Q2 2024 Report on Market Issues and Performance

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California Independent System Operator

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Executive summary

This report covers market performance during the second quarter of 2024 (April–June). Key highlights during this quarter include the following:

- **Prices decreased substantially compared to the same quarter of 2023** (Figure E.1). Day-ahead California ISO balancing area prices and real-time market prices across the WEIM footprint decreased by about 40 percent, driven by significantly lower natural gas prices.
- **Natural gas prices in the West were significantly lower.** Average gas prices at Henry Hub, the national index, decreased by only about 3 percent from the same quarter of 2023. However, prices at PG&E Citygate and SoCal Citygate decreased 47 percent and 60 percent, respectively, while prices at Northwest Sumas were down 54 percent and prices at El Paso Permian decreased 111 percent compared to Q2 2023 (Figure E.2). This was the major driver of lower electricity prices across western markets.
- **Average hourly battery discharge increased relative to the second quarter of 2023 by around 105 percent, while solar and wind generation increased around 21 percent and 10 percent, respectively**. Hydroelectric generation decreased by around 17 percent. Average hourly generation by natural gas resources decreased around 8 percent.
- **Average day-ahead peak energy prices at the Mid-Columbia bilateral trading hub were more than double average Palo Verde bilateral prices and California ISO day-ahead prices in April and May.** In June, Mid-Columbia and Palo Verde prices were both around $38/MWh, about 50 percent higher than the California ISO balancing area (CAISO) day-ahead prices.
- **Average hourly net imports including WEIM transfers into the CAISO balancing area were about 520 MW, a decrease of 18 percent** compared to the second quarter of 2023. This average net interchange was in the export direction in hours-ending 9 through 18, driven by high solar output and large transfers out of the California ISO area to the rest of the Western Energy Imbalance Market (WEIM). Average net exports, including WEIM transfers, peaked around 4,500 MW in hour-ending 16. This was about 200 MW more than the largest hourly average net export out of CAISO in Q2 2023.
- **Resource adequacy bids from imports into the CAISO area increased 105 percent in June 2024** compared to June 2023.
- **For June 2024, the ISO implemented its new policy to issue high priority wheeling-through rights based on its estimation of transmission capacity available for these wheels.** The ISO significantly underestimated transmission capacity needed by native load for resource adequacy imports. However, the sum of priority wheel-through contracts and native load needs only exceeded available transmission capacity on the two major northern interties on two days in June, when the NOB intertie was de-rated to 0 MW.
- **The average total volume of capacity procured through the residual unit commitment (RUC) process in the second quarter of 2024 was 3 percent lower than the same quarter of 2023.** Although total volumes were lower, operator adjustments to the RUC procurement target increased by about 104 percent compared to the second quarter of 2023, and by about 47 percent compared to the second quarter of 2022. This was largely due to the ISO beginning to use the mosaic quantile regression method to determine RUC adjustments in the summer of 2023. The ISO continued to use this method throughout Q2 2024. The ISO balancing area significantly reduced the amount of net load uncertainty that the RUC adjustments were intended to cover in Q1 and Q2 2024 compared to Q4 2023.

- **Overall day-ahead market congestion rents on internal and intertie constraints was $164 million, similar to the $162 million in the second quarter of 2023.** Intertie congestion rent was $13 million. In day-ahead and real-time markets, the average impact of congestion on price differences between load areas was notably greater in Q2 2024 than in the same quarter of 2023. On average, real-time congestion was in the south-to-north direction, resulting in lower prices in the Desert Southwest and Southern California compared to the Pacific Northwest, Intermountain West, and Northern California.
- **Payouts to congestion revenue rights (CRRs) sold in the California ISO auction exceeded auction revenues received for these rights by about $14 million** in the second quarter of 2024. This was a significant increase from $1 million in CRR auction losses in the same quarter of 2023. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. The Department of Market Monitoring (DMM) continues to recommend further changes to eliminate or further reduce these losses. DMM recently posted a whitepaper analyzing a potential option for an alternative CRR auction design that only involves offers from willing sellers of these financial instruments.[1]
- **Real-time imbalance offset costs in the CAISO balancing area decreased to $59 million,** down from $71 million in the second quarter of 2023. The congestion portion of these costs was $62 million in Q2 2024, while the energy portion was a $5.3 million credit that counteracted some of the costs from the congestion and loss portions of the real-time imbalance offset charge.
- **Real-time imbalance offset costs in non-CAISO WEIM balancing areas were a $33 million credit to WEIM entities**, compared to a $58 million credit in the second quarter of 2023. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $43 million credit. The energy and loss portions of the offset combined to be a $10 million charge.
- **Bid cost recovery payments from the day-ahead market increased, while residual unit commitment and real-time market bid cost recovery payments decreased slightly** compared to Q2 2023. Day-ahead bid cost recovery increased to $12.4 million from $5.6 million in the second quarter of 2023. Residual unit commitment market bid cost recovery decreased by $1.6 million to $6.9 million. Bid cost recovery over all balancing areas in the real-time market decreased by about $1.4 million to a total of $20.1 million. About $2.6 million of these real-time payments were to resources participating in non-CAISO WEIM areas, down from $3.7 million in Q2 2023.
- **Ancillary service payments totaled $18.4 million, a 40 percent decrease from the same quarter last year.** The percentage reduction in ancillary service costs was similar to the decrease in energy prices.
- **Upward load adjustments in the 15-minute market increased on average compared to Q2 2023** due to large increases during morning solar ramping hours. The highest hourly average adjustment was about 1,615 MW during hour-ending 20, similar to the highest average adjustment from Q2 2023. The combination of high load adjustments up in the 15-minute market and much lower adjustments in the 5-minute market contributed to price differences between these markets during the morning and evening ramp hours.
- **Flexible ramping product system level prices were zero for over 99.9 percent of intervals** in the 15-minute market and in the 5-minute market. The frequency of zero system level prices was higher

[1] *Willing seller market design for congestion revenue rights,* Department of Market Monitoring, October 23, 2024: https://www.caiso.com/documents/willing-counterparty-whitepaper-oct-23-2024.pdf

in Q2 2024 than in the same quarter prior to the implementation of nodal pricing in February 2023. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 53 percent of upward capacity and 65 percent of downward capacity. Balancing areas in the Pacific Northwest made up 30 percent of upward flexible capacity and 16 percent of downward flexible capacity.

- **The forecasted movement portion of flexible ramping product was settled incorrectly since the implementation of the nodal procurement enhancements on February 1, 2023.** The flexible ramping price from the wrong advisory interval was used to pay the forecasted movement. The ISO is working on correcting and resettling forecasted movement for the impacted period.
- **The mosaic quantile regression method for estimating the flexible ramping product uncertainty requirements used the wrong set of balancing areas to determine the regression coefficients during 17 percent of intervals in the second quarter.** DMM continues to recommend the ISO consider options for addressing inconsistencies between 1) the group of balancing areas used to determine the regression coefficients for the pass-group and 2) the group of balancing areas whose forecast information gets multiplied by those coefficients to determine the uncertainty requirement.
- **The ISO enhanced the mosaic quantile regression method for forecasting flexible ramping product and resource sufficiency evaluation uncertainty on April 4, 2024.** The ISO stopped differentiating weekends from weekdays, significantly increasing the sample size used for the regressions.
- **The mosaic quantile regression model coefficients for predicting system level flexible ramping product uncertainty were statistically significant in about 31 percent of intervals** in the second quarter of 2024, up substantially from 20 percent of intervals in Q1 2024. The enhancement to increase sample size contributed to this improvement, but in 69 percent of intervals the coefficients were still not significantly different from zero. Average 15-minute market uncertainty forecasts from the regression method were about 200 MW less than forecasts that would have been produced by the ISO's previous histogram method, while covering about the same percentage of realized uncertainty.
- **The mosaic quantile regression model coefficients for predicting resource sufficiency evaluation uncertainty were statistically significant in about 35 percent of intervals** in the second quarter of 2024, up substantially from only 13 percent of intervals in Q1 2024. DMM replicated the Q2 regression results without the sample size enhancement described above. Regression coefficients would have been statistically significant in only 10 percent of intervals in Q2 2024 without the April 4 enhancement.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the beginning of the hour.** This is because the model is designed to predict uncertainty in forecasts produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.

Figure E.1 Monthly load-weighted average energy prices California ISO (all hours)

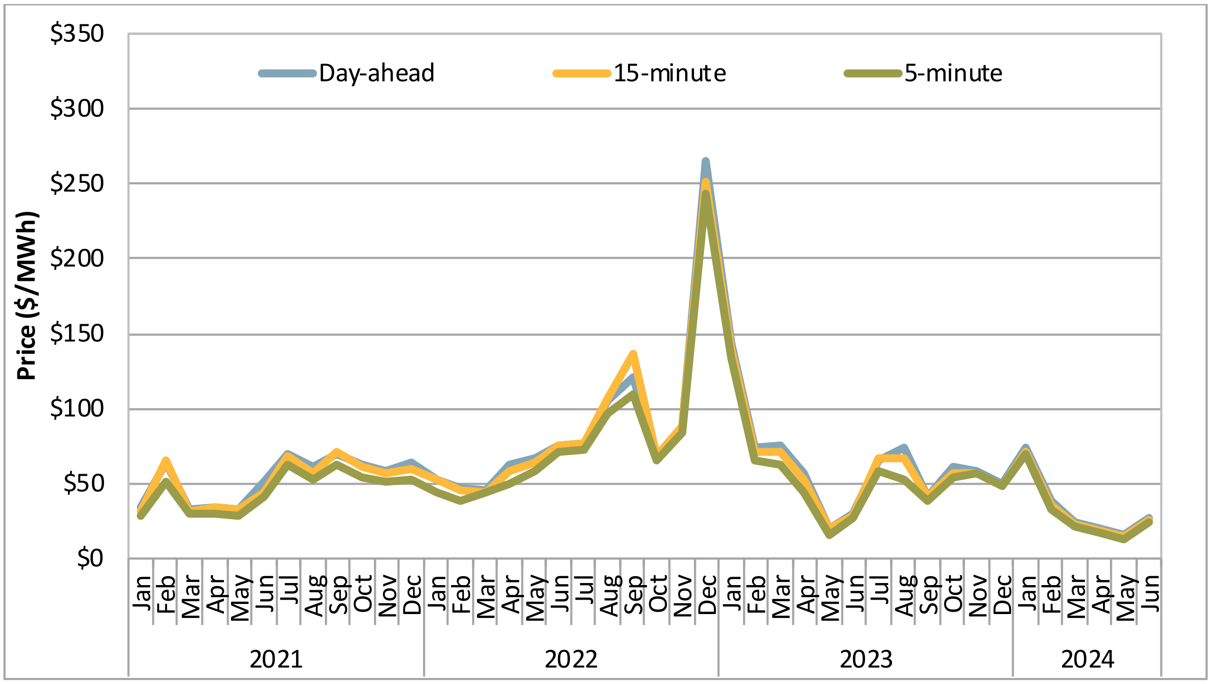
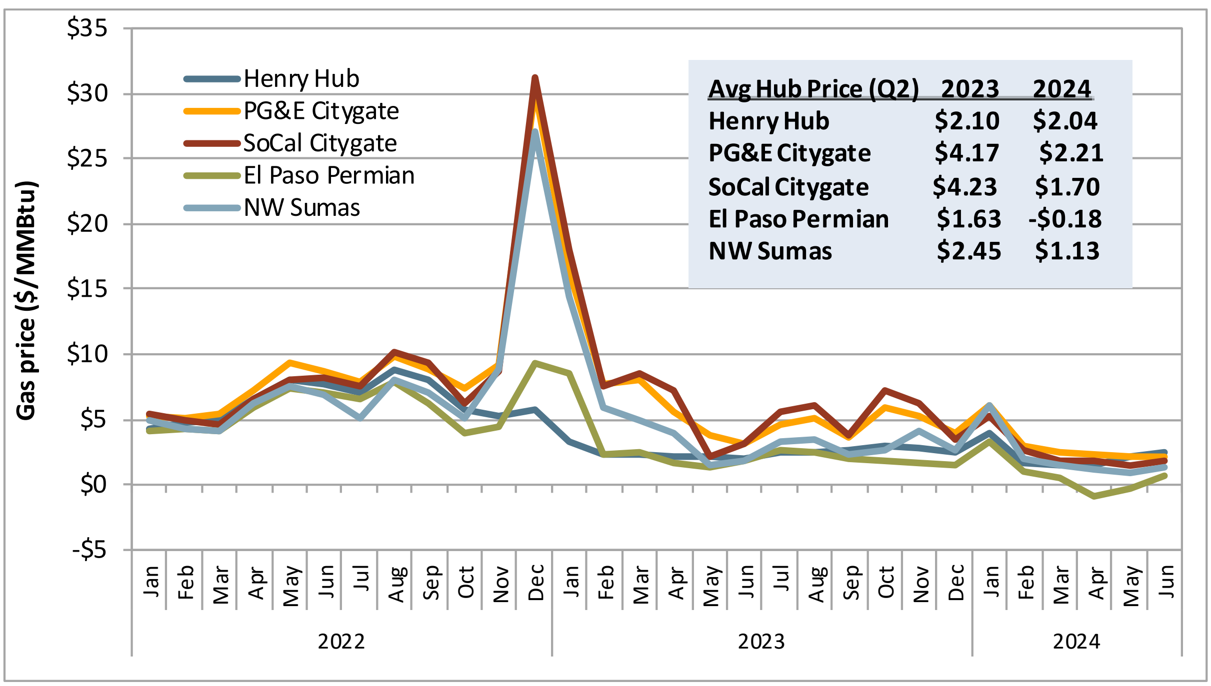


Figure E.2 Average monthly natural gas prices by hub



Western Energy Imbalance Market

- **Natural gas prices fell significantly across the WEIM** compared to the second quarter of 2023, resulting in substantial decreases in average electricity prices in all regions.
- **Energy prices across the WEIM were down 40 percent** compared to Q2 2023. Prices in both the 15-minute and 5-minute markets averaged around $19/MWh, down from $32/MWh in Q2 2023.
- **Prices in the Pacific Northwest and Northern California were higher on average than prices in the Desert Southwest and Southern California during Q2 2024.** This was largely due to south-to-north congestion on both internal transmission and WEIM transfer constraints during mid-day solar generation hours.
- **Powerex continued to have significantly higher prices than other WEIM areas.** This was due to transfer congestion into the area during most intervals.
- **California ISO balancing area operators did not implement peak hour dynamic WEIM transfer restrictions into the CAISO area during any hours of the second quarter of 2024.** Operators had restricted most Western Energy Imbalance Market (WEIM) transfers into the CAISO area in the hour-ahead and 15-minute markets during peak net load hours from July 26 through November 15, 2023.
- **The major net exporters of WEIM transfers shifted significantly** between the mid-day hours—when solar generation is typically at its highest—and the peak net load hours.
- **During the peak solar mid-day hours, the CAISO balancing area was the major net exporter of WEIM transfers,** exporting an average of over 2,900 MW between hours 10 and 17 to areas in the Pacific Northwest, California, and Desert Southwest. Nevada Power and Arizona Public Service were also significant net exporters during solar hours. Powerex, Salt River Project, and BANC were major net importers of WEIM transfers during these hours.
- **During peak net-load hours, major net exporters were Salt River Project, Arizona Public Service, and PacifiCorp West.** Powerex and BANC were the major net importers during these hours.
- **Seven balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** Five of these balancing areas received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[2]
- **Appendix A includes hourly price and transfer figures for each WEIM area.**

[2] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations#weim-resource

1 Market Performance

This section covers performance of the California ISO balancing area wholesale energy markets and resource adequacy program during the second quarter of 2024.

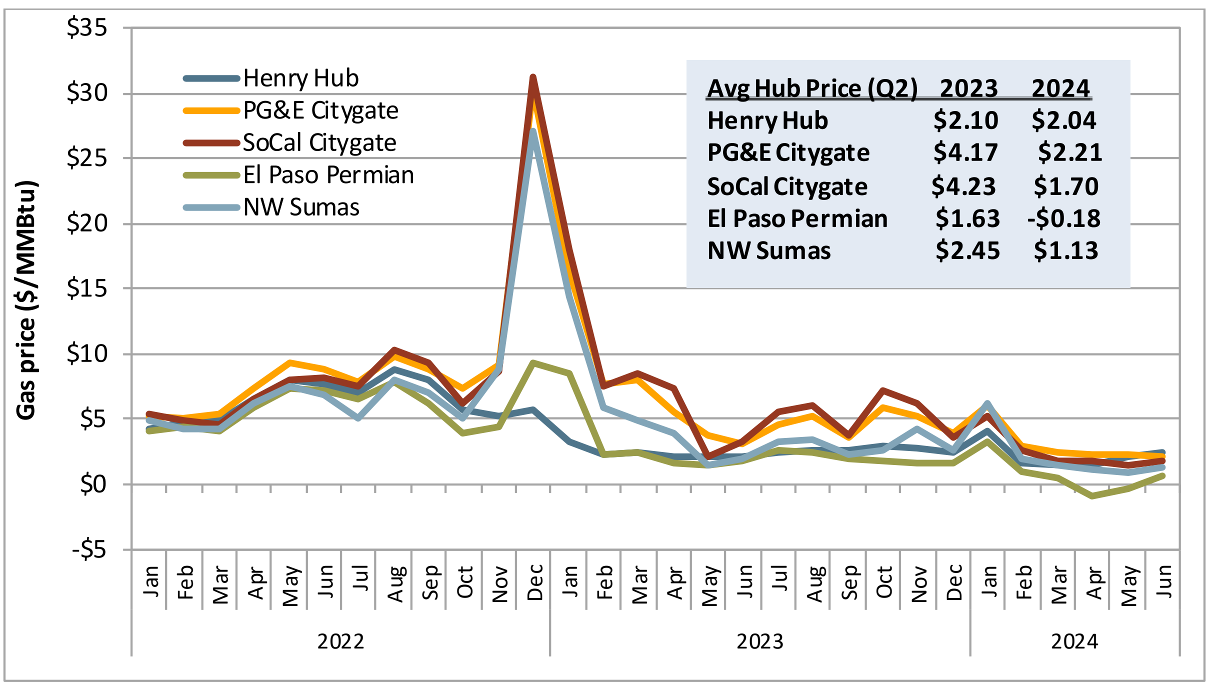
1.1 Supply conditions

1.1.1 Natural gas prices

Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in the California ISO balancing area (CAISO) and other regional markets. Average gas prices at major Western U.S. gas trading hubs continued to decrease or remain flat in the second quarter, following a trend that began towards the end of the first quarter of this year. The only exception was the El Paso Permian hub in June, which increased at the end of the second quarter following two months of negative average monthly prices, resulting from high levels of supply and limited "takeaway capacity"[3].

Figure 1.1 shows monthly average natural gas prices at key delivery points across the West, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

Figure 1.1 Monthly average natural gas prices



3 *Price Headwinds Evident in Natural Gas Forwards as Weak Demand Trumps Falling Production*, Natural Gas Intelligence (NGI), April 19, 2024: https://naturalgasintel.com/news/price-headwinds-evident-in-natural-gas-forwards-as-weak-demand-trumps-falling-production/

Average second quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) decreased by 43 percent and 48 percent compared to the previous quarter, respectively. The Henry Hub, Northwest Sumas, and El Paso Permian gas prices decreased by 16 percent, 64 percent and 111 percent, respectively, during the same time period. Compared to the second quarter of 2023, average gas prices at Henry Hub decreased by only about 3 percent. However, prices at PG&E Citygate and SoCal Citygate decreased 47 percent and 60 percent, respectively, while prices at Northwest Sumas were down 54 percent and prices at El Paso Permian decreased 111 percent compared to Q2 2023. This was the major driver of lower electricity prices across western markets.

For historical context, on August 31, 2023, the CPUC issued an order increasing the inventory limit for the Aliso Canyon storage facility from 41.16 Bcf to 68.6 Bcf, which builds on the storage level set in 2021 of about 34 Bcf.[4] This action contributed to increasing SoCalGas total authorized storage inventory capacity to 119.5 Bcf.[5] Second quarter 2024 storage inventory for SoCalGas steadily increased from about 96 Bcf on April 1, 2024 to about 103 Bcf on June 30, 2024. For comparison, the second quarter 2023 storage levels increased from a much lower level, around 37 Bcf in April 2023 to about 67 Bcf by the end of June 2023.[6]

1.1.2 Renewable generation

In the second quarter, the average hourly generation from renewable resources increased to 14,740 MW. This was an increase of 670 MW, or 5 percent, compared to the second quarter of 2023.[7] The availability of variable energy resources, such as wind and solar resources, contributes to price patterns, both seasonally and hourly, due to their low marginal cost relative to other resources. Geothermal, biomass, and biogas resources provide a more constant and predictable availability, but represent a lower share of generation compared to the variable energy resources.

Figure 1.2 shows the average hourly renewable generation by month and fuel type.[8] Between April and June 2024, average hourly solar generation increased by around 1,810 MW. Solar generation increased by about 1,120 MW per hour in Q2 2024 compared to Q2 2023. Wind generation increased 10 percent compared to the second quarter of 2023, while generation from geothermal and biogas-biomass resources decreased by about 6 percent and 1 percent, respectively. Hydroelectric generation was around 3,310 MW, which was about a 17 percent decrease from the above-average conditions in 2023.

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4 *CPUC Proposed Decision to Protect Against Natural Gas Price Spikes in Southern California (I.17-02-002)*, July 28, 2023: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/ac-storage-level-pd-0722823.pdf

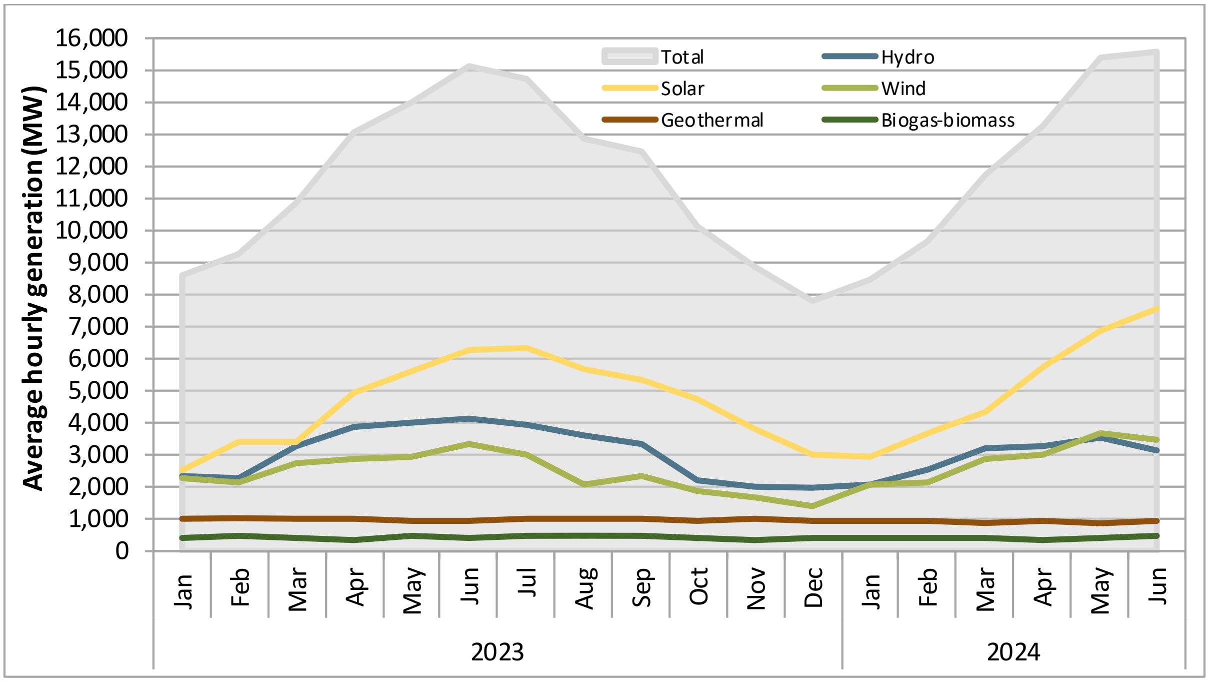
5 SoCalGas owns and operates four underground storage facilities: Aliso, Honor Rancho, La Goleta, and Playa Del Rey: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M328/K289/328289863.PDF

6 SoCalGas ENVOY Storage Inventory (Bcf): https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome

7 Figures and data provided in this section are preliminary and may be subject to change as final meter data is submitted.

8 Hydroelectric generation greater than 30 MW is included.

Figure 1.2 Average monthly renewable generation



1.1.3 Generation by fuel type

Average hourly battery discharge increased relative to the second quarter of 2023 by around 530 MW (105 percent) to 1,030 MW.[9] Solar generation increased by around 1,120 MW to 6,720 MW. Average hourly generation by natural gas resources was around 4,140 MW, down from 4,480 MW during the same quarter of 2023. Average hourly net imports, excluding WEIM transfers, increased by around 5 percent to 1,750 MW. California ISO was a net exporter from hours-ending 11 through 17.[10]

Figure 1.3 shows the average hourly generation by fuel type during the second quarter of 2024, as measured by preliminary meter data. Net battery discharge peaked during hour-ending 20 at about 4,850 MW. During mid-day hours, there is significant load from batteries charging, represented by the net negative points below the zero-axis. On average, net battery generation for the second quarter of 2024 was the lowest during hour-ending 12, at around -3,500 MW.

[9] This statistic refers to battery discharge only, while Figure 1.3 and Figure 1.4 display *net* battery generation.

[10] Figures and data provided in this section are preliminary and may be subject to change as final meter data is submitted.

Figure 1.3 Average hourly generation by fuel type (Q2 2024)

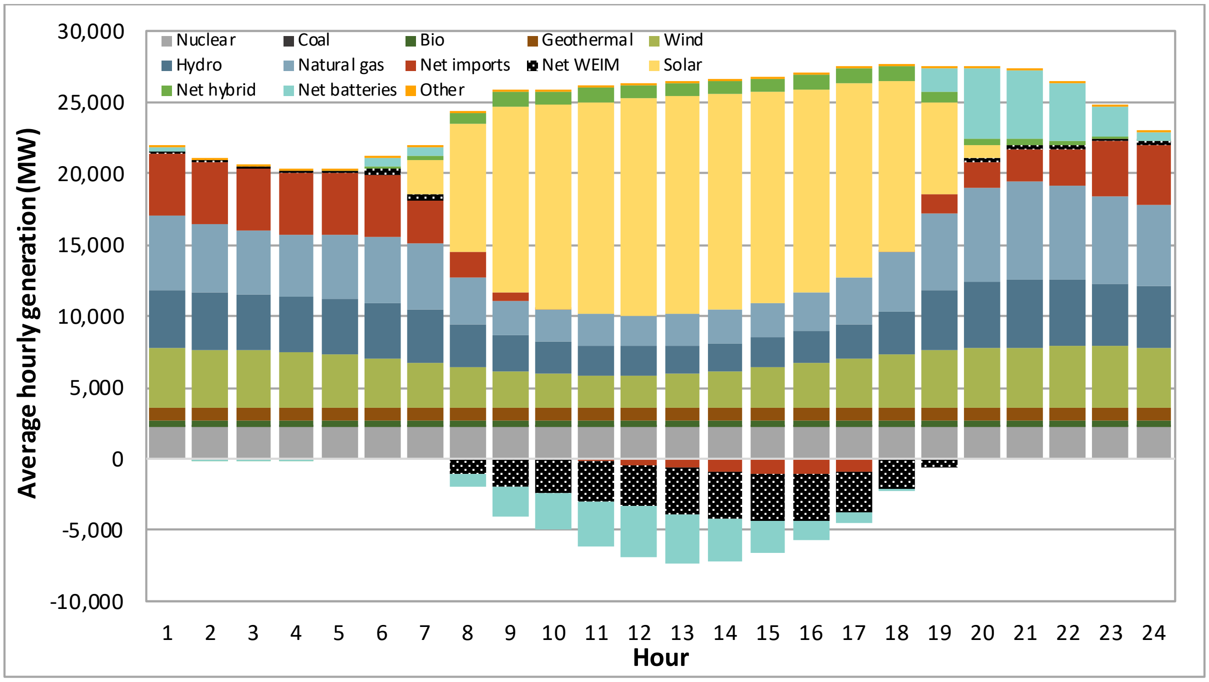


Figure 1.4 shows the change in hourly generation by fuel type between the second quarters of 2023 and 2024.[11] In the chart, positive values represent increased generation relative to the same time last year, and negative values represent a decrease in generation.

Natural gas generation decreased significantly during the morning and evening hours. Batteries have been increasingly participating in energy arbitrage by charging during high solar hours mid-day, and discharging during the high net-load periods in the evening. Both battery charging and discharging have doubled in magnitude compared to the second quarter of 2023. Increased mid-day battery charging was met largely by greater solar and hybrid production.

Figure 1.5 shows the monthly average hydroelectric generation from 2020 to 2024. Hydroelectric generation in the second quarter of 2024 was lower than in 2023, but it was higher than the three years prior to 2023.

Figure 1.4 Change in average hourly generation by fuel type (Q2 2023 to Q2 2024)

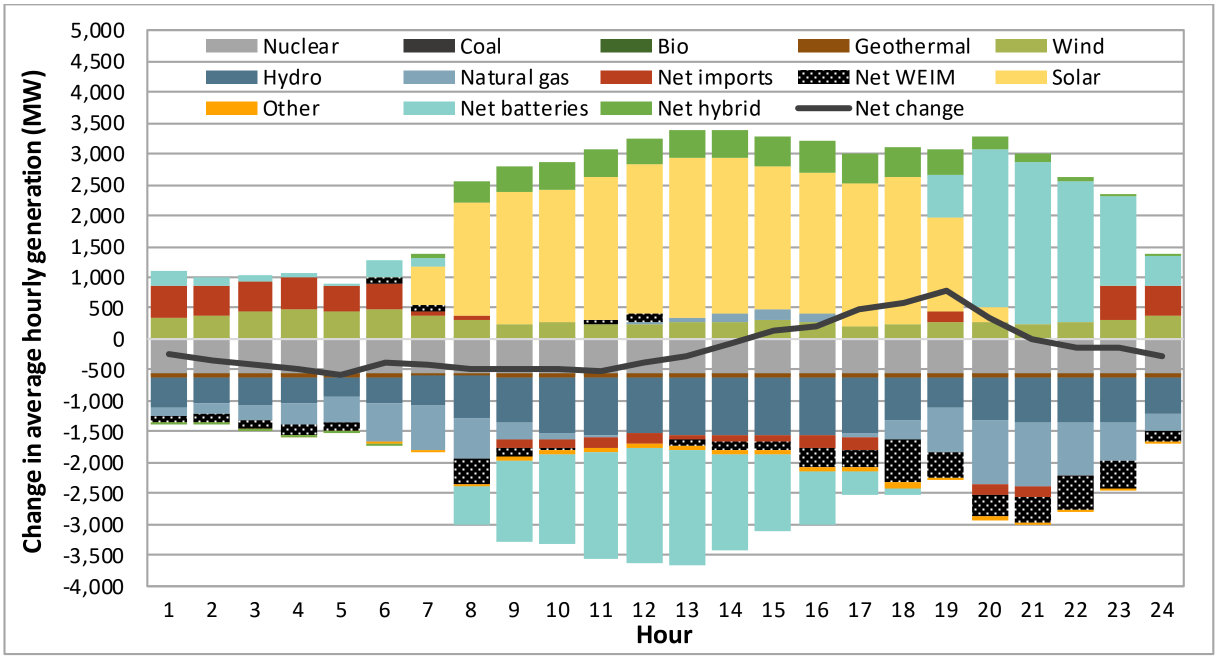
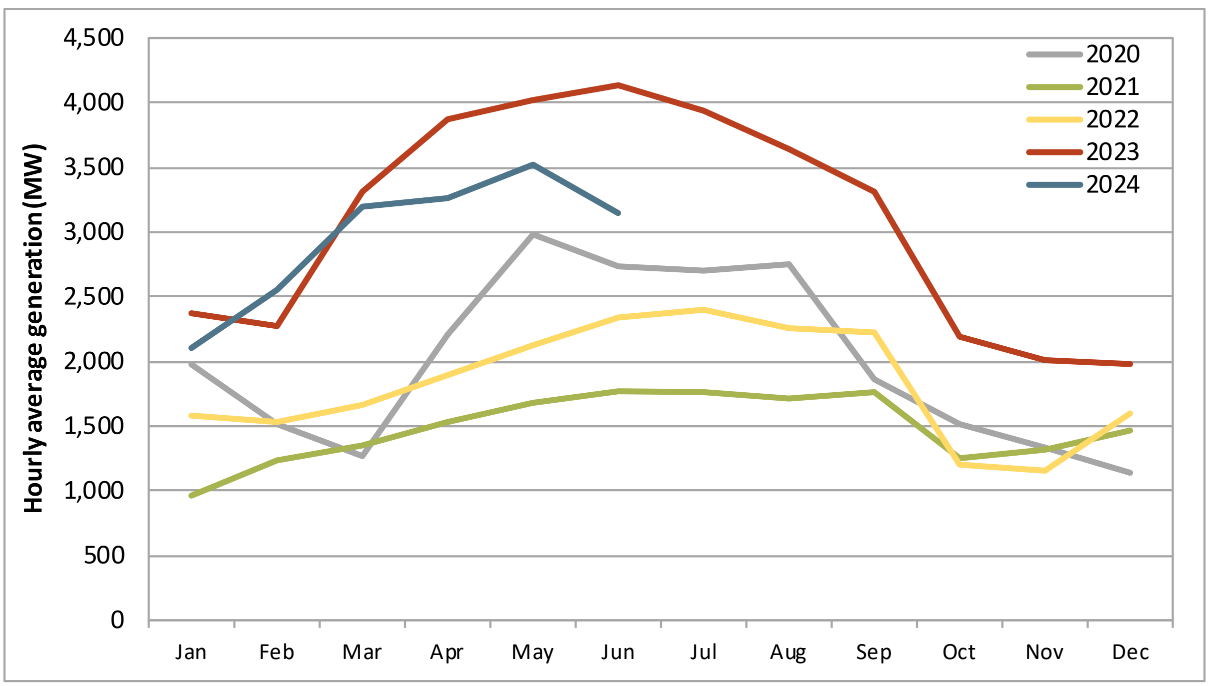


Figure 1.5 Monthly average hydroelectric generation by year



1.1.4 Generation outages

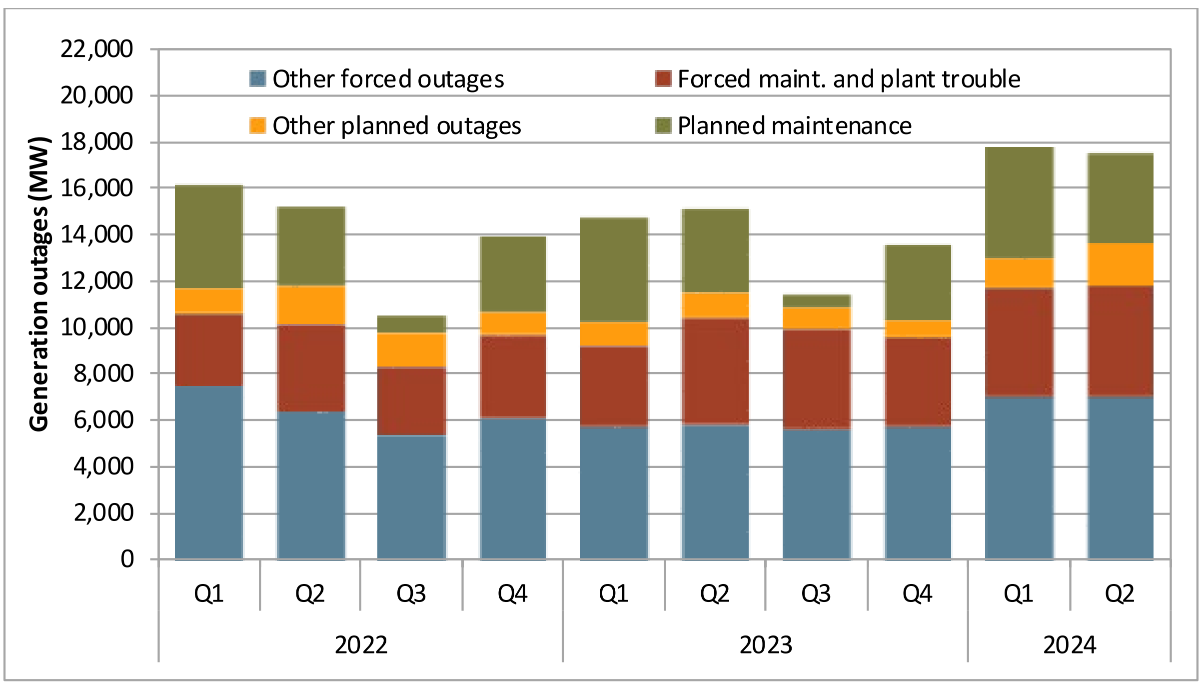
Total generation on outage in the California ISO balancing area (CAISO) averaged about 17,501 MW in the second quarter of 2024. This was an increase of 16 percent from the second quarter of 2023. This was a generalized increase across both the planned and forced outage categories when compared to the second quarter of 2023.

Under the current California ISO outage management system, known as WebOMS, all outages are categorized as either “planned” or “forced”. An outage is considered *planned* if a participant submitted it more than 7 days prior to the beginning of the outage. WebOMS has a menu of subcategories indicating the reason for the outage. Examples of such categories include plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations, and unit cycling.

Figure 1.6 and Figure 1.7 show the quarterly and monthly averages, respectively, of maximum daily outages during peak hours by type from 2022 through the second quarter of 2024.[12] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period. Looking at the monthly outages, there are usually a higher number of outages in the fall, winter, and early spring than in the summer months. This trend continued in 2024, with planned maintenance outages reaching their seasonal peak in March and falling over the course of the second quarter.

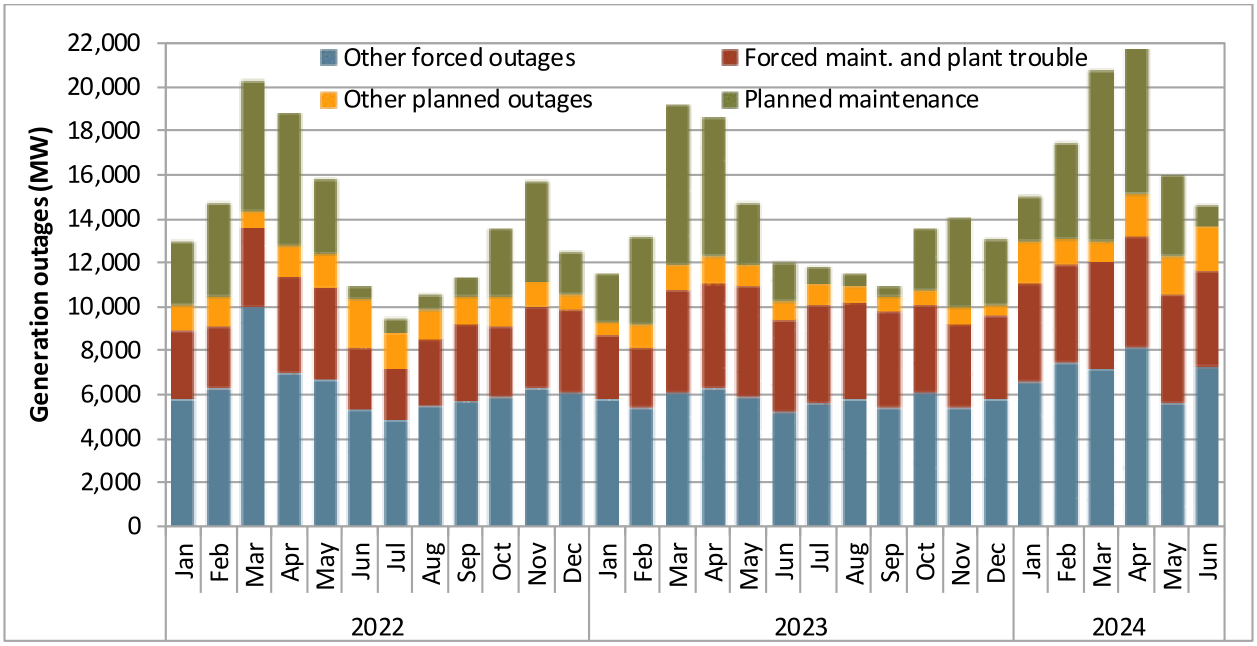
During the second quarter of 2024, the average total generation on outage in the California ISO balancing area was 17,501 MW, about 2,400 MW greater than the second quarter of 2023, as shown in Figure 1.6. Forced outages increased by 13 percent when compared to the same quarter last year, while planned outages increased by 23 percent.

Figure 1.6 Quarterly average of maximum daily generation outages by type – peak hours



[12] This is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the California ISO balancing area and do not include outages in the Western Energy Imbalance Market.

Figure 1.7 Monthly average of maximum daily generation outages by type – peak hours



Generation outages by fuel type

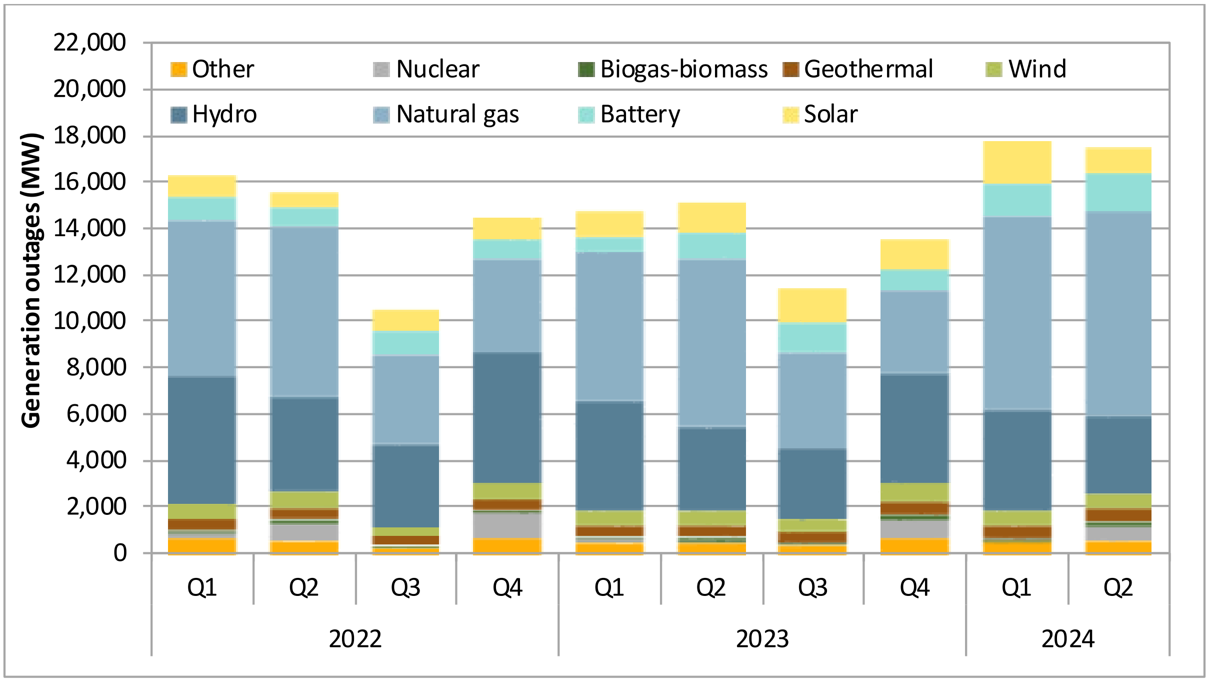
Figure 1.8 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[13] Hydro, solar, and biogas-biomass outages decreased compared to the second quarter of 2023, while outages for all other resource types increased.

Natural gas and hydroelectric generation on outage averaged about 8,840 MW and 3,290 MW during the second quarter of 2024, respectively. These two fuel types accounted for a combined 69 percent of the generation outages for the second quarter. The amount of natural gas generation outages increased 21 percent relative to the second quarter of 2023. The generalized increase in natural gas outages in the first two quarters is in part due to the implementation of California's Strategic Reliability Reserve programs whose natural gas resources are on outages unless activated under specific circumstances set forth by the program and CAISO operating procedures.

The quarterly average for battery storage resources increased by 61 percent, with an average of 1,700 MW of capacity on outage in quarter two of 2024, compared to 1,060 MW in the second quarter of 2023. This increase in the average MW on outage was in the context of a significant increase in the total amount of battery storage capacity, from approximately 6,500 MW in June of 2023, to 10,300 MW in June of 2024. The average percent of battery capacity on outage in the second quarter of 2024 was approximately 17 percent and in the second quarter of 2023 it was approximately 16 percent. As such, the increase in battery outages is largely explained by a significant increase in the total battery capacity that came on-line in the CAISO footprint.

13 In this figure, the "Other" category contains demand response, coal, and additional resources of unique technologies.

Figure 1.8 Quarterly average of maximum daily generation outages by fuel type – peak hours



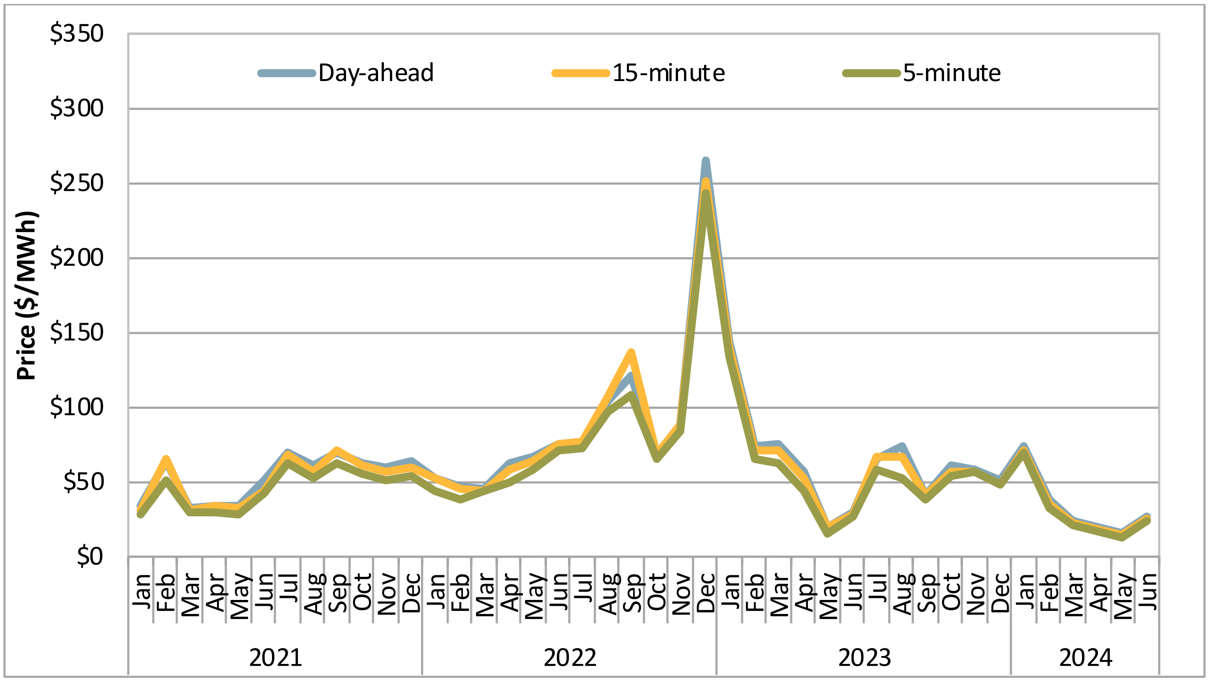
1.2 Energy market performance

1.2.1 Energy market prices

This section analyzes day-ahead and real-time market prices in the CAISO balancing area. In the second quarter of 2024, prices in the day-ahead, 15-minute, and 5-minute markets dropped by about 40 percent compared to the second quarter of the previous year. The average price of the three markets this quarter decreased to $19/MWh from $33/MWh in the same quarter of 2023.

Figure 1.9 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from January 2021 to June 2024.

Figure 1.9 Monthly load-weighted average energy prices for California ISO (all hours)



Over the quarter, day-ahead prices averaged $21/MWh, 15-minute prices averaged $20/MWh, and 5-minute prices averaged $18/MWh. Prices across all three markets were about 40 percent less than those in the second quarter of the prior year. June had the highest prices, with an average over the three markets of about $25/MWh.

Lower gas prices contributed to the significant decrease in electricity prices compared to the second quarter of 2023. Figure 1.10 shows monthly average gas prices at SoCal Citygate and load-weighted energy prices from July 2022 to June 2024. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. Over the past 24 months, both gas and energy prices exhibited similar fluctuations. The SoCal City gas price has remained down after declining from its peak in December 2022, averaging about $1.7/MMBtu during the second quarter of 2024.

This strong correlation between energy and gas prices can be attributed to gas-fired units often serving as the price-setting units within the market. A high gas price increases the marginal cost of generation for gas-fired units and non-gas-fired resources with opportunity costs indexed to gas prices. Market bids reflect these higher marginal costs.

Figure 1.10 Monthly average SoCal City gas price and load-weighted average electricity prices for California ISO

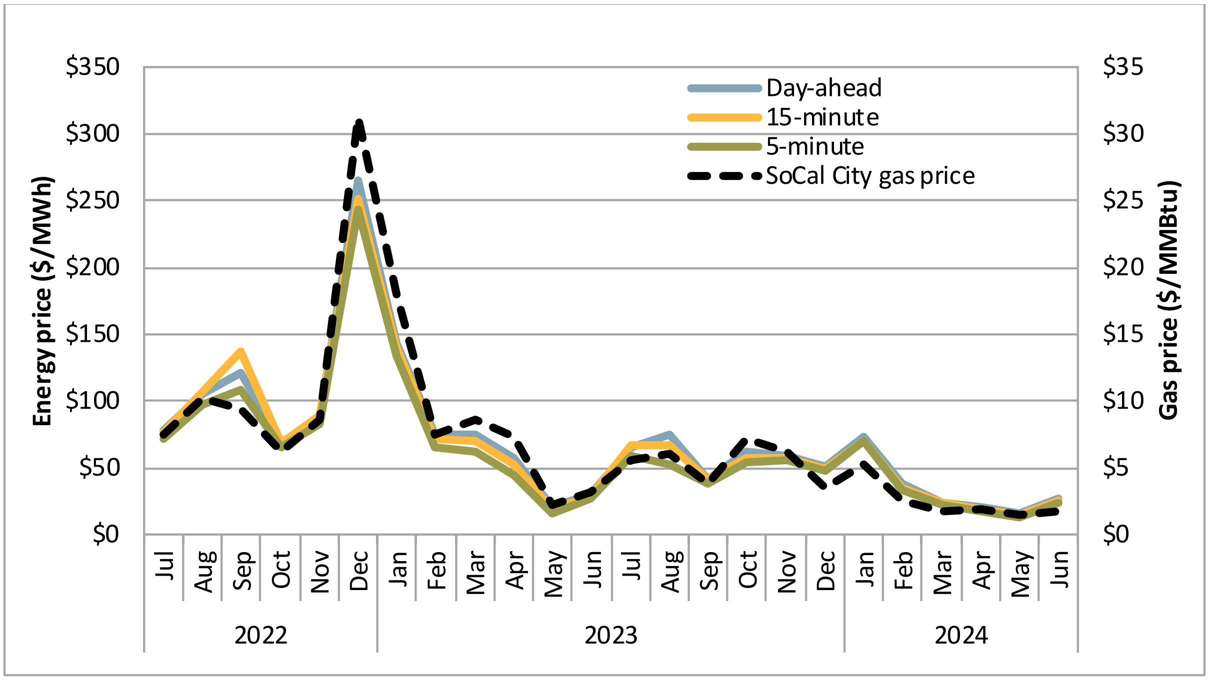


Figure 1.11 illustrates the hourly load-weighted average energy prices for the second quarter compared to the average hourly net load.[14] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening. Prices peaked at hour-ending 20, when demand was still high but solar generation was substantially below its peak. The average net load in this quarter reached 22,449 MW at hour-ending 21, one hour later than the peak price hour.

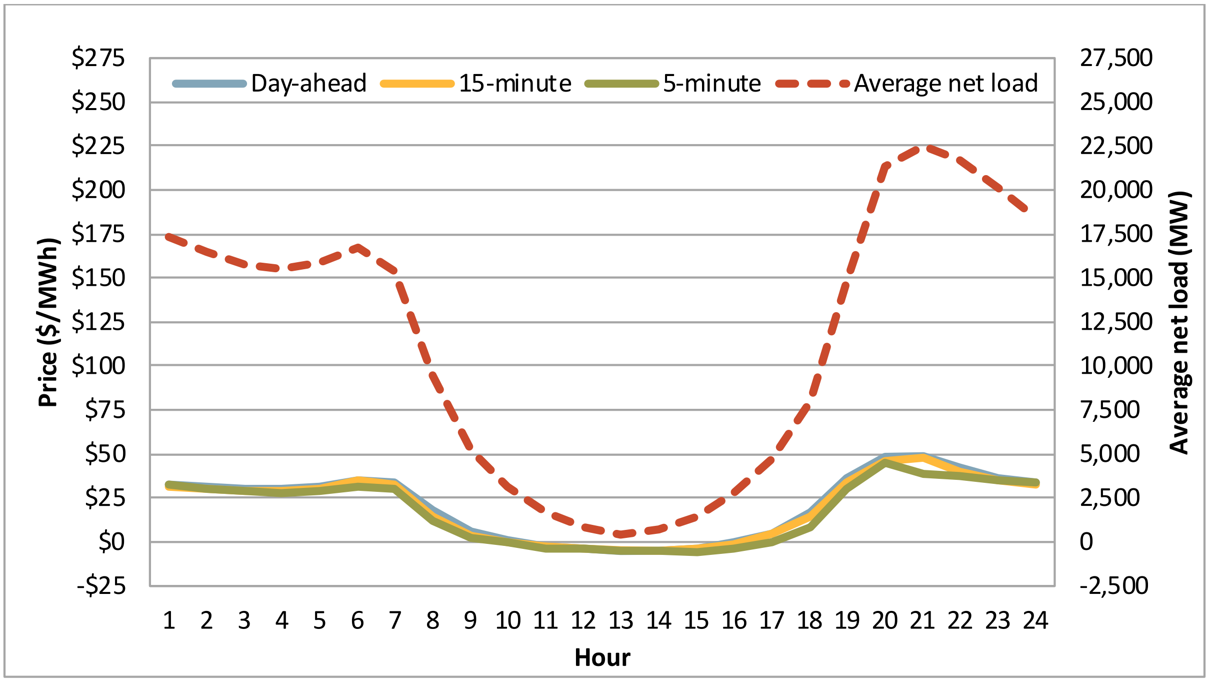
During hour-ending 20, the day-ahead load-weighted average energy price was $48/MWh, the 15-minute price was $47/MWh, and the 5-minute price was $45/MWh. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding.

One major cause of price separation between the 15-minute and 5-minute markets this quarter was load conformance during evening peak net load hours. California ISO operators typically adjust the load forecast up significantly more in the 15-minute market than in the 5-minute market over these hours.[15]

[14] Net load is calculated by subtracting the generation produced by wind and solar that is directly connected to the California ISO grid from actual load.

[15] Please see Section 1.12 for a detailed discussion on load conformance.

Figure 1.11 Hourly load-weighted average energy prices (April–June)



1.2.2 Bilateral price comparison

Figure 1.12 shows the California ISO day-ahead load weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

The California ISO FERC Order 831 policy will increase the California ISO energy bid cap to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of California ISO hourly prices, exceeds $1,000/MWh. The scaled and shaped bilateral prices did not reach $1,000/MWh in the second quarter. There were no periods of raised energy bid cap and penalty prices in the second quarter. In the first quarter however, the California ISO raised its energy bid cap and penalty prices to $2,000/MWh on four days[16] during an extreme cold temperature period between January 13 and 16, 2024. Regional differences in prices reflect transmission constraints and greenhouse gas compliance costs.

[16] The ISO increased the energy bid cap from $1,000/MWh to $2,000/MWh for some hours on January 13 and January 14-16 due to high power prices detected at the Mid-C bilateral power price hub. *Market Update Call Meeting Minutes*, California ISO, January 25, 2024: https://www.caiso.com/Documents/MeetingMinutesMarketUpdateCallJan252024.pdf

Figure 1.12 Day-ahead California ISO and bilateral market prices (April–June)

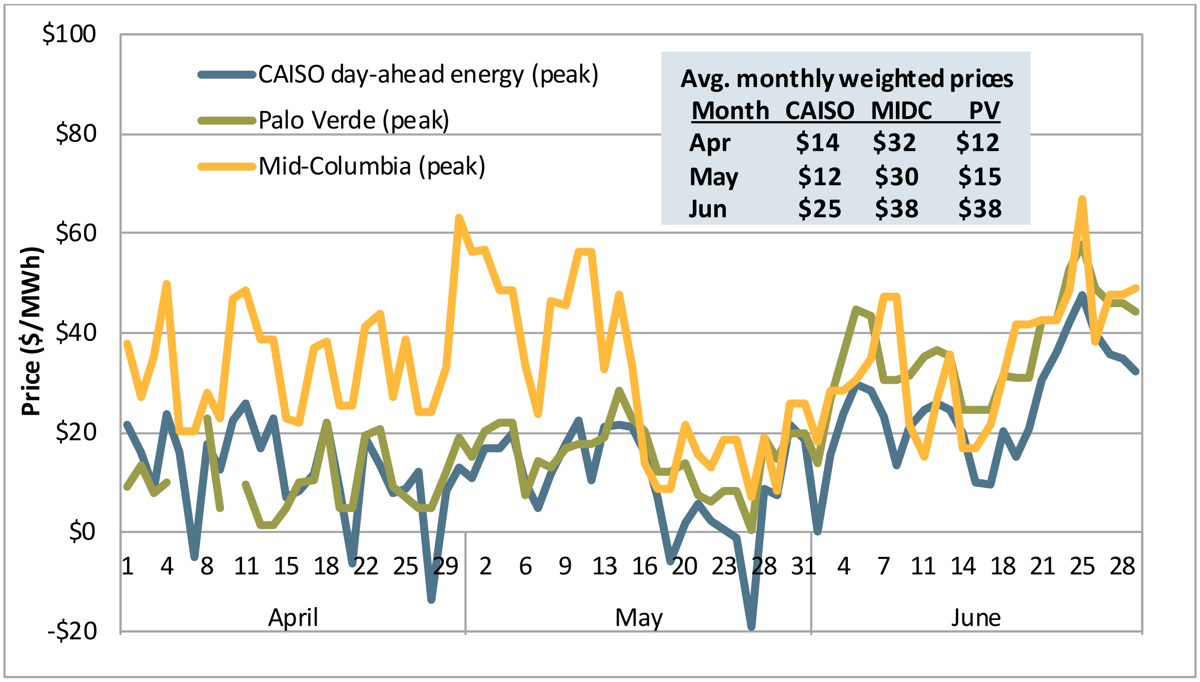
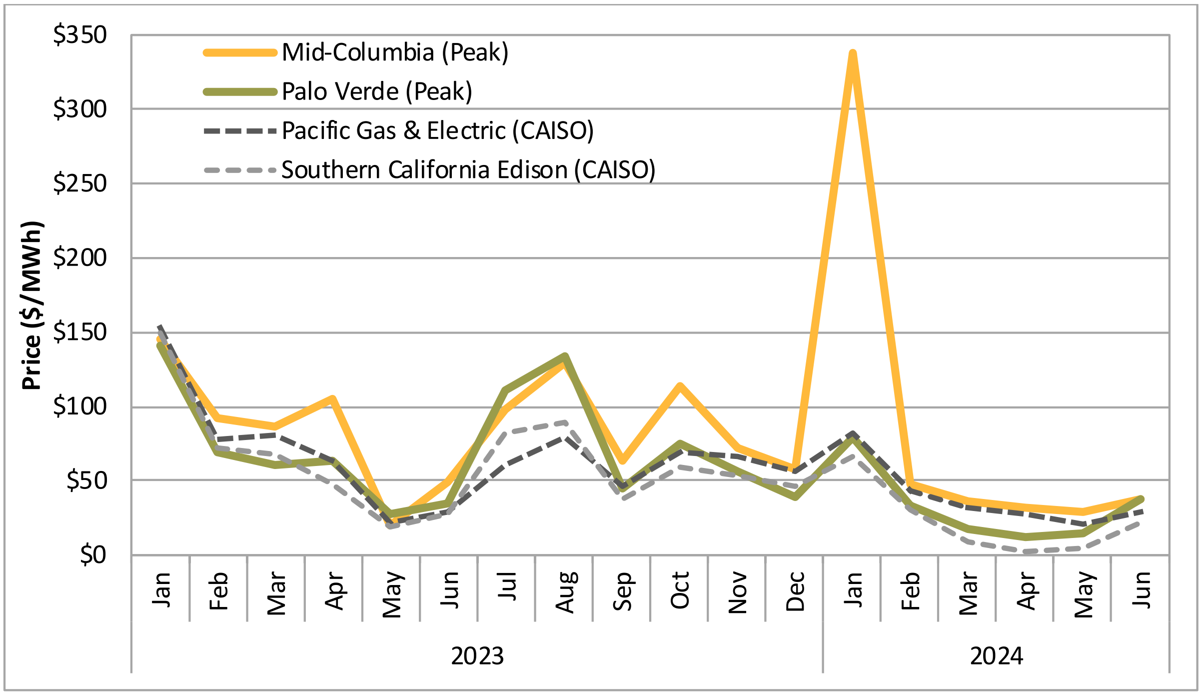


Figure 1.13 compares monthly average bilateral and California ISO day-ahead market prices for 2023 through the second quarter of 2024. Prices in the California ISO balancing area are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). Average bilateral prices for Mid-Columbia (Peak) significantly exceeded prices at the California ISO DLAPs in January 2024. This was a result of a large arctic air mass in mid-January,[17] which covered much of the Pacific Northwest and Intermountain West regions. No comparable price spike occurred in the second quarter, as prices gradually increased from the beginning to the end of the quarter. The Palo Verde (Peak) prices were between the PG&E and SCE prices for April and May. In June, both the Mid-Columbia (Peak) and Palo Verde (Peak) prices exceeded the prices in the California ISO balancing area.

[17] *Arctic Chill Sweeps U.S.*, NASA Earth Observatory, January 15, 2024: https://earthobservatory.nasa.gov/images/152333/%0barctic-chill-sweeps-us

Figure 1.13 Monthly average day-ahead and bilateral market prices



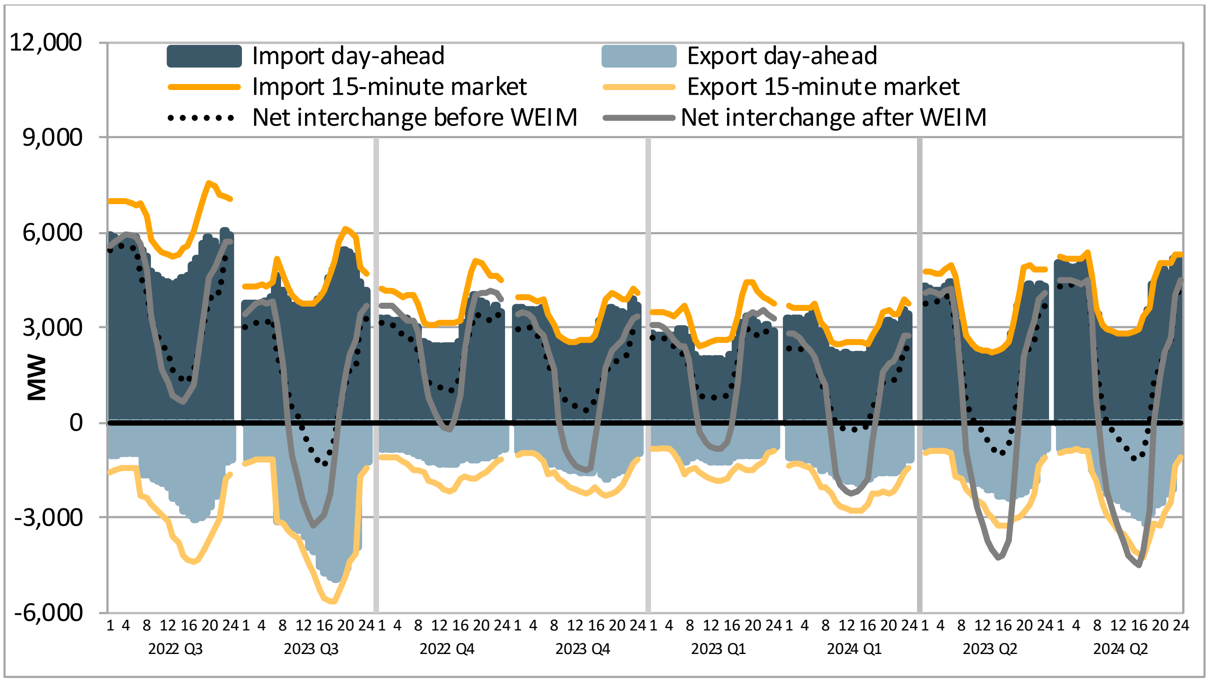
Average day-ahead prices in the California ISO balancing area and bilateral hubs (from the Intercontinental Exchange—or ICE) were also compared to real-time hourly energy prices traded at the Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average day-ahead hourly prices in the California ISO balancing area were lower than the average real-time prices at Mid-Columbia and Palo Verde by about $5/MWh and $1.50/MWh, respectively. Average day-ahead prices at Mid-Columbia from ICE were greater than the average real-time Mid-Columbia prices (from Powerdex) by about $4/MWh. Average day-ahead prices at Palo Verde, on the other hand, were about $0.5/MWh lower than average real-time Palo Verde prices.

1.2.3 Imports and exports

Figure 1.14 shows power flowing into the ISO balancing area as positive and power flowing out of the CAISO area as negative. The dashed black line shows net interchange with the CAISO area before including WEIM transfers into or out of the CAISO area. The dashed black line is the sum of the 15-minute imports (dark yellow line) and the 15-minute exports (pale yellow line). Compared to the second quarter of 2023, the average net interchange before considering WEIM transfers increased by about 80 MW across all hours. This average net interchange decreased (i.e., in the direction of less imports and more exports) in the mid-day hours and most hours while solar generation was ramping down. This average net interchange increased (i.e., more imports) in the late evening and early morning hours compared to the same quarter of the prior year.

The solid grey line adds WEIM transfers onto the net interchange calculation (dashed black line). When the grey line is below the dashed black line, this indicates WEIM transfers out of the CAISO balancing area. WEIM transfers flowed out of the CAISO area on average during daylight hours in Q2 2024. Net interchange including WEIM transfers (solid grey line) were in the export direction on average between hours-ending 9 and 18. Net exports including WEIM transfers peaked at over 4,500 MW in hour-ending 16.

Figure 1.14 Average hourly net interchange by quarter



Import resource adequacy bids

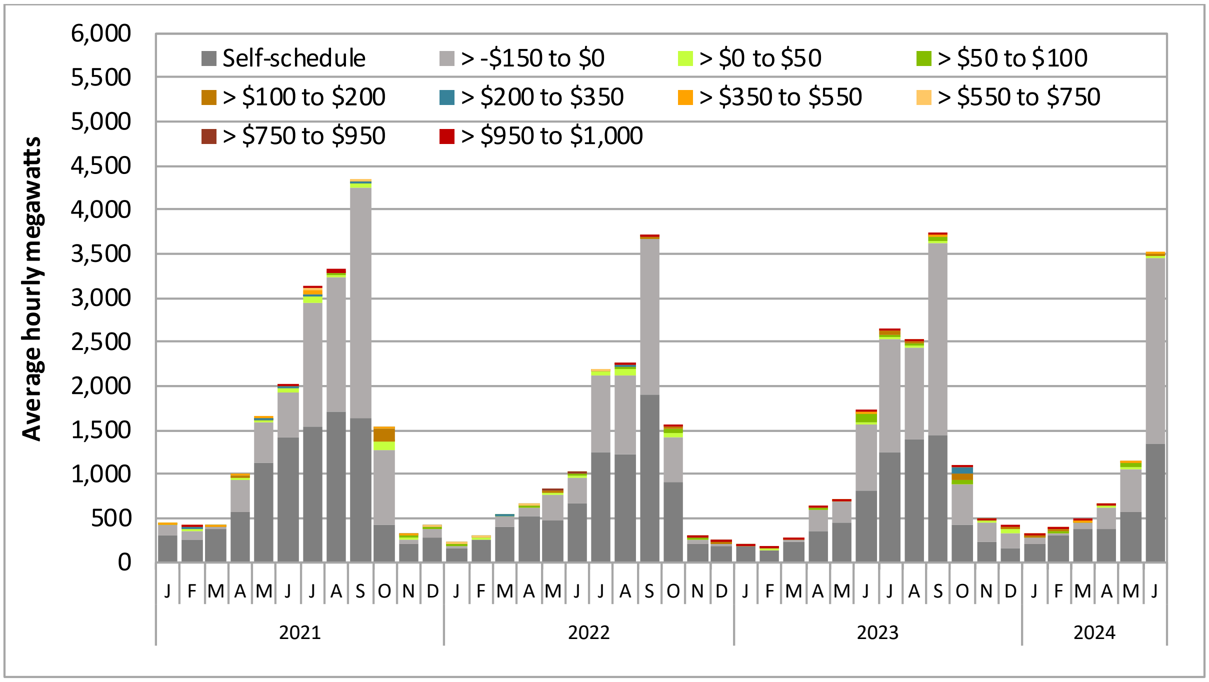
In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource specific import resource adequacy resources must bid into the California ISO markets at or below $0/MWh during the availability assessment hours.[18] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices of imports. An overall decline in volumes began in late 2020 and continued throughout 2021, but appear to have stabilized since then. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 1.15 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[19] The dark grey bars reflect import capacity that was self-scheduled. The light grey bars show imports bid at or below $0/MWh. The remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market bid above $0/MWh. Combined resource adequacy import bids and self-schedules increased 60 percent in May 2024 compared to May 2023, and over 105 percent in June 2024 compared to June 2023.

[18] In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh or when the California ISO has accepted a cost-verified bid over $1,000/MWh. Phase 2 imposed bidding rules capping resource adequacy import bids over $1,000/MWh at the greater of the MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

[19] Peak hours in this analysis reflect non-weekend and non-holiday periods between hours-ending 17 and 21.

Figure 1.15 Average hourly resource adequacy imports by price bin



1.3 Wheeling rights

The ISO began developing a framework that establishes high-priority wheeling through scheduling priorities in the CAISO market following the power outages in the summer of 2020. In July 2021, the ISO started the Transmission Service and Market Scheduling Priorities (TSMSP) initiative that had two phases: an interim phase to establish wheeling through priorities for the challenging system conditions in the summer of 2022, and a longer-term framework that started in 2024. External suppliers and load serving entities can now reserve the capacity to self-schedule wheel-through transactions that have the same scheduling priority as CAISO demand in advance of the market runs on rolling monthly and daily timeframes.

Implementation details

ATC reservation process

The ISO manually disseminated available transmission capacity (ATC) calculations and processed priority wheel-through (PWT) reservations before the automated system was operational. On January 17, 2024, the ISO posted monthly ATC values for a set of interties selected based on historic wheel-through activity. The ISO calculated these values based on expected total transmission capacity (TTC), legacy ownership rights (ETC/TORs), native load needs, and a transmission reliability margin (TRM). Starting on January 18, 2024, market participants submitted power contracts to the ISO for validation during the first reservation window, with reservations beginning June 2024. The ISO awarded priority wheel-through capacity, and updated intertie available transmission capacity values based on these awards and evolving ATC component expectations. The ISO followed this process for the first three reservation windows in 2024.

As of April 19, 2024, market participants can reserve and establish priority wheel-through access on the CAISO system via the WebWheel application. This application allows participants to submit power contracts, request PWT access on the monthly and daily horizons, and view PWT awards. The ISO also began posting aggregated available transmission capacity and ATC components on OASIS[20] on the same date.

Wheel-through reservation resales

The ISO included resale and assignment provisions for priority wheel-through reservations in the TSMSP framework that FERC accepted in October 2023. On April 12, 2024, the ISO requested a waiver from FERC to extend the effective date of the tariff provisions that allow for resale of monthly wheel-through priority until no later than December 17, 2024. This is because the ISO needed more time to modify systems to make sure the market recognizes when a scheduling coordinator receives priority wheel-through status after a resale, and settlements correctly applies the wheeling access charge to the appropriate parties. DMM will monitor resales when the WebWheel functionality is completed and the ISO makes the data available.

Malin available transmission capacity

The Malin intertie is one of two major interties linking the Pacific Northwest to the CAISO balancing authority area (BAA). This intertie is a key intertie for scheduling power into, from and across the CAISO BAA. The ISO initially released limited available transmission capacity on the Malin intertie for priority wheel-through reservations. For the first reservation window, the ISO calculated a Malin available transmission capacity for wheel imports of 248 MW for June, 77 MW for July, 149 MW for August, and 0 MW for September.

Participants reserved 72 MW of priority wheel-through capacity for June, 77 MW for July, and 97 MW for August. Despite the available transmission capacity made available for the first reservation window exceeding final participant reservations for June and August, Malin had no excess monthly transmission capacity for these months. This is because unanticipated transmission outages reduced capacity after the first reservation window. This is explained in more detail with the figures in the following subsection.

Transmission capacity reservations and usage

The following analysis shows the reserved priority wheel-through capacity, native load need estimates, and the actual market usage of the reserved capacity on the Malin and Nevada-Oregon Border (NOB) interties. The ISO calculates transmission capacity values for many interties in the CAISO system. However, this analysis focuses on these two large northern interties, which are the primary interties used to wheel from north-to-south across the CAISO system. Stakeholders were concerned about the congestion impacts that priority wheel-through transactions—importing from the north at Malin and exporting from the south—could have on the system during the policy development. Imports at the NOB intertie are an injection into the southern portion of the CAISO balancing area via the Pacific DC Intertie, and do not create north-to-south flows on Path 26. However, this intertie is an important source of import capacity into the CAISO system from the Pacific Northwest.

The analysis uses data as of September 2024, which means any data shown for June to October are the final values for those months. Data for November and December are preliminary and subject to change based on changing priority wheel-through reservations, native load needs, or intertie availability in subsequent reservation windows. Though some graphs show multiple months, the focus of this

[20] The Open Access Same-Time Information System (OASIS) is a platform that provides real-time data on system demand forecasts, transmission outages, capacity status, market prices, and other relevant information.

discussion will be on June 2024, which is the first month the policy took effect. Future quarterly reports will cover the analysis of other months.

Figure 1.16 to Figure 1.19 show monthly and daily capacity categories for the Malin and NOB interties. The red lines show the available capacity, which is the total transmission capacity leftover after accounting for outages and existing transmission rights (TTC – outages – ETC/TORs). Scheduling coordinators can reserve available priority wheel-through capacity (grey bars) at interties if there is leftover transmission capacity after accounting for native load need (green bars), a transmission reliability margin (yellow bars), and any previously reserved priority wheel-through capacity (blue bars). The stacked capacity bars can total more than the available capacity of an intertie if intertie outage conditions or native load need values change between reservation windows. For example, the final capacity values for June could total more than the final available transmission capacity if the ISO underestimates the native load need before the final resource adequacy (RA) showings, or if new intertie outages decrease intertie availability below capacity values reserved in previous months.

Figure 1.16 shows the monthly transmission capacity reservations at Malin. For June, Malin had an available capacity of 1,241 MW; a native load need of 1,192 MW; a transmission reliability margin (TRM) of 180 MW; and priority wheel-through reservations of 72 MW. Due to the iterative nature of transmission capacity reservations—where the ISO may update intertie availability and native load needs while honoring priority wheel-through (PWT) reservations made in previous reservation windows—final intertie capacity values may be oversubscribed compared to the final transmission availability number.

Figure 1.16 Monthly transmission capacity values at MALIN500

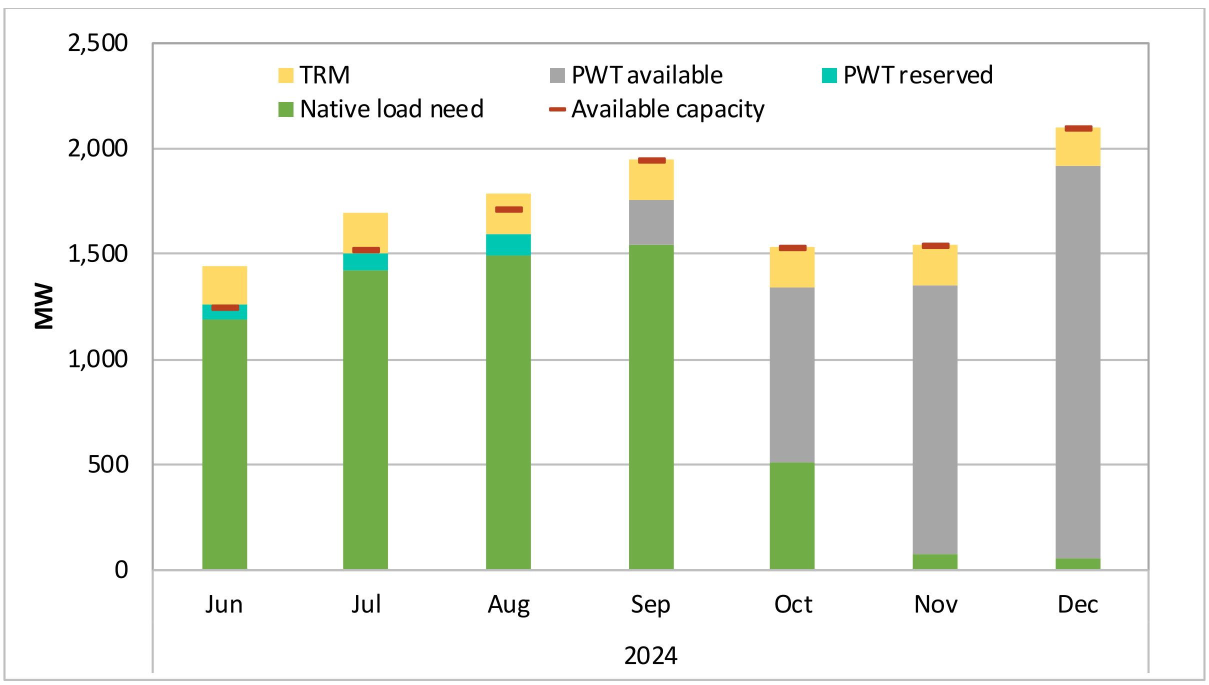


Figure 1.17 shows daily transmission capacity reservations at Malin. Monthly capacity values carry over to the daily timeframe. Scheduling coordinators and load serving entities can reserve more capacity for priority wheel-throughs and native load needs in the daily timeframe when there is additional available transmission capacity. This can happen if there is available transmission capacity left over from the monthly reservation process or if there is an increase in available transmission capacity due to a change

in outage status. The daily timeframe ATC increased above the monthly capacity values for 15 days in June. As a result, the grey bars indicate the amount of extra priority wheel-through reservation capacity that became available. Market participants made no incremental priority wheel-through reservations between the monthly and daily timeframes.

Figure 1.17 Daily transmission capacity values at MALIN500

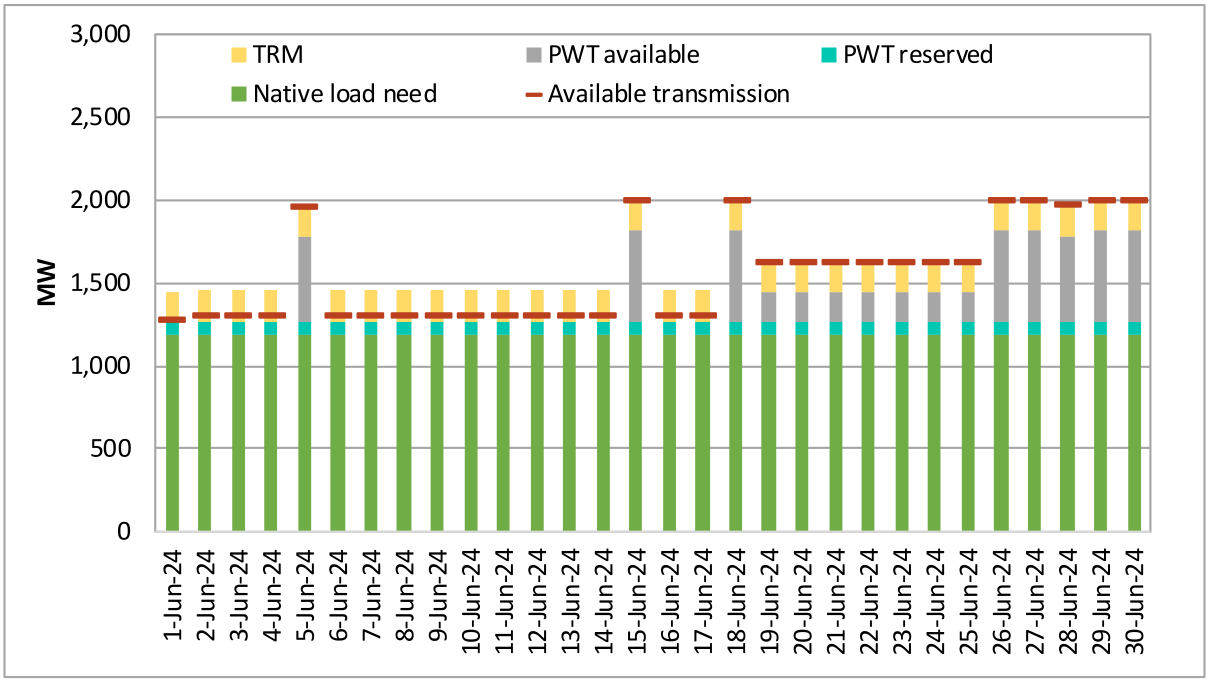


Figure 1.18 shows the monthly transmission capacity reservations at NOB. For the final June values, NOB had an available capacity of zero MW, a native load need of 958 MW, a transmission reserve margin of 97 MW, and priority wheel-through reservations of 378 MW. Due to the iterative nature of transmission capacity reservations, scheduling coordinators reserved priority wheel-through capacity and the ISO determined available transmission capacity component values before an outage drove the monthly ATC value to zero.

Figure 1.18 Monthly capacity values at NOB

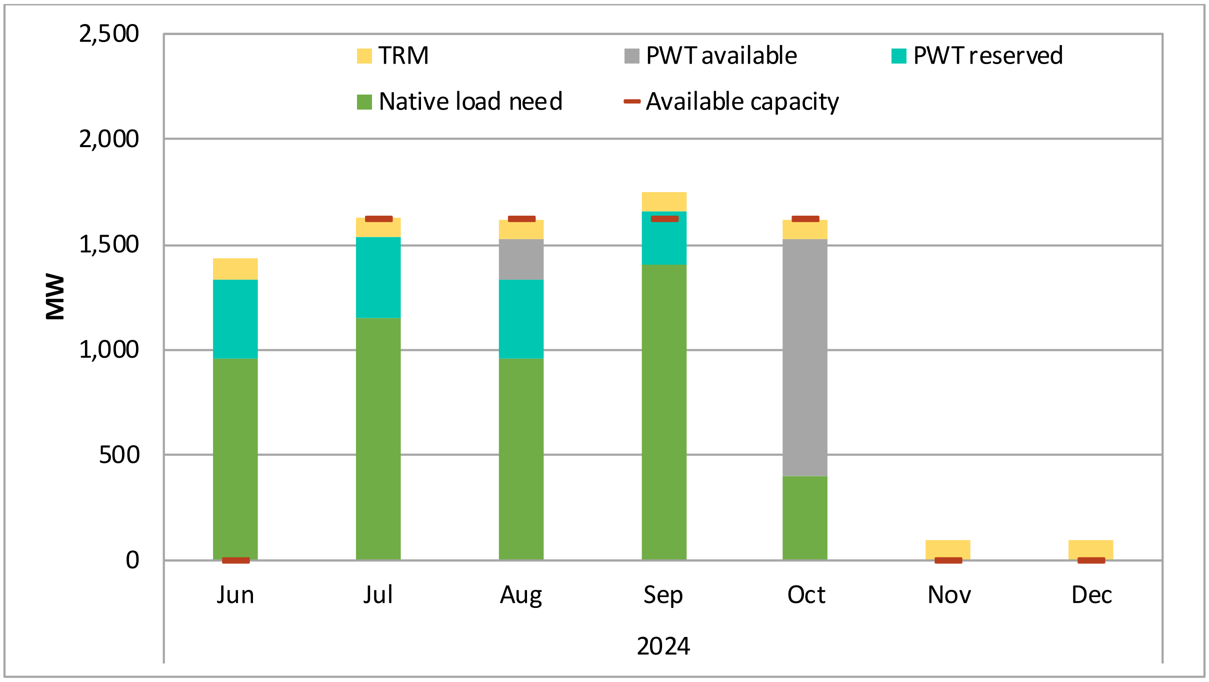


Figure 1.19 shows that the complete NOB intertie outage lasted for two days in June. This happened on June 22 and June 23. On the other days, available transmission capacity equaled NOB's total transmission capacity value, which indicates there were no outages and ETC/TOR rights on the intertie. The higher daily available transmission capacity values allowed for more priority wheel-through reservations on the other days (189 MW); however, there were no incremental priority wheel-through reservations between the monthly and daily timeframes.

Figure 1.19 Daily capacity rights at NOB

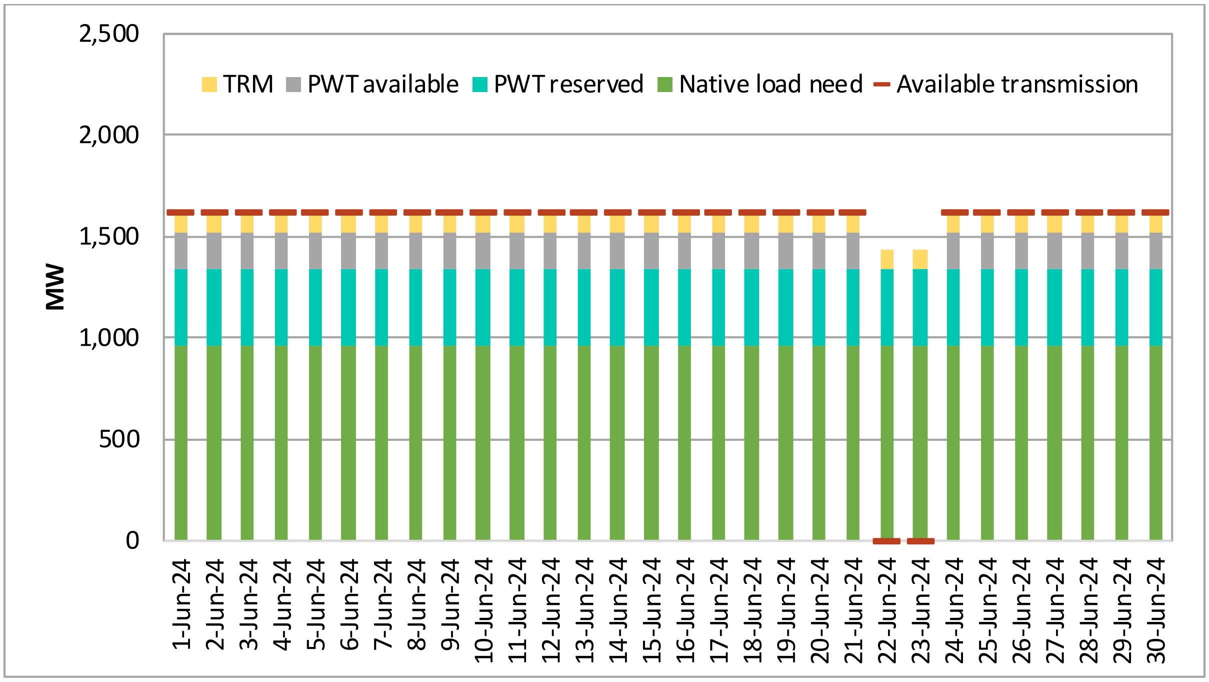
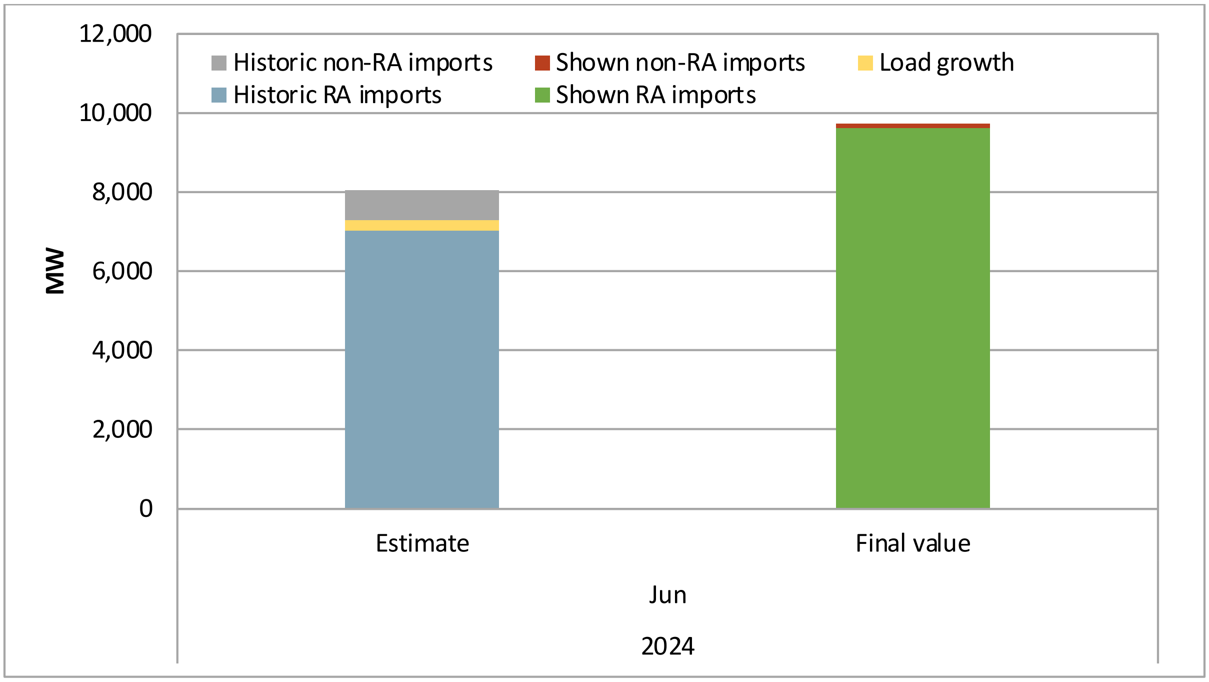


Figure 1.20 to Figure 1.22 show how native load need estimates compare to final import showings from load serving entities. In calculating available transmission capacity for priority wheel-throughs for future months, the ISO sets aside transmission capacity by estimating what native load needs will be. Ultimately, the amount of native load need capacity on interties is the sum of shown import resource adequacy (RA), as well as non-resource adequacy contracts that load serving entities (LSEs) may show the ISO. Final resource adequacy plans are due 30 days prior to the relevant month. Before this T-30 date, the ISO estimates how much intertie transmission capacity native loads will need by taking the maximum amount of shown import RA and non-RA contracted imports delivered on that intertie for the same month over the previous two years. In addition, the ISO accounts for the impact that load growth may have on native load needs by calculating a load growth value from the California Energy Commission's load forecast. This is because loads may have increased over the value that determined maximum resource adequacy obligations over the past two years. The ISO updates these native load need numbers after load serving entities submit their final resource adequacy plans.

Figure 1.20 shows the cumulative native load need estimates and final values on all of the interties for which the ISO made the calculations. The ISO estimated the native load need would be about 8,075 MW for June. This is comprised of about 7,056 MW of historic resource adequacy (RA) import showings, 220 MW of load growth, and 797 MW of non-resource adequacy import showings. This underestimated actual native load needs (9,727 MW) by about 1,650 MW, or 17 percent. The ISO did not underestimate native load need for all interties, but did in aggregate. This suggests load serving entities are currently more dependent on imports to fulfill capacity obligations than in previous years, and at a rate that is outpacing load growth.

Figure 1.20 Native load need capacity set aside vs. final import RA at all relevant interties



If the ISO overestimates actual native load needs, and the final resource adequacy and non-resource adequacy import showings are below the estimate based on historic data, the ISO will release excess transmission as available capacity that scheduling coordinators can reserve for priority wheel-throughs. Conversely, if the ISO underestimates native load needs, the ISO will reduce any previously unreserved available transmission capacity. However, if there is not any remaining available transmission capacity, then the ISO will revert to the originally calculated native load need estimate and will honor all of the previously reserved priority wheel-through capacity.

Figure 1.21 shows the native load need estimate and final value for the Malin intertie. The ISO estimated native loads would need about 1,087 MW of transmission capacity for June. This is comprised of 782 MW of historic resource adequacy import showings, 30 MW of load growth, and 275 MW of non-resource adequacy import showings. This underestimated actual native load needs (1,192 MW) by about 105 MW, or 9 percent.

Figure 1.21 Native load need estimate vs. final import RA at MALIN500

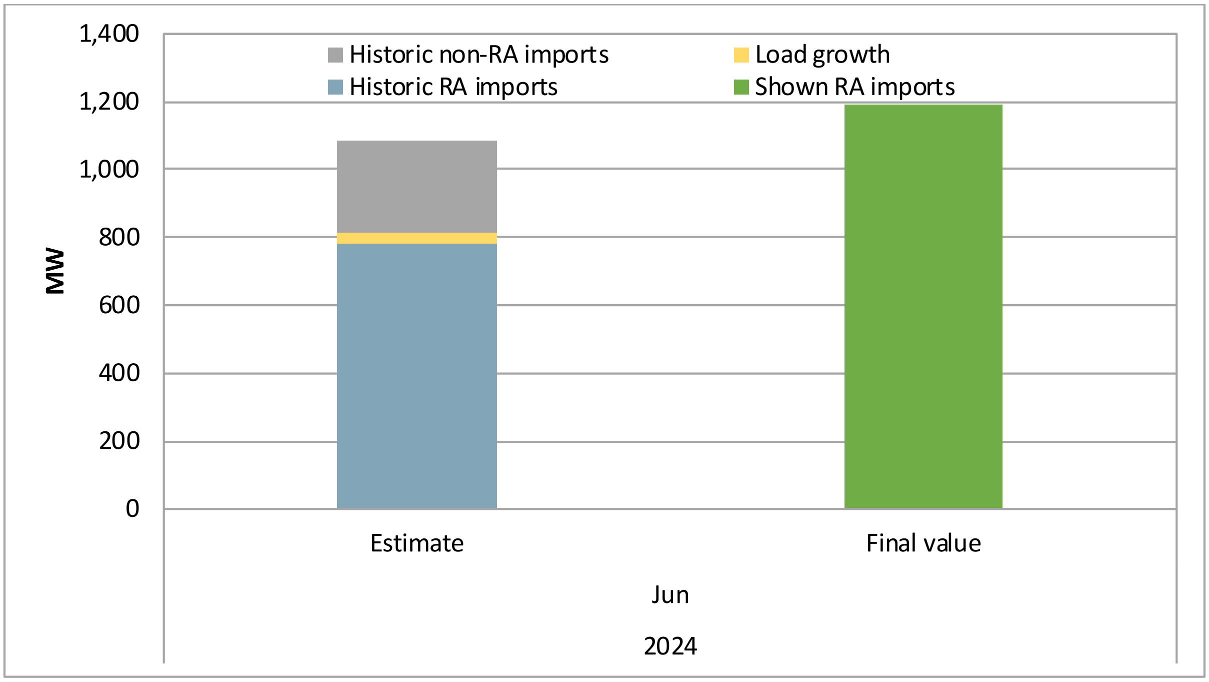


Figure 1.22 shows the native load need estimate and final value for the NOB intertie. The ISO estimated native loads would need about 467 MW of transmission capacity for June. This is comprised of 454 MW of historic resource adequacy import showings and 13 MW of load growth. This underestimated actual native load needs (958 MW) by about 491 MW, or 52 percent.

Figure 1.22 Native load need estimate vs. final import RA at NOB

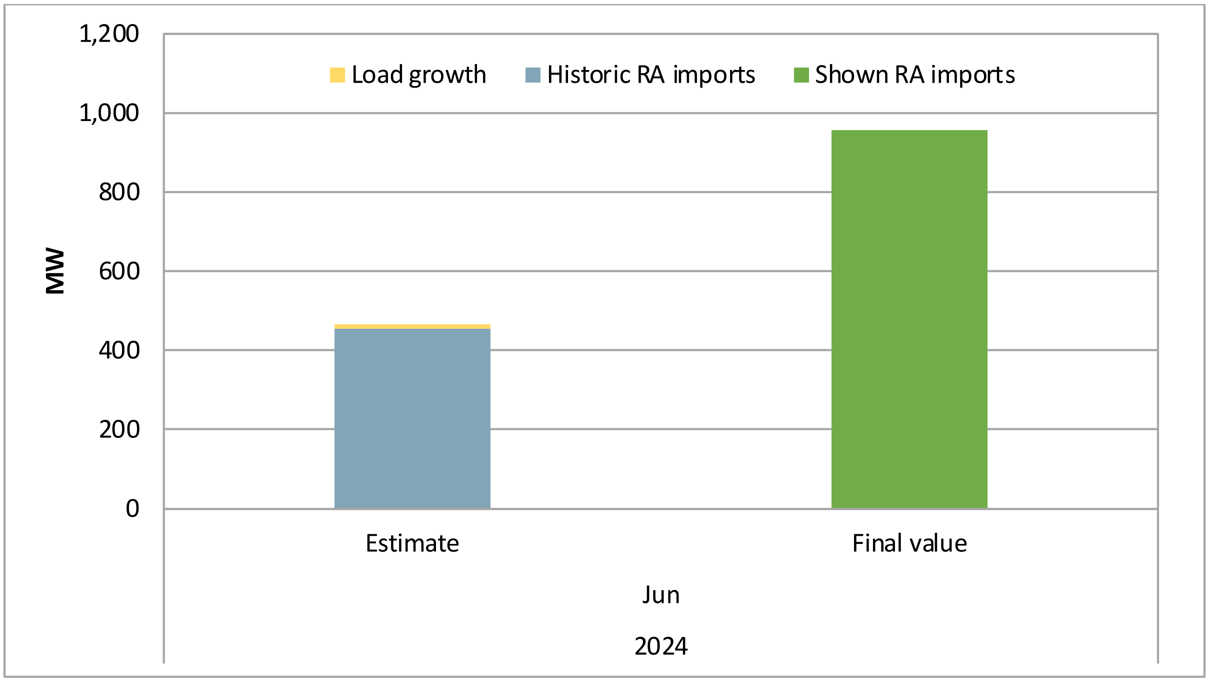


Figure 1.23 to Figure 1.26 show how scheduling coordinators used priority wheel-through reservations on Malin and NOB in June. Priority wheel-through reservation values (blue lines) are dependent on the contract parameters that scheduling coordinators submit to the ISO. Priority wheel-through awards can vary by hour. For example, a scheduling coordinator may show a contract with an outside load serving entity for a 16-hour block. In this case, the ISO would award the contract amount for 16 hours and zero MW for the other 8 hours. Integrated forward market (IFM) self-schedules (green bars) show how often, and to what extent, scheduling coordinators used their priority wheel-through awards. This analysis aggregates awards and schedules by intertie.

Figure 1.23 shows the hourly priority wheel-through awards and associated average hourly IFM self-schedules for Malin in June. The ISO awarded 72 MW of priority wheel-throughs for hours-ending 7 to 22, and zero MW for the other hours. On average for the month, scheduling coordinators self-scheduled about 7 MW, or about 10 percent, of priority wheel-through capacity during awarded hours in the IFM.

Figure 1.23 Average hourly PWT reservations vs. IFM self-schedules at MALIN500

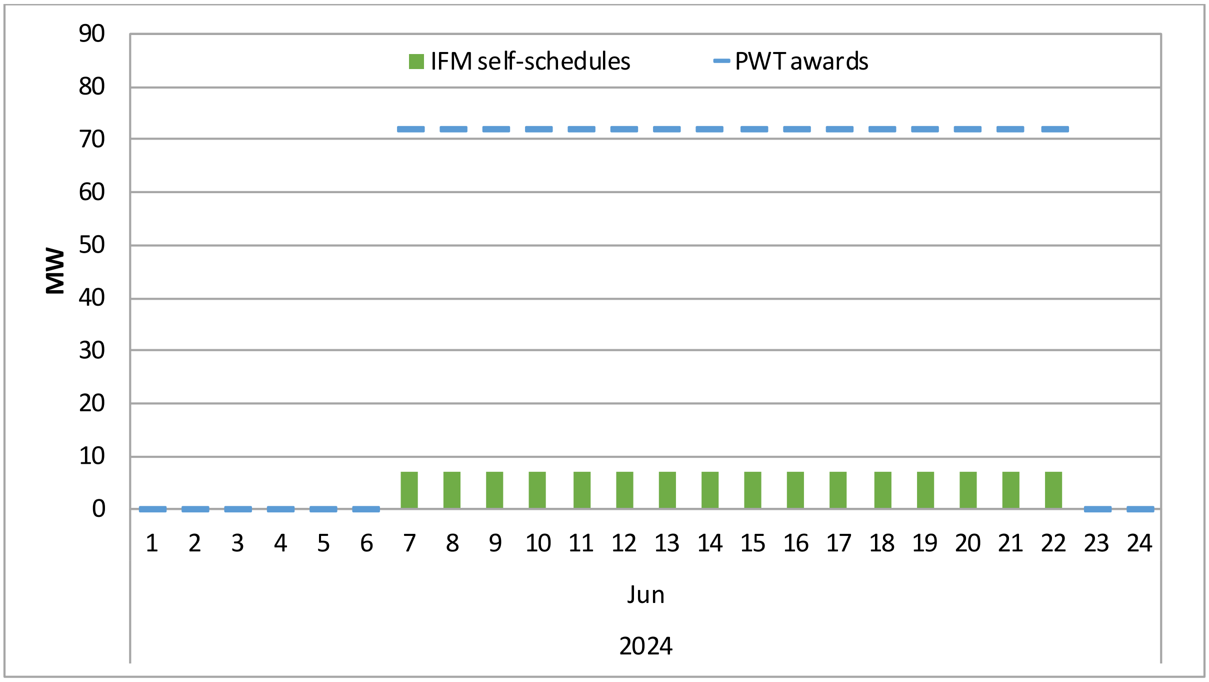


Figure 1.24 uses hour-ending 19 as a representative hour to show the low average priority wheel-through award usage is due to bidding infrequency—as opposed to bidding amount—on the Malin intertie. Scheduling coordinators bid the full PWT award amount (72 MW) in the IFM on three days in June, and did not bid the other days.

Figure 1.24 Hour-ending 19 PWT reservations vs. IFM self-schedules at MALIN500

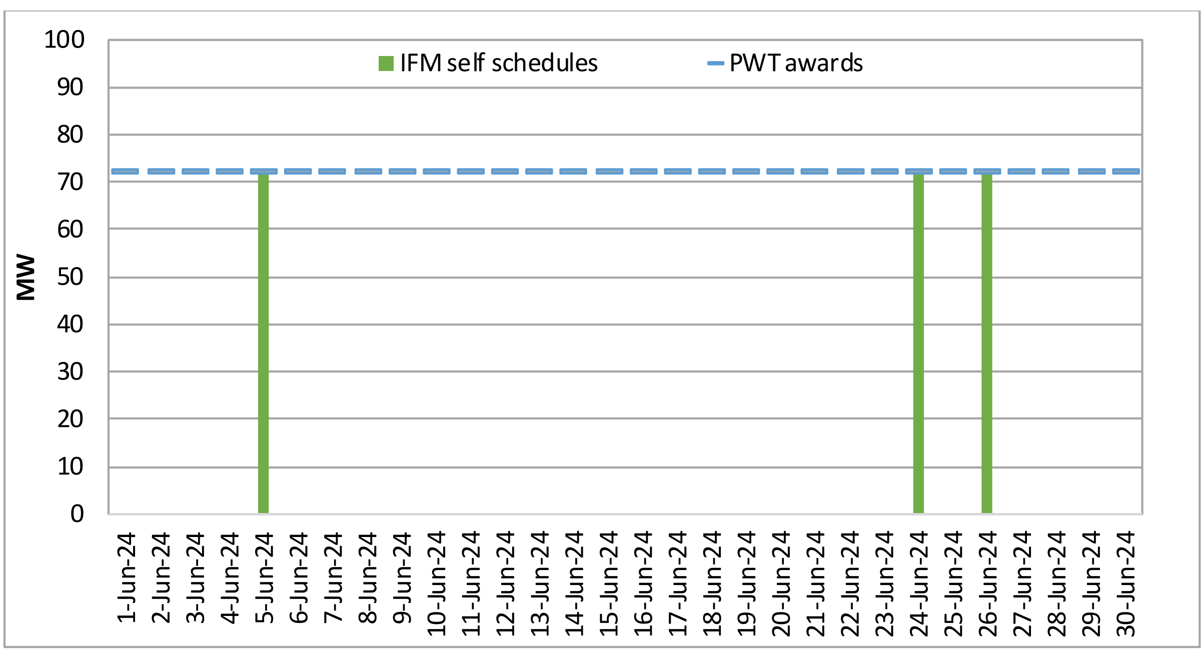


Figure 1.25 shows the hourly priority wheel-through awards and associated average hourly IFM self-schedules for NOB in June. The ISO awarded 128 MW for priority wheel-throughs for hours-ending (HE) 7 to 14, 153 MW for HE15-HE18, 378 MW for HE19-HE22, and zero MW for the other hours. On average for the month, scheduling coordinators self-scheduled about 4 MW, or about one to three percent, of priority wheel-through capacity during awarded hours in the IFM.

Figure 1.25 Average hourly PWT reservation vs. IFM self-schedules at NOB

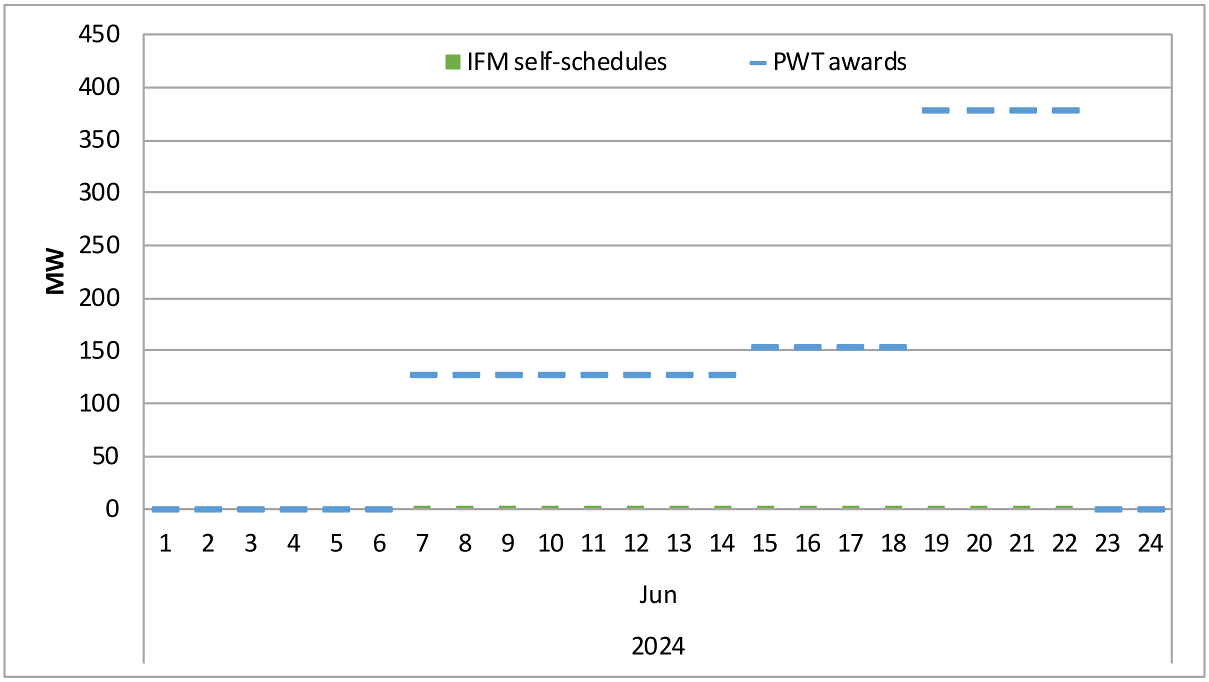
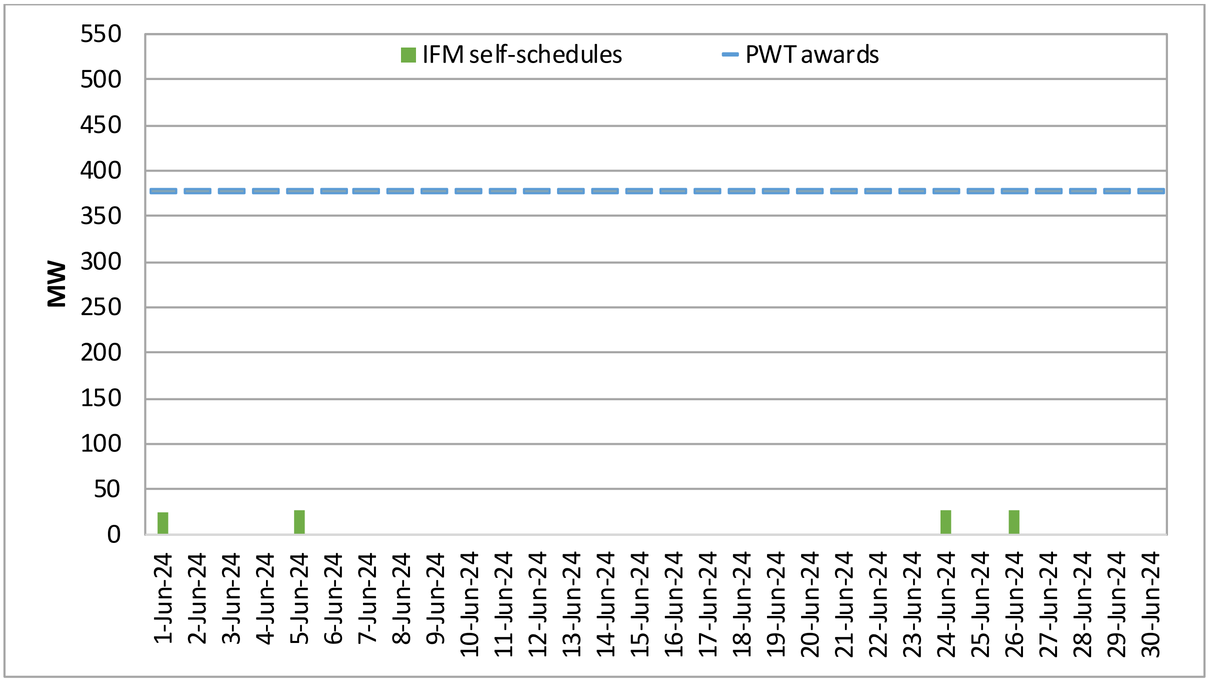


Figure 1.26 uses HE19 as a representative hour to show the low average priority wheel-through award usage is due to both bidding infrequency and bidding amount on the NOB intertie. Scheduling coordinators bid 25-28 MW (or about seven percent of total priority wheel-through awards) during HE19 in the IFM on four days in June and did not bid the other days.

Figure 1.26 Hour-ending 19 PWT reservations vs. IFM self-schedules at NOB



1.4 Price variability

In the second quarter of 2024, instances of prices exceeding $250/MWh decreased to 0.02 percent from 0.15 percent in the same quarter of 2023. The proportion of intervals with zero or negative prices increased to 16 percent from 9 percent.

High prices

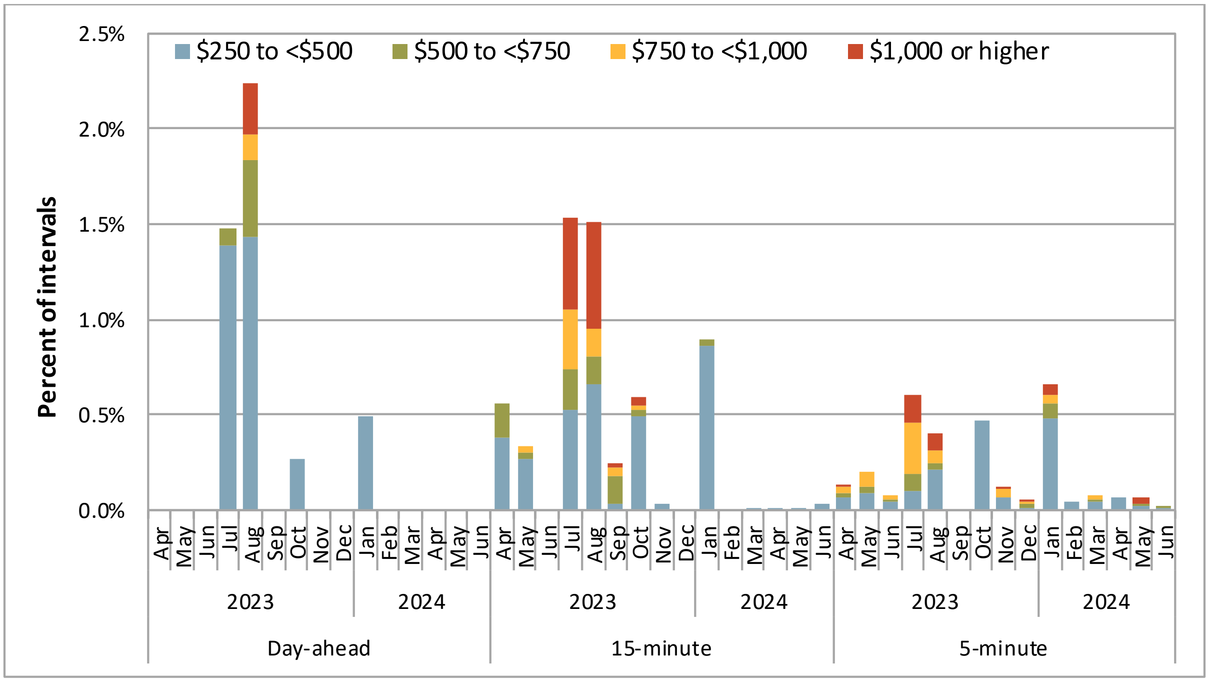
Figure 1.27 shows the frequency of high prices across all three markets for the three largest California ISO balancing area load aggregation points (LAP) by month between April 2023 and June 2024.

In the day-ahead market, there were no occurrences of high prices exceeding $250/MWh in this quarter, consistent with the absence of such prices in the same quarter last year.

The 15-minute market had a lower frequency of price spikes in this quarter compared to the second quarter of 2023. The percentage of intervals with prices above $250/MWh was 0.02 percent, a decrease from 0.3 percent in the same quarter of 2023.

Similarly, the 5-minute market had a reduced frequency of high prices this quarter. The percentage of intervals with prices above $250/MWh decreased to 0.05 percent in the second quarter of 2024 from 0.14 percent in the same quarter of the previous year.

Figure 1.27 Frequency of high prices ($/MWh) by month



High price spikes typically occur during extreme load conditions. However, in the second quarter of both this year and last year, the load remained relatively moderate compared to the higher load days seen in the third quarter.

Negative prices

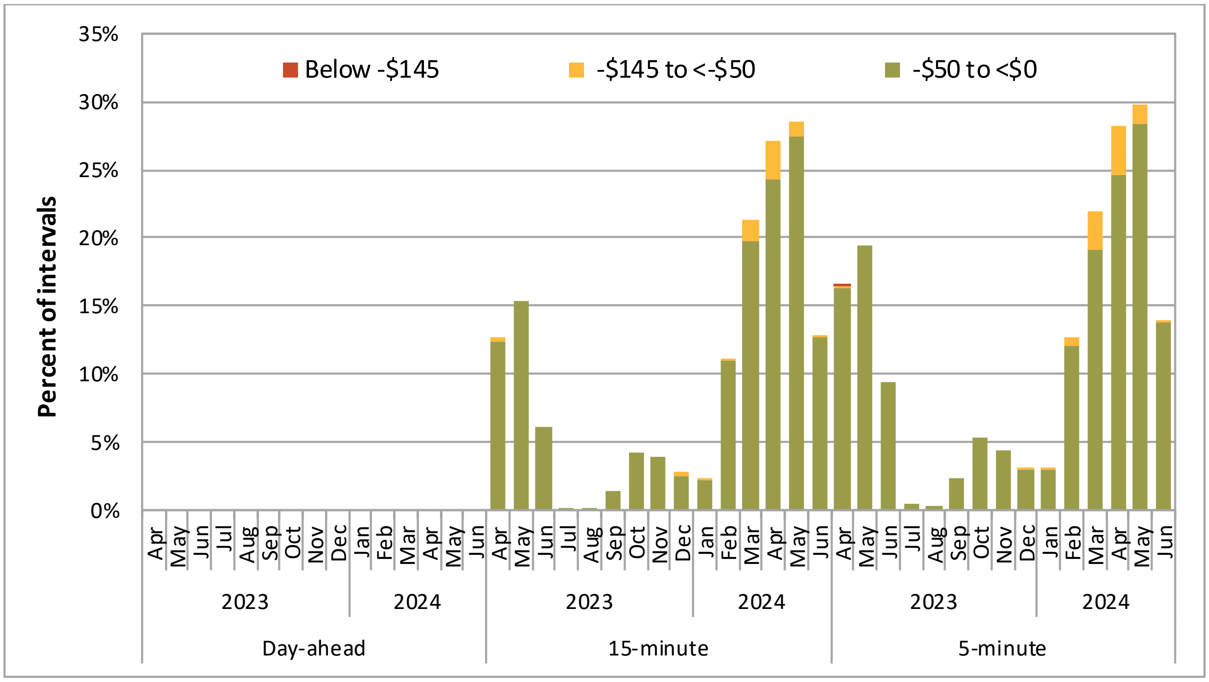
Figure 1.28 shows the frequency of negative prices across all three markets for the three largest load aggregation points (LAPs) by month between April 2023 and June 2024. On average, across the day-ahead, 15-minute, and 5-minute markets, the frequency of negative prices significantly increased from 9 percent to 16 percent in the second quarter of 2024 compared to the same period in 2023.

Negative prices tend to be most common when renewable production is high and demand is low. This is because in these scenarios, renewable resources are more likely to be the marginal energy source, and low-cost renewable resources often bid at or below zero dollars.

In the 15-minute market, the frequency of negative prices increased to 23 percent this quarter compared to 11 percent in the second quarter of 2023. In the 5-minute market, negative prices increased to 24 percent this quarter compared to 15 percent in the second quarter of 2023. There were no negative prices in the day-ahead market during the second quarters of 2023 or 2024.

The rise in negative pricing in the second quarter of 2024 compared to the same quarter of 2023 can be attributed to lower demand and higher renewable generation around mid-day in 2024.

Figure 1.28 Frequency of negative prices ($/MWh) by month



1.5 Convergence bidding

Convergence bidding is designed to align day-ahead and 15-minute market prices by allowing financial arbitrage between the two markets. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. In the second quarter, financial entities and marketers continued to receive the vast majority of profits from convergence bidding.

1.5.1 Convergence bidding revenues

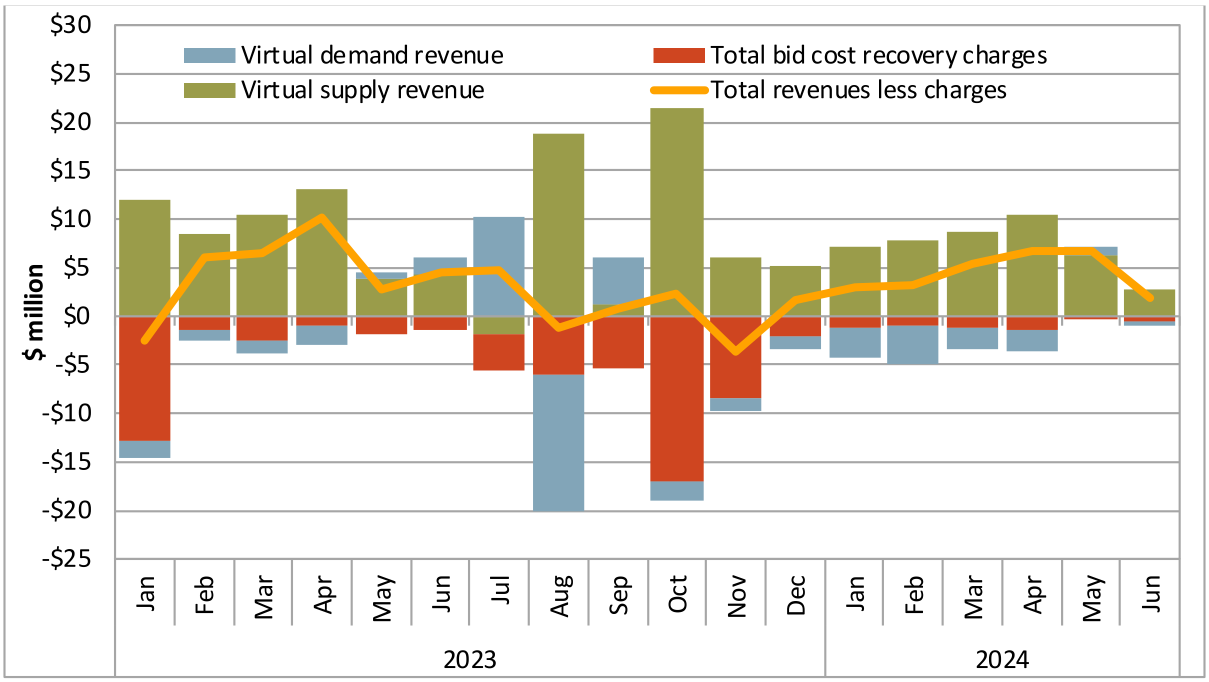
Net revenues for convergence bidders were about $15.4 million for the second quarter, after inclusion of about $2.2 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[21] Figure 1.29 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

- Total market revenues were positive during all months of the quarter. Net revenues for the quarter overall represent a 13 percent decrease compared to the second quarter of 2023.
- Virtual demand revenues were about -$2.1 million, $810,000, and -$580,000 for April, May, and June, respectively.
- Before accounting for bid cost recovery, virtual supply revenues were about $10.4 million, $6.3 million, and $2.8 million for April, May, and June, respectively.

[21] Figures and data provided in this section are preliminary and may be subject to change.

Bid cost recovery charges allocated to virtual bids were about $1.4 million, $340,000, and $430,000 for April, May, and June, respectively. The majority of bid cost recovery allocated to virtual bidding participants in this quarter was charged to the residual unit commitment (RUC) tier 1 allocation, which helps offset costs related to periods with net virtual supply. Virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in RUC. When market revenues do not cover the commitment costs of resources committed in RUC, the resources receive bid cost recovery payments, and some of this bid cost recovery is allocated to virtual supply during periods with net virtual supply.

Figure 1.29 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.1 compares the distribution of convergence bidding cleared volumes and revenues, before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.[22,23]

After accounting for bid cost recovery, nearly all virtual bidding revenue was split between financial entities and marketers, at around 90 percent and 10 percent, respectively. Financial entities and

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22 This table summarizes data from the California ISO settlements database and is based on a snapshot of a given day after the end of the period. DMM strives to provide the most up-to-date data before publishing. Updates occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. More detail on the settlement cycle can be found on the California ISO settlements page: http://www.caiso.com/market/Pages/Settlements/Default.aspx

23 DMM has defined financial entities as participants who do not own physical power, and only participate in the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the California ISO markets as physical generators and load serving entities, respectively. Marketers include participants on the interties, and participants whose portfolios are not primarily focused on physical or financial participation in the California ISO market.

marketers accounted for about 78 percent and 19 percent, respectively, of the cleared volume of virtual trades in the second quarter.

Table 1.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2024 Q2								
Financial	3,014	3,239	6,253	-$0.84	$16.26	-$1.37	$14.89	$14.05
Marketer	731	803	1,534	-$1.06	$2.94	-$0.38	$2.56	$1.50
Physical load	11	55	66	$0.03	$0.19	-$0.10	$0.09	$0.12
Physical generation	33	142	175	$0.00	$0.13	-$0.36	-$0.23	-$0.23
Total	**3,789**	**4,239**	**8,028**	**-$1.87**	**$19.52**	**-$2.21**	**$17.31**	**$15.44**

1.6 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the second quarter of 2024 was 3 percent lower than the same quarter of 2023. Although total volumes were lower, operator adjustments to the RUC procurement target increased 104 percent compared to the second quarter of 2023. This was in large part because of a change in the methodology for determining the adjustments in the summer of 2023.[24]

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real-time. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of physical supply cleared in the day-ahead market and the amount of physical supply that may be needed to meet actual real-time demand.

Residual unit commitment requirement

The quantity of residual unit commitment procured is determined by several automatically calculated components, as well as any adjustments that operators make to increase residual unit commitment requirements for reliability purposes. Figure 1.30 shows the average incremental residual unit commitment requirement by component relative to the day-ahead market.

The green bars reflect the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply decreased each month over the quarter from 850 MW per hour in April to about 40 MW per hour in June.

The blue bar in Figure 1.30 depicts the day-ahead forecasted load versus cleared day-ahead capacity, which includes both physical supply and net virtual supply. This represents the difference between the CAISO day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). This factor contributed towards decreasing residual unit commitment requirements in April and May by about 440 MW per hour and 40 MW per hour, respectively; however, in June, this increased the

[24] The methodology is based on the Imbalance Reserve product proposed as part of the California ISO day-ahead market enhancements initiative (DAME). More information on the results of this change can be found in the Q3 *Market Performance and Planning Forum* presentation, California ISO, September 27, 2023, slides 210-227: https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Sep27-2023.pdf

requirement by about 600 MW due to less load clearing the IFM than the day-ahead load forecast on average.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market, illustrated by the yellow bars in Figure 1.30.

Lastly, operators will often increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply. The red bars in Figure 1.30 show the average adjustment to the residual unit commitment requirement. During 2023 and 2024, there were significant changes to how these amounts were determined. The operator adjustments and the changes in the methodology are described in the following section.

Figure 1.31 shows the hourly distribution of these operator adjustments during the second quarter of 2024. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour.

Figure 1.30 Average incremental residual unit commitment requirement by component

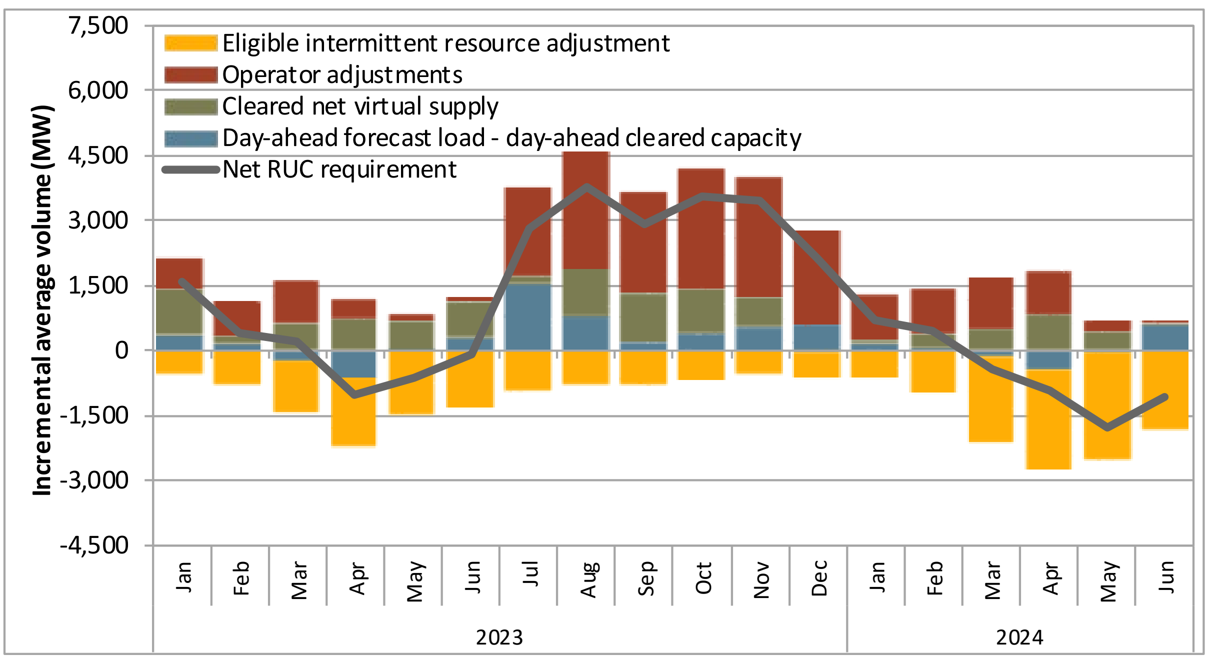
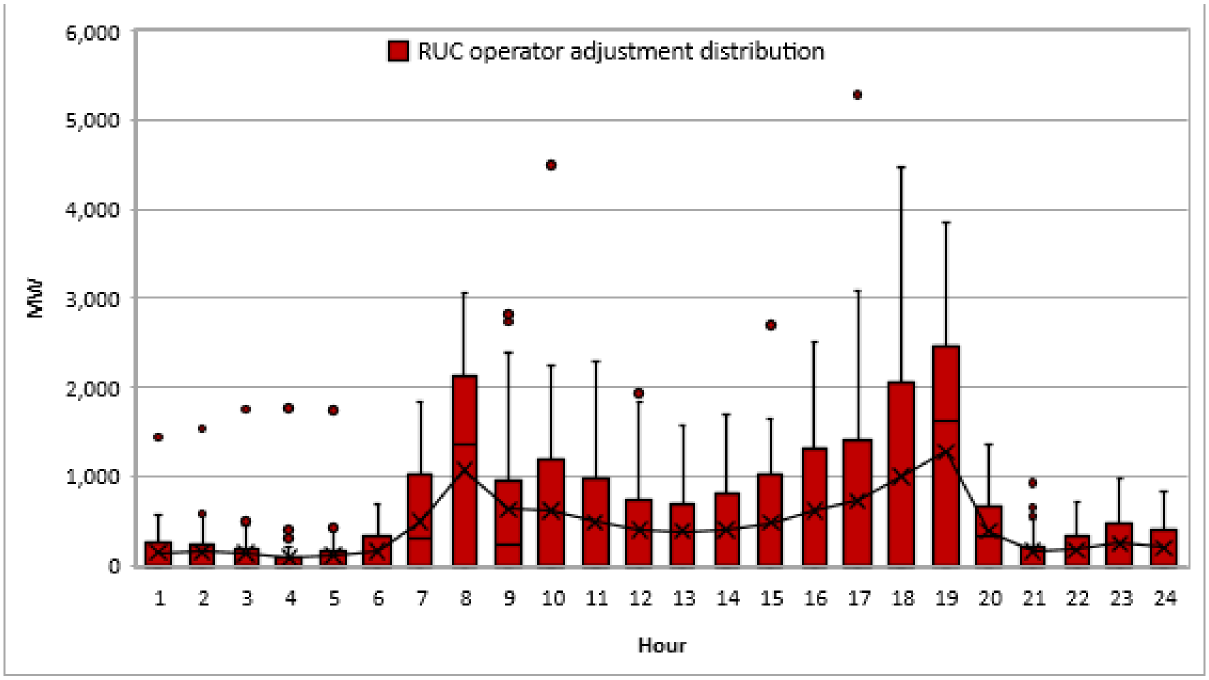


Figure 1.31 Hourly distribution of residual unit commitment operator adjustments (April–June 2024)



Residual unit commitment operator adjustments

Starting on June 30, 2023, the ISO began using the *mosaic quantile regression* method to calculate the RUC adjustments. This calculation is similar to that used to measure flexible ramping product uncertainty, except that it is based on the historical difference between the *day-ahead* and real-time market forecasts for load, solar, and wind uncertainty. This calculation was originally based on the 97.5th percentile of net load uncertainty that might materialize in real-time.

On December 21, the ISO implemented a new operating procedure that modifies the percentile target for calculating the adjustment based on conditions in the system. Under *normal* conditions, the RUC adjustments were calculated based on the 50th percentile of upward net load uncertainty. Operators could adjust the calculation any day to instead be based on the 75th or 97.5th percentile during periods of higher forecast uncertainty or extreme conditions.

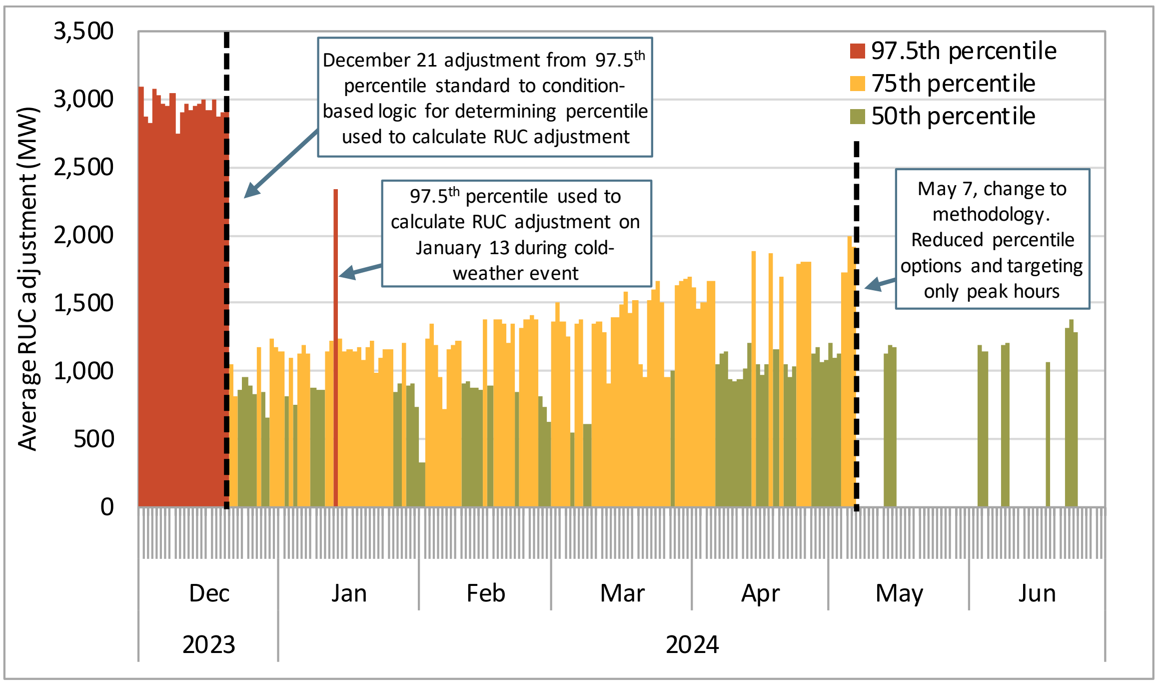
On May 7, 2024, the ISO adjusted the operating procedure again for calculating the adjustments used in the residual unit commitment process.[25] The changes limited the adjustments to only the peak morning and peak evening hours as well as added percentile options below the 50th percentile. Under periods with moderate operational uncertainty, the procedure calls for using a RUC adjustment that will procure enough capacity to cover uncertainty 50 percent of the time (i.e., the 50th percentile of upward uncertainty). During periods with low or very low operational uncertainty, the procedure instead specifies use of either the 25th percentile or no adjustment, respectively. This indicates that there is still

[25] See *CAISO Operating Procedure 1210*, May 7, 2024, pp 12-13: https://www.caiso.com/Documents/1210.pdf

a substantial degree of judgment and discretion used in setting the RUC adjustment, even when using the mosaic quantile regression method to calculate the uncertainty component.

Figure 1.32 shows the average RUC adjustment on each day since December 2023 during the peak morning and evening hours (hours 7 to 9 and 19 to 21). Starting on May 7, operator adjustments outside the peak hours have been zero. The figure also shows the estimated percentile that was used to determine the additional requirements for the peak hours of each day.[26] Between May 7 and June 30, the average operator adjustment in the peak hours was zero on 44 days (80 percent). On these days, perceived risk or uncertainty was low such that no RUC adjustment was applied.[27] On the remaining days during this period, the 50th percentile was presumed to be applied during the peak hours.

Figure 1.32 Average residual unit commitment adjustment by day (Peak morning and evening hours, December 1, 2023 to June 30, 2024)



[26] Data on the percentile used to calculate the RUC adjustments for each day was not available. The percentiles shown here were estimated from the magnitude of the adjustments and DMM recalculation of the uncertainty.

[27] As noted in the day-ahead market operating procedure, dispatchable resources in the market, WEIM transfers, or regulating resources can instead manage uncertainty during periods with lower uncertainty. In some cases, the use of the 25th percentile for procuring uncertainty may have resulted in a negative value that was capped at zero, resulting in the same outcome as no operator adjustment.

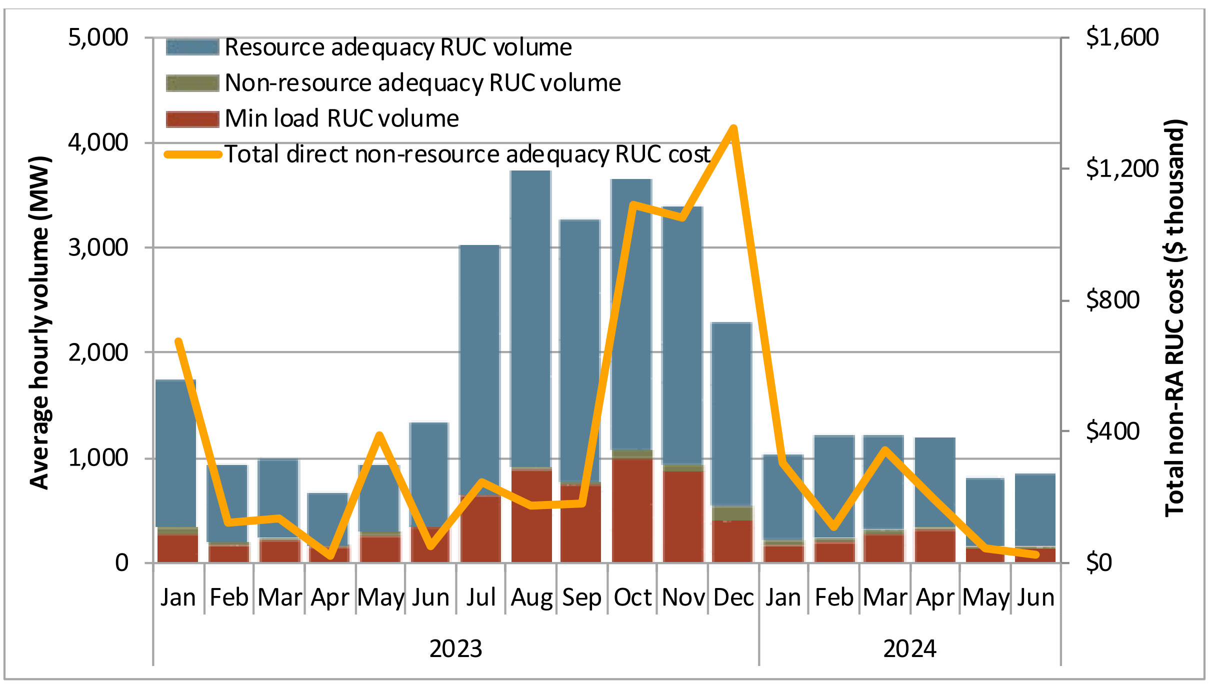
Given the importance of RUC adjustments in terms of costs and reliability, DMM recommends that the CAISO balancing area continue working on a method for determining the appropriate level of RUC load adjustment.

Residual unit commitment procurement and costs

Figure 1.33 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The average residual unit commitment procurement for the quarter decreased by 3 percent to about 950 MW in the second quarter of 2024, from an average of about 981 MW in the same quarter of 2023. Of the 950 MW capacity, the capacity committed to operate at minimum load averaged about 200 MW.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units receiving awards in this process receive RUC capacity payments.[28] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.33. In the second quarter of 2024, these costs were about $260,000, about 56 percent of the costs in the same quarter of 2023.

Figure 1.33 Residual unit commitment costs and volume



28 If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

1.7 Ancillary services

Ancillary service payments totaled $18.4 million, a 40 percent decrease from the same quarter last year. Average requirements were higher for regulation down and regulation up, while those for operating reserves decreased compared to the second quarter of 2023.

1.7.1 Ancillary service requirements

The California ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum operating reliability criteria, and North American Electric Reliability Corporation's (NERC) control performance standards.

The California ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions.[29] Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency, or (3) 10 percent of forecasted solar production.[30] Operating reserve requirements in real-time are calculated similarly, except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

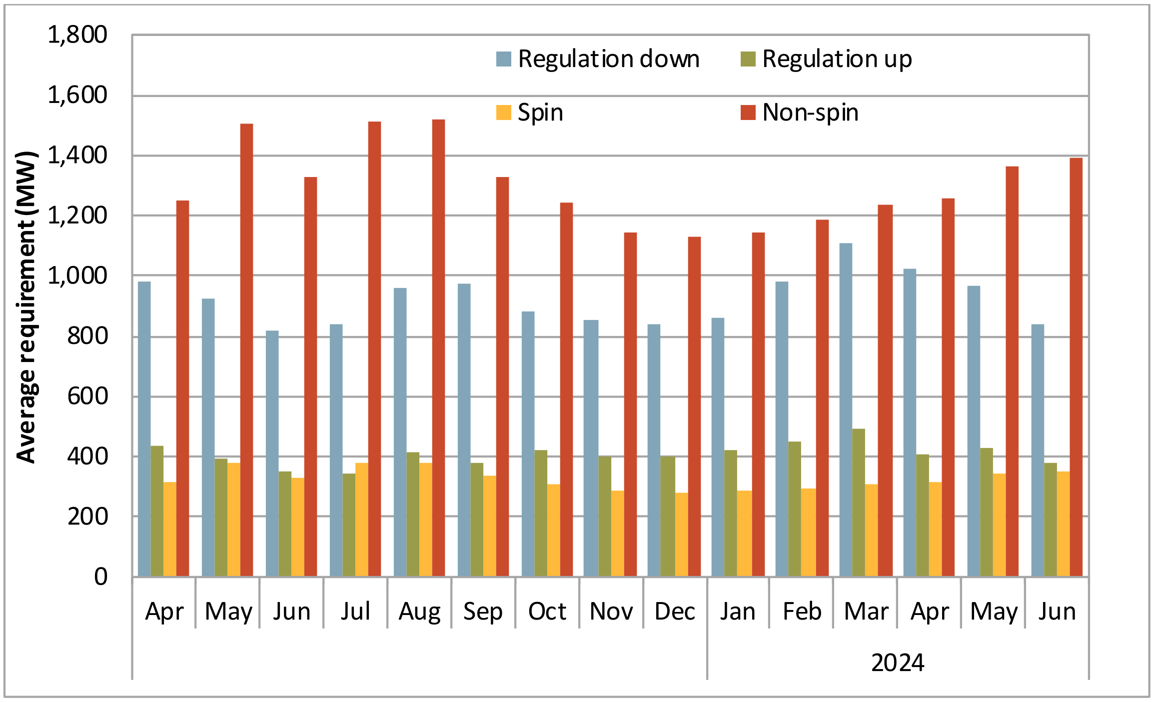
Starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. Since the second quarter of 2023, CAISO operators have procured 20 percent of operating reserves as spinning reserves and the rest as non-spinning reserves.

Figure 1.34 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation down and regulation up requirements increased 4 percent and 3 percent, respectively, compared to the second quarter of 2023. Average requirements for operating reserves decreased 2 percent compared to the second quarter of 2024.

29 More information on ancillary services requirements and procurement for internal and expanded regions is available in: *2020 Annual Report on Market Issues & Performance*, Department of Market Monitoring, August 2021, p 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

30 As of April 2024, CAISO operators lowered the contribution of forecasted solar production in determining day-ahead operating reserve requirements from 15 percent to 10 percent. CAISO operators determined they could change the requirement because of the growing fleet of new solar resources that can respond quickly to voltage issues.

Figure 1.34 Average monthly day-ahead ancillary service requirements



1.7.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California ISO balancing area pays a predetermined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger. No scarcity events occurred in the second quarter of 2024.

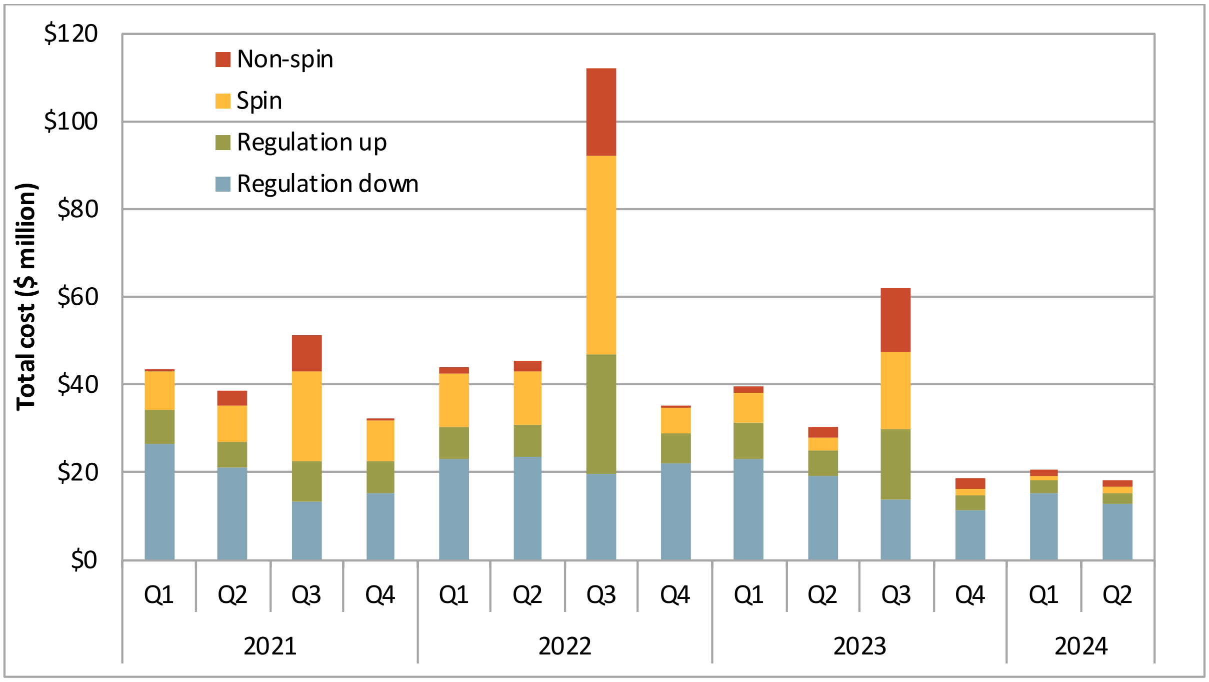
1.7.3 Ancillary service costs

Ancillary service payments totaled $18.4 million in the second quarter of 2024, around $12 million less than the same quarter of the previous year.

Figure 1.35 shows the total cost of procuring ancillary service products by quarter.[31] Payments for regulation down, regulation up, spinning reserve, and non-spinning reserve decreased 34 percent, 51 percent, 59 percent, and 42 percent respectively, compared to the second quarter of 2023. Regulation down payments had the largest absolute decrease, at around $6.6 million.

31 The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. As noted elsewhere in the report, settlements values are based on statements available at the time of drafting and will be updated in future reports.

Figure 1.35 Ancillary service cost by product



1.8 Congestion

This section presents analysis of day-ahead and real-time market internal congestion.[32] Additionally, it examines the impact of day-ahead congestion on California ISO balancing area interties. Analysis of WEIM transfer congestion impact is addressed in Section 2.2.

Total day-ahead market congestion rent decreased to $164 million in the second quarter of 2024, similar to the $162 million in the same quarter of 2023. Intertie congestion rent was $13 million of the $164 million total, down from $15 million in the second quarter of 2023.

In the second quarter of 2024, congestion on internal constraints had a greater impact on local area price separation than in the same quarter of 2023. The overall congestion pattern continued to show a south-to-north flow within California and across the WEIM. In the day-ahead market, internal congestion increased prices in PG&E and decreased pries in SCE and SDG&E. In the real-time market, congestion increased prices in the Pacific Northwest, Intermountain West, and Northern California and decreased prices in the Desert Southwest and Southern California.

The following sections provide an assessment of the frequency and impact of congestion on major load node prices in the day-ahead, 15-minute, and 5-minute markets.

Congestion in a nodal energy market occurs when the market model determines that flows have reached or exceeded the limit of a transmission constraint. Within areas where flows are constrained by

[32] This report defines internal congestion as congestion on any constraint within a balancing authority area. Therefore, the effect of internal congestion on the CAISO balancing area may include effects of congestion from transmission elements within WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission-constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

The impact of congestion on each pricing node in the system is calculated as the product of the shadow price of that constraint, and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[33]

1.8.1 Congestion in the day-ahead market

Congestion rent and loss surplus

Figure 1.36 shows that in the second quarter of 2024, congestion rent and loss surplus was $164 million and $20 million, respectively.[34] These amounts represent an increase of 1 percent and a decrease of 47 percent relative to the same quarter of 2023. The significant reduction in the loss component is due mainly to lower prices in this quarter compared to the same period in 2023.

Congestion rent consists of rents from internal constraints and interties. Intertie congestion increased slightly from $10 million to $13 million this quarter compared to the same quarter in 2023.

In the day-ahead market, hourly congestion rent collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day.

The 47 percent decrease in the loss surplus compared to Q2 2023 can largely be attributed to lower system energy costs. The loss surplus represents the difference between what load pays for the loss component of the locational marginal price (LMP) and what generation gets paid from the loss component of LMP in the day-ahead market. The magnitude of the loss component of LMP is directly proportional to the energy component of LMP, so the loss surplus values should correlate with electricity prices and load quantities over time. In settlements, the loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[35]

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33 This approach does not include price differences that result from transmission losses.

34 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

35 For more information on marginal loss surplus allocation, refer to: *Business Practice Manual Change Management – Settlements and Billing,* CG CC6947 IFM Marginal Losses Surplus Credit Allocation, California ISO: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

Figure 1.36 Day-ahead congestion rent and loss surplus by quarter (2022–2024)

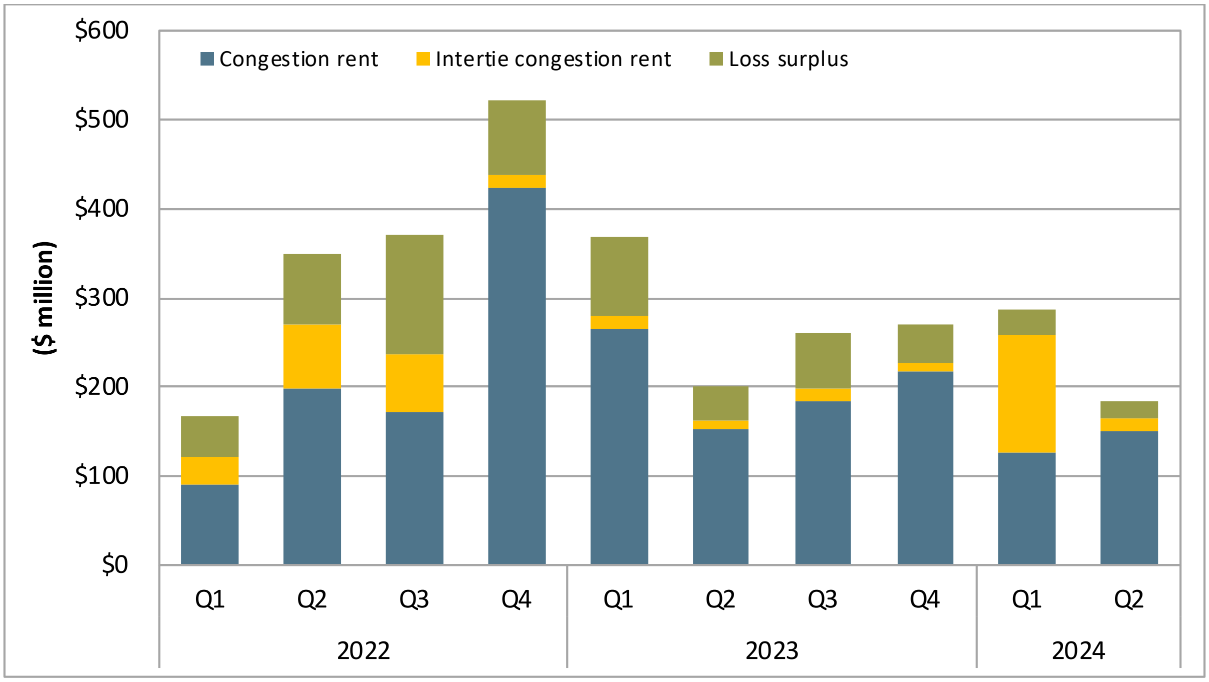

Figure 1.37 shows the overall impact of congestion on day-ahead prices in each load area from 2022 to 2024. Figure 1.38 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in this quarter was higher than during the same quarter of 2023.
- Day-ahead congestion increased quarterly average prices in PG&E by $5.96/MWh, while it decreased average SCE and SDG&E prices by $4.93/MWh and $2.36/MWh, respectively.[36]
- The percentage of hours in which congestion impacts DLAP prices has continued to increase, with the PG&E DLAP experiencing congestion in an average of 81 percent of the hours.
- The primary constraints affecting day-ahead market prices were the Moss Landing-Las Aguilas #1 230kV line, Gates-Midway #1 500kV line, and Los Banos-Gates #1 500kV line.

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[36] Language in the report describing congestion as "increasing" or "decreasing" a price is describing the change relative to the particular reference bus used in that market. The ISO uses a particular reference bus—distributed amongst load nodes according to the load at each node's percentage of total load. However, in theory, any node could be used as the reference bus, and changing the reference bus would change the value of how much congestion "increased" or "decreased" prices at a node relative to the reference bus. While the specific value of an increase or decrease in congestion price is relative to the reference bus, the *difference* between the impact of congestion on one node and another node is not dependent on the reference bus. Therefore, in assessing the impacts of congestion on prices, DMM suggests the reader focus on the difference of the price impacts between nodes or areas, and not on the specific value of an increase or decrease to one node or area.

Figure 1.37 Overall impact of congestion on price separation in the day-ahead market

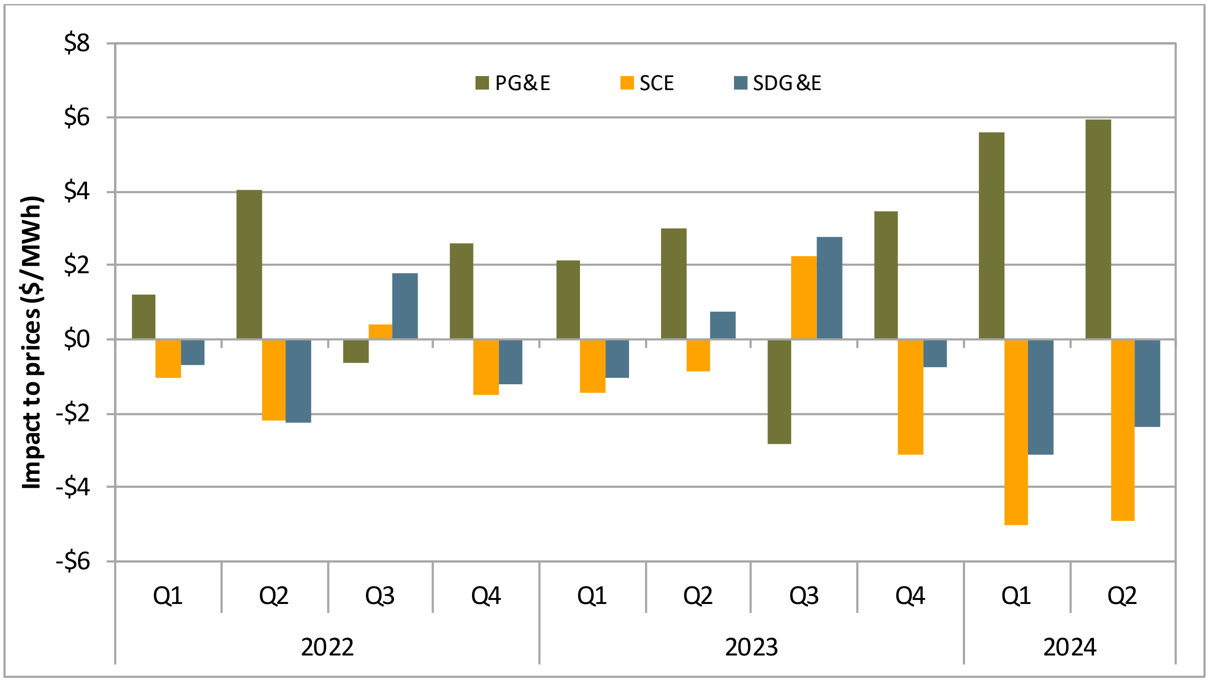
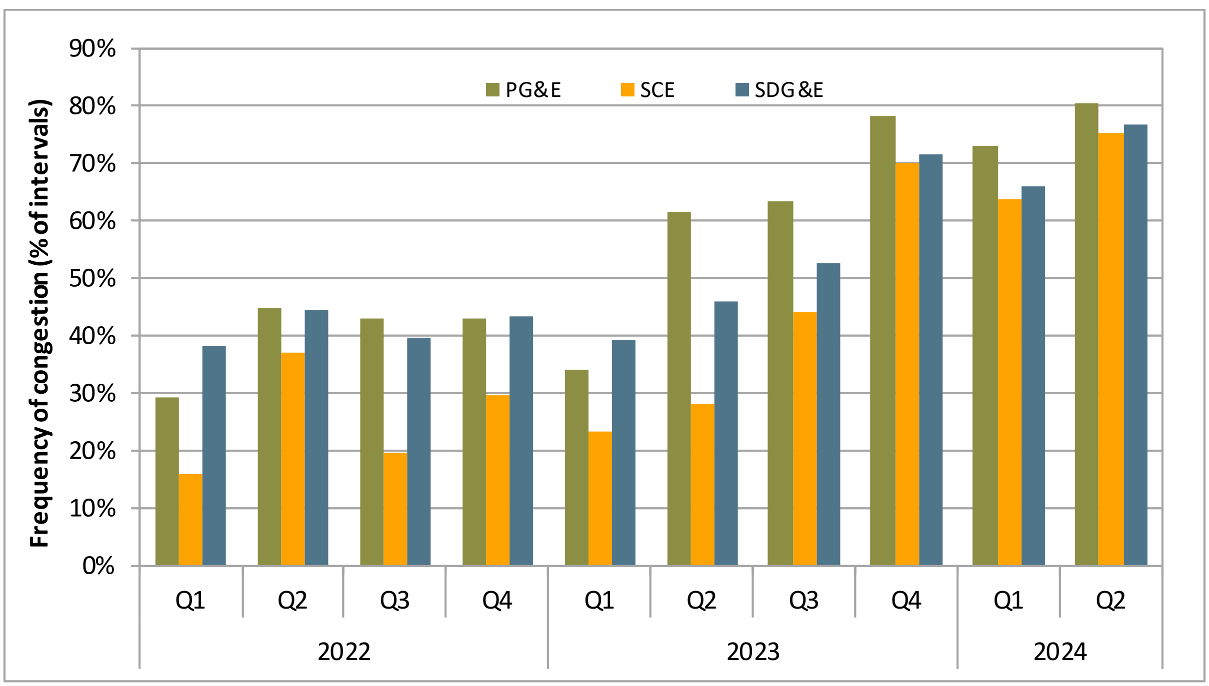


Figure 1.38 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion effect on price separation during the quarter by constraint.[37] The table presents the top 25 most congested lines, ranked by their impact, while the "Other" category shows the average impact of the remaining constraints. Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact—the stronger the shading, the greater the impact in either the positive or the negative direction.

The constraints with the greatest impact on day-ahead price separation for the quarter were Moss Landing-Las Aguilas #1 230kV line, Gates-Midway #1 500kV line, and Los Banos-Gates #1 500kV line.

Moss Landing-Las Aguilas #1 230 kV line

The Moss Landing-Las Aguilas #1 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in about 45.5 percent of hours. For the quarter, the constraint increased average PG&E prices by about $2.28/MWh, and decreased average SCE and SDG&E prices by $1.69/MWh and $1.6/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 8 through hour-ending 18.

Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) bound in 9.5 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $1.55/MWh and decreased average SCE and SDG&E prices by $1.24/MWh and $1.15/MWh, respectively. This transmission line was generally binding during solar production hours, from hour-ending 10 through hour-ending 17.

Los Banos-Gates #1 500 kV line

The Los Banos-Gates #1 500 kV line (30050_LOSBANOS_500_30055_GATES1_500_BR_1_2) bound in 9.1 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $0.71/MWh and decreased average SCE and SDG&E prices by $0.55/MWh and $0.51/MWh, respectively. This transmission line was generally binding during solar production hours, from hour-ending 9 through hour-ending 18.

[37] DMM calculates the congestion impact from constraints by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *"Other"*. In addition, constraints with price impact of less than $0.01/MWh for all load aggregation points (LAPs) in the region are grouped in "*Other*".

Table 1.2 Impact of congestion on overall day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	45.5%	2.28	-1.69	-1.60
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	9.5%	1.55	-1.24	-1.15
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	9.1%	0.71	-0.55	-0.51
6410_CP10_NG	7.4%	0.63	-0.50	-0.47
MIGUEL_BKs_MXFLW_NG	4.7%	-0.12	-0.04	0.83
30790_PANOCHE_230_30900_GATES_230_BR_2_1	8.8%	0.30	-0.22	-0.21
35621_IBM-HRJ_115_35642_METCALF_115_BR_1_1	3.6%	0.13	-0.11	-0.11
7820_TL23040_IV_SPS_NG	4.3%	-0.03	-0.01	0.30
30900_GATES_230_30970_MIDWAY_230_BR_1_1	2.2%	0.15	-0.10	-0.09
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	2.6%	-0.04	-0.01	0.24
24021_CENTERS_230_24091_MESACAL_230_BR_1_1	1.2%	-0.09	0.08	0.09
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	2.1%	0.10	-0.08	-0.07
7820_TL230S_TL50001OUT_NG	3.0%	-0.03	-0.01	0.20
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	4.4%	0.09	-0.07	-0.06
30055_GATES1_500_30900_GATES_230_XF_11_P	5.0%	0.09	-0.07	-0.06
30105_COTTNWD_230_30245_ROUNDMT_230_BR_3_1	8.4%	0.08	-0.06	-0.08
7820_TL50002_IV-NG-OUT_TDM	2.7%	-0.02	-0.01	0.17
24084_LITEHIPE_230_24091_MESACAL_230_BR_1_1	1.6%	-0.07	0.06	0.05
32214_RIOOSO_115_32244_BRNSWKT2_115_BR_2_1	18.5%	-0.06	0.05	0.07
30797_LASAGUIL_230_30790_PANOCHE_230_BR_2_1	2.6%	0.06	-0.05	-0.05
7440_MetcalfImport_Tes-Metcalf	1.3%	0.06	-0.04	-0.04
7690-INYOKN_VOLTAGE_EX_NG	13.3%	0.02	-0.06	0.06
32056_CORTINA_60.0_30451_CRTNAM_1.0_XF_1	8.1%	0.03	-0.03	-0.03
30580_ALTMMDW_230_30625_TESLAD_230_BR_1_1	4.3%	0.03	-0.03	-0.03
OMS_15570615_IV-SXOutage_NG	0.6%	-0.01	0.00	0.07
Other	3.8%	0.12	-0.13	0.12
Total		5.96	-4.93	-2.36

1.8.2 Congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across WEIM.[38] This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas. The impact from transfer constraints are discussed in greater depth in Section 2.2.

Internal congestion in the real-time market followed trends in solar production. There was significant congestion in the south-to-north direction during solar hours, resulting in average congestion across all hours also being in the south-to-north direction.

[38] This report defines internal congestion as congestion on any constraint within a balancing authority area. Therefore, the effect of internal congestion on the CAISO balancing area may include effects of congestion from transmission elements within WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

Figure 1.39 illustrates the overall impact of internal congestion on prices at the default load aggregation point (DLAP) and EIM load aggregation point (ELAP) in the second quarter of 2024. The blue bars represent the 15-minute price impact, and the yellow bars indicate the 5-minute price impact from internal constraints.

The average impact of congestion in the real-time markets suggested a south-to-north congestion pattern. This resulted in increased prices in balancing authority areas (BAAs) in Northern California, the Intermountain West, and the Pacific Northwest, while prices of BAAs in Southern California and the Desert Southwest decreased.

Figure 1.39 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (April–June 2024)

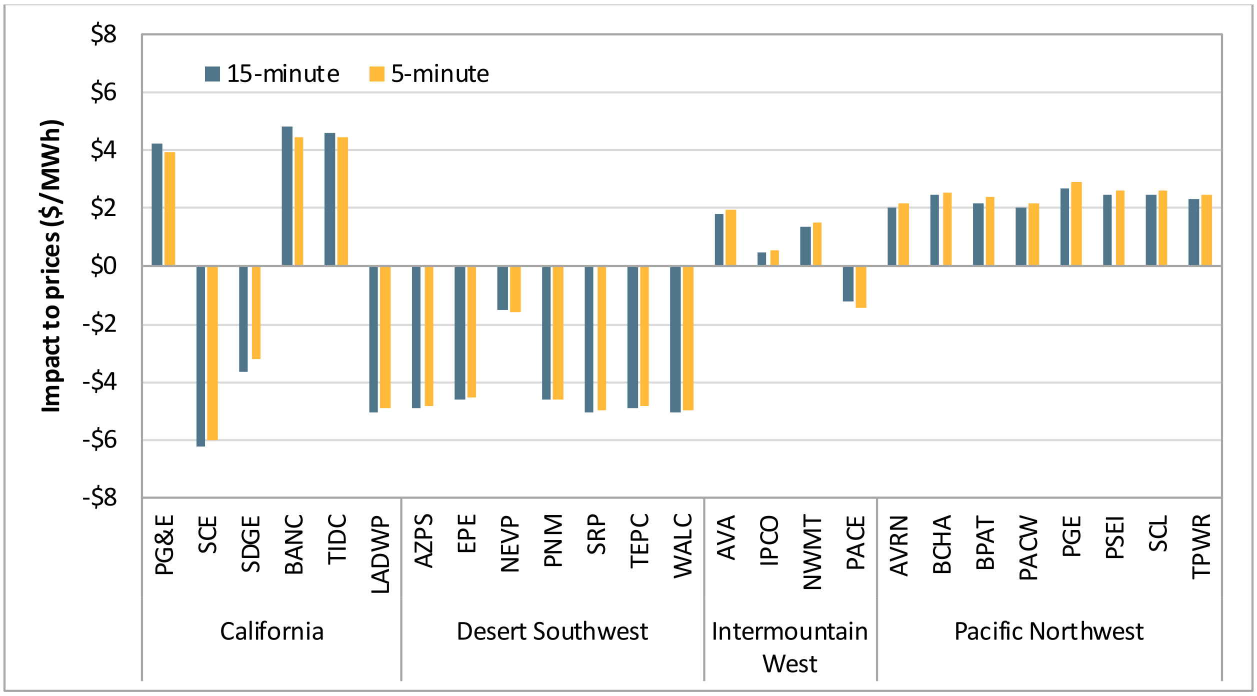


Figure 1.40 displays the average impact of internal congestion on prices in the second quarter of 2023 and 2024. The blue bar represents the impact for 2023, and the red bar shows the impact for 2024. This impact was calculated as the average of the 15-minute and 5-minute price impacts of internal constraints for all intervals.

The price separation due to internal flow-based congestion across WEIM in the second quarter of 2023 and 2024 shows similar patterns, with increased prices in Northern California, Intermountain West, and Pacific Northwest, and decreased prices in Southern California and the Desert Southwest. While the pattern remain consistent between the two years, the magnitude of the price separation was significantly higher in 2024.

The overall trend in congestion was driven by solar production in the Desert Southwest and Southern California. During the daytime, this energy travels to the northern regions of the WEIM, leading to congestion and contributing to the price separation.

Figure 1.40 Average impact of internal congestion on real-time market price (2023-2024)

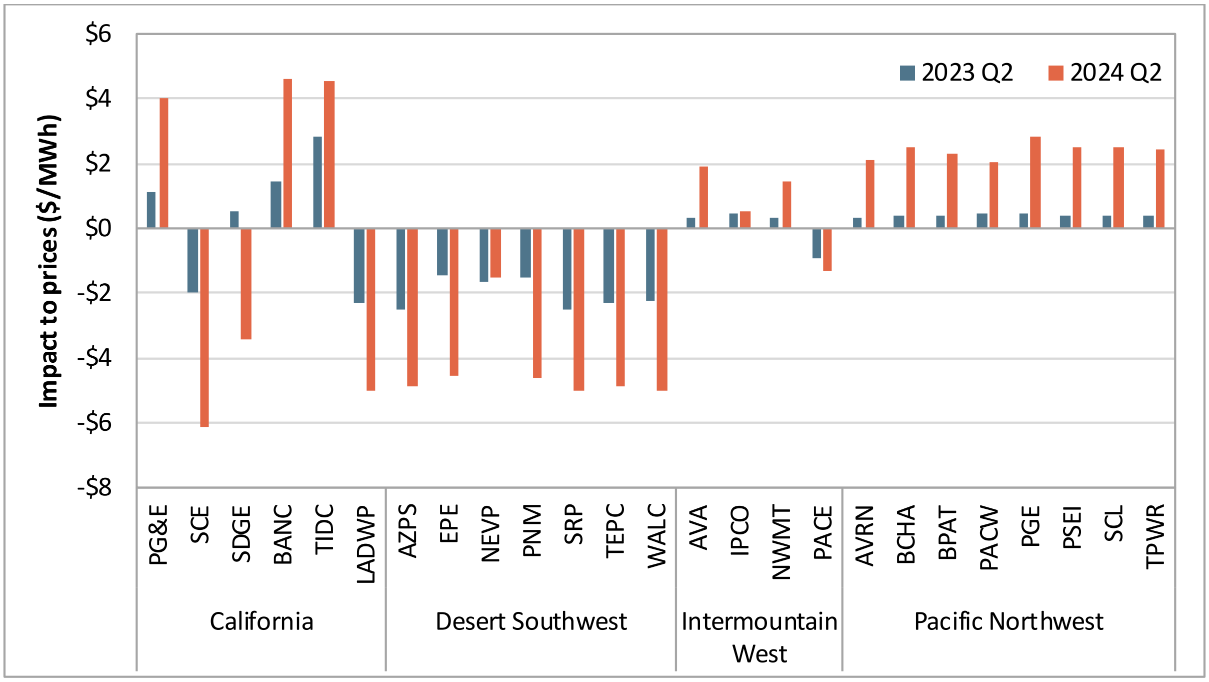


Figure 1.41 and Figure 1.42 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the second quarter of 2024 and 2023, respectively. During solar hours, the congestion patterns in both 2024 and 2023 were similar, with south-to-north congestion across WEIM. The second quarter of 2024, compared to that of 2023, showed a shift in congestion patterns, particularly in the Desert Southwest. After solar hours, congestion generally had a negative impact on prices in this area, whereas in 2023, the region experienced an overall positive impact from congestion. The table highlights the reason for the lower overall magnitude of price separation in 2023, when the direction of congestion impacts on regions shifted more prominently between solar and non-solar hours.

PacifiCorp East was an outlier, as this area experienced a negative impact from internal congestion during most hours.

Figure 1.41 Overall impact of internal congestion on price separation in the 15-minute market by hour (April–June 2024)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	0.7	1.1	1.2	1.2	1.2	1.0	1.5	7.1	10.1	9.6	6.9	6.6	5.8	5.9	6.4	6.5	8.3	7.3	2.7	2.6	3.2	1.8	1.4	0.9
BANC	1.0	1.8	2.0	1.8	1.8	1.4	1.9	5.3	8.7	8.7	8.2	8.3	6.7	6.5	7.5	8.5	10.3	7.9	3.6	3.5	4.0	2.5	2.2	1.4
Turlock ID	0.5	1.0	1.0	1.0	1.0	0.8	1.4	5.5	9.7	10.0	9.9	10.0	8.7	8.9	9.3	10.9	11.4	6.0	0.9	0.6	0.8	0.5	0.4	0.3
SCE	0.6	0.5	0.6	0.6	0.7	0.6	-0.2	-8.1	-15.2	-16.0	-14.9	-14.8	-14.6	-15.3	-15.7	-14.7	-15.3	-10.6	-0.6	0.6	0.5	0.3	0.6	0.4
SDG&E	2.4	1.9	1.5	1.7	1.6	1.8	1.2	-2.9	-9.1	-10.7	-11.7	-11.7	-11.9	-12.6	-13.3	-11.8	-12.3	-7.1	1.4	2.5	3.6	3.6	2.8	1.7
LADWP	0.4	0.2	0.3	0.4	0.4	0.3	-0.8	-6.2	-11.8	-12.6	-12.8	-12.1	-11.8	-12.1	-12.1	-10.4	-11.3	-8.2	-0.8	-0.2	-0.4	-0.3	-0.1	0.1
NV Energy	0.3	0.4	0.4	0.1	0.1	0.0	-0.4	-3.3	-5.1	-4.6	-5.7	-4.6	-3.9	-2.6	-1.8	-2.3	-4.0	-2.6	2.1	1.1	-0.2	-0.1	-0.2	0.1
Arizona PS	-0.3	-0.3	0.0	0.1	0.1	-0.1	-0.9	-7.3	-11.6	-12.1	-12.0	-11.0	-10.5	-10.1	-9.6	-9.3	-10.0	-7.0	-0.9	-0.9	-1.6	-1.4	-0.7	-0.4
Tucson Electric	-0.3	-0.5	-0.3	-0.3	-0.3	-0.3	-1.0	-7.0	-11.1	-11.7	-11.6	-10.7	-10.2	-10.1	-9.9	-10.0	-10.4	-7.3	-1.0	-0.9	-1.4	-1.3	-0.7	-0.4
Salt River Project	-0.3	-0.4	0.0	0.1	0.1	-0.2	-0.9	-7.4	-11.6	-12.2	-12.0	-11.0	-10.6	-10.6	-10.0	-10.1	-10.8	-7.6	-1.0	-0.9	-1.5	-1.3	-0.7	-0.4
PSC New Mexico	-1.1	-1.0	-1.1	-1.0	-0.7	-0.4	-1.4	-7.2	-10.2	-11.0	-10.6	-9.4	-8.9	-8.7	-8.5	-8.6	-9.1	-6.2	-0.4	0.1	-1.2	-2.0	-1.2	-1.0
WAPA - Desert SW	-0.4	-0.3	-0.1	0.0	0.0	-0.2	-1.0	-7.2	-11.7	-12.1	-12.0	-11.0	-10.5	-10.6	-10.4	-10.3	-10.7	-7.5	-1.0	-0.9	-1.5	-1.4	-0.7	-0.4
El Paso Electric	-0.6	-0.8	-0.7	-0.6	-0.5	-0.3	-1.2	-7.0	-10.5	-11.3	-11.1	-9.9	-9.5	-9.3	-8.9	-8.9	-9.0	-6.4	-0.3	0.3	-1.0	-1.6	-0.9	-0.7
PacifiCorp East	-0.6	-0.6	-0.5	-0.5	-0.6	-0.6	-0.6	-1.5	-1.9	-1.9	-2.2	-2.0	-2.1	-2.1	-2.1	-1.9	-1.8	-1.4	-0.9	-1.0	-1.1	-0.9	-0.7	-0.6
Idaho Power	-0.3	-0.3	-0.3	-0.2	-0.3	-0.3	0.1	0.9	1.6	1.7	1.0	1.3	1.0	1.1	1.2	1.6	1.9	1.4	-0.3	-0.4	-0.2	-0.1	-0.1	-0.1
NorthWestern	-0.8	-0.9	-1.0	-1.0	-1.0	-0.8	-0.5	2.1	3.9	4.3	4.5	4.5	4.2	4.4	4.5	4.9	5.3	3.3	-1.0	-1.7	-1.6	-0.8	-0.9	-0.7
Avista Utilities	-1.2	-1.4	-1.5	-1.4	-1.4	-1.1	-0.6	2.9	5.4	6.0	6.4	6.2	5.7	6.0	6.1	6.6	7.0	4.3	-1.8	-2.4	-2.3	-1.3	-1.5	-1.1
Avangrid	-1.3	-1.6	-1.7	-1.6	-1.6	-1.3	-0.6	3.8	7.1	7.5	6.2	6.6	5.9	6.0	6.5	7.1	7.7	5.2	-2.1	-2.6	-2.4	-1.4	-1.6	-1.2
BPA	-1.2	-1.4	-1.6	-1.5	-1.5	-1.2	-0.6	3.2	6.3	6.7	7.5	7.1	6.8	7.2	7.3	7.6	8.3	4.8	-1.9	-2.5	-2.3	-1.3	-1.5	-1.1
Tacoma Power	-1.2	-1.4	-1.6	-1.5	-1.5	-1.2	-0.6	3.2	6.1	6.7	8.3	7.5	7.0	7.6	7.5	8.1	8.8	4.9	-1.9	-2.5	-2.3	-1.3	-1.5	-1.1
PacifiCorp West	-1.3	-1.5	-1.6	-1.6	-1.6	-1.2	-0.6	3.4	6.5	7.0	6.7	6.6	6.0	6.3	6.5	7.0	7.7	4.8	-2.0	-2.6	-2.4	-1.4	-1.6	-1.2
Portland GE	-1.3	-1.5	-1.6	-1.6	-1.5	-1.2	-0.6	3.3	6.4	7.1	9.8	8.4	7.8	8.8	8.7	9.3	10.2	5.4	-1.9	-2.5	-2.4	-1.4	-1.6	-1.2
Puget Sound Energy	-1.2	-1.4	-1.6	-1.5	-1.5	-1.2	-0.6	3.2	6.1	6.6	8.5	7.8	7.9	8.3	8.2	8.4	9.0	4.9	-1.9	-2.5	-2.3	-1.3	-1.5	-1.1
Seattle City Light	-1.2	-1.4	-1.6	-1.5	-1.5	-1.2	-0.6	3.1	6.0	6.6	8.3	7.8	8.3	8.4	8.4	8.4	8.8	4.8	-1.9	-2.5	-2.3	-1.3	-1.5	-1.1
Powerex	-1.2	-1.4	-1.6	-1.5	-1.5	-1.2	-0.6	3.1	5.9	6.5	8.0	7.7	8.7	8.6	8.7	8.4	8.5	4.7	-1.9	-2.4	-2.3	-1.3	-1.5	-1.1

Hour

Figure 1.42 Overall impact of internal congestion on price separation in the 15-minute market by hour (April–June 2023)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	0.0	-0.6	-0.7	-0.8	-0.9	0.5	0.4	3.0	4.5	3.8	2.9	2.7	1.8	2.2	1.8	1.6	1.2	1.1	0.7	-1.4	-0.6	-0.1	-0.1	-0.4
BANC	-1.4	-1.2	-1.5	-1.9	-1.6	-1.1	-0.1	2.9	5.6	5.0	5.2	5.0	4.3	4.1	3.5	3.7	3.4	3.5	1.3	-1.6	-0.8	-0.6	-0.9	-0.9
Turlock ID	-0.9	-0.9	-0.9	-0.8	-1.0	-0.8	-0.4	4.2	10.1	10.0	8.8	8.1	7.2	7.4	6.7	6.6	6.3	4.8	1.1	-2.5	-2.0	-1.0	-0.7	-0.9
SCE	0.9	1.1	1.0	1.1	1.2	1.1	0.4	-3.5	-9.8	-9.8	-8.8	-7.9	-7.6	-6.7	-5.7	-4.8	-5.3	-3.8	1.9	6.8	4.5	2.1	1.6	1.1
SDG&E	2.3	2.6	2.3	2.8	3.4	3.0	3.8	1.6	-3.1	-5.1	-4.4	-3.2	-5.3	-4.9	-4.1	-3.3	-3.6	-0.4	4.6	8.9	6.6	4.1	3.6	2.8
LADWP	0.8	1.0	0.9	1.0	1.1	1.0	0.2	-3.7	-10.0	-10.1	-9.0	-8.1	-7.8	-6.6	-6.0	-5.3	-5.5	-4.0	1.7	6.0	4.0	2.0	0.9	0.9
NV Energy	-1.0	-0.5	-0.2	-0.1	0.4	-0.2	-1.0	-4.6	-5.7	-4.6	-4.3	-3.3	-2.9	-2.3	-1.7	-1.4	-1.9	-2.2	0.0	1.6	0.4	-1.1	-2.0	-1.2
Arizona PS	0.4	0.6	0.7	0.7	0.7	0.5	-0.7	-4.6	-10.6	-10.3	-8.9	-8.2	-7.6	-6.7	-5.7	-5.0	-5.1	-3.9	0.9	4.9	3.1	1.3	0.7	0.5
Tucson Electric	0.4	0.6	0.6	0.7	0.7	0.5	-0.6	-4.1	-10.0	-9.5	-8.1	-7.5	-7.1	-6.1	-5.4	-4.6	-4.6	-3.3	1.0	4.7	2.9	1.4	0.6	0.5
Salt River Project	0.4	0.5	0.6	0.7	0.7	0.4	-0.7	-4.7	-10.6	-10.2	-8.7	-7.9	-7.5	-6.7	-5.9	-5.2	-5.4	-4.0	0.9	4.9	3.0	1.4	0.7	0.5
PSC New Mexico	0.3	0.4	0.5	0.6	0.5	0.3	-0.7	-2.9	-5.9	-5.8	-5.3	-5.0	-4.9	-4.3	-3.4	-3.2	-3.5	-2.4	0.7	3.7	2.3	1.1	0.5	0.4
WAPA - Desert SW	0.5	0.6	0.6	0.7	0.7	0.5	-0.7	-4.3	-9.3	-9.0	-8.1	-8.1	-7.1	-6.4	-5.5	-4.7	-4.7	-2.8	1.4	5.1	3.3	1.4	0.8	0.7
El Paso Electric	-0.4	-0.4	0.0	0.0	0.0	-0.5	-1.6	-3.7	-6.4	-5.9	-5.3	-5.0	-3.8	-3.3	-2.4	-2.4	-2.9	-1.7	1.3	4.4	2.9	1.3	0.6	-0.1
PacifiCorp East	-0.7	-0.6	-0.5	-0.5	-0.4	-0.2	-1.1	-1.0	-1.1	-1.0	-0.9	-0.8	-0.6	-0.6	-0.5	-0.4	-0.4	-0.3	-1.2	-2.0	-2.1	-1.4	-1.1	-0.8
Idaho Power	0.4	0.3	0.3	0.3	0.3	1.0	0.3	0.7	1.8	1.7	1.7	1.6	1.9	1.5	1.5	1.3	1.7	1.9	-1.1	-3.1	-2.2	-1.0	-0.2	0.2
NorthWestern	-0.5	-0.6	-0.5	-0.5	-0.5	-0.6	-0.2	1.0	2.7	2.6	2.6	2.5	2.9	2.3	1.7	1.6	2.0	1.2	-2.2	-4.8	-3.0	-1.4	-0.8	-0.5
Avista Utilities	-0.8	-0.8	-0.7	-0.9	-1.0	-1.2	-0.3	1.3	3.3	3.2	3.2	3.1	3.5	2.8	2.0	1.9	2.2	1.2	-2.6	-5.9	-3.8	-1.7	-1.2	-0.9
Avangrid	-0.9	-1.0	-0.9	-1.0	-1.1	-1.3	-0.3	1.6	4.3	4.1	4.1	3.9	4.0	3.2	2.4	2.1	2.5	1.4	-3.3	-7.2	-4.6	-2.1	-1.3	-0.9
BPA	-0.8	-0.9	-0.8	-0.9	-1.1	-1.3	-0.3	1.4	3.8	3.6	3.7	3.5	3.8	3.1	2.3	2.1	2.5	1.4	-2.7	-6.2	-3.6	-1.6	-1.2	-0.9
Tacoma Power	-0.8	-0.9	-0.8	-0.9	-1.0	-1.3	-0.3	1.4	3.8	3.6	3.6	3.5	3.8	3.1	2.3	2.1	2.4	1.4	-2.7	-6.3	-4.0	-1.8	-1.2	-0.9
PacifiCorp West	-0.8	-0.9	-0.8	-1.0	-1.1	-1.3	-0.3	1.5	4.0	3.8	3.8	3.6	4.0	3.3	2.4	2.2	2.6	1.5	-2.8	-6.5	-4.1	-1.9	-1.3	-0.9
Portland GE	-0.8	-0.9	-0.8	-0.9	-1.1	-1.3	-0.3	1.4	4.1	3.7	3.8	3.6	3.9	3.2	2.4	2.2	2.7	1.6	-2.8	-6.4	-4.2	-1.8	-1.2	-0.8
Puget Sound Energy	-0.8	-0.9	-0.8	-0.9	-1.0	-1.3	-0.3	1.4	3.8	3.6	3.6	3.5	3.8	3.1	2.3	2.1	2.4	1.4	-2.7	-6.3	-4.0	-1.8	-1.2	-0.9
Seattle City Light	-0.8	-0.9	-0.8	-0.9	-1.0	-1.3	-0.3	1.4	3.8	3.6	3.6	3.5	3.8	3.1	2.3	2.1	2.4	1.4	-2.7	-6.3	-4.0	-1.8	-1.2	-0.9
Powerex	-0.8	-0.9	-0.8	-0.9	-1.0	-1.2	-0.3	1.4	3.7	3.5	3.5	3.4	3.7	3.1	2.2	2.1	2.4	1.3	-2.6	-6.2	-3.9	-1.8	-1.2	-0.9

Congestion in the 15-minute market from internal, flow-based constraints

Table 1.3 and Table 1.4 show the quarterly impact of congestion from individual constraints on prices across the WEIM for the 15-minute market. The three constraints that had the greatest impact on price separation in the 15-minute market were Gates-Midway #1 500kV line, Los Banos-Gates #1 500kV line, and Moss Landing-Las Aguilas #1 230kV line.

Gates-Midway #1 500kV line

The Gates-Midway #1 500kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) increased prices in Northern California, the Intermountain West, and the Pacific Northwest, while it decreased prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar hours, from hour-ending 9 to 17.

Los Banos-Gates #1 500kV line

The Los Banos-Gates #1 500kV line (30050_LOSBANOS_500_30055_GATES1_500_BR_1_2) increased prices in Northern California, the Intermountain West, and the Pacific Northwest, while it decreased prices in Southern California and the Desert Southwest. This line experienced congestion during solar hours, from hour-ending 8 to 18.

Moss Landing-Las Aguilas #1 230kV line

The Moss Landing-Las Aguilas #1 230kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) increased prices in Northern California and the Pacific Northwest, while it decreased prices in Southern

California and the Desert Southwest. The impact of this line was more significant within the California region, rather than across the WEIM. The Intermountain West area experienced minimal effects from this constraint. This CAISO balancing area constraint was binding during 33 percent of intervals, and typically experienced congestion during solar hours, from hour-ending 8 to 18.

Table 1.3 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 25 primary congestion constraints (CAISO, April–June 2024)

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	9.4%	1.50	-2.21	-2.10
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	32.7%	1.21	-1.83	-1.74
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	6.9%	0.60	-0.92	-0.87
6410_CP10_NG	7.5%	0.67	-0.70	-0.67
30105_COTTNWD_230_30245_ROUNDMT_230_BR_3_1	8.8%	0.74	0.44	0.40
MIGUEL_BKs_MXFLW_NG	3.0%	0.06	0.14	1.21
NOPE	0.9%	-0.20	-0.19	-0.18
7820_TL230S_OVERLOAD_NG	3.0%	0.01	0.02	0.39
30055_GATES1_500_30900_GATES_230_XF_11_P	7.6%	-0.18	-0.11	-0.11
30797_LASAGUIL_230_30790_PANOCHE_230_BR_2_1	1.8%	0.11	-0.12	-0.11
OMS15113777_50001_OOS_NG	1.2%	0.01	0.03	0.27
7690-INYOKN_VOLTAGE_EX_NG	10.8%	.	-0.15	0.10
30005_ROUNDMT_500_30245_ROUNDMT_230_XF_1_P	2.3%	-0.11	-0.06	-0.06
30500_BELLOTA_230_30515_WARNERVL_230_BR_1_1	0.7%	0.01	-0.11	-0.11
32214_RIOOSO_115_32244_BRNSWKT2_115_BR_2_1	2.8%	-0.17	-0.03	-0.01
7440_MetcalfImport_Tes-Metcalf	0.9%	0.09	-0.06	-0.06
24801_DEVERS_500_99014_CALCAPS2_500_BR_2_1	2.8%	0.04	0.09	0.06
39536_FINKSS_230_38402_WSTLYTID_230_BR_1_1	0.6%	0.03	-0.08	-0.08
34116_LEGRAND_115_34115_ADRATAP_115_BR_1_1	45.1%	-0.18	0.00	0.00
INTNEL	0.5%	-0.06	-0.06	-0.06
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	1.9%	0.00	-0.09	-0.08
30790_PANOCHE_230_30900_GATES_230_BR_2_1	3.5%	0.03	-0.06	-0.05
OMSIV-SXOUTAGE_NG	0.7%	0.01	0.01	0.12
6410_CP1_NG	0.4%	-0.05	0.04	0.04
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	0.5%	0.01	0.01	0.11
Other	1.9%	0.05	-0.24	-0.03
Total		4.20	-6.23	-3.63

Table 1.4 Impact of internal transmission constraint congestion on 15-minute market prices during all hours (WEIM, April–June 2024)

		Average quarter impact ($/MWh)																					
		California			Desert Southwest							Intermountain West				Pacific Northwest							
Constraint location	Constraint	BANC	TIDC	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	CCXFMR8A69KV	.	.	.	0.14	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
BPAT	NOPE	-0.21	-0.20	-0.18	-0.18	-0.17	-0.17	-0.17	-0.18	-0.18	-0.18	0.11	-0.11	0.05	-0.12	-0.25	0.31	0.26	.	0.75	0.44	0.36	0.43
	INTNEL	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.02	-0.05	-0.01	-0.05	-0.06	0.29	.	-0.06	-0.07	0.11	0.20	-0.02
CISO	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	1.82	1.88	-2.20	-1.86	-1.71	-1.06	-1.61	-1.86	-1.81	-1.86	1.16	0.46	0.92	-0.28	1.45	1.23	1.26	1.32	1.30	1.25	1.25	1.25
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	0.90	0.93	-0.90	-0.79	-0.73	-0.46	-0.69	-0.79	-0.77	-0.79	0.64	0.16	0.47	-0.14	0.80	0.67	0.69	0.73	0.72	0.69	0.69	0.69
	30105_COTTNWD_230_30245_ROUNDMT_230_BR_3_1	1.24	0.40	0.20	0.10	0.00	.	.	0.09	0.01	0.10	-0.95	-0.18	-0.65	.	-1.07	-0.98	-1.00	-1.03	-1.03	-1.00	-1.00	-1.00
	6410_CP10_NG	0.64	0.66	-0.69	-0.61	-0.57	-0.35	-0.55	-0.61	-0.60	-0.61	0.41	0.10	0.30	-0.12	0.51	0.43	0.44	0.47	0.46	0.44	0.44	0.44
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	0.19	0.38	-0.67	-0.44	-0.28	-0.08	-0.22	-0.44	-0.38	-0.45	0.08	.	.	.	0.13	0.09	0.09	0.10	0.10	0.09	0.09	0.09
	MIGUEL_BKs_MXFLW_NG	.	.	.	-0.36	-0.31	.	-0.27	-0.38	-0.35	-0.36	.	.	.	.	.	.	.	.	.	.	.	.
	30055_GATES1_500_30900_GATES_230_XF_11_P	0.06	0.09	-0.12	-0.10	-0.09	-0.03	-0.08	-0.10	-0.09	-0.10	0.10	0.02	0.08	0.00	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	30005_ROUNDMT_500_30245_ROUNDMT_230_XF_1_P	-0.20	-0.10	-0.06	-0.05	-0.03	0.00	-0.02	-0.05	-0.04	-0.05	0.12	0.08	0.10	0.01	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
	39536_FINKSS_230_38402_WSTLYTID_230_BR_1_1	0.12	0.26	-0.08	-0.07	-0.07	-0.04	-0.07	-0.07	-0.07	-0.07	0.05	0.01	0.04	.	0.06	0.05	0.05	0.06	0.06	0.05	0.05	0.05
	24801_DEVERS_500_99014_CALCAPS2_500_BR_2_1	0.04	0.04	0.04	-0.15	-0.13	-0.03	-0.11	-0.15	-0.14	-0.12	0.01	-0.01	.	-0.04	0.03	0.01	0.02	0.02	0.02	0.02	0.02	0.02
	6110_COI_S-N	-0.05	-0.05	-0.03	-0.03	-0.03	-0.02	-0.02	-0.03	-0.03	-0.03	0.04	0.02	0.03	0.00	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04
	6410_CP1_NG	-0.05	-0.05	0.04	0.04	0.03	0.03	0.03	0.04	0.04	0.04	-0.03	-0.01	-0.02	0.00	-0.04	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03
	30056_GATES2_500_30060_MIDWAY_500_BR_2_3	0.04	0.04	-0.04	-0.04	-0.03	-0.02	-0.03	-0.04	-0.04	-0.04	0.03	0.01	0.02	-0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	7440_MetcalfImport_Tes-Metcalf	0.04	0.06	-0.06	-0.05	-0.05	-0.03	-0.05	-0.05	-0.05	-0.05	0.01	.	.	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	32214_RIOOSO_115_32244_BRNSWKT2_115_BR_2_1	-0.06	-0.01	.	.	.	0.54	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	0.15	0.36	-0.07	0.00	.	.	.	0.00	.	0.00	.	.	.	.	0.01	.	.	.	.	.	.	.
	7820_TL230S_OVERLOAD_NG	0.00	0.01	0.01	-0.08	-0.08	-0.02	-0.07	-0.09	-0.09	-0.08	.	-0.01	.	-0.03	0.00	.	.	.	.	.	.	.
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	0.05	0.08	-0.03	-0.03	-0.02	0.00	-0.02	-0.03	-0.03	-0.03	0.02	.	0.01	.	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	0.03	0.02	-0.03	-0.02	-0.02	-0.01	-0.02	-0.02	-0.02	-0.02	0.02	0.01	0.02	.	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1_1	-0.03	-0.03	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02	-0.02	-0.01	-0.02	.	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
	30763_Q0577SS_230_39536_FINKSS_230_BR_1_1	0.03	0.07	-0.02	-0.02	-0.02	-0.01	-0.02	-0.02	-0.02	-0.02	0.01	0.00	0.01	.	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	38615_DSAMIGO_230_30790_PANOCHE_230_BR_1_1	0.03	0.07	-0.03	-0.02	-0.02	.	.	-0.02	-0.02	-0.02	0.00	.	.	.	0.03	0.00	0.02	0.02	0.02	0.01	0.01	0.01
	30500_BELLOTA_230_30515_WARNERVL_230_BR_1_1	0.06	-0.28	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	6410_CP7_NG	0.02	0.02	-0.02	-0.02	-0.02	-0.01	-0.02	-0.02	-0.02	-0.02	0.01	0.00	0.01	0.00	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	OMS15113777_50001_OOS_NG	.	.	.	-0.06	-0.04	-0.02	-0.03	-0.04	-0.04	-0.09	.	.	.	-0.01	.	.	.	.	.	.	.	.
	6410_CP5_NG	-0.02	-0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02	-0.01	-0.01	-0.01	0.00	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	30797_LASAGUIL_230_30790_PANOCHE_230_BR_2_1	0.00	.	-0.12	-0.03	-0.01	.	0.00	-0.03	-0.03	-0.03	0.00	.	.	.	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	32214_RIOOSO_115_32225_BRNSWKT1_115_BR_1_1	-0.05	.	.	.	.	0.22	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	0.02	0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.	.	.	-0.04	-0.03	-0.01	-0.03	-0.04	-0.03	-0.04	.	.	.	-0.01	.	.	.	.	.	.	.	.
	24084_LITEHIPE_230_24091_MESACAL_230_BR_1_1	-0.02	-0.02	-0.04	.	.	.	.	.	.	.	0.00	.	.	.	-0.01	0.00	0.00	-0.01	0.00	0.00	0.00	0.00
	99002_MOE-ELD_500_24042_ELDORDO_500_BR_1_2	0.00	0.00	0.00	-0.01	-0.01	0.00	-0.02	-0.01	-0.01	-0.01	0.00	.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	92321_SYCATP2_230_22832_SYCAMORE_230_BR_2_1	.	.	.	-0.01	-0.01	.	-0.01	-0.01	-0.01	-0.01	.	.	.	.	.	.	.	.	.	.	.	.
EPE	15200_ARR_LCS	.	.	.	.	0.06	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
LADWP	TARBKE	.	.	0.11	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
PACE	WINDSTAREXPORTTCOR	.	.	.	.	.	.	.	.	.	.	.	.	.	-0.22	.	.	.	.	.	.	.	.
	TOTAL_WYOMING_EXPORT	.	.	.	.	.	.	.	.	.	.	.	.	.	-0.17	.	.	.	.	.	.	.	.
	EAST_WYO_EXP	.	.	.	.	.	.	.	.	.	.	.	.	.	-0.05	.	.	.	.	.	.	.	.
PNM	CZ345kV	.	.	.	.	-0.22	.	-0.47	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvML	.	.	.	.	0.09	.	0.07	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
SRP	KYT230|5008	.	.	.	0.01	-0.01	.	.	0.02	-0.01	.	.	.	.	.	.	.	.	.	.	.	.	.
	Other	-0.01	0.02	-0.04	-0.05	-0.01	0.00	-0.03	-0.04	-0.03	-0.05	0.01	0.00	0.00	-0.01	0.00	0.01	0.02	0.00	0.01	0.01	0.01	0.01
Total	Total	4.81	4.61	-5.07	-4.90	-4.60	-1.52	-4.61	-5.05	-4.94	-5.07	1.81	0.50	1.38	-1.25	2.01	2.47	2.20	1.99	2.70	2.46	2.47	2.32

1.8.3 Congestion on interties

In the second quarter of 2024, total intertie congestion rent in the day-ahead market increased from $9.6 million to $13.4 million compared to the same quarter in 2023. The major driver was increased import congestion on Malin. While export congestion on this intertie decreased by nearly $3 million, import congestion rent rose by $5.6 million in this quarter compared to the same quarter in 2023.

The total import congestion charges reported by DMM represent the products of the shadow prices multiplied by the binding limits for the intertie constraints. For a supplier or load serving entity trying to import power over an intertie congested in the import direction, assuming a radial line, the congestion price represents the difference between the higher price of generation on the California ISO side of the intertie and the lower price of import bids outside of the California ISO area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO area at points corresponding to these interties.

Figure 1.43 shows total import congestion charges in the day-ahead market from 2023 to the second quarter of 2024. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 1.44 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 1.5 provides a detailed summary of congestion rent and frequency over a broader set of interties distinguishing by imports and exports. As highlighted in these charts and table:

- Compared to the second quarter of 2023, import congestion rent increased from $5.8 million to $11 million, whereas export congestion rent decreased from $3.7 million to $2.2 million.
- The majority of import congestion rent was from the Malin and NOB interties. These two interties accounted for over 95 percent of the total congestion rent during this quarter.

- Import congestion on Malin accounted for 60 percent of the total intertie congestion rent in this quarter. While average binding limits and shadow prices remained similar to the second quarter of 2023, the frequency of binding hours on Malin in the import direction significantly increased from 5 percent to 15 percent this quarter compared to the same quarter in 2023.

Figure 1.43 Day-ahead congestion charges on major interties

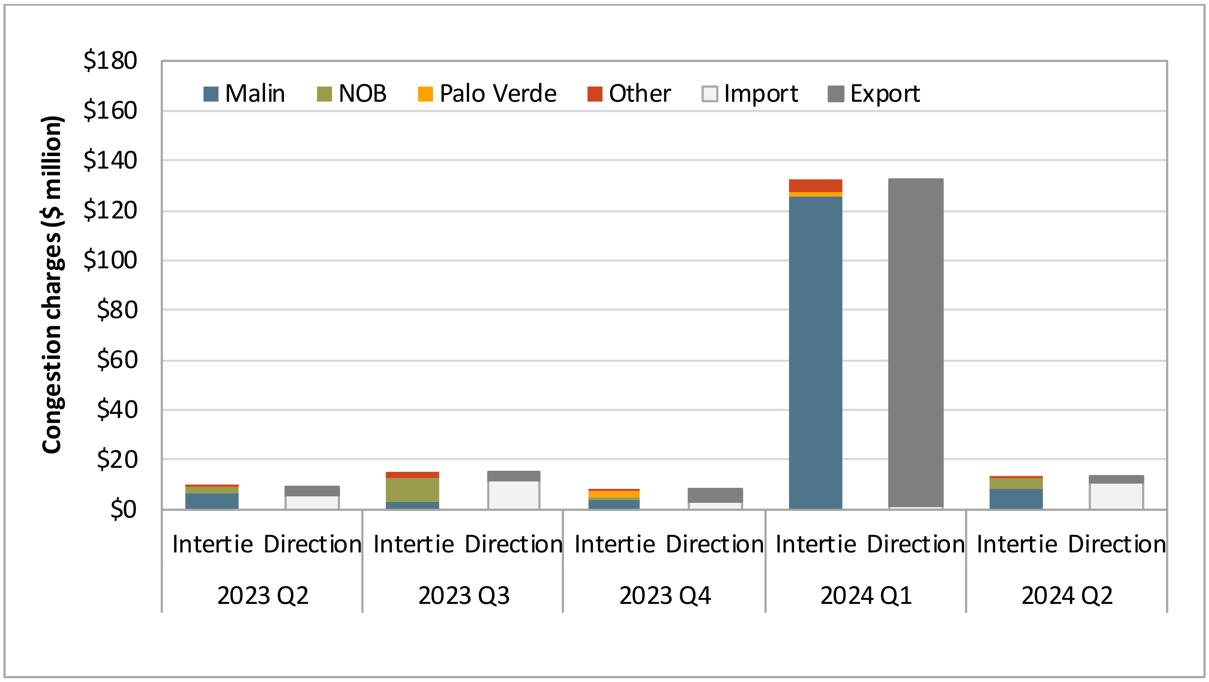


Figure 1.44 Frequency of congestion on major interties in the day-ahead market

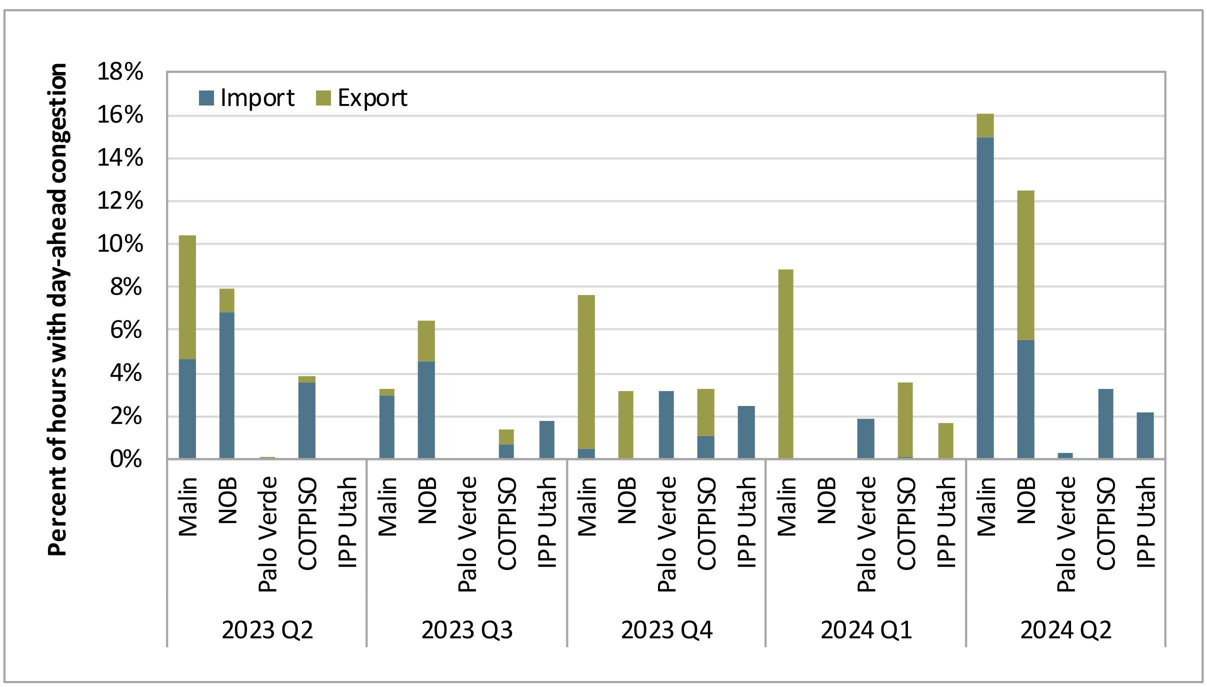


Table 1.5 Summary of intertie congestion in day-ahead market (2023–2024)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2
Northwest											
Malin	I	$2,616	$3,127	$243		$8,229	4.7%	2.9%	0.5%		15.0%
	E	$3,650	$339	$3,866	$125,571	$292	5.8%	0.3%	7.2%	8.8%	1.1%
NOB	I	$3,009	$8,755			$2,608	6.9%	4.6%			5.5%
	E	$66	$252	$851		$1,665	1.1%	1.9%	3.1%		7.0%
COTPISO	I	$74	$16	$103	$1	$98	3.6%	0.6%	1.1%	0.0%	3.3%
	E	$3	$30	$55	$1,367		0.3%	0.7%	2.2%	3.5%	
Cascade	I										
	E	$0			$2,147		0.1%			8.0%	
Summit	I		$42	$5		$14		1.4%	0.2%		0.8%
	E										
Southwest											
Palo Verde	I			$2,593	$1,909	$61			3.1%	1.8%	0.3%
	E	$33					0.0%				
IPP Utah	I		$59	$186		$141		1.8%	2.4%		2.2%
	E				$401					1.7%	
IPP DC Adelanto	I										
	E				$1,071					4.0%	
Mona	I										
	E		$77	$143	$75	$180		0.4%	0.7%	0.4%	2.2%
Mead	I				$1	$23				0.0%	0.2%
	E		$2,370					1.5%			
Merchant	I										
	E										
Silver Peak	I										
	E	$13	$2				1.7%	1.0%			
Mercury	I										
	E										
Other	I	$91	$21	$81		$8					
	E	$0	$0		$58	$70					
Import total (I)		$5,789	$12,021	$3,213	$1,911	$11,182					
Export total (E)		$3,766	$3,071	$4,915	$130,690	$2,207					
Total		$9,555	$15,092	$8,128	$132,601	$13,389					

* I: import, E: export

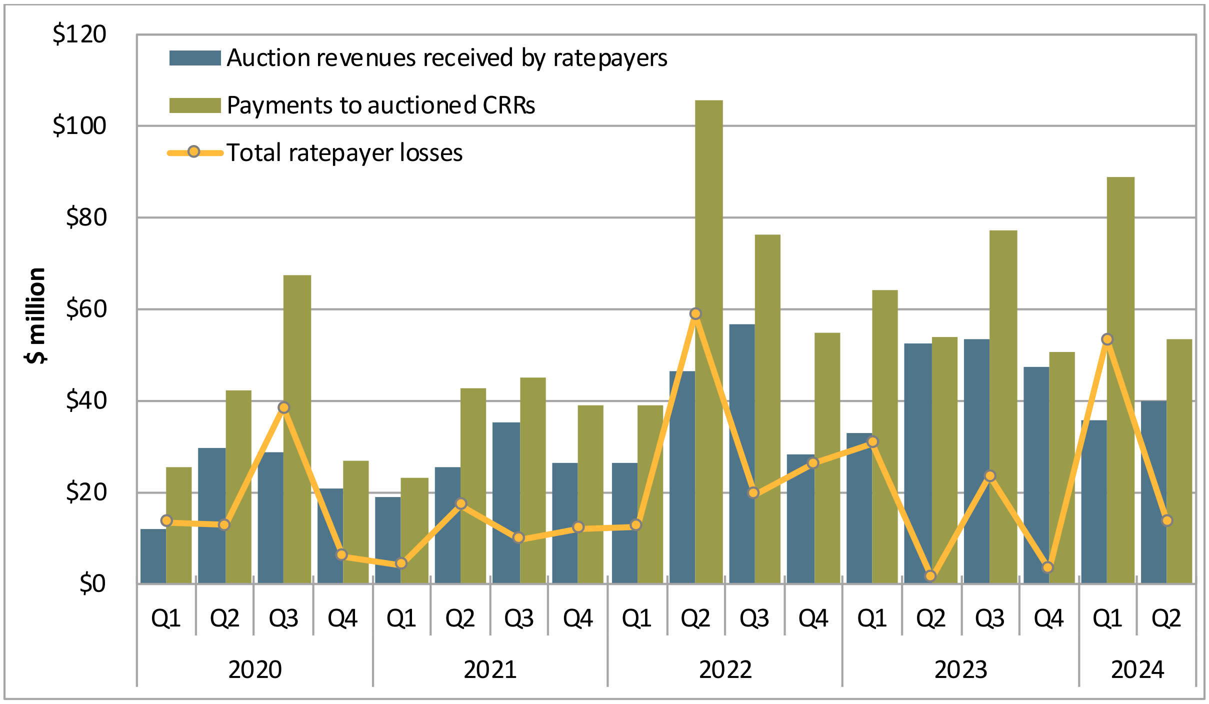
1.9 Congestion revenue rights

Congestion revenue right auction returns

Profits from the congestion revenue rights (CRR) auction by non-load serving entities are calculated by summing revenue paid out to congestion revenue rights purchased by these entities, and then subtracting the auction price paid for these rights. While this represents a profit to entities purchasing rights in the auction, it represents a loss to transmission ratepayers.

As shown in Figure 1.45, transmission ratepayers lost almost $14 million during the second quarter of 2024, as payments to auctioned congestion revenue rights holders were higher than auction revenues. This was a significant increase from ratepayer losses of about $1 million in the second quarter of 2023.

Figure 1.45 Auction revenues and payments to non-load serving entities



During the second quarter of 2024:

- Financial entities received profits of about $10 million, up from about $5 million during the same quarter of 2023. Total revenue deficit offsets were about $16 million.[39]
- Marketers made about $2 million from auctioned rights, up from a $3 million loss in Q2 2023. Total revenue deficit offsets were over $5 million.
- Physical generation entities gained almost $2 million from auctioned rights, up from a less than a half million dollar loss in Q2 2023. Total revenue deficit offsets were about $2 million.

The $14 million in second quarter 2024 auction losses was about 8 percent of day-ahead congestion rent. This is down from the 20 percent from the previous quarter and up from less than 1 percent in the second quarter of 2023. The losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the track 1A and 1B changes (2016 through 2018).[40,41]

39 The total congestion rent is calculated by constraint and compared to the total CRR payments across all scheduling coordinators (SCs) from the constraint. If the CRR payments are greater than the congestion rent collected for a constraint, the difference is charged as an offset to the SCs with net flows on the constraint.

40 *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, California ISO, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

41 *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, California ISO, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

The impact of track 1A changes, which limit the types of congestion revenue rights that can be sold in the auction, cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under track 1B reduced total payments to non-load serving entities by about $23 million in the first quarter. The track 1B effects on auction bidding behavior and reduced auction revenues are not known.

Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction consistently continues to cause millions of dollars in losses to transmission ratepayers each year, while exposing transmission ratepayers to a risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends the ISO convert the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers. DMM recently posted a whitepaper analyzing a potential option for this kind of alternative CRR auction design.[42]

1.10 Real-time imbalance offset costs

Real-time imbalance offset costs in the California ISO balancing area were $59 million in the second quarter of 2024.[43] This was a decrease from the $71 million of real-time imbalance offset costs in the same quarter of 2023. In the second quarter of 2024, the large majority of these costs came from real-time *congestion* imbalance offset costs ($62 million). Real-time *loss* imbalance offset costs were around $2 million. Real-time imbalance *energy* offsets were a $5.3 million credit that counteracted some of the congestion and loss costs.

Real-time imbalance offset costs in non-CAISO WEIM balancing areas were a $33 million credit to WEIM entities, compared to a $58 million credit in the second quarter of 2023. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $43 million credit. The energy and loss portions of the offset combined to be a $10 million charge.

The real-time imbalance offset cost is the difference between the total money *paid out* by a balancing area and the total money *collected* by the area for energy settled in the real-time energy markets. Within the California ISO balancing area system, the charge is allocated as an uplift to measured demand (physical load plus exports). Any revenue shortfall or revenue surplus in a WEIM balancing area is allocated to the WEIM entity scheduling coordinator.[44]

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the *loss* component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge,*

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42 *Willing seller market design for congestion revenue rights,* Department of Market Monitoring, October 23, 2024: https://www.caiso.com/documents/willing-counterparty-whitepaper-oct-23-2024.pdf

43 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

44 The ISO allocates real-time congestion imbalance shortfalls and surpluses to the balancing authority area in which the constraints are located. The balancing authority areas then allocate these imbalances based on their tariffs, which can include allocations to third-party customers.

while any remaining revenue imbalance is *recovered* through the *real-time imbalance energy offset charge* (RTIEO). Figure 1.46 shows monthly imbalance offset costs for the California ISO balancing area by component since 2022.

Figure 1.46 Monthly California ISO real-time imbalance offset costs

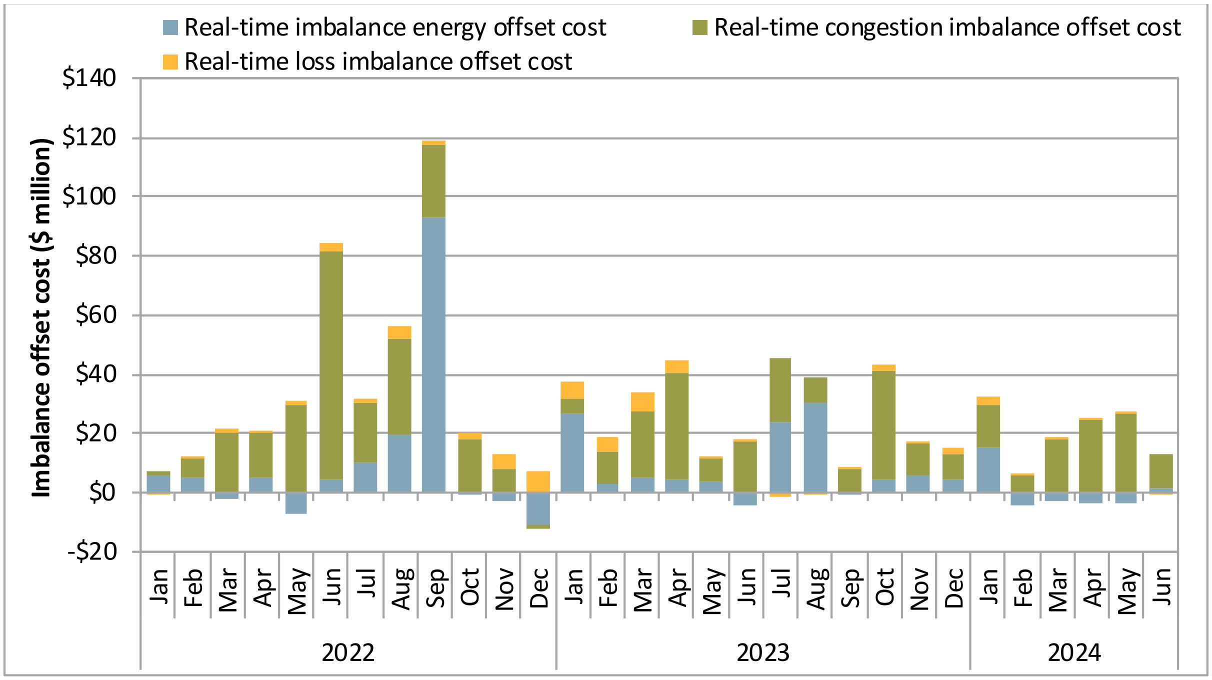


Figure 1.47 shows monthly imbalance offset costs for WEIM balancing areas, excluding the CAISO area. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month, and shown collectively in the corresponding bars. The lighter-colored bars reflect positive amounts (or charges for revenue shortfall), while the darker bars reflect negative amounts (or credits for revenue surplus).

Figure 1.48 through Figure 1.50 show the monthly real-time energy, congestion, or loss imbalance offset charges for each balancing area in the WEIM. Negative amounts (or credits for revenue surplus) are shown in parentheses. Figure 1.51 shows the *total* real-time imbalance offset charges for each month and balancing area. The final column in each of these figures shows the total amount for each balancing area during the latest quarter.

Of note in the second quarter:

- Imbalance energy offsets for Avangrid were around $12 million (revenue shortfall) during April and -$6.5 million (revenue surplus) over May and June.
- Congestion imbalance offsets for Powerex were almost -$16 million (revenue surplus).
- Congestion imbalance offsets for PacifiCorp East were around -$6.6 million (revenue surplus).

Figure 1.47 Monthly WEIM real-time imbalance offset costs

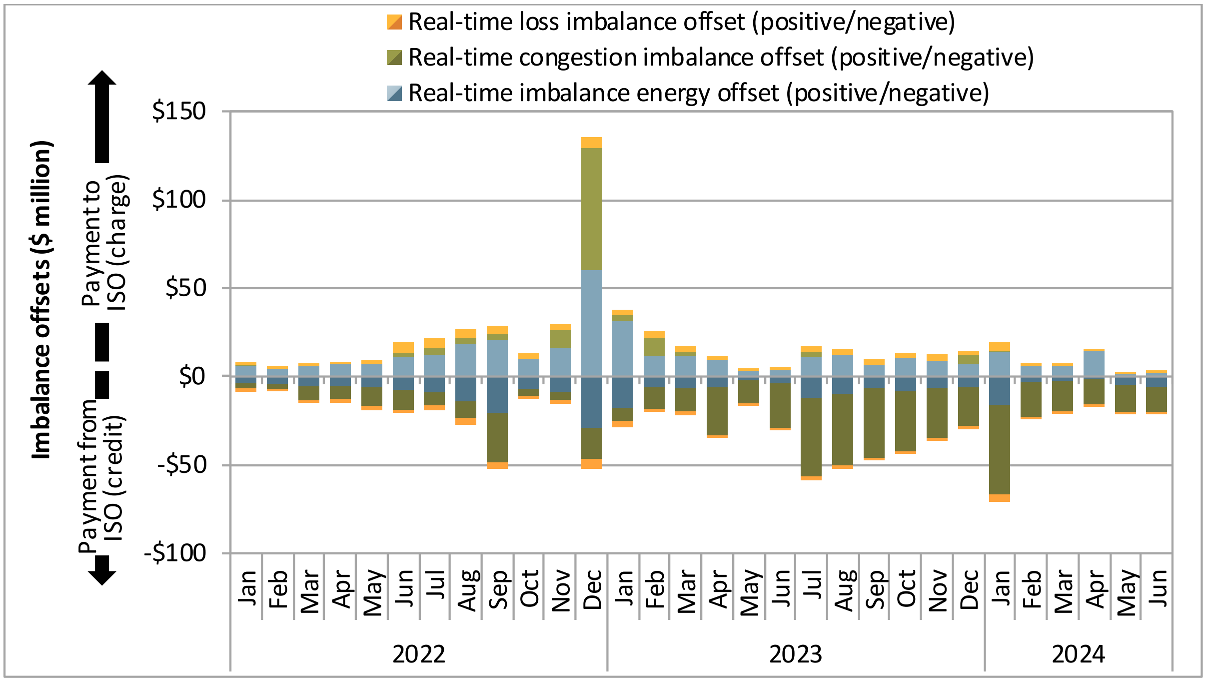


Figure 1.48 Real-time imbalance energy offset charges (credits) by month and balancing area ($ millions)

	2023									2024						Q2 '24
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	*Total*
Arizona Publ. Serv.	1.1	0.2	0.8	1.9	2.0	0.9	1.5	1.4	1.2	2.5	1.4	0.7	0.7	0.4	0.3	1.3
Avangrid	(0.1)	0.0	(0.0)	1.1	1.6	0.2	0.2	(0.2)	0.2	0.2	0.1	3.0	12	(3.1)	(3.4)	5.0
Avista	0.1	0.1	0.0	0.1	0.1	(0.1)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.1	0.0	0.1
BANC	(0.0)	0.1	(0.1)	0.1	0.1	(0.2)	(0.3)	0.1	(0.1)	(0.1)	0.2	0.3	0.2	0.0	(0.1)	0.1
BPA	(0.1)	(0.0)	0.1	0.4	0.3	0.0	0.1	0.2	(0.1)	(1.0)	0.0	0.0	0.1	0.1	0.1	0.3
El Paso Electric	(0.4)	(0.1)	(0.2)	(0.4)	0.0	(0.2)	(0.2)	(0.0)	(0.1)	0.1	(0.1)	0.0	(0.1)	(0.0)	0.1	(0.0)
Idaho Power	0.3	1.4	(0.1)	(0.9)	(0.1)	(0.1)	0.9	0.2	(0.5)	2.8	0.1	0.0	0.2	0.1	(0.1)	0.1
LADWP	(0.1)	(0.1)	(0.3)	0.3	0.1	0.0	(0.4)	0.0	0.0	0.1	0.1	(0.0)	(0.0)	(0.1)	0.0	(0.1)
NorthWestern En.	2.3	0.4	0.4	1.8	1.4	0.9	1.6	2.3	2.4	3.0	1.1	0.5	0.5	0.3	0.6	1.4
NV Energy	0.3	0.1	0.1	0.2	0.1	0.1	0.6	0.5	0.7	0.5	0.2	0.2	0.1	(0.2)	(0.1)	(0.2)
PacifiCorp East	1.2	0.3	1.3	2.6	3.4	3.0	4.2	2.1	1.0	1.7	1.1	0.2	(0.2)	0.0	0.8	0.6
PacifiCorp West	(1.5)	(0.2)	(1.5)	(4.0)	(5.6)	(3.3)	(4.3)	(2.3)	(1.3)	(8.2)	(1.4)	(0.7)	(0.4)	(0.2)	(0.7)	(1.2)
Portland G.E.	0.1	0.1	0.0	0.4	0.2	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	(0.0)	0.0
Powerex	(0.6)	(0.4)	(0.0)	(0.0)	0.5	0.2	(0.2)	(0.3)	(0.2)	0.7	0.1	(0.1)	(0.1)	(0.1)	0.0	(0.2)
PSC of New Mexico	2.8	0.4	0.6	1.2	1.3	0.7	1.0	1.6	1.0	1.5	1.4	0.8	0.8	0.3	0.2	1.3
Puget Sound En.	(2.0)	(0.6)	(0.9)	(2.2)	(2.3)	(1.2)	(1.8)	(2.2)	(2.0)	(4.4)	(1.4)	(1.0)	(0.6)	(0.5)	(0.8)	(1.8)
Salt River Proj.	(1.3)	(0.8)	(0.8)	(4.4)	(1.7)	(1.1)	(1.2)	(1.4)	(2.0)	(2.4)	(0.1)	(0.5)	(0.3)	(0.5)	(0.6)	(1.4)
Seattle City Light	0.1	(0.0)	(0.1)	(0.1)	0.1	0.0	0.0	0.1	0.1	0.4	(0.0)	0.0	(0.0)	(0.1)	(0.0)	(0.1)
Tacoma Power	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
Tucson Elec. Pow.	0.4	0.1	0.1	0.1	0.2	(0.0)	0.2	0.2	0.3	0.4	0.0	0.0	0.1	(0.0)	(0.0)	0.1
Turlock Irrig. Dist.	0.3	0.1	0.2	0.6	0.7	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2	0.4
WAPA DSW	0.4	(0.1)	0.0	0.2	0.1	0.1	(0.5)	(0.0)	(0.0)	(0.1)	0.0	0.0	0.0	(0.0)	0.0	0.1

Figure 1.49 Real-time congestion imbalance offset charges (credits) by month and balancing area ($ millions)

Arizona Publ. Serv.	(0.7)	(0.3)	(1.4)	0.4	0.0	(0.1)	0.0	(0.2)	(0.2)	(0.0)	(0.2)	0.1	(0.0)	0.0	0.1	0.1
Avangrid	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.0)	(0.0)	(0.1)	(0.0)	(0.6)	(0.1)	(0.3)	(0.1)	(0.2)	(0.1)	(0.4)
Avista	(0.2)	(0.2)	(0.0)	(0.1)	(0.0)	(0.1)	(0.3)	(0.1)	0.0	(1.2)	(0.0)	(0.0)	(0.1)	(0.1)	(0.0)	(0.3)
BANC	0.1	0.2	0.0	(0.0)	(0.0)	0.0	0.0	0.0	(0.1)	0.0	0.0	(0.0)	0.0	(0.2)	0.0	(0.2)
BPA	(0.4)	(0.9)	(0.1)	(0.5)	(0.4)	(0.4)	(0.6)	(0.2)	(0.1)	(0.8)	0.1	(0.5)	0.2	(0.6)	(0.4)	(0.8)
El Paso Electric	(0.1)	(0.4)	(0.3)	(1.1)	(0.3)	(0.2)	(0.9)	(0.0)	(0.0)	(0.1)	(0.2)	(0.0)	(0.2)	(0.3)	(0.2)	(0.7)
Idaho Power	(1.1)	(0.9)	(0.3)	(0.4)	(0.3)	(0.3)	(1.0)	(0.5)	(0.1)	(4.7)	(0.1)	(0.1)	(0.4)	(0.4)	(0.2)	(1.0)
LADWP	(0.4)	(0.4)	(0.4)	(1.9)	(1.2)	(0.8)	(0.5)	(0.3)	(0.3)	(1.4)	(0.3)	(0.5)	(0.4)	(0.4)	(0.5)	(1.3)
NorthWestern En.	(0.1)	(0.1)	(0.1)	0.1	(0.1)	(0.1)	(0.2)	(0.1)	(0.0)	(1.0)	(0.0)	(0.0)	(0.1)	(0.2)	(0.0)	(0.2)
NV Energy	(0.8)	(0.4)	(0.5)	(0.1)	(0.0)	(0.1)	(0.7)	(0.3)	(0.0)	(1.2)	(0.1)	(0.2)	(0.2)	(0.3)	(0.6)	(1.1)
PacifiCorp East	(5.3)	(1.0)	(1.1)	(2.9)	(2.9)	(3.4)	(3.6)	(8.8)	(11)	(12)	(6.9)	(3.8)	(2.6)	(1.4)	(2.6)	(6.6)
PacifiCorp West	(1.1)	(1.3)	(0.5)	(1.3)	(1.2)	(0.6)	(1.5)	(0.7)	(0.2)	(8.0)	(0.3)	(0.4)	(0.3)	(0.8)	(0.3)	(1.3)
Portland G.E.	(0.8)	(0.5)	(0.5)	(0.9)	(3.6)	(0.3)	(2.3)	(0.5)	(0.2)	(5.8)	(0.2)	(0.3)	(0.2)	(1.3)	(0.7)	(2.2)
Powerex	(12)	(2.0)	(16)	(29)	(26)	(30)	(17)	(13)	(7.8)	(6.1)	(9.5)	(8.9)	(7.5)	(4.2)	(4.3)	(15.9)
PSC of New Mexico	(1.0)	(0.3)	(0.0)	2.3	(0.1)	(0.2)	(0.1)	(0.7)	5.3	(0.8)	(0.5)	(0.1)	(0.4)	(0.4)	(0.4)	(1.2)
Puget Sound En.	(0.6)	(0.5)	(0.9)	(2.2)	(1.7)	(0.8)	(2.4)	(0.0)	(0.4)	(3.7)	(0.4)	(0.7)	(0.5)	(1.0)	(0.6)	(2.0)
Salt River Proj.	(1.8)	(2.2)	(1.9)	(2.5)	(1.1)	(1.3)	(1.5)	(2.4)	(1.0)	(2.3)	(0.5)	(0.8)	(0.7)	(1.7)	(2.4)	(4.8)
Seattle City Light	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	(0.0)	(0.3)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.1)
Tacoma Power	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.2)	(0.0)	(0.1)	(0.0)	(0.1)
Tucson Elec. Pow.	(0.8)	(1.4)	(1.3)	(1.4)	(1.1)	(1.0)	(1.3)	(0.1)	(0.2)	(0.9)	(0.6)	(0.6)	(0.5)	(1.8)	(1.0)	(3.3)
Turlock Irrig. Dist.	(0.0)	0.0	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
WAPA DSW	(0.0)	(0.1)	0.0	(0.0)	(0.2)	(0.0)	(0.0)	(0.0)	(0.0)	0.1	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	*Total*
	2023									2024						Q2 '24

Figure 1.50 Real-time loss imbalance offset charges (credits) by month and balancing area ($ millions)

Arizona Publ. Serv.	(0.3)	(0.1)	(0.1)	(0.7)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.3)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	(0.2)
Avangrid	(0.0)	(0.0)	(0.0)	0.0	0.1	0.0	(0.0)	(0.0)	(0.0)	(0.3)	(0.0)	0.0	0.1	0.1	0.0	0.2
Avista	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	(0.0)
BANC	0.0	(0.1)	(0.0)	0.0	0.1	0.0	0.0	0.0	0.0	0.1	(0.0)	0.0	0.0	(0.0)	0.0	(0.0)
BPA	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	0.1	(0.0)	0.0	0.9	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0
El Paso Electric	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Idaho Power	0.1	(0.0)	0.2	0.0	0.7	0.6	0.1	0.3	0.4	(0.3)	(0.1)	(0.0)	(0.1)	(0.0)	(0.0)	(0.1)
LADWP	(0.1)	0.0	0.0	(0.1)	(0.0)	0.0	0.1	(0.1)	0.1	(0.4)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0
NorthWestern En.	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	0.1	0.1	0.0	(0.0)	0.0	0.0	0.0	0.0
NV Energy	(0.1)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.3)	(0.0)	(0.1)	(0.0)	0.0	0.0	0.0
PacifiCorp East	0.1	0.2	0.0	(0.4)	(0.9)	(0.6)	(0.6)	(0.5)	(1.0)	(1.5)	(0.3)	(0.2)	(0.0)	0.1	(0.1)	(0.1)
PacifiCorp West	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	(0.2)	(0.2)	0.2	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.3)
Portland G.E.	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.1	(0.0)	2.0	(0.0)	(0.0)	(0.0)	0.0	0.1	0.0
Powerex	1.5	0.0	0.9	2.4	2.6	2.7	2.0	3.1	1.7	1.0	1.4	1.0	0.7	0.4	0.4	1.5
PSC of New Mexico	0.3	0.1	0.4	0.3	0.0	0.0	0.1	0.1	(0.0)	0.1	0.0	(0.0)	(0.0)	0.0	0.0	0.1
Puget Sound En.	(0.0)	(0.0)	0.0	0.1	0.0	0.0	0.1	(0.0)	0.1	0.4	0.1	0.0	(0.0)	(0.0)	0.0	(0.0)
Salt River Proj.	(0.3)	(0.0)	(0.1)	(0.3)	(0.2)	(0.2)	(0.1)	(0.2)	(0.3)	(0.4)	(0.2)	(0.1)	(0.1)	(0.1)	0.0	(0.1)
Seattle City Light	0.2	0.0	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.3	0.0	0.0	0.0	0.0	0.1	0.2
Tacoma Power	0.0	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.3)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	0.0
Tucson Elec. Pow.	(0.1)	0.0	0.1	(0.3)	(0.2)	(0.0)	(0.1)	(0.2)	(0.1)	(0.2)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)
Turlock Irrig. Dist.	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	(0.0)
WAPA DSW	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.2)	(0.0)	0.0	0.0	0.0	0.0	0.0
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	*Total*
	2023									2024						Q2 '24

Figure 1.51 Total real-time imbalance offset charges (credits) by month and balancing area ($ millions)

	2023 Apr	2023 May	2023 Jun	2023 Jul	2023 Aug	2023 Sep	2023 Oct	2023 Nov	2023 Dec	2024 Jan	2024 Feb	2024 Mar	2024 Apr	2024 May	2024 Jun	*Total* Q2 '24
Arizona Publ. Serv.	0.2	(0.2)	(0.6)	1.7	1.9	0.6	1.4	1.1	0.9	2.2	1.1	0.8	0.6	0.3	0.3	1.3
Avangrid	(0.3)	(0.1)	(0.1)	1.1	1.5	0.2	0.1	(0.3)	0.2	(0.6)	(0.0)	2.7	12	(3.2)	(3.5)	4.8
Avista	(0.2)	(0.2)	(0.0)	0.0	0.1	(0.2)	(0.2)	(0.0)	0.0	(1.2)	(0.0)	0.0	(0.1)	(0.1)	0.0	(0.2)
BANC	0.0	0.2	(0.1)	0.1	0.1	(0.2)	(0.2)	0.1	(0.1)	0.0	0.1	0.3	0.2	(0.2)	(0.1)	(0.0)
BPA	(0.6)	(1.0)	(0.1)	(0.2)	(0.2)	(0.4)	(0.3)	(0.1)	(0.2)	(1.0)	0.1	(0.5)	0.3	(0.5)	(0.3)	(0.5)
El Paso Electric	(0.5)	(0.5)	(0.5)	(1.5)	(0.4)	(0.4)	(1.1)	(0.0)	(0.1)	(0.1)	(0.3)	(0.0)	(0.3)	(0.3)	(0.1)	(0.7)
Idaho Power	(0.7)	0.4	(0.1)	(1.2)	0.2	0.1	0.0	(0.0)	(0.2)	(2.2)	(0.1)	(0.1)	(0.3)	(0.4)	(0.4)	(1.0)
LADWP	(0.5)	(0.5)	(0.7)	(1.6)	(1.2)	(0.8)	(0.9)	(0.4)	(0.3)	(1.7)	(0.3)	(0.5)	(0.4)	(0.5)	(0.4)	(1.3)
NorthWestern En.	2.2	0.3	0.3	1.9	1.3	0.8	1.4	2.3	2.4	2.1	1.1	0.5	0.5	0.2	0.6	1.2
NV Energy	(0.5)	(0.4)	(0.5)	(0.0)	(0.1)	(0.0)	(0.2)	0.2	0.5	(1.0)	0.0	(0.0)	(0.2)	(0.5)	(0.6)	(1.3)
PacifiCorp East	(4.0)	(0.5)	0.2	(0.8)	(0.4)	(1.0)	(0.0)	(7.3)	(11)	(11)	(6.1)	(3.8)	(2.8)	(1.3)	(1.9)	(6.0)
PacifiCorp West	(2.7)	(1.5)	(2.0)	(5.3)	(6.9)	(3.9)	(5.8)	(3.2)	(1.7)	(16)	(1.9)	(1.2)	(0.8)	(1.0)	(1.0)	(2.8)
Portland G.E.	(0.6)	(0.4)	(0.4)	(0.4)	(3.3)	(0.2)	(2.1)	(0.4)	(0.2)	(3.8)	(0.2)	(0.3)	(0.1)	(1.3)	(0.6)	(2.1)
Powerex	(11)	(2.3)	(15)	(27)	(23)	(27)	(15)	(10)	(6.3)	(4.4)	(8.0)	(8.0)	(6.9)	(3.9)	(3.8)	(14.6)
PSC of New Mexico	2.0	0.2	0.9	3.8	1.2	0.5	0.9	1.0	6.3	0.8	0.9	0.7	0.3	(0.0)	(0.2)	0.1
Puget Sound En.	(2.6)	(1.1)	(1.7)	(4.4)	(4.0)	(1.9)	(4.1)	(2.2)	(2.3)	(7.8)	(1.7)	(1.6)	(1.1)	(1.5)	(1.3)	(3.9)
Salt River Proj.	(3.4)	(3.0)	(2.8)	(7.1)	(2.9)	(2.7)	(2.9)	(4.0)	(3.3)	(5.1)	(0.7)	(1.4)	(1.0)	(2.2)	(3.0)	(6.3)
Seattle City Light	0.2	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	0.1	0.4	0.0	0.0	(0.0)	(0.1)	0.0	(0.0)
Tacoma Power	0.0	(0.0)	(0.0)	0.0	(0.1)	(0.0)	(0.0)	(0.1)	(0.0)	(0.3)	(0.0)	(0.2)	(0.0)	(0.1)	(0.0)	(0.1)
Tucson Elec. Pow.	(0.5)	(1.3)	(1.1)	(1.6)	(1.1)	(1.1)	(1.1)	(0.1)	(0.1)	(0.7)	(0.6)	(0.6)	(0.5)	(1.8)	(1.1)	(3.3)
Turlock Irrig. Dist.	0.3	0.1	0.2	0.5	0.7	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2	0.4
WAPA DSW	0.4	(0.2)	0.0	0.2	(0.1)	0.0	(0.5)	(0.1)	(0.0)	(0.2)	0.1	0.1	0.1	(0.0)	0.0	0.1

1.11 Bid cost recovery

During the second quarter of 2024, estimated bid cost recovery payments for units in the California ISO and Western Energy Imbalance Market (WEIM) balancing areas totaled about $37 million and $2.6 million, respectively. In the CAISO area, the payments were an increase from that of the same quarter of 2023, when they totaled $31.9 million. WEIM area bid cost recovery payments decreased from $3.7 million.[45]

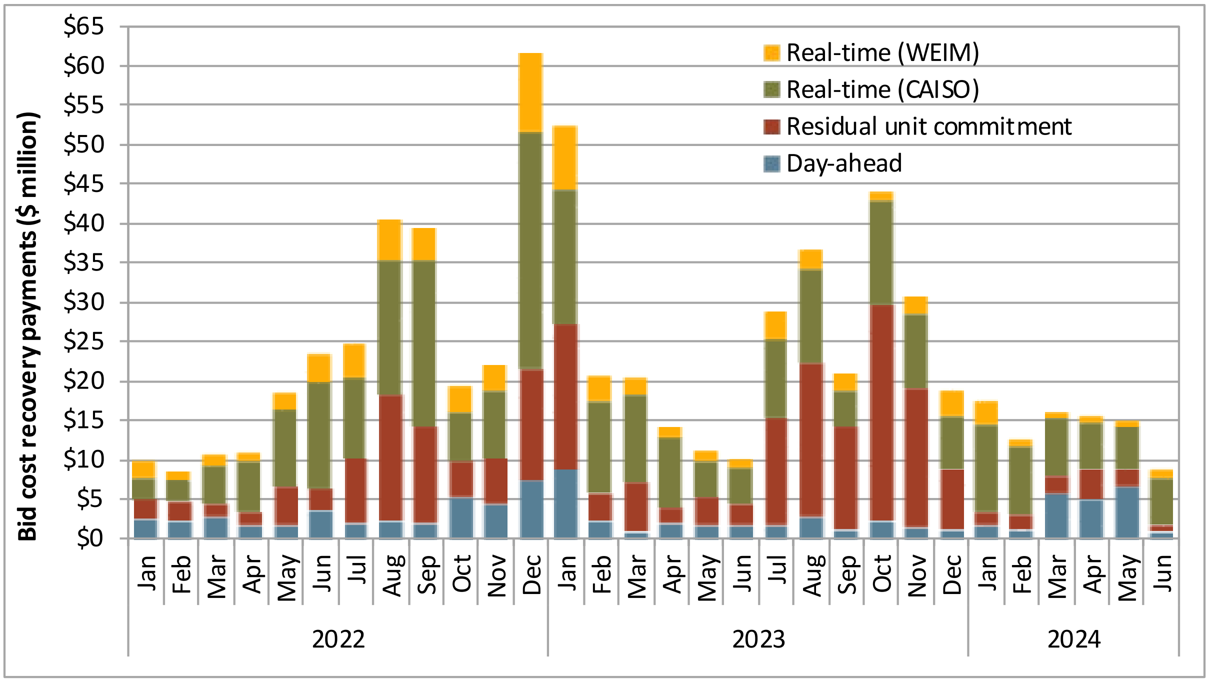
Figure 1.52 shows monthly bid cost recovery payments in the second quarter of 2024. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $12.4 million, which was greater than the $5.6 million in the second quarter of 2023. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $6.9 million, or about $1.6 million lower than the second quarter of 2023. Bid cost recovery over all balancing areas in the real-time market totaled about $20.1 million, which was about $1.4 million lower than the same quarter of 2023. Out of the total real-time payments, about $2.6 million was allocated to resources participating in non-CAISO WEIM areas.

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. In the second quarter of 2024, about $31 million of bid cost recovery payments were made

45 The bid cost recovery payment amounts for 2022 and 2023 in this report are different than what is reported in the Q2 2023 report due to resettlements.

to gas resources, 94 percent of which were paid to units in the California ISO area. About $3.2 million of payments were made to battery energy storage resources, over 99 percent of which went to units in the CAISO area. Bid cost recovery payments to solar and hydroelectric resources totaled $3.3 million and $1.3 million, respectively.

Figure 1.52 Monthly bid cost recovery payments



1.12 Imbalance conformance

Operators in the California ISO and the WEIM balancing areas can manually adjust the load forecasts used in the real-time markets in order to help maintain system reliability. The ISO refers to this as *imbalance conformance*. These adjustments are to account for potential modeling inconsistencies and inaccuracies, and to create additional unloaded ramping capacity in the real-time market.

Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 1.53 shows imbalance conformance adjustments in real-time markets for the second quarter of 2023 and 2024. Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets increased in the second quarter of 2024 relative to the same quarter of 2023. This increase was mainly during the morning solar ramping hours. During the morning hours, the highest average hourly adjustments were around 930 MW. This was an increase of about 630 MW compared to the second quarter of 2023. Adjustments during the evening peak net load hours were very similar to the same quarter of the prior year and peaked at about 1,615 MW.

The 5-minute market adjustments increased in the second quarter of 2024 in all hours compared to the second quarter of 2023. Low levels of negative adjustments occurred in hours-ending 3 to 5 and hour-ending 13.

Figure 1.53 Average hourly imbalance conformance adjustment (Q2 2023 and Q2 2024)

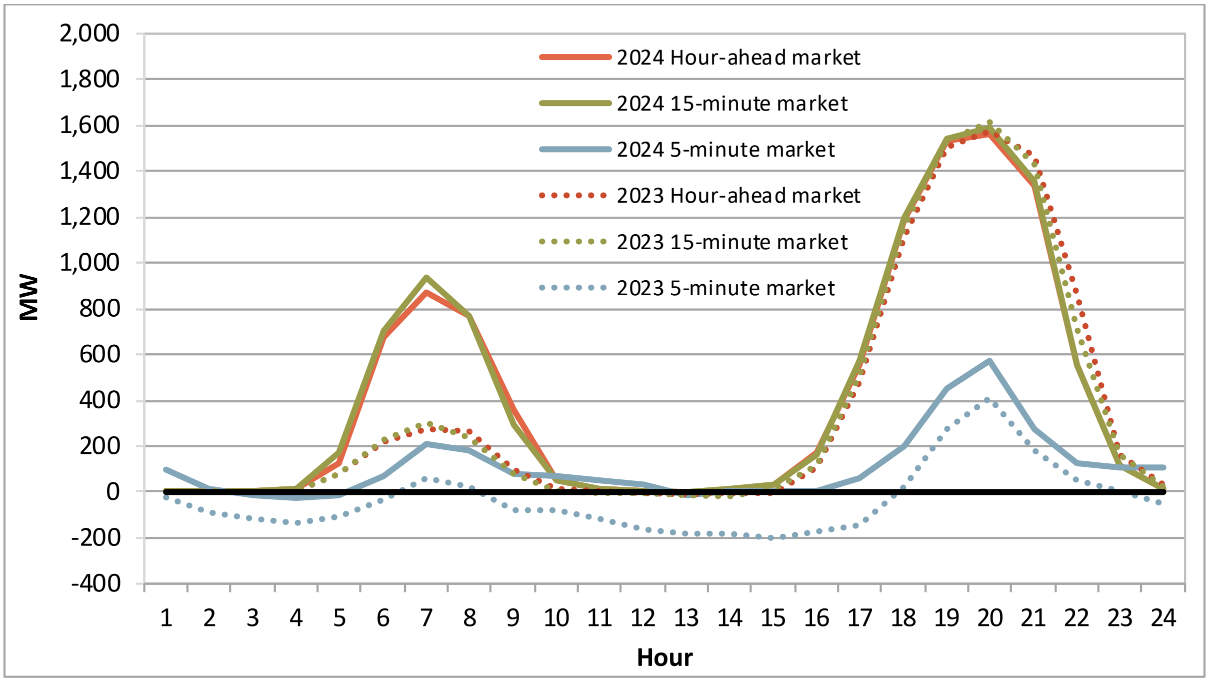
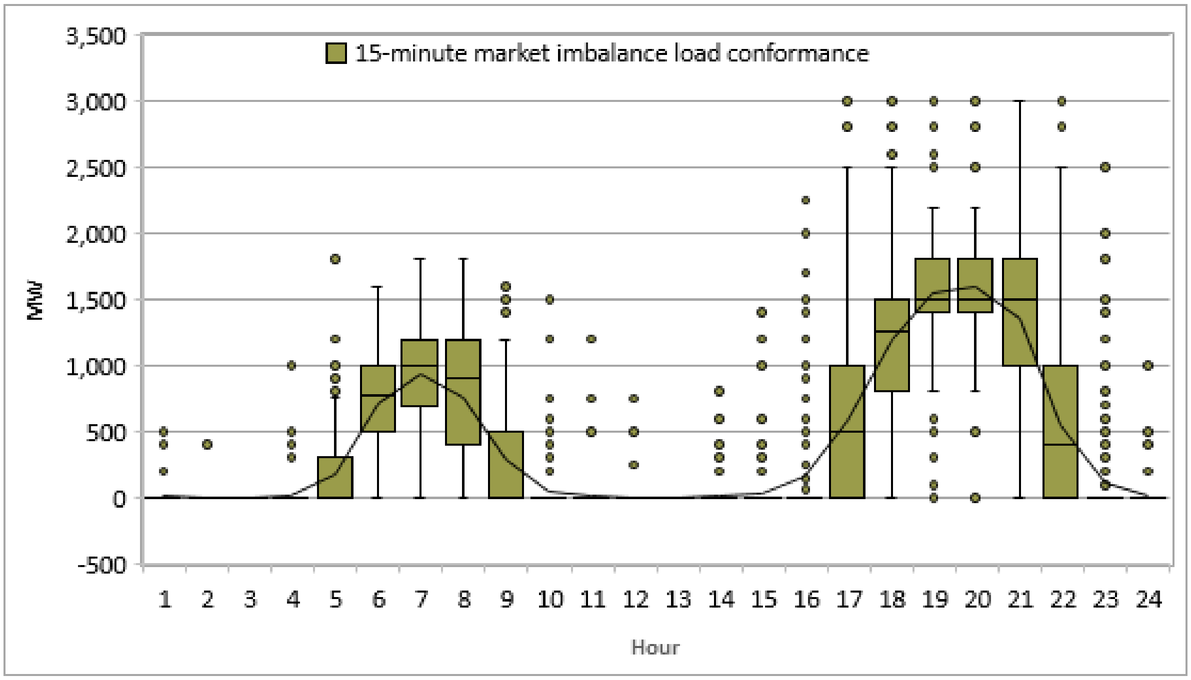


Figure 1.54 shows an hourly distribution of the 15-minute market load adjustments for the second quarter of 2024. This box and whisker graph highlights extreme outliers[46] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well as the mean (line). The extreme outliers are represented by the filled "dots". The outside whiskers do not include these outliers. For the quarter, the 3,000 MW outliers in hours-ending 17 to 22 occurred between June 24 and 28.

[46] A data point is an outlier if it is more than 1.5 * IQR above the third quartile or below the first quartile. The upper outliers are greater than the 3rd quartile + 1.5 x Interquartile Range (IQR), while lower outliers are values less than the 1st quartile less 1.5 x Interquartile Range (IQR).

Figure 1.54 15-minute market hourly distribution of operator load adjustments (Q2 2024)



1.13 Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market, to help manage volatility and uncertainty surrounding net load forecasts.[47] The amount of flexible capacity the product procures is derived from a demand curve, which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs. Flexible capacity is procured and priced at a nodal level to better ensure that sufficient transmission is available for the capacity to be utilized.

1.13.1 Flexible ramping product market outcomes and settlement

Flexible ramping product requirement

The flexible ramping product demand curves are implemented in the ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This "requirement" for rampable capacity reflects the upper end of

[47] The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the three corresponding 5-minute market runs. Procurement in the 5-minute market is aimed at ensuring that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

uncertainty in each direction that might materialize.[48] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for the group of balancing areas that instead pass the resource sufficiency evaluation are pooled together to meet the uncertainty requirement for the rest of the system. Both the requirement for the pass-group and the requirement for balancing areas that fail the resource sufficiency valuation are calculated using a method called *mosaic quantile regression*. This method applies regression techniques on historical data to produce a series of coefficients that define the relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval).

Flexible capacity awards are produced through two deployment scenarios that adjust the expected net load forecast in the following interval by the lower and upper ends of uncertainty that might materialize. The uncertainty requirement is distributed at a nodal level to load, solar, and wind resources based on allocation factors that reflect the estimated contribution of these resources to potential uncertainty. The result is more deliverable upward and downward flexible capacity awards that do not violate transmission or transfer constraints.

Flexible ramping product prices

As part of flexible ramping product enhancements, in 2023, the ISO began determining flexible ramping product prices locationally at each node. This nodal price can be made up of multiple components.[49] The first component is the shadow price associated with meeting the flexible ramp requirement either for the group of balancing areas that pass the resource sufficiency evaluation or the individual balancing areas that fail the tests.

The nodal price also includes components to reflect any congestion based on the dispatch of flexible capacity in the deployment scenarios. This accounts for any congestion on WEIM transfer constraints between balancing areas as well as congestion on transmission constraints.[50] These components can create price differences across nodes in the WEIM based on the demand for flexibility in the system and the feasibility for flexible capacity at a node to meet that demand. For the transmission constraints, only base-case flow based constraints were modeled in the deployment scenarios at implementation of the enhancements on February 1, 2023. Nomogram constraints were later enforced for flexible ramping product procurement on September 7, 2023. Contingency flowgate constraints were activated on June 4, 2024 and de-activated on June 12 due to performance issues with the solution run-times.[51] Using the same constraints for both the real-time market and flexible ramping product deployment scenarios is

48 Based on a 95 percent confidence interval.

49 For details on the deployment scenario constraints and how the ISO derives flexible ramping prices from them, see *Business Requirements Specification – Flexible Ramp Product: Deliverability*, California ISO, August 19, 2022, pp 89-90: https://www.caiso.com/documents/businessrequirementsspecifications12-flexiblerampingproduct-deliverability.pdf

50 Congestion on WEIM transfer constraints is reflected through the individual balancing area power balance constraint in the deployment scenarios. This constraint considers both flexible ramping awards and flexible ramping requirements in addition to WEIM supply, load, and WEIM transfers between the areas.

51 *Market Performance and Planning Forum*, Q2, California ISO, June 27, 2024, slides 170-171: https://www.caiso.com/documents/presentation-market-performance-planning-forum-jun-27-2024.pdf

important in order to prevent conditions in which procured flexible capacity is actually stranded behind transmission constraint congestion, and therefore not able to address materialized uncertainty.

The pass-group constraint maintains that the sum of flexible capacity in the group of balancing areas that pass the resource sufficiency evaluation equals the group's uncertainty requirement (minus any relaxation). The ability to relax the requirement is allowed by *slack variables*. This allows flexible capacity to be forgone when the cost of procuring flexible capacity is higher than the benefit it provides (or when flexible capacity is not available).

The slack variables are implemented for each balancing area.[52] The cost associated with the slack variable (cost of relaxing the requirement) is reflected by a demand curve. The demand curves are based on each balancing area's expected cost of a power balance constraint violation for the level of flexible capacity forgone.[53] The more flexibility forgone, the greater the likelihood of a power balance constraint violation and therefore greater expected cost. For a balancing area in the pass-group, the slack variable (or end of the demand curve) is limited by its distributed share of the pass-group uncertainty requirement.

The shadow price on the constraint for procuring flexible capacity in the pass-group has frequently been zero since the enhancements were implemented. When the shadow price on this constraint is zero, this generally reflects that flexible capacity within the wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available.[54] Here, the flexible capacity requirement for the group of balancing areas that passed the resource sufficiency evaluation can be met by resources with zero opportunity cost for providing that flexibility.

Figure 1.55 shows the percent of intervals since implementation of the enhancements in which the shadow price on the pass-group constraint was non-zero. This reflects more widespread prices for flexible capacity within the group of balancing areas that passed the resource sufficiency evaluation, but does not account for any congestion that may affect the price of flexible capacity at the nodal level.[55] This is compared against the frequency of non-zero prices on the constraint for *system-wide* flexible capacity that was in place prior to the enhancements. The constraint for procuring pass-group flexible capacity was binding very infrequently during the quarter, and less frequent compared to the system-level constraint prior to the enhancements. Prices in the 15-minute market for flexible capacity via the pass-group constraint were non-zero in less than 0.1 percent of intervals in both directions. In the 5-minute market, the frequency of non-zero prices were similarly infrequent.

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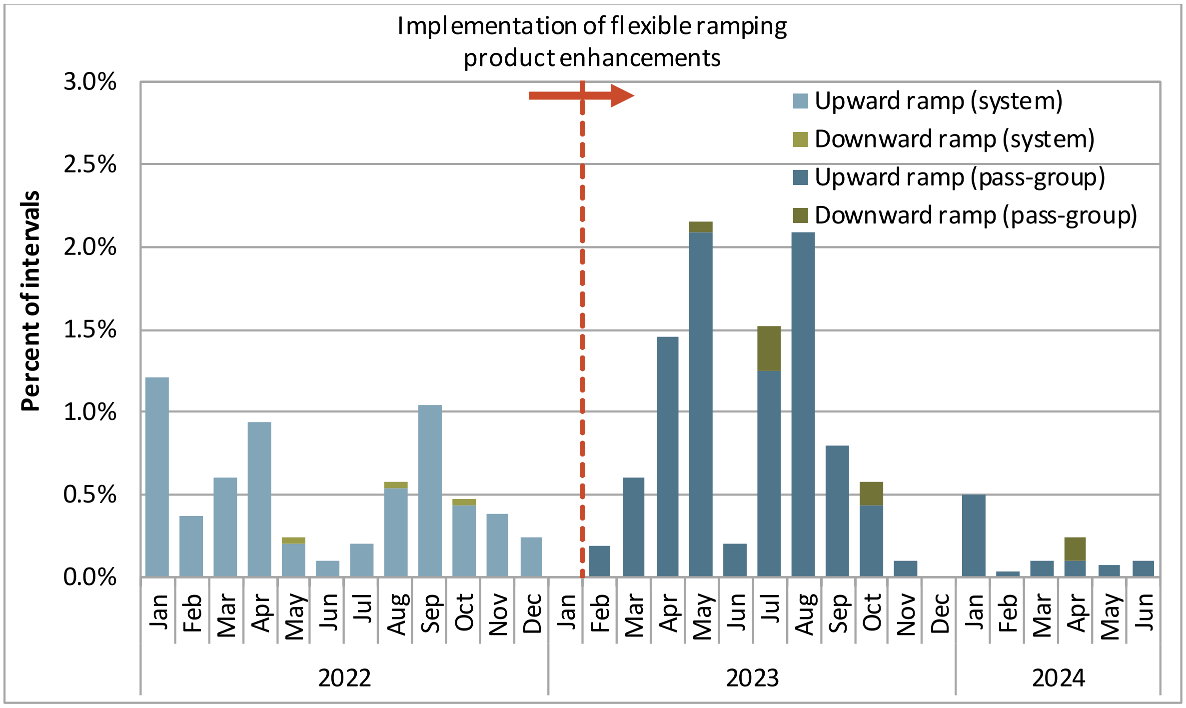
52 Or for each surplus zone in the case of the CAISO balancing area (by TAC area) and BANC (by custom load aggregation point).

53 For upward flexible capacity, the demand curves are capped at $247/MWh.

54 This pass-group constraint is intended to limit the sum of all flexible ramp capacity in the passing group. The limit is the group's total flexible ramp requirement. The formulation of the deployment scenario also includes an individual power balance constraint for each balancing area in the pass-group, which considers the balancing area's energy load and supply, flexible ramping product requirement and supply, and transfers of energy and flexible ramping product. Given this individual power balance constraint for each balancing area, the pass-group flexible ramping capacity constraint may be redundant. This complicates the interpretation of the meaning of the shadow price of this pass-group constraint, and other constraints, in the deployment scenario in some cases. The potential redundancy of the constraint may also result in abnormal flexible ramping prices in some situations.

55 This figure does not account for congestion on WEIM transfer constraints between the areas in the pass-group. It also does not account for any congestion on flow-based constraints.

Figure 1.55 Frequency of flexible ramping product prices from pass-group constraint (15-minute market)



The price of flexible capacity for a node in a balancing area that passed the resource sufficiency evaluation can still be positive even when the shadow price on the constraint for procuring pass-group-level flexible capacity is zero (e.g., not binding). This can occur because of congestion on WEIM transfer constraints that might separate a balancing area from the rest of the system. Here, outside flexible capacity may not be feasible to meet the isolated balancing area's share of pass-group uncertainty and this requirement may be relaxed, resulting in a localized price for flexible capacity. Congestion on binding transmission constraints in the deployment scenario can also create a localized price for flexible capacity.

Figure 1.56 summarizes the frequency of flexible ramping product prices in either the wider pass-group or transfer-constrained balancing areas within the pass-group. The blue bars are identical to the information shown in Figure 1.56, summarizing the frequency in which the constraint for meeting pass-group flexible capacity requirements was binding. The figure adds the percent of interval in which the constraint that reflects WEIM transfer congestion in the deployment scenario was binding for one or more balancing areas in the pass-group—*and the pass-group constraint was not also binding*. This reflects additional flexible ramping product prices within at least one balancing area. In most cases, these prices were within one isolated balancing area in the pass-group that was not able to meet its share of pass-group uncertainty. Localized flexible ramping product prices within the pass-group that are entirely driven by congestion on transmission constraints are not reflected in this figure.

Figure 1.56 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

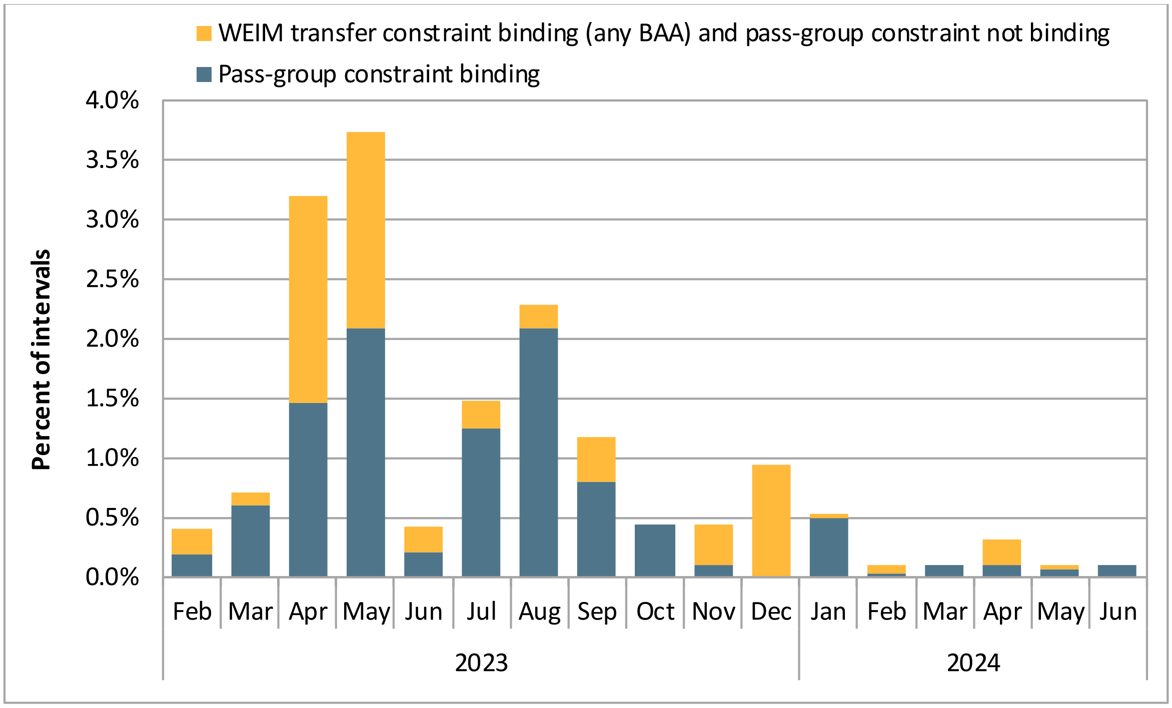


Figure 1.57 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

- **Pass-group constraint binding and WEIM transfer constraint not binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group.
- **Pass-group constraint binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group; but because of WEIM transfer congestion out of the balancing area, there is typically no price for upward flexible capacity within the balancing area.
- **Pass-group constraint not binding and WEIM transfer constraint binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is no price for upward flexible capacity within the wider pass-group; but because of WEIM transfer congestion into the balancing area, there is a price for upward flexible capacity within the balancing area.
- **Balancing area constraint binding (failed resource sufficiency evaluation)** indicates that the balancing area failed the resource sufficiency evaluation and there is a price for upward flexible capacity within the balancing area.

During the quarter, the pass-group constraint was binding very infrequently for upward flexible capacity in the 15-minute market, during less than 0.1 percent of intervals. In many of these intervals, balancing areas in the Pacific Northwest region had sufficient flexible capacity, but because of congestion on

WEIM transfer constraints out of the balancing area in the deployment scenario, flex ramp prices here were typically zero.

Figure 1.57 Frequency of upward flexible ramping product prices by balancing area and constraint (15-minute market, April–June 2024)

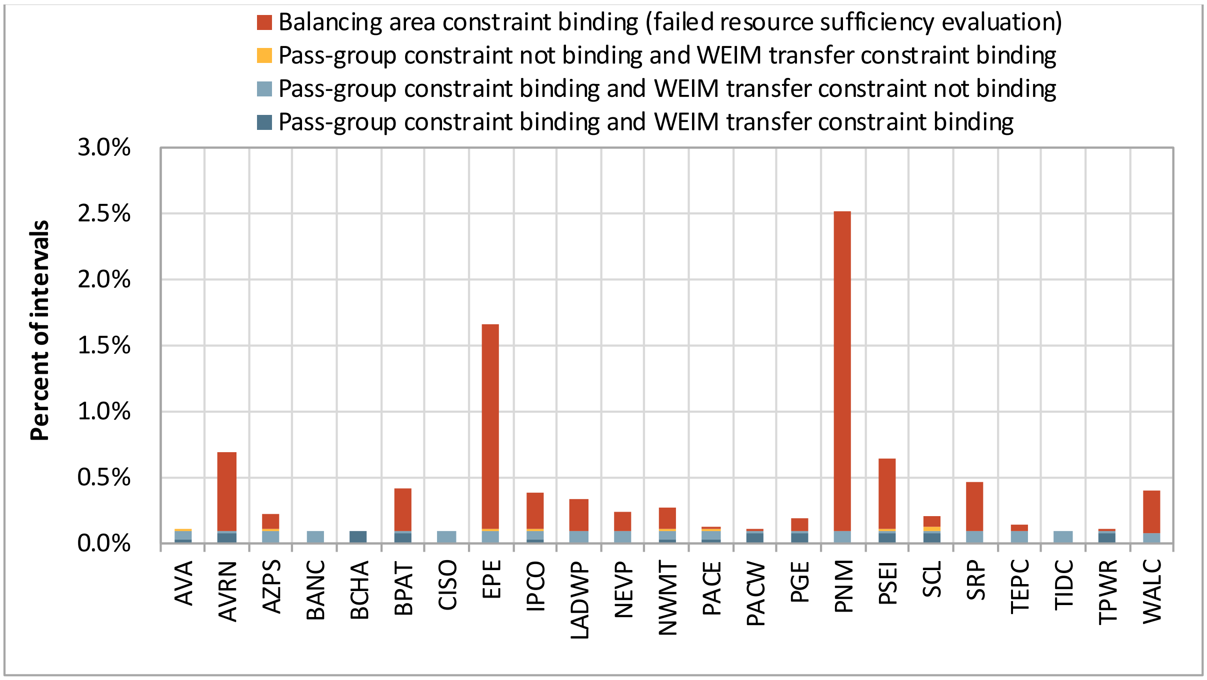


Figure 1.57 also summarizes flexible capacity prices that can exist following a resource sufficiency evaluation failure (red bars). When a balancing area fails the resource sufficiency evaluation, the area will not have access to any diversity benefit of reduced uncertainty over a larger footprint and will instead need to meet its uncertainty needs from flexible capacity within its area only. The Public Service Company of New Mexico (PNM) frequently had prices for flexible capacity in the balancing area following a failure of the resource sufficiency evaluation, during around 2.4 percent of intervals. Most of these were associated with failure of the second run of the resource sufficiency evaluation at 55 minutes prior to the hour, which impacts the first interval of each hour.[56]

Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the greater WEIM system during the quarter.

Figure 1.58 and Figure 1.59 show the percent of upward or downward flexible capacity that was procured from various fuel types, both before and after the enhancements that were implemented at the start of February, 2023. Prior to the enhancements, these amounts reflect the percent of *system-*

56 There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each evaluation. The first and second runs are sometimes considered the advisory runs, with the final evaluation occurring at 40 minutes prior to the hour. For procuring and pricing flexible capacity in the first 15-minute market interval of each hour, the market uses the results from the second run of the resource sufficiency evaluation. This is based on the latest information available at the time of this market run.

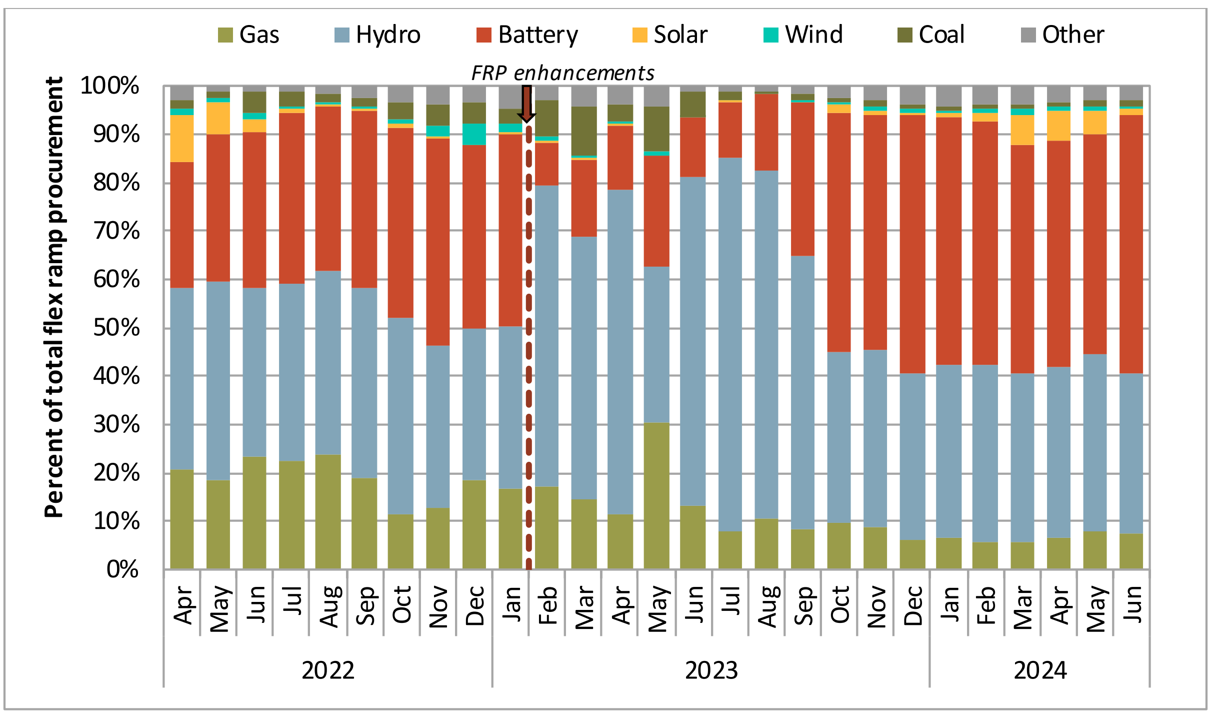
wide uncertainty. After the enhancements, these amounts instead reflect the percent of *pass-group* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation.

During the quarter, battery resources continued contributing to much of the upward and downward flexible capacity. Battery resources made up almost 50 percent of upward flexible capacity and 30 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (35 percent). Wind and solar resources combined made up around 45 percent of downward flexible capacity.

Figure 1.60 and Figure 1.61 show the percent of upward or downward flexible capacity that was procured in various regions.[57] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained, along with one or more other balancing areas relative to the greater WEIM system.

During the quarter, CAISO continued to make up the majority of upward and downward flexible capacity awards, at around 53 percent of upward capacity and 65 percent of downward capacity. Balancing areas in the Pacific Northwest made up 30 percent of upward flexible capacity and 16 percent of downward flexible capacity.

Figure 1.58 Percent of upward system or pass-group flexible ramp procurement by fuel type



[57] California (WEIM) includes BANC, LADWP, and Turlock Irrigation District. Desert Southwest includes Arizona Public Service, NV Energy, PNM, Salt River Project, El Paso Electric, Tucson Electric Power, and WAPA (DSW). Intermountain West includes Idaho Power, NorthWestern Energy, PacifiCorp East, and Avista. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Figure 1.59 Percent of downward system or pass-group flexible ramp procurement by fuel type

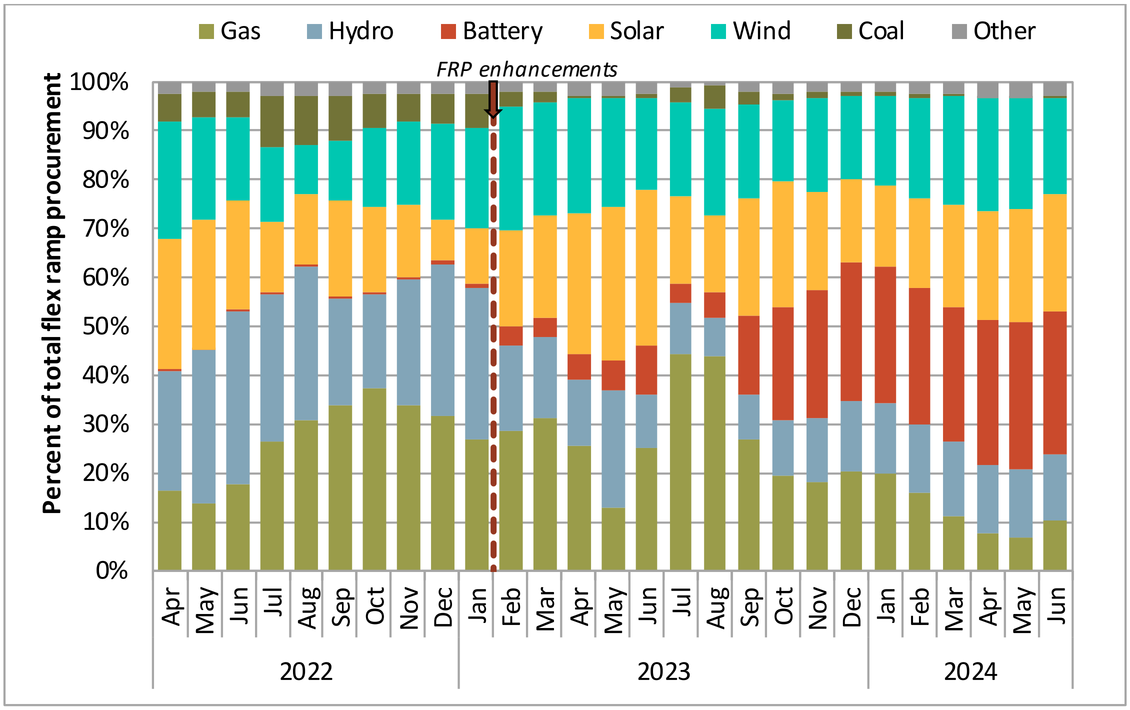


Figure 1.60 Percent of upward system or pass-group flexible ramp procurement by region

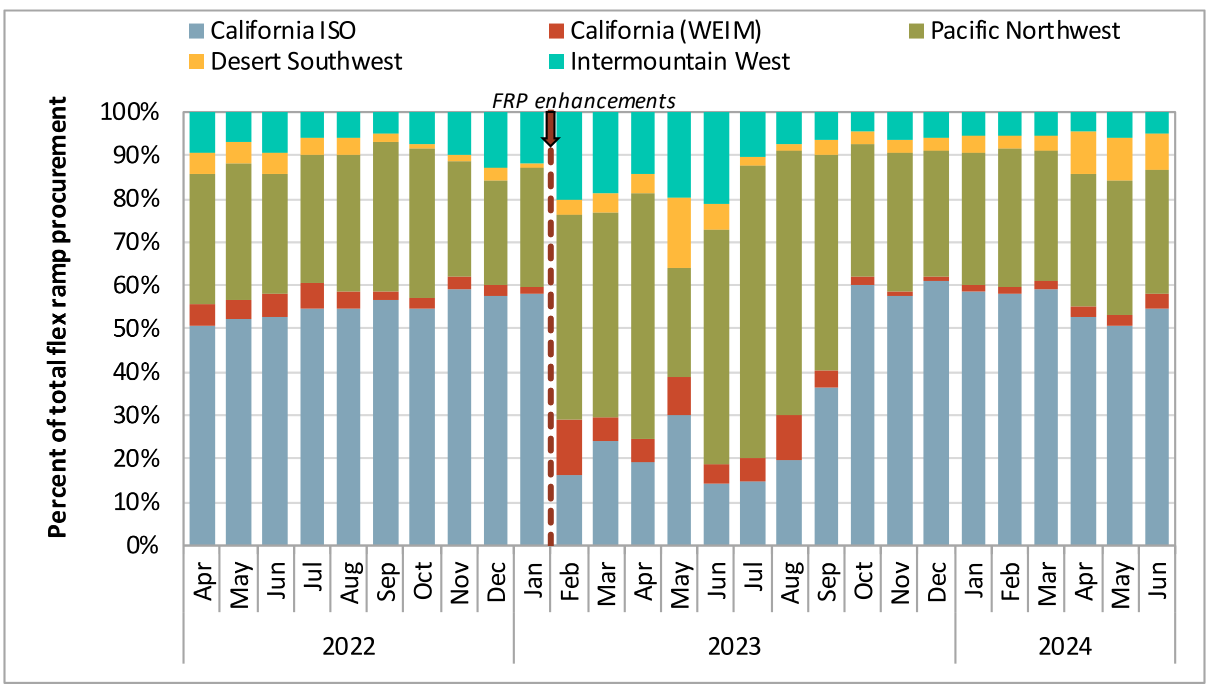
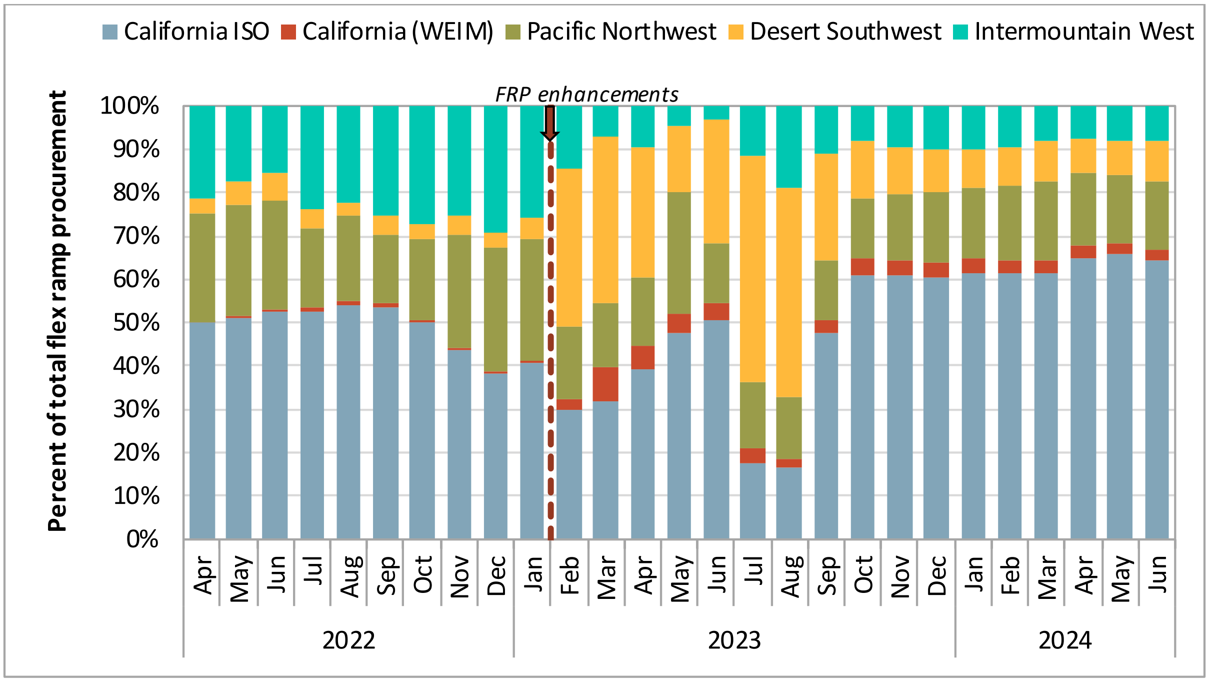


Figure 1.61 Percent of downward system or pass-group flexible ramp procurement by region



Flexible ramping product error for forecasted movement settlement

Flexible ramping capacity awards reflect the ability for a resource to ramp above or below their expected schedule in the next interval to address uncertainty that might materialize. Flexible ramping capacity that satisfies the demand for upward or downward flexibility receives payments based on the price for flexible capacity at that node. In addition, the flexible ramping product price is used to pay or charge for *forecasted movements*. Forecasted movement is a resource's expected change in schedule in the next interval. A payment indicates that the resource was given an advisory dispatch by the market in the same direction as the demand for flexibility (e.g., supporting flexibility).[58] A charge indicates that the resource was given an advisory dispatch by the market in the opposite direction as the demand for flexibility (e.g., consuming flexibility).

The settlement of forecasted movement was incorrect following the implementation of flexible ramping product enhancements on February 1, 2023. The quantity used to settle forecasted movement was incorrectly selected from the following interval in a way that was inconsistent with the price conditions at the time of the movement. The settlement of flexible capacity awards to meet uncertainty was not impacted. The ISO is working on correcting and resettling forecasted movement for the impacted period.

[58] A resource that is given an advisory dispatch by the market to increase output is paid the upward flexible ramping price and charged the downward flexible ramping price. A resource that is given an advisory dispatch by the market to decrease output is paid the downward flexible ramping price and charged the upward flexible ramping price.

1.13.2 Net load uncertainty for the flexible ramping product

The uncertainty requirement is used as part of the flexible ramping product design to capture the extreme ends of net load uncertainty, such that it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. Net load uncertainty is also included in the requirement of the flexible ramp sufficiency test (flexibility test) to capture additional flexibility needs that may be required in the evaluation hour due to variation in either load, solar, or wind forecasts.

The calculation of uncertainty uses a method called mosaic quantile regression. This method applies regression techniques on historical data to produce a series of coefficients that define the relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval).[59]

Net load uncertainty for the group of balancing areas that passed the resource sufficiency evaluation

The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation, which can only be met by flexible capacity within that area. Here, the regressions can be performed in advance and local uncertainty targets can be readily determined based on current forecast information when a balancing area fails the test. However, for the group of balancing areas that pass the resource sufficiency evaluation (known as the pass-group), the uncertainty calculation needs to first know which balancing areas make up this group so that it can perform the regression using historical data accordingly for that group.

To perform the regressions to estimate the pass-group uncertainty, the composition of balancing areas in this group is based on earlier test results for the first and second 15-minute market interval of each hour. In the first interval, the results from the earliest resource sufficiency evaluation (T-75) is used to define the pass-group. In the second interval, the results from the second resource sufficiency evaluation (T-55) is used to define the pass-group. This is based on the latest information available at the time of this process.

However, the current weather information that is ultimately combined with the regression results to calculate uncertainty are instead consistent with the group of balancing areas in the pass-group for flexible ramping capacity procurement. This is based on the second run of the resource sufficiency evaluation (T-55) for interval 1 and the final resource sufficiency evaluation (T-40) for intervals 2 through 4. Table 1.6 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

59 For a detailed explanation of the mosaic quantile regression calculation, see the *Q1 2023 Report on Market Issues and Performance*, Department of Market Monitoring, September 19, 2023, pp 66-70: http://www.caiso.com/Documents/2023-First-Quarter-Report-on-Market-Issues-and-Performance-Sep-19-2023.pdf

Table 1.6 Source of pass-group for calculating uncertainty and procuring flexible ramping capacity

15-minute market interval	Regression inputs and outputs	Current weather information for calculating uncertainty and flex ramp procurement
1	First run (T-75)	Second run (T-55)
2	Second run (T-55)	Final run (T-40)
3	Final run (T-40)	Final run (T-40)
4	Final run (T-40)	Final run (T-40)

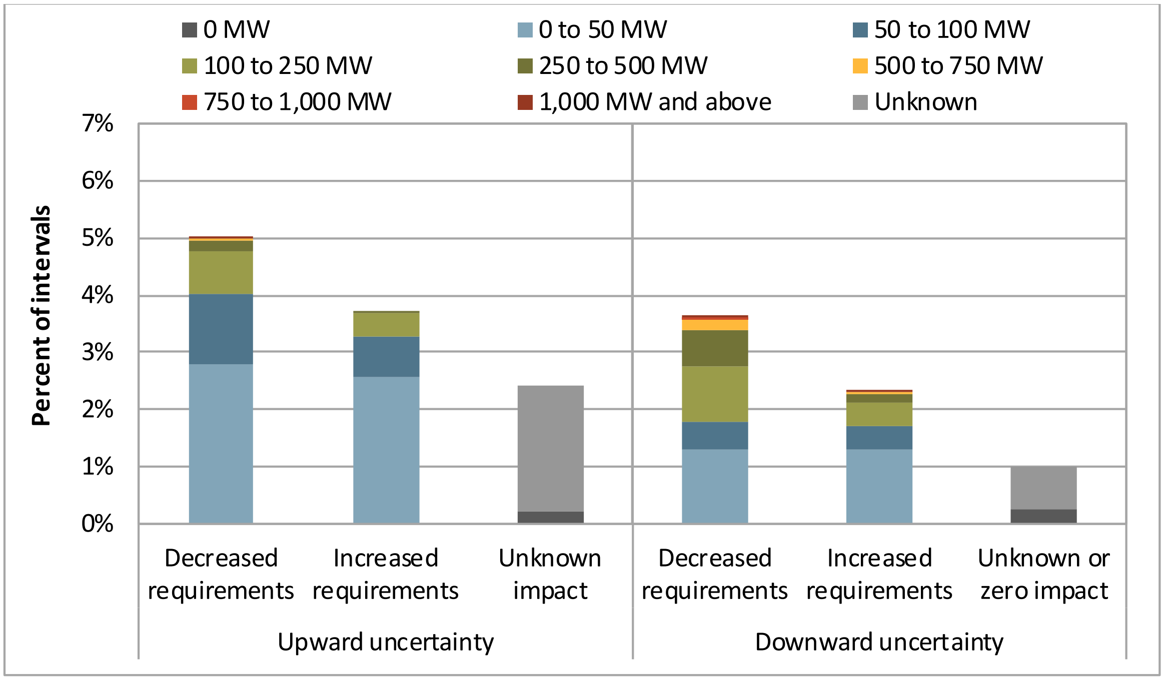
Using an inconsistent composition of balancing areas in the pass-group between the forecast and regression information can create significant swings in the calculated uncertainty for this group. For example, if you have a model to predict uncertainty based on forecast information of all but one balancing area passing the test (based on earlier test results), but then combine this with current forecast information of all balancing areas (based on later test results), then the calculated uncertainty can be disconnected from forecasted conditions in the system. DMM has requested that the ISO consider options to resolve inconsistencies in the composition of balancing areas in the pass-group.

During about 17 percent of intervals for the quarter, the composition of balancing areas in the pass-group used for regression information was inconsistent with the composition of balancing areas in the pass-group used for current forecast information. Figure 1.62 summarizes the impact of this inconsistency on pass-group uncertainty requirements in cases when the composition of balancing areas differed between the two sets of data. The figure shows the percent of intervals in which the market uncertainty requirements (with inconsistent balancing areas in the pass-group) were higher or lower than counterfactual uncertainty requirements with a consistent composition of balancing areas in the pass-group.[60] These results are shown separately for the following categories to highlight the impact of this inconsistency on uncertainty requirements.

- **Decreased requirements** indicate that market uncertainty requirements for the pass-group were lower as a result of inconsistent balancing areas in the pass-group.
- **Increased requirements** indicate that market uncertainty requirements for the pass-group were higher as a result of inconsistent balancing areas in the pass-group.
- **No impact** indicates that uncertainty requirements were capped by thresholds in a way that resulted in the same uncertainty requirements.
- **Unknown impact** indicates that there was an inconsistent composition of balancing areas in the pass-group but data was not available to calculate the impact.

60 This analysis accounts for any thresholds that capped, or would have capped, calculated uncertainty requirements.

Figure 1.62 Impact of pass-group inconsistency on uncertainty requirements (April–June 2024)



Threshold for capping uncertainty

Uncertainty calculated from the quantile regressions is capped by the lesser of two thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from the previous 180 days. The seasonal threshold is updated at minimum of quarterly and is calculated based on the 1st and 99th percentile using observations over the previous 90 days. For the seasonal threshold, each hour is calculated separately and the greatest upward and downward uncertainty across all hours sets the threshold for each hour of the same direction.

During the quarter, the thresholds capped *upward* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 17 percent of intervals in the 15-minute market and 10 percent of intervals in the 5-minute market. *Downward uncertainty* was capped in around 10 percent of intervals in the 15-minute market and 7 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the seasonal threshold.

A threshold is also in place that sets the floor for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. During the quarter, downward uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this threshold in 0.5 percent of intervals in the 15-minute market, and never in the 5-minute market. Upward uncertainty was set near zero by this floor in less than 0.2 percent of intervals in both the 15-minute and 5-minute markets.

Results of quantile regression uncertainty calculation

The uncertainty regressions use a distribution of historical forecast observations separate for each balancing area and hour. Prior to April 4, 2024, the distributions were also separate for each day-type, either weekday or weekend.[61] On April 4, the ISO changed the calculation to not make any distinction between weekday or weekend in the historical distributions. The goal of this change was to increase the sample size, particularly on the weekends.[62] By increasing the sample size the ISO hoped to enhance the regression's performance.

Figure 1.63 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation, both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the previous 180 days) and with the mosaic quantile regression method between April 4 and June 30, 2024. The green and blue lines show the average upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the month. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively, during the period.

Figure 1.64 shows the same information for 5-minute market uncertainty, which reflects the difference between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach was typically lower or comparable to uncertainty calculated with the histogram approach. This is most clear during the midday hours. However, results of the regression-based approach vary more widely, including periods with much lower uncertainty.

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61 Weekend observations include holidays.

62 For information regarding the impact of this change on the uncertainty calculations, see DMM's resource sufficiency evaluation report for the second quarter of 2024: https://www.caiso.com/documents/q2-2024-metrics-report-on-resource-sufficiency-evaluation-in-western-energy-imbalance-market-aug-1-2024.pdf

Figure 1.63 15-minute market pass-group uncertainty requirements (April 4–June 30, 2024)

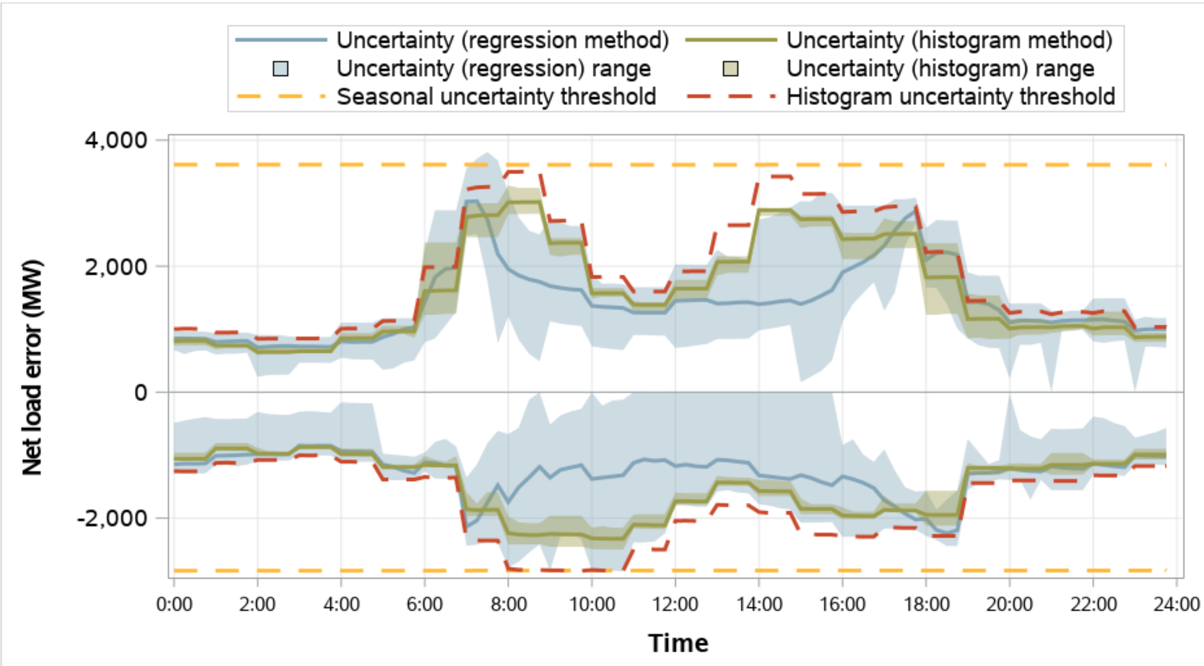

Figure 1.64 5-minute market pass-group uncertainty requirements (April 4–June 30, 2024)

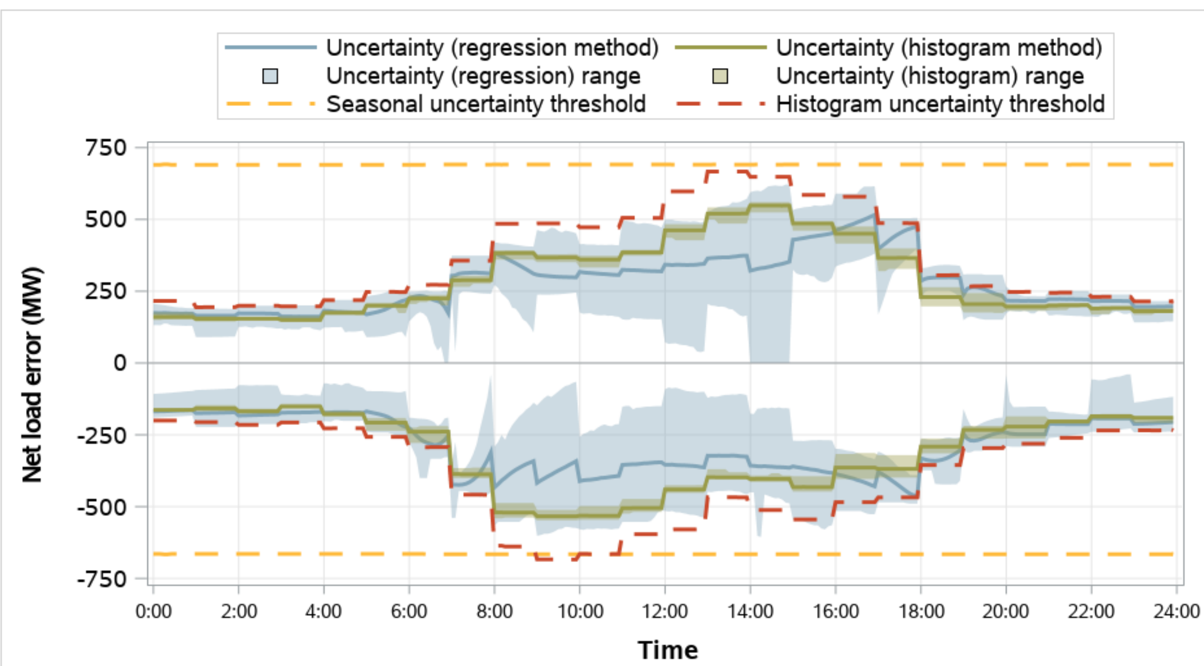

Table 1.7 summarizes the average uncertainty requirement for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. On average across all hours, the 15-minute uncertainty calculated from the regression method was less than the histogram method for both directions by roughly 200 MW.

Table 1.8 summarizes the actual net load error for the pass-group and how that compares to the mosaic regression uncertainty requirements for the same interval.[63] The left side of the table summarizes the closeness of the actual net load error to the pass-group uncertainty requirements when the actual net load error was within (or covered) by the upward or downward requirements. The mosaic regression requirements covered between 96 and 97 percent of actual net load errors across all markets and directions. The right side of the table summarizes when the actual net load error instead exceeded upward or downward uncertainty requirements.

Table 1.9 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was more than the mosaic regression method, but by less than 1 percent across all directions and markets.

For more information on the calculated uncertainty used in the resource sufficiency evaluation for each balancing area, see DMM's WEIM resource sufficiency evaluation reports.[64]

Table 1.7 Average pass-group uncertainty requirements (April–June 2024)

		Pass-group uncertainty		
Market	**Uncertainty type**	**Histogram**	**Mosaic**	***Difference***
15-minute market	Upward	1,606	1,413	-193
	Downward	1,497	1,273	-225
5-minute market	Upward	292	278	-15
	Downward	311	287	-23

Table 1.8 Actual net load error compared to mosaic regression pass-group uncertainty requirements (April–June 2024)

		Actual net load error falls within calculated uncertainty requirements		*Actual net load error exceeds requirement*	
Market	**Uncertainty type**	**Percent of intervals**	**Average distance to requirement (MW)**	**Percent of intervals**	**Average amount (MW)**
15-minute market	Upward	96%	1,341	4%	314
	Downward	97%	1,447	3%	242
5-minute market	Upward	97%	292	3%	72
	Downward	97%	292	3%	93

63 Actual 15-minute market net load error is measured as the difference between binding 5-minute market net load forecasts and the advisory 15-minute market net load forecast. Actual 5-minute market net load error is measured as the difference between the binding 5-minute market net load forecast and the advisory 5-minute market net load forecast. Both measurements are for the group of balancing areas that passed the resource sufficiency evaluation.

64 https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

Table 1.9 Actual net load error compared to histogram regression pass-group uncertainty requirements (April–June 2024)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*		*Actual net load error exceeds requirement*	
		Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	97%	1,538	3%	340
	Downward	98%	1,662	2%	259
5-minute market	Upward	97%	308	3%	72
	Downward	98%	315	2%	90

1.14 Uncertainty calculation assessment

This section reviews the mosaic quantile regression and assesses the regression method for different applications in the market, including the residual unit commitment (RUC) adjustment, flexible ramping product (FRP), and the resource sufficiency evaluation (RSE).

The California ISO introduced a regression method to calculate uncertainty on February 1, 2023.[65] This methodology is a forecasting approach to manage uncertainty. Uncertainty in the market is defined as forecasting error. For example, the 15-minute and 5-minute markets utilize available forecasts for load, wind, and solar at the time when the market runs. If the target is hour-ending 18, both markets run for the same target hour, but calculations are made at different times. The 15-minute market runs earlier than the 5-minute markets, leading to differences in forecast data due to updates in weather and other variables in the interim period. This difference in forecast data is the uncertainty.

Uncertainty in the market can take many forms. When discussing uncertainty in this section, we are specifically referring to net load uncertainty. This is the net load forecasting error between different market runs for the same ultimate interval of power flow. This section focuses on uncertainty across two different markets. The first is the forecasting error from the day-ahead market to the 15-minute market, which is the uncertainty considered in the residual unit commitment adjustment. The other is the forecast difference from the 15-minute market to the 5-minute market that is used for the flexible ramping product and the resource sufficiency evaluation.

Uncertainty for an upcoming interval cannot be known in advance. For example, for the 15-minute market flexible ramping product, uncertainty is defined as the difference between the first advisory 15-minute forecast and the binding 5-minute forecasts.[66] At the start time of the advisory 15-minute

[65] Before the February changes, uncertainty was calculated by selecting the 2.5th and 97.5th percentile of observations from a distribution of historical net load errors. This is known as the *histogram method*. For the 15-minute market product and the resource sufficiency evaluation, the historical net load error observations in the distribution are defined as the difference between binding 5-minute market net load forecasts and corresponding advisory 15-minute market net load forecasts.

[66] In comparing the 15-minute observation to the three corresponding 5-minute observations for the 15-minute market product, the minimum and maximum net load errors were each used as a separate observation in the distribution. The 5-minute market product instead used the difference between a binding 5-minute market net load forecast and advisory 5-minute market net load forecast.

market run, the 15-minute market uses a forecast of what net load is expected to be. However, at that time, the net load that the corresponding 5-minute markets will use when those market runs start 45-55 minutes later is not known. The uncertainty calculation uses historical data to forecast what the uncertainty might be. This allows for better preparation and adjustment in the market operations.

Background on calculating net load uncertainty

In calculating uncertainty, the ISO has employed two different methods. The first method involved estimating future uncertainty by analyzing the historical distribution of uncertainty. By examining past data, the method identified lower and upper extremes of uncertainty and used these to predict future uncertainty. This approach assumes that future uncertainty will fall within the historical range, with uncertainty fluctuating between the observed high and low extremes. This histogram method was used in the market until February 1, 2023.

On February 1, 2023, the ISO began using a second method to calculate uncertainty. This was the mosaic quantile regression method. The regression approach adds another layer to uncertainty calculation by incorporating the mosaic variable—a predictor constructed by the ISO. Unlike the first method that only considers historical uncertainty, this approach looks for patterns between uncertainty and the mosaic variable, and uses it for forecasting. For example, if uncertainty was high when the mosaic variable was high in the past, it suggests that high uncertainty might occur in future periods, when the mosaic variable is also high. The regression method quantifies the patterns observed in the past, providing exact numbers rather than just indicating high or low. Once the pattern is known, it can be applied to future scenarios. The variable is derived from a combination of load, solar, and wind forecasts.[67]

For a regression methodology to produce better forecasting results than a histogram methodology, there must be a strong pattern between the uncertainty and the mosaic variable. Also, this pattern should persist in the future period being forecasted. If the pattern does not persist over time, it may suggest the pattern is driven by noise in the past data, providing incorrect information for forecasting uncertainty. This could result in less accurate and potentially erroneous forecasts. If the pattern is weak or nonexistent, the regression method essentially reverts to the histogram method, which relies solely on past uncertainty distributions without the added insight from the mosaic variable.[68]

Patterns in regression are essentially a formula. This formula shows the historical level of uncertainty for any given mosaic variable value. In simple terms, regression answers the question: if the mosaic variable was, for example, 1,000 MW, what was the level of uncertainty in the past? Plugging mosaic variable values for upcoming intervals into the historical pattern can forecast uncertainty.

Quantile regression focuses on specific parts of the data pattern. Instead of analyzing the overall pattern between uncertainty and the mosaic variable, it targets specific percentiles. For example, if the target percentile is 97.5, the regression mainly focuses on the top 2.5th percent of uncertainty. It puts the most weight on finding patterns between this extreme uncertainty and the mosaic variable.

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[67] For a more detailed description of the mosaic quantile regression method, see the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

[68] For further information on the weak pattern and its implication, details can be found in the DMM special report, *Review of the Mosaic Quantile Regression,* Nov 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

The ISO uses quantile regression with target percentiles of 97.5 and 2.5. Therefore, the regression method aims to find patterns at the extreme ends of historical data samples. The regression method produces a forecast as its output. This forecast is interpreted as a prediction range. The realized net load uncertainty between a current and upcoming market run is expected to fall within the upper and lower bounds of the prediction range with 95 percent probability.

Background on assessing performance of the mosaic quantile regression forecast

One important criteria for assessing the performance of the quantile regression forecast method is its *accuracy*. A useful metric for evaluating the accuracy of the forecast is called the coverage rate. The coverage rate indicates the percentage of realized uncertainty that falls within the forecasted prediction range described above. For the flexible ramping product and resource sufficiency evaluation, the target coverage rate is 95 percent. This means that for an accurate regression model, we would expect that 95 percent of the realized uncertainty will be within the model's predicted range.

Another important criteria for assessing the regression model is *efficiency*. An efficient model would produce a narrow prediction range while maintaining this 95 percent coverage rate. The efficiency is often measured by the average upward and downward requirement. These requirements represent the prediction range for uncertainty, with the upward requirement corresponding to the 97.5th percentile and the downward requirement corresponding to the 2.5th percentile of uncertainty.

Accuracy and efficiency are critical metrics for evaluating the performance of a forecasting model, but assessing them can be more complex. Accuracy has an absolute benchmark, such as achieving 95 percent coverage. In contrast, efficiency lacks a clear standard. A model might achieve 95 percent accuracy, but this could come at the expense of very high upward and very low downward requirements. Efficiency can be meaningful when compared to other models. Since the current forecast method relies on a single regression model, evaluating the performance can be less insightful.

In addition to accuracy and efficiency, this section evaluates the model's validity by examining the statistical significance of its coefficients. These coefficients reflect patterns in historical data, and their statistical significance confirms whether these patterns are strong enough for forecasting. For example, in load forecasting, if temperature and load have a significant historical relationship, this can be useful for future prediction, assuming the pattern holds. However, if the relationship is non-significant, the forecast is likely based on unreliable patterns, making the prediction questionable.

In uncertainty forecasting, the relationships between variables are not always as intuitive as those between load and temperature, making actual testing crucial. Statistical significance alone does not guarantee good forecasts, especially when historical and future conditions are different. However, it can serve as a reliable indicator for forecasting, particularly when only a single predictor is used to estimate uncertainty.

Statistical testing determines whether the historical patterns represented by regression coefficients are actually different from zero. Simply comparing the size of the coefficient to zero is not always helpful, as coefficients can be very small yet still meaningfully different from zero. This section uses tests on these coefficients to determine their significance. If the coefficient is significantly different from zero, it indicates a pattern in the historical data. While this does not guarantee that the pattern will be useful for forecasting, it at least suggests some relationship exists. However, if the coefficient is not significantly different from zero, it may imply either no pattern at all or that the quantified pattern is unreliable or irrelevant, potentially leading to erroneous forecasts.

If in a larger percentage of intervals, the regression method produces statistically significant coefficients, the regression forecast results should have greater divergence from the histogram method results. This is because the regression incorporates the histogram method. When the pattern detected by regression is not statistically significant, one possibility is that the coefficient may be zero, causing the regression results to resemble the histogram.[69] Another possibility is that the coefficient is non-zero but unreliable, potentially leading to erroneous forecasts. In practice, mosaic regression often encounters a combination of these two issues.

In the following subsections, this report presents performance metrics for the mosaic quantile regression in the residual unit commitment market adjustment, flexible ramping product uncertainty, and resource sufficiency evaluation uncertainty. Note that these performance metrics are based on the regression coefficients and resulting forecasts from DMM's replication of the ISO's mosaic quantile regression method. The performance metrics are not based on the coefficients and forecasts produced by the ISO.[70]

1.14.1 RUC adjustment

For the residual unit commitment market (RUC) adjustment, uncertainty is defined as the difference between the day-ahead net load forecast and binding 15-minute market forecasts.

Figure 1.65 shows this quarter's distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. The first notable feature is that the uncertainty is symmetric, with values distributed evenly around zero, making zero the most frequently occurring value. The distribution also exhibits a long tail. The area between the red dashed and the black dashed lines highlights the upper 2.5 percent of uncertainty, which ranges from around 2,500 MW to 5,000 MW. A long tail could indicate rare but impactful events, such as unexpected weather changes or some other cause of a sudden shift in demand or renewable resource output.

Figure 1.66 shows the daily average RUC adjustment imposed by the CAISO balancing area during peak hours from April 2024 to June 2024 (blue shaded area). A major change in the ISO's method for determining the RUC adjustment began on May 7. In cases of very low operational uncertainty, the adjustment was set to zero. This was a manual decision rather than an output from the regression model. For this quarter, the replication includes the 25th percentile regression, primarily focused on peak hours, as the majority of non-peak hour adjustments were manually set to zero.

The black dots represent the average realized uncertainty between the RUC and 15-minute market forecasts by day. The chart also shows the results of DMM's replication of the mosaic quantile regression model. These results feature four different percentile quantile regressions. Since the ISO can adjust the percentile value for the RUC adjustment daily, it is challenging to determine the exact percentile used each day in 2024. However, comparing the results of DMM's replication to CAISO's actual RUC adjustments indicates that the majority of the RUC adjustments during this quarter likely used the 50th percentile, with a significant number of days utilizing the 75th percentile in April. The use of

[69] For further information about the statistical significance test and its implementation, details can be found in the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023 (p 5, section 3): https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

[70] This choice is made because there are no statistical significance tests available based on the ISO's estimations. DMM's performance test requires considering statistical significant tests alongside coverage and requirement. Therefore, the requirement and coverage metrics in this section are also based on DMM's replication.

the 25th percentile in RUC adjustments remains unclear. Some ISO requirements align with the 25th percentile replication, likely due to a combination of 50th percentile and zero requirement being used for different hours in the day. Moreover, DMM's replication of the 25th percentile regression resulted in negative values 45 percent of the time, casting doubt on its active application in the market.

Figure 1.65 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (April–June 2024)

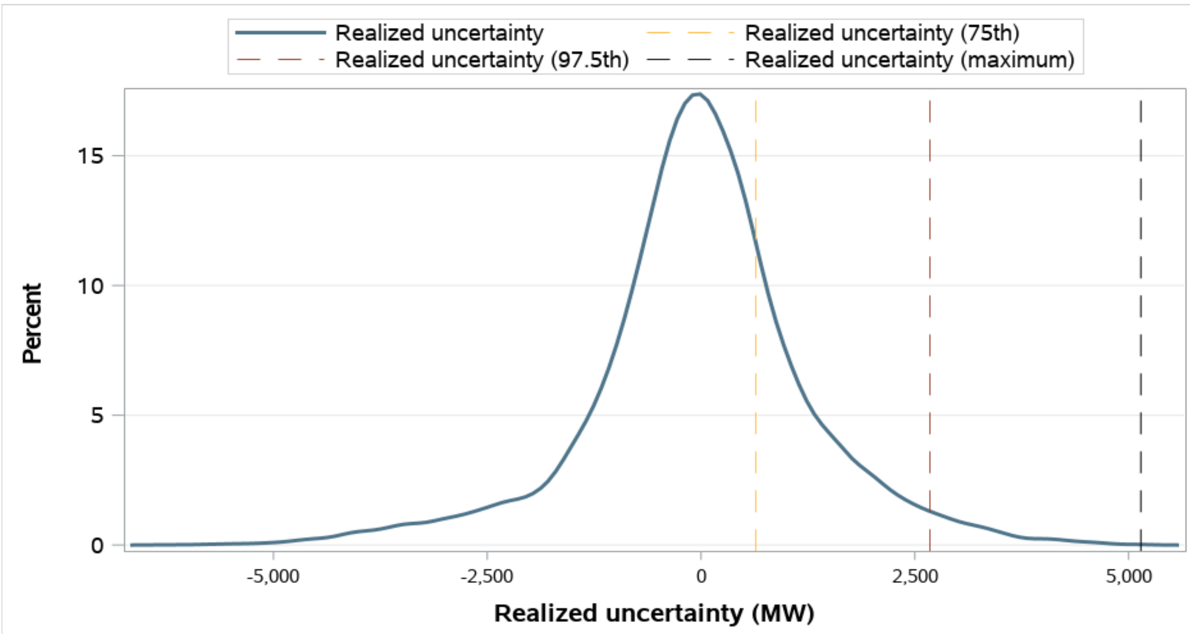


Figure 1.66 Daily average of RUC adjustment replication results during peak hours[71]

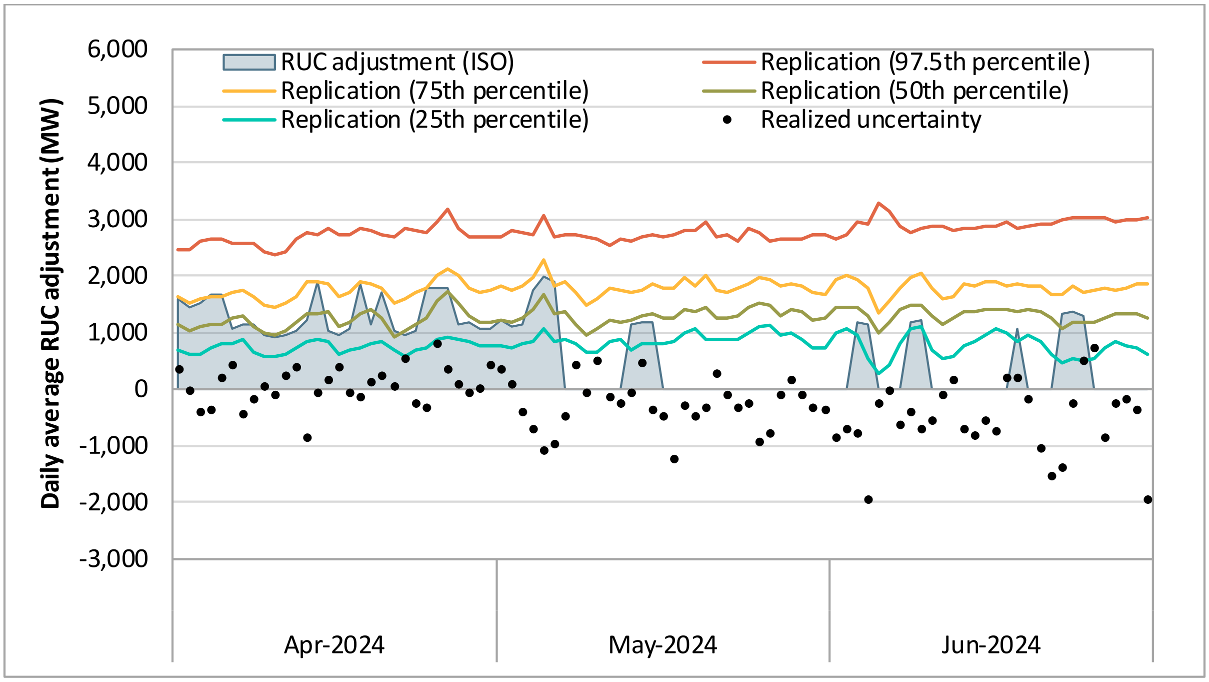


Table 1.10 shows performance metrics for the mosaic quantile regression utilizing DMM's replication of the ISO's mosaic quantile regression model. Each of the first four rows represents the results of DMM's replication using a different target percentile for upward uncertainty. The last row shows the actual RUC adjustment used by the ISO in the market. The average requirements are divided between all hours and "risk hours". Risk hours refer to periods when the ISO applied a non-zero RUC adjustment. This decision was based on the ISO's assessment of potential operational risk during these hours. Non-zero hours accounted for 42 percent of hours in the second quarter of 2024.

The first section of the table shows the average requirement across different percentile values from the DMM replication. It also includes the average values the ISO actually used in the market. In the second quarter, the ISO largely used a combination of the 75th and 50th percentile to calculate the adjustment used in RUC. Since many of the ISO's requirements were set to zero, this affects the average requirement for all hours. A more accurate assessment came from examining the value during risk hours, where an actual RUC adjustment was used, excluding zeros. During these risk hours, the average requirement was around 1,000 MW.

The middle section of the table shows the percentage of significant coefficients, indicating how often regression coefficients were statistically different from zero. Notably, the regression targeting the 97.5th percentile shows that only 3 percent of these regressions had significant coefficients. This indicates that 97 percent of the time, the pattern between net load uncertainty and the mosaic variable either did not exist or was unreliable.[72] This low significance is partly due to the 97.5th percentile regression focusing

71 Peak hours include hours-ending 7 to 9 and 17 to 21.

72 The pattern here refers to the relationship based on percentile values. A 50th percentile regression reflects the overall pattern of all samples, while a 97.5th percentile regression focuses on the extreme cases, representing mostly the upper 2.5 percent of the realized uncertainty and the mosaic variable.

only on 2.5 percent of the sample (about 4-5 data points). The small quantity of data points is insufficient to identify a pattern, leading to non-significant coefficients.

The regression targeting the 50th percentile of uncertainty focuses on all 180 data points. For this regression, still only 34 percent of coefficients were significant during all hours.

The right side of the table shows the coverage rate for DMM's replication of the three regressions and the CAISO area's actual RUC adjustment. As explained above, the coverage rate indicates the percentage of realized uncertainty that falls within the range predicted by the quantile regression. Note that the RUC adjustment is intended to only cover upward uncertainty. Therefore, the coverage rate metric considers all negative realized uncertainty as falling within the regression's prediction range—regardless of how far the 15-minute market load forecast ends up being below the day-ahead market load forecast. The one-sidedness of the prediction range for the RUC uncertainty regression will tend to inflate the coverage rate metric relative to the same regression whose target range was between the 2.5th and 97.5th percentile.

Table 1.10 Mosaic quantile regression performance for RUC adjustment (April–June 2024)

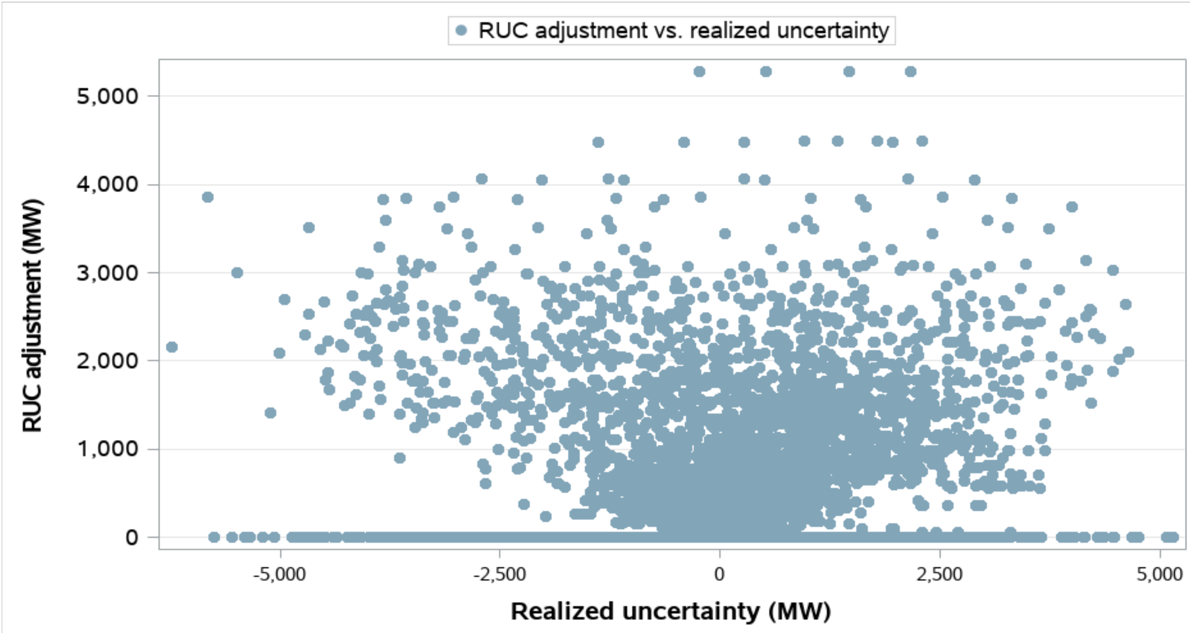
	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Risk Hours[1]	All hours	Risk hours	All hours	Risk hours
Replication (97.5th)	2,296	2,329	3%	5%	98%	97%
Replication (75th)	1,249	1,333	23%	19%	86%	81%
Replication (50th)	745	850	34%	35%	71%	65%
Replication (25th)	284	398	40%	46%	54%	48%
ISO	441	1,041			63%	71%

(1): Risk hours refers to hours when the ISO applies a non-zero RUC adjustment in response to assessed operational risks due to uncertainty.

Figure 1.67 displays a scatterplot of the RUC adjustment used in the market, plotted against the realized uncertainty during the second quarter of 2024. The scatter plot can help to assess if the CAISO balancing area's overall method for determining the RUC adjustment resulted in setting higher RUC adjustments during periods of greater uncertainty in the day-ahead market net load forecast.

In Q2 2024, there appears to be very little correlation between higher RUC adjustments and higher positive realizations of net load uncertainty. The graph indicates that, regardless of whether the realized uncertainty is high, low, positive, or negative, the RUC adjustment typically varies between 0 MW and 4,000 MW. The scatter plot also shows instances where the RUC adjustment equals zero (vertical axis at zero), while the realized uncertainty spans from -5,000 MW to 5,000 MW.

Figure 1.67 Comparing RUC adjustments to realized uncertainty (April–June 2024)

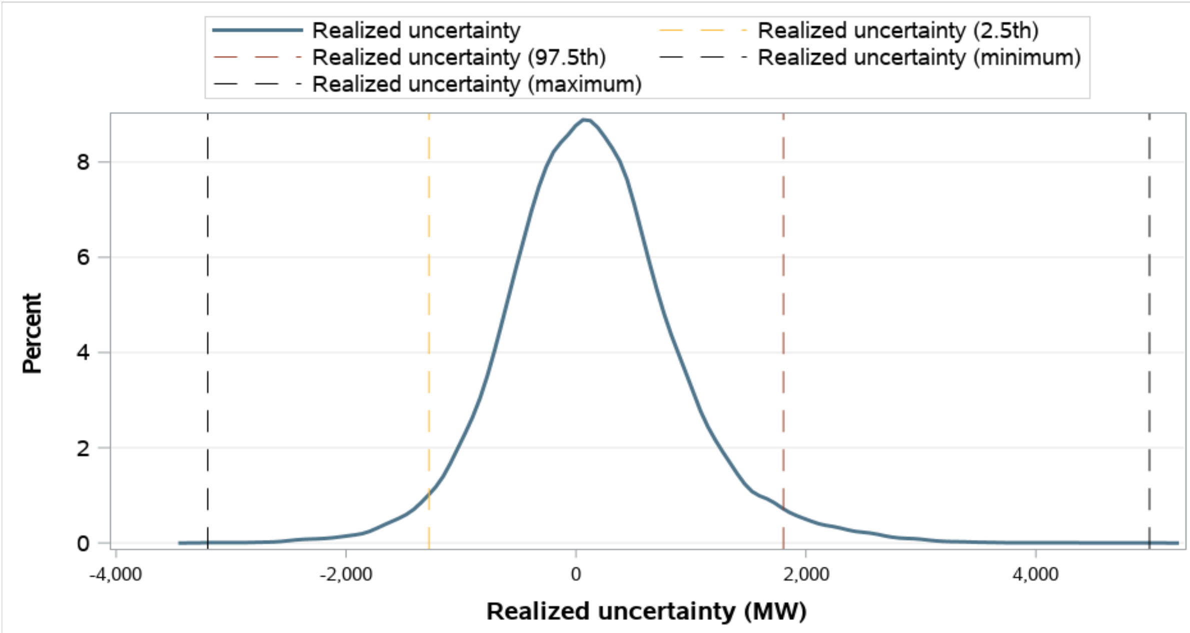


1.14.2 Flexible ramping product

For the 15-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 15-minute market net load forecast and the binding 5-minute market forecasts. Figure 1.68 illustrates the distribution of realized uncertainty in the flexible ramping product (FRP) for the group of balancing areas that passed the resource sufficiency evaluation (RSE) for the second quarter of 2024. The distribution is depicted as a blue line, with the extreme percentiles highlighted: the lowest 2.5th percentile in yellow, the 97.5th percentile in red, and the black dashed lines indicating the minimum and maximum values. The range from the upper 2.5 percent of uncertainty to its maximum spans from 2,000 MW to over 5,000 MW, reflecting a long tail distribution. These long tails in the distribution could indicate that the uncertainty is influenced by rare, extreme events rather than typical fluctuations.

The extreme long tail in the distribution of realized uncertainty is potentially influenced by several factors. One key factor is the variability in the number of balancing authority areas within the RSE pass-group; the composition is not always constant. Sometimes all balancing areas in the WEIM pass the RSE, while other times only a subset does. This variability affects the scale of aggregated uncertainty for the pass-groups. Additionally, extreme weather events and rapid changes in demand further contribute to this long tail.

Figure 1.68 Distribution of realized uncertainty in FRP (pass-group, April 4–June 30, 2024)



Effective April 4, the ISO removed the day-type distinction when collecting samples for the regression. Previously, if the forecasted day was a weekend, the ISO would only filter weekend days from the past 180 days for regression. This distinction has been removed, and the regression pulls samples from all past 180 days regardless of day-type. As a result, each regression now starts with 720 data points, focusing on the upper or lower 2.5 percent of those points.[73] Prior to this update, weekday regression used around 514 data points, while weekend regression had 205 data points.

Given this new policy, all analysis, including performance evaluations and statistical tests, was conducted following the policy update on April 4 through June, 2024.

Table 1.11 summarizes performance metrics for the mosaic quantile regression used in the flexible ramping product. All metrics in the table are based on DMM's replication, rather than the actual requirements used by the ISO in the market.[74] The table includes the following metrics:

- Percentage of significant coefficients: The table highlights the percentage of significant coefficients across different regressions, including mosaic and three other quantile regressions (load, solar, and wind).[75] The three other quantile regressions contribute to constructing the

[73] The regression sample is collected from the same hour over the past 180 days. Each hour includes four 15-minute intervals, with corresponding data points. For each regression, it uses data from the past 180 days for the same hour, multiplied by 4 (the 15-minute intervals), resulting in a total of 720 data points.

[74] The performance of the mosaic regression based on the actual market methodology, which includes some additional thresholds to put ceilings and floors on the mosaic quantile regression outputs, can be found in Section 1.13.2.

[75] The mosaic quantile regression includes three coefficients: an intercept, a quadratic term for the mosaic variable, and a linear term for the mosaic variable. The percentage of significant coefficients is determined by whether either the quadratic term or the linear term is statistically different from zero at the 0.1 significance level. This significance is calculated for both upward and downward uncertainty estimations, and then averaged.

mosaic variable, and the mosaic regression is used in the final regression to forecast the uncertainty.[76]

- Coverage: This metric compares the coverage rates between the mosaic quantile regression and the histogram method previously used by the ISO, providing insight into how well each method captures the realized uncertainty.
- Requirement: These metrics assess the efficiency of the uncertainty methodologies, comparing the requirements generated by the mosaic quantile regression and the histogram method. Efficiency metrics are meaningful when paired with the coverage rate. A more efficient method would produce a lower requirement while maintaining the same coverage.

Table 1.11 Mosaic quantile regression performance for FRP (pass-group, April 4–June 30, 2024)

Metrics	Type	All hours	Peak hours(1)
Percent of significant coefficient	Mosaic	31%	38%
	Load	24%	33%
	Solar	78%	89%
	Wind	62%	65%
Coverage	Mosaic	96%	97%
	Histogram	94%	94%
Requirement (MW)(2)	Mosaic (M)	1,431	1,722
	Histogram (H)	1,503	1,695
	M/H Ratio(3)	0.95	1.02
	DMM-ISO(4)	155	170

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

(2): The requirement is the average value without the extreme outliers that the regression generates, with the upper and lower 5 percent of extreme requirements removed from this calculation.

(3): The M/H ratio is the requirement of the mosaic quantile regression divided by the histogram requirement.

(4): DMM-ISO indicates the average requirement difference between DMM's replication and the requirement calculated based on ISO's coefficients.

Table 1.11 shows that on average, the mosaic regression provided a 2 percent higher coverage rate with a 70 MW lower requirement than the histogram method. Over just peak hours, the mosaic regression provided 3 percent more coverage with a 27 MW higher requirement than the histogram method.

The similarity between the regression and histogram methods can be explained by several factors, with a significant factor being the percentage of statistically significant coefficients. The coefficient for the mosaic variable was statistically significant during only 31 percent of intervals.

[76] For a more detailed description of how the three other quantile regressions are used to construct the mosaic variable, see the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023, pp 6-10: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

This means that in 69 percent of cases, the mosaic variable does not show a strong pattern with historical uncertainty.[77] Whether the mosaic variable is high or low, the uncertainty does not consistently respond with similarly high or low levels of uncertainty. Consequently, when looking at future data, even if the mosaic variable is high, it is unclear whether the uncertainty will be high or low.

When the regression relies only on the mosaic variable, which has weak patterns with uncertainty, the outcome can become very similar to simply analyzing the historical distribution of uncertainty without the mosaic variable—essentially, what the histogram methodology does.[78] The low percentage of significant coefficients is likely to lead to similar requirements and coverage results as the histogram method.

This analysis is based on the DMM replication, which tends to produce slightly higher requirements than the ISO calculation. As shown in the last row of Table 1.11, the DMM replication of the regression requirement averages around 155 MW higher than the estimates based on the ISO's coefficients.[79]

Figure 1.69 and Figure 1.70 display scatter plots comparing the mosaic regression forecast to the realized uncertainty in both upward and downward scenarios for Q2 2024. As noted above, the DMM replication removes the ceiling and floor thresholds in order to assess the uncertainty forecast produced by the mosaic regression model. However, these plots exclude the top and bottom 5 percent of extreme outliers to focus on the core data.[80]

The analysis explores whether, when realized uncertainty is high, the mosaic method predicts this by setting a higher requirement, and conversely, if realized uncertainty is low, whether the mosaic prediction similarly produces a lower requirement. This pattern was not evident in Q2 2024. Regardless of whether the realized uncertainty is high, low, or zero, the forecasted values consistently range between 0 and 3,000 MW for upward, and between -500 and -2,500 MW for downward.

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77 The pattern here corresponds to specific percentile values. When the percentile is set at 97.5th or 2.5th, the pattern reflects the extreme upper and lower 2.5 percent of uncertainty relative to the mosaic variable. If the pattern is strong, it indicates a clear relationship at these extremes. Conversely, a weak pattern suggests that the relationship is less pronounced or not robust.

78 When the coefficients are non-significant, it is possible that data patterns are inconsistent, causing the regression model to produce unreliable coefficients. In such cases, the output of the histogram and regression method can differ significantly, as seen in some abnormal requirements generated by the regression method. Both weak and unreliable coefficients stem from the same issue—a lack of clear patterns between the mosaic variable and uncertainty in the historical data.

79 The DMM replication and ISO calculations are based on the same sample and methodology, aside from the DMM replication removing ceiling and floor thresholds. However, the nature of quantile regression requires an algorithm to determine the coefficients. This algorithm can differ from the one used by the ISO. Different algorithms may produce varying coefficients, especially when there is no clear pattern in the data.

80 The decision to remove the outliers stems from the quantile regression producing abnormal requirements, such as an instance of negative 11,300 MW for flexible ramp up (FRU) this quarter. This issue arises primarily due to the inconsistent composition of the pass-groups and the low percentage of significant coefficients.

Figure 1.69 Comparing FRP forecast to realized uncertainty (upward pass-group, April 4–June 30, 2024)

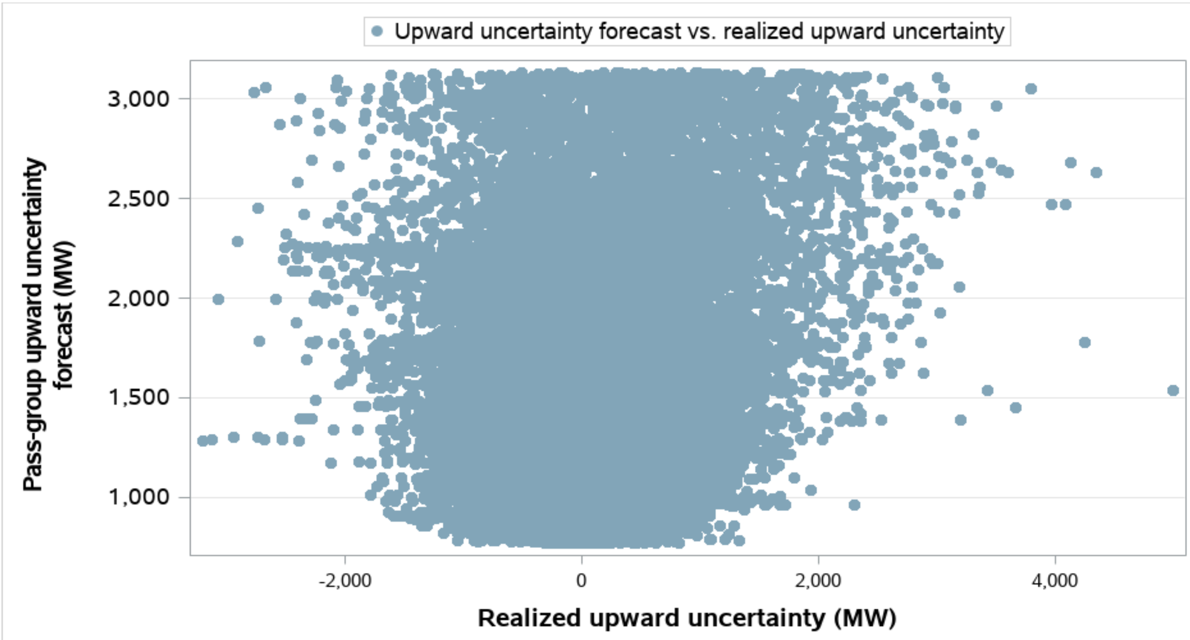
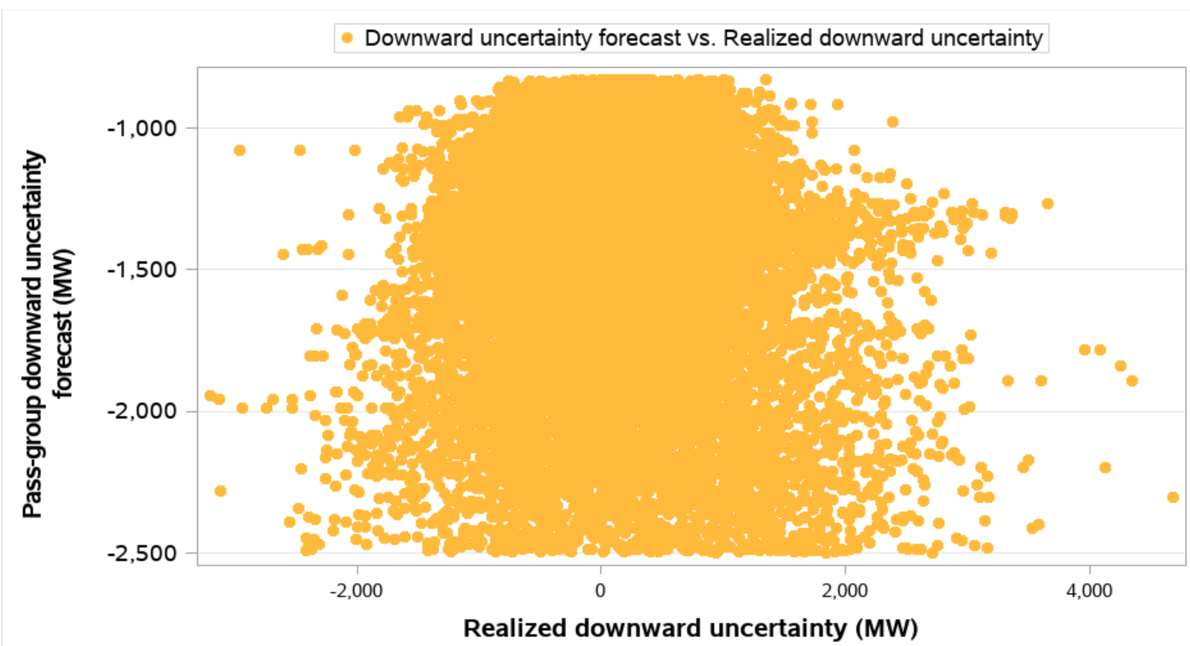


Figure 1.70 Comparing FRP forecast to realized uncertainty (downward pass-group, April 4–June 30 2024)



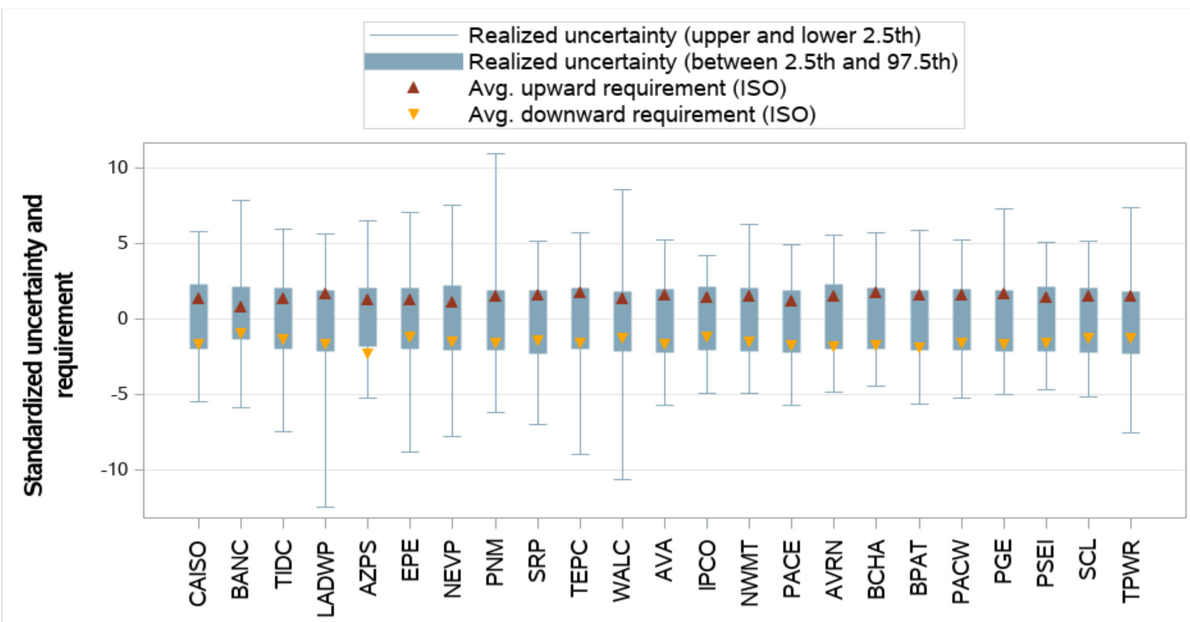
1.14.3 Resource sufficiency evaluation

This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation (RSE). In this section, the realized uncertainty, which the regression should forecast, is the net load forecast difference between the forecasts used in the resource sufficiency evaluation runs and those in the binding 5-minute market runs.

Effective April 4, the ISO removed the day-type distinction when collecting samples for regression. The following analysis was conducted after this policy update, from April 4 through June 2024.

Figure 1.71 shows the distribution of realized uncertainty in the RSE for each balancing authority area (BAA) for the second quarter of 2024. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation.[81] This eliminates scale issues and allows for a clear assessment of relative volatility in realized uncertainty among BAAs. Additionally, the figure displays the standardized average upward and downward requirement imposed in the market, enabling a comparison of each BAA's requirement relative to its own uncertainty, as well as in relation to other areas.

Figure 1.71 Standardized realized uncertainty and requirement for RSE (April 4–June 30, 2024)



This figure provides a comparison of the realized uncertainty across different BAAs for this quarter. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th

81 Standardizing involves calculating the z-score, which is done by subtracting the mean of uncertainty from each data point and then dividing the result by the standard deviation. This process transforms the data so that it has a mean of zero and a standard deviation of one. This is helpful for comparing uncertainty across different BAAs because it removes the scale difference between them. Each BAA has different absolute levels of uncertainty, but by standardizing, all areas are brought onto the same scale. This allows for a direct comparison of their relative volatility and makes it easier to see which BAA experiences more or less uncertainty.

percentile to the minimum value of realized uncertainty. The triangle markers show the average upward and downward requirement applied in the market, based on the ISO estimates.

Key observations include:

- **Long tails**: Most BAAs exhibit a long tail distribution. The range of uncertainty beyond the 2.5^{th} and 97.5^{th} percentiles is wider than the main distribution of data.
- **Asymmetry in uncertainty:** Not all have symmetric uncertainty distributions. Some tend to have more positive uncertainty, while others skew more negative.
- **Requirement vs. uncertainty**: Generally, the average requirement for each BAA falls within the 2.5^{th} and 97.5^{th} percentiles of realized uncertainty. Average upward requirements for BANC and NEVP were notably lower than the 97.5^{th} percentile of realized uncertainty.

Table 1.12 Mosaic quantile regression performance for RSE using DMM's replication (April 4–June 30, 2024)[82]

BAA	Percent of significant coefficients		Coverage		Requirement (MW)(2)			
	All hours	Peak hours(1)	Mosaic	Histogram	Mosaic (M)	Histogram (H)	M/H Ratio(3)	DMM-ISO(4)
Avangrid	93%	95%	93%	90%	199	198	1.00	12
BPA	74%	79%	94%	91%	256	249	1.03	20
PacifiCorp West	71%	74%	93%	91%	111	114	0.98	9
Avista Utilities	52%	50%	92%	91%	54	58	0.94	4
Idaho Power	44%	61%	89%	85%	139	131	1.07	10
NorthWestern	44%	52%	91%	90%	72.4	75.7	0.96	6
Portland GE	42%	46%	92%	89%	142	127	1.12	12
Arizona PS	39%	29%	91%	88%	257.9	235.6	1.09	19
CAISO	39%	49%	91%	89%	953	1,050	0.91	98
LADWP	39%	47%	93%	91%	149	149	1.00	14
PacifiCorp East	38%	41%	88%	87%	400	398	1.00	31
NV Energy	34%	53%	82%	84%	194	214	0.91	21
PSC New Mexico	26%	34%	93%	89%	155.7	137.8	1.13	15
Puget Sound Energy	26%	21%	89%	88%	136.5	134.2	1.02	11
Salt River Project	24%	29%	91%	89%	135.9	120.7	1.13	13
El Paso Electric	22%	31%	87%	82%	36	33	1.12	4
Powerex	22%	15%	93%	94%	142	146	0.97	15
Tucson Electric	19%	21%	92%	91%	93	87	1.06	7
WAPA - Desert SW	17%	24%	86%	86%	23.0	22.2	1.04	2
BANC	13%	17%	88%	85%	40.0	41.2	0.97	4
Seattle City Light	13%	20%	89%	93%	17.2	21.6	0.80	1
Turlock ID	8%	13%	87%	87%	8.1	7.6	1.06	1
Tacoma Power	4%	6%	90%	93%	11.0	12.6	0.87	1
Average	**35%**	**39%**	**90%**	**89%**	**162**	**164**	**1.01**	**14**

(1): Peak hours include hour-ending (HE) from 7 to 9 and HE from 17 to 21.

(2): The requirement is the average value without the extreme outliers that the regression generates, with the upper and lower 5 percent of extreme requirements removed from this calculation.

(3): The M/H ratio is the requirement of the mosaic quantile regression divided by the histogram requirement.

(4): DMM-ISO indicates the average requirement difference between DMM's replication and the requirement calculated based on ISO's coefficients.

Table 1.12 summarizes the performance of the mosaic quantile regression for the resource sufficiency evaluation across each BAA, using DMM's replication of the regression. The analysis includes the percentage of significant coefficients during all hours and peak hours, as well as the coverage and requirement comparison between the mosaic and histogram approaches. The BAAs are listed in descending order, starting with those that have the highest percentage of significant coefficients to those with the lowest.

[82] The coverage and requirements are calculated based on DMM's replication of the ISO's regression method, without applying the ISO's ceiling and floor thresholds, thus the number may differ from the actual market result. For actual market outcomes, refer to DMM's Western Energy Imbalance Market resource sufficiency evaluation reports: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

Overall, the coverage rate of the quantile regression forecasts was 90 percent in the second quarter of 2024, short of the 95 percent target. NV Energy had the lowest coverage rates, at 82 percent. BPA had the highest coverage at 94 percent, which is nearly in line with the target coverage of 95 percent.

On average, only about 35 percent of the regression coefficients were statistically significant in Q2 2024, meaning that 65 percent of coefficients were still based on either weak or irrelevant patterns.

Although the percentage of statistically significant coefficients remains low, there was a notable improvement in Q2 2024 compared to Q1 2024, when only 13 percent of the coefficients were statistically significant. This improvement can be attributed to the ISO's decision on April 4 to increase the sample size, which DMM found contributed to a rise in statistical significance. The detailed analysis is provided in Section 1.14.4 below. DMM tested the impact of the sampling change on statistical significance using the same Q2 data. DMM found that under the previous sampling scheme, statistical significance remained around 10 percent, substantially lower than the 35 percent achieved with the new sampling method.

Mosaic variable inconsistencies in RSE: regression vs. forecasting

The forecasts used for load, solar, and wind in the resource sufficiency evaluation (RSE) runs are based on data available at the time of each RSE run. These RSE forecasts are typically predicted between 47.5 to 102.5 minutes before the corresponding 5-minute market runs. This uncertainty is what the mosaic quantile regression method should be trying to forecast for the RSE.

However, in determining the coefficients for the regression used to predict RSE uncertainty, the ISO instead uses the difference between the net load forecasts of the first advisory 15-minute market and the corresponding three binding 5-minute markets. The first advisory 15-minute market forecast uses data available when the real-time pre-dispatch (RTPD) run for that interval begins, 45 to 55 minutes before the corresponding 5-minute market runs. This makes the net load prediction used in the first advisory 15-minute market a much shorter-term forecast than the prediction used in the resource sufficiency evaluation runs.

As a result, the determination of the regression coefficients for predicting net load uncertainty for the RSE does not capture the increased net load uncertainty associated with the longer time between RSE net load forecasts and the corresponding 5-minute market runs. Instead, the regression coefficients are built using the shorter-term net load difference between the first advisory 15-minute market and the corresponding 5-minute markets. This is the same data set used to create the regression coefficients for the flexible ramping product. Note that this data set is appropriate to use for creating the regression coefficients for predicting flexible ramping product (FRP) uncertainty, because the net load uncertainty that is being predicted for FRP is the uncertainty between the first advisory 15-minute market and the three corresponding binding 5-minute markets. This is not the case for the uncertainty that the regression should be trying to predict for the resource sufficiency evaluation.

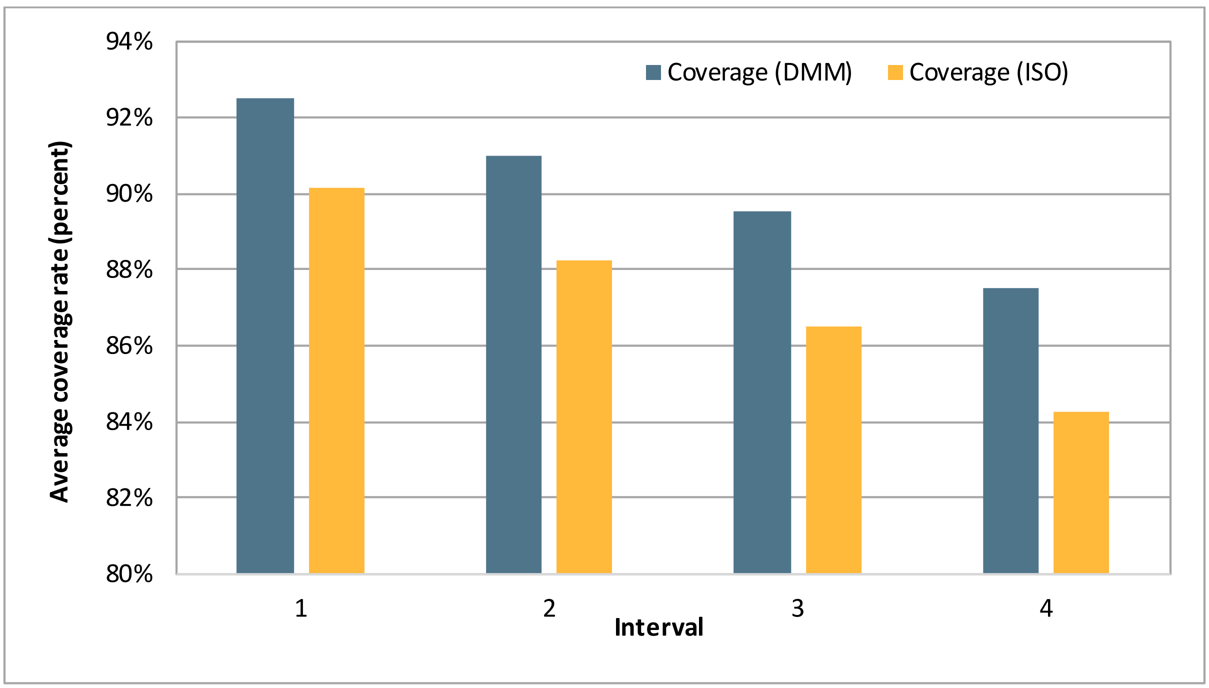
To create the regression coefficients for the resource sufficiency evaluation, the ISO constructs the mosaic variable based on the first advisory 15-minute market forecast rather than the long-term RSE forecast. The regression then identifies patterns between this short-term net load uncertainty and the mosaic variable in past data. For example, past patterns may show that a high mosaic variable correlates with high uncertainty, while a low mosaic variable correlates with low uncertainty.

The mosaic variable that gets multiplied by these regression coefficients to predict uncertainty in the upcoming RSE runs' net load forecast uses the long-term RSE forecast rather than the shorter-term first advisory 15-minute market forecast that was used to create the regression coefficients. This creates an inconsistency in the mosaic variable used to define historical patterns in uncertainty and the mosaic variable used for forecasting.[83] While the long-term and short-term forecast-based mosaic variables are likely correlated, their characteristics can differ due to the longer timeframe involved in the RSE. These two forecasts may have different characteristics in terms of trends and volatility, as seen in the discrepancies between day-ahead, 15-minute, and 5-minute forecasts.

This inconsistency likely results in lower performance in coverage rate for the resource sufficiency evaluation requirements. Figure 1.72 shows the average coverage rate across all BAAs by interval. The blue bar represents the coverage rate based on the DMM replication, while the yellow bar indicates the average coverage rate from the requirements actually used in production by the ISO. The chart shows a clear trend in Q2 2024, where the coverage rate decreases from interval 1 to interval 4.

The decline in coverage rate from interval 1 to interval 4 can be attributed to the inconsistency between the mosaic variable used in regression and forecasting, described above. For interval 1, the RSE forecasting horizon is similar to that of the first advisory 15-minute market forecast. However, intervals 3 and 4 introduce greater discrepancies, with RSE interval 4 having more than double the forecasting horizon of the first advisory 15-minute market forecast.

Figure 1.72 Average coverage rate by intervals in RSE (April 4–June 30, 2024)



83 For further information on the mismatch, details can be found in the Western Energy Imbalance Market resource sufficiency evaluation reports: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

1.14.4 Uncertainty calculation model update

A major update in the uncertainty calculation occurred on April 4, 2024. Previously, when collecting samples for the regression, the ISO selected data for the same hour, going back six months. This data was then filtered based on whether the forecasted day was a weekend or weekday. For example, if the forecast was for a weekend, only weekend data from the previous six months was used. However, this sampling method has been modified. The updated approach no longer distinguishes between weekday and weekend data, and instead uses the last six months of data without filtering by day type. This change applied to the mosaic regression that is currently used in the flexible ramping product (FRP) and resource sufficiency evaluation (RSE).

As a result, each regression now starts with 720 data points, focusing on the upper or lower 2.5 percent of those points.[84] Prior to this update, weekday regression used around 514 data points, while weekend regression had 205 data points.

Table 1.13 highlights the performance metrics in RSE and FRP after the sampling method update on April 4. In this table, the *Current* column presents the performance based on the new sampling method implemented after April 4, while the *Past* column indicates the previous sampling methodology used before that date. Except for the change in sampling method, both the *Current* and *Past* regression are the same in terms of methodology and how they both look at the past six months of data. The *Histogram* column shows the performance of the histogram methodology with the *Current* sampling method.

The key findings include:

- **Percentage of significant coefficients:** Across all BAAs, including RSE pass-groups, statistical significance improved after the update. On average, 35 percent of regression coefficients showed statistical significance with the new sampling method, compared to only 10 percent with the previous sampling method. Notable increases were observed in Avangrid, BPA, and PacifiCorp West.
- **Coverage:** Coverage rates increased uniformly across all BAAs and RSE pass-groups with the new sampling method. The average increase was 3 percent, with significant improvements seen in Turlock Irrigation District. Turlock saw a 12 percent increase, from 75 percent to 87 percent.
- **Requirement:** On average, the requirements increased by 3 percent under the new sampling method. Turlock showed notable increase. Requirements for Tacoma Power, BANC, and NV Energy decreased while their coverage rate increased under the new sampling method.

[84] The regression sample is collected from the same hour over the past 180 days. Each hour includes four 15-minute intervals, with corresponding data points. For each regression, it uses data from the past 180 days for the same hour, multiplied by 4 (the 15-minute intervals), resulting in a total of 720 data points.

Table 1.13 Mosaic regression performance in RSE and FRP after policy update on new sampling method (April 4 to June 2024)

BAA/Group	Percent of significant coefficients		Coverage			Requirement (MW)(3)		
	Current(1)	Past(2)	Current	Past	Histogram	Current	Past	Histogram
RSE:								
Avangrid	93%	45%	93%	90%	90%	199	194	198
BPA	74%	30%	94%	91%	91%	256	242	249
PacifiCorp West	71%	16%	93%	90%	91%	111	109	114
Avista Utilities	52%	15%	92%	90%	91%	54.4	54.1	57.8
Idaho Power	44%	8%	89%	85%	85%	139	132	131
NorthWestern	44%	12%	91%	89%	90%	72.4	70.1	75.7
Portland GE	42%	7%	92%	89%	89%	142	135	127
Arizona PS	39%	14%	91%	86%	88%	258	257	236
CAISO	39%	11%	91%	87%	89%	953	927	1,050
LADWP	39%	8%	93%	90%	91%	149	145	149
PacifiCorp East	38%	7%	88%	86%	87%	400	391	398
NV Energy	34%	7%	82%	78%	84%	194	203	214
PSC New Mexico	26%	3%	93%	91%	89%	156	146	138
Puget Sound Energy	26%	5%	89%	88%	88%	136	134	134
Salt River Project	24%	6%	91%	88%	89%	136	131	121
El Paso Electric	22%	5%	87%	79%	82%	36	34	33
Powerex	22%	8%	93%	90%	94%	142	133	146
Tucson Electric	19%	9%	92%	88%	91%	92.5	84.7	87.1
WAPA - Desert SW	17%	2%	86%	77%	86%	23.0	21.5	22.2
BANC	13%	1%	88%	86%	85%	40.0	43.5	41.2
Seattle City Light	13%	1%	89%	87%	93%	17.2	17.1	21.6
Turlock ID	8%	2%	87%	75%	87%	8.1	6.9	7.6
Tacoma Power	4%	2%	90%	89%	93%	11.0	11.3	12.6
FRP:								
RSE passed-group	31%	22%	96%	95%	94%	1,431	1,406	1,503
Average	**35%**	**10%**	**90%**	**87%**	**89%**	**215**	**210**	**219**

(1): The current sampling method, implemented after April 4th, 2024, no longer filtered data based on weekday/weekend.

(2): The previous sampling methodology, used before the April 4th update, filtered data based on weekday/weekend.

(3): The requirement is the average value without the extreme outliers that the regression generates, with the upper and lower 5 percent of extreme requirements removed from this calculation.

1.15 Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an *out-of-market* or *manual* dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs because out-of-market payments to the resources may exceed market prices. Manual dispatch compensation may also create opportunities for the exercise of temporal market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.
- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would have likely cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as in-sequence real-time energy.
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market-clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to the local market power mitigation provisions in the California ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

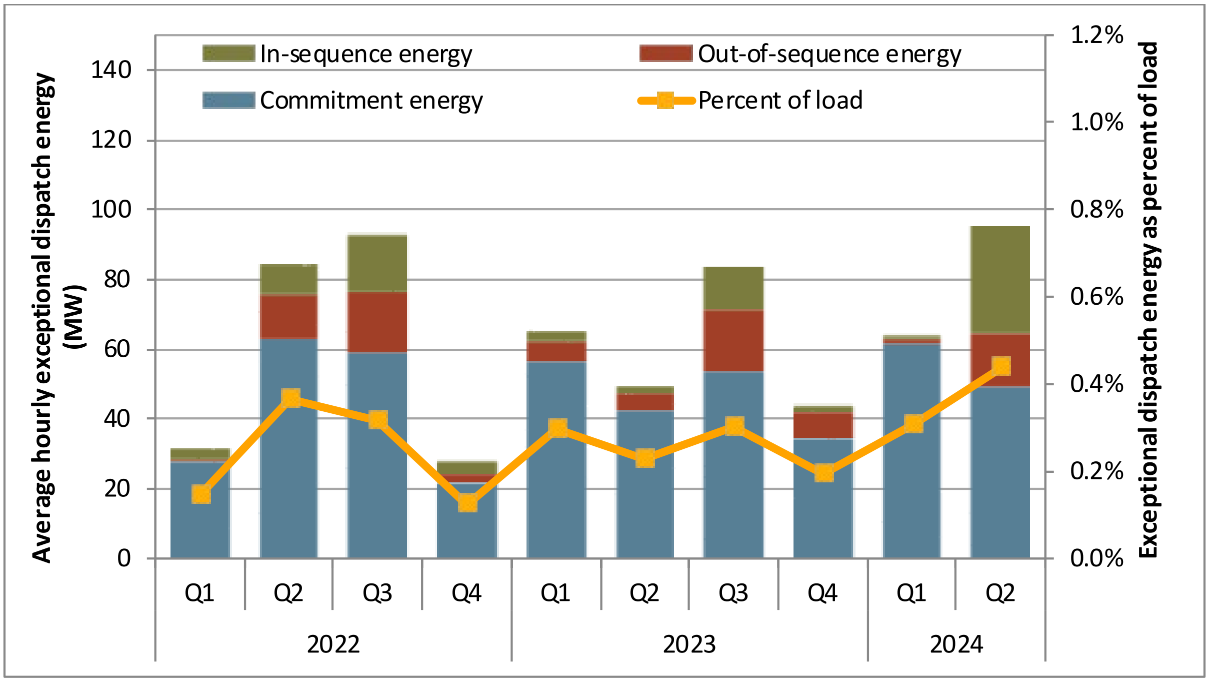
Energy from exceptional dispatch

Energy from exceptional dispatches continued to account for under 1 percent of total load in the California ISO balancing area, represented by the yellow line in Figure 1.73. As shown in Figure 1.73, the average hourly total energy from exceptional dispatches—including minimum load energy from unit commitments—was 95 MW in the second quarter of 2024, which is a 93 percent increase from the second quarter of 2023.[85]

In the second quarter of 2024, exceptional dispatches for unit commitments (blue) accounted for about 52 percent of all exceptional dispatch energy, about 16 percent was from out-of-sequence energy (red), and the remaining 32 percent was from in-sequence energy (green), as shown in Figure 1.73.

85 All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

Figure 1.73 Average hourly energy from exceptional dispatch



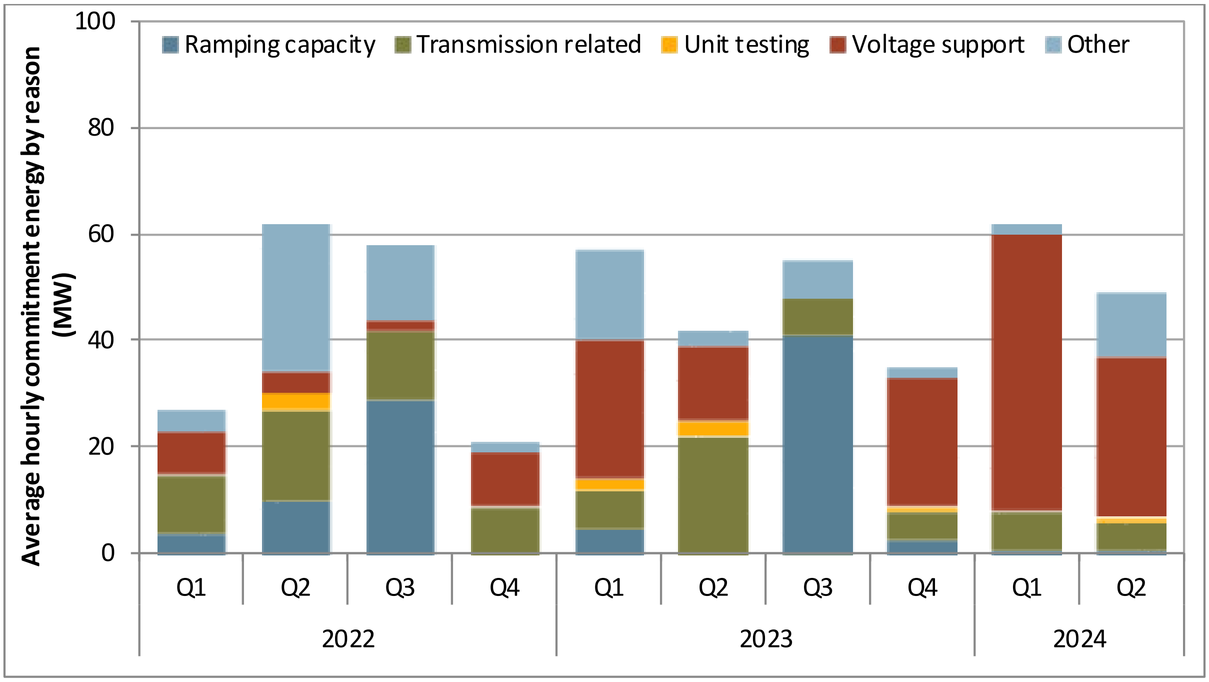
Exceptional dispatches for unit commitment

The California ISO balancing area operators occasionally find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. In these instances, the California ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load. Multi-stage generating units may be committed to operate at the minimum output of a specific multistage generator configuration, e.g., one-by-one or duct firing.

Figure 1.74 shows the reasons for minimum load energy exceptional dispatches: ramping capacity (dark blue), transmission related (green), unit testing (yellow), voltage support (red), and other (light blue). The average minimum load energy from unit commitment exceptional dispatches in the second quarter of 2024 was 49 MW, which was slightly above the 42 MW of average minimum load energy from unit commitment in the second quarter of 2023.

Minimum load energy from unit commitment exceptional dispatches to provide voltage support (red bars) in the second quarter of 2024 increased by 114 percent from the same quarter in 2023. Meanwhile, minimum load energy from transmission related unit commitment exceptional dispatches (green bars) in the second quarter of 2024 decreased by 77 percent from the same quarter in 2023.

Figure 1.74 Average minimum load energy from exceptional dispatch unit commitments

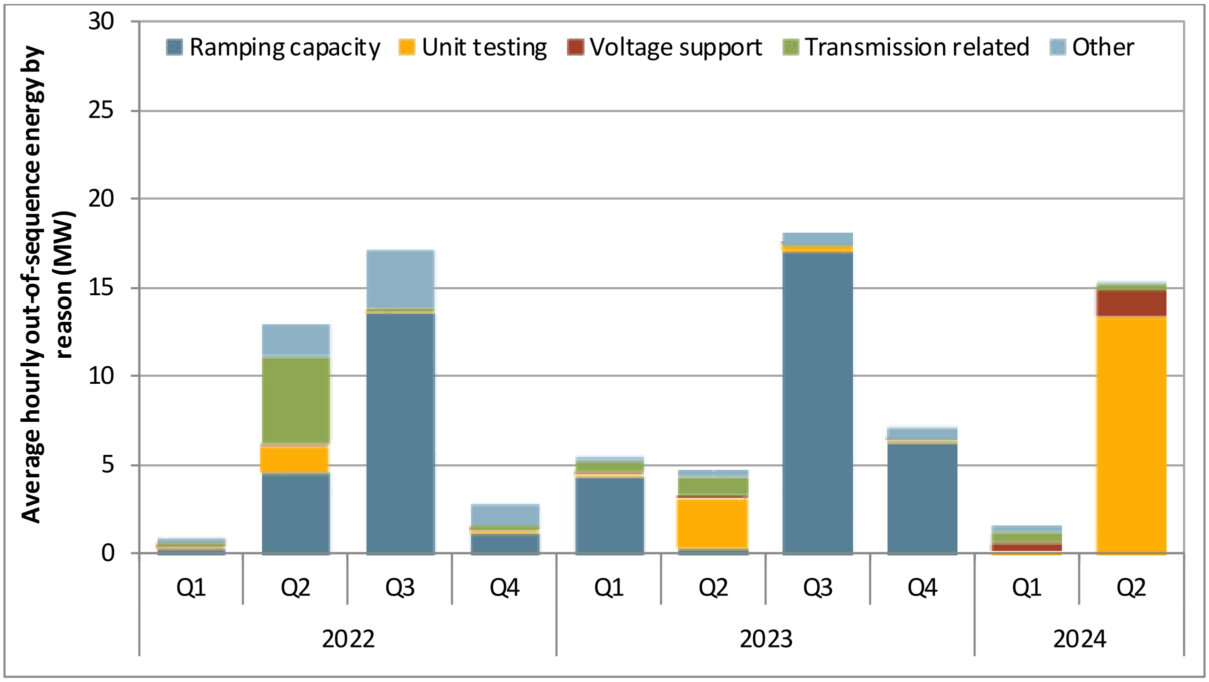


Exceptional dispatches for energy

Figure 1.75 shows the average out-of-sequence exceptional dispatch energy by quarter for 2022, 2023, and 2024. The primary reasons logged for out-of-sequence energy in the second quarter of 2024 were unit testing and voltage support. Unit testing exceptional dispatches are issued for general reliability testing or for unit-specific purposes, such as pre-commercial or post-outage operational testing. Voltage support exceptional dispatches are issued to ensure that proper voltage is maintained on the grid via the generation or absorption of reactive power by the exceptionally dispatched resources.

Out-of-sequence exceptional dispatch energy due to unit testing (yellow bars) increased by 390 percent in the second quarter of 2024 when compared to the second quarter of 2023. This increase is largely due to pre-commercial unit testing for a new resource that came on-line in June 2024. Because this resource was pre-commercial during unit testing, it did not submit any bids to the market. Therefore, the identified out-of-sequence energy is due to the resource's default energy bid being out-of-sequence. Exceptional dispatches for unit testing are settled at the locational marginal price, so there is no settlement impact associated with this energy, despite being out-of-sequence.

Figure 1.75 Out-of-sequence exceptional dispatch energy by reason



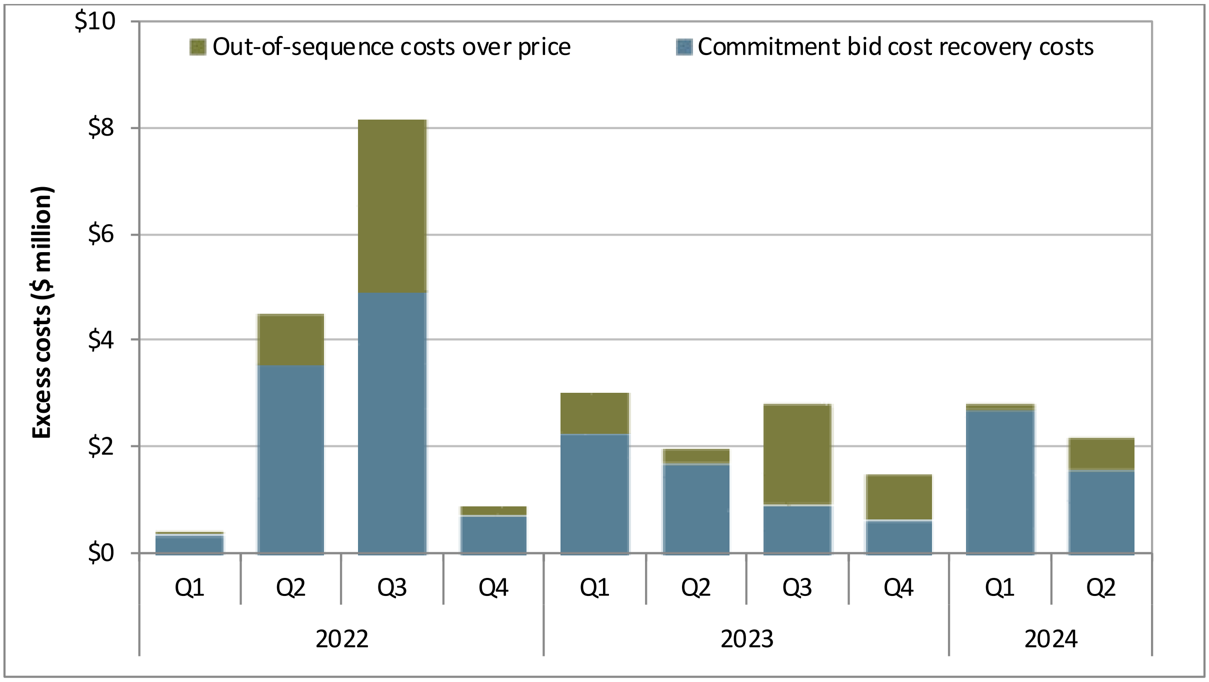
Exceptional dispatch costs

Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.
- Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 1.76 shows the estimated costs for unit commitment and exceptional dispatch for energy above minimum load whose bid price exceeded the resource's locational marginal price. In the second quarter of 2024, out-of-sequence energy costs were $0.59 million, a 103 percent increase from the second quarter of 2023. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the second quarter were $1.6 million, a 7 percent decrease from the second quarter of 2023. Overall, the additional costs associated with the exceptional dispatches in the second quarter of 2024 increased by 9 percent when compared to the second quarter of 2023.

Figure 1.76 Excess exceptional dispatch cost by type



2 Western Energy Imbalance Market

The Western Energy Imbalance Market (WEIM) allows balancing authority areas outside of the California ISO balancing area (CAISO) to voluntarily take part in the ISO real-time market. The WEIM was designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reducing renewable curtailment, and reducing total requirements for flexible reserves.

The ISO real-time market software solves a cost minimization problem for dispatch instructions to generation considering all of the resources available to the market, including both the WEIM and CAISO areas. This can allow the market to increase efficiency by optimizing *energy transfers* economically in real-time between WEIM areas—balancing supply and demand across the footprint with lower-cost generation. Energy transfers between balancing areas also help to reduce curtailment of low cost renewables during times of excess generation.

This section covers Western Energy Imbalance Market (WEIM) performance during the second quarter.

2.1 Prices in the WEIM

This section summarizes prices in the Western Energy Imbalance Market (WEIM) during the second quarter.

Figure 2.1 and Figure 2.2 show the average 15-minute and 5-minute market price by component for each balancing authority area in the second quarter of 2024. These components are listed below.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion within California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the CAISO area or within other WEIM areas by replicating the nodal congestion component of the price from individual constraints using shadow prices and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder was flagged as *Other internal congestion.*
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limits WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraints (ITC) and intertie scheduling limits (ISL).

Significant factors impacting the locational marginal price (LMP) include congestion on WEIM transfer constraints and internal congestion from flow-based constraints. GHG costs also contributed to lowering prices in non-California balancing areas relative to California. This indicates resources with non-zero GHG costs were often sending the last increment of power to California in the real-time markets.

Internal congestion also impacts LMP separation between the southern regions of the WEIM, such as Southern California and the Desert Southwest, and leads to increased LMP in the northern regions including Northern California, the Pacific Northwest, and the Intermountain West, in both the 15-minute and 5-minute markets.

Figure 2.1 Quarterly average 15-minute price by component (April–June 2024)

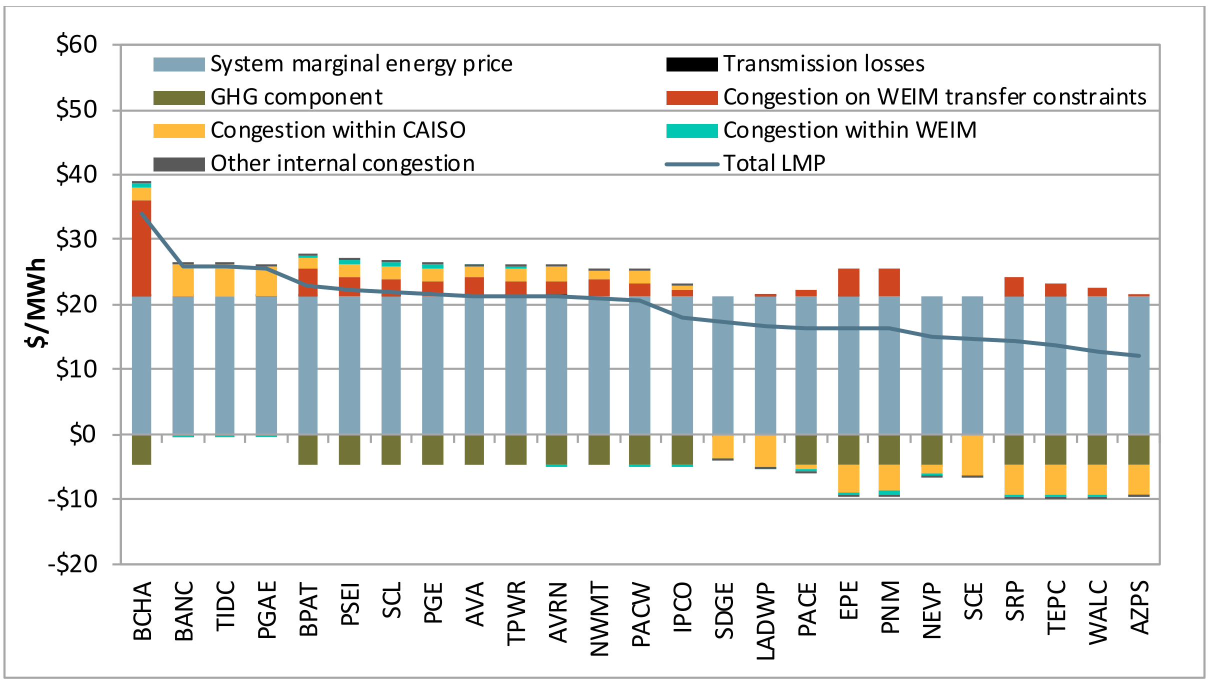


Figure 2.2 Quarterly average 5-minute price by component (April–June 2024)

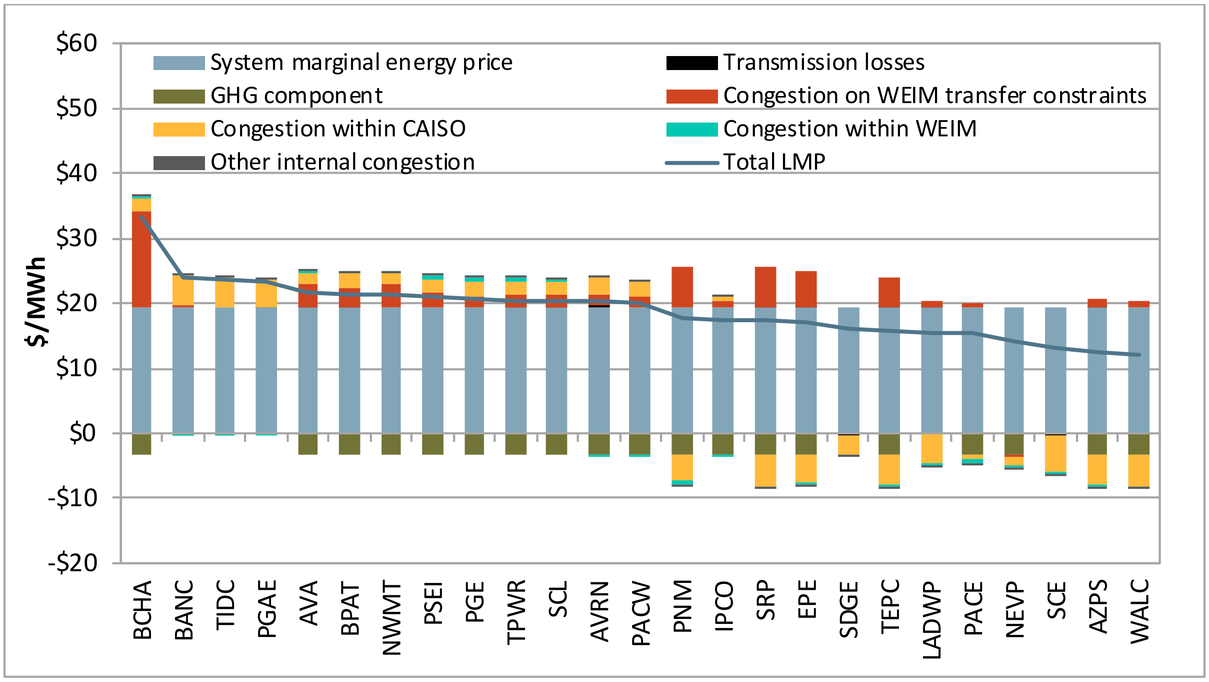


Table 2.1 and Table 2.2 show average 15-minute and 5-minute market prices by month. Table 2.3 and Table 2.4 show instead average hourly prices in the 15-minute and 5-minute markets during the second quarter. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Here, blue indicates prices below that month's average system price and orange indicates prices above. The CAISO prices in the Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) areas are included as points of comparison.

The average monthly price in this quarter was around $19/MWh in both the 15-minute and 5-minute markets, compared to $32/MWh in the second quarter of 2023. Regionally, the Pacific Northwest and Northern California had higher prices than the Desert Southwest, Southern California, and the Intermountain West. During solar generation hours, prices in Northern California, the Intermountain West, and the Pacific Northwest were higher than those in Southern California and the Desert Southwest. During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM due to California greenhouse house gas pricing.

The mid-day price separation pattern was primarily driven by south-to-north congestion on WEIM transfer and internal flow-based constraints. When internal or transfer constraints limit the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply. Greenhouse gas compliance costs contribute to higher prices in California relative to the rest of the system.

Table 2.1 Monthly 15-minute market prices

	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024
SMEC	$69	$97	$125	$69	$90	$246	$140	$73	$73	$55	$19	$28	$66	$67	$42	$57	$58	$50	$89	$38	$28	$22	$16	$26
PG&E (CAISO)	$74	$103	$136	$73	$95	$257	$140	$75	$76	$57	$18	$29	$58	$65	$44	$62	$62	$54	$78	$40	$30	$28	$21	$28
SCE (CAISO)	$78	$108	$136	$64	$83	$246	$140	$68	$65	$48	$20	$27	$73	$68	$39	$51	$53	$45	$65	$31	$17	$11	$9	$24
BANC	$72	$105	$131	$75	$95	$252	$142	$75	$76	$59	$19	$30	$56	$54	$42	$59	$62	$53	$77	$41	$31	$29	$22	$27
Turlock ID	$72	$100	$136	$76	$95	$266	$142	$76	$77	$61	$19	$30	$56	$54	$43	$60	$63	$54	$78	$41	$33	$31	$21	$25
LADWP	$77	$108	$135	$67	$87	$256	$142	$73	$68	$49	$20	$27	$67	$50	$36	$45	$52	$46	$68	$32	$18	$12	$11	$27
NV Energy	$69	$93	$117	$58	$79	$243	$131	$66	$66	$50	$17	$23	$59	$40	$33	$38	$48	$42	$65	$30	$19	$13	$10	$22
Arizona PS	$72	$97	$118	$56	$80	$250	$130	$66	$65	$50	$17	$24	$63	$41	$30	$34	$45	$38	$59	$28	$18	$8	$8	$21
Tucson Electric	$72	$96	$111	$57	$77	$222	$129	$63	$60	$47	$21	$26	$58	$38	$30	$33	$45	$39	$59	$27	$15	$9	$11	$21
Salt River Project	$67	$88	$93	$56	$76	$157	$119	$52	$60	$50	$22	$24	$62	$46	$28	$34	$44	$38	$54	$25	$14	$9	$10	$25
PSC New Mexico	$67	$84	$103	$58	$64	$114	$127	$64	$65	$67	$17	$24	$59	$40	$30	$40	$50	$40	$69	$35	$18	$14	$10	$24
WAPA - Desert SW										$57	$20	$24	$62	$41	$30	$34	$45	$40	$60	$29	$14	$7	$10	$21
El Paso Electric										$33	$18	$23	$48	$37	$29	$30	$20	$20	$53	$24	$15	$9	$13	$27
PacifiCorp East	$65	$81	$99	$59	$72	$193	$120	$63	$67	$52	$18	$26	$53	$38	$31	$40	$46	$40	$76	$31	$22	$16	$12	$13
Idaho Power	$69	$81	$92	$63	$84	$237	$132	$71	$73	$59	$16	$27	$52	$39	$33	$56	$53	$45	$112	$35	$27	$20	$13	$22
NorthWestern	$41	$69	$73	$64	$87	$243	$133	$72	$75	$61	$13	$27	$53	$39	$34	$62	$54	$46	$151	$38	$29	$24	$18	$21
Avista Utilities	$36	$67	$73	$65	$86	$246	$133	$72	$74	$64	$12	$27	$49	$39	$34	$63	$55	$46	$155	$38	$30	$26	$18	$21
Avangrid										$61	$7	$28	$49	$40	$37	$63	$56	$48	$164	$38	$31	$25	$18	$21
BPA	$46	$80	$92	$65	$86	$251	$133	$73	$73	$62	$5	$29	$55	$49	$38	$65	$57	$47	$182	$39	$30	$27	$20	$23
Tacoma Power	$39	$74	$80	$64	$85	$248	$134	$72	$73	$62	$6	$29	$50	$43	$37	$64	$55	$47	$165	$39	$31	$26	$18	$20
PacifiCorp West	$42	$76	$89	$64	$85	$244	$132	$71	$72	$61	$6	$28	$48	$39	$35	$64	$55	$47	$170	$38	$30	$25	$17	$20
Portland GE	$43	$77	$92	$65	$87	$244	$132	$71	$72	$62	$9	$29	$50	$43	$37	$65	$55	$47	$165	$38	$32	$27	$17	$21
Puget Sound Energy	$40	$74	$81	$64	$85	$249	$133	$73	$74	$62	$8	$29	$59	$44	$37	$69	$58	$48	$167	$39	$31	$27	$18	$21
Seattle City Light	$40	$74	$80	$64	$85	$249	$133	$75	$72	$61	$6	$28	$50	$45	$37	$64	$55	$47	$167	$40	$30	$28	$18	$20
Powerex	$37	$61	$69	$67	$82	$212	$129	$79	$84	$79	$14	$55	$94	$99	$83	$102	$98	$62	$72	$54	$49	$43	$27	$32

Table 2.2 Monthly 5-minute market prices

	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024
SMEC	$62	$88	$97	$66	$86	$241	$135	$68	$66	$47	$16	$27	$58	$53	$39	$53	$57	$49	$85	$35	$26	$20	$14	$24
PG&E (CAISO)	$73	$95	$110	$73	$92	$254	$136	$70	$68	$49	$16	$28	$52	$52	$42	$58	$62	$53	$79	$38	$28	$26	$19	$26
SCE (CAISO)	$72	$98	$107	$60	$77	$234	$133	$63	$58	$41	$16	$26	$62	$53	$35	$48	$52	$44	$63	$29	$16	$9	$8	$22
BANC	$70	$97	$107	$74	$92	$249	$138	$71	$68	$49	$16	$29	$54	$53	$42	$57	$62	$53	$79	$39	$30	$27	$20	$25
Turlock ID	$71	$94	$113	$77	$94	$263	$139	$72	$69	$52	$16	$30	$54	$53	$42	$58	$63	$54	$79	$40	$31	$29	$19	$24
LADWP	$70	$98	$106	$61	$81	$244	$134	$67	$59	$42	$16	$26	$62	$55	$37	$51	$53	$45	$66	$30	$17	$10	$10	$27
NV Energy	$67	$90	$90	$57	$76	$235	$126	$62	$60	$42	$14	$22	$56	$45	$34	$44	$50	$43	$65	$29	$19	$12	$9	$21
Arizona PS	$67	$89	$96	$54	$77	$240	$123	$66	$61	$42	$15	$24	$59	$45	$32	$40	$46	$40	$59	$26	$17	$8	$8	$21
Tucson Electric	$67	$89	$90	$54	$73	$215	$123	$60	$54	$40	$20	$26	$58	$44	$31	$38	$46	$40	$58	$28	$16	$10	$14	$24
Salt River Project	$68	$83	$75	$51	$72	$149	$109	$49	$54	$45	$23	$26	$61	$48	$27	$38	$49	$39	$53	$24	$17	$10	$13	$29
PSC New Mexico	$64	$78	$80	$57	$63	$123	$122	$60	$58	$53	$14	$24	$56	$44	$33	$46	$51	$42	$70	$34	$18	$16	$12	$25
WAPA - Desert SW										$40	$19	$26	$58	$44	$33	$38	$47	$40	$59	$28	$14	$6	$9	$21
El Paso Electric										$28	$16	$23	$47	$40	$30	$33	$23	$23	$52	$24	$15	$8	$18	$25
PacifiCorp East	$59	$74	$76	$57	$70	$192	$116	$59	$62	$45	$14	$25	$52	$43	$34	$44	$47	$40	$73	$30	$21	$15	$11	$20
Idaho Power	$60	$75	$76	$61	$80	$233	$127	$66	$68	$51	$13	$26	$52	$44	$35	$61	$54	$46	$119	$34	$25	$19	$13	$21
NorthWestern	$37	$64	$66	$64	$86	$241	$128	$67	$69	$56	$9	$27	$55	$46	$37	$67	$55	$48	$161	$37	$28	$26	$18	$20
Avista Utilities	$31	$63	$65	$64	$83	$242	$129	$67	$69	$56	$10	$27	$51	$44	$37	$68	$55	$48	$164	$37	$29	$27	$18	$20
Avangrid										$56	$6	$27	$51	$44	$38	$68	$55	$48	$168	$37	$29	$24	$16	$20
BPA	$34	$68	$78	$63	$83	$247	$130	$68	$68	$57	$4	$28	$53	$48	$37	$69	$56	$47	$184	$37	$28	$26	$17	$22
Tacoma Power	$33	$67	$71	$62	$82	$246	$130	$67	$69	$56	$5	$28	$50	$45	$37	$69	$54	$47	$170	$37	$29	$26	$17	$20
PacifiCorp West	$37	$68	$69	$63	$83	$239	$129	$66	$68	$56	$6	$26	$50	$42	$37	$68	$54	$47	$171	$37	$28	$24	$16	$20
Portland GE	$37	$68	$72	$63	$84	$239	$129	$66	$68	$56	$9	$27	$50	$45	$37	$69	$54	$47	$169	$37	$29	$26	$16	$20
Puget Sound Energy	$34	$66	$71	$62	$83	$247	$131	$68	$69	$56	$7	$28	$61	$47	$38	$74	$56	$47	$175	$37	$29	$27	$16	$20
Seattle City Light	$33	$67	$70	$62	$82	$247	$130	$69	$68	$56	$5	$27	$50	$46	$37	$68	$55	$47	$171	$37	$28	$26	$16	$20
Powerex	$32	$57	$67	$65	$80	$209	$127	$77	$83	$77	$14	$52	$87	$94	$77	$102	$101	$61	$72	$53	$48	$43	$27	$30

Table 2.3 Hourly 15-minute market prices (April–June)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$31	$29	$28	$28	$29	$34	$32	$15	$8	$4	$3	$2	$2	$2	$2	$4	$9	$16	$33	$45	$46	$39	$34	$32
PG&E (CAISO)	$32	$30	$29	$29	$30	$35	$34	$23	$18	$14	$10	$9	$7	$8	$9	$11	$17	$24	$35	$48	$49	$41	$35	$33
SCE (CAISO)	$32	$30	$29	$28	$30	$35	$32	$7	-$8	-$12	-$12	-$13	-$13	-$13	-$13	-$10	-$7	$5	$32	$45	$46	$39	$34	$32
BANC	$32	$31	$30	$30	$31	$36	$34	$21	$16	$13	$11	$10	$8	$8	$10	$13	$19	$24	$36	$48	$50	$42	$36	$33
Turlock ID	$32	$30	$29	$29	$30	$35	$34	$21	$17	$14	$13	$12	$10	$11	$12	$15	$20	$22	$34	$45	$47	$40	$34	$32
LADWP	$35	$30	$28	$28	$29	$35	$32	$13	-$4	-$8	-$10	-$11	-$10	-$9	-$9	-$5	-$2	$9	$32	$47	$46	$39	$34	$32
NV Energy	$24	$22	$21	$21	$23	$25	$20	$10	$0	-$1	-$3	-$2	-$3	-$1	$0	$2	$4	$12	$30	$38	$36	$29	$28	$24
Arizona PS	$23	$21	$21	$21	$22	$25	$21	$5	-$5	-$8	-$8	-$9	-$6	-$8	-$7	-$5	-$2	$8	$30	$36	$34	$28	$28	$23
Tucson Electric	$22	$20	$19	$19	$21	$24	$19	$4	-$4	-$7	-$7	-$5	-$4	-$1	$2	$4	$10	$13	$28	$40	$34	$28	$28	$23
Salt River Project	$23	$21	$20	$21	$22	$25	$18	$1	-$5	-$3	-$7	$0	-$2	$2	$2	$7	$4	$10	$32	$35	$33	$28	$33	$26
PSC New Mexico	$28	$21	$19	$20	$27	$34	$31	$19	$10	-$6	-$8	-$7	-$7	-$7	-$6	$1	-$1	$19	$33	$49	$40	$28	$28	$23
WAPA - Desert SW	$31	$31	$20	$21	$22	$25	$20	$5	-$5	-$8	-$9	-$9	-$9	-$9	-$8	-$6	-$3	$7	$27	$38	$35	$28	$37	$24
El Paso Electric	$23	$19	$17	$18	$19	$24	$22	$6	-$1	-$2	-$3	-$1	$2	$3	$1	$15	$11	$30	$38	$39	$34	$27	$27	$23
PacifiCorp East	$23	$21	$20	$21	$22	$25	$21	$12	$7	$5	$3	$3	$2	$2	$3	$5	$7	$14	$27	$36	$35	$29	$28	$24
Idaho Power	$23	$21	$20	$21	$22	$25	$27	$14	$10	$9	$6	$6	$5	$5	$7	$5	$10	$15	$28	$36	$36	$30	$28	$24
NorthWestern	$22	$21	$20	$20	$22	$25	$22	$17	$16	$15	$15	$15	$15	$14	$14	$16	$17	$22	$28	$34	$34	$28	$28	$23
Avista Utilities	$22	$20	$19	$20	$21	$24	$22	$18	$18	$16	$16	$17	$16	$16	$16	$18	$18	$23	$27	$33	$33	$28	$27	$23
Avangrid	$22	$20	$19	$20	$21	$24	$21	$18	$17	$16	$16	$17	$16	$16	$17	$18	$19	$21	$26	$32	$32	$28	$27	$23
BPA	$22	$21	$20	$20	$21	$24	$27	$25	$22	$18	$20	$19	$18	$18	$18	$19	$22	$25	$29	$33	$32	$28	$29	$24
Tacoma Power	$24	$20	$19	$20	$21	$24	$21	$17	$17	$16	$17	$19	$19	$17	$18	$19	$20	$21	$25	$31	$31	$27	$26	$23
PacifiCorp West	$22	$20	$19	$20	$21	$23	$21	$18	$17	$16	$16	$17	$16	$16	$16	$18	$19	$20	$25	$31	$31	$27	$26	$23
Portland GE	$22	$20	$19	$20	$21	$23	$21	$18	$17	$16	$19	$19	$18	$18	$19	$20	$21	$21	$28	$33	$31	$28	$26	$23
Puget Sound Energy	$22	$20	$19	$20	$21	$24	$22	$23	$18	$16	$18	$18	$18	$18	$18	$19	$22	$26	$26	$31	$34	$30	$28	$23
Seattle City Light	$22	$20	$19	$20	$21	$24	$22	$17	$16	$15	$18	$18	$20	$18	$19	$19	$20	$29	$25	$31	$31	$30	$26	$25
Powerex	$34	$31	$30	$29	$31	$33	$36	$33	$33	$32	$32	$32	$33	$33	$33	$33	$34	$35	$38	$40	$40	$39	$36	$35

Table 2.4 Hourly 5-minute market prices (April–June)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$32	$30	$28	$28	$28	$30	$30	$12	$6	$4	$2	$2	$1	$1	$0	$1	$4	$10	$30	$44	$38	$36	$34	$33
PG&E (CAISO)	$33	$31	$29	$29	$29	$31	$31	$19	$17	$14	$9	$9	$7	$7	$7	$7	$11	$17	$31	$46	$40	$38	$35	$33
SCE (CAISO)	$32	$30	$28	$28	$29	$31	$30	$4	-$9	-$12	-$13	-$13	-$14	-$14	-$15	-$12	-$11	$1	$30	$44	$38	$36	$34	$33
BANC	$33	$31	$30	$29	$29	$32	$31	$17	$15	$13	$11	$11	$16	$7	$8	$9	$14	$17	$32	$47	$41	$38	$35	$34
Turlock ID	$32	$30	$29	$28	$29	$31	$31	$17	$16	$14	$12	$12	$9	$9	$9	$11	$15	$16	$30	$44	$39	$36	$34	$33
LADWP	$36	$30	$28	$28	$28	$31	$30	$11	-$6	-$9	-$11	-$12	-$10	-$10	-$3	-$8	-$4	$4	$31	$44	$38	$36	$34	$33
NV Energy	$25	$23	$21	$22	$23	$25	$19	$3	$0	-$2	-$3	-$3	-$3	-$3	-$3	-$1	-$1	$8	$31	$42	$33	$29	$29	$25
Arizona PS	$24	$22	$21	$22	$23	$25	$20	$9	-$7	-$9	-$8	-$9	-$1	-$9	-$9	-$5	-$7	$4	$38	$40	$35	$28	$29	$25
Tucson Electric	$23	$21	$20	$20	$22	$24	$18	$1	-$6	-$8	-$7	-$1	$2	$1	$16	$10	$17	$18	$31	$45	$32	$27	$28	$24
Salt River Project	$27	$25	$20	$21	$22	$25	$17	-$2	-$6	-$2	$2	$3	$3	$6	$11	$13	$3	$13	$48	$42	$31	$31	$35	$25
PSC New Mexico	$27	$21	$20	$25	$33	$35	$39	$16	$7	-$7	-$8	-$7	-$8	-$8	-$6	-$3	-$3	$22	$45	$54	$39	$31	$34	$24
WAPA - Desert SW	$36	$29	$21	$21	$23	$25	$20	$2	-$7	-$9	-$10	-$9	-$10	-$10	-$11	-$9	-$7	$3	$29	$41	$32	$27	$34	$25
El Paso Electric	$27	$19	$17	$18	$21	$24	$20	$1	-$5	-$3	-$6	-$2	-$5	-$1	$9	$25	$17	$35	$42	$43	$32	$26	$28	$24
PacifiCorp East	$24	$22	$21	$21	$22	$24	$20	$7	$4	$3	$1	$2	$1	$0	$1	$2	$2	$9	$28	$42	$32	$28	$28	$24
Idaho Power	$24	$22	$21	$22	$23	$25	$24	$12	$8	$9	$3	$4	$3	$4	$6	$3	$5	$11	$28	$46	$35	$29	$29	$25
NorthWestern	$23	$22	$21	$21	$22	$25	$26	$15	$14	$22	$13	$14	$13	$13	$14	$14	$14	$23	$28	$39	$32	$28	$29	$25
Avista Utilities	$23	$21	$21	$21	$22	$24	$26	$16	$16	$23	$15	$15	$15	$15	$14	$16	$16	$19	$27	$38	$31	$28	$28	$24
Avangrid	$23	$21	$21	$21	$22	$24	$21	$14	$14	$13	$14	$15	$14	$14	$14	$15	$15	$17	$26	$38	$31	$28	$28	$24
BPA	$23	$21	$21	$21	$22	$24	$22	$16	$16	$16	$17	$18	$17	$17	$17	$18	$18	$19	$28	$33	$32	$28	$29	$24
Tacoma Power	$24	$21	$20	$20	$22	$24	$20	$13	$13	$14	$15	$17	$17	$16	$16	$16	$17	$16	$26	$36	$30	$27	$27	$24
PacifiCorp West	$23	$21	$20	$20	$22	$24	$20	$13	$13	$13	$14	$15	$15	$14	$14	$15	$15	$16	$26	$36	$30	$27	$29	$24
Portland GE	$23	$21	$20	$20	$22	$24	$20	$13	$13	$15	$15	$16	$17	$17	$16	$17	$17	$16	$26	$37	$30	$27	$27	$24
Puget Sound Energy	$23	$21	$20	$20	$22	$24	$23	$13	$13	$14	$16	$16	$19	$19	$16	$16	$18	$20	$26	$36	$30	$28	$28	$24
Seattle City Light	$23	$21	$20	$20	$22	$24	$20	$13	$13	$14	$16	$16	$17	$16	$16	$16	$17	$16	$26	$36	$30	$28	$27	$25
Powerex	$33	$30	$29	$29	$30	$32	$35	$32	$32	$31	$31	$31	$32	$32	$33	$32	$33	$34	$37	$40	$39	$38	$36	$35

2.2 Transfers, limits, and congestion

Energy transfers

One of the key benefits of the WEIM is the ability to transfer energy between balancing areas in the 15-minute and 5-minute markets. These transfers are the result of regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint.[86] WEIM transfers are constrained by *transfer limits* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 2.3 and Figure 2.4 highlight typical transfer patterns during two key periods that typically produce a high volume of transfers.[87] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area.

Figure 2.3 shows average dynamic 15-minute market exports out of each area during *mid-day hours* (between hours 10 and 17) during the quarter.[88] CAISO exported on average over 2,900 MW during these mid-day hours, out to neighboring areas. The mid-day hours typically contain the highest levels of exports out of the CAISO area because of significant solar production. Figure 2.4 instead shows average dynamic transfers during *peak net load hours* (between hours 19 and 22) during the quarter.

86 See Appendix A for figures on the average hourly transfers by quarter for each WEIM area.

87 In Figure 2.3, each small tick is 100 MW, each large tick is 500 MW, and average WEIM transfer paths less than 50 MW are excluded. In Figure 2.4, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

88 These figures exclude the fixed bilateral transactions between WEIM entities (base WEIM transfer schedules) and therefore reflect only *dynamic* market flows optimized in the market.

Figure 2.3 Average 15-minute market WEIM exports (mid-day hours, April–June 2024)

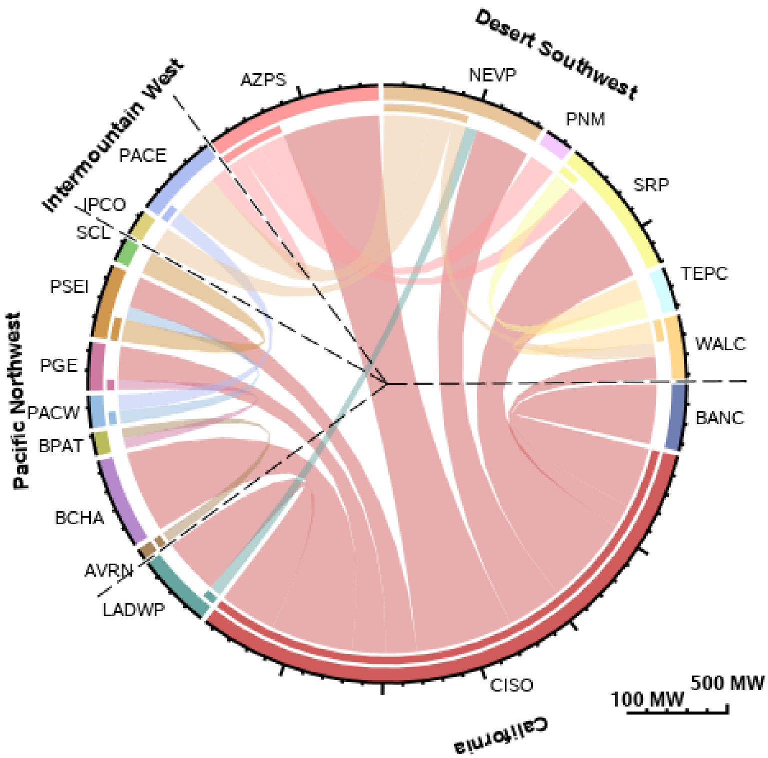
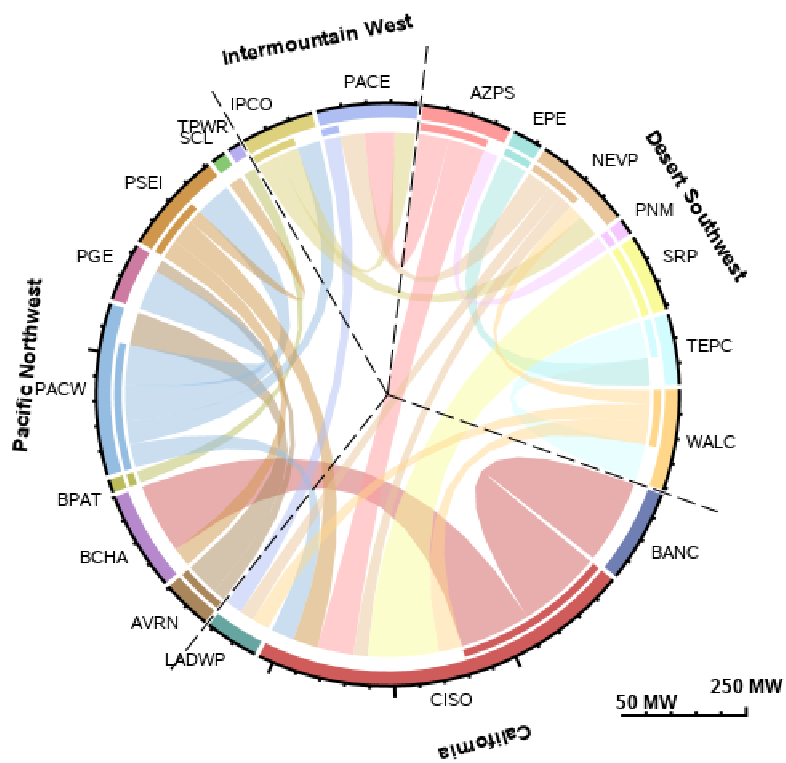


Figure 2.4 Average 15-minute market WEIM exports (peak load hours, April–June 2024)



Transfer limits

WEIM transfers between areas are constrained by transfer limits. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities. Table 2.5 shows average 15-minute market import and export limits for each balancing area. These amounts exclude base WEIM transfer schedules and therefore reflect transfer capability, which is made available by WEIM entities to optimally transfer energy between areas.

The balancing areas in Table 2.5 are grouped in one of four regions: California, Desert Southwest, Intermountain West, or Pacific Northwest. These regions reflect a combination of general geographic location, as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system. The last two columns in Table 2.5 show WEIM transfer limits between these regions (out-of-region import and export limits).

Import and export transfer capacity into or out of the Desert Southwest region was around 32,800 MW and 25,100 MW, respectively. For the Pacific Northwest region, there was an average of around 1,500 MW of import and 900 MW of export transfer capacity into or out of the region.

Table 2.5 Average 15-minute market WEIM limits (April–June 2024)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**24,363**	**32,090**
California ISO	32,017	34,906	21,287	27,420
BANC	3,681	3,635	0	0
LADWP	6,586	11,316	3,076	4,670
Turlock Irrig. District	1,595	1,749	0	0
Desert Southwest			**32,784**	**25,124**
Arizona Public Service	32,813	21,917	24,896	15,685
El Paso Electric	563	479	0	0
NV Energy	4,608	3,643	3,880	2,910
PSC New Mexico	955	1,223	0	0
Salt River Project	6,763	8,918	1,403	3,321
Tucson Electric	4,725	5,759	662	832
WAPA - Desert SW	4,820	5,648	1,941	2,376
Intermountain West			**2,084**	**2,614**
Avista Utilities	656	1,011	128	109
Idaho Power	2,420	2,676	618	716
NorthWestern Energy	669	840	21	11
PacifiCorp East	3,120	2,867	1,317	1,778
Pacific Northwest			**1,533**	**935**
Avangrid	749	760	14	20
Powerex	477	50	428	0
BPA	487	566	92	117
PacifiCorp West	1,666	1,742	411	366
Portland General Electric	693	668	197	117
Puget Sound Energy	1,521	1,287	389	297
Seattle City Light	409	419	1	18
Tacoma Power	325	240	0	0

Congestion on WEIM transfer constraints

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Figure 2.5 shows the percent of intervals and price impact of 15-minute and 5-minute market transfer constraint congestion in each WEIM area during the quarter.[89] The congestion on the WEIM transfer constraints are measured relative to a reference price in the CAISO balancing area. *Congested from area* reflects that prices are lower in the balancing area because of limited export capability out of the area or

[89] The frequency is calculated as the number of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices. This accounts for any constraint that can limit WEIM transfers between balancing areas, including (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits, or (3) intertie constraint and intertie scheduling limits.

region, relative to the CAISO (and connected WEIM system). *Congestion into area* reflects that prices are higher within an area or region, because of limited import capability into the area or region.[90]

Powerex was frequently import constrained relative to the CAISO balancing area because of WEIM transfer congestion. Powerex was congested into the area during around 72 and 75 percent of intervals in the 15-minute and 5-minute markets, respectively. On average for the quarter, prices in Powerex were around $15/MWh higher because of WEIM transfer congestion. The rest of the Pacific Northwest region, as well as Avista and NorthWestern Energy, were also frequently import constrained relative to the rest of the WEIM system, during around 18 percent of 15-minute intervals and 15 percent of 5-minute intervals. When a balancing area has net WEIM transfer import congestion into the area, the market software triggers local market power mitigation procedures for resources in that area.[91]

Table 2.6 Frequency and impact of transfer congestion in the WEIM (April–June 2024)

	15-minute market				5-minute market			
	Congested from area		Congested into area		Congested from area		Congested into area	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	0.0%	$0.00	0.0%	$0.00	0.0%	-$0.01	0.0%	$0.34
WAPA – Desert Southwest	0.0%	-$0.01	0.4%	$1.28	0.0%	-$0.02	0.4%	$1.17
NV Energy	0.4%	-$0.28	0.0%	$0.11	0.5%	-$0.30	0.0%	$0.00
Arizona Public Service	0.1%	-$0.05	0.3%	$0.40	0.2%	-$0.10	0.3%	$1.50
Turlock Irrigation District	1.0%	-$0.07	0.0%	$0.00	1.0%	-$0.09	0.0%	$0.00
Public Service Company of NM	0.2%	-$0.12	2%	$4.32	0.1%	-$0.11	2%	$6.43
L.A. Dept. of Water and Power	1%	-$0.13	0.7%	$0.49	1%	-$0.22	0.6%	$1.17
PacifiCorp East	0.1%	-$0.03	8%	$1.00	0.4%	-$0.10	5%	$0.89
Idaho Power	1%	-$0.38	8%	$1.33	1%	-$0.36	5%	$1.34
El Paso Electric Company	4%	-$1.00	8%	$5.30	3%	-$0.80	8%	$6.30
Salt River Project	4%	-$0.84	11%	$3.71	4%	-$0.91	11%	$7.16
Tucson Electric Power	5%	-$0.54	11%	$2.51	5%	-$0.50	12%	$5.18
NorthWestern Energy	2%	-$0.22	18%	$3.02	2%	-$0.20	17%	$3.97
Avista Utilities	2%	-$0.17	18%	$3.08	2%	-$0.18	17%	$3.73
PacifiCorp West	7%	-$0.62	17%	$2.66	6%	-$0.54	12%	$2.30
Avangrid Renewables	7%	-$0.62	17%	$2.66	6%	-$0.55	12%	$2.22
Puget Sound Energy	7%	-$0.63	17%	$3.69	7%	-$0.58	13%	$2.97
Seattle City Light	7%	-$0.62	17%	$3.41	7%	-$0.57	13%	$2.50
Tacoma Power	7%	-$0.68	18%	$3.01	7%	-$0.60	14%	$2.62
Portland General Electric	7%	-$0.61	18%	$2.91	7%	-$0.60	13%	$2.32
Bonneville Power Admin.	9%	-$0.94	25%	$5.08	8%	-$0.90	24%	$4.01
Powerex	2%	-$0.29	72%	$15.17	8%	-$0.87	75%	$15.57

2.3 Resource sufficiency evaluation

As part of the WEIM design, each area, including the California ISO balancing area, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize

90 When prices are higher within an area, this indicates that WEIM transfer congestion limited the ability for outside energy to serve that area's load.

91 If bid in supply after removing the three largest suppliers is less than the generation dispatched in the area in the market power mitigation run, bids in excess of the higher of default energy bids and the competitive LMP will be replaced by the higher of default energy bids and the competitive LMP. The California ISO balancing area is not subject to market power mitigation when WEIM transfer limits into the CAISO area are constrained.

transfers between participating WEIM entities while deterring WEIM balancing areas from relying on other WEIM areas for capacity.

The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation is made up of four tests: the power flow feasibility test, the balancing test, the bid range capacity test, and the flexible ramping sufficiency test. Failures of two of the tests can constrain transfer capability:

- **The bid range capacity test (capacity test)** requires that each area provide incremental bid-in capacity to meet the imbalance between load, intertie, and generation base schedules.
- **The flexible ramping sufficiency test (flexibility test)** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area that has not opted in to assistance energy transfers fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[92] If an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

Frequency of resource sufficiency evaluation failures

Figure 2.5 and Figure 2.6 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.7 and Figure 2.8 provide the same information for the downward direction.[93] The dash indicates the area did not fail the test during the month.

In the second quarter of 2024:

- Public Service Company of New Mexico (PNM) failed the upward flexibility test in around 1.4 percent of intervals.
- All other balancing areas failed each test type in less than one percent of intervals.

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92 Normally, if an area fails either test in the upward direction, net WEIM imports during the hour cannot exceed the greater of either the base transfer or the optimal transfer from the last 15-minute interval. Assistance energy transfers (AETs) give balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Balancing areas can opt in to AET to prevent their WEIM transfers from being limited during a test failure but will be subject to an ex-post surcharge.

93 Results exclude known invalid test failures. These can occur because of a market disruption, software defect, or other error.

Figure 2.5 Frequency of upward capacity test failures by month and area (percent of intervals)

	2023									2024					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	0.2	0.0	0.1	—	—	—	0.0	—	0.1	—	—	—	—	—	—
Avangrid	0.0	—	—	—	—	0.8	—	—	—	—	—	—	—	—	—
Avista	0.1	0.0	—	—	—	—	0.0	0.1	—	0.3	0.1	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	0.2	—	0.3	0.4	—	0.1	—	—	—	0.3	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	0.0	0.1	0.3	0.8	0.0	0.1	0.1	—	—	—	—	0.1	0.2	0.6	0.1
Idaho Power	0.0	0.1	—	—	—	—	—	0.1	—	0.0	—	—	—	—	—
LADWP	—	—	—	0.1	0.0	—	—	—	0.0	0.1	0.0	—	0.0	0.0	—
NorthWestern En.	—	—	—	0.3	—	—	—	—	—	—	0.1	—	—	—	—
NV Energy	—	0.0	—	0.0	0.0	—	0.0	—	—	—	—	—	—	0.1	0.0
PacifiCorp East	—	—	—	0.0	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	0.1	—	—	—	—	0.8	0.0	—	0.1	0.0	—
Portland Gen. Elec.	0.1	0.4	0.1	0.0	—	0.0	0.0	0.6	—	—	—	—	—	0.0	0.1
Powerex	—	0.1	—	—	—	0.1	0.0	0.0	—	—	—	—	—	—	—
PSC of New Mexico	0.3	0.2	0.0	—	0.0	0.1	0.1	—	0.1	—	—	—	0.1	0.1	0.1
Puget Sound En.	—	0.1	0.5	1.5	0.5	0.2	0.7	1.0	0.2	0.8	0.1	0.2	0.3	0.2	—
Salt River Proj.	0.9	0.2	0.0	2.8	1.2	0.0	0.8	0.2	0.1	0.1	0.1	0.2	0.1	—	0.2
Seattle City Light	—	—	—	0.1	0.9	—	0.1	0.6	—	0.5	—	—	0.4	—	0.0
Tacoma Power	—	0.1	—	—	0.1	—	0.1	0.0	—	—	—	0.3	—	0.0	—
Tucson Elec. Pow.	—	—	—	0.3	—	—	0.2	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	0.0	—	—	0.1	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	2.3	0.8	0.7	1.1	0.6	0.1	0.3	0.4	0.1	—	—	0.1	—	0.5	0.3

Figure 2.6 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2023									2024					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	1.1	0.2	0.1	—	0.0	—	—	0.2	0.1	0.2	0.1	0.5	0.1	0.3	—
Avangrid	1.0	0.7	0.1	0.2	0.0	0.9	0.1	0.1	0.2	0.2	0.1	0.1	0.0	0.2	0.5
Avista	0.2	0.2	0.0	—	—	—	0.1	0.1	—	0.1	—	0.1	—	—	—
BANC	—	0.1	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	0.2	1.2	0.3	1.3	0.2	0.2	0.1	—	—	0.4	0.0	—	0.1	0.1	0.1
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	0.8	0.7	0.3	2.1	0.5	0.6	0.4	0.2	0.1	0.3	0.0	1.0	0.9	1.0	0.9
Idaho Power	0.3	0.5	0.1	—	—	—	0.1	—	—	1.1	—	0.1	0.6	0.6	0.1
LADWP	0.1	0.0	0.1	0.0	0.2	0.0	—	—	0.1	0.1	—	0.1	0.4	0.1	0.0
NorthWestern En.	0.8	0.3	0.2	1.0	0.4	0.2	0.2	0.0	0.1	0.5	0.1	0.0	0.0	0.1	0.3
NV Energy	0.1	0.1	0.0	0.1	0.2	0.1	—	0.1	0.0	—	0.1	0.0	—	0.1	—
PacifiCorp East	0.1	—	0.0	0.2	—	—	—	—	—	—	—	—	0.0	0.0	—
PacifiCorp West	0.1	0.6	0.0	0.2	—	—	0.0	0.0	0.1	1.0	—	0.1	—	—	0.1
Portland Gen. Elec.	0.1	1.5	0.7	0.1	—	—	0.6	0.0	—	—	—	0.0	—	0.2	0.2
Powerex	—	—	—	—	—	—	—	—	—	0.2	—	—	—	—	—
PSC of New Mexico	5.1	0.9	0.6	0.7	0.5	0.3	1.9	1.9	0.3	2.0	2.3	0.4	1.8	1.1	1.2
Puget Sound En.	0.2	1.0	0.6	2.6	1.3	0.2	1.3	1.9	0.5	0.8	0.1	0.2	0.4	0.5	0.5
Salt River Proj.	2.0	0.6	0.2	3.7	1.1	0.3	0.6	0.4	0.2	0.2	0.1	0.7	0.4	0.1	0.3
Seattle City Light	—	—	—	—	0.5	0.0	0.0	—	—	0.3	—	0.1	0.1	0.1	—
Tacoma Power	—	0.1	—	—	—	—	0.2	0.0	—	0.1	0.0	0.4	0.0	0.0	—
Tucson Elec. Pow.	0.1	0.1	—	0.2	0.3	—	0.1	0.2	0.1	0.0	0.2	—	0.1	0.1	—
Turlock Irrig. Dist.	0.0	—	—	0.1	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	2.7	0.7	0.8	0.3	0.6	0.2	0.3	0.5	0.1	1.1	2.5	3.5	0.3	0.8	0.2

Figure 2.7 Frequency of downward capacity test failures by month and area (percent of intervals)

	2023									2024					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	—	—	—	—	—	—	—	—	0.8	0.1	0.0	0.1	0.2	—	—
Avangrid	—	—	—	—	—	—	—	0.3	—	—	—	—	—	—	—
Avista	0.0	—	—	—	—	—	—	—	—	—	—	0.1	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	0.2	0.1	—	—	—	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	0.2	0.1	0.3	0.2	0.1	0.2	—	—	—	0.2	—	0.4	0.2	0.4	0.3
Idaho Power	—	—	0.0	—	—	—	—	—	—	—	—	—	0.5	—	—
LADWP	—	—	0.0	—	—	—	—	—	—	—	—	—	—	—	—
NorthWestern En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	0.1	0.1	0.6	0.1	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	—	—	0.0	—	—	—	—	—	—	—	—	0.0	—	—
PSC of New Mexico	0.3	—	—	—	—	0.1	—	—	—	—	—	—	—	—	—
Puget Sound En.	—	0.1	—	—	—	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	0.3	0.6	0.4	0.7	—	0.1	0.1	—	—	—	0.1	0.1	0.4	0.7	—
Seattle City Light	—	—	—	—	0.3	0.1	—	0.1	0.2	0.0	—	—	—	—	—
Tacoma Power	—	—	—	0.0	—	0.0	—	—	—	—	—	—	—	—	0.0
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	0.2	—	0.8	0.1	0.4	0.5	0.2	0.2	—	—	—	—	—	—	—

Figure 2.8 Frequency of downward flexibility test failures by month and area (percent of intervals)

	2023									2024					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	0.7	1.2	0.1	—	—	—	—	—	0.3	0.1	0.1	0.2	0.1	—	—
Avangrid	0.1	—	—	—	—	0.1	—	—	—	0.1	—	—	—	—	—
Avista	0.1	0.1	—	—	—	—	—	0.1	—	—	0.0	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	0.6	5.5	0.0	0.4	—	0.0	0.2	—	—	0.4	0.1	—	0.0	0.1	0.1
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	0.2	0.9	1.9	0.5	—	0.3	—	0.2	0.3	0.3	0.2	0.4	0.8	0.7	0.1
Idaho Power	0.2	—	—	—	—	0.0	—	0.1	—	—	—	0.0	1.0	—	—
LADWP	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NorthWestern En.	—	0.2	0.2	—	0.1	0.0	—	—	—	0.2	—	0.1	—	0.3	0.2
NV Energy	0.0	0.1	0.4	0.1	0.1	0.0	0.1	0.1	—	—	—	0.1	0.0	—	0.1
PacifiCorp East	—	—	—	—	—	0.0	0.1	—	—	—	0.2	0.0	0.5	0.2	0.0
PacifiCorp West	0.0	0.2	0.0	—	—	1.1	—	0.1	—	—	—	0.2	—	—	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.2	—	—	0.0	—	0.2	0.1	—	0.1	—	0.1	0.4	0.0	—	—
PSC of New Mexico	1.6	2.1	—	0.1	0.4	1.1	0.4	0.2	0.2	0.9	0.9	0.4	0.0	0.6	0.1
Puget Sound En.	—	0.8	—	—	—	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	0.3	0.1	0.1	0.1	—	—	—	0.1	0.0	0.1	0.1	0.7	0.7	0.7	0.0
Seattle City Light	0.3	0.0	0.3	0.4	1.1	0.2	—	0.8	0.2	0.2	0.1	0.1	0.2	—	0.1
Tacoma Power	—	—	—	0.0	—	0.1	—	0.0	—	—	0.0	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	0.1	—	—	—	—
Turlock Irrig. Dist.	0.1	0.4	—	—	—	—	—	0.1	—	—	0.0	—	—	0.2	0.0
WAPA DSW	2.7	0.5	0.7	0.1	0.2	0.6	0.8	0.2	0.1	0.3	0.1	0.0	0.0	—	—

Assistance energy transfers

Assistance energy transfers (AET) give balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Without AET, a balancing area failing either the upward flexibility or upward capacity test would have net WEIM imports limited to the greater of either the base transfer or the optimal transfer from the last 15-minute market interval. Balancing areas can voluntarily opt in to the AET program to prevent their WEIM transfers from being limited during an upward resource sufficiency evaluation failure, but will be subject to an ex-post surcharge. Balancing areas must opt in or opt out of the program in advance of the trade date.[94]

The assistance energy transfer surcharge is applied during any interval in which an opt-in balancing area fails the upward flexibility or capacity test. The surcharge is calculated as the *applicable real-time assistance energy transfer* times the real-time bid cap.[95] The applicable AET quantity is based on the lesser of either (1) the tagged dynamic WEIM transfers or (2) the amount by which the balancing area failed the resource sufficiency evaluation. If the tagged dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the ISO balancing area.

Opting in to the assistance energy transfer program does not guarantee that the balancing area will achieve additional WEIM supply following a resource sufficiency evaluation failure (compared to opting out of the program). It only removes the import limit that would have been in place following a test failure, allowing the market to freely and optimally schedule WEIM transfers based on supply and demand conditions in the system. If the import limit following a test failure was set high such that it is not restricting the optimal solution, then opting in or opting out of the program will have no effect on WEIM import supply in that interval.

Table 2.7 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the second quarter. Seven balancing areas were opted in to the program on at least one day during this period: Avangrid, CAISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, and PacifiCorp West.[96] Avangrid and NV Energy were opted in to AET during all days during the quarter, and NorthWestern Energy was opted in to AET during most of the quarter (82 days).

On April 8, 2024, a partial solar eclipse occurred over most of the western United States.[97] This primarily impacted grid-scale solar and behind-the-meter rooftop solar across a number of WEIM balancing areas

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94 Assistance energy transfer designation requests are submitted to Master File as *opt-in* or *opt-out* and include both a start and end date. The standard timeline to implement an opt-in or opt-out request is at least five business days in advance of the start date. An *emergency* opt-in request is also available, should reliability necessitate this, for two business days in advance of the start date. For more information, see: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1525&IsDlg=0

95 The soft bid cap is $1,000/MWh and can increase to the hard bid cap of $2,000/MWh under certain conditions.

96 The CAISO balancing area can opt in to assistance energy transfers based on upcoming system conditions and operator experience. For more information, see the Business Practice Manual for the Western Energy Imbalance Market, section 11.3.2: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market The CAISO area did not fail the resource sufficiency evaluation during the quarter.

97 *Solar Eclipse Technical Bulletin*, California ISO, March 6, 2024: https://www.caiso.com/documents/april-8-solar-eclipse-technical-bulletin-march-11-2024.pdf

between hours-ending 11 and 13. The California ISO opted in to receiving assistance energy transfers on April 8 as a mitigation measure in preparation for the event. Idaho Power also opted in to AET for this day. All balancing areas passed the *upward* resource sufficiency evaluation during the eclipse period such that assistance energy transfers had no impact on procuring additional WEIM supply during the eclipse.[98] Idaho Power, El Paso Electric, and Arizona Public Service failed the *downward* flexibility test in at least one interval during the eclipse.

Table 2.8 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the quarter and its impact following a resource sufficiency evaluation failure. First, the table shows the number of 15-minute intervals in which a balancing area failed the upward resource sufficiency evaluation after opting in to AET. These are the intervals in which the WEIM import limit following the test failure was removed—giving the WEIM entity access to WEIM supply that may not have been available otherwise. Table 2.8 also shows the percent of failure intervals in the 5-minute market in which the balancing area achieved additional WEIM imports due to opting in to AET. The table also shows the average and maximum WEIM imports added in the 5-minute market because of AET.

[98] The assistance energy transfer functionality only removes the import limit after failing the *upward* resource sufficiency evaluation. This functionality does not address oversupply conditions that can occur following a downward resource sufficiency evaluation failure (and imposed export limit).

Table 2.7 Assistance energy transfer opt-in designations by balancing area (April–June 2024)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Apr. 1 - Jun. 30	91
California ISO	Apr. 8	1
Idaho Power	Apr. 8, Jun. 1 - Jun 30	31
NorthWestern Energy	Apr. 10 - Jun. 30	82
NV Energy	Apr. 1 - Jun. 30	91
PacifiCorp East	May 31 - Jun. 30	31
PacifiCorp West	May 31 - Jun. 30	31

Table 2.8 Resource sufficiency evaluation failures during assistance energy transfer opt-in (April–June 2024)

Balancing area	RSE failures under AET (15-min. intervals)	Percent of failure intervals with additional WEIM imports due to AET	Average WEIM imports added (MW)	Max WEIM imports added (MW)
Avangrid	20	38%	38	198
California ISO	0	N/A	N/A	N/A
Idaho Power	2	100%	184	278
NorthWestern Energy	12	39%	16	101
NV Energy	7	67%	195	626
PacifiCorp East	0	N/A	N/A	N/A
PacifiCorp West	2	50%	40	99

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[99] These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.

[99] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/library/western-energy-imbalance-market-resource-sufficiency-evaluation-reports

2.4 WEIM imbalance conformance

Frequency and size of imbalance conformance

Table 2.9 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM and California ISO for the 15-minute and 5-minute markets during the quarter.[100]

The Bonneville Power Administration, Seattle City Light, El Paso Electric, and Avista Utilities areas used negative imbalance conformance in the 15-minute market most frequently. Other areas had little to no negative conformance in the 15-minute market. Negative imbalance conformance in the 5-minute market was much more frequent in nearly all areas, the exception being Balancing Authority of Northern California (BANC), NorthWestern Energy, and the Turlock Irrigation District, with very low levels of imbalance conformance for the quarter.

The Bonneville Power Administration, CAISO, and El Paso Electric areas had the greatest percent of positive imbalance conformance in the 15-minute market. Other areas had very little or no positive conformance in the 15-minute market. Nearly all areas used positive imbalance conformance in the 5-minute market; however, Puget Sound Energy, Portland General Electric, Tacoma Power, Seattle City Light, PacifiCorp West, Avista Utilities, Balancing Authority of Northern California (BANC), and Turlock Irrigation District used positive imbalance in five percent or less of intervals.

[100] Powerex is not identified in this table. Powerex is not a balancing authority area like other participating WEIM entities and instead uses residual capability of the BC Hydro system to participate in the WEIM. Powerex therefore does not have the ability to enter load bias in the market.

Table 2.9 Average frequency and size of imbalance conformance (April–June)

Balancing area	Market	Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
		Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO	FMM	36.5%	1,155	4.8%	0.0%	N/A	N/A	422
	RTD	51.1%	308	1.3%	20.3%	-233	1.2%	110
Avangrid Renewables*	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	45.5%	36	N/A	7.6%	-37	N/A	14
BANC	FMM	0.2%	74	3.3%	0.3%	-74	3.6%	0
	RTD	0.4%	81	3.8%	0.7%	-69	3.5%	0
Turlock Irrigation District	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	0.2%	19	6.3%	0.0%	-16	4.5%	0
LADWP	FMM	1.5%	43	2.0%	0.3%	-57	2.7%	0
	RTD	20.6%	41	1.7%	20.6%	-43	1.8%	0
NV Energy	FMM	0.1%	75	2.1%	0.0%	-125	3.6%	0
	RTD	36.6%	111	2.5%	23.5%	-134	2.9%	9
Arizona Public Service	FMM	0.0%	N/A	N/A	0.5%	-70	N/A	0
	RTD	39.4%	54	1.4%	38.0%	-66	1.7%	-4
Tucson Electric Power	FMM	0.0%	N/A	N/A	0.1%	-25	N/A	0
	RTD	10.3%	39	2.9%	13.5%	-45	3.8%	-2
WAPA - Desert Southwest	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	37.4%	18	2.1%	31.9%	-15	2.4%	2
El Paso Electric	FMM	6.0%	23	2.0%	4.9%	-17	1.7%	1
	RTD	17.3%	20	1.6%	13.6%	-20	1.9%	1
Salt River Project	FMM	1.6%	74	1.5%	0.1%	-50	1.9%	1
	RTD	11.3%	66	1.5%	5.1%	-66	1.4%	4
Public Service Co. of New Mexico	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	37.0%	94	6.3%	19.4%	-100	7.3%	15
PacifiCorp East	FMM	0.0%	165	3.5%	0.0%	N/A	N/A	0
	RTD	7.9%	95	1.5%	49.3%	-121	2.2%	-52
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	9.9%	57	2.7%	21.0%	-58	2.9%	-7
NorthWestern Energy	FMM	1.7%	20	1.6%	0.0%	N/A	N/A	0
	RTD	58.1%	27	2.2%	0.2%	-28	2.3%	15
Avista Utilities	FMM	0.1%	35	2.9%	3.7%	-36	3.4%	-1
	RTD	1.2%	26	2.3%	50.2%	-27	2.5%	-13
Bonneville Power Administration	FMM	51.9%	30	0.5%	47.7%	-27	0.5%	3
	RTD	52.0%	30	0.5%	47.4%	-28	0.5%	3
Tacoma Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	3.5%	7	1.5%	11.0%	-8	2.0%	-1
PacifiCorp West	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	2.6%	34	1.5%	22.8%	-41	1.9%	-8
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	4.2%	44	1.9%	2.4%	-52	2.2%	1
Puget Sound Energy	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	4.6%	43	1.6%	35.7%	-41	1.6%	-13
Seattle City Light	FMM	0.2%	12	1.3%	5.2%	-14	1.5%	-1
	RTD	2.8%	18	2.0%	72.5%	-20	2.1%	-14

*Avangrid Renewables is a generation-only entity and therefore load conformance cannot be measured as a percent of load.

APPENDIX

Appendix A | Western Energy Imbalance Market area specific metrics

Sections A.1 to A.23 include figures by WEIM area on the hourly locational marginal price (LMP) and dynamic transfers.[101] These figures are included for both the 15-minute and 5-minute markets. Key highlights of the quarter include:

- In this quarter, internal flow-based constraints pushed prices higher in the Pacific Northwest, Northern California, Intermountain West regions, while lowering prices in the Desert Southwest and Southern California. WEIM transfer congestion increased prices in the Pacific Northwest and Desert Southwest regions. Most of the price impacts from internal and WEIM transfer congestion occurred during the daytime. In the Pacific Northwest, both types of congestion generally lead to higher prices. In contrast, the Desert Southwest showed a different trend, where internal congestion tends to lower price, while transfer congestion drive prices higher.
- Compared to the second quarter of 2023, this quarter saw California BAAs increase import transfers from CAISO. In the Desert Southwest region, there were notable increases in both import and export volumes for the WAPA Desert Southwest. In the intermountain West region, transfer volumes slightly decreased. In the Pacific Northwest region, Puget Sound Energy, Seattle City Light, and Tacoma Power had a marked rise in daytime imports.

The hourly locational marginal price decomposition figures break down the price into seven separate components. These components, listed below, can influence the prices in an area positively or negatively depending on the circumstances.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion within California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the

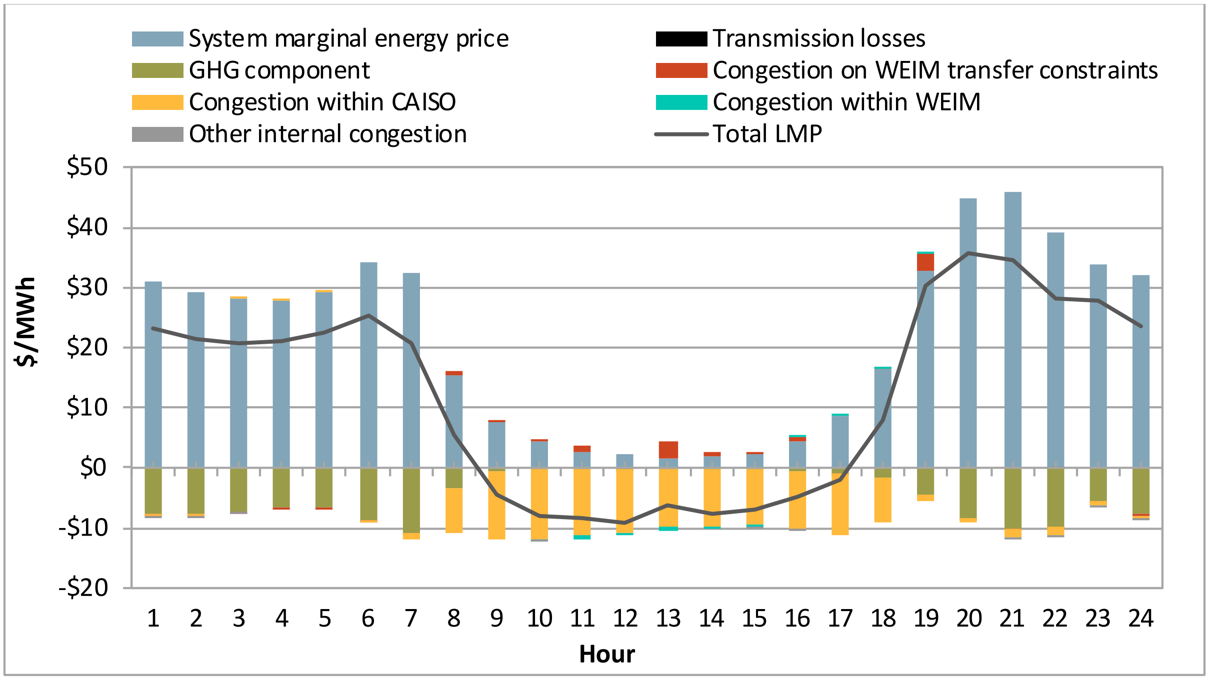
[101] These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*

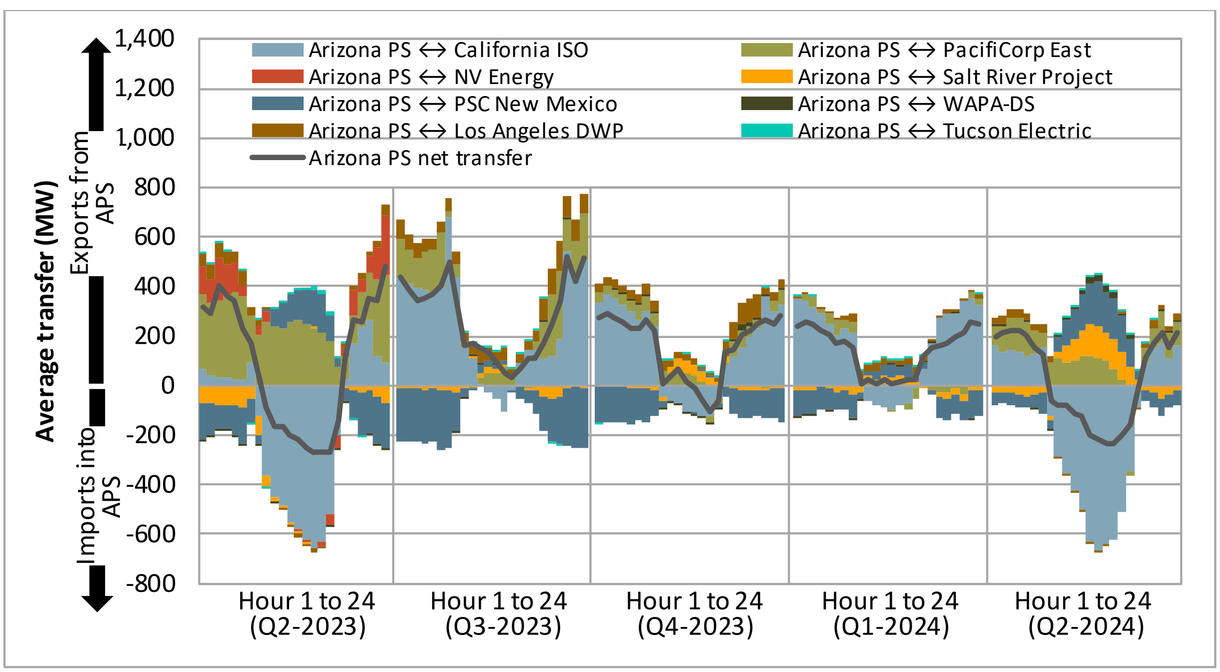
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limit WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits following a resource sufficiency evaluation failure, or (3) intertie constraint (ITC) and intertie scheduling limit (ISL).

A.1 Arizona Public Service

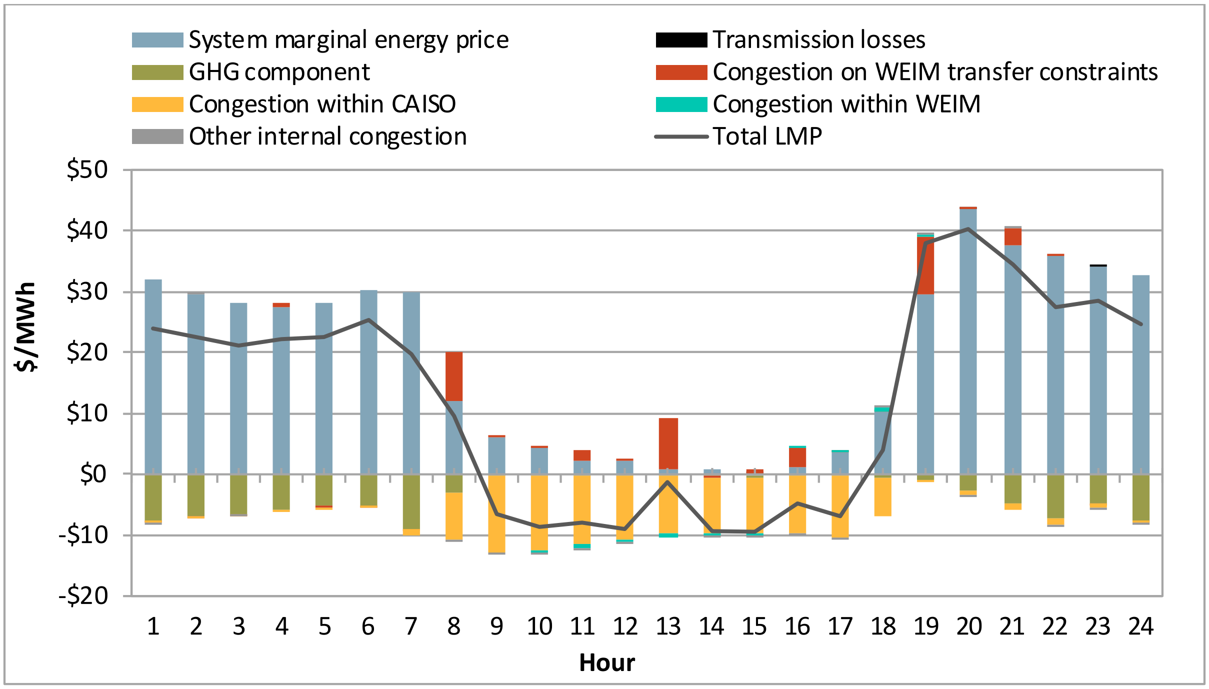
Appendix Figure A.1 Average hourly 15-minute price by component (Q2 2024)



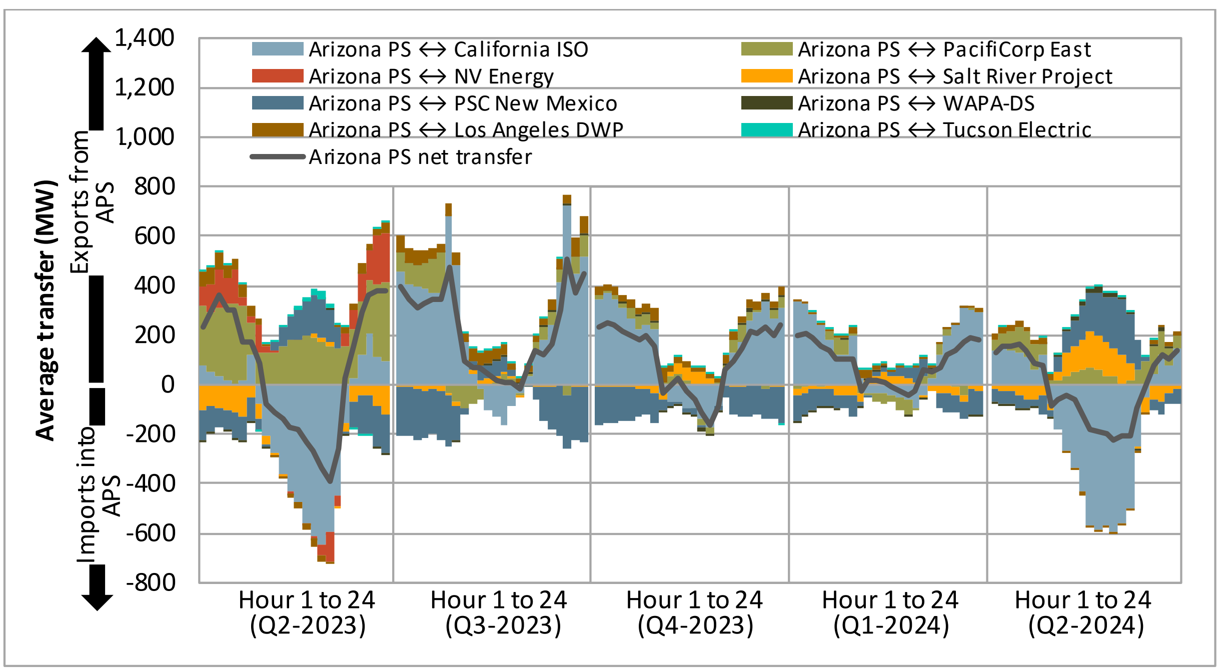
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q2 2024)

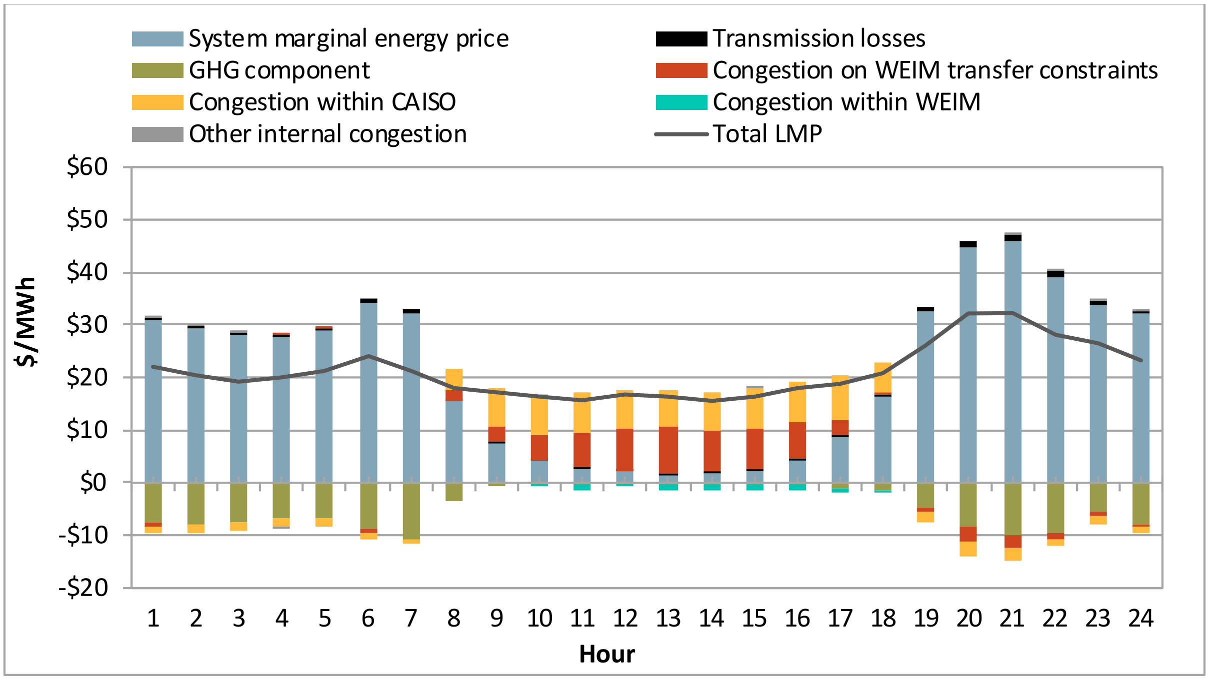


Appendix Figure A.4 Average hourly 5-minute market transfers

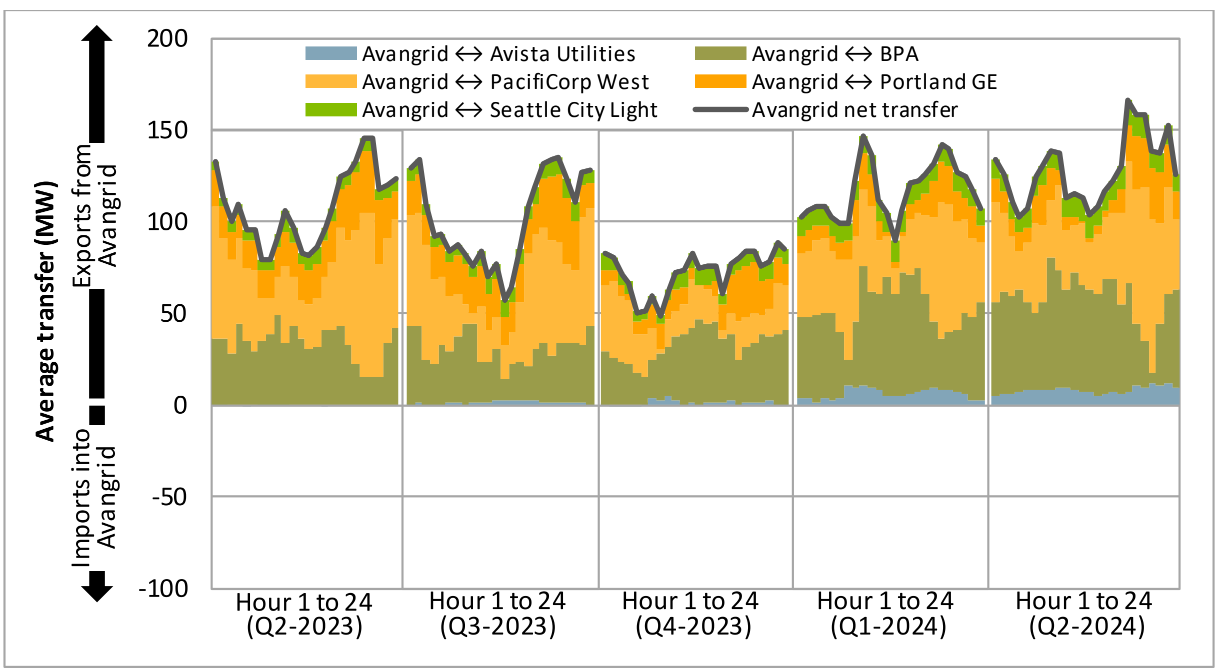


A.2 Avangrid

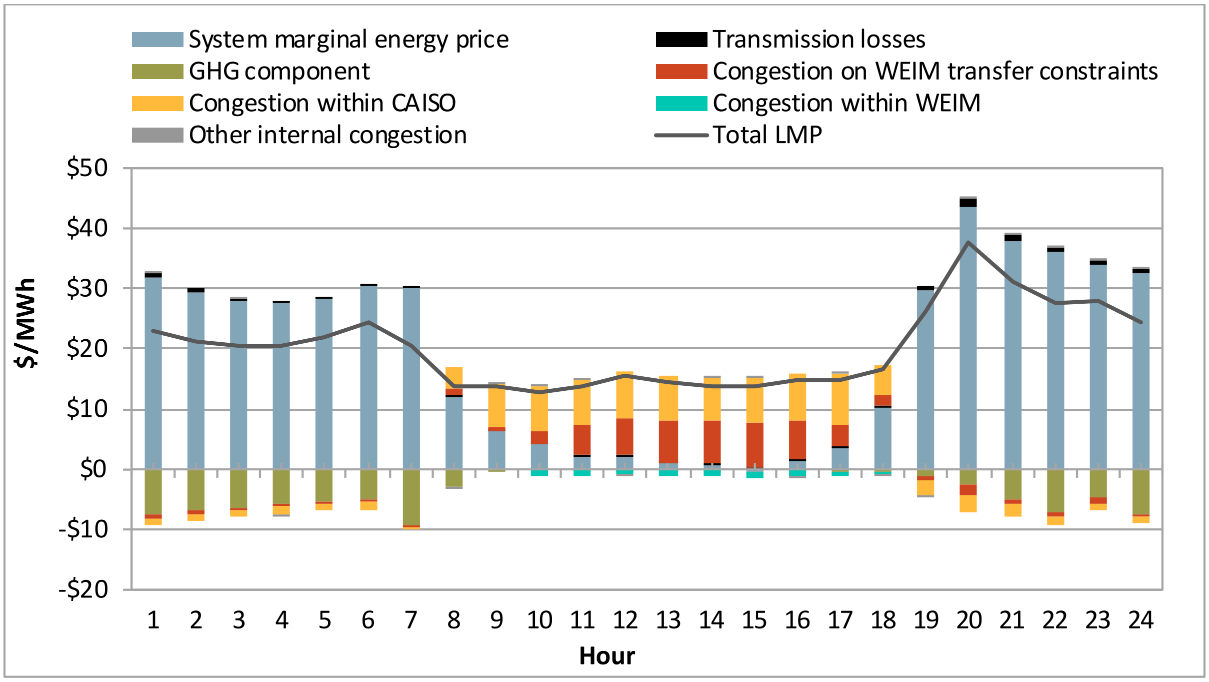
Appendix Figure A.5 Average hourly 15-minute price by component (Q2 2024)



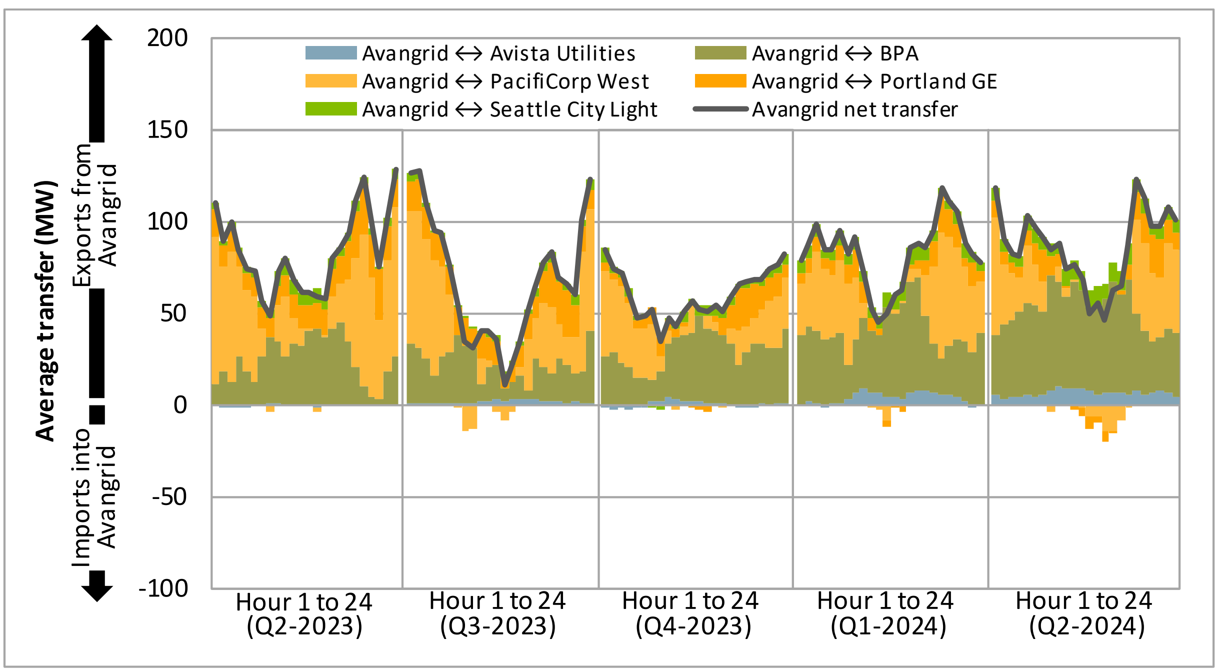
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q2 2024)

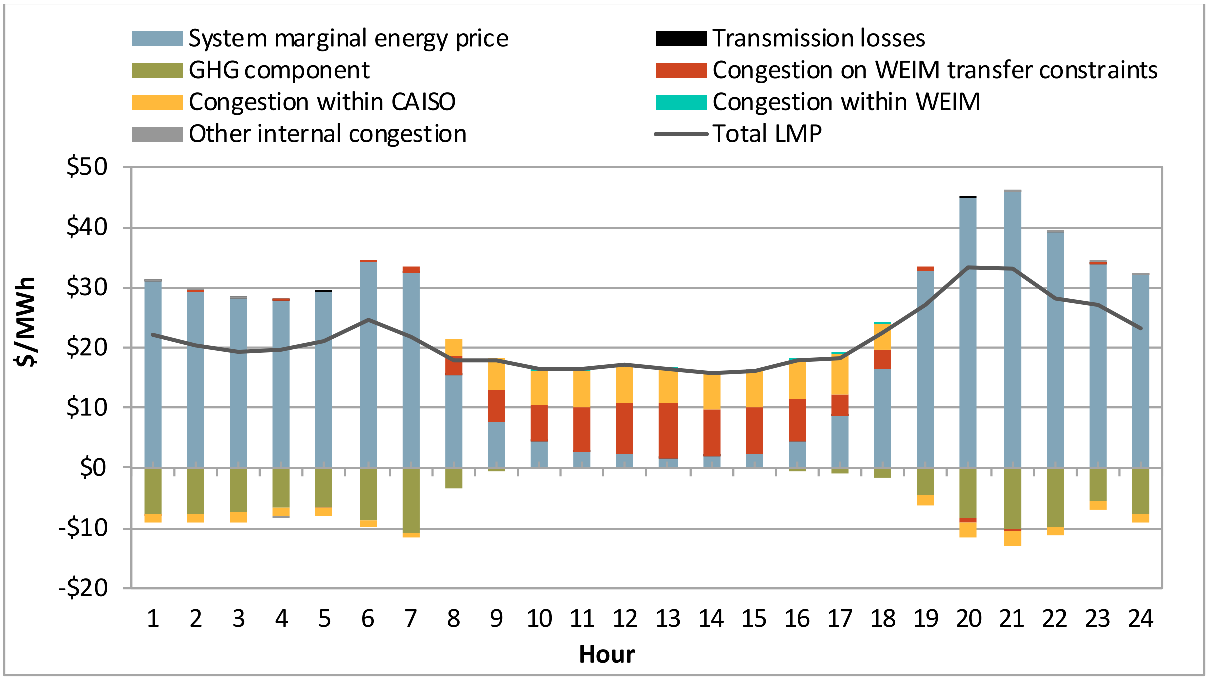


Appendix Figure A.8 Average hourly 5-minute market transfers

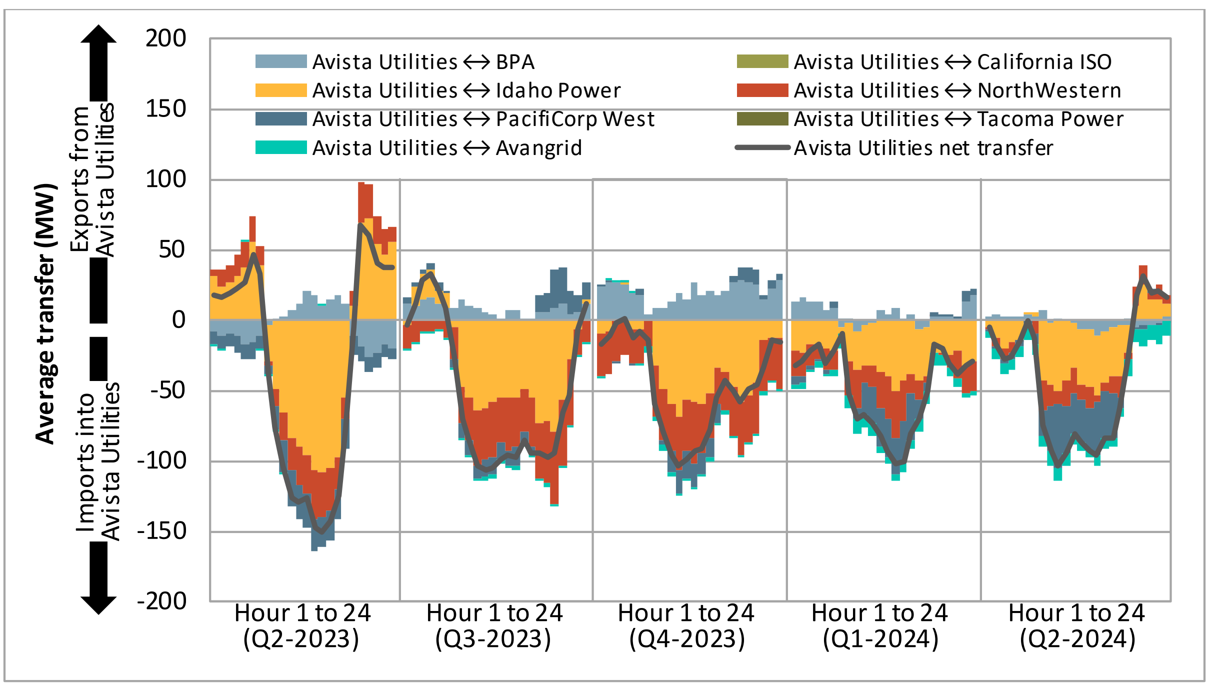


A.3 Avista Utilities

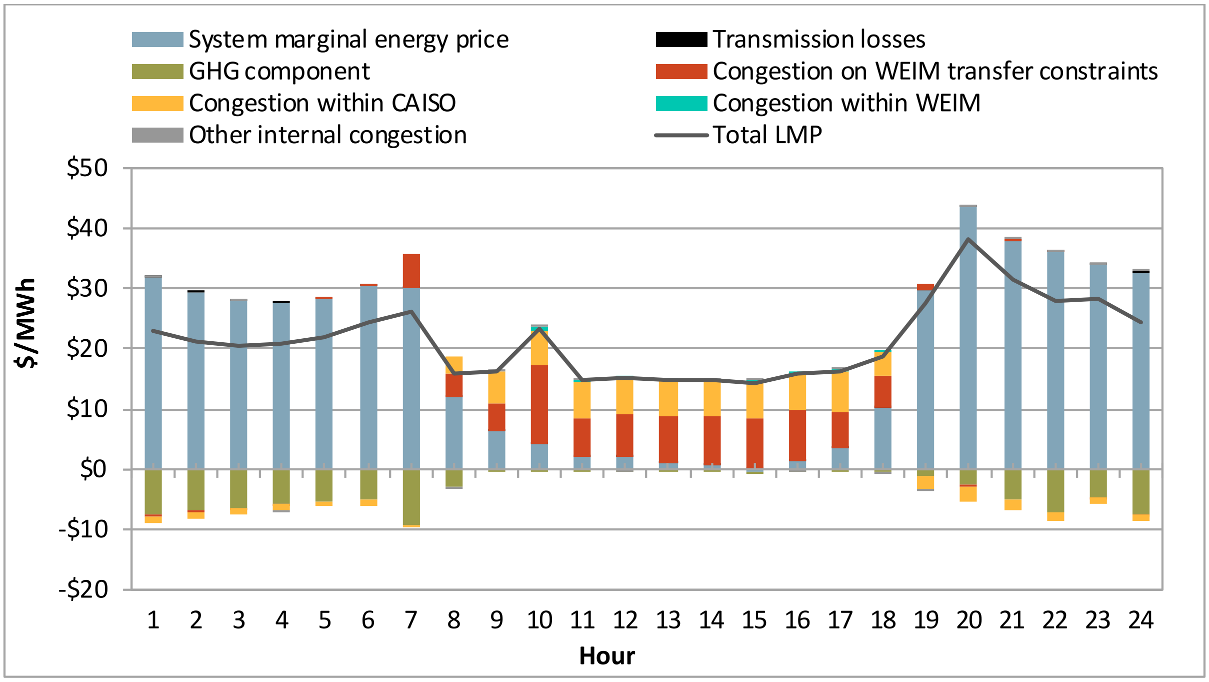
Appendix Figure A.9 Average hourly 15-minute price by component (Q2 2024)



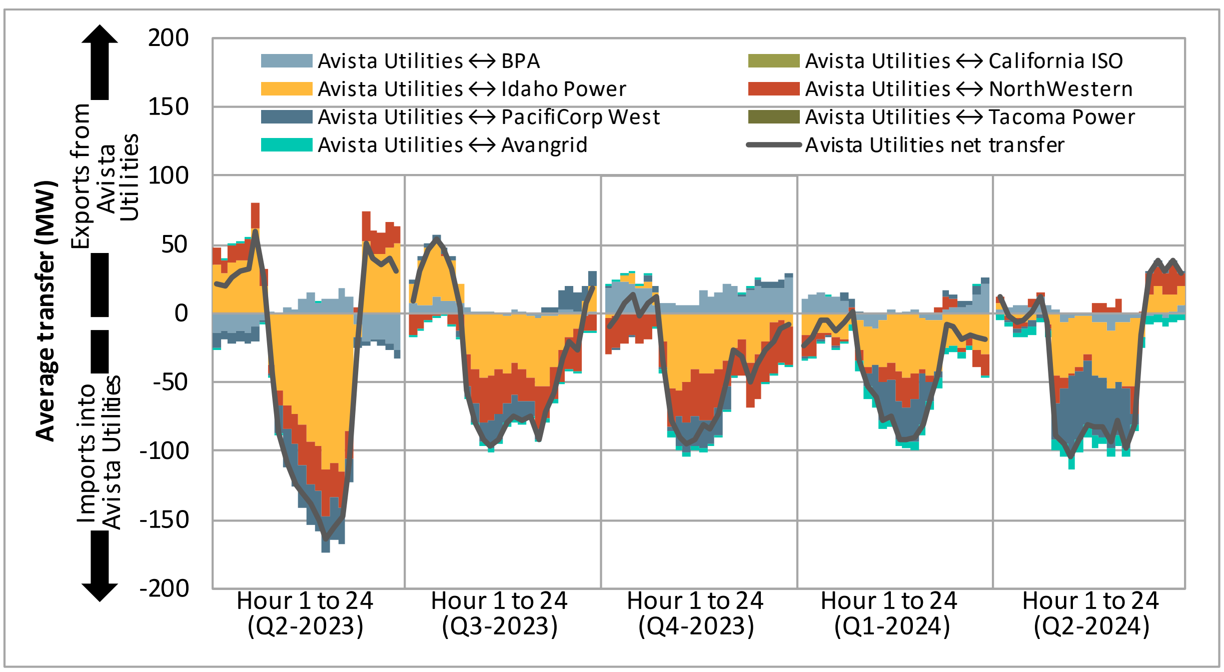
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q2 2024)

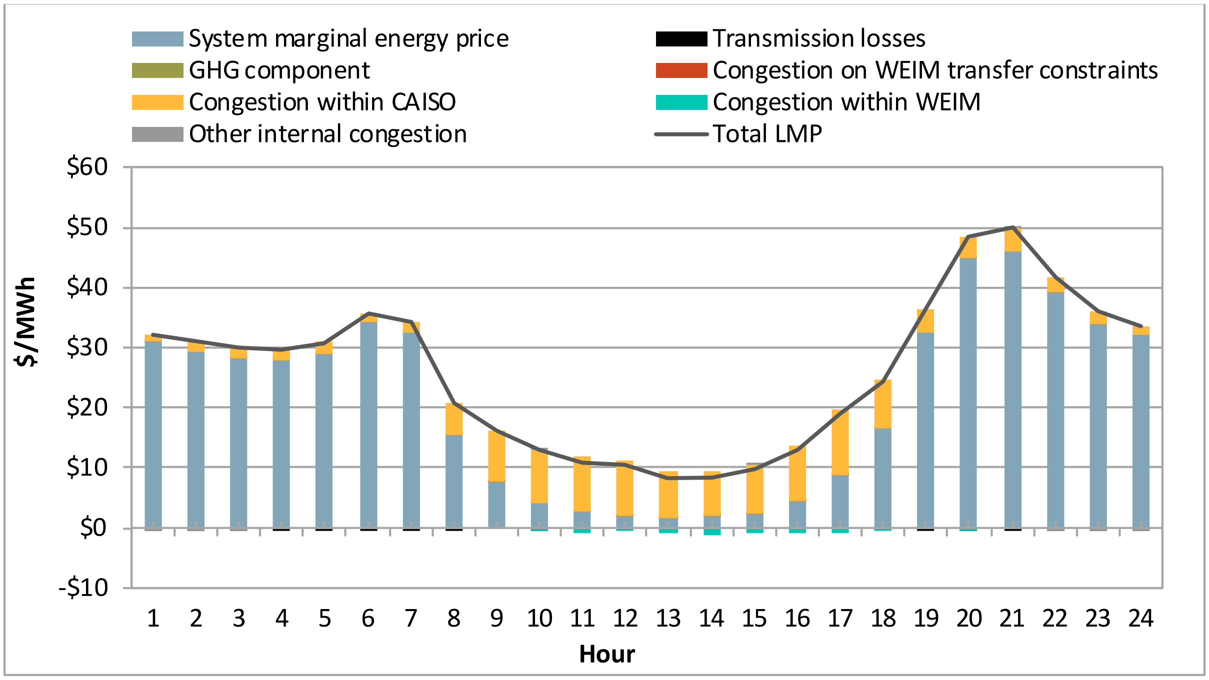


Appendix Figure A.12 Average hourly 5-minute market transfers

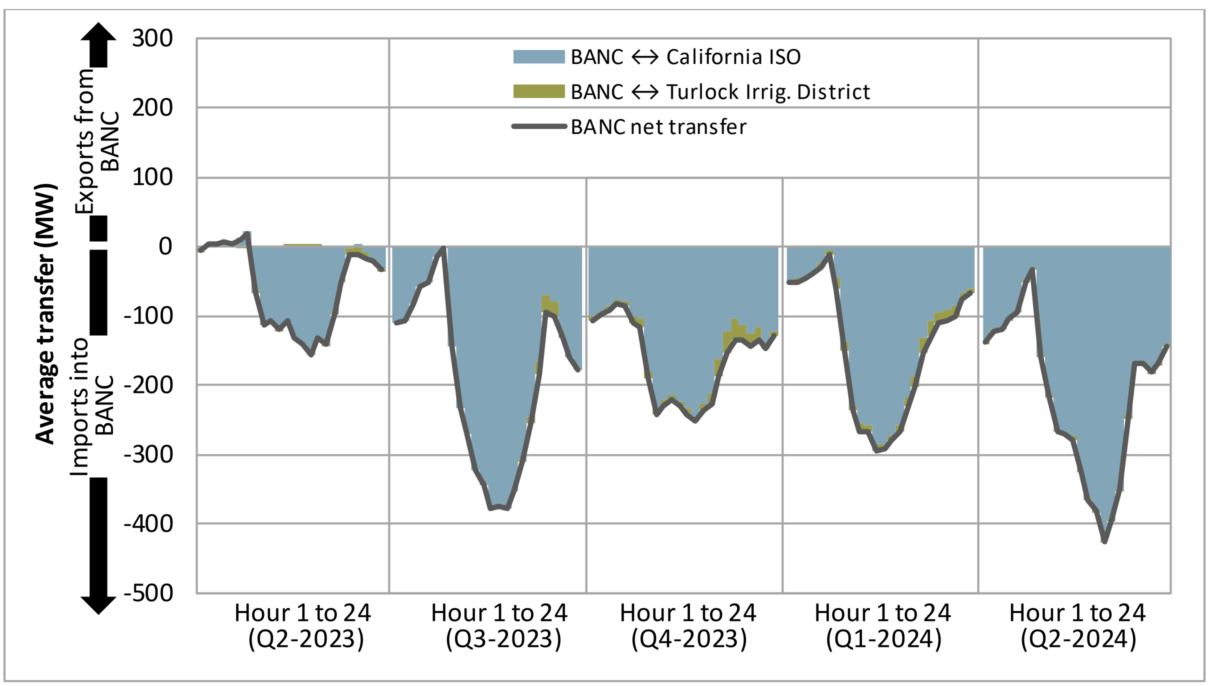


A.4 Balancing Authority of Northern California

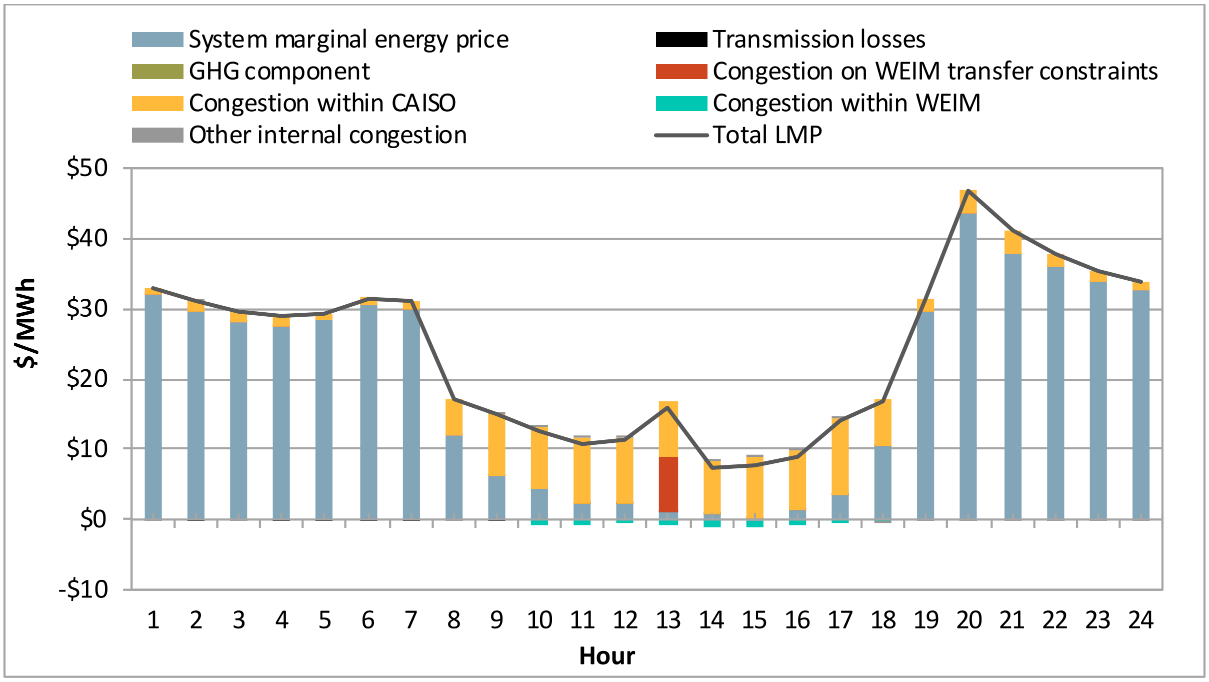
Appendix Figure A.13 Average hourly 15-minute price by component (Q2 2024)



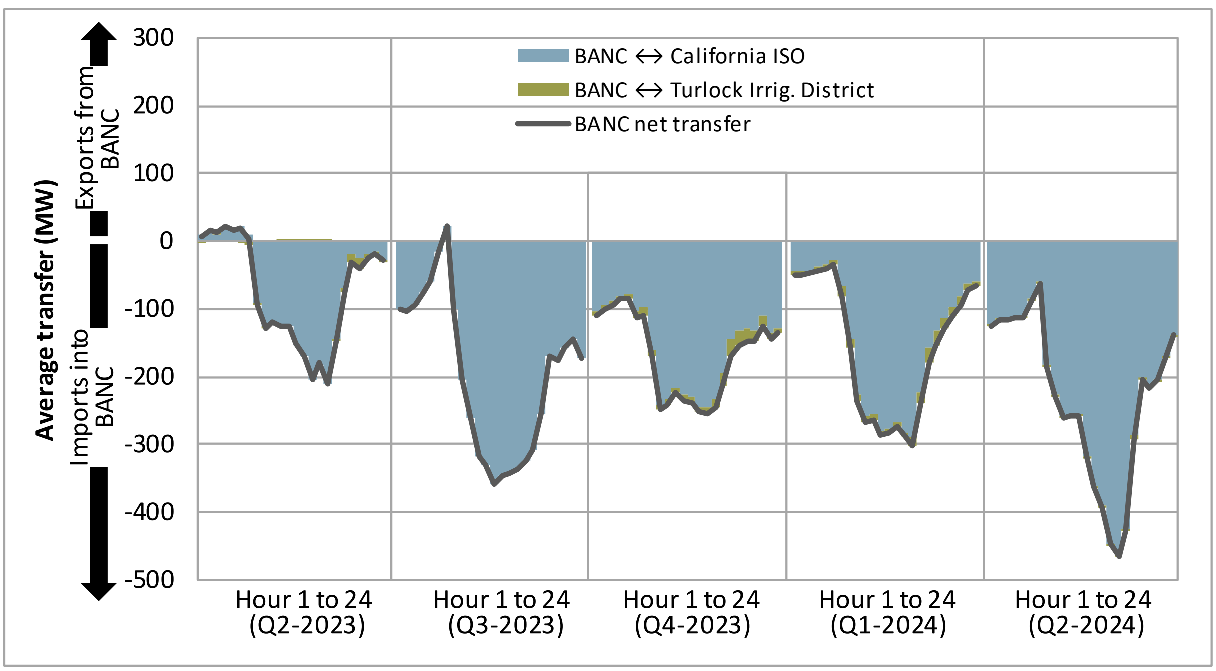
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q2 2024)

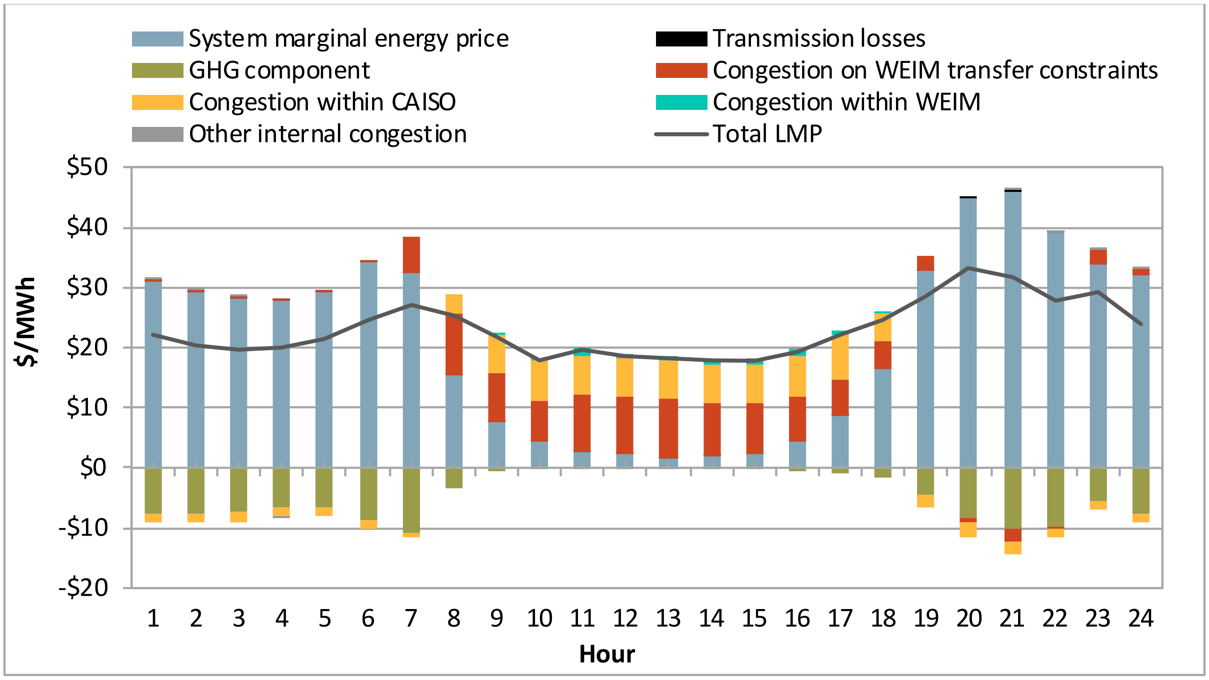


Appendix Figure A.16 Average hourly 5-minute market transfers

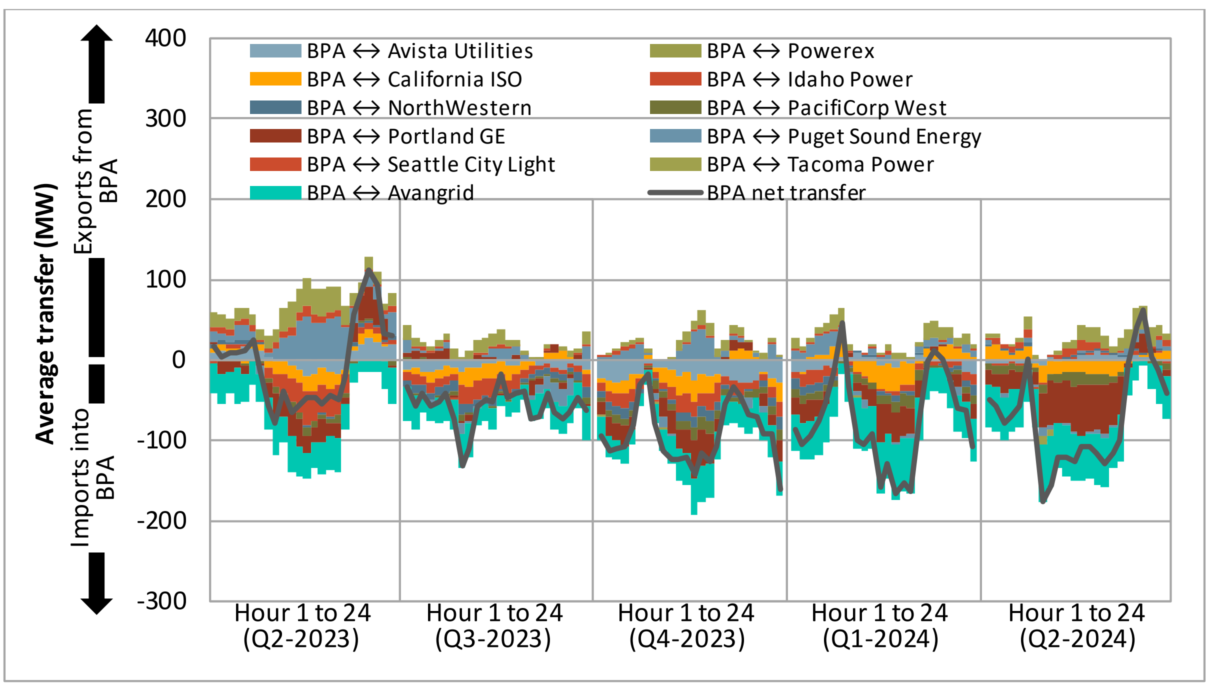


A.5 Bonneville Power Administration

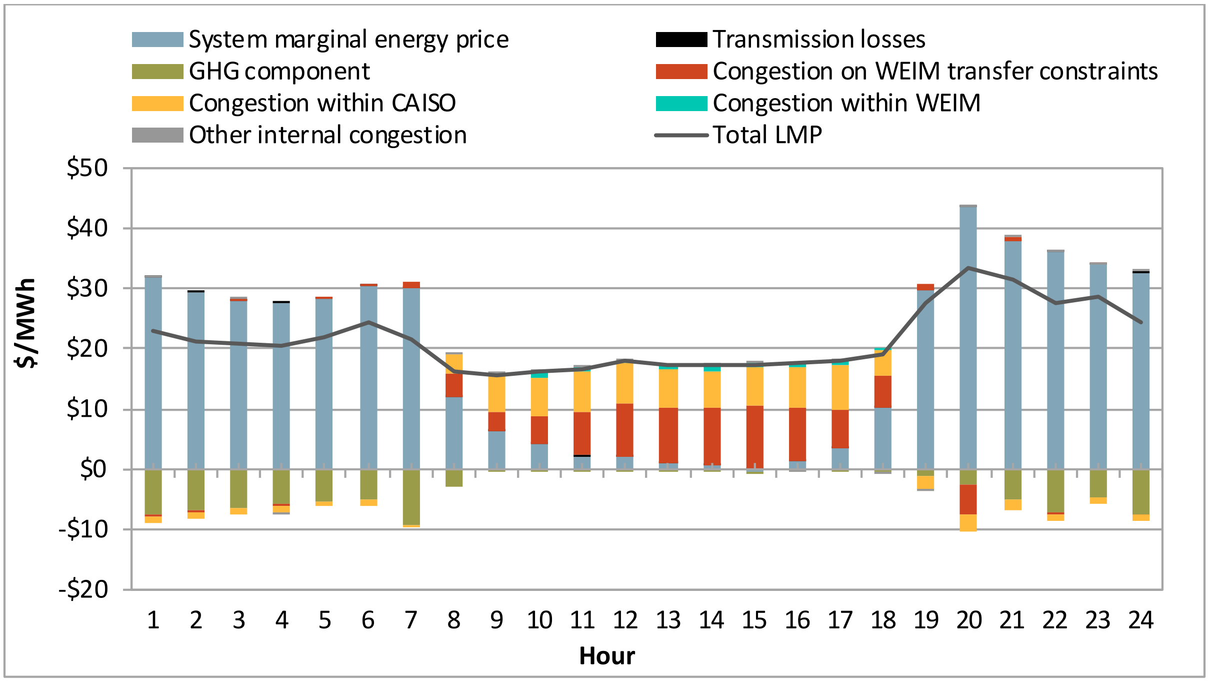
Appendix Figure A.17 Average hourly 15-minute price by component (Q2 2024)



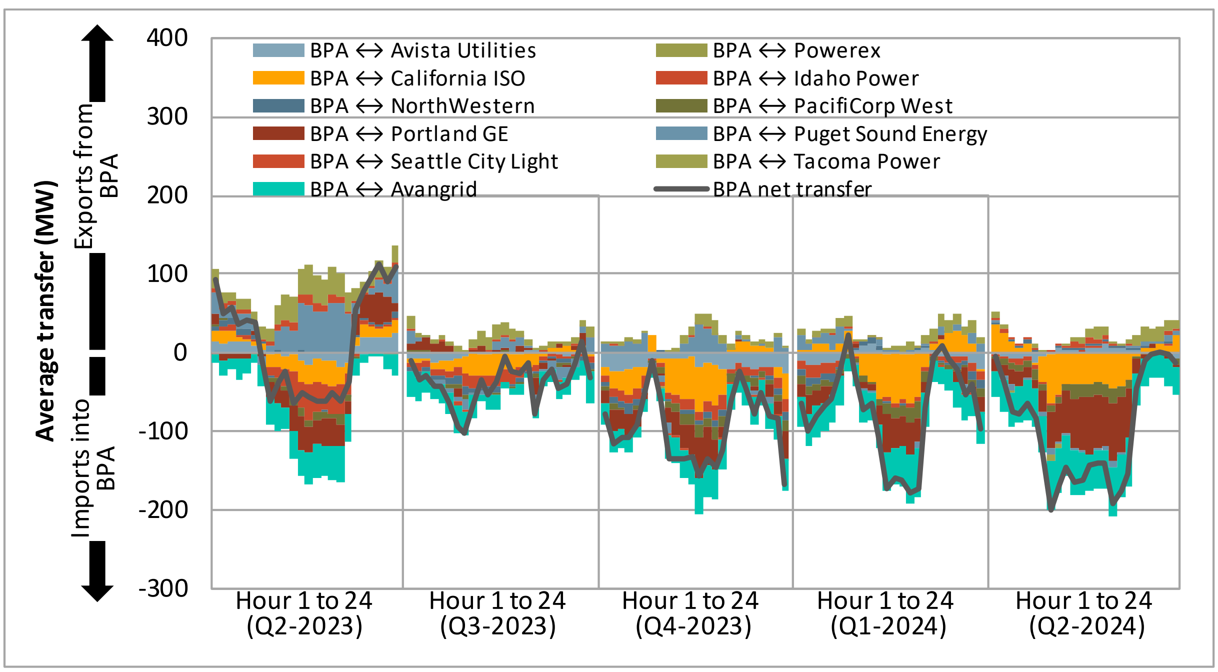
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q2 2024)

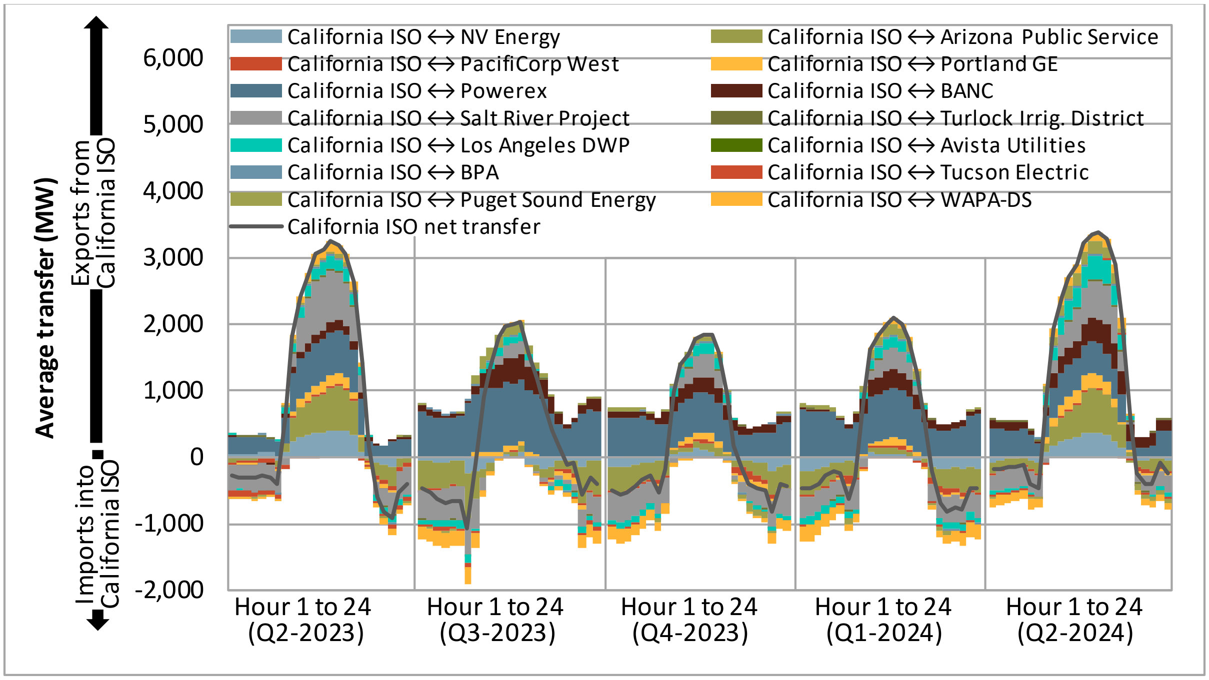


Appendix Figure A.20 Average hourly 5-minute market transfers

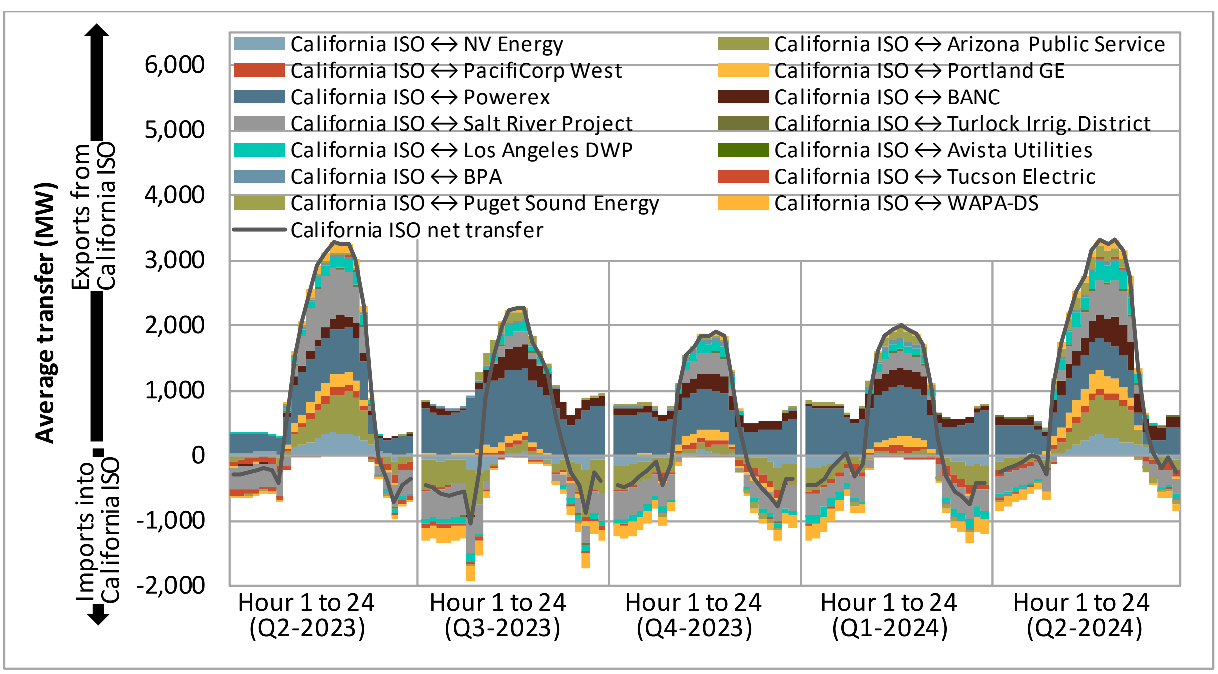


A.6 California ISO

Appendix Figure A.21 Average hourly 15-minute market transfers

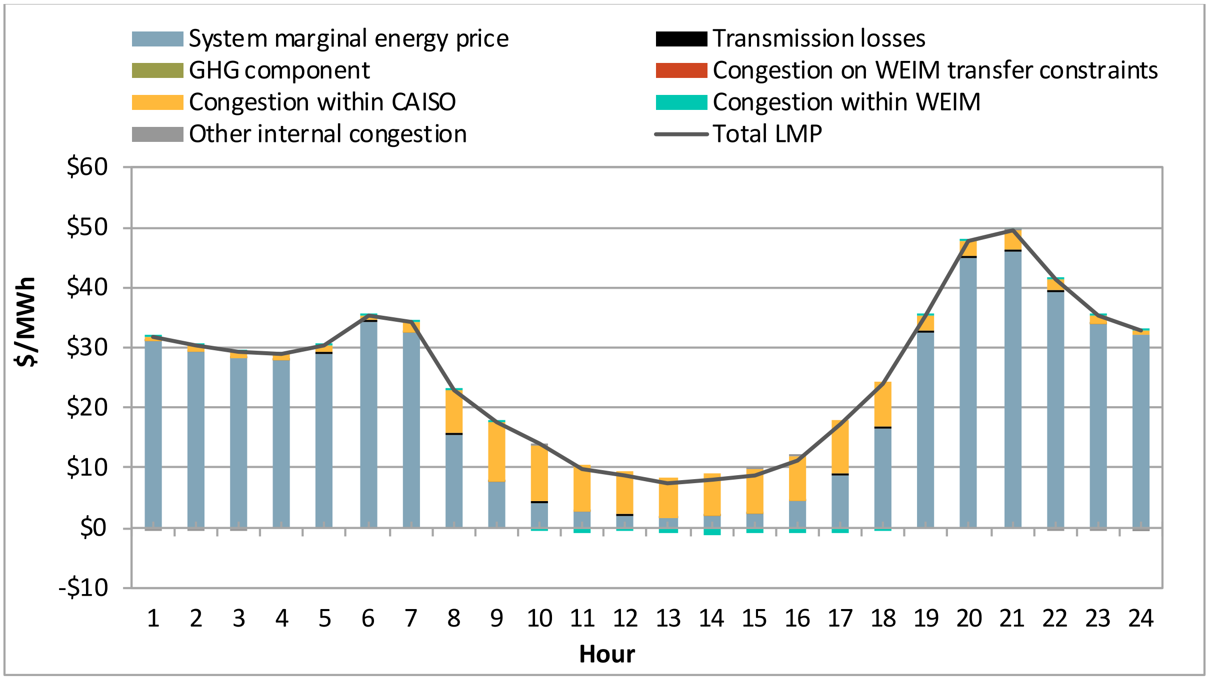


Appendix Figure A.22 Average hourly 5-minute market transfers

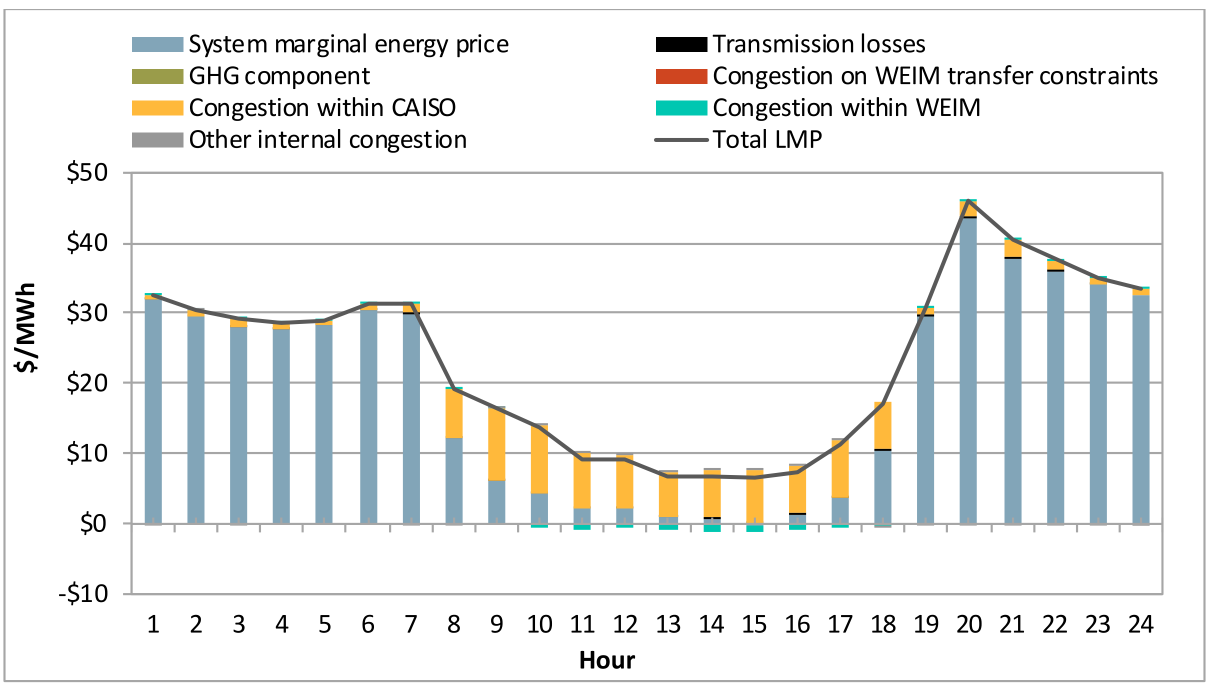


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q2 2024)

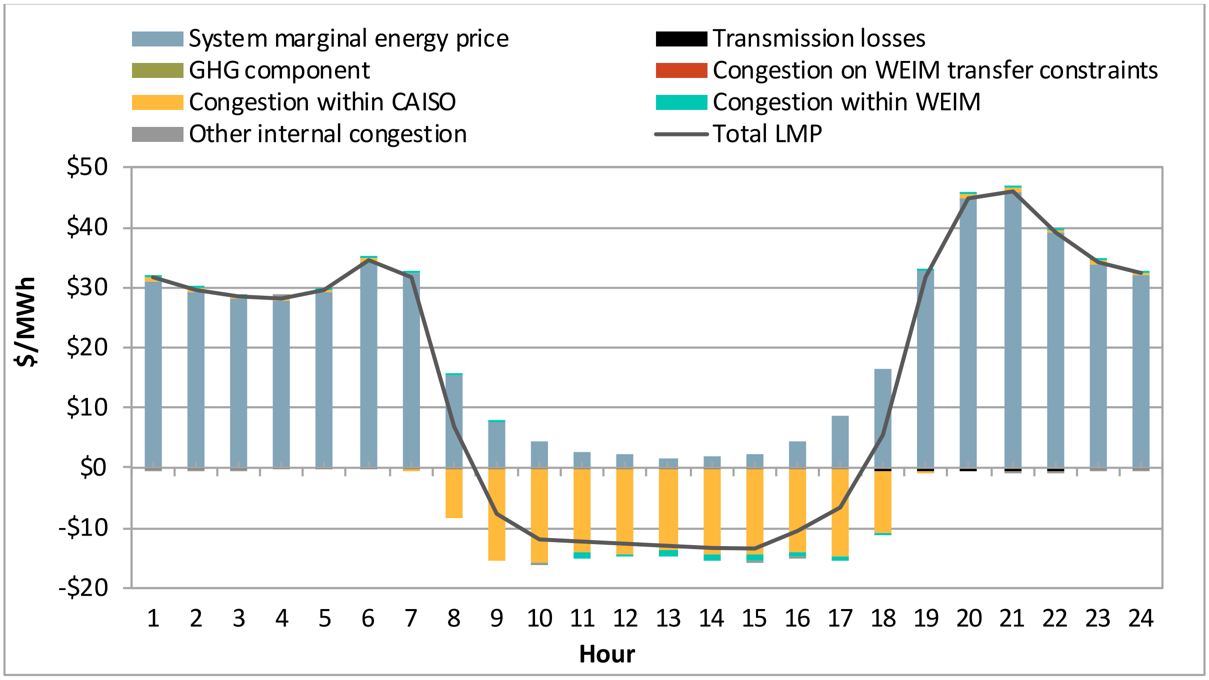


Appendix Figure A.24 Average hourly 5-minute price by component (Q2 2024)

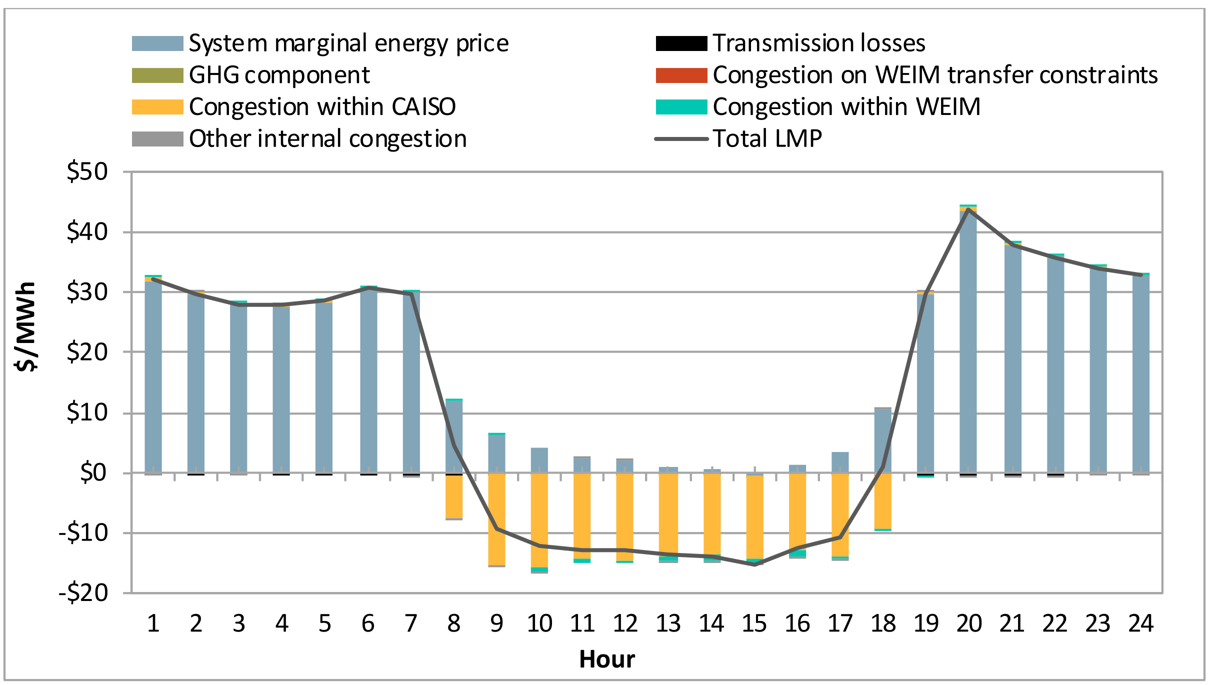


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q2 2024)

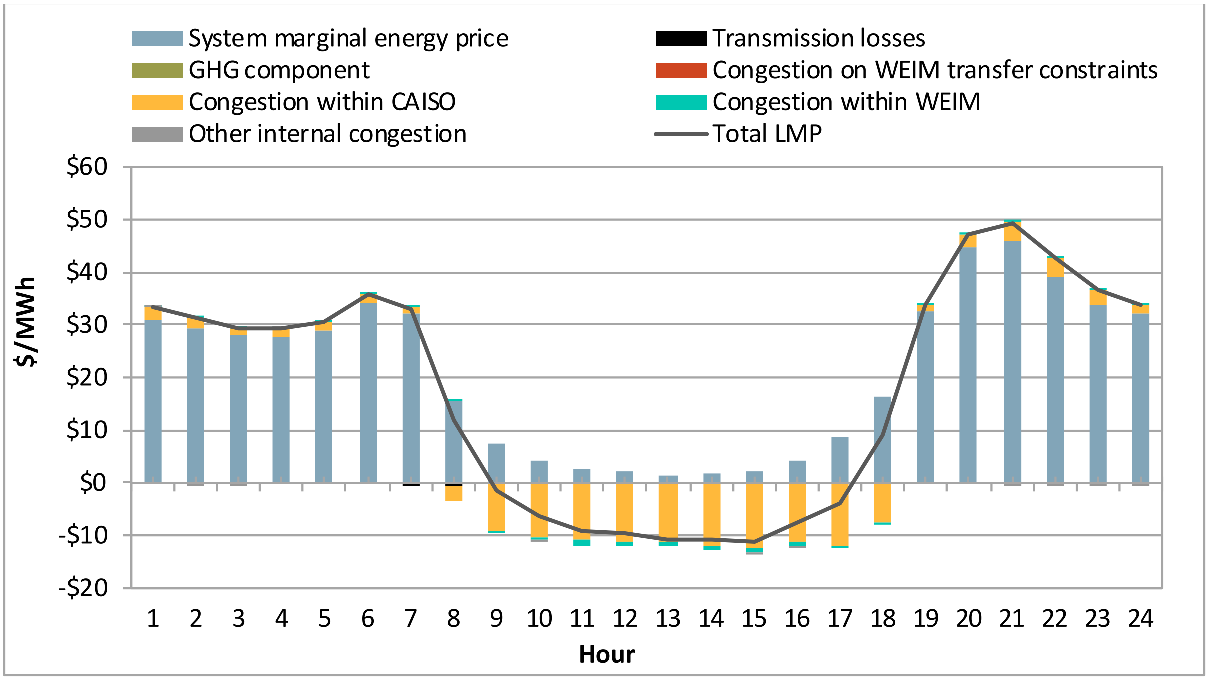


Appendix Figure A.26 Average hourly 5-minute price by component (Q2 2024)

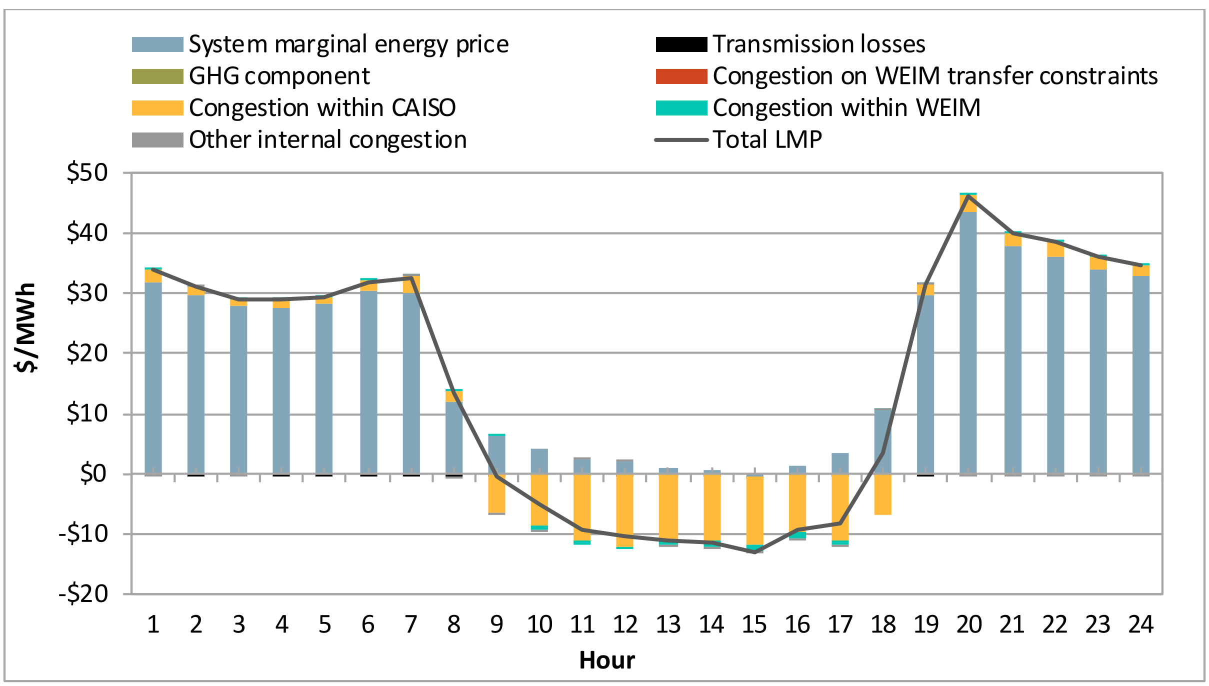


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q2 2024)

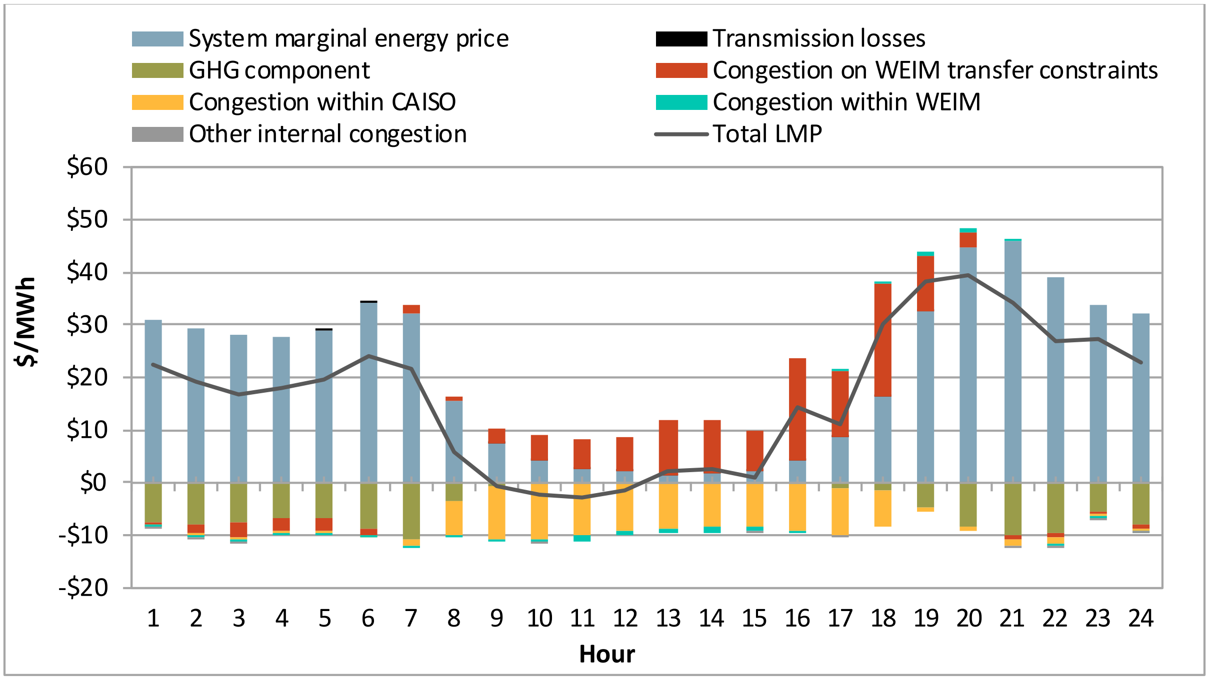


Appendix Figure A.28 Average hourly 5-minute price by component (Q2 2024)

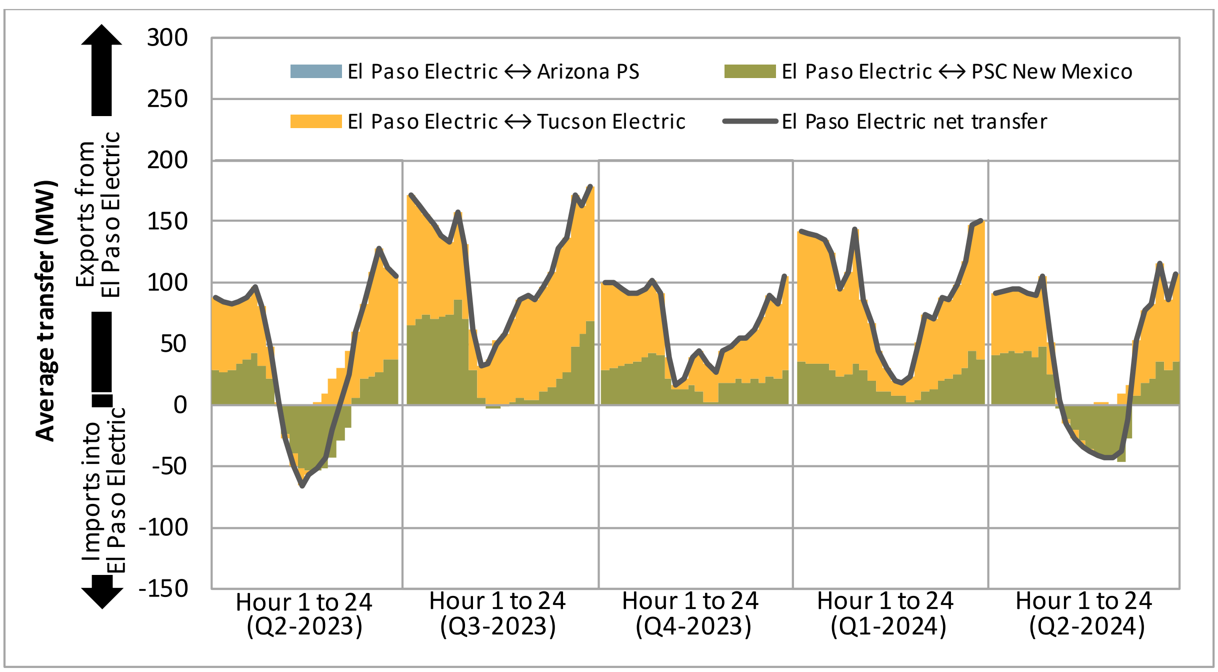


A.7 El Paso Electric

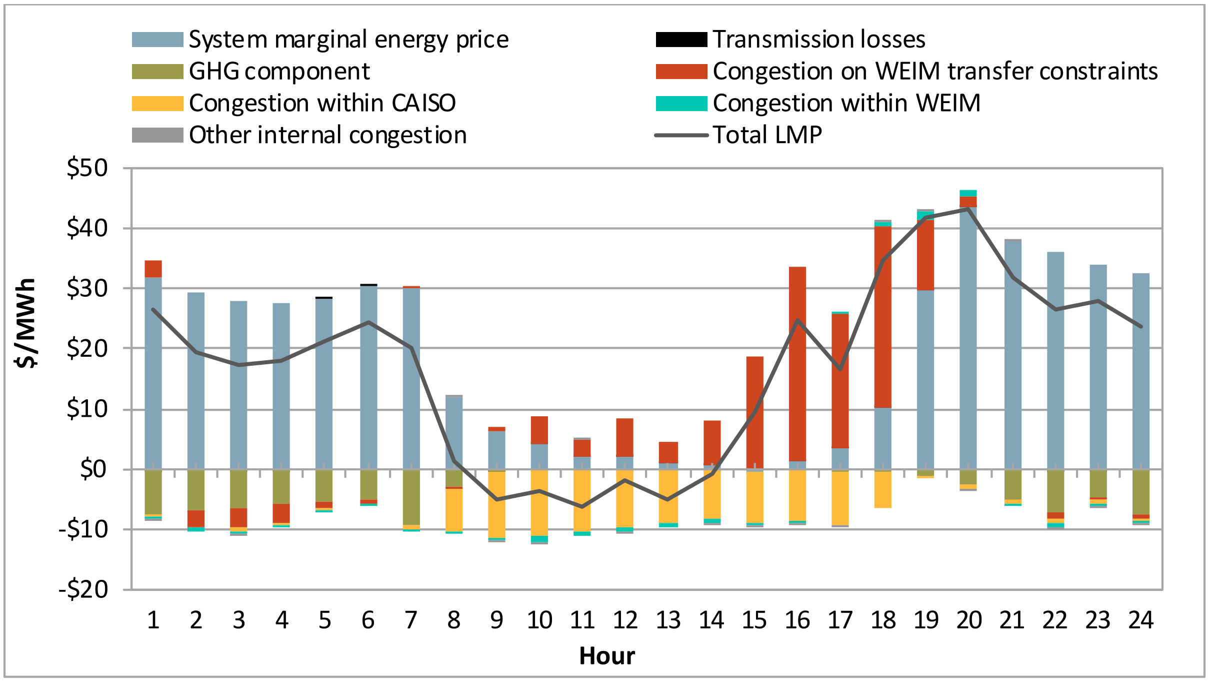
Appendix Figure A.29 Average hourly 15-minute price by component (Q2 2024)



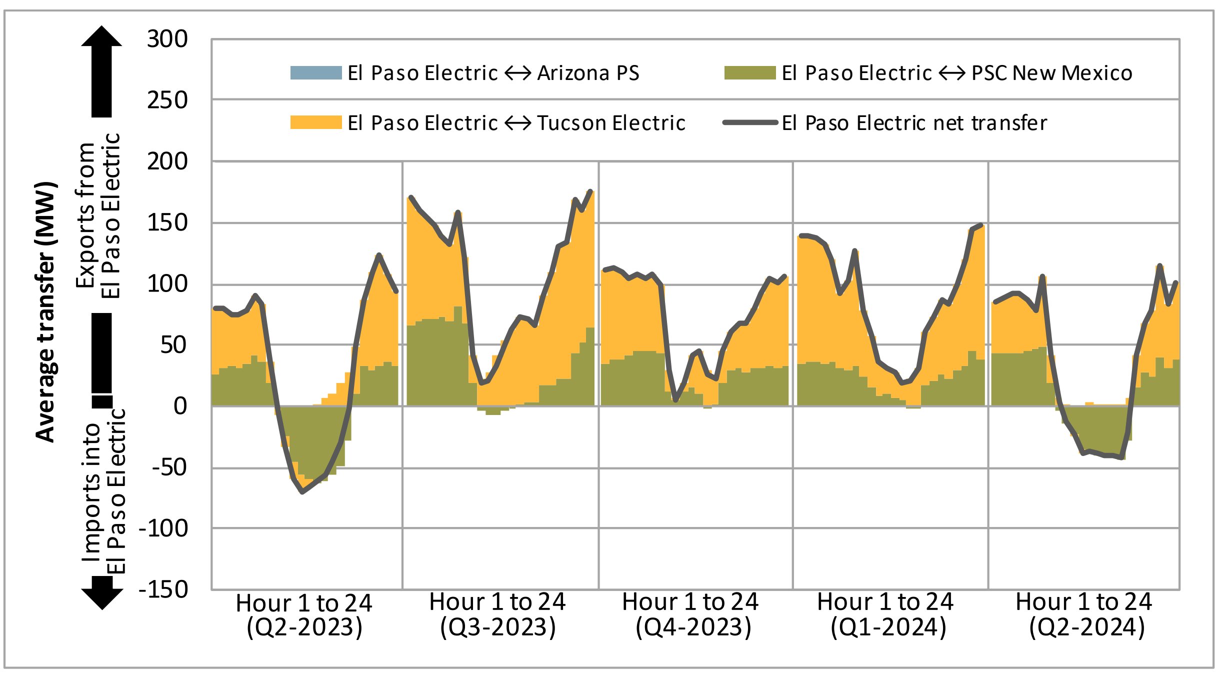
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q2 2024)

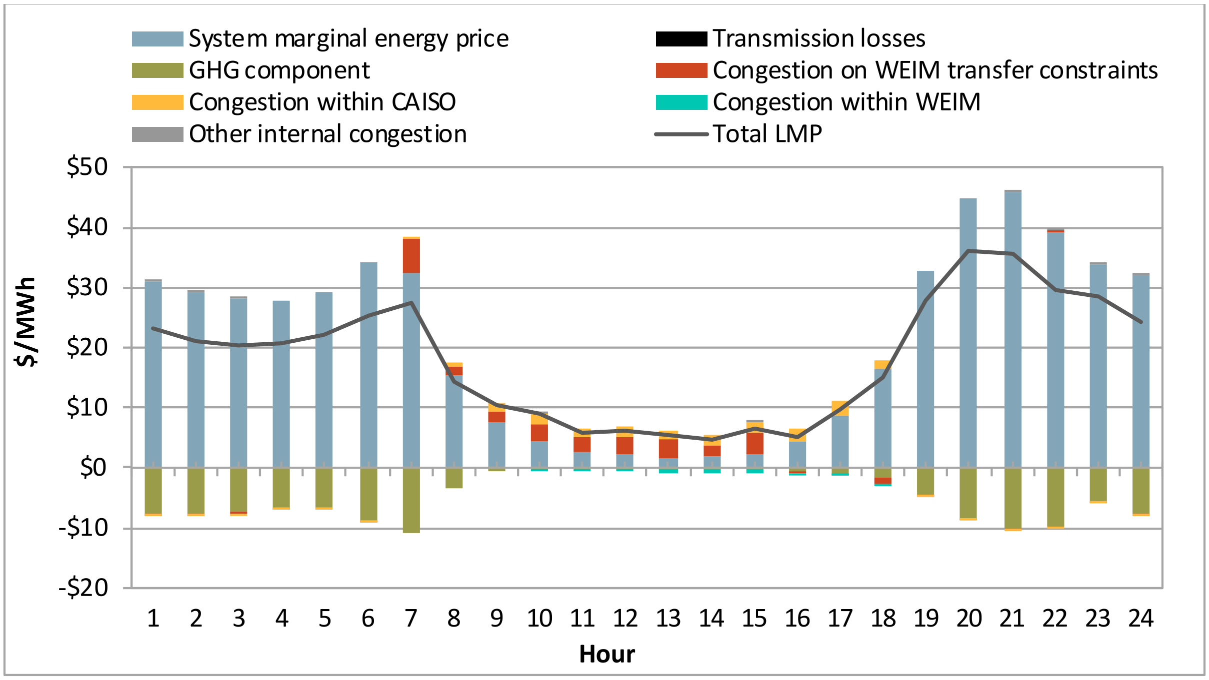


Appendix Figure A.32 Average hourly 5-minute market transfers

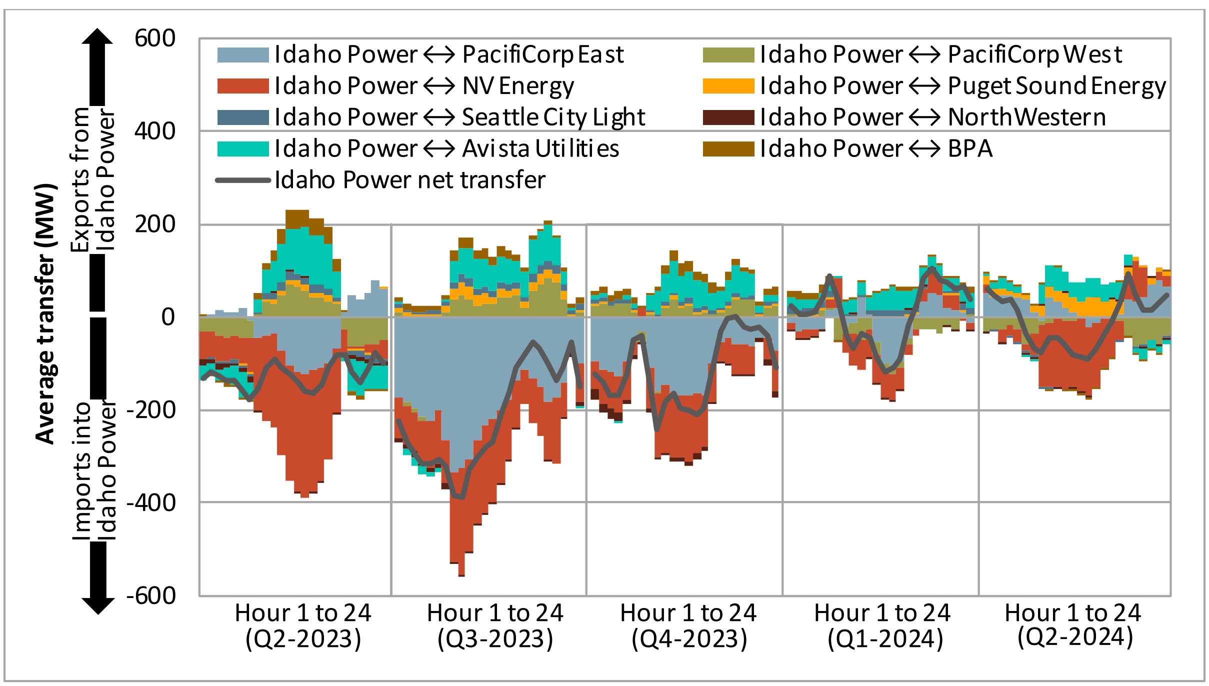


A.8 Idaho Power

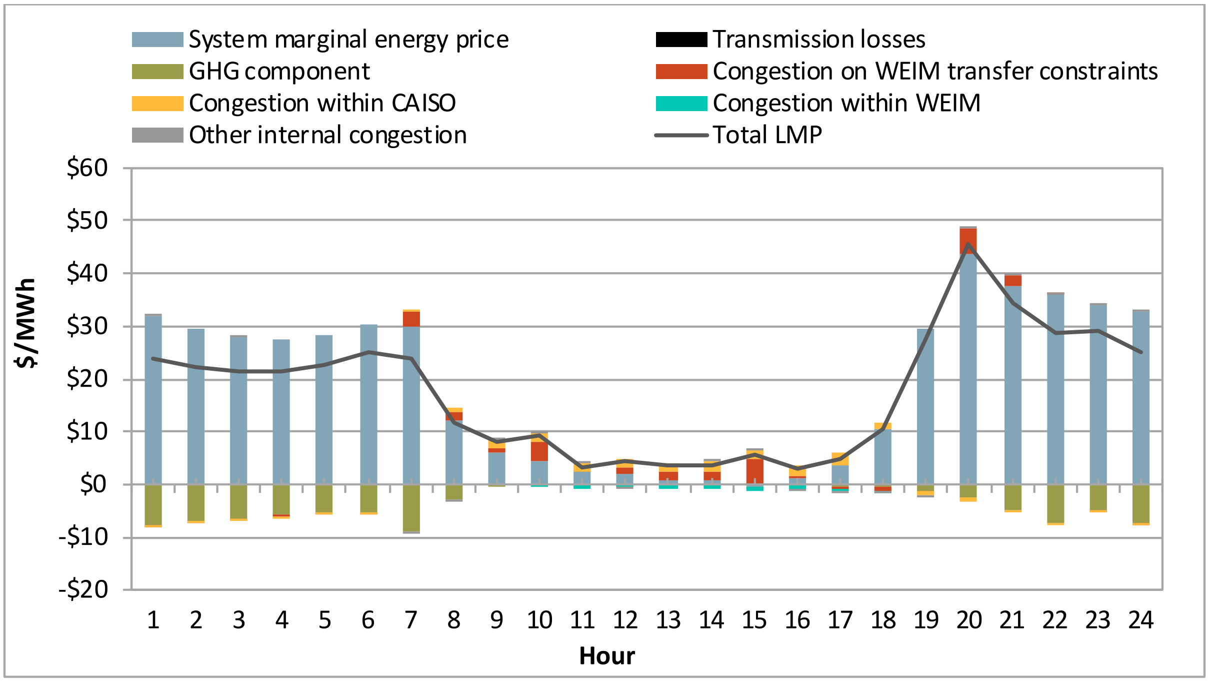
Appendix Figure A.33 Average hourly 15-minute price by component (Q2 2024)



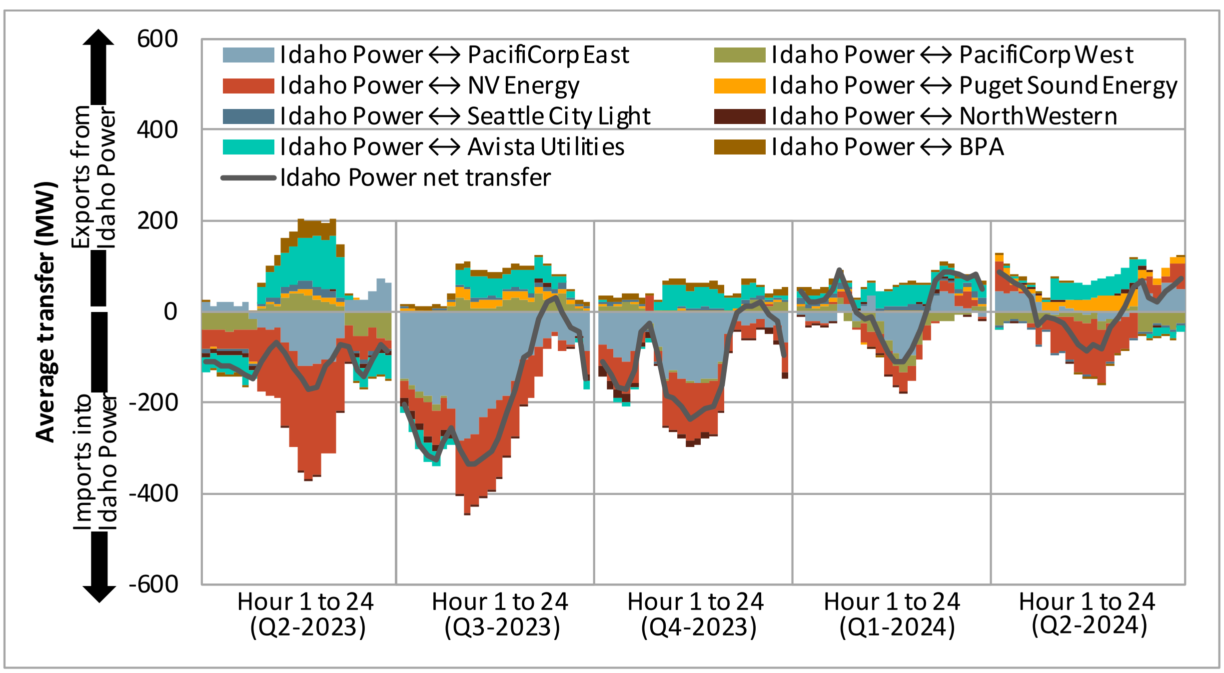
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q2 2024)

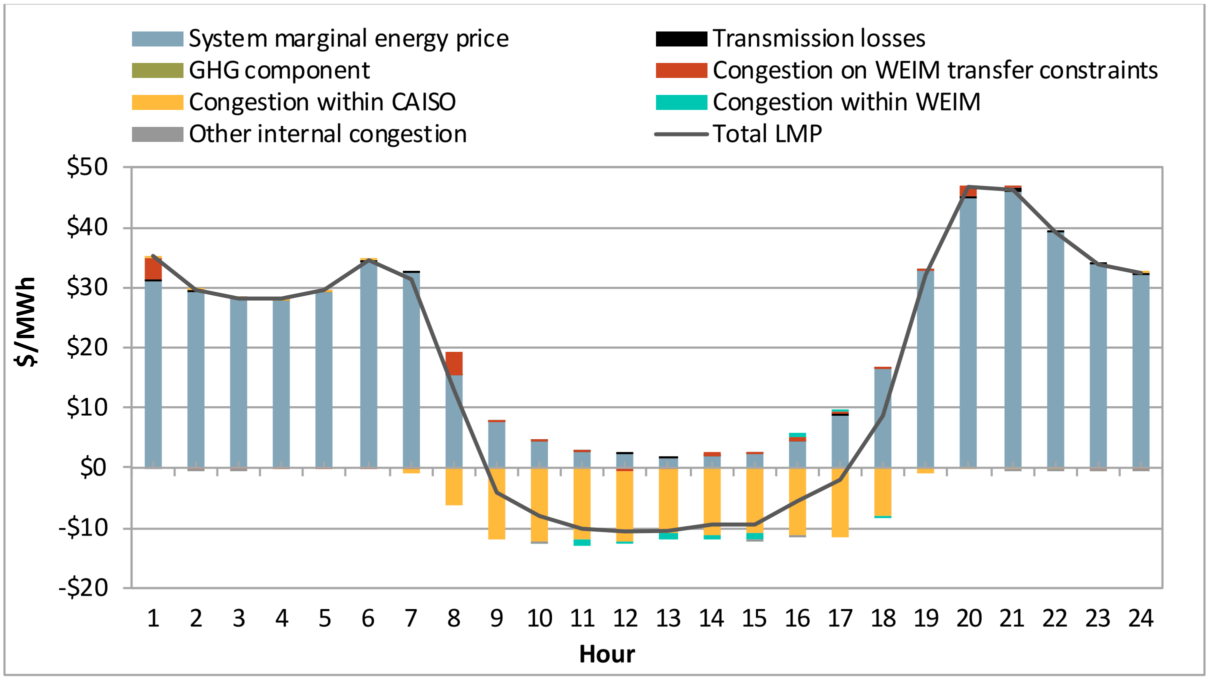


Appendix Figure A.36 Average hourly 5-minute market transfers

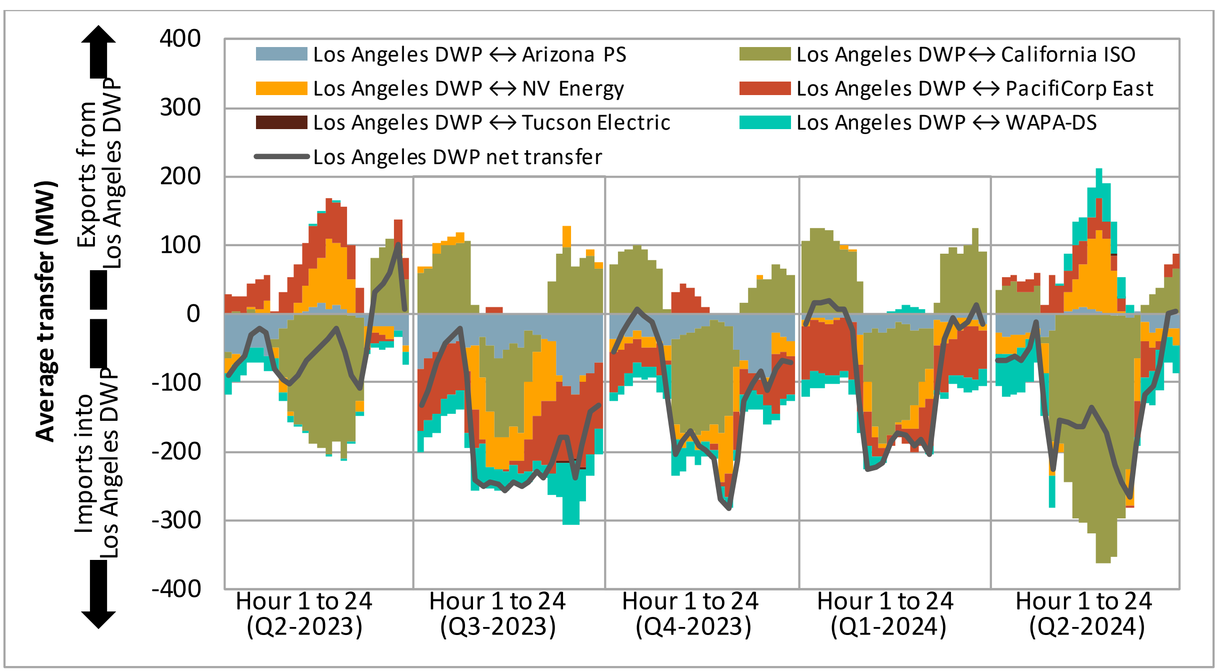


A.9 Los Angeles Department of Water and Power

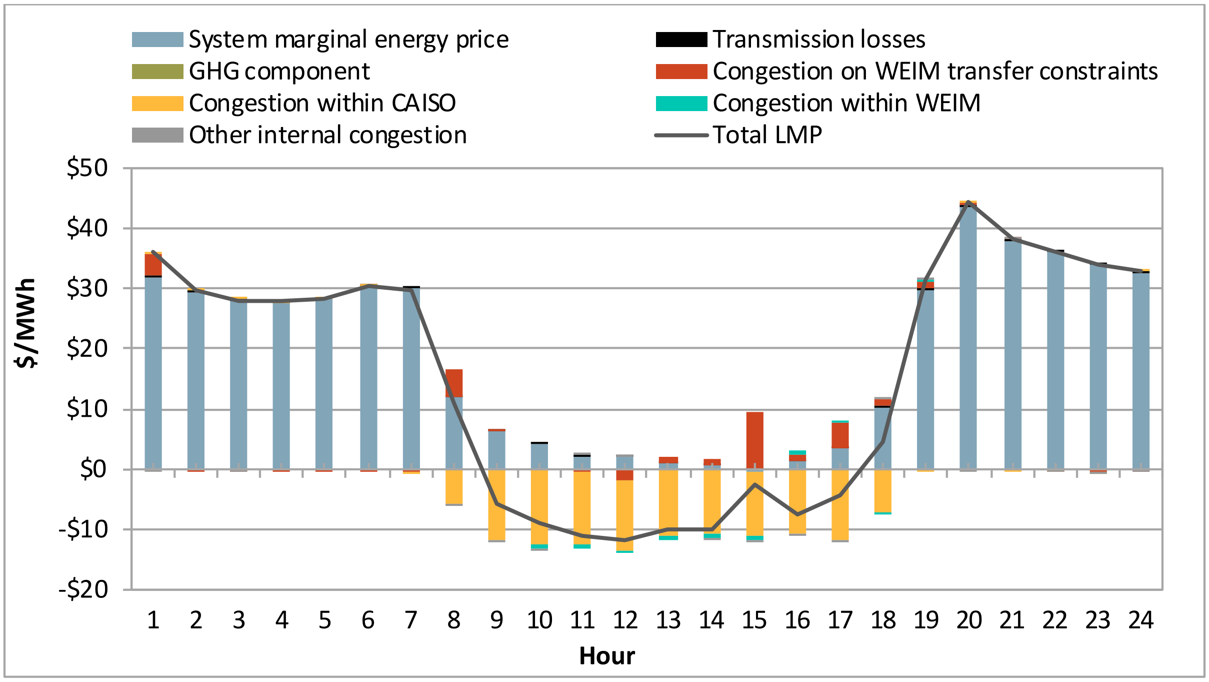
Appendix Figure A.37 Average hourly 15-minute price by component (Q2 2024)



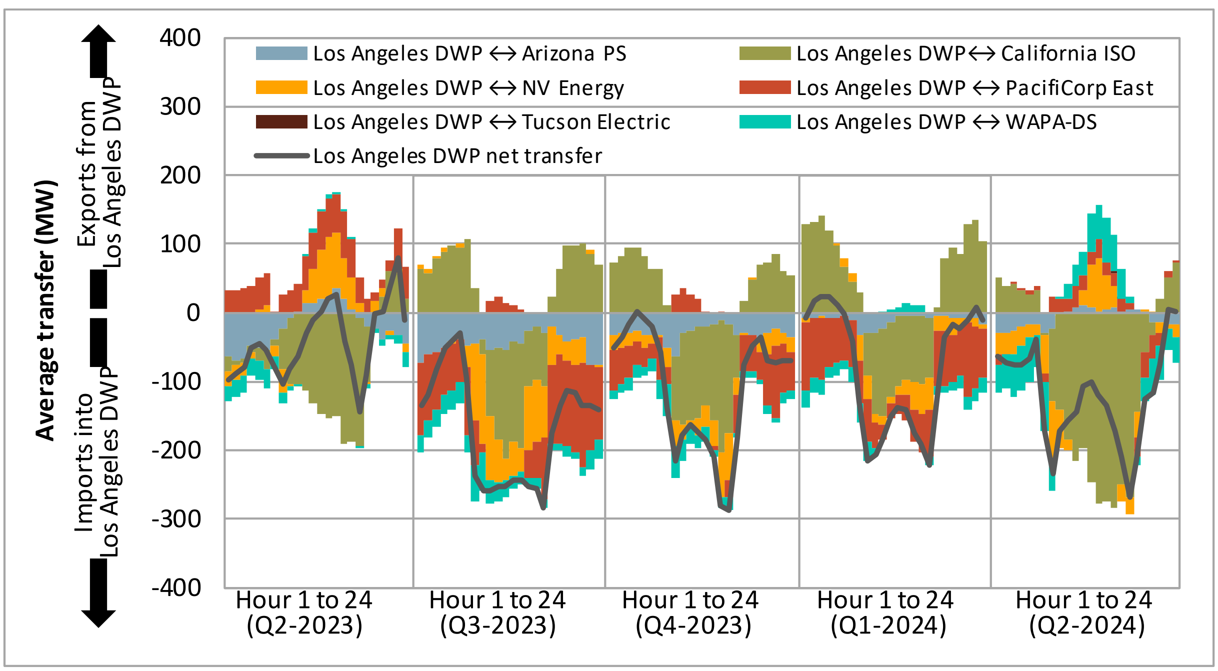
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q2 2024)

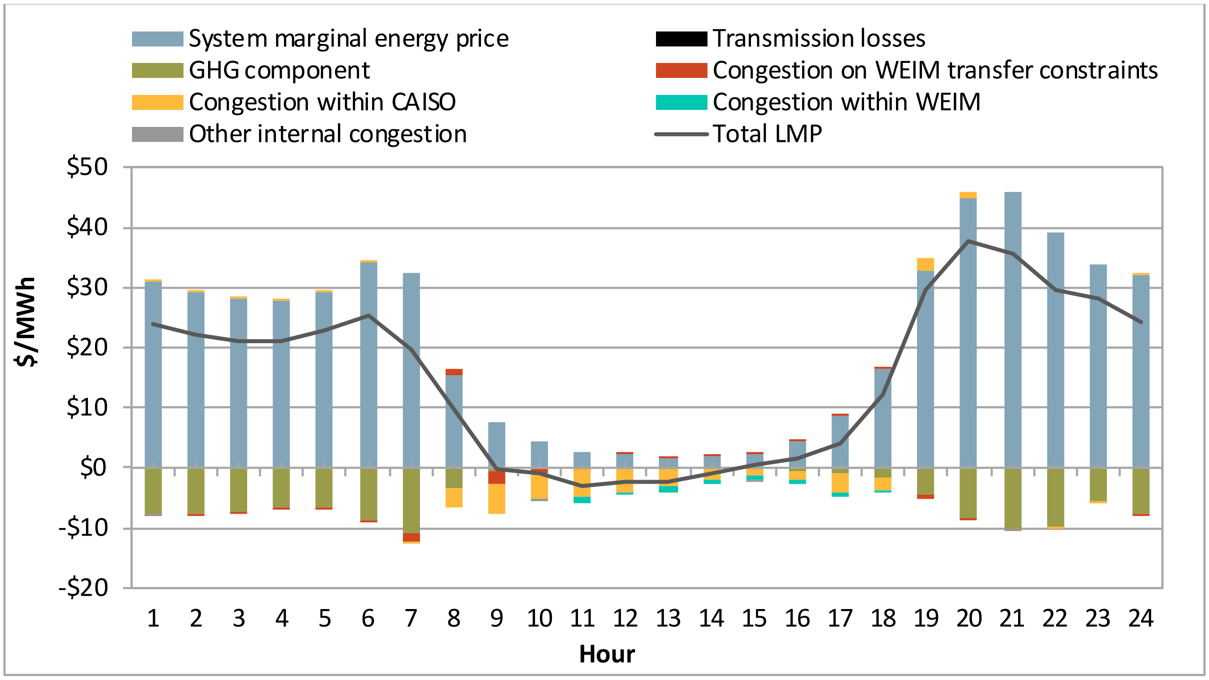


Appendix Figure A.40 Average hourly 5-minute market transfers

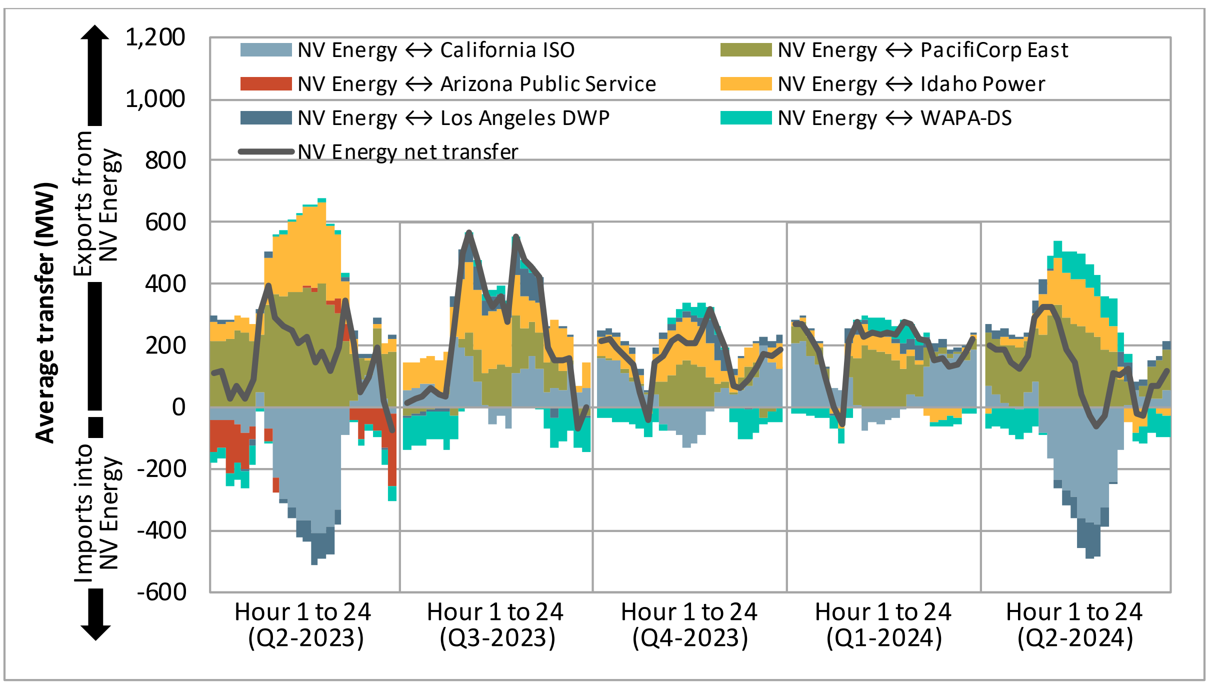


A.10 NV Energy

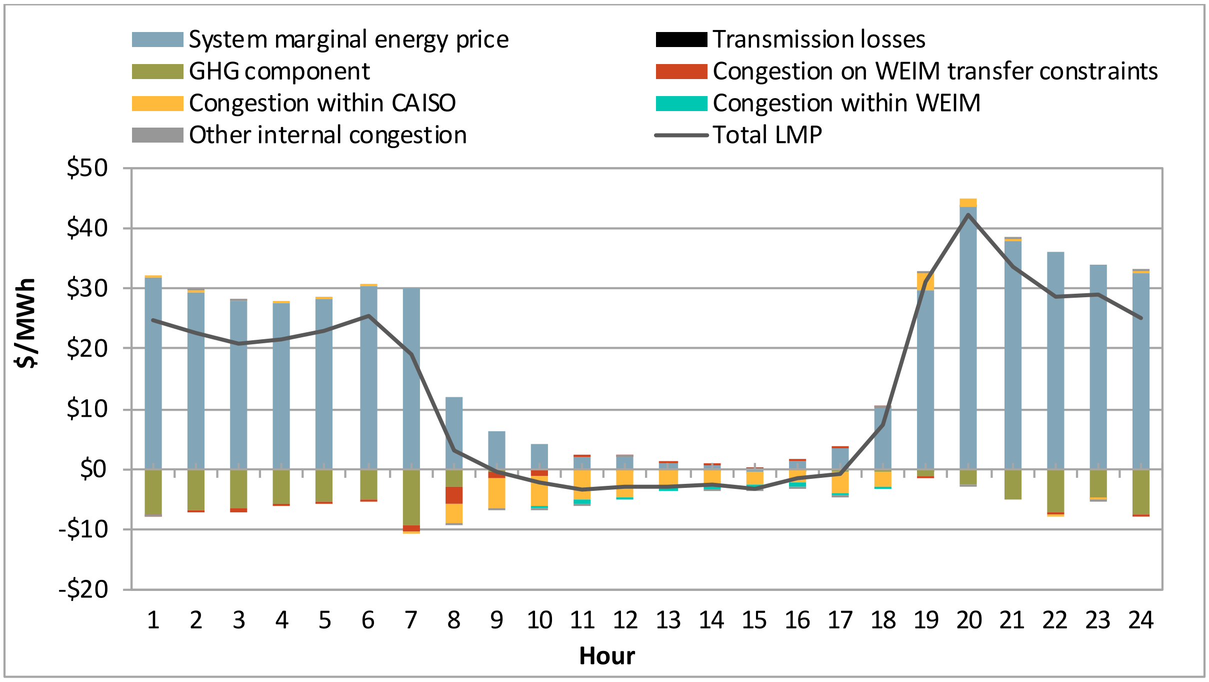
Appendix Figure A.41 Average hourly 15-minute price by component (Q2 2024)



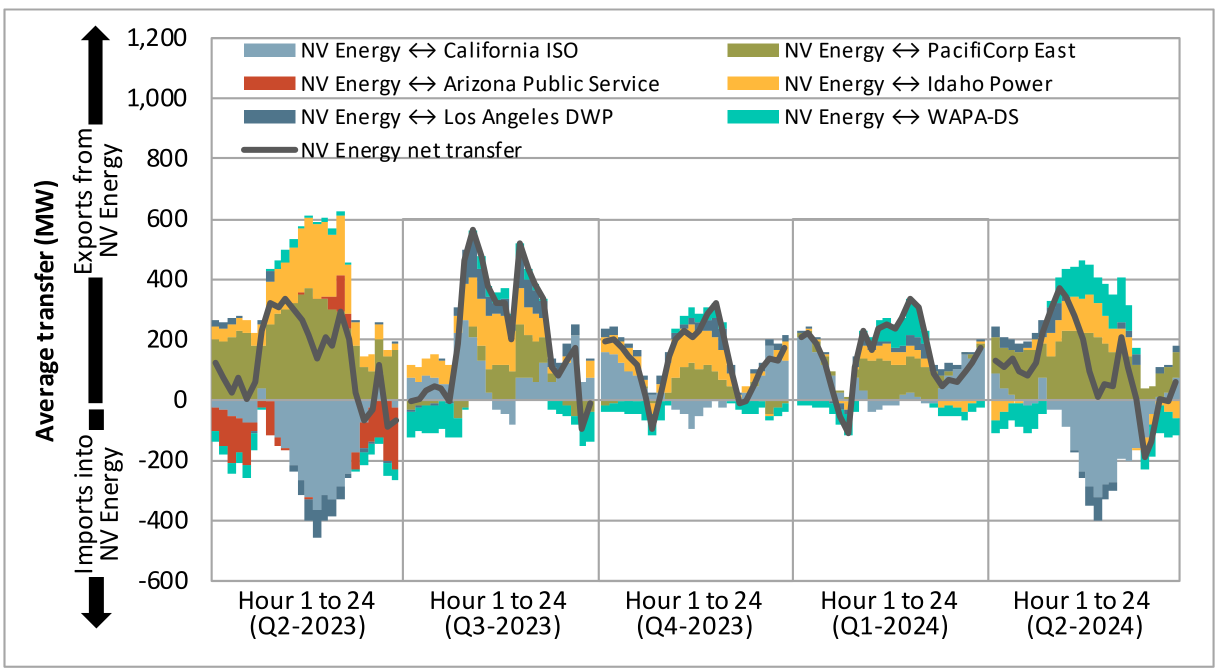
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q2 2024)

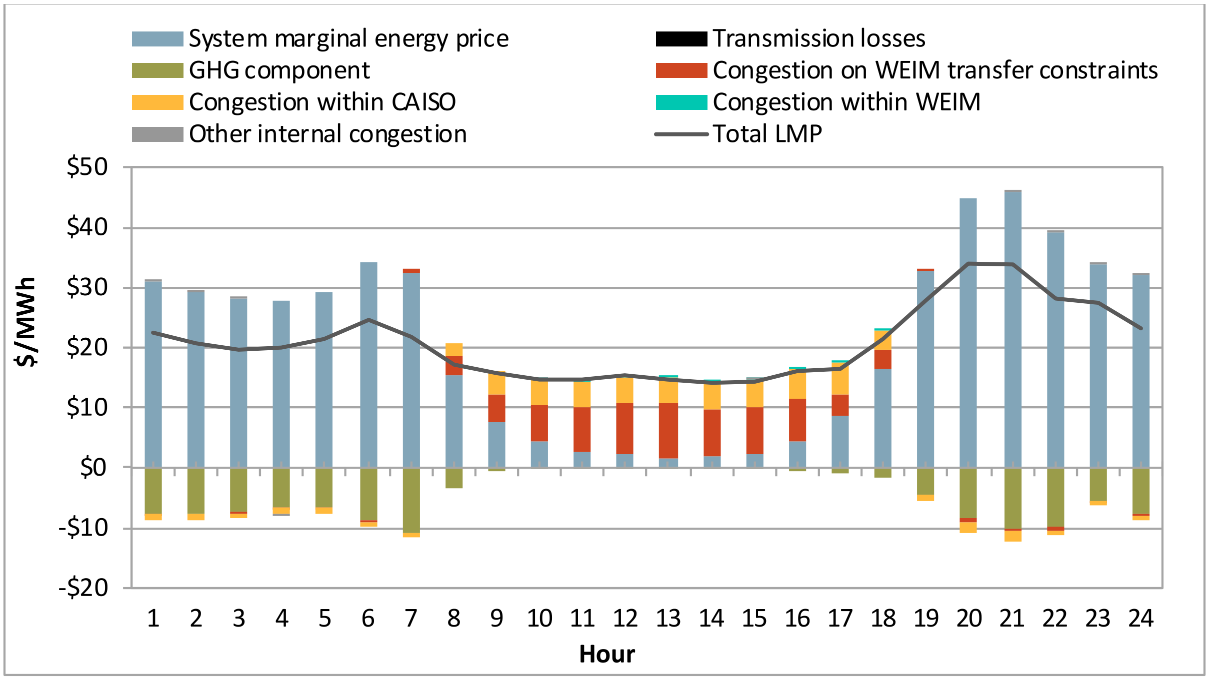


Appendix Figure A.44 Average hourly 5-minute market transfers

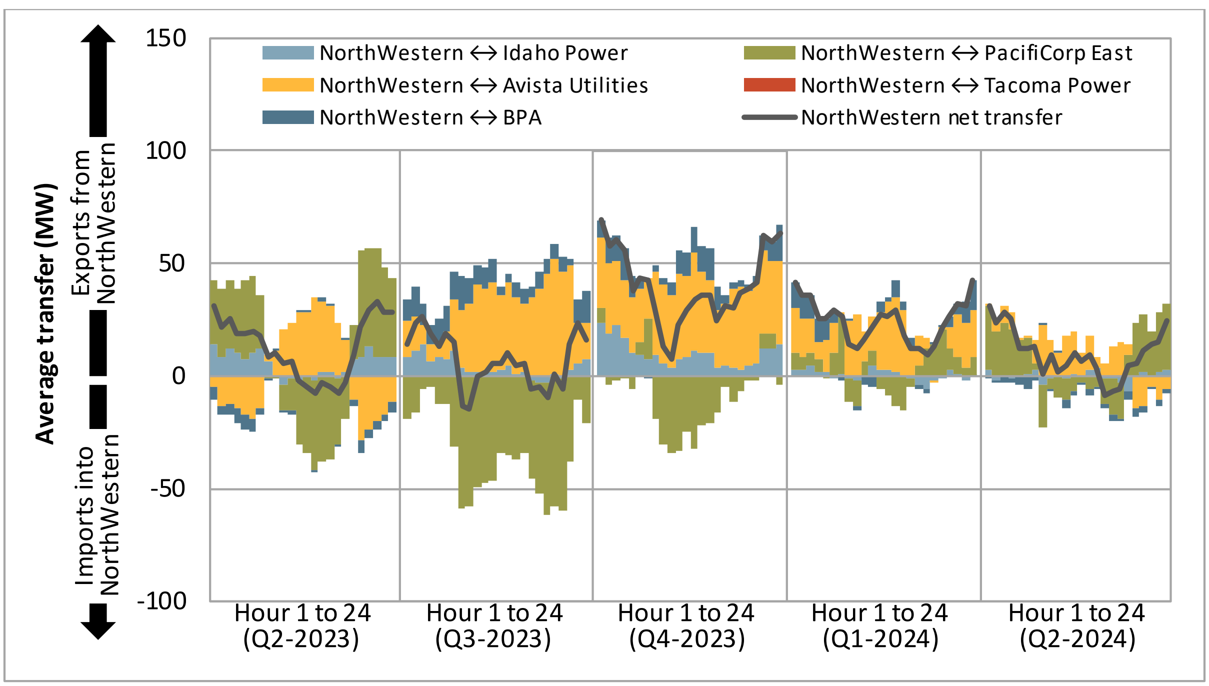


A.11 NorthWestern Energy

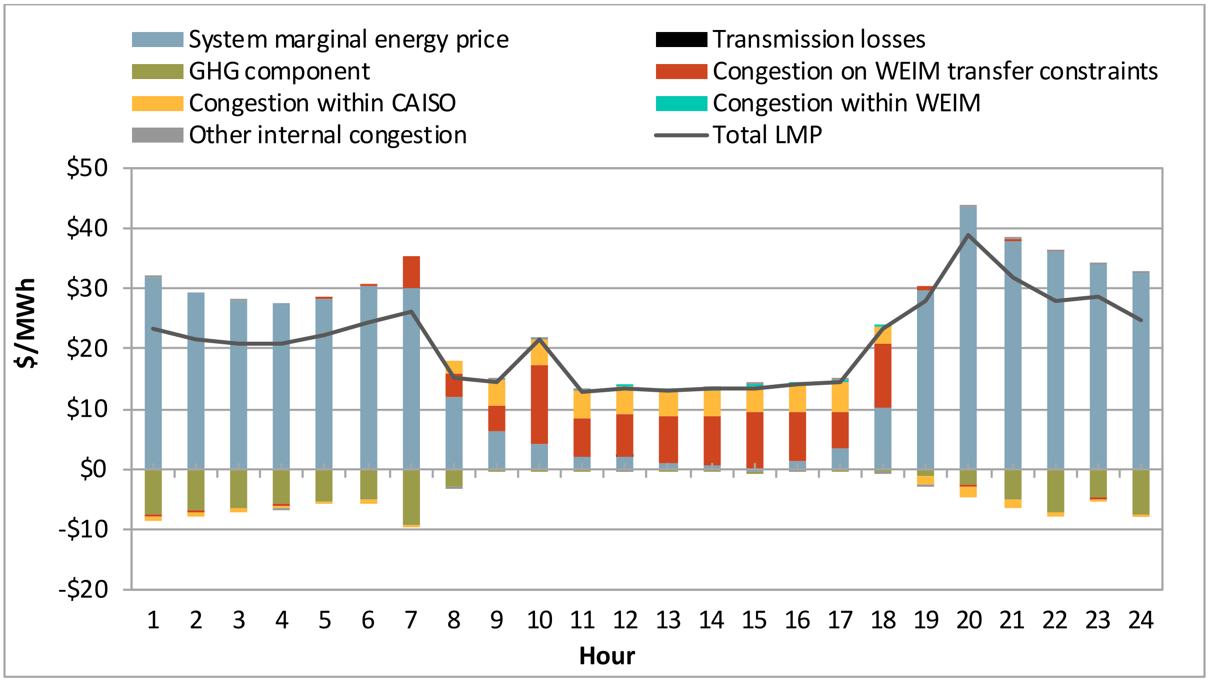
Appendix Figure A.45 Average hourly 15-minute price by component (Q2 2024)



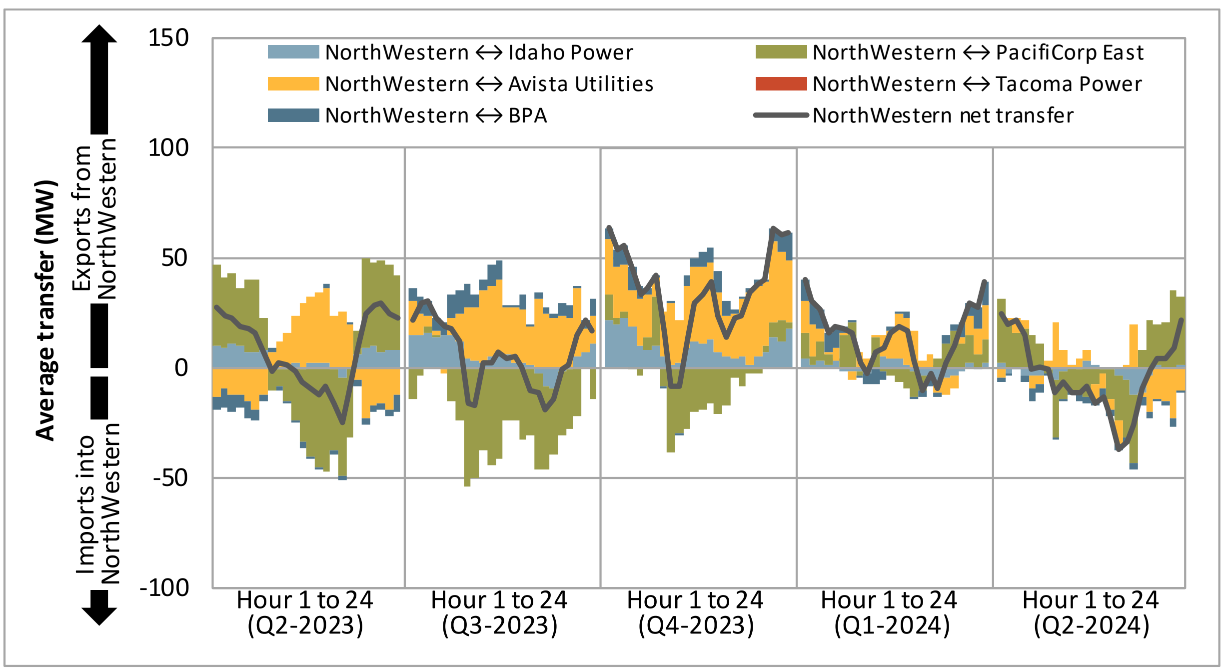
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q2 2024)

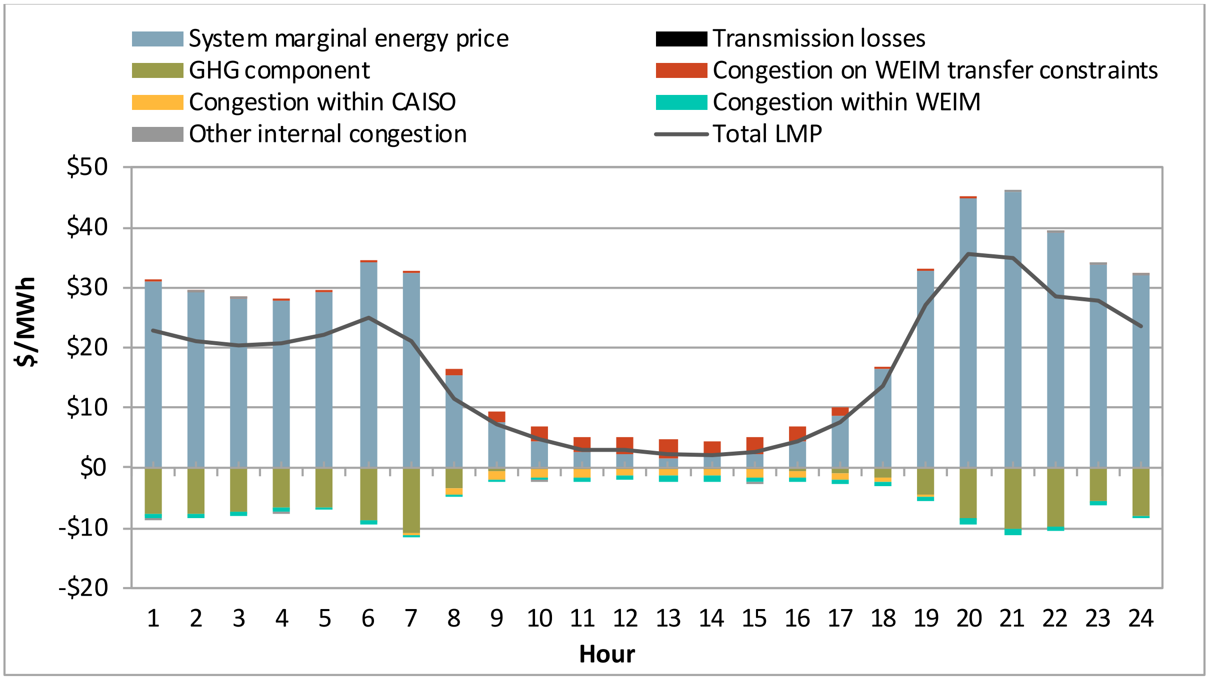


Appendix Figure A.48 Average hourly 5-minute market transfers

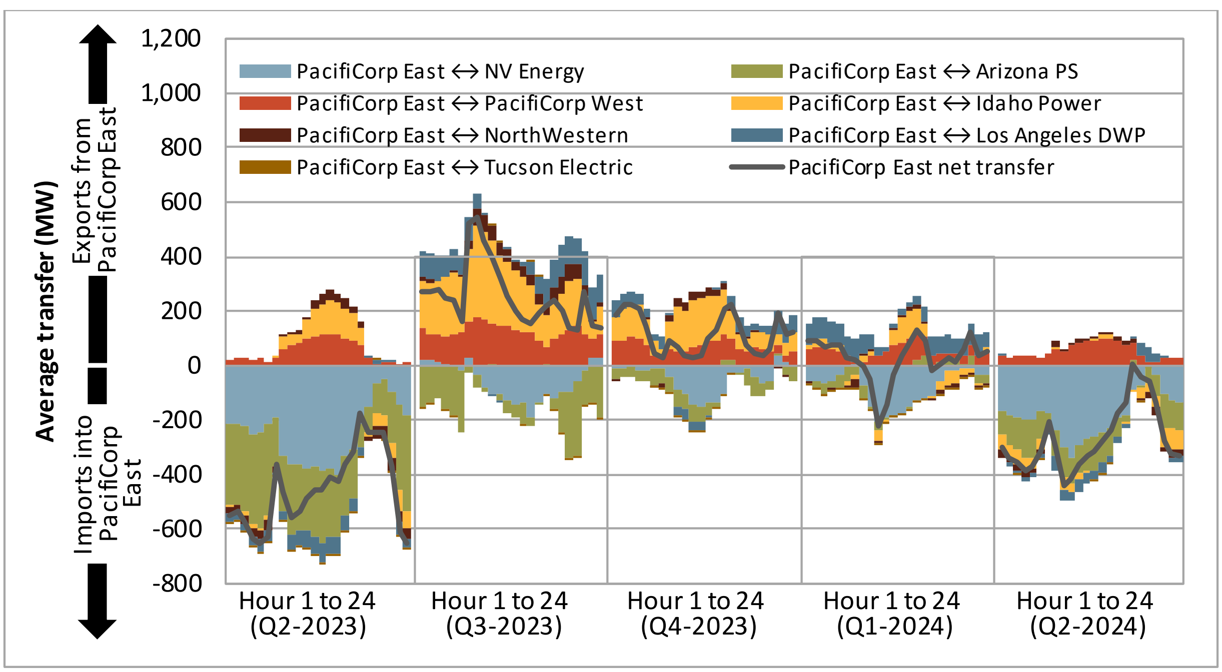


A.12 PacifiCorp East

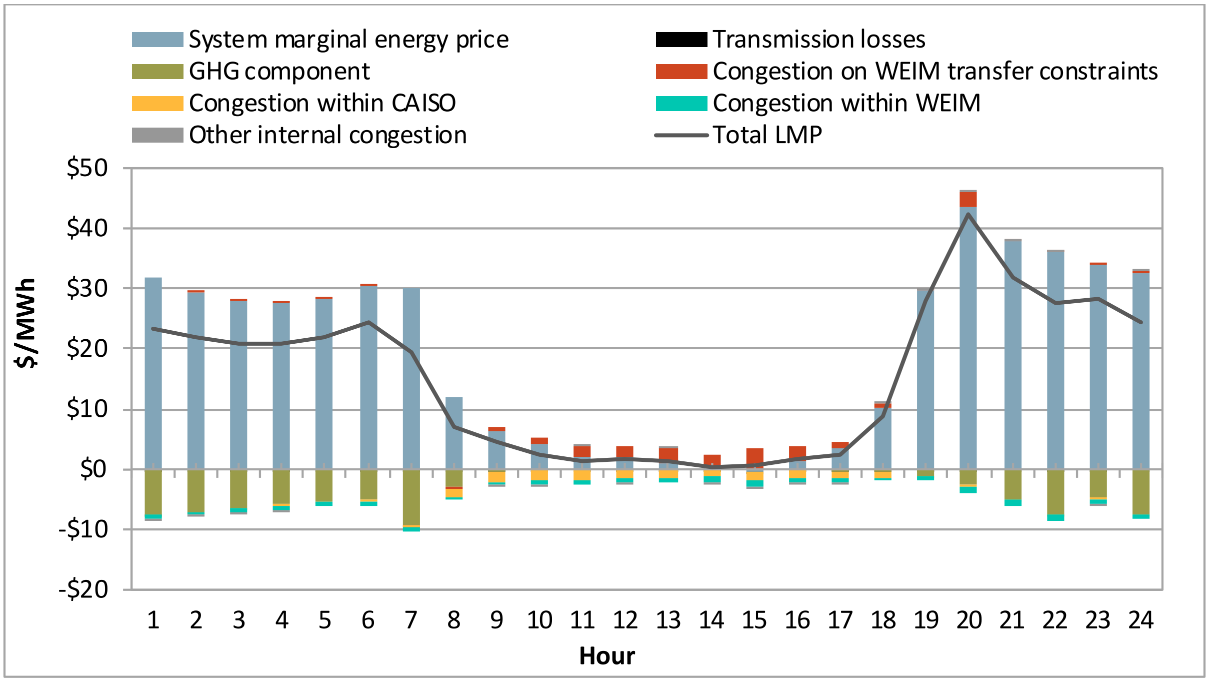
Appendix Figure A.49 Average hourly 15-minute price by component (Q2 2024)



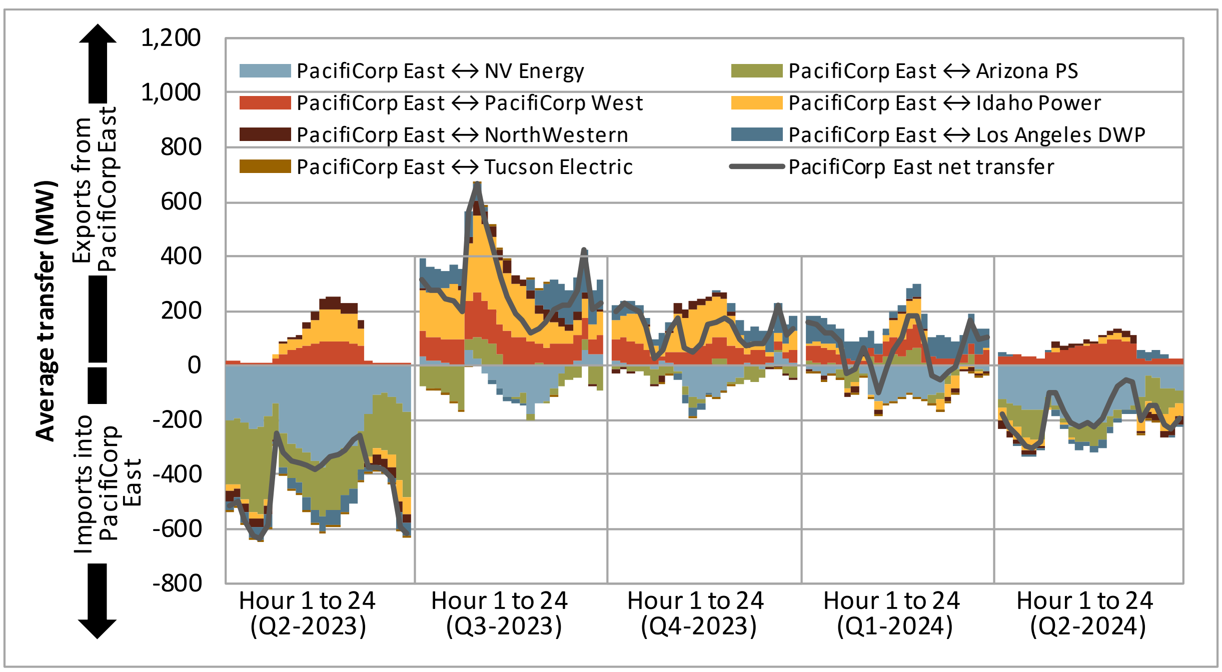
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q2 2024)

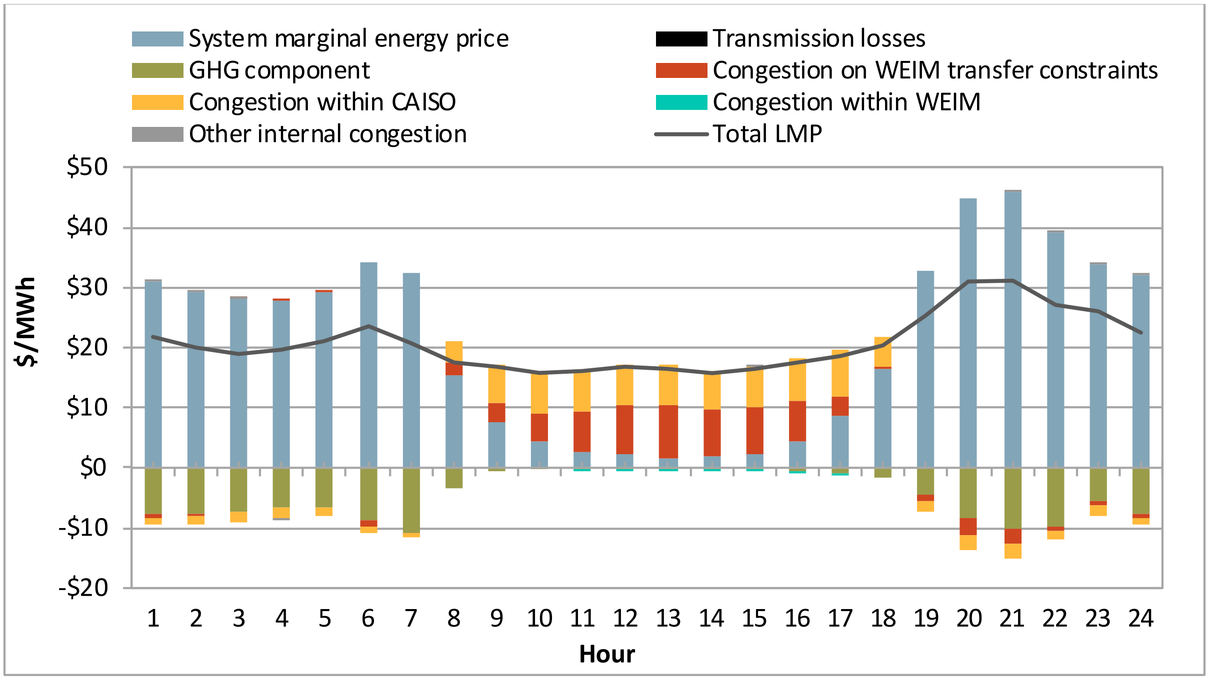


Appendix Figure A.52 Average hourly 5-minute market transfers

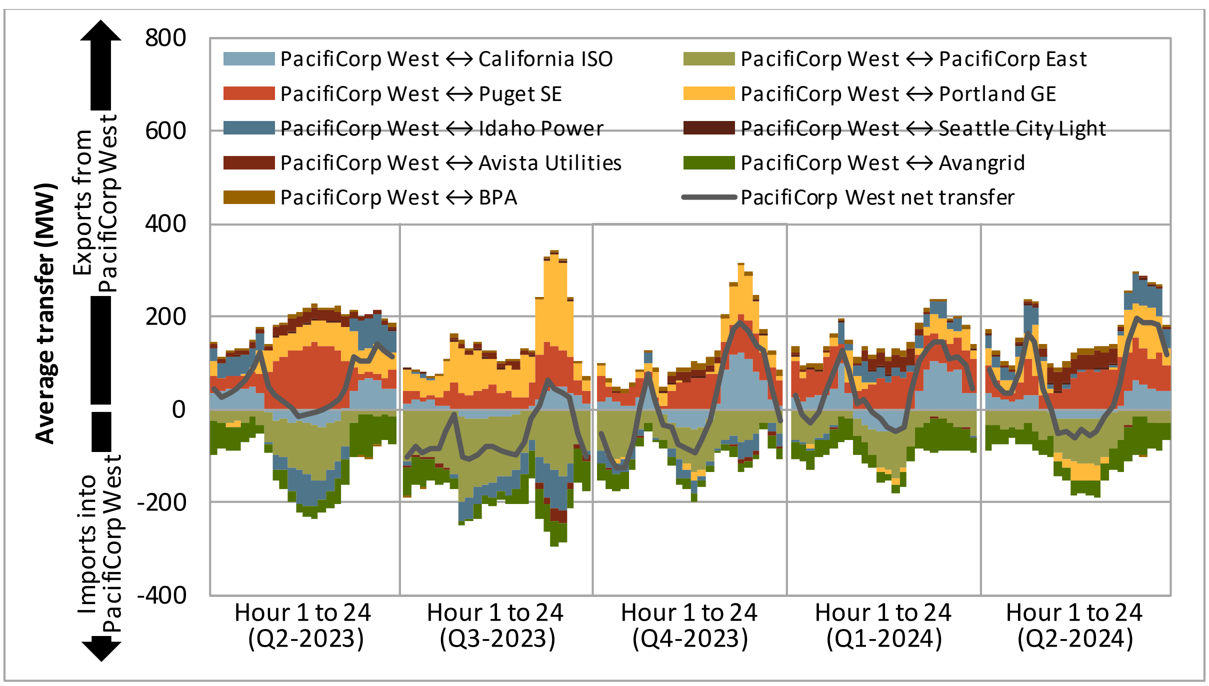


A.13 PacifiCorp West

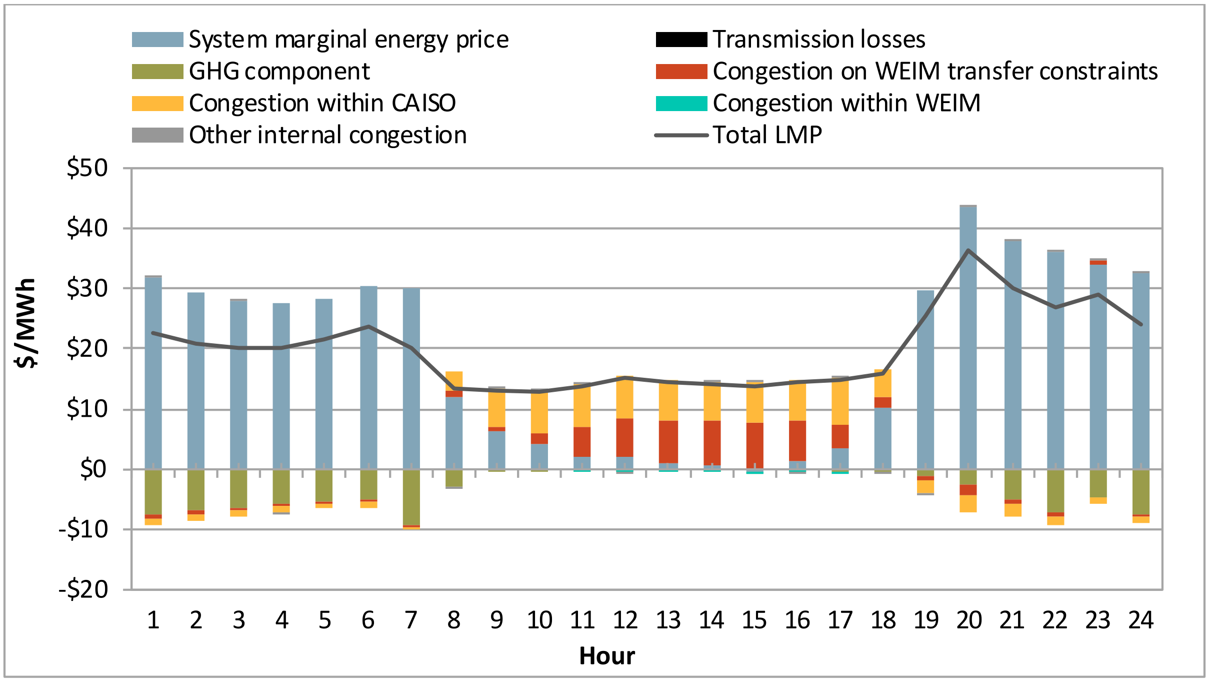
Appendix Figure A.53 Average hourly 15-minute price by component (Q2 2024)



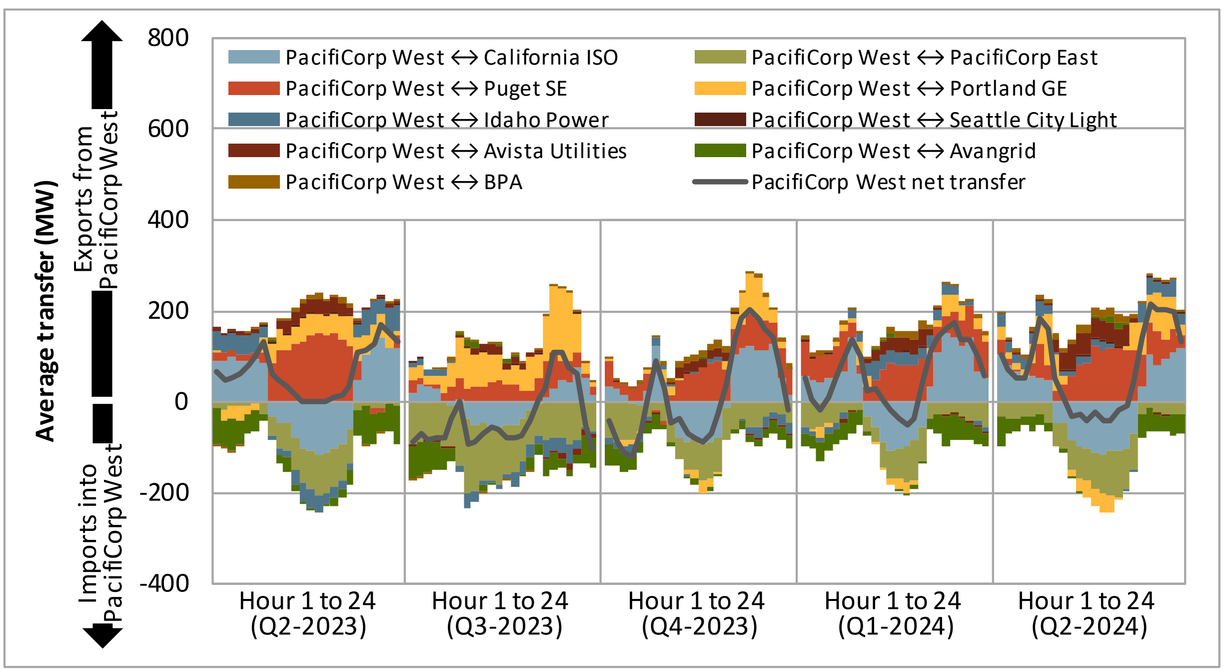
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q2 2024)

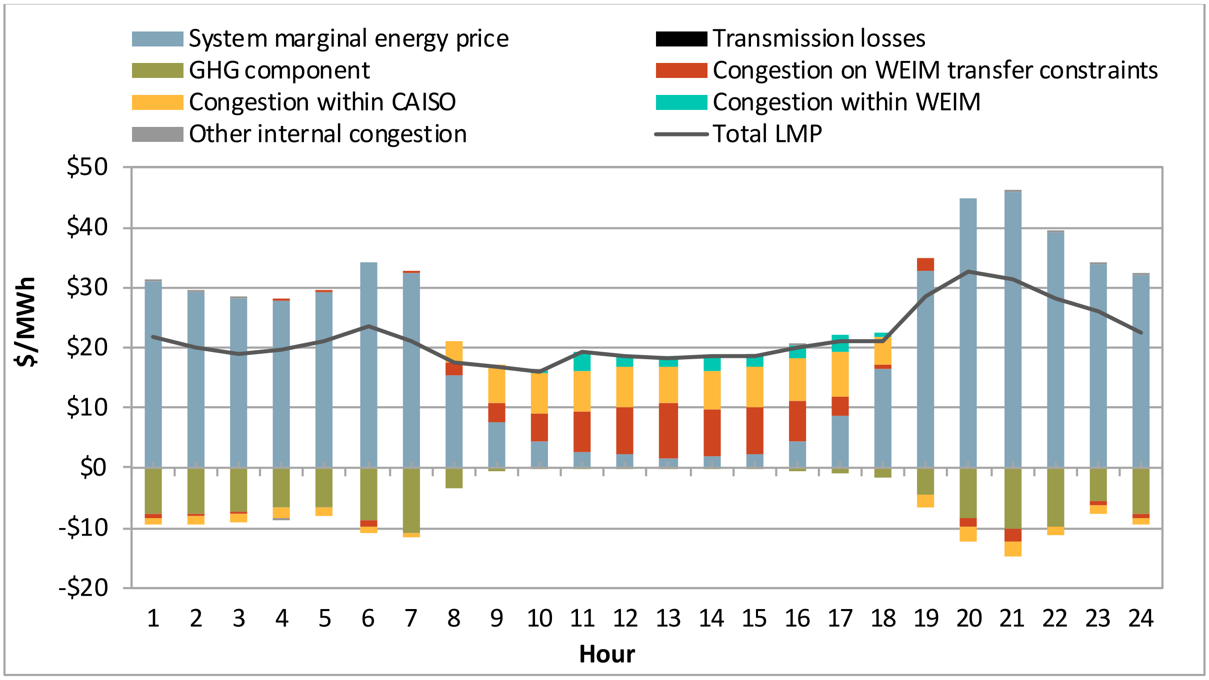


Appendix Figure A.56 Average hourly 5-minute market transfers

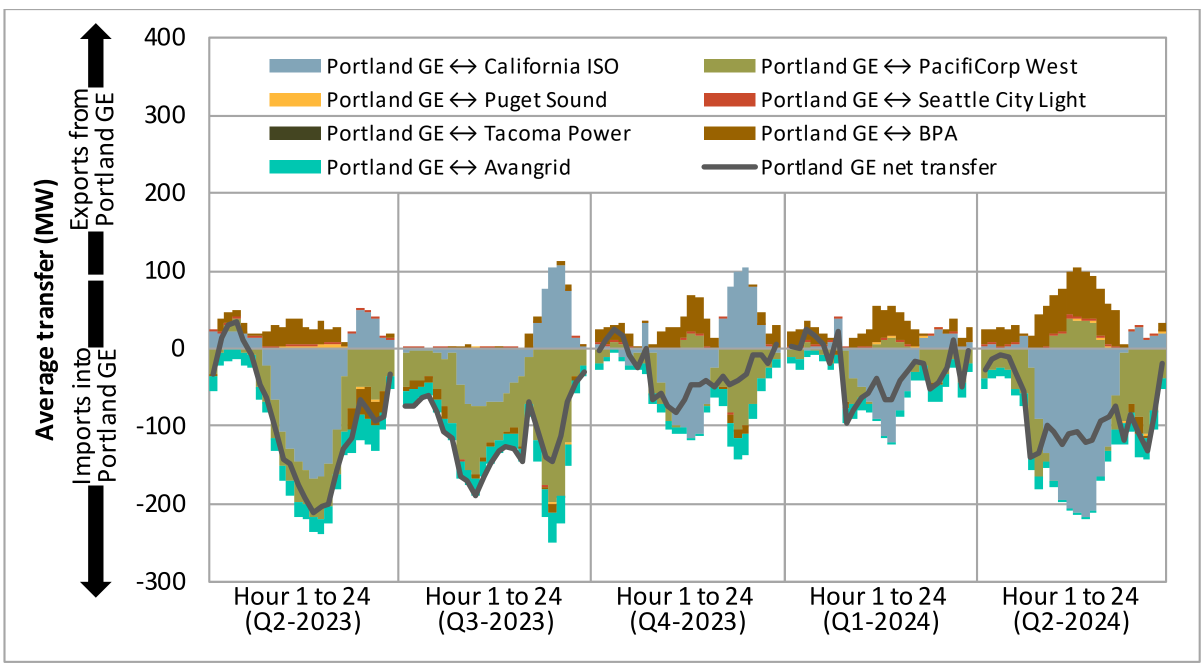


A.14 Portland General Electric

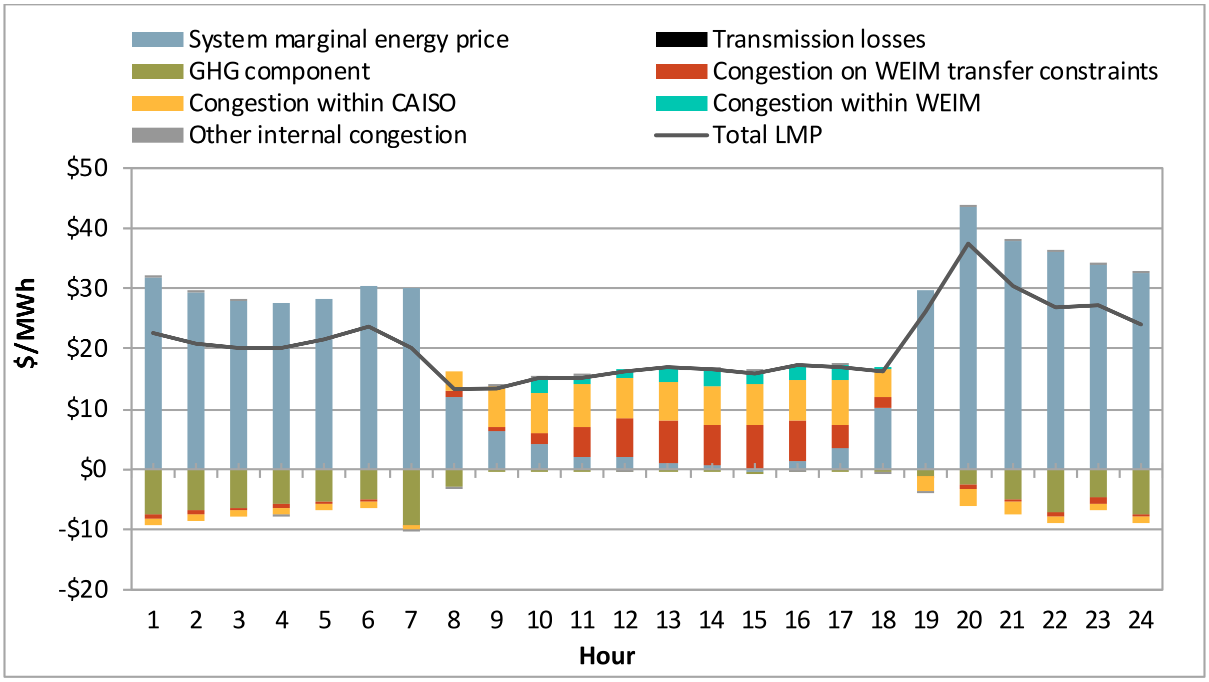
Appendix Figure A.57 Average hourly 15-minute price by component (Q2 2024)



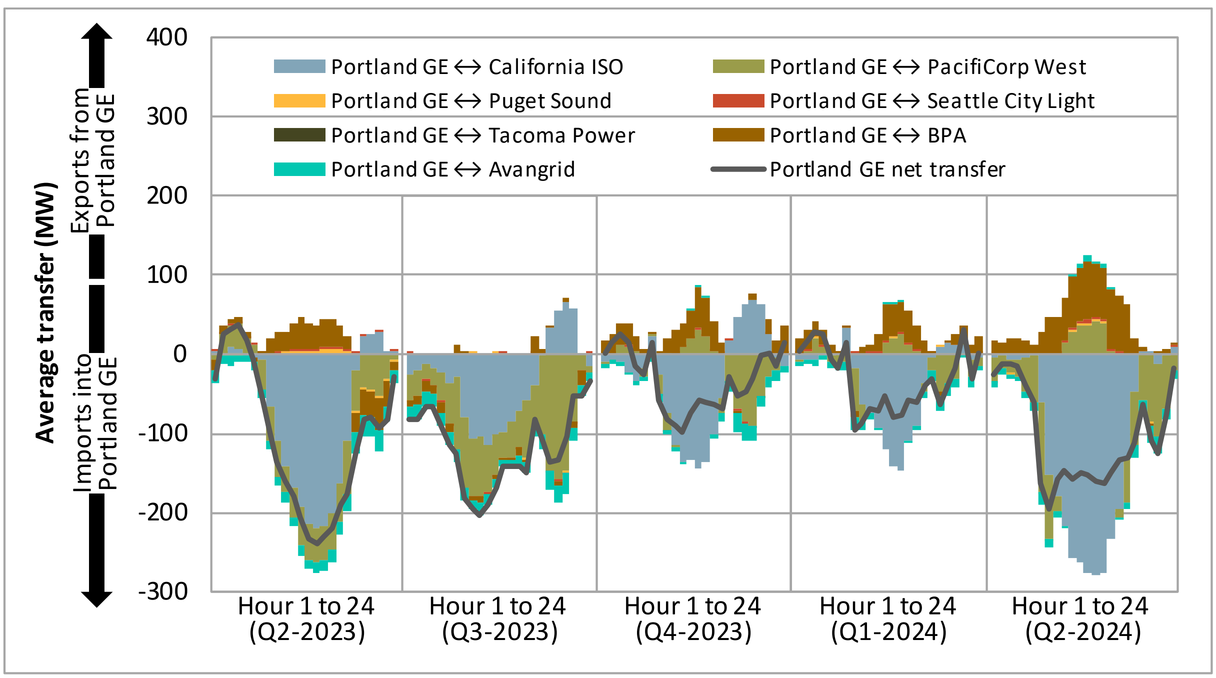
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q2 2024)

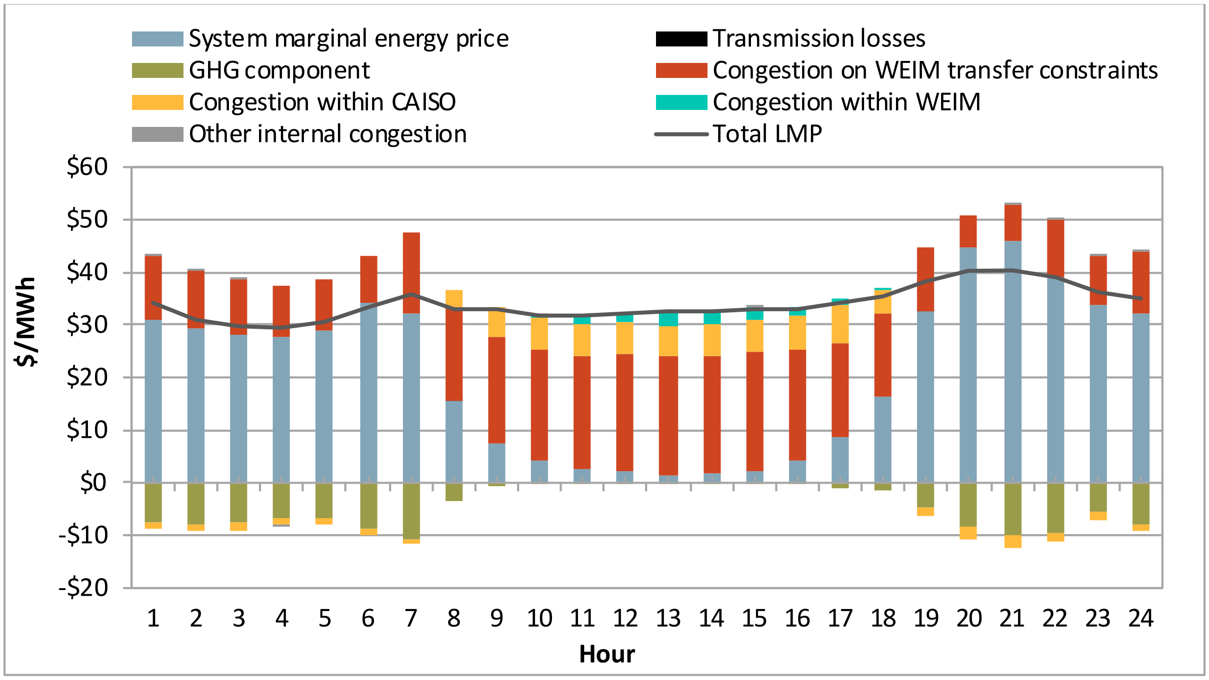


Appendix Figure A.60 Average hourly 5-minute market transfers

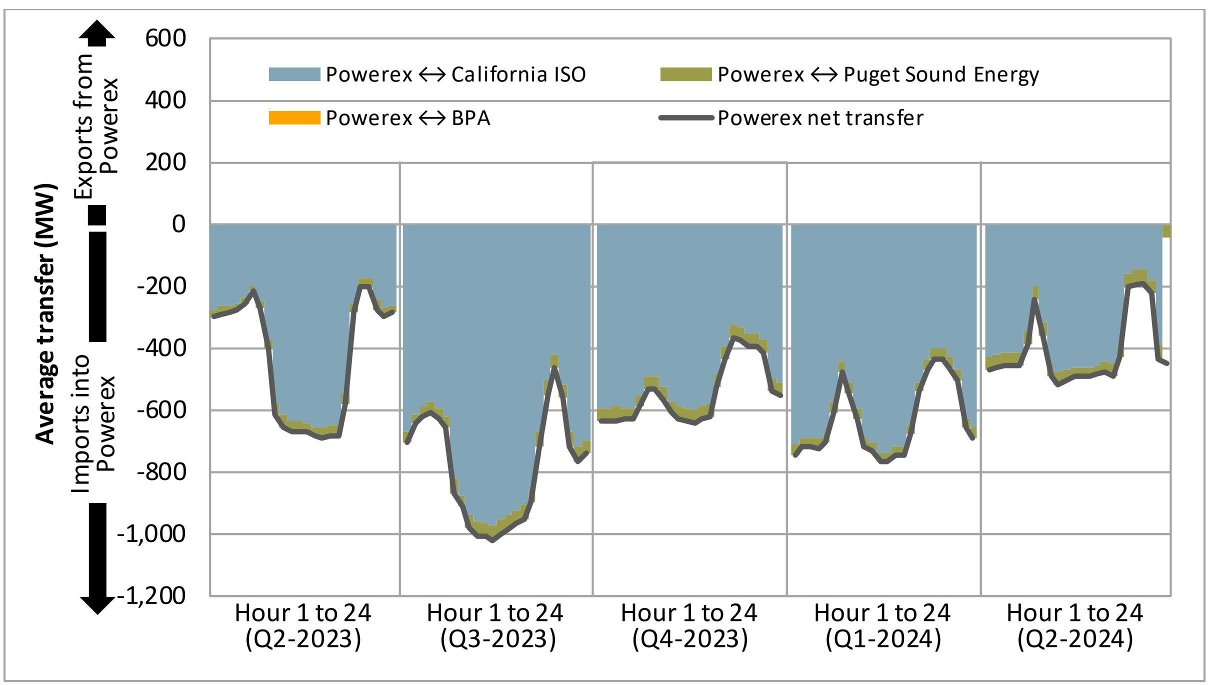


A.15 Powerex

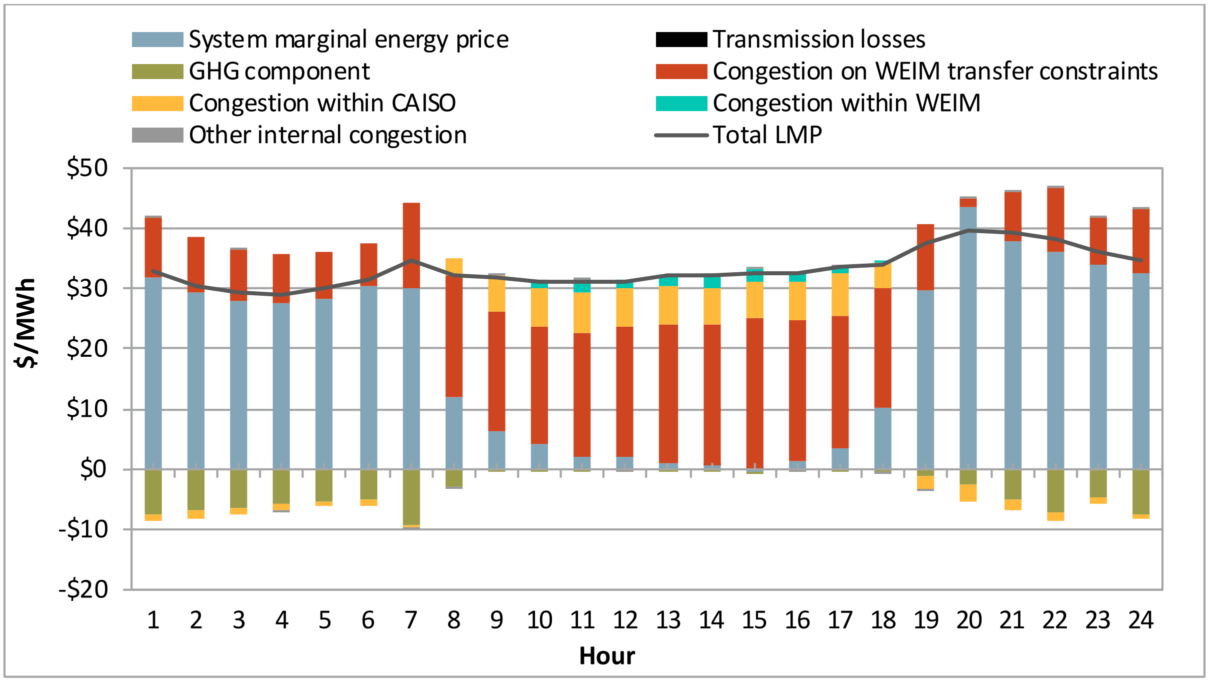
Appendix Figure A.61 Average hourly 15-minute price by component (Q2 2024)



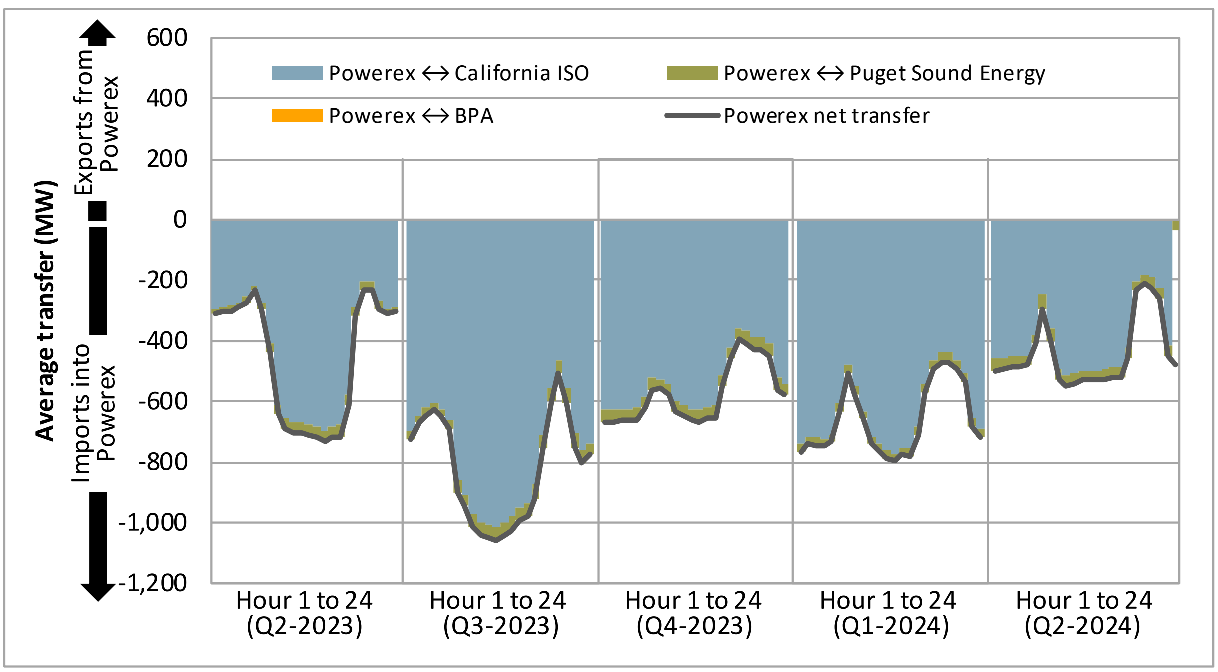
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q2 2024)

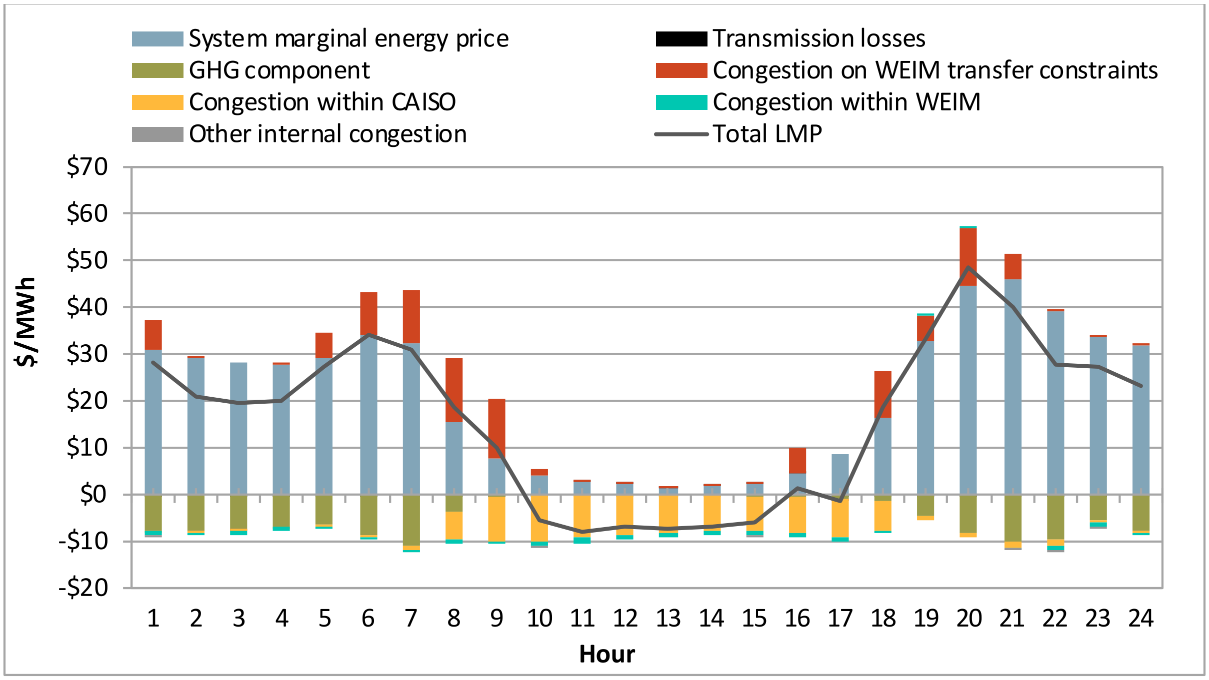


Appendix Figure A.64 Average hourly 5-minute market transfers

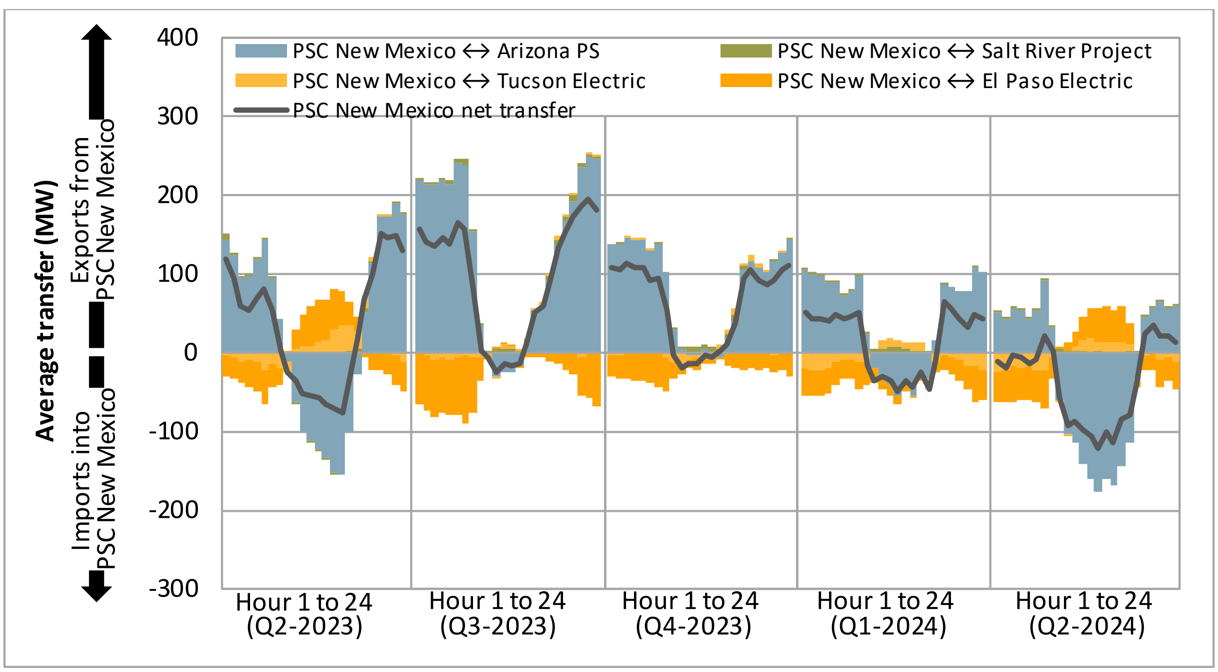


A.16 Public Service Company of New Mexico

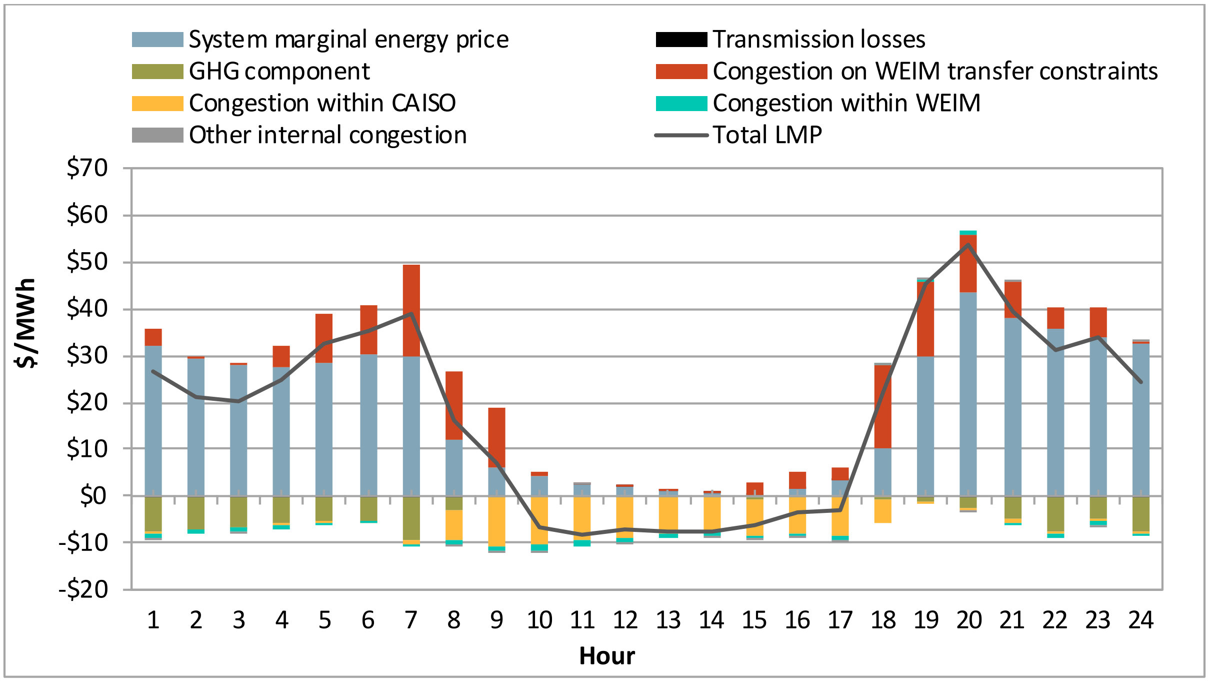
Appendix Figure A.65 Average hourly 15-minute price by component (Q2 2024)



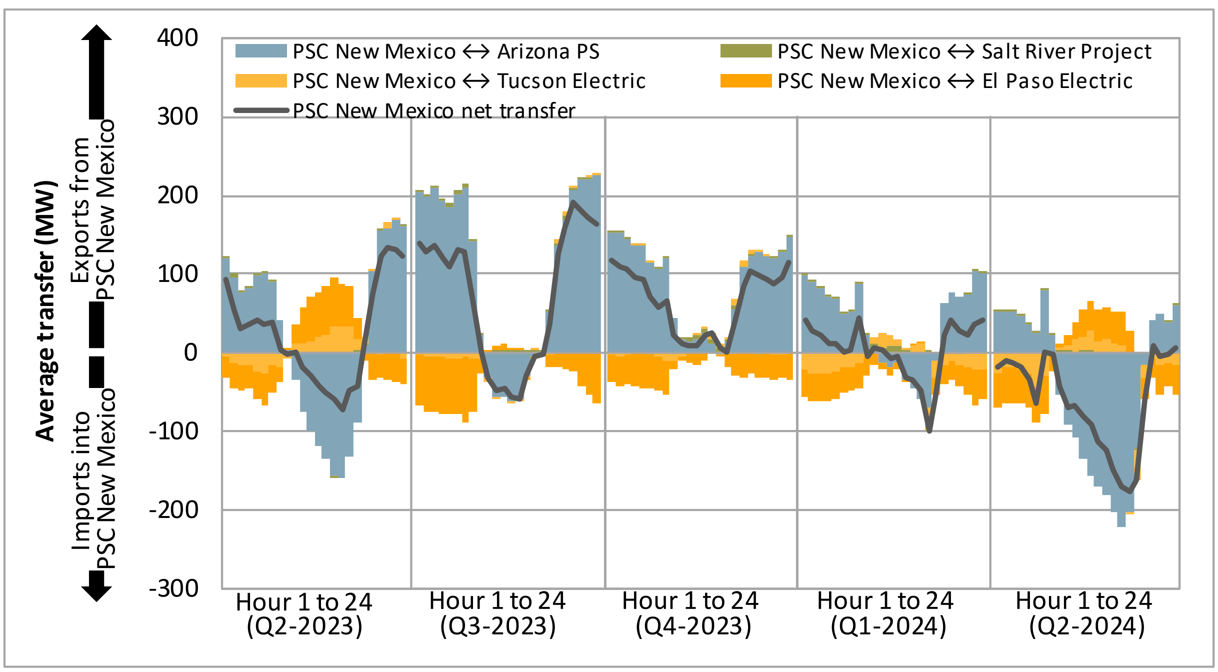
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q2 2024)

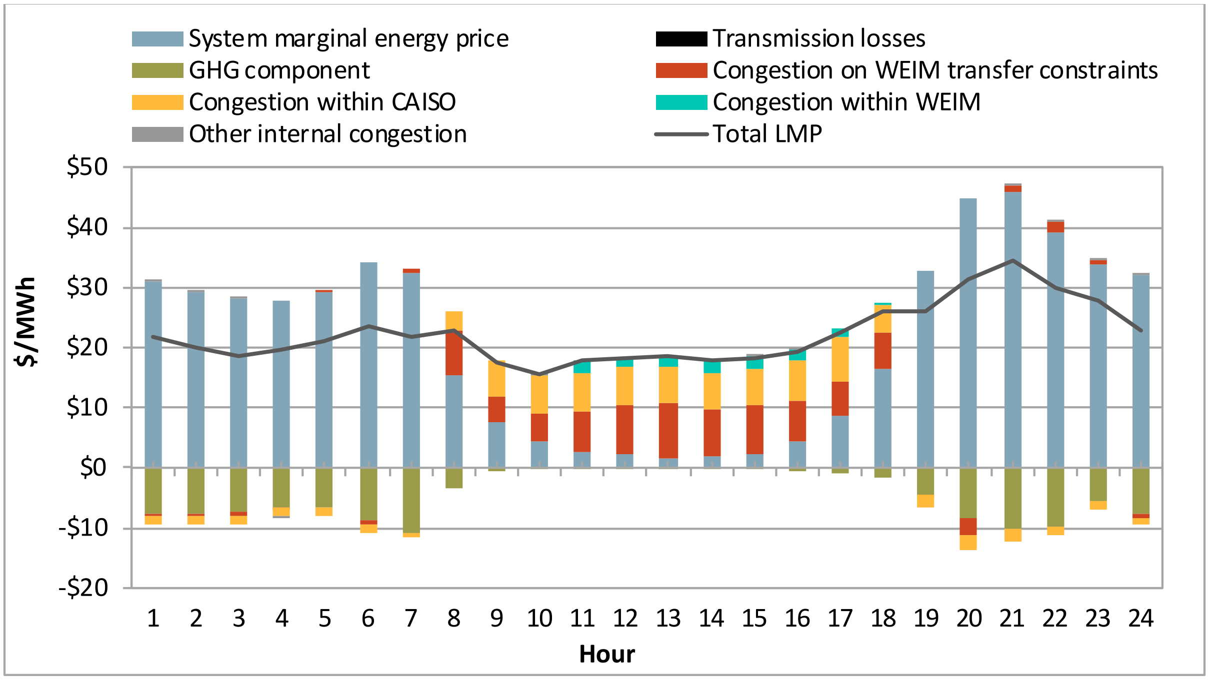


Appendix Figure A.68 Average hourly 5-minute market transfers

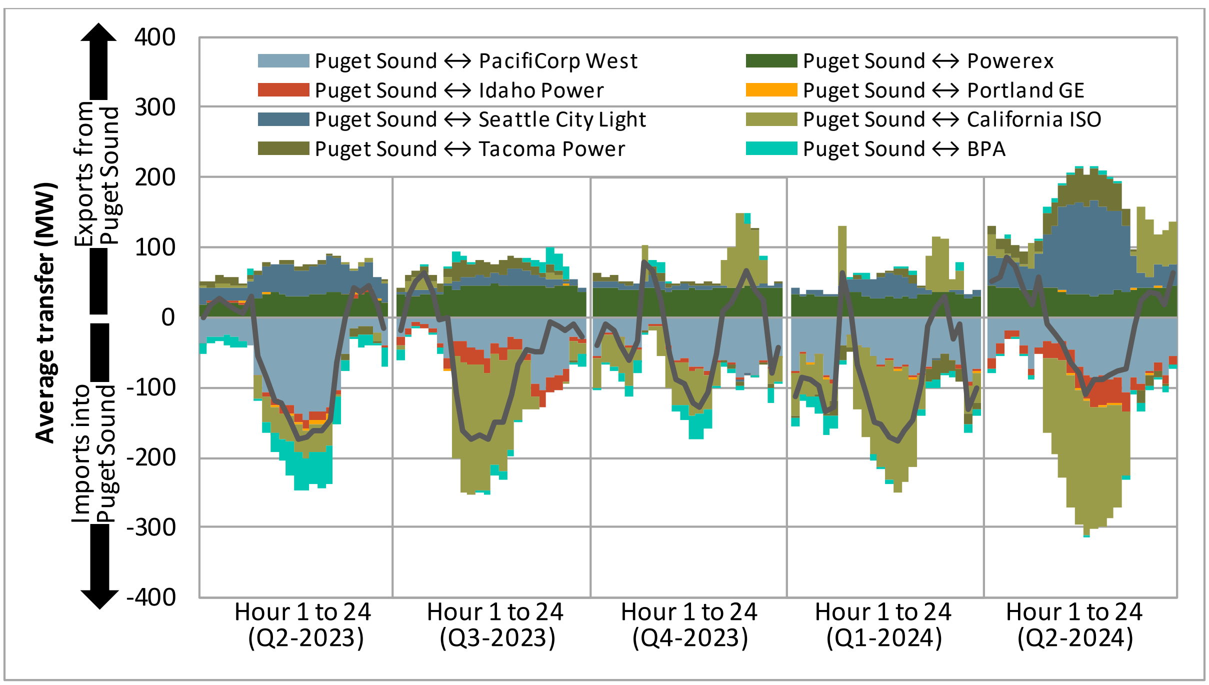


A.17 Puget Sound Energy

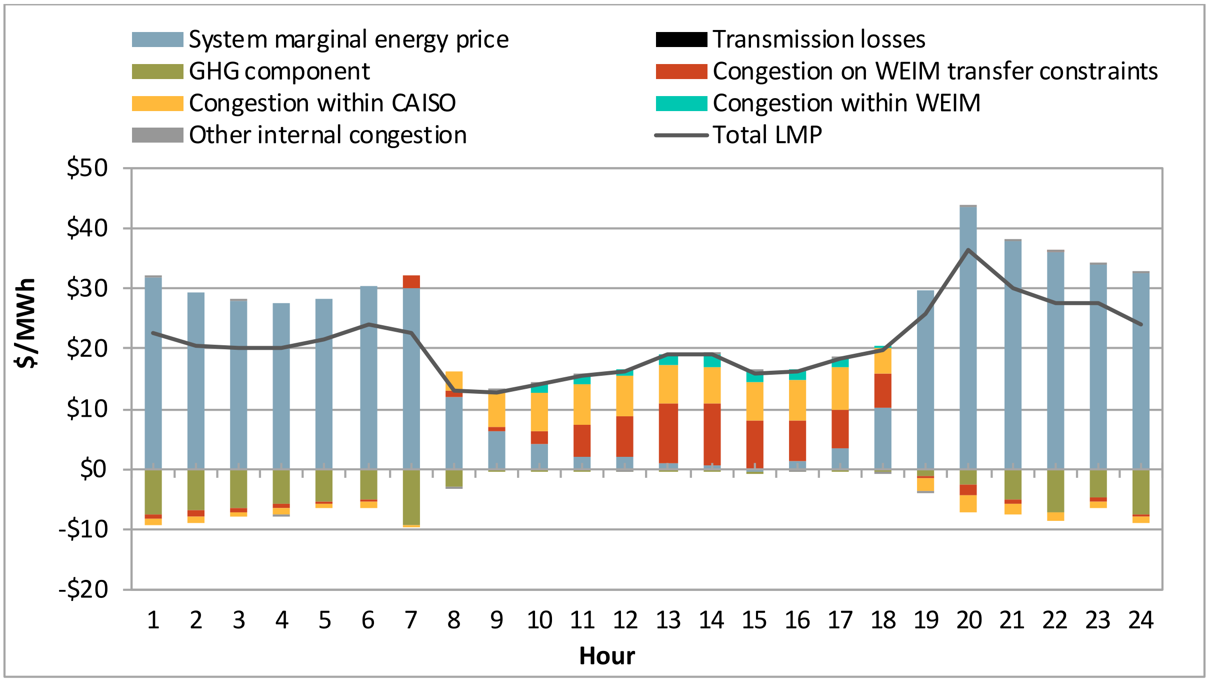
Appendix Figure A.69 Average hourly 15-minute price by component (Q2 2024)



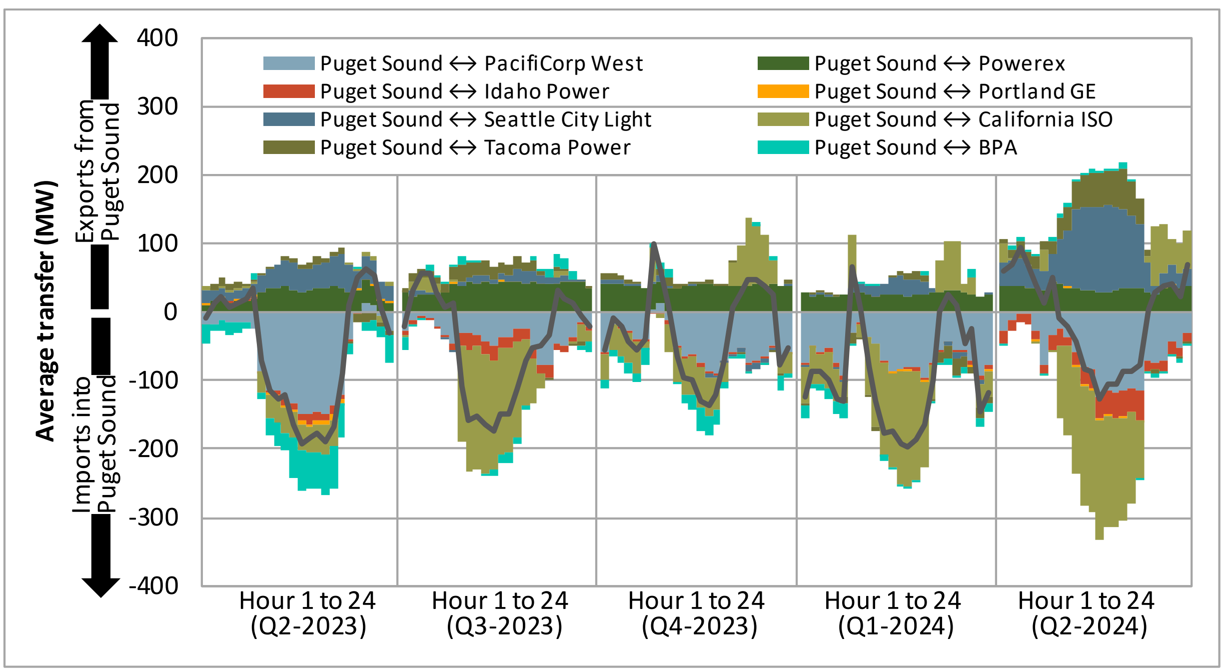
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q2 2024)

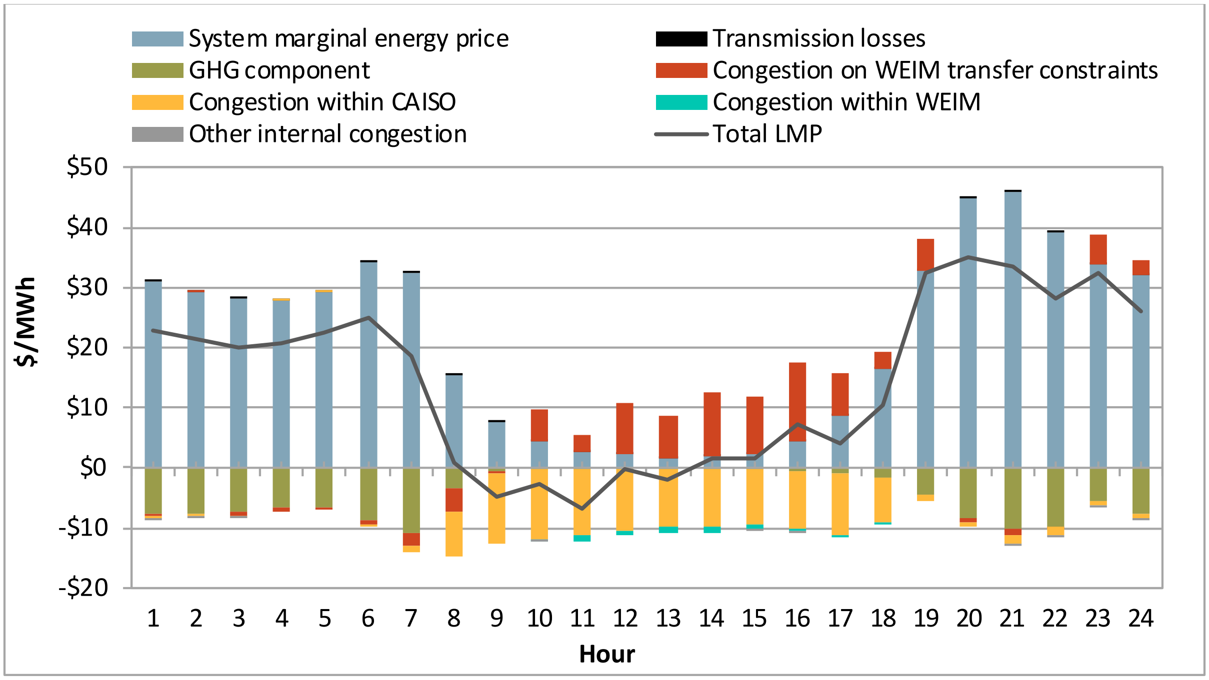


Appendix Figure A.72 Average hourly 5-minute market transfers

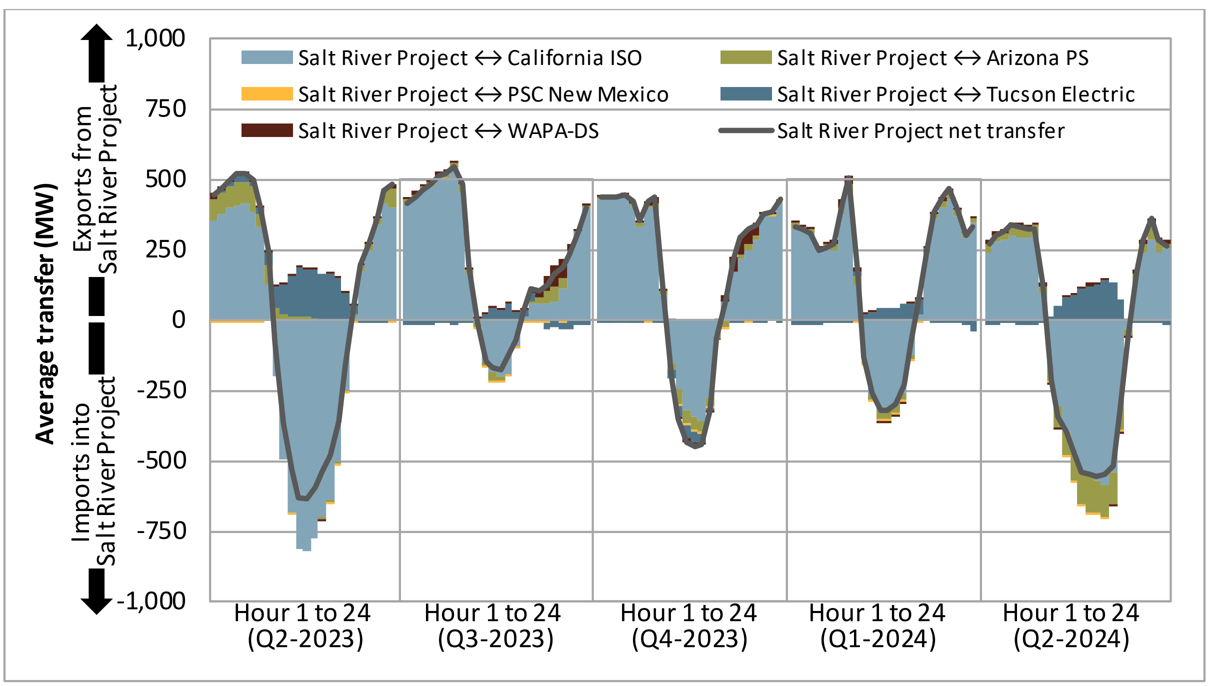


A.18 Salt River Project

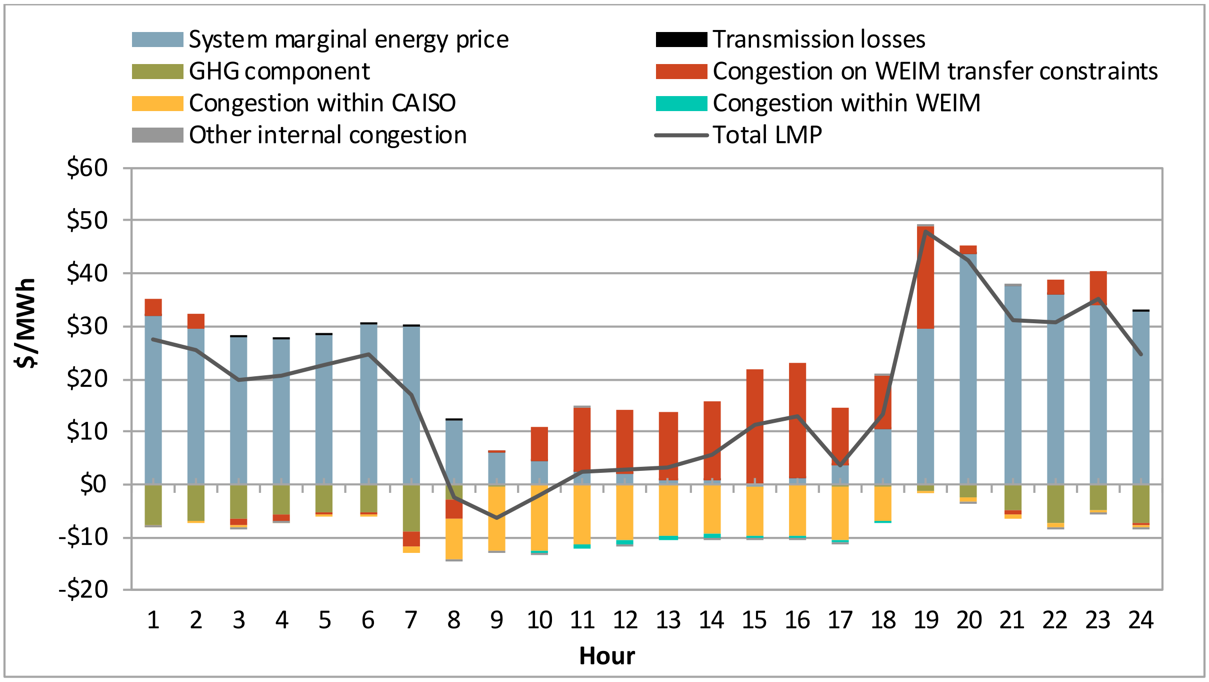
Appendix Figure A.73 Average hourly 15-minute price by component (Q2 2024)



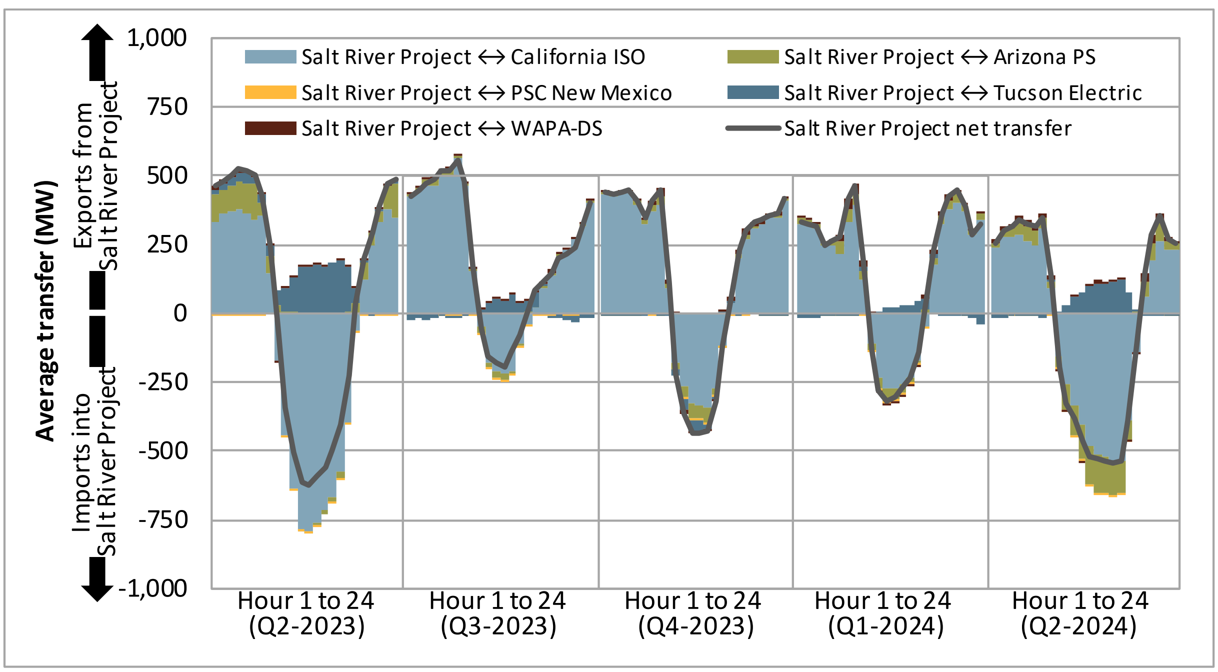
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q2 2024)

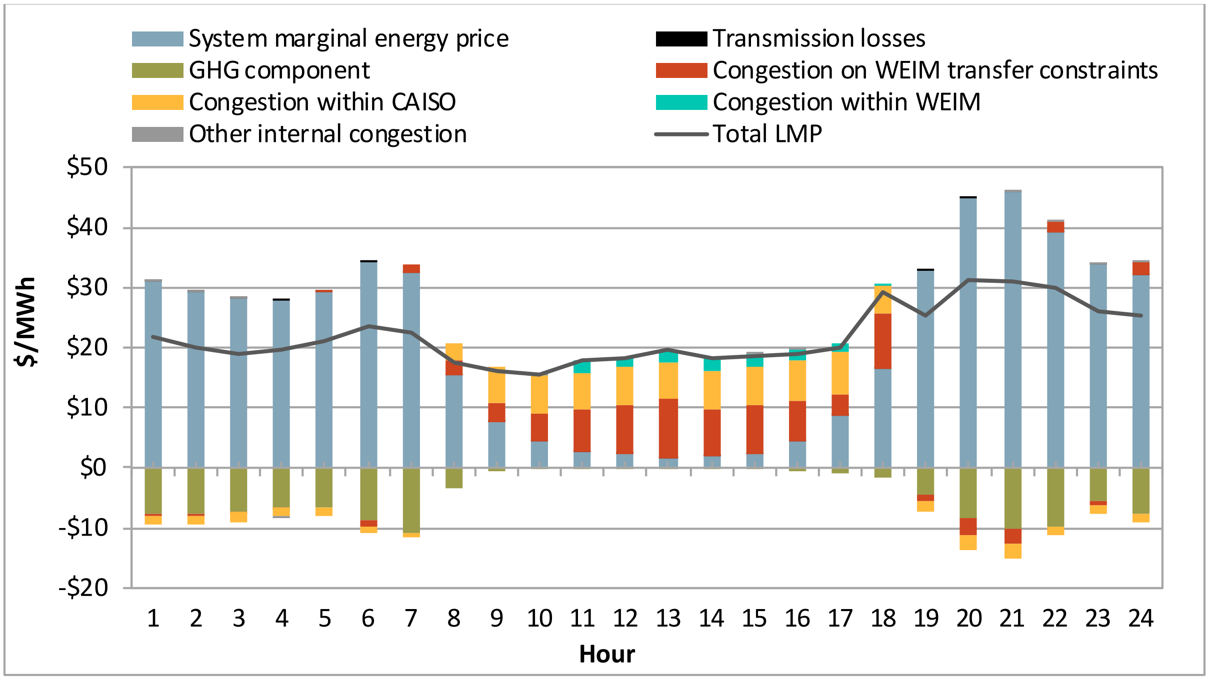


Appendix Figure A.76 Average hourly 5-minute market transfers

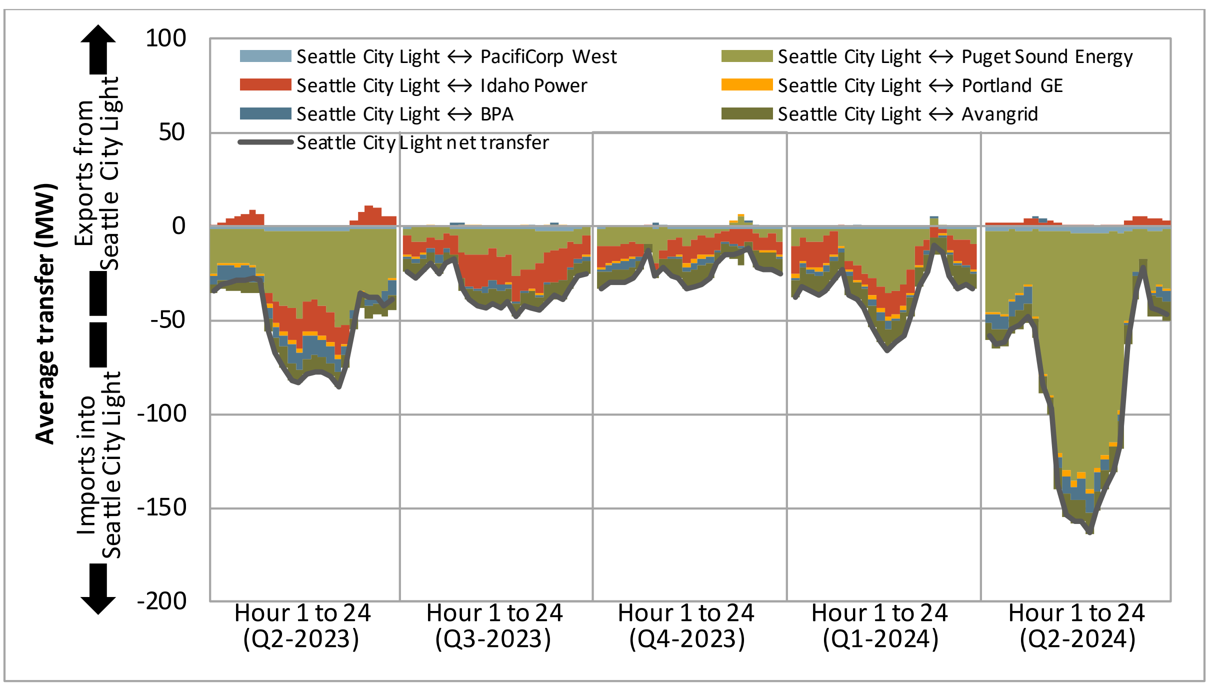


A.19 Seattle City Light

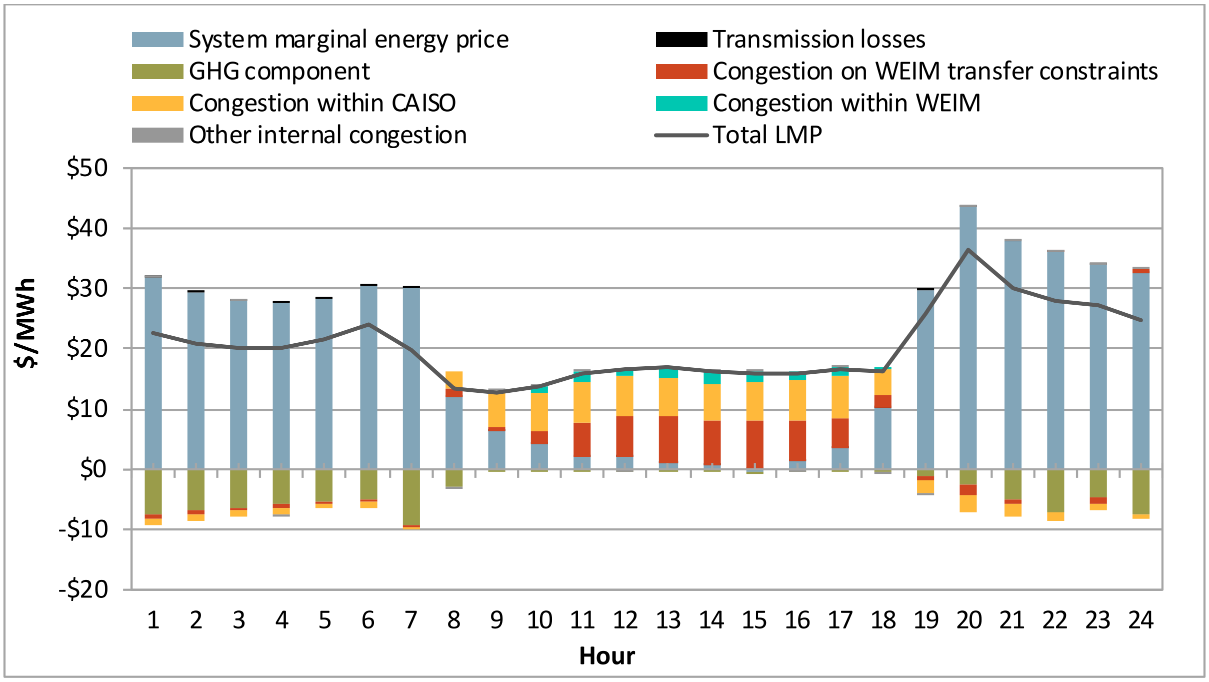
Appendix Figure A.77 Average hourly 15-minute price by component (Q2 2024)



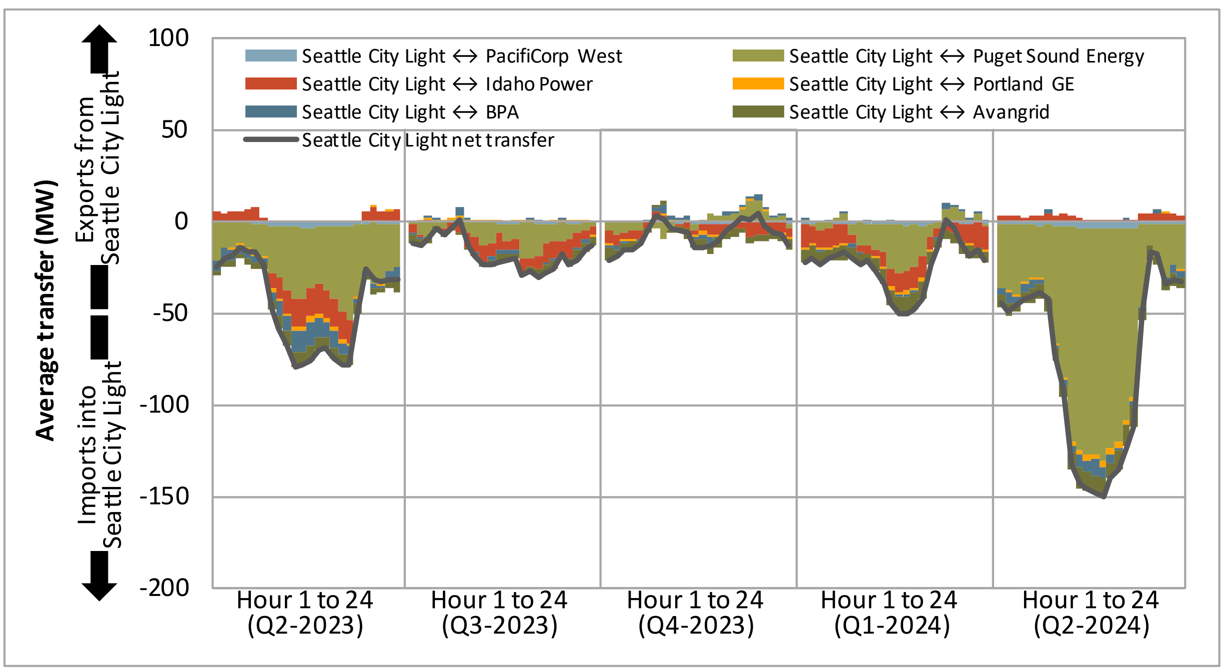
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q2 2024)

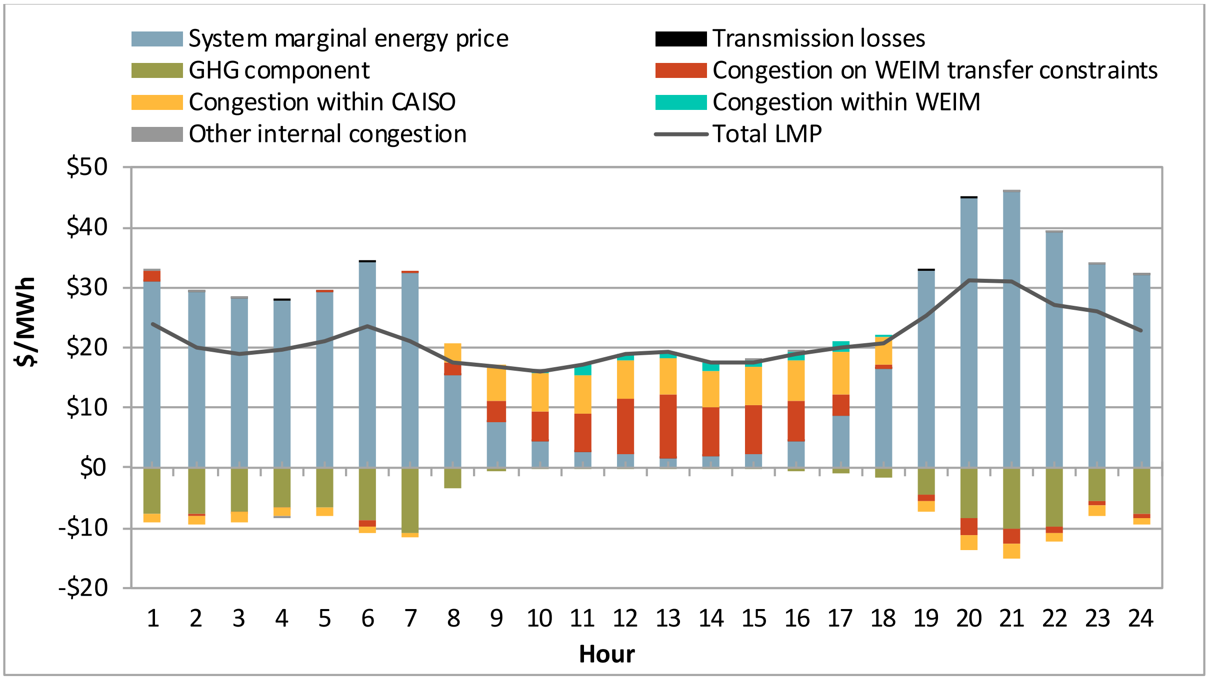


Appendix Figure A.80 Average hourly 5-minute market transfers

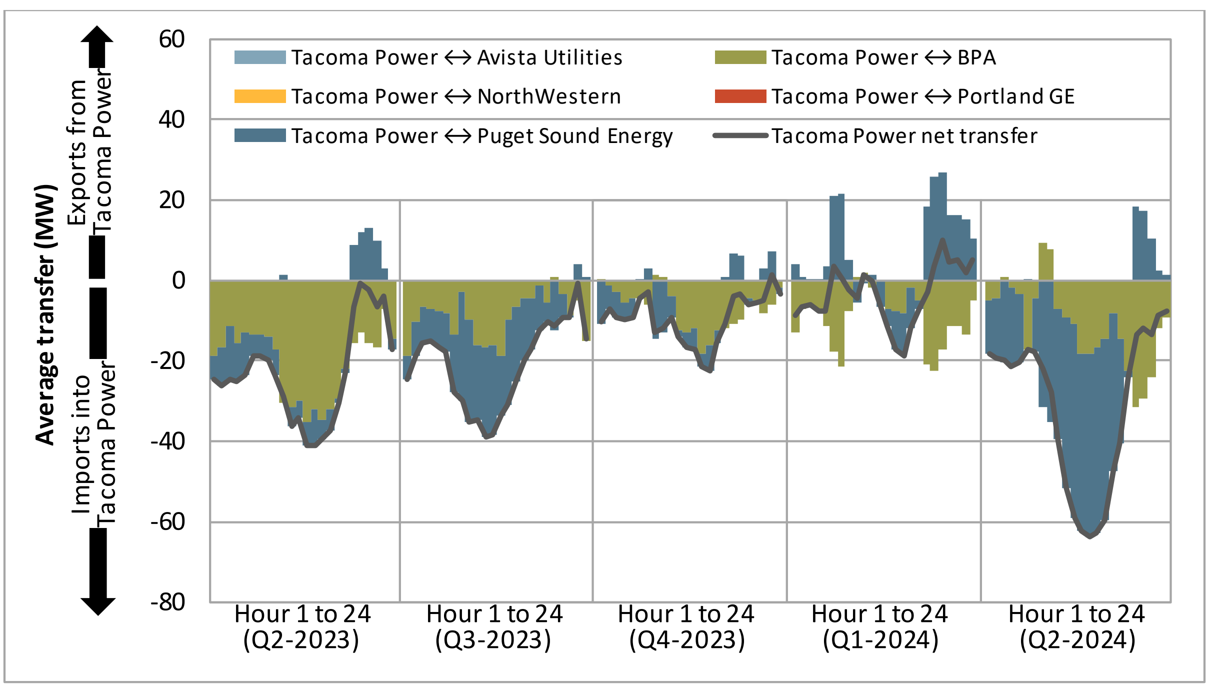


A.20 Tacoma Power

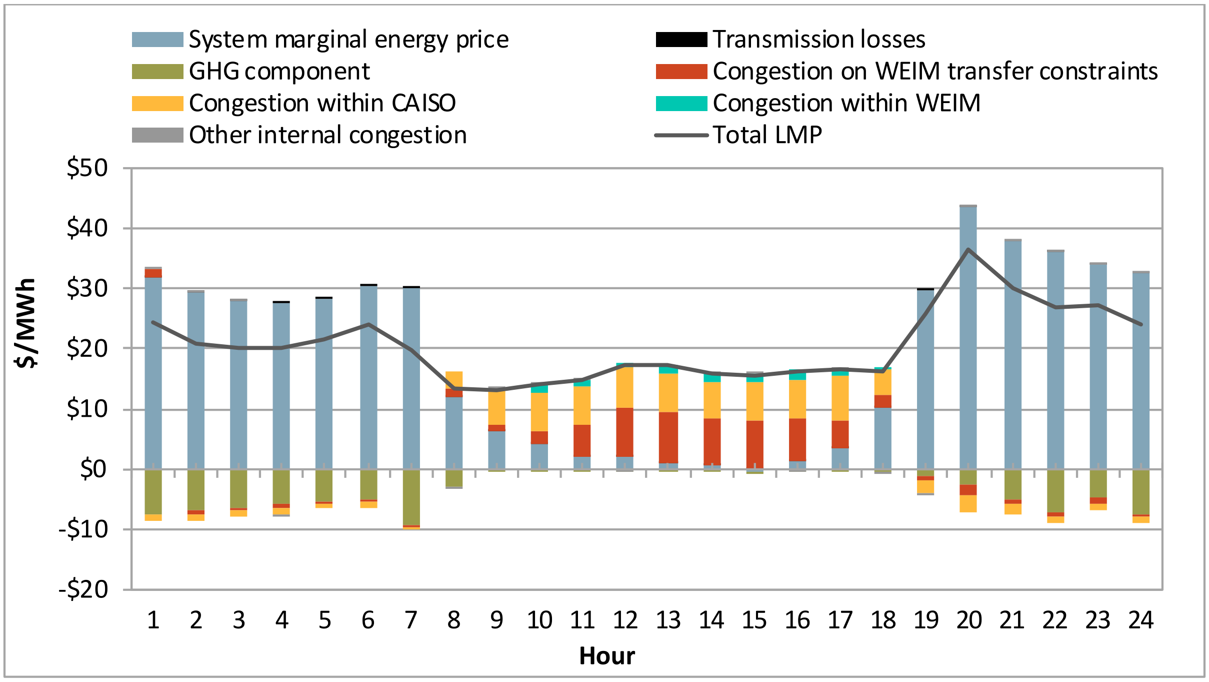
Appendix Figure A.81 Average hourly 15-minute price by component (Q2 2024)



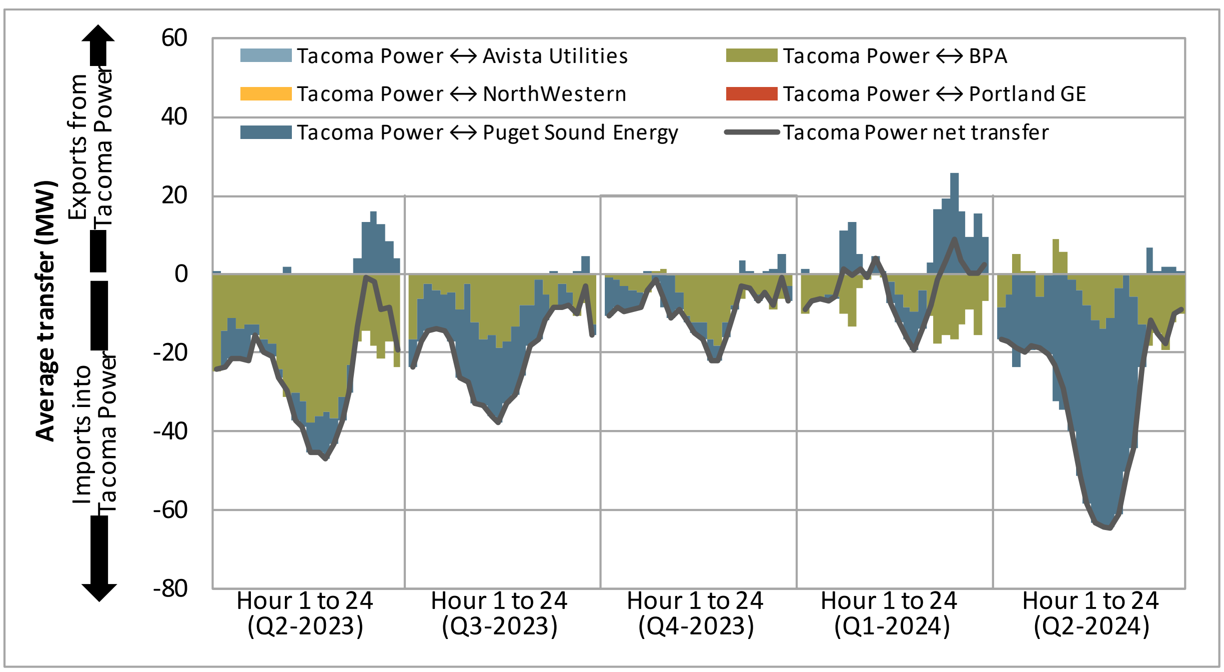
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q2 2024)

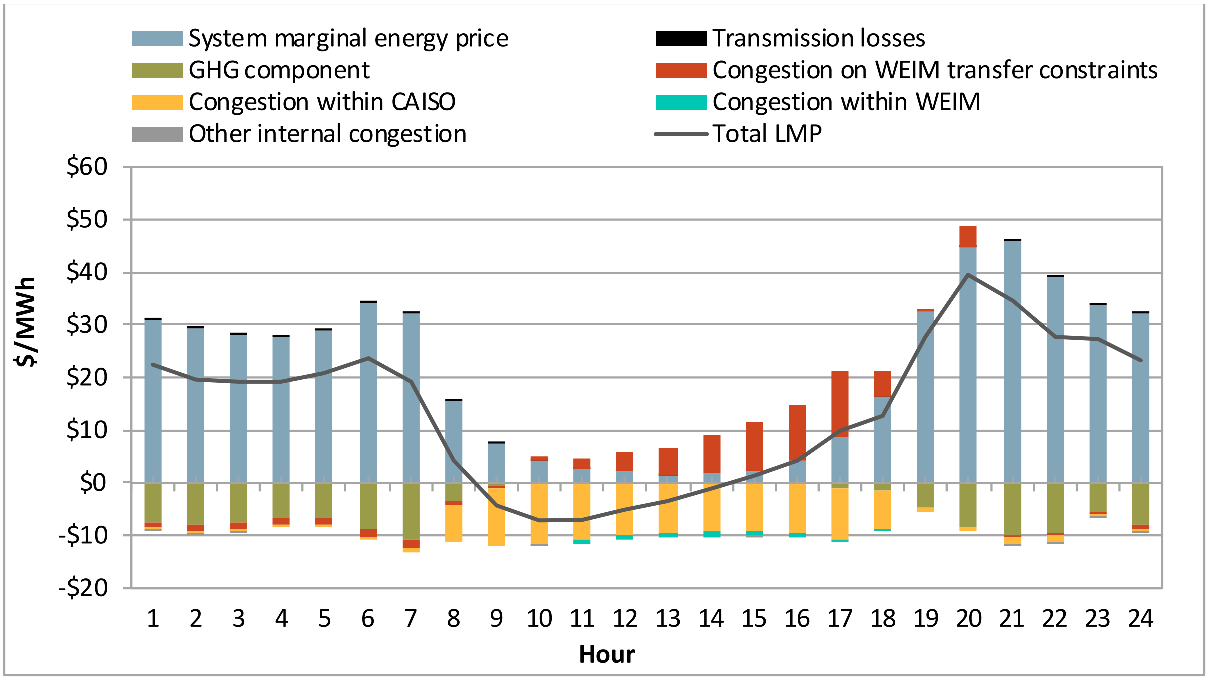


Appendix Figure A.84 Average hourly 5-minute market transfers

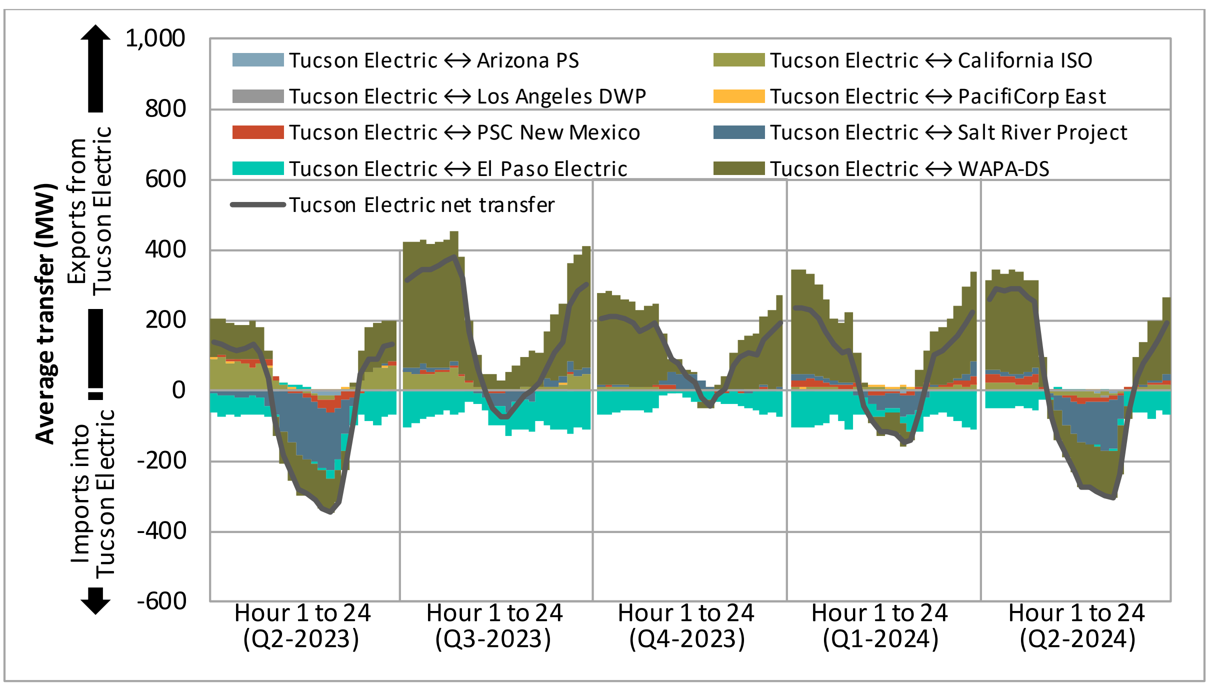


A.21 Tucson Electric Power

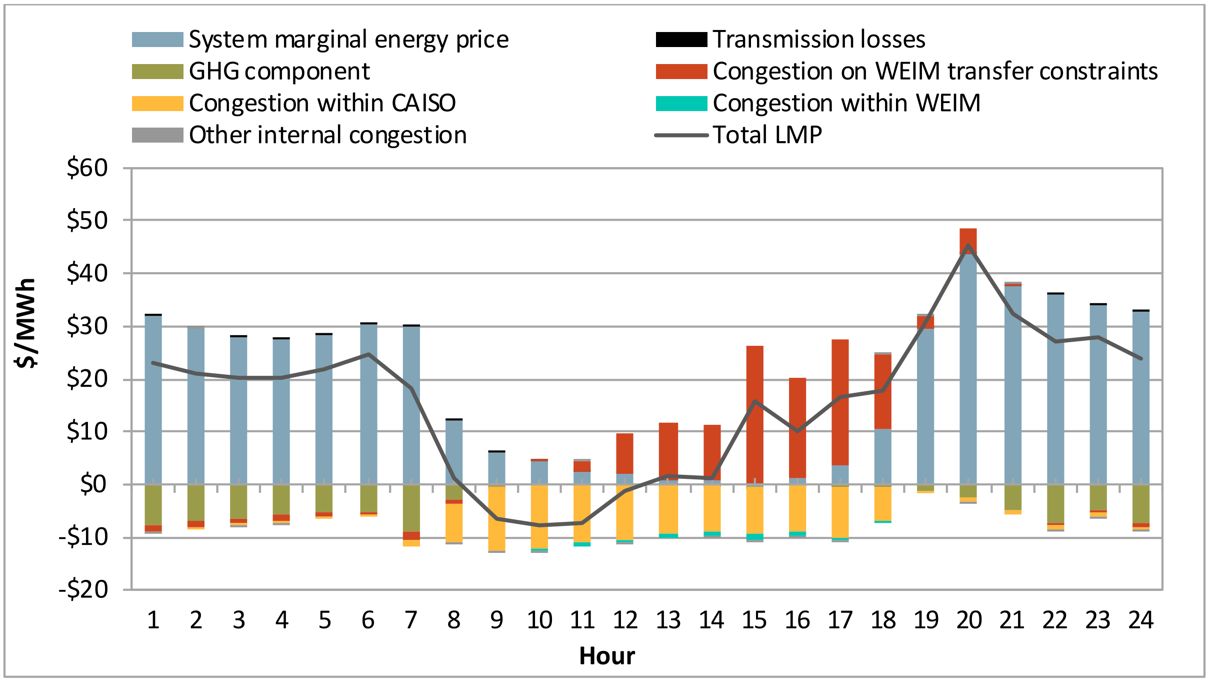
Appendix Figure A.85 Average hourly 15-minute price by component (Q2 2024)



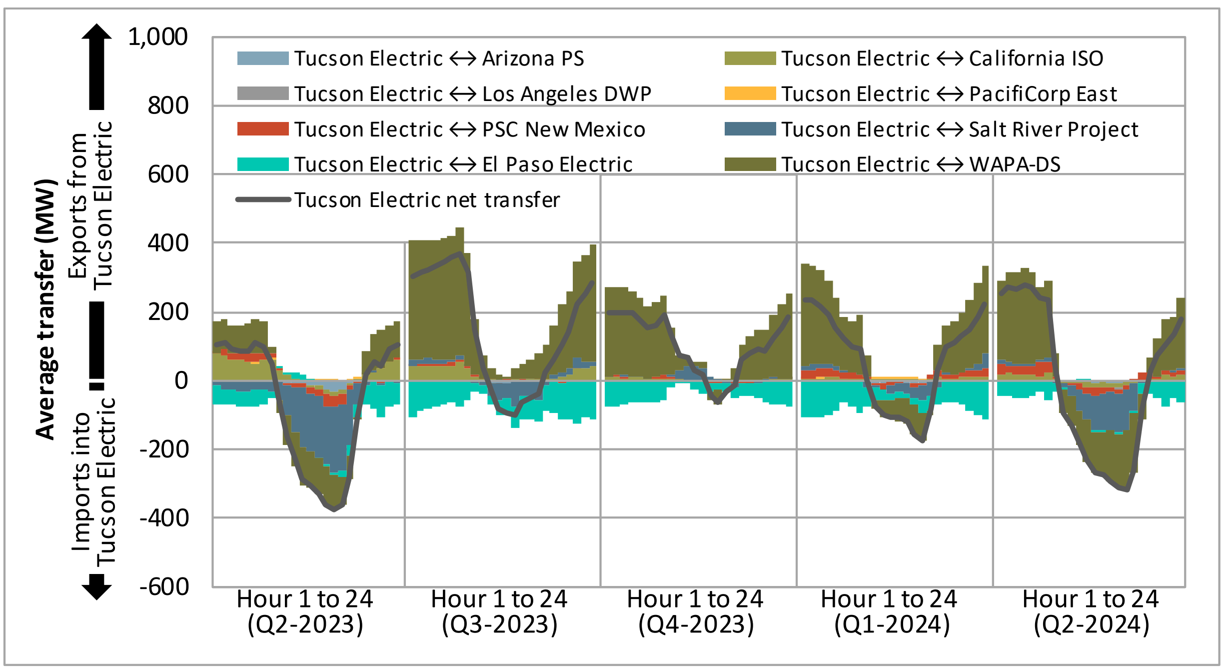
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q2 2024)

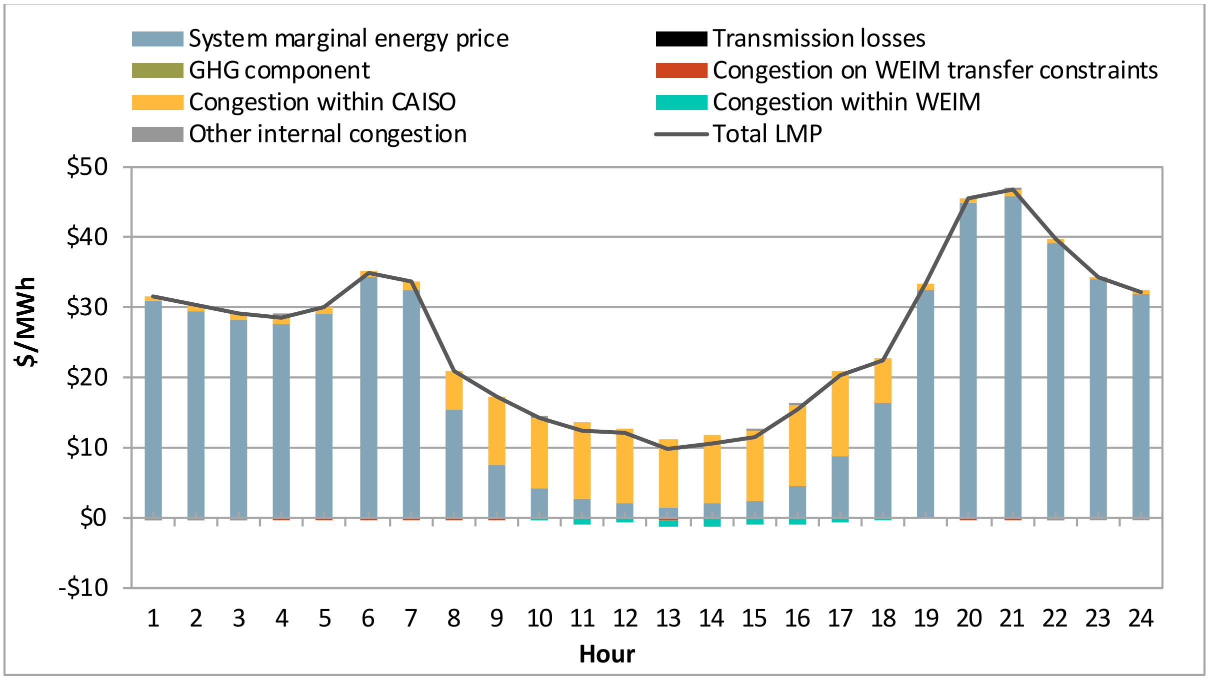


Appendix Figure A.88 Average hourly 5-minute market transfers

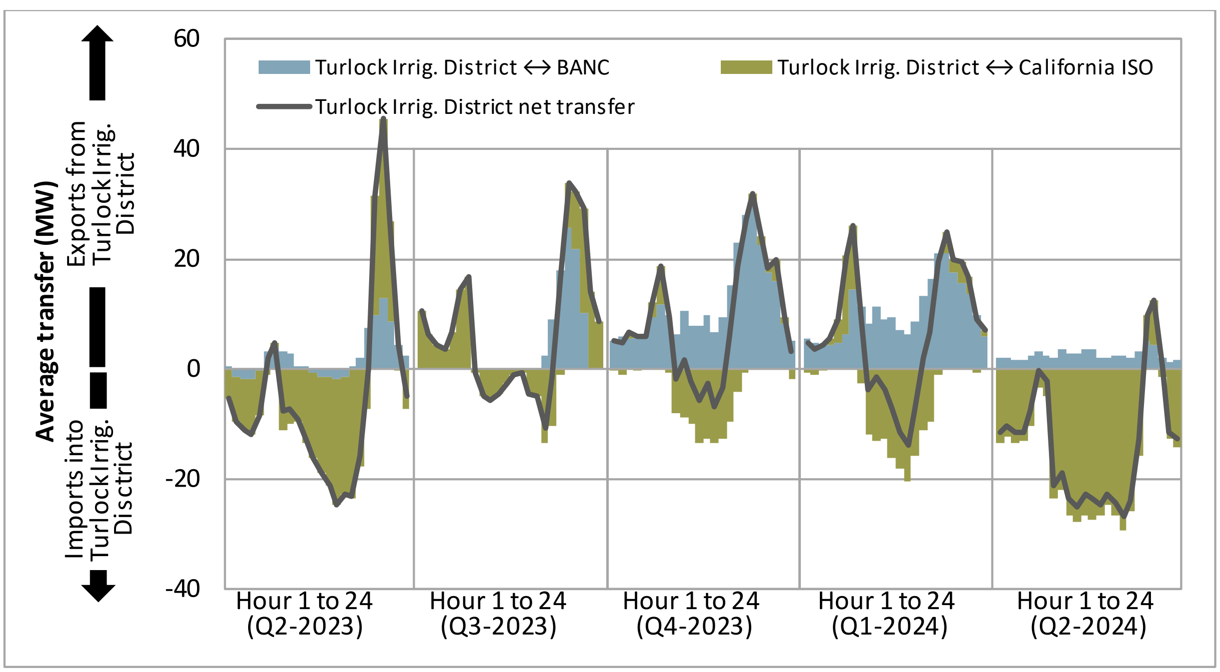


A.22 Turlock Irrigation District

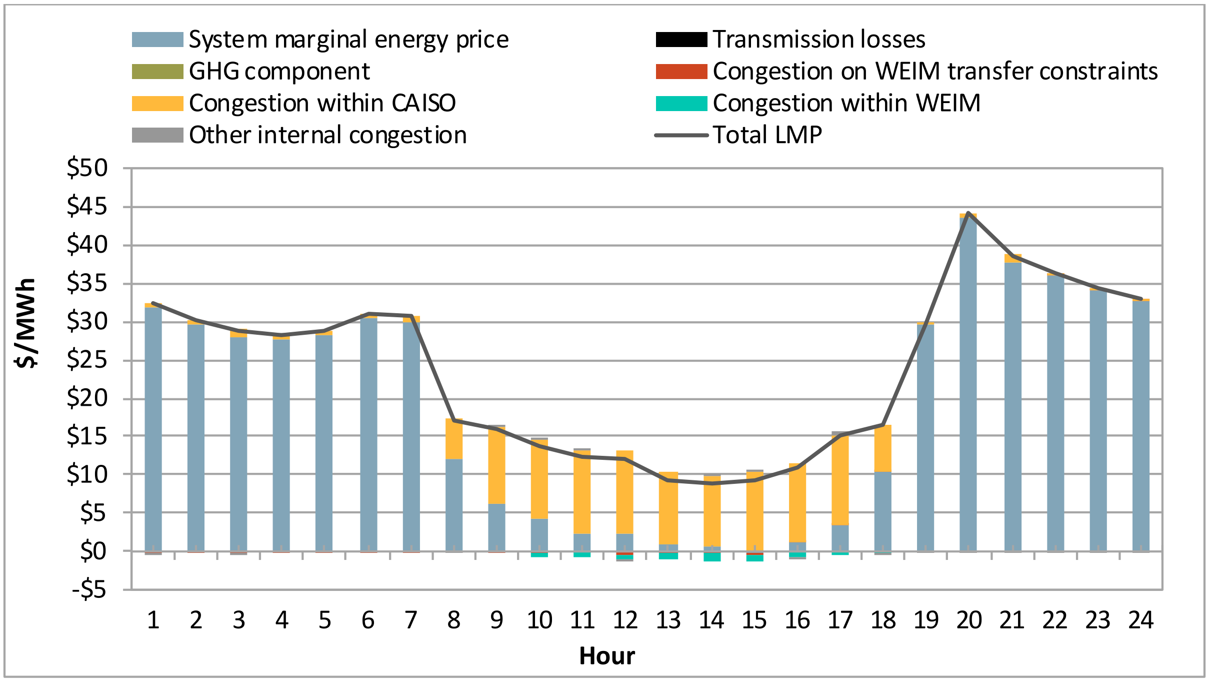
Appendix Figure A.89 Average hourly 15-minute price by component (Q2 2024)



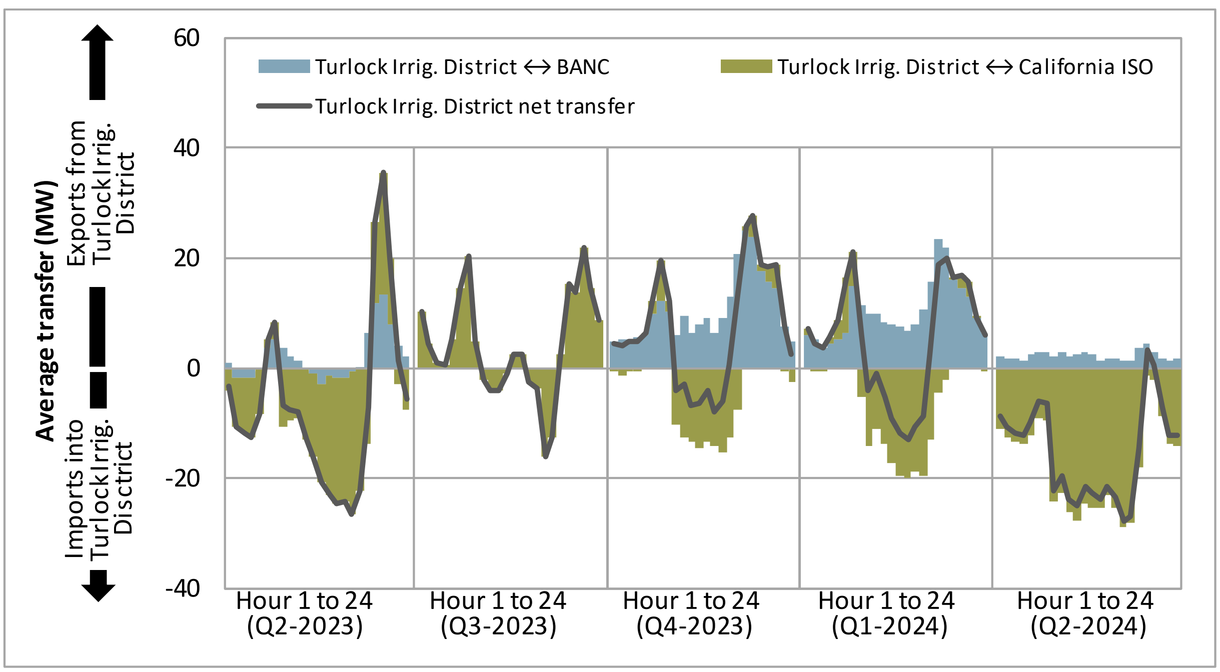
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q2 2024)

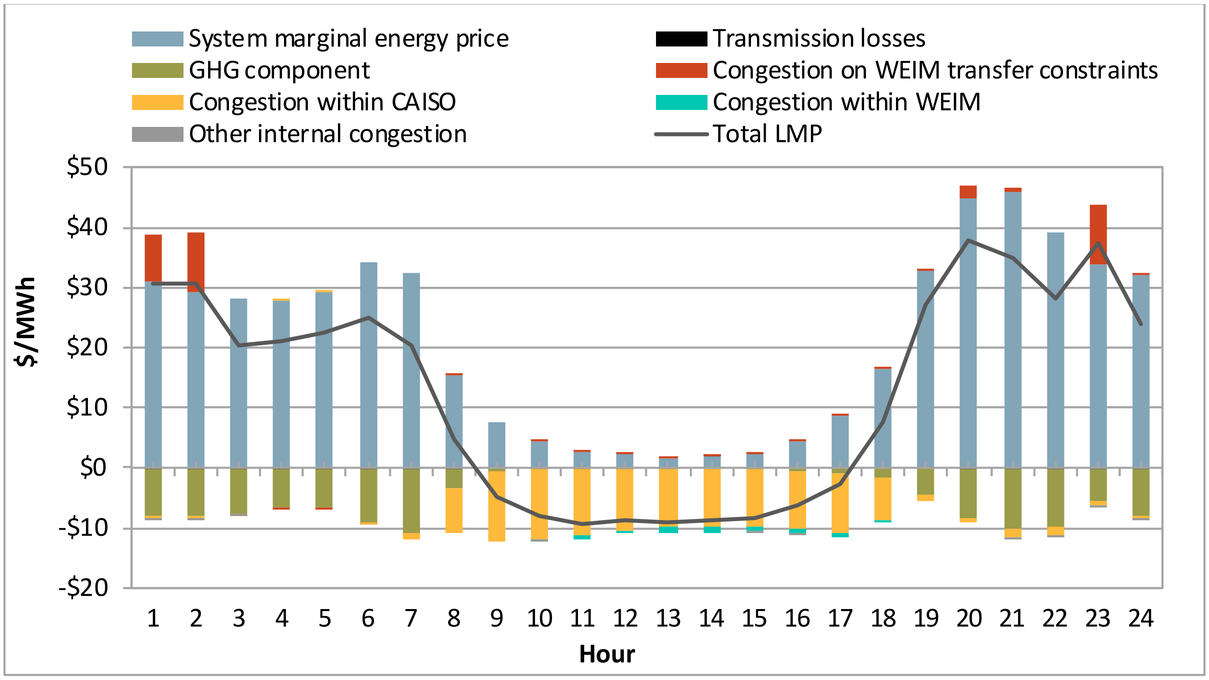


Appendix Figure A.92 Average hourly 5-minute market transfers

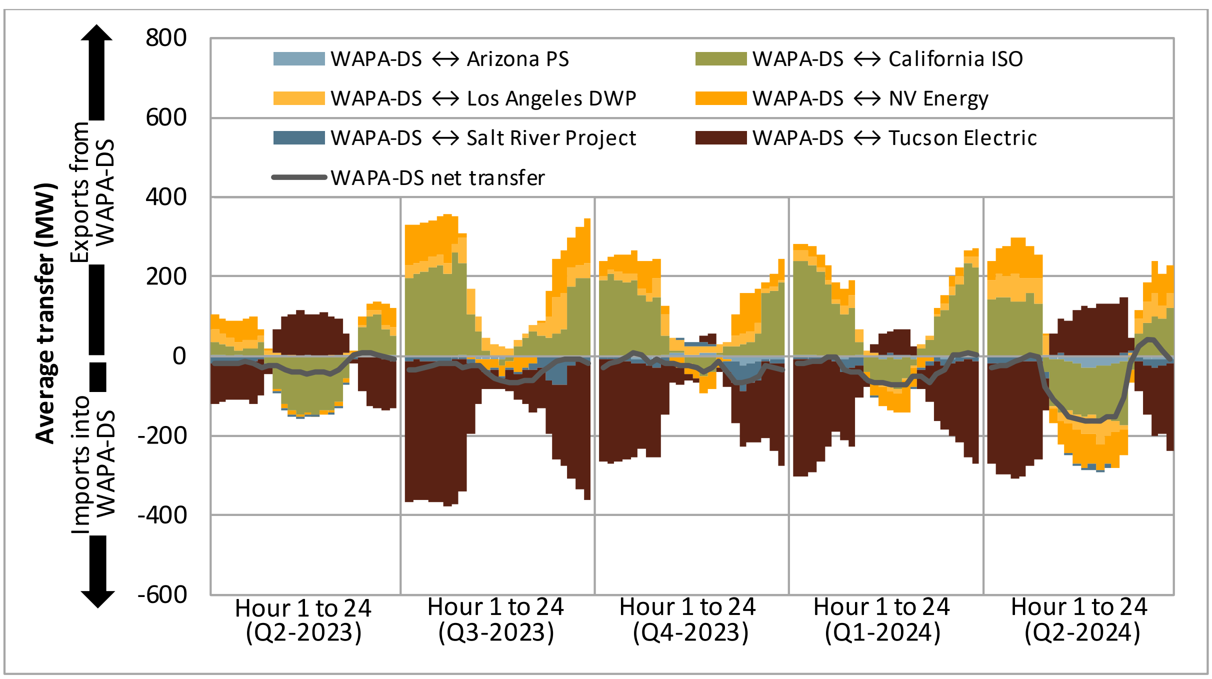


A.23 Western Area Power Administration Desert Southwest

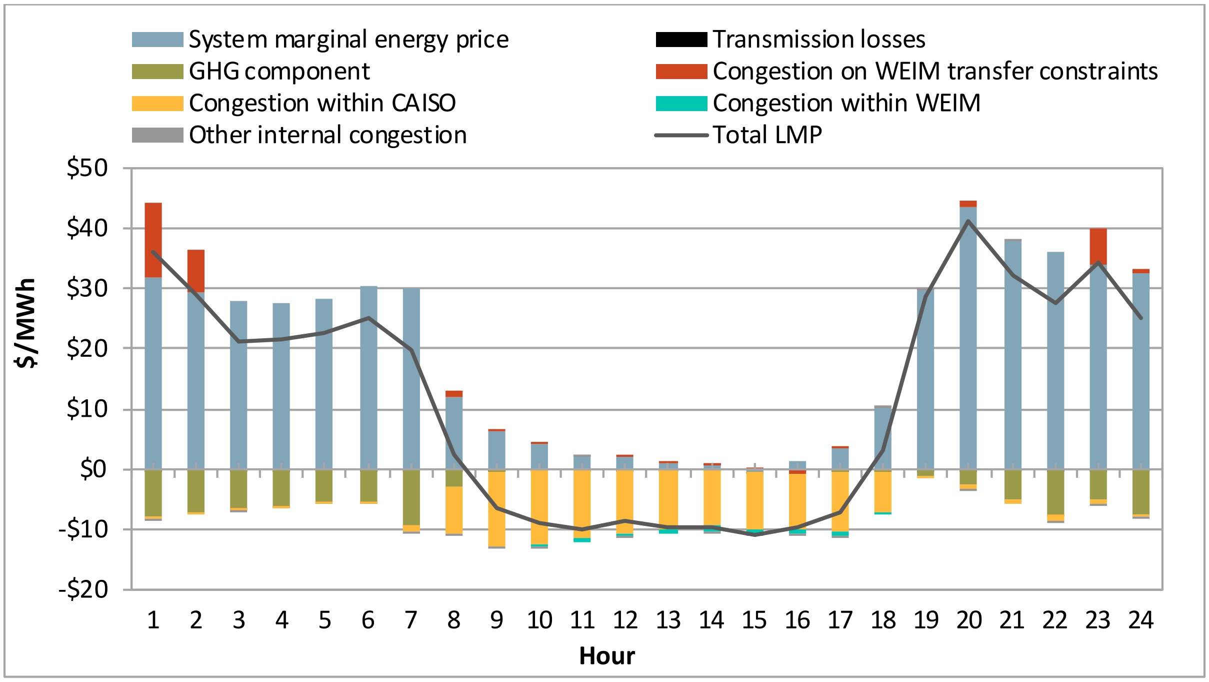
Appendix Figure A.93 Average hourly 15-minute price by component (Q2 2024)



Appendix Figure A.94 Average hourly 15-minute market transfers



Appendix Figure A.95 Average hourly 5-minute price by component (Q2 2024)



Appendix Figure A.96 Average hourly 5-minute market transfers