



California ISO

Summer Market Performance Report September 2021

October 27, 2021

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Market Analysis and Forecasting

Summer Monthly Performance Report

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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 last in a series of customized monthly reports focusing on the CAISO's market performance and system conditions during the 2021 summer months of June through September, when system conditions are particularly constrained in California and the Western Interconnection. These monthly reports will also provide a performance assessment of specific market enhancements implemented as part of the CAISO's summer readiness market rules changes.¹

September 2021 Highlights

The CAISO implemented all elements of the summer readiness initiative by August 4. The last element of the summer enhancements, which was implemented on August 4, addresses the scheduling priorities for load, exports and wheel-through transactions. With this enhancement, aimed at securing a high scheduling priority equal to ISO load, scheduling coordinators must register in advance the wheel-through transactions that meet certain requirements. To the extent a wheel-through self-schedule does not meet those requirements, it will have a low scheduling priority.

September experienced above-average and much-about-average temperatures across the Western United States including California, but conditions were not as extreme as in previous months. For CAISO, the warmest period was September 4 through 9. This period of above normal temperatures was balanced out by prolonged periods of below-normal temperatures through the rest of the month.

System continued to see reduced levels of hydroelectric production due to drought conditions. Reservoir conditions for California and the West continued to be significantly below normal. Storage in major reservoirs statewide was 58 percent of average for this time of the year and 33 percent of capacity overall.² Hydro production in September 2021 was about the same observed in September 2020 production, but about 54 percent of 2019 production.

The CAISO called for Flex Alerts on September 8 and 9. CAISO estimates that energy conservation triggered by the Flex Alerts resulted in hourly load reductions between 40 and 650 MW during the peak hours.

The CAISO's load peak for the year happened on September 8 at about 43,947 MW. This load level was below the September 2021 monthly showings forecast of 44,175 MW used in resource adequacy (RA) programs. RA capacity made available in the day-ahead market was sufficient to cover the net load peak.

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

² <https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM>

Monthly RA capacity was at 47,838 MW and was above the level of actual load needs, which is demand plus operating reserves. RA capacity from hydro resources for September 2021 was 338 MW less than it was in September 2020, and static imports --not including dynamics and pseudo ties-- were 2,425 MW lower than in September 2020. RA capacity from storage resources increased by 1,027MW. Above RA capacity available in the market was consistently over 4,000 MW through the month, and consisted of both internal supply and imports.

CAISO's prices showed moderated convergence across markets during September. Prices increased during the period of September 7 through 9 following higher demand levels; price convergence improved through the second half of September. With no emergencies triggered in September, summer enhancements for improving real-time pricing did not trigger.

The residual unit commitment (RUC) process was able to meet the adjusted load forecast in all hours of the month. There were low-priority and economic exports reduced in the RUC process on September 8 and 9. There were also export curtailments in the real-time market on September 7 and 8.

Hourly average of net imports was about 7,500 MW for peak hours (17-21) in September, an increase from 6,020 MW in August. Net imports reached their minimum levels on September 7 through 9 when CAISO experienced the largest volume of exports from the system for the month. The larger volume of exports was generally observed prior to the peak hours.

Western EIM transfers into the CAISO area were consistently over 1,000 MW in September and higher than those of August. Transfers into CAISO's were from multiple areas, including adjacent areas and also from farther reaching areas. Overall, EIM transfers reflect the economic and operational benefits that EIM offers to participating entities by maximizing supply diversity.

About 99 percent of RA imports bid at \$0/MWh or lower prices in both the day-ahead market and real-time markets. This is assessed for static RA imports related to CPUC-jurisdictional load serving entities and for hours ending 17 through 21 on weekdays.

Self-scheduled wheel-through transactions in September were at minimum level of the summer months. A maximum of 96 MW self-schedule wheels in both the day-ahead and real-time markets were scheduled on September 5 through 9 between Malin and ELDORADO locations. These all were low-priority wheel transactions. There were 687 MW of wheels registered with high priority in September, down from 1,021 MW registered in August. Only 96 MW of these registered wheels were intended to be used in September through CAISO's markets.

Reliability demand response resources were not activated in the real-time market in the month of August, while proxy demand response was dispatched up to 251 MW.

Due to storage resources outages, the capacity available from storages resources in the markets and systems reduced in September. The maximum discharge for storage resources occurred between hour ending 19 and 21, while charging mostly occurred in midday hours when solar supply was plentiful. The majority of the state of charge was in the range of 4,000 MWh down from about 5,000 MWh in August.

The addition of uncertainty to the energy imbalance market (EIM) capacity test resulted in an increase of about 2.7 times of capacity test failures for the entire footprint, with the CAISO area experiencing five upward capacity failures in September. The total number of capacity test failures in September for all EIM

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entities increased from 71 when uncertainty was not included in the test to 193 when it was included. The majority of the test failures in September occurred in the peak hours 17 through 21. This enhancement was implemented on June 15, 2021.

On average, the CAISO's daily market costs were \$50.2 million in September, an increase from \$47.5 million in August. The highest daily cost accrued during summer was on September 9 at about \$157 million. These cost levels are consistent with summer conditions when increasing loads 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
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
LPT	Low priority export. This is a scheduling priority assigned to price-taker exports that do not have a non-RA supporting resource
LSE	Load Serving Entity
MSG	Multi-Stage Generator
MW	Megawatt
MWh	Megawatt-hour
NEVP	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

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PST	Pacific Standard Time
PTO	Participating Transmission Owner
PTK	High priority assigned to a schedule. Exports are assigned this priority when they can have a non-RA resource supporting its export.
QC	Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RTM	Real-Time Market
RUC	Residual Unit Commitment
SCL	Seattle City Light
SMEC	System Marginal Energy Component
SOC	State of Charge
SRP	Salt River Project
TIDC	Turlock Irrigation District
TOR	Transmission Ownership Right

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.³

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

1. The extreme heat wave experienced in mid-August 2020 was a 1-in-30 year weather event in California and resulted in higher loads that exceeded resource adequacy and planning targets. This weather event extended across the Western United States, impacting loads in other balancing areas and straining supply across the West.
2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand for both the gross and net load (gross peak of demand less solar and wind production) peaks.
3. Some existing practices in the day-ahead energy market at that time exacerbated the supply challenges under highly stressed conditions.

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

³ California Independent System Operator, California Public Utilities Commission, and California Energy Commission. Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave. January 13, 2021. <http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>

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Following 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 initiative⁴.

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 were implemented at different times during summer 2021.

⁴ 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 into two main efforts. The second phase of the initiative largely focuses on Load, Export, and Wheeling Priorities. The first phase includes all other items of the summer readiness initiative.

The first phase of the summer readiness initiative was approved by FERC on May 25, 2021⁵ and includes the following components, which have been implemented at different times earlier this year:

1. EIM resource capacity sufficiency test. This enhancement adds the uncertainty component utilized in the flexible ramp sufficiency test to the capacity test and applies 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 month of September.

2. Import market incentives during tight system conditions. This enhancement provides improved incentives for import supplies to be available during tight system conditions because the prior settlement rules may have paid imports less than they bid, which could exacerbate conditions when supplies are tight. During very tight system conditions (*i.e.*, when CAISO has issued an alert by 3 PM PST, or a warning or emergency notice), the CAISO will provide bid cost make-whole payments for real-time hourly block economic imports.

Implementation date: June 15, 2021.

This feature was triggered on July 9 and 10 between 5pm and 9pm. This calculation is based on settlements data, which were 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 26, 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

⁵ FERC order accepting Tariff revisions for the Summer readiness initiative can be found at <http://www.cao.com/Documents/May25-2021-OrderAcceptingSummerReadinessFiling-ER21-1536.pdf>

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

Implementation date: June 15, 2021.

This feature was active on July 9 while the CAISO had an emergency and spinning and non-spinning reserves were indeed released at the price caps.

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 Real Time Market (RTM) to meet the Day Ahead Market (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. New OASIS display to report on the critical hours used to calculate the minimum state-of-charge and the hours with RUC shortfalls. There is also a new resource-specific report via the CAISO Market Results Interface (CMRI).

Implementation date: June 30, 2021.

In the month of July, the MSOC was utilized on July 9, 28 and 29 since these were days with RUC infeasibilities.

6. Reliability demand response (RDRR) dispatch and real-time price impacts. This enhancement expands 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.

Implementation date: August 4, 2021.

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The second part of the initiative (Load, Export, and Wheeling Priorities) was approved by FERC on June 25, 2021⁶ and was implemented on August 4, 2021. This enhancement involves a revised set of scheduling priorities for exports, wheel transactions and the CAISO load, including a newly specified priority for wheeling through transactions.

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

1. Interconnection process enhancements. This enhances the independent study interconnection process to provide the ISO additional capacity for summer 2021, removes the 100MW/125% cap on behind the meter expansion requests and enables 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 the 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, the 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, has been 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. This enhancement was activated on August 17, 2021.

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

⁶ 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 and used in September

Summer enhancement	Date Implemented	Trigger	Dates 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	Not triggered
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	Not triggered
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	4-Aug	Activation of RDRR	Not triggered
Load, export and wheeling priorities	4-Aug	Permanent feature ⁷	All the time
Interconnection process enhancements	25-May	Permanent feature	Not used yet
CAISO's public communication protocols	29-May	System Event driven	Not triggered
Today's Outlook displays	Aug 18	Permanent feature	All the time

⁷ The wheeling through priorities the CAISO placed into effect are interim only and will sunset after May 31, 2022.

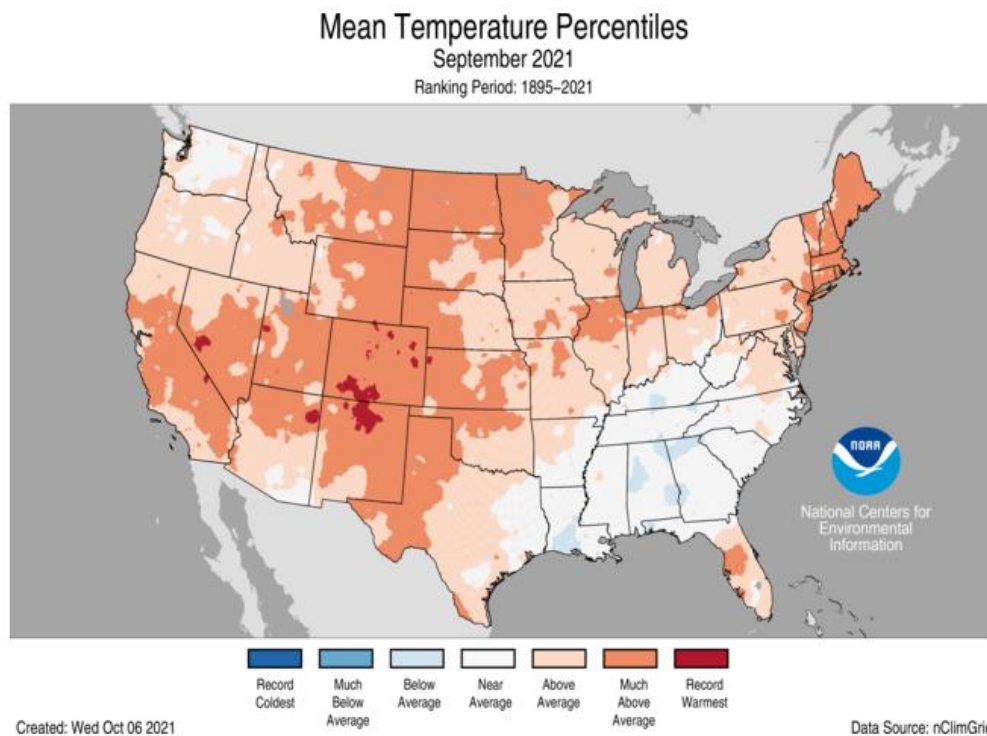
7 Weather and Demand Conditions

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 September. This is shown in Figure 1 and Figure 2.

Figure 1: Mean temperature percentiles for September 2021⁸

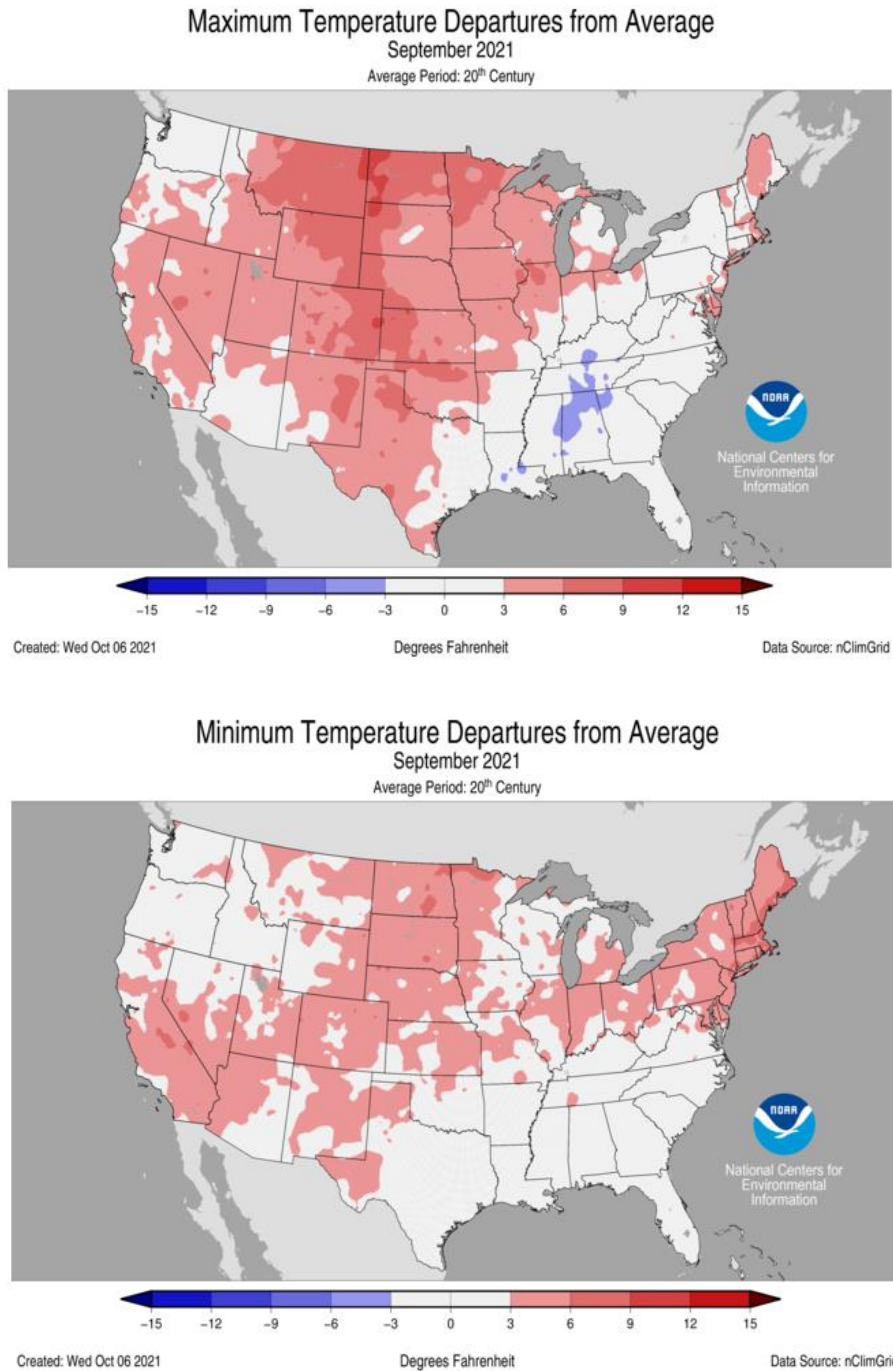


There were more widespread maximum temperature departures from normal versus minimum, as shown in Figure 2. Regionally, there were more widespread above normal temperatures across California and the desert southwest, while the Pacific Northwest remained closer to normal.

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

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Figure 2: Maximum and minimum CONUS temperature departures from normal⁹



Looking at the Desert Southwest EIMs more closely in Figure 3, the first half of the month experienced the warmest conditions. Phoenix had high temperatures 100+ for the 15 consecutive days during the first 17 days of the month while Las Vegas had 12 consecutive 100+ days during the same period.

⁹ <https://www.ncdc.noaa.gov/temp-and-precip/us-maps/>

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Temperatures during the second half of the month dropped significantly, cooling over 20 degrees compared to the start. Throughout CAISO, above normal temperatures were also observed during the second week of the month, but not as extreme as Nevada and Arizona. The CAISO high temperature departures from normal are shown in Figure 4. These periods of above normal temperatures were balanced out by prolonged periods of below normal temperatures, with the month ending overall with an average high temperature of 2 degrees below normal. For CAISO, the warmest period was September was the 4 – 9, where temperatures across the Valley and deserts were 100+.

Figure 3: Desert Southwest EIM Entity high temperature departure from normal

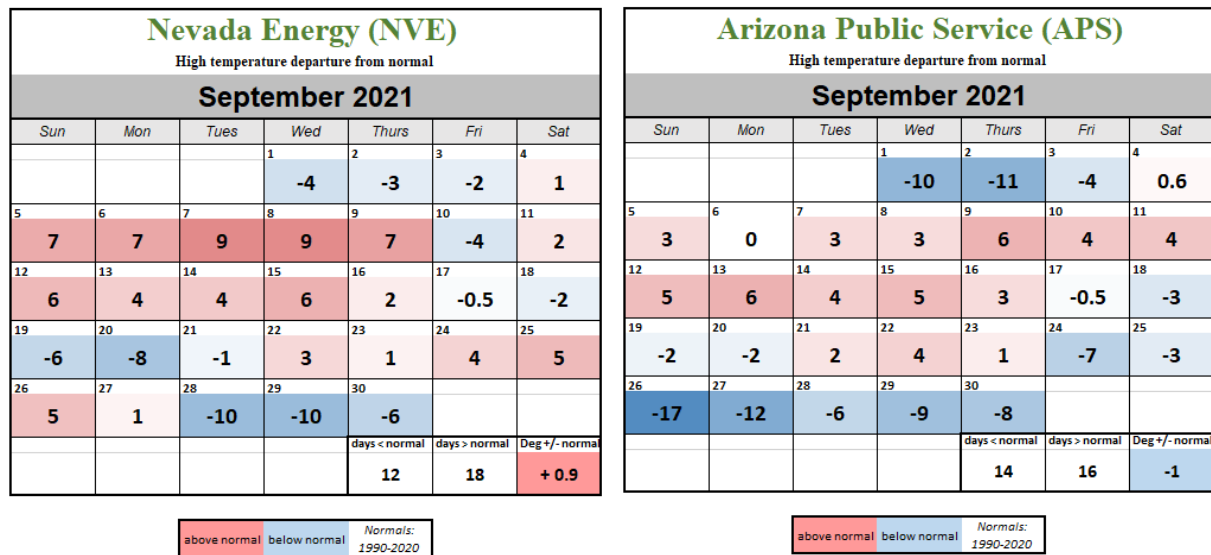


Figure 4: CAISO high temperature departure from normal

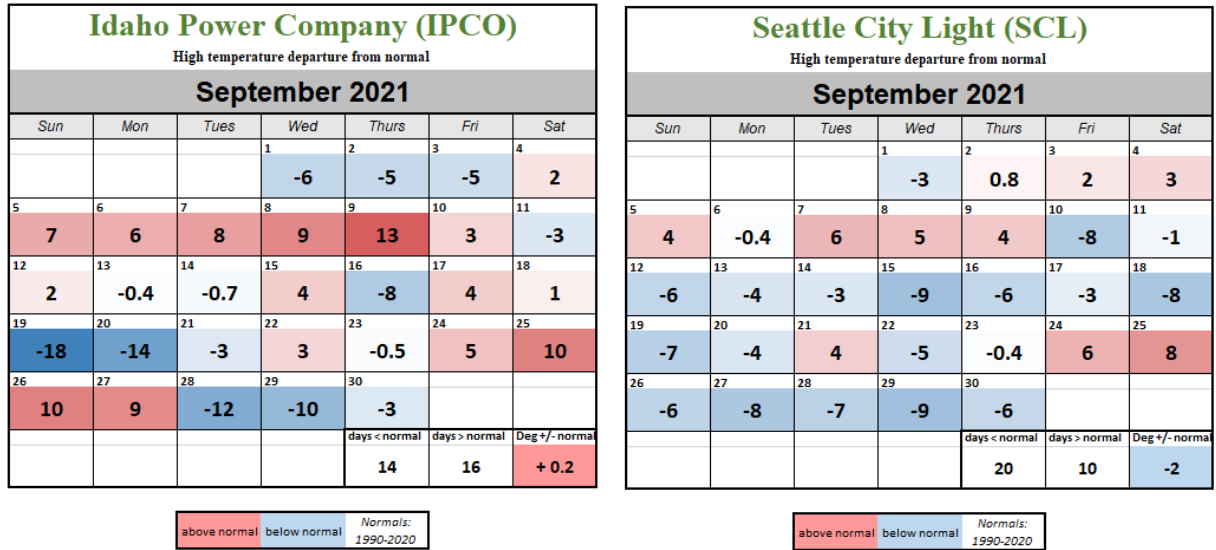


The Pacific Northwest experienced monthly average temperatures near normal. Much like the Desert Southwest and CAISO, the period of warmest temperatures for the month came during the second

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week. High temperature departures from normal for Idaho Power Company and Seattle City Light are shown in Figure 5 below.

Figure 5: High temperature departure from normal for Northwestern EIM entities



Looking at the entire Western United States high temperature records in Figure 6, there were 1,410 maximum temperature records which were tied or broken during the month of September. This is an increase compared to the 960 records that were tied or broken in August, but a reduction from the 5,652 in June and 1,977 in July.

Figure 6: Maximum temperature records broken or tied in September 2021¹⁰



¹⁰ <https://www.ncdc.noaa.gov/cdo-web/datatools/records>

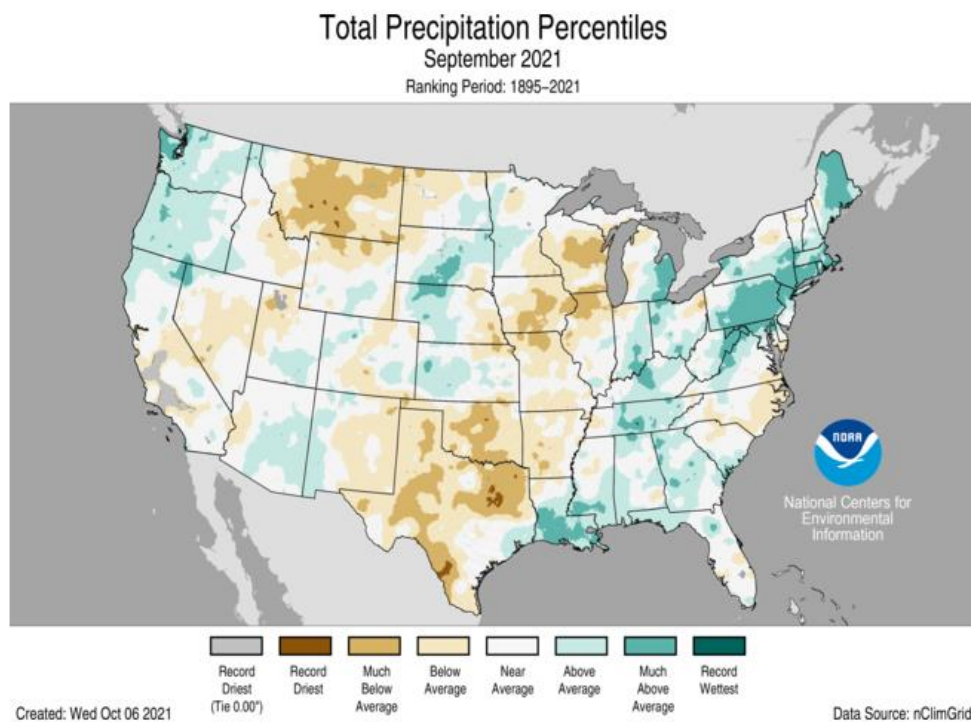
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Excessive heat, depending on the day of week, has the potential to bring load to the electrical system that may higher than those anticipated during long-term planning and forecasts about the supply expected to be necessary to meet demand. In addition,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

7.2 Hydro conditions

The Western United States, including California, experienced one of the driest water years on record. The October 2020 – September 2021 water year was the 3rd driest on record for California and 4th driest for Nevada.¹¹ During the month of September, precipitation was above average throughout the Pacific Northwest and parts of the desert Southwest. This is shown in Figure 7, which also shows that the record driest precipitation, or lack thereof, was observed for portions of western California. Near below average throughout much of the rest of the west.

Figure 7: The United States total precipitation percentiles for September 2021¹²



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 exceptionally dry. The extent of the drought coverage is shown in Figure 8 below.

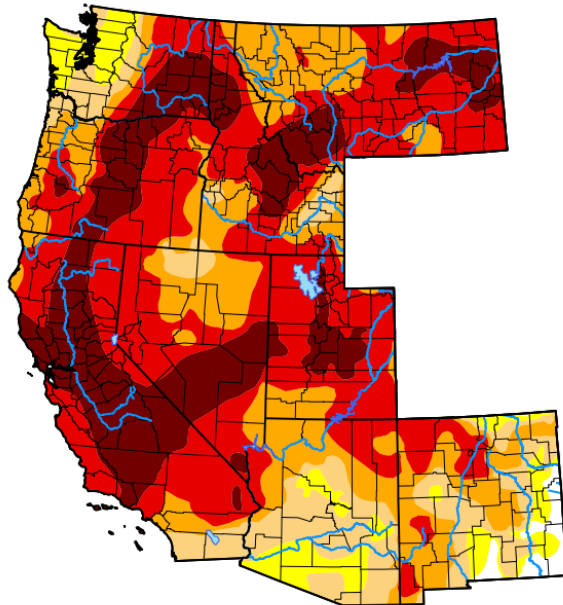
¹¹ [https://www.ncdc.noaa.gov/temp-and-precip/us-maps/12/202109?products\[\]=statewidepcpnrank](https://www.ncdc.noaa.gov/temp-and-precip/us-maps/12/202109?products[]=statewidepcpnrank)

¹² <https://www.ncdc.noaa.gov/temp-and-precip/us-maps/>

Figure 8: The Western United States drought monitor as of October 5, 2021 ¹³

U.S. Drought Monitor West

October 5, 2021
(Released Thursday, Oct. 7, 2021)
Valid 8 a.m. EDT



Intensity:

- None
- D0 Abnormally Dry
- D1 Moderate Drought
- D2 Severe Drought
- D3 Extreme Drought
- D4 Exceptional Drought

The Drought Monitor focuses on broad-scale conditions. Local conditions may vary. For more information on the Drought Monitor, go to <https://droughtmonitor.unl.edu/About.aspx>

Author:

Brian Fuchs
National Drought Mitigation Center



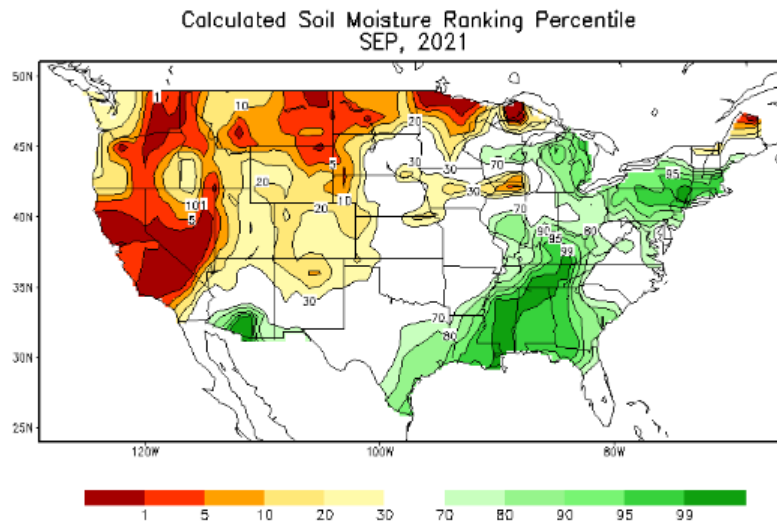
droughtmonitor.unl.edu

Despite some above average rainfall for much of Washington, Oregon and parts of far northern California, soil moisture for nearly all of the western US is among the lowest ever observed for September. Figure 9 below, shows that nearly all of California is currently in the bottom 1% of soil moisture. This has led to increased potential for extreme fire risk across the state during the summer months and heading into Autumn. In addition, once precipitation does begin to fall, a very dry ground can lead to less of this rain water being absorbed by the soil and higher amount of runoff and/or risk for flash flooding.

¹³ <https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?West>

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Figure 9: The United States soil moisture anomaly for September 2021 (top) and the soil moisture as of September 2021 rank (bottom)¹⁴



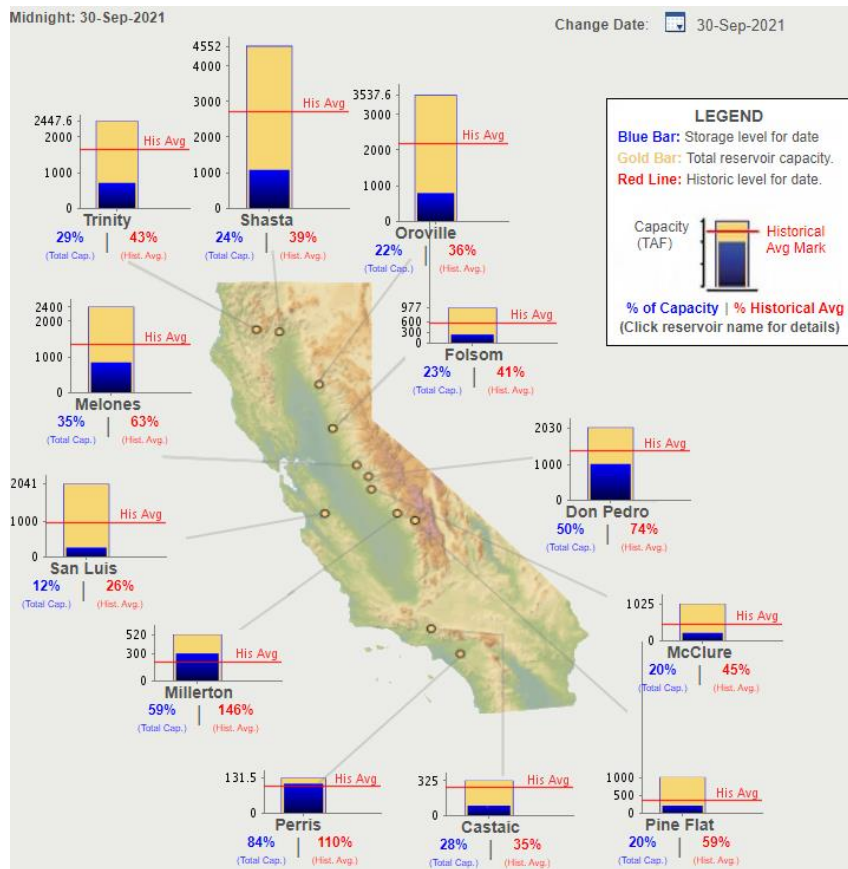
Based on all the factors discussed above related to temperatures, precipitation, drought conditions, and soil moisture levels, reservoir conditions for California and the west are significantly below normal, as shown in Figure 9. The statewide storage in major reservoirs is currently 58 percent of average and at 33 percent of capacity¹⁵. This is compared to 93 percent of average and 53 percent of capacity at the end of September 2021.

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

¹⁵ <https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM>

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Figure 10: California's reservoir conditions as of October 12, 2021¹⁶

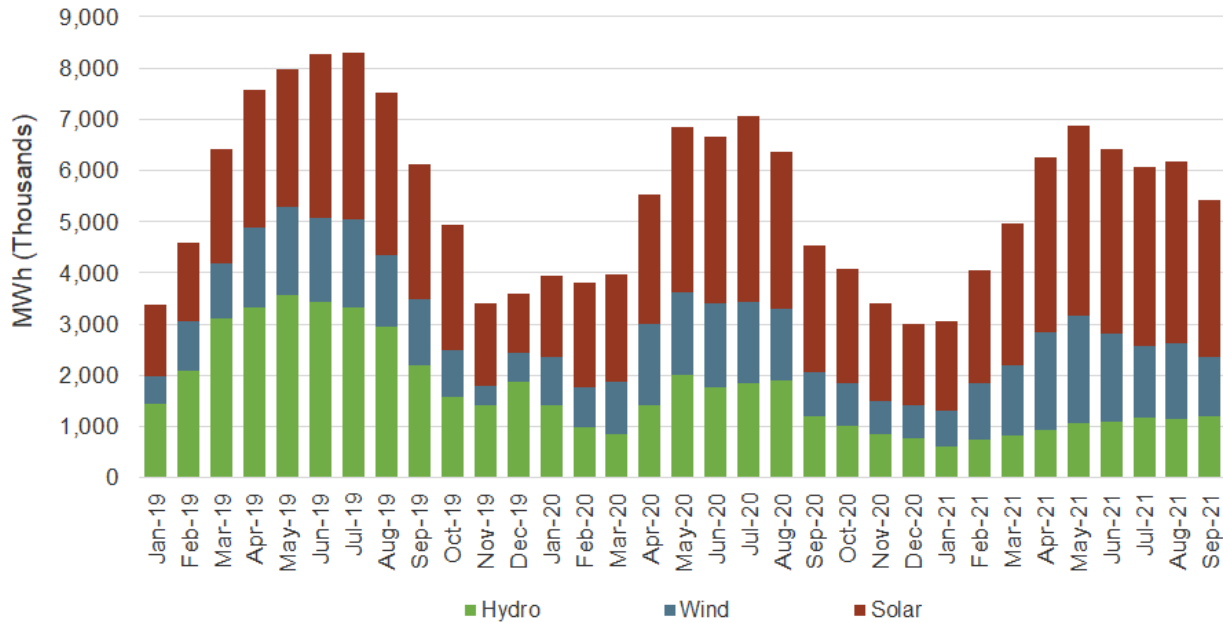


The CAISO's electrical system utilizes hydro production throughout the year to meet the CAISO demand needs. Due to the significant reduction in available water capacity currently observed in the reservoirs, the CAISO continues to see reduced capacity in hydro production this year. Figure 11 below shows the historical trend of total energy produced from hydro resources, as well as renewable resources, in which hydro production for 2021 so far has been significantly lower than the previous two years. Hydro production in September 2021 is about the same as that of September 2020, but about 54 percent of the production in September 2019. The monthly volume of hydro production was relative flat through the summer. Although such conditions continue to reduce the overall available energy available over the summer, hydro resource operators typically strive to conserve their more limited water to provide peaking energy, which helps mitigate the adverse impact of limited hydro.

¹⁶ <https://cdec.water.ca.gov/resapp/RescondMain>

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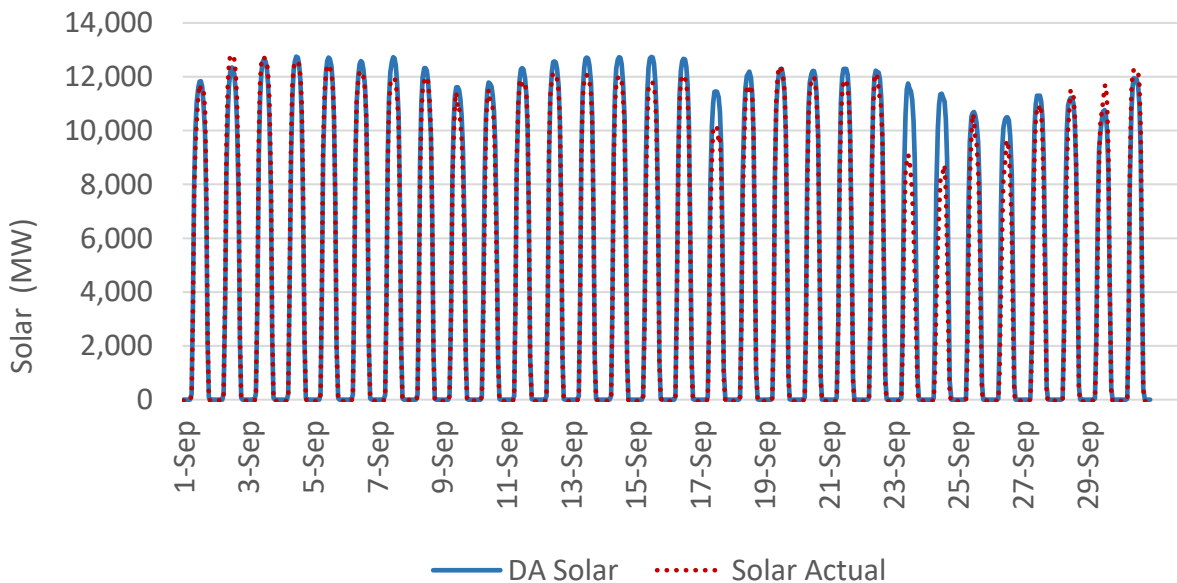
Figure 11: Historical trend of hydro and renewable production



7.3 Renewable forecasts

September 2021 led to continued challenges with smoke and moisture moving through California. Due to this we saw accuracy values slightly higher than previous summer months falling slightly below the range of what has been observed during previous years for the month of September. Figure 12 and 13 below show the solar and wind day-ahead renewable forecasts compared to actual plus supplemental dispatch.

Figure 12: Day-ahead solar forecasts for CAISO's area



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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.

During the month of September, there were periods of increased moisture over the California mountain ranges, as well as the Desert Southwest, leading to increased cloud cover, rain showers, and thunderstorms; however, these weren't as widespread or heavy as the previous summer months. This caused more variable and reduced solar production on those days. In addition to moisture, we continued to see periods of smoke impacts during the month of September that affected Behind-the-Meter solar as well as grid-connected solar. During these periods of increased moisture and smoke, the day-ahead forecast for solar resources had greater uncertainty, as shown in Figure 13. Although there was some increased error compared to August, the average error¹⁷ for the day-ahead solar forecast in August had a 3.69 percent mean absolute percent error and the average error for the day-ahead solar forecast in September was 4.09 percent. The average error observed in September 2021 is lower the day-ahead solar forecast error observed for the month of September in 2019 and 2020¹⁸.

Figure 13: Day-ahead wind forecasts for CAISO's area

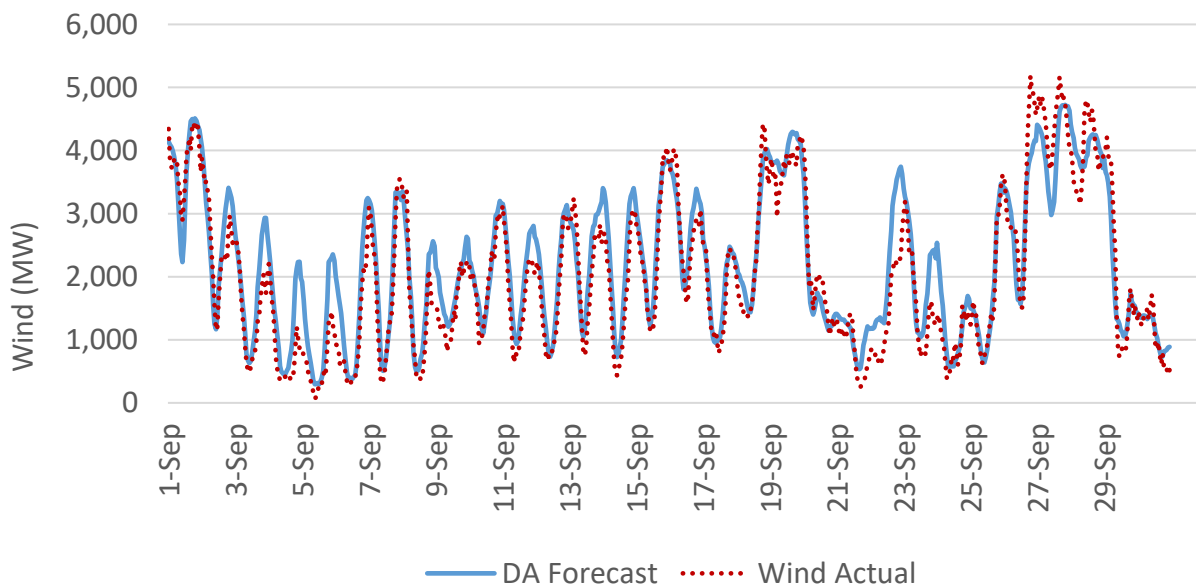


Figure 13 shows the day-ahead wind forecast compared to the actuals plus curtailments throughout the month of September for wind in the CAISO's system. The average error¹⁹ for the day-ahead wind forecast in September was 4.88 percent. The average error observed in September 2021 is comparable to the day-

¹⁷ Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); $((\text{Forecast}-\text{Actual})/\text{Nameplate Capacity})$.

¹⁸ <http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2021.pdf>

¹⁹ Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); $((\text{Forecast}-\text{Actual})/\text{Nameplate Capacity})$.

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ahead demand forecast error observed for the month of September in 2019 and lower than the day-ahead wind forecast error observed for September 2020.²⁰

²⁰ <http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2021.pdf>

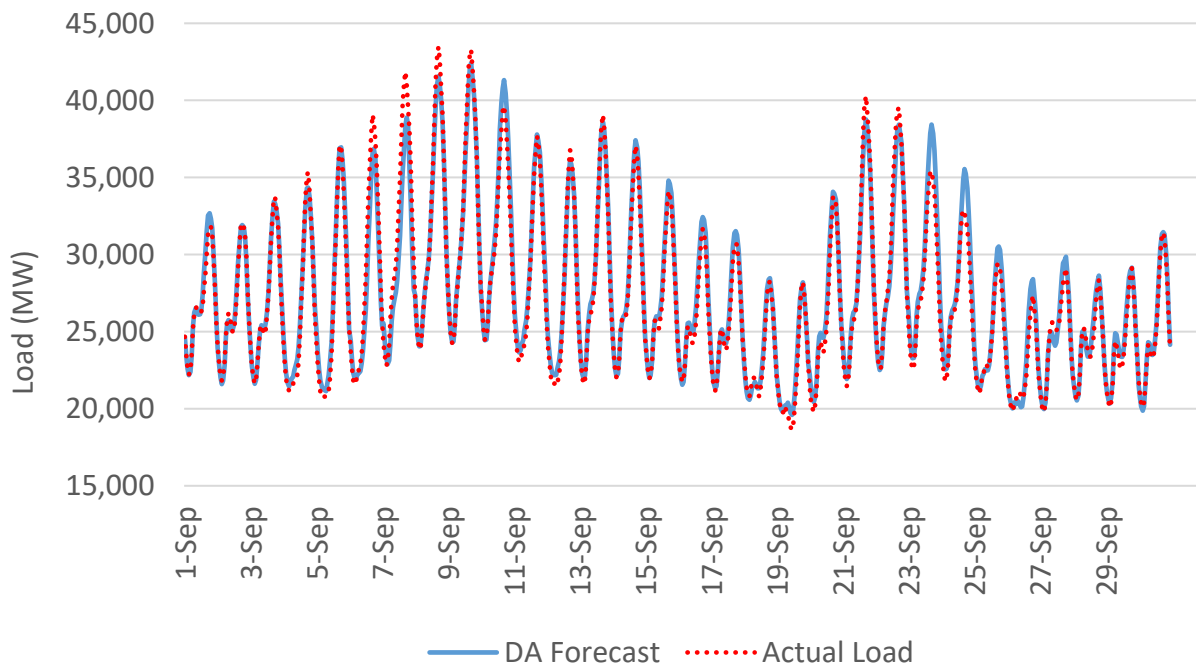
7.4 Demand forecasts

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

7.4.1 CAISO’s demand forecasts

The CAISO demand during the month of September 2021 continued to be very responsive to the temperature changes observed throughout the month. Figure 14 shows the trend of the CAISO’s load. The highest hourly average July load of 43,777MW²¹ was observed on September 8, 2021 when the CAISO footprint was running 4 degrees F above normal for maximum temperatures. The maximum hourly average load observed within a single hour in September 2021 was 398 MW under the CEC month ahead forecast for September Peak of 44,175 MW. During the month of September, the CAISO called on demand response in addition to issuing a Flex Alert for September 8 and September 9. These actions have been accounted for in the Actual Load displayed below to compare the Day-Ahead (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 titled Impact of Energy Conservation.

Figure 14: Day-ahead demand forecast for CAISO’s area



The average accuracy error²² for the day-ahead demand forecast in September was 2.05 percent, while the error for peak hours was 2.61 percent. The average error observed in 2021 is less than the day-ahead demand forecast error observed for September 2020 and comparable to the day-ahead demand forecast

²¹ Averaged Hourly Load Value is CAISO System TAC at the peak hour, please note at the peak hour there was 232 MWs of scheduled and cleared demand Response.

²² Accuracy error is measured with the Mean Absolute Percentage Error (MAPE); ((Forecast-Actual)/Actual).

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error observed in 2019. Looking at the month of September, increased error in the Day-Ahead forecast was observed during September 6th through September 10th. The errors observed during September 6th through September 10th were due to temperatures coming in warmer than expected throughout the state as well as model error present in some regions throughout the CAISO footprint. Table 2 and Table 3 below detail the range of the error by region.

Table 2: Temperature error for September 7, 2021

Weather Regions	Forecast Max	Actual Max	Deviation	Forecast Min	Actual Min	Deviation
PGE Bay	87	89	2	61	62	1
PGE Non Bay	101	102	1	65	67	2
SCE Coast	80	82	2	68	68	0
SCE Inland	101	101	0	71	72	1
SDGE	84	85	1	65	63	-2
CAISO (weighted)	92	93	1	66	67	1

Table 3: Temperature error for September 8, 2021

Weather Regions	Forecast Max	Actual Max	Deviation	Forecast Min	Actual Min	Deviation
PGE Bay	89	92	3	64	64	0
PGE Non Bay	102	103	1	68	66	-2
SCE Coast	80	80	0	67	65	-2
SCE Inland	102	101	-1	72	71	-1
SDGE	86	87	1	64	63	1
CAISO (weighted)	93	94	1	68	66	-2

7.5 Energy Conservation

7.5.1 September impact of energy conservation

The CAISO issued Flex Alerts²³ to assist in meeting the net load peak on September 8 and September 9. Table 4 summarizes the estimated Flex Alert range of conservation, which fluctuates based on hourly impacts during the declared Flex Alert. On September 8 and September 9, 2021, Flex Alerts impacted the overall energy demand, with a more pronounced impact on September 9. During September 8, 2021, the hourly conservation impacts from the Flex Alerts ranged from 0 MW to 120 MW, with the biggest impacts observed during HE 21. The following day on September 9, 2021, the hourly conservation impacts ranged from 40 MW to 650 MW, with the biggest impacts observed in HE 19 and HE 20. The beginning of both events showed lower conservation impacts as customers transitioned off of pre-cooling behavior and into more conservatory habits. These observations are illustrated in Figure 15. For September 8, the Flex Alert

²³ The Flex Alerts for September 8 and 9 were effective from 4pm to 9pm.

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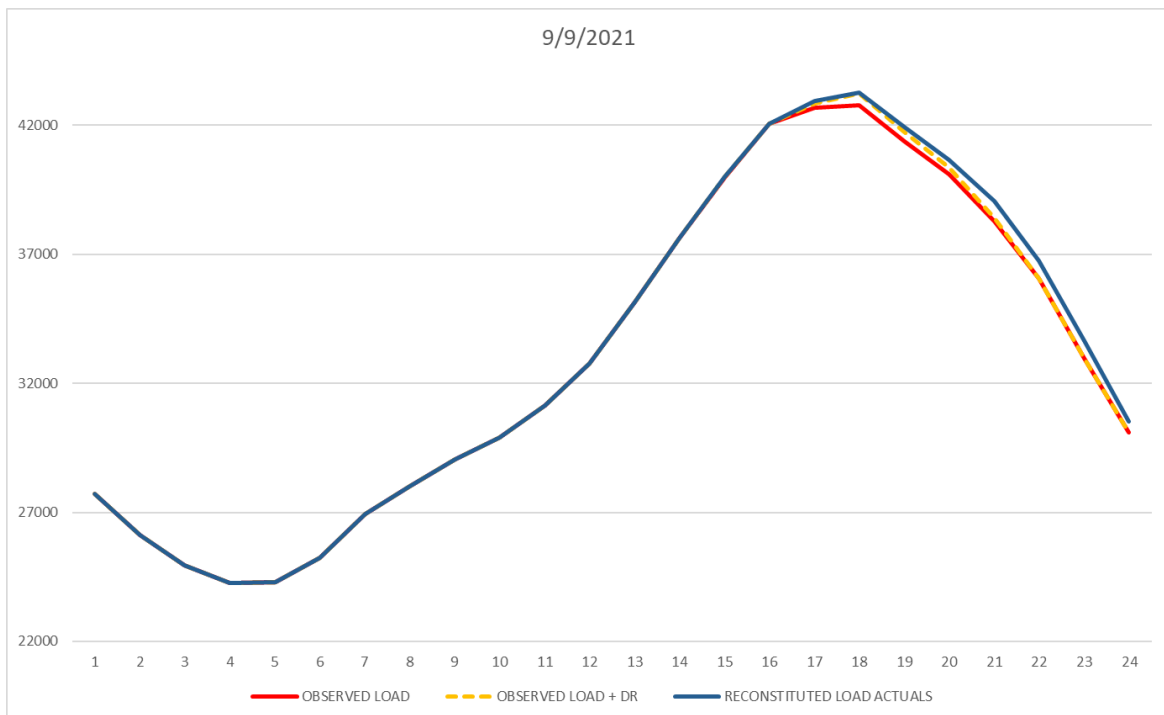
was not issued in advance within the day-ahead timeframe; this may have been the cause for the limited effectiveness of the alert and requests for conservation.

Table 4: Estimated Flex Alert impact

Date	Conservation
8-Sep-21	0-120MW
9-Sep-21	40-650MW

Further details of the estimated savings can be seen during the net load peak hours in Figure 15 below for September 9, 2021.

Figure 15: Flex Alert impact for September 9, 2021



7.5.2 Methodology for reconstituting load actuals

The objective is to estimate how much a given Flex Alert reduced ISO load. This is an imperfect task as the Flex Alert happens on extreme days that are either close to or beyond the boundary of our statistical models. The current steps the ISO uses for estimating the Flex Alert savings are as follows.

We compare the actual (observed load) versus what the load would have been in absence of a flex alert. Actual (observed load) is measured and recorded via our energy management system (EMS). We will call this “observed load.”

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The more challenging portion is to calculate what the load would have been in the absence of a flex alert. We use a multi-step process to calculate what the load would have been in absence of a flex alert. First, we estimate what the load would have been on a given day using our statistical models for load, using actual observed weather and behind-the-meter solar data and assuming no Flex Alert impact. This is a backcast that produces our load estimate without weather and behind-the-meter solar error.

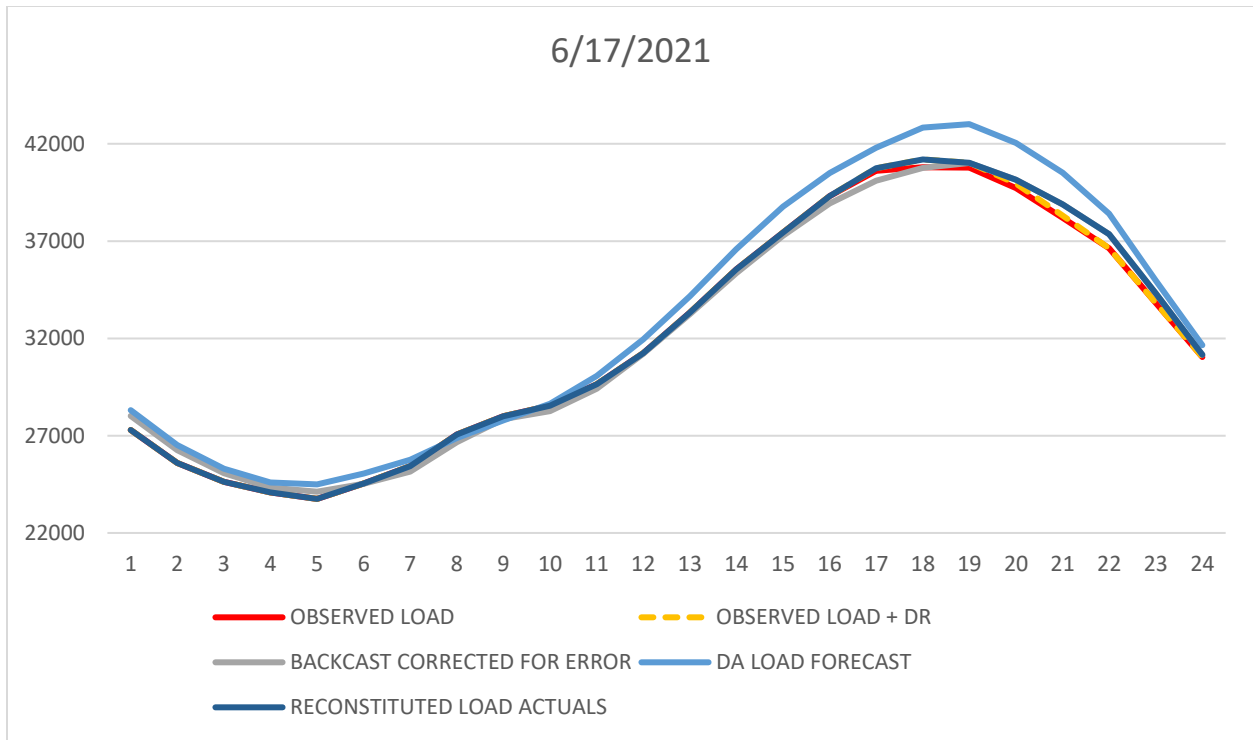
The load estimate does not include any reductions due to supply-side Demand Response (DR) as the statistical models used to produce the backcast estimate load before it has been modified or reduced by Demand Response. Conversely, the observed load does include DR because DR reduces load and is not measured separately from load. We need to adjust for DR and can do so in one of two ways (they both have the same effect). The first is to subtract the amount of DR scheduled by IOUs and the amount of DR cleared in the markets from our load estimate. The second is to add the total hourly DR to the observed load. We chose the second method and added the total hourly DR to the observed load. We call this "Observed Load + DR" in the data below. Future considerations are to model the actual response of DR instead of using DR awarded or scheduled capacity.

This DR adjusted load estimate is not perfect. Conceptually, it is comprised of a perfect estimate of load in absence of a Flex Alert plus unexplained error. In other words, the unexplained error is error that was not explained by the statistical load model, weather, behind-the-meter solar, or DR adjustments. As a result, we need to remove this error in order to get a final estimate of what load would have been in the absence of a flex alert. This error is termed "backcast corrected for error" in the data below. The error trends from hour to hour and we need to adjust the results to remove this error. As a result, we use previous days with similar weather conditions to estimate the error that is within the unexplained error by hour. This allows the ability to estimate the error and then remove it from the hours that are in the Flex Alert time period. The result is an estimate of load in the absence of a flex alert, sometimes referred to as backcast corrected for error. Note that it is likely that the impact of flex alerts are not confined solely to the periods the Flex Alert is active. As a result there are times we see pre-cooling impacts during the demand ramp prior to the event. Note for the reconstituted actuals we keep the pre-cooling impacts.

Finally, we compare the estimated load (backcast corrected for error) with the Observed Load + Demand Response. The difference during these two fields result in the Flex Alert savings reported. Figure 16 shows all the fields present from 6/17/2021 to assist visually with the method described above.

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Figure 16: Flex Alert impact for June 17, 2021



8 Demand and Supply

8.1 Resource adequacy

The CAISO manages the resource adequacy (RA) program established by the CPUC for its jurisdictional load serving entities (LSEs), which include Investor Owned Utilities (IOUs), Community Choice Aggregators (CCAs) and Energy Service Providers (ESPs). Collectively, these LSEs cover about 90 percent of CAISO's load. The RA program ensures through contractual obligations that there is sufficient supply capacity to meet the system's needs and to operate the grid reliably. The CPUC RA program sets and enforces the program's rules within the jurisdictional LSE's footprint. This program also includes setting the monthly obligations based on an electric load forecast and planning reserve margin (PRM). The California Energy Commission estimates the electric load forecast used by the CPUC in its RA program. Non-CPUC jurisdictional LSEs can set their own RA program. RA capacity from both CPUC and non-CPUC jurisdictional LSEs is shown to the CAISO annually and monthly following a process established by the CAISO.

Through the RA program, there are three types of capacity: System, Local and Flexible. All three products serve a purpose in ensuring a reliable operation of the system. The events of August 2020 were primarily a result of insufficient system RA since it was a condition of insufficient supply to meet the overall system demand. For system capacity, the RA requirement ensures the contracted capacity is sufficient to cover the 1-in-2-year (average) peak load plus a 15 percent PRM.²⁴ This PRM is to cover the 6 percent of operating reserves while the rest is a contingent headroom to account for higher-than-expected load forecast and resource outages.

The monthly RA showing for September 2021 was 47,838 MW, which is lower than September's 2020 monthly showing of 49,217 MW.²⁵ Figure 17 compares the total monthly RA capacity in September 2020 and September 2021 by fuel type. Although the total RA capacity in September 2021 is about 1,379 MW lower than that of 2020, there are some marked variations in the RA composition. RA capacity increased by 1027 MW in storage resource which partially offset the reduction of 2,425 MW of static imports. The hydro RA reduced by 338MW, which is expected given drought conditions materializing in 2021.

Static RA imports decreased from 6435 MW in September 2020 to 4,009 MW in September 2021.²⁶ The composition by intertie varied between years as shown in Figure 18; RA imports through Malin decreased from 2,340 MW to 1,919 MW from September 2020 to September 2021, while imports through NOB decreased from 1,531 MW to 1,046 MW across the same timeframe. Imports on Malin and NOB account

²⁴ The official planning reserve margin is 15 percent for the CPUC jurisdictional entities. Per Decision 21-03-056, the CPUC increased the "effective" planning reserve margin to 17.5 percent for 2021 and 2022 but this is met with both RA and above RA resources that may also not be in the wholesale market.

²⁵ These values are based on the monthly showings estimates available at the time of preparing this report. These monthly showings are provided through the supply plans to meet the final RA obligation. The final RA obligation is composed of the forecast plus PRM and then all credits, including DR, are deducted. The total RA values can change through the month, with weekend showing typically a significant reduction. For simplicity in the reporting and comparison, the simple average through the month is used as a reference in this report. Also, the total RA values represented in this report include any CPM and RMR capacity.

²⁶ 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.

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for about 74 percent of all static RA imports in September 2021, up from the 60 percent observed in September 2020.

Figure 17: September 2021 RA organized by fuel type

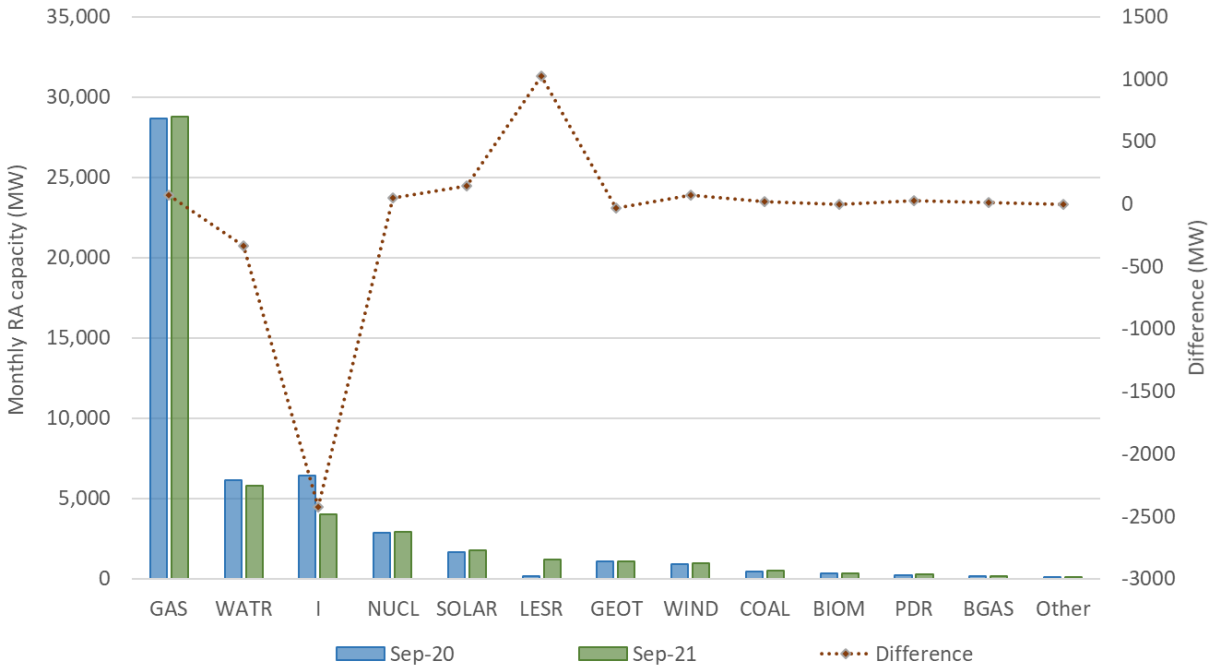
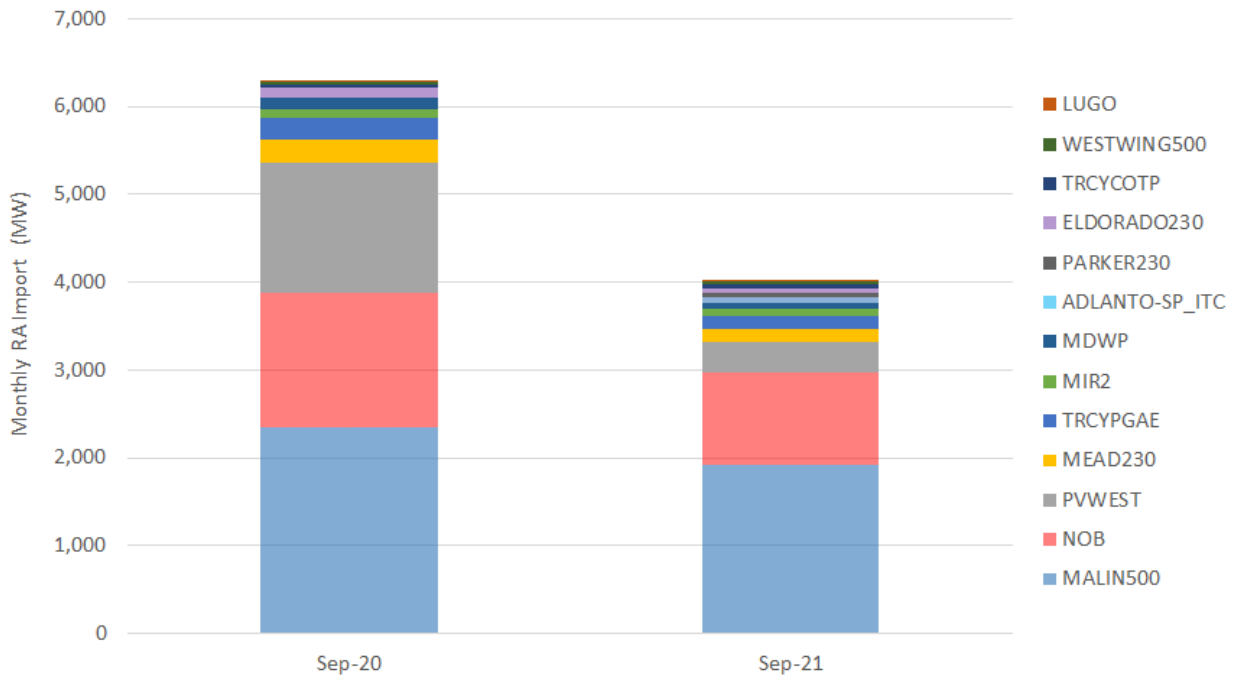


Figure 18: Monthly RA organized by tie



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RA imports declined in September 2021 to 4,009 MW relative to 6,435 MW in September 2020. However, RA imports in September 2021 were higher than RA imports in August 2021. These trends are shown in Figure 19 and Figure 20.

Figure 19: Monthly RA showings

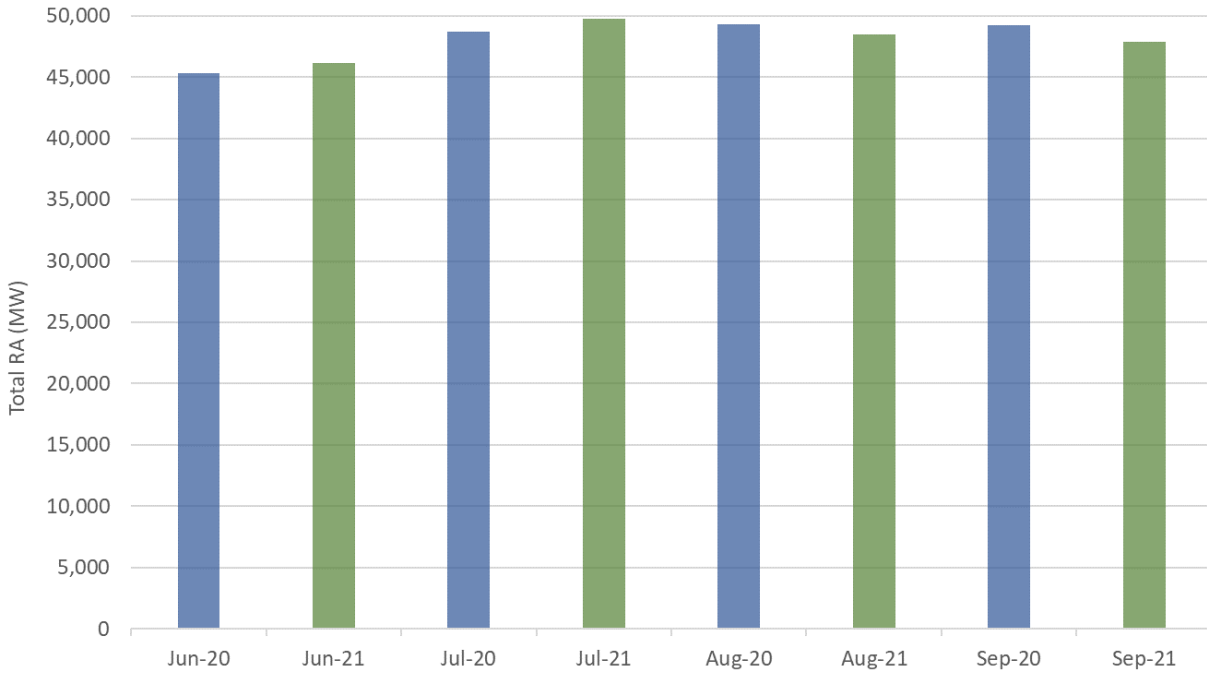
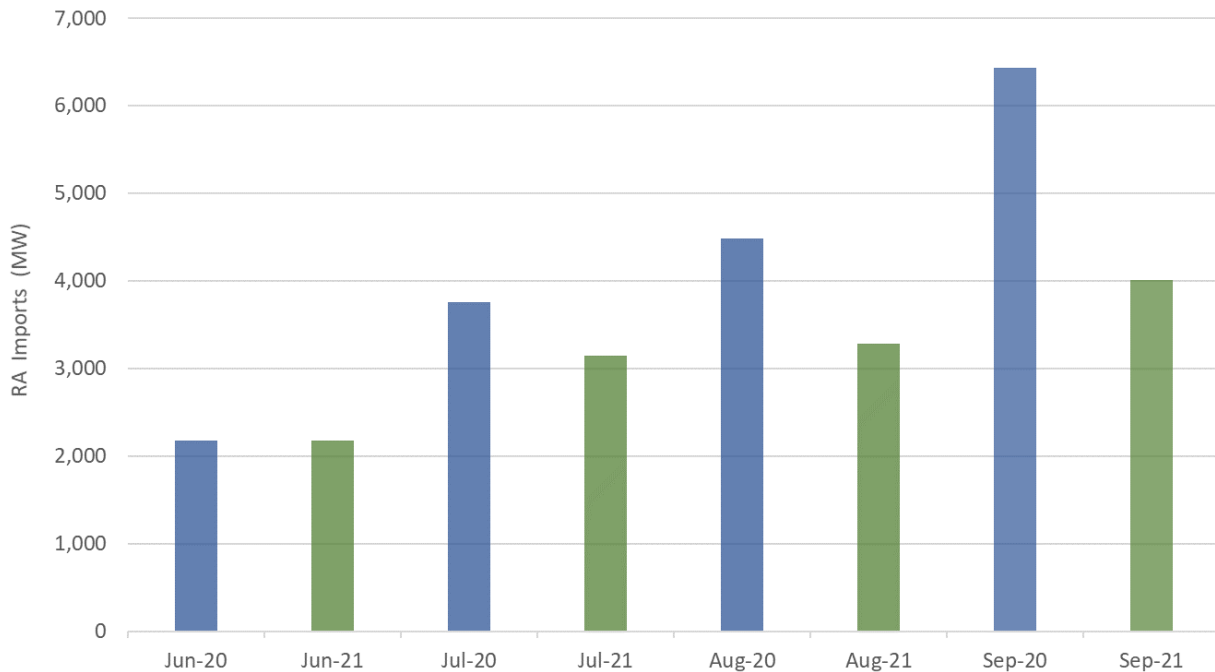


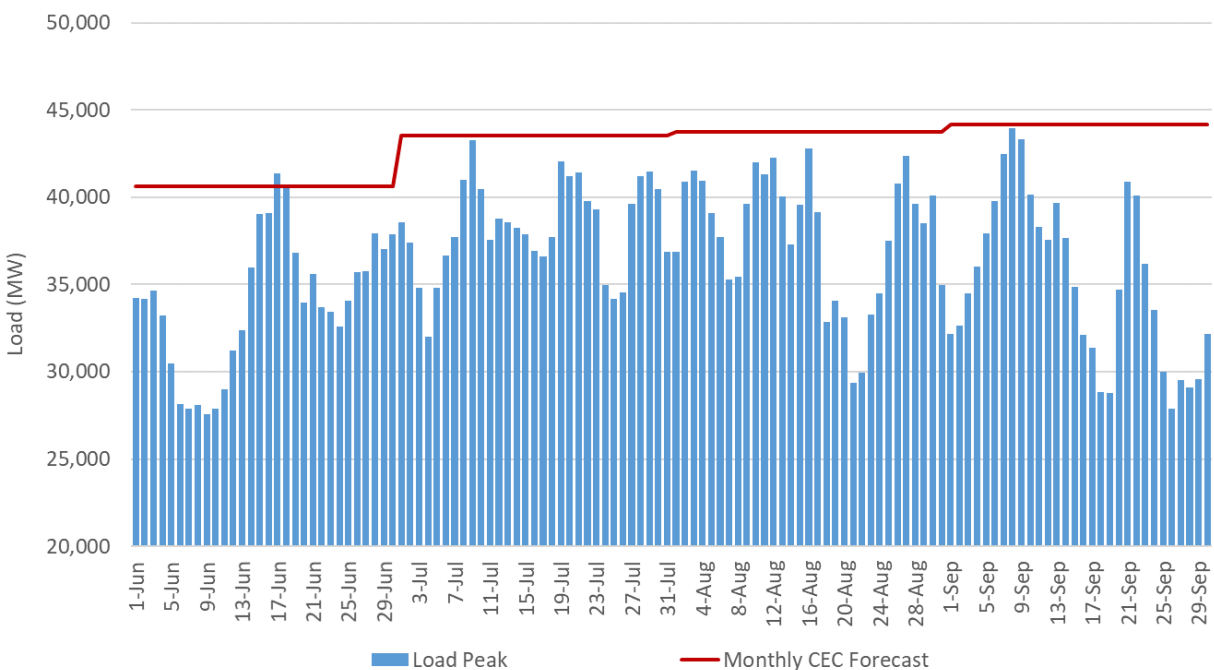
Figure 20: Monthly trend of static RA Imports



8.2 Peak loads

Peak loads in September 2021 exceeded 40,000 MW on multiple days. The average peak load in August was about 37,837 MW and decreased to an average of 35,194 MW in September. As temperature cooled down through the second half of the month, the peak load dropped under 30,000 MW in multiple days of September. Figure 21 shows the 5-minute daily load peak for the months of June through September 2021 relative to the CEC month ahead forecast used to assess the resource adequacy requirements. The highest peak load in the month happened on September 8 at 43,947 MW and was below the CEC month-ahead forecast of 44,175 MW. This peak load observed on September 8 MW is so far the peak for the year.

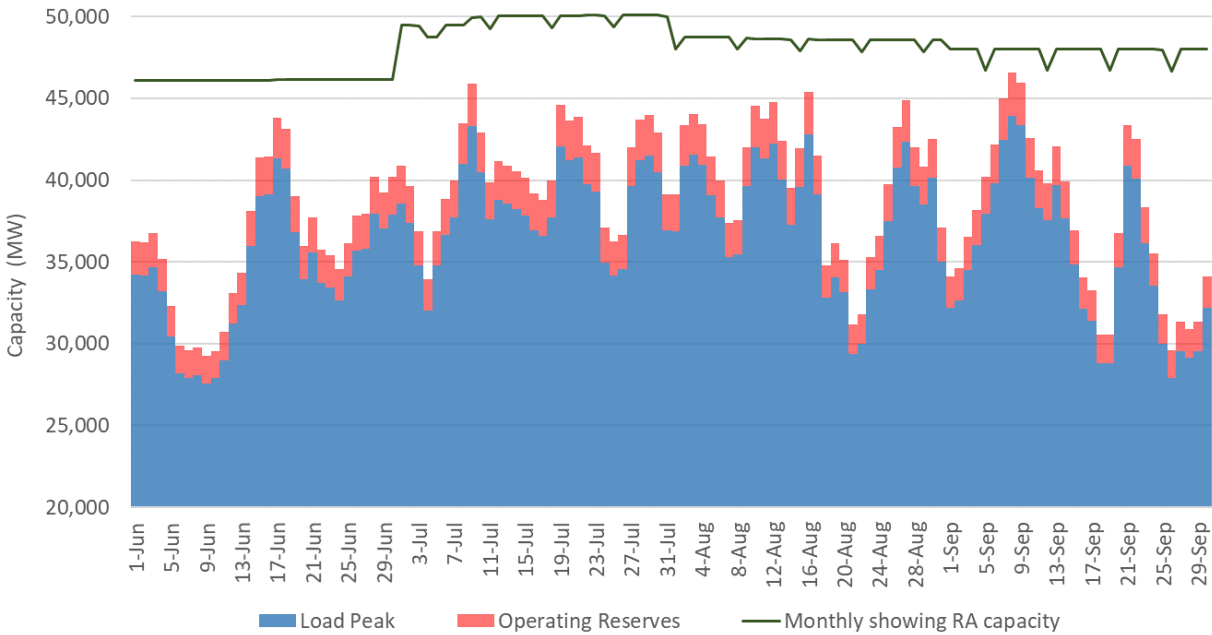
Figure 21: Daily peaks of actual load in summer months of 2021



The actual load did not exceed the monthly RA showings for the month of September 2021 as a whole, as illustrated in Figure 22. The green line indicates nominal monthly RA showings. As discussed later in this report, the actual capacity made available into the CAISO’s market (accounting for outages and other factors) during September 2021 was generally lower than the nominal RA monthly showings but was above the load forecast plus operating reserves. In subsequent sections, the actual RA capacity made available in the market is represented as a trend over for the month on an hourly basis, which more accurately represents RA capacity available to meet demand.

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Figure 22: Daily peaks and RA capacity for June through September 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: 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 23 compares the average prices across CAISO's markets.²⁷ In the month of September, prices were generally under \$100/MWH with the exception of September 7 through 9 when system experienced the load peak conditions of the year. Figure 24 shows average daily prices across markets in the summer months; price divergence can be observed primarily in the peak hours.

²⁷ 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.

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Figure 23: Average daily prices across markets

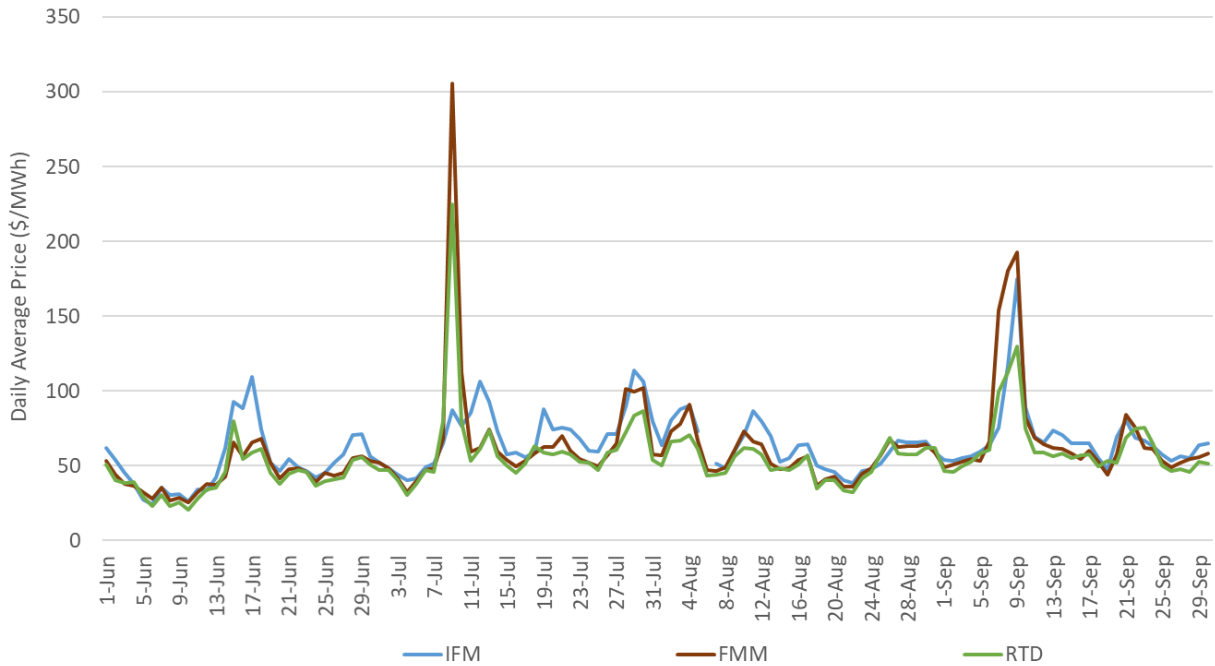


Figure 24: Average hourly prices across markets

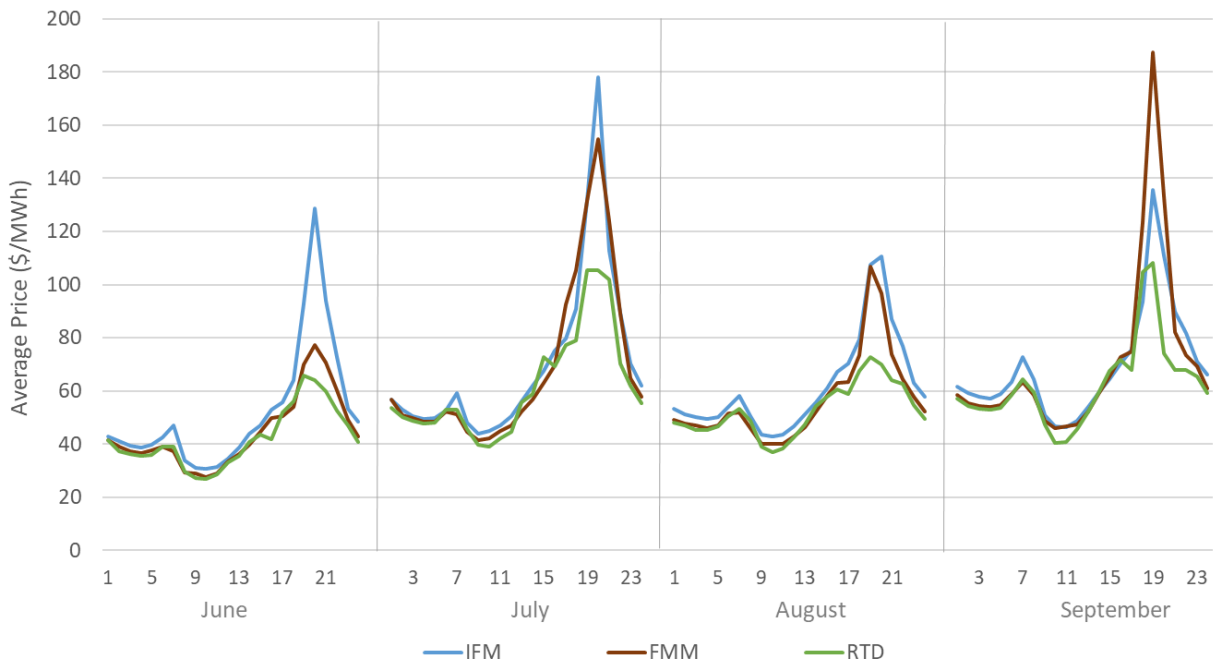


Figure 25 and Figure 26 show the daily and hourly distribution of summer months day-ahead prices with box-whisker plots. The whiskers represent the maximum and minimum prices in a given day or hour, while the boxes represent the 10th and 90th percentile of the prices. The red dots represent the average prices for the day. These plots better illustrate the full distribution of prices in the summer months. Prices in

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September saw similar prices to previous months, with September 9 observing the highest price in the summer 2021 of about \$635/MWh.

Figure 25: Daily distribution of IFM prices

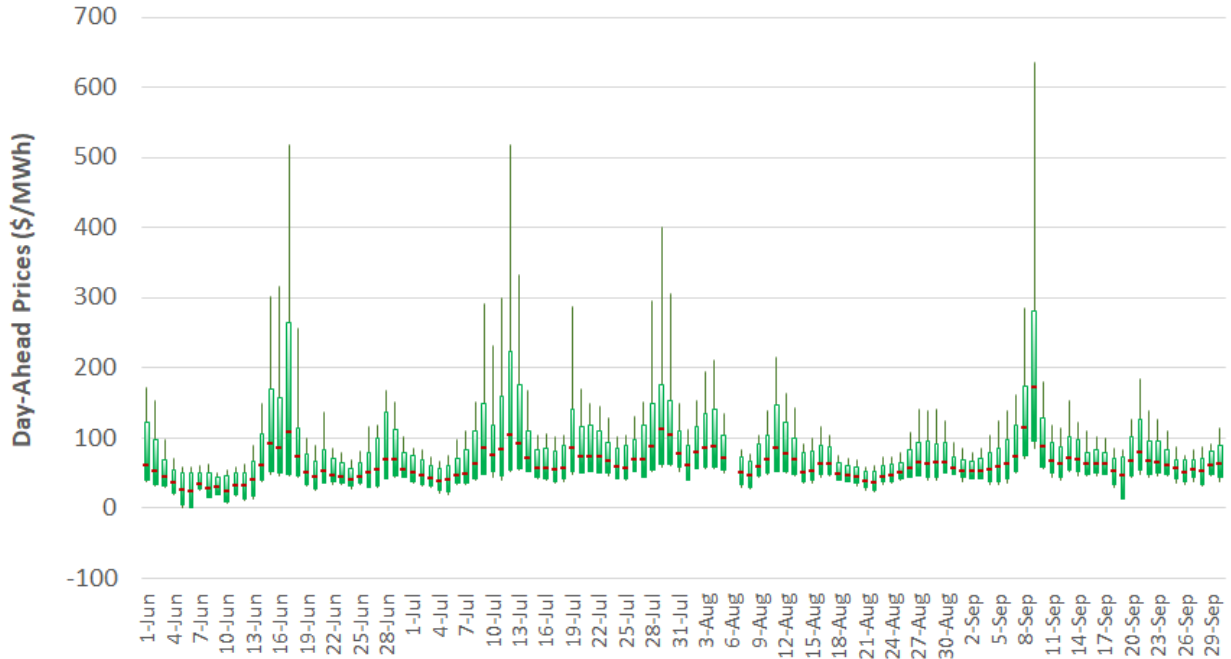
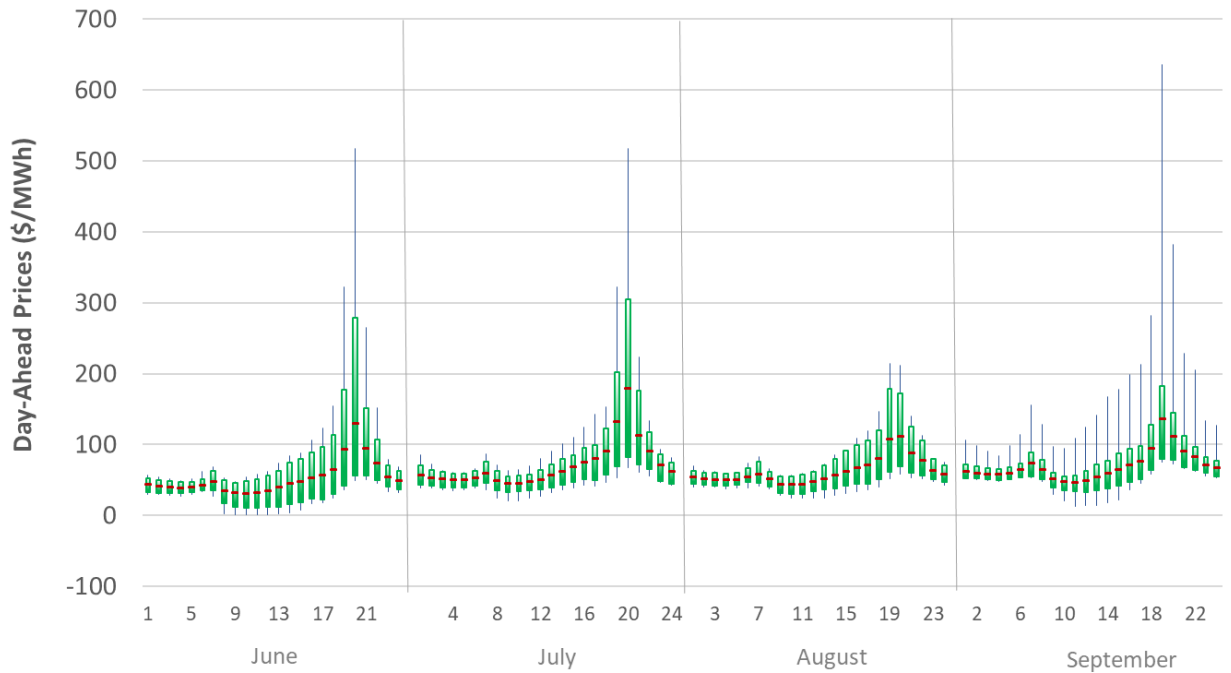


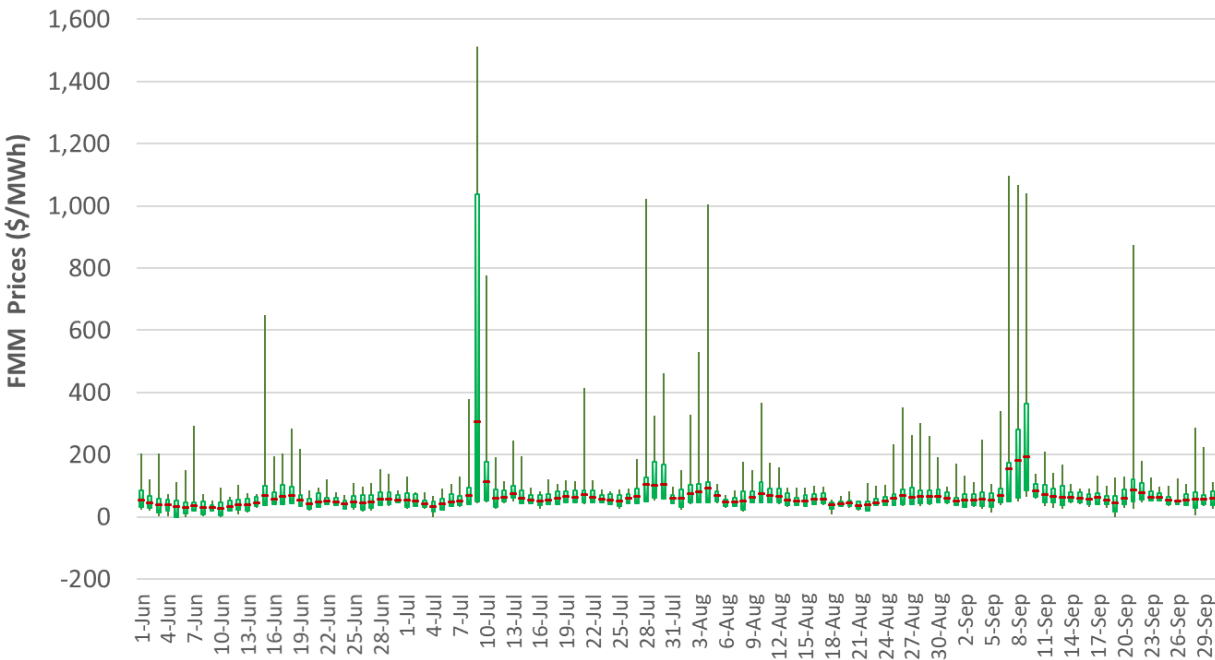
Figure 26: Hourly distribution of IFM prices



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Similarly, Figure 27 and Figure 28 show distributions of real-time (FMM) prices in the summer months. The day-ahead prices exhibit a larger spread, mainly in the days and hours when higher demand occurred. In contrast, real-time prices show 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. However, in September, real-time did see more price spreads.

Figure 27: Distribution of FMM prices by day



With the CAISO's generation fleet consisting of a meaningful share of gas resources, dynamics from the gas market and system can typically have an impact on the electric market. Electricity prices generally track gas prices. Figure 29 shows the average prices (bars in blue and green), and the maximum and minimum prices (whiskers in purple), for the two main gas hubs in California. September saw the highest gas prices in the summer with averages of \$6.63/MMBTu and \$7.57/MMBTu for PG&E Citygate and SoCal Citygate, respectively.

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Figure 28: Distribution of FMM prices by hour

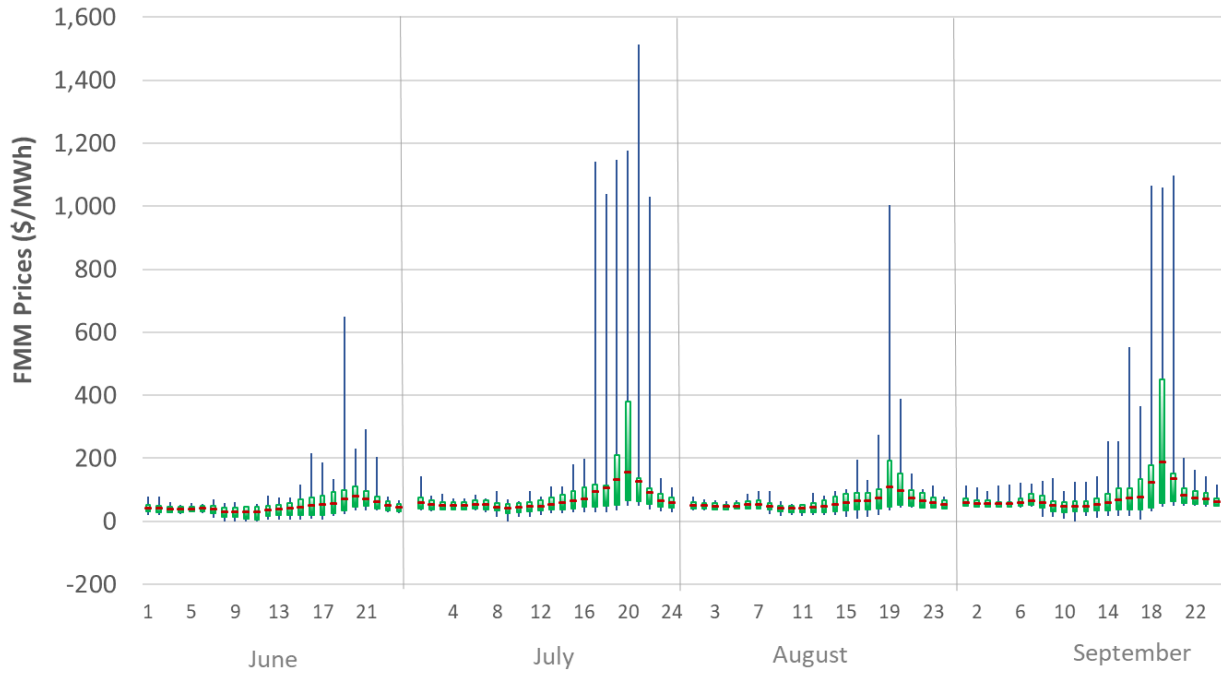


Figure 29: Gas prices at the two main California hubs

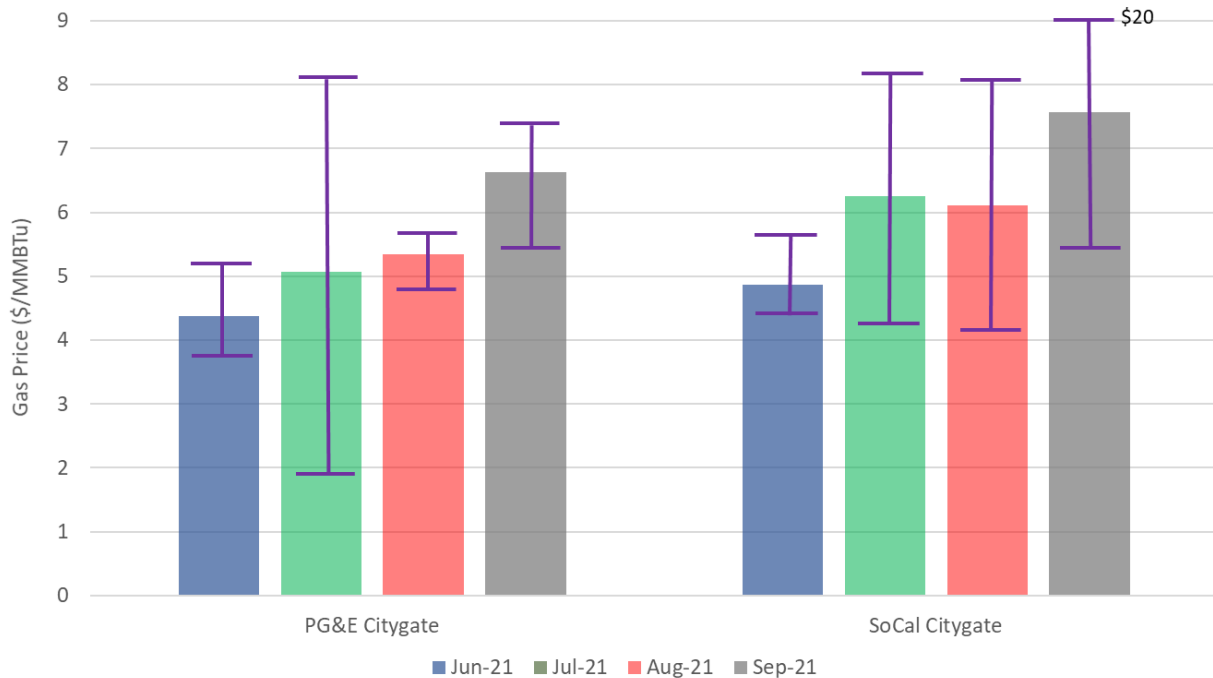
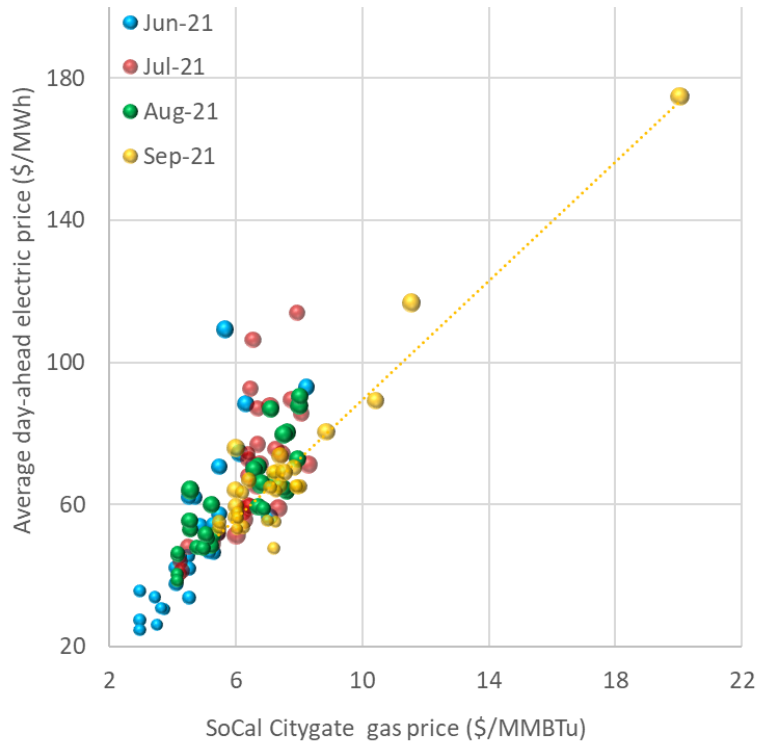


Figure 30 shows daily average electricity prices from the CAISO day-ahead market (y-axis) relative to next-day gas prices at SoCal Citygate (x-axis) and the peak load (size of the bubbles) on a daily basis for summer months. Peak loads ranged widely and this comparison exhibits a good degree of correlation between

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electricity and gas prices. In addition, it can be observed that electricity prices rise when load levels are higher.

Figure 30: Correlation between electricity prices, gas prices and peak load level



9 Bid-In Supply

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

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

9.1 Supply and RA Capacity

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

Figure 31 shows the breakdown of the day-ahead supply capacity²⁸ as RA capacity and above RA capacity. The purple line represents the day-ahead load forecast plus the capacity required to meet operating reserves (OR), which is typically about 6 percent of the load value. The dashed line represents the adjusted load forecast plus OR plus export self-schedules, which represents the overall need to be met in the day-ahead market. Figure 32 has the same capacity breakdown but the comparison is relative to the net load

²⁸ 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.

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(gross load minus VER forecast). Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

Figure 31: Supply capacity available relative to load forecast in the day-ahead market

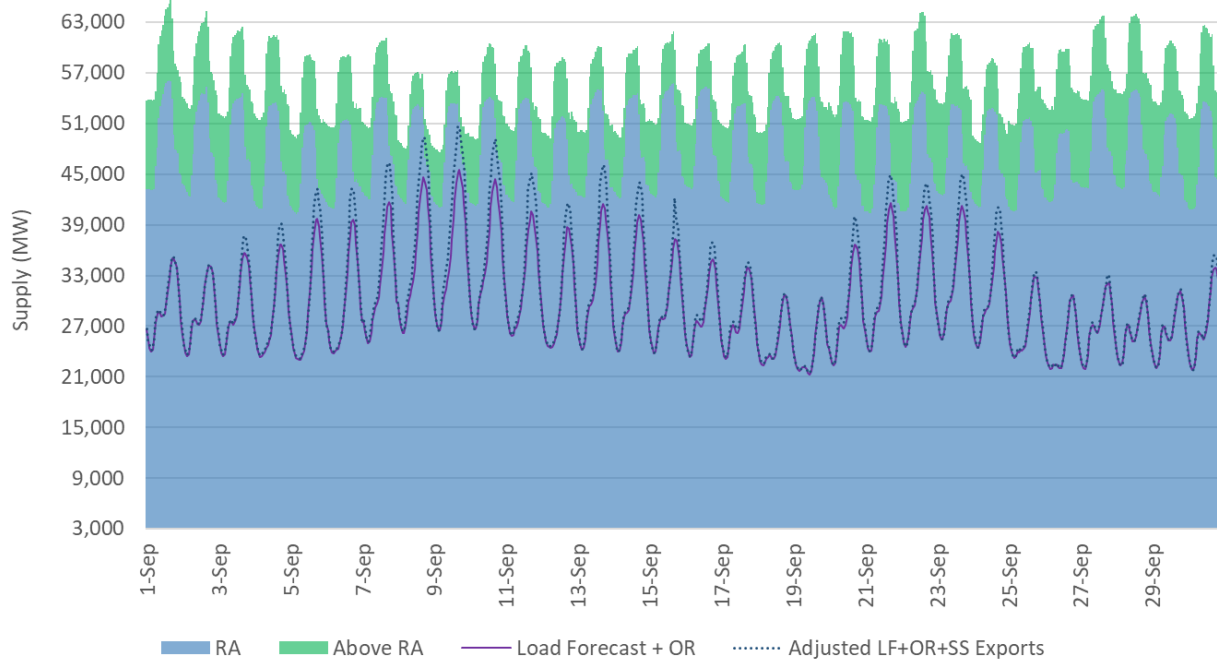
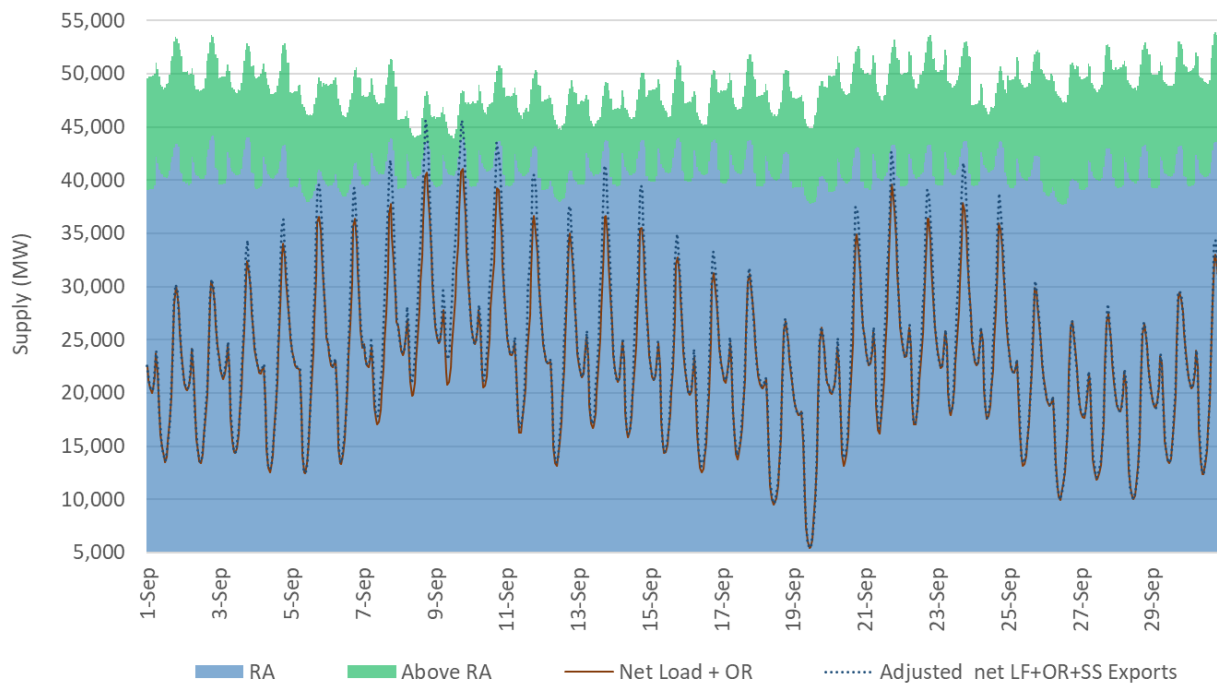


Figure 32: Supply capacity available relative to net load forecast in the day-ahead market



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In both trends, the load peaked on September 7 through 9. A more granular view of the supply-demand conditions are provided for this period in Figure 33 and Figure 34. The RA capacity was sufficient relative to both the standard and the adjusted load forecast during both the gross and net load peak.

Figure 33: Supply capacity available relative to load forecast in the day-ahead market –September 8

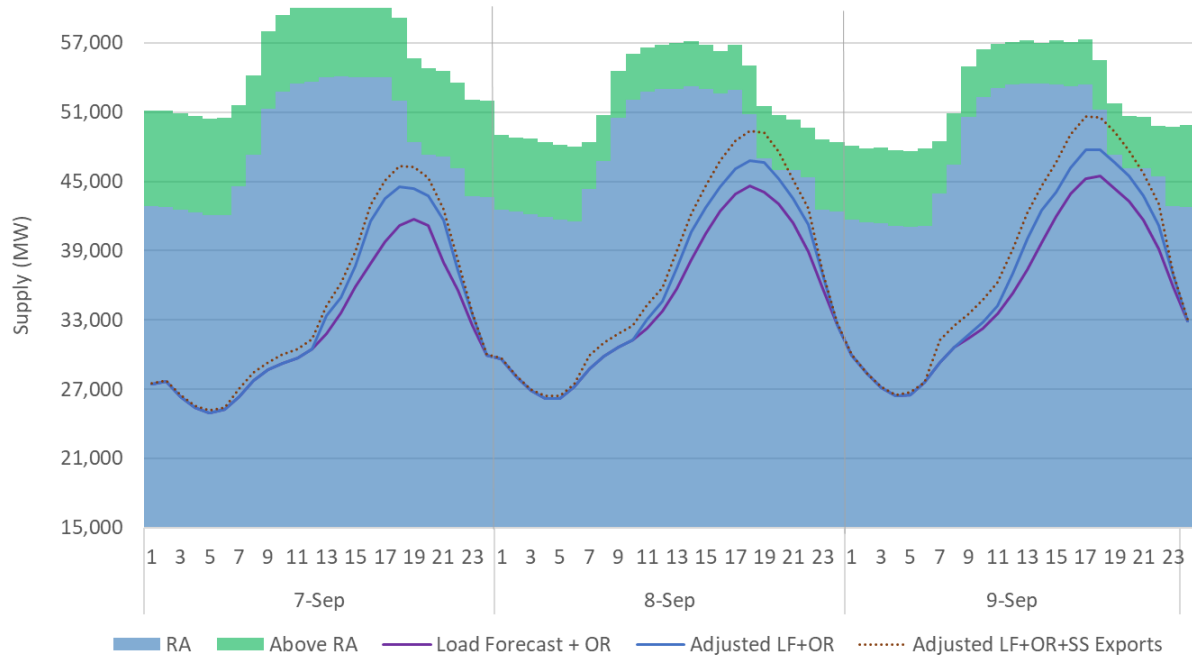
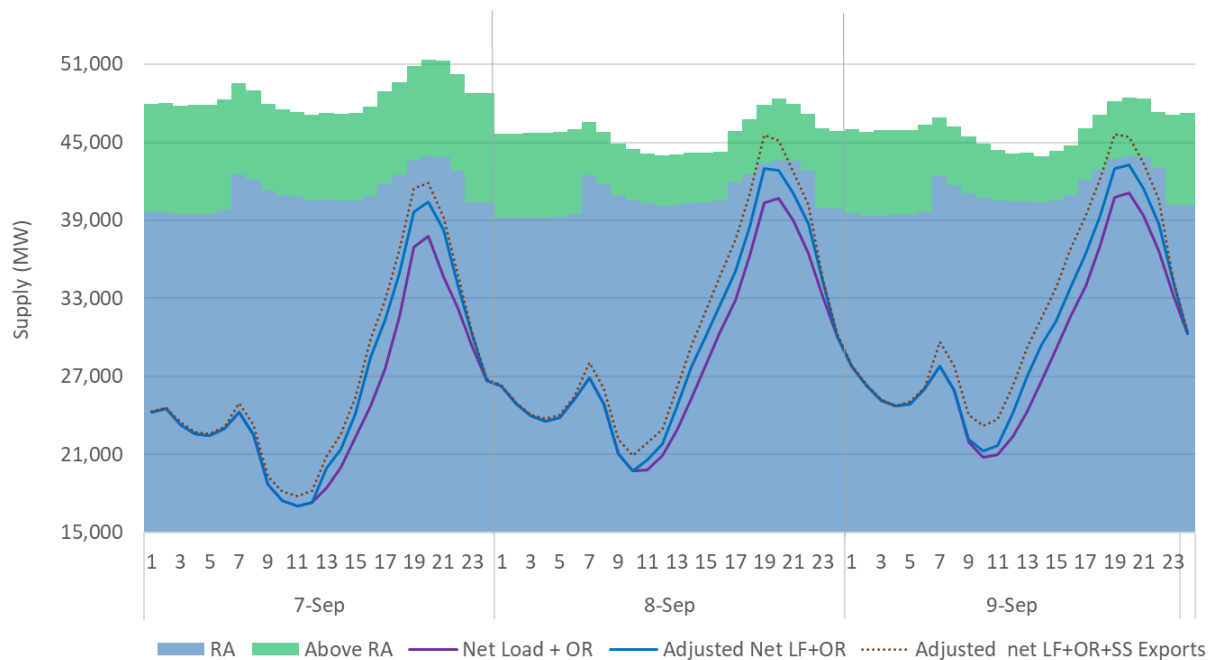


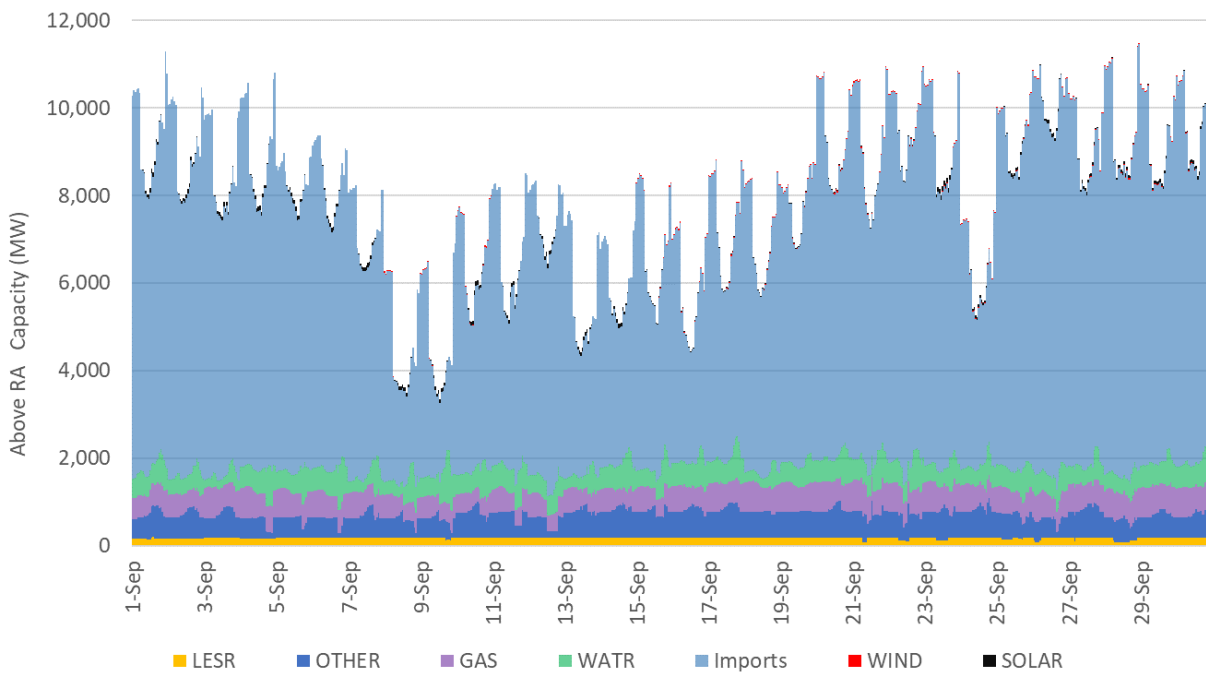
Figure 34: Supply capacity available relative to net load forecast in the day-ahead market –September 8



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For instances in which the load needs exceed the available RA capacity, the market will utilize any other above RA available capacity. For the month of September, above RA capacity was consistently bid into the market. Figure 35 shows the above RA capacity available in the day-ahead market organized by fuel type. The major contributor to this above RA capacity is imports. Since imports are limited by the inertia scheduling limits, not all of that supply could actually be utilized in the market if needed. Because of how RA is accounted for wind and solar resources in this metric, there is essentially no above RA capacity classified for these type of resources. Furthermore, some of that above RA capacity may be actually supporting exports.²⁹ Lacking information of what other types of contractual arrangements may exist for that above RA capacity, this metric serves as an upper range of how much supply capacity available in the market is above.

Figure 35: Above RA capacity available in the CAISO's market



²⁹ Since September had some days in which high priority (non-recallable) exports were bid-in and cleared, the maximum hourly high priority export quantity is used as a reference to estimate how much of that above RA capacity is actually in the market to support the high priority 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.

9.2 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 36 compares the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast eventually used in the RUC process. Day-ahead load forecast varied through the month, going from high-load days such as September 8 and 9 to other days with very mild loads under 30,000MW such as those of September 18 and 19.

Figure 36: Day-ahead demand

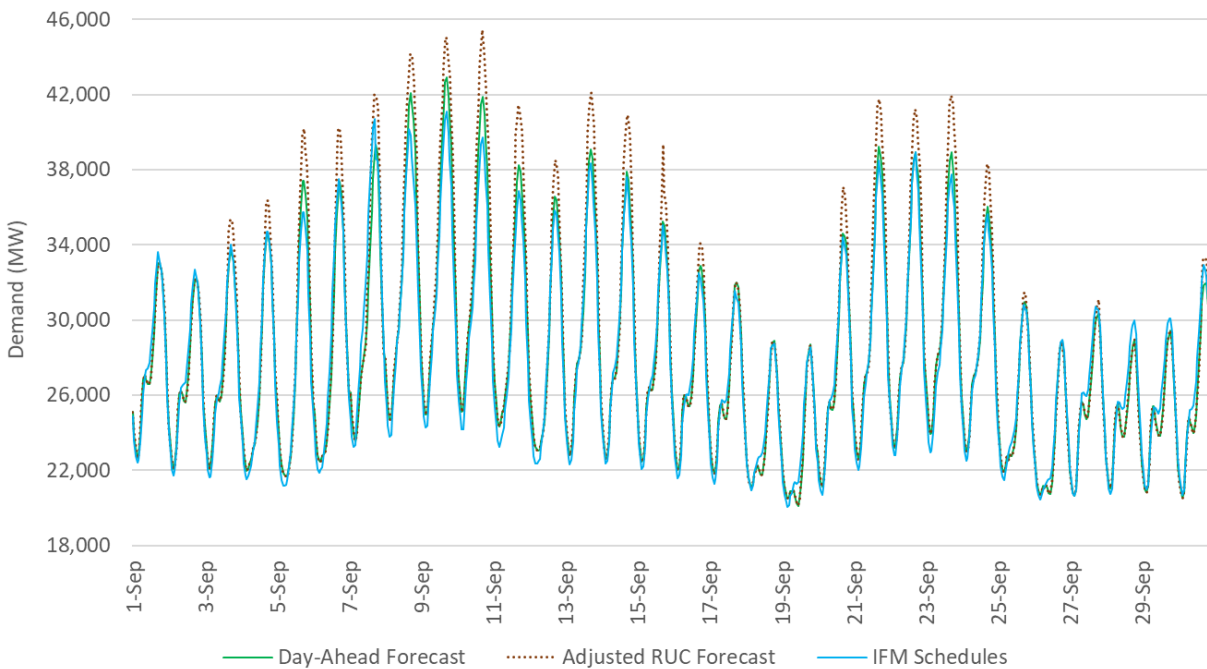
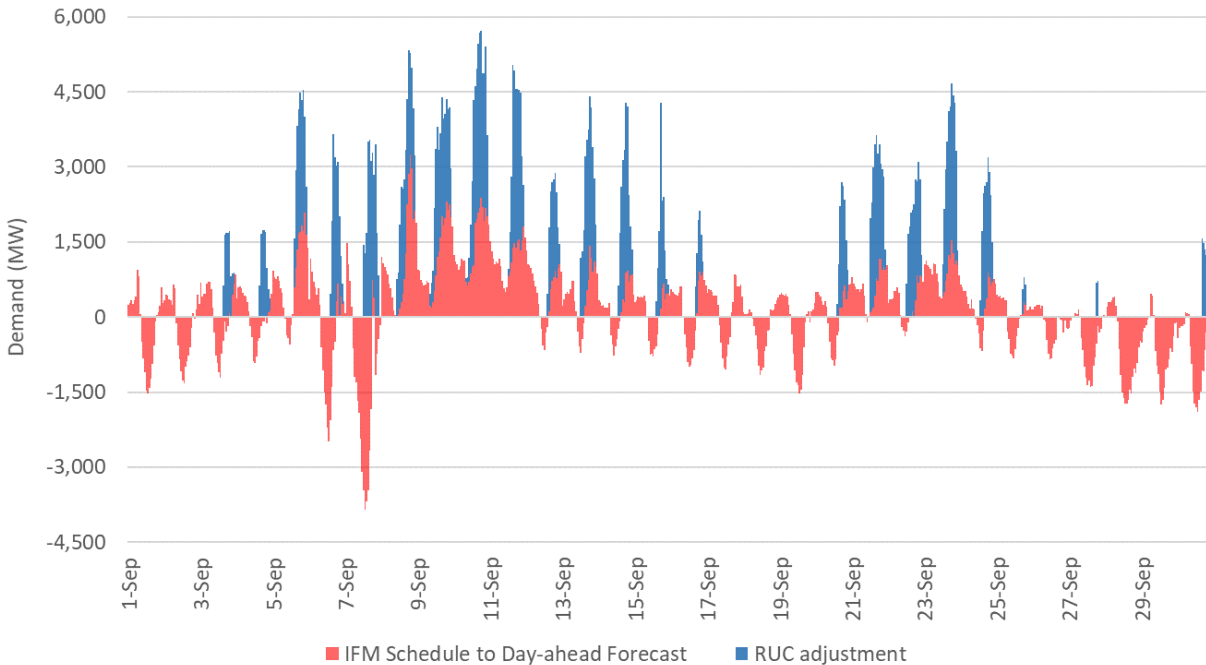


Figure 37 shows the differences between the IFM schedules for physical resources versus the nominal day-ahead load forecast. This is the additional capacity starting from the IFM solution RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus capacity from IFM that RUC has to meet. The delta is driven by the difference between cleared bid-in demand and the load forecast, as well as any displacement driven by convergence bids. The area in blue is the RUC

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adjustment to the day-ahead load forecast. In cases when RUC is infeasible, some of this additional capacity will not be met.

Figure 37: Differences of day-ahead demand for September



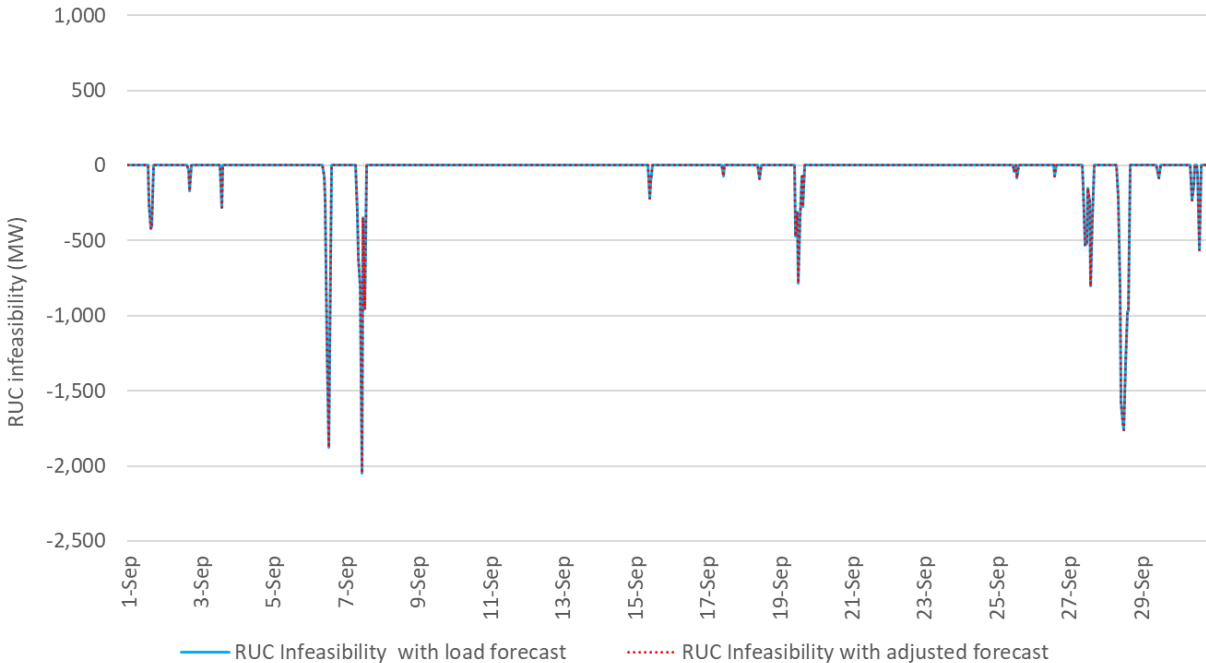
The RUC forecast adjustment is typically guided by a reference of an upper confidence bound and is estimated by the CAISO with consideration to weather and load model and renewables uncertainty. In some cases, there may be other factors to consider by operators to determine the final adjustments. With summer conditions fully at play, for at least the first half of September, IFM schedules and RUC adjustments were predominantly positive, meaning that RUC had to clear higher physical supply than IFM. However, given the milder loads observed in September, there were multiple days with no additional RUC adjustment applied to the day-ahead load forecast, and IFM already cleared above the needs projected with the day-ahead forecast, as reflected with the negative red area.

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

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exhausted and RUC has curtailed all the economic and LPT exports,³⁰ which leaves just the power balance constraint to be relaxed and reducing PTK (high priority) exports, to allow RUC to clear. Figure 38 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. For the whole month of September, there were no RUC under-supply infeasibilities relative to the standard load forecast. There were only over-supply infeasibilities various days of the month.

Figure 38: RUC infeasibilities in September



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

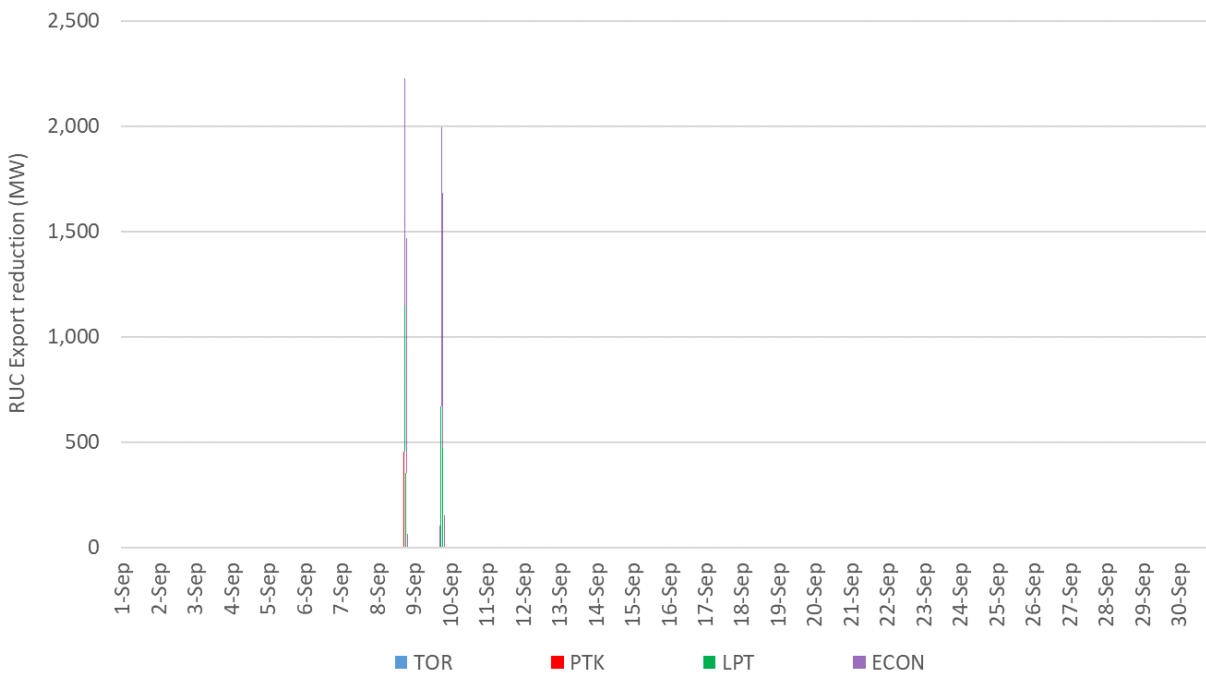
³⁰ There are different type of exports participation. They can be based on economic bids with prices between the bid floor and the bid cap; they can be price takers, also referred to as low priority exports and labeled as LPT (i.e., exports that may be backed by capacity that is committed to CAISO load 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.

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priority price-taker exports. Only when RUC has exhausted these LPT exports, PTK exports may be reduced concurrently to relaxing the power balance constraint.³¹

Figure 39 shows the volume of hourly export reduction in the RUC process, which only happened on September 8 and 9. The majority of export reductions were for economic and LPT exports. Since they have the lowest priority and are reduced first. In September 8, there were 456 MW of PTK exports reduction.

Figure 39: Exports reduction in RUC

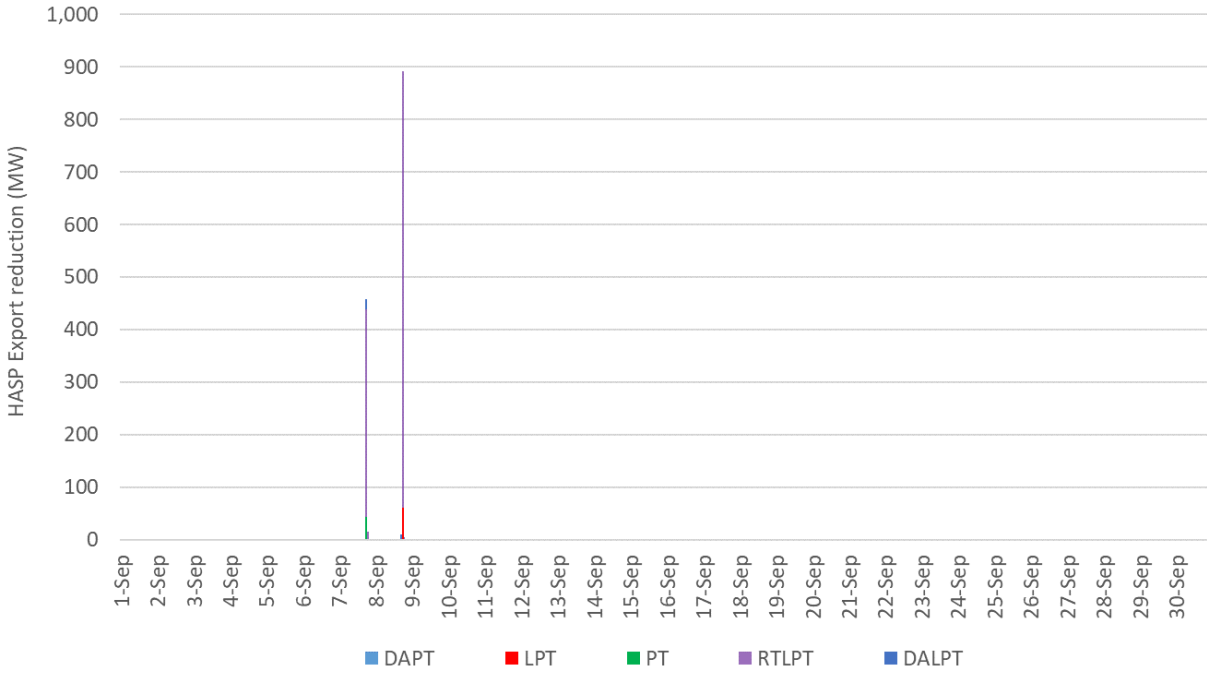


If any PTK export is reduced in the day-ahead process, subsequent market participants can rebid the PTK exports that were curtailed in RUC into the real-time market. Market participants can self-schedule exports cleared in the day-ahead into the real-time market. Under the new market rules and scheduling priorities post August 4, these cleared day-ahead schedules are treated in the real-time market as having a day-ahead priority, which is above the priority of LPT and PTK exports submitted in the real-time. Thus, exports cleared in the day-ahead are less likely to be cut in the real-time. Participants can also submit 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 September 7 and 8, the real-time market saw some self-schedule export reductions in HASP mainly on the low priority exports.

³¹ 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 an RUC solution under tight supply conditions.

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Figure 40: Exports reductions in HASP



10 Intertie Transactions

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

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

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

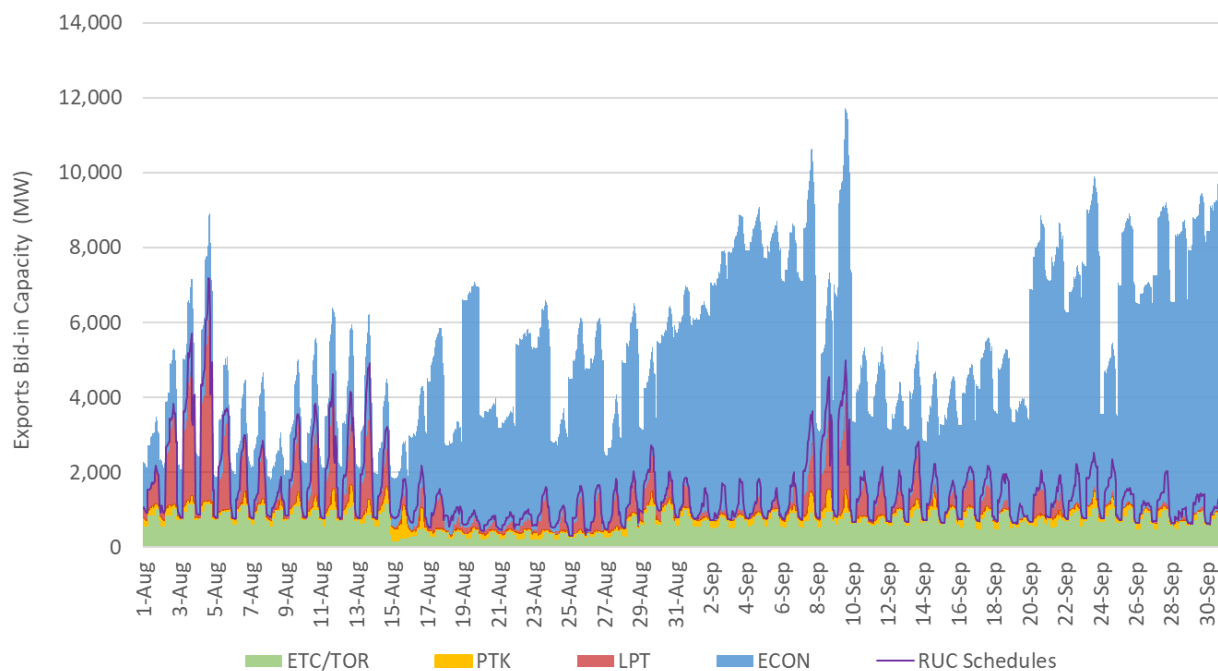
The CAISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into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

10.1 Intertie supply

Figure 41 shows the capacity from static export-based transactions in the day-ahead market for the month of August and September 2021 organized by the various types of exports. This capacity does not include export capacity associated with explicit wheel transactions³² 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 41: Bid-in and RUC cleared export capacity



³² An explicit wheel is an import and an export transaction matched in the system such that the market will always consider them as a single transaction that must clear in balance; i.e., the import and export will be forced to clear at the same MW value. The wheeling feature has to be explicitly defined by the scheduling coordinator at the time of bidding in the imports and exports. 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 cleared 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.

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

Export bid capacity in the day-ahead market varies by hour and typically follows a daily profile. About 67 percent, 16 percent, 14 percent and 2 percent of the export capacity were for economic bids, ETC/TOR, LPT and PTK, respectively. This is driven by at least two factors. With milder load conditions in September, there was naturally less need for exports as reflected by the self-schedule volumes. The Second factor is the change in bidding behavior of exports for the second half of the month. There was a marked change of pattern starting since August 15 when economic bids for exports increased steeply and the majority of these exports were not in merit.

Even the volume of self-schedule capacity for TOR/ETC exports was lower in August and early September compared with July. The volume of PTK exports was modest for most of the month. The volume of LPT in September reduced fairly, while economic exports continue to see a higher. This marked change in pattern may be related to hydro restrictions changes in the northwest.

Figure 42: Bid-in and RUC cleared import capacity

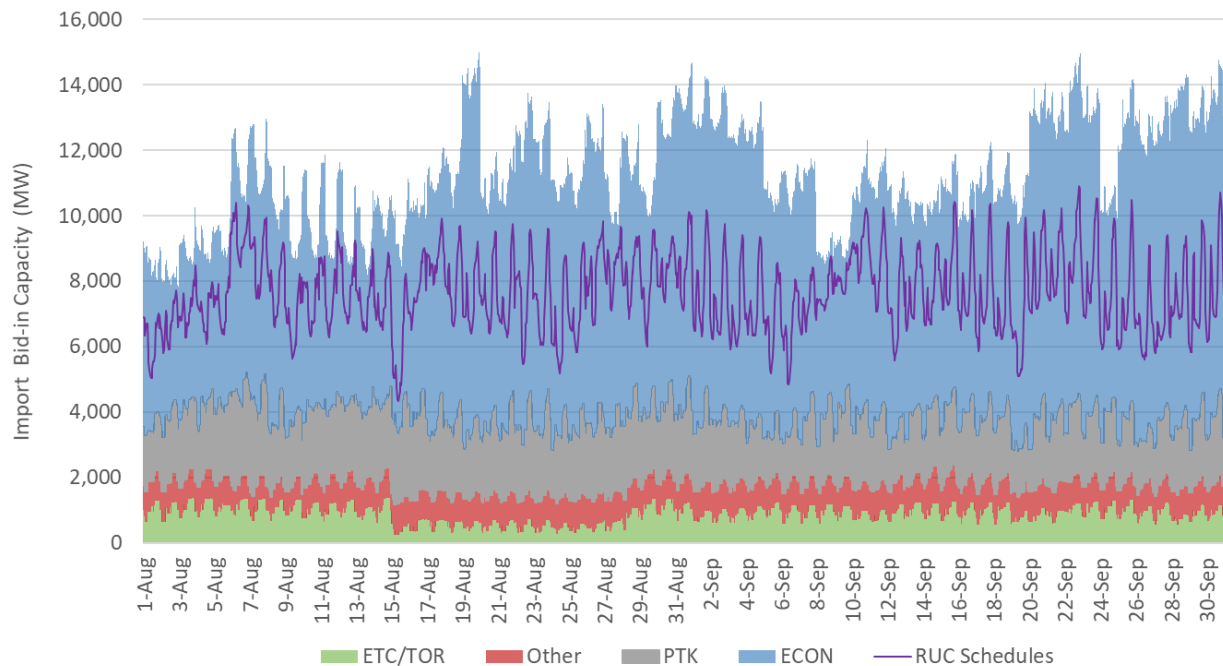


Figure 42 shows the same illustration for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the month, while hourly economic imports continued to see a high volume over 5000MW. The “Other” group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

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Figure 43 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution. The net interchange projected in the RUC process was over 2,000 MW for the majority through all hours in September given milder loads and lower level of exports.

Figure 43: Breakdown of RUC cleared schedules

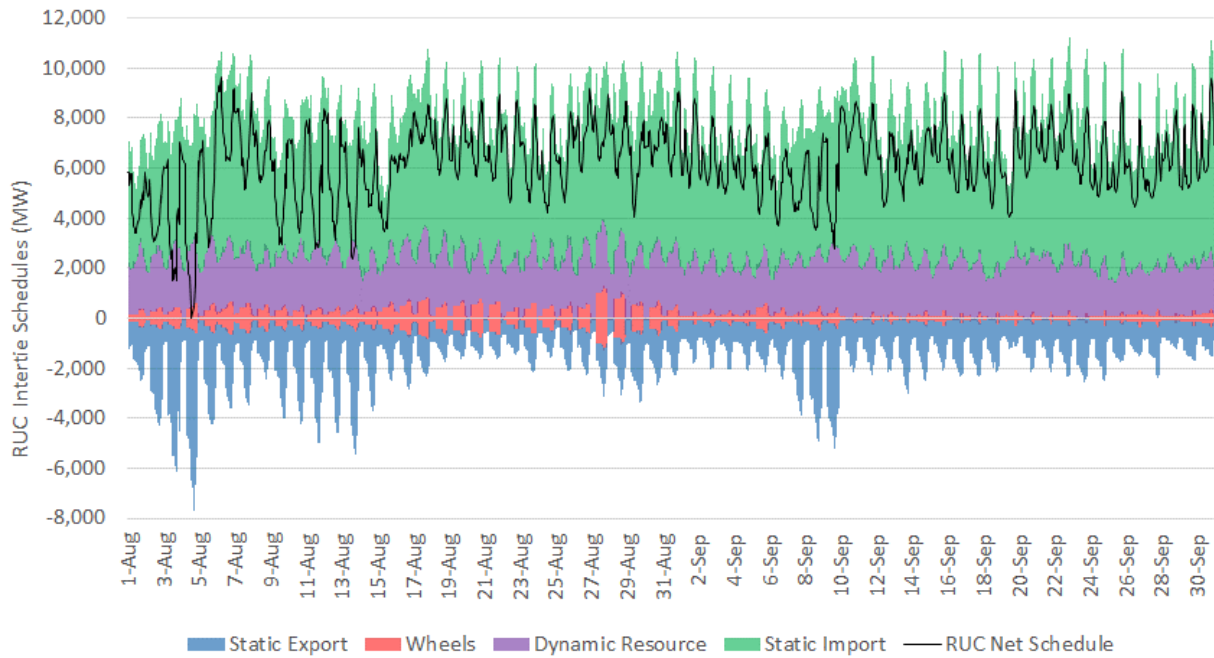
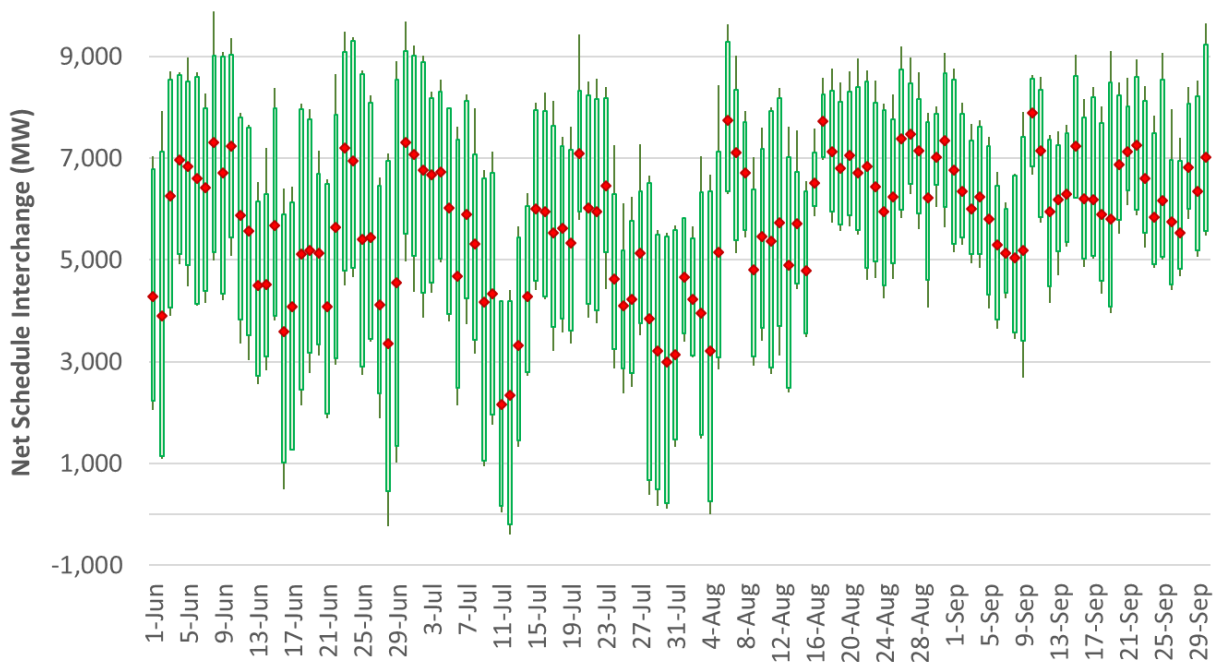


Figure 44: Daily distribution of hourly RUC net schedule interchange

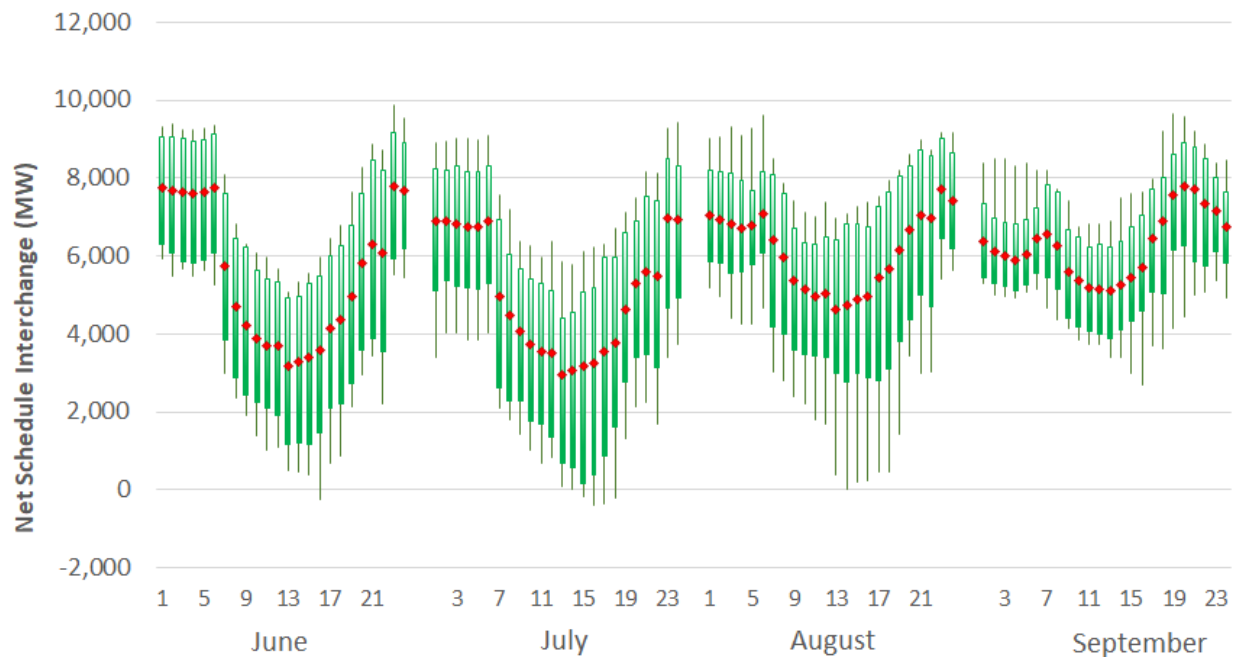


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Net schedule interchange is the algebraic balance of static imports, dynamic and pseudo resources and exports, and it measures the overall contribution to the system supply from scheduling over the interties. Figure 44 is a box-whisker plot to illustrate the distribution of hourly net schedule interchanges using the RUC schedules. The hourly net schedule interchanges were consistently over 2,000 MW with minimum levels above 5,000 MW by the end of the month.

Figure 45 illustrates the hourly net schedule interchange distribution by hour in the summer months. This trend is useful to visualize the hourly profile of schedules and shows that net schedules reduce in midday hours when solar production comes in and start to increase as the solar production fades away in the evening hours. It also shows two well-defined blocks of On- and Off-peak schedules. The lowest net interchange values are attained in hours prior to the gross peak when solar supply is still plentiful.

Figure 45: Hourly RUC net schedule interchange



An area of interest since summer 2020 is the trend of exports in the CAISO's system. Figure 46 trends the distribution of hourly RUC schedule for exports for summer months. Export levels were generally low in September with the exception of September 7 and 8 when load levels were higher and there was more need for supply elsewhere.

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Figure 46: Daily distribution of hourly RUC exports

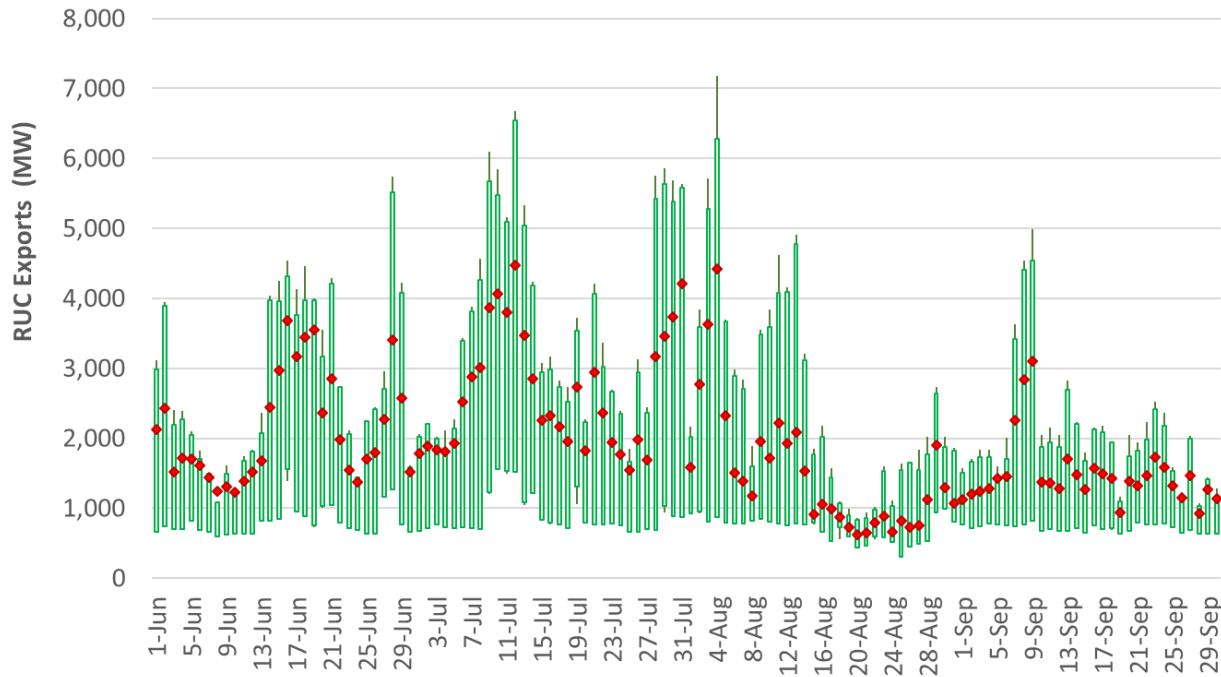
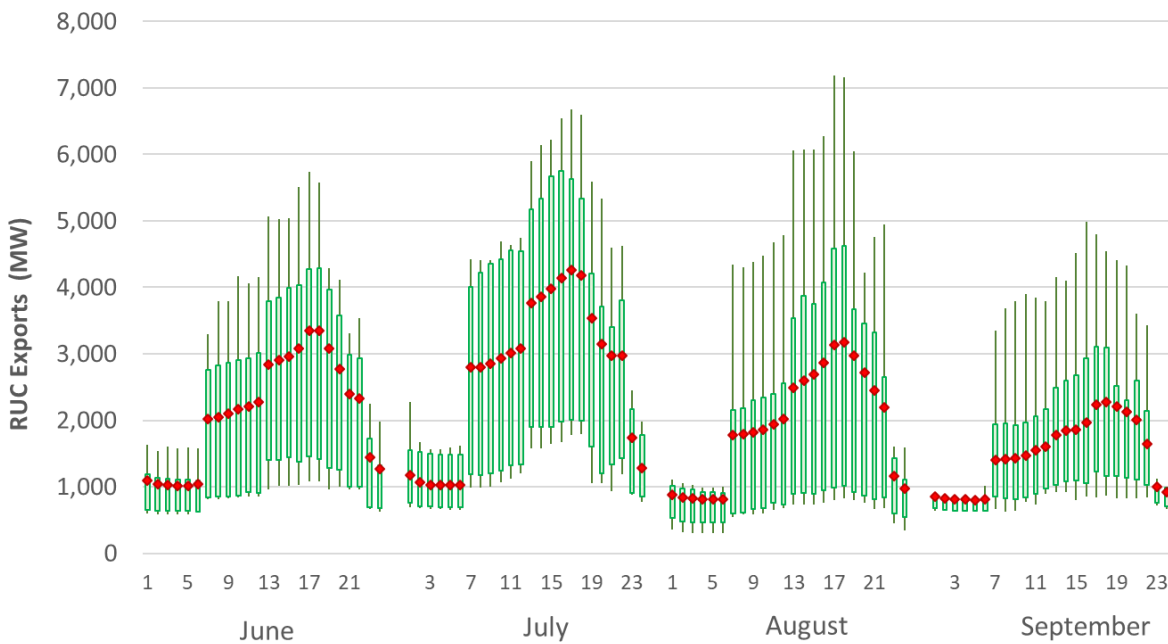


Figure 47 illustrates the hourly distribution of RUC schedules for exports, and that the highest volume occurred during midday hours when CAISO’s system has excess solar supply; exports were in high demand during the afternoon hours at the beginning of the month.

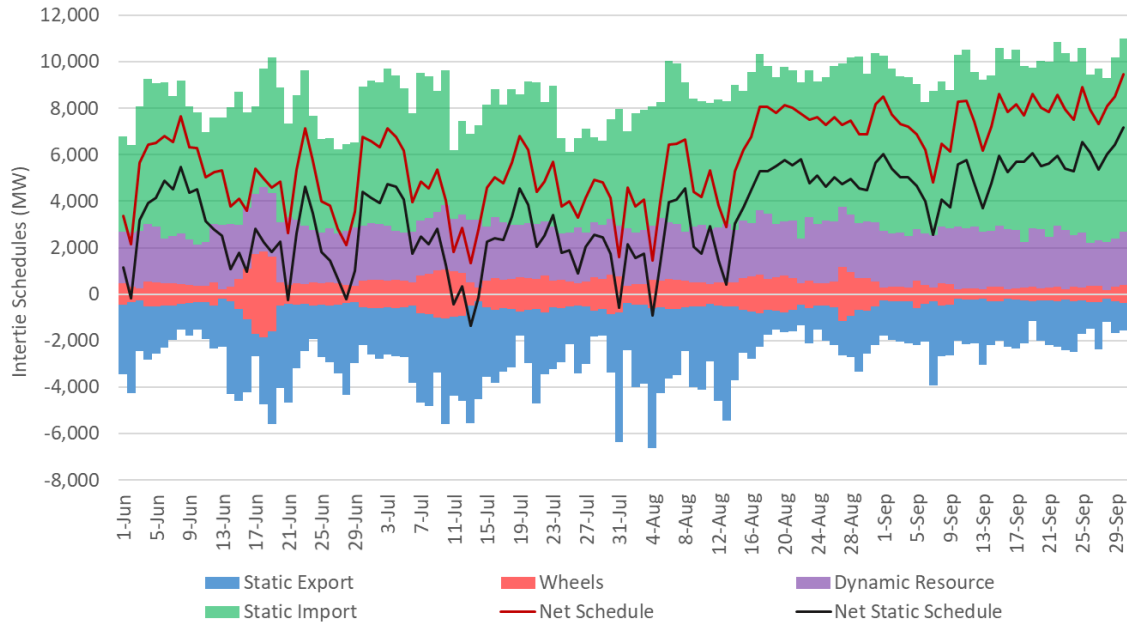
Figure 47: Hourly RUC exports



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Figure 48 shows the inertia capacity available in the day-ahead market for hour ending 19 to highlight the conditions around peak time, when the CAISO’s system faces the highest supply needs.

Figure 48: RUC schedules for interties for hour ending 19



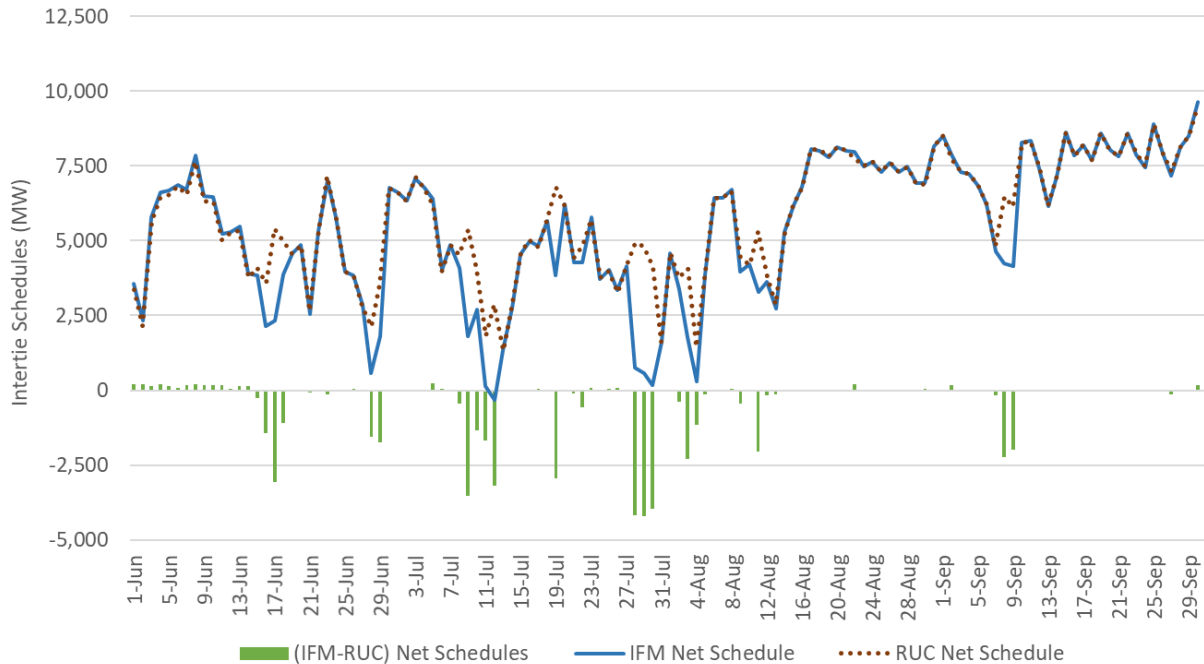
This balance does not include any imports or exports associated with explicit wheeling transactions. Including wheels will increase the volume of imports and exports by the same amount such that the net schedule remains the same. The red line represents the net schedules cleared in RUC (imports plus dynamics less exports), while the blue line represents the net schedule in RUC when considering only static imports and exports.

The RUC process may schedule additional supply to meet the load forecast, above what was scheduled in the IFM. Under tight supply conditions, the RUC process may also identify that export schedules cleared in the IFM process are not feasible, and signals to the participant that their exports is not feasible in the real-time. Therefore, for interties, the RUC schedules are the relevant schedules for assessing what is feasible to flow into real-time, and they are what should be tagged if participants submit a day-ahead tag for their export. IFM schedules are still financially binding. Figure 49 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.³³ IFM schedules for exports were reduced in the RUC process mainly for September 8 and 9. With these export reductions, the RUC net schedules were higher than IFM schedules.

³³ The June report had the bars in green reporting an incorrect value. This has been corrected in this report.

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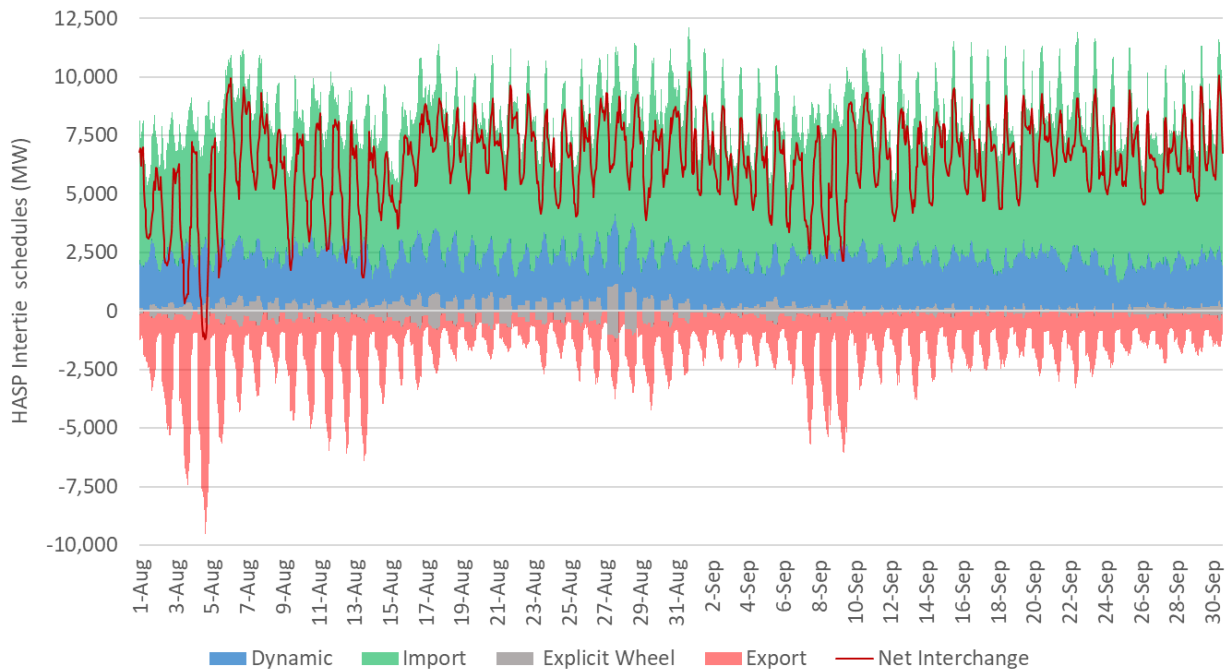
Figure 49: IFM and RUC schedule interchange for hour ending 19



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. 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 50 shows the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred as Net Schedule Interchange. The net schedule interchange is at its lowest value in September 7, 8 and 9 due to the highest level of exports cleared on that day prior to the evening peak. These levels of exports are, however, significantly lower than the ones observed in August. The real-time market largely follows the trend observed in the day-ahead market. On average, for September the net schedule in HASP was about 7,500 MW for peak hours, an increase from the 6,020 MW observed in August.

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Figure 50: HASP cleared schedules for interties in August and September



The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Interties cleared in the day-ahead market can submit self-schedules into. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC.³⁴ Additionally, exports can participate directly into the real-time market with either self-schedules or economic bids.

Each market, RUC or HASP, can assess reduction of exports based on the overall system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority but they are able to be rebid into the real-time market and be fully assessed based on real-time conditions. LPT or economic exports cuts in the RUC process are most likely to be cut again in HASP since they will have the lowest priority in the presence of tight supply conditions. Figure 51 shows all the exports cleared in the HASP process and identifies the nature of such exports. TOR is for export with scheduling priorities associated with transmission rights. The groups of DA_PTK or DA_LPT stand for day-ahead exports coming into real-time as self-schedules with high or low priorities. Similar classification is followed for those high and low priority exports coming into real-time directly (RT_PTK and RT_LPT). ECON stands for economic exports. The group of wheels stands for all type of wheels observed in the real-time market (low- or high-priority). With different framework of priorities before August 4, this classification is an approximation to

³⁴ Based on these rules implemented on August 4, through the summer enhancements described earlier and now in place, the CAISO will no longer provide exports a higher priority than load in the real-time, and will only provide them equal in priority to load if the participant demonstrates that they continue to be supported by resources contracted to serve external load.

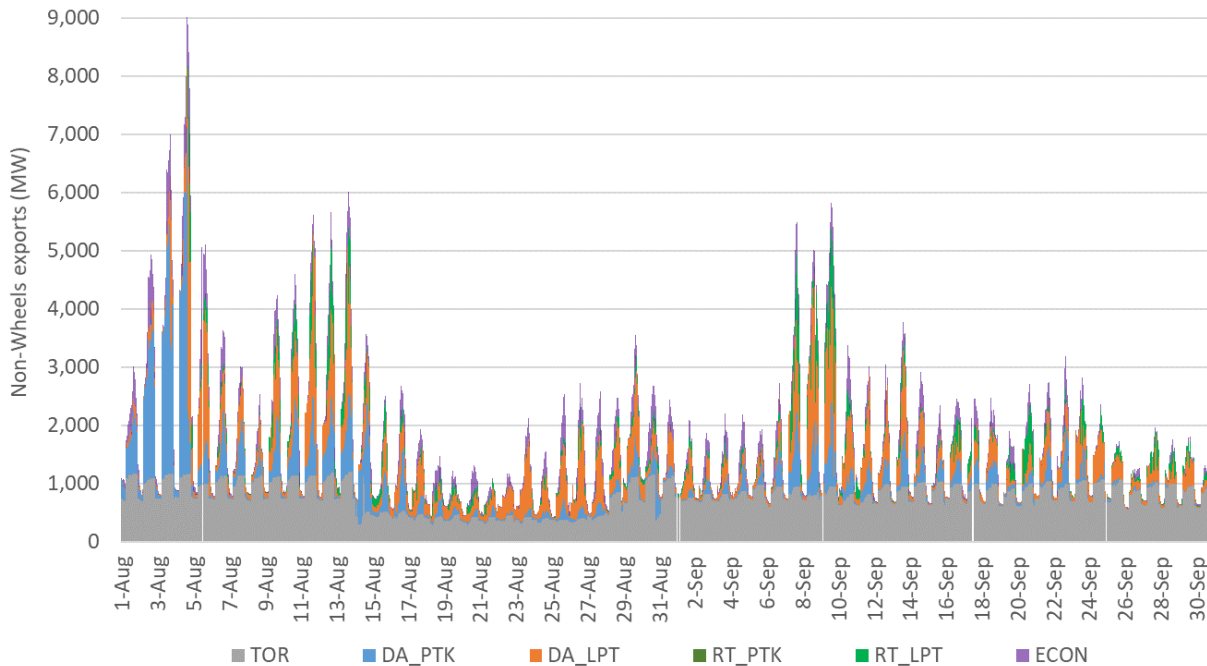
Details are available at <http://www.aiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf>

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the new framework post-August 4 that is applicable for the first 4 days of August. Given the many different groups for exports, wheels are shown in this metric explicitly. These exports are only for non-wheel transactions. A granular breakdown of wheels is provided in a subsequent section of wheels.

The volume of exports cleared in real time follows the pattern of loads with a fair reduction since the second half of August and with an increase only during days of high loads around September 8 and 9.

Figure 51: Exports schedules in HASP



Imports and exports were scheduled over multiple intertie scheduling points in September, with Malin, Paloverde and NOB seeing the highest volume of transactions. Figure 52 through Figure 54 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.³⁵ In September Exports trended down on Palo Verde intertie, when the Southwest was experiencing less stringent supply conditions.

³⁵ The breakdown of imports and exports at the system or tie level may be subject to different levels of aggregation. For instance, wheels are in balance and the import side of a wheel nets out with the export side of the wheel. There are some transactions like TORs that behave like wheels although they are not explicit wheels in the market clearing process; i.e., the market can clear the import at a value different than the export's value. Generally they may clear in balance and thus the export side may not add demand needs to the system, like stand-alone exports, even though it is counted in the total volume of exports for a specific tie.

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Figure 52: HASP schedules at Malin intertie

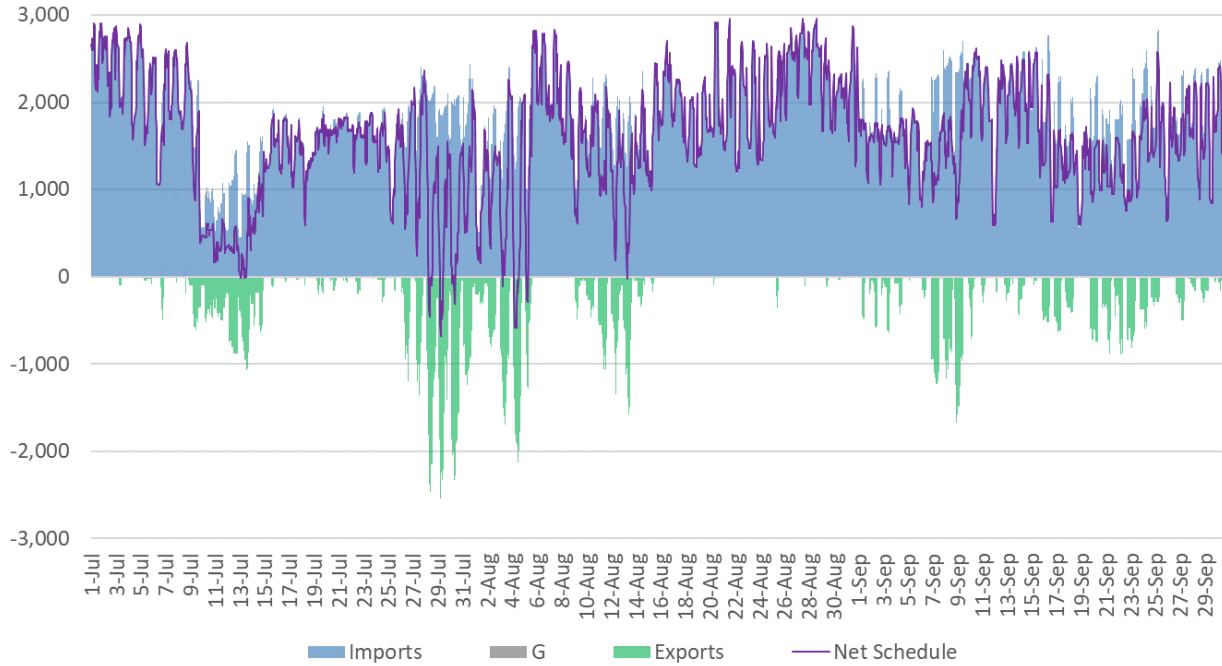
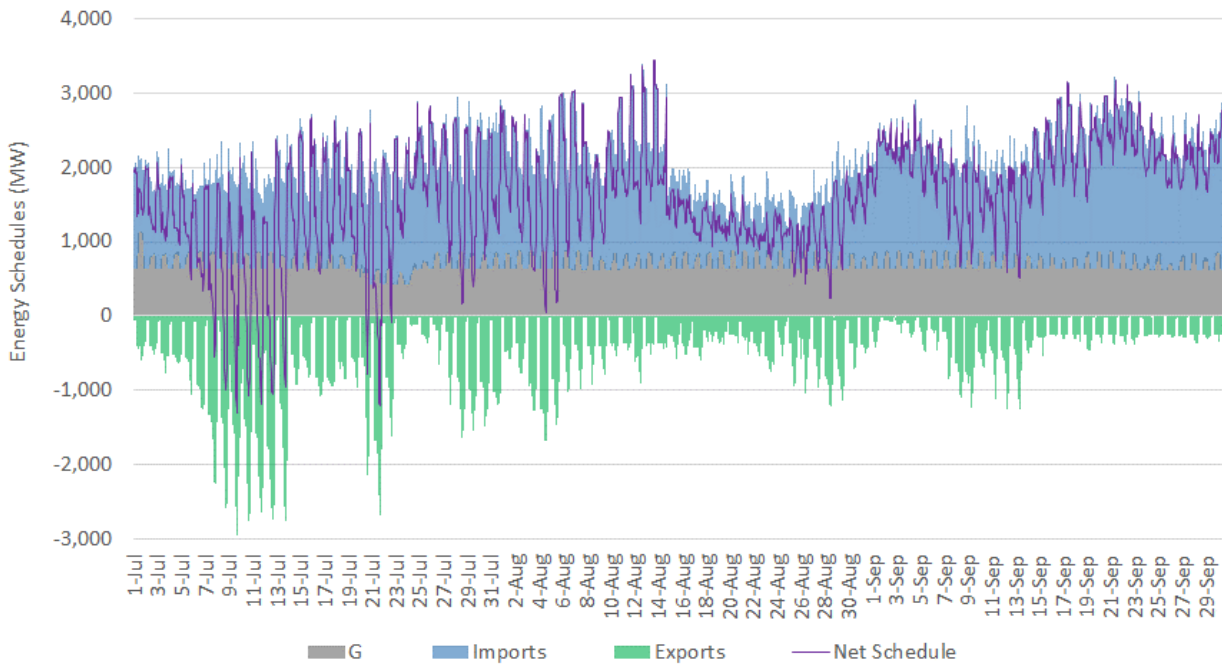
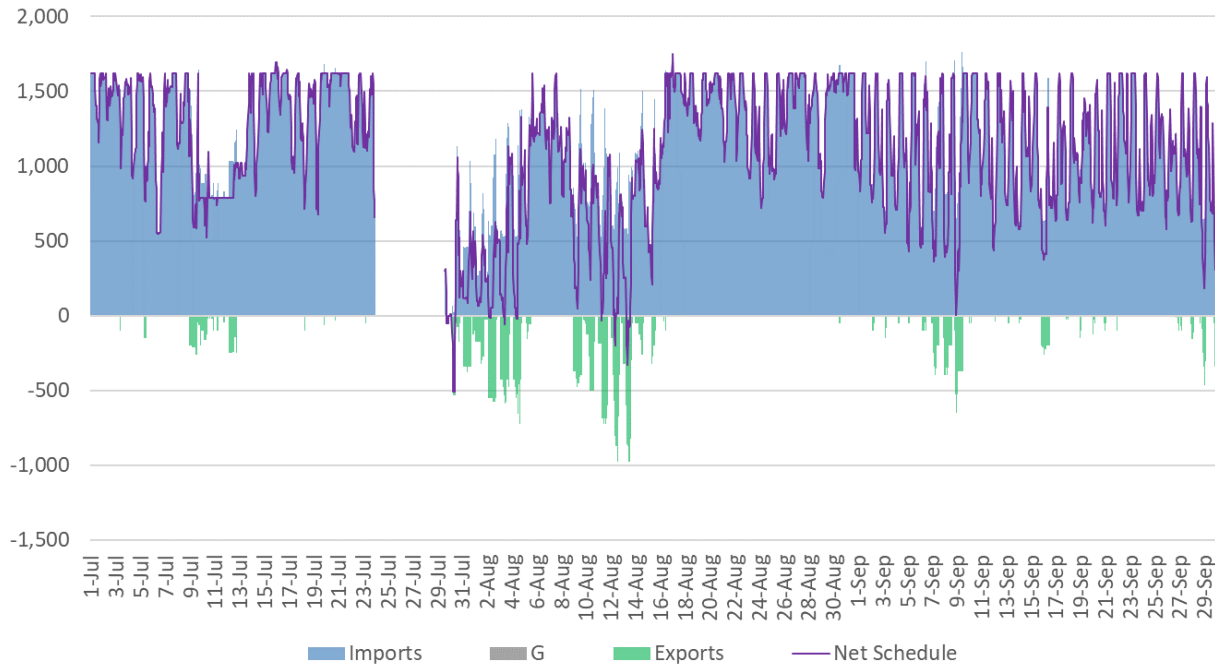


Figure 53: HASP schedules at PaloVerde intertie



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Figure 54: HASP schedules at NOB intertie



10.2 Resource adequacy imports

Imports can be used to meet Resource Adequacy (RA) requirements and they can be resource-specific or non-resource specific. For simplicity, this analysis relies on static imports as a proxy for non-specific resources. The other type of imports are dynamic or pseudo tie resources, which typically will be resource-specific. The total amount of RA supported by static imports in September was about 3,613 MW related to LSEs under CPUC jurisdiction.

Under RA rules, non-resource specific RA imports for LSEs under CPUC jurisdiction must self-schedule or bid with economics bids between $-\$150/\text{MWh}$ and $\$0/\text{MWh}$ at least for the availability assessment hours. Figure 55 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 99 percent of the total RA import capacity was bid with either self-schedules or economic bid at or below $\$0/\text{MWh}$ in September. This plot also shows the cleared imports, which largely covered all imports with self-schedules and bids with prices at or below $\$0/\text{MWh}$. A small volume of imports with high bid prices did not clear in the day-ahead market.

Figure 56 shows the same information for the real-time market using the HASP bids. The majority of RA imports come in as self-schedules in the real-time market, with only a small fraction of imports coming with an economic bid. In the day-ahead market, 8.8 percent in August came with an economic bid. The majority of RA imports were bidding at least up to the RA level, while a few RA imports indeed bid-in above their RA level.

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Figure 55: Day-Ahead RA import for hour endings 17 through 21 for weekdays

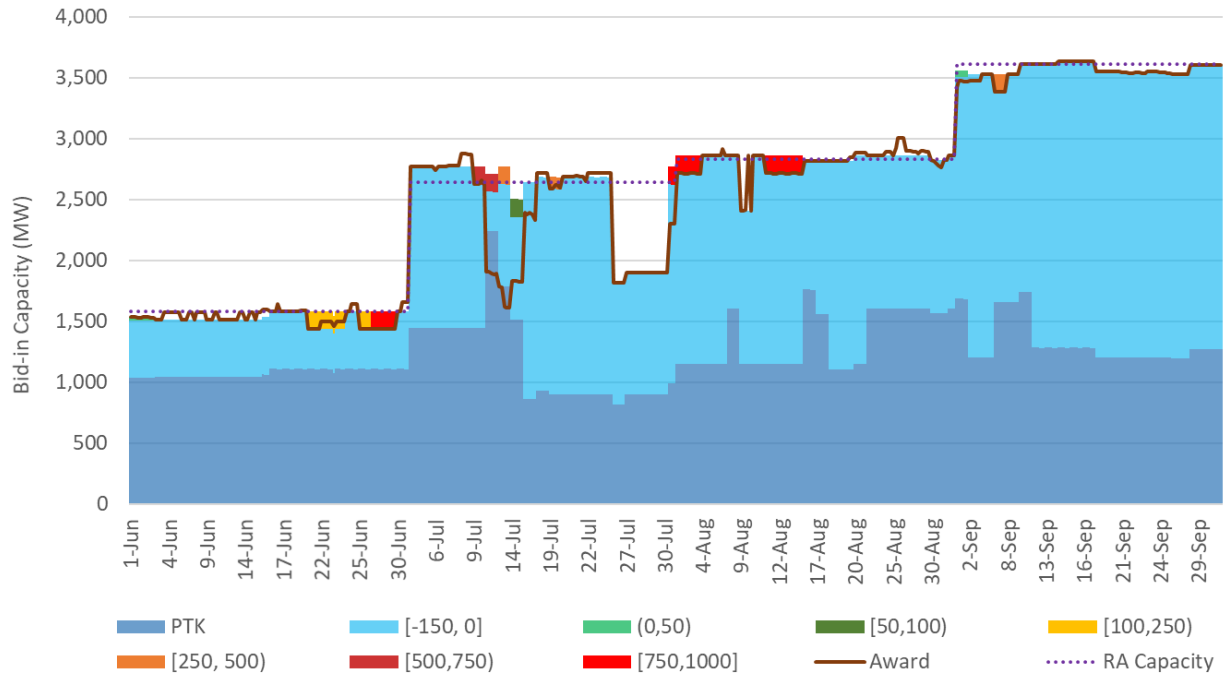
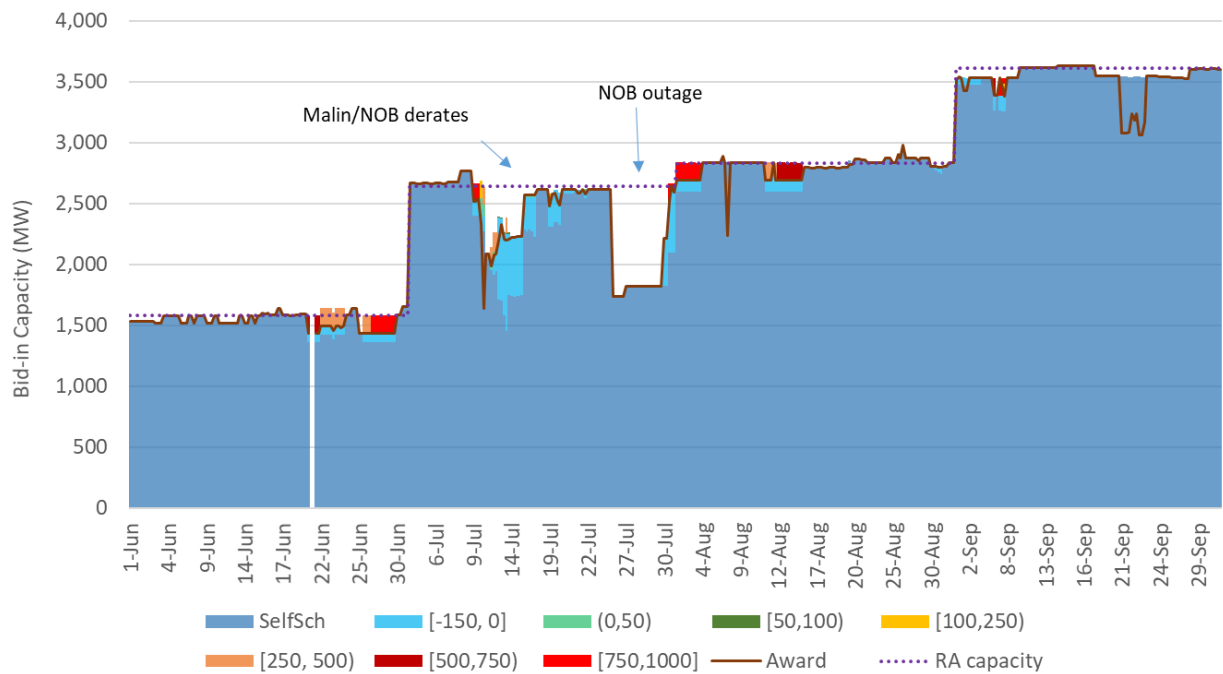


Figure 56: HASP RA import for hour endings 17 through 21 for weekdays



10.3 Wheel transactions

With the summer enhancements for Exports, Loads and wheels scheduling priorities, wheels seeking a high scheduling priority in the market equal to ISO load are required to register in advance their wheel transactions by meeting specific requirements up to 45 days prior to the start of month.³⁶ If the requirements are not met and the wheel transaction is not registered, the transaction receives low scheduling priority. Since the enhancement was activated in August, the CAISO received registration requests for September from six different scheduling coordinators for a set of wheel transactions, which totaled 687 MW. Table 5 shows all the wheel-through paths registered by all scheduling coordinators. From all requests submitted for registration, only one wheel-through transaction for 30 MW was not approved.

Table 5: Wheel-through transaction registered for September

Source	Sink	MW
MALIN	PVWEST	33
MALIN	PVWEST	75
MALIN	MEAD230	20
MALIN	ELDORADO	96
MALIN	PVWEST	150
NOB	MEAD230	65
NOB	MEAD230	35
NOB	MCCULLOUG500	75
NOB	PVWEST	100
SYLMAR	MCCULLOUG500	38
Total		687

Once these transactions are registered, they can be scheduled in the CAISO's markets and receive the applicable scheduling priority. Scheduling coordinators can opt to utilize these wheels on an hourly basis through September. Figure 57 shows an hourly average of wheels cleared in the RUC process. Wheels participating in the day-ahead market in the month of September were ETC/TOR, or self-schedules. There were no wheels with economic bids. The volume of explicit wheels associated with ETC/TOR was stable throughout the month. Figure 58 provides an hourly breakdown of self-schedule wheels, with the maximum hourly cleared RUC volumes of 96 MW between September 5 and 9; this is significantly lower than the volumes observed in August when RUC reached a maximum wheel volume of 702 MW, and even lower than the 1,204 MW of June. These figures reflect the wheels and their scheduling priorities used in the day-ahead market.

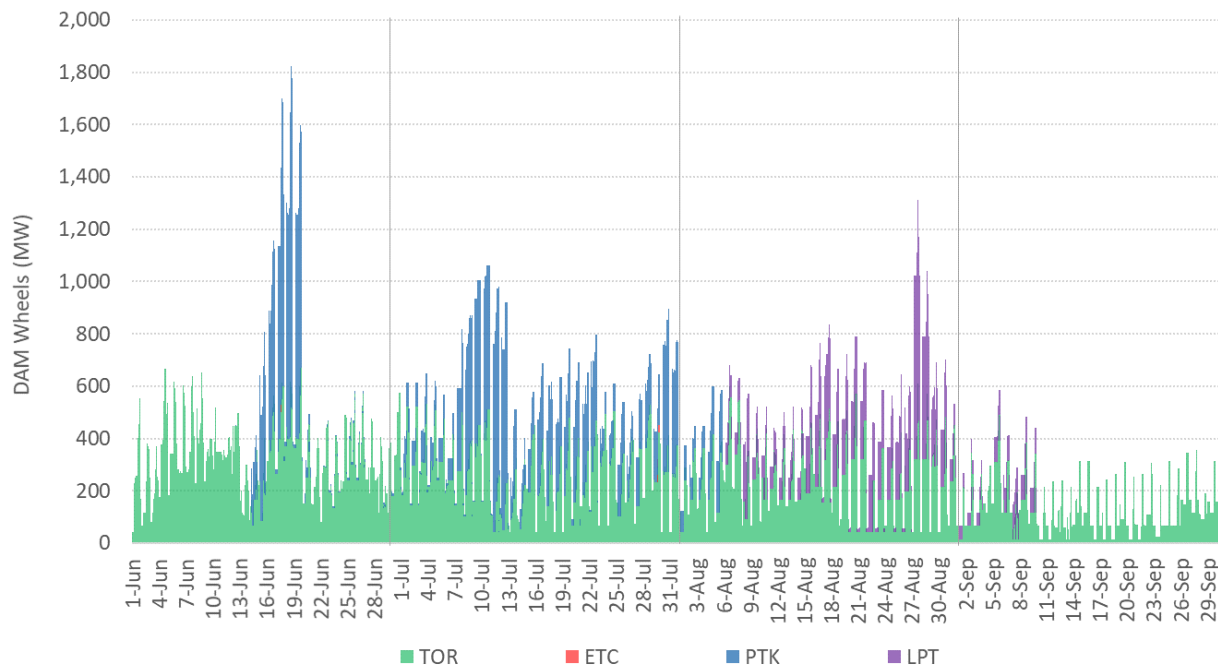
Similar to July and August, wheels generally came as block schedules matching the time-of-use of the day in September as shown in Figure 60; i.e., the submitted self-schedules were at the same MW value for blocks of multiple hours that define off-peak (hours ending 1 through 6 and hours ending 23 through 24) and on-peak hours (hours ending 7 through hour ending 22).

³⁶ Market Operations Business Practice Manual, section 2.5.5 (2021).

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In comparing the high priority wheels registered in advance for the month of September with the wheel records that were actually bid in the day-ahead market, Figure 61 shows that up to 96 MW out of the 867 MW of registered wheels in September were intended to be used in the market. However, due to either mapping issues internal to the bid application to recognize these wheels or the lack of familiarity of scheduling coordinators with the nuances of the new functionality, these wheels intended to be high priority came into the market as low priority wheels as previously shown in Figure 58.

Figure 57: Hourly volume of wheel transactions used in the day-ahead market by type of bid



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Figure 58: Hourly volume high- and low priority wheels used in the market

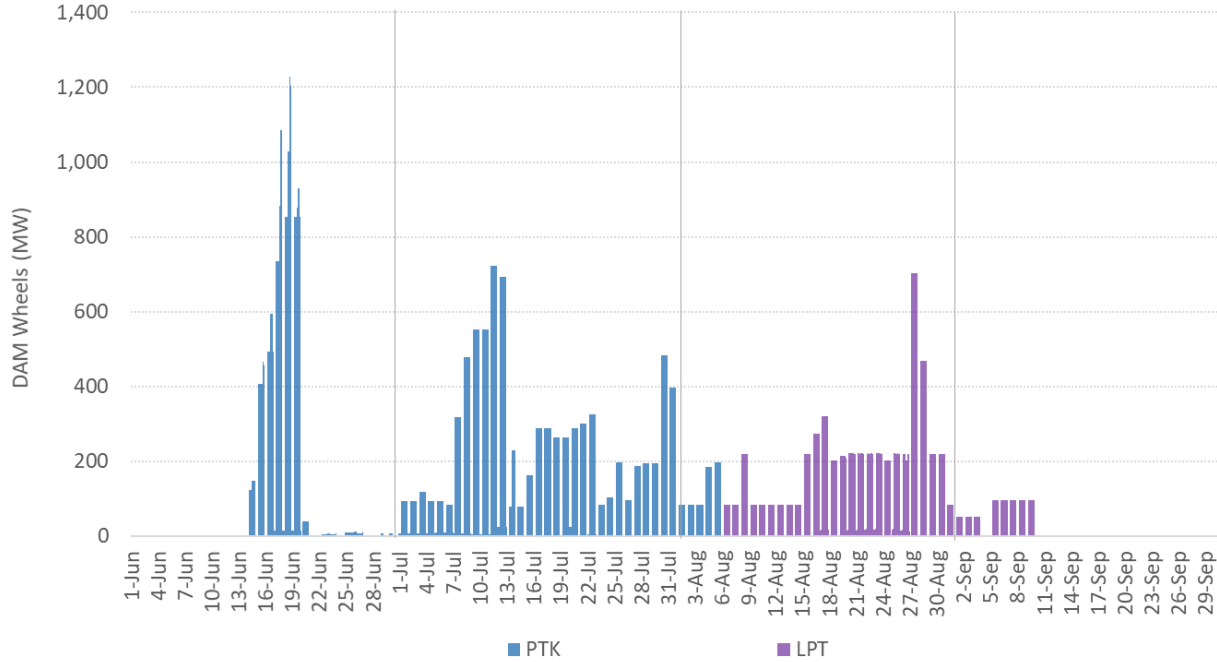
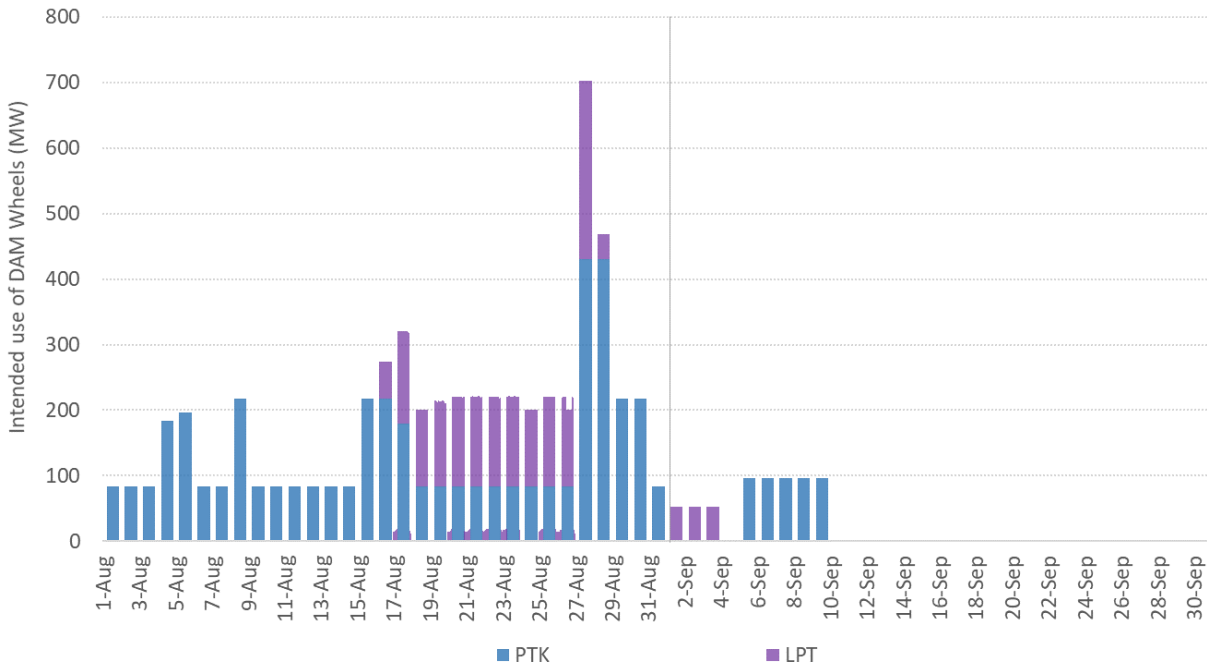
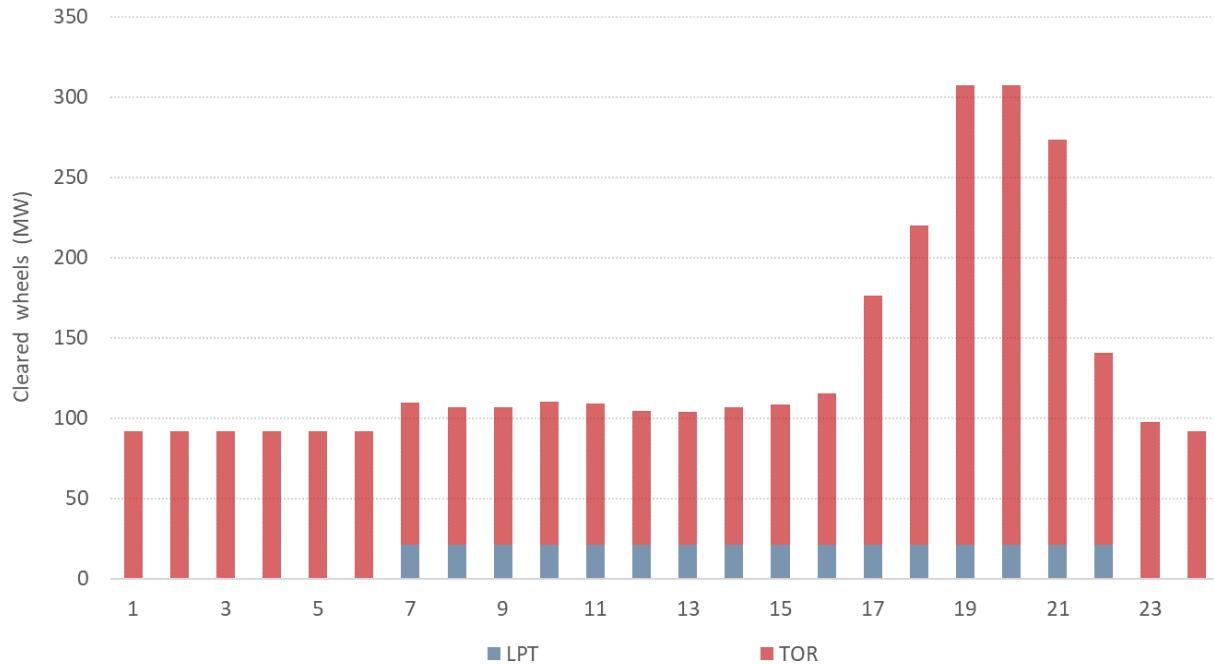


Figure 59: Day-ahead hourly profile of wheels intended to be used in August and September



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Figure 60: Day-ahead hourly profile of wheels in September



Wheels are defined with a source and sink location in the CAISO’s markets to factor in their contribution to the flows on either intertie constraints or internal transmission constraints. Figure 61 summarizes the hourly average of wheels organized by source and sink combinations. An empty entry reflects that no wheels were present for that given source-to-sink combination in September. *Source* refers to the import scheduling point while *sink* refers to the export scheduling point. The path with the largest volume of wheels in September in the day-ahead market was from Malin to El Dorado, followed by wheels from Sylmar to Palo Verde.

Figure 61: Hourly average volume (MWh) of wheels by path in September

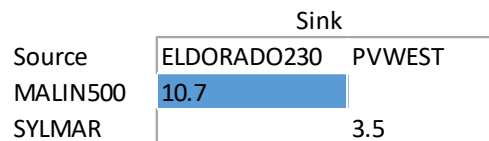
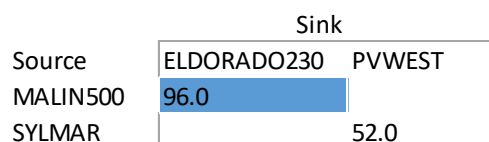


Figure 62 summarizes the maximum hourly wheels cleared in any hour in September in the day-ahead market by source-to-sink combination. The maximum wheel transaction of 96 MW in September occurred from Malin to El Dorado.

Figure 62: Maximum hourly volume (MW) of wheels by path in September

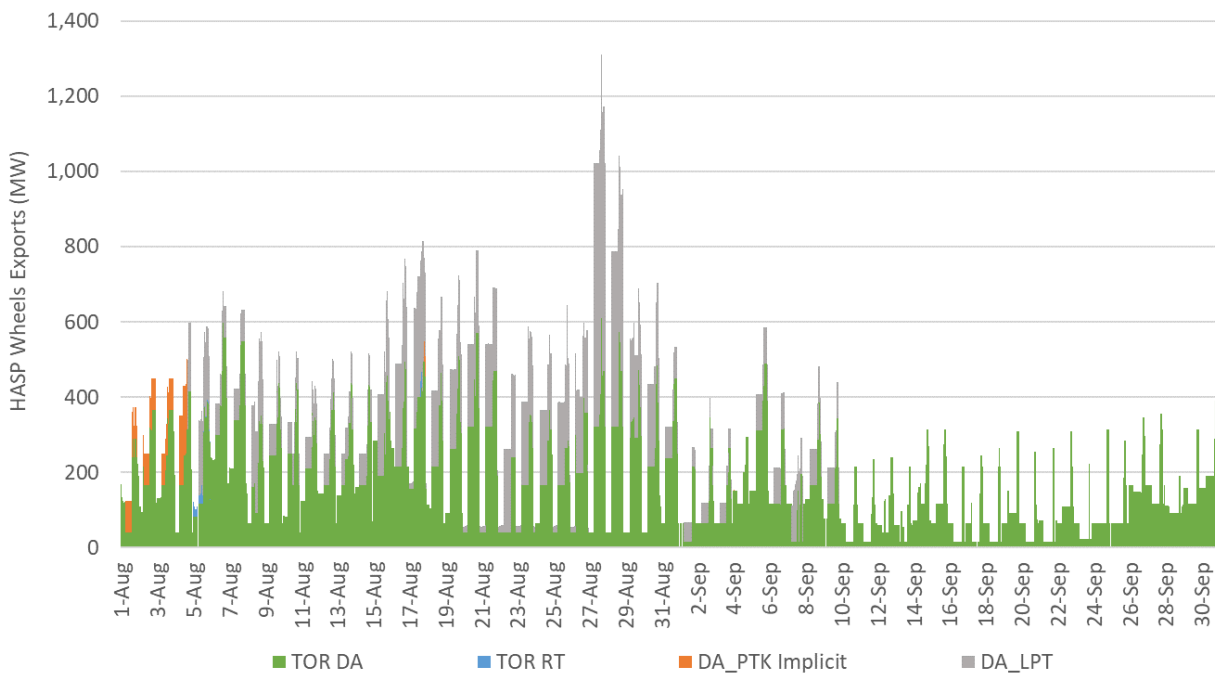


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Although wheels do not add or subtract capacity to the overall power balance of the CAISO market, they compete for limited scheduling and transmission capacity. With self-schedule wheels having higher priority than stand-alone imports or exports, wheels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

Wheels cleared in the day-ahead market can be carried over into the real-time market with a day-ahead priority or be directly self-scheduled in HASP process. Figure 63 shows the volume of wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 63: Wheels cleared in real-time market



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

The *DAM_PTK* implicit applies basically to the wheels prior to the summer enhancements where a wheel cleared in the day-ahead market carried over real-time as a self-schedule but then they did not come as explicit wheels in real time. Instead, they came in as default day-ahead priority imports or exports into the real-time market. The *DA_LPT* group reflects wheels that cleared in the day-ahead market and came in explicitly with a day-ahead low priority into the real-time market under the new framework of scheduling priorities implemented on August 4.

Notably, a large portion of the wheels cleared in real-time are essentially the same wheels cleared in the day-ahead market, with basically no incremental volumes of new wheel bids coming in to real-time. The maximum volume of wheels in real-time were 796 MW in the days of September 5 to 9, which also saw the largest *TOR* wheel of 490 MW.

11 Demand Response

The CAISO markets consider demand response programs designed to reduce demand based on system needs, and trigger demand response programs through market dispatches. In the CAISO’s markets, there are two main 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 64 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 September, PDR resources were consistently dispatched in both the day-ahead and real-time markets. The largest volume of PDR dispatches in real-time occurred on September 9 at about 251 MW.

Figure 64: PDR Dispatches in day-ahead and real-time markets

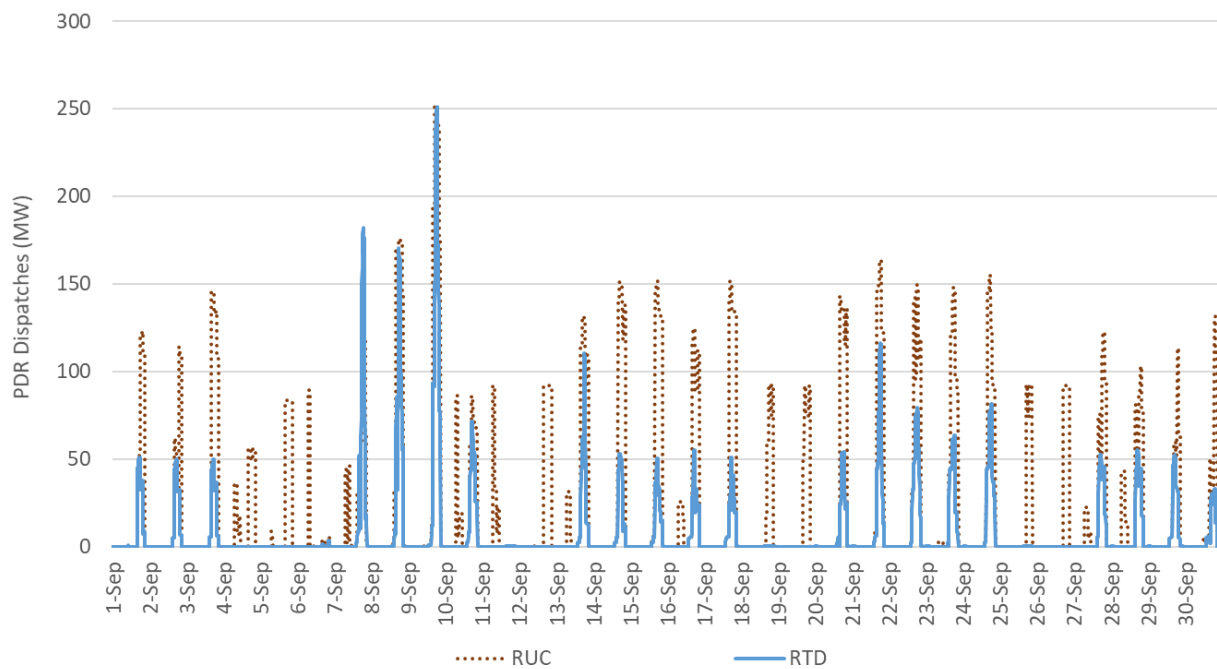
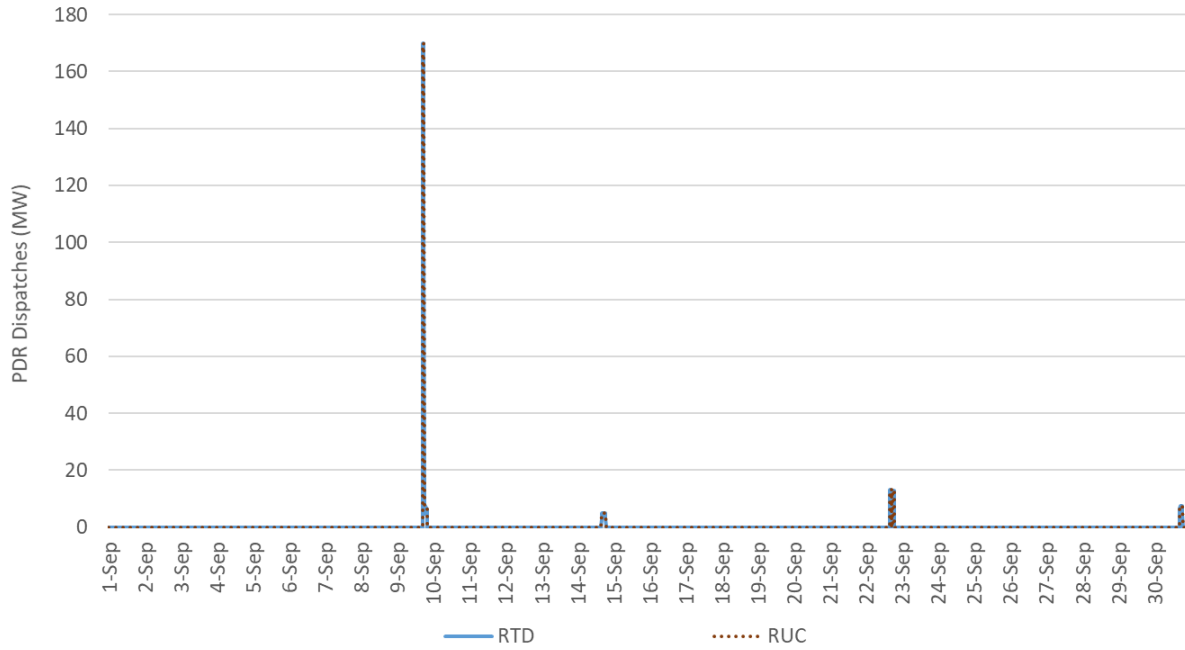


Figure 65 shows the dispatches for reliability demand response resources (RDRRs) in both the day-ahead and real-time markets. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market even when there is no energy emergency declaration. Although most RDRRs are only deployed in the real-time when the CAISO has declared at least a CAISO Warning, some RDRRs may bid-in economically into the CAISO day-ahead market. In that case, any cleared RDRRs will come into the real-time market as a self-schedule and be dispatched generally at the same level of the day-ahead market award. RDRRs were dispatched in the real-time market only on September 9 up to 170 MW.

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Figure 65: RDRR dispatches in day-ahead and real-time markets for September



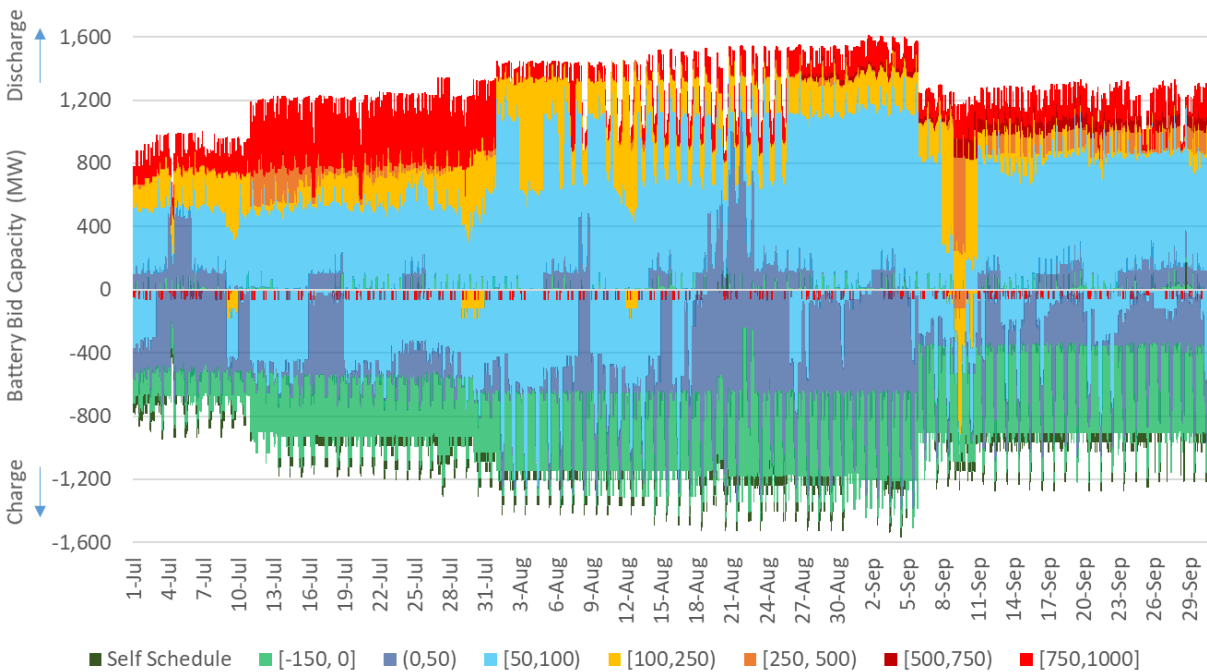
At the time this report was prepared, there were no estimates yet of the demand response performance. Estimates become available about two months after the trade date based on settlement data submitted by the scheduling coordinators and are used to measure the performance of demand response resources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

12 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 September 2021, there were 28 storage resources actively participating in the CAISO markets. Of these 28 resources, 27 storage resources participated in both the energy and ancillary service market, whereas one resource 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 September, the smallest size of the 28 storage resources was 4 MWh, and the largest size was 920 MWh. In September the total storage from all the active resources participating in the market was 6,440 MWh. In terms of the capacity made available to the markets, Figure 66 shows the bid-in capacity for storage resources in the day-ahead market.

Figure 66: Bid-in capacity for batteries in the day-ahead market



The negative area represents charging while the positive area represents discharging. The bid-in capacity is organized by \$/MWh price ranges. The green area represents batteries bidding negative prices for charging and shows a consistent pattern in the summer months. There is a fair amount of capacity willing to charge at positive prices only when prices are higher than \$50/MWh, as shown in light blue. On July 11 and then at the beginning of August the overall capacity increased with additional units available in the market. The overall capacity saw a reduction since early September due to certain resources unavailability. The bright red shows bids close to or at the bid cap and shows that there is certain volume

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of storage capacity that is expecting to discharge only at these high prices. Figure 67 shows the bid-in capacity for the real-time market. The majority of bids into the real-time market are between $-\$150/\text{MWh}$ and $\$100/\text{MWh}$.

Figure 67: Bid-in capacity for batteries in the real-time market

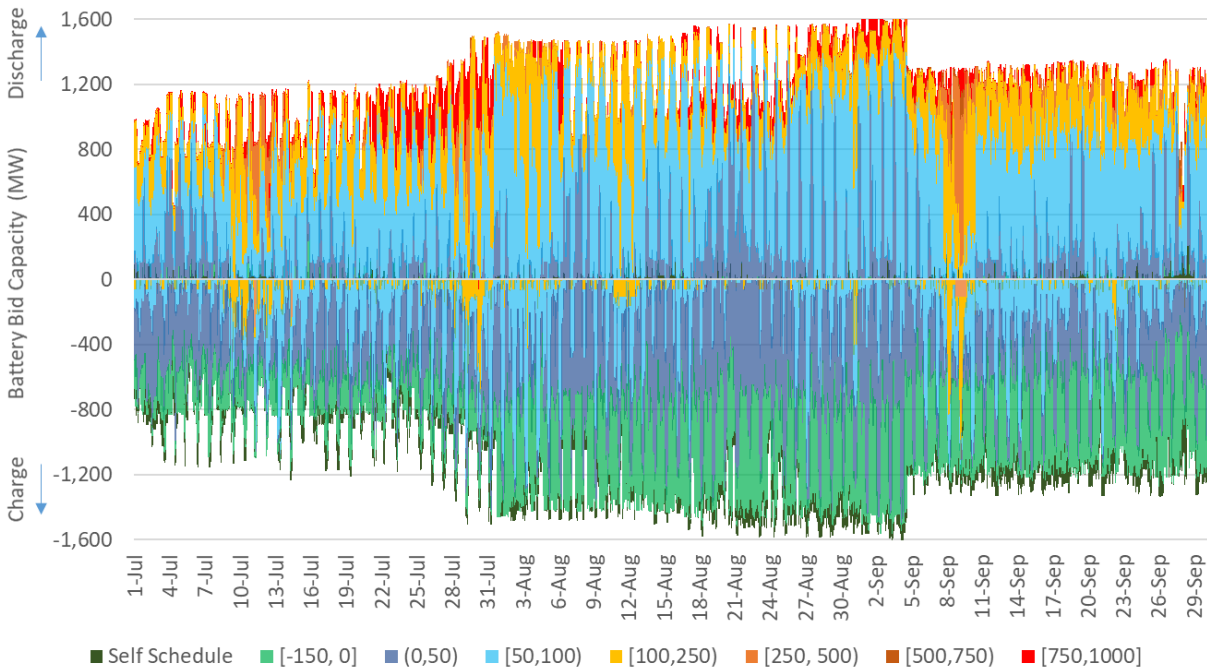
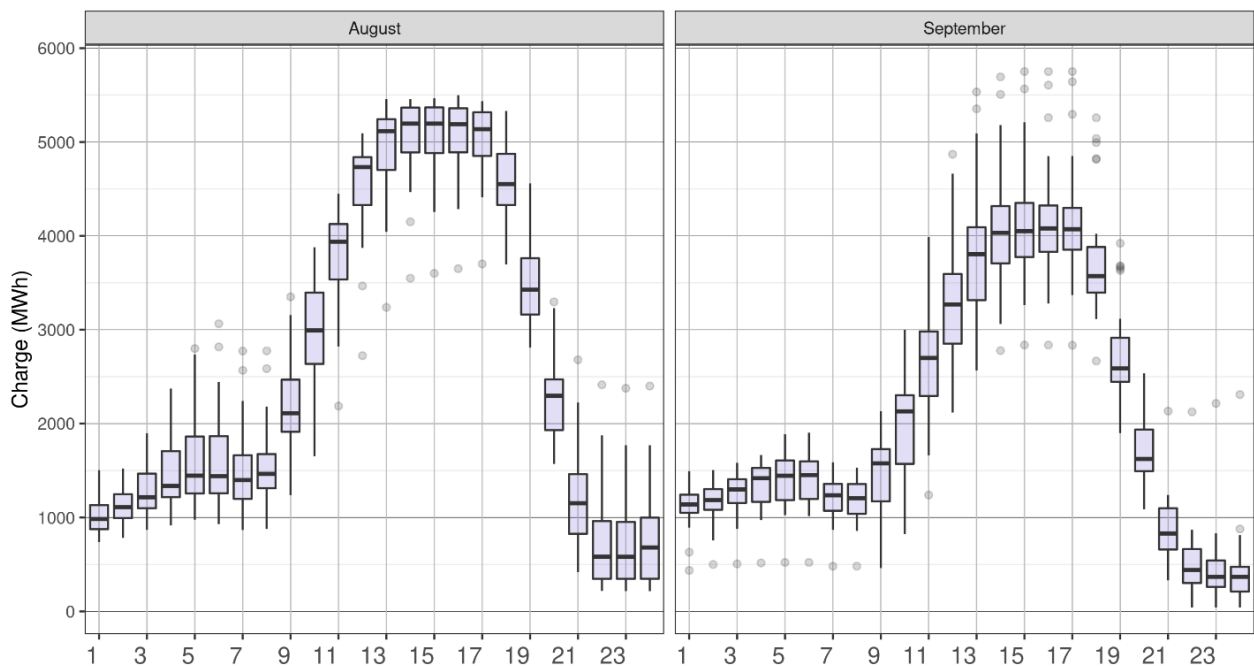


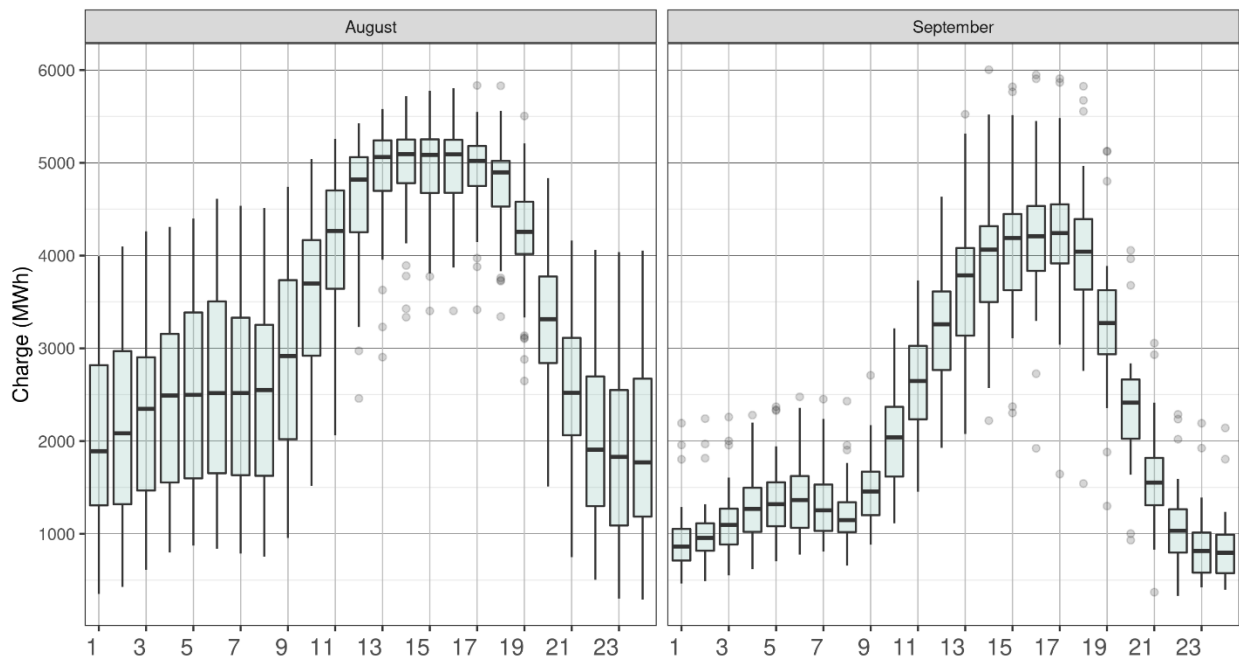
Figure 68 IFM distribution of state of charge for August and September 2021



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Figure 68 shows the hourly distribution of the storage capacity of resources participating in IFM for August and September 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. In September, the highest median system state of charge was 4080 MWh, which occurred in the hour ending 16, which was lower than the median total system state of charge in August because there was an outage for several storage resources in September. Figure 69 shows the distribution of state of charge for the real-time market for August and September 2021. The hourly average state of charge in the real-time market was in the same ball park range as the day-ahead hourly average state of change in September.

Figure 69 Real-Time Market distribution of state of charge for August and September 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 70 shows the average hourly system marginal energy component (SMEC) of the locational marginal price in IFM for September 2021. The hourly average SMEC is the highest in hours ending 18, 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. The chart in Figure 71 and Figure 72 shows the distribution of energy awards in hours ending 18 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.

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Figure 70: IFM hourly average system marginal energy price for September 2021

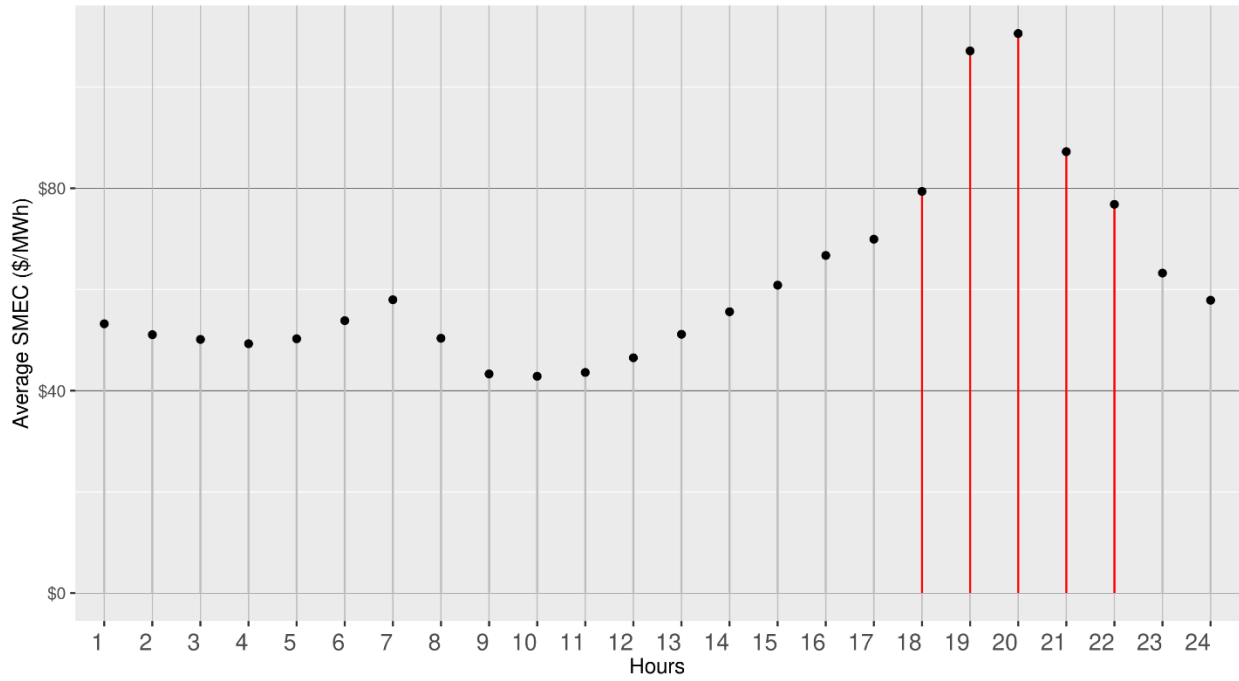
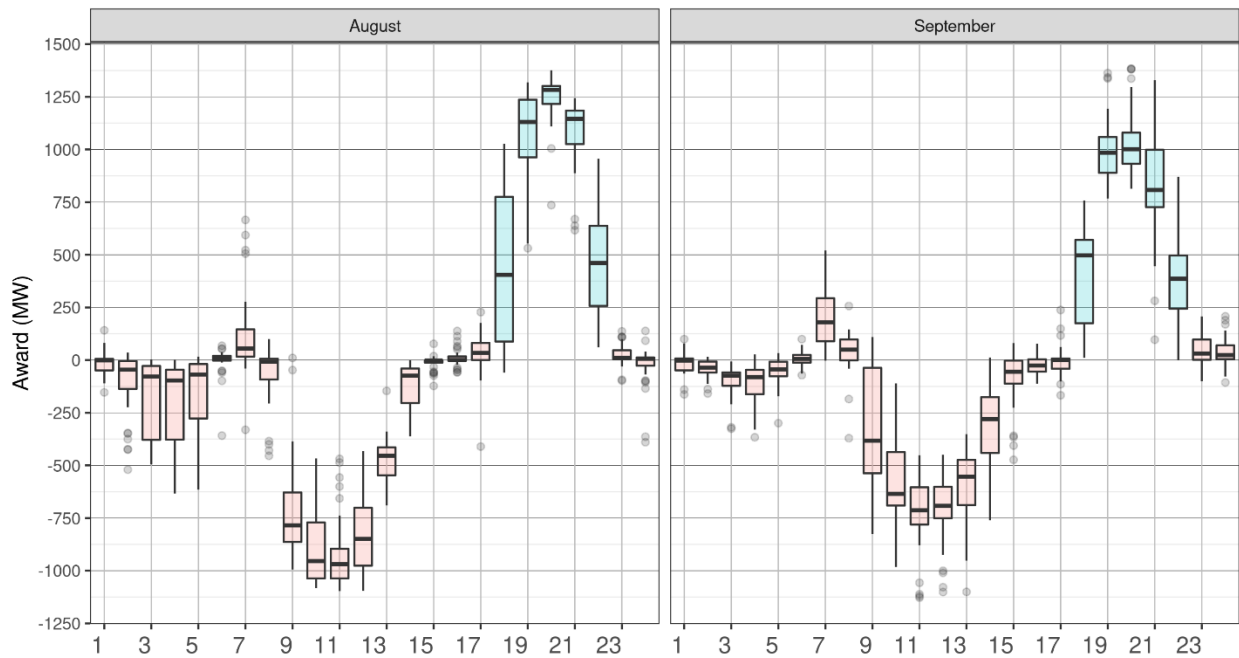


Figure 71: Hourly distribution of IFM energy awards for batteries in August and September 2021



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Figure 72: Hourly Distribution of real-time dispatch for batteries in August and September 2021

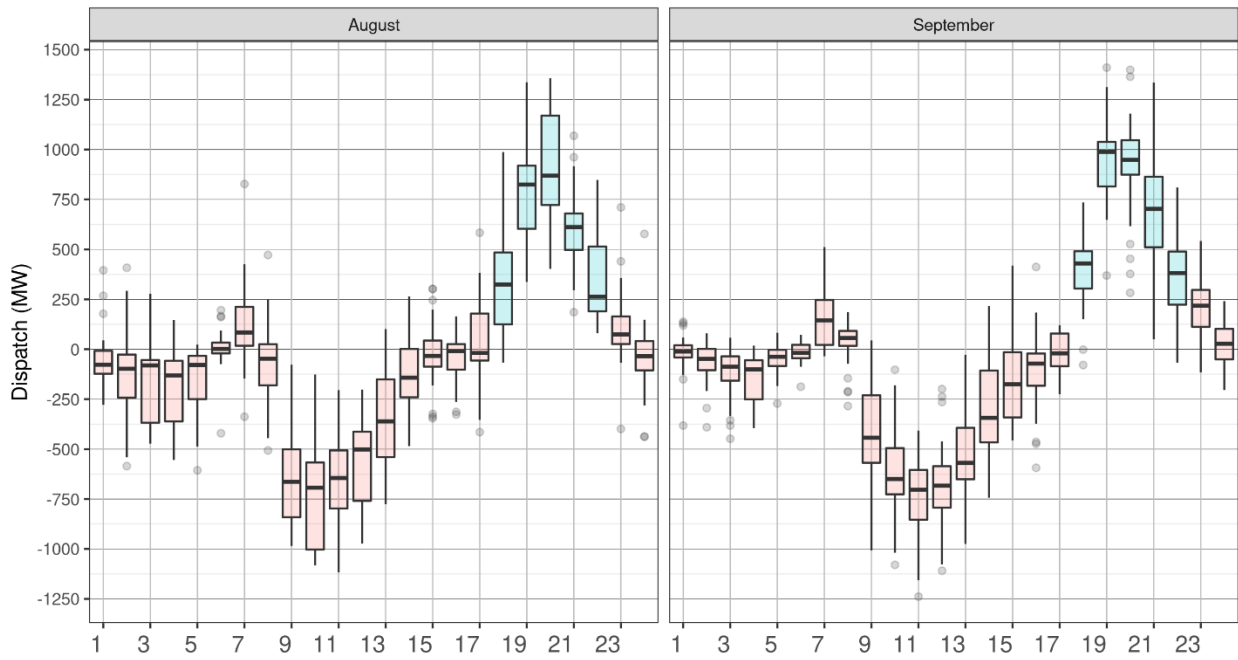
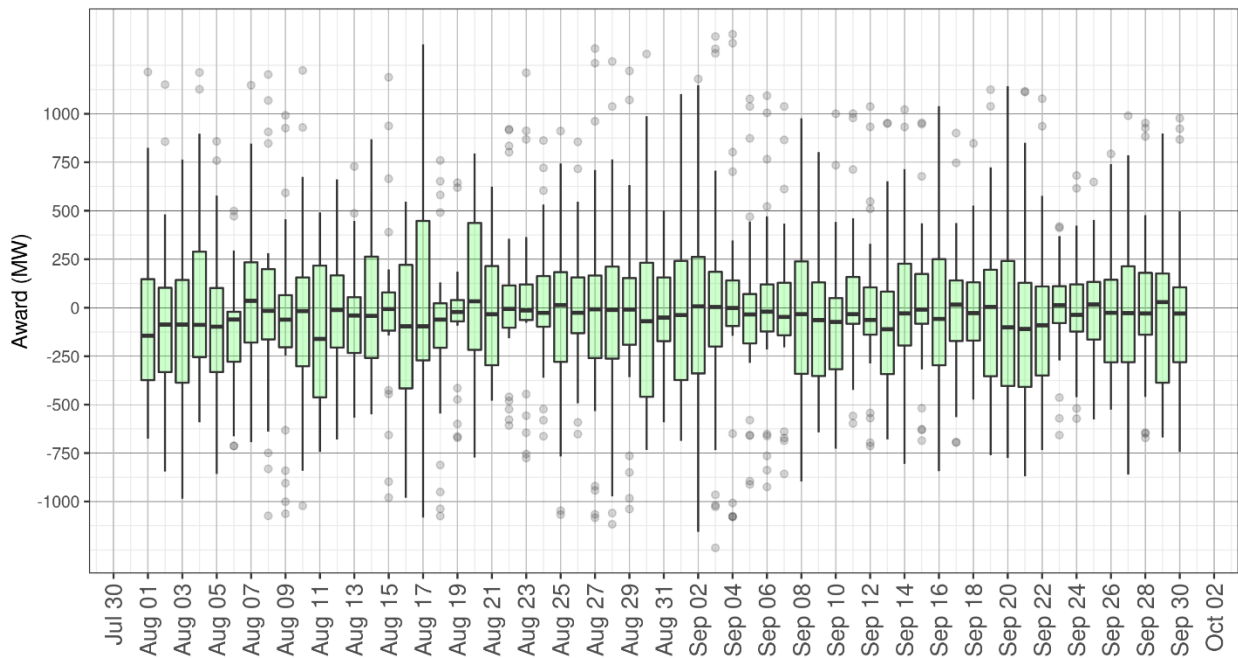


Figure 73: Daily RTD award in August and September 2021



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Figure 74 Hourly average real-time dispatch in September 2021



13 Energy Imbalance Market

13.1 EIM transfers

The Energy Imbalance Market, or EIM, provides an opportunity for participating balancing authority areas to serve their load while realizing the benefits of increased resource diversity. The CAISO estimates EIM’s gross economic benefits on a quarterly basis.³⁷ One main benefit of the EIM is the realized economic transfers among areas. These transfers are the realization of a least-cost dispatch by reducing more expensive generation in an area and replacing it with cheaper generation from other areas. In a given interval, one area may have an import transfer with another area while concurrently having an export transfer with another area. Figure 75 shows the distribution of five-minute EIM transfers for the CAISO area. A negative value represents an export from the CAISO area to other EIM areas. This trend shows that for the first half of June, the CAISO area had a predominant EIM export condition which evolved to a more dominant import position as it entered into the mid-June heat wave. On June 16 through June 19, CAISO’s area saw net import transfers for almost the whole time. With the exception of the period of August 20 and 21, where EIM transfers into the CAISO were mainly exports, the predominant trend of imports continued through July and August and the first part of September

Figure 75: Daily distribution of EIM transfers for CAISO area

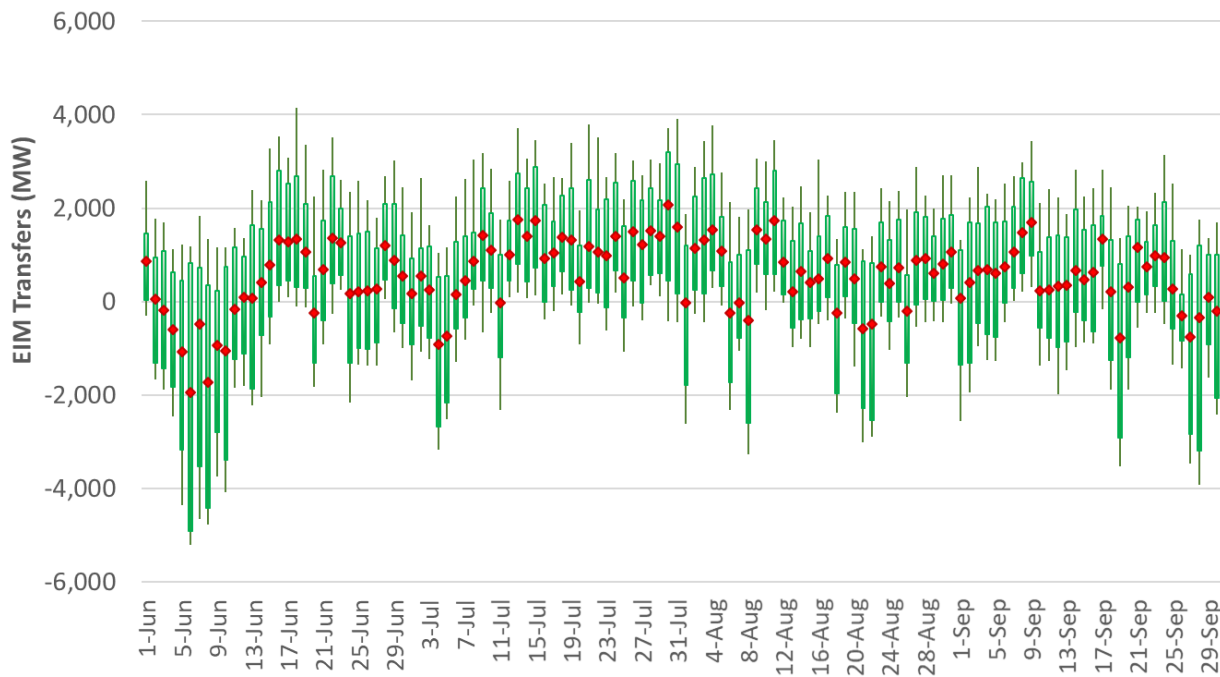


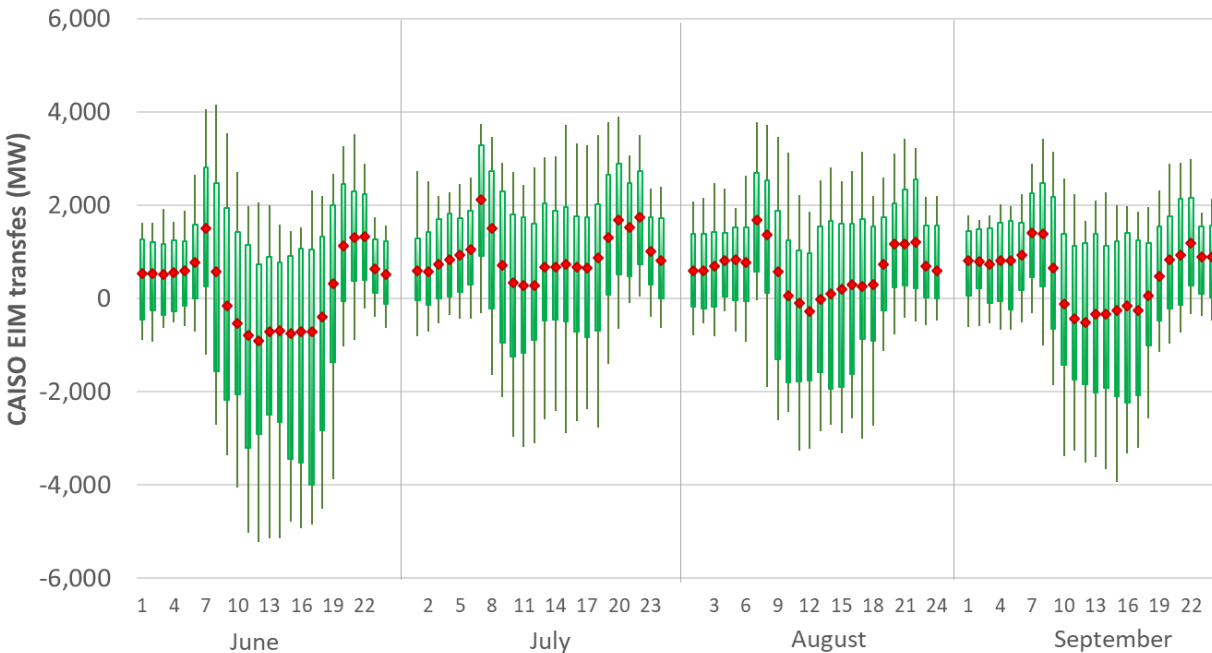
Figure 76 shows the EIM transfers in an hourly distribution, which highlights the typical profile of the CAISO transfers which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the CAISO area. This trend is persistent across summer months but the magnitude of these export transfer reduced as

³⁷ The EIM quarterly reports are available at <https://www.westerneim.com/pages/default.aspx>

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summer conditions evolved through September.

Figure 76: Hourly distribution of 5-minute EIM transfers for CAISO area



13.2 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 EIM balancing areas 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 sufficient supply to meet its demand forecast and uncertainty in tagging import and export transactions.³⁸ Starting on June 15, 2021, due to the recent Market Enhancements for 2021 Summer Readiness,³⁹ 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

³⁸ [Bautista Alderete, Guillermo and Kalaskar, Rahul. Resource Sufficiency Evaluation Bid Range Capacity Test. Mar 2021- PowerPoint Presentation](#)

³⁹ [Market Enhancements for Summer 2021 Readiness- Final Proposal](#)

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Figure 78 Hourly frequency of upward capacity test failures for September 2021

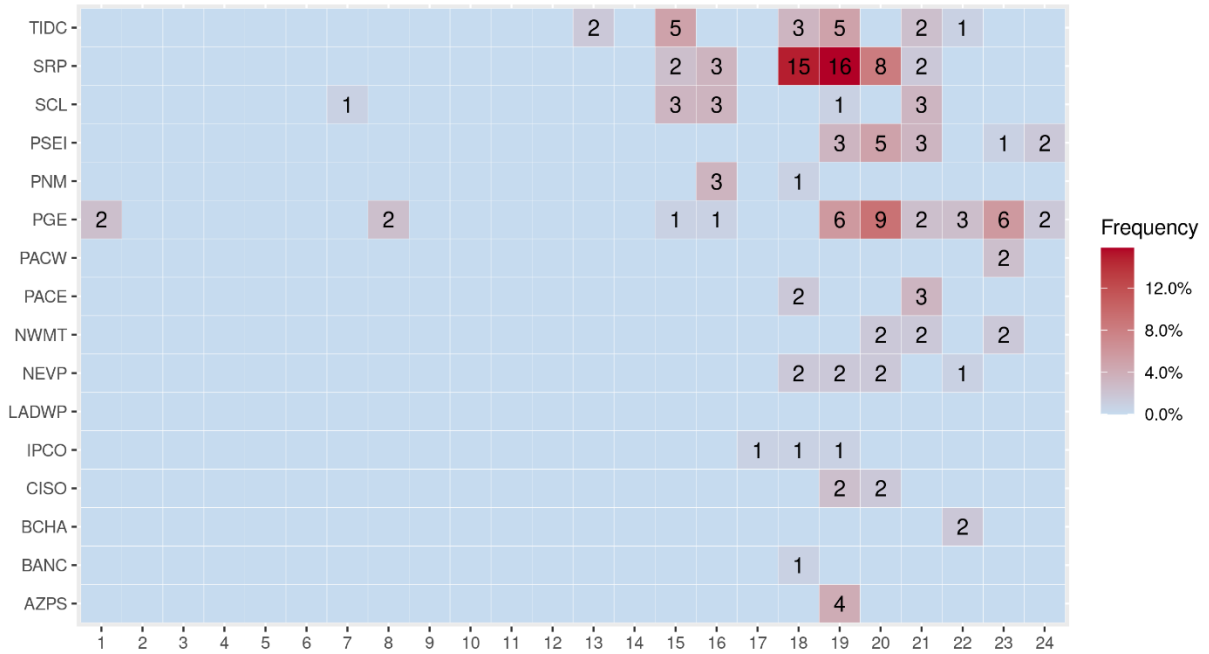
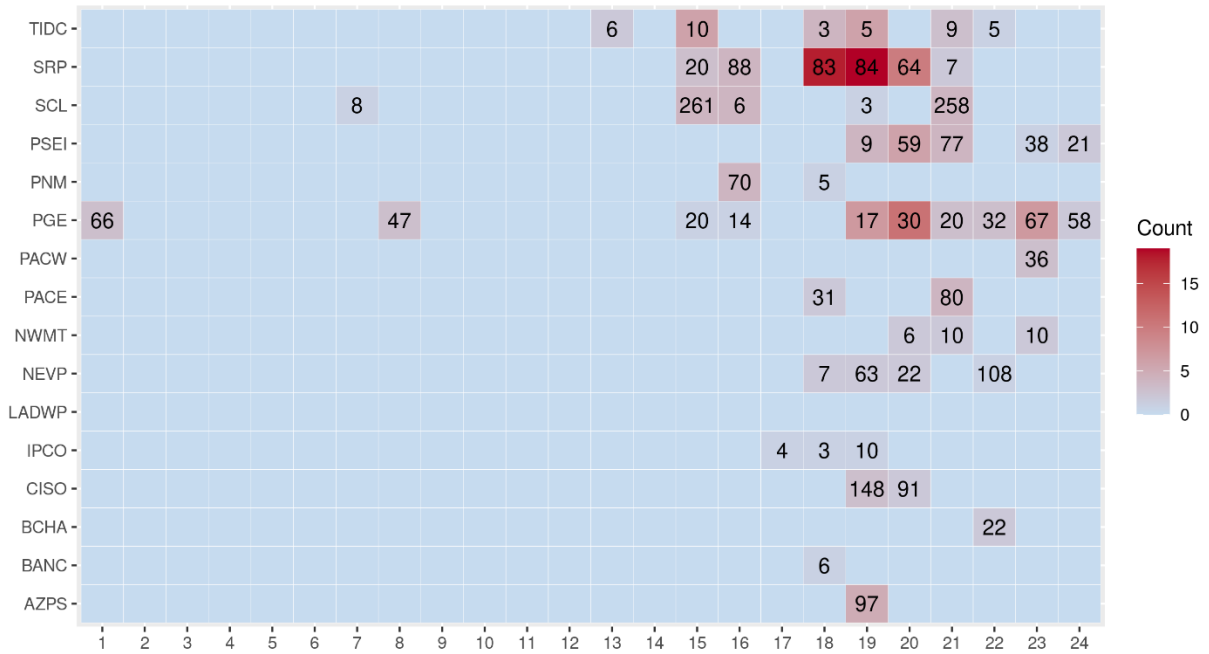


Figure 79 shows the heat map for the amount of upward capacity test failures for September 2021. The color in each cell reflects the level of capacity test failures, where a darker red shows higher MW failures. The number in each cell represents the average MW imbalance of the capacity test failure. 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 SRP BAA had the average imbalance for the upward capacity test failures, occurring in hour ending 19 and 23. The CAISO BAA had five intervals with capacity test failures in hours ending 19 and 20. The average imbalance from the upward capacity test of 147 MW for the hour ending 19 and the average imbalance of 91 MW for hours ending 20.

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Figure 79 Hourly frequency of upward capacity test and average imbalance for September 2021



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 80 shows the comparison of the upward capacity test failures with and without uncertainty. This is a plain comparison between the capacity test scenarios and does not include any outcome of the flexible ramp sufficiency test. Overall, the number of failures for capacity test with the addition of the uncertainty component increased to 193 interval in September, relative to 71 failures when no uncertainty is considered in the test (counterfactual).

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Figure 80: Daily Frequency of upward capacity test failures for all EIM BAAs



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 but including the impact of the flexible ramp up sufficiency test. If an EIM BAA fails either the capacity up test or the flexible ramp up sufficiency test then it affects the import EIM transfer capability for the BAA. Therefore, if an EIM entity passed the capacity test when the effect of net load uncertainty was not considered but failed the flexible ramp up test in the same interval, that interval is counted as a failure for the dataset used to create the heat map for the chart labeled without net load uncertainty and flex ramp sufficiency impact. For September, the SRP BAA had failed the upward capacity test in 1.94 percent of intervals, which reduced to a failure rate of 1.25 percent when the counterfactual calculation was performed. On the other hand, for September, the CAISO BAA had failed the upward capacity test in 0.17 percent of intervals, which increased to 0.38 percent when the counterfactual calculation was performed; the CISO has five capacity test failure but eleven flexible ramp sufficiency test failures.

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Figure 81: Daily Frequency of upward capacity test failures for all EIM BAAs with consideration of flex failures



Figure 82 below shows the daily frequency of downward capacity test failures for all EIM BAAs for August 1, 2021 until September 30, 2021. In September, there were 16 EIM BAAs participating in the real-time EIM including the CAISO. There were minimal capacity test down failures for September 2021; the BC hydro BAA had the maximum number of intervals with the downward capacity test failure for a total of 0.83 percent of intervals in the month, whereas, there were thirteen EIM BAAs that passed the downward capacity test in all 15-minute intervals for the month. Figure 83 shows the hourly frequency of downward capacity test failures for all EIM BAAs for September 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.

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Figure 82: Daily frequency of downward capacity test failures in August and September 2021

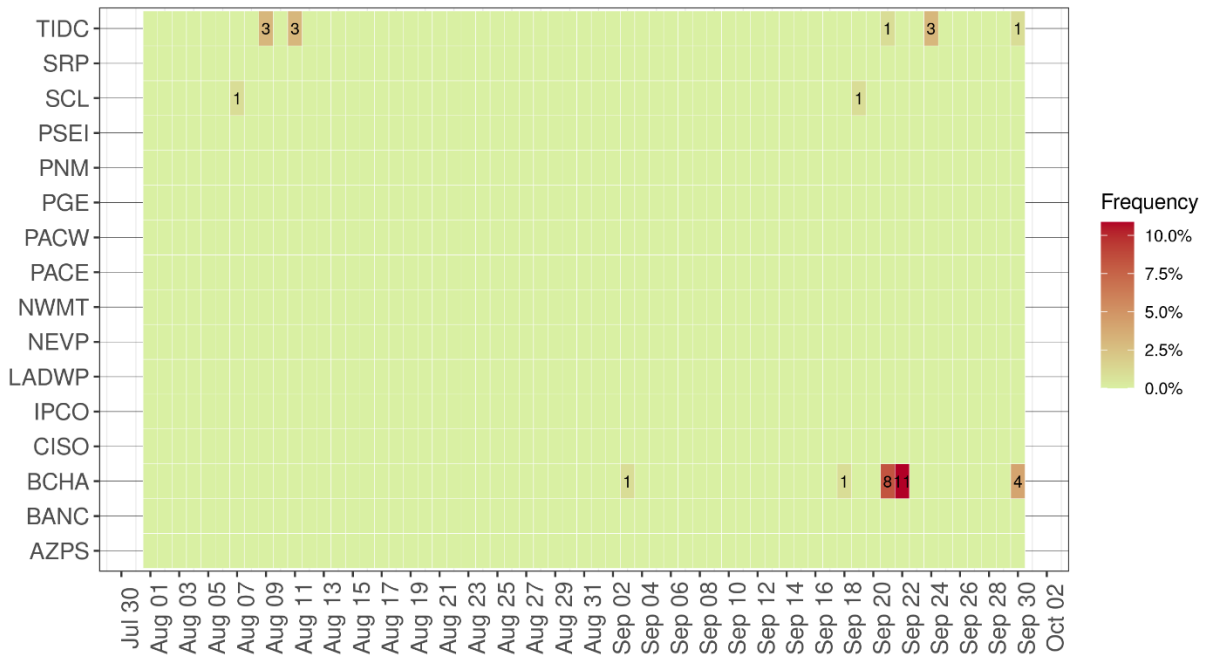
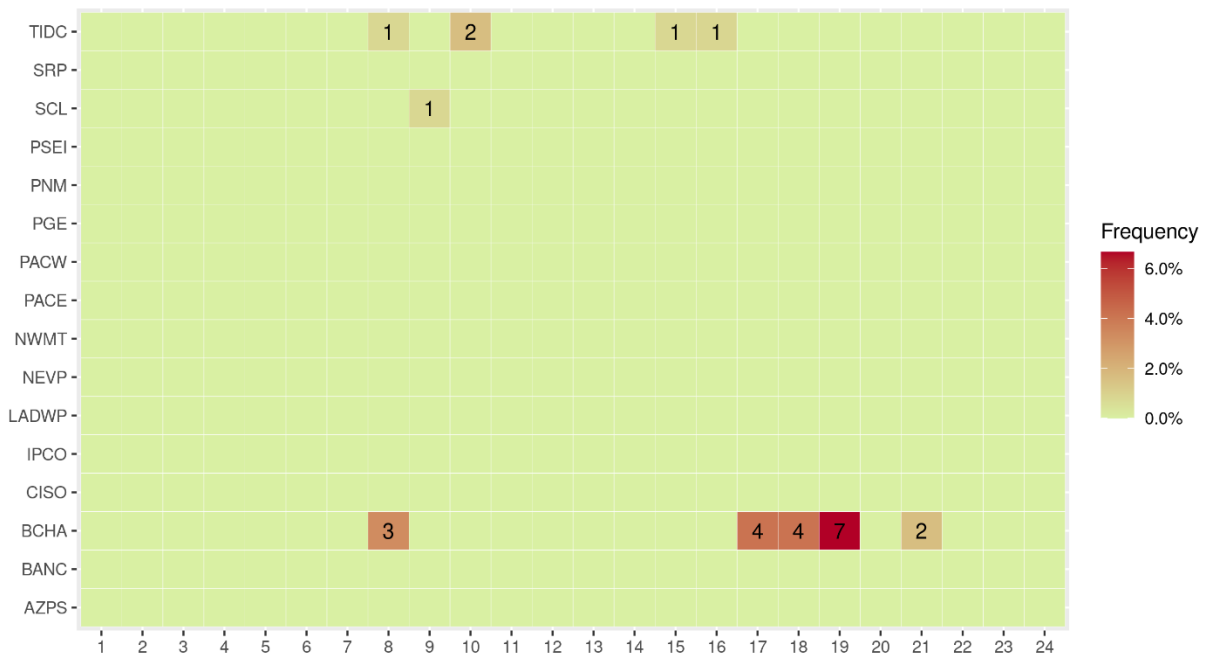


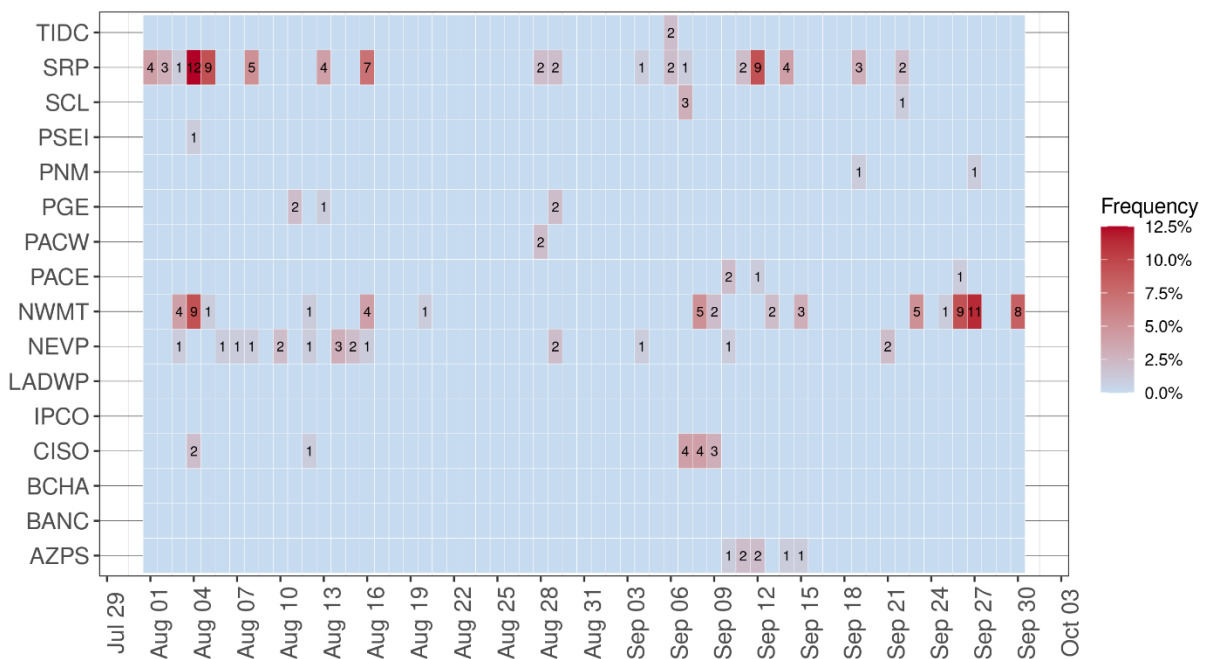
Figure 83: Hourly frequency of downward capacity test failures in September



13.3 Flexibility test

The flexible ramp sufficiency, or flexibility, test ensures EIM BAAs have sufficient ramping capabilities to meet load forecast change and net load uncertainty, i.e., 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 the upward and downward direction. If an EIM BAA fails the flexibility test, the system caps its 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 August and September 2021.⁴⁰ In September, NWMT BAA had the highest monthly percentage of upward flexibility ramp test failure at 1.6 percent, whereas there were seven EIM BAAs that passed the upward flexibility test in all 15-minute intervals. The CAISO BAA failed the upward flexibility ramp test in 0.38 percent of 15-minute intervals, which is equal to failing the test in 11 intervals for September 2021. Figure 85 displays the hourly frequency of upward flexibility ramp test failures for September 2021.⁴¹ Out of the total number of failures, about 63 percent of upward flexibility test failures occurred in hours ending 18, 19, 20 and 21.

Figure 84 Daily frequency of upward flexibility test failures for August and September 2021



⁴⁰ The daily frequency of failures are fractional numbers that are rounded up to whole numbers.

⁴¹ The hourly frequency of failures are fractional numbers that are rounded up to whole numbers.

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Figure 85: Hourly frequency of upward flexibility test failures

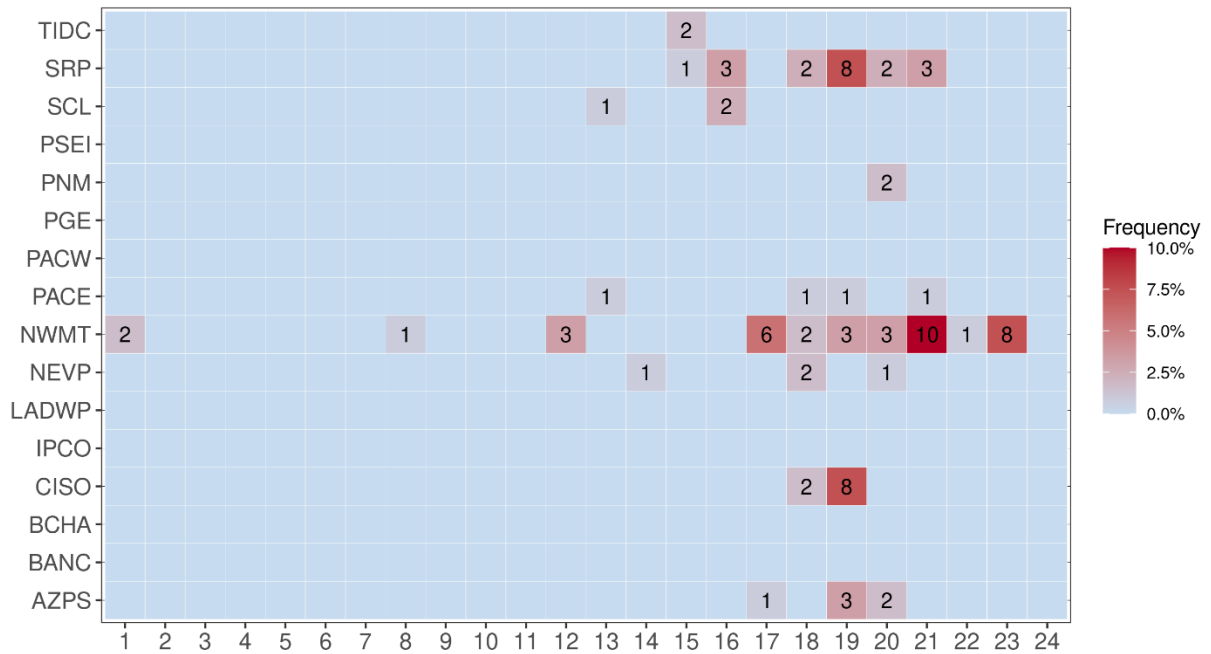


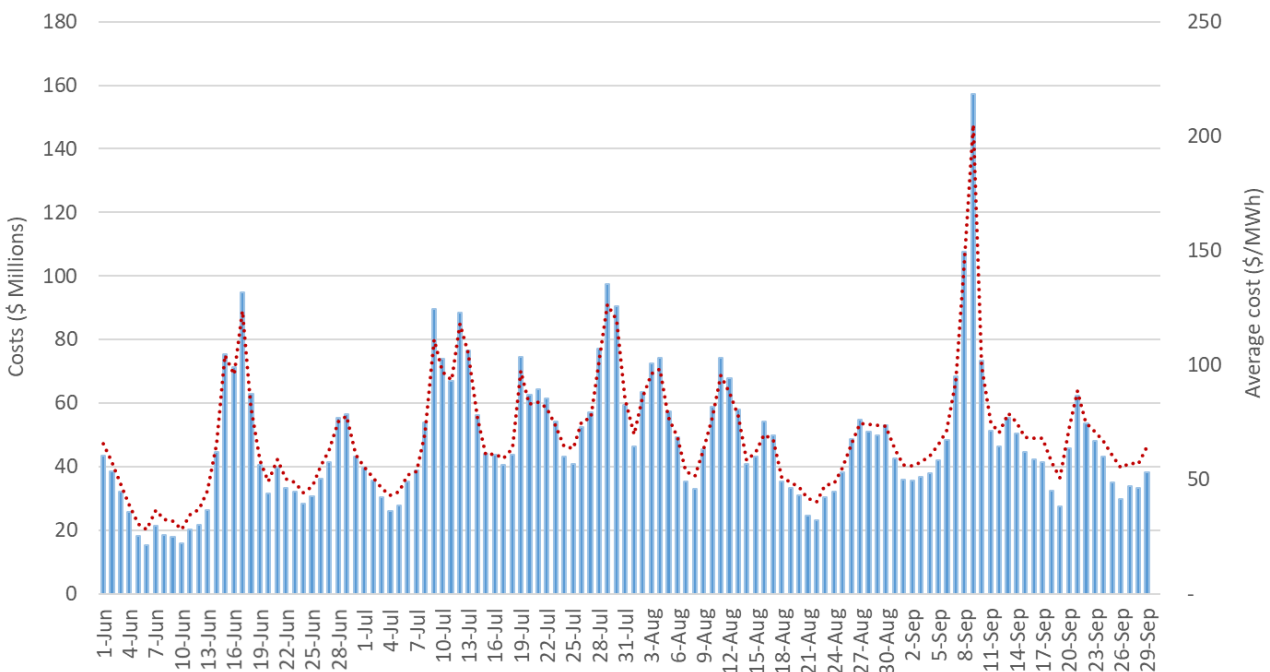
Figure 86 shows the daily frequency of downward flexibility test failures for August and September 2021.⁴² In September, the NEVP BAA had the highest monthly percentage of downward flexibility ramp test failure at 1.67 percent, whereas there were ten EIM BAAs that passed the downward flexibility test in all 15-minute intervals. The CAISO was among the 10 EIM BAAs without any downward flexibility test failures in September. Figure 87 shows the hourly frequency of downward flexibility test failures in September. More than 25 percent of the downward flexibility test failures in September occurred in hours ending 7, 8 and 9.

⁴² The daily frequency of failures are fractional numbers that are rounded up to whole numbers.

14 Market Costs

The CAISO markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy, and ancillary services, among others. The majority of the overall costs accrue on the day-ahead settlements. Figure 88 shows the daily overall settlements costs for the CAISO balancing area; this does not include EIM settlements. As demand and prices rise, the overall settlements are expected to increase. This trend shows the increase in the overall costs during July in the mid-month and end-of-month heat waves, reaching a maximum daily value of about \$157 million on September 9. When considering the overall costs relative to the volume of demand transacted, the dotted red line provides a reference of an average cost per MWh.

Figure 88: CAISO’s market costs in summer months of 2021



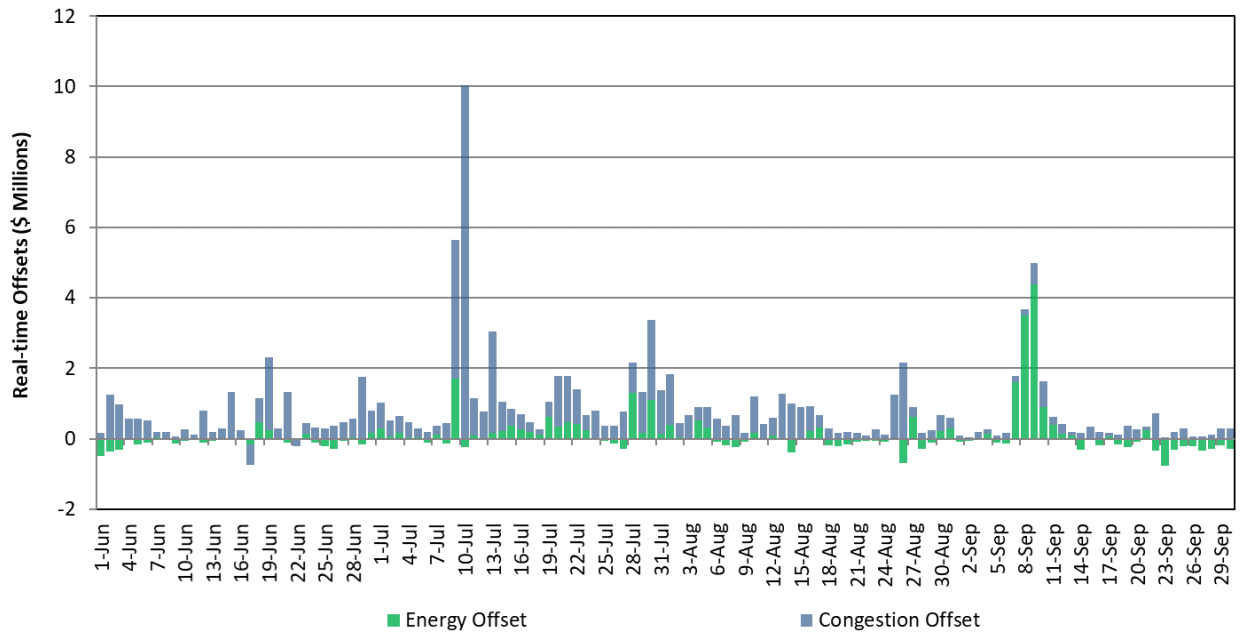
The average daily cost in August was \$47.5 million (or an average daily price of \$566.47/MWh), which increased to an average cost of \$50.2 million in September (or an average daily price of \$75.3/MWh).

Two components of this overall cost are the real-time energy and congestion offsets. These costs reflect the settlements of differences between the day ahead and real-time markets for energy and congestion. These cost typically track system conditions. After the increase in July driven largely by the derates of Malin and NOB interties, August saw a reduction of these offset costs. September saw an increase in the energy offset during the high load days of September 7 through 9, as shown in

Figure 89.

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Figure 89: Real-time energy and congestion offsets



15 Minimum-State-of-Charge Constraint

The minimum State-Of-Charge (SOC) requirement is a new tool to ensure that Limited Energy Storage (LES) resources with RA capacity obligations maintain sufficient SOC to provide energy during tight system conditions. This requirement was implemented as part of the market enhancements for the summer readiness 2021 stakeholder initiative and has a two-year sunset provision.

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

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

Since there were no RUC undersupply infeasibilities in September, the MOSC constraint was not enforced in September.

16 Scarcity Pricing Enhancements

When the CAISO meets its real-time demand requirement with generation it has originally reserved to meet its contingency reserve requirement, the market may produce lower energy price at a time when it should be signaling very tight supply conditions with high prices. When the CAISO is in a Stage 2 Energy Emergency, it is allowed to use generators providing contingency reserves to serve demand and meet its contingency reserve requirement by arming load. CAISO generally enters into Stage 2 Energy Emergency with the intent to begin “arming load” to meet reserve requirements. “Arming load” is a process where the CAISO system operators inform load-serving entities to make all preparations necessary to be able to drop load in a controlled manner. With the summer enhancement implemented on June 15, when arming load to meet contingency reserve requirements, the CAISO will release both the contingency and non-contingency operating reserves at the bid cap price. This will set prices at the offer cap when there is insufficient generation supply to meet both energy and contingency reserve requirements and the released operating reserves are dispatched for energy.

There were no energy emergencies for the month of September and consequently the scarcity pricing logic did not trigger in September.

17 Market Issues

Through the analysis of the market outcomes and performance, there were several market issues identified during the month of September 2021, which either have been resolved or are expected to be addressed. These include:

1. Wheel transaction not treated as a wheel.

There was one wheel transaction on September 16 that was not correctly passed into the markets from the bidding system. Therefore, the market did not enforce the transaction as a wheel. Instead, only the import part of the transaction was considered in the market.

This software issue was fixed on September 23.