Summer Market Performance Report
June 2021

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Prepared by

Market Analysis and Forecasting

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1 Executive Summary

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

June 2021 Highlights -

CAISO implemented four elements of the summer readiness initiative: i) make-whole incentives for hourly imports during tight system conditions, ii) real-time pricing of use of contingency reserves at the bid cap, iii) adding an uncertainty component to the capacity test requirements in the Energy Imbalance Market (EIM), and iv) improvements to the management of storage resources under resource adequacy requirements during tight supply system conditions.[2]

June experienced record temperatures across the Western United States, with two heat events and above average temperatures throughout California and the EIM footprint. The first heat event occurred from June 12 through June 20, impacting California, the Southwest, and Northern Mountain West. The second heat event occurred over the Pacific Northwest from June 24 through June 30.

Reduced levels of hydroelectric production due to drought conditions. Reservoir conditions for California and the West are significantly below normal. The statewide storage in major reservoirs is currently 67 percent of average for this time of year and 51 percent of capacity overall[3]. Hydro production in June 2021 was about the same of 2020's production but a half of the 2019's production.

CAISO called for a Flex Alert on June 17 and 18. CAISO estimates that energy conservation triggered by the Flex Alerts resulted in hourly load reductions from 77 to 735 MW during the peak hours. These conservation estimates were in part due to an emergency proclamation signed by Governor Newsom of California to free up additional energy capacity amid a major heat wave.[4]

Monthly resource adequacy (RA) capacity was at 46,113 MW and was above the level of actual load needs (demand plus operating reserves). RA capacity from hydro resources for June 2021 was 670 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] Additional market rule changes will be implemented in July 2021, and CAISO will report on the performance of those changes as they become functional in the CAISO's production systems. The complete list of enhancements that will be implemented this summer and their expected activation dates are provided in the next section.

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

[4] https://www.gov.ca.gov/wp-content/uploads/2021/06/6.17.21-Extreme-Heat-proclamation.pdf

less than it was in June 2020, while storage resource capacity increased by 460 MW. Non-resource specific imports remained about the same level as it was in June 2020.

On June 17 and 18, CAISO's load exceeded the June 2021 1-in-2 forecast of 40,629 MW used in resource adequacy programs. Because aggregated temperatures in the CAISO system rose up to 10 degrees Fahrenheit above normal, CAISO's load exceeded the 1-in-2 forecast in four hours in June 2021.

RA capacity available in the market was generally sufficient to cover actual load needs. Only two hours after the gross peak were not fully covered by RA capacity, which was covered by above or non-RA capacity. Non-RA capacity available in the market was consistently over 4,000 MW through the month, and was supported by both internal supply and imports.

CAISO's prices diverged across markets during June 14 through June 18. Real-time prices were lower than day-ahead prices during the heat wave of June 14-18, and mainly during peak hours of the day. This partly attributable to the day-ahead market having procured more supply capacity to meet projected high loads that did not materialize in the real-time market because of cooler than forecasted temperatures along the coast, reductions in actual load because of energy conservation and demand response, in addition to the incremental adjustment to the load forecast in the day-ahead market.

The residual unit commitment process (RUC) was unable to meet the adjusted load forecast in one hour of June 17, and concurrently found over 3,000 MW of exports to be infeasible. The infeasible exports were a combination of exports that were bid-in economically or self-scheduled with either low or high priority. The high priority exports, which are exports that are backed by resources contracted to serve external load, were rebid into the real-time market, and were fully scheduled given changed conditions. In the real-time market, export curtailments were minimal and only for low priority exports, which are exports not backed by resources contracted to serve external load, with the largest volume curtailed on June 21. These curtailments were not due to tight supply conditions but rather due to congestion management on an intertie that observed high volume of schedules relative to its scheduling capacity.

Hourly average of net schedule interchange was about 4,800 MW for peak hours in June. Net schedule interchange reached its minimum levels on June 16, 21 and 28 when CAISO experienced the largest volume of exports in the system. On June 28, the net interchange was a net export when total exports over 7,000 MW were greater than total imports. Export schedules on Palo Verde increased steeply during the mid-June heat event.

EIM transfers into the CAISO area were about 4,000 MW on June 17 during peak hours. Transfers into CAISO were from multiple areas, including adjacent areas and also from farther reaching areas. During the second heatwave that struck the Pacific Northwest, similar benefits materialized with EIM transfers going into the Pacific Northwest entities. These transfers reflect the economic and operational benefits that EIM offers to participating entities by maximizing supply diversity.

About 94 percent of RA imports bid at $0/MWh or lower prices in the day-ahead market, which is assessed for static RA imports related to CPUC jurisdictional load serving entities and for hours ending 17 through 21 in weekdays.

Self-scheduled wheel-through transactions on June 18 reached 1,200 MW on the system as a whole. The bulk of wheel-through transactions were self-scheduled between June 14 and June 19, and were mainly on two paths: NOB to Paloverde (max of 413 MW) and from Malin to Paloverde (max of 317 MW). These intertie constraints did not become congested in the markets during this period.

Proxy demand response was dispatched up to 160 MW on June 17, while reliability demand response resources (RDRR) were not activated and dispatched in the real-time market.

Storage resources contributed up to 600 MW during critical intervals across the gross and net load peaks. Their maximum discharge dispatches occurred between hour ending 19 and 21, while charging the most in early hours when solar supply was plentiful. The maximum level of state of charge of about 3,000 MWh was reached as early as in hour ending 14.

The addition of uncertainty to the capacity test has increased the frequency of capacity test failures, with CAISO area experiencing three more capacity failures during the mid-June heat wave. Other EIM entities also experienced an increase in failures. The majority of test failures occurred during peak hours when supply conditions were tight.

Overall, CAISO's daily market costs reached $95 million on June 17. This is more than three times the cost of a more typical day in the first half of June (approximately $25 million), but it is consistent with costs observed for days in other summer months in previous years. This higher cost reflects the increased load and services settled at higher energy prices.

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4 Acronyms

AZPS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
BCHA	Powerex
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
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
LSE	Load Serving Entity
MSG	Multi-Stage Generator
MW	Megawatt
MWh	Megawatt-hour
NEVP	NV Energy
NGR	Non-Generating Resource
NOB	Nevada-Oregon Border
NSI	Net Scheduled Interchange
NWMT	Northwestern Energy
OASIS	Open Access Same-Time Information System
OR	Operating Reserves
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PRM	Planning Reserve Margin
PSEI	Puget Sound Energy
PST	Pacific Standard Time

PTO	Participating Transmission Owner
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

5 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.[5]

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, CAISO identified one area of improvement to existing market practices regarding the treatment of export priorities. 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 process (RUC) 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 scheduled. With the change, exports cleared in the day-ahead market receive a day-ahead priority up to the cleared schedule in the RUC process. This practice remains in place even after the policy initiative changes scheduled for summer 2021.

[5] 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

After 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.[6]

The Summer 2021 enhancements include:

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 are being implemented at different times during summer 2021.

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

6 Summer Readiness Enhancements

The summer readiness initiative was organized in two main efforts. The second part of the initiative largely focuses on Load, Exports and wheeling priorities. The first part includes all other items of the summer readiness initiative.

The first part of the summer readiness initiative was approved by FERC on May 25, 2021[7] and includes the following components, which have been implemented at different times in early Summer 2021:

1. EIM resource capacity sufficiency test. These enhancement add the uncertainty component utilized in the flexible ramp sufficiency test to the capacity test and are applied to all areas participating in the Western Energy Imbalance Market, (EIM) including the CAISO's area.

   Implementation date: June 15, 2021.
   This feature is evaluated in this report for the second part of June.

2. Import market incentives during tight system conditions. This enhancement provides improved incentives for import supply to be available during tight system conditions because the prior settlement rules may have paid imports less than they bid, which could be exacerbated under tight supply conditions. 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.

   Implementation date: June 15, 2021.

   This featured was triggered on June 17 between 6pm and 9pm. This calculation is based on settlements data, which was not available at the time this analysis was performed and prevented a full evaluation of the implications of triggering this feature. This will be evaluated in subsequent reports as the settlements data becomes available.

3. Additional publication of intertie schedules information on OASIS. This provides greater transparency of intertie schedules through a new OASIS display. Intertie schedules are organized by Import and Exports and by individual intertie location.

   Implementation date: July 22, 2021.

4. Enhanced real-time pricing signals during tight supply conditions. The enhancement allows the CAISO to price energy released from operating reserves deployed to serve load at the applicable

[7] FERC order accepting Tariff revisions for the Summer readiness initiative can be found at http://www.caiso.com/Documents/May25-2021-OrderAcceptingSummerReadinessFiling-ER21-1536.pdf

energy bid cap. This applies to energy associated with either contingent or non-contingent operating reserves. This new logic can trigger when CAISO is in a warning or emergency.

Implementation date: June 15, 2021.

This feature was active on June 17 while CAISO had a warning/emergency. However, given the system conditions, there was no need to release spinning or non-spinning capacity into energy.

5. Management of storage resources during tight system conditions. This enhancement includes three features involving the management of storage resources:

    a. Updated state-of-charge requirements when storage resources provide regulation. In scheduling and awarding storage resources, the market ensures resources will have a State- of-Charge (SOC) that can maintain the awarded Regulation Up and Regulation Down for a defined period of time. This specific change was implemented on May 30, 2021.

    b. Minimum state-of-charge requirement. This is to ensure storage resources providing RA capacity are sufficiently charged in the RTM to meet DAM discharge schedules when storage resources are needed to meet the evening net-load peak. This is implemented through a minimum state-of-charge (MSOC) tool and will be used when the RUC process identifies supply shortfalls.

    c. CAISO will report on the critical hours used to calculate the minimum state-of-charge and the hours RUC shortfalls through a new OASIS display. There will also be a new resource-specific report via CMRI.

    Implementation date: June 30, 2021.

6. Reliability demand response dispatch and real-time price impacts. This enhancement expands RDRR functionality to dispatch RDRR resources in the fifteen-minute market (FMM). RDR resources have new bidding options to be 15- or 60-minute dispatchable, allowing them to reflect their operational capabilities more accurately. This will also allow RDRR resources to be marginal resources in FMM.
    Expected implementation date: July 29, 2021.

The second part of the initiative (Load, export and wheeling priorities) was approved by FERC on June 25, 2021[8] and the target implementation date is no later than July 30, 2021. This enhancement involves a revised set of scheduling priorities for Exports, wheel transactions and CAISO load, including a newly specified priority for wheeling through transactions. The activation of this enhancement is expected for July 29, 2021.

In addition to market enhancements and based on the lessons learned from the summer 2020 events, CAISO has also implemented

1. Interconnection process enhancements. This enhances the independent study interconnection process to provide ISO additional capacity for summer 2021, removes the 100MW/125% cap on behind the meter expansion requests and enable the ISO to award available deliverability on a temporal basis to online projects. This took effect with the Tariff provision of May 25, 2021.

2. Additions to CAISO's public communications messaging and protocols to enable more transparent and timely communication of projected and existing conditions that may impact the supply conditions of the system. In addition to communication protocols with involved system entities, CAISO is providing communication to the public and market at large in advance of possible stress on the system to allow them time to prepare and participate in conservation efforts.

   These include expanded communication on the CAISO social media platforms for high temperature conditions, a Heat Bulletin news release, and a System Conditions Bulletin posted to the News page and updated as needed during a heat event. The Heat Bulletin alerts media and public that hot weather in any of the next seven days could affect grid conditions; the System Conditions Bulletin continually provides the most recent and developing information on grid conditions, including load and weather forecasts, operational actions, Flex Alerts, and emergency notifications.

3. The Today's Outlook display, available on the CAISO's website, is being enhanced to increase transparency on the electric system's projected conditions, with new charts for daily resource adequacy capacity trends for the current day, as well as resource adequacy capacity with seven-day trends. This also includes load and net load trends for seven days. The activation of this enhancement is expected for July 29, 2021.

Table 1 summarizes the different enhancements being implemented through the summer.

[8] FERC order accepting Tariff revisions for the Summer readiness initiative can be found at http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

Table 1: Summary of enhancements implemented in the Summer 2021

Summer enhancement	Date Implemented	Trigger	Dates/Hours Triggered
1. EIM resource capacity sufficiency test	15-Jun	Permanent feature	All the time
2. Import market incentives during tight system conditions	15-Jun	Warning or Emergency	June 17, 6-9pm
3. Intertie schedules information on OASIS	26-Jul	Permanent feature	All the time
4. Enhanced real-time pricing signals during tight supply conditions	15-Jun	Warning or Emergency	June 17, 6-9pm
5. Management of storage resources during tight system conditions	30-Jun	RUC undersupply	Not triggered
6. Reliability demand response dispatch and real-time price impacts	29-Jul	Activation of RDRR	Not active yet
Load, export and wheeling priorities	29-Jul	Permanent feature[9]	Not active yet
Interconnection process enhancements	25-May	Permanent feature	Not used yet
CAISO's public communication protocols	29-May	System Event driven	29-May, 11-Jun, 15-Jun, 27-Jun
Today's Outlook displays	29-Jul	Permanent feature	Not active yet

[9] This provision will expire in summer 2022.

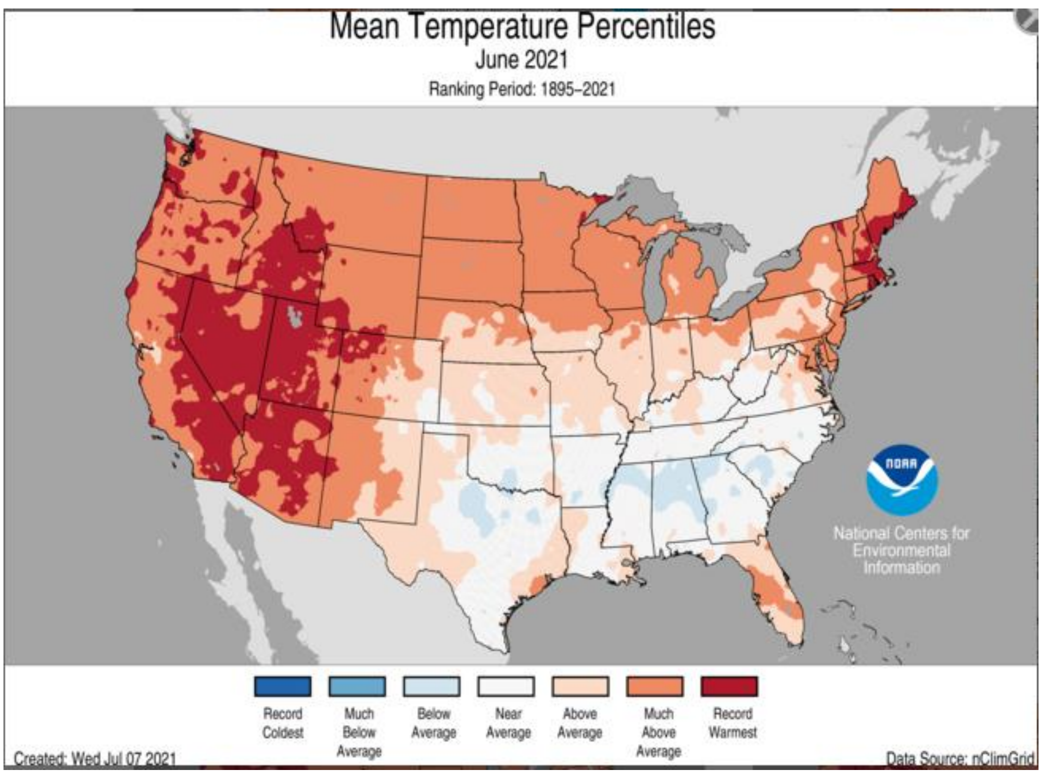
7 Weather and Demand Conditions

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.

7.1 Temperature

Above average, much above average, and record warmest temperature percentiles were observed throughout California and the Western United States for minimum, maximum, and average temperatures during the month of June, with two significant heat events noted throughout the Western United States. The first significant heat event occurred from June 12th through June 20th, 2021. Extreme heat occurred in California, the Southwest, and the Northern Mountain West, leading to record-breaking or near record heat. This is shown in Figure 1, June Maximum Temperature Weather Records, above.

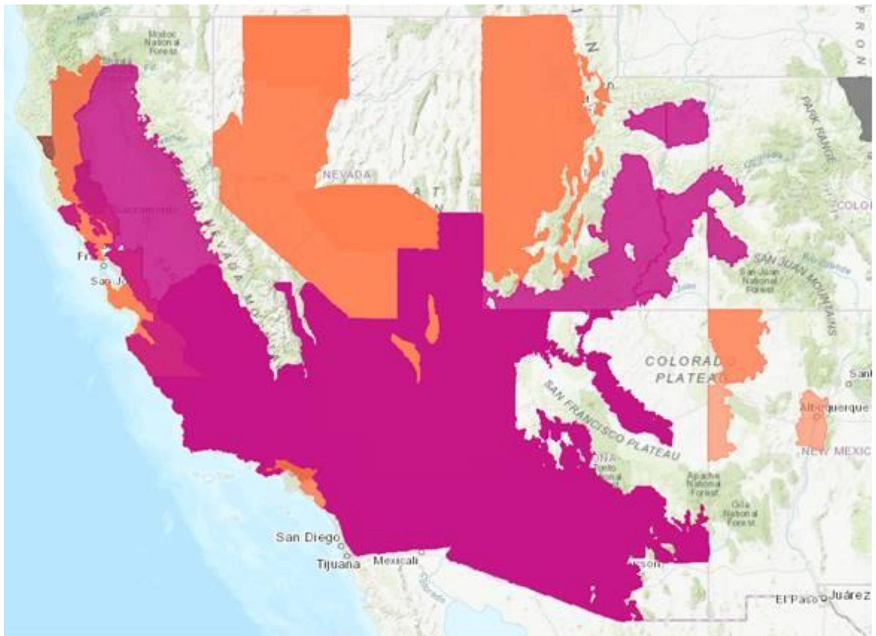
Figure 1: Mean temperature percentiles for June 2021[10]



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

During the mid-June event, much of the Western United States was within an Excessive Heat Warnings, Heat Advisories, or an Excessive Heat Watch issued by the National Weather Service on June 16th, 2021, as depicted by Figure 2.

Figure 2: National Weather Service alerts and warnings on heat for the Western United States[11]



Excessive Heat Warning Heat Advisory Excessive Heat Watch

During the mid-June event, California, the Southwestern EIM, and Northeastern Mountain West entities were impacted as the high pressure ridge built throughout the week. The coastal Pacific Northwest warmed as the remainder of the EIM footprint was cooling on Monday June 21st, 2021. During this event, the Southwestern EIM entities (APS, PNM, NVE, and SRP) were running 8-15 degrees Fahrenheit (F) above normal starting on Monday June 14th, 2021 through June 20th, 2021, with the warmest days being the weekdays. Phoenix, Arizona had a total of 6 days with a temperature of 115 degrees F or higher during this event. This event put 2021 in 3rd place for all-time days with high temperatures of 115 degrees F or higher for Phoenix as of June 20, 2021. By looking at the whole Western United States in Figure 3 below, there are many maximum temperature records which were tied or broken during the mid-June event, as this heat wave was expansive across the entire Western footprint.

[11] National Weather Service (https://www.wrh.noaa.gov/map/?obs=true&wfo=mtr) from 6/16/2021 @ 1300

Figure 3: Maximum temperature records -June 12th through June 20th, 2021[12]

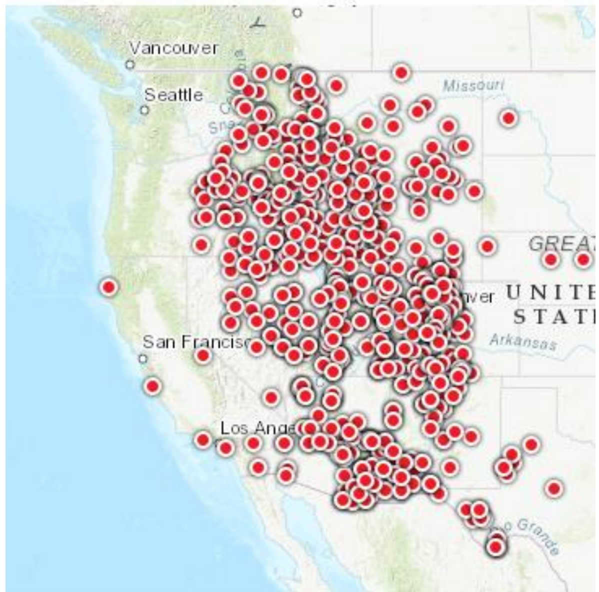
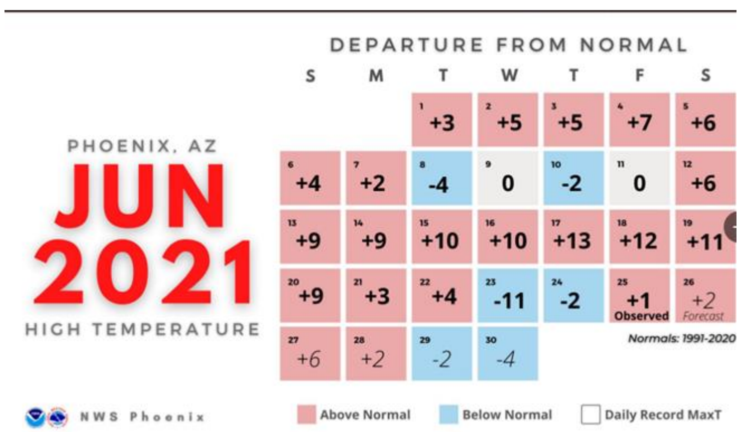


Figure 4 and Figure 5 show that Phoenix, AZ was running 10-13 degrees F above normal during June 15 through 29, and the CAISO area was running 6-10 degrees F above normal for that same time period.

Figure 4: Phoenix, AZ high temperature departure from normal[13]



After a week of near-record to record-breaking temperatures across California, the Southwest, and Northern Mountain West, a second significant heat wave developed mainly over the Pacific Northwest. This led to record-breaking temperatures throughout the region from June 24th through June 30th, 2021. This late-June event, which occurred predominately over the Pacific Northwest, was one of the most extreme recorded heat wave in the region's history, affecting the Pacific Northwest and Western Canada. The observed temperatures did not just break previously set daily records for the area, but shattered

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

[13] National Weather Service (NWS Phoenix Twitter)

them for multiple days, as well as set multiple all-time record high temperatures. Some details of a few specific weather stations for the area are shown in Table 2.

Figure 5: CAISO high temperature departure from normal

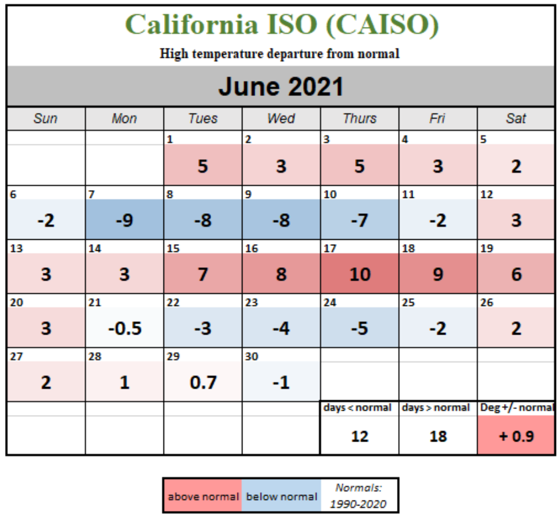


Table 2: Pacific Northwest temperatures in June[14]

	New Record All-Time High Temperature (°F)	Number of Days All-Time High Temperature Records were Broken	Previous Record All-Time High Temperature (°F)
Portland, OR (PDX)	116 On June 28th, 2021	3	107 On August 8/10, 1981 & July 20th, 1965
Seattle, WA (SEA)	108 On June 28th, 2021	2	103 on July 29th, 2009

During the hottest days, Portland was running nearly 40 degrees F above normal and eclipsed the hottest three-day period on record by 6 degrees F. All three days within this extreme heat event set all-time records for Portland. At the same time. Seattle was running nearly 35 degrees F above normal, and set all-time records two days in a row. Moreover, Seattle has only hit 100 degrees F three times during the previous 126 years, yet during this heat event, temperatures in the city exceeded 100 degrees F three days in a row.[15] Portland and Seattle were not the only weather stations that tied or broke records during this historic event. Figure 6 and Figure 7 below show how the intense heat was throughout the entire region.

[14] Information available at http://xmacis.rcc-acis.org/

[15] https://www.climate.gov/news-features/event-tracker/astounding-heat-obliterates-all-time-records-across-pacific-northwest

Figure 6: Maximum temperature records - June 24th, 2021 through June 30th, 2021[16]

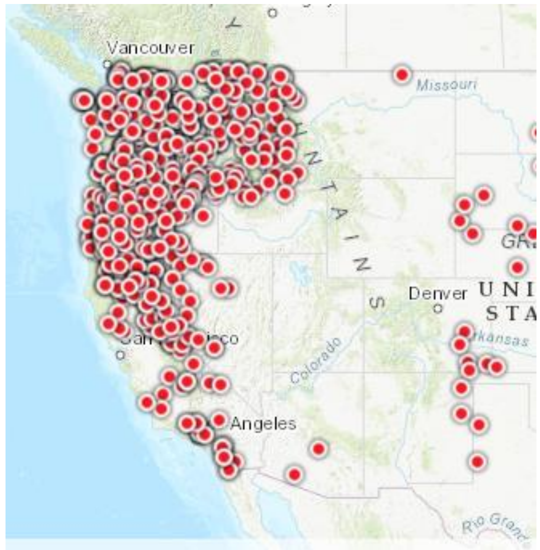


Figure 7: High temperature departure from normal for Coastal Pacific Northwest EIM entities

Portland Gas and Electric (PGE)
High temperature departure from normal
June 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
		1: 23	2: 18	3: 12	4: 6	5: -7
6: -8	7: -7	8: -7	9: -4	10: -6	11: -10	12: 6
13: -7	14: -3	15: -5	16: 6	17: 10	18: 6	19: 7
20: 17	21: 20	22: 8	23: 8	24: 12	25: 17	26: 31
27: 35	28: 36	29: 14	30: -1			
				days < normal	days > normal	Deg +/- normal
				11	19	+ 7.6

above normal | below normal | Normals: 1990-2020

Puget Sound Energy (PSE)
High temperature departure from normal
June 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
		1: 18	2: 15	3: 6	4: -0.5	5: -7
6: -16	7: -8	8: -4	9: -5	10: -6	11: -10	12: 1
13: -8	14: -5	15: -5	16: 1	17: 8	18: 3	19: 6
20: 10	21: 18	22: 5	23: 4	24: 11	25: 15	26: 28
27: 30	28: 34	29: 10	30: -2			
				days < normal	days > normal	Deg +/- normal
				12	18	+ 4.8

above normal | below normal | Normals: 1990-2020

Seattle City Light (SCL)
High temperature departure from normal
June 2021

Sun	Mon	Tues	Wed	Thurs	Fri	Sat
		1: 17	2: 15	3: 6	4: -1	5: -5
6: -15	7: -9	8: -3	9: -4	10: -5	11: -11	12: 2
13: -7	14: -7	15: -4	16: 1	17: 7	18: 2	19: 4
20: 9	21: 16	22: 4	23: 4	24: 9	25: 14	26: 28
27: 29	28: 33	29: 10	30: -1			
				days < normal	days > normal	Deg +/- normal
				12	18	+ 4.6

above normal | below normal | Normals: 1990-2020

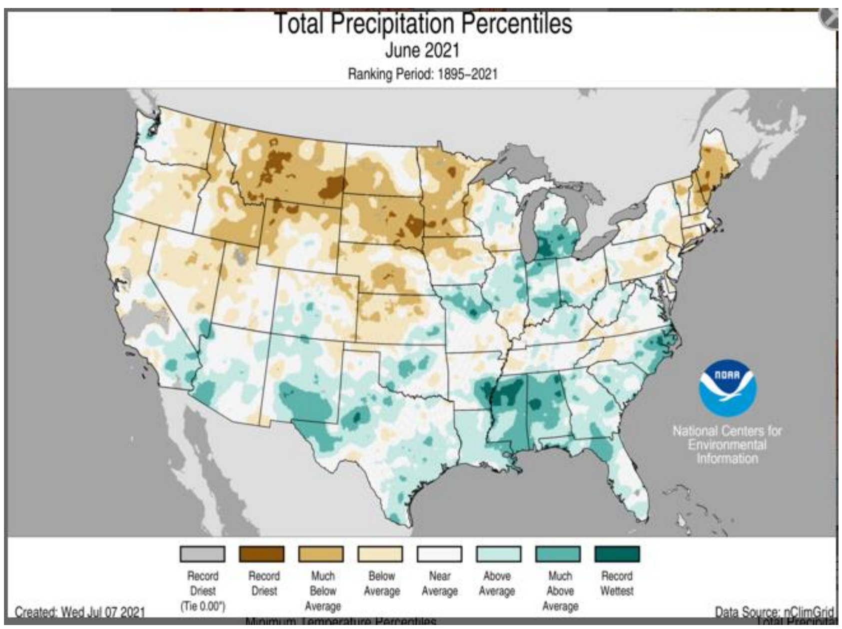
[16] https://www.ncdc.noaa.gov/cdo-web/datatools/records

Excessive heat, depending on the day of week, has the potential to bring higher load to the electrical system that may be above the long-term planning set forth when setting the supply needs to serve demand. In addition, during excessive heat events, supply resources (thermal and renewable) typically operate less efficiently creating de-rates on the maximum energy that can be produced depending on the temperature and other characteristics such as air flow.

7.2 Hydro conditions

The Western United States, including California, has experienced one of the driest water years on record. For the Northern Sierra 8-station index, the water year of October 2020 through May 2021 currently ranks third on driest water years on record with observed precipitation of 23.1 inches.[17] During the month of June that trend continued with much of the West receiving below average precipitation. Figure 8 illustrates the total precipitation in the United States.

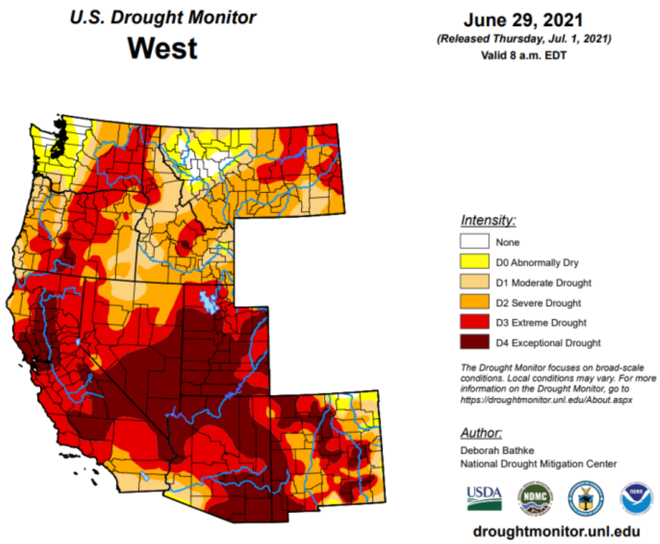
Figure 8: The United States total precipitation percentiles for June 2021[18]



Due to the lack of total precipitation throughout this water year, the majority of the Western United States remains in drought conditions, extending from abnormally dry to exceptional dry. The extent of the drought coverage is shown in Figure 9 below.

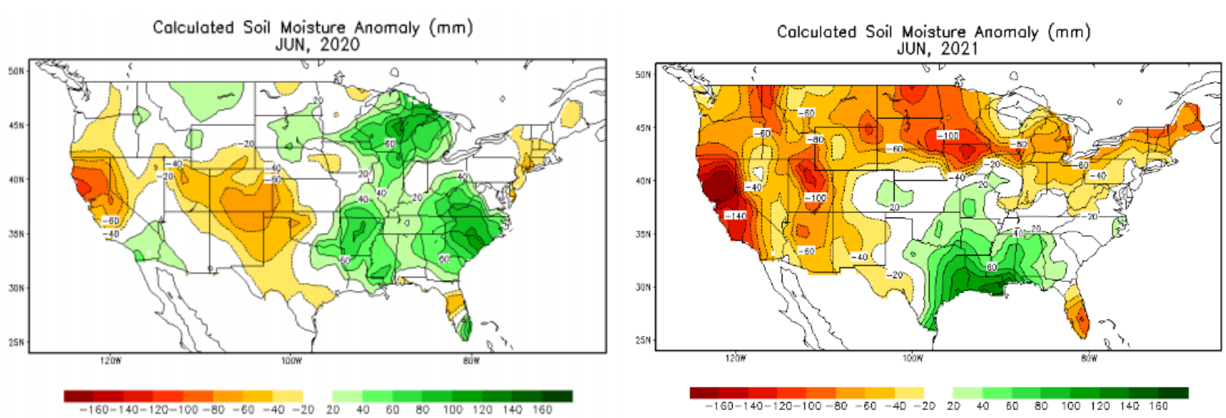
[17] Sacramento National Weather Service Spring 2021 Climate and Drought Summary
[18] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

Figure 9: The Western United States drought monitor[19]



As shown in Figure 10, drought conditions and reduced rainfall have also led to soil moisture that is much drier throughout the West for 2021 compared to 2020, which has reduced the amount of water flowing into the California reservoirs from the snowpack during the 2020 -2021 water season.

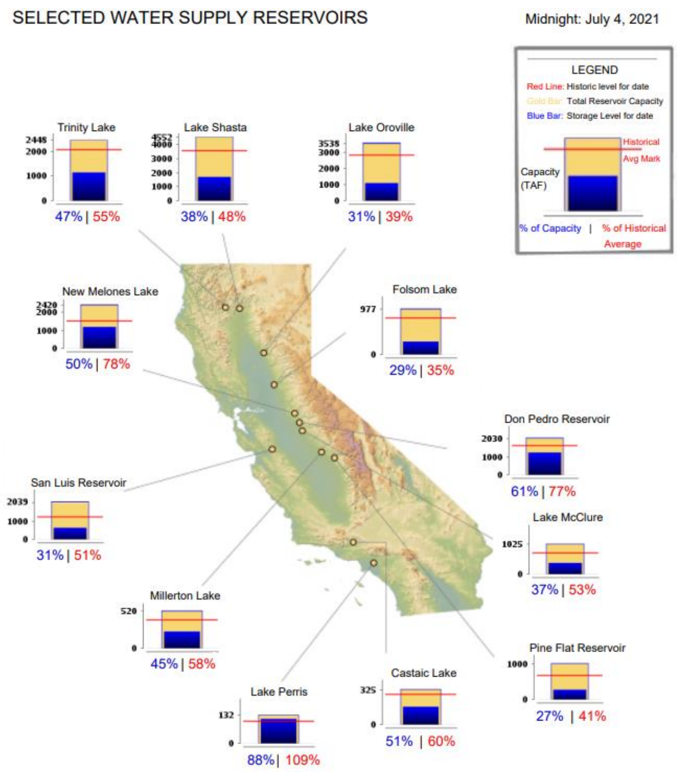
Figure 10: The United States soil moisture anomaly June 2020 vs June 2021[20]



Based on all the factors discussed above related to temperatures, precipitation, drought conditions, and soil moisture levels, reservoir conditions for California and the West are below normal, as shown in Figure 11. The statewide storage in major reservoirs is currently 67 percent of average and at 51 percent of capacity[21].

[19] https://droughtmonitor.unl.edu/data/pdf/20210629/20210629_west_text.pdf
[20] https://www.cpc.ncep.noaa.gov/products/Soilmst_Monitoring/US/Soilmst/Soilmst.shtml#
[21] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM

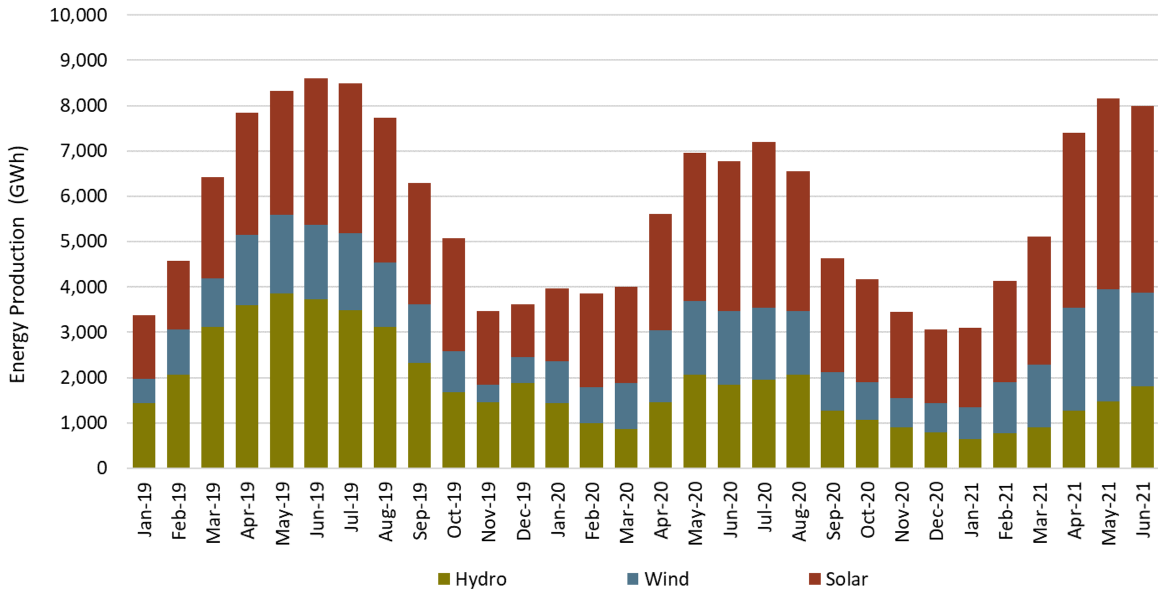
Figure 11: California's reservoir conditions as of July 2021[22]



CAISO's 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 and the expectation of deteriorating conditions throughout the summer, the CAISO is expecting significantly reduced capacity in hydro production this year. Figure 12 below shows the historical trend of total energy produced from hydro resources, as well as renewable resources, in which hydro production for 2021 so far has been significantly lower than the previous two years. Hydro production in June 2021 is comparable to that of production in June 2020, but is about half the production of June 2019. In contrast, renewable production has grown over the three year span, with the bulk of the growth within solar. Although such conditions will reduce the overall available energy available over the summer, typically hydro resources strive to conserve their more limited water to provide peaking energy, which helps mitigate the adverse impact of limited hydro.

[22] Department of water resources. Available at https://cdec.water.ca.gov/cgi-progs/products/rescond.pdf

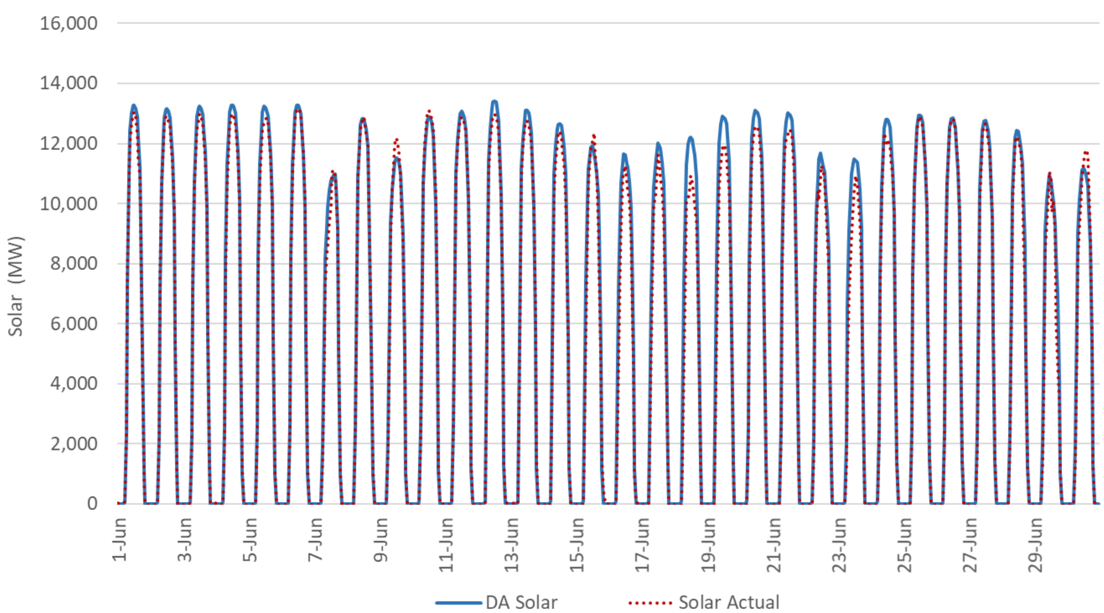
Figure 12: Historical trend of hydro and renewable production



7.3 Renewable forecasts

June 2021 led to a more typical summer pattern for both solar and wind forecasting, with accuracy values falling in line with what has been observed during previous years for the month of June. Figure 13 below shows 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



During the mid-June heat wave, increased moisture moved in with the high pressure ridge, leading to high- and middle-level cloud cover developing over some of the Southern California grid-connected solar sites. During this time period, the day-ahead forecast for solar resources had larger uncertainty and the forecast came in higher than actuals observed, as shown in Figure 13. Although there was some increased error during the middle of June, the average error[23] for the day-ahead solar forecast in June was 2.5 percent mean absolute percent error. The average error observed in June 2021 is lower than the day-ahead solar forecast error observed for the month of June in 2019 and 2020[24].

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

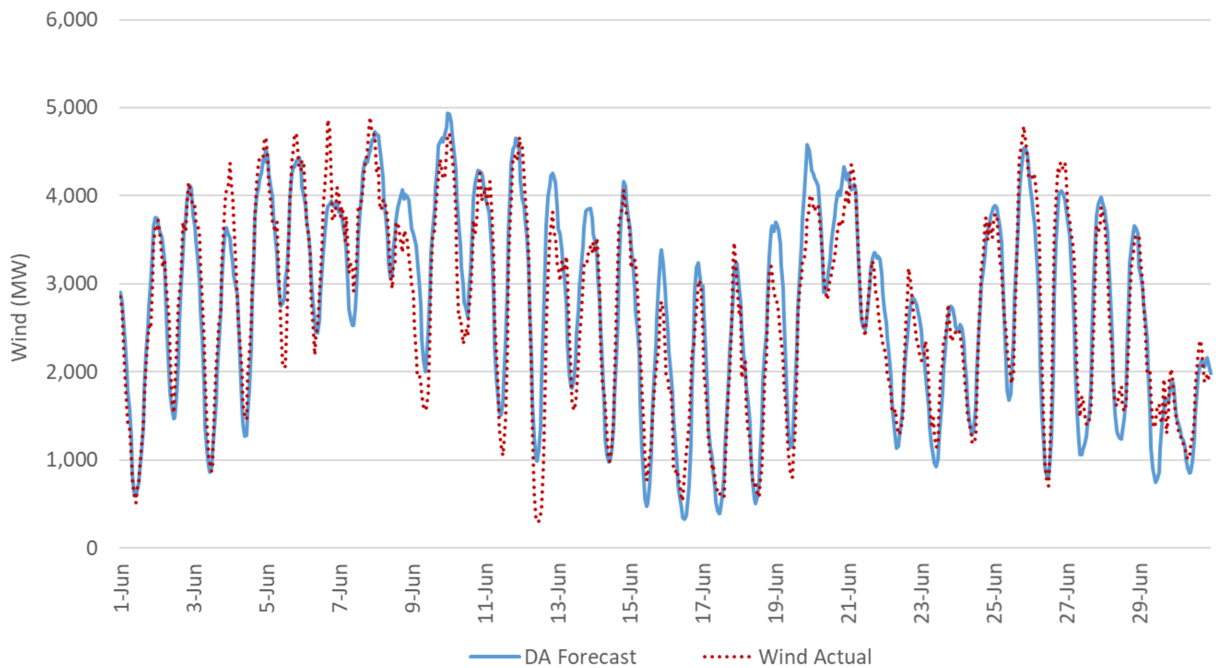


Figure 14 shows the profile for wind in the CAISO's system. The average error[25] for the day-ahead wind forecast in June was 5.17 percent. The average error observed in June 2021 is comparable to the day-ahead demand forecast error observed for the month of June in 2019 and lower than the day-ahead wind forecast error observed for June 2020.[26]

[23] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[24] http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Jun222021.pdf
[25] Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Nameplate Capacity).
[26] http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Jun222021.pdf

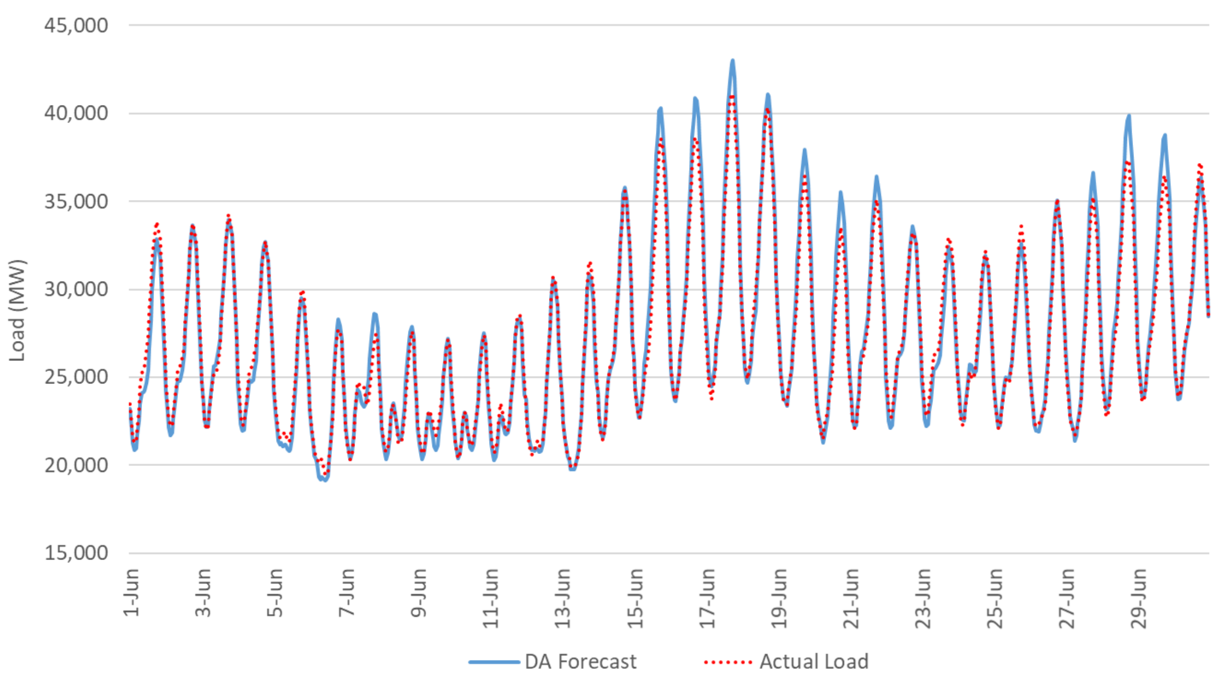
7.4 Demand forecasts

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

7.4.1 CAISO's demand forecasts

CAISO demand during the month of June 2021 was very responsive to the temperature changes observed throughout the month. Figure 15 shows the trend of CAISO's load. The highest hourly average June load of 41,107MW[27] was observed on June 17th, 2021 when the CAISO footprint was running 10 degrees F above normal for maximum temperatures. The max hourly average load observed within a single hour in June 2021 was 478 MW above the CEC 1-in-2 IEPR Forecasted June Peak of 40,629 MW. During the mid-June heat wave, the CAISO called on demand response in addition to issuing a Flex Alert for June 17th and June 18th, and these actions have been accounted for in the actuals displayed below to compare DA forecast against what actuals would have been based on the estimated response from Demand Response as well as the Flex Alerts. Further details on the Flex Alert analysis is described below in the section on Impact of Energy Conservation.

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



The average accuracy error[28] for the day-ahead demand forecast in June was 2.00 percent, while the error for peak hours was 2.43 percent. The peak and average error observed in 2021 is less than the day-ahead demand forecast error observed for the month of June in 2019 and 2020. Looking at the month of June,

[27] Averaged Hourly Load Value is CAISO System TAC at the peak hour, please note at the peak hour there was 331 MWs of market cleared demand Response.

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

increased error in the Day-Ahead forecast was observed during some of the higher load days in the middle of June. The errors observed during June 17th and June 18th were due to temperatures coming in cooler than expected throughout the state, with the largest temperature errors observed in SCE Coast and SDGE. Table 3 and Table 4 below detail the range of the error by region.

Table 3: Temperature error for June 17, 2021

Weather Regions	Forecast Max	Actual Max	Deviation	Forecast Min	Actual Min	Deviation
PGE Bay	96.8	96.8	0.1	65.2	63	-2.2
PGE Non Bay	106.7	105.5	-1.2	67.9	63.4	-4.5
SCE Coast	84.2	79.5	-4.7	68.7	65.6	-3.1
SCE Inland	107	106.8	-0.2	76.9	70.5	-6.5
SDGE	87.8	83.8	-4	66.2	61.7	-4.6
CAISO (weighted)	97.8	95.8	-1.9	69.8	65.5	-4.3

Table 4: Temperature error for June 18, 2021

Weather Regions	Forecast Max	Actual Max	Deviation	Forecast Min	Actual Min	Deviation
PGE Bay	94.5	95.2	0.7	64.8	63.3	-1.5
PGE Non Bay	107	108.2	1.2	74.1	70.9	-3.1
SCE Coast	79	77.1	-1.9	66.3	65.6	-0.7
SCE Inland	105.1	102.9	-2.2	82.6	79.6	-3
SDGE	84.6	79.5	-5.1	65	62	-3
CAISO (weighted)	95.4	94.3	-1.1	72	69.7	-2.2

7.4.2 EIM area demand forecasts

Similar to load in the CAISO area, throughout the month of June demand in other EIM areas was very responsive to temperature changes experienced throughout the month.

Figure 16 to Figure 18 below show the impact of the differing heat events described within the weather section above throughout the EIM footprint areas. The graphs in the figures capture the sum of the maximum energy demand by day grouped by geographical regions.

Similar to CAISO, the Southwestern EIM areas observed peaking conditions during the mid-June heatwave, while the EIM in the Coastal Pacific Northwestern peaked during the second heatwave at the end of June. The Mountain Northwestern areas saw a less pronounced trend, even though also peak in mid-June.

Figure 16: Demand actuals for Southwestern EIM areas

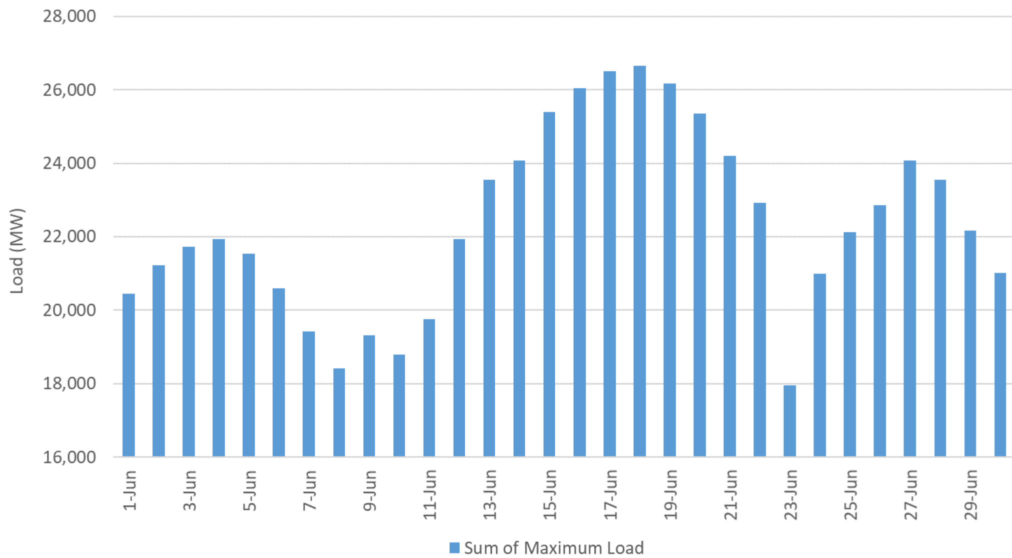


Figure 17: Day-ahead demand actuals for Coastal Pacific Northwest EIM areas

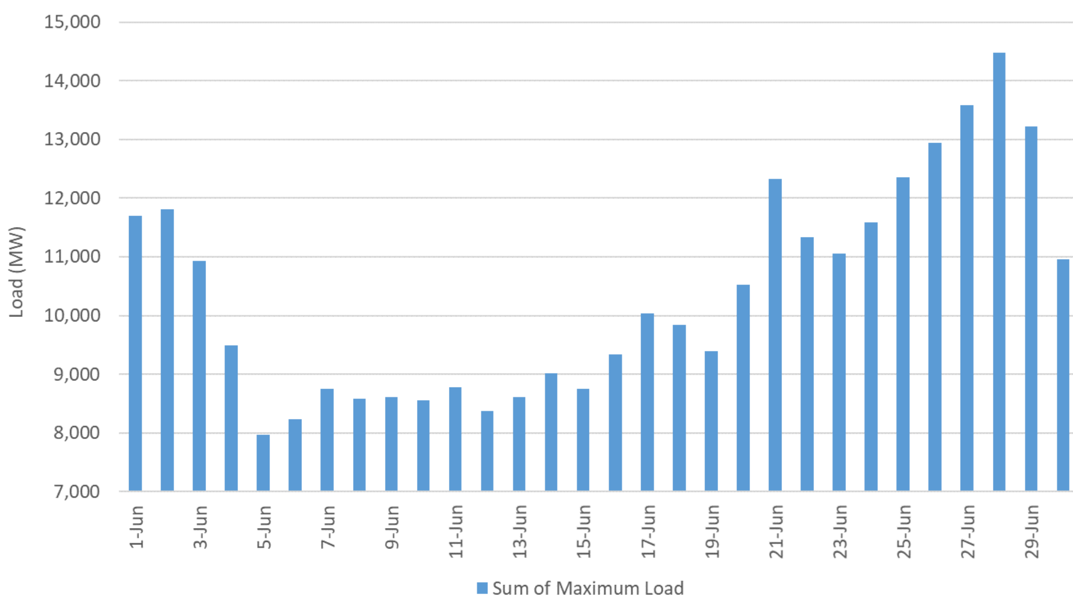
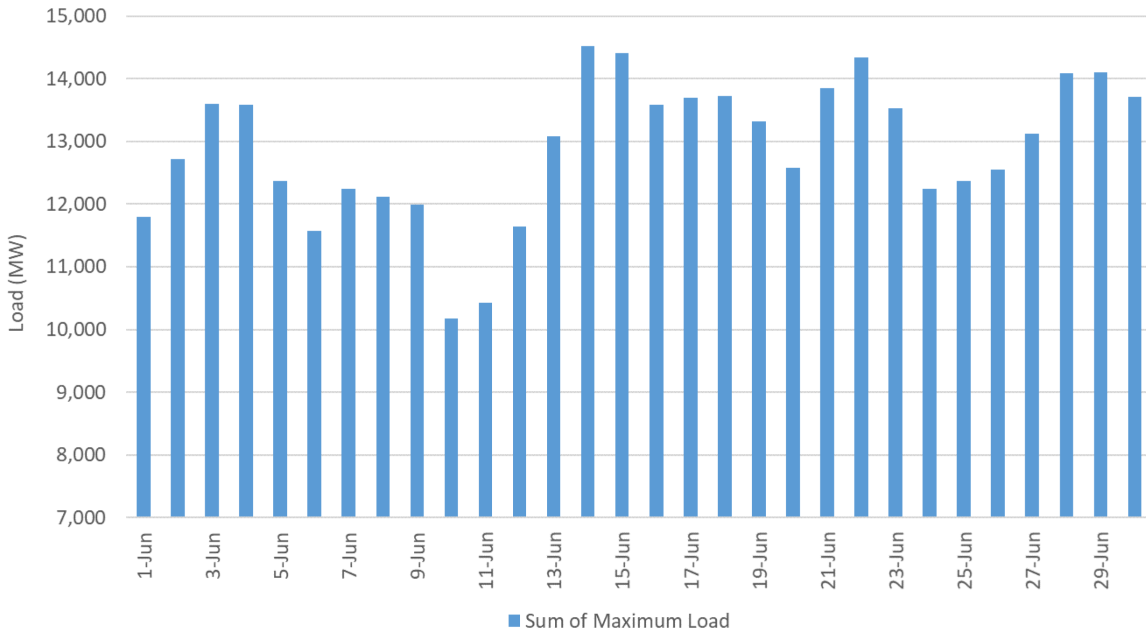


Figure 18: Day-ahead demand actuals for Mountain Northwest EIM areas



7.5 Impact of energy conservation

During the mid-June heat wave, the CAISO issued Flex Alerts[29] to assist in meeting the net load peak on June 17th and June 18th. In addition, on June 17 Governor Newsom of California signed an emergency proclamation to free up additional energy capacity in the midst of the heat wave, which also impacted conservation responses.[30] The estimated response to Flex Alerts looks at the back casted model results taking in actual weather and behind the meter (BTM) solar conditions. This allows the CAISO to isolate weather and BTM solar error within the demand forecast. In addition, the CAISO also estimates the hourly model error that exists looking at similar day model performance. Table 5 summarizes the estimated Flex Alert range of conservation, which fluctuates based on hourly impacts during the declared Flex Alert. On June 17th, 2021 the hourly conservation impacts range from 85 MWs to 735 MWs, with the biggest impacts observed during HE 21 and 22. On June 18th, 2021 the hourly conservation impacts range from 77 MWs to 413 MW, with the biggest impacts observed during HE 21. The beginning of both events showed lower conservation impacts. These observations are illustrated in Figure 19.

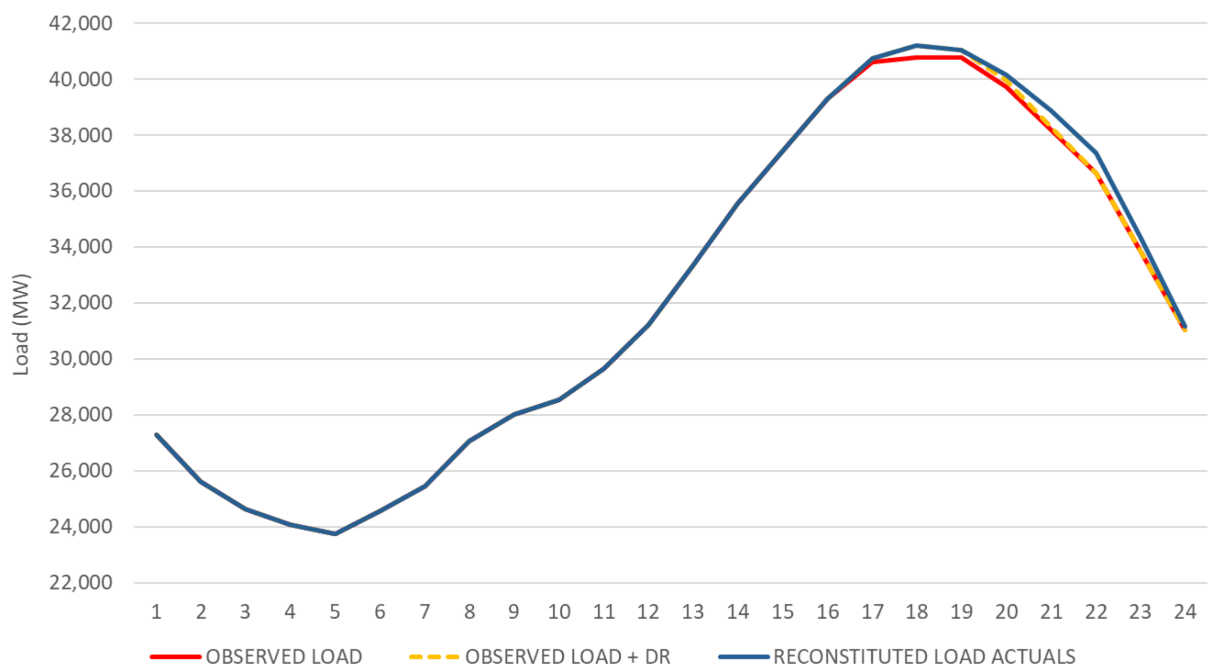
[29] The Flex Alerts for June 17th and 18th were effective from 5pm to 10pm.
[30] https://www.gov.ca.gov/wp-content/uploads/2021/06/6.17.21-Extreme-Heat-proclamation.pdf

Table 5: Estimated Flex Alert impact

Date	Conservation
June 17th, 2021	85-735 MWs
June 18th, 2021	77-413 MWs

Further details of the estimated savings can be seen during the net load peak hours in the below graph for June 17th, 2021.

Figure 19: Flex Alert impact for June 17th, 2021



As CAISO's CEO discussed in the Energy Matters Blog[31] on the CAISO website, the public's cooperation during the event assisted in the CAISO's ability to balance supply and demand with no major disruptions.

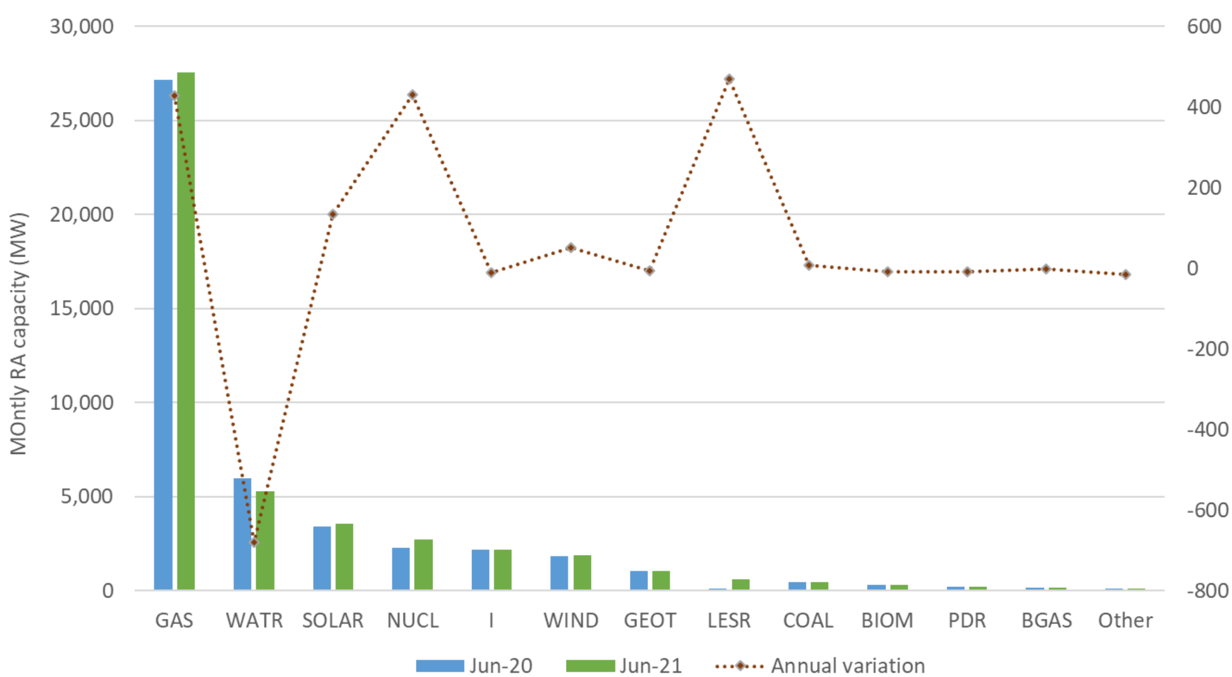
[31] http://www.caiso.com/about/Pages/Blog/Posts/Early-heat-shows-we-need-to-be-prepared-for-anything-big-thanks-to-consumers-and-other--partners-for-keeping-the-grid.aspx

8 Demand and Supply

8.1 Resource adequacy

The CAISO manages the resource adequacy (RA) program established by 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.

Figure 20: June 2021 RA organized by fuel type

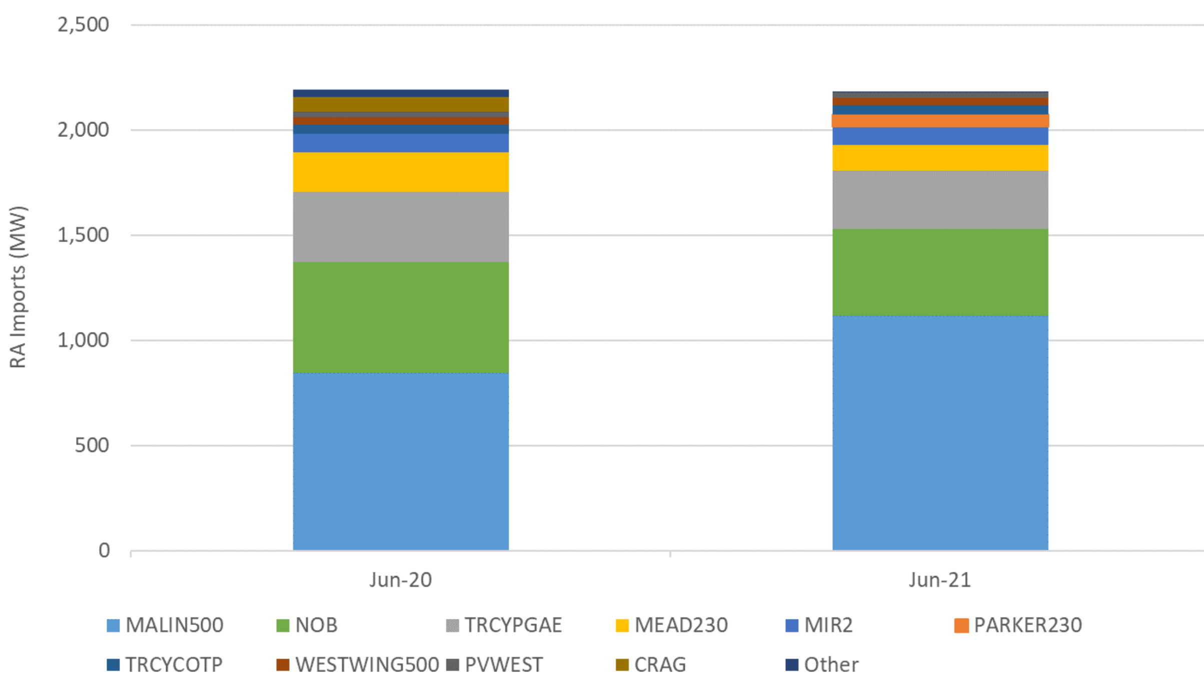


Through the RA program, there are three types of capacity: System, Local and Flexible. All three products serve a purpose in ensuring a reliable operation of the system. The events of August 2020 were primarily a result of insufficient system RA since it was a condition of insufficient supply to meet 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.[32] 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 2021 was 46,113 MW, which is slightly higher than June's 2020 monthly showing of 45,323 MW.[33] Figure 20 compares the total monthly RA capacity in June 2020 and June 2021 by fuel type. Although the total RA capacity between the two years remains relatively similar, June 2021 has several meaningful variations that offset each other. RA capacity from gas and nuclear resources increased by about 860 MW while hydro RA capacity reduced by 670 MW. The hydro reduction is expected given drought conditions materializing in 2021. RA capacity also increased for storage resources by 460 MW.

Static imports remained about the same level of capacity as compared to June 2020 at 2,182 MW[34], the composition by intertie varied between years as shown in Figure 21. Imports through Malin increased from 845 MW to 1,119 MW from June 2020 to June 2021 while imports through NOB decreased from 524 MW to 412 MW across the same timeframe.

Figure 21: Monthly RA organized by tie



[32] 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 non-RA resources that may also not be in the wholesale market.
[33] These values are based on the monthly showings estimates available at the time of preparing this report. The total RA values can change through the month, with weekend showing typically a significant reduction. For simplicity in the reporting and comparison, the first day of the month that is a weekday is used as a reference in this report.
[34] 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.

The RA capacity shown to the CAISO for July and August 2021 were 49,456MW and 48,741MW, respectively. Imports saw a decline in July and August with respect to previous year, reducing by 605MW and 1,054MW, respectively. These trends are shown in Figure 22 and Figure 23.

Figure 22: Monthly RA showings

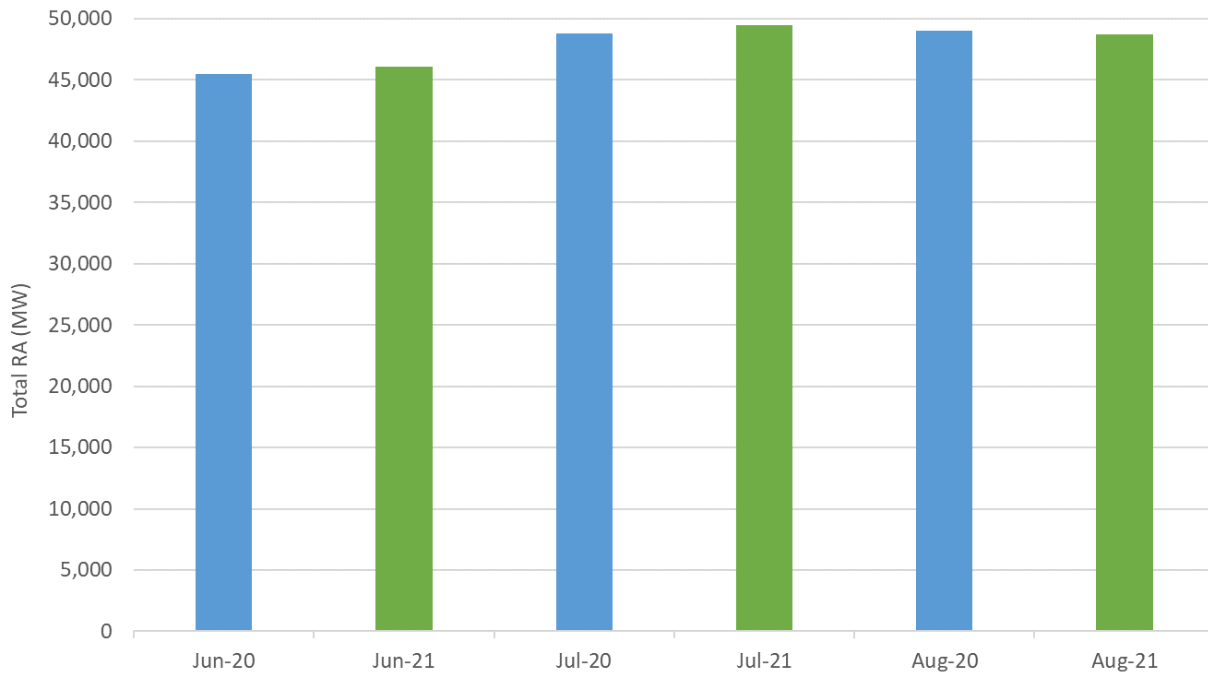
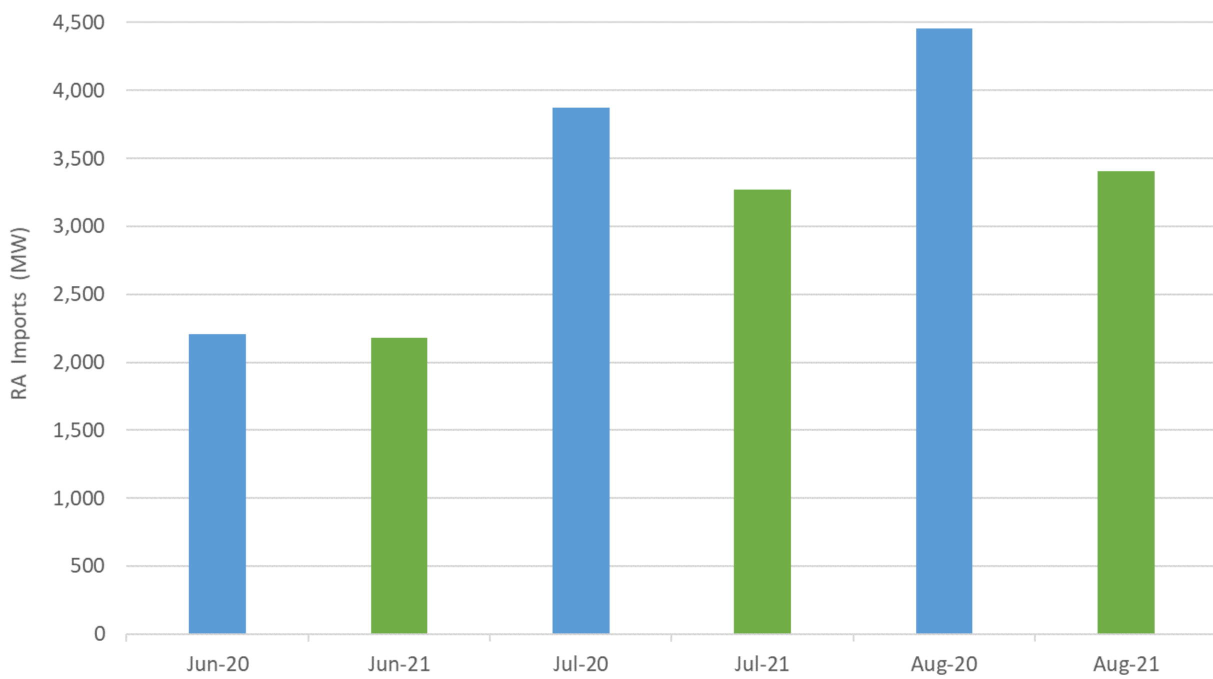


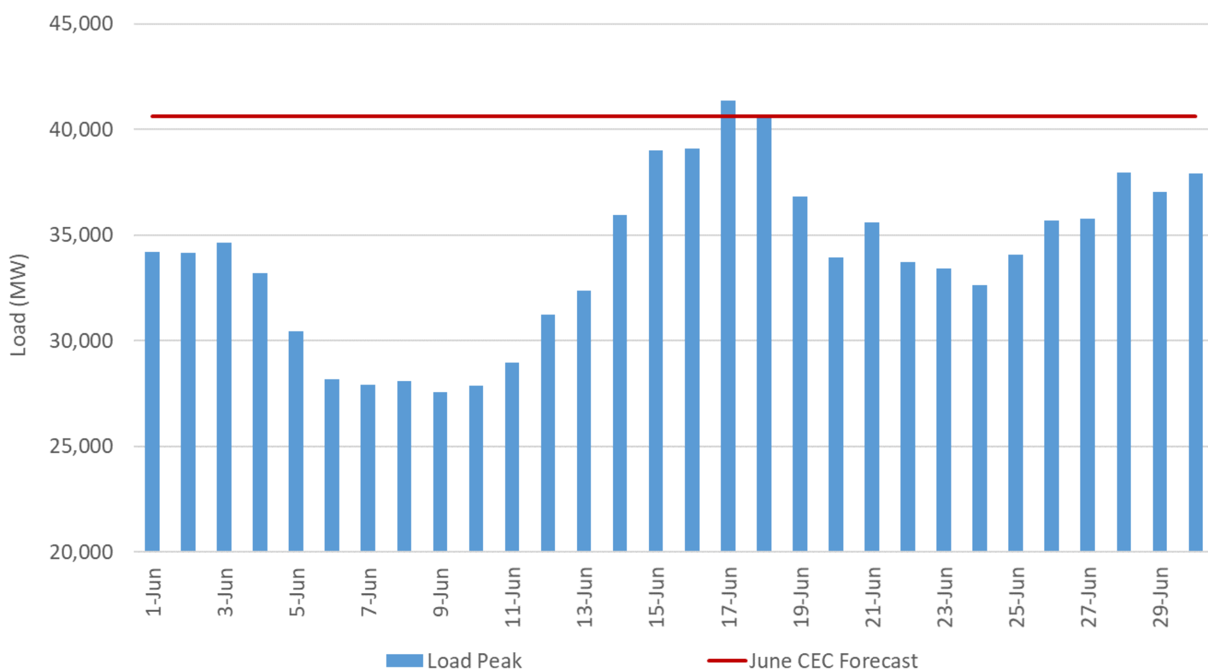
Figure 23: Monthly trend of static RA Imports



8.2 Peak loads

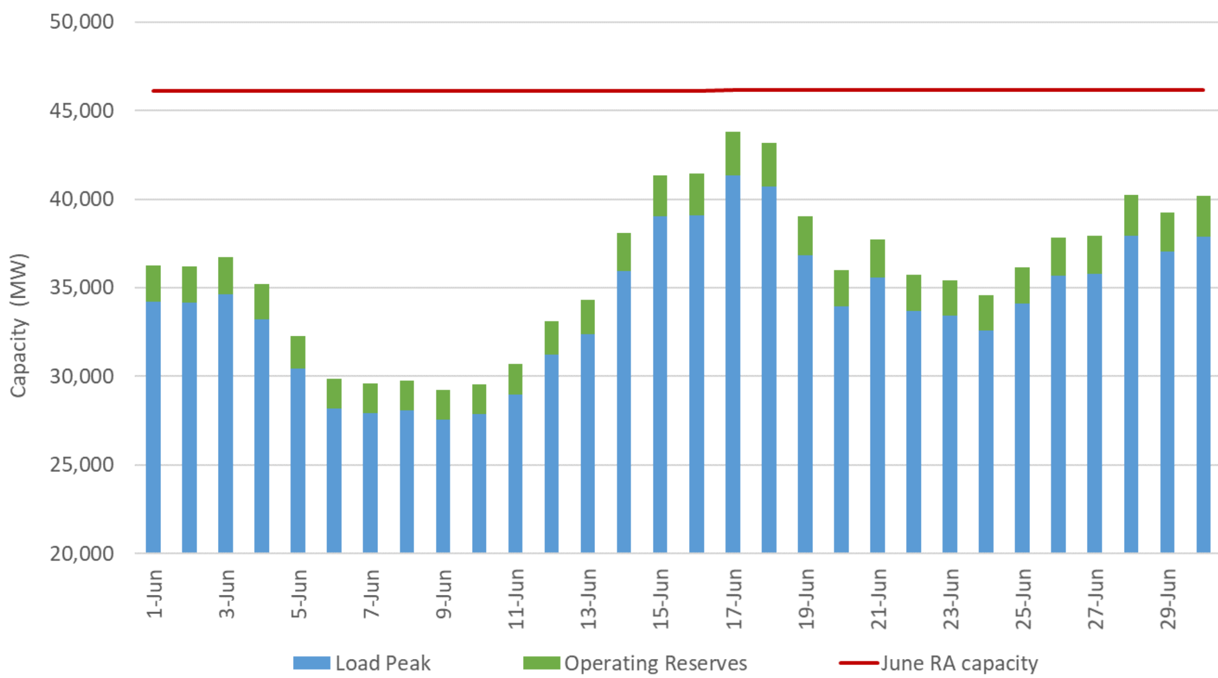
Peak loads in the beginning of June 2021 were well under 35,000 MW, dipping to about 28,000 MW in the second week of June. Load quickly rose to a peak of 41,345 MW on June 17 due to excessive heat. For subsequent days, loads trended down. Figure 24 shows the five-minute daily load peak for the month of June 2021 in comparison to the 1-in-2 CEC forecast used to assess the resource adequacy requirements. Actual load exceeded the 1-in-2 forecast in three hours of June 17 and one hour of June 18.

Figure 24: Daily peaks of actual load in June



The actual load did not exceed the monthly RA showings for the month of June 2021 as a whole, as illustrated in Figure 25. The red line stand for the 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) during June 2021 was generally lower than the nominal RA monthly showings and in some critical hours of June 17 and 18 it was below the load forecast plus operating reserves. In subsequent sections, the actual RA capacity made available in the market is trended for the month on an hourly basis.

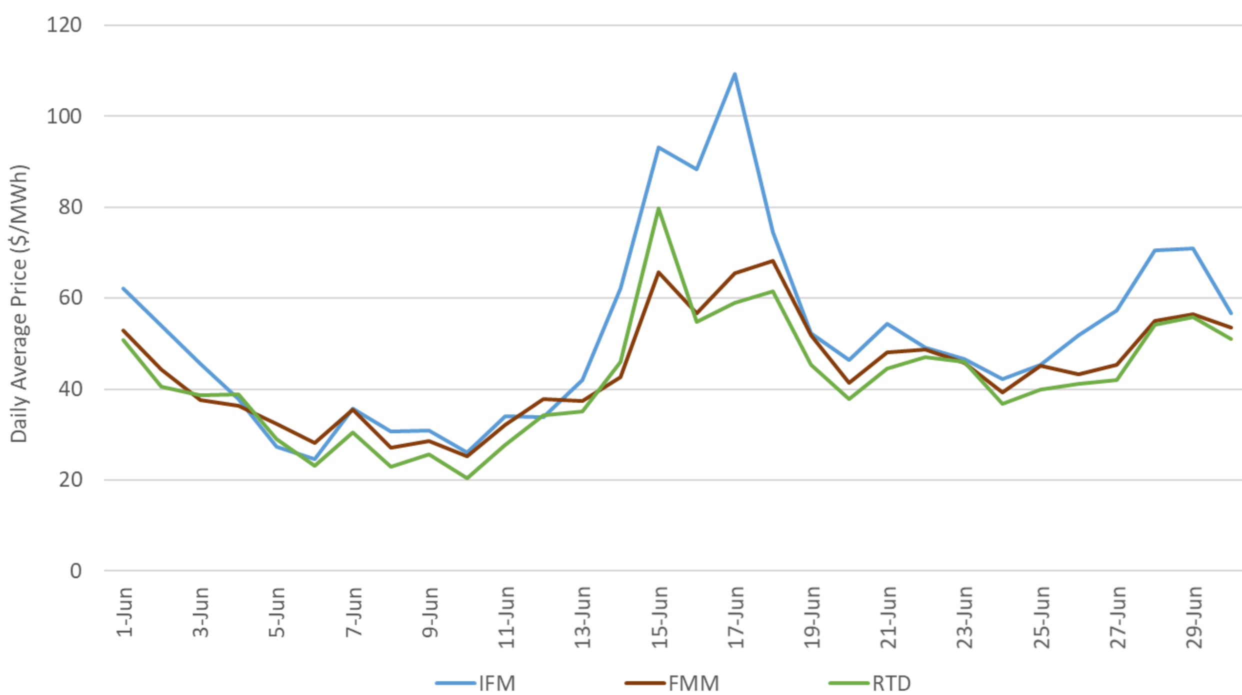
Figure 25: Daily peaks and RA capacity for June 2021



8.3 Market prices

Market prices naturally reflect supply and demand conditions; as the market supply tightens, prices rise. Locations marginal prices have three components reflecting 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 26 compares the average prices across CAISO's markets.[35] Naturally, prices increased during the period of the first heat event from June 14 through June 19, and increased slightly again at the end of the month, concurrent with the second heat event. In addition, day-ahead prices were higher than real-time prices during these periods of higher demand. A contributing factor may be that there was additional capacity required in RUC through the adjusted load forecast, actual loads came in lower than forecasted, including some load reduction by energy conservation and Flex Alerts and the Governors Proclamation order, as well as additional supply through EIM transfers. Figure 27 shows an hourly profile of average prices, where the price divergence is concentrated mostly on peak hours. As part of the summer readiness enhancements, on June 15 CAISO implemented a provision to set contingency reserves at the energy cap when they are released for energy. This logic triggers based on operational conditions once CAISO's system is in a warning or emergency. Although CAISO was in a warning, CAISO triggered this feature but there were no resources flagged to be released at the bid cap given the supply conditions observed in real time.

Figure 26: Average daily prices across markets



[35] 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 27: Average hourly prices across markets

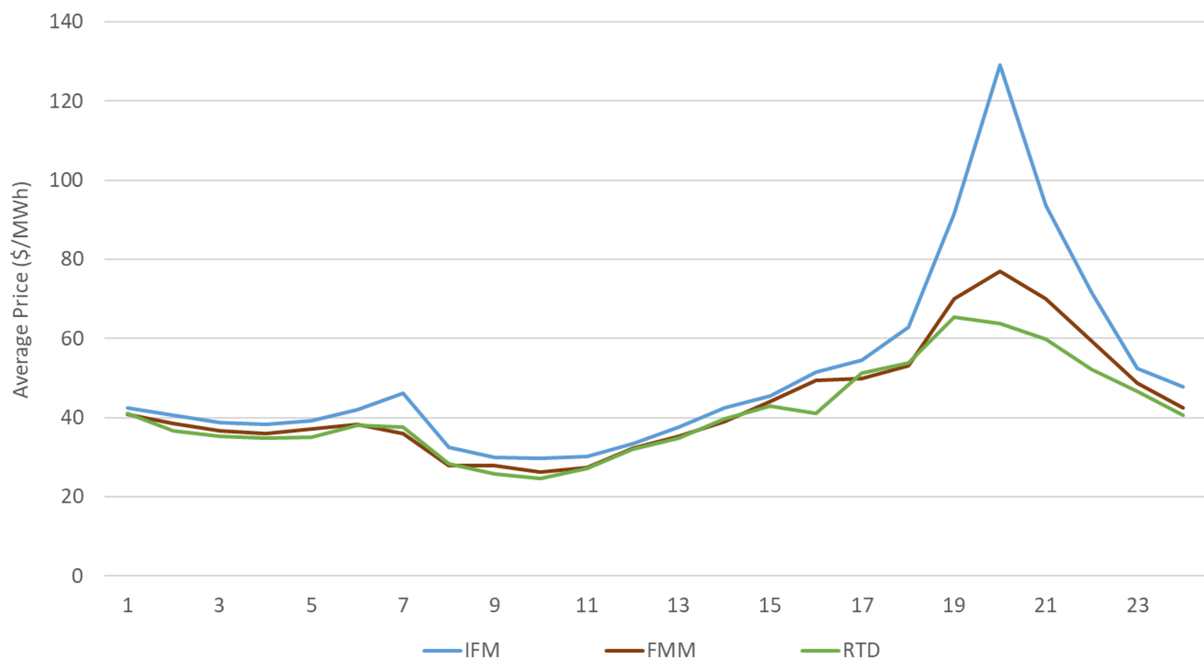
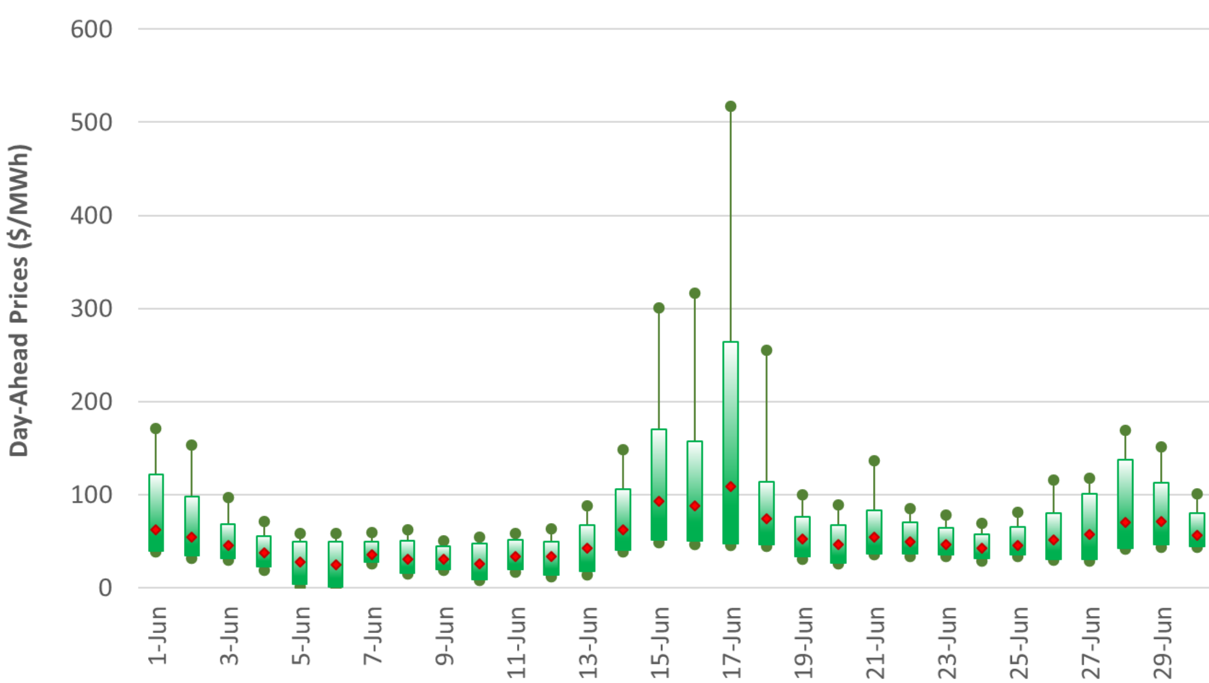


Figure 28 and Figure 29 show the daily and hourly distribution of day-ahead prices with box-whisker plots. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for the day. These plots better illustrate the full distribution of prices in the month.

Figure 28: Daily distribution of IFM prices



Similarly, Figure 30 and Figure 31 show distributions of real-time (FMM) prices in June. The day-ahead prices exhibit a larger spread, mainly in the days and hours when higher demand occurred. In contrast, real-time prices are in a narrower distribution under $100/MWh with a few outliers. Given the dynamic conditions of real-time, such price excursions are expected to happen even though they are short in duration.

Figure 29: Hourly distribution of IFM prices in June

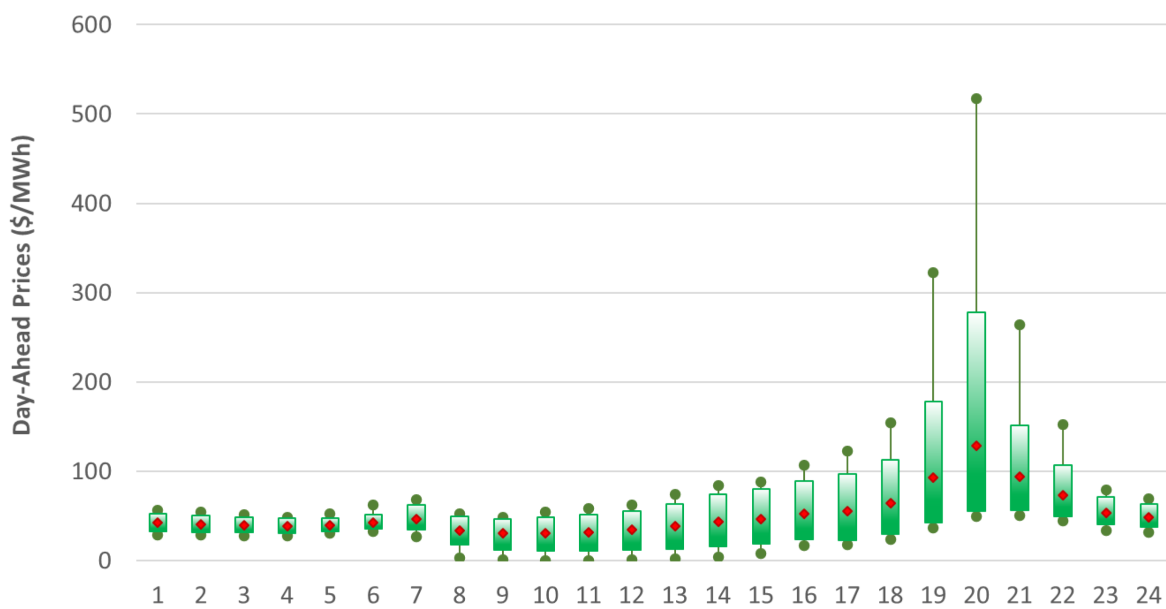


Figure 30: Distribution of FMM prices by day

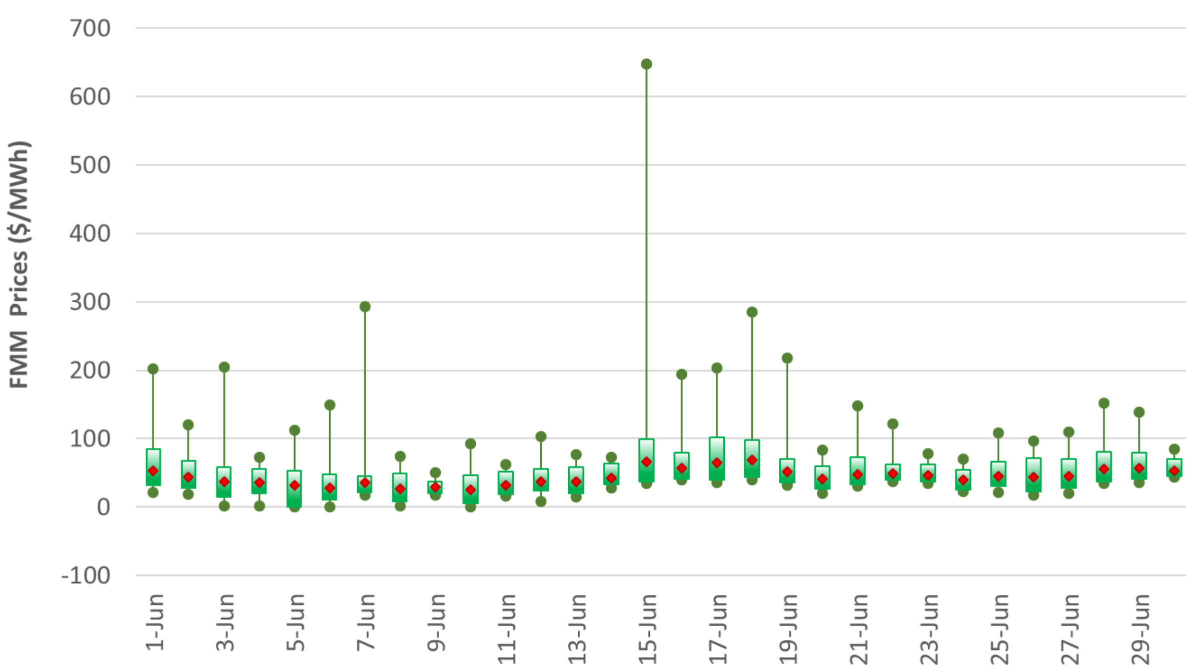
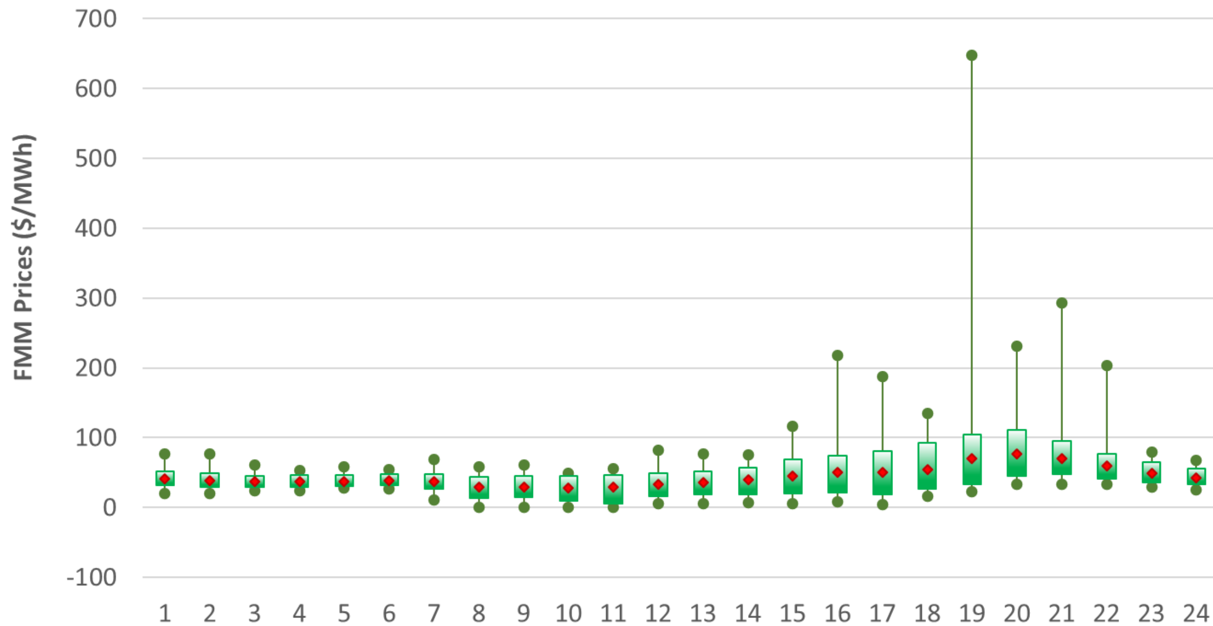
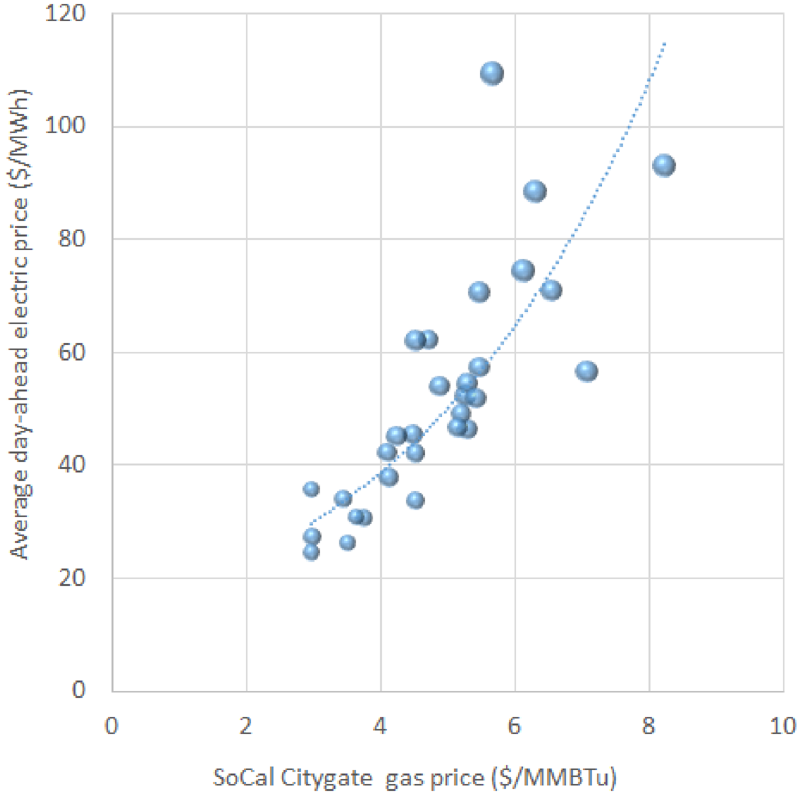


Figure 31: Distribution of FMM prices by hour



With 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. Electric prices are generally tracking gas prices. In the first half of June gas prices at the main CAISO's hubs were below $4/MMBTu and they increased to about $7.5/MMBTu concurrent with the heatwave of mid-June and end of June. Figure 32 shows daily average electric prices from the day-ahead market (Y axis) relative to next-day gas prices (X axis) and the peak load (size of the bubbles) on a daily basis for June. Peak loads were in a wide range and this comparison exhibits a good degree of correlation between electric, and gas prices and that electric prices rise steeper when load level are higher.

Figure 32: Correlation between electric prices, gas prices and peak load level



8.4 Bid-in supply

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 non-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 non-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.

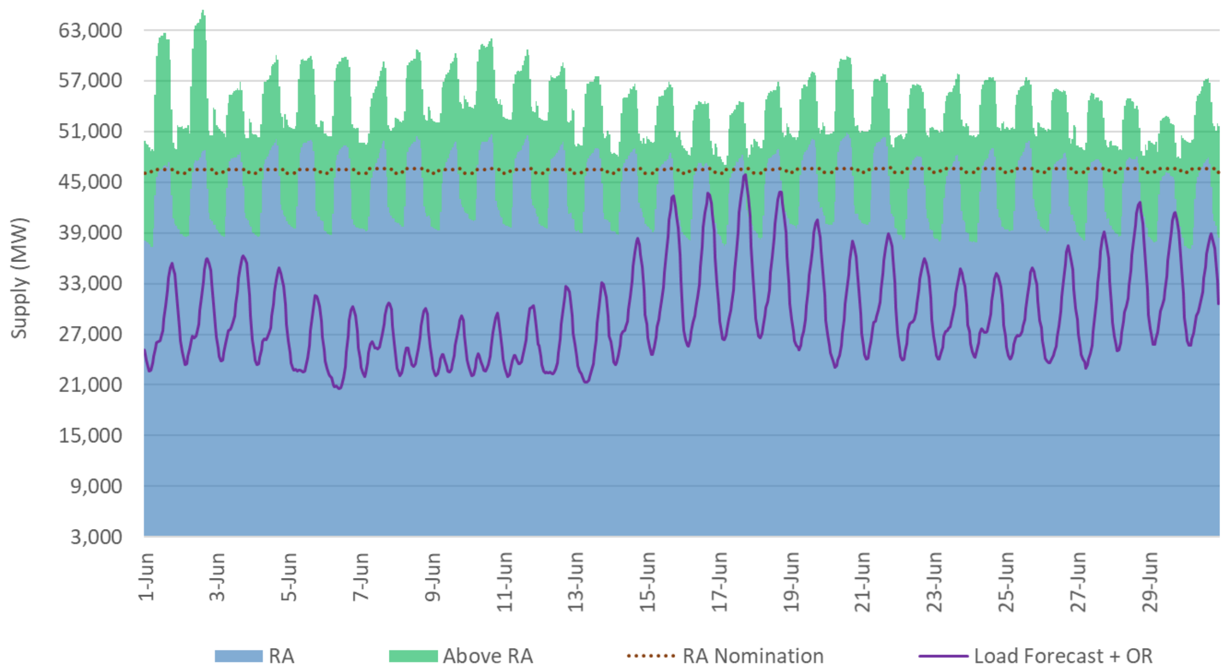
In the RA program, there are certain qualifiers for a resource's capacity to be eligible to count towards meeting the RA requirements. The CPUC developed a Qualifying Capacity (QC) requirement based on what a resource can produce during peak load hours. For conventional resources such as gas and hydro, 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.

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 non-RA (or above RA).

Figure 33 shows the breakdown of the day-ahead supply capacity[36] as RA capacity and non-RA capacity. The black dotted line is a reference of the nominal RA showings for the month, which stays relatively consistent for June. The line in purple shows the day-ahead load forecast plus the capacity required to meet operating reserves (OR), which is typically about 6 percent of the load value. Figure 34 has the same capacity breakdown but the comparison is relative to the net load (gross load minus VER forecast). Tracking the available capacity for the net load peak hour is as important as tracking for the gross peak hour.

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

Figure 33: Supply capacity available relative to load forecast in the day-ahead market



In both figures, the load increases steeply during the heat event of June 17 to the point where the RA capacity may not be sufficient to support the load and operating reserves obligation, mainly in the hours after the gross peak.

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

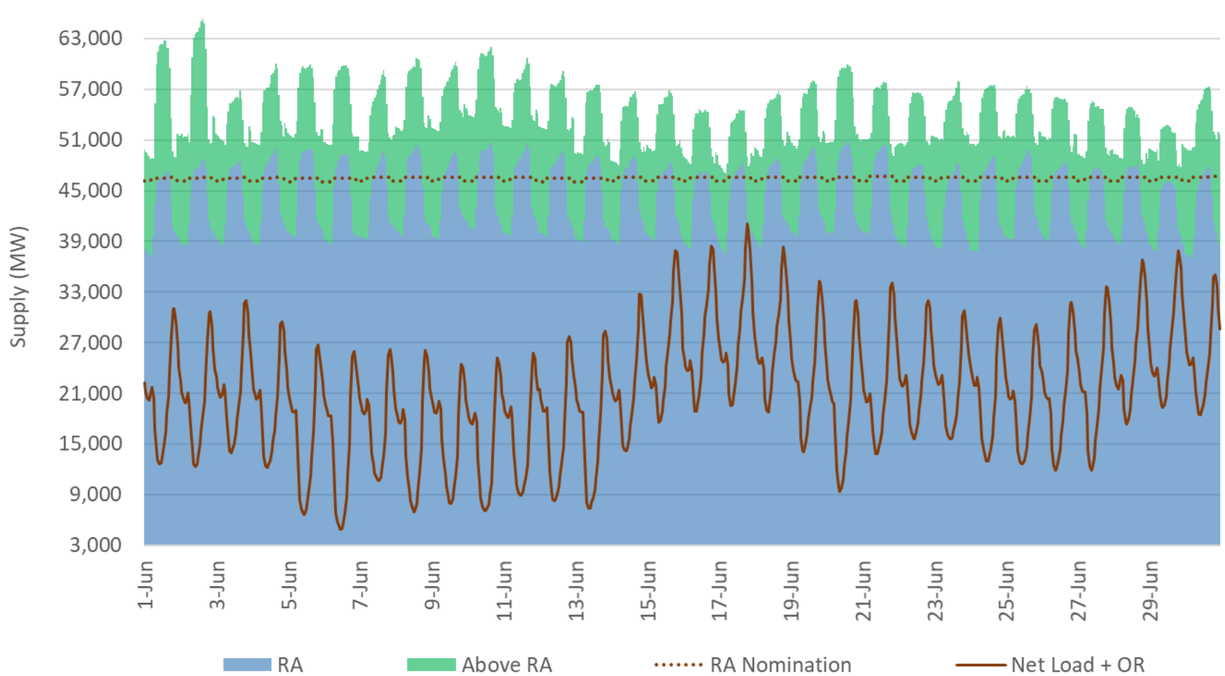
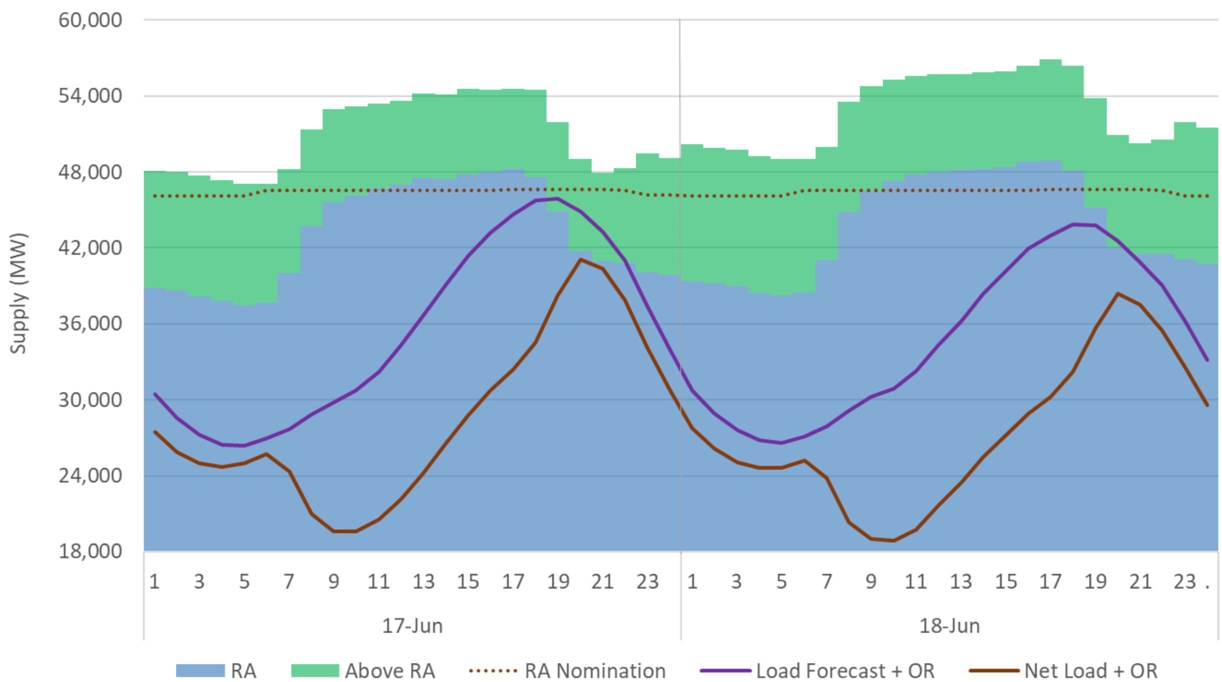


Figure 35 provides a more granular detail of the capacity conditions for June 17 and 18. For a period of four hours during the gross peak, June 17's RA capacity was below the load and operating reserves obligation, while June 18 had only one hour under this condition, after the gross peak. For both days, the RA capacity level was above the net load needs. Under this condition, there was still non-RA capacity that could have been utilized to meet CAISO's load needs. As these conditions unfolded, CAISO issued a heat bulletin and a system conditions bulletin warning about the potential for RA supply shortfall.[37]

Figure 35: Supply capacity available in the day-ahead market on June 17 and 18

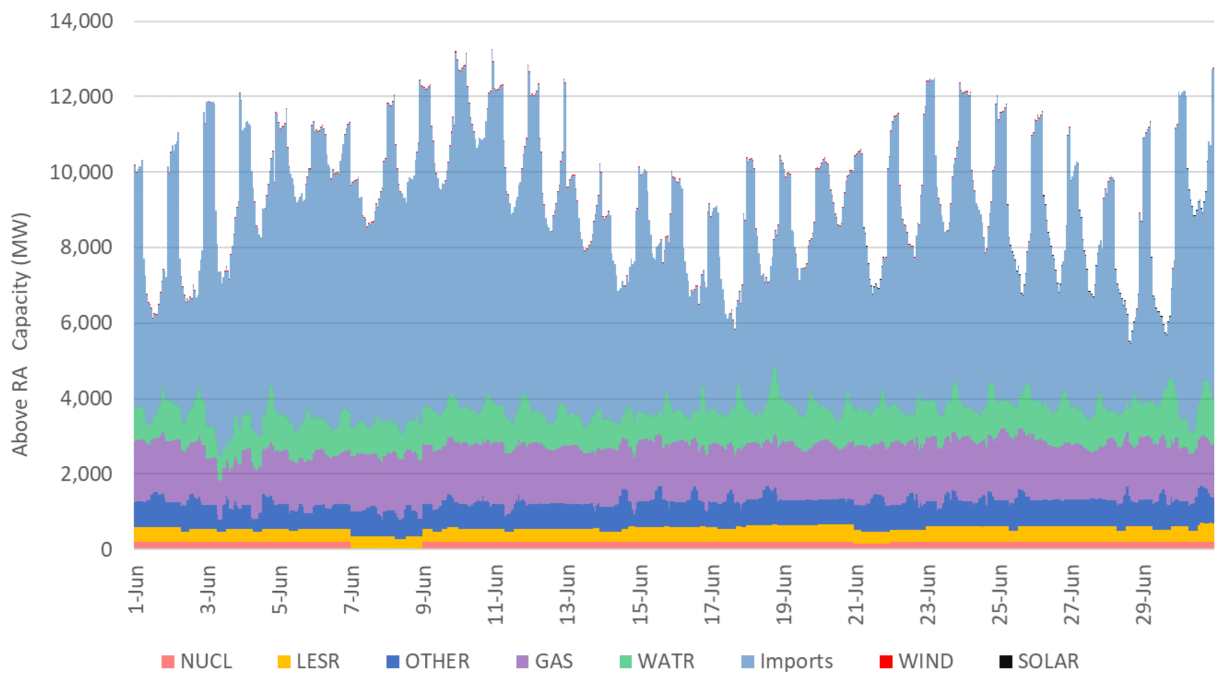


For instances in which the load needs exceed the available RA capacity, the market will utilize any other non-RA available capacity. For the month of June, non-RA capacity was consistently bid into the market. Figure 36 shows the non-RA capacity available in the day-ahead market organized by fuel type. The major contributor to this non-RA capacity is imports. Since imports are limited by the intertie scheduling limits, not all of that supply could actually be utilized in the market if needed. The import share shows a trend of more availability in the beginning of the month and then reduces as CAISO and the West enters into the heat events of mid-June and late June. Furthermore, some of that non-RA capacity may be supporting

[37] In the material presented in the Market Performance and Planning Forum (MPPF) held on June 22, CAISO presented similar material focused on the performance of June 17, 2021. In that material, slide # 16, the load and net load used to compare relative to the RA capacity was based on the RUC adjusted forecast. The metrics presented in this report utilizes the standard load forecast as the reference. MPPF material is available at http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Jun222021.pdf

exports.[38] Because of how RA is accounted for wind and solar resources, there is basically no non-RA capacity classified for these type of resources. Lacking information of what other types of contractual arrangements may exist for that non-RA capacity, this metric serves as an upper bound of how much supply capacity is not currently under the RA program yet is still being bid into the CAISO's market.

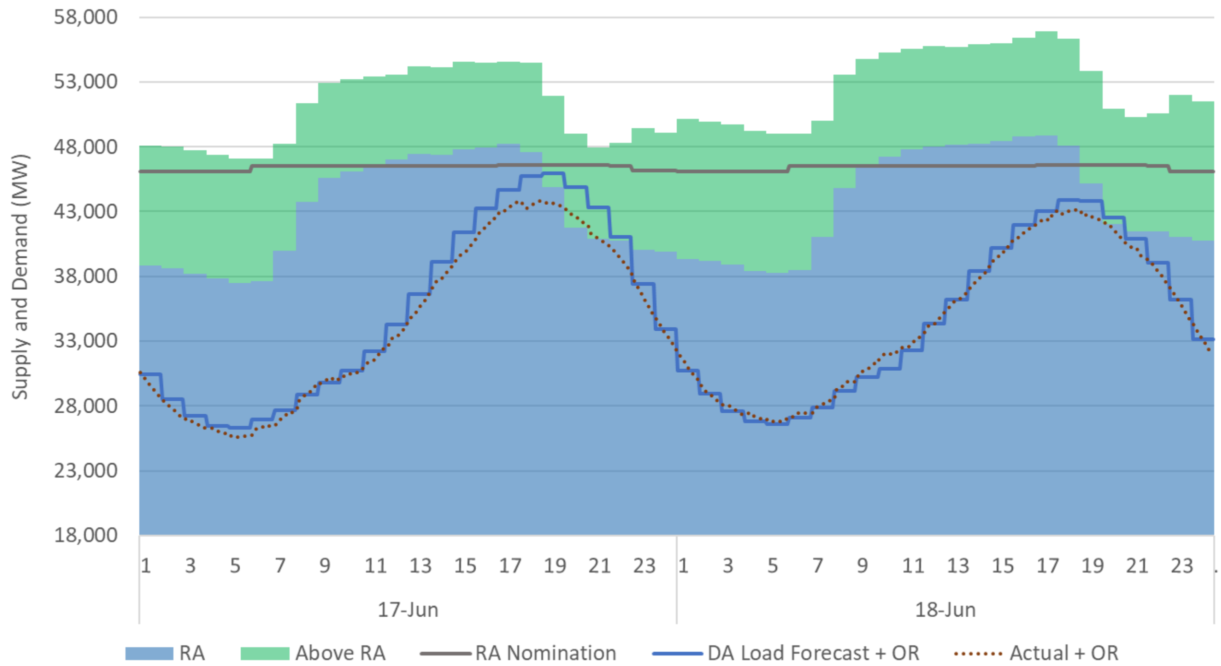
Figure 36: Non-RA capacity available in the CAISO's market



In the real-time market for June 17 and 18, the actual peak load came in lower than the day-ahead forecast as illustrated in Figure 37. Also, on June 17 actual load peaked earlier in the day than forecasted in the day-ahead. These two conditions together show that RA capacity was sufficient to cover CAISO's load needs with the exception of hour ending 20 on June 17.

[38] Since June had some days in which PTK exports were bid-in and cleared, the maximum hourly PTK export quantity is used as a proxy to estimate how much of that non-RA capacity is actually in the market to support PTK exports and, thus, is not included as capacity available towards meeting CAISO's load. For simplicity, that capacity is discounted to the gas-based generation portion across all hours of the month.

Figure 37: Actual load relative to RA capacity on June 17 and 18



8.5 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 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.

Figure 38: Day-ahead demand

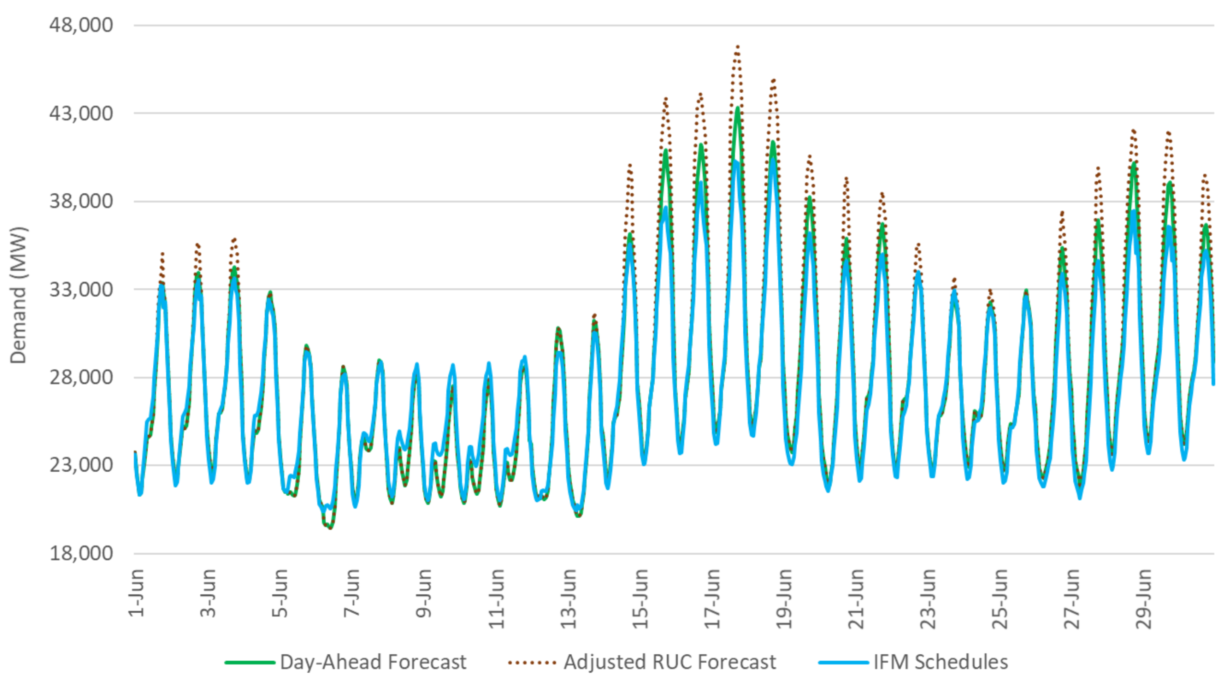
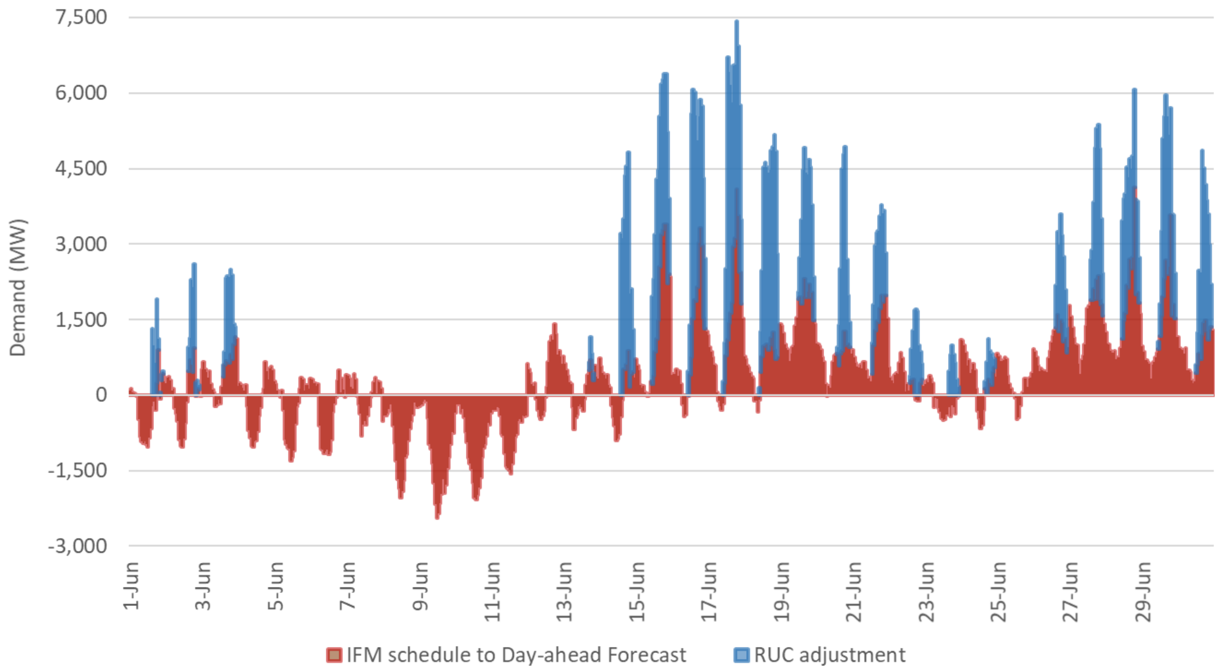


Figure 39 shows the differences between the IFM schedules for physical resources versus the nominal day-ahead load forecast. This is the additional capacity RUC process needs to supply to meet the day-ahead load forecast, starting from the IFM solution. Effectively, this is the shortfall or surplus capacity from IFM that RUC has to meet. That 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.

Figure 39: Differences of day-ahead demand



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, even though there may be other factors to consider. During the weeks of the excess heat in June, IFM schedules and RUC adjustments were positive, meaning that RUC had to clear higher physical supply than IFM.

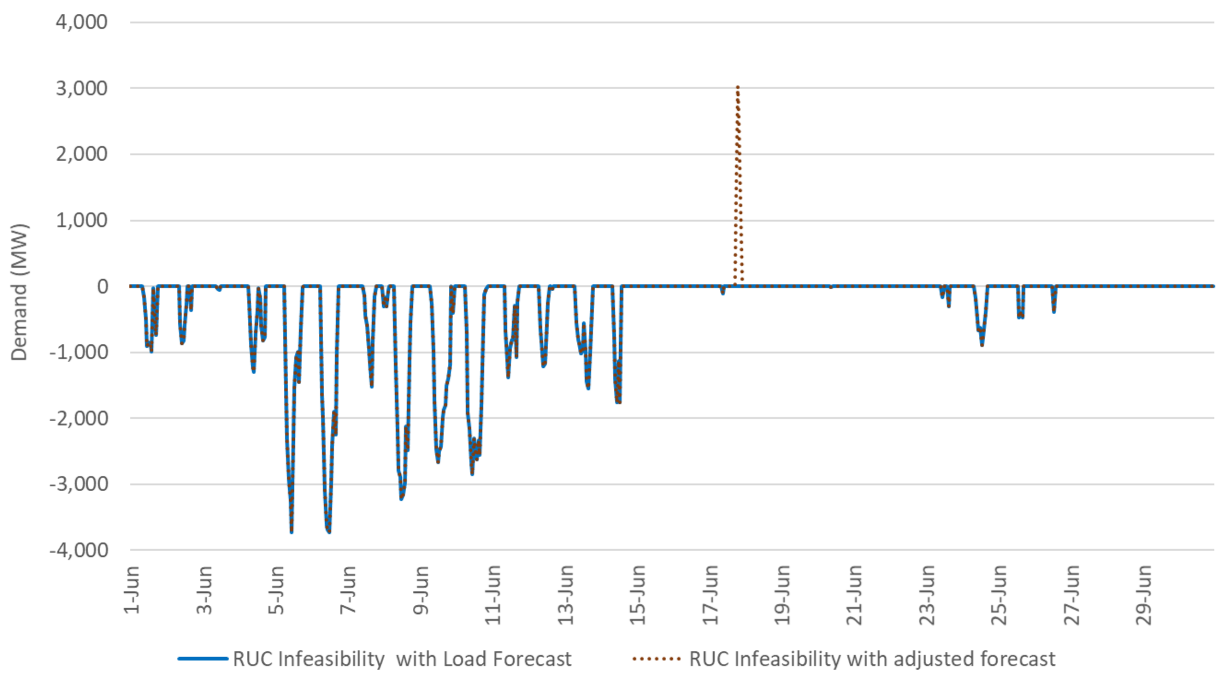
Since RUC clears against a load forecast which is not price sensitive, under certain conditions RUC may relax the power balance constraint due to a surplus or shortfall of supply capacity. A relaxation signals that there is an imbalance between the load requirements and the supply available. An infeasible power balance can be in either direction. In hours with low levels of load and minimum downward capability, RUC may observe an oversupply condition, resulting in a negative infeasibility. Conversely, in hours where there is insufficient supply to meet the load requirement, RUC may have an undersupply condition, resulting in a positive infeasibility. Negative RUC infeasibilities result 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 result because all incremental RUC bids have been exhausted and RUC has curtailed all the economic and LPT exports,[39] which leaves just the power balance

[39] 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 (*i.e.*, exports that may be backed by capacity that is committed to CAISO load under its resource adequacy program). 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.

constraint to be relaxed, concurrent with reduction of PTK exports, to allow RUC to clear. Figure 40 shows the RUC infeasibility against two metrics: one infeasibility is relative to the final RUC adjusted forecast, while the other is relative to the standard day-ahead forecast. The majority of RUC infeasibilities in June 2021 were for oversupply conditions. Only June 17 had an undersupply infeasibility relative to the adjusted load forecast; there was no RUC infeasibilities relative to the standard load forecast. June 17 is the day that CAISO issued a system conditions alert indicating a projected supply shortfall.

Figure 40: RUC infeasibilities



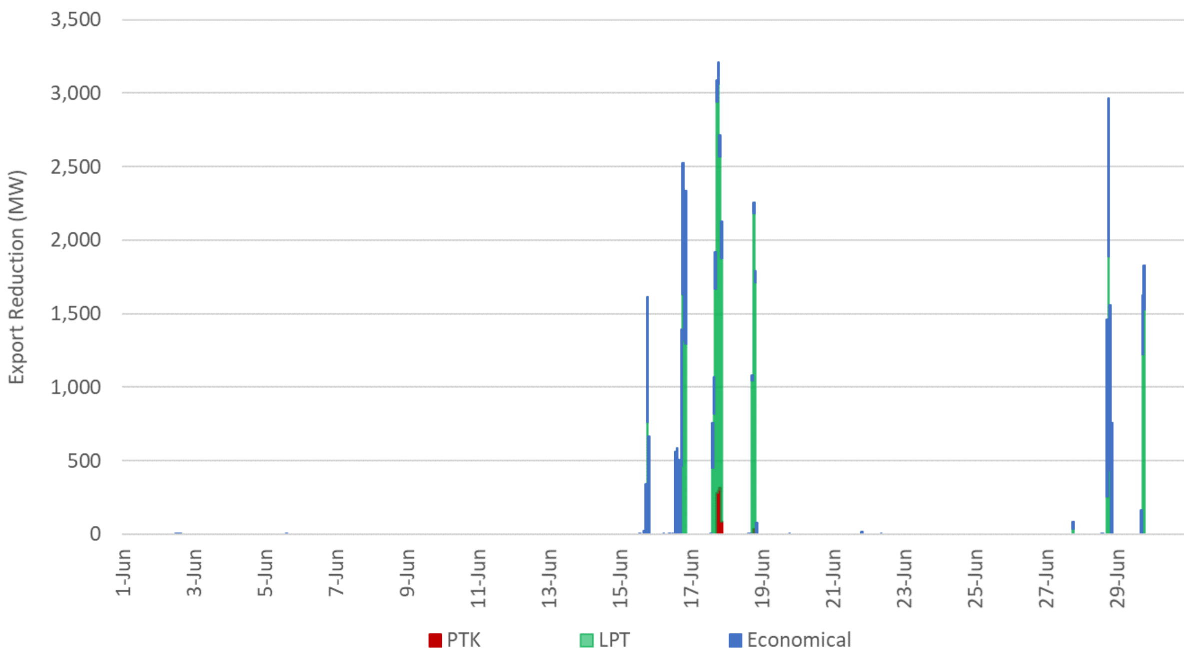
In addition to relaxing the power balance constraint, the RUC process utilized other scheduling priorities to enforce the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and lower priority price-taker exports. Only when RUC has exhausted these LPT exports, PTK exports may be reduced concurrently to relax the power balance constraint.[40]

Figure 41 shows the volume of hourly export reduction in the RUC process, which mainly happened in the periods of June 15 through June 18 and June 28 and 29. The majority of export reductions were for economic and price taker exports. However, on June 17, RUC reduced up to 317 MWs of PTK exports,

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

concurrent with RUC power balance infeasibilities because both PTK exports and CAISO's load are treated at the same scheduling priority in the RUC process.

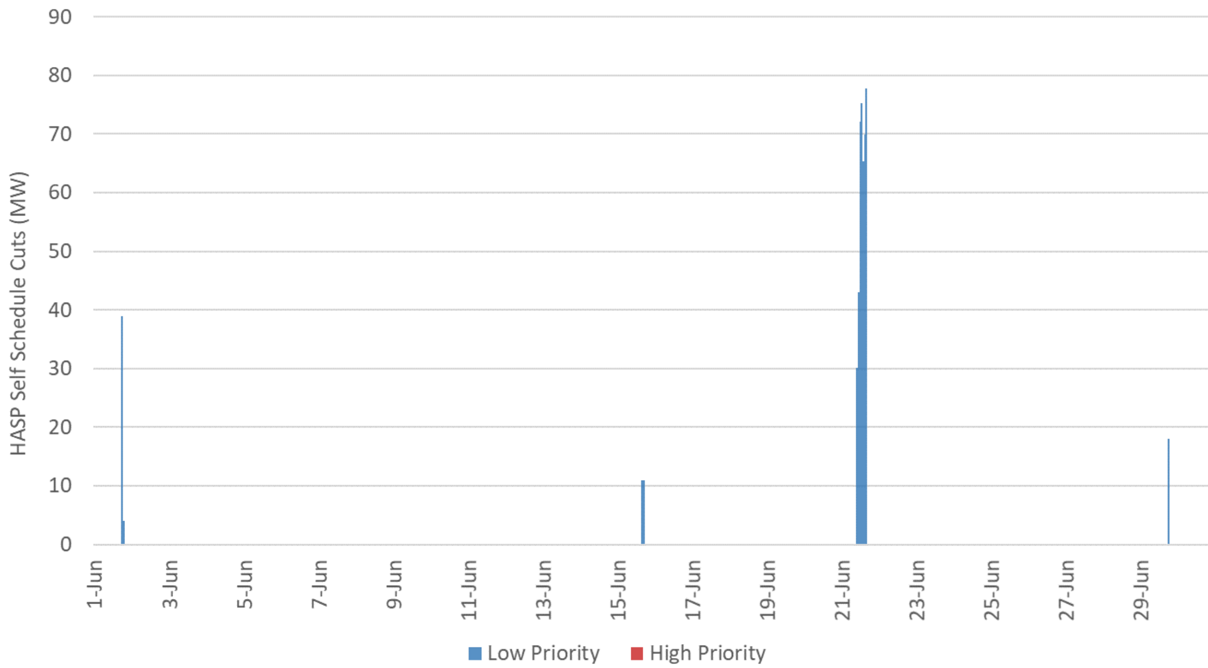
Figure 41: Exports reduction RUC



Subsequently, market participants rebid the PTK exports that were curtailed in RUC into the real-time market, and given real-time conditions, the real-time market ultimately cleared these exports with no reductions.[41] Market participants can self-schedule exports cleared in the day-ahead into the real-time market. Under the market rules still applicable in June, these cleared day-ahead schedules are treated in the real-time market as having a higher day-ahead priority, which is above the priority of LPT and PTK exports. Thus, exports cleared in the day-ahead are unlikely to be cut in the real-time. Participants can also submit PTK 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 2021, the real-time market curtailed very few exports through HASP. The most significant export curtailments happened on June 21 for both LPT and PTK exports. However, these were not due to supply limitations but rather due to congestion management on the MONAIPPDC intertie. The curtailments of PTK exports were not actually issued by the market because they were reinstated by CAISO operators having found these to be feasible in the operational timeframe. Only LPT exports curtailments were actually issued by the market as shown in Figure 42 below.

[41] The CAISO identified a limitation in the logic that limits the amount of non-RA capacity an export can claim to support it. For multi-stage generators (MSGs), the current logic uses the maximum capacity of the default configuration in which the RA capacity falls, instead of the maximum bid of the plant. Thus, if an export intends to use any capacity above the configuration in which the RA is defined, the export is not assigned a PTK status and it defaults the export to be LPT for all the capacity. A logic change was implemented on July 14 to address this issue.

Figure 42: Exports reductions in HASP



9 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 resource 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, 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 ($1000/MWh or $2000/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. CAISO's market utilizes a series of self-schedules which defines 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.

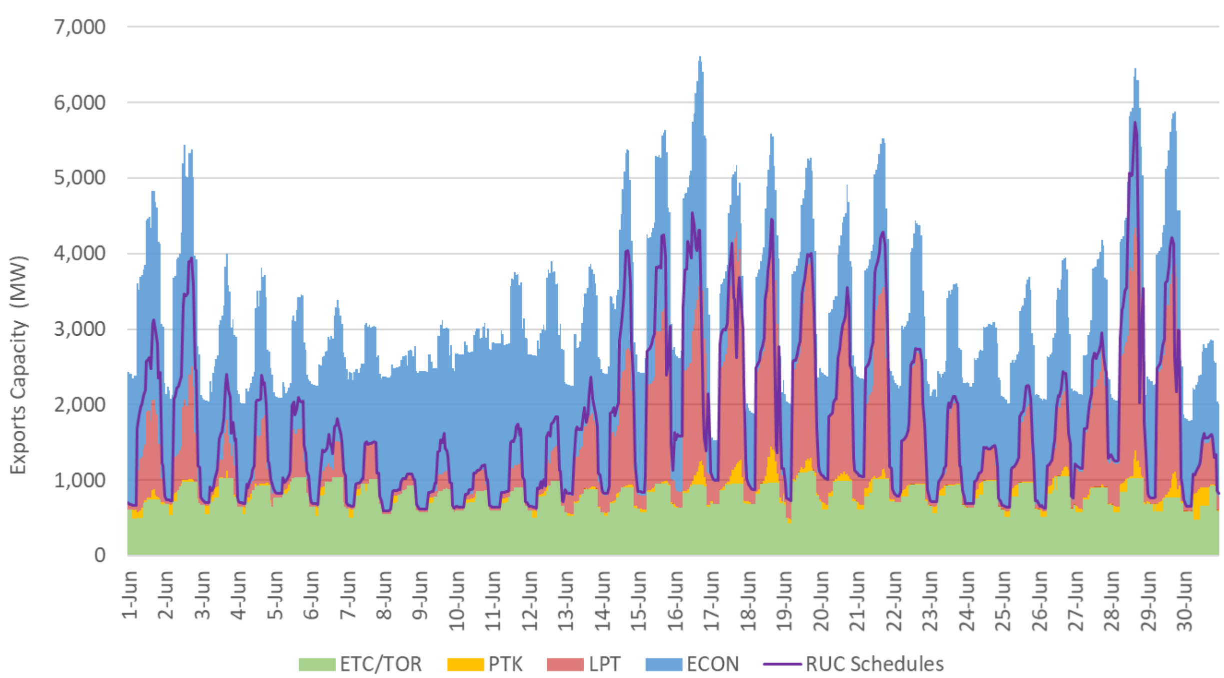
CAISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into account.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

9.1 Intertie supply

Figure 43 shows the capacity from static export-based transactions in the day-ahead market for the month of June 2021 organized by the various types of exports. This capacity does not include export capacity associated with explicit wheel transactions[42] 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: Bid-in and cleared export capacity



[42] An explicit wheel is an import and an export transaction matched in the system such that the market will always considered them as a single transaction that must clear in balance; i.e., the export and export will be forced to clear at the same MW value. However, there are other transactions that are not explicitly submitted as wheels and, thus, not treated as wheels. Given the assigned priorities for those imports and exports, however, they are typically in balance. Cases like that are present for TOR/ETC self-schedules that have very high penalty prices and even when they are not submitted as explicit wheels, the market is typically clearing them in balance.

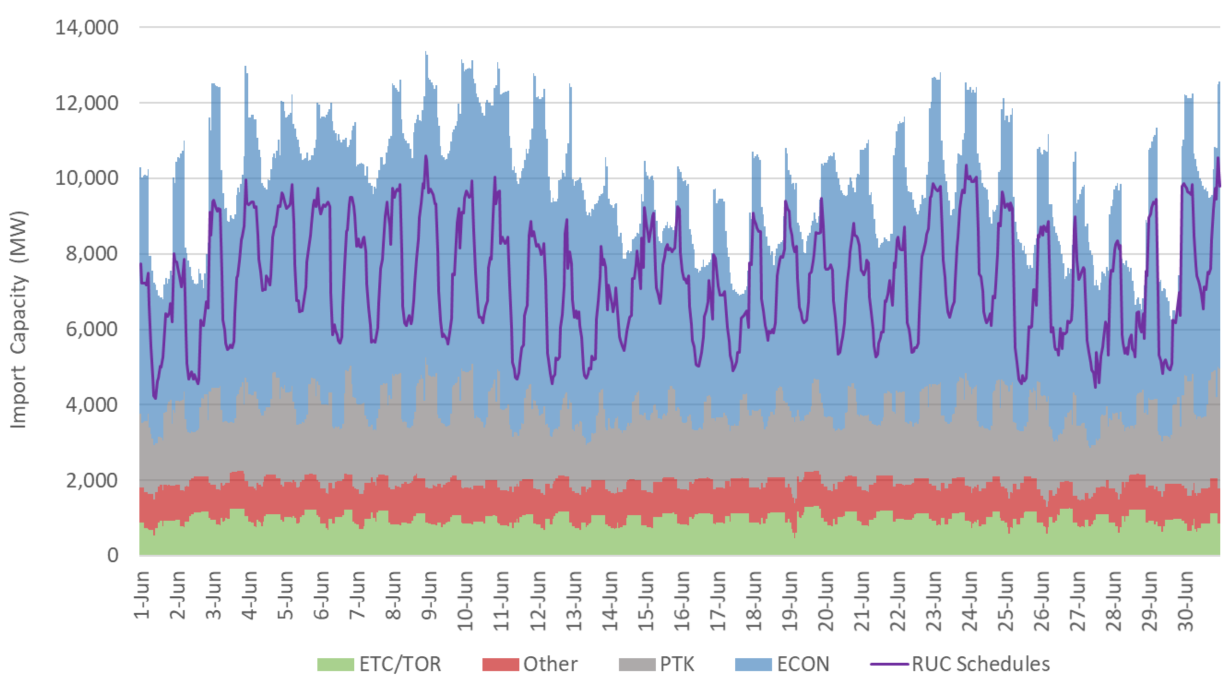
The RUC schedule represents the expected delivery and E-tags that market participants should submit in the pre-scheduling timeframe, and not the IFM schedule. While not required to submit their E-tags in the day-ahead timeframe, market participants are encouraged to do so and in such cases should base 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 follows a daily profile. About 52 percent, 25 percent, 22 percent and 2 percent of the export capacity were for economic bids, ETC/TOR, LPT and PTK, respectively. Overall, for the month of June, about 53 percent of all export bids in in the day-ahead market were cleared in RUC.

The volume of self-schedule capacity for TOR/ETC exports remained generally stable through the month, which is expected because rights are used consistently by their holders. The volume of PTK exports was modest for most of the month, and increased in the periods of heat and higher loads around June 17 and June 28. The hourly volume of LPT exports increased during the high load periods, rising from about 550 MW in the second week of June to reach 3,000 MW per hour on June 17. Hourly economic bids for exports were generally over 1,000 MW throughout the month, reaching up 3,000 MW in mid-June.

Figure 44 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR and high-priority imports show a stable trend throughout the month with averages of about 970 MW and 1,990 MW, respectively. Hourly economic imports were about 6,000 MW on average for the month, with decreasing volumes during the two period of higher load. The "Other" group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0MW.

Figure 44: Bid-in and cleared import capacity



Net schedule interchange is the algebraic balance of static imports, dynamic and pseudo resources and exports, and it measures the overall contribution of scheduling over the interties. Figure 45 is a box-whisker plot to illustrate the distribution of hourly net schedule interchanges using the RUC schedules. The hourly net schedule interchange reaches its minimum levels on June 16 and 28, which were the periods of heat and higher load. This outcome reflects both a reduction of imports and an increase of exports.

Figure 45: Daily distribution of hourly RUC net schedule interchange

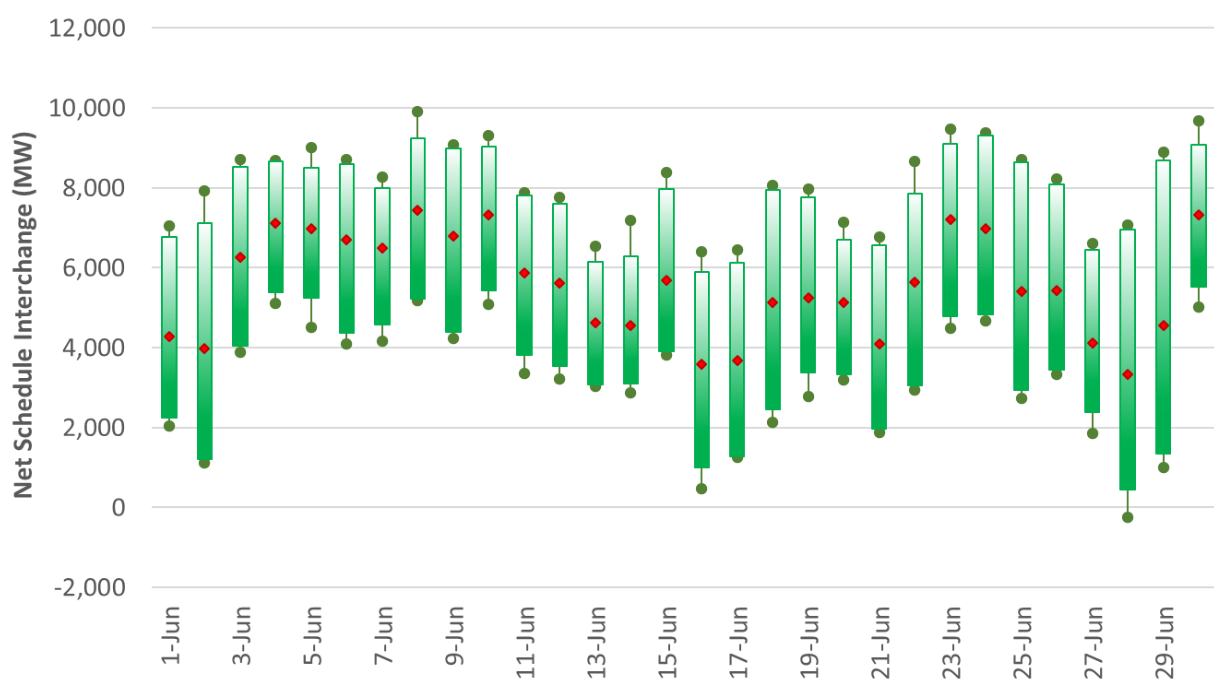


Figure 46 illustrates the hourly net schedule interchange distribution by hour in the month of June. This trend is useful to visualize the hourly profile of schedules and shows that net schedules reduce in midday hours when solar production comes in and start to increase as the solar production fades away in the evening hours. It also shows two well-defined blocks of On- and Off-peak schedules.

An area of interest since summer 2020 is the trend of exports in the CAISO's system. Figure 47 trends the distribution of hourly RUC schedule for exports for each day of June. There are two clear periods, June 14 through June 21, and June 28 and 29, when the market cleared the most exports. These periods coincide with the periods of heat and high loads experienced by the CAISO system and across the Southwest and Northwest. In particular, June 28 observed cleared exports close to 6,000 MW. The maximum levels typically happened when solar production was still high.

Figure 46: Hourly RUC net schedule interchange

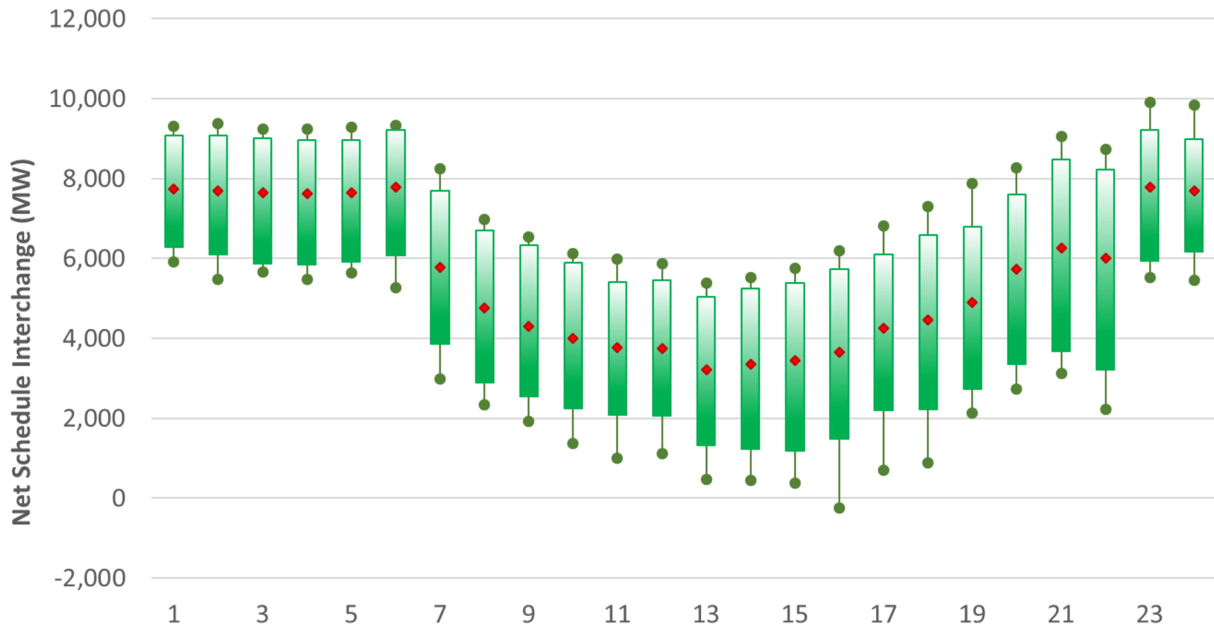


Figure 47: Daily distribution of hourly RUC exports

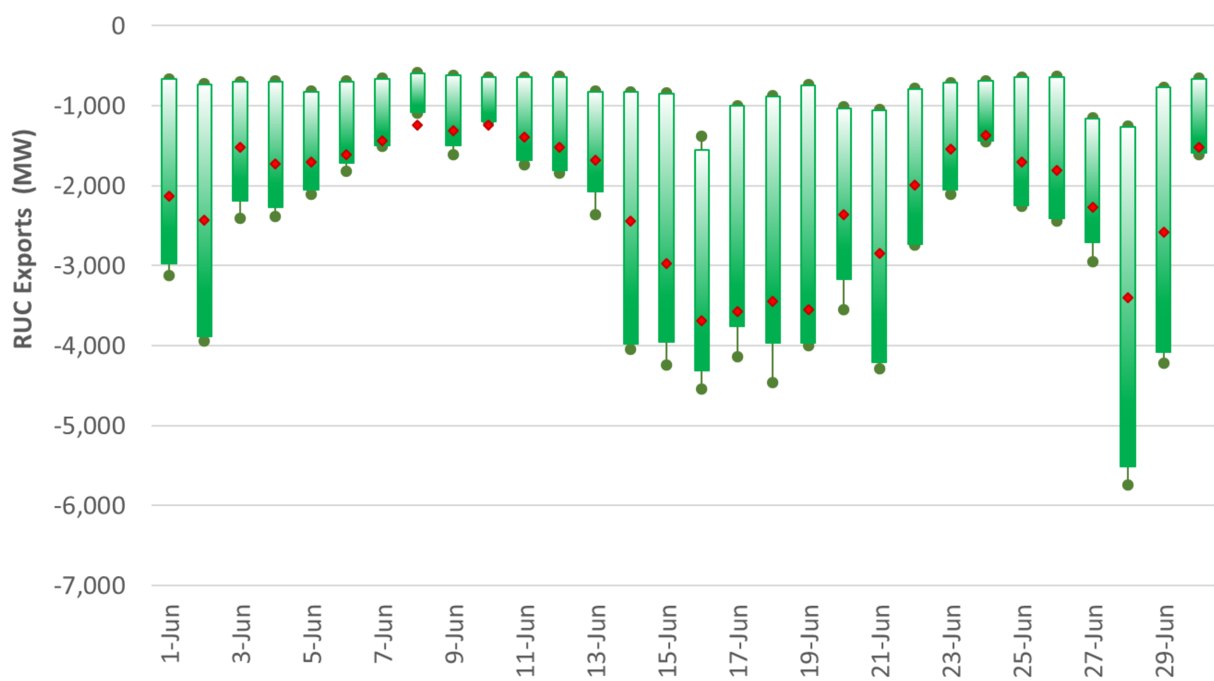
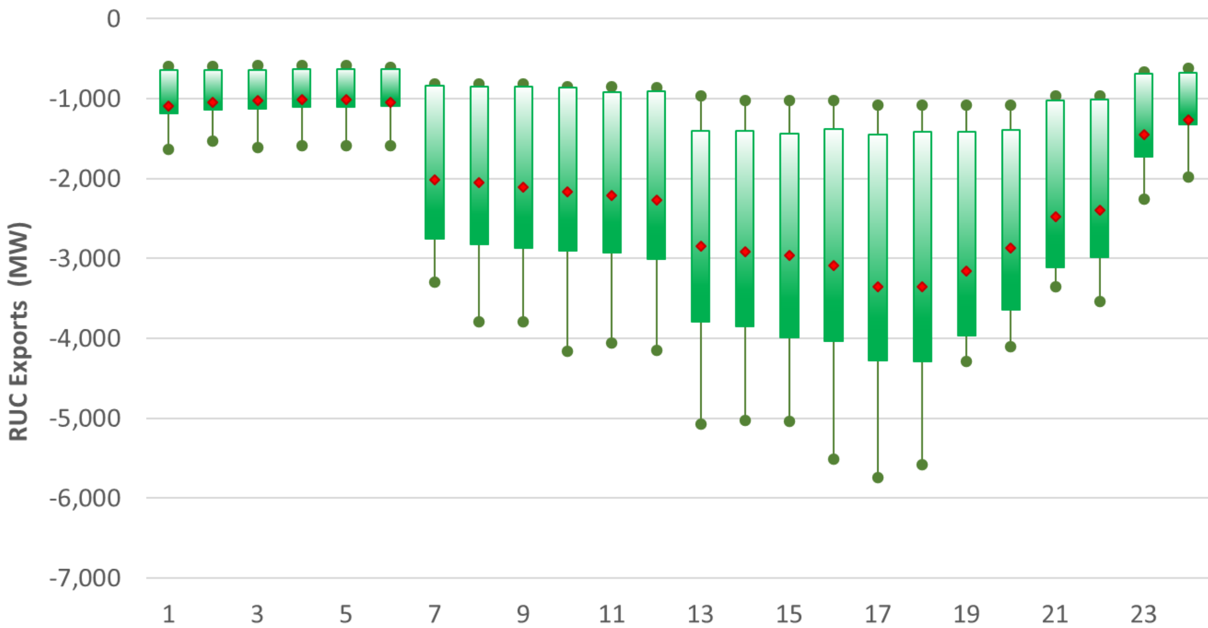


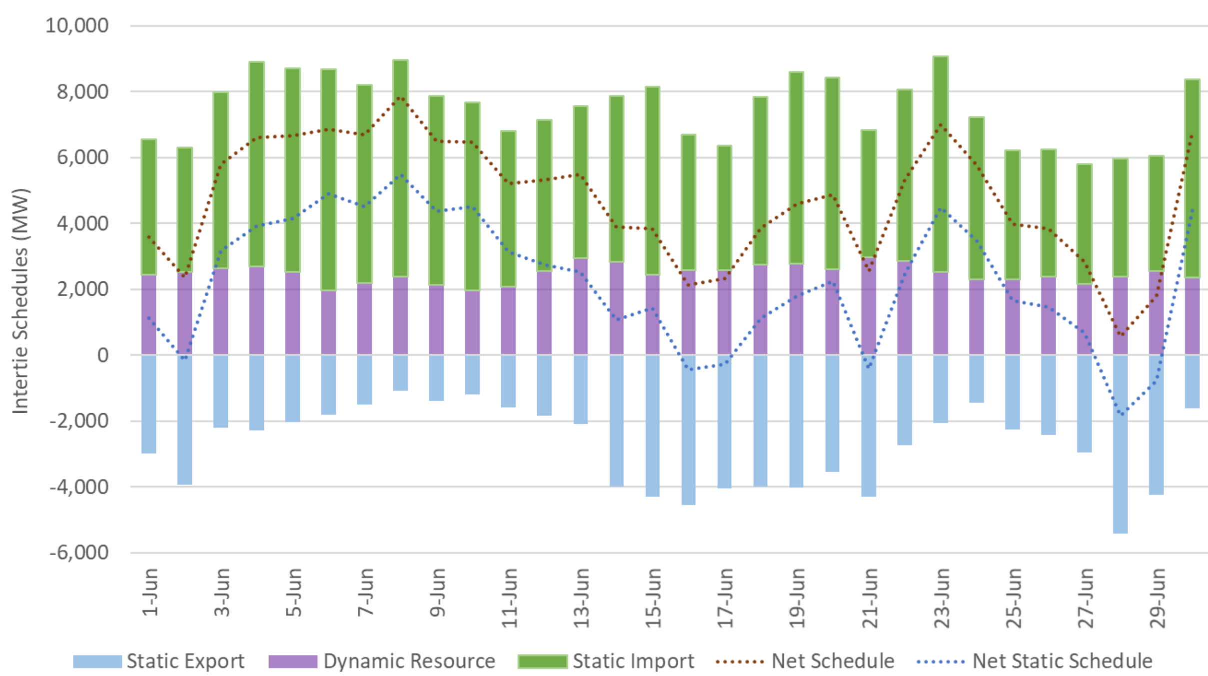
Figure 48 illustrates the hourly distribution of RUC schedules for exports, and that the highest volume occurred during midday hours when CAISO's system has plenty of solar supply; exports were in high demand during the evening hours of June 28 and 29, when the heat wave led to tight supply conditions outside the CAISO's system.

Figure 48: Hourly RUC exports



About 56 percent of the time, CAISO's gross load peaked in hour ending 19. Figure 49 shows the intertie capacity available in the day-ahead market for hour ending 19 to highlight the conditions around peak time, when CAISO's system needs supply the most.

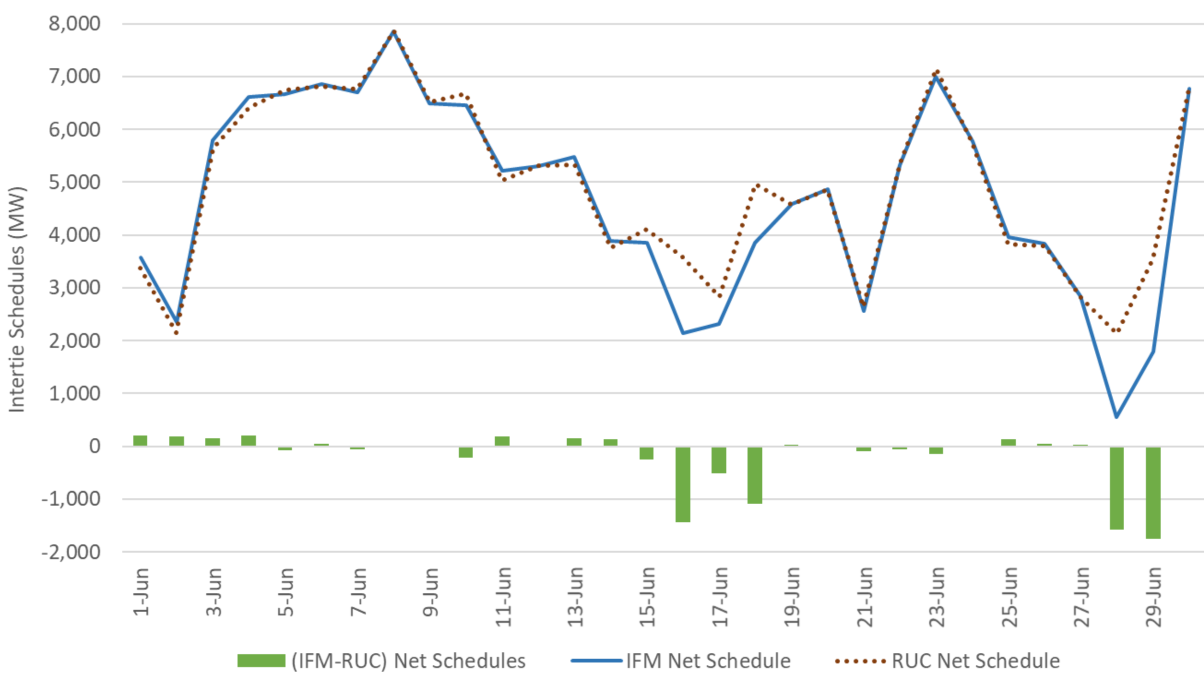
Figure 49: IFM schedules for interties for hour ending 19



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 dotted line represents the net schedules cleared in RUC (imports plus dynamics less exports), while the blue dotted line represents the net schedule in RUC when considering only static imports and exports. The net static schedule was negative for June 16, 17, 28, and 29, indicating the volume of static exports outpaced the volume of static import.

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 is what should be tagged if participants submit a day-ahead tag for their export. IFM schedules are still financially binding. Figure 50 compares the net schedule cleared in both IFM and RUC for hour ending 19, and provides the relative change of schedules between the two processes as shown with the bars in green. IFM schedules for exports were reduced in the RUC process during the periods of June 15 through June 18, and June 28 and 29. With these export reductions, the RUC net schedules were higher than IFM schedules.

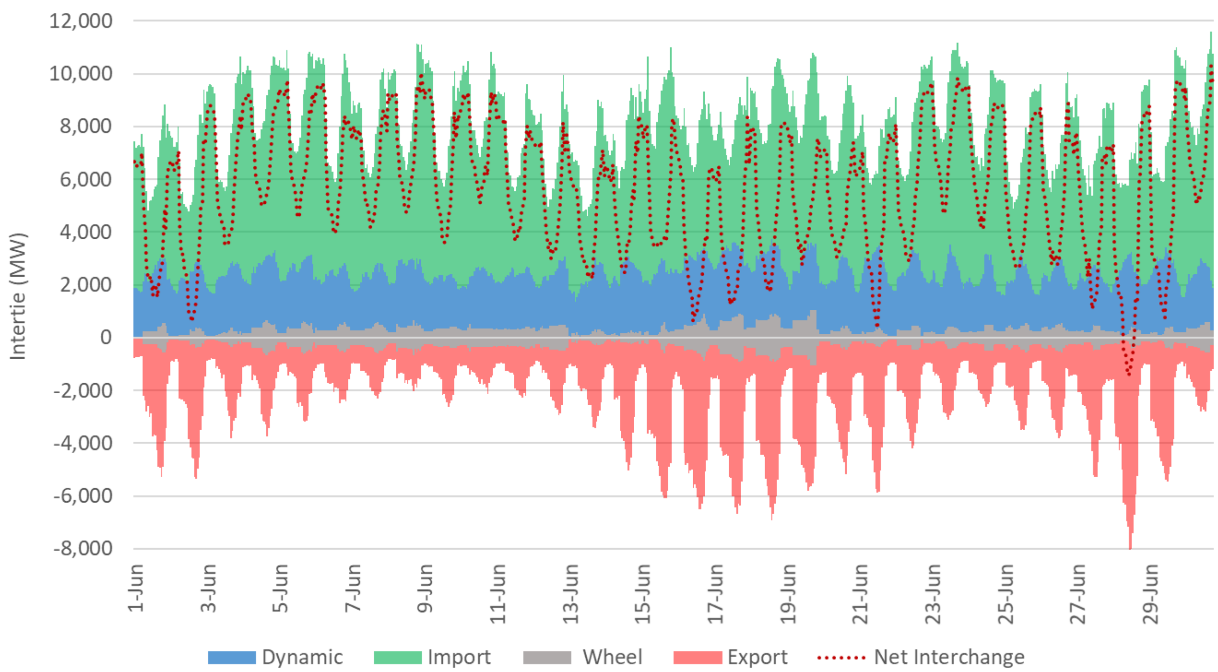
Figure 50: IFM and RUC schedule interchange for hour ending 19



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 by being given a day-ahead priority. 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 51 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 the lowest value during peak hours in mid-June, in part due to the increased level of exports. The net schedule indeed becomes negative (net export) on June 28 driven by the large volume of exports. The real-time market largely follows the trend observed in the day-ahead market.

Figure 51: HASP cleared schedules for interties

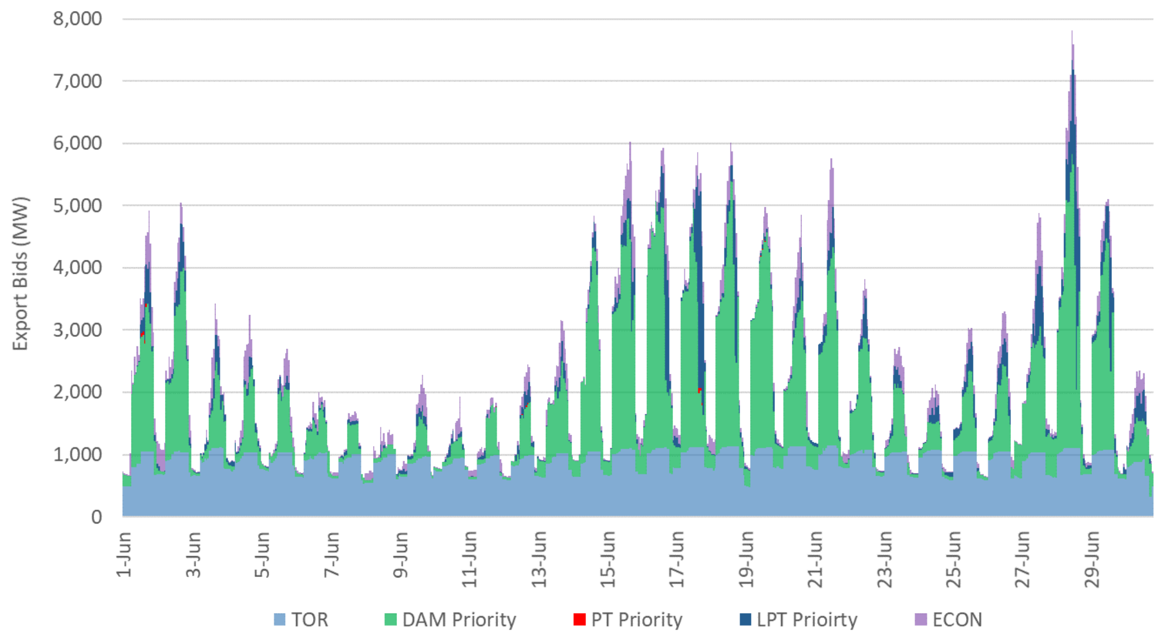


The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Interties cleared in the day-ahead market can submit self-schedules into HASP and will have, under current practices, a day-ahead priority that is higher than PTK or LPT schedules in the real-time market. Effectively, these day-ahead schedules cleared in the IFM and RUC are presumed to be feasible through the DAM and the CAISO considers them as inputs to the real-time market and provides them higher priority than bids coming in to the real-time. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC.[43] Additionally, exports can participate directly into the real-time market with either PTK self-schedules, LPT self-schedules, or economic bids. Figure 52 shows the breakdown of all HASP exports bids by the type of bid, including self-schedules. About 40 percent of the exports in HASP were related to TORs, while about 43 percent of the

[43] Based on these rules as they exist today, export schedules cleared in the day-ahead are also treated with higher priority than the power balance constraint (effectively load) in the real-time market. Through the summer initiatives enhancements described above, the CAISO will no longer provide this higher priority to exports a higher priority than load in the real-time, and will only provide them equal 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

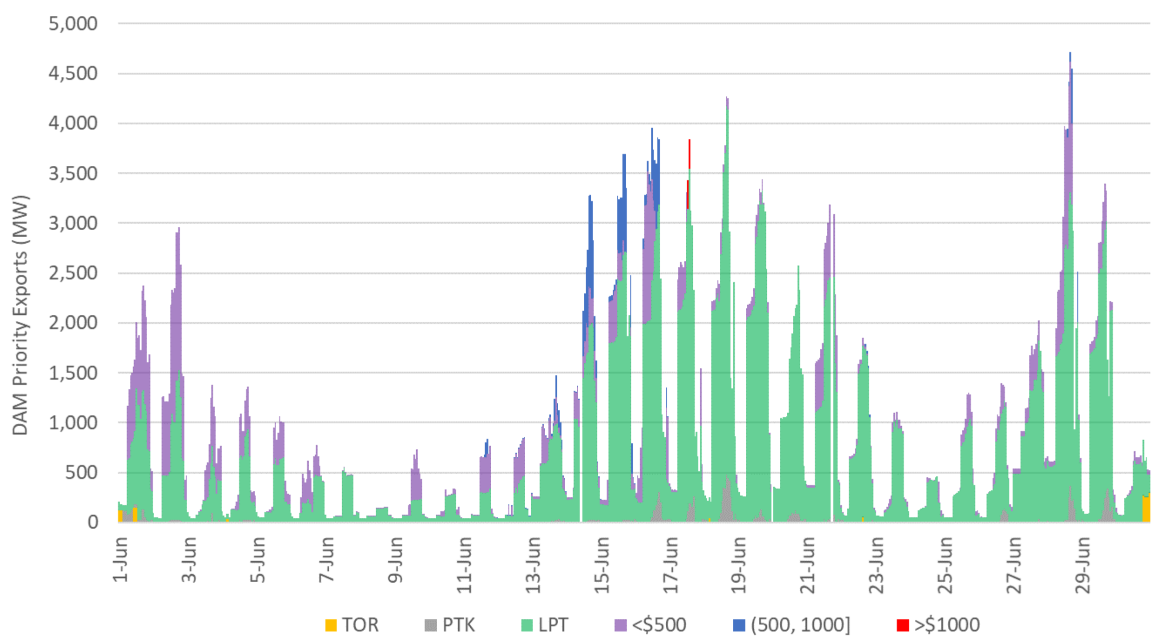
export volume had a day-ahead priority, indicating they had been previously cleared in the day-ahead market. In mid-June, there were up to 500MW of hourly economic exports cleared in the real-time market.

Figure 52: Exports bids in HASP



Exports cleared in the RUC process can be self-scheduled in the real-time market with a day-ahead priority, regardless of the type of exports submitted in the day-ahead market.

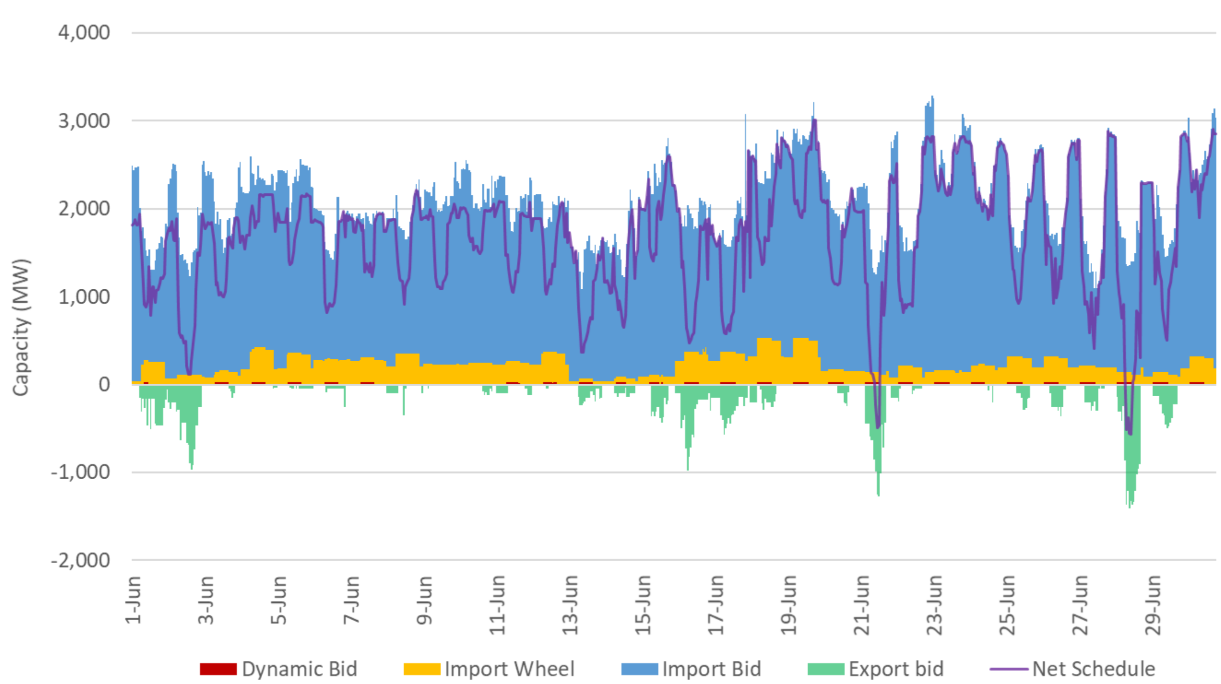
Figure 53: Exports in HASP with a DAM priority



For instance, either an economic bid or a price taker export cleared in RUC will have a day-ahead priority in real-time by virtue of having cleared in the day-ahead market. About 75 percent of these exports that cleared in the RUC process and had day-ahead priority in real-time were submitted as LPT in the day-ahead market, while about 17 percent were exports with economic bids under $500/MWh in the day-ahead market. Figure 53 shows the trend of exports with DAM priority in the HASP process. The largest volume of these exports happened during the heatwave of mid-June and late June. During the heatwave, the vast majority of exports were self-schedules in the day-ahead market.

Imports and exports were scheduled over more than 20 different intertie scheduling points in June, with Malin, Paloverde, NOB and Mead seeing the highest volume of transactions. Figure 54 through Figure 56 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[44]. The trend of increasing exports in mid-June, when the southwest was with high demands, is fairly marked at the Palo Verde intertie.

Figure 54: HASP schedules at Malin intertie



[44] The breakdown of imports and export 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 standing alone exports, even though it is counted in the total volume of exports for a specific tie.

Figure 55: HASP schedules at PaloVerde intertie

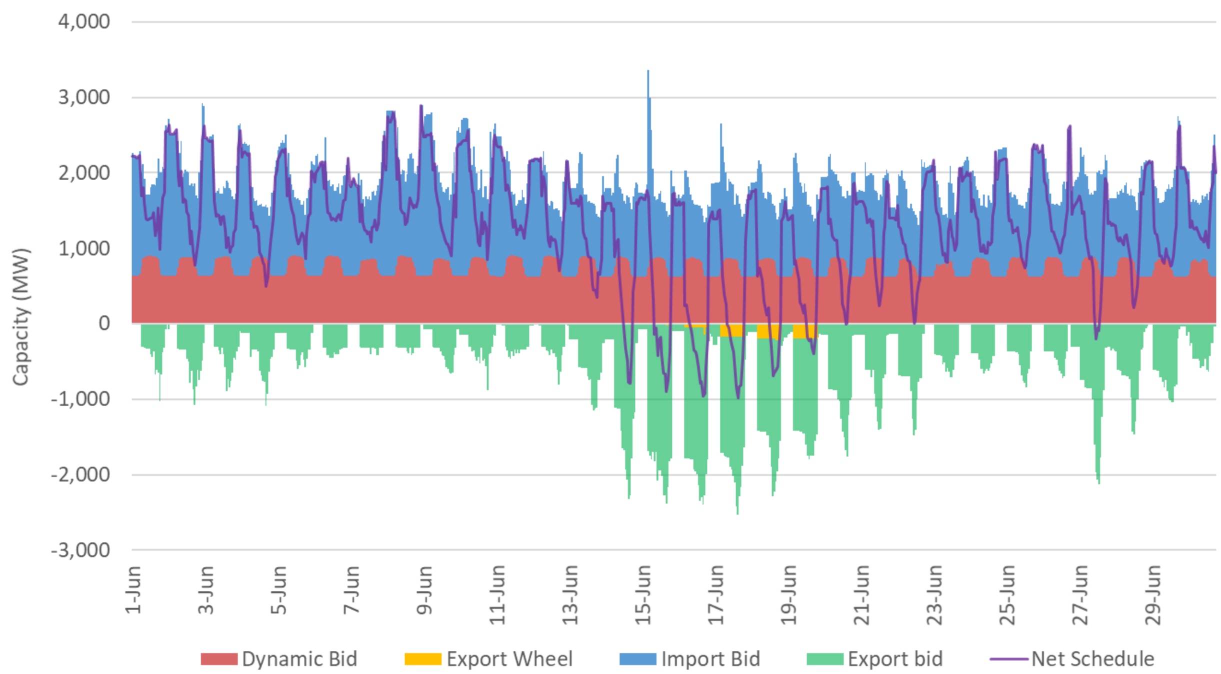
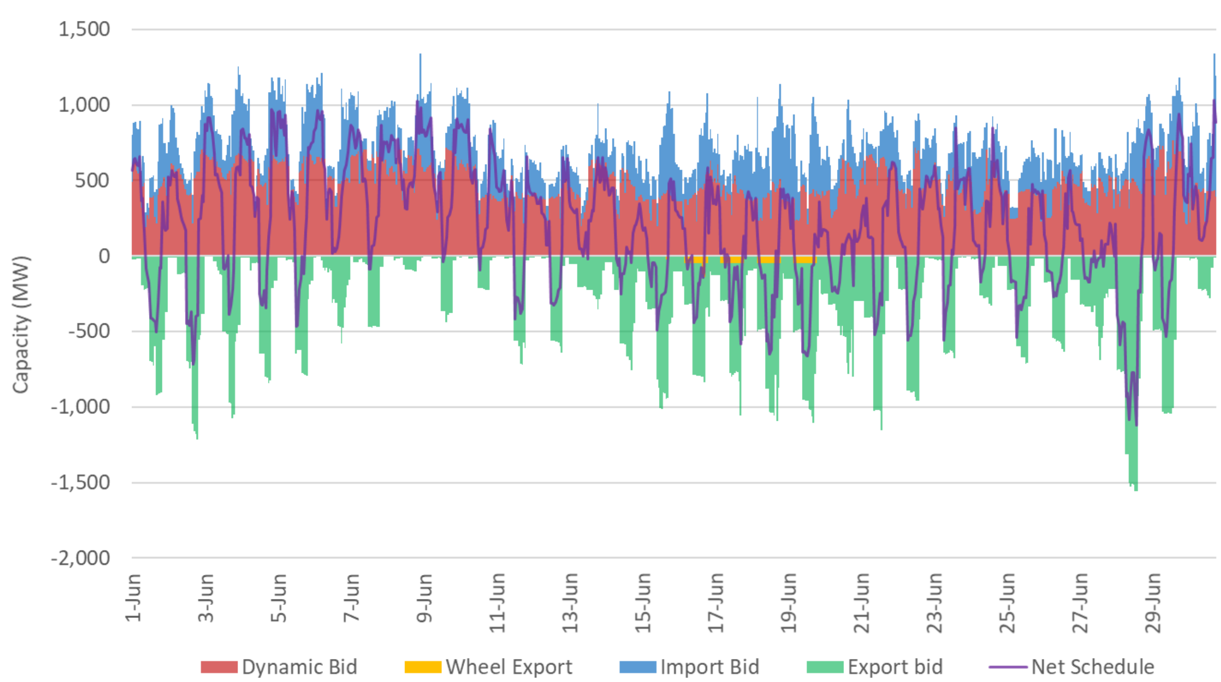


Figure 56: HASP schedules at MEAD230 intertie



9.2 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 no-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 2021 was 2,182 MW. Figure 57 shows the static RA import volumes with bids in the day-ahead market, organized by price ranges, as well as by type of self-schedules (TOR, ETCs, PTK self-schedules or LPT self-schedules). This includes all static RA imports that are CPUC or non-CPUC jurisdictional. Using all hours in the month of June as a reference, about 50 percent of all static RA imports bids came in the day-ahead market at $0/MWh or lower, and 27 percent of import bids were for prices under $50/MWh. There are some specific days and hours in which static RA imports came in at prices higher than $500/MWh, like those of June 28 and 29.

Figure 57: Bid volume of non-resource specific RA imports by type of import

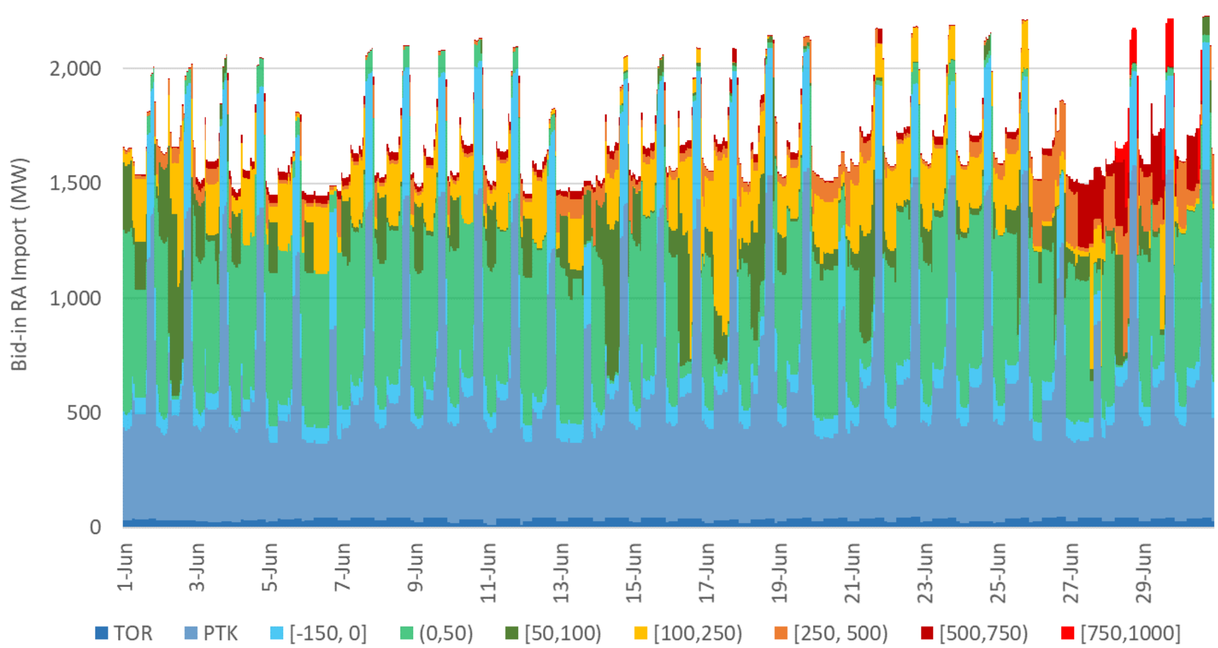


Figure 58 shows the bid-in volume of static RA imports to the nominal monthly showing of 2,182 MW. Several RA import resources actually bid in quantities above their RA obligation, which reflects economic participation in the CAISO markets beyond their RA requirement. On average, there was about 5 percent of additional bid-in capacity by RA imports; this is highlighted with the area in blue in Figure 58. The bid-in capacity associated with RA imports exhibits a daily and hourly profile. For instance, RA imports do not have an obligation to bid-in on weekends, which can be observed clearly on the graph by the low values over each weekend in June. Also, there is a marked profile for the On-peak and Off-peak hours, where

Off-peak hours see lower volumes of participation. For reference, the dotted line illustrates the cleared schedules for all static RA imports.

Figure 58: Bid-in volume associated with RA imports

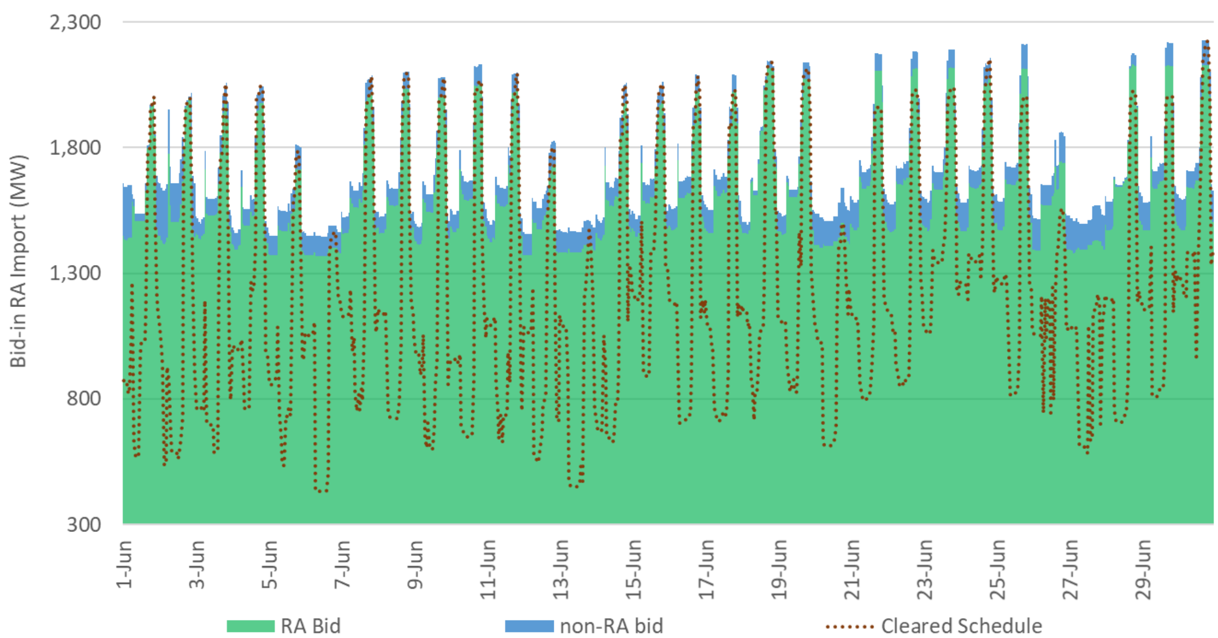


Table 6 illustrates the profile by day and hour in which RA imports bid into the day-ahead market in June. The darker orange color reflects a lower number of resources, while a darker blue reflects a higher number of resources bidding in the day-ahead market. The peak hours (availability assessment hours) are when the majority of resources bid in. The weekends like June 5-6 see a lower number of resources in all hours. Table 7 shows the same structure based on the bid-in volume of RA imports.

Table 6: Number of RA Import resources bidding in the day-ahead market

	Hour																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1-Jun	32	33	33	33	33	33	37	36	35	35	35	35	35	35	35	35	40	41	41	42	42	39	35	33
2-Jun	33	34	33	33	33	35	39	37	36	36	36	36	36	36	37	39	41	42	42	42	42	39	35	34
3-Jun	34	35	34	34	35	35	39	38	37	37	37	37	37	37	37	40	41	41	42	42	42	41	36	35
4-Jun	32	33	32	32	33	34	38	36	35	35	35	35	35	35	35	37	41	42	42	42	42	39	35	33
5-Jun	33	32	32	32	32	32	36	36	36	36	36	36	36	36	36	36	37	37	38	37	37	37	34	34
6-Jun	32	32	32	32	32	32	33	33	33	33	33	33	33	33	33	33	34	34	35	34	34	34	34	33
7-Jun	34	33	34	34	34	36	40	37	37	37	37	37	37	37	39	39	41	41	42	42	42	40	36	34
8-Jun	35	33	34	34	35	36	40	37	37	37	37	37	37	38	39	39	41	41	42	42	42	41	36	35
9-Jun	35	34	34	34	35	36	40	37	37	37	37	37	37	37	37	39	41	41	42	42	42	40	37	35
10-Jun	35	35	35	34	35	36	40	37	37	37	37	37	37	37	37	38	41	41	42	42	42	40	37	35
11-Jun	34	35	35	34	35	36	40	37	37	37	37	37	37	37	37	38	41	42	42	42	42	40	37	35
12-Jun	33	33	33	33	33	33	36	36	36	36	36	36	36	36	36	36	37	37	38	37	37	37	34	34
13-Jun	33	33	32	32	32	32	33	33	33	33	33	33	33	33	33	33	34	35	35	34	34	34	34	34
14-Jun	34	35	35	34	35	35	39	38	37	37	37	37	37	38	38	39	42	42	42	42	42	40	37	35
15-Jun	34	35	35	34	35	35	39	37	37	37	37	37	38	38	38	40	42	42	42	41	41	41	36	35
16-Jun	34	34	34	34	34	34	39	37	37	37	37	38	39	39	38	39	41	41	41	40	40	39	36	35
17-Jun	33	34	34	34	34	34	38	37	37	37	37	38	38	37	38	39	41	41	41	40	40	40	37	34
18-Jun	33	34	34	34	34	34	38	37	37	37	37	38	38	38	39	40	42	42	42	42	42	40	37	34
19-Jun	33	33	33	33	33	33	37	37	37	37	37	37	37	37	37	37	38	39	38	38	38	38	34	34
20-Jun	33	33	33	33	33	33	34	34	34	34	34	34	34	34	34	34	35	36	36	35	35	35	34	34
21-Jun	34	33	34	34	34	34	39	37	37	37	37	38	38	38	39	40	42	42	42	41	41	40	36	35
22-Jun	33	33	34	34	34	34	39	38	37	37	37	38	38	38	39	40	42	42	42	42	42	41	36	35
23-Jun	33	33	33	33	33	35	40	38	37	37	37	37	37	38	38	41	41	42	42	41	41	40	37	34
24-Jun	33	33	33	33	33	35	40	38	37	37	37	37	37	37	38	40	41	42	42	41	41	41	37	35
25-Jun	34	33	33	33	33	35	39	38	37	37	37	37	37	37	37	40	41	42	42	41	41	41	36	34
26-Jun	32	32	32	32	32	32	36	36	36	36	36	36	36	36	36	37	38	38	38	37	37	37	34	32
27-Jun	32	32	32	32	32	32	33	33	33	33	33	33	33	33	33	34	35	35	35	34	34	34	34	32
28-Jun	33	33	33	33	33	34	39	38	37	37	37	37	37	39	39	41	42	42	42	41	41	41	38	35
29-Jun	34	33	33	33	33	34	39	38	38	37	37	37	39	39	39	41	42	42	42	41	41	41	38	35
30-Jun	33	33	33	33	33	34	39	38	38	37	37	37	38	39	39	41	42	42	42	41	41	41	38	34

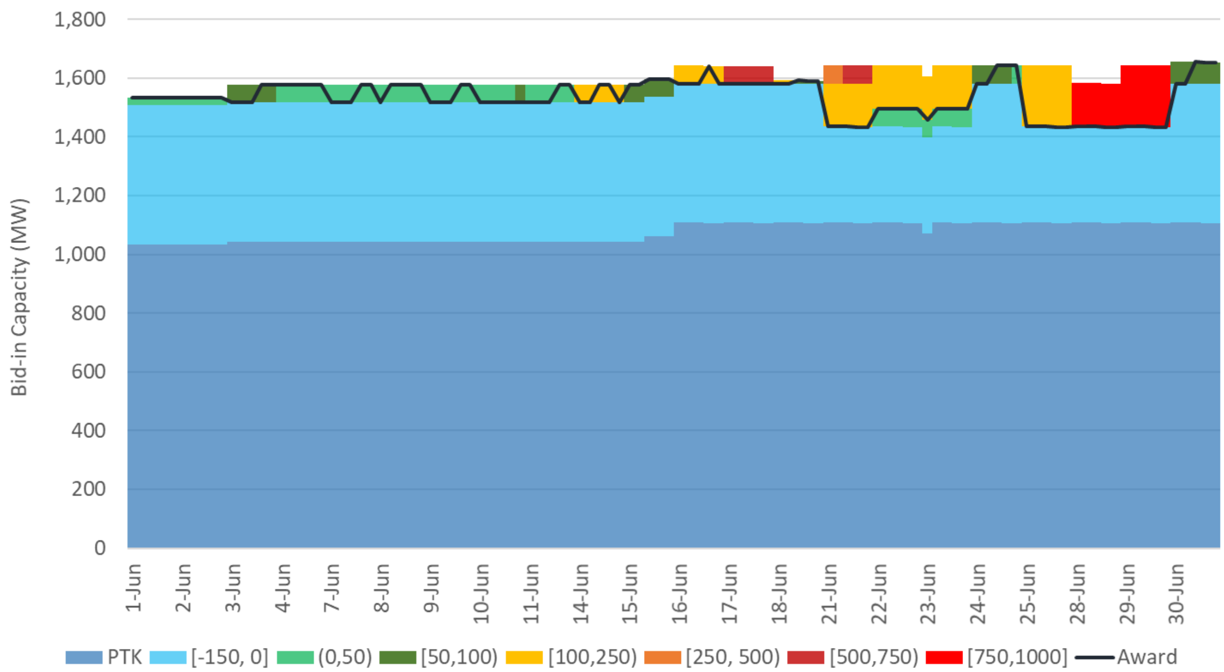
Table 7: Volume of RA Imports bidding in the day-ahead market

	Hour																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1-Jun	1660	1645	1644	1652	1653	1653	1614	1597	1538	1538	1538	1538	1537	1537	1537	1658	1808	1812	1969	1979	2006	1854	1689	1663
2-Jun	1660	1641	1631	1628	1636	1655	1954	1725	1658	1659	1660	1659	1658	1699	1753	1843	1801	1967	1989	2002	2002	2020	1687	1657
3-Jun	1528	1520	1505	1498	1514	1523	1788	1603	1596	1596	1597	1596	1597	1599	1606	1720	1848	1849	2008	2046	2059	1982	1553	1531
4-Jun	1483	1473	1461	1460	1476	1477	1710	1563	1557	1556	1555	1555	1611	1594	1596	1845	2012	2016	2048	2048	2045	1893	1509	1484
5-Jun	1462	1451	1451	1451	1451	1451	1568	1551	1550	1549	1549	1548	1546	1579	1547	1617	1638	1641	1812	1810	1806	1802	1465	1467
6-Jun	1460	1450	1450	1450	1450	1450	1465	1448	1448	1448	1448	1447	1447	1447	1447	1462	1490	1490	1491	1489	1489	1476	1465	1465
7-Jun	1546	1523	1524	1525	1525	1540	1666	1647	1631	1630	1631	1629	1663	1649	1698	1880	2058	2069	2074	2080	2088	1963	1536	1546
8-Jun	1546	1523	1525	1525	1526	1539	1671	1654	1636	1639	1637	1635	1635	1637	1702	1830	1986	2100	2102	2101	2101	1974	1537	1546
9-Jun	1508	1497	1486	1484	1487	1501	1667	1653	1616	1616	1616	1613	1613	1693	1759	1869	2078	2076	2080	2081	2080	1954	1531	1508
10-Jun	1555	1547	1535	1534	1548	1548	1789	1706	1688	1667	1667	1664	1665	1670	1671	1898	2126	2121	2123	2131	2131	2004	1580	1555
11-Jun	1519	1510	1494	1492	1511	1507	1683	1651	1651	1639	1639	1637	1638	1647	1803	1767	1990	2093	2094	2096	2098	1969	1543	1520
12-Jun	1465	1456	1456	1456	1456	1456	1600	1585	1586	1560	1560	1560	1559	1597	1615	1628	1646	1781	1811	1823	1828	1821	1470	1471
13-Jun	1476	1467	1466	1466	1466	1462	1484	1467	1467	1467	1467	1466	1466	1466	1466	1483	1509	1510	1512	1511	1509	1495	1481	1483
14-Jun	1533	1514	1510	1500	1513	1524	1801	1664	1662	1641	1643	1640	1665	1680	1677	1786	1921	1929	2048	2053	2058	1935	1557	1534
15-Jun	1547	1539	1517	1516	1529	1531	1810	1662	1661	1652	1654	1652	1677	1674	1678	1796	1909	2009	2044	2047	2061	1939	1570	1547
16-Jun	1575	1567	1556	1556	1558	1567	1815	1665	1666	1667	1668	1680	1689	1686	1686	1831	1959	1961	2092	2088	2088	1960	1611	1588
17-Jun	1574	1564	1554	1554	1554	1554	1712	1693	1672	1673	1672	1683	1699	1685	1685	1831	1962	1954	2090	2090	2087	1961	1612	1588
18-Jun	1526	1506	1506	1506	1493	1506	1674	1681	1628	1628	1628	1753	1866	1884	1887	2047	2085	2145	2144	2146	2144	2126	1790	1766
19-Jun	1549	1540	1538	1527	1529	1535	1689	1678	1634	1634	1634	1633	1632	1643	1764	1912	2054	2139	2141	2140	2139	2125	1665	1554
20-Jun	1546	1537	1537	1536	1524	1524	1515	1509	1510	1510	1509	1509	1509	1526	1526	1527	1581	1582	1639	1639	1582	1568	1551	1550
21-Jun	1606	1591	1580	1580	1581	1593	1749	1729	1704	1704	1703	1714	1716	1732	1841	1973	2175	2176	2175	2173	2174	2046	1636	1613
22-Jun	1592	1583	1575	1574	1576	1585	1729	1719	1719	1720	1718	1743	1736	1747	1746	1880	2154	2182	2182	2183	2181	1998	1630	1608
23-Jun	1604	1595	1595	1582	1589	1630	1730	1706	1704	1704	1703	1702	1704	1753	1801	2017	2146	2190	2190	2190	2189	1980	1645	1618
24-Jun	1595	1582	1580	1580	1580	1597	1728	1712	1709	1709	1707	1708	1709	1721	1729	1874	2122	2136	2127	2145	2157	1988	1636	1610
25-Jun	1613	1589	1586	1586	1586	1600	1743	1725	1723	1723	1722	1722	1722	1731	1739	1898	2089	2214	2214	2209	2211	2083	1639	1614
26-Jun	1530	1520	1518	1517	1517	1517	1656	1652	1651	1652	1650	1650	1650	1689	1698	1830	1728	1732	1861	1865	1859	1846	1537	1530
27-Jun	1529	1520	1518	1507	1509	1519	1504	1497	1497	1497	1496	1496	1496	1513	1513	1514	1568	1572	1571	1570	1569	1555	1535	1529
28-Jun	1607	1585	1585	1585	1587	1598	1683	1654	1653	1653	1653	1652	1667	1680	1683	1830	2125	2168	2177	2176	2170	1967	1648	1622
29-Jun	1606	1583	1583	1583	1583	1585	1847	1714	1708	1708	1707	1723	1738	1737	1738	1884	2199	2219	2217	2216	2216	1982	1646	1618
30-Jun	1614	1601	1596	1594	1595	1609	1710	1708	1707	1707	1705	1720	1738	1738	1800	2082	2227	2229	2229	2228	2227	2101	1656	1629

The previous metrics consider all static imports with RA for all hours in the month, regardless if they are related to CPUC jurisdictional LSEs. However, 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 59 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. Based on this subset, about 94 percent of the total import capacity was bid with either self-schedules or economic bid at or below $0/MWh. This plot also shows the cleared imports, which largely covered all imports with self-schedules and bids with prices at or below $0/MWh. A small volume of imports with bids above $0/MWh did not clear in the day-ahead market.

Figure 59: RA import for hour endings 17 through 21 for weekdays



9.3 Wheel transactions

Figure 60 shows an hourly average of wheels cleared in the RUC process. Wheels participating in the day-ahead market in the month of June were of the type ETC/TOR, or self-schedules. There were no wheels with economic bids. The volume of wheels associated with ETC/TOR was stable throughout the month, while self-schedule wheels not under such entitlements increased from June 14 through June 20. Figure 61 provides an hourly breakdown of self-schedule wheels, with hourly cleared RUC volumes of up to 1,200 MW on June 18.

Figure 60: Daily average volume of wheel transactions by type of bid

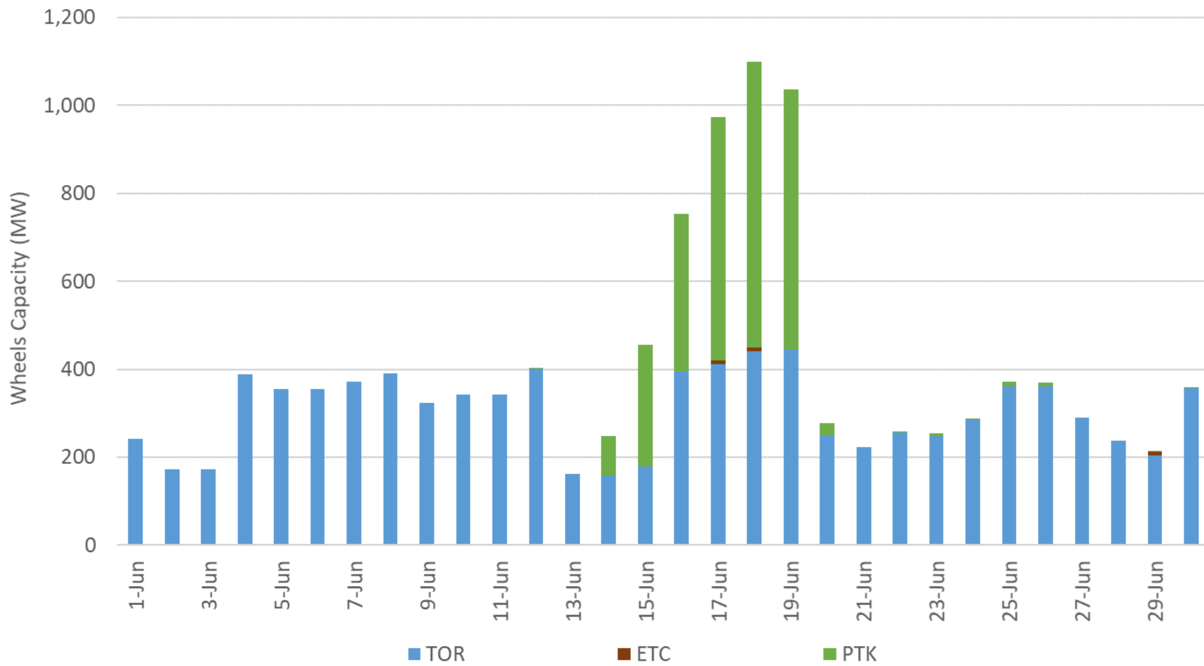
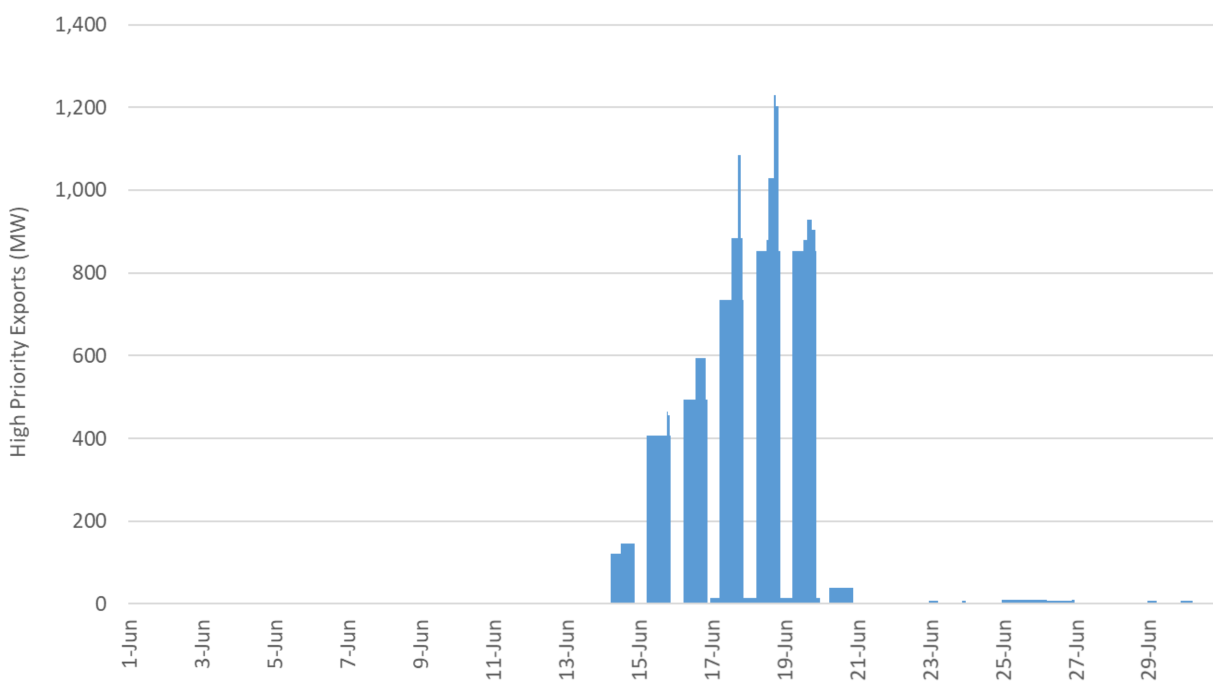


Figure 61: Hourly volume high-priority wheels



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. 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-schedules having higher priority than stand-alone imports or exports, wheels can clear before other imports or exports on paths with limited capacity available. On June 17, Malin and NOB, where the majority of the wheels came in, did not bind in the day-ahead market. This means these wheels did not crowd out other imports on Malin or NOB. However, Malin was binding on peak hours on June 15 and NOB was binding on peak hours on June 19. Figure 62 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. "Source" refers to the import scheduling point while "sink" refers to the export scheduling point. The largest volume of wheels in the day-ahead market were cleared for the path from Malin to Palo Verde, followed by wheels from NOB to PaloVerde. These are expected paths that wheel power through California from the Northwest to the Southwest.

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

	Sink				
Source	MEAD230	PaloVerde	MCCULLOUG500	MIR2	MDWP
CFEROA	0.4	0.3			
CFETIJ		0.7			
CRAG	0.8	6.0			
MALIN500	1.1	20.3	2.3	0.0	
MEAD230				2.2	
NOB	9.0	14.3	6.6	0.0	4.9
SYLMAR		12.9	4.3		

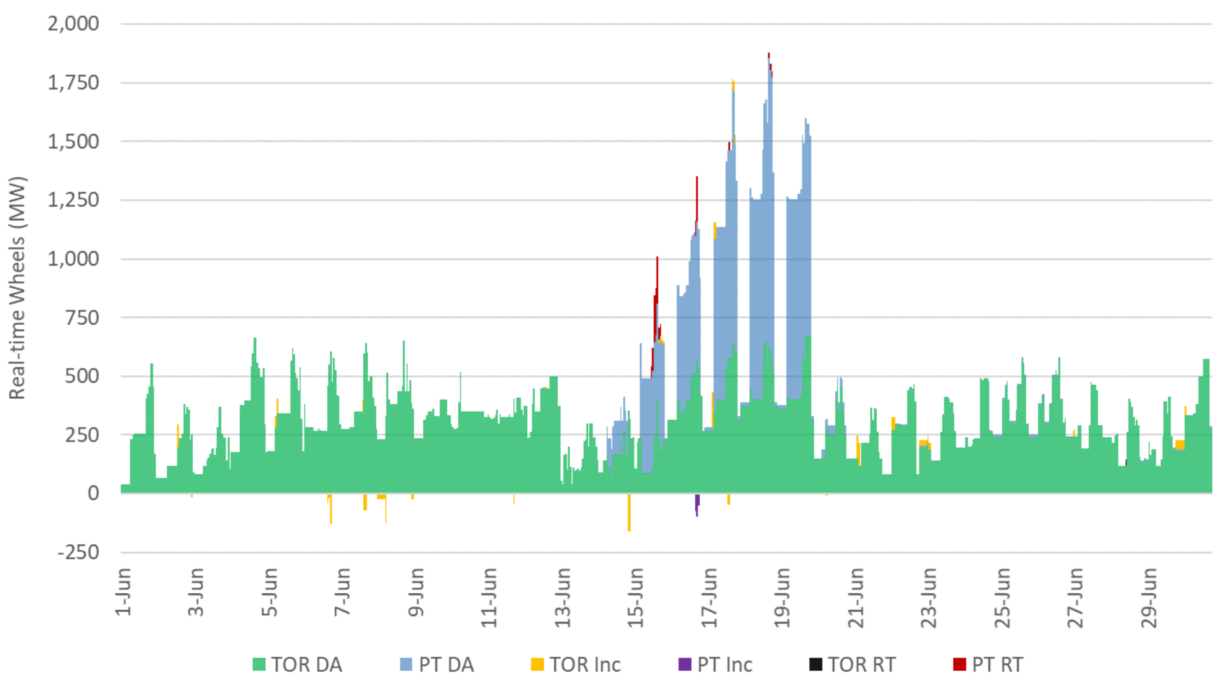
Figure 63 summarizes the maximum hourly wheels cleared in the day-ahead market by source-to-sink combination. The maximum wheel transaction of 413 MW in June occurred from NOB to Paloverde.

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

	Sink				
Source	MEAD230	PaloVerde	MCCULLOUG500	MIR2	MDWP
CFEROA	100	75			
CFETIJ		100			
CRAG	37	79			
Malin	11	317	133		
MEAD230				89	
NOB	250	413	142		125
SYLMAR		122	122		

Wheels cleared in the day-ahead market can be carried over into the real-time market with a day-ahead priority or self-scheduled HASP process. Figure 64 shows the volume of wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes. The *TOR DA* and PTK *DA* capture the wheels cleared in the HASP market for wheels awarded in the RUC process and that did not rebid in the real-time market, and, thus, they came in as default day-ahead priority into the real-time market. *TOR Inc* and PTK *Inc* capture any difference of wheels cleared between RUC and HASP for those wheels cleared in RUC. This difference can be positive or negative. A positive difference will mean that wheel bid in and cleared above the scheduled cleared in RUC. The groups *TOR RT* and PTK *RT* reflect wheels that came in directly into real-time and that they did not have any scheduled cleared in the RUC process. These are incremental bids and procurement of wheels in real-time.

Figure 64: Explicit wheels cleared in real-time market



Notably the wheels cleared in real-time are basically the same cleared in the day-ahead market. Although the volume of incremental changes or new wheel bids coming in to real-time were minimal over the month, they came up to 200MW on June 15, 16 and 17 during peak hours.

10 Demand Response

The CAISO markets consider demand response programs designed to reduce demand based on system needs, and triggers demand response programs through market dispatches. In the CAISO' markets there are two main 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 65 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 market. The largest volume of PDR dispatches occurred from June 15 through 18, and on June 28.

Figure 65: PDR Dispatches in day-ahead and real-time markets

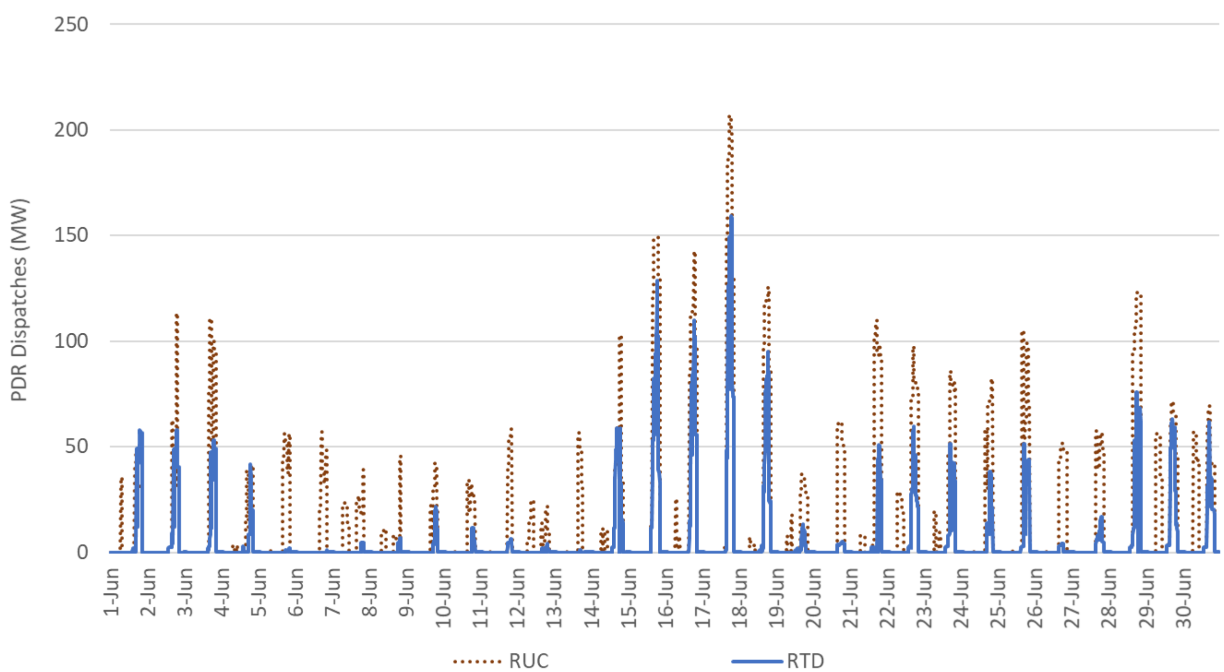
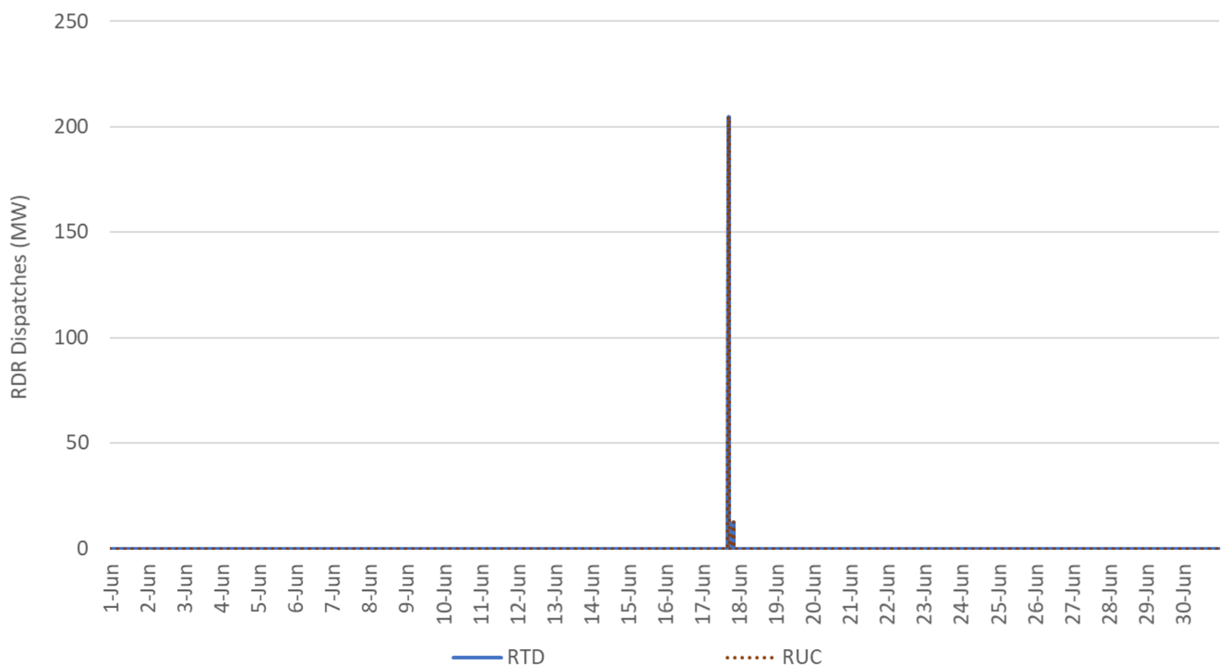


Figure 66 shows the dispatches for reliability demand response resources (RDRRs) in both the day-ahead and real-time market. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market even when there is no energy emergency declaration. Although most RDRRs are triggered in real-time by, at minimum, a CAISO Warning declaration, some RDRRs may be economically bid 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 can be dispatched directly in the real-time market when, at a minimum, the CAISO declares a Warning. With that declaration, RDRR becomes part of the market supply stack, and RDRR can be dispatched economically or forced to be dispatched by operators. RDRRs were dispatched in the day-ahead market on June 17 HE 18 and HE21 at 204 MW and 124 MW respectively. Consequently, the real-time market considered the day-ahead awards as self-schedules and will dispatch them at the same day-ahead level. RDRR are expected to follow these instructions.[45]

Figure 66: RDR dispatches in day-ahead and real-time markets



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. CAISO will report on their performance when the data becomes available.

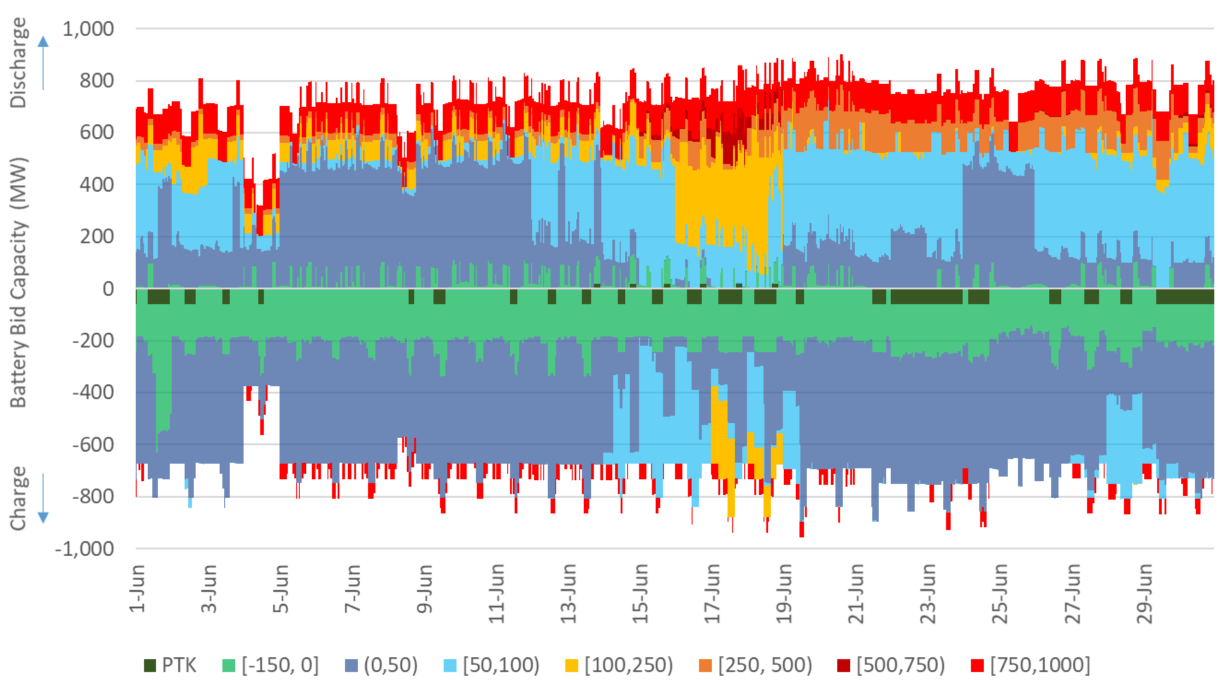
[45] Currently, RDRR dispatches originated from day-ahead awards are expected to be followed based on the CMRI displays. For this summer enhancements, there is an improvement to send ADS instructions for these RDRR dispatches originated from day-ahead awards even when there I no RDRR triggering event.

11 Storage 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 2021, there were 28 storage resources actively participating in the CAISO markets. Of these 28 resources, 26 storage resources participated in both the energy and ancillary service market, whereas two resources participated only in the regulation 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.

In June, the smallest storage capacity of the 28 storage resources was 4.4 MWh, and the largest storage capacity was 460 MWh. The total storage capacity of all the active resources participating in the market was 3,884 MWh. Figure 67 shows the bid-in capacity for storage resources in the day-ahead market. Negative area is for charging while positive area is for discharging. The bid-in capacity is organized by price ranges. The green area represents batteries bidding negative for charging and shows a consistent pattern in June. There is a fair amount of capacity willing to charge at positive prices less than $50/MWh, as shown with the dark blue. On June 4 the overall capacity is reduced due to outages. As CAISO entered to the mid-June heatwave, batteries were bidding to charge even at prices higher than $50/MWh. Conversely, in this period they were willing to discharge at higher prices.

Figure 67: Bid-in capacity for batteries in the day-ahead market



There is a consistent pattern of batteries bidding to discharge only at high prices of over $250/MWh. The bright red shows bids close to or at the bid cap and shows that there is certain volume of storage capacity that is expecting to discharge only at these high prices. Figure 68 shows the bid-in capacity for the real-time market. The majority of bids into the real-time market are between -$150/MWh and $100/MWh.

Figure 68: Bid-in capacity for batteries in the real-time market

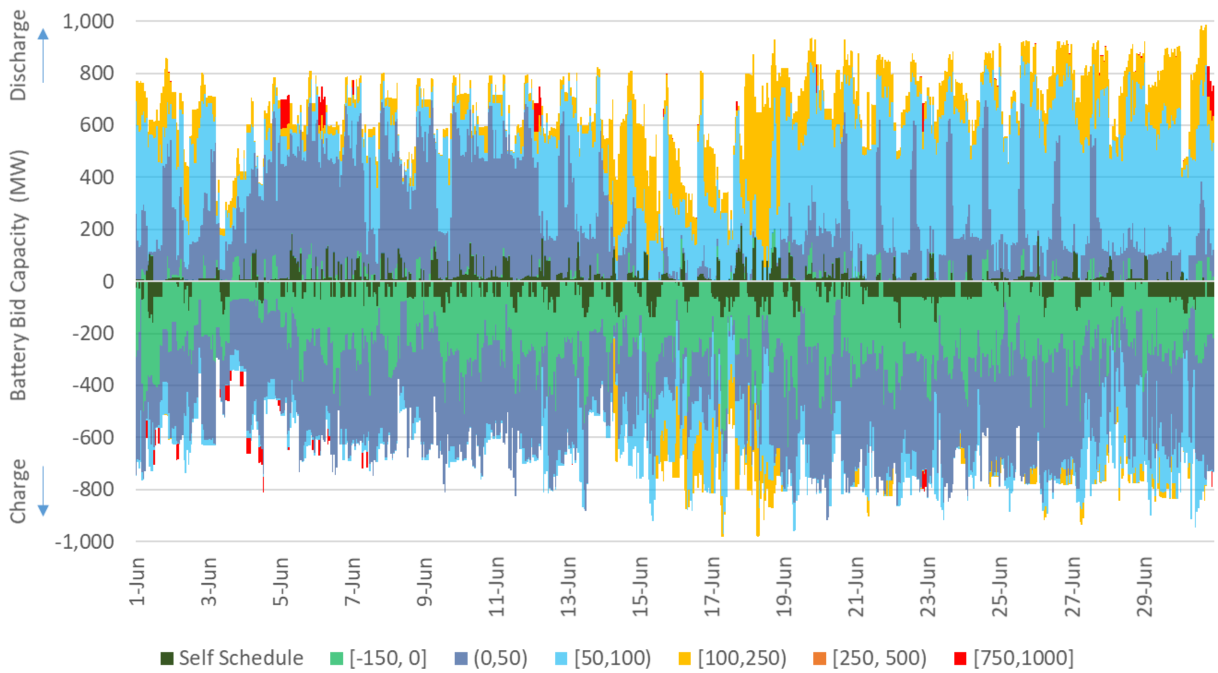
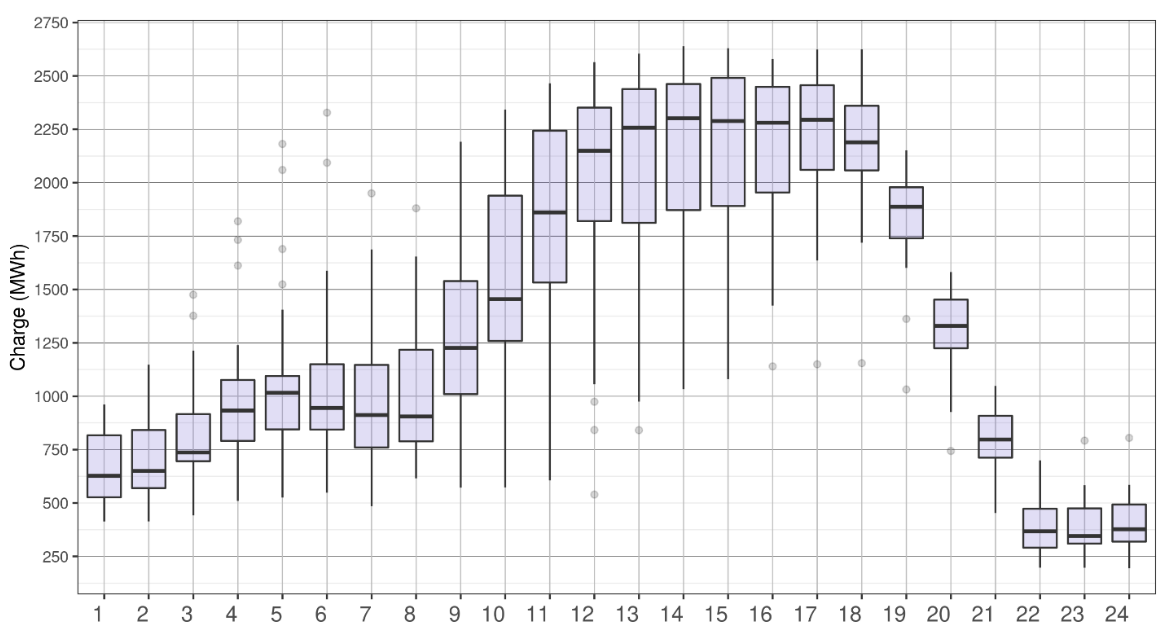


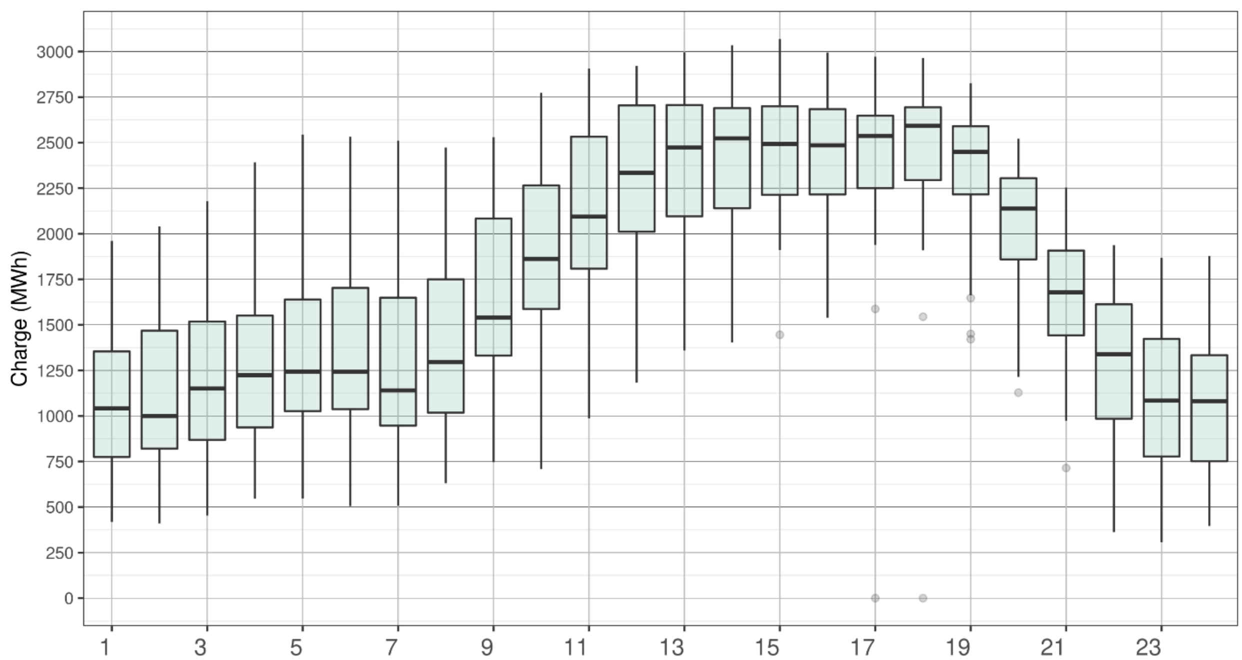
Figure 69 shows the hourly distribution of the storage capacity of resources participating in IFM.

Figure 69 IFM distribution of state of charge for June 2021



The box bar 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 during the morning and early afternoon, between hour ending eight and 17. The system reached maximum stored energy by hour ending 17, followed by a period of steady discharge from hours ending 18 through 24. Figure 70 shows the distribution of state of charge for real-time market.

Figure 70 Real-Time Market distribution of state of charge for June 2021



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. Figure 71 shows the average hourly system marginal energy component (SMEC) of the locational marginal price in IFM for June 2021. The hourly average SMEC is the highest in hours ending 19, 20, 21, and 22 compared to all other hours, and these hours are indicated in red. With the need for more supply as solar production diminishes, it is expected that storage resources would be discharging during these hours. Figure 72 shows the distribution of the IFM energy and Figure 73 shows the distribution of energy awards for storage resources in real-time. In both IFM and the real-time market, it is observed that storage resources were discharging between hour ending 19 through hours ending 22. The chart in Figure 72 and Figure 73 shows the distribution of energy awards in hours ending 19 through hours ending 22 in a different color than the energy awards in other hours, to show that the storage resources are being discharged in intervals with the highest energy prices.

Figure 71: IFM hourly average system marginal energy price for June 2021

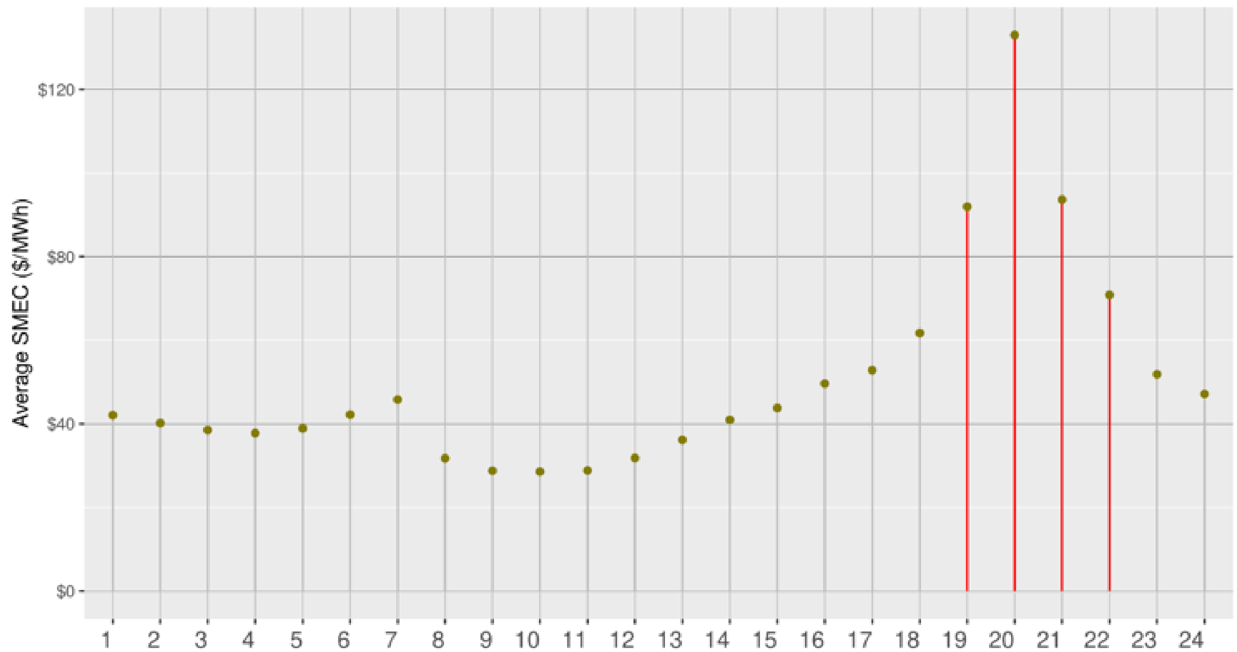


Figure 72 Hourly distribution of IFM energy awards for batteries in June 2021

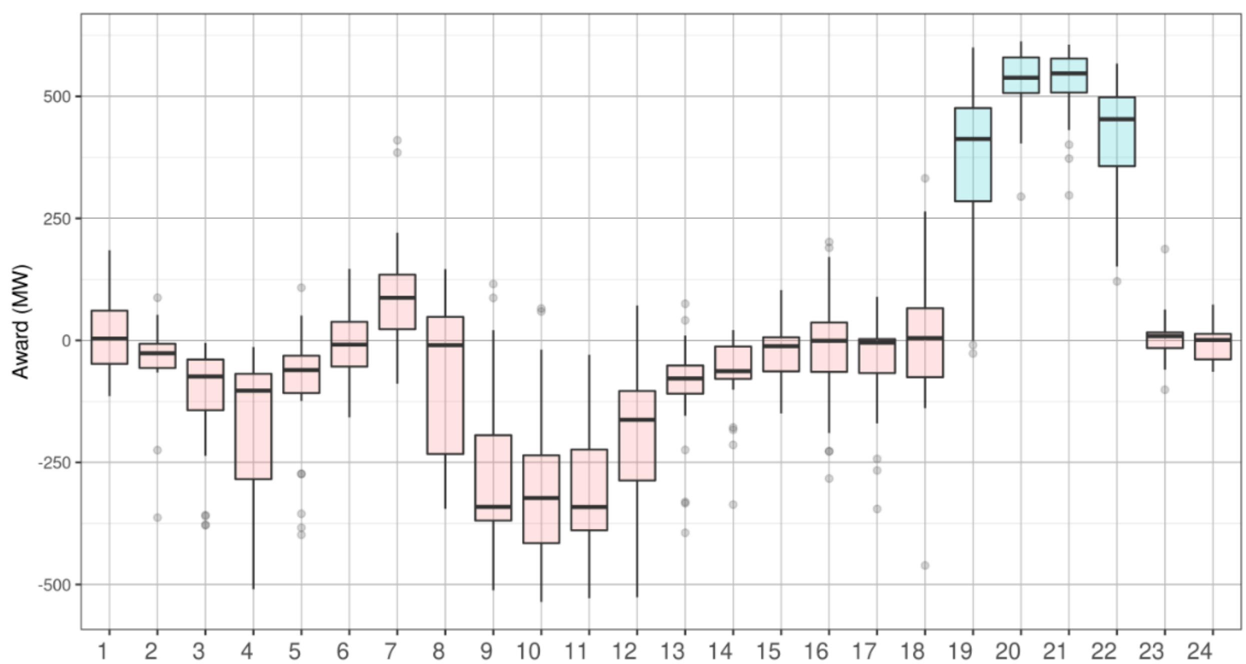


Figure 73 Hourly Distribution of real-time dispatch for batteries in June 2021

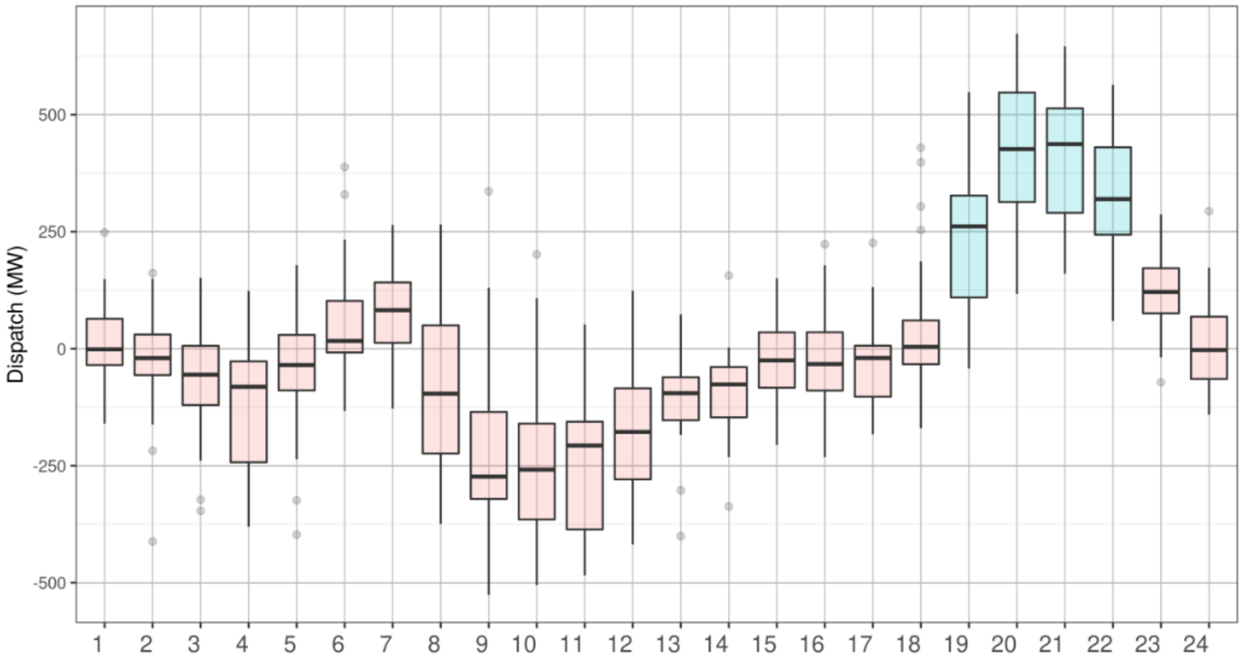


Figure 74 Hourly average real-time dispatch in June 2021

12 Energy Imbalance Market

12.1 EIM transfers

The EIM provides an opportunity for participating balancing authority areas to serve its load while realizing the benefits of increased resource diversity. CAISO estimates quarterly the EIM gross economic benefits.[46] One main benefit of the EIM market 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 other area while concurrently having an export transfer with another area. Figure 75 shows the distribution of five-minute EIM transfer for CAISO area. A negative value represents an export from CAISO area. This trend shows that for the first half of the month CAISO area has a predominant EIM export condition which evolved to a more dominant Import position as it entered into the mid-June heatwave. On June 16 through June 19, CAISO's area basically had a net import transfers for almost the whole time.

Figure 75: Daily distribution of EIM transfers for CAISO area

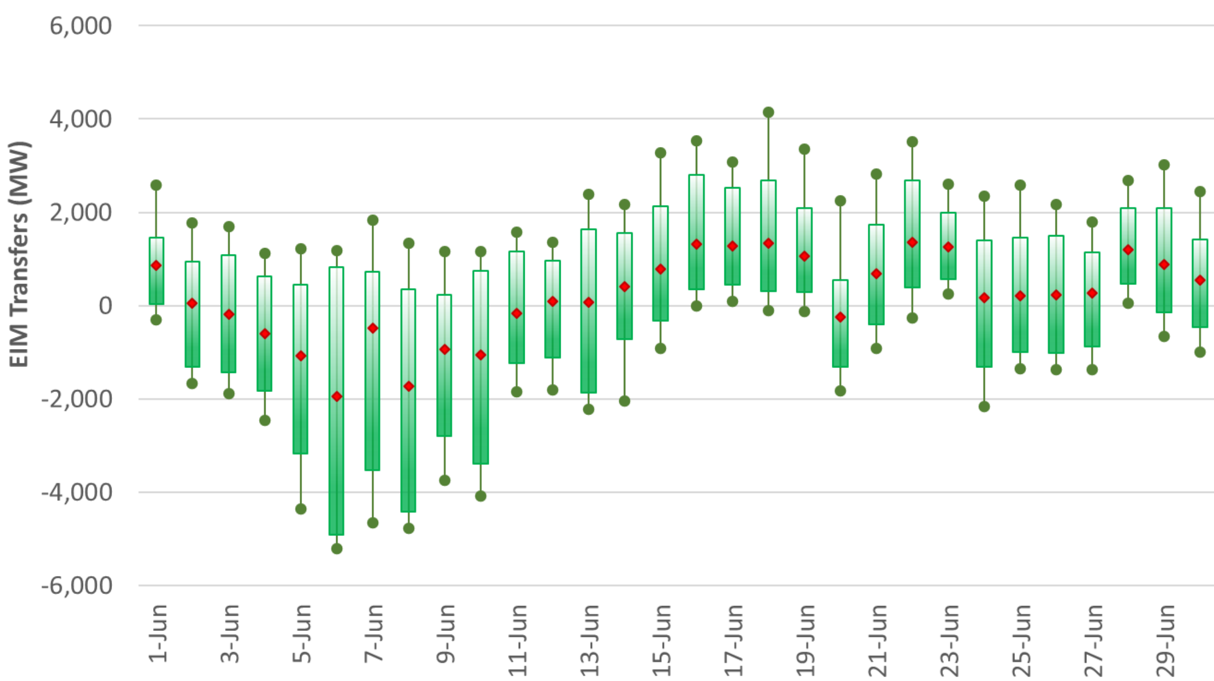


Figure 76 shows the EIM transfers in an hourly distribution, which highlights the typical profile of CAISO transfers which are generally export transfers during periods of solar production and as the time of the evening ramp and the nigh peak approaches, the transfers become a net import to CAISO.

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

Figure 76: Hourly distribution of five-minute EIM transfers for CASIO area

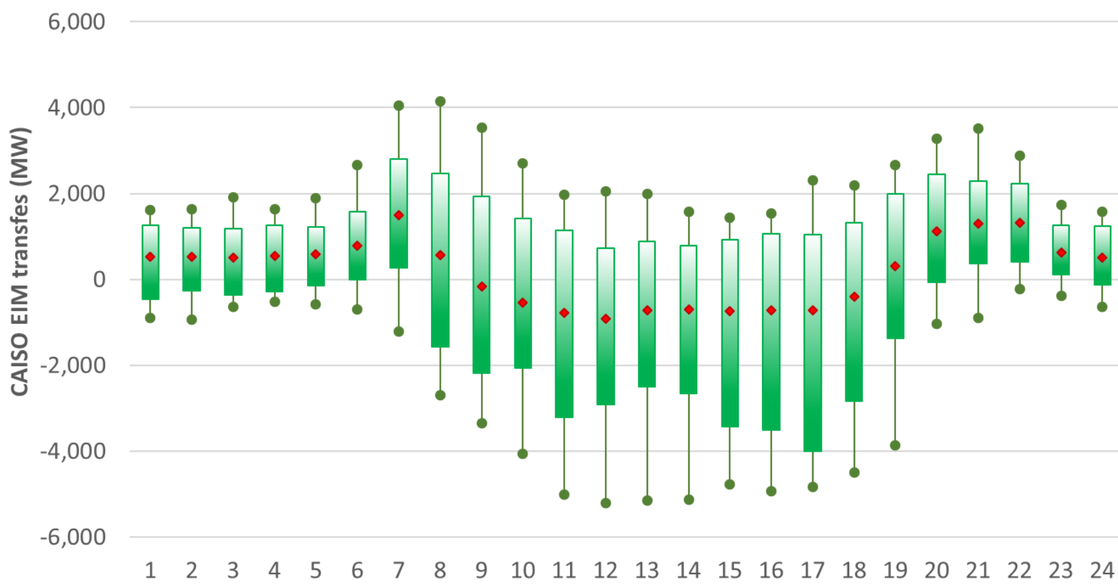
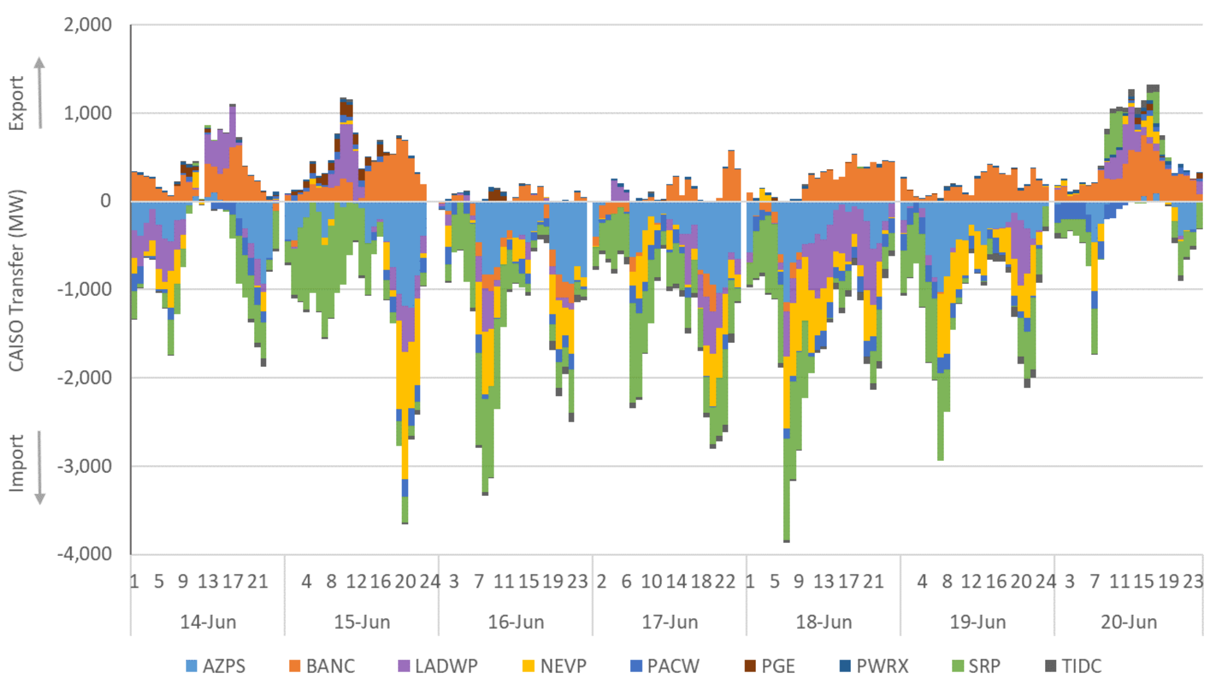


Figure 77 shows a more granular trend of the CAISO EIM transfers with all adjacent balancing areas. To ease the illustration the five-minute transfers are averaged on an hourly basis. Each color bar represent the EIM transfer with another area –either import or export. These are direct transfers between CAISO and its adjacent balancing areas. In some cases, the EIM transfers are wheeling through these adjacent areas and not necessarily being all sourced from the adjacent areas.

Figure 77: Hourly EIM transfers breakdown for CAISO area during the heatwave period



During the week of the heatwave, EIM transfers into CAISO were largely imports. Some of these transfers wheeled through CAISO into the BANC area.

12.2 Capacity test

The EIM system performs a series of resource sufficiency evaluations to ensure each EIM entity is able to meet its demand with its net-supply prior to engaging in transfers with other balancing areas in the EIM in the real-time market. The resource sufficiency evaluation is comprised of four tests: 1) feasibility, 2) balancing, 3) capacity and 4) flexibility. The capacity and flexibility test results affect the ability of a balancing authority area to utilize the benefits of EIM transfers. Thus, this section will mainly focus on these two tests.

The capacity test determines whether an EIM entity balancing authority area (BAA) is participating in the EIM with sufficiency supply to meets its demand forecast and uncertainty in tagging import and export transactions.[47] Starting on June 15, 2021, due to the recent Market Enhancements for 2021 Summer Readiness,[48] the capacity test also requires an additional amount of resource capacity to account for net-load uncertainty. Before June 15, 2021, if an EIM entity failed the bid-range capacity test, it automatically failed the flexible ramp sufficiency test; however, starting on June 15, 2021 the market application performs the capacity test independent of the flexible ramp sufficiency tests. This means that if the EIM entity fails the capacity test, it does not automatically fail the flexible ramp sufficiency test. The CAISO performs the bid capacity test in both upward and downward directions. If an EIM entity fails the upward capacity test, then its import EIM transfers are capped to the optimized EIM transfers from the last 15-minute interval before the test failure. The net effect of failing the capacity test has not changed after the Market Enhancements for the 2021 Summer Readiness; in other words, even though the capacity test and flexible ramp sufficiency test are performed independent of each other, if an EIM entity fails the capacity tests, its EIM Transfers are capped at the last cleared amounts.

Figure 78 below shows the daily frequency of upward capacity test failures for all EIM BAAs for June 2021. There were 16 EIM BAAs participating in the real-time EIM in June, including the CAISO. The PSE BAA had the most intervals with the upward capacity test failure for a total 1.57 percent of intervals for the month, whereas there were six EIM BAAs that passed the upward capacity test in all 15-minute intervals for the month. The PSE BAA failed the upward capacity test most frequently, in 19 percent of intervals on June 2, 2021. The CAISO failed the upward capacity test in 0.14 percent of the 15-minute intervals, which account for four intervals of the month. The CAISO failed the upward capacity test in three intervals on June 17 and a single interval on June 18. Figure 79 displays the hourly frequency of capacity test failures for all EIM BAAs for June 1, 2021 until June 30, 2021. Of the total upward capacity test failures for the month, 41 percent of the upward capacity test failures occurred in hours ending 19, 20 and 21.

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[47] Bautista Alderete, Guillermo and Kalaskar, Rahul. Resource Sufficiency Evaluation Bid Range Capacity Test. Mar 2021- PowerPoint Presentation

[48] Market Enhancements for Summer 2021 Readiness- Final Proposal

Figure 78 Daily frequency of upward capacity test failures

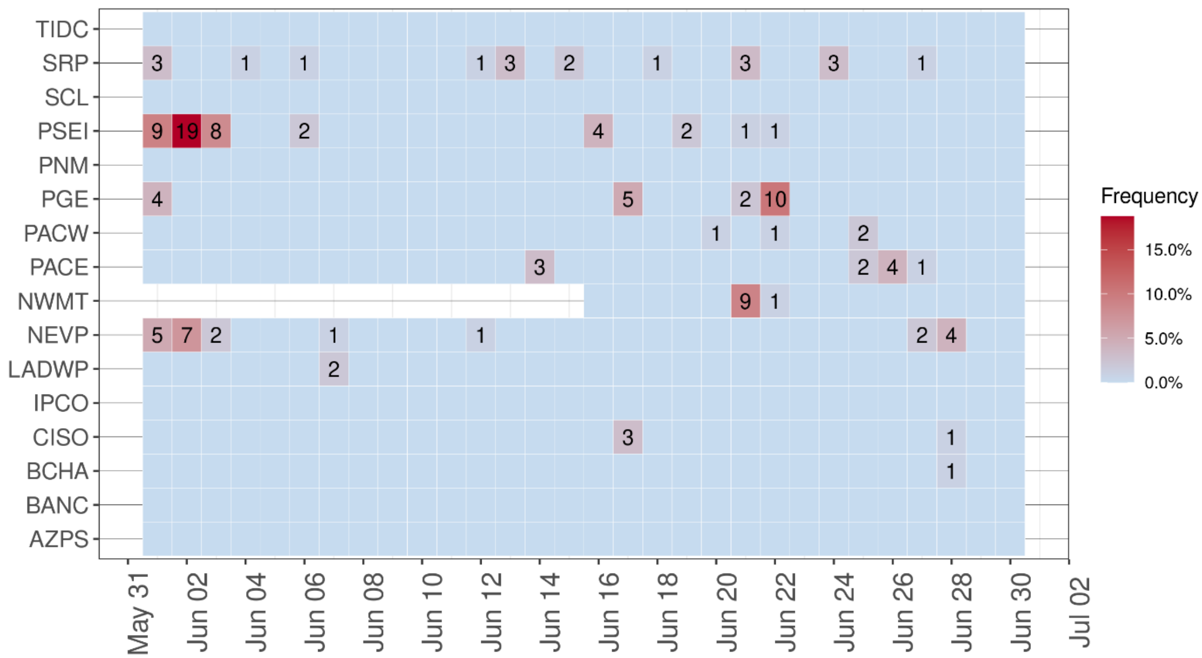


Figure 79 Hourly frequency of upward capacity test failures

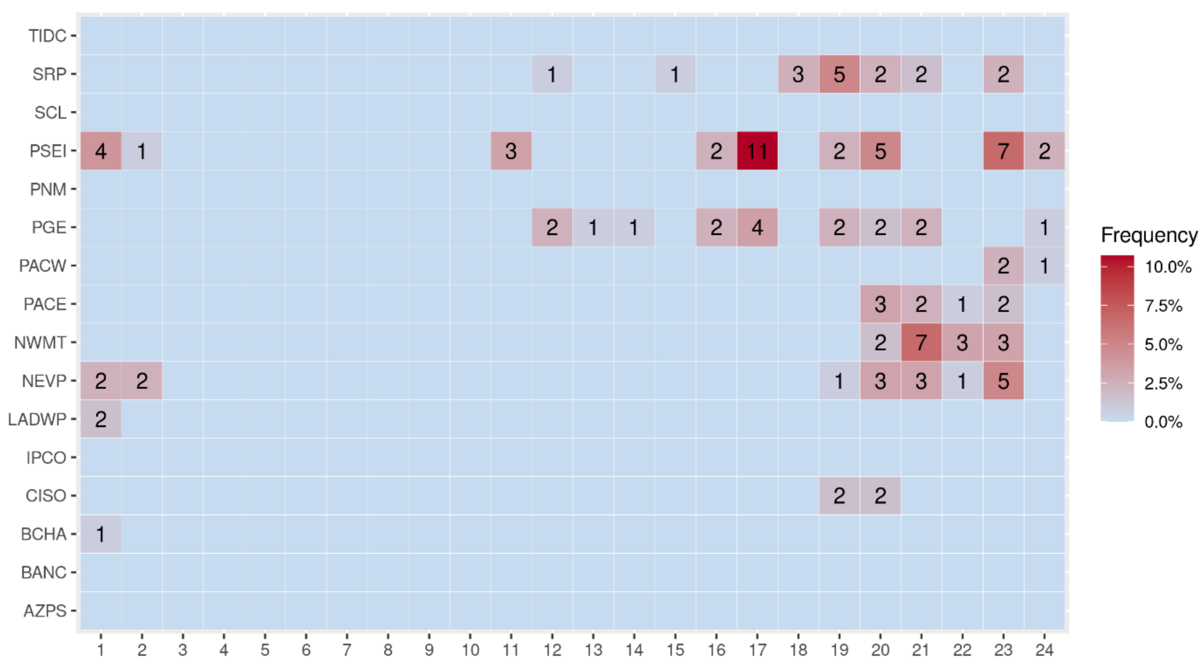
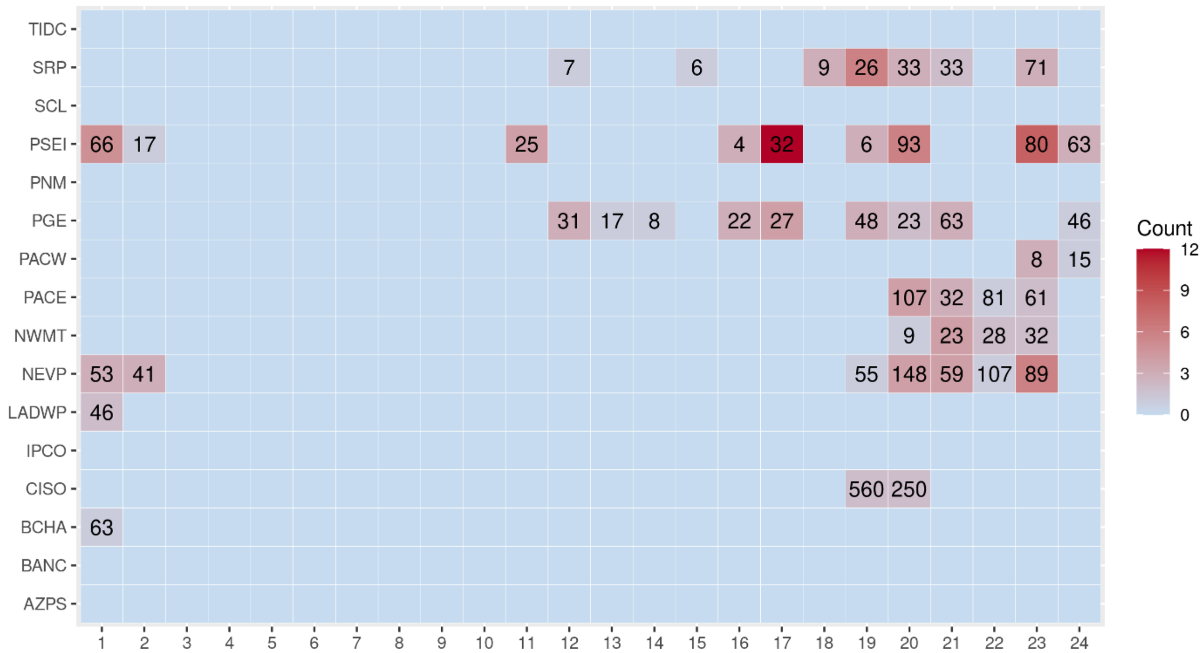


Figure 80 shows the heat map for the upward capacity test failures for June 2021. The color in each cell reflects the level of capacity test failures, where a darker red shows higher MW failures, whereas the number in each cell represents the average MW imbalance of the capacity test failure. This imbalance represents the difference between the BAA's requirement for the upward capacity test and the available supply for the upward capacity test. The PSE BAA had the highest frequency of upward capacity test failures, occurring in hour ending 17 and shown in the darker red color. The CAISO BAA had the maximum average imbalance from the upward capacity test of 560 MW occurring in hour ending 19.

Figure 80 Hourly frequency of upward capacity test and average imbalance



A policy change based on the Market Enhancement for Summer 2021 led the CAISO to enhance the capacity test on June 15, 2021 to include the net load uncertainty in the capacity test requirement. The CAISO performed a counterfactual calculation to determine the upward capacity test failure without net load uncertainty included in the test. Figure 81 shows two heat maps: the top heat map shows the original capacity test results and the bottom heat map shows the capacity test results excluding the net load uncertainty requirement. For June, the PSE BAA had failed the upward capacity test in 1.57 percent of intervals, which reduced to a failure rate of 1.31 percent when the counterfactual calculation was performed. Similarly, for June, the CAISO BAA had failed the upward capacity test in 0.14 percent of intervals, which reduced to 0.034 percent when the counterfactual calculation was performed; the CAISO's total count of upward capacity test failures in June went from four intervals to one interval. The PGE BAA had 21 15-minute intervals of upward capacity test failures in June, which reduced to four intervals when the counterfactual calculation was performed. The capacity test results for the three BAAs are highlighted by similar color box for the top and bottom chart.

Figure 81: Daily Frequency of upward capacity test failures for all EIM BAAs under two scenarios

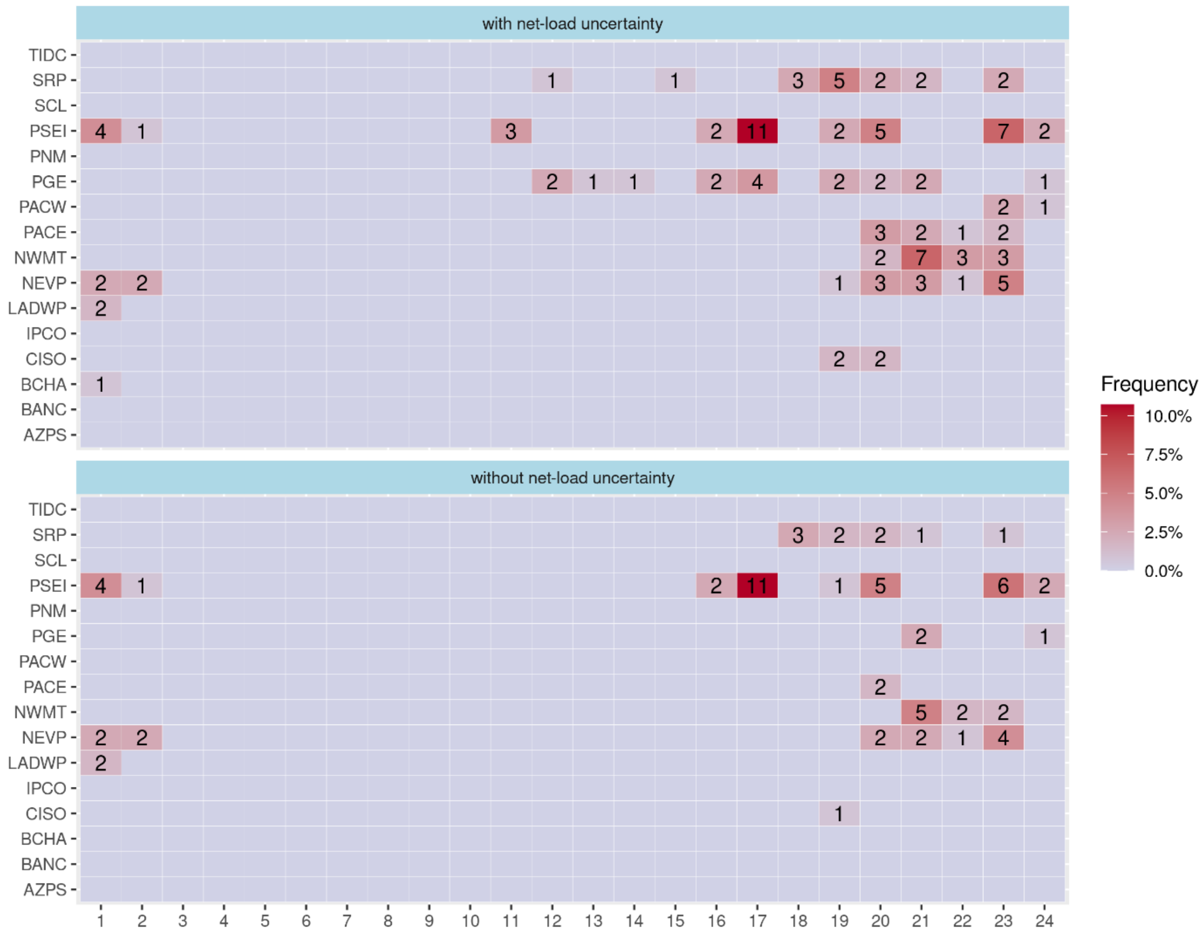


Figure 82 below shows the daily frequency of downward capacity test failures for all EIM BAAs for June 1, 2021 until June 30, 2021. In June there were 16 EIM BAAs participating in the real-time EIM including the CAISO. The BCHA BAA had the maximum number of intervals with the downward capacity test failure for a total 0.28 percent of intervals in the month, whereas, there were eleven EIM BAAs that passed the downward capacity test in all 15-minute intervals for the month. On June 12, 2021, the BCHA BAA failed the downward capacity test in four intervals and on June 23, 2021, the TIDC BAA failed the downward capacity test in four intervals. Both BCHA and TIDC had the maximum frequency of downward capacity test failures on June 12 and June 23 respectively. Figure 83 shows the hourly frequency of downward capacity test failures for all EIM BAAs for June 2021. There were very few hours with downward capacity test failures for the EIM BAAs, and occurrence of downward capacity test failure was spread evenly across all 24 hours.

Figure 82 Daily frequency of downward capacity test failures

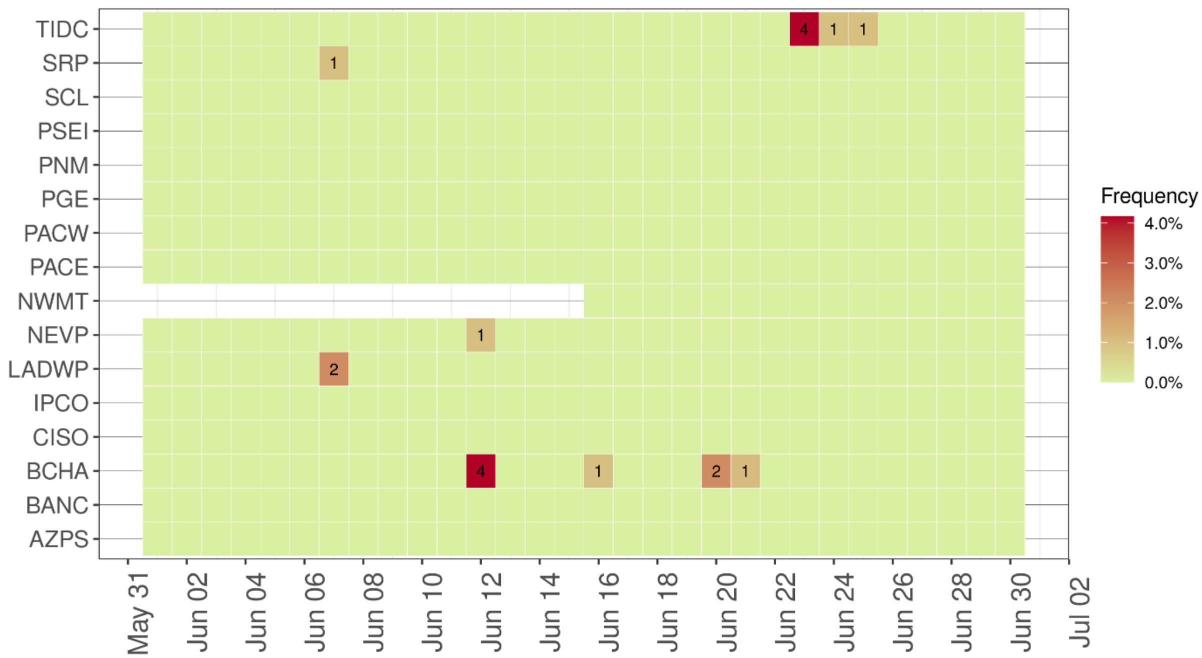
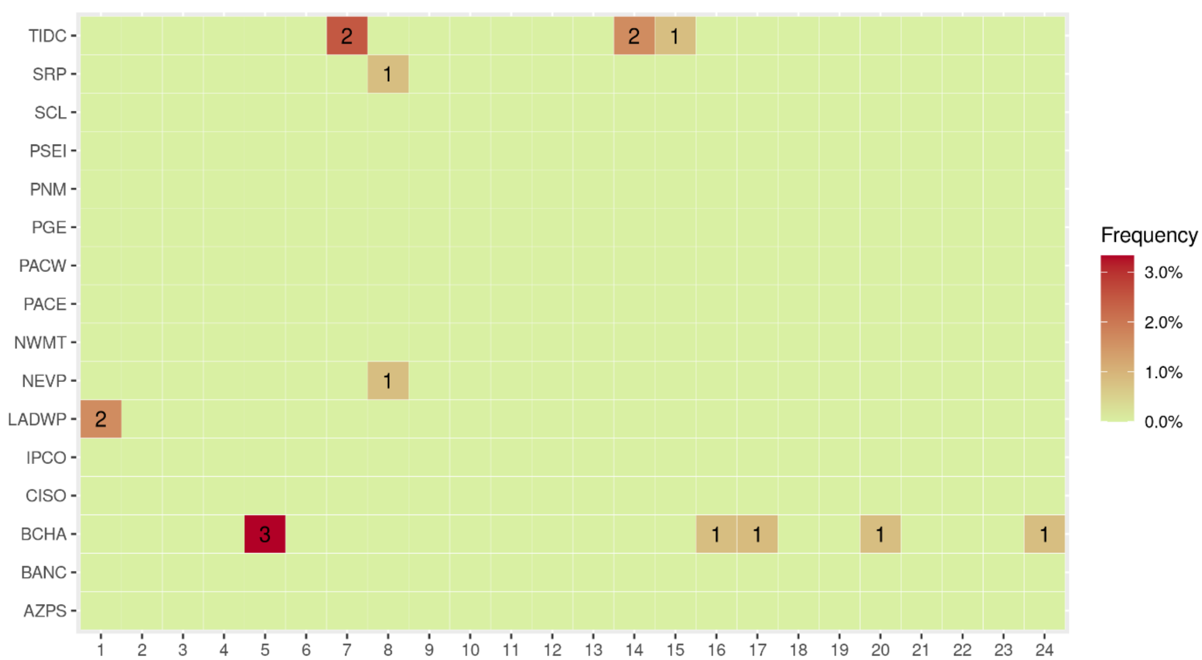


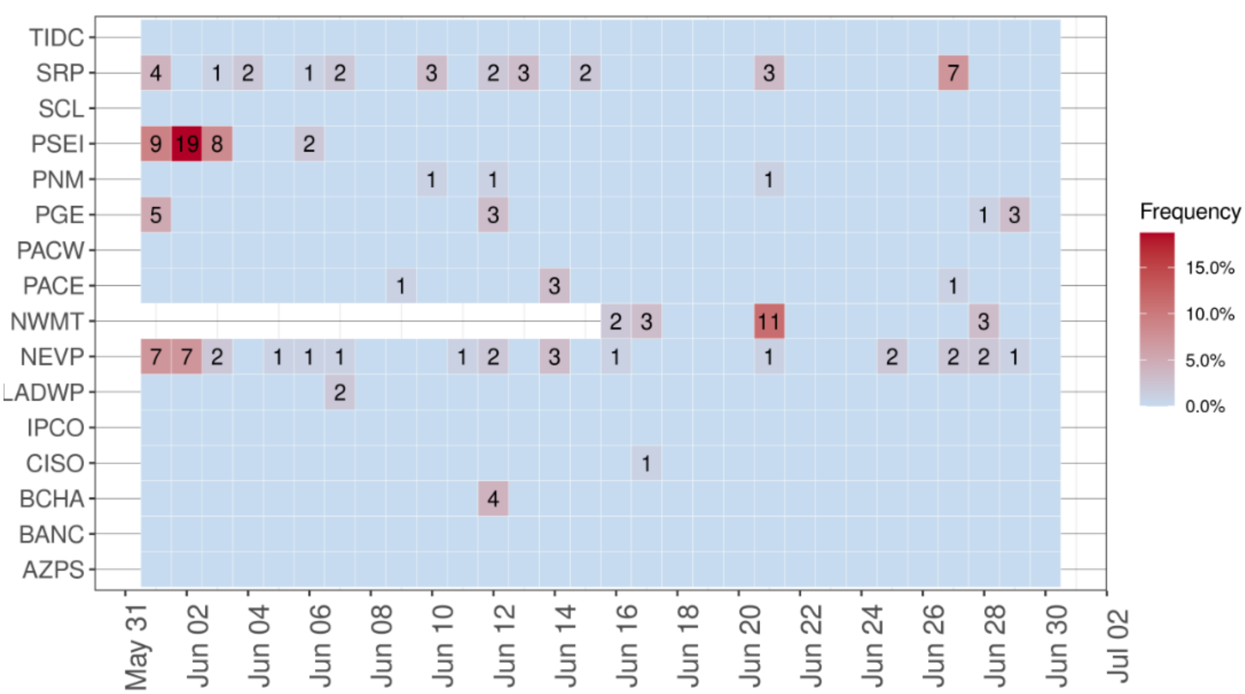
Figure 83 Hourly frequency of downard capacity test failures



12.3 Flexibility test

The flexible ramp sufficiency, or flexibility, test ensures EIM BAA have sufficiency ramping capabilities to meet load forecast change and net load uncertainty (uncertainty in demand forecast, solar generation forecast and wind generation forecast). The system performs the flexibility ramp tests for each 15-minute interval in both upward and downward direction. If an EIM BAA fails the flexibility test, the system caps their EIM transfers level to least restrictive of the either the last 15-minute transfer or the base schedule transfer. After the June 15 implementation of the Market Enhancement for 2021 Summer Readiness, the net effect of failing the capacity and flexibility test are the same. Figure 84 shows the daily frequency of upward flexibility test failures for June 2021[49]. In June, PSE BAA had the highest monthly percentage of upward flexibility ramp test failure at 1.28 percent, whereas there were six EIM BAAs that passed the upward flexibility test in all 15-minute intervals. The CAISO BAA failed the upward flexibility ramp test in 0.034 percent of 15-minute intervals, which is equal to failing the test in a single interval for June 2021. Figure 85 displays the hourly frequency of upward flexibility ramp test failures for June 2021.[50] Out of the total number of failures, about 45 percent of upward flexibility test failures occurred in hours ending 19, 20 and 21, with about 16 percent of the total upward flexibility ramp test failures occurring in hour ending 23.

Figure 84 Daily frequency of upward flexibility test failures



[49] The daily frequency of failures are fractional numbers that are rounded up to whole numbers.
[50] The hourly frequency of failures are fractional numbers that are rounded up to whole numbers.

Figure 85 Hourly frequency of upward flexibility test failures

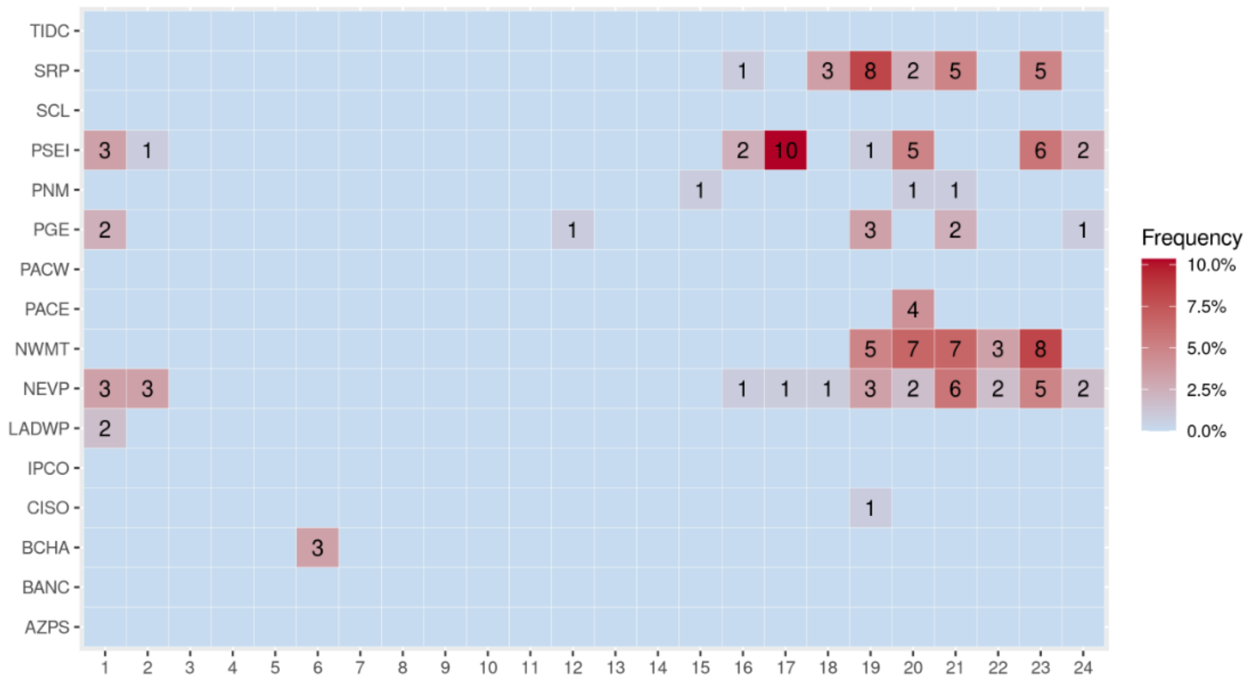


Figure 86 shows the daily frequency of downward flexibility test failures for June 2021[51]. In June, the NEVP BAA had the highest monthly percentage of downward flexibility ramp test failure at 2 percent, whereas there were eight EIM BAAs that passed the downward flexibility test in all 15-minute intervals. The CAISO was among the eight EIM BAAs without any downward flexibility test failures in June. Figure 87 shows the hourly frequency of downward flexibility test failures in June. More than 45 percent of the downward flexibility test failures in June occurred in hours ending 7, 8 and 9.

[51] The daily frequency of failures are fractional numbers that are rounded up to whole numbers.

Figure 86 Daily frequency of downward flexibility test failures

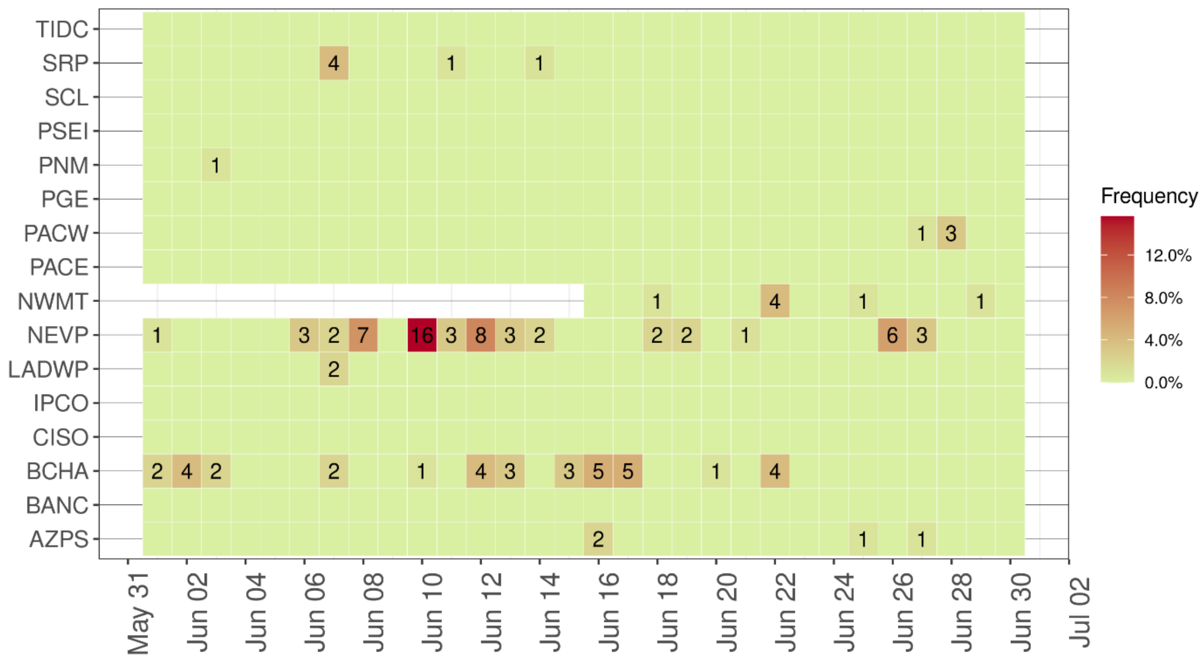
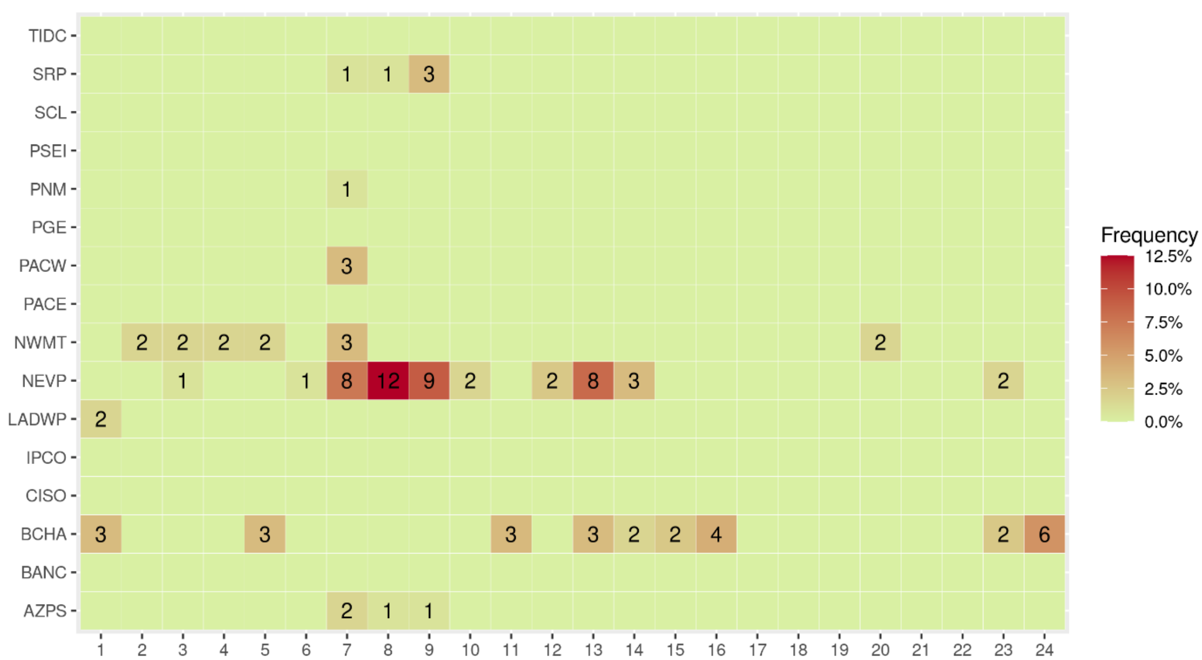


Figure 87 Hourly frequency of downward flexibility test failures



12.4 CAISO's capacity test failures

The CAISO failed the upward capacity test in four 15-minute intervals in June 2021.The first three upward capacity test failures occurred on June 17, 2021 in hour ending 19 interval 4, and hour ending 20 intervals 3 and 4. The fourth upward capacity test failure occurred on June 28, 2021 in hour ending 19 interval 4. Figure 88 below shows the upward capacity test requirement and bid range capacity for the four 15-minute intervals in which the CAISO failed the capacity test. This figure shows two capacity test requirements: the "Requirement" bar shows the capacity test requirement for all four days when the CAISO failed the capacity test, whereas, the "Requirement (no Uncertainty)" bar shows the requirement excluding the effect of net load uncertainty. The "Imbalance" bar shows the difference between the test requirements and the incremental supply. An additional "Imbalance (no uncertainty)" bar shows the difference between the "Requirement (without uncertainty)" and "Incremental Supply" columns. Out of the four 15-minute intervals in June when the CAISO failed the capacity test, the imbalance amount for the three intervals was less than the net load uncertainty such that if net load uncertainty was not included in the capacity test requirement, the CAISO would have passed the capacity test. The CAISO would have failed the upward capacity test only on June 17, 2021 in hour ending 19 interval 4 even if the net load uncertainty were not included in the capacity test requirement.

Figure 88 CAISO's upward capacity test requirement and imbalance for intervals with failure

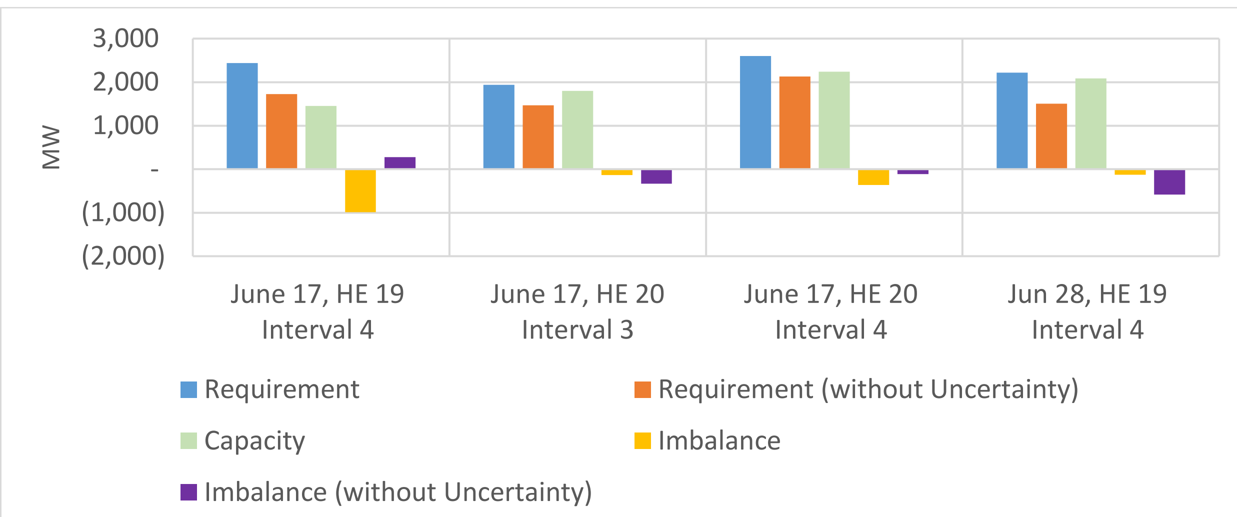
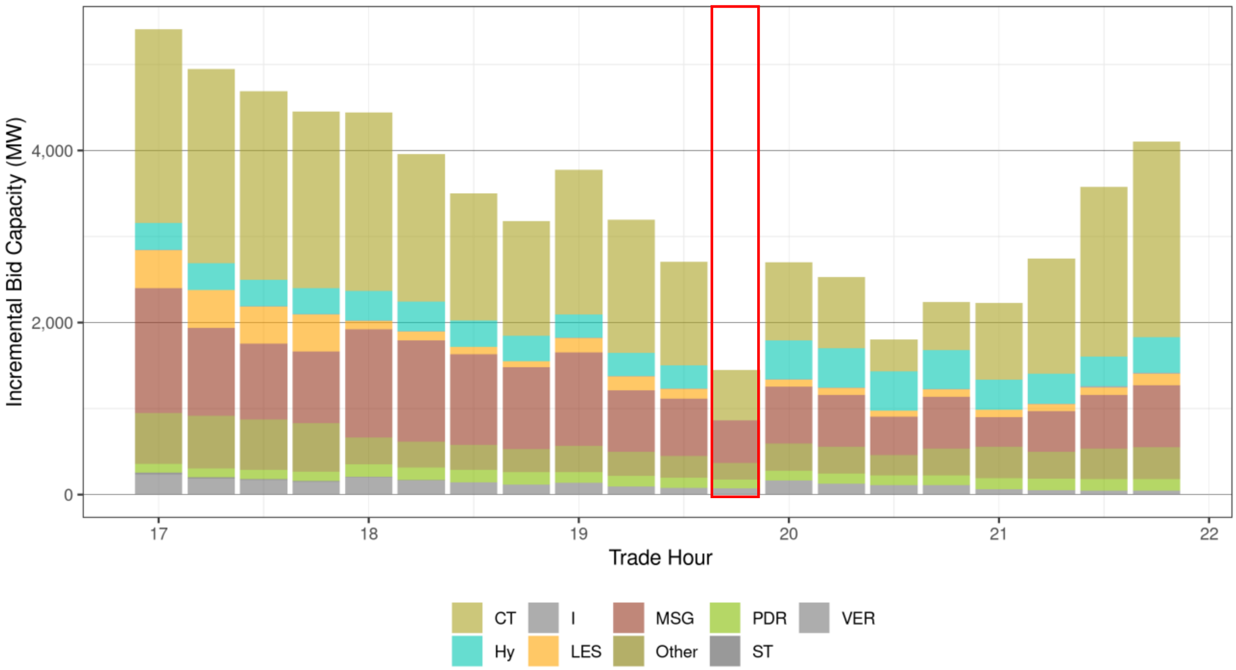


Figure 89 below shows the five inputs used to calculate the upward capacity test requirements between hour ending 17 through 21. These inputs are: Demand Forecast, Net Load Uncertainty, Net Scheduled Interchange uncertainty, Net Scheduled Interchange, and Supply. The capacity test requirement is calculated by summing up Demand forecast, Net Schedule Interchange, Net Load Uncertainty and Net Schedule Interchange Uncertainty, and subtracting the Supply. The Supply for the CAISO BAA represents the 15-minute optimized schedule from the Real-Time pre-dispatch. Hour ending 19 interval 4 is shown as the failed interval and all other intervals are represented as passing the upward capacity test. Figure 90 shows the incremental bid range across fuel type for the CAISO upward capacity test on June 17, 2021 for hours 17 through 21. The failure of the upward capacity test in hour ending 19 interval 4 is highlighted by the box in Figure 90. Hour ending 19 interval 4 has the lowest incremental bid range for the duration.

On June 17, 2021, the ISO failed the bid-range capacity test in hour ending 19 interval 4 with a shortfall of 988 MW. The key measure for the capacity test is to ensure that a balancing area has enough bid range to meet any incremental imbalance. There is an additional requirement for uncertainty: first uncertainty for net load and second uncertainty for deviation of net scheduled inter-change. When the net load uncertainty requirement of 713 MW and uncertainty for the net-scheduled interchange of 141 MW is removed from the capacity test, the shortfall is 134 MW.

Figure 89: June 17 Inputs for the upward capacity test

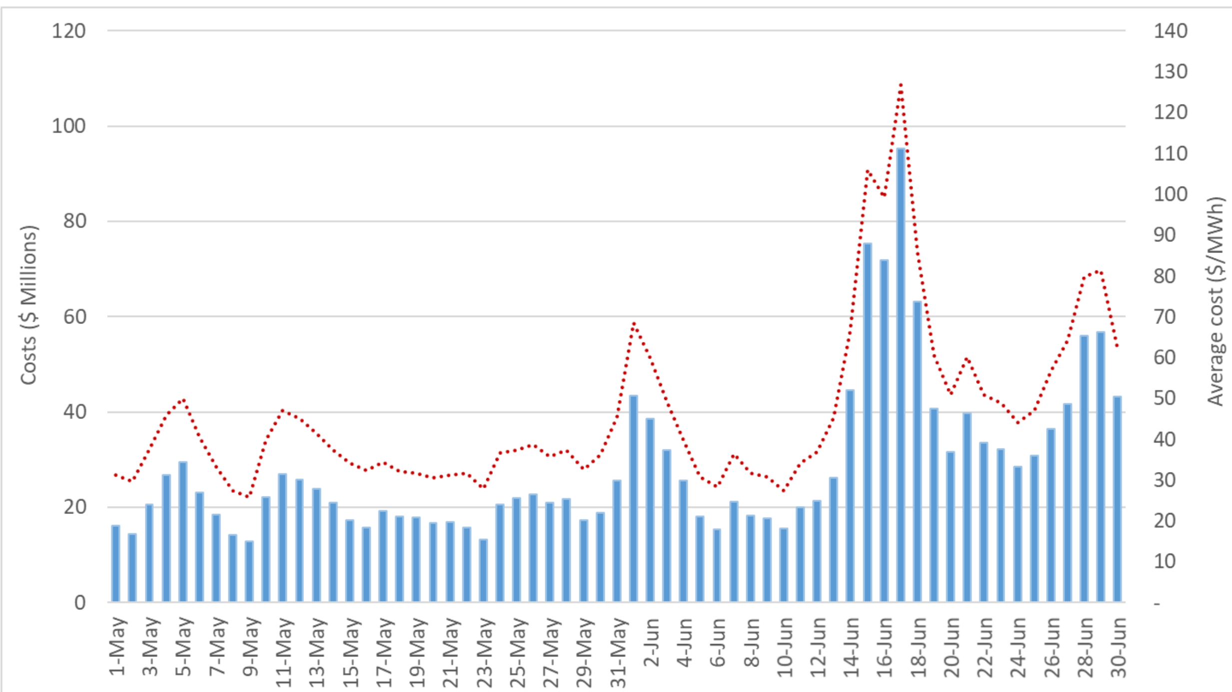
Figure 90 June 17 Incremental bid-range for upward capacity test



13 Market Costs

CAISO's 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 91 shows the daily overall settlements costs for the CAISO balancing area; this does not include EIM settlements. The daily trend for a typical day in the first half of Jun was on average about $25 million. As demand and prices rise, the overall settlements is expected to increase. This trend shows the increase in the overall costs during the mid-June heatwave, reaching a maximum daily value of about $95 million on June 17. 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. For June 17, that average costs rose up to $130/MWh. These costs were relatively higher than in other days in June but are within the realm of costs observed during summer conditions.

Figure 91: CAISO's market costs in June 2021



14 Market Issues

In June 2021, the CAISO identified and fixed, or expects to fix, issues impacting the market functionality, including:

1. The validation of non-RA capacity to support exports, when the supporting resource is a multi-stage generating resource, is limited to the maximum bid of the default configuration in which the RA capacity falls. Any capacity above that level submitted to support a PTK export is not considered. If an export requests any capacity above the Bid max of the default configuration, the priority of the export defaults to an LPT priority. The CAISO implemented this enhancement on July 14, 2021.

2. The Import Bidding and Market Parameters initiative was activated on June 13, 2021. However, due the sequential nature of deploying the new functionality across different systems, the functionality became partially active as the new logic was promoted into each system. This resulted in the bid cap being set at $1000/MWh (from $2000/MWh) during the transition period of June 11 and 12, while the official date for the Import Bidding and Market Parameters functionality to take effect was June 13. CAISO applied price corrections to any infeasibility observed during June 11 and 12.

3. Under certain scenarios of the day-ahead market run, the logic to scale the penalty prices from $1000/MWh to $2000/MWh triggered incorrectly. This resulted in certain intervals in the real-time market having penalty prices of $2000/MWh. The CAISO is evaluating additional logic to prevent these cases from occurring.

4. Under a specific combination of bid conditions, SIBR logic inadvertently accepted resource-specific resource bids above $1000/MWh that were not cost-verified, causing the bid cap to raise to $2000/MWh in specific hours. This issue arose on June 30th and was fixed on July 2. There were no bids above $1000/MWh that passed to the market under this scenario.