Q1 2025 Report on Market Issues and Performance

June 23, 2025

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California Independent System Operator

TABLE OF CONTENTS

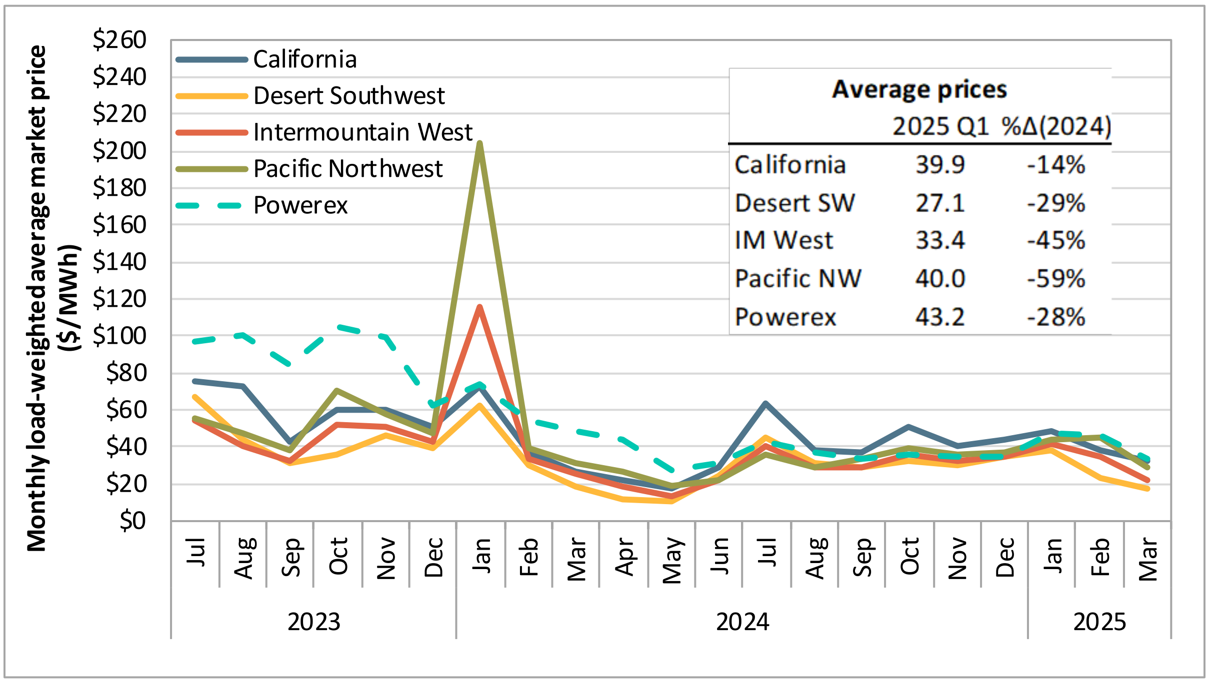
LIST OF FIGURES

LIST OF TABLES

Executive summary

This report covers market performance during the first quarter of 2025 (January–March). Prices decreased significantly compared to the same quarter of 2024 (Figure E. 1). Prices in the 15-minute market across the Western Energy Imbalance Market (WEIM) averaged about $37/MWh, down 39 percent. Prices in the 5-minute market were down 38 percent and day-ahead market prices were down 15 percent compared to Q1 2024. The decrease is largely due to the absence of extreme cold weather events in the Pacific Northwest and Intermountain West that occurred during the middle portion of January 2024.

Figure E. 1 Monthly load-weighted average 15-minute market energy prices by region



Other key highlights during this quarter include the following:

Supply and load conditions

- **Natural gas prices in the West increased at most major trading hubs but decreased at others.** Average first quarter prices at Henry Hub, El Paso Permian, SoCal Citygate and NW Opal Wyoming increased by 76 percent, 29 percent, 28 percent, and 1 percent, respectively, compared to the first quarter of 2024. Average prices at Northwest Sumas and PG&E Citygate decreased by 33 percent and 3 percent, respectively.
- **Average hourly generation from renewable resources in the WEIM footprint increased by about 4,910 MW** (13 percent) compared to the first quarter of 2024. Solar and wind generation increased 1,900 MW (33 percent) and 840 MW (11 percent), respectively, across the WEIM footprint.[1]

[1] California includes BANC, CISO, LADWP, and TIDC. Desert Southwest includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC. Intermountain West includes AVA, IPCO, NWMT, and PACE. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

Hydroelectric generation represented 88 percent of all renewable generation in the Pacific Northwest and increased by 2,310 MW (15 percent) compared to Q1 2024.

- **Average hourly battery discharge in the California and Desert Southwest regions increased** relative to the first quarter of 2024 by 520 MW (59 percent) and 390 MW (132 percent), respectively**.** Average net battery generation across the WEIM was lowest during hour-ending 13, at around negative 6,370 MW.
- **Average net imports into the Pacific Northwest region, excluding dynamic WEIM transfers, decreased by around 630 MW**. Coal generation in the Intermountain West region increased by 710 MW (23 percent) while natural gas generation decreased by 220 MW (7 percent).
- **Overall net interchange into the Intermountain West and the Pacific Northwest regions decreased by 1,190 MW and 820 MW,** respectively, compared to the first quarter of 2024.[2] The Intermountain West region was a net exporter in the first quarter of 2025. The California and Desert Southwest regions saw increases to their overall net interchange by 880 MW and 810 MW, respectively.
- **WEIM transfers averaged 4,520 MW, up about 5 percent from the first quarter of 2024.** During morning and evening hours, transfers out of the Intermountain West increased significantly compared to any quarter over the last year, making it the most significant net exporting region during non-solar hours. During mid-day solar hours, the majority of regional transfers continue to come from the CAISO area.
- **Transfer limits from California into the Desert Southwest region decreased significantly during the quarter, by roughly 10,000 MW**. This was because of reduced transfer limits for dynamic WEIM transfers from the California ISO to Arizona Public Service on the North Gila and Willow Beach interties. However, there was little price separation or congestion between these regions because of sufficient transfer capability elsewhere in the system.
- **Generation outages decreased in some WEIM regions and increased in others compared to the first quarter of 2024.** The Pacific Northwest region averaged about 2,400 MW of total generation outage, a 9 percent decrease from the first quarter of 2024. The Intermountain West region averaged about 2,300 MW of total generation outages, a 14 percent decrease. The California (non-CAISO) region averaged 4,700 MW of total generation outages, a 10 percent decrease. The Desert Southwest region averaged about 11,400 MW of total generation outages, a 10 percent increase from the first quarter of 2024. The CAISO balancing area averaged about 19,000 MW of outages in the first quarter of 2025, a 15 percent increase from the first quarter of 2024.
- **Load across the WEIM averaged 75.7 GW, an increase of about 2 percent compared to the same quarter of 2024.** The Pacific Northwest region had the largest load increase at about 4 percent. Peak 5-minute market load for the quarter was 99.7 GW on February 12, 2025, hour-ending 8, interval 5.

Prices and congestion

- **Average real-time prices were highest in the Pacific Northwest and Northern California and lowest in the Desert Southwest.**
- **Transmission congestion impact on regional prices continued to be different during mid-day solar hours than during evening hours.** During solar hours, congestion contributed to higher prices in the Pacific Northwest and Northern California relative to the Desert Southwest and Southern California.

[2] Overall net interchange includes base imports and exports from both WEIM and non-WEIM balancing areas, as well as dynamic and static WEIM transfers optimized by the real-time market software.

During evening hours, prices in California balancing areas were higher than the rest of the WEIM due mainly to California greenhouse gas pricing.

- **Prices in the day-ahead market averaged $41/MWh, similar to average 15-minute market prices ($39/MWh) and 5-minute market prices ($40/MWh)** for balancing areas participating in the day-ahead market. Day-ahead market prices were down about 15 percent compared to Q1 2024.
- **Day-ahead peak prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about $35/MWh over the quarter**, almost 49 percent higher than ISO 15-minute market prices in the Desert Southwest. Day-ahead ICE prices for the Mid-Columbia trading hub averaged about $51/MWh, which was roughly 24 percent higher than ISO 15-minute market prices in the Pacific Northwest. In the ISO's day-ahead market, prices were also higher in the north than in the south, with Pacific Gas & Electric prices averaging around $41/MWh and Southern California Edison prices averaging around $30/MWh.
- **Most balancing areas in the Pacific Northwest region, plus Avista and NorthWestern, had elevated prices due to transfer congestion into their balancing area or region in about 13 percent of 5-minute market intervals.** This same group of balancing areas had lower prices due to transfer congestion out of their balancing area or region in about 9 percent of 5-minute market intervals.
- **Overall day-ahead market congestion rents on internal and intertie constraints were $231 million,** down 11 percent from the first quarter of 2024**.** This was driven by intertie congestion rents decreasing to $9 million in Q1 2025 from $133 million in Q1 2024.
- **Payouts to congestion revenue rights (CRRs) sold in the California ISO auction exceeded auction revenues received for these rights by about $19.3 million** in the first quarter of 2025. 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.

Resource sufficiency evaluation

- **The frequency of resource sufficiency evaluation failures was very low.** All balancing areas failed the capacity and flexibility tests in less than one percent of intervals over the quarter.
- **Seven balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** All seven 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.[3]

[3] 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

Uplift costs and credits

- **Real-time imbalance offsets for balancing areas participating only in the WEIM real-time markets were a $13 million credit** to WEIM entities, compared to a $78 million credit in the first quarter of 2024. The congestion portion of this offset, which is largely congestion rent from WEIM transfer constraints, was a $21 million credit. Powerex received roughly $10 million in congestion credits, while Public Service Company of New Mexico received roughly $10 million in congestion charges.
- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $41 million in uplift in the first quarter of 2025.** This was a decrease from $49 million in the same quarter of 2024. During the first quarter of 2025, real-time *congestion* imbalance offset costs made up $34 million of these costs.
- **Bid cost recovery payments for units in balancing areas participating in both the day-ahead and real-time markets totaled about $45 million, up about 10 percent** from the $40 million in bid cost recovery in the first quarter of 2024.
- **Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM**) totaled about $3 million, down about 38 percent from Q1 2024.

Operator adjustments and manual dispatch

- **Operator adjustments to load forecasts in most balancing areas were higher in the 5-minute market than in the 15-minute market.** Notable exceptions included the CAISO balancing area and Bonneville Power Administration. CAISO balancing area load adjustments in the 15-minute market during evening peak net load ramping hours were lower in the first quarter of 2025 compared to the first quarter of 2024.
- **Operator adjustments to the residual unit commitment process (RUC) procurement target decreased by about 92 percent in the first quarter of 2025 compared to the same quarter of 2024.** This was in large part because of significant changes in the methodology for determining the adjustments on May 7, 2024.
- **Manual dispatch energy increased in the Desert Southwest and California (non-CAISO) regions** compared to the first quarter of 2024 by 17 percent and 95 percent, respectively. Total manual dispatch energy in the Intermountain West and Pacific Northwest regions decreased by 30 percent and 29 percent, respectively.

Uncertainty in residual unit commitment, resource sufficiency evaluation, and flexible ramping product

- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were on average lower than requirements would have been using the previous histogram method.** For flexible ramping products, the coverage rate was 95 percent or higher, but the regression coefficients were statistically different from zero in only 36 percent of intervals. The coverage rate for the resource sufficiency evaluation varied between 84 percent and 91 percent across balancing areas, and only 38 percent of regression coefficients were statistically significant.
- **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 that are 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.

- **The ISO did not set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on any days in the quarter.** The 75th percentile target was applied on 6 days. The 50th percentile target was applied on 4 days. During most of the quarter, no adjustment was applied (89 percent of days). The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address this same uncertainty, but the requirement will be set to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in the residual unit commitment (RUC) indicates that the imbalance reserve product demand curve may be much too high during most hours.

Ancillary services, available balancing capacity, and flexible ramping product

- **Upward flexible ramping product prices at the system and balancing area level for the 15-minute market were greater than zero in one or more balancing areas that passed the resource sufficiency evaluation tests in less than 1 percent of intervals in the fourth quarter.** Battery and hydro resources made up 56 percent and 29 percent of upward flexible capacity, respectively. Wind and solar combined to provide 42 percent of downward flexible capacity, and batteries provided 31 percent of downward flexible capacity. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 60 percent of each. Balancing areas in the Pacific Northwest made up 25 percent of upward flexible capacity and 15 percent of downward flexible capacity.
- **DMM recommends the ISO settle base scheduled bilateral hourly-block imports and exports between WEIM areas the same way the ISO settles base scheduled bilateral hourly block imports and exports with non-WEIM areas.** DMM became aware that the ISO settles import base schedules from a non-WEIM area or from the CAISO balancing area as flexible ramping product forecasted movement. However, the ISO does not settle import base schedules from a WEIM area as flexible ramping product forecasted movement.
- **Ancillary service payments totaled $36.2 million in the first quarter of 2025, around $15.5 million (or 75 percent) more than the same quarter of the previous year.** Regulation down costs accounted for about $13 million of this increase. The major cause of this increase was likely large battery outages in Northern California in January. The total proportion of regulation down provided by batteries decreased from about 90 percent in the first quarter of 2024 to about 80 percent in the first quarter of 2025.
- **Similar to previous quarters, available balancing capacity was dispatched for generation shortfalls in less than 1 percent of intervals in every WEIM balancing area.**

California ISO balancing area transmission and resource adequacy capacity

- **No reservations were made for CAISO balancing area high priority wheeling-through rights for the first quarter of 2025.**
- **Real-time resource adequacy bids were sufficient to cover the market requirements for energy and upward ancillary services in the CAISO balancing area in all hours of the first quarter.**
- **Resource adequacy import bid quantity into the CAISO area increased 256 percent** compared to the first quarter of 2024.

1 Supply conditions

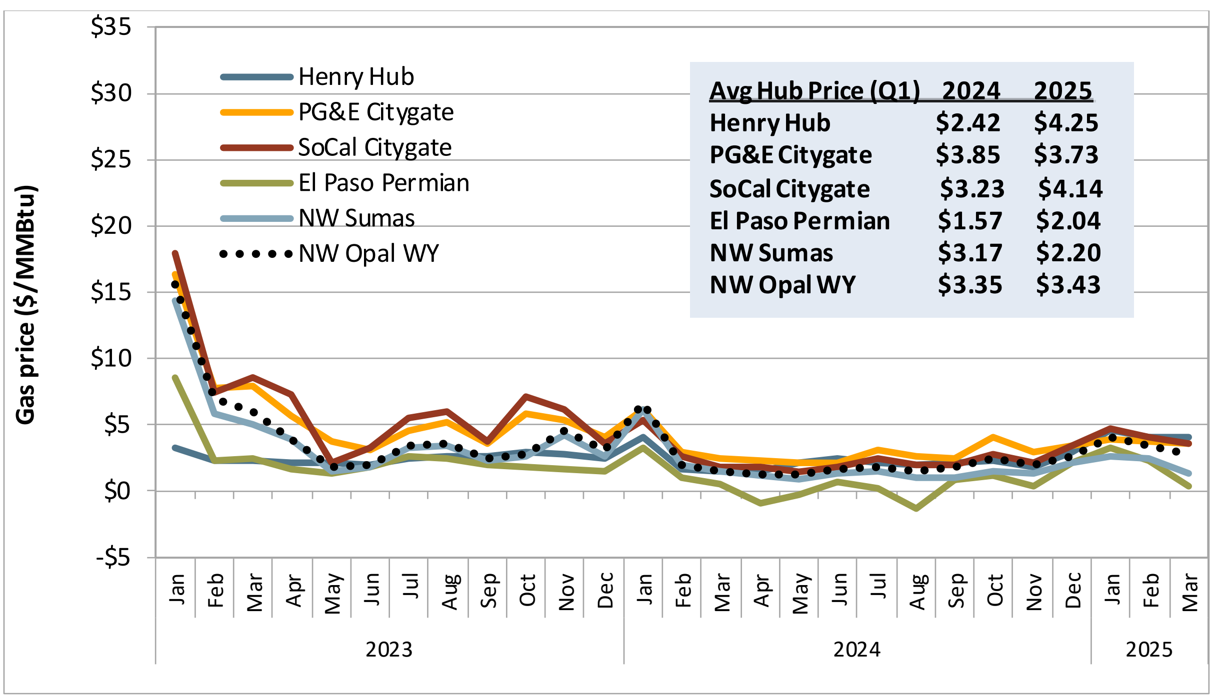
1.1 Natural gas prices

Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in Western Energy Imbalance Market (WEIM) balancing areas and other regional markets. 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.

Average natural gas prices increased at most major Western trading hubs and decreased at others in the first quarter of 2025 compared to the same quarter of 2024. Average first quarter prices at Henry Hub, El Paso Permian, SoCal Citygate and NW Opal Wyoming increased by 76 percent, 29 percent, 28 percent, and 1 percent, respectively, compared to the first quarter of 2024. Average prices at Northwest Sumas and PG&E Citygate decreased by 33 percent and 3 percent, respectively.

Compared to the fourth quarter of 2024, natural gas prices at PG&E Citygate and SoCal Citygate increased by 7 percent and 46 percent, respectively. The Henry Hub, El Paso Permian, Northwest Opal Wyoming, and Northwest Sumas gas prices increased by about 79 percent, 63 percent, 44 percent, and 28 percent, respectively, compared to last quarter.

Figure 1.1 Monthly average natural gas prices



1.2 Renewable generation

In the first quarter, the average hourly generation from renewable resources in the WEIM footprint increased by about 4,910 MW (13 percent) compared to the same quarter of 2024.[4] Solar and wind generation increased 1,900 MW (33 percent) and 840 MW (11 percent), respectively, across the WEIM footprint. Solar generation increased in every region from the same quarter of 2024.[5] 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.

Figure 1.2 to Figure 1.5 show the average monthly renewable generation by fuel type.[6]

- Generation from solar resources made up 40 percent of all renewable output in the California region and increased by 860 MW (22 percent) compared to the first quarter of 2024.
- Solar generation represented 47 percent of the renewable fuel mix in the Desert Southwest region and increased by 830 MW (67 percent) from the first quarter of 2024.
- Overall, renewable generation in the Intermountain West region increased by 960 MW (22 percent) relative to the first quarter of 2024, with the largest increases coming from wind (700 MW) and solar (170 MW), respectively.
- In the first quarter of 2025, hydroelectric generation represented 88 percent of all renewable generation in the Pacific Northwest and increased by 2,310 MW (15 percent) from the same quarter of the previous year. The Pacific Northwest also saw a 110 MW (5 percent) decrease in wind generation.
- Average hourly generation from biogas-biomass resources decreased 80 MW (9 percent) across the overall WEIM footprint compared to the first quarter of 2024. This decrease largely comes from the California region. Geothermal generation across the WEIM decreased less than 1 percent.

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4 Figures and data provided in this section are preliminary and may be subject to change.

5 California includes BANC, CISO, LADWP, and TIDC. Desert Southwest includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC. Intermountain West includes AVA, IPCO, NWMT, and PACE. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

6 Hydroelectric generation greater than 30 MW is included.

Figure 1.2 California - Average monthly renewable generation

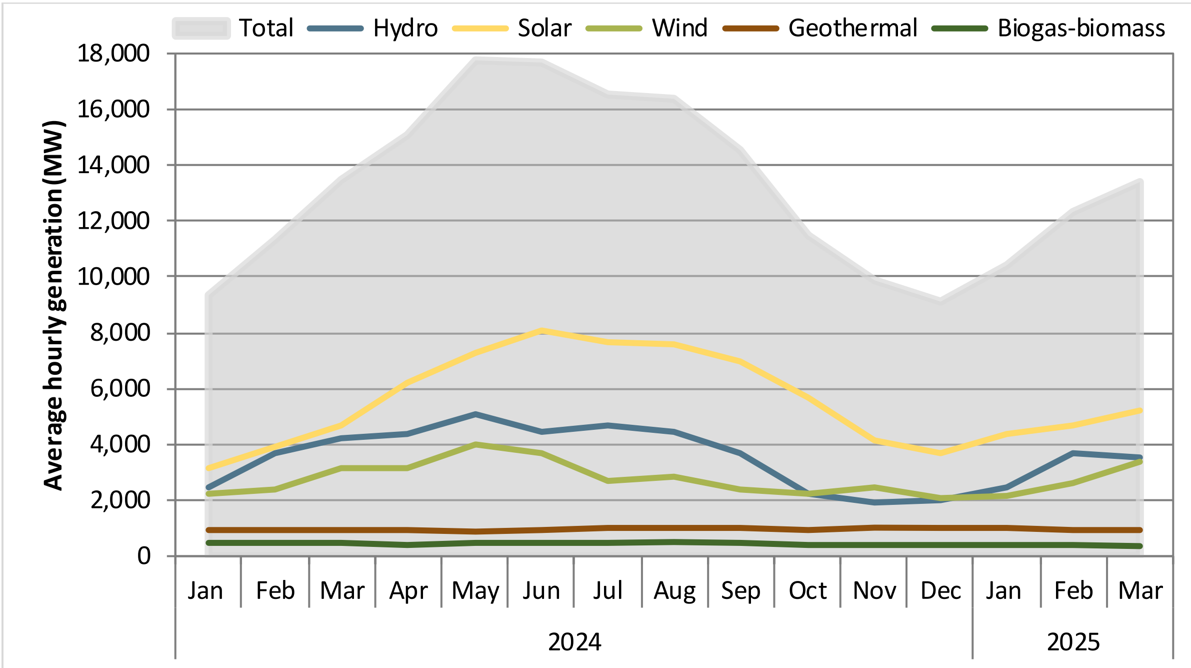


Figure 1.3 Desert Southwest - Average monthly renewable generation

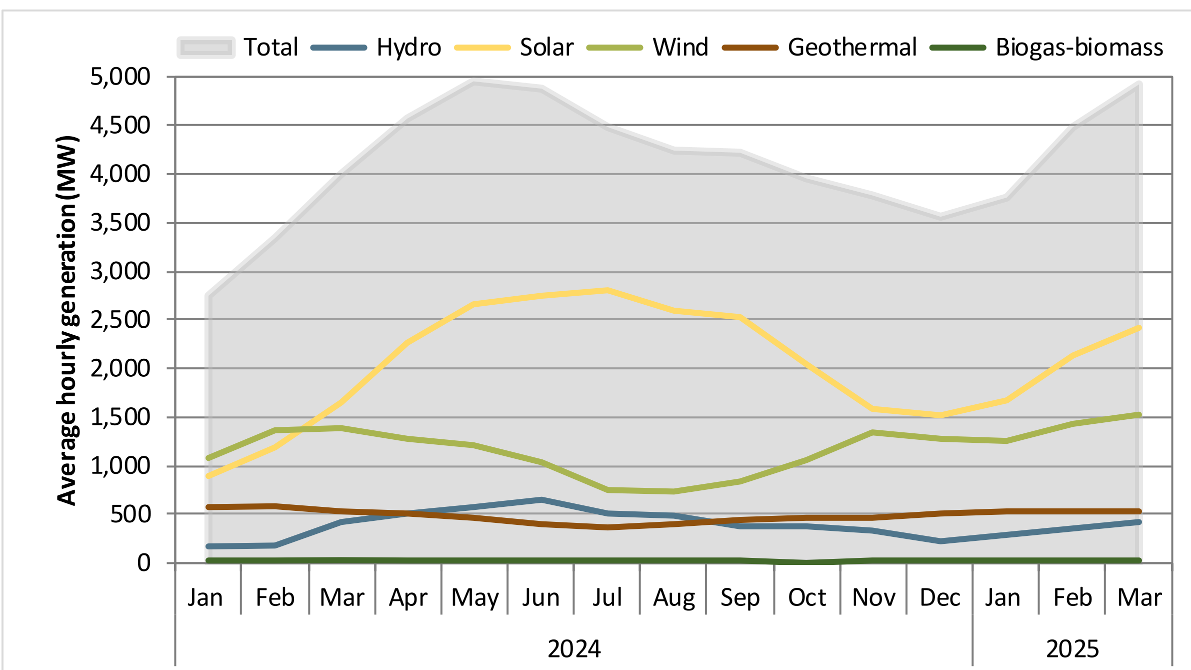


Figure 1.4 Intermountain West - Average monthly renewable generation

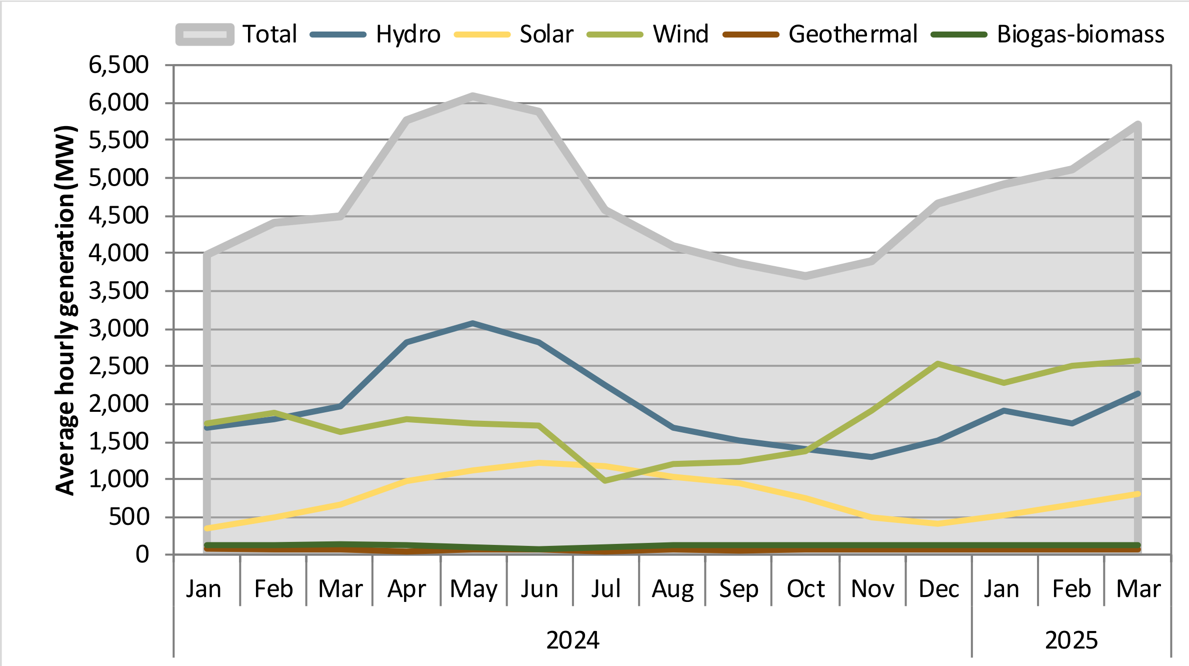
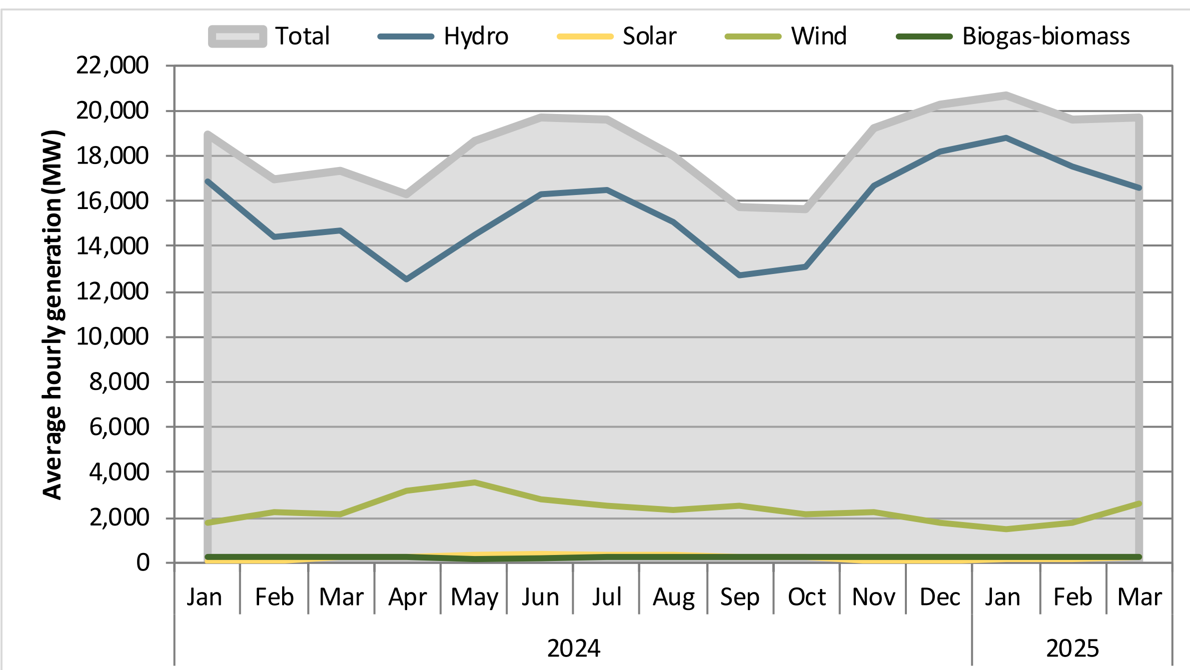


Figure 1.5 Pacific Northwest - Average monthly renewable generation



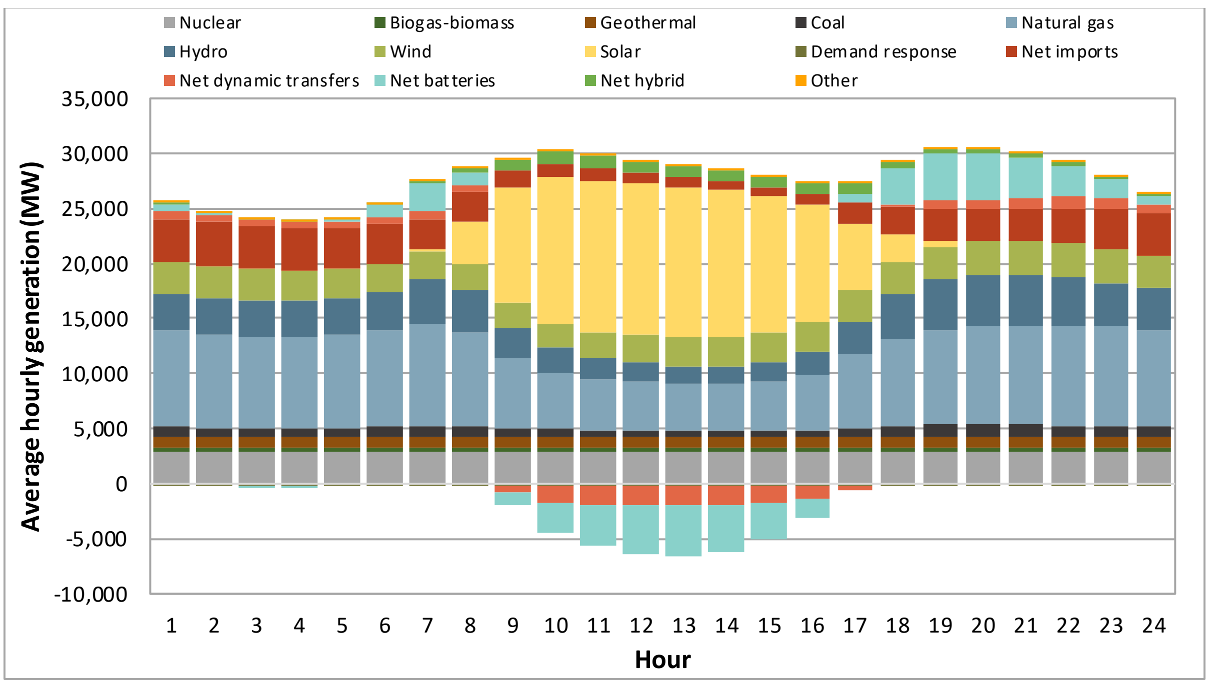
1.3 Generation by fuel type

Figure 1.6 to Figure 1.9 show the average hourly generation by fuel type during the first quarter of 2025 for each region in the WEIM. Total hourly average generation peaks at hour-ending 19 in the California and Desert Southwest regions. The Intermountain West and Pacific Northwest regions peak in the morning during hour-ending 8 and 9, respectively.

Average hourly battery discharge in the California and Desert Southwest regions increased relative to the first quarter of 2024 by 520 MW (59 percent) and 390 MW (132 percent), respectively.[7] Coal generation in the Intermountain West region increased by 710 MW (23 percent) while natural gas generation decreased by 220 MW (7 percent). Average hourly net imports into the Pacific Northwest region, excluding dynamic WEIM transfers, decreased by around 630 MW.[8]

As shown in Figure 1.6 and Figure 1.7, there is significant load from batteries charging in California and the Desert Southwest during mid-day hours (represented by the aqua bars below the zero-axis). Average net battery generation across the WEIM for the first quarter of 2025 was lowest during hour-ending 13, at around negative 6,370 MW.

Figure 1.6 California - Average hourly generation by fuel type (Q1 2025)



7 This statistic refers to battery discharge only, while Figures 1.6 to 1.13 display *net* battery generation.

8 *Net imports* includes transfers scheduled ahead of the real-time market and therefore, not optimized in the market. This includes both schedules on interties between WEIM and non-WEIM balancing areas as well as bilateral base WEIM transfers.

Figure 1.7 Desert Southwest - Average hourly generation by fuel type (Q1 2025)

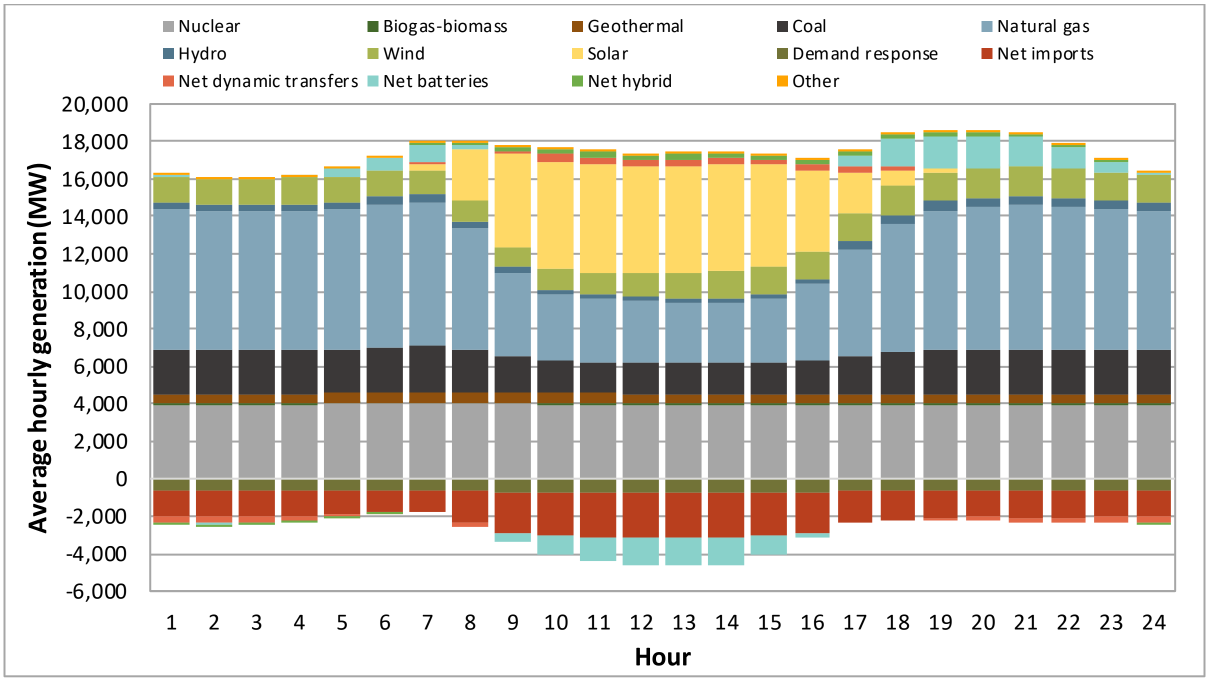


Figure 1.8 Intermountain West - Average hourly generation by fuel type (Q1 2025)

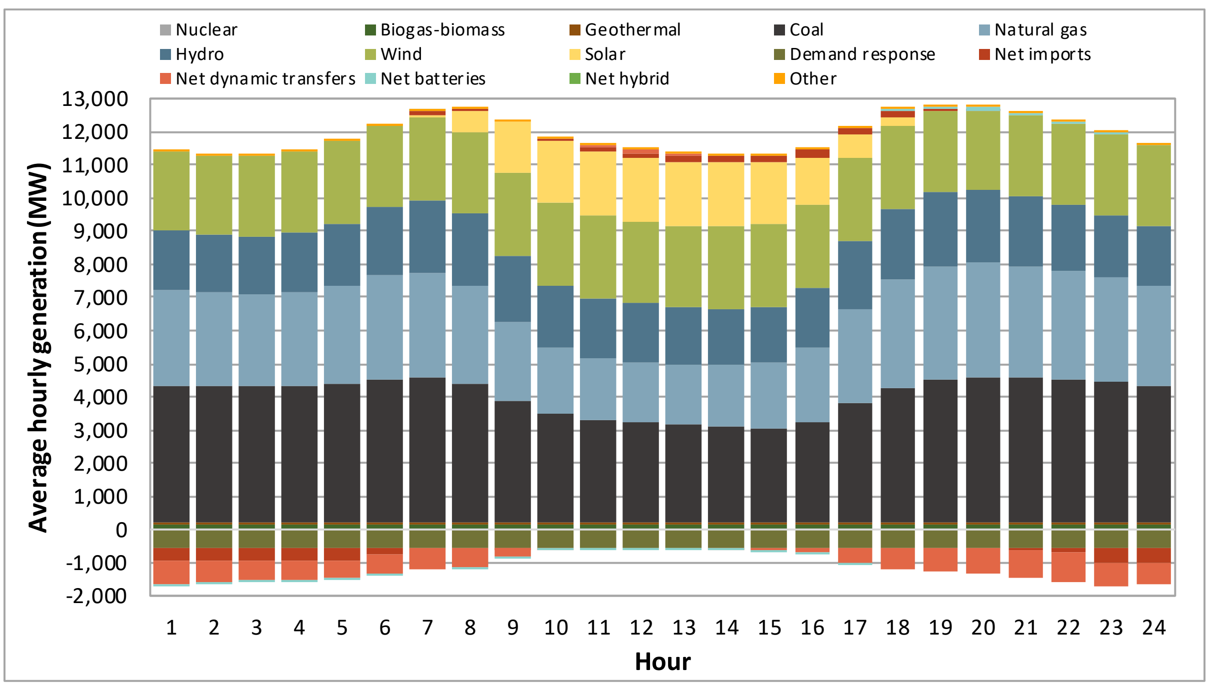


Figure 1.9 Pacific Northwest - Average hourly generation by fuel type (Q1 2025)

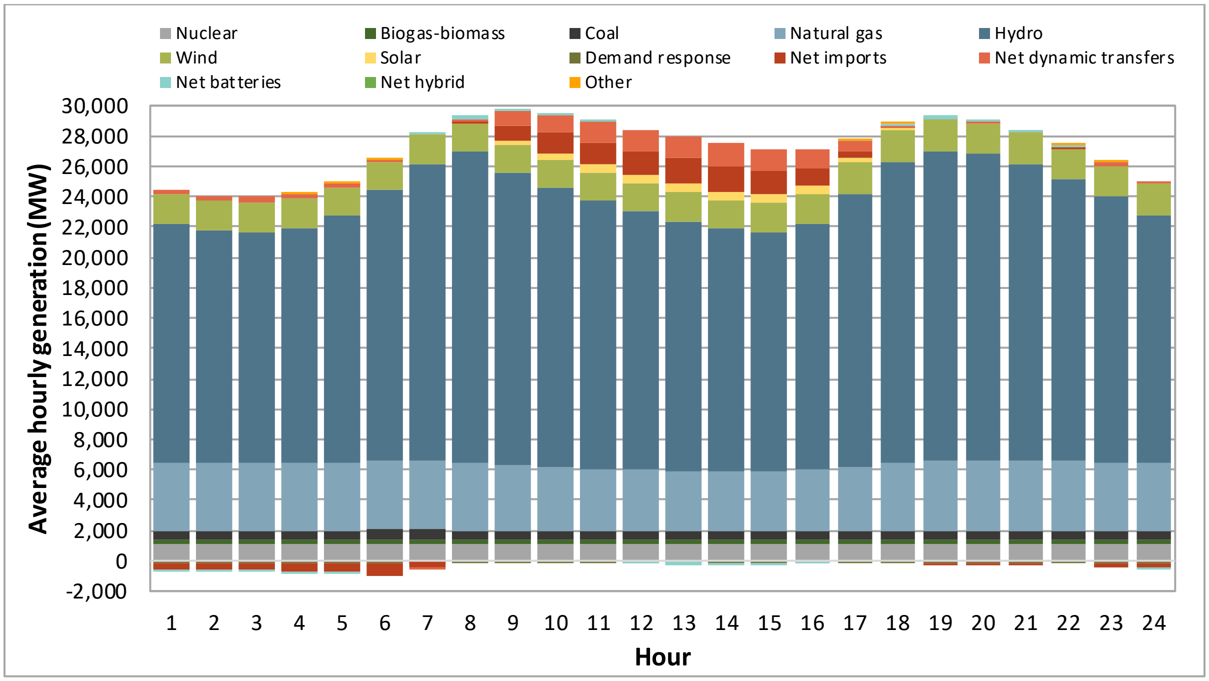


Figure 1.10 to Figure 1.13 show the change in hourly generation by fuel type between the first quarters of 2024 and 2025. Positive values represent increased generation relative to the same time last year, and negative values represent a decrease in generation. Change in total load is denoted by the black line.

- Natural gas generation decreased in all regions with the largest decrease amounting to 2,250 MW (23 percent) in the California region.
- Batteries have been increasingly participating in energy arbitrage by charging during the high solar hours mid-day, and discharging during the high net load periods in the evening. Increased mid-day battery charging was met largely by greater solar and hybrid production in the California region. Net hybrid generation in the Desert Southwest was similar to the first quarter of 2024.
- In the Pacific Northwest, increased hydro production led to significant decreases in net imports across all hours.
- Coal generation in California increased by 560 MW (183 percent) due to a large coal resource in Utah under contract to some California utilities having an outage during Q1 2024 that ended in Q3 2024.

Figure 1.10 California - Change in average hourly generation by fuel type (Q1 2025 vs. Q1 2024)

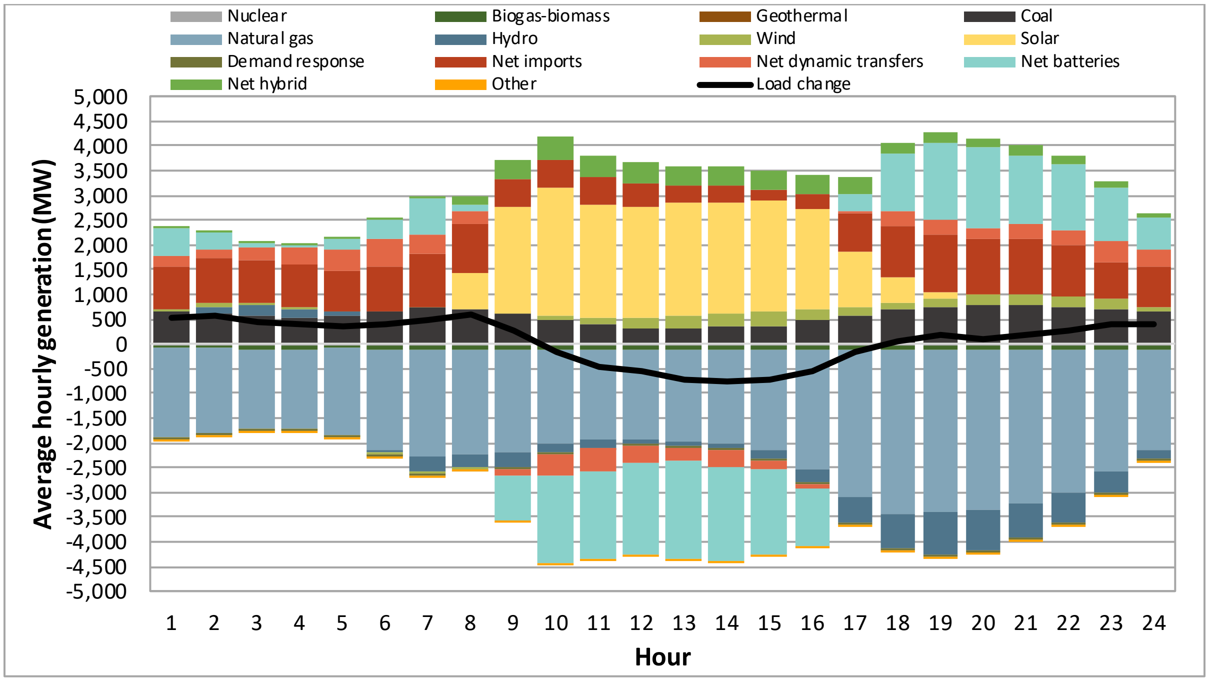


Figure 1.11 Desert Southwest - Change in average hourly generation by fuel type (Q1 2025 vs. Q1 2024)

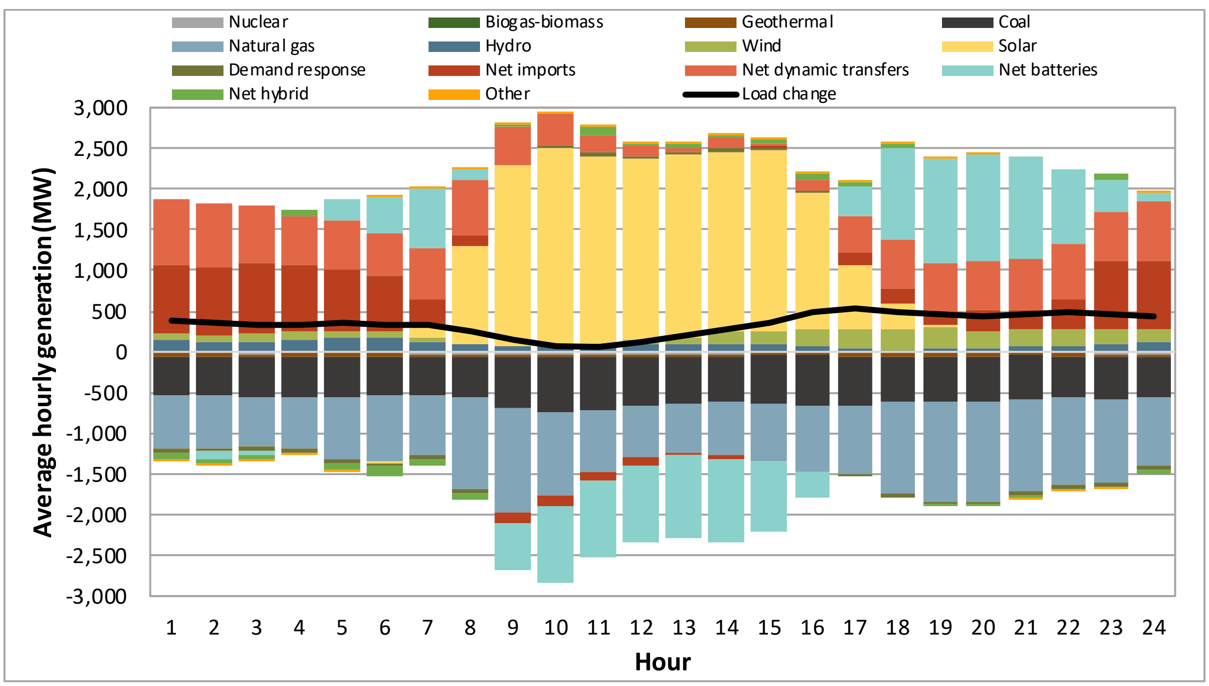


Figure 1.12 Intermountain West - Change in average hourly generation by fuel type (Q1 2025 vs. Q1 2024)

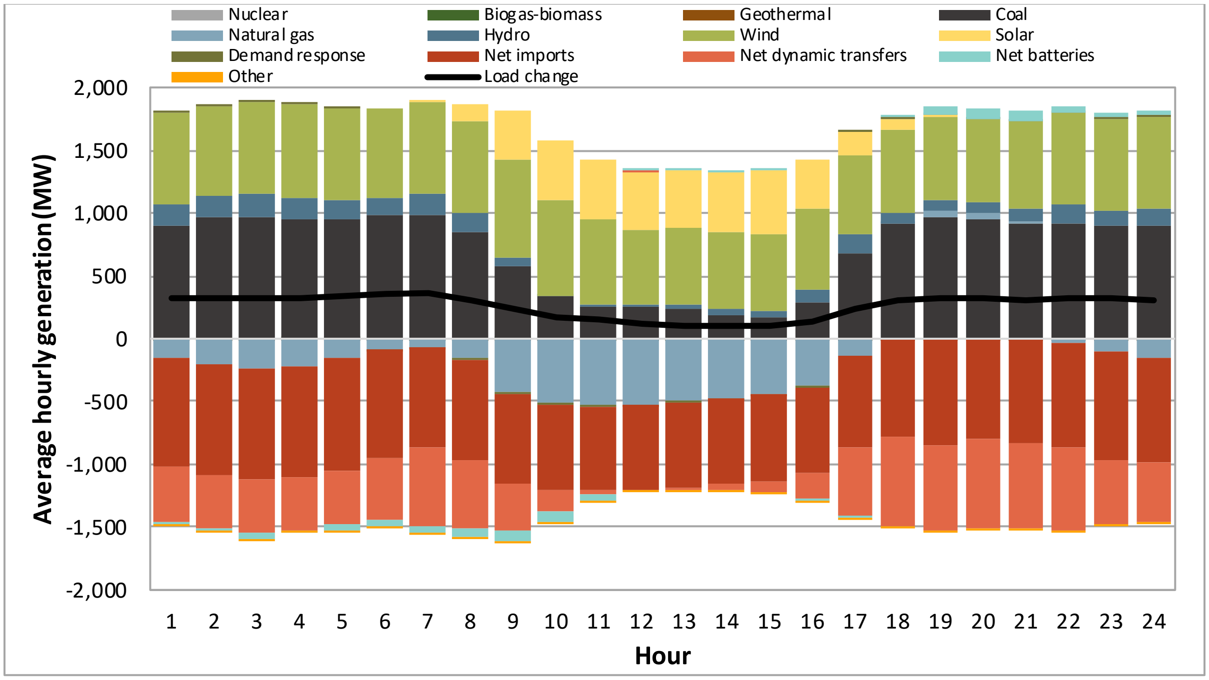


Figure 1.13 Pacific Northwest - Change in average hourly generation by fuel type (Q1 2025 vs. Q1 2024)

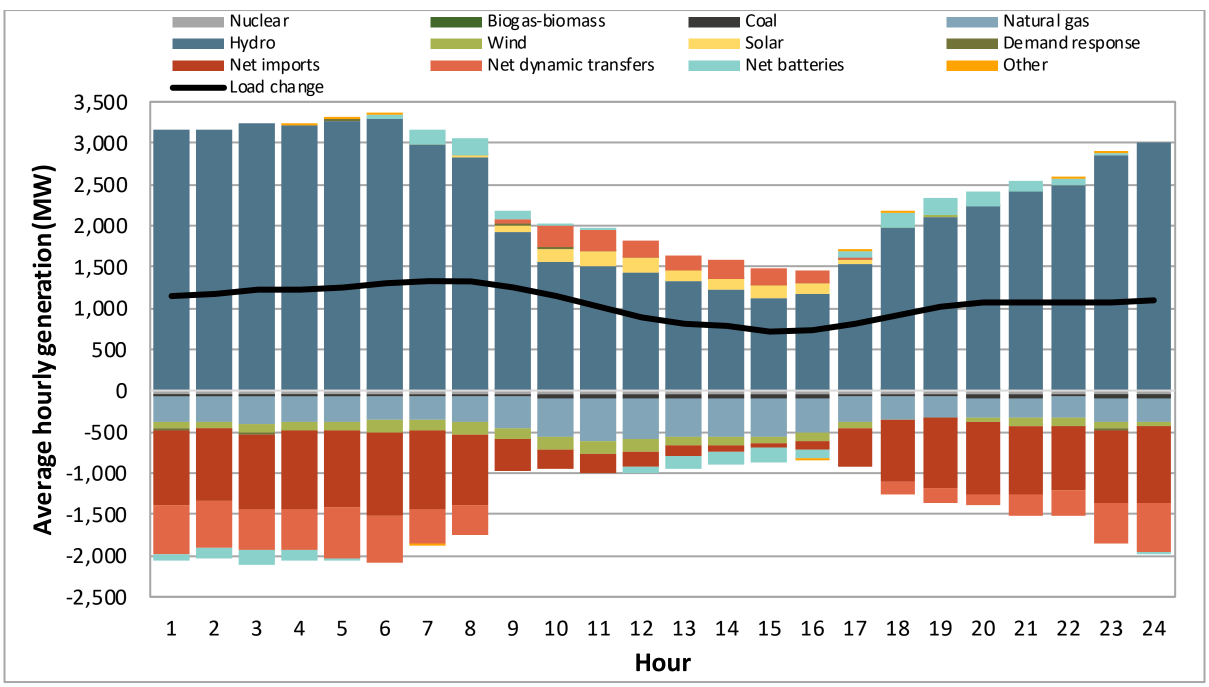
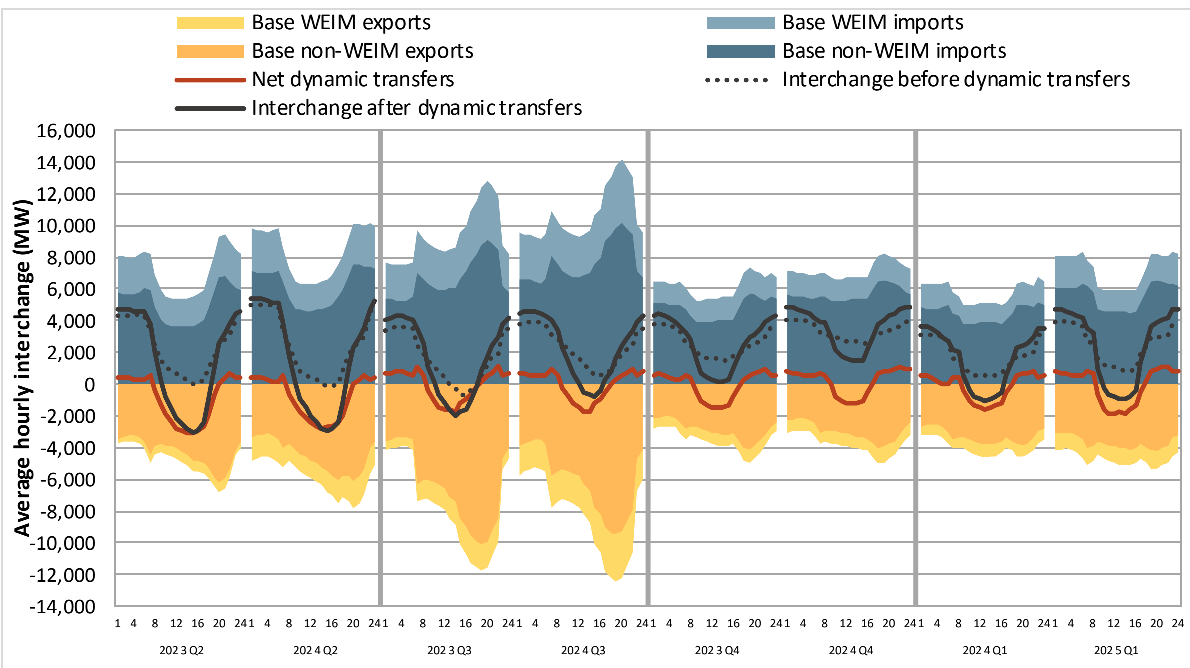


Figure 1.14 to Figure 1.17 shows imports, exports, and WEIM transfers for each region in the WEIM. Power flowing into a balancing area is represented as positive while power flowing out of a balancing area is shown as negative. The dark orange and dark blue areas show fixed bilateral exports and imports between a WEIM and a non-WEIM balancing area. The legend refers to these as base non-WEIM exports or imports. Base WEIM exports and base WEIM imports (light yellow and light blue areas), on the other hand, are fixed bilateral transfers between two WEIM balancing areas that are not optimized in the market.[9]

The red line shows the net WEIM dynamic transfers into and out of all balancing areas optimized by the market software. This line also includes static transfers which are optimized in the 15-minute market but held fixed in the 5-minute market. The dotted black line nets all base non-WEIM and base WEIM exports and imports. The solid black line represents the final net interchange after adding the net dynamic transfers (red line) to the dotted black line.

In comparing the first quarters of 2024 and 2025, interchange after dynamic transfers (solid black line) have decreased in the Intermountain West and the Pacific Northwest regions by 1,190 MW and 820 MW, respectively. The Intermountain West region was a net exporter in the first quarter of 2025. The California and Desert Southwest regions saw increases to their interchange after dynamic transfers by 880 MW and 810 MW, respectively.

Figure 1.14 California - Average hourly net interchange by quarter



9 The export and import values in Figures 1.14 to 1.17 also include both sides of a base transfer between balancing areas in the same region. For example, base transfers from BANC into LADWP would count towards both the base WEIM exports and base WEIM imports in the figures.

Figure 1.15 Desert Southwest - Average hourly net interchange by quarter

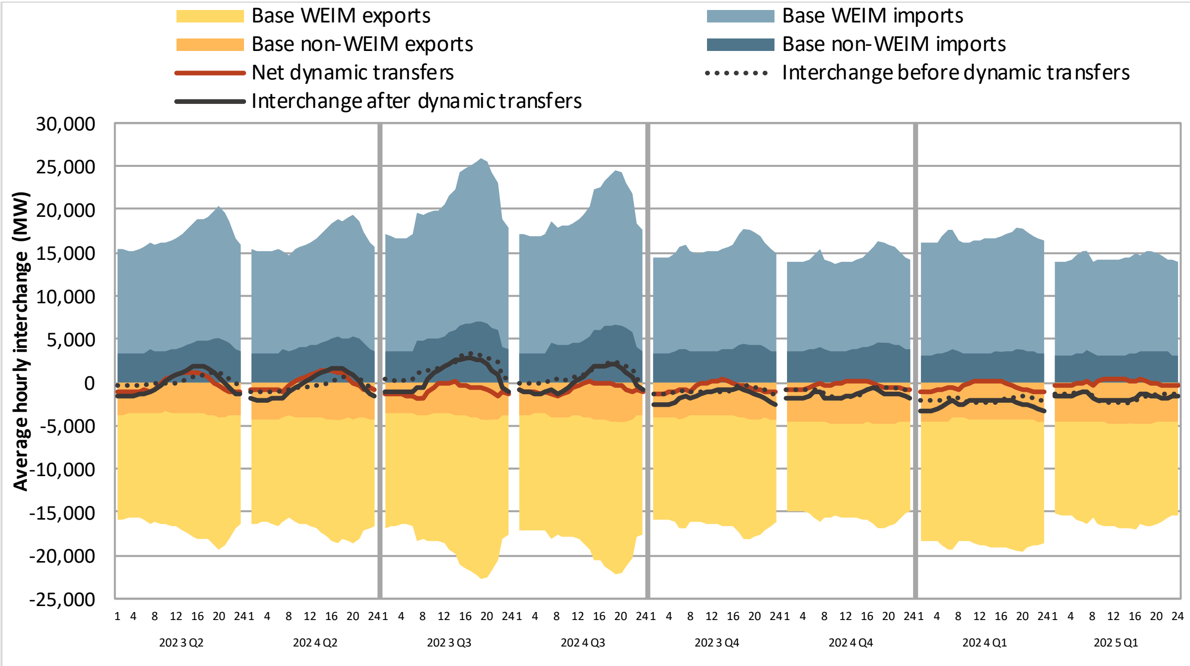


Figure 1.16 Intermountain West - Average hourly net interchange by quarter

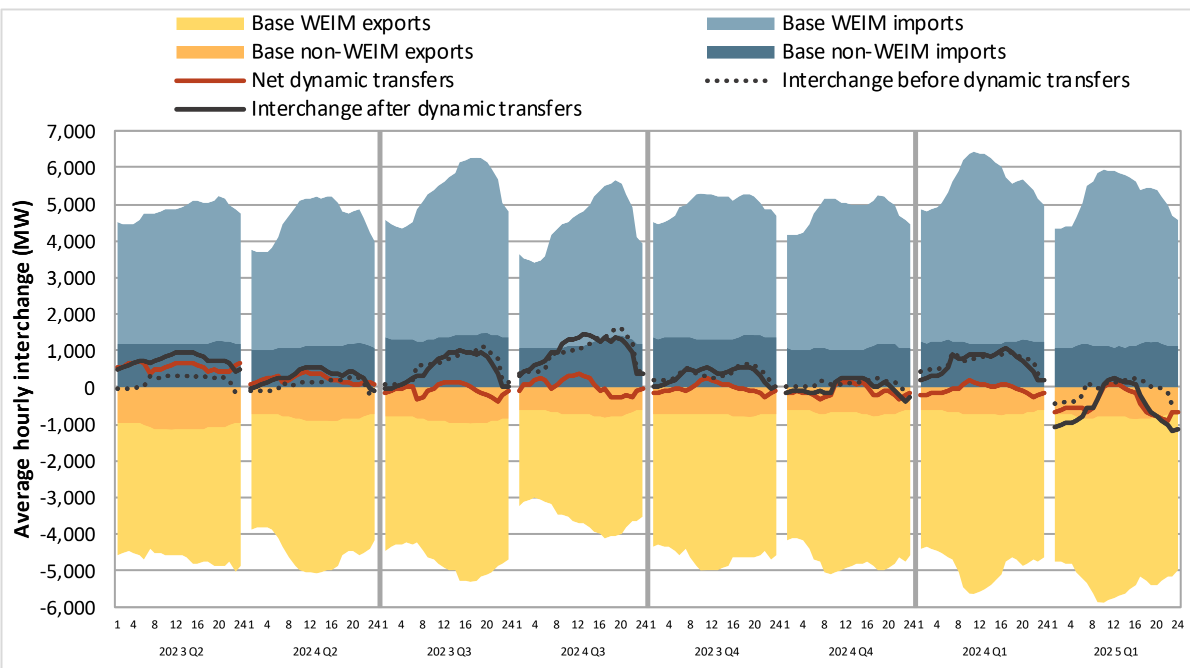


Figure 1.17 Pacific Northwest - Average hourly net interchange by quarter

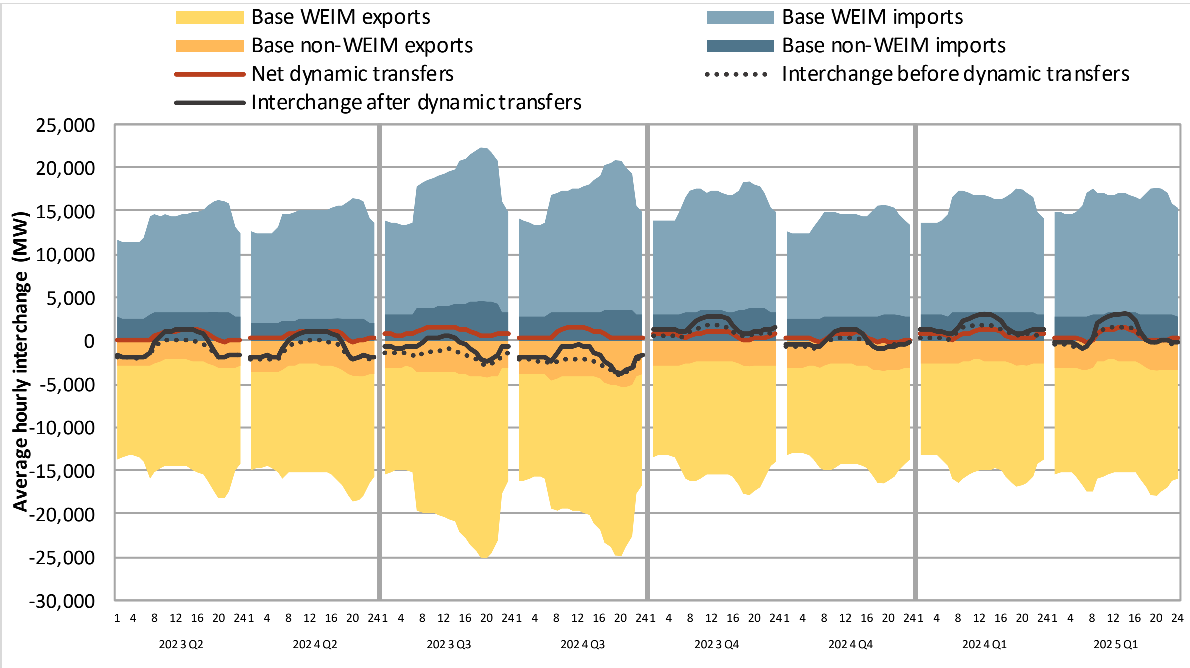
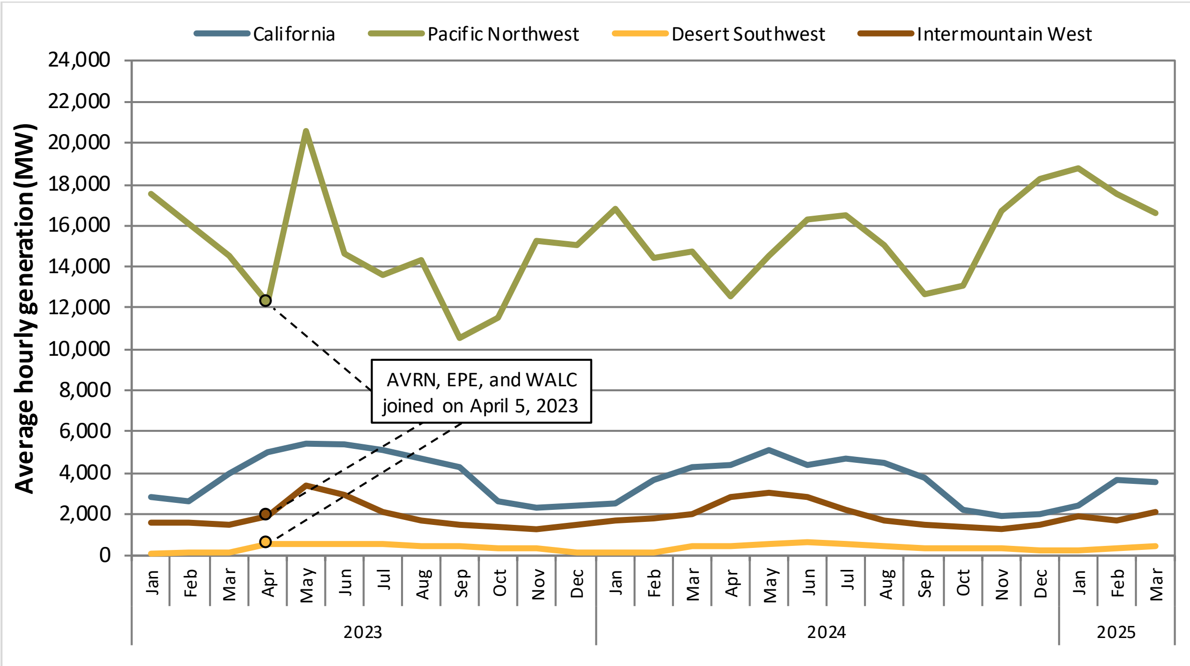


Figure 1.18 shows the monthly average hydroelectric generation from January 2023 to March 2025.

- In the Pacific Northwest, hydroelectric generation in the first quarter of 2025 tracked 2,307 MW (15 percent) higher than the same quarter of 2024, and tracked similarly to 2023 levels.
- In the California region, hydroelectric generation decreased by 240 MW (7 percent) relative to the first quarter of 2024, but increased by 60 MW (2 percent) compared to 2023.
- Hydroelectric output in the Intermountain West increased by 100 MW (5 percent) compared to the first quarter of 2024.
- In the Desert Southwest, hydroelectric generation increased by 100 MW (38 percent) from the first quarter of 2024, and has increased by 230 MW (176 percent) from 2023.

Figure 1.18 Average monthly hydroelectric generation by region



2 Load conditions

This section provides an overview of load conditions across WEIM regions. The analysis examines load conditions at quarterly, monthly, and hourly levels, categorized by regional groups and individual balancing areas.

The regions are divided into five categories:

- **CAISO**: represents the California ISO balancing authority area.
- **California**: includes all balancing areas in California except CAISO, such as Balancing Authority of Northern California (BANC), Los Angeles Department of Water and Power (LADWP), and Turlock Irrigation District (TIDC).
- **Desert Southwest**: includes Arizona Public Service (AZPS), El Paso Electric (EPE), NV Energy (NEVP), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric (TEPC), and WAPA-Desert Southwest.
- **Intermountain West**: includes Avista Corporation (AVA), Idaho Power Company (IPCO), NorthWestern Energy (NWMT), and PacifiCorp East (PACE).
- **Pacific Northwest**: includes Avangrid Power (AVRN), Bonneville Power Administration (BPA), PacifiCorp West (PACW), Portland General Electric (PGE), Powerex, Puget Sound Energy (PSE), Seattle City Light (SCL), and Tacoma Power (TPWR).

2.1 Average load and load distribution

Figure 2.1 shows the total market load distribution in the 5-minute market.[10] The distribution incorporates all 5-minute load data for Q1 2025 (blue line) and Q1 2024 (grey dashed line).

The horizontal axis represents the load in gigawatts (GW), while the vertical axis displays the probability density function (PDF), which indicates the relative frequency of different load levels.

The distribution shows how the load values are distributed. Higher points on the curve represent load levels that occurred more frequently during the quarter.[11] For instance, if the curve peaks around 70 GW, this indicates that 70 GW was a commonly observed load level.

The distribution shows more instances of high system loads—particularly above about 85 GW—in the first quarter of 2025, compared to the same quarter last year. The blue line is generally above the grey dashed line over 85 GW, reflecting an increased frequency of high-load intervals. Conversely, at the lower end of the load range, the blue line falls below the dashed line, indicating fewer instances of low-load intervals in Q1 2025, particularly below about 68 GW.

10 The total market load includes any load conformance.

11 To determine the likelihood of the load falling within a specific range, such as between 100 GW and 120 GW, one can assess the area under the curve within that range. The total area under the curve equals 1, so the proportion of the area in any range reflects the probability of the load being in that range.

Figure 2.1 Quarterly system-wide total 5-minute market load distribution

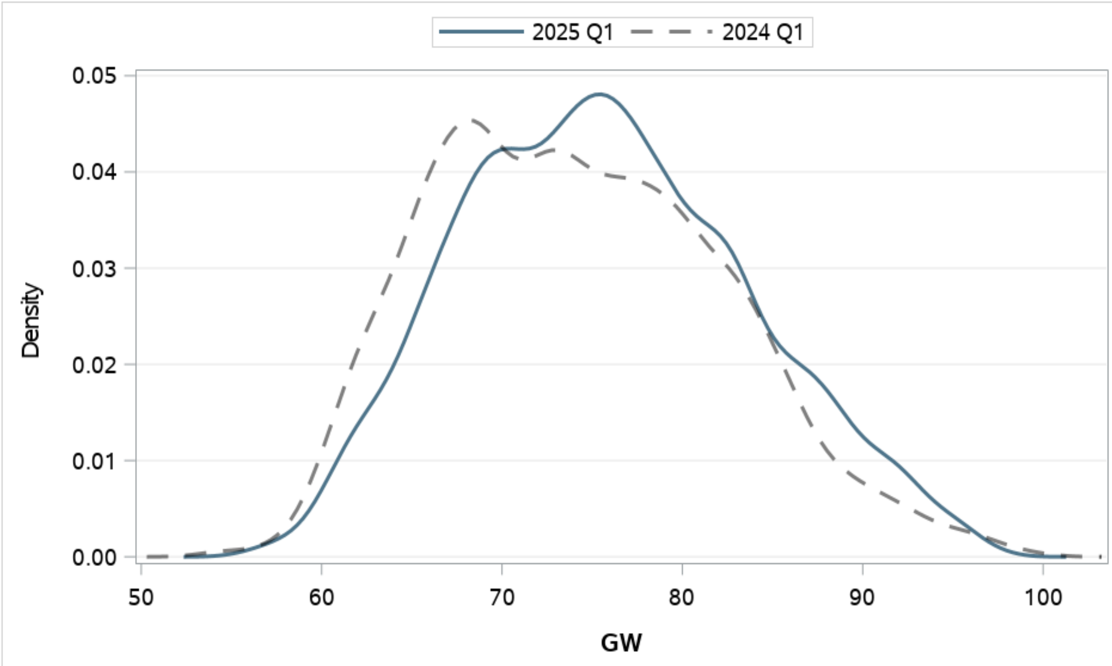


Figure 2.2 shows the monthly average 5-minute market load categorized by region from January 2023 to March 2025. The total system load for this quarter averaged 75.7 GW, representing an approximately 2 percent increase compared to the same quarter of last year. Most regions' average load increased relative to the first quarter of 2024, ranging from 1 percent to 4 percent:

- **Pacific Northwest** (green) averaged **26.1 GW**, a 4 percent increase.
- **CAISO** (dark blue) averaged **21.2 GW** and decreased by 0.1 percent.
- **Desert Southwest** (yellow) averaged **13.9 GW**, a 2 percent increase.
- **Intermountain West** (red) averaged **10.3 GW** and rose by 2 percent.
- **California** (light blue) averaged **4.3 GW**, a 1 percent increase.

The WEIM total market load tends to be lowest in April and tends to peak in July. Regions such as CAISO, California (non-CAISO), and Desert Southwest closely aligned with the overall seasonal trends of the total WEIM load, showing higher loads during the summer months. However, in the Pacific Northwest, peak loads occur in the winter months, with comparatively low load during summer, and particularly in May, June, and September. The Intermountain West peaks in the summer while also maintaining high loads during winter months.

Figure 2.2 Monthly average 5-minute market load by region (GW)

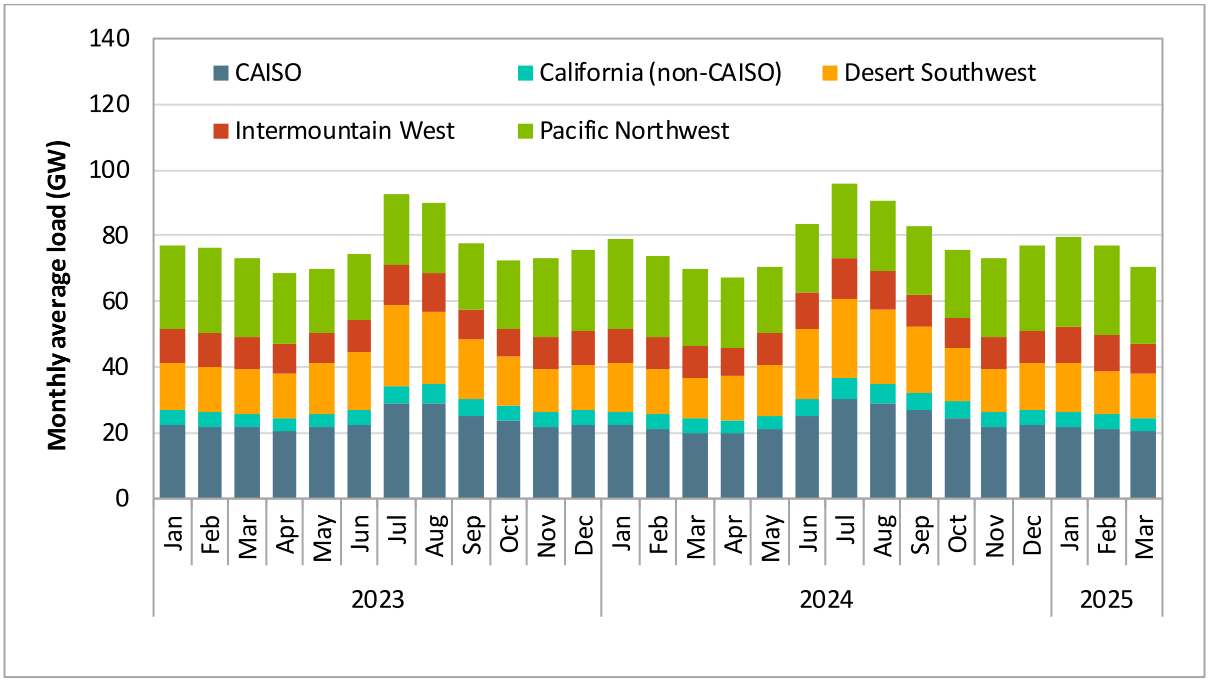


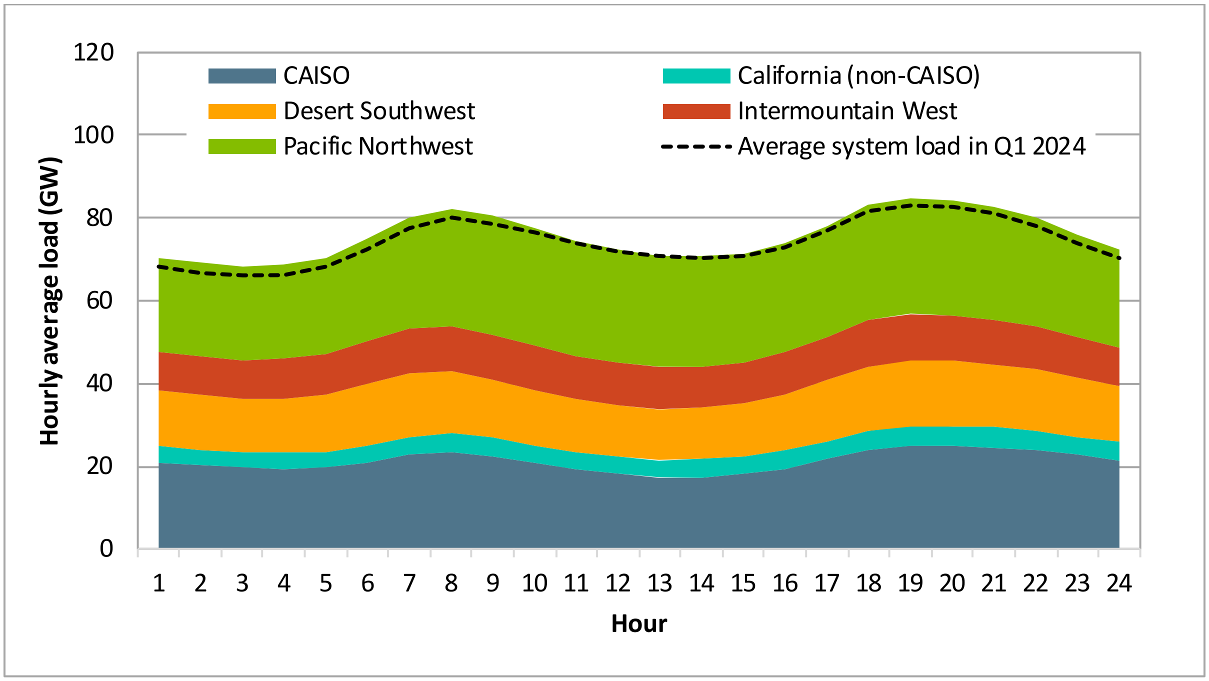
Figure 2.3 displays the hourly average 5-minute market load across different regions in Q1 2025. Each color represents a specific region, while the black dashed line indicates the average system-wide WEIM total load for the same quarter last year.

The total WEIM hourly average load peaked at hour-ending 19, reaching 84.8 GW, while the lowest load occurred at hour-ending 3, at 68.2 GW. Across all hours, the Pacific Northwest recorded the largest regional load.

In Q1, the average hourly load in the Pacific Northwest and Intermountain West peaked during the morning hours, while the rest of the WEIM regions reached their peak during the evening hours. The peak average hourly load for each region was:

- **Pacific Northwest:** peak load of 28.7 GW at hour-ending 9.
- **CAISO:** peak load of 24.9 GW at hour-ending 19.
- **Desert Southwest**: peak load of 15.9 GW at hour-ending 19.
- **Intermountain West**: peak load of 11.1 GW at hour-ending 8.
- **California (non-CAISO):** peak load of 4.9 GW at hour-ending 20.

Figure 2.3 Hourly average 5-minute market load by region (GW)



2.2 Peak load

Figure 2.4 shows the highest 5-minute market *system* load forecast for each hour on February 12, 2025—the day with the highest system load during the quarter. The figure also shows corresponding load forecast data for each balancing area for the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 99.7 GW during hour-ending 8, interval 5. This was lower than the peak WEIM load during Q1 2024 (103 GW).

This heatmap highlights the hour with the peak load for each balancing area on this day. Red indicates the hour of highest load for each balancing area and yellow indicates hours with above-average load for that day. Peak load for balancing areas varied across hours. While the system peak occurred during hour-ending 8, many balancing areas reached their peak at different times. Even within the same region, peaking hours varied among balancing areas.

Overall, many balancing authority areas (BAAs) peaked during the morning hours, typically between hour-ending 6 and hour-ending 9. Within California and Desert Southwest regions, about half of the BAAs reached their peak during the morning hours, while the other half peaked during the evening hours.

Figure 2.4 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, February 12, 2025)

Hour	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
SYSTEM	85.4	92.4	98.2	99.7	98.5	94.6	90.9	87.3	85.4	84.2	84.5	87.6	92.4	98.0	98.4	97.8	96.4	93.5
CAISO	21.4	23.3	25.6	26.3	25.8	24.6	23.8	22.7	22.4	22.3	23.3	24.7	26.3	27.9	28.2	27.6	27.0	26.0
BANC	1.74	1.93	2.15	2.18	2.15	2.08	2.05	2.00	1.85	1.76	1.71	1.81	1.93	2.07	2.08	2.04	2.00	1.93
Turlock ID	.26	.28	.31	.31	.30	.29	.26	.28	.28	.27	.28	.29	.30	.32	.32	.31	.31	.31
LADWP	2.21	2.39	2.61	2.70	2.76	2.90	2.95	2.96	2.98	2.98	2.97	2.97	3.01	3.18	3.20	3.16	3.09	3.01
NV Energy	3.91	4.16	4.28	4.21	4.06	3.85	3.68	3.55	3.48	3.58	3.67	3.97	4.09	4.41	4.43	4.43	4.42	4.34
Arizona PS	3.64	3.96	3.90	3.84	3.62	3.26	3.22	3.10	3.10	3.16	3.33	3.51	3.72	3.93	3.94	3.91	3.86	3.72
Tucson Electric	1.17	1.29	1.28	1.25	1.23	1.04	.89	.83	.86	.84	.93	1.00	1.22	1.27	1.27	1.27	1.23	1.16
Salt River Project	3.15	3.43	3.38	3.35	3.29	3.21	3.23	3.11	3.12	3.16	3.16	3.23	3.41	3.56	3.57	3.56	3.47	3.36
PSC New Mexico	1.65	1.74	1.70	1.69	1.59	1.50	1.46	1.43	1.43	1.45	1.53	1.70	1.79	1.82	1.80	1.81	1.77	1.70
WAPA - Desert SW	.63	.69	.67	.67	.66	.64	.60	.57	.58	.56	.56	.57	.61	.63	.62	.66	.65	.61
El Paso Electric	.79	.85	.83	.84	.87	.83	.83	.83	.82	.79	.84	.87	.93	.98	.98	.97	.94	.88
PacifiCorp East	6.45	6.84	7.01	7.04	6.94	6.81	6.63	6.47	6.33	6.28	6.36	6.48	6.81	7.05	7.02	7.00	6.86	6.68
Idaho Power	2.67	2.86	2.94	2.91	2.84	2.73	2.60	2.52	2.46	2.41	2.39	2.43	2.55	2.73	2.74	2.76	2.71	2.62
NorthWestern	1.81	1.96	1.95	1.97	1.95	1.91	1.85	1.82	1.79	1.76	1.75	1.77	1.90	1.94	1.94	1.93	1.89	1.84
Avista Utilities	1.92	2.05	2.19	2.22	2.21	2.14	2.05	1.97	1.90	1.85	1.77	1.78	1.89	2.01	2.02	2.02	2.00	1.95
BPA	9.78	10.54	11.21	11.42	11.34	10.84	10.10	9.56	9.13	8.77	8.40	8.48	8.84	9.42	9.53	9.60	9.60	9.43
Tacoma Power	.75	.83	.88	.90	.91	.88	.82	.80	.78	.74	.69	.70	.73	.79	.79	.80	.79	.78
PacifiCorp West	3.47	3.81	4.14	4.20	4.15	3.92	3.66	3.42	3.25	3.14	3.02	3.06	3.23	3.54	3.55	3.56	3.54	3.45
Portland GE	3.19	3.47	3.80	3.89	3.84	3.66	3.45	3.35	3.25	3.19	3.15	3.28	3.44	3.69	3.72	3.73	3.69	3.60
Puget Sound Energy	4.09	4.45	4.84	4.98	4.96	4.77	4.50	4.25	4.09	3.92	3.77	3.83	4.06	4.34	4.38	4.38	4.36	4.27
Seattle City Light	1.43	1.55	1.73	1.78	1.79	1.74	1.65	1.59	1.53	1.49	1.42	1.43	1.48	1.58	1.58	1.58	1.57	1.54
Powerex	9.34	9.94	10.74	11.07	11.23	10.92	10.63	10.23	10.09	9.86	9.56	9.70	10.18	10.79	10.79	10.77	10.59	10.31

Table 2.1 shows the peak 5-minute market load and date for each balancing area (or region) during the first quarter. Many BAAs reached their peak in February, while most in the Desert Southwest peaked in January. The table also shows each balancing area's load during the system peak load interval on February 12, 2025 (99,717 MW).

Table 2.1 Peak WEIM load (January–March 2025)

	Peak load (January–March, 2025)		Load during WEIM system peak (12-Feb-2025)	
Region/balancing area	**Date**	**Load (MW)**	**Load (MW)**	**Percent**
WEIM system	**12-Feb-25**	**99,717**	**99,717**	
California	**12-Feb-25**	**33,792**	**31,486**	**32%**
California ISO	12-Feb-25	28,198	26,298	26%
BANC	11-Feb-25	2,231	2,181	2%
LADWP	13-Feb-25	3,304	2,697	3%
Turlock Irrig. District	25-Mar-25	365	311	.3%
Desert Southwest	**22-Jan-25**	**20,133**	**15,855**	**16%**
Arizona Public Service	22-Jan-25	5,031	3,840	4%
El Paso Electric	9-Jan-25	1,252	844	.8%
NV Energy	26-Mar-25	5,202	4,209	4%
PSC New Mexico	24-Jan-25	2,156	1,691	2%
Salt River Project	25-Mar-25	4,846	3,353	3%
Tucson Electric	22-Jan-25	1,760	1,248	1%
WAPA - Desert SW	22-Jan-25	859	669	.7%
Intermountain West	**13-Feb-25**	**14,192**	**14,147**	**14%**
Avista Utilities	12-Feb-25	2,222	2,221	2%
Idaho Power	12-Feb-25	2,943	2,915	3%
NorthWestern Energy	12-Feb-25	1,994	1,966	2%
PacifiCorp East	20-Jan-25	7,349	7,045	7%
Pacific Northwest	**12-Feb-25**	**38,283**	**38,230**	**38%**
BPA	12-Feb-25	11,421	11,417	11%
PacifiCorp West	12-Feb-25	4,202	4,195	4%
Portland General Electric	13-Feb-25	3,976	3,892	4%
Powerex	4-Feb-25	11,504	11,067	11%
Puget Sound Energy	12-Feb-25	4,986	4,977	5%
Seattle City Light	12-Feb-25	1,800	1,777	2%
Tacoma Power	27-Jan-25	923	904	.9%

3 Energy market performance

3.1 Real-time energy market prices by region

This section analyzes real-time market prices across the Western Energy Imbalance Market (WEIM). The analysis focuses on monthly and hourly load-weighted average prices at the regional level.[12] Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).[13]

Figure 3.1 and Figure 3.2 display the weighted average monthly electricity prices in the 15-minute and 5-minute markets by region from July 2023 to March 2025. Prices in the 15-minute market across the WEIM averaged about $37/MWh in the first quarter of 2025, down 39 percent from the same quarter of last year. Prices in the 5-minute market were also $37/MWh, a 38 percent decrease compared to Q1 2024.

Compared to the first quarter of 2024, prices across the WEIM were lower despite higher loads, primarily due to the absence of abnormally high prices seen in January 2024, which were driven by extreme cold weather and constrained supply conditions.

In Q1 2025, Powerex recorded the highest average price at $43/MWh, followed by California and the Pacific Northwest at $40/MWh. Average prices in these regions were notably higher than prices in the Intermountain West ($33/MWh) and Desert Southwest regions ($27/MWh). Congestion contributed to higher prices in Powerex and the Pacific Northwest, while the greenhouse gas (GHG) costs contributed significantly to the higher prices in California compared to other regions.[14]

12 The California region includes CAISO, BANC, TIDC, and LADWP. The Desert Southwest region includes NEVP, AZPS, TEPC, SRP, PNM, WALC, and EPE. The Intermountain West region includes PACE, IPCO, NWMT, and AVA. The Pacific Northwest includes AVRN, BPA, TWPR, PGE, PSEI, and SCL. Powerex is categorized separately due to transmission limitations that frequently isolate it from the rest of the WEIM system.

13 The load-weighted average is calculated by weighting each interval's price by its corresponding load relative to the total over a specific time period. Monthly average prices for each real-time interval are weighted by their respective loads and divided by the total monthly load for the region. For hourly averages over the quarter, each interval's price is weighted by its load relative to the total load during that hour for the region.

14 The GHG component of electricity prices reflects the additional costs associated with complying with California's cap-and trade program, which requires entities to purchase allowances for their carbon emission to serve load of WEIM balancing areas within California.

Figure 3.1 Weighted average monthly 15-minute market prices by region

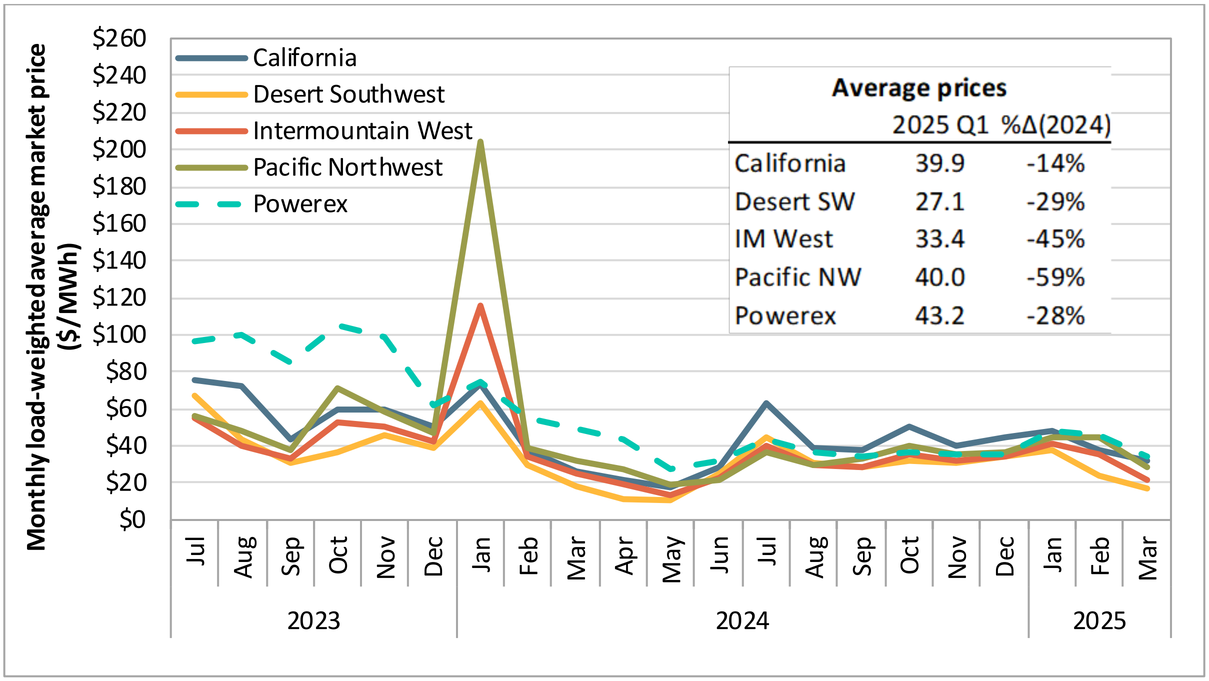


Figure 3.2 Weighted average monthly 5-minute market prices by region

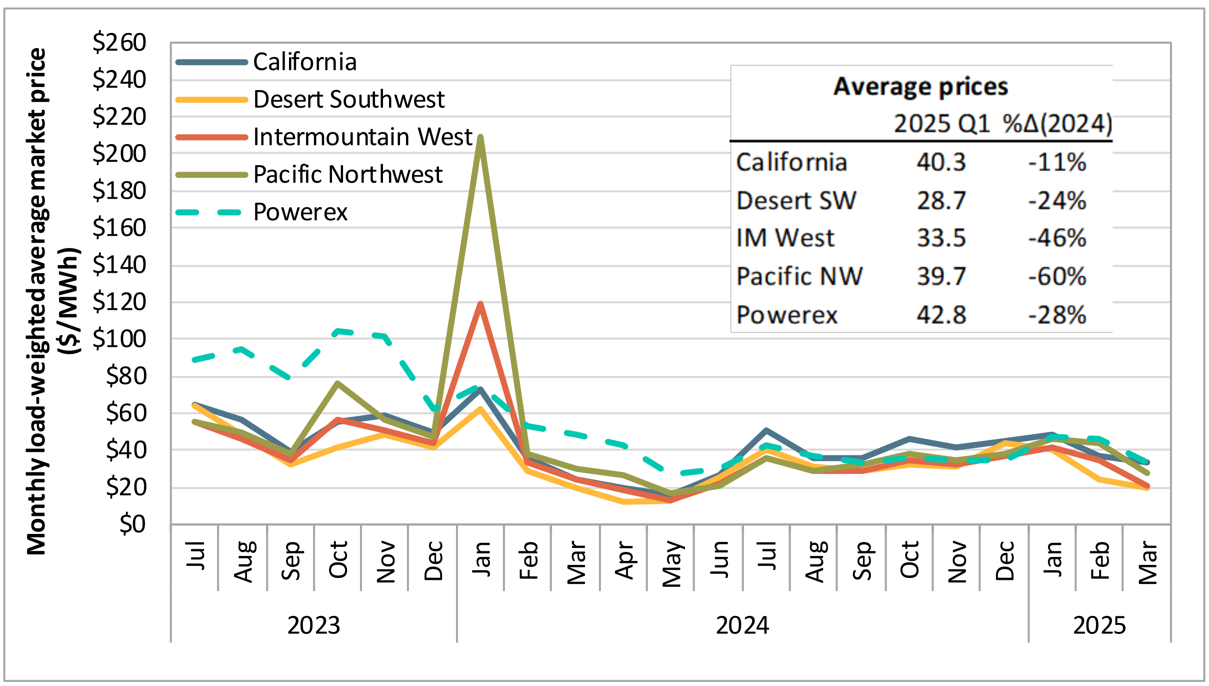


Figure 3.3 and Figure 3.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions, along with average system net load schedules. The shape of hourly prices tended to follow the net load pattern. This trend was most prominent for prices in the California, Desert

Southwest and Intermountain West regions, with relatively high prices during the morning and evening ramping hours, and lower prices during solar production hours.

The system's peak net load occurred at hour-ending 20 in both the 15-minute and 5-minute markets, reaching around 76.3 GW and 75.9 GW, respectively. In both the 15-minute and the 5-minute markets, all regions experienced peak average prices at hour-ending 7.

Real-time market prices in the California region were higher than prices in other regions during non-solar production hours. The main contributor for higher prices in California is the GHG cost, which tends to lower prices in non-California regions.

Pricing patterns were very different during mid-day solar hours. The Desert Southwest experienced lower prices compared to other regions, while the Pacific Northwest saw relatively higher prices. This pattern aligned with congestion trends, where south-to-north congestion increased during high solar energy production.

Figure 3.3 Weighted average hourly 15-minute market prices by region (January–March 2025)

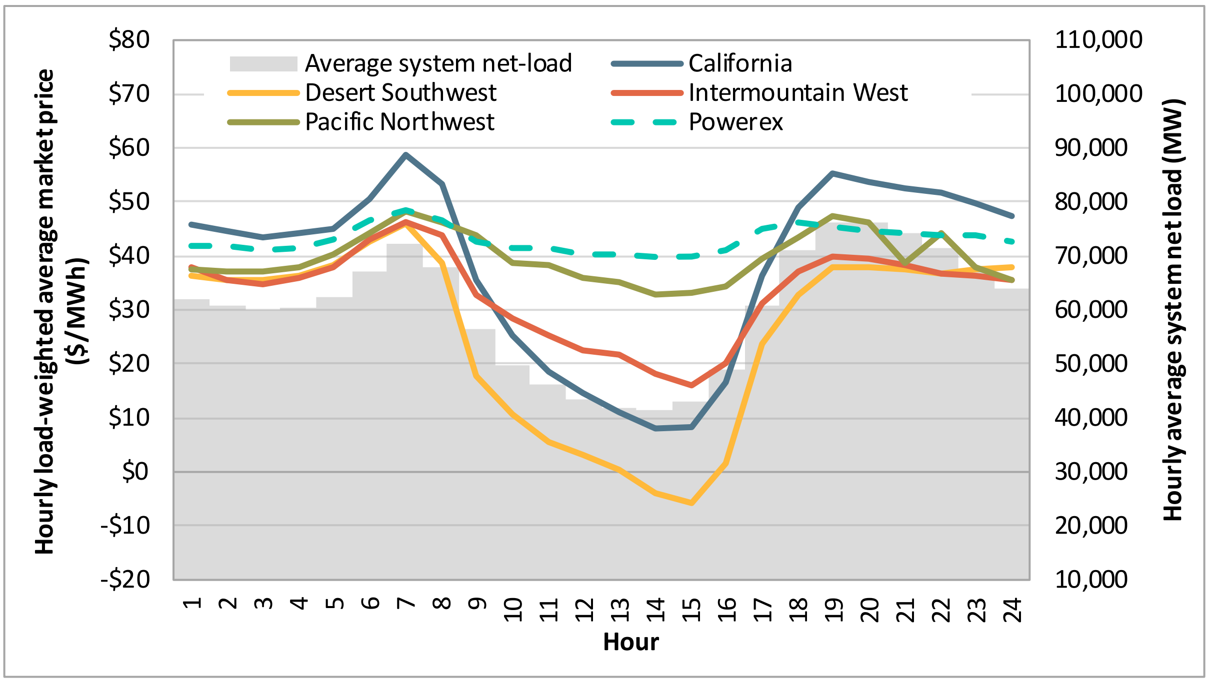
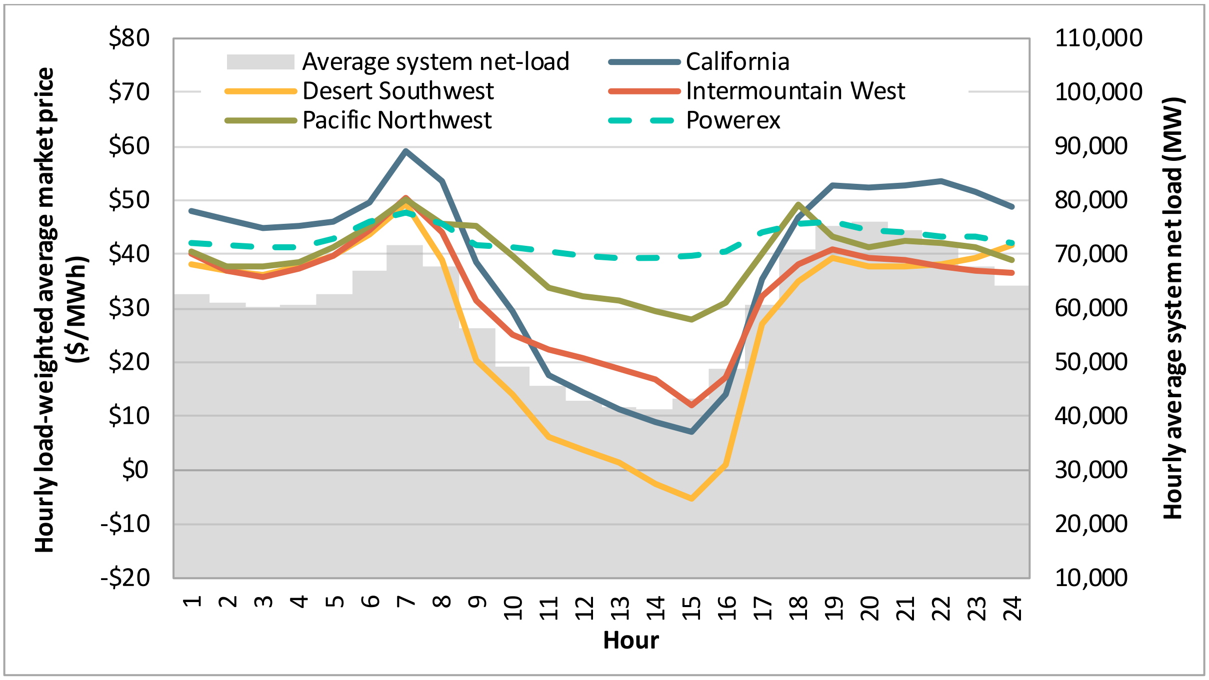


Figure 3.4 Weighted average hourly 5-minute market prices by region (January–March 2025)



3.2 Real-time market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during the first quarter of 2025. Figure 3.5 and Figure 3.6 show the average 15-minute and 5-minute market price by component for each balancing authority area in this quarter. These figures highlight how price differences between regions are determined by differences in transmission losses, greenhouse gas compliance costs, and congestion. These components are listed below.

- **System marginal energy cost**, 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 California ISO area transmission constraints 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 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 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) differences between balancing areas included 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 areas. These compliance costs are embedded within system marginal energy costs, but are reflected as negative costs (or payments) that are received by other WEIM areas making transfers into California areas through the WEIM. This indicates resources with non-zero GHG costs were often sending the last increment of power to California in the real-time markets.

In both the 5-minute and 15-minute markets, internal flow-based constraints in CAISO increased prices in Northern California and the Pacific Northwest, while lowering prices in Southern California and the Desert Southwest. WEIM internal congestion primarily affected EPE and PNM, decreasing prices in those areas relative to the rest of the WEIM.

Figure 3.5 Average 15-minute market prices by balancing area (January–March 2025)

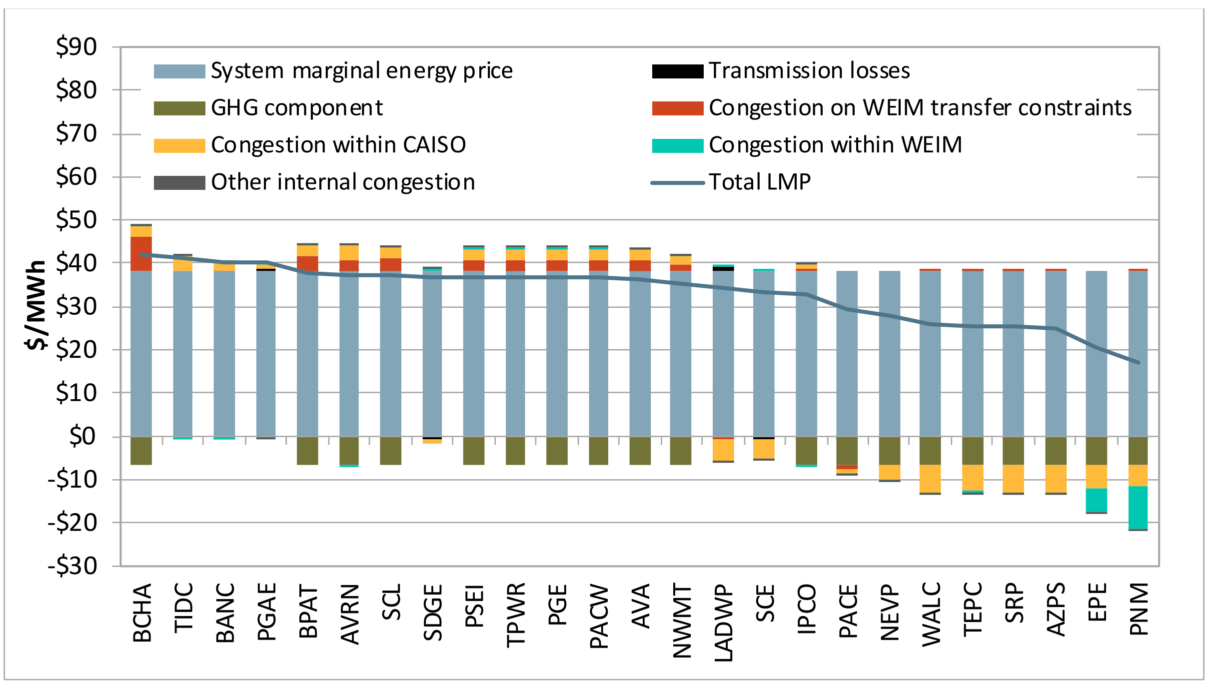


Figure 3.6 Average 5-minute market prices by balancing area (January–March 2025)

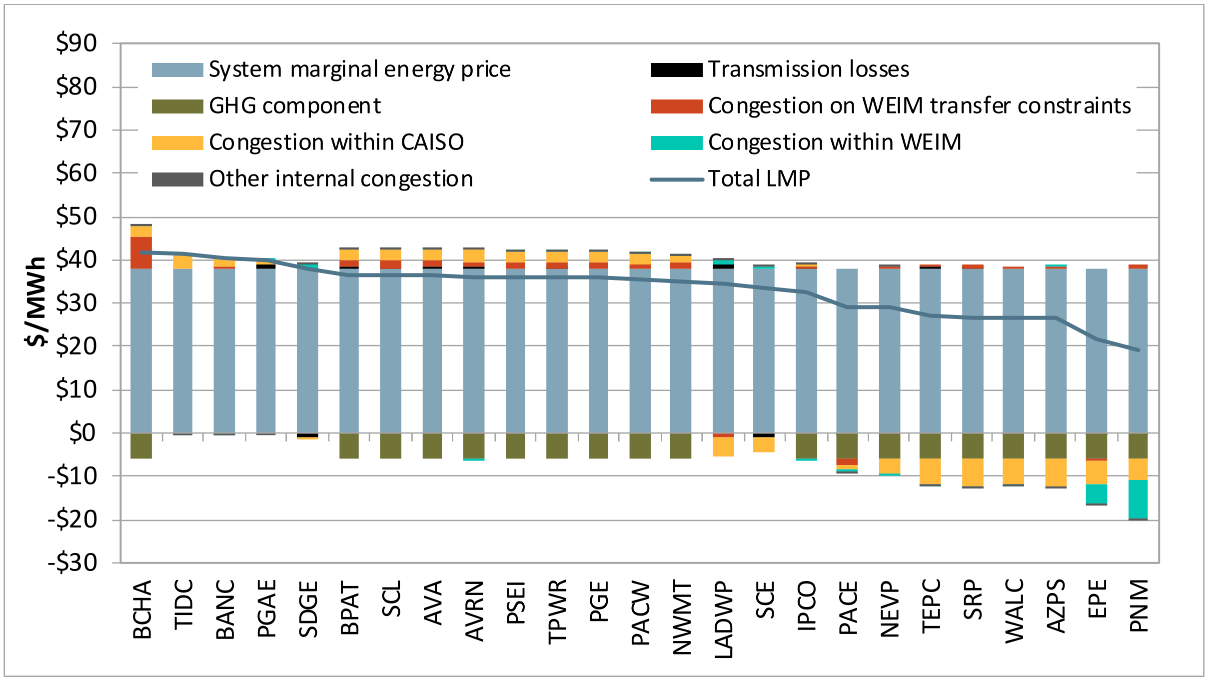


Table 3.1 and Table 3.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Blue indicates prices below that month's average system price and orange indicates prices above. As shown in these tables, average prices in the Desert Southwest and Southern California were generally lower than in other regions, in both the 15-minute and 5-minute markets in Q1 2025. This pattern aligns with south-to-north congestion during solar production hours.

Table 3.3 and Table 3.4 show average hourly prices in the 15-minute and 5-minute markets during the first quarter. During mid-day solar hours, prices were generally higher in the Pacific Northwest, Intermountain West, and Northern California than in the Desert Southwest and Southern California. This 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.

During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM due mainly to California greenhouse house gas pricing.

Table 3.1 Average monthly 15-minute market prices

SMEC	$55	$19	$28	$66	$67	$42	$57	$58	$50	$89	$38	$28	$22	$16	$26	$51	$36	$35	$46	$41	$42	$46	$40	$28
PG&E (CAISO)	$57	$18	$29	$58	$65	$44	$62	$62	$54	$78	$40	$30	$28	$21	$28	$61	$36	$36	$56	$46	$46	$49	$40	$31
SCE (CAISO)	$48	$20	$27	$73	$68	$39	$51	$53	$45	$65	$31	$17	$11	$9	$24	$50	$35	$33	$38	$35	$40	$43	$30	$25
BANC	$59	$19	$30	$56	$54	$42	$59	$62	$53	$77	$41	$31	$29	$21	$27	$58	$37	$37	$56	$46	$45	$49	$40	$31
Turlock ID	$61	$19	$30	$56	$54	$43	$60	$63	$54	$78	$41	$33	$31	$21	$25	$54	$37	$39	$61	$47	$45	$51	$40	$32
LADWP	$49	$20	$27	$67	$50	$36	$45	$52	$46	$68	$32	$18	$12	$11	$27	$55	$40	$35	$40	$37	$38	$45	$30	$28
NV Energy	$50	$17	$23	$59	$40	$33	$38	$48	$42	$65	$30	$19	$13	$10	$22	$42	$29	$28	$33	$29	$31	$38	$26	$20
Arizona PS	$50	$17	$24	$63	$41	$30	$34	$45	$38	$59	$28	$18	$8	$8	$21	$45	$30	$27	$30	$26	$31	$35	$22	$18
Tucson Electric	$47	$21	$26	$58	$38	$30	$33	$45	$39	$59	$27	$15	$9	$11	$21	$39	$26	$26	$28	$27	$31	$36	$22	$18
Salt River Project	$50	$22	$24	$62	$46	$28	$34	$44	$38	$54	$25	$14	$9	$10	$25	$38	$31	$28	$30	$26	$30	$35	$22	$19
PSC New Mexico	$67	$17	$24	$59	$40	$30	$40	$50	$40	$69	$35	$18	$14	$10	$24	$43	$29	$28	$27	$57	$29	$37	$14	-$1
WAPA - Desert SW	$57	$20	$24	$62	$41	$30	$34	$45	$40	$60	$29	$14	$7	$10	$21	$42	$29	$27	$32	$26	$32	$36	$22	$19
El Paso Electric	$33	$18	$23	$48	$37	$29	$30	$20	$20	$53	$24	$15	$9	$13	$27	$38	$25	$26	$27	$27	$30	$34	$19	$8
PacifiCorp East	$52	$18	$26	$53	$38	$31	$40	$46	$40	$76	$31	$22	$16	$12	$21	$39	$28	$27	$35	$31	$33	$39	$30	$19
Idaho Power	$59	$16	$27	$52	$39	$33	$56	$53	$45	$112	$35	$27	$20	$13	$22	$37	$28	$28	$37	$34	$35	$42	$35	$22
NorthWestern	$61	$13	$27	$53	$39	$34	$62	$54	$46	$151	$38	$29	$24	$18	$21	$36	$28	$29	$30	$33	$33	$41	$39	$25
Avista Utilities	$64	$12	$27	$49	$39	$34	$63	$55	$46	$155	$38	$30	$26	$18	$21	$33	$28	$29	$39	$36	$35	$43	$41	$26
Avangrid	$61	$7	$28	$49	$40	$37	$63	$56	$48	$164	$38	$31	$25	$18	$21	$32	$28	$33	$40	$37	$36	$44	$44	$26
BPA	$62	$5	$29	$55	$49	$38	$65	$57	$47	$182	$39	$30	$27	$20	$23	$40	$31	$33	$40	$37	$35	$43	$45	$26
Tacoma Power	$62	$6	$29	$50	$43	$37	$64	$55	$47	$165	$39	$31	$26	$18	$20	$32	$27	$32	$38	$36	$36	$43	$43	$26
PacifiCorp West	$61	$6	$28	$48	$39	$35	$64	$55	$47	$170	$38	$30	$25	$17	$20	$31	$27	$32	$39	$36	$36	$43	$43	$25
Portland GE	$62	$9	$29	$50	$43	$37	$65	$55	$47	$165	$38	$32	$27	$17	$21	$32	$27	$32	$39	$36	$35	$43	$43	$25
Puget Sound Energy	$62	$8	$29	$59	$44	$37	$69	$58	$48	$167	$39	$31	$27	$18	$21	$33	$28	$32	$38	$35	$36	$43	$43	$26
Seattle City Light	$61	$6	$28	$50	$45	$37	$64	$55	$47	$167	$40	$30	$28	$18	$20	$31	$27	$32	$40	$36	$37	$43	$43	$26
Powerex	$79	$14	$55	$94	$99	$83	$102	$98	$62	$72	$54	$49	$43	$27	$32	$42	$36	$33	$36	$35	$34	$48	$46	$33
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
	2023									2024												2025		

Table 3.2 Average monthly 5-minute market prices

SMEC	$47	$16	$27	$58	$53	$39	$53	$57	$49	$85	$35	$26	$20	$14	$24	$43	$34	$34	$44	$40	$43	$47	$39	$29
PG&E (CAISO)	$49	$16	$28	$52	$52	$42	$58	$62	$53	$79	$38	$28	$26	$19	$26	$49	$34	$35	$51	$45	$46	$50	$39	$32
SCE (CAISO)	$41	$16	$26	$62	$53	$35	$48	$52	$44	$63	$29	$16	$9	$8	$22	$42	$33	$32	$37	$35	$41	$44	$30	$26
BANC	$49	$16	$29	$54	$53	$42	$57	$62	$53	$79	$39	$30	$27	$20	$25	$48	$34	$36	$52	$45	$45	$50	$39	$32
Turlock ID	$52	$16	$30	$54	$53	$42	$58	$63	$54	$79	$40	$31	$29	$19	$24	$45	$35	$38	$57	$46	$46	$51	$39	$33
LADWP	$42	$16	$26	$62	$55	$37	$51	$53	$45	$66	$30	$17	$10	$10	$27	$50	$45	$35	$39	$37	$38	$45	$30	$28
NV Energy	$42	$14	$22	$56	$45	$34	$44	$50	$43	$65	$29	$19	$12	$9	$21	$37	$29	$28	$33	$30	$32	$40	$25	$21
Arizona PS	$42	$15	$24	$59	$45	$32	$40	$46	$40	$59	$26	$17	$8	$8	$21	$40	$32	$27	$30	$27	$33	$37	$23	$19
Tucson Electric	$40	$20	$26	$58	$44	$31	$38	$46	$40	$58	$28	$16	$10	$14	$24	$34	$26	$27	$27	$28	$32	$38	$23	$21
Salt River Project	$45	$23	$26	$61	$48	$27	$38	$49	$39	$53	$24	$17	$10	$13	$29	$37	$31	$29	$30	$27	$32	$37	$23	$20
PSC New Mexico	$53	$14	$24	$56	$44	$33	$46	$51	$42	$70	$34	$18	$16	$12	$25	$37	$28	$28	$27	$50	$30	$39	$15	$3
WAPA - Desert SW	$40	$19	$26	$58	$44	$33	$38	$47	$40	$59	$28	$14	$6	$9	$21	$37	$29	$27	$32	$27	$32	$37	$22	$20
El Paso Electric	$28	$16	$23	$47	$40	$30	$33	$23	$23	$52	$24	$15	$8	$18	$25	$36	$24	$26	$27	$27	$32	$36	$19	$10
PacifiCorp East	$45	$14	$25	$52	$43	$34	$44	$47	$40	$73	$30	$21	$15	$11	$20	$35	$27	$27	$34	$31	$34	$40	$30	$18
Idaho Power	$51	$13	$26	$52	$44	$35	$61	$54	$46	$119	$34	$25	$19	$13	$21	$34	$28	$28	$36	$34	$35	$43	$34	$21
NorthWestern	$56	$9	$27	$55	$46	$37	$67	$55	$48	$161	$37	$28	$26	$18	$20	$33	$28	$30	$31	$34	$34	$42	$39	$25
Avista Utilities	$56	$10	$27	$51	$44	$37	$68	$55	$48	$164	$37	$29	$27	$18	$20	$32	$28	$29	$37	$36	$36	$43	$41	$25
Avangrid	$56	$6	$27	$51	$44	$38	$68	$55	$48	$168	$37	$29	$24	$16	$20	$33	$28	$31	$39	$37	$37	$44	$42	$24
BPA	$57	$4	$28	$53	$48	$37	$69	$56	$47	$184	$37	$28	$26	$17	$22	$38	$29	$32	$38	$35	$36	$44	$43	$24
Tacoma Power	$56	$5	$28	$50	$45	$37	$69	$54	$47	$170	$37	$29	$26	$17	$20	$32	$27	$31	$37	$35	$36	$43	$42	$24
PacifiCorp West	$56	$6	$26	$50	$42	$37	$68	$54	$47	$171	$37	$28	$24	$16	$20	$32	$27	$31	$38	$36	$36	$43	$41	$23
Portland GE	$56	$9	$27	$50	$45	$37	$69	$54	$47	$169	$37	$29	$26	$16	$20	$32	$27	$31	$38	$35	$36	$43	$41	$24
Puget Sound Energy	$56	$7	$28	$61	$47	$38	$74	$56	$47	$175	$37	$29	$27	$16	$20	$33	$27	$31	$37	$34	$36	$43	$41	$24
Seattle City Light	$56	$5	$27	$50	$46	$37	$68	$55	$47	$171	$37	$28	$26	$16	$20	$31	$27	$31	$38	$35	$36	$45	$41	$24
Powerex	$77	$14	$52	$87	$94	$77	$102	$101	$61	$72	$53	$48	$43	$27	$30	$42	$36	$33	$36	$35	$34	$47	$45	$33
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
	2023									2024												2025		

Table 3.3 Average hourly 15-minute market prices (January–March)

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	$46	$44	$44	$44	$45	$49	$57	$50	$33	$26	$21	$17	$15	$11	$11	$17	$32	$45	$53	$53	$51	$51	$49	$47
PG&E (CAISO)	$46	$44	$43	$44	$45	$50	$59	$54	$40	$32	$26	$20	$15	$12	$14	$21	$36	$49	$56	$55	$53	$52	$49	$47
SCE (CAISO)	$46	$44	$43	$44	$44	$49	$57	$49	$26	$13	$7	$3	$1	-$3	-$4	$5	$28	$43	$52	$51	$51	$50	$49	$47
BANC	$45	$44	$43	$43	$44	$49	$58	$52	$40	$36	$30	$23	$17	$14	$17	$23	$36	$47	$54	$53	$51	$51	$49	$46
Turlock ID	$46	$44	$43	$43	$44	$49	$58	$52	$41	$40	$34	$27	$21	$19	$20	$26	$36	$47	$54	$53	$52	$51	$49	$46
LADWP	$45	$45	$42	$42	$42	$47	$60	$48	$28	$15	$5	$6	$4	$0	-$1	$8	$31	$45	$54	$54	$53	$52	$50	$51
NV Energy	$36	$36	$35	$36	$38	$42	$46	$39	$25	$17	$12	$8	$5	$1	$0	$7	$25	$34	$39	$39	$39	$38	$38	$36
Arizona PS	$36	$35	$35	$36	$38	$42	$46	$37	$17	$8	$4	$1	$0	-$4	-$6	$1	$22	$32	$38	$38	$38	$37	$37	$36
Tucson Electric	$36	$35	$35	$37	$38	$42	$45	$37	$18	$9	$5	$2	$0	-$4	-$6	$3	$26	$34	$38	$38	$38	$37	$37	$36
Salt River Project	$36	$35	$35	$36	$38	$42	$46	$39	$11	$7	$5	$3	$1	-$2	-$5	$0	$22	$32	$37	$38	$38	$37	$37	$47
PSC New Mexico	$33	$33	$33	$33	$34	$36	$38	$19	$6	$0	-$9	-$9	-$13	-$20	-$24	-$13	$12	$27	$34	$34	$32	$30	$33	$33
WAPA - Desert SW	$36	$35	$35	$36	$43	$42	$46	$37	$17	$9	$4	$2	$0	-$4	-$6	$1	$25	$32	$38	$39	$38	$41	$43	$36
El Paso Electric	$30	$32	$31	$32	$34	$38	$40	$26	$11	$4	$0	-$2	-$5	-$10	-$12	-$3	$23	$30	$34	$33	$32	$31	$35	$31
PacifiCorp East	$34	$34	$34	$35	$36	$40	$43	$38	$28	$23	$19	$16	$15	$11	$8	$13	$26	$34	$38	$38	$37	$36	$35	$34
Idaho Power	$35	$34	$35	$35	$37	$40	$46	$49	$33	$29	$25	$22	$21	$19	$17	$19	$29	$36	$39	$39	$38	$37	$36	$35
NorthWestern	$34	$34	$33	$35	$37	$40	$44	$41	$37	$34	$32	$31	$30	$27	$26	$29	$34	$38	$40	$40	$38	$37	$36	$34
Avista Utilities	$35	$35	$35	$36	$38	$41	$46	$43	$38	$36	$34	$33	$32	$30	$29	$31	$36	$40	$41	$41	$39	$38	$37	$35
Avangrid	$36	$36	$36	$36	$38	$41	$45	$44	$39	$37	$36	$34	$33	$31	$31	$32	$37	$40	$41	$46	$40	$38	$38	$36
BPA	$36	$36	$36	$36	$39	$40	$46	$43	$39	$38	$37	$35	$33	$32	$32	$34	$40	$41	$41	$40	$41	$38	$38	$36
Tacoma Power	$37	$36	$36	$36	$38	$41	$45	$42	$38	$36	$36	$34	$33	$31	$30	$32	$36	$39	$40	$40	$39	$38	$38	$36
PacifiCorp West	$35	$36	$36	$36	$37	$40	$44	$43	$38	$36	$35	$33	$33	$31	$30	$32	$36	$39	$40	$45	$39	$38	$37	$35
Portland GE	$35	$36	$36	$36	$37	$40	$44	$43	$38	$36	$35	$34	$33	$31	$30	$32	$36	$39	$40	$40	$39	$41	$37	$35
Puget Sound Energy	$36	$36	$36	$36	$38	$41	$45	$42	$38	$36	$36	$34	$33	$31	$30	$31	$36	$39	$40	$41	$39	$38	$38	$36
Seattle City Light	$36	$36	$36	$36	$38	$41	$45	$42	$38	$36	$36	$34	$36	$31	$30	$31	$36	$39	$40	$41	$39	$37	$38	$38
Powerex	$41	$41	$40	$41	$42	$44	$46	$44	$42	$40	$40	$39	$39	$39	$39	$40	$44	$45	$45	$44	$44	$43	$43	$42

Table 3.4 Average hourly 5-minute market prices (January–March)

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	$49	$46	$45	$45	$46	$48	$57	$50	$36	$28	$19	$17	$14	$12	$9	$15	$32	$44	$51	$51	$51	$52	$51	$49
PG&E (CAISO)	$49	$46	$45	$45	$46	$49	$58	$54	$42	$34	$24	$19	$14	$12	$12	$18	$36	$47	$54	$53	$53	$54	$52	$49
SCE (CAISO)	$48	$46	$45	$45	$45	$48	$57	$49	$29	$16	$6	$4	$2	-$1	-$5	$3	$28	$42	$49	$49	$51	$52	$51	$49
BANC	$48	$47	$44	$44	$45	$48	$57	$52	$42	$37	$27	$21	$16	$14	$14	$20	$36	$45	$52	$51	$52	$53	$51	$48
Turlock ID	$48	$46	$44	$45	$45	$48	$57	$52	$43	$41	$30	$25	$19	$18	$17	$22	$36	$45	$52	$51	$52	$53	$51	$48
LADWP	$47	$47	$42	$43	$43	$48	$59	$48	$30	$17	$4	$6	$4	$1	-$2	$6	$30	$45	$52	$52	$53	$54	$53	$50
NV Energy	$38	$37	$36	$37	$40	$42	$49	$40	$28	$19	$11	$8	$5	$2	-$2	$5	$26	$36	$41	$39	$39	$40	$40	$41
Arizona PS	$38	$37	$36	$37	$39	$42	$48	$36	$20	$11	$4	$2	$0	-$3	-$2	$0	$24	$34	$39	$38	$38	$38	$39	$37
Tucson Electric	$38	$37	$36	$37	$39	$43	$48	$35	$19	$12	$6	$3	$0	-$2	-$6	$2	$35	$40	$40	$38	$38	$38	$40	$37
Salt River Project	$39	$37	$36	$37	$40	$44	$49	$37	$12	$11	$5	$3	$2	-$1	-$6	-$2	$24	$34	$39	$38	$38	$38	$39	$50
PSC New Mexico	$35	$34	$33	$34	$35	$38	$43	$24	$9	$1	-$7	-$9	-$12	-$19	-$24	-$10	$17	$30	$34	$34	$32	$31	$37	$40
WAPA - Desert SW	$37	$36	$36	$37	$39	$43	$48	$36	$18	$12	$4	$3	$1	-$3	-$7	$0	$28	$34	$39	$38	$38	$41	$44	$37
El Paso Electric	$34	$33	$32	$34	$36	$39	$43	$28	$11	$7	$1	-$2	-$3	-$9	-$13	-$2	$24	$32	$35	$33	$33	$33	$34	$33
PacifiCorp East	$37	$35	$34	$36	$38	$42	$47	$37	$27	$19	$16	$14	$12	$11	$3	$10	$27	$35	$39	$38	$38	$36	$36	$35
Idaho Power	$36	$35	$35	$36	$39	$42	$53	$49	$31	$25	$22	$20	$18	$16	$13	$16	$29	$37	$41	$39	$39	$38	$37	$36
NorthWestern	$37	$35	$34	$36	$39	$43	$48	$44	$36	$31	$29	$28	$26	$24	$23	$26	$35	$40	$42	$40	$39	$38	$37	$35
Avista Utilities	$37	$36	$36	$38	$42	$43	$49	$43	$37	$33	$31	$29	$28	$26	$24	$28	$36	$41	$42	$41	$39	$39	$38	$36
Avangrid	$38	$36	$36	$37	$39	$42	$48	$43	$35	$33	$31	$29	$28	$26	$25	$28	$35	$39	$42	$41	$40	$39	$39	$36
BPA	$37	$36	$36	$37	$40	$42	$47	$42	$35	$35	$33	$31	$30	$29	$26	$29	$37	$40	$42	$41	$40	$39	$39	$36
Tacoma Power	$39	$36	$36	$37	$39	$42	$47	$42	$35	$33	$33	$30	$29	$27	$25	$28	$35	$39	$41	$41	$40	$38	$38	$36
PacifiCorp West	$37	$36	$36	$37	$39	$42	$47	$42	$35	$32	$30	$29	$27	$26	$24	$27	$35	$39	$41	$40	$40	$39	$38	$36
Portland GE	$37	$36	$36	$37	$39	$42	$47	$42	$35	$32	$30	$29	$28	$26	$25	$28	$36	$39	$41	$40	$40	$44	$38	$36
Puget Sound Energy	$38	$36	$36	$37	$39	$42	$47	$42	$35	$33	$32	$30	$29	$27	$25	$28	$35	$39	$41	$41	$40	$39	$39	$36
Seattle City Light	$38	$36	$36	$37	$39	$42	$47	$42	$35	$33	$33	$30	$34	$27	$25	$28	$35	$39	$46	$41	$40	$38	$39	$37
Powerex	$41	$41	$40	$40	$42	$44	$46	$44	$41	$40	$39	$39	$38	$39	$39	$40	$43	$45	$45	$44	$43	$43	$43	$41

3.3 Day-ahead market price comparison

This section analyzes day-ahead and real-time market prices for balancing areas in the day-ahead market. Currently, this is just the California ISO balancing area.

Load weighted average day-ahead market prices were about $41/MWh in the first quarter of 2025, down 15 percent from $48/MWh in the first quarter of 2024. Average prices in the CAISO balancing area's day-ahead, 15-minute, and 5-minute markets combined dropped by about 12 percent compared to the first quarter of the previous year. The average price of the three markets this quarter decreased to $40/MWh from $46/MWh in the same quarter of 2024.

Figure 3.7 shows load-weighted average monthly energy prices during all hours across all Aggregated Pricing Nodes (APnodes). Prices are calculated based on the load schedules and corresponding prices at these pricing nodes.[15] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from April 2023 to March 2025.

Over the quarter, day-ahead prices averaged $41/MWh, 15-minute prices averaged $39/MWh, and 5-minute prices averaged $40/MWh. January had the highest prices, with an average over the three markets of about $48/MWh.

Figure 3.7 also shows monthly average gas prices at PG&E Citygate from April 2023 to March 2025. 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 PG&E Citygate gas price declined to $3.72/MMBtu this quarter, down from $3.85/MMBtu in the same quarter last year.

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.

[15] The load-weighted average is calculated by weighting each interval's price by its corresponding load relative to the total over a specific time period. For monthly average, prices for each real-time interval are weighted by their respective loads and divided by the total monthly load for the region. For hourly averages over the quarter, each interval's price is weighted by its load relative to the total load during that hour for the region.

Figure 3.7 Monthly average PG&E Citygate gas price and load-weighted average electricity prices for balancing areas in day-ahead market

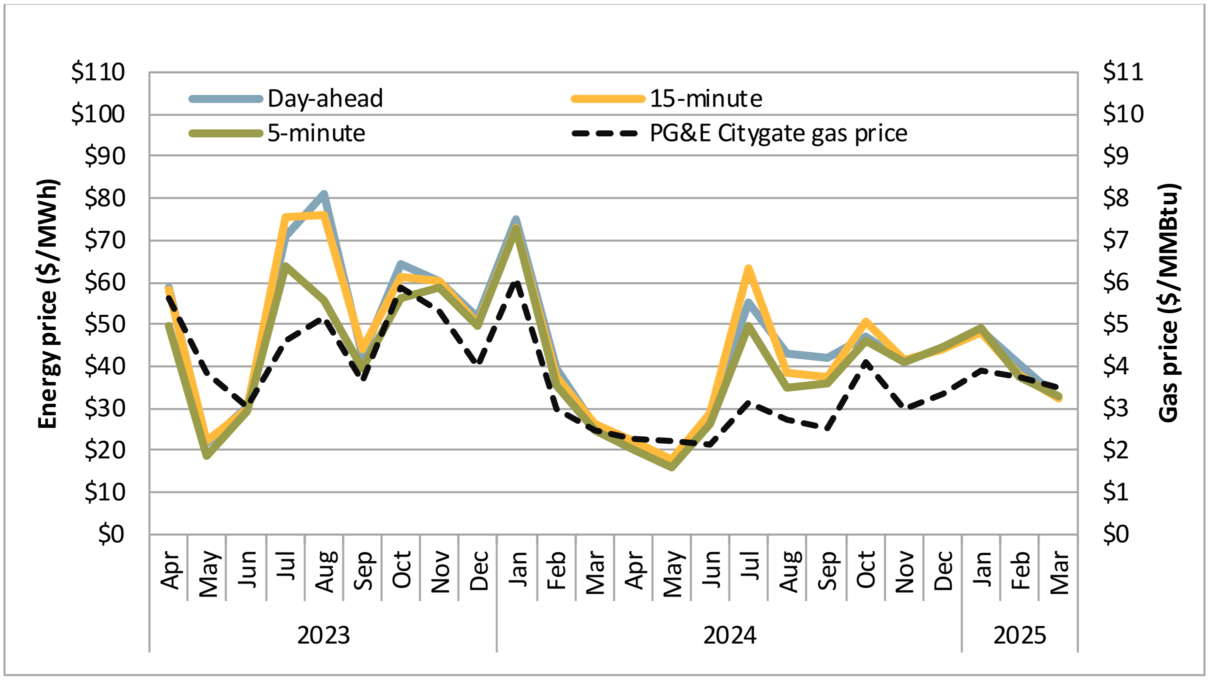


Figure 3.8 illustrates the hourly load-weighted average energy prices for the first quarter compared to the average hourly net load.[16] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

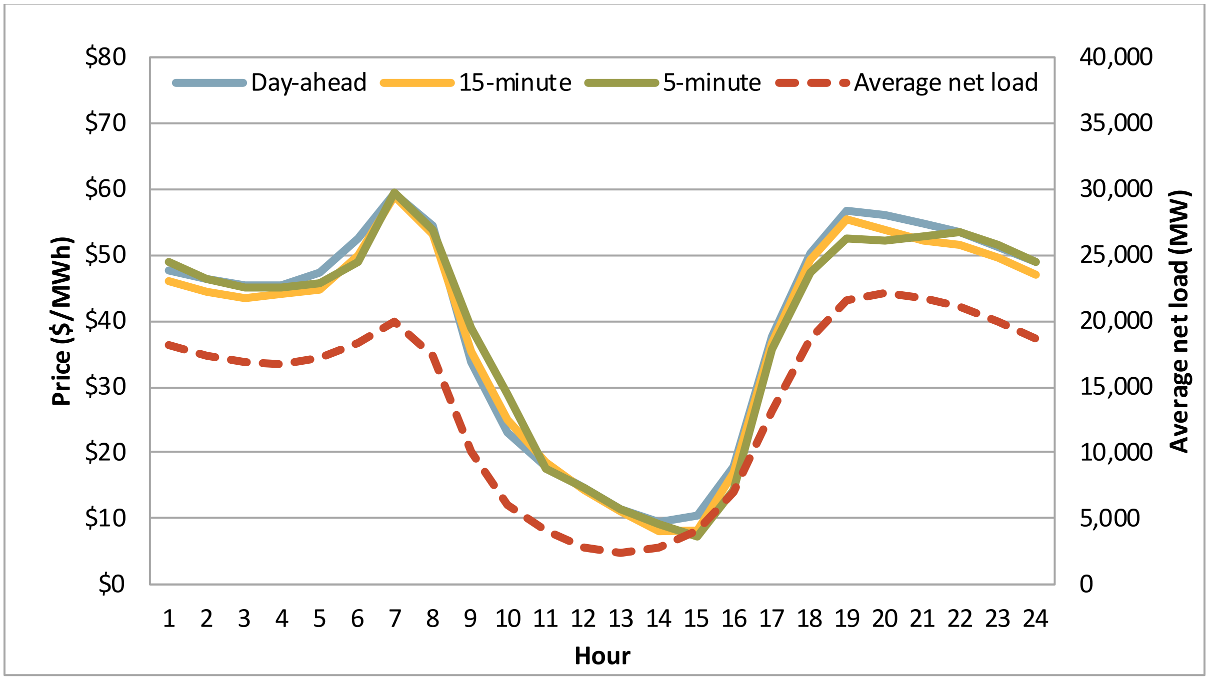
Average hourly prices continue to follow the net load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the morning and early evening. Energy prices across all three markets peaked at hour-ending 7, averaging around $59/MWh, while net load peaked at hour-ending 20, reaching 22,118 MW.

During hour-ending 7, the day-ahead load-weighted average energy price was $59.3/MWh, the 15-minute price was $58.4/MWh, and the 5-minute price was $59.5/MWh. Overall, prices across the three markets converged well during most hours. Prices in the day-ahead and 15-minute markets were higher than the 5-minute market during hours 18 and 19 due largely to California ISO operators adjusting the load forecast up significantly more in the 15-minute market than in the 5-minute market over these hours.[17]

16 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.

17 Please see Section 8 for a detailed discussion on load conformance.

Figure 3.8 Hourly load-weighted average energy prices for balancing areas in day-ahead market (CAISO January–March)



3.4 Bilateral price comparison

Figure 3.9 and Figure 3.10 compare 15-minute prices in different regions of the WEIM during peak hours (hours-ending 7 through 22) to day-ahead prices for comparable markets. These figures show the monthly 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.

As shown in these figures, in January and February, the day-ahead prices in the Intercontinental Exchange for the Mid-Columbia trading hub were higher than ISO 15-minute market prices in the Pacific Northwest, and ISO 15-minute and day-ahead market prices at Pacific Gas and Electric. These prices converged significantly in March. Over the quarter, Mid-Columbia prices averaged about $51/MWh, which was roughly 24 percent higher than ISO 15-minute market prices in the Pacific Northwest.

Day-ahead prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about $35/MWh over the quarter, almost 49 percent higher than ISO 15-minute market prices in the Desert Southwest. Palo Verde ICE prices were higher than ISO 15-minute market prices in the Desert Southwest during each month of the quarter, while ISO day-ahead market prices at Southern California Edison load node were relatively more converged to ISO 15-minute market prices at the same node.

Figure 3.9 Mid-C bilateral ICE vs. Pacific Northwest 15-minute market prices (peak hours)

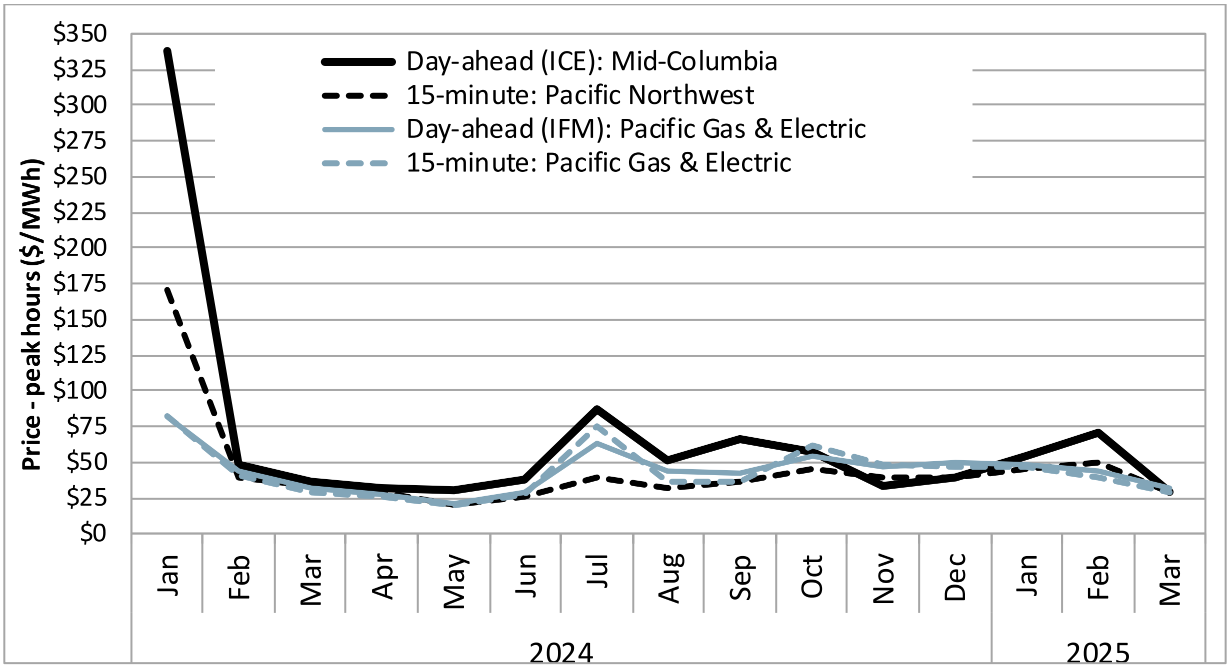


Figure 3.10 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)

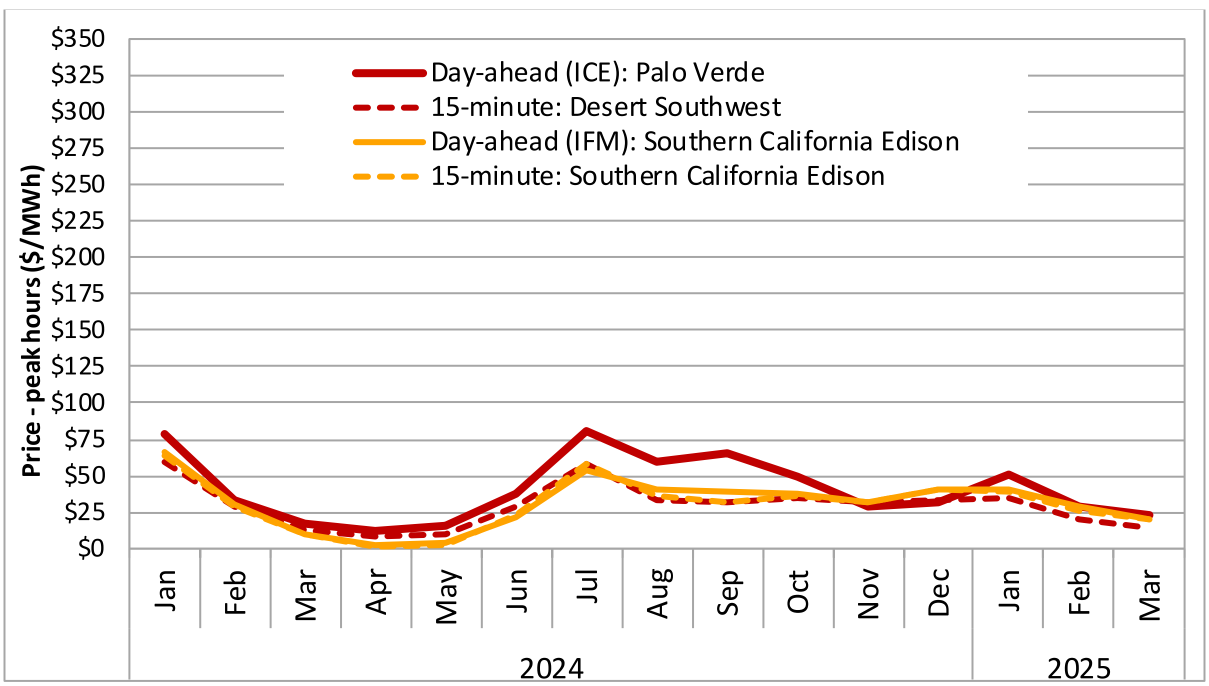


Figure 3.11 compares monthly average prices in the bilateral and ISO day-ahead market for 2024 through the first quarter of 2025. The California ISO market day-ahead prices are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). Average

bilateral prices for Mid-Columbia (Peak) significantly exceeded ISO market day-ahead prices in February 2025. This was a result of a large arctic air mass in the first week of February,[18] which covered much of the Pacific Northwest and Intermountain West regions.

Over the quarter, bilateral day-ahead prices at Mid-Columbia and Palo Verde averaged about $51/MWh and $35/MWh, respectively, while ISO day-ahead prices at Pacific Gas and Electric and Southern California Edison averaged around $41/MWh and $30/MWh, respectively.

Figure 3.11 Monthly average day-ahead and bilateral market prices

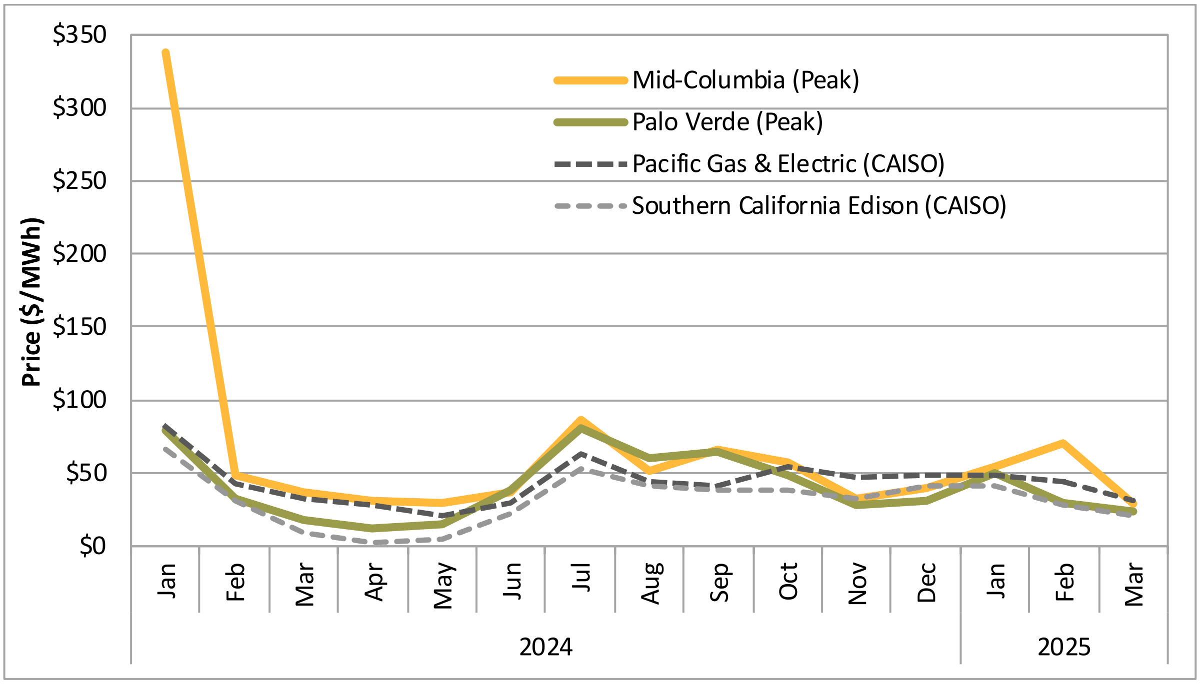


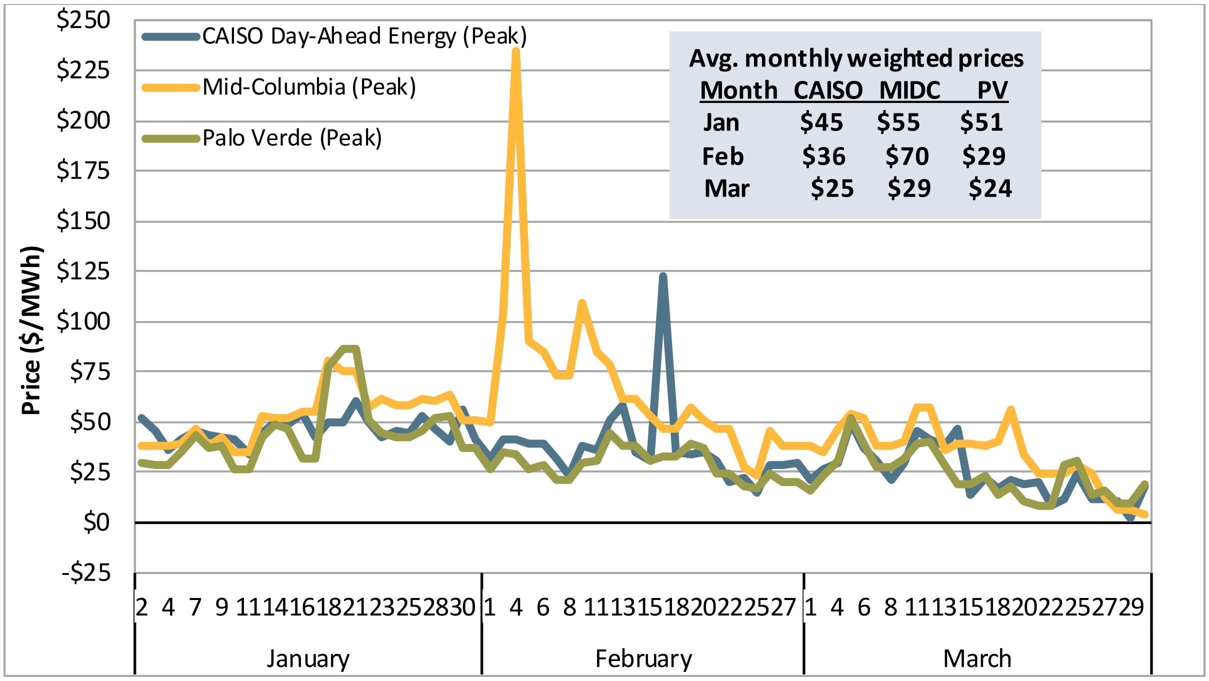
Figure 3.12 shows daily California ISO market day-ahead load weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as averages for the bilateral day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO markets. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays. On average, prices at Mid-Columbia were 8 percent higher than Palo Verde in January, 139 percent higher in February, and 23 percent higher in March.

The California ISO FERC Order 831 policy will increase the ISO market 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 ISO market hourly prices, exceeds $1,000/MWh. The ISO implemented enhancements to the maximum

18 National Weather Service Climate Prediction Center, February 1, 2025: https://www.cpc.ncep.noaa.gov/products/archives/short_range/2025/02/01/610temp.20250201.fcst.gif

import bid price (MIBP) hourly energy shaping factor on November 16, 2024.[19] The ISO did not raise the energy bid cap and penalty prices to $2,000/MWh in the first quarter of 2025.

Figure 3.12 Day-ahead California ISO and bilateral market prices (January–March)



Average day-ahead bilateral prices from the Intercontinental Exchange 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. For the Mid-Columbia hub, average day-ahead prices were greater than the average real-time prices (from Powerdex) by about $8.50/MWh. For the Palo Verde hub, average day-ahead prices were lower than average real-time prices (from Powerdex) by about $0.25/MWh.

3.5 Price variability

This section analyzes the frequency of prices exceeding $250/MWh and the occurrence of negative prices. Two groups of balancing authority areas (BAAs) were included: the first group consists of those participating in both the day-ahead and real-time markets, which as of this quarter includes only the California ISO balancing area.[20] The second group comprises balancing areas participating exclusively in the real-time market, which includes all WEIM entities aside from the California ISO balancing area.

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19 *Modification of Maximum Import Bid Price Hourly Energy Shaping Factor effective 11/16/24*, California ISO market notice, November 13, 2024: https://www.caiso.com/notices/modification-of-maximum-import-bid-price-hourly-energy-shaping-factor-effective-11-16-24#:~:text=The%20California%20ISO's%20Price%20Formation%20Enhancements%20modification,modification%20is%20in%20Business%20Practice%20Manual%20(BPM)

20 The frequency is calculated by counting the number of intervals with extreme prices at either the Default Load Aggregation Point (DLAP) for the CAISO balancing area, or EIM Load Aggregation Point (ELAP) for the WEIM areas not participating in the day-ahead market. The frequency is expressed as a ratio of these occurrences to the total number of intervals for each month, multiplied by the number of DLAPs and ELAPs within each group.

High prices

Figure 3.13 shows the monthly frequency of high prices across all three markets for the balancing area participating in both the day-ahead and real-time markets from January 2024 to March 2025.[21] Figure 3.14 illustrates the monthly frequency of high prices for balancing areas participating only in the real-time market during the same period.[22]

In the day-ahead market, the frequency of high prices over $250/MWh decreased compared to the same quarter of 2024. In the first quarter of 2025, the day-ahead market recorded zero percent of intervals with an average price exceeding $250/MWh. In the same quarter of the previous year, 0.17 percent of intervals had prices above $250/MWh.

In the 15-minute market, the frequency of high prices for the balancing area participating in the day-ahead market decreased by 86 percent, dropping from 0.31 percent in Q1 2024 to 0.04 percent in Q1 2025. For balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices also decreased from 2.5 percent in Q1 2024 to 0.05 percent in Q1 2025.

In the 5-minute market, the frequency of high prices for the balancing area participating in the day-ahead market decreased by 34 percent, dropping from 0.27 percent to 0.18 percent. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market dropped by 96 percent, from 2.5 percent to 0.09 percent.

The sharp decline in the frequency of high prices in this quarter was due to the absence of extreme weather events. In contrast, January 2024 saw severe cold weather and constrained supply in the Pacific Northwest, which led to an abnormally large number of intervals with high prices.

21 The frequency of high prices was measured at the three largest DLAPs within the California ISO balancing area: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

22 The frequency of high prices was measured at EIM Load Aggregation Points (ELAPs).

Figure 3.13 Frequency of high prices in BAAs participating in the day-ahead market (CAISO)

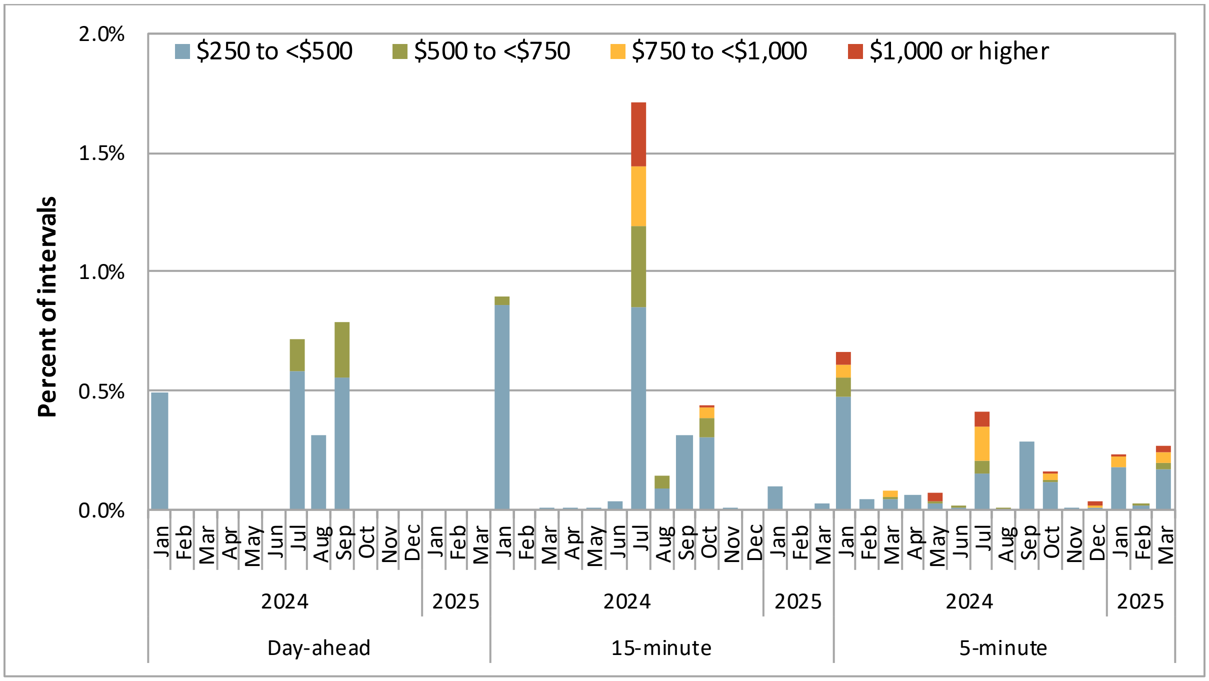
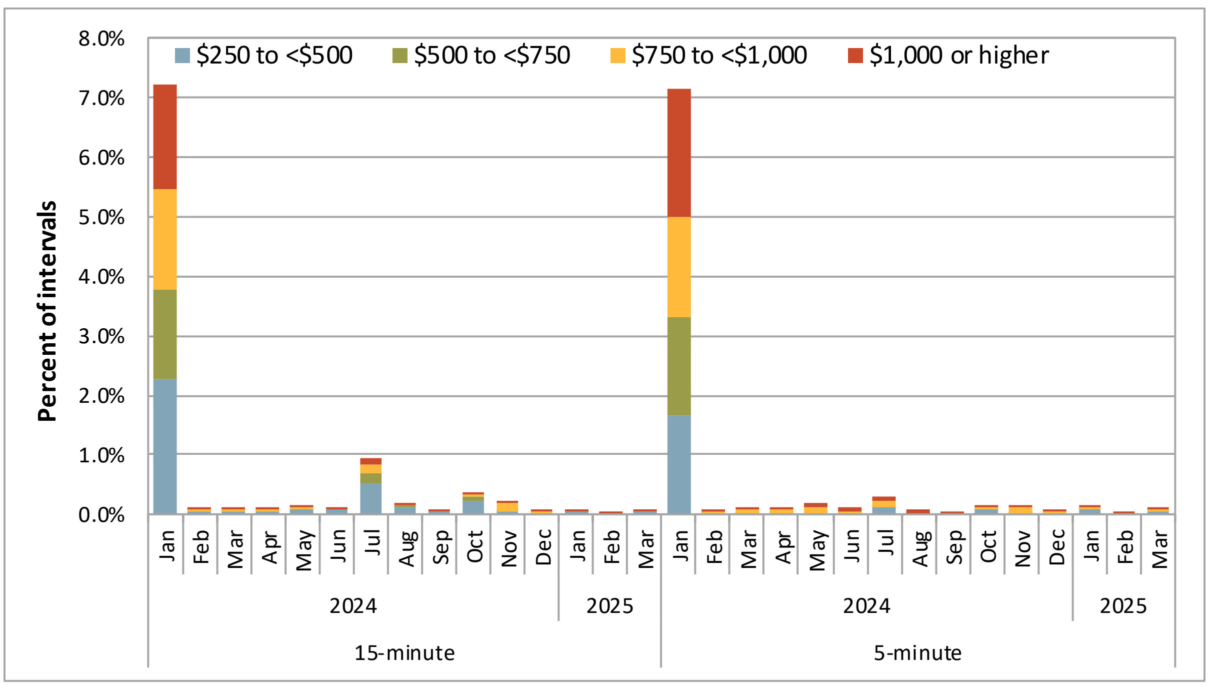


Figure 3.14 Frequency of high prices in BAAs participating only in the real-time markets



Negative prices

Figure 3.15 and Figure 3.16 show the frequency of negative prices across two groups of balancing areas: those participating in the day-ahead market and those participating only in the real-time markets, spanning the period from January 2024 to March 2025. Overall, the frequency of negative prices increased for the day-ahead and the real-time market participating group.

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.

For balancing areas participating in the day-ahead market—currently just the CAISO balancing area—the frequency of negative prices increased in the three markets. In the day-ahead market, the frequency increased from 9.9 percent to 11.1 percent compared to the same quarter of the previous year. In the 15-minute market, it increased from 11.6 percent to 13.5 percent, and in the 5-minute market, it increased from 12.6 percent to 13.8 percent.

For the BAAs participating exclusively in the real-time markets—all balancing areas in WEIM besides CAISO—the frequency of negative prices showed an increase across the 15-minute and 5-minute markets, with an average rise of 36 percent compared to the same quarter of the previous year. For instance, in the 15-minute market, the frequency increased from 6 percent to 8.5 percent, while in the 5-minute market, it rose from 7.4 percent to 9.7 percent during this quarter.

Figure 3.15 Frequency of negative prices in BAAs participating in the day-ahead market (CAISO)

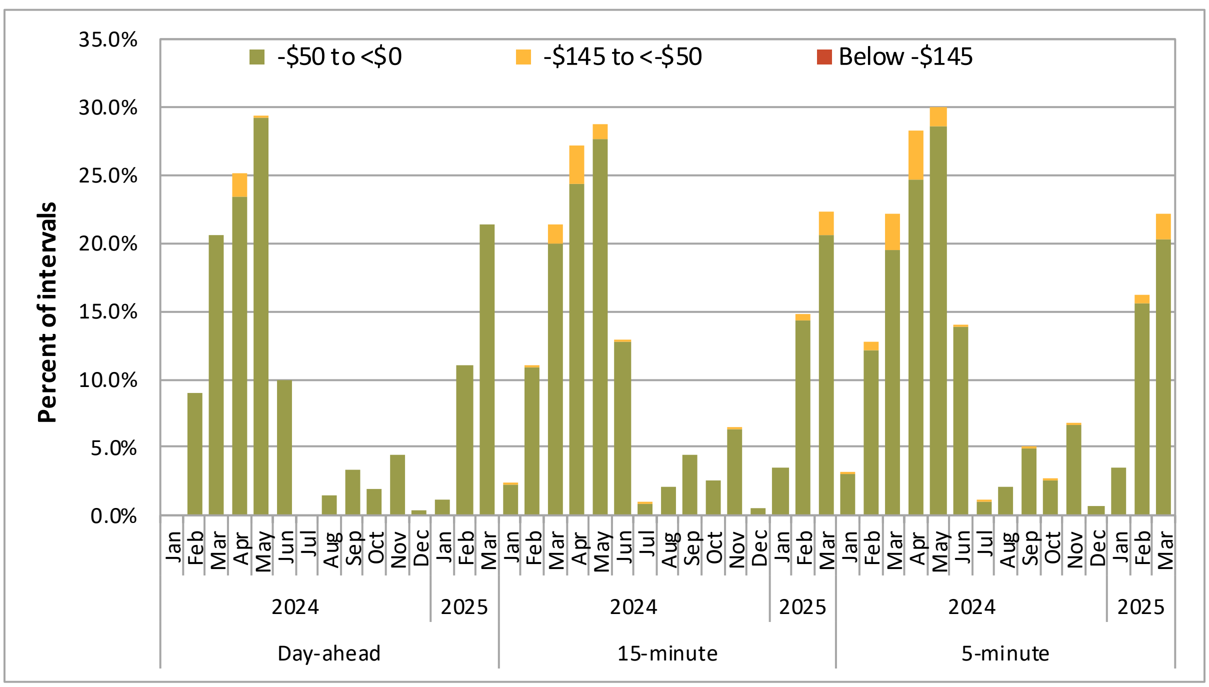
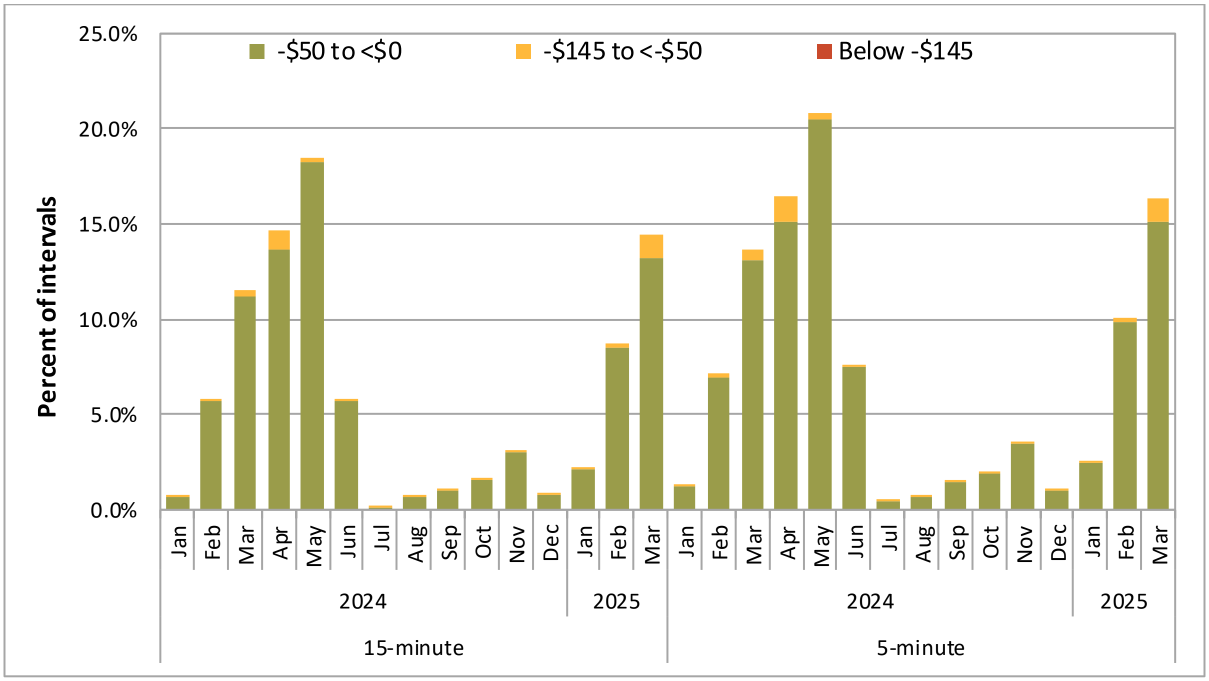


Figure 3.16 Frequency of negative prices in BAAs participating only in the real-time markets



3.6 WEIM transfers and transfer limits

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.

Figure 3.17 summarizes the average volume of dynamic WEIM transfers in the 5-minute market by hour during the last five quarters.[23] During the quarter, the average volume of transfers across the system was up, at around 4,520 MW, compared to around 3,870 MW in the previous quarter, and around 4,320 MW from the same quarter of the previous year.

Figure 3.18 summarizes average inter-regional transfers during the last five quarters. The bars show *net* WEIM transfers for each region by hour.[24] 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. Net WEIM exports for a region are shown as negative and net WEIM imports for a

[23] WEIM transfers in this section exclude the fixed bilateral transactions between WEIM entities (base WEIM transfer schedules) and therefore reflect only *dynamic* WEIM transfer schedules optimized in the market.

[24] See Appendix A for figures on the average hourly transfers by quarter for each WEIM balancing area.

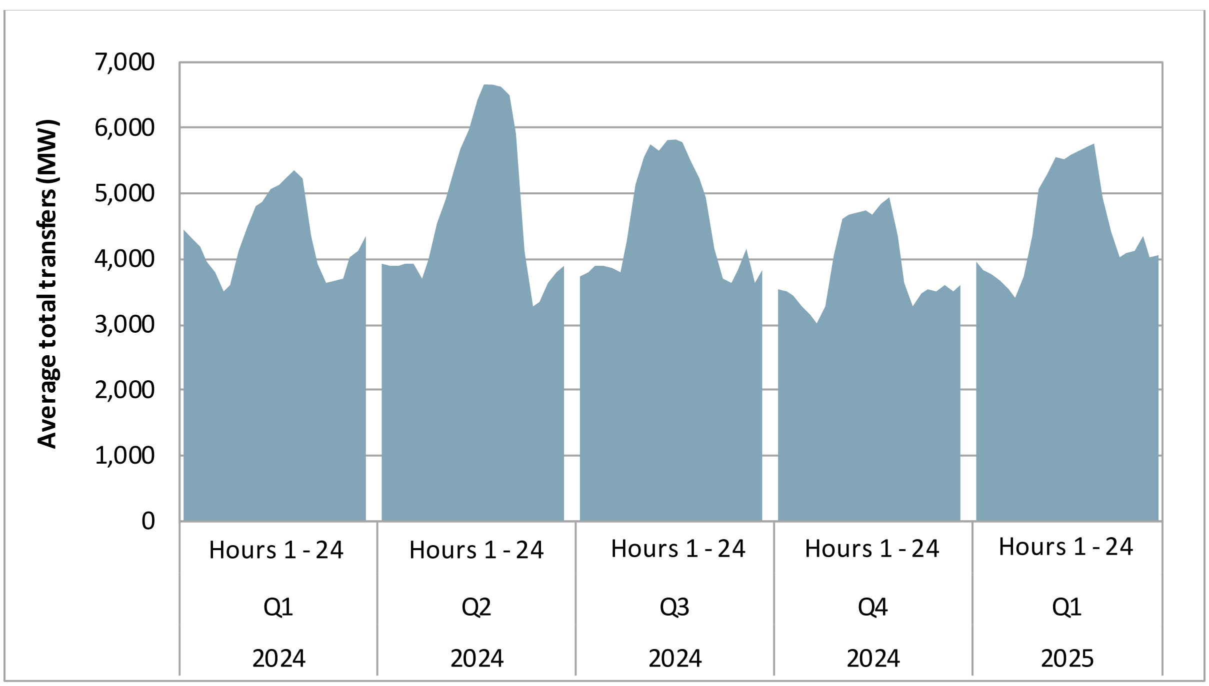
region are shown as positive. During the quarter, net exports from the Intermountain West region increased significantly, both compared to the previous quarter and same quarter of the previous year.

Figure 3.19 shows the same information for only Q1 2025. The figure highlights two key periods: mid-day and peak. During the mid-day hours, regional WEIM transfers are typically highest with significant levels of exports from the CAISO balancing area. During the peak hours—when net load in the WEIM system is highest—regional WEIM transfers were lower. On net, balancing areas in the Intermountain West and Desert Southwest regions were mostly exporting out to balancing areas in California during this peak period.

Figure 3.20 and Figure 3.21 show average WEIM transfers in the 5-minute market by balancing area in the mid-day and peak periods during the quarter.[25] 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.

As shown in Figure 3.20, the CAISO balancing area exported on net over 1,800 MW on average out to neighboring balancing areas during the mid-day hours. These hours typically contain the highest levels of exports out of the CAISO balancing area because of significant solar production. These exports were mostly to balancing areas in the Pacific Northwest region. During the peak period (Figure 3.21), balancing areas in the Intermountain West region exported on net over 800 MW on average out to balancing areas outside the region.

Figure 3.17 Average dynamic WEIM transfer volume by hour and quarter (5-minute market, Q1 2024 – Q1 2025)



25 In Figure 3.20 and Figure 3.21, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 3.18 Average dynamic inter-regional WEIM transfers by hour (5-minute market, Q1 2024 – Q1 2025)

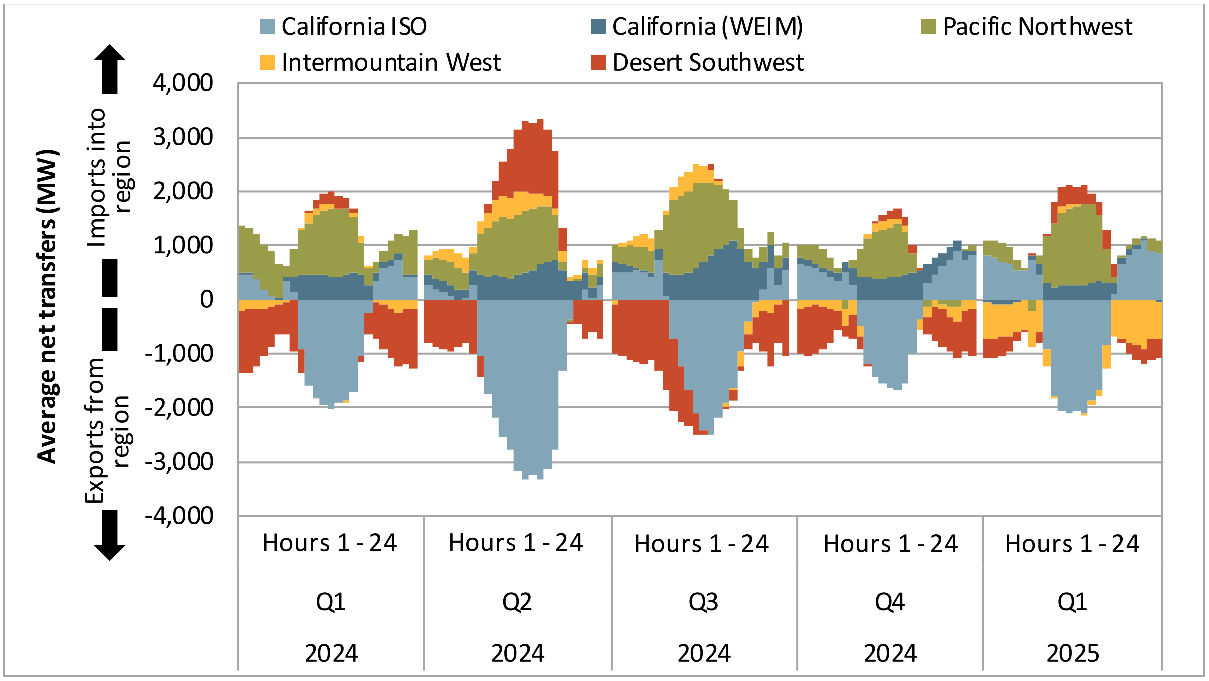


Figure 3.19 Average dynamic inter-regional WEIM transfers by hour (5-minute market, Q1 2025)

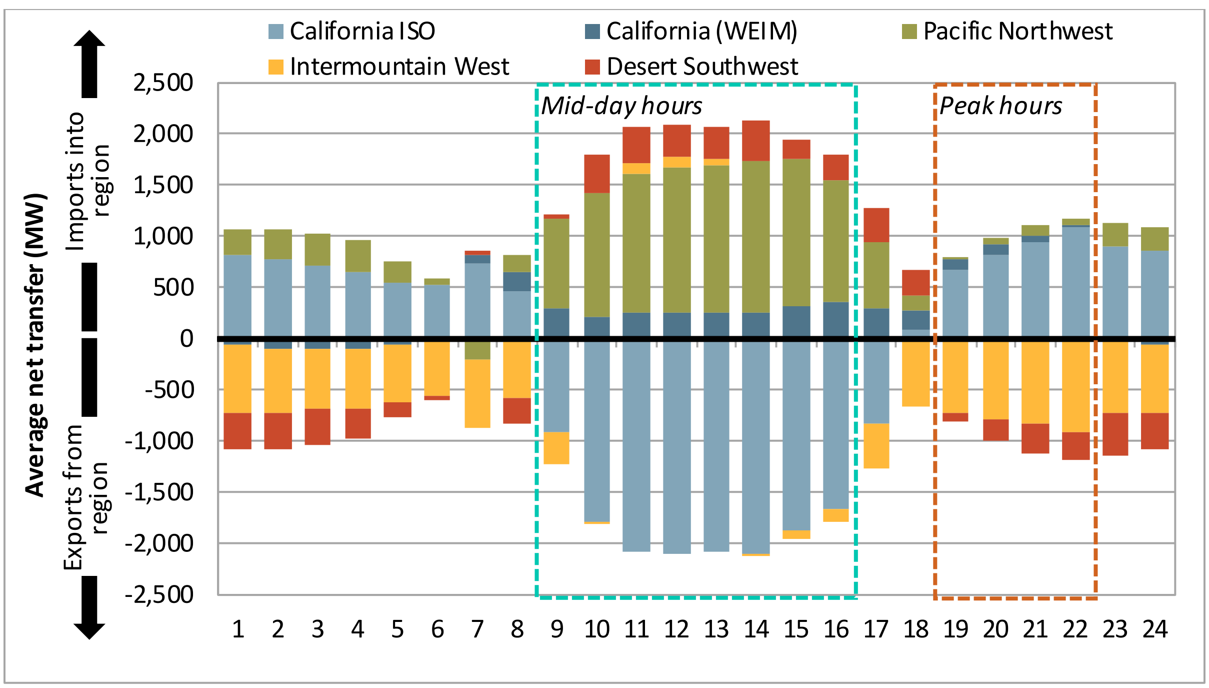


Figure 3.20 Average 5-minute market WEIM exports (mid-day hours, Q1 2025)

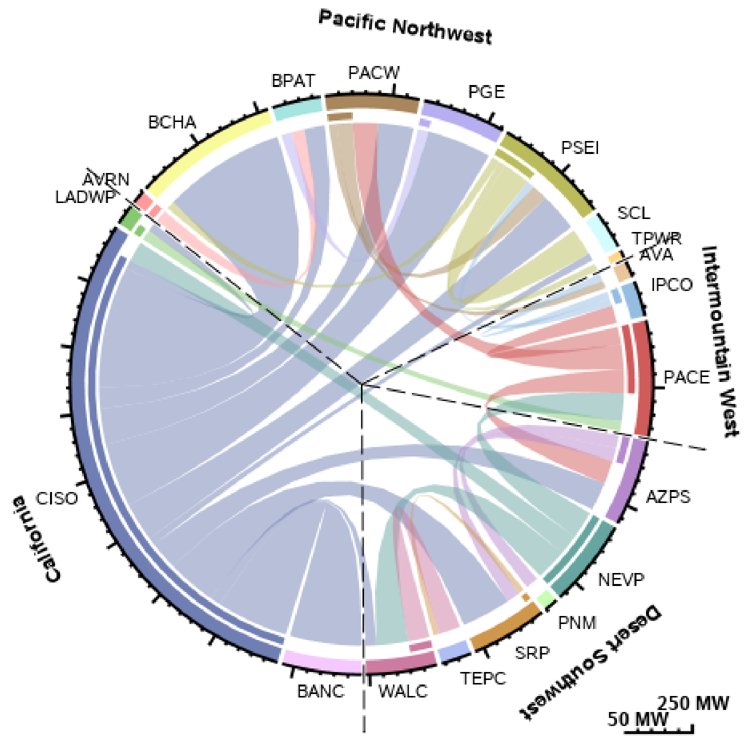
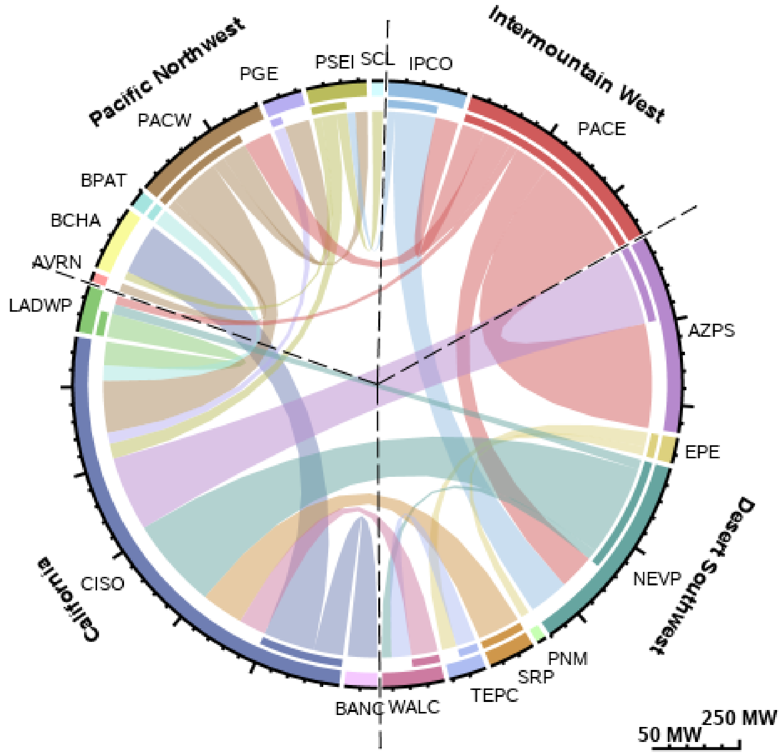


Figure 3.21 Average 5-minute market WEIM exports (peak load hours, Q1 2025)



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 3.5 summarizes all import or export scheduling limits from individual WEIM transfer points for each balancing area in the 5-minute market.[26] 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 last two columns in Table 3.5 show WEIM transfer limits between regions (out-of-region import and export limits).

Out-of-region transfer limits from California into the Desert Southwest region decreased significantly during the quarter, by roughly 10,000 MW. This was because of reduced transfer limits for dynamic WEIM transfers from the California ISO to Arizona Public Service on the North Gila and Willow Beach interties. However, there was little price separation or congestion between these regions because of sufficient transfer capability elsewhere in the system.

For the Pacific Northwest region, there was an average of around 1,500 MW of import and 800 MW of export transfer capacity into or out of the region. The lack of transfer capability out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

[26] These amounts only reflect scheduling limits on individual WEIM Energy Transfer System Resources (ETSRs) and therefore do not account for either (1) total scheduling limits that can be the result of a resource sufficiency evaluation failure or (2) intertie constraints that can limit WEIM transfers.

Table 3.5 Average 5-minute market WEIM limits (Q1 2025)

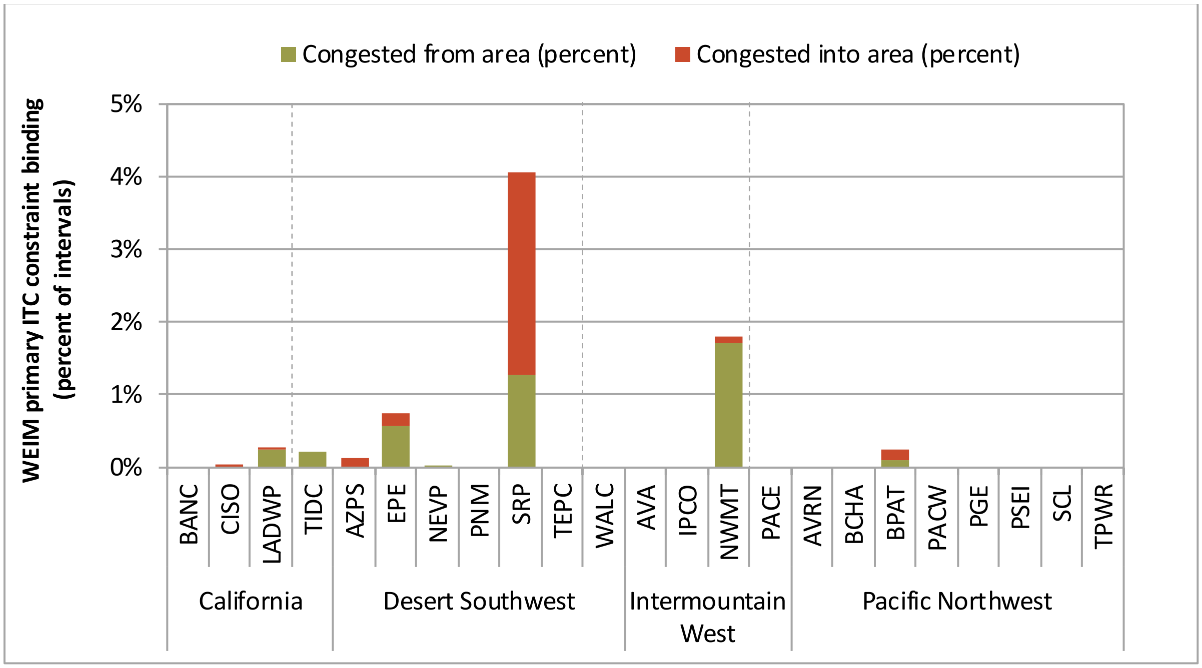
Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**32,160**	**22,158**
California ISO	39,230	24,964	29,333	17,351
BANC	4,445	4,218	0	0
LADWP	5,396	9,804	2,827	4,808
Turlock Irrig. District	1,898	1,982	0	0
Desert Southwest			**22,784**	**33,110**
Arizona Public Service	37,907	45,732	13,373	24,020
El Paso Electric	651	521	0	0
NV Energy	4,462	3,634	3,729	2,567
PSC New Mexico	1,039	1,119	0	0
Salt River Project	23,179	25,486	2,608	3,324
Tucson Electric	4,848	6,623	785	1,106
WAPA - Desert SW	5,873	5,168	2,290	2,093
Intermountain West			**1,999**	**2,366**
Avista Utilities	492	1,001	93	88
Idaho Power	1,989	2,726	504	819
NorthWestern Energy	652	821	7	7
PacifiCorp East	3,243	2,196	1,395	1,451
Pacific Northwest			**1,515**	**825**
Avangrid	844	803	23	27
Powerex	355	44	305	0
BPA	579	668	131	180
PacifiCorp West	1,684	1,693	568	467
Portland General Electric	836	642	266	48
Puget Sound Energy	1,068	933	179	75
Seattle City Light	444	417	44	28
Tacoma Power	299	219	0	0

WEIM intertie constraints

An intertie constraint (ITC) is a scheduling limit applied to a specified set of scheduling points or intertie resources. This ensures that net transfers of the imports or exports (considering counterflow) do not violate the physical or contractual limits. In the WEIM, these can also be used to manage WEIM transfers in a balancing area. Here, a *primary* intertie constraint is modeled for each balancing area that is mapped to all of their dynamic WEIM transfers. A WEIM entity can use this constraint to effectively manage all dynamic WEIM transfers into or out of their system, on net, without needing to adjust individual transfer limits.

Figure 3.22 shows the percent of intervals in the 5-minute market in which the primary intertie constraint—that limits all dynamic WEIM transfers on net for a balancing area—was binding in either the import or export direction, resulting in congestion. Of note, net imports or net exports for Salt River Project were constrained in around 4 percent of intervals because of this constraint. When this constraint was binding, net transfers were limited to roughly 300 MW on average in each direction. The constraint limiting net exports for NorthWestern Energy was also binding in around 2 percent of intervals (at around 80 MW on average).

Figure 3.22 Frequency of primary ITC constraint binding for net WEIM transfers (5-minute market, Q1 2025)



A WEIM entity can also set up intertie constraints that are mapped to a subset of their WEIM transfers (non-primary). For example, the entity can set up an intertie constraint that is mapped to only WEIM transfers at a specific intertie. A WEIM entity can also create an intertie constraint that is mapped to either only WEIM imports or only WEIM exports, which will limit total imports or total exports rather than net WEIM transfers. During the quarter, Tucson Electric enforced an intertie constraint that was binding for total WEIM imports in around 2.6 percent of intervals and for total WEIM exports in around 1.5 percent of intervals. The limit was around 500 MW on average in both directions when these constraints were binding.

4 Congestion

This section analyzes the impact of congestion from various constraint types in the real-time market and in the day-ahead market. 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 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.

Section 4.1 addresses congestion on the constraints limiting WEIM transfers between balancing areas in the real-time market. Section 4.2 addresses real-time market internal congestion.[27] Section 4.3 analyzes day-ahead market congestion rent and loss surpluses. Section 4.4 addresses intertie constraint congestion in the day-ahead market. Section 4.5 addresses the impact of internal congestion on the day-ahead market. Lastly, Section 4.6 addresses congestion revenue rights.

4.1 WEIM transfer constraint congestion

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 4.1 shows the percent of intervals and overall price impact of 15-minute market WEIM transfer constraint congestion in each balancing area during the quarter.[28] Figure 4.2 shows the same information for the 5-minute market. 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 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.[29]

Powerex was frequently constrained relative to the CAISO balancing area because of WEIM transfer congestion during the quarter. In the 5-minute market, Powerex was import constrained during around 60 percent of intervals and export constrained during around 20 percent of intervals. On average for the

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27 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.

28 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.

29 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. 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 locational marginal price (LMP) will be replaced by the higher of default energy bids and the competitive LMP.

quarter, Powerex prices were $8/MWh higher because of WEIM transfer congestion in the 15-minute market, and $7/MWh higher in the 5-minute market.

The rest of the Pacific Northwest region was also frequently transfer constrained relative to the rest of the WEIM system. In the 5-minute market, these balancing areas were import constrained in around 13 percent of intervals and export constrained in around 9 percent of intervals. Avista and NorthWestern Energy were also transfer constrained in a similar frequency.

Figure 4.1 Frequency and impact of WEIM transfer congestion in the 15-minute market (Q1 2025)

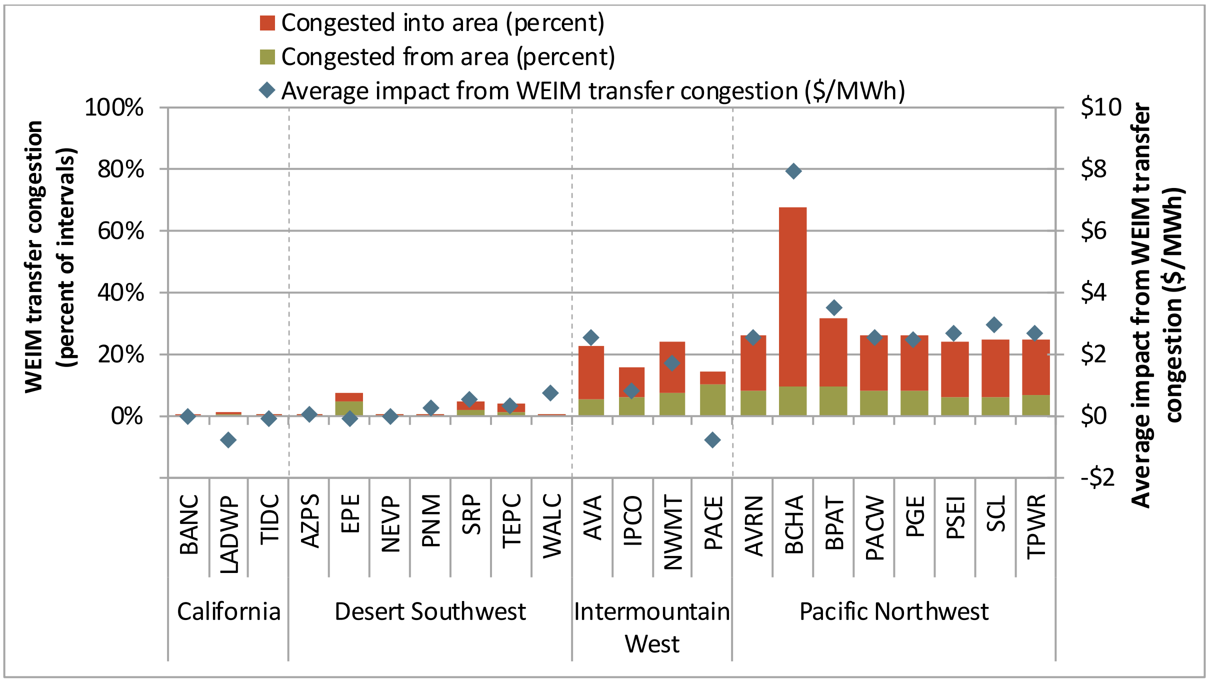
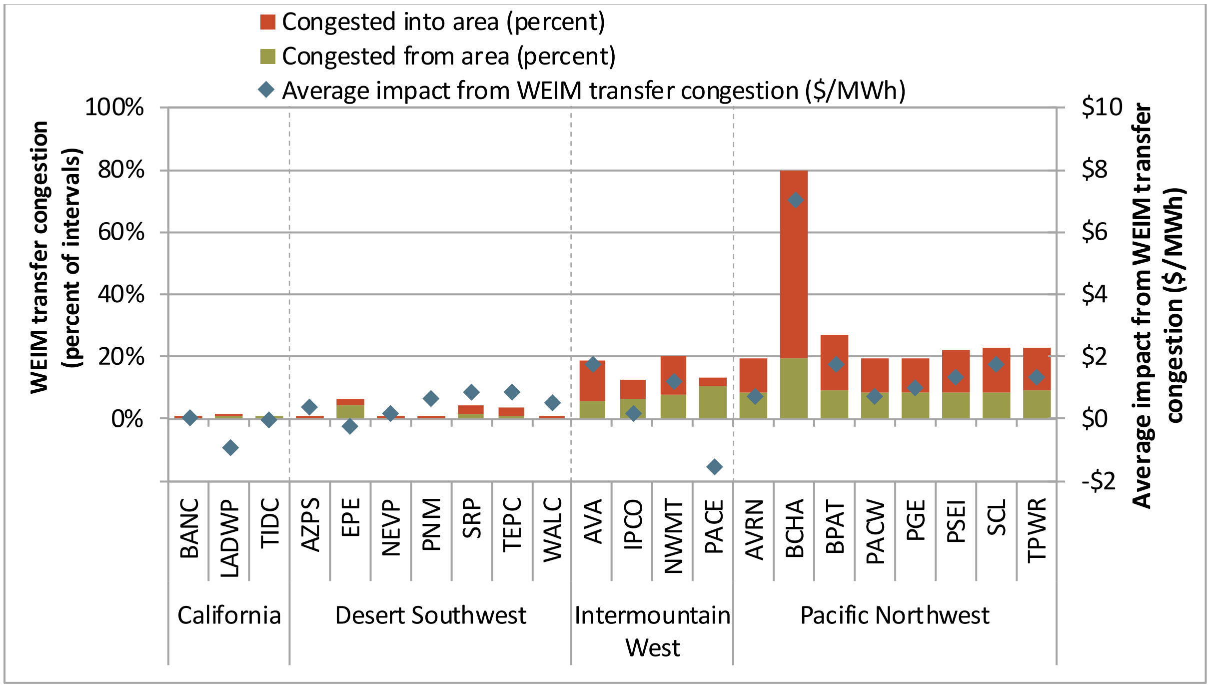


Figure 4.2 Frequency and impact of WEIM transfer congestion in the 5-minute market (Q1 2025)



4.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM.[30] 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 is discussed above in Section 4.1.

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.[31]

In this quarter, internal congestion in the real-time market was on average in the south-to-north direction. This trend was more pronounced during mid-day. This congestion contributed to increasing

30 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 other WEIM balancing areas. Analysis of internal congestion excludes transfer constraints and intertie constraint congestion.

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

prices in the Northern California and Pacific Northwest regions—as well as most of the Intermountain West region—relative to balancing areas in Southern California and the Desert Southwest.[32]

Figure 4.3 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAPs) and EIM load aggregation points (ELAPs) in the first quarter of 2025. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

Figure 4.3 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (January–March 2025)

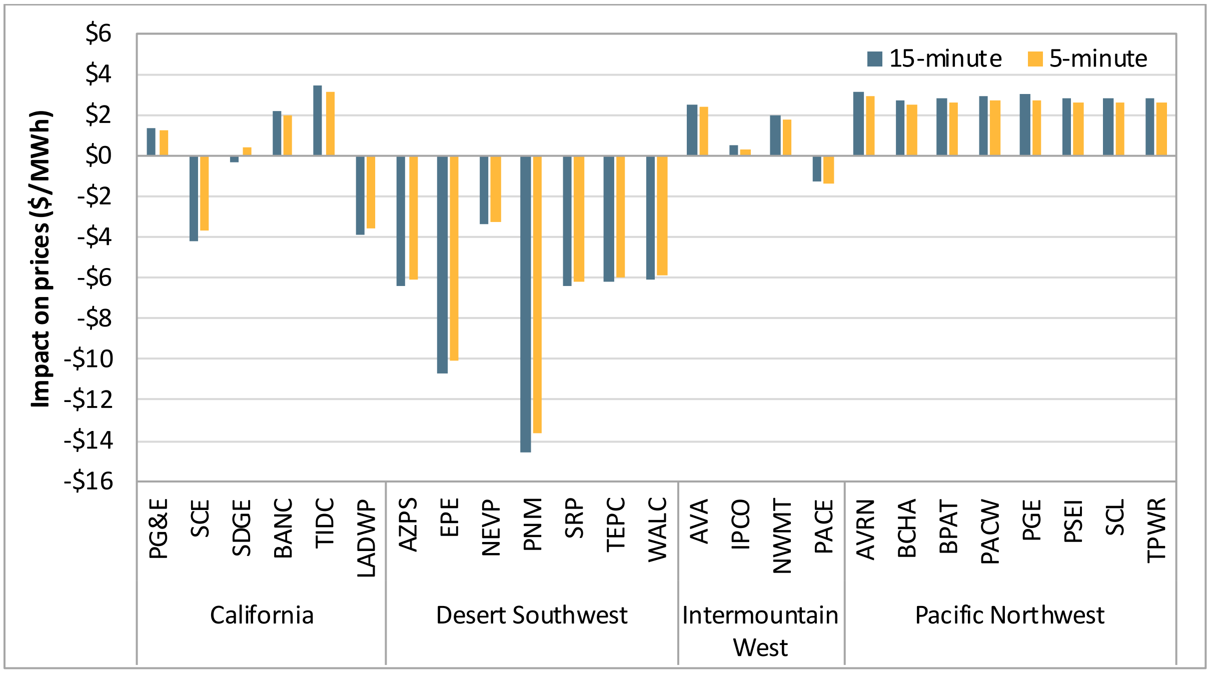


Figure 4.4 displays the average impact of internal congestion on prices in the first quarter of 2024 and 2025. The blue bars represent the impact for 2024, and the red bars show the impact for 2025. This impact was calculated as the average of the 15-minute and 5-minute market price impacts of internal constraints for all intervals.

In both Q1 2024 and Q1 2025, internal congestion generally led to increased prices in the Pacific Northwest and the Intermountain West, while prices decreased in the Desert Southwest with a higher price impact in 2025. Within the California region, internal congestion increased prices in Northern California more in Q1 2025 than Q1 2024.

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[32] 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 4.4 Average impact of internal congestion on real-time market price (2024–2025)

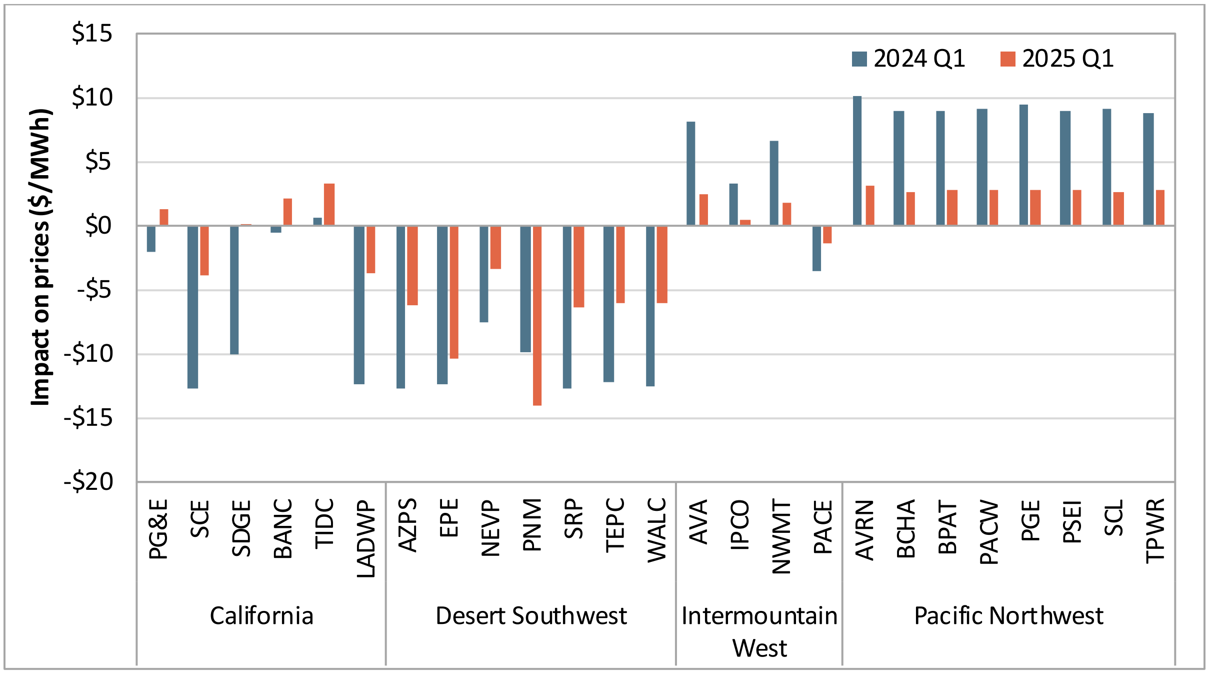


Figure 4.5 and Figure 4.6 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the first quarter of 2025 and 2024, respectively. Overall, both years exhibited south-to-north congestion during solar production hours. However, the magnitude of congestion impact was notably higher in 2024, driven by extreme cold weather and transmission outages in the Pacific Northwest. During the evening peak hours, this quarter saw increased congestion into SDG&E and Northern California.

Figure 4.5 Overall impact of internal congestion on price separation in the 15-minute market by hour (January–March 2025)

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	-0.2	-0.4	-0.6	-0.7	-0.4	0.0	0.6	2.9	5.2	4.9	3.8	1.9	-0.9	0.0	2.7	4.1	3.5	2.4	1.4	0.8	0.5	0.5	0.2	-0.3
BANC	-0.4	-0.7	-0.9	-1.0	-0.7	-0.4	0.3	2.0	6.1	9.3	8.5	5.8	1.9	2.9	5.7	6.6	3.8	1.8	0.9	0.4	0.2	0.2	0.0	-0.4
Turlock ID	-0.3	-0.5	-0.7	-0.8	-0.6	-0.2	0.3	2.1	7.7	13.3	12.6	9.8	6.1	7.5	9.4	9.2	4.3	2.0	1.0	0.7	0.3	0.2	0.0	-0.4
SCE	0.5	0.3	0.2	0.1	0.0	0.1	0.5	-0.1	-5.7	-12.1	-14.0	-13.4	-13.4	-13.8	-14.9	-11.7	-3.7	-1.0	0.1	0.2	0.5	0.4	0.8	0.7
SDG&E	2.1	1.4	0.8	0.7	0.7	1.3	3.3	5.3	5.5	-2.3	-8.8	-9.7	-9.8	-10.1	-11.1	-7.4	-0.4	6.3	6.5	5.3	4.4	3.1	3.2	2.2
LADWP	-0.1	0.1	0.1	0.0	-0.1	-0.1	0.0	-1.4	-5.9	-11.4	-12.9	-11.8	-11.7	-11.9	-12.5	-8.8	-1.9	-0.9	-0.6	-0.5	-0.1	0.1	0.1	0.4
NV Energy	-0.2	0.0	0.0	0.0	-0.1	-0.1	-0.4	-2.4	-6.5	-8.3	-8.8	-8.7	-9.8	-10.0	-10.1	-8.3	-3.2	-1.8	-1.1	-0.9	-0.5	-0.3	-0.2	0.2
Arizona PS	-0.5	-0.2	-0.1	-0.2	-0.3	-0.4	-0.9	-5.2	-14.8	-17.4	-16.6	-15.4	-15.0	-15.6	-16.9	-14.6	-6.1	-4.2	-2.9	-2.1	-1.4	-0.9	-0.5	0.0
Tucson Electric	-0.5	-0.2	-0.1	-0.2	-0.3	-0.4	-1.3	-5.1	-14.1	-16.7	-15.9	-14.8	-14.5	-15.0	-16.3	-14.0	-5.9	-4.1	-2.8	-2.1	-1.7	-1.2	-0.7	-0.2
Salt River Project	-0.5	-0.2	-0.1	-0.2	-0.3	-0.4	-1.0	-5.3	-15.0	-17.5	-16.6	-15.5	-15.0	-15.7	-17.1	-14.8	-6.2	-4.3	-3.0	-2.2	-1.5	-1.0	-0.5	0.0
PSC New Mexico	-3.1	-2.8	-2.3	-3.0	-3.9	-5.8	-9.7	-22.8	-26.8	-28.2	-28.9	-26.4	-27.5	-31.2	-34.2	-29.0	-16.3	-9.7	-6.9	-6.4	-7.0	-8.6	-4.6	-2.8
WAPA - Desert SW	-0.5	-0.2	-0.1	-0.2	-0.3	-0.4	-1.0	-4.9	-13.9	-16.7	-16.0	-14.9	-14.4	-15.0	-16.3	-14.0	-5.8	-3.9	-2.7	-2.0	-1.4	-0.9	-0.5	0.0
El Paso Electric	-3.4	-3.0	-2.8	-3.1	-2.9	-2.8	-5.2	-13.1	-19.6	-21.4	-21.3	-19.9	-19.6	-21.4	-23.6	-20.6	-10.6	-7.1	-7.1	-6.5	-6.8	-6.1	-4.3	-3.5
PacifiCorp East	-0.4	-0.2	-0.1	-0.2	-0.2	-0.3	-0.6	-1.5	-2.8	-2.8	-2.6	-2.6	-2.7	-2.7	-3.0	-2.6	-1.3	-1.1	-0.8	-0.8	-0.6	-0.6	-0.4	-0.3
Idaho Power	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.4	-0.1	1.0	1.8	1.8	1.8	1.7	1.8	2.2	1.9	0.2	-0.2	-0.2	-0.3	-0.2	-0.4	-0.3	-0.2
NorthWestern	0.0	0.1	0.1	0.2	0.2	0.1	0.0	0.5	3.1	5.0	5.6	5.4	5.8	5.8	6.4	5.4	1.5	0.7	0.3	0.3	0.1	0.0	-0.1	-0.2
Avista Utilities	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.8	4.2	6.5	7.2	6.8	7.4	7.5	8.1	6.8	2.1	1.1	0.5	0.5	0.2	0.1	-0.1	-0.2
Avangrid	0.1	0.1	0.1	0.3	0.3	0.2	0.0	1.2	5.7	8.5	9.0	8.4	9.1	9.2	10.0	8.3	2.8	1.4	0.7	0.6	0.3	0.1	-0.1	-0.2
BPA	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.9	4.6	7.2	7.8	7.6	8.3	8.4	9.0	7.3	2.3	1.1	0.5	0.5	0.3	0.2	-0.1	-0.2
Tacoma Power	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.9	4.5	7.0	7.7	7.7	8.5	8.5	9.1	7.4	2.4	1.2	0.5	0.5	0.2	0.1	-0.1	-0.2
PacifiCorp West	0.1	0.1	0.2	0.3	0.3	0.2	0.1	1.0	4.9	7.5	8.2	7.8	8.6	8.6	9.2	7.5	2.5	1.2	0.5	0.5	0.3	0.1	-0.1	-0.2
Portland GE	0.1	0.1	0.2	0.3	0.3	0.2	0.1	1.0	4.8	7.3	8.0	8.2	9.5	9.2	9.7	7.9	2.5	1.2	0.5	0.5	0.3	0.1	-0.1	-0.2
Puget Sound Energy	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.9	4.5	7.0	7.7	7.7	8.5	8.5	9.1	7.4	2.4	1.2	0.5	0.5	0.2	0.1	-0.1	-0.2
Seattle City Light	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.9	4.5	7.0	7.7	7.6	8.4	8.4	9.0	7.3	2.4	1.2	0.5	0.5	0.2	0.1	-0.1	-0.2
Powerex	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0.9	4.4	6.9	7.5	7.4	8.2	8.2	8.8	7.2	2.3	1.2	0.5	0.5	0.2	0.1	-0.1	-0.2

Figure 4.6 Overall impact of internal congestion on price separation in the 15-minute market by hour (January–March 2024)

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	-0.6	-2.6	-0.6	0.7	0.4	0.3	0.4	2.1	1.0	2.5	-2.7	-4.1	-3.1	-2.7	0.2	-4.6	-11.6	-11.0	-12.1	-10.6	-8.3	-6.8	0.1	-1.7
BANC	-1.2	-3.1	-1.3	0.1	-0.3	0.0	0.1	2.1	2.7	6.6	2.8	0.8	1.2	1.9	5.3	-0.1	-9.7	-11.2	-12.8	-11.0	-8.7	-7.2	-0.3	-2.3
Turlock ID	-1.1	-3.0	-1.3	0.1	-0.3	0.1	0.2	2.4	4.2	9.3	6.3	4.7	5.1	5.6	9.1	2.7	-8.0	-10.1	-12.5	-10.8	-8.5	-7.0	-0.2	-2.2
SCE	-0.7	-2.5	-1.1	0.1	-0.3	0.3	0.2	-3.0	-16.8	-24.7	-33.8	-36.1	-34.3	-33.2	-31.2	-27.8	-22.2	-13.7	-12.7	-11.1	-8.9	-5.7	0.3	-1.6
SDG&E	1.4	-0.8	0.3	1.2	1.3	1.3	0.7	-1.4	-12.2	-20.8	-29.8	-32.8	-30.4	-29.6	-26.3	-23.8	-19.0	-10.9	-11.1	-9.7	-7.7	-3.4	3.1	-0.2
LADWP	0.1	-2.6	-1.3	-0.1	-0.5	0.0	0.0	-3.4	-16.7	-24.1	-33.1	-35.3	-33.6	-32.5	-30.5	-27.3	-21.9	-13.6	-12.4	-11.0	-8.7	-5.8	0.0	-1.7
NV Energy	-0.9	-1.9	-0.9	-0.1	-0.4	0.0	-0.1	-2.5	-10.7	-13.8	-19.0	-20.2	-18.9	-18.4	-16.9	-16.1	-14.0	-9.3	-8.1	-7.6	-6.2	-4.2	-0.2	-1.3
Arizona PS	-1.7	-2.9	-1.7	-0.5	-0.9	-0.1	0.8	-4.8	-18.3	-24.4	-32.7	-34.7	-32.5	-31.8	-30.4	-27.3	-20.7	-13.2	-11.1	-9.7	-7.8	-5.6	-1.0	-1.9
Tucson Electric	-1.6	-2.8	-1.6	-0.7	-1.1	-0.5	-0.7	-4.6	-17.4	-23.4	-31.5	-33.5	-31.4	-30.6	-29.0	-25.8	-19.4	-12.3	-10.6	-9.2	-7.4	-5.3	-0.9	-1.8
Salt River Project	-1.6	-2.9	-1.7	-0.6	-0.9	-0.3	-0.5	-5.0	-18.5	-24.4	-32.8	-34.7	-32.6	-31.9	-30.5	-27.3	-20.7	-13.2	-11.1	-9.9	-7.8	-5.5	-1.0	-1.8
PSC New Mexico	-0.3	-1.8	-0.8	0.0	-0.4	0.1	0.5	-3.5	-14.2	-19.2	-26.3	-28.2	-26.6	-26.1	-24.3	-21.4	-16.1	-10.0	-8.8	-7.1	-5.6	-3.7	0.2	-0.5
WAPA - Desert SW	-1.7	-2.9	-1.7	-0.6	-1.0	-0.3	-0.5	-4.8	-18.0	-24.0	-32.3	-34.2	-32.2	-31.4	-30.0	-26.8	-20.4	-13.0	-11.0	-9.6	-7.7	-5.5	-0.9	-1.9
El Paso Electric	-3.1	-5.0	-4.3	-3.1	-3.4	-2.7	-2.1	-5.3	-17.2	-22.0	-29.5	-31.6	-29.4	-28.6	-27.1	-24.2	-18.2	-11.8	-10.6	-9.6	-8.2	-5.9	-1.7	-2.9
PacifiCorp East	-2.8	-2.8	-2.9	-2.7	-2.4	-2.5	-2.7	-3.0	-4.6	-4.8	-5.5	-5.7	-5.4	-5.3	-4.8	-4.4	-3.1	-2.3	-2.0	-2.1	-2.2	-2.1	-2.3	-2.3
Idaho Power	0.4	1.3	0.5	0.0	0.2	-0.1	-0.1	0.7	3.4	5.0	6.9	6.7	6.1	6.3	6.4	6.8	7.5	6.1	6.2	5.3	4.4	3.1	0.1	0.9
NorthWestern	0.8	2.3	1.0	0.0	0.3	-0.1	-0.1	1.6	8.1	10.9	15.3	15.5	14.3	14.3	14.0	14.4	14.3	10.7	10.6	9.2	7.4	5.2	0.1	1.5
Avista Utilities	1.0	2.7	1.2	0.0	0.3	-0.1	-0.1	2.1	10.0	13.7	19.2	19.5	18.0	18.0	17.4	17.8	17.4	12.8	12.7	11.0	8.9	6.2	0.1	1.7
Avangrid	1.2	3.3	1.5	0.0	0.4	-0.1	-0.1	2.7	12.2	17.4	24.2	22.8	19.5	22.2	21.8	21.6	21.3	15.8	15.4	13.3	10.9	7.5	0.1	2.1
BPA	1.0	2.9	1.3	0.0	0.4	-0.1	-0.1	2.3	11.1	14.9	20.8	21.7	20.2	20.0	19.1	19.6	18.7	13.8	13.6	11.8	9.5	6.6	0.1	1.9
Tacoma Power	1.0	2.9	1.3	0.0	0.4	-0.1	-0.1	2.3	11.0	14.8	20.6	21.2	19.5	19.5	18.8	19.2	18.5	13.7	13.5	11.7	9.5	6.6	0.1	1.9
PacifiCorp West	1.0	3.0	1.3	0.0	0.4	-0.1	-0.1	2.4	10.8	15.5	21.6	21.6	20.0	20.1	19.7	19.7	19.1	14.2	14.0	12.0	9.9	6.8	0.1	1.9
Portland GE	1.0	3.0	1.3	0.0	0.4	-0.1	-0.1	2.4	11.5	15.3	21.3	24.2	23.2	22.4	21.0	22.2	18.9	14.0	13.8	11.9	9.8	6.8	0.1	1.9
Puget Sound Energy	1.0	2.9	1.2	0.0	0.4	-0.1	-0.1	2.3	12.1	15.0	21.0	22.2	20.7	20.4	19.1	20.0	19.1	13.8	13.6	12.0	9.4	6.5	0.1	1.9
Seattle City Light	1.0	2.9	1.2	0.0	0.4	-0.1	-0.1	2.3	13.0	15.1	21.2	22.7	21.0	20.6	19.2	20.5	19.5	14.0	13.7	12.2	9.4	6.5	0.1	1.8
Powerex	1.0	2.8	1.2	0.0	0.4	-0.1	-0.1	2.2	13.6	14.9	21.1	22.9	21.2	20.8	19.1	20.7	19.6	13.9	13.7	12.2	9.3	6.4	0.1	1.8

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

Table 4.1 shows the quarterly impact of congestion from individual constraints on prices across the WEIM for the 15-minute market. The table reports the top 50 constraints based on their aggregate impact and price separation across DLAPs and ELAPs. Constraints with minimal impact are consolidated under the “other” category, which appears in the second-to-last row of the second column.

The three constraints that had the greatest impact on price separation in the 15-minute market were Tesla-Los Banos #1 500 kV line, California-Oregon Intertie nomogram, and Gates-Midway #1 500 kV line.

Tesla-Los Banos #1 500 kV line

Tesla-Los Banos #1 500 kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) increased prices in Northern California, the Pacific Northwest, and Intermountain West, while it decreased prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar production hours, from hour-ending 8 to 16.

California-Oregon Intertie (COI) nomogram

California-Oregon Intertie nomogram (6110_COI_S-N) increased prices in the Intermountain West and Pacific Northwest, while it decreased prices in California and the Desert Southwest. This line experienced congestion during solar production hours, from hour-ending 11 to 16.

Gates-Midway #1 500 kV line

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

Table 4.1 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, January–March)[33]

BAA	Constraint	Average quarter impact ($/MWh)																								
		California						Desert Southwest							Intermountain West				Pacific Northwest							
		PG&E	BANC	TIDC	SCE	SDG&E	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	Line_OD-AR_69KV	.	.	.	.08	0.38	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Line_PR-CVN_345KV	.01	.	.	.01	.01	.01	.02	-.08	.00	-.09	.02	-.05	.00	.	-.01	.	-.02	.	.	.	.	.	.	.	.
BPAT	NOPE	-.04	-.04	-.04	-.03	-.03	-.03	-.03	-.03	-.03	-.03	-.03	-.03	-.03	.02	-.02	.00	-.02	-.05	.04	.04	-.01	.13	.07	.05	.07
CISO	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	.51	1.04	.74	-1.62	-1.55	-1.58	-1.39	-1.27	-.97	-1.19	-1.39	-1.35	-1.39	.89	.29	.70	-.22	1.13	.94	.98	1.02	1.00	.96	.95	.96
	6110_COI_S-N	-.97	-1.01	-.98	-.71	-.67	-.69	-.59	-.52	-.47	-.49	-.59	-.57	-.59	.71	.35	.60	.01	.87	.75	.77	.80	.79	.76	.76	.76
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	.67	.79	.83	-1.00	-.95	-.98	-.87	-.80	-.62	-.76	-.86	-.85	-.86	.46	.10	.35	-.20	.61	.49	.51	.54	.53	.50	.50	.50
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	.28	.47	.49	-.61	-.59	-.59	-.53	-.49	-.38	-.47	-.53	-.52	-.53	.32	.07	.25	-.08	.40	.33	.32	.36	.35	.34	.34	.34
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P	.35	.32	.34	.22	.15	.33	-1.15	-1.01	-.33	-.91	-1.21	-1.07	-.95	.	.	.	-.30	.07	.	.	.00	.00	.	.	.
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	.06	.93	2.07	-.60	-.57	-.59	-.44	-.21	-.03	-.14	-.44	-.40	-.44	.	.	.	.	.02	.	.	.	.	.	.	.
	MIGUEL_BKs_MXFLW_NG	.06	.	.	.18	1.44	.	-.40	-.36	.	-.32	-.41	-.39	-.38	.	.	.	.	.	.	.	.	.	.	.	.
	7820_TL230S_OVERLOAD_NG	.03	.00	.01	.08	1.35	.00	-.25	-.24	-.09	-.21	-.27	-.26	-.23	.	-.02	.	-.09	.	.	.	.	.	.	.	.
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	.19	.24	.28	-.24	-.23	-.23	-.21	-.18	-.12	-.15	-.21	-.20	-.21	.03	.	.	.	.07	.04	.03	.05	.05	.04	.04	.04
	30005_ROUNDMT_500_30245_ROUNDMT_230_XF_1_P	-.15	-.26	-.13	-.08	-.08	-.08	-.06	-.04	-.03	-.03	-.06	-.06	-.06	.11	.05	.10	.	.12	.12	.12	.12	.12	.12	.12	.12
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-.12	-.11	-.11	.12	.11	.11	.10	.09	.07	.09	.10	.10	.10	-.07	-.02	-.05	.01	-.08	-.07	-.07	-.08	-.07	-.07	-.07	-.07
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	.20	.	.00	-.35	-.33	-.29	-.08	-.05	.	-.05	-.07	-.07	-.07	.	.	.	.	.	.	.	.	.	.	.	.
	24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	-.12	-.12	-.12	.34	.27	.00	.	.	.	.	.	.	.	-.04	.	-.01	.	-.09	-.05	-.06	-.07	-.07	-.06	-.06	-.06
	30015_TABLEMT_500_30068_TBMT5M_1.0_XF_5	-.18	-.23	-.08	-.04	-.04	.	.	.	-.13	.	.	.	.	.00	.	.	.	.06	.03	.04	.05	.05	.03	.03	.03
	24086_LUGO_500_26105_VICTORVL_500_BR_1_1	.04	.03	.04	.05	.02	-.09	-.06	-.06	-.07	-.06	-.06	-.06	-.06	.01	-.01	.00	-.03	.02	.01	.02	.02	.02	.02	.02	.02
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	.03	.04	.04	-.05	-.05	-.05	-.05	-.04	-.04	-.04	-.05	-.04	-.05	.03	.01	.02	-.01	.03	.03	.03	.03	.03	.03	.03	.03
	7820_TL23040_IV_SPS_NG	.01	.	.	.04	.28	.	-.08	-.07	.00	-.06	-.08	-.08	-.08	.	.	.	.00	.	.	.	.	.	.	.	.
	OMSIV-SXOUTAGE_NG	.01	.	.	.03	.28	.	-.05	-.04	-.02	-.04	-.05	-.05	-.05	.	.	.	-.02	.	.	.	.	.	.	.	.
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_S	.01	.	.	.02	.19	.	-.05	-.04	-.02	-.04	-.06	-.05	-.05	.	.	.	-.02	.	.	.	.	.	.	.	.
	99013_CALCAPS_500_24801_DEVERS_500_BR_1_1	.02	.01	.02	.03	.00	.02	-.05	-.05	-.02	-.04	-.06	-.05	-.05	.	.	.	-.02	.01	.	.00	.00	.00	.00	.00	.00
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.01	.	.	.02	.13	.	-.04	-.03	-.01	-.03	-.04	-.04	-.04	.	.	.	-.01	.	.	.	.	.	.	.	.
	30105_COTTNWD_230_30245_ROUNDMT_230_BR_2_1	.02	.02	.02	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	-.02	-.01	-.01	.	-.02	-.02	-.02	-.02	-.02	-.02	-.02	-.02
	39536_FINKSS_230_38402_WSTLYTID_230_BR_1_1	.01	.02	.03	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.01	.00	.01	.	.01	.01	.01	.01	.01	.01	.01	.01
	6110_COI_N-S	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	-.01	-.01	-.01	.00	-.02	-.01	-.01	-.01	-.01	-.01	-.01	-.01
	35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	.12	.	.	-.06	-.06	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	OMS_17337774_ML_BK81_NG	.00	.	.	.01	.07	.	-.02	-.02	.	-.01	-.02	-.02	-.02	.	.	.	.	.	.	.	.	.	.	.	.
	COI_600S-N	.	-.01	-.01	.	.	-.01	-.01	.00	.00	.00	-.01	-.01	-.01	.01	0.00	.01	.00	.01	.01	.01	.01	.01	.01	.01	.01
	OMS_17200828_23055OUT_NG	.00	.	.	.01	.05	.	-.01	-.01	.00	-.01	-.01	-.01	-.01	.	.	.	.00	.	.	.	.	.	.	.	.
	36850_KIFER_115_35615_FMC_115_BR_1_1	.06	.	.	-.04	-.04	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	35356_MNTAVSA_115_30705_MONTAVIS_230_XF_4	.05	.	.02	-.02	-.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	22652_PENSQTOS_230_22596_OLDTOWN_230_BR_1_1	.00	.	.	.01	-.01	.	-.01	-.01	.	-.01	-.01	-.01	-.01	.	.	.	.	.	.	.	.	.	.	.	.
	22464_MIGUEL_230_22468_MIGUEL_500_XF_81	.00	.	.	.00	.04	.	-.01	-.01	.	-.01	-.01	-.01	-.01	.	.	.	.	.	.	.	.	.	.	.	.
	OMS_16903115_23001_23004_NG	.00	.	.	.01	-.07	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	LugoAAbankoutageAreaEXP	.00	.	.	-.04	.00	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	OMS_17417611_ML_BK80_OOS	.00	.	.	.00	.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	34116_LEGRAND_115_34115_ADRATAP_115_BR_1_1	-.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30500_BELLOTA_230_30515_WARNERVL_230_BR_1_1	.	.01	-.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
LADWP	HWD_FARAREA	-.03	.	.	-.03	-.03	.89	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
PACE	WINDSTAREXPORTTCOR	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	-.11	.	.	.	.	.	.	.	.
PACW	HURRICAW_WALAWALA_230	.	.	.	-.04	-.04	.	.	-.06	-.08	-.06	.	-.01	.	.08	-.27	.	-.13	.	.08	.08	.07	.07	.08	.08	.08
PNM	CZ345kV	.18	.	.	.15	.13	.	.	-3.76	.	-7.95	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	FRCE-PINT1	.04	.	.	.04	.03	.	.	-.90	.	-2.09	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	WMesaWT2_448MVA	-.02	.	.	-.02	-.02	.	.	-.21	.	1.12	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115WTGatPEGS	.	.	.	.	.	.	.	.	.	-.34	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvLK	.	.	.	.	.	.	.	-.10	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvNH	.	.	.	.	.	.	.	-.02	.	-.04	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
WALC	Line_GIX-ARFH_69KV	.	.	.	.02	.08	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Other	.01	.02	.02	-.05	.01	.00	-.05	-.06	-.02	-.07	-.03	-.03	-.03	.00	.00	-.02	-.04	.00	.00	.00	.01	.00	.00	.01	.00
	Total	1.33	2.17	3.47	-4.16	-.32	-3.84	-6.36	-10.67	-3.40	-14.52	-6.43	-6.18	-6.10	2.54	.50	1.94	-1.30	3.17	2.73	2.80	2.90	2.99	2.81	2.79	2.81

4.3 Congestion rent and loss surpluses

Figure 4.7 shows that in the first quarter of 2025, congestion rent and loss surpluses were $231 million and $35 million, respectively.[34] The congestion rent surplus was down $29 million, or 11 percent, compared to the first quarter of 2024. The loss surplus was up about $7 million compared to Q1 2024.

[33] For visualization purposes, numbers are rounded to two decimal points. As a result, values below 0.005 appear as 0.00, even if they are non-zero. Blank cells with dots indicate that no shift factor exists for the pricing node within the DLAP or ELAP, signifying either no impact from the constraint or their shift factors were too small.

[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.

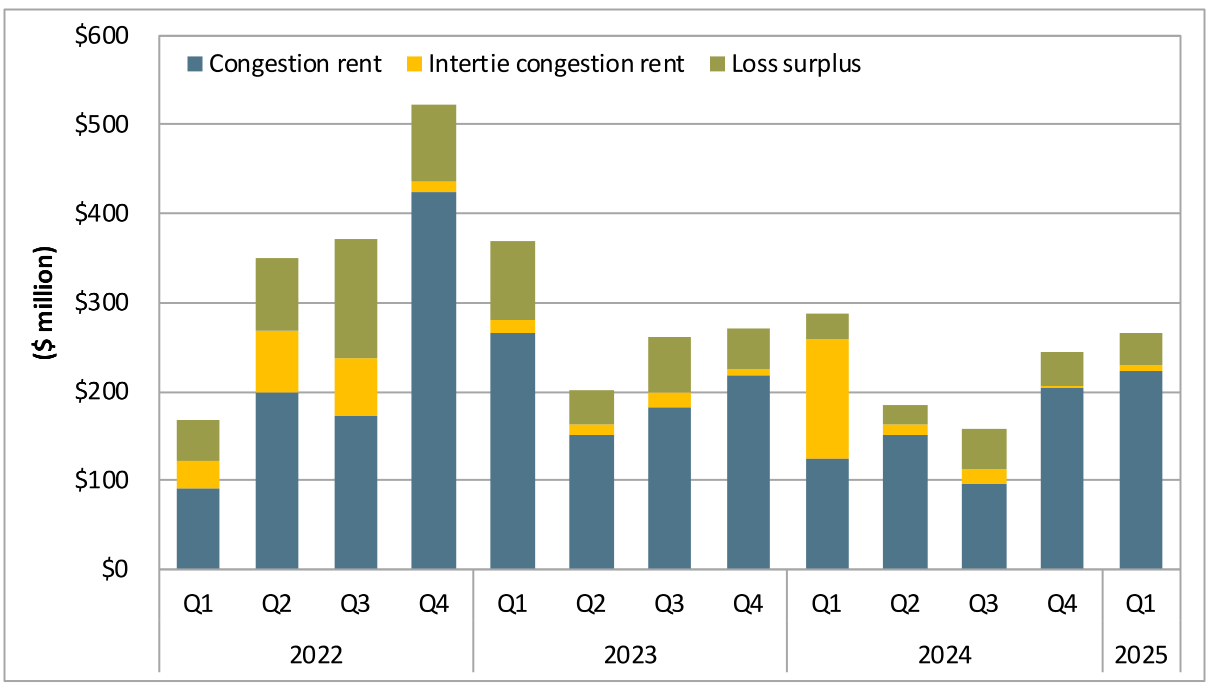
The reduction in the congestion component can be attributed to a significant decrease in congestion rent from intertie congestion rent.

Congestion rent consists of rents from internal constraints and interties. Intertie congestion significantly decreased from $133 million to $9 million this quarter compared to the same quarter in 2024. The sharp decline reflects the absence of the extreme cold weather event that occurred in the Pacific Northwest last year, which caused abnormally high intertie congestion and made Q1 2024 an outlier.

In the day-ahead market, hourly congestion rent collected on a constraint is roughly 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 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 day-ahead market electricity prices and load quantities over time. Day-ahead market load in Q1 2025 was very similar to Q1 2024. Although energy prices dropped compared with the same quarter last year, changes in grid conditions—such as rerouting power through less efficient paths during outages—can increase loss surplus. Those combined effects can push the day-ahead loss component higher, even when overall prices are lower.

Figure 4.7 Day-ahead congestion rent and loss surplus by quarter (2022–2025)



4.4 Congestion on interties

Total intertie congestion rent in the day-ahead market was $9 million, significantly down from $133 million in the first quarter of 2024. The major driver was the absence of severe winter conditions and major transmission outages that occurred in Q1 2024. For example, congestion revenue at the Malin intertie dropped from $126 million in Q1 2024 to $1 million this quarter.

The total intertie 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 4.8 shows total intertie congestion charges in the day-ahead market from the first quarter of 2024 to the first quarter of 2025. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 4.9 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 4.2 provides a detailed summary of congestion rent and frequency over a broader set of interties, differentiating imports and exports. As highlighted in these charts and table:

- Compared to the first quarter of 2024, the total intertie congestion rent decreased from $133 million to $9 million. Export congestion significantly declined, falling from $131 million to $5 million.
- The majority of congestion occurred in the export direction at Malin and NOB and in the import direction at IPP Utah. These three interties accounted for 84 percent of total congestion rent this quarter.
- Congestion frequency was notably high on the IPP Utah import, occurring in 18 percent of hours, while the NOB export recorded congestion in 16 percent of hours.

Figure 4.8 Day-ahead congestion charges on major interties

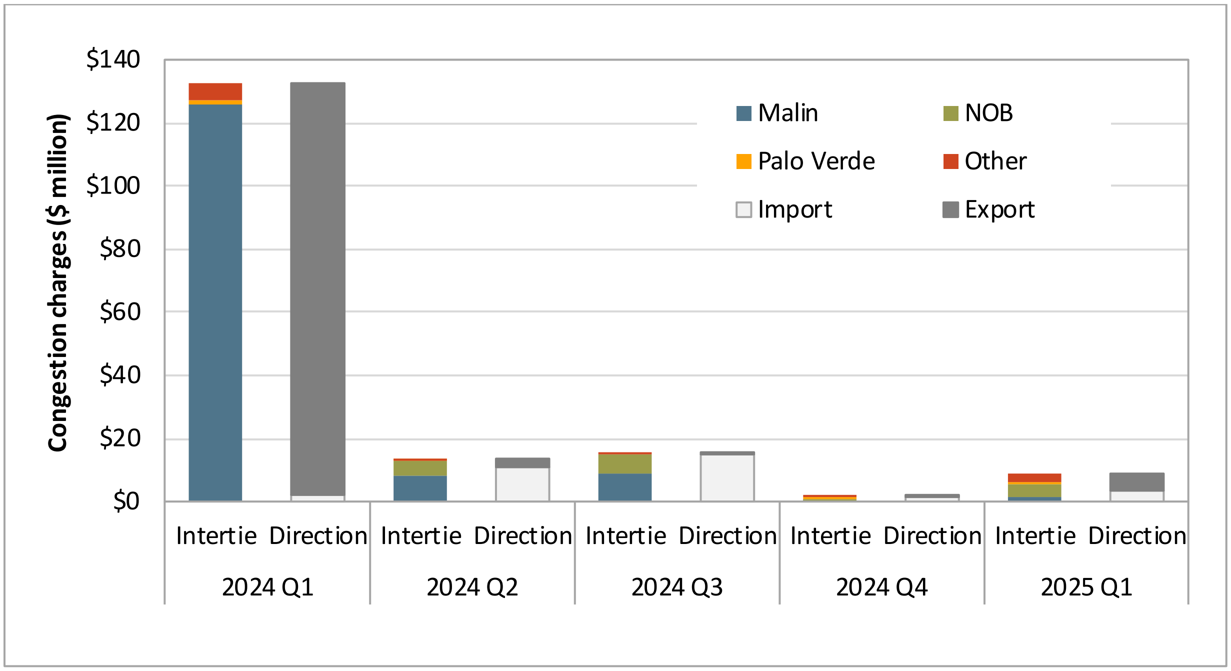


Figure 4.9 Frequency of congestion on major interties in the day-ahead market

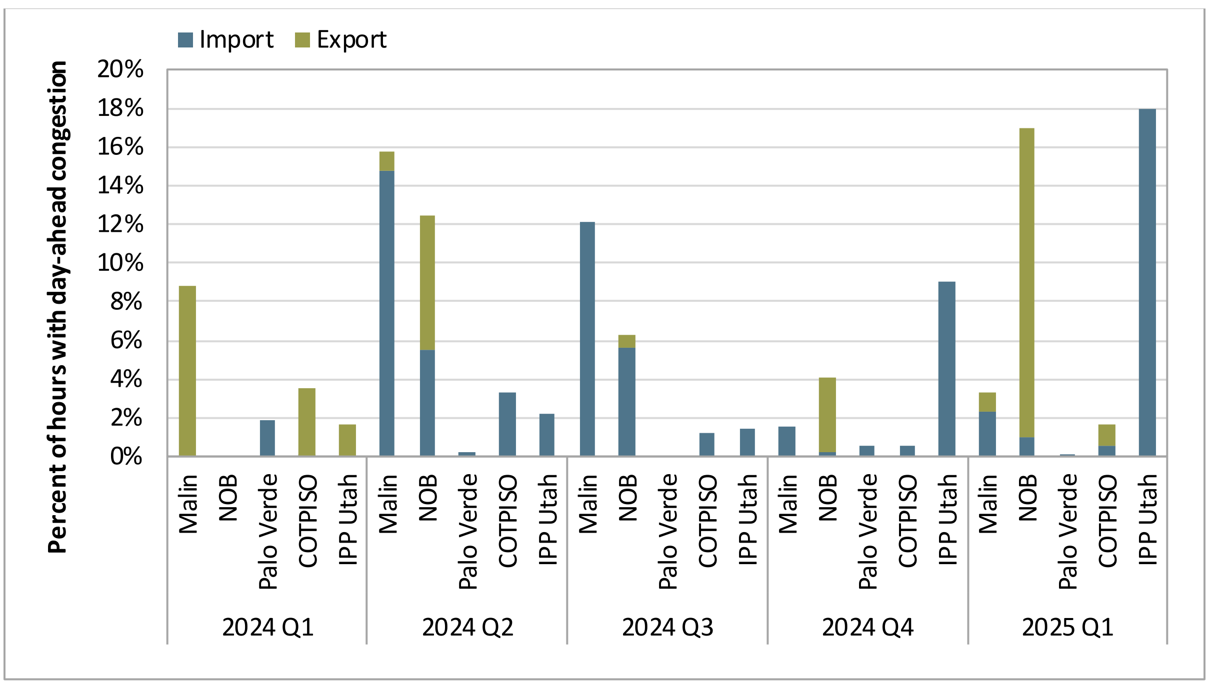


Table 4.2 Summary of intertie congestion in day-ahead market (2024–2025)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1
Northwest											
Malin	I		$8,229	$8,805	$396	$565		14.7%	12.1%	1.5%	2.3%
	E	$125,571	$292			$1,169	8.8%	1.1%			1.0%
NOB	I		$2,608	$5,947	$76	$190		5.5%	5.7%	.3%	1.0%
	E		$1,665	$103	$573	$3,483		7.0%	.6%	3.8%	16.0%
COTPISO	I	$1	$98	$14	$26	$12	.0%	3.3%	1.3%	.5%	.6%
	E	$1,367				$397	3.5%				1.1%
Cascade	I										
	E	$2,147					8.0%				
Summit	I		$14					.8%			
	E										
Southwest											
Palo Verde	I	$1,909	$61		$412	$944	1.8%	.3%		.5%	.0%
	E										
IPP Utah	I		$141	$115	$782	$1,754		2.2%	1.4%	9.0%	18.0%
	E	$401					1.7%				
IPP DC Adelanto	I										
	E	$1,071					4.0%				
Mona	I			$19	$3				.2%	.0%	
	E	$75	$180	$712		$30	.4%	2.2%	1.5%		.6%
Mead	I	$1	$23			$9	.0%	.2%			.0%
	E										
Merchant	I										
	E										
Silver Peak	I										
	E										
Mercury	I										
	E										
Other	I		$8	$0	$0						
	E	$58	$70	$0		$16					
Import total (I)		$1,911	$11,182	$14,900	$1,696	$3,475					
Export total (E)		$130,690	$2,207	$815	$573	$5,096					
Total		$132,601	$13,389	$15,715	$2,268	$8,570					

* I: import, E: export

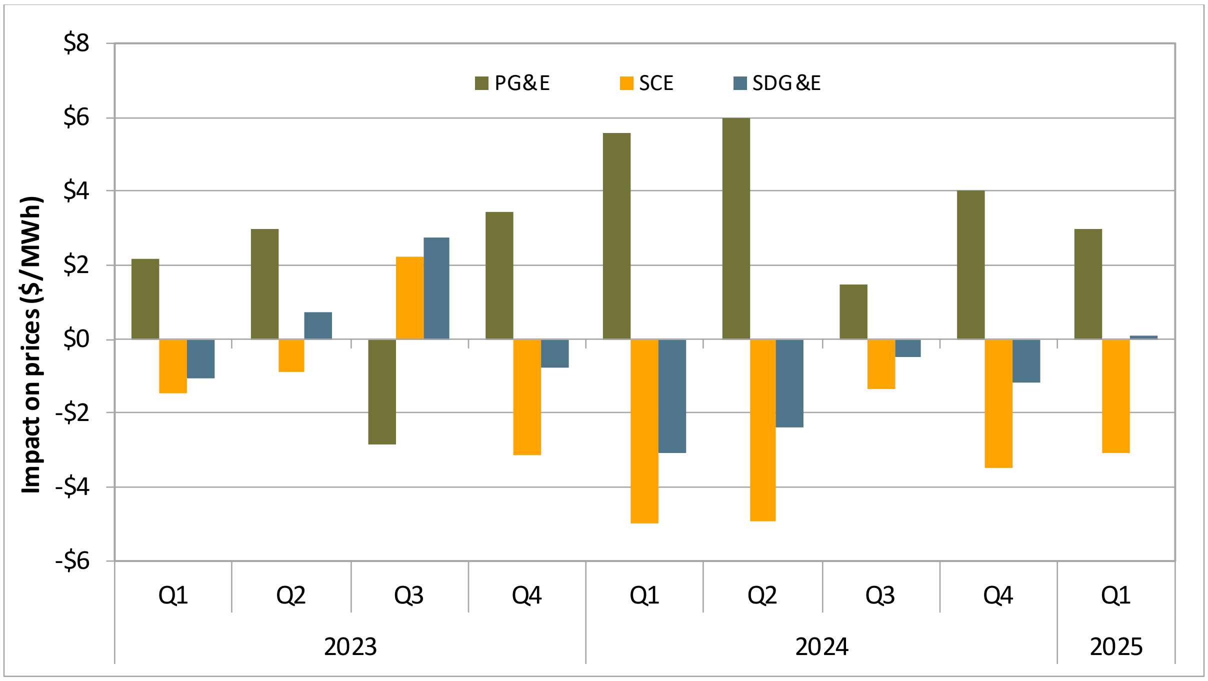
4.5 Internal congestion in the day-ahead market

Figure 4.10 shows the overall impact of congestion on day-ahead market prices in each load area from Q1 2023 to Q1 2025. Figure 4.11 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in this quarter was slightly higher compared to the same quarter in 2024, with a general trend of south-to-north congestion. A notable distinction, however, is that the congestion impact increased prices in SDG&E.

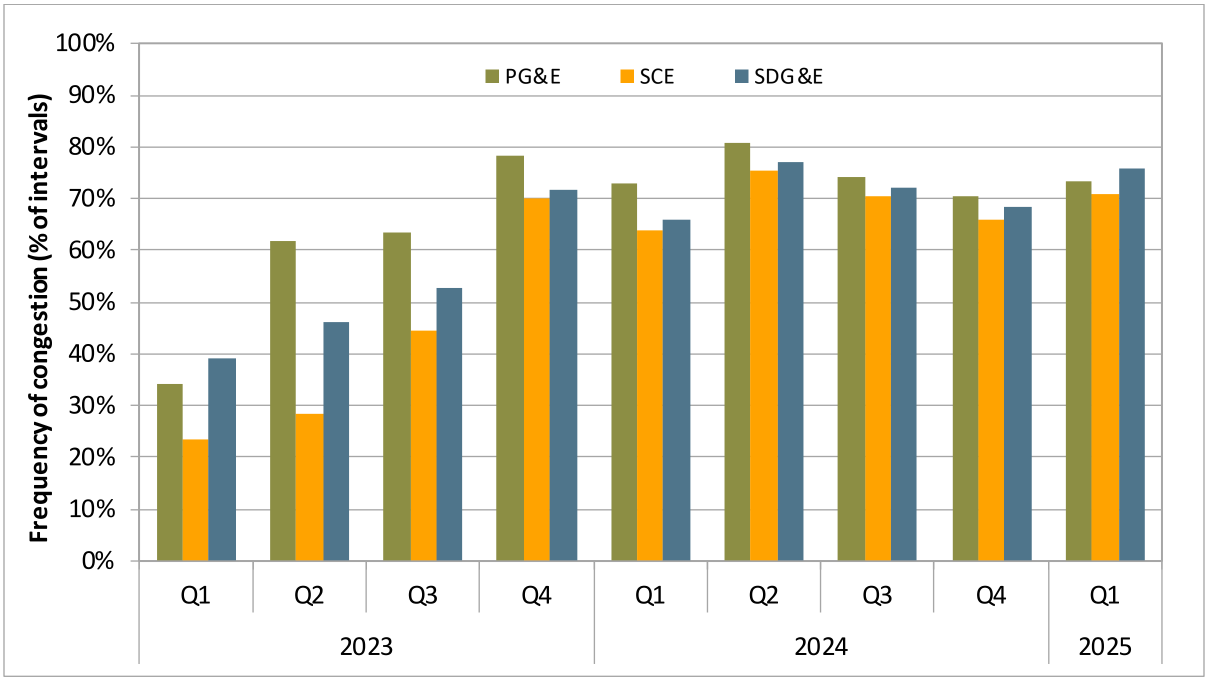
- Day-ahead congestion increased quarterly average prices in PG&E and SDG&E by $3/MWh and $0.1/MWh respectively, while it decreased average SCE prices by $3.1/MWh.[35]
- The percentage of hours in which congestion impacted DLAP prices remained high this quarter, with SDG&E experiencing congestion during an average of 76 percent of hours.
- The primary constraints affecting day-ahead market prices were the Tesla-Los Banos #1 500 kV line, Gates-Midway #1 500 kV line, and San Diego area nomogram.

Figure 4.10 Overall impact of congestion on price separation in the day-ahead market



35 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 4.11 Hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 4.3 breaks down the congestion effect on price separation during the quarter by constraint.[36] 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 on prices, while blue represents a negative impact—the stronger the shading, the greater the impact in either the positive or negative direction.

The constraints with the greatest impact on day-ahead price separation for the quarter were the Tesla-Los Banos #1 500 kV line, Gates-Midway #1 500 kV line, and San Diego area nomogram.

Tesla-Los Banos #1 500 kV line

The Tesla-Los Banos #1 500 kV line (30040_TESLA_500_30050_LOSBANOS_500_BR_1_1) bound in 16.9 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $1.41/MWh and decreased average SCE and SDG&E prices by $1.2/MWh and $1.11/MWh, respectively. This transmission line was generally binding during solar generation hours, from hour-ending 10 through hour-ending 16.

[36] 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*".

Gates-Midway #1 500 kV line

The Gates-Midway #1 500 kV line (30055_GATES1_500_30060_MIDWAY_500_BR_1_1) bound in about 7.3 percent of hours. For the quarter, the constraint increased average PG&E prices by about $0.64/MWh, and decreased average SCE and SDG&E prices by $0.53/MWh and $0.5/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 8 through hour-ending 19.

San Diego area nomogram

The San Diego area nomogram (7820_TL23040_IV_SPS_NG) bound in 15.2 percent of hours over the quarter. For the quarter, congestion on the constraint increased SDG&E prices by $1.11/MWh and decreased average PG&E and SCE prices by $0.16/MWh and $0.05/MWh, respectively. This line was frequently binding during the morning and evening ramping hours.

Table 4.3 Impact of congestion on day-ahead prices – top 25 primary congestion constraints

Day-ahead market

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	16.9%	1.41	-1.20	-1.11
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	7.3%	.64	-.53	-.50
7820_TL23040_IV_SPS_NG	15.2%	-.16	-.05	1.11
7820_TL230S_OVERLOAD_NG	24.9%	-.12	-.06	.90
30790_PANOCHE_230_30900_GATES_230_BR_2_1	9.0%	.40	-.33	-.31
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	14.6%	.37	-.30	-.28
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	11.2%	.25	-.21	-.20
MIGUEL_BKs_MXFLW_NG	3.8%	-.08	-.02	.53
24091_MESACAL_230_24076_LAGUBELL_230_BR_2_1	9.5%	-.29	.26	.07
24801_DEVERS_500_24804_DEVERS_230_XF_1_P	46.2%	-.08	.11	-.41
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	1.5%	.21	-.18	-.17
OMSIV-SXOUTAGE_NG	4.4%	-.07	-.01	.44
35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	5.3%	.13	-.11	-.10
30705_MONTAVIS_230_30730_HICKS_230_BR_2_1	6.8%	.08	-.07	-.07
30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	.7%	.08	-.07	-.06
36850_KIFER_115_35615_FMC_115_BR_1_1	11.6%	.05	-.06	-.06
OMSIV-MLOUTAGE_NG	1.1%	-.02	.00	.13
7820_TL230S_TL50001OUT_NG	1.5%	-.01	.00	.10
22357_IVPFC1_230_22358_IVPFC_230_PS_1	1.0%	-.01	.00	.08
30640_TESLAC_230_30040_TESLA_500_XF_6H	1.4%	.02	-.02	-.02
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	4.1%	.01	-.02	-.02
HUMBOLDT_IMP_NG	31.6%	.02	-.01	-.01
30580_ALTMMDW_230_30625_TESLAD_230_BR_1_1	2.5%	.02	-.02	-.02
OMS_17337774_ML_BK81_NG	.3%	-.01	.00	.04
99013_CALCAPS_500_24801_DEVERS_500_BR_1_1	1.2%	-.01	.01	-.03
Other		.17	-.17	.04
Total		3.00	-3.06	.07

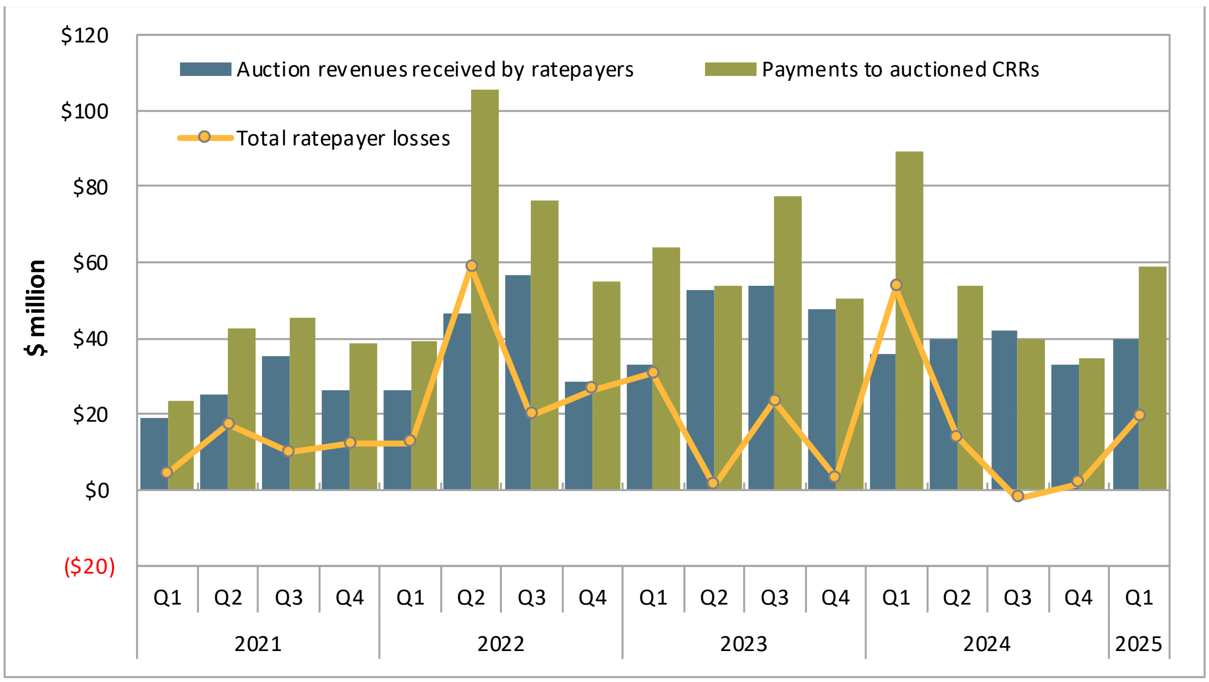
4.6 Congestion revenue rights

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 4.12, transmission ratepayers lost $19.3 million during the first quarter of 2025, as payments to auctioned congestion revenue rights holders were higher than auction revenues.

Figure 4.12 Auction revenues and payments to non-load serving entities



During the first quarter of 2025:

- Financial entities recorded a profit of $16 million, a decrease from $26.6 million in profit in the same quarter of 2024. Total revenue deficit offsets were about $18 million.[37]
- Marketers had a profit of $3 million from auctioned rights, a decrease from $10 million in profit in the same quarter of 2024. Total revenue deficit offsets were over $7 million.
- Physical generation entities had a profit of $0.1 million from auctioned rights, down from $16.4 million in Q1 2024. Total revenue deficit offsets were $1.2 million.

The $19.3 million auction loss in the first quarter of 2025 was about 8 percent of day-ahead congestion rent. This was up from 0.08 percent in Q4 2024, and down from 20.6 percent in Q1 2024. The average

[37] 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.

ratepayer losses were 28 percent of day-ahead congestion rent during the three years before the track 1A and 1B changes (2016 through 2018).[38,39]

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 $26 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. In late 2024, DMM posted a whitepaper analyzing a potential option for this kind of alternative CRR auction design.[40]

38 *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

39 *Congestion Revenue Rights Auction Efficiency - Track 1B Draft Final Proposal Second Addendum*, California ISO, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRights AuctionEfficiencyTrack1B.pdf

40 *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

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

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.[41] If an area fails either test in the downward direction, transfers out of that area cannot be increased.

5.1 Frequency of resource sufficiency evaluation failures

Figure 5.1 and Figure 5.2 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 5.3 and Figure 5.4 provide the same information for the downward direction.[42] The dash indicates the area did not fail the test during the month.

In the first quarter of 2025, the frequency of resource sufficiency evaluation failures was very low. All balancing areas failed the capacity and flexibility tests in less than one percent of intervals.

[41] 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. The assistance energy transfers (AET) option gives 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.

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

Figure 5.1 Frequency of upward capacity test failures by month and area (percent of intervals)

	2024												2025		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	—	—	—	—	—	—	—	—	—	—	—	.1	—	—	—
Avangrid	—	—	—	—	—	—	.1	—	—	—	—	—	.1	—	—
Avista	.3	.1	—	—	—	—	.1	—	—	.1	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	.3	—	—	—	—	—	—	—	—	—	—	—	.1	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	—	—	.1	.2	.6	.1	.3	.1	.0	—	.1	.0	.1	.1	.1
Idaho Power	.0	—	—	—	—	—	—	—	—	—	—	—	—	—	—
LADWP	.1	.0	—	.0	.0	—	.1	.3	—	—	—	—	.1	—	—
NorthWestern En.	—	.1	—	—	—	—	—	—	.3	—	—	.3	—	—	—
NV Energy	—	—	—	—	.1	.0	.1	.0	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	.8	.0	—	.1	.0	—	—	—	—	.1	.3	.0	.4	.2	.1
Portland Gen. Elec.	—	—	—	—	.0	.1	.0	—	—	—	—	—	—	.0	.0
Powerex	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PSC of New Mexico	—	—	—	.1	.1	.1	.3	.1	—	.4	3.1	—	.1	—	.1
Puget Sound En.	.8	.1	.2	.3	.2	—	.2	.1	—	.1	—	.1	—	—	—
Salt River Proj.	.1	.1	.2	.1	—	.2	.1	.1	.2	.1	—	—	.1	—	—
Seattle City Light	.5	—	—	.4	—	.0	.4	.1	.1	.3	.0	.1	.1	—	.0
Tacoma Power	—	—	.3	—	.0	—	—	—	—	.0	.1	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	.0	—	.0	—	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	—	—	.1	—	.5	.3	.2	.2	—	.1	—	—	.3	—	.1

Figure 5.2 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2024												2025		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	.2	.1	.5	.1	.3	—	.0	.0	—	—	—	.1	.0	—	—
Avangrid	.2	.1	.1	.0	.2	.5	.2	—	.1	.5	.1	.4	.1	.2	.2
Avista	.1	—	.1	—	—	—	.1	—	—	.0	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	.4	.0	—	.1	.1	.1	.3	.3	.0	—	.1	.1	—	.1	.5
California ISO	—	—	—	—	—	—	.0	—	—	—	—	—	—	—	—
El Paso Electric	.3	.0	1.0	.9	1.0	.9	.6	.8	.3	.2	.3	.4	.1	—	.4
Idaho Power	1.1	—	.1	.6	.6	.1	.1	—	—	.0	—	—	.1	.4	1.2
LADWP	.1	—	.1	.4	.1	.0	.3	.3	.0	—	.1	—	—	—	.1
NorthWestern En.	.5	.1	.0	.0	.1	.3	.2	—	.4	.1	.2	.2	.1	1.2	—
NV Energy	—	.1	.0	—	.1	—	—	—	—	—	—	—	.1	—	.1
PacifiCorp East	—	—	—	.0	.0	—	—	.1	—	.1	.0	—	.1	.1	.0
PacifiCorp West	1.0	—	.1	—	—	.1	—	—	—	—	.3	.1	.3	.1	.0
Portland Gen. Elec.	—	—	.0	—	.2	.2	—	—	.0	.1	—	—	—	—	.2
Powerex	.2	—	—	—	—	—	.6	—	—	—	—	—	—	—	—
PSC of New Mexico	2.0	2.3	.4	1.8	1.1	1.2	1.0	1.0	.9	.3	7.1	.2	.3	.3	.4
Puget Sound En.	.8	.1	.2	.4	.5	.5	.7	.3	—	.4	—	.5	—	—	.1
Salt River Proj.	.2	.1	.7	.4	.1	.3	.3	.4	.5	.2	—	—	.0	—	.1
Seattle City Light	.3	—	.1	.1	.1	—	—	—	.0	.1	.1	—	—	—	—
Tacoma Power	.1	.0	.4	.0	.0	—	—	—	—	—	.1	.0	.0	—	.0
Tucson Elec. Pow.	.0	.2	—	.1	.1	—	.1	.3	.7	.2	.1	.1	.1	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	1.1	2.5	3.5	.3	.8	.2	—	—	—	.2	—	.1	.1	—	.4

Figure 5.3 Frequency of downward capacity test failures by month and area (percent of intervals)

	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024	Jul 2024	Aug 2024	Sep 2024	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Arizona Publ. Serv.	.1	.0	.1	.2	—	—	—	—	.4	—	—	—	—	—	—
Avangrid	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avista	—	—	.1	—	—	—	—	—	—	.0	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	—	—	—	—	—	—	—	—	.1	.1	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.2	—	.4	.2	.4	.3	.1	.1	.0	.1	.0	—	.1	—	.1
Idaho Power	—	—	—	.5	—	—	—	—	—	—	—	—	—	—	—
LADWP	—	—	—	—	—	—	—	—	.0	—	—	—	.0	.1	—
NorthWestern En.	—	—	—	—	—	—	—	—	.1	—	.0	—	—	.1	.1
NV Energy	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	.1	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	—	—	.0	—	—	—	—	—	—	.1	—	—	—	—
PSC of New Mexico	—	—	—	—	—	—	.1	—	—	—	.2	—	—	—	—
Puget Sound En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	.0
Salt River Proj.	—	.1	.1	.4	.7	—	—	.2	—	—	—	.3	.1	.0	.1
Seattle City Light	.0	—	—	—	—	—	.3	—	—	—	.1	.0	—	—	—
Tacoma Power	—	—	—	—	—	.0	.1	.0	—	—	—	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	—	—	—	—	—	—	.1	—	—	—	—	—	—	—	—

Figure 5.4 Frequency of downward flexibility test failures by month and area (percent of intervals)

	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024	Jul 2024	Aug 2024	Sep 2024	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Arizona Publ. Serv.	.1	.1	.2	.1	—	—	—	—	—	—	.3	.2	—	—	.1
Avangrid	.1	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avista	—	.0	—	—	—	—	.1	—	.0	.6	—	—	—	.0	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	.4	.1	—	.0	.1	.1	—	—	—	—	—	.8	.2	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.3	.2	.4	.8	.7	.1	—	.1	—	.0	—	.2	.2	.4	.4
Idaho Power	—	—	.0	1.0	—	—	—	—	—	—	—	—	—	—	.1
LADWP	—	—	—	—	—	—	—	—	.1	—	—	—	.2	1.5	.6
NorthWestern En.	.2	—	.1	—	.3	.2	.2	.1	.0	2.2	.2	.1	.2	—	.6
NV Energy	—	—	.1	.0	—	.1	—	—	—	—	—	—	—	.0	—
PacifiCorp East	—	.2	.0	.5	.2	.0	.0	—	.1	—	—	—	—	—	.5
PacifiCorp West	—	—	.2	—	—	—	—	—	—	.0	.0	—	—	—	.1
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	.1	.4	.0	—	—	1.1	.2	—	—	.1	—	—	.0	.0
PSC of New Mexico	.9	.9	.4	.0	.6	.1	.1	.0	.9	.3	2.0	.1	—	—	—
Puget Sound En.	—	—	—	—	—	—	.1	—	—	—	—	—	—	—	—
Salt River Proj.	.1	.1	.7	.7	.7	.0	—	—	—	.1	—	.5	.6	.4	1.2
Seattle City Light	.2	.1	.1	.2	—	.1	.5	.1	—	.0	.2	.1	—	—	.2
Tacoma Power	—	.0	—	—	—	—	—	—	—	—	—	—	—	.0	—
Tucson Elec. Pow.	—	.1	—	—	—	—	—	—	—	—	—	—	—	.0	—
Turlock Irrig. Dist.	—	.0	—	—	.2	.0	—	.0	—	.1	.1	—	—	—	.0
WAPA DSW	.3	.1	.0	.0	—	—	.1	.0	.1	—	.0	—	—	.1	—

5.2 Assistance energy transfers

The assistance energy transfer (AET) option gives 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.[43]

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.[44] 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 5.1 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the quarter. Seven balancing areas were opted in to the program on at least one day during this period: Avangrid, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, and the Public Service Company of New Mexico (PNM). Avangrid, NorthWestern Energy, NV Energy, PacifiCorp East, and PacifiCorp West were opted in to AET during most days during the quarter.

[43] 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

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

Table 5.1 Assistance energy transfer opt-in designations by balancing area (January–March 2025)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Jan. 1 - Mar. 31	90
Idaho Power	Jan. 1 - Feb. 28	59
NorthWestern Energy	Jan. 6 - Mar. 31	85
NV Energy	Jan. 1 - Mar. 31	90
PacifiCorp East	Jan. 1 - Mar. 31	90
PacifiCorp West	Jan. 1 - Mar. 31	90
PSC of New Mexico	Jan. 20 - Feb. 9	21

Table 5.2 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. During the quarter, seven balancing areas (Avangrid, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, and PNM) failed the resource sufficiency evaluation during at least one interval while opted in to the program.

Table 5.2 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. During the quarter, NorthWestern Energy failed the resource sufficiency evaluation in the most intervals while opted in to receiving assistance energy transfers (37 intervals). NorthWestern Energy achieved an additional 21 MW on average during these intervals (and maximum of 140 MW). PNM achieved the most additional imports from assistance energy transfers during the quarter (551 MWh). PNM achieved an additional 184 MW on average during the failure intervals while opted in (and maximum of 634 MW).

Table 5.2 Resource sufficiency evaluation failures during assistance energy transfer opt-in (January–March 2025)

Balancing area	Days opted in to AET	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)	Total WEIM imports added (MWh)
Avangrid	90	17	24%	11	115	46
Idaho Power	59	12	39%	40	149	119
NorthWestern Energy	85	37	51%	21	140	198
NV Energy	90	5	60%	141	532	176
PacifiCorp East	90	6	33%	98	359	147
PacifiCorp West	90	30	26%	13	125	96
PSC of New Mexico	21	12	75%	184	634	551

Table 5.3 summarizes the total cost from assistance energy transfers.[45] AET is settled during any interval in which the balancing area both opted in to receiving assistance energy transfers and failed the resource sufficiency evaluation. The applicable quantity that is settled for AET is based on the lower of the resource sufficiency evaluation insufficiency or the WEIM imports.[46] The price is the real-time bid cap, typically $1,000/MWh. Table 5.3 also shows the total cost per *WEIM imports added*. WEIM imports added are measured as net WEIM imports in the 5-minute market above what the limit would have been following the resource sufficiency evaluation failure without opting in to AET.

Table 5.3 Cost of assistance energy transfers (January–March 2025)

Balancing area	RSE failures under AET (15-min. intervals)	Total WEIM imports added (MWh)	Total cost of assistance energy transfers	Total cost per added WEIM imports
Avangrid	17	46	$27,372	$595
Idaho Power	12	119	$91,895	$774
NV Energy	5	176	$54,763	$312
NorthWestern Energy	37	198	$4,738	$24
PacifiCorp East	6	147	$48,343	$330
PacifiCorp West	30	96	$91,170	$947
PSC of New Mexico	12	551	$326,185	$591

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[47] 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.

45 Total costs are based on settlement values available at the time of drafting and can be subject to change. 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.

46 If the 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.

47 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

6 Real-time imbalance offset costs

Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $41 million in the first quarter of 2025.[48,49] This was a decrease from $49 million in the same quarter of 2024. During the first quarter of 2025, real-time *congestion* imbalance offset costs made up the majority of these costs ($34 million).

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $13 million credit to WEIM entities, compared to a $78 million credit in the first quarter of 2024. During the first quarter of 2025, the congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $21 million credit. The energy portion of the offset was an $8 million charge.

The real-time imbalance offset cost is the difference between the total money *paid out* and the total money collected by the California ISO settlement process for energy in the real-time markets. This charge is calculated separately for each balancing area. Any revenue surplus or revenue shortfall within this charge is allocated to measured demand (for the California ISO balancing area) or the WEIM entity scheduling coordinator (for the WEIM balancing areas).[50]

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, while any remaining revenue imbalance is recovered through the real-time imbalance energy offset charge (RTIEO). Figure 6.1 shows monthly imbalance offset costs for balancing areas participating in the day-ahead market by component since 2023.

48 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.

49 CAISO is currently the only balancing area participating in the day-ahead market.

50 Measured demand is physical load plus exports.

Figure 6.1 Monthly real-time imbalance offset costs (balancing areas in day-ahead market)

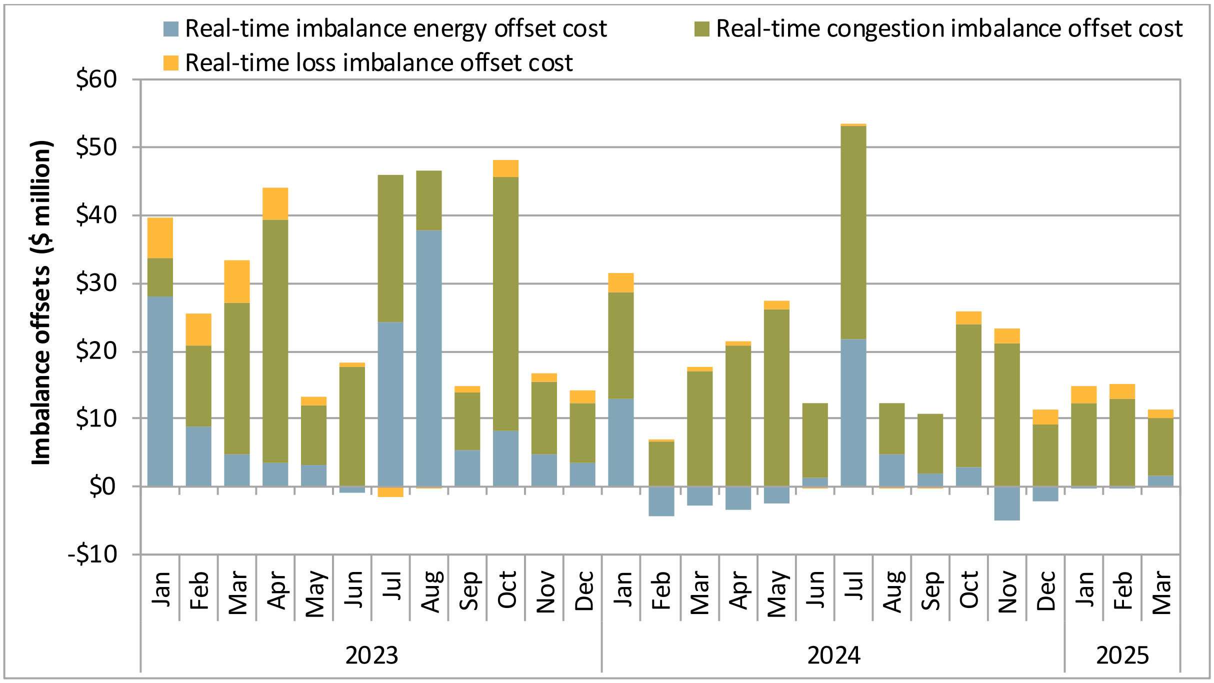


Figure 6.2 shows monthly imbalance offset costs for balancing areas only participating in the WEIM real-time markets. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month, and shown collectively in the corresponding 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 6.3 through Figure 6.5 show the quarterly real-time energy, congestion, or loss imbalance offsets for each balancing area participating only in the WEIM. Figure 6.6 shows the *total* real-time imbalance offset charges for each quarter and balancing area. Charges for revenue shortfall are shown in red, while credits for revenue surplus are shown in black. The color gradient highlights balancing areas with either greater revenue shortfall (orange) or revenue surplus (blue) over the period. Of note in the first quarter:

- Revenue *shortfall* from congestion imbalance offsets for PNM was $9.6 million (charge).
- Revenue *surplus* from congestion imbalance offsets for Powerex was $9.6 million (credit).
- Revenue *shortfall* from imbalance energy offsets for both NorthWestern Energy and PacifiCorp East was roughly $4.8 million each (charge).
- Revenue *surplus* from imbalance energy offsets for PacifiCorp West was $5.8 million (credit).

Figure 6.2 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)

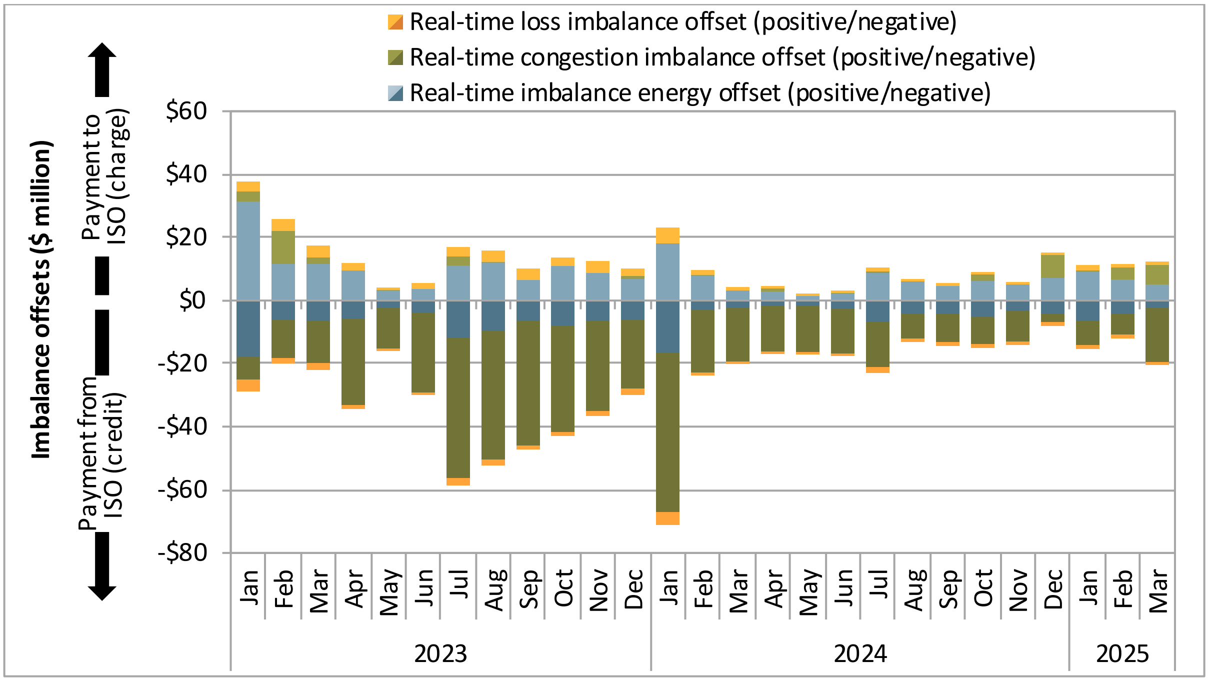


Figure 6.3 Real-time imbalance energy offsets by quarter and balancing area ($ millions)

	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1
Arizona Public Service	7	1	4	3	3
Avangrid	2	.1	.3	.5	.4
Avista	.1	.1	.1	.1	.1
BANC	.4	.1	1	.3	0
Bonneville Power Administration	.6	.3	.5	.6	.6
El Paso Electric	0	0	.3	.1	0
Idaho Power	3	.1	1	.3	2
LADWP	.2	.2	2	.2	.2
NorthWestern Energy	5	1	3	4	5
NV Energy	.9	.3	.6	1	2
PacifiCorp East	3	.7	5	4	5
PacifiCorp West	10	1	6	5	6
Portland General Electric	.1	0	.4	.1	.2
Powerex	.7	.2	.4	.2	.1
Public Service Company of NM	6	1	.9	3	3
Puget Sound Energy	7	2	4	4	4
Salt River Project	4	1	3	2	2
Seattle City Light	.4	.1	.1	.5	0
Tacoma Power	0	0	0	0	0
Tucson Electric Power	.4	.1	0	0	.1
Turlock Irrigation District	.3	.4	.9	.4	.2
WAPA Desert Southwest	0	.1	.3	0	.4

Figure 6.4 Real-time congestion imbalance offsets by quarter and balancing area ($ millions)

	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1
Arizona Public Service	.1	.1	.7	.2	.6
Avangrid	.8	.2	.3	.1	.3
Avista	1	.3	.4	.1	.3
BANC	0	.2	0	0	0
Bonneville Power Administration	.7	0	2	0	2
El Paso Electric	.3	.7	.8	.1	.1
Idaho Power	5	1	1	0	1
LADWP	2	1	4	5	2
NorthWestern Energy	1	.2	.1	.6	.5
NV Energy	2	1	.2	.3	1
PacifiCorp East	22	7	7	12	5
PacifiCorp West	9	1	1	.8	3
Portland General Electric	6	2	1	1	3
Powerex	25	16	6	1	10
Public Service Company of NM	1	1	.5	2	10
Puget Sound Energy	5	2	2	.9	2
Salt River Project	4	5	1	.7	.9
Seattle City Light	.3	.1	.2	.2	.6
Tacoma Power	.2	.1	.1	0	.1
Tucson Electric Power	2	3	4	2	.7
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	.1	0	0	0	.1

Figure 6.5 Real-time loss imbalance offsets by quarter and balancing area ($ millions)

	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1
Arizona Public Service	.4	.2	.8	.2	.2
Avangrid	.3	.1	.2	.2	.1
Avista	0	0	.1	0	0
BANC	.1	0	0	0	0
Bonneville Power Administration	.9	0	.1	.1	.1
El Paso Electric	.1	0	.2	.1	.1
Idaho Power	.4	.2	.3	.5	.4
LADWP	.5	0	0	.2	.2
NorthWestern Energy	.1	0	.1	.1	.1
NV Energy	.4	0	.3	.1	.1
PacifiCorp East	2	.1	1	2	1
PacifiCorp West	0	.3	.3	.4	.5
Portland General Electric	2	0	.4	.1	.1
Powerex	3	1	1	.6	2
Public Service Company of NM	0	.1	0	.1	.2
Puget Sound Energy	.5	0	.2	0	0
Salt River Project	.7	.1	.4	.2	.1
Seattle City Light	.4	.2	.5	.3	.5
Tacoma Power	.3	0	0	0	0
Tucson Electric Power	.3	.1	.4	.3	.1
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	.2	0	0	0	.1

Figure 6.6 Total real-time imbalance offsets by quarter and balancing area ($ millions)

	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2025 Q1
Arizona Public Service	6	1	4	3	4
Avangrid	1	.2	.2	.2	.1
Avista	1	.2	.1	.1	.2
BANC	.5	0	1	.3	0
Bonneville Power Administration	.4	.3	.9	.7	1
El Paso Electric	.4	.7	.7	.1	.2
Idaho Power	2	1	3	.8	.1
LADWP	3	1	2	6	2
NorthWestern Energy	4	1	3	4	4
NV Energy	1	1	.1	.6	.5
PacifiCorp East	21	6	3	9	1
PacifiCorp West	19	3	7	6	10
Portland General Electric	4	2	.3	.8	3
Powerex	20	15	4	.4	7
Public Service Company of NM	4	.1	.4	6	12
Puget Sound Energy	11	4	6	5	6
Salt River Project	8	6	4	3	3
Seattle City Light	.4	0	.2	.5	0
Tacoma Power	.5	.1	0	0	0
Tucson Electric Power	2	3	4	2	.7
Turlock Irrigation District	.3	.4	.8	.4	.2
WAPA Desert Southwest	.1	.1	.4	0	.4

7 Bid cost recovery

During the first quarter of 2025, estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market totaled about $44.7 million.[51] This was a 10 percent increase from the $40.1 million in bid cost recovery in the first quarter of 2024. Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM) totaled about $3 million. WEIM area bid cost recovery payments decreased about 38 percent from $4.8 million in Q1 2024.[52]

Figure 7.1 shows monthly bid cost recovery payments in the first quarter of 2025 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $9.9 million, up from $8.9 million in the first quarter of 2024. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $11 million, or about $5 million higher than the first quarter of 2024. Bid cost recovery associated with the real-time market (green bars) for areas that participate in the day-ahead market totaled about $23.7 million, which was about $2.3 million lower than the same quarter of 2024.

Figure 7.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM. Bid cost recovery payments to these units were greatest in the Desert Southwest and California[53] regions at $2 million and $356,000, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around $345,000 and $322,000, respectively.

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 first quarter of 2025, about $37.4 million of bid cost recovery payments were made to gas resources, 94 percent of which were paid to units participating in both the day-ahead market and the WEIM. About $6.5 million and $2.4 million of payments were made to battery and hydroelectric resources, respectively.

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51 CAISO is the only balancing area currently participating in the day-ahead market.

52 The bid cost recovery payment amounts for 2023 and 2024 in this report are different than what is reported in the previous reports due to resettlements.

53 Figure 7.2 includes only non-CAISO balancing authority areas.

Figure 7.1 Monthly bid cost recovery payments for day-ahead market area

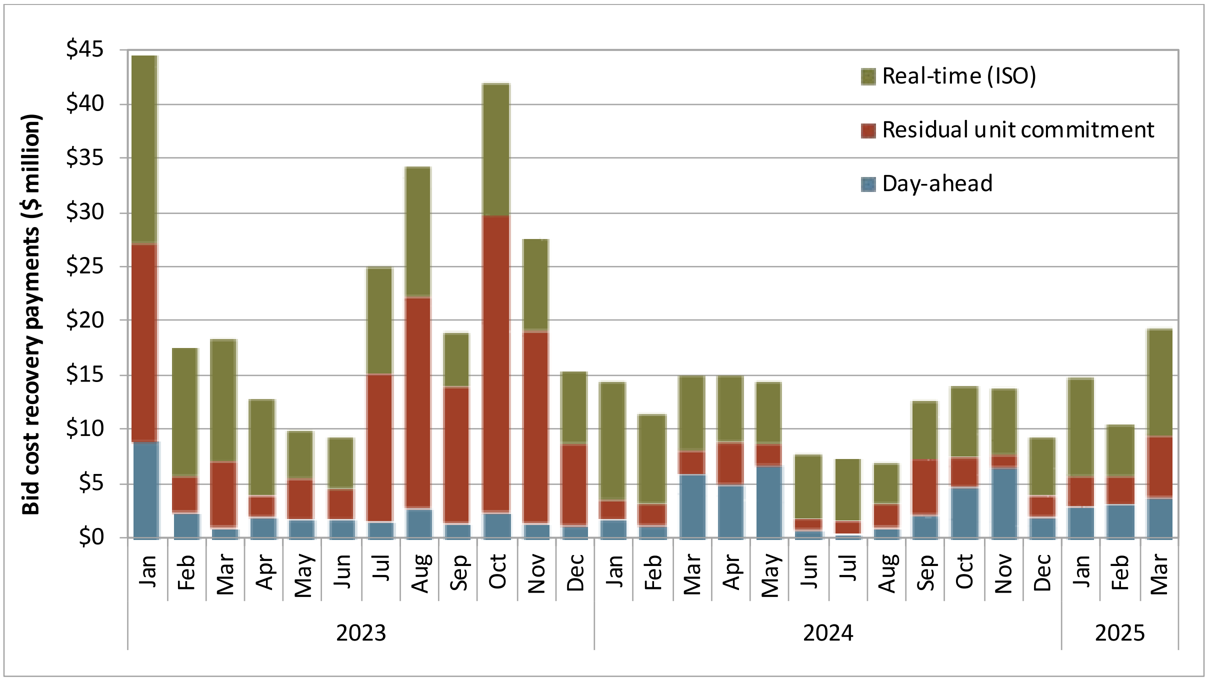
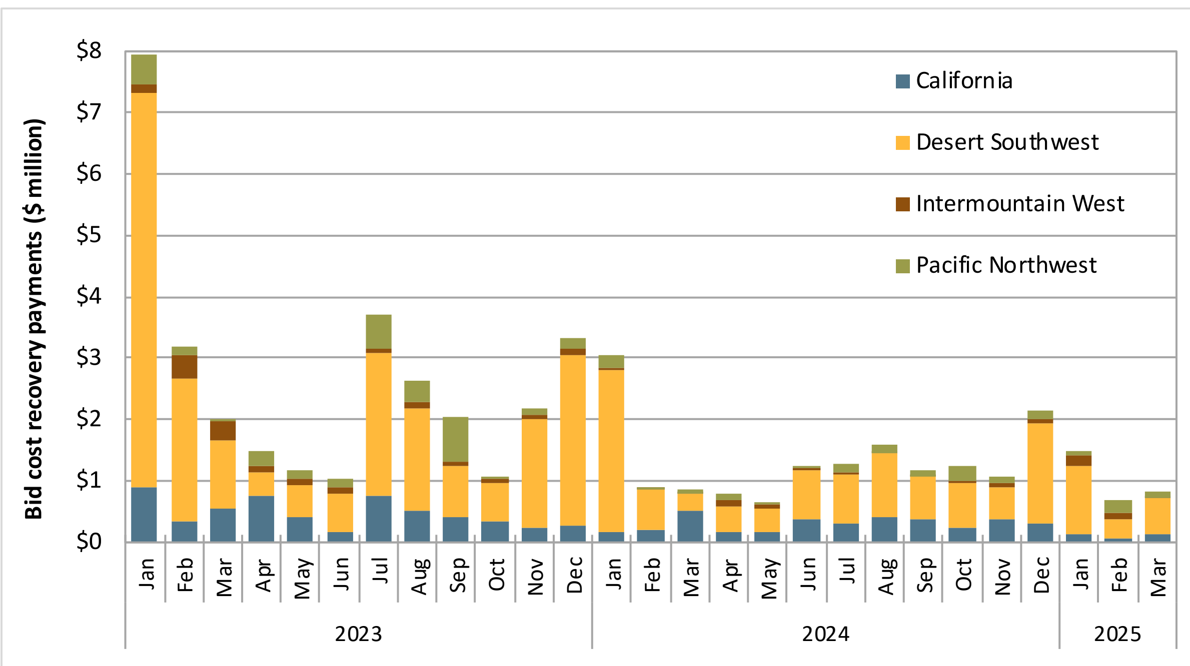


Figure 7.2 Monthly bid cost recovery payments for the WEIM



8 Imbalance conformance

Operators in 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.

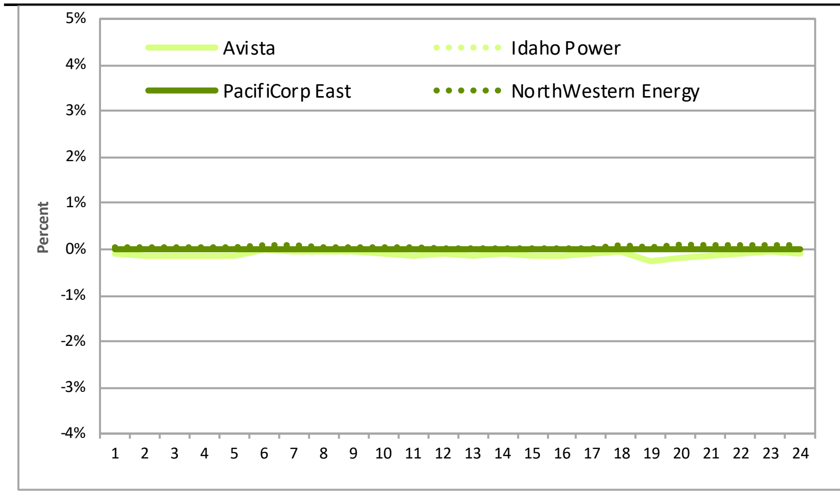
8.1 Imbalance conformance by balancing area

The figures below show first quarter 15-minute market and 5-minute market average hourly imbalance conformance for each balancing area as a percentage of the average load of the balancing area.[54] Generally, imbalance conformance levels were much higher in the 5-minute market than the 15-minute market, with exceptions being the CAISO balancing area and Bonneville Power Administration (BPA).

54 Avangrid Power and Powerex are not shown in this figure. Avangrid Power is a generation-only entity and therefore load conformance cannot be measured as a percent of load. 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.

Figure 8.1 Intermountain West: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2025)

15-minute market



5-minute market

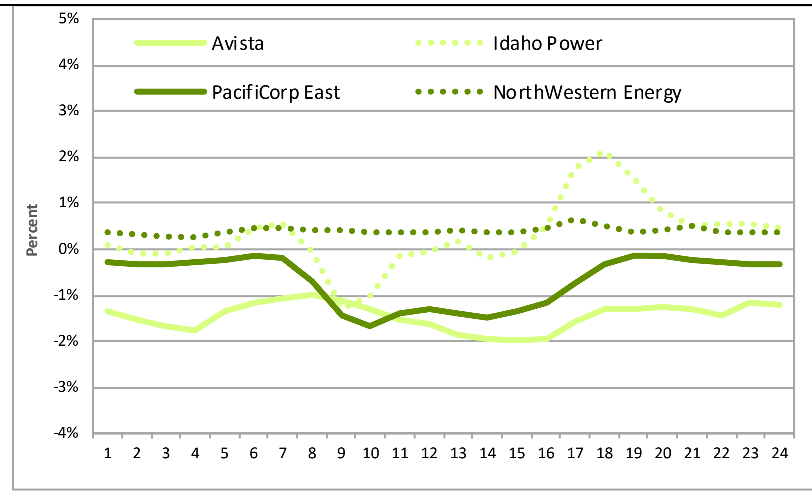
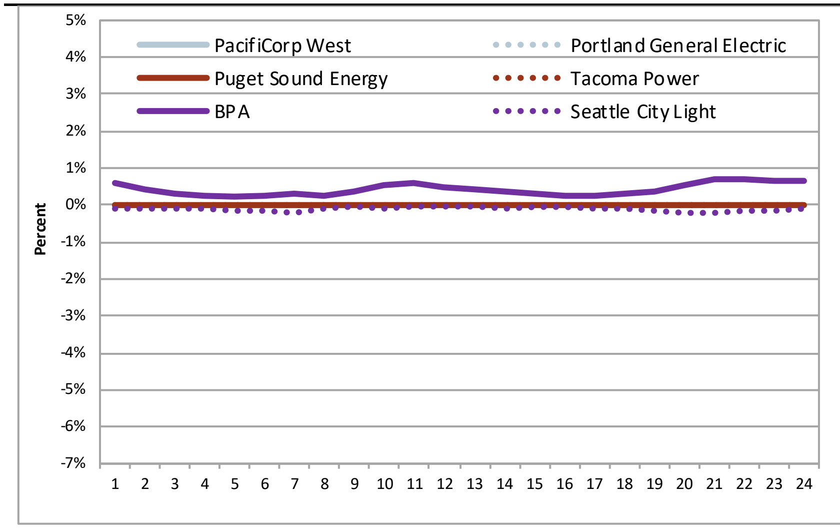


Figure 8.2 Pacific Northwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2025)

15-minute market



5-minute market

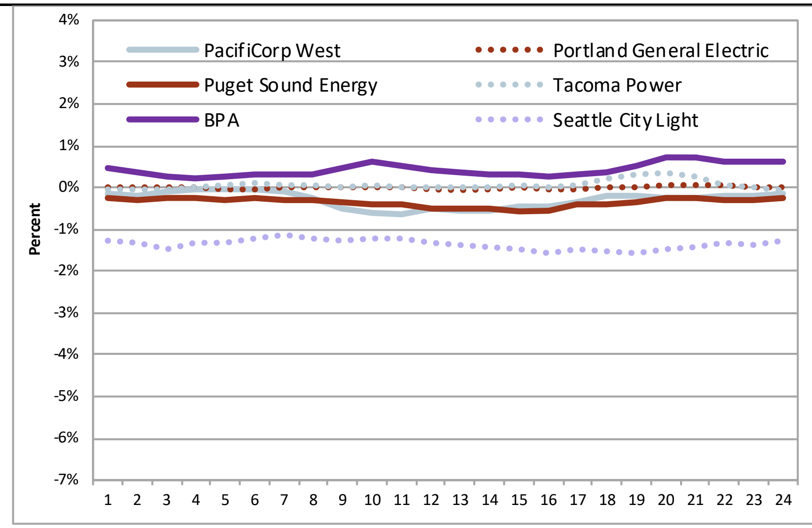


Figure 8.3 Desert Southwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2025)

15-minute market *5-minute market*

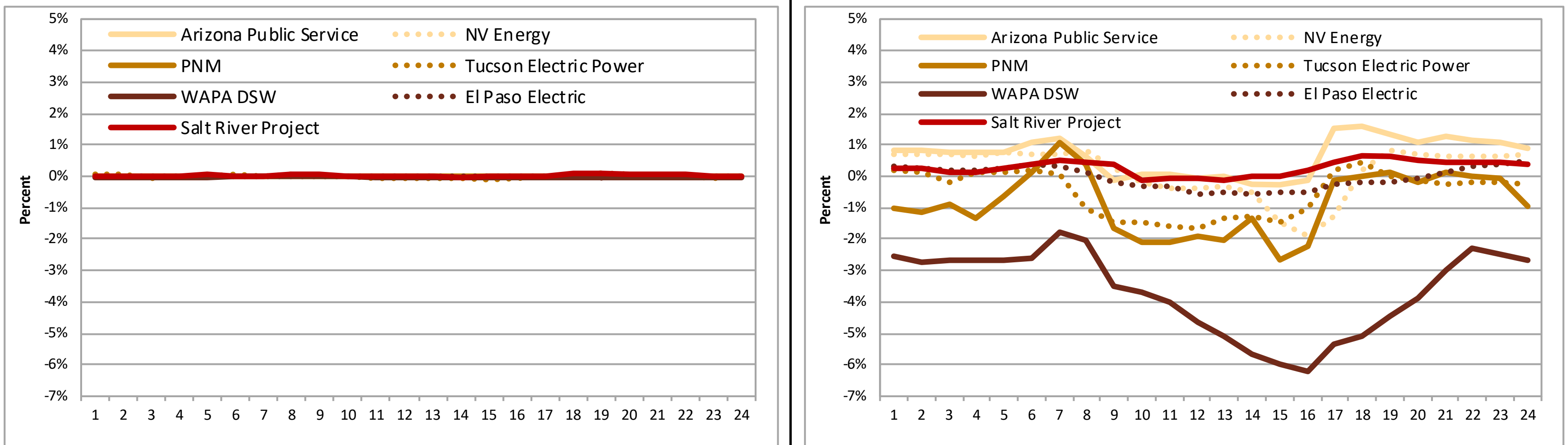
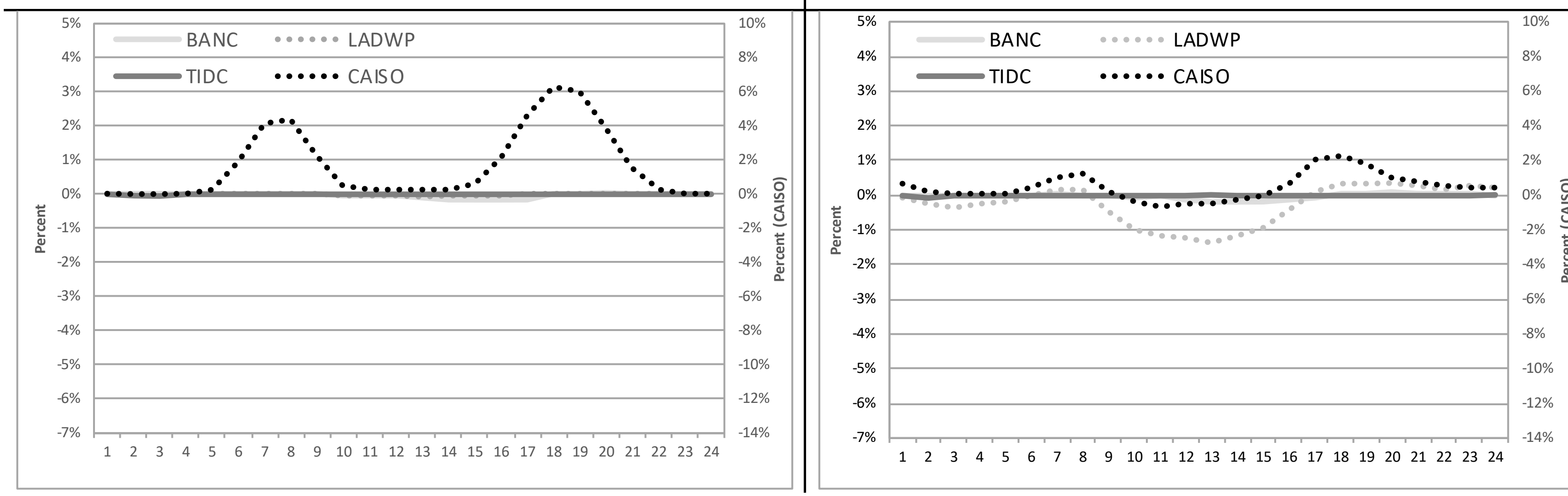


Figure 8.4 California: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2025)

15-minute market *5-minute market*



8.2 Imbalance conformance — special report on CAISO balancing area

The size and frequency of CAISO balancing area operators' use of imbalance conformance in the 15-minute market made it an outlier amongst WEIM areas in the first quarter of 2025. This section analyzes the use of imbalance conformance by CAISO balancing area operators.

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 8.5 shows CAISO area imbalance conformance adjustments in real-time markets for the first quarter of 2024 and 2025. Imbalance conformance over the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. This contributes to higher prices in the 15-minute market than in the 5-minute market over these hours.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets increased during morning ramp hours and decreased during evening ramp hours in the first quarter of 2025 relative to the same quarter of 2024. During the morning hours, the highest average hourly adjustments were around 900 MW. Imbalance conformance over the evening peak hours reached about 1,300 MW, about 300 MW lower than the largest average hourly evening adjustments over Q1 2024.

The 5-minute market adjustments were more pronounced in all hours of the first quarter of 2025, e.g., more positive in non-solar hours and more negative during the midday hours, compared to the first quarter of 2024. The positive adjustments peaked in hour-ending 18 at about 480 MW while negative adjustments peaked at -140 MW in hour-ending 11.

Figure 8.5 Average CAISO balancing area hourly imbalance conformance adjustment (Q1 2024 and Q1 2025)

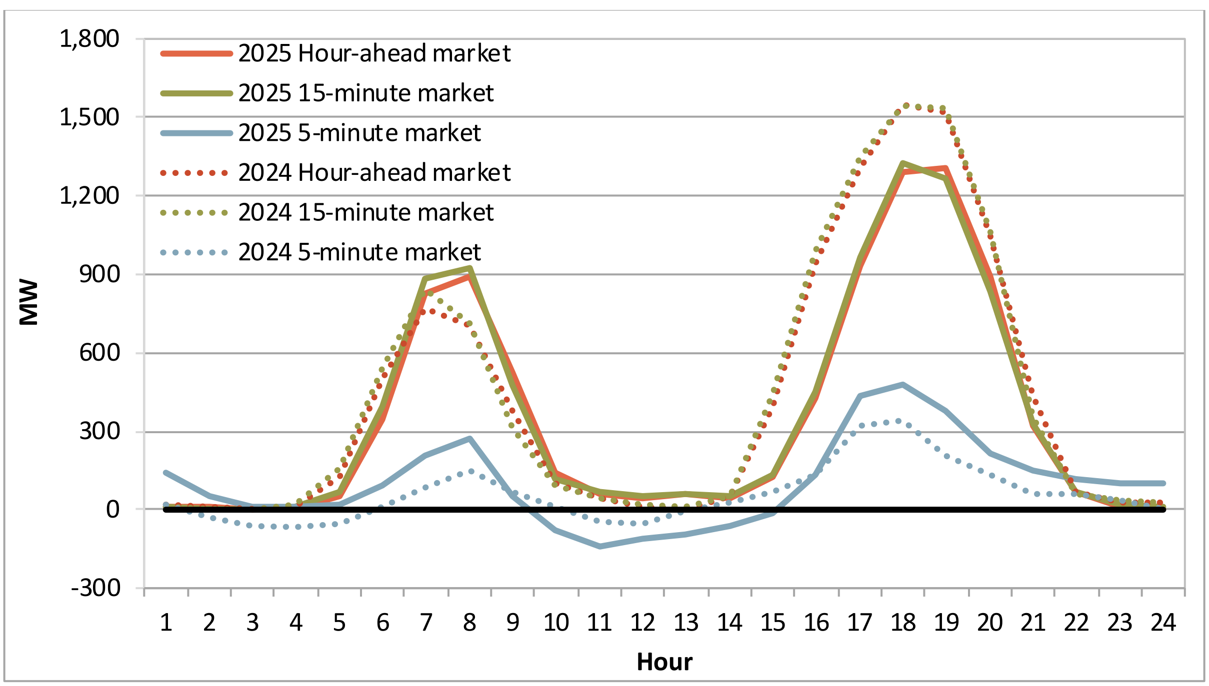
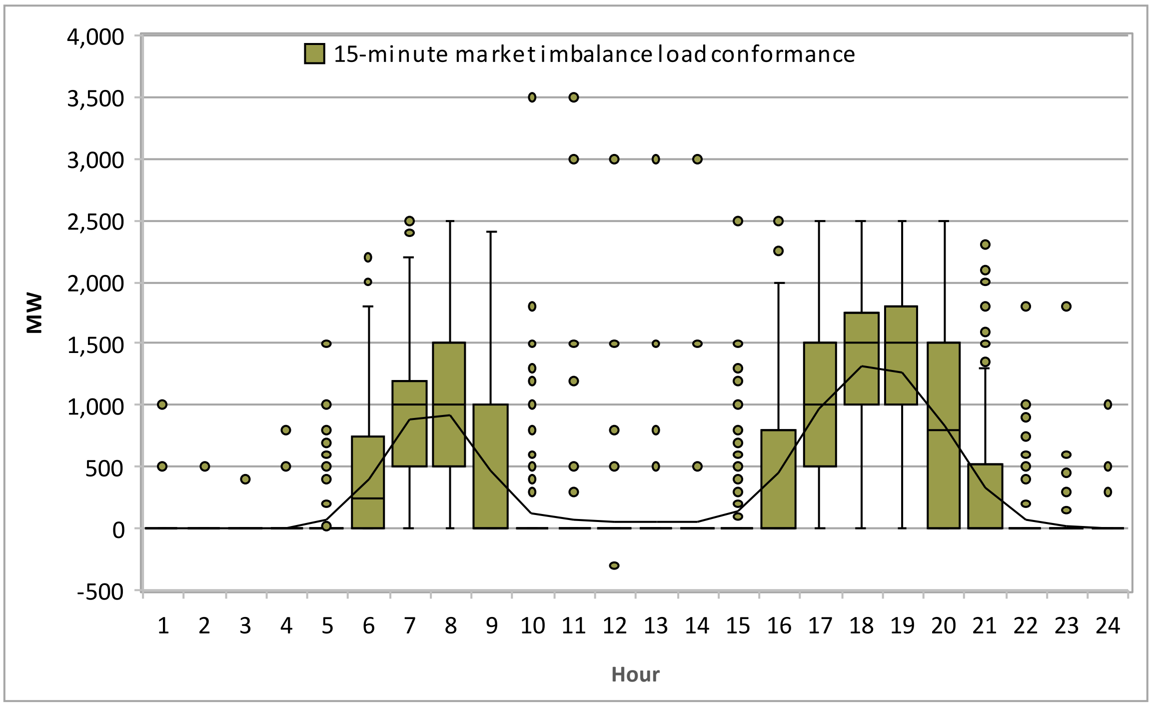


Figure 8.6 shows an hourly distribution of the 15-minute market load adjustments for the first quarter of 2025. This box and whisker graph highlights extreme outliers[55] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well 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 maximums and major outliers in hours-ending 10 to 15, e.g., 2,500 MW or greater, primarily occurred between March 14 and March 15,[56] associated with resource deviation possibly related to weather and very low solar generation.

Figure 8.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (Q1 2025)



55 A data point is an outlier if it is more than 1.5 * Interquartile Range (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).

56 *California Takes Action During October Heat Wave*, California Governor’s Office of Emergency Services (Cal OES), October 2, 2024: https://news.caloes.ca.gov/california-takes-action-during-october-heat-wave/

9 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.[57] 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.

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 uncertainty in each direction that might materialize.[58] 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). These coefficients are then combined with current forecast information for each interval to determine the uncertainty requirement.

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.

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57 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.

58 Based on a 95 percent confidence interval.

9.1 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[59] 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.[60] 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 the base-case flow based constraints and nomogram constraints are modeled and enforced in the deployment scenarios. Contingency flowgate constraints were briefly activated on June 4, 2024, and de-activated on June 12 due to performance issues with the solution run-times.[61] Using the same constraints for both the real-time market and flexible ramping product deployment scenarios is 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.[62] 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.[63] 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. 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

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59 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

60 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.

61 *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

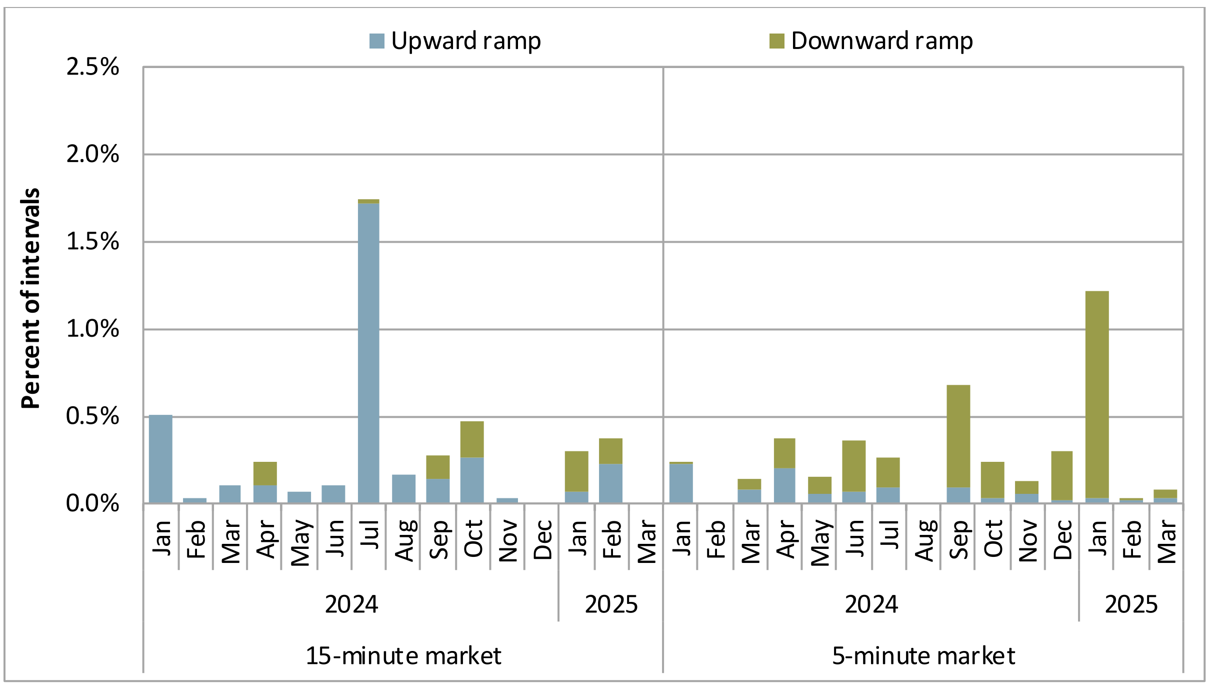
62 Or for each surplus zone in the case of the CAISO balancing area (by TAC area) and BANC (by custom load aggregation point).

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

available.[64] 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 9.1 shows the percent of intervals in which the shadow price on the pass-group constraint was non-zero (constraint binding) for upward and downward flexible capacity. 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.[65] The pass-group constraint for procuring *upward* flexible capacity in the 15-minute market was binding in around 0.1 percent of intervals during the quarter. In the 5-minute market, the constraint for procuring flexible capacity within the pass-group was also binding very infrequently. The pass-group constraint for procuring downward flexibility in the 5-minute market was binding in 1.2 percent of intervals during January, but otherwise was binding very infrequently.

Figure 9.1 Frequency of flexible ramping product prices from pass-group constraint



64 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.

65 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.

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 9.2 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 15-minute market upward ramping capacity information shown in Figure 9.1, summarizing the frequency in which the constraint for meeting pass-group flexible capacity requirements was binding. The figure adds the percent of intervals 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 9.2 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

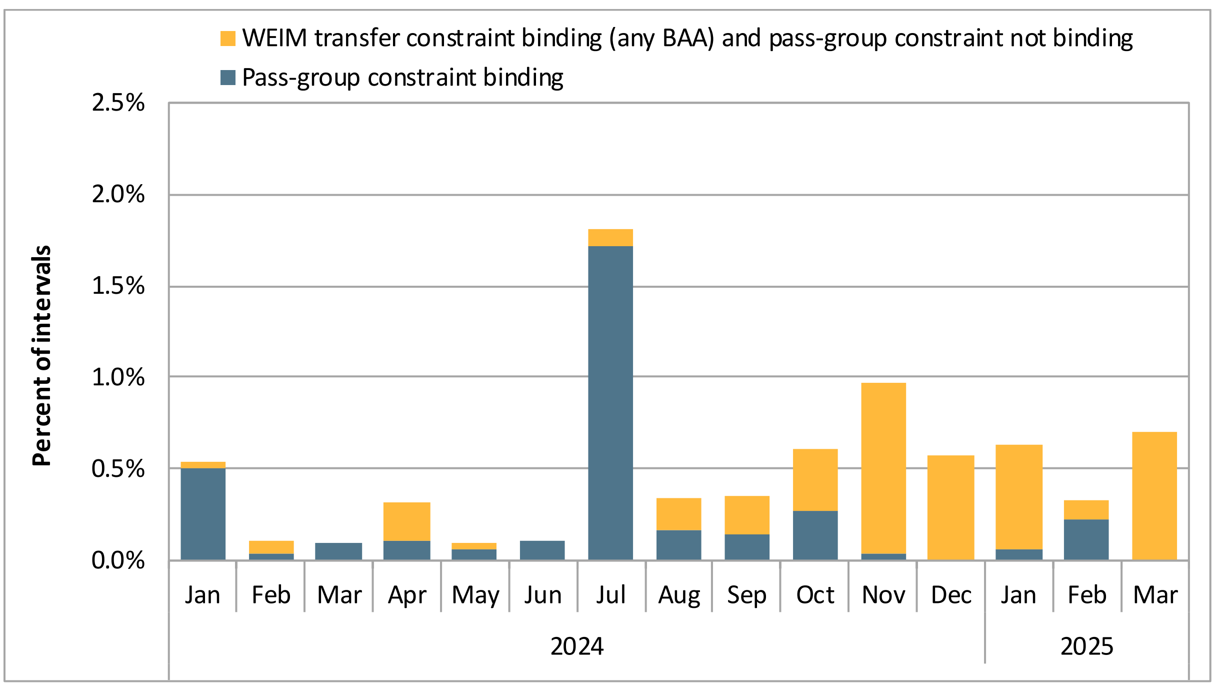


Figure 9.3 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

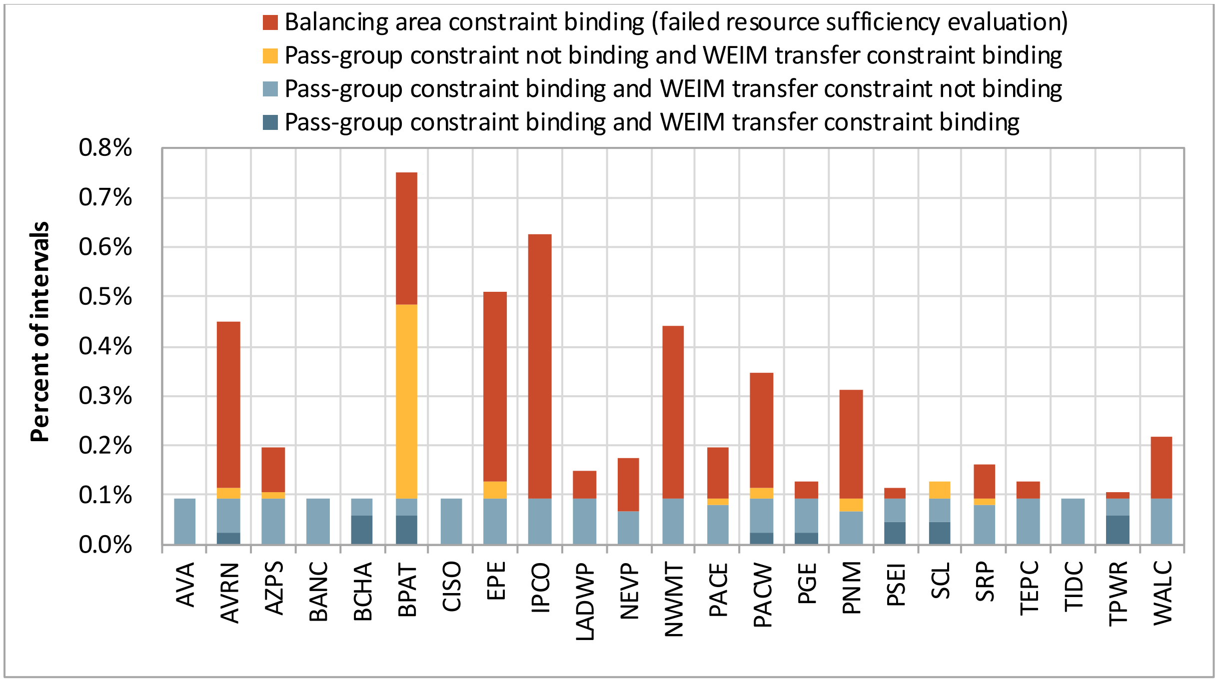
- **Pass-group constraint binding and WEIM transfer constraint not binding** indicates that the balancing area passed the resource sufficiency evaluation, and there is a price for upward flexible capacity within the wider pass-group.
- **Pass-group constraint binding and WEIM transfer constraint binding** 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 around 0.1 percent of intervals. In some 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 9.3 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. Idaho Power had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 0.5 percent of intervals. Some of these can be 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.[66] BPA regularly had prices for flexible capacity associated with meeting its share of the pass-group uncertainty requirement while the price for flexible capacity in the wider system was zero. This was because of WEIM transfer congestion and occurred during around 0.4 percent of intervals for the quarter.

[66] 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.

Figure 9.3 Frequency of upward flexible ramping product prices by balancing area and constraint (15-minute market, January–March 2025)



9.2 Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that pass the resource sufficiency evaluation. Figure 9.4 and Figure 9.5 show the average upward or downward flexible capacity that was procured from various fuel types.

During the quarter, battery resources continued contributing to much of the upward and downward flexible capacity. Battery resources made up almost 56 percent of upward flexible capacity and 31 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (29 percent). Wind and solar resources combined made up around 42 percent of downward flexible capacity.

Figure 9.6 and Figure 9.7 show the average upward or downward flexible capacity that was procured in various regions.[67] 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, the California ISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 60 percent for both directions. Balancing areas in the Pacific Northwest made up 25 percent of upward flexible capacity and 15 percent of downward flexible capacity.

[67] 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 9.4 Average upward pass-group flexible ramp procurement by fuel type (15-minute market, Q1 2025)

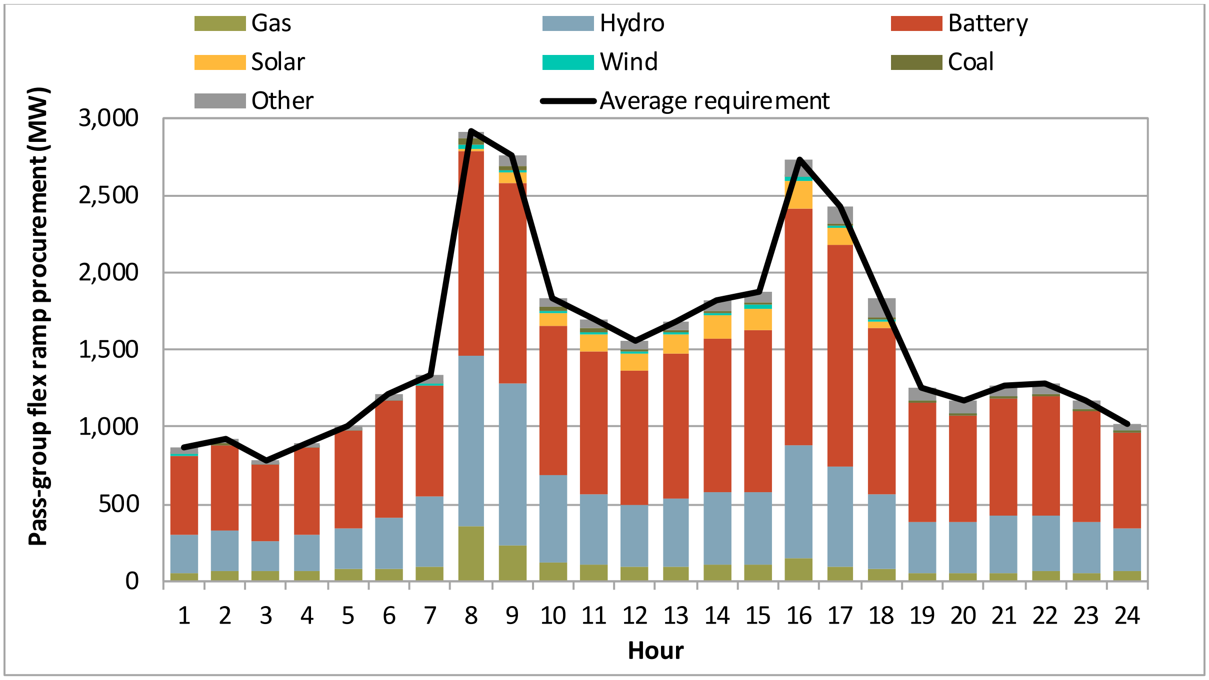


Figure 9.5 Average downward pass-group flexible ramp procurement by fuel type (15-minute market, Q1 2025)

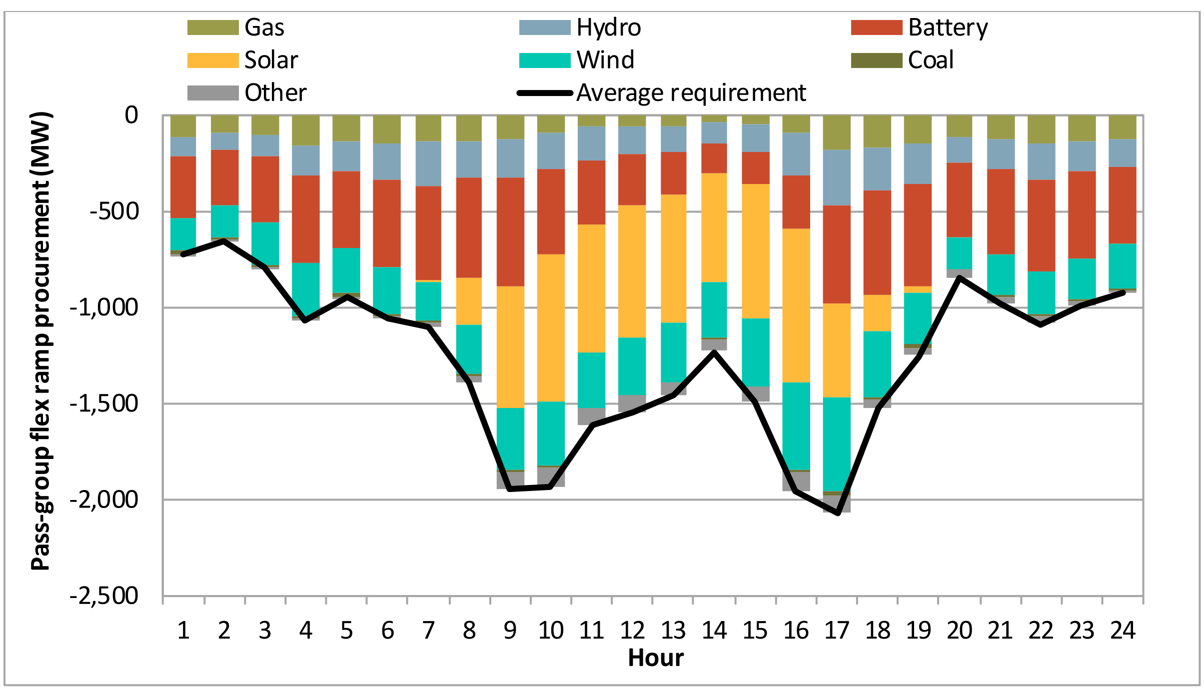


Figure 9.6 Average upward pass-group flexible ramp procurement by region (15-minute market, Q1 2025)

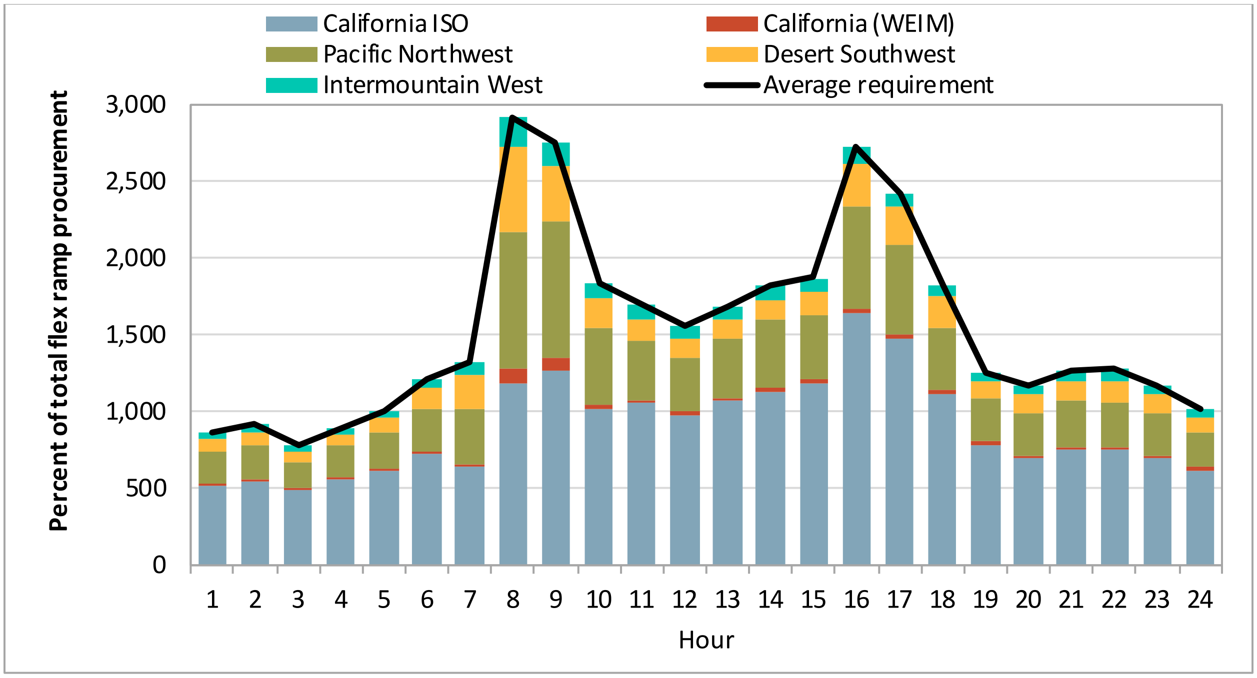
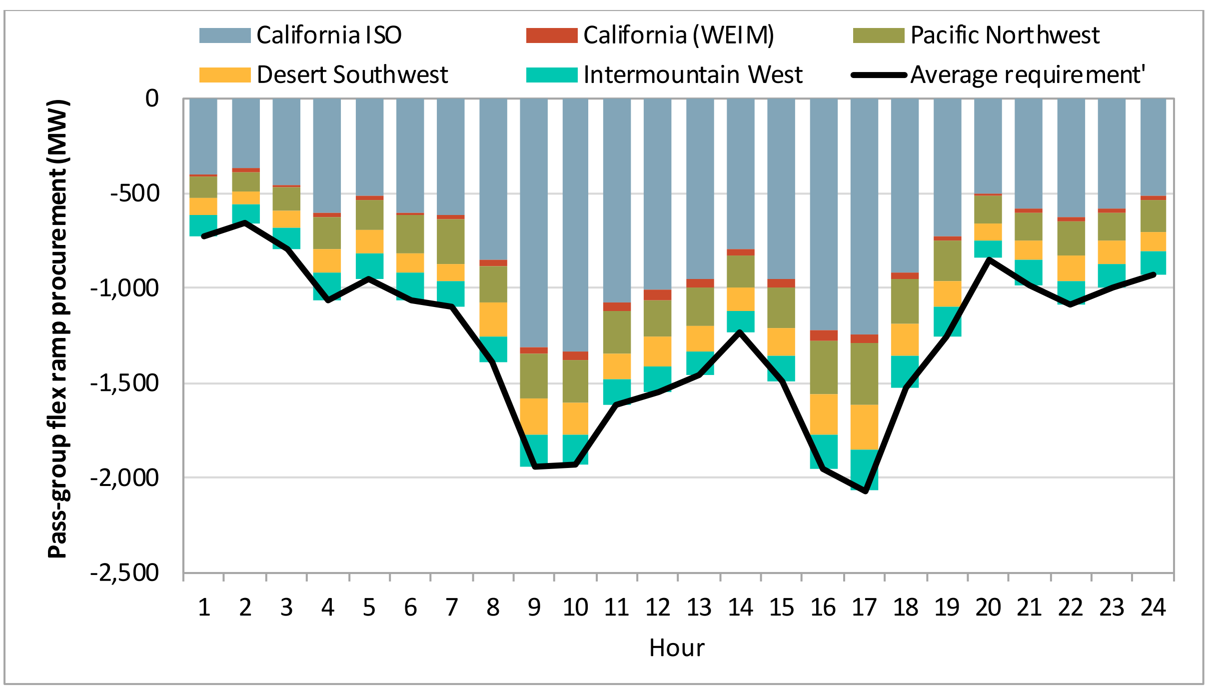


Figure 9.7 Average downward pass-group flexible ramp procurement by region (15-minute market, Q1 2025)



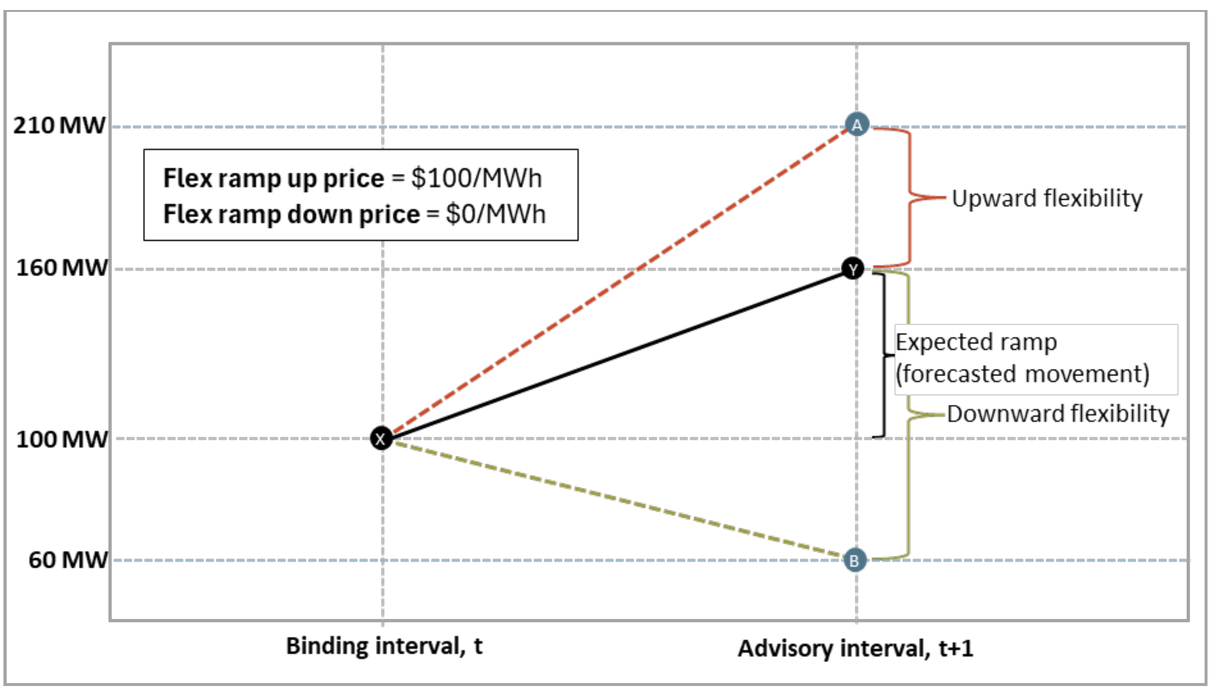
9.3 Forecasted movement settlement and exclusion of base WEIM transfers

Variation in net load forecasts creates a demand for real-time ramp. This can be split up into two components: (1) the amount of ramp needed to meet the expected net load forecast in the next interval of the same market run (“forecasted movement”) and (2) additional ramping capability that may be needed if the net load forecast materializes higher or lower in a subsequent market run (“uncertainty”). The flexible ramping product pays resources for both.

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). 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).

Figure 9.8 illustrates each of these components of flexible ramping product settlement for an example resource. In this example, the resource is expected to move upward from 100 MW in the binding interval to 160 MW in the next interval (advisory). Further, the resource has the flexibility to ramp between 60 MW and 210 MW in the next interval. The price for upward ramping capacity is $100 while the price for downward ramping capacity is $0. Here, the resource is paid for providing upward flexibility (50 MW × $100 = $5,000). In addition, the resource is moving in the same direction as the demand for flexibility and is paid for forecasted movement (60 MW × $100 = $6,000). The price for downward ramping capacity is zero so there is no settlement for the downward flexibility.

Figure 9.8 Example resource flexible ramping product settlement

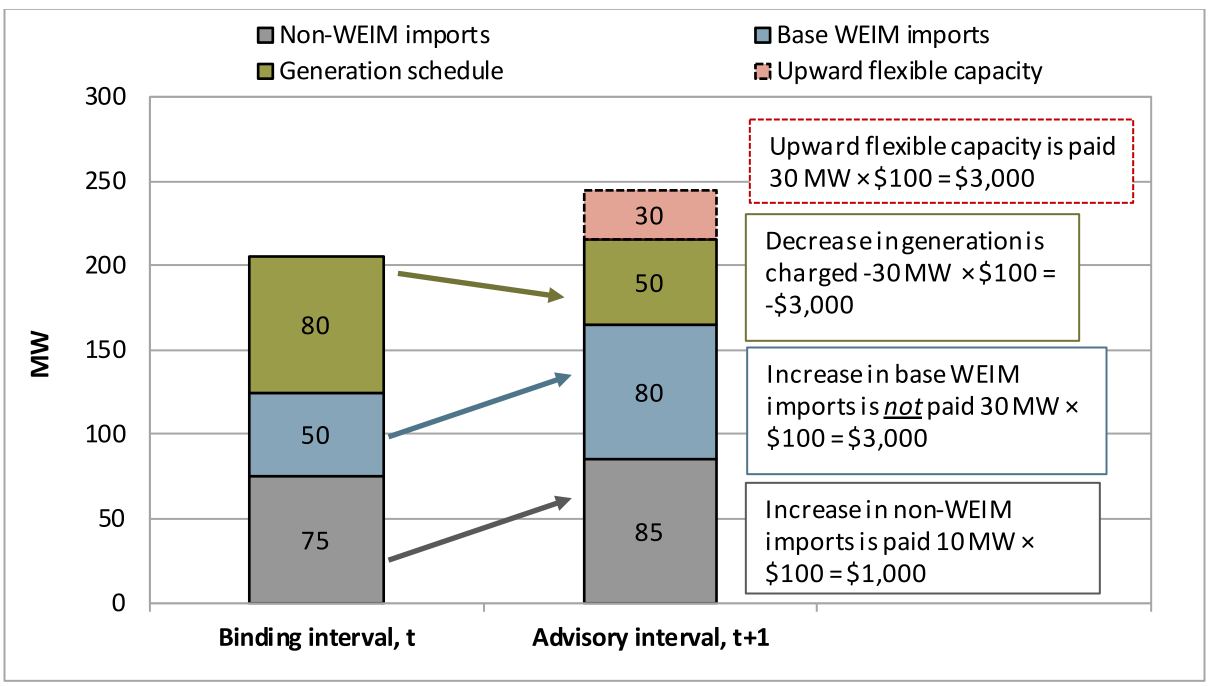


Base WEIM transfers (fixed bilateral transactions between two WEIM entities) are excluded from the forecasted movement settlement. All other generation and intertie schedules (non-WEIM) are paid or charged for forecasted movement based on their expected change in schedule in the next interval. This is highlighted by the example in Figure 9.9 below.[68]

In this example, the price for upward flexible capacity in the advisory interval is again $100. Here, the balancing area secures more base WEIM imports in advance of the market run to better manage internal flexibility in their system, increasing base WEIM imports from 50 MW to 80 MW. Generation is then unloaded, decreasing from 80 MW to 50 MW. The 30 MW decrease in the generation schedule is charged for downward movement but the resource is also paid for upward flexible capacity. However, the +30 MW increase in the base WEIM import is currently *not* paid for supporting flexibility.[69] In contrast, non-WEIM imports and exports including transfers with the California ISO balancing area are compensated for forecasted movement.[70] This is shown in the example below as the 10 MW increase in the non-WEIM import schedule that is paid (10 MW × $100 = $1,000).

DMM believes that base WEIM transfers between two WEIM entities ahead of the market optimization should not be treated differently in the forecasted movement settlement from other bilateral hourly-block import or export transactions that are scheduled with CAISO or a non-WEIM balancing area. DMM recommends that base WEIM transfers be accounted for in the forecasted movement settlement to better align cost-causation for sources that support or consume flexibility within each balancing area.

Figure 9.9 Example balancing area flexible ramping product settlement



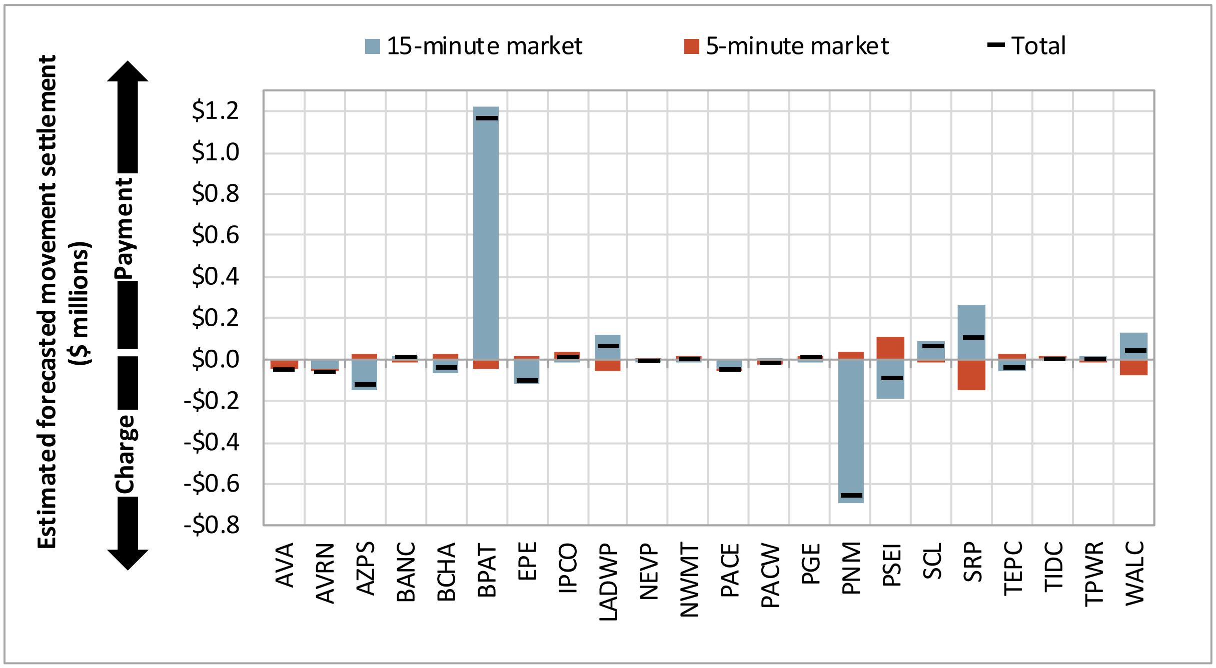
[68] For simplicity, base WEIM exports and non-WEIM exports are zero in this example.

[69] Changes in a base WEIM import or base WEIM export from one hour to the next *is* considered in the flexible ramp sufficiency test but is not considered for forecasted movement settlement.

[70] A WEIM mirror resource will reflect the WEIM balancing area perspective of one or more CAISO import or export schedules at an intertie. Changes in these intertie schedules are considered in the forecasted movement settlement.

Figure 9.10 shows the estimated impact for settling forecasted movement of base WEIM transfers during 2024. Net *payments* for forecasted movement in the same direction as the demand for flexibility are shown as positive. Net charges for forecasted movement in the opposite direction as the demand for flexibility are shown as negative. Of note, BPA would have been paid around $1.2 million on net during 2024 had base WEIM transfers been included in the forecasted movement settlement. The large majority of this was associated with the demand for upward flexible capacity in the 15-minute market following failure of the second resource sufficiency evaluation run (T-55) in the first interval of an hour.[71] All other balancing areas would have been paid less than $0.2 million (or would have been charged) for forecasted movement associated with base WEIM transfers.

Figure 9.10 Estimated impact of settling forecasted movement of base WEIM transfers (2024)



[71] 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 hour. Flexible ramping product procurement and pricing in the first 15-minute market interval of each hour is dependent on the second run of the resource sufficiency evaluation at 55 minutes prior to the evaluation hour (T-55).

10 Uncertainty

This section discusses uncertainty considered in different applications of the market, including the flexible ramping product (FRP), resource sufficiency evaluation (RSE), and the residual unit commitment (RUC) adjustment. Each of these market processes use a method called *mosaic quantile regression* to calculate and account for uncertainty that may materialize. This chapter reviews the results of the uncertainty calculation and assesses the regression method.

Background defining the uncertainty analyzed in this section

The California ISO introduced a regression method to calculate uncertainty on February 1, 2023.[72] 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. One 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.[73] At the start time of the advisory 15-minute 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

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72 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.

73 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.

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 the 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.[74]

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.[75]

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.

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

74 For a more detailed description of the mosaic quantile regression method, see the DMM special report, *Review of the mosaic quantile regression*, November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

75 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,* November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

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.[76] Another possibility is that the coefficient is non-zero but unreliable,

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[76] 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*, November 20, 2023 (p 5, section 3): https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

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 performed for the flexible ramping product, resource sufficiency evaluation, and the residual unit commitment market adjustment. Measurements of the uncertainty requirements and coverage in this section are based on actual market results. The statistical significance metrics are based on DMM's replication of the ISO's mosaic quantile regression method.[77]

10.1 Flexible ramping product uncertainty

The flexible ramping product procures flexible capacity to cover uncertainty that may materialize in the real-time market. By design, the *uncertainty requirement* captures the extreme ends of net load uncertainty and 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. 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. For the 5-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 5-minute market forecast and the binding 5-minute market forecast.

The flexible ramping product uses 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. For the group of balancing areas that instead pass the resource sufficiency evaluation (known as the pass-group), flexible capacity is pooled together to meet the group's uncertainty requirement.

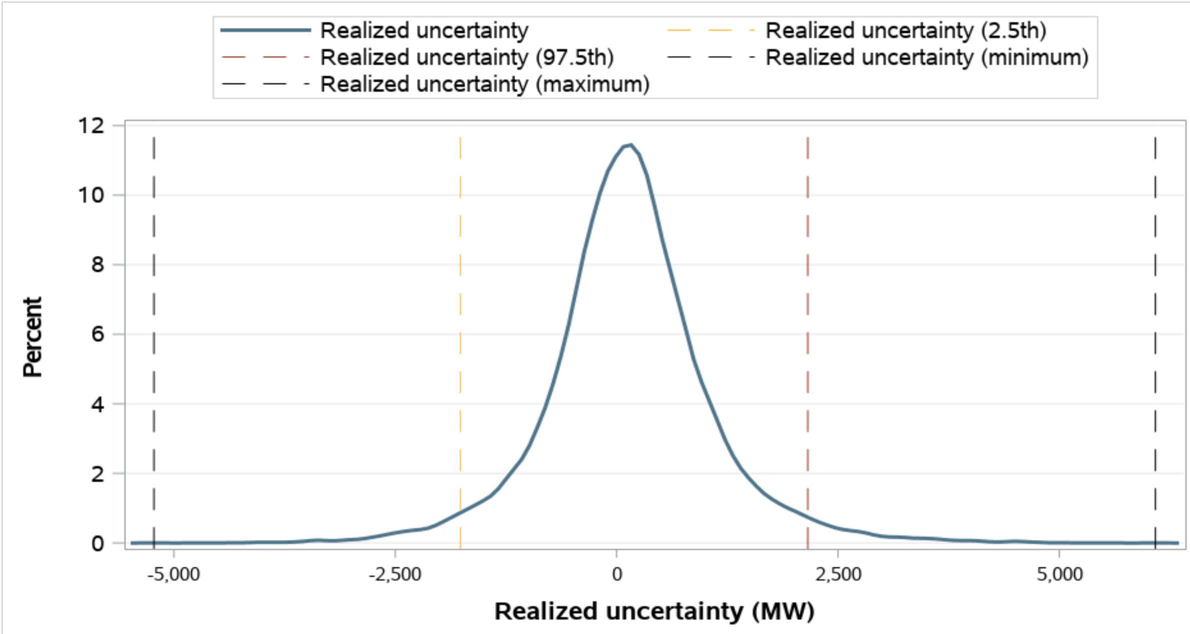
Figure 10.1 illustrates the distribution of realized uncertainty in the flexible ramping product (FRP) for the group of balancing areas that passed the resource sufficiency evaluation (RSE) for the first quarter of 2025. The distribution is depicted as a blue line, with the extreme percentiles highlighted: 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 2,100 MW to over 6,000 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. When the distribution is skewed upward, the result is a longer tail on the upper end. This may indicate the influence of systematic patterns, rather than purely random variations. These factors may provide valuable information for forecasting uncertainty.

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.

[77] This choice is made because there are no statistical significance tests available based on the ISO's estimations.

Figure 10.1 Distribution of realized uncertainty in FRP (pass-group, January–March 2025)



10.1.1 Results of flexible ramping product uncertainty calculation

Figure 10.2 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the historical 180-day period) and with the mosaic quantile regression method. 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 quarter. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively, during the period.[78]

Figure 10.3 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. Of note, between 8:00 and 10:00, the regression-based upward uncertainty was much lower on average, in comparison to the histogram-based uncertainty. However, results of the regression-based approach vary more widely, including periods with much lower (or zero) uncertainty.

[78] Two ceiling thresholds are applied to help prevent extreme outlier results from impacting the final uncertainty.

Figure 10.2 15-minute market pass-group uncertainty requirements (January–March 2025)

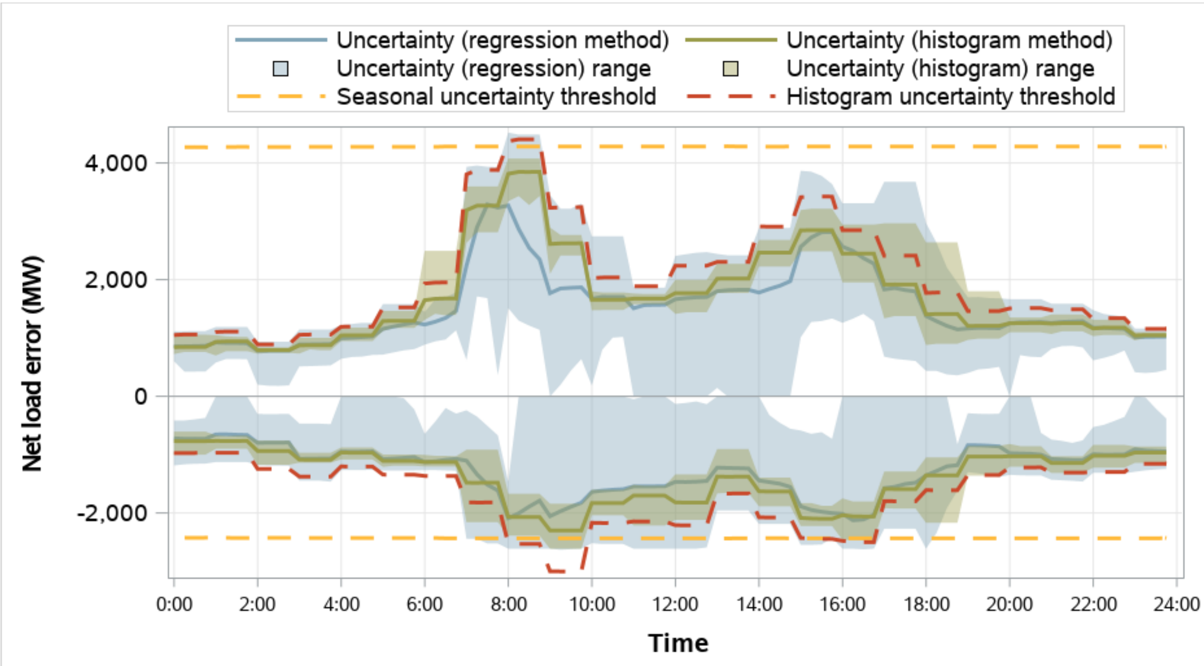


Figure 10.3 5-minute market pass-group uncertainty requirements (January–March 2025)

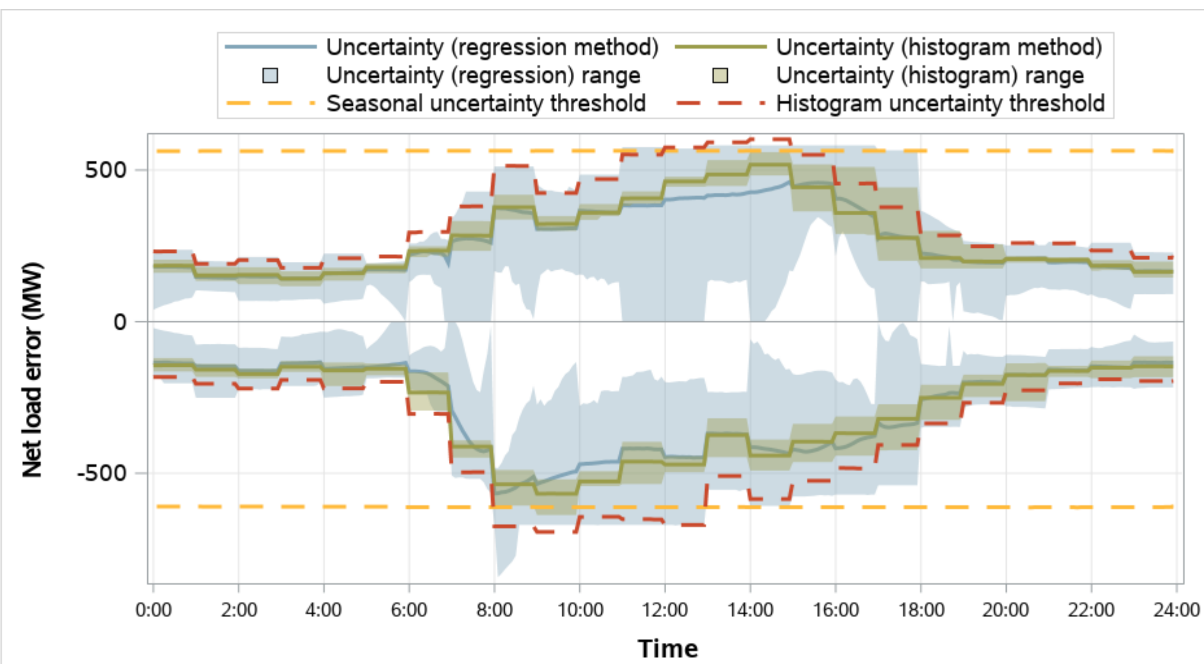


Table 10.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the pass-group (based on a 95 percent confidence interval). The coverage shows how often the realized uncertainty fell within the requirement for the same interval.[79]

In flexible ramping product (FRP), due to the different composition of the upward and downward RSE pass-group, each direction is evaluated with a target coverage of 97.5 percent.[80] In the 15-minute market, uncertainty forecasted by mosaic regression generally had lower coverage and lower requirements, whereas the histogram method showed slightly higher coverage and higher requirements. In the 5-minute market, the difference between the two methods was minimal.

Table 10.1 Average pass-group uncertainty requirements (January–March 2025)

Market	Direction	Requirement			Coverage		
		Histogram	Mosaic	*Difference*	Histogram	Mosaic	*Difference*
15-minute market	Up	1,728	1,558	-170	96.5%	95.2%	-1.2%
	Down	1,388	1,278	-111	96.5%	95.1%	-1.3%
5-minute market	Up	278	267	-11	96.6%	96.2%	-0.4%
	Down	298	285	-12	96.8%	96.4%	-0.4%

Table 10.2 presents the percentage of statistically significant coefficients across various quantile regressions for the 15-minute market calculation of pass-group uncertainty. The results are based on DMM's replication.

The mosaic regression is primarily designed to forecast net load uncertainty, with the mosaic variable serving as the main predictor in this regression. The three additional quantile regressions—load, solar, and wind—function as intermediate regressions used to construct the mosaic variable.[81]

The percentages in the table indicate the proportion of estimated coefficients that were statistically different from zero among all regression estimation in this quarter. Each regression includes two primary coefficients: a quadratic term and a linear term.[82] The percentages represent the proportion of

[79] Realized 15-minute market uncertainty is measured as the difference between binding 5-minute market net load forecasts and the advisory 15-minute market net load forecast. Realized 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.

[80] The composition of the RSE pass-group differs for each direction. For instance, at a given interval, the RSE pass-group for upward uncertainty might include all 23 BAAs, while for the same interval the pass-group for downward uncertainty could include only 20. These disparities mean that the actual uncertainty for the pass-group is different in each direction. Since the regression employs the 97.5th percentile for upward uncertainty and the 2.5th percentile for downward uncertainty, the target coverage for each direction is set at 97.5 percent.

[81] 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*, November 20, 2023, pp 6-10: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

[82] 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.

regression where at least one of these coefficients was statistically significant. The significance level was set at 10 percent.

Table 10.2 Test for statistical significance of the mosaic quantile regression in FRP (January–March 2025)[83]

Regression type	All hours	Peak hours[(1)]
Mosaic	36%	39%
Load	30%	38%
Solar	61%	74%
Wind	54%	61%

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

The coefficient for the mosaic variable was statistically significant during only 36 percent of intervals. This means that in 64 percent of cases, the mosaic variable does not show a strong pattern with historical uncertainty.[84] 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.

Low statistical significance suggests that the regression often fails to identify a meaningful relationship. This failure could stem from either no relationship or inconsistent relationship. While it is difficult to quantify the proportion of cases due to no relationship versus inconsistency, mathematically, if no relationship exists, the quantile regression outcomes will converge to the histogram results.[85] Intuitively, this occurs because a no relationship implies that the mosaic variable provides no additional information for forecasting. As a result, the forecast relies solely on the historical net load uncertainty data, which is the histogram method.

In Figure 10.2 and Table 10.1, the average hourly requirement and performance metrics show a high degree of similarity between the histogram and mosaic regression method. This resemblance can be explained by the low percentage of statistically significant coefficients.

10.1.2 Threshold for capping flexible ramping product uncertainty

Flexible ramping product and resource sufficiency evaluation uncertainty calculated from the quantile regressions is capped by the lesser of two ceiling thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled

83 The current ISO regression sample in FRP includes duplicate independent variables, which can artificially inflate statistical significance. DMM addresses this by aggregating data to remove duplicates before running regression.

84 Quantile regression assesses patterns that may exist at a specific percentile of the sample. For the flexible ramping product, the 97.5th and 2.5th percentiles reflect the extreme upper or 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.

85 For a detailed discussion on the theoretical background and empirical findings regarding the resemblance between the mosaic quantile regression and the histogram method, see the DMM special report, *Review of the Mosaic Quantile Regression*, Nov 20, 2023, p 5 and pp 31-33: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

for each hour from the 1st and 99th percentile of net load error observations from a 180-day period.[86] The seasonal threshold is updated each quarter and is calculated based on the 1st and 99th percentile using observations over the previous 90 days. For the upward seasonal threshold, the 99th percentile is calculated separately for each of the 24 hours in a day. The maximum value out of these 24 hours is used as the threshold for all hours.[87]

During the quarter, the ceiling thresholds capped *upward* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 11 percent of intervals in the 15-minute market and 6 percent of intervals in the 5-minute market. Downward uncertainty was capped by the ceiling thresholds in around 13 percent of intervals in the 15-minute market and 9 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the seasonal threshold.

The ceiling threshold implies that the requirement is set at the highest 1 percent of uncertainty over the past 90 or 180 days. The expected frequency of reaching this threshold is around 1 percent of the time. However, the observed frequency of over 10 percent in the 15-minute market significantly exceeded this expectation.

A floor 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, uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this threshold in less than 1 percent of intervals in both directions and in both the 15-minute and 5-minute markets.

10.2 Resource sufficiency evaluation uncertainty

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the resource sufficiency evaluation (RSE). Here, balancing areas must show enough upward and downward ramping flexibility over an hour to meet both the forecasted change in demand *as well as uncertainty*.[88] This additional requirement in the flexibility test is also based on a 95 percent confidence interval for uncertainty that might materialize. This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation.

Figure 10.4 shows the distribution of realized 15-minute uncertainty in the RSE for each balancing authority area (BAA) for the first quarter of 2025. Here, realized uncertainty is defined as the net load forecast difference between the forecasts used in the resource sufficiency evaluation and those in the binding 5-minute market runs. To facilitate comparison across different BAAs, the realized uncertainty

86 As of August 14, 2024, the histogram threshold uses symmetric sampling, from historical observations from the previous 90 days as well as the next 90 days minus one year.

87 For the downward seasonal threshold, the 1st percentile is calculated separately for each of the 24 hours in a day. The minimum value out of these 24 is used as the threshold for all hours.

88 The flexibility test also includes a discount to account for *diversity benefit*. System-level flexible ramping needs are smaller than the sum of the needs of individual balancing areas because of reduced uncertainty across a larger footprint. Balancing areas therefore receive a prorated diversity benefit discount in the test based on this proportion.

has been standardized by its mean and standard deviation.[89] 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 10.4 Standardized realized uncertainty and requirement for RSE (January–March 2025)

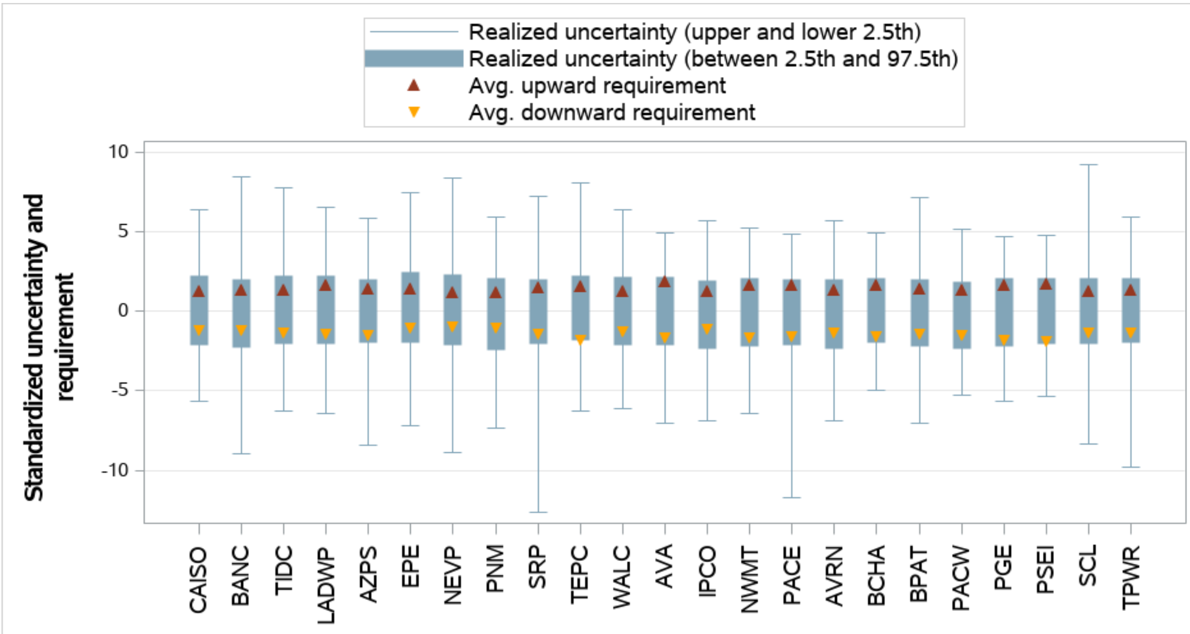


Figure 10.4 provides a comparison of the realized uncertainty across different BAAs for this quarter. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th 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 2.5th and 97.5th 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**: The requirements reflect the forecasted outcomes of the mosaic regression. Some BAAs exhibited a narrower range of requirements compared to others, which may indicate the regression model performed differently across BAAs.

[89] 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.

10.2.1 Results of resource sufficiency evaluation uncertainty calculation

Table 10.3 summarizes the average requirements and coverage for uncertainty in the resource sufficiency evaluation using both the histogram and mosaic quantile regression methods. In this table, *requirement* shows the average uncertainty component considered in the upward and downward flexibility test requirements. Coverage measures how frequently realized uncertainty—as measured by the difference between binding 5-minute market net load forecasts and net load forecasts in the resource sufficiency evaluation (RSE)—fell within the calculated uncertainty requirements for the same interval.

In the RSE, both the histogram and mosaic regression showed overall coverage levels significantly below the 95 percent target. The mosaic regression method mostly remained below 90 percent coverage. This is largely due to a disparity with the underlying data used to estimate resource sufficiency evaluation uncertainty, as discussed in the following section. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for all of the WEIM entities. The resource sufficiency evaluation uncertainty calculated from the regression method covered between 84 and 91 percent of realized uncertainty across all balancing areas.

Table 10.3 Average resource sufficiency evaluation uncertainty requirements and coverage (January–March 2025)

	Upward uncertainty			Downward uncertainty			Coverage		
Balancing area	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
Arizona Public Service	268	249	-19	229	199	-30	91%	89%	-2%
Avangrid	200	154	-46	175	124	-51	92%	89%	-2%
Avista	62	58	-4	62	55	-7	93%	91%	-2%
BANC	41	40	-1	41	35	-6	90%	88%	-2%
Bonneville Power Admin.	216	179	-36	238	190	-48	91%	88%	-4%
California ISO	1,240	1,101	-139	866	756	-110	89%	86%	-3%
El Paso Electric	35	31	-4	31	23	-8	91%	86%	-5%
Idaho Power	115	106	-9	148	130	-18	87%	84%	-3%
LADWP	165	150	-15	143	133	-10	91%	88%	-3%
NorthWestern Energy	76	68	-7	81	68	-13	92%	90%	-2%
NV Energy	226	178	-47	202	159	-43	92%	88%	-4%
PacifiCorp East	379	352	-27	516	477	-39	91%	88%	-3%
PacifiCorp West	92	86	-7	150	126	-25	90%	88%	-2%
Portland General Electric	124	111	-13	119	114	-5	93%	91%	-2%
Powerex	153	144	-9	154	147	-6	91%	88%	-3%
PNM	155	143	-12	158	142	-16	88%	86%	-2%
Puget Sound Energy	142	131	-11	132	128	-5	93%	90%	-3%
Salt River Project	122	114	-8	122	100	-22	93%	89%	-4%
Seattle City Light	21	20	-1	23	21	-1	88%	85%	-3%
Tacoma Power	13	12	-1	13	13	-1	89%	85%	-3%
Tucson Electric Power	100	92	-8	90	78	-11	94%	91%	-3%
Turlock Irrigation District	7	7	0	7	6	0	89%	87%	-3%
WAPA Desert Southwest	25	24	-1	22	21	-1	87%	85%	-2%

Table 10.4 summarizes the percentage of statistically significant coefficients during all hours and peak hours, based on DMM's replication of the regression. The balancing areas are listed in descending order, starting with those with the highest percentage of significant coefficients. Overall, 38 percent of regression coefficients were significant in Q1 2025, indicating that 62 percent of the regression estimations were based on either weak or inconsistent patterns.

Table 10.4 Test for statistical significance of mosaic quantile regression in RSE (January–March 2025)[90]

BAA	Percent of significant coefficients	
	All hours	Peak hours(1)
Avangrid	86%	85%
PacifiCorp West	70%	69%
BPA	60%	57%
Arizona PS	50%	45%
NorthWestern	39%	38%
Idaho Power	46%	48%
CAISO	45%	49%
Salt River Project	34%	29%
NV Energy	42%	45%
Avista Utilities	47%	44%
Seattle City Light	24%	33%
LADWP	37%	32%
PSC New Mexico	34%	33%
Portland GE	36%	32%
Puget Sound Energy	34%	31%
Tucson Electric	28%	27%
PacifiCorp East	31%	31%
BANC	28%	28%
El Paso Electric	32%	35%
Tacoma Power	25%	33%
Turlock ID	14%	19%
WAPA - Desert SW	20%	25%
Powerex	23%	30%
Average	38%	39%

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

10.2.2 RSE uncertainty special issue — time horizon for predicting uncertainty

The regression model used for the resource sufficiency evaluation is currently 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, typically produced between 47.5 and 102.5 minutes before real-time.

90 The current ISO regression sample in RSE includes duplicate independent variables, which can artificially inflate statistical significance. DMM addresses this by aggregating data to remove duplicates before running regression.

The resource sufficiency evaluation uses exactly the same underlying historical data to perform the regressions and calculate uncertainty as the flexible ramping product in the 15-minute market.[91] This data is based on the difference from advisory forecasts in the 15-minute market to the corresponding binding forecasts in the 5-minute market. The regressions use this data to produce hourly coefficients that define the relationship between the forecasts and uncertainty. This calculation reflects 45 to 55 minutes in which uncertainty may materialize between the applicable 15-minute and 5-minute market runs.

However, the resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 10.5 illustrates the timeframe of uncertainty considered for the flexible ramping product in the 15-minute market, and how it compares with the timeframe of the resource sufficiency evaluation.[92] For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the resource sufficiency evaluation considers forecast information from *four* 15-minute intervals within an hour. When comparing the forecast values used in each interval of the resource sufficiency evaluation to corresponding 5-minute market intervals, there exists a larger gap of time for uncertainty to materialize.

In comparing the first 15-minute test interval of the RSE to corresponding 5-minute market intervals, the timeframe and potential for net load uncertainty to materialize is similar to the timeframe of the 15-minute market flexible ramping product uncertainty calculation. However, in the later test intervals, the gap between the predicted forecasts at the time of the resource sufficiency evaluation and the real-time forecasts widens, reaching above 100 minutes. The current determination of the regression coefficients for predicting net load uncertainty for the resource sufficiency evaluation (based on short-term historical data) does not capture the increased net load uncertainty associated with the longer-term horizon of this market process.[93]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the resource sufficiency evaluation. Figure 10.6 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized uncertainty from the forecasts considered in the resource sufficiency evaluation to the 5-minute market forecasts fell within the calculated uncertainty requirement for the same interval. The calculated uncertainty covered the realized uncertainty much less for intervals at the end of the hour compared to the beginning of the hour because the current calculation is not designed to capture uncertainty that can realize over a longer-term horizon.

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91 A balancing-area-specific flexible ramping product uncertainty requirement will be enforced for any balancing area that failed the resource sufficiency evaluation.

92 The figure shows the time horizon for the resource sufficiency evaluation ran 55 minutes prior to the hour (T-55 RSE). While the final test is run at 40 minutes prior to the hour, the load and renewable forecasts used in the final test are held fixed from the forecasts in the T-55 RSE. This is intended to reduce unexpected failures that would be caused by forecast variation between the T-55 and T-40 resource sufficiency evaluations.

93 The resource sufficiency evaluation and flexible ramping product uncertainty calculations for a single balancing area use the same hourly regression coefficients (produced from same short-term historical data) but are combined with the current forecast information at the time of each market process to determine the final uncertainty. Here, longer-term forecast information at the time of the resource sufficiency evaluation is combined with the short-term regression coefficients.

Figure 10.5 Comparison of timeframe considered for the flexible ramping product and resource sufficiency evaluation

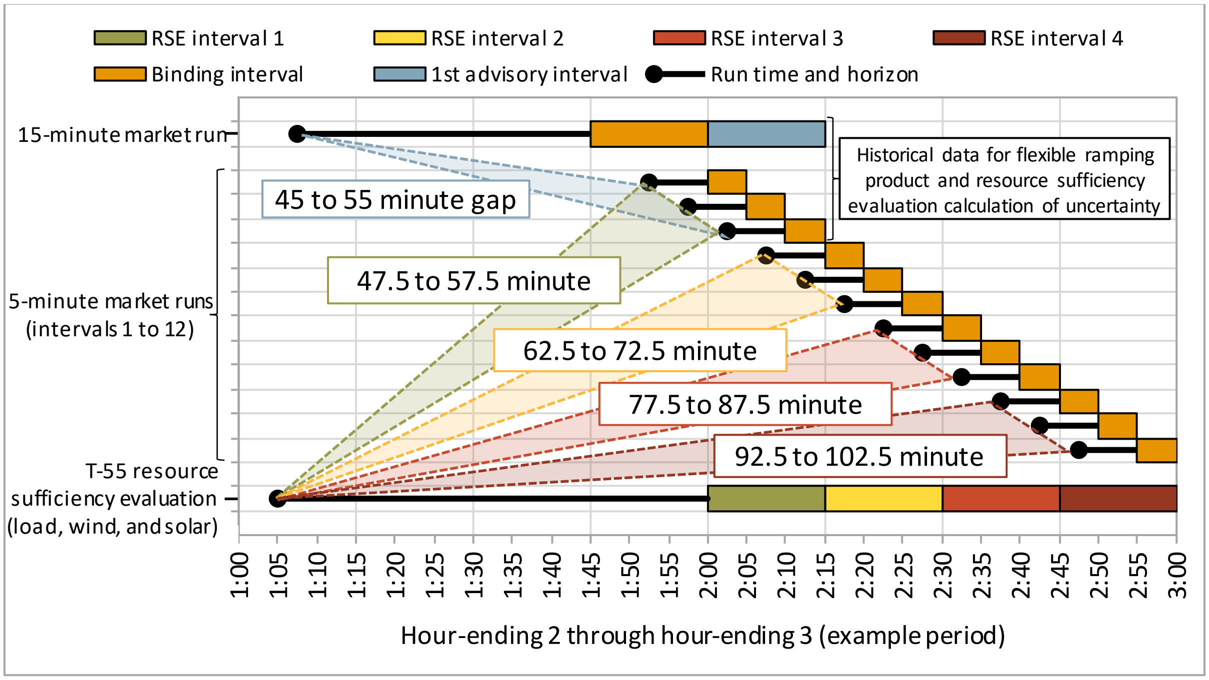
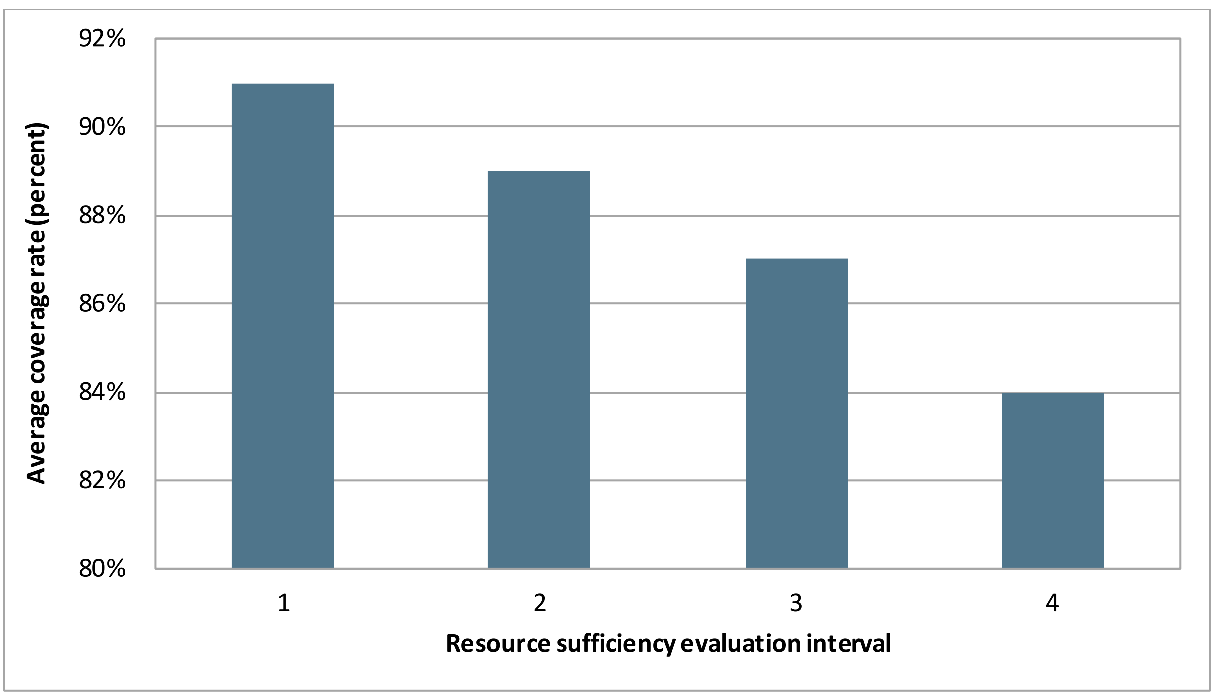


Figure 10.6 Average coverage rate by resource sufficiency evaluation interval (January–March 2025)



10.3 Residual unit commitment uncertainty

Uncertainty is often added to the residual unit commitment (RUC) target load requirement. This adjustment is used to ensure there is sufficient capacity to account for uncertainty that may materialize between the day-ahead and real-time markets. For the residual unit commitment market adjustment, uncertainty is defined as the difference between the day-ahead net load forecast and 15-minute market forecasts.

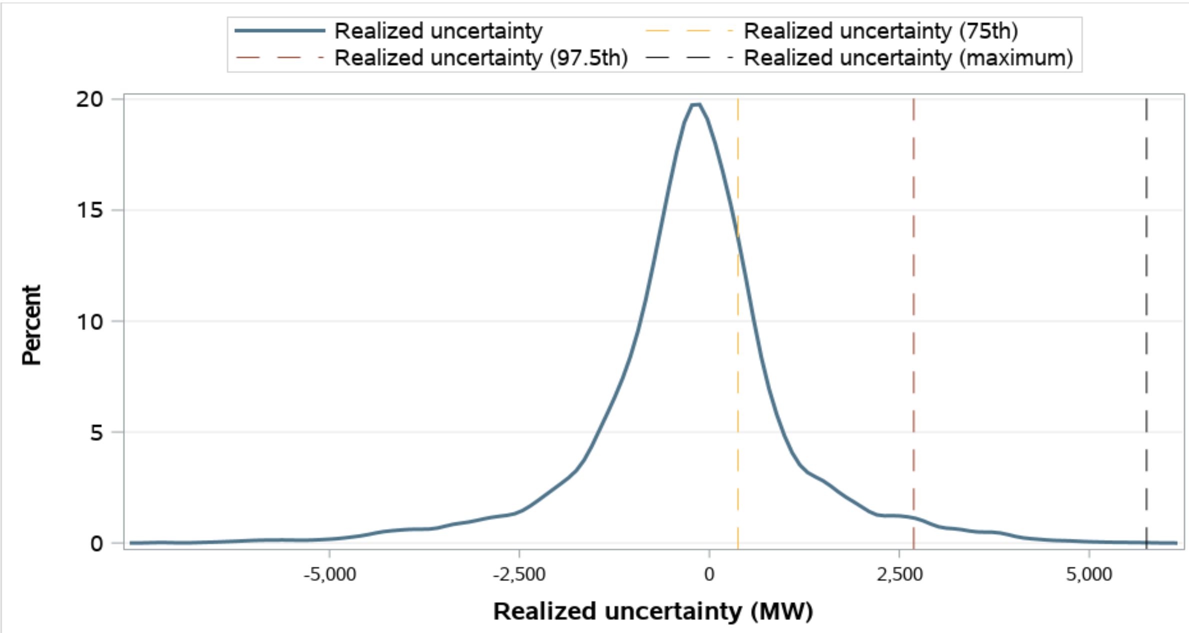
The ISO uses *mosaic quantile regression* to calculate the RUC adjustments. The percentile target is adjusted each day based on conditions in the system. Under periods with moderate operational uncertainty, the operating procedure calls for using an adjustment that will procure enough capacity 50 percent of the time (i.e., the 50th percentile of upward uncertainty).[94] The ISO can adjust the calculation on any day to instead use the 75th or 97.5th percentile during periods of higher forecast uncertainty or in extreme conditions. During periods with low operational uncertainty, the 25th percentile or no adjustment can also be applied.

The adjustment can also be applied to only select hours. During periods with moderate uncertainty, the adjustment is typically applied only to the peak morning and peak evening hours (around six hours). During periods with more operational uncertainty, the adjustment is generally applied to either mid-day hours (around 16 hours) or all hours.

Figure 10.7 shows this quarter's distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. This distribution represents all uncertainties observed in the 15-minute market intervals for this quarter and serves as the forecasting target. The first notable feature is that net load uncertainty in the day-ahead time horizon ranged from -7,200 MW to 5,700 MW. The distribution shows a long tail, with the area between the red dashed line and the black dashed line highlighting the range from the 97.5th percentile of uncertainty up to the maximum value. This area ranged from 2,700 MW to 5,700 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.

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

Figure 10.7 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (January–March 2025)



10.3.1 Results of uncertainty calculation for residual unit commitment

Figure 10.8 shows the average RUC adjustment on each day since May 7, 2024 during the peak morning and evening hours (hours 7 to 9 and 19 to 21). The figure also shows the estimated percentile that was used to determine the additional requirements for the peak hours of each day.[95] During most of the first quarter, no adjustment was applied (89 percent of days). The 75th percentile target was applied on 6 days while the 50th percentile target was applied on 4 days. Figure 10.9 instead shows the average RUC adjustment for each day *across all hours*.[96] The dotted black line (right axis) shows the number of hours in which the adjustment was applied. During January, when many of the operator adjustments for the quarter were applied, the adjustment was typically applied to the mid-day hours.

The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty as this RUC adjustment, but the imbalance reserve up requirement will be set to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in RUC indicates that the imbalance reserve product demand curve may be much too high during most hours.

95 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.

96 In the hours when no adjustment is applied, the residual unit commitment adjustment for uncertainty is 0 MW, resulting in a lower daily average.

Figure 10.8 Average residual unit commitment adjustment by day (peak morning and evening hours, May 7, 2024–March 31, 2025)

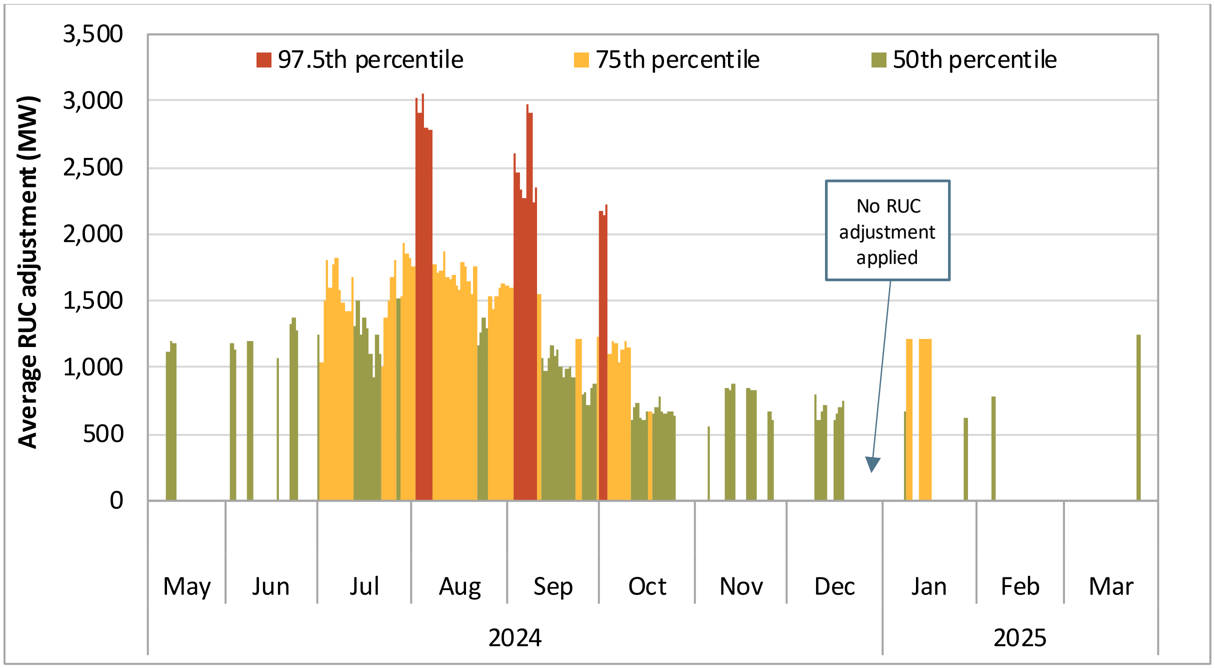


Figure 10.9 Average residual unit commitment adjustment by day (all hours, May 7, 2024–March 31, 2025)

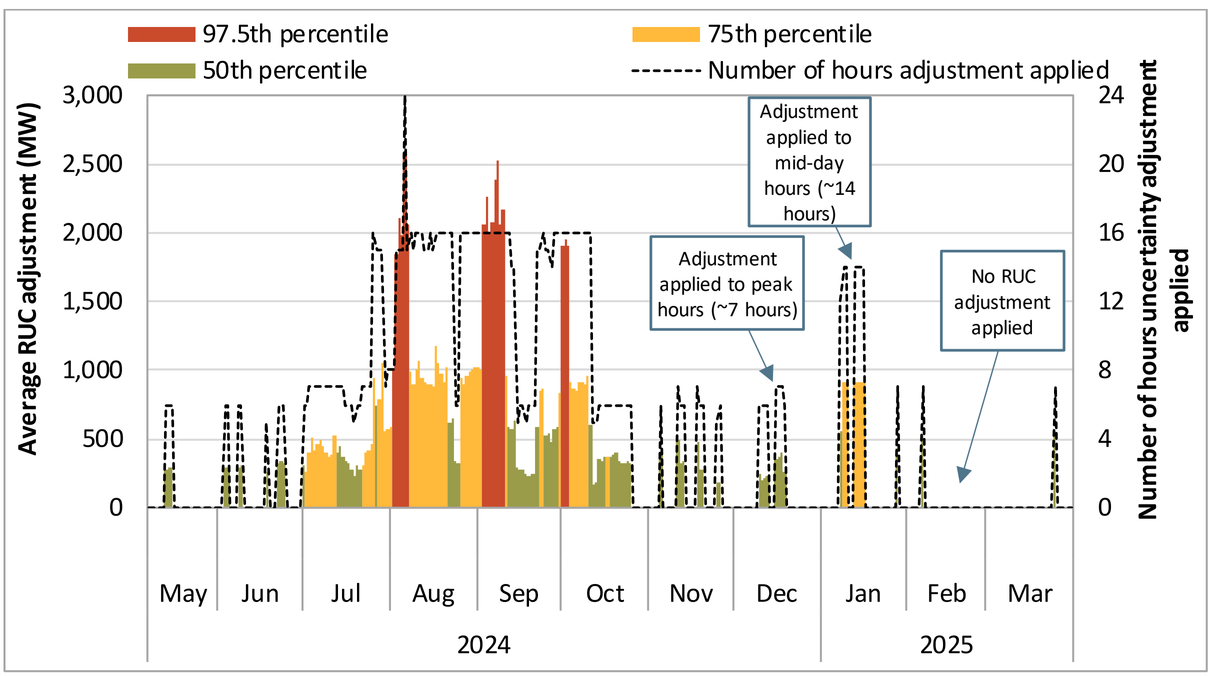


Table 10.5 summarizes the average requirement and coverage based on the percentile target that was selected and the hours it was applied (either mid-day hours or peak hours). Coverage shows the percent of 15-minute market intervals in which realized uncertainty from the day-ahead market to the real-time market was below the RUC adjustment quantity. The average requirement and coverage were assessed only in hours the uncertainty adjustment was applied.

Table 10.5 Average residual unit commitment uncertainty adjustment and coverage (January–March 2025)

Percentile target	Hours applied	Number of days	Percent of days	Average requirement (MW)	Coverage
75th percentile	Mid-day hours	6	7%	1,571	94%
50th percentile	Mid-day hours	1	1%	1,119	79%
	Peak hours	3	3%	1,726	94%

Table 10.6 represents DMM's simulation of the RUC adjustment using the mosaic quantile regression. It provides insight into the different percentiles used in the market and illustrates the likely outcomes if a specific percentile were applied to forecast the RUC adjustment.

The first section of the table shows the average requirement across different percentile values from the DMM replication. The middle section of the table shows the percentage of statistically significant coefficients, and the last section shows the coverage rate for each percentile regression.

The 97.5th percentile regression showed one percent rate of statistical significance, likely due to sample size. This specific percentile regression focuses on only 4 to 5 observations.[97] While an underlying pattern may exist, the small sample size of 4 to 5 observations is insufficient to find such a pattern, resulting in only one percent statistical significance.

The coverage rates for regression were notably inflated. For example, the 50th percentile regression, designed to capture 50 percent of realized uncertainty, showed coverage rates of 79 percent, and 82 percent during peak hours.

This inflation arises from two key factors. First, while the realized uncertainty represents the difference between day-ahead and 15-minute net load forecasts, available as four uncertainty realizations per hour, the regression model forecasts the maximum uncertainty for each hour. This discrepancy inflated the result. As shown in Figure 10.7, the realized uncertainty distribution indicated the 50th percentile value was around -180 MW, meaning that a -180 MW requirement would effectively achieve 50 percent coverage. However, the 50th percentile regression averaged around 790 MW (as shown in Table 10.6). This means that the regression is producing over 970 MW more than ideal, due to the practice of

[97] Quantile regression identifies patterns within a subset of data. A 97.5th percentile regression targets the upper 2.5 percent of uncertainty, requiring a large sample size. The sampling methodology in mosaic regression shares similarities between the RUC adjustment and other market applications, employing either symmetric or past 180-day sampling, ultimately selecting data from 180 days. The ISO further filters for the same hour as the forecasting hour. A key distinction for the RUC adjustment forecast lies in its day-ahead forecast data, resulting in only one observation per hour. In contrast, other real-time uncertainty calculations have mosaic variable and uncertainties available across 4 to 12 intervals per hour, leaving the RUC adjustment forecast's sampling size at 180 observations.

forecasting the maximum uncertainty per hour. Second, the regression in RUC estimates only the upper bound of uncertainty, meaning any negative uncertainty is automatically covered, contributing to the inflated coverage rate.

Table 10.6 DMM simulation for RUC adjustment using mosaic quantile regression (January–March 2025)

	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Peak hours(1)	All hours	Peak hours	All hours	Peak hours
Replication (97.5th)	2,297	2,780	1%	4%	99%	99%
Replication (75th)	1,301	1,857	23%	52%	91%	92%
Replication (50th)	794	1,345	32%	61%	79%	82%
Replication (25th)	288	802	42%	64%	62%	66%

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

11 Wheeling rights

The ISO began developing a framework that establishes high-priority wheeling through scheduling priorities in the CAISO balancing area 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.[98]

No reservations were made for CAISO balancing area high priority wheeling-through rights for the first quarter of 2025.

98 For more information about specific TSMSP implementation details, please refer to the wheeling rights section of the *Q2 2024 Report on Market Issues and Performance*, November 22, 2024: https://www.caiso.com/documents/2024-second-quarter-report-on-market-issues-and-performance-nov-22-2024.pdf

12 Resource adequacy

12.1 Available resource adequacy bids compared to CAISO balancing area market requirements

The CPUC resource adequacy (RA) program and CAISO availability incentive mechanisms are intended to ensure suppliers make sufficient generation capacity available to the CAISO balancing area to meet the area's load and ancillary service requirements. Insufficient available resource adequacy capacity to meet the balancing area's load and ancillary service requirements may indicate a shortcoming in the overall CPUC-CAISO resource adequacy program. Insufficient capacity can arise from a combination of factors, including:

1) Low procurement requirements for load serving entities;
2) Rules that may over-count capacity from resources, such as variable energy resources and use-limited resources, that may not be available during tight system conditions;
3) Procurement of low quality or poorly maintained resources that may not be available during tight system conditions; and
4) CAISO balancing area performance penalties not properly incentivizing resources to maintain availability during tight system conditions.

However, some resource adequacy capacity does not have an obligation to bid into the real-time markets if it did not receive a day-ahead market award. Therefore, non-resource adequacy capacity displacing resource adequacy capacity in the real-time market can cause insufficient resource adequacy capacity in real-time to cover market requirements, rather than being a shortcoming in the resource adequacy program design.

Real-time resource adequacy bids, including bids from variable energy resource (VERs) above their resource adequacy values, were sufficient to cover the market requirements for energy and upward ancillary services in the CAISO balancing area in all hours of the first quarter.

12.2 Resource adequacy import bids

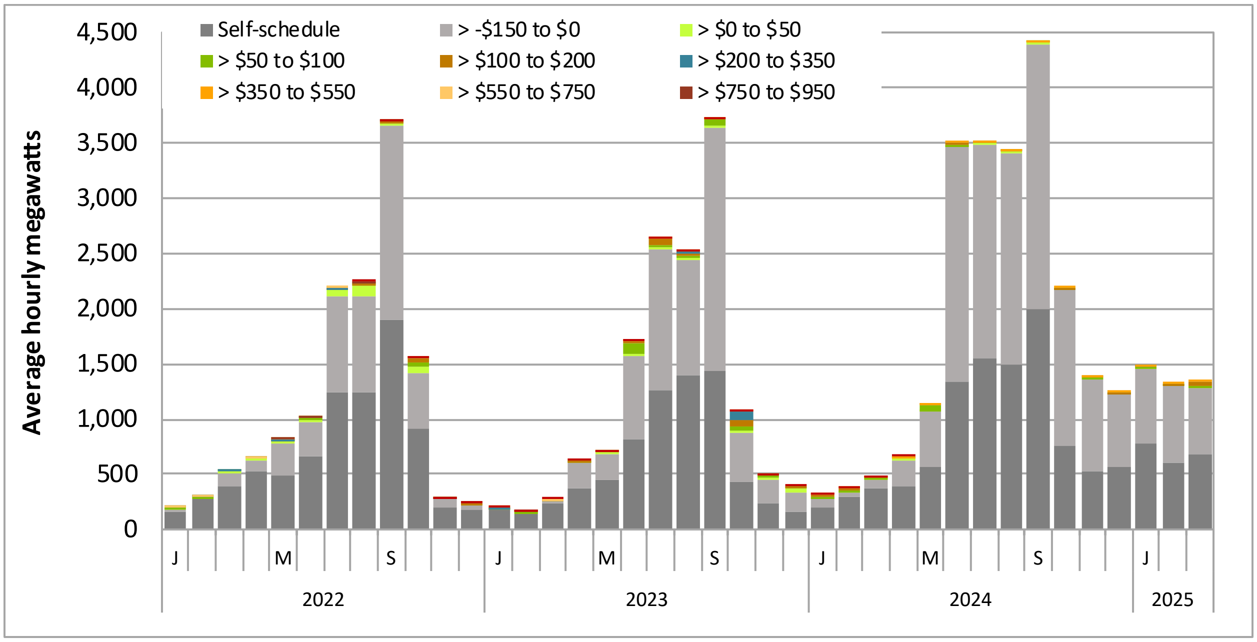
In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource specific import resource adequacy resources must bid into the California ISO markets at or below $0/MWh during the availability assessment hours.[99] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices of imports. An overall decline in volumes began in

[99] 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.

late 2020 and continued throughout 2021, but appears to have stabilized since then. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 12.1 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[100] 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. Overall bid-in levels of resource adequacy imports increased in January, February, and March compared to the same months of 2024, by 366 percent, 250 percent, and 186 percent, respectively. Overall, resource adequacy import bids in Q1 2025 increased 256 percent over Q1 2024.

Figure 12.1 Average hourly resource adequacy imports by price bin



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

13 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the first quarter of 2025 was 3 percent higher than the same quarter of 2024. Operator adjustments to the RUC procurement target decreased by about 92 percent for the same period. This was in large part because of changes in the methodology for determining the adjustments on May 7, 2024. CAISO balancing area methods for determining operator adjustments are discussed in detail in Section 10 above on uncertainty.

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 is a key component of the day-ahead market that runs immediately after the integrated forward market. The residual unit commitment market procures capacity sufficient to bridge the gap between the amount of physical supply cleared in the integrated forward market and the amount of physical supply that may be needed to meet actual real-time demand.

13.1 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 13.1 shows the average incremental residual unit commitment requirement by component relative to the integrated forward market component of the day-ahead market.

The green bars reflect the need to replace cleared net virtual supply bids, which can offset physical supply in the integrated forward market run.

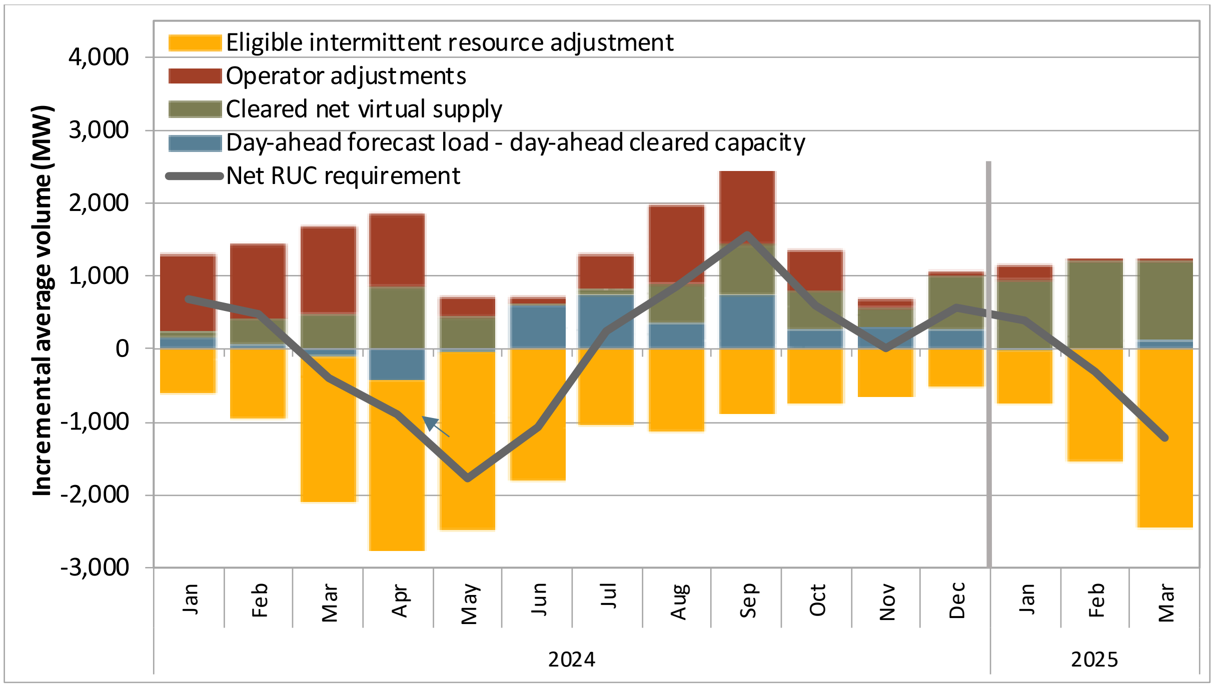
The blue bars in Figure 13.1 depict the day-ahead forecasted load versus cleared day-ahead capacity, which includes both physical supply and net virtual supply. This represents the difference between the California ISO day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed towards increasing residual unit commitment requirements by about 40 MW per hour in the first quarter of 2025, which is about the same as Q1 2024.

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 13.1.

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 13.1 show the average adjustment to the residual unit commitment requirement. During 2023 and 2024, there were significant changes to how these amounts were determined, and this has resulted in very low levels of operator adjustments. The operator adjustments and the changes in the methodology are described in Section 10 above on uncertainty.

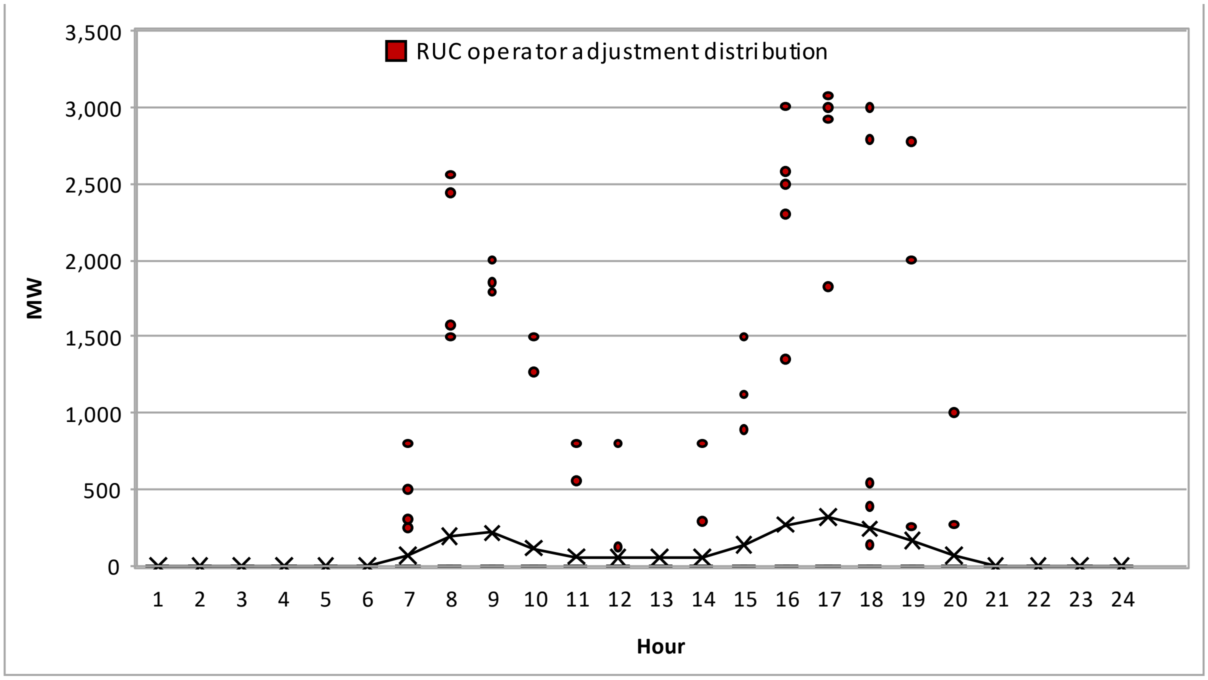
Figure 13.2 shows the hourly distribution of these operator adjustments during the first quarter of 2025. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour. Most of the outliers occurred in January associated with a handful of extremely large wildfires[101] in the Los Angeles metro area.

Figure 13.1 Average incremental residual unit commitment requirement by component



101 *The weather and climate influences on the January 2025 fires around Los Angeles*, National Oceanic and Atmospheric Administration (NOAA), February 19, 2025: https://content-drupal.climate.gov/news-features/event-tracker/weather-and-climate-influences-january-2025-fires-around-los-angeles

Figure 13.2 Hourly distribution of residual unit commitment operator adjustments (January–March 2025)



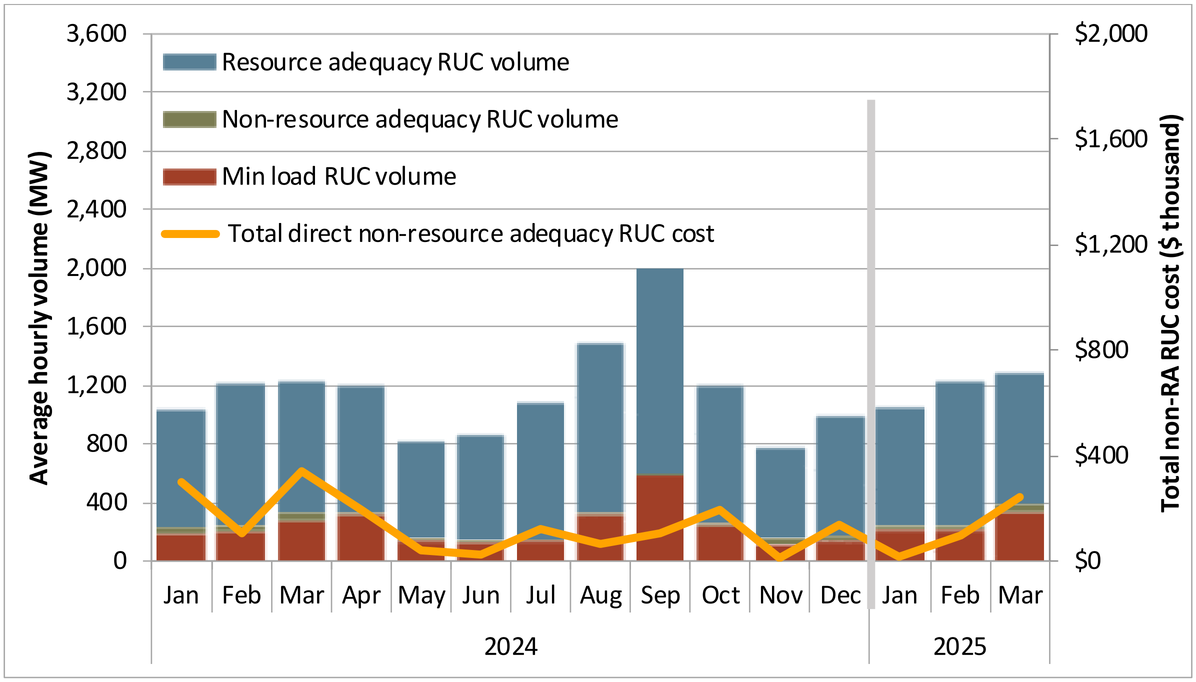
13.2 Residual unit commitment procurement and costs

Figure 13.3 shows the monthly average hourly residual unit commitment (RUC) procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The average residual unit commitment procurement for the first quarter of 2025 increased by 3 percent to about 1,190 MW, from an average of about 1,150 MW in the same quarter of 2024. Of the 1,190 MW capacity, the capacity committed to operate at minimum load averaged about 260 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.[102] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 13.3. In the first quarter of 2025, these costs were about $357,000, or about 48 percent of the costs in the same quarter of 2024.

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

Figure 13.3 Residual unit commitment costs and volume



14 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 first quarter, financial entities and marketers continued to receive the vast majority of profits from convergence bidding.

14.1 Convergence bidding revenues

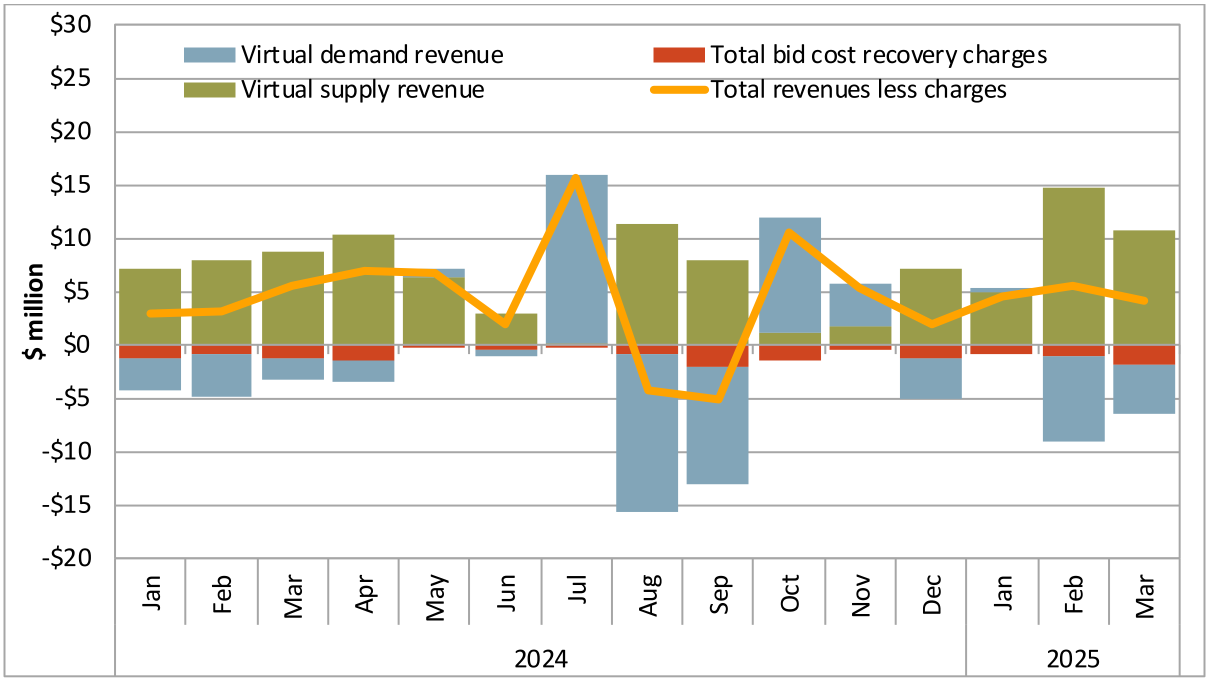
Net revenues for convergence bidders were about $14.2 million for the first quarter, after inclusion of about $3.9 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[103] Figure 14.1 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total bid cost recovery charges (red bars), and net payments for all convergence bidding after accounting for bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

- Convergence bidding revenues were positive during all months of the quarter, totaling $14.2 million. In comparison, total market revenues were around $11.5 million in the first quarter of 2024.
- Virtual demand revenues were about $510,000, -$8.0 million, and -$4.7 million for January, February, and March, respectively.
- Before accounting for bid cost recovery, virtual supply revenues were about $4.9 million, $14.7 million, and $10.7 million for January, February, and March, respectively.

Bid cost recovery charges allocated to virtual bids were about $870,000, $1.2 million, and $1.9 million for January, February, and March, 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.

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

Figure 14.1 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 14.1 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.[104,105]

After accounting for bid cost recovery, financial entities received nearly 88 percent of the total revenue earned from convergence bidding. Financial entities and marketers accounted for about 81 percent and 10 percent, respectively, of the cleared volume of virtual trades in the first quarter.

104 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

105 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.

Table 14.1 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 Q1								
Financial	2,281	2,395	4,676	-$7.19	$19.66	-$1.70	$17.95	$10.76
Marketer	511	573	1,084	-$1.78	$3.85	-$.75	$3.10	$1.31
Physical load	6	27	32	-$.02	$.15	-$.35	-$.21	-$.23
Physical generation	28	140	167	-$.13	$.25	-$.5	-$.24	-$.37
Total	**2,826**	**3,135**	**5,959**	**-$9.12**	**$23.91**	**-$3.30**	**$20.60**	**$11.47**

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	
2025 Q1								
Financial	3,697	4,226	7,922	-$9.81	$24.71	-$2.42	$22.29	$12.48
Marketer	450	576	1,026	-$1.31	$3.41	-$.38	$3.03	$1.72
Physical load	39	186	226	-$.12	$.57	-$.3	$.27	$.15
Physical generation	171	438	609	-$.92	$1.54	-$.8	$.74	-$.18
Total	**4,357**	**5,426**	**9,783**	**-$12.16**	**$30.23**	**-$3.90**	**$26.33**	**$14.17**

15 Ancillary services and available balancing capacity

Ancillary service payments totaled $36.2 million, a 75 percent increase from the same quarter last year. Average requirements for regulation up increased, while regulation down and operating reserves decreased slightly compared to the first quarter of 2024. Available balancing capacity was dispatched to address power balance infeasibilities in less than 1 percent of intervals in every WEIM balancing area.

15.1 Ancillary service requirements

The California ISO procures four ancillary services for the CAISO balancing area 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.[106] 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.[107] 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.

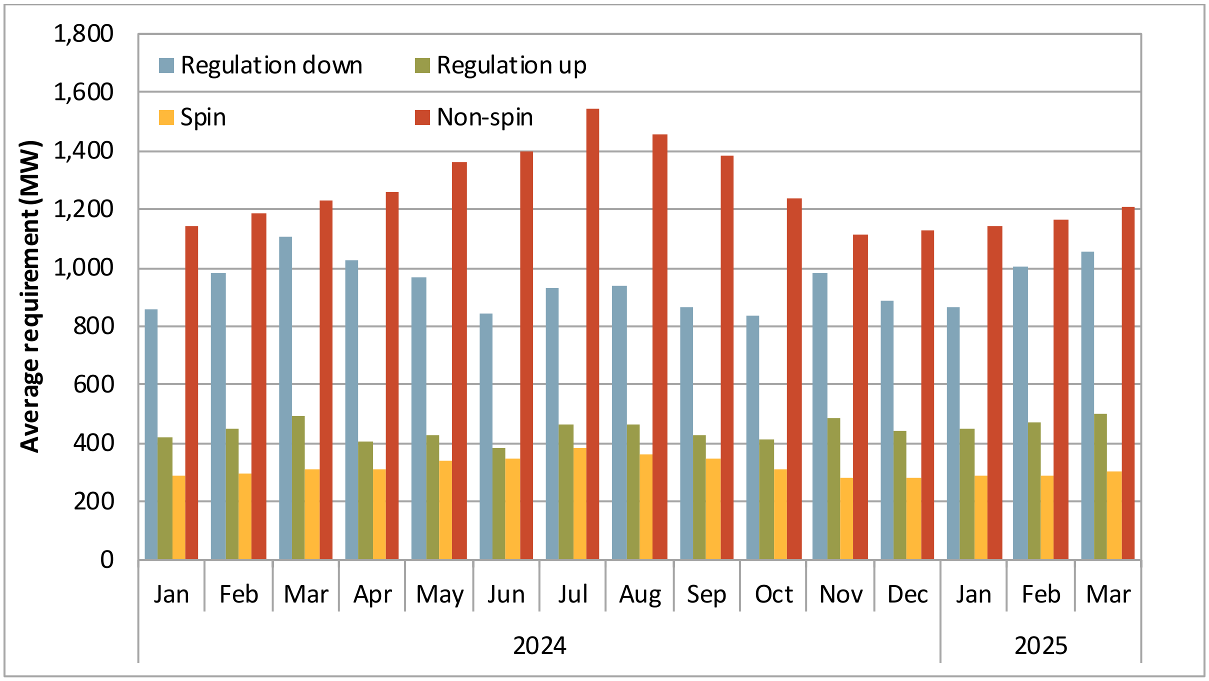
Starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. Since the second quarter of 2023, CAISO operators have procured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

Figure 15.1 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Average operating reserves and regulation down requirements decreased about 1 percent each compared to the first quarter of 2024. Average requirements for regulation up increased about 4 percent year-over-year.

106 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

107 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 15.1 Average monthly day-ahead ancillary service requirements



15.2 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.

There were six scarcity events in the first quarter of 2025, an increase from zero scarcity events in the first quarter of 2024. Each event occurred in February for regulation down in the expanded region north of Path 26, likely due to large battery outages that occurred in Northern California in January.

15.3 Ancillary service costs

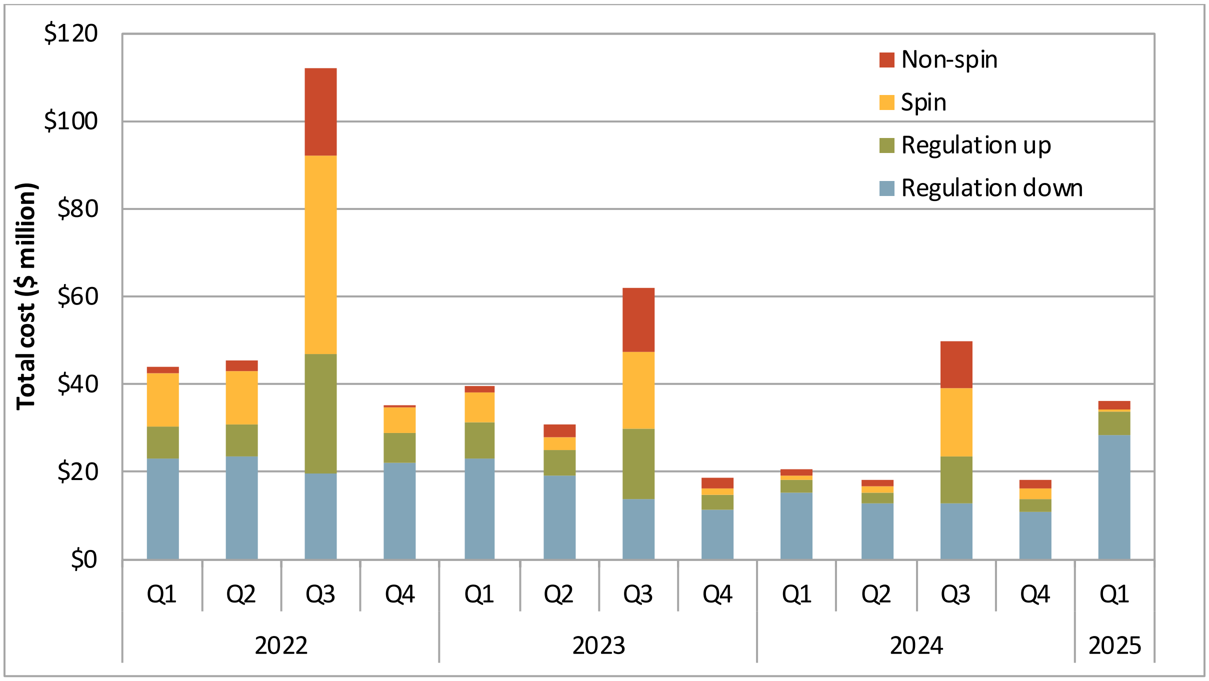
Ancillary service payments totaled $36.2 million in the first quarter of 2025, around $15.5 million (or 75 percent) more than the same quarter of the previous year.

Figure 15.2 shows the total cost of procuring ancillary service products by quarter.[108] Payments for regulation up, regulation down, spinning reserve, and non-spinning reserve increased 78 percent, 85 percent, 12 percent, and 6 percent, respectively, compared to the first quarter of 2024.

[108] 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.

Regulation up and down costs rose considerably this quarter (78 and 85 percent, respectively) without a proportionate rise in regulation requirements (4 and -1 percent, respectively). Because batteries provide a large proportion of regulation down requirements, previously mentioned battery outages this quarter brought the total proportion of regulation down provided by batteries from about 90 percent in the first quarter of 2024 to about 80 percent in the first quarter of 2025. This decrease contributed to higher ancillary service costs in the CAISO balancing area.

Figure 15.2 Ancillary service cost by product



15.4 Available balancing capacity

Available balancing capacity (ABC) allows for market recognition and accounting of capacity that WEIM participants have available for reliable system operations but is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each WEIM entity in their hourly resource plans. The available balancing capacity mechanism enables the ISO system software to deploy such capacity through the market and prevents market infeasibilities that may arise without the availability of this capacity.

Table 15.1 summarizes the frequency of upward and downward available balancing capacity offered in each area in the first quarter. Available balancing capacity was dispatched in less than 1 percent of intervals for all areas in the 15-minute and 5-minute markets.

Table 15.1 Frequency of available balancing capacity offered (Q1)

	ABC Up Offered		ABC Down Offered	
	Percent of Hours	Average MW	Percent of Hours	Average MW
BANC	100%	88	100.0%	104
Bonneville Power Admin.	100%	317	100.0%	600
Turlock Irrigation District	100%	15	100.0%	333
Avista Utilities	100%	10	100.0%	5
Powerex	100%	1,179	100.0%	10
Tucson Electric	100%	28	100.0%	28
Salt River Project	100%	99	44.0%	15
WAPA - Desert Southwest	43%	15	97.0%	5
NV Energy	89%	74	97.0%	49
Portland General Electric	99%	30	93.0%	4
Tacoma Power	86%	6	100.0%	100
NorthWestern Energy	97%	5	80.0%	74
Arizona Public Service	100%	100	36.0%	37
LADWP	83%	58	97.0%	201
PacifiCorp East	72%	72	25.0%	64
Seattle City Light	0%	N/A	0.0%	N/A
PacifiCorp West	4%	22	0.0%	N/A
PSC New Mexico	0%	N/A	0.0%	N/A
El Paso Electric	53%	25	0.0%	N/A
Puget Sound Energy	0%	N/A	0.0%	N/A
Avangrid	100%	58	0.0%	N/A
Idaho Power	0%	N/A	0.0%	N/A

16 Generation outages[109]

This section covers information on generation outages in the California ISO balancing area and the WEIM by region.[110] The average generation on outage in the California ISO balancing area was 19,000 MW in the first quarter of 2025, a 15 percent increase from the first quarter of 2024.[111] In the WEIM, the California region—excluding the CAISO balancing area—averaged about 4,700 MW of total generation outages, a 10 percent decrease from the first quarter of 2024. The Desert Southwest region averaged about 11,400 MW of total generation outages, a 10 percent increase from the first quarter of 2024. The Intermountain West region averaged about 2,300 MW of total generation outages, a 14 percent decrease from the first quarter of 2024. The Pacific Northwest region averaged about 2,400 MW of total generation outage, a nine percent decrease from the first quarter of 2024.

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.

16.1 California ISO balancing area

Figure 16.1 and Figure 16.2 show the quarterly and monthly averages for the California ISO balancing area, respectively, of maximum daily outages during peak hours by type from the first quarter of 2023 through the first quarter of 2025. 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 presented in Figure 16.2, there are usually a higher number of outages in the fall, winter, and early spring than in the summer months, and this trend continued in the first quarter of 2025.

During the first quarter of 2025, the average total generation on outage in the California ISO balancing area was 19,000 MW, about 2,400 MW greater than the first quarter of 2024, as shown in Figure 16.1. Planned non-maintenance outages increased by 60 percent when compared to the same quarter last year, a 500 MW increase. The largest magnitude outage increase was in the other forced category, and was largely due to a few large gas resources that experienced gas fuel line and telemetry related issues for much of this reporting period.

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[109] The data for 2024 has been updated from 2024 quarterly reports to reflect the new accounting method used to exclude outages of available California Strategic Reliability Reserve participating resource capacity that were submitted to prevent these units from being committed and dispatched by the market. As a result, the total outages reported here for 2024 will be lower for those periods than reported in 2024 reports.

[110] WEIM regions are as follows: California includes BANC, CISO, LADWP, and TIDC. Desert Southwest includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC. Intermountain West includes AVA, IPCO, NWMT, and PACE. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

[111] This is calculated as the average of the daily maximum level of outages, excluding off-peak hours, and excludes the outages used to prevent California Strategic Reliability Reserve participating resource capacity from being committed and dispatched by the market.

Figure 16.1 CAISO balancing area quarterly average of maximum daily generation outages by type – peak hours

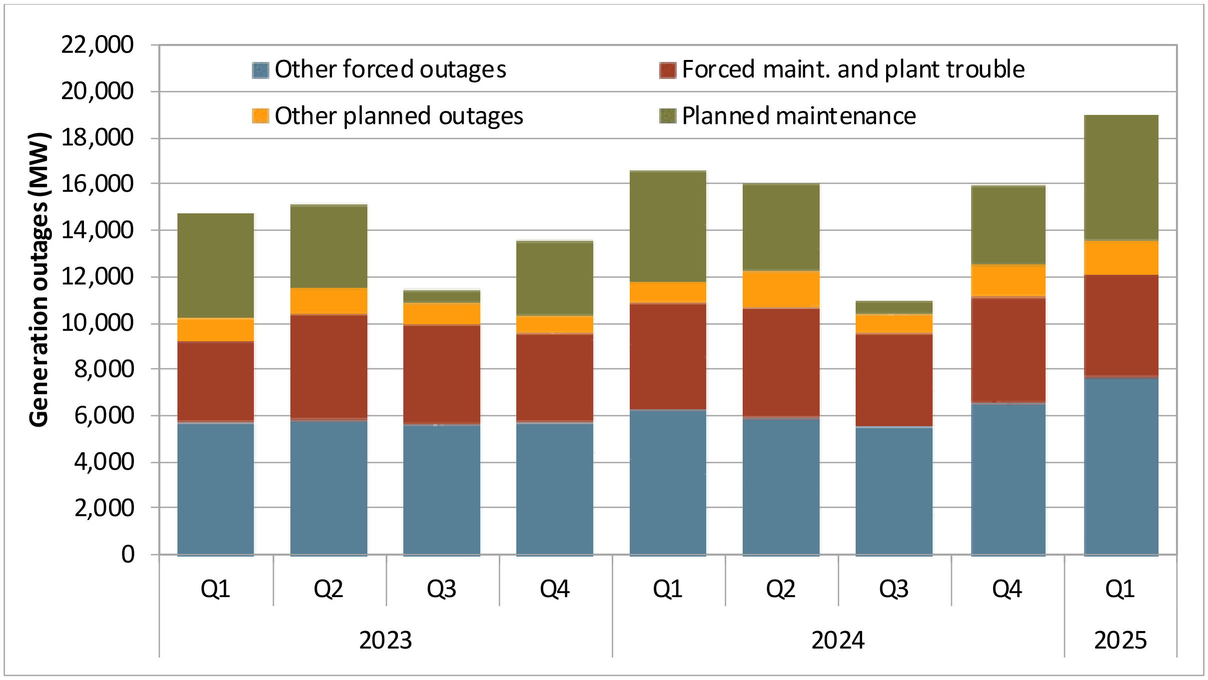
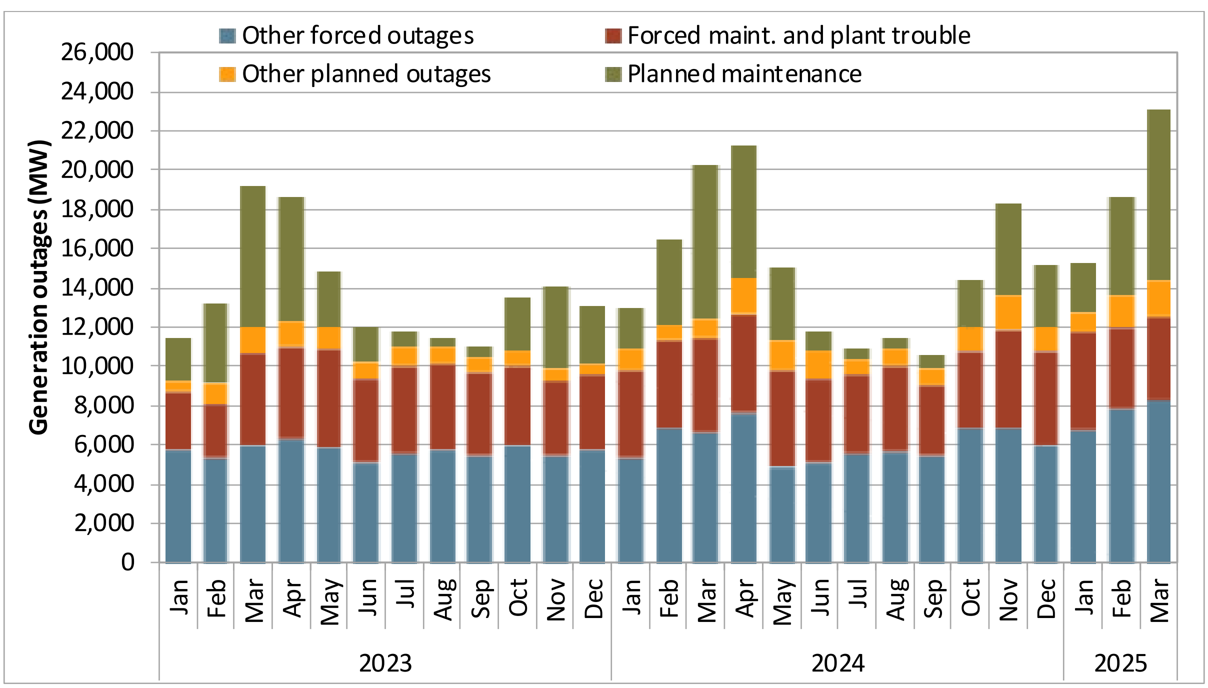


Figure 16.2 CAISO balancing area monthly average of maximum daily generation outages by type – peak hours



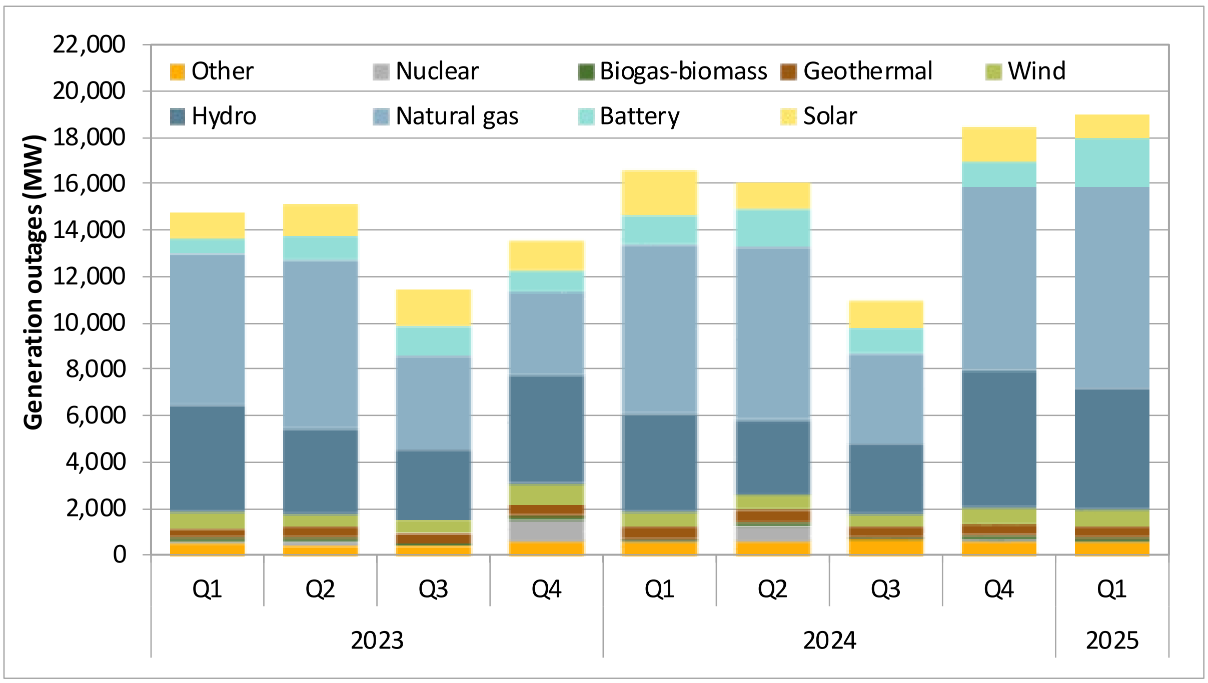
Generation outages by fuel type

Natural gas and hydroelectric generation had the largest volume of outages in the first quarter of 2025 and averaged about 8,700 MW and 5,200 MW, respectively. These two fuel types accounted for a combined 73 percent of the generation outages for the quarter. The amount of natural gas generation outages increased 20 percent relative to the first quarter of 2024. As noted earlier, this is due to a number of large gas resources out in this period.

The quarterly average megawatts of battery storage resources on outage increased by 57 percent in the first quarter of 2025 when compared to the first quarter of 2024. The year-over-year increase is due to the loss of a number of large storage resources during a fire in the first quarter of 2025.

Figure 16.3 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[112] Natural gas, hydroelectric, biogas-biomass, nuclear, and battery storage outages increased compared to the first quarter of 2024, while outages for all other resource types decreased.

Figure 16.3 CAISO balancing area quarterly average of maximum daily generation outages by fuel type – peak hours



16.2 California WEIM region

Figure 16.4 and Figure 16.5 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the first quarter of 2025 for resources in the California WEIM region, excluding the CAISO balancing area.[113] The typical seasonal

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

113 The California region includes BANC, LADWP, and TIDC.

outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2025. Average total outages decreased by approximately 500 MW, or 10 percent, when compared to the first quarter of 2024. The year-over-year decrease was primarily driven by reduced natural gas, solar, and coal outages in the first quarter of 2025 when compared to the first quarter of 2024.

Figure 16.4 California WEIM region quarterly average of maximum daily generation outages by type – peak hours

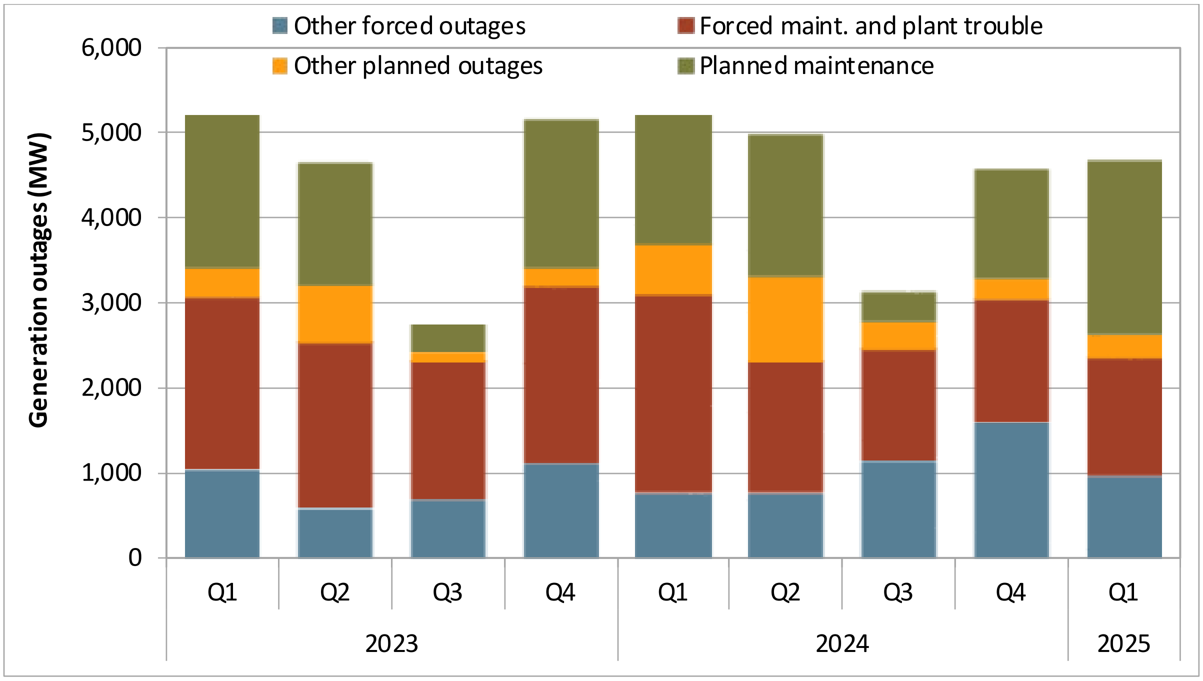
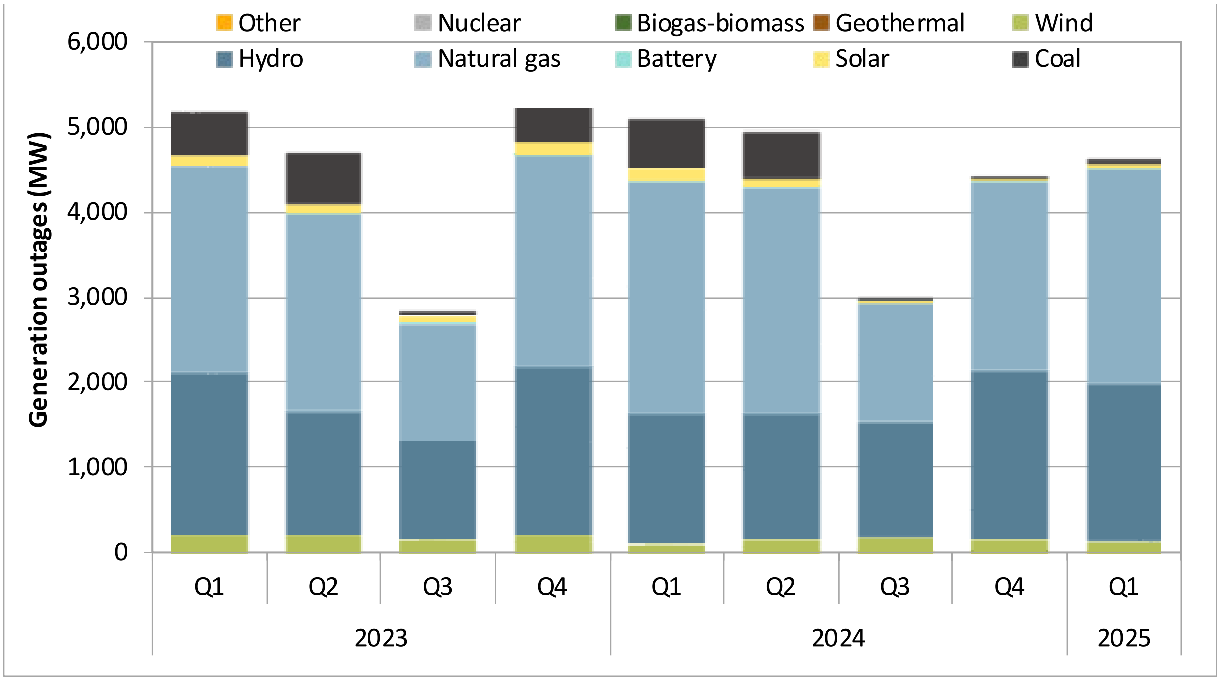


Figure 16.5 California WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



16.3 Desert Southwest WEIM region

Figure 16.6 and Figure 16.7 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the first quarter of 2025 for entities in the Desert Southwest WEIM region.[114] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in the first quarter of 2025. Average total outages increased by approximately 1,100 MW or 10 percent, comparing the first quarter of 2025 to the first quarter of 2024. The year-over-year increase was primarily driven by increases in natural gas and coal outages in the first quarter of 2025 when compared to the first quarter of 2024.

[114] The Desert Southwest region includes AZPS, EPE, NEVP, PNM, SRP, TEPC, and WALC.

Figure 16.6 Desert Southwest WEIM region quarterly average of maximum daily generation outages by type – peak hours

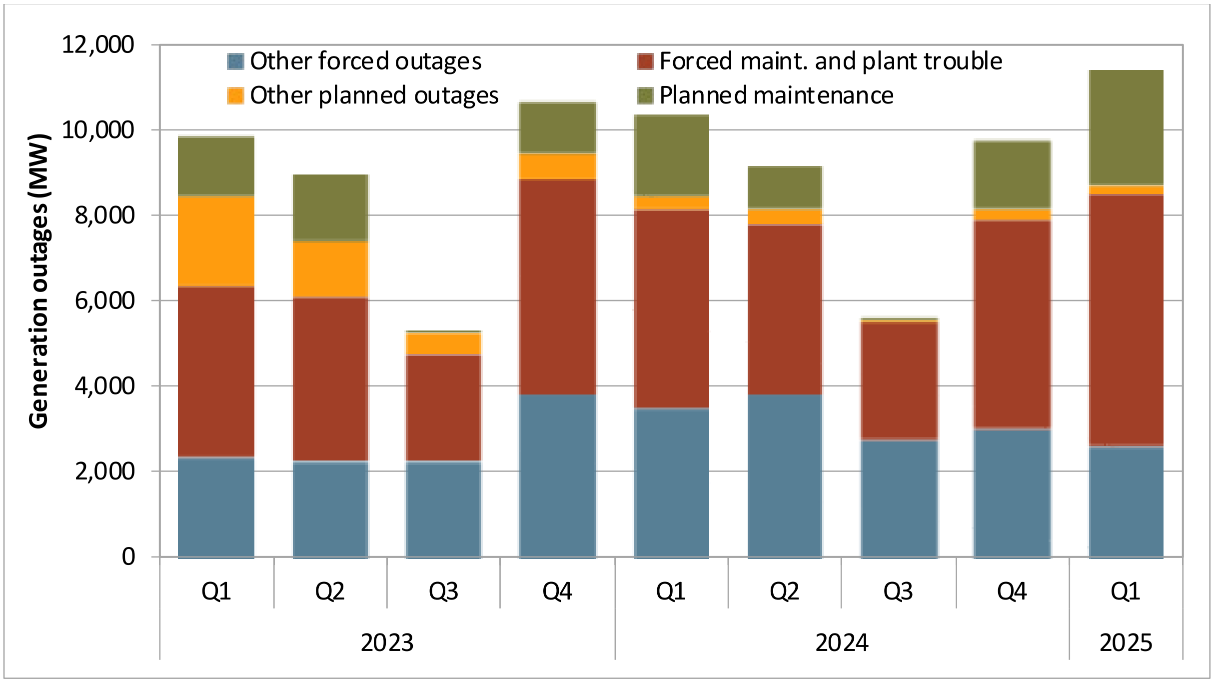
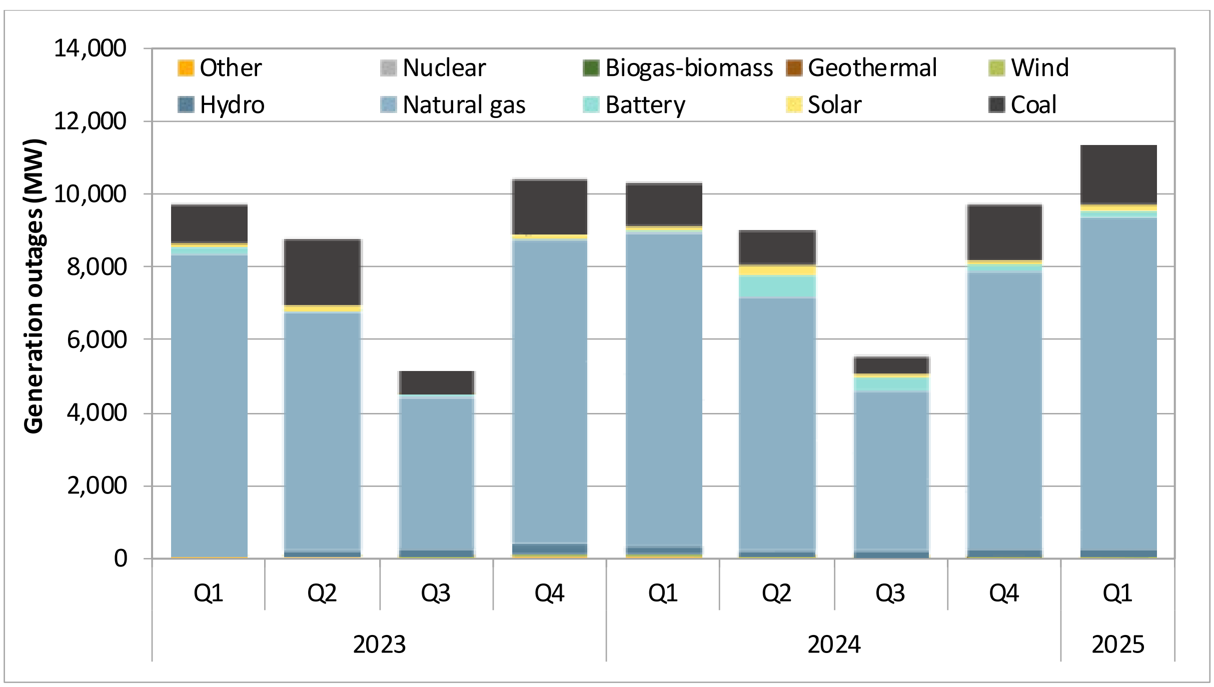


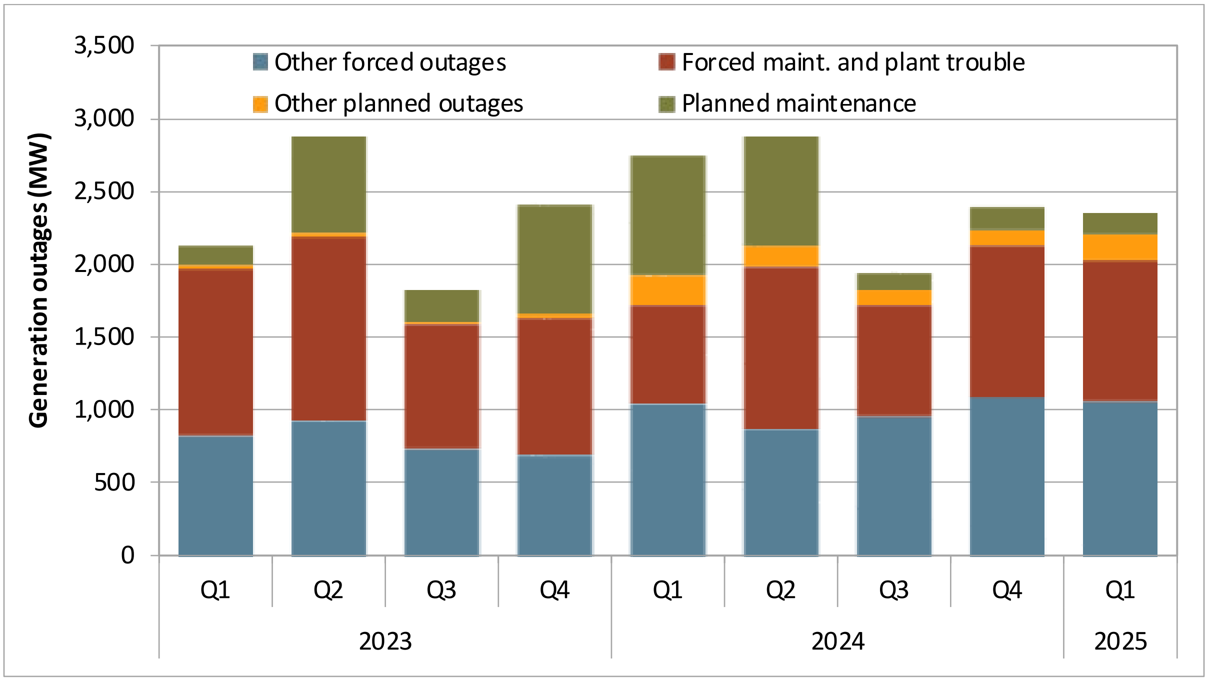
Figure 16.7 Desert Southwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



16.4 Intermountain West WEIM Region

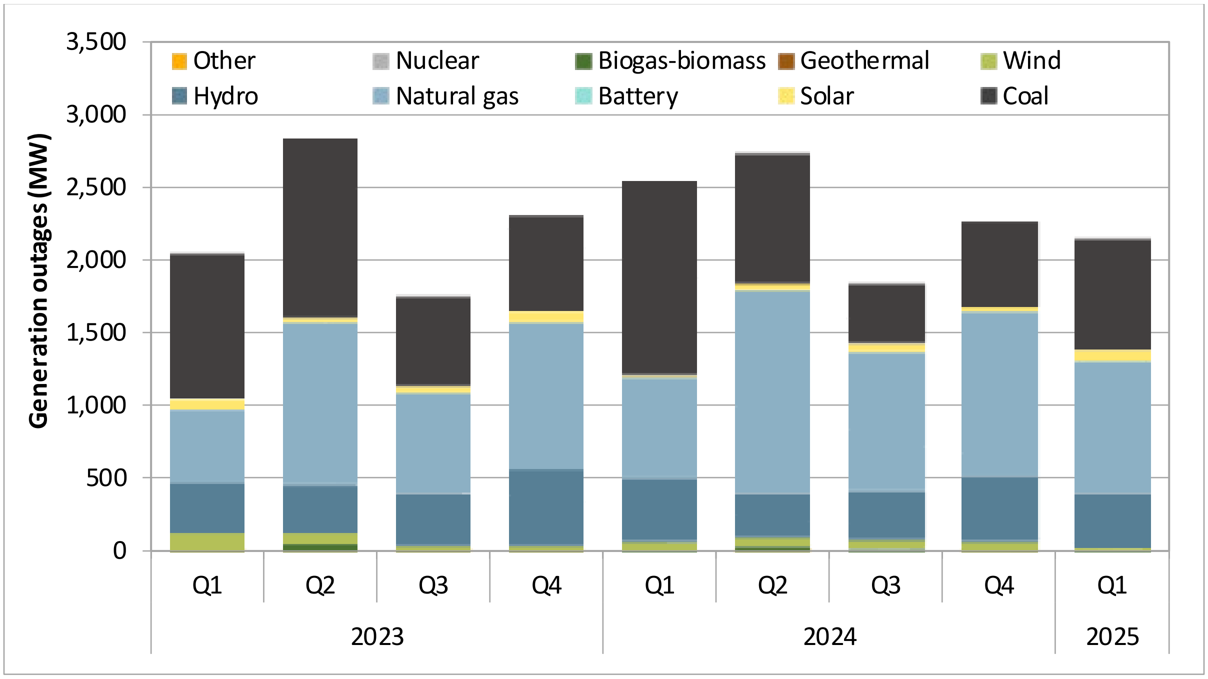
Figure 16.8 and Figure 16.9 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the first quarter of 2025 for entities in the Intermountain West WEIM region.[115] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in 2025. Average total outages decreased by approximately 400 MW or 14 percent. The decrease in outages was driven by a reduction in natural gas and coal generation outages in the first quarter of 2025 compared to the first quarter of 2024.

Figure 16.8 Intermountain West WEIM region quarterly average of maximum daily generation outages by type – peak hours



[115] Intermountain West region includes AVA, IPCO, NWMT, and PACE.

Figure 16.9 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



16.5 Pacific Northwest WEIM region

Figure 16.10 and Figure 16.11 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2023 through the first quarter of 2025 for resources in the Pacific Northwest WEIM region.[116] The typical seasonal outage pattern for the Pacific Northwest region diverges from the others, with outages typically peaking in the second quarter while outages in all other quarters remain low. The trend is still primarily driven by planned outages for maintenance, which are generally performed outside of the higher load periods. Average total outages decreased by nine percent, or approximately 230 MW, in the first quarter of 2025 when compared to the first quarter of 2025. The reduction in outages was largely due to a reduction in hydro and solar outages.

[116] The Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

Figure 16.10 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by type – peak hours

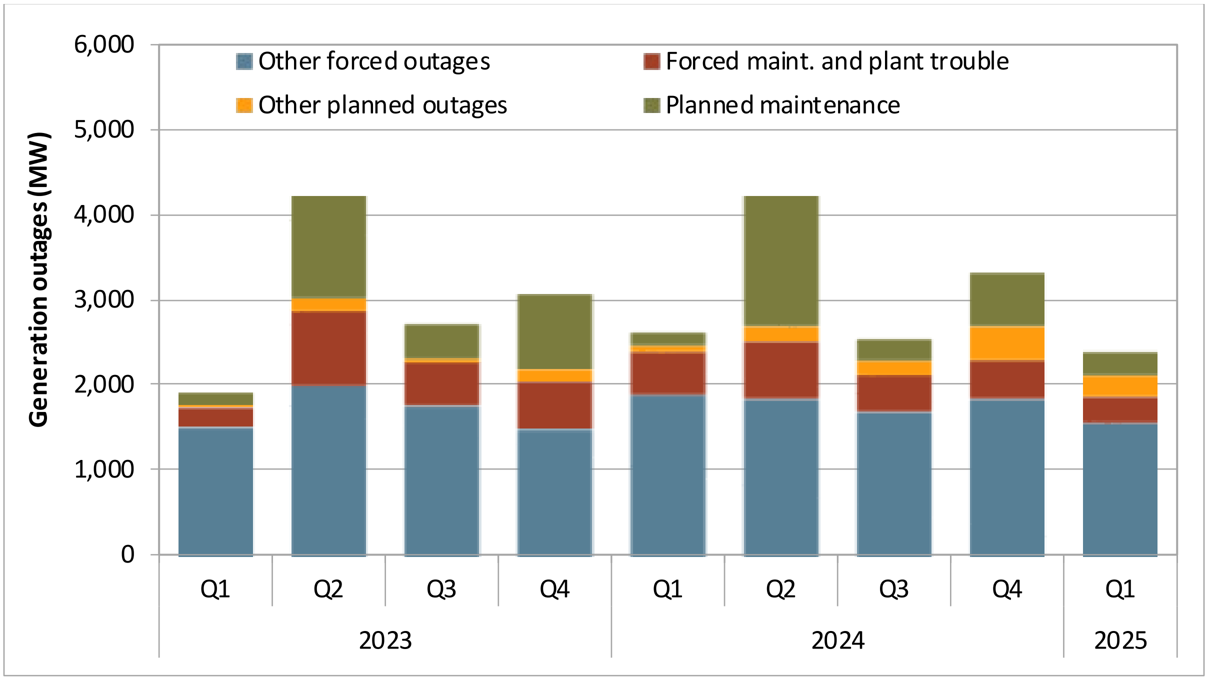
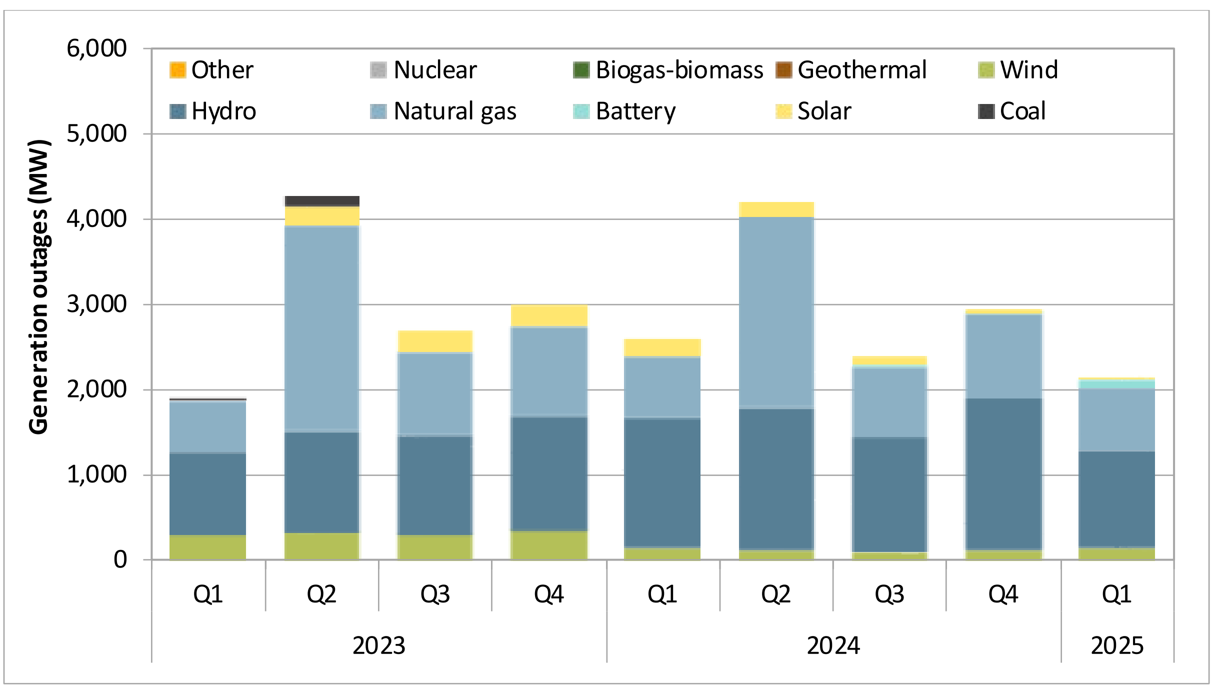


Figure 16.11 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



17 Manual dispatch

This section analyzes manual dispatches for the California ISO balancing area, known as exceptional dispatches, as well as manual dispatches in balancing areas across the WEIM. CAISO balancing area exceptional dispatches are covered in a separate subsection from the rest of the WEIM because of significant differences in how manual dispatches are settled in the CAISO balancing area relative to other balancing areas in the WEIM.

17.1 California ISO exceptional dispatch

This section analyzes exceptional dispatches for the California ISO balancing area. 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:

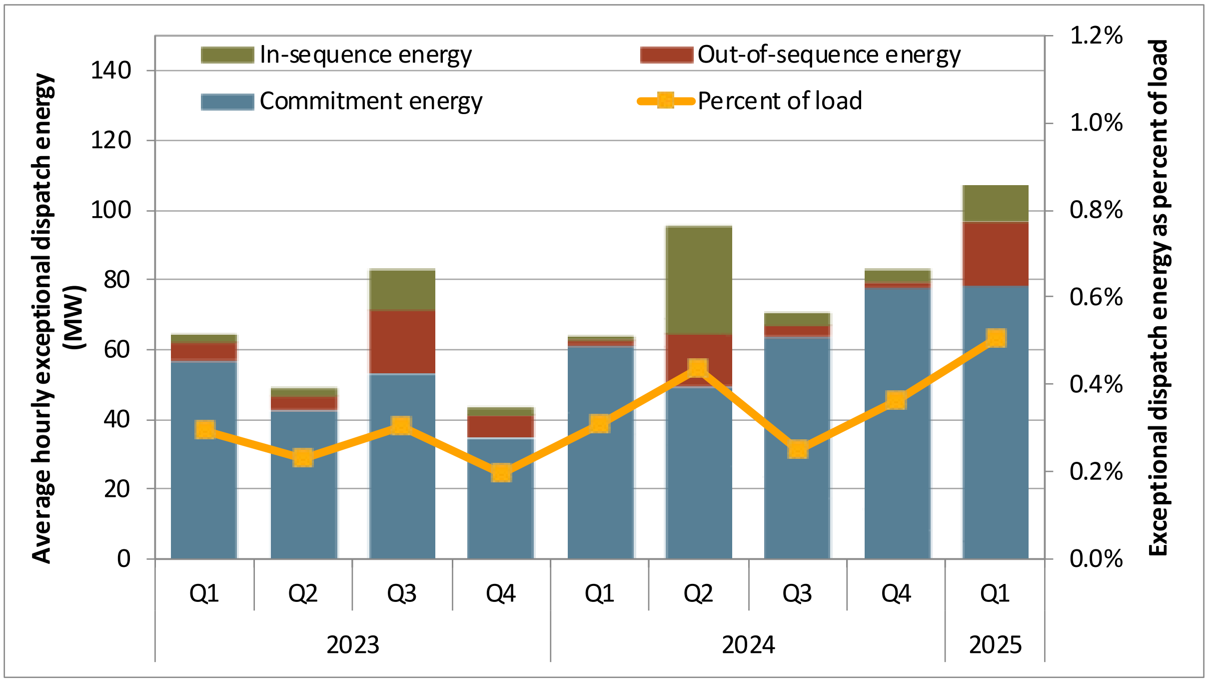
- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments 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 17.1. As shown in Figure 17.1, the average hourly total energy from exceptional dispatches—including minimum load energy from unit commitments—was 107 MW in the first quarter of 2025, which is a 67 percent increase from the first quarter of 2024.[117]

In the first quarter of 2025, exceptional dispatches for unit commitments (blue) accounted for about 73 percent of all exceptional dispatch energy—about 17 percent was from out-of-sequence energy (red), and the remaining 10 percent was from in-sequence energy (green), as shown in Figure 17.1.

Figure 17.1 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

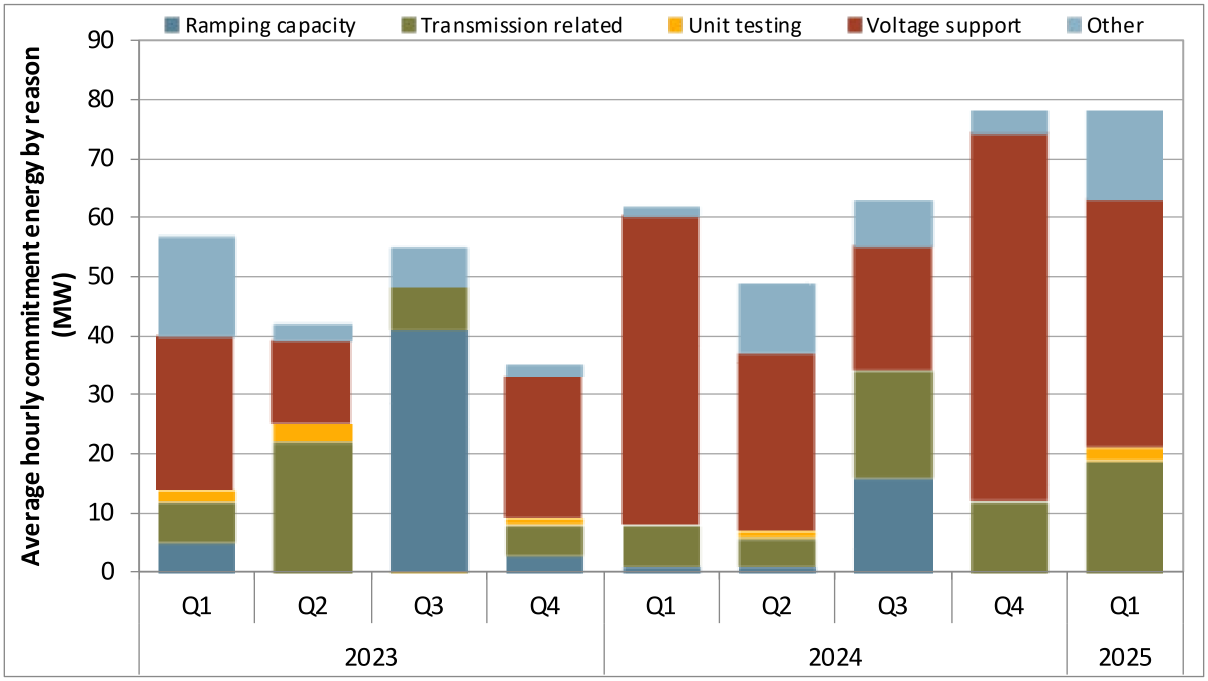
The California ISO balancing area operators occasionally find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. In these instances, the California ISO may commit additional 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 17.2 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 total average minimum load energy from unit commitment exceptional dispatches in the first quarter of 2025 was 78 MW, which was above the 62 MW of average minimum load energy from unit commitment in the first quarter of 2024.

[117] 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.

Minimum load energy from unit commitment exceptional dispatches to provide voltage support (red bars) in the first quarter of 2025 decreased by 19 percent from the same quarter of 2024. Meanwhile, minimum load energy from transmission related unit commitment exceptional dispatches (green bars) in the first quarter of 2025 increased by 171 percent from the same quarter in 2024.

Figure 17.2 Average minimum load energy from exceptional dispatch unit commitments



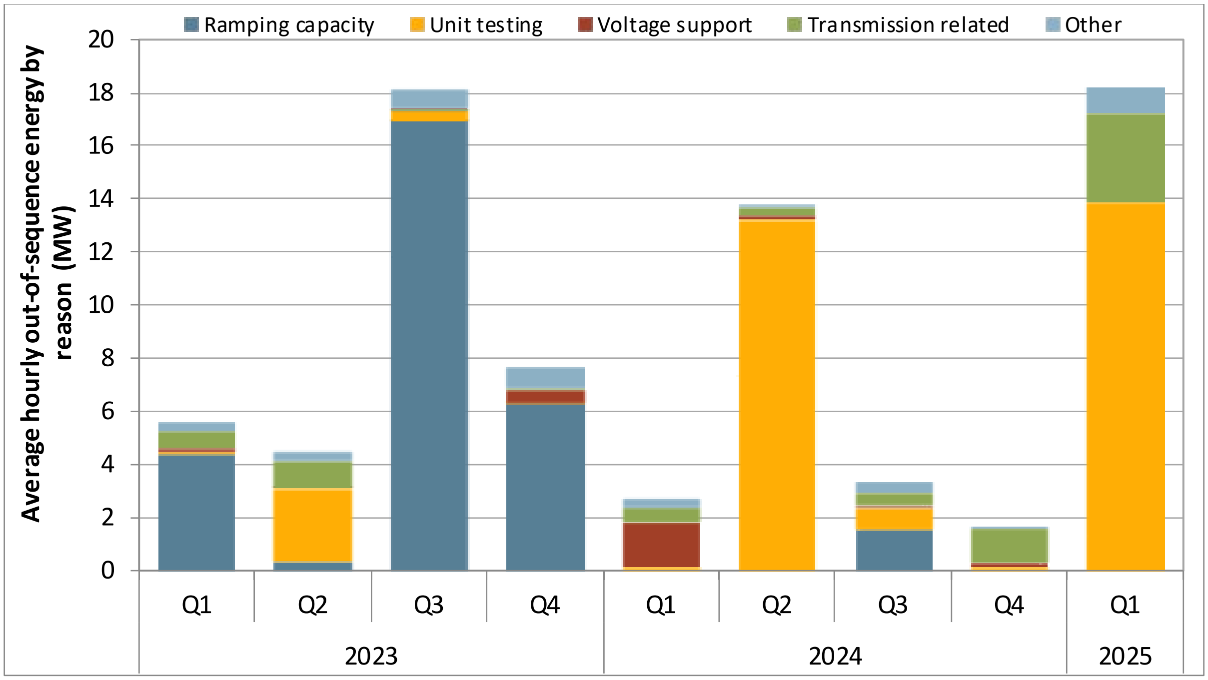
Exceptional dispatches for energy

Figure 17.3 shows the average hourly out-of-sequence exceptional dispatch energy by quarter for 2023, 2024, and 2025. The primary reasons logged for out-of-sequence energy in the first quarter of 2025 were unit testing and transmission-related. Unit testing exceptional dispatches are issued for general reliability testing or for unit-specific purposes, such as pre-commercial or post-outage operational testing. Transmission-related exceptional dispatches are issued for any transmission-related modeling limitations that may arise from transmission maintenance, lack of voltage support at proper levels, and incomplete or inaccurate information about the transmission network.

Average hourly out-of-sequence energy due to unit testing (yellow bars) increased by 8,053 percent in the first quarter of 2025 compared to the same quarter in 2024. This increase is largely due to pre-commercial unit testing for a new resource that came on-line in April 2025. As shown in Figure 16.3, it is common to see an increase in unit testing during the second quarter of each year. However, this particular unit happened to conduct the majority of its unit testing in March 2025. 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.

Out-of-sequence energy due to transmission-related exceptional dispatches (green bars) increased by 483 percent in the first quarter of 2025 when compared to the first quarter of 2024. This increase is largely due to exceptional dispatches to mitigate transmission outages during the January 2025 wildfires in Los Angeles and other parts of Southern California.

Figure 17.3 Out-of-sequence exceptional dispatch energy by reason



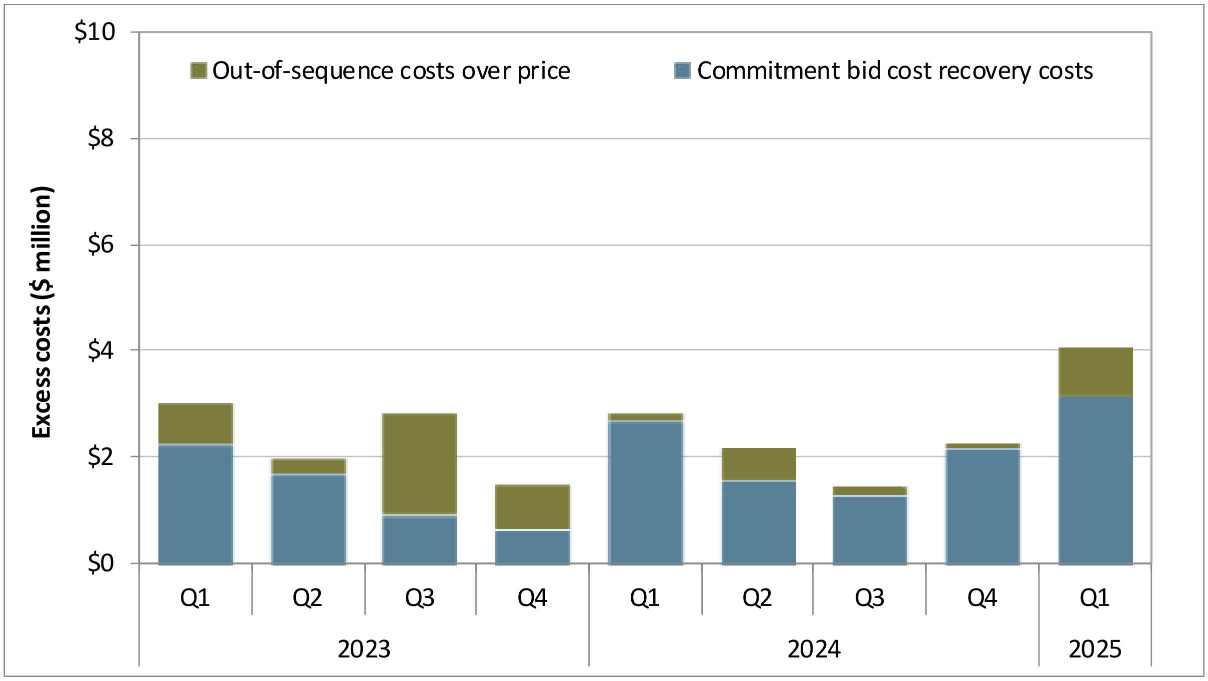
Exceptional dispatch costs

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 17.4 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 first quarter of 2025, out-of-sequence energy costs were $0.93 million, a 559 percent increase from the first quarter of 2024. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the first quarter were $3.2 million, an 18 percent increase from the first quarter of 2024. Overall, the additional costs associated with the exceptional dispatches in the first quarter of 2025 increased by 45 percent when compared to the first quarter of 2024.

Figure 17.4 Excess exceptional dispatch cost by type



17.2 Western Energy Imbalance Market manual dispatch

Western Energy Imbalance Market (WEIM) areas sometimes need to dispatch resources out-of-market for reliability, to manage transmission constraints, or for other reasons. These manual dispatches are similar to exceptional dispatches in the California ISO. Manual dispatches within the WEIM are not issued by the CAISO and can only be issued by a WEIM entity for their respective balancing authority area. Manual dispatches may be issued for both participating and non-participating resources.

Like exceptional dispatches in the CAISO balancing area, manual dispatches in the WEIM do not set prices, and the reasons for these manual dispatches are similar to those given for the CAISO exceptional dispatches. However, manual dispatches in the WEIM are not settled in the same manner as exceptional dispatches within the CAISO balancing area. Energy from these manual dispatches is settled on the market clearing price, similar to uninstructed energy. This eliminates the possibility of exercising market power either by setting prices or by being paid "as-bid" at above-market prices.

Figure 17.5 through Figure 17.8 summarize average hourly incremental and decremental manual dispatch activity of participating and non-participating resources for each WEIM region. The California region, however, has no manual dispatch energy from non-participating resources.

When comparing the first quarter of 2025 to the first quarter of 2024, incremental manual dispatch energy from participating resources (yellow bars) increased in the Desert Southwest region by 9 percent, but decreased in the California, Intermountain West, and Pacific Northwest regions by 57 percent, 18 percent, and 75 percent, respectively. Similarly, when comparing the first quarter of 2025 to the same quarter in 2024, incremental manual dispatch energy from non-participating resources (red bars) increased by 18 percent for the Desert Southwest region, but decreased for the Intermountain West and Pacific Northwest regions by 77 percent and 48 percent, respectively.

From the first quarter of 2024 to the first quarter of 2025, decremental manual dispatch energy from participating resources (green bars) increased in the California, Desert Southwest, and Pacific Northwest by 355 percent, 16 percent, and 649 percent, respectively. Meanwhile, decremental manual dispatch energy from participating resources decreased by 20 percent in the Intermountain West region. When comparing the first quarter of 2025 to the same quarter in 2024, decremental manual dispatch energy from non-participating resources (blue bars) increased in the Desert Southwest and Pacific Northwest regions by 165 percent and 6 percent, respectively, but decreased in the Intermountain West by 10 percent.

Overall, combined incremental and decremental manual dispatch energy increased in the Desert Southwest and California (non-CAISO) regions compared to the first quarter of 2024 by 17 percent and 95 percent, respectively. Total manual dispatch energy in the Intermountain West and Pacific Northwest regions decreased by 30 percent and 29 percent, respectively.

Figure 17.5 WEIM manual dispatches – California

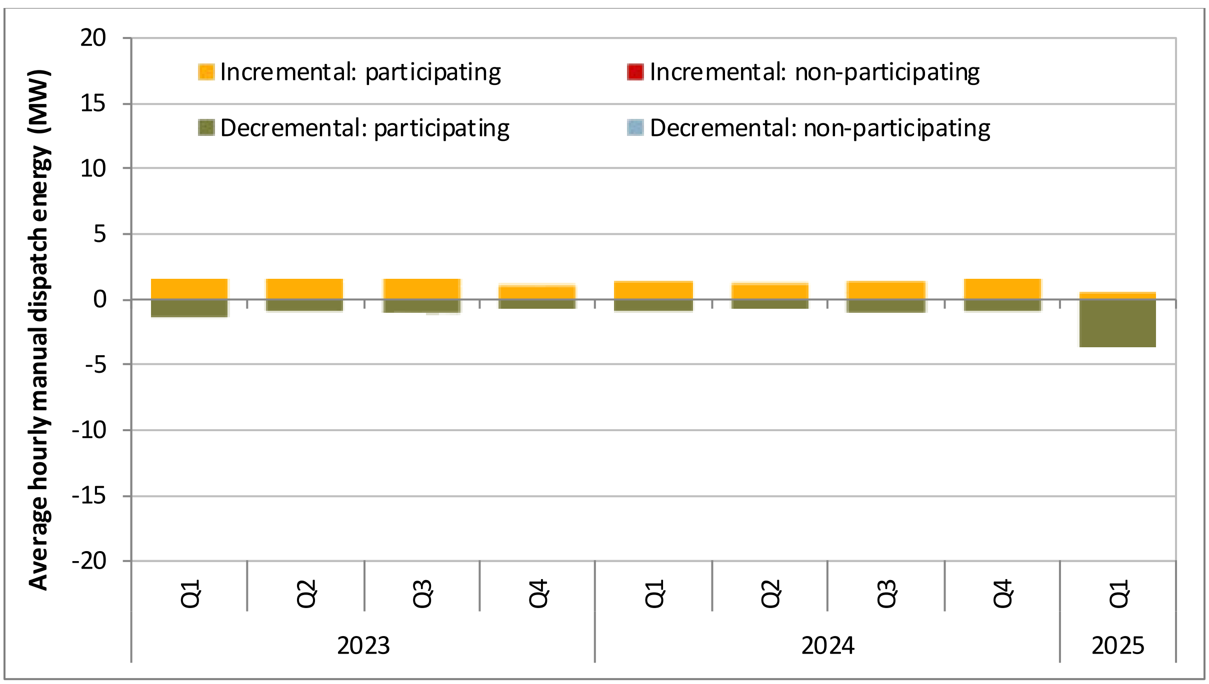


Figure 17.6 WEIM manual dispatches – Desert Southwest

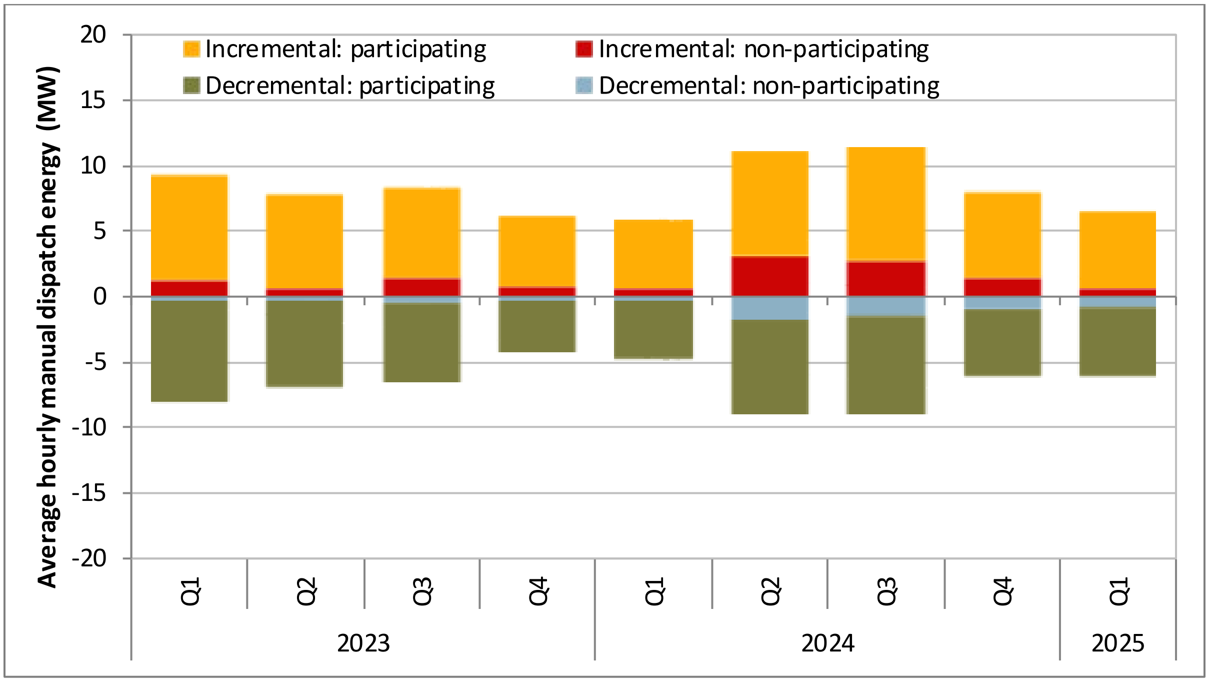


Figure 17.7 WEIM manual dispatches – Intermountain West

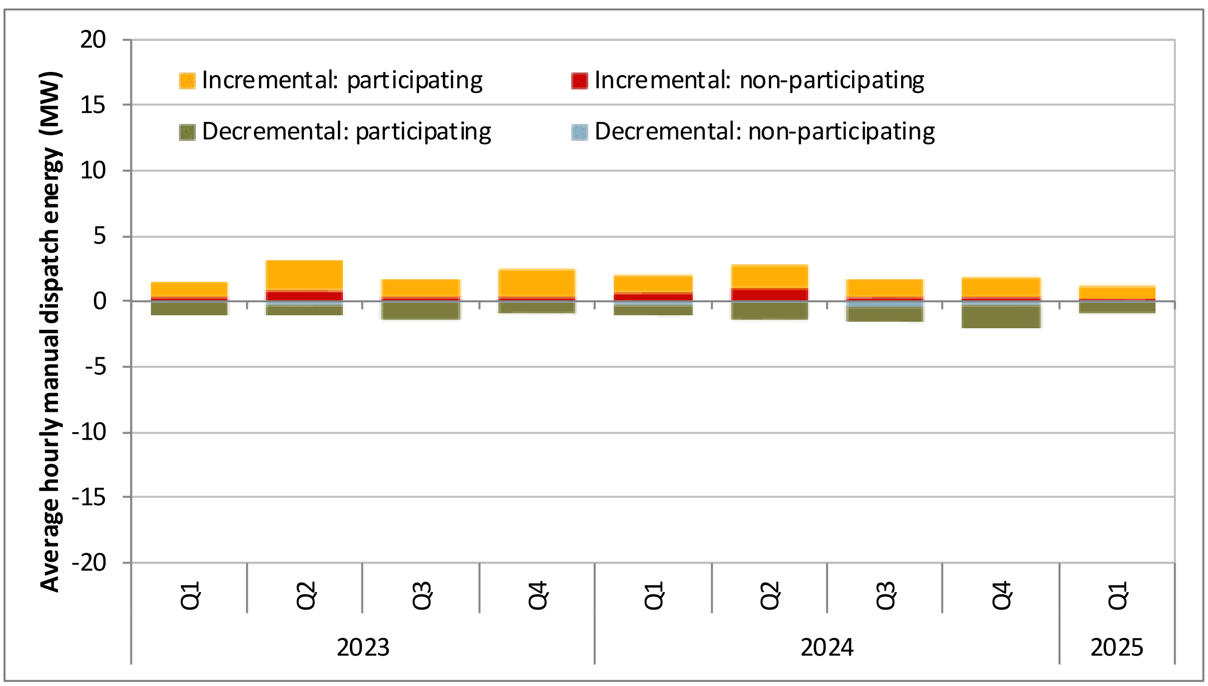
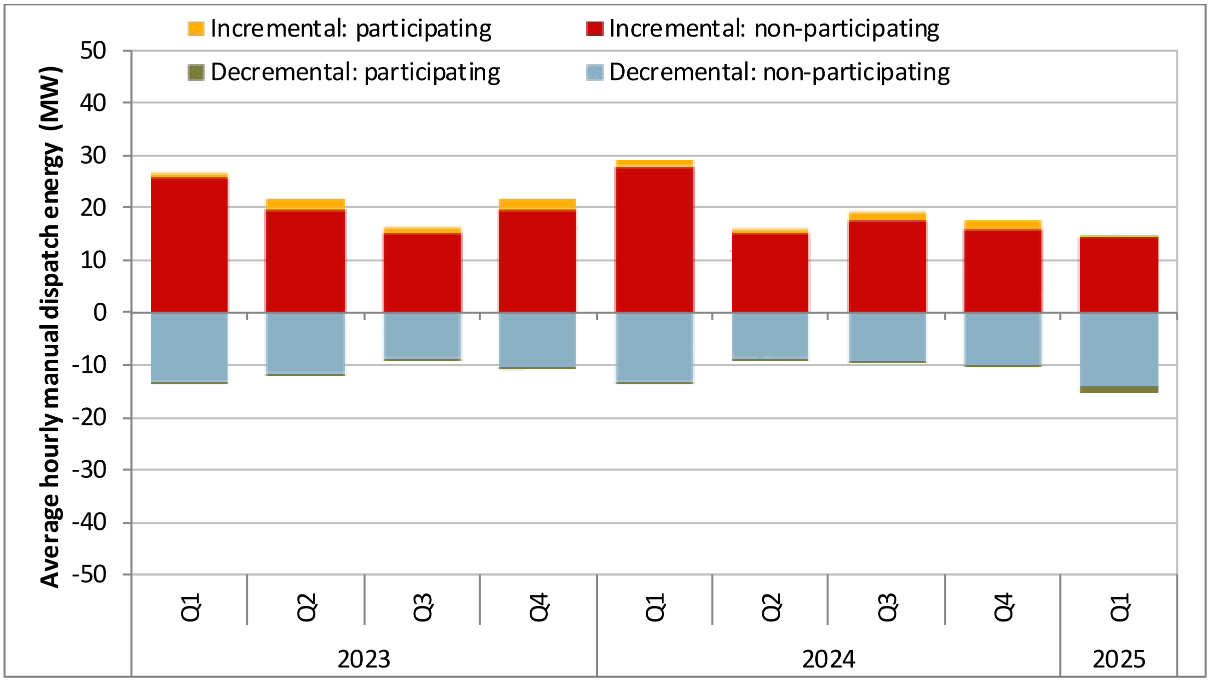


Figure 17.8 WEIM manual dispatches – Pacific Northwest



APPENDIX

Appendix A | Western Energy Imbalance Market area specific metrics

Sections A.1 to A.23 include figures for each WEIM area showing hourly locational marginal price (LMP) and dynamic transfers.[118] These figures are included for both the 15-minute and 5-minute markets. Key highlights of the quarter include:

- In this quarter, the overall hourly LMP trend showed higher prices during the morning and evening peak hours than during mid-day solar production hours. This discrepancy between relatively low mid-day prices and relatively high evening prices was most pronounced in balancing areas in the California and Desert Southwest regions.
- In this quarter, WEIM dynamic transfers exhibited distinct patterns both across regions and BAAs. Within the California region, CAISO and LADWP typically exported during the day and imported during non-solar hours, while other BAAs in California showed the opposite trend, importing mid-day and exporting during non-solar hours, with most energy flowing to CAISO. In the Desert Southwest, most BAAs exported throughout the day, with exports more pronounced during morning and evening peak hours. NEVP exhibited strong exports during mid-day hours, primarily directed toward the Intermountain West region. The Intermountain West exhibited a notable shift in transfer patterns this quarter, with IPCO and PACE showing strong exports during morning and evening peak hours—mostly toward the Desert Southwest and neighboring BAAs. The Pacific Northwest tended to import, with the exception of AVRN, BPA, and PACW in non-solar hours.

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.

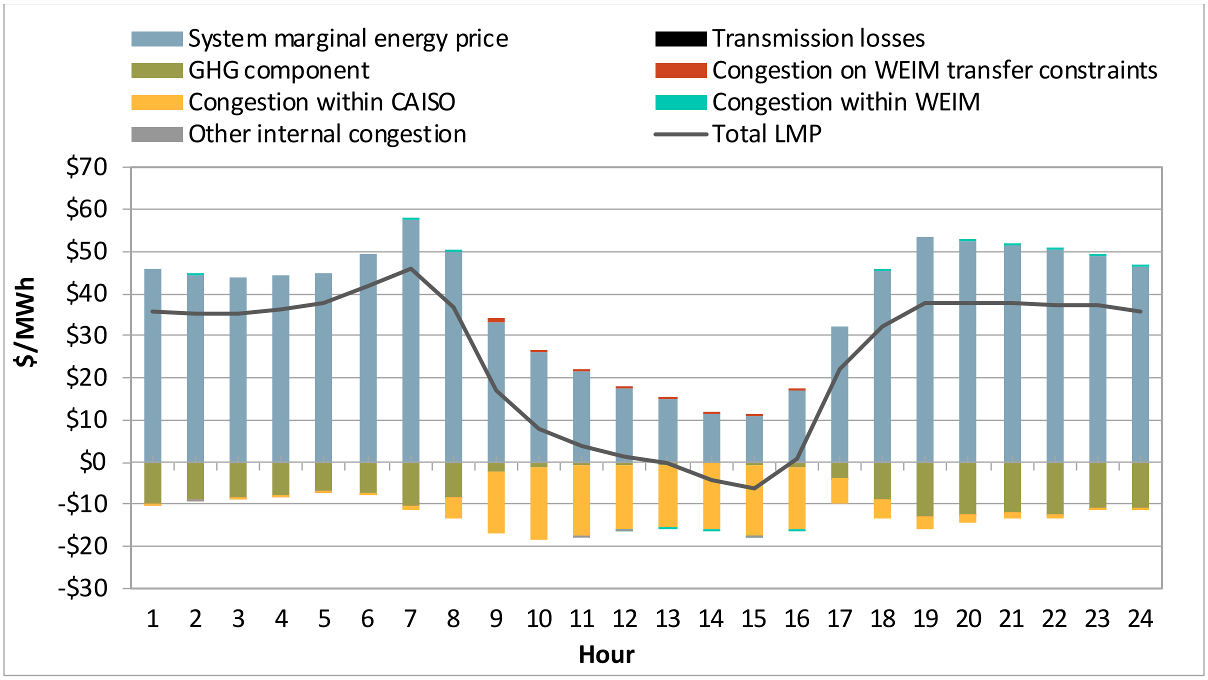
- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse 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.

[118] 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.

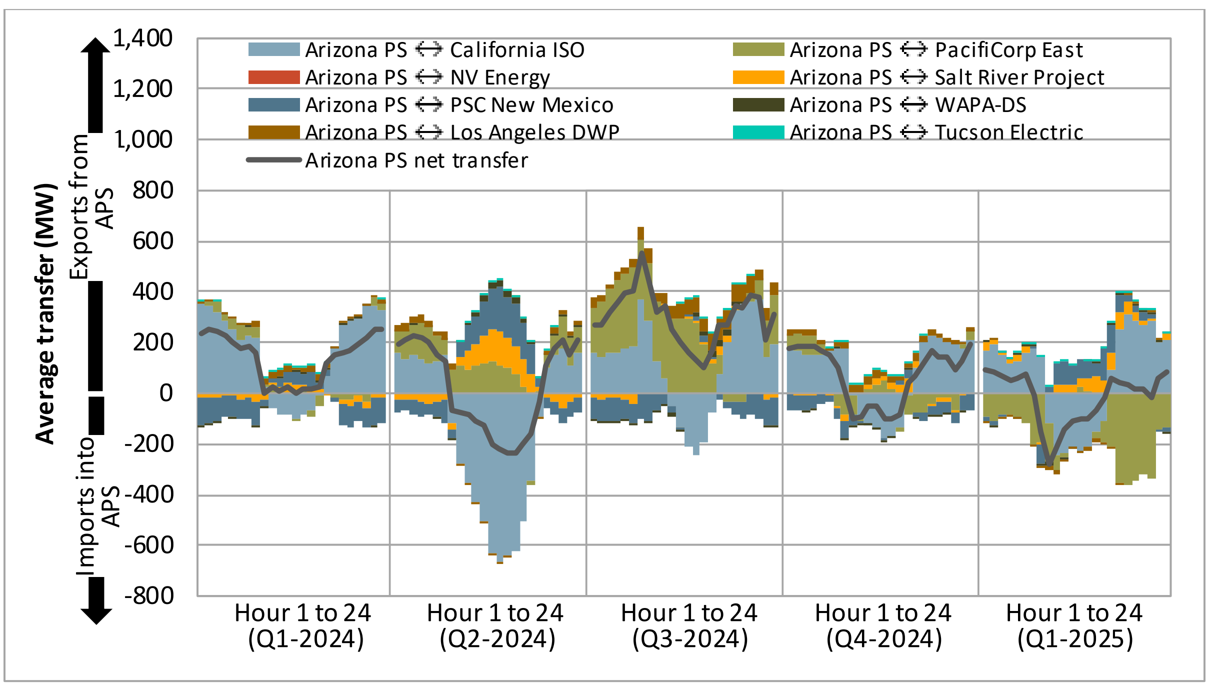
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion 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 constraints 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

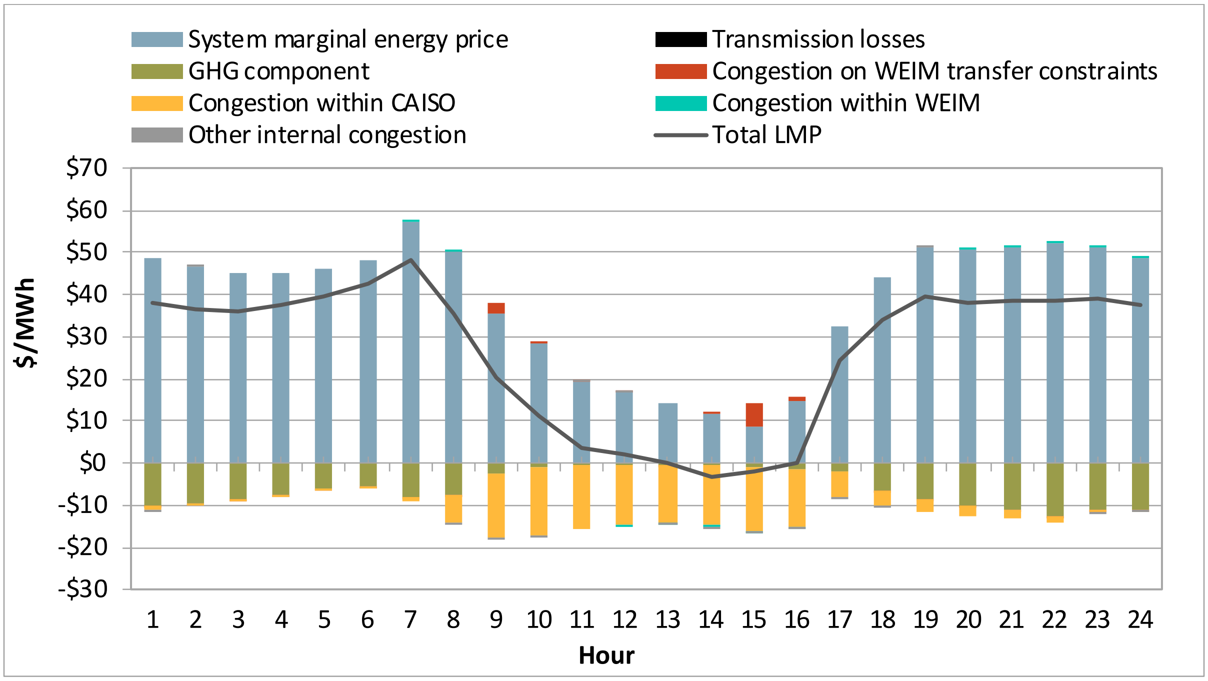
Appendix Figure A.1 Average hourly 15-minute price by component (Q1 2025)



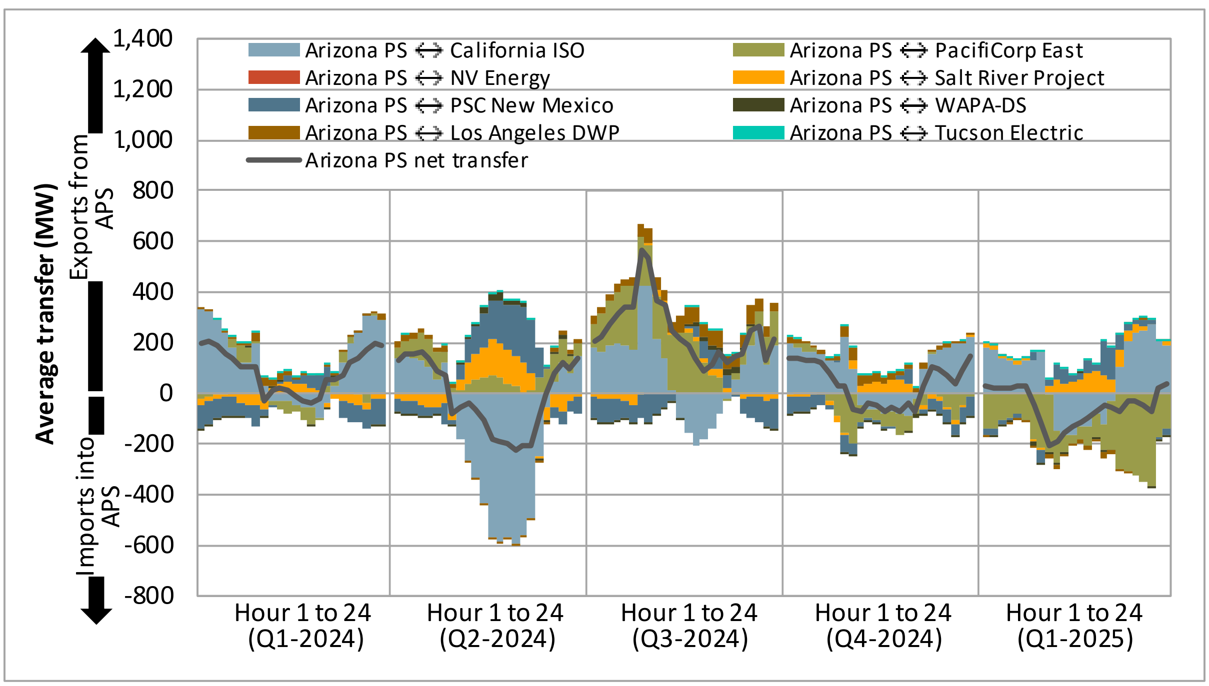
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q1 2025)

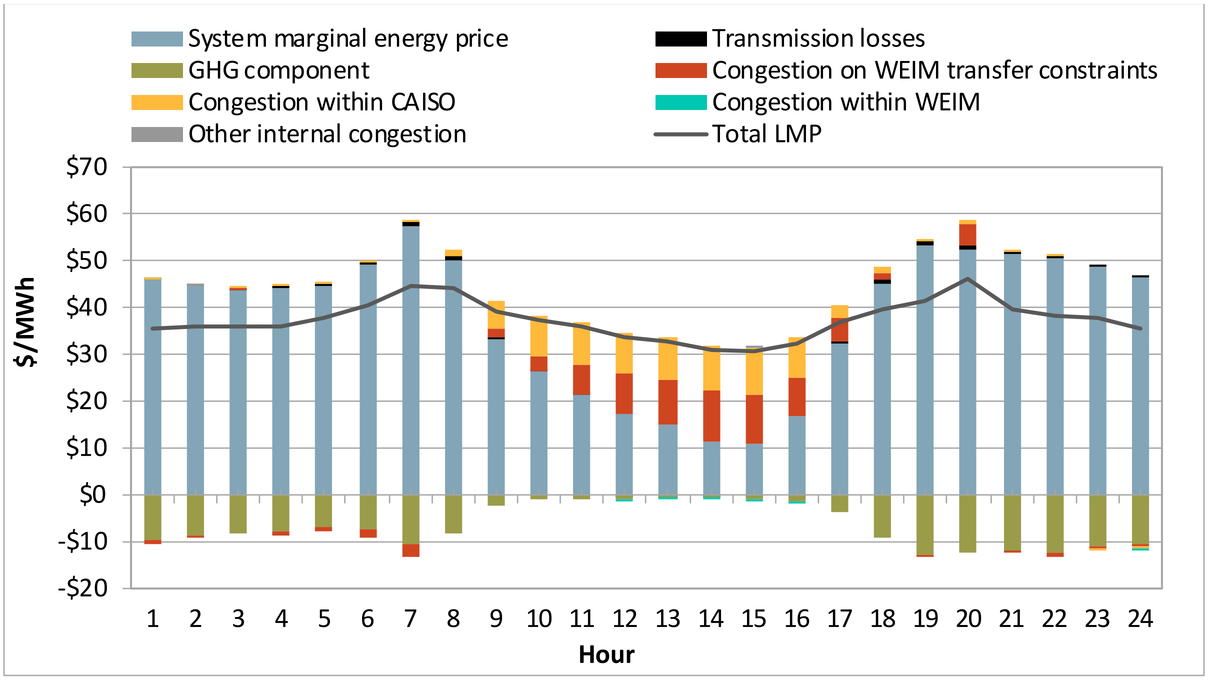


Appendix Figure A.4 Average hourly 5-minute market transfers

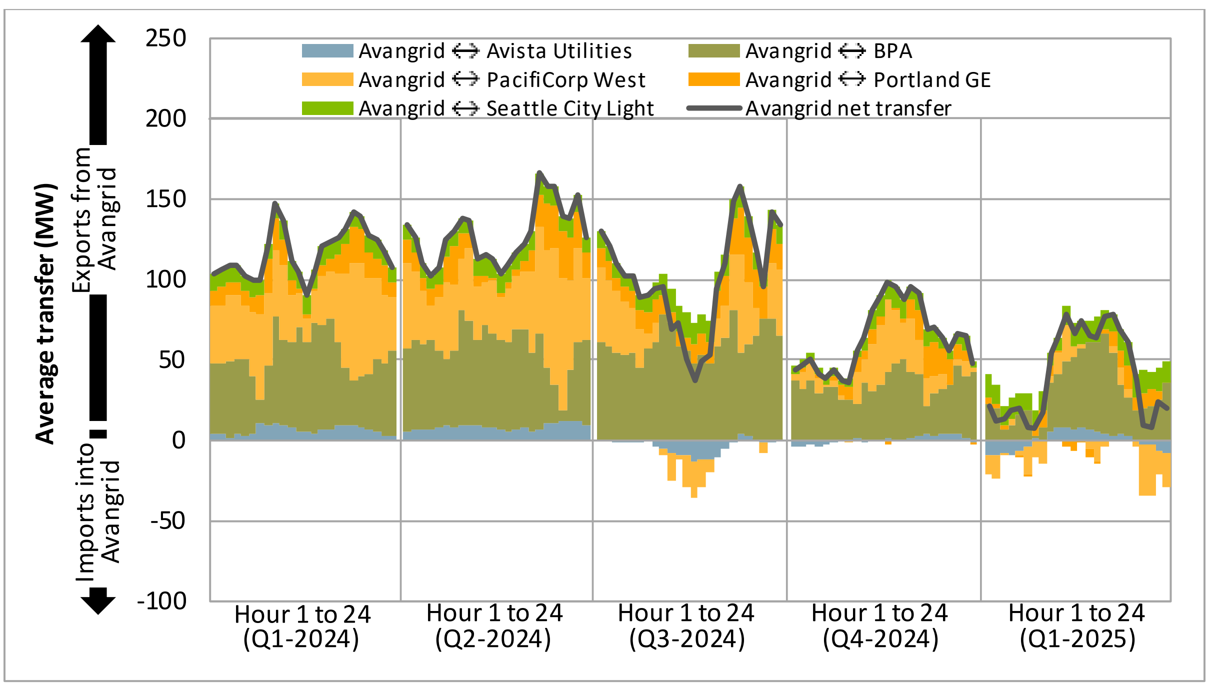


A.2 Avangrid

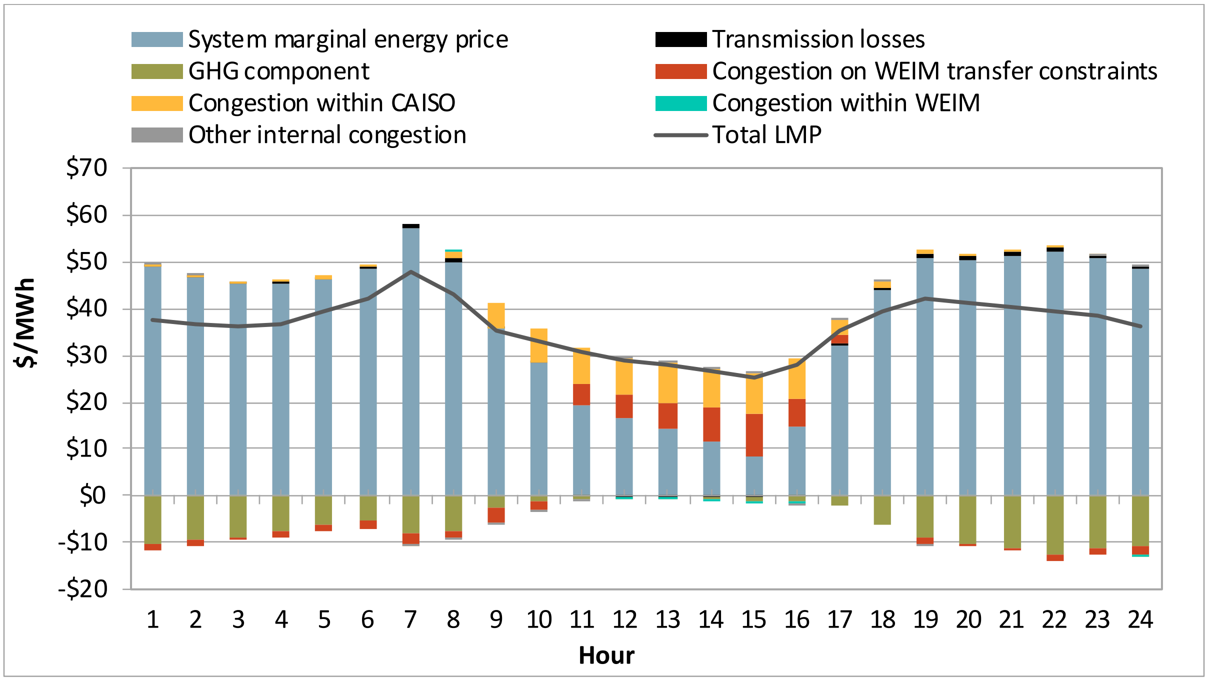
Appendix Figure A.5 Average hourly 15-minute price by component (Q1 2025)



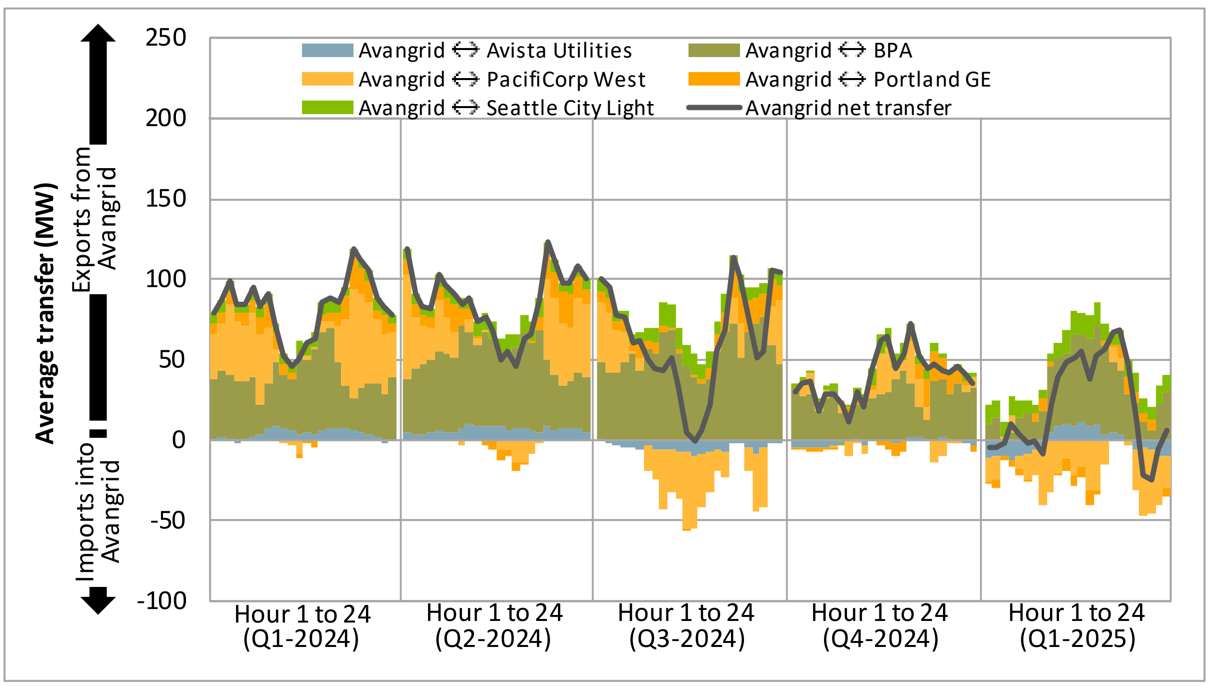
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q1 2025)

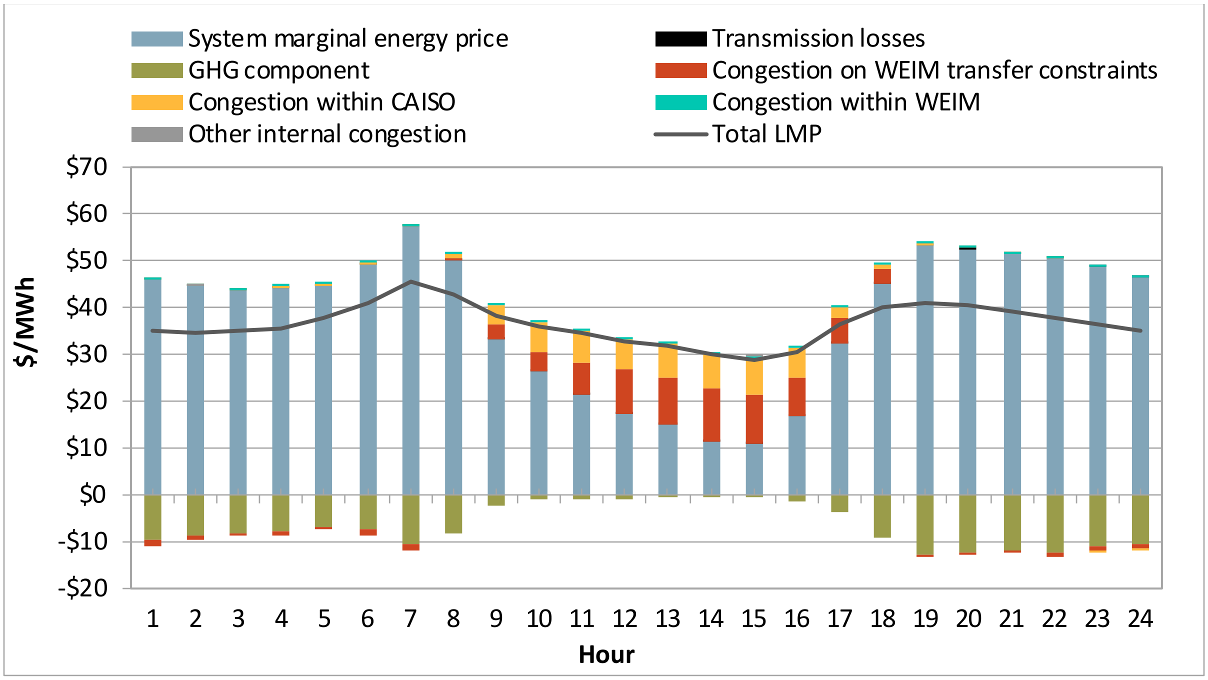


Appendix Figure A.8 Average hourly 5-minute market transfers

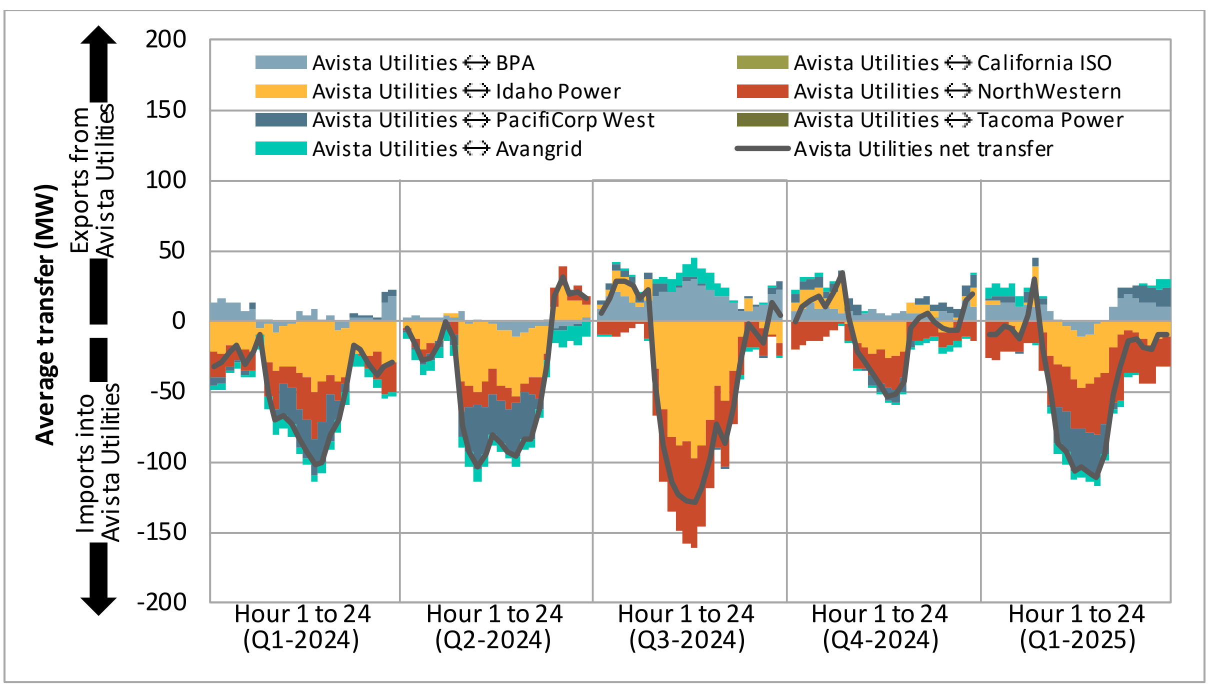


A.3 Avista Utilities

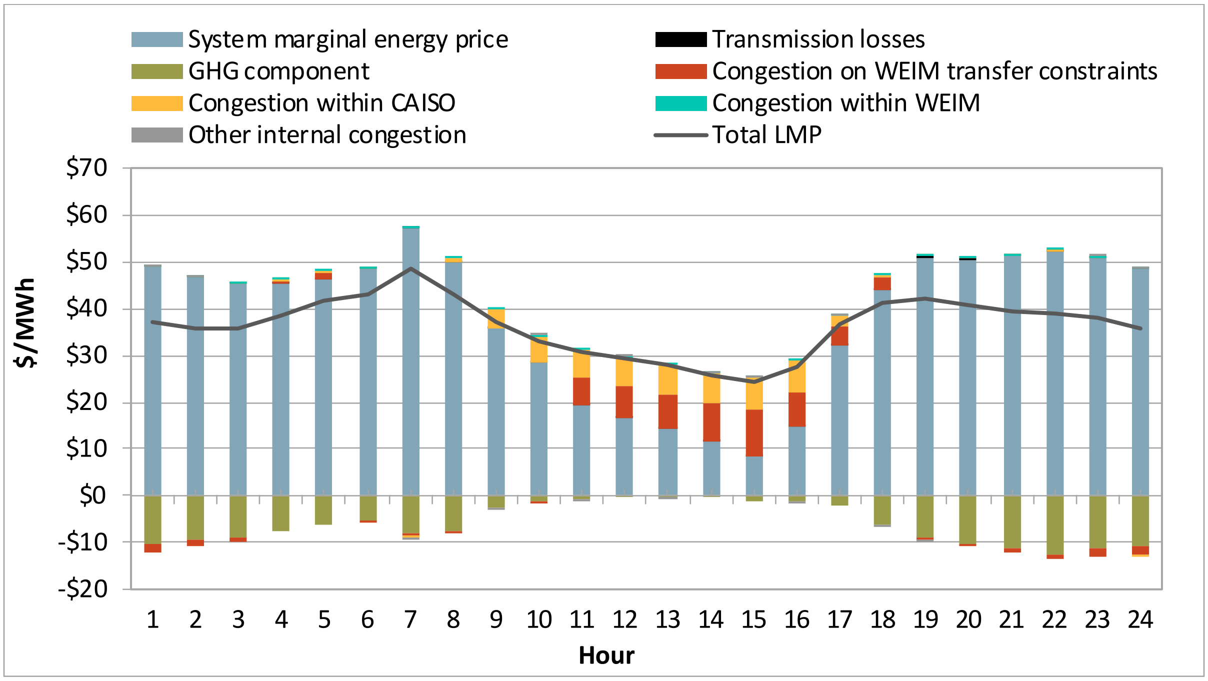
Appendix Figure A.9 Average hourly 15-minute price by component (Q1 2025)



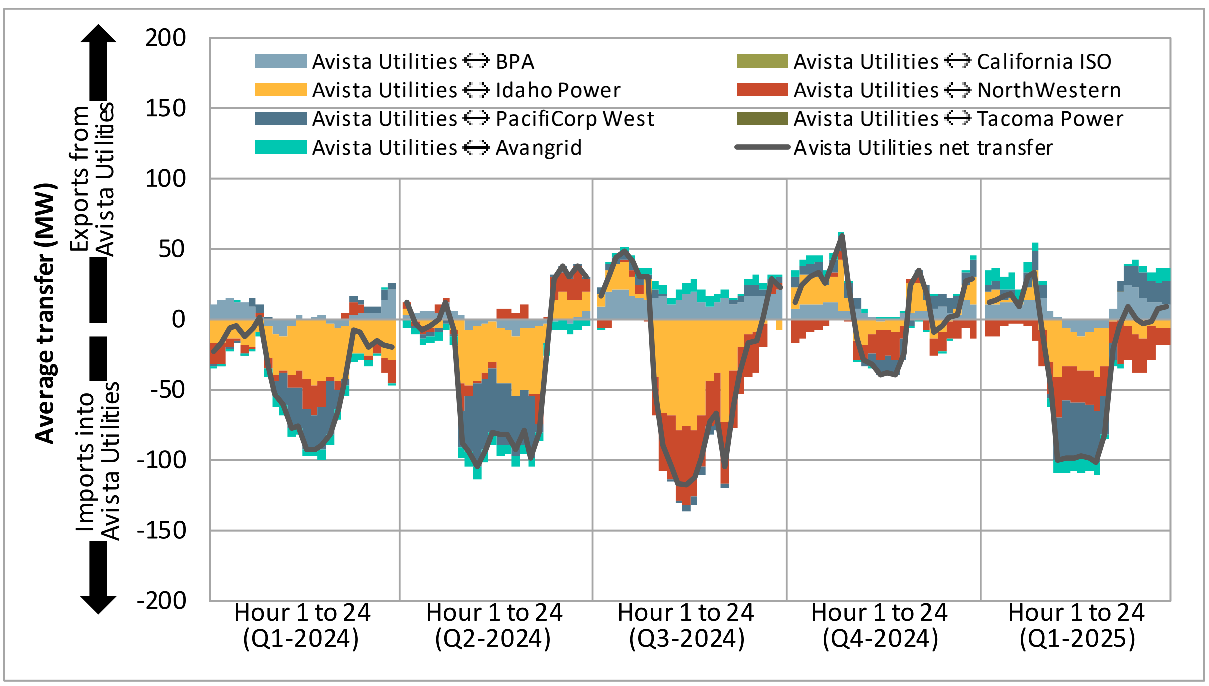
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q1 2025)

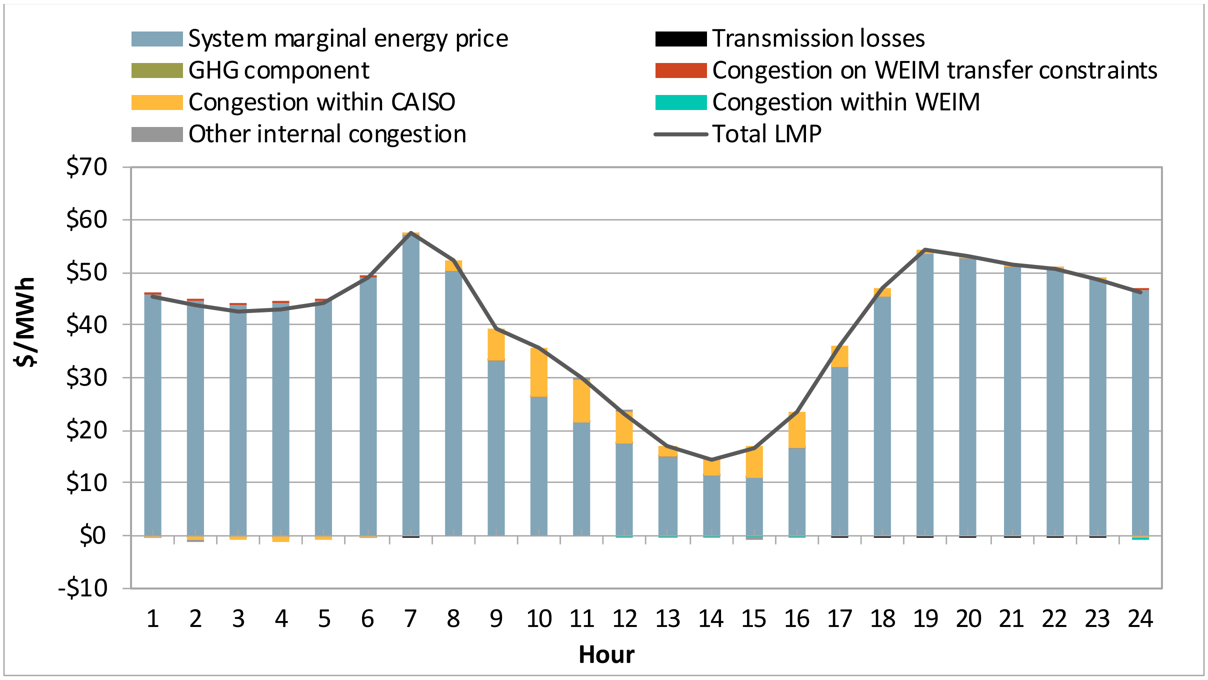


Appendix Figure A.12 Average hourly 5-minute market transfers

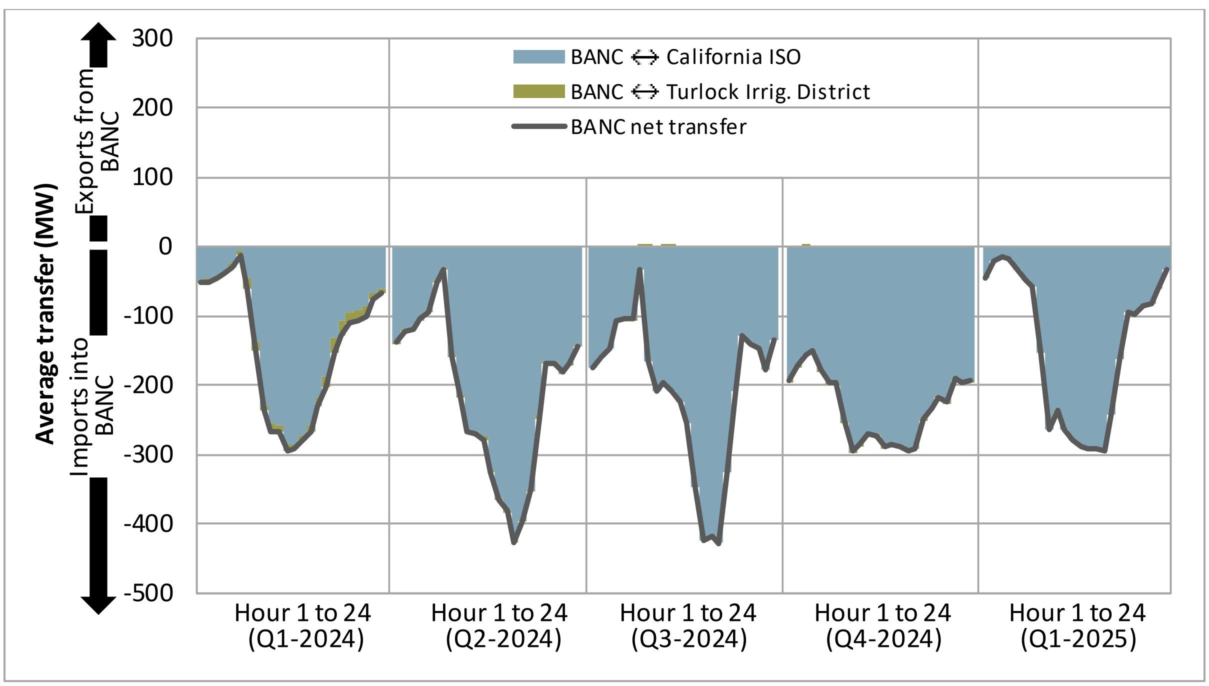


A.4 Balancing Authority of Northern California

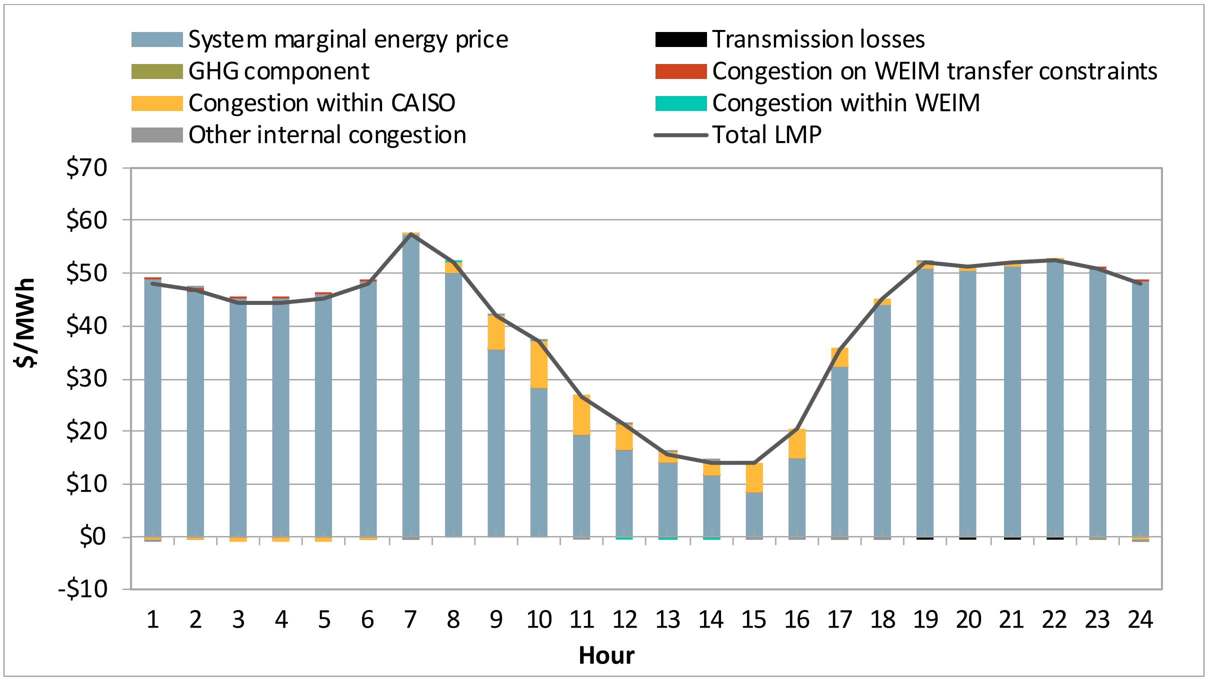
Appendix Figure A.13 Average hourly 15-minute price by component (Q1 2025)



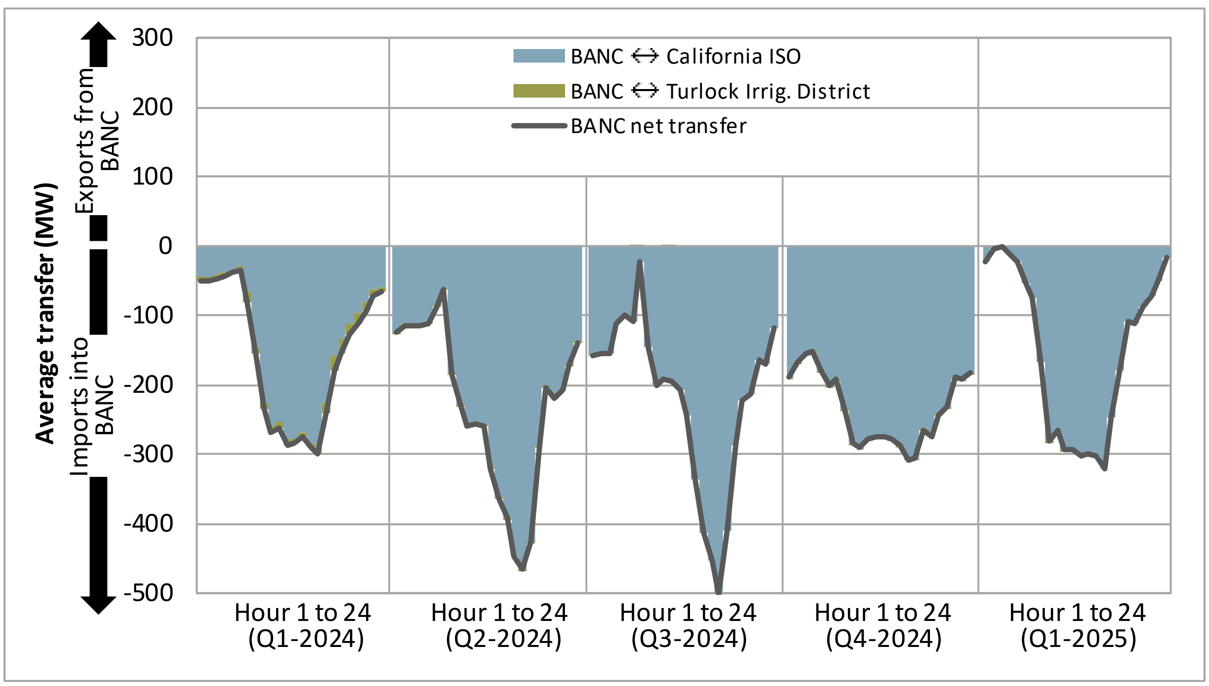
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q1 2025)

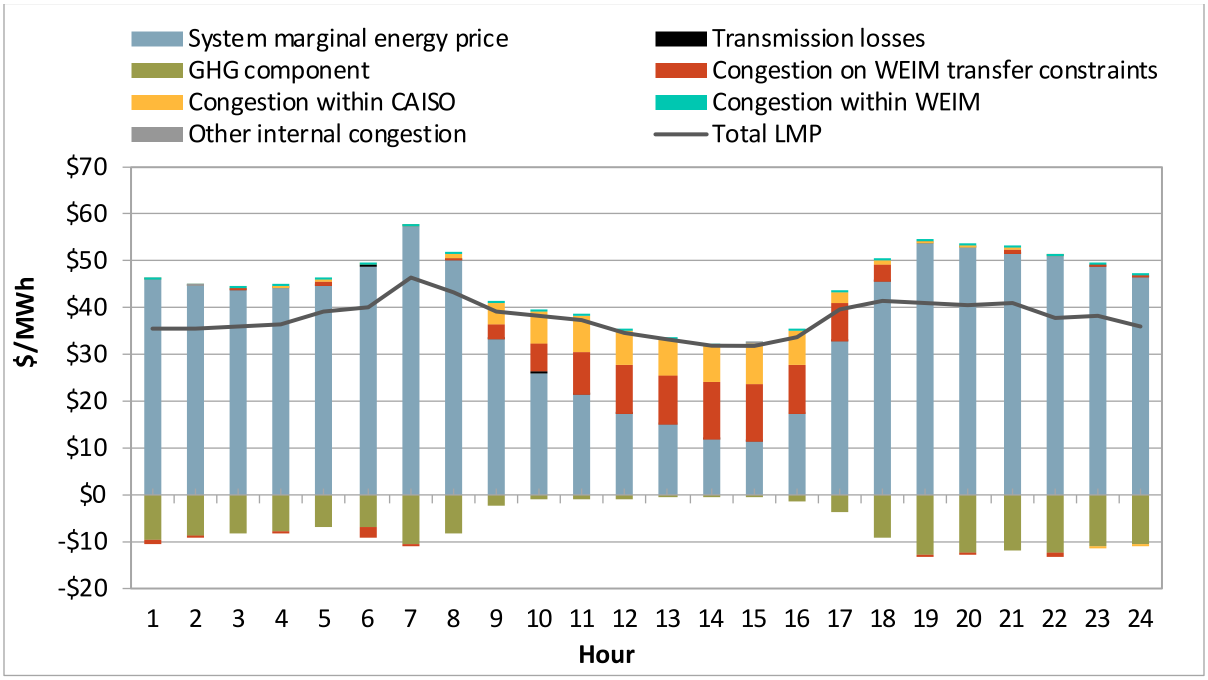


Appendix Figure A.16 Average hourly 5-minute market transfers

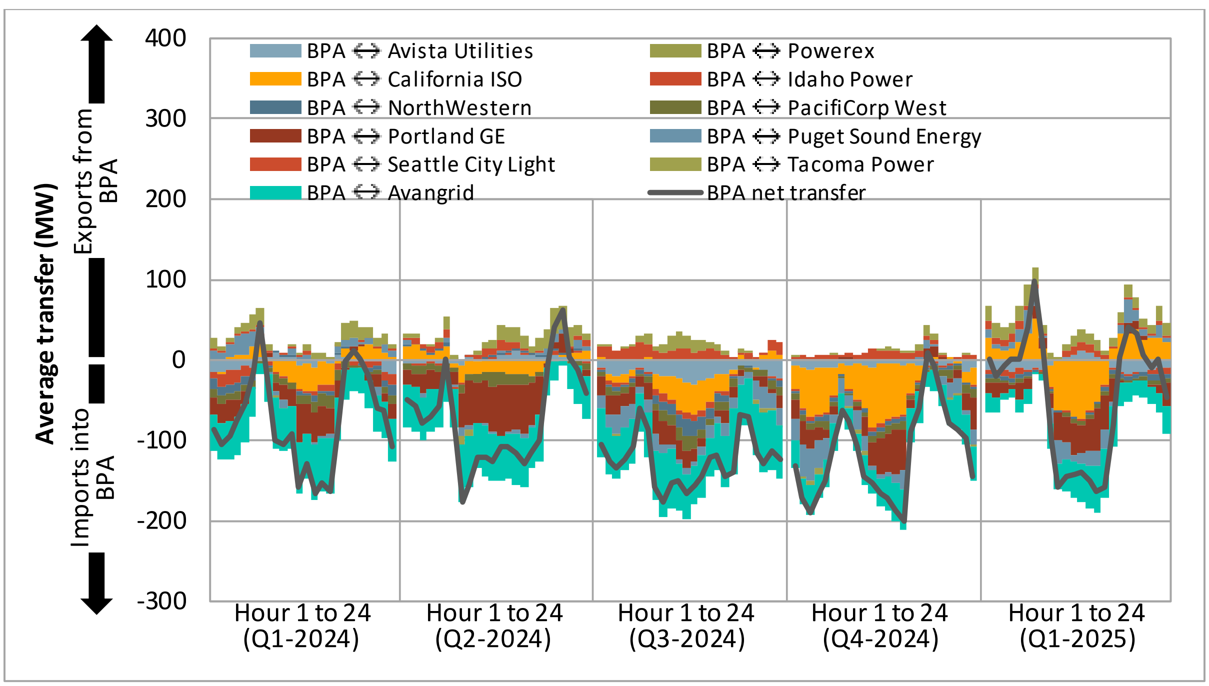


A.5 Bonneville Power Administration

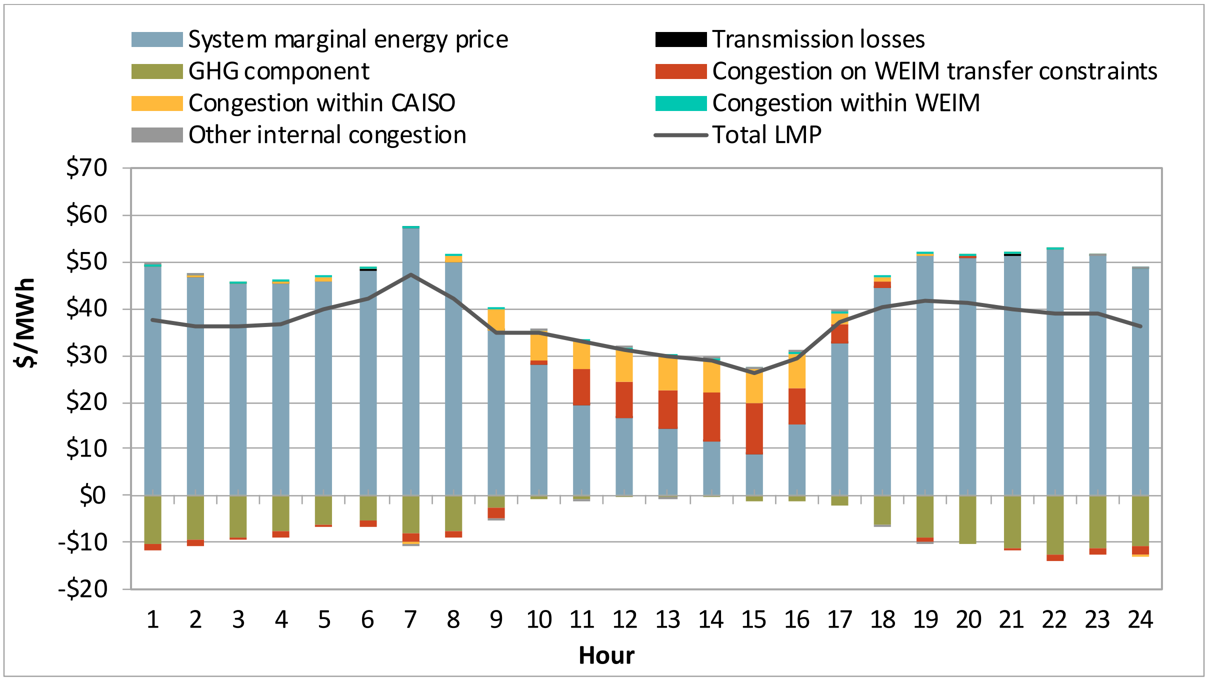
Appendix Figure A.17 Average hourly 15-minute price by component (Q1 2025)



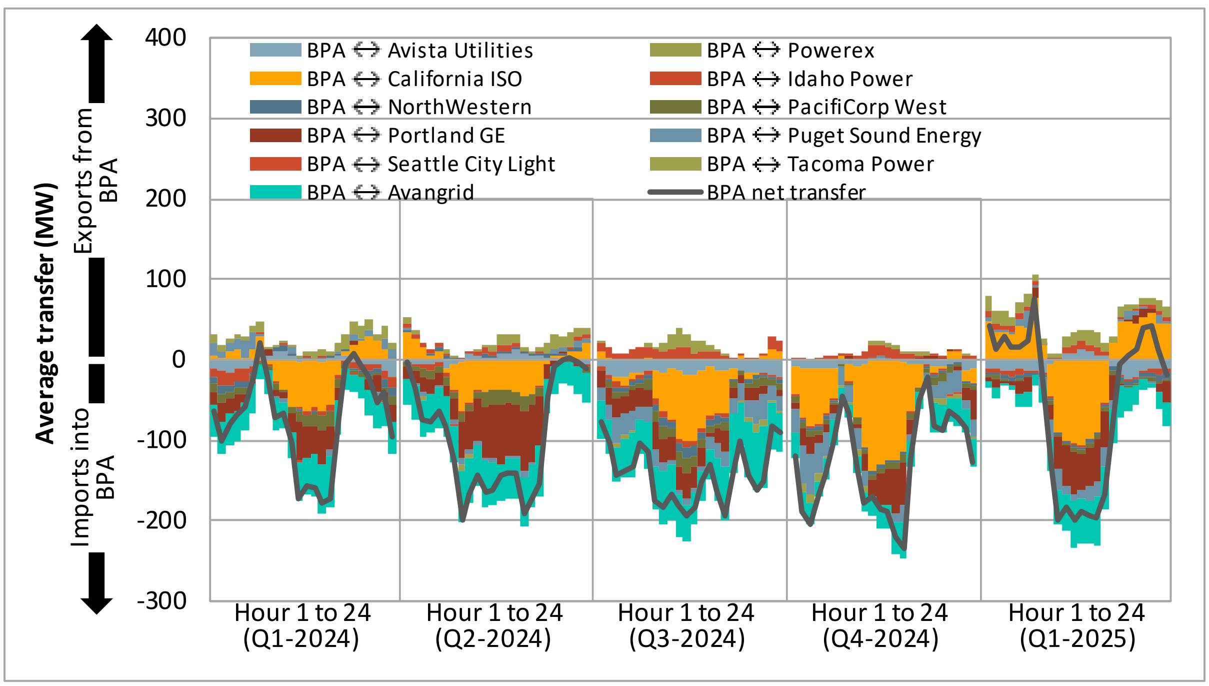
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q1 2025)

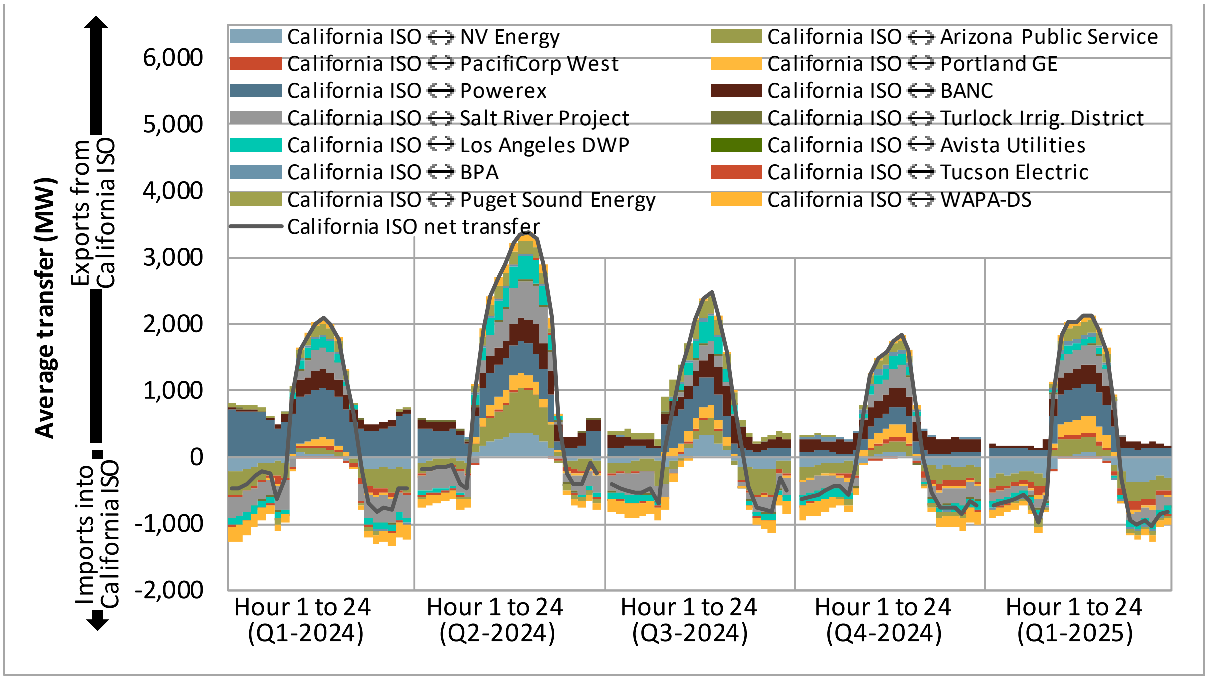


Appendix Figure A.20 Average hourly 5-minute market transfers

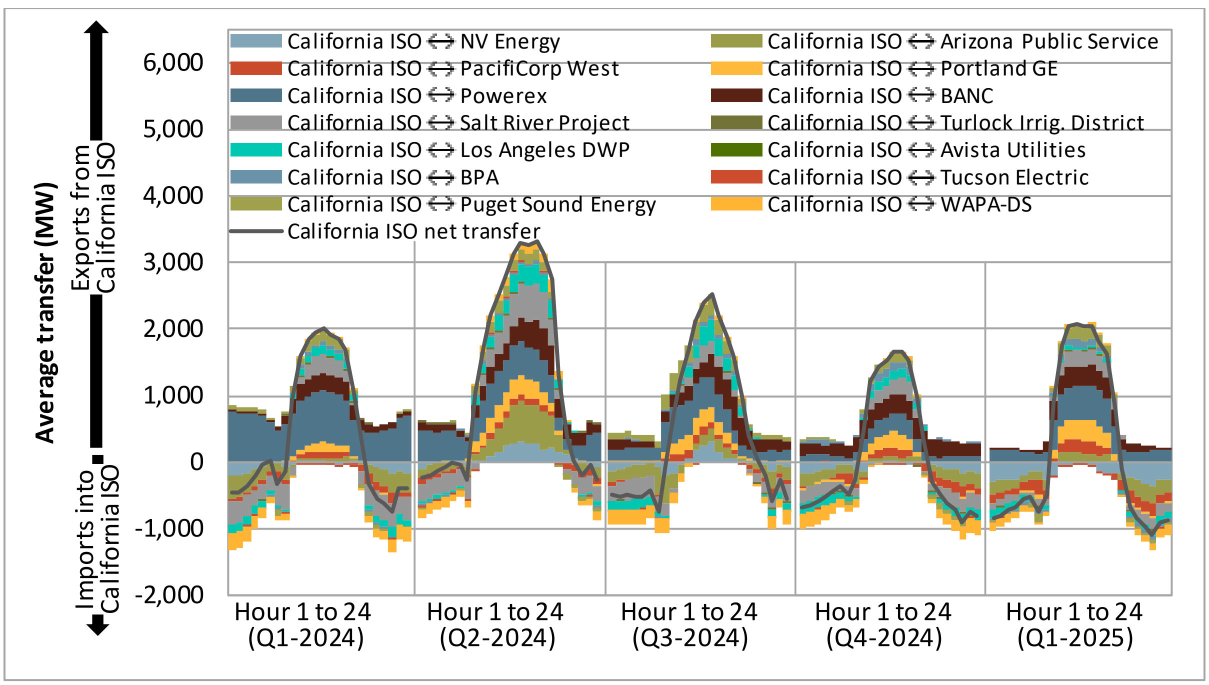


A.6 California ISO

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

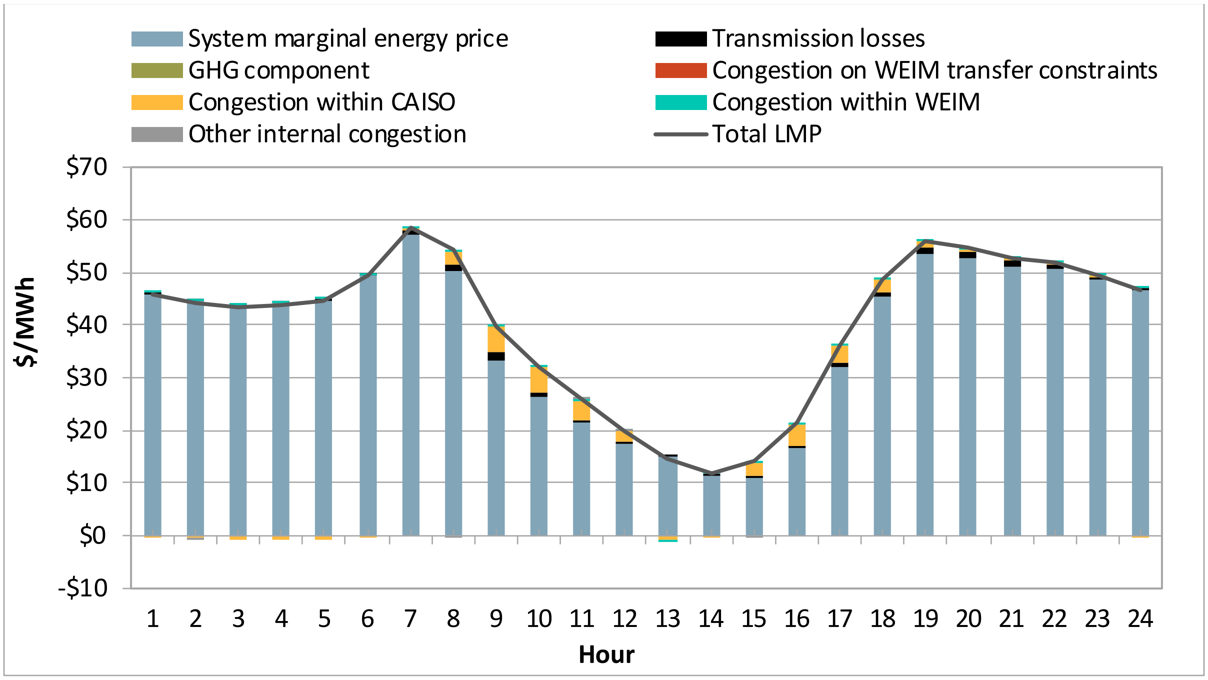


Appendix Figure A.22 Average hourly 5-minute market transfers

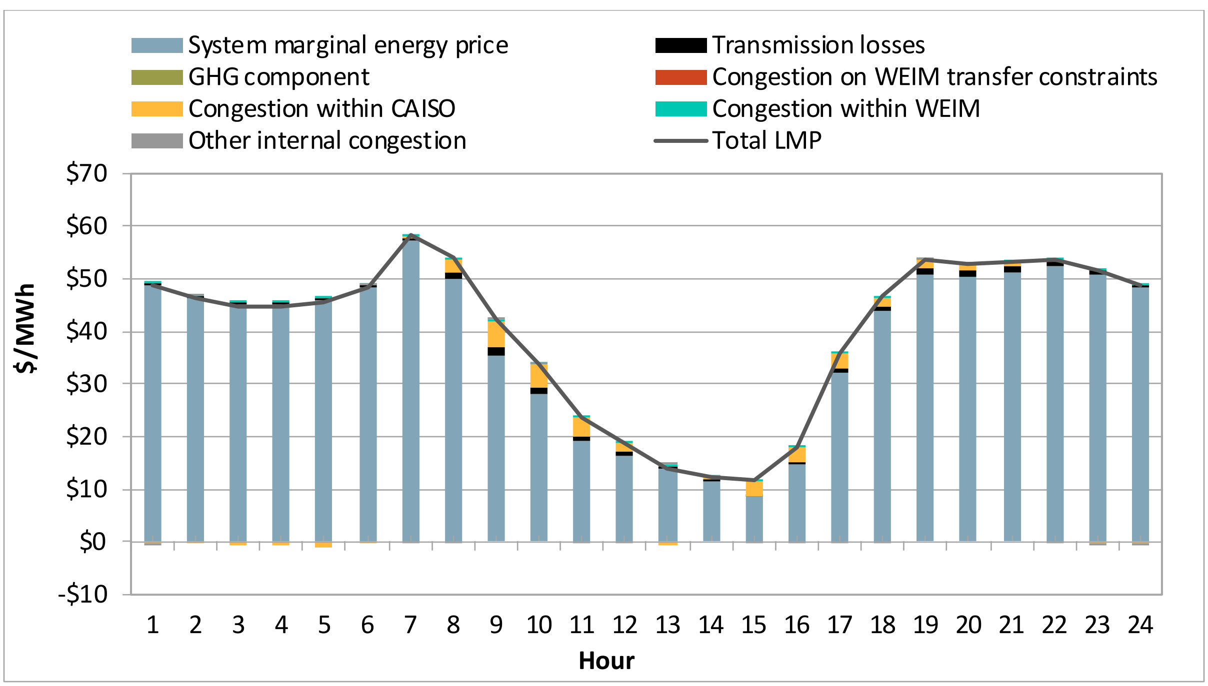


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q1 2025)

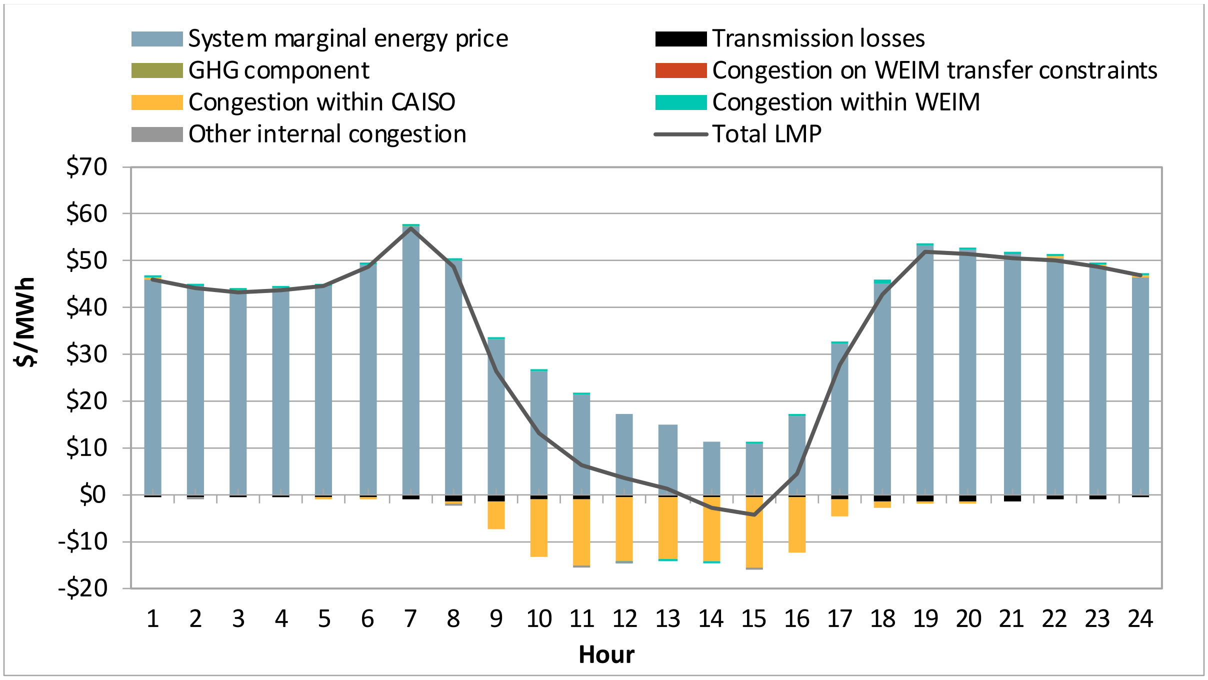


Appendix Figure A.24 Average hourly 5-minute price by component (Q1 2025)

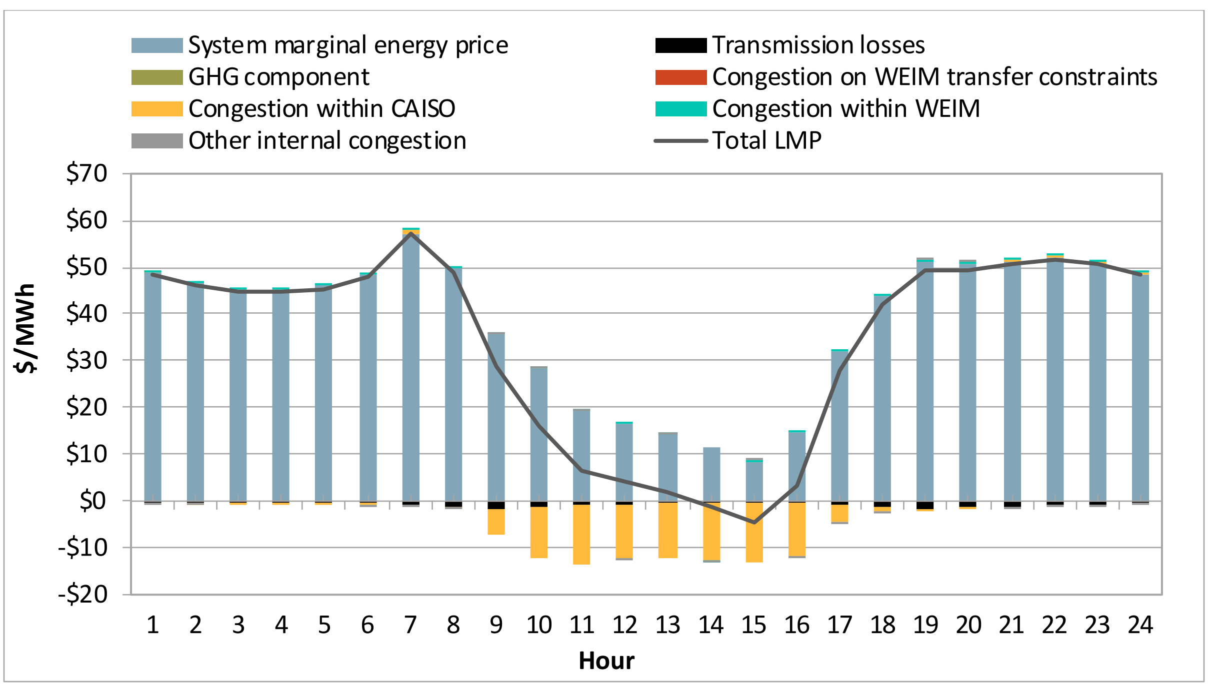


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q1 2025)

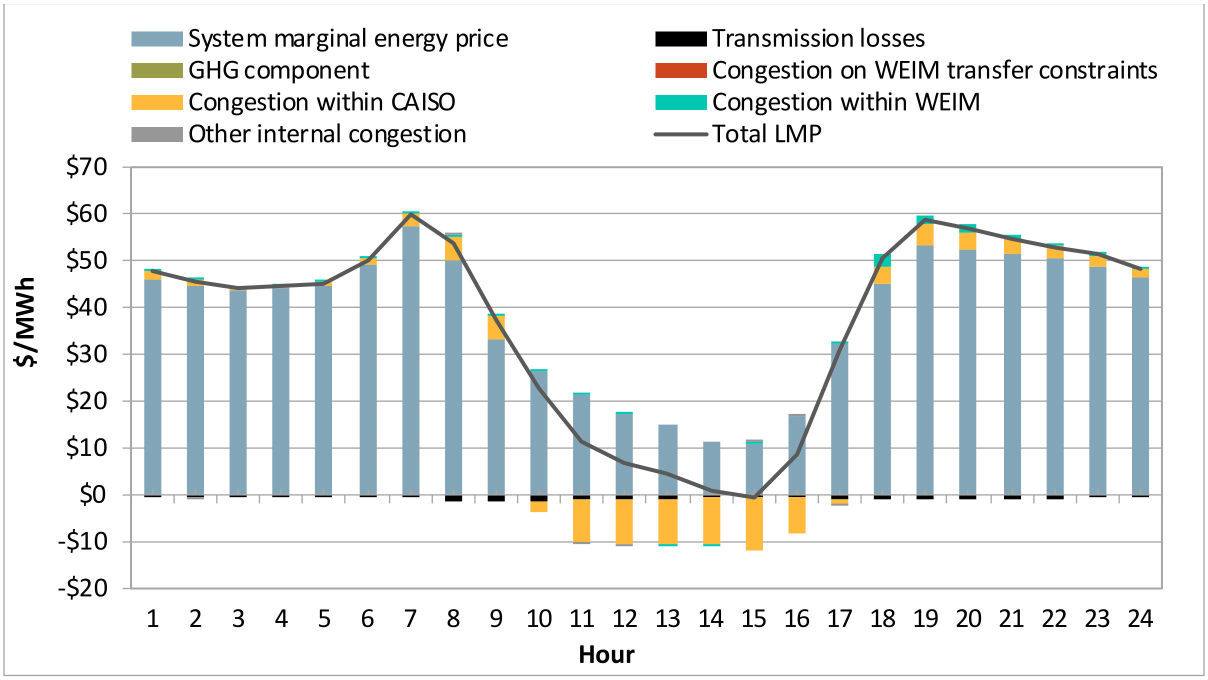


Appendix Figure A.26 Average hourly 5-minute price by component (Q1 2025)

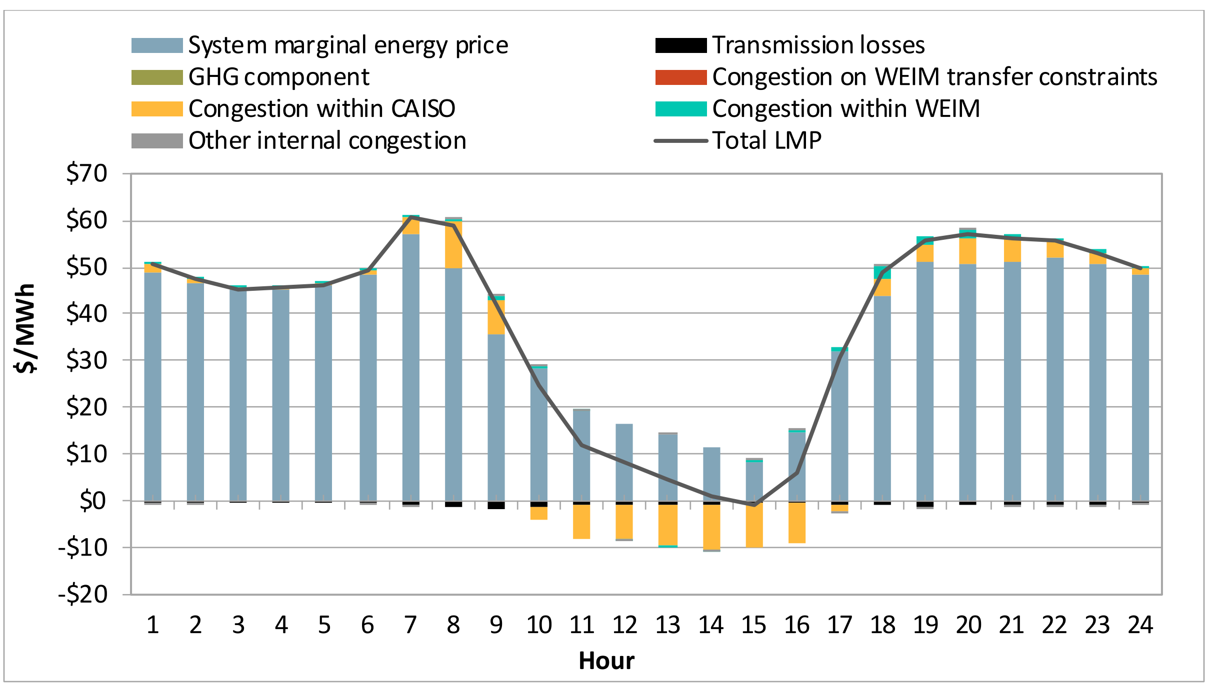


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q1 2025)

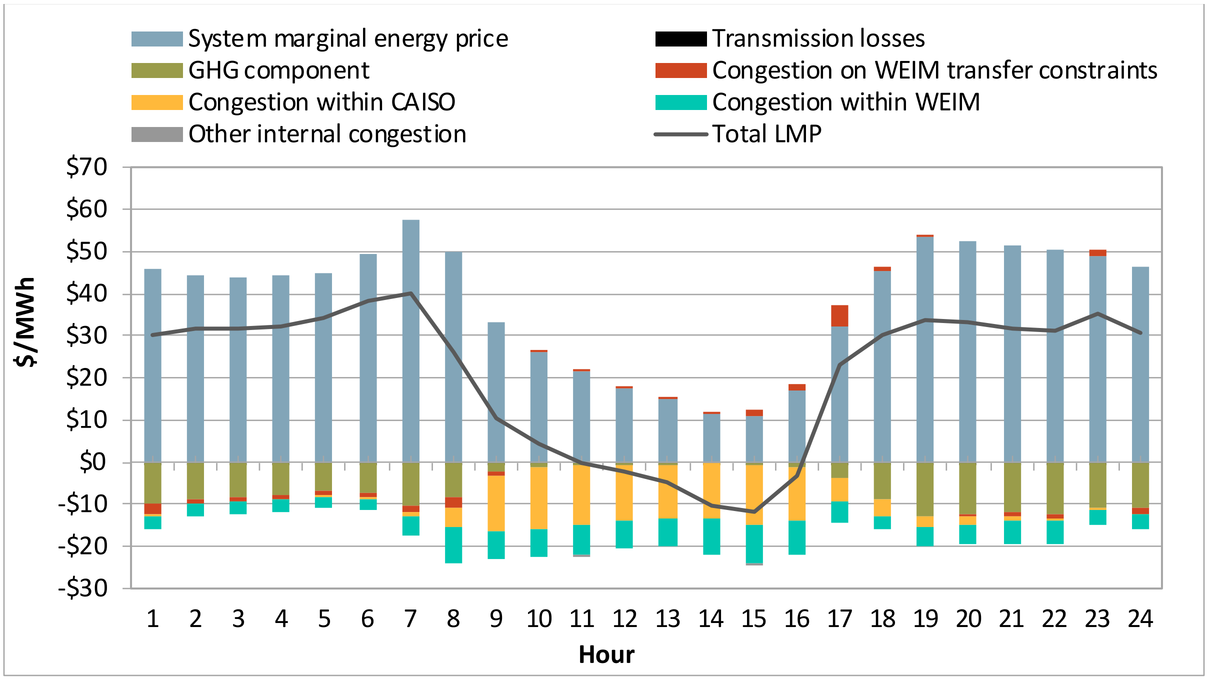


Appendix Figure A.28 Average hourly 5-minute price by component (Q1 2025)

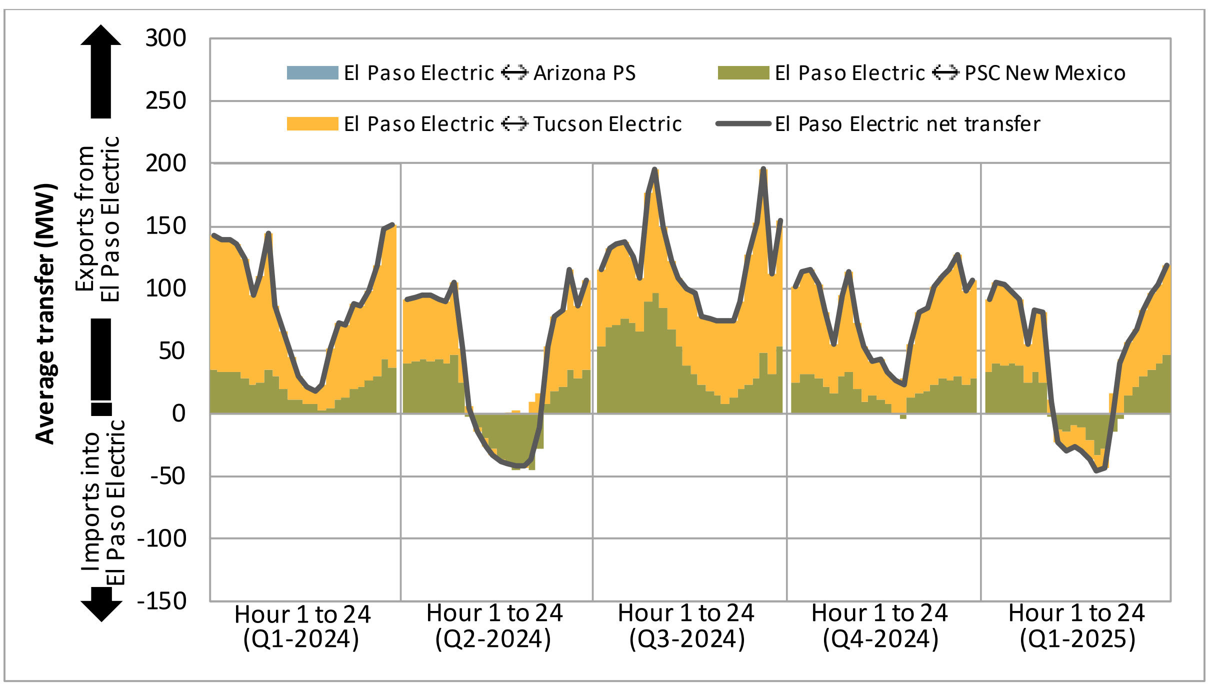


A.7 El Paso Electric

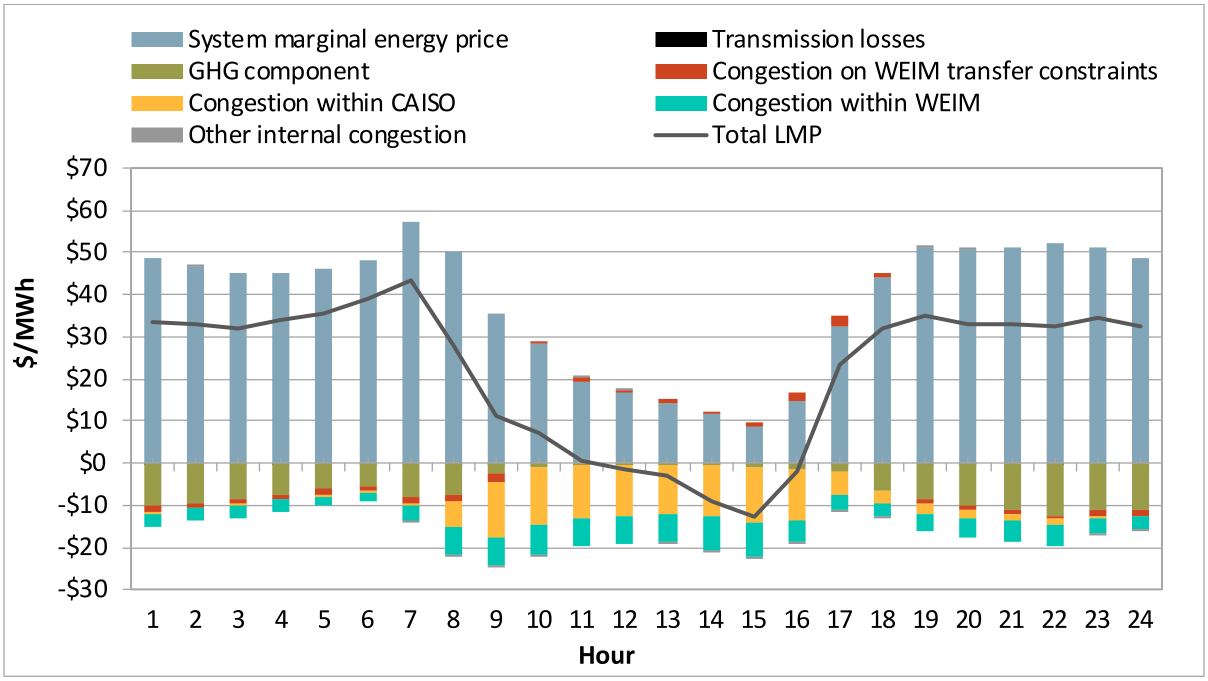
Appendix Figure A.29 Average hourly 15-minute price by component (Q1 2025)



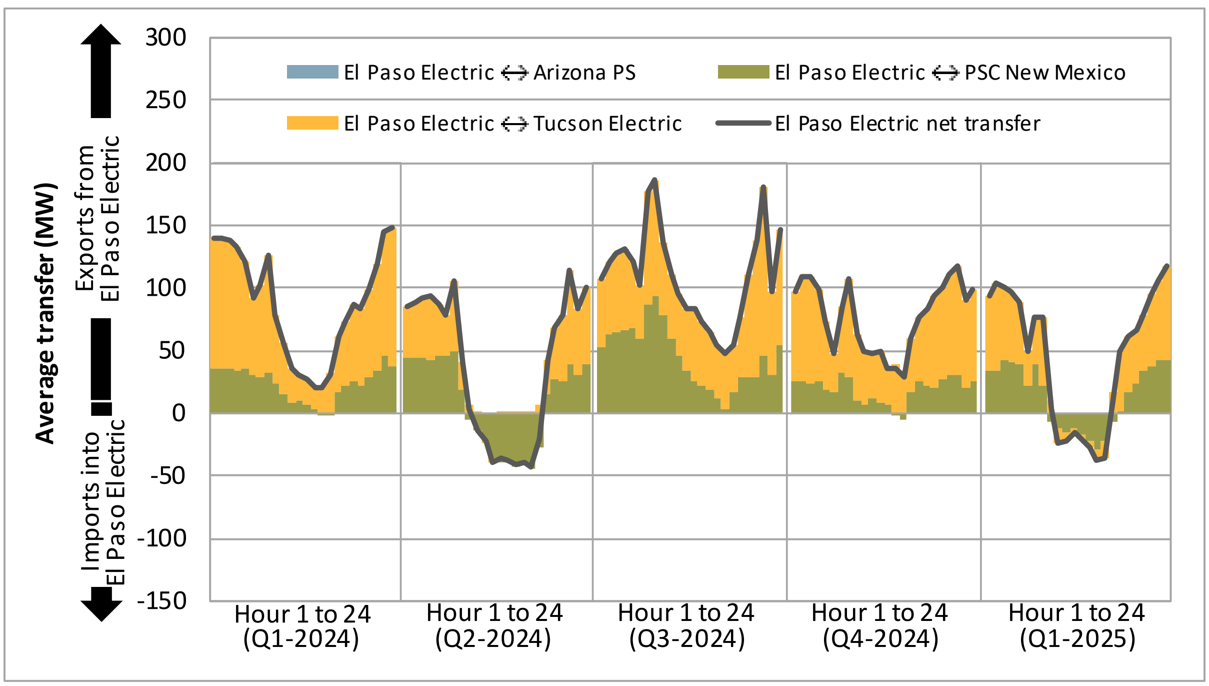
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q1 2025)

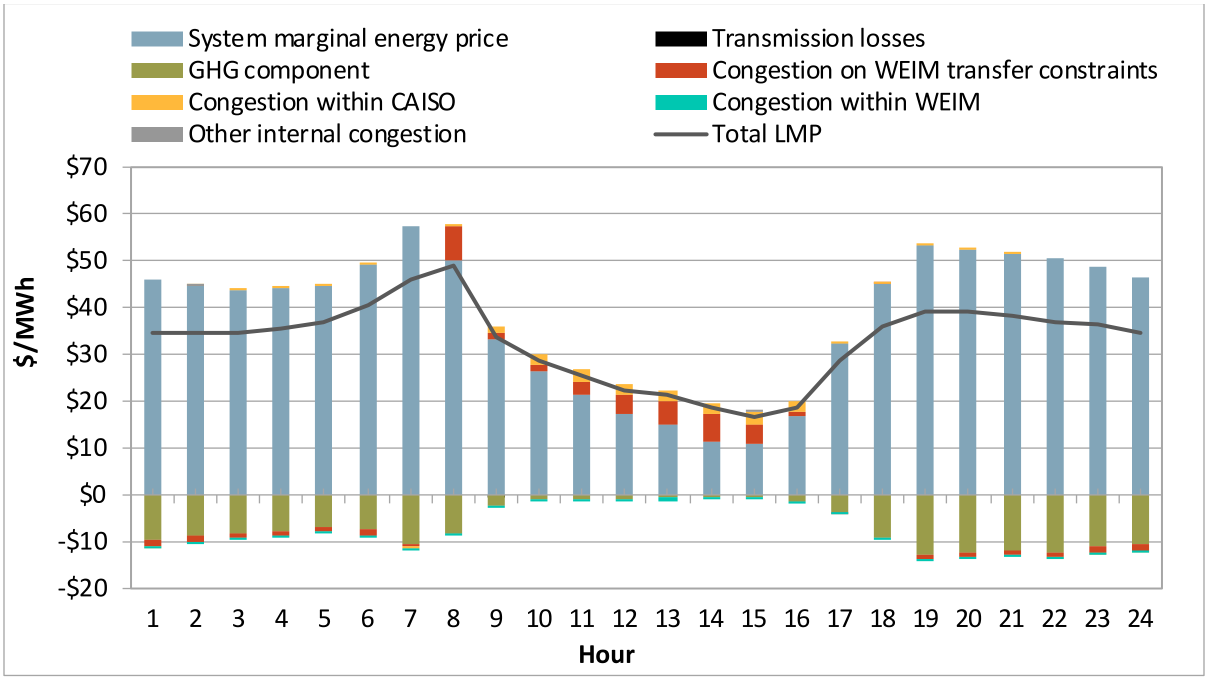


Appendix Figure A.32 Average hourly 5-minute market transfers

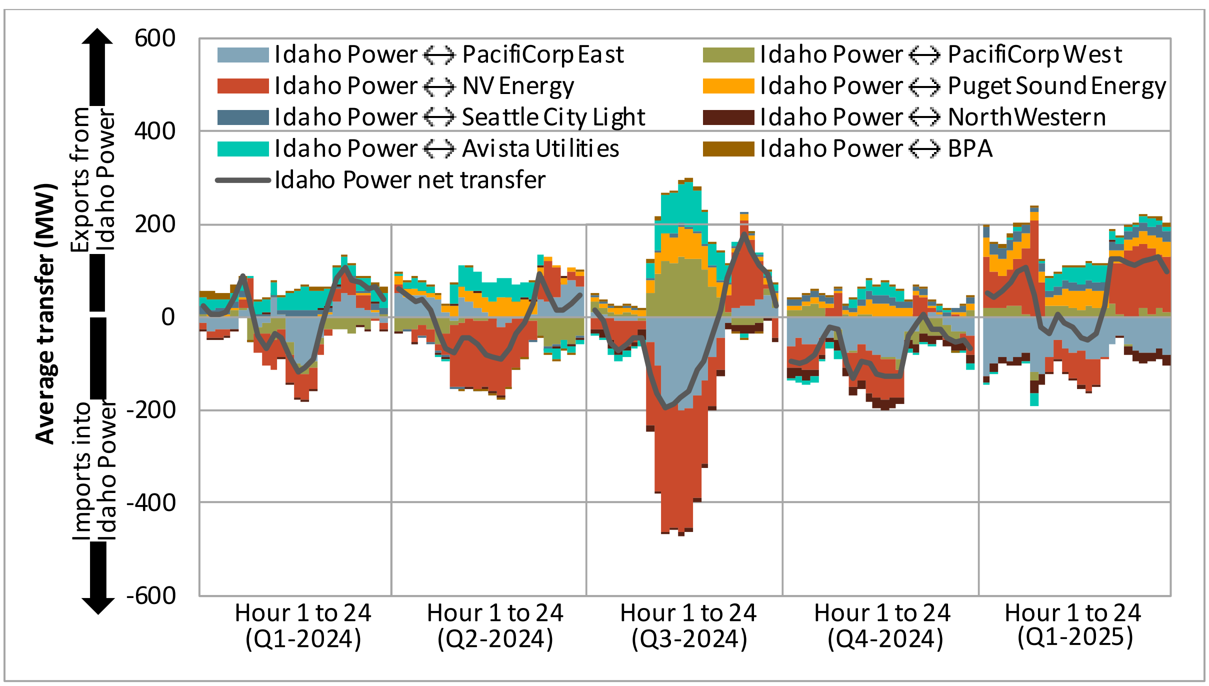


A.8 Idaho Power

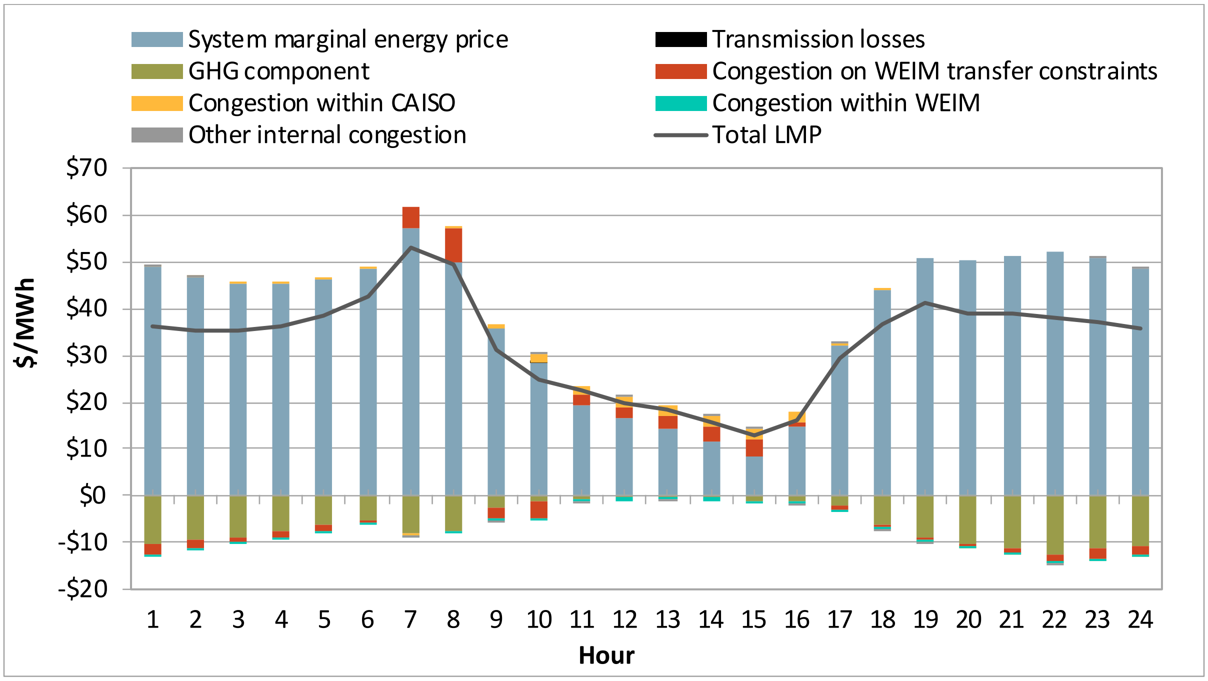
Appendix Figure A.33 Average hourly 15-minute price by component (Q1 2025)



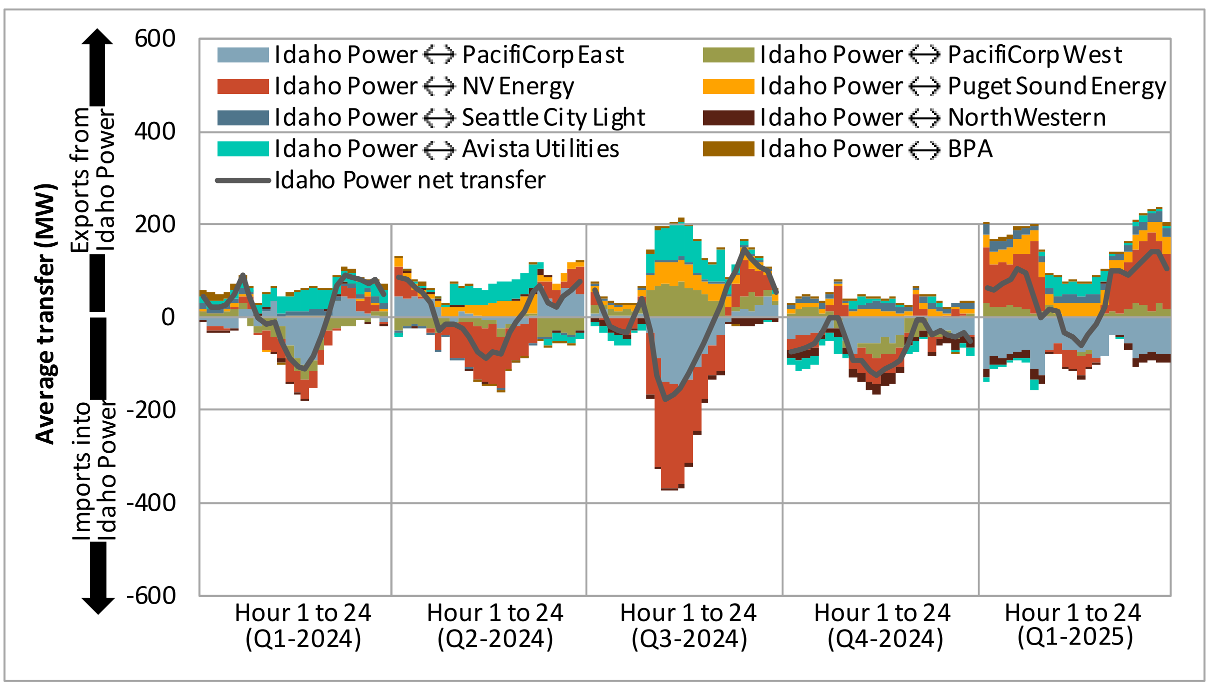
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q1 2025)

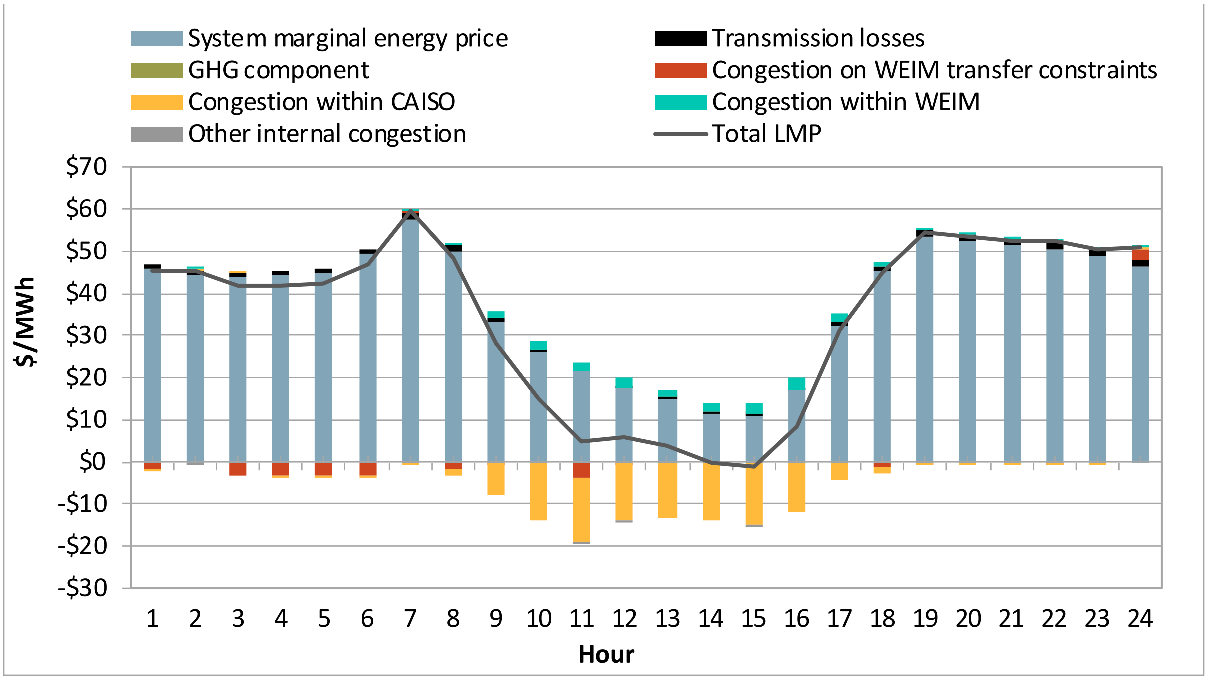


Appendix Figure A.36 Average hourly 5-minute market transfers

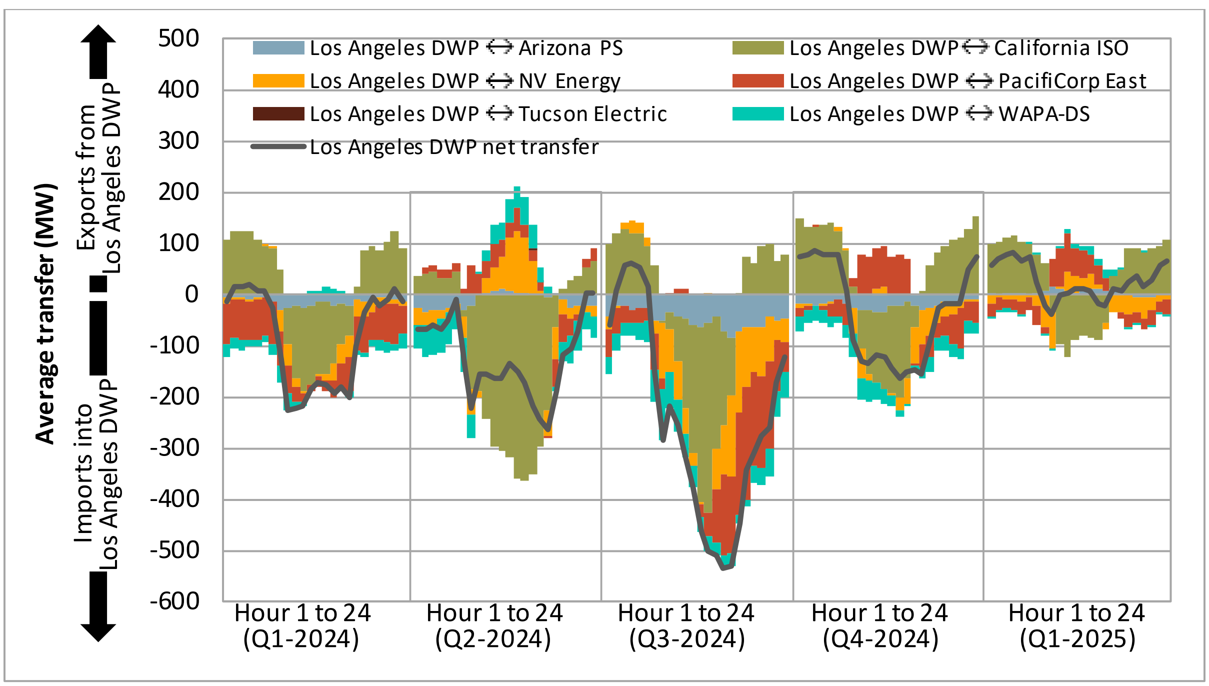


A.9 Los Angeles Department of Water and Power

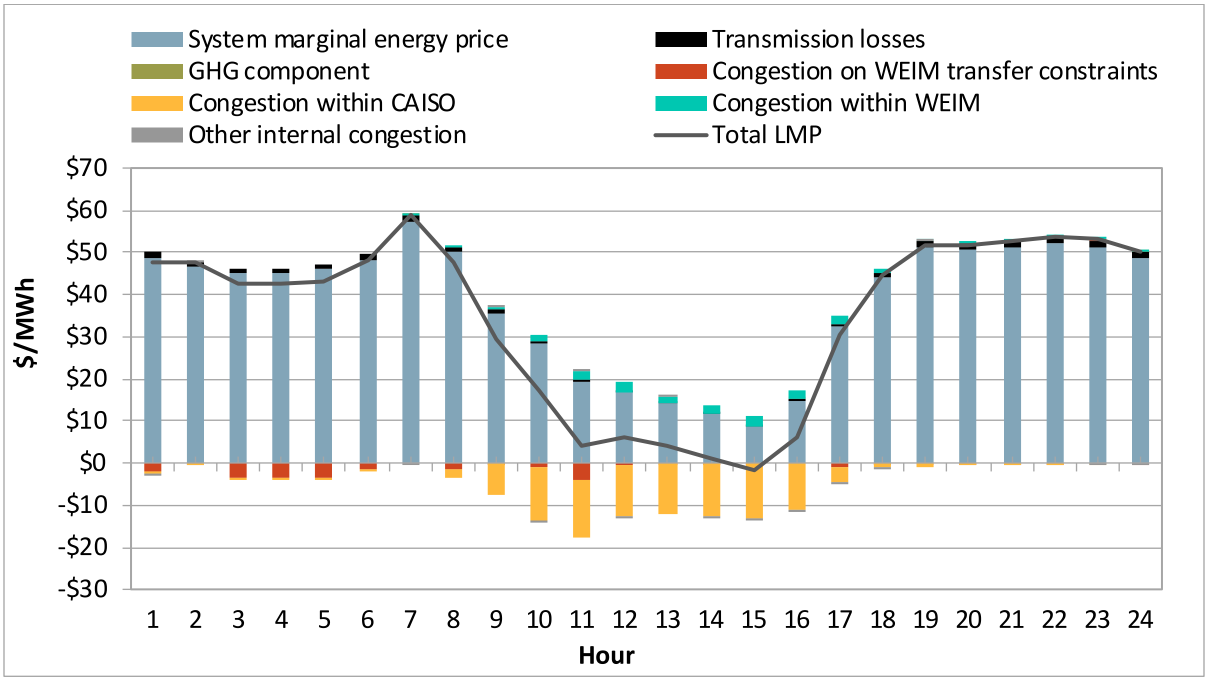
Appendix Figure A.37 Average hourly 15-minute price by component (Q1 2025)



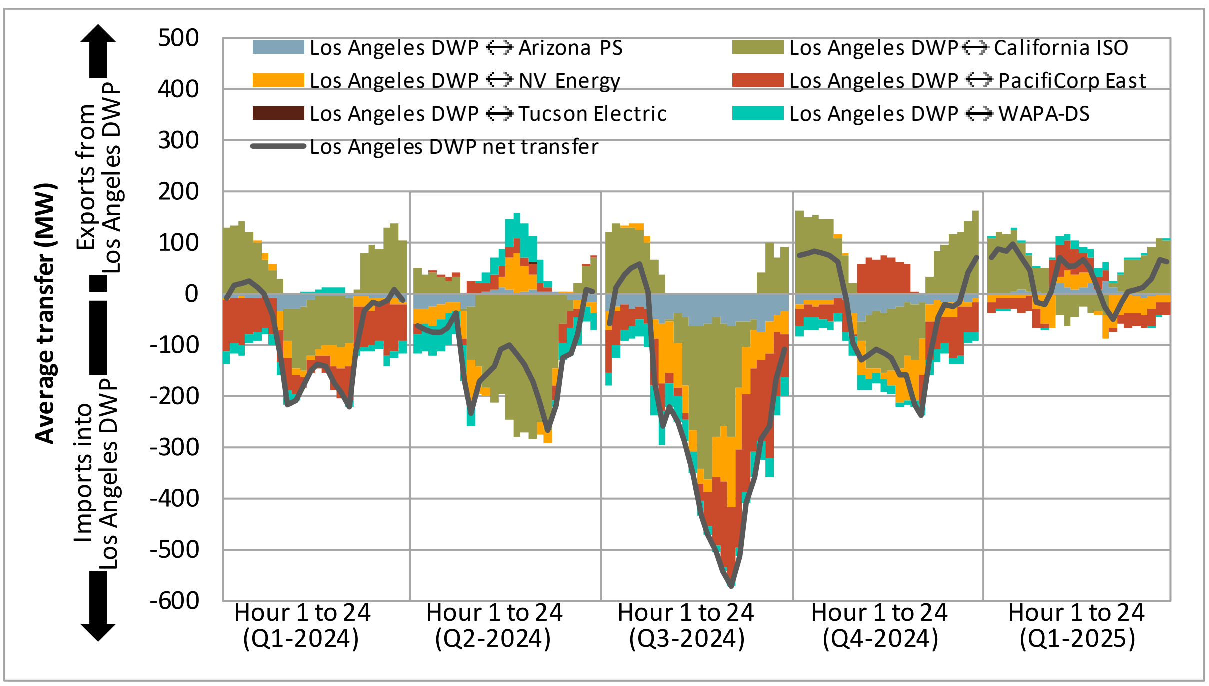
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q1 2025)

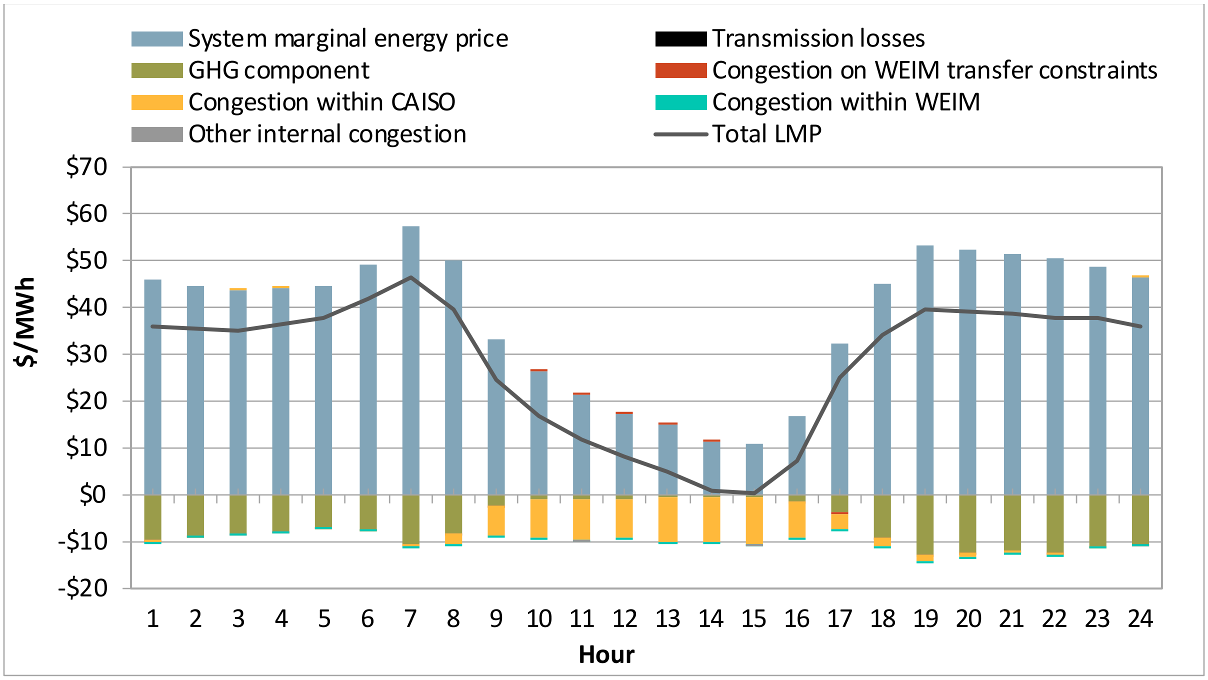


Appendix Figure A.40 Average hourly 5-minute market transfers

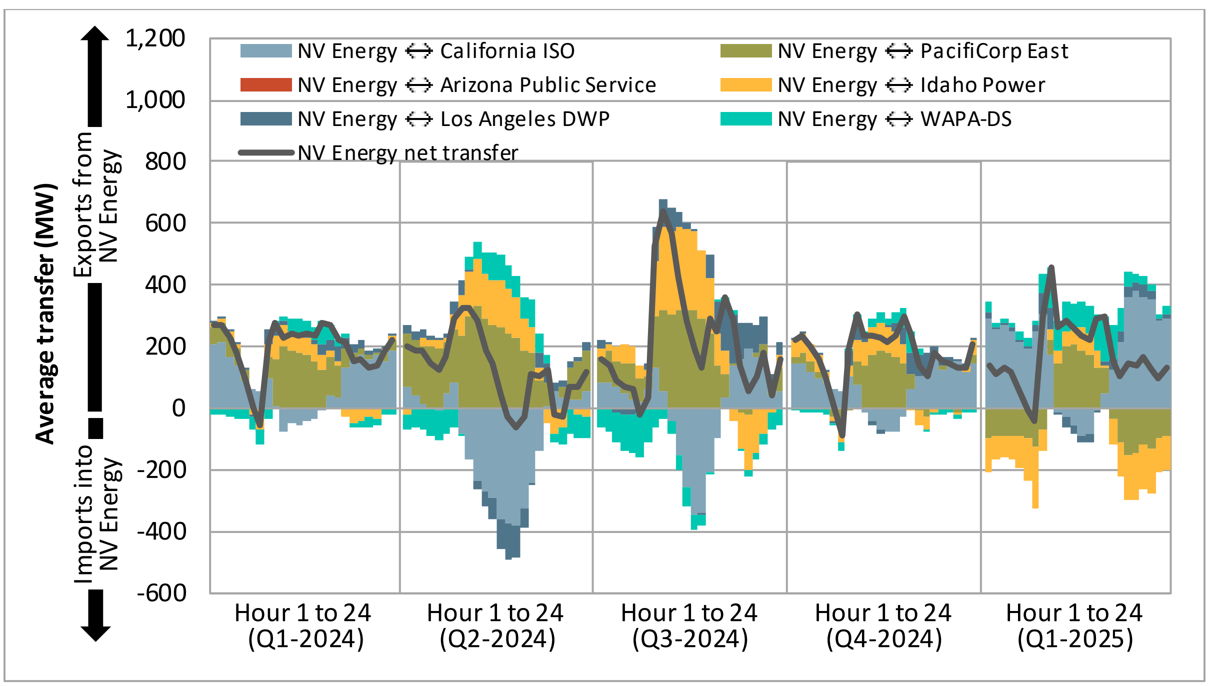


A.10 NV Energy

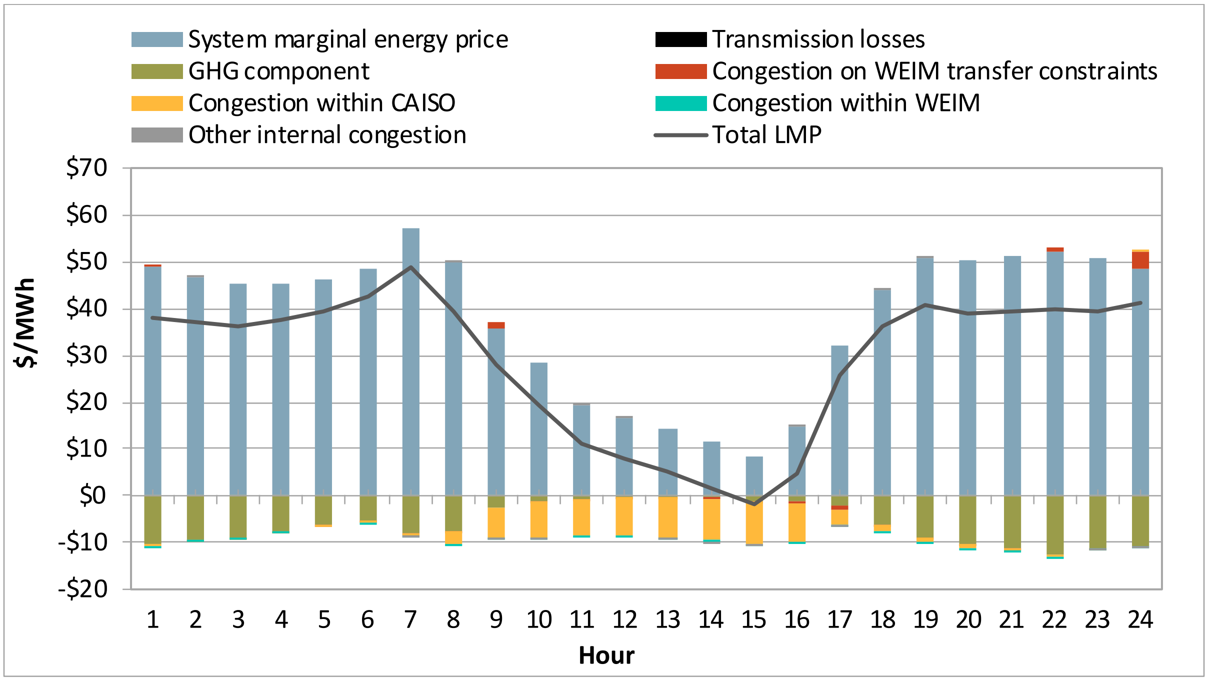
Appendix Figure A.41 Average hourly 15-minute price by component (Q1 2025)



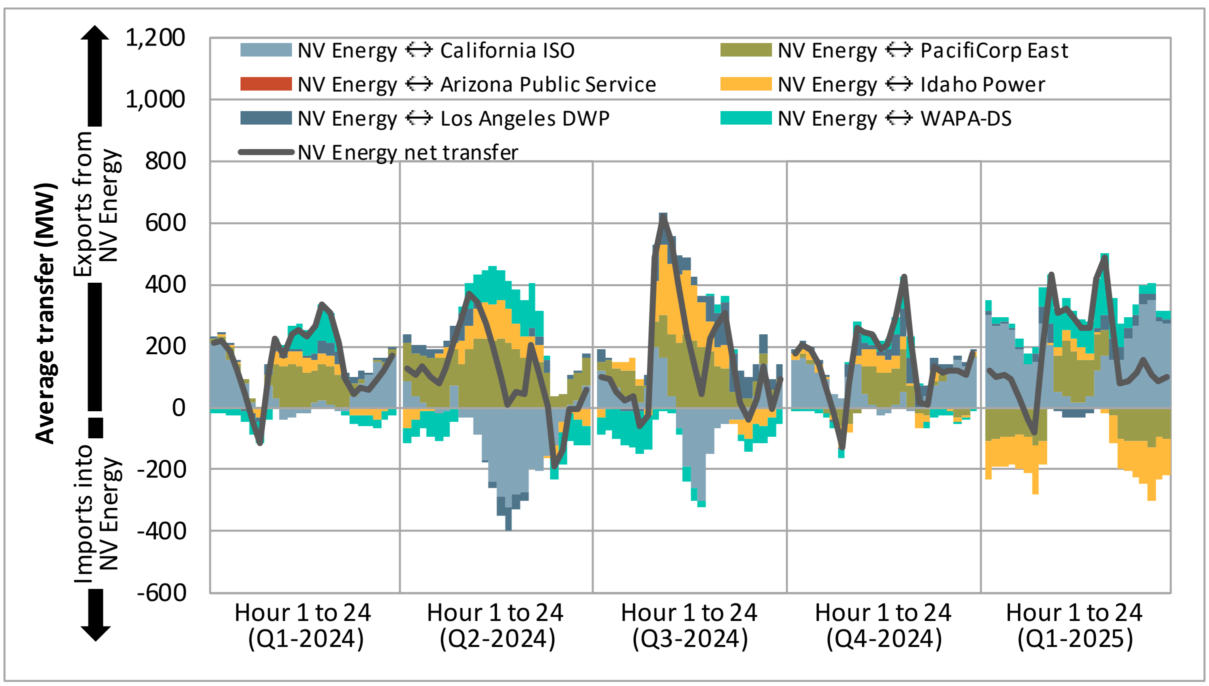
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q1 2025)

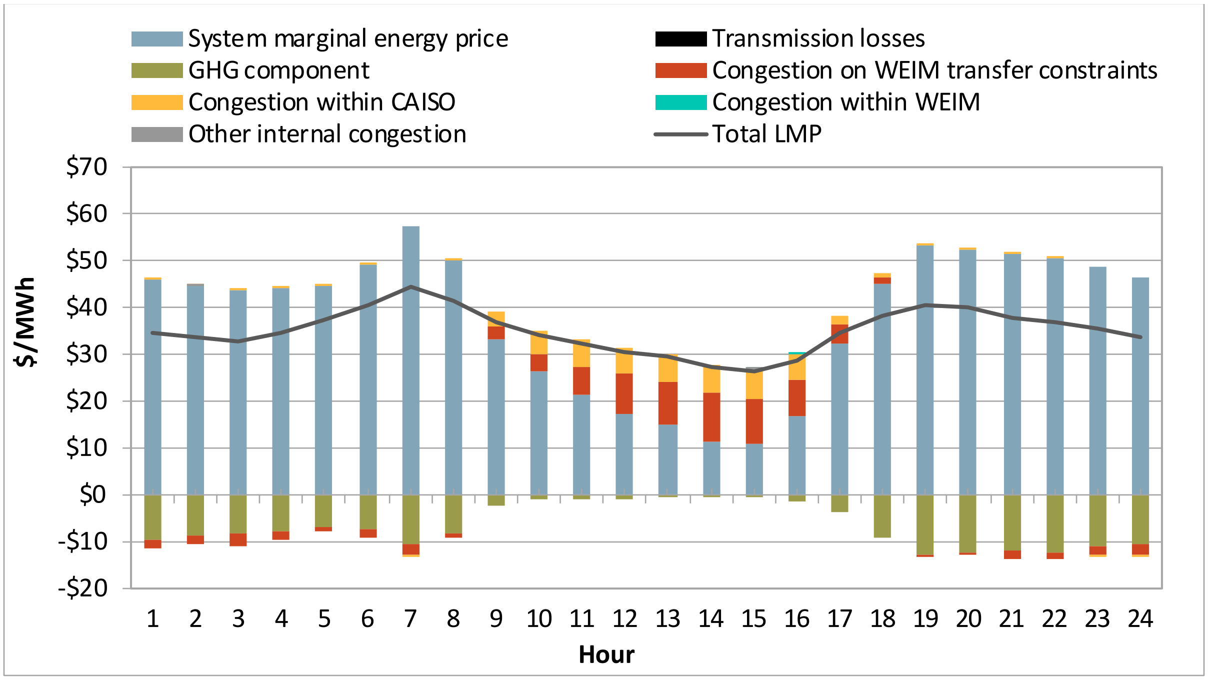


Appendix Figure A.44 Average hourly 5-minute market transfers

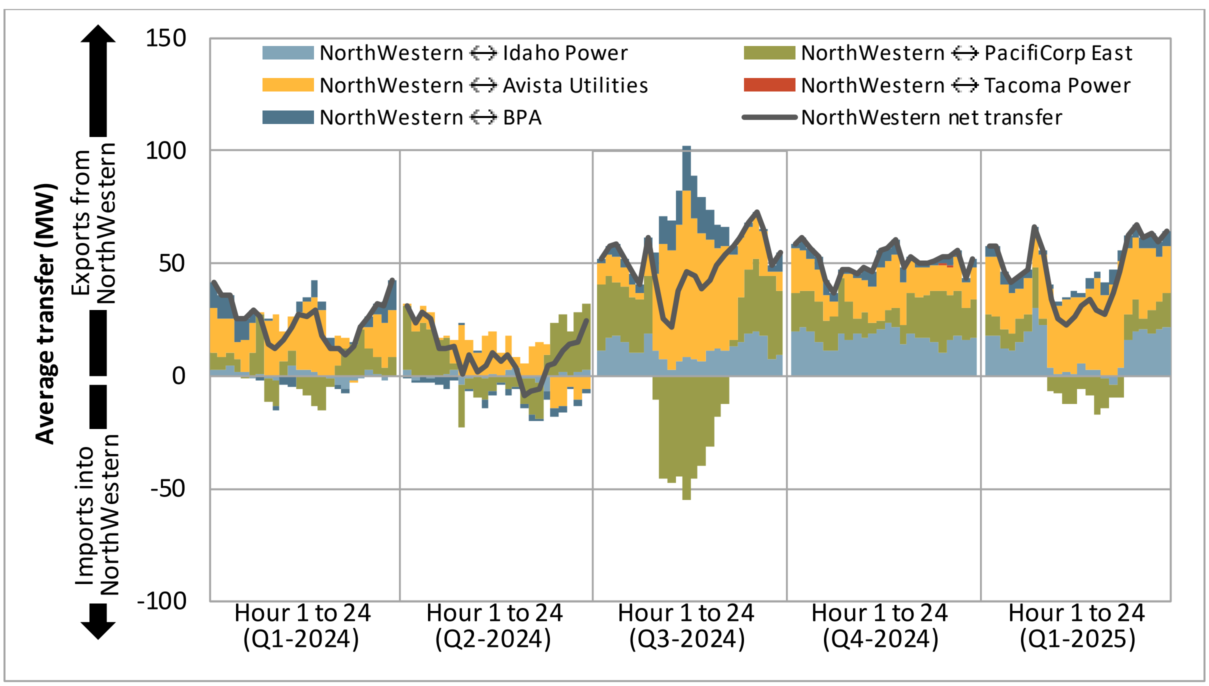


A.11 NorthWestern Energy

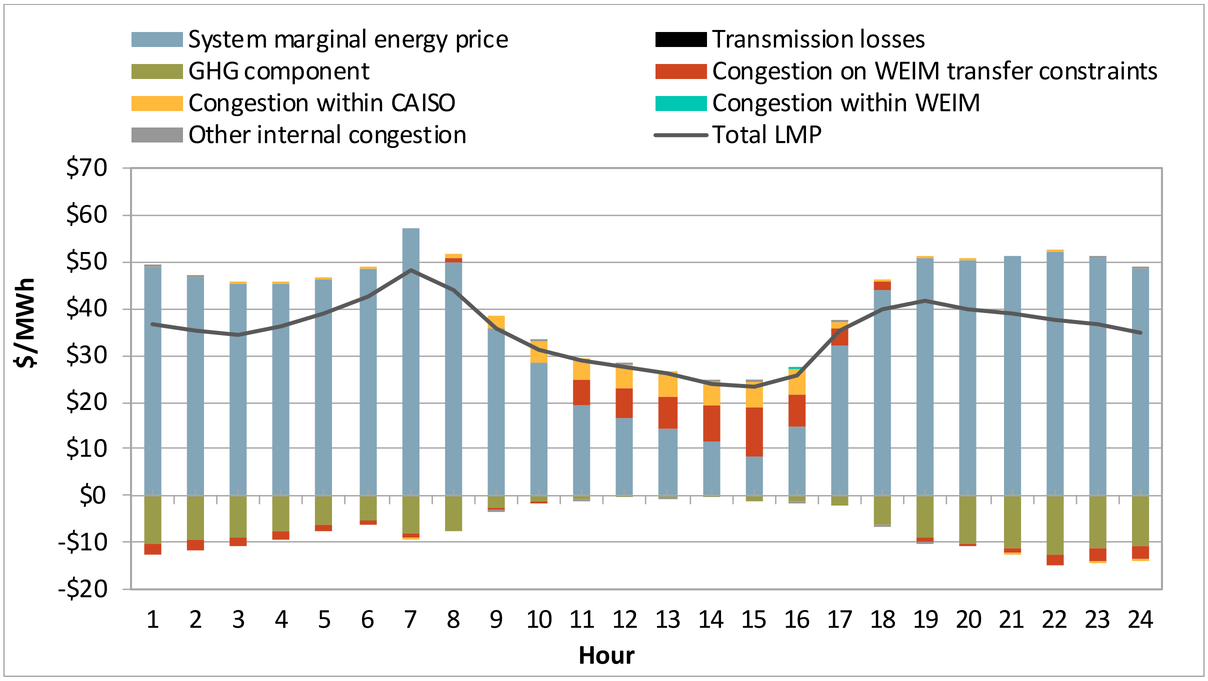
Appendix Figure A.45 Average hourly 15-minute price by component (Q1 2025)



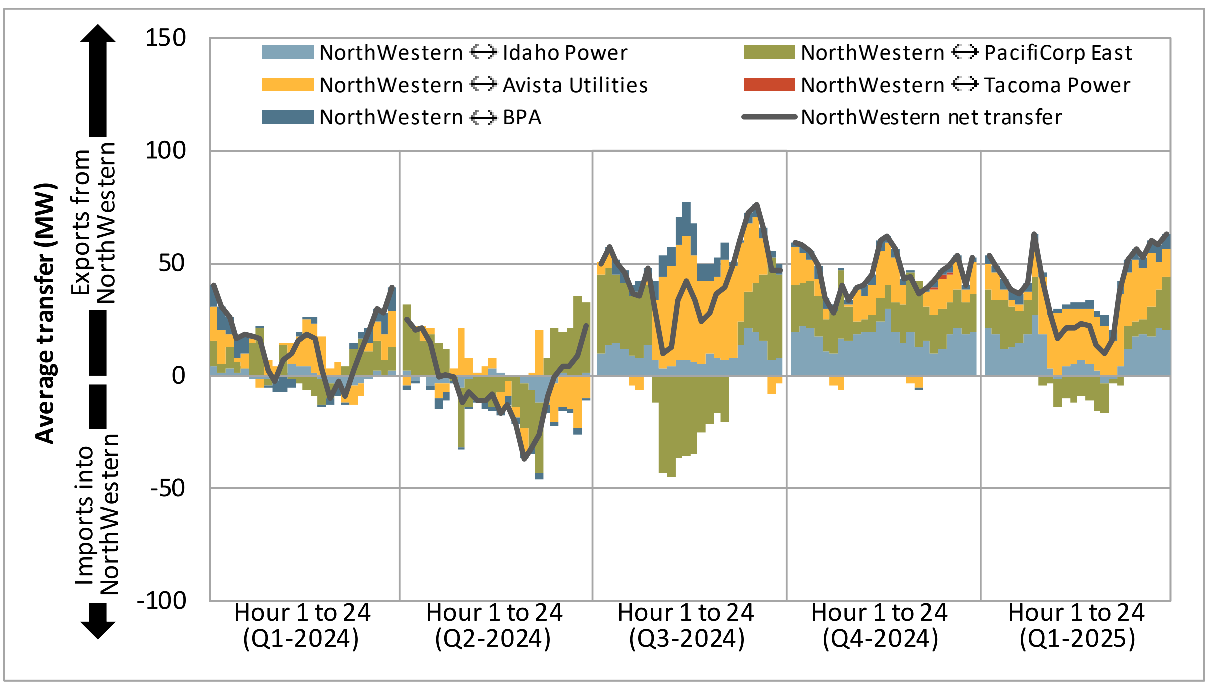
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q1 2025)

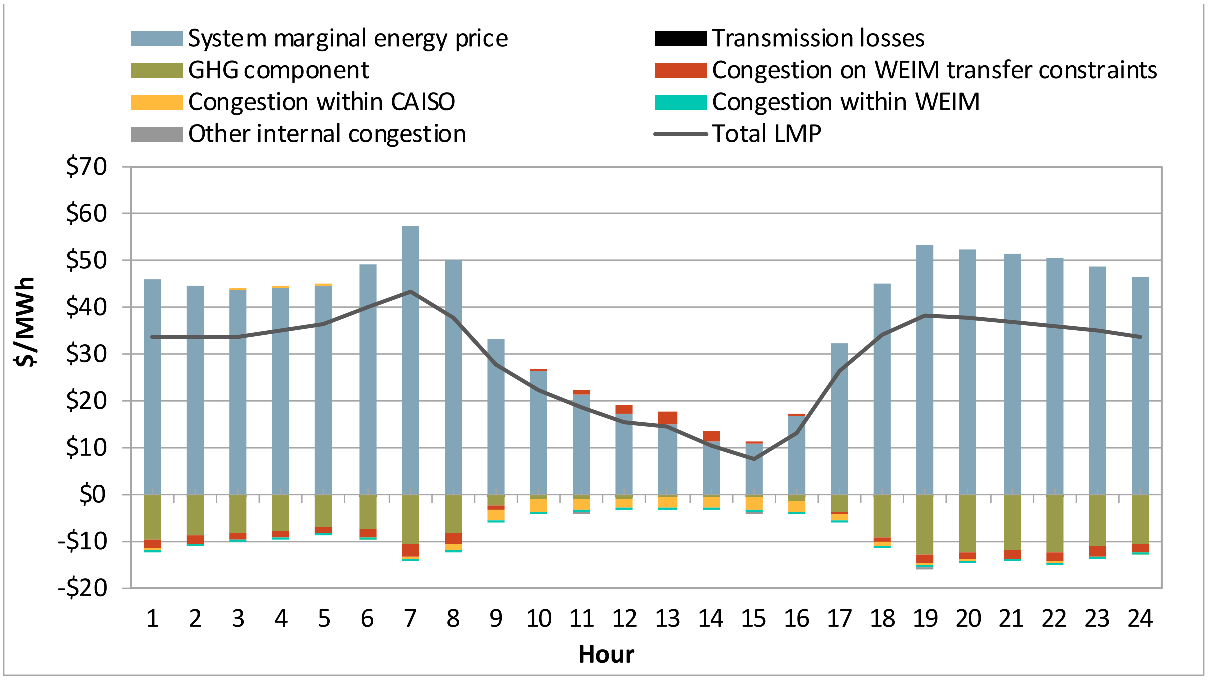


Appendix Figure A.48 Average hourly 5-minute market transfers

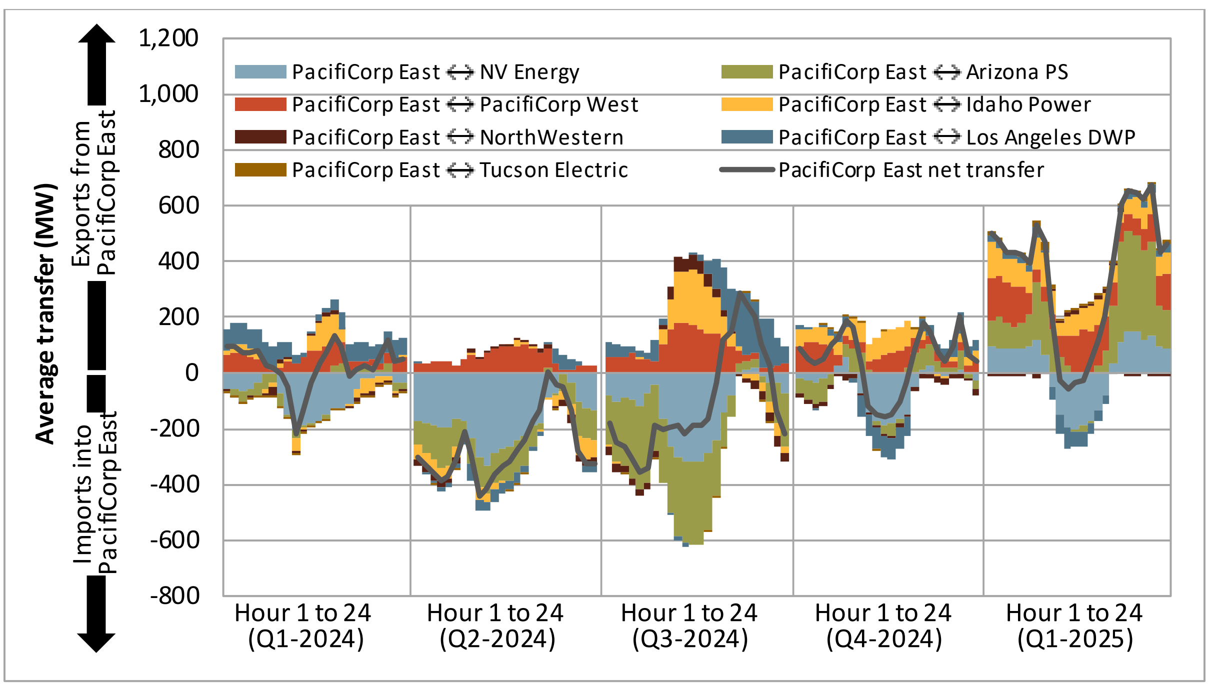


A.12 PacifiCorp East

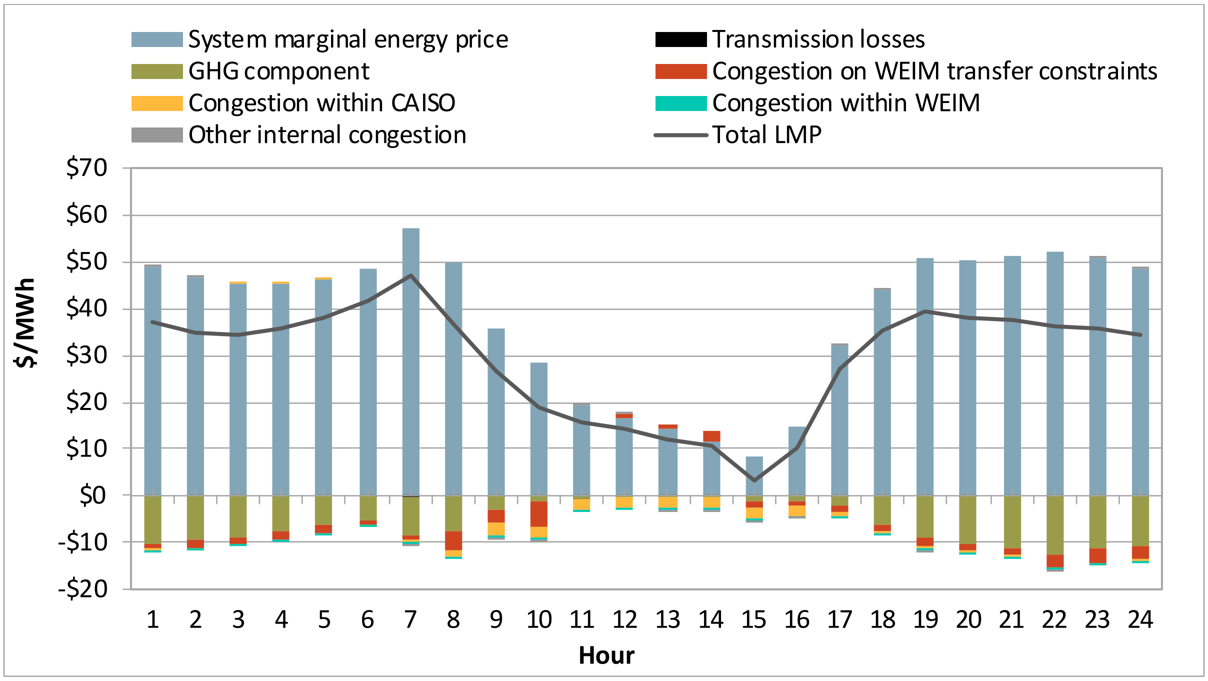
Appendix Figure A.49 Average hourly 15-minute price by component (Q1 2025)



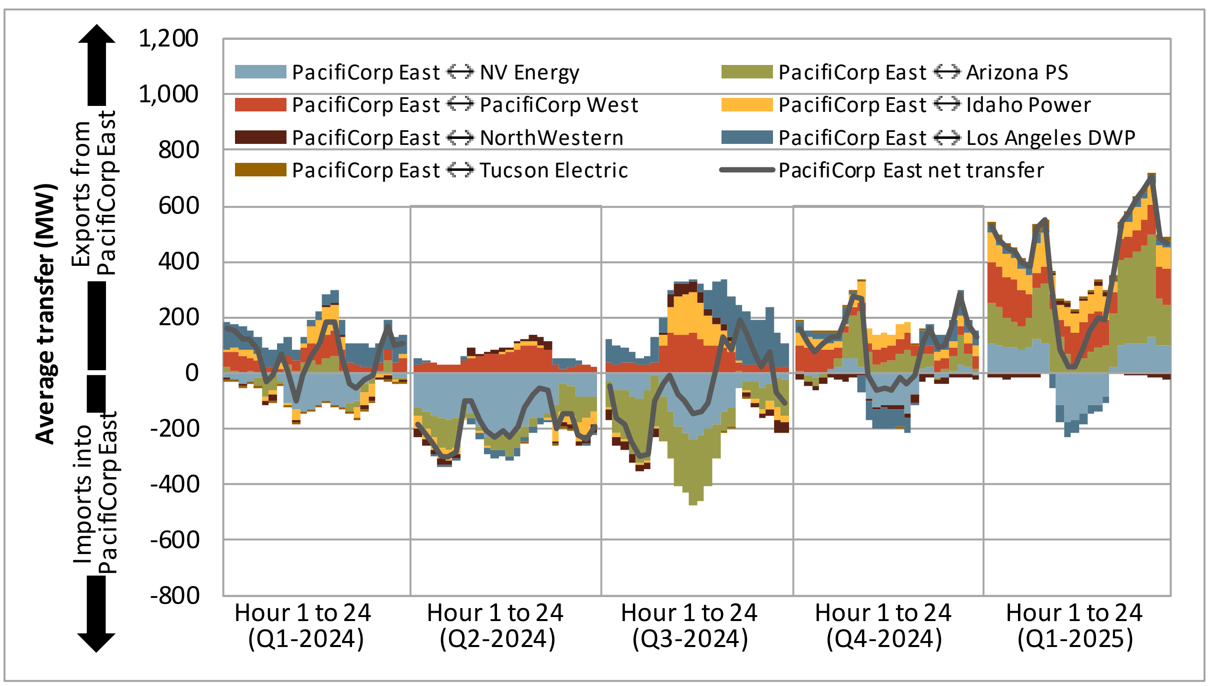
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q1 2025)

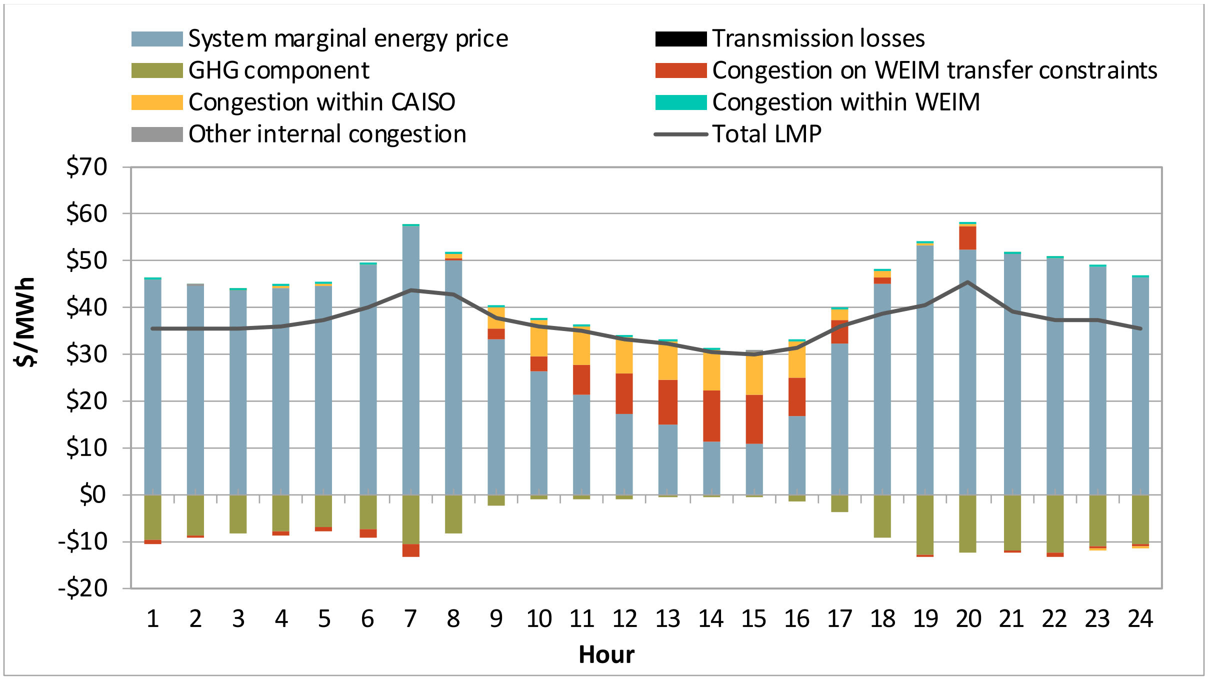


Appendix Figure A.52 Average hourly 5-minute market transfers

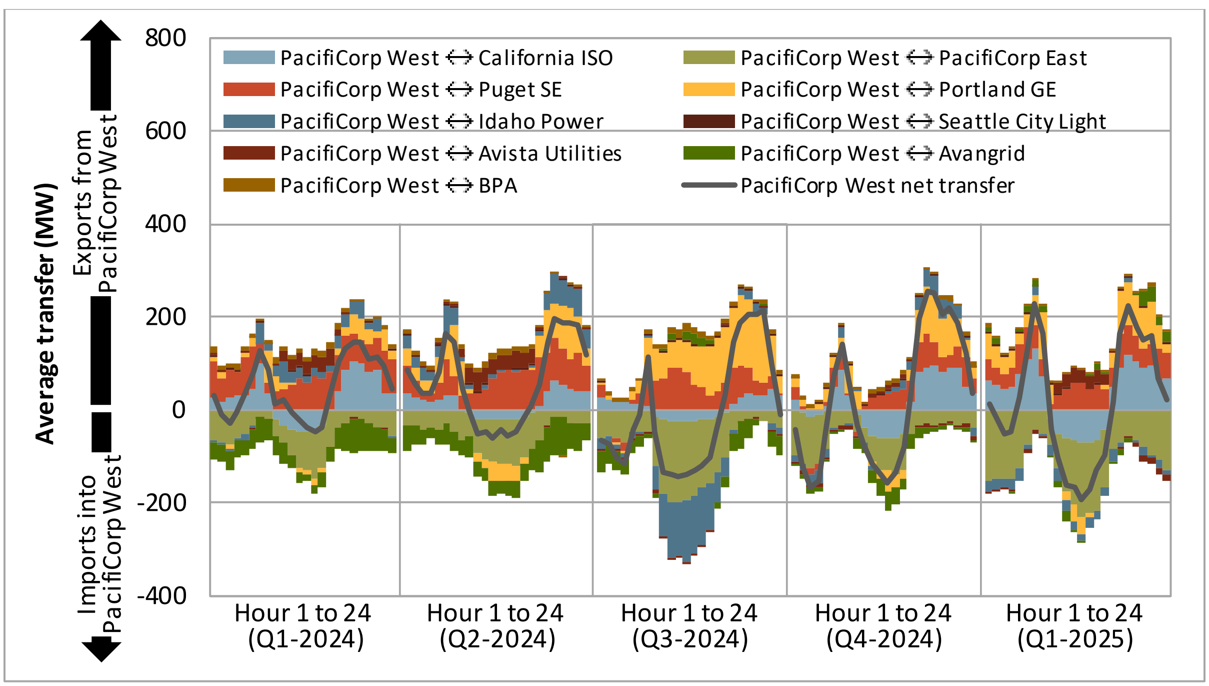


A.13 PacifiCorp West

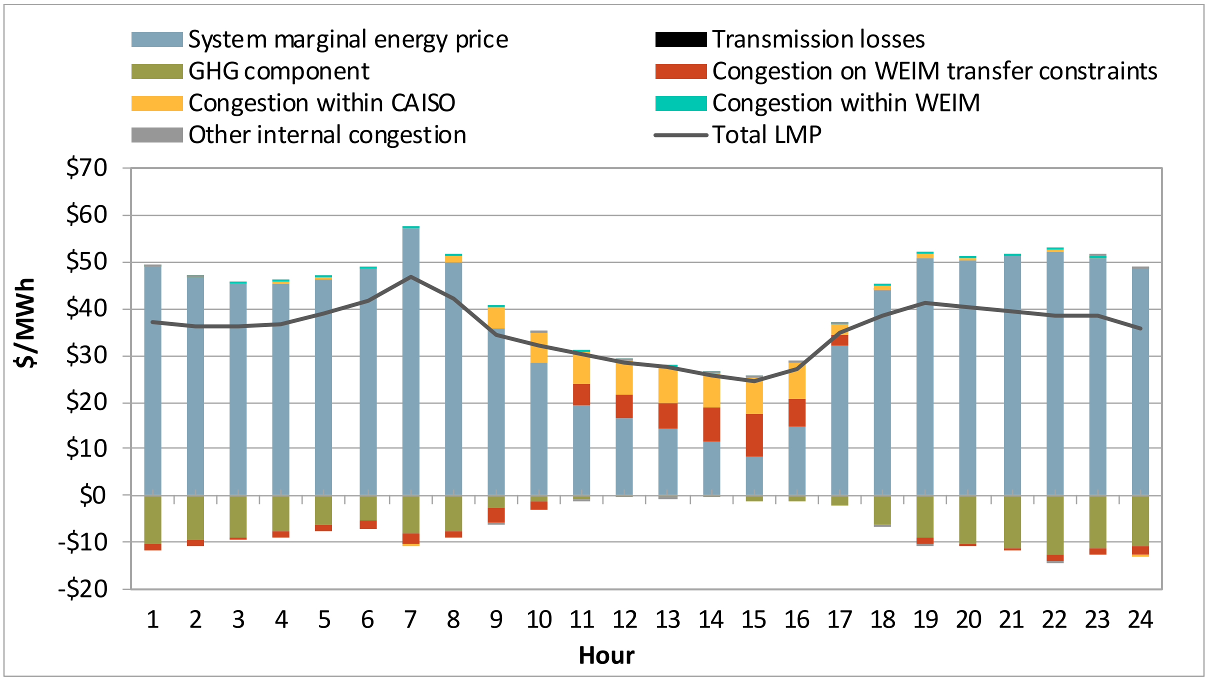
Appendix Figure A.53 Average hourly 15-minute price by component (Q1 2025)



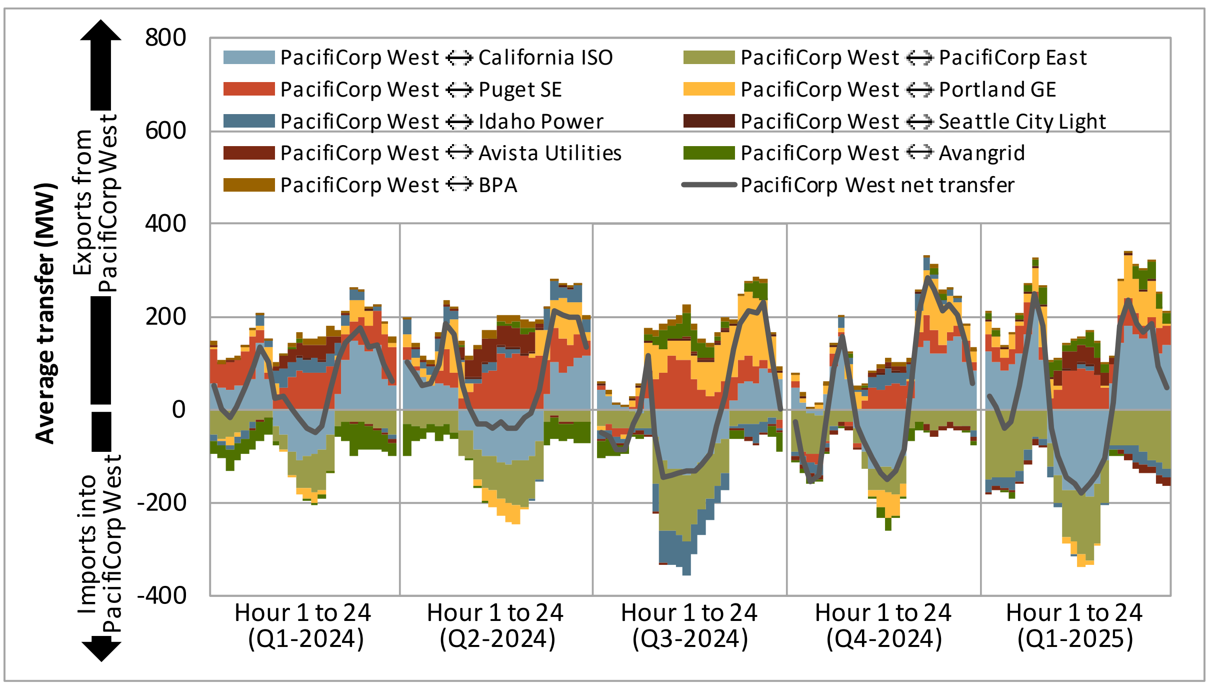
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q1 2025)

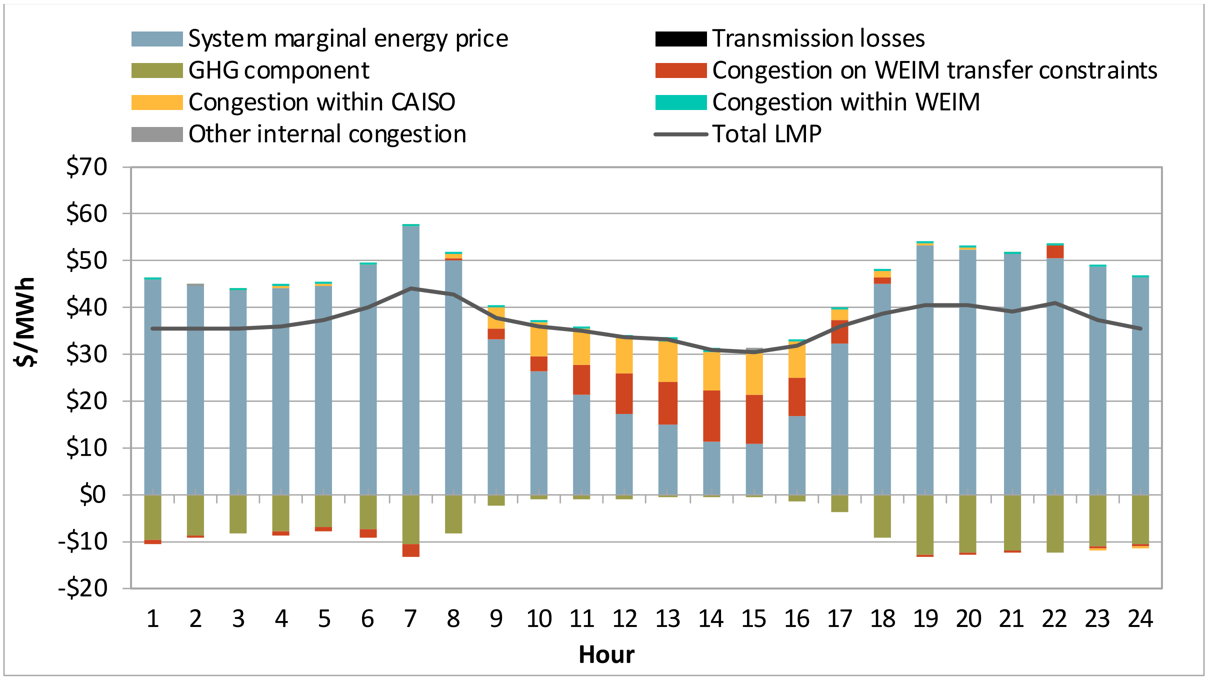


Appendix Figure A.56 Average hourly 5-minute market transfers

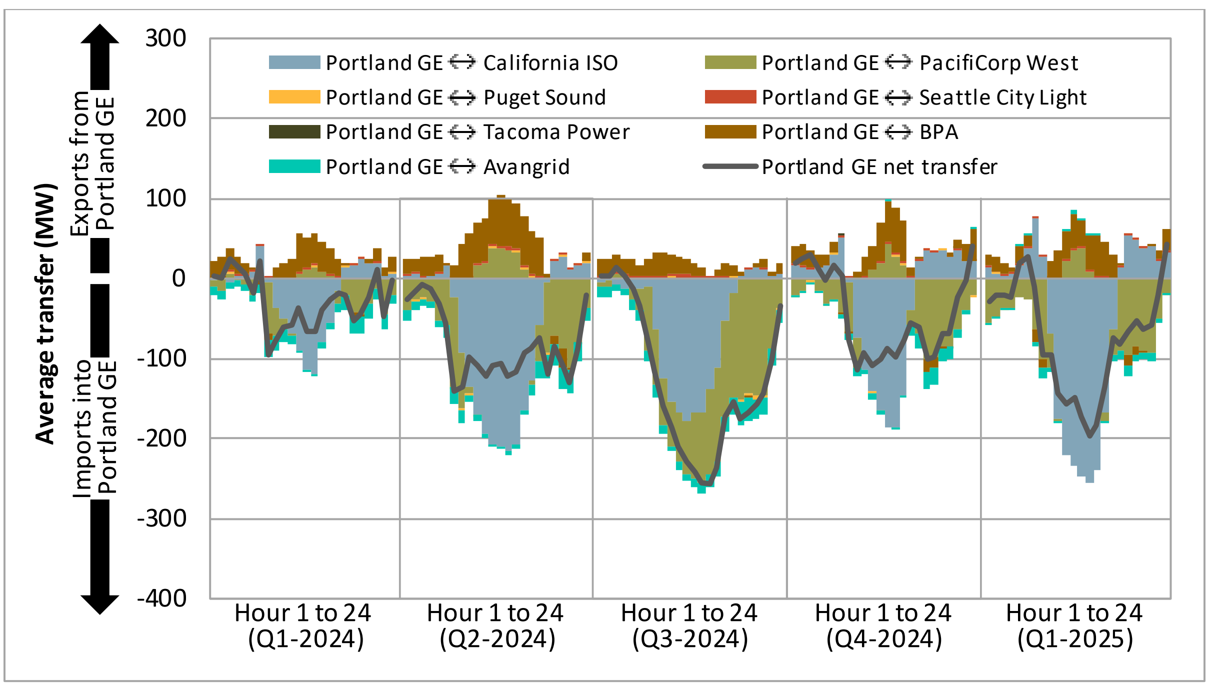


A.14 Portland General Electric

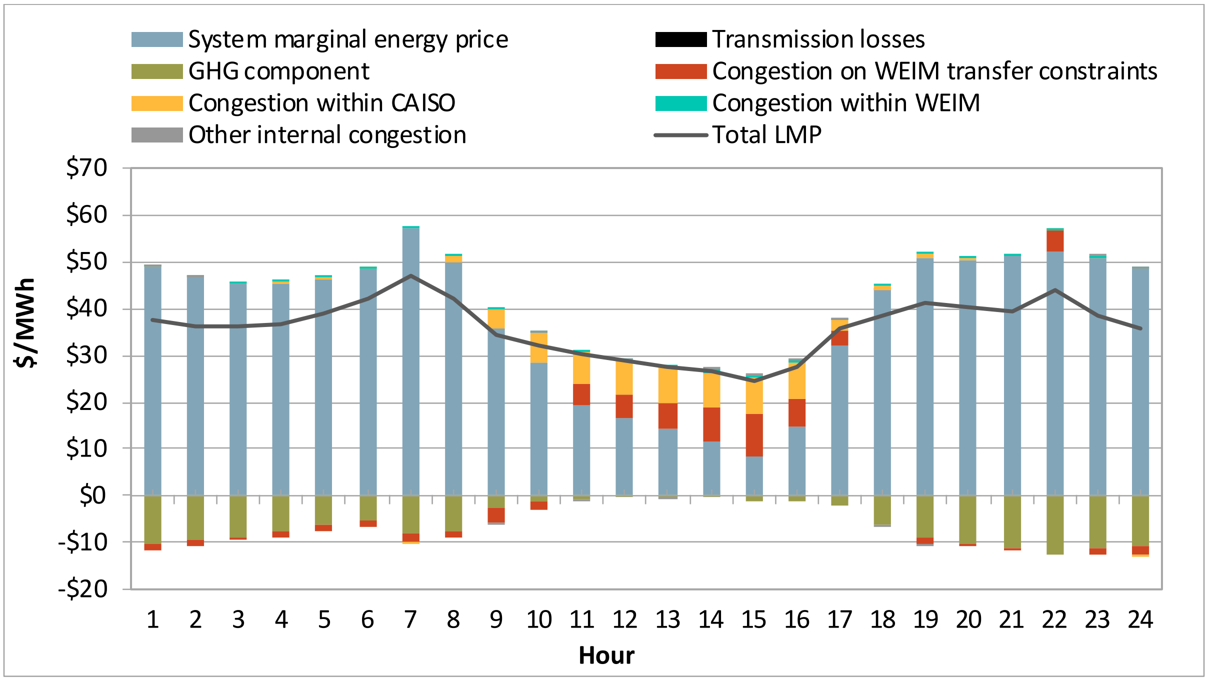
Appendix Figure A.57 Average hourly 15-minute price by component (Q1 2025)



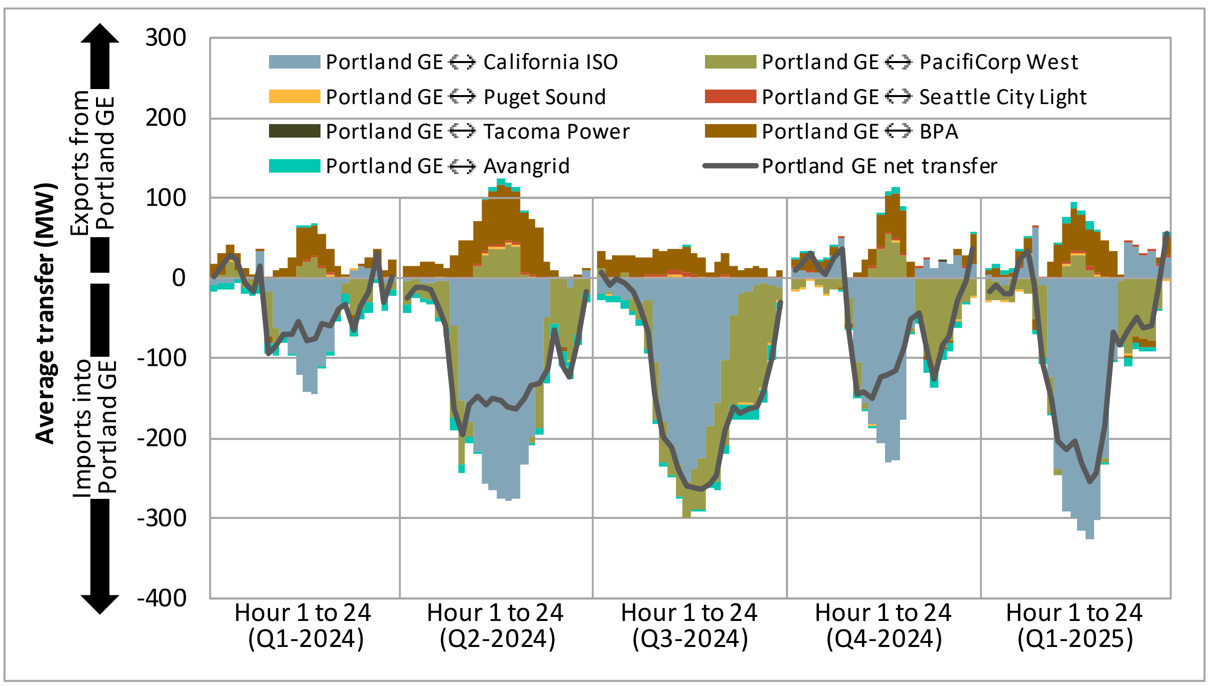
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q1 2025)

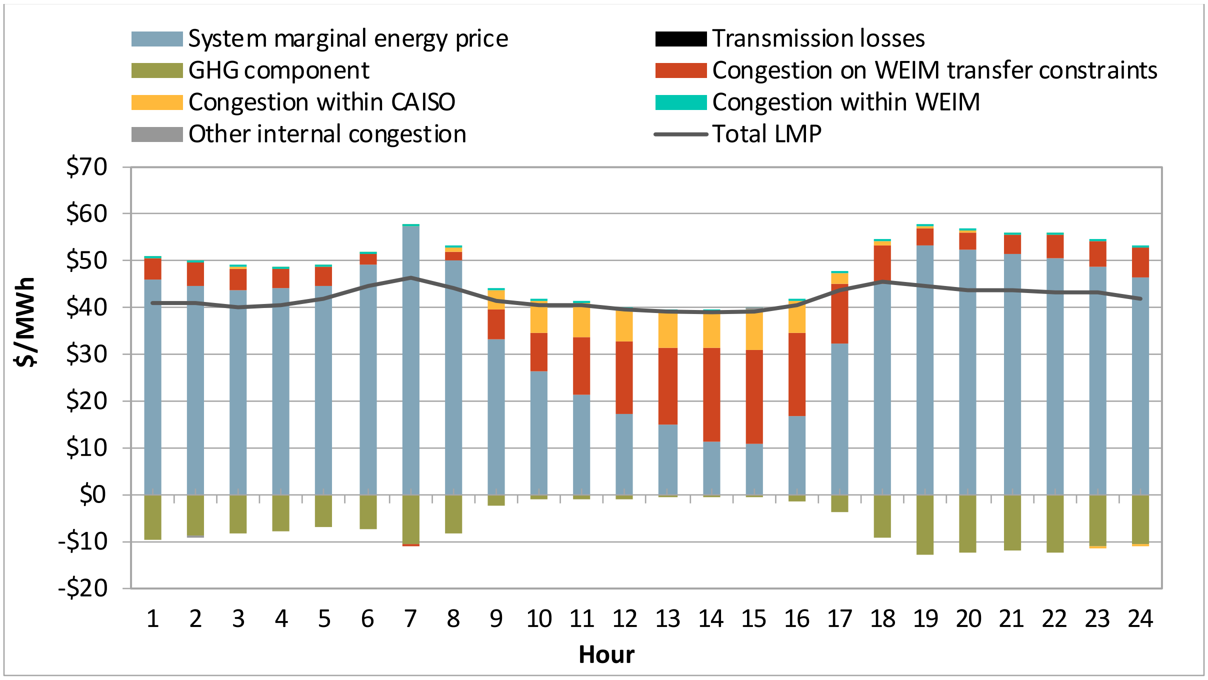


Appendix Figure A.60 Average hourly 5-minute market transfers

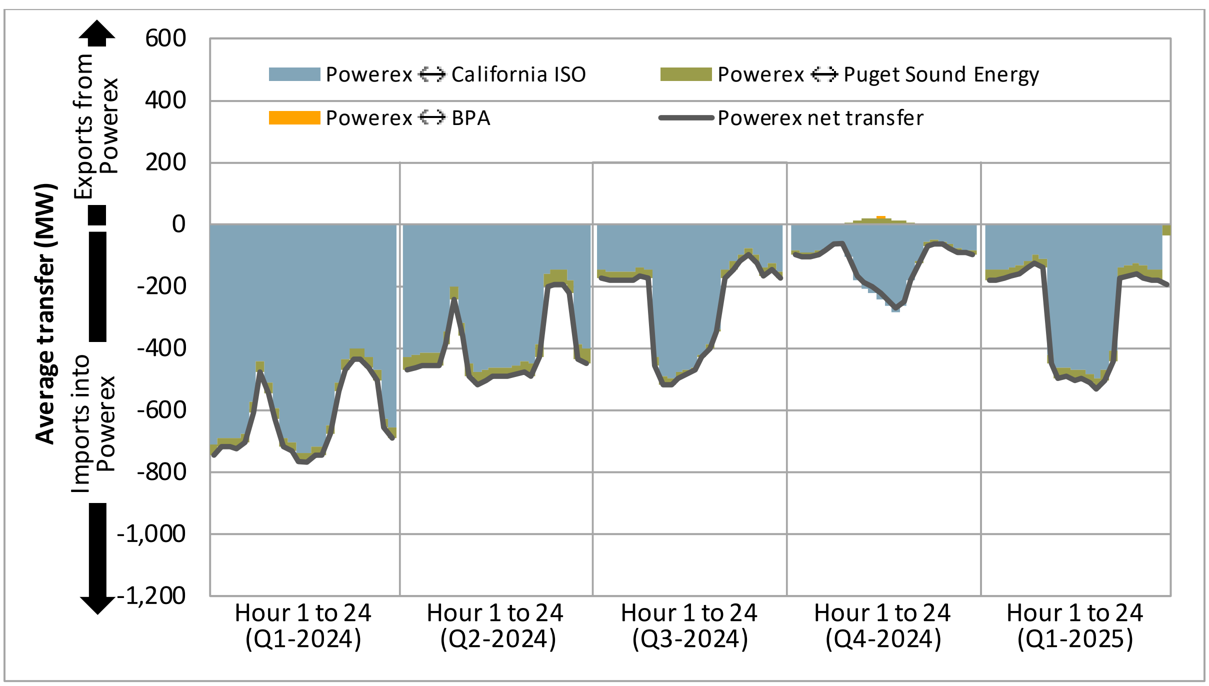


A.15 Powerex

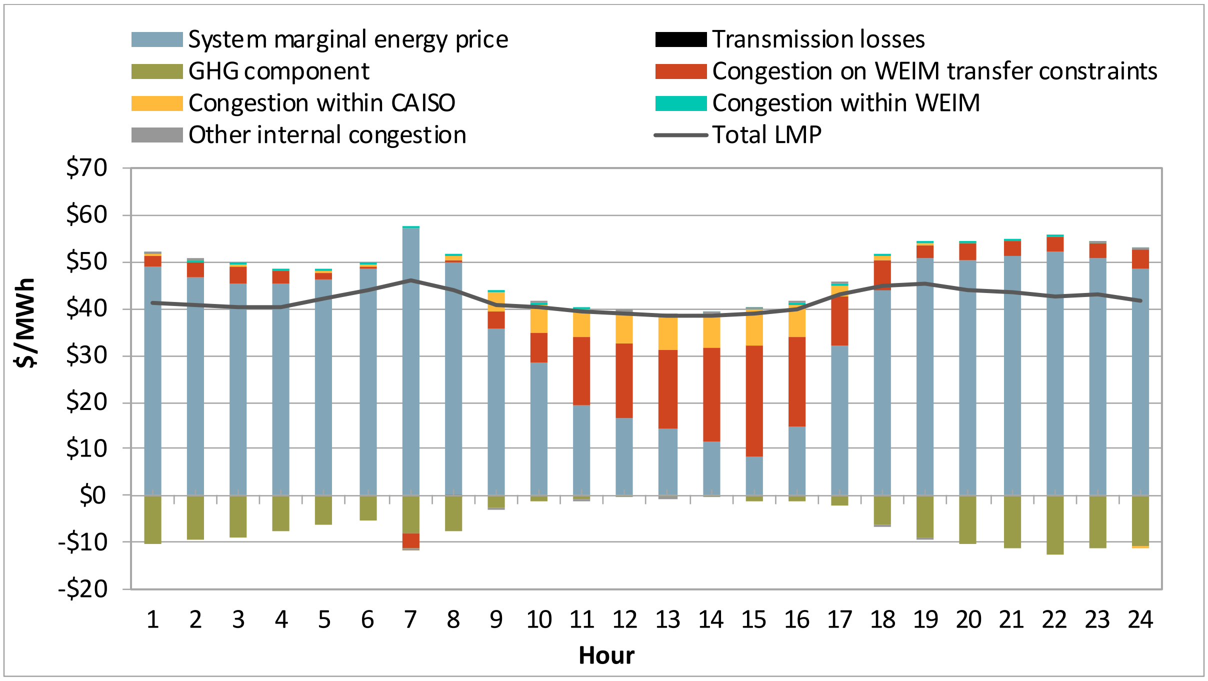
Appendix Figure A.61 Average hourly 15-minute price by component (Q1 2025)



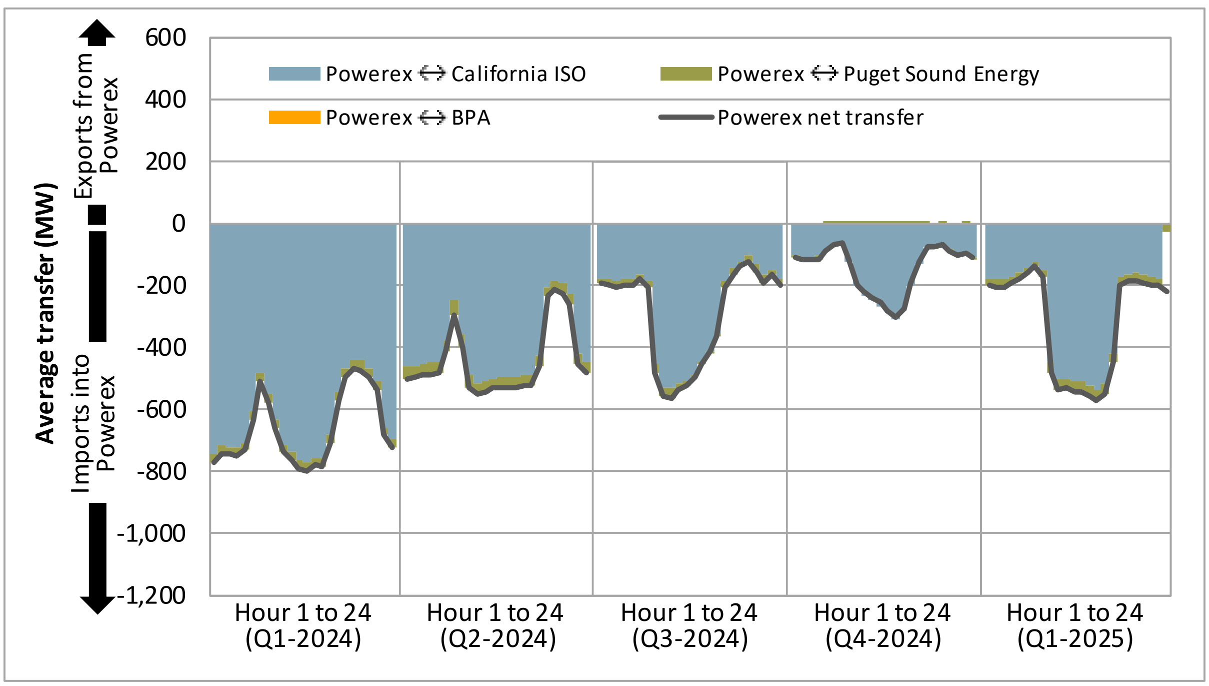
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q1 2025)

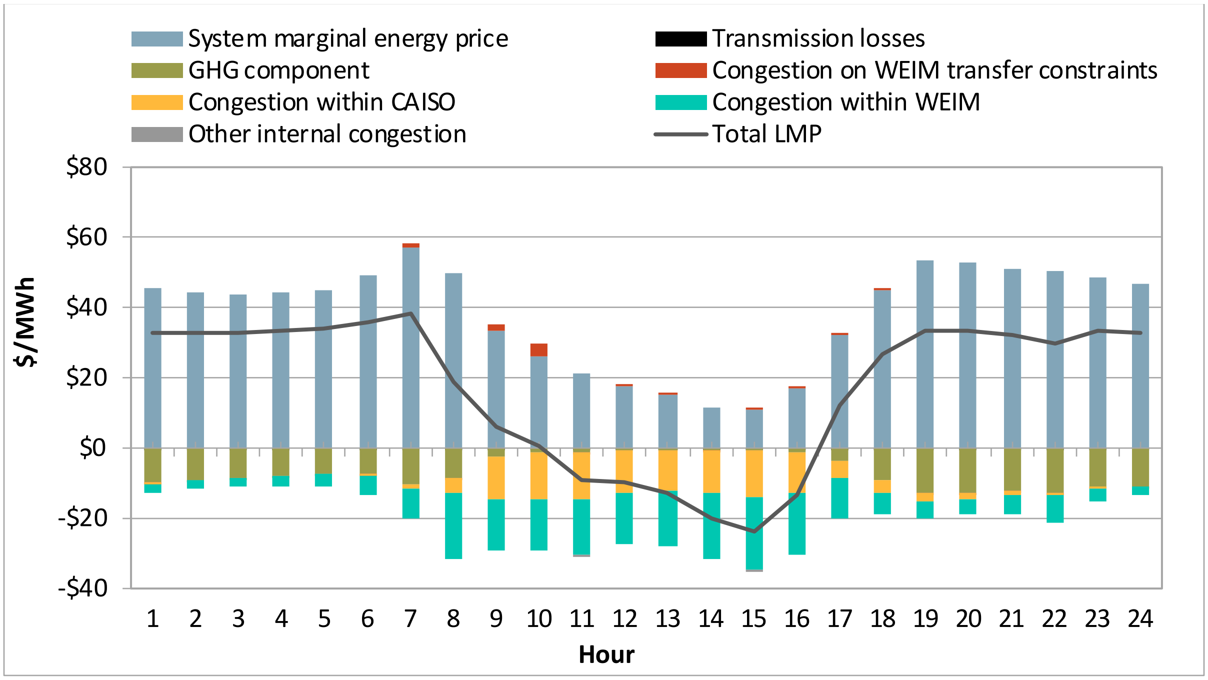


Appendix Figure A.64 Average hourly 5-minute market transfers

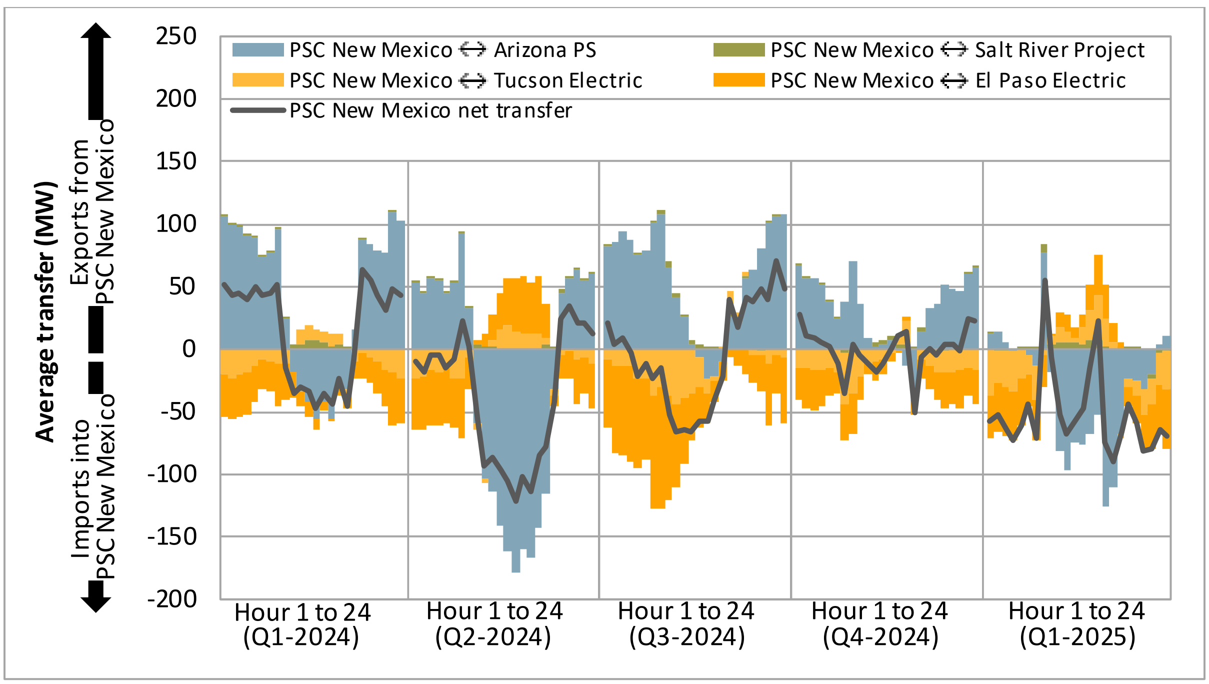


A.16 Public Service Company of New Mexico

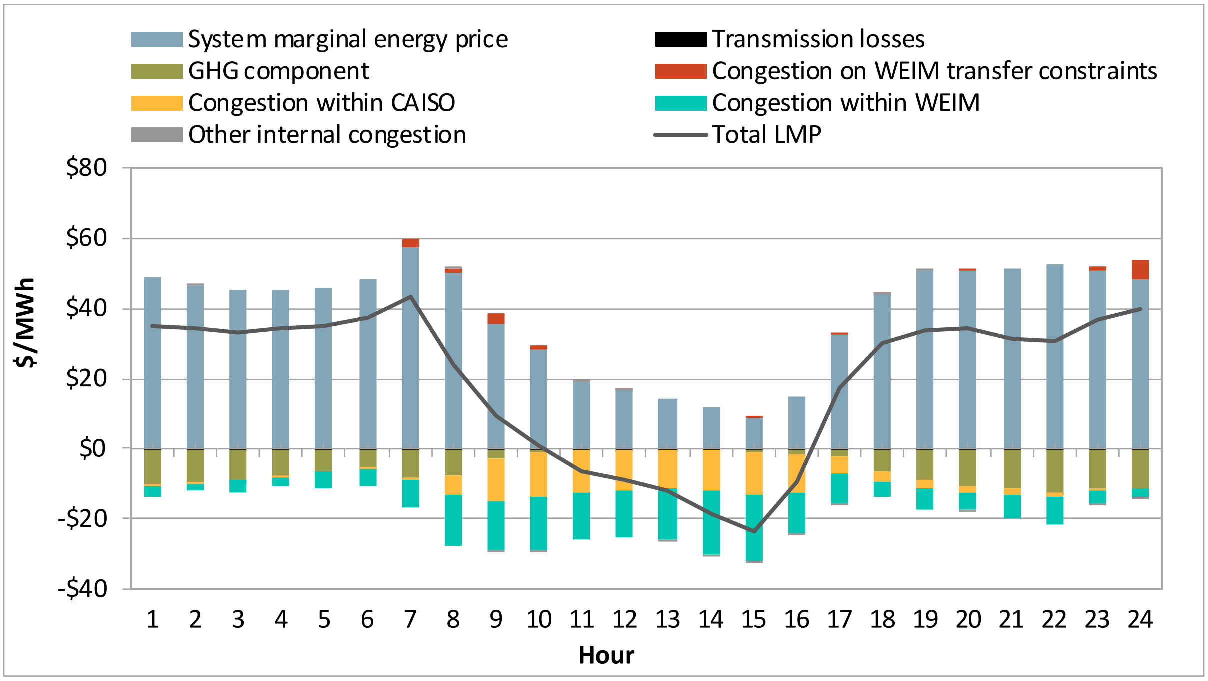
Appendix Figure A.65 Average hourly 15-minute price by component (Q1 2025)



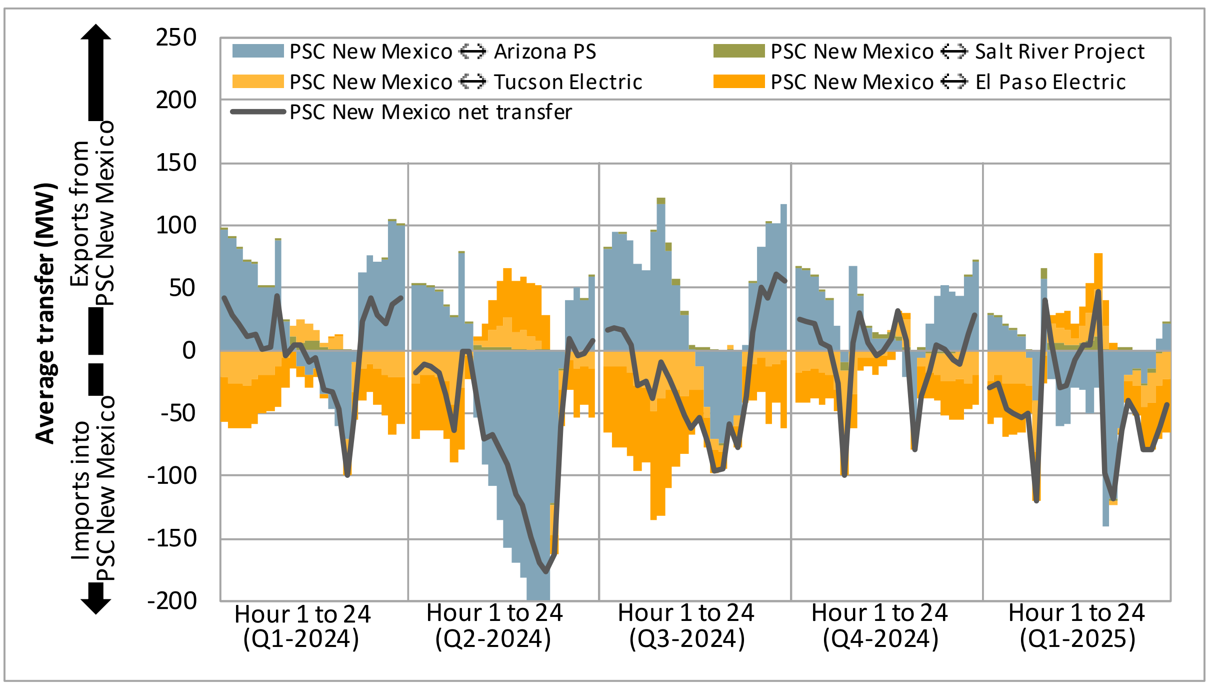
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q1 2025)

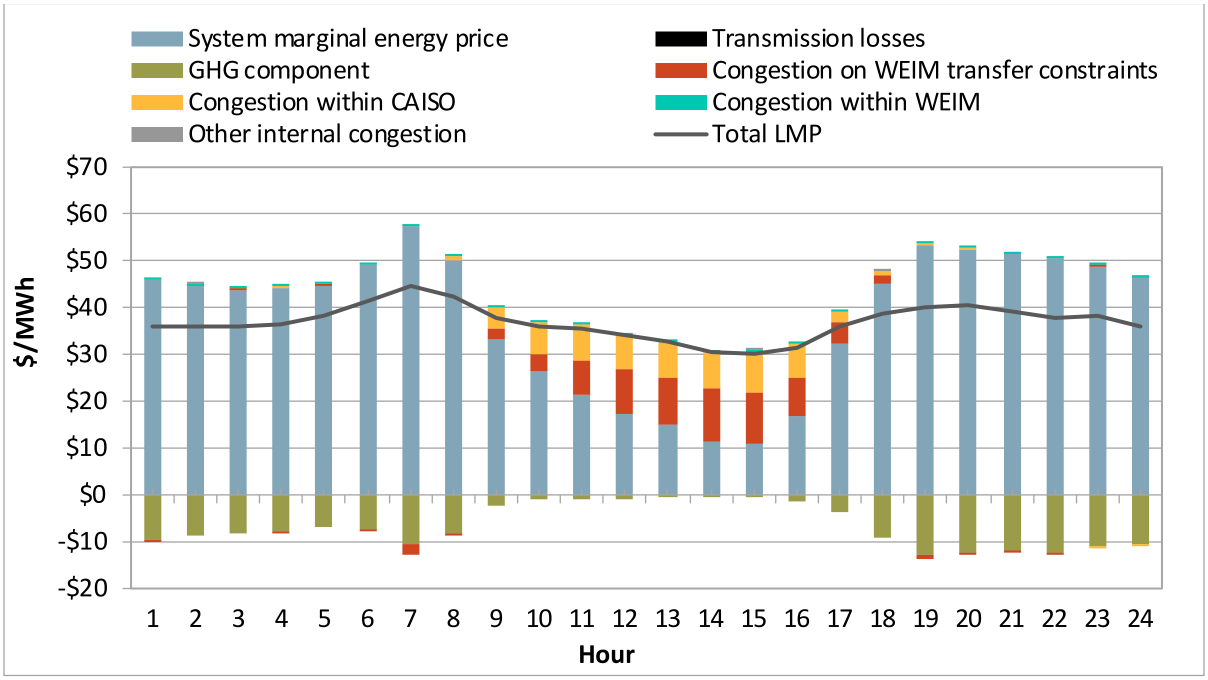


Appendix Figure A.68 Average hourly 5-minute market transfers

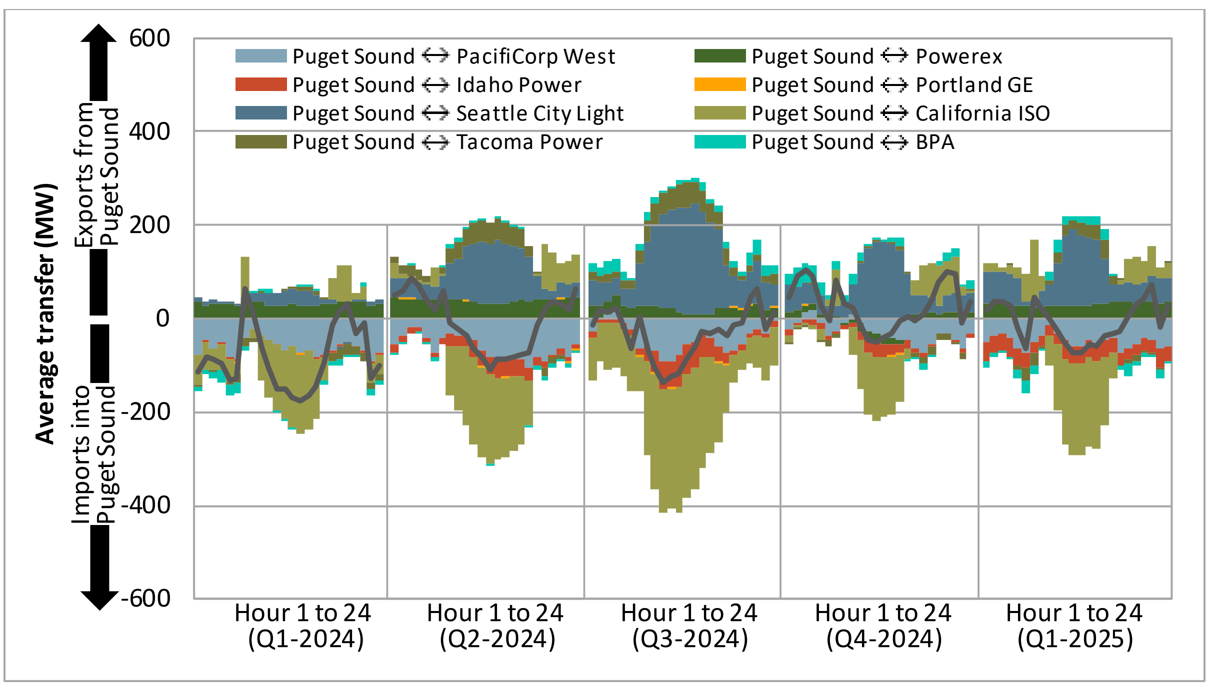


A.17 Puget Sound Energy

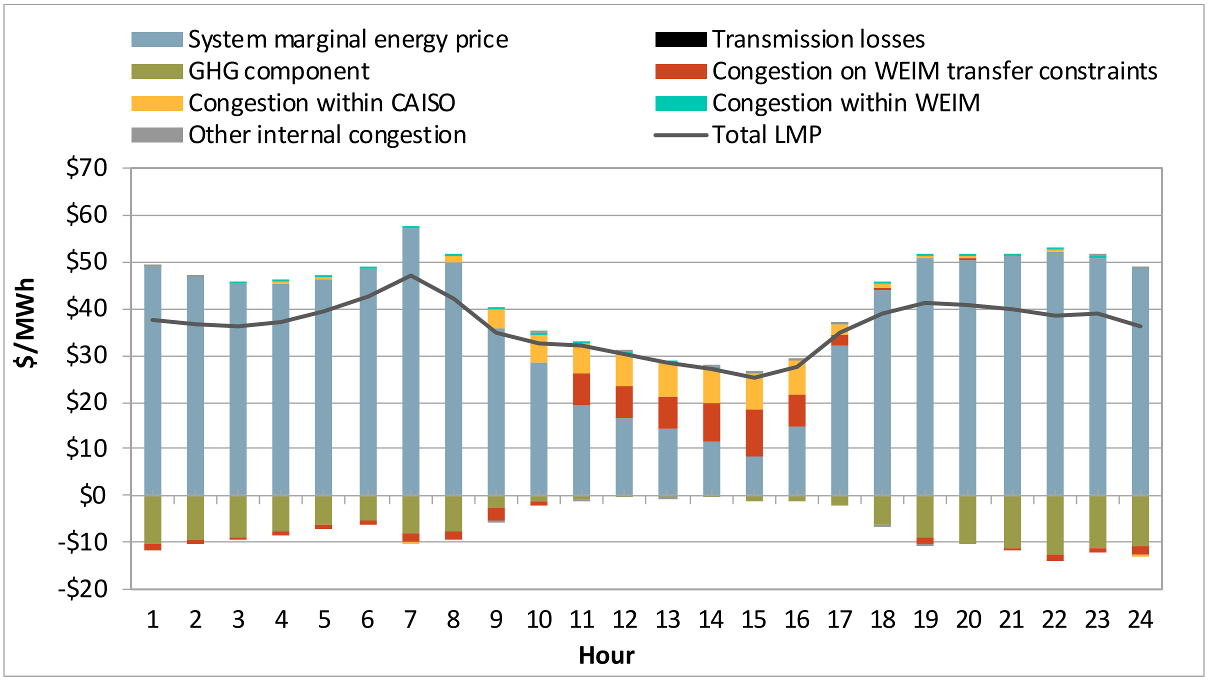
Appendix Figure A.69 Average hourly 15-minute price by component (Q1 2025)



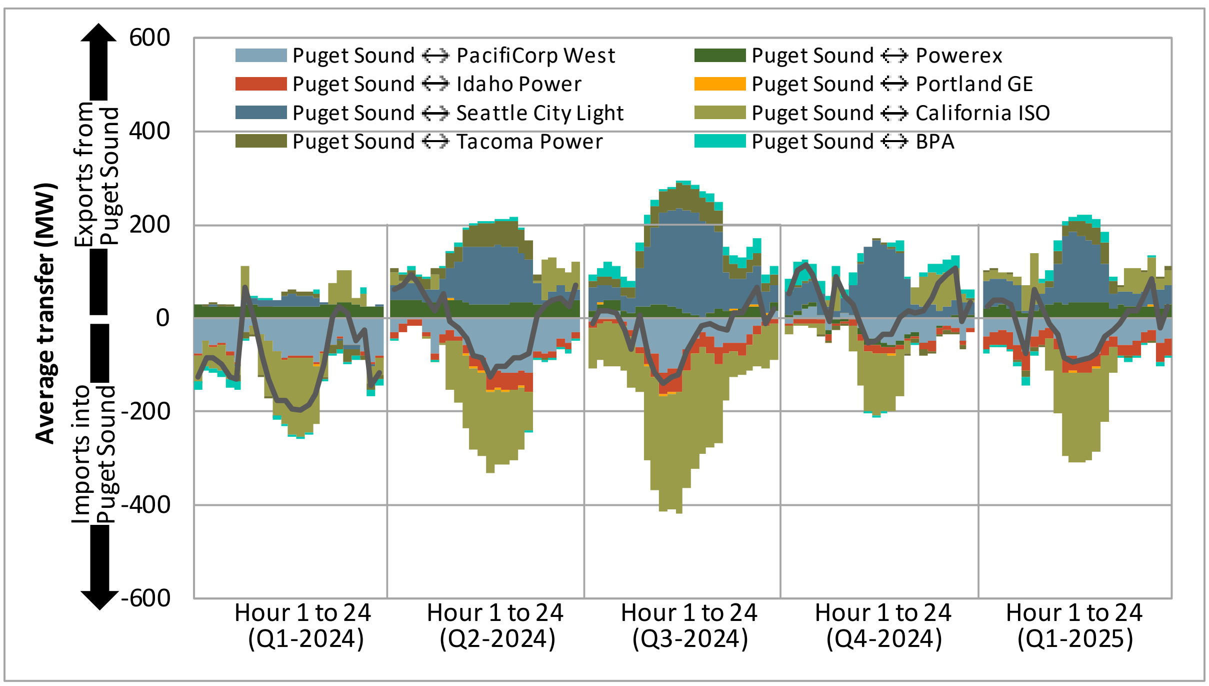
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q1 2025)

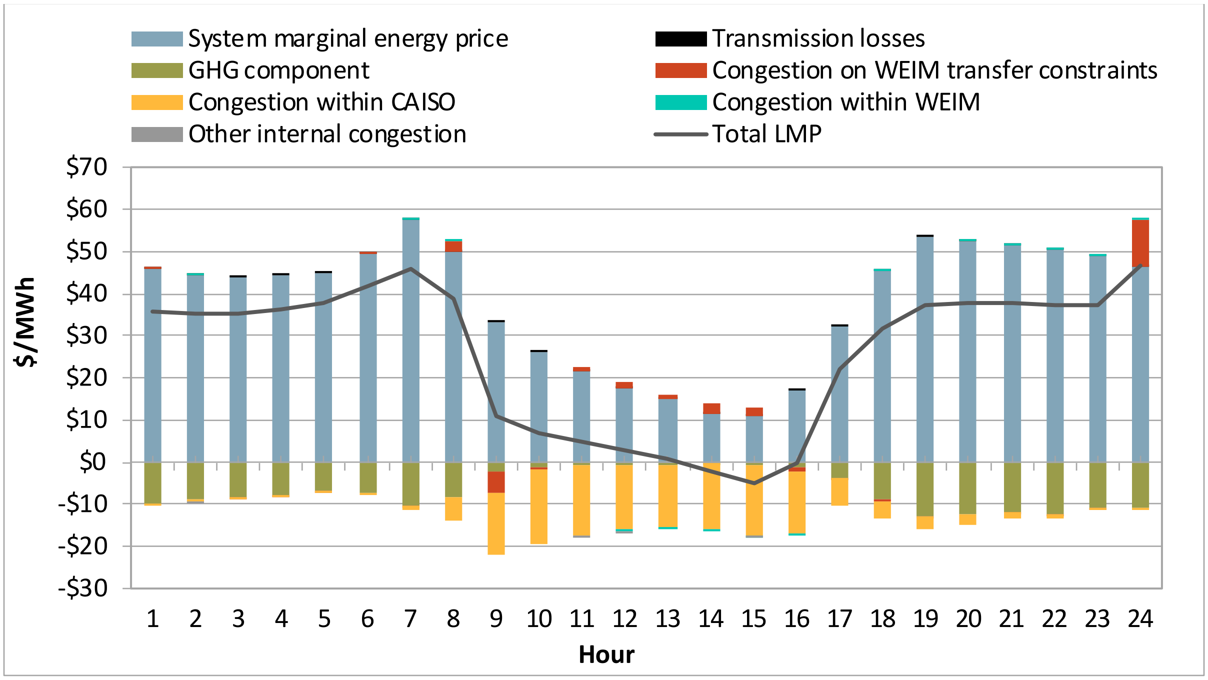


Appendix Figure A.72 Average hourly 5-minute market transfers

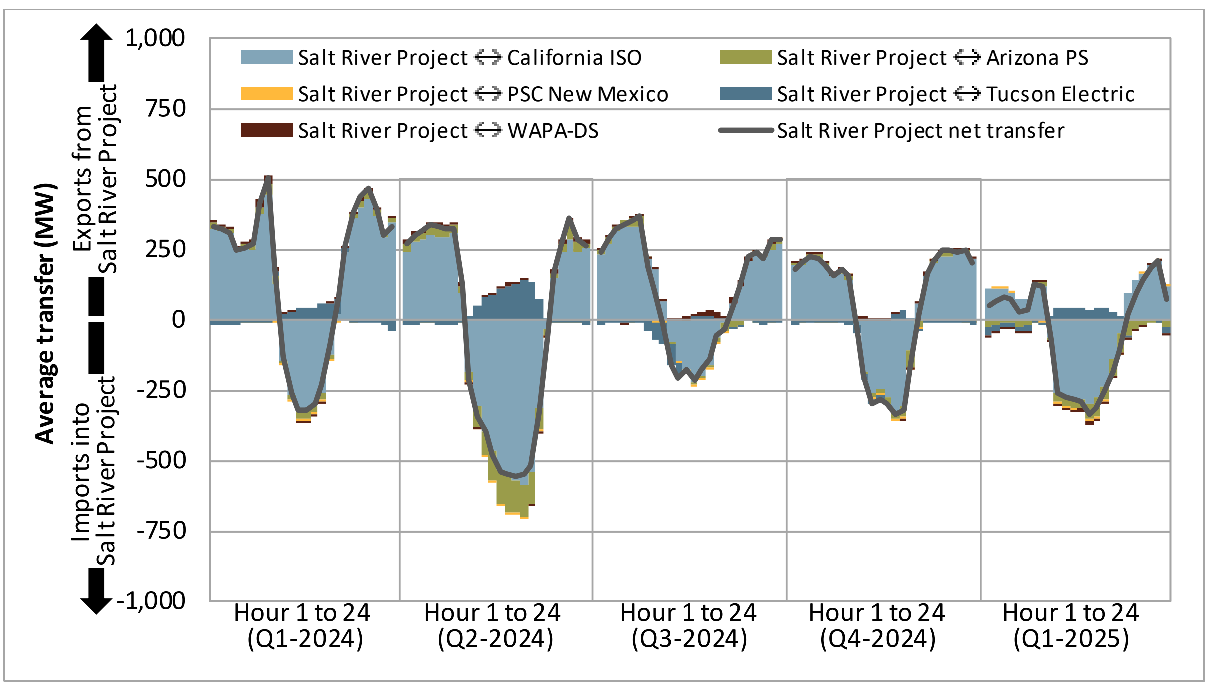


A.18 Salt River Project

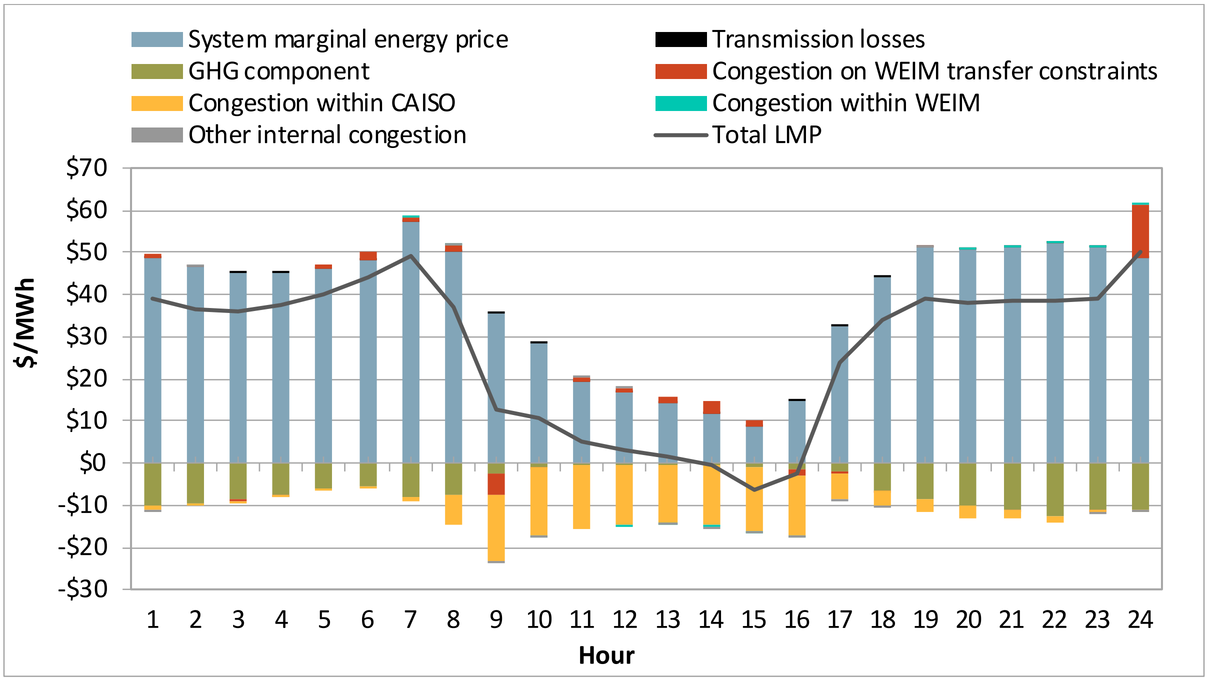
Appendix Figure A.73 Average hourly 15-minute price by component (Q1 2025)



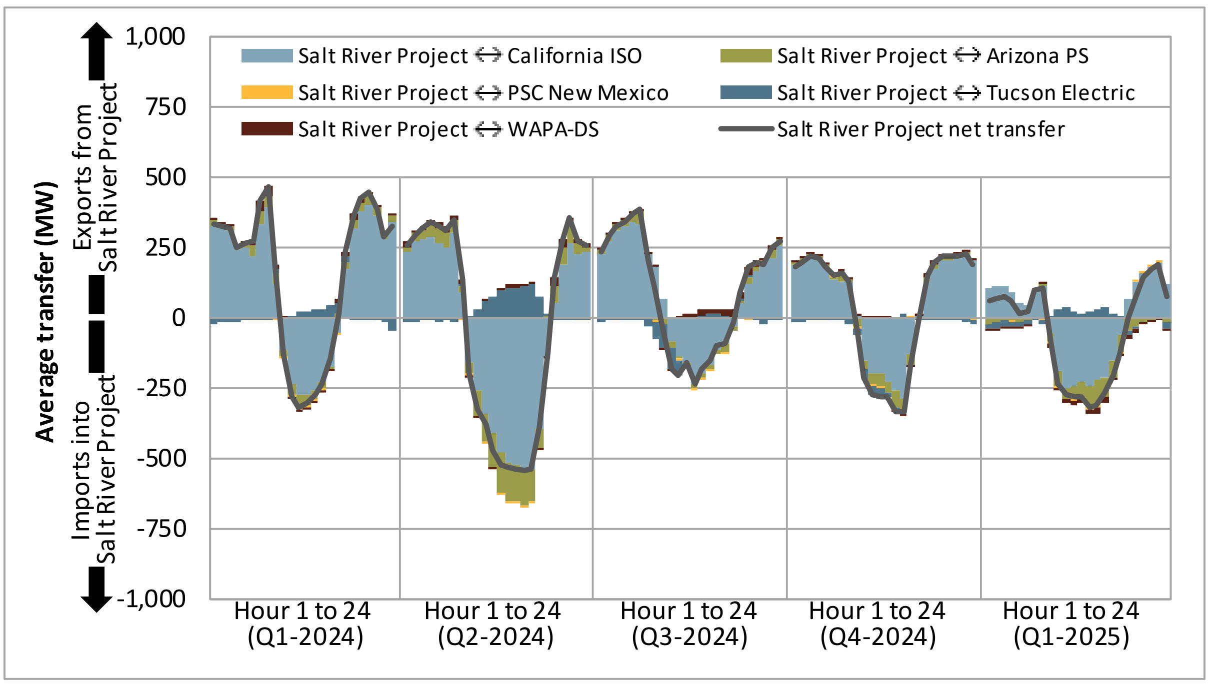
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q1 2025)

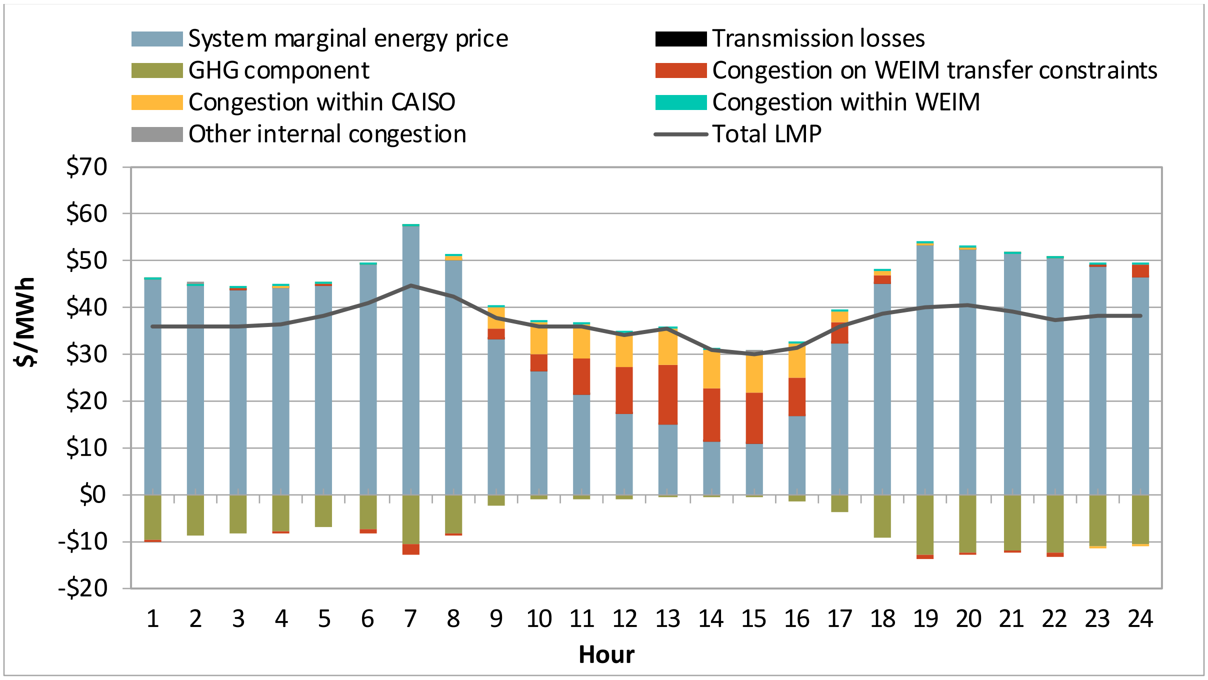


Appendix Figure A.76 Average hourly 5-minute market transfers

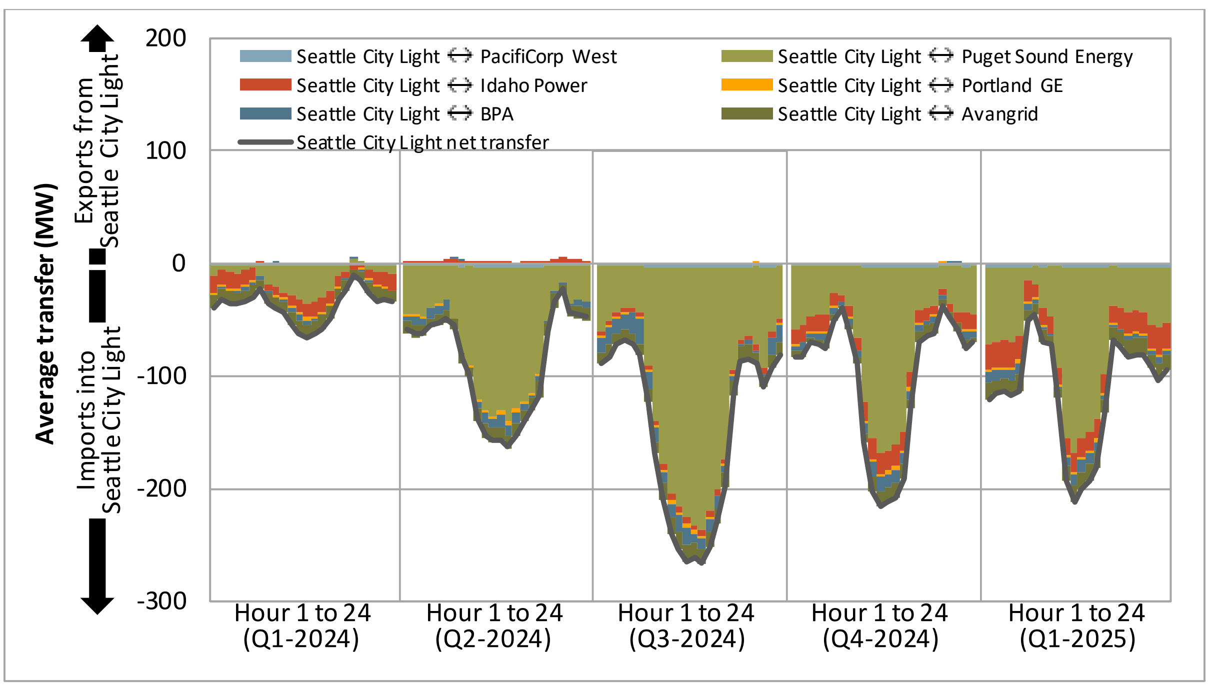


A.19 Seattle City Light

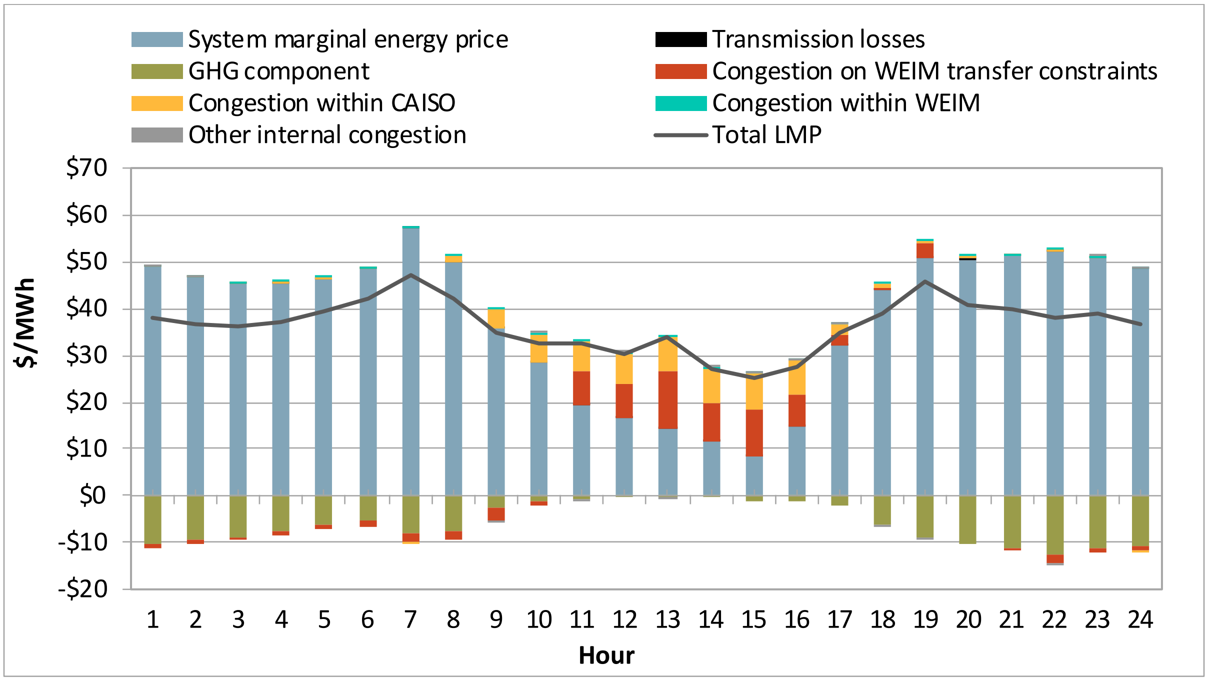
Appendix Figure A.77 Average hourly 15-minute price by component (Q1 2025)



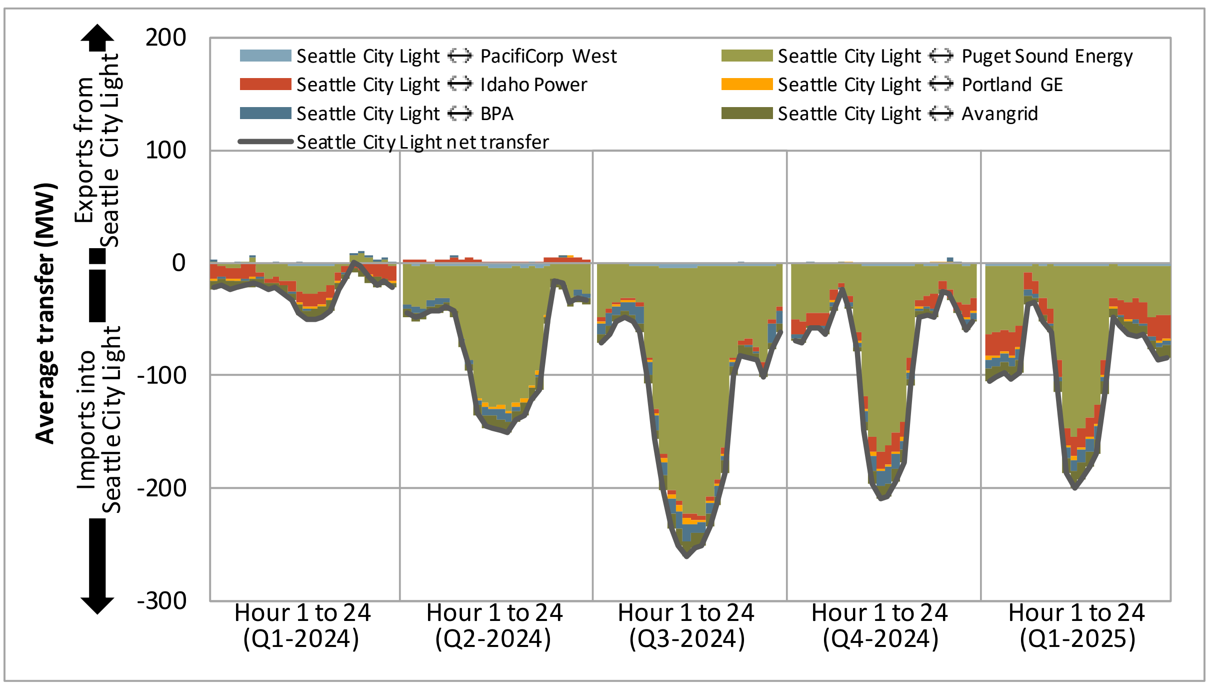
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q1 2025)

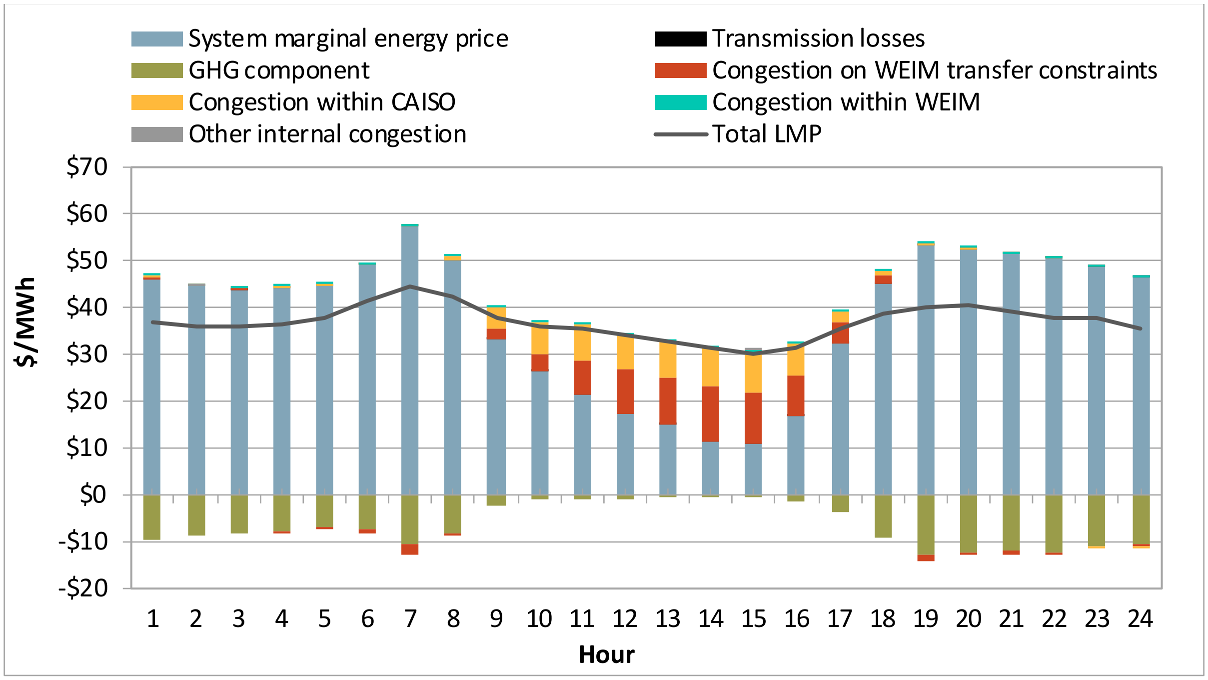


Appendix Figure A.80 Average hourly 5-minute market transfers

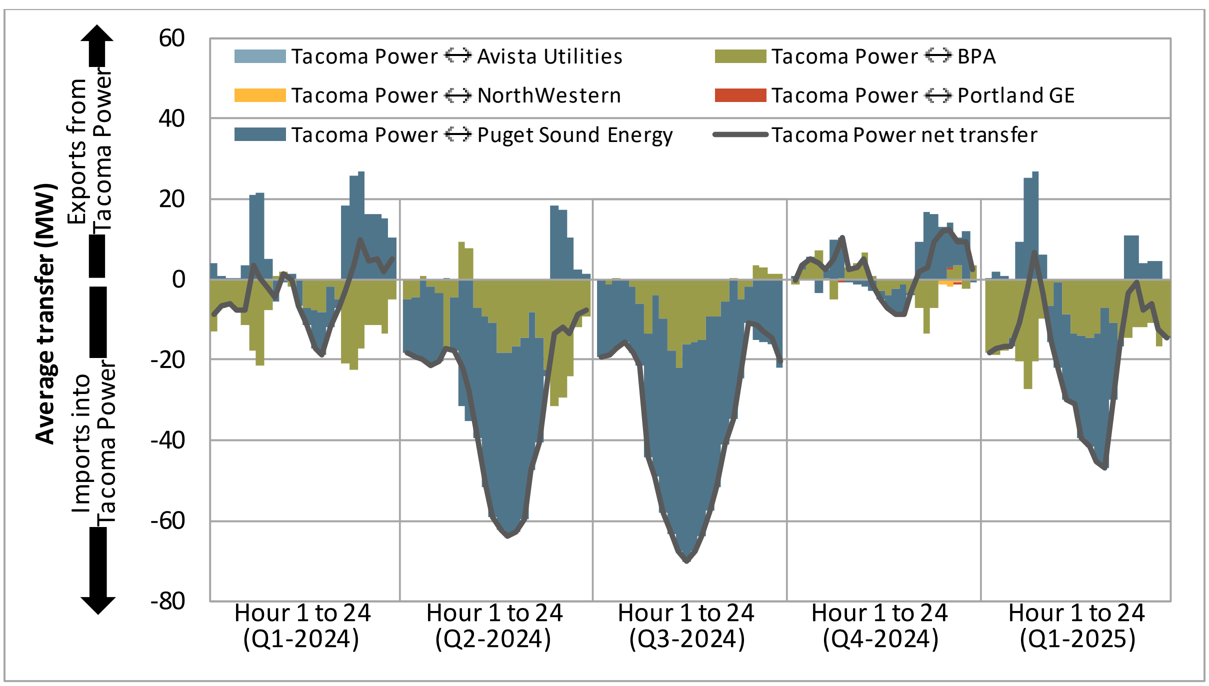


A.20 Tacoma Power

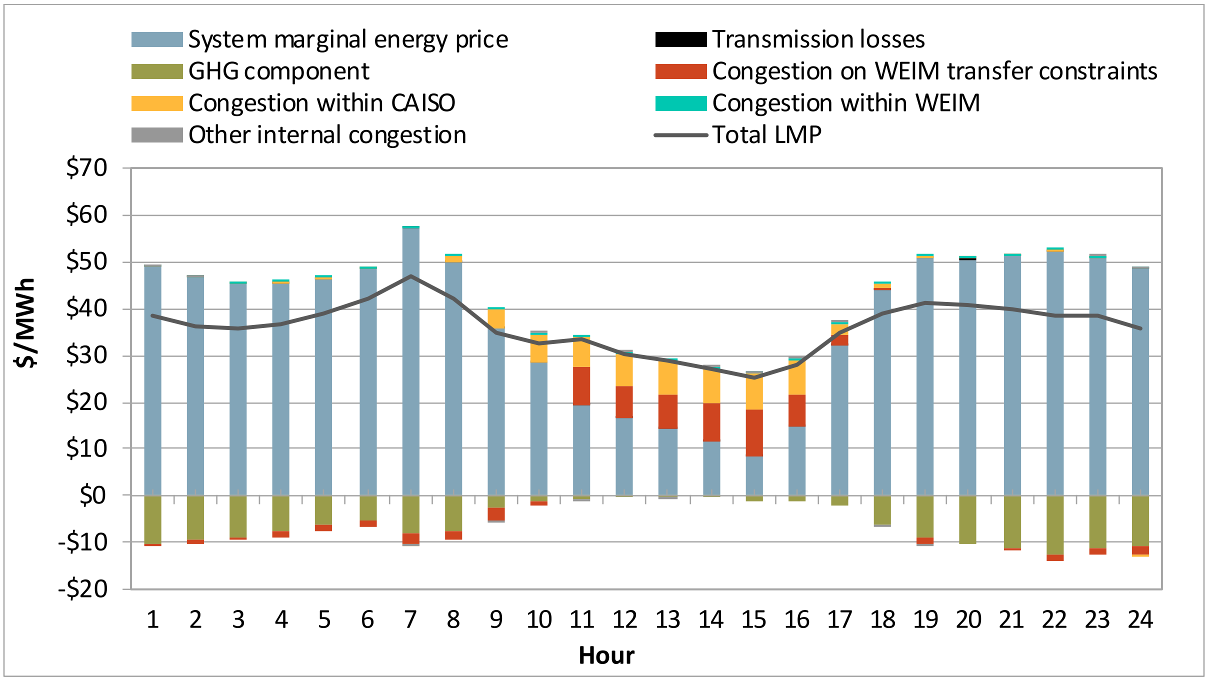
Appendix Figure A.81 Average hourly 15-minute price by component (Q1 2025)



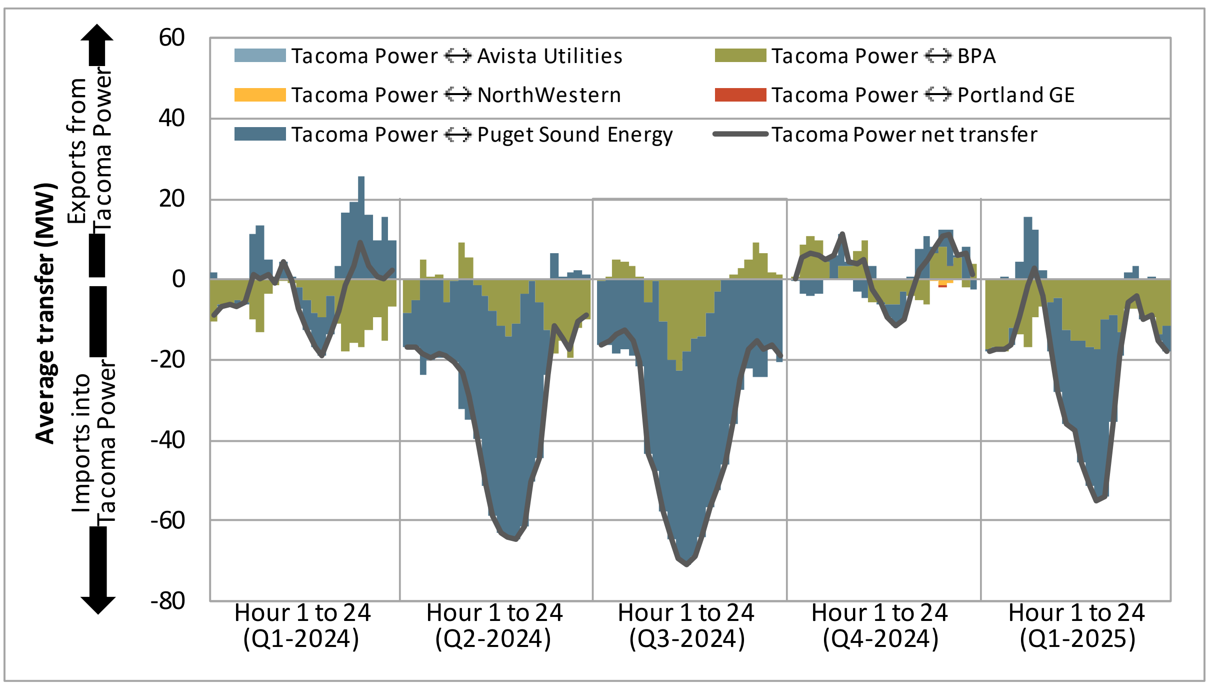
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q1 2025)

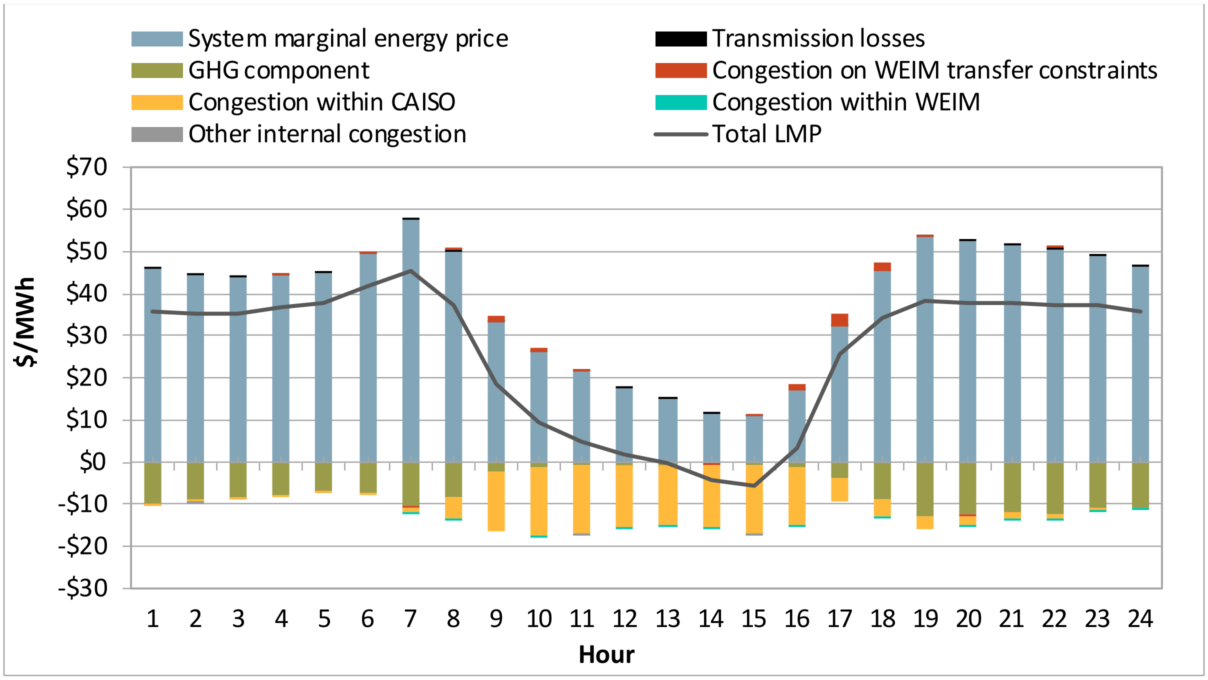


Appendix Figure A.84 Average hourly 5-minute market transfers

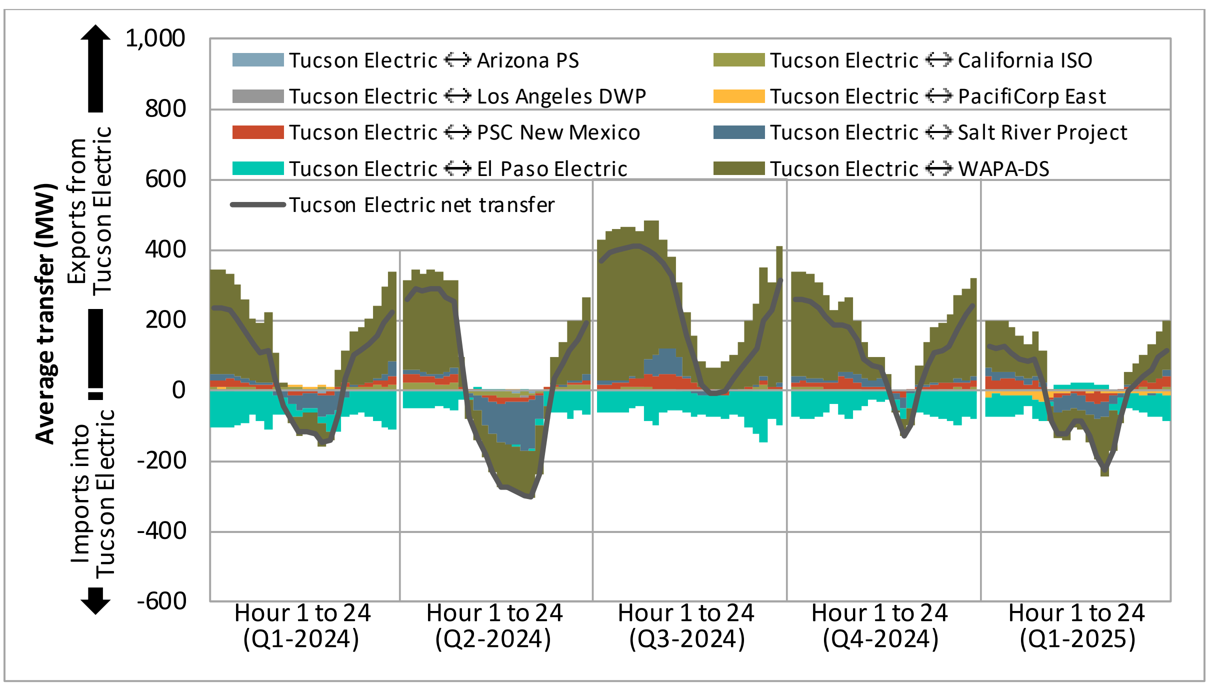


A.21 Tucson Electric Power

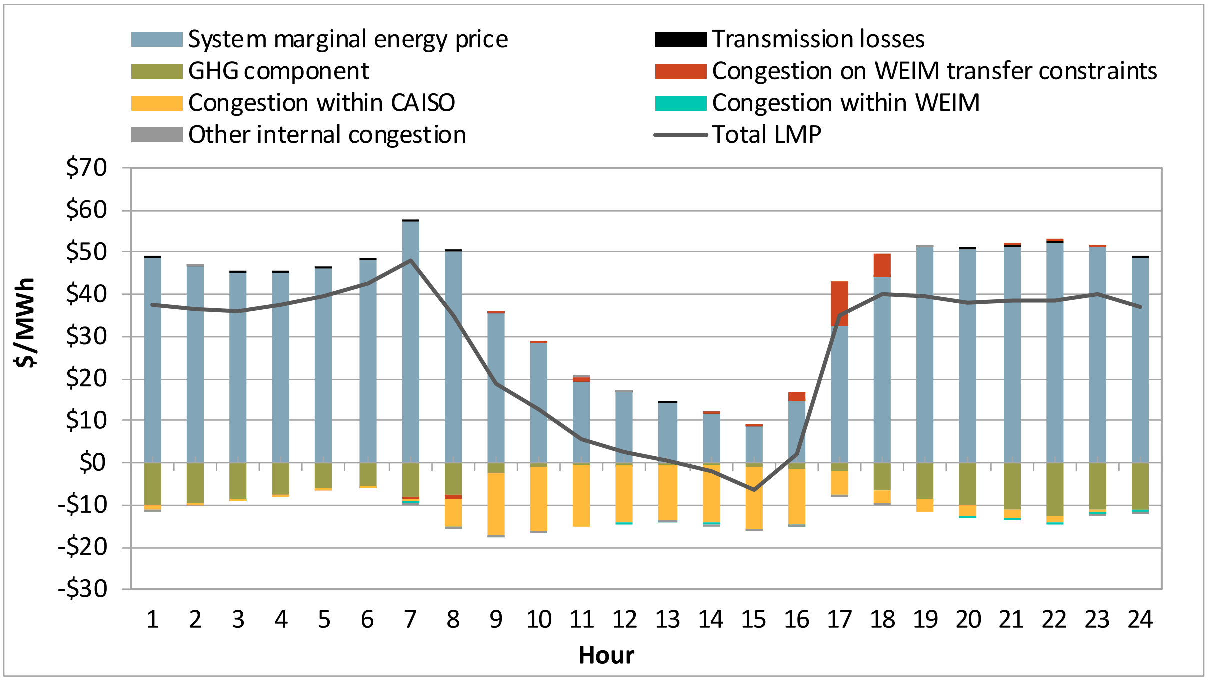
Appendix Figure A.85 Average hourly 15-minute price by component (Q1 2025)



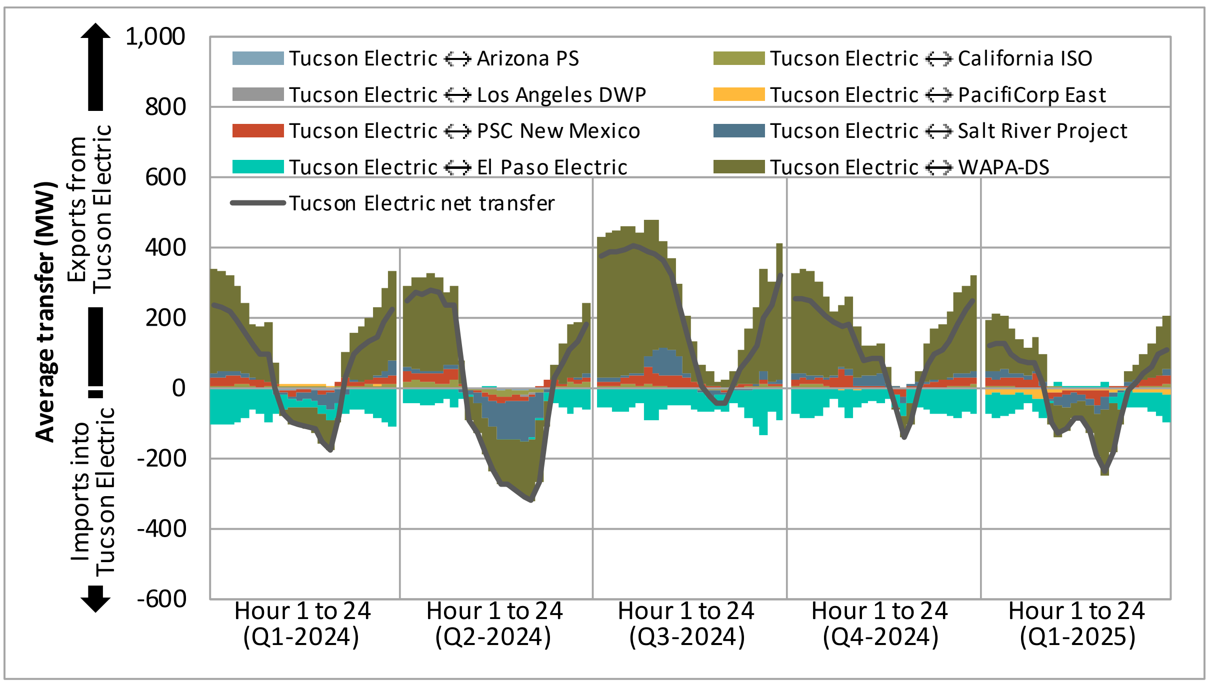
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q1 2025)

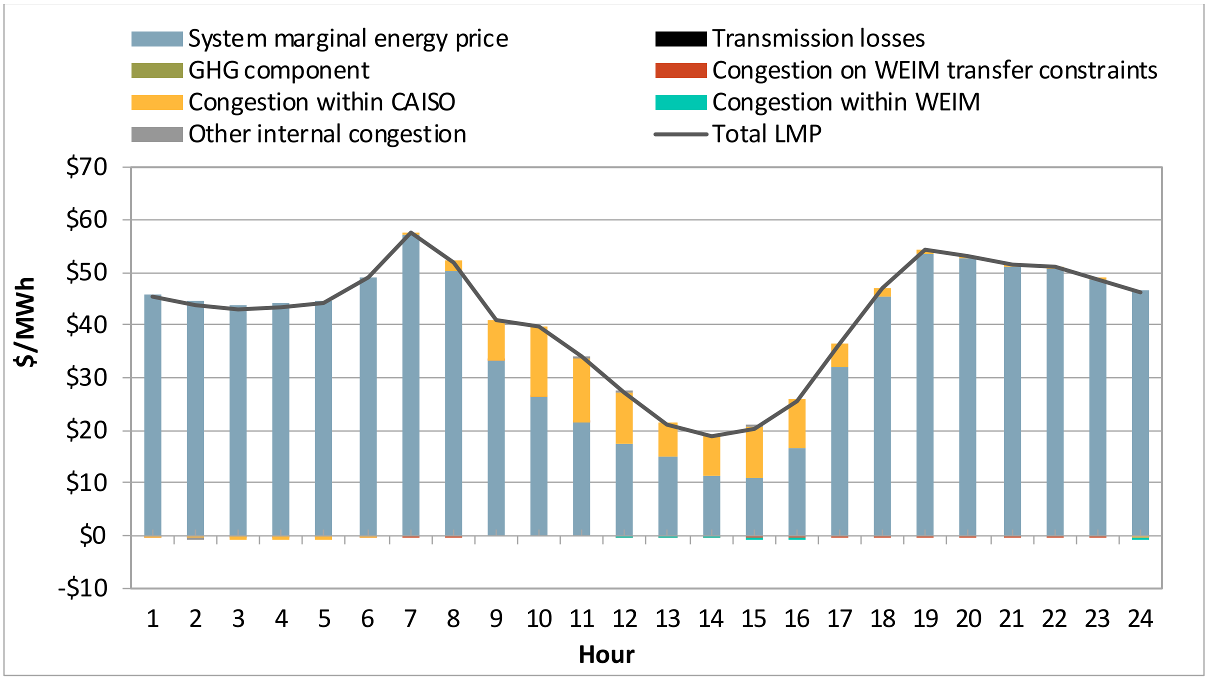


Appendix Figure A.88 Average hourly 5-minute market transfers

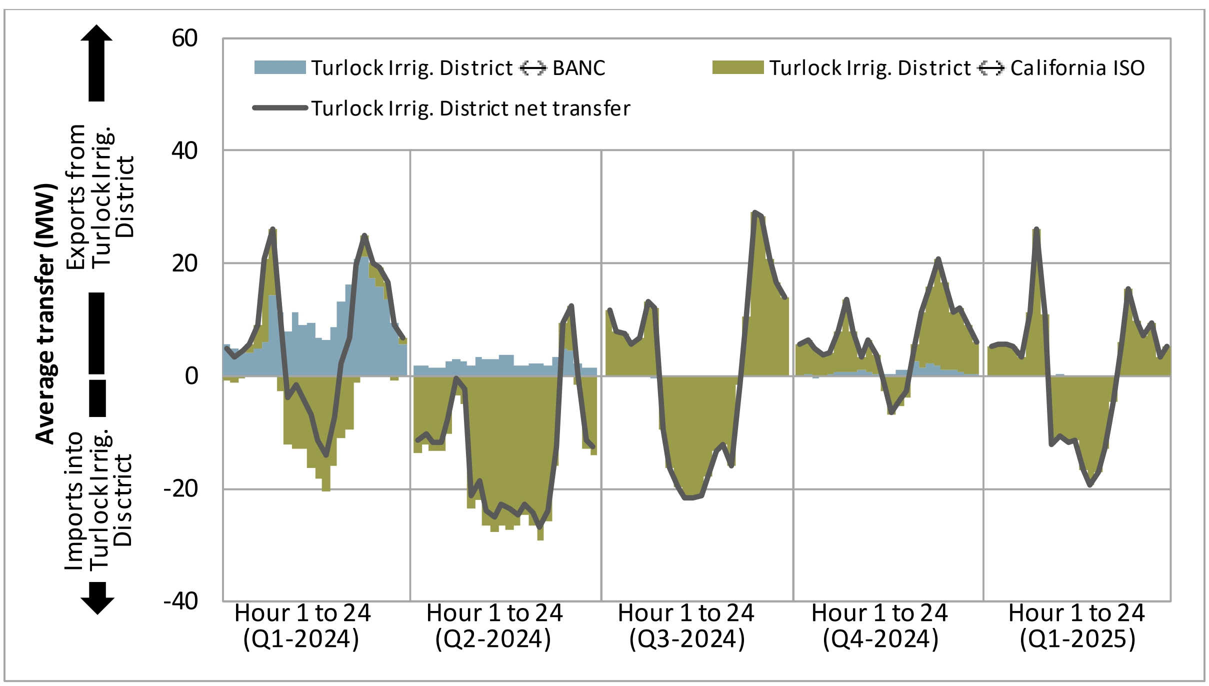


A.22 Turlock Irrigation District

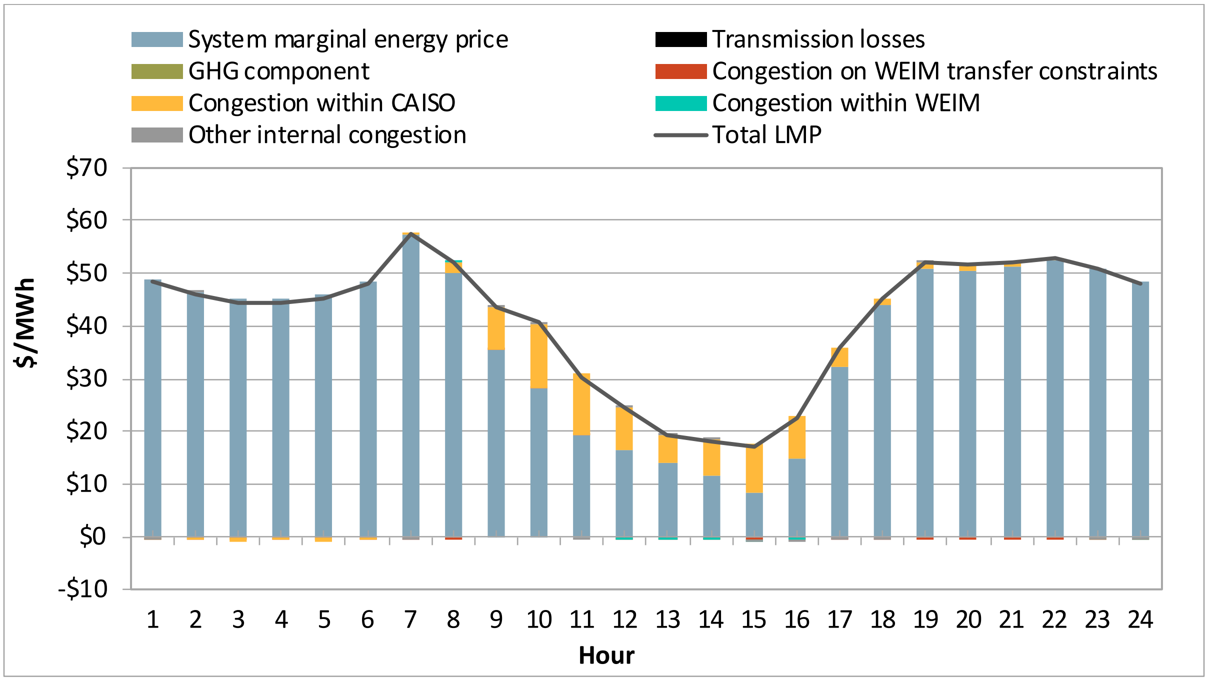
Appendix Figure A.89 Average hourly 15-minute price by component (Q1 2025)



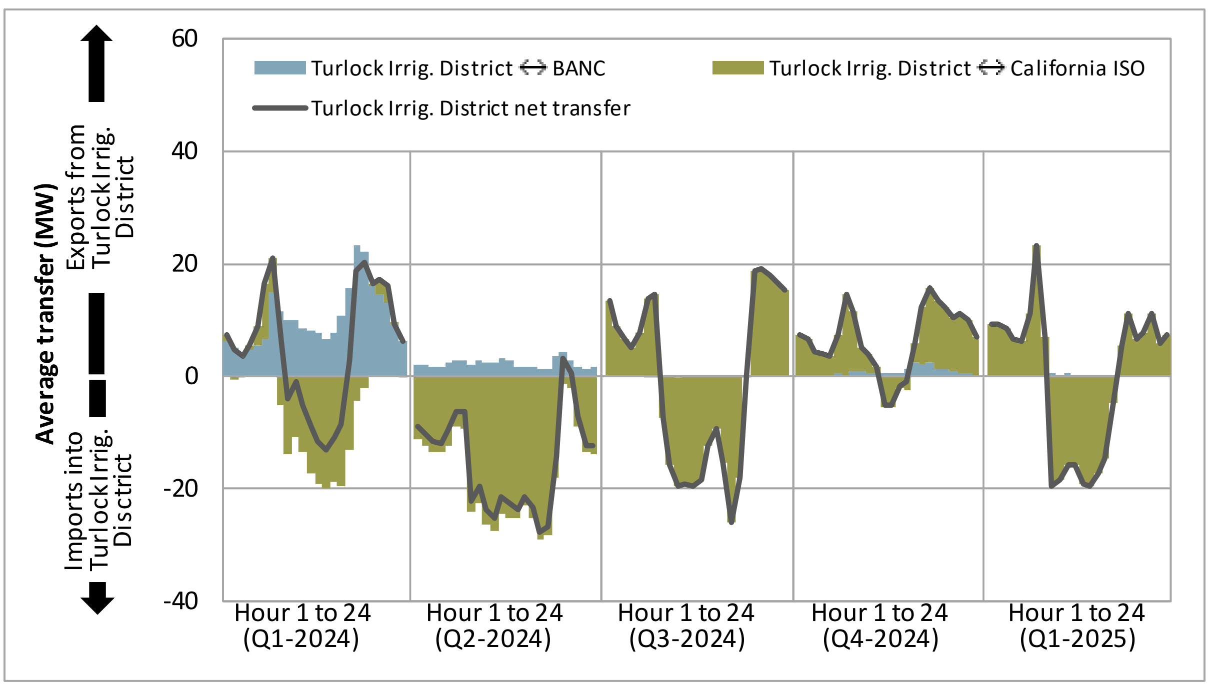
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q1 2025)

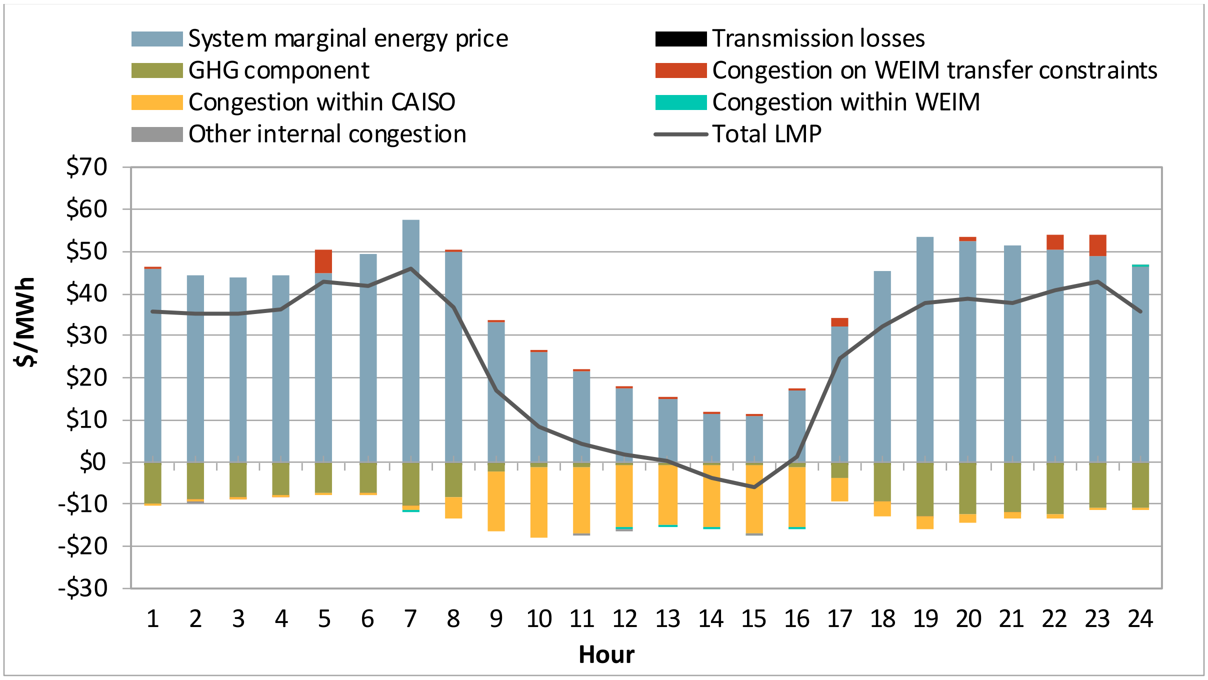


Appendix Figure A.92 Average hourly 5-minute market transfers

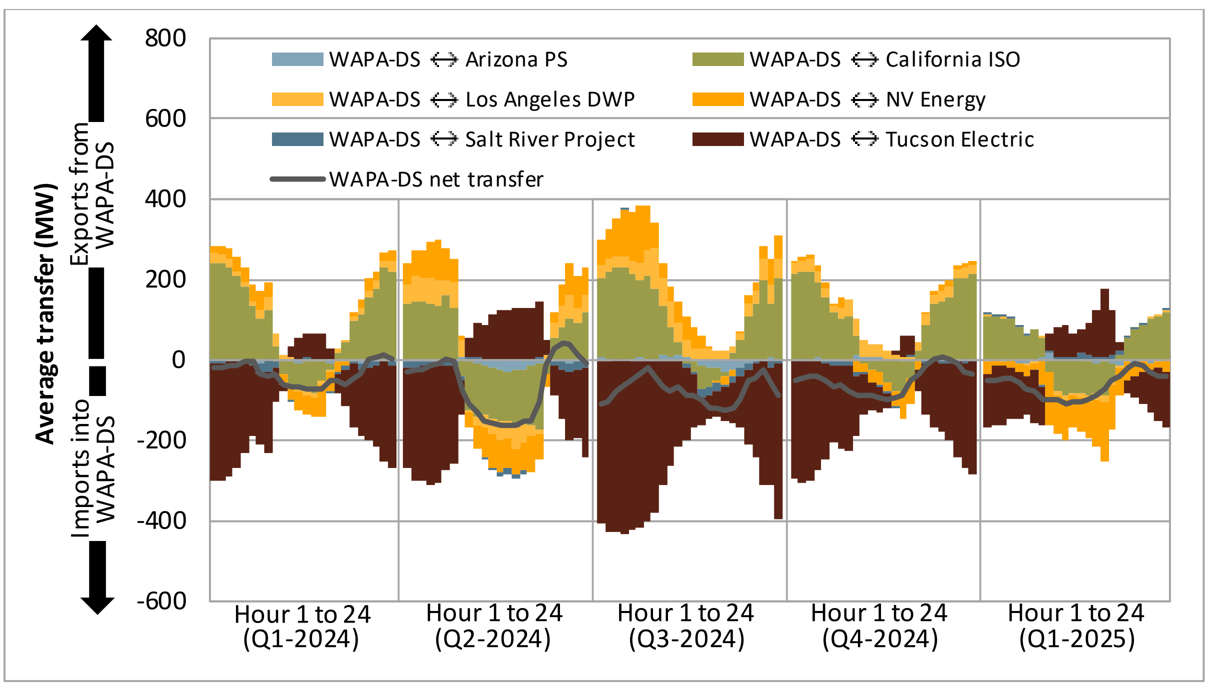


A.23 Western Area Power Administration Desert Southwest

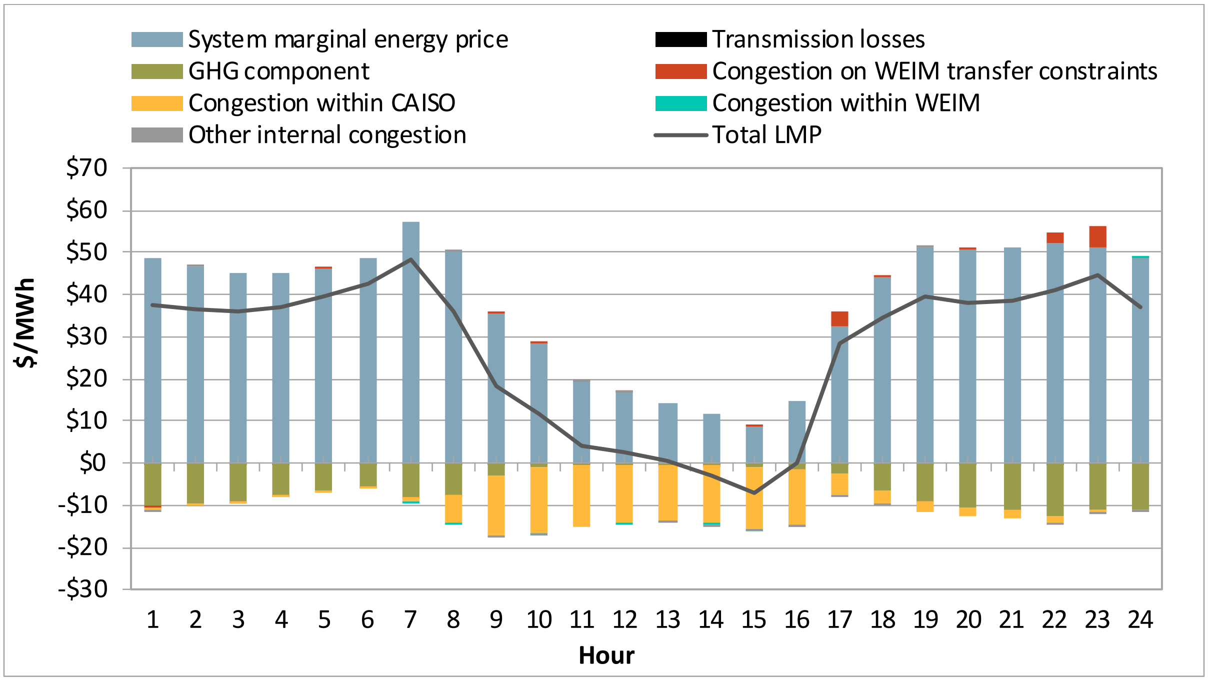
Appendix Figure A.93 Average hourly 15-minute price by component (Q1 2025)



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



Appendix Figure A.95 Average hourly 5-minute price by component (Q1 2025)



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