Summer Market Performance Report
June 2024

July 30, 2024

Prepared by

Market Performance and Advanced Analytics

Content

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Acronyms

AET	Assistance Energy Transfer
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
ISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DAM	Day ahead market
DALPT	Day-ahead low priority exports
DLAP	Default Load Aggregated Point
ED	Exceptional Dispatch
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capacity
ESP	Energy Service Provider
ETC	Existing Transmission Contract
FMM	Fifteen Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IFM	Integrated Forward Market
IOU	Investor-Owned Utility
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
LRA	Local Regulatory Authority
MW	Megawatt
MWh	Megawatt-hour
NGR	Non-Generating Resource
NOB	Nevada-Oregon Border

NSI	Net Scheduled Interchange
OASIS	Open Access Same-Time Information System
OR	Operating Reserves
PDR	Proxy Demand Response Resource
PRM	Planning Reserve Margin
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.
PV	Palo Verde
QC	Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RTM	Real-Time Market
RTLPT	Real-time low priority export
RUC	Residual Unit Commitment
SMEC	System Marginal Energy Component
SOC	State of Charge
TOR	Transmission Ownership Right

1 Executive Summary

The California ISO (ISO) regularly reports on the performance of its markets to provide timely and relevant information. This report is part of a series of customized monthly reports focusing on the ISO's market performance and system conditions during summer months. The months of June through September are of targeted interest because it is when system conditions are particularly constrained in California and the Western Interconnection. These monthly reports also provide a performance assessment of specific market enhancements implemented as part of the ongoing ISO's effort to ensure readiness for summer conditions.[1]

The month of June was generally uneventful. The market and system operated well while ensuring demand was met. The major highlights for the month are:

June 2024 Highlights

Average peak ISO loads in June 2024 were moderate at 32,379 MW, which was higher than the average daily peak loads in June 2023 of 28,463 MW. The highest instantaneous load peak was 39,306 MW on June 24, which was below the CEC month-ahead forecast of 42,295 MW.

The ISO area saw a decrease in hydroelectric production. Hydro production in June 2024 was about 20 percent lower than the production in June 2023.

Monthly resource adequacy capacity was 49,635 MW and above the level of load needs, which includes demand, operating reserves and supply and demand uncertainties. This is higher than the 48,910 MW for June 2023. Compared to June 2023, RA capacity for storage resources increased by 3,285 MW while static imports increased by 1,515 MW. Hydro and gas resources saw a decrease of 979 MW and 3,568 MW, respectively.

The ISO's daily average prices reached a maximum of $60/MWh in the fifteen-minute market. The hourly average prices for the month of June for the integrated forward market and the fifteen-minute market reached a maximum of $54/MWh and $56/MWh, respectively. These prices were higher than the real-time dispatch market, which was $46/MWh.

There was sufficient supply to meet the adjusted California ISO load forecast in peak hours in the residual unit commitment process for all days in June. There were no export reductions in the residual commitment process for the month of June.

With the addition of more solar resources into the system, solar production in June 2024 was 26 percent higher than the production in June 2023.

Capacity offered to the ISO market by storage resources continues to increase. In June 2024, there were 161 storage resources actively participating in the ISO markets. The bid-in capacity for energy was consistently over 6,000 MW for the month of June. The maximum state of charge in real time was about

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

29,899 MWh, and real-time dispatches reached a maximum of 8,006 MW. This capacity helped to meet peak conditions. Storage resources continue to procure a significant portion of regulation capacity.

The hourly average of net imports was 1,482 MW for peak hours 17 through 21 in June. The ISO experienced the largest volume of exports on June 25. The larger volume of exports generally occurred prior to the peak hours when solar production was plentiful and prices were moderate. These exports could have been driven by increasing demand in the West.

WEIM transfers were predominantly exports for the ISO BAA during midday hours. Overall, WEIM transfers reflect the economic and operational benefits that WEIM offers to participating entities by maximizing supply diversity and transferring supply from where it was available to where it was needed in real-time.

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

Up to 565 MW of the 675 MW of registered high-priority wheel-through transactions for the month of June participated in the day-ahead market. This represents 83 percent utilization of the registered wheels. For low priority wheels, the maximum transaction was 110 MW from Palo Verde to Mirage locations. All high-priority wheels were honored in the markets in June.

Reliability demand response resources were economically dispatched at a maximum of 225 MW in the real-time market on June 25 after they were bid and cleared in the day-ahead market economically. The largest volume of dispatches for proxy demand response resources in the day-ahead timeframe occurred on June 5 at 105 MW, whereas in the real-time market, it was a maximum of 45 MW on June 26.

On average, the ISO's daily average market costs were $18.35 million in June, representing an average daily cost of $85/MWh. The highest daily cost accrued on June 25 at about $36 million.

2 Background

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

Following the publication of the Final Joint Root Cause Analysis, the ISO initiated an effort to identify, discuss with market participants, and propose enhancements across different areas of the market practices. This effort was initiated with educational workshops to level the understanding of existing market practices and their implications. This was followed by the formal launch of the Market Enhancements for the summer 2021 Readiness initiative[2].

For summer 2024, the following enhancements continue to be in place:

1. Import market incentives during tight system conditions
2. Real-time scarcity pricing enhancements
3. Reliability demand response dispatch and real-time price impacts
4. Transmission service and market scheduling priorities

The minimum state of charge was active only through the summer 2023, and is no longer in place for summer 2024. As part of the energy storage enhancements, new functionality was implemented for storage resources through exceptional dispatches for better management of state of charge during tight system conditions.

As part of the ISO's effort to assess market performance, the summer performance reports are published for the months of June through September.

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

3 Demand and Supply Conditions

Resource adequacy

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

Through the RA program, there are three types of capacity: System, Local and Flexible. All three products serve a purpose in ensuring a reliable operation of the system. For system capacity, the RA requirement ensures the contracted capacity is sufficient to cover the 1-in-2-year (average) peak load plus a PRM.[3] This PRM is to cover the 6 percent of operating reserves plus a contingent headroom to account for higher-than-expected load forecast and resource outages.

The monthly RA showing for June 2024 was 49,635 MW, which is higher than June 2023's monthly showing of 48,910 MW.[4] Figure 1 compares the total monthly RA capacity by fuel type in June 2023 and June 2024. In general, total RA capacity increased across fuel types from year to year with some exceptions. For June 2024, RA capacity for storage resources increased by 3,285 MW to about 7,222 MW, and also increased by 1,515 MW for static imports. Hydro RA saw a decrease of about 979 MW and gas-fired RA saw a decrease of 3,568 MW.

Static RA imports increased from 1,845 MW in June 2023 to 3,360 in June 2024.[5] The composition by intertie varied between years as shown in Figure 2. RA imports through the Malin intertie between Oregon and California increased from 782 MW to about 1089 MW from June 2023 to June 2024, and imports through Nevada-Oregon Border (NOB) intertie increased from 454 MW to about 891 MW across the same timeframe. There were no RA imports through PVWEST intertie for June 2023. Monthly RA capacity tends to increase as the summer progresses and was generally on par with quantities from 2023. Generally,

[3] The planning reserve margin is 17 percent for the CPUC jurisdictional entities in2024. Other LRAs may set their own respective PRMs. Per Decision 21-12-015, the CPUC increased the "effective" planning reserve margin to 20-22.5 percent for 2022 and 2023 which may be met with both RA and non-RA resources that may not be in the wholesale market.

[4] 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.

[5] 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.

monthly static RA imports also increase as the summer progresses through the months of July and August. These trends are shown in Figure 3 and Figure 4.

Figure 1: RA capacity organized by fuel type

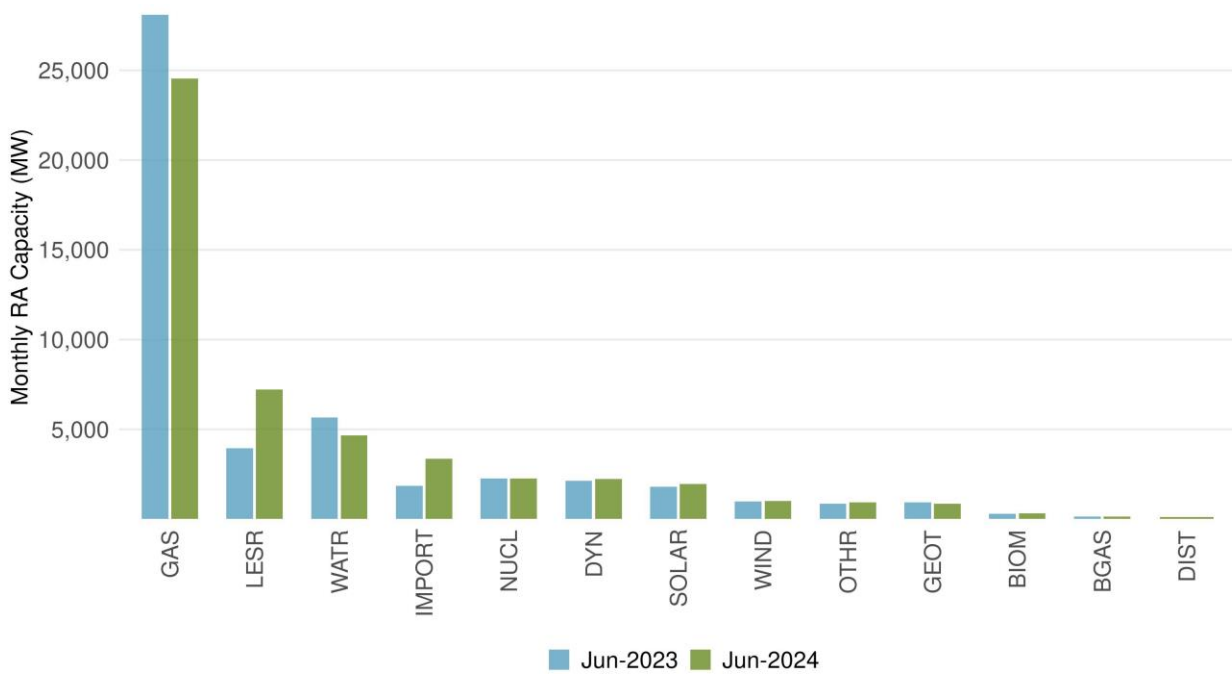


Figure 2: Monthly RA imports organized by tie

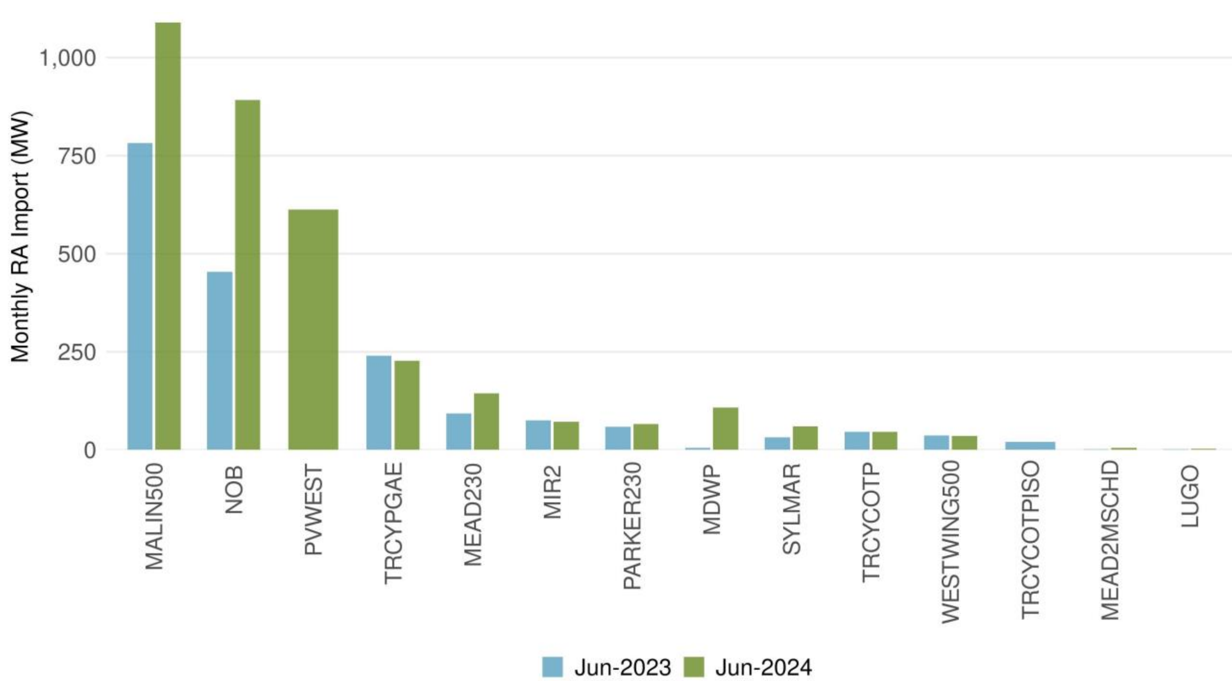


Figure 3: Monthly RA showings

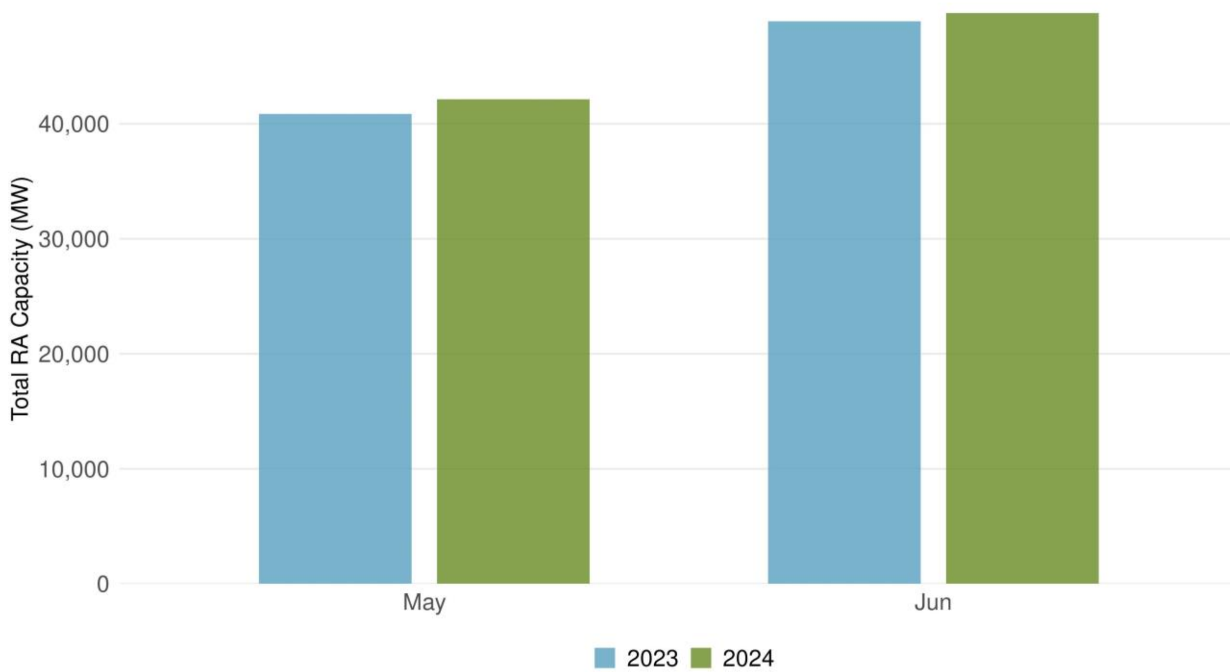
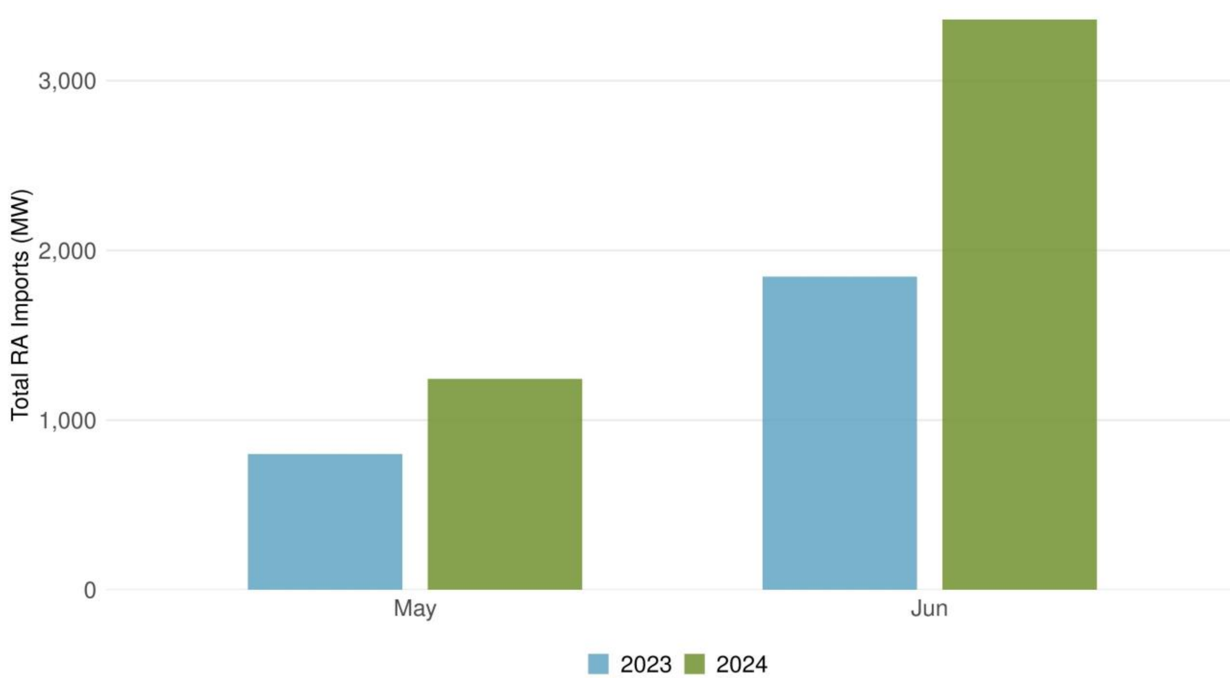


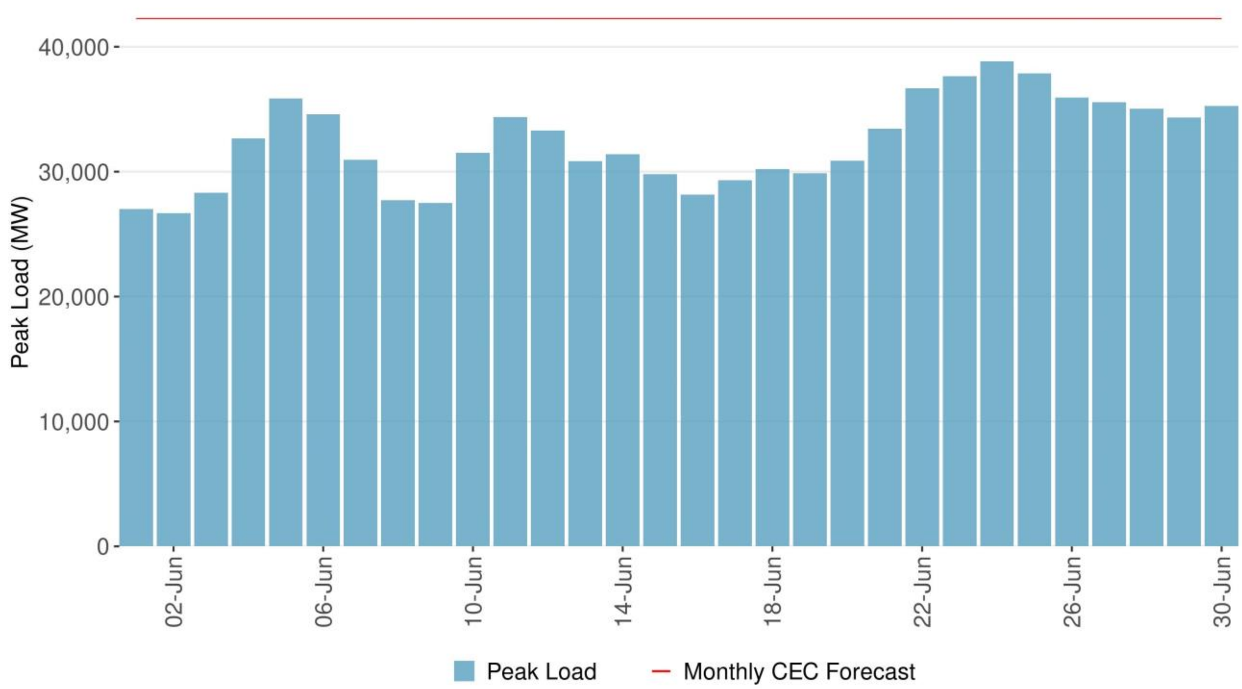
Figure 4: Monthly trend of static RA Imports



Peak ISO loads

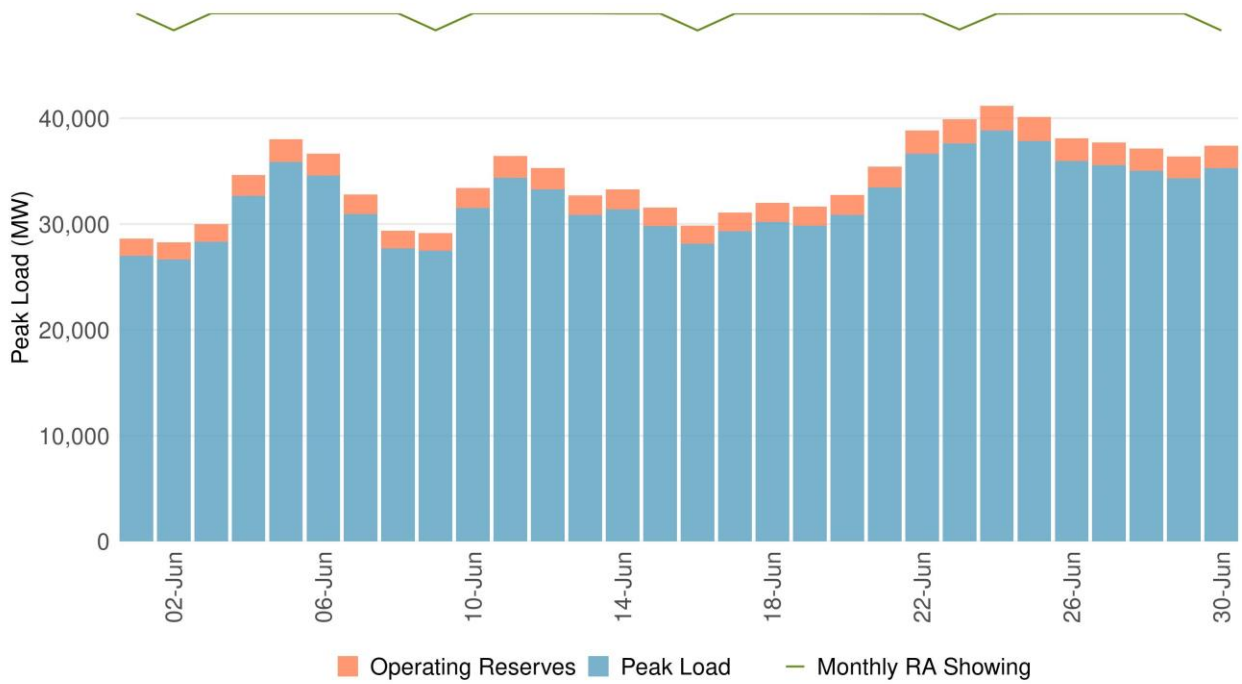
Peak loads did not exceed 40,000 MW through the month of June 2024. The average daily peak load in June 2024 was 32,379 MW which was lower than the average daily peak load in June 2023 of 28,463 MW. Figure 5 shows the 5-minute average daily load for June relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The highest instantaneous load peak in June 2024 was 39,306 MW, which occurred on June 24. This peak was below the CEC month-ahead forecast of 42,295 MW.

Figure 5: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings in June 2024 as illustrated in Figure 6. The green line indicates nominal monthly RA showings. As discussed later in this report, the actual capacity made available into the ISO's market (accounting for outages and other factors) varies from day to day. In subsequent sections, the actual RA capacity made available in the market is shown more granularly for the month on an hourly basis.

Figure 6: Daily peak load, operating reserves and RA capacity



Market prices

Market prices naturally reflect supply and demand conditions. As the market supply tightens, prices tend to rise. Locational marginal prices in the ISO have three components: the marginal cost of energy on the system, the marginal cost of congestion reflecting constraints, and the marginal cost of losses. Under the WEIM construct, there is also a component for green-house-gas emissions. The marginal energy component reflects the overall supply and demand conditions. Congestion conditions may also create local or regional price separations. Figure 7 compares the daily average prices across ISO's markets.[6] The daily average fifteen minute market prices reached $60/MWh while the daily average day-ahead prices trailed at about $45/MWh, while the five minute market prices reached a maximum of about $54/MWh. Figure 8 shows average hourly prices across ISO's markets for June 2024. The daily average prices reached a maximum on June 25. The hourly average prices for both the integrated forward market and the fifteen-minute market during the peak time trended at $55/MWh and $54/MWh, respectively, higher than the real-time dispatch market prices of about $46/MWh.

[6] Default Load Aggregation Point (DLAP) prices are a good indicator of overall prices. However, congestion may create price separation among DLAPs. The metrics presented here are based on a weighted average price of the DLAPs within the ISO area.

Figure 7: Average daily prices across markets- June 2024

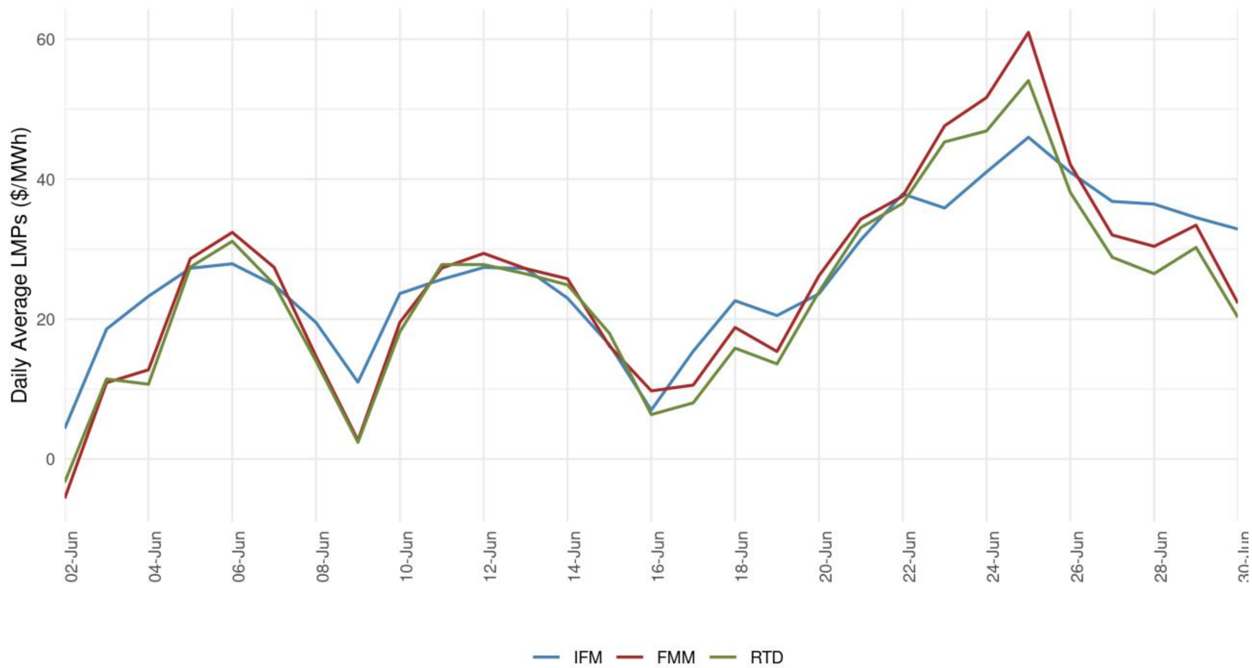
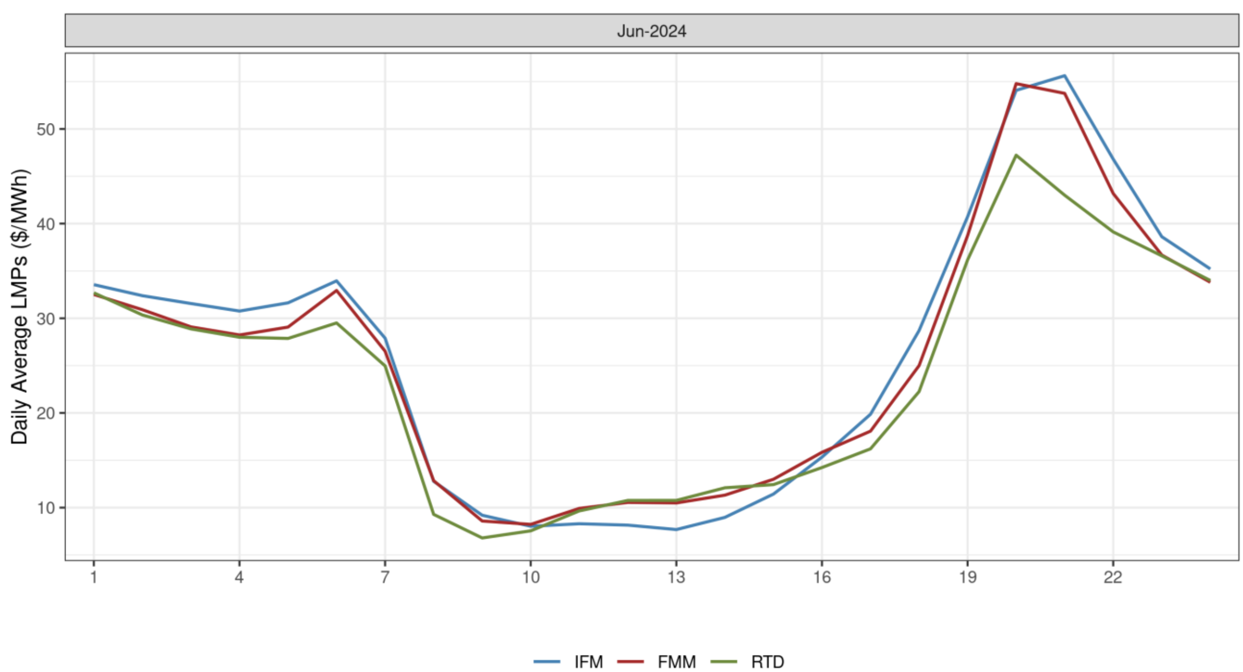


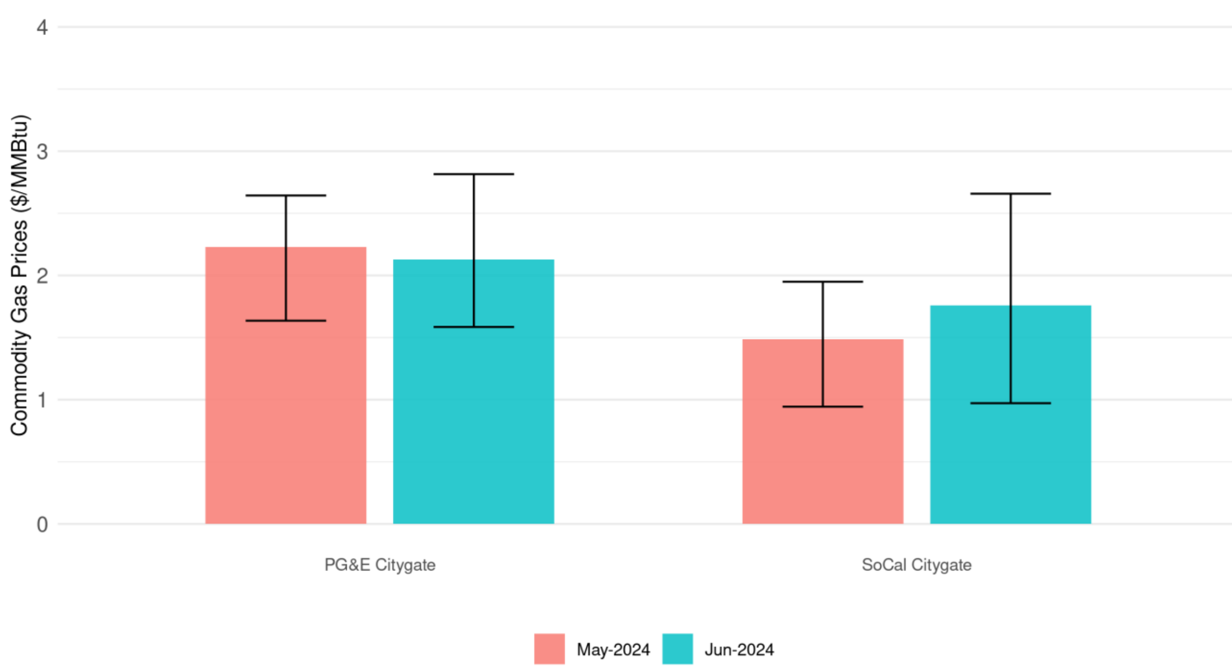
Figure 8: Average hourly prices across markets



Index prices

With a considerable share of the ISO's generation fleet consisting of gas resources, gas market and system conditions can have an impact on the electric market. Electricity prices generally track gas prices. Figure 9 shows the average prices (bars in red and blue), and the maximum and minimum prices (whiskers in black), for the two main gas hubs in California, PG&E Citygate and SoCal Citygate. For June 2024, next-day gas prices averaged $2.12/MMBtu and $1.76/MMBtu for PG&E Citygate and SoCal Citygate, respectively. The maximum next-day gas prices were $2.97/MMBtu and $2.69/MMBtu for PG&E Citygate and SoCal Citygate, respectively. These are generally moderate gas prices.

Figure 9: Gas prices at the two main California hubs



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

Next-day power trades in blocks for on-peak and off-peak periods.[7] Trading is conducted for next-day delivery and typically concludes prior to 10:00 AM PST. The figures below show a comparison between northern and southern hubs and their corresponding day-ahead LMP for the PG&E DLAP. For the northern

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

region, Figure 10 shows that the Mid-C on-peak bilateral price generally traded lower than the highest hourly day-ahead LMP for the corresponding trading day. However, due to the block nature of the bilateral power prices, the block price for Mid-C was generally higher than IFM LMPs for hours outside the evening ramp period. The NP15 bilateral price traded more infrequently throughout the month, hence the sporadic availability of data in the trend. Figure 11 for the southern region shows a similar pattern of bilateral on-peak prices at PV and SP15 where SP15 prices were trading lower than the highest hourly IFM LMP for the SCE DLAP. PV prices traded closely while SP15 prices tended to trade lower for on-peak periods. Because bilateral prices trade in block intervals, Figure 10 and Figure 11 below show similar trends with the corresponding day-ahead LMP averaged over the on-peak block interval. This trend attempts to smooth out the highest peak prices and provide a similar comparison to the block nature of the bilateral prices. Once averaged, the day-ahead LMPs are generally lower or closer to the corresponding bilateral prices throughout the month.

Figure 10: Northern hub prices and PG&E IFM LMP (block average) for on-peak

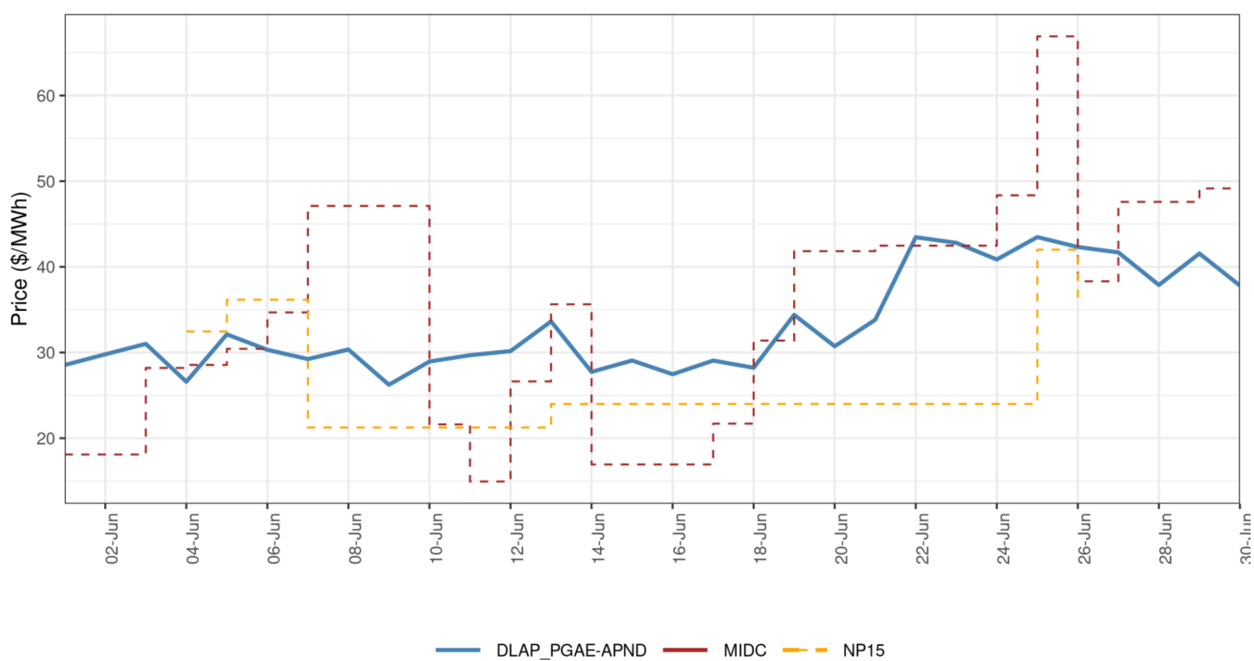


Figure 11: Southern hub prices and SCE IFM LMP (block average) for on-peak

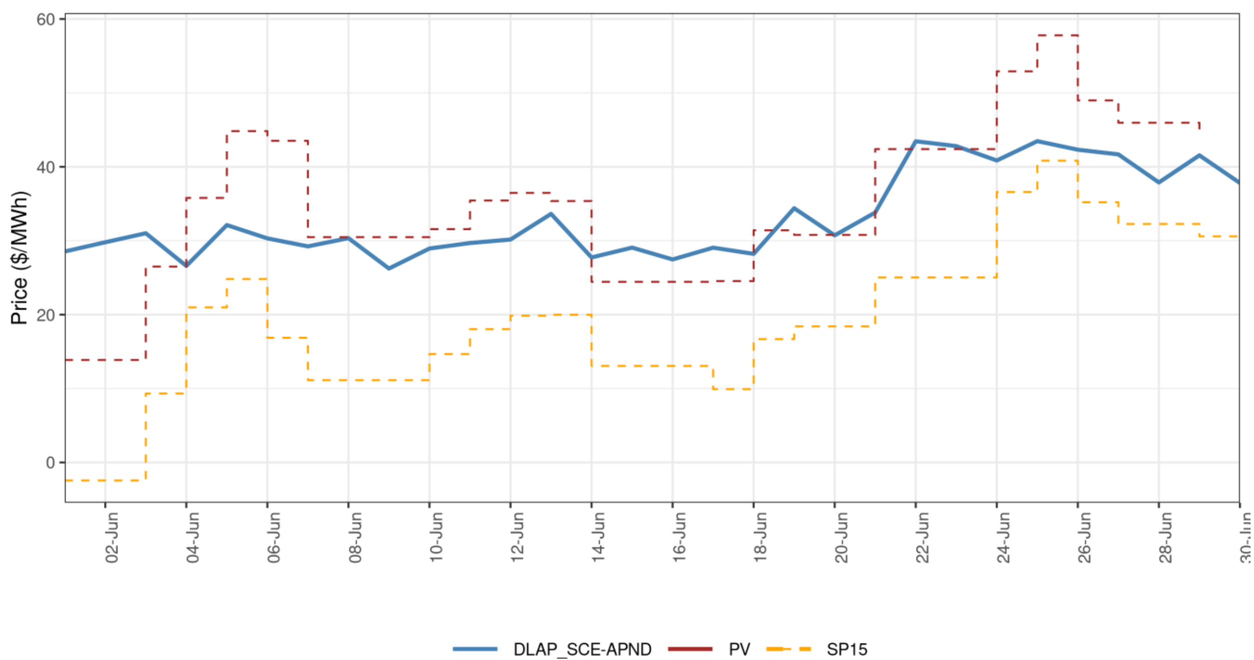
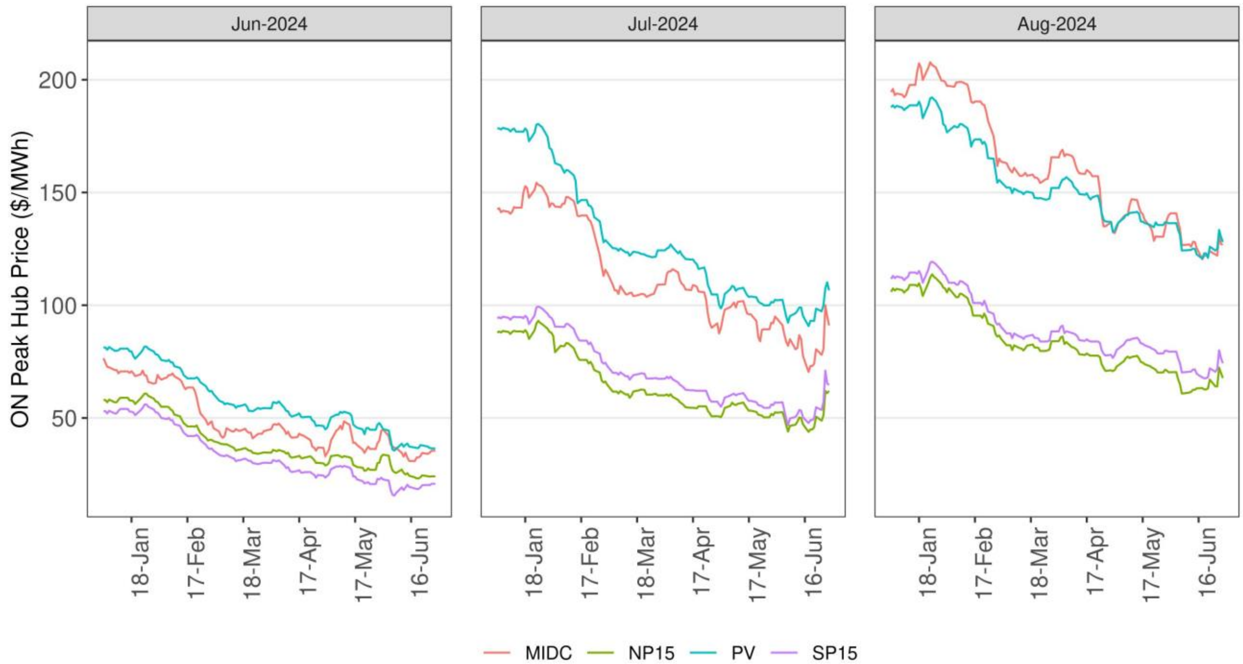


Figure 12 shows a year-to-date trend of on-peak future power prices traded for the 2024 summer months of June, July and August. Price trends are captured for Mid-C and Palo Verde, as well as the NP15 and SP15 options that trade bilaterally. On-peak future prices have traded dynamically for summer months. Price separation can be observed between the two groups of hubs, with Mid-C and PV generally trading higher than SP15 and NP15.

Figure 12: On-peak future power prices for summer 2024



4 Bid-In Supply

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

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

Supply and RA Capacity

Since the summer 2020 events, the ISO has been tracking whether RA capacity available in the ISO's markets is 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 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 above-RA capacity.

Figure 13 shows the breakdown of the day-ahead supply capacity[8] as RA capacity and above-RA capacity. The purple line represents the day-ahead load forecast plus the capacity required to meet operating reserves (OR), which is typically about 6 percent of the load value. The dashed line shows the adjusted load forecast, plus OR, plus high-priority export self-schedules. It represents the overall load obligation to be met in the day-ahead market.

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

Figure 14 has similar convention for the same capacity breakdown, but the comparison is relative to the net load (gross load minus VER forecast). Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

Figure 13: Supply capacity available relative to load forecast in the day-ahead market

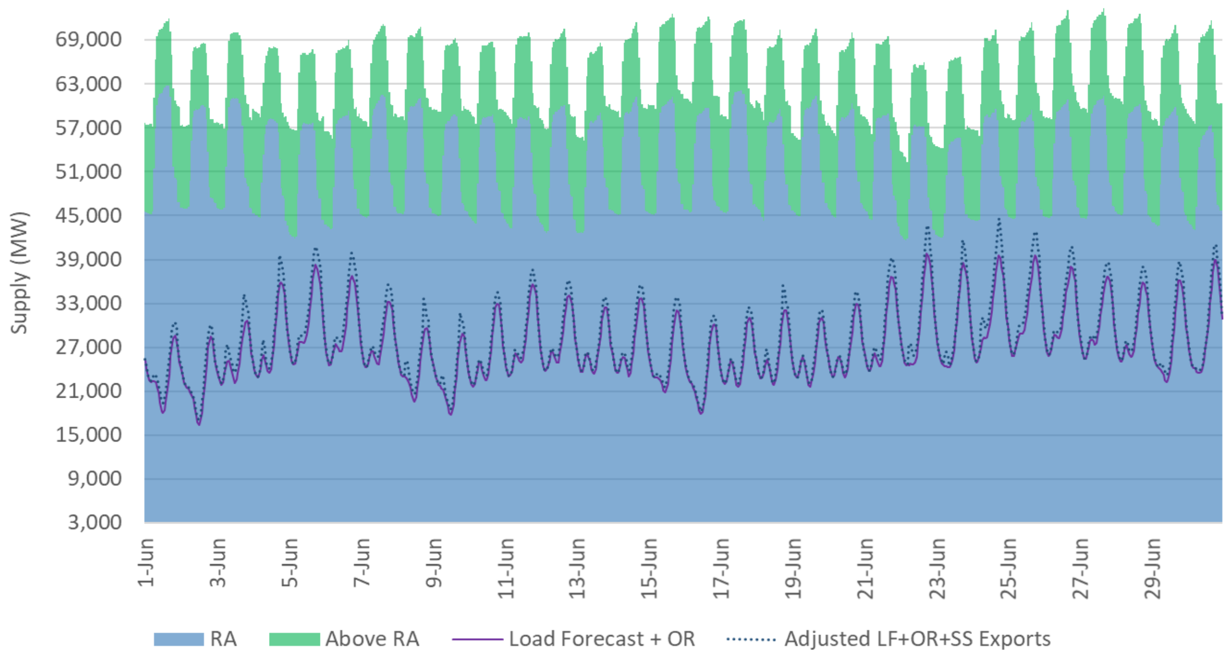
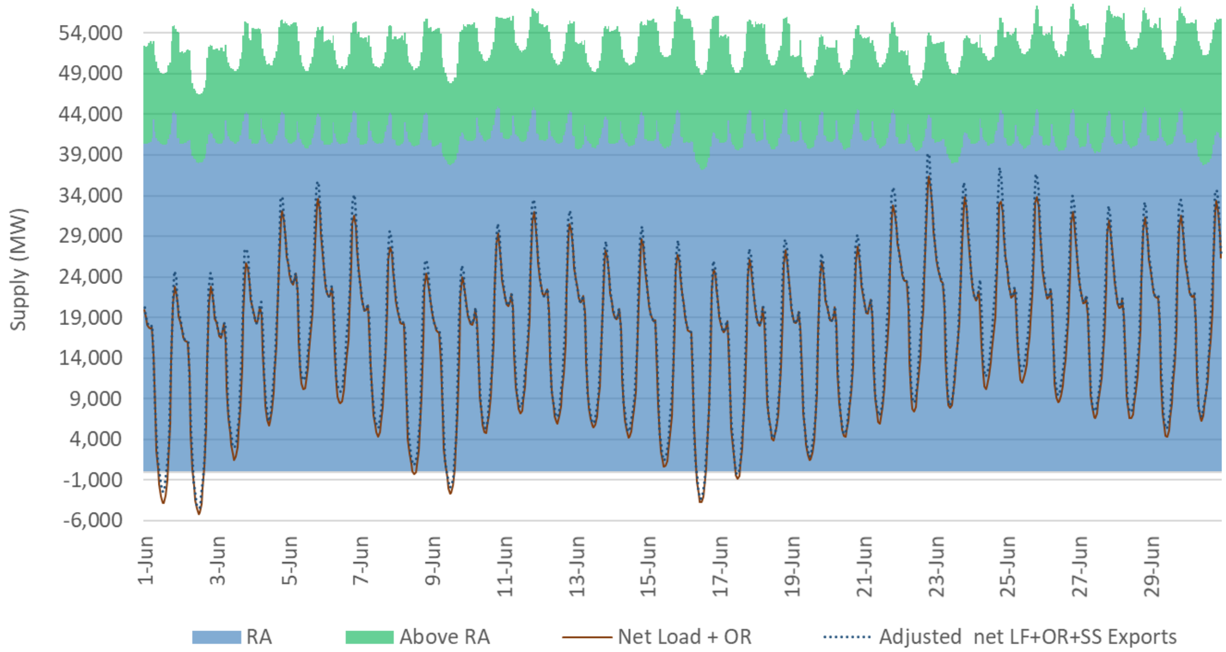


Figure 14: Supply capacity available relative to net load forecast in the day-ahead market

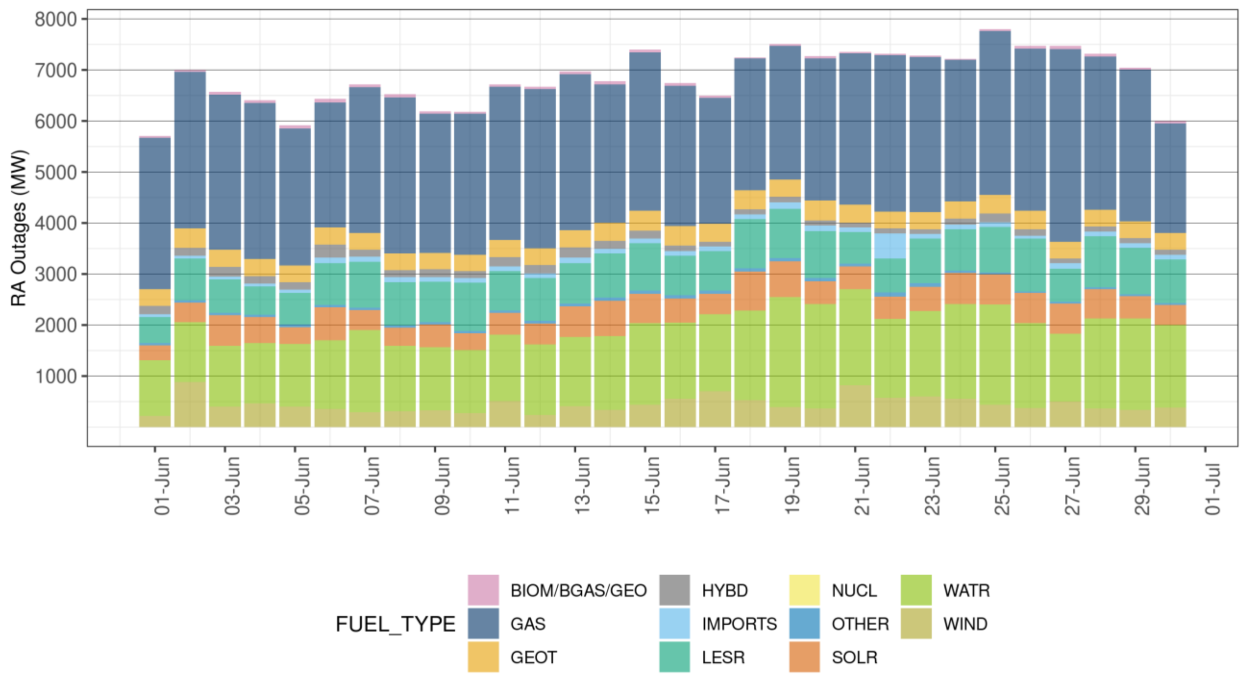


For the month of June, above-RA capacity was consistently available into the market. The supply available in the market was sufficient to cover the load forecast, and also the load forecast plus the RUC adjustments. For some hours in June, the net-load needs were negative when the VER forecast was high but loads were mild.

Unavailable RA capacity

Generating units can face operating conditions that require them to be derated or to be offline. The ISO tracks these outages through the outage system and the outages are reflected in the resource capacity made available in the market. The market considers the outages and derates to impose these limitations on the units, making them unavailable or derating their capacity accordingly. Some outages may be planned while others may be forced. Figure 15 provides the trend of RA capacity on outage organized by fuel type during the month of June. The average daily capacity on outage was about 6,800 MW.

Figure 15: Volume of RA capacity by fuel type on outage in June



Renewable Production

The ISO's area utilizes hydro production throughout the year to meet demand needs. Figure 16 shows the historical trend of total energy produced from hydro and other renewable resources. Hydro production for 2024 so far has been higher than in 2022 but lower than 2023. Hydro production in June 2024 was about 20 percent lower than the production observed in June 2023. With the addition of more solar resources into the system, solar production in June 2024 was 26 percent higher than the production in June 2023. Figure 17 shows the historical trend of solar production. Generation from hydro tends to be higher in the morning and evening hours while reaches lower values during midday hours when solar production is plentiful. Figure 18 below shows the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for June 2024.

Figure 16: Historical trend of hydro and renewable production

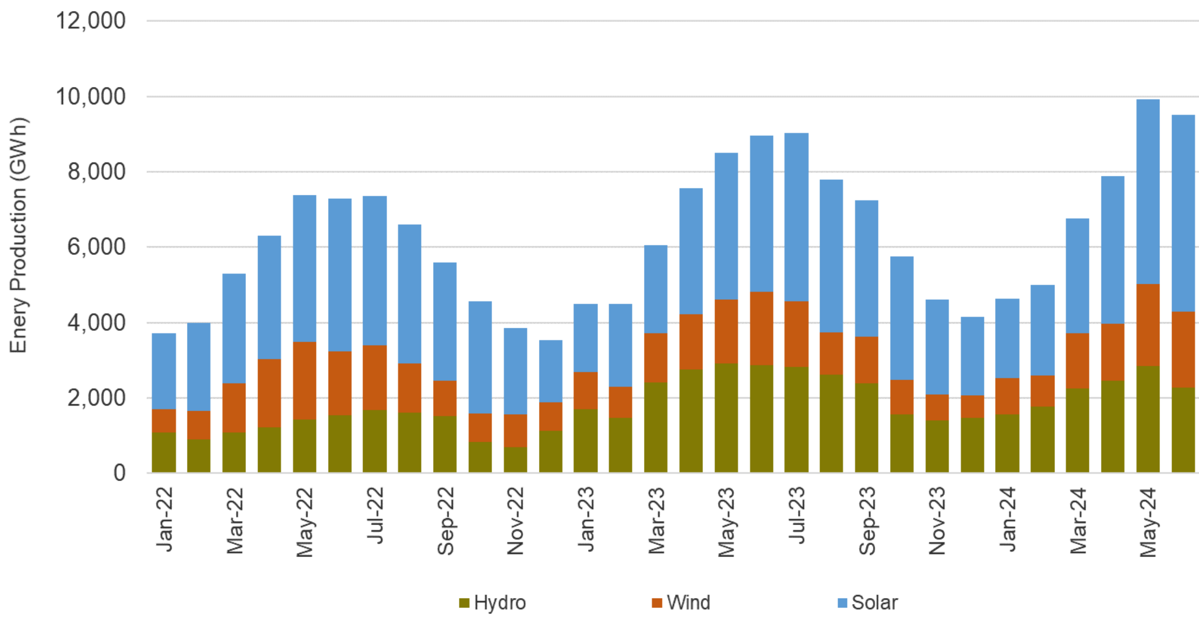


Figure 17: Historical trend of solar production

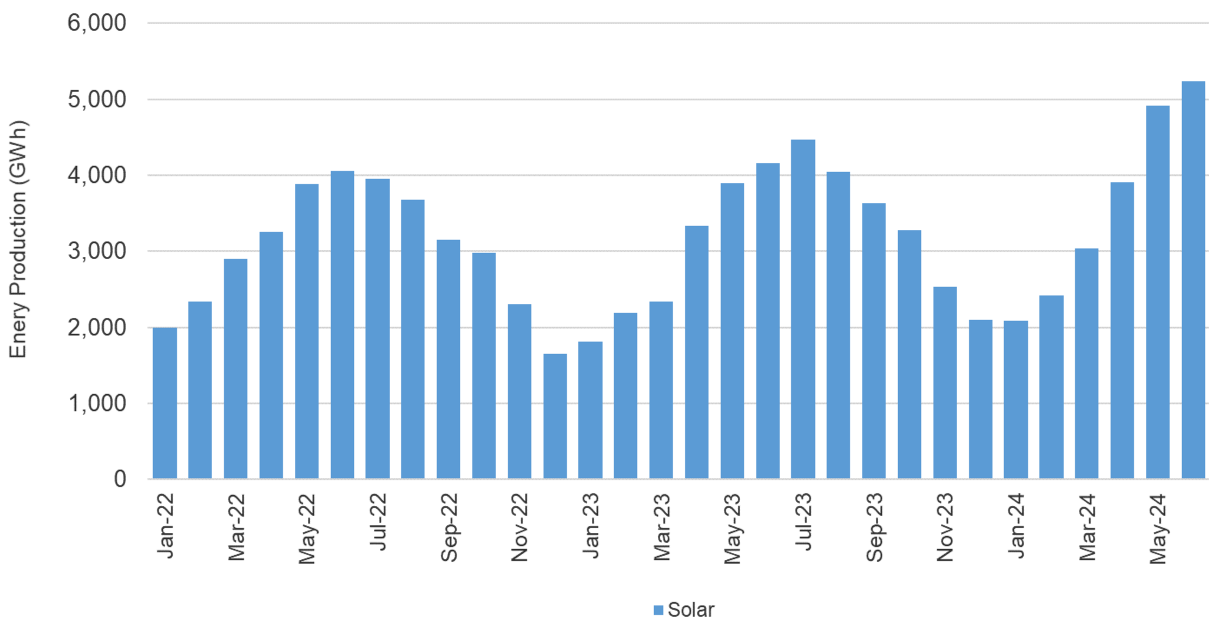
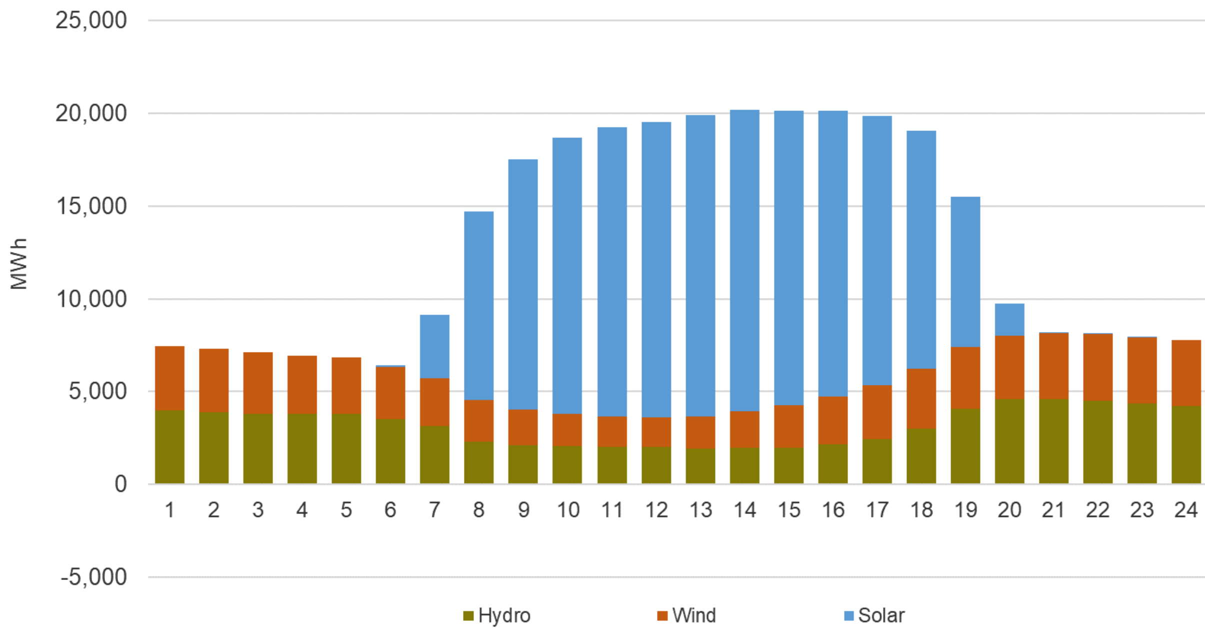


Figure 18: Hourly profile of wind, solar and hydro production for June



Demand and supply cleared in the markets

The IFM process is the financial 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. Afterwards, the RUC process uses the IFM solution as a starting point to further refine the supply schedules that can meet the day-ahead load forecast. Operators may adjust the day-ahead forecast to factor in other foreseeable conditions such as load and renewable uncertainties. The RUC process will clear supply against the final adjusted load forecast. Figure 19 compares the IFM schedules for physical resources versus the day-ahead load forecast and the adjusted load forecast eventually used in the RUC process. Day-ahead load forecasts varied through the month with relatively mild levels. Since RUC adjustments were used occasionally for morning and peak hours only, the adjusted load forecast used in the RUC process followed similar trend to day-ahead load forecast.

Figure 19: Day-ahead demand trend in June 2024

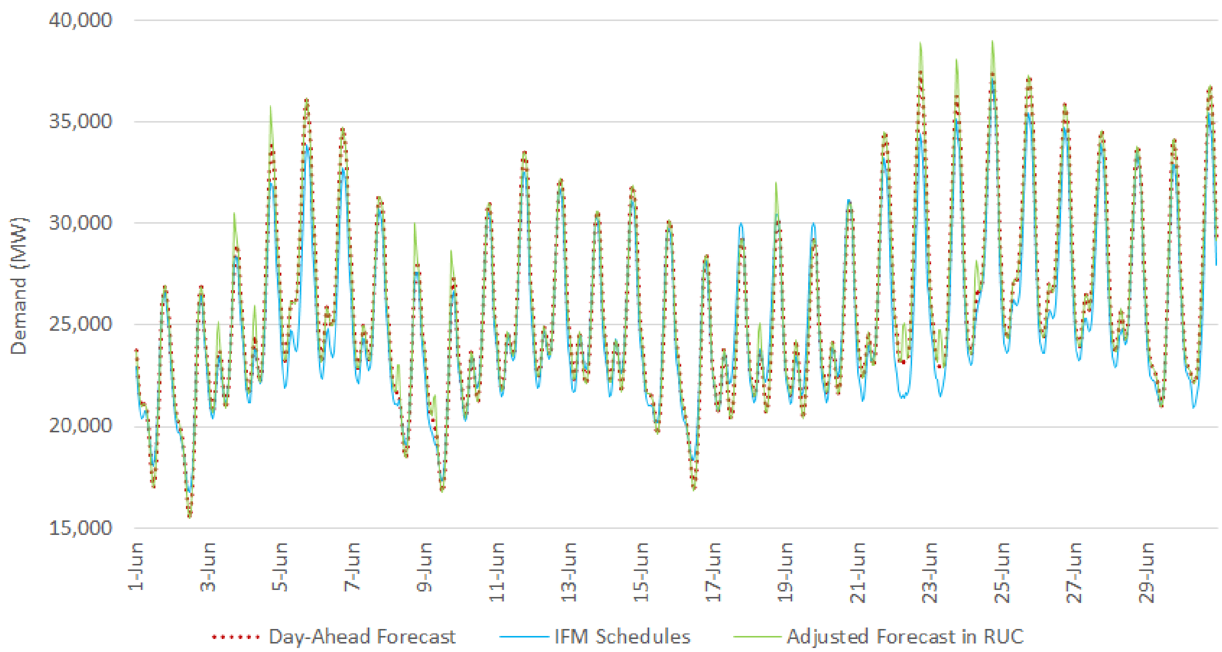
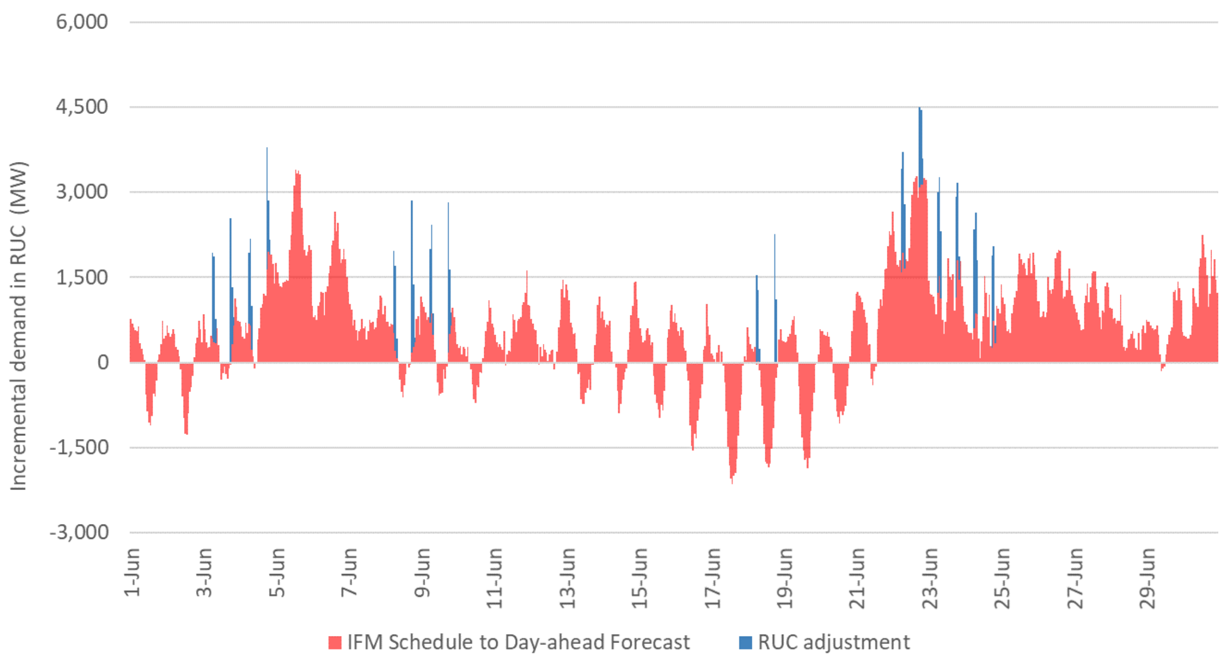


Figure 20 shows the differences between the IFM schedules versus the nominal day-ahead load forecast for RUC. This is the additional capacity relative to the IFM solution that RUC determines is needed to meet the day-ahead load forecast. Effectively, this is either the shortfall or surplus capacity from IFM that RUC has to rebalance. The delta is driven by the difference between cleared bid-in demand and the load forecast, as well as any displacement driven by convergence bids. The area in blue is the RUC adjustment to the day-ahead load forecast. In cases when RUC is infeasible, some of this additional capacity will not be met. After further enhancements to the estimation of RUC adjustments, they were used occasionally in June.

Figure 20: Incremental demand required in RUC in June 2024



The RUC forecast adjustment is guided by historical uncertainty of load, wind and solar from the day-ahead to the real time market. In some cases, there may be other factors to consider by operators to determine the final adjustments. ISO continues to further tune and assess the conditions and the need for RUC adjustments.[9]

Since RUC clears against a load forecast which is not price sensitive, under certain conditions RUC may relax the power balance constraint due to a surplus or shortfall of supply capacity. A relaxation signals that there is an imbalance between the load requirements and the supply available. An infeasible power balance can be in either direction. In hours with low levels of load and minimum downward capability, RUC may observe an oversupply condition, resulting in a negative infeasibility. Conversely, in hours where there is insufficient supply to meet the load requirement, RUC may have an undersupply condition, resulting in a positive infeasibility. Negative RUC infeasibilities occur because RUC can only dispatch a resource down to its minimum load and cannot actually de-commit a resource or set up additional exports. Conversely, positive RUC infeasibilities occur because all incremental RUC bids have been exhausted and RUC has reduced all possible economic and low priority exports,[10] which leaves just the

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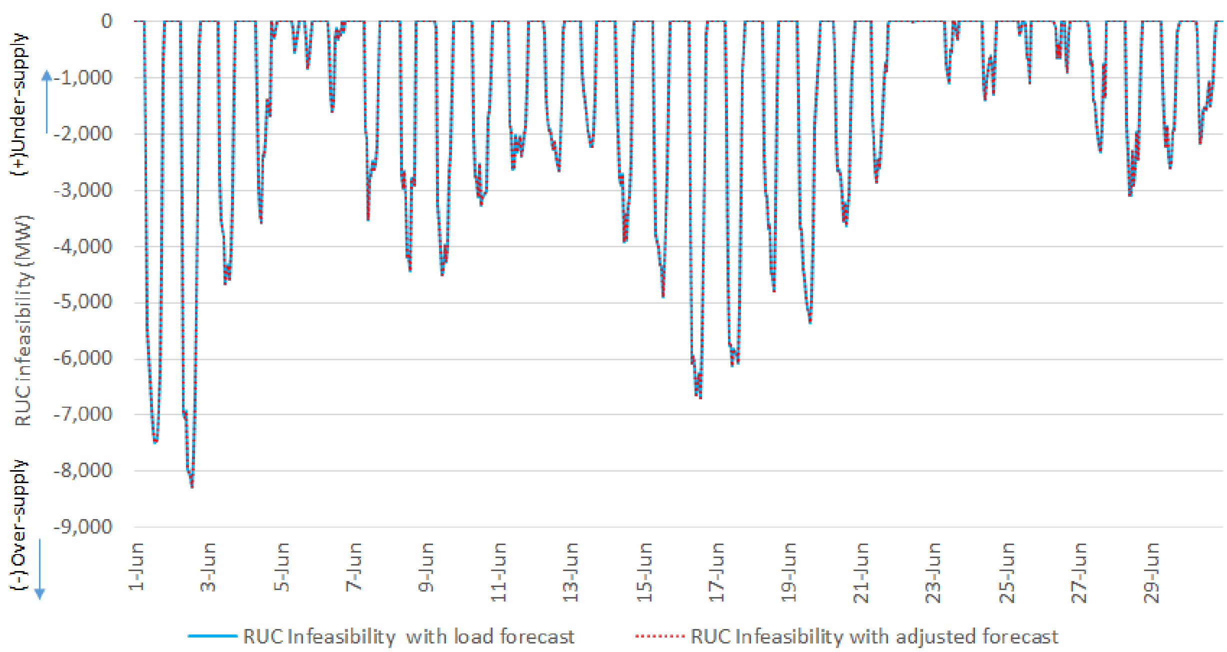
[9] Recent enhancements to the estimation of RUC adjustments can be found in the Market Performance and Market forum meeting material at https://www.caiso.com/meetings-events/topics/market-performance-and-planning-forum

[10] There are different type of exports participation. They can be based on economic bids with prices between the bid floor and the bid cap. They can be price takers, also referred to as low priority exports and labeled as LPT. Exports can also be high priority self-schedule labeled as PTK (i.e., not backed by capacity that may be committed to ISO load under its resource adequacy

power balance constraint to be relaxed and reducing PTK (high priority) exports to allow RUC to clear. Figure 21 shows the RUC infeasibility against two reference points: one infeasibility is relative to the final adjusted forecast in RUC, while the other is relative to the raw day-ahead forecast. In June there were only over-supply infeasibilities.

Figure 21: RUC infeasibilities in June 2024



In addition to relaxing the power balance constraint, the RUC process utilized other scheduling priorities to enforce the power balance. Indeed, before relaxing the power balance (and based on current scheduling priorities), RUC will first reduce economic exports (exports bid-in at a given price) and lower priority price-taker exports. Only when RUC has exhausted these LPT exports, PT exports may be reduced concurrently to relaxing the power balance constraint.[11]

In the month of June there were no instances of export reductions in the RUC process.

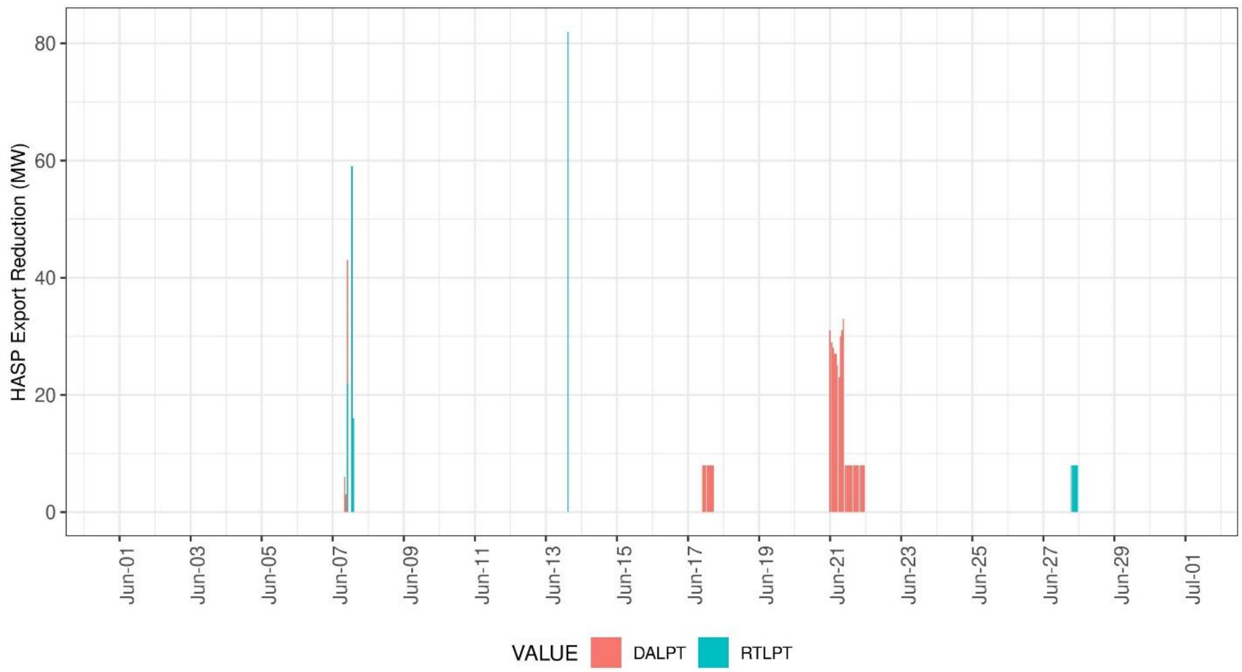
Exports can still participate in the real-time market by rebidding relative to the DAM solution, or directly into the real-time market with either high or low priority, as well as with economical bids. Figure 22 shows

program). If the market clearing process encounters constraints, the ISO will treat PTK exports similar to internal loads, but treats LPT exports as recallable, and the market will reduced LPT exports before relaxing the power balance constraint.

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

the instances when the real-time market reduced exports in June, with the largest reduction happening on June 13 mainly for low priority exports. These volumes were relative mild.

Figure 22: Exports reductions in HASP



Demand Response

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

Figure 23 shows the dispatch for proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in all markets based on their bid-in prices. During the month of June, PDR resources were consistently dispatched in both the day-ahead and real-time markets. The largest volume of PDR dispatches in the day-ahead timeframe occurred on June 5 at about 105 MW, whereas in the real-time market, it was a maximum of 45 MW on June 26 trade date.

Figure 23: PDR Dispatches in day-ahead and real-time markets in June 2024

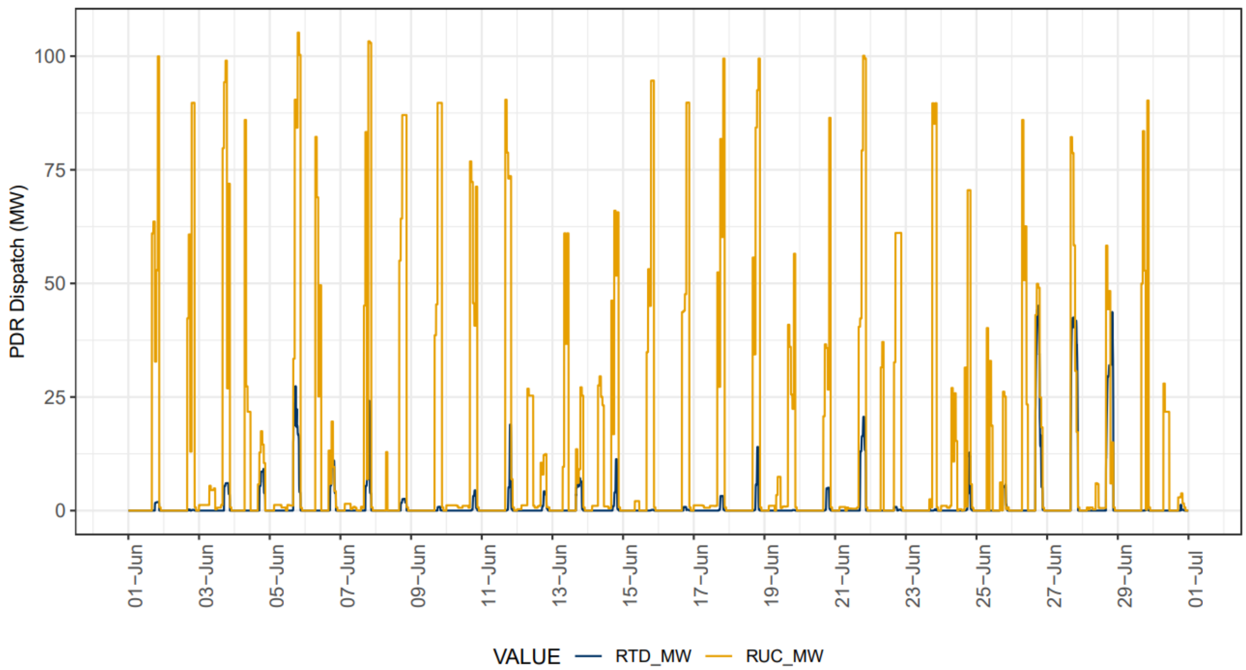
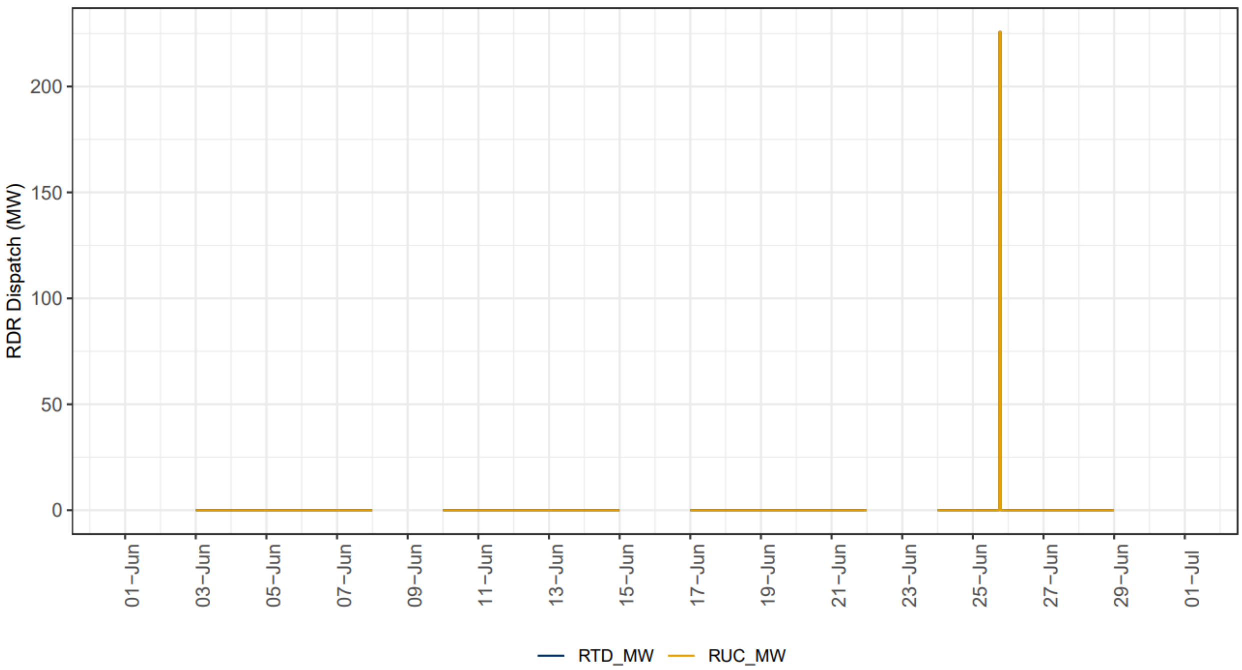


Figure 24 shows the dispatches of reliability demand response resources (RDRRs) in both the day-ahead and real-time markets for the month of June. In the day-ahead market, these types of resources can be dispatched based on economics. The real-time market will consider these DAM dispatches as self-schedules. Therefore, these RDRRs will be dispatched in the real-time market even when there is no energy emergency alert declaration. RDRRs were dispatched in the real time market on June 25 to about 225 MW for HE 19. RDRRs were dispatched in RUC and RTD market to the same amount of 225 MW on June 25 for HE 19. Hence the yellow line for RUC MW and blue line for RTD MW are overlapping.

Figure 24: RDRR dispatches in day-ahead and real-time markets for June 2024



5 Intertie Transactions

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

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

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

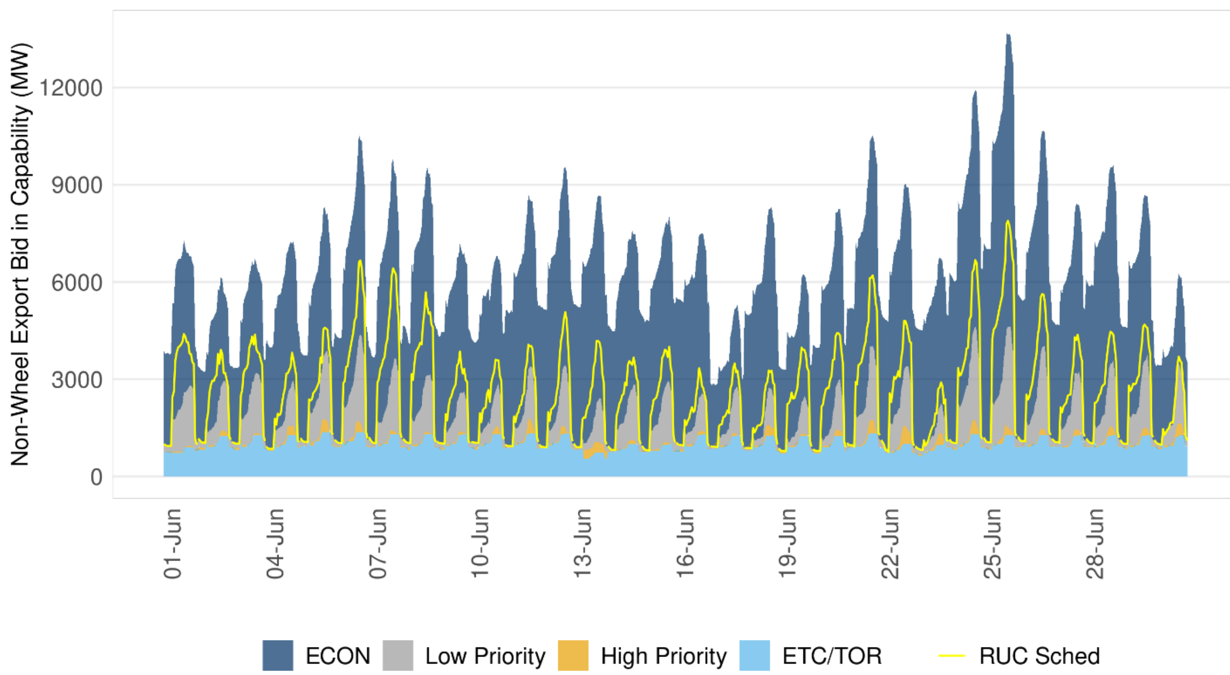
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are taken into account.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

Intertie supply

Figure 25 shows the capacity from static export transactions in the day-ahead market for June 2024 organized by types of exports. This capacity does not include export capacity associated with wheel transactions of any type because wheels are in balance on a net basis, and the export side of wheels does not reduce supply to the ISO supply stack.

This figure also illustrates the clearing schedules from the RUC process with the line in yellow. 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,

Figure 25: Day-ahead Bid-in capacity and RUC cleared export



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

Export bid capacity in the day-ahead market varies by hour and typically follows a daily profile. About 70 percent, 13 percent, 16 percent and 1 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. Due to mild load conditions and ample supply in the day-ahead conditions in June, there were robust level of exports, maxing out on June 25 at about 7,888 MW.

Figure 26: Day-ahead bid-in capacity and RUC-cleared imports

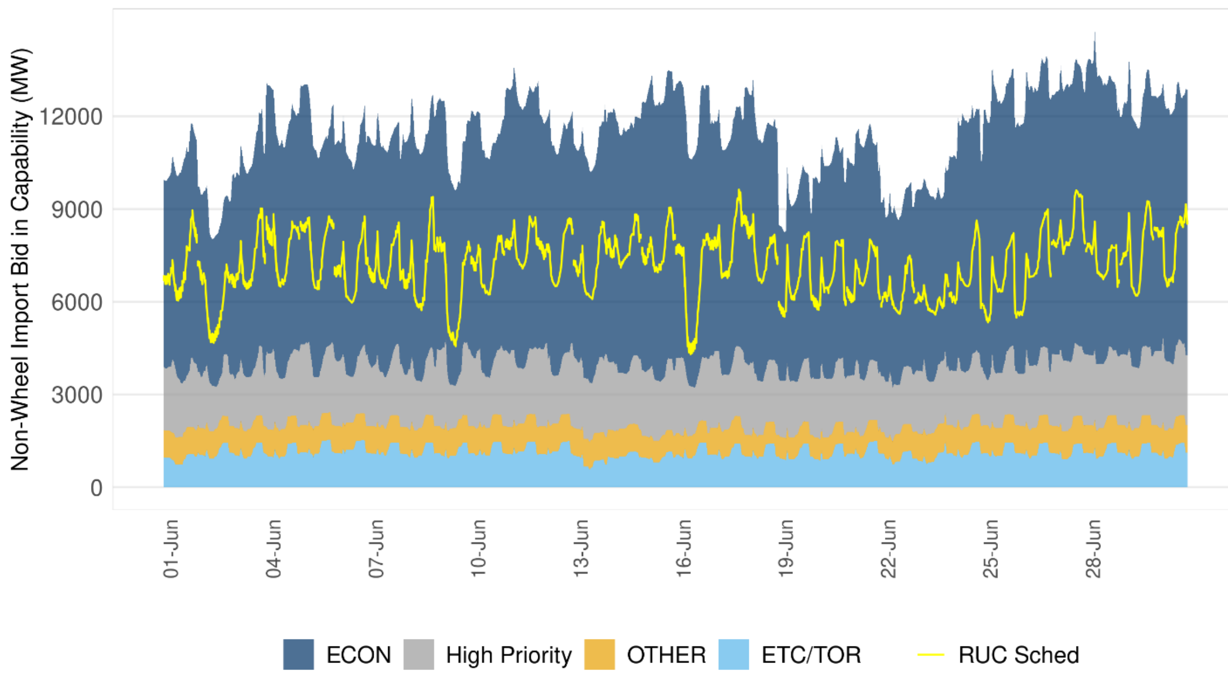
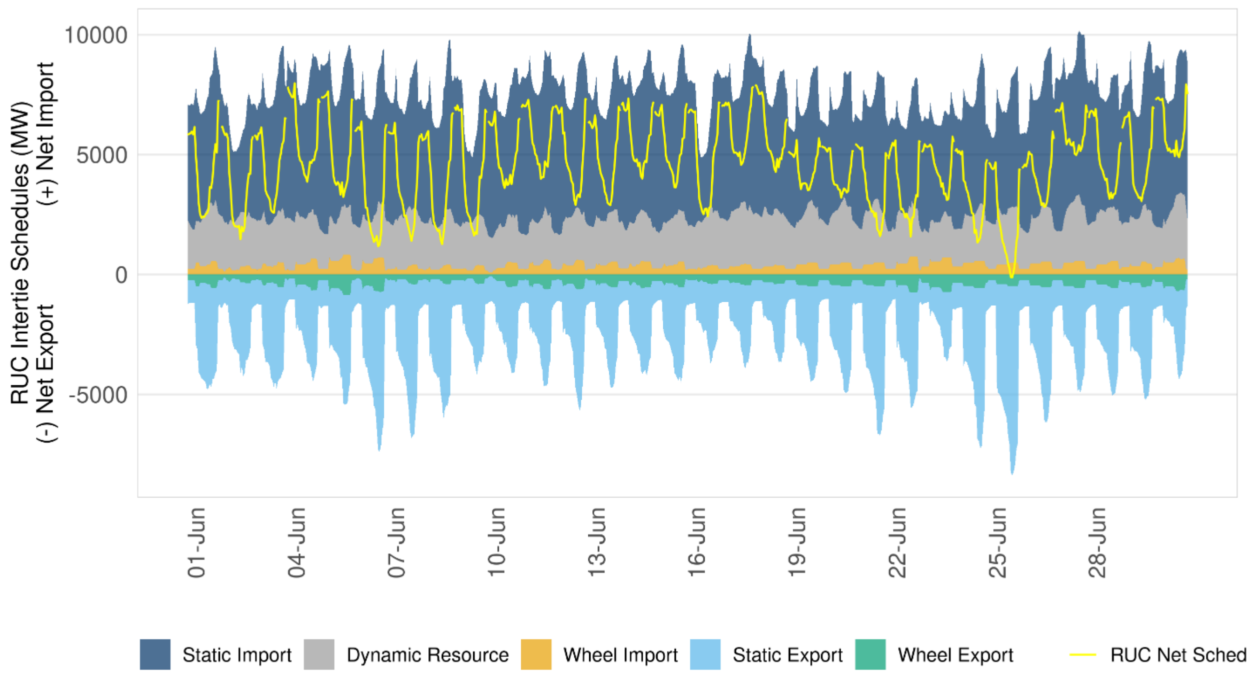


Figure 26 shows the same metric for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the month, while economic imports remained at volumes over 5,000 MW. The “other” group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

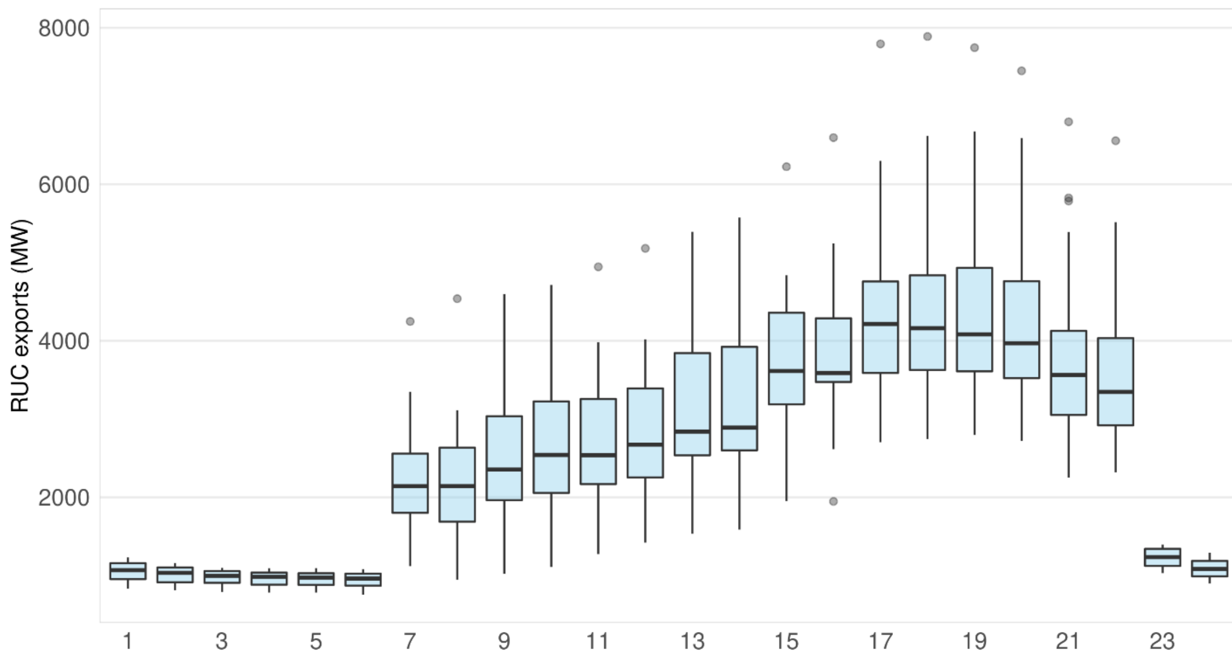
Figure 27 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution. The net interchange projected in the RUC process reached its lowest level on June 25 in HE 18 at about -118 MW due to the higher level of exports cleared.

Figure 27: Breakdown of RUC cleared schedules



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 28 illustrates the hourly distribution of RUC schedules for exports and that the highest volume occurred during midday hours when the ISO's system has high levels of solar supply. The largest volume of exports in June were observed in the evening hours.

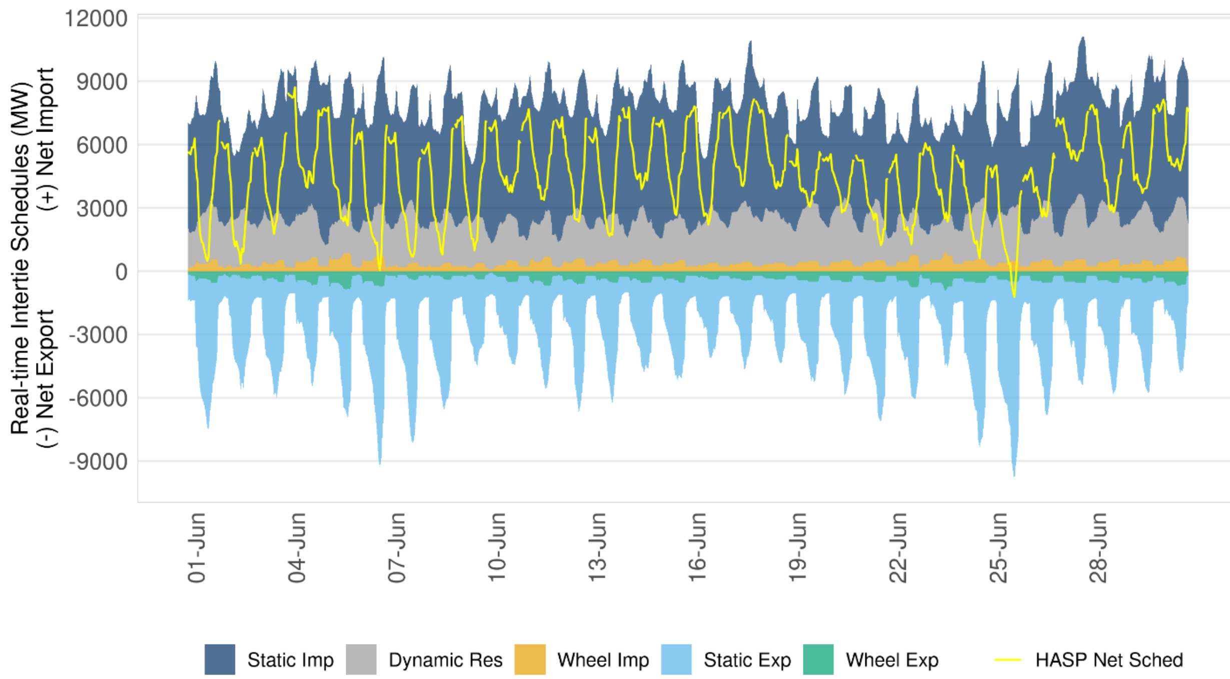
Figure 28: Hourly RUC exports



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 their day-ahead priority. There may still be incremental participation in the real-time market through the HASP process, which allows resources to bid-in economically to buy back their day-ahead position or additional capacity in the real-time market.

Figure 29 shows both the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred to as net schedule interchange. The net schedule interchange was at its lowest value on June 25 due to the highest level of exports cleared on that day. The real-time market largely follows the trend observed in the day-ahead market. On average, for June, the net schedule in HASP was about 4,600 MW across all the hours of the month and about 3,800 MW for peak hours.

Figure 29: HASP cleared schedules for interties in June



The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC.[12]

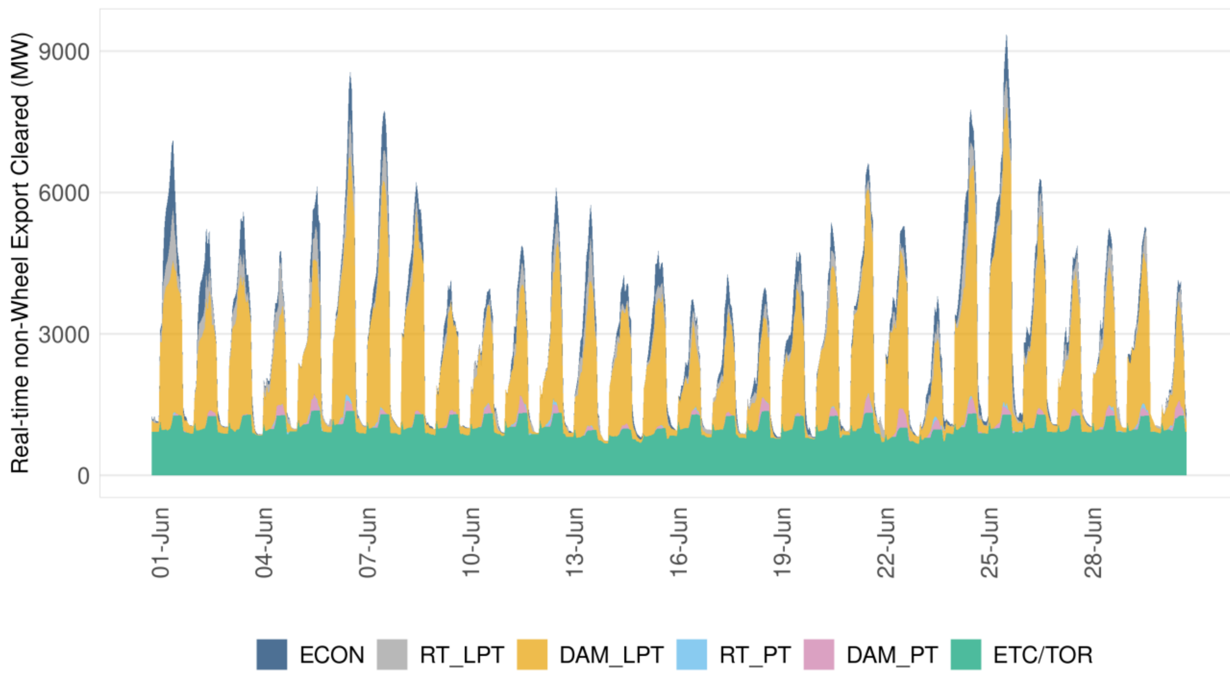
Each market, RUC or HASP, can assess reduction of exports based on the prevalent system conditions and economics. Export reductions in RUC cannot self-schedule into real-time with day-ahead priority, but they are able to be rebid into the real-time market and be fully assessed based on real-time conditions.

Figure 30 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 DAM_PT or DAM_LPT stand for day-ahead exports coming into real-time market as self-schedules with high or low priorities. Similar classification is followed for those high and low priority exports coming into real-time directly (RT_PT and RT_LPT). ECON stands for economic exports. 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 peaked at 9,432MW on June 25. In June, low priority and economical bids constituted a significant portion of cleared exports.

[12] Based on these rules implemented on August 4, 2021, through the summer enhancements described earlier and now in place, the ISO will no longer provide exports a higher priority than load in the real-time, and will only provide them equal in priority to load if the participant demonstrates that they continue to be supported by resources contracted to serve external load.
Details are available at http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

Figure 30: Exports schedules in HASP



Imports and exports were scheduled over multiple intertie scheduling points in June, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 31 through Figure 33 illustrate the trend of import and export schedules cleared in HASP for these top three intertie points. In June, the prevailing schedules were in the import direction.[13] In Figure 33 the gap in the HASP schedules for the NOB intertie for trade dates June 22 and June 23 was due to an outage on the NOB intertie.

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

Figure 31: HASP schedules at Malin intertie

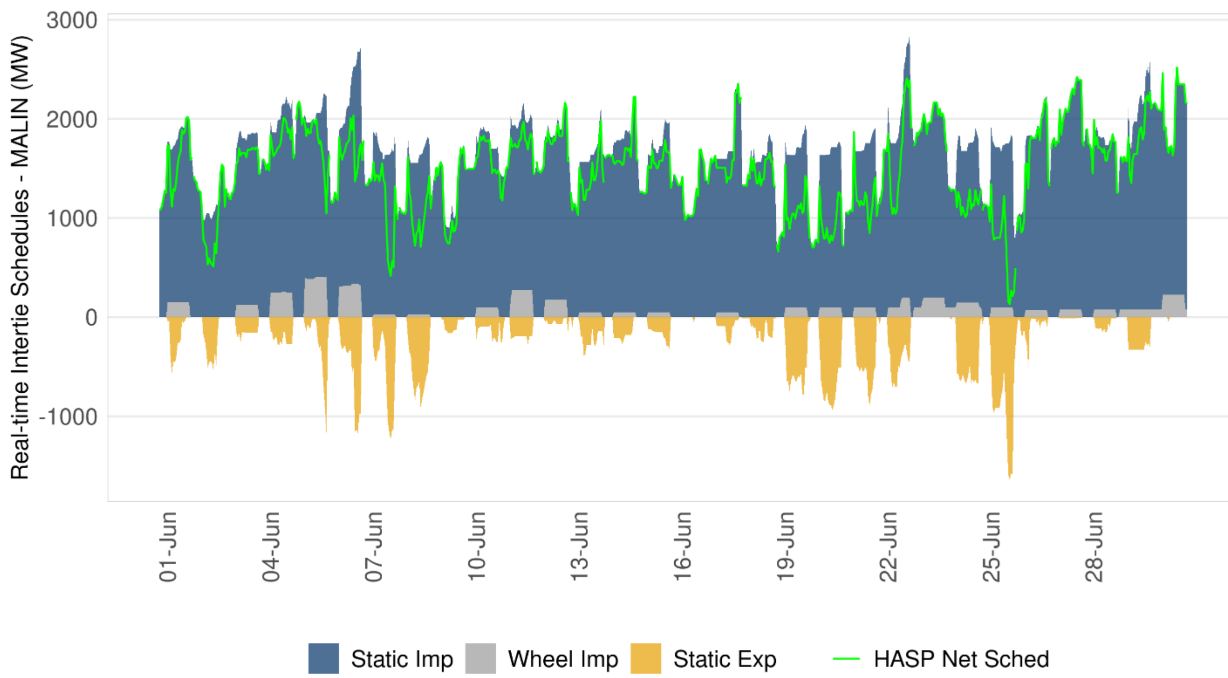


Figure 32: HASP schedules at Palo Verde intertie

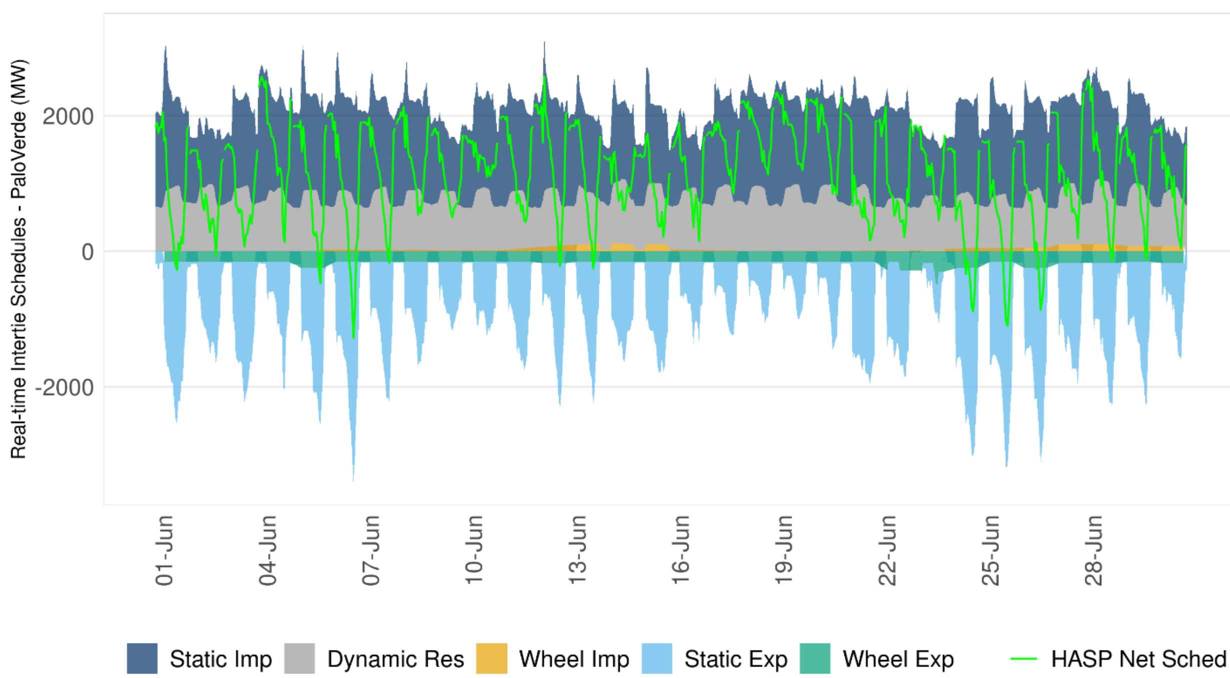
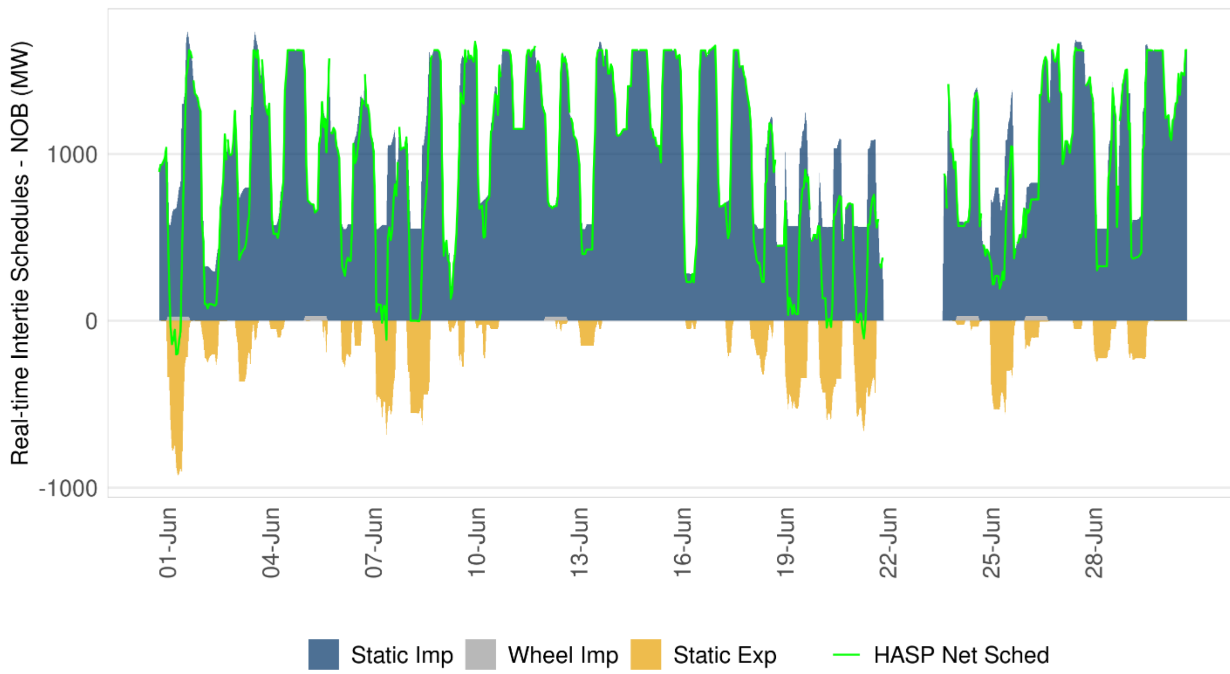


Figure 33: HASP schedules at NOB intertie



Resource adequacy imports

Imports can be used to meet Resource Adequacy (RA) requirements and they can be resource-specific or non-resource specific. For simplicity, this analysis relies on static imports as a proxy for non-specific resources. The other type of imports are dynamic or pseudo tie resources, which typically will be resource-specific. The total amount of RA supported by static imports in June was about 3,017 MW related to LSEs under CPUC jurisdiction.

Under RA rules, non-resource specific RA imports for LSEs under CPUC jurisdiction must self-schedule or bid economically with prices between -$150/MWh and $0/MWh at least for the availability assessment hours. Figure 34 is an approximation of the supply bid in the day-ahead market by static RA imports associated with LSEs under CPUC jurisdiction and for hours ending 17 through 21 of weekdays only. This supply is organized by price range, including self-schedules, and also differentiates between RA capacity and above RA capacity. Based on this subset, about 99 percent of all RA import capacity bid with either self-schedules or economic bids at or below $0/MWh in the day ahead timeframe in June. This plot also shows the cleared imports, which largely utilized all the bid-in volume for RA and above RA.

Figure 34: Day-Ahead RA import for hour endings 17 through 21 for weekdays

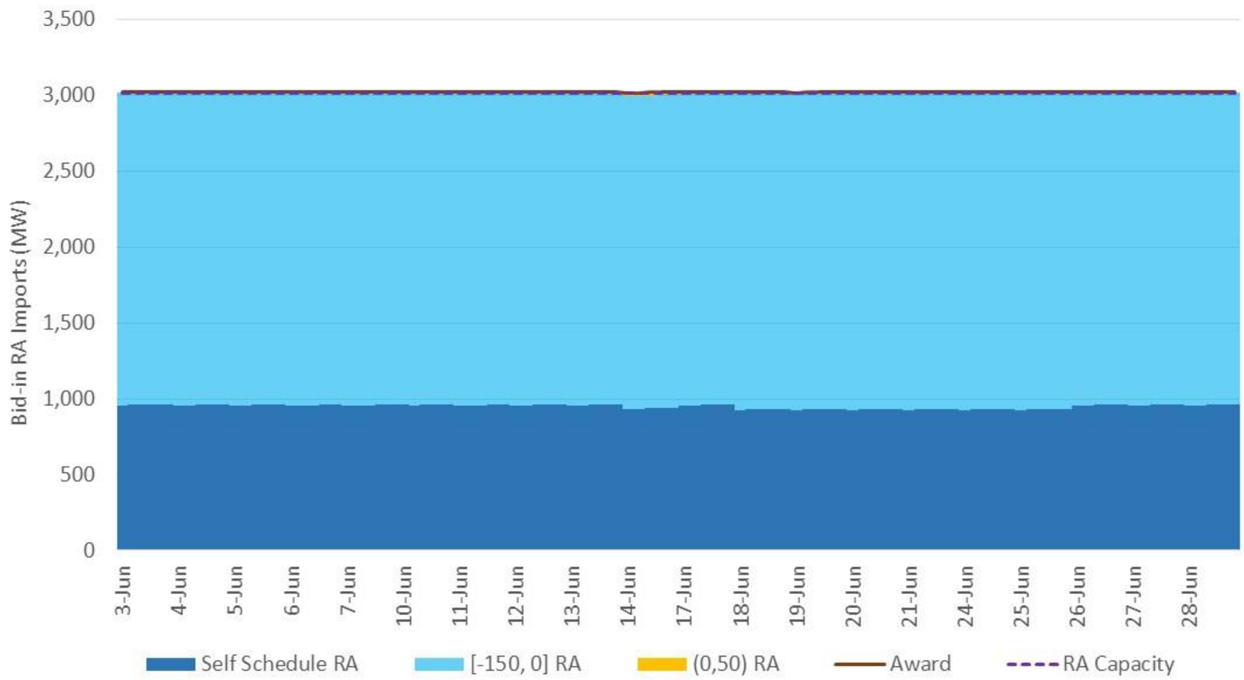
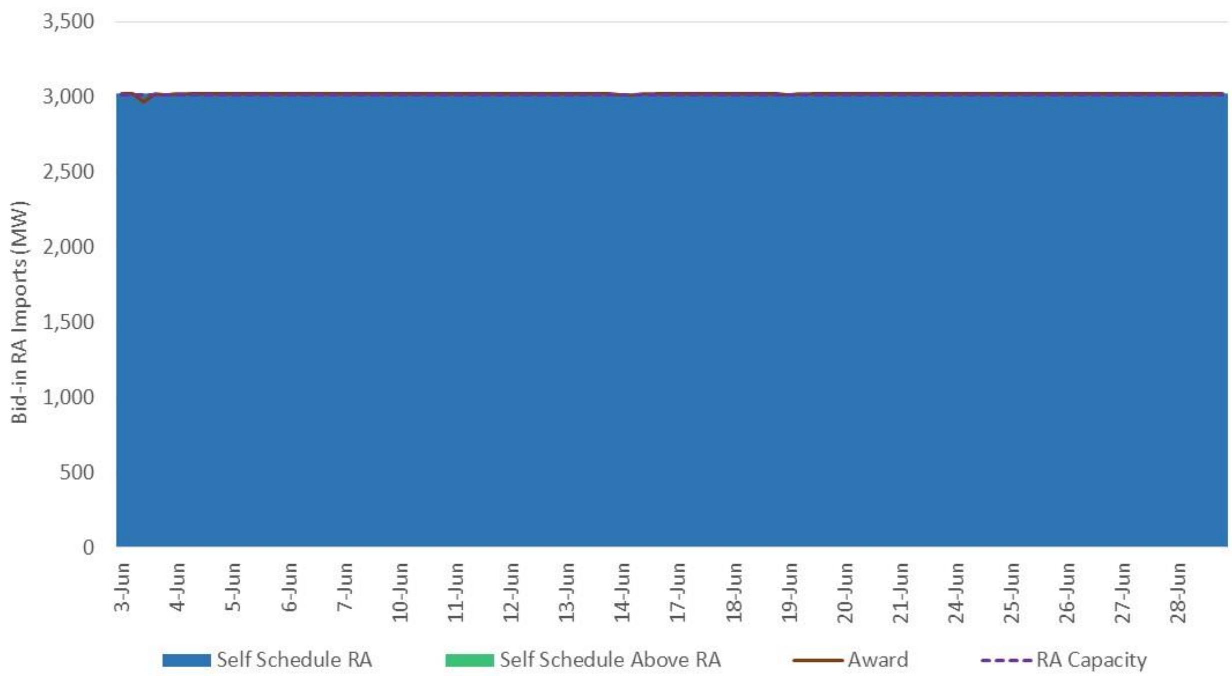


Figure 35 shows the same information for the real-time market using the HASP bids. All RA imports submitted in the real-time market were with self-schedules. There were also small volumes of RA imports bid above their RA level with self-schedules.

Figure 35: HASP RA import for hour endings 17 through 21 for weekdays



Wheel Transactions

With the summer enhancements for exports, loads and wheeling scheduling priorities extended for summer 2024, wheels can seek higher priority for their wheels.[14] For the month of June 2024, there was a total of 675 MW of high-priority wheels from eight different scheduling coordinators. Table 1 lists all the wheel-through definitions used in June

Table 1. Wheel-through quantities registered for June 2024

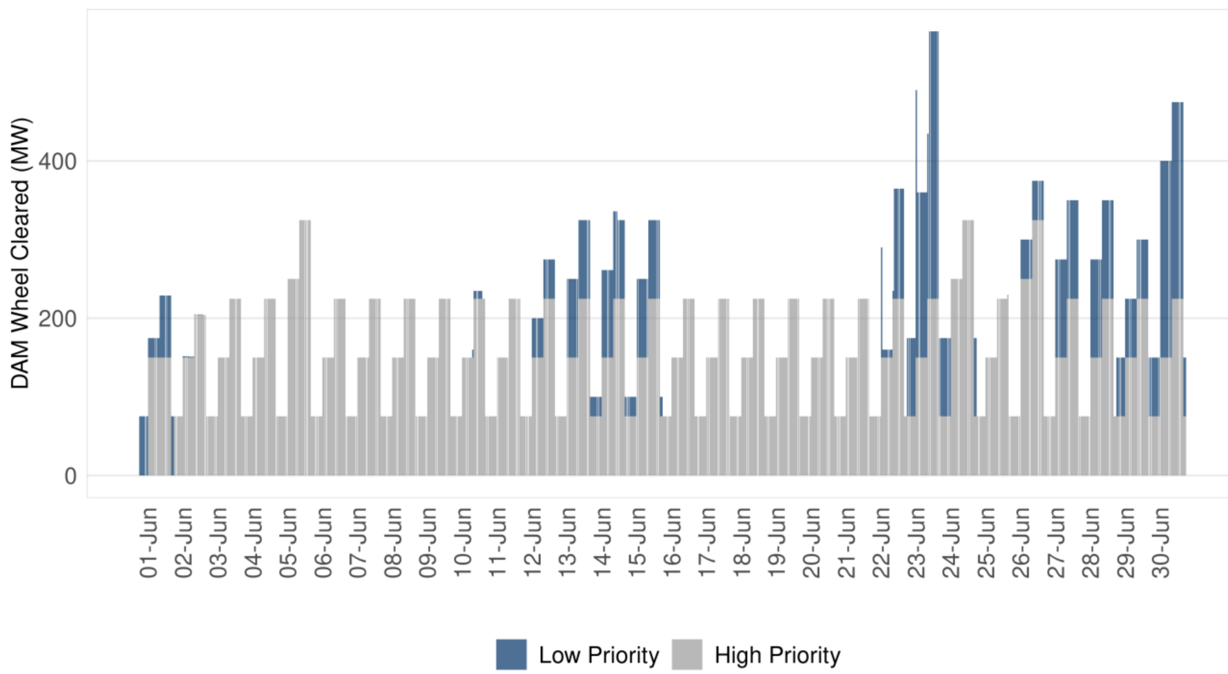
Source	Sink	MW
MALIN500	PVWEST	72
NOB	PVWEST	28
NOB	MEAD230	75
NOB	PVWEST	25
NOB	MEAD230	250
RDM230	PVWEST	150
RDM230	MCCULLOUG500	75
	Total	675

[14] Insert here short description of the enhancement implemented for estimating the PT wheels capacity replacing the old registration process

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

Figure 36 shows the hourly high and low priority wheels cleared in the RUC process throughout the month. ETC/TOR wheels are excluded. Wheels participating in the day-ahead market with high- and low-scheduling priority, reached a total maximum at 565 MW on June 23, with 225 MW of high priority and 340 MW of low priority wheels.

Figure 36: Hourly volume high- and low-priority wheels cleared in RUC



Wheels are defined with a source and sink location in the ISO's markets to factor in their contribution to the flows on either intertie constraints or internal transmission constraints.

Figure 37 summarizes the hourly average of wheels organized by source and sink combinations. An empty entry reflects that no wheels were present for that given source-to-sink combination in June. Source refers to the import scheduling point while sink refers to the export scheduling point. The path with the largest volume of wheels in June in the day-ahead market was from RDM (Round Mountain located in norther California) to PVWEST (Palo Verde located in Southern California).

Figure 37: Hourly average volume (MWh) of wheels by path in June

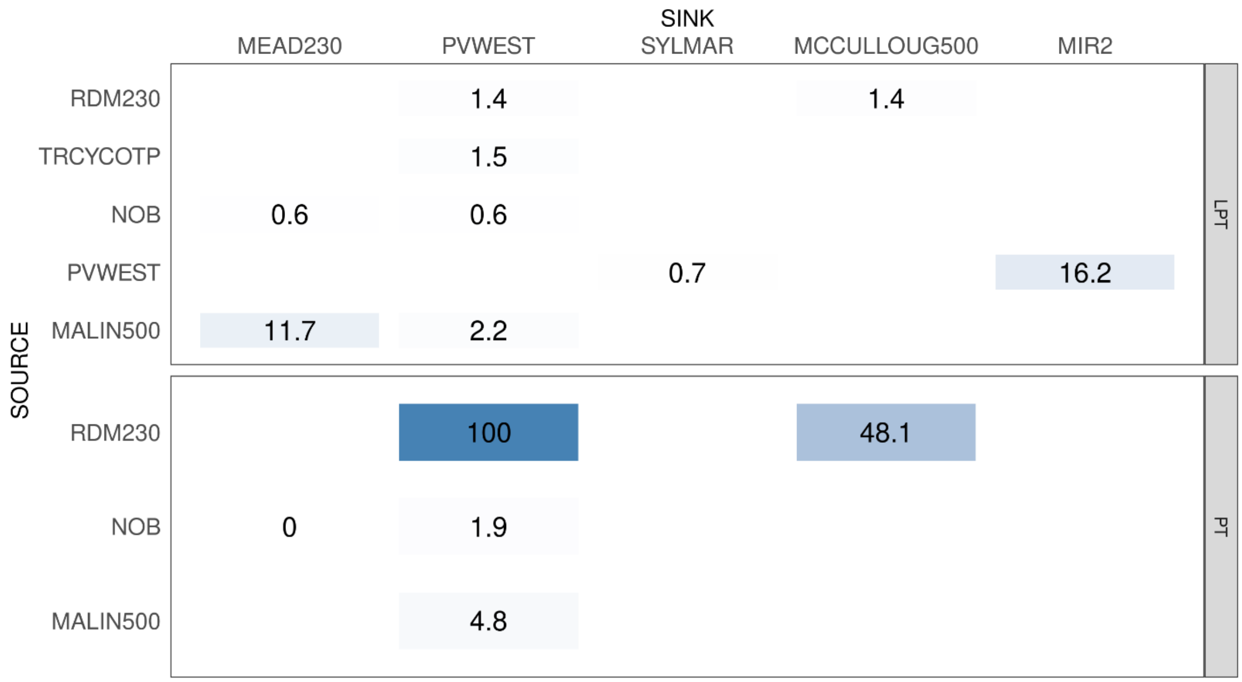
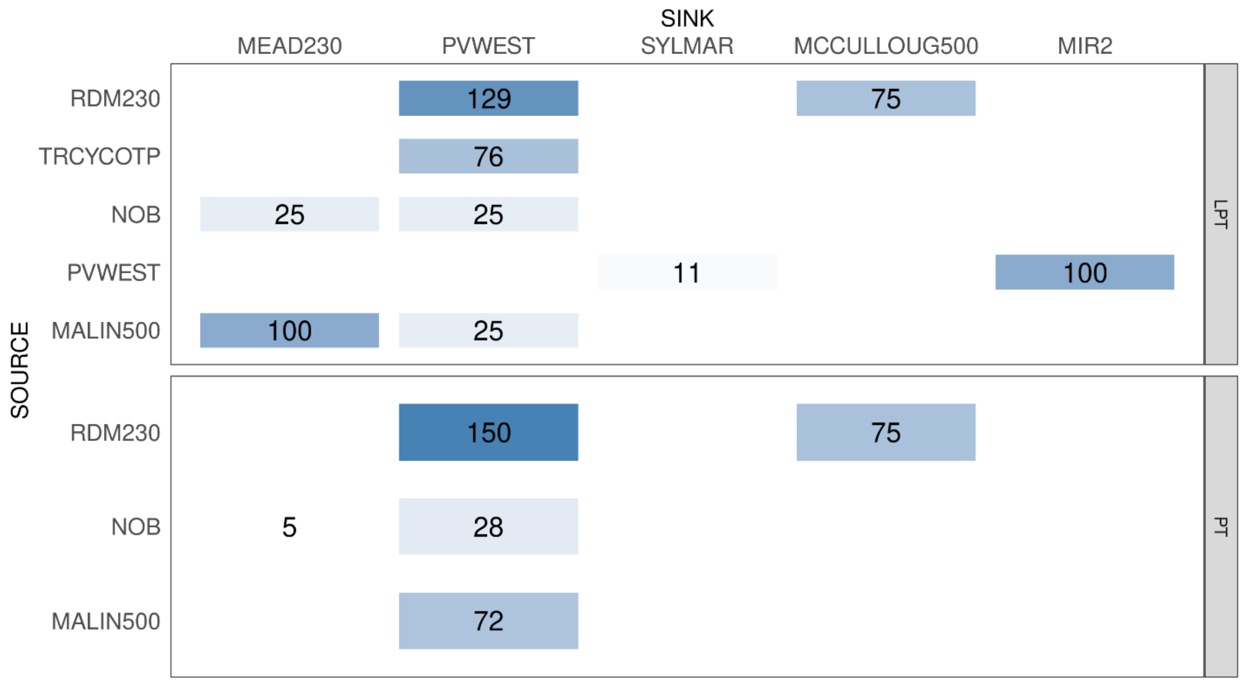


Figure 38 summarizes the maximum hourly wheels cleared in any hour in June in the day-ahead market by source-to-sink combination. The maximum volume of wheels in a given path occurred from RDM to PV West.

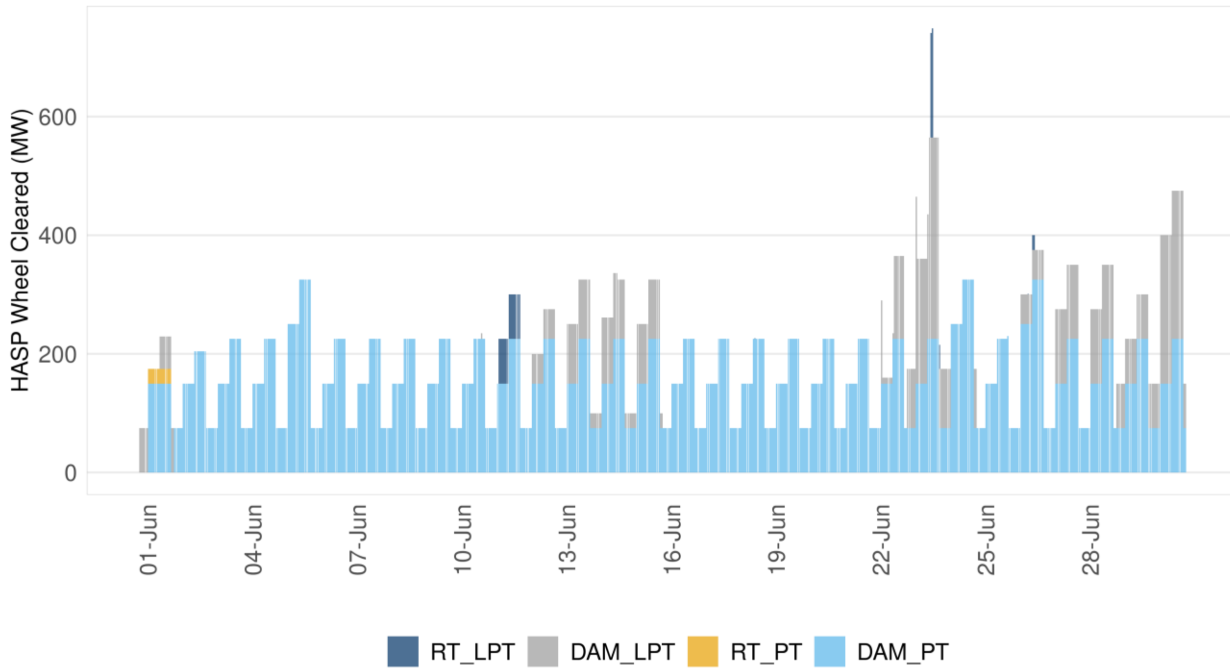
Figure 38: Maximum hourly volume (MW) of wheels by path in June



Although wheels do not add or subtract capacity to the overall power balance of the ISO market, they compete for limited scheduling and transmission capacity.

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 39 shows the volume of high- and low-priority wheels cleared eventually in the real-time market, organized by the various types of priority and relative changes.

Figure 39: Wheels cleared in real-time market



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

6 Storage and Hybrid Resources

In June 2024, there were 161 storage resources actively participating in the ISO markets. Storage resource here refers to the Limited Energy Storage Resource (LESR) type. Most storage resources participated in both the energy and ancillary service market. Batteries can arbitrage the energy price by consuming energy (charging) when prices are low, then subsequently delivering energy (discharging) during market intervals when prices are higher. Each storage resource has a maximum storage capability that reflects the physical ability of the resource to store energy.

The total storage of charge from all the active resources participating in the market was 34,205 MWh. In terms of the capacity made available to the markets, Figure 40 and Figure 41 present the daily average and the hourly average of bid-in capacity for storage resources in the day-ahead market in June, organized by price ranges.

Figure 40: Bid-in capacity for batteries in the day-ahead market, daily average

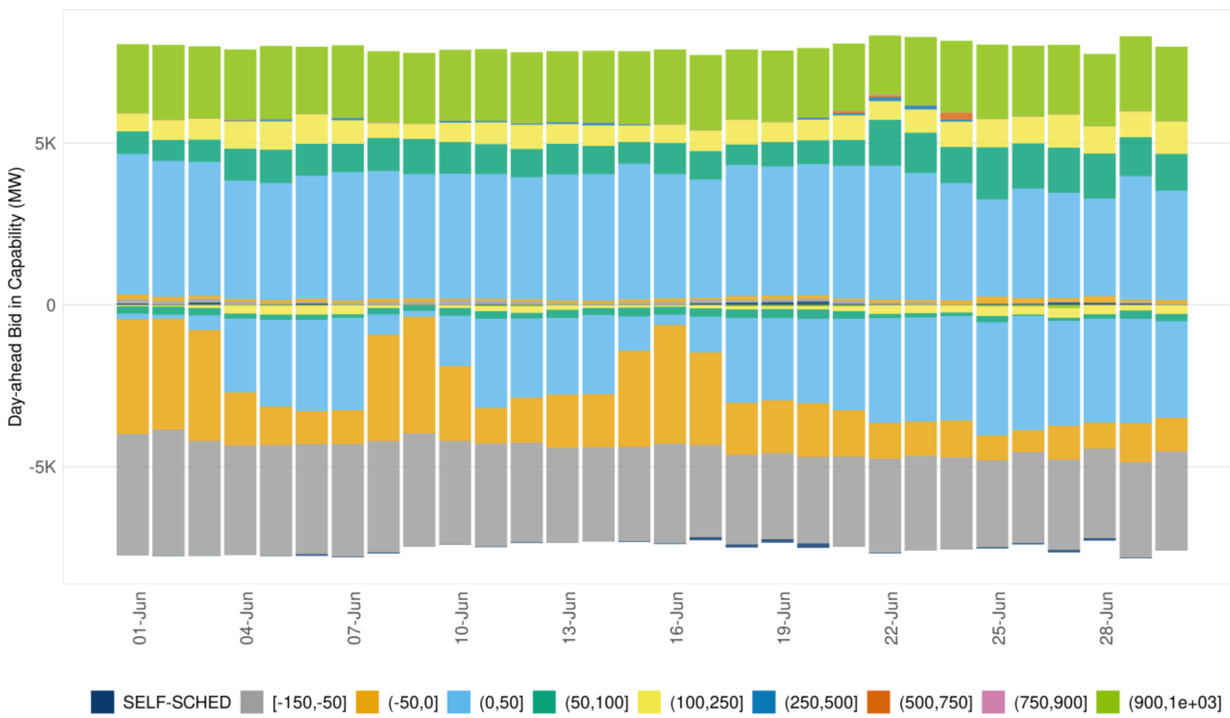
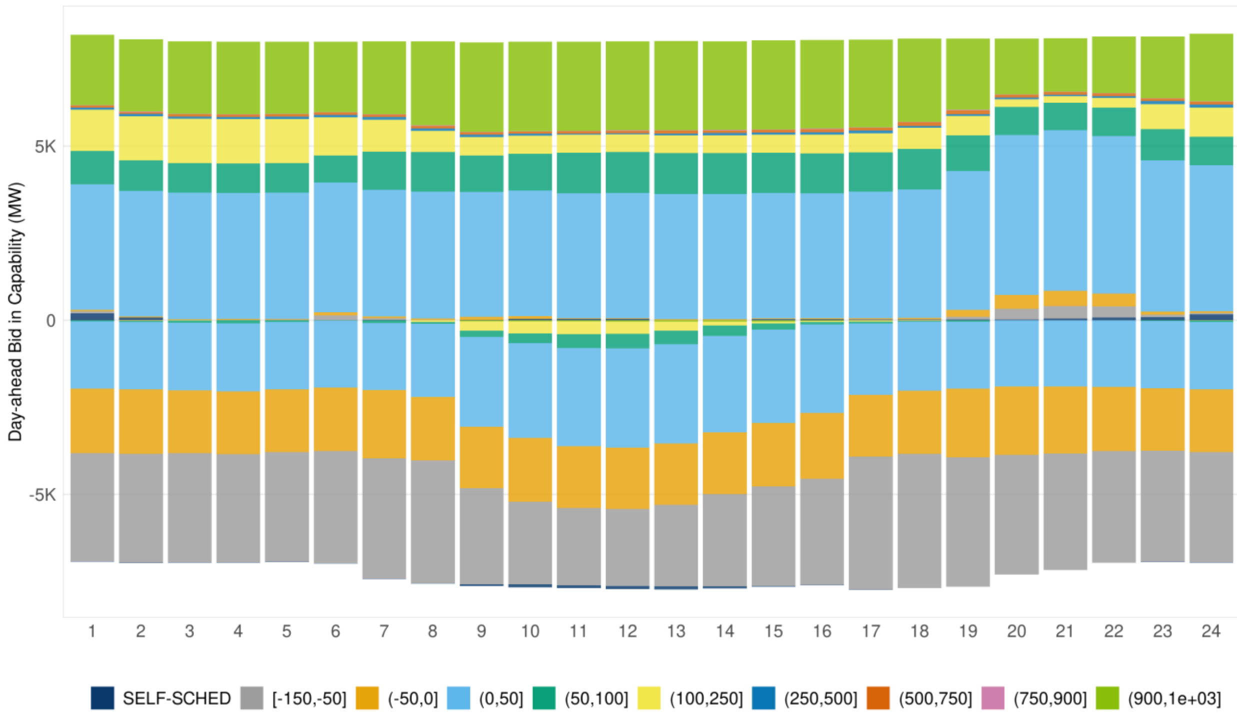


Figure 41: Bid-in capacity for batteries in the day-ahead market, hourly average



The negative area represents charging while the positive area represents discharging. The overall capacity in the market was roughly consistent through the month at about 7,500 – 8,000 MW. The bid-in capacity is organized by $/MWh price ranges. There were consistent patterns of batteries bidding to charge at negative prices and discharge at positive prices. In June, some resources bid reflected the willingness to charge when prices were up to $50. Conversely, they were almost always willing to discharge at higher prices. The green segments show bids close to or at the soft energy bid cap of $1,000/MWh and show that there was a certain volume of storage capacity expecting to discharge only at these high prices.

Figure 42 and Figure 43 present the bid-in capacity for the real-time market. The overall capacity follows the similar trend as the day-ahead market.

Figure 42: Bid-in capacity for batteries in the real-time market, daily average

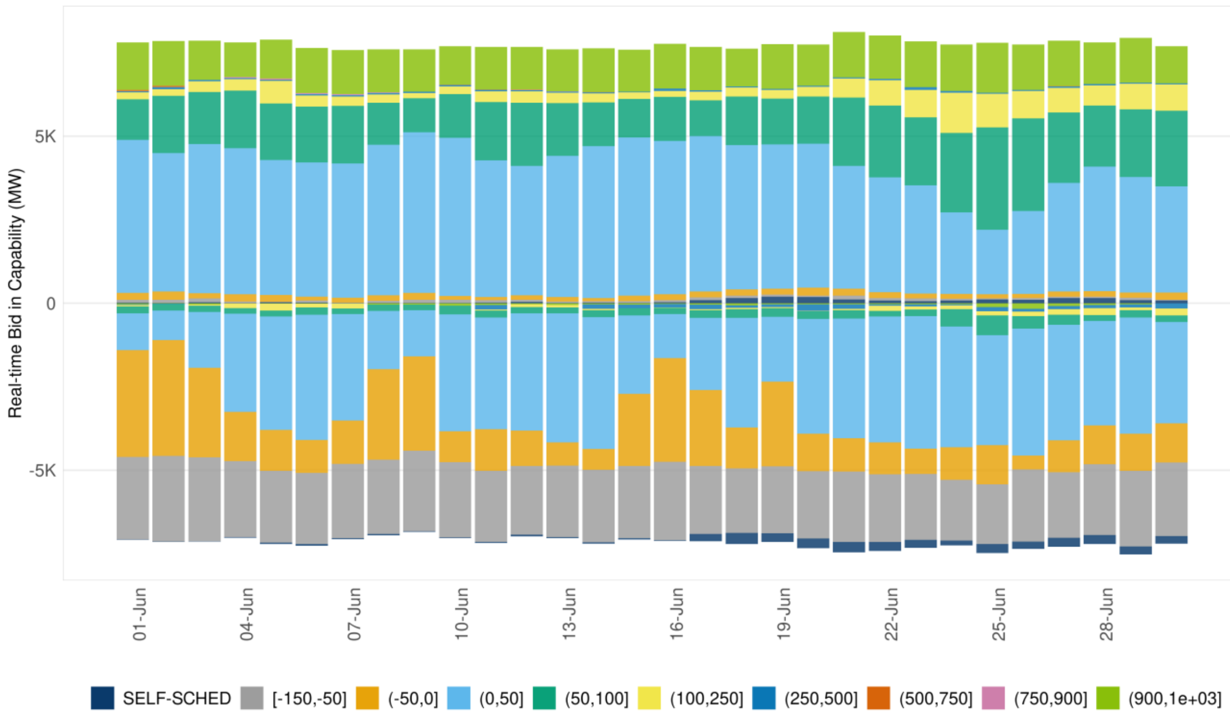


Figure 43: Bid-in capacity for batteries in the real-time market, hourly average

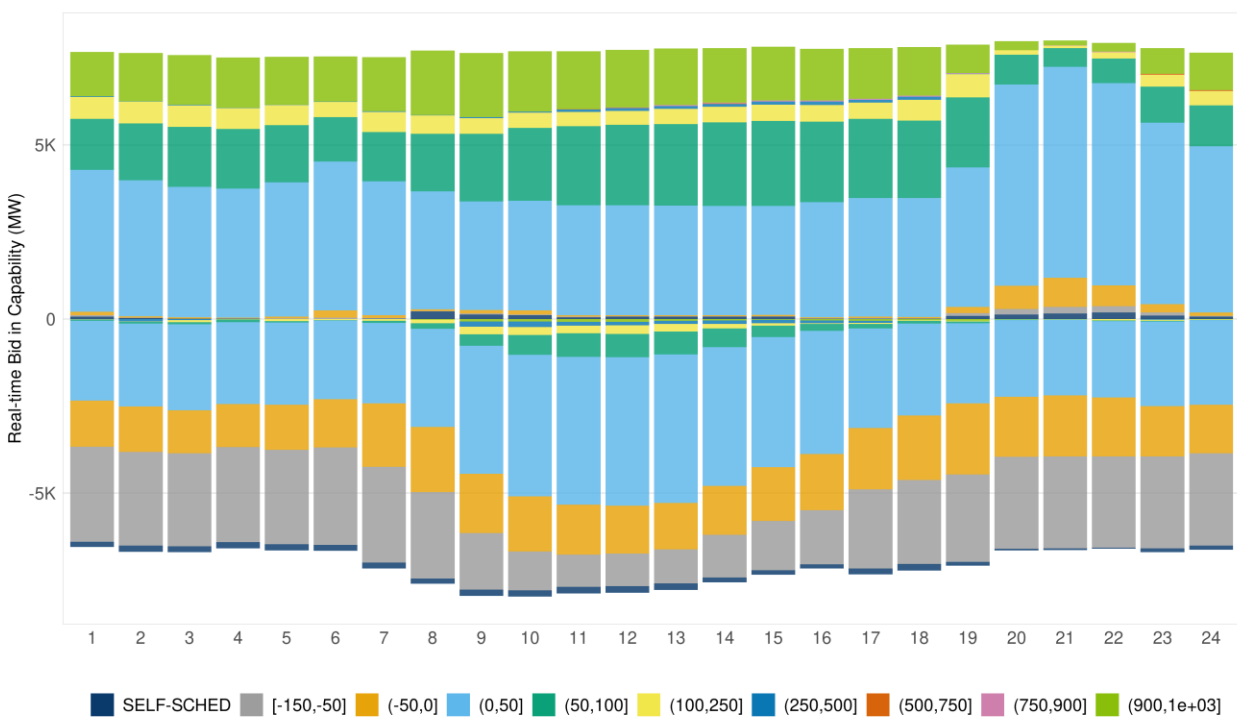


Figure 44: Distributions of state of charge for June 2024

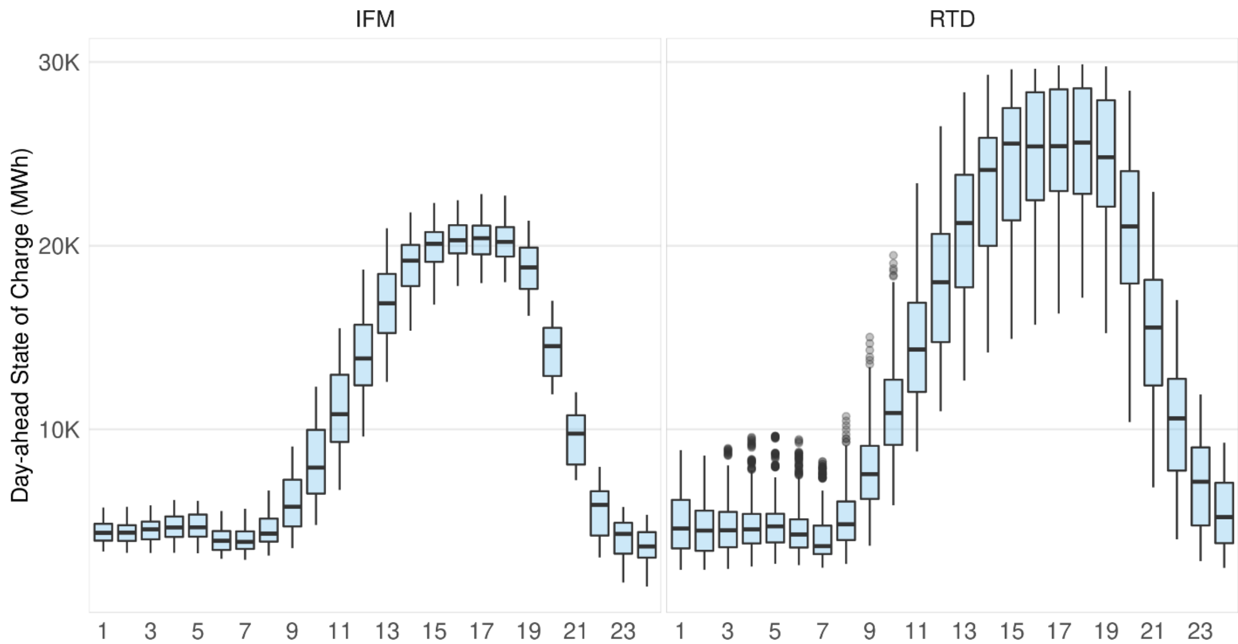


Figure 44 shows the hourly distribution of the storage capacity of resources participating in IFM and RTD for June. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime, between hours ending 9 to 18. The system reached maximum stored energy by hour ending 16, followed by a period of steady discharge from hours ending 18 through 24. In June, the highest system state of charge in IFM was around 22,810 MWh, roughly 67 percent of the total capacity, which occurred in the hour ending 17. The peak hourly state of charge in the real-time market was 29,880 MWh at roughly 87 percent of the total capacity, higher than the day-ahead peak state of change. Also, the state of charge in the real-time market had a wider spread compared to the day-ahead market.

Most of the storage resources in the ISO market are four-hour batteries, which implies that if a resource is fully charged, it will take four hours to discharge this resource completely. To arbitrage prices, it is expected that the resource would be charged as much as possible just prior to the hours with high energy prices. With the need for more supply as solar production diminishes, it is expected that storage resources would be discharging during net load peak hours. Figure 45 shows the distributions of energy awards in IFM, and Figure 46 shows the hourly distribution of real-time dispatch for batteries in June. These statistics are for batteries, either stand alone or the battery component of col-located resources; they do not include hybrid resources.

Figure 45: Hourly distribution of IFM energy awards for batteries in June

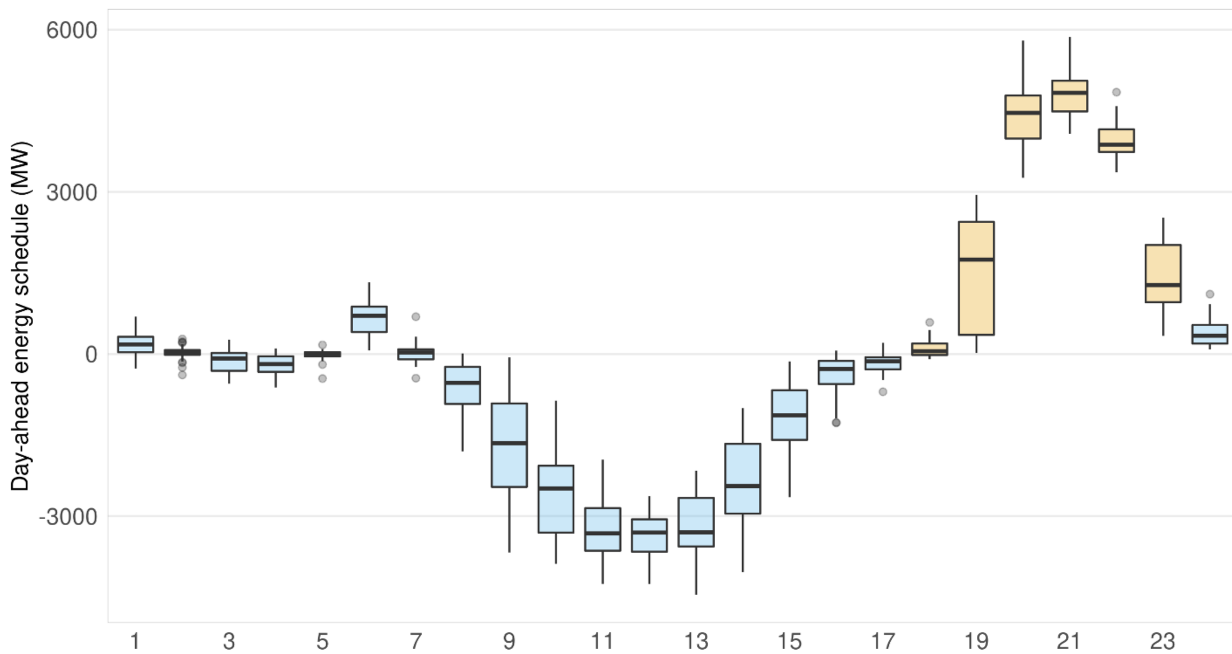
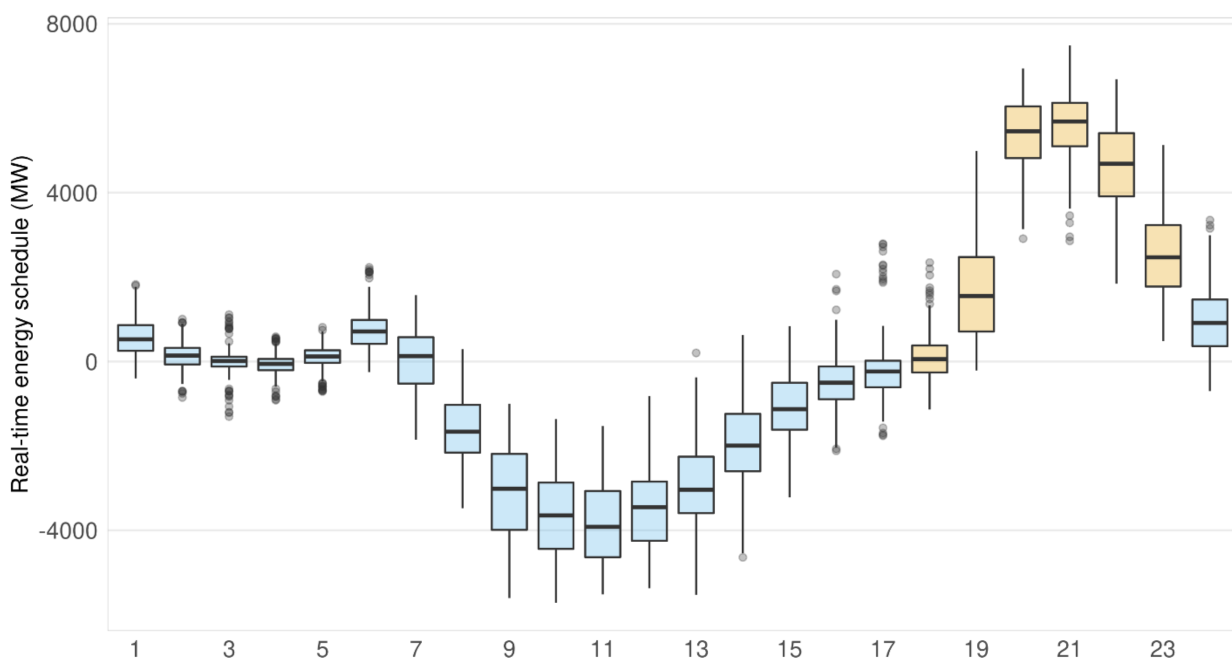
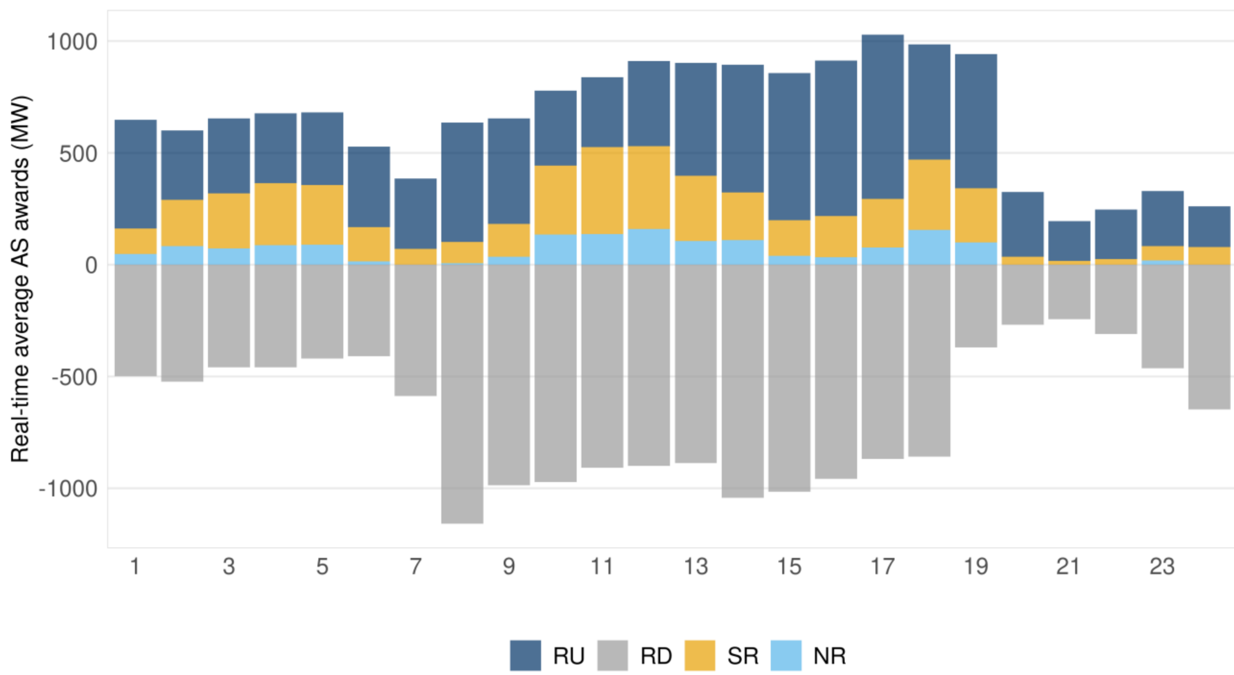


Figure 46: Hourly distribution of real-time dispatch for batteries in June



The storage resources continue to provide ancillary services to the market for the following products: regulation up, regulation down, spinning reserve, and non-spinning reserve. Figure 47 shows the average hourly AS awards in the real-time market.

Figure 47: Hourly average real-time storage AS awards in June 2024



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

Figure 48 and Figure 49 show the IFM and real-time energy awards for hybrid resources, respectively. The pattern matches more closely the dispatch patterns of solar resources with some differences. The energy awards dip in the middle of the day when solar resources typically reach peak output. This is likely due to the energy storage component of the resource charging off of the solar component of the resource, resulting in a lower energy award. Another notable difference is that the evening ramp down as the sun sets is less steep compared to solar resources. This pattern is attributed to the storage component of the resource discharging in these evening hours, offsetting the decreased production of the solar component and resulting in a flatter decline in output.

Figure 48: Hourly distribution of IFM energy awards for hybrid resources in June 2024

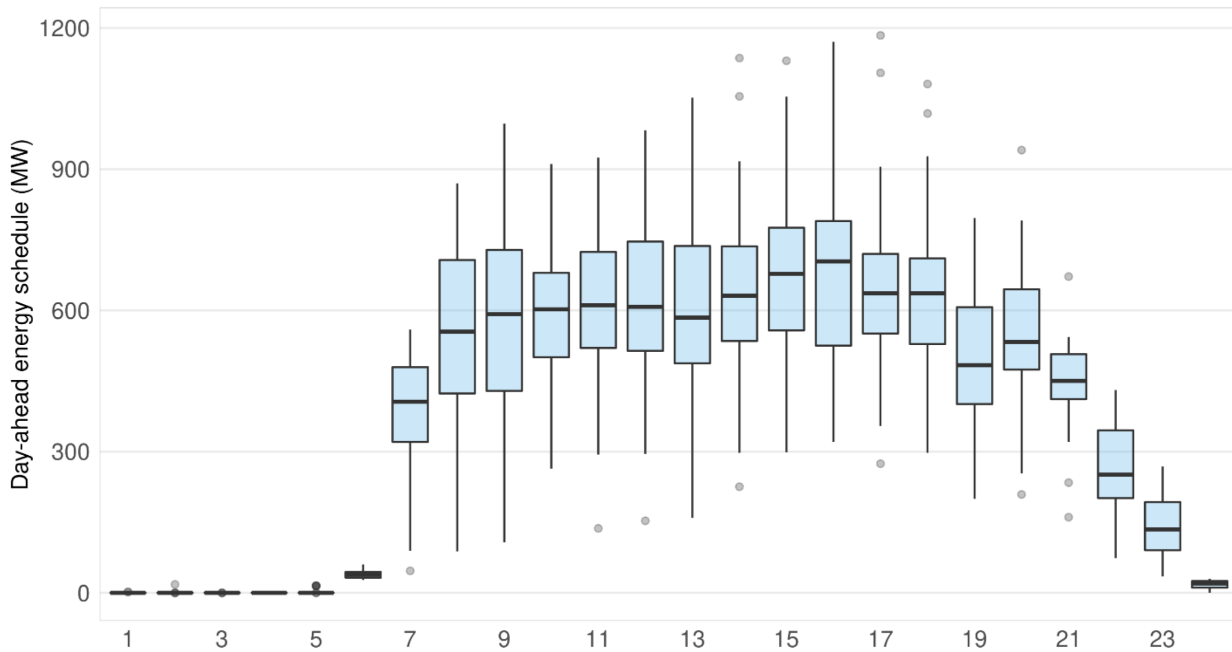
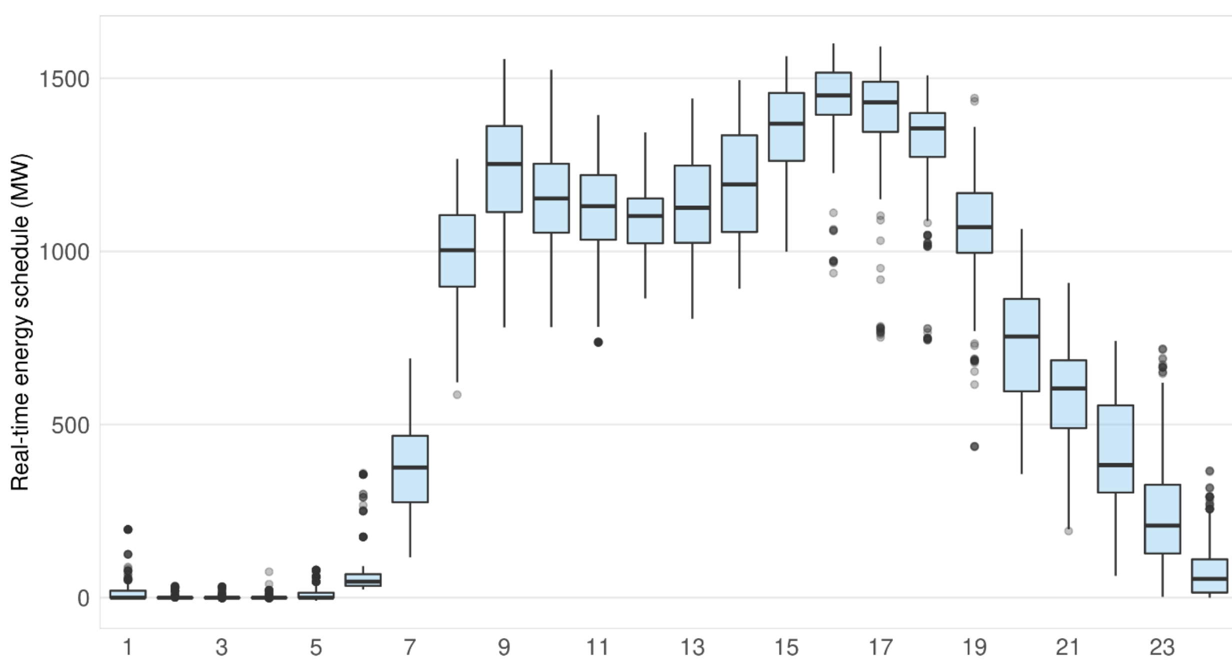
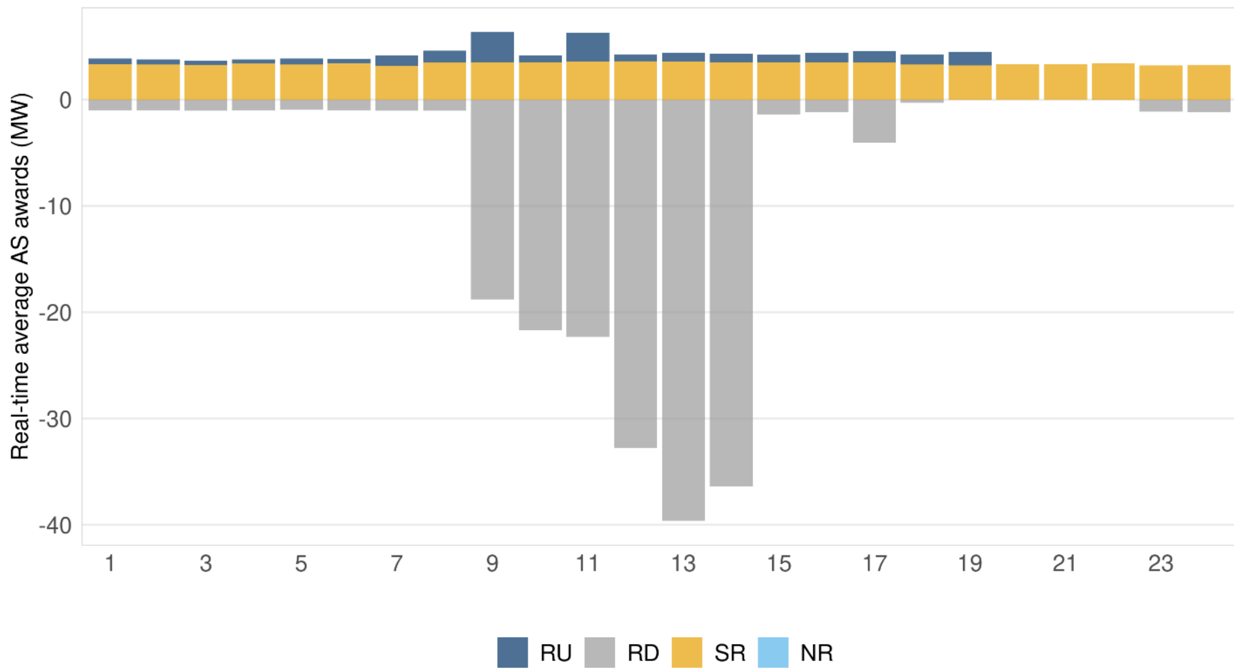


Figure 49: Hourly distribution of real-time dispatch for hybrid resources in June 2024



Similar to storage resources, hybrid resources can also provide ancillary services to the market. Figure 50 shows the average hourly AS awards in real-time June 2024.

Figure 50: Hourly average real-time hybrid AS awards in June 2024



7 Western Energy Imbalance Market

WEIM transfers

The Western Energy Imbalance Market, or WEIM, provides an opportunity for participating balancing authority areas to serve their load while realizing the benefits of increased resource diversity. The ISO estimates WEIM's gross economic benefits on a quarterly basis.[15] One main benefit of the WEIM is the realized economic transfers among areas. These transfers are the realization of a least-cost dispatch by reducing more expensive generation in one area and replacing it with cheaper generation from other area. In a given interval, import and export transfers can concurrently happen for one area. In June, the ISO did not apply any transfer limits to dynamic transfers.

Figure 51 shows the distribution of five-minute WEIM transfers for the ISO area. A negative value represents an import into the ISO from other WEIM entities. In June the majority of the transfers were exports from ISO area to other areas in the WEIM.

Figure 51: Daily distribution of EIM transfers for ISO area in RTD

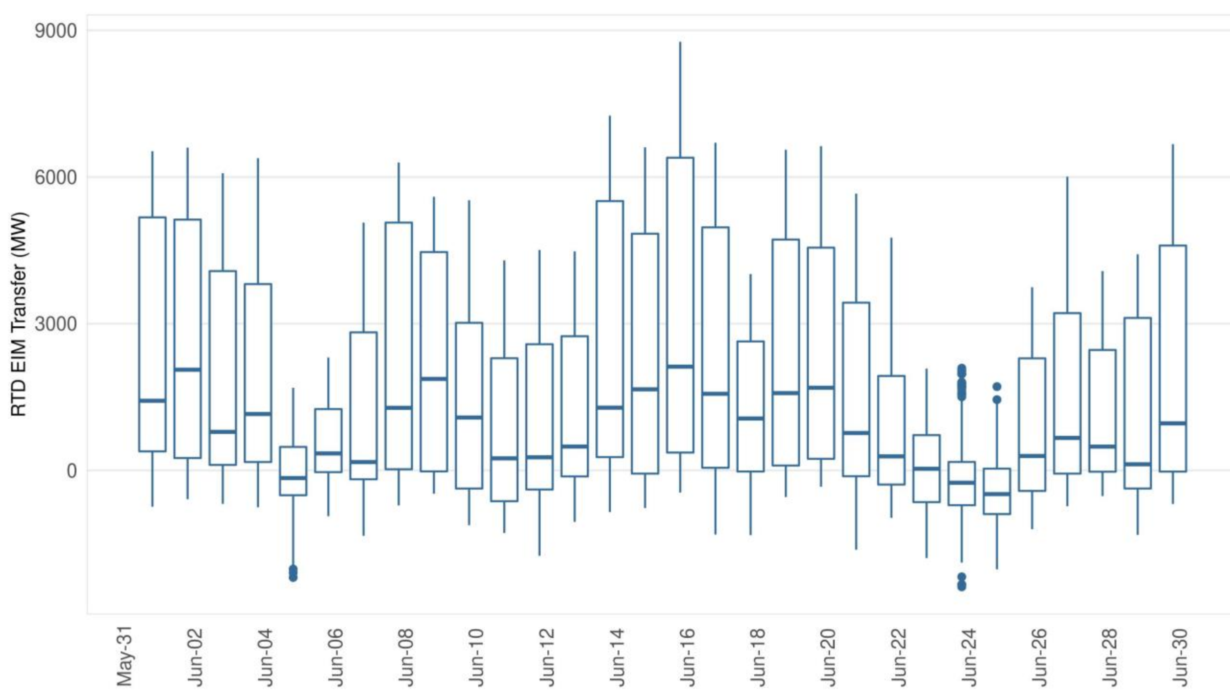
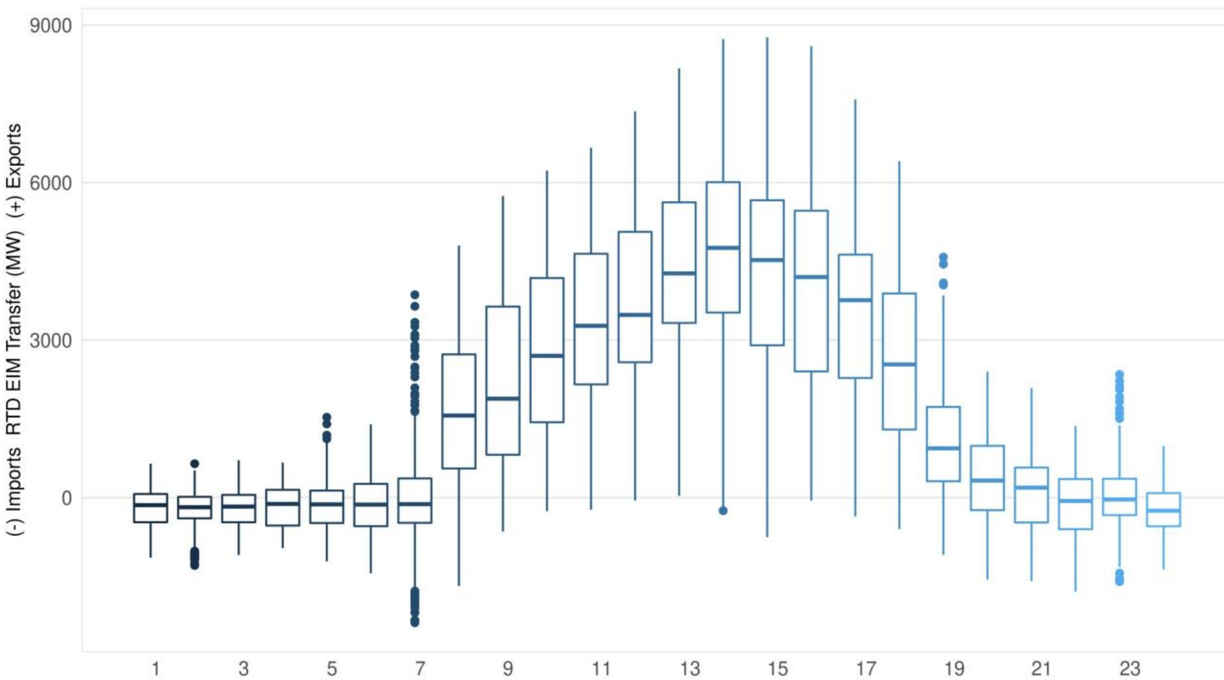


Figure 52 shows the WEIM transfers in an hourly distribution, which highlights the typical profile of the ISO transfers which are generally export transfers during periods of solar production. During the evening ramp as the evening peak approaches, the transfers become a net import to the ISO area. This trend is

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

typical across summer months.

Figure 52: Hourly distribution of 5-minute EIM transfers for ISO area



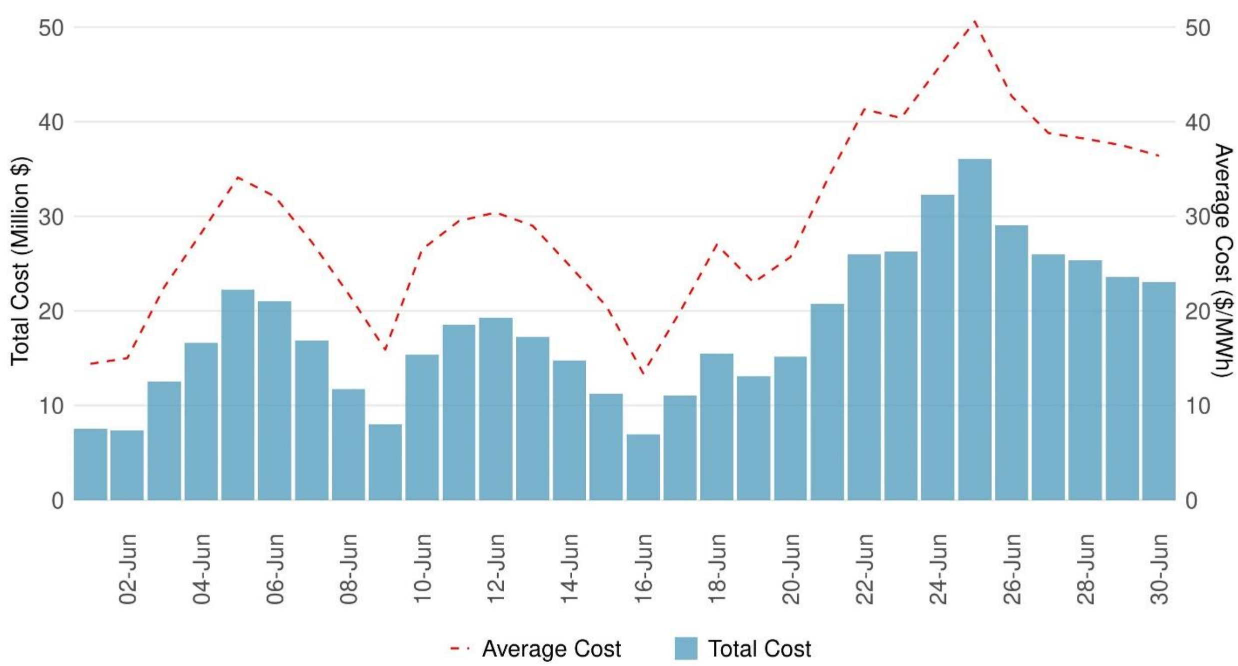
8 Market Costs

The ISO markets are settled based on awards and prices derived from the markets through specific settlement charge codes; these include day-ahead and real-time energy, and ancillary services, among others. The majority of the overall costs accrue on the day-ahead settlements.

Figure 53 shows the daily overall settlements costs for the ISO balancing area; this does not include WEIM settlements. As demand and prices rise, the overall settlements are expected to increase. When considering the overall costs relative to the volume of demand transacted, the dotted red line provides a reference of an average cost per MWh. The average daily cost in June was $18.35 million, representing an average daily price of $29.55/MWh. The maximum daily cost of $36.06 million occurred on June 25. [16]

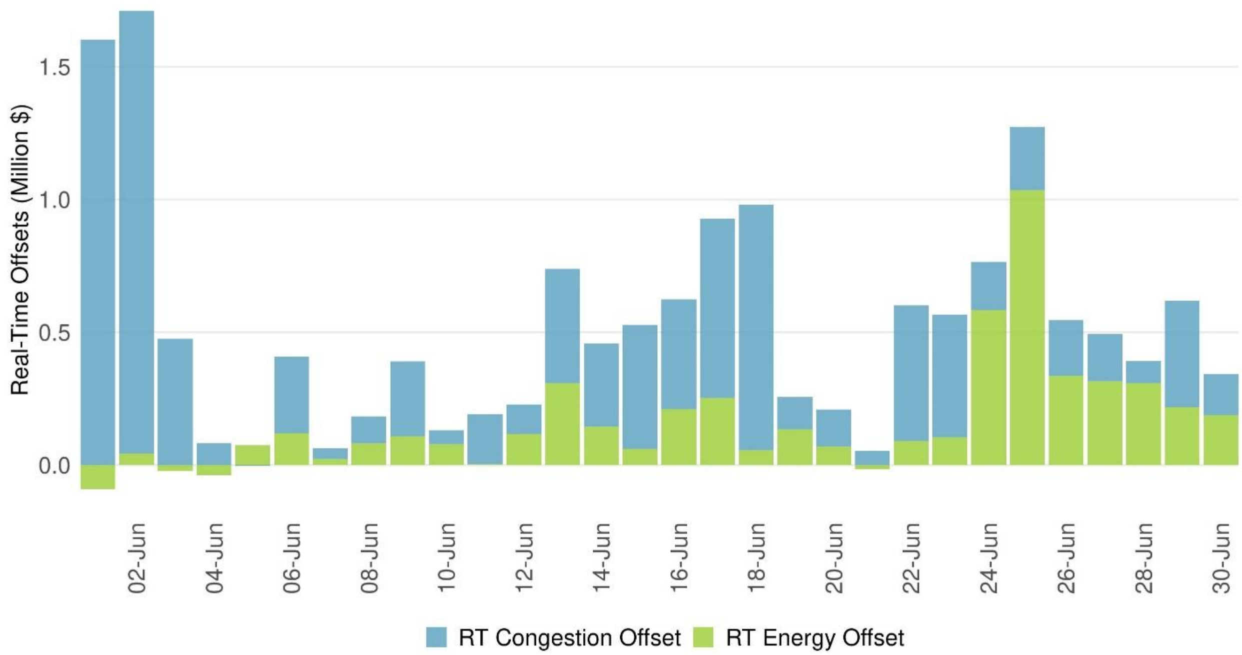
Two components of this overall cost are the real-time energy and congestion offsets. These costs reflect the settlements of differences between the day ahead and real-time markets for energy and congestion. These costs typically track system conditions. The daily trend is shown below in Figure 54.

Figure 53: ISO's daily total and average market costs



[16] These estimates are based on preliminary settlements data, which are subject to changes in subsequent settlements updates.

Figure 54: Real-time energy and congestion offsets for ISO area



9 Import market incentives during tight system conditions

On June, 15, 2021, the ISO implemented an enhancement that provides improved incentives for import supplies to be available during tight system conditions because the prior settlement rules may have paid imports less than they bid, which could exacerbate conditions when supplies are tight. During very tight system conditions (*i.e.,* when the ISO has issued an alert by 3 PM PST or a warning or emergency notice), the ISO will provide bid cost make-whole payments for real-time hourly block economic imports rather than simply settling the imports at the FMM price. This feature was implemented as part of summer readiness in 2021.

This feature was not triggered in June 2024.

10 Exceptional Dispatch for Storage resources

Exceptional Dispatch (ED) refers generally to a subset of manual commitment or dispatch instructions that are not determined as a result of the market software in the IFM, RUC, FMM or RTM. ISO operators can issue ED through the ISO's Automated Dispatch System (ADS) or direct communication with the Scheduling Coordinator (SC) and, at times, direct communication with the resource operator. There are several categories of ED, all of which are summarized in Business Practice Manual (Attachment K). As part of the Energy Storage Enhancements, a new functionality was introduced that will allow storage resources to hold a certain state of charge (MWh), in addition to the traditional (MW) exceptional dispatch. This functionality will allow for dispatch of storage resources to charge to and hold a specific level of state of charge for a specific duration of time in the real-time market. In June 2024, there was no ED to hold or charge SOC to any energy storage resources.

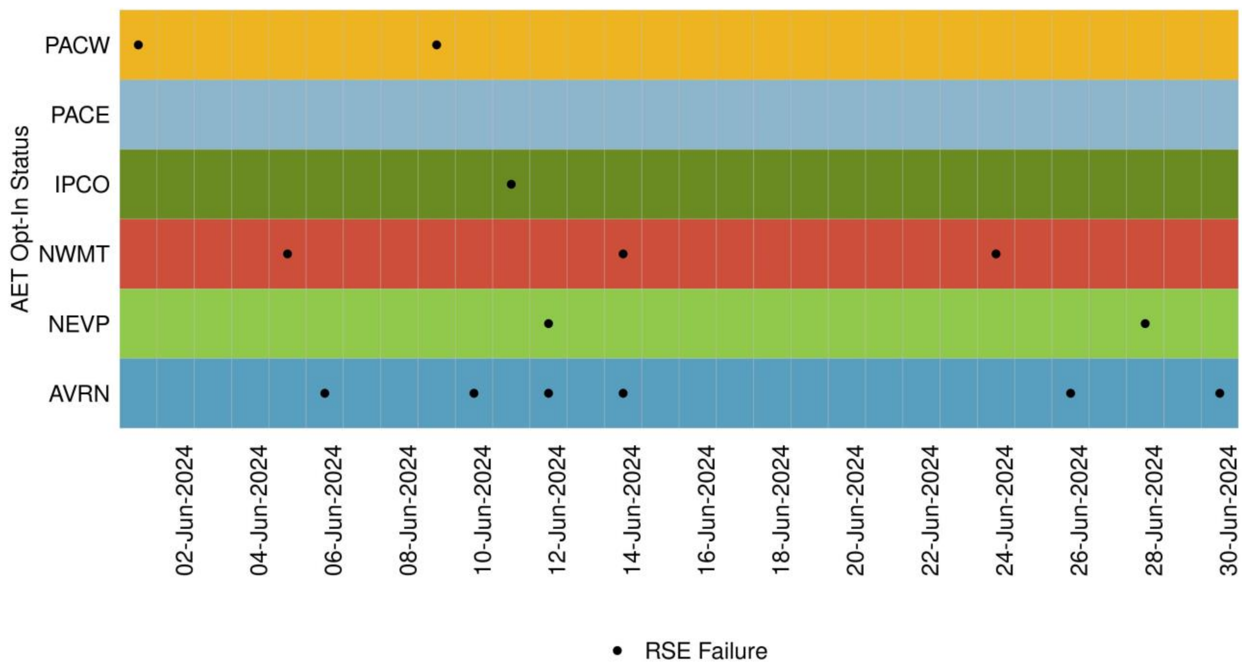
11 Assistance Energy Transfer

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

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

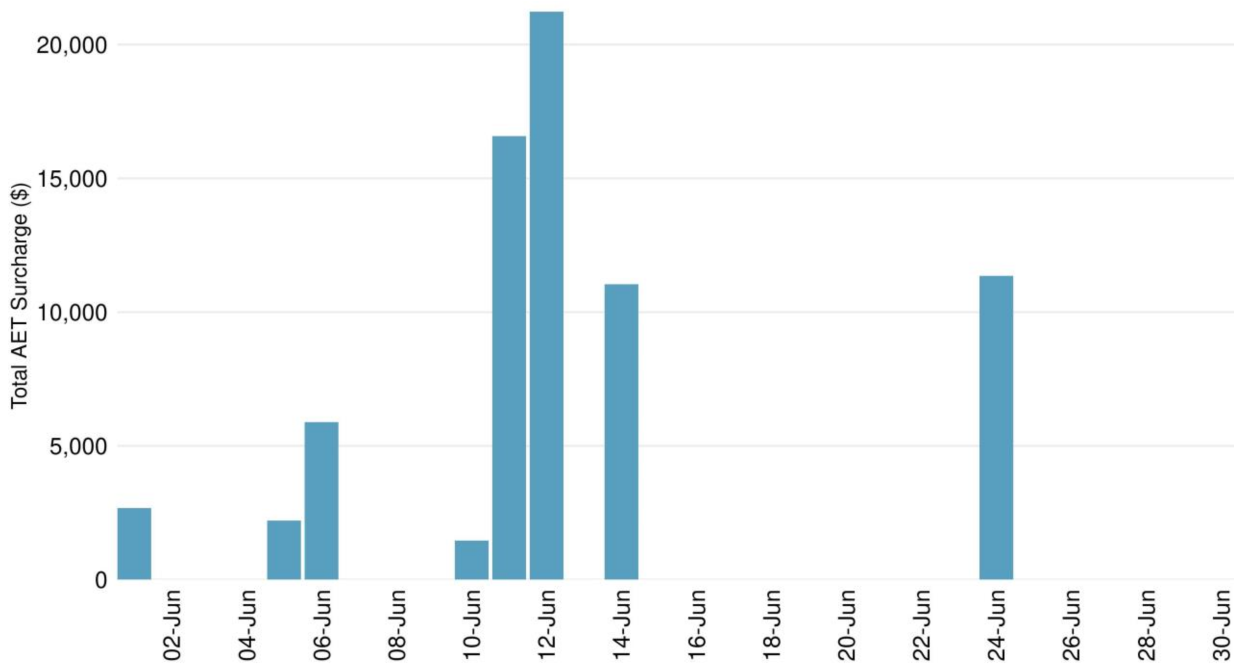
In June 2024, six WEIM BAAs opted into AET for the entire month. Figure 55 shows the number of BAAs that opted in for each trade date during the month with a shaded box indicating opt-in status for that date. The black dots indicate instances where the BAAs failed the RSE, specifically the upward capacity test and/or the upward flexible ramping test. The ISO BAA did not opt into AET in June 2024.

Figure 55: BAAs opted into Assistance Energy Transfers, June 2024



The total AET surcharges assessed in June were approximately $72,453 for all the BAAs that opted in. Figure 56 shows the breakdown of total AET surcharges assessed per day for June 2024. By the nature of its design, AET is only assessed for WEIM BAAs that fail the RSE and opt in ahead of time. Thus, the AET surcharge was only assessed for a total of eight trading days in June. In addition, the ISO did not opt-in for AET for any days in the month of June, hence no AET surcharge was assessed for the ISO.

Figure 56: Total daily AET surcharge assessed, June 2024



12 Areas for Improvement

Through the analysis of the market outcomes and performance, the ISO tracks any areas for improvements. There were no issues identified in June.