Extended Day-Ahead Market Performance July Report

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California Independent System Operator

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Executive Summary

On May 1, 2026, the California ISO, in partnership with PacifiCorp, successfully launched the Extended Day-Ahead Market (EDAM) alongside a suite of Day-Ahead Market Enhancements (DAME). This July report is the third in a series of customized monthly reports assessing market performance during EDAM's first three months of operation. The report focuses on market outcomes across participating balancing authority areas (BAAs), including price formation, reliability, new product performance, congestion, transfers, and settlement outcomes.

July marked the first sustained period of summer operating conditions since EDAM implementation. Higher temperatures across the Western Interconnection, increasing electricity demand, and a regional heat event, from July 24-27, created operating conditions that were materially different from those observed in May and June. As a result, many of the changes observed in July market outcomes were driven by seasonal fundamentals rather than changes in EDAM market design or performance. At the same time, EDAM market outcomes continued to stabilize as participants gained experience with the new market framework and settlement processes matured.

Key Takeaways

Summer conditions drove higher prices and shifting trade patterns
July demand conditions were significantly stronger than in May and June. The Western Interconnection recorded a peak load of 168.5 GW on July 24, while the ISO area reached its highest load of the year so far at 43,625 MW on July 15. Although ISO peak loads remained below monthly Resource Adequacy showings and California Energy Commission forecasts, loads increased noticeably relative to prior months and contributed to higher prices throughout the EDAM footprint.

Day-ahead energy prices rose across all participating BAAs, with daily average prices exceeding $40/MWh near the end of July. Daily average energy prices reached approximately $40/MWh in CAISO, $32/MWh in PACE, and $31/MWh in PACW. July was also the first month in 2026 in which average CAISO energy prices exceeded those observed during the same month in 2025.

The July 24-27 heat event was a significant contributor to elevated prices and increased price volatility, particularly in PACE where higher real-time prices reduced day-ahead and real-time price convergence. Price distributions across the EDAM footprint showed a substantially higher frequency of high-price intervals compared to May, June, and July 2025.

Summer conditions altered energy transfer patterns between regions. After serving as a net exporter in May and June, CAISO became a net importer of energy in July as higher regional demand increased the value of imports during morning and evening peak periods. Conversely, PACE shifted from a net importer to a net exporter, while PACW remained a net importer but increased exports to CAISO. These changes reflect EDAM's ability to efficiently shift energy across the broader footprint in response to changing regional supply and demand conditions.

The shift highlights the value of EDAM's expanded footprint during July's higher-demand conditions. Transfer capability reached approximately 600 MW and was actively utilized for energy, imbalance reserves, and reliability capacity transactions in both import and export directions.

During the highest-load days in the West, intertie exports sourced from the ISO area reached as much as 8,000 MW, helping meet regional demand both within and outside of organized market areas. These exports allowed participating BAAs to access the lowest-cost available resources while leveraging geographic diversity in demand patterns and resource availability.

During the July 24 to July 27 period of peak regional demand, active wildfires across portions of the Western Interconnection also affected power system operations. Wildfires increase operational uncertainty by placing some transmission corridors at risk and require grid operators to closely manage transfer capability and power flows in affected areas. As a result, energy transfers across portions of the West were more constrained than under normal conditions, reducing operational flexibility at a time when regional electricity demand was near its seasonal maximum.

The direction and mix of transfers evolved as summer conditions strengthened, demonstrating that market signals and transfer capability responded dynamically to changing system needs rather than remaining fixed across regions.

Market costs increased primarily because of seasonal fundamentals

The higher-demand summer environment increased overall market costs. Total wholesale energy costs in CAISO rose from approximately $24/MWh in June to $45.4/MWh in July, exceeding July 2025 levels of $41.1/MWh.

At the same time, several indicators pointed to improving market efficiency. Bid Cost Recovery (BCR) payments declined from May through July across market runs and regions, suggesting improved market commitment and dispatch outcomes as participants adapted to EDAM operations. Additional settlement corrections associated with issues identified in May are expected to further reduce previously reported BCR values.

Energy storage and demand response resources played an increasingly important role during higher-load periods. Storage and hybrid resources maintained up to 50,000 MWh of state of charge while providing more than 11,000 MW of peak discharge capability. Both economic and reliability demand response resources were dispatched in day-ahead and real-time markets, helping support reliability during summer peak conditions.

Reliability products performed as intended during higher-load conditions

The first summer peak period provided an important test of the new EDAM capacity products. Both Imbalance Reserves (IR) and Reliability Capacity (RC) continued to support system reliability while displaying signs of market maturation.

Despite higher load levels, imbalance reserve prices became more stable compared to May, with the largest improvement occurring in PACW. Price patterns continued to align with morning and evening ramping periods when operational flexibility was most valuable. The geographic diversity provided by the broader EDAM footprint continued to reduce aggregate reserve requirements by sharing renewable forecast uncertainty and load variability across participating areas.

The procurement of imbalance reserves also contributed to a reduction in manual uncertainty adjustments within the ISO balancing area. During July, residual unit commitment (RUC) adjustments occurred 19 percent of the time compared to 61 percent during July 2025, highlighting the operational value of the new reserve procurement framework during periods of elevated summer demand.

Reliability capacity prices declined substantially from May levels across all BAAs, indicating improved supply-demand balance and lower reliability procurement costs as participants gained experience with the new products. While some price volatility remained, particularly in CAISO and PACW, the product continued to function as designed by securing both upward and downward capacity needed to manage forecast deviations.

Reliability readiness mechanisms supported summer operations

July's higher demand conditions also provided an important assessment of EDAM's reliability safeguards. The optional EDAM net export constraint, which allows balancing authorities to limit exports when capacity may be needed for local reliability, did not bind in any hour for CAISO during May through July, indicating sufficient available capacity throughout the period.

As summer loads increased, Reliability Unit Commitment (RUC) adjustments were used more frequently to ensure adequate procurement for real-time reliability needs. CAISO applied RUC adjustments in 139 hours during July, compared to 19 hours in June and none in May. However, adjustment frequency and magnitude remained substantially below July 2025 levels, when adjustments occurred in 452 hours and reached a maximum of 4,670 MW. These results suggest that while higher summer demand required additional reliability procurement actions, the combination of EDAM resource sharing and the new imbalance reserve product reduced reliance on manual adjustments relative to historical summer operations. RUC performance remained robust, with only a minor 5 MW oversupply infeasibility observed in PACW on July 19.

Congestion and regional price differences reflected changing summer flow patterns

Congestion patterns in July largely reflected changing power flows associated with higher regional demand. During the first half of the month, congestion impacts resembled those seen in May and June, with internal CAISO constraints creating price separation between Northern and Southern California. In the second half of July, congestion patterns shifted along with changing regional flow conditions associated with higher summer loads.

Although congestion episodes in PACE were relatively limited in duration, they produced noticeable financial impacts due to interactions with CAISO parallel flows. Overall, average congestion impacts across participating areas remained relatively modest, indicating that transfers continued to move efficiently throughout much of the EDAM footprint even during periods of elevated demand.

Revised settlement estimates also indicate lower congestion revenue allocation transfers to PacifiCorp areas than previously reported. While previous estimates report congestion revenue allocation to PAC at $1.3 million for each of the first two months of operations, revised estimates indicate approximately $360,000 in May, negative $160,000 in June, and negative $190,000 in July. These values remain subject to future settlement adjustments. The root cause for that revision is discussed in the Market Issues section.

Other market performance indicators remained strong

Operational performance remained generally strong despite more challenging summer conditions.

- No Resource Sufficiency Evaluation failures occurred in any EDAM BAA.
- Convergence bidding activity remained comparable to pre-EDAM levels.
- Average day-ahead GHG prices were approximately $8.9/MWh and followed expected intraday patterns.
- EDAM results were posted before 1:00 p.m. on 53 percent of July operating days, down from 73 percent in June, with most delays occurring during periods of higher market demand and increased complexity.
- Market issues continued to be tracked through stakeholder forums and monthly reporting processes.

Conclusion

July provided the first meaningful assessment of EDAM performance under sustained summer operating conditions. Higher temperatures, stronger regional demand, and a late-July heat event drove most of the notable differences between July and the May-June implementation period, including higher prices, changing transfer patterns, greater reliance on imports during peak periods, and increased market costs.

Despite these more challenging conditions, EDAM continued to operate reliably and largely as expected. Market outcomes generally became more stable over the first three months of operation, reliability products functioned effectively during periods of elevated demand, and interregional transfers helped balance supply and demand across the Western footprint. These results suggest that EDAM provides value under both moderate spring conditions and more demanding summer operating environments, while market participants continue to gain experience with the new framework.

ISO's responses to stakeholder comments

In response to stakeholder feedback, the July report scope was expanded to include analysis of price discovery, load conformance in ISO markets, summer operating conditions, intertie transactions, assistance energy transfers, and additional congestion revenue metrics. The report is also complemented by the ISO's detailed responses to stakeholder comments on the June report.

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Introduction

The California ISO implemented Extended Day-Ahead Market (EDAM) operations on May 1, 2026, marking a significant transition from a single-BAA day-ahead market to a broader, multi-BAA EDAM footprint. Concurrently, new features were introduced as part of the day-ahead market enhancements (DAME). This July report provides an overview of market performance during the first three months of EDAM/DAME operations, focusing on price formation, resource sufficiency outcomes, congestion costs and settlement cost trends across participating balancing authority areas for EDAM. As with CAISO's prior monthly performance reports, the objective is to offer timely and transparent insights into market performance, particularly during the initial period of a major market design transition.

The implementation of EDAM/DAME introduced two new market products: imbalance reserves up and down (IRU/IRD) and reliability capacity up and down (RCU/RCD). The analysis includes a review of IRU/IRD and RCU/RCD prices, procurement volumes, requirements and cost allocation for the new market products. The report also provides a detailed assessment of energy prices, bilateral hub price comparisons, ancillary service procurement, imbalance reserve awards, reliability capacity procurement, and greenhouse gas (GHG) cost adders. The analysis also includes a review of convergence bidding in EDAM, highlighting changes in bid volumes and awards for virtual generation and virtual demand.

The report evaluates costs associated with congestion revenue allocation, and settlement cost trends across the EDAM footprint. This includes an assessment of congestion revenues, breakdown of marginal component of congestion (MCC) at the transmission constraint level among participating BAAs.

Also, as the system experienced high loads in July, this report includes various metrics on market performance during summer conditions.

The CAISO will continue to monitor and evaluate market performance and will provide further analysis and reporting in upcoming monthly reports.

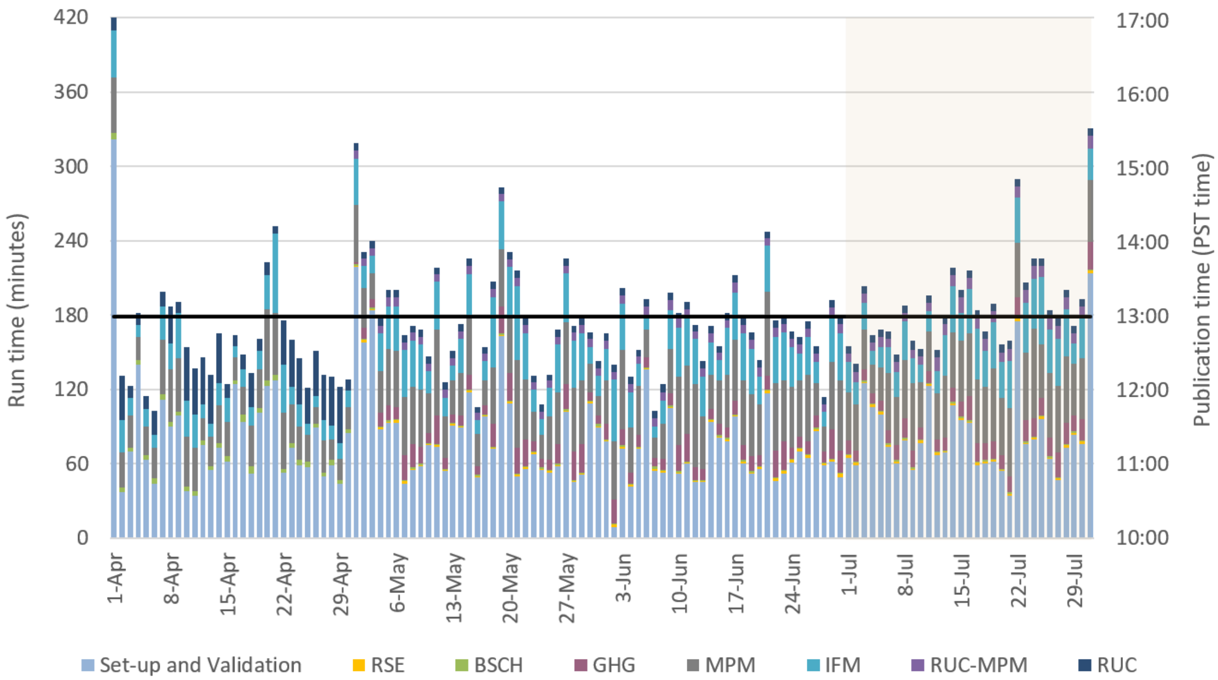
Day-Ahead Market Run

The Day-ahead (DA) market follows a daily schedule, unchanged by new market functionality. All bids submission is due by 10:00 a.m. Pacific Time, after which the CAISO runs multiple processes that comprise the day-ahead market. The standard window to run the day-ahead market is between 10:00 a.m. and 1:00 p.m., with the goal of publishing results by 1:00 p.m. To complete a day-ahead market run after the launch of the EDAM, multiple steps are performed, including:

i) Market closing and setting up of inputs
ii) running the binding resource sufficiency evaluation (RSE). New process
iii) running the base schedule set up (BSCH)
iv) running the green-house-gas emission market (GHG). New process
v) running market power mitigation (MPM)
vi) running the integrated forward market (IFM)
vii) running market power mitigation for residual unit commitment (MPM-RUC). New process
viii) running the residual unit commitment (RUC)
ix) publishing market results
x) validation of results after each run

In addition to running three new processes within the standard window, EDAM is inherently more complex because it solves for a wider market footprint and so has a larger optimization problem to solve multiple times. This has increased the overall computational workload. Despite the complexity, CAISO maintains the goal of a 1:00 p.m. publication time. Figure 1 illustrates the additional time the CAISO took in the first days of EDAM operations to ensure all processes and runs were properly executed, and results could be closely assessed. This has taken longer to publish market results. After the first two weeks, CAISO gradually returned to more standard runs of the market and the market was able to publish DA results before 1:00 p.m. In July, EDAM results were posted before 1:00 p.m. in 17 out of 31 days, a reduction from the posting of 23 out of 30 days in June. This higher frequency of late posting was mainly in the second part of the month when the market was solving for the peak days so far in the year, which represent higher loads and more complex numerical problem to solve. For a relative comparison, the day-ahead market published before 1:00 p.m. in 23 out of 30 days in April prior to EDAM implementation.

Figure 1: Run times for the extended day-ahead market



Resource Sufficiency Evaluation

The EDAM resource sufficiency evaluation (RSE) is a forward-looking test to ensure that each participating EDAM area has sufficient supply to meet their own forecasted demand, ancillary services, and uncertainty before engaging in economic transfers with other EDAM BAAs. Specifically, the RSE evaluates whether a unit-commitment optimization problem can be solved without relaxing (1) the power balance constraint, (2) the IRU/IRD procurement constraints, and (3) the ancillary services procurement constraints. These conditions are evaluated separately, and the entity passes the test without relaxing any of these constraints. This evaluation is performed on an hourly basis, in both upward and downward directions.

Table 1 shows the total monthly passing rate of each EDAM BAA for the IRU and IRD RSE tests for May and June. Aside from May 4 when PACW passed 16 out of the 24 hours and June 17 when PACE passed 23 out of the 24 hours, all three EDAM BAAs have passed both the IRU and IRD RSE tests across all hours of the day since EDAM go-live. In July, there were no RSE failures.

Table 1: RSE monthly passing rate by BAA for upward and down requirements

	IRU RSE Passing Rate (%)			***IRD RSE Passing Rate (%)***		
BAA	**May**	**June**	**July**	**May**	**June**	**July**
CAISO	100	100	100	100	100	100
PACE	100	99.86	100	100	100	100
PACW	98.92	100	100	99.87	100	100

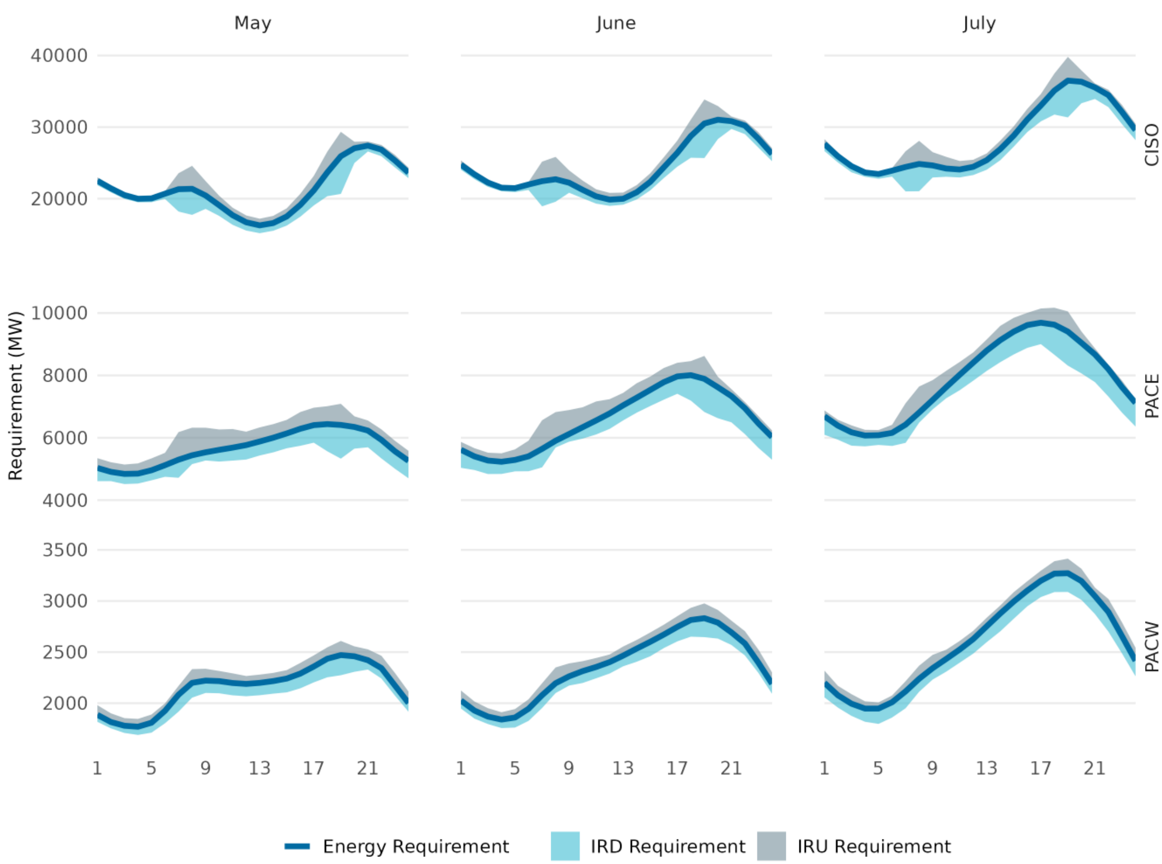
Imbalance reserves are used to address uncertainty between the day-ahead and real-time forecasts for load, wind and solar by providing upwards and downwards dispatch capability. The requirements for IRU/IRD are based on historical load, wind, and solar forecast errors between day ahead and real time.

Figure 2 displays average hourly IRU and IRD requirements for each EDAM BAA over the months of May and June, with respect to the average energy requirement. The imbalance reserve requirements are calculated for each EDAM BAA separately. Requirements for IRU and IRD tend to be the largest for CAISO around the morning and evening peaks on the edges of solar hours. The IRD requirement during solar hours is higher than in the early morning and night hours, but noticeably smaller than in the morning and evening peaks. These trends remain consistent through July. While the peak demand changed, the general shape of IRU and IRD requirements remained relatively consistent. Table 2 gives the highest imbalance reserve upward and downward requirements for each BAA in May, June, and July.

Table 2: Maximum imbalance reserve requirements by BAA

	Maximum IRU Requirement (MW)			***Maximum IRD Requirement (MW)***		
BAA	**May**	**June**	**July**	**May**	**June**	**July**
CAISO	3,629	3,486	3,312	5,320	5,487	5,142
PACE	1,028	1,028	834	1,099	1,125	1,090
PACW	225	228	143	241	259	192

Figure 2: Average upward and downward requirements by area and month



For an EDAM entity to pass the RSE, it must have at least enough supply to meet the requirement for each hour. For the upward direction the RSE requirement is the summation of the energy requirement and the upward IR requirements while for the downward direction the requirement is assessed by subtracting the IRD requirement form the energy requirement.

Day-Ahead Market Products

Day-Ahead Demand

In IFM, bid-in supply is cleared to meet bid-in demand. However, bid-in demand does not necessarily match the day-ahead load forecast. Supply in RUC is cleared to meet the day-ahead demand forecast. Figure 3 shows the average day-ahead demand forecast and the average IFM schedule for each EDAM BAA in May and July 2026. On average, the bid-in demand for CAISO is greater than the day-ahead demand forecast during solar hours but less than the forecast otherwise. In May, the bid-in demand for PACE was almost always lower than the demand forecast, with the difference between the two largest during the evening peak. In June and July, however, this relationship flipped with the bid-in demand exceeding the forecast for much of the day, with the difference between the two being the smallest during the evening peak. Generally, the day-ahead demand forecast and the bid-in demand for PACW closely match, with June and July seeing a slightly higher bid-in demand compared to the day-ahead forecast.

The shape of the day-ahead demand forecast hourly profile changed significantly from May to June for all three BAAs, and then in July the general shapes remained the same but with higher peaks. CAISO saw a smaller mid-day dip and higher evening peak, leading to a steeper afternoon ramp. Both PACE and PACW saw a significant increase in the evening peak demand with a steeper but also steadier increase in demand across daylight hours.

Figure 3: Bid-in demand vs. day-ahead demand

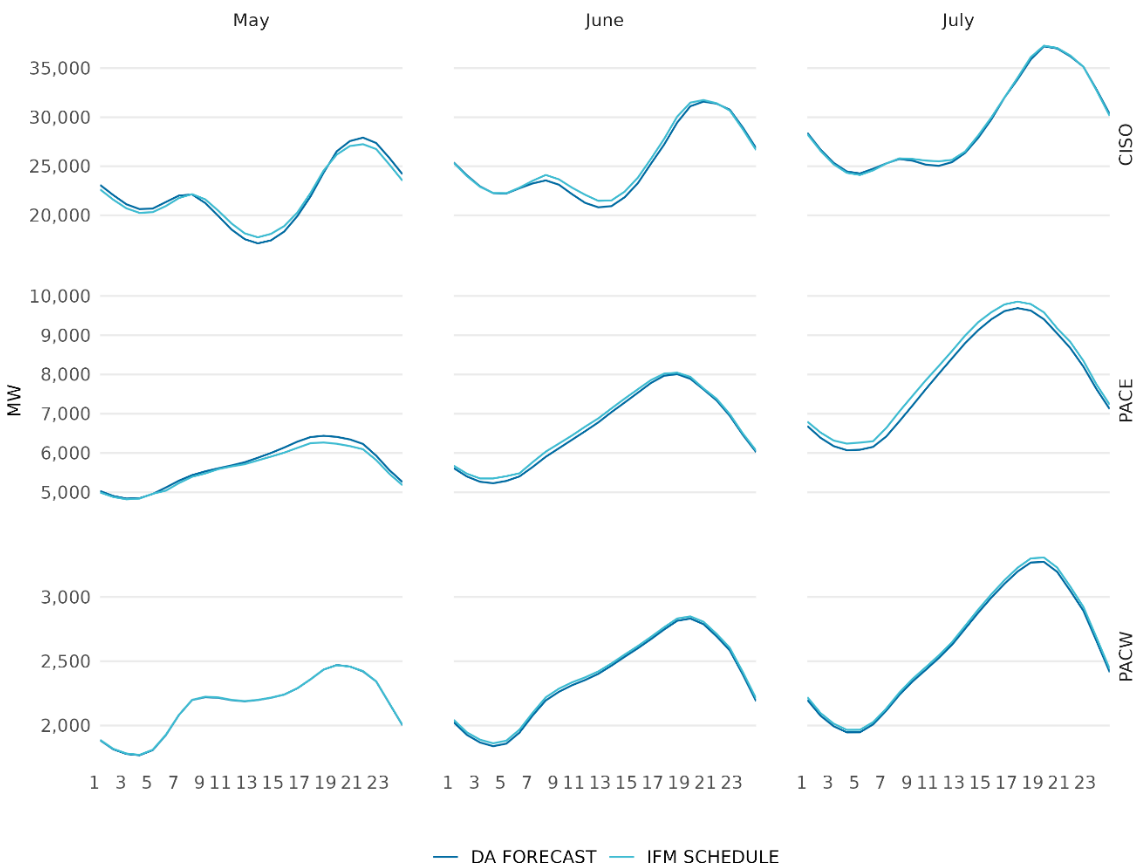


Table 3 shows the highest day-ahead demand forecast for a single hour for each EDAM BAA across May and June. All three BAAs saw an increase in the forecasted peak demand. The percent increases were 14.8, 12.5, and 6.3 percent for CAISO, PACE, PACW, respectively.

Table 3: Peak day-ahead demand forecasts

	Peak DA Demand Forecast (MW)		
BAA	**May**	**June**	**July**
CAISO	34,673	37,399	42,927
PACE	8,047	9,358	10,527
PACW	2,893	3,635	3,866

As part of the day-ahead market enhancements, two new market products have been introduced: imbalance reserves and reliability capacity. These additions are designed to strengthen the market's ability to address evolving system needs while supporting reliable grid operations.

The imbalance reserve product enables the market to procure flexible capacity in advance to manage the uncertainty that exists between day-ahead scheduling and real-time operations. By securing this flexibility through a competitive market process, operators can ensure that sufficient resources are available to respond to changing system conditions while maintaining reliability.

The reliability capacity product represents supply procured in the residual unit commitment process in both the upward and downward direction to meet differences between market-cleared load schedules and demand forecast.

Procuring flexibility through the market promotes economic efficiency by identifying and securing the least-cost resources capable of providing these services. It also establishes transparent price signals that explicitly value flexibility, helping market participants better understand system needs and providing incentives to resources that can support reliable and efficient grid operations. Additionally, EDAM prices the greenhouse gas emissions associated with transfers between BAAs within the day-ahead market. This same formulation has been adapted for the real-time market.

Therefore, in the day-ahead market, different products are procured and priced explicitly:

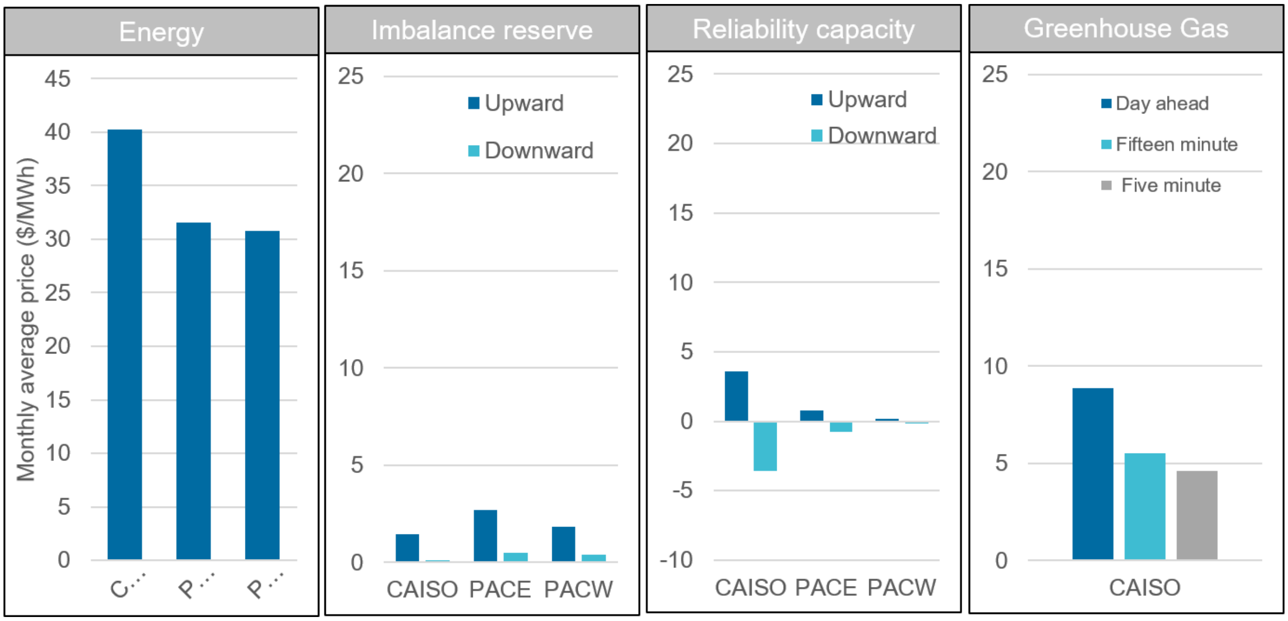
i) energy,
ii) ancillary services (regulation up and down, spinning reserves and non-spinning reserves),
iii) imbalance reserves up and down,
iv) reliability capacity up and down, and
v) greenhouse-gas emission allocation

Energy, ancillary services and imbalance reserves are all co-optimized in the integrated forward market, while reliability capacity are optimally procured in the residual unit commitment process that is run after the financial market. The residual unit commitment process considered as fixed the procurement of ancillary services, imbalance reserves, and only procures reliability capacity relative to the energy awards form IFM. This section provides an assessment of each of these market products during June. With more than a month of operational experience, the results offer an initial indication of how EDAM/DAME functionality is performing. However, as the market continues to mature, participants gain experience operating under this new framework, and seasonal conditions transition toward summer patterns, the results should be viewed as preliminary and may not yet fully reflect the extent of the changes introduced by EDAM/DAME.

The CAISO will continue to monitor and evaluate market performance and will provide further analysis in upcoming monthly reports.

Figure 4 compares prices across all EDAM products for the month of July. Prices across all commodities, including energy, imbalance reserves, and reliability capacity, remain within expected economic ranges. These results reflect underlying supply and demand fundamentals across the broader market footprint and demonstrate that the market is effectively valuing available resources while maintaining competitive and efficient outcomes.

Figure 4: Pricing of EDAM products for July 2026



Seasonal conditions also play an important role in shaping price patterns as observed in the month of July. During the summer months, due to higher load, typically sees higher energy prices as compared to spring months. As solar production declines and demand increases during the morning and evening ramp periods, prices tend to rise, reflecting the changing balance between supply and demand. These recurring price dynamics underscore the market's ability to respond to evolving system conditions and provide transparent economic signals that support efficient resource utilization across the region.

Regional differences in supply and demand conditions are reflected in the pricing of all market products, including energy, imbalance reserves, and reliability capacity. As a result, prices exhibit expected regional variations, with PACE generally posting the lowest prices while PACW has tended to clear at higher price levels. These outcomes demonstrate that market prices properly reflect local system conditions and resource availability across the footprint when transfer capabilities are fully utilized.

The other pattern is that IR and RC products command lower prices than energy prices, which is expected given that these products provide services like flexibility.

Energy prices

Figure 5 shows the average hourly IFM LMPs for the three EDAM BAAs for May through July and the CAISO average hourly IFM LMPs in April. The ELAP LMPS are used for PACE and PACW, while the load-weighted average based on demand of the four DLAP LMPs is used for CAISO area.

Day-ahead prices for energy are responsive to system conditions and daily changes in supply and demand. Compared to May, June exhibited significantly less price separation between the three BAAs, particularly during solar hours. In July, PACE and PACW had minimal price separation, but CAISO saw higher prices across most hours of the day. Prices in all three BAAs increased across all hours of the day compared to June. This is typical behavior, as summer months bring higher demands.

Figure 6 shows the daily average IFM LMPs across June and July. The daily average IFM LMPs grew steadily across July.

Figure 5: Hourly IFM LMP averaged by month

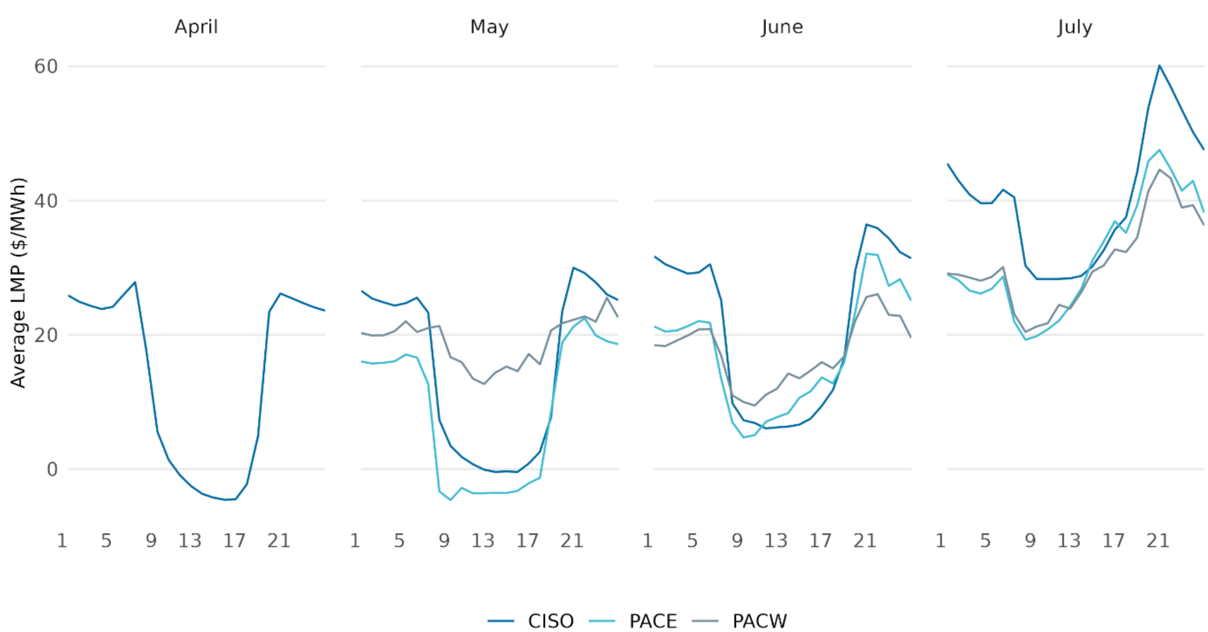
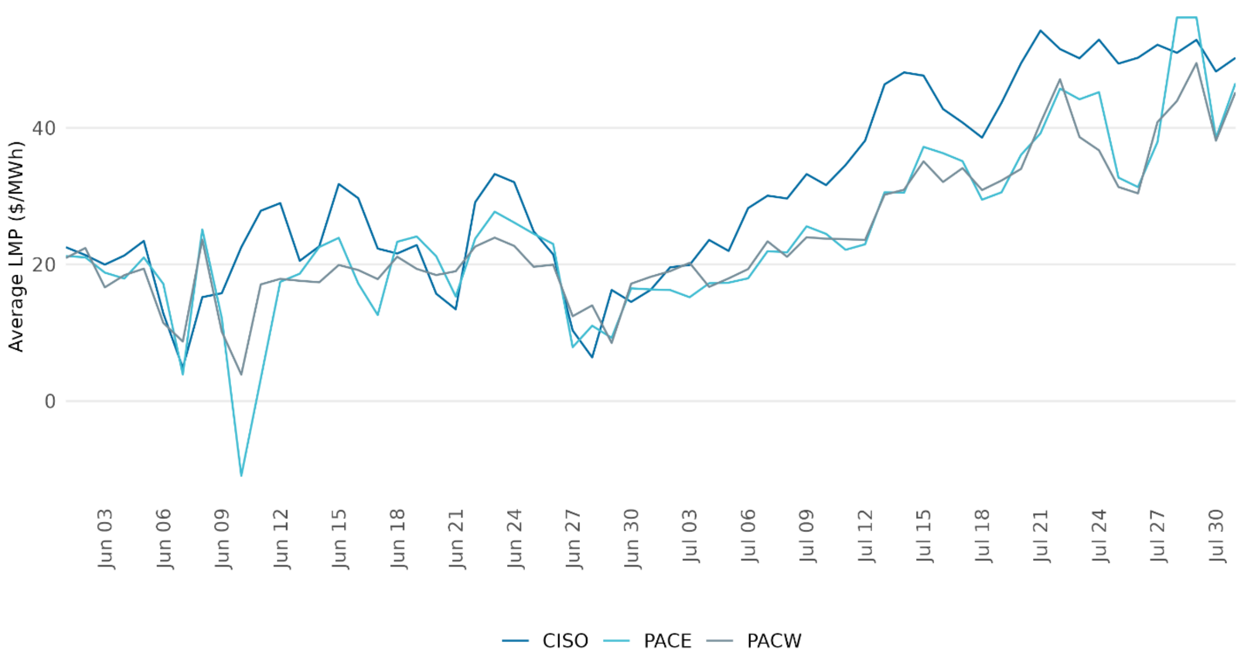
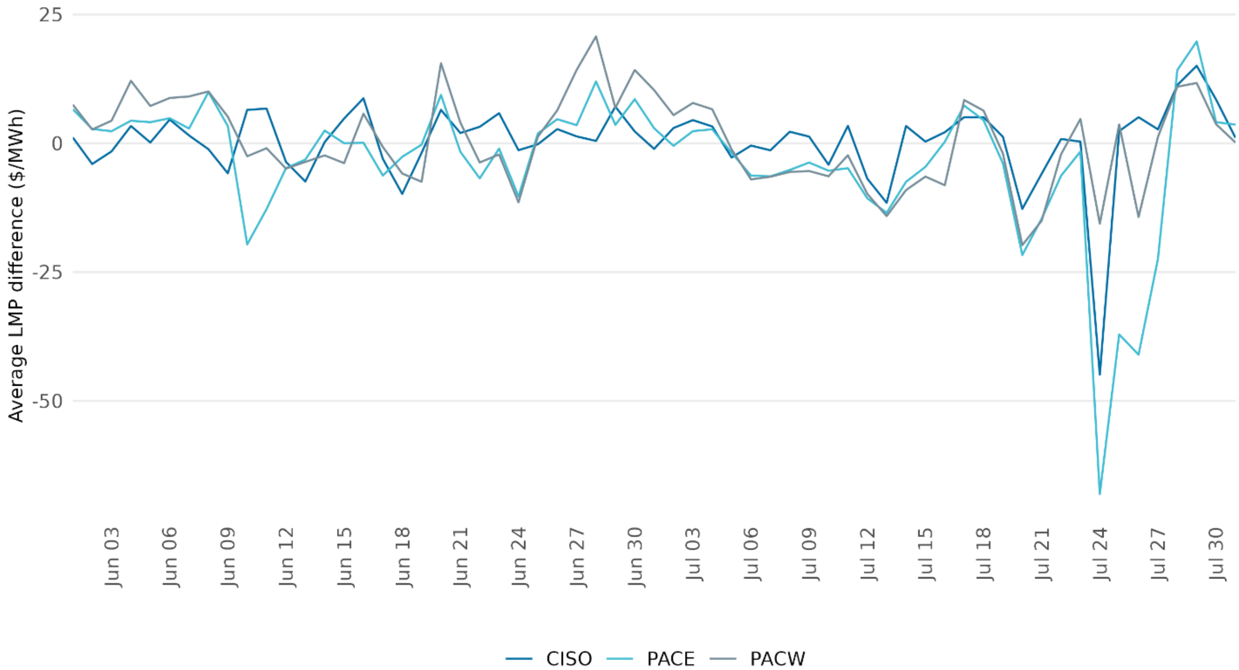


Figure 6: Daily average LMP by BAA



Ideally, day-ahead prices accurately represent the value of supply and demand realized in in real time. Forecast errors, congestion, shifts in supply or demand, and available transfer capability can create differences between day-ahead and real-time prices. Figure 7 compares prices from the day-ahead market (IFM) to the fifteen-minute market (FMM) for EDAM BAA in June and July 2026. Specifically, Figure 7 shows the daily average IFM LMP minus the daily average FMM LMP. A negative price reflects a higher real-time price compared to day-ahead price. A zero in the plot represents perfect convergence from day-ahead to real-time. In general, price convergence remained consistent from June to July except during July 24-27. Day-ahead LMPs were significantly lower than real-time prices during this time, particularly on July 24. The market saw high loads across the footprint during this time due to high temperatures.

Figure 7: Average difference between IFM LMP and FMM LMP



Prices tend to vary from day to day as conditions vary. Trends in price convergence are better understood over longer time spans. Figure 8, Figure 9, and Figure 10 show the average monthly LMPs across the three markets for the EDAM BAAs, with only CAISO having IFM prices prior to May 2026. Looking backwards to the beginning of 2025, Figure 8 illustrates that the price convergence observed in May through July between day-ahead and real-time for CAISO was like levels observed prior to EDAM implementation.

There is no day-ahead price data available for the PacifiCorp balancing authority areas prior to May 2026; therefore, historical convergence trends cannot be evaluated. Figure 9 shows that PACW saw some level of improvement in price convergence in June, and further improvement in July. Figure 10 shows that PACE also saw significantly improved price convergence in June compared to May, but also that IFM prices were significantly lower than real-time prices on average in July. The very large discrepancy between day-ahead and real-time prices during July 24-27 likely played a significant role in this difference.

Figure 8, Figure 9, and Figure 10 also illustrate the seasonal trends in prices. Prices in 2026 have been overall lower compared to 2025. The increasing prices across May, June, and July align with seasonal trends of increasing prices from May through September. This was the first month in 2026 where average prices were higher than the same month in 2025.

Figure 8: Monthly average price for CAISO area

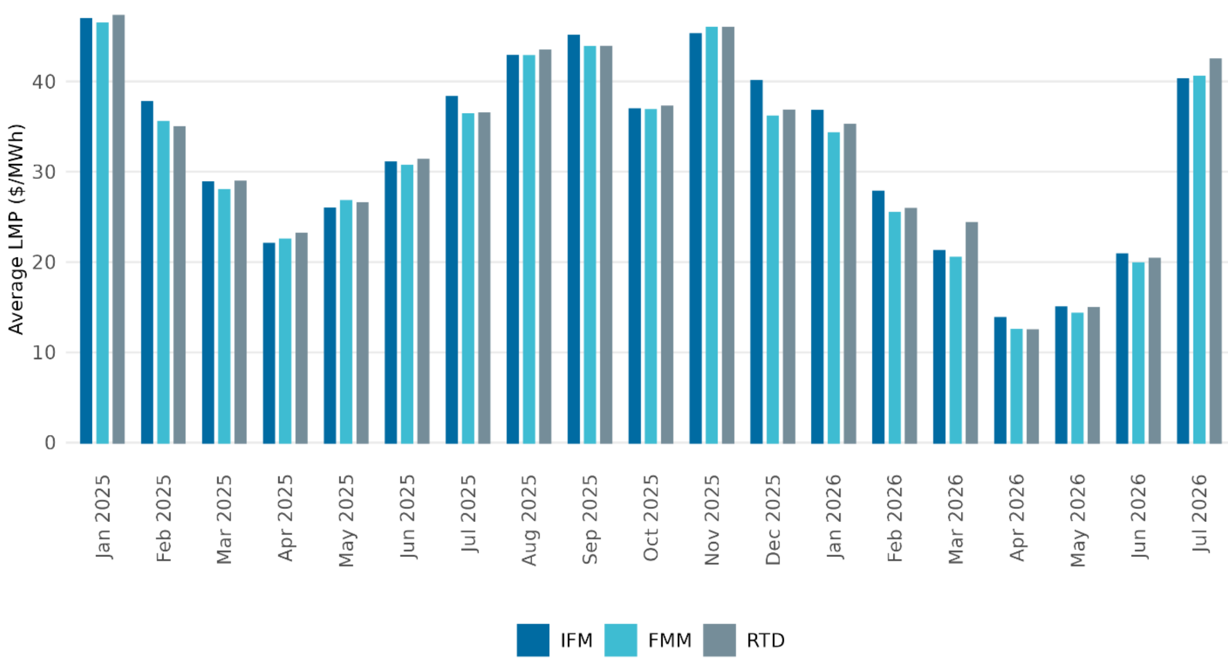


Figure 9: Monthly average price for PACW

Figure 10: Monthly average price for PACE Average LMPs

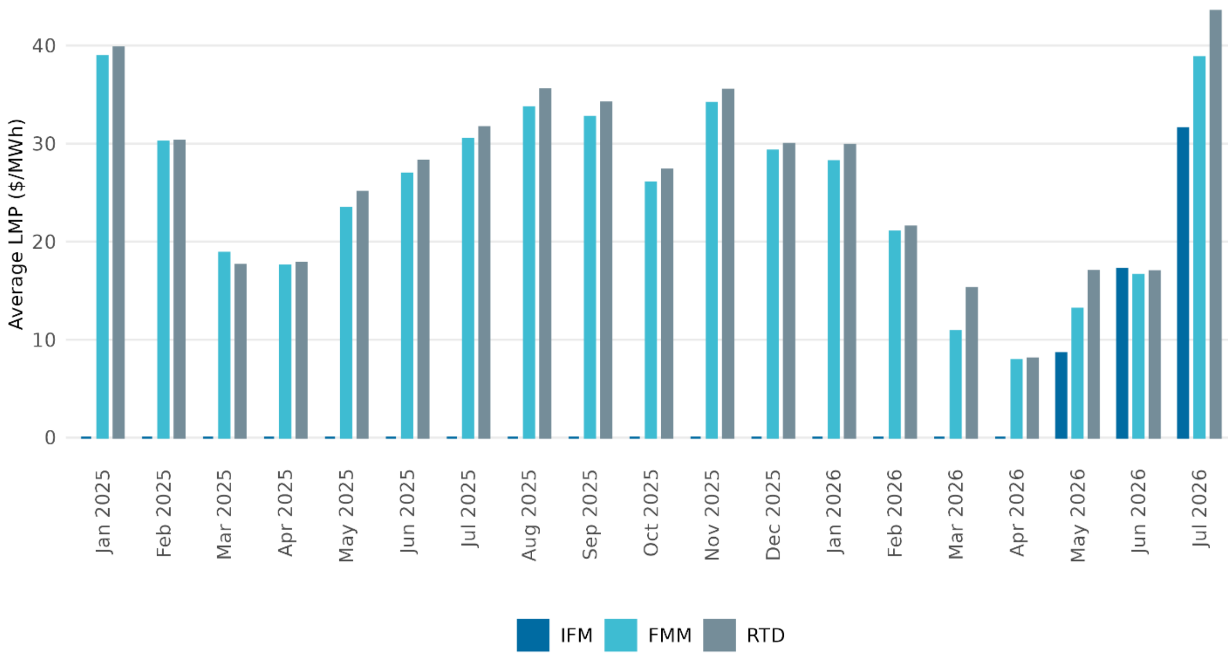
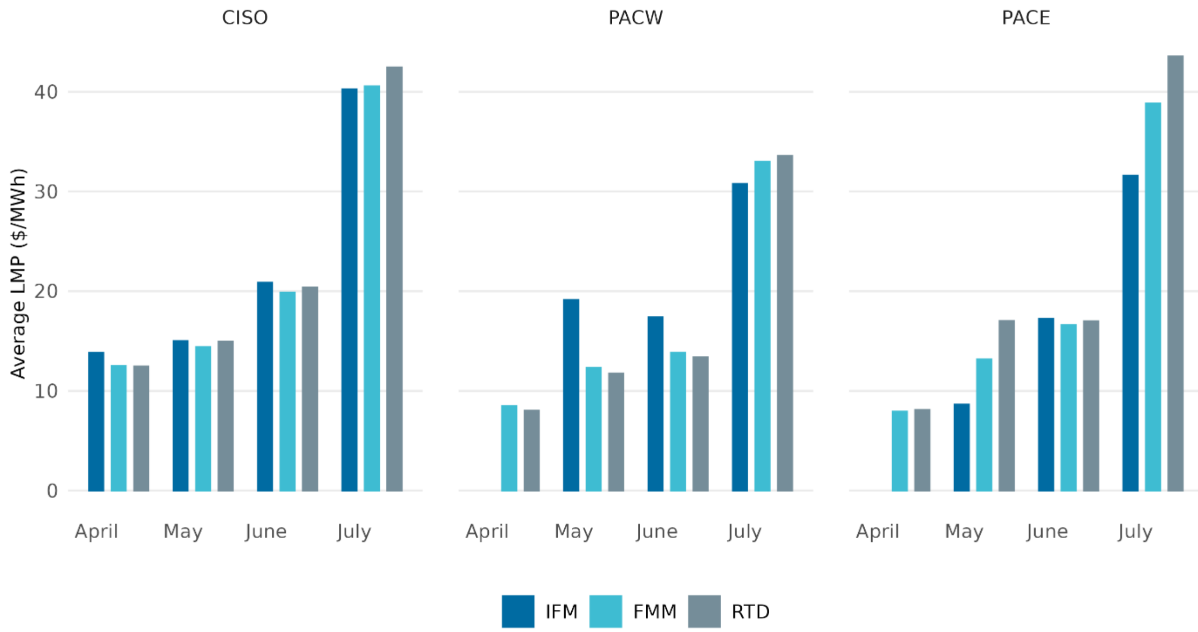


Figure 11 presents the same monthly average LMPs for April through July 2026 to ease the comparison among areas and months. Table 4 summarizes the average LMP across each month for each market and BAA.

Table 4: Monthly average LMP by BAA

	Average IFM LMP ($/MWh)				*Average FMM LMP ($/MWh)*				*Average RTD LMP ($/MWh)*			
BAA	April	May	June	July	April	May	June	July	April	May	June	July
CAISO	13.8	15	20.8	40.2	12.5	14.4	19.9	40.5	12.4	14.9	20.4	42.4
PACE		8.62	17.2	31.6	7.91	13.2	13.8	38.8	8.07	17	17	43.5
PACW		19.1	17.4	30.7	8.47	12.3	12.4	33	8.01	11.7	13.4	33.6

Figure 11: Monthly average LMPs



Price Volatility

Figure 12, Figure 13 and Figure 14 show the frequency of prices falling in predefined $/MWh ranges in the given month for each BAA. For example, in June 2026 the CAISO RTD LMP was between -50 and 0 $/MWh in less than a quarter of all intervals in the month. For all three BAAs, the fraction of intervals with lower LMPs in July decreased compared to the same time last year.

Compared to June, all three BAAs saw more LMPs in the range of 40 to 100 $/MWh, with the 40 to 100 $/MWh range the most frequent for CAISO.

Looking at last summer suggests that this trend of the increasing frequency of higher LMPs is normal for this time of year, but July 2026 represented a steeper increase than 2025. In general, the frequency of low and even negative LMPs has been much higher in 2026 compared to 2025 until July. These figures suggest that EDAM had no noticeable impact on the volatility of real-time prices. However, it is difficult to see any changes in the frequency of extreme prices, i.e. below -50 $/MWh or above 100 $/MWh.

Figure 15 shows only the frequency of LMPs in the price ranges below -50 $/MWh and above 100 $/MWh. This more specific view shows that after EDAM go-live CAISO had no LMPs above 200 $/MWh and the frequency of LMPS between 100 and 200 $/MWh was within the normal range.

Figure 15 shows that PACE saw an increase in high LMPs in July compared to the last year and a half, particularly for prices between 200 and 500 $/MWh.

Figure 12: CAISO RTD LMP range frequency

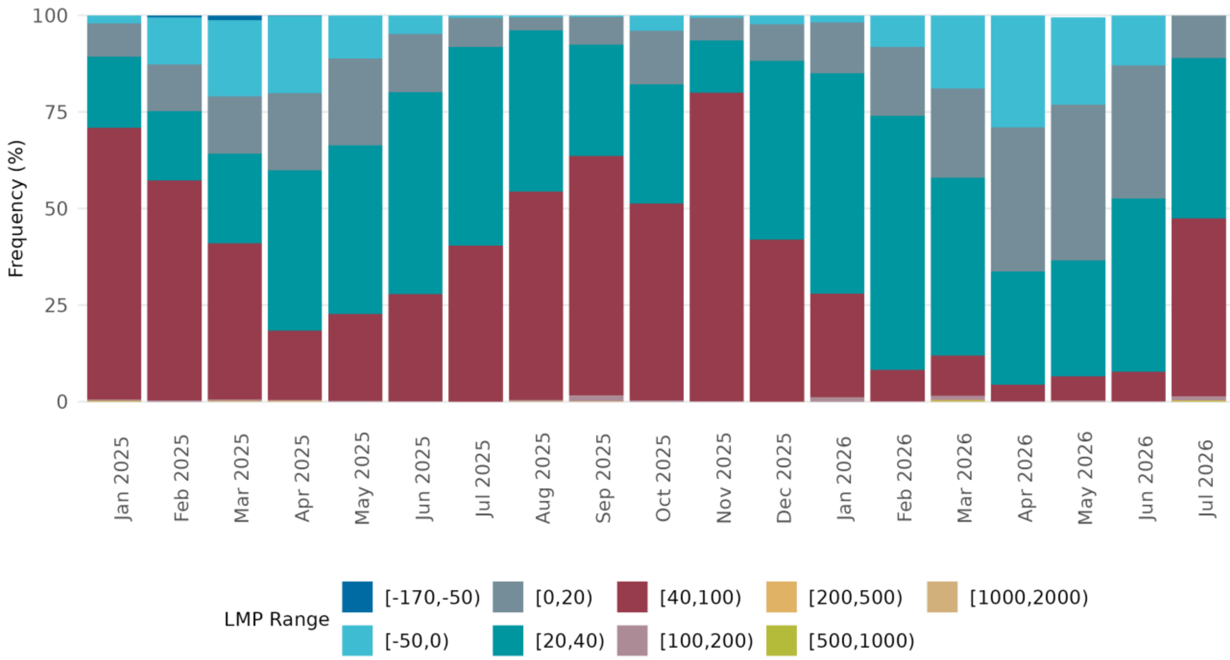


Figure 13: PACW RTD LMP range frequency

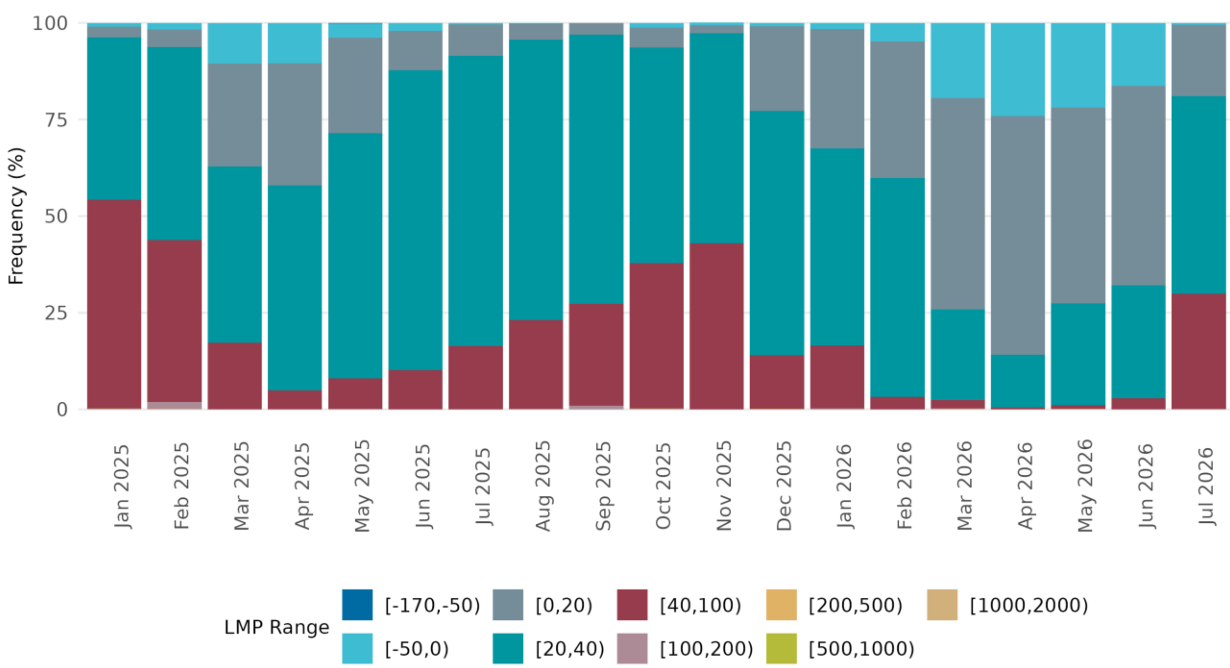


Figure 14: PACE RTD LMP Range Frequency

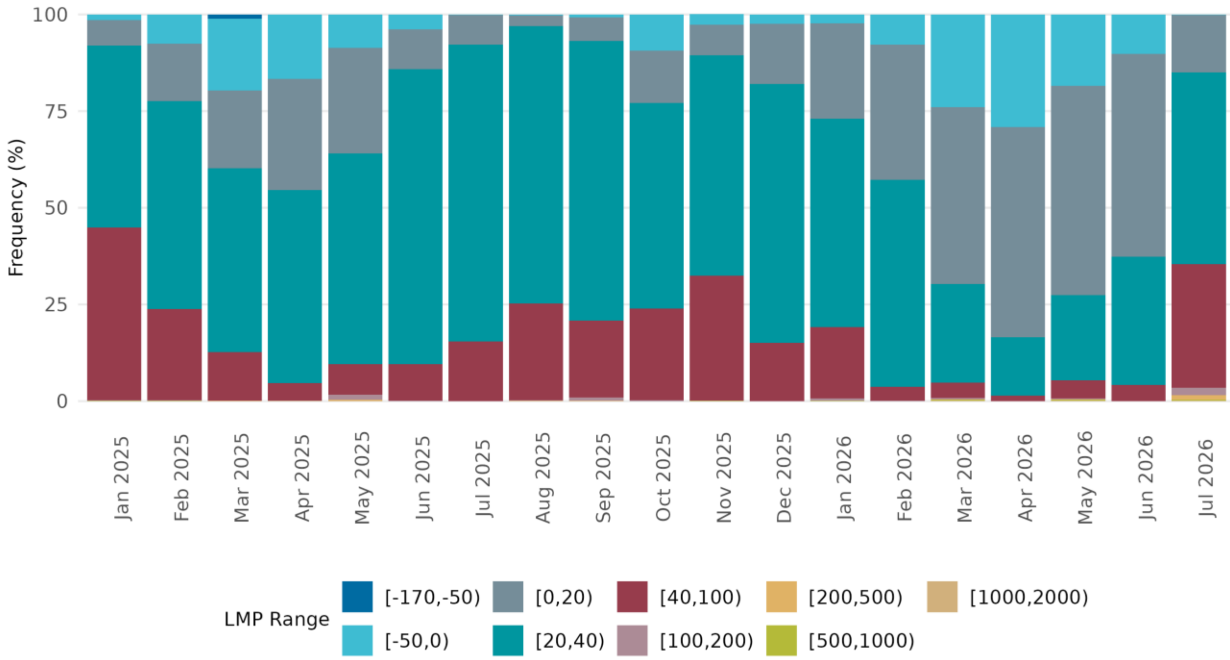
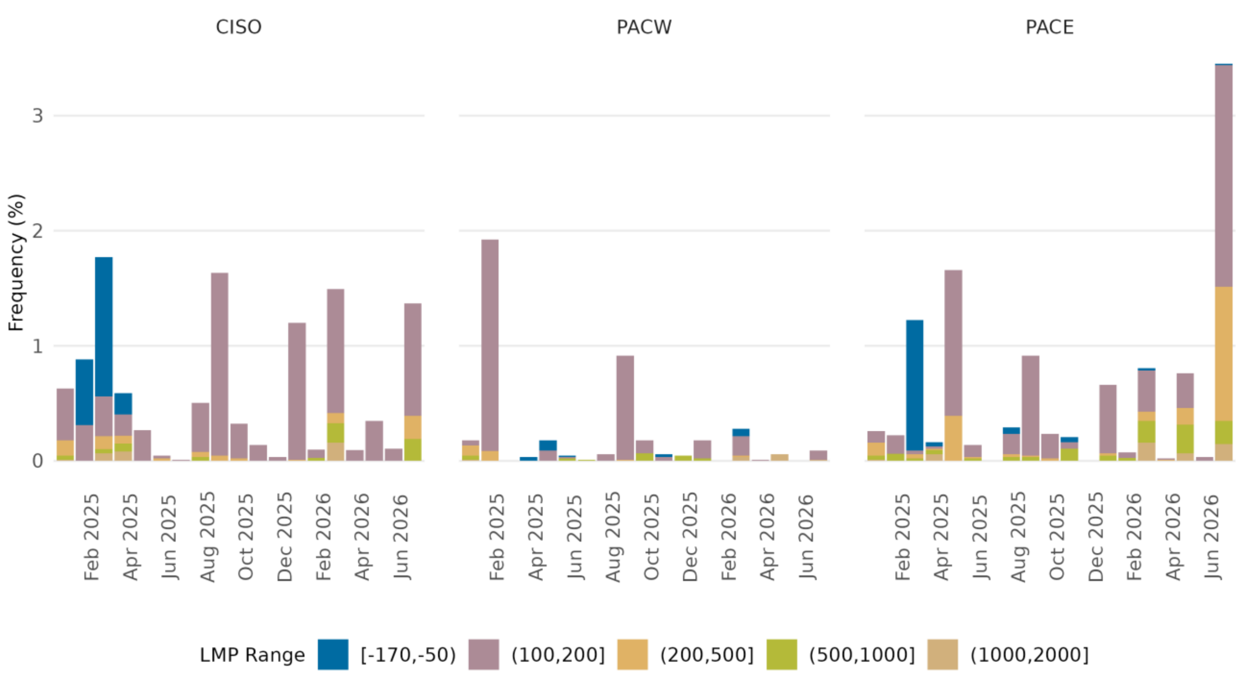


Figure 15: Frequency of extreme LMPs



Changes in price formation with EDAM

The previous assessment is based on the full locational marginal price (LMP). However, LMPs have different components:

i) marginal energy cost (MEC),
ii) marginal congestion cost (MCC),
iii) marginal losses cost (MLC), and
iv) marginal greenhouse gas emissions cost (MGHG).

With the introduction of EDAM/DAME, there are several significant changes to price formation in the day-ahead market.

Marginal energy cost

Before EDAM, there was a single system-level marginal energy cost (SMEC). After May 1, the marginal energy cost (MEC) is calculated separately for each BAA.

Before May 1, the day-ahead market enforced a power balance constraint (PBC) for only CAISO as there were no other BAAs in the day-ahead market. The real-time market, however, enforced two types of PBCs – a system-wide PBC and a BAA-specific PBC for every WEIM BAA except CAISO. The shadow price of the system-wide PBC (λ) served as the system marginal energy cost (SMEC) shared by all BAAs in the WEIM. On the other hand, the shadow price of the BAA-specific PBC (λ_j where *j* denoted BAA *j* other than CAISO) was included in the marginal congestion cost to drive price separation from the rest of the WEIM. See Figure 16 for the LMP decomposition of any given node in a non-CAISO WEIM BAA:

Figure 16: LMP Decomposition for Non-CAISO WEIM BAA

$$\left.\begin{aligned} &SMEC = \lambda \\ &MLC_i = (\lambda + \lambda_j - \psi)\left(\frac{1}{LPF_i} - 1\right) \\ &MCC_i = \lambda_j - \sum_{m}\sum_{n \epsilon N_m} a_{m,n}\, SF_{m,n,i}\, \mu_m \\ &MGC_i = -\psi \end{aligned}\right\}, \qquad \forall i \in BAA_j \wedge j \in EIM \wedge j > 0$$

Note: i denotes node i, j = 0 denotes CAISO, and j > 0 denotes BAAs other than CAISO

The term λ_j itself consisted of multiple sub-components. Specifically, λ_j was the sum of the shadow price of the EIM Transfer Distribution Constraint for BAA j (ϕ_j) and the shadow price of either the upper EIM Transfer Scheduling Limit for BAA j (v_j) or the lower EIM Transfer Scheduling Limit for BAA j (ξ_j):

$$\lambda_j = \phi_j + \nu_j \ or \ \lambda_j = \phi_j + \xi_j$$

First, the EIM Transfer Distribution Constraint ensured that the "WEIM Transfer for each WEIM BAA is distributed optimally to the applicable Energy Transfer Schedules" (Section 16.2.1.1.4 of the BPM for EIM). The WEIM Transfer for each WEIM BAA (T_j) was the sum of the schedules of all energy transfer system resources (ETSRs) defined for that BAA. $ET_{j,k,l}$ denoted an export ETSR l from BAA j to BAA k, and $IT_{j,k,l}$ denoted an import ETSR l to BAA j from BAA k:

$$\sum_{\substack{k \in EIM \\ k \neq j}} \sum_{l} \left(ET_{j,k,l} - IT_{j,k,l} \right) = T_j \quad \forall j \in EIM \wedge j > 0$$

The EIM Transfer Scheduling Limits constrained the total WEIM Transfer for a WEIM BAA to an upper limit $\overline{T}_j$ and a lower limit $\underline{T}_j$. These limits were defined by the WEIM BAAs:

$$\underline{T}_j \le T_j \le \overline{T}_j, \qquad \forall j \in EIM$$

In summary, prior to May 1, the shadow price of the system-wide PBC was applied uniformly to all WEIM BAAs via the SMEC. Price separation across the individual WEIM BAAs was achieved via the MCC, which included the shadow price of the BAA-specific PBC which, in turn, consisted of the shadow prices of transfer constraints.

With the implementation of the extended day-ahead market, a new formulation of the energy component went into effect for both day-ahead and real-time markets. The formulation no longer uses a system-wide PBC; consequently, there is no longer the calculation of a system-wide SMEC. To facilitate the settlement of transfer revenues which arise when there is MEC separation between BAAs, EDAM and WEIM now only enforce BAA-specific power balance constraints for each EDAM or WEIM BAA. The shadow price of the BAA-specific PBC is the MEC for the BAA. The shadow price of the BAA-specific PBC (λ_j) still contains the shadow prices of the transfer constraints:

$$\lambda_j = \phi_j + \nu_j \ or \ \lambda_j = \phi_j + \xi_j$$

The Transfer Distribution Constraint continues to be enforced for every WEIM BAA in the real-time market and is now enforced for every EDAM BAA in the day-ahead market. The Transfer Scheduling Limits continue to be enforced for every WEIM BAA in the real-time market and are now enforced for every EDAM BAA in the day-ahead market.

While the formulation of the transfer constraints did not change, the way their respective shadow prices feed into the LMP definition did change. Namely, the transfer constraint shadow prices are now part of the MEC and are no longer part of the MCC. The MCC now only reflects congestion from transmission elements (flow gates, nomograms and contingencies) and does not include any shadow price from a BAA-specific PBC.

Table 5: Comparison of LMP decomposition before and after May 1, 2026

Before 5/1/2026		5/1/2026 - Present	
SMEC Components	**MCC Components**	**MEC Components**	**MCC Components**
	ϕ_j	ϕ_j	μ_j
	ν_j	ν_j	
	ξ_j	ξ_j	
	μ_j		

Note: μ_j denotes shadow price of transmission constraint (e.g., flowgate, nomogram)

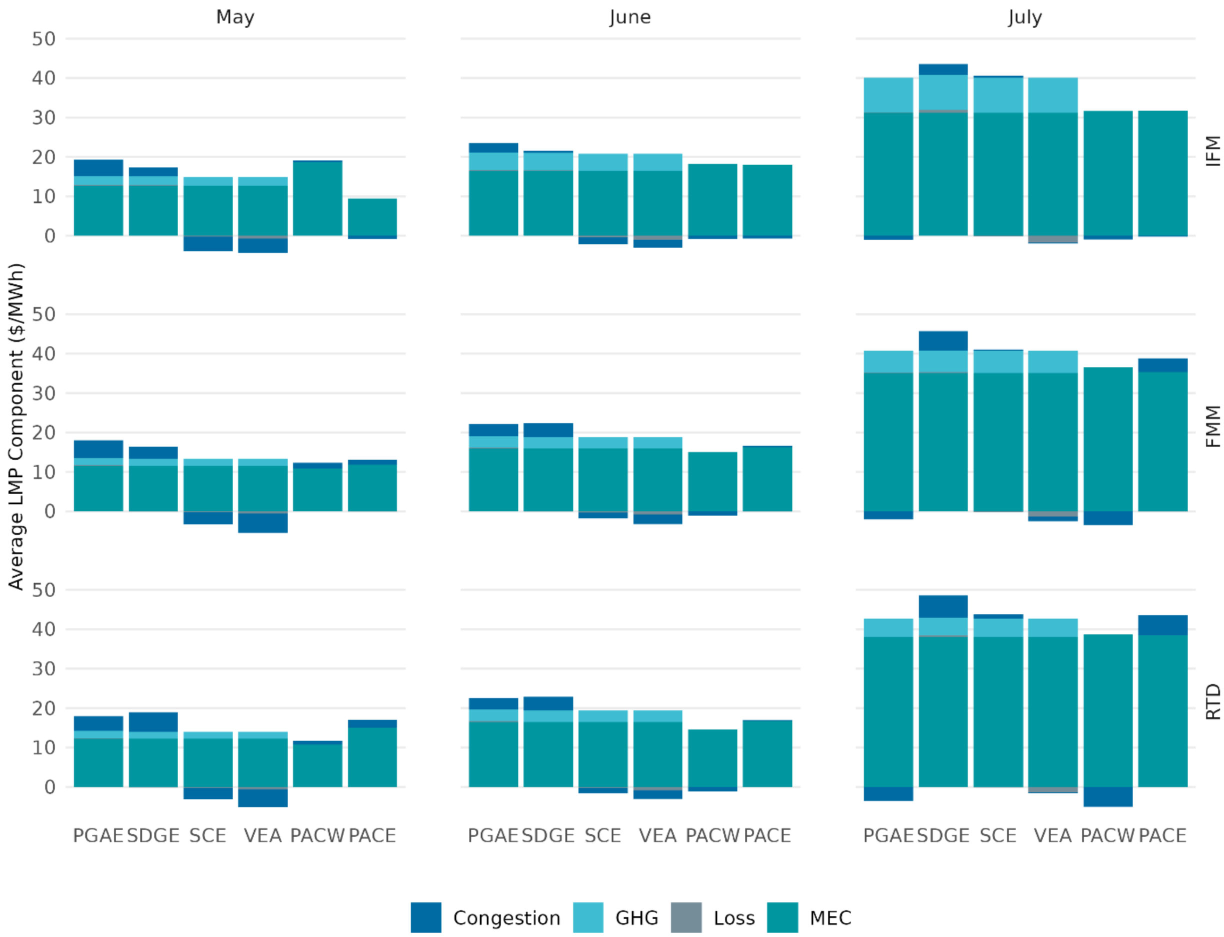
GHG prices

Before EDAM, the marginal cost of greenhouse gas (GHG) emissions was embedded into the SMEC and then subtracted from non-California BAA LMPs. With this formulation, the GHG component was applied only to non-California-area locations, and it was a negative component. After May 1, the marginal cost of GHG emissions is accounted for outside of the MEC and only applies within GHG regulation areas[1]. With EDAM/DAME the GHG component is positive and applied only to California-area locations.

Figure 17 shows the average LMP composition in IFM, FMM, and RTD for the PACE and PACW ELAPs as well as the four CAISO default load aggregation points (DLAPs) across May, June, and July. In April, the MEC was the same across all areas, reflecting the SMEC. In May and June, the MEC varied between BAAs. The variation in the MEC across BAAs was more pronounced in the IFM and RTD. The change in GHG cost accounting can also be seen in Figure 17. In April, the GHG component of the LMP was negative and only applied to PAC areas BAAs. After May 1, the GHG component of the LMP is positive and only applies to California-area LMPs. In general, the GHG component of the LMP increased across the four CAISO DLAPs for the month of July. Excluding PACW IFM, the MEC increased across the market footprint from May to June. In June, PACE saw very little congestion impact on the LMP in IFM however saw some increase in congestion component in FMM and RTD market across all markets. The congestion component went from positive to negative in PACW from May to July, decreasing the overall effect of the higher MEC. The CAISO DLAPS also saw a small decrease in the congestion component from May to July.

[1] California is currently the only GHG regulation area active within the market footprint.

Figure 17: Average monthly LMP components



Bilateral power price comparisons

Outside the CAISO's markets, power is historically traded through forward-looking transactions between buyers and sellers. The Intercontinental Exchange (ICE) is a bilateral power marketplace where power contracts can be bilaterally traded between two counterparties.

Comparing bilateral power prices from ICE to CAISO market prices is useful as both CAISO and ICE markets reflect the willingness of buyers and sellers to trade next-day power and can provide some reference of how the marketplace valued power in the West. The comparison of power prices and energy quantity traded is also useful to assess what impact the new EDAM market may have on bilateral next-day power trading.

Figure 18 and Figure 19 below show a comparison between EDAM BAA LMPs and next-day bilateral power prices at the Mid-Columbia (MidC) and Palo Verde (PV) hubs. These two hubs are highly liquid and geographically cover the north (MidC) and south (PV). While CAISO prices are hourly, next-day bilateral power trades in blocks for on-peak and off-peak periods[2], thus the bilateral prices shown are calculated as the average of hourly prices where each hour is assigned the applicable time of use price. The CAISO LMP is calculated as the load weighted average of its four DLAP LMPs.

Figure 18 shows that, on average in July, CAISO day-ahead LMPs were most strongly correlated with MidC and PV next-day bilateral power prices. PACE MidC and PV prices rose during three periods in July, hitting peaks on July 21, 26 and 15. During these periods CAISO day-ahead LMPs were elevated, with highest daily average prices on July 21, 29 and 24. For several days, CAISO day-ahead LMPs fell between the MidC and PV next-day prices. For PACW and PACE day-ahead LMPs there was some correlation with next-day bilateral prices as prices were elevated during the peak price days – both hubs saw some of the highest daily average prices from July 21 to 22 and July 26 to 29.

Figure 18: Daily average LMPs and bilateral power prices

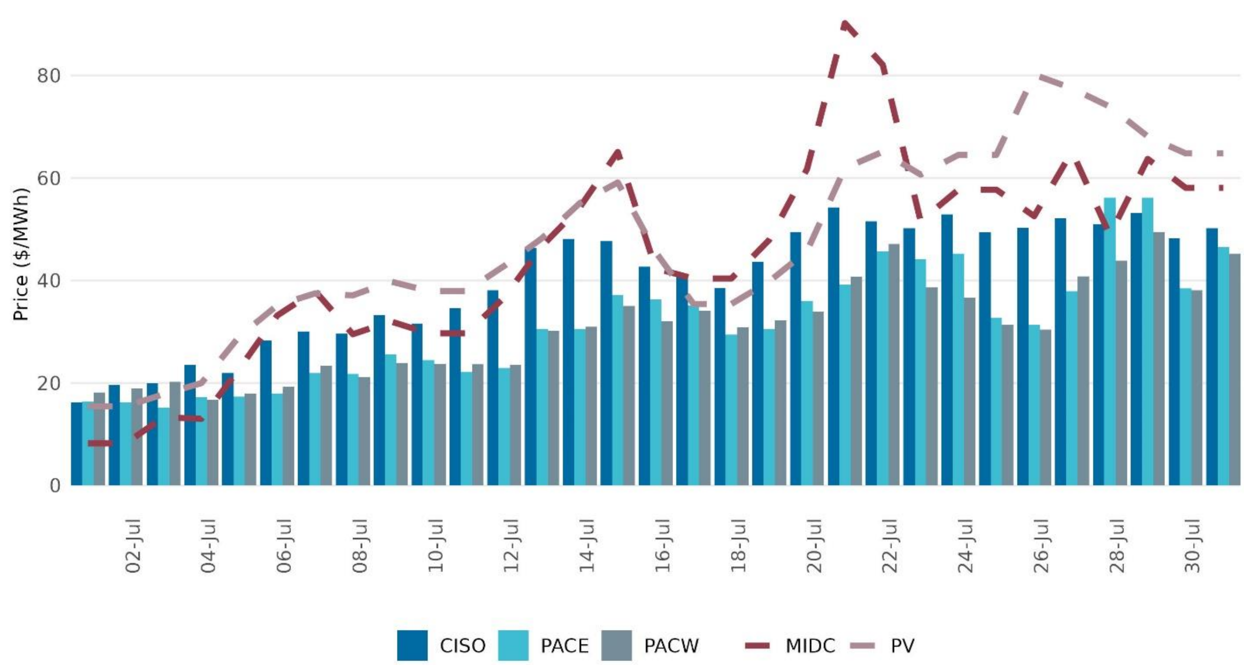


Figure 19 shows that CAISO day-ahead LMPs have historically shown some correlation with next-day bilateral power prices at MidC and PV. The high MidC price in February 2025 was due to a major Arctic cold snap. The first two months of EDAM appears to show some divergence between MidC and PV price and with CAISO day-ahead LMPs; However, historial trends also showed this trend. A more robust assessment of this correlation will require observation over a longer period of EDAM operations.

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

Figure 19: Monthly average LMPs and bilateral power prices

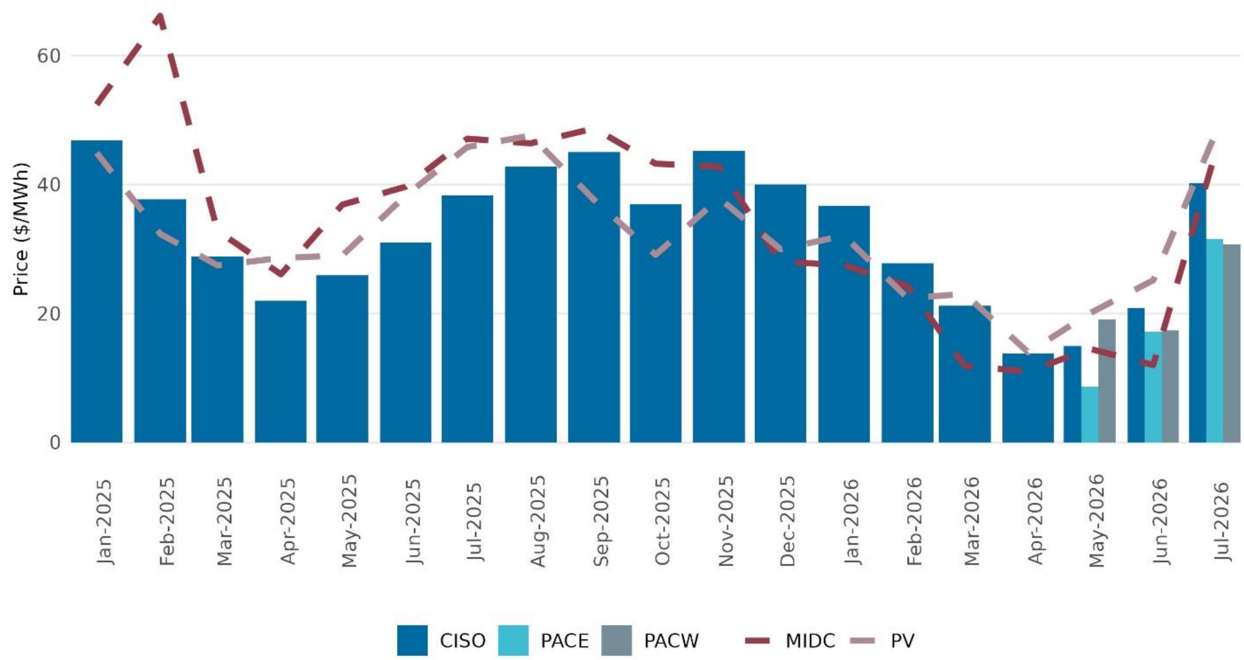


Figure 20 and Figure 21show the daily energy volume traded for bilateral next-day power at MidC and PV hubs from April to July. For on peak, no power is traded on Sundays, which is an off-peak day. For off-peak, volumes are lowest during the weekdays. For both on- and off-peak, volumes are usually highest at the end of the week when power delivery is for Sunday and Monday. These figures show no observable change in the volume traded for on- or off-peak from April to July.

Figure 22 and Figure 23 show the monthly average energy volume traded since January 2025. The volume traded in May - July 2026 is like April 2026 and shows slight increase for the month of July. Observing this metric after several months of EDAM operations will provide a better indication of any impact of the EDAM market on bilateral power trading.

Figure 20: Total daily energy volume of bilateral trades (On-peak)

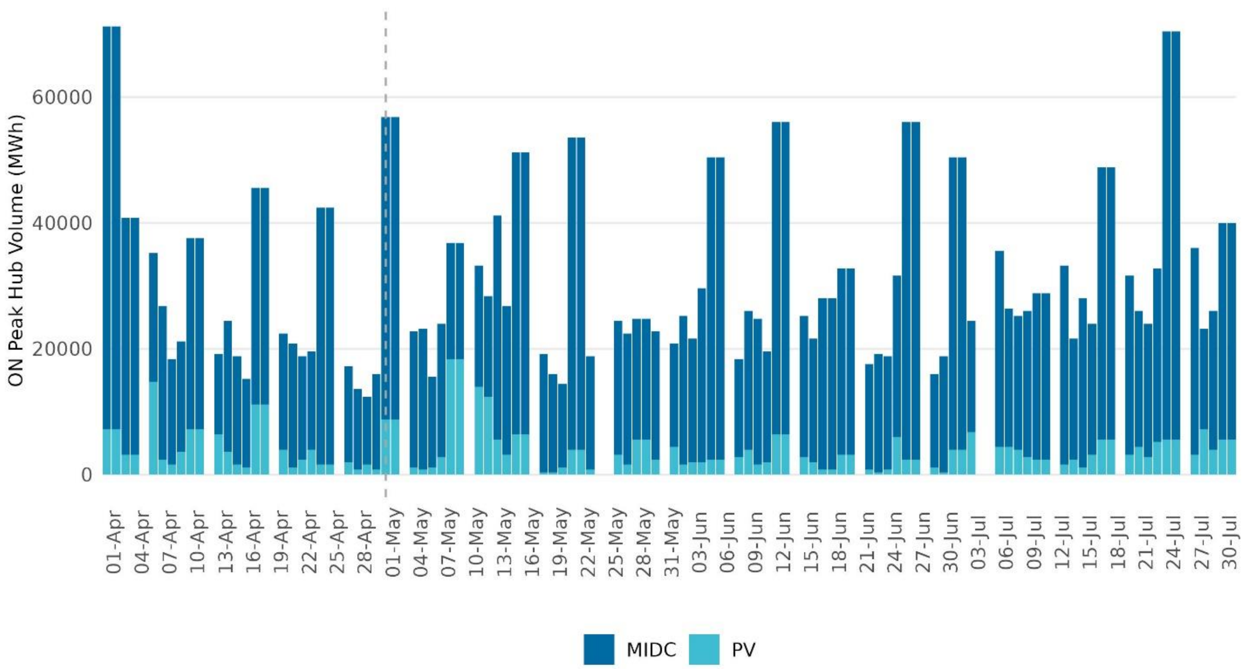


Figure 21: Total daily energy volume of bilateral trades (Off-peak)

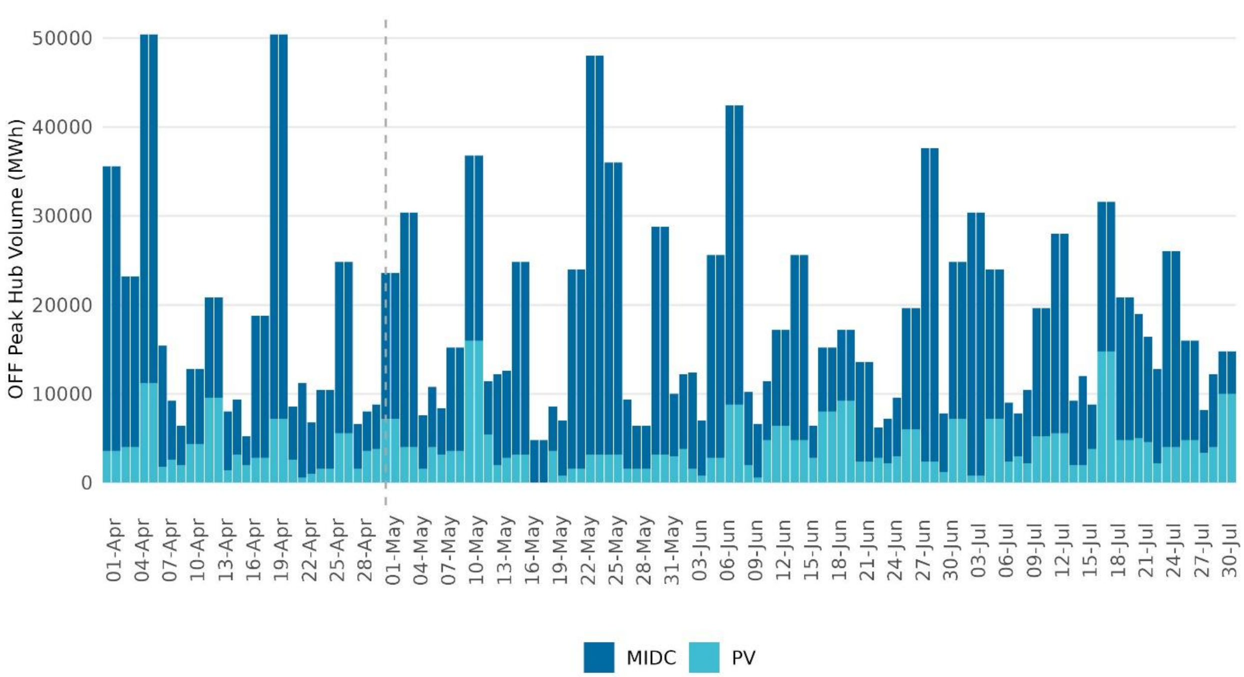


Figure 22: Total monthly energy volume of bilateral trades (On-peak)

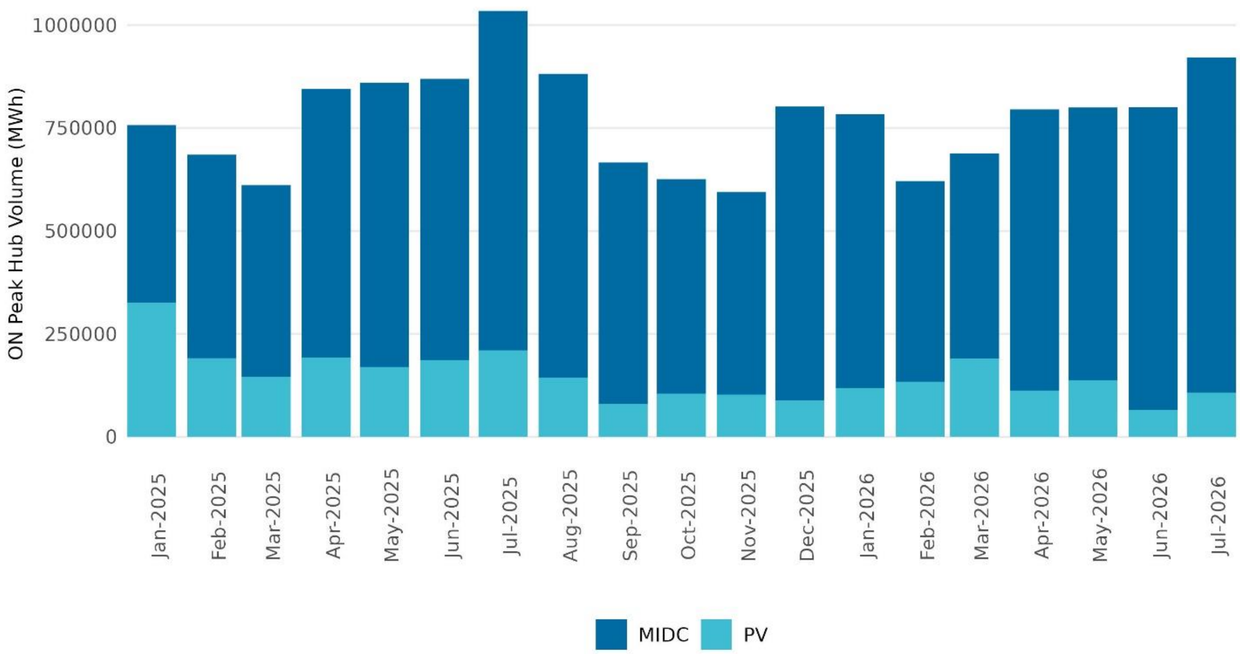
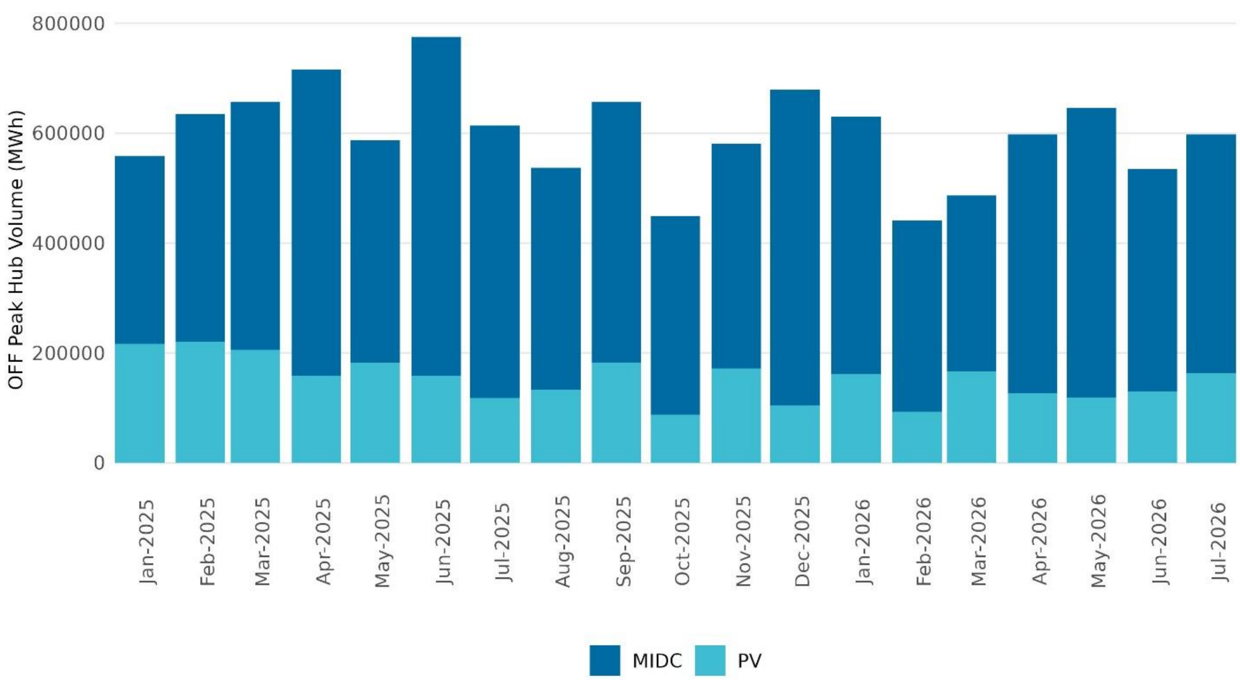


Figure 23: Monthly total energy volume of bilateral trades (Off-peak)



Ancillary services

EDAM go-live made few changes to ancillary service procurement market design. The one major change applies to battery storage resource type (LESR). For these resources, new commodities were added to the envelope constraint which models the impact on state of charge of various commodities, including regulation up and down for CAISO and the new commodities imbalance reserve and reliability capacity for resources in all EDAM BAAs.

Figure 24 shows CAISO ancillary services prices in IFM from April 1st to July 31st. Overall, AS prices remained within typical ranges for all four commodities in July, with slightly elevated prices during the latter half of the month reflecting summer conditions.

Figure 24: Daily average of CAISO ancillary services prices in IFM

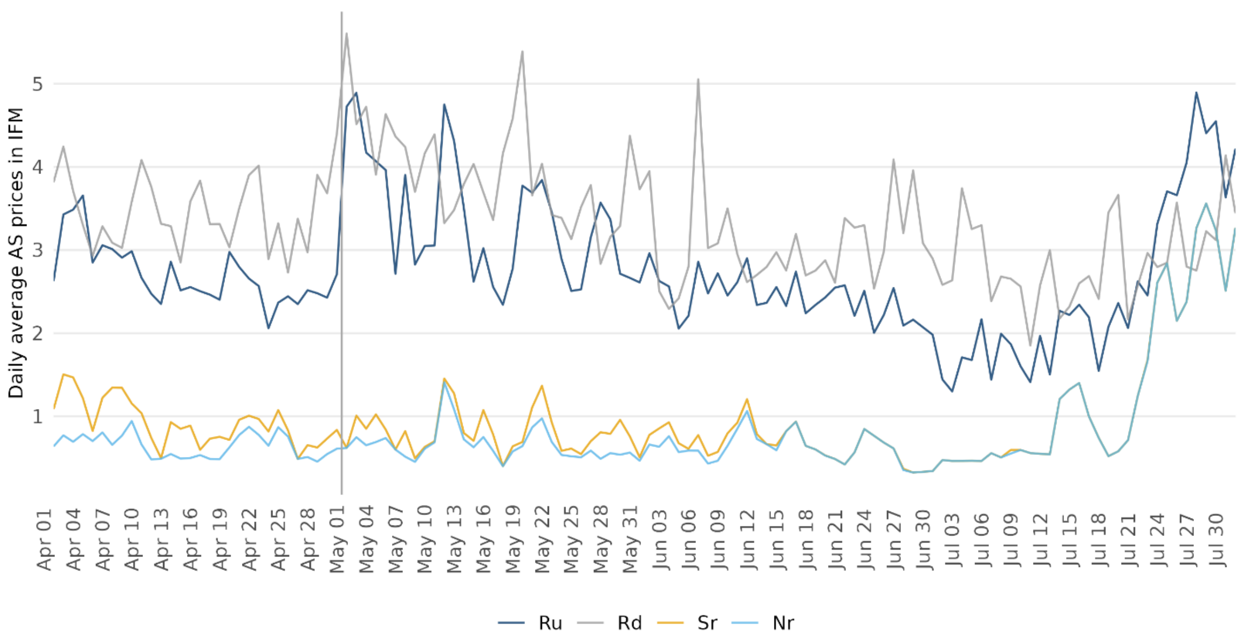
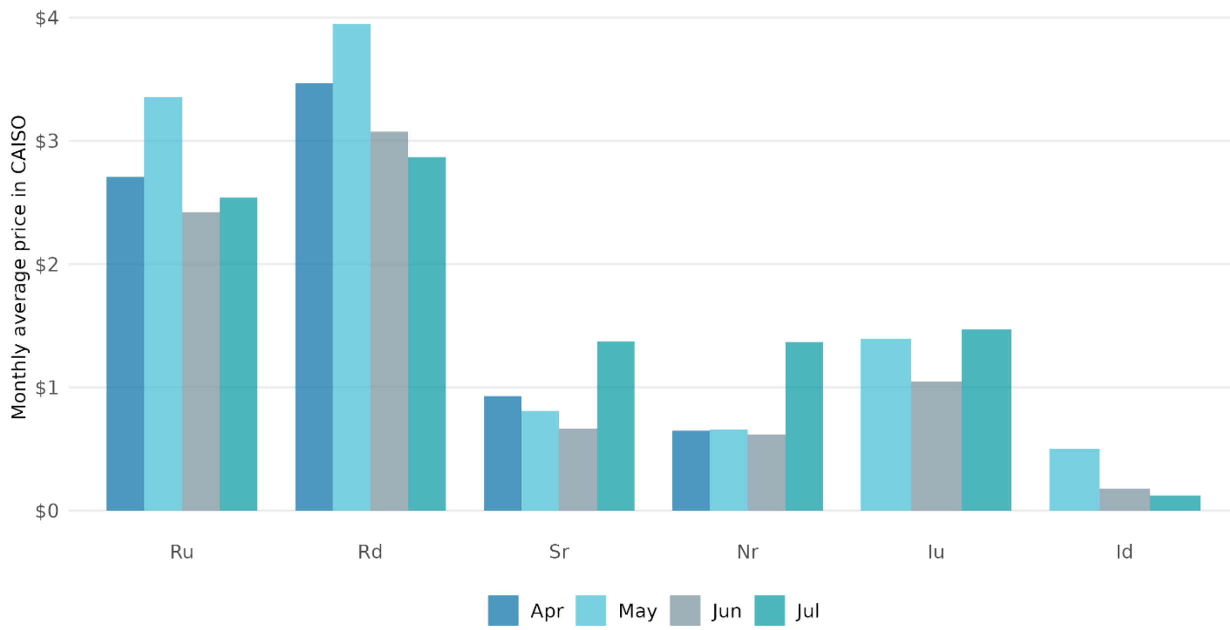


Figure 25 compares the monthly average AS prices in CAISO for the same period. Average regulation up and down prices remained in similar ranges, while spin and non-spin prices showed slight increases. New imbalance reserve prices in CAISO after May are added for reference. Average price of imbalance reserve up fell between average prices of regulation up and spin.

Figure 25: Monthly average AS prices in CAISO



A feature of CAISO's market regarding provisions of AS is the flexibility to cascade procurement for upward AS commodities. Cascaded procurement is where capacity of a higher quality AS type can be counted towards meeting the requirements for a lower quality type. From highest to lowest quality, the upward AS product ranking is: regulation up, spin, non-spin. This cascading structure is embedded directly into the market clearing process, which simultaneously clears energy and ancillary services.

Figure 26 compares the frequency of cascading in regulation up and spin across April, May, and June. The frequency of cascading in regulation up was 28.8% in April, decreased to 4.7% in May, increased to 15.8% in June, and further increased to 20.3% in July. The frequency of cascading in spin increased from 74.3% in April to 85.6% in May, 91.5% in June, and 95.3% in July. The requirement for each AS is still fully met with the bids explicitly submitted for these services.

Figure 26: Frequency of cascading in Regulation and Spin reserves

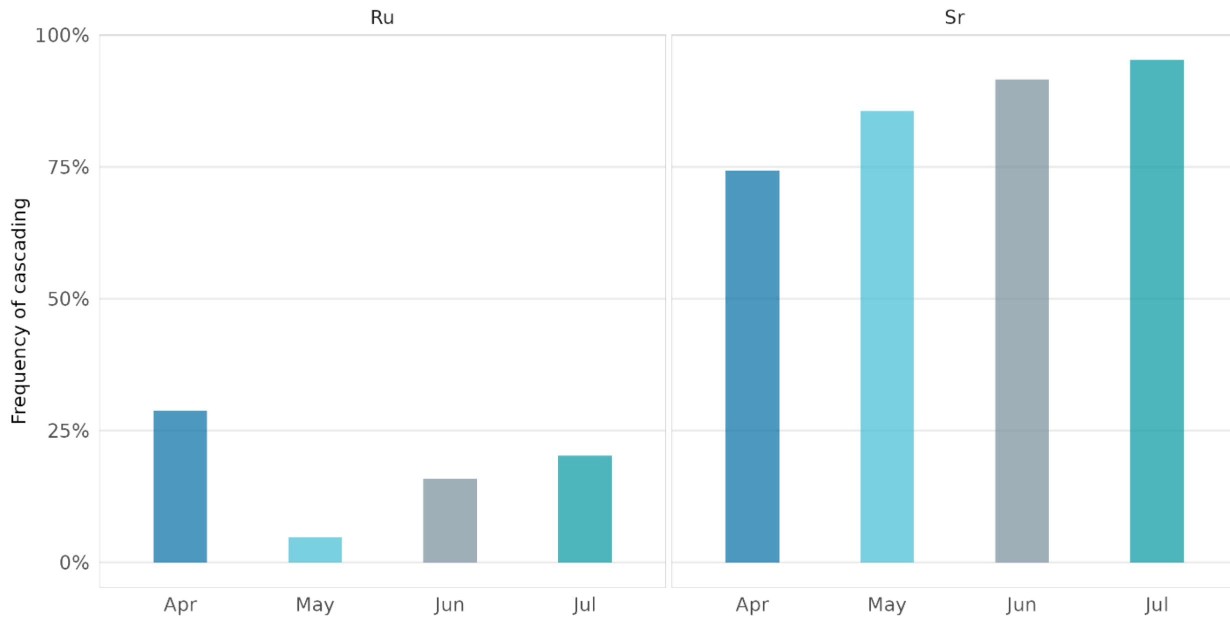


Figure 27 shows the percentage procurement for upward AS commodities in April through Julye. Figure 28 shows the daily distributions of percentage procurement for regulation up for the same period. Percentage procurement is defined as procurement divided by the requirement for the corresponding product. When cascading happens in one commodity, its percentage procurement will be higher than 100%, showing the extra capacity procured to fulfill the requirement of the lower quality commodity. Percentage procurement of regulation up in July increased slightly from previous month. Percentage procurement in spin remained in similar ranges in July comparing to June.

Figure 27: Comparison of monthly procurement in percentage

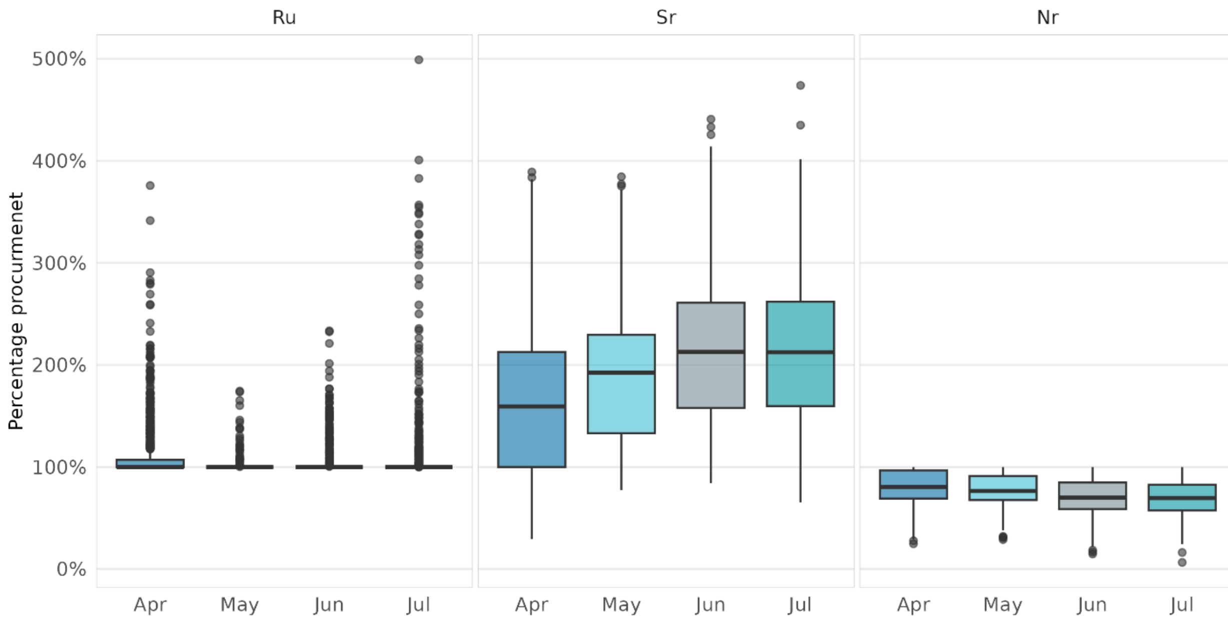


Figure 28: Daily distribution of regulation up percentage procurement in IFM

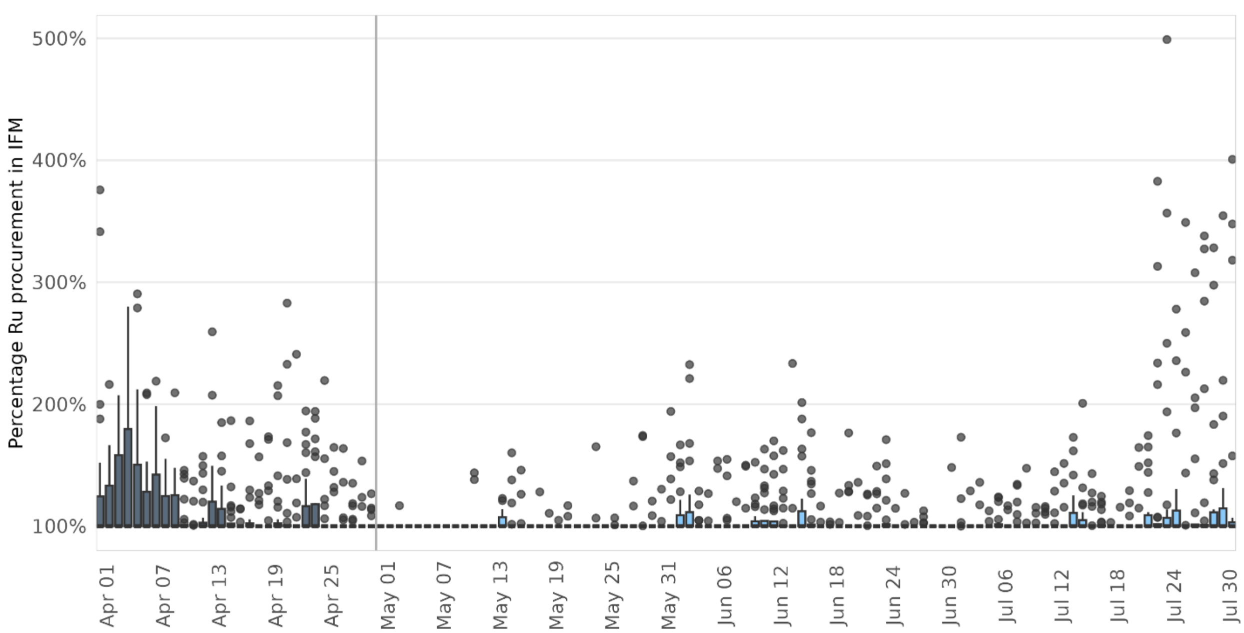
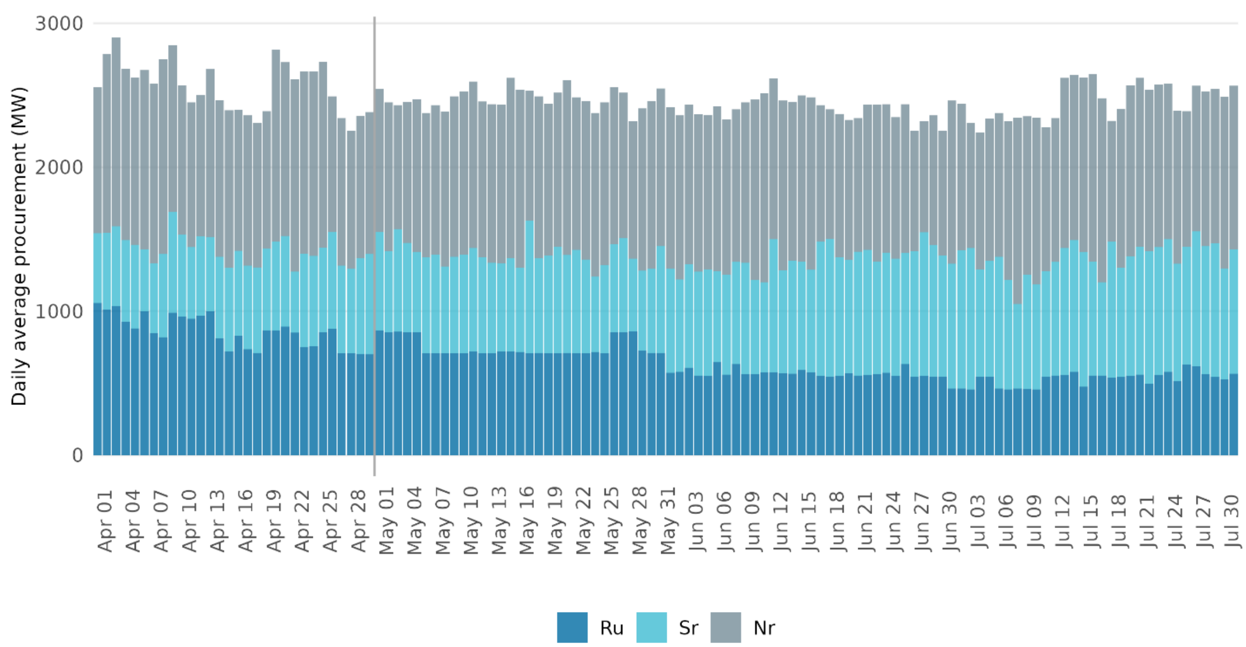


Figure 29 shows daily average procurement volume (MW) in upward AS commodities in IFM. After EDAM go-live, regulation up procurement showed slightly decrease while spin showed slightly increase.

Figure 29: Daily average Upward AS procurement in IFM



Cascading in upward AS is driven by AS prices and only happens when it is economical in the co-optimization process. Figure 30 to Figure 32 show price comparisons in upward AS commodities, April through July. In July, the price trends for regulation up, spin, and non-spin showed increases in hours ending 19 to 22. Compared with previous months, average regulation up prices in July remained at a level comparable to April, while average prices for spin and non-spin increased slightly.

Figure 30: Regulation up prices for CAISO extended area

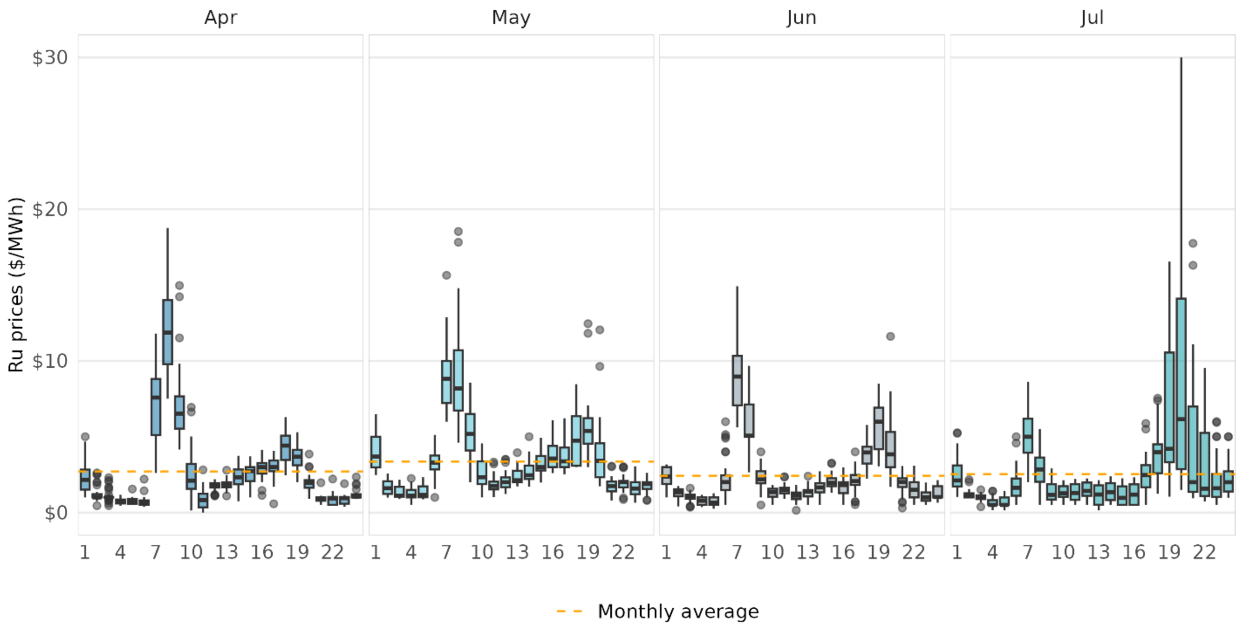


Figure 31: Spin prices for CAISO extended area

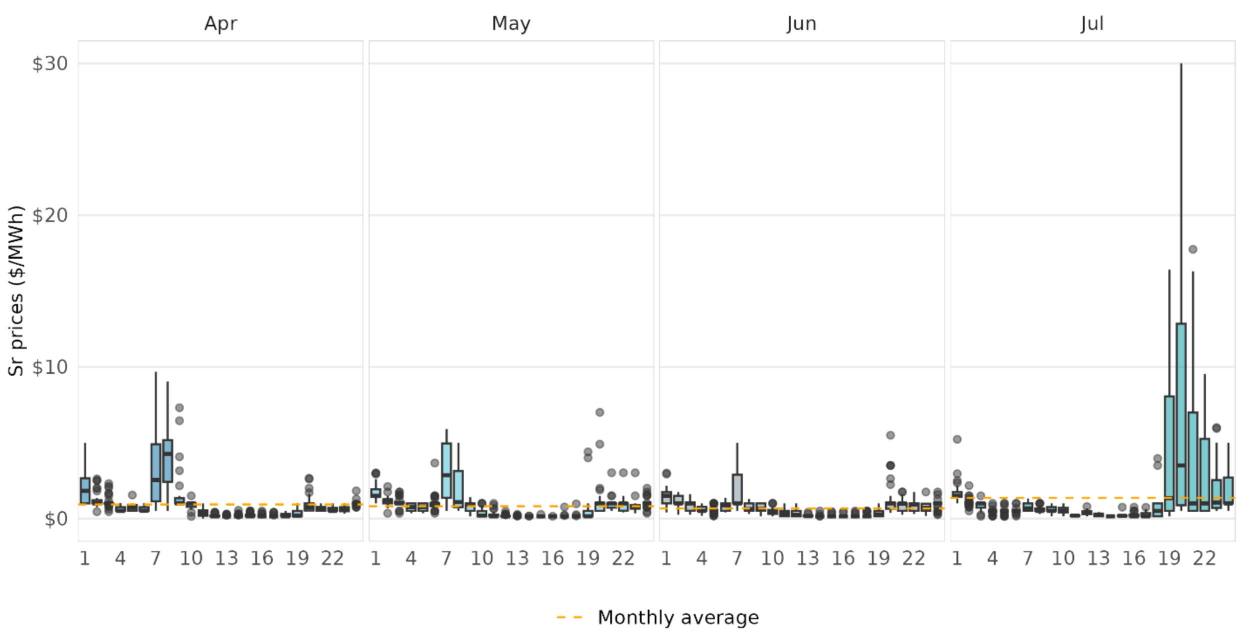
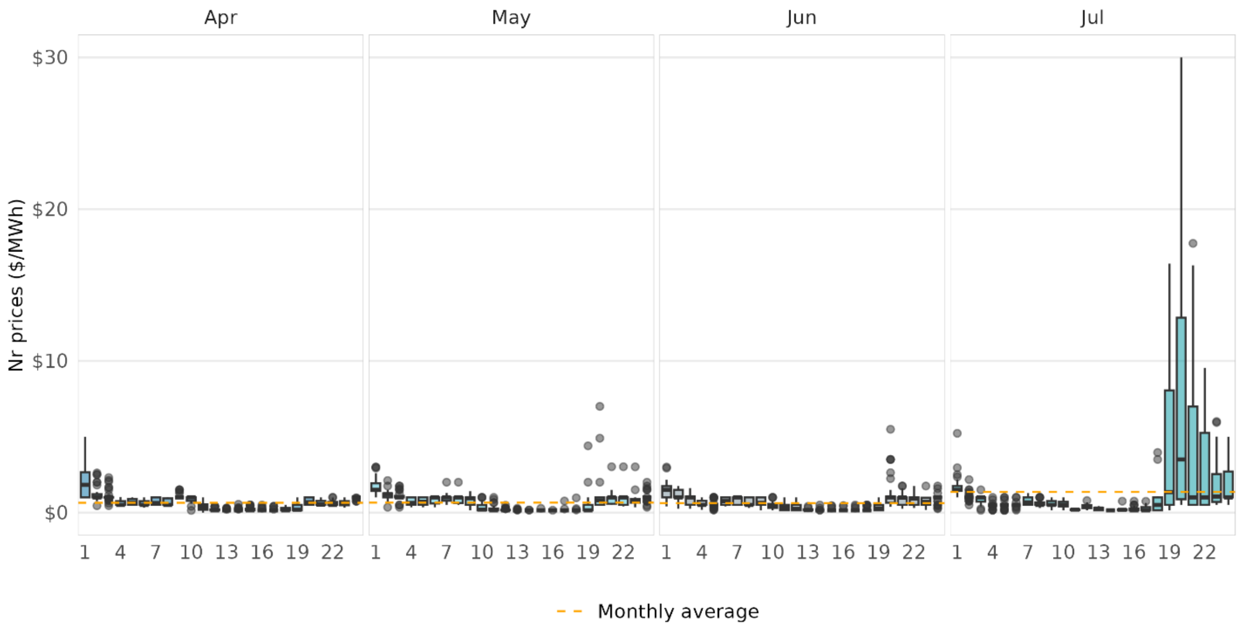


Figure 32: Non-spin prices for CAISO extended area



Imbalance reserves

Imbalance Reserves (IR) are a new flexible reserve day-ahead product introduced with the EDAM market. The IR product covers uncertainty that materializes between the day-ahead and the real-time net load forecast, and real-time ramping needs not covered by hourly day-ahead market schedules. Net load forecast uncertainty is driven by variability in variable energy resource production forecasts and load forecasts. Imbalances in the net load forecasts between the day-ahead and real-time markets have grown due to rapid growth in variable energy resource capacity on the CAISO grid and more extreme weather throughout the Western grid. Imbalances also exist because real-time net load moves continuously and flat hourly schedules from the day-ahead market inherently cannot cover the fluctuation. The IR product ensures that each balancing authority area in EDAM has sufficient flexible capacity scheduled to meet net load imbalances between the day-ahead and real-time markets. The market procures imbalance reserves bi-directionally to ensure upward and downward net load imbalances are covered.

Figure 33 shows that monthly average July IRU prices for CAISO and PACE were higher than in previous months, but lower for PACW. Average July IRU prices in CAISO were lower than PACE and PACW, consistent with previous months. Average IRD prices in July were low for all three BAAs. Figure 34 and Figure 35 show that daily average July IR prices remained stable compared to June, except for IRU prices in PACE which were more volatile. Daily average prices were high on July 3-4 for IRU in PACW (5.63 $/MWh on July 3), IRD in CAISO (0.47 $/MWh on July 4), IRD in PACE (0.90 $/MWh on July 4) and IRD in PACW (2.84 $/MWh on July 3). Daily average prices for IRU in CAISO were highest on July 24 (2.46 $/MWh), and for IRU in PACE were highest on July 28 (10.94 $/MWh). The hourly average profiles for all BAAs showed the highest prices typically occurred during evening peak hours, coinciding with the hours having the highest demand and indicating that the need for ramping is highest at these times if the net load forecast changes. The imbalance reserve price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint and each BAA's imbalance reserve requirement, available supply mix and EDAM transfers.

Figure 33: Monthly average IR prices

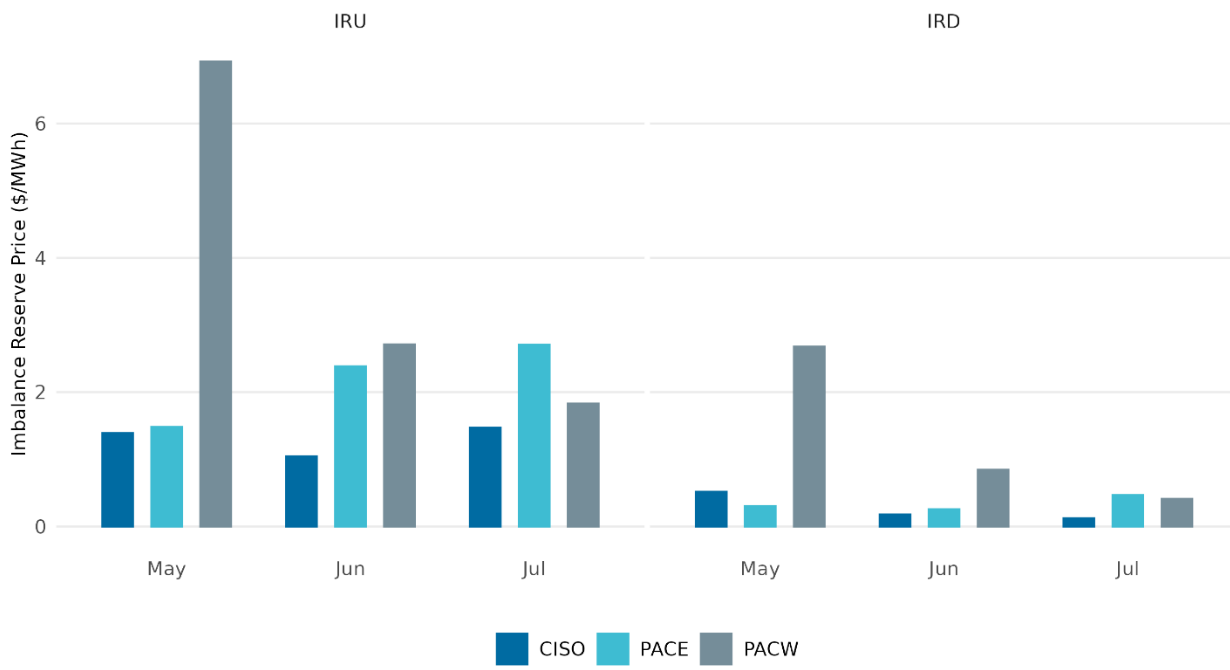


Figure 34: Daily average price of IRU

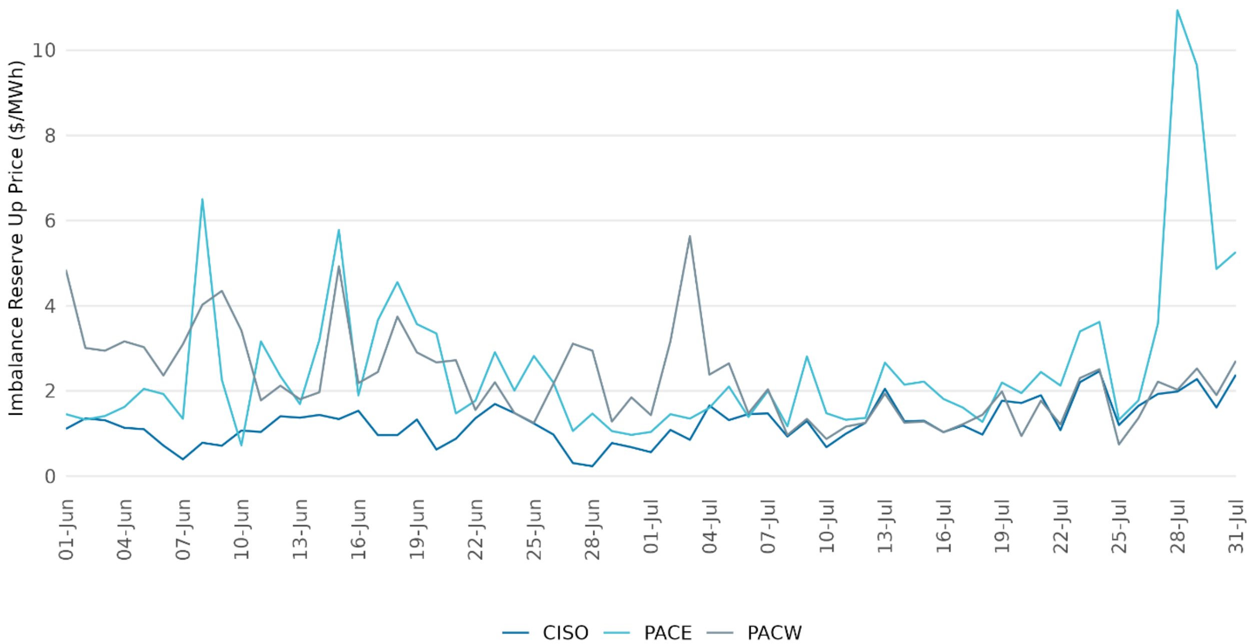


Figure 35: Daily average price of IRD

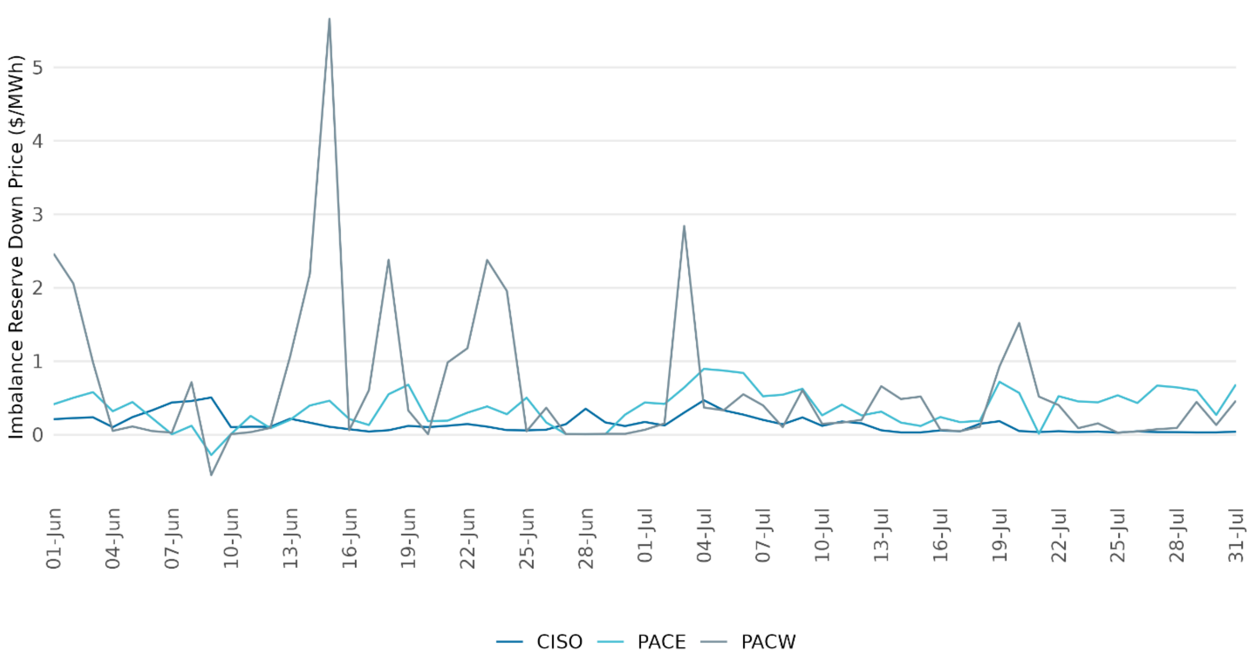


Figure 36: Hourly average price of IRU

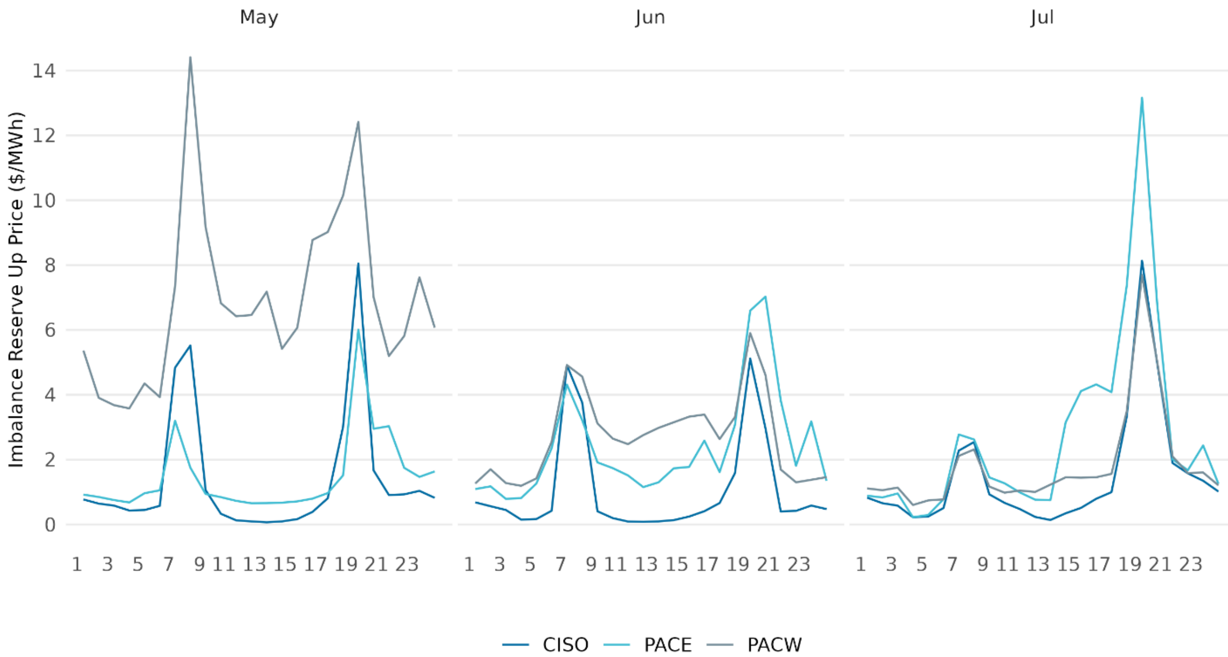
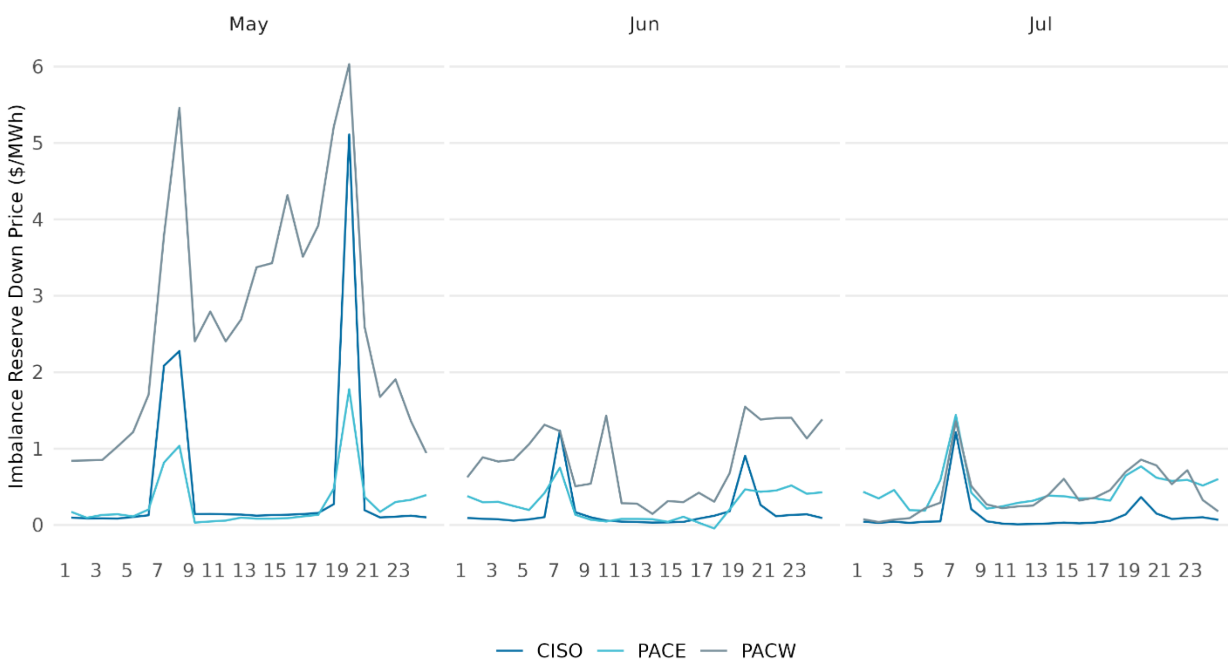


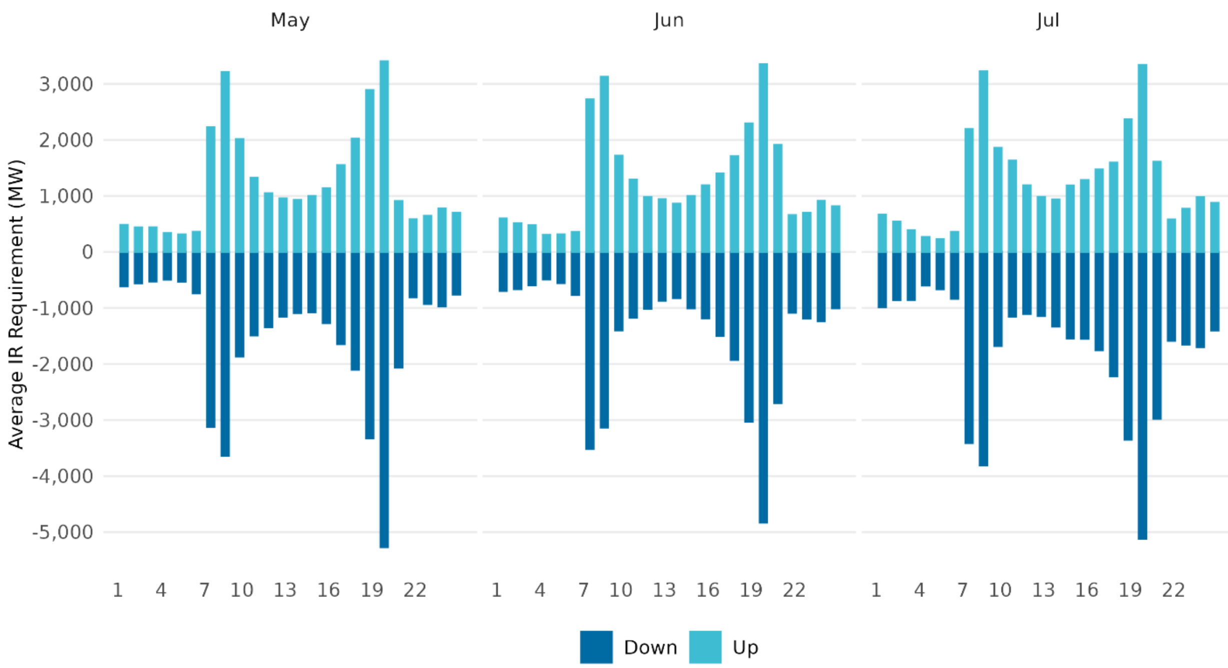
Figure 37: Hourly average price of IRD



IR Requirements are calculated hourly for each BAA. Figure 38 to Figure 40 illustrate average IR requirements for each BAA by direction. The magnitude of IR procured is proportional to the magnitude of net load uncertainty associated with that BAA. CAISO is the largest footprint in the EDAM with a large assortment of variable energy resources, so naturally it sees the highest amount of IR procurement.

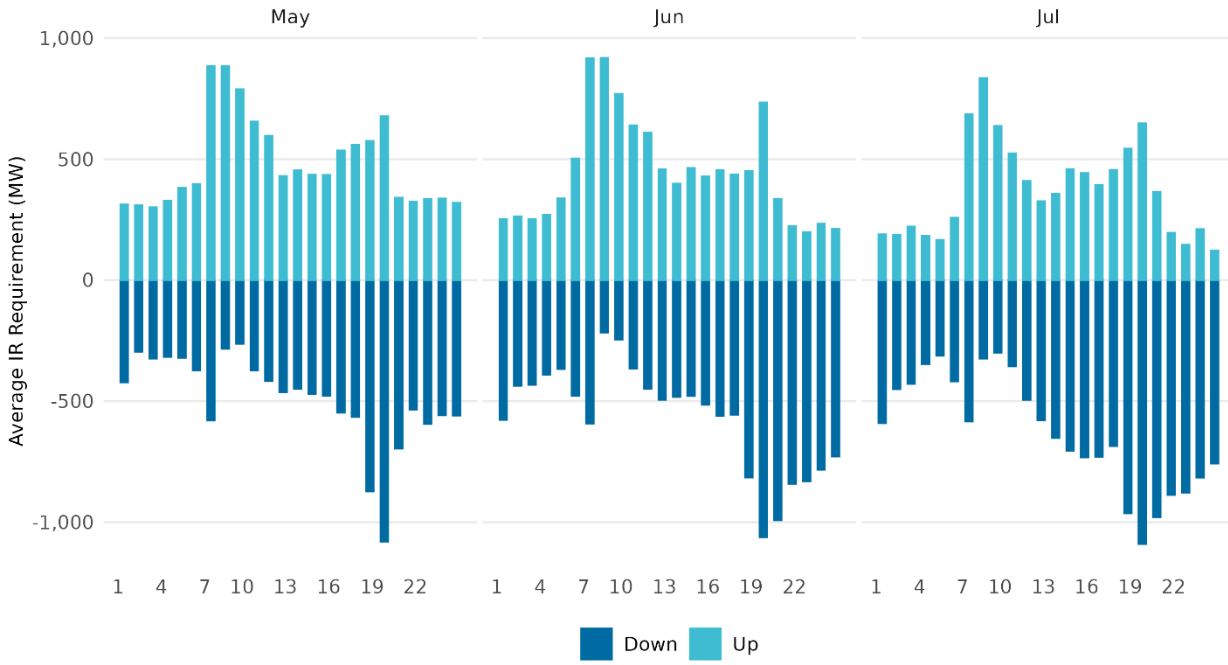
IR requirements for CAISO BAA are consistent in shape and magnitude since May. The highest requirements typically occur during the solar ramping hours where flexibility is required if the net load forecast changes.

Figure 38: Hourly average of IR requirements for CAISO



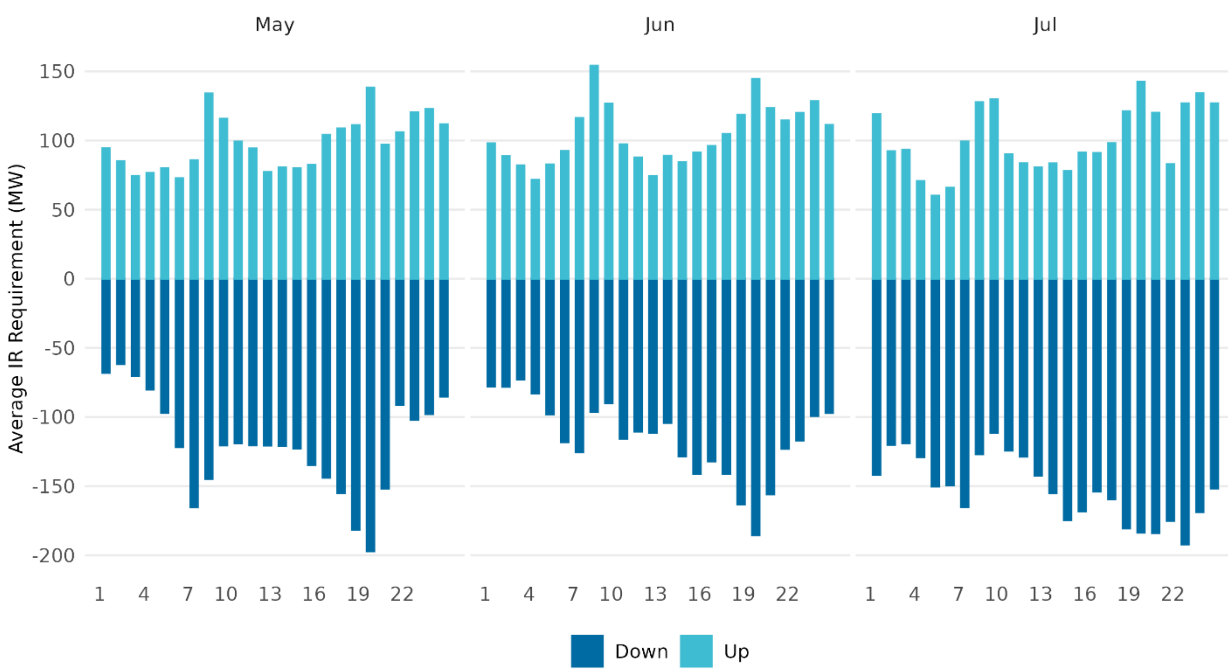
PACE IR requirements, on average, also saw the highest IRU requirements during the morning ramping hours and the highest IRD requirements during the evening peak. PACE IR requirements shape and magnitude also is stable since May.

Figure 39: Hourly average of IR requirements for PACE



PACW IRU requirements are relatively consistent throughout the day on average for both IRU and IRD.

Figure 40: Hourly average for IR requirements for PACW



EDAM expands the day-ahead market footprint. Uncertainty in each area, due to load and renewable variability, does not usually occur at the same time. Sharing supply and demand variability across a broader footprint brings diversity benefit to the EDAM BAAs, by reducing the total requirement needed compared with the total requirements when assessing area needs separately. Figure 41 and Figure 42 presents the hourly average diversity benefit by EDAM BAA by product. Diversity benefit is defined as the difference between the sum of individual BAA IR requirement and the IR requirement of the entire EDAM footprint. The reduction of requirements is then allocated pro-rata to each EDAM BAA based on its original individual BAA requirement. In July 2026, the average diversity benefit allocation is shown in Table 6.

Table 6 Average Diversity benefit allocation for July 2026

BAA	CISO		PACE		PACW	
IRU	350.0	68.6%	122.7	24.0%	37.6	7.4%
IRD	327.5	66.3%	133.0	26.9%	33.4	6.8%

Figure 41: Hourly average diversity benefit, IRU

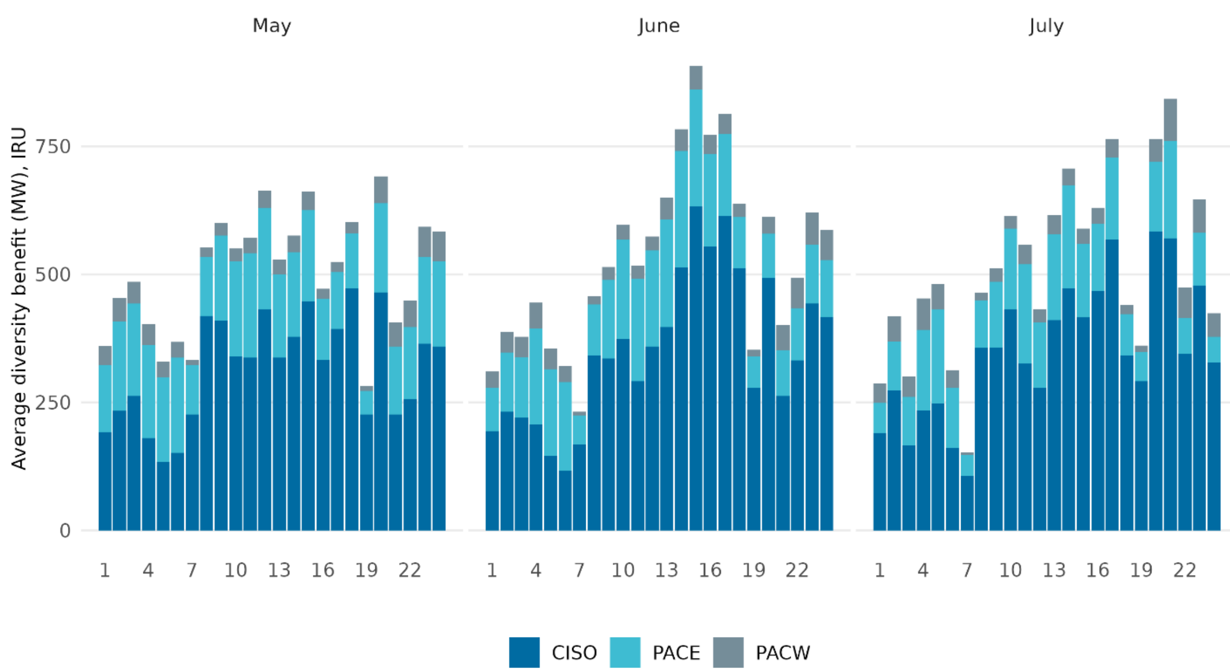


Figure 42 Hourly average diversity benefit, IRD

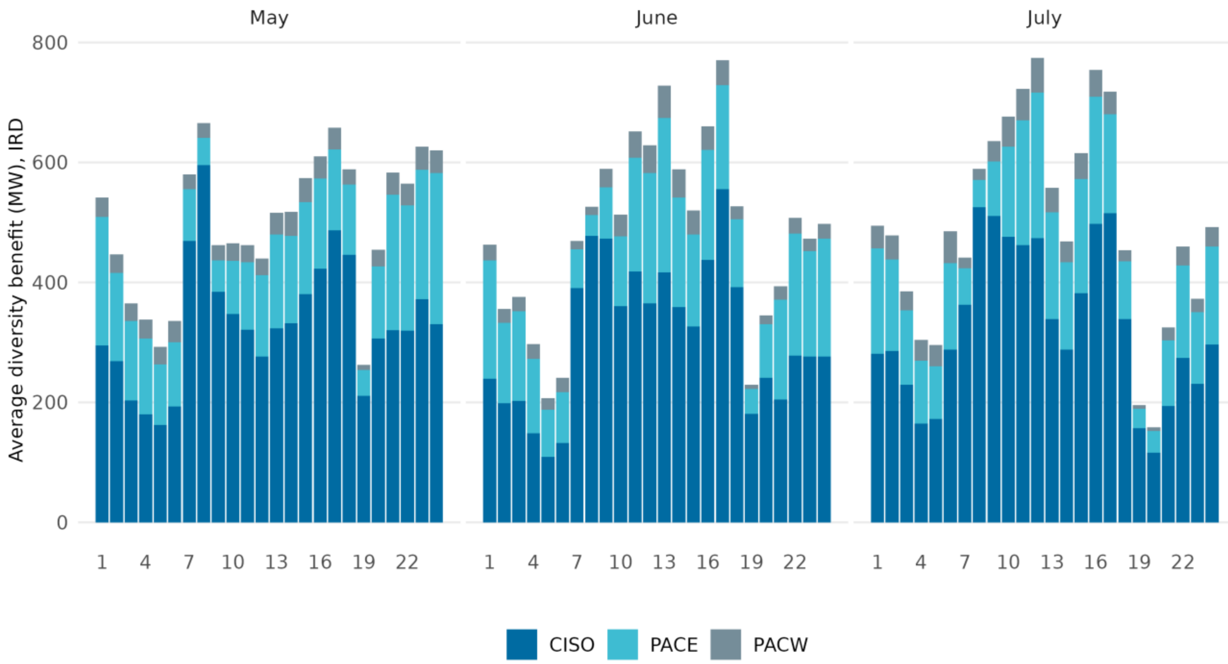


Figure 43 illustrates hourly average cleared IR by fuel type, positive direction indicates IRU and negative values indicate IRD, respectively. For the IRU direction, the resource mix exhibits a well-defined pattern, with gas resources providing the majority of IRU supply during overnight hours and remaining a significant contributor throughout the day. Solar resources become the dominant technology during daylight hours, and batteries show narrow procurement only during morning and evening ramp periods. As for IRD, solar resources show the greatest contribution during daylight hours, while wind resources become the main technology during night hours.

Figure 43: Hourly average cleared IR by fuel type for CAISO

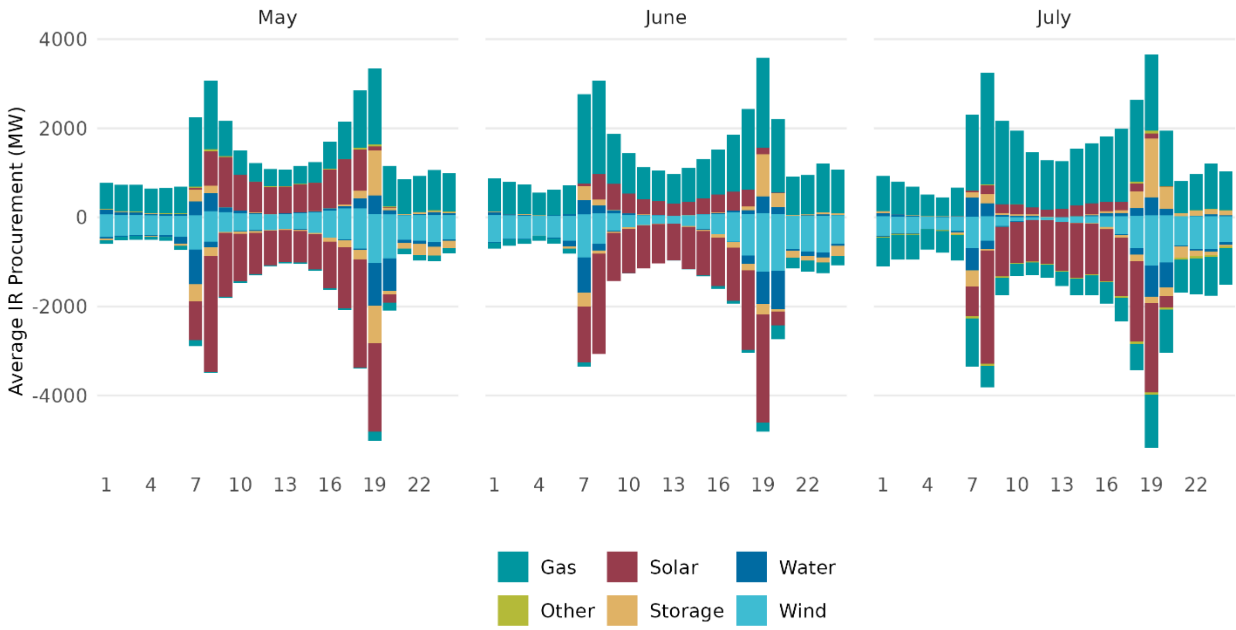


Figure 44 shows PACW's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO, the dominant resources in PACW are water and wind, while gas has minor contribution. Water resources provide nearly all the IRU supply, and wind resources contribute the most of IRD supply.

Figure 44: Hourly average cleared IR by fuel type for PACW

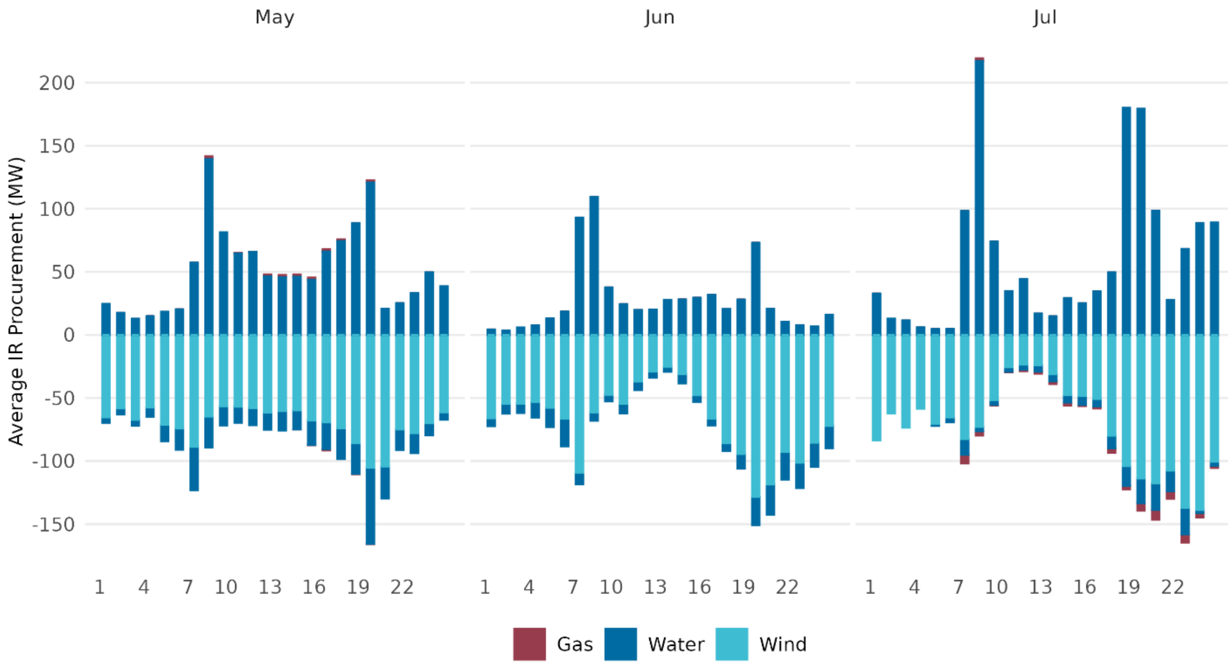
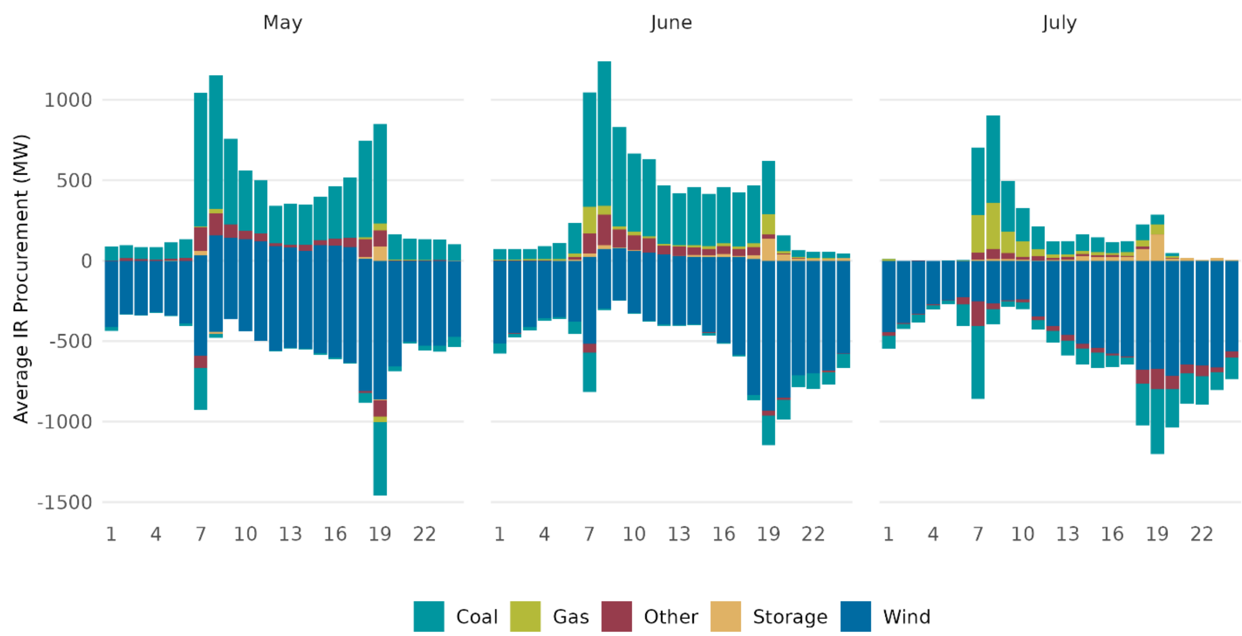


Figure 45 shows PACE's hourly average cleared IRU and IRD by fuel type, respectively. Unlike CAISO and PACW, the dominant resources in PACE are coal and wind, while gas and storage have minimal contribution. Coal resources provide the majority of the IRU supply, with wind resources contributing to the remaining during daylight hours. In IRD supply, wind resources contribute the most, with the morning and evening ramp requirements provided by coal resources.

Figure 45: Hourly average cleared IR by fuel type for PACE



The technology supporting the procurement of IRU/IRD is organized by the host balancing area. However, as DAM enables economic transfers, a portion of the procured IR is indeed supported by areas transferring IR. These transfers are explicitly tracked and analyzed in subsequent.

Imbalance reserves input bids

Imbalance reserves are co-optimized with energy and ancillary services in the IFM, therefore, resources need to submit economic energy bids for intervals in which imbalance reserve bids are submitted. The energy bid includes the portion that overlaps with the imbalance reserve bid. Imbalance reserve bids are subject to a cap of 55 $/MWh.

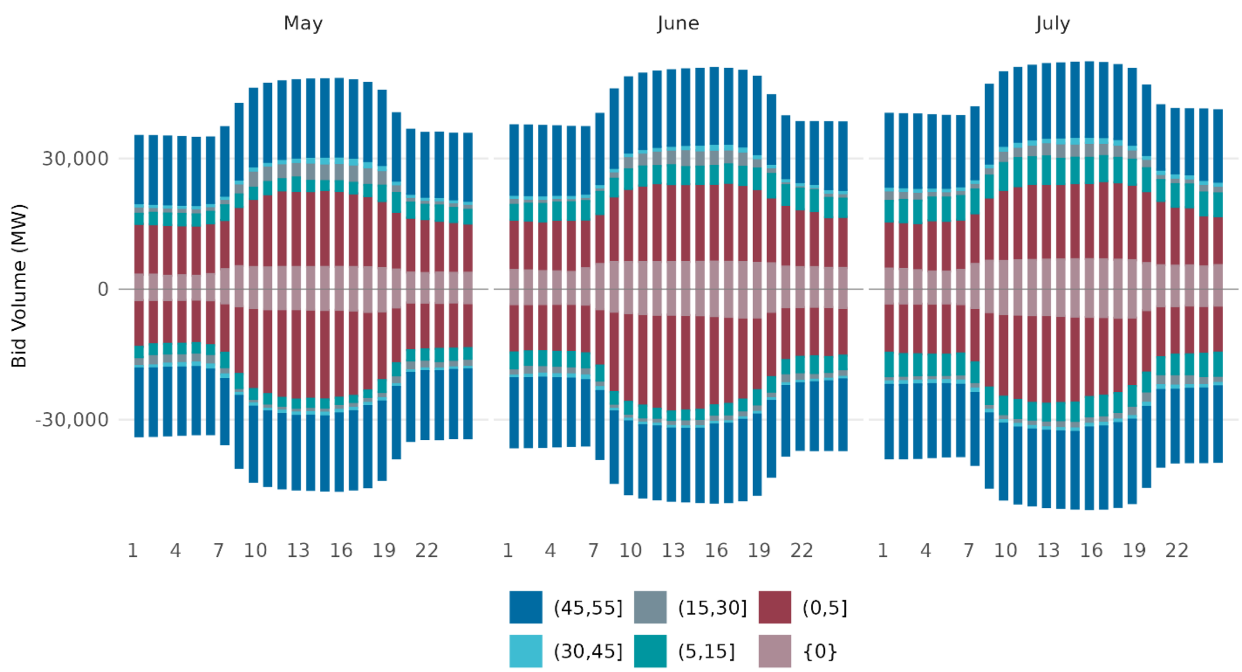
Figure 46 and Figure 47 illustrate CAISO's hourly and daily average IFM supply input bids for IR by bid price range, positive values represent up direction and negative represent down direction, respectively. Low-priced bids (0–5 $/MWh) and high-priced bids (45–55 $/MWh) consistently accounted for the largest share of submitted IR capacity throughout May and June with about 20,000 MW (80 percent. The remaining price ranges, including zero prices, and mid-priced ranges (5–30 $/MWh) represented a relatively small share of total submitted capacity. Hourly bid volumes were generally higher during daytime hours and lower during overnight hours.

Generally, CAISO's submitted IR capacity remained relatively stable, with only a few days exhibiting lower bid volumes. July shows the same bid pattern as May and June, with a very minimal increase in total bid volume. The overall bid-price composition showed limited variation across both hourly and daily views, indicating a stable supply offer pattern for

CAISO's IR throughout May to July. The volume of bids in the upward direction is very symmetrical to the volume for the downward direction.[3]

Figure 48 and Figure 49 illustrate CAISO's hourly and daily average IFM supply input bids for IR by fuel type. Energy storage, gas, and solar resources accounted for the largest share of submitted IR capacity throughout May and July, followed by water, wind and hybrid resources.

Figure 46: Hourly average volume of IR bids organized by price for CAISO



[3] This is a measure of the bid volume in the market that can be utilized to procure IR; however, much of that capacity can also be made available to meet energy needs. In the end, the market clearing process determines how to optimally allocate the supply available among the different market commodities.

Figure 47: Daily average volume of IR bids organized by price for CAISO

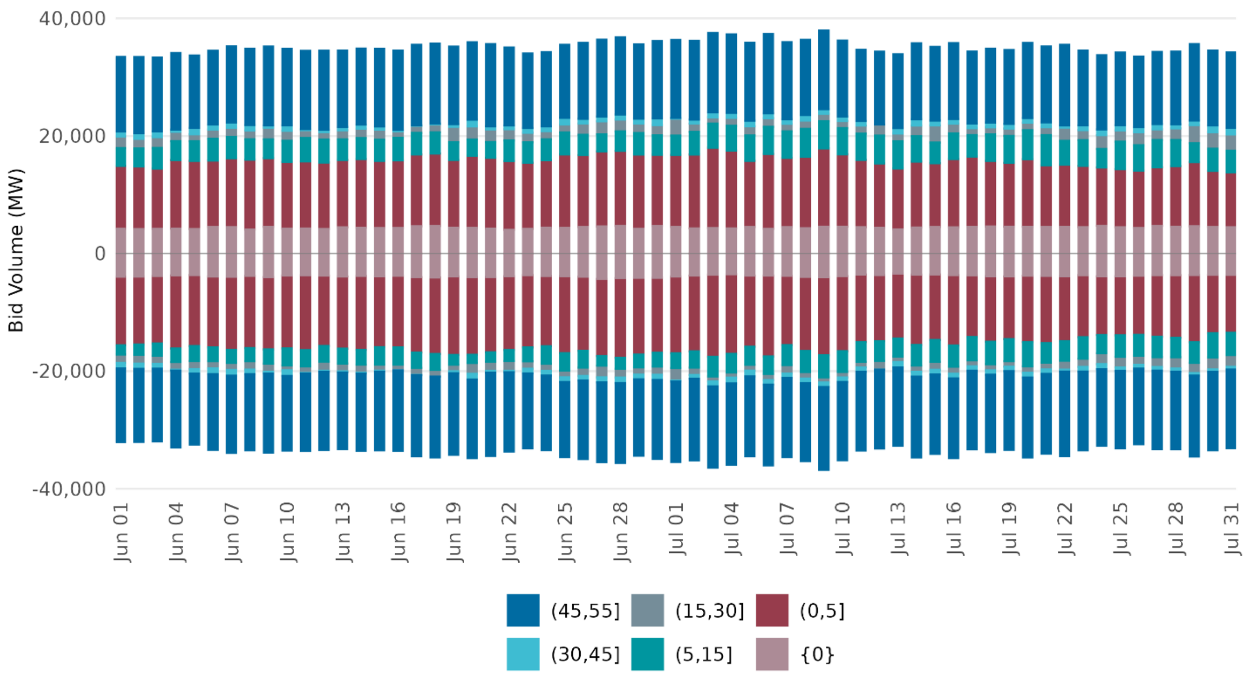


Figure 48: Hourly average volume of IR bids organized by fuel type for CAISO

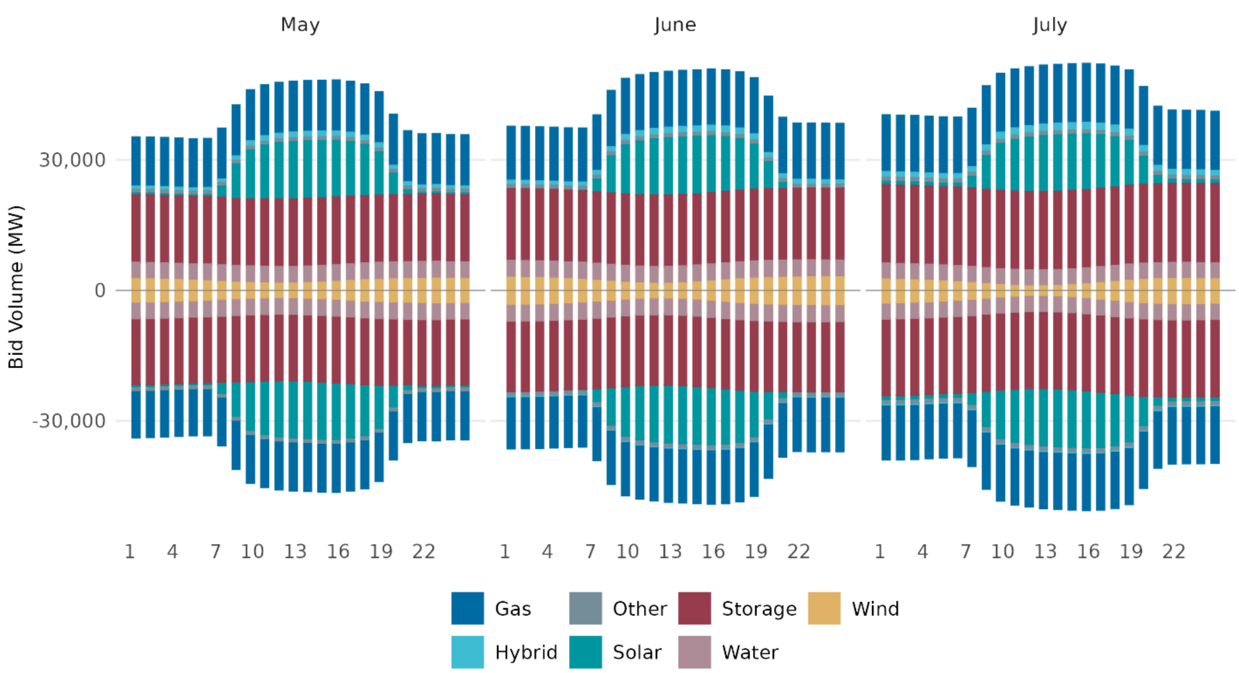


Figure 49: Daily average volume of IR bids organized by fuel type for CAISO

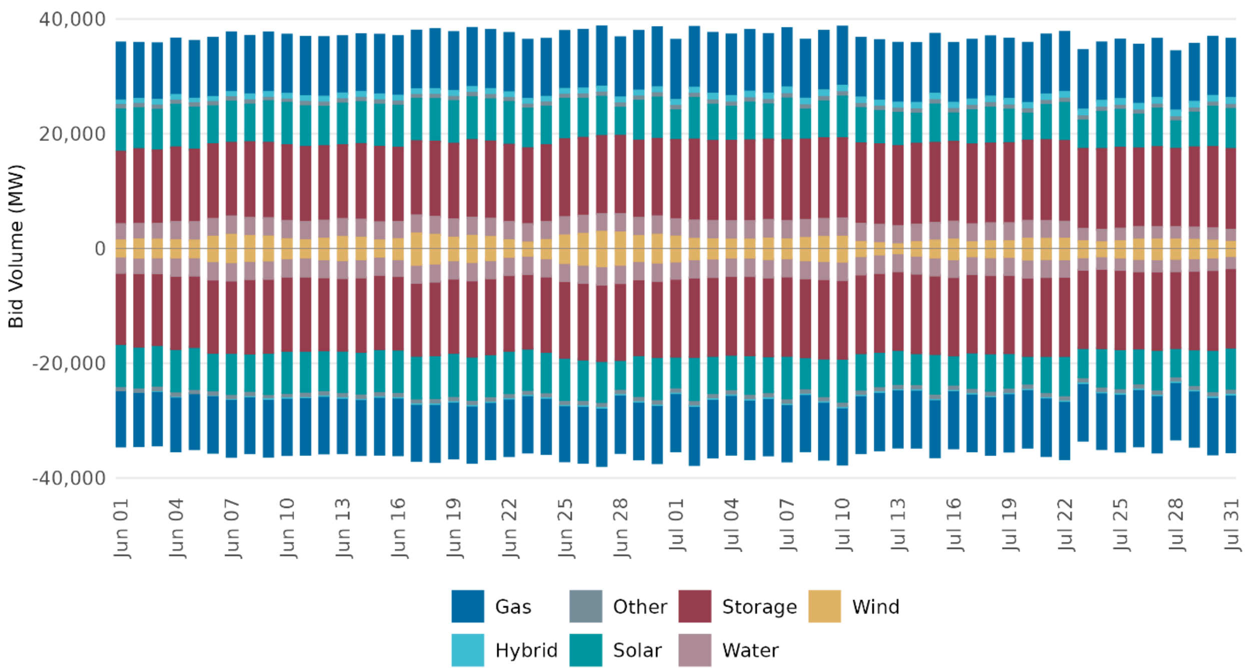


Figure 50 to Figure 53 illustrate the PACE's hourly and daily average IFM supply input bids for IR by bid price range. Low-priced bids ($0–5/MW) consistently accounted for the largest share of submitted IR capacity throughout the month with about 3,000 MW (or 90 percent), followed by bids in the 45–55 $/MWh range. The remaining price ranges represented a relatively small share of total submitted capacity. Hourly bid volumes were generally higher during daytime hours and lower during overnight hours. Generally, PACE's submitted IR capacity remained relatively stable during May and June, with a higher volume in July. The overall bid-price composition showed limited variation across both hourly and daily views, indicating a stable supply offer pattern for PACE's IR during the months. Figure 51 to Figure 53 illustrate PACE's hourly and daily average IFM supply input bids for IR by fuel type. Wind and coal accounted for the largest share of PACE's submitted IR capacity throughout May and July, followed by gas and storage resources.

Figure 50: Hourly average volume of IR bids by price for PACE

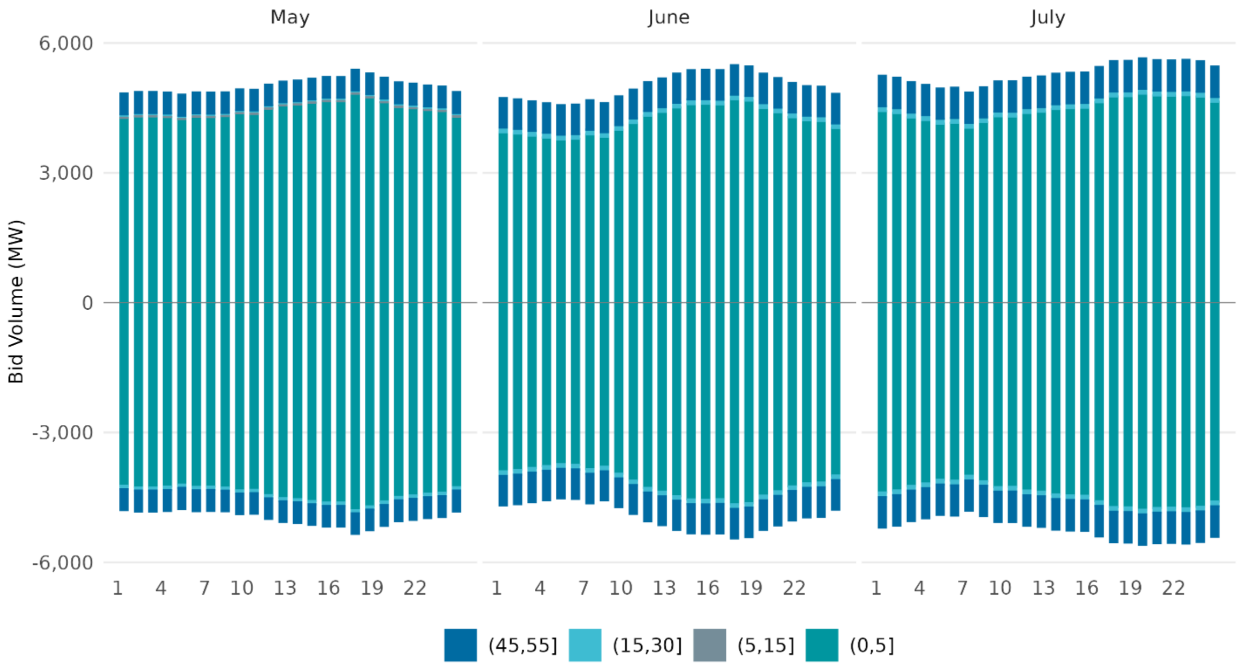


Figure 51: Hourly average volume of IR bids by fuel type for PACE

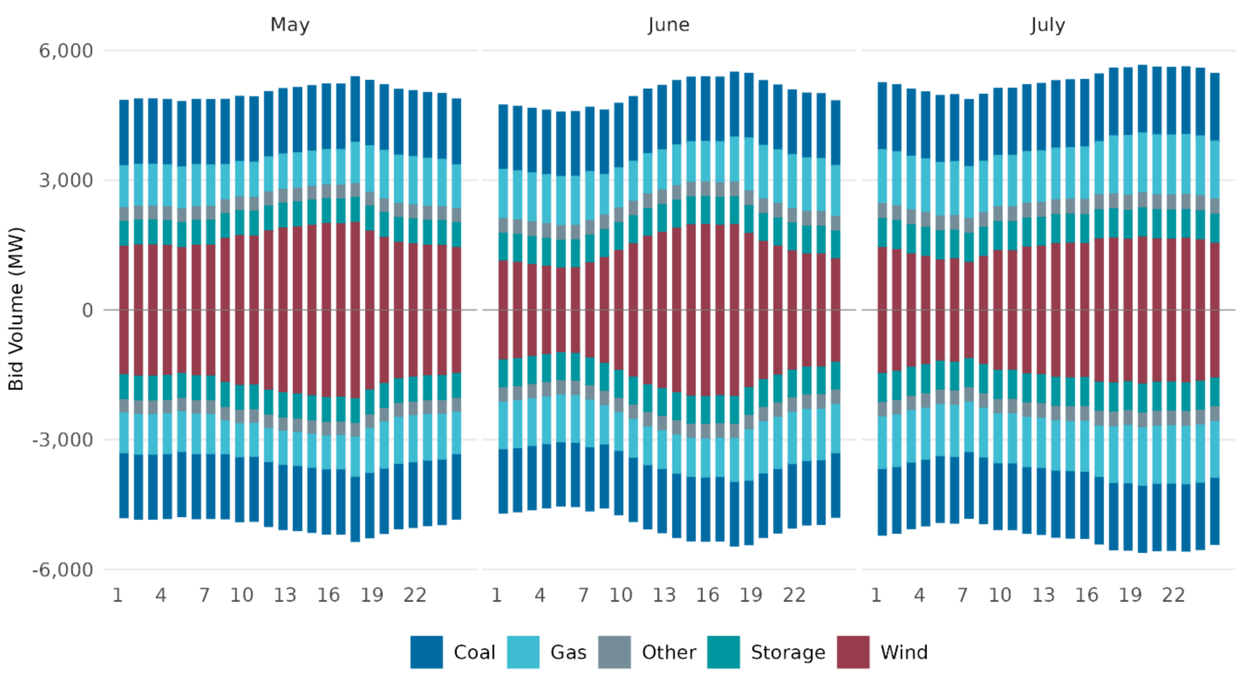


Figure 52: Daily average volume of IR bids by price for PACE

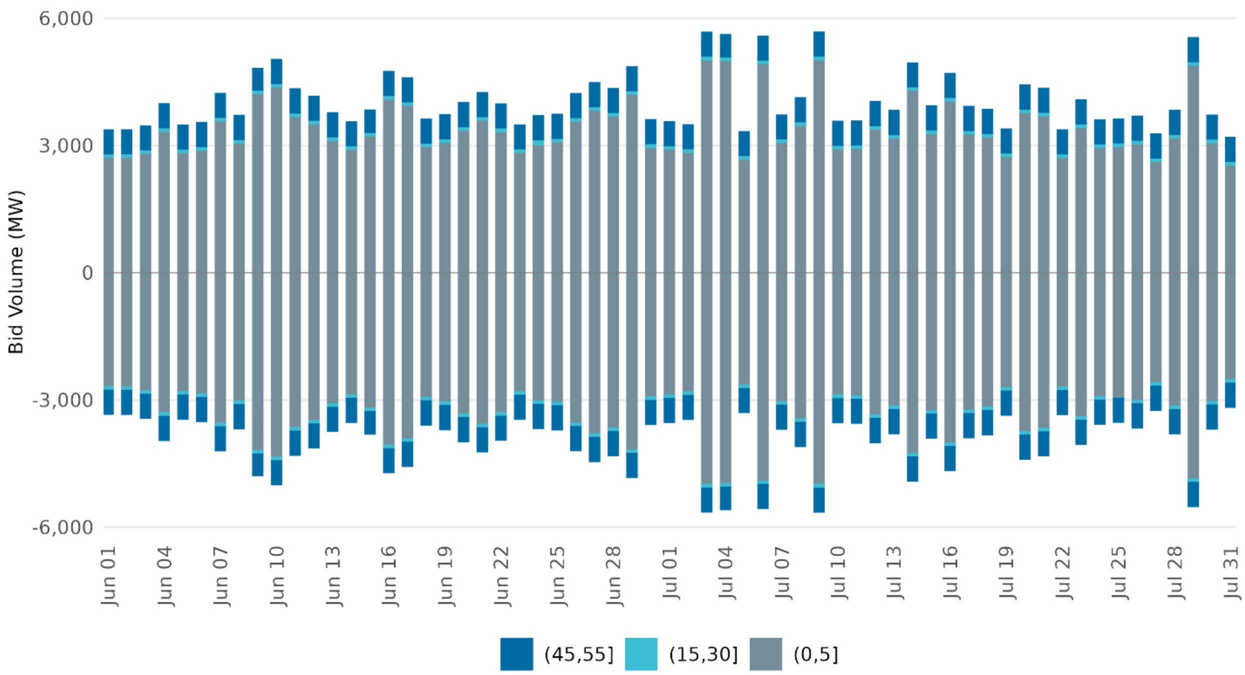


Figure 53: Daily average volume of IR bids by fuel type for PACE

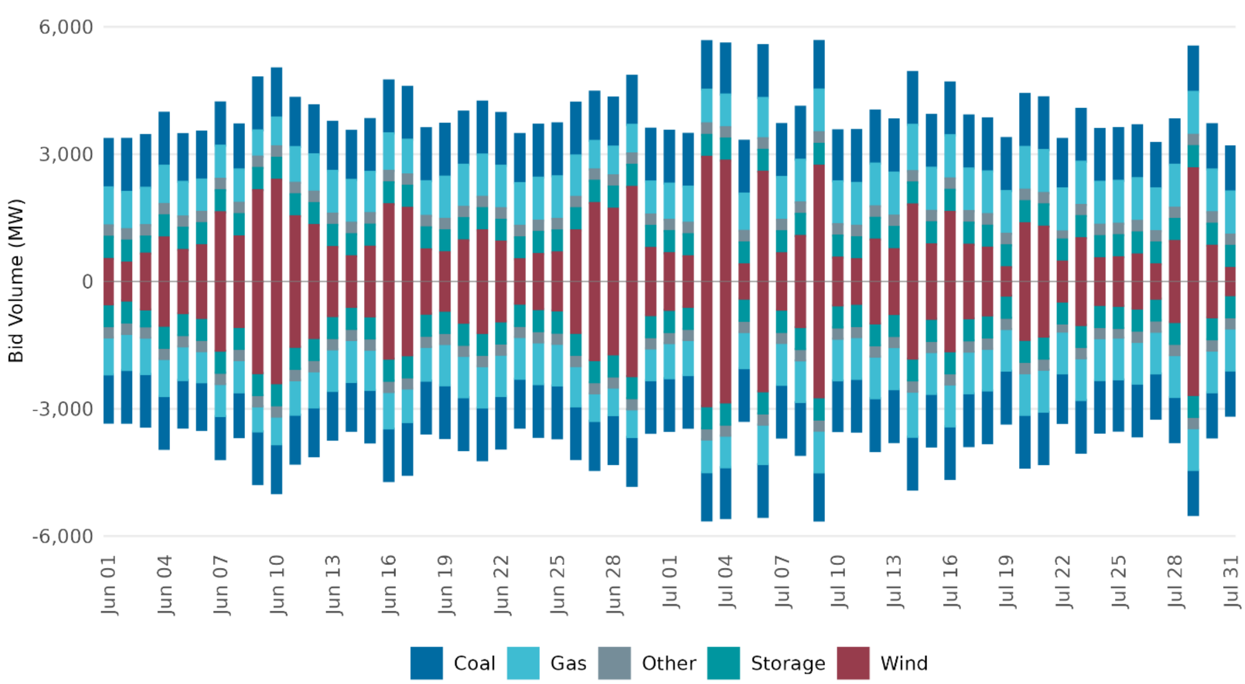


Figure 54 to Figure 57 illustrate the PACW's hourly and daily average IFM supply input bids for IR by bid price range and by fuel type. The price ranges are distributed across price ranges (0–5 $/MWh) and (5–15 $/MWh), and (45–55 $/MWh) with about 900 MW, and the remaining price range (15–30 $/MWh) represented a relatively small share of total submitted capacity. Water, gas, and wind accounted for the PACW's submitted IR capacity throughout May to July. The total bid volumes in May and June are almost the same, while an obvious increase volume is observed in July. PACW's submitted IR capacity exhibited a more variable pattern in both price ranges and volumes, as the overall bid-price composition showed variation across both the daily views. The IR bid volumes increased as EDAM launches, and prices slightly decreased as more bids fall in (0–5 $/MWh) bucket at the end of July.

Figure 54: Hourly average volume of IR bids organized by price for PACW

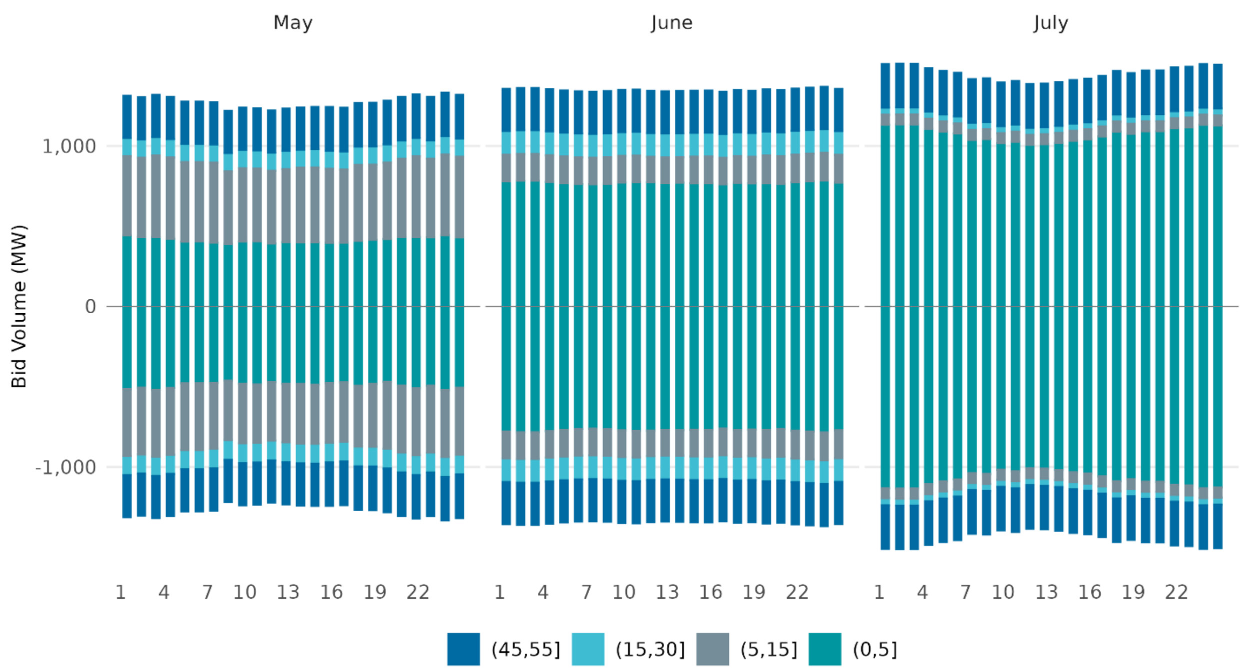


Figure 55: Hourly average volume of IR bids organized by fuel type for PACW

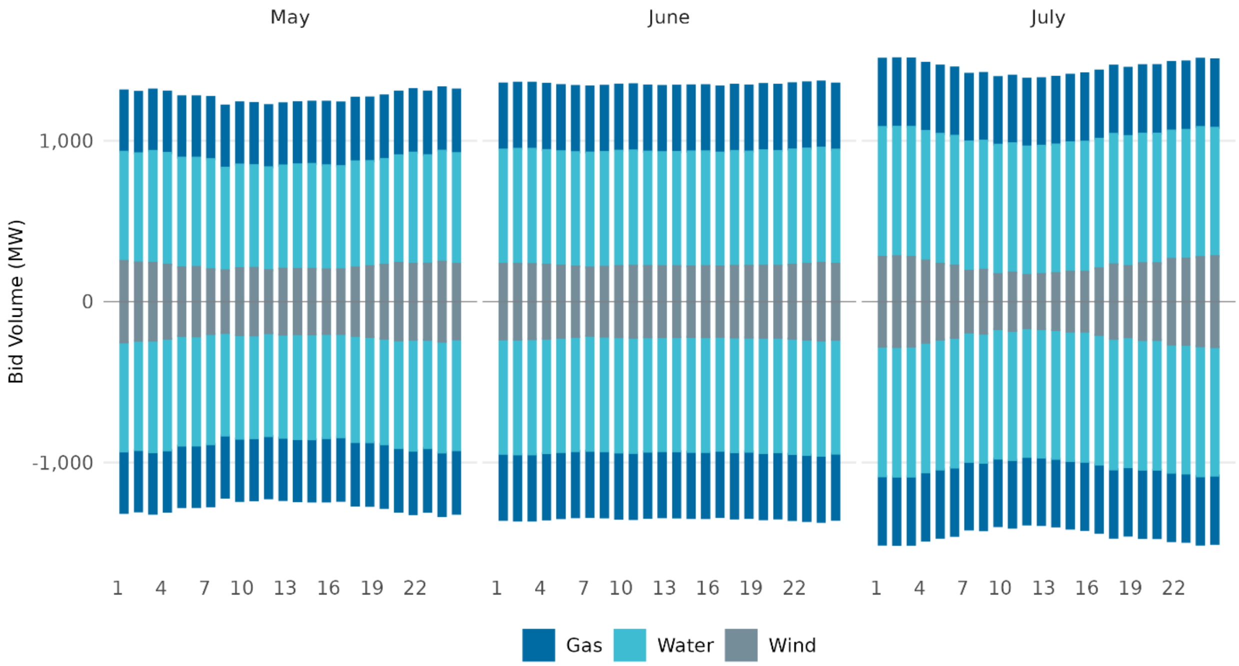


Figure 56: Daily average volume of IR bids organized by price by PACW

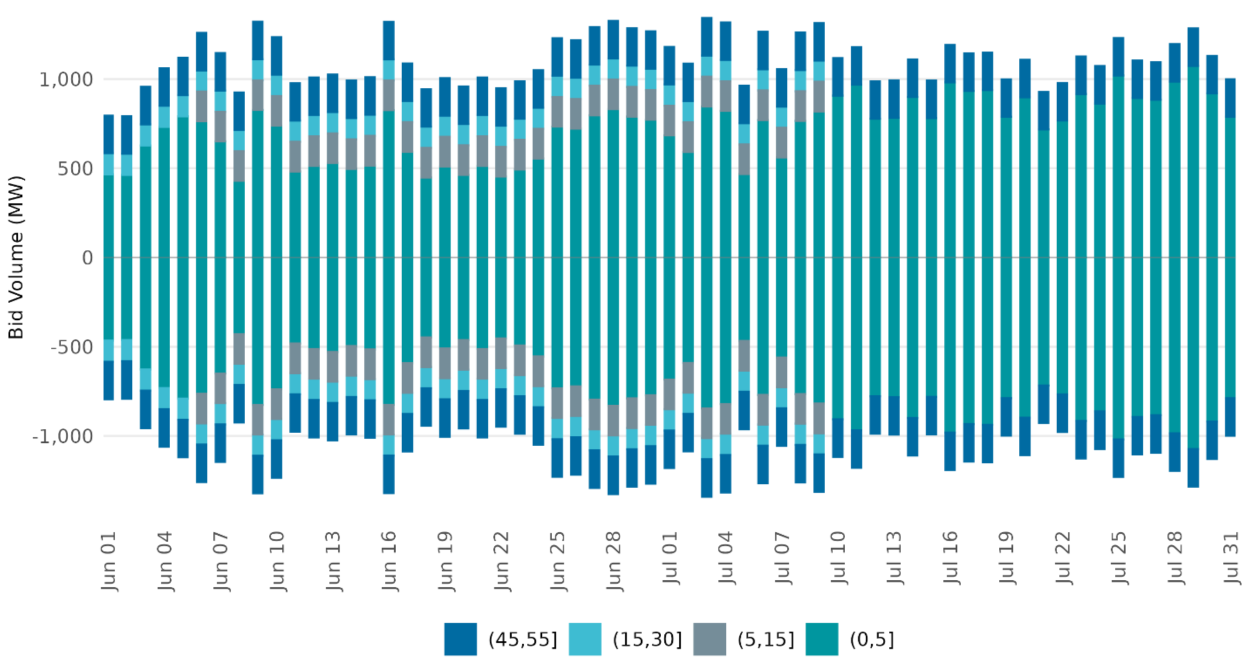
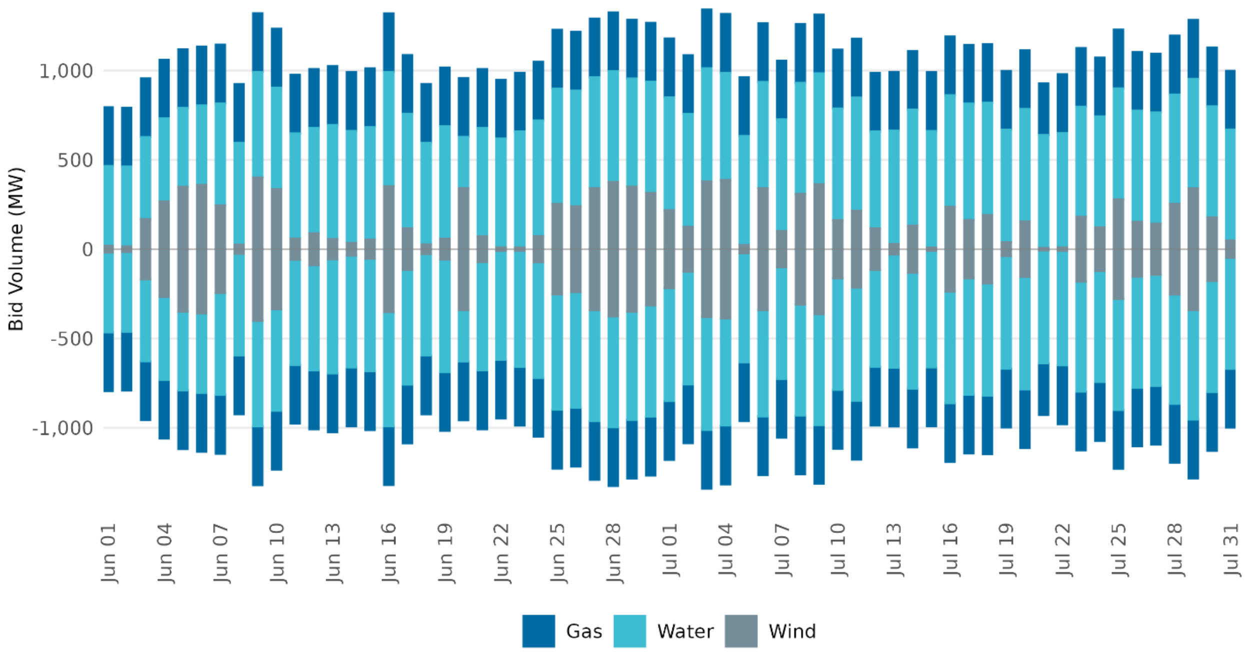


Figure 57: Daily average volume of IR bids organized by fuel type for PACW



When supply is tight, energy prices may rise to a level where IR is not procured. By design, the IR requirements may be relaxed at a cost. The IR demand curve represents the willingness to relax the IR requirement at certain price levels, capped to 55 $/MWh, reflecting the tradeoff between meeting uncertainty needs and avoiding excessive system costs. In July 2026, CAISO and PACW did not relax the IR requirements. PACE had demand curve procurement in the upward direction for 12 hours over three days. Hourly averages of demand curve procurements are shown in Figure 58 and Figure 59. Finally, some IR requirements for a BAA can be met with IR transfers from other BAAs or a BAA can also export IR transfers to other BAAs. These IR transfers are not shown explicitly in the previous metrics, and they are explicitly tracked in a subsequent section on transfers.

Figure 58: Average imbalance reserve demand curve procurement, IRU

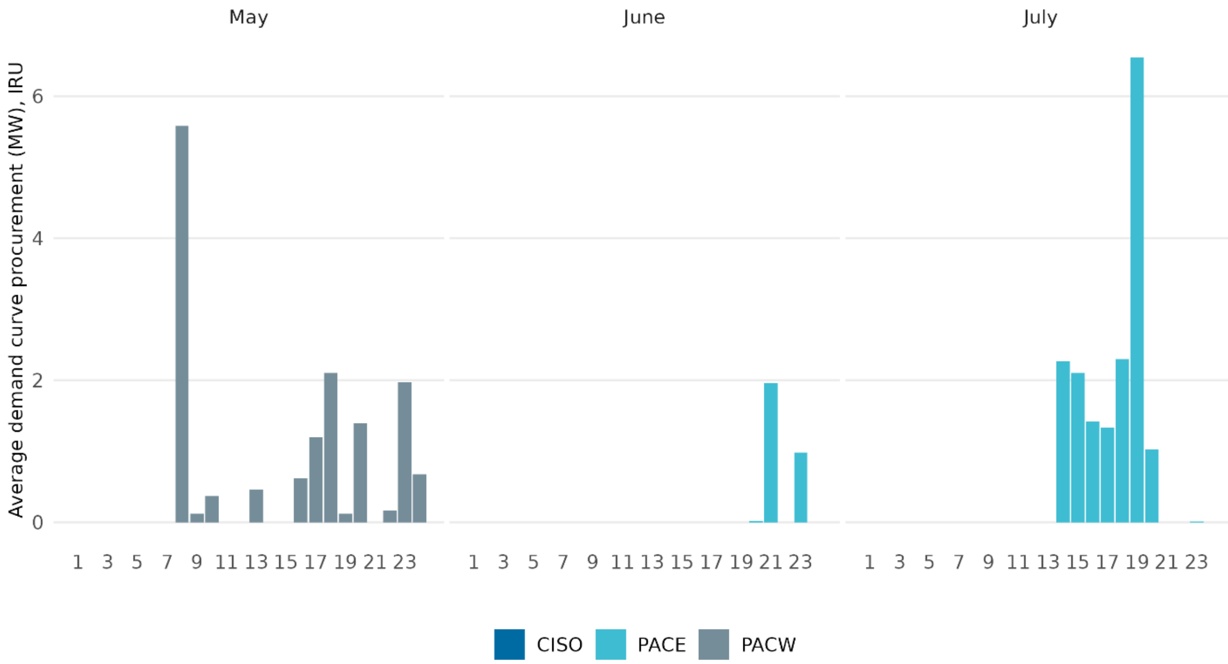


Figure 59: Average imbalance reserve demand curve procurement, IRD

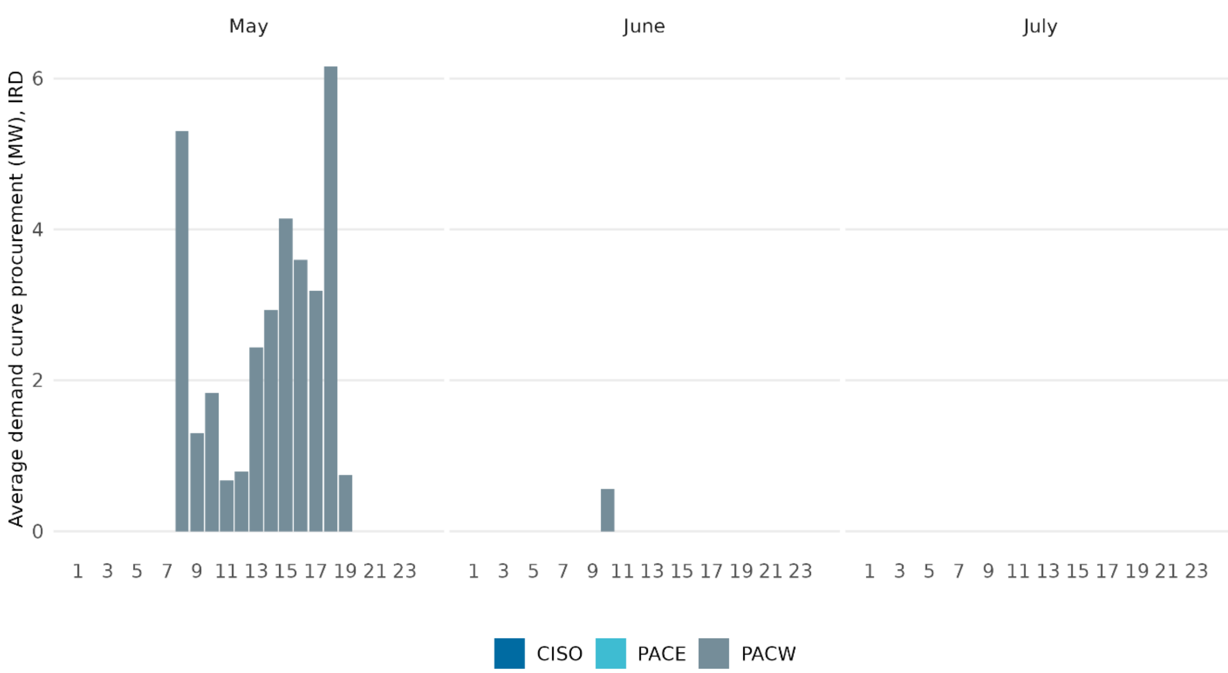


Figure 60 and Figure 62 show the hourly average net demand by EDAM BAA in May through July. Net demand is derived from demand forecast, net solar and wind forecast. The figures overlay hourly average IR procurement and requirement, for both up and down directions, and hourly average FMM net load uncertainty, on the net demand profile by BAA. Procurement reflects internal capacity procurement net BAA imbalance reserve transfer. Overlaying the IR requirements on the net demand profile visually shows how the imbalance reserves create an envelope of flexible capacity around the net demand. Overlaying the FMM net load certainty shows how the average uncertainty falls within the envelope of flexible capacity created by the imbalance reserve products.

Figure 60: Average net demand with imbalance reserve procurement, CISO

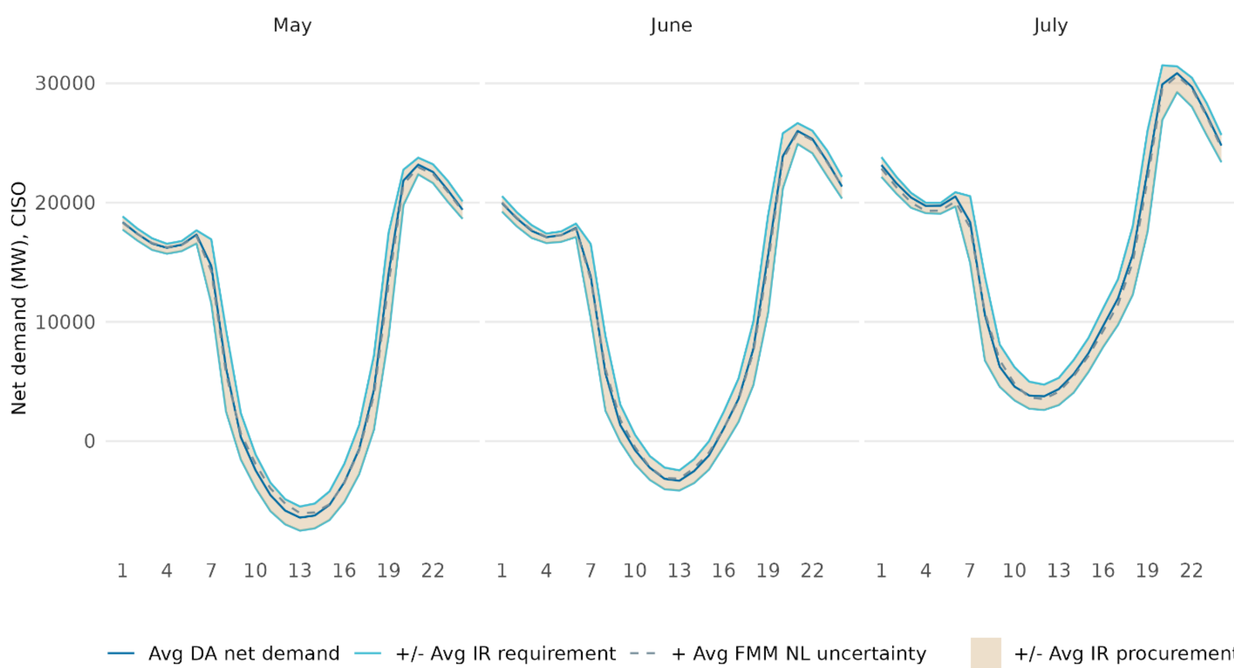


Figure 61: Average net demand with imbalance reserve procurement, PACE

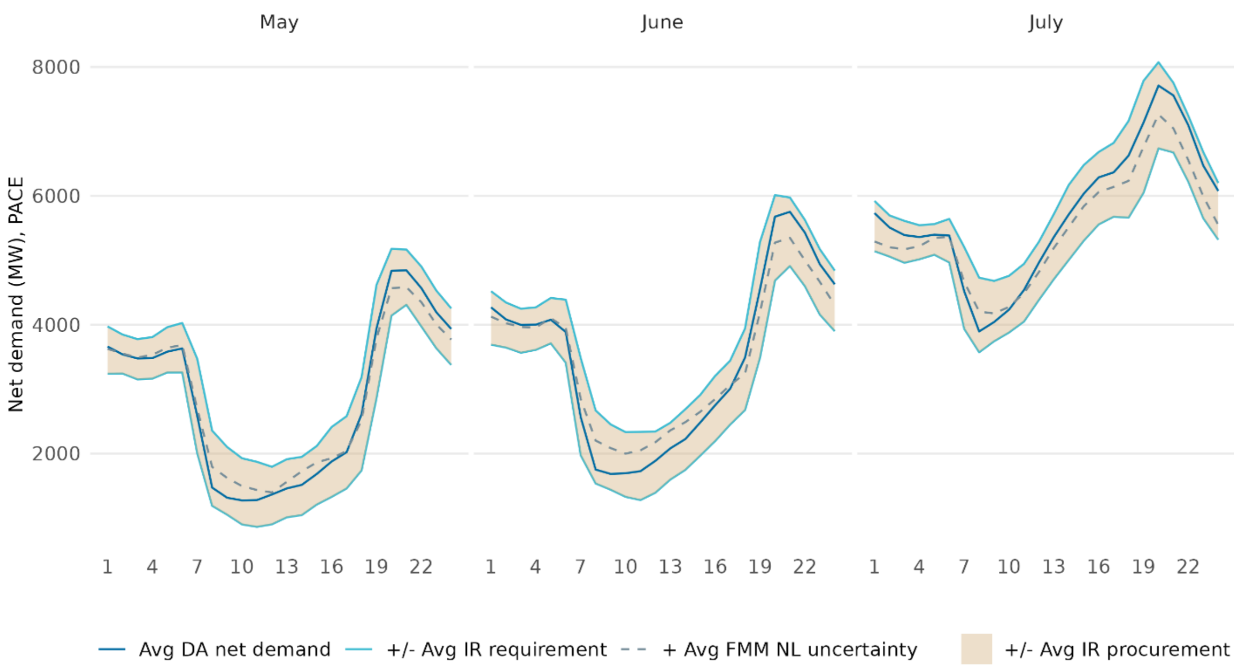


Figure 62: Average net demand with imbalance reserve procurement, PACW

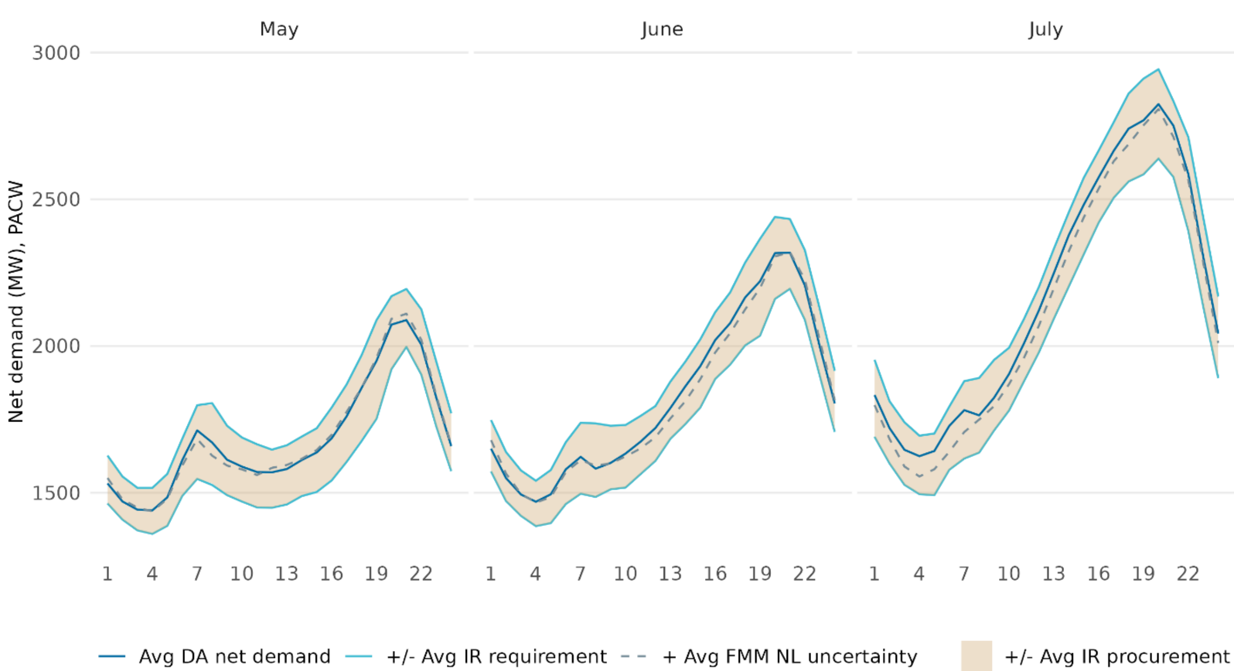


Figure 63 to Figure 65 illustrate for each EDAM BAA, average available capacity in the fifteen-minute market corresponding to day-ahead imbalance reserve awards in stacked bar, breaking down by average utilized and unutilized capacity in both upward and downward directions. Average day-ahead imbalance reserve requirements and procurements from internal resources are included as reference. Internal procurement reflects the aggregated imbalance reserve awards within each BAA, to satisfy its own requirements and imbalance reserve transfer schedules. Hourly average upward and downward net load uncertainties are also included. Net load uncertainty is derived from the net load changes from day-ahead to fifteen-minute market. Real-time availability generally aligns with day-ahead procurement for all EDAM BAAs. Utilized capacity is relatively small compared to available capacity and realized net load uncertainty, indicating that other resources in the system provided the capacity to meet the remaining uncertainty.

Figure 63: Hourly average IR requirement, procurement, and utilization, CISO

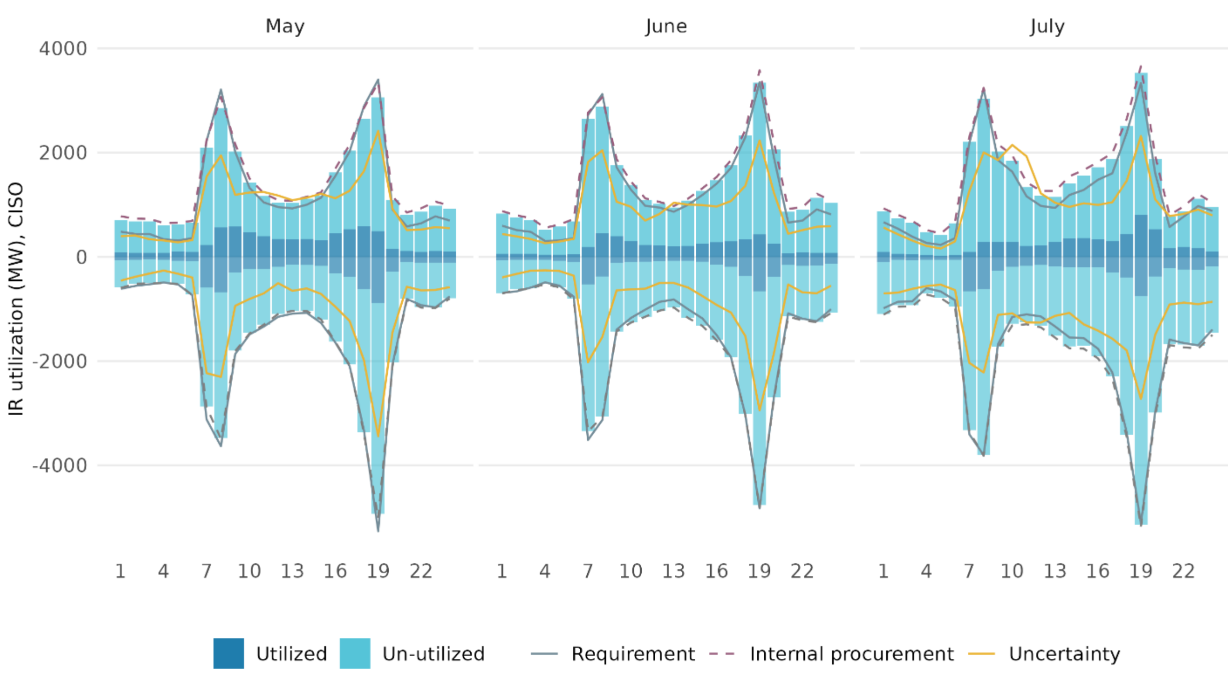


Figure 64: Hourly average IR requirement, procurement, and utilization, PACE

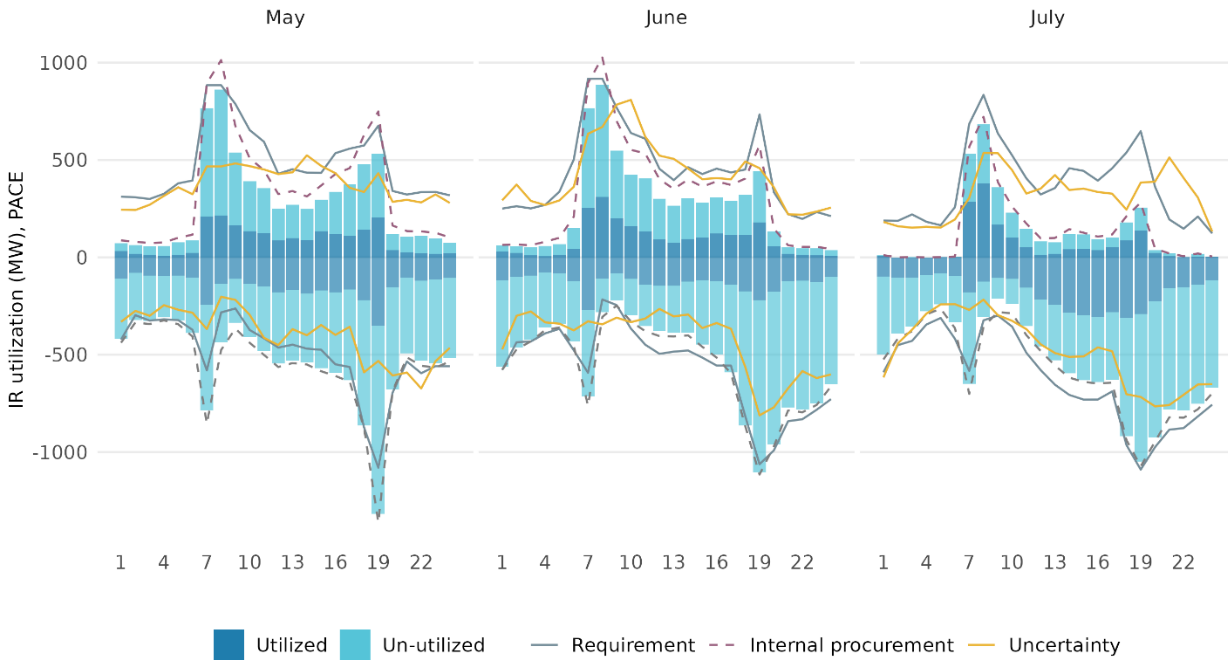


Figure 65: Hourly average IR requirement, procurement, and utilization, PACW

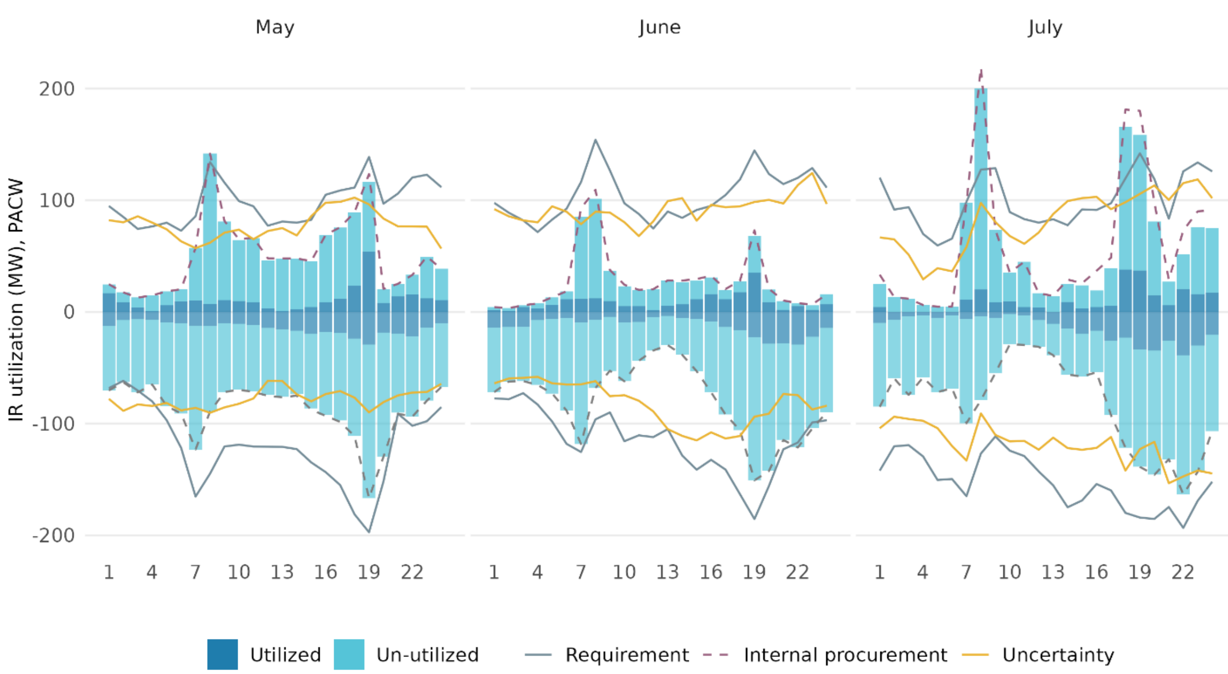


Figure 66 through Figure 68 present the average utilized IR capacity for each EDAM BAA, with the EDAM to real-time delta transfer stacked on top, in both upward and downward directions. Delta transfer represents the additional transfers scheduled in real time beyond the day-ahead market volume, positive for additional imports and negative for additional exports. The WEIM footprint in real time is considerably larger than the current EDAM footprint, providing EDAM BAAs access to additional transfer capacity in both directions. On average, much of the net load uncertainty not covered by IR utilization was met through delta transfer from day ahead to real time.

Figure 66: Average utilized IR capacity for CAISO

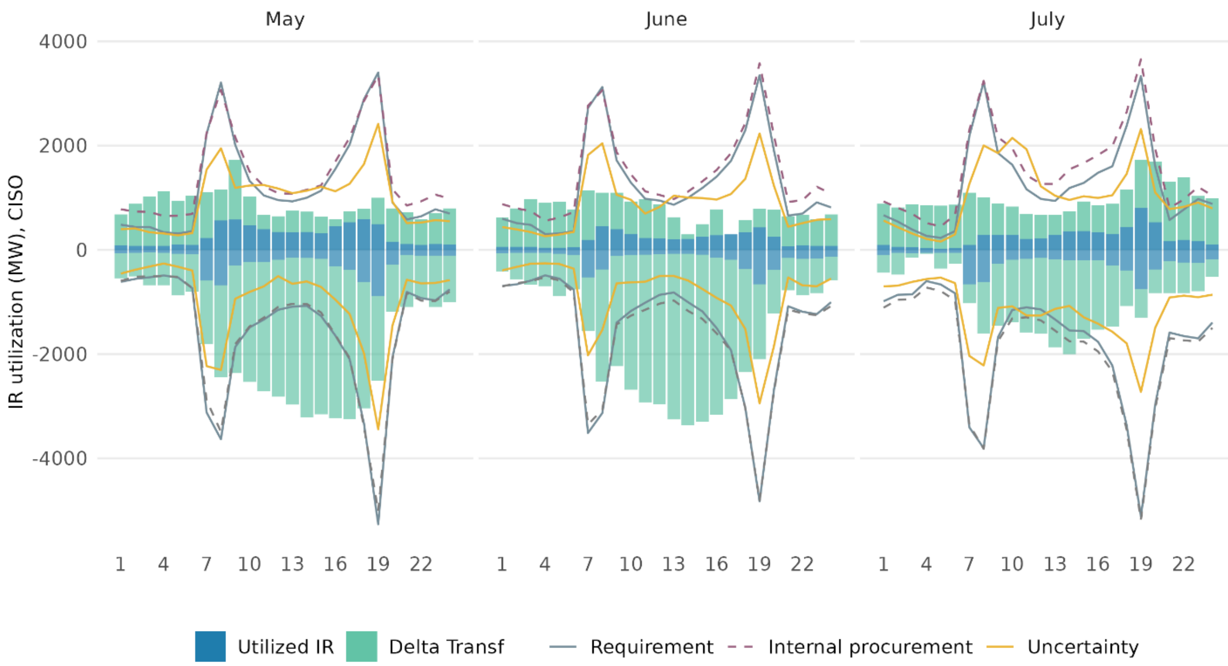


Figure 67: Average utilized IR capacity for PACE

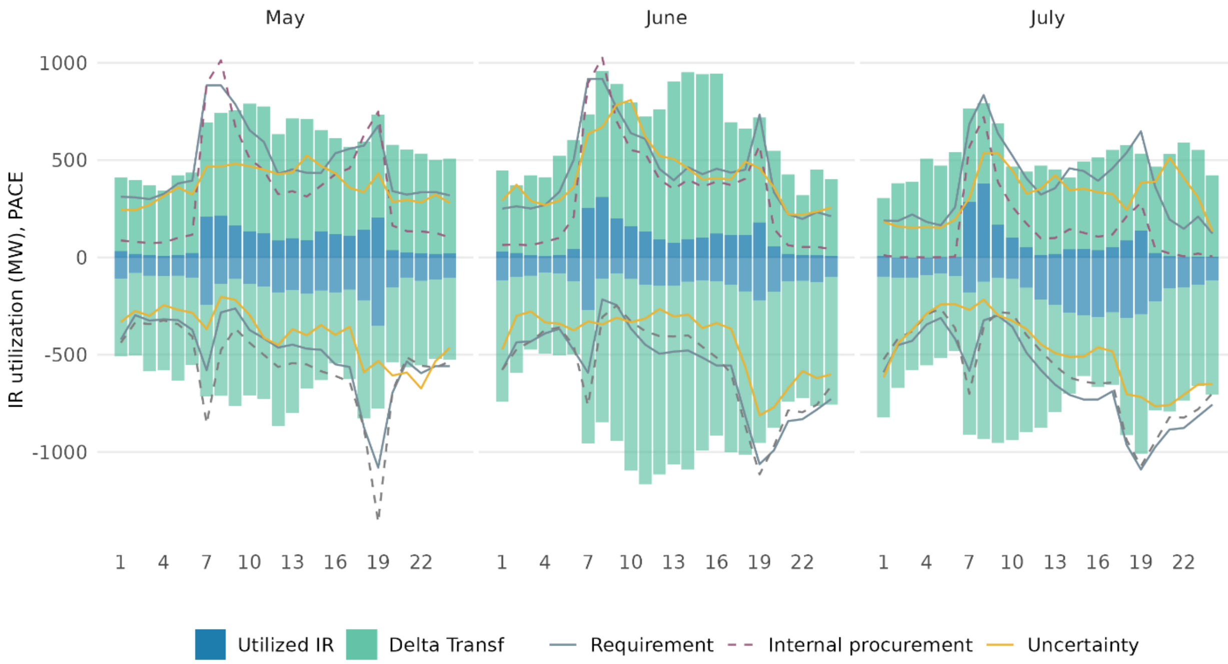
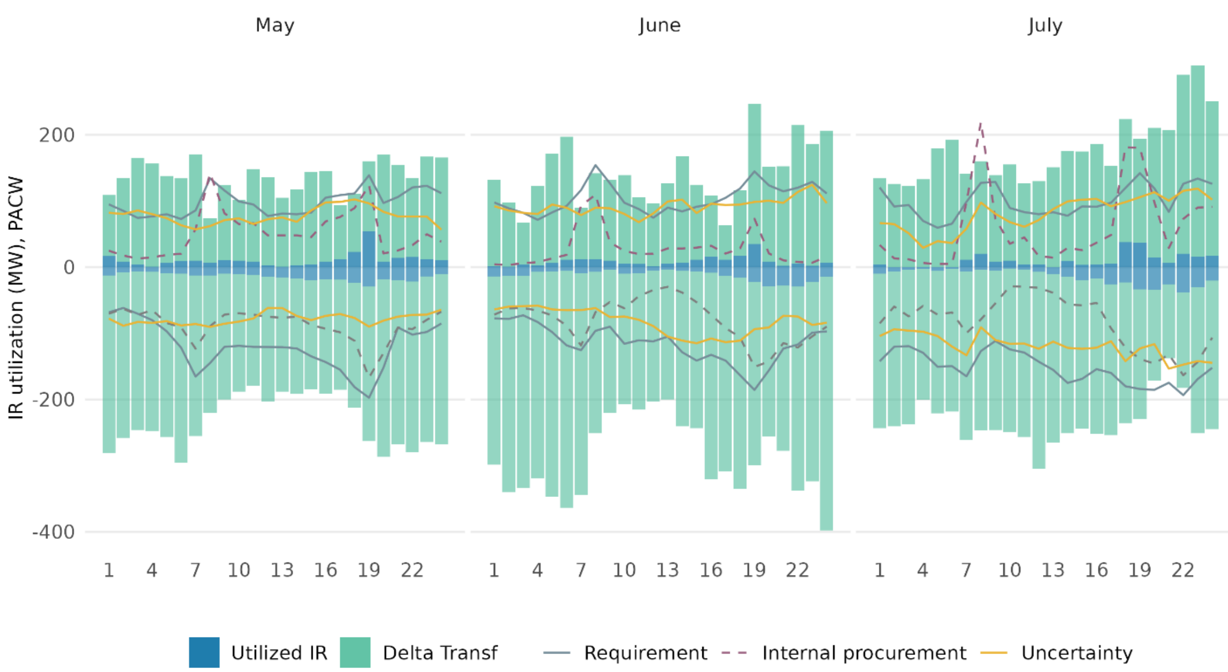


Figure 68: Average utilized IR capacity for PACW



EDAM resources receiving imbalance reserve awards in the day-ahead market will have bidding obligations in the real time market. Figure 69 and
Figure 70 show real time available capacity corresponding to IR awards in the EDAM footprint, expressed as a percentage of imbalance reserve procurement. In the upward direction, over 80 percent of the IR capacity has been made available in the real time market in all hours. In the downward direction, the availability exceeds 90 percent majority of the time.

Figure 69: Percentage IRU availability in FMM for EDAM footprint

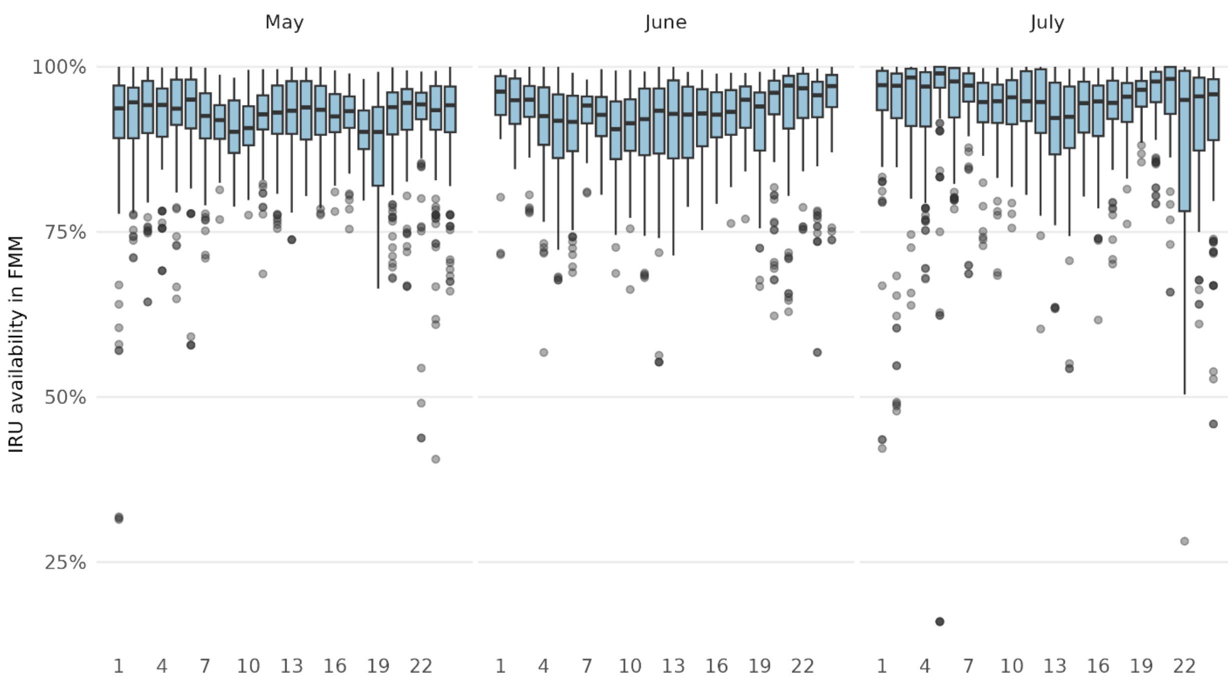


Figure 70: Percentage IRD availability in FMM for EDAM footprint

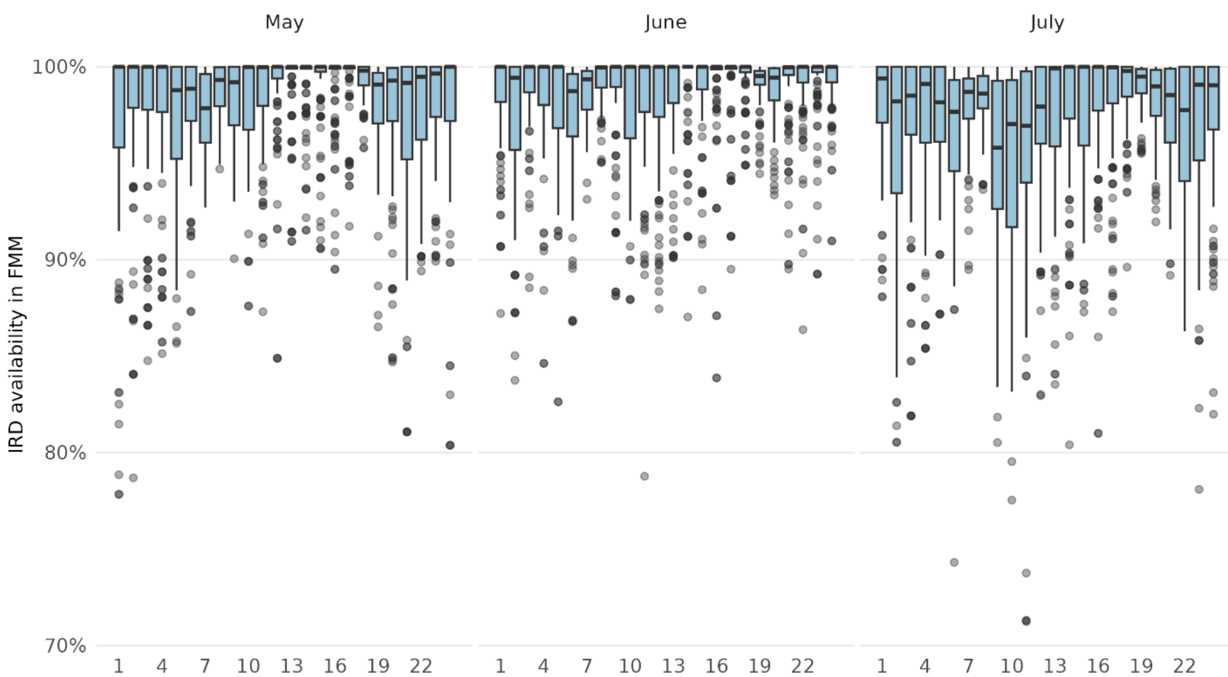


Figure 71 and Figure 72 show the hourly distributions of the utilized imbalance reserve up and down volumes, in the EDAM footprint in FMM. The utilization trends follow the shape of the imbalance reserve requirements, higher in the morning and evening peak hours for both up and down directions.

Figure 71: Hourly IR up utilization distribution in EDAM footprint

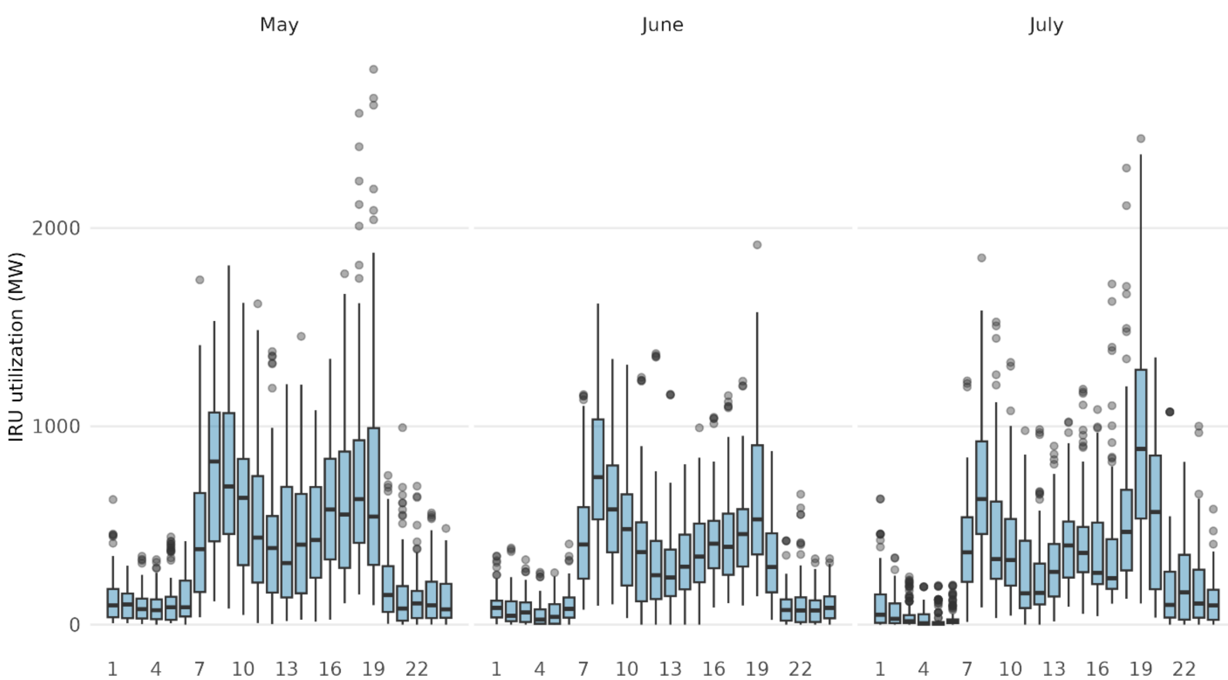
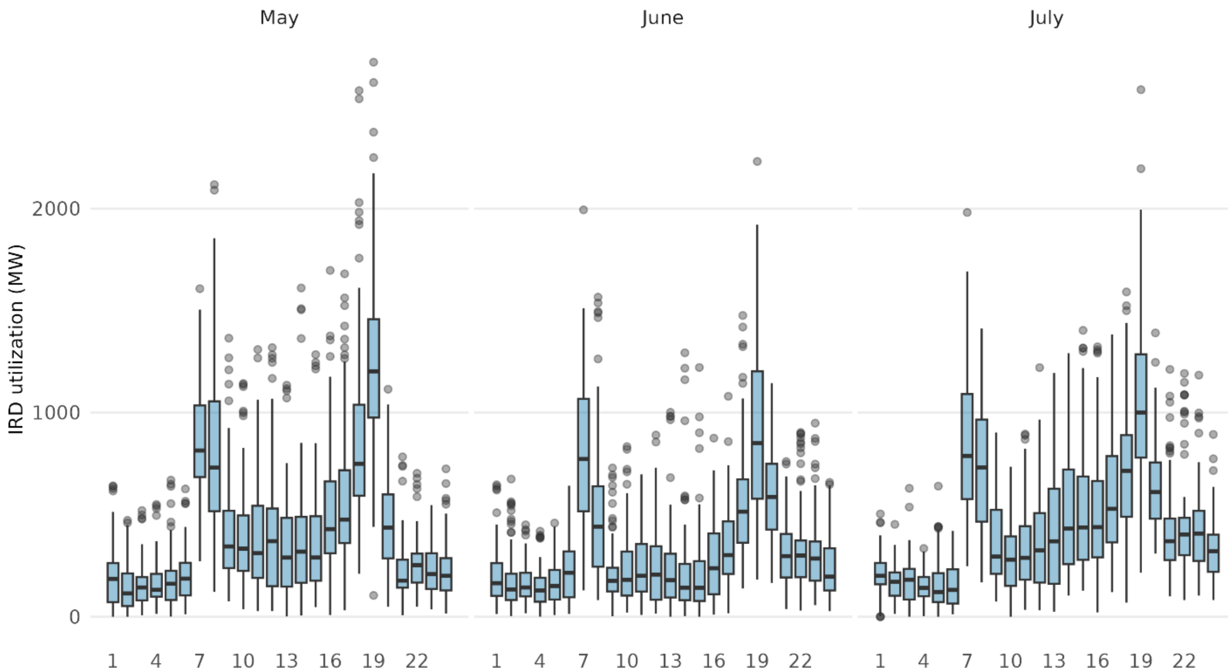


Figure 72: Hourly IR down utilization distribution in EDAM footprint



The congestion component of IRU/IRD marginal prices is impacted only by the IRU and IRD deployment scenarios and its trend is an estimate of how much congestion is impacting IRU/IRD marginal pricing. Figure 73 and Figure 74 show the nodal congestion components of the imbalance reserve marginal prices in upward and downward directions. For both the months of June and July, the imbalance reserve congestion is minimal and centered around $0/MWh. The MCC breakdown for monthly average IR congestion is provided in Table 9.

Figure 73: Nodal IRU congestion component of the IRU marginal price

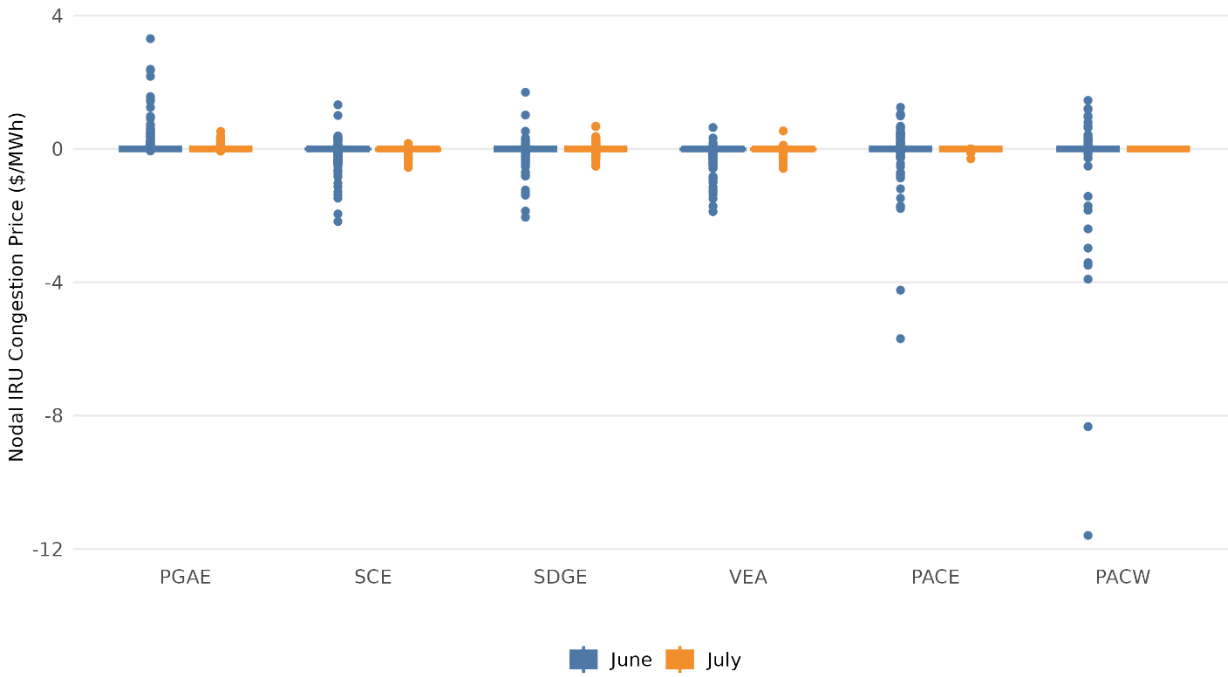
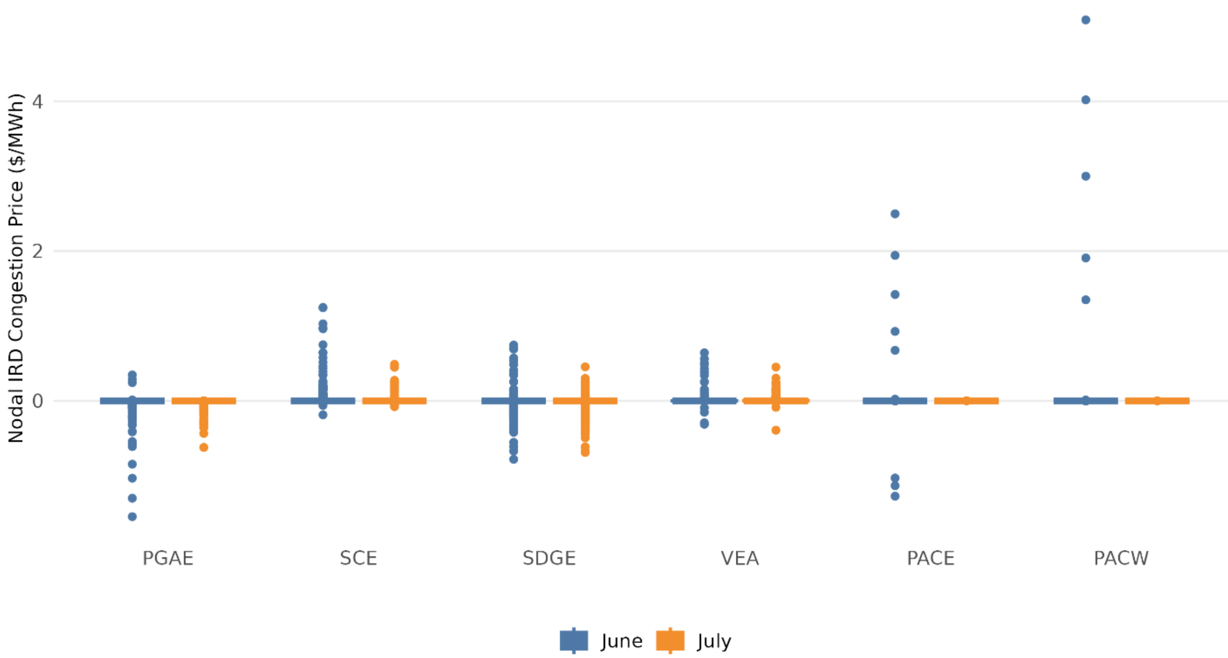


Figure 74: Nodal IRD congestion component of the IRD marginal price



Reliability capacity

Reliability Capacity (RC) is the other new bi-directional day-ahead product introduced with the EDAM market. The reliability capacity product ensures there is enough capacity procured in the RUC process to meet the demand forecast. Like imbalance reserves, reliability capacity is procured in both upward and downward directions. The market procures reliability capacity to meet positive or negative differences between cleared physical supply in IFM and the load forecast. It is like the existing RUC capacity product, except RUC capacity is only procured when the forecast exceeds cleared physical supply. Reliability capacity up (RCU) covers supply shortfalls and reliability capacity down (RCD) accounts for over-supply.

Overall, prices for RC increased in July compared to June and were positive as shown in Figure 75, indicating that RCU needs were higher. CAISO RC prices were most volatile in July compared to PACE and PACW. However, CAISO RC prices in July were less volatile than in previous months. PACE and PACW RC prices were slightly more volatile in July than in June. Daily average RC prices were highest on July 24 for CAISO (31.61 $/MWh) and PACW (10.28 $/MWh), and on July 14 for PACE (10.45 $/MWh). For CAISO, this was the highest daily mean RC price since May 1st. The lowest daily mean RC price for CAISO was 0 $/MWh (several days), for PACE was -2.76 $/MWh on July 4 and for PACW was -12.39 $/MWh on July 20. On an hourly basis, average prices were highest in the evening peak for all three BAAs, coinciding with the hours of highest demand. The reliability capacity price separation observed between the three BAAs reflects the economics of the wider EDAM market footprint available supply mix and EDAM transfers.

A feature of the reliability capacity prices is that RCU and RCD prices are equal and opposite. This price symmetry is by design and a natural consequence of RUC optimization. The RUC process procures both reliability capacity up and down to address supply shortfalls or over-supply in different parts of the system. At the system level, however, there is either a net supply shortfall or over-supply. In a net supply shortfall for instance, the system needs RCU to balance the RUC optimization constraint, and the RCU price is set by the marginal resource. If conditions materialize such that one additional megawatt of RCU is needed, the value to the system of that incremental RCU is set by the price of the marginal resource. Conversely, if another resource moved downward in the opposite direction providing one additional megawatt of RCD, there is a cost to the system in the amount of the lost value of the additional RCU megawatt. Therefore, the RCD price must be equal to the opposite of the RCU price.

Figure 75: Monthly average price of RCU and RCD

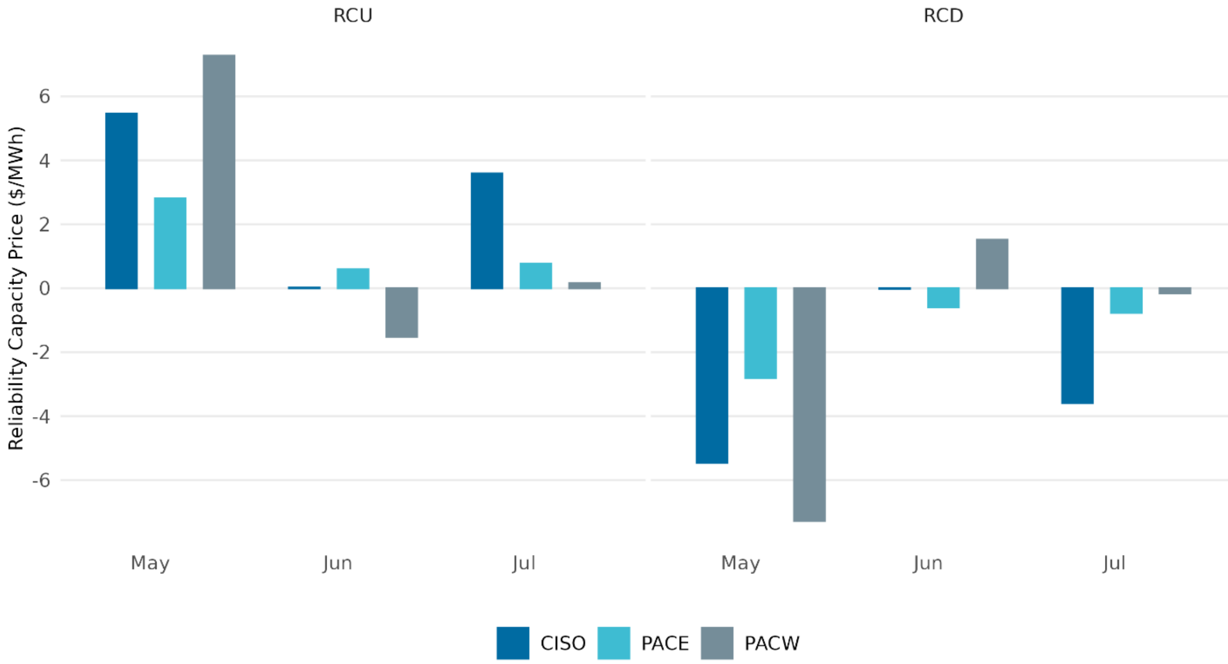


Figure 76: Daily average price of RCU

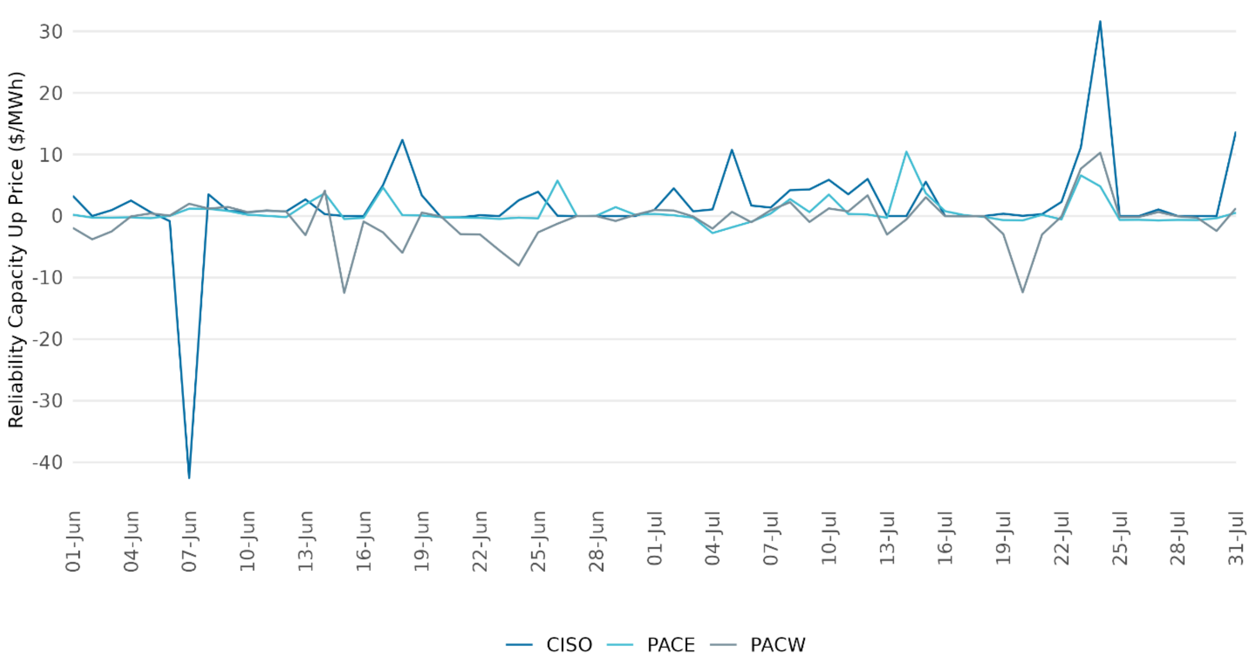


Figure 77: Daily average price of RCD

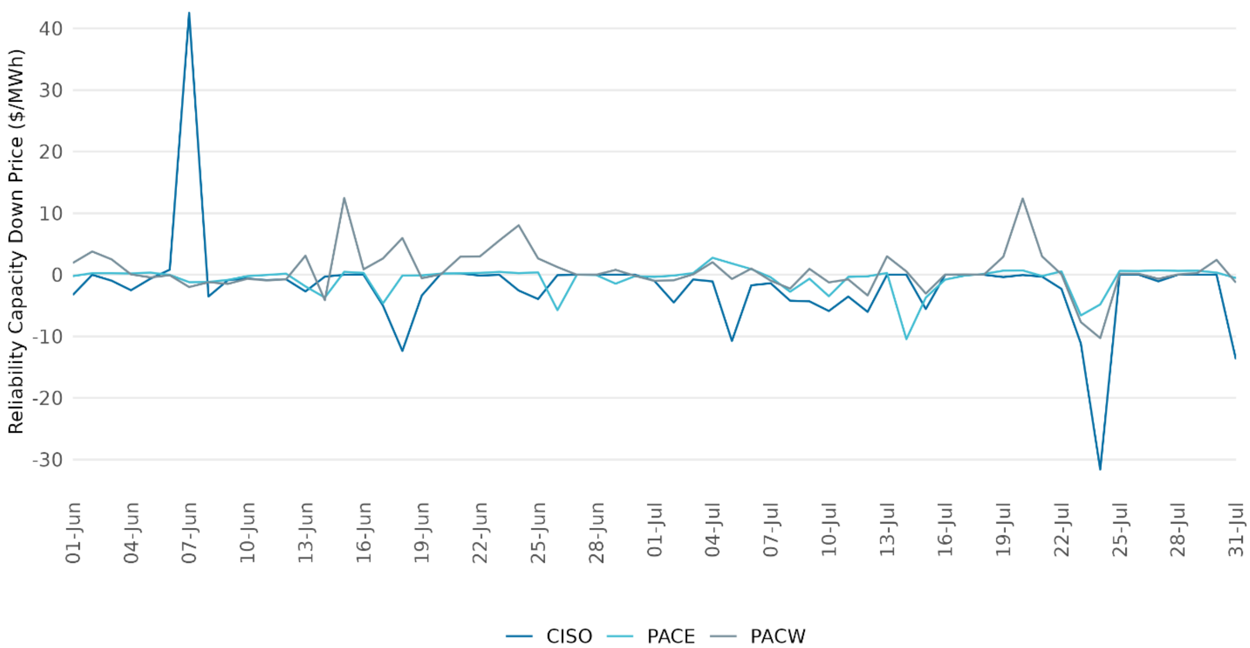


Figure 78: Hourly average price of RCU

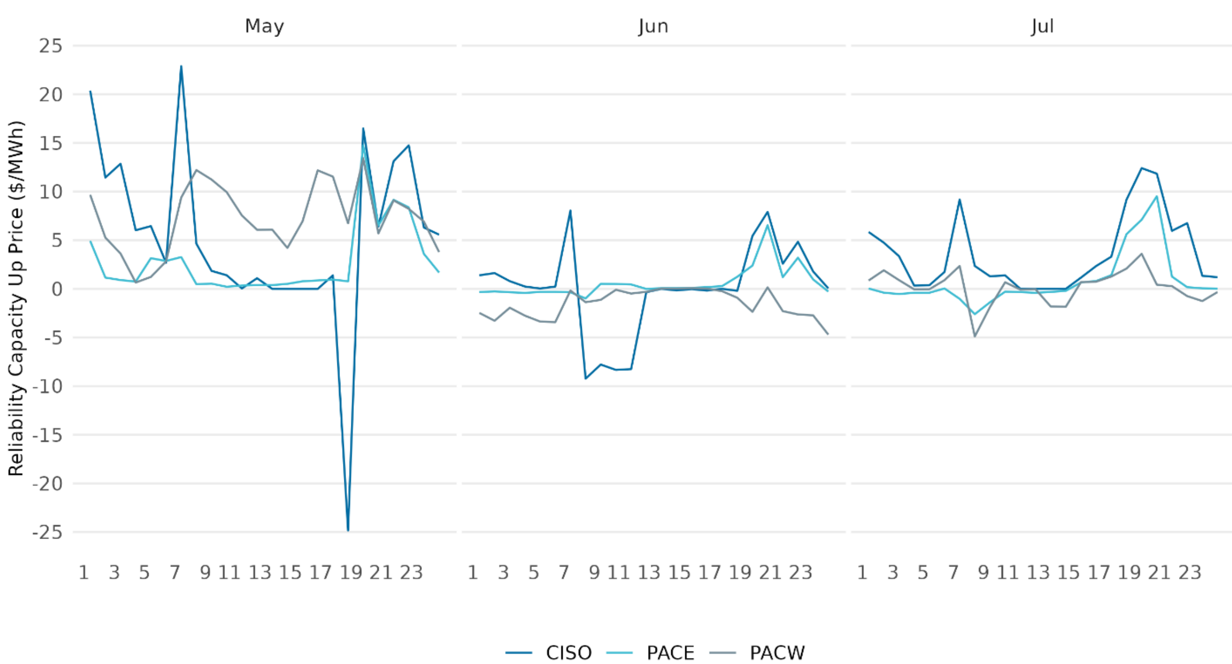
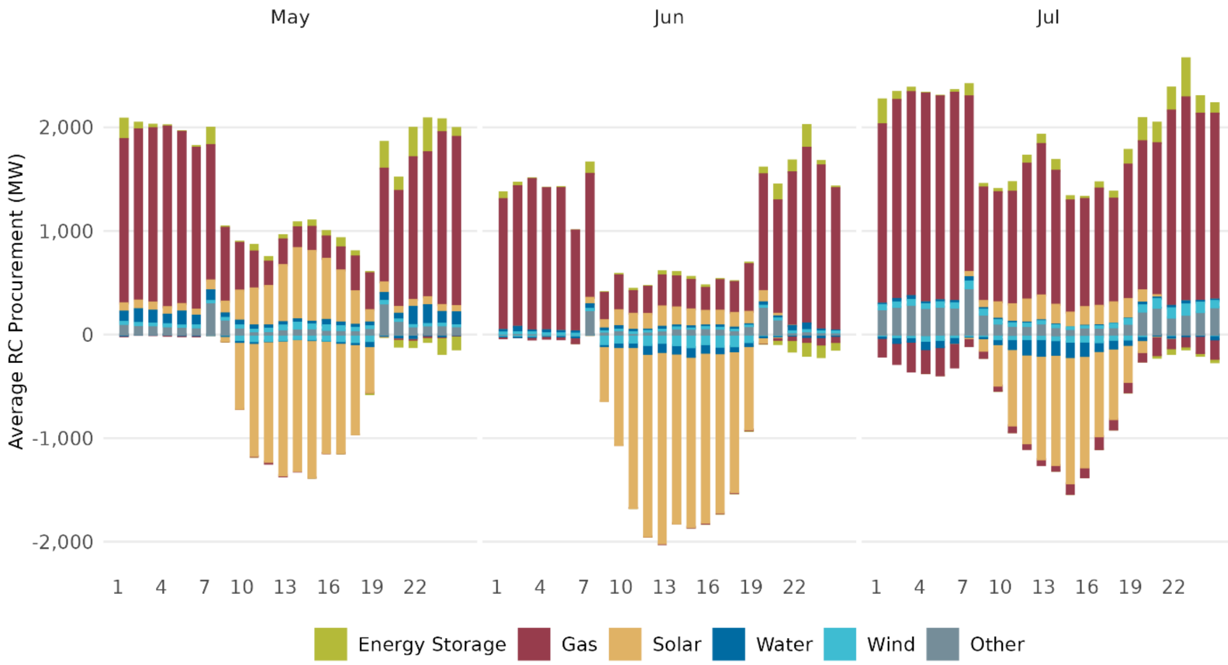


Figure 79: Hourly average price of RCD

Figure 80 to Figure 82 illustrate the hourly average by technology supporting the procurement for each BAA.

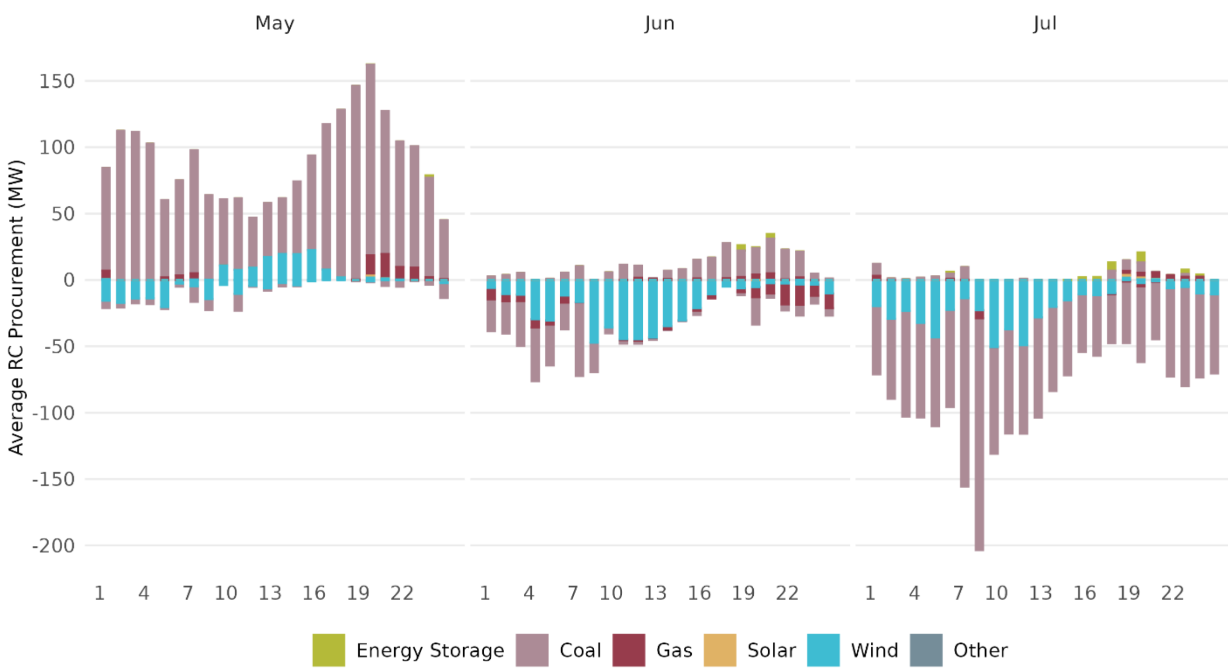
For CAISO in July, gas resources continue to make up the highest proportion (78 percent of the total) of RCU, mostly during non-solar hours. 73 percent of RCD is procured during solar hours by solar resources. July procured significantly more RCU on average than May and June.

Figure 80: Hourly average of RC procurement for CAISO



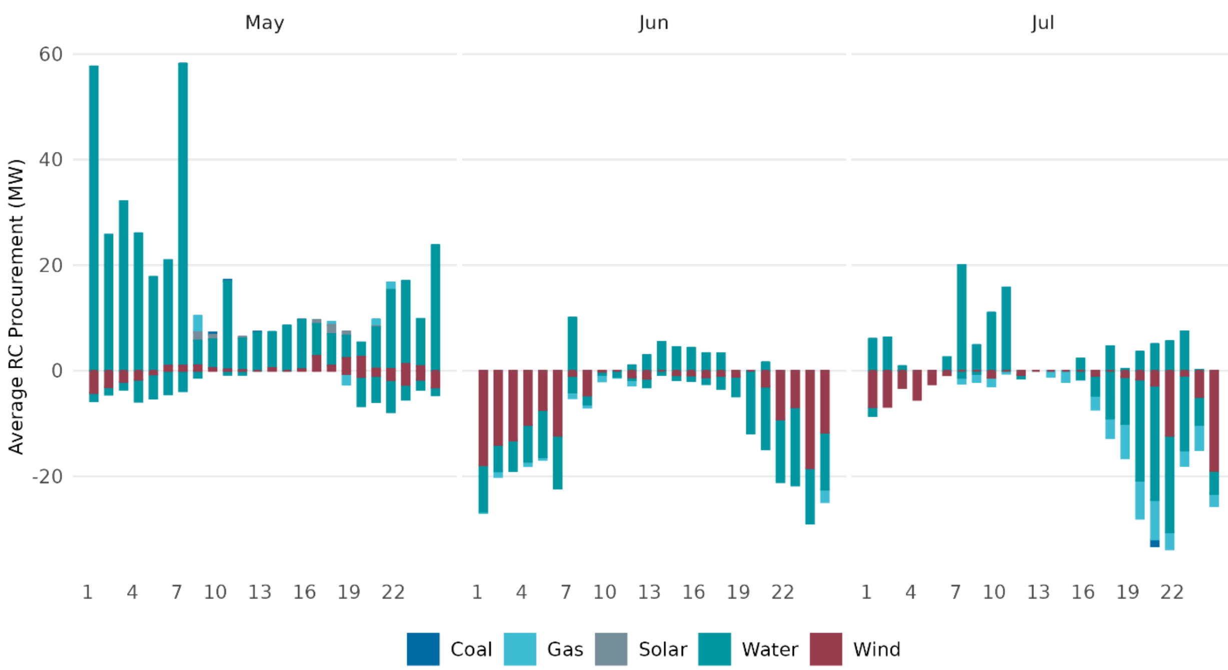
PACE reliability capacity is largely procured in the up direction and supplied primarily by coal and wind resources. In comparison to May and June, RCD procurement has increased significantly, primarily from coal.

Figure 81: Hourly average of RC procurement for PACE



PACW RC is primarily supplied by hydro and wind resources. In July, RCD procurement has been slightly less in early morning hours, with more in the late evening.

Figure 82: Hourly average of RC procurement for PACW



Reliability capacity input bids

Figure 83 and Figure 84 illustrate CAISO's hourly average volume of RC bids by bid price range and fuel type throughout May to July 2026, respectively. Zero-priced bids consistently accounted for the largest share of submitted RC capacity throughout May and June with about above 30,000 MW (or over 40 percent of the total), followed by bids in the (40–60 $/MWh) range. The remaining high-price ranges (100–250 $/MWh) represented a small share of total submitted capacity. Hourly bid volumes were generally higher during daylight hours. Energy storage and solar resources accounted for approximately over 70 percent of the total. Generally, CAISO's submitted RC capacity remained slow growth from May to July, with only a few days exhibiting lower or higher bid volumes.

Figure 83: Hourly average volume of RC bids by price for CAISO

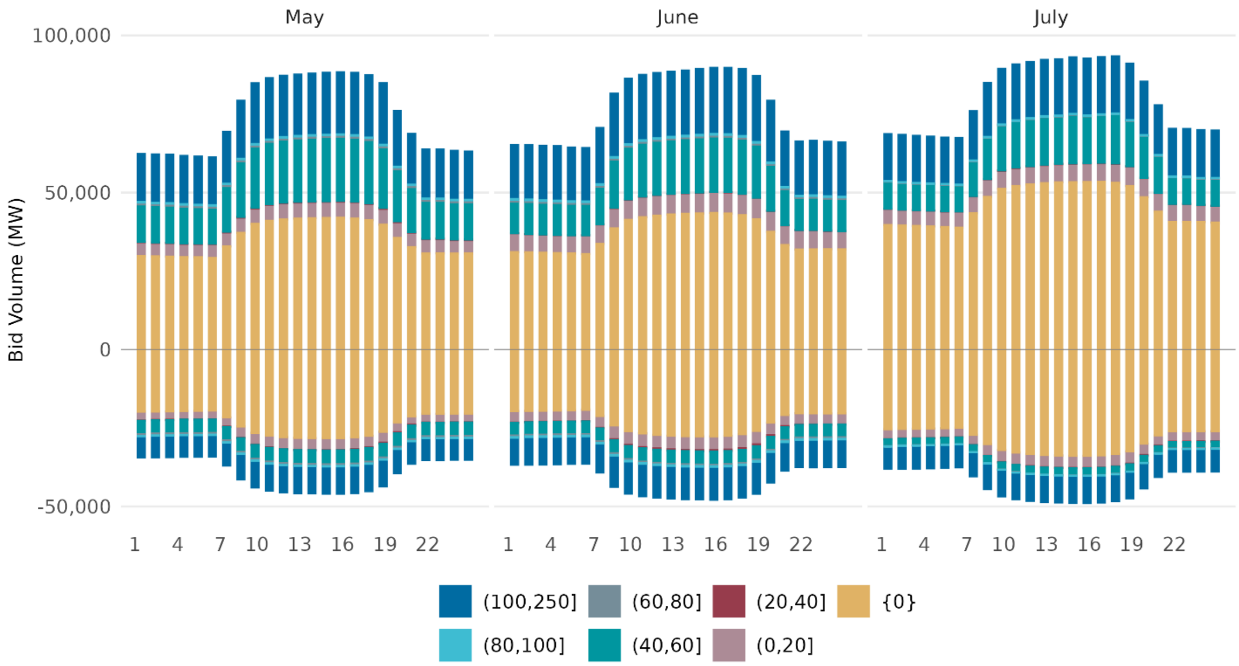


Figure 84: Hourly average volume of RC bids by fuel type by CAISO

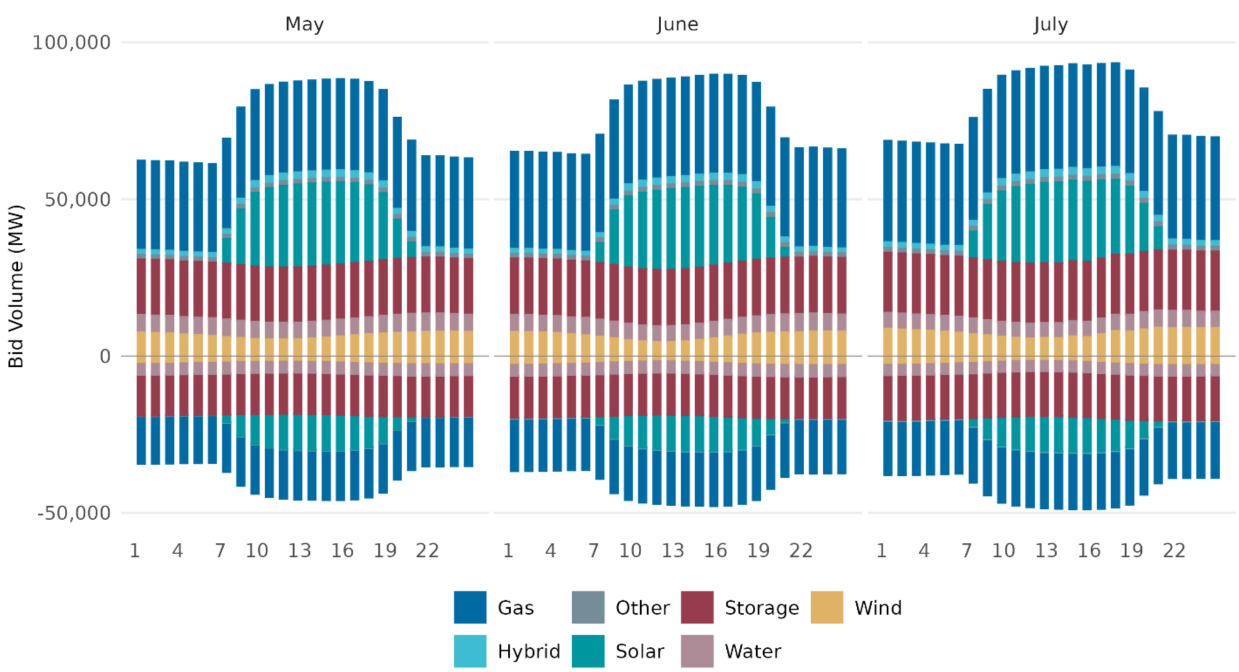


Figure 85 and and Figure 86 illustrate the CAISO's daily average volume of RC bids by bid price range and fuel type, respectively. Generally, CAISO's submitted RC capacity remained relatively stable throughout May to July, with only a few days exhibiting higher volumes. Gas, solar, and energy storage accounted for the largest share of RC bid volumes.

Figure 85: Daily average volume RC bids by price for CAISO

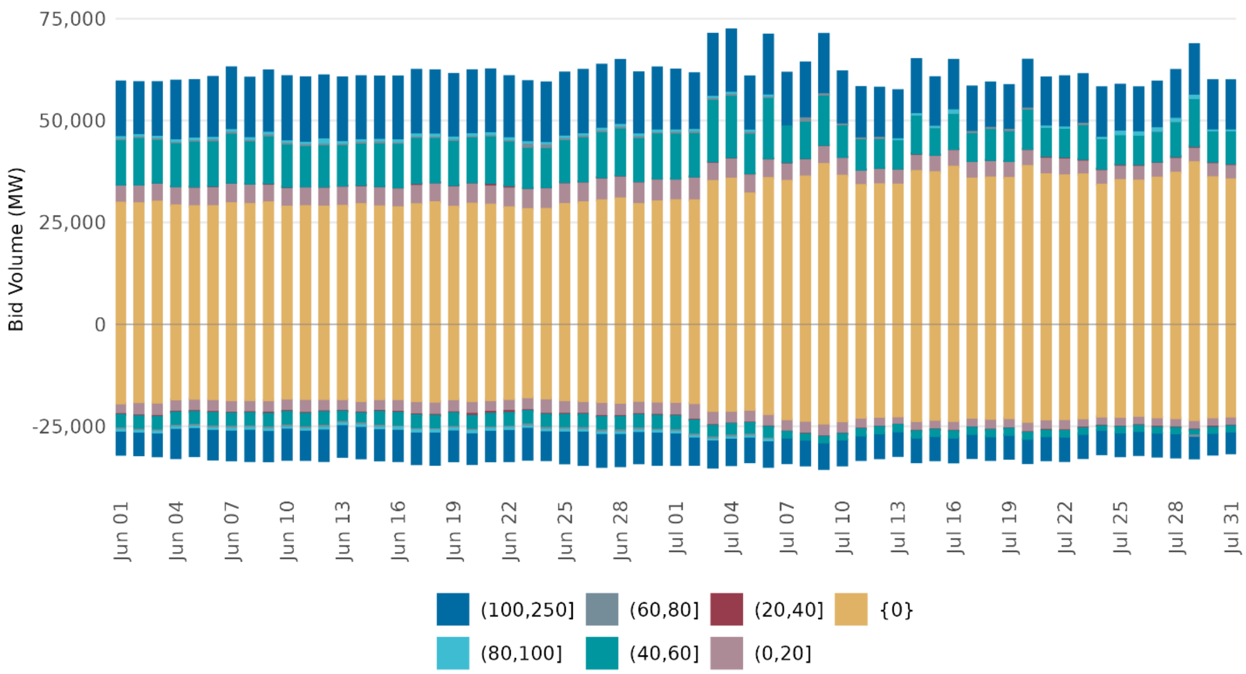


Figure 86: Daily average volume of RC bids by fuel type for CAISO

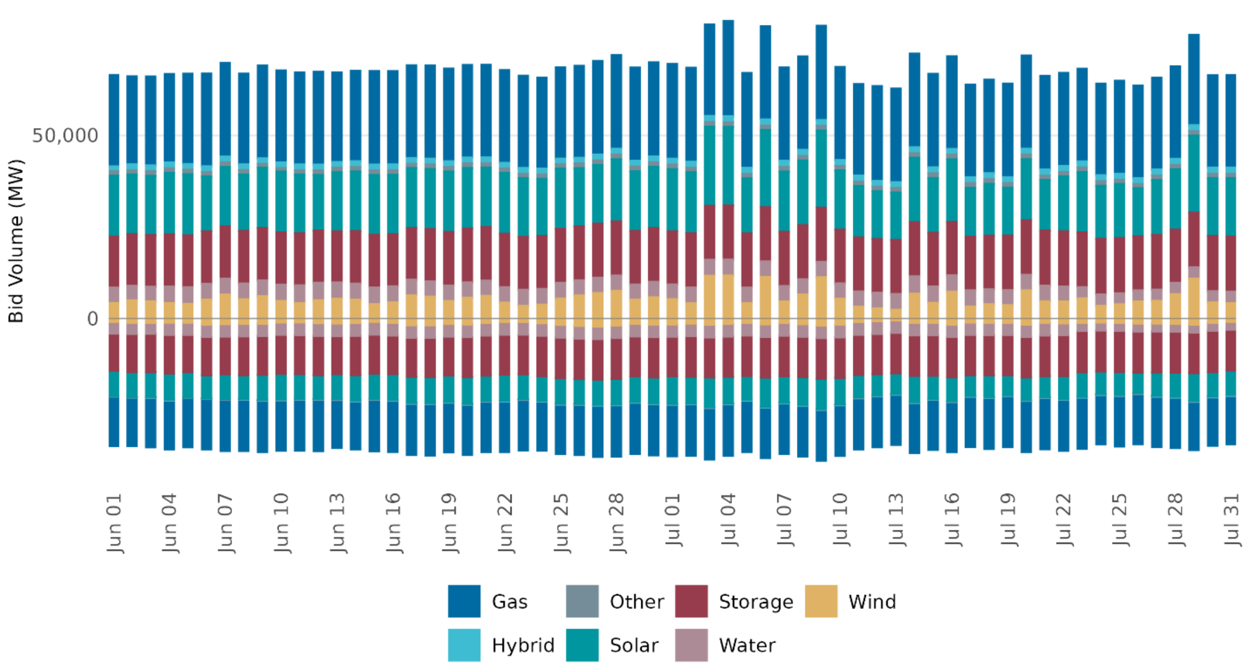


Figure 87 and Figure 88 illustrate the PACE's hourly and daily average volume of RC bids by bid price range and fuel type, respectively. Similarly, low-priced bids ($0–20/MW) and moderate priced bids (40–60 $/MWh) consistently accounted for almost all the share of submitted RC capacity throughout the month with about 90 percent, followed by some bids in the (100–250 $/MWh) range. Hourly bid volumes remained stable throughout the day but decreased slightly during daylight hours. Coal, gas, and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only.

Figure 87: Hourly average volume of RC bids by price for PACE

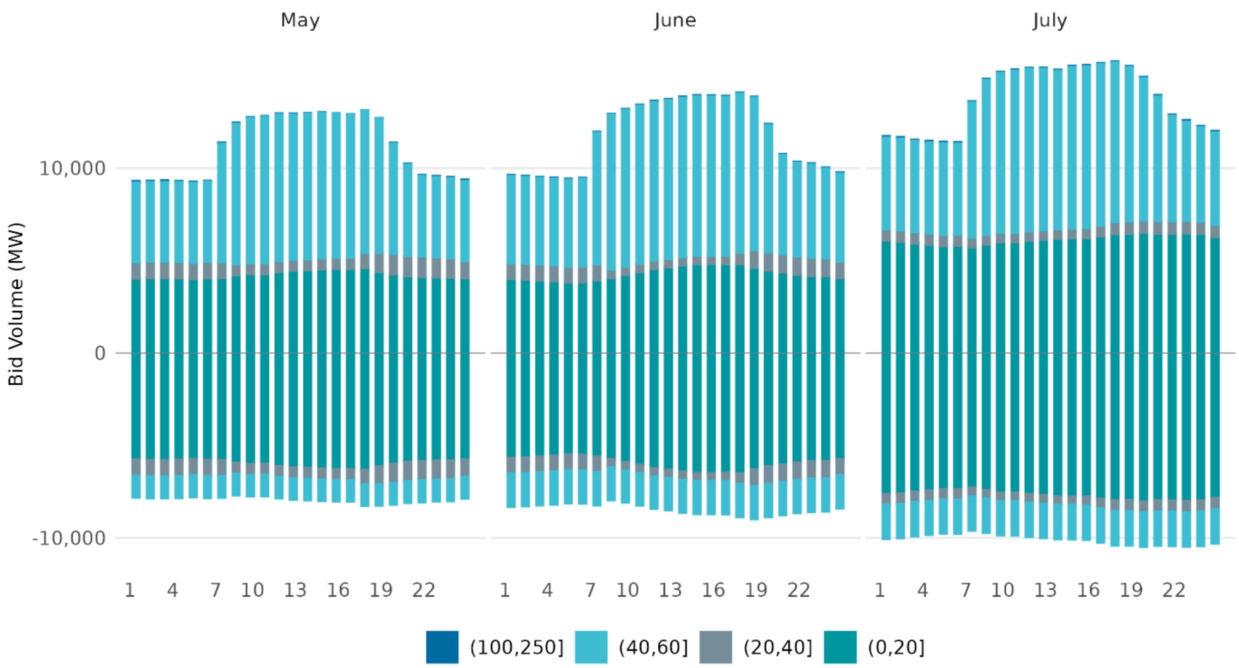


Figure 88: Hourly average volume of RC bids by fuel type for PACE

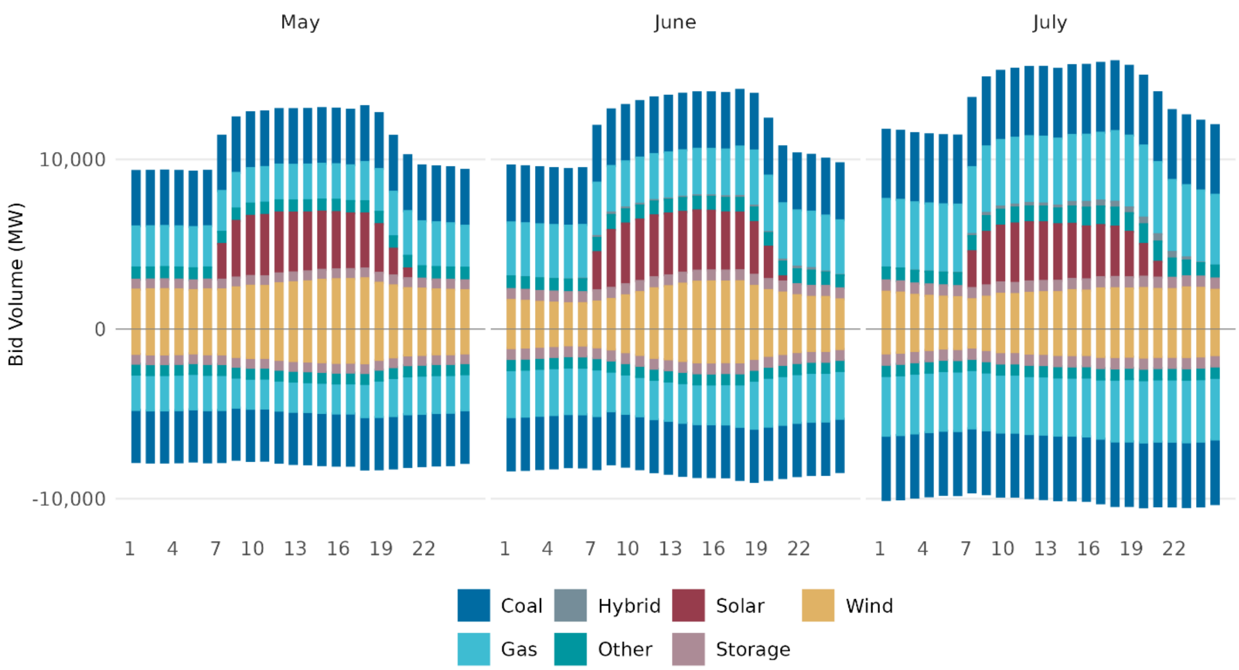


Figure 89: Daily average volume of RC bids by price by PACE

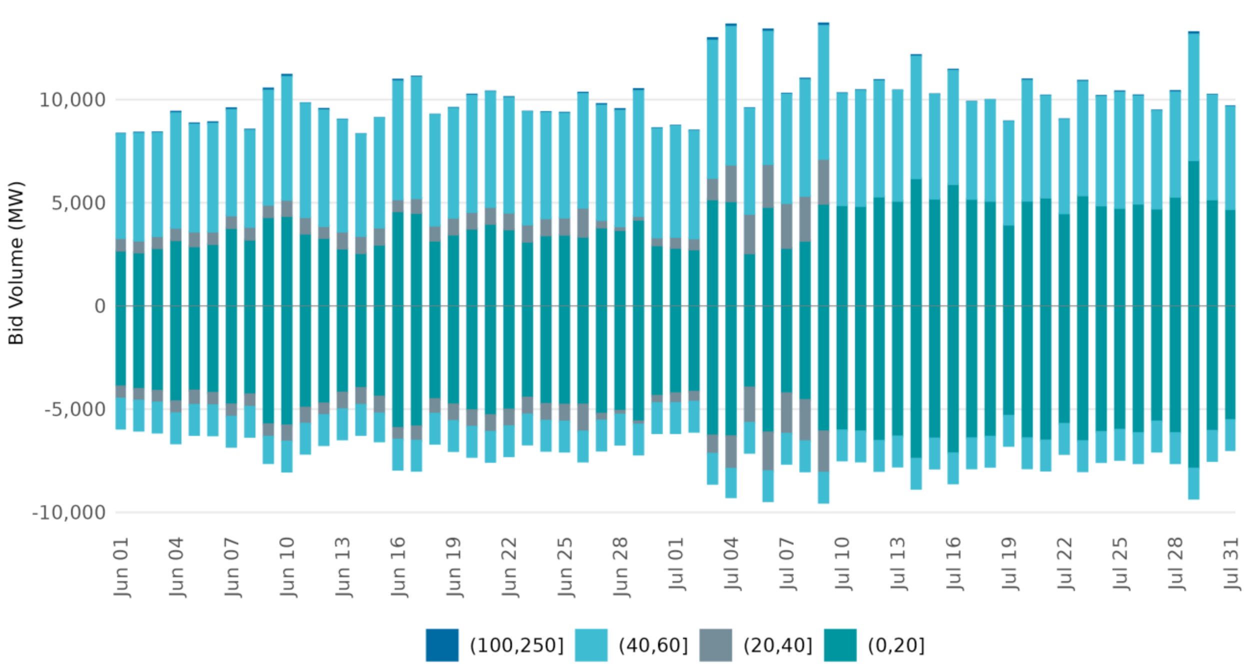


Figure 90: Daily average volume of RC bids by fuel type by PACE

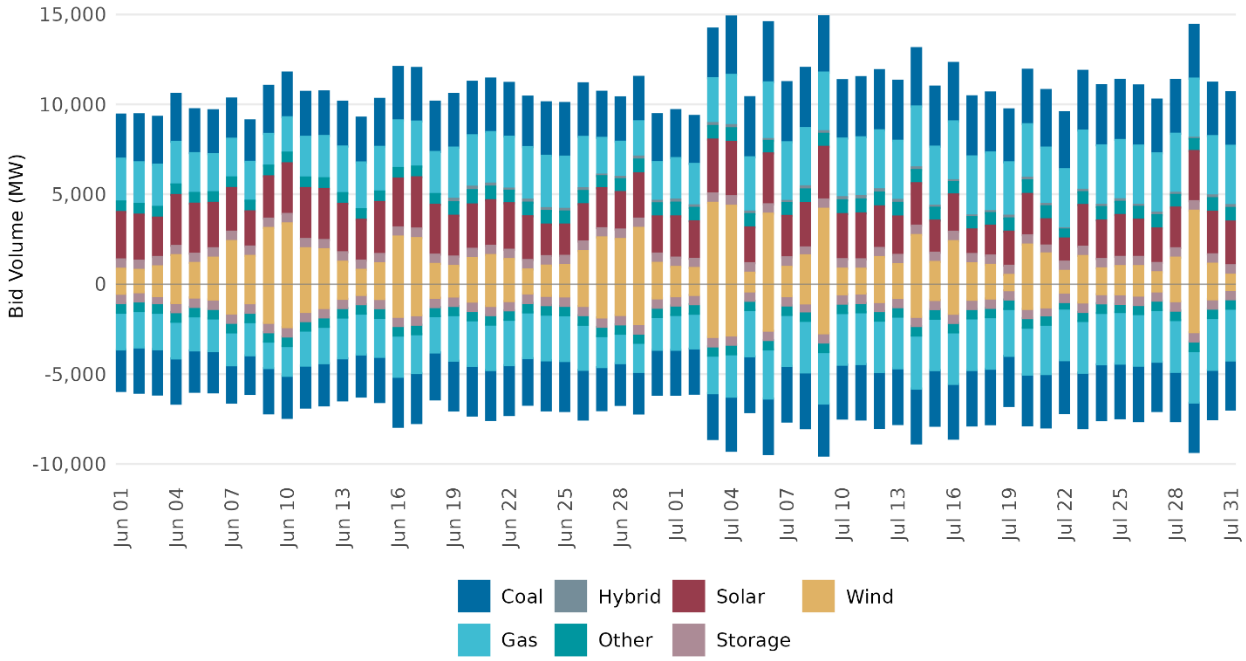


Figure 91 and Figure 92 illustrate PACW's hourly average volume of RC bids by price range and fuel type, respectively. Low-priced bids (0-20 $/MW) and moderate priced bids (40–60 $/MW) consistently accounted for the largest share of submitted RC capacity throughout the month with over 2,000 MW (or 90 percent of the total), followed by bids in the (100–250 $/MWh) range. It is noteworthy that in the down direction there are only low-priced bids submitted. Hourly bid volumes were slightly higher during daylight hours. Water and wind resources accounted for the largest share of submitted RC capacity, with some solar capacity bidding in RCU only.

Figure 93 and Figure 94 illustrate PACW's daily average volume of RC bids. Generally, PACW's submitted RC capacity showed variations across both bid volumes and prices.

Figure 91: Hourly average volume of RC bids by price for PACW

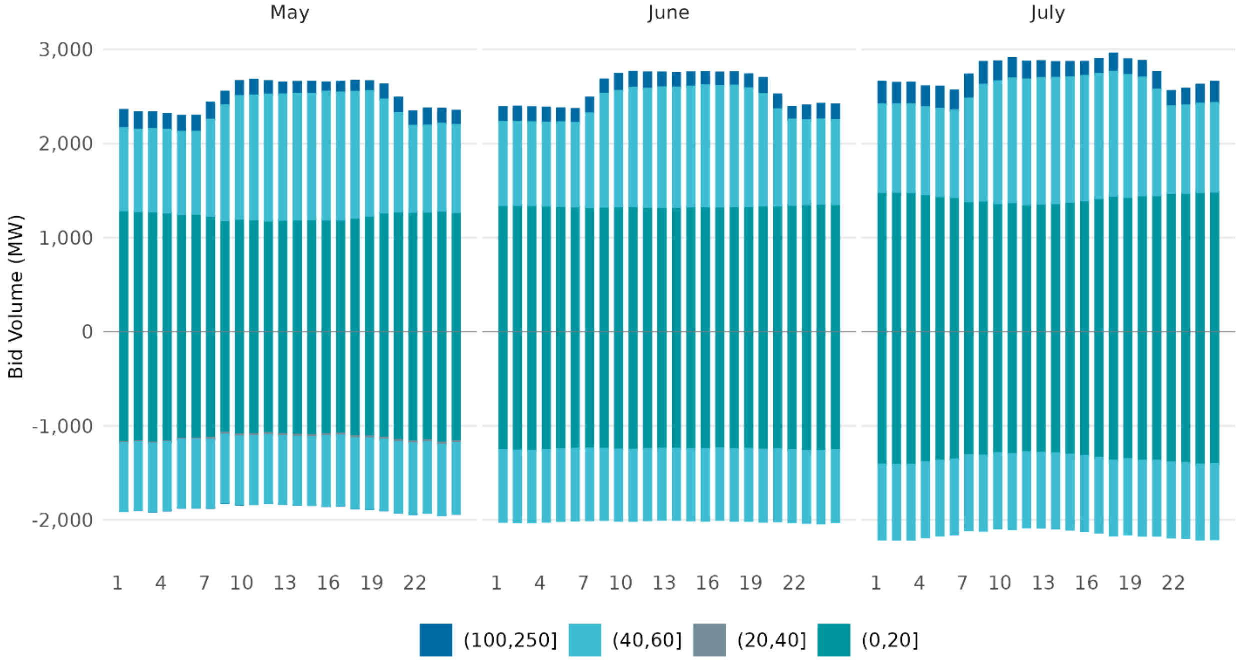


Figure 92: Hourly average volume of RC bids by fuel type for PACW

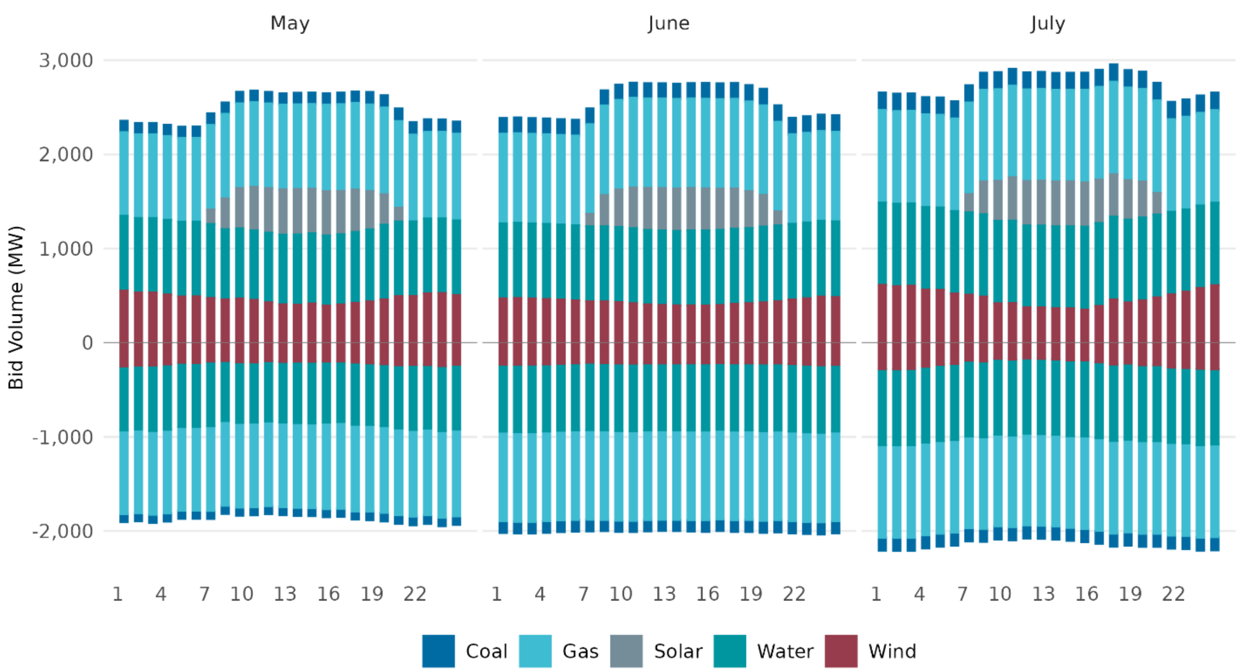


Figure 93: Daily average volume of RC bids by price for PACW

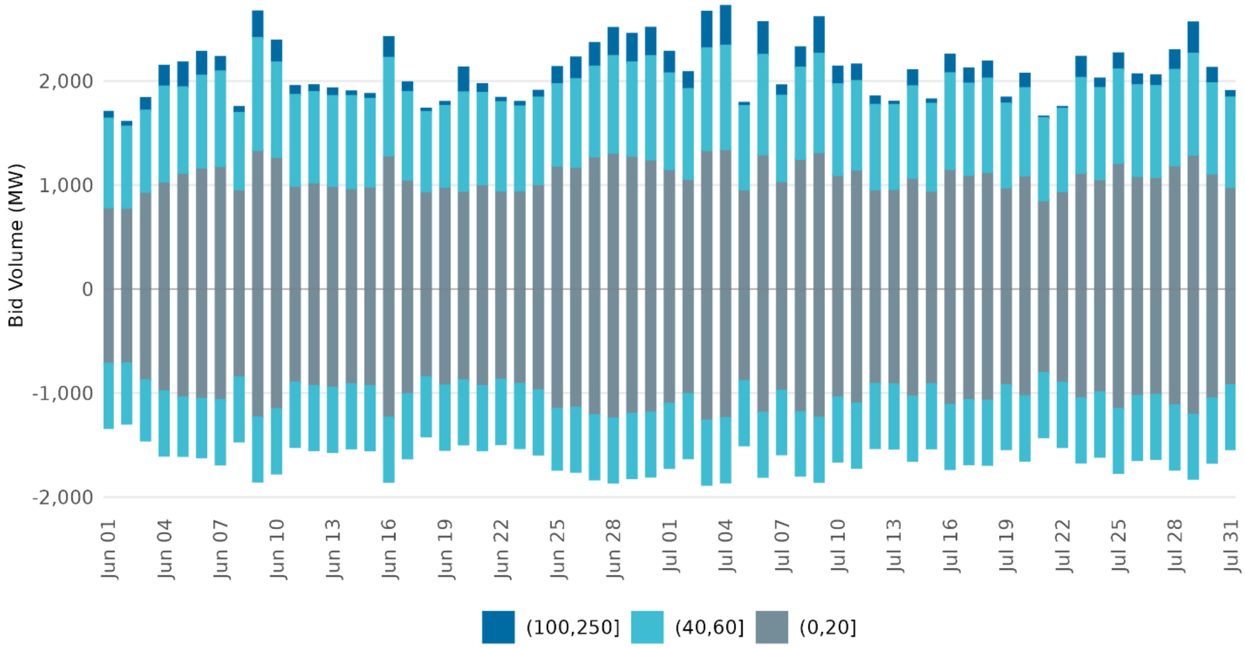
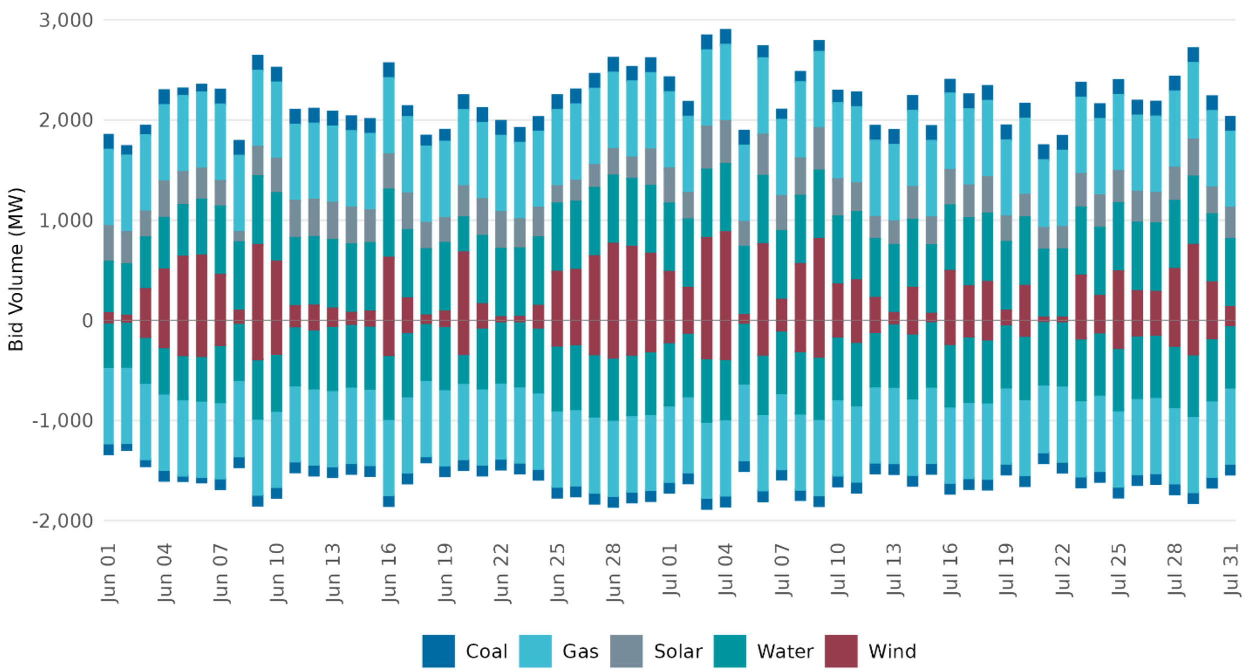


Figure 94: Daily average volume of RC bids by fuel type for PACW



Export reduction

In the month of July there were instances of economic export reductions in the RUC process, shown in Figure 95. 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 96 shows the instances when the real-time market reduced exports in July, with the largest reduction happening on July 27 for low priority exports.

Figure 95: RUC export reduction

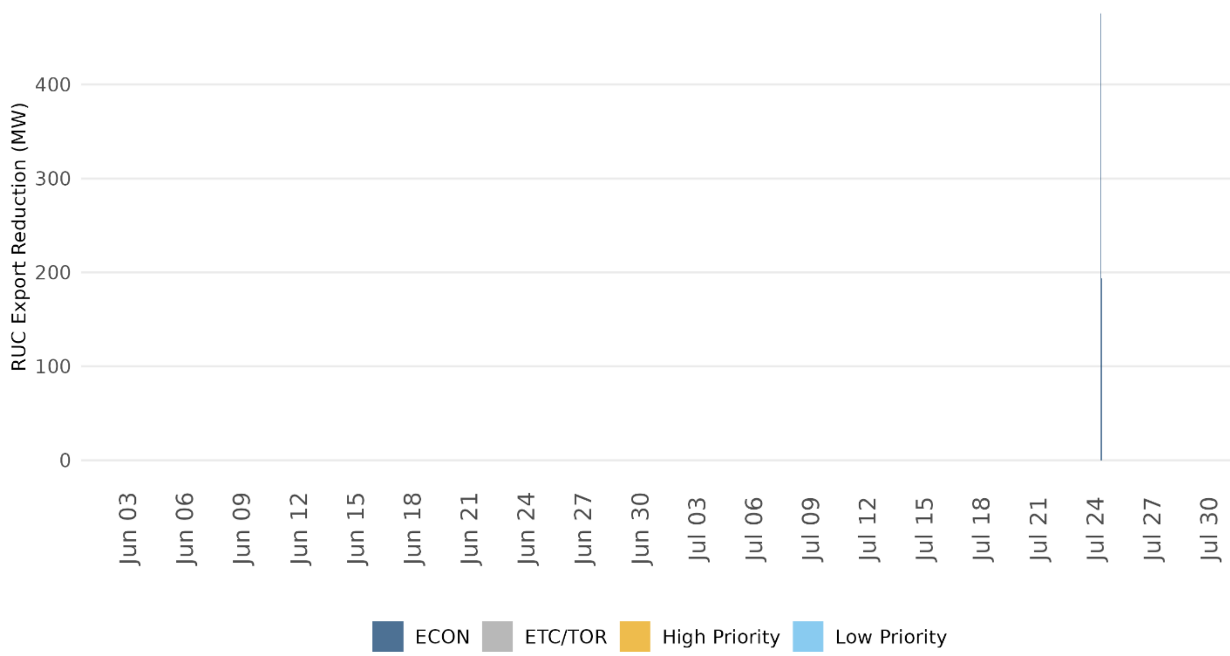
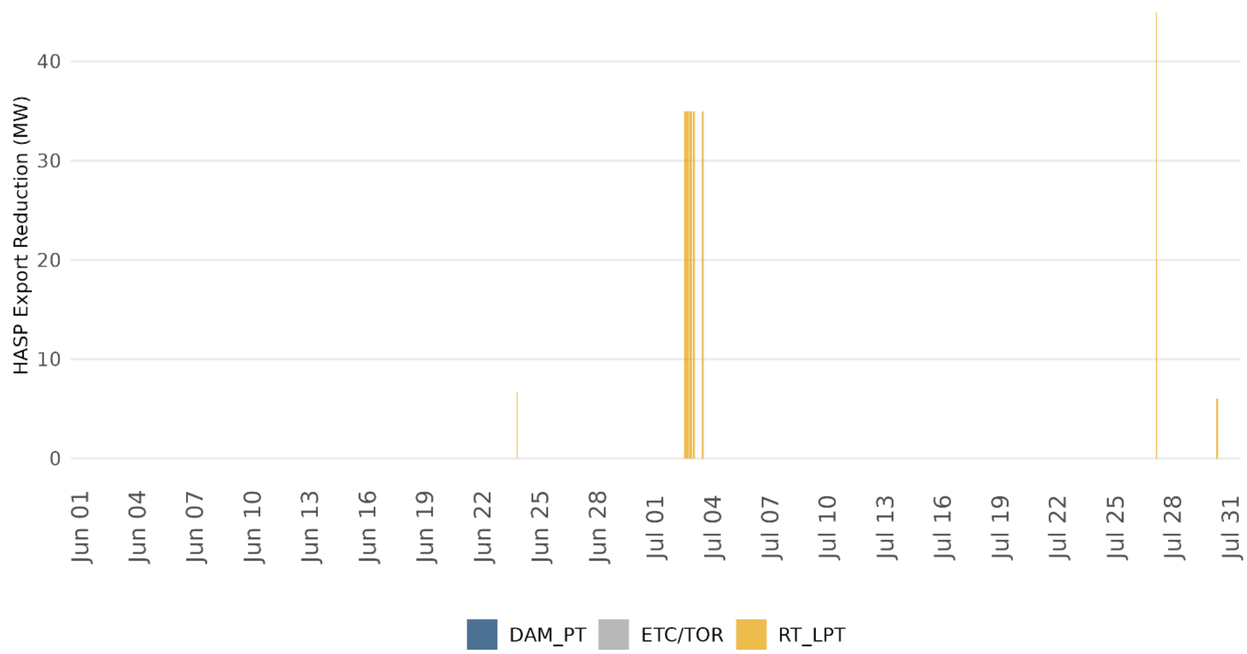


Figure 96: Exports reductions in HASP



Convergence bids

In addition to bids backed by physical resources, market participants within the CAISO area can submit virtual bids for generation or demand. Virtual generation and demand bids, also known as convergence bids, are intended to help convergence the day-ahead and real-time markets by arbitraging price differences between these two markets. Any virtual supply or demand cleared in the day-ahead market is liquidated in the real-time market.

Figure 97 shows the average hourly cleared virtual generation, virtual load, and the net virtual bids for each day in June and July. The net cleared virtual bid is defined as the total cleared virtual generation minus the total cleared virtual demand. A software defect led to convergence bids, both virtual generation and virtual demand, to not be included in the day-ahead market for trade date 7/29. This explains the missing data in Figure 97. For more information on this issue, see the section on Market Issues. Generally, the net cleared virtual bids were marginally higher in July compare to June. There were multiple days in June and July where more virtual demand cleared compared to virtual generation.

Figure 97: Average hourly cleared virtual bids

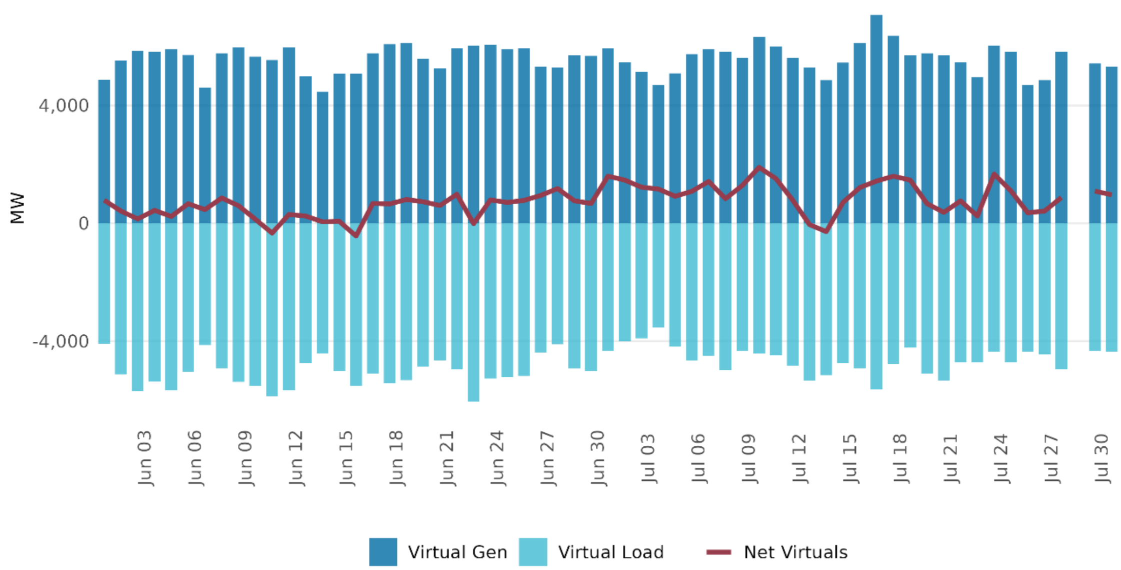


Figure 98 and Figure 99 show the hourly profile of average virtual supply and virtual demand, respectively, in April through July Figure 98 shows a decrease in cleared virtual supply during morning hours starting in May. Compared to April and May, June and July saw an increase in cleared virtual generation across solar hours and into the evening. Between June and July, the largest increase occurred during the peak evening hours. Figure 99shows a similar trend for cleared virtual load, except that from June to July there was a decrease in cleared virtual load during the middle of the day. There was a similar increase in cleared virtual generation bids from June to July 2025.

Figure 100 shows the hourly profile of average net cleared virtual bids in April through July, where the net is cleared virtual supply minus cleared virtual demand. In other words, a positive value represents net virtual supply while a negative value reflects net virtual demand. The trends of reduced net cleared virtual bids in June compared to April and the higher virtual demand compared to virtual generation during solar hours also occurred in 2025. The decline in difference between virtual demand and virtual generation during solar hours in July compared to June was also seen in 2025. This means it is unlikely that EDAM led to the changes.

Figure 98: Average hourly cleared virtual supply

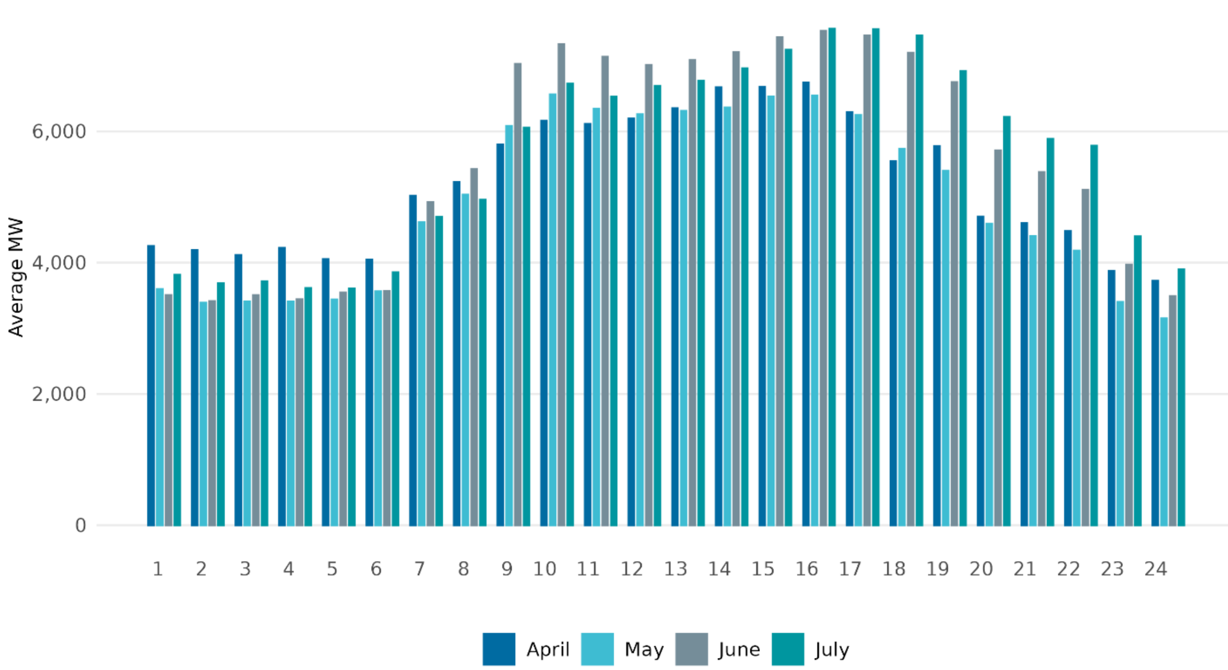


Figure 99: Average hourly cleared virtual demand

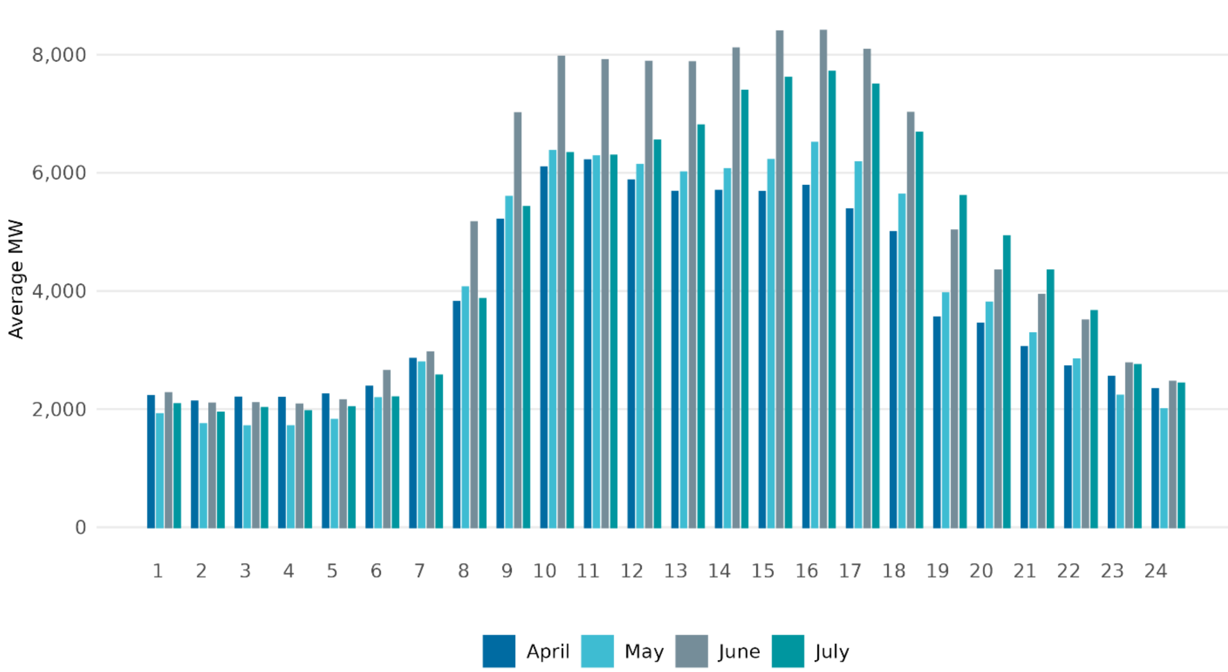
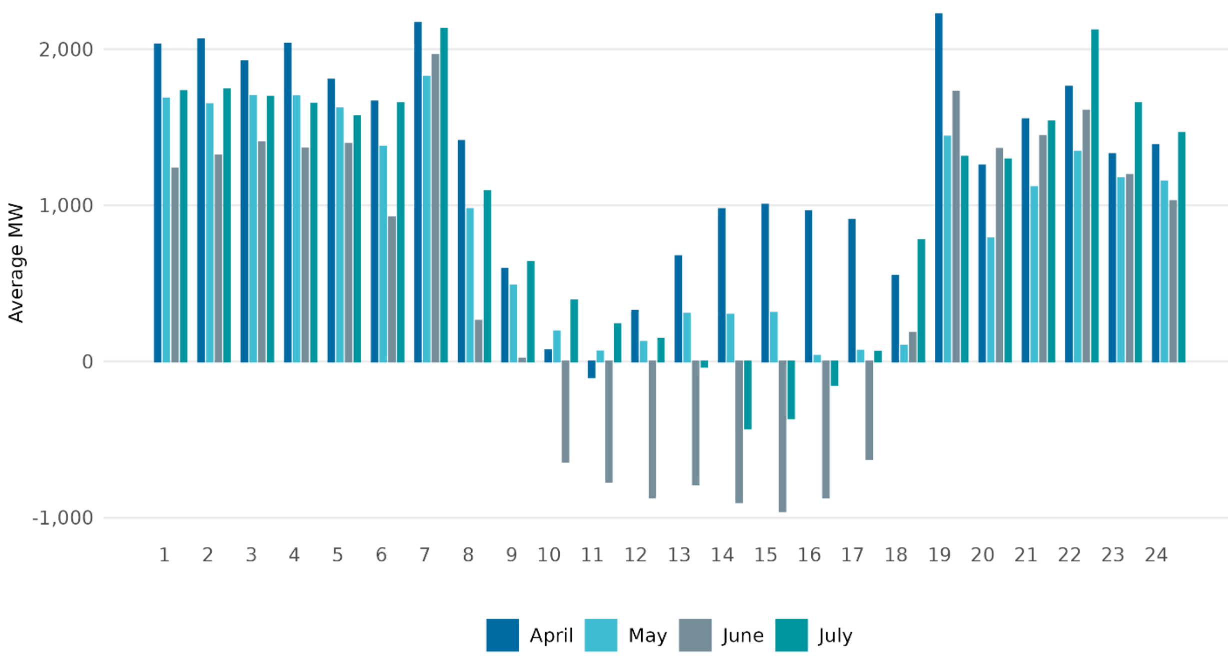


Figure 100: Average net hourly cleared virtual bids



Greenhouse gas emission product

Greenhouse gas (GHG) regulations are designed to reduce carbon emissions associated with electricity generation and imports. In regions or states subject to GHG policies, such as California, imported electricity may incur additional costs when it is generated by resources located outside the regulated area. To ensure these environmental costs are properly reflected in market outcomes, the EDAM also incorporates the GHG model into the market optimization process.

Eligible resources located outside GHG regulation areas may voluntarily submit GHG bids in addition to their regular energy bids. The GHG model introduces GHG allocations as optimization variables that are assigned to generation outside (or across) GHG regulated areas, representing the portion of their generation attributed to serving demand within a specific GHG regulated area.

The link between GHG allocations and net imports into the regulation area is enforced through the GHG import allocation constraint in the market optimization. The shadow price of this constraint defines the GHG price (or marginal GHG cost), which becomes part of the locational marginal price (LMP) within the regulated area, while remaining zero outside. Resources receiving GHG allocations are paid at the corresponding marginal GHG cost. This payment is separate from the regular energy schedule settlement and provides a mechanism for recovering the GHG regulation costs imposed on imports into the GHG regulation area.

Overall, the model incorporates GHG regulation costs into market optimization to ensure that dispatch decisions reflect both economic and environmental considerations. By accounting for the cost of emissions, the model prevents external resources from being dispatched solely based on energy costs while ignoring the associated GHG impacts. Throughout July, the highest GHG price reached 26.9 $/MWh during Trade Hour 1 on July 14. The maximum hourly GHG allocation was 525 MW, occurring on multiple days in July.

Figure 101 shows the daily average GHG allocation for both June and July. In July, the daily average GHG allocation reached highest levels near the middle of the month, peaking at 361 MW on July 14, followed by 256 MW on July 25. The average GHG allocations were substantially lower at the beginning and end of July. Overall, GHG allocations in July increased compared with June.

Figure 101: Daily average GHG allocation

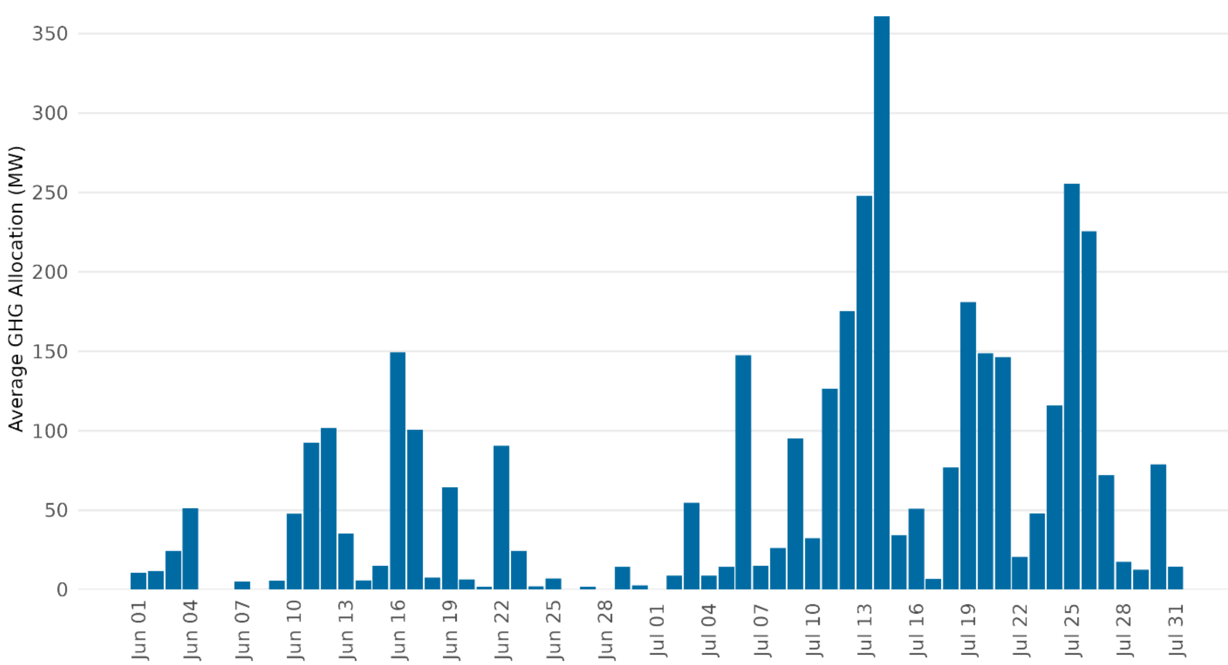


Figure 102 shows the daily average GHG prices in both June and July. In July, daily average GHG prices fluctuated throughout the month, with the highest daily average price reaching 15.0 $/MWh on July 13. Prices were generally higher around the middle of the month, and overall, GHG prices in July were higher than those in June.

Figure 102: Daily average GHG price

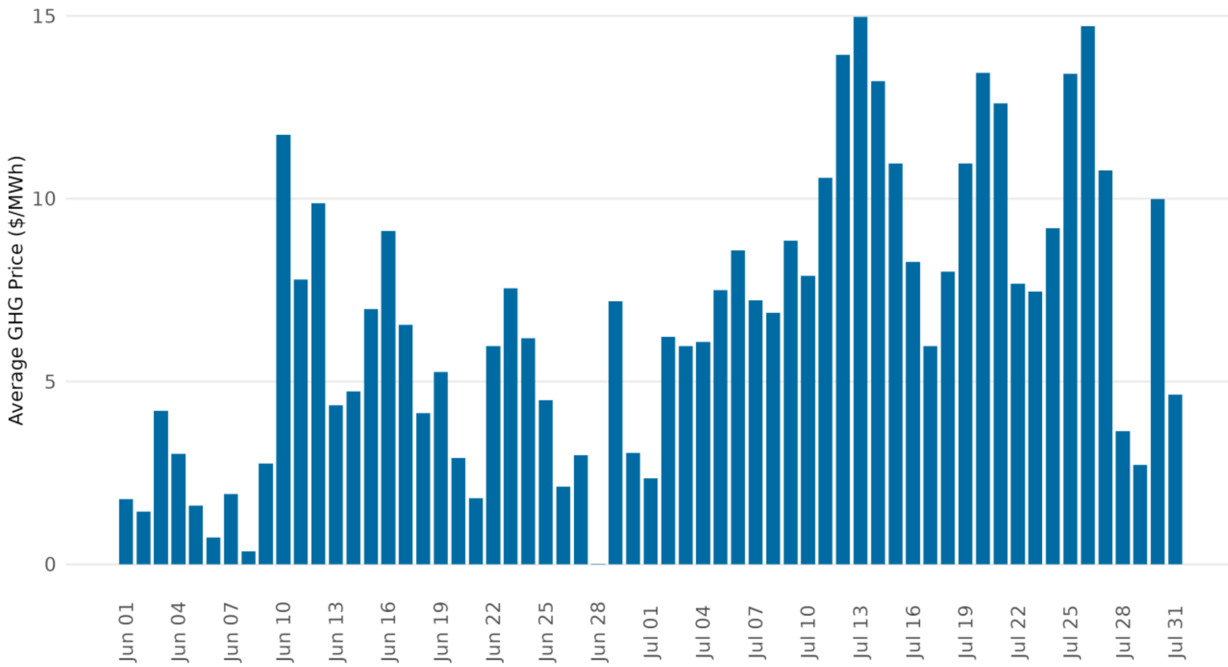
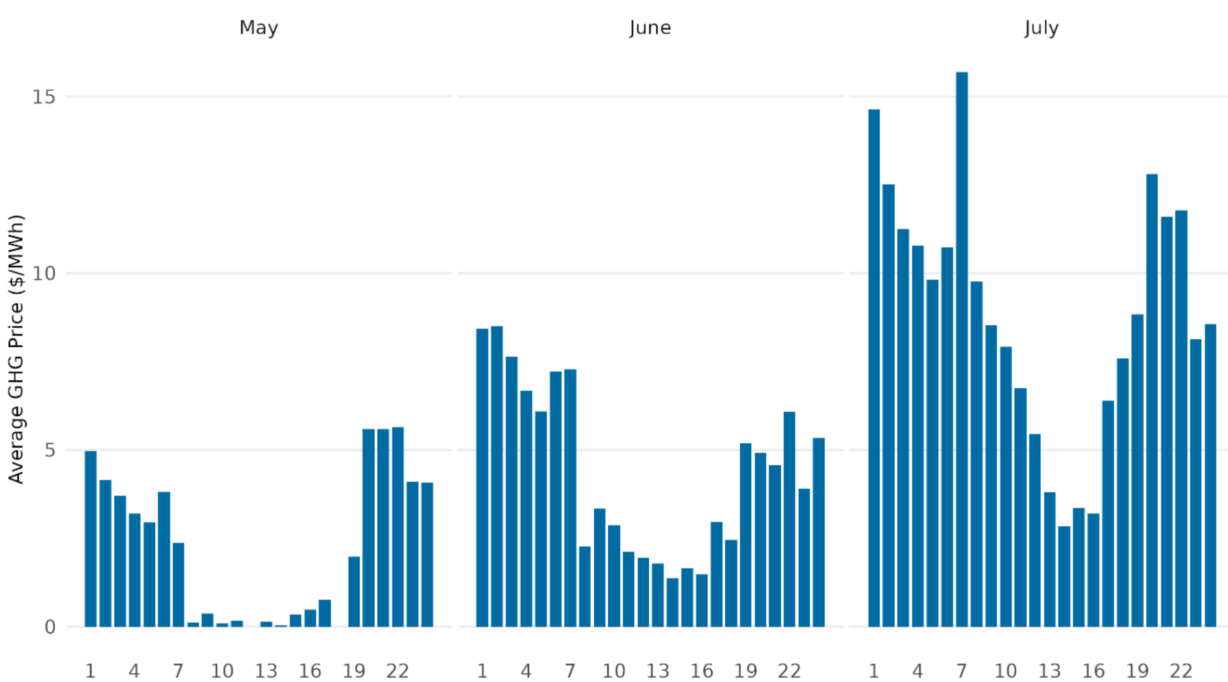


Figure 103 shows the hourly average GHG price by trade hour for May, June, and July. GHG prices were generally higher during the early morning hours (Hours 1–7), declined during the midday period (approximately Hours 10–17), and increased again during the evening hours (Hours 19–24). The lower midday prices coincided with periods when imports into the California area were reduced due to abundant solar generation within the CAISO area.

Figure 103: Hourly average GHG price



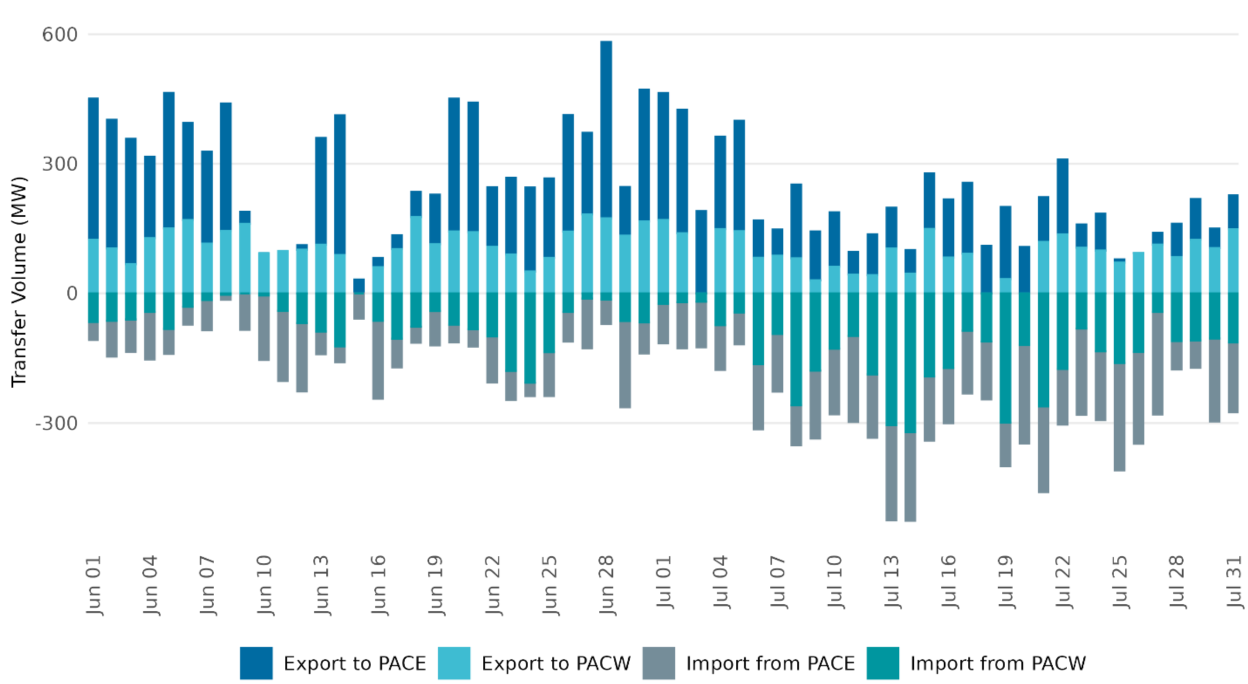
EDAM Transfers

Available transfer capability among the three participating areas is enabling the market to capture the economic benefits of a larger, more integrated regional footprint. By facilitating the movement of cheaper supply across balancing areas, the market can more effectively access the most economical supply available while supporting reliable system operations. Transfer flows are determined dynamically to these economic signals and can vary from hour to hour as market conditions evolve. Beyond supporting economic efficiency, transfers also enhance access to the geographic and fuel diversity available across the extended market footprint. This broader resource pool increases operational flexibility and improves the utilization of available generation.

Energy transfers

Figure 104 illustrates CAISO daily average energy transfers in IFM in June and July 2026 on both export (+) and import (-) directions, and the breakdown for transfer paring entities. CAISO was a net exporter in both months, and the main transfer pairing BAA is PACE. At the beginning of May, CAISO had more imported energy than exported. Then the average export volume generally decreased while imports started to increase in July.

Figure 104: Daily average energy transfers for CAISO



The hourly profile in Figure 105 exhibits a diurnal pattern. May and June show a very similar pattern, with exports increasing significantly during daylight hours and peaking in the late afternoon and early evening. This pattern is consistent with availability of solar generation during midday hours, enabling substantial exports to PAC areas. In July there was noticeable increase in energy imports and reduction in exports due to summer weather. The average energy imports are about more than 250 MW in July while the average exports are below 250 MW, indicating that the CAISO switched to a net importer in July.

Figure 105: Hourly average energy transfers for CAISO

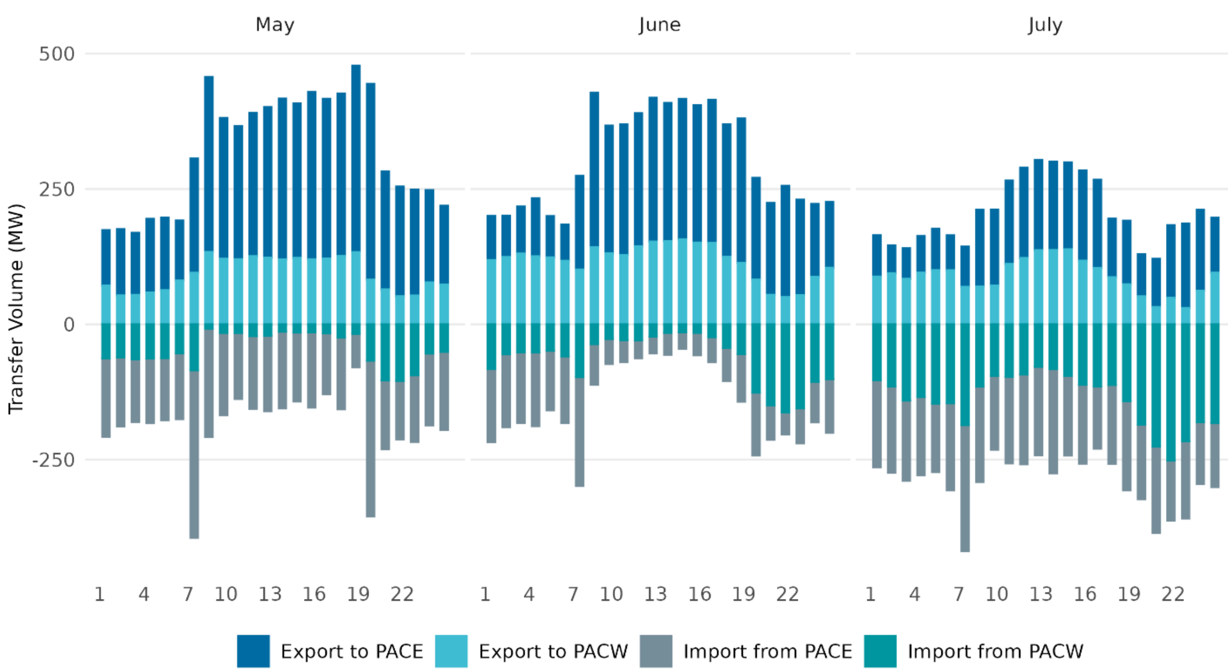


Figure 106 and Figure 107 show PACE's daily and hourly average energy transfers throughout June to July 2026 in both export (+) and import (-) directions. Generally, PACE remained an importer to CISO in May and June but changed to a net exported to PACW after June 3. In July the daily exports increased and reached the highest of over 400 MW on several days. While there was noticeable decrease in energy imports.

The hourly profile also shows PACE's increasing exports as market evolves in July, with hourly average exports over 200 MW. In contrast, imports from CISO solar peak hours decreased compared with May and June, from peak average import over 280 MW in May to about 180 MW in July.

Figure 106: Daily average energy transfers for PACE

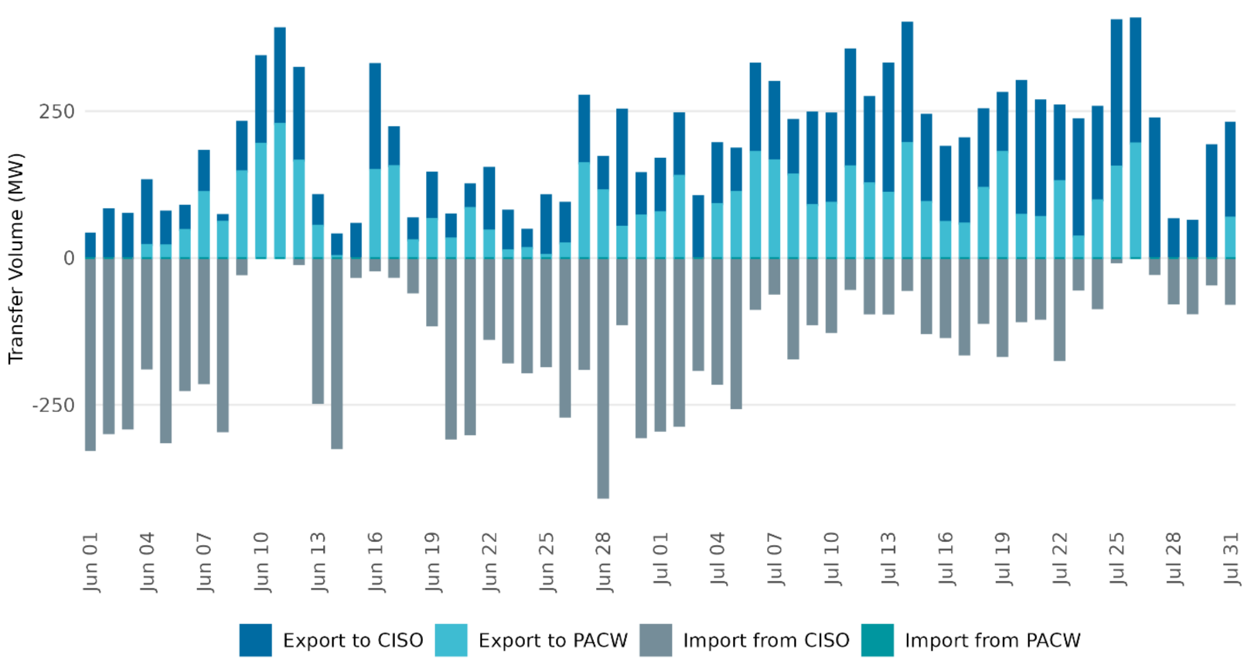


Figure 107: Hourly average energy transfers for PACE

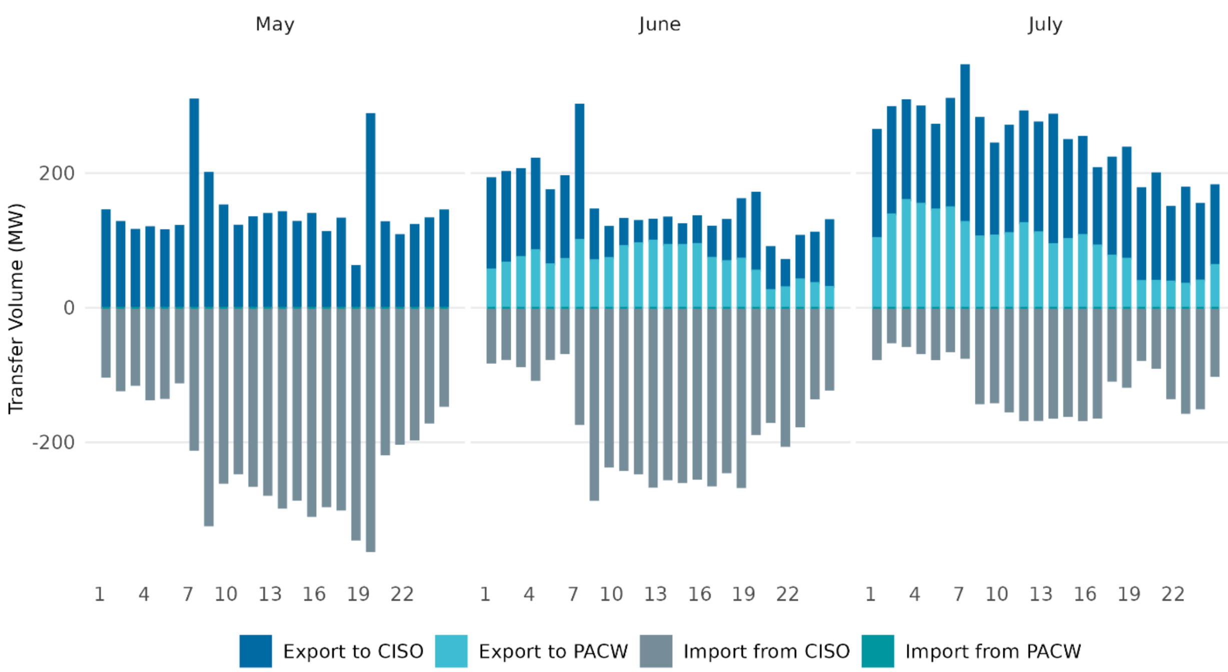


Figure 108 and Figure 109 show PACW's daily and hourly average energy transfers throughout June to July 2026 on both export (+) and import (-) directions. PACW was a net importer in May and June while energy exported to CAISO started to increase in July. The average import volume from PACE increased after June 3.

The hourly profile exhibits a significant increase in average imports in June and July compared with May, the hourly average import is over 200 MW on peak hours in June and July while it was only over 100 MW in May. In contrast, exports continued increasing throughout May to July, with the peak export increased from 100 MW to 230 MW in HE 21.

Figure 108: Daily average energy transfers for PACW

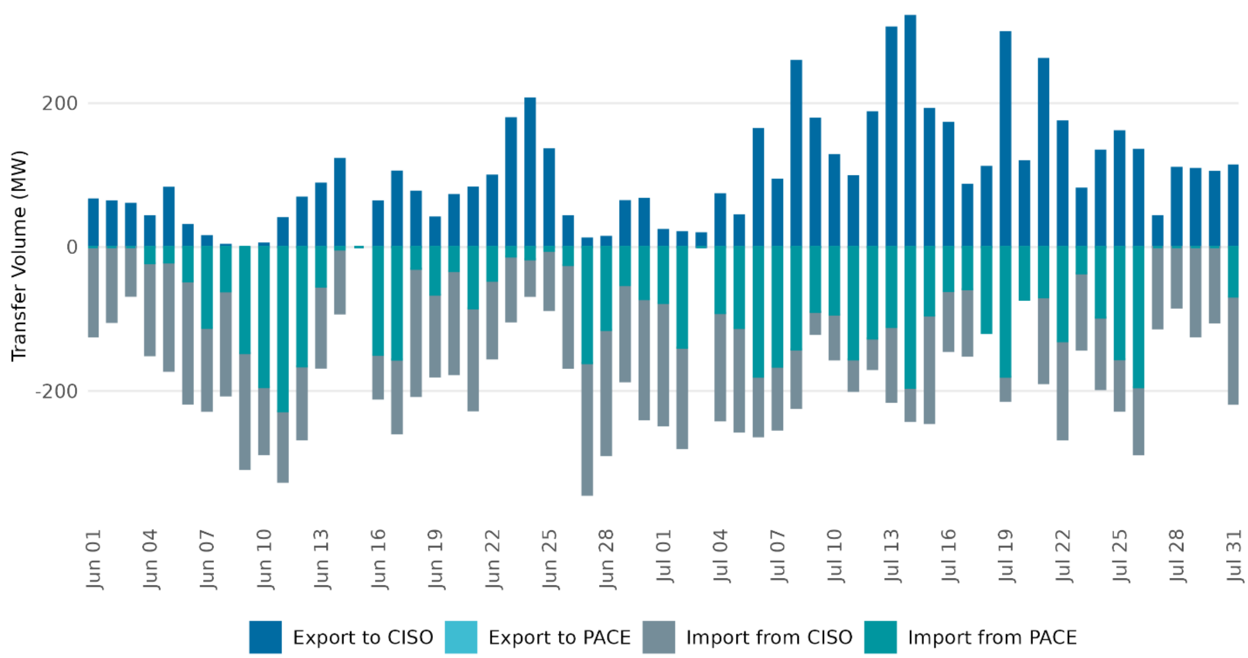


Figure 109: Hourly average energy transfers for PACW

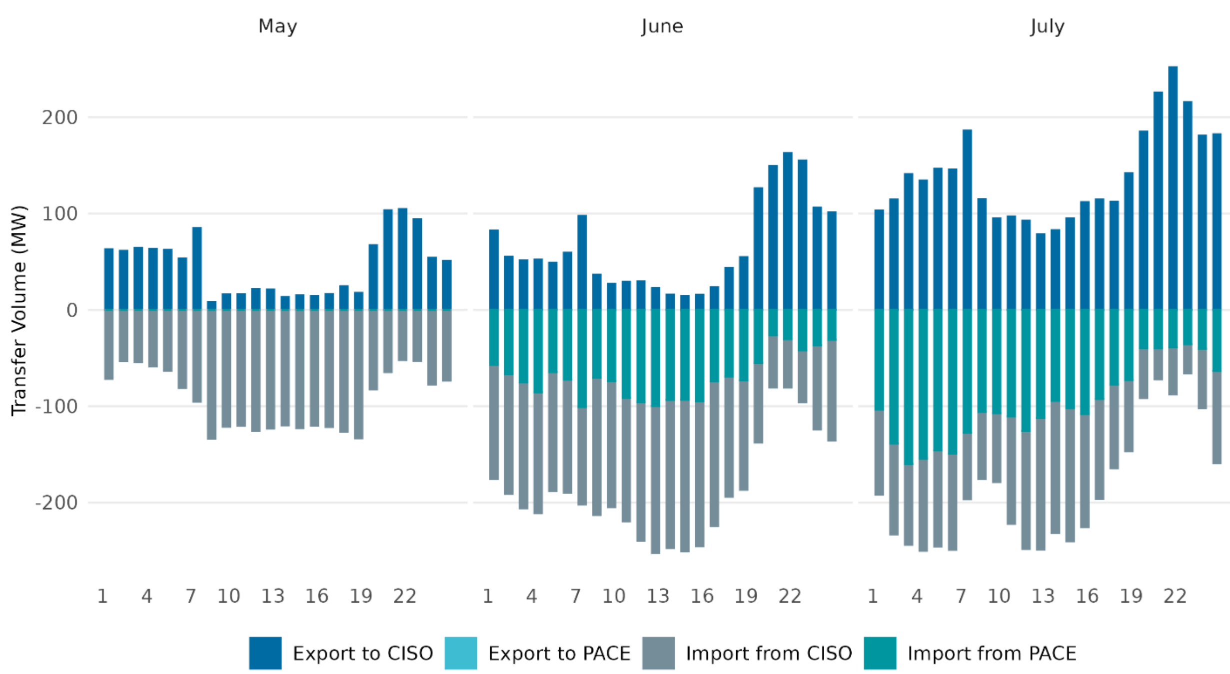
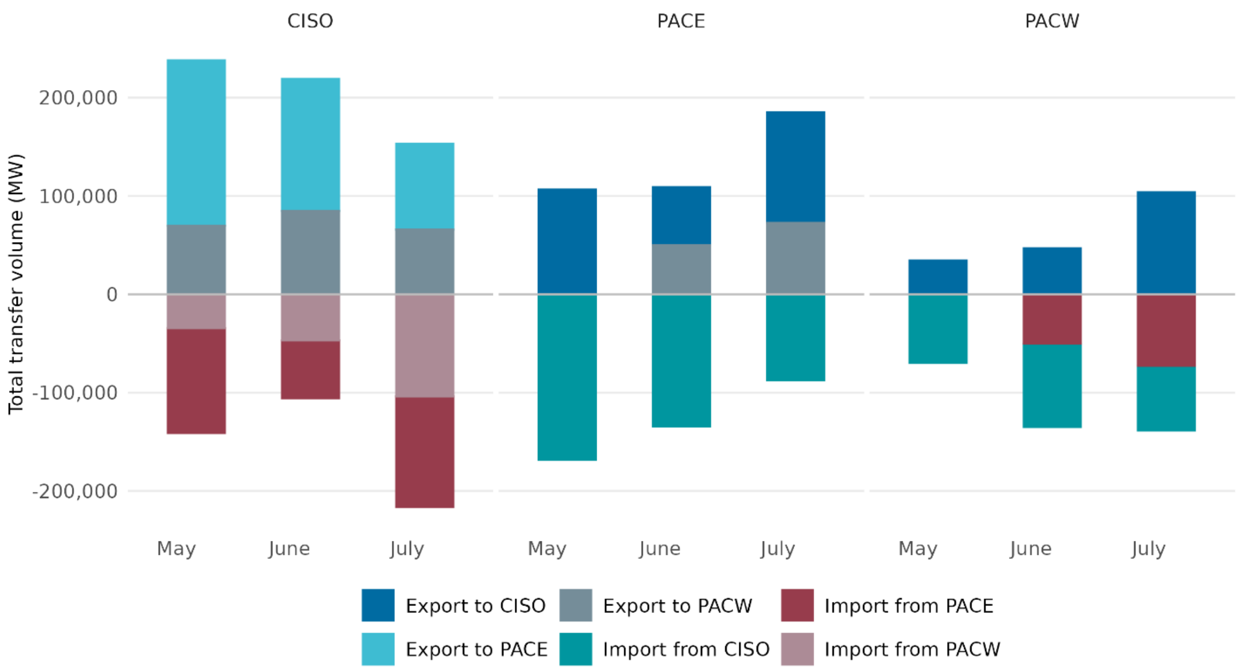


Figure 110 shows the summary of three BAAs' total energy transfer volumes throughout May to July in both export (+) and import (-) directions. For CAISO, the total export volumes reduced while imports increase a lot in July. Besides, the transfer between PACW and PACE increased a lot in June and July, compared with almost no direct transfer between PACEW and PACE in May.

Figure 110: Total energy transfers volumes for 3 BAAs per month



Imbalance reserves

Imbalance reserves are a new day-ahead flexible reserve product introduced with EDAM to procure upward and downward reserve capacity for managing differences between day-ahead schedules and real-time conditions, including net load forecast uncertainty and real-time ramping needs. This section summarizes the patterns of imbalance reserves transfers among BAAs throughout May to July 2026.

EDAM enables the transfer of imbalance reserves between balancing authority areas, allowing available reserves to be shared where they are needed most. These transfers improve the efficient use of resources while supporting reliable system operations. The following sections summarize the overall transfer activity during the month and examine the underlying patterns and market outcomes in greater detail for both up and down direction.

Imbalance reserve up

As with energy, the market can transfer imbalance reserves among BAAs, which provide revenue to exporting areas and lower costs capacity reserves to importing areas.
Figure 111 and

Figure 112 show CAISO's daily and hourly average IRU transfers throughout June to July on both export (+) and import (-) directions. Generally, in both months, CAISO exported IRU and most of the exports went to PACE. And there was noticeable increase in July, with the peak IRU exports over 400 MW in afternoon peak hours.

Figure 111: Daily average IRU transfers for CAISO

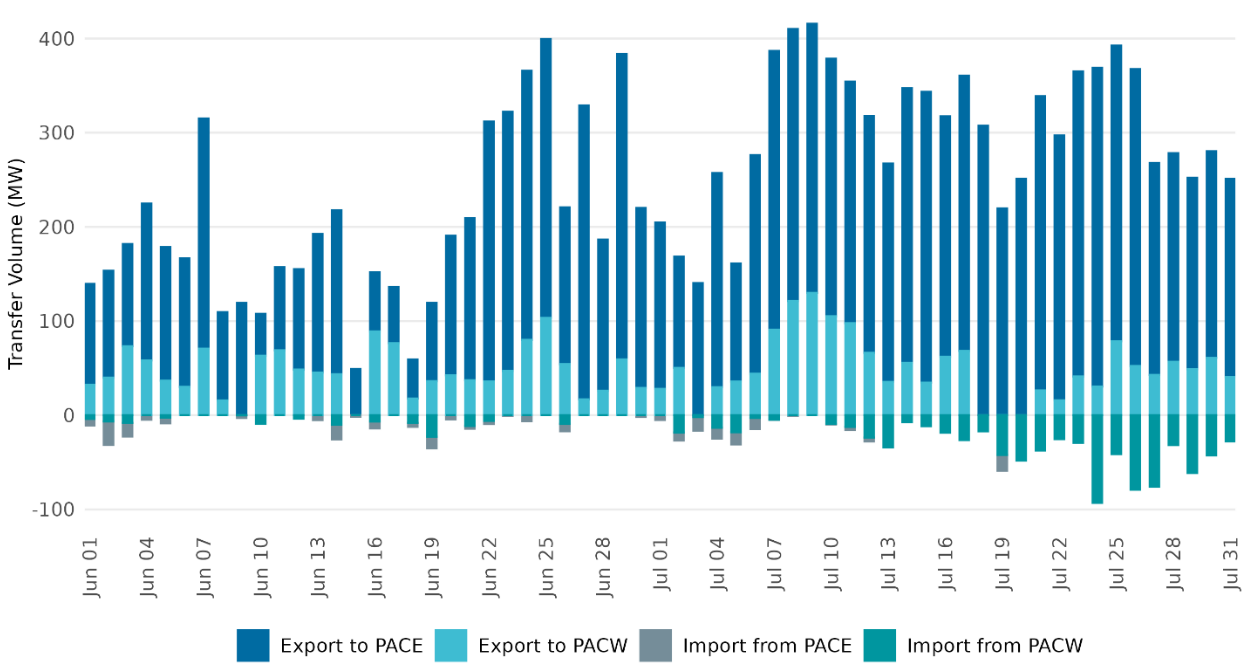


Figure 112: Hourly average IRU transfers for CAISO

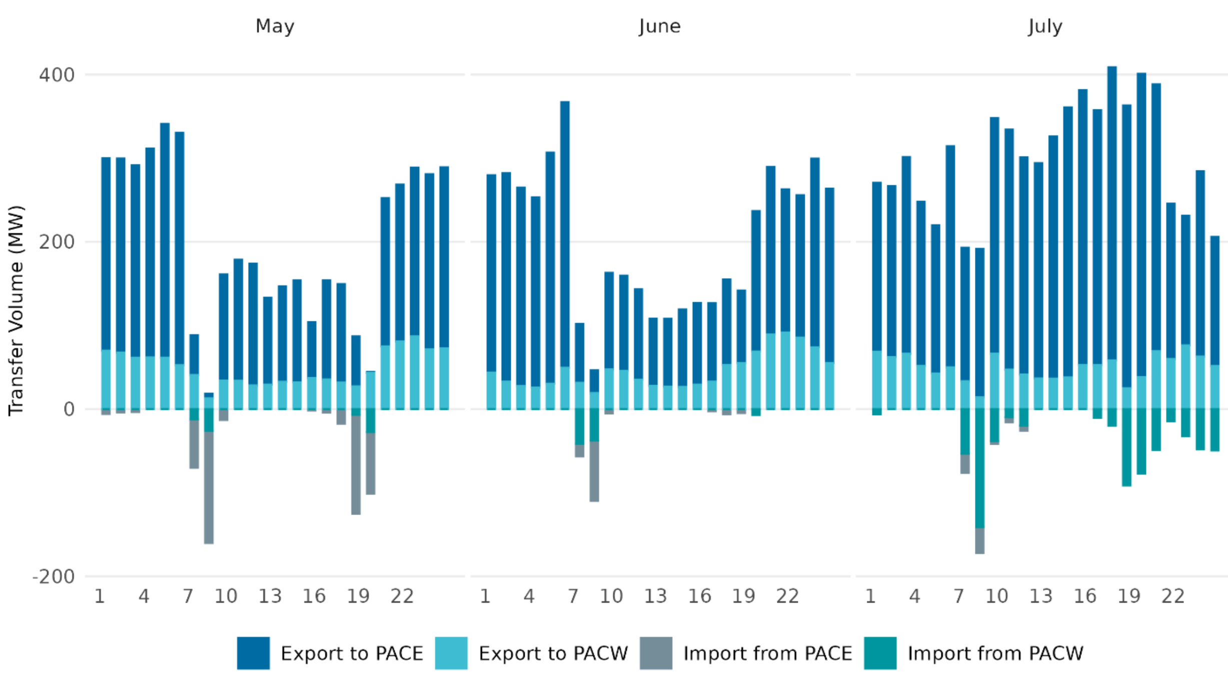


Figure 113 - Figure 114 show PACE's daily and hourly average IRU and IRD transfers throughout May to July 2026 on both export (+) and import (-) directions, respectively. For IRU products, PACE remained a net importer in both the months, and the main import is almost from CAISO. The daily and hourly charts showed that PACE's IRU imports increased in July, and peak imports were over 300 MW and mainly from the CAISO. However, for the IRU exports, PACE started to export IRU to PACW in June and July, although only a small

proportion of exports, and the export to CAISO during afternoon ramping hours decreased in June and July.

Figure 113: Daily average IRU transfers for PACE

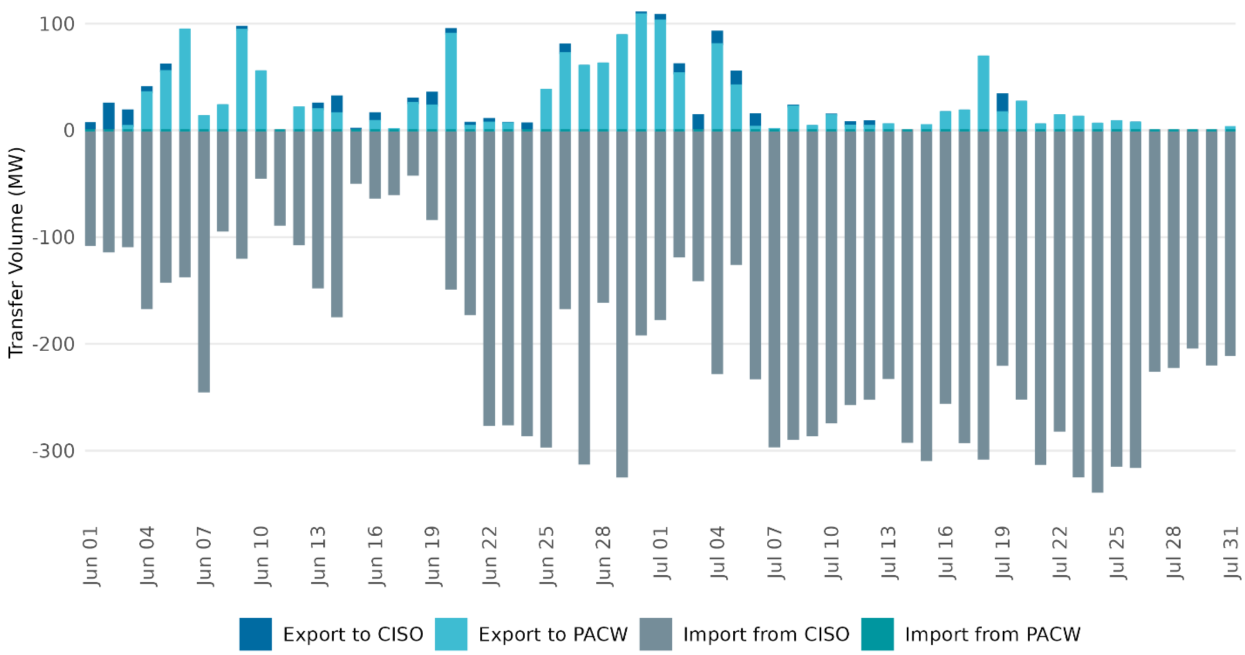


Figure 114: Hourly average IRU transfers for PACE

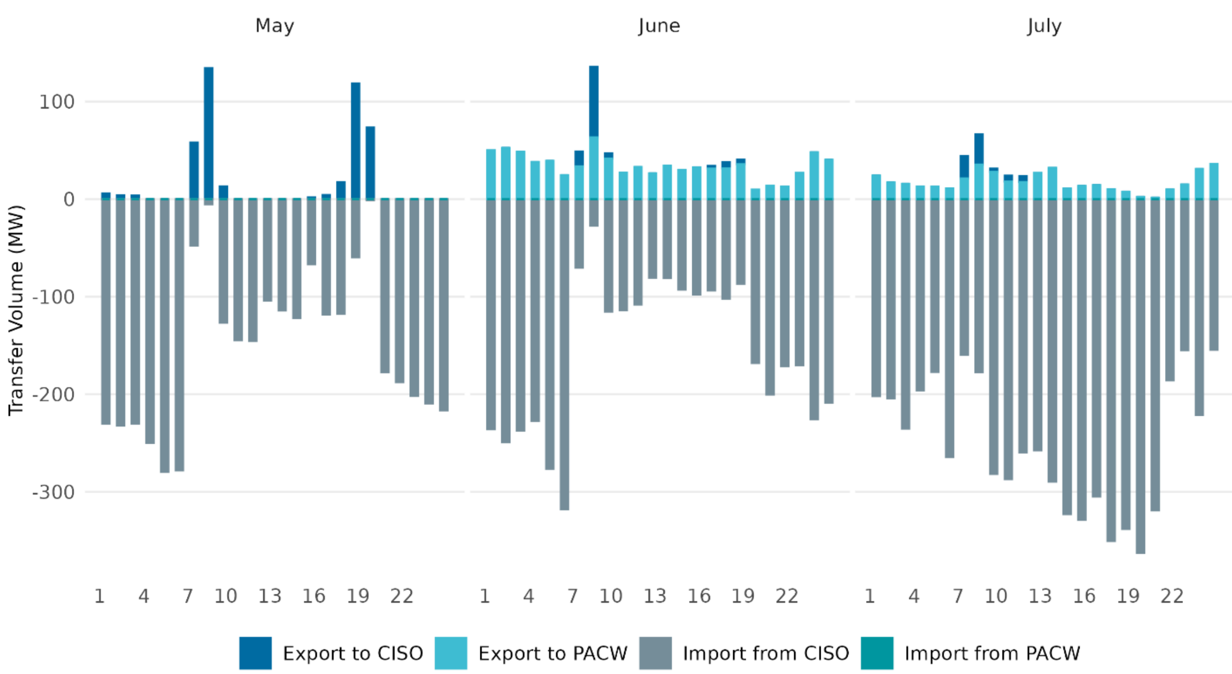


Figure 115 and Figure 116 show PACW's daily and hourly average IRU transfers throughout May to July 2026 on both export (+) and import (-) directions, respectively. Similar with energy transfer, PACW's IRU transfers were generally dominated by imports, and imports from PACE started to increase after June. In the hourly profile, there is an obvious IRU imports increase in June and July compared with May. The peak hours for IRU import are nighttime hours. However, PACW exported more IRU to CAISO in morning and afternoon peak hours in July, with maximum hourly average reached 145 MW in HE 8.

Figure 115: Daily average IRU transfers for PACW

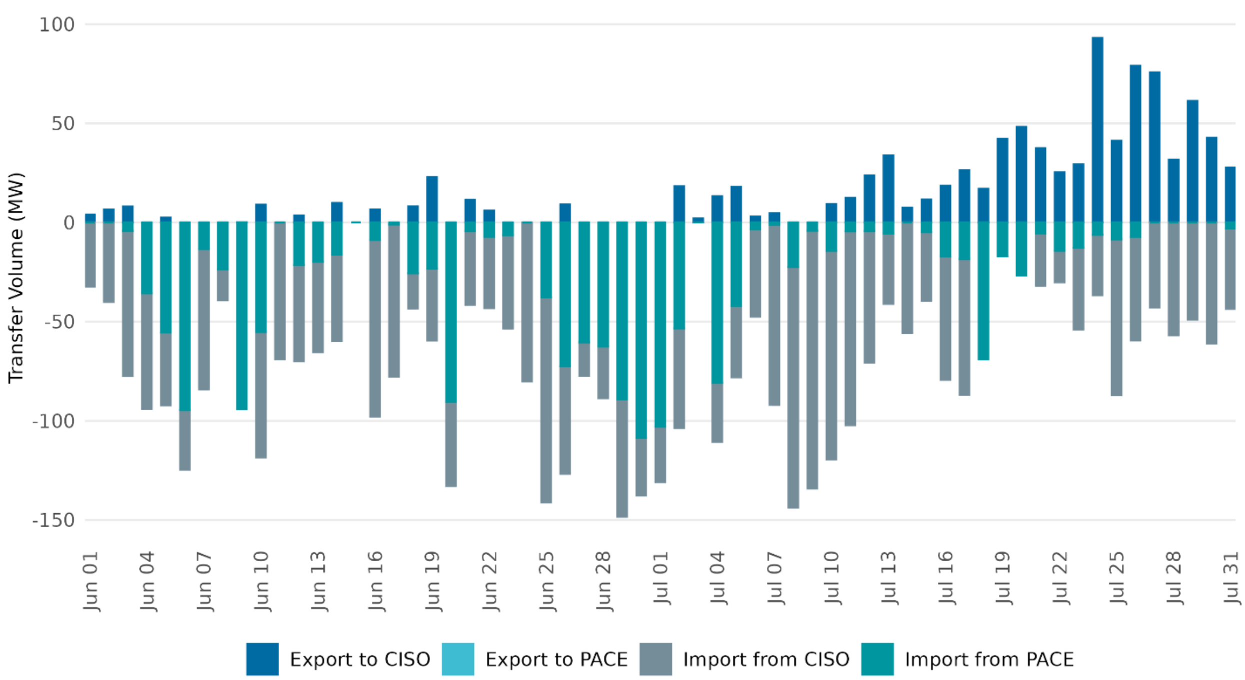


Figure 116: Hourly average IRU transfers for PACW

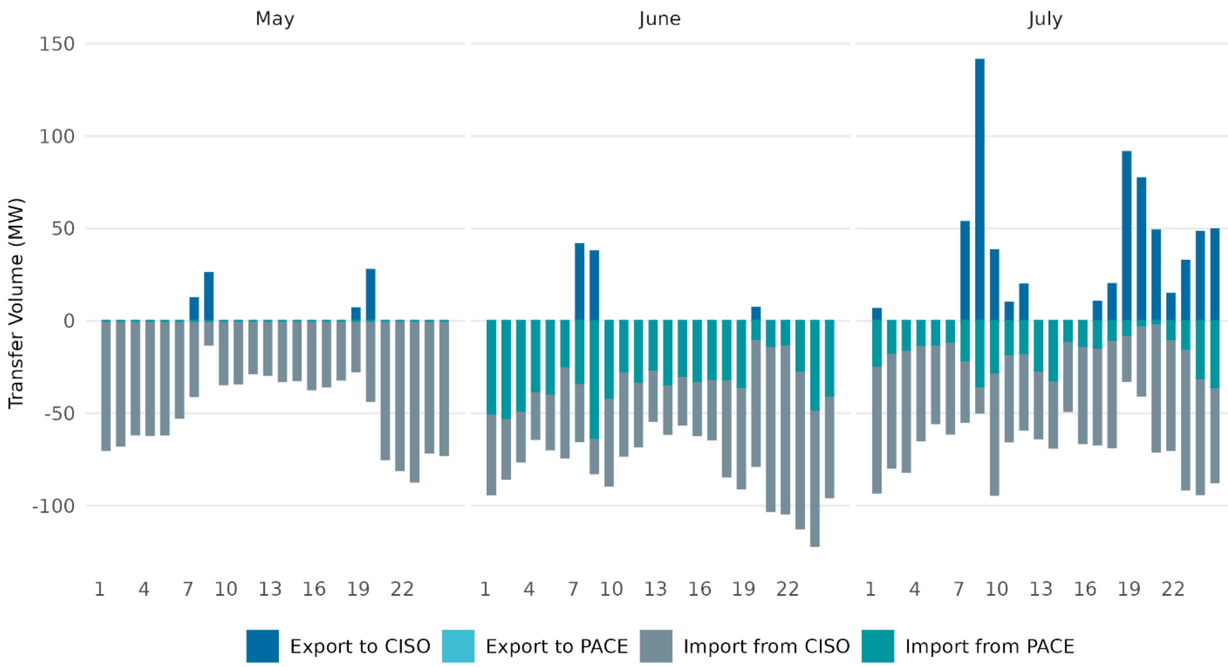
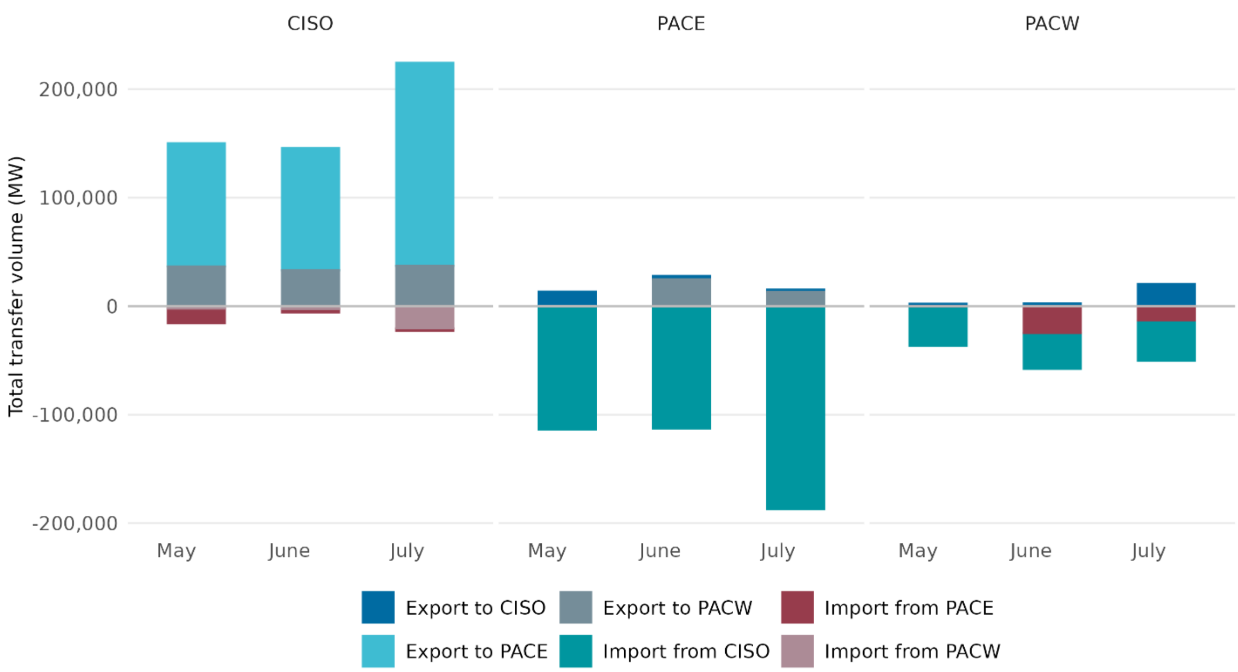


Figure 117 shows the summary of three BAAs' total IRU transfer volumes throughout May to June in both export (+) and import (-) directions. For CISO, the total transfer volumes are almost the same in May and June, with only a noticeable increase in exports to PACE in July. In July, PACW also increased its IRU exports to CAISO.

Figure 117: Total IRU transfers volumes for 3 BAAs per month



Imbalance reserve down

For IRD products, as Figure 118 and Figure 119 show, CAISO's main IRD imports were from PACE, and the IRD imports realized mainly in May. The IRD imports decreased in June and July, the peak IRD imports reached 300 MW in May and decreased significantly to 120 MW in July, While IRD exports to both PACE and PACW increased in June and July, with peak IRD exports reached 200 MW in solar peak hours.

Figure 118: Daily average IRD transfers for CAISO

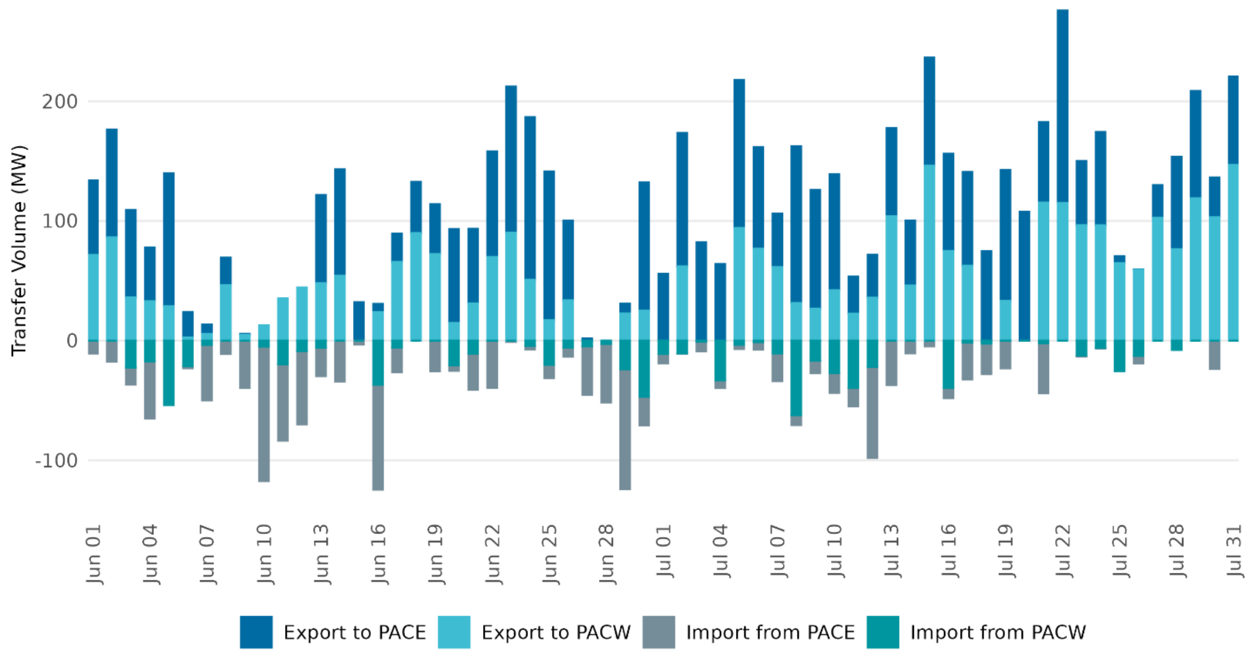
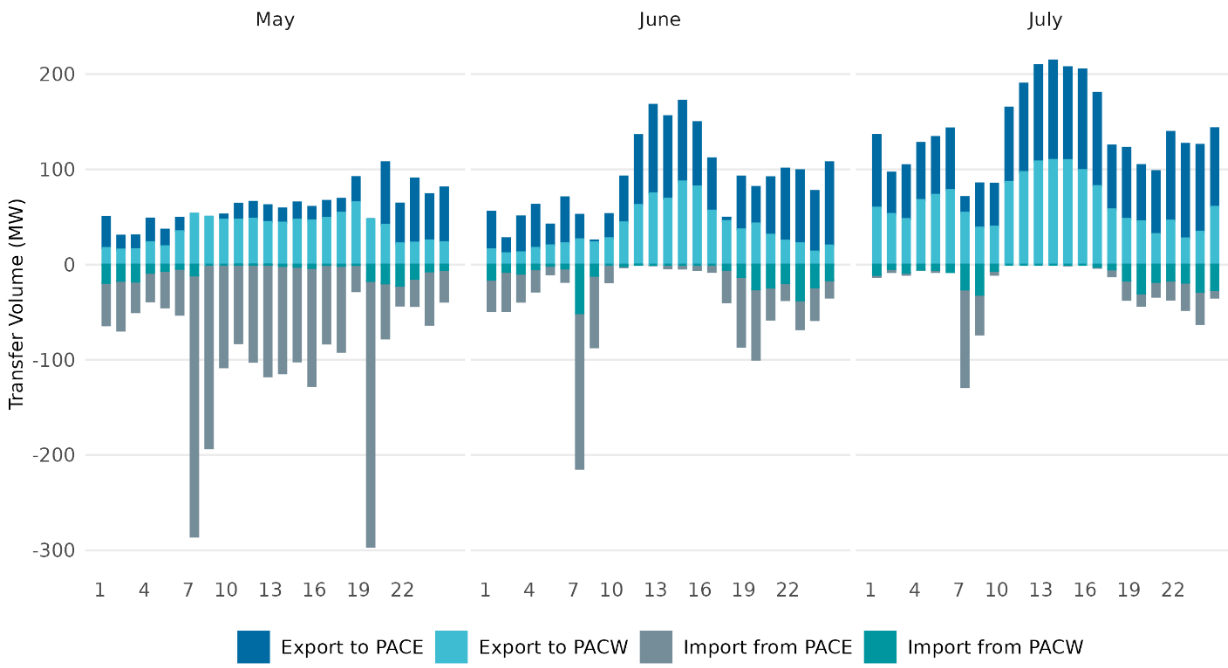


Figure 119: Hourly average IRD transfers for CAISO



PACE's IRD transfer showed a more dynamic pattern throughout May to July. In May, PACE remained a net exporter of IRD throughout the month and then switched to net importer in June and July. In May, PACE's IRD peak exports was about 300 MW but decreased to 200 MW in June and 140 MW in July. However, the average IRD imports increased in June and July, with peak imports over 100 MW, and the main transfer pairing entity is CAISO.

Figure 120: Daily average IRD transfers for PACE

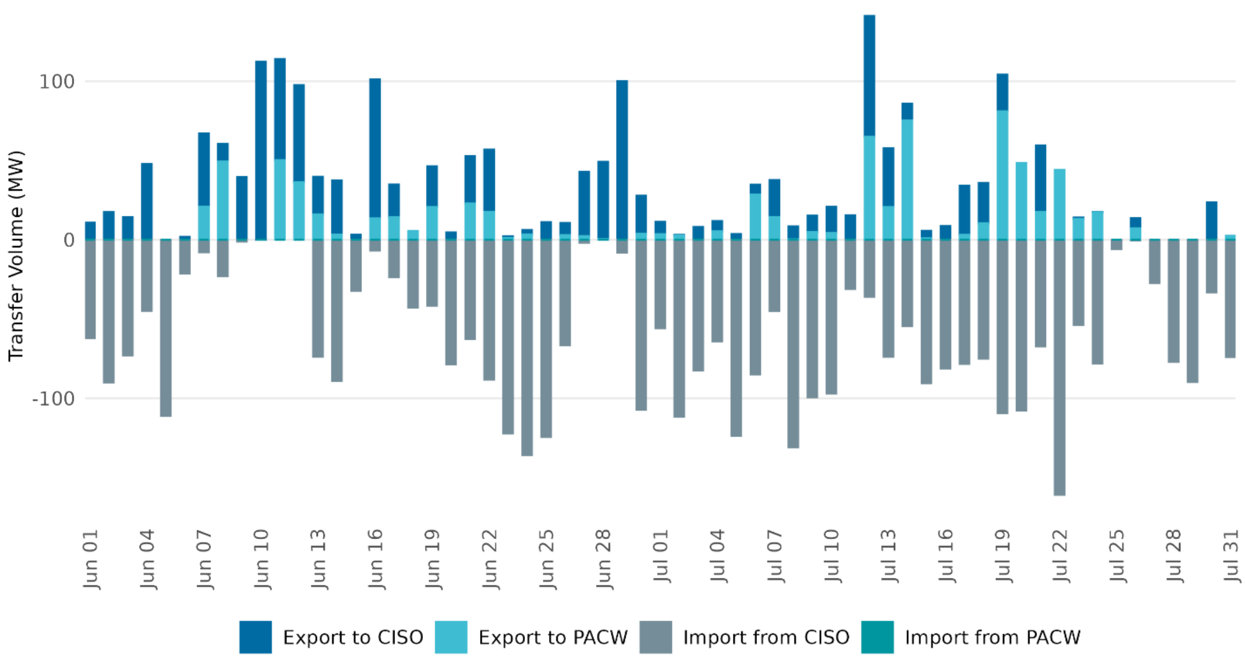
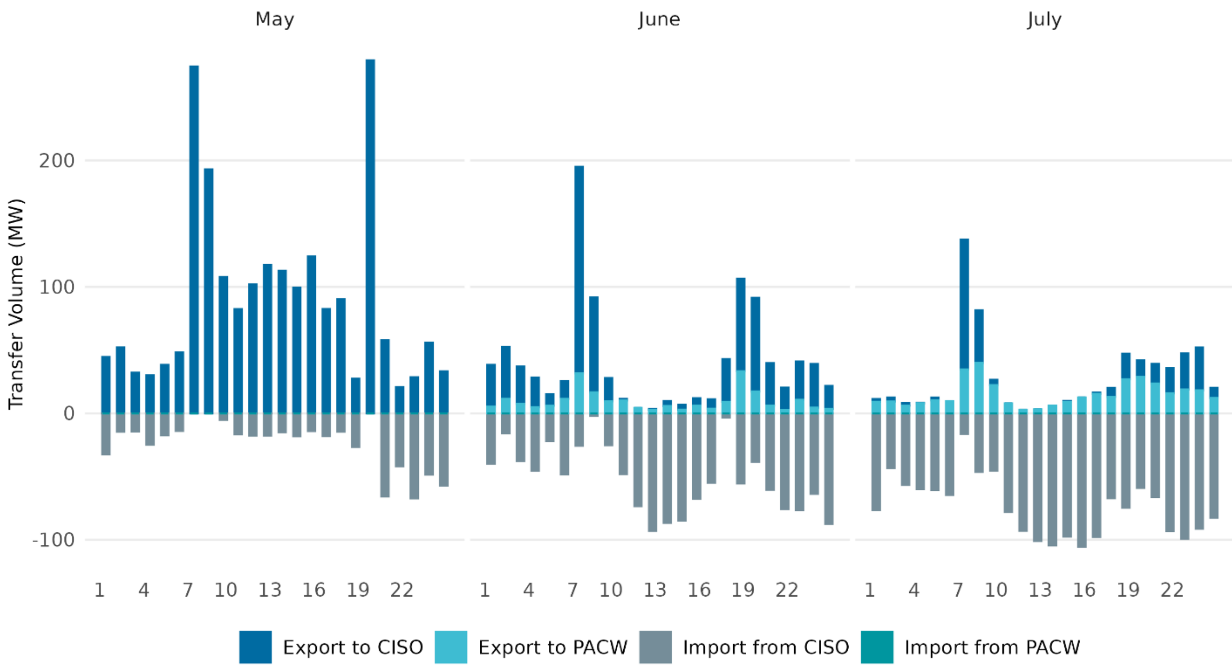


Figure 121: Hourly average IRD transfers for PACE



For IRD products, PACW remained a net importer in the three months. In June and July, PACW increased the IRD export to CAISO in morning and afternoon peak hours, with peak imports over 120 MW in solar peak hours. Besides, PACW also increased IRD imports from both CAISO and PACE in June and July, mainly in morning and evening peak hours.

Figure 122: Daily average IRD transfers for PACW

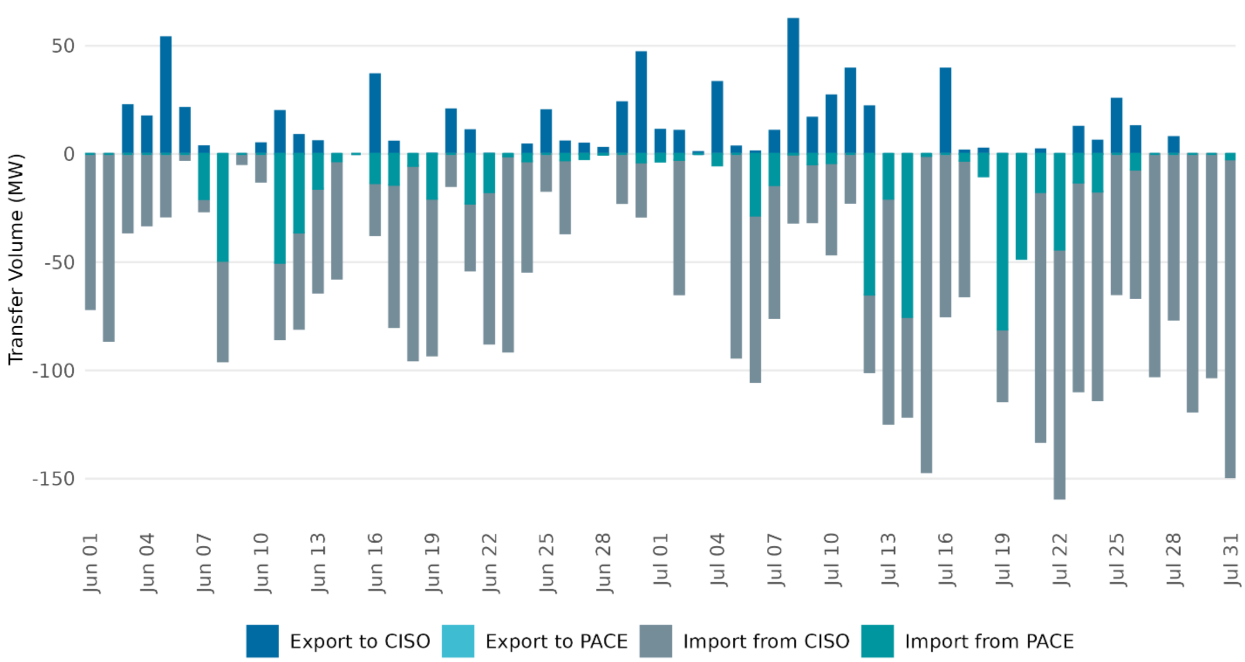


Figure 123: Hourly average IRD transfers for PACW

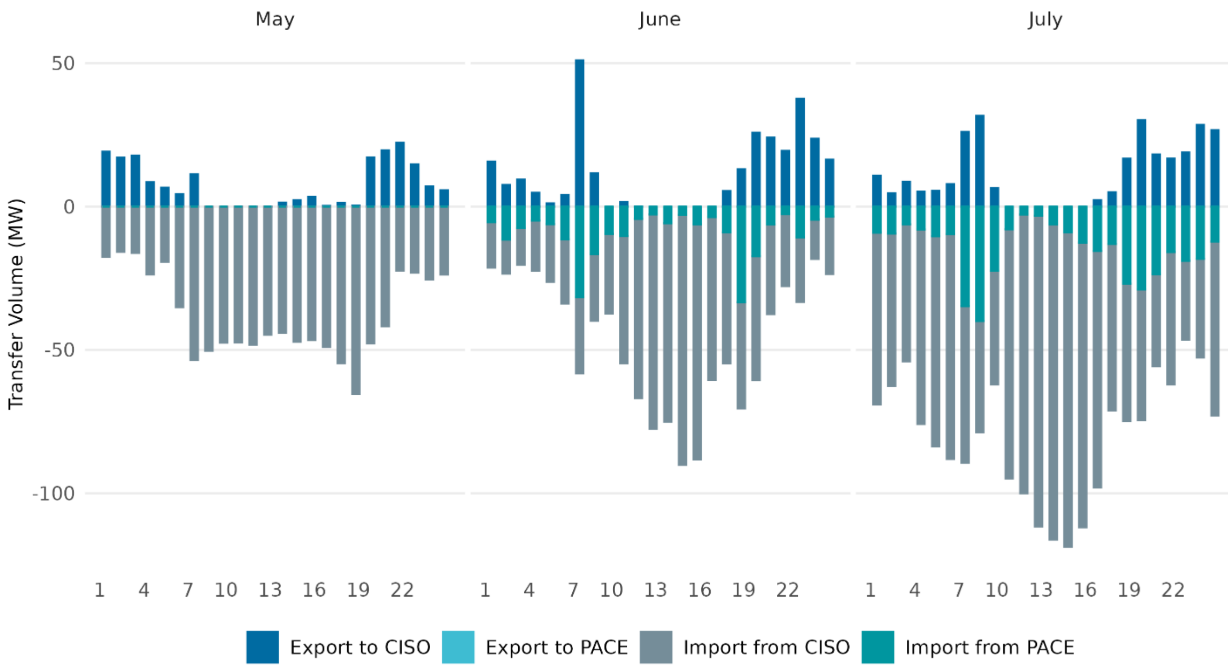
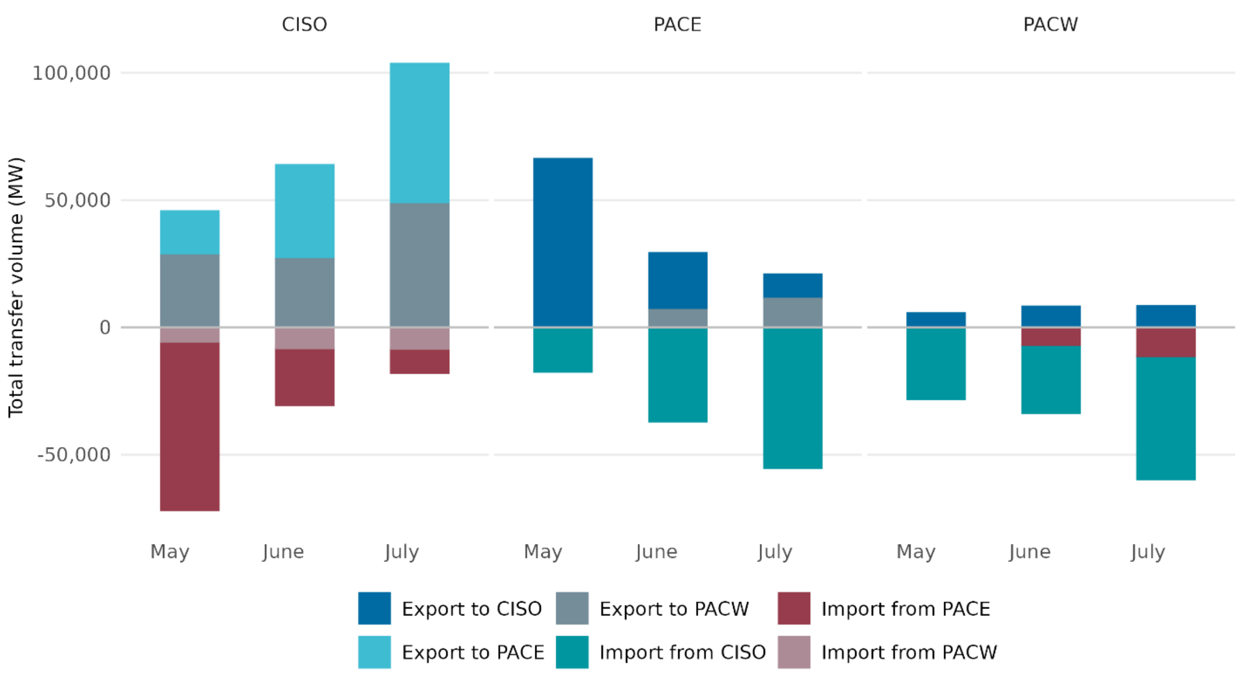


Figure 124 shows the summary of three BAAs' total IRD transfer volumes throughout May to June in both export (+) and import (-) directions. Compared with May and June, CAISO increased total IRD exports to PACE while decreased imports from PACE in July. PACE decreased IRD exports to CAISO and increased imports from CAISO, while PACW showed increase in both IRD import and export volumes in June and July.

Figure 124: Total IRD transfers volumes for 3 BAAs per month



Reliability capacity transfers

Reliability capacity is a new day-ahead product introduced with EDAM to procure upward and downward capacity needed to balance differences between cleared day-ahead physical supply and the load forecast. Reliability capacity ensures sufficient capacity is available to address both supply shortfalls and oversupply. This section summarizes the patterns of reliability capacity transfers among BAAs throughout May to July 2026.

Reliability capacity up

Figure 125 to Figure 126 show CAISO's daily and hourly average RCU transfers on both export (+) and import (-) directions. Generally, CAISO remained a net importer for RCU in three months. In June and July there were only limited RCU exports, and the main RCU importing pairing entity is PACW.

The hourly profile shows there were some RCU exports in May but almost reduced to zero in most hours in June and July. The RCU products were mainly imported from PACW, and peak RCU imports were over 130 MW in morning and afternoon peak hours.

Figure 125: Daily average RCU transfers for CAISO

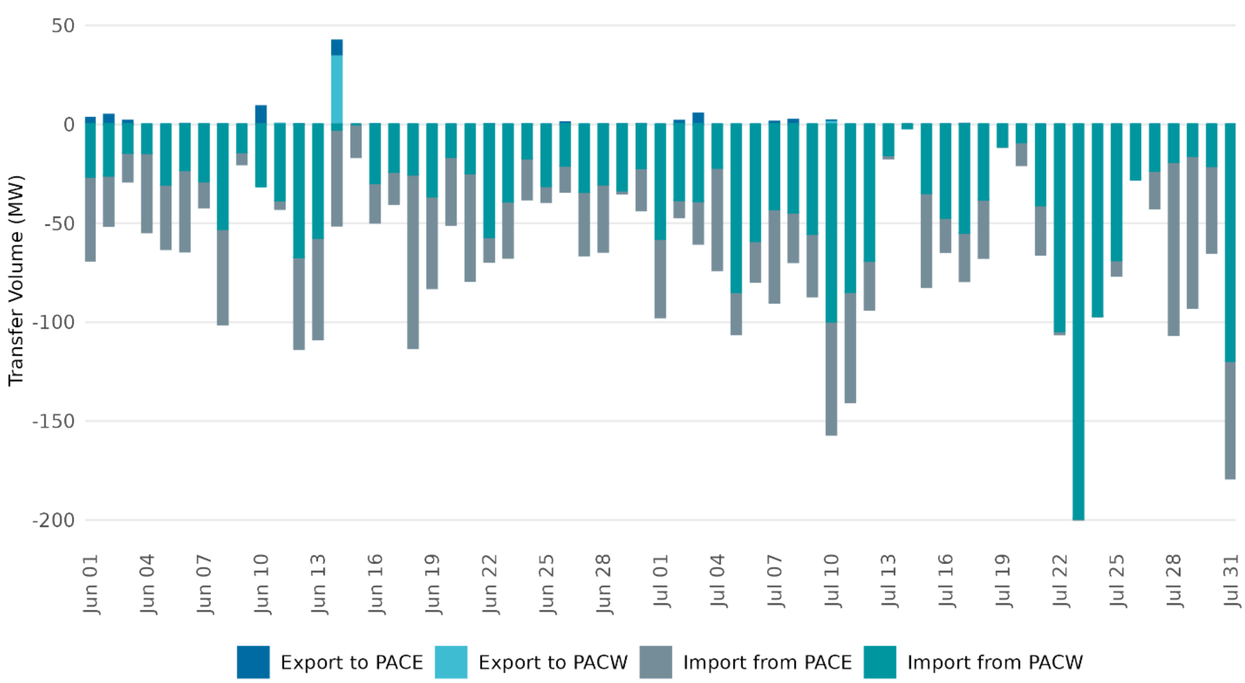


Figure 126: Hourly average RCU transfers for CAISO

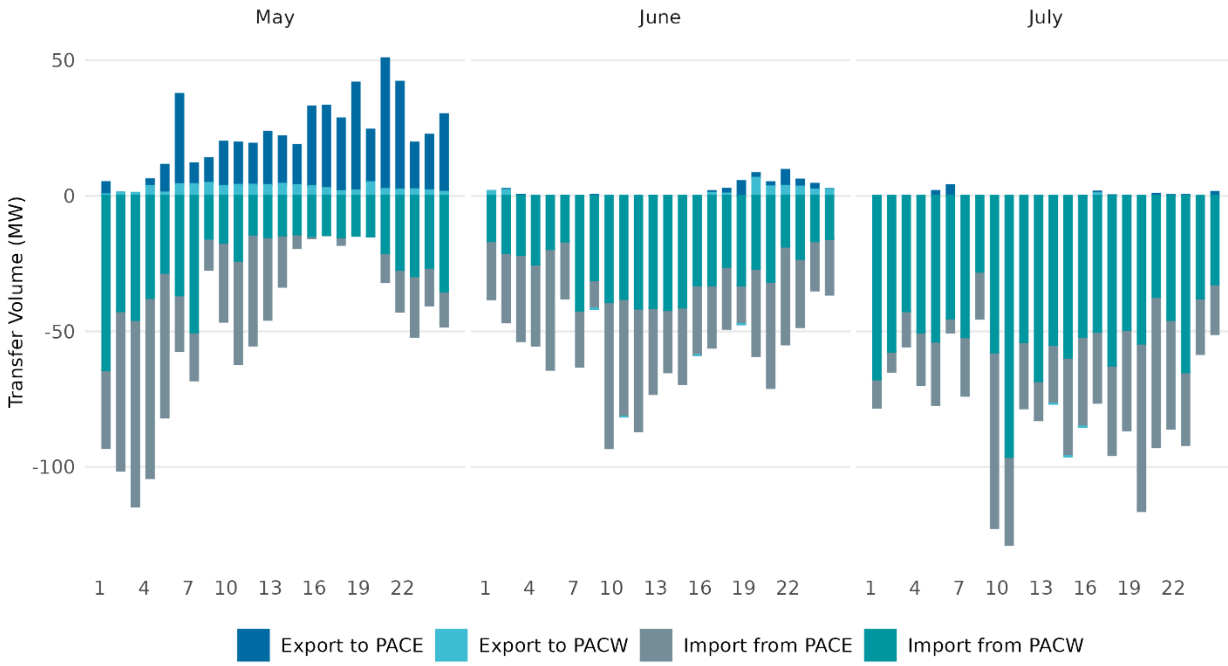


Figure 127 to Figure 128 show PACW's daily and hourly average RCU transfers throughout May to July 2026 on both export (+) and import (-) directions. Generally, exports dominate PACW's RCU transfer volumes in all three months. While there was limited RCU imports from CAISO in May, the import volume increased a lot in June and July and was mainly imported from PACE. Almost all the RCU exports were to CAISO.

In May, the hourly profile shows a persistent net export pattern across all hours, with the largest export occurring during the overnight and early morning hours. But later in June and July, the RCU exports were more concentrated to daylight hours, and the peak RCU exports were about 100 MW in July. Besides, PACW also increased RCU imports from PACE across all hours, and peak imports were over 60 MW in July.

Figure 127: Daily average RCU transfers for PACW

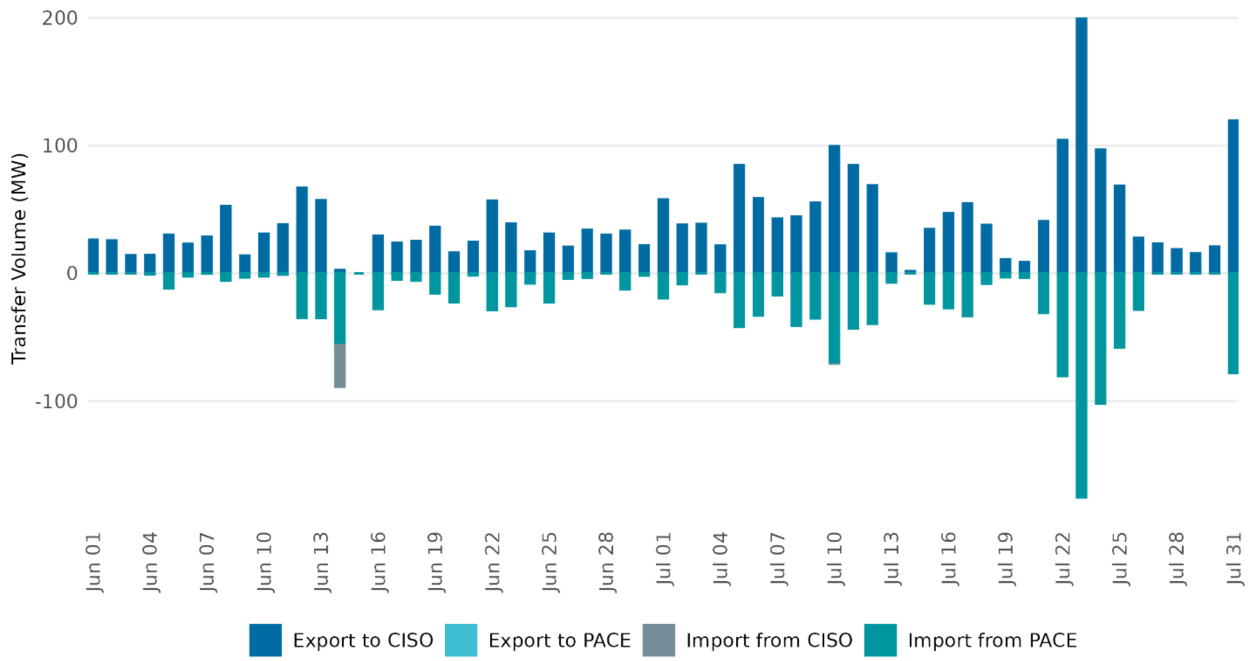


Figure 128: Hourly average RCU transfers for PACW

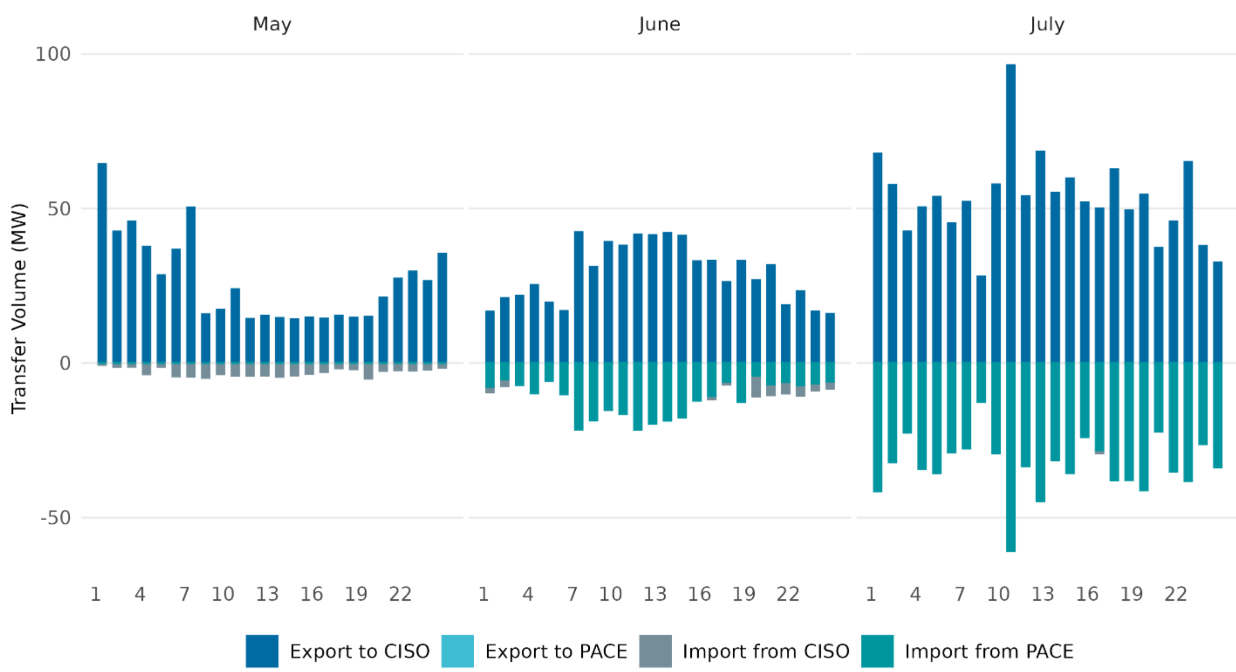


Figure 129 to Figure 130 show PACE's daily and hourly average RCU transfers in June and July 2026 on both export (+) and import (-) directions. The daily average profile shows that RCU transfer there was almost no RCU imports for PACE, and the daily maximum RCU export volume about 180 MW on July 23.

The hourly profile shows a more dynamic pattern in PACE's RCU transfers, as a net exported in May then turned into a net exporter in June and July. Besides, there was noticeable increase in RCU exports in July, with peak imports over 100 MW in HE 19.

Figure 129: Daily average RCU transfers for PACE

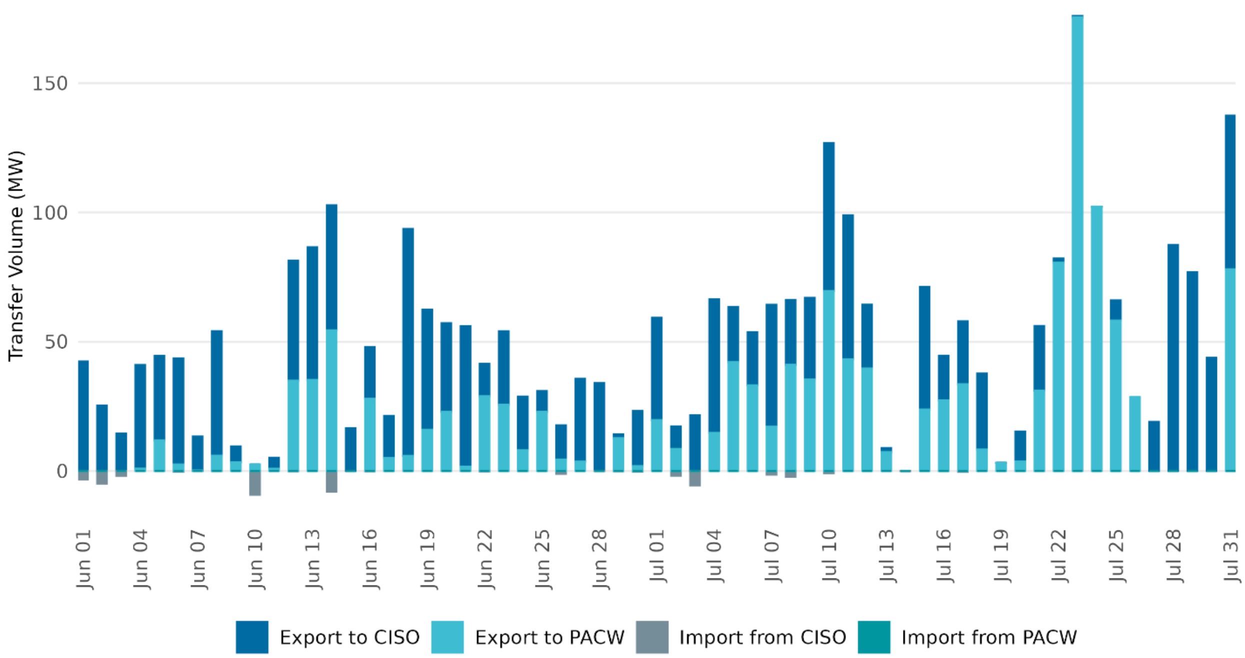


Figure 130: Hourly average RCU transfers for PACE

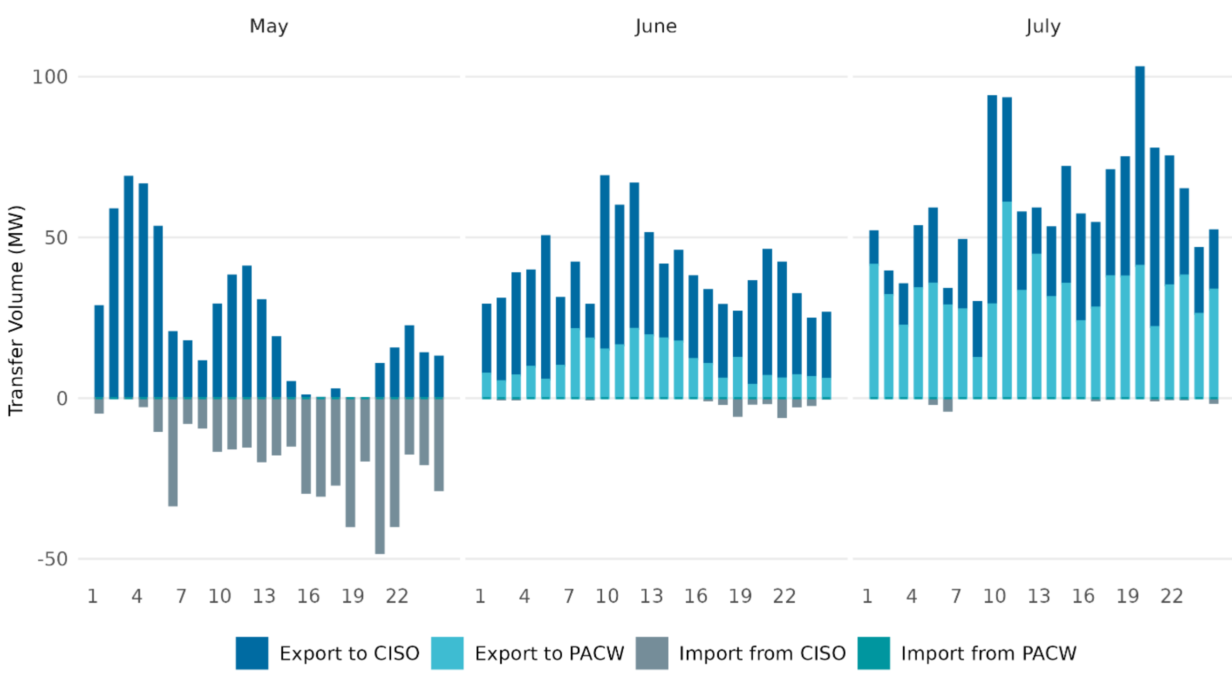
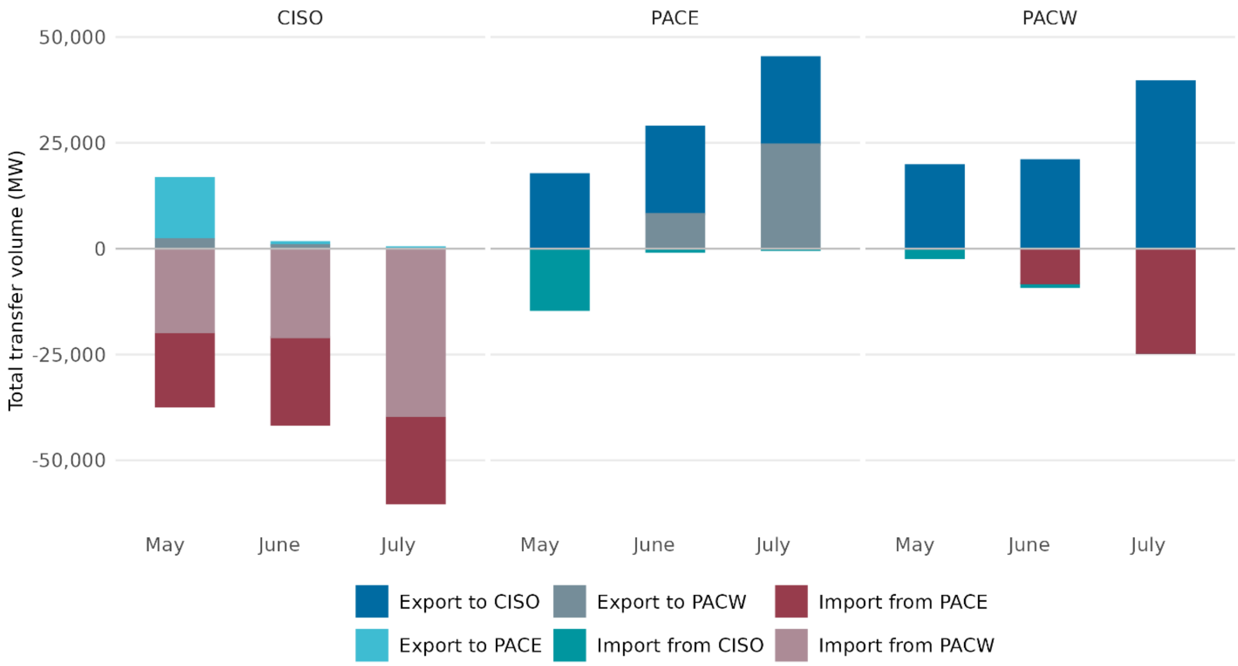


Figure 131 shows the summary of three BAAs' total RCU transfer volumes throughout May to July in both export (+) and import (-) directions. Compared with May, CAISO reduced significant RCU exports to PACE while imports from PACE and PACW increased in June and July. Accordingly, PACE decreased RCU imports from CAISO, while the RCU transfer between PACE and PACW showed significant increase.

Figure 131: Total RCU transfers volumes for 3 BAAs per month



Reliability capacity down

CAISO's RCD transfers were more concentrated on the exports side in June and July, with several days' imports dominating the transfers. Generally, CAISO remained a net exporter in June and July. The hourly profile shows the average import peak is in evening hours in May. In June and July, CAISO's RCD imports during night hours decreased, while exports increased during morning peak hours.

Figure 132: Daily average RCD transfers for CAISO

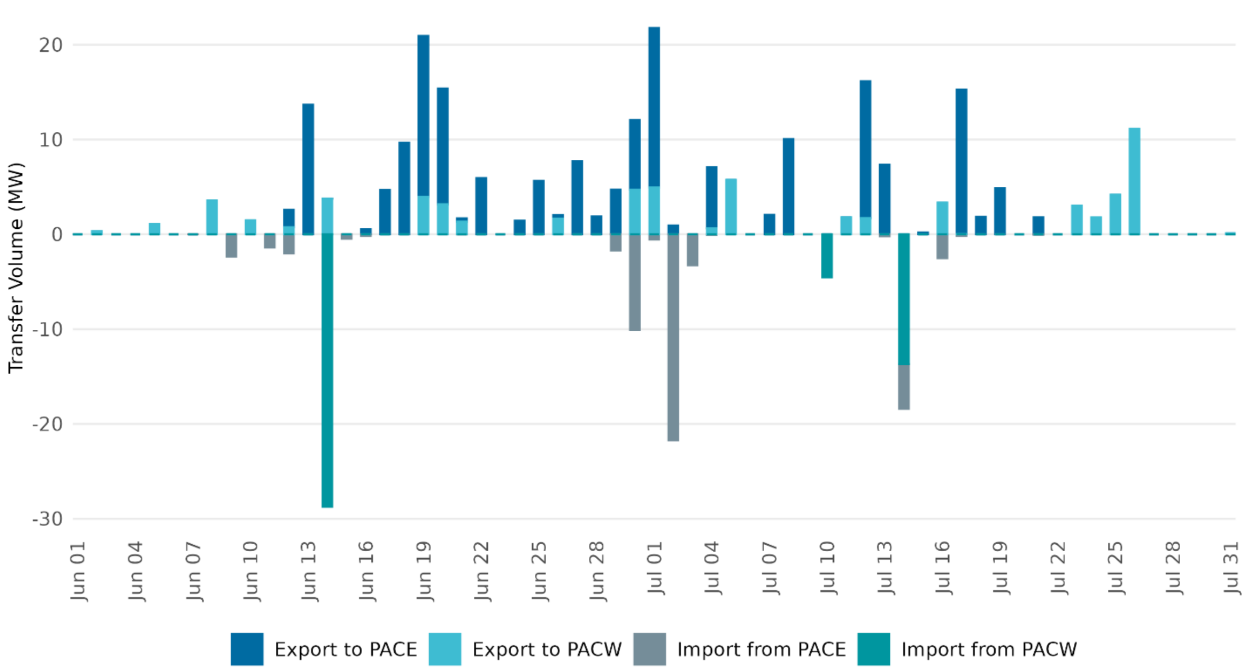
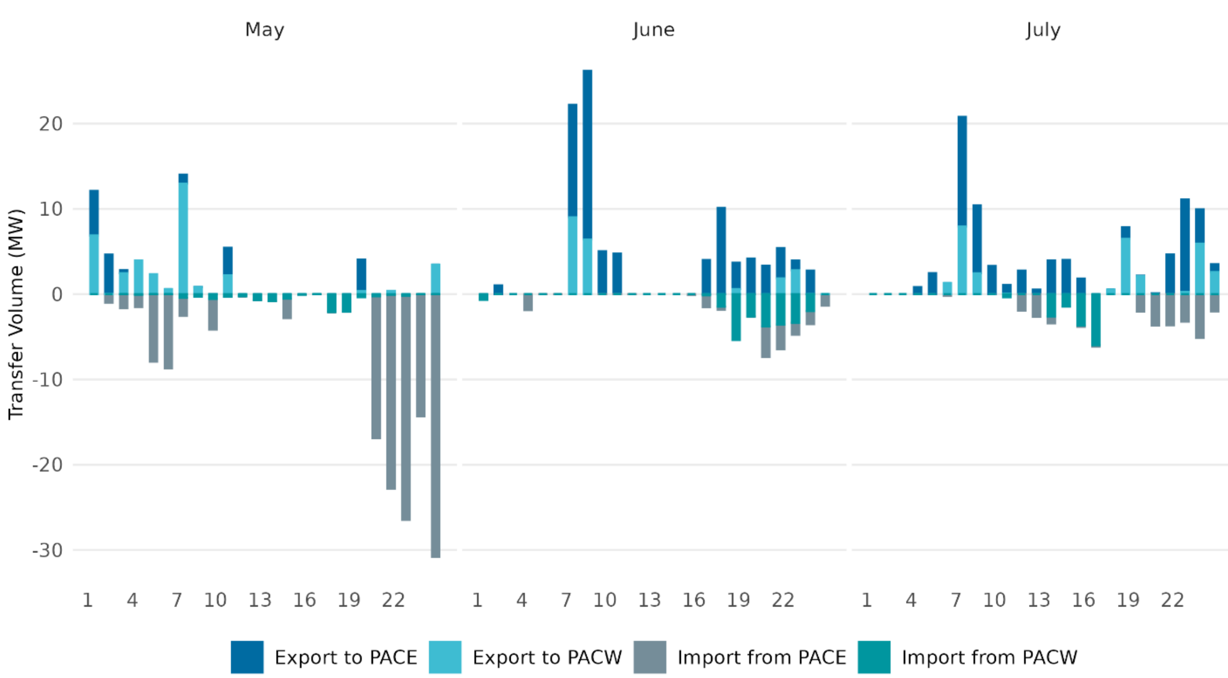


Figure 133: Hourly average RCD transfers for CAISO



For RCD products, PACE's average transfer showed different patterns in May but stayed the same in June and July. RCD exports were mainly to PACW, and most imports were from

CAISO. The hourly profile shows that net exports dominated in May. In June and July, the night hours of RCD exports decreased while PACE increased its import from CAISO during morning and afternoon peak hours.

Figure 134: Daily average RCD transfers for PACE

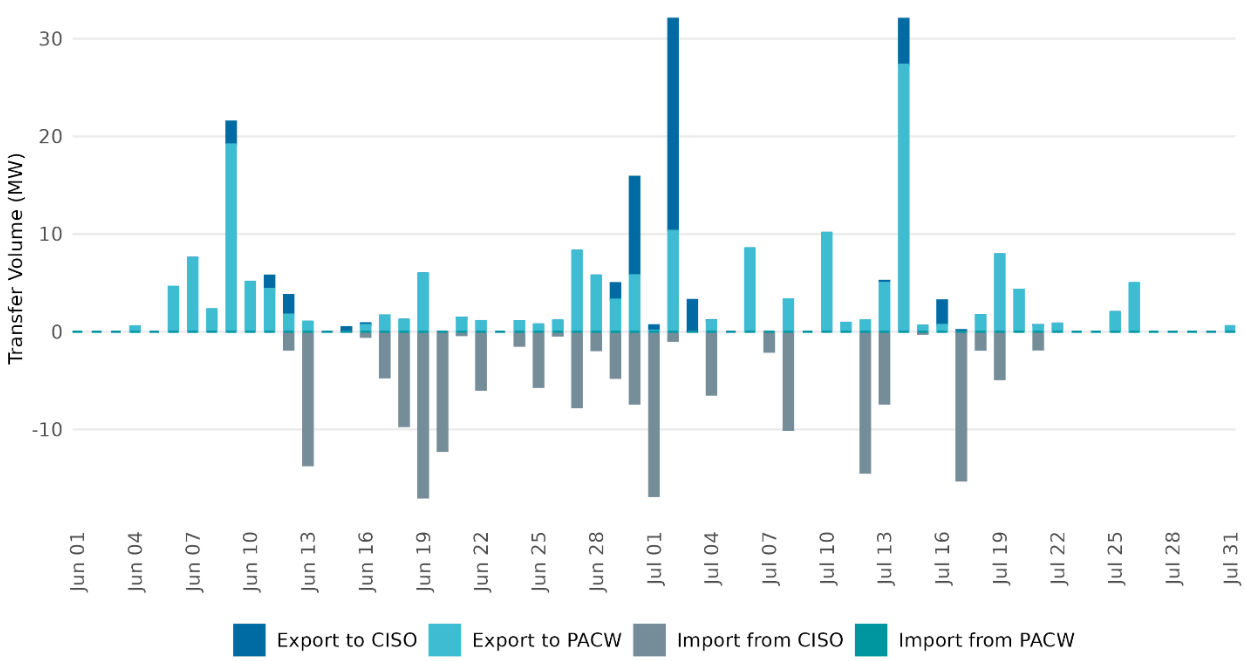
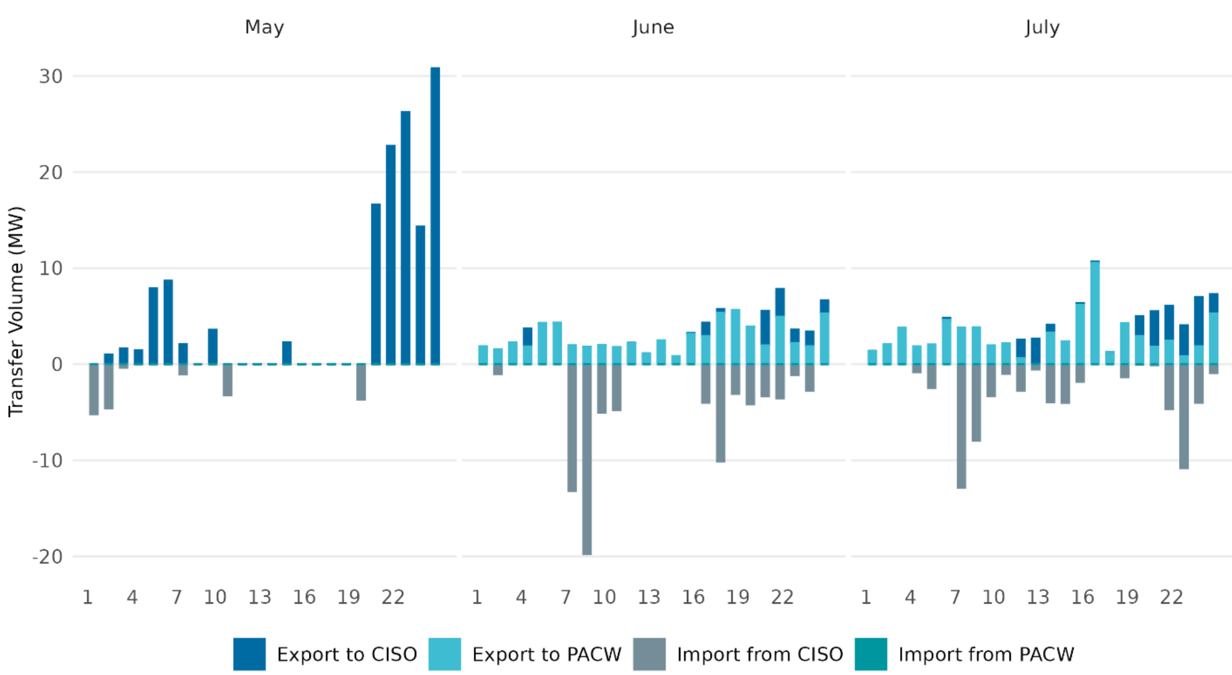


Figure 135: Hourly average RCD transfers for PACE



As for RCD transfer in PACW, the average imports were more concentrated in June and July, as a result PACW remained a net importer. The hourly RCD transfer profile showed the import peak is mainly at Hour 7 in all the months, while the export peak was during night hours in June and afternoon hours in July.

Figure 136: Daily average RCD transfers for PACW

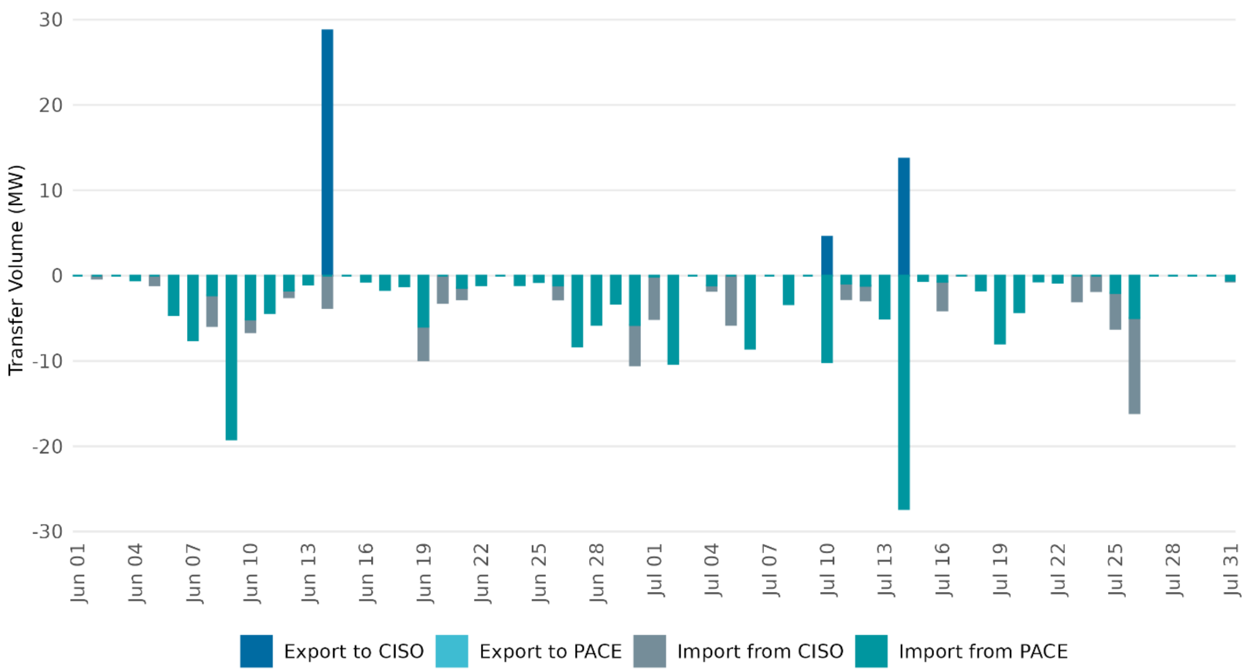


Figure 137: Hourly average RCD transfers for PACW

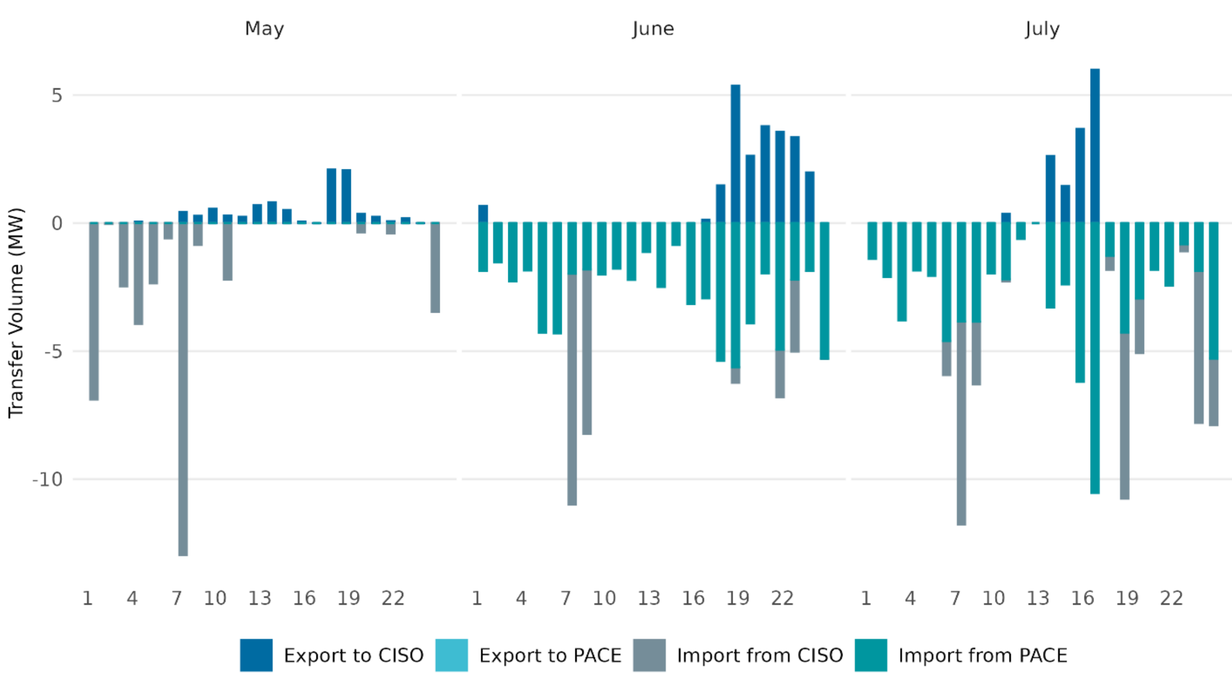
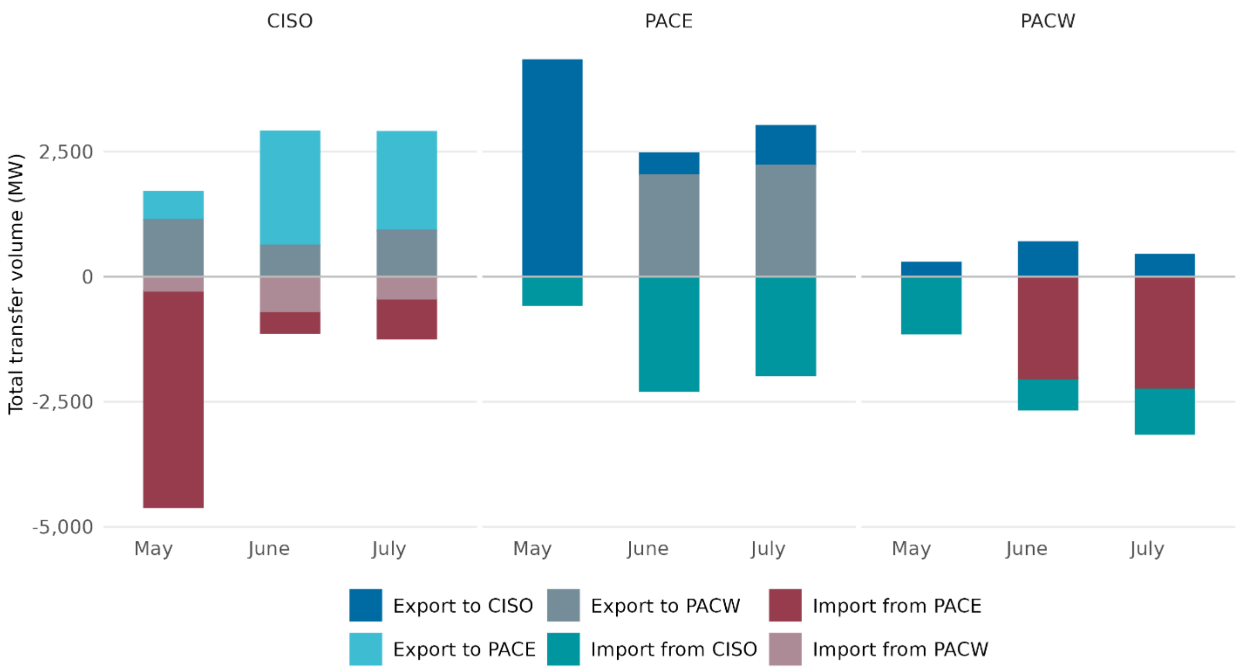


Figure 138 shows the summary of three BAAs' total RCD transfer volumes throughout May to July in both export (+) and import (-) directions. Generally, both BAAs have very similar patterns in June and July. Compared with May, CAISO reduced RCD imports from PACE while increasing imports to PACE in June and July. Accordingly, PACE decreased RCD exports to CAISO in June and July but increased more imports from CAISO.

Figure 138: Total RCD transfers volumes for 3 BAAs per month



Congestion

Congestion can occur when the lowest cost energy cannot be transmitted to meet demand where it is needed due to a lack of transmission capacity. In that situation, higher cost, local resources must be used to meet that demand in a constrained area. The added cost of bringing on these resources is reflected in the Locational Marginal Price (LMP) through Marginal Cost of Congestion (MCC) component. In other words, the MCC is the cost of delivering one additional MW to that node/location due to congestion on the system.

Table 7 shows the average MCC for the month of May for the EDAM DLAP/ELAP APnodes[4]. Since congestion is defined at each location, using the DLAP/ELAP of the market areas is a simple and reasonable representation of the overall congestion in each area.

[4] These results are preliminary and subject to revision. A known data issue is currently under investigation, which may result in discrepancies in the analysis.

Table 7: Average congestion costs

	Average MCC ($/MWh)		
DLAP/ELAP	May	June	July
PACE	(0.80)	(0.75)	(0.19)
PACW	0.48	(0.87)	(0.93)
PGAE	4.04	2.29	(1.10)
SCE	(3.68)	(1.76)	0.56

A positive number for MCC represents an increase in DLAP/ELAP LMP due to system congestion while a negative number represents a decrease in LMP from congestion. A positive MCC for a DLAP/ELAP indicates a more constrained area where cheaper energy may not be able to flow. In July, congestion continues to have low impacts on PACE and PACW ELAP locational marginal prices, at -$0.19 and -$0.93, respectively. In contrast, within CAISO DLAPs, SCE MCC averaged $0.56, while PGAE MCC averaged -$1.10. CAISO DLAPs saw lower than usual average monthly congestion impacts than in past months due to a shift in congestion direction in the second half of July. Typically, there is notable congestion price separation between Northern and Southern California with PGAE MCC in the positive direction and SCE in the negative. This is indicative of the Northbound congestion. In the second half of July, the overall direction of congestion shifted to Southbound. This was primarily driven by the 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 constraint binding consistently from July 12th onward.

This constraint congestion also resulted in negative MCCs at PACW. The monthly average congestion price at PACE was minimal, driven from a variety of CISO constraints.

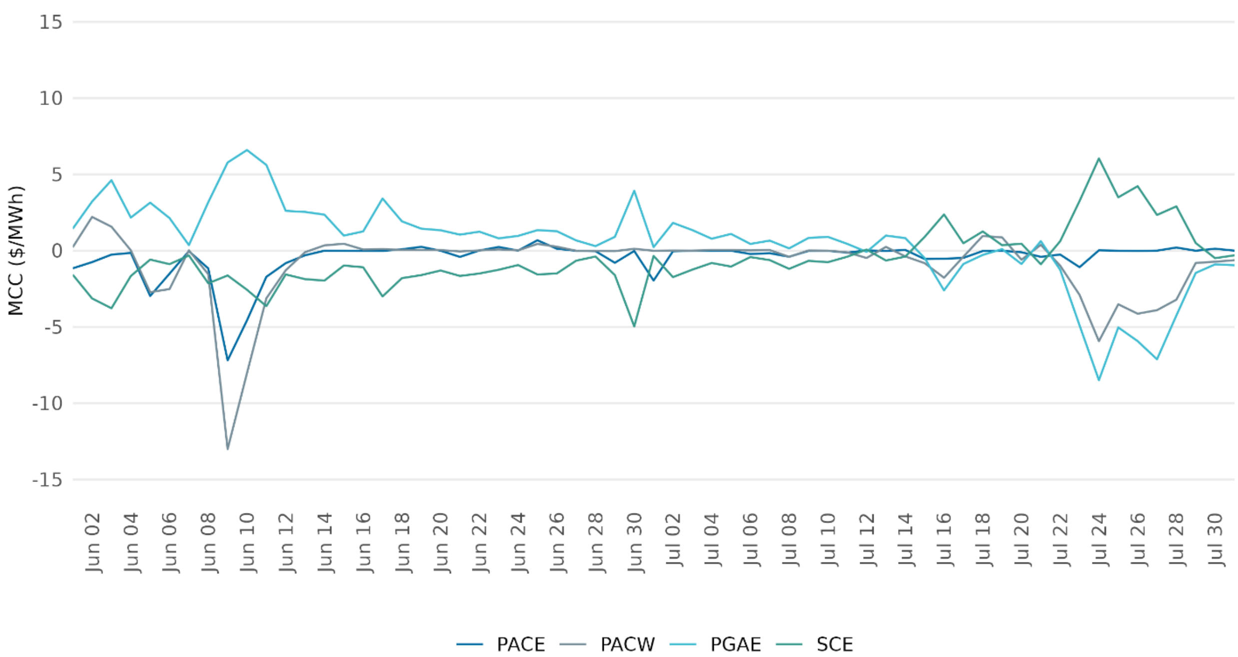
Table 8 provides an hourly average of congestion costs across areas with the green gradient indicating larger positive MCC prices and the gradient of violet indicates larger negative MCC prices. Unlike the last couple months, the hourly monthly averages for all areas are not concentrated around solar hours. Again, this is largely driven by the 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 constraint binding with its highest impact to all areas in evening into the early morning. During this period of congestion, PACE congestion prices tracked Southern California while PACW tracked Northern California.

Table 8: Hourly average congestion costs

	May				Jun				Jul			
Trade Hour	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE	PACE	PACW	PGAE	SCE
1	-0.64	-0.63	-0.48	-0.37	-0.99	-1.46	0.32	0.16	0.00	-0.94	-1.16	0.85
2	-0.55	-1.37	-0.45	-0.08	-0.89	-1.61	0.35	0.10	0.04	-0.93	-1.13	0.90
3	-0.48	-0.43	-0.54	-0.35	-0.65	-1.00	0.23	0.10	-0.05	-0.53	-0.59	0.47
4	-0.40	-0.97	-0.65	-0.05	-0.70	-1.33	0.32	0.11	-0.11	-0.49	-0.62	0.53
5	-0.37	-0.34	-0.46	-0.36	-0.68	-1.00	0.28	-0.06	-0.20	-0.43	-0.54	0.49
6	-0.50	-1.09	-0.60	-0.21	-0.87	-1.41	0.39	-0.01	-0.01	-0.44	-0.60	0.42
7	-0.55	-0.32	0.24	-0.59	-0.33	-0.52	0.17	-0.08	-0.03	-0.33	-0.47	0.30
8	-1.10	1.53	6.58	-6.39	-0.55	0.03	3.18	-3.04	-0.33	-0.11	0.11	-0.30
9	-0.85	2.96	10.48	-9.80	-0.45	0.45	5.14	-4.69	-0.30	-0.09	0.44	-0.96
10	-0.52	2.74	10.33	-9.29	-0.44	0.35	5.39	-4.73	-0.33	-0.17	0.52	-0.96
11	-0.39	2.28	8.44	-7.45	-0.27	0.54	3.31	-3.85	-0.30	-0.44	-0.20	-0.40
12	-0.27	2.24	7.92	-6.77	-0.30	0.34	3.75	-3.41	-0.19	-0.57	-0.54	-0.19
13	-0.09	2.32	7.85	-6.53	-0.17	0.66	3.70	-3.39	-0.15	-0.66	-0.68	-0.13
14	-0.15	2.46	7.73	-6.46	-0.28	0.69	4.11	-3.56	-0.26	-0.65	-0.78	0.07
15	-0.19	2.50	7.66	-6.34	-0.22	1.07	4.25	-3.91	-0.46	-0.68	-1.22	0.44
16	-1.26	2.56	8.92	-6.80	-0.19	0.44	4.47	-4.04	-0.60	-1.42	-2.06	1.09
17	-1.48	2.50	8.37	-6.79	-0.37	0.50	4.31	-3.91	-0.56	-1.54	-2.97	0.00
18	-2.50	-0.38	8.03	-6.16	-0.65	-0.90	3.45	-2.80	-0.50	-2.66	-2.76	1.89
19	-1.75	-1.35	3.18	-2.79	-1.23	-2.19	1.89	-0.87	-0.09	-2.86	-3.13	2.50
20	-1.62	-1.92	2.14	-1.66	-2.16	-4.30	2.25	-0.58	-0.07	-1.58	-1.75	1.38
21	-1.28	-1.01	1.62	-1.51	-1.56	-3.03	1.40	-0.27	-0.03	-1.06	-1.16	0.98
22	-1.00	-1.21	0.71	-0.85	-1.58	-3.04	1.15	-0.05	-0.01	-1.49	-1.91	1.50
23	-0.73	-0.81	0.02	-0.47	-1.19	-2.16	0.68	0.16	-0.01	-1.14	-1.50	1.26
24	-0.48	-0.79	-0.19	-0.28	-1.16	-2.06	0.54	0.27	0.00	-1.21	-1.73	1.40

Figure 139 provides a daily trend of congestion costs across the last two months. Overall congestion price in the first half of July were similar to June with south to north congestion patterns between CISO areas and mild prices for PAC areas. Once the 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 constraint started to bind around July 12th, CISO area congestion prices change direction, and PACW congestion prices increased. The most significant congestion impact occurred between July 22nd and July 29th.

Figure 139: Daily average congestion cost by area



Parallel flows

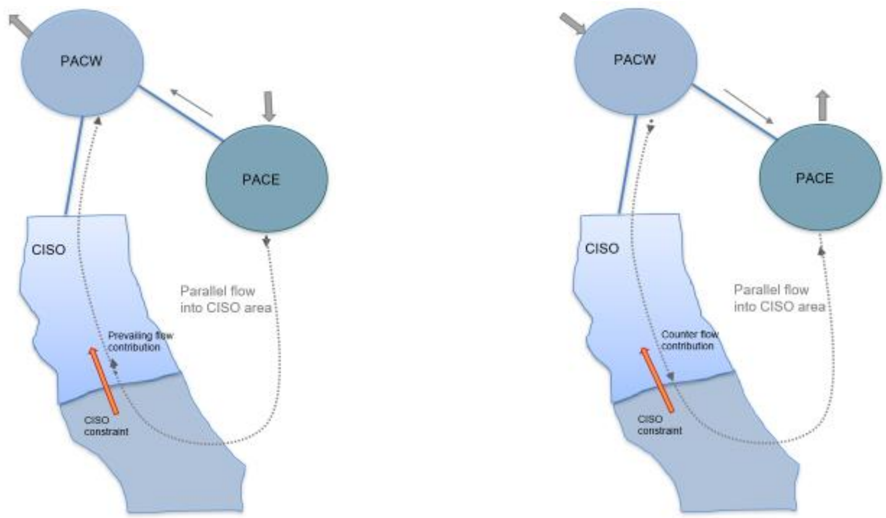
A more fundamental assessment of EDAM transaction effects is to examine their flow contributions on transmission constraints. Transactions in one BAA can contribute to flows on transmission constraints in another BAA; these are known as *parallel flow*. The data is presented in a matrix of transactions vs. constraints to highlight potential parallel flows across PAC and CAISO constraints due to transactions in these areas.

Figure 140: Parallel flow matrix example

	PACE transaction	PACW transaction	CISO transaction
PACE constraint	Internal flow on PACE	Parallel flow on PACE	Parallel flow on PACE
PACW constraint	Parallel flow on PACW	Internal flow on PACW	Parallel flow on PACW
CISO constraint	Parallel flow on CISO	Parallel flow on CISO	Internal flow on CISO

Figure 140 also highlights the impact of transactions on internal flows within each BAA, illustrating how CAISO transactions affect CAISO constraints. Parallel flows are a physical reality, independent of market constructs, economics, or contracts. They can either align with the prevailing direction of congestion or oppose it, creating counterflows. Transactions in the prevailing direction are charged for contributing to congestion, while transactions in the opposite direction are credited for relieving congestion. Figure 141 illustrates the concepts of prevailing and counter flows from a transaction between PAC areas creating a parallel flow in CAISO BAA.

Figure 141: Illustration of parallel flows



In July, the impact of transactions in PAC areas over constraints in the CAISO area were meaningful, while the impact of CAISO transactions on PAC areas was minimal.

With the launch of EDAM/DAME, priced flows from one EDAM BAA can directly impact transmission constraints in another BAA based on current system topology.

Table 9 goes a step further and breaks down the MCCs based on where the congestion is sourced. This is calculated by taking the shift factors of each DLAP/ELAP and applying them to across all binding transmission constraints and their shadow prices for each hour. Then, the hourly MCCs are aggregated and normalized to $/MWh to reconstruct the monthly average MCC in the previous figure, but with a breakdown of where the congestion is occurring. With the inclusion of DAME, the table is also broken out to include constraints binding during imbalance reserve deployment scenarios, which ultimately contribute towards the total MCC.

These totals ideally should align closely with the final MCC prices found on Table 9, but due to ongoing issues around data required to decompose MCCs such as availability of shift factors, there may be small discrepancies in past reports. June has been recalculated with the latest data and better aligns to the published monthly averages.

Table 9: Estimated MCC breakdown by source of congestion[5]

Congestion Price Impact ($/MWh)								
	June				July			
Congestion Area	**PACE**	**PACW**	**PGAE**	**SCE**	**PACE**	**PACW**	**PGAE**	**SCE**
CISO	**-0.82**	**-0.90**	**2.29**	**-1.71**	**-0.19**	**-0.93**	**-1.05**	**0.59**
Base	-0.71	-0.74	2.14	-1.59	-0.19	-0.93	-1.11	0.65
IRD	-0.02	-0.05	0.04	-0.05	-0.00001	-0.000003	0.02	-0.01
IRU	-0.08	-0.11	0.11	-0.07	-0.002		0.03	-0.05
PACE	**0.08**	**0.03**	**-0.03**	**-0.06**			**-0.05**	**-0.05**
Base	0.02	0.01	-0.03	-0.03			-0.05	-0.05
IRD	0.01		-0.003	-0.004				
IRU	0.04	0.03	-0.002	-0.03			-0.001	-0.001

CAISO constraints across all deployment scenario constraint types, on average, had a -0.19 and -0.92 $/MWh MCC impact on PACE and PACW, respectively. PACE constraints on average impacted PGAE and SCE DLAPS by -0.05 and
-0.05 $/MWh respectively. PACW congestion was limited to ITC constraints; therefore, there was not any direct parallel flow impacts to the MCC of other LAPs. Still, the most significant congestion impact was realized from CAISO constraints on CAISO area (internal flows). PACE binding hours were limited to three hours across two constraints. BENLOMON 230|138 T1 for one hour on 7/14 and two hours for ANGEL_SYRACUSE_138_1-1 on 7/27. ANGEL_SYRACUSE_138_1-1 bound with a $13,963 shadow prices during HE17, resulting in significant MCC impacts to CISO DLAPs of -$34.9 for that single hour. While this event is significant, PACE congestion on CISO areas is minimal overall across July.
Table 10 takes this breakdown even further and attributes these MCC impacts to individual transmission constraints.

[5] These results are preliminary. An identified data issue impacting the availability of shift factors will result in discrepancies between the total MCC reported in Table 9 and the breakdown by transmission constraint.

Table 10: Congestion costs by constraint for July 2026

July 2026 Average Congestion Costs by Source of Congestion		PACE			PACW			PGAE			SCE		
BAA	Constraint Name	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU	Base	IRD	IRU
CISO	22256_ESCNDIDO_69.0_22404_LILAC _69.0_BR_1 _1							0.00			0.00		
CISO	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	-0.03		0.00				-0.01		0.00	0.00		0.00
CISO	22532_MURRAY _69.0_22306_GARFIELD_69.0_BR_1 _1										0.00		
CISO	22640_PENDLETN_69.0_22708_SANLUSRY_69.0_BR_1 _1							0.00			0.00		
CISO	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	0.00									0.00		
CISO	22844_TALEGA _230_24131_S.ONOFRE_230_BR_2 _1	0.00			0.00			0.00			0.00		
CISO	22846_SANJCP_230-22260_ESCNDO_230-BR1	-0.01			-0.01			-0.01			-0.01		
CISO	24016_BARRE _230_24044_ELLIS _230_BR_2 _1				0.00			0.00			0.00		
CISO	24114_PARDEE _230_24128_S.CLARA _230_BR_1 _1							-0.06			0.11		
CISO	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P				-0.02			-0.03			0.03		
CISO	24254_WINDHUB _230_29401_WINDHUB _500_XF_2 _P										0.00		
CISO	24386_MESA CAL_500_24394_MESA4I _13.8_XF_4H	-0.01			-0.01			-0.01			0.01		
CISO	24701_KRAMER _230_24601_VICTOR _230_BR_2 _1							0.02		0.00	-0.04		0.00
CISO	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	-0.02						0.00			0.01		
CISO	29400_ANTELOPE_500_24156_VINCENT _500_BR_2 _1							0.00			0.00		
CISO	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1				-0.12			-0.16			0.12		
CISO	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.01			-0.99			-1.38			1.04		
CISO	30300_TABLMTN _230_30325_PALERMO _230_BR_1 _1				0.00			0.00			0.00		
CISO	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1				-0.01			0.01		0.00	0.00		0.00
CISO	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1				0.09			0.40		0.00	-0.31		0.00
CISO	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1							-0.05		0.00	0.00		0.00
CISO	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1				0.14			0.06			-0.10		
CISO	30790_PANOCHE _230_30900_GATES _230_BR_1 _1				0.00			0.00			0.00		
CISO	30790_PANOCHE _230_30900_GATES _230_BR_2 _1				0.01			0.01			-0.01		
CISO	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1							0.00			0.00		
CISO	31227_HGHLNDJ2_115_31950_CORTINA _115_BR_1 _1							-0.01					
CISO	32056_CORTINA _60.0_30451_CRTNA M_ 1.0_XF_1							0.00			0.00		
CISO	33008_GRIZLYJ2_115_33010_SOBRANTE_115_BR_2 _1							-0.01					
CISO	33315_RAVENSWD_115_38028_PLO ALTO_115_BR_1 _1							0.00			0.00		
CISO	33315_RAVENSWD_115_38028_PLO ALTO_115_BR_2 _1							0.00			0.00		
CISO	33541_AEC_TP1 _115_33540_TESLA _115_BR_1 _1							-0.01	0.00	0.00	0.00	0.00	0.00
CISO	33543_AEC_TP2 _115_33540_TESLA _115_BR_1 _1							0.00			0.00		
CISO	33724_LOCKEFRD_60.0_33726_VICTOR _60.0_BR_1 _1										0.00		
CISO	33932_MELONES _115_33936_MELNS JB_115_BR_1 _1							0.00					
CISO	33936_MELNS JB_115_33951_VLYHMTP1_115_BR_1 _1							0.00					
CISO	34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1							0.01	0.00				
CISO	34116_LE GRAND_115_34115_ADRA TAP_115_BR_1 _1							-0.01		0.00	-0.01		0.00
CISO	34134_WILSONAB_115_30800_WILSON _230_XF_1							0.00			0.00		
CISO	34158_PANOCHE _115_34350_KAMM _115_BR_1 _1							0.00					
CISO	34256_BORDEN _70.0_30805_BORDEN _230_XF_1							0.00					
CISO	34366_SANGER _115_34370_MC CALL _115_BR_3 _1							0.02			-0.01		
CISO	34418_KINGSBRG_115_34428_CONTADNA_115_BR_1 _1							0.02			-0.01		
CISO	34540_HENRITTA_70.0_30881_HENRIETA_230_XF_4							-0.03	0.00	0.00			
CISO	34706_WESTPARK_115_34752_KERN PWR_115_BR_1 _1							0.08			-0.03		
CISO	34724_KRN OL J_115_34736_MAGUNDEN_115_BR_1 _1							0.00			0.00		
CISO	34774_MIDWAY _115_34225_BELRDG J_115_BR_1 _1							0.00	0.00	0.00	0.00	0.00	
CISO	34873_Q484TP _70.0_34850_BLACKWLL_70.0_BR_1 _1							0.00	0.00				
CISO	35061_PSEMCKIT_115_34225_BELRDG J_115_BR_1 _1							0.00	0.00				
CISO	35120_NEWARK D_115_36851_NORTHERN_115_BR_1 _1							0.00					
CISO	35122_NWARK EF_115_36851_NORTHERN_115_BR_2 _1							0.00			0.00		
CISO	35618_SN JSE A_115_35616_SNJOSEB _115_BR_1 _1							0.04			-0.02		
CISO	35618_SN JSE A_115_35620_EL PATIO_115_BR_1 _1							0.01			-0.01		
CISO	35621_IBM-HR J_115_35642_METCALF _115_BR_1 _1							0.00			0.00		
CISO	35658_LS ESTRS_115_35659_NORTECH _115_BR_1 _1							0.00			0.00		
CISO	36851_NORTHERN_115_36852_SCOTT _115_BR_2 _1							0.02			-0.01		
CISO	38610_DELTAPMP_230_30580_ALTM MDW_230_BR_1 _1								0.01			-0.01	
CISO	39021_SC21ATP _70.0_34888_ARVIN _70.0_BR_1 _1							0.01					
CISO	7320_CP6_NG							0.00	0.00	0.00			
CISO	7430_CP6_NG							0.03	0.00	0.03	-0.04	0.00	-0.03
CISO	7690-CONTRL-INYOKN_EXP_NG										-0.08	0.00	-0.03
CISO	7690-COOLWATER_IM_NG											0.00	
CISO	7690-COOLWATER_KRAMER_IM_NG										0.00	0.00	0.01
CISO	7720_JHINDS_CP2_NG										0.00	0.00	0.00
CISO	7820_TL 230S_OVERLOAD_NG	0.00	0.00		0.00	0.00		0.00	0.00		0.00	0.00	
CISO	7820_TL23040_IV_SPS_NG	0.00						0.00			0.00		
CISO	8610_SylmarBNK_N-S_Import_NG	-0.02		0.00				0.00		0.00	0.01		0.00
CISO	99254_J.HINDS2_230_24806_MIRAGE _230_BR_1 _1											0.00	0.00
CISO	DOSMGO-PNOCHE_230_2_1				0.01			-0.02			-0.06		
CISO	HUMBOLDT_EXP_NG							0.00		0.00			0.00
CISO	HUMBOLDT_IMP_NG							0.00	0.00		0.00	0.00	
CISO	MIGUEL_BKs_MXFLW_NG	-0.06						-0.02			0.01		
CISO	OMS_19695948_DEV_RDB_ALIS	0.00		0.00				0.00		0.00	0.00		0.00
CISO	OMS_20420463_DEV-RDB_NG	-0.04						0.00			0.02		
CISO	OMS_TL23054_OUTAGE_NG	-0.01						-0.01			0.00		
PACE	ANGEL_SYRACUSE_138_1-1							-0.05			-0.05		
PACE	BENLOMON 230|138 T1									0.00			0.00

In summary, the preliminary assessment 2026 congestion under EDAM is in line with the projections provided in the CRA Phase 1 analysis that leveraged historical data from the Western Energy Imbalance (See figure below)[6] That is:

1. PAC transactions can have a sizable impact on CAISO constraints, and this is reflected with sizable MCC prices in PACE and PACW areas
2. CAISO transactions have negligible impact on PAC constraints, and this is reflected with minimal MCC prices in CAISO areas

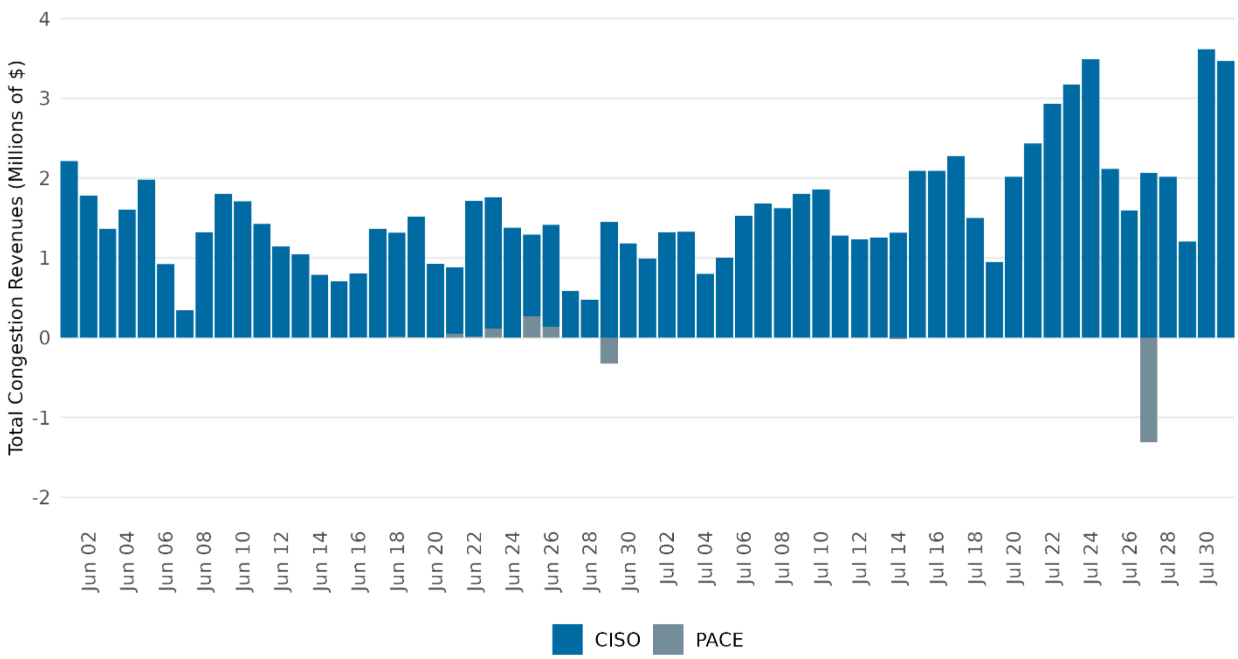
Congestion revenues

Congestion revenues are the financial surpluses based on the MCC resources are paid or getting charged when the transmission grid is constrained. This is the net total of congestion charges/credits for resources within each BAA. When a transaction at the resource level results in a charge, this is due to a generator having a negative MCC or a load resource with a positive MCC. These transactions are in aggregate contributing to congestion. Congestion credits occur in the opposite scenario where a generator resource has a positive MCC or a load resource has a negative MCC. This reflects the effect of relieving congestion.
Please note that these results are preliminary and are subject to change. The following figures are representative of available data at the time of developing this report.

Figure 143 provides the daily BAA totals for congestion revenues based on what area the congestion occurred.

[6] https://stakeholdercenter.caiso.com/InitiativeDocuments/Stage-1-Analysis-Extended-Day-Ahead-Market-Congestion-Revenue-Allocation-Dec-11-2025.pdf

Figure 142: Daily congestion total by BAA



Total EDAM congestion revenues in July were $56.7 M, with $58.1M sourced from the CAISO BAA and a negative balance of -$1.3M from PACE. Negative congestion revenues in PACE on July 27th are associated to the ANGEL_SYRACUSE_138_1-1 constraint which bound on July 27th with a $13,963 shadow price in a single hour.

The current methodology implemented in EDAM allocates day-ahead congestion revenues, attributable to parallel flows, to the areas where market participants paid the congestion costs rather than to the areas where they were collected if they are associated with exercised transmission rights and self-scheduled transactions.
Figure 143provides the breakdown of total congestion rents collected in the CISO area generated by parallel flows from PAC areas transactions, after adjustments for credits associated with firm transmission rights. The estimates in vivid blue are the congestion revenues that are returned to PAC for being associated with self schedules supported with OATT rights; the bars in grey stand for the congestion revenues collected on CAISO constraints from PAC transactions that stay in CAISO area since they are not associated with self-schedules supported by OATTs rights. Since EDAM launch, PAC transactions resulted in net total of $200k in May, $1.5M in June, and -$220k in July.

Figure 143: Net congestion revenues on CAISO constraints from PAC schedules

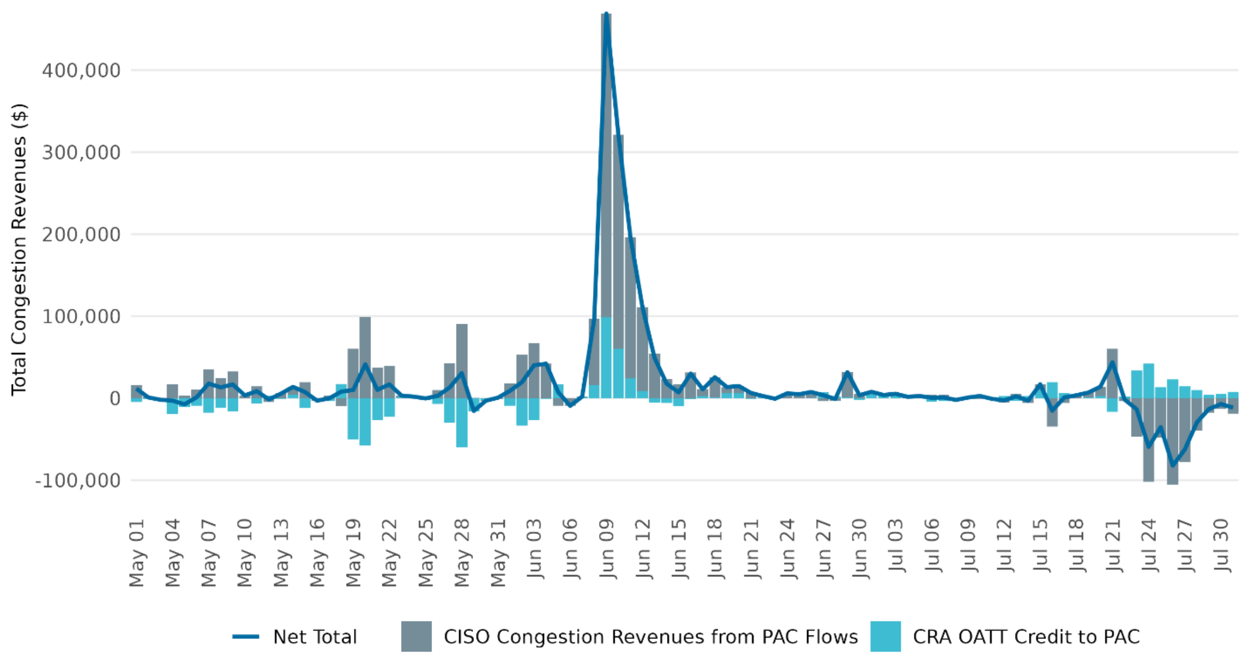


Figure 144 illustrates the daily total congestion revenues from CISO congestion that are returned to PAC areas given that they are associated with self-schedules supported by OATTs rights. These rights are either point-to-point rights or for Network service (NITS). Those rights are exercised and can be tracked through balanced CRN self-schedules. Negative values indicate a payment, while positive values indicate a charge.

In previous reports, the ISO reported a $1.3 million credit back to PAC areas in both May and June. An issue impacting the congestion revenues associated with DLAPs/ and ELAPs resulted in erroneous settlements estimates. This resulted in congestion revenues being incorrectly allocated to the nodal location rather than the location where the congestion occurred. This resulted in over allocating contributions from CISO congestion to the total credit back to PAC areas. A fix was implemented in time for T+70B resettlement.

This report provides updated estimates of the credits associated with PAC for all three months that already address the incorrect calculation. The allocation to PAC areas is $360,000 in May, -$160,000 in June and about -$190,000 in July. The negative values for June and July reflect a charge back to PAC due to their schedules originally received congestion payments for providing counterflows to congestion in the ISO areas.

Figure 144: Estimated total CRN congestion credit to PAC from CISO congestion

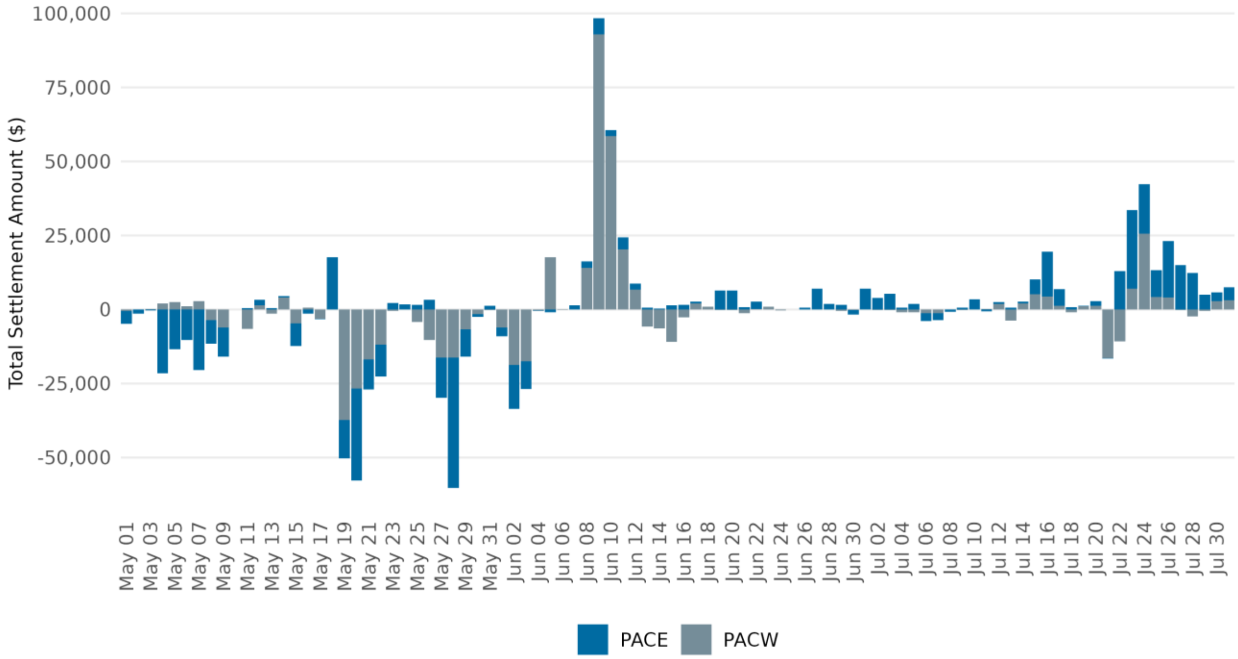


Figure 145 shows the volumes of OATT balanced self-schedules with respect to the total volume of all types of self-schedules for each PAC area. The proportions of OATT balanced self-schedules for PACE and PACW were 39% and 62% in July, respectively. Figure 135 provides the volumes of OATT balanced self-schedules for each PAC area. In July, PACE averaged 1,605 MW while PACW averaged 1,880 MW.

Figure 145: Total self-schedules compared to OATT self-schedules by PAC area

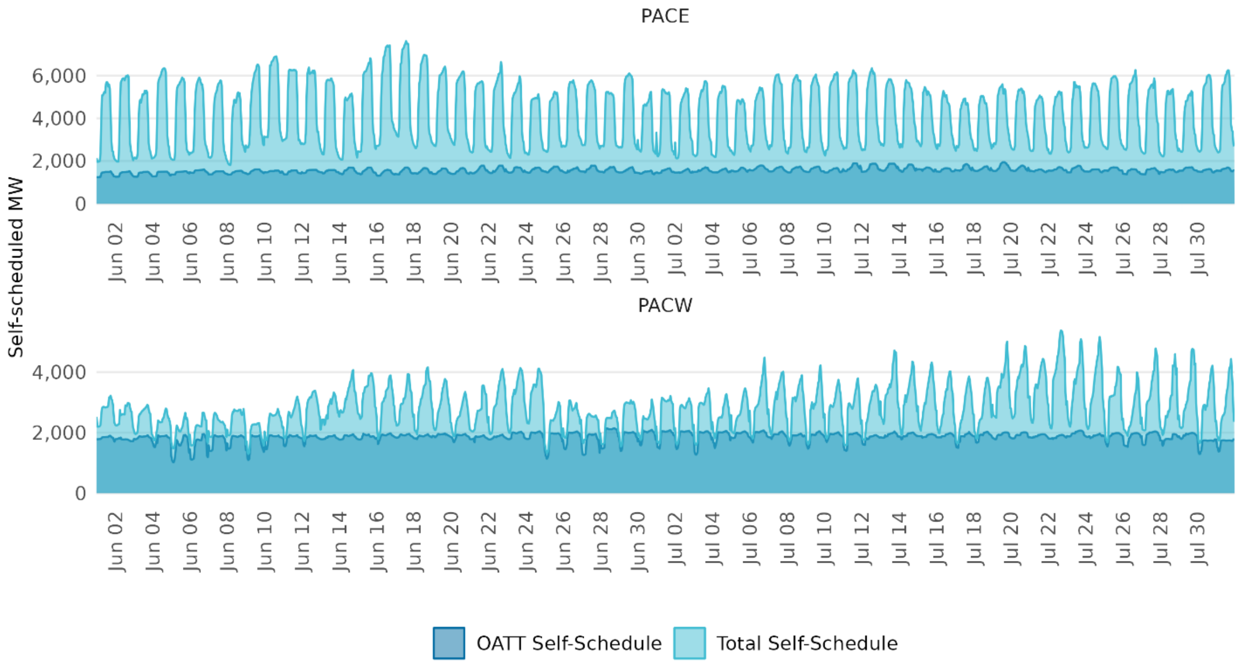
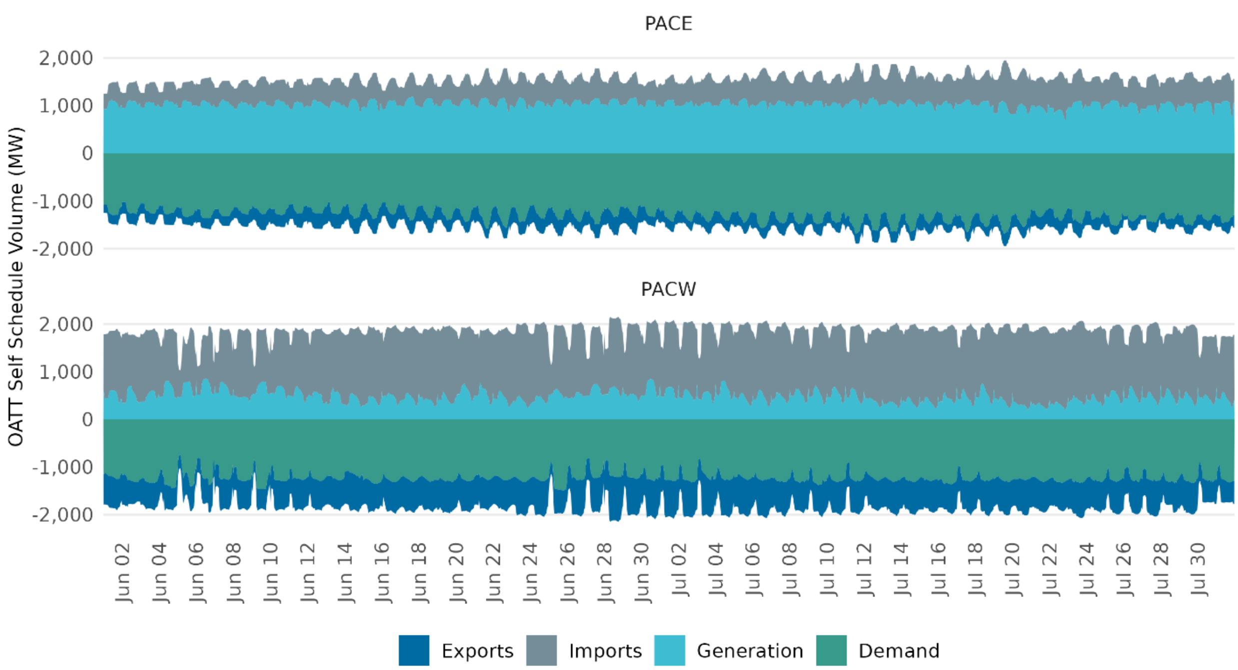


Figure 146: Total OATT self schedule volumes by PAC area



EDAM Net Export Constraints and RUC Adjustments

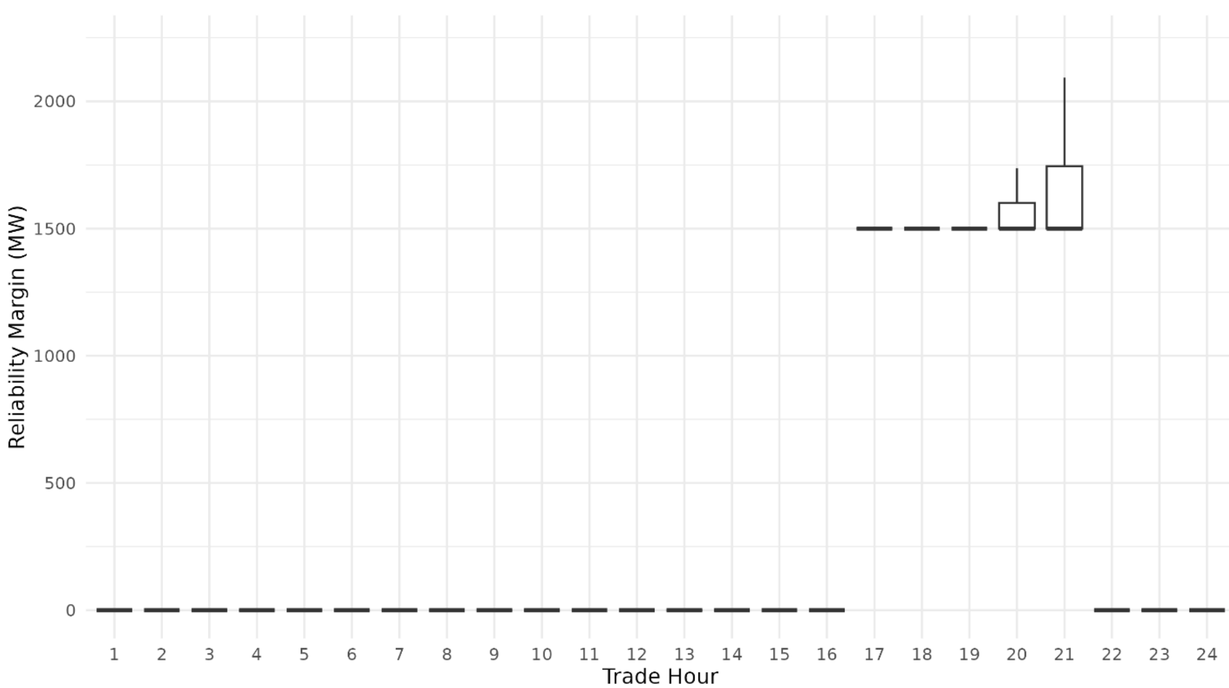
The EDAM export constraint and RUC adjustments are optional BA level constructs that help ensure sufficient procurement to support reliability going into the real-time market.

EDAM net export constraints

The EDAM net export constraint allows a BAA to limit the net exports on their TSRs to avoid exporting capacity on the TSRs that they may need for reliability. The constraint is optional and is enforced at the BA level. The constraint limits the net exports on the TSRs based on the total RSE eligible supply available above the RSE demand, with additional inputs to allow BAs to fine tune the constraint as needed.

There are two parameters that each BAA sets when the constraint is enforced: the confidence factor and the reliability margin. The confidence factor sets the percentage of supply that is not eligible for the RSE that will count in the BAA's supply that is eligible for export on the TSRs. The reliability margin is an additional buffer that the BAA may set to further limit the amount of supply that is eligible for export. The reliability margin is defined for each hour of the day as a specific MW value.

Figure 147: CAISO Reliability Margin



Based on stakeholder feedback, CAISO enforces the EDAM net export constraint on all days, with a 0% confidence factor and a reliability margin that tracks with the most severe single contingency. Full details of the CAISO implementation of the constraint are available in the Business Practice manual for EDAM. In May, June, and July, this constraint did not bind in CAISO area. Neither PACE nor PACW opted to enforce this constraint so far.

RUC adjustments

The RUC load adjustment is an optional hourly MW value added to the forecasted load in RUC. It allows for manual adjustments to the forecast to provide extra capacity to a BAA to account for situations that aren't fully captured in the day-ahead market forecast. With the launch of the Imbalance Reserve product, there is now an additional option for a BAA to add RUC adjustments based off any Imbalance Reserve amount that did not clear in IFM, along with the peak load for the day. The exact formulation for how CAISO sets the RUC adjustment is defined in the EDAM BPM. No RUC adjustments were applied in May for any EDAM BAA. In June, RUC adjustments were applied for CAISO in 19 total hours across June 11 and June 12 up to a maximum of 810 MWs.

Figure 148 shows a comparison of RUC adjustments used in July 2025 and 2026. In July 2026 there were 139 hours with a RUC adjustment, a reduction from the 452 hours with RUC adjustments observed in July 2025. The maximum adjustment observed in July 2025 was 4,670 MW versus 3,500 MW in 2026. Figure 149 shows the trend over time on the use of RUC adjustment for ISO area, highlighting some key events relevant to the trends. Historically, more frequent and higher RUC adjustments are observed during conditions of high demand and tight supply conditions such as summer months. For summer 2026 and with the introduction of imbalance reserve, the daily trend of RUC adjustments has come down.

Figure 148: Manual adjustments and demand levels in the ISO area for day-ahead market

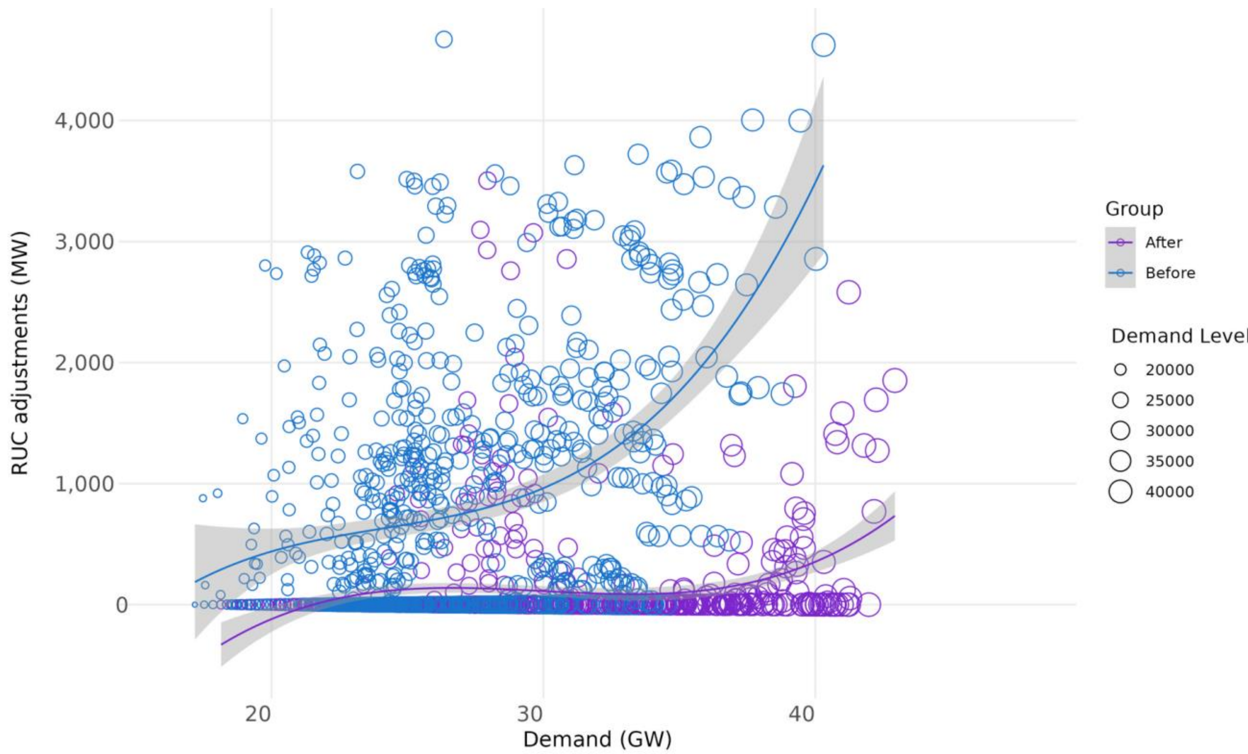


Figure 149: Historical RUC adjustments in the day-ahead market

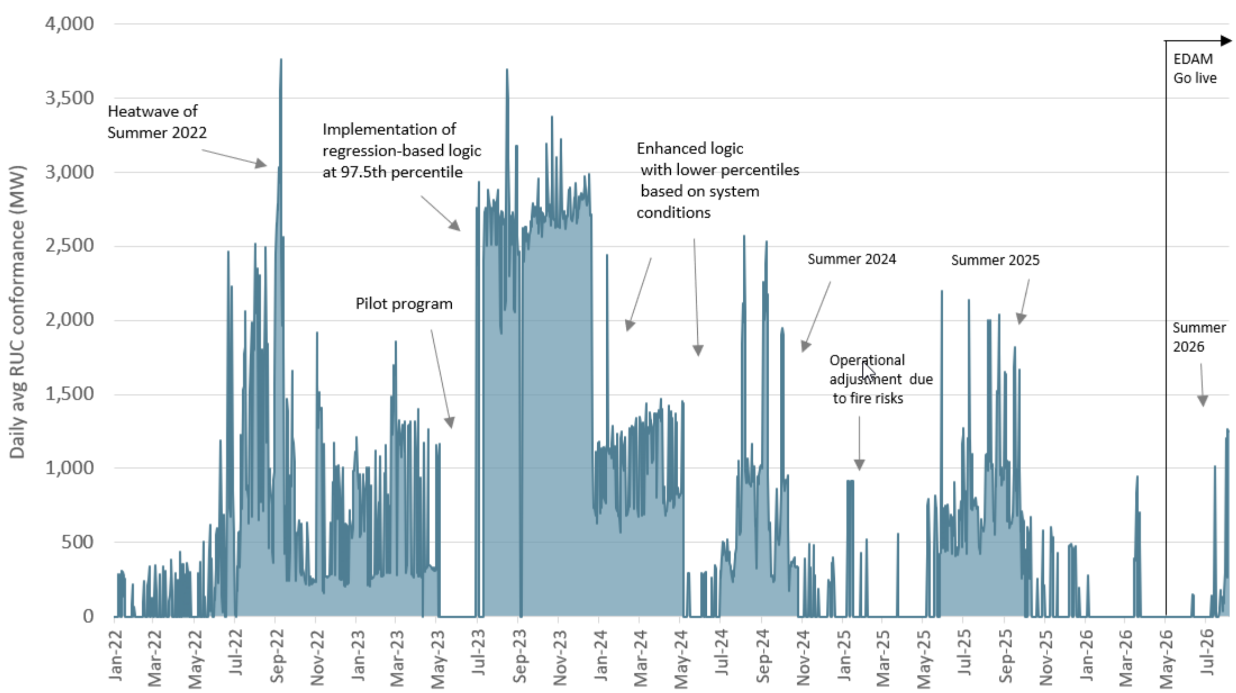
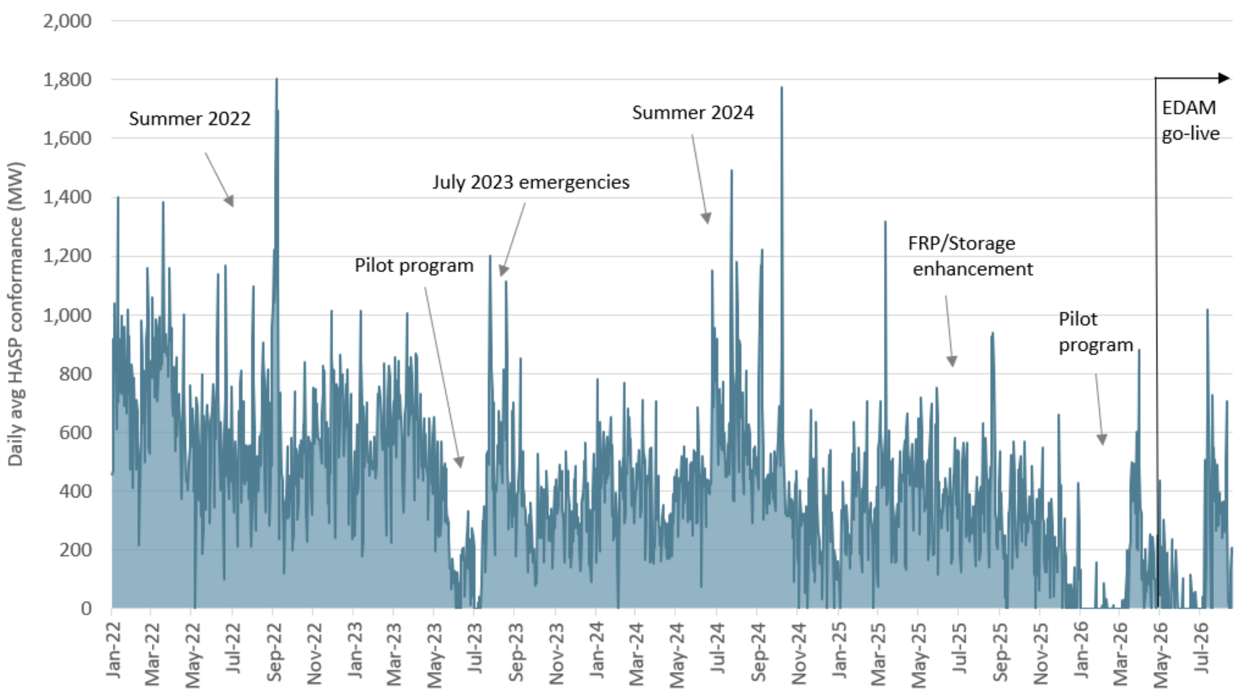


Figure 150 shows similar trend of load conformance for the hour ahead scheduling process (HASP). Historically, this market is utilized to gain additional ramping flexibility for peak hours since it is the last opportunity to schedule additional interties. Overall, the use of HASP load conformance has been consistent over time with higher use during summer conditions. In early 2026, its use was minimum during a pilot program used to understand the drivers for load conformance and its implications in subsequent real-time submarkets. This pilot ended in early March, and its use afterwards continue to be low until the first week of July, two months after the EDAM launched. The load conformance reached up to 3,500 MW for peak hours during days when ISO area observed the peak of the year so far and again in the last week of July when demand was high overall in the west. During this time, there were also operational conditions such as fire risks to manage.

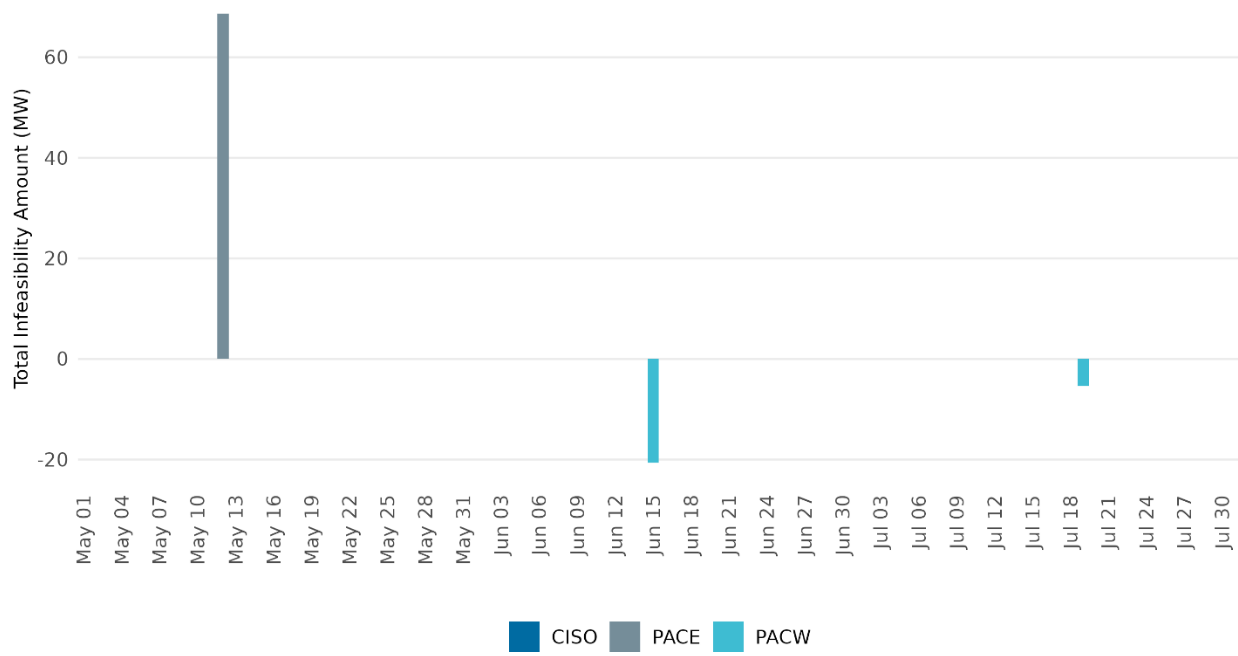
Figure 150: Historical load conformance in the hour ahead scheduling process



RUC infeasibilities

As part of the market construct, the RUC process may not be able to balance supply with total demand, which may include any RUC adjustments. This condition is known as infeasibility or RUC shortfall. The infeasibility may be in either the under-supply direction, which is indicated by a positive infeasibility, or the over-supply direction, which is indicated by a negative infeasibility. PACW observed an over-generation infeasibility of about five MW on July 19.

Figure 151: RUC Infeasibilities



Transitional Pricing

For the first six months following a new EDAM Entity's EDAM implementation, when power balance and/or transmission constraints within that entity's Balancing Authority Area are relaxed, CAISO will determine prices based on the last economic bid rather than administrative (penalty) prices. This transition-period pricing applies only to the new EDAM Entity's Balancing Authority Area. It does not apply to the CAISO Balancing Authority Area. This practice is also limited to the day-ahead market, and it does not apply in the real-time market[7]. The RUC infeasibilities reported in the prior section were priced using the last economic bid instead of the RUC infeasibility penalty price.

For HE08 on July 19th and HE10 on June 15th, PACW had positive RCD requirements in RUC and their IFM TSR transfers were at the export limit. This meant that PACW had to internally reduce their generation to meet the RCD requirement. As this was insufficient on both days, RUC shortfall ensued.

[7] A new WEIM Entity will receive transitional pricing in the real-time market for the first six months of its WEIM implementation.

For July 19th, PACW RCD price of $55.4/MWh was set by a marginal generator. During this hour, CAISO RCD price was $0/MWh and PACE RCD price was $0.9/MWh. Without the transitional pricing, the $250 over-generation RCD penalty price would have applied to calculate the BAA RCD price.

For June 15th, there was no internal RCD dispatch available and so the price was set by the next marginal generator that had the lowest RCU bid price of $10.09/MWh. PACW RCD price was negative and equal to -$10.09/MWh as the price was set by an RCU bid. During this hour, CAISO RCD price was $0/MWh and PACE RCD price was $0.11/MWh. Without the transitional pricing, the $250 over-generation RCD penalty price would have applied to calculate the BAA RCD price.

For HE19 on May 12th, PACE had a positive RCU requirement and was able to procure 27.45 MW of RCU imports from CISO. The import limits on the TSR transfers were reached because of these RCU transfers. Even after increasing the internal generation to meet the RCU requirement, PACE was 68.66 MW short. PACE RCU price of $106.7/MWh was set by the marginal generator. During this hour, CAISO RCU price was $56.28/MWh and PACW RCU price was $10.44/MWh. Without the transitional pricing, the $250 under-generation RCU penalty price would have applied to calculate the BAA RCU price.

Market Power Mitigation

Bids submitted into CAISO markets are subject to market power mitigation (MPM) to maintain a competitive market. In the day-ahead market, MPM uses a competitive path assessment for binding transmission constraints to determine whether a path is competitive or not. If a path is non-competitive, MPM procedures identify any non-competitive contribution of those binding transmission constraints to locational marginal prices for energy and reliability capacity up prices. Bids from resources within that EDAM balancing authority area will be subject to mitigation if the net contribution from non-competitive binding transmission constraints for these prices is positive.

MPM for the IFM market is a market process that existed before EDAM. Before EDAM/DAME, separate bids were not submitted for RUC. Any bid considered in the RUC process before EDAM/DAME had already been subject to the IFM MPM. As part of EDAM/DAME and the introduction of reliability capacity products that require separate bids, a MPM pass was added to assess the competitiveness of RUC reliability capacity bids. Figure 152 and Figure 153 show the total number of resources subject to mitigation as determined by the IFM MPM and RUC MPM passes daily, broken down by fuel type. Note, a resource is counted based on the number of day-ahead intervals it was subject to mitigation in, i.e., if a single resource was subject to mitigation in hours ending one through six then it will be counted six times. There was a market issue resulting from a patch that impacted market power mitigation on day-ahead trade dates July 8-18. During the impacted trade dates, no PACE or PACW resources were subjected to mitigation. There was also significantly fewer CAISO resources subjected to IFM mitigation, particularly gas resources. No resources were subject to mitigation in RUC from July 8-18. Outside of the impacted dates, gas and energy storage make up most resources subject to mitigation in IFM. In RUC, there were almost no gas resources subject to mitigation. In general, there were many few resources subject to mitigation in RUC.

Figure 152: Resources subject to mitigation in IFM MPM, by fuel type

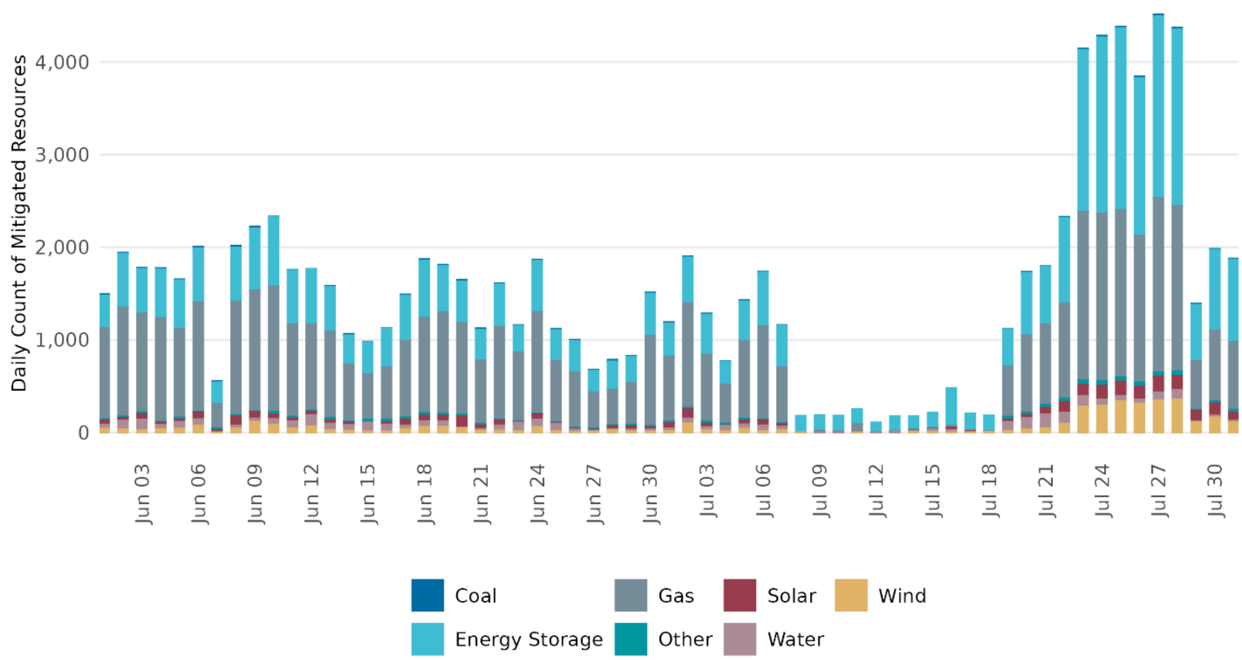


Figure 153: Resources subject to mitigation in RUC MPM, by fuel type

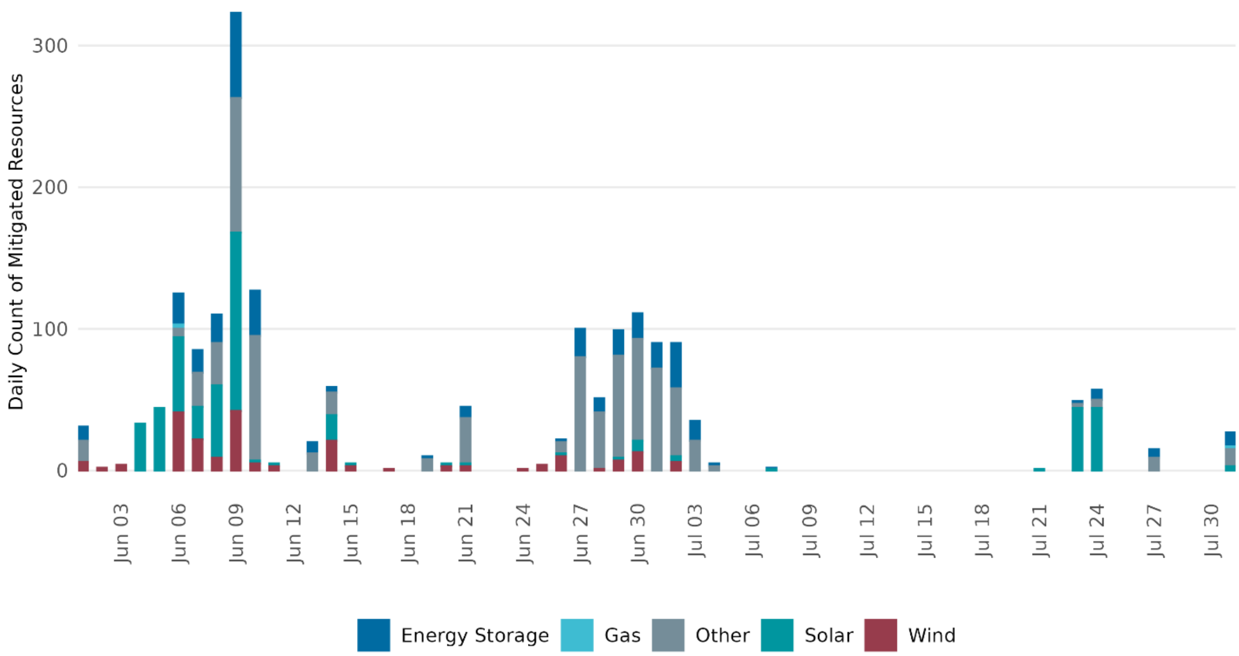


Figure 154 and Figure 155show the same total counts as above but broken down by BAA. Figure 154 shows that the number of PACE resources subject to mitigation in IFM has been consistent, excluding July 8-18. Even when excluding July 8-18, the number of resources subject to mitigation in RUC was significantly lower in July compared to June, especially for PAC.

Figure 154: Resources subject to mitigation in IFM MPM, by BAA

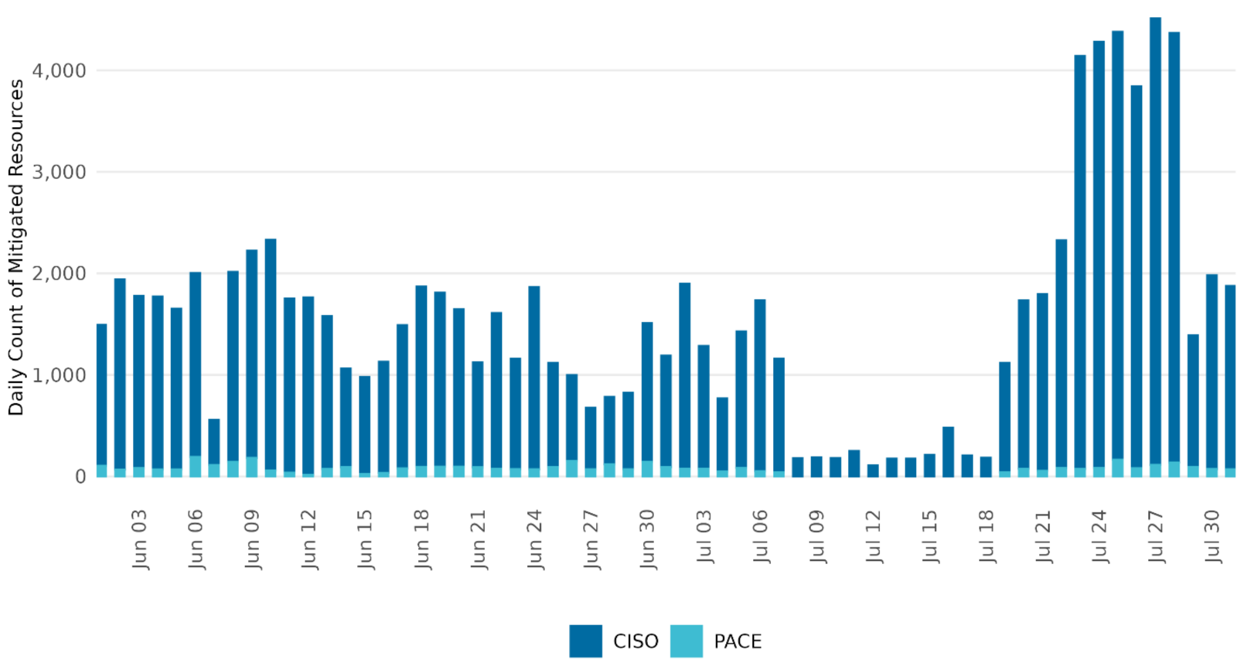


Figure 155: Resources subject to mitigation d in RUC MPM, by BAA

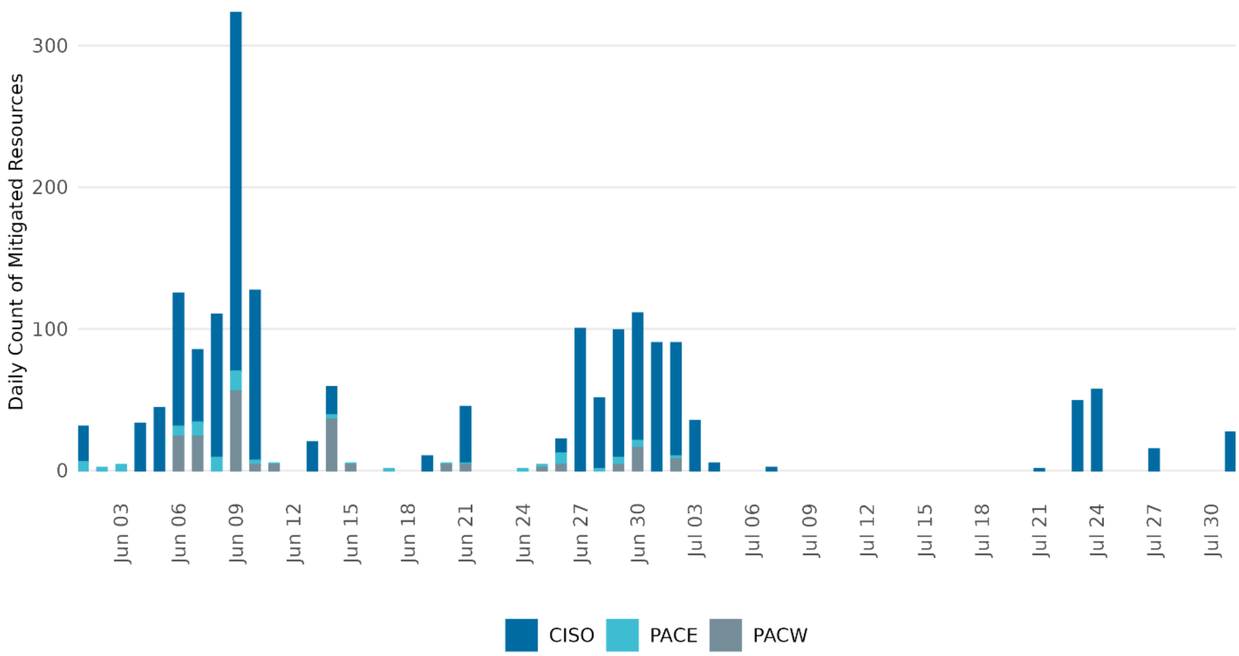


Figure 156 and Figure 157 show the average number of resources subject to mitigation in each hour of the day, by month for IFM and RUC, broken down by fuel type. Figure 156 shows that mitigation in IFM is typically highest during the middle of the day when there is a lot of solar production and during July it was highest during the evening peak. There is less consistent of a pattern in RUC.

Figure 156: Resources subject to mitigation in IFM MPM, by fuel type hourly

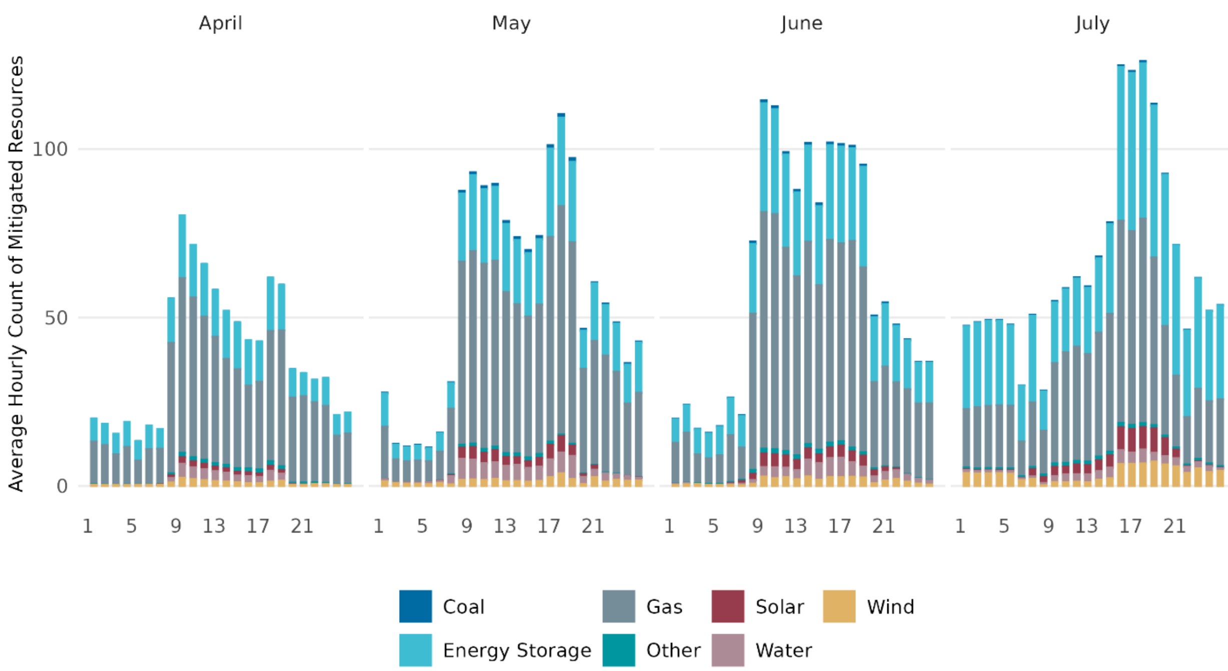
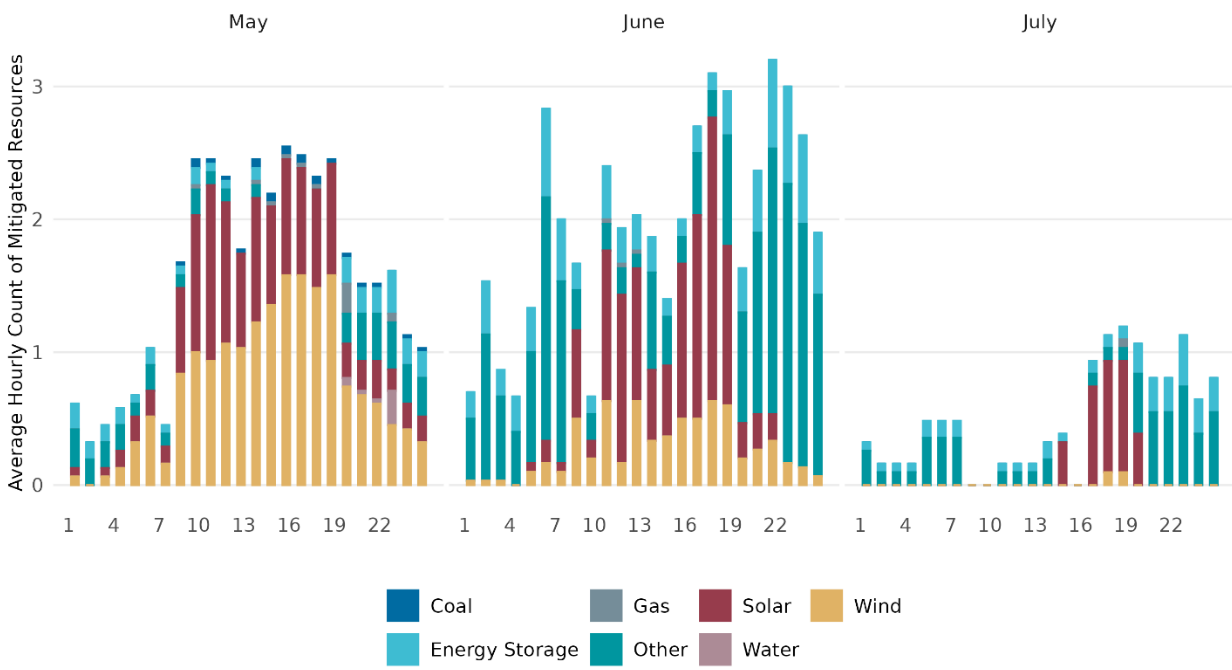


Figure 157: Resources subject to mitigation in RUC MPM, by fuel type hourly



Summer Conditions

Peak ISO Load

The ISO area recorded its highest load of the year so far on July 15 at 43,625 MW. This level is typical for July and largely consistent with load levels observed in previous years. Load peaks in July were elevated from the previous month, exceeding 40,000 MW on several days, but did not exceed 45,000 MW. The average daily peak load in July 2026 was 37,423 MW. Figure 159 shows the 5-minute average daily load for June and July relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The instantaneous load peak in July 2026 was 43,625 MW on July 15. This peak was below the CEC month-ahead forecast of 45,629 MW. The highest five-minute average peak load for the month of July was 43,534 MW.

Figure 158 shows the historical load level distributions in the ISO area over the past six years. Load levels have generally remained within a tight range with few outliers that would indicate extreme conditions. The short distribution tails suggest that load variability has been limited.

Load peaks in July were elevated from the previous month, exceeding 40,000 MW on several days, but did not exceed 45,000 MW. The average daily peak load in July 2026 was 37,423 MW. Figure 159 shows the 5-minute average daily load for June and July relative to the CEC month-ahead forecast used to assess the resource adequacy requirements. The instantaneous load peak in July 2026 was 43,625 MW on July 15. This peak was below the CEC month-ahead forecast of 45,629 MW. The highest five-minute average peak load for the month of July was 43,534 MW.

Figure 158: Historical distribution of load levels in the ISO area

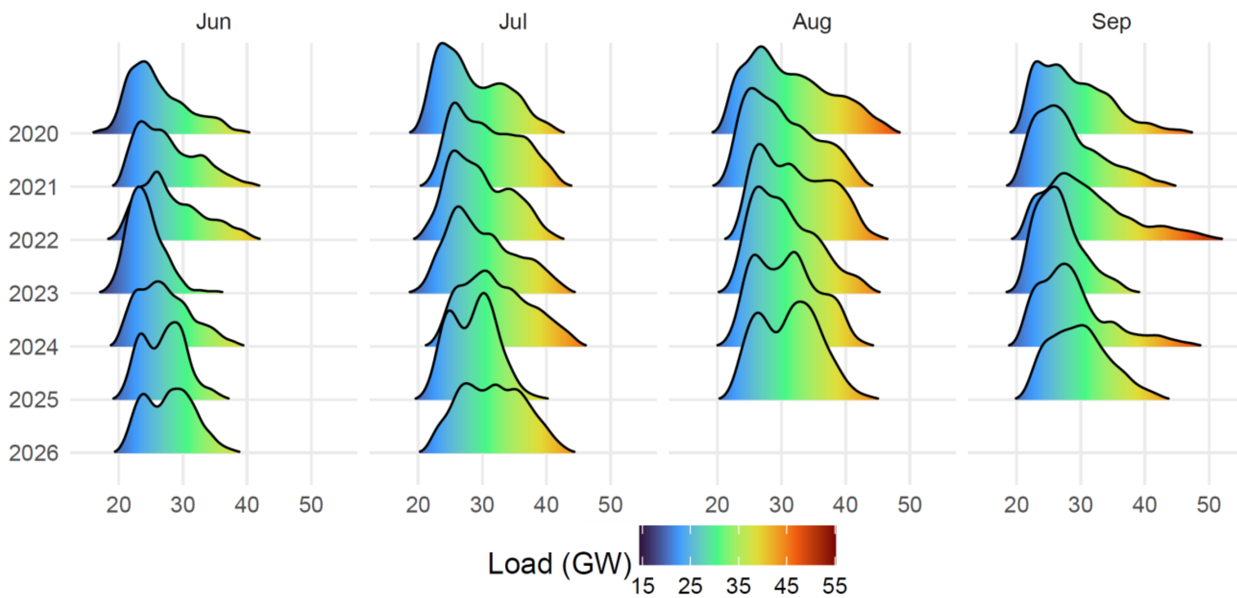
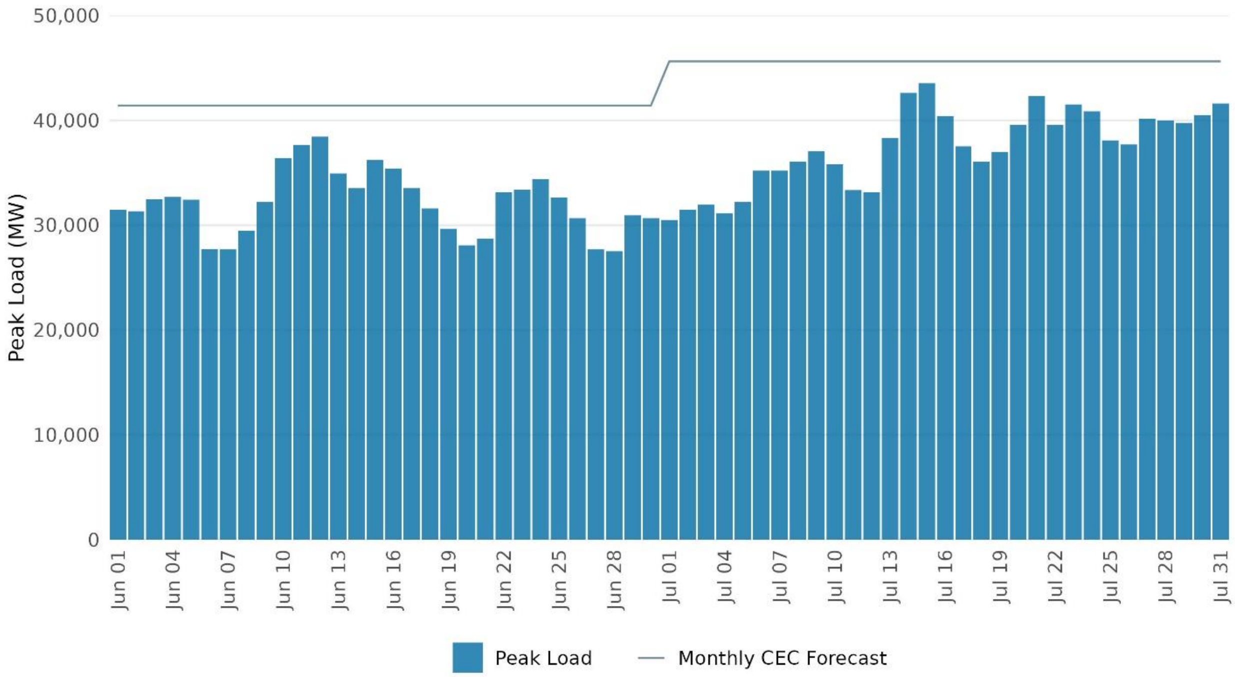


Figure 159: Daily peak load and CEC month-ahead forecast



The actual load did not exceed the monthly RA showings in July 2026 as illustrated in

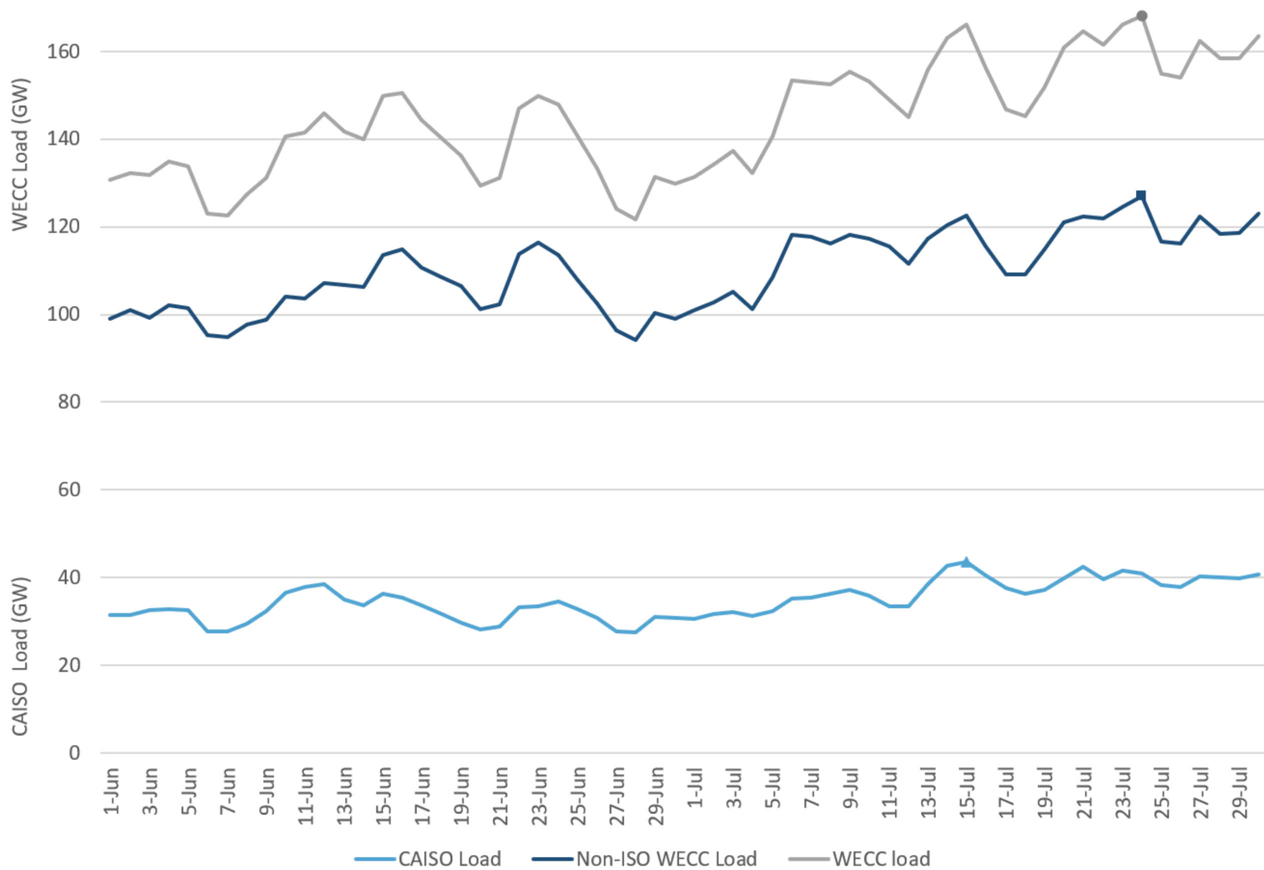
Figure 160. There was plenty of headroom in the monthly RA supply in July to meet the observe levels of load. The gray line indicates nominal monthly RA showings. As discussed later in this report, the actual capacity made available into the ISO's market (accounting for outages and other factors) varies 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 160: Daily peak load, operating reserves and RA capacity

Although July observed elevated loads in the Western Interconnection (WECC), load in the ISO area remained within moderate summer levels. The WECC area demand reached a record peak of 168.5 GW on July 24. The summer peak load for ISO area in July occurred on July 15 at 43,625 MW. The July's peaks for WECC and ISO areas are shown in the daily-peak profile in Figure 161.

During the July 24 to July 27 period of peak regional demand, active wildfires across portions of the Western Interconnection also affected power system operations. Wildfires increase operational uncertainty by placing some transmission corridors at risk and require grid operators to closely manage transfer capability and power flows in affected areas. As a result, energy transfers across portions of the West were more constrained than under normal conditions, reducing operational flexibility at a time when regional electricity demand was near its seasonal maximum.

Figure 161: Daily load peak for WECC and ISO area in summer months



Market Prices

Market prices naturally reflect supply and demand conditions. As the market supply tightens, prices tend to rise.

Figure 162 compares the daily average prices across ISO's markets for the months of June and July.[8] The daily average fifteen-minute market prices reached $109/MWh ($33 in June), while the daily average day-ahead prices reached about $55/MWh ($33 in June), and the five-minute market prices reached a maximum of about $117/MWh ($35 in June). In July, the maximum prices for IFM, FMM, and RTD all occurred on July 24.

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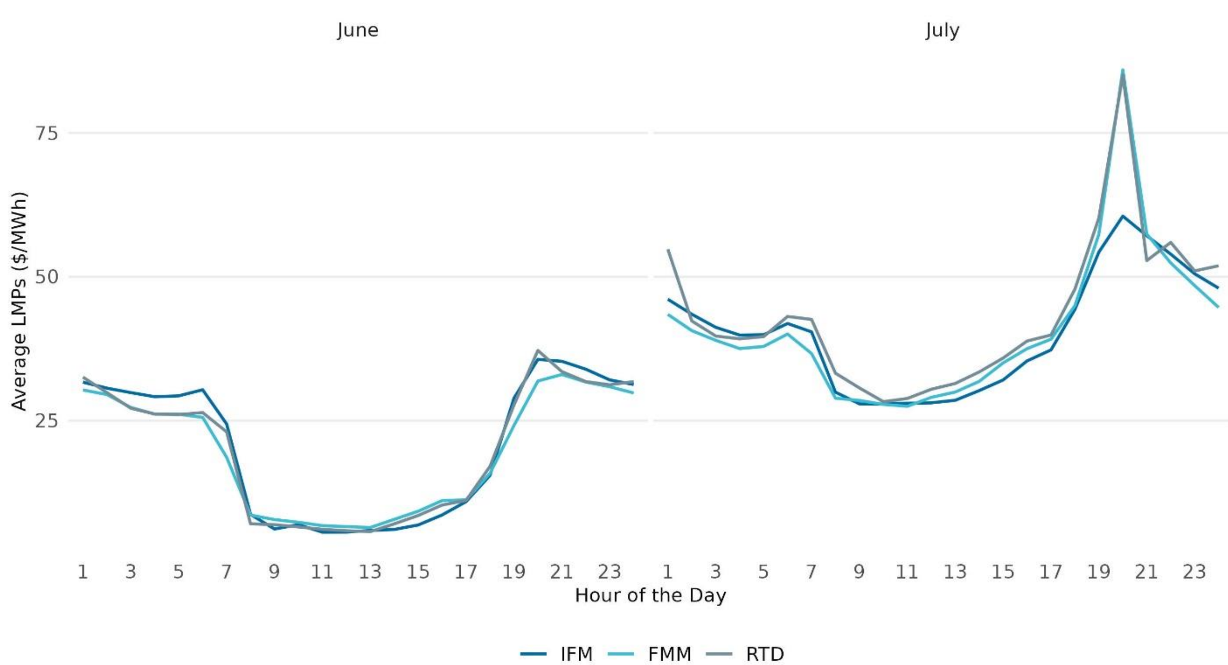
[8] Default Load Aggregation Point (DLAP) prices are a good indicator of overall prices. However, congestion may create price separation among DLAPs. The metrics presented here are based on a weighted average price of the DLAPs within the ISO area.

Figure 162: Average daily prices across markets, June and July 2026

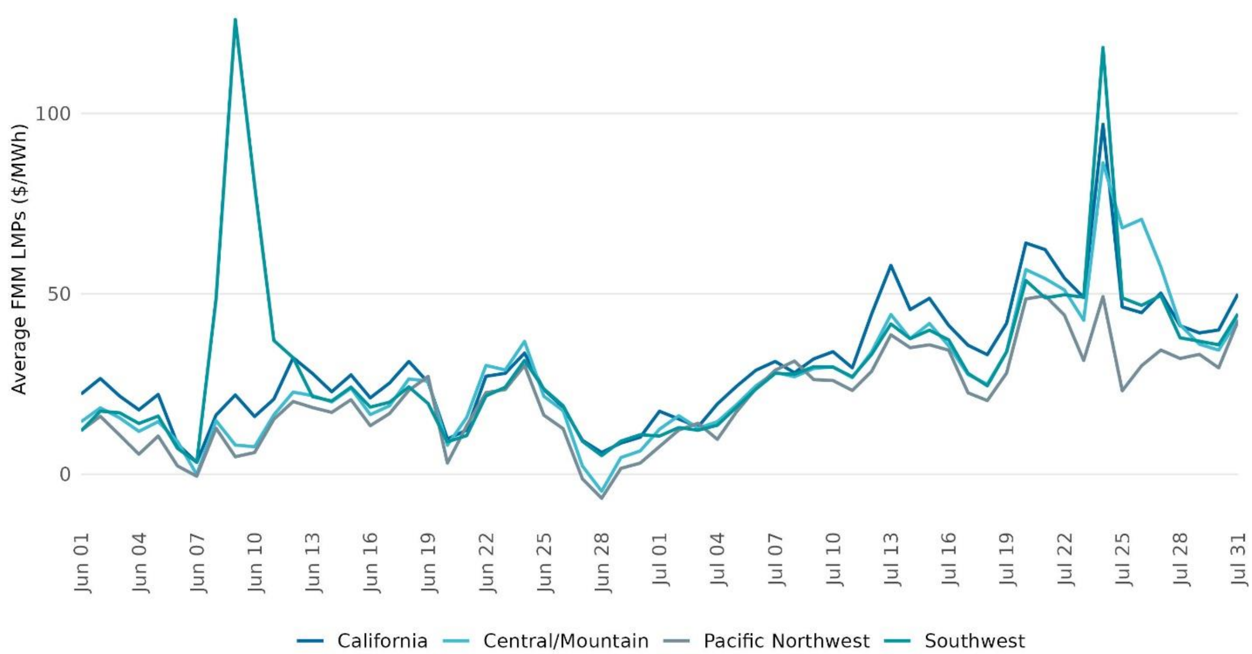
Figure 163 shows average hourly prices across ISO's markets for both June and July 2026. In July, the hourly average prices for the integrated forward market, the fifteen-minute market, and the real-time dispatch market all peaked in trade hour 20 at $61/MWh, $86/MWh, and $85/MWh, respectively.

Figure 163: Average hourly prices across markets



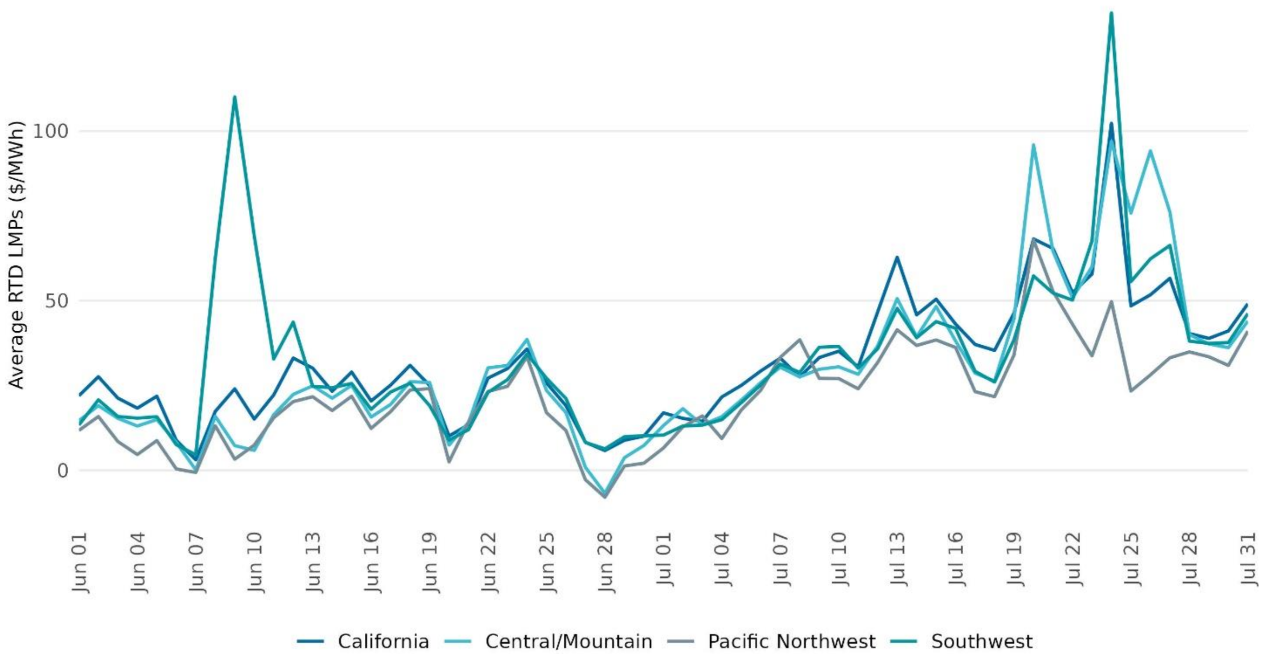
The figure below shows daily average LMPs for all four regions in FMM for the months of June and July. In June, the highest FMM regional daily average was observed in Southwest on June 09 at about $126/MWh, while the highest RTD regional daily average occurred in Southwest on June 09 at about $110/MWh. In July, the highest FMM regional daily average was observed in Southwest on July 24 at about $118/MWh, while the highest RTD regional daily average occurred in Southwest on July 24 at about $135/MWh. On the June FMM peak date, prices across the four regions ranged from about $5/MWh to $126/MWh. On the July FMM peak date, average prices were about $97/MWh in California, $86/MWh in Central/Mountain, $49/MWh in Pacific Northwest, and $118/MWh in Southwest. Figures in the following page will further explore the peaks by depicting three-day periods of hourly averages for WEIM Load Aggregation Point (ELAP) prices aggregated by geographical region for RTD and FMM.[9]

Figure 164: Average daily prices across region for FMM market, June and July 2026



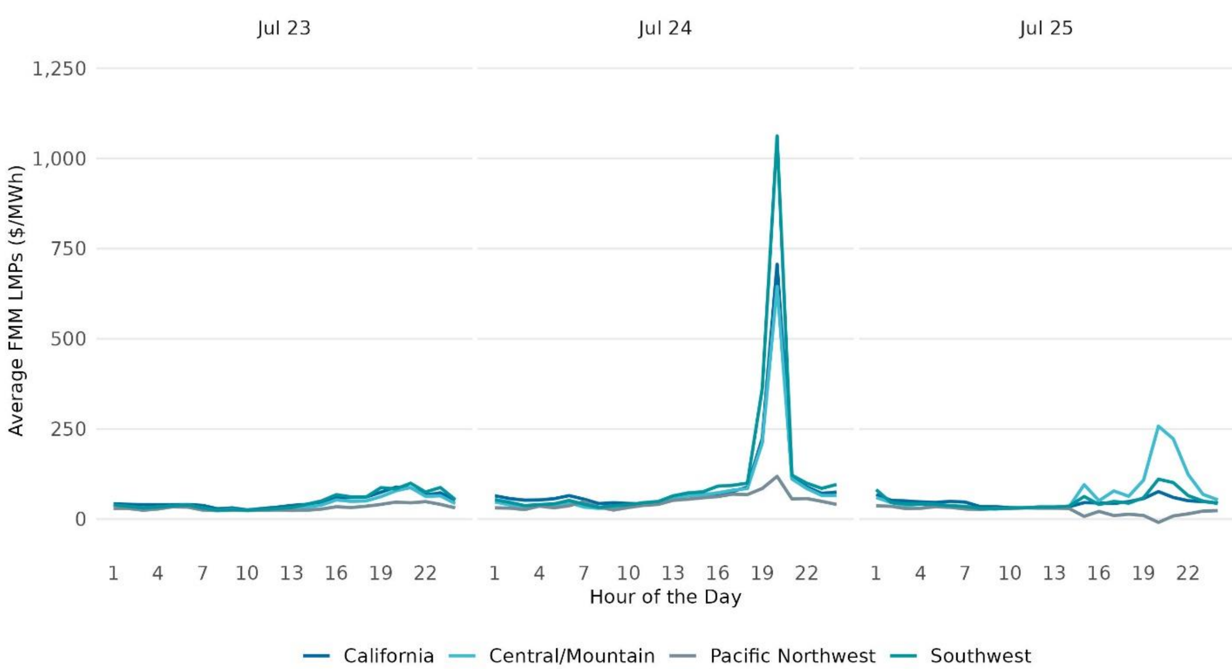
[9] The Pacific Northwest region includes balancing areas such as Bonneville Power Administration, Powerex, Avista Corporation, Avangrid Renewables, Tacoma Power, Seattle City Light, Puget Sound Energy, Portland General Electric Company, and PacifiCorp West. Southwest region includes Tuscon Electric Power, Public Service Company of New Mexico, Salt River Project, Western Area Power Administration, Arizona Public Service Company, El Paso Electric Company, and Nevada Power Company. Central/Mountain region includes Idaho Power Company, NorthWestern Energy, PacifiCorp East, Black Hills, and PowerWatch (formerly BHE Montana). California region includes ISO, Los Angeles Department of Water & Power, Balancing Authority of Northern California, and Turlock Irrigation District.

Figure 165: Average daily prices across region for RTD market, June and July 2026



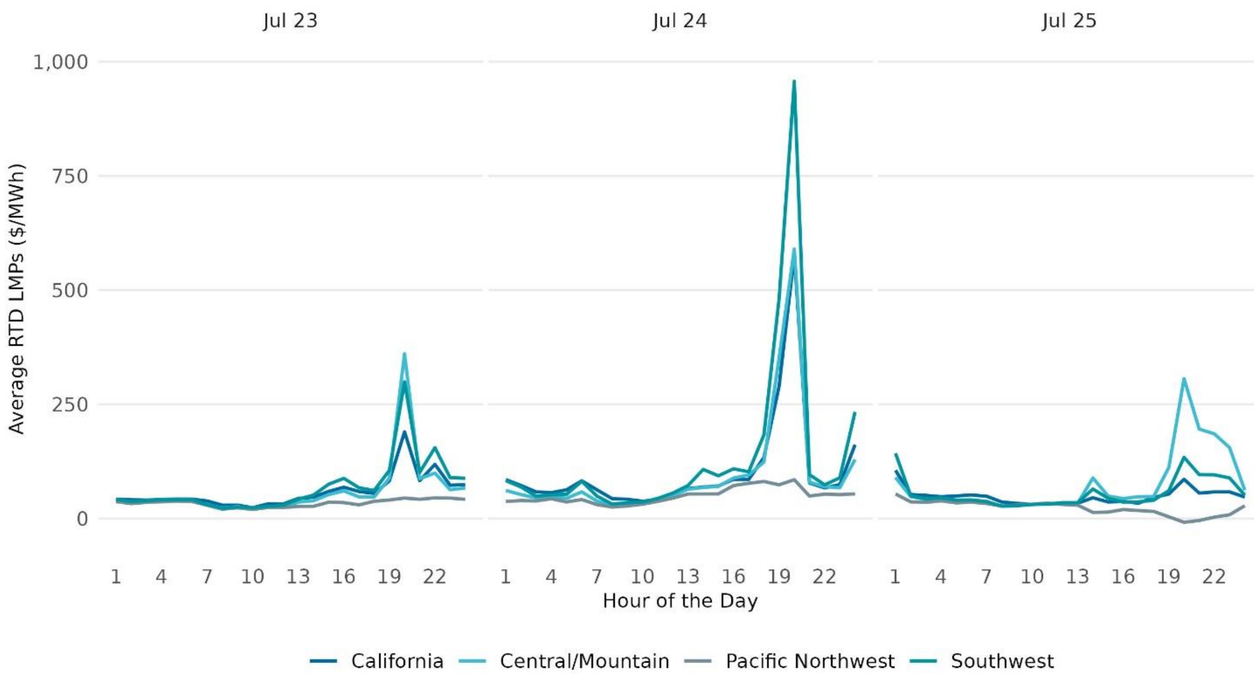
For FMM, the Southwest region is the highest at $99/MWh on July 23, followed by California at $89/MWh. On July 24, Southwest peaked at $1,062/MWh, followed by California at $707/MWh. On July 25, Central/Mountain peaks at $258/MWh, followed by Southwest at $111/MWh.

Figure 166: Average hourly prices across region for FMM market, July 23-25, 2026



For RTD, the Central/Mountain region is the highest at $361/MWh on July 23, followed by Southwest at $299/MWh. On July 24, Southwest peaks at $957/MWh, followed by Central/Mountain at $590/MWh. On July 25, Central/Mountain peaks at $306/MWh, followed by Southwest at $143/MWh.

Figure 167: Average hourly prices across region for RTD market, July 23-25, 2026



Renewable Production

The CAISO's area utilizes hydro production throughout the year to meet demand needs.

Figure *168* shows the historical trend of total energy produced from hydro and other renewable resources. Hydro production for 2026 so far has been lower than previous years. Hydro production in July 2026 was about 2 percent lower than the production observed in July 2025. With the addition of more solar resources into the system, solar production in July 2026 was about 5 percent higher than the production in July 2025. Figure 169 shows the daily renewable production for May, June and July. Figure 170 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 171 below shows the hourly profile of the average energy produced from hydro resources as well as solar and wind resources for July 2026. Figure 172 shows the hourly profile of hydro, wind and solar for July 23-25.

Figure 168: Historical trend of hydro and renewable production

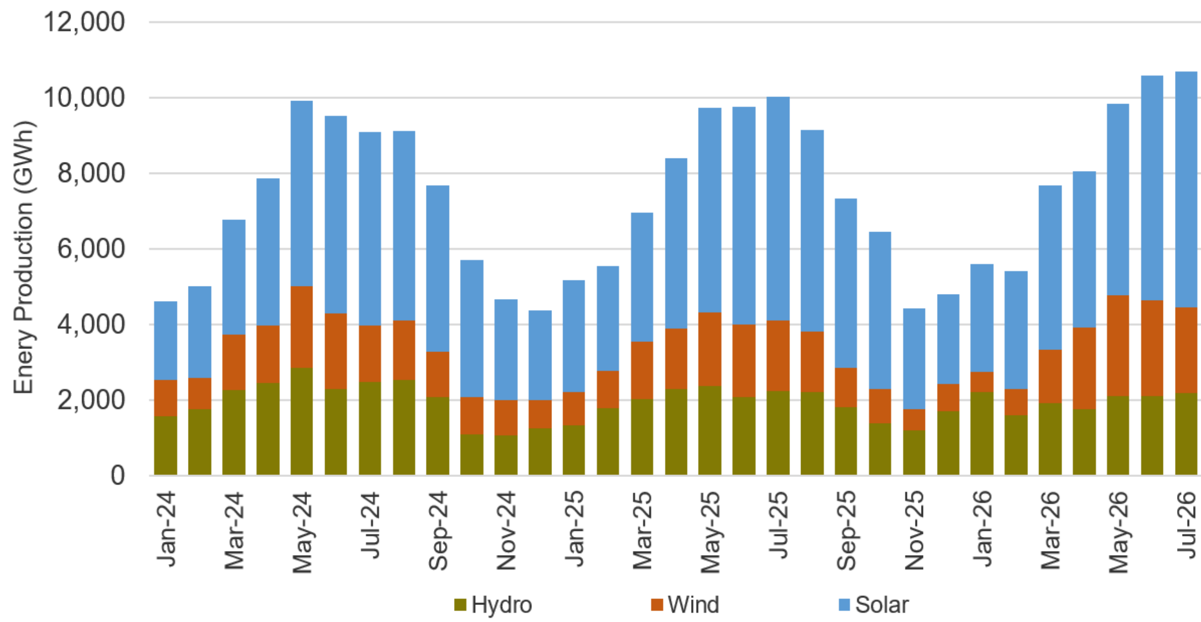


Figure 169: Daily trend of hydro and renewable production

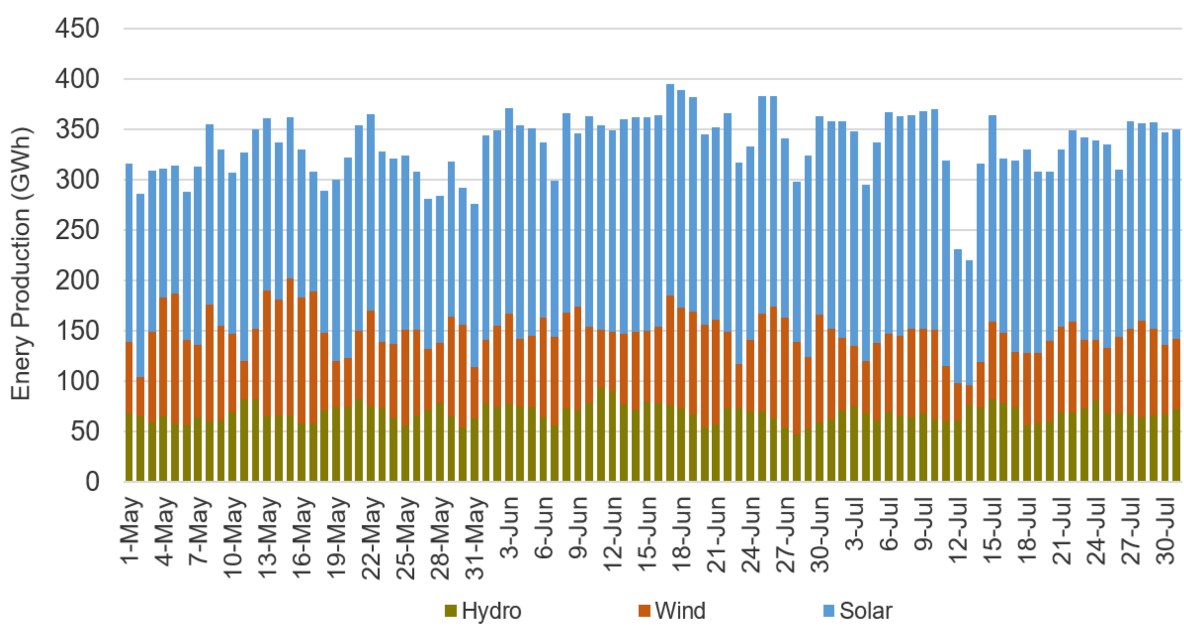


Figure 170: Historical trend of solar production

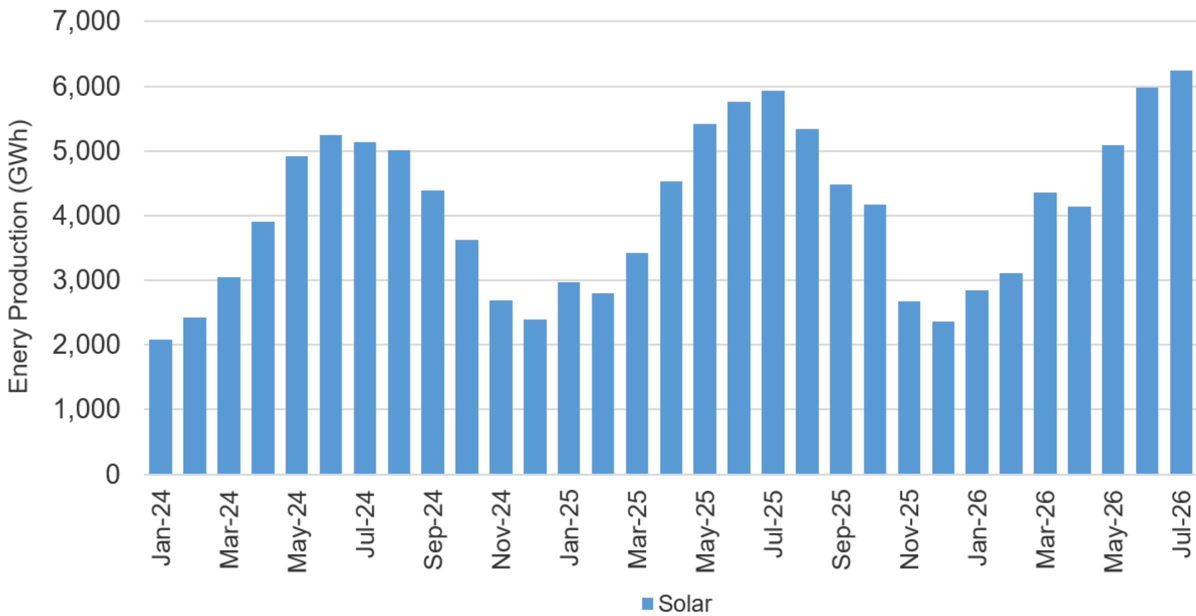


Figure 171: Hourly profile of wind, solar and hydro production for July

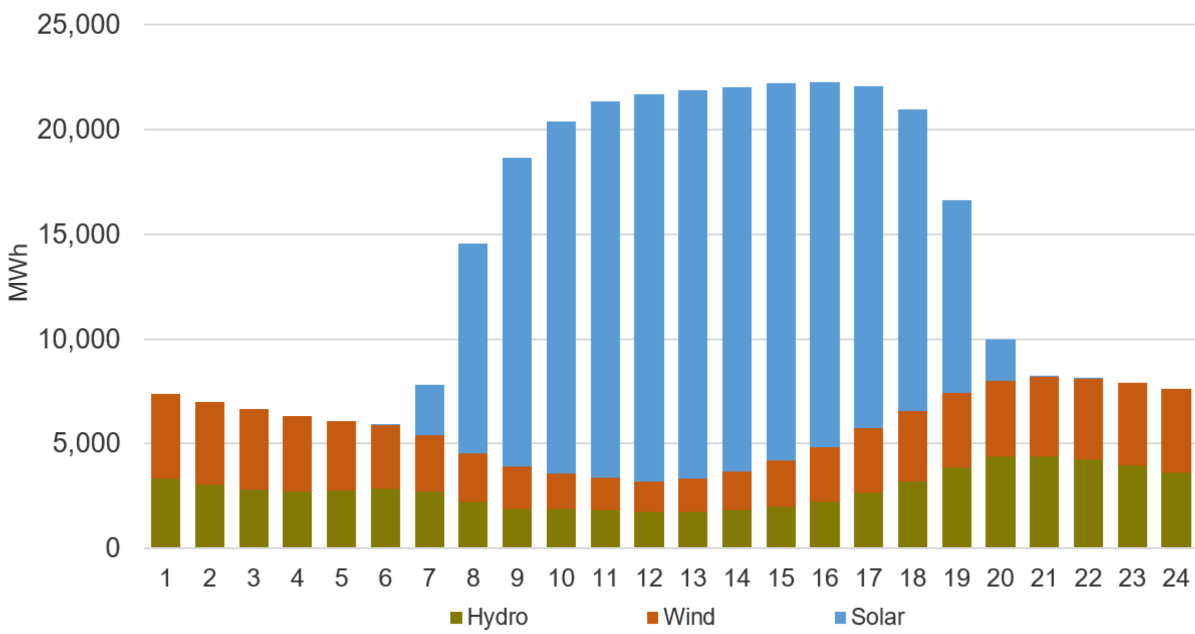
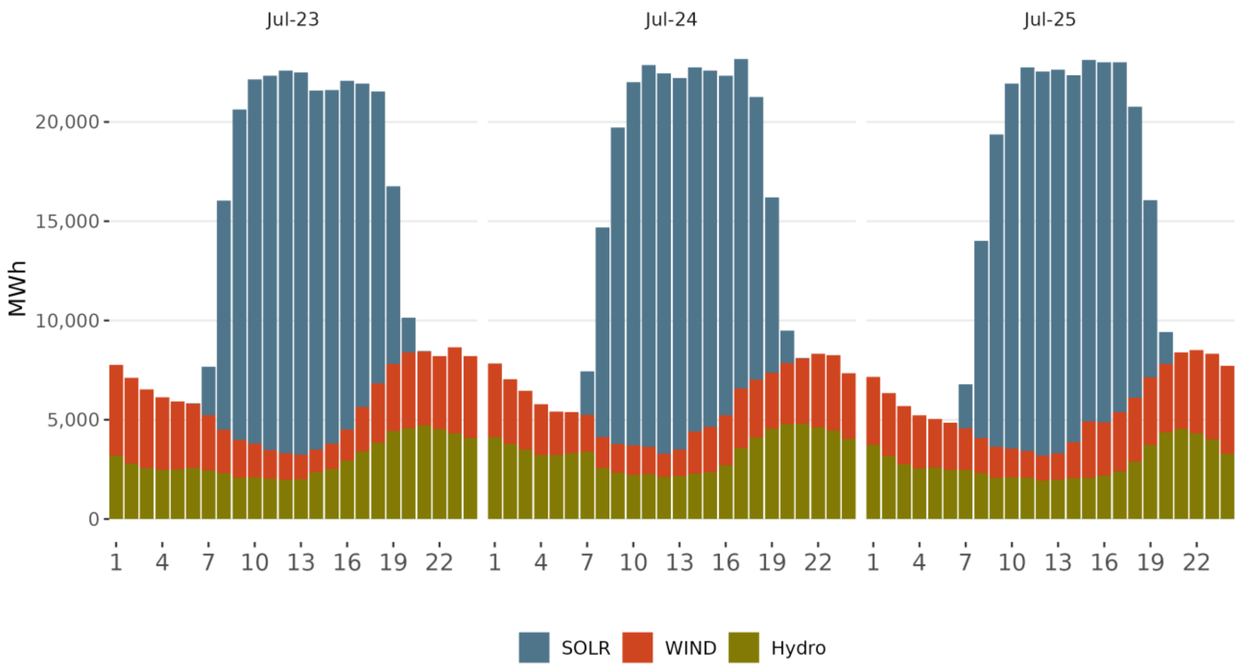


Figure 172: Hourly profile of wind, solar and hydro production for July 23-25

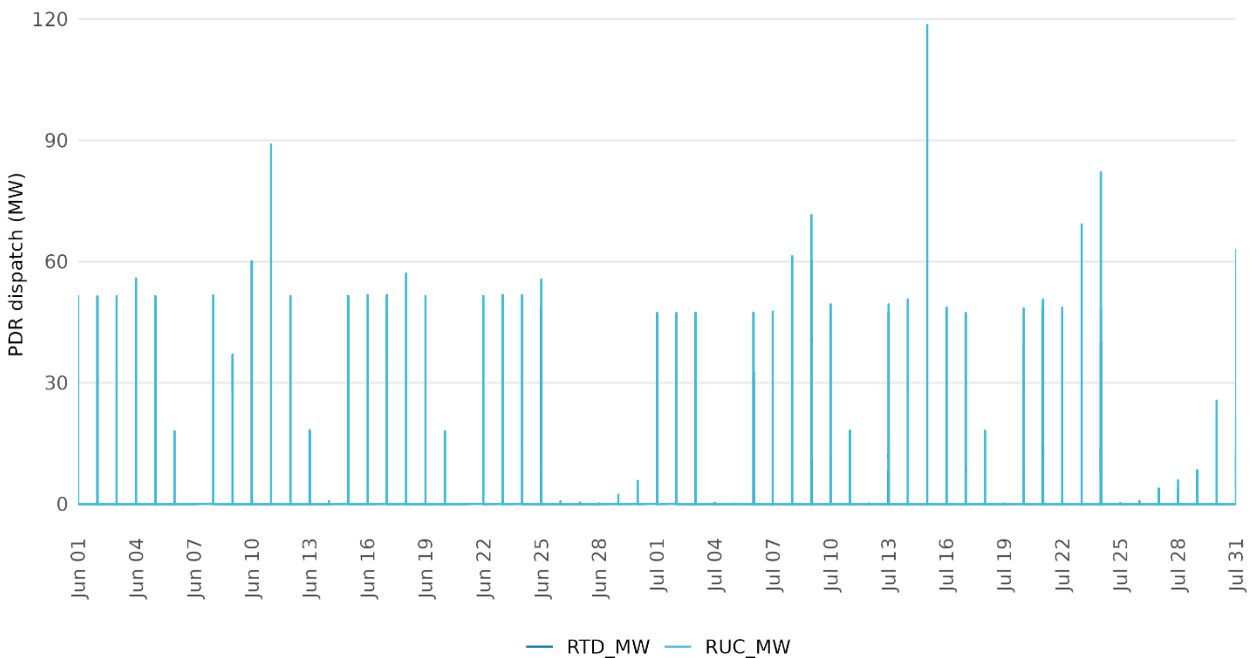


Demand Response

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.

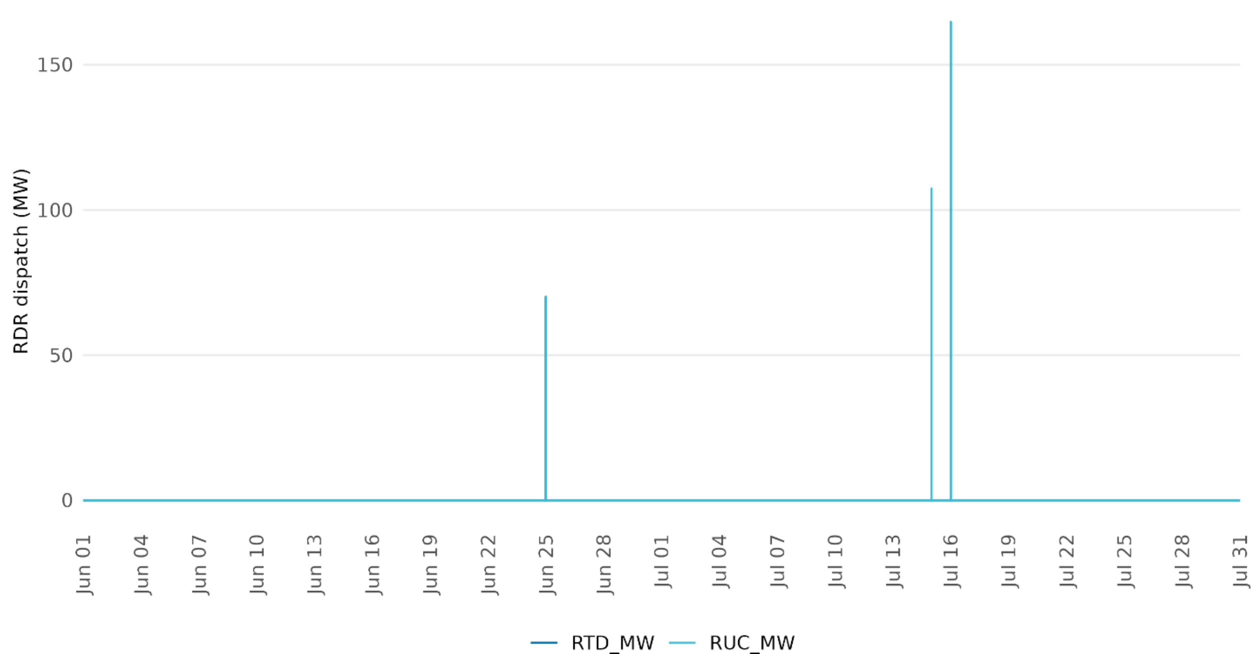
Figure 173 shows the dispatch for proxy demand resources (PDR) in both the day-ahead and real-time markets. PDRs are dispatched economically in all markets based on their bid-in prices. During the month of June and July, PDR resources were consistently dispatched in both the day-ahead and real-time markets and the times overlap but values are slightly different. The largest volume of PDR dispatches in the day-ahead timeframe occurred on July 15 at about 118 MW, whereas in the real-time market, it was a maximum of 86 MW on the same day.

Figure 173: PDR Dispatches in day-ahead and real-time markets



Reliability demand response resources (RDRRs) were not triggered in the real-time market during July. Figure 174 shows the dispatches of RDRRs in both the day-ahead and real-time markets for July. 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. The largest volume of RDRR dispatches in the real time market was on July 16 to about 165 MW for HE 17. RDRRs were dispatched in RUC and RTD market to the same amount of 165 MW on July 16 for HE 17, hence the red line for RUC MW and blue line for RTD MW are overlapping.

Figure 174: RDRR dispatches in day-ahead and real-time markets



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.

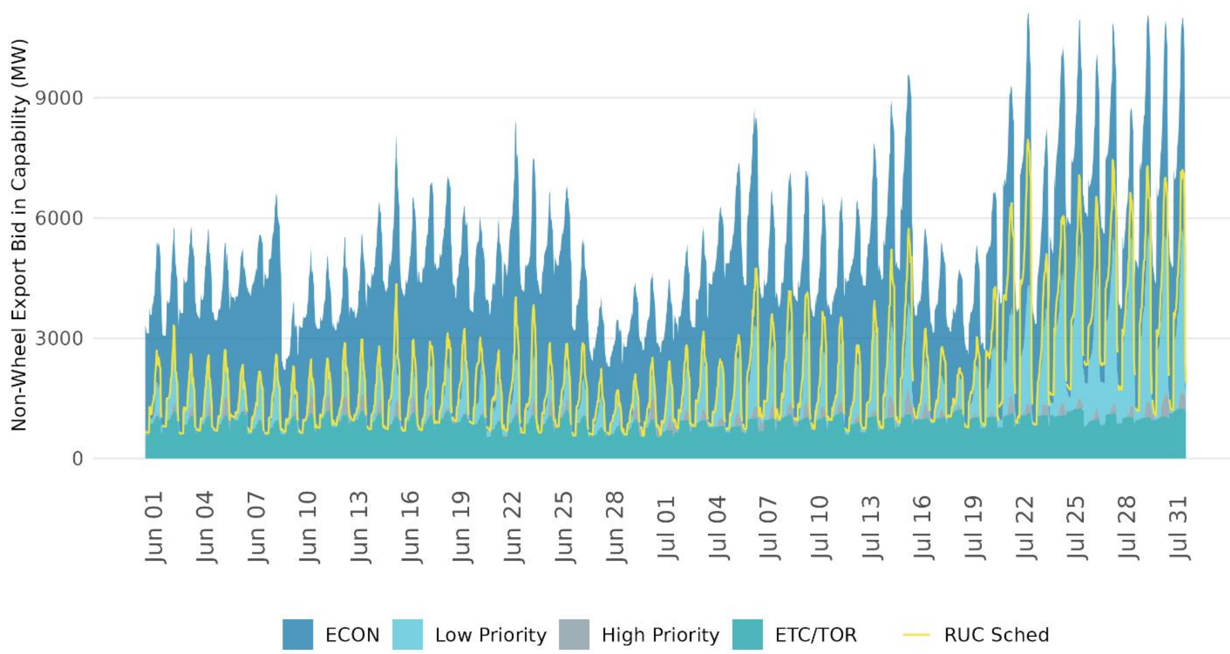
The ISO's markets will clear intertie transactions utilizing its least-cost optimization process in each of its market runs. Bids and self-schedules are considered in a merit order to determine the clearing schedules, and all resource bids and characteristics, and system conditions, are considered. In 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 175 shows the capacity from static export transactions in the day-ahead market 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. Given the high loads in July in the west, export volumes significantly increased towards the second part of July.

Figure 175: Day-ahead Bid-in capacity and RUC cleared export



The RUC schedule plus RCD minus RCU 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 66 percent, 14 percent, 18 percent and 2 percent of the export capacity were for economic bids, LPT, ETC/TOR and PTK, respectively. There were larger volumes of LPT in July comparing to June, resulting in a slightly higher total of bid in export volume. The highest RUC scheduled was in hour ending 18 on July 22, at about 8,000 MW.

Figure 176 shows the same metric for imports. These volumes include both static imports and dynamic resources. Both ETC/TOR remained relatively stable through the months. There were smaller volumes of economic bids in July comparing to June, resulting in a slightly lower total of bid in capacity. The “other” group includes regulatory must run priority capacity and the portion of Pmin for dynamic resources with a Pmin above 0 MW.

Figure 176: Day-ahead bid-in capacity and RUC-cleared imports

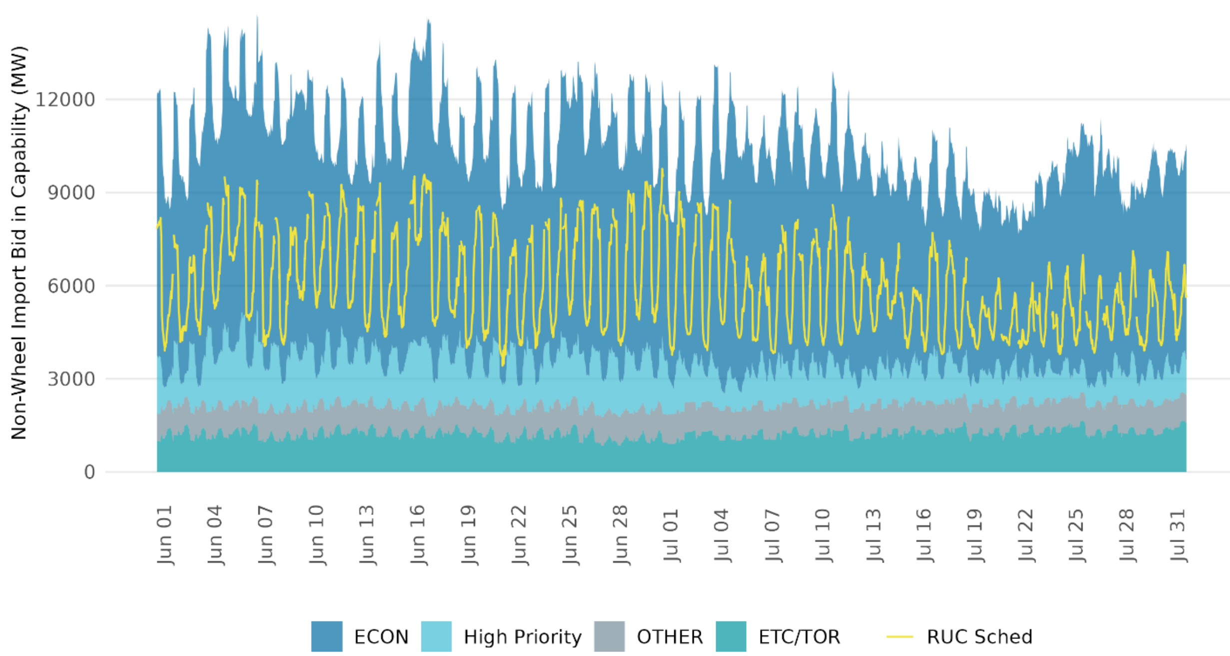


Figure 177 shows the overall intertie schedules organized by type of schedule, as well as the net interchange based on the RUC solution for two months. Figure 178 shows the overall intertie RUC schedules during the heatwave, July 23 – 25. The net interchange projected in the RUC process reached its lowest level on July 22 in HE 18 at about -2,641.3 MW due to the higher level of exports cleared.

Figure 177: Breakdown of RUC cleared schedules

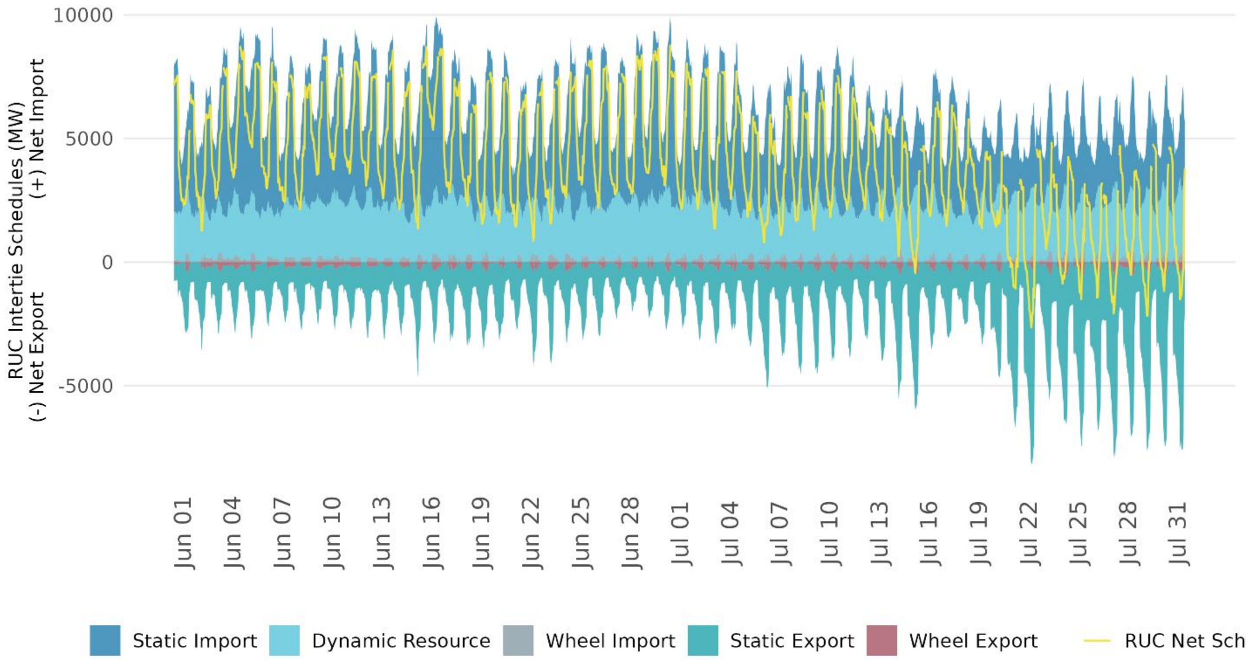
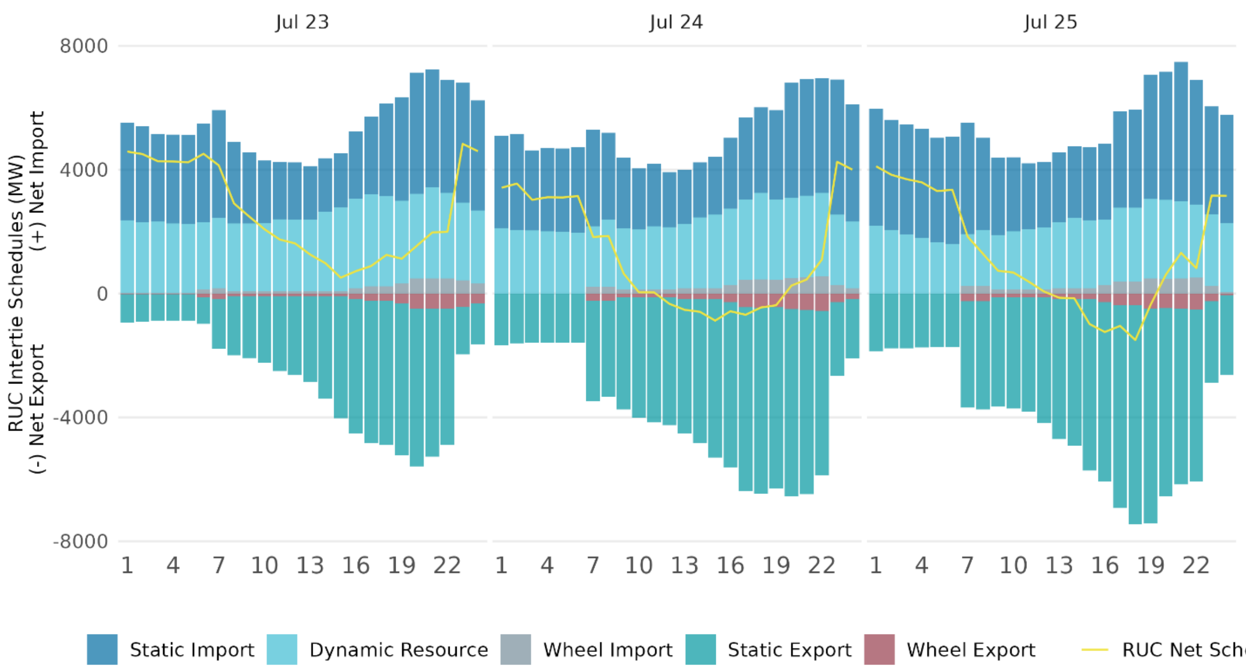
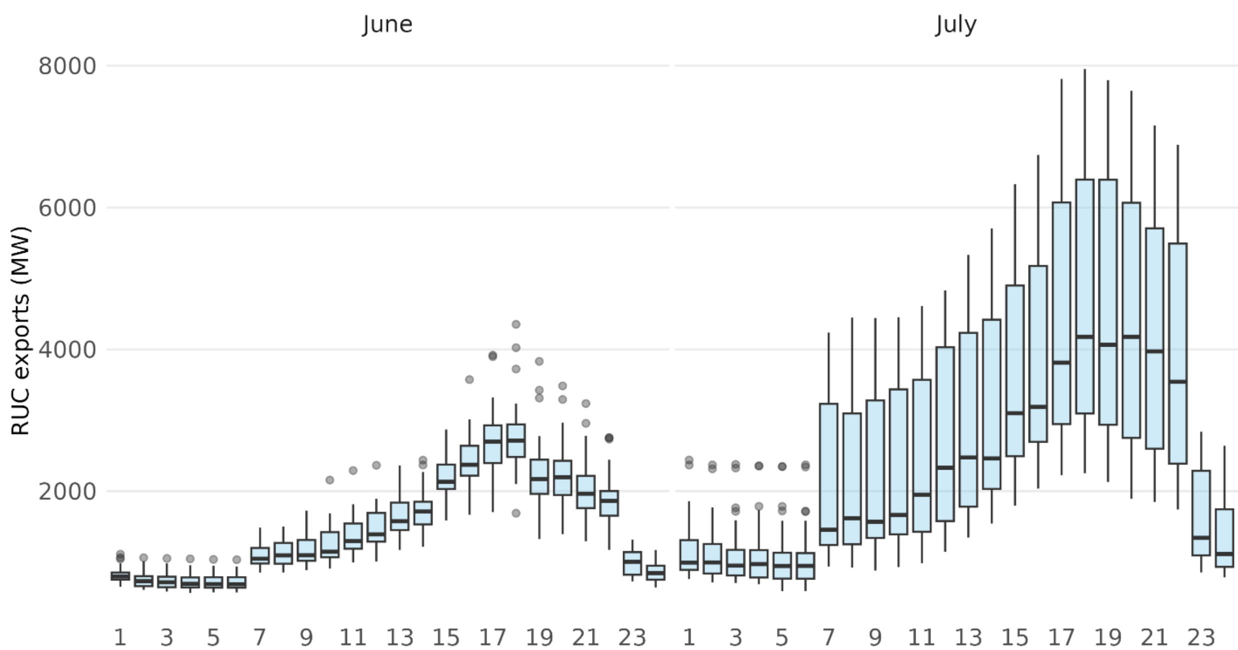


Figure 178: Breakdown of RUC cleared schedules, July 23-25, 2026



An area of interest since summer 2020 is the trend of exports in the ISO's system. Figure 179 illustrates the hourly distribution of RUC schedules for exports and that the highest volume occurred during afternoon hours. Comparing to June, July had higher RUC exports for all hours. The highest volumes were cleared in hour ending 18 and 19.

Figure 179: 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 180 shows both the cleared schedules in real time for interties of different groups, and the net intertie schedules cleared, referred to as net schedule interchange. The net schedule interchange was at its lowest value on July 31 due to the high level of exports cleared on that day. The real-time market largely follows the trend observed in the day-ahead market. The net schedule is generally lower in July comparing to June. On average, for July, the net schedule in HASP was about 3,240 MW across all the hours of the month and about 1,772 MW for peak hours.

Figure 181 shows the cleared and net schedules during the heatwave, July 23 – 25. The net schedule was close to or below 0 for a few early afternoon hours on 23 and 24.

Figure 180: HASP cleared schedules for interties

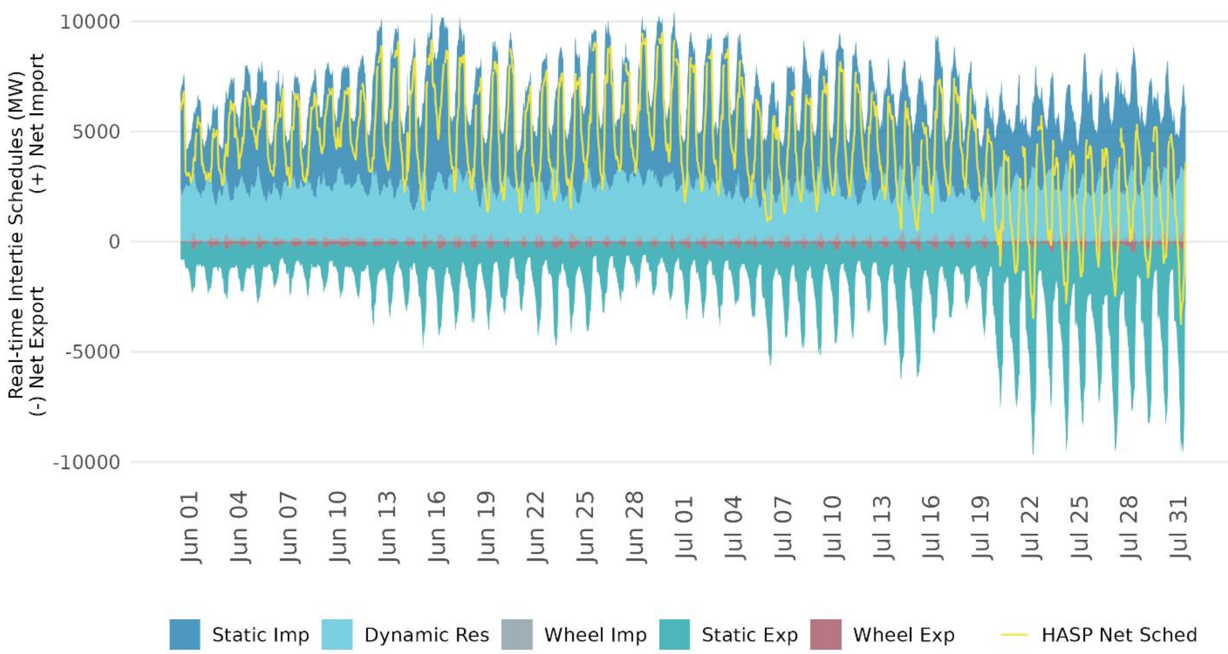
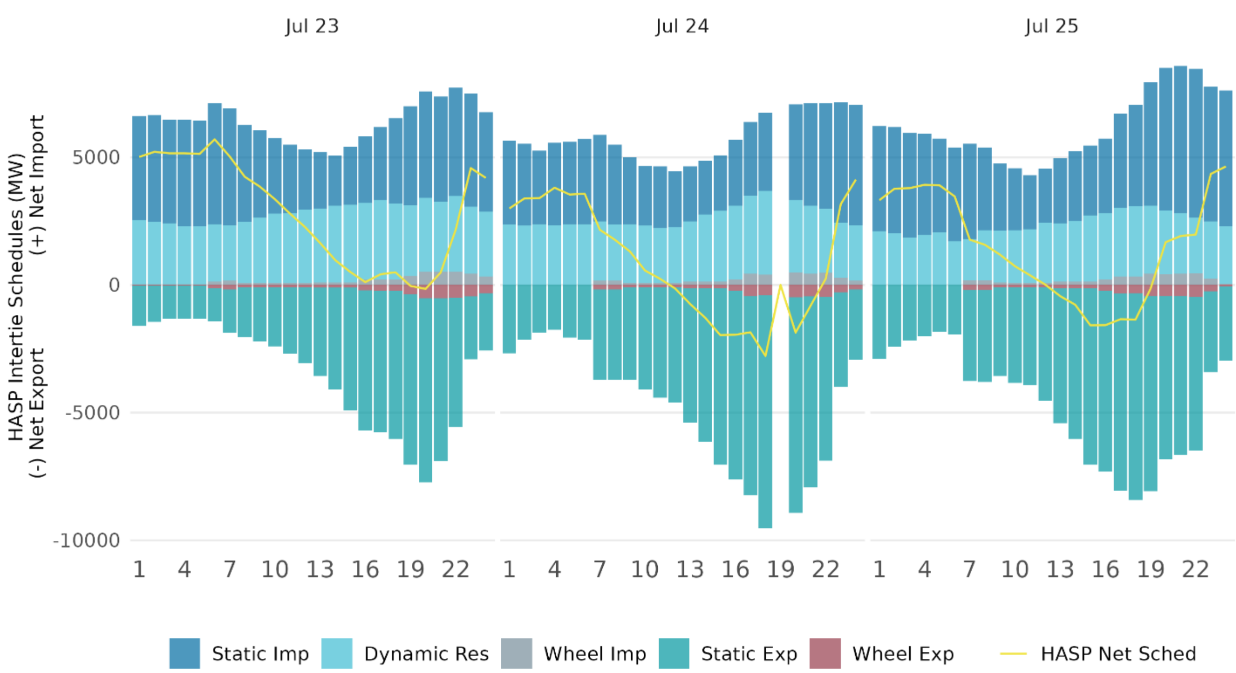


Figure 181: HASP cleared schedules for interties, July 23 – 25, 2026



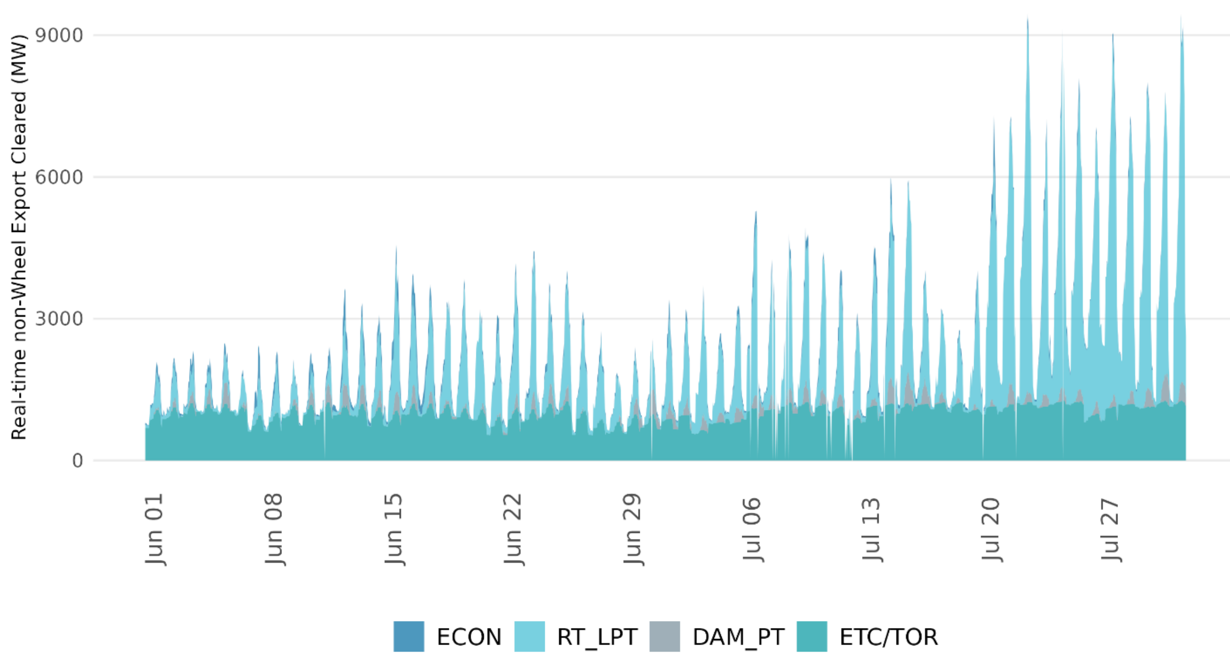
The HASP market presents an opportunity for interties to clear through the market clearing process after the DAM is complete. Clearing the RUC process indicates that these exports were feasible to flow based on the projected system conditions in RUC and will be reassessed in real time.[10]

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

Figure 182 shows all the exports cleared in the HASP process and identifies the nature of such exports. Figure 183 shows the exports cleared for the period of July 23 – 25. 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.

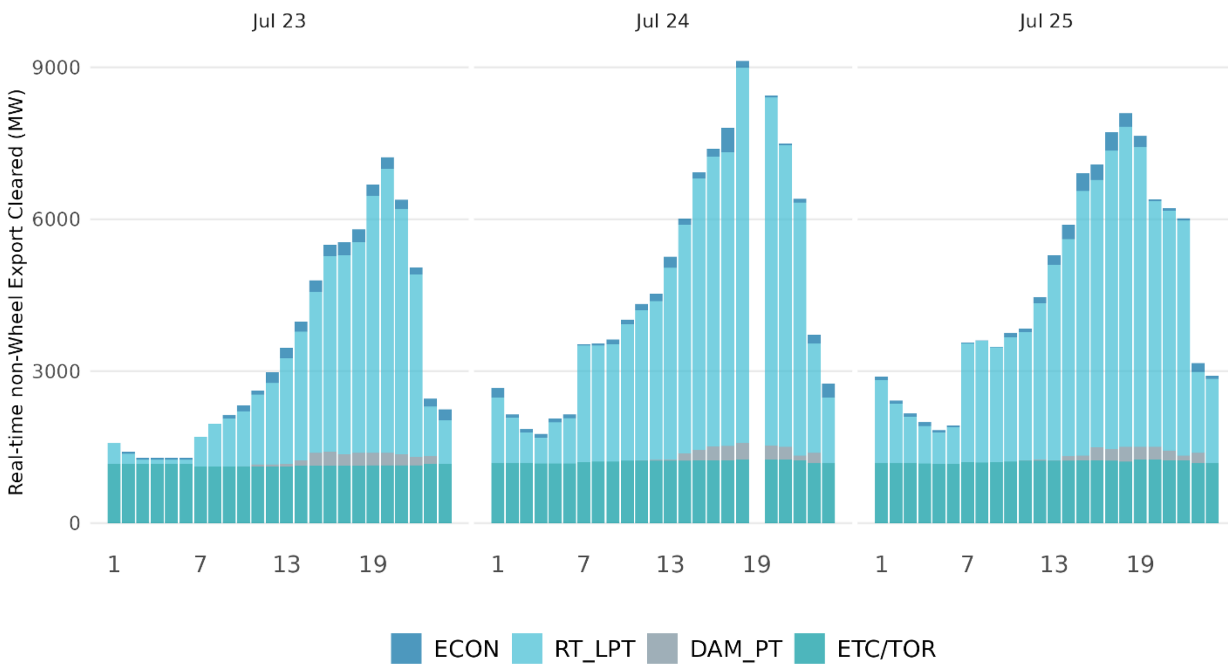
The volume of exports cleared in real time peaked at 9,450MW on July 22. In July, higher volumes of exports were cleared relative to June, and low-priority bids constituted a significant portion of cleared exports.

Figure 182: Exports schedules in HASP



[10] 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 183: Exports schedules in HASP, July 23 – 25



Imports and exports were scheduled over multiple intertie scheduling points in July, with Malin, Palo Verde and NOB seeing the highest volume of transactions. Figure 184 through Figure 186 illustrate the trend of import and export schedules cleared in HASP for these top three intertie points. In July, the prevailing schedules were in the import direction.

Figure 184: HASP schedules at Malin intertie

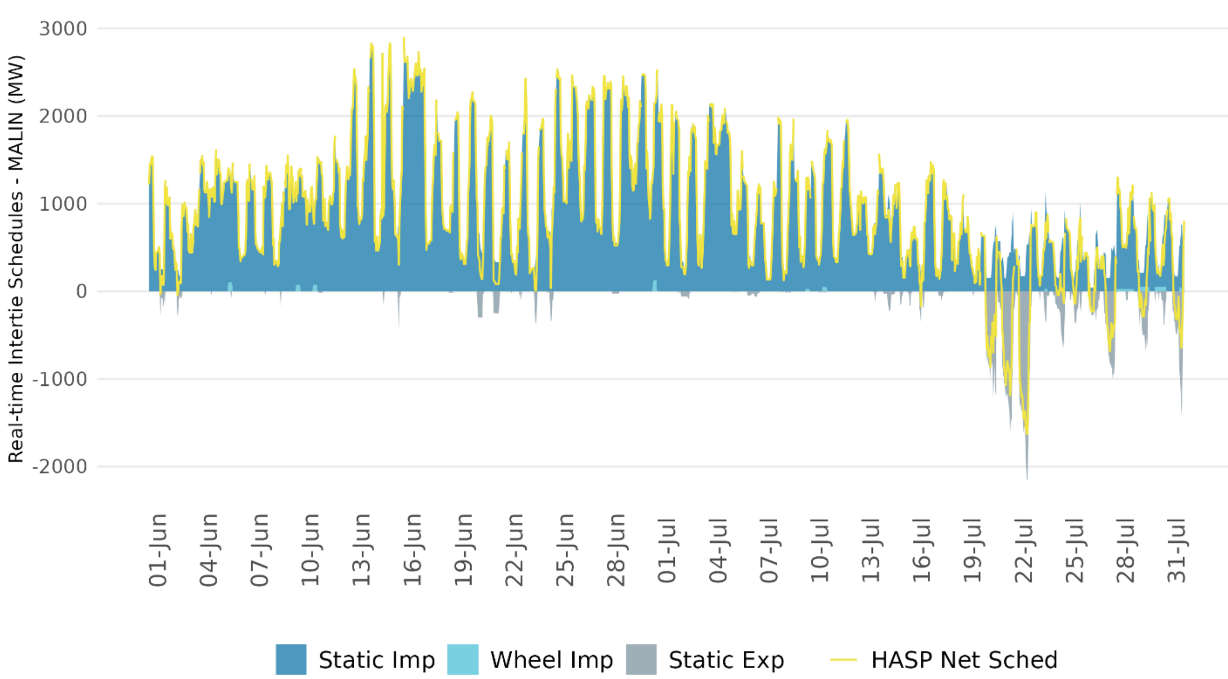


Figure 185: HASP schedules at Palo Verde intertie

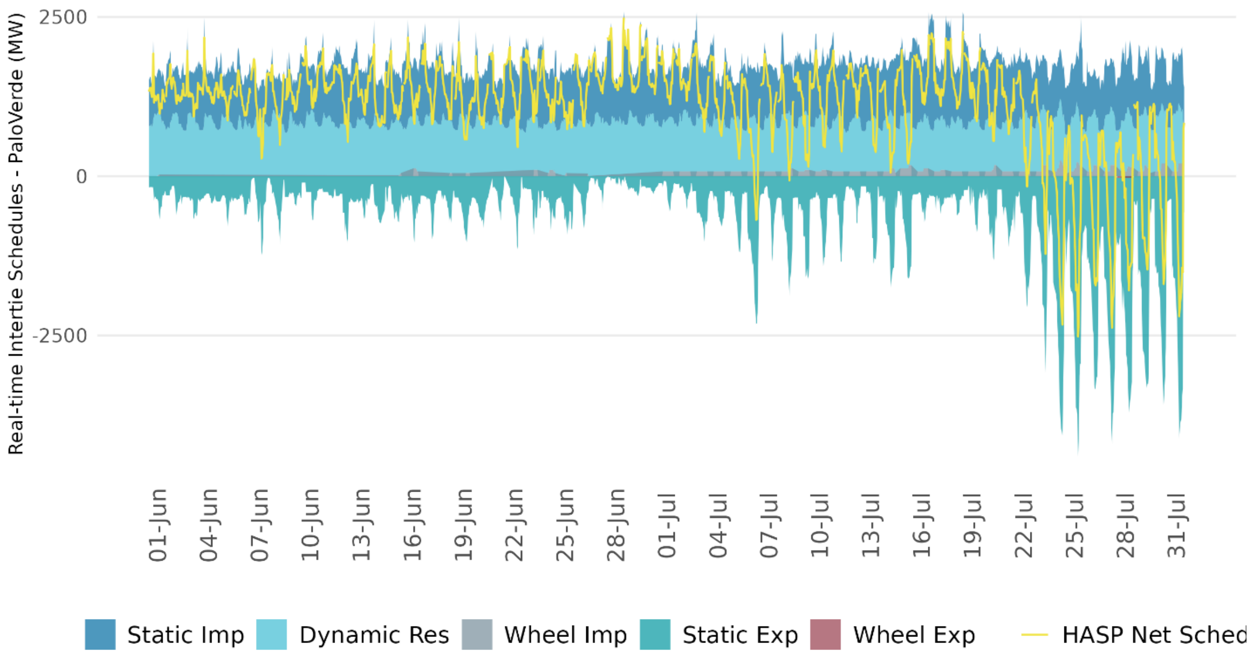


Figure 186: HASP schedules at NOB intertie

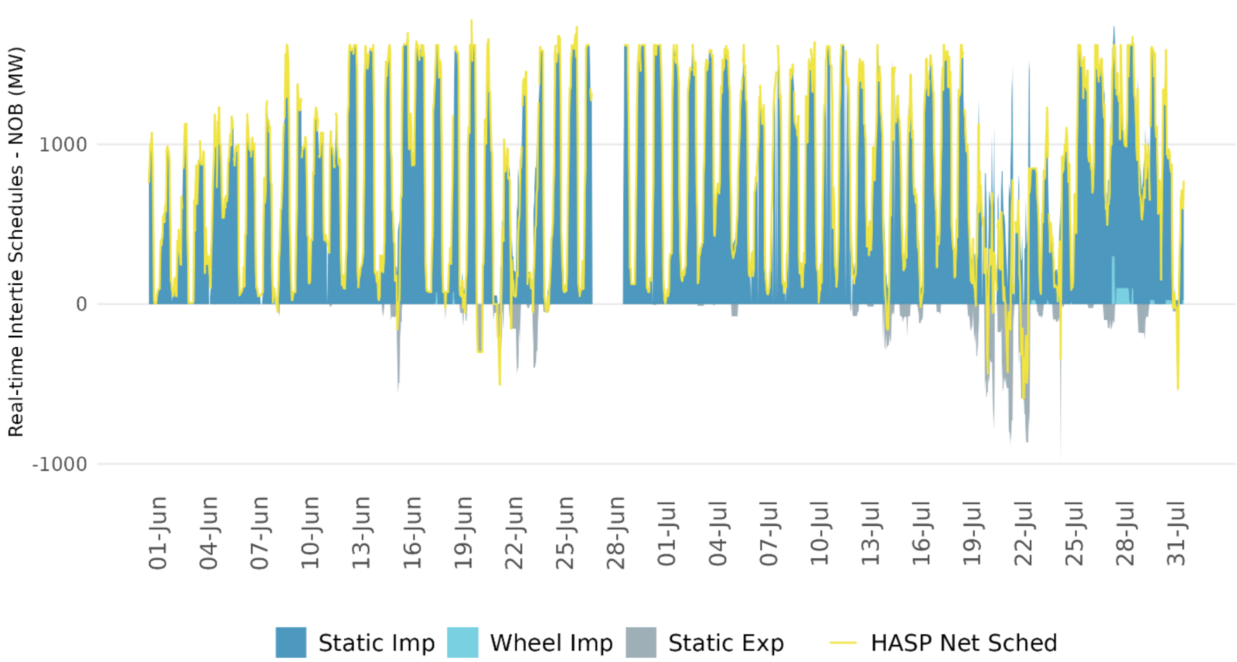
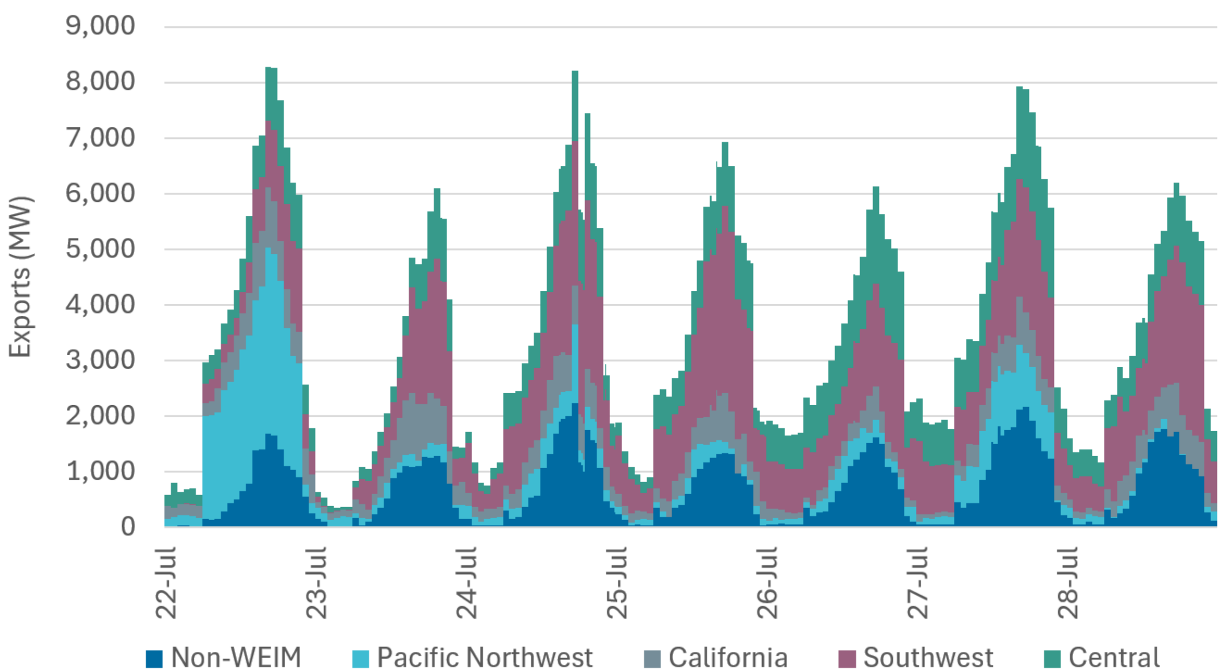


Figure 187 shows the total volume of intertie exports that sourced from the ISO area and organized by the different areas in which the exports sink. For simplicity, these sink areas are grouped in regions of the western interconnection for all areas that are in the western energy imbalance market. There is one group also used to refer to the volume of export sinking into areas that are not part of the western energy imbalance market. During that week of July, up to 8,000 MW of exports sourced from the ISO area supported multiple areas in the western interconnection.

Figure 187: HASP schedules at NOB intertie



Storage and Hybrid Resources

In July 2026, there were 248 storage resources registered in the ISO market. 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 state of charge from all the active resources participating in the market was about 71,000 MWh. In terms of the capacity made available to the markets, Figure 188 and Figure 189 present the daily average and the hourly average of bid-in capacity for storage resources in the day-ahead market in June and July, organized by price ranges.

Figure 188: Bid-in capacity for batteries in the day-ahead market, daily average

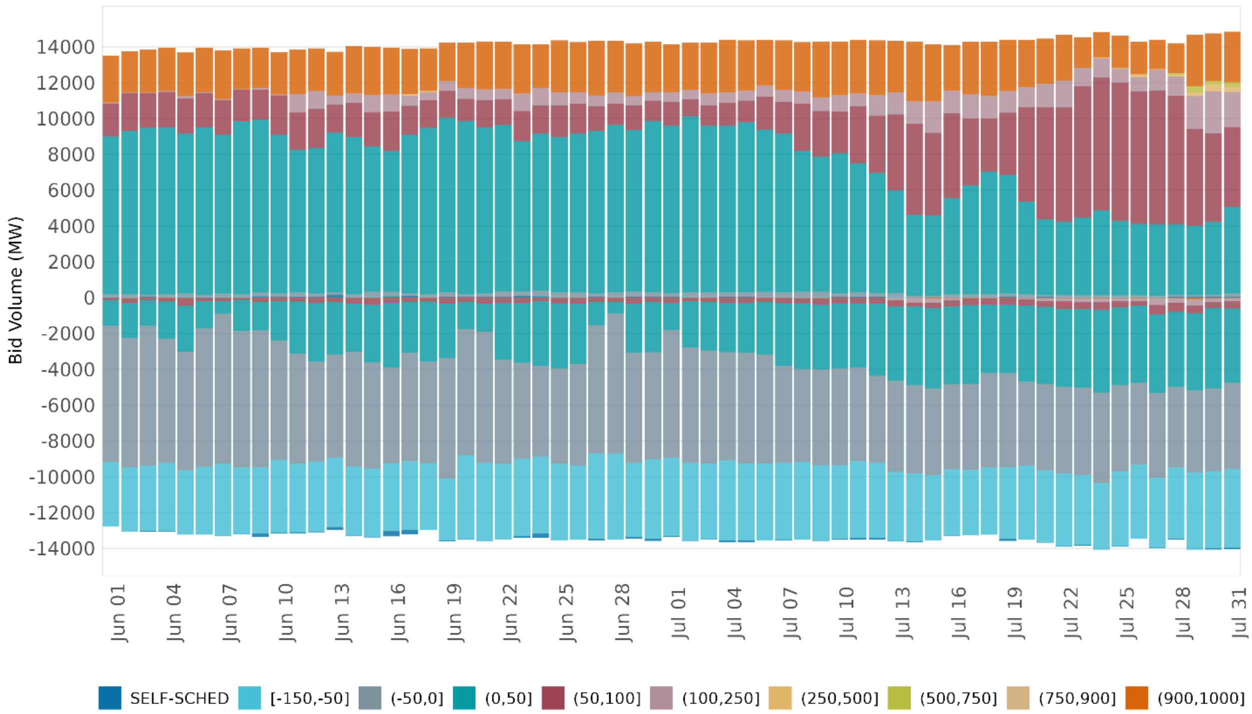
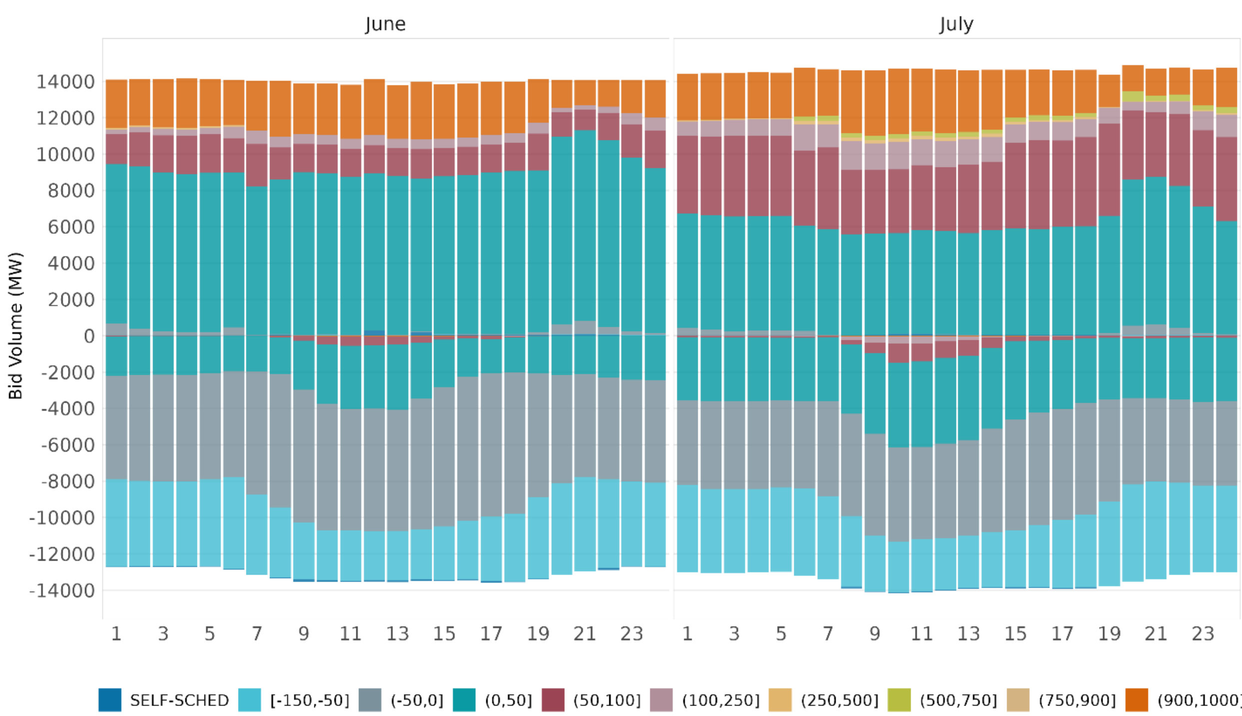


Figure 189: Bid-in capacity for batteries in the day-ahead market, hourly average



The negative area represents charging while the positive area represents discharging. The overall capacity in the market was roughly consistent through the months at about 14,000 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. 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 190 and Figure 191 present the bid-in capacity for the real-time market. The overall capacity follows the similar trend as the day-ahead market.

Figure 190: Bid-in capacity for batteries in the real-time market, daily average

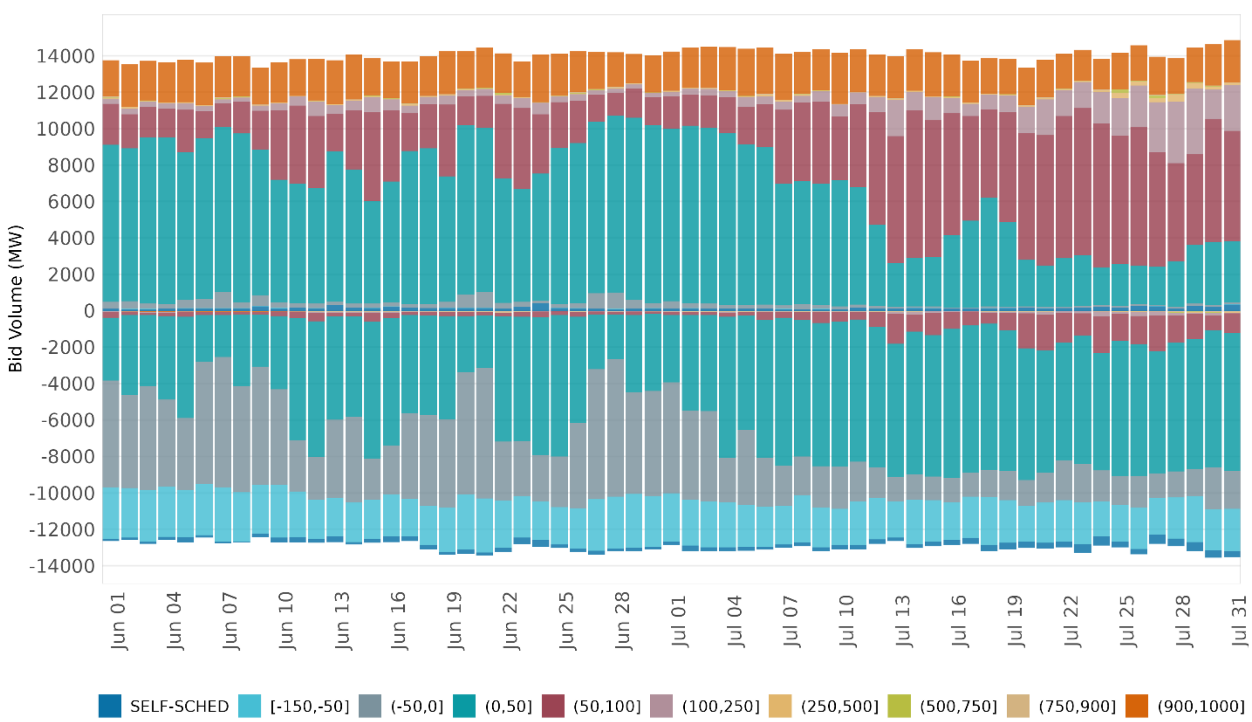


Figure 191: Bid-in capacity for batteries in the real-time market, hourly average

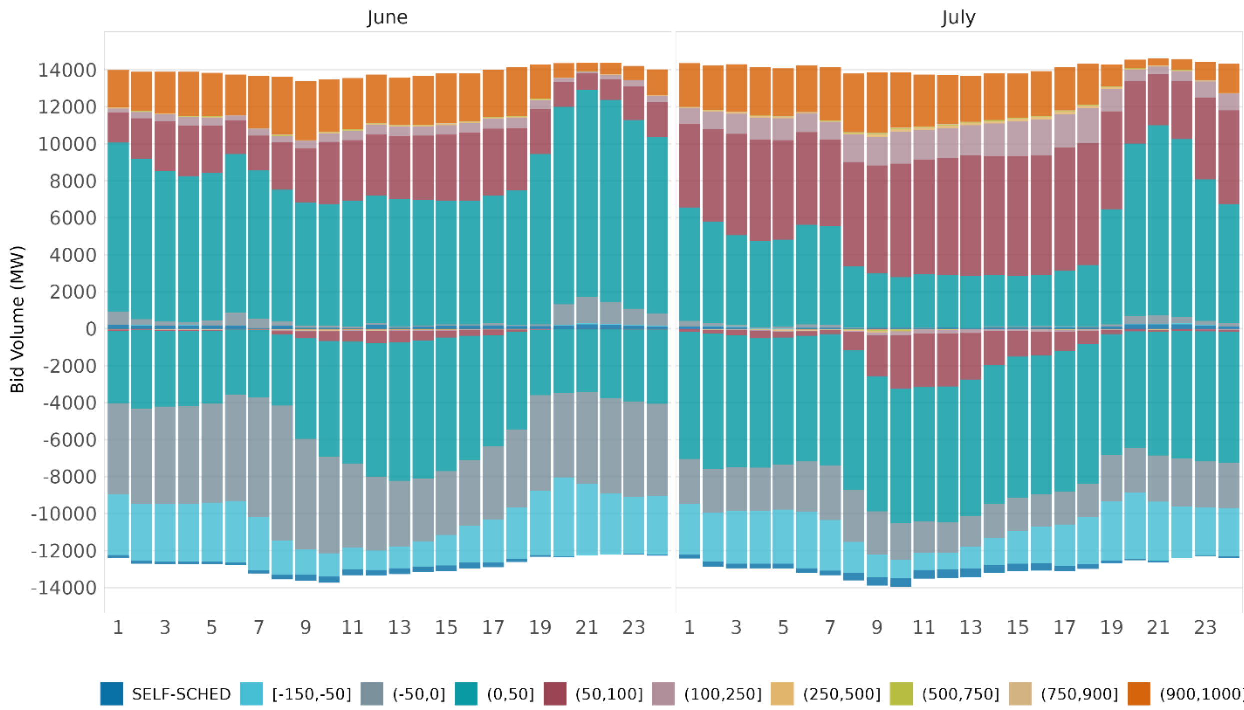


Figure 192 shows the hourly distribution of the storage capacity of resources participating in IFM and RTD for June and July. The box plot shows the median, 25th percentile, 75th percentile, and outliers for the total state of charge. Storage resources charge in hours when there is abundantly cheap energy from solar resources in the daytime. The system reached maximum stored energy by hour ending 16, followed by a period of steady discharge from hours ending 18 through 24. In July, the highest system state of charge in IFM was around 48,000 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 55,000 MWh in hour ending 18, at roughly 77 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.

Figure 192: Distributions of day-ahead state of charge

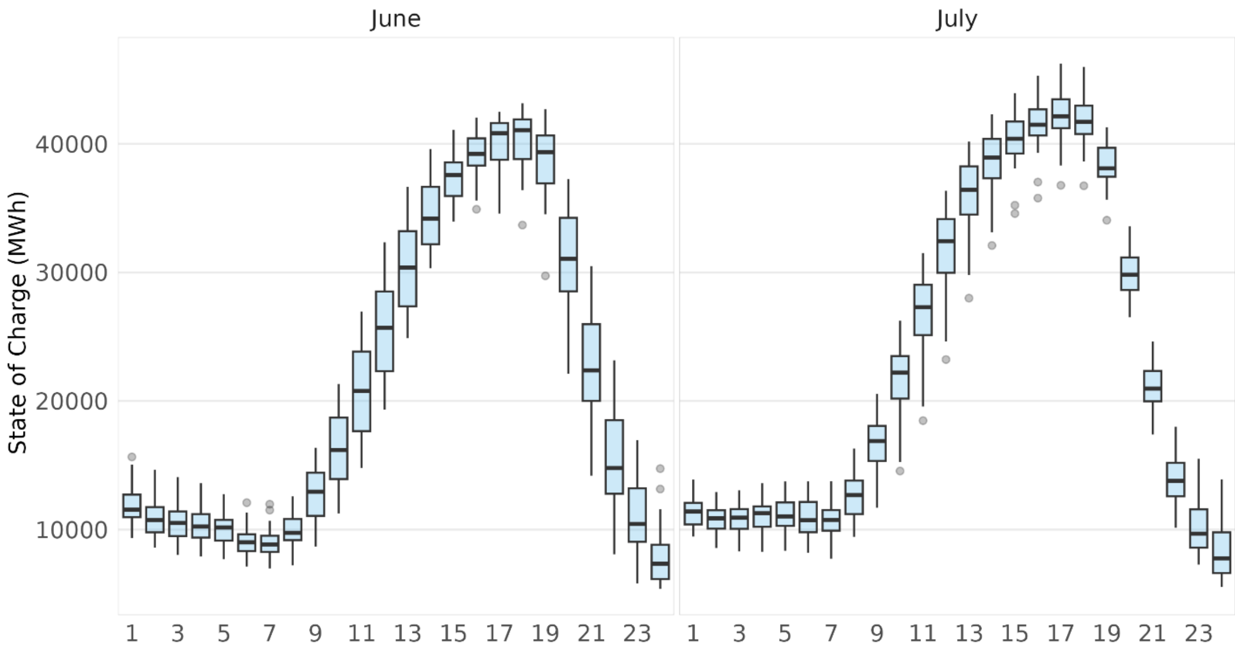


Figure 193: Distributions of real-time state of charge

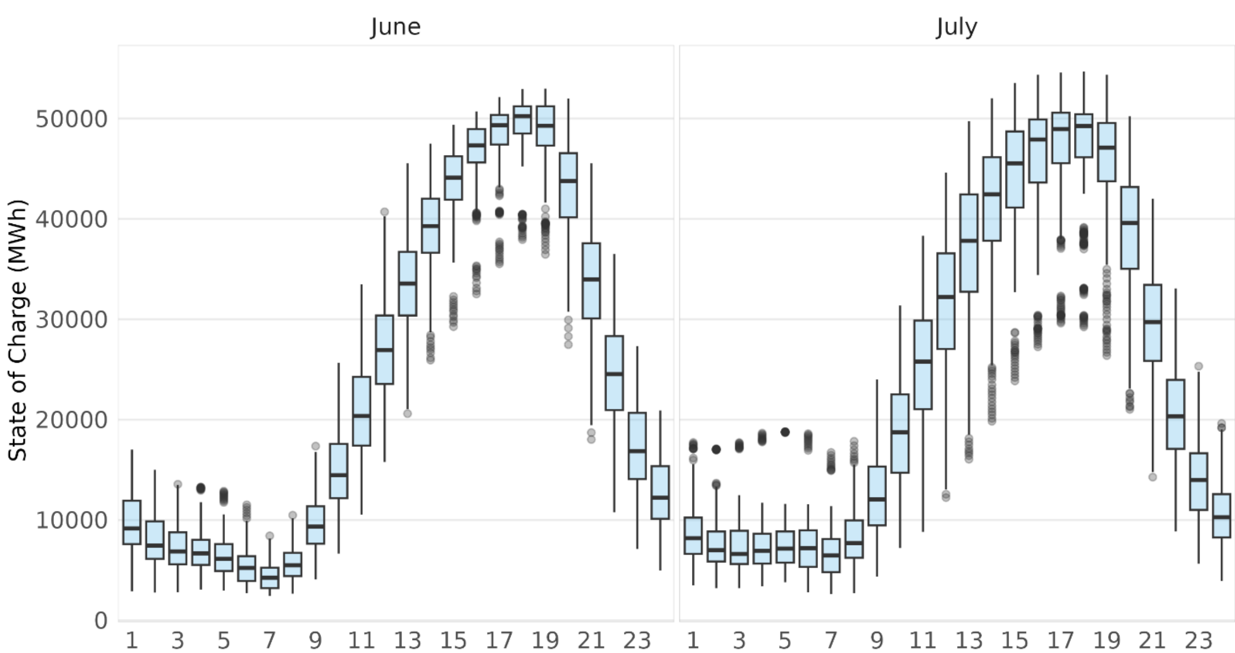
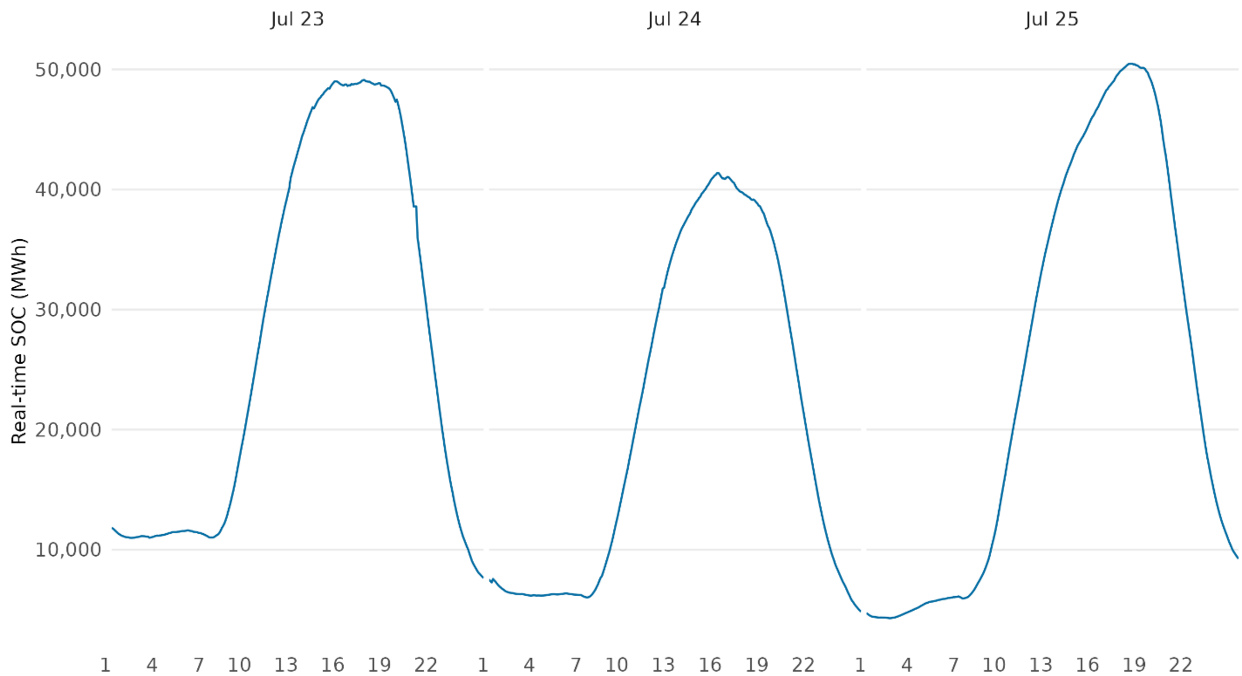


Figure 196 and

Figure 197 shows the real-time energy schedule and state of charge of all batteries specifically from July 23 to July 25. The peak energy discharge is about 11,000 MW in HE 22 on July 25, and peak charge is about 8,000 MW in HE 11 on July 23. The peak hourly state of charge in the real-time market was above 50,000 MWh in HE 19 on July 25.

Figure 194: Real-time energy awards of batteries, July 23 – July 25

Figure 195: Real-time state of charge of batteries, July 23 – July 25



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 196 shows the distributions of energy awards in IFM, and

Figure 197 shows the hourly distribution of real-time dispatch for batteries in June and July. These statistics are for batteries, either stand alone or the battery component of co-located resources; they do not include hybrid resources.

Figure 196: Hourly distribution of IFM energy awards for batteries

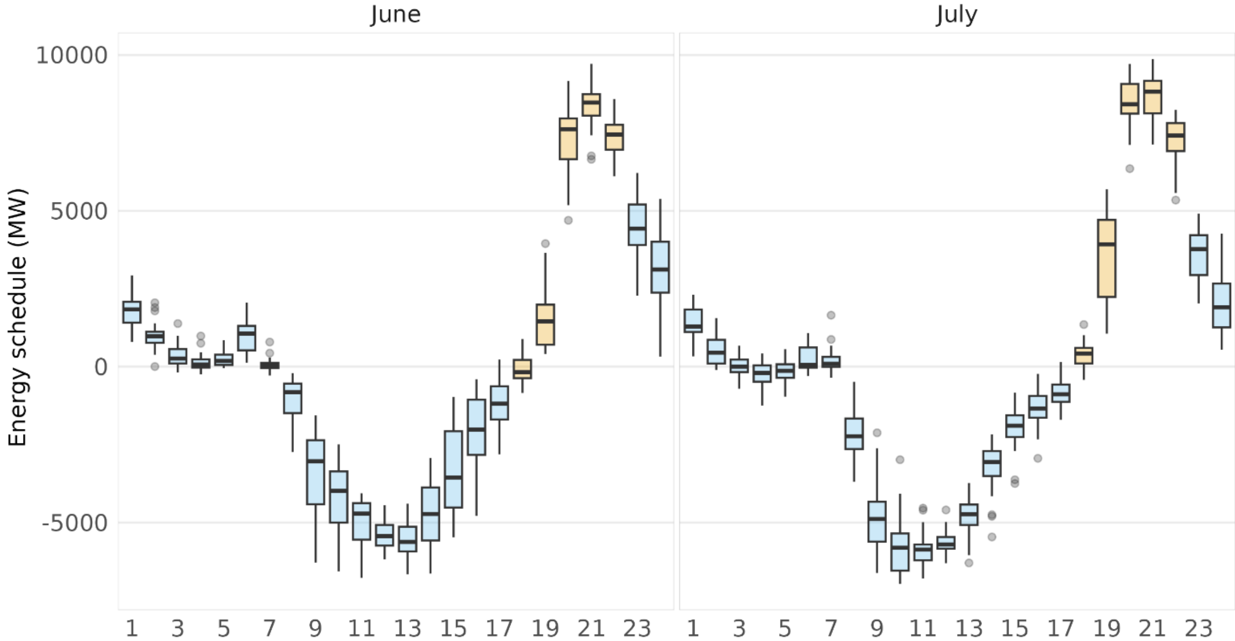
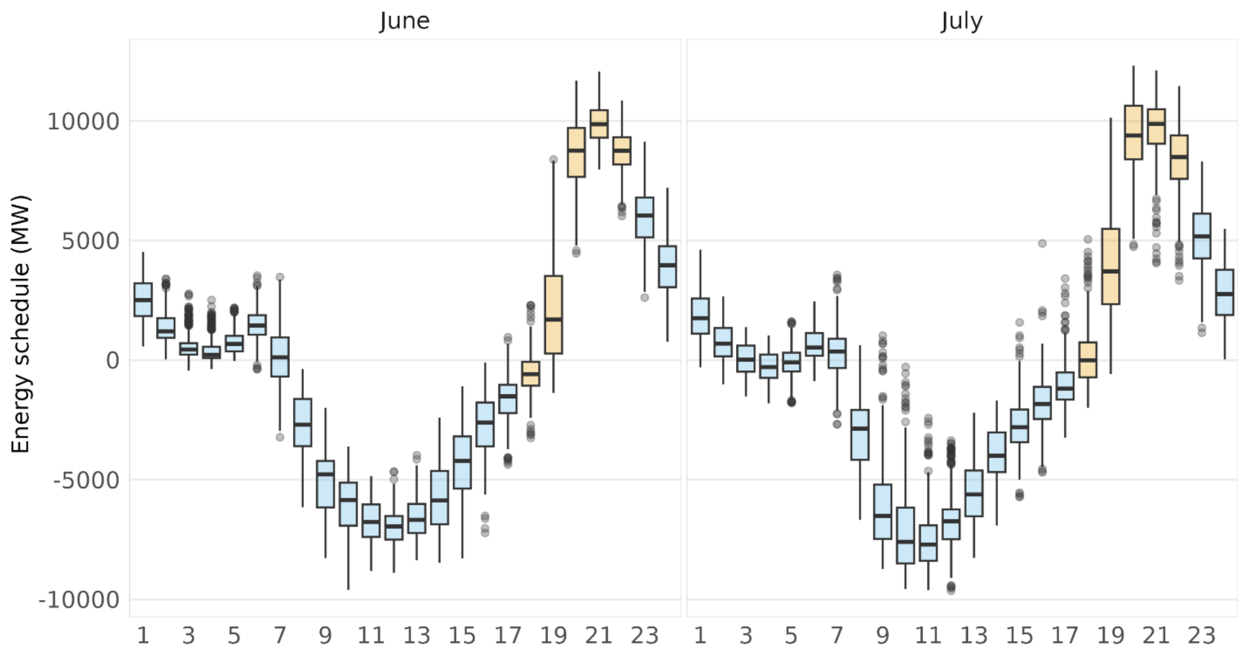
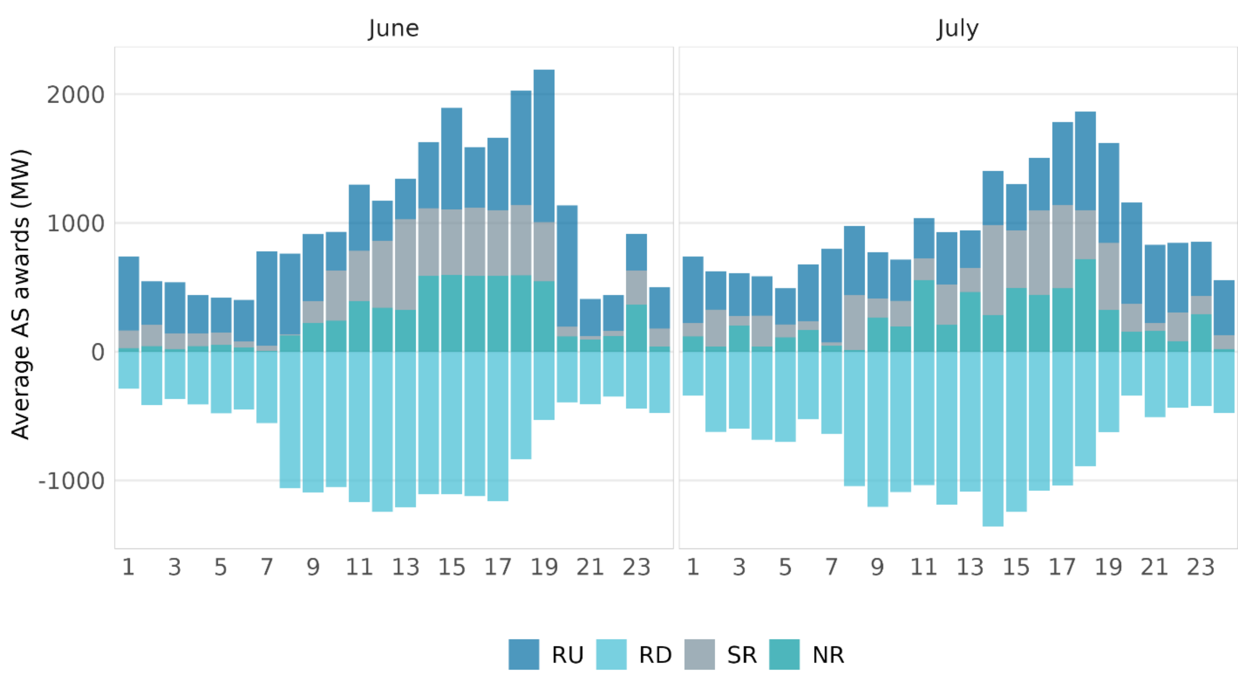


Figure 197: Hourly distribution of real-time dispatch for batteries



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 198 shows the average hourly AS awards in the real-time market.

Figure 198: Hourly average real-time storage AS awards



Beginning with the implementation of the Hybrid Resources Phase 2B project in February 2023, the ISO began tracking 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 199 and

Figure 200 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. The energy schedules in IFM in July had a roughly 30 percent increase in the midday hours comparing to schedules in June, while the scales remain similar in the real time market.

Figure 199: Hourly distribution of IFM energy awards for hybrid resources

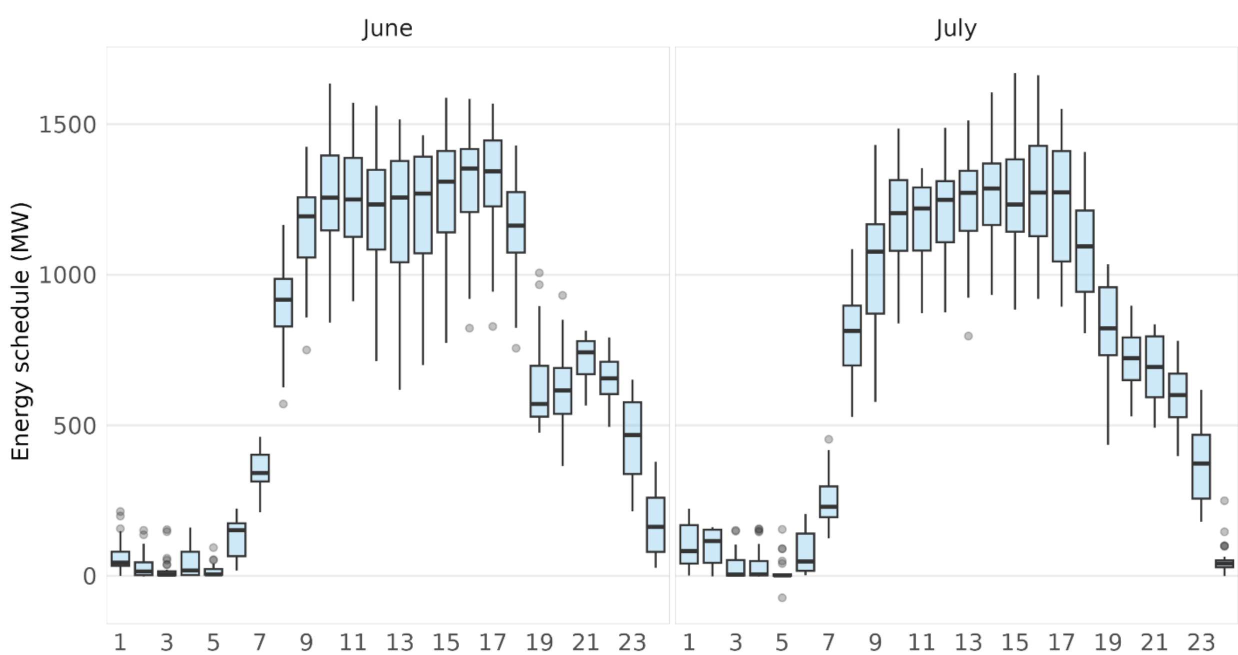


Figure 200: Hourly distribution of real-time dispatch for hybrid resources

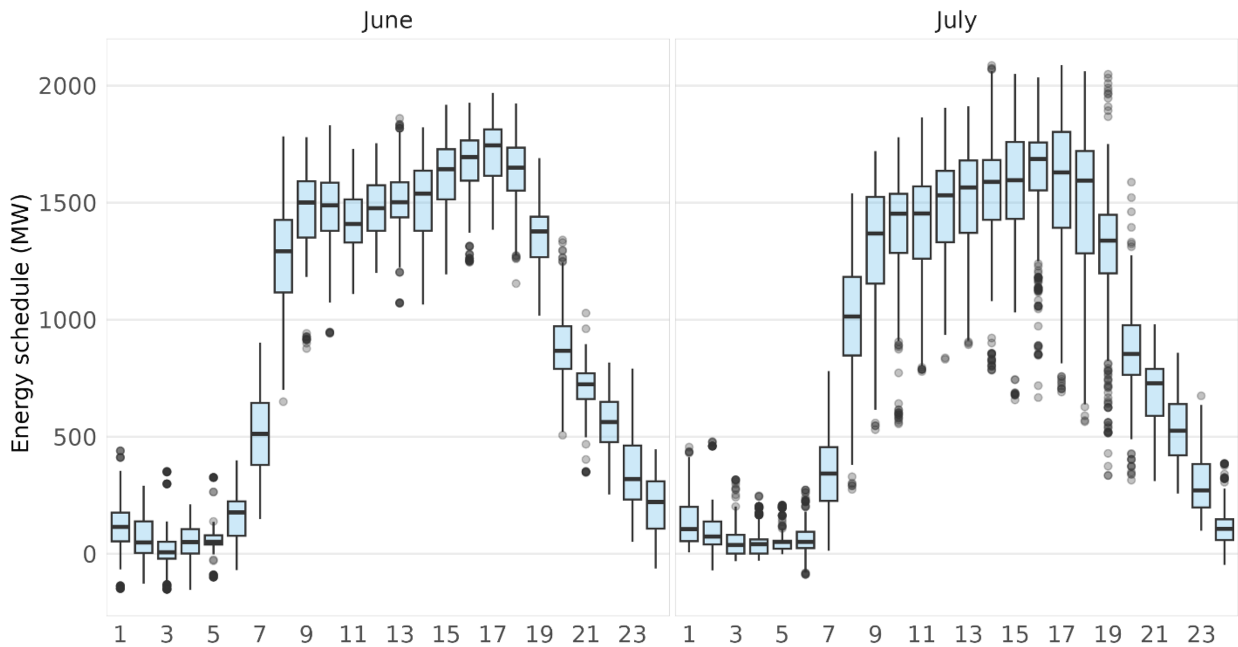
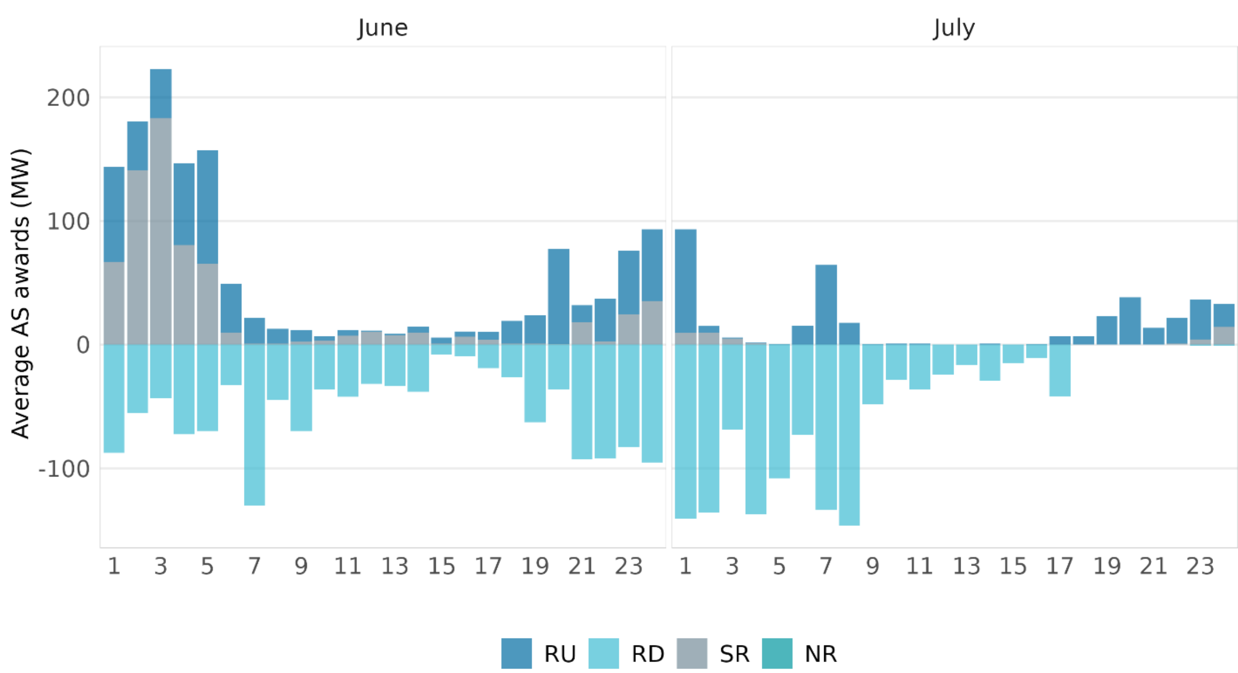


Figure 201 shows the real-time energy schedule of all hybrid resources specifically from July 23 to July 25. The peak energy discharge is about 2,100 MW in HE 19 on July 25.

Figure 201: Real-time energy awards of hybrid resources, July 23 – July 25

Similar to storage resources, hybrid resources can also provide ancillary services to the market. Figure 202 shows the average hourly AS awards in real-time June and July 2026.

Figure 202: Hourly average real-time hybrid AS awards



Western Energy Imbalance Market

July experienced high load conditions across the western interconnection, with a record peak at 168.5 GW on July 24. Regarding the WEIM footprint, load peaks occurred on different days and times across the different regions of WEIM. The historical distributions of load levels are shown in Figure 203. July load levels remained within a tight range with short tails in the distribution, indicating few extreme days. Instead, the distribution suggests load levels were consistent throughout the month. Load levels observed in July 2026 are relatively typical to levels from previous years.

Figure 203: Historical distribution of load level in the western interconnection

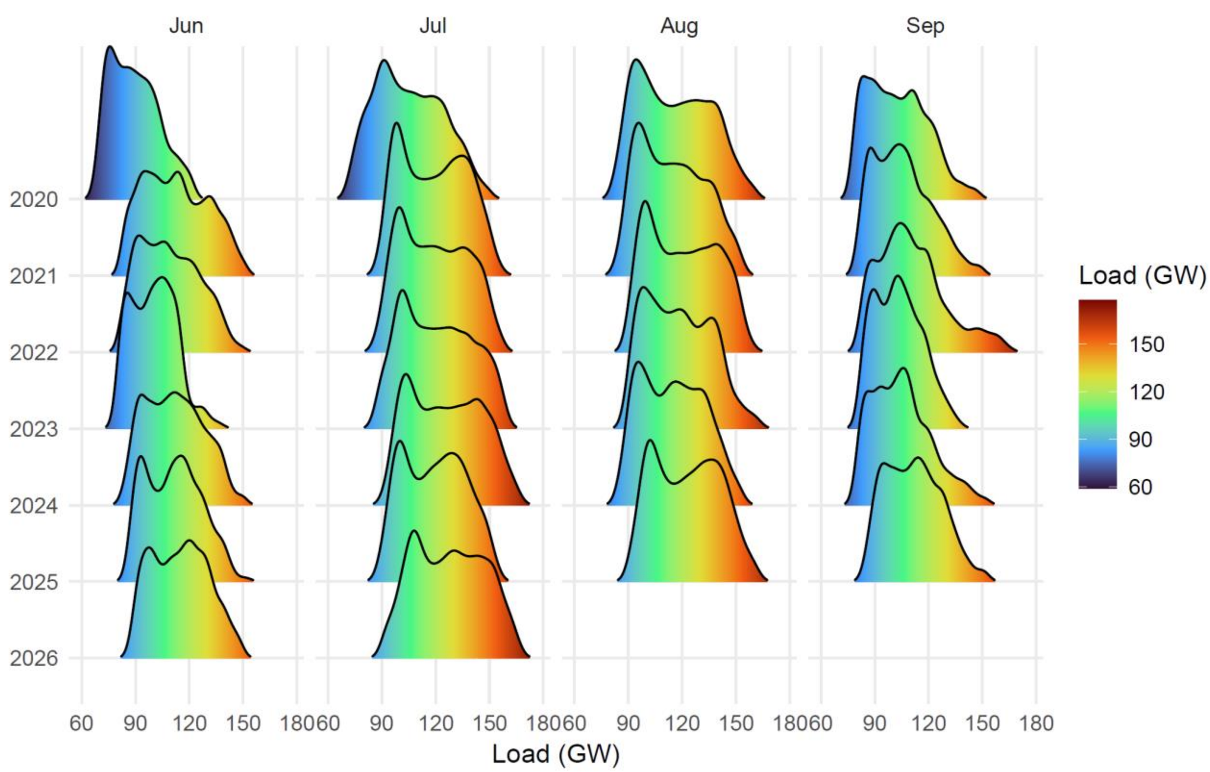


Figure 204 shows the daily peak load aggregated by WEIM regions for the month of July[11]. The California region reached a maximum of 52,931 MW on July 15. The Central/Mountain reached a peak of 17,373 MW on July 20. The Pacific Northwest region reached a maximum of 35,288 MW on July 21. The Southwest region reached a maximum load of about 37,636 MW on July 24. The figures show the circle marker indicating the peak load for that region for the month of July. Figure 205 shows the hourly peak load by WEIM region, and all four regions peak hourly load occurred between HE 17-19 in July.

Figure 204: Daily peak load for June and July 2026, by WEIM region

[11] These regions are only for display purposes of the regional dynamics. The WEIM market clears supply and demand for each individual balancing area.

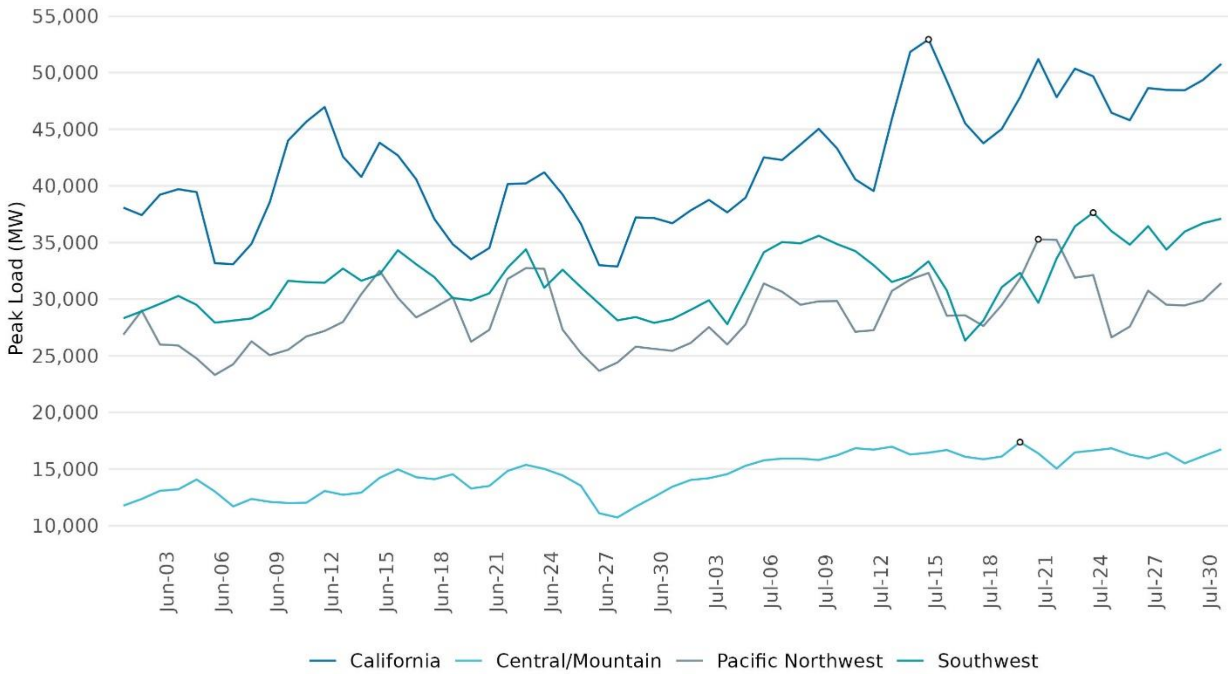


Figure 205: Hourly peak load for June and July 2026, by WEIM region

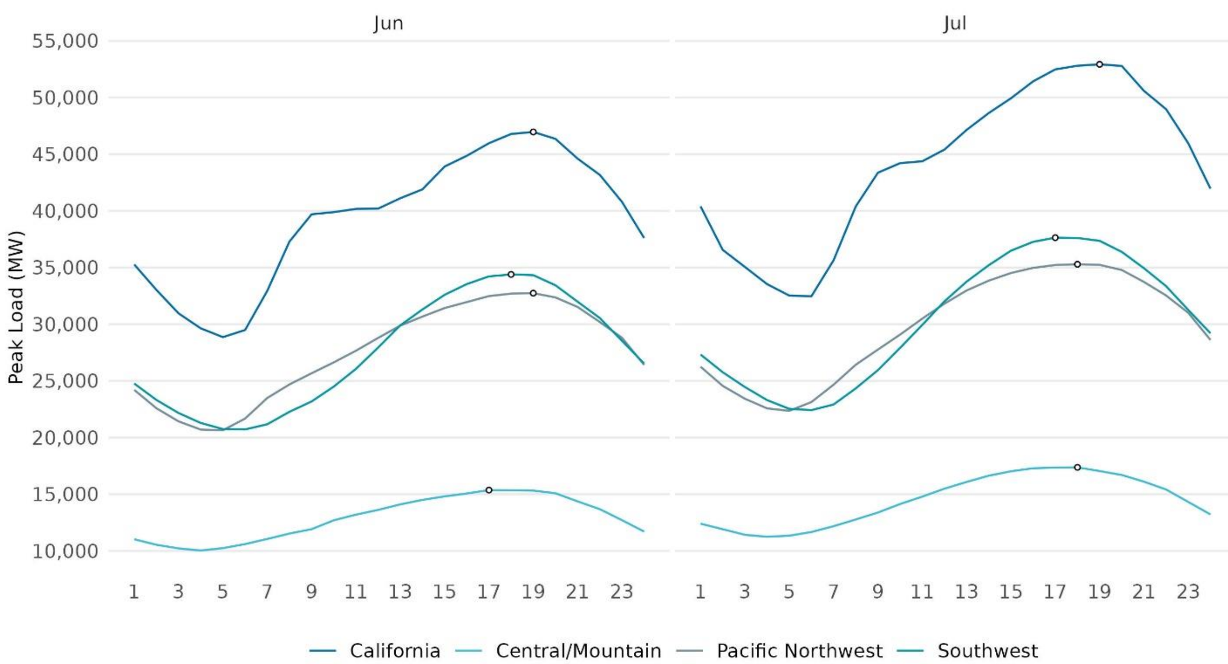
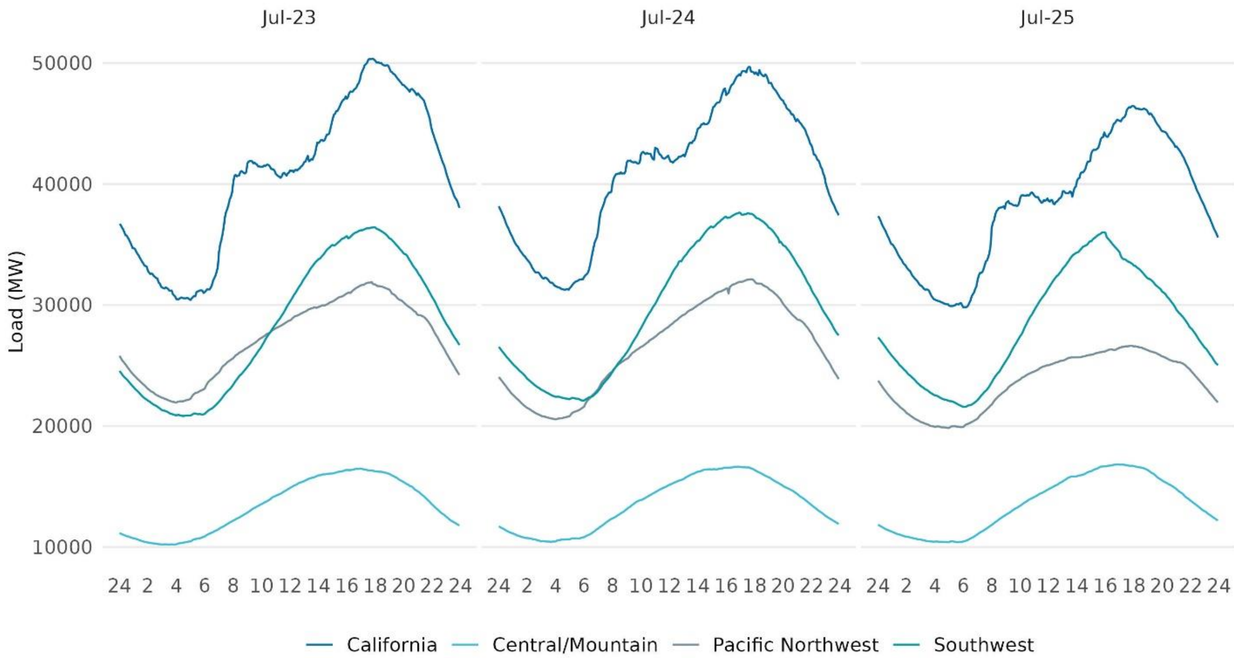


Figure 206 shows the hourly profile of actual load for the WEIM regions for July 23 – 25, 2026. Loads for California, Central/Mountain and Pacific Northwest regions were higher on July 23 and 24 before falling on July 25. Southwest region loads remained unchanged during the three days.

Figure 206: Hourly load profile for July 23 - 25, 2026, by WEIM region



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.[12] 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 areas. In a given interval, import and export transfers can concurrently happen for one area.

Figure 207 shows the distribution of five-minute WEIM transfers for the CAISO area. A negative value represents an import into the CAISO from other WEIM entities. On average in July, CAISO transfers were exports to other areas in the WEIM but less than it was in June. On July 12 and 13, CAISO net transfers were imports from other WEIM areas. This corresponds with CAISO LMPs being higher than WEIM areas in RTD on those days when CAISO area peaked. On July 24, CAISO net transfers peaked in the export direction supporting other areas in the west.

Figure 208 shows the CAISO's WEIM 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

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

become a net import to the CAISO area. This trend is typical across summer months.

Exports during the midday hours were lower in July than in June, while imports in remaining hours, particularly the morning and evening ramps, increased in July, reflecting higher demand in CAISO. Figure 209 shows WEIM transfers for CAISO surrounding the WECC peak load day of July 24. From July 23-25, CAISO export transfers hit a high of 3,569.4 MW on July 24 in hour ending 17 while CAISO import transfers were also highest (2,337.2 MW) on July 24 hour ending 7.

Figure 207: Daily distribution of 5-minute RTD WEIM transfers for CAISO area

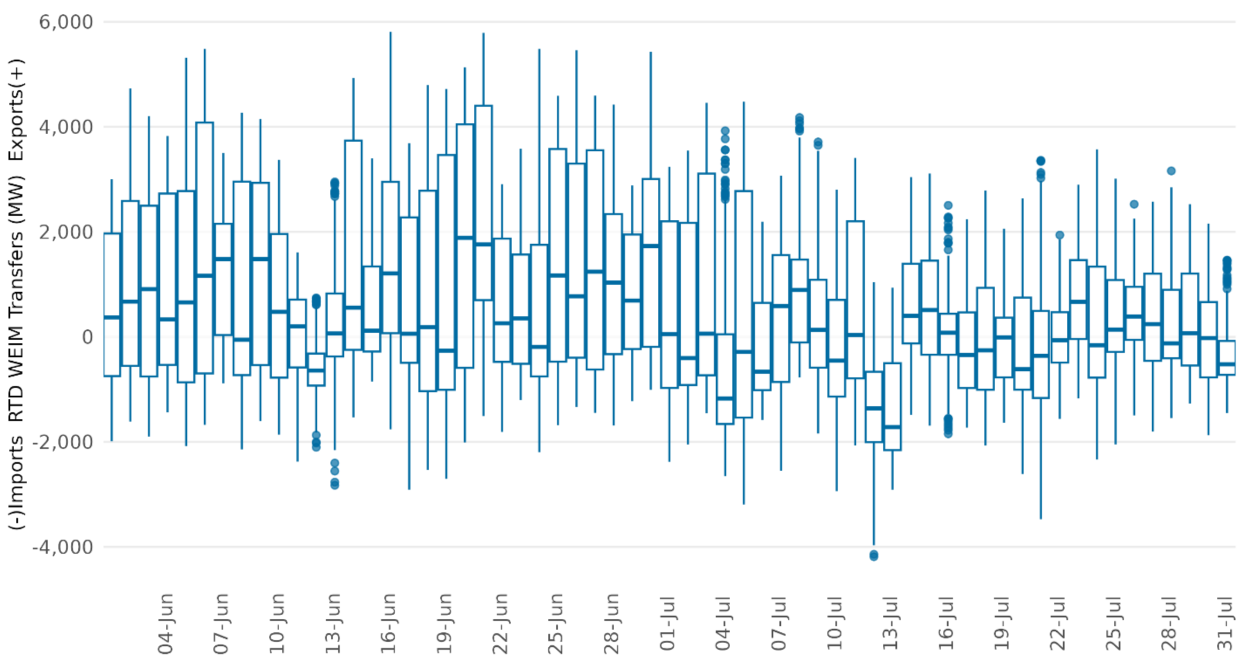


Figure 208: Hourly distribution of 5-minute RTD WEIM transfers for CAISO area

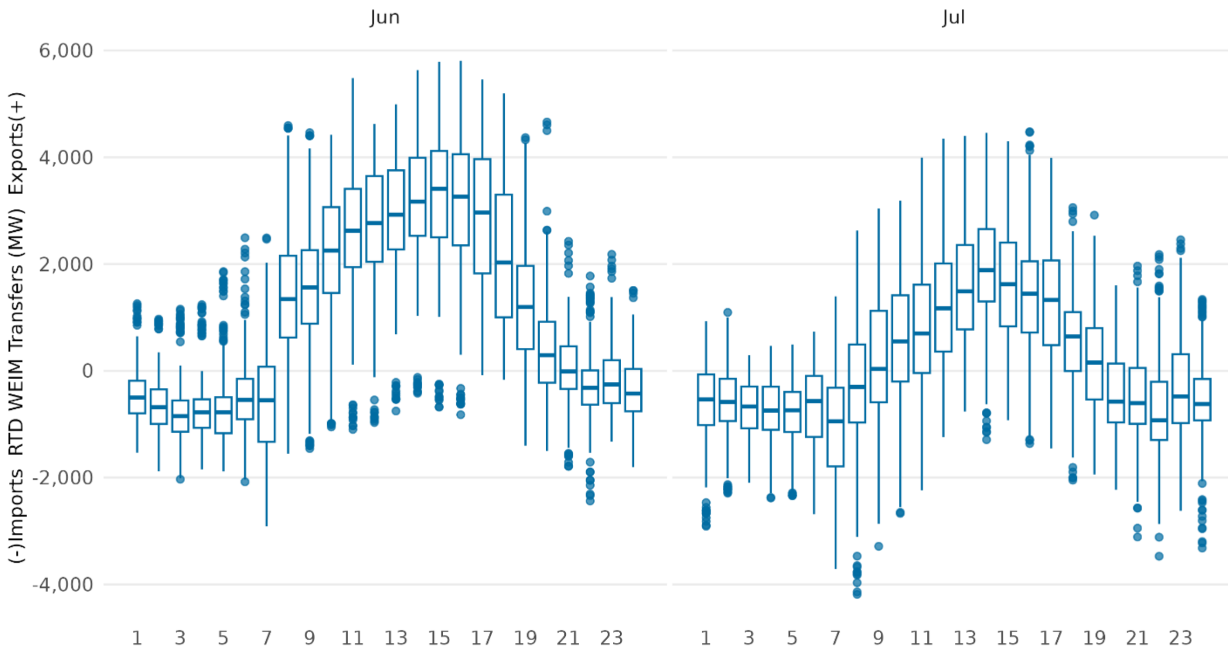


Figure 209: Hourly distribution of 5-minute RTD WEIM transfers for CAISO area, July 23 - 25, 2026

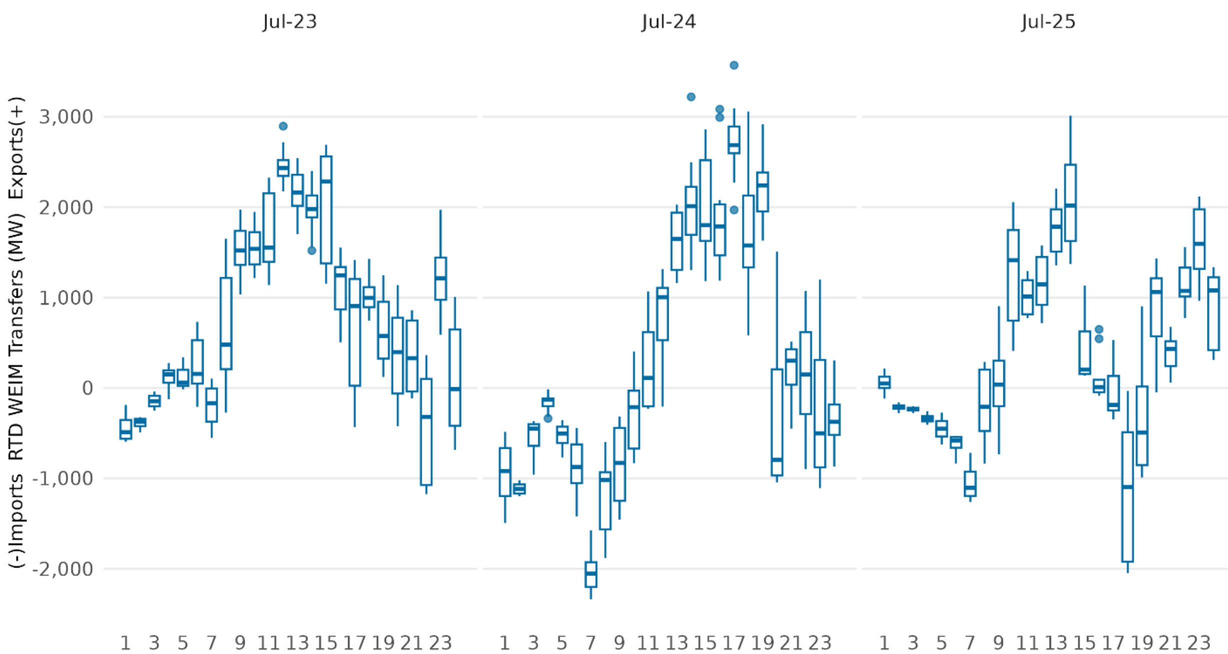


Figure 210 shows the distribution of WEIM transfers by region. The California region transfers were on average net exports in July, but lower than in June. For Central/Mountain region, transfers on average in July were net exports while in June were net imports. For Pacific Northwest region, transfers in July on average were imports while in June were net exports.

For the Southwest region, transfers in July on average were net exports while in June were net imports. On average, California and Southwest regions saw the biggest shift in WEIM transfers from June to July.

Figure 211 and Figure 212 show the hourly distribution of WEIM transfers by region in June and July. For Central/Mountain and Pacific Northwest regions, the volume of WEIM transfers increased on average from June to July but followed a similar hourly profile – the regions were importing during the midday hours and exporting in the remaining hours. For the Southwest region, midday imports reduced on average in July compared to June.

Figure 213 shows the hourly distribution of WEIM transfers by region for July 23-25. Compared to the average for July, Central/Mountain and Pacific Northwest region transfers showed higher imports in the evening hours while California and Southwest region transfers showed higher exports in the same hours. In the hours leading up to the morning ramp, California region transfers showed less imports from July 23-25 than the monthly average while Southwest region showed less exports than the monthly average.

Figure 210: Daily distribution of 5-minute RTD WEIM transfers by region

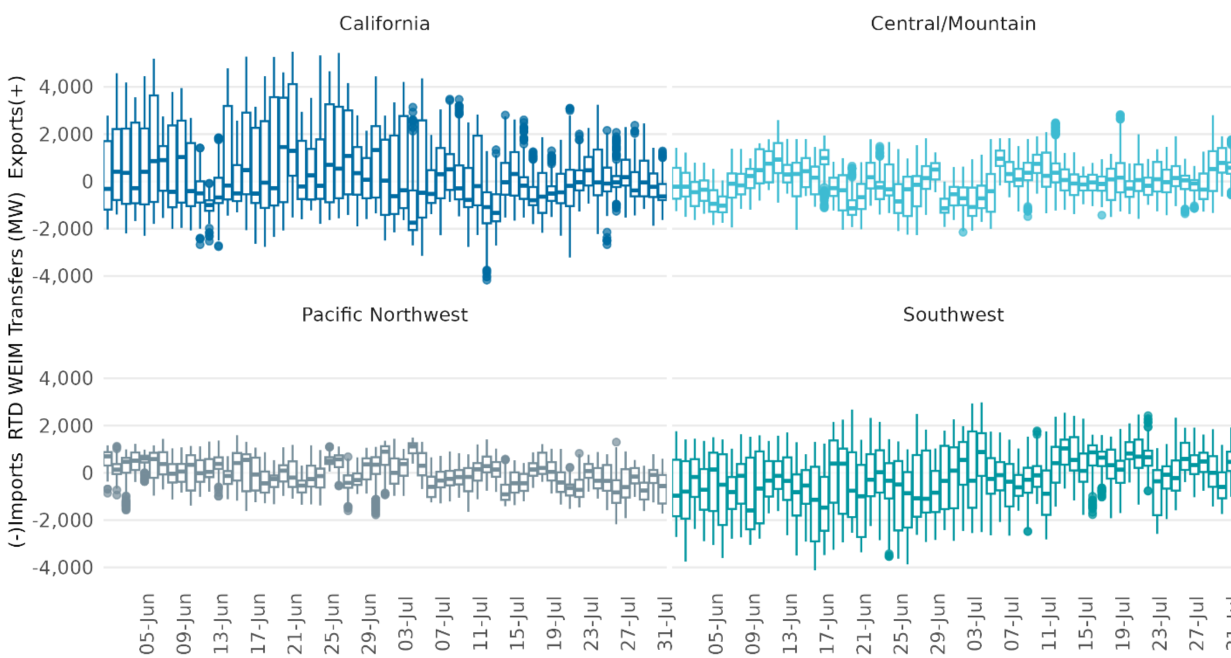


Figure 211: Hourly distribution of 5-minute RTD WEIM transfers by region, June 2026

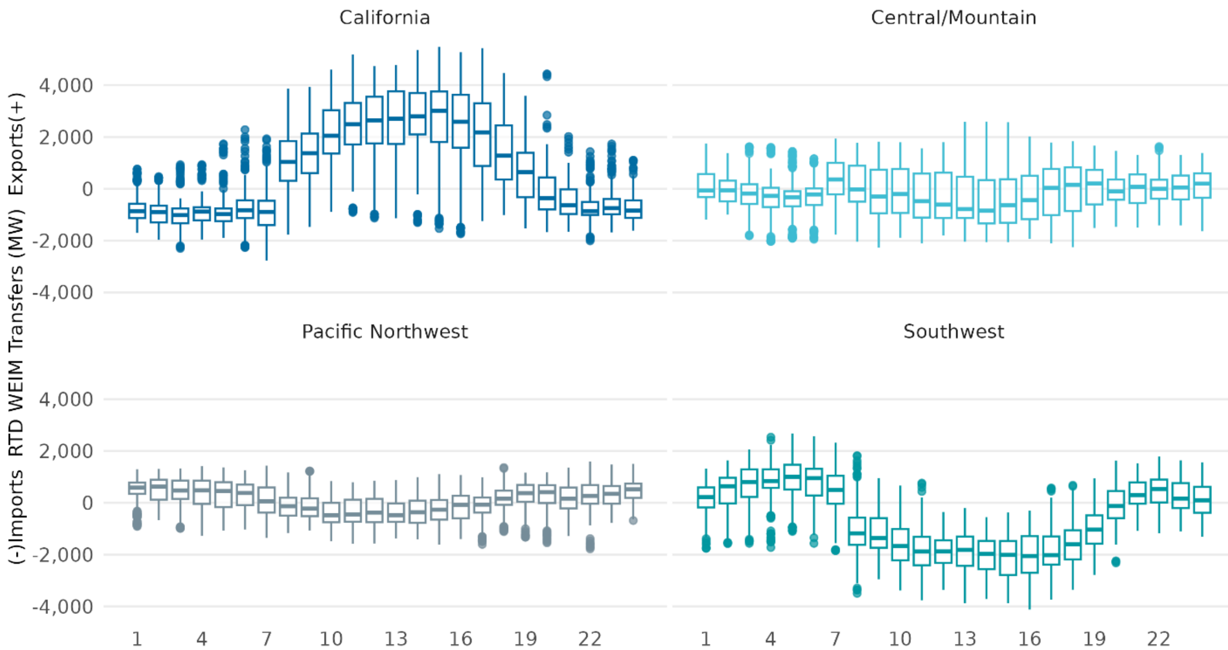


Figure 212: Hourly distribution of 5-minute RTD WEIM transfers by region, July 2026

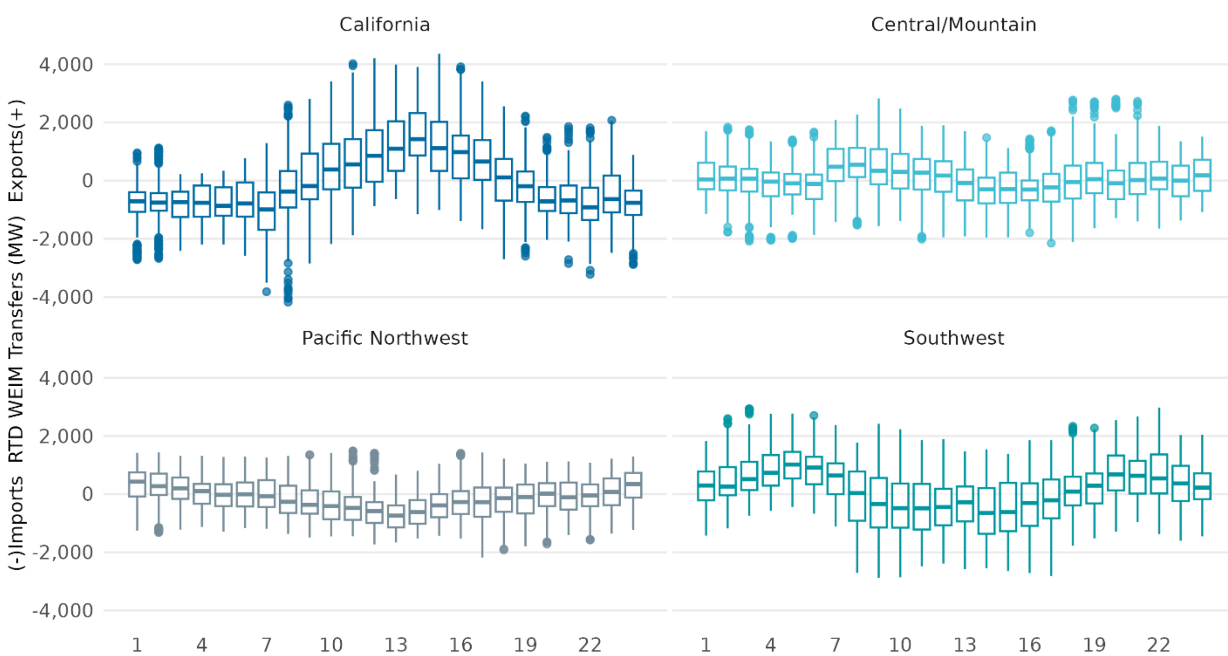
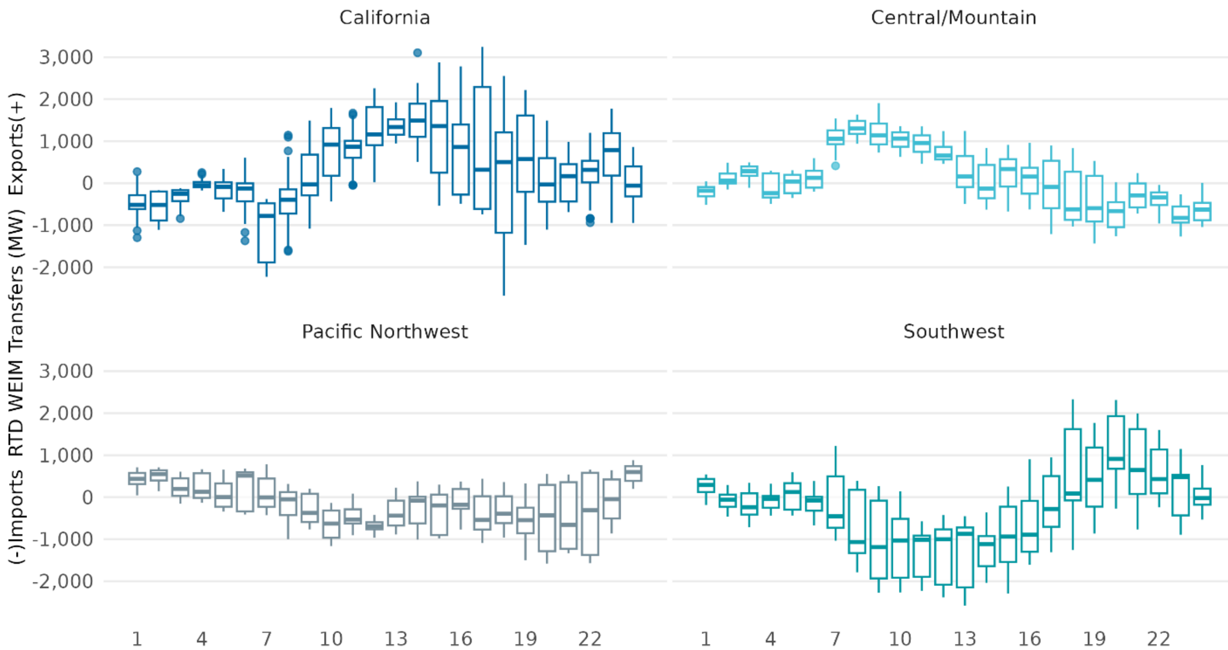


Figure 213: Hourly distribution of 5-minute RTD WEIM transfers by region, July 23 – 25, 2026



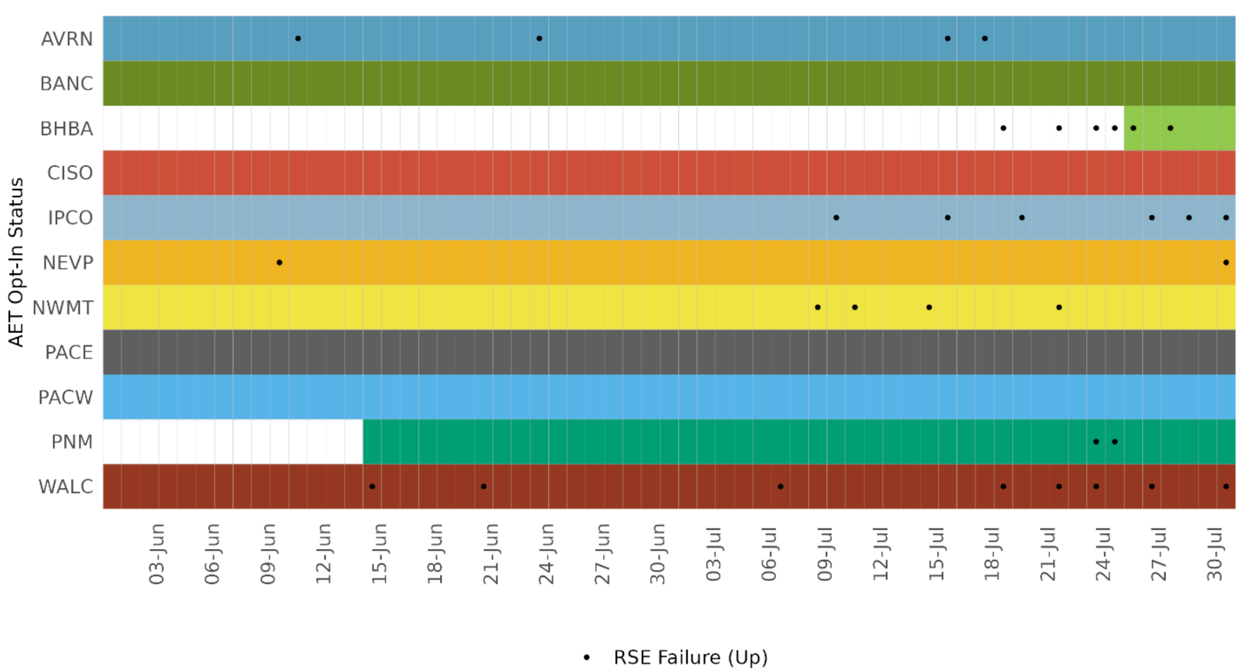
Assistance energy transfer

The Assistance Energy Transfer (AET) program 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.

Figure 214 shows days when WEIM BAAs opted-in to AET and when they failed either the upward capacity test and/or the upward flexible ramping test. In July 2026, eleven WEIM BAAs opted into AET for some duration of the month. The ISO BAA did opt-in to AET in July and did not fail the upwards RSE tests. WEIM BAAs experienced upwards RSE failures more frequently in July than in June.

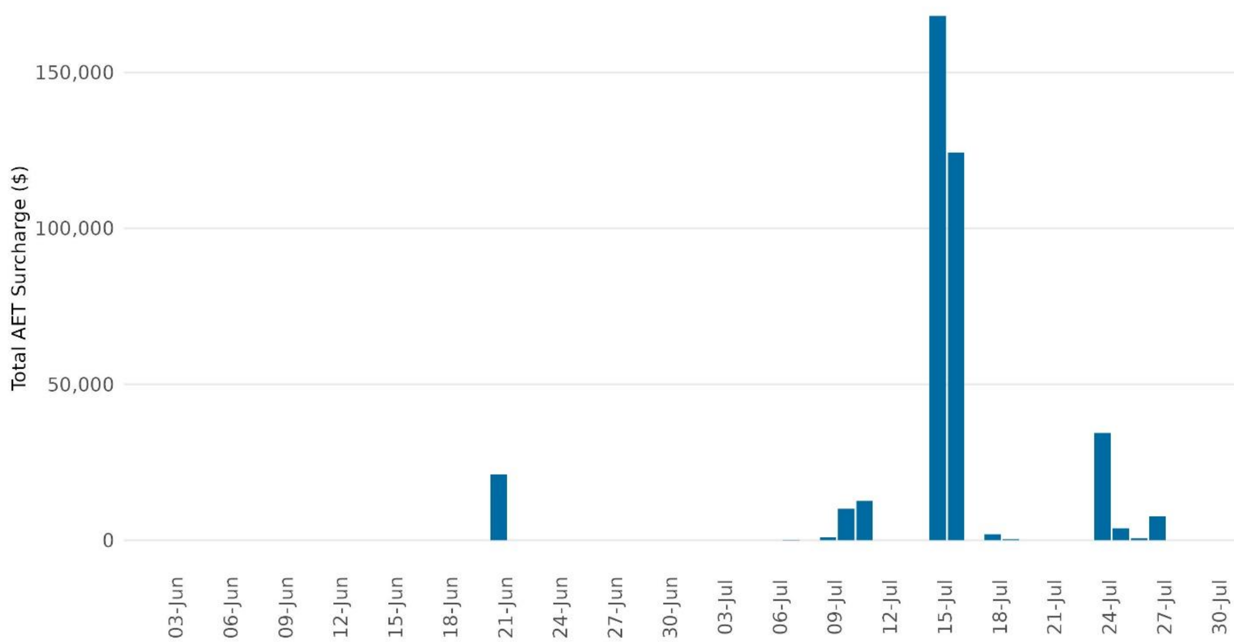
Figure 214: BAAs opted into Assistance Energy Transfers, June and July 2026



The total AET surcharges assessed in July were approximately $364,946 for all the BAAs that opted in.

Figure 215 shows the breakdown of total AET surcharges assessed per day for July 2026. By 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 thirteen trading days in July.

Figure 215: Total daily AET surcharge assessed, June and July 2026



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. Most of the overall costs accrue on the day-ahead settlements.

The estimates presented in this section are from the first cycle (T-9 business days) of CAISO's market settlements. These numbers are subject to change in subsequent cycles given standard data updates, inclusion of price corrections within the extended price correction window, and the ongoing resolution of a series of issues impacting the inputs and calculations of settlements. Some of these issues are described in this report in the section for market issues.

Wholesale costs

Figure 216 to Figure 218 show the total wholesale costs for CAISO at a daily and monthly level. The average total cost per MWh is also shown in Figure 216 and Figure 217[13]. There is no notable change in total or average costs for CAISO after EDAM. Looking at the monthly

[13] Total costs include market costs for energy, ancillary services, for both day-ahead and real-time markets, real-time offsets, bid cost recovery. For May 2026 and onwards they now include IR and RC costs.

level, the total costs for June continue the trend of lower total costs in 2026 relative to 2025, but total costs in July 2026 increased obviously compared with May and June, which is typical for this time of the year when demand increases as the weather gets hotter.
The total costs in May, June this year were lower than those of 2025, while July 2026 were higher by 18 percent as shown in Table 11.

Figure 216: Total daily costs CAISO

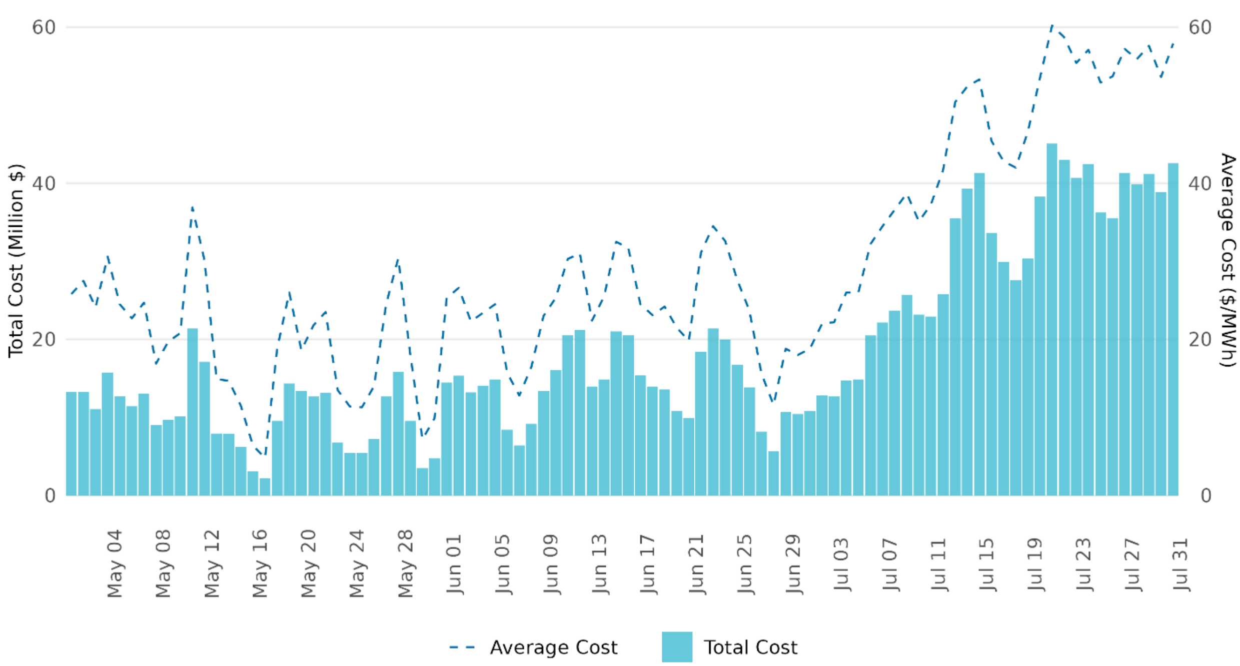


Table 11: Monthly Total Costs for CAISO

Month	Year 2025		Year 2026	
	Cost ($ Million)	Avg cost ($/MW)	Cost ($ Million)	Avg cost ($/MW)
May	518.65	31.4	319.64	19.8
Jun	622.08	35	426.48	24.25
Jul	803.08	41.1	952.82	45.4

Figure 217: Monthly total costs CAISO

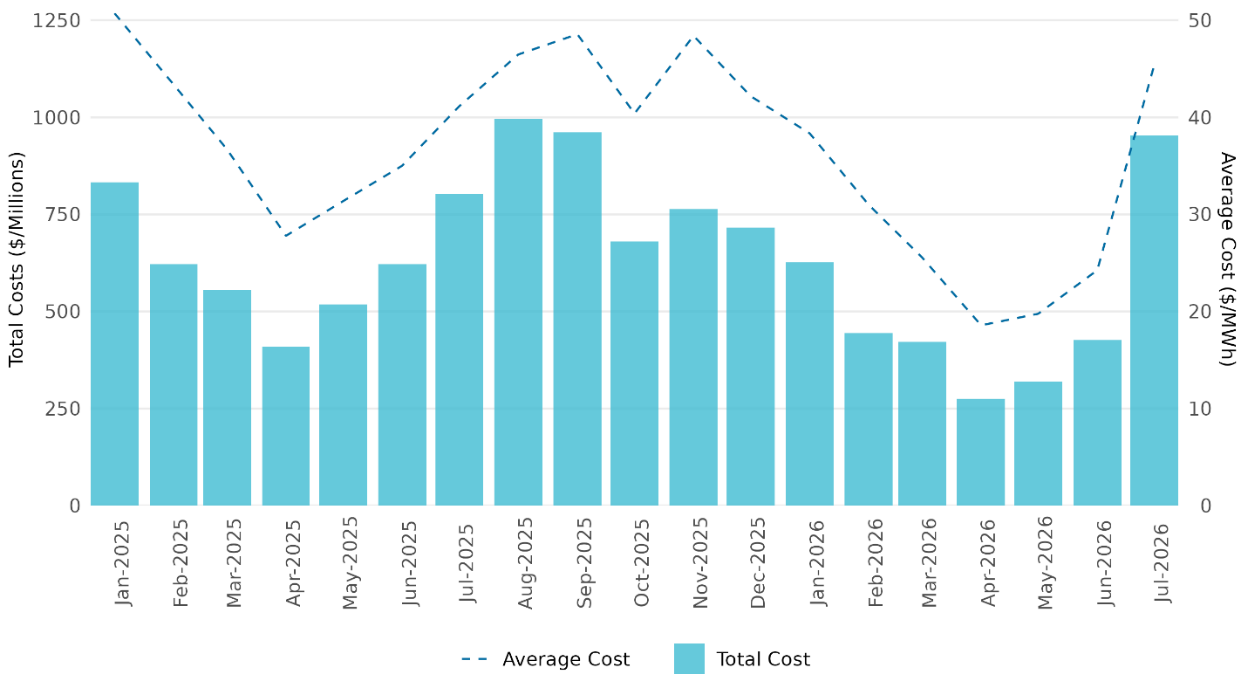
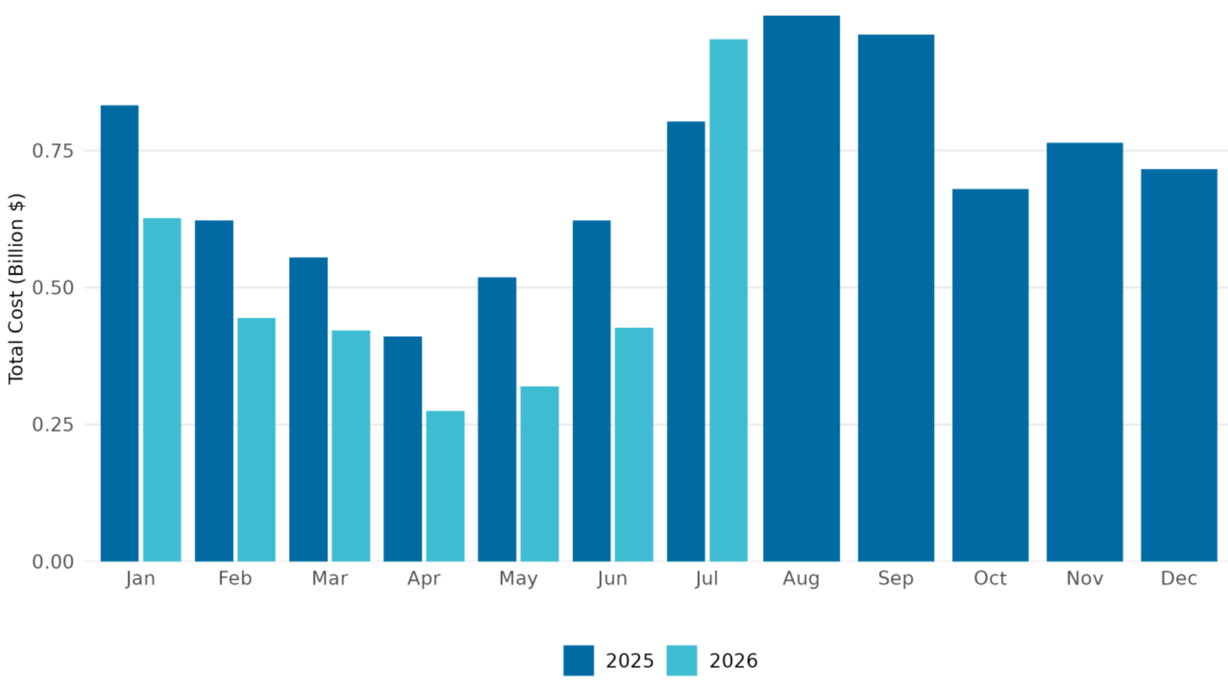


Figure 218: Monthly Total Costs CAISO, comparing 2025 to 2026



Bid cost recovery

Bid cost recovery (BCR) is a settlements mechanism in CAISO's markets to ensure participating resources are made-whole when the revenues collected on participating in the market are not enough to cover their total costs. It is defined as the difference between total costs and market revenue when the revenue is less than the cost.

At this time, we are aware of data issues that are impacting the settlement statements, which in turn may be reflected in the BCR estimates. Therefore, the estimates provided here should be considered as preliminary and subject to change once the revised settlement statements are run. For example, IFM BCR for May 19 and 31, was high at approximately $500k and $1.2 million, respectively. Internal monitoring identified one bid cost calculation issue for each trade date that will be corrected and reflected in the T+72 settlement statement[14]. There were other issues identified for RTM BCR for May 1 and May 29 trade dates, which are expected to be corrected in T+70 settlement cycle. These corrections will impact the numbers reported below and we will update these in the next monthly report.

From Figure 219 to Figure 223 illustrate the Bid Cost Recovery (BCR) trends for CAISO, PACW, and PACE across May, June and July. Figure 222 to Figure 223 compare BCR of three different BAAs in IFM and RTM. Note that PACE's IFM BCR for the last three days of July are inaccurate and will be corrected in the T+70 settlement statement. Table 12 shows the BCR comparison between IFM and RTM for all EDAM BAAs from May to July. Overall, BCR has been higher in real-time than in day-ahead across all areas.

Table 12: BCR comparison between IFM and RTM for EDAM BAAs in $ millions

Area	IFM			RTM		
	May	June	July	May	June	July
CISO	3.17	2.22	1.23	8.06	3.57	7.03
PACE	0.36	0.08	0.545	1.41	0.115	0.99
PACW	0.097	0.005	0	0.26	0.0265	0.06

[14] Refer to the section of Market Issues for more details.

Figure 219: BCR of CAISO by market

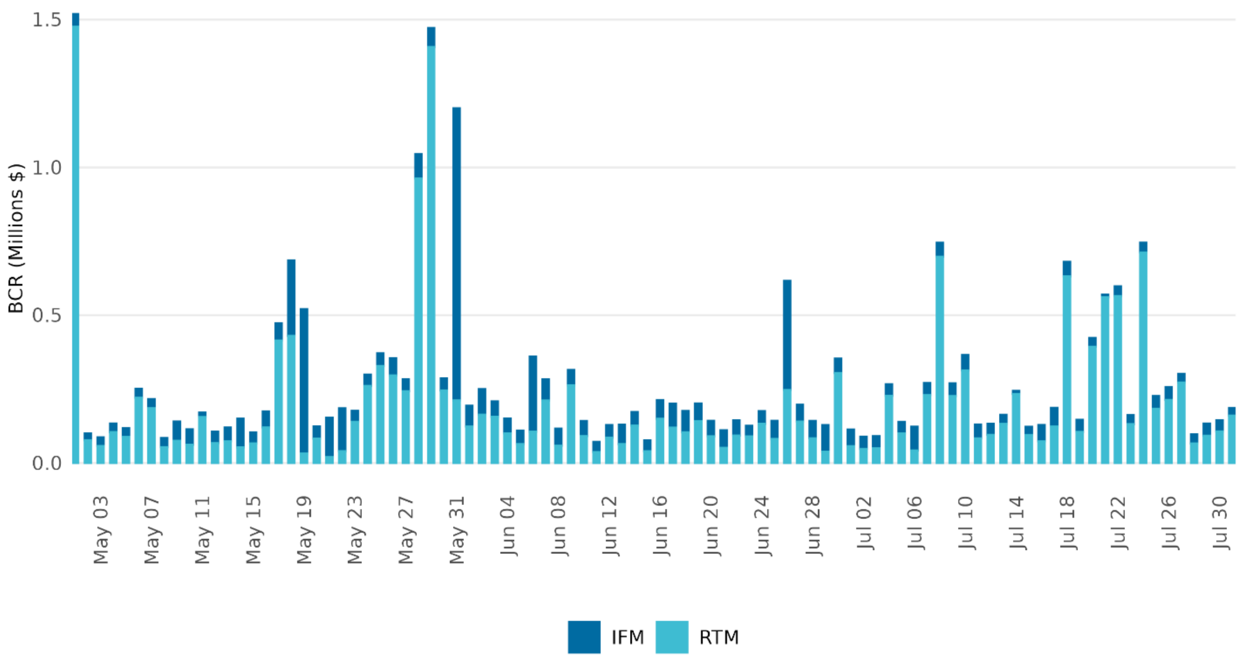


Figure 220: BCR of PACE by market

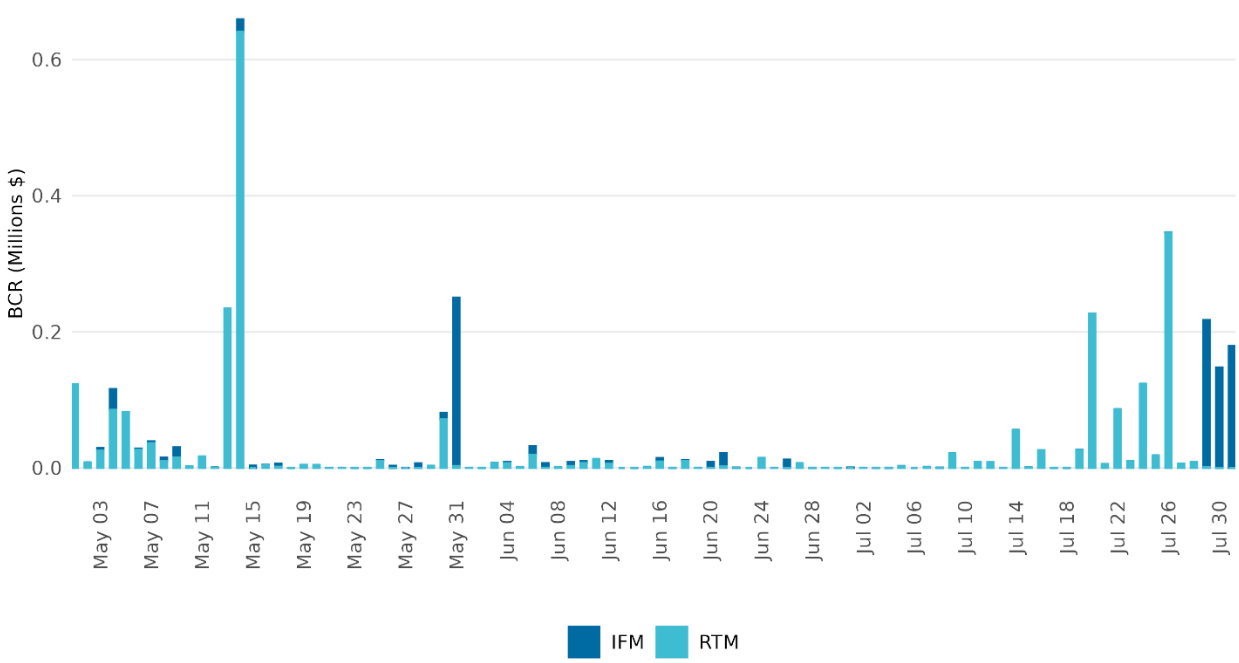


Figure 221: BCR of PACW by market

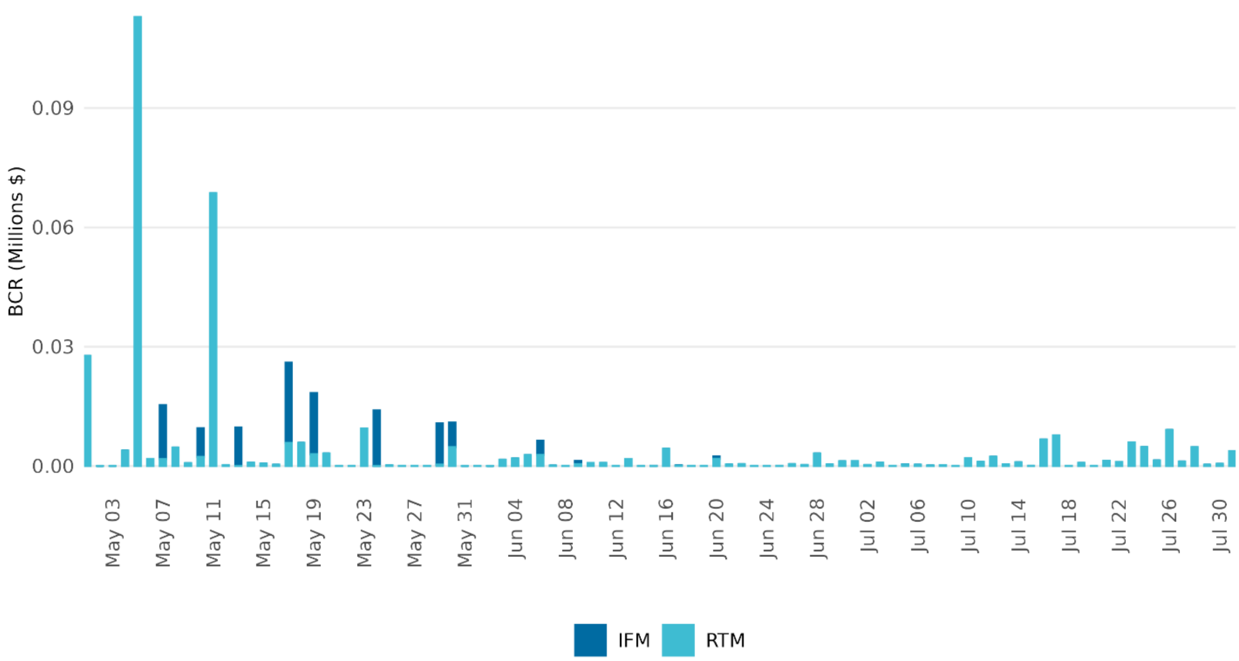


Figure 222: IFM BCR by BAA

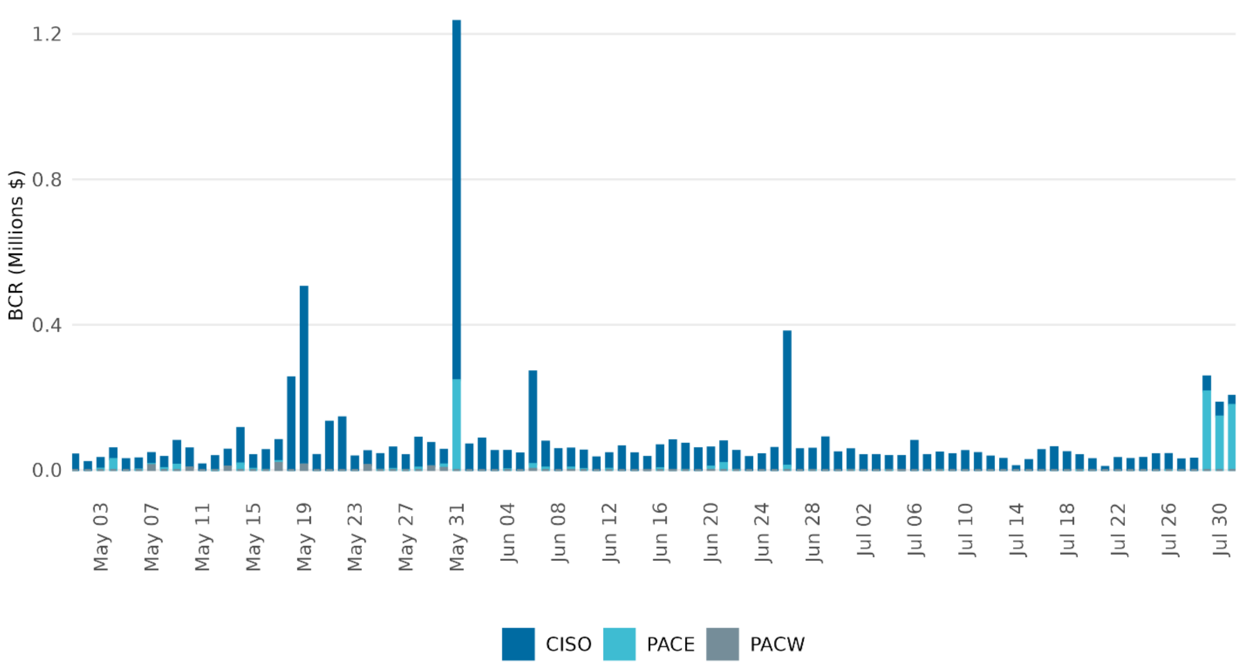
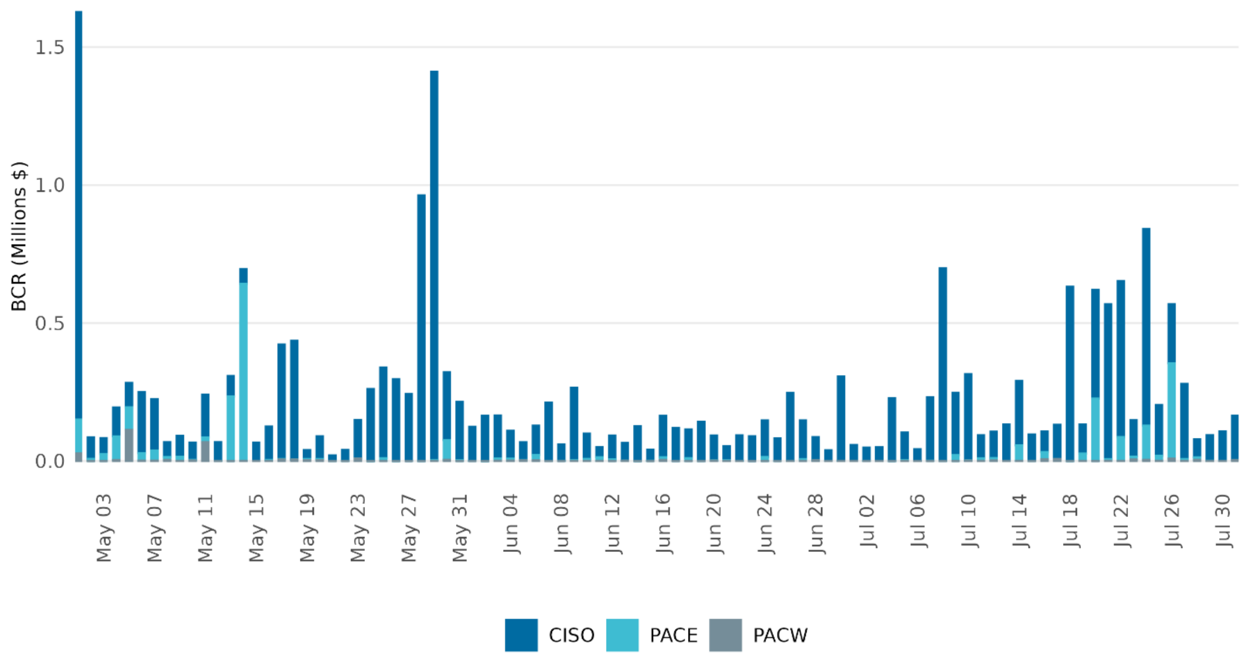


Figure 223: RTM BCR by BAA



Market offsets

In CAISO's market settlements, participants are paid or charged. The money collected from some transactions is used to pay others. However, due to the multiple configurations of the various components of settlements such as different prices used to settle different components of energy, the total money collected may not perfectly match the money paid out. The differences are balanced through settlements offsets. These offsets are the funds that CAISO needs to collect or redistribute to maintain revenue neutrality.

Day-Ahead congestion offset

This is a new settlements component introduced with the EDAM. Day ahead congestion offset (DACO) is a settlement charge code 8704. For more information on the calculation of DA congestion offset charge code, please refer to the BPM. CAISO does not have DACO because it has a specific CRR-based balancing mechanism, while PACW and PACE use DACO to handle the congestion refunds.

In Figure 224 shows the daily DA congestion offset for PAC areas. A negative amount reflects payment to the entity. A spike in DACO indicated that congestion has a significant impact on the market dispatch during corresponding intervals. For example, the large DACO on May 10 was caused by congestion on the binding flowgate *CLOVER_SIGURD_345_2*. Table 13 shows the DA congestion offset comparison for PACE and PACW for the months of May to July.

Figure 224: DA Congestion Offset for PAC areas

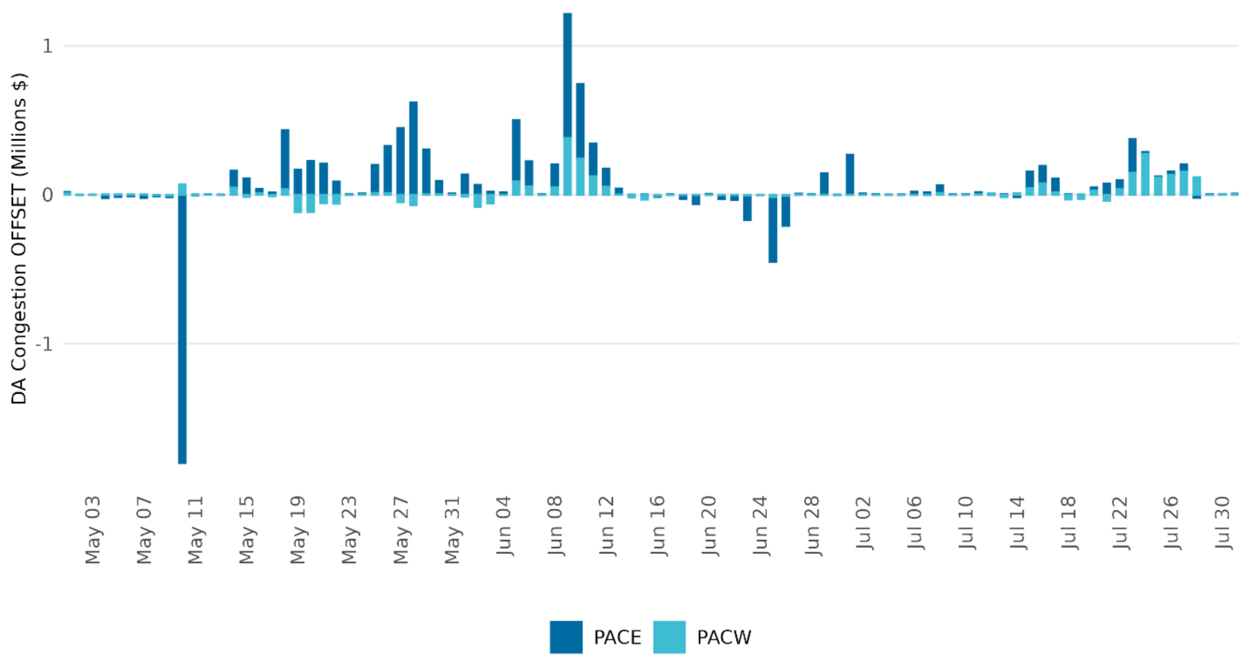


Table 13: DA Congestion Offset comparison in $ millions

Area	May	Jun	Jul	Total
PACE	0.39	1.90	1.17	3.47
PACW	(0.22)	0.75	1.06	1.59
Total	0.17	2.65	2.23	5.05

Day-Ahead energy offset

It captures the net financial difference between the total payments owed to supply-side resources (generation and imports) and the total revenues collected from demand-side participants (load and exports) for energy. It is an hourly accounting tool to make sure the day ahead energy market balances to zero. It adds up all the money collected from day energy schedules and convergence bidding at the marginal energy cost minus the congestion and GHG components. Any resulting imbalance within an external EDAM region is allocated directly to that specific EDAM entity's scheduling coordinator, whereas the imbalance within the CAISO region is allocated broadly to CAISO measured demand.

CAISO continues to investigate these instances on an ongoing basis, review the underlying components and will implement corrections in the T+70 cycle if any discrepancies are identified. Any corrections will impact the numbers reported below and we will update these in the next monthly report.

Positive DA energy offset means charge to the entity, while negative means additional payments needed to be sent out. The spike of May 19 for CAISO was related to slightly higher loads at higher marginal energy cost. It was accrued in the morning and evening hours. Table 14 shows the DA energy offset comparison between EDAM BAAs from May to July.

Figure 225: DA Energy Offset

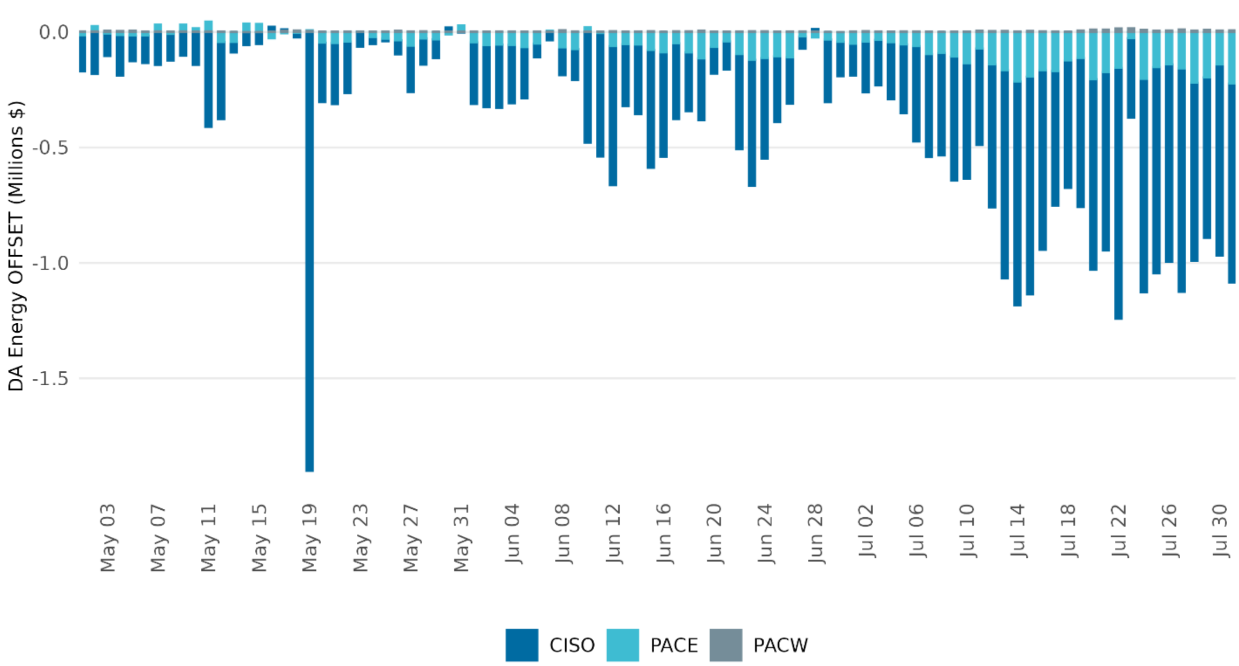


Table 14: DA Energy Offset for EDAM BAAs –in $ millions

Area	May	Jun	Jul	Total
CISO	(6.39)	(8.21)	(19.67)	(34.26)
PACE	(0.23)	(1.81)	(4.07)	(6.12)
PACW	0.08	0.07	0.17	0.33
Total	(6.53)	(9.95)	(23.56)	(40.05)

Real-Time congestion offset

Real time congestion offset (RTCO) is very similar to DACO of external BAAs in IFM market. It is used to achieve revenue neutrality for congestion. An increase means the congestion in the corresponding intervals has large impact onto market dispatch. Figure 226 displays the Real-Time Congestion Offset (RTCO) for the three balancing areas, where a negative value denotes a payment to the BAA and a positive value denotes a charge.

Figure 226: Real-Time Congestion Offset

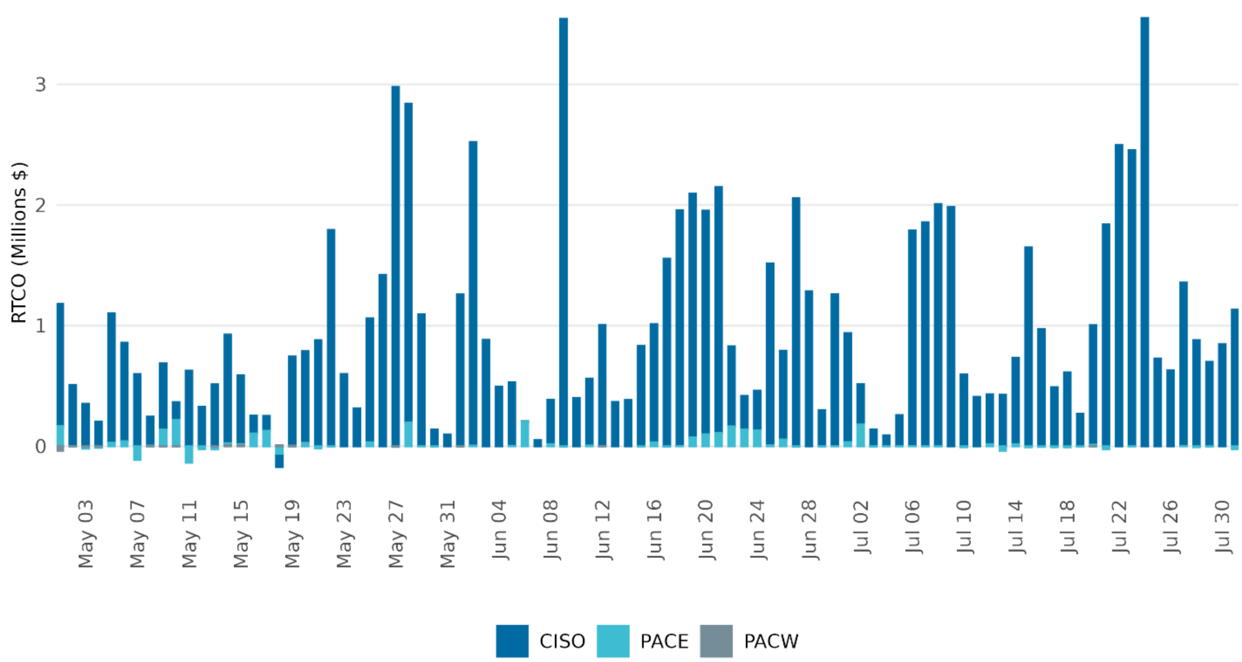


Table 15: Real-tTime congestion offset for EDAM BAAs in $ millions

Area	May	Jun	Jul	Total
CISO	21.92	32.01	33.52	87.44
PACE	0.68	1.05	0.14	1.87
PACW	(0.04)	(0.00)	(0.00)	(0.04)
Total	22.56	33.06	33.66	89.28

Real-Time imbalance energy offset

Real time imbalance energy offset (RTIEO) is very similar to DAEO. In settlements, RTIEO is a market neutrality charge code that ensures CAISO remains revenue neutral in the real time market. RTIEO is a residual amount due to an imbalance between real time energy payments and charges. RTIEO allocates this residual amount back to measured demand. Figure 227 illustrates a notable shift in RTIEO following the implementation of EDAM. While external

BAAs, such as PACW and PACE, experienced an increase in RTIEO, there was a simultaneous reduction in CAISO's own offset.

CAISO is actively investigating several issues and disputes that may impact the T+9 settlement results. As these reviews are completed, CAISO will make appropriate corrections and adjustments as needed. These will be reflected in subsequent settlement recalculations, including at the T+70 settlement true-up. Any corrections will impact the numbers reported below and we will update these in the next monthly report.

Figure 227 illustrates the Real-Time Imbalance Energy Offset (RTIEO) for the three balancing areas, where a positive value indicates an additional charge collected from the BAA and a negative value indicates an additional payment sent out to them.

The real-time imbalance energy offset results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily due to fundamental design changes in the settlement calculations, including the transition from a single system marginal energy cost (SMEC) to individual area marginal energy cost references, as well as the incorporation of the GHG component within the GHG area framework. These structural differences inherently change how RTIEO values are calculated. Table 16 shows the real time energy offset comparison for EDAM BAAs.

Table 16: Real time energy offset for EDAM BAAs in $ millions

Area	May	Jun	Jul	Total
CISO	0.43	(23.47)	(4.20)	(27.24)
PACE	0.27	3.42	1.35	5.03
PACW	0.80	2.17	(0.18)	2.79
Total	**1.50**	**(17.89)**	**(3.03)**	**(19.42)**

Figure 227: Real-Time Imbalance Energy Offset

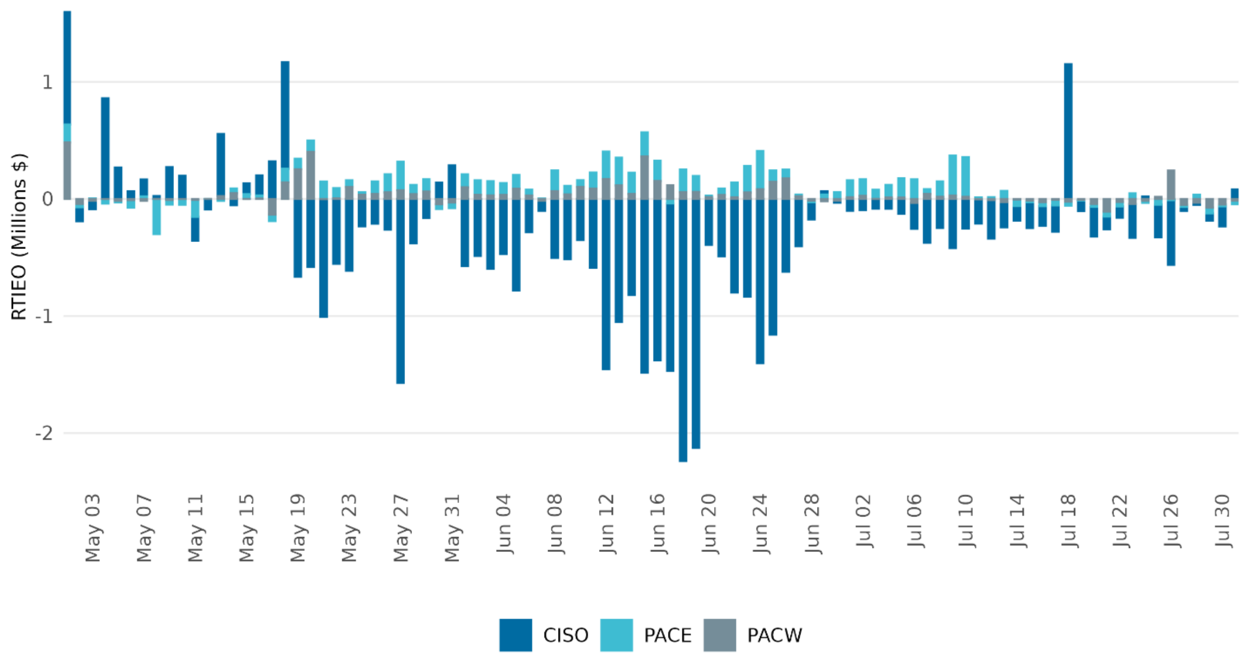
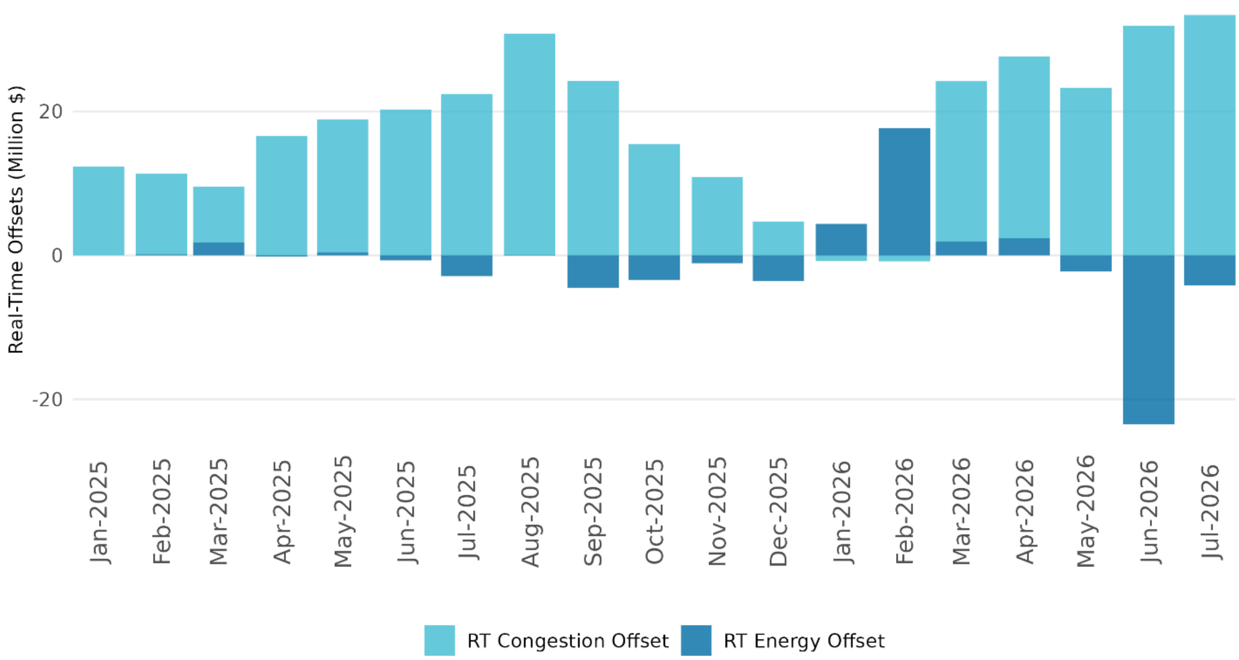


Figure 228 and Figure 229 show the monthly real-time congestion and energy offsets for CAISO area and the WEIM excluding CAISO area, respectively. CAISO offsets remained within normal ranges, with an energy offset slightly more negative than seen in other months since the start of 2025. In June, the energy offset remained negative but got significantly larger. Figure 229 shows that in May and June, the WEIM not including CAISO saw a positive congestion offset and a large, positive energy offset. The positive congestion offset is uncommon but not unheard of.

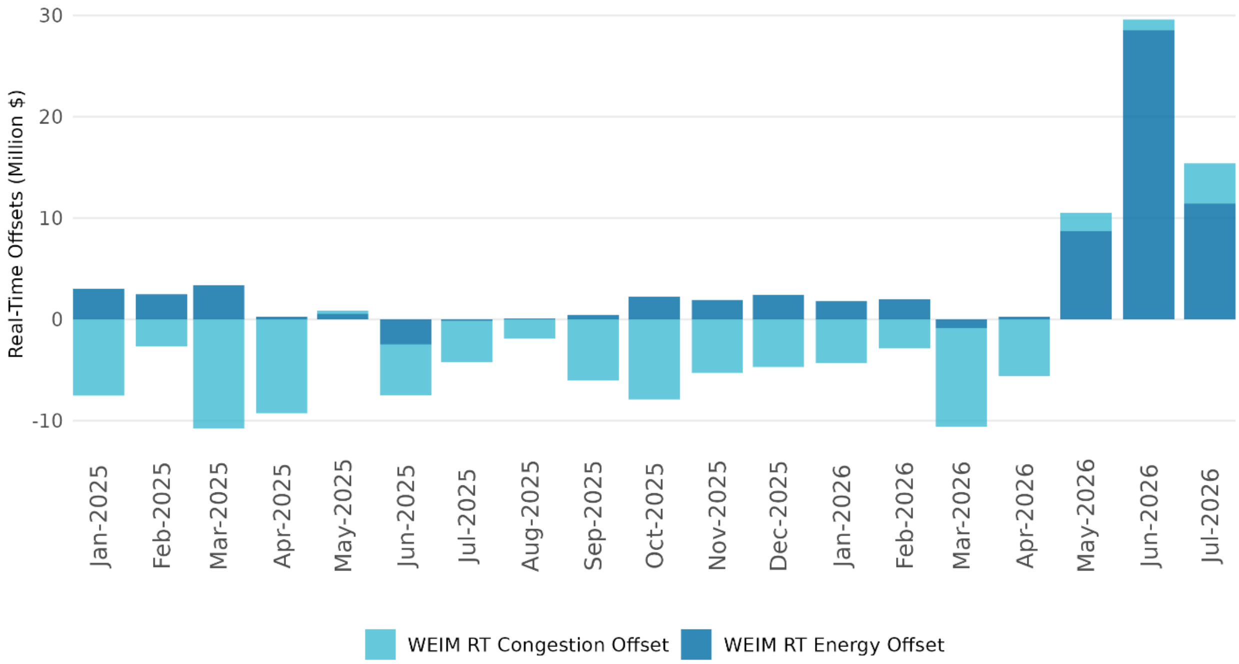
The magnitude of the real-time energy offsets for May and June are very high compared to historical offsets. First, it is important to note that the real-time imbalance energy offset (RTIEO) results observed after the May 1 EDAM go-live are not directly comparable to pre-EDAM outcomes. This is primarily due to fundamental design changes, including the transition from a single system marginal energy cost (SMEC) to individual area marginal energy cost references, as well as the incorporation of the GHG component within the GHG area framework. These structural differences inherently change how RTIEO values are calculated

Figure 228: Monthly Total Real-Time Offsets for CAISO



While pre- and post-EDAM RTIEO results are not directly comparable, they should be explainable. The ISO has been focused on identifying the corresponding, counterbalancing sources associated with RTIEO charges. The ISO is actively investigating several issues and disputes that may affect and be reflected in the T+9 day real-time offsets settlement results. As these reviews are taking place, the ISO has and will continue to implement corrections and adjustments as needed. These will be reflected in subsequent settlement recalculations, including at the T+70 true-up and future T+9 calculations. Any corrections will impact the numbers reported here and we will update these in the next monthly report.

Figure 229: Monthly Total Real-Time Offsets for WEIM



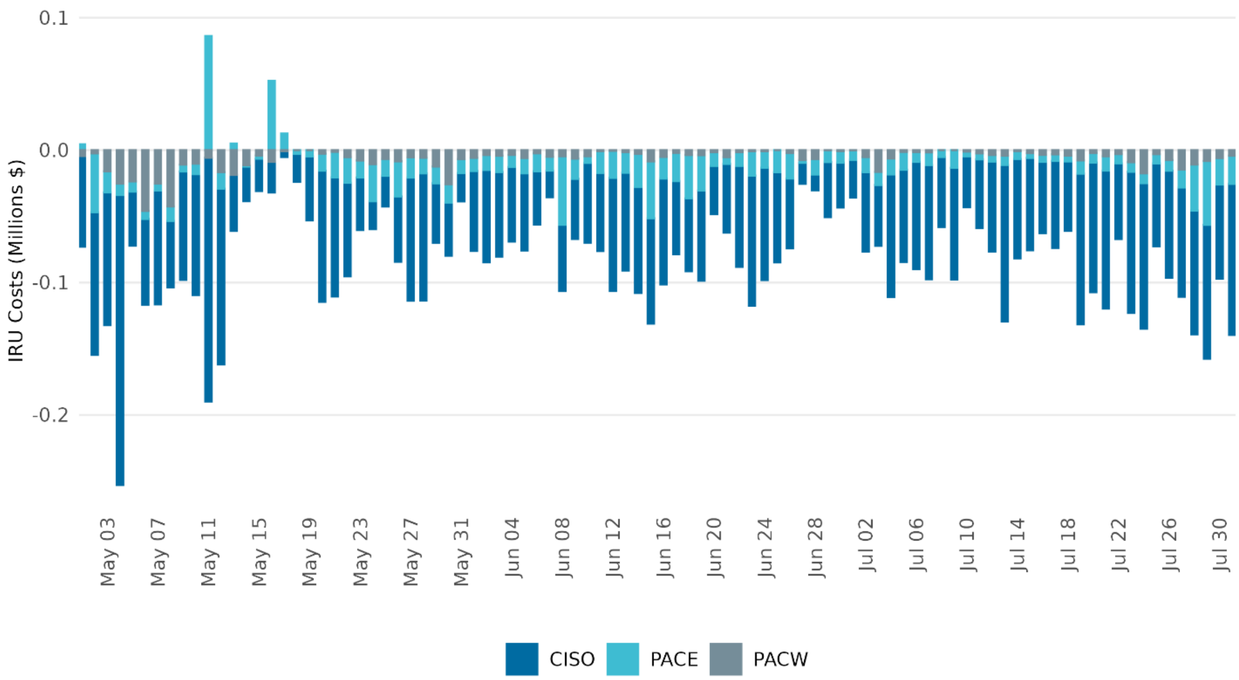
Imbalance reserves

Imbalance reserve up/down are two components of the imbalance reserve product designed to provide upward/downward dispatch capability. Procured within the IFM, Imbalance Reserves up/down (IRU and IRD) is used to ensure that sufficient dispatchable capacity is available to meet positive/negative net load imbalance that occur between the EDAM and Real-Time markets. Only resources that can be dispatched in the 15-min market would be eligible to provide imbalance reserves and the maximum award capacity would be based on a resource's 30-min ramp capability.

An IRU payment is calculated by multiplying the resources awarded IRU quantity by the locational IRU price. A negative Imbalance Reserve (IR) settlement indicates net payment to the scheduling coordinators (SC) of resources located in Balancing Authority Area (BAA). To enforce compliance, CAISO applies a no pay unavailability non-compliance charge if a resource fails to maintain its day-ahead flexible capability relative to its upper economic limit and five-minute ramp capability. Undelivered quantities are penalized using a resource-specific price equal to the higher of the real-time flexible ramp up price or the locational IRU price. PACE has five days with positive settlement values for IRU over five different days. These are days impacted by some calculation issues currently being addressed.

Figure 230 shows the daily trend of IRU costs for May and June.

Figure 230: IRU settlement costs



Similarly, The IRD payment charge code settles day-ahead market awards for resources and transfer resources on an hourly basis. The IRD payment for each resource is calculated by multiplying its hourly awarded IRD quantity by the resource's IRD price. The system tracks the resource's 5-minute ramp capable capacity portion along with IRD allocated capacity range in FMM, and If a resource fails to maintain its downward capability, it faces unavailability non-compliance charges at FMM flexible ramp down price. Figure 231 shows the daily costs for procuring IRD in May and June.

Figure 231: IRD settlement costs

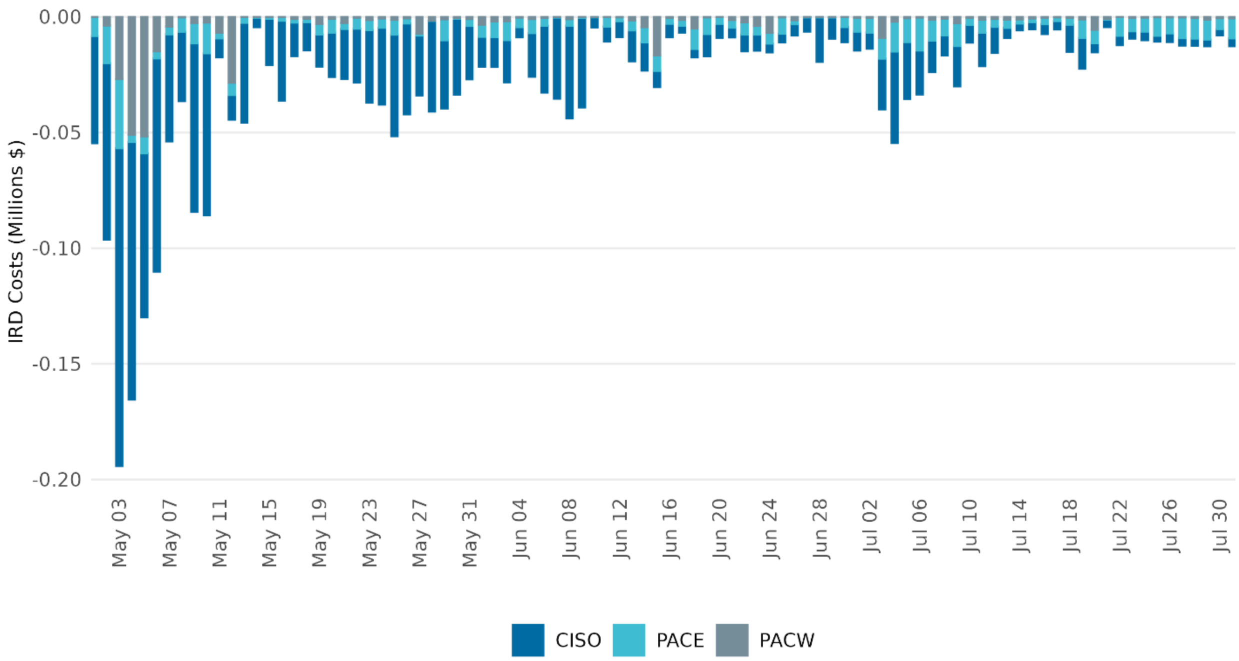


Table 17: Imbalance Reserves Total Monthly Settlement Costs

	IRU Total Costs ($million)			IRD Total Costs ($million)		
BAA	May	June	July	May	June	July
CAISO	-2.11	-1.73	-2.39	-1.28	-0.360	-0.276
PACW	-0.372	-0.102	-0.156	-0.215	-0.0550	-0.034
PACE	-0.171	-0.493	-0.337	-0.164	-0.12	-0.2

Reliability capacity

Reliability Capacity (RC), consisting of RCU and RCD, is procured in the Residual Unit Commitment (RUC) process. The RCU settlement costs is calculated on an hourly interval to manage day-ahead awards for resources. A negative value is indicated as a payment to the scheduling coordinator, while a charge is tracked as positive values. RC settlement is the hourly financial compensation provided to resources for awarded capacity, calculated as the product of the awarded quantity and the RUC Reliability capacity price. CAISO assesses a no-pay unavailability charge if a resource fails to keep its day-ahead reliability commitment available relative to its upper economic limit and real-time outages. This penalty is calculated as the product of the unavailable quantity and the resource's RCU price.

Figure 232 shows the daily RCU costs organized by BAA in May and June. Similarly for RCD settlements, it is calculated by multiplying its hourly RCD quantity by the locational RCD price. While RCU checks resource's availability to ensure it has enough upward capability relative to its upper economic limit, RCD checks resource's downward flexibility to verify that its lower economic limit (including real-time outages) does not exceed its day-ahead energy schedule minus any downward regulations.

Figure 233 provides the daily trend of RCD cost by BAA in May and June.

Figure 232: RCU settlement costs

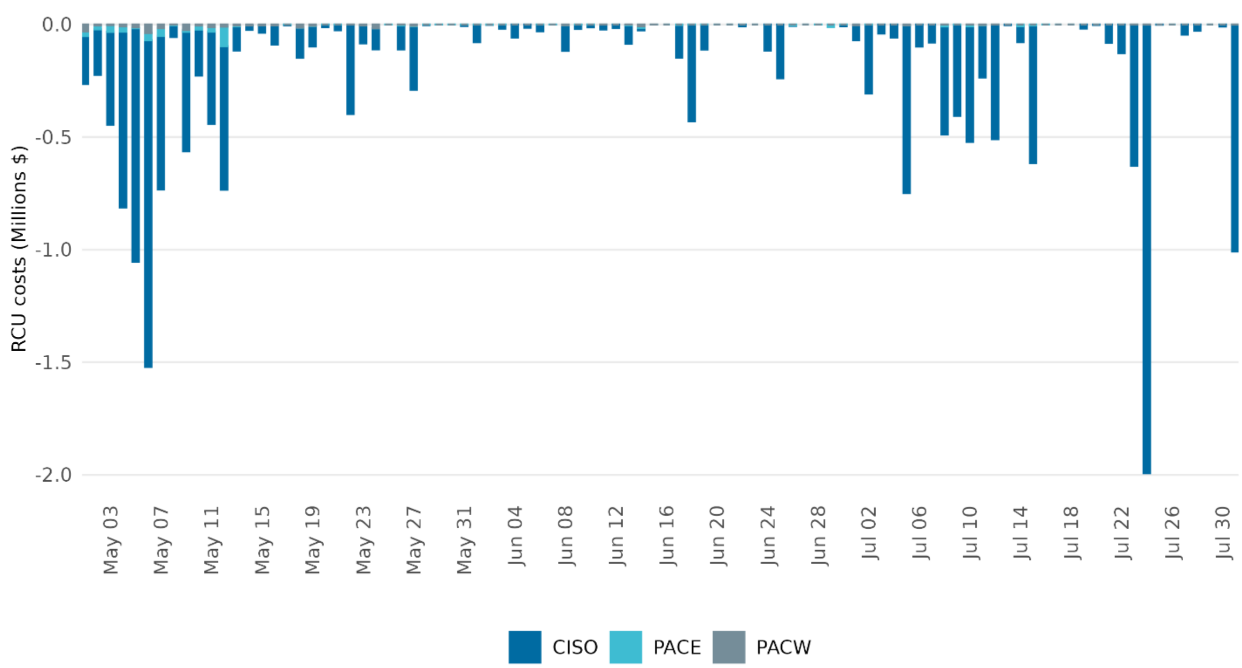
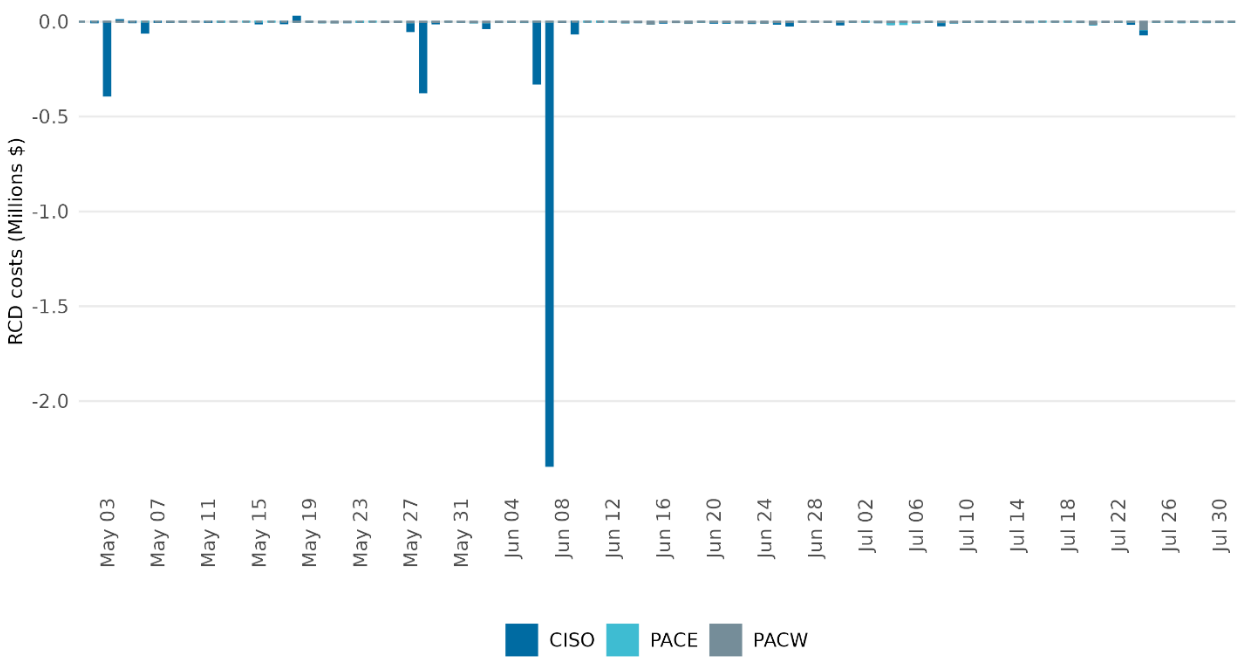


Figure 233: RCD settlement costs



Insert here a table that summarizes the cost for IRU/IRD/RCU/RCD all together showing totals of both months

Table 18: Reliability Capacity Total Monthly Settlement Costs

	RCU Total Costs ($million)			RCD Total Costs ($million)		
BAA	May	June	July	May	June	July
CAISO	-8.09	-1.53	-8.16	-0.865	-2.82	-0.059
PACW	-0.221	-0.011	-0.01	-0.018	-0.05	-0.066
PACE	-0.316	-0.0297	-0.031	-0.0025	-0.014	-0.052

GHG settlement

The California Cap and Trade regulation on greenhouse gas emissions requires market participants to surrender compliance instruments to the California Air Resources Board (CARB) for GHG emissions associated with energy generated from CO_2-emitting resources within California and energy imported into California. Energy generated outside California that is not imported into the state is not subject to this compliance obligation. To address these requirements, EDAM incorporates the cost of the GHG compliance obligation when dispatching generation within an EDAM entity area to serve load located in a GHG regulation area (in this case, California). This cost is not considered when the same generation is dispatched to serve load outside a GHG regulation area.

The GHG settlement mechanism is calculated on an hourly settlement interval basis. CAISO compensates the scheduling coordinator for energy deemed to have been imported into a GHG regulation area at the marginal GHG price. The settlement amount is calculated as the product of the deemed greenhouse gas quantity to the GHG regulation area and the applicable marginal GHG price. The marginal GHG price is included as a component of the LMP within the GHG regulation area. Figure 234 shows the GHG payments to EDAM entities that are supporting the energy imported into the GHG regulation area (California). Conversely, Figure 235 shows the Real Time GHG payment for the EDAM entities. Negative values indicate a payment to the Scheduling Coordinator and positive values, which will only occur in RTM, indicate a buyback amount. Table 19 summarizes the monthly total GHG costs for PACE and PACW.

Figure 234: Greenhouse Gas Settlement Costs in IFM

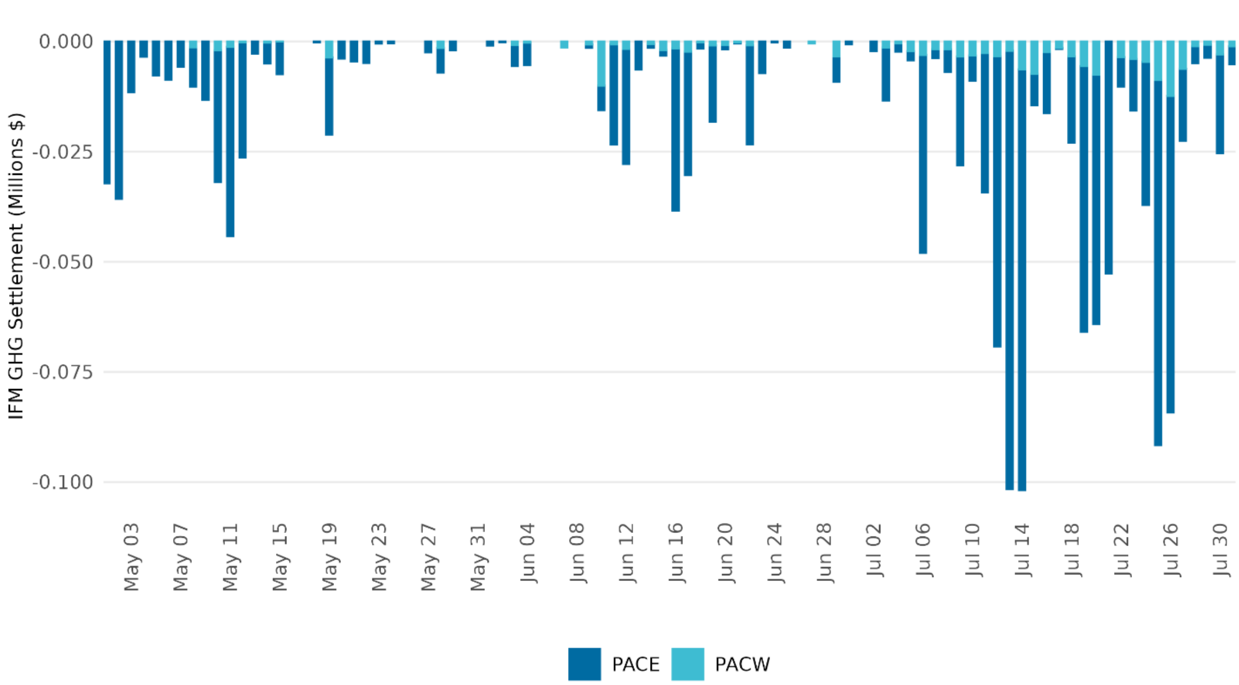


Figure 235: Greenhouse Gas Settlement Costs in RTM

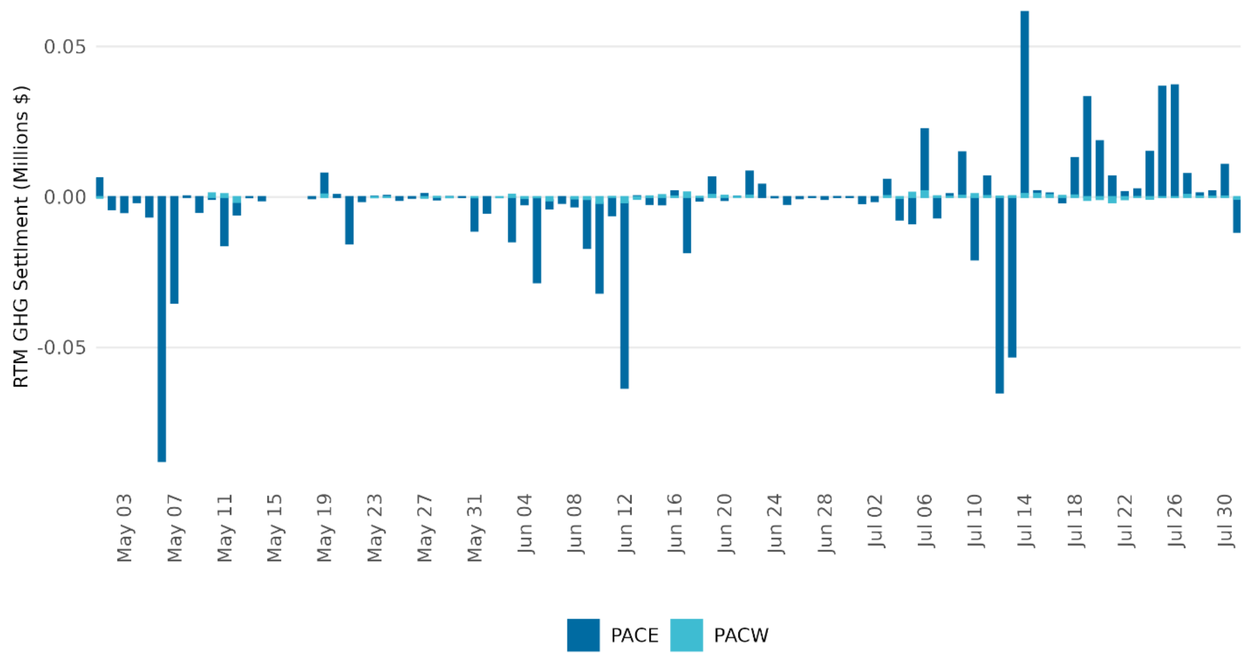


Table 19: IFM and RTM Monthly GHG Settlement Costs

	IFM GHG Costs ($ million)			RTM GHG Costs ($ million)		
BAA	May	June	July	May	June	July
PACW	-0.01	-0.029	-0.105	0.0005	-0.002	0.00532
PACE	-0.283	-0.197	-0.858	-0.182	-0.18	0.116

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 July 2026, exceptional dispatches to charge SOC for energy storage resources were used in two days.

For July 12, there was one resource that was exceptionally dispatched for SOC Charge to about 116 MW for System Emergency (Reason for ED). For July 13, there was one resource that was exceptionally dispatched for SOC Charge to about 127 MW during the afternoon hours.

Market Issues

Through the analysis of the market outcomes and performance and settlements, CAISO tracks any areas for improvements and identifies any market issues. Given the significant change in systems and processes with the implementation of the extended day-ahead market and the day-ahead market enhancements, the ISO identified several issues impacting the market outcomes as early as May. Several of the items listed in this section have been previously introduced and discussed in either EDAM implementation calls, the market update calls or the settlement user group calls. The ISO will continue to address the resolution of these issues as necessary.

- Reliability Capacity Awards at Negative Prices: Reliability Capacity has been awarded to resources at negative prices due to several issues, including software issues with MSG transitions, market-driven conditions related to optimality of solution and price formation. For price formation, negative marginal losses or congestion can drive prices below $0. Additionally, CAISO has identified a software issue impacting the congestion component for tie-generators where the congestion component for nomograms and transmission constraints is not included in the RC price. The software issue for tie-generator RC congestion will be resolved in an upcoming patch. CAISO did not correct RC prices for this issue because the impact is on the capacity awards and not the prices. Other negative RC prices may simply reflect the optimality of solution or the effect of marginal losses. CAISO continues to monitor these market outcomes to ensure new products are functioning as intended.
- In RUC when RCU and RCD bid prices are zero dollars; the optimization may procure both RCU and RCD in the same hour. Reliability Capacity consists of two distinct products that are procured when there is a difference between the CAISO forecast of CAISO demand and the cleared physical supply. Procuring both products in the same hour from different resources is not a software issue and reflects the complications of achieving an optimal solution when the upward and downward capacity have zero prices. CAISO will continue monitoring to ensure the new market functionality is working as intended.
- Missing Shift Factors in the Market Participant Portal: Market Participant Portal due to missing values in the payload transmitted from the market application. This issue was fixed on August 4, 2026 and data has been re-posted back to May 1, 2026.

- Missing Shift Factors in the CRR settlements system: The CRR settlement system is missing shift factors related to the IRU and IRD deployment scenarios. The omission has resulted in misallocation of congestion revenues. This issue affects trade dates from May 1, 2026 and onward and CAISO is working to correct it for T+70 BD settlement statements.
- Storage Resources and RCD: Storage resources are unable to provide RCD despite being economic and having sufficient state-of-charge headroom. When operating in a neutral state or charging state, the minimum energy bid limit is incorrectly constrained to 0 MWh or the IFM charging value. This issue is open and is expected to be resolved in an upcoming software patch in September.
- Flow Discrepancies for Intertie Constraints in the CRR system: Discrepancies in Intertie Constraint flows are impacting the CRR Settlement. When interties are mapped to multiple Intertie Constraints, the IFM flow calculation logic produces inaccurate results, leading to downstream misallocation of CRR revenues. This issue affects trade dates beginning May 1, 2026 and is open. CAISO is working to correct this in the T+70 BD settlement statements.
- Missing IRU and IRD deployment scenarios in the CRR clawback mechanism: The CRR clawback calculation does not account for IRU and IRD deployment scenarios due to incomplete payload data from the market application to the CRR system. This issue impacts May 1, 2026 and is open. CAISO is working to correct this in the T+70 BD settlement statements.
- High Reliability Capacity Down prices due to solution limited by IFM commitment: Reliability Capacity Down can only be awarded to resources that are on-line and committed by the IFM. Additionally, down capacity range is limited by energy self-schedules, Ancillary Services and Imbalance Reserves awarded in IFM. This issue is not a software issue but due to the requirement to run RUC only after IFM is complete. CAISO will continue monitoring to ensure the new market functionality is working as intended.
- Commitment Costs in the day-ahead Resource Sufficiency Evaluation (RSE): The RSE test is considering non-zero minimum load costs and transition costs which economically prevents some resources from providing energy and Imbalance Reserve. CAISO is working with its software vendor to ensure that commitment costs are considered $0 in the RSE test only and this issue is expected to be fixed in an upcoming software patch in September.
- Missing MPM Results on OASIS: The Market Power Mitigation mechanism is working in the day-ahead market by identifying non-competitive constraints and mitigating applicable resources, however the results of the MPM are not fully published on OASIS on the MPM Nomogram/Branch Shadow Prices and MPM Nomogram/Branch

Competitive Paths displays. This issue was fixed for trade date August 6, 2026 and CAISO is working on backfilling the data from May 1 – August 5, 2026.

- Incorrect Non-competitive Congestion Component in the Real-Time Market (RTM): With EDAM implementation, there were changes to the Dynamic Competitive Path Assessment related to BAA-level mitigation, However, these changes resulted in software issue where non-competitive congestion was deemed competitive and this prevented appropriate mitigation of resources in the RTM. This issue was fixed on July 17, 2026.
- Marginal Congestion Component Breakdown and mapping to DLAP/ELAP pricing nodes: With the implementation of EDAM, congestion revenue allocation are charged and credited to the balancing area where the constraint is binding. There is a mapping issue in the settlements system and all congestion revenue at DLAP and ELAP pricing nodes is allocation to the location of the Apnode rather than the pnodes at the location of the constraint. This issue impacts congestion revenue allocation since May 1, 2026 and was fixed on August 7, 2026. The fix will be reflected on the T+70 BD settlement statement for May 1, 2026 to July 18, 2026 and on the T+9 BD settlement statement for trade date July 19, 2026 and trade dates moving forward.
- Non-Participating Resources in RUC: To prevent RUC solution failures and ensure timely day-ahead market publication, select generator and MSG configurations were excluded from RUC participation[15]. CAISO determined that removing some MSG configuration bids in RUC resulted in a shutdown of affected MSG plants. CAISO continues to assess and monitor underlying causes of these RUC failures and continues to monitor and assess this issue.
- Virtual Bids for July 29, 2026: During the day-ahead market run for trade date July 29, 2026, duplicate virtual bids caused by a SIBR issue were identified. CAISO implemented a workaround to remove the duplicate virtual bids and resume processing; however, the workaround inadvertently deleted all virtual bids. As a result, the DAM cleared with no virtual awards. The ISO has implemented additional validation controls to detect and address this issue prior to market publication in the future.
- Daily Energy Limit not counted in EDAM Resource Sufficiency Evaluation (RSE): Due to a software issue, the daily energy limit for use-limited resources is not enforced in the EDAM RSE allowing these resources to be credited for more capacity than is available in the market. This issue affects trade dates from May 1, 2026 and is open.
- Bid Cost Recovery for Hybrid Resources: There is an issue processing the submitted bid costs for hybrid resources which is resulting in high bid cost recovery payments. This issue affects trade dates from May 1, 2026 and is open.

[15] CAISO contacts the Scheduling Coordinators for resources that have bids removed in any market run.

Stakeholder Feedback and ISO's responses

There were four sets of stakeholder comments submitted in response to June's report. The ISO has posted concurrent to this July report the responses to all these stakeholder comments. This section provides a summary of these comments and a summary of the responses as an easy reference. The detailed responses are available on the site where the stakeholder comments were originally posted.

CAISO appreciates the comments and recommendations provided by stakeholders regarding EDAM market performance, reporting transparency, congestion and transfer revenue allocation, imbalance reserve procurement, settlements, pricing mechanisms, self-scheduling, and market operations. The ISO values constructive feedback and stakeholder engagement during the initial months of EDAM operations. As the market continues to stabilize, CAISO is reviewing the requests for additional analyses, metrics, and reporting enhancements and will consider incorporating expanded information and clarifying existing metrics in future monthly EDAM performance reports and stakeholder discussions where appropriate. CAISO also recognizes the importance of continued transparency regarding operational challenges, market outcomes, and benefit allocation, and appreciates stakeholders' ongoing participation and feedback as the ISO works to further improve EDAM reporting and market understanding.

1. The Six Cities commended CAISO for a generally smooth EDAM launch and reliable market operations, while noting continued progress in resolving settlement issues. They indicated that the economic benefits of EDAM remain uncertain, with limited benefits observed during the first two months compared with WEIM. The Six Cities emphasized the importance of continued cost-benefit evaluation as the EDAM footprint expands and requested that future EDAM reports provide BAA-level benefit and market participation cost metrics, normalized by peak load, for both EDAM and WEIM. They also requested additional analysis of Imbalance Reserve procurement costs and resource utilization to assess whether IR procurement is appropriately targeted and delivering value commensurate with payments to participating resources.

   <u>CAISO response</u>: Six Cities' comments regarding the reduction of EDAM gross economic benefits by congestion revenue allocations misconstrue the nature of these estimates. Congestion revenues allocated under EDAM were neither collected nor visible prior to EDAM; they arise from locational marginal pricing and are a

settlement construct. EDAM benefits are based on production cost savings, not settlement outcomes.
It is also inappropriate to attribute all implementation or market costs solely to EDAM, as the implementation included Day-Ahead Market Enhancements (DAME). In fact, Six Cities' primary concerns regarding imbalance reserve costs are a feature of DAME, not EDAM. For a detailed response, please refer to the ISO's responses to Six Cities comments.

2. Powerex acknowledged CAISO's efforts to improve transparency around EDAM performance and requested additional reporting on congestion revenues and transfer revenues. Specifically, Powerex noted that current reports do not clearly show where market participants incurred congestion costs or how transitional congestion revenue allocations offset those costs, making it difficult to assess the financial impacts of EDAM participation. Powerex also requested clarification of discrepancies between congestion cost metrics presented in different report tables and recommended more detailed reporting on EDAM transfer revenues, including their value and allocation among balancing authority areas, to better support stakeholder evaluation of market outcomes and potential design changes.

   CAISO response: Thank you for the suggestions for additional metrics and analysis in future reports. In the June's report, the ISO indicated that estimates based on original prices and the constructed prices for MCC breakdowns will show a difference due to issues related to missing shift factors; please refer to the June's report footnote number.

3. The Energy Authority (TEA) commended CAISO for its comprehensive and transparent EDAM performance reporting, noting that recent enhancements have improved stakeholders' ability to assess market outcomes and trends. TEA encouraged continued tracking and reporting of operational and settlement issues as the EDAM footprint expands and requested additional analysis in future reports on the use and impacts of the EDAM transitional pricing mechanism, the volume and role of self-scheduled transactions, and the drivers and market impacts of real-time load conformance interventions. TEA emphasized that greater transparency in these areas would support stakeholder understanding of price formation, scheduling behavior, market efficiency, and future market design discussions. TEA also encouraged CAISO to continue facilitating stakeholder discussions on EDAM performance and to incorporate key themes, takeaways, or references to related meeting materials in future reports.

CAISO response: Thank you for the suggestions for additional metrics and analysis in future reports; metrics about load conformance and price discovery have been already incorporated in this July's report.

4. CPUC Energy Division (ED) staff appreciated CAISO's EDAM performance reporting and raised several questions regarding both EDAM operations and market transparency. ED staff sought additional transparency regarding market operations, particularly the large Reliability Capacity Up (RCU) adjustments made for Imbalance Reserve Up (IRU) deficiencies on June 11 and August 4, questioning whether the reported deficiencies were supported by available procurement data. The comments requested further clarification on IRU procurement requirements, availability of reserve capacity in real time, attribution of RCU costs, virtual supply and demand reporting, and access to EDAM counterfactual analyses comparing EDAM outcomes with a CAISO-only market. Staff also encouraged improvements to OASIS data transparency and more consistent visualization standards in future market performance reports.

   CAISO response: A comment submitted by CPUC staff pertained to a topic that is outside the scope of this EDAM/DAME and, therefore, is not addressed in this effort. For those comments specifically related to OASIS data in the context of EDAM/DAME, detailed responses have been provided.

   In comments, CPUC staff draws conclusions and requests several clarifications regarding the estimated RUC adjustments based on their calculations for two specific hours. However, those calculations do not match the values used in the market. The market values are accurate and can be independently reproduced using the appropriate OASIS data and by following the methodology outlined in the BPM for EDAM and Operating Procedure 1210.
   The apparent discrepancy from CPUC staff's estimates is because they are erroneous. They were based on incorrect reference of OASIS data and a misunderstanding of the calculation process described in both the EDAM BPM and Operating Procedure 1210. This methodology was publicly discussed and adjusted by participants feedback, including CPUC staff's suggestions, prior to market go-live. In its responses to comments, the ISO shows the correct calculation using data that can be used from OASIS and the calculations required to reproduce the values used in the market.