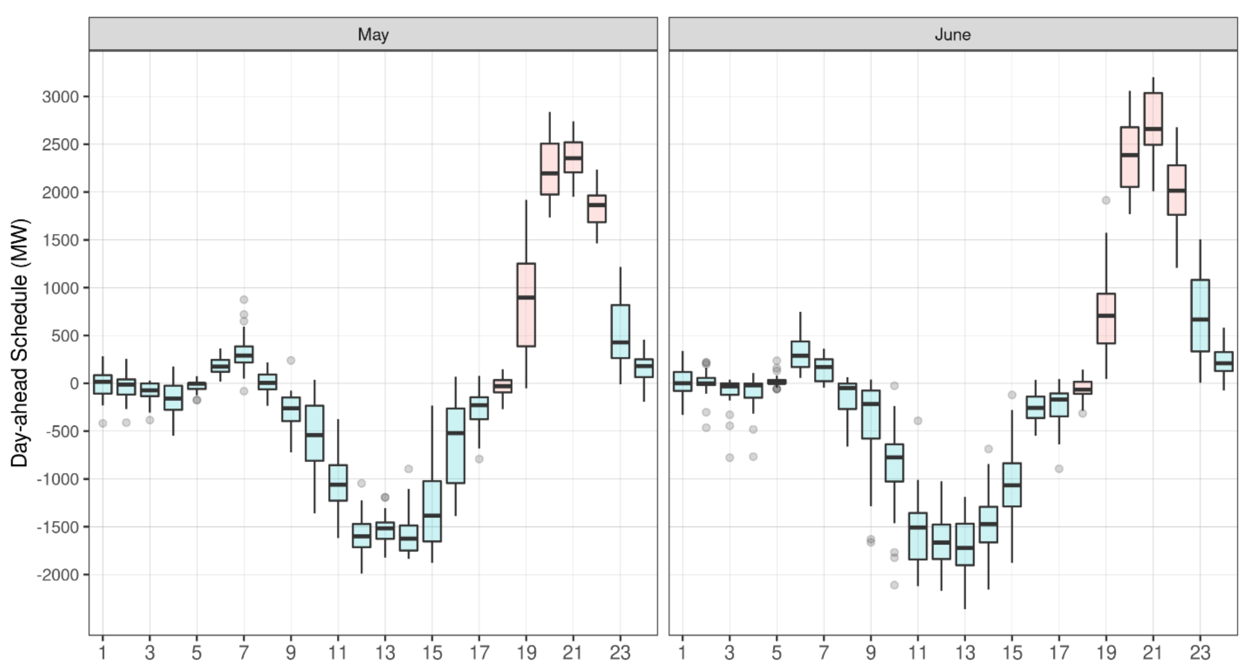
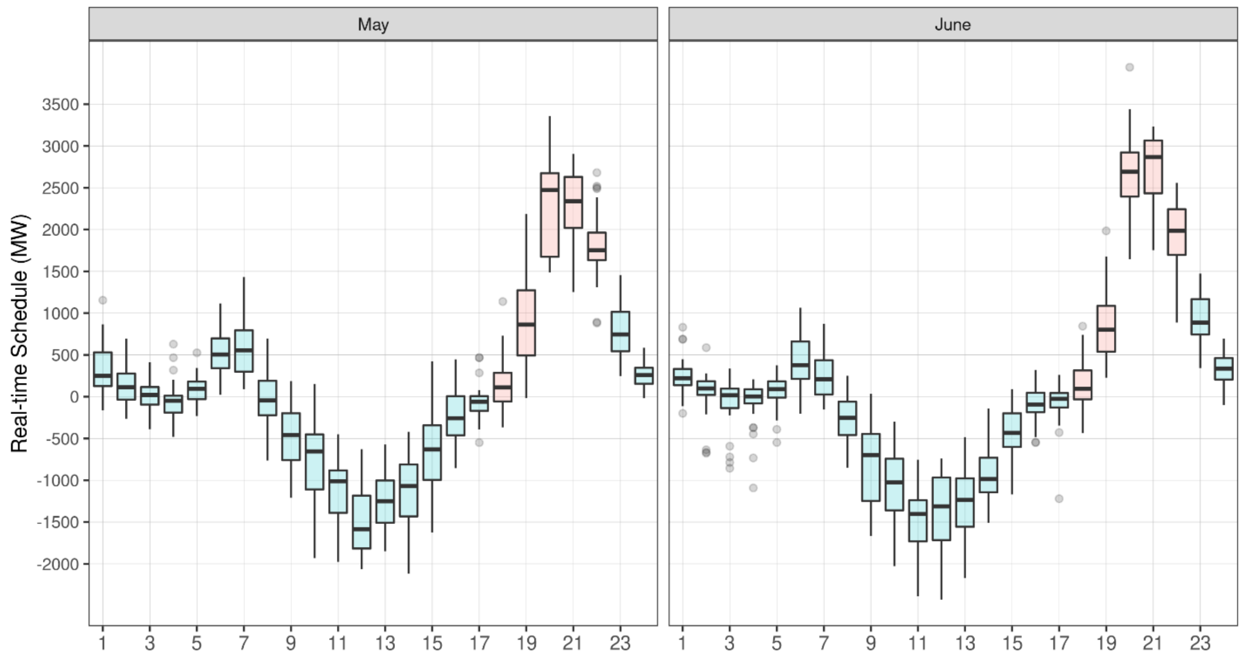


Figure 66: Hourly distribution of real-time dispatch for batteries in May and June 2023



The storage resources continue to provide ancillary services to the market for the following products: regulation up, regulation down, and spinning reserve. Figure 67 shows the average hourly AS awards in day-ahead, and Figure 68 shows the average hourly AS awards in real-time, for May and June 2023.

Figure 67 Hourly average day-ahead storage AS awards in May and June 2023

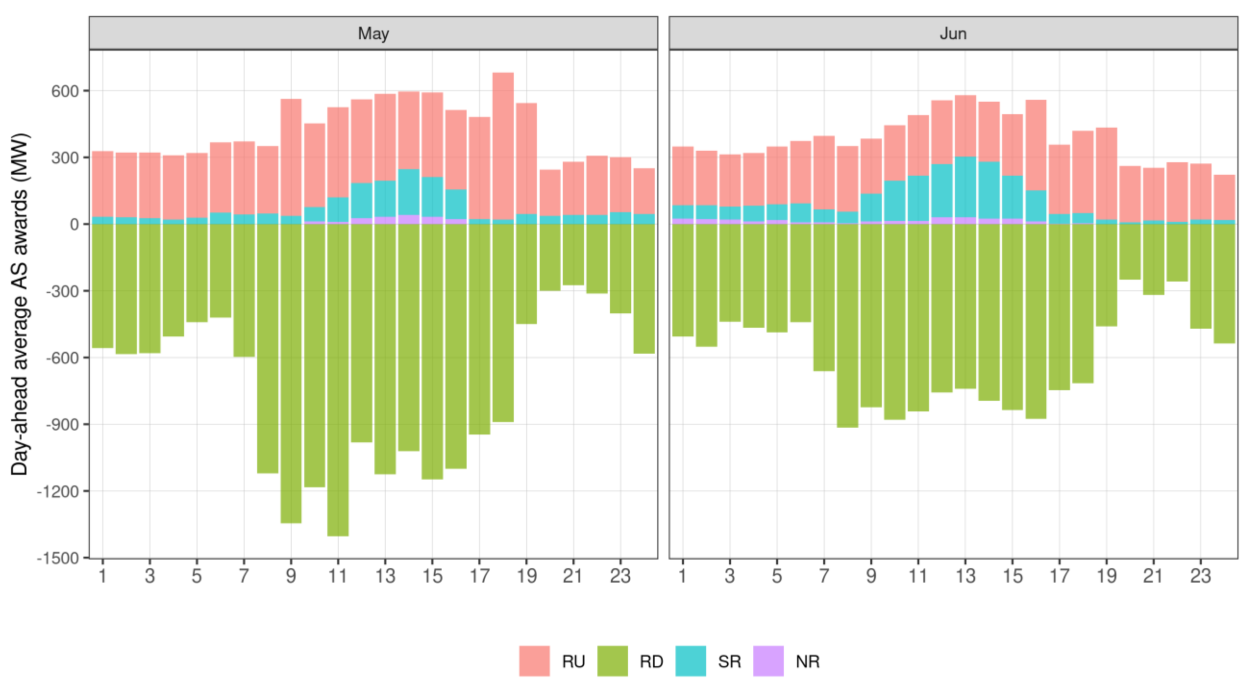
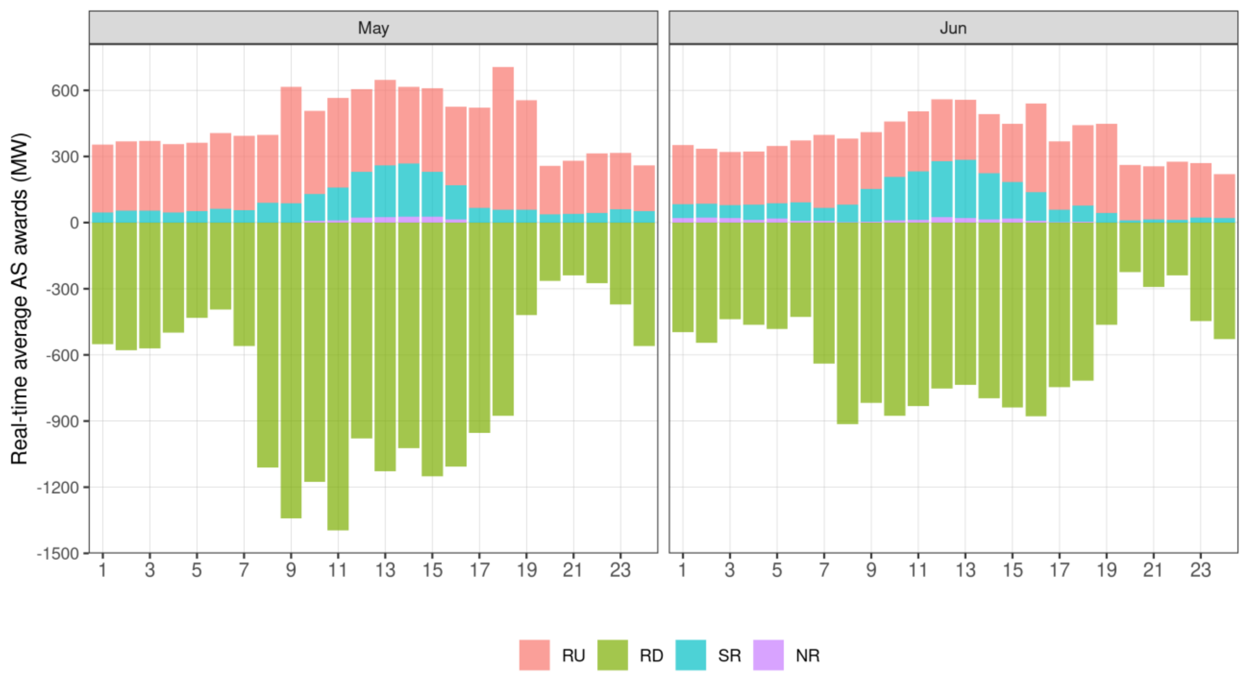


Figure 68 Hourly average real-time storage AS awards in May and June 2023



ginning with the implementation of the Hybrid Resources Phase 2B project in February 2023, CAISO began tracking more formally tracking 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 69 and Figure 70 show the IFM and real-time energy awards for hybrid resources, respectively. The pattern is markedly different than energy storage resources and instead matches more closely the dispatch patterns of solar resources with some differences. An important difference with solar energy dispatch is that the energy awards dip in the middle of the day when solar resources typically reach peak output. This is likely due to the energy storage component of the resource charging off of the solar component of the resource, thus resulting in a lower energy award. Another notable difference is that the evening ramp down as the sun sets is less steep compared to solar resources. This pattern can be attributed to the storage component of the resource discharging in these evening hours thus offsetting the decreased production of the solar component, resulting in flatter decline in output.

Figure 69: Hourly distribution of IFM energy awards for hybrid resources in May and June 2023

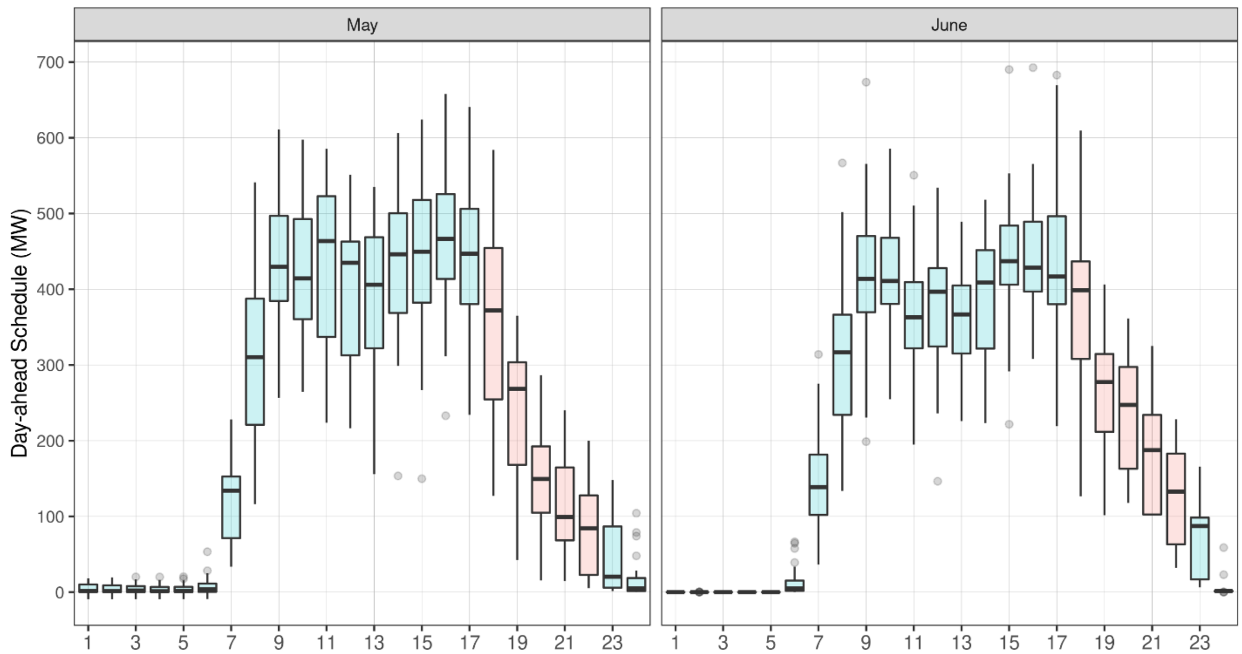
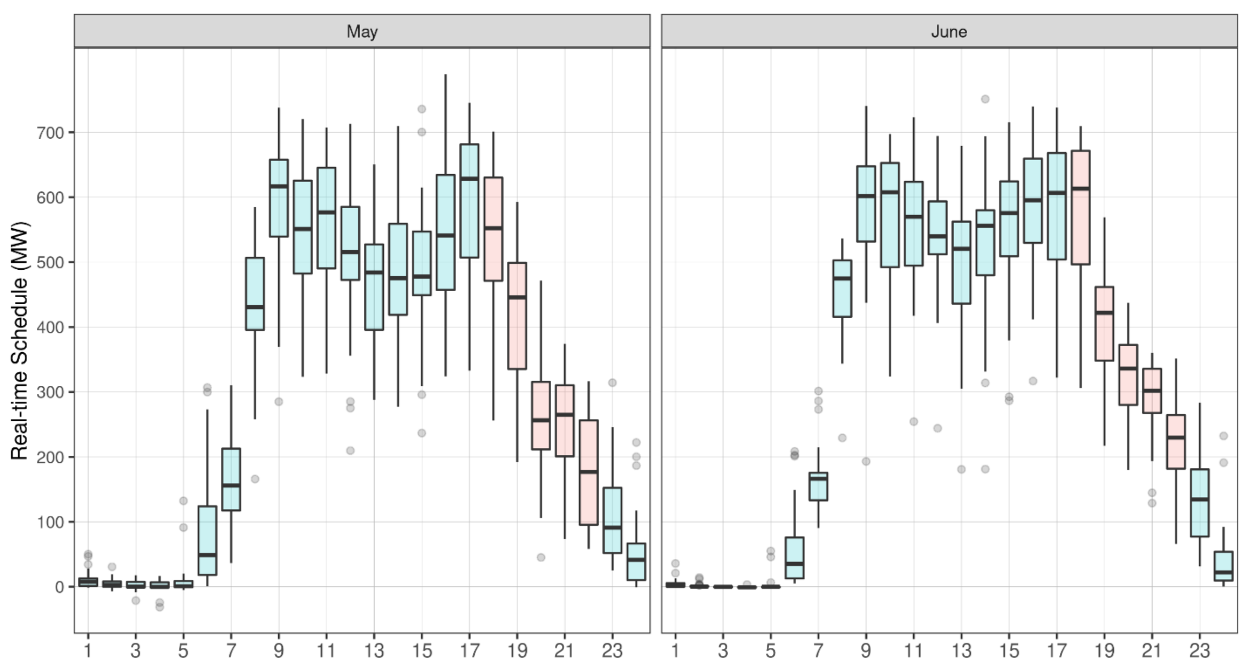


Figure 70: Hourly distribution of real-time dispatch for hybrid resources in May and June 2023



Similar to storage resources, hybrid resources can also provide ancillary services to the market for the following products: regulation up, regulation down, and spinning reserve. Figure 71 shows the average hourly AS awards in day-ahead, and Figure 72 shows the average hourly AS awards in real-time, for May and June 2023.

Figure 71: Hourly average day-ahead hybrid AS awards in May and June 2023

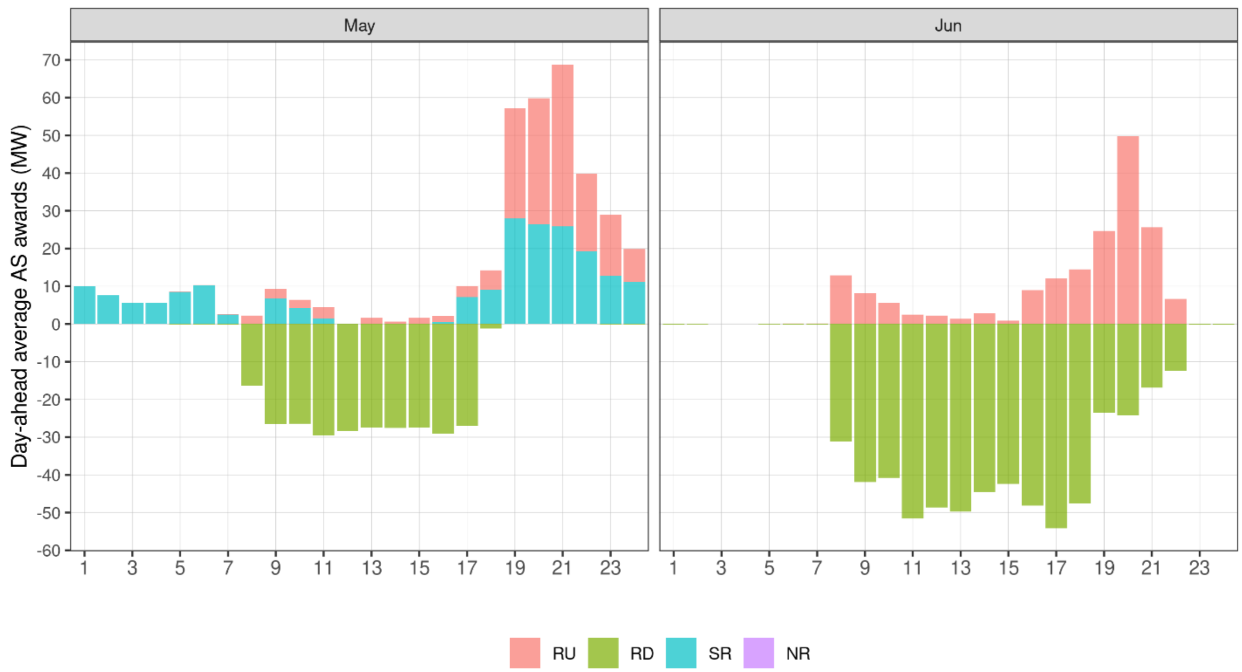
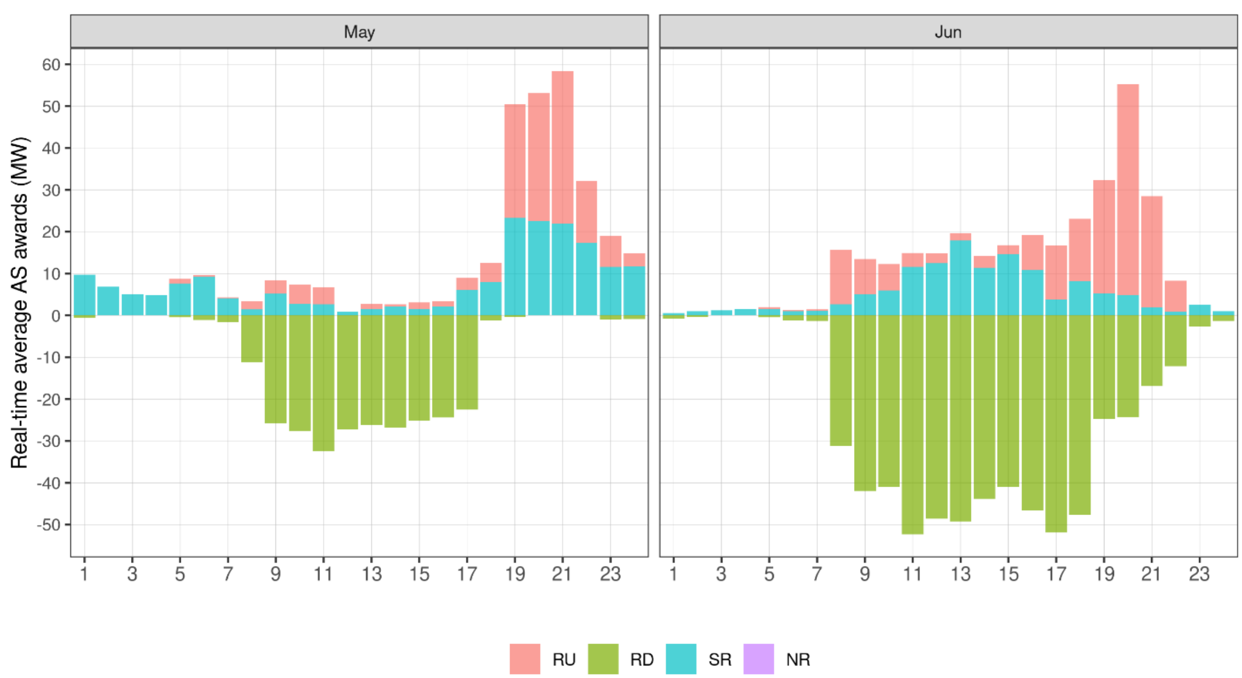


Figure 72: Hourly average real-time hybrid AS awards in May and June 2023



8 Energy Imbalance Market

8.1 EIM transfers

The Energy Imbalance Market, or EIM, provides an opportunity for participating balancing authority areas to serve their load while realizing the benefits of increased resource diversity. The CAISO estimates EIM's gross economic benefits on a quarterly basis.[33] One main benefit of the EIM is the realized economic transfers among areas. These transfers are the realization of a least-cost dispatch by reducing more expensive generation in an area and replacing it with cheaper generation from other areas. In a given interval, one area may have an import transfer with another area while concurrently having an export transfer with another area.

Figure 73 shows the distribution of five-minute EIM transfers for the CAISO area. A negative value represents an import into the CAISO area from other EIM areas.

Figure 73: Daily distribution of EIM transfers for CAISO area

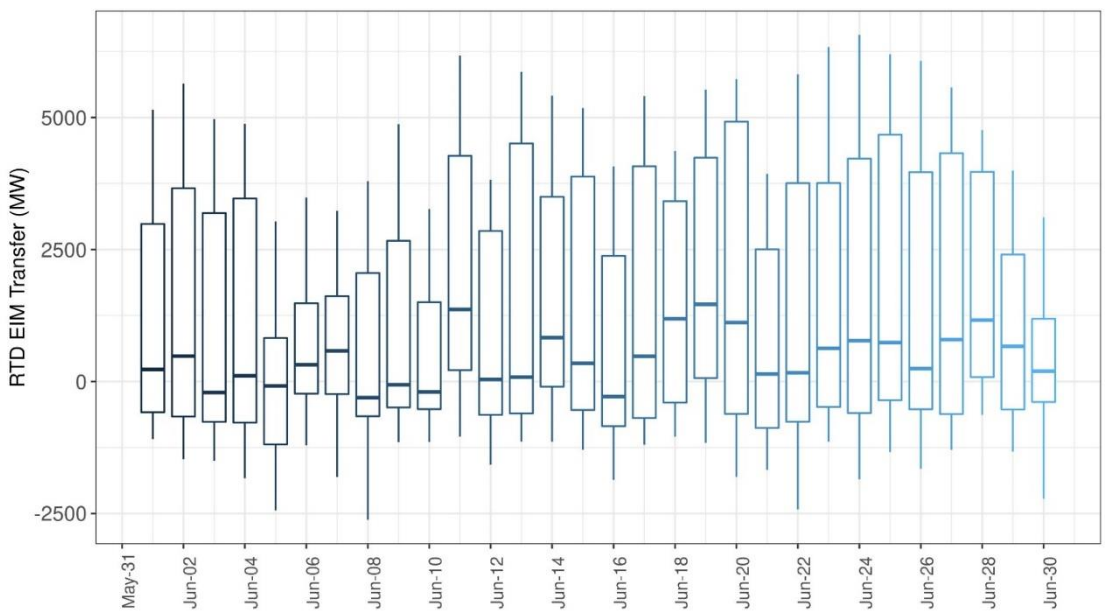
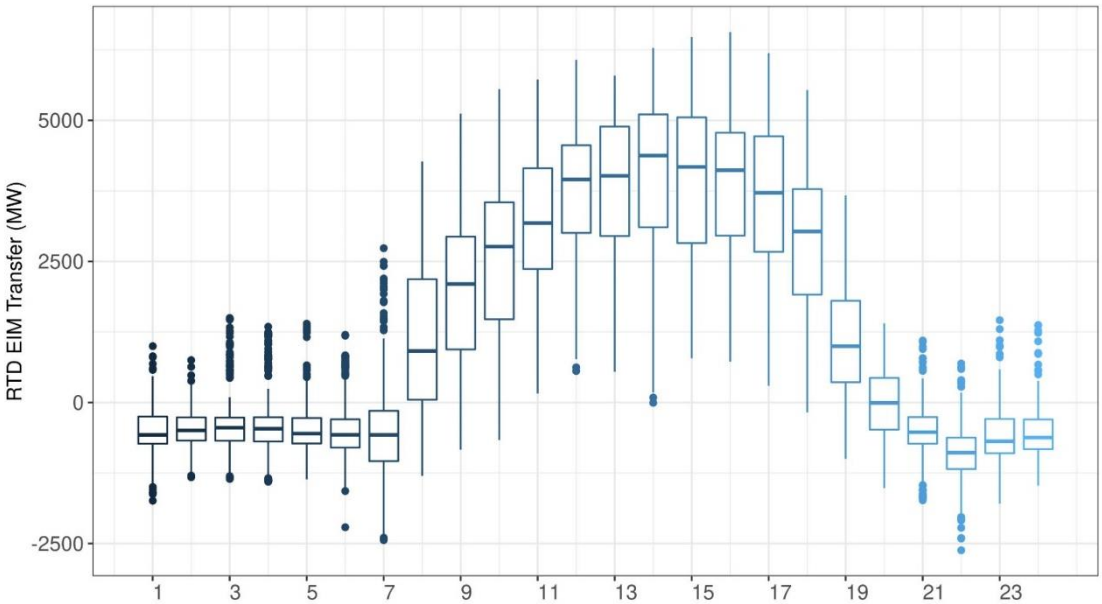


Figure 75 shows the EIM transfers in an hourly distribution, which highlights the typical profile of the CAISO transfers which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the CAISO area.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

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

Figure 74: Hourly distribution of 5-minute EIM transfers for CAISO area



9 Market Costs

The CAISO 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 76 shows the daily overall settlements costs for the CAISO balancing area; this does not include EIM settlements. As demand and prices rise, the overall settlements are is 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 June was $16.80 million, representing an average daily price of $31.06/MWh. The maximum daily cost of $28.1 million occurred on June 29.

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 in

Figure 75: CAISO's market costs, June 2023

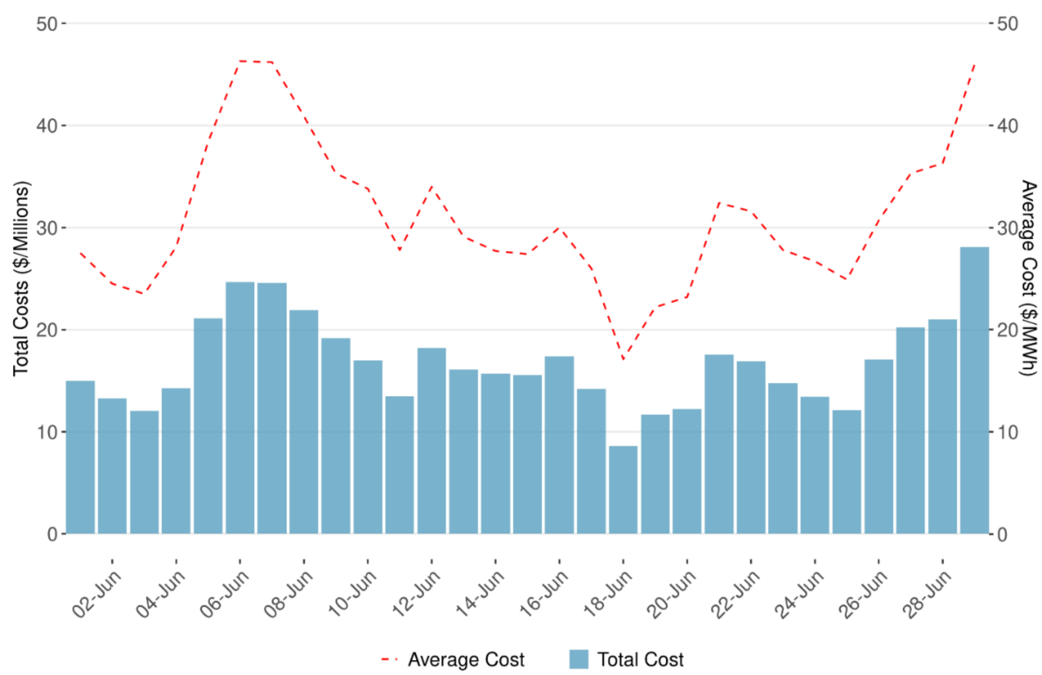
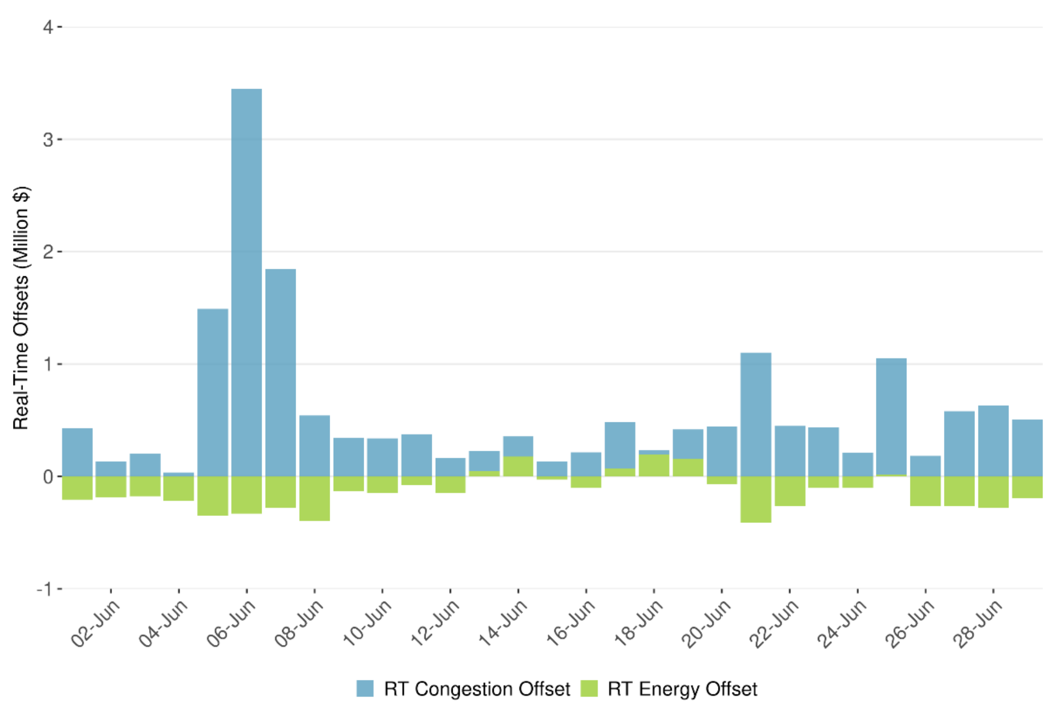


Figure 76: Real-time energy and congestion offsets in June 2023



10 Import market incentives during tight system conditions

This enhancement 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 CAISO has issued an alert by 3 PM PST, or a warning or emergency notice), the CAISO will provide bid cost make-whole payments for real-time hourly block economic imports. This feature was implemented as part of the summer readiness in 2021. The implementation date was June 15, 2021.

This feature was not triggered for the month of June 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 CAISO 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 will be available for summer 2023.

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

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

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

12 Market Issues

Through the analysis of the market outcomes and performance, there was one item identified related to summer readiness conditions identified during the month of June 2023, in which two high-priority wheel-through transactions were not awarded in the day-ahead market. This was due to the wheel-through definition missing record during the transition between network model update.