Q1 2026 Report on Market Issues and Performance

September 14, 2026

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Prepared by: Department of Market Monitoring

California Independent System Operator

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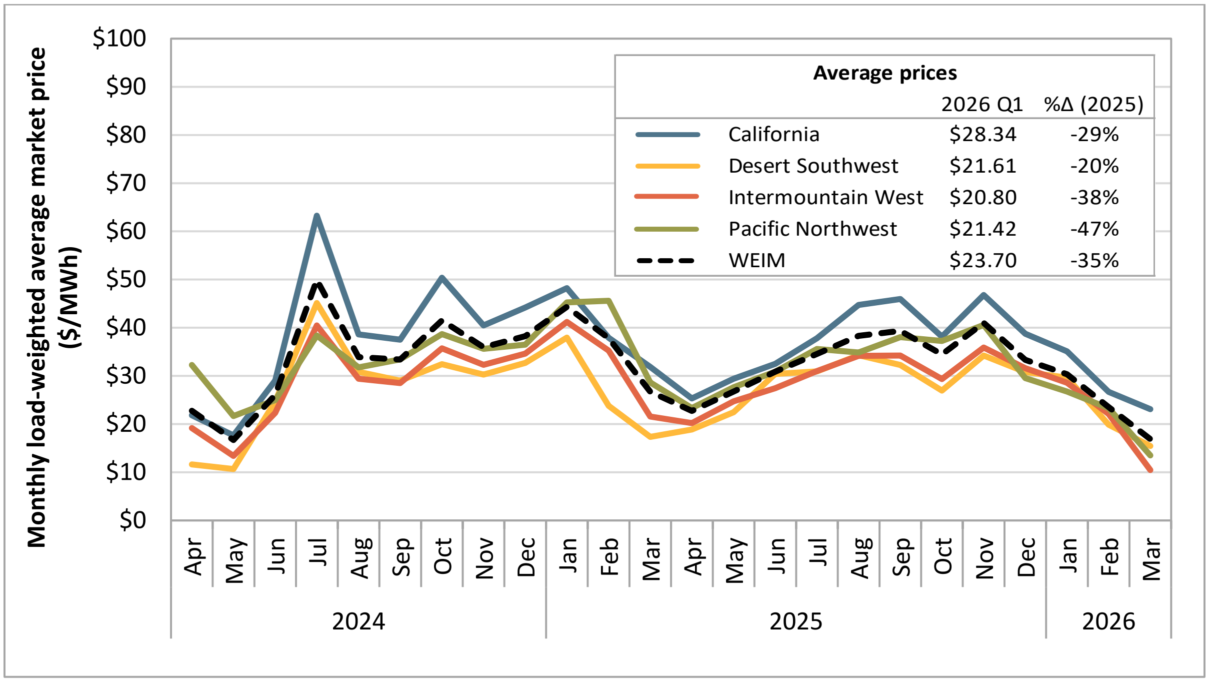
Executive summary

This report covers market performance during the first quarter of 2026 (January–March). Overall 15-minute market prices across the Western Energy Imbalance Market (WEIM) averaged \$24/MWh, down 35 percent compared to the first quarter of 2025 due to lower natural gas prices and increased renewable energy production (Figure E. 1).

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 decreased at most major Western hubs in Q1 2026**, with prices at many hubs nearing historic lows. Prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, and NW Opal Wyoming decreased by 45 percent, 31 percent, 24 percent, and 36 percent, respectively, compared to the first quarter of 2025, and El Paso Permian prices declined to average -\$0.52/MMBtu. Henry Hub prices increased 9 percent in the first quarter of 2026 compared to Q1 2025.
- **Renewable output increased significantly across the WEIM footprint, with average hourly renewable generation up 6,800 MW (16 percent)** from Q1 2025.[1] The majority of this increase was from hydro in the Pacific Northwest, which was up 4,800 MW (27 percent). Across the WEIM, hydro

[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.

increased 5,200 MW (22 percent), solar generation increased by about 1,400 MW (18 percent) and wind increased by about 270 MW (3 percent).

- **Fuel-mix patterns reflected strong solar production and increased hydro generation** compared to Q1 2025. Mid-day battery charging and evening battery discharging continued to increase in California and the Desert Southwest, contributing to meet significant increases in load during peak evening hours. Increased wind, solar, and hydro production in the Intermountain West offset reductions in coal and natural gas. A large increase in hydro in the Pacific Northwest led to decreased gas generation and made the region a net exporter on average across all hours.
- **Net interchange patterns shifted across the WEIM** compared to Q1 2025, with increased hydro in the Pacific Northwest driving a reduction in net imports into the region of 2,900 MW and an increase of net imports into the California region of 2,400 MW.
- **WEIM transfers averaged 4,010 MW in the first quarter of 2026, down about 500 MW compared to Q1 2025.** Transfers between regions continued to be significantly different during mid-day solar hours than during evening and early morning hours. During solar hours, transfers were largely from CAISO and the Intermountain West to other WEIM regions. During non-solar hours, transfers were lower and were largely into California from the rest of the WEIM.
- **Total generation outages increased substantially in the Intermountain West region and CAISO balancing area,** while decreasing in the Pacific Northwest. Outages were up slightly in the Desert Southwest and California (non-CAISO) regions.
- **Load across the WEIM averaged 76.3 GW, an increase of about 0.7 percent compared to the same quarter of 2025.** Average load in the Intermountain West and Pacific Northwest decreased by 2.8 percent and 1.7 percent, respectively. Average load in the Desert Southwest and California increased by 5.9 percent and 1.8 percent, respectively. Peak 5-minute market load for the first quarter was 102.7 GW on March 19, 2026, hour-ending 19, interval 9, up from the Q1 2025 peak load of about 99.7 GW.

Prices and congestion

- **Real-time prices decreased significantly across the WEIM.** WEIM prices averaged $24/MWh in the 15-minute market and $25/MWh in the 5-minute market, down 35 percent and 31 percent, respectively, from Q1 2025. Prices were highest in California at $28/MWh in the 15-minute market, primarily due to greenhouse gas costs during non-solar hours. Prices in the other regions averaged between $21 and $22/MWh. Prices followed the net-load pattern, with the highest prices during the morning and evening ramps and lower prices during solar hours.
- **Trends in regional price differences continued to be different during mid-day solar hours than during early morning and evening hours.** During mid-day hours, prices in the Pacific Northwest and Northern California were relatively higher than prices in the Desert Southwest and Southern California due largely to excess solar in southern regions. During early morning and 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 $30/MWh, down about 26 percent compared to Q1 2025.** Average prices in the 15-minute and 5-minute markets were $29/MWh and $31/MWh, respectively, for balancing areas participating in the day-ahead market.
- **Day-ahead peak prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about $28/MWh over the quarter, about 33 percent higher than the ISO 15-minute market prices in the Desert Southwest ($21/MWh).** Day-ahead ICE prices for the Mid-Columbia trading hub

averaged about $21/MWh, very similar to ISO 15-minute market prices in the Pacific Northwest ($22/MWh).

- **Congestion patterns for the quarter were significantly impacted by a late March heatwave in California and the Desert Southwest** which created congestion from northern WEIM regions to southern WEIM regions. The magnitude of the impact of congestion on price differences between balancing areas was generally lower in Q1 2026 than Q1 2025.
- **Balancing areas in the Pacific Northwest region were more frequently separated from the larger WEIM system by transfer congestion than balancing areas in other regions.** Averaging across both 15-minute and 5-minute markets, Pacific Northwest balancing areas were transfer constrained in about 11 percent of intervals in the import direction and about 19 percent of intervals in the export direction.
- **170 MW of SDG&E load was shed at 7:46 PM on March 26, 2026 to prevent potential overload of transmission into San Diego.** Several anomalous issues occurred in a short period of time, causing significant battery capacity to switch from discharging to charging within a single interval. The one-interval charging surge was sufficient to exceed transmission limits. While operators acted quickly to issue manual dispatch instructions to the batteries to stop charging, it can take several 5-minute market intervals for battery resources to respond to manual dispatch instructions. As a result, load was automatically curtailed to protect the critical transmission elements while the batteries continued to charge. This situation indicates that reliability could be improved in wholesale electricity markets with significant battery capacity by implementing the technology and processes to curtail battery charging prior to curtailing load.
- **Day-ahead congestion rent totaled $87.4 million, down $53 million (38 percent)** from Q1 2025.

Resource sufficiency evaluation

- **Resource sufficiency test failures remained rare across the WEIM** in Q1 2026, with all areas except WAPA Desert Southwest failing fewer than 1 percent of intervals across all test types and directions. WAPA Desert Southwest failed the flexibility test in the upward direction in 1.4 percent of all intervals.
- **Seven balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** Four of these entities received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. PacifiCorp East received the largest amount of additional transfers in any single interval (425 MW) and the largest amount of additional transfer energy over the quarter (323 MWh).
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in separate quarterly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.[2]

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

Uplift costs and credits

- **Real-time imbalance offsets for balancing areas participating only in the WEIM real-time markets were a $15 million credit** to WEIM entities, up from a $12 million credit in the same quarter of 2025. The congestion portion of this offset, largely consisting of congestion rent from WEIM transfer constraints, was a $16.8 million credit.
- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $46 million in uplift** in the first quarter of 2026, an increase from $41 million in the same quarter of 2025. The congestion and energy portions of the offset each accounted for about $22 million of the total.
- **Bid cost recovery payments for units in balancing areas participating in both the day-ahead and real-time markets totaled about $33 million** in the first quarter of 2026, down 24 percent from the $44 million in bid cost recovery in the first quarter of 2025.
- **Bid cost recovery for units in areas participating only in the WEIM totaled about $1.9 million**, a 34 percent decrease from Q1 2025.

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 adjustments to hour-ahead and 15-minute market load in the morning and evening ramp periods were down significantly compared to Q1 2025 as part of a pilot program from January to early March 2026 aimed at reducing manual interventions.
- **Operator adjustments to the residual unit commitment process (RUC) procurement target decreased by about 37 percent in the first quarter of 2026 compared to the same quarter of 2025.**
- **Manual dispatch energy trends were divergent across WEIM regions.** Compared to Q1 2025, combined incremental and decremental manual dispatch energy decreased in the California (non-CAISO), Desert Southwest and the Intermountain West regions by 63 percent, 28 percent, and 39 percent, respectively, and increased in the Pacific Northwest by 78 percent. The average hourly total energy from exceptional dispatches in the CAISO balancing area was 280 MW in the first quarter of 2026, up 160 percent from the first quarter of 2025.

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 again on average lower than requirements produced using the histogram method.** For the flexible ramping product, coverage rates generally remained close to the 95–97.5 percent target, but the regression coefficients were statistically significant in only 29 percent of intervals. In the resource sufficiency evaluation, coverage ranged between roughly 84 percent and 95 percent across balancing areas, and only 36 percent of regression coefficients were statistically significant.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty 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 set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on zero days in the quarter.** The 75th percentile target was applied on two days and the 50th percentile target was applied on 6 days. No adjustment was applied on the remaining days.

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 during 0.9 percent of intervals** in the first quarter of 2026, up from 0.6 percent in the same quarter of 2025. Battery and hydro resources made up 68 percent and 16 percent of upward flexible capacity, respectively. Wind and solar combined to provide 43 percent of downward flexible capacity, and batteries provided 31 percent of downward flexible capacity.
- **Regulation up requirements increased 250 MW (54 percent) on average compared to Q1 2025 due largely to a CAISO balancing area pilot program** designed to increase regulation up requirements in order to reduce uncertainty and minimize the use of load conformance in the real-time markets. Despite the increased requirements, regulation up costs were similar to Q1 2025 due in part to lower natural gas prices.
- **Ancillary service payments totaled $17.0 million in the first quarter of 2026, down 53 percent from the same quarter of the previous year.**
- **Available balancing capacity up and down was dispatched to address power balance infeasibilities in 1.0 percent of intervals for NV Energy.** Available balancing capacity was dispatched in less than 0.1% of intervals for all other WEIM balancing areas.

California ISO balancing area congestion revenue rights, transmission and resource adequacy capacity

- **Transmission ratepayers made roughly $3.4 million from the congestion revenue rights (CRR) auction** in the first quarter of 2026, as payments to auctioned congestion revenue rights holders were lower than auction revenues. This was the third quarterly profit for ratepayers in the auction since CRR auction reforms were made in 2016, with the first occurring in Q3 2024.
- **No monthly reservations were made for CAISO balancing area high priority wheel-through rights** for the first quarter of 2026. Incremental daily reservations of 1 MW were made for two days in the quarter, with the import portion of the wheel-through at the Palo Verde intertie. To use this reserved capacity, entities may self-schedule up to the reserved amount in the day-ahead market. The reserved wheel-through rights were used at the full 1 MW limit in four hours on March 5.
- **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 bids decreased 78 percent from the first quarter of 2025.**

1 Supply conditions

1.1 Natural gas prices

Electricity prices in Western states typically track natural gas price trends, reflecting that gas-fired units have often been 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.[3] In the first quarter of 2026, average natural gas prices decreased compared to the same quarter of 2025. Gas prices declined to be near historic lows across most major Western trading hubs.[4] Average first quarter prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, and NW Opal Wyoming decreased by 45 percent, 31 percent, 24 percent, and 36 percent, respectively, compared to the first quarter of 2025. El Paso Permian prices also declined significantly, averaging -$0.52/MMBtu compared with $2.04/MMBtu in the first quarter of 2025.

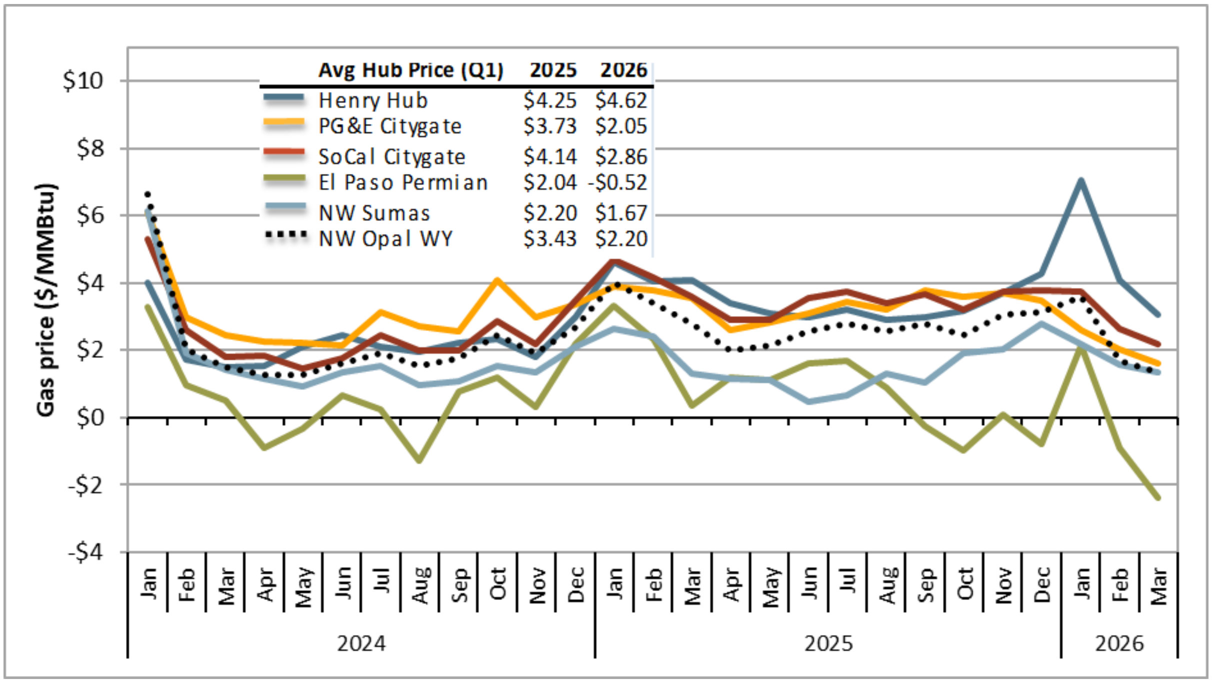
Henry Hub was the notable exception to the broader decline in average prices, with prices increasing 9 percent in the first quarter of 2026 compared to the same period in 2025.

Natural gas prices at most major Western trading hubs also decreased in the first quarter of 2026 compared to the fourth quarter of 2025. PG&E Citygate, SoCal Citygate, El Paso Permian, Northwest Sumas, and Northwest Opal Wyoming decreased about 43 percent, 20 percent, 13 percent, 26 percent, and 23 percent, respectively. In contrast, prices at Henry Hub increased by 25 percent.

3 Updated data resulted in an adjustment to average quarterly natural gas prices for the second quarter of 2024.

4 U.S. Energy Information Administration (EIA), California natural gas prices reach historic lows in early 2026, June 2, 2026. https://www.eia.gov/todayinenergy/detail.php?id=67744

Figure 1.1 Monthly average natural gas prices



1.2 Renewable generation

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. In the first quarter of 2026, the average hourly generation from renewable resources in the WEIM footprint increased by about 6,800 MW (16 percent) compared to the same quarter of 2025.[5] Hydroelectric generation increased by approximately 5,200 MW (22 percent) across the WEIM footprint. Solar generation increased in every region, by approximately 1,400 MW (18 percent) across the WEIM.[6] Average hourly generation from wind increased by about 270 MW (3 percent), and geothermal and biogas-biomass resources decreased by about 18 MW (1 percent) and 27 MW (3 percent), respectively, across the WEIM footprint compared to the first quarter of 2025.

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

- Generation from solar resources made up 44 percent of all renewable output in the California region and increased by 700 MW (15 percent) compared to the first quarter of 2025. Hydroelectric generation increased by about 150 MW (5 percent), while wind generation decreased by about 440 MW (16 percent), year-over-year.

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

[6] California includes BANC, CAISO, 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.

- The Desert Southwest region saw increases in solar (470 MW or 23 percent) and decreases in hydroelectric generation (50 MW or 12 percent), contributing to an overall increase in renewable generation of 300 MW (7 percent) compared to the first quarter of 2025.
- Renewable generation in the Intermountain West increased by approximately 970 MW (18 percent) compared to the first quarter of 2025, with the largest increase from wind generation (500 MW or 21 percent, respectively). Solar increased by 210 MW (32 percent), and hydroelectric generation increased by about 250 MW (13 percent) year-over-year.
- In the first quarter of 2026, hydroelectric generation represented 89 percent of all renewable generation in the Pacific Northwest, with an increase of 4,800 MW (27 percent) from the same quarter of the previous year. Wind generation increased by about 300 MW (15 percent), while solar generation remained the same year-over-year.

Figure 1.2 California - Average monthly renewable generation

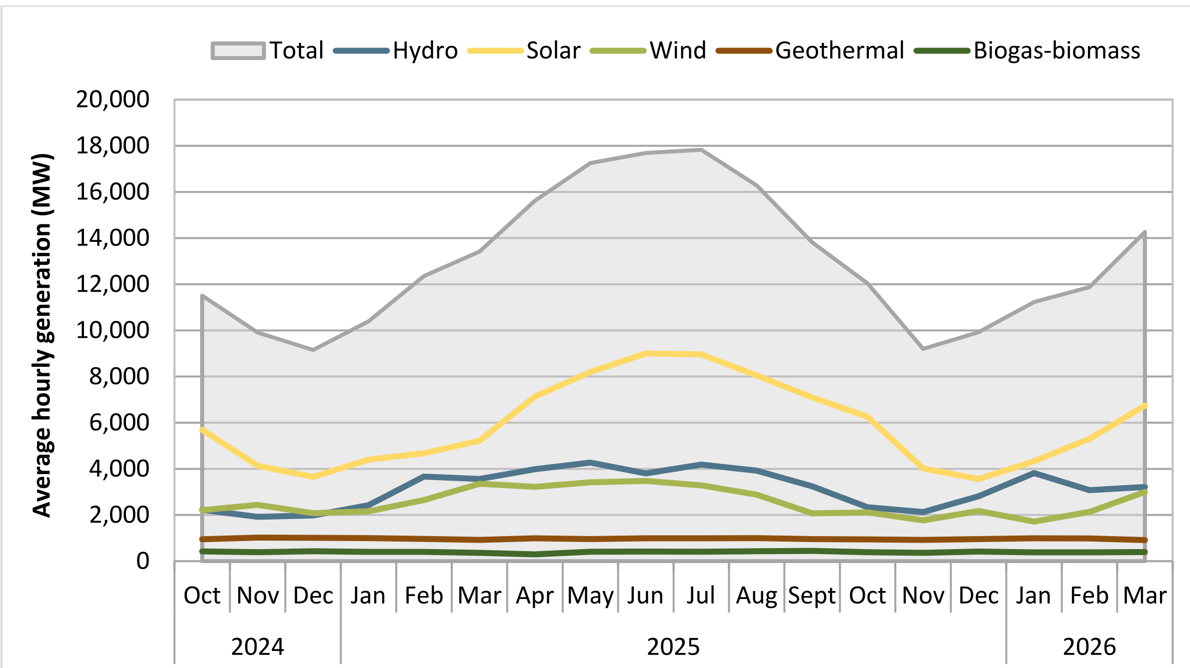


Figure 1.3 Desert Southwest - Average monthly renewable generation

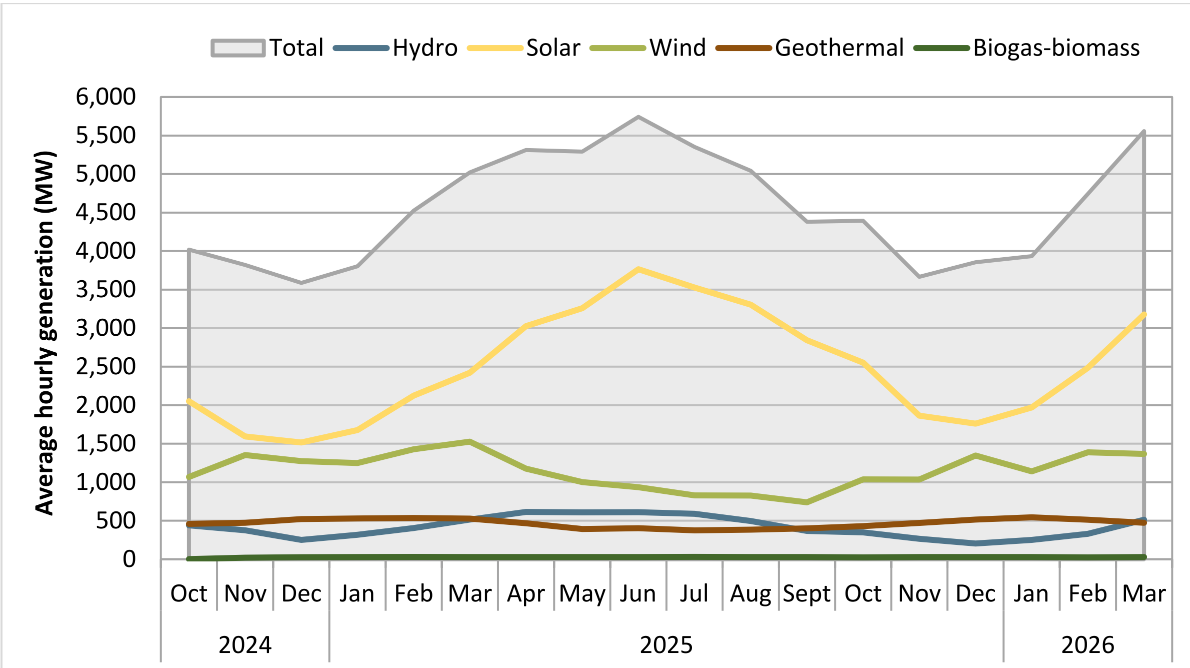


Figure 1.4 Intermountain West - Average monthly renewable generation

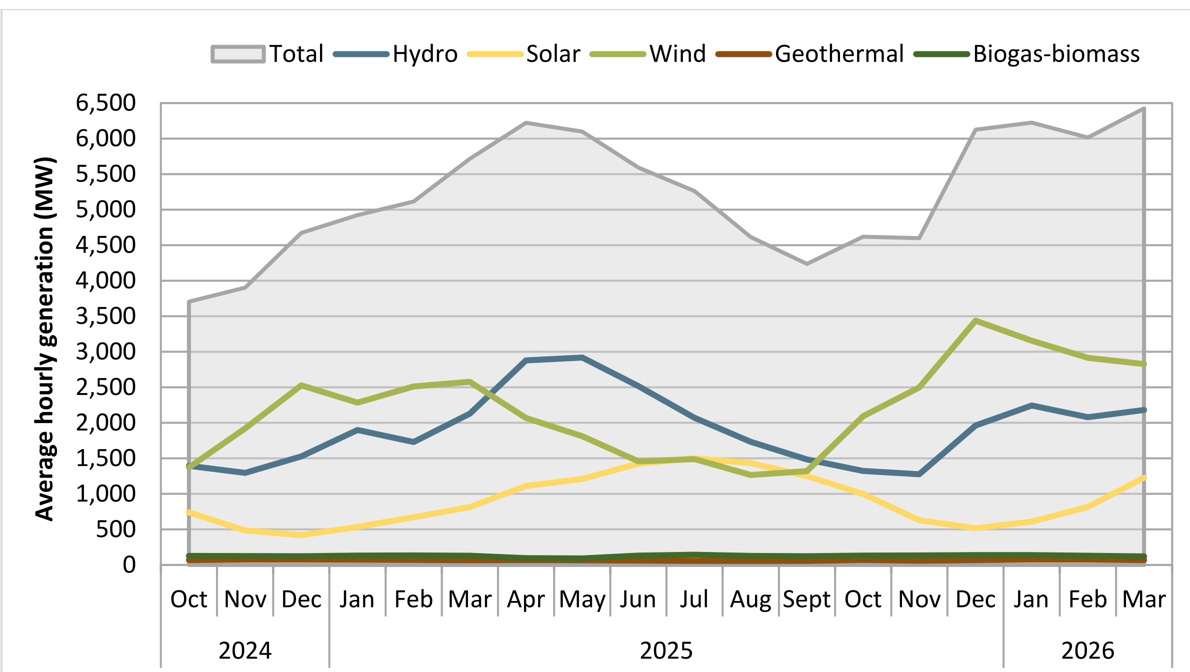


Figure 1.5 Pacific Northwest - Average monthly renewable generation

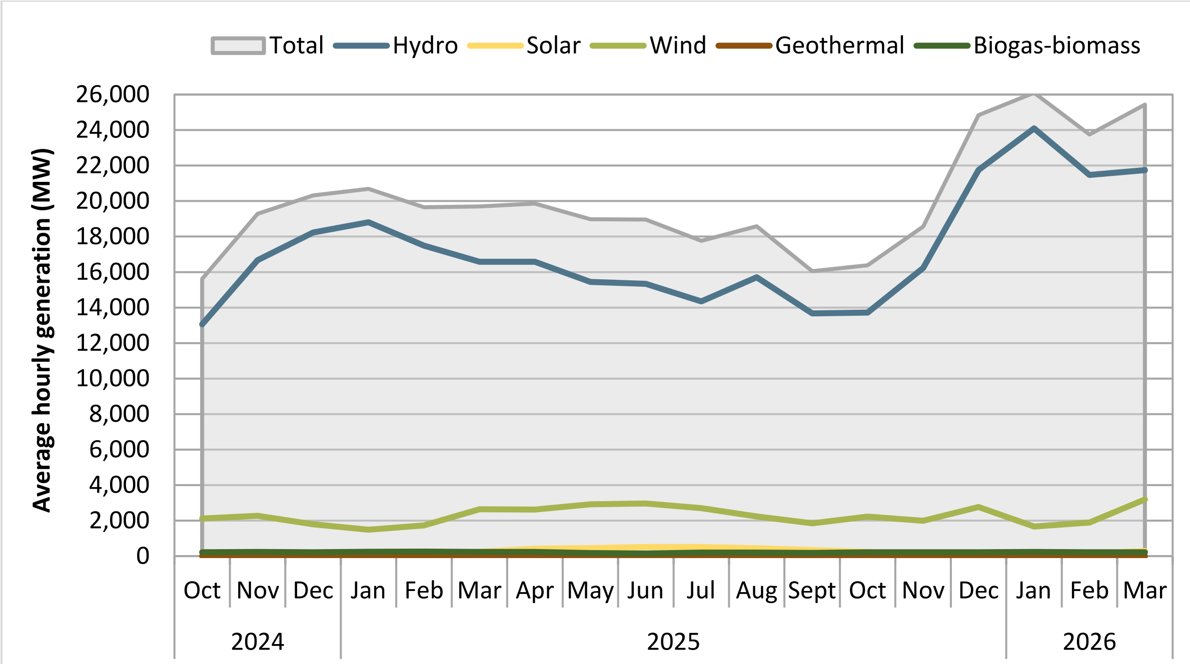
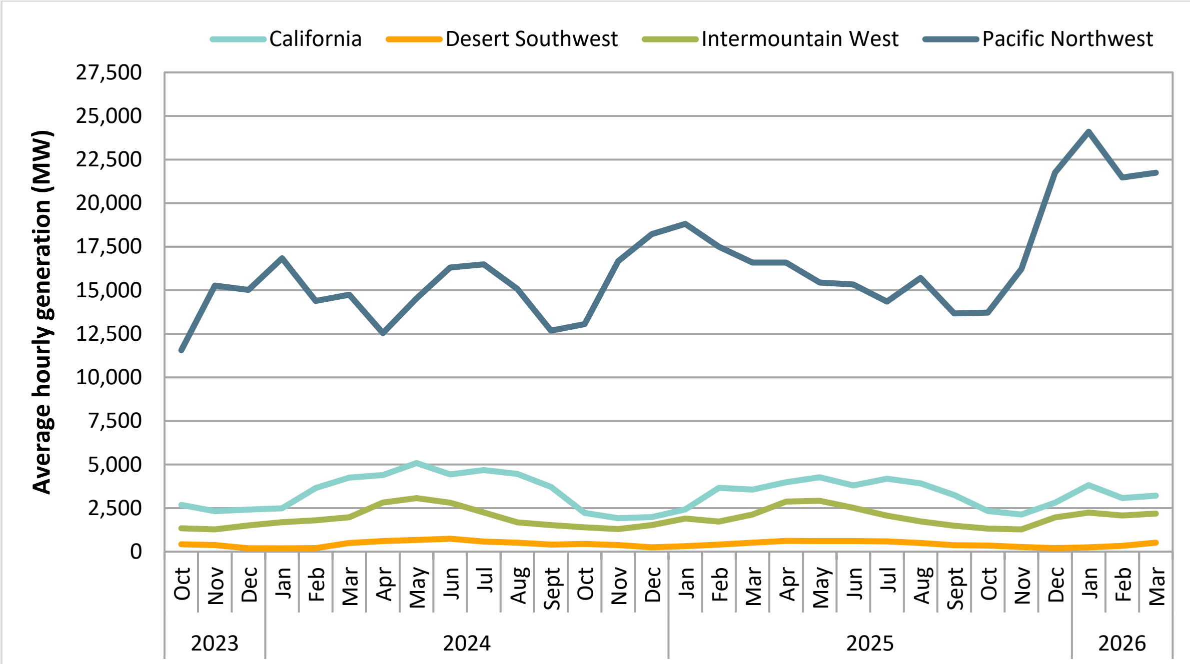


Figure 1.6 shows the monthly average hydroelectric generation from October 2023 to March 2026.

- In the California region, hydroelectric generation increased by 150 MW (5 percent) compared to the first quarter of 2025.
- In the Desert Southwest, hydroelectric generation decreased by 50 MW (12 percent) from the first quarter of 2025.
- Hydroelectric output in the Intermountain West increased by 250 MW (13 percent) compared to the first quarter of 2025.
- In the Pacific Northwest, hydroelectric generation in the first quarter of 2026 increased 4,800 MW (27 percent) compared to the same quarter of 2025, and increased 7,100 MW (46 percent) compared to the first quarter of 2024.

Figure 1.6 Average monthly hydroelectric generation by region



1.3 Generation by fuel type

Figure 1.7, Figure 1.9, Figure 1.11, and Figure 1.13 show the average hourly generation by fuel type during the first quarter of 2026 for each region in the WEIM. Figure 1.8, Figure 1.10, Figure 1.12, and Figure 1.14 show the change in hourly generation by fuel type between the first quarters of 2025 and 2026. Positive values represent increased generation compared to the same time last year, and negative values represent a decrease in generation. Change in total load is denoted by the black line.

Total hourly average generation peaks at hour-ending 19 in all four regions in the WEIM. As shown in Figure 1.7, there was significant solar generation (represented by the yellow bars) and corresponding load from batteries charging during mid-day hours (represented by the aqua bars below the zero-axis) in California. Natural gas generation decreased in all hours in the California region. This was partially due to higher imports across all hours and increased battery discharge during evening hours. The Intermountain Power Plant in Utah, which supplies energy to LADWP, officially finalized its transition from coal to natural gas in December 2025, also contributing to a decrease in coal generation in the California region year-over-year.[7]

Natural gas remained the largest source of generation in the Desert Southwest, with increases in all hours compared to the first quarter of 2025. The Desert Southwest also saw large increases in solar generation and corresponding battery charging in the solar hours and discharging in evening and early morning hours. Net imports increased by an average of 280 MW (16 percent) across all hours.

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[7] See https://www.latimes.com/environment/story/2025-12-04/los-angeles-says-so-long-to-coal and https://ipprenewed.com/ for more information.

In the Intermountain West, coal and natural gas continued to be the largest overall sources of generation in the first quarter of 2026, although coal generation decreased in all hours by an average of 900 MW (24 percent). Wind generation increased by an hourly average of 500 MW (21 percent) compared to the first quarter of 2025. Exports increased significantly, by an average of 440 MW (620 percent) each hour, as the Intermountain West shifted from being a net importer in most hours of the first quarter of 2025 to a net exporter in all hours of the first quarter of 2026.

Hydroelectric generation dominated the generation mix in the Pacific Northwest, accounting for about 89 percent of total generation, as shown in Figure 1.13, and increasing by about 4,800 MW (27 percent) on average year-over-year. Net imports and natural gas generation decreased across all hours, with the Pacific Northwest also shifting from being a net importer in most hours of the first quarter of 2025 to a net exporter in all hours of the first quarter of 2026.

Figure 1.7 California - Average hourly generation by fuel type (Q1 2026)

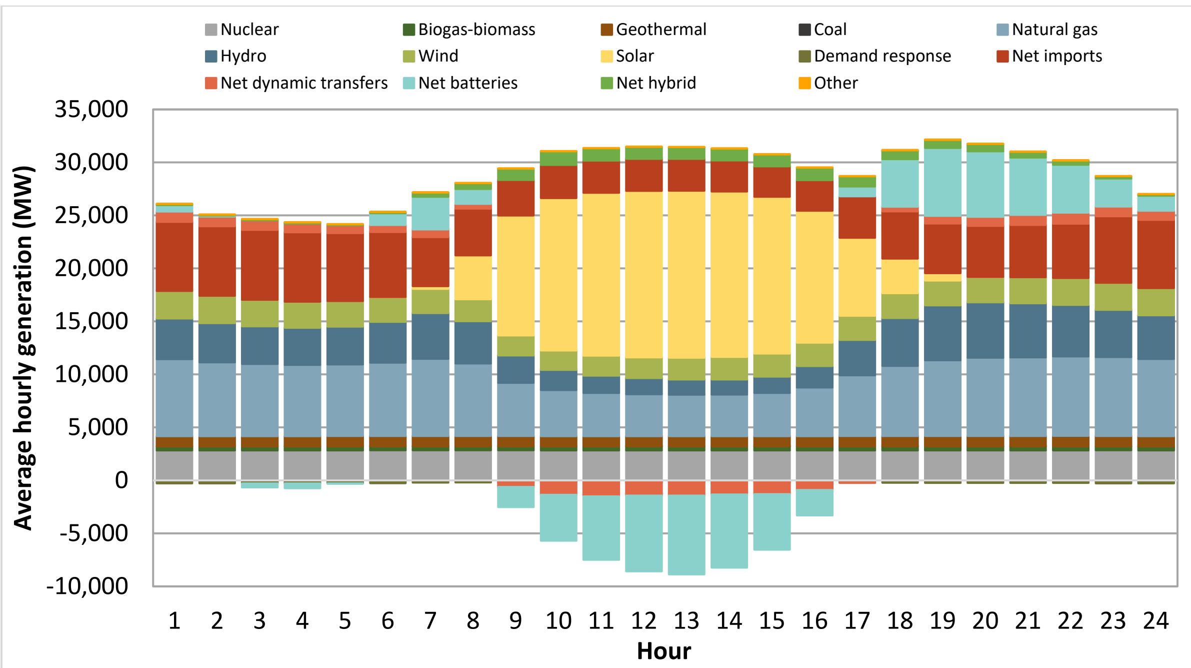


Figure 1.8 California - Change in average hourly generation by fuel type (Q1 2026 vs. Q1 2025)

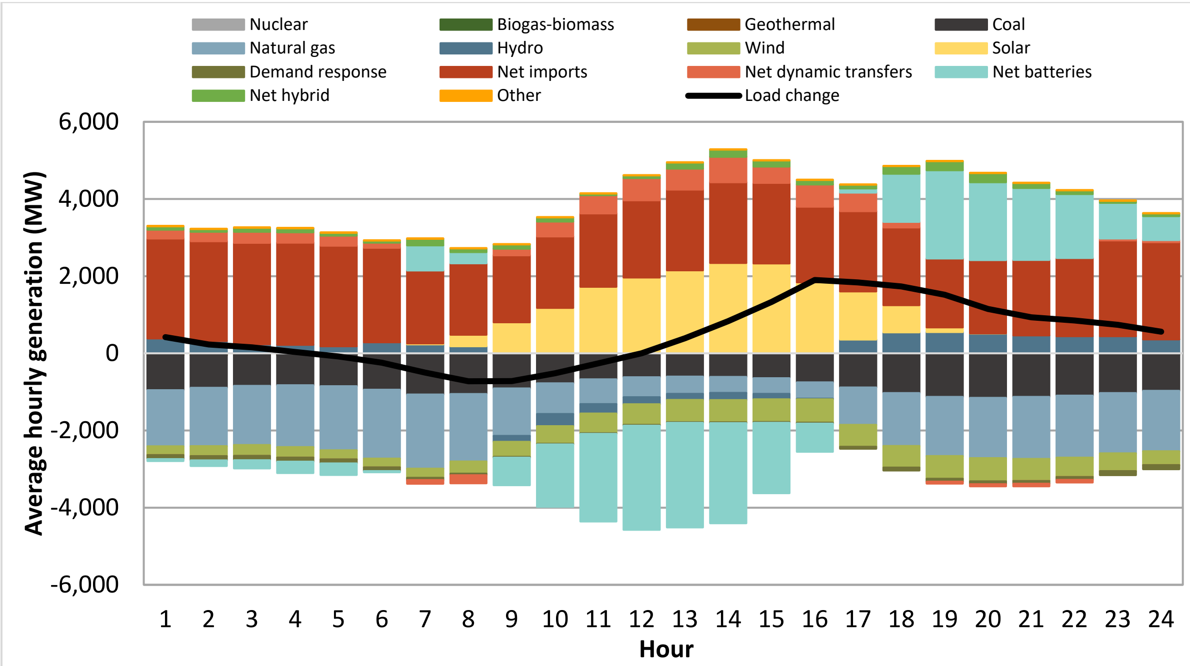


Figure 1.9 Desert Southwest - Average hourly generation by fuel type (Q1 2026)

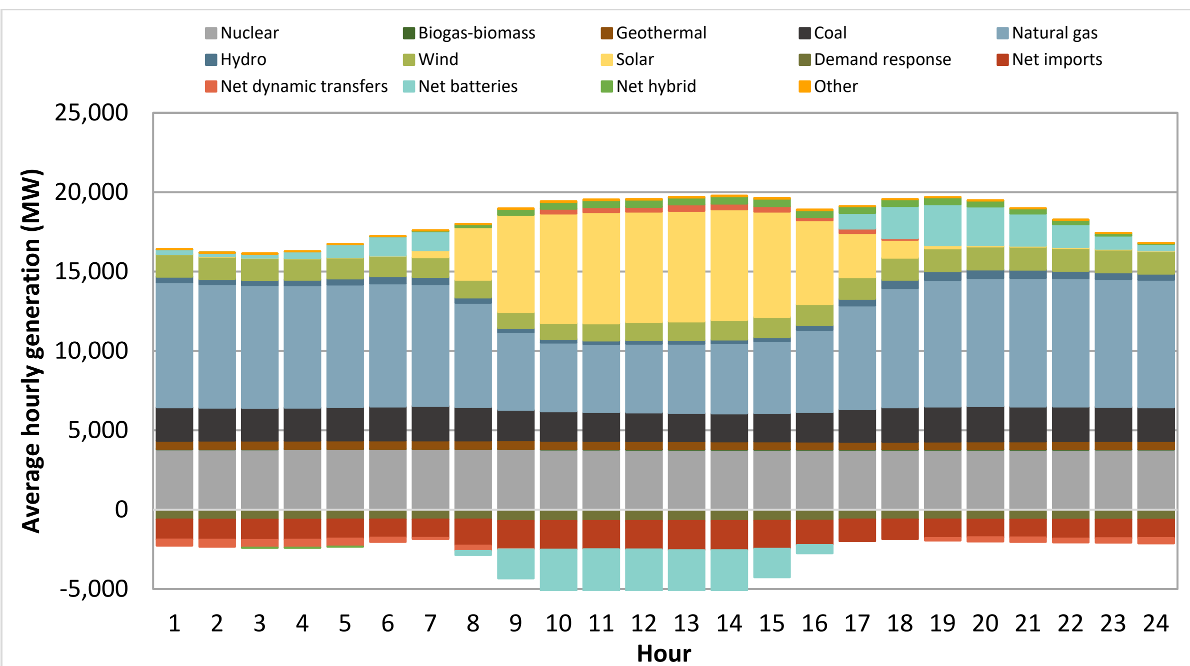


Figure 1.10 Desert Southwest - Change in average hourly generation by fuel type (Q1 2026 vs. Q1 2025)

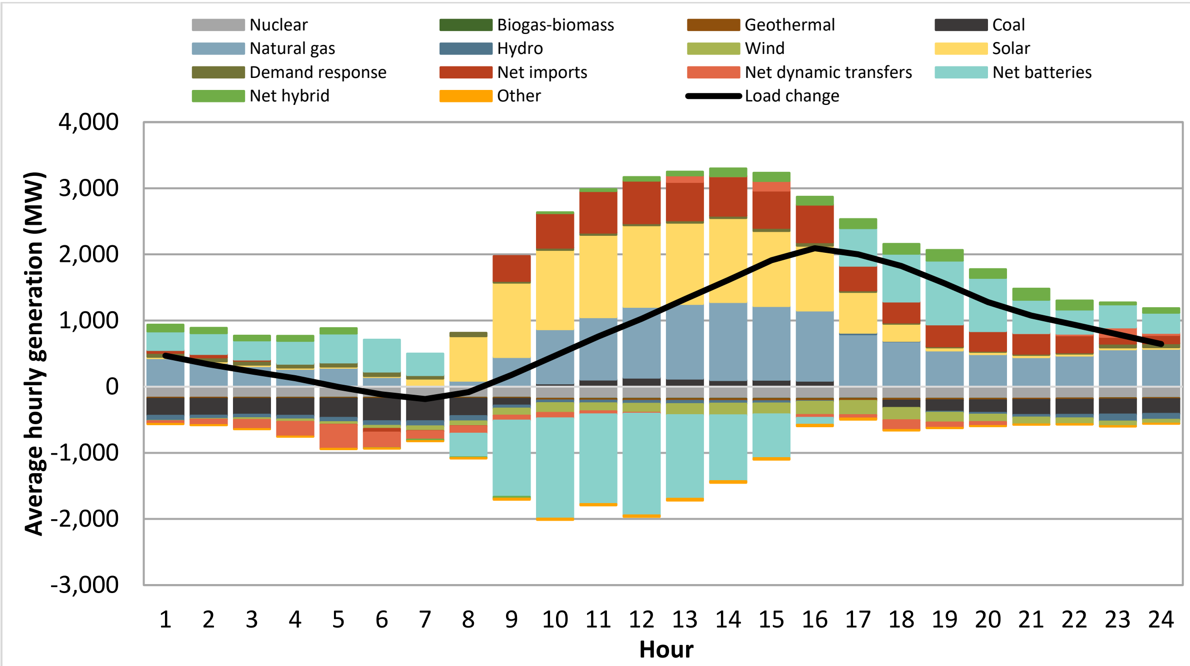


Figure 1.11 Intermountain West - Average hourly generation by fuel type (Q1 2026)

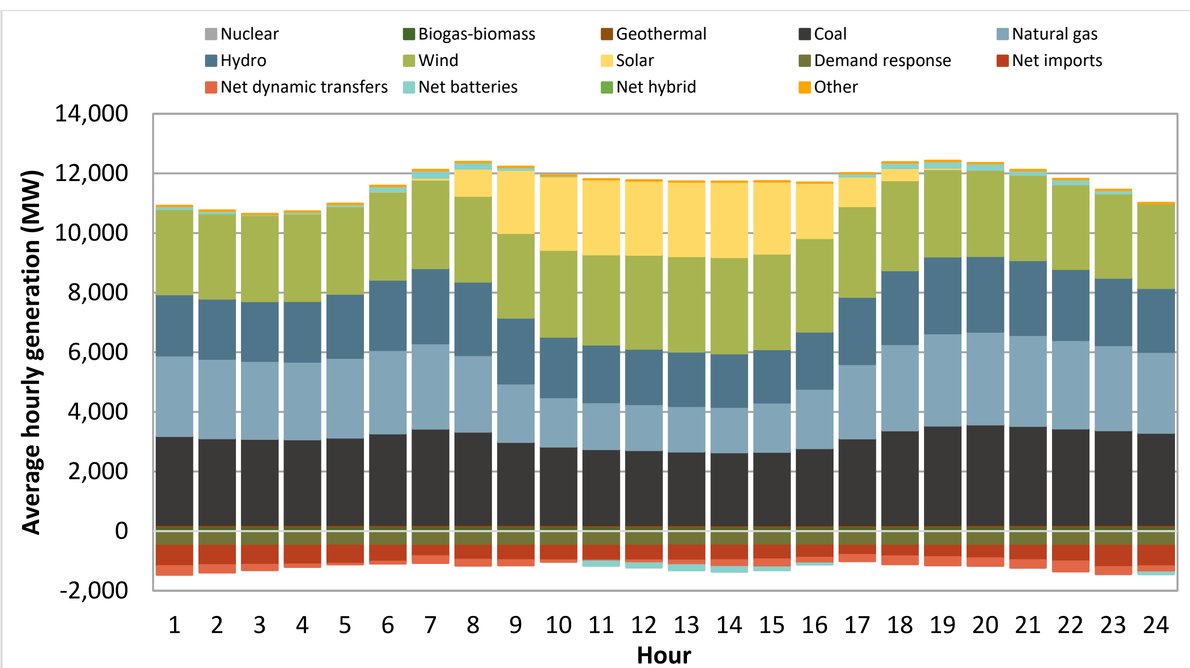


Figure 1.12 Intermountain West - Change in average hourly generation by fuel type (Q1 2026 vs. Q1 2025)

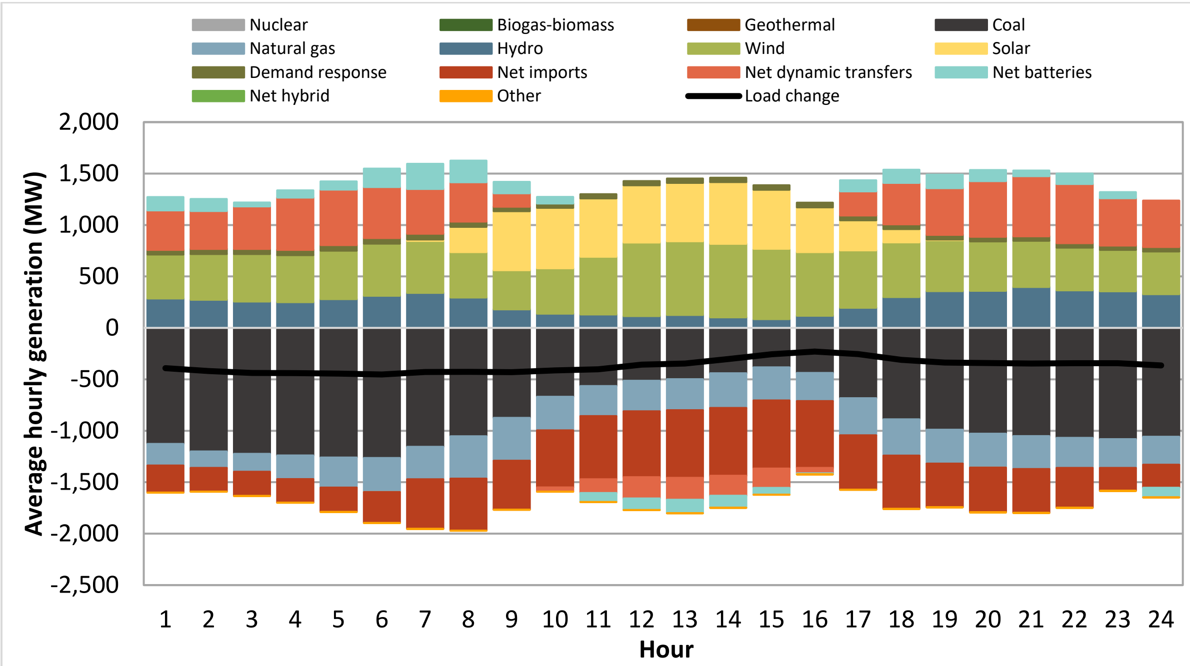


Figure 1.13 Pacific Northwest - Average hourly generation by fuel type (Q1 2026)

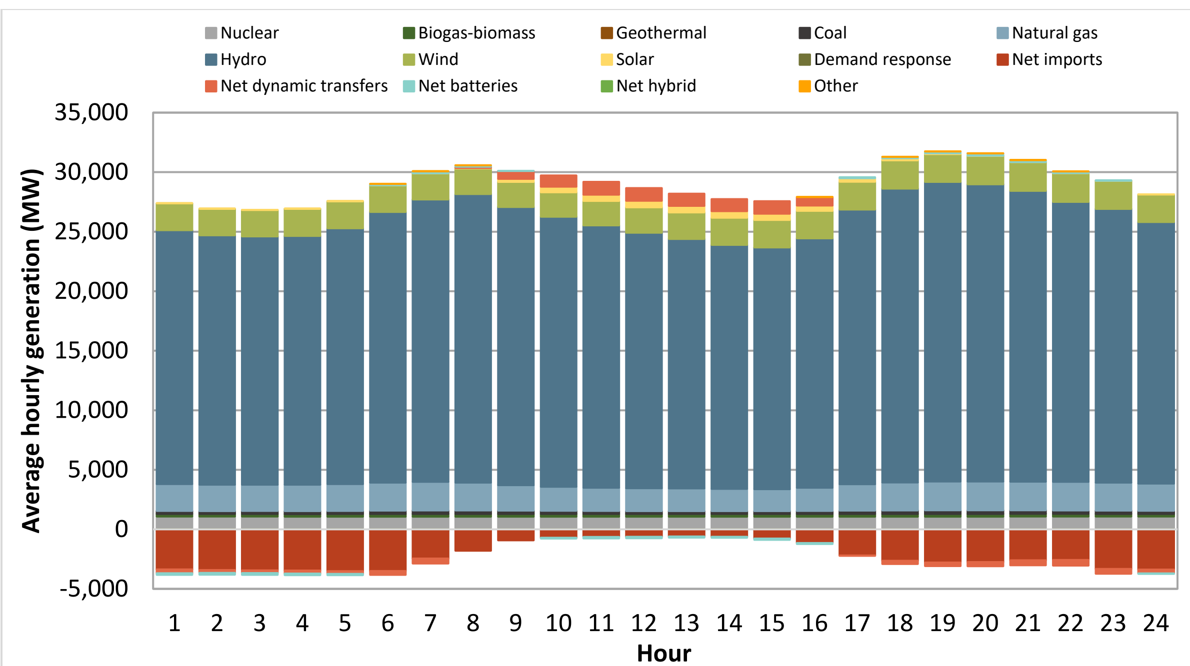
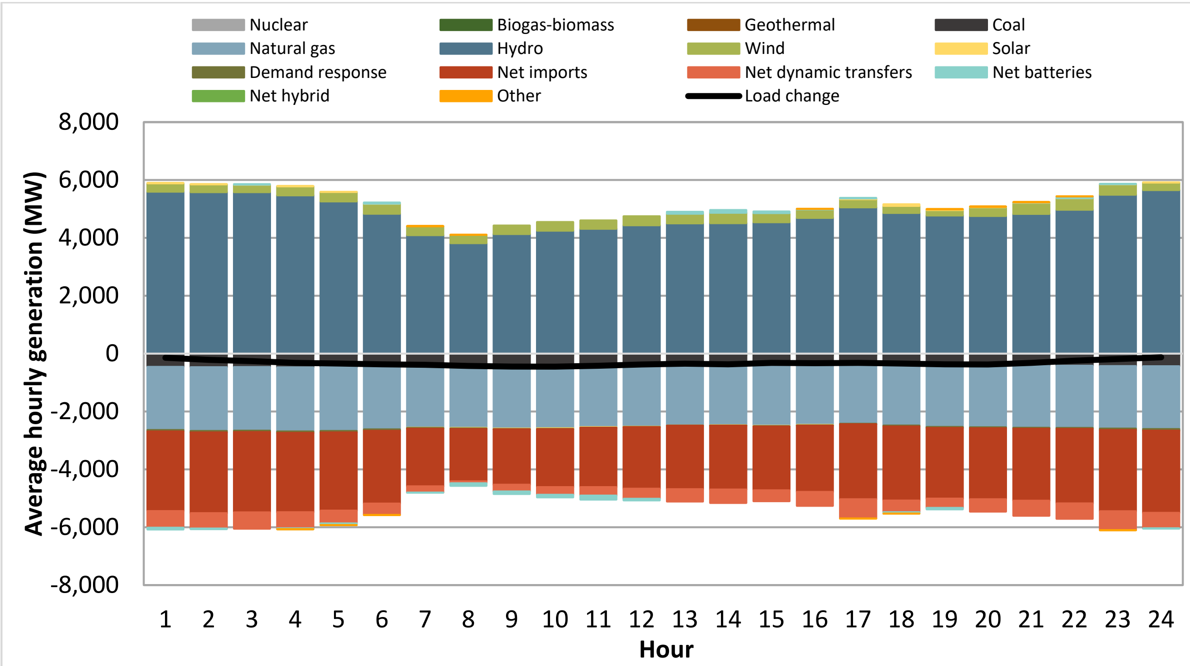


Figure 1.14 Pacific Northwest - Change in average hourly generation by fuel type (Q1 2026 vs. Q1 2025)



1.4 Interchange

Figure 1.15 to Figure 1.22 show average 5-minute market imports, exports, and WEIM transfers (collectively, “interchange”) for each region in the WEIM. For each region, the first figure shows the total imports and exports, while the second figure shows only the net interchange.[8] Power flowing into a balancing area is represented as a positive value, while power flowing out of a balancing area is shown as negative. This energy is categorized as follows:

- **Interchange before dynamic transfers** (black line) represents the net interchange into the region before accounting for dynamic WEIM transfers. This includes:
    - **Base WEIM intertie schedules** (stacked blue bars) are fixed intertie transactions between two non-CAISO balancing areas within the WEIM. These transfers are not optimized in the market.

[8] For the total import and export figures, interchange between two balancing areas within the same region is counted as both an import and an export. For example, a 200 MW base WEIM transfer from Arizona Public Service to Salt River Project within the Desert Southwest appears as a 200 MW export for AZPS and a 200 MW import for SRP in the region’s total interchange figure. The net interchange figures show only the region’s net flow, so this transfer would net to zero and would not appear in the net interchange figure.

- **Non-WEIM intertie schedules** (stacked aqua bars) are fixed intertie transactions between a WEIM and a non-WEIM balancing area. These transfers are not optimized in the market.
- **CAISO intertie schedules** (stacked green bars) are import and export schedules into or out of the CAISO balancing area that result from bid-in or self-scheduled participation in the market.[9] Most CAISO intertie schedules are scheduled in hourly blocks where the hour-ahead scheduling process (HASP) is the final opportunity for these schedules to be optimized in the market.[10]

- **Interchange after dynamic transfers** (red line) represents the final net interchange into and out of all balancing areas, including WEIM transfers that are optimized in the market. This includes the categories above, plus:
    - **Dynamic WEIM transfers** (stacked gold bars) are energy transfers between any two WEIM balancing areas that are optimized in the real-time market.[11]

In comparing the first quarters of 2025 and 2026, net interchange after dynamic transfers (red line) increased in California and the Desert Southwest by approximately 2,400 MW (97 percent) and 215 MW (13 percent), respectively. Net interchange after dynamic transfers decreased (i.e., net exports increased) in the Intermountain West and Pacific Northwest by roughly 175 MW (34 percent) and 2,900 MW (320 percent), respectively.

These decreases reflect significant shifts toward net exports in the Intermountain West and Pacific Northwest, consistent with Figure 1.12 and Figure 1.14, which show both regions moving from net imports in many hours in Q1 2025 to net exports across nearly all hours in Q1 2026. The increase in net exports in the Pacific Northwest was due largely to increased hydro, while the increase in net exports in the Intermountain West was due mainly to higher wind, hydro and solar production.

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9 This category includes all schedules from mirror system resources (MSRs). For CAISO intertie schedules with a WEIM balancing area, a mirror system resource reflects the WEIM balancing area perspective of the intertie schedule. For example, if the hour-ahead scheduling process (HASP) clears a 50 MW import schedule for CAISO on an intertie that includes NV Energy, an equal 50 MW export schedule will be shown on the mirror system resource from NV Energy. Both sides of the intertie schedule are accounted for in these figures.

10 A small subset of CAISO intertie schedules can be modified and optimized in the 15-minute market.

11 This category also includes static transfers, which are optimized in the 15-minute market but held fixed in the 5-minute market.

Figure 1.15 California - Average hourly interchange by quarter

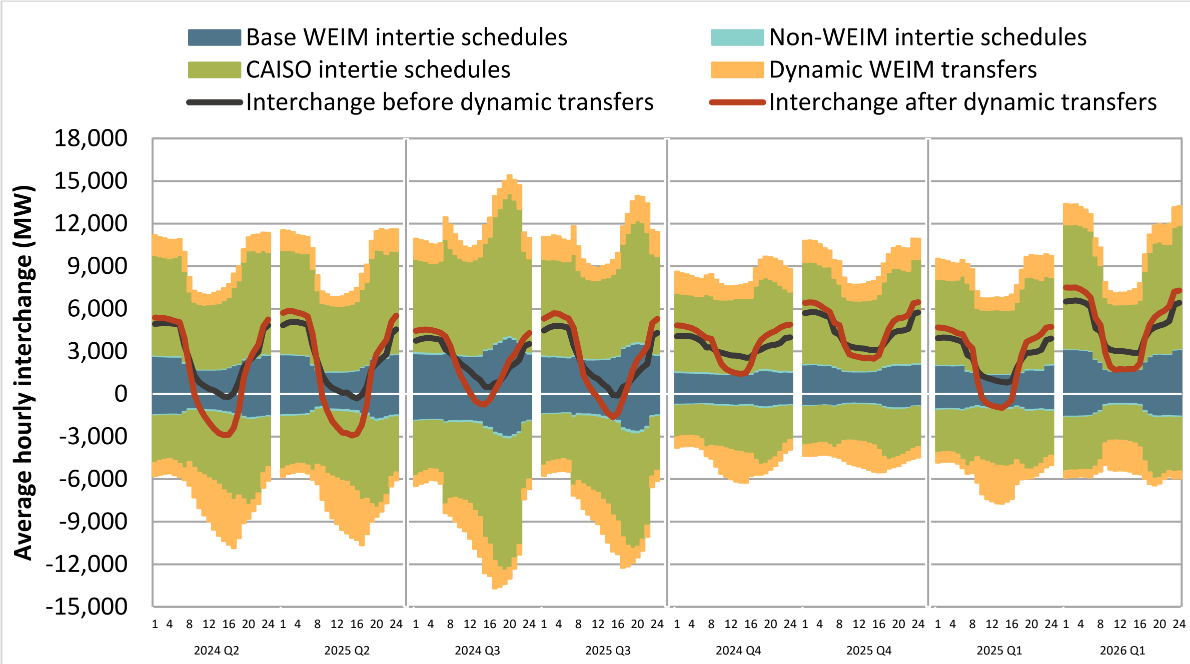


Figure 1.16 California - Average hourly net interchange by quarter

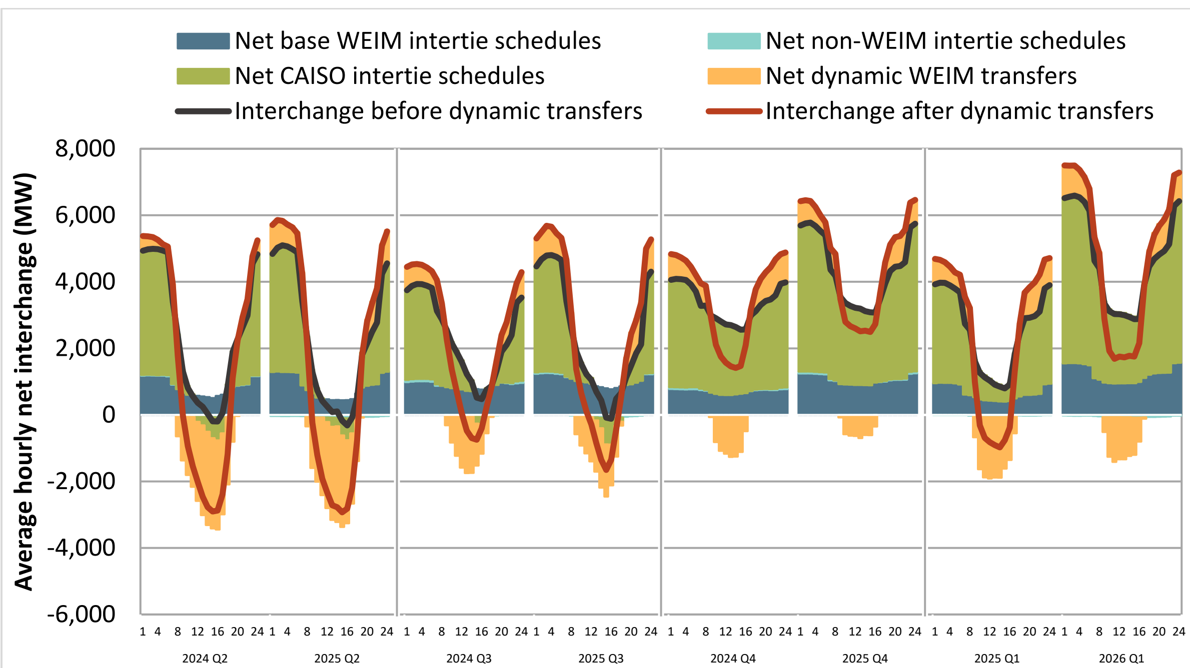


Figure 1.17 Desert Southwest - Average hourly interchange by quarter

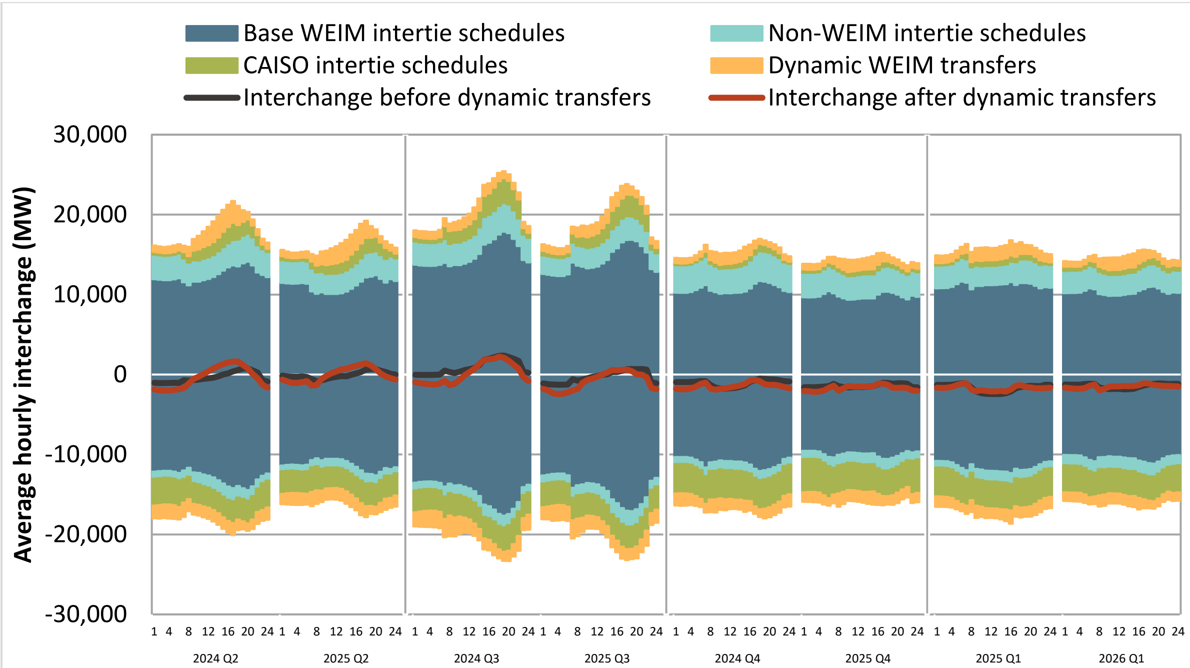


Figure 1.18 Desert Southwest - Average hourly net interchange by quarter

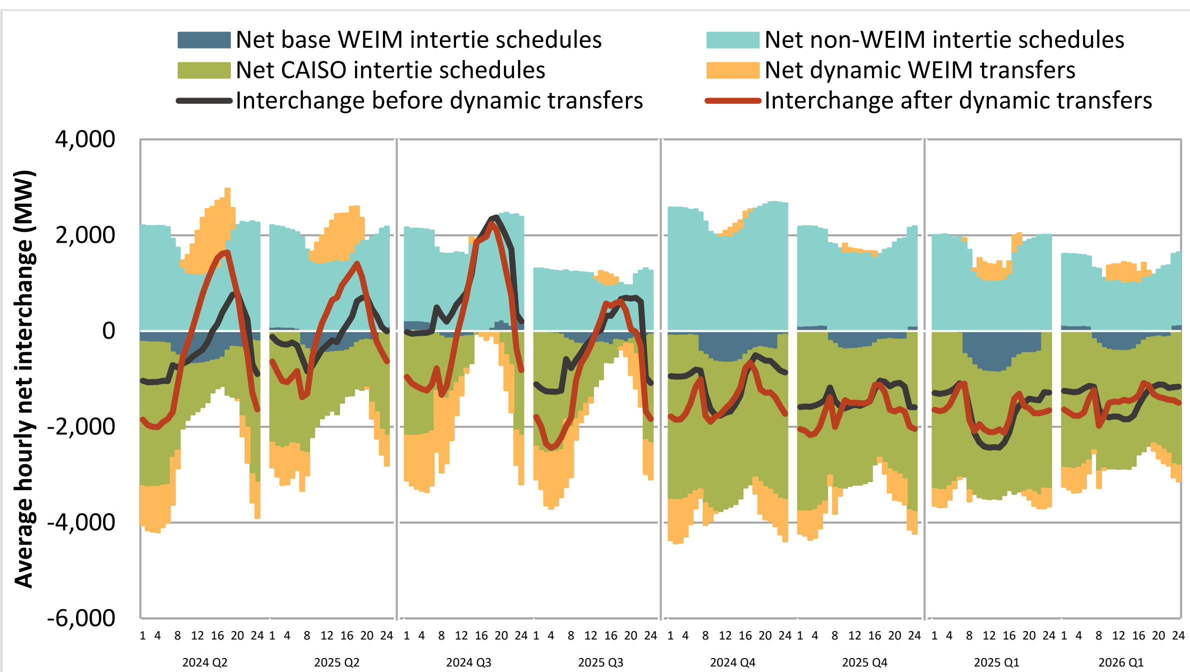


Figure 1.19 Intermountain West - Average hourly interchange by quarter

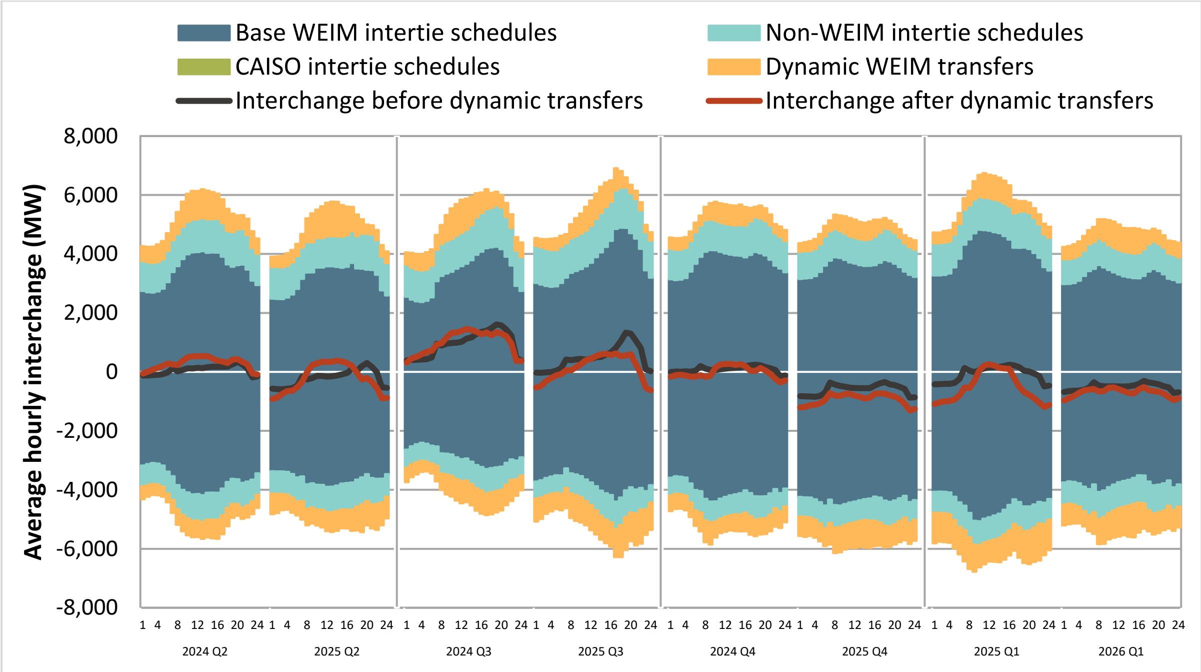


Figure 1.20 Intermountain West - Average hourly net interchange by quarter

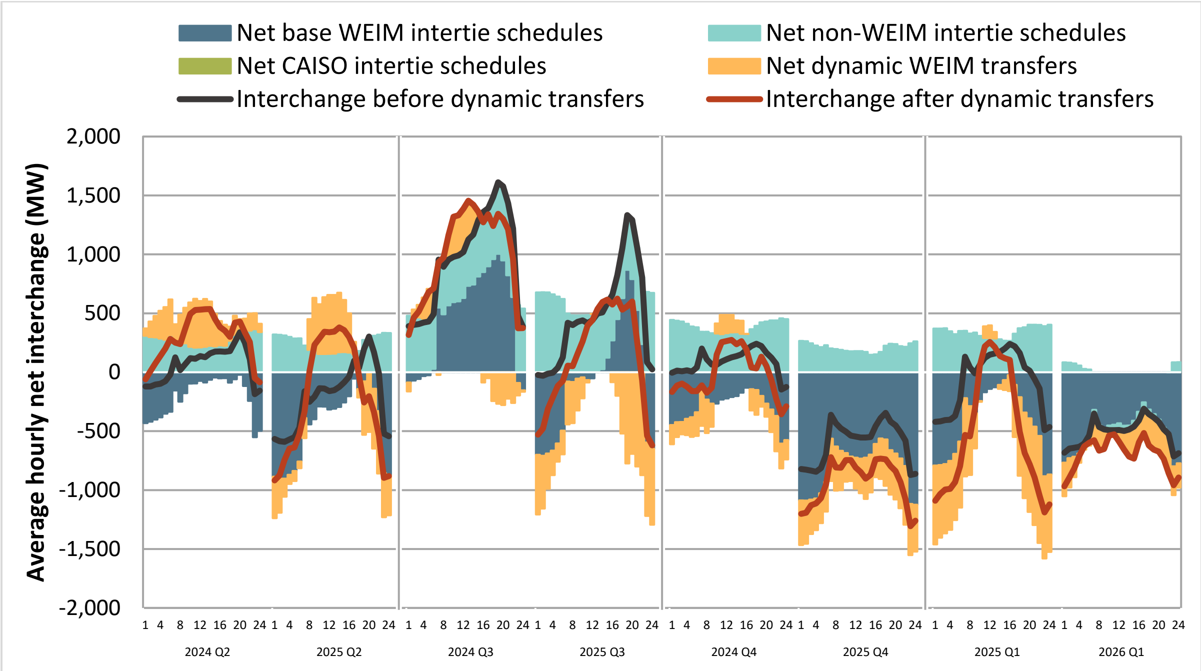


Figure 1.21 Pacific Northwest - Average hourly interchange by quarter

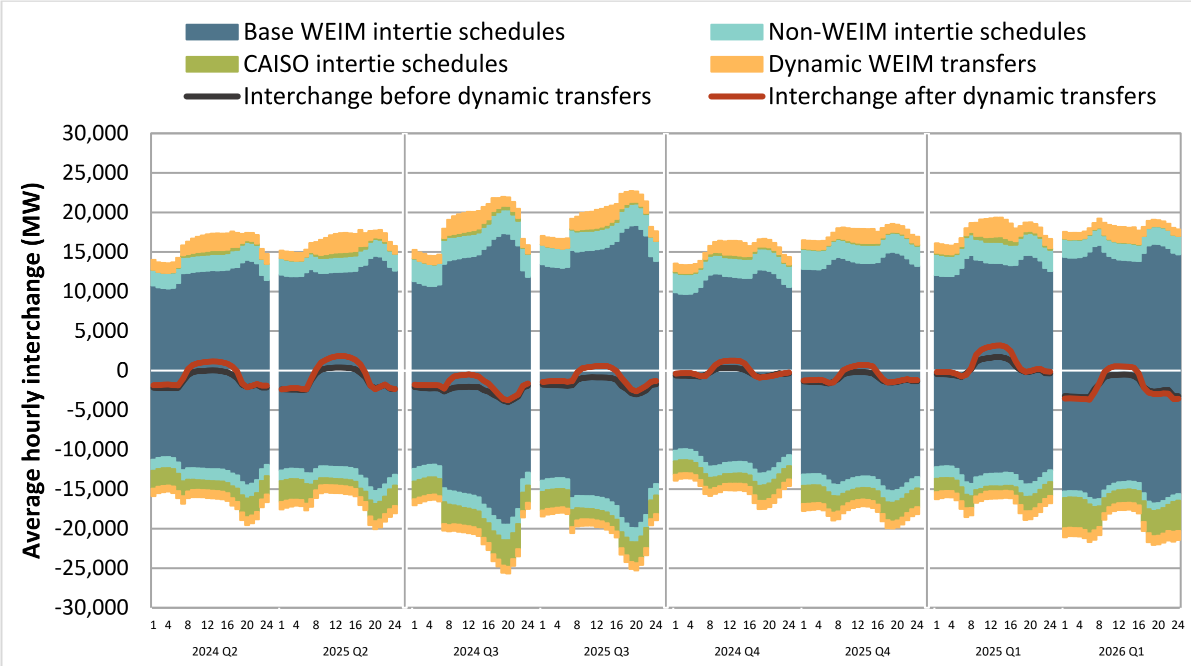
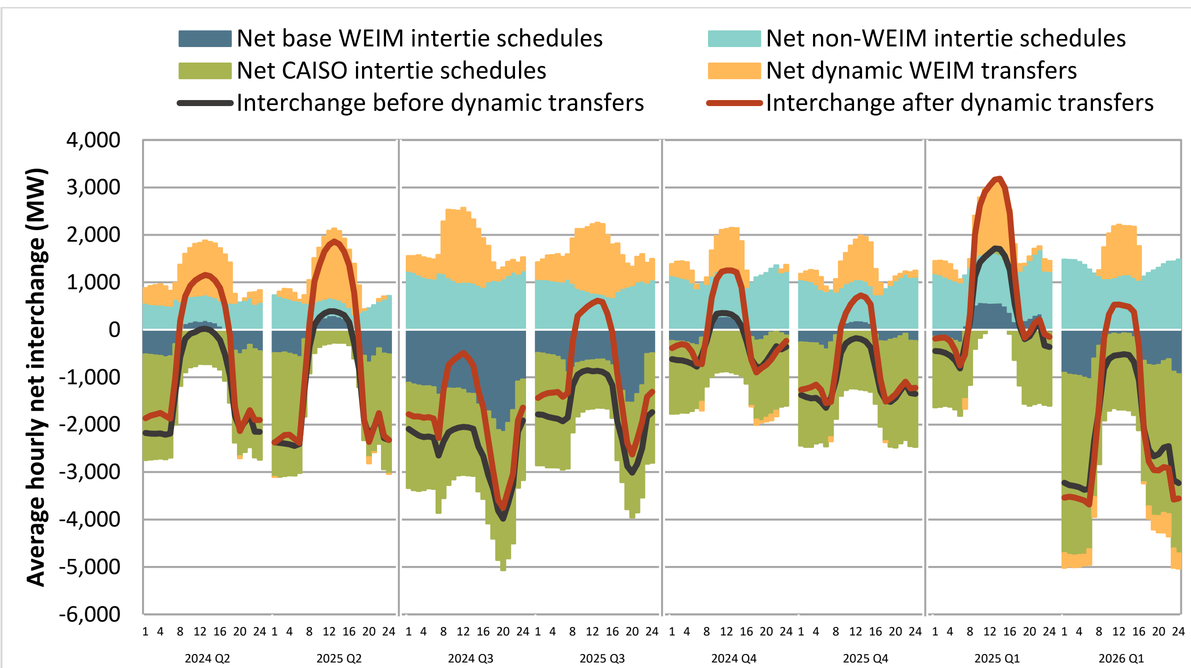


Figure 1.22 Pacific Northwest - Average hourly net interchange by quarter



1.5 Generation outages

This section covers information on generation outages in the California ISO balancing area and the WEIM by region.[12,13] The average generation on outage in the California ISO balancing area was 20,900 MW in the first quarter of 2026, about a 10 percent increase compared to the first quarter of 2025.[14] In the California (non-CAISO) region of the WEIM, outages averaged about 5,000 MW, an increase of about 280 MW from the first quarter of 2025. The Desert Southwest region averaged about 11,900 MW of total generation outages, a four percent increase from the first quarter of 2025. The Intermountain West region averaged about 3,200 MW of total generation outages, a 37 percent increase from the first quarter of 2025. The Pacific Northwest region averaged about 1,900 MW of total generation outages, about a 19 percent decrease from the first quarter of 2025.

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 seven 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.

1.5.1 Generation outages by region

California ISO balancing area

Figure 1.23 and Figure 1.24 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the first quarter of 2026 for the California ISO balancing area. 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 quarterly outages presented in Figure 1.23, there are usually more outages in the fall, winter, and early spring than in the summer months, and this trend continued in the first quarter of 2026.

During the first quarter of 2026, the average total generation on outage in the California ISO balancing area was 20,900 MW, which is an increase of about ten percent compared to the first quarter of 2025, as shown in Figure 1.23. Other forced outages increased by about 32 percent (2,700 MW). Forced maintenance and plant trouble outages increased by about 1 percent when compared to the same quarter last year. Planned maintenance outages and other planned outages decreased by 8 percent (340 MW) and 31 percent (490 MW) on average, respectively, compared to the same quarter last year.

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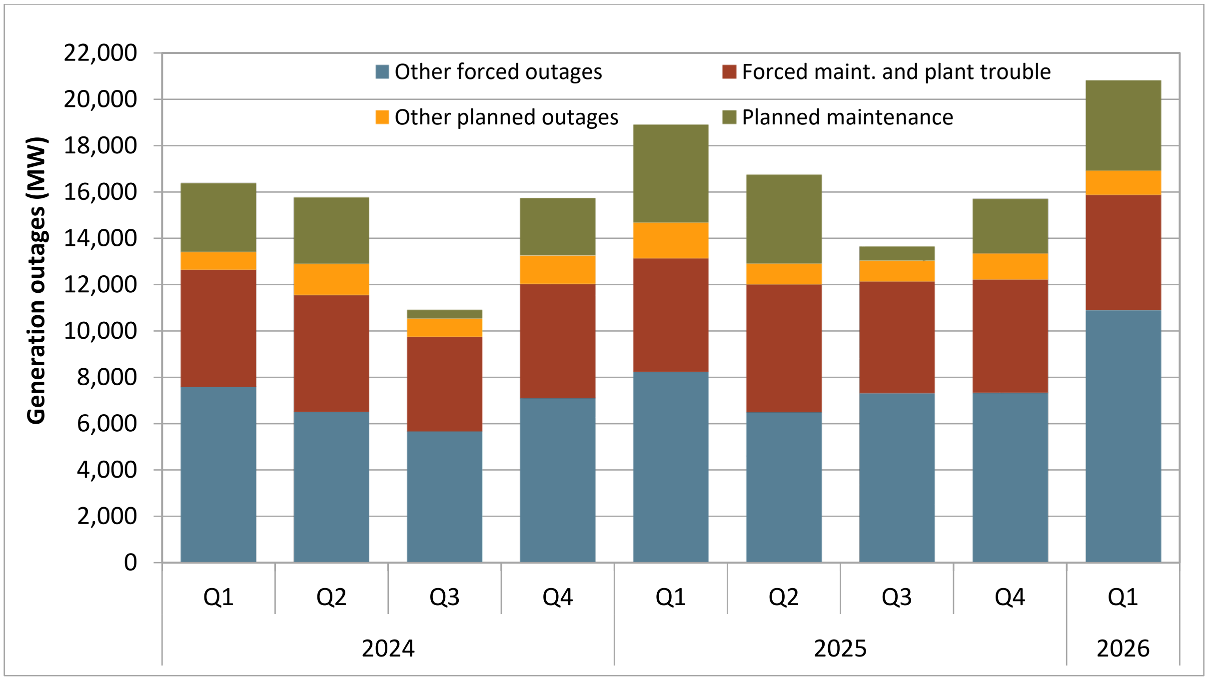
12 The data for 2024 has been updated from 2024 quarterly reports to reflect the new accounting method used to exclude outages of available California Strategic Reliability Reserve participating resource capacity that were submitted to prevent these units from being committed and dispatched by the market.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

13 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.

14 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 1.23 CAISO balancing area quarterly average of maximum daily generation outages by type – peak hours

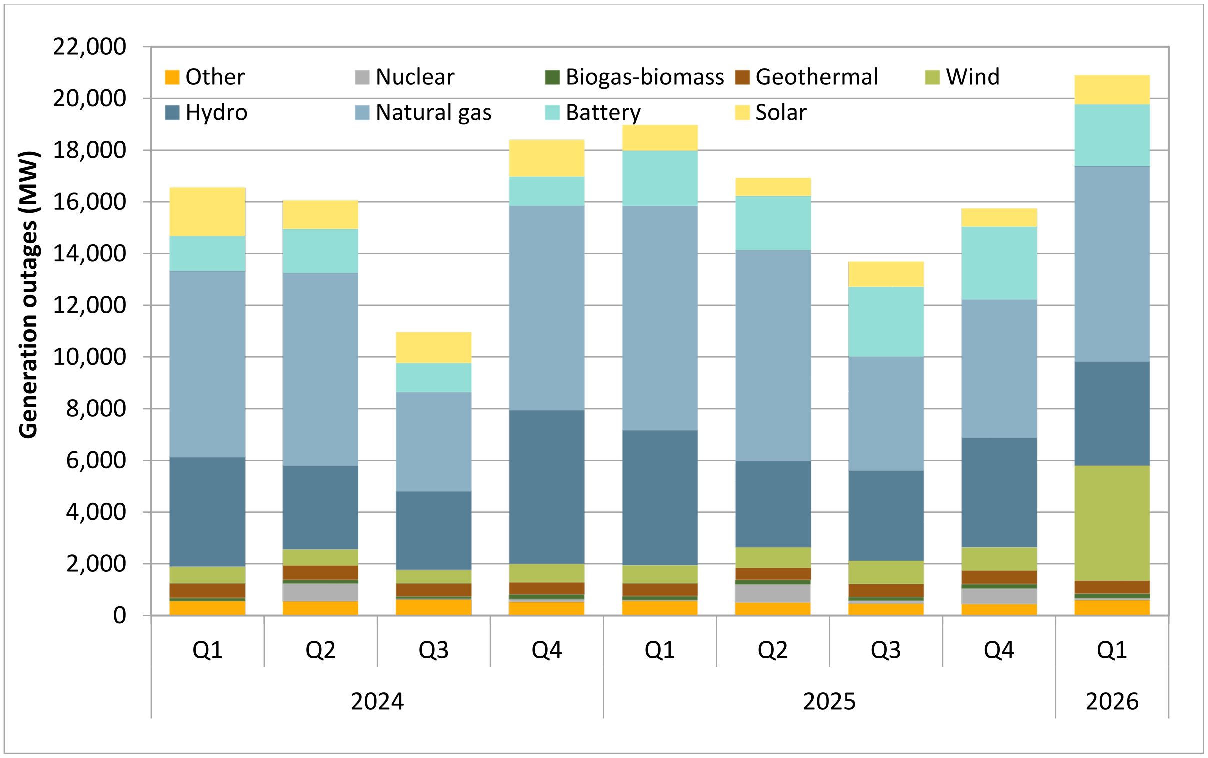


Natural gas, wind, hydroelectric generation, and batteries had the largest volume of outages in the first quarter of 2026 and averaged about 7,600 MW, 4,400 MW, 4,000 MW, and 2,400 MW, respectively. These four fuel types accounted for a combined 88 percent of the generation outages for the quarter. The quarterly average megawatts of wind resources on outage increased more than 500 percent in the first quarter of 2026 compared to the first quarter of 2025 due to testing of a large new wind resource. The amount of natural gas generation outages decreased 13 percent relative to the first quarter of 2025.

Figure 1.24 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[15] Nuclear, wind, solar, biogas-biomass, battery storage, other, and geothermal outages increased compared to the first quarter of 2025, while outages for all other fuel types decreased.

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

Figure 1.24 CAISO balancing area quarterly average of maximum daily generation outages by fuel type – peak hours



California (non-CAISO) region

Figure 1.25 and Figure 1.26 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the first quarter of 2026 for resources in the California WEIM region, excluding the CAISO balancing area.[16] 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 2026. Average total outages in the first quarter were about 5,000 MW, comparable to the first quarter of 2025. Total forced outages increased by about 40 percent while total planned maintenance outages decreased by 30 percent. Outages from natural gas resources increased by about 13 percent.

[16] The California region includes BANC, LADWP, and TIDC.

Figure 1.25 California WEIM region quarterly average of maximum daily generation outages by type – peak hours

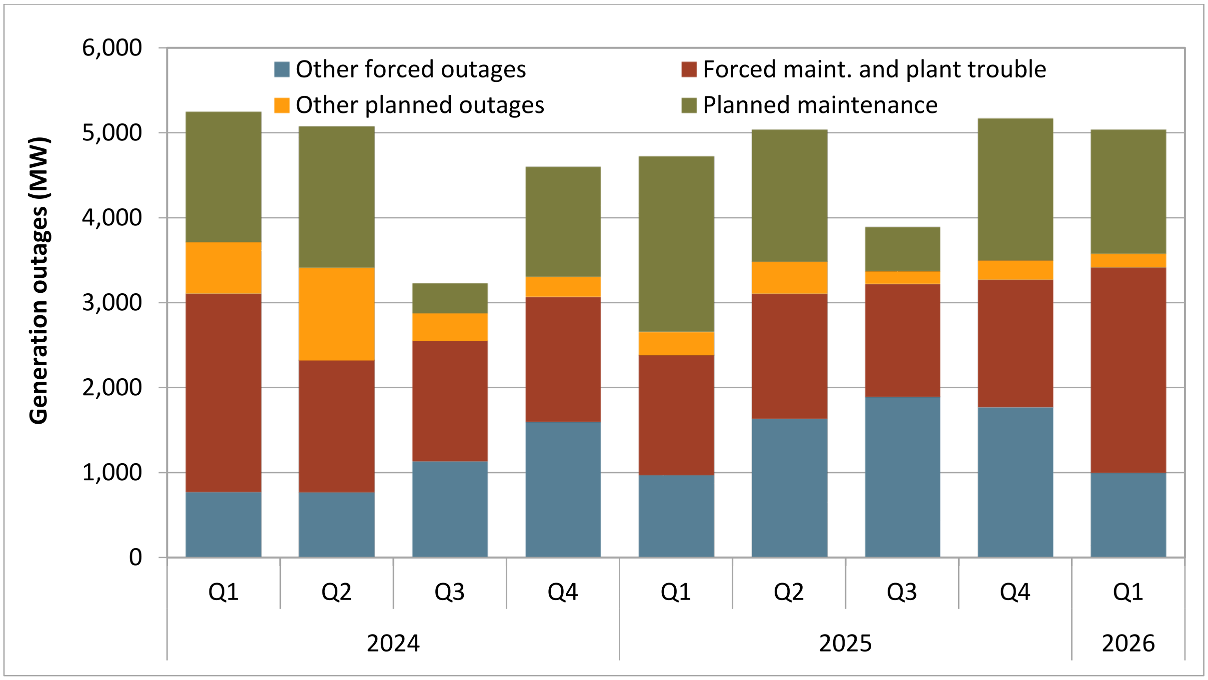
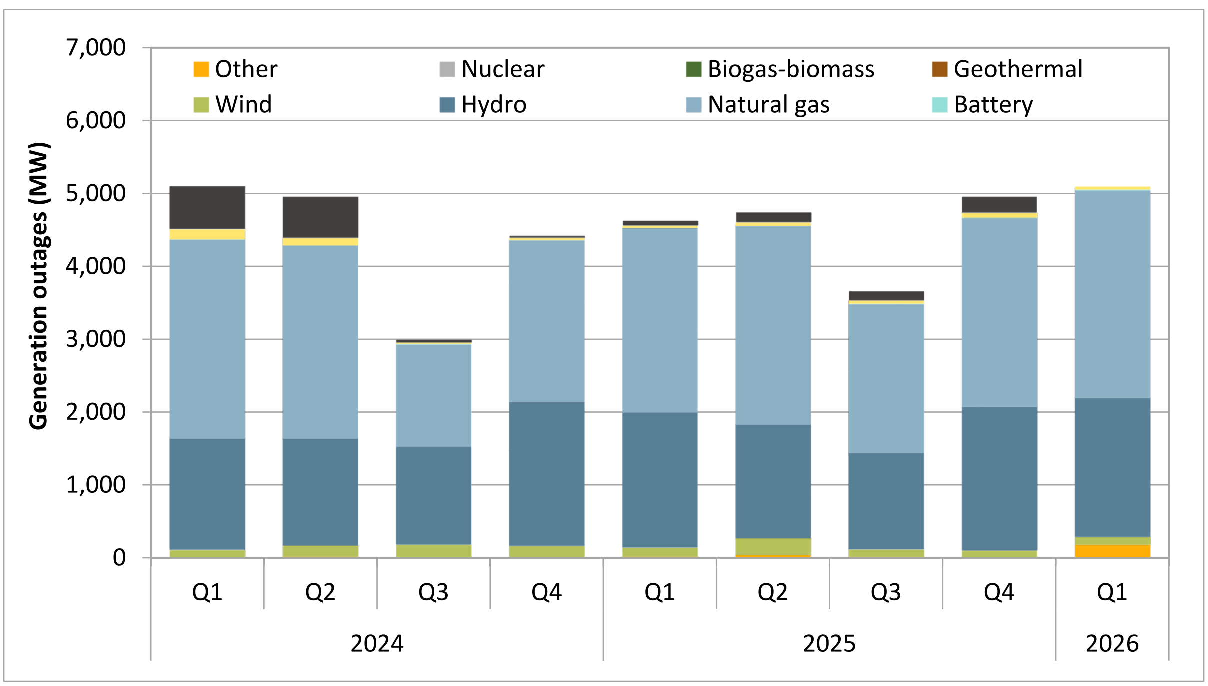


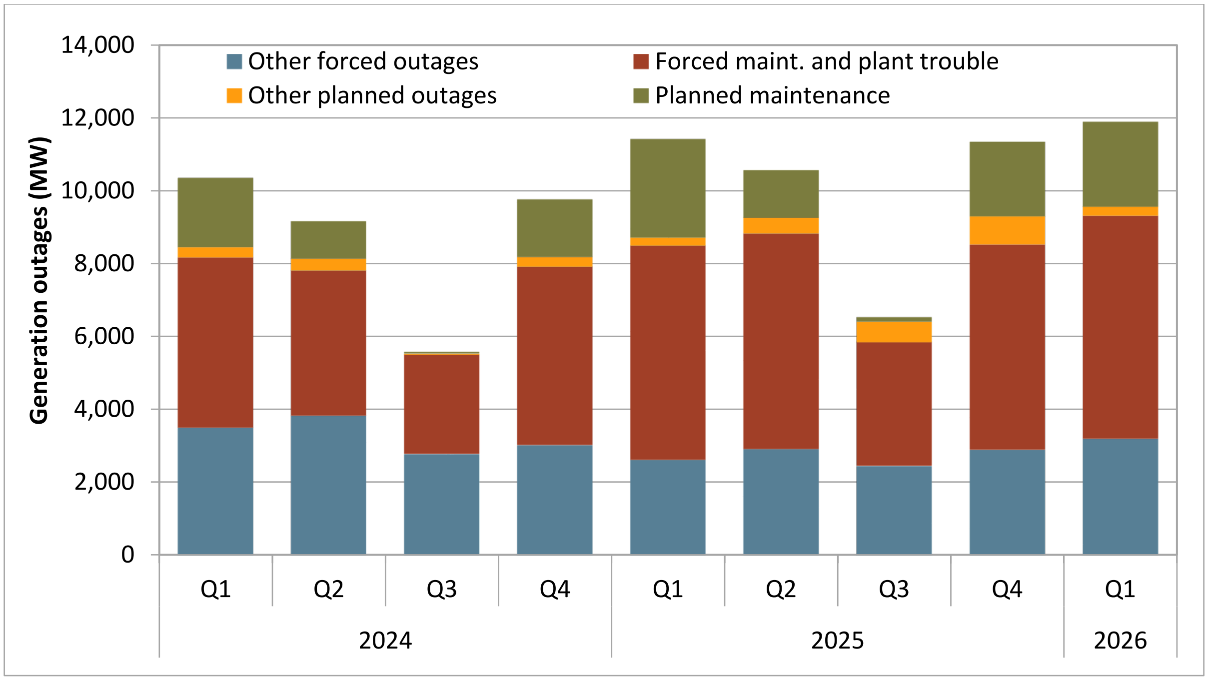
Figure 1.26 California WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Desert Southwest

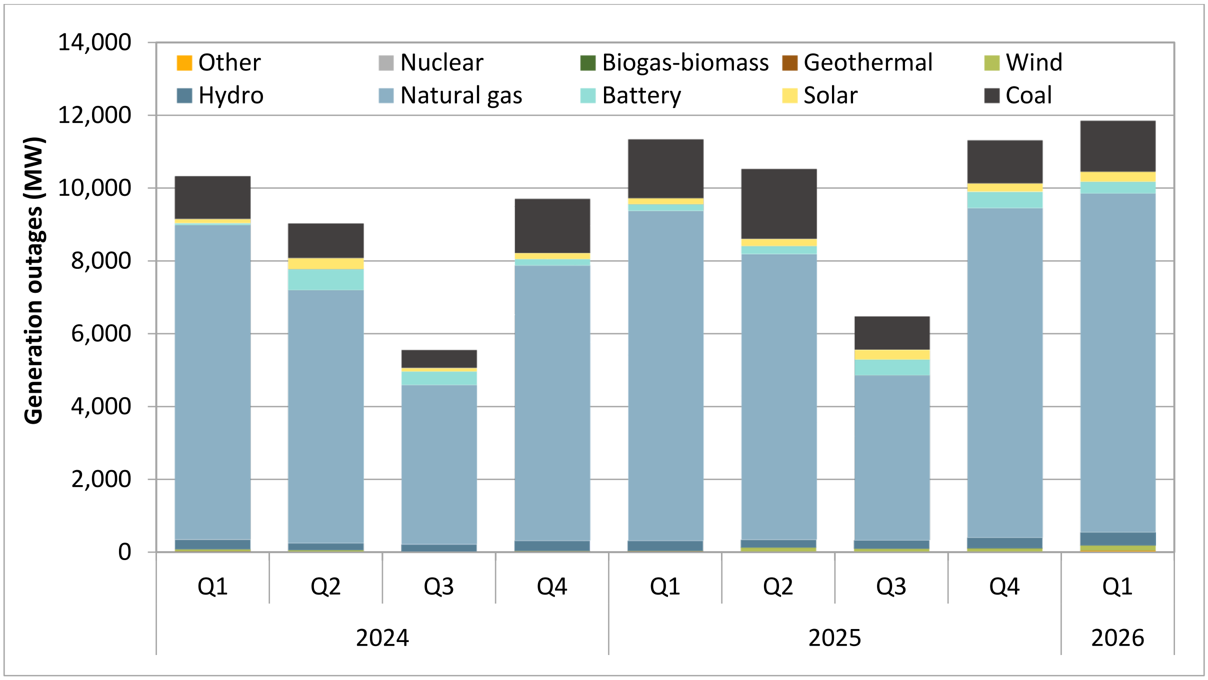
Figure 1.27 and Figure 1.28 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the first quarter of 2026 for entities in the Desert Southwest WEIM region.[17] The typical seasonal outage pattern is 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 2026. Average total outages by fuel type were comparable to the first quarter of 2025, with the small year-over-year increase primarily driven by increases in natural gas outages.

Figure 1.27 Desert Southwest WEIM region quarterly average of maximum daily generation outages by type – peak hours



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

Figure 1.28 Desert Southwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Intermountain West

Figure 1.29 and Figure 1.30 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the first quarter of 2026 for entities in the Intermountain West WEIM region.[18] 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 2026. The increase in outages in the first quarter of 2026 compared to the first quarter of 2025 was driven by increases in coal, solar, wind, and natural gas outages.

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

Figure 1.29 Intermountain West WEIM region quarterly average of maximum daily generation outages by type – peak hours

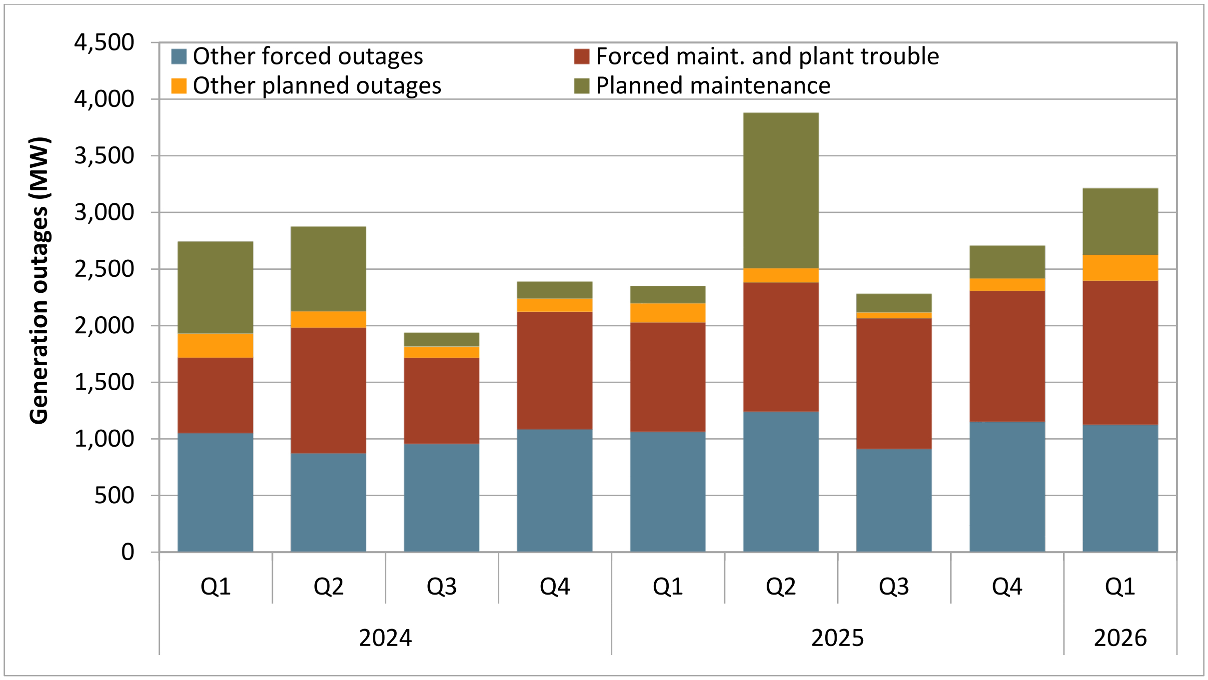
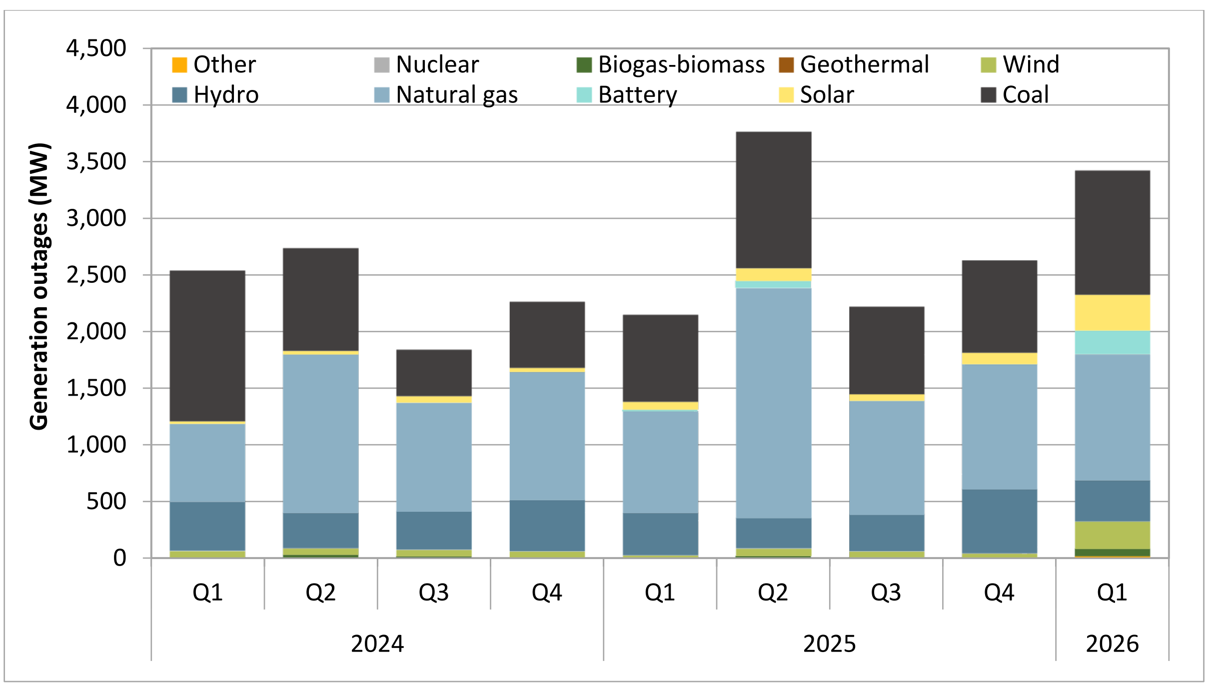


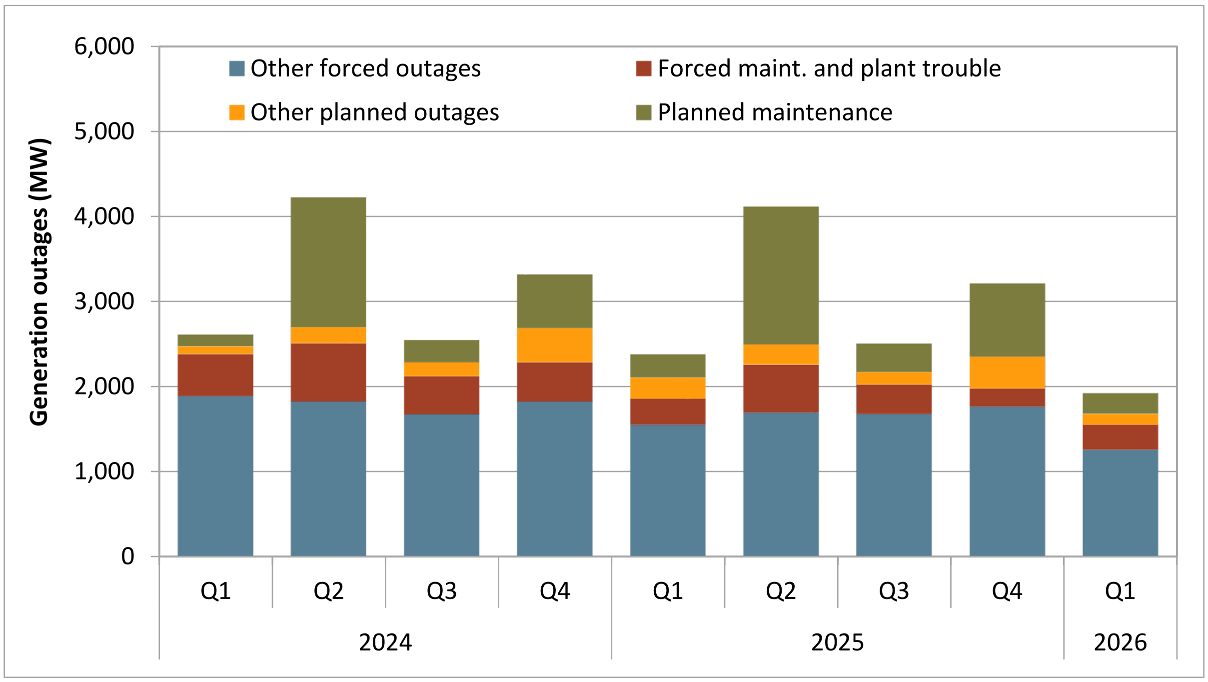
Figure 1.30 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Pacific Northwest

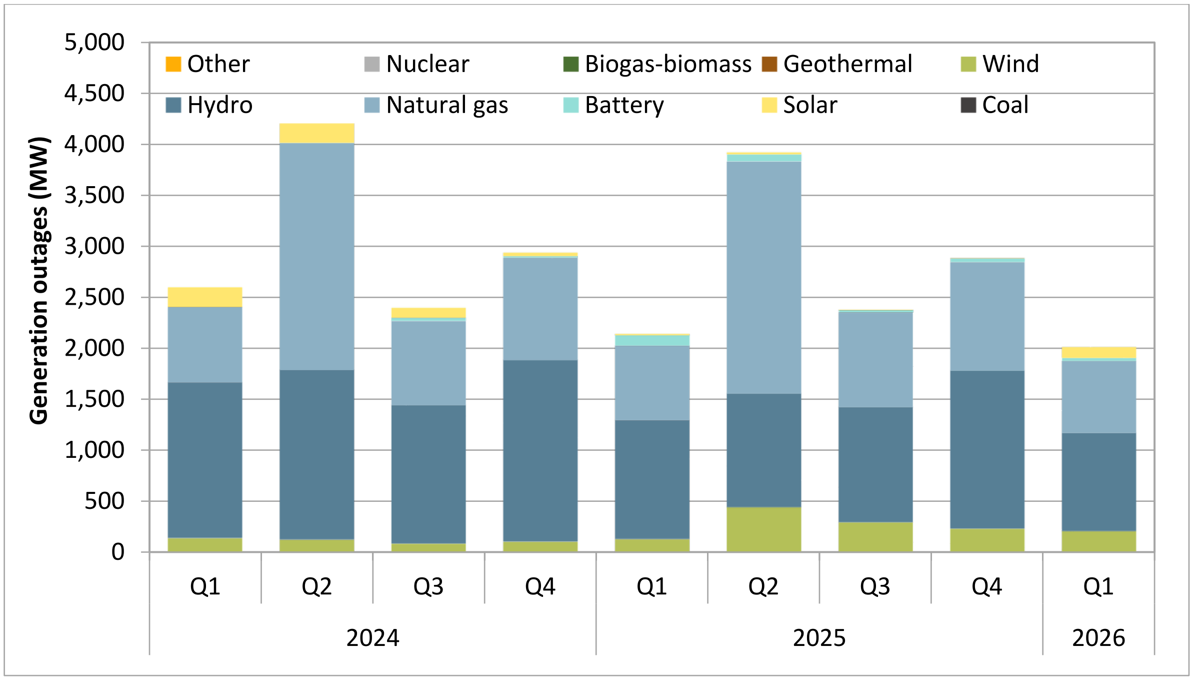
Figure 1.31 and Figure 1.32 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the first quarter of 2026 for resources in the Pacific Northwest WEIM region.[19] The typical seasonal outage pattern for the Pacific Northwest region diverges from the others, with outages typically peaking in the second quarter while outages in all other quarters remain low. This trend is still primarily driven by planned outages for maintenance, which are generally performed outside of the higher load periods. The decrease in Pacific Northwest outages was driven primarily by reductions in hydro and battery outages, which more than offset increases in solar and wind during the first quarter of 2026 compared to the same period in 2025.

Figure 1.31 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by type – peak hours



19 The Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

Figure 1.32 Pacific Northwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



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 balancing areas are categorized into four geographical regions:

- **California**: includes all balancing areas in California: California ISO (CAISO), the 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.[20] The distribution incorporates load levels from all 5-minute market intervals in Q1 2026 (blue line) and Q1 2025 (gray 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.

Figure 2.1 shows how the load in the first quarter was distributed across load levels (measured in GW). Higher points on the curve represent load levels that occurred more frequently during the quarter.[21] For instance, in Q1 2026, the curve peaks between 70 and 75 GW, indicating that these load levels were most frequently observed.[22]

The system load distribution in the first quarter of 2026 was very similar to the system load distribution in the same quarter of 2025, indicating comparable load levels in the first quarter of both years.

[20] The total market load includes any load conformance.

[21] 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.

[22] The most frequently observed value in a distribution is also called the mode (or modal value).

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

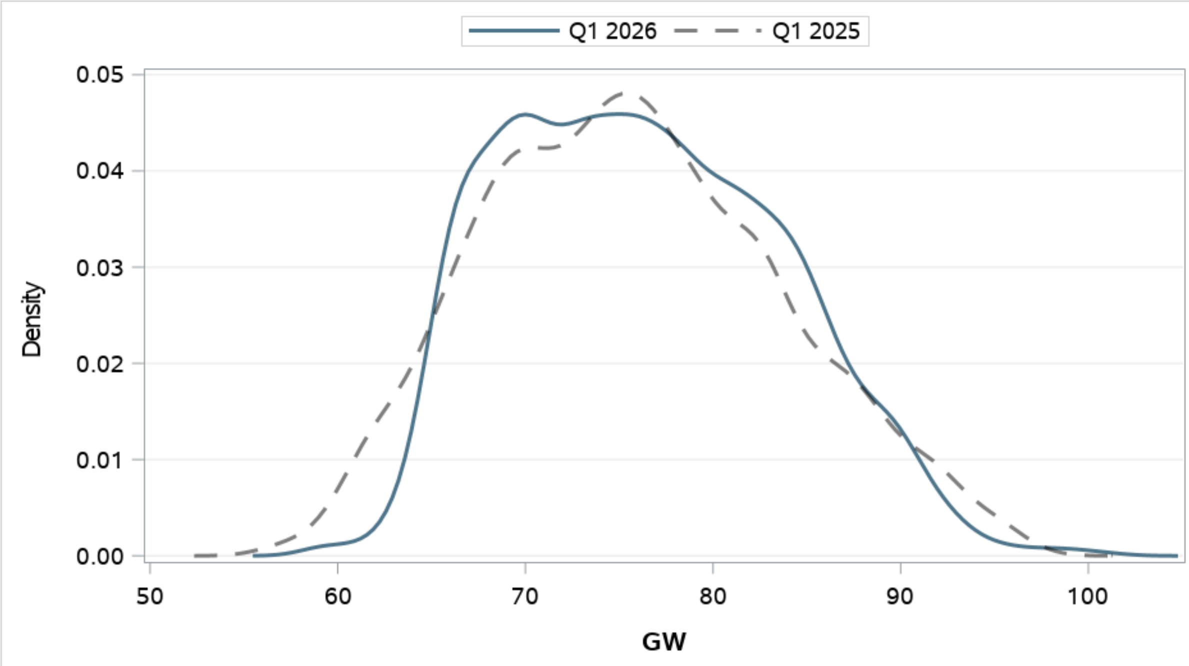


Figure 2.2 shows the monthly average 5-minute market load categorized by region from January 2024 through March 2026. The total system load for this quarter averaged 76.3 GW, representing approximately a 0.7 percent increase compared to the same quarter of 2025. Relative to the first quarter of 2025, average load in the first quarter of 2026 increased in the southern regions but decreased in the northern regions:

- **Pacific Northwest** (green) averaged **25.6 GW**, a 1.7 percent decrease.
- **California** (blue) averaged **25.9 GW**, a 1.8 percent increase.
- **Desert Southwest** (yellow) averaged **14.8 GW**, a 5.9 percent increase.
- **Intermountain West** (red) averaged **10.0 GW**, a 2.8 percent decrease.

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 the Desert Southwest closely aligned with the overall seasonal trends of the total WEIM load, recording higher loads during the summer months. However, in the Pacific Northwest, the highest average loads occur in the winter months, with comparatively low load during summer, and particularly in May, June, and September.

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

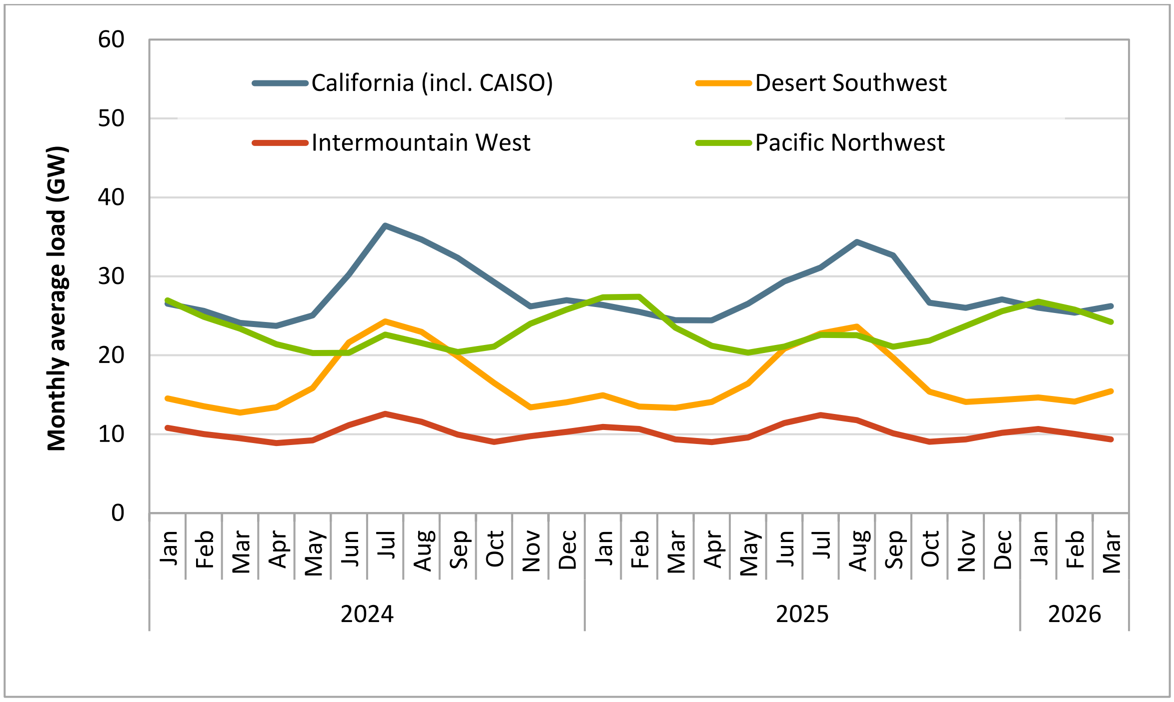
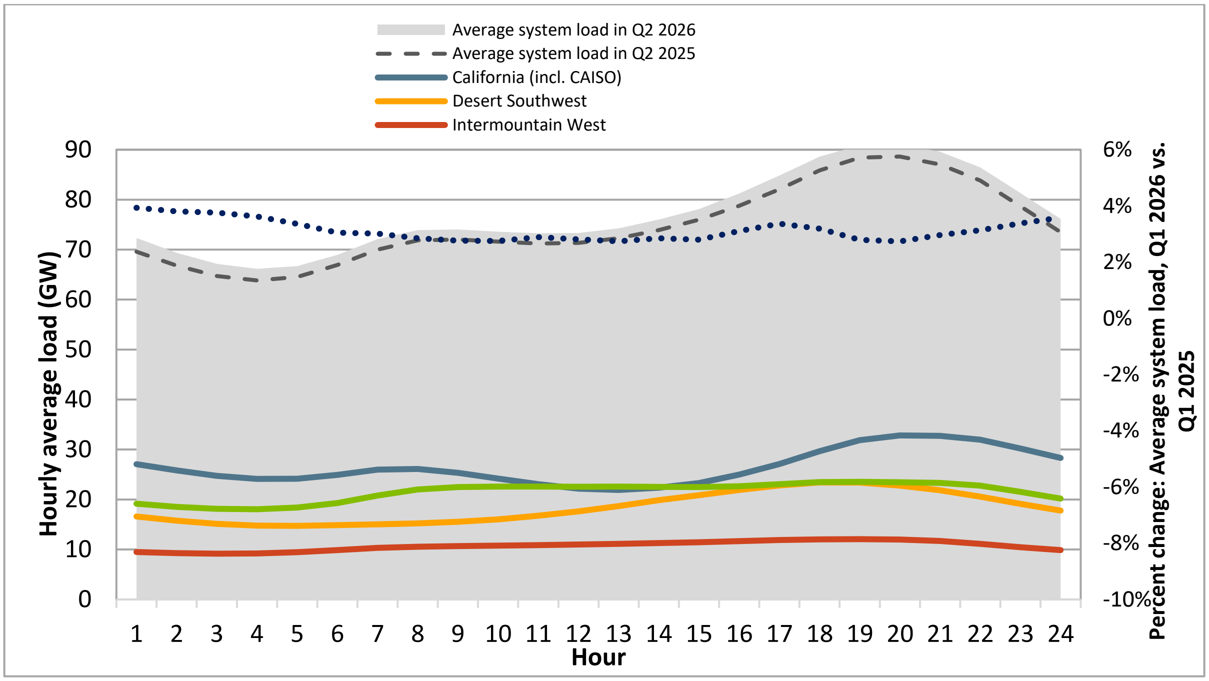


Figure 2.3 displays the hourly average 5-minute market load across different regions in Q1 2026. Each color represents a specific region. The gray area represents the average WEIM system-wide total load for the first quarter of 2026 while the gray dashed line represents the same for the first quarter of 2025. The navy blue dotted line represents the percent change of load between Q1 2025 and Q1 2026, computed for each hour by taking the difference in average system load levels between Q1 2026 and Q1 2025, and then dividing the difference by the average system load level in Q1 2025. The percent change for each hour measures how the average system load has changed in Q1 2026 relative to Q1 2025, expressed as a percentage.

The WEIM system-wide hourly average load peaked at hour-ending 18, reaching 87.0 GW, while the lowest load occurred at hour-ending 4, at 67.8 GW. In Q1 of 2026, all regions except the Pacific Northwest recorded peak hourly average loads during the evening hours, between hours-ending 18 and 19. In the Pacific Northwest, the hourly average load peaked in the morning, in hour-ending 9. The peak average hourly load for each region is given below:

- **Pacific Northwest:** peak load of 28.1 GW at hour-ending 9.
- **California:** peak load of 31.2 GW at hour-ending 19.
- **Desert Southwest**: peak load of 17.4 GW at hour-ending 18.
- **Intermountain West**: peak load of 10.8 GW at hour-ending 19.

Figure 2.3 Hourly average 5-minute market load by region (Q1 2026)



2.2 Peak load

Figure 2.4 shows the highest 5-minute market *system* load forecast for each hour on March 19, 2026, the day with the highest system load during the first quarter of 2026. The figure also shows load forecast data for each balancing area during the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 102.7 GW during hour-ending 19, interval 9. This was higher than the peak WEIM load during Q1 2025 (99.7 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 of the day. The system peak occurred during hour-ending 19, and all balancing areas in the California and Desert Southwest regions recorded their peak load around the same time. In the Pacific Northwest and Intermountain West regions, about half of all balancing areas recorded peak load in the morning hours, while the rest recorded peak loads during the evening hours.

Northwestern Energy, Avista Utilities, Bonneville Power Administration, PacifiCorp West, and Seattle City Light recorded peak loads of the day during hours-ending 7 through 10. All other balancing areas recorded peak loads between hours-ending 17 and 21.

Figure 2.4 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, March 19, 2026)

Hour	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SYSTEM	72.8	77.8	79.4	78.8	77.5	76.7	77.9	80.7	84.4	88.8	93.9	98.7	101.8	102.7	101.5	99.2	93.0	87.3	80.2
CAISO	22.0	23.7	24.2	23.9	22.9	21.9	21.6	22.6	24.3	26.5	29.4	32.0	34.1	34.8	34.5	33.4	31.9	29.8	26.9
BANC	1.58	1.73	1.76	1.71	1.72	1.75	1.86	1.94	2.07	2.23	2.38	2.50	2.58	2.57	2.55	2.46	2.31	2.13	1.92
Turlock ID	.29	.31	.32	.32	.31	.31	.33	.35	.37	.39	.41	.42	.44	.44	.43	.41	.39	.36	.33
LADWP	2.32	2.50	2.57	2.59	2.74	2.86	3.18	3.43	3.75	4.08	4.28	4.45	4.46	4.25	4.13	3.90	3.66	3.40	3.10
NV Energy	3.80	3.90	3.88	3.83	3.75	3.75	3.99	4.25	4.59	4.91	5.31	5.59	5.73	5.80	5.71	5.43	5.11	4.81	4.48
Arizona PS	3.63	3.73	3.71	3.61	3.50	3.50	3.88	4.27	4.72	5.19	5.68	6.09	6.27	6.60	6.59	6.74	4.97	4.80	4.39
Tucson Electric	1.02	1.06	1.05	1.00	0.94	0.93	1.08	1.22	1.41	1.60	1.77	1.94	1.98	1.94	1.85	1.69	1.54	1.41	1.26
Salt River Project	3.28	3.35	3.42	3.48	3.62	3.76	4.42	4.77	5.28	5.64	5.87	6.05	6.04	5.92	5.67	5.25	4.85	4.51	4.11
PSC New Mexico	1.40	1.37	1.34	1.30	1.28	1.25	1.28	1.34	1.38	1.46	1.55	1.66	1.71	1.74	1.72	1.65	1.56	1.47	1.39
WAPA - Desert SW	.58	.60	.60	.60	.59	.63	.74	.80	.87	.94	1.00	1.05	1.06	1.01	.96	.87	.79	.74	.68
El Paso Electric	.78	.78	.78	.77	.77	.78	.88	.98	1.07	1.19	1.25	1.28	1.27	1.24	1.20	1.09	1.00	.90	.82
PacifiCorp East	5.49	5.71	5.76	5.64	5.53	5.52	5.53	5.58	5.66	5.87	6.02	6.17	6.22	6.26	6.18	6.08	5.77	5.41	5.08
Idaho Power	1.81	1.92	1.93	1.86	1.79	1.74	1.68	1.66	1.70	1.73	1.80	1.85	1.86	1.95	1.94	1.91	1.78	1.64	1.52
NorthWestern	1.30	1.35	1.35	1.33	1.31	1.26	1.21	1.20	1.20	1.18	1.19	1.21	1.22	1.25	1.26	1.24	1.17	1.12	1.06
Avista Utilities	1.09	1.22	1.26	1.26	1.25	1.25	1.22	1.21	1.18	1.16	1.14	1.18	1.20	1.21	1.22	1.20	1.15	1.06	0.99
BPA	6.72	7.23	7.43	7.43	7.33	7.25	7.15	7.10	7.06	7.00	7.03	7.15	7.25	7.29	7.24	7.37	7.09	6.74	6.39
Tacoma Power	.49	.54	.56	.57	.57	.56	.57	.56	.55	.55	.55	.56	.57	.57	.58	.58	.55	.51	.47
PacifiCorp West	2.14	2.40	2.48	2.48	2.39	2.29	2.16	2.16	2.14	2.16	2.18	2.25	2.30	2.33	2.33	2.37	2.28	2.13	1.97
Portland GE	2.43	2.69	2.78	2.79	2.76	2.72	2.63	2.76	2.67	2.74	2.74	2.77	2.79	2.82	2.79	2.82	2.76	2.62	2.45
Puget Sound Energy	2.71	3.03	3.13	3.16	3.17	3.16	3.13	3.11	3.05	3.03	3.07	3.11	3.19	3.19	3.20	3.20	3.09	2.87	2.64
Seattle City Light	1.02	1.15	1.20	1.21	1.23	1.23	1.20	1.19	1.18	1.16	1.17	1.18	1.19	1.18	1.18	1.19	1.15	1.08	1.00
Powerex	6.91	7.54	7.86	7.96	8.14	8.28	8.23	8.25	8.17	8.09	8.10	8.29	8.44	8.35	8.29	8.32	8.16	7.75	7.25

Table 2.1 shows the peak 5-minute market load and date for each balancing area (or region) during the first quarter. Nearly all balancing areas in California and the Desert Southwest reached their quarterly peak load in March, while nearly all balancing areas in the Intermountain West and the Pacific Northwest recorded their Q1 2026 peak load in January. The table also shows each balancing area's load during the system peak load interval on March 19, 2026 (102,720 MW).

Table 2.1 Peak WEIM load (January–March 2026)

Region/balancing area	Peak load (January–March, 2026)		Load during WEIM system peak (19-Mar-2026)	
	Date	Load (MW)	Load (MW)	Percent
WEIM system	**19-Mar-26**	**102,720**	**102,720**	
California	**19-Mar-26**	**42,189**	**42,051**	**41%**
California ISO	19-Mar-26	34,996	34,797	34%
BANC	20-Mar-26	2,650	2,567	2%
LADWP	19-Mar-26	4,474	4,251	4%
Turlock Irrig. District	20-Mar-26	446	436	.4%
Desert Southwest	**20-Mar-26**	**24,586**	**24,252**	**24%**
Arizona Public Service	19-Mar-26	6,862	6,601	6%
El Paso Electric	25-Mar-26	1,606	1,242	1.2%
NV Energy	24-Mar-26	6,047	5,801	6%
PSC New Mexico	26-Jan-26	2,012	1,736	2%
Salt River Project	20-Mar-26	6,256	5,918	6%
Tucson Electric	20-Mar-26	2,025	1,939	2%
WAPA - Desert SW	20-Mar-26	1,085	1,015	1.%
Intermountain West	**26-Jan-26**	**13,432**	**10,677**	**10%**
Avista Utilities	26-Jan-26	1,878	1,215	1%
Idaho Power	26-Jan-26	2,773	1,952	2%
NorthWestern Energy	18-Feb-26	1,808	1,254	1%
PacifiCorp East	26-Jan-26	7,039	6,256	6%
Pacific Northwest	**26-Jan-26**	**34,952**	**25,740**	**25%**
BPA	25-Jan-26	10,283	7,295	7%
PacifiCorp West	22-Jan-26	3,541	2,333	2%
Portland General Electric	22-Jan-26	3,702	2,817	3%
Powerex	20-Feb-26	10,862	8,347	8%
Puget Sound Energy	26-Jan-26	4,479	3,193	3%
Seattle City Light	26-Jan-26	1,665	1,180	1%
Tacoma Power	26-Jan-26	823	575	.6%

3 Operator load forecast adjustments

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 help account for potential modeling inconsistencies and inaccuracies, and to create additional unloaded ramping capacity in the real-time market.

3.1 Imbalance conformance – all balancing areas

The figures below show first quarter average hourly imbalance conformance in the 15-minute and 5-minute markets for each balancing area, as a percentage of the balancing area's average load.[23] Generally, the magnitude of 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).

[23] Avangrid Power and Powerex are not shown in these figures. 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 3.1 Intermountain West: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2026)

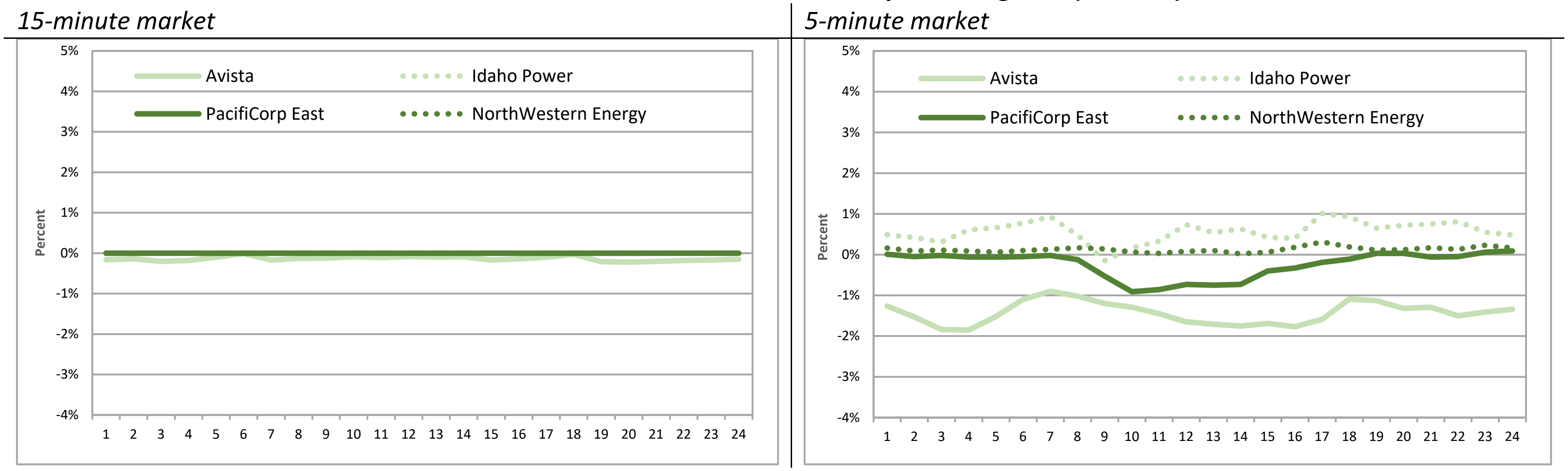


Figure 3.2 Pacific Northwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2026)

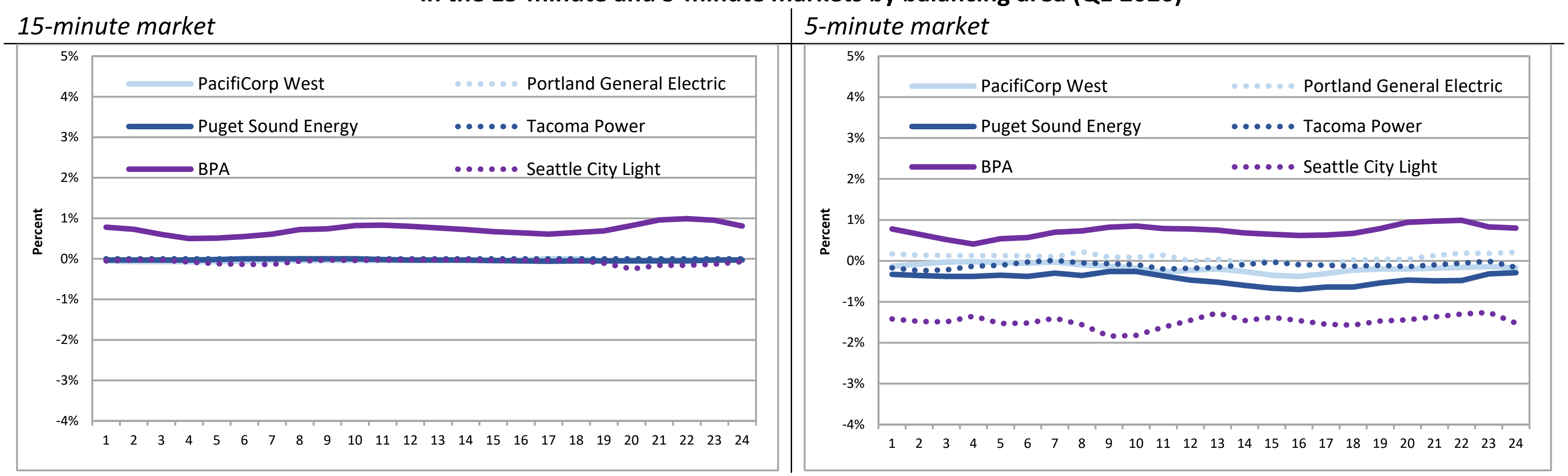
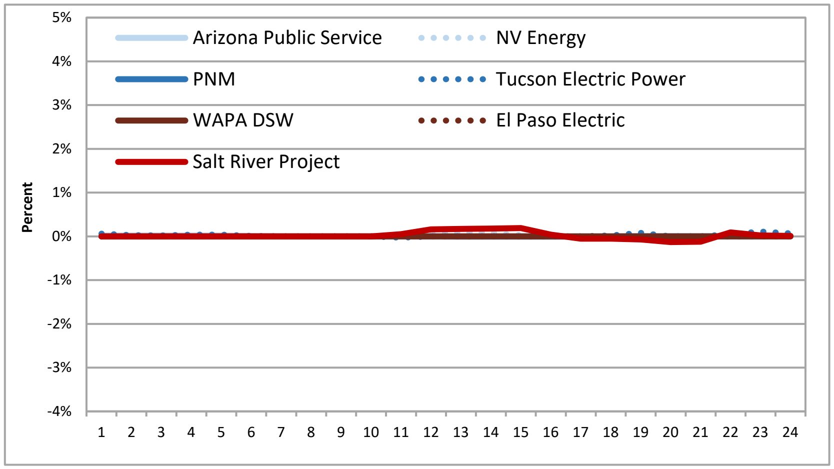


Figure 3.3 Desert Southwest: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2026)

15-minute market



5-minute market

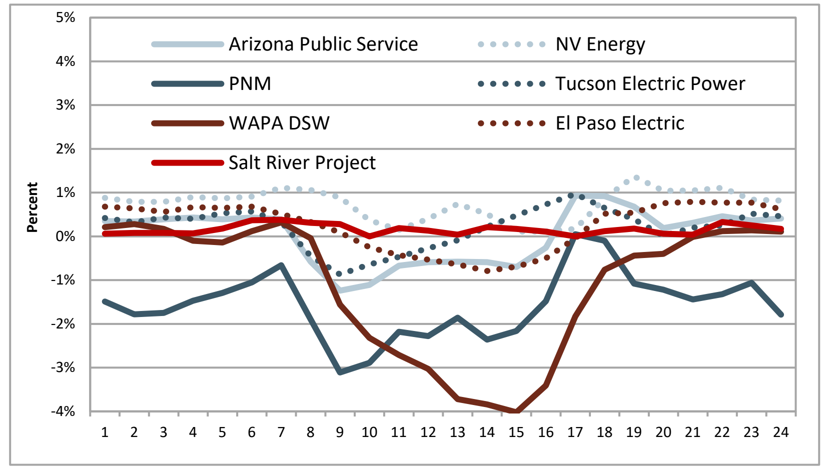
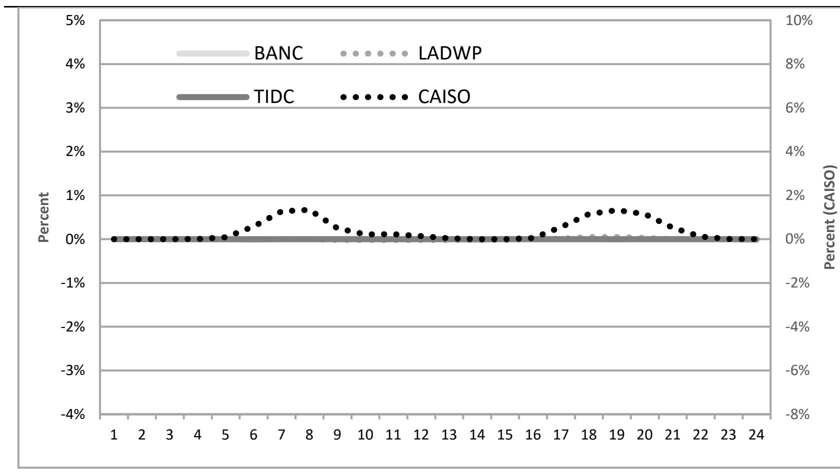
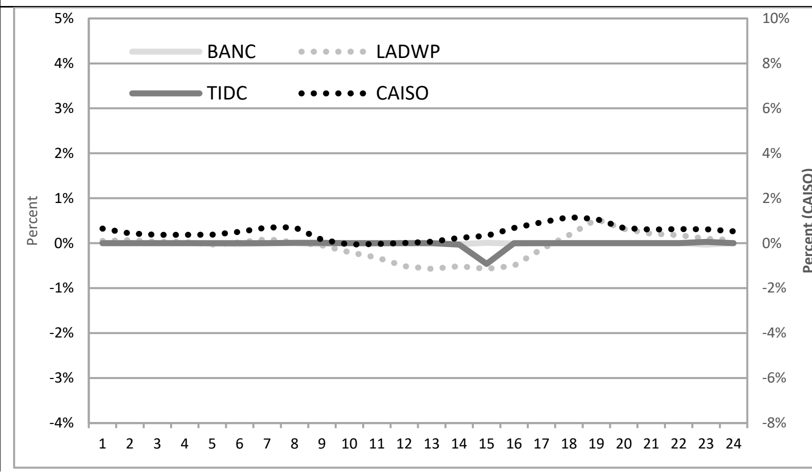


Figure 3.4 California: Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q1 2026)

15-minute market



5-minute market



3.2 Imbalance conformance in CAISO balancing area

Between January and early March 2026, the CAISO balancing area initiated a pilot program[24] designed to minimize the use of load conformance in the real-time markets. This program aimed at reducing reliance on manual interventions to improve the accuracy of market schedules and pricing. These changes appear to have contributed to greater convergence between the prices in the 15-minute market and the 5-minute market during this period.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets declined during morning and evening ramp hours in the first quarter of 2026 compared to the same period in 2025. During these hours, peak average hourly adjustments were about 120 MW in the morning and 150 MW in the evening—roughly 350 MW and 750 MW lower, respectively, than adjustments observed in Q1 2025.

The 5-minute market adjustments decreased in the morning ramp hours for the first quarter of 2026 compared to the first quarter of 2025. Evening 5-minute market adjustments peaked in hour-ending 18 at about 250 MW, about 230 MW lower than in the first quarter of 2025.

[24] *Market Performance and Planning Forum Q2*, California ISO, April 27, 2026: caiso.com/documents/presentation-market-performance-planning-forum-q2-apr-27-2026.pdf

Market performance update, Joint ISO Board of Governors and WEM Governing Body meeting - General Session, California ISO, March 4, 2026: https://www.caiso.com/documents/market-performance-update-mar-2026.pdf

Figure 3.5 Average CAISO balancing area hourly imbalance conformance adjustment (Q1 2025 and Q1 2026)

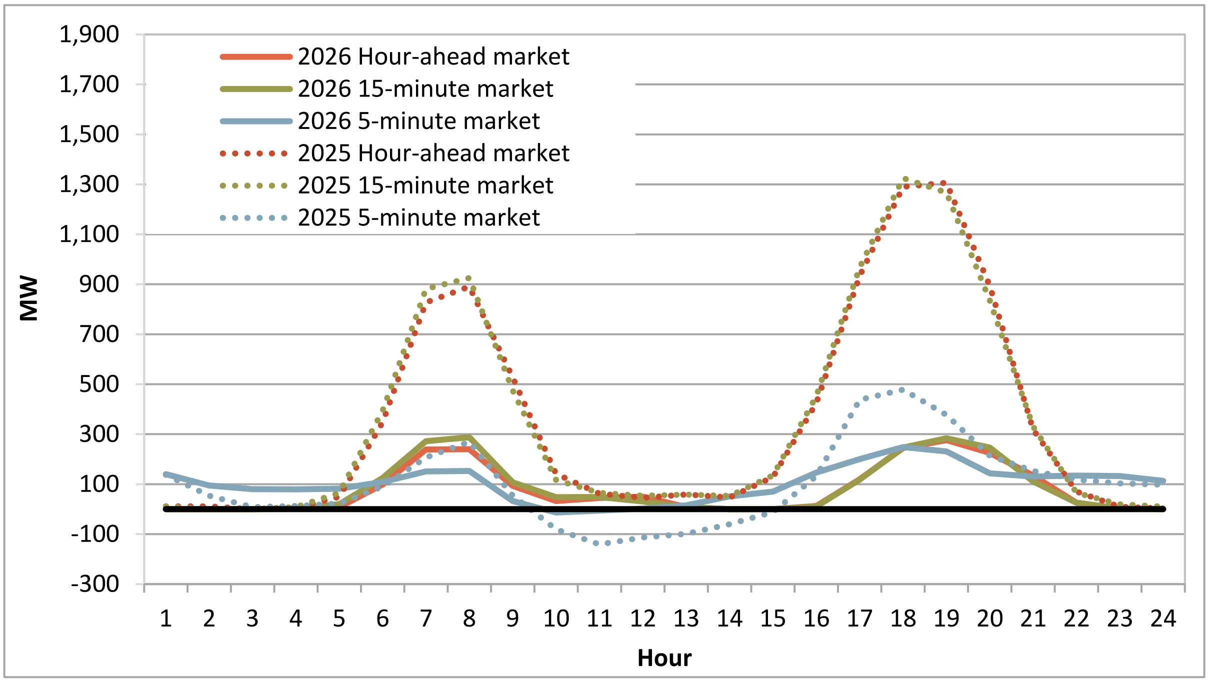
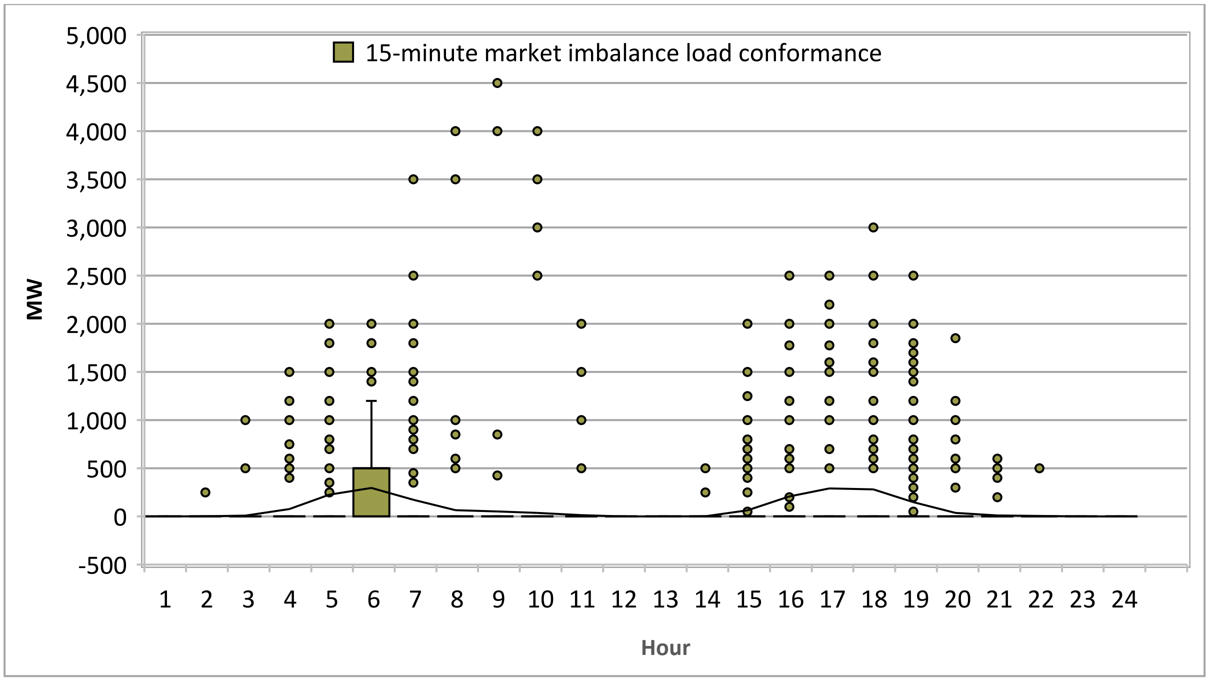


Figure 3.6 shows an hourly distribution of the 15-minute market load adjustments for the first quarter of 2026. This box and whisker graph highlights extreme outliers[25] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well as the mean (line). The extreme outliers are represented by the filled “dots”. The outside whiskers do not include these outliers. Outliers in the figure below occurred during a period in late March when California recorded both its warmest and driest March in 132 years.[26] Despite these outliers, most hourly adjustments were close to zero, indicating limited reliance on imbalance conformance during typical conditions.

[25] 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).

[26] *Assessing the U.S. Temperature and Precipitation Analysis in March 2026*, National Centers for Environmental Information, National Oceanic and Atmospheric Administration (NOAA), April 8, 2026: https://www.ncei.noaa.gov/news/national-climate-202603

Figure 3.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (Q1 2026)



4 Energy prices

4.1 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.[27] Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).[28]

Figure 4.1 and Figure 4.2 display the weighted average monthly electricity prices in the 15-minute and 5-minute markets, respectively, by region from April 2024 to March 2026. Prices in the 15-minute market across the WEIM averaged about $24/MWh in the first quarter of 2026, down 35 percent from the same quarter of last year. Prices in the 5-minute market were $25/MWh, a 31 percent decrease compared to Q1 2025.

In the 15-minute market, California recorded the highest average price at $28/MWh, followed by the Desert Southwest at $22/MWh. Average prices in these regions were slightly higher than prices in the Pacific Northwest ($21/MWh) and Intermountain West regions ($21/MWh). Greenhouse gas (GHG) costs during non-solar hours contributed to higher average prices in California compared to other regions.[29]

[27] 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, BCHA, TWPR, PGE, PSEI, and SCL.

[28] 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.

[29] 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 4.1 Weighted average monthly 15-minute market prices by region

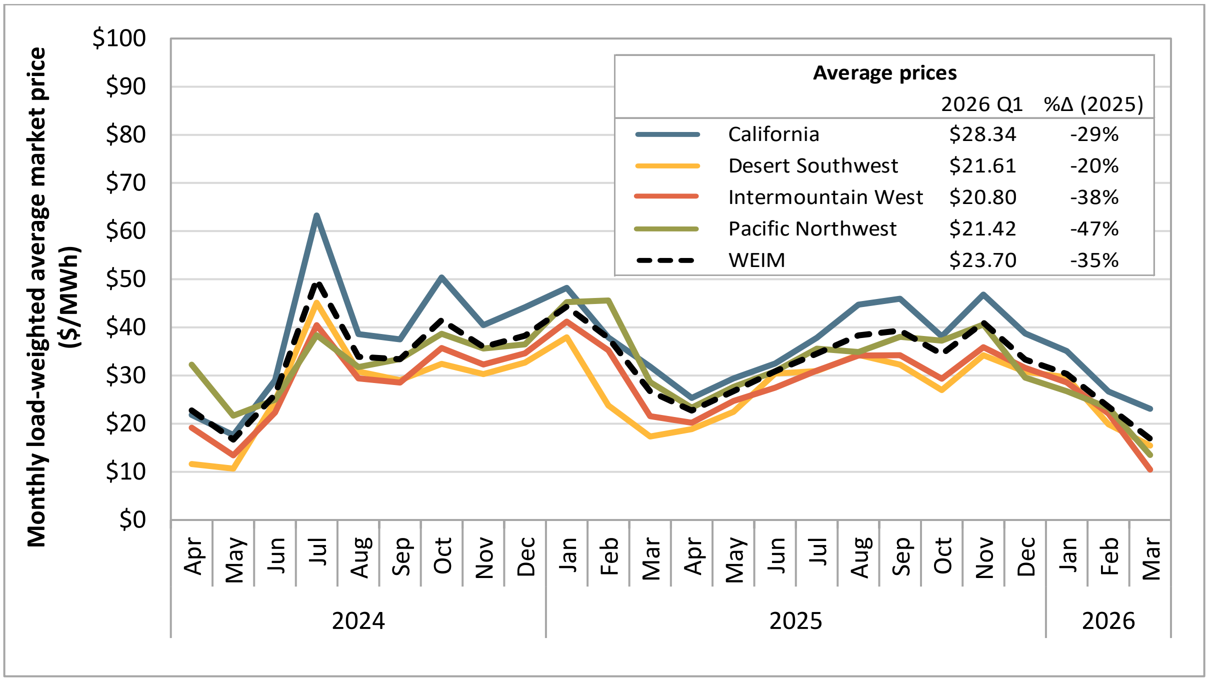


Figure 4.2 Weighted average monthly 5-minute market prices by region

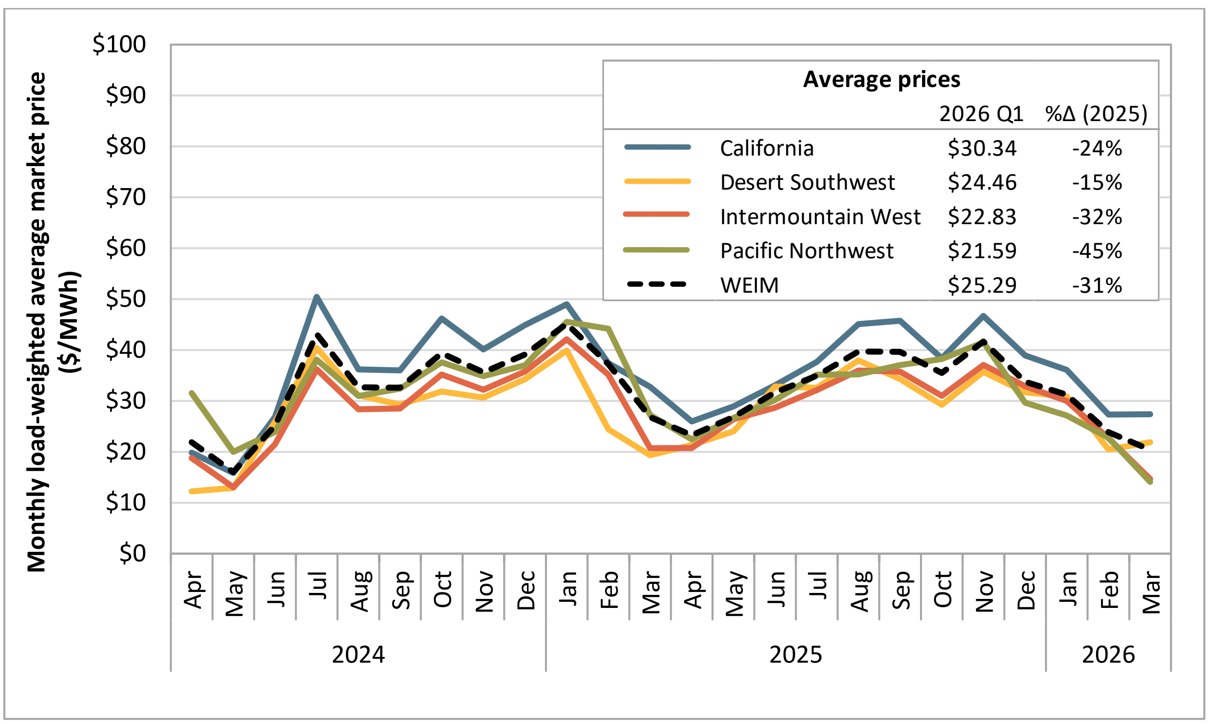


Figure 4.3 and Figure 4.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions, along with average system net-load schedules, for the first quarter of 2026. The shape of hourly prices tended to follow the net-load pattern. This trend was most prominent for 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 average hourly peak net load occurred at hour-ending 20 in the 15-minute market, reaching 77.5 GW. In the 5-minute market, average hourly peak net load occurred at hour-ending 19, reaching 77.6 GW. In the 15-minute market, the California and Desert Southwest regions experienced peak average prices at hour-ending 19, while the Intermountain West and Pacific Northwest regions had their highest average prices at hour-ending 7 and 18, respectively. In the 5-minute market, the California and Desert Southwest regions experienced peak average prices at hour-ending 19, while the Intermountain West and Pacific Northwest region both experienced peak prices in the morning at hour-ending 8 and 7, respectively.

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 raise prices in California balancing areas relative to the non-California regions.

Pricing patterns were very different during mid-day solar hours. During these hours, WEIM transfers tended to flow out of California, so GHG costs did not raise California prices relative to other regions. South-to-north congestion patterns during solar hours increased prices in the Pacific Northwest and Northern California relative to the Desert Southwest, Southern California, and Intermountain West.

Figure 4.3 Weighted average hourly 15-minute market prices by region (January–March 2026)

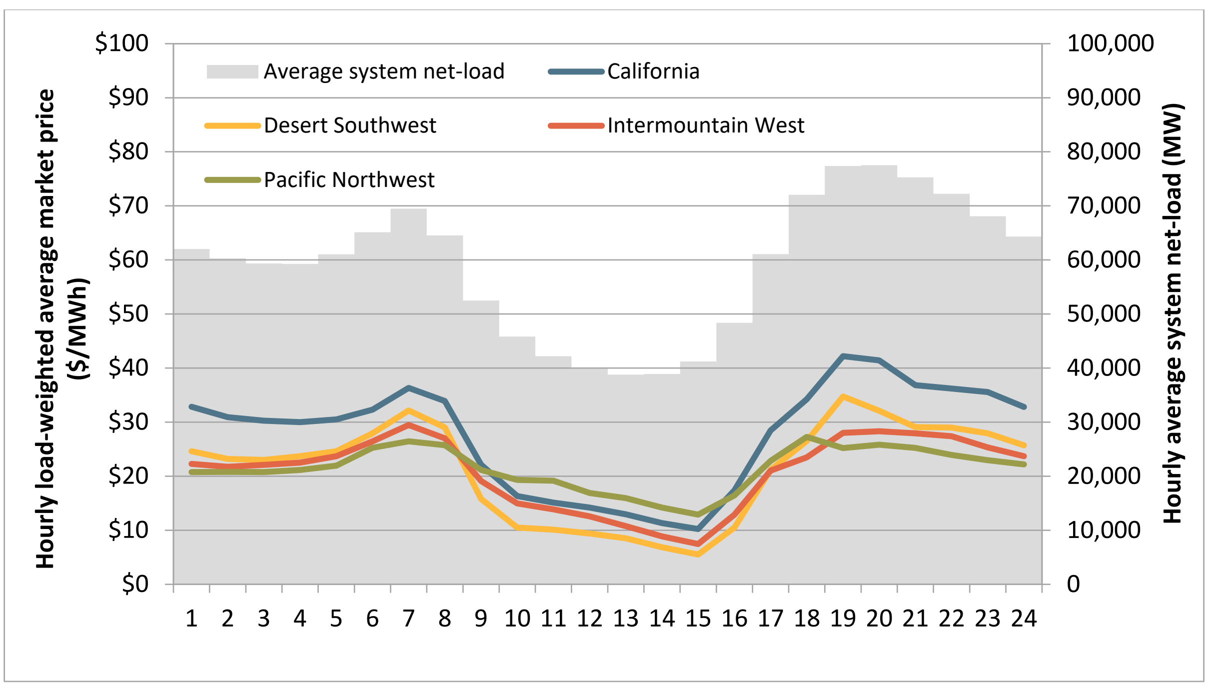
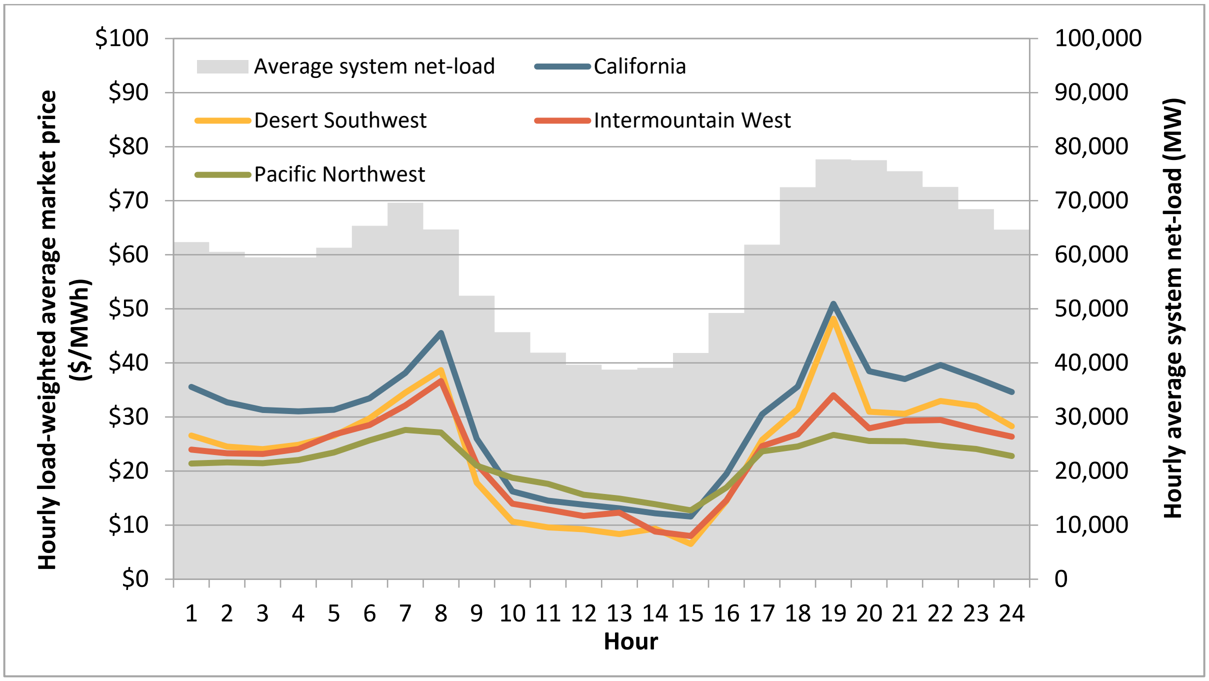


Figure 4.4 Weighted average hourly 5-minute market prices by region (January–March 2026)



4.2 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 2026. Figure 4.5 and Figure 4.6 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 from local constraints** is the price impact from transmission constraints within its own balancing area that are restricting the flow of energy. While these constraints are located locally, they can create price impacts across the WEIM and show up as external constraints to other balancing areas, as shown in the figures below.
- **Congestion from external constraints** is the price impact from transmission constraints in an outside WEIM balancing 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 lower 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.

Internal flow-based constraints impacted prices in both the 15-minute and 5-minute markets. Congestion on these constraints contributed to decreasing prices in the Pacific Northwest and Intermountain West relative to California on average due mainly to south-to-north congestion patterns during a March heatwave in southern regions.

Figure 4.5 Average 15-minute market prices by balancing area (January–March 2026)

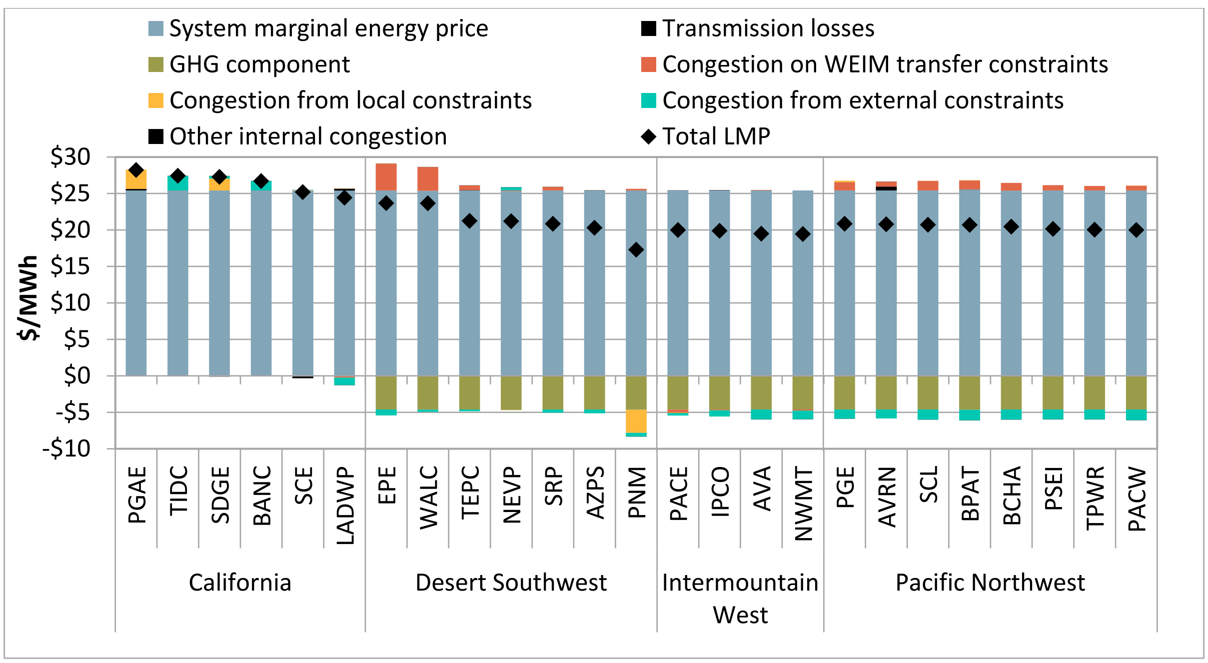


Figure 4.6 Average 5-minute market prices by balancing area (January–March 2026)

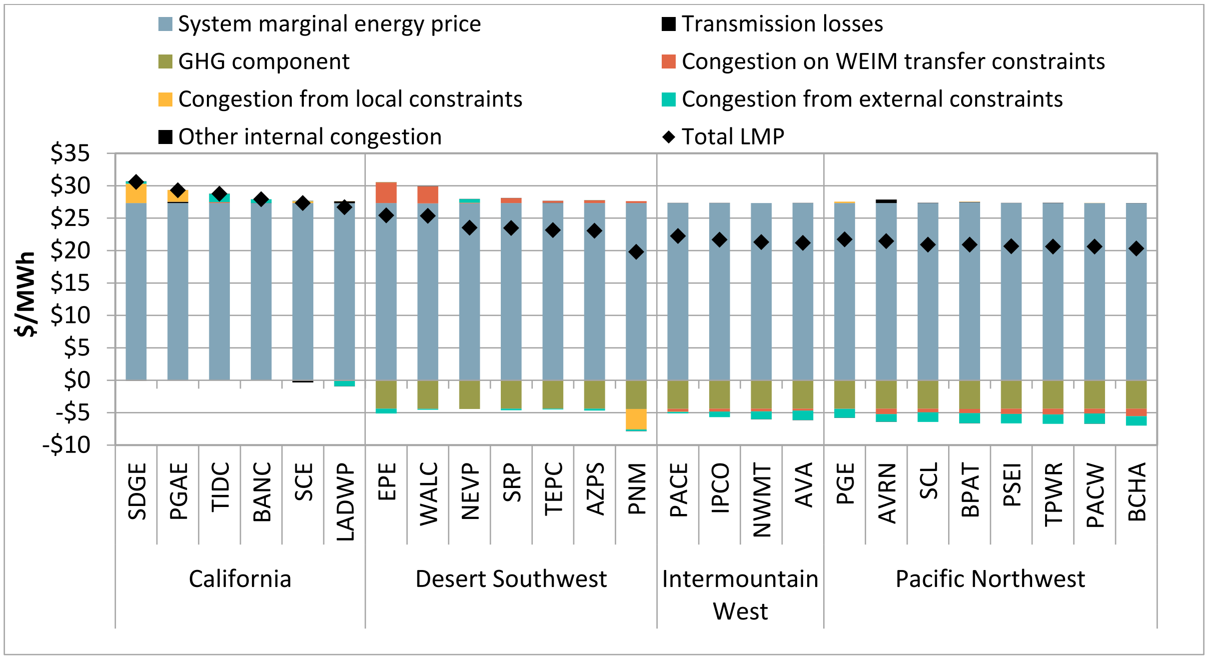


Table 4.1 and Table 4.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Blue indicates prices below that month's average system price and orange indicates prices above. As shown in these tables, average prices in California balancing areas were generally higher than balancing areas in other regions in both the 15-minute and 5-minute markets in Q1 2026. This was due primarily to California greenhouse gas pricing.

Table 4.3 and Table 4.4 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 and Northern California than in the Desert Southwest, Southern California, and parts of the Intermountain West. 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 gas pricing.

Table 4.1 Average monthly 15-minute market prices

SMEC	$22	$16	$26	$51	$36	$35	$46	$41	$42	$46	$40	$28	$24	$28	$32	$37	$42	$43	$38	$46	$36	$34	$26	$17
PG&E (CAISO)	$28	$21	$28	$61	$36	$36	$56	$46	$46	$49	$40	$31	$27	$30	$34	$38	$43	$48	$42	$50	$37	$34	$28	$23
SCE (CAISO)	$11	$9	$24	$50	$35	$33	$38	$35	$40	$43	$30	$25	$18	$24	$28	$35	$42	$39	$32	$42	$34	$34	$23	$18
SDGE (CAISO)	$17	$10	$25	$50	$36	$37	$40	$38	$43	$49	$35	$27	$21	$25	$29	$38	$47	$45	$33	$44	$37	$37	$25	$20
BANC	$29	$21	$27	$58	$37	$37	$56	$46	$45	$49	$40	$31	$25	$29	$35	$39	$43	$48	$43	$49	$36	$33	$27	$20
Turlock ID	$31	$21	$25	$54	$37	$39	$61	$47	$45	$51	$40	$32	$28	$30	$36	$41	$44	$51	$46	$49	$36	$33	$28	$21
LADWP	$12	$11	$27	$55	$40	$35	$40	$37	$38	$45	$30	$28	$21	$27	$31	$37	$43	$42	$34	$44	$36	$34	$23	$16
NV Energy	$13	$10	$22	$42	$29	$28	$33	$29	$31	$38	$26	$20	$18	$24	$28	$31	$33	$33	$28	$35	$30	$29	$20	$14
Arizona PS	$8	$8	$21	$45	$30	$27	$30	$26	$31	$35	$22	$18	$15	$19	$25	$30	$33	$31	$26	$34	$29	$29	$19	$13
Tucson Electric	$9	$11	$21	$39	$26	$26	$28	$27	$31	$36	$22	$18	$16	$20	$26	$30	$32	$31	$27	$34	$30	$29	$20	$15
Salt River Project	$9	$10	$25	$38	$31	$28	$30	$26	$30	$35	$22	$19	$24	$20	$30	$30	$33	$32	$26	$34	$29	$28	$19	$15
PSC New Mexico	$14	$10	$24	$43	$29	$28	$27	$57	$29	$37	$14	-$1	$14	$19	$43	$31	$40	$32	$24	$31	$25	$26	$15	$11
WAPA - Desert SW	$7	$10	$21	$42	$29	$27	$32	$26	$32	$36	$22	$19	$15	$19	$25	$30	$33	$31	$28	$33	$28	$29	$23	$19
El Paso Electric	$9	$13	$27	$38	$25	$26	$27	$27	$30	$34	$19	$8	$17	$26	$32	$31	$33	$33	$26	$34	$29	$37	$19	$14
PacifiCorp East	$16	$12	$21	$39	$28	$27	$35	$31	$33	$39	$30	$19	$18	$23	$27	$30	$34	$33	$26	$34	$29	$28	$21	$11
Idaho Power	$20	$13	$22	$37	$28	$28	$37	$34	$35	$42	$35	$22	$26	$25	$28	$31	$34	$34	$33	$36	$30	$28	$21	$10
NorthWestern	$24	$18	$21	$36	$28	$29	$30	$33	$33	$41	$39	$25	$21	$24	$28	$31	$33	$34	$32	$38	$30	$28	$22	$9
Avista Utilities	$26	$18	$21	$33	$28	$29	$39	$36	$35	$43	$41	$26	$21	$24	$28	$31	$33	$35	$34	$38	$30	$28	$22	$9
Avangrid	$25	$18	$21	$32	$28	$33	$40	$37	$36	$44	$44	$26	$21	$27	$30	$33	$34	$38	$38	$40	$28	$27	$23	$13
BPA	$27	$20	$23	$40	$31	$33	$40	$37	$35	$43	$45	$26	$22	$28	$33	$36	$36	$41	$39	$40	$28	$27	$23	$13
Tacoma Power	$26	$18	$20	$32	$27	$32	$38	$36	$36	$43	$43	$26	$22	$26	$29	$35	$34	$38	$36	$39	$28	$27	$22	$12
PacifiCorp West	$25	$17	$20	$31	$27	$32	$39	$36	$36	$43	$43	$25	$20	$26	$29	$31	$33	$37	$37	$39	$27	$27	$22	$12
Portland GE	$27	$17	$21	$32	$27	$32	$39	$36	$35	$43	$43	$25	$20	$26	$29	$32	$34	$38	$37	$39	$28	$27	$22	$14
Puget Sound Energy	$27	$18	$21	$33	$28	$32	$38	$35	$36	$43	$43	$26	$23	$27	$29	$37	$34	$39	$36	$39	$28	$27	$22	$12
Seattle City Light	$28	$18	$20	$31	$27	$32	$40	$36	$37	$43	$43	$26	$22	$26	$29	$37	$34	$39	$36	$39	$29	$27	$22	$13
Powerex	$43	$27	$32	$42	$36	$33	$36	$35	$34	$48	$46	$33	$27	$29	$31	$36	$33	$34	$36	$39	$29	$25	$22	$14
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
					2024										2025								2026	

Table 4.2 Average monthly 5-minute market prices

SMEC	$20	$14	$24	$43	$34	$34	$44	$40	$43	$47	$39	$29	$25	$28	$32	$37	$42	$43	$38	$46	$36	$34	$26	$21
PG&E (CAISO)	$26	$19	$26	$49	$34	$35	$51	$45	$46	$50	$39	$32	$28	$29	$34	$38	$43	$48	$43	$50	$38	$35	$28	$25
SCE (CAISO)	$9	$8	$22	$42	$33	$32	$37	$35	$41	$44	$30	$26	$19	$24	$29	$35	$43	$40	$33	$42	$35	$35	$24	$23
SDGE (CAISO)	$16	$9	$23	$42	$34	$36	$38	$38	$43	$49	$35	$29	$21	$25	$30	$38	$49	$45	$33	$44	$38	$38	$25	$28
BANC	$27	$20	$25	$48	$34	$36	$52	$45	$45	$50	$39	$32	$26	$29	$35	$39	$43	$48	$44	$49	$37	$34	$28	$22
Turlock ID	$29	$19	$24	$45	$35	$38	$57	$46	$46	$51	$39	$33	$30	$30	$36	$41	$44	$51	$46	$49	$37	$34	$29	$23
LADWP	$10	$10	$27	$50	$45	$35	$39	$37	$38	$45	$30	$28	$21	$27	$32	$38	$45	$43	$34	$44	$36	$35	$24	$20
NV Energy	$12	$9	$21	$37	$29	$28	$33	$30	$32	$40	$25	$21	$22	$25	$29	$32	$35	$34	$30	$37	$32	$30	$21	$20
Arizona PS	$8	$8	$21	$40	$32	$27	$30	$27	$33	$37	$23	$19	$16	$20	$27	$32	$37	$32	$29	$35	$31	$30	$20	$19
Tucson Electric	$10	$14	$24	$34	$26	$27	$27	$28	$32	$38	$23	$21	$18	$23	$27	$32	$35	$33	$28	$35	$31	$30	$20	$19
Salt River Project	$10	$13	$29	$37	$31	$29	$30	$27	$32	$37	$23	$20	$26	$23	$34	$32	$36	$33	$28	$35	$30	$30	$20	$21
PSC New Mexico	$16	$12	$25	$37	$28	$28	$27	$50	$30	$39	$15	$3	$15	$20	$44	$32	$43	$34	$27	$32	$25	$28	$15	$16
WAPA - Desert SW	$6	$9	$21	$37	$29	$27	$32	$27	$32	$37	$22	$20	$16	$20	$27	$31	$36	$32	$29	$34	$30	$30	$21	$24
El Paso Electric	$8	$18	$25	$36	$24	$26	$27	$27	$32	$36	$19	$10	$17	$27	$33	$32	$39	$34	$27	$33	$32	$37	$20	$20
PacifiCorp East	$15	$11	$20	$35	$27	$27	$34	$31	$34	$40	$30	$18	$18	$25	$28	$32	$36	$34	$27	$36	$30	$30	$22	$15
Idaho Power	$19	$13	$21	$34	$28	$28	$36	$34	$35	$43	$34	$21	$25	$27	$29	$32	$35	$35	$35	$37	$31	$29	$22	$14
NorthWestern	$26	$18	$20	$33	$28	$30	$31	$34	$34	$42	$39	$25	$22	$25	$29	$32	$35	$35	$33	$39	$35	$29	$23	$13
Avista Utilities	$27	$18	$20	$32	$28	$29	$37	$36	$36	$43	$41	$25	$22	$25	$29	$32	$34	$36	$36	$39	$30	$29	$23	$12
Avangrid	$24	$16	$20	$33	$28	$31	$39	$37	$37	$44	$42	$24	$20	$26	$30	$33	$35	$37	$38	$40	$29	$28	$23	$14
BPA	$26	$17	$22	$38	$29	$32	$38	$35	$36	$44	$43	$24	$20	$26	$31	$35	$36	$40	$38	$40	$28	$27	$22	$14
Tacoma Power	$26	$17	$20	$32	$27	$31	$37	$35	$36	$43	$42	$24	$21	$26	$29	$34	$35	$37	$36	$39	$29	$27	$22	$13
PacifiCorp West	$24	$16	$20	$32	$27	$31	$38	$36	$36	$43	$41	$23	$19	$25	$29	$32	$34	$36	$37	$39	$29	$28	$22	$12
Portland GE	$26	$16	$20	$32	$27	$31	$38	$35	$36	$43	$41	$24	$19	$25	$29	$32	$34	$37	$37	$39	$28	$27	$22	$15
Puget Sound Energy	$27	$16	$20	$33	$27	$31	$37	$34	$36	$43	$41	$24	$22	$26	$29	$36	$35	$37	$36	$39	$28	$27	$22	$13
Seattle City Light	$26	$16	$20	$31	$27	$31	$38	$35	$36	$45	$41	$24	$21	$25	$29	$36	$35	$37	$36	$39	$29	$27	$22	$13
Powerex	$43	$27	$30	$42	$36	$33	$36	$35	$34	$47	$45	$33	$27	$28	$30	$36	$33	$34	$36	$39	$29	$25	$22	$14
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
					2024										2025								2026	

Table 4.3 Average hourly 15-minute market prices (January–March)

SMEC	$31	$30	$29	$29	$30	$31	$35	$32	$20	$15	$14	$13	$11	$10	$8	$13	$23	$30	$36	$36	$35	$35	$33	$31
PG&E (CAISO)	$32	$30	$30	$30	$30	$31	$36	$36	$27	$21	$18	$15	$13	$12	$11	$18	$28	$36	$42	$44	$38	$36	$34	$32
SCE (CAISO)	$33	$31	$31	$30	$31	$33	$36	$31	$15	$10	$10	$11	$10	$8	$7	$10	$23	$31	$39	$37	$35	$36	$36	$33
SDGE (CAISO)	$35	$32	$32	$31	$31	$33	$37	$33	$19	$12	$12	$12	$12	$10	$9	$13	$27	$35	$41	$40	$38	$39	$37	$34
BANC	$32	$30	$30	$30	$30	$31	$35	$33	$24	$18	$16	$15	$13	$11	$10	$15	$25	$33	$38	$38	$35	$34	$34	$31
Turlock ID	$32	$30	$30	$30	$30	$31	$35	$34	$25	$21	$18	$16	$14	$13	$11	$16	$26	$33	$38	$40	$35	$34	$34	$32
LADWP	$33	$31	$28	$27	$29	$31	$36	$29	$14	$8	$7	$8	$9	$7	$5	$10	$24	$32	$40	$38	$36	$36	$36	$33
NV Energy	$24	$22	$23	$23	$24	$28	$31	$26	$18	$13	$12	$12	$10	$8	$6	$10	$20	$27	$33	$30	$29	$28	$27	$25
Arizona PS	$24	$23	$23	$23	$24	$27	$30	$25	$14	$9	$9	$9	$9	$6	$4	$8	$19	$26	$33	$30	$29	$28	$28	$26
Tucson Electric	$25	$24	$23	$24	$24	$28	$34	$25	$18	$9	$9	$9	$9	$6	$4	$8	$19	$27	$32	$31	$29	$34	$29	$26
Salt River Project	$25	$23	$23	$23	$24	$27	$30	$25	$14	$10	$10	$8	$9	$8	$8	$9	$20	$26	$33	$33	$29	$29	$28	$26
PSC New Mexico	$25	$23	$21	$22	$23	$26	$29	$21	$11	$5	$5	$5	$1	-$1	-$3	$3	$17	$25	$30	$27	$26	$26	$25	$23
WAPA - Desert SW	$25	$24	$23	$23	$24	$27	$39	$73	$20	$9	$9	$9	$9	$7	$4	$7	$20	$27	$34	$41	$29	$29	$28	$27
El Paso Electric	$27	$24	$24	$26	$27	$28	$37	$49	$19	$10	$9	$9	$7	$6	$2	$7	$26	$33	$43	$35	$32	$31	$30	$27
PacifiCorp East	$22	$22	$22	$22	$23	$26	$29	$26	$17	$13	$12	$11	$9	$7	$6	$9	$18	$24	$29	$29	$28	$27	$26	$24
Idaho Power	$21	$21	$21	$22	$23	$25	$28	$26	$19	$14	$14	$13	$10	$8	$7	$11	$18	$21	$26	$28	$27	$27	$24	$23
NorthWestern	$20	$20	$20	$21	$22	$24	$27	$26	$20	$15	$14	$12	$11	$9	$8	$11	$18	$21	$25	$26	$26	$26	$23	$22
Avista Utilities	$19	$20	$21	$21	$22	$24	$28	$27	$20	$16	$15	$13	$11	$10	$8	$11	$18	$20	$24	$26	$26	$25	$23	$21
Avangrid	$21	$21	$21	$21	$22	$25	$27	$26	$20	$17	$17	$15	$13	$11	$10	$13	$21	$24	$26	$29	$26	$26	$24	$23
BPA	$20	$20	$20	$20	$21	$27	$27	$27	$21	$18	$20	$16	$16	$12	$11	$14	$23	$25	$24	$26	$25	$23	$21	$21
Tacoma Power	$20	$20	$20	$20	$21	$24	$26	$26	$20	$16	$16	$15	$14	$11	$10	$13	$20	$24	$25	$25	$25	$24	$23	$22
PacifiCorp West	$20	$20	$20	$20	$21	$24	$26	$26	$20	$17	$16	$15	$13	$11	$10	$13	$20	$24	$25	$25	$25	$24	$23	$22
Portland GE	$20	$20	$20	$20	$21	$24	$26	$26	$22	$21	$23	$16	$15	$13	$11	$14	$21	$24	$25	$25	$25	$24	$23	$22
Puget Sound Energy	$21	$20	$20	$20	$22	$24	$26	$26	$20	$17	$17	$16	$14	$12	$8	$12	$20	$24	$25	$26	$25	$24	$24	$22
Seattle City Light	$20	$20	$20	$20	$22	$24	$30	$26	$20	$17	$17	$15	$14	$12	$10	$13	$20	$27	$25	$25	$25	$24	$23	$27
Powerex	$20	$21	$20	$20	$21	$22	$22	$21	$19	$19	$18	$17	$17	$16	$15	$17	$22	$24	$24	$24	$24	$23	$22	$22
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

Hour

Table 4.4 Average hourly 5-minute market prices (January–March)

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

Hour

4.3 Day-ahead market price comparison

This section analyzes day-ahead and real-time market prices for balancing areas in the day-ahead market. Up until May 1, 2026, this was just the CAISO balancing area.

Load weighted average day-ahead market prices were about $30/MWh in the first quarter of 2026, down 26 percent from $40/MWh in the first quarter of 2025. Average prices in the CAISO balancing area's 15-minute and 5-minute markets decreased by about 28 and 23 percent, respectively compared to the first quarter of the previous year. The average price of the three markets this quarter decreased to $30/MWh from $40/MWh in the same quarter of 2025.

Figure 4.7 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.[30] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from April 2024 to March 2026.

Over the quarter, prices in the day-ahead market averaged $30/MWh, and prices in the 15-minute and 5-minute markets averaged $29/MWh and $31/MWh, respectively. January had the highest prices, with an average over the three markets of about $36/MWh.

Figure 4.7 also shows monthly average gas prices at PG&E Citygate from April 2024 to March 2026. The chart shows that the monthly variation of the electricity prices is correlated with gas prices. The PG&E Citygate gas price decreased to $2.08/MMBtu this quarter, down from $3.72/MMBtu in the same quarter last year.

This correlation between electricity 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.

30 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 4.7 Monthly average PG&E Citygate gas price and load-weighted average electricity prices for balancing areas in day-ahead market

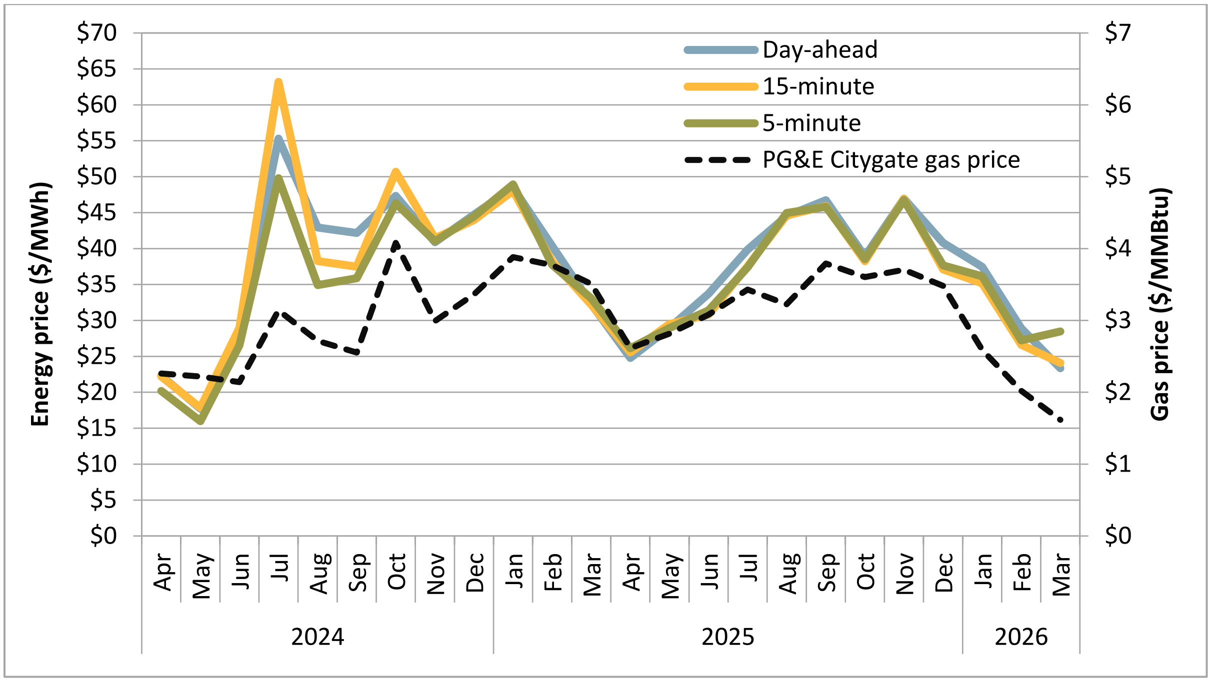


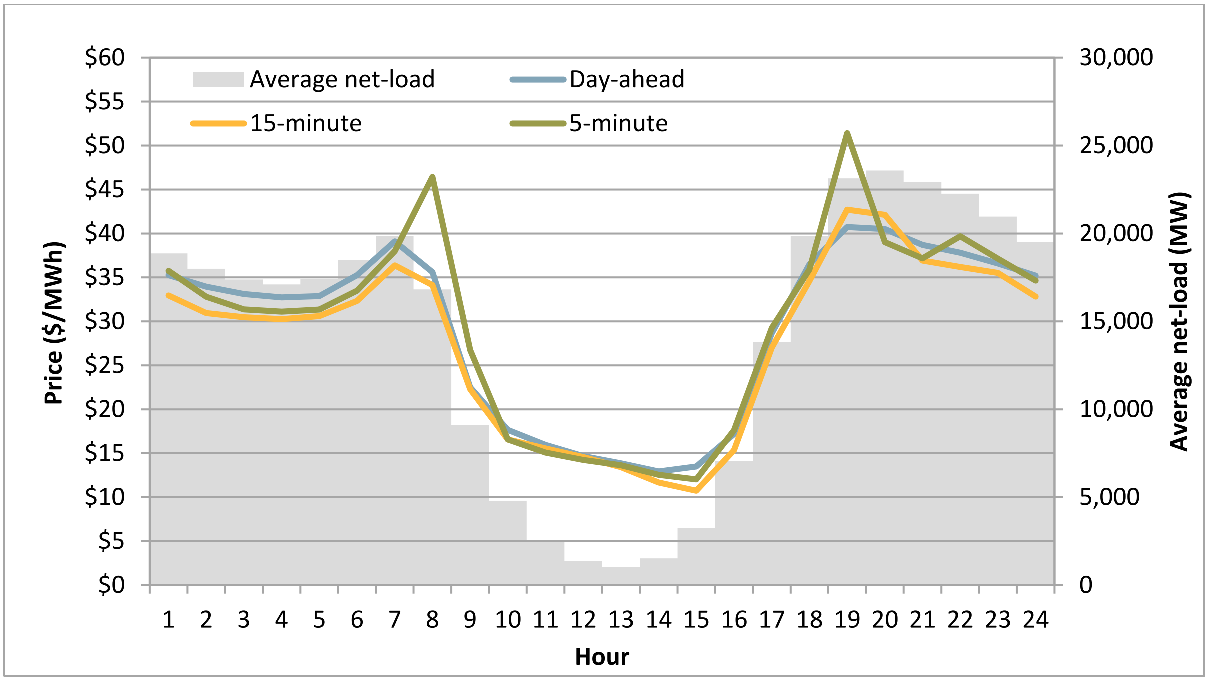
Figure 4.8 illustrates the hourly load-weighted average electricity prices for the first quarter compared to the average hourly net-load.[31] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets are measured by the left axis, while the average 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 early evening hours. Average energy prices across all three markets peaked at hour-ending 19, at around $45/MWh, while average net-load peaked at hour-ending 20, reaching 23,583 MW.

During hour-ending 19, the day-ahead load-weighted average electricity price was $41/MWh, the 15-minute price was $43/MWh, and the 5-minute price was $51/MWh. Overall, prices across the three markets converged well during most hours.

[31] 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.

Figure 4.8 Hourly load-weighted average energy prices for balancing areas in day-ahead market (CAISO January–March)



4.4 Bilateral price comparison

Figure 4.9 and Figure 4.10 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 Figure 4.9, day-ahead prices in the Intercontinental Exchange for the Mid-Columbia trading hub averaged $21/MWh in Q1 2026, very similar to ISO 15-minute market prices in the Pacific Northwest ($22/MWh). Day-ahead Mid-Columbia ICE prices were notably lower than average ISO day-ahead market prices at the Pacific Gas and Electric load node ($29/MWh).

As shown in Figure 4.10, day-ahead prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about $28/MWh over the quarter, about 33 percent higher than the ISO 15-minute market prices in the Desert Southwest ($21/MWh). Day-ahead Palo Verde ICE prices were notably higher than average ISO day-ahead market prices at the Southern California Edison load node ($24/MWh).

Figure 4.9 Mid-C bilateral ICE vs. Pacific Northwest 15-minute market prices (peak hours)

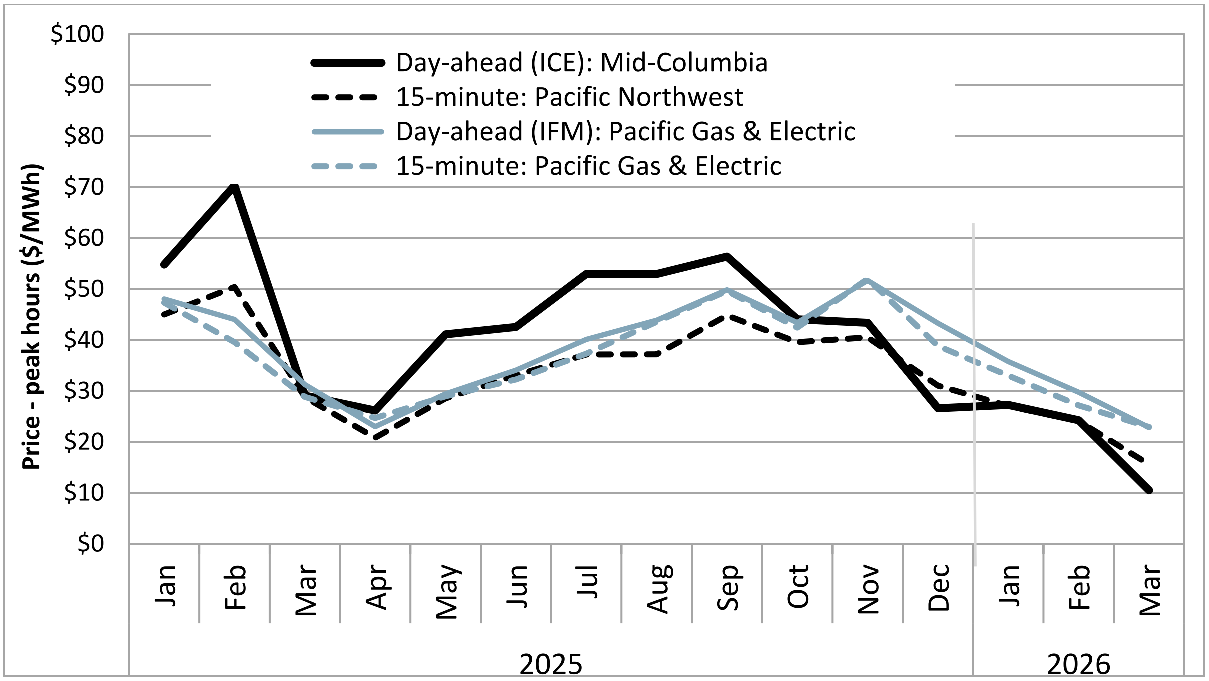


Figure 4.10 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)

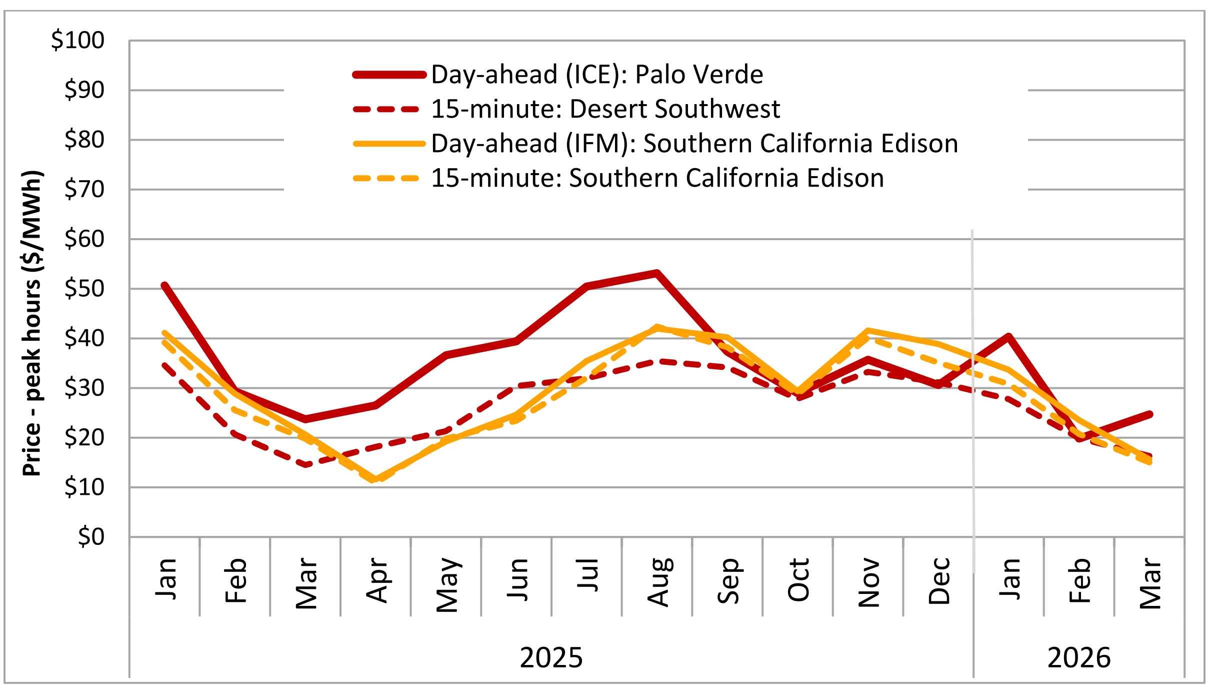


Figure 4.11 compares monthly average prices in the bilateral and ISO day-ahead markets for 2024 through the first quarter of 2026. The California ISO market day-ahead prices are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs).

Over the quarter, bilateral day-ahead prices at Mid-Columbia and Palo Verde averaged about $21/MWh and $28/MWh, respectively, while ISO day-ahead prices at Pacific Gas and Electric and Southern California Edison averaged around $29/MWh and $24/MWh, respectively. On average, prices at Mid-Columbia were lower than those at Palo Verde in January and March by 32 percent and 58 percent, respectively; however, in February, prices at Mid-Columbia were 22 percent higher.

Figure 4.11 Monthly average day-ahead and bilateral market prices

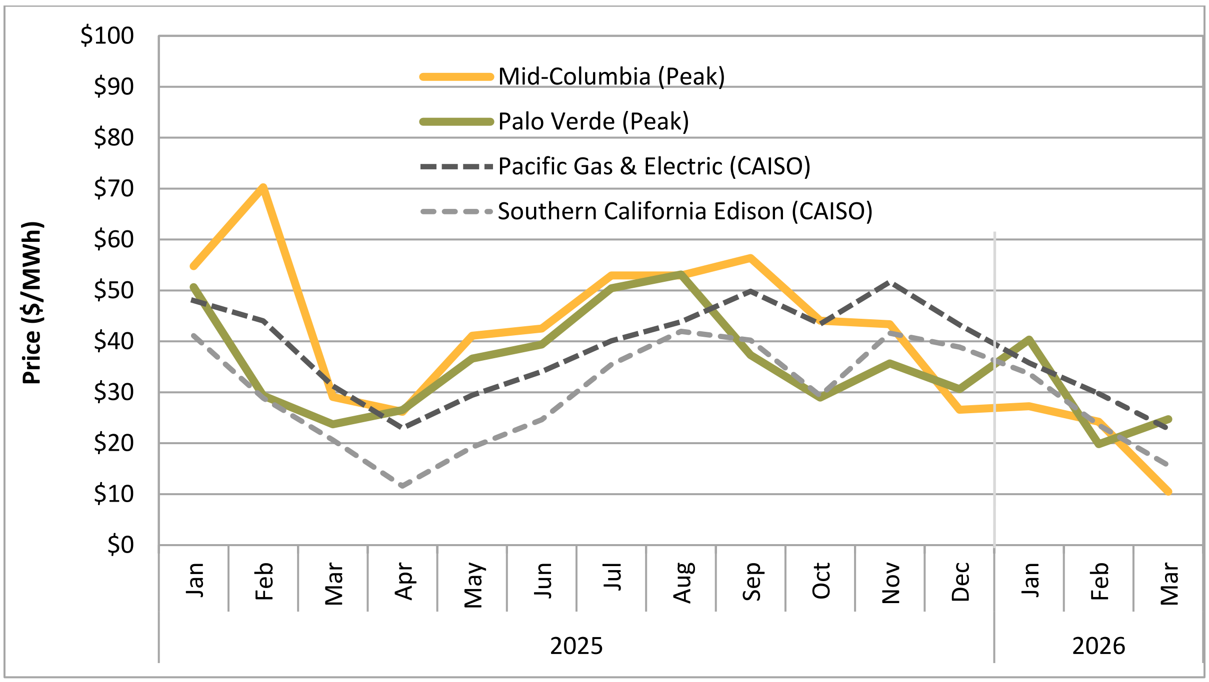


Figure 4.12 shows daily California ISO market day-ahead load weighted average peak prices across the three largest load aggregation points—Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric—as well as averages for the bilateral day-ahead peak energy prices from the Intercontinental 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.

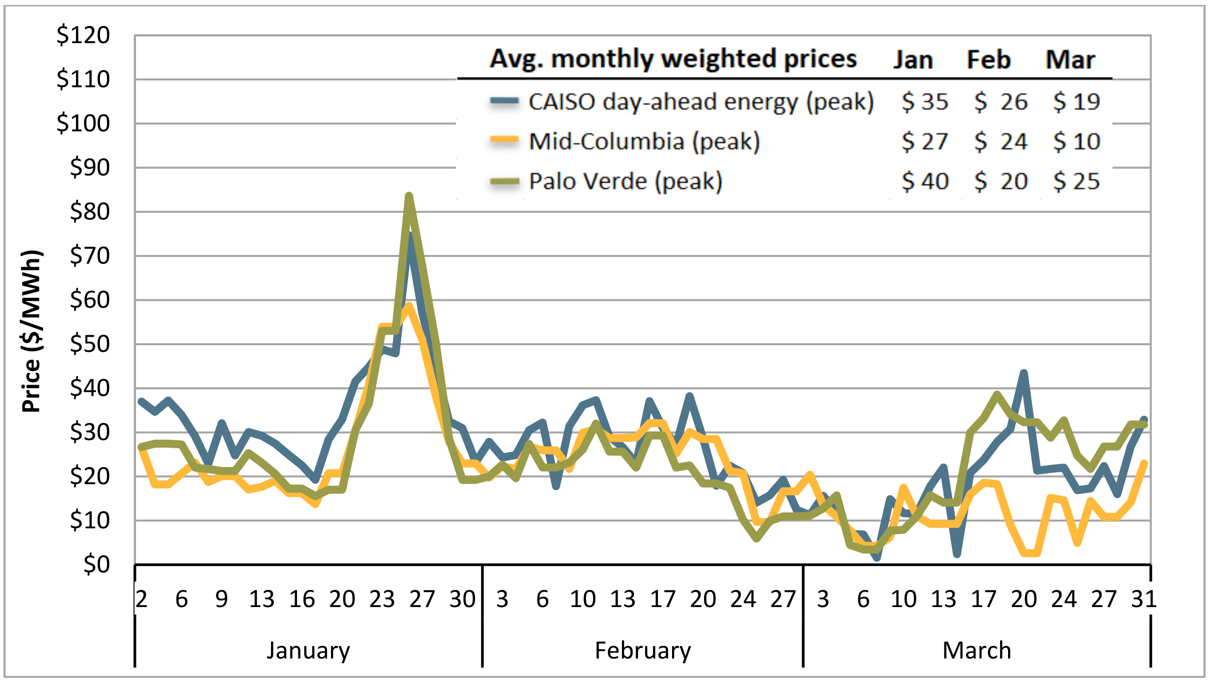
January exhibited the highest prices and volatility, including a late-month price spike indirectly associated with a major winter storm[32] in the Midwest and Eastern United States. The California ISO market (CAISO) day-ahead peak prices were consistently above Mid-Columbia but mixed relative to Palo Verde. In January, CAISO day-ahead averaged $35/MWh, exceeding Mid-Columbia by $8/MWh or about

[32] *Electricity Learnings From Great Freeze Of January 2026 In U.S.*, Forbes, February 5, 2026: https://www.forbes.com/sites/ianpalmer/2026/02/05/electricity-learnings-from-great-freeze-of-january-2026-in-us/

28 percent, but trailing Palo Verde by $5/MWh or 13 percent. In February, CAISO averaged $26/MWh, remaining slightly above Mid-Columbia by $2/MWh or 8 percent and rose above Palo Verde by $6/MWh or about 30 percent. During March, California ISO (CAISO) day-ahead peak prices significantly exceeded Mid-Columbia by $8/MWh or about 90 percent but again fell below Palo Verde by $6/MWh or about 25 percent.

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 import bid price hourly energy shaping factor on November 16, 2024.[33] The ISO did not raise the energy bid cap and penalty prices to $2,000/MWh in the first quarter of 2026.

Figure 4.12 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. At the Mid-Columbia hub, average day-ahead prices were lower than the average real-time prices (from Powerdex) by about $1.15/MWh. At the Palo Verde hub, average day-ahead prices were higher than average real-time prices (from Powerdex) by about $3.40/MWh.

33 *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)

4.5 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.[34] 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.

High prices

Figure 4.13 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 2025 to March 2026.[35] Figure 4.14 illustrates the monthly frequency of high prices for balancing areas participating only in the real-time market during the same period.[36]

In the day-ahead market, the frequency of high prices over $250/MWh was zero percent this quarter, in line with the same quarter last year.

In the 15-minute market, the frequency of high prices for the balancing area participating in the day-ahead market increased by 45 percent, up from 0.04 percent in Q1 2025 to 0.06 percent in Q1 2026. For balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices also increased, from 0.05 percent in Q1 2025 to 0.09 percent in Q1 2026.

In the 5-minute market, the frequency of high prices for the balancing area participating in the day-ahead market increased by 7 percent, up from 0.18 percent in Q1 2025 to 0.19 percent in Q1 2026. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market also increased by 35 percent, from 0.09 percent to 0.13 percent.

Most of the high prices in this quarter occurred in March, during the early heat wave period this year.

[34] 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.

[35] 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.

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

Figure 4.13 Frequency of high prices in BAAs participating in the day-ahead market (CAISO)

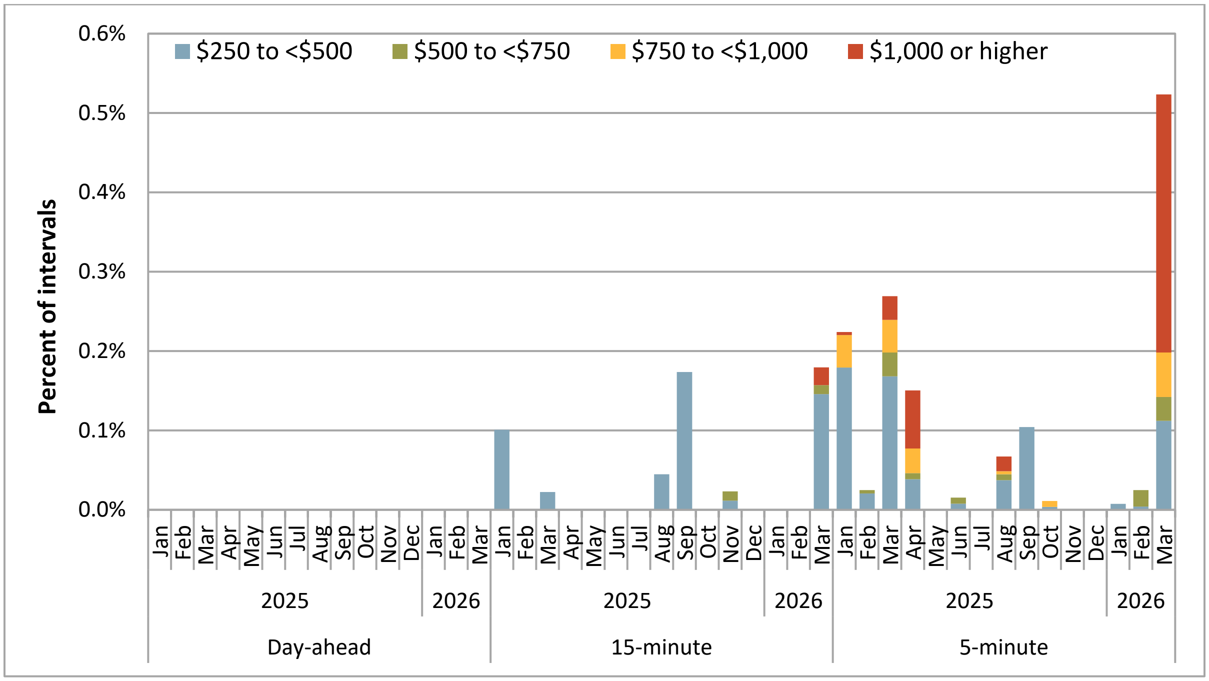
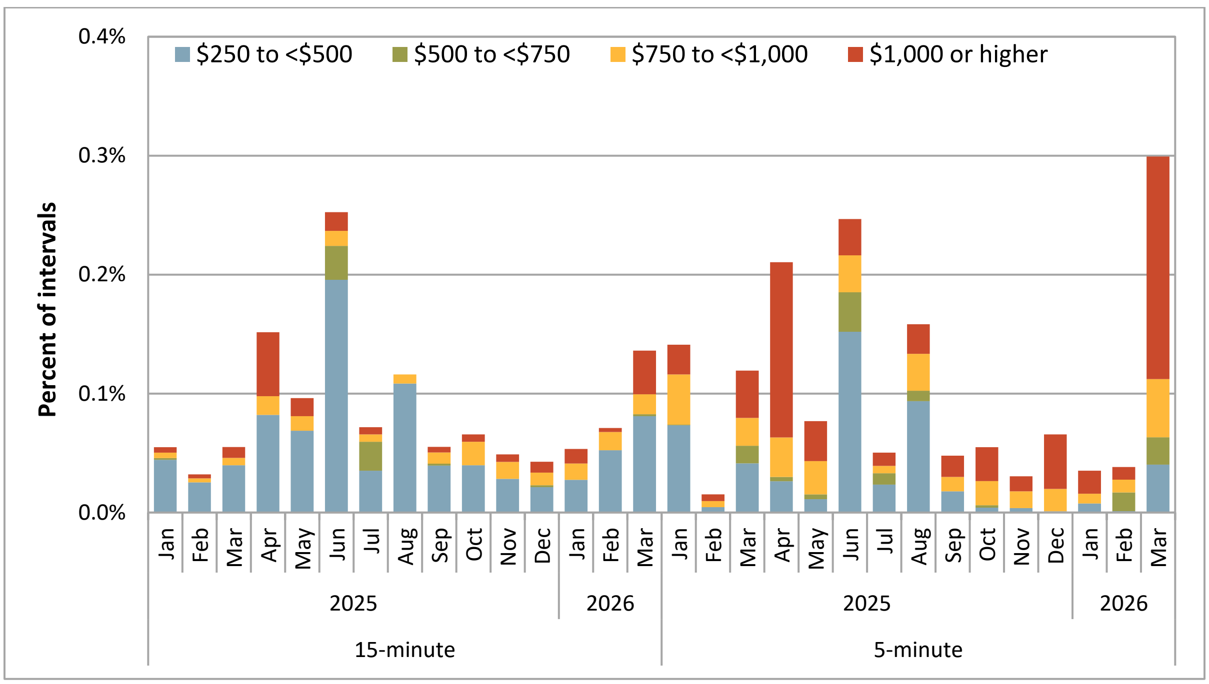


Figure 4.14 Frequency of high prices in BAAs participating only in the real-time markets



Negative prices

Figure 4.15 and Figure 4.16 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 2025 to March 2026.

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 decreased in the three markets. In the day-ahead market, the frequency decreased from 11 percent to 7 percent compared to the same quarter of the previous year. In the 15-minute market, it decreased from 13.5 percent to 11 percent, and in the 5-minute market, it decreased from 14 percent to 12 percent.

For the BAAs participating exclusively in the real-time markets—all balancing areas in the WEIM besides CAISO—the frequency of negative prices showed an increase across the 15-minute and 5-minute markets, with an average increase of 8 percent compared to the same quarter of the previous year. For instance, in the 15-minute market, the frequency increased from 8.5 percent to 9 percent. In the 5-minute market, it increased from 9.7 percent to 10.3 percent during this quarter.

Figure 4.15 Frequency of negative prices in BAAs participating in the day-ahead market (CAISO)

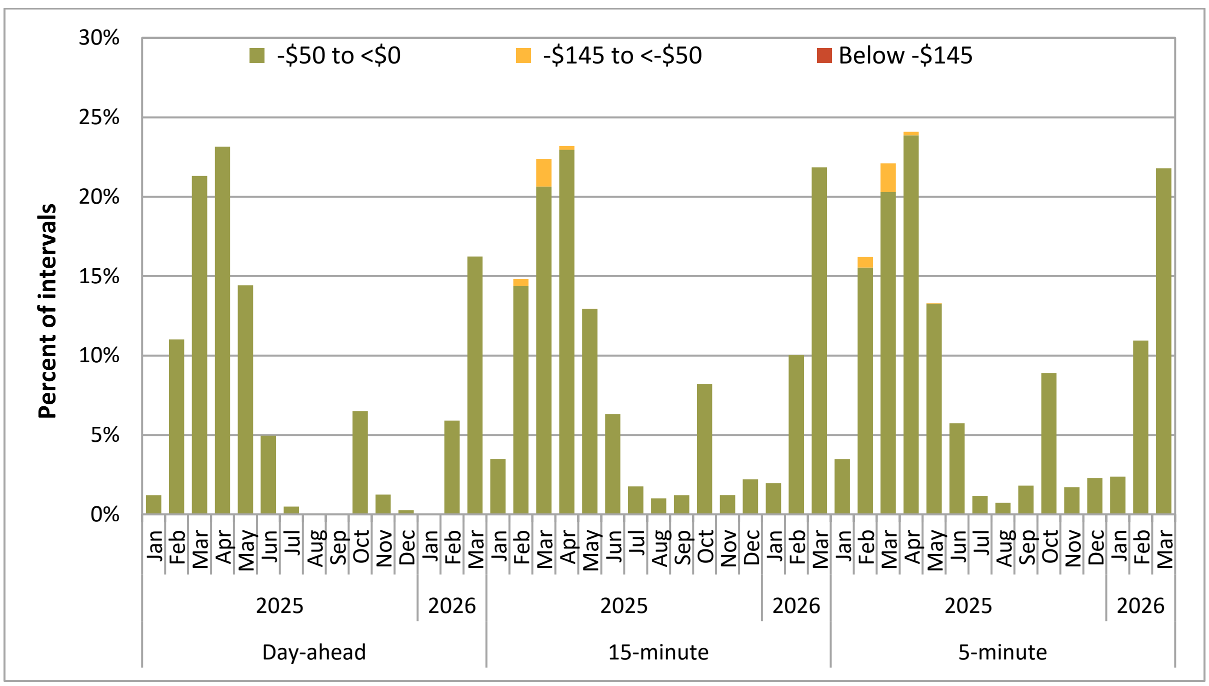
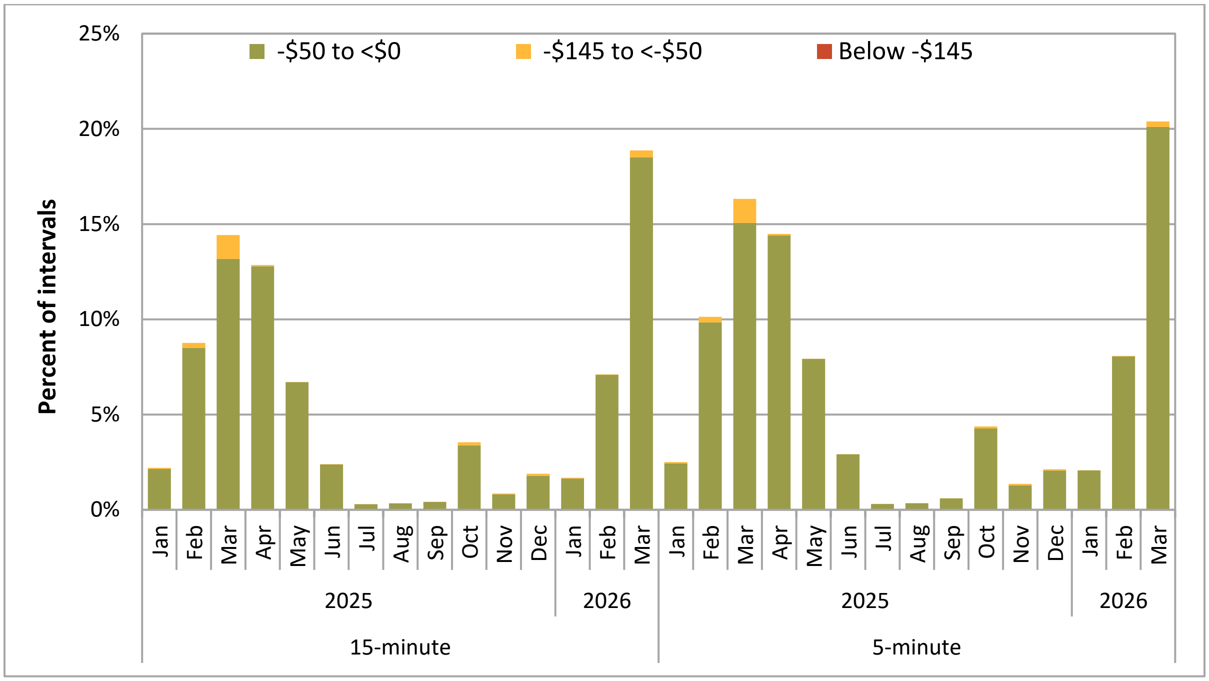


Figure 4.16 Frequency of negative prices in BAAs participating only in the real-time markets



5 WEIM transfers

This section provides an overview of WEIM transfers as well as constraints impacting WEIM transfers. Key observations from the quarter include the following:

The average volume of WEIM transfers across the system was 4,010 MW during the first quarter of 2026, about 500 MW lower compared to the same quarter of 2025. These transfers helped to displace expensive generation and meet load across the footprint.

WEIM transfers between regions continued to be significantly different during mid-day (solar) hours than during evening and early morning (non-solar) hours. During solar hours, transfers were largely from the CAISO and Intermountain West balancing areas to other WEIM regions. During non-solar hours, transfers were lower and largely from the regions outside California toward California.

The Pacific Northwest region continued to have the lowest transfer capacity into and out of their region. The lack of transfer capacity into or out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Transfers for Salt River Project were regularly constrained by intertie constraints that each balancing area can use to manage total or net WEIM transfers into or out of their system. Net imports for Salt River Project were constrained in around 4.5 percent of intervals at 1,050 MW because of this constraint.

5.1 Energy transfer

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 reflect regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint.

WEIM transfers are defined as either base, dynamic, or static. Base WEIM transfers are fixed bilateral transactions between WEIM entities and are not optimized in the market. Dynamic WEIM transfers are optimized in all markets. Static WEIM transfers are a smaller set of transfers between the Pacific Northwest and California regions that are only optimized in the 15-minute market. WEIM transfers in this section exclude the base WEIM transfer schedules and therefore reflect only dynamic or static WEIM transfer schedules optimized in the market.

Figure 5.1 summarizes the average volume of WEIM transfers in the 5-minute market by hour during the last five quarters. During the first quarter of 2026, the average volume of transfers across the system was around 4,010 MW, about 500 MW lower compared to the same quarter of the previous year.

Figure 5.2 summarizes average inter-regional transfers by hour during the last five quarters.[37] Figure 5.3 shows the same information for only the recent quarter. The bars show *net* WEIM transfers for each region by hour.[38] Net WEIM exports for a region are shown as negative and net WEIM imports for a

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

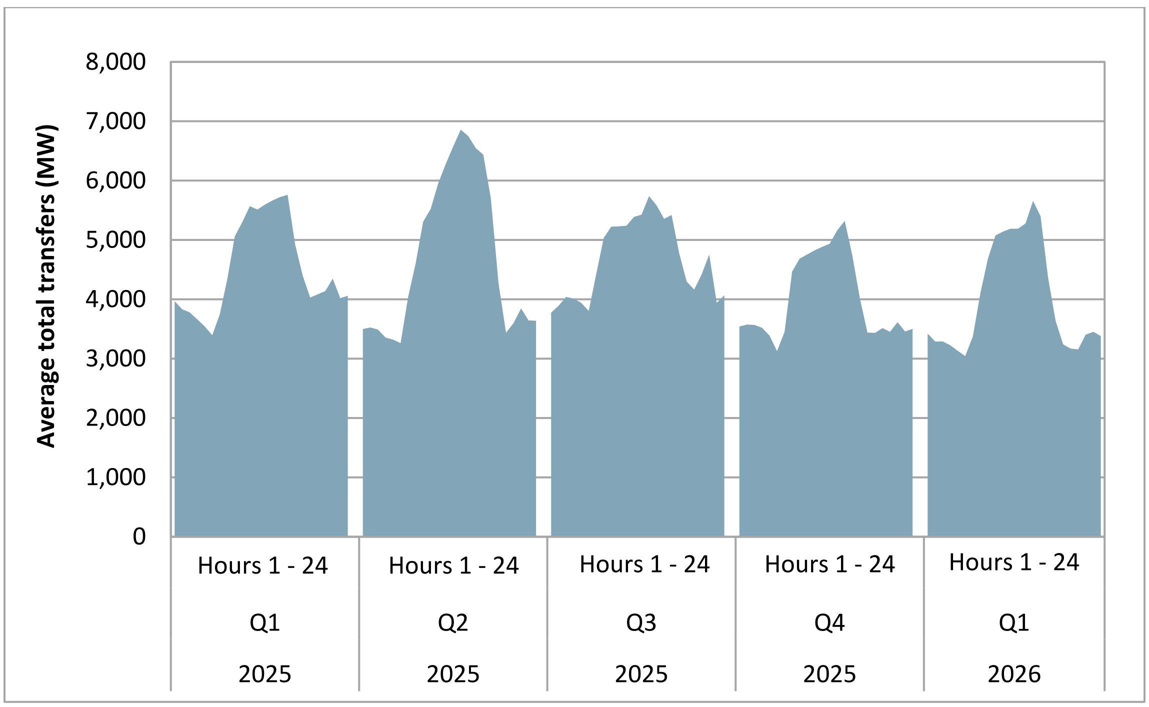
[38] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system.

region are shown as positive. WEIM transfers between regions continued to be significantly different during mid-day (solar) hours than during evening and early morning (non-solar) hours. During solar hours, transfers were largely from the CAISO and Intermountain West balancing areas to other WEIM regions. During non-solar hours, transfers were lower and largely from the regions outside California toward California.

Figure 5.4 and Figure 5.5 show average WEIM transfers in the 5-minute market by balancing area in the mid-day and peak periods during the quarter.[39] 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 5.4, the CAISO balancing area exported on net over 1,500 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. During the peak period (Figure 5.5), balancing areas in the Intermountain West, Desert Southwest, and Pacific Northwest regions exported on net almost 900 MW on average out to balancing areas in California.

Figure 5.1 Average 5-minute market WEIM transfer volume by hour and quarter (5-minute market, Q1 2025 – Q1 2026)



39 In these charts, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 5.2 Average 5-minute market inter-regional WEIM transfers by hour (Q1 2025 – Q1 2026)

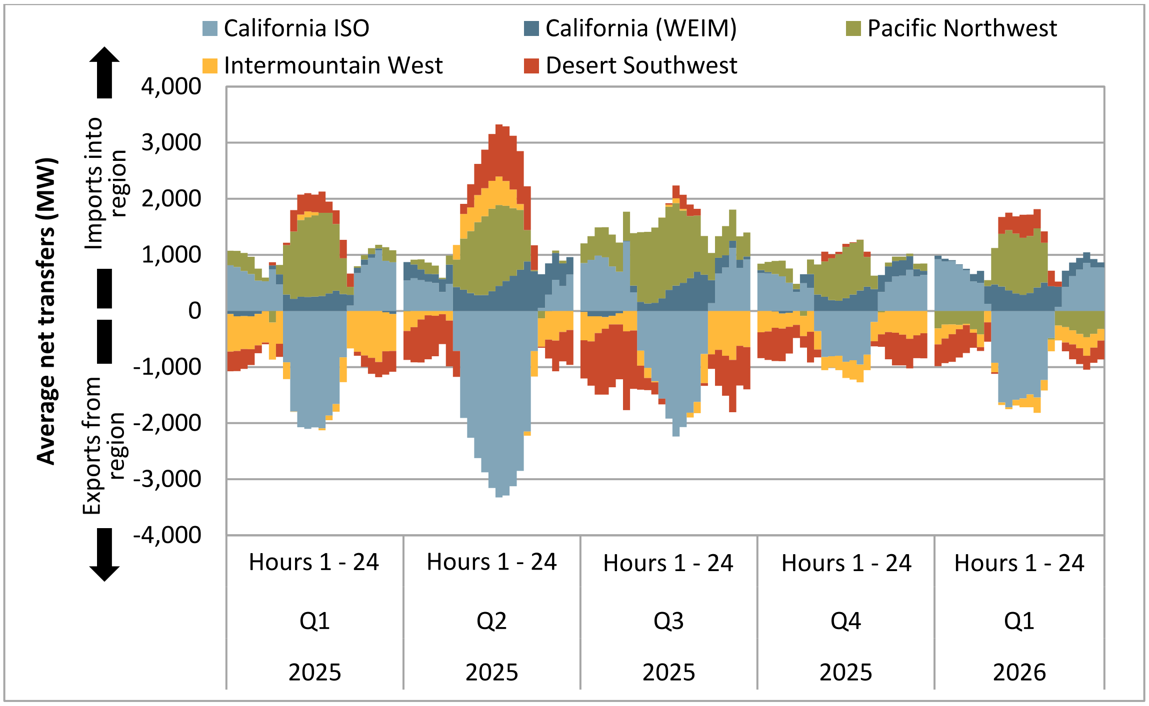


Figure 5.3 Average 5-minute market inter-regional WEIM transfers by hour (Q1 2026)

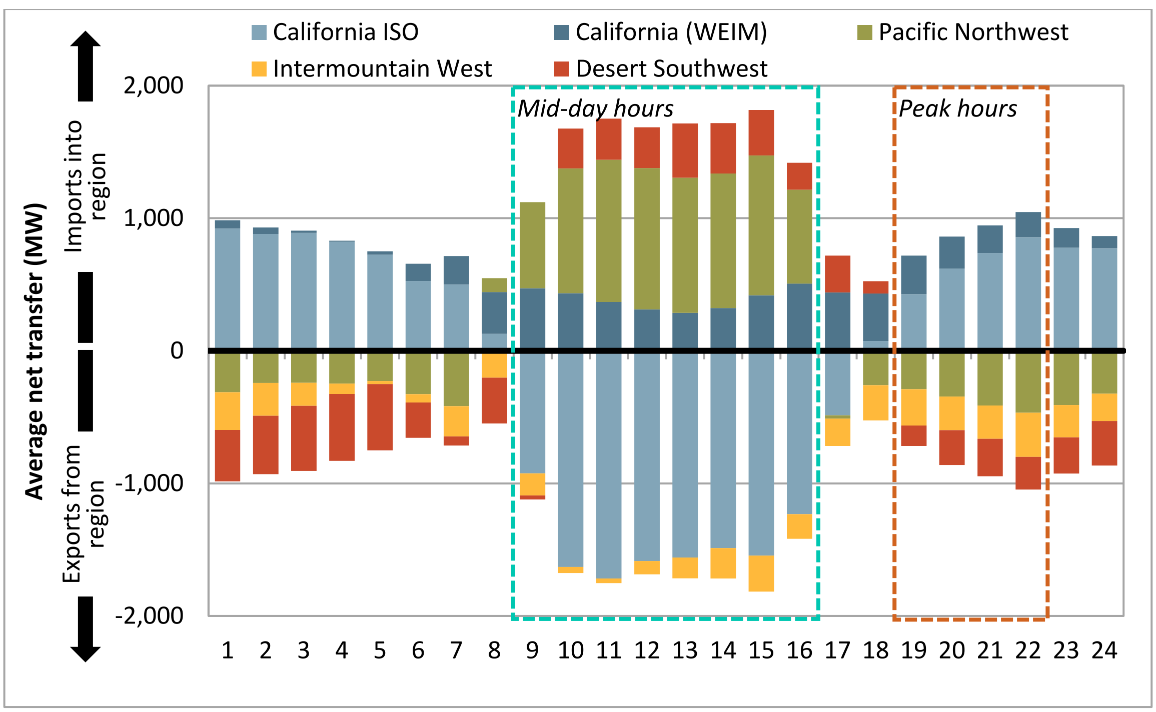


Figure 5.4 Average 5-minute market WEIM exports in mid-day hours (Q1 2026)

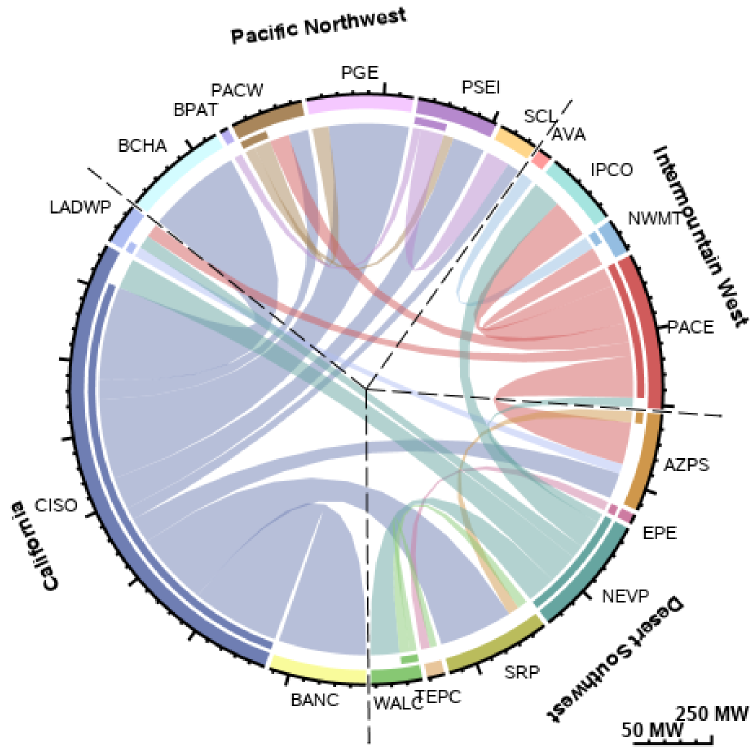
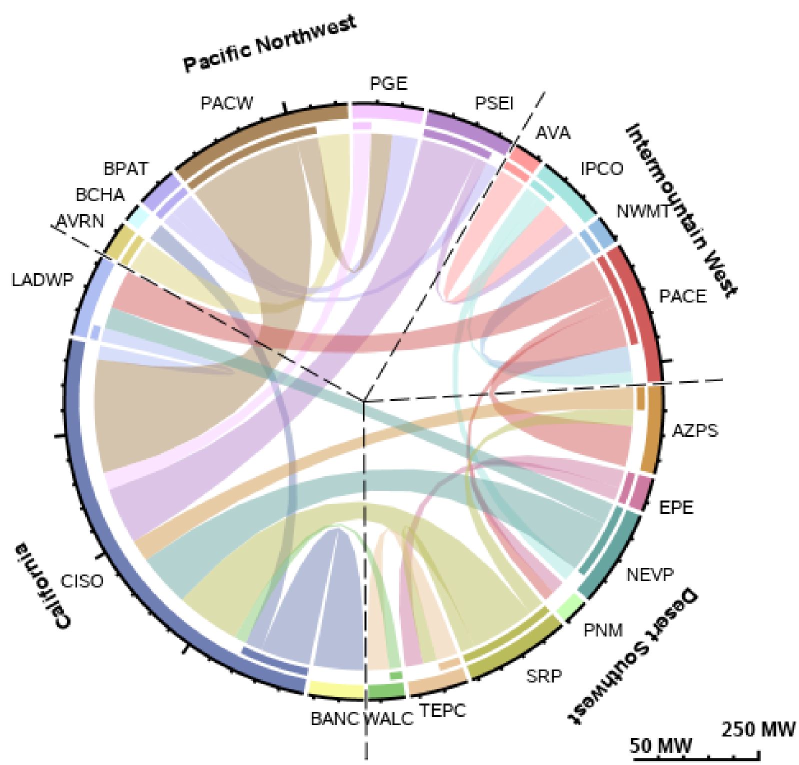


Figure 5.5 Average 5-minute market WEIM exports in peak load hours (Q1 2026)



5.2 WEIM 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.

Figure 5.6 shows WEIM transfer capacity (or transfer limits) available in the 5-minute market to support the transfer of energy between balancing areas and regions in the Western Energy Imbalance Market.[40] The width of each path reflects the size of the WEIM transfer capacity. WEIM transfer capacity between each balancing area within a region is shown in gray, while transfer capacity from a balancing area into and out of the region is aggregated, and shown in the colored paths.

40 Transfer capacity (limits) were categorized by the average limit from both the import and export direction. Transfer paths with 5 or less MW of transfer capacity on average for the quarter are not shown.

Figure 5.6 Average 5-minute market WEIM transfer limits by balancing area (Q1 2026)

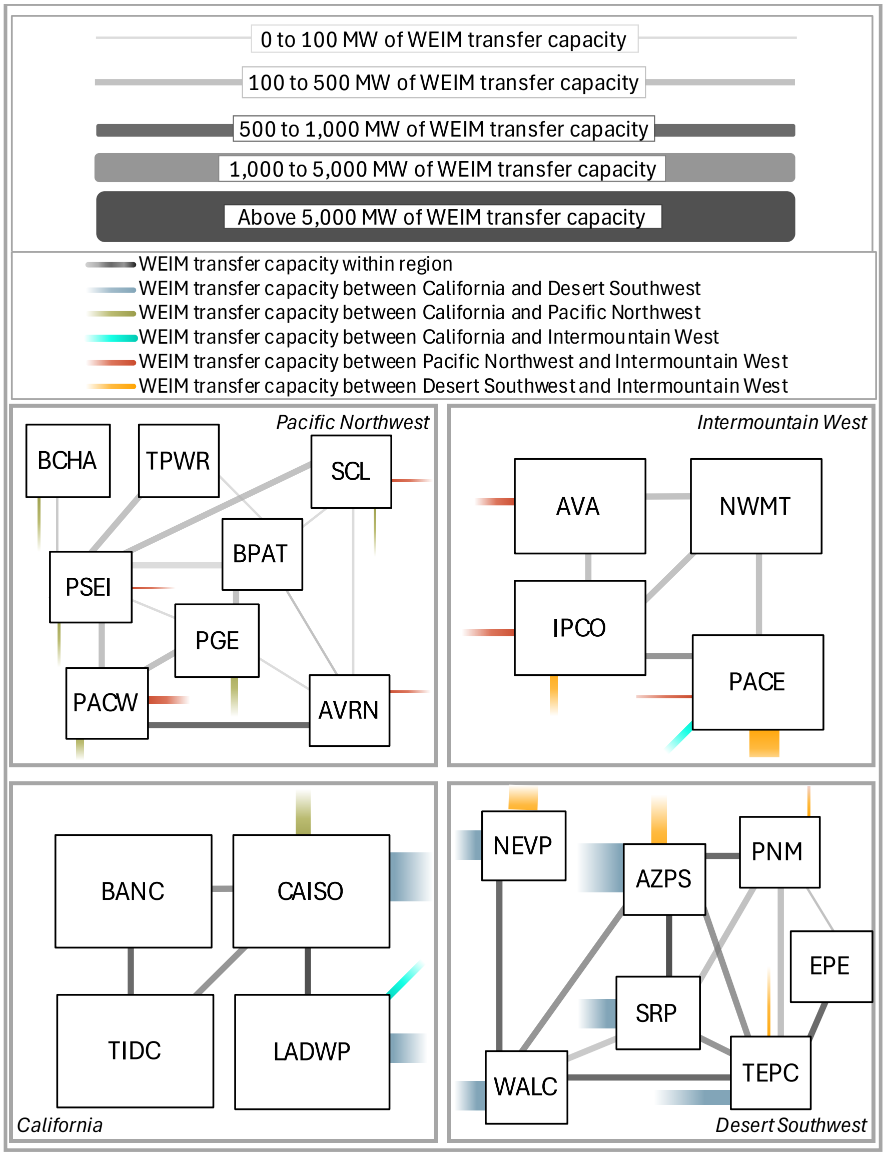


Table 5.1 summarizes average regional transfer capacity.[41] Total WEIM transfer capacity between balancing areas *within a region* is shown in the gray cells. Transfer capacity *between regions* is shown in the remaining cells. The sum of each column reflects the average total import capacity into the region, while the sum of each row reflects the average total export capacity out of the region.

Most WEIM transfer schedules are defined as *dynamic* where transfers are optimized in both the 15-minute and 5-minute markets, generally using the same transmission limits. However, for paths between California and the Pacific Northwest where there are dynamic transmission capability constraints, it is necessary to differentiate between static WEIM transfers that are used for the 15-

41 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.

minute energy transfer schedule and limit (and are not re-optimized in the 5-minute market); and dynamic WEIM transfers that are only used for the incremental 5-minute energy transfer schedule and limit. For transfers between California and the Pacific Northwest (green cells), the first number shows the transfer capacity on static transfers in the 15-minute market, while the second number shows the incremental transfer capacity that is available on dynamic transfers in the 5-minute market.

For the Pacific Northwest region, there was an average of around 1,428 MW of import transfer capacity and 891 MW of export transfer capacity into or out of the region in the 15-minute market. The lack of transfer capacity out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Table 5.1 Average regional WEIM transfer limits (Q1 2026)

Dynamic WEIM transfer capacity within region (15-minute market)
Dynamic WEIM transfer capacity out of region (15-minute market)
Static WEIM transfer capacity out of region (15-minute market) / Incremental dynamic capacity out of region (5-minute market)

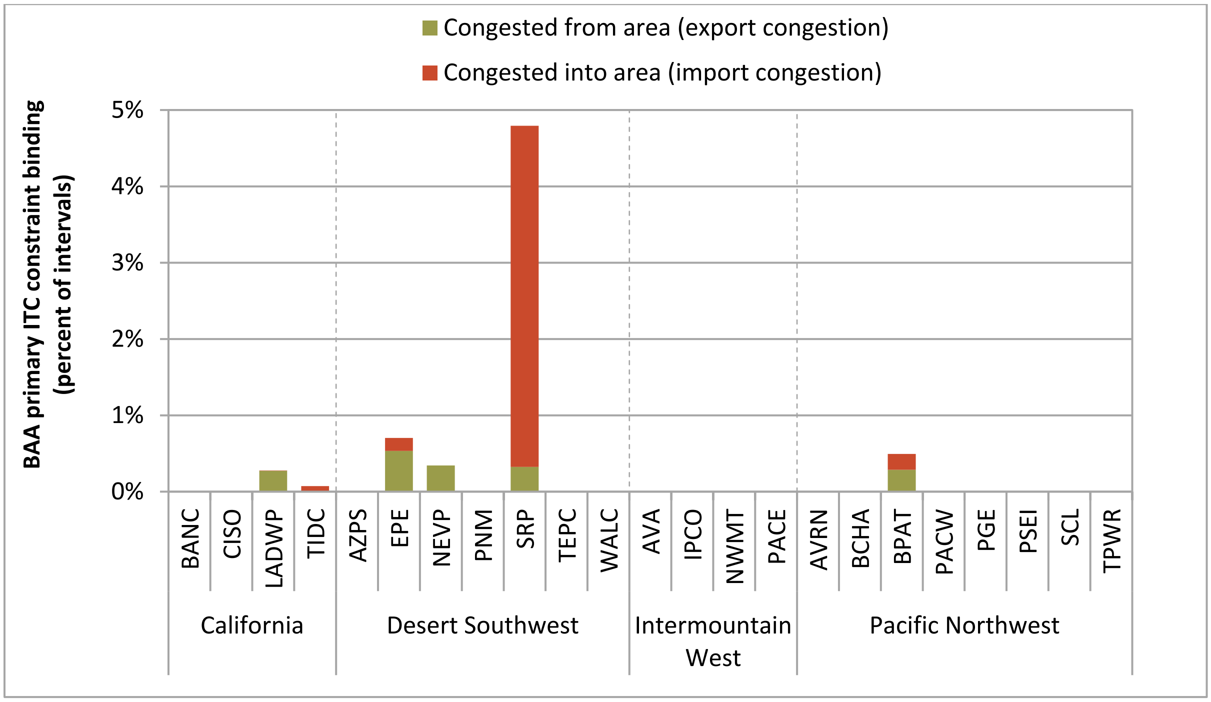
From region	To region: California	Desert Southwest	Intermountain West	Pacific Northwest	*Total out-of-region export limit*
California	24,918	33,177	65	873 / 396	34,115 / 396
Desert Southwest	33,798	58,682	1,891		35,689
Intermountain West	296	1,661	4,301	555	2,512
Pacific Northwest	633 / 221		258	4,786	891 / 221
Total out-of-region import limit	34,726 / 221	34,839	2,215	1,428 / 396	

5.3 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 non-base WEIM transfers. A WEIM entity can use this constraint to effectively manage all these WEIM transfers into or out of their system, on net, without needing to adjust individual transfer limits.

Figure 5.7 shows the percent of intervals in the 5-minute market in which the primary intertie constraint—that limits all non-base WEIM transfers on net for a balancing area—was binding in either the import or export direction, resulting in congestion. Of note, net *imports* for Salt River Project were constrained in around 4.5 percent of intervals because of this constraint. When this constraint was binding in the import direction, net imports were limited to 1,050 MW.

Figure 5.7 Frequency of primary ITC constraint binding for net WEIM transfers (5-minute market, Q1 2026)



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 two intertie constraints that were binding for total WEIM imports and total WEIM exports in around 1 percent of intervals each. The limit was around 500 MW on average in both directions when these constraints were binding.

6 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.

Figure 6.1 through Figure 6.3 show the average impact of congestion on real-time market prices in Q1 of 2025 and 2026. Blue bars represent the 2025 impact, while red bars represent the 2026 values. The congestion impact was calculated as the average price impact across both the 15-minute and 5-minute markets for all intervals during the quarter.

Figure 6.1 shows the total price impact from all congestion sources—WEIM transfer and internal flow-based constraints. Figure 6.2 isolates the impact from WEIM transfer constraints. Figure 6.3 shows the impact from internal flow-based constraints.[42]

Unlike the first quarter of last year, Q1 congestion this year was driven largely by flow into California and the Desert Southwest from the Intermountain West and the Pacific Northwest. This pattern reflected the March heat wave, which increased temperatures and demand in California and the Desert Southwest.[43] Outside of March, congestion patterns were closer to typical south-to-north flows during solar production hours. Overall, March conditions drove the first quarter congestion pattern.

WEIM transfer constraints remained a key contributor to the overall price impact, elevating prices across many balancing areas relative to the CAISO balancing area in the first quarter of both 2026 and 2025. Transfer congestion was most significant into the Desert Southwest balancing areas of El Paso and WAPA Desert Southwest.

Internal congestion typically contributes to south-to-north price separation. This quarter, however, overall price separation was less pronounced than in the same quarter last year. Prices in the Desert Southwest were less depressed by internal congestion this quarter, likely reflecting the March heat wave. Outside of March, south-to-north congestion during solar hours typically depressed prices in the Desert Southwest relative to northern regions. In March, however, heat wave conditions increased flows into the Desert Southwest and offset part of that usual pattern. The March heatwave also caused a deviation from the typical impact of congestion on the Pacific Northwest and Intermountain West

42 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.

43 The March 2026 heat wave affected California and the Desert Southwest mainly from March 16 to March 26, with temperatures in many areas reaching 20 to 30 degrees above normal. The event likely increased weather-driven electricity demand across the region.

regions. In the first quarter of 2025, prices in these regions were elevated by internal congestion. In Q1 2026, however, internal congestion lowered prices in those regions overall compared to southern regions due to north-to-south power flow patterns during the March heat wave offsetting typical south-to-north congestion patterns during solar hours.

Section 6.2 provides a further hourly breakdown of congestion impacts during the March heat wave period.

Figure 6.1 Average impact of total congestion on real-time market price (2025–2026)

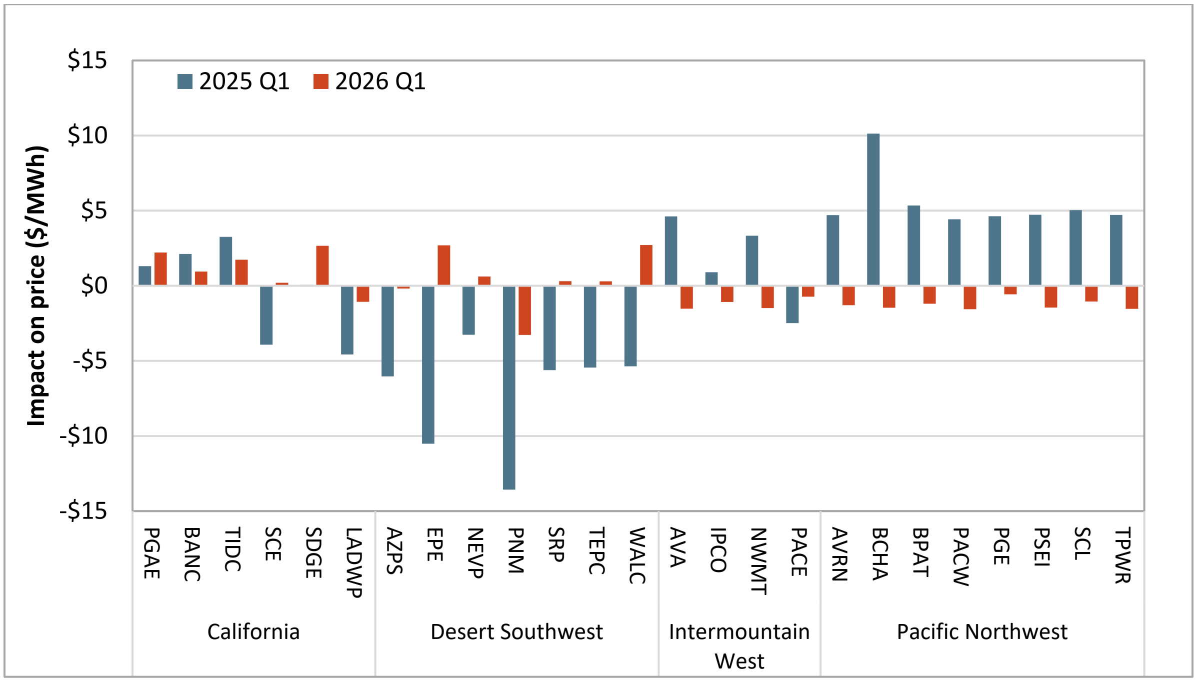


Figure 6.2 Average impact of transfer congestion on real-time market price (2025–2026)

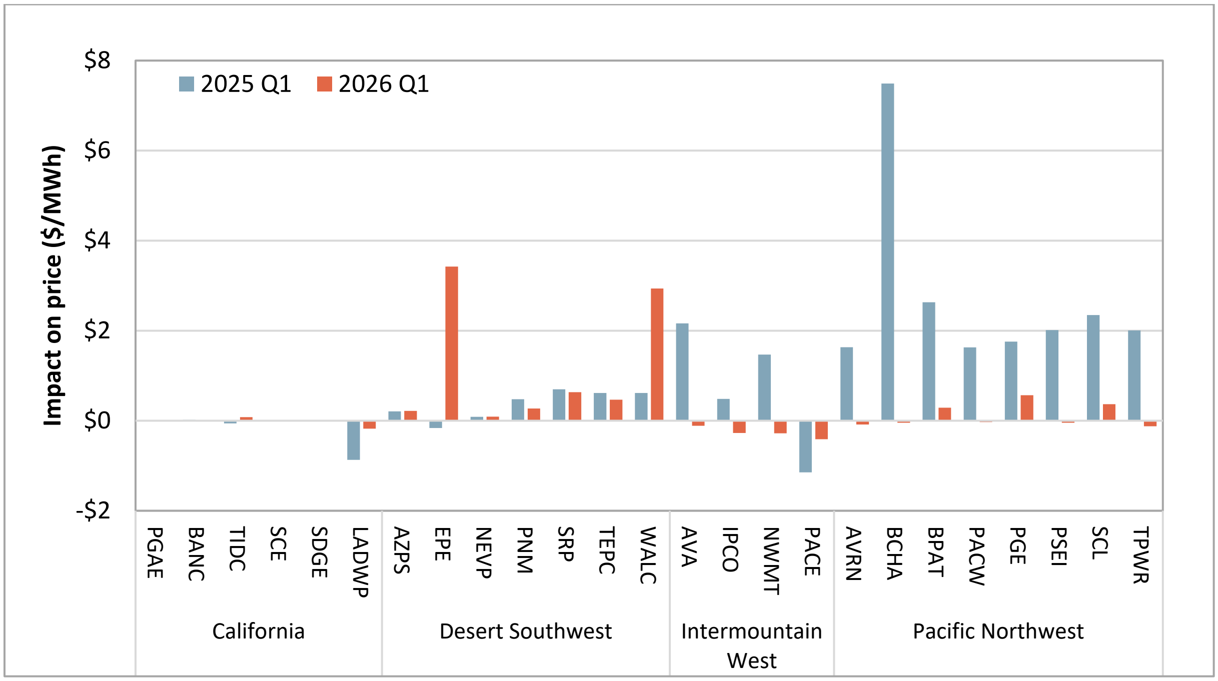
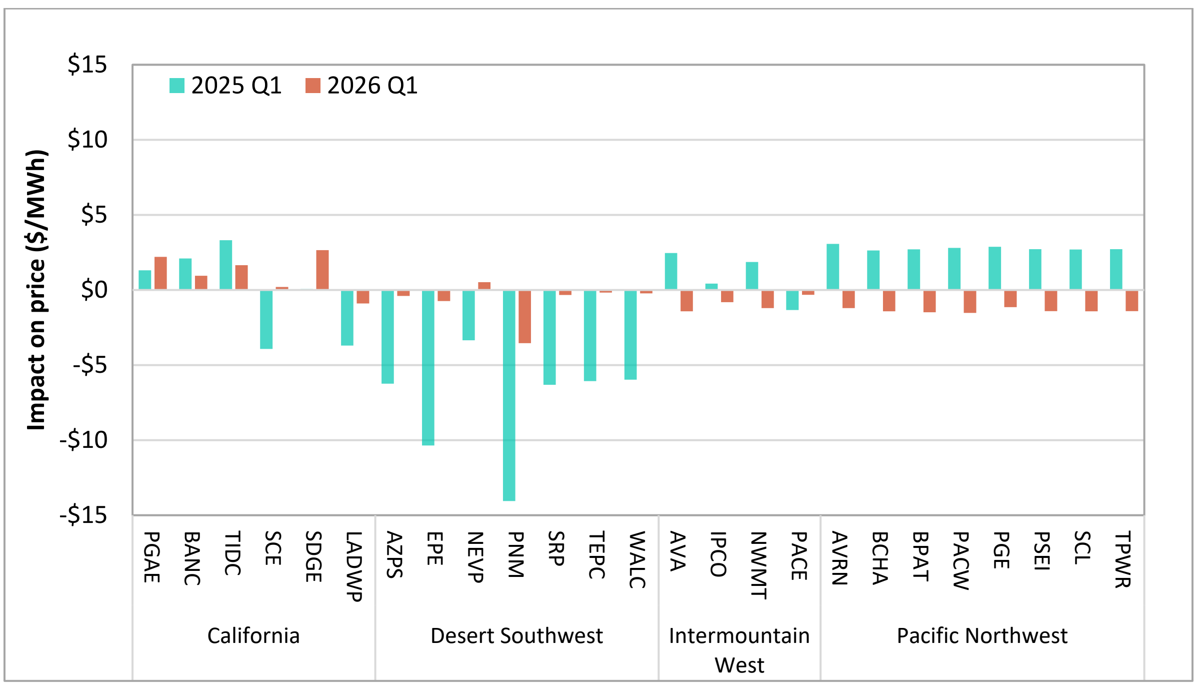


Figure 6.3 Average impact of internal congestion on real-time market price (2025–2026)



The following sections present further details on price impacts from different sources of congestion. Section 6.1 addresses congestion on the constraints limiting WEIM transfers between balancing areas in the real-time market. Section 6.2 addresses real-time market internal congestion.[44] Section 6.3 analyzes day-ahead market congestion rent and loss surpluses. Section 6.4 addresses intertie constraint congestion in the day-ahead market. Lastly, Section 6.5 addresses the impact of internal congestion on the day-ahead market.

6.1 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 6.4 shows the percent of intervals and overall price impact of 15-minute market WEIM transfer constraint congestion in each balancing area during the quarter.[45] Figure 6.5 shows the same information for the 5-minute market. The congestion on the WEIM transfer constraints is 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.[46]

WEIM transfer congestion was especially prevalent this quarter in the Pacific Northwest. The average frequency of congested intervals was 11 percent in the import direction and 19 percent in the export direction, measured across both the 15-minute and 5-minute markets. As a result, prices in the Pacific Northwest were elevated by an average of $0.9/MWh in the 15-minute market, and decreased by about $0.7/MWh in the 5-minute market.

Overall, transfer congestion impacts in the Pacific Northwest were more pronounced in the 5-minute market. Export congestion occurred more frequently in the 5-minute market than in the 15-minute market. As a result, prices in the region were elevated in the 15-minute market, while they were depressed in the 5-minute market.

Powerex (BCHA) 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 28 percent of intervals and export constrained during around 41 percent of intervals. On average for the quarter, Powerex prices were $1.1/MWh higher because of WEIM transfer congestion in the 15-minute market, and $1.2/MWh lower in the 5-minute market. The overall price impact remained

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44 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.

45 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.

46 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.

relatively small as Powerex experienced congestion in both import and export directions—offsetting price increases from import congestion with decreases from export congestion.

In the Desert Southwest, prices were on average elevated relative to system prices due to transfer congestion. EPE and WALC experienced some of the largest price impacts from transfer congestion in the region, with prices elevated by about $3/MWh on average across the 15-minute and 5-minute markets.

Figure 6.4 Frequency and impact of WEIM transfer congestion in the 15-minute market (Q1 2026)

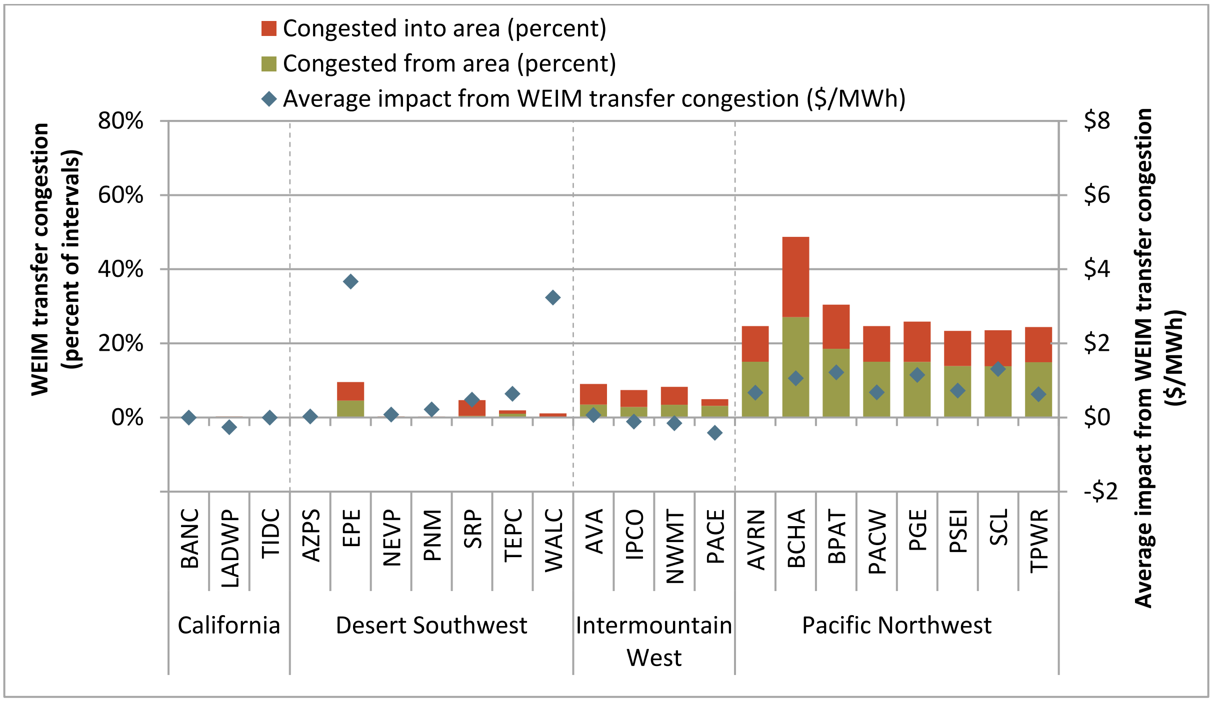
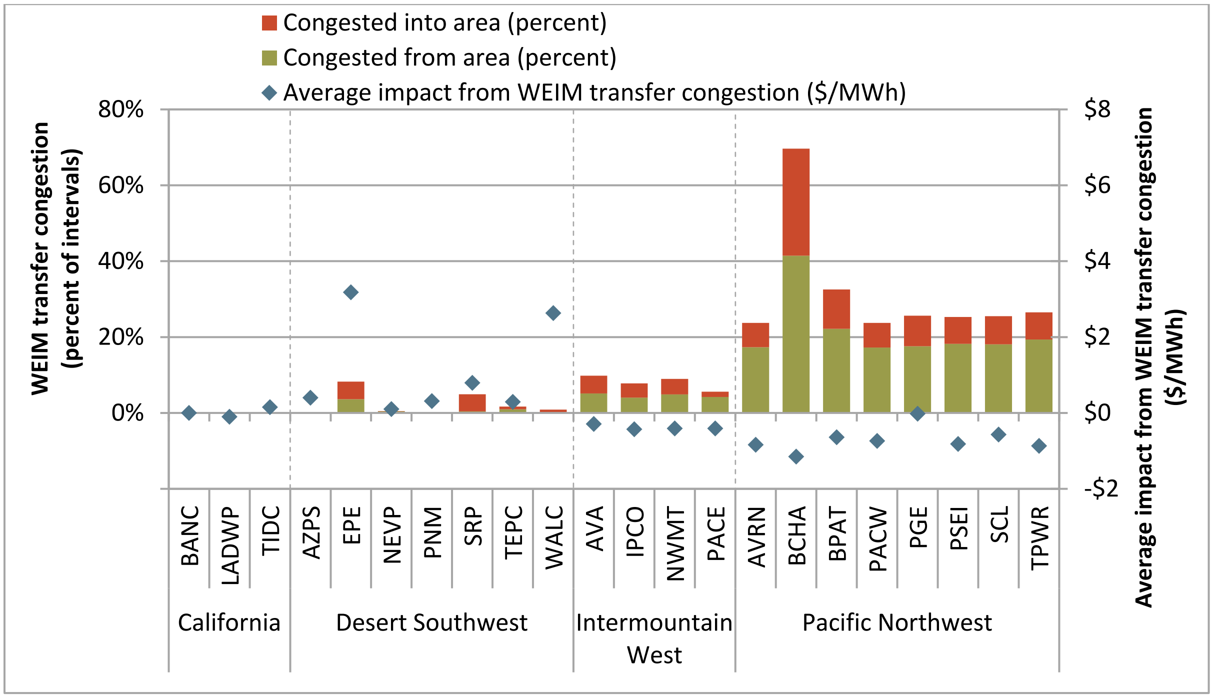


Figure 6.5 Frequency and impact of WEIM transfer congestion in the 5-minute market (Q1 2026)



6.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM.[47] 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 6.1.

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.[48]

In this quarter, internal congestion was concentrated on paths into California and out of the Pacific Northwest and Intermountain West. As a result, prices were elevated in California and reduced in the Pacific Northwest and Intermountain West. The Desert Southwest showed a small impact of net

47 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.

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

congestion on prices overall. This result likely reflects an offsetting congestion pattern, with congestion out of the region during solar hours and into the region during non-solar hours.

Figure 6.6 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 2026. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

Congestion patterns in the 15-minute and 5-minute markets were generally similar in direction and magnitude. Overall, congestion impact was slightly higher in the 15-minute market than in the 5-minute market.

Figure 6.6 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (January–March 2026)

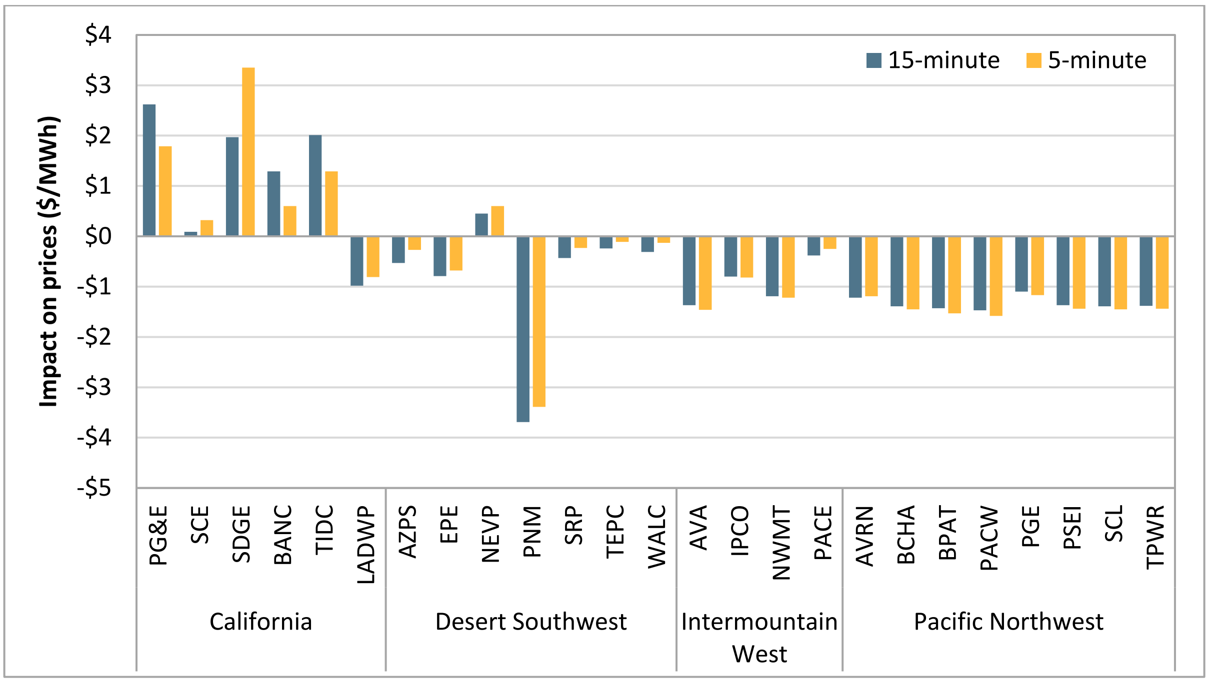


Figure 6.7 and Figure 6.8 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the first quarter of 2026 and 2025, respectively. Overall, both years exhibited south-to-north congestion during solar production hours. The magnitude of price separation during solar hours was modest this quarter. However, strong north-to-south congestion occurred during non-solar hours. During those hours, congestion was associated with higher prices in California and the Desert Southwest and lower prices in the Pacific Northwest and Intermountain West. This non-solar congestion pattern was driven mainly by the March heat wave. Figure 6.9 shows that the congestion pattern from January to February this quarter was broadly similar to the pattern in the same period last year.

Figure 6.7 Overall impact of internal congestion on price separation in the 15-minute market by hour (January–March 2026)

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	1.0	0.5	0.5	0.4	0.3	0.2	0.8	3.3	5.6	4.8	3.4	2.3	1.7	1.8	2.9	4.6	5.0	6.5	4.9	7.1	2.4	0.8	1.0	0.9
BANC	0.6	0.5	0.4	0.4	0.2	0.0	-0.2	1.6	3.3	3.1	2.4	1.9	1.6	1.6	2.1	2.7	2.4	3.6	1.2	1.3	-0.1	-0.4	0.3	0.4
Turlock ID	0.8	0.5	0.5	0.5	0.5	0.3	0.2	2.3	5.0	5.2	3.7	3.4	2.9	2.9	3.1	3.7	3.1	4.1	1.2	3.4	-0.2	-0.2	0.5	0.7
SCE	2.1	1.6	1.4	1.3	1.4	2.0	1.2	-0.2	-4.3	-4.9	-3.3	-2.0	-1.2	-1.1	-1.4	-2.1	0.1	1.5	2.7	0.8	0.4	1.4	2.3	2.2
SDG&E	3.0	2.2	1.9	1.8	1.5	2.0	2.1	1.6	-0.9	-2.9	-1.7	-0.2	1.1	1.2	1.3	0.7	3.7	5.4	5.2	4.1	3.1	4.0	3.9	3.1
LADWP	1.1	0.9	0.6	0.8	0.1	-0.2	0.4	-2.8	-6.1	-7.9	-6.9	-4.5	-2.2	-2.5	-3.7	-2.3	0.5	2.0	3.2	0.5	0.4	1.1	2.0	1.9
NV Energy	1.0	0.7	0.8	1.0	1.4	1.8	1.9	-0.7	-3.1	-0.9	-1.1	-0.3	-0.2	-0.2	-0.7	-0.9	0.2	2.2	3.0	0.2	0.7	1.0	1.5	1.4
Arizona PS	1.6	1.3	1.0	1.0	0.8	1.0	0.8	-1.3	-5.0	-5.4	-4.2	-3.0	-2.1	-2.1	-2.8	-3.1	-0.7	1.3	2.5	0.4	0.4	1.1	1.8	1.7
Tucson Electric	2.6	1.9	1.5	1.3	0.9	1.0	0.8	-1.3	-4.8	-5.2	-4.1	-2.8	-2.0	-1.9	-2.7	-2.9	-0.7	1.5	2.6	0.7	1.0	1.8	2.6	2.4
Salt River Project	2.0	1.6	1.3	1.2	0.9	1.0	0.8	-1.3	-5.0	-5.4	-4.2	-3.0	-2.1	-2.1	-2.9	-3.1	-0.8	1.4	2.6	0.5	0.7	1.4	2.2	2.0
PSC New Mexico	-0.6	-0.7	-0.7	-0.6	-0.5	0.1	-0.4	-6.2	-8.1	-9.4	-8.0	-7.6	-8.9	-9.4	-9.8	-8.2	-2.7	-0.1	0.1	-2.4	-2.0	-1.4	-0.6	-0.5
WAPA - Desert SW	2.2	1.7	1.3	1.2	0.9	1.0	0.8	-1.3	-4.9	-5.2	-4.1	-2.8	-1.8	-1.7	-2.7	-2.8	-0.6	1.5	2.6	0.6	0.8	1.6	2.3	2.2
El Paso Electric	1.6	1.0	0.7	0.5	0.3	0.6	0.3	0.0	-5.4	-5.8	-4.6	-3.9	-3.5	-3.2	-3.3	-3.1	-1.0	1.2	3.1	0.2	0.9	1.4	1.8	1.5
PacifiCorp East	-0.3	-0.2	-0.2	-0.1	-0.1	0.0	0.0	-0.4	-1.0	-0.9	-0.9	-0.5	-0.4	-0.4	-0.5	-0.5	-0.5	-0.5	-0.3	-0.7	-0.3	0.1	-0.3	-0.2
Idaho Power	-1.1	-0.8	-0.7	-0.7	-0.6	-0.7	-0.6	-0.4	0.2	0.3	-0.1	-0.2	-0.3	-0.3	-0.3	-0.4	-1.3	-2.8	-3.6	-2.1	-0.5	-0.1	-1.3	-1.2
NorthWestern	-1.8	-1.4	-1.2	-1.2	-1.0	-1.2	-1.0	-0.5	0.6	0.7	0.3	-0.1	-0.3	-0.3	-0.2	-0.2	-1.5	-3.6	-4.8	-3.5	-0.9	-1.2	-2.2	-2.0
Avista Utilities	-2.2	-1.7	-1.4	-1.4	-1.2	-1.5	-1.3	-0.6	1.0	1.1	0.6	0.0	-0.2	-0.3	-0.1	-0.2	-1.7	-4.3	-5.7	-3.9	-1.2	-1.6	-2.7	-2.4
Avangrid	-1.7	-1.6	-1.2	-1.3	-1.3	-1.4	-1.3	-0.6	1.3	1.5	0.7	0.1	-0.5	-0.4	-0.1	-0.2	-2.1	-5.0	-7.1	-1.8	-0.6	-0.7	-2.0	-2.1
BPA	-2.3	-1.8	-1.5	-1.5	-1.3	-1.5	-1.4	-0.6	1.0	1.2	0.8	0.2	-0.1	-0.2	0.0	-0.1	-1.8	-4.6	-6.2	-4.2	-1.3	-1.7	-2.8	-2.6
Tacoma Power	-2.3	-1.8	-1.5	-1.5	-1.3	-1.5	-1.3	-0.6	1.0	1.3	0.9	0.3	0.0	-0.1	0.1	0.0	-1.7	-4.5	-6.0	-4.1	-1.3	-1.7	-2.8	-2.5
PacifiCorp West	-2.4	-1.9	-1.5	-1.6	-1.3	-1.6	-1.4	-0.6	1.1	1.3	0.7	0.1	-0.2	-0.3	0.0	-0.1	-1.9	-4.6	-6.3	-4.3	-1.3	-1.8	-2.9	-2.6
Portland GE	-2.4	-1.9	-1.5	-1.5	-1.3	-1.6	-1.4	-0.6	2.7	2.2	1.6	1.0	0.9	1.0	0.6	0.6	-1.2	-4.6	-6.3	-4.2	-1.3	-1.8	-2.9	-2.6
Puget Sound Energy	-2.3	-1.8	-1.5	-1.5	-1.3	-1.5	-1.3	-0.6	1.0	1.3	1.0	0.3	0.0	-0.1	0.1	0.0	-1.7	-4.5	-6.0	-4.1	-1.3	-1.7	-2.8	-2.5
Seattle City Light	-2.3	-1.8	-1.5	-1.5	-1.3	-1.5	-1.3	-0.6	1.0	1.3	0.9	0.2	-0.1	-0.1	0.1	-0.1	-1.7	-4.5	-6.0	-4.1	-1.3	-1.7	-2.8	-2.5
Powerex	-2.3	-1.8	-1.5	-1.5	-1.3	-1.5	-1.3	-0.6	1.0	1.2	0.8	0.2	-0.1	-0.2	0.0	-0.1	-1.7	-4.4	-6.0	-4.0	-1.3	-1.7	-2.8	-2.5

Figure 6.8 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 6.9 Overall impact of internal congestion on price separation in the 15-minute market by hour (January–February 2026)

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	-0.5	-0.6	-0.5	-0.6	-0.5	-0.7	0.2	2.8	5.3	4.8	3.0	1.5	1.2	1.2	2.2	2.8	0.7	0.0	0.2	-0.1	-0.2	-0.5	-0.6	-0.7
BANC	-0.5	-0.5	-0.5	-0.6	-0.5	-0.8	-0.7	0.5	2.8	3.0	2.6	1.9	1.5	1.5	2.1	2.4	0.6	0.0	0.2	-0.1	-0.1	-0.5	-0.6	-0.7
Turlock ID	-0.5	-0.6	-0.6	-0.6	-0.5	-0.8	-0.5	1.4	4.7	4.7	3.7	3.3	2.7	2.8	3.1	3.5	0.8	0.0	0.2	0.0	0.0	-0.5	-0.6	-0.7
SCE	1.1	0.9	0.8	0.7	0.6	0.9	0.7	-0.9	-4.1	-5.0	-3.3	-1.9	-1.4	-1.2	-1.8	-2.8	-0.3	0.3	0.0	0.4	0.3	1.0	0.8	0.9
SDG&E	2.3	1.7	1.7	1.4	1.2	2.0	2.2	2.0	-0.3	-2.6	-1.5	-0.2	1.0	1.3	0.9	0.2	3.5	4.6	3.2	3.9	3.1	4.4	2.9	2.2
LADWP	1.2	1.0	0.9	0.9	0.7	1.1	0.8	-0.8	-3.8	-4.7	-3.9	-2.0	-1.5	-2.1	-4.2	-2.5	-0.6	0.3	-0.1	0.2	0.3	0.7	0.9	1.1
NV Energy	0.7	0.5	0.5	0.5	0.4	0.6	0.5	-0.6	-2.9	-1.1	-0.7	-0.3	-0.4	-0.4	-1.0	-1.1	-0.4	0.1	0.0	0.2	0.2	0.6	0.5	0.6
Arizona PS	1.1	0.9	0.8	0.8	0.6	0.9	0.7	-1.2	-4.4	-4.7	-3.6	-2.7	-2.4	-2.5	-3.4	-3.4	-0.8	-0.1	-0.1	0.2	0.2	0.8	0.8	0.9
Tucson Electric	1.0	0.9	0.8	0.7	0.6	0.9	0.7	-1.2	-4.3	-4.5	-3.4	-2.5	-2.3	-2.3	-3.3	-3.2	-0.7	-0.1	-0.1	0.2	0.2	0.8	0.8	0.9
Salt River Project	1.1	0.9	0.8	0.8	0.6	0.9	0.7	-1.3	-4.5	-4.7	-3.6	-2.7	-2.5	-2.5	-3.5	-3.5	-0.8	-0.1	-0.1	0.2	0.2	0.8	0.8	0.9
PSC New Mexico	-0.6	-0.9	-0.8	-1.0	-0.9	-0.2	-1.0	-7.3	-8.2	-10.0	-8.2	-8.3	-10.6	-11.4	-11.9	-9.4	-1.9	-0.9	-2.3	-2.7	-1.8	-1.3	-0.9	-0.8
WAPA - Desert SW	1.1	0.9	0.8	0.8	0.6	0.9	0.7	-1.2	-4.3	-4.4	-3.5	-2.5	-2.0	-2.0	-3.3	-3.2	-0.7	-0.1	-0.1	0.2	0.2	0.8	0.8	0.9
El Paso Electric	0.3	0.1	0.0	-0.1	-0.1	0.4	-0.1	0.9	-5.3	-5.5	-4.0	-3.6	-3.8	-3.5	-3.7	-3.0	-0.5	0.0	-0.3	0.0	0.8	1.1	0.6	0.3
PacifiCorp East	0.1	0.1	0.1	0.1	0.0	0.1	0.0	-0.3	-0.6	-0.6	-0.4	-0.3	-0.3	-0.3	-0.4	-0.5	-0.2	-0.1	-0.1	0.0	0.0	0.6	0.1	0.1
Idaho Power	-0.3	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.2	0.0	-0.1	0.0	0.0	-0.1	0.6	-0.1	-0.2
NorthWestern	-0.7	-0.5	-0.5	-0.4	-0.3	-0.5	-0.5	-0.1	0.3	0.5	0.3	0.1	0.1	0.1	0.3	0.4	0.0	-0.2	0.0	-0.2	-0.2	-0.5	-0.4	-0.5
Avista Utilities	-0.9	-0.7	-0.6	-0.5	-0.4	-0.6	-0.6	-0.1	0.4	0.6	0.4	0.1	0.2	0.1	0.4	0.6	0.1	-0.2	0.0	-0.2	-0.3	-0.7	-0.5	-0.7
Avangrid	-0.4	-0.4	-0.4	-0.5	-0.4	-0.4	-0.5	-0.1	0.6	0.8	0.6	0.3	0.3	0.3	0.6	0.8	0.1	-0.2	0.0	-0.2	-0.2	-0.4	-0.4	-0.3
BPA	-0.9	-0.7	-0.6	-0.6	-0.4	-0.7	-0.6	-0.1	0.4	0.6	0.3	0.2	0.2	0.2	0.5	0.6	0.1	-0.2	-0.1	-0.2	-0.3	-0.8	-0.6	-0.7
Tacoma Power	-0.9	-0.7	-0.6	-0.6	-0.4	-0.7	-0.6	-0.1	0.5	0.7	0.4	0.2	0.2	0.1	0.5	0.6	0.1	-0.2	-0.1	-0.2	-0.3	-0.8	-0.6	-0.7
PacifiCorp West	-1.0	-0.7	-0.6	-0.6	-0.5	-0.7	-0.6	-0.1	0.5	0.7	0.4	0.2	0.2	0.2	0.5	0.7	0.1	-0.2	-0.1	-0.2	-0.3	-0.8	-0.6	-0.7
Portland GE	-1.0	-0.7	-0.6	-0.6	-0.4	-0.7	-0.6	-0.1	3.0	1.9	0.4	0.2	0.2	0.3	0.5	0.6	0.1	-0.2	-0.1	-0.2	-0.3	-0.8	-0.6	-0.7
Puget Sound Energy	-0.9	-0.7	-0.6	-0.6	-0.4	-0.7	-0.6	-0.1	0.5	0.7	0.4	0.2	0.2	0.1	0.5	0.6	0.1	-0.2	-0.1	-0.2	-0.3	-0.8	-0.6	-0.7
Seattle City Light	-0.9	-0.7	-0.6	-0.6	-0.4	-0.7	-0.6	-0.1	0.5	0.7	0.4	0.2	0.2	0.1	0.4	0.6	0.1	-0.2	-0.1	-0.2	-0.3	-0.8	-0.6	-0.7
Powerex	-0.9	-0.7	-0.6	-0.5	-0.4	-0.7	-0.6	-0.1	0.4	0.6	0.4	0.2	0.2	0.1	0.4	0.6	0.1	-0.2	0.0	-0.2	-0.3	-0.7	-0.6	-0.7

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

Table 6.1 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 the COI_600N-S, 6410_CP5_NG, and 6110_COI_N-S.

California-Oregon Intertie (COI) nomograms

Two California-Oregon Intertie (COI) nomograms (COI_600N-S and 6110_COI_N-S) contributed to north-to-south congestion. As a result, prices in California and the Desert Southwest were elevated relative to prices in the Intermountain West and the Pacific Northwest. This line typically experienced congestion during non-solar production hours and they were congested mainly during March.

Path 26 nomogram

The Path 26 nomogram (6410_CP5_NG) contributed to north-to-south congestion. As a result, prices in Northern California, the Intermountain West, and the Pacific Northwest were pushed downward relative to prices in Southern California and the Desert Southwest. This line typically experienced congestion during non-solar production hours and was congested only in March.

Other notable constraints were the PNM constraints. These constraints consistently contributed to significant price separation of EPE and PNM from the rest of the WEIM.

Table 6.1 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, January–March)[49]

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	CHXFMR3A345KV	.00	.	.	.02	.05	.	.	.10	.	-.18	.12	.27	.16	.	.	.	-.09	.	.	.	.	.	.	.	.
	Line_AR-ARFHT_69KV	.	.	.	.01	.07	.	.	.	.	.	.	.	.02	.	.	.	.	.	.	.	.	.	.	.	.
BPAT	NOPE	-.04	-.04	-.04	-.04	-.04	-.04	-.04	-.04	-.04	-.04	-.04	-.04	-.04	.01	-.02	.	-.03	-.05	.04	.05	.	.18	.07	.05	.06
CISO	COI_600N-S	.80	.83	.82	.56	.52	.55	.45	.39	.30	.36	.45	.44	.45	-.90	-.51	-.74	-.06	-1.07	-.94	-.97	-.98	-.98	-.96	-.95	-.96
	6410_CP5_NG	-.39	-.37	-.38	.34	.32	.34	.29	.27	.20	.25	.29	.29	.29	-.26	-.11	-.20	.08	-.20	-.27	-.28	-.29	-.29	-.28	-.28	-.28
	6110_COI_N-S	.26	.27	.27	.17	.16	.17	.14	.12	.09	.10	.14	.13	.14	-.34	-.20	-.29	-.04	-.16	-.35	-.36	-.36	-.36	-.35	-.35	-.36
	7440_MetcalfImport_Tes-Metcalf	.50	.25	.42	-.30	-.29	-.30	-.27	-.25	-.19	-.24	-.27	-.26	-.27	.13	.	.05	-.06	.12	.14	.15	.16	.15	.15	.15	.15
	8610_SylmarBNK_N-S_Import_NG	.14	.11	.12	.18	-.03	-1.12	-.18	-.18	-.18	-.18	-.18	-.18	-.19	.01	.	.00	-.06	.04	.02	.03	.04	.03	.02	.02	.03
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-.18	-.16	-.16	.18	.17	.17	.16	.15	.10	.14	.16	.16	.16	-.11	-.01	-.09	.04	-.08	-.11	-.11	-.12	-.11	-.11	-.11	-.11
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	.22	.26	.34	-.27	-.26	-.26	-.23	-.21	.	-.15	-.23	-.23	-.23	.	.	.	.	.01	.	.00	.00	.00	.00	.00	.00
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	.05	.07	.06	-.10	-.10	-.09	-.09	-.08	-.05	-.08	-.09	-.09	-.09	.06	.02	.04	-.02	.07	.06	.06	.06	.06	.06	.06	.06
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	.36	.	.06	-.35	-.34	-.21	-.07	-.03	.	.00	-.07	-.05	-.07	.	.	.	.	.	.	.	.	.	.	.	.
	30635_NWKDIST_230_30731_LSESTRS_230_BR_1_1	.62	-.11	.10	-.02	-.03	.	.	.	.	.	.	.	.	-.06	.00	-.03	.	-.03	-.07	-.07	-.08	-.07	-.07	-.07	-.07
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	-.02	.18	.44	-.12	-.12	-.12	-.09	-.06	.	-.02	-.09	-.09	-.09	.	.	.	.	.00	.	.	.00	.00	.	.	.
	24801_DEVERS_500_24804_DEVERS_230_XF_2_P	.05	.05	.05	.04	.02	.06	-.18	-.16	-.02	-.14	-.20	-.17	-.15	.	.	.	-.04	.01	.	.	.00	.00	.	.	.
	22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	.	.	.	.	.92	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	.03	.04	.04	-.06	-.05	-.05	-.05	-.04	-.03	-.04	-.05	-.05	-.05	.03	.01	.02	-.01	.04	.03	.03	.03	.03	.03	.03	.03
	6410_CP10_NG	.05	.04	.04	-.05	-.05	-.05	-.05	-.04	-.03	-.04	-.05	-.05	-.05	.03	.01	.02	-.02	.03	.03	.03	.03	.03	.03	.03	.03
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	.03	.04	.04	-.05	-.05	-.05	-.04	-.04	-.03	-.04	-.04	-.04	-.04	.03	.01	.02	-.01	.03	.03	.03	.03	.03	.03	.03	.03
	MIGUEL_BKs_MXFLW_NG	.01	.	.	.03	.30	.	-.08	-.07	.	-.06	-.08	-.08	-.08	.	.	.	.	.	.	.	.	.	.	.	.
	39536_FINKSS_230_38402_WSTLYTID_230_BR_1_1	.01	.04	.08	-.03	-.02	-.03	-.02	-.02	-.01	-.02	-.02	-.02	-.02	.02	.00	.01	.00	.02	.02	.02	.02	.02	.02	.02	.02
	32214_RIOOSO_115_32244_BRNSWKT2_115_BR_2_1	-.09	-.13	.	.00	.00	.	.	.	.32	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	99013_CALCAPS_500_24801_DEVERS_500_BR_1_1	.01	.01	.01	.03	.00	.01	-.05	-.04	-.01	-.04	-.05	-.05	-.04	.	.	.	-.01	.00	.	.	.00	.	.	.	.
	35120_NEWARKD_115_36851_NORTHERN_115_BR_1_1	.03	.	-.31	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.00	.	.	.01	.12	.	-.03	-.03	.	-.03	-.04	-.03	-.03	.	.	.	-.01	.	.	.	.	.	.	.	.
	OMS_19558673_TL23054_NG	.00	.	.	.01	.12	.	-.03	-.03	.	-.03	-.04	-.03	-.03	.	.	.	.	.	.	.	.	.	.	.	.
	32218_DRUM_115_32244_BRNSWKT2_115_BR_2_1	-.05	-.07	.	.00	.00	.	.	.	.14	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	7820_TL230S_OVERLOAD_NG	.00	.	.00	.00	.09	.00	-.01	-.01	.00	-.01	-.02	-.02	-.01	.	.	.	.00	.	.	.	.	.	.	.	.
	6410_CP7_NG	.01	.01	.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.00	.00	.00	.00	.01	.00	.01	.01	.01	.01	.01	.01
	25201_LEWIS_230_24137_SERRANO_230_BR_1_1	-.01	.	.	.04	.05	.	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.	.	.	.	.	.	.	.	.	.	.	.
	37585_TRCYPMP_230_30625_TESLAD_230_BR_1_1	.05	-.03	-.02	-.02	-.02	.00	.00	.00	.00	.00	.00	.00	.00	.00	.	.00	.	.	.00	.00	.00	.00	.00	.00	.00
	24156_VINCENT_500_24155_VINCENT_230_XF_4_P	-.01	-.01	-.01	.01	.01	.01	.00	.00	.	.00	.00	.00	.00	-.01	.00	.00	.	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01
	OMSIV-SXOUTAGE_NG	.00	.	.	.01	.06	.	-.01	-.01	.00	-.01	-.01	-.01	-.01	.	.	.	.00	.	.	.	.	.	.	.	.
	7690-CONTRL-INYOKN_EXP_NG	.	.	.	-.13	-.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1_1	.03	.	.	.	.	.	.	.	-.09	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	.04	.	.	-.03	-.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30735_METCALF_230_30042_METCALF_500_XF_13	.03	.	.01	-.01	-.01	.00	.00	.00	.	.00	.00	.00	.00	.00	.	.00	.	.00	.00	.00	.00	.00	.00	.00	.00
PACW	WPTH75	.	.00	.00	.	.	.	.00	.00	-.01	-.01	.00	.00	.00	.00	-.02	.00	-.02	.	.01	.01	.01	.01	.01	.01	.01
PGE	PERL_SHWD_V2924	-.01	.	.	-.01	-.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.10	.	.	.
	MRHL_SHWD_V1607	-.01	.	.	-.01	-.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.09	.	.	.
PNM	115kvNH	.01	.	.	.00	.00	.	.	-.40	.	-.93	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115WTGatPEGS	.00	.	.	.01	.02	.	.	-.10	.	-.98	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	LaJara_116_69_Xf	.	.	.	.	.	.	.	-.07	.	-.48	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	PINT-RIPU1	.	.	.	.	.	.	.	-.12	.	-.28	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvMEB_Ca_AL	.	.	.	.	.	.	.	.18	.	-.21	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	CZ345kV	.	.	.	.	.	.	.	-.10	.	-.18	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvDL_Mi_Wm	.	.	.	.	.	.	.	.15	.	.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	FRCE-PINT1	.	.	.	.	.	.	.	-.04	.	-.07	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	GYTH_Gallup_Enr	.	.	.	.	.	.	.	-.02	.	-.05	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
WALC	Line_GIX-ARFH_69KV	.	.	.	.04	.19	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Other	.09	.01	.02	.01	.26	.04	-.03	.06	.01	.00	.00	-.02	-.02	-.01	.02	.00	-.02	.00	-.02	-.05	-.02	-.02	-.02	-.03	-.02
	Total	2.62	1.29	2.01	0.09	1.97	-.98	-0.53	-.79	.45	-3.69	-0.43	-0.24	-0.31	-1.37	-.80	-1.19	-.38	-1.22	-1.39	-1.43	-1.47	-1.10	-1.37	-1.39	-1.38

49 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.

6.2.1 Battery-driven transmission overload and load shedding in SDG&E

Repeated flow exceedance occurred on the 7820 CP4 San Diego area nomogram (7820_TL 50002_IV-NG-OUT_SOS) between hour-ending 20 on March 26 and hour-ending 1 on March 27. Flows exceeded the 1,500 MW limit multiple times and peaked above 2,400 MW. A large and rapid increase in storage charging in the San Diego area contributed to the event. This event ultimately resulted in about 170 MW of load shedding in the San Diego area, affecting approximately 100,000 customers.

Figure 6.10 Transmission overloads on the 7820 CP4 nomogram and storage impact on flow (March 26–27, 2026)

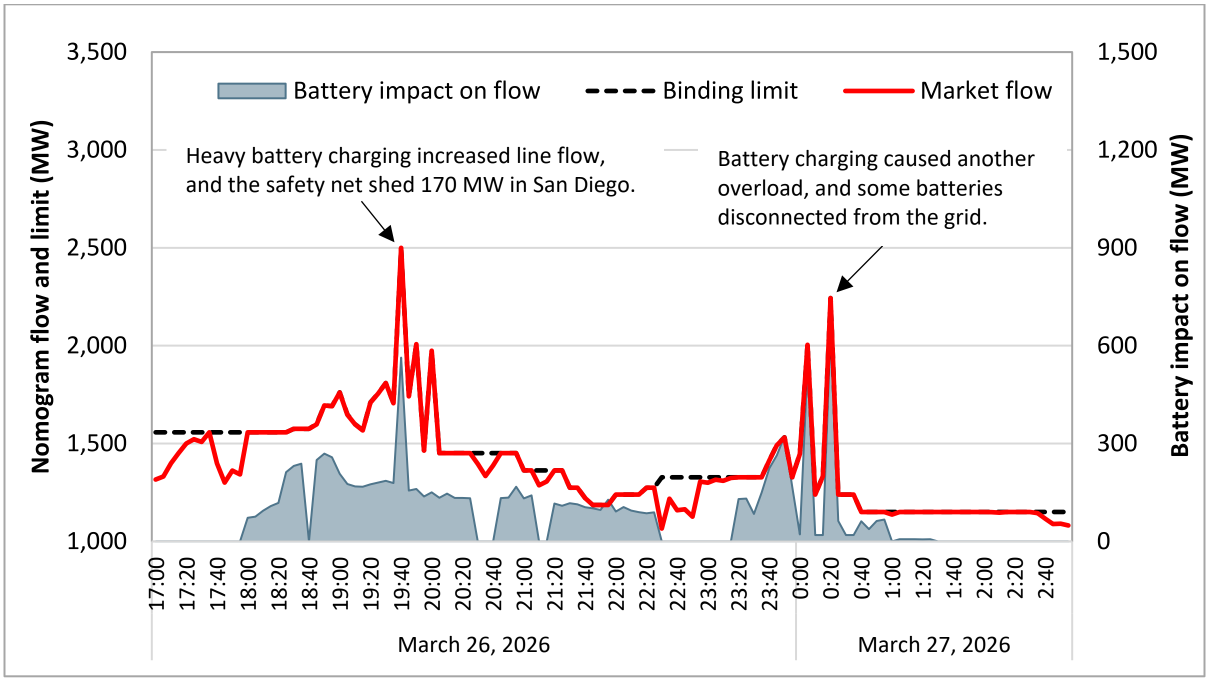


Figure 6.10 shows the 5-minute market flow and binding limit for the 7820 CP4 San Diego nomogram on the primary y-axis, along with the total storage schedule impact on the nomogram on the secondary y-axis, shown as the blue area. The battery flow impact was shown only when the nomogram was binding. During other periods, batteries may also have affected flow.

The first major flow exceedance occurred between 19:40 and 19:45 on March 26 when operators observed a sharp increase in battery charging and rising flows above the nomogram limit. Several battery resources switched from discharging to charging within a single dispatch interval, causing a sudden increase in energy flow into the San Diego area. Operators responded by instructing batteries to stop charging. At 19:46, the South of Songs safety net activated, resulting in an estimated 170 MW of involuntary load shedding in the San Diego area to protect system reliability. The event required multiple out-of-market actions, including manual unit dispatch.

The CAISO balancing area is completing a detailed analysis of the causes of the event. Several anomalous issues occurred in a short period of time, causing significant battery capacity to switch from discharging to charging within a single interval. The one-interval charging surge was sufficient to overload the nomogram.

While operators acted quickly to issue manual dispatch instructions to the batteries to stop charging, it can take several 5-minute market intervals for battery resources to respond to manual dispatch instructions. As a result, load was automatically curtailed to protect the critical transmission elements while the batteries continued to charge. This situation indicates that reliability could be improved in wholesale electricity markets with significant battery capacity integration by implementing the technology and processes to curtail battery charging prior to curtailing load.

Another overload occurred on March 27 at approximately 00:15 when battery charging rose to 200 MW. CAISO and SDG&E had already discussed the possibility of the batteries charging again and causing another overload. Thus, at 00:22, SDG&E disconnected the batteries from the grid before the safety net activated.

6.3 Congestion rent and loss surpluses

Figure 6.11 shows that in the first quarter of 2026, congestion rent and loss surpluses were $87.4 million and $48.5 million, respectively.[50] The congestion rent surplus was down $53 million, or 38 percent, compared to the first quarter of 2025.[51] The loss surplus was up about $14 million compared to Q1 2025.

Congestion rent consists of rents from internal constraints and interties. Congestion rent from internal constraints decreased from $132 million to $81 million, and intertie congestion rent decreased from $8.6 million to $6.5 million this quarter compared to the same quarter in 2025.

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 net excess of loss charges collected from demand over loss credits paid to supply. The marginal cost of losses at each node is determined by the product of the system marginal energy cost (SMEC) and the marginal loss factor, which measures the sensitivity of total system losses to an incremental injection at that location.[52] Changes in the total loss surplus can be driven by changes in the SMEC or by changes in marginal loss factors due to shifts in generation and load patterns, transmission outages, or increased electrical distance between supply and demand.

The loss surplus increased from $35 million to $48.5 million—a 39 percent increase—this quarter compared to the same period last year. The increase in the loss surplus this quarter was driven by higher marginal loss factors, particularly in the SCE and SDG&E default load aggregation points (DLAPs), despite a decline in the SMEC. Possible contributing factors include changes in transmission outages, shifts in

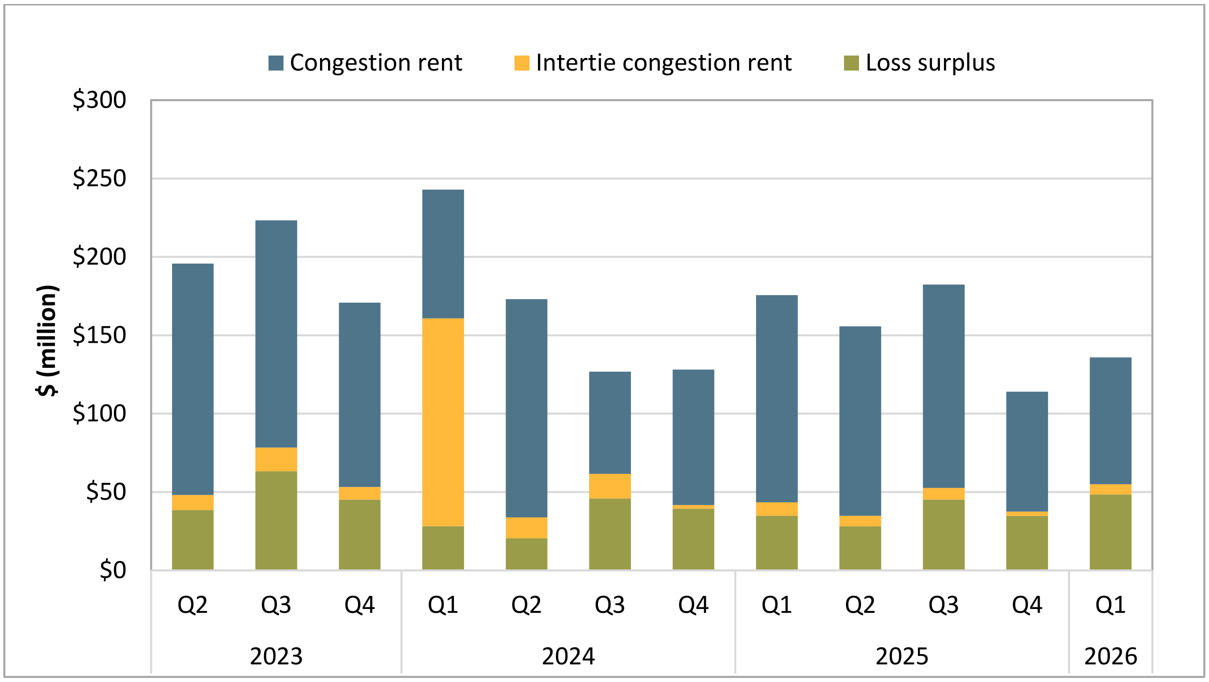
50 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after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

51 DMM adjusted the source data for congestion rent by removing day-ahead congestion rent calculated through the Nodal Pricing Model (NPM). The ISO provides the Nodal Pricing Model day-ahead service for PacifiCorp, which is used solely for internal Net Power Cost allocation within PACW and PACE balancing areas. As a result, updated congestion rent values no longer include NPM-based congestion rent in any of DMM's quarterly or annual reports published after July 2025.

52 See CAISO Tariff, Appendix C, Section E, Marginal Losses Component Calculation: https://www.caiso.com/library/current-tariff-appendices-a-z

the generation mix serving SCE and SDG&E load, or other network conditions that may have increased the electrical distance between supply and demand in the area.

Figure 6.11 Day-ahead congestion rent and loss surplus by quarter (2023–2026)



6.4 Congestion on interties

Total intertie congestion rent in the day-ahead market was $6.5 million, down from $8.6 million in the first quarter of 2025. The major driver was decreased congestion rent on Palo Verde and IPP Utah by $2.6 million in this quarter compared to the same quarter of 2025. The reduction was offset by $0.7 million in gains on the Malin and NOB intertie congestion rent.

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 6.12 shows total intertie congestion charges in the day-ahead market from the first quarter of 2025 to the first quarter of 2026. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 6.13 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 6.2 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 2025, the total intertie congestion rent decreased from $8.6 million to $6.5 million.
- The majority of congestion occurred at Malin and NOB. These two interties accounted for 98 percent of total congestion rent this quarter.
- A notable change in congestion frequency was the increase in import congestion frequency at Malin and NOB, which reached 10 percent and 7 percent, respectively. Congestion at IPP Utah decreased from 18 percent in Q1 2025 to 1 percent this quarter.

Figure 6.12 Day-ahead congestion charges on major interties

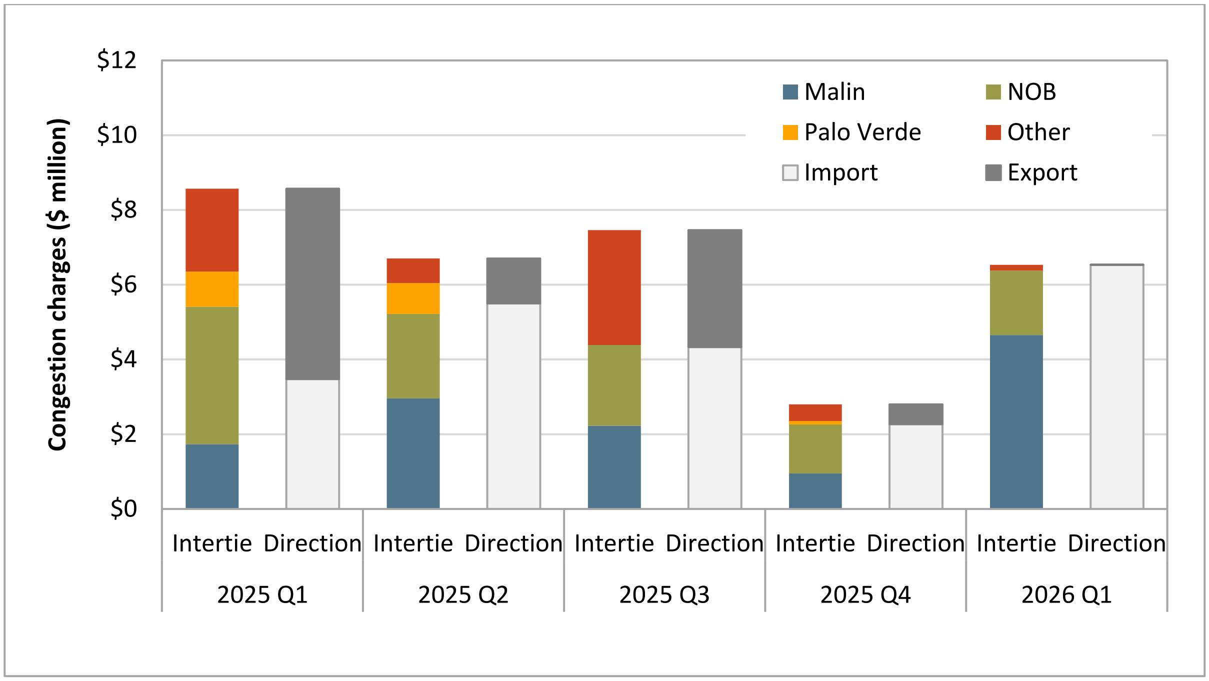


Figure 6.13 Frequency of congestion on major interties in the day-ahead market

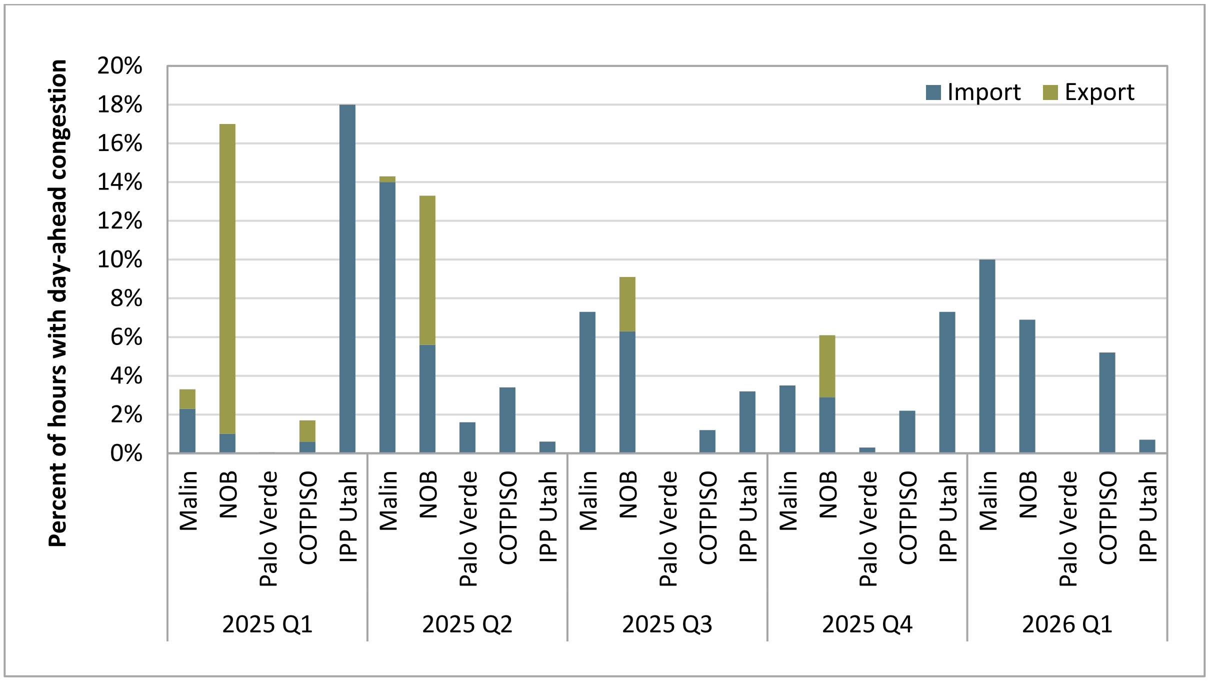


Table 6.2 Summary of intertie congestion in day-ahead market (2025–2026)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1
Northwest											
Malin	I	$565	$2,904	$2,223	$949	$4,650	2.3%	14.0%	7.3%	3.5%	10.0%
	E	$1,169	$53				1.0%	.3%			
NOB	I	$190	$1,600	$1,983	$781	$1,725	1.0%	5.6%	6.3%	2.9%	6.9%
	E	$3,483	$661	$180	$530		16.0%	7.7%	2.8%	3.2%	
COTPISO	I	$12	$29	$11	$92	$122	.6%	3.4%	1.2%	2.2%	5.2%
	E	$397					1.1%				
Cascade	I										
	E										
Summit	I		$23	$11				.5%	.1%		
	E										
Southwest											
Palo Verde	I	$944	$828		$92		.0%	1.6%		.3%	
	E										
IPP Utah	I	$1,754	$13	$103	$354	$33	18.0%	.6%	3.2%	7.3%	.7%
	E										
IPP DC Adelanto	I										
	E		$33	$92				.7%	.8%		
Mona	I										
	E	$30	$238	$2,856			.6%	2.0%	3.7%		
Mead	I	$9					.0%				
	E		$155					.2%			
Merchant	I										
	E										
Silver Peak	I										
	E		$11	$1		$0		1.3%	.5%		.3%
Mercury	I										
	E										
Other	I		$104								
	E	$16	$50								
Import total (I)		$3,475	$5,501	$4,332	$2,268	$6,530					
Export total (E)		$5,096	$1,200	$3,128	$530	$0					
Total		$8,570	$6,701	$7,460	$2,798	$6,531					

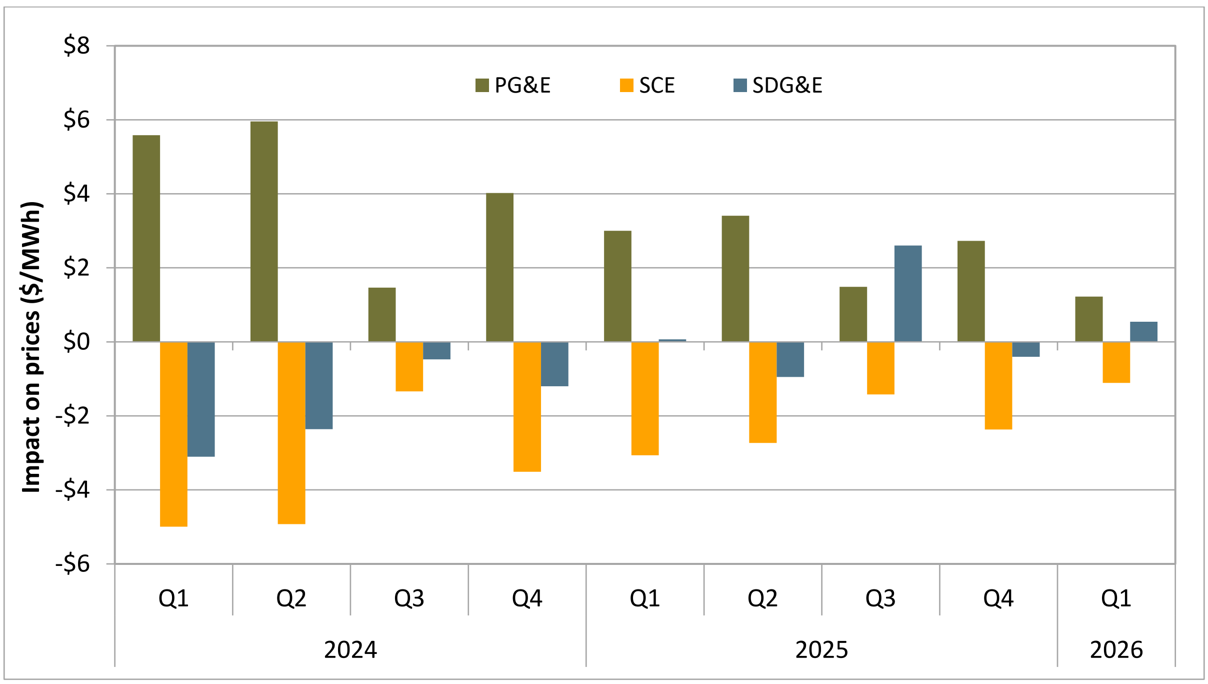
* I: import, E: export

6.5 Internal congestion in the day-ahead market

Figure 6.14 shows the overall impact of congestion on day-ahead market prices in each load area from Q1 2024 to Q1 2026. Figure 6.15 shows the frequency of congestion. Highlights for this quarter include:

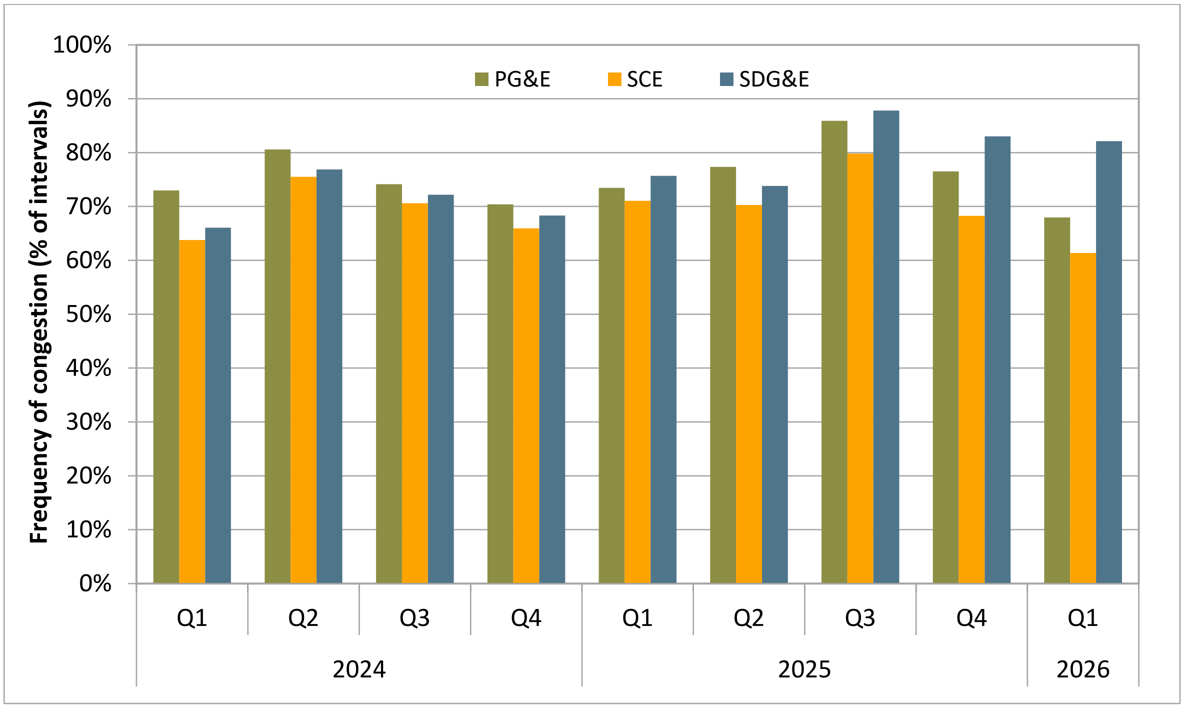
- Day-ahead congestion continued to exhibit a south-to-north pattern this quarter, similar to the same period last year, though the resulting price separation was less pronounced.
- Prices in PG&E and SDG&E were elevated by $1.2/MWh and $0.5/MWh, respectively, while prices in SCE were reduced by $1.1/MWh due to internal congestion.[53]
- The percentage of hours in which congestion impacted DLAP prices remained high this quarter, with SDG&E experiencing congestion during 83 percent of hours on average.
- The primary constraints affecting day-ahead market prices were the Moss Landing-Las Aguilas #1 230 kV line, El Cajon-Los Coches #1 69 kV line, and Metcalf 230/500 kV transformer.

Figure 6.14 Overall impact of congestion on price separation in the day-ahead market



[53] 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 6.15 Hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 6.3 breaks down the congestion effect on price separation during the quarter by constraint.[54] 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 table 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 Moss Landing-Las Aguilas #1 230 kV line, El Cajon-Los Coches #1 69 kV line, and Metcalf 230/500 kV transformer.

Moss Landing-Las Aguilas #1 230 kV

The Moss Landing-Las Aguilas #1 230 kV (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in 15.5 percent of hours over the quarter. For the quarter, on average, prices in PG&E were pushed upward by $0.42/MWh and prices in SCE and SDG&E were pushed down by $0.3/MWh and $0.29/MWh,

[54] 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*".

respectively, due to this constraint. This transmission line was generally binding during solar generation hours, from hour-ending 9 through hour-ending 16. This line was congested mainly during March.

El Cajon-Los Coches #1 69 kV

The El Cajon-Los Coches #1 69 kV line (22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1) bound in 47 percent of hours over the quarter. For the quarter, on average, prices in PG&E and SCE were lowered by $0.04/MWh and 0.02/MWh, respectively, and prices in SDG&E were elevated by $0.78/MWh due to this constraint. This transmission line was generally binding across all hours and mostly congested during January.

Metcalf 230/500 kV transformer

The Metcalf 230/500 kV transformer (30735_METCALF_230_30042_METCALF_500_XF_13) bound in 12.8 percent of hours over the quarter. For the quarter, on average, prices in PG&E were raised by $0.27/MWh and prices in SCE and SDG&E were both decreased by $0.22/MWh due to this constraint. This transmission line was generally binding during the morning ramp hours between hour-ending 8 and hour-ending 12 and mostly congested during February and March.

In this quarter, SDG&E prices were elevated due to multiple constraints, each primarily affecting the SDG&E area.

Table 6.3 Impact of congestion on day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	15.5%	.42	-.30	-.29
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	47.1%	-.04	-.02	.78
30735_METCALF_230_30042_METCALF_500_XF_13	12.8%	.27	-.22	-.22
30635_NWKDIST_230_30731_LSESTRS_230_BR_1_1	7.5%	.28	-.19	-.19
30790_PANOCHE_230_30900_GATES_230_BR_2_1	10.1%	.22	-.19	-.18
7440_MetcalfImport_Tes-Metcalf	3.8%	.19	-.13	-.13
7820_TL230S_OVERLOAD_NG	13.8%	-.05	-.03	.36
6410_CP5_NG	3.7%	-.16	.11	.11
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	14.1%	.11	-.1	-.09
MIGUEL_BKs_MXFLW_NG	1.3%	-.03	-.01	.2
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	5.0%	-.08	.06	.05
24084_LITEHIPE_230_24091_MESACAL_230_BR_1_1	1.2%	-.07	.08	-.02
25201_LEWIS_230_24137_SERRANO_230_BR_1_1	1.9%	-.05	.03	.03
22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	0.8%	-.01	.	.08
OMSIV-SXOUTAGE_NG	1.3%	-.01	.	.08
30055_GATES1_500_30060_MIDWAY_500_BR_1_3	0.9%	.03	-.03	-.03
35618_SNJSEA_115_35620_ELPATIO_115_BR_1_1	1.4%	.03	-.03	-.03
24801_DEVERS_500_24804_DEVERS_230_XF_2_P	11.7%	-.01	.01	-.05
LugoAAbankoutageAreaEXP	7.8%	.02	-.03	.02
33020_MORAGA_115_35101_SNLNDRO_115_BR_2_1	14.4%	.02	-.02	-.02
6410_CP10_NG	0.9%	.02	-.02	-.01
35352_WHISMAN_115_35356_MNTAVSA_115_BR_1_1	3.8%	.02	-.02	-.02
30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	0.4%	.02	-.01	-.01
37585_TRCYPMP_230_30625_TESLAD_230_BR_2_1	.6%	.01	-.01	-.01
36851_NORTHERN_115_36852_SCOTT_115_BR_2_1	1.2%	.01	-.01	-.01
Other		.06	-.03	.14
Total		1.22	-1.11	.54

7 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.[55] If an area fails either test in the downward direction, transfers out of that area cannot be increased.

7.1 Frequency of resource sufficiency evaluation failures

Figure 7.1 and Figure 7.2 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 7.3 and Figure 7.4 provide the same information for the downward direction.[56] The dash indicates the area did not fail the test during the month.

In the first quarter, the frequency of resource sufficiency evaluation failures was very low. During the first quarter of 2026:

- WAPA Desert Southwest failed the flexibility test in the upward direction in 1.4 percent of all intervals. WAPA Desert Southwest failed all other tests in all directions in under one percent of all intervals.
- All other balancing areas failed the capacity and flexibility tests in less than one percent of intervals.

[55] 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.

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

Figure 7.1 Frequency of upward capacity test failures by month and area (percent of intervals)

	2025 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2026 Jan	Feb	Mar
Arizona Publ. Serv.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avangrid	.1	—	—	—	—	—	—	.3	—	—	—	—	—	.0	—
Avista	—	—	—	—	.1	—	—	—	.1	—	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	.1	—	—	—	—	—	—	.0	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.1	.1	.1	.3	—	.2	.1	.0	—	.1	.1	—	—	.0	.1
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
LADWP	.1	—	—	—	.1	—	—	—	—	—	—	—	—	—	.1
NorthWestern En.	—	—	—	—	—	—	—	—	.2	.0	—	.1	—	—	—
NV Energy	—	—	—	—	—	—	.0	.1	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	.0	.0	—	—	—	—	—
PacifiCorp West	.4	.2	.1	.0	.1	.0	.1	.1	.7	.4	.2	.7	.1	.4	.2
Portland Gen. Elec.	—	.0	.0	—	—	.1	—	.1	—	—	—	—	—	.1	.1
Powerex	—	—	—	—	—	—	—	—	.0	—	—	—	—	—	.1
PSC of New Mexico	.1	—	.1	.1	—	—	—	—	—	.1	—	.1	—	—	—
Puget Sound En.	—	—	—	.1	.2	—	.1	.0	—	.1	—	—	—	.2	—
Salt River Proj.	.1	—	—	.7	—	.3	—	.2	.0	.1	.0	—	—	—	.1
Seattle City Light	.1	—	.0	—	—	.1	.0	—	—	.0	—	.2	.1	.1	.2
Tacoma Power	—	—	—	—	.1	—	.2	—	—	—	—	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	.0	—	—	—	—	—	—	.2
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	.1	—	—	—	—	—
WAPA DSW	.3	—	.1	.1	.1	.1	.0	.1	1.1	—	—	—	.1	.1	1.8

Figure 7.2 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2025 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2026 Jan	Feb	Mar
Arizona Publ. Serv.	.0	—	—	—	—	—	—	—	—	—	.0	—	—	.1	—
Avangrid	.1	.2	.2	.1	.0	—	.2	—	.0	—	.1	.1	.1	.4	.2
Avista	—	—	—	—	.3	—	—	—	—	—	—	—	—	—	.2
BANC	—	—	—	—	.0	—	—	—	—	—	—	—	—	—	—
BPA	—	.1	.5	.1	.0	.0	—	—	—	.1	.1	.3	.3	.2	.4
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.1	—	.4	.2	.3	.2	.4	.1	.0	.6	1.2	.6	.4	1.0	.8
Idaho Power	.1	.4	1.2	2.9	.6	.0	—	.1	—	.1	—	—	—	.0	—
LADWP	—	—	.1	.1	.0	—	—	.0	—	—	—	—	—	—	—
NorthWestern En.	.1	1.2	—	—	—	.0	—	—	.0	.0	—	—	—	—	—
NV Energy	.1	—	.1	.0	.0	—	—	.1	.0	—	—	—	.1	—	—
PacifiCorp East	.1	.1	.0	.0	—	—	.0	.2	.2	.4	.1	.1	.0	.1	.1
PacifiCorp West	.3	.1	.0	.1	.2	.0	—	.0	.5	.2	.3	.5	.5	.1	.3
Portland Gen. Elec.	—	—	.2	.1	—	.0	—	—	—	—	.0	.1	—	.1	.1
Powerex	—	—	—	—	—	—	—	—	.0	—	—	.0	—	.1	.3
PSC of New Mexico	.3	.3	.4	.8	—	.0	.1	—	.0	.7	.3	.4	.3	.1	.2
Puget Sound En.	—	—	.1	.7	1.0	.0	.1	.0	.1	—	—	—	.0	.1	.1
Salt River Proj.	.0	—	.1	1.8	.0	.6	—	.2	.3	.0	.1	—	—	—	.2
Seattle City Light	—	—	—	—	—	—	—	—	—	—	—	.1	—	.0	.1
Tacoma Power	.0	—	.0	.0	—	—	—	—	—	—	.1	.0	—	—	—
Tucson Elec. Pow.	.1	—	—	.0	.2	.0	—	—	.0	.1	.2	.1	—	.3	.7
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	.0	—	—	—	—	—	—
WAPA DSW	.1	—	.4	.1	.2	—	.0	—	—	—	—	—	.0	1.7	2.3

Figure 7.3 Frequency of downward capacity test failures by month and area (percent of intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avangrid	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avista	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	.1	—	—	—	—	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.1	—	.1	.2	.0	.2	.3	.1	.2	.2	.4	.3	.0	.1	.1
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
LADWP	.0	.1	—	—	.0	—	—	—	.1	—	—	—	—	—	—
NorthWestern En.	—	.1	.1	.0	—	—	—	—	.1	—	—	—	—	—	.4
NV Energy	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	.1	—	—	—	—	—	—	—
PacifiCorp West	—	.1	—	.1	.1	.3	.0	—	.2	—	.6	.0	.2	.1	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PSC of New Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound En.	—	—	.0	—	—	—	—	—	—	—	—	—	—	—	.3
Salt River Proj.	.1	.0	.1	—	—	.1	—	—	—	—	—	—	—	—	—
Seattle City Light	—	—	—	—	—	—	—	—	—	—	—	—	—	—	.0
Tacoma Power	—	—	—	—	—	—	.1	—	—	—	—	—	—	—	—
Tucson Elec. Pow.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA DSW	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	2025												2026		

Figure 7.4 Frequency of downward flexibility test failures by month and area (percent of intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	—	—	.1	.1	.0	.0	—	—	—	.1	.0	.1	.0	—	—
Avangrid	—	—	—	—	—	.1	—	—	—	—	—	—	.2	—	.0
Avista	—	.0	—	—	—	—	—	.1	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	.2	—	—	—	.1	—	—	—	.3	.1	—	.2	.0	.0	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.2	.4	.4	.6	.5	.0	—	—	.0	.8	1.0	2.2	1.0	1.1	.6
Idaho Power	—	—	.1	—	.1	—	—	—	—	.0	—	—	—	.6	.2
LADWP	.2	1.5	.6	—	—	—	—	—	—	.2	.0	.1	.1	.4	—
NorthWestern En.	.2	—	.6	—	.1	.0	.0	—	.1	.2	—	.8	.1	—	.8
NV Energy	—	.0	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	.5	—	.0	—	.0	.4	—	—	—	—	—	—	—
PacifiCorp West	—	—	.1	.0	.0	.0	.1	.1	.0	—	.5	—	.1	—	—
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	.0	.0	.0	—	—	—	—	—	—	—	—	.1	—	.1
PSC of New Mexico	—	—	—	—	—	—	.0	—	—	—	—	—	—	—	—
Puget Sound En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	.1
Salt River Proj.	.6	.4	1.2	—	—	.1	—	.0	—	—	.0	.0	.3	—	—
Seattle City Light	—	—	.2	.0	—	.1	.3	—	—	.1	.0	—	—	—	.0
Tacoma Power	—	.0	—	—	.1	—	.3	—	—	—	.1	—	—	—	—
Tucson Elec. Pow.	—	.0	—	—	—	.1	—	—	—	—	—	—	.2	—	.2
Turlock Irrig. Dist.	—	—	.0	.1	.1	—	.3	.1	—	—	—	.0	—	—	.2
WAPA DSW	—	.1	—	—	—	—	—	—	—	—	.7	1.5	.3	.1	—
	2025												2026		

7.2 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.[57]

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.[58] 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 7.1 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, California ISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, and PacifiCorp West. Avangrid, PacifiCorp East, and PacifiCorp West were opted in to AET on all days during the quarter.

[57] 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

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

Table 7.1 Assistance energy transfer opt-in designations by balancing area (January–March 2026)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Jan. 1 - Mar. 31	90
California ISO	Mar. 16 - Mar. 20	5
Idaho Power	Jan. 1 - Feb. 28	59
NorthWestern Energy	Feb. 6 - Mar. 31	54
NV Energy	Feb. 6 - Mar. 31	54
PacifiCorp East	Jan. 1 - Mar. 31	90
PacifiCorp West	Jan. 1 - Mar. 31	90

Table 7.2 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, four balancing areas (Avangrid, Idaho Power, PacifiCorp East, and PacifiCorp West) failed the resource sufficiency evaluation during at least one interval while opted in to the program.

Table 7.2 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, PacifiCorp West failed the resource sufficiency evaluation in the most intervals while opted in to receiving assistance energy transfers (43 intervals). PacifiCorp West achieved an additional 15 MW on average during these intervals (and maximum of 188 MW). PacifiCorp East achieved the most additional imports from assistance energy transfers during the quarter (323 MWh). PacifiCorp East achieved an additional 161 MW on average during the failure intervals while opted in (and maximum of 425 MW).

Table 7.2 Resource sufficiency evaluation failures during assistance energy transfer opt-in (January–March 2026)

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	20	23%	23	198	116
California ISO	5	0	N/A	N/A	N/A	N/A
Idaho Power	59	1	100%	170	217	42
NorthWestern Energy	54	0	N/A	N/A	N/A	N/A
NV Energy	54	0	N/A	N/A	N/A	N/A
PacifiCorp East	90	8	75%	161	425	323
PacifiCorp West	90	43	30%	15	188	158

Table 7.3 summarizes the total cost from assistance energy transfers.[59] 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.[60] The price is the real-time bid cap, typically $1,000/MWh. Table 7.3 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 7.3 Cost of assistance energy transfers (January–March 2026)

Balancing area	RSE failures under AET (15-min. intervals)	Total WEIM imports added (MWh)	Total cost of assistance energy transfers ($)	Total cost per added WEIM import ($/MWh)
Avangrid	20	116	$68,885	$596
California ISO	0	N/A	N/A	N/A
Idaho Power	1	42	$913	$22
NorthWestern Energy	0	N/A	N/A	N/A
NV Energy	0	N/A	N/A	N/A
PacifiCorp East	8	323	$162,329	$503
PacifiCorp West	43	158	$491,685	$3,115

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[61] 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.

8 Real-time imbalance offset costs

Total real-time imbalance offset costs for balancing areas participating in the day-ahead market were $46 million in the first quarter of 2026.[62,63] The energy and congestion portions of the offset made up

59 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.

60 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.

61 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

62 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.

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

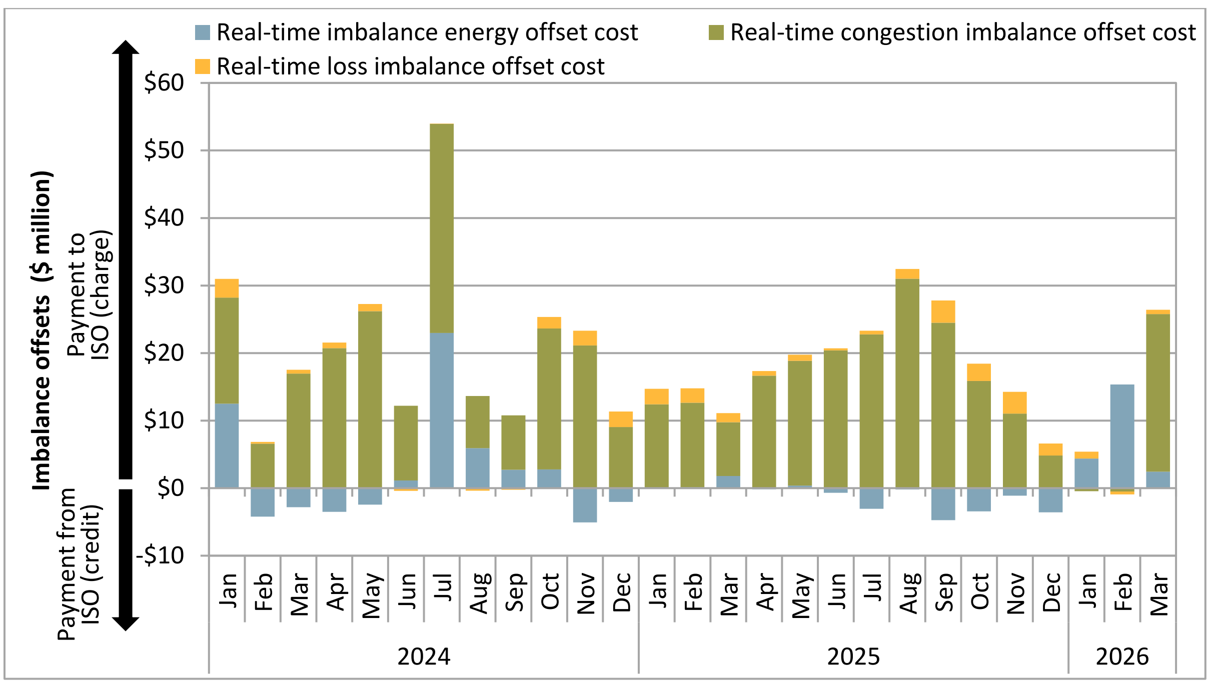
the large majority of the costs at around $22 million each. Total real-time imbalance offset costs in the first quarter of 2026 were higher compared to the same quarter of 2025, when they were $41 million.

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $15 million credit to WEIM entities, higher compared to the $12 million credit in the same quarter of 2025. During the first quarter of 2026, the congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $16.8 million credit. The energy portion of the offset was around a $2.5 million charge while the loss portion of the offset was a $0.7 million credit.

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 settlement is calculated separately for each balancing area. Any revenue surplus or revenue shortfall within this settlement is allocated to measured demand (for the California ISO balancing area) or the WEIM entity scheduling coordinator (for the WEIM balancing areas).[64]

The real-time imbalance offset settlement consists of three components. Any revenue imbalance from the congestion components of real-time energy prices is collected through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the loss component of real-time energy prices is collected through the *real-time loss imbalance offset charge*, while any remaining revenue imbalance is recovered through the r*eal-time imbalance energy offset charge* (RTIEO). Figure 8.1 shows monthly imbalance offset costs by component since 2024 for balancing areas participating in the day-ahead market.

Figure 8.1 Monthly real-time imbalance offset costs (balancing areas in day-ahead market)



64 Measured demand is physical load plus exports.

Figure 8.2 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). Total imbalance offsets in 2024 and 2025 were largely lower compared to 2023.

Figure 8.3 through Figure 8.5 show the quarterly real-time energy, congestion, or loss imbalance offsets from Q1 2025 through Q1 2026 for each balancing area participating only in the WEIM. Figure 8.6 shows the *total* real-time imbalance offset charges for each quarter and balancing area during the same period. 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 imbalance energy offsets for NV Energy was $3.2 million (charge).
- Revenue *shortfall* from imbalance energy offsets for NorthWestern Energy was $1.9 million (charge).
- Revenue *surplus* from congestion imbalance offsets for PacifiCorp East was $5.1 million (credit).
- Revenue *surplus* from congestion imbalance offsets Powerex was $2.7 million (credit).

Figure 8.2 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)

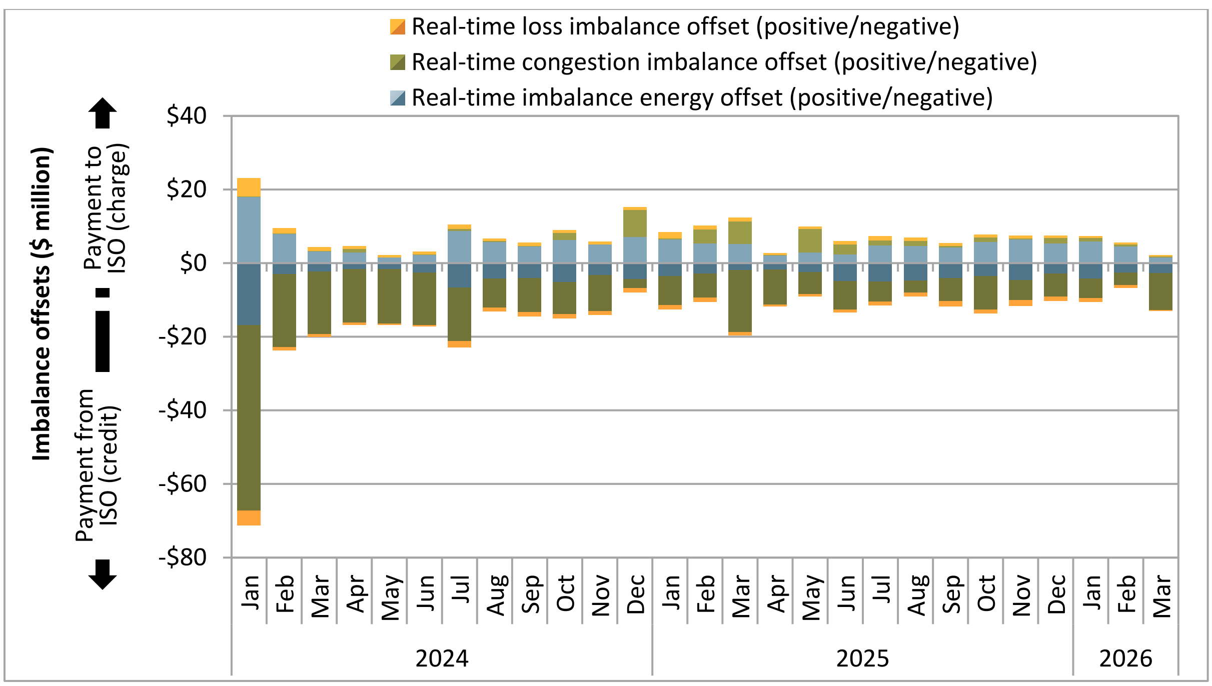


Figure 8.3 Real-time imbalance energy offsets by quarter and balancing area ($ millions)

	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1
Arizona Public Service	3	1	4	3	1
Avangrid	.3	0	.1	.3	.2
Avista	.1	0	0	0	0
BANC	0	.5	.6	.8	.1
BPA	.6	.4	.4	.2	0
El Paso Electric	0	.3	.1	.1	.1
Idaho Power	2	0	.9	.8	1
LADWP	.2	.2	.1	.1	.2
NorthWestern Energy	5	2	3	5	2
NV Energy	2	1	2	4	3
PacifiCorp East	.7	.6	2	.3	1
PacifiCorp West	2	2	3	2	2
Portland General Electric	.2	.1	.1	0	.1
Powerex	0	.2	.2	.2	.3
PNM	3	.8	1	2	1
Puget Sound Energy	4	2	4	4	3
Salt River Project	2	3	3	2	2
Seattle City Light	0	.3	1	1	1
Tacoma Power	0	0	0	0	0
Tucson Electric Power	.1	0	0	.1	.2
Turlock Irrigation District	.2	.4	.7	.7	.2
WAPA Desert Southwest	.4	.1	.7	.2	.4

Figure 8.4 Real-time congestion imbalance offsets by quarter and balancing area ($ millions)

	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1
Arizona Public Service	.6	.1	1	.5	.4
Avangrid	.3	.4	.5	.3	.1
Avista	.2	.3	.2	.3	.2
BANC	0	0	0	0	0
BPA	2	1	.3	.9	.9
El Paso Electric	.1	.4	.9	.8	1
Idaho Power	1	.9	.7	1	.6
LADWP	1	.1	.3	1	.4
NorthWestern Energy	.5	.2	0	.5	.3
NV Energy	1	.8	.3	.5	.4
PacifiCorp East	4	.4	2	7	5
PacifiCorp West	3	2	1	2	2
Portland General Electric	3	3	2	2	2
Powerex	9	6	2	2	3
PNM	10	9	.6	2	.8
Puget Sound Energy	2	2	1	.9	1
Salt River Project	.8	4	.6	.2	1
Seattle City Light	.6	.5	.5	.3	.2
Tacoma Power	.1	.1	.1	.1	.1
Tucson Electric Power	.8	2	1	.7	.2
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	.1	0	0	.1	.2

Figure 8.5 Real-time loss imbalance offsets by quarter and balancing area ($ millions)

	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1
Arizona Public Service	.2	.2	.3	0	.1
Avangrid	.1	.1	.1	.2	.1
Avista	0	0	0	0	0
BANC	0	0	.2	.1	0
BPA	.1	.1	.1	0	.1
El Paso Electric	.1	.1	.2	.1	0
Idaho Power	.4	.2	.3	.1	.1
LADWP	.2	.1	.1	.5	.2
NorthWestern Energy	.1	.1	.1	.1	0
NV Energy	.1	.2	.2	.1	.2
PacifiCorp East	1	.5	2	2	.6
PacifiCorp West	.5	.3	0	.4	.3
Portland General Electric	.1	.2	.4	.1	0
Powerex	2	.7	1	.7	.3
PNM	.2	.1	.1	.1	0
Puget Sound Energy	0	0	0	.2	.1
Salt River Project	.1	0	.3	.5	.2
Seattle City Light	.5	.4	.6	.4	.2
Tacoma Power	0	0	0	0	0
Tucson Electric Power	.1	0	.2	.1	0
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	.1	0	0	0	0

Figure 8.6 Total real-time imbalance offsets by quarter and balancing area ($ millions)

	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1
Arizona Public Service	4	1	4	3	2
Avangrid	.1	.5	.6	.3	0
Avista	.1	.3	.2	.3	.2
BANC	0	.5	.5	.7	.1
BPA	1	.8	.8	.7	1
El Paso Electric	.2	.2	.9	.8	.9
Idaho Power	.1	1	2	.2	.7
LADWP	1	.1	.5	1	.4
NorthWestern Energy	4	1	3	4	2
NV Energy	.5	.2	2	3	3
PacifiCorp East	5	.3	2	9	4
PacifiCorp West	5	4	5	4	4
Portland General Electric	3	2	2	1	2
Powerex	7	5	1	.8	2
PNM	12	9	2	5	2
Puget Sound Energy	6	4	5	5	4
Salt River Project	3	7	4	3	3
Seattle City Light	0	.4	1	1	1
Tacoma Power	0	.1	.1	.1	.1
Tucson Electric Power	.7	2	1	.8	0
Turlock Irrigation District	.2	.4	.7	.7	.2
WAPA Desert Southwest	.4	.1	.6	.1	.2

9 Bid cost recovery

During the first quarter of 2026, estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market totaled about $33 million.[65] This was a 24 percent decrease from the $44 million in bid cost recovery in the first quarter of 2025. Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM) totaled about $1.9 million. WEIM area bid cost recovery payments decreased 34 percent from Q1 2025.[66]

Figure 9.1 shows monthly bid cost recovery payments in the first quarter of 2026 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $5.1 million, down from $9.9 million in the first quarter of 2025. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $13.6 million, or about $2.6 million higher than the first quarter of 2025. Bid cost recovery associated with the real-time market (green bars) for areas that participate in the day-ahead market totaled about $12.8 million, which was about $7 million lower than the same quarter of 2025.

Figure 9.2 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[67] regions at $1.5 million and $201,000, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around $112,000 and $110,000, 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 2026, about $29.3 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 $2.1 million and $1.3 million of payments were made to battery and hydroelectric resources, respectively. California ISO implemented changes[68] to the real-time bid cost recovery calculation for battery resources in September 2025. The ISO will continue to re-settle bid cost recovery payments for earlier trade dates going back to December 1, 2024.

65 Prior to May 1, 2026, CAISO was the only balancing area participating in the day-ahead market.

66 The bid cost recovery payment amounts in this report are different than what is reported in previous reports due to resettlements.

67 Figure 9.2 includes only non-CAISO balancing authority areas.

68 See here for more information: https://stakeholdercenter.caiso.com/StakeholderInitiatives/storage-bid-cost-recovery-and-default-energy-bids-enhancements?_gl=1*xtuuk2*_ga*MTU1OTc5MzcwNi4xNzUwNDM5NjY0*_ga_NDS4B4M2WP*czE3NzA2NzIxMjMkbzk3JGcxJHQxNzcwNjczMzAzJGo2MCRsMCRoMA..

Figure 9.1 Monthly bid cost recovery payments for day-ahead market area

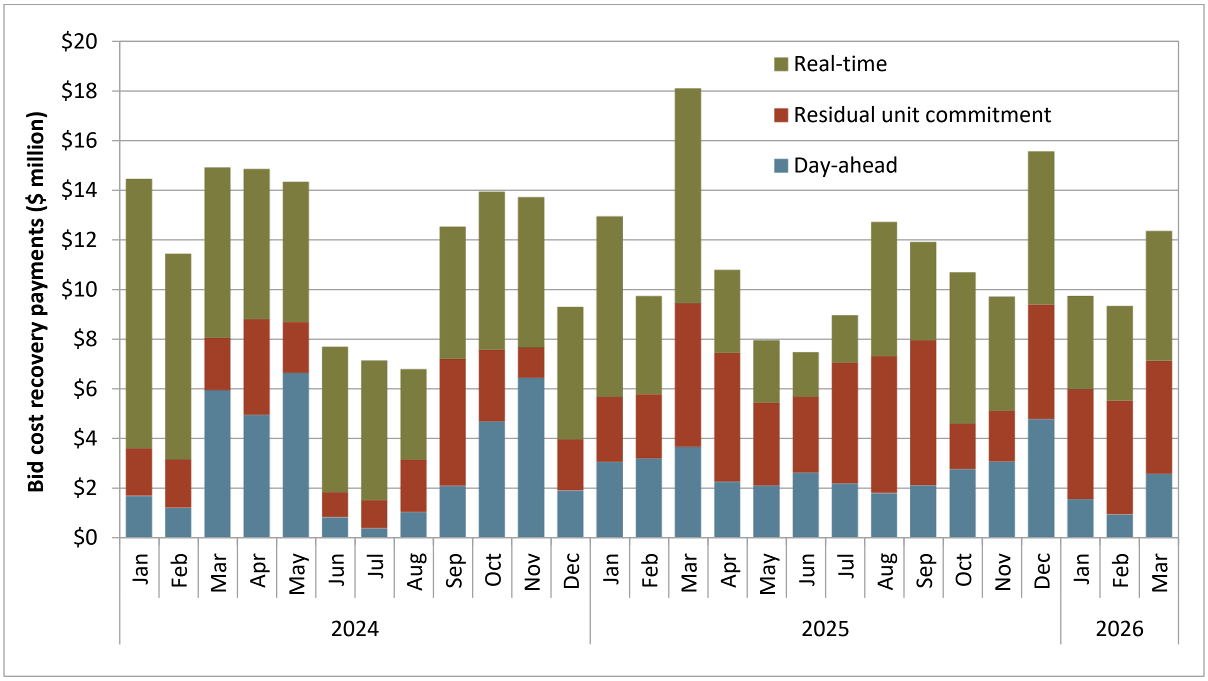
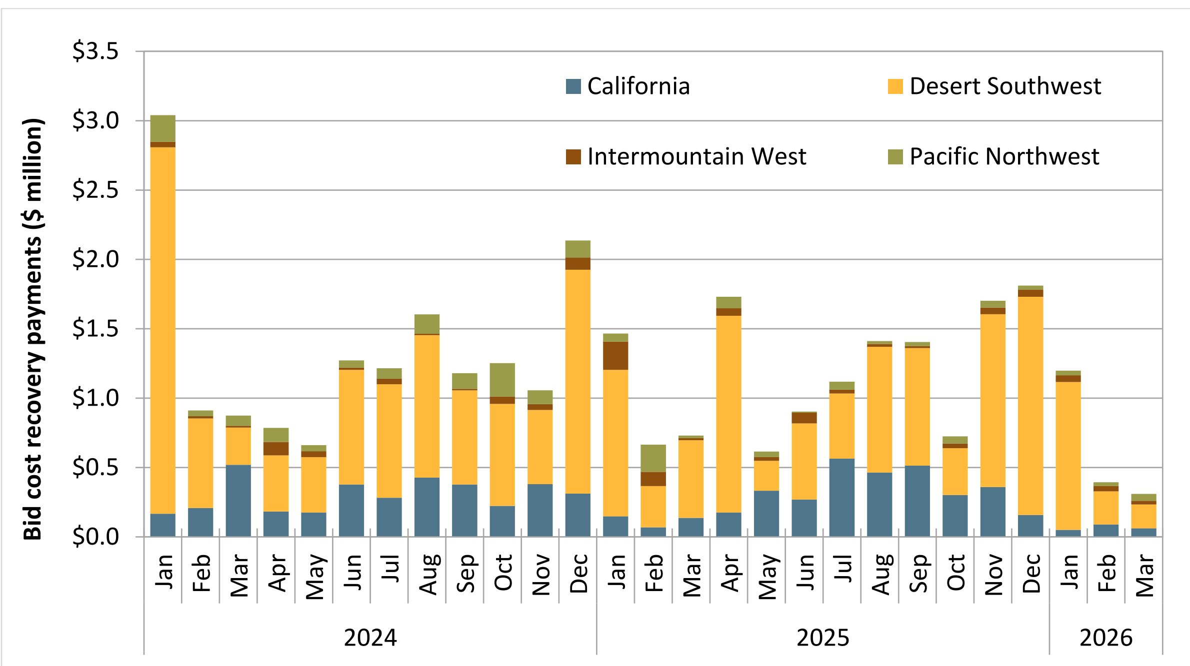


Figure 9.2 Monthly bid cost recovery payments for the WEIM



10 Flexible ramping product

This chapter analyzes flexible ramping product prices and procurement. Key findings in this chapter include:

- For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in this system during about 0.9 percent of intervals in the first quarter of 2026, up from 0.6 percent in the same quarter of 2025. At the balancing area level, El Paso Electric, Nevada Power, and WALC had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 1.3, 1.2, and 1.1 percent of intervals, respectively.
- Battery and hydro resources made up 68 percent and 16 percent of upward flexible ramping product, respectively. Wind and solar combined to provide 43 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 ramping product awards, at around 58 percent in the upward direction and 54 percent in the downward direction. Balancing areas in the Pacific Northwest made up 16 percent of upward flexible capacity and 18 percent of downward flexible capacity.

10.1 Background

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.[69] 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.[70] 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 is pooled together to meet the uncertainty requirement for the rest of the system. Both the requirement

[69] 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.

[70] Based on a 95 percent confidence interval.

for the pass-group and the requirement for balancing areas that fail the resource sufficiency evaluation 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.

10.2 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[71] 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.[72] 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.[73] 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).

71 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

72 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.

73 *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

The slack variables are implemented for each balancing area.[74] 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.[75] 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 available.[76] 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 10.1 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.[77] The pass-group constraint for procuring *upward* flexible capacity in both the 15-minute and 5-minute markets was binding in about 0.2 percent or less of intervals on average during the quarter. The pass-group constraint for procuring *downward* flexibility in the 15- and 5-minute markets was also binding very infrequently, in less than 0.3 percent of intervals on average.

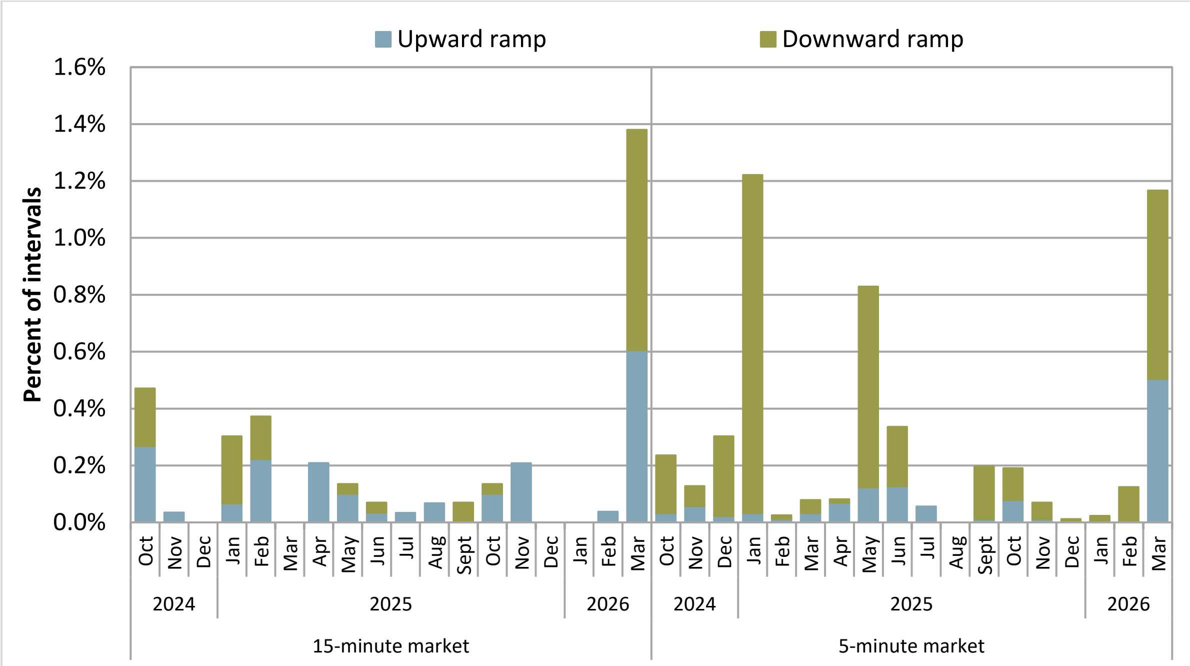
[74] Or for each surplus zone in the case of the CAISO balancing area (by transmission access charge—or TAC—area) and the Balancing Authority of Northern California (by custom load aggregation point).

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

[76] 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.

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

Figure 10.1 Frequency of flexible ramping product prices from pass-group constraint



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 10.2[78] 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 10.1, 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.

The frequency of upward flexible ramping product prices was very low across the pass-group. For balancing areas that passed the resource sufficiency evaluation, upward flexible ramping product prices in the 15-minute market were greater than zero for one or more balancing areas in the system during

78 Localized flexible ramping product prices within the pass-group that are entirely driven by congestion on transmission constraints are not reflected in this figure.

about 0.9 percent of intervals in the first quarter of 2026, up from 0.6 percent in the same quarter of 2025. In January, there were no intervals in which the constraint for meeting pass-group upward flexible capacity requirements was binding.

Figure 10.2 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

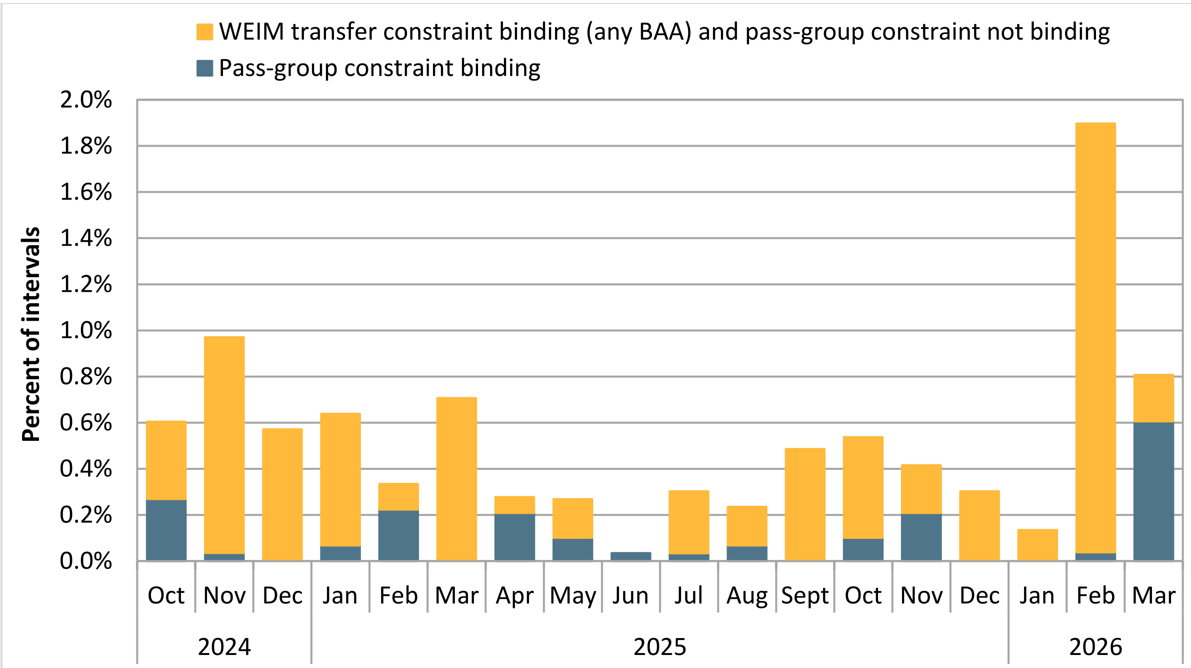


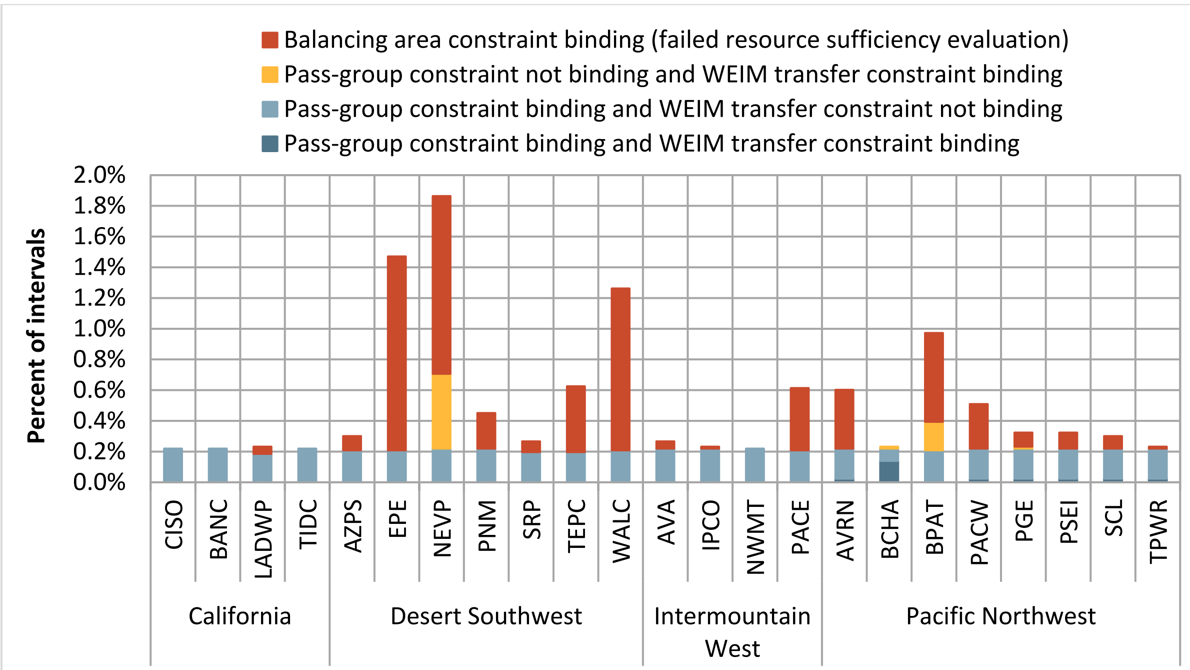
Figure 10.3 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

- **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. 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. This is shown by the red bars in Figure 10.3.
- **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. This is shown in yellow.
- **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. This is shown in light blue below.
- **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. This is shown in dark blue.

During the quarter, the pass-group constraint was binding very infrequently for upward flexible capacity in the 15-minute market, during around 0.2 percent of intervals. Most balancing areas in the California region did not fail the resource sufficiency evaluation during the quarter or experience flexible ramping product prices as a result. El Paso Electric, Nevada Power, and WALC had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 1.3, 1.2, and 1.1 percent of intervals, respectively. 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.[79]

Figure 10.3 Frequency of upward flexible ramping product prices by balancing area and constraint



[79] 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.

10.3 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 10.4 and Figure 10.5 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, making up about 68 percent of upward flexible capacity and 31 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (16 percent). Wind and solar resources combined made up around 43 percent of downward flexible capacity.

Figure 10.4 Average upward pass-group flexible ramp procurement by fuel type (15-minute market, Q1 2026)

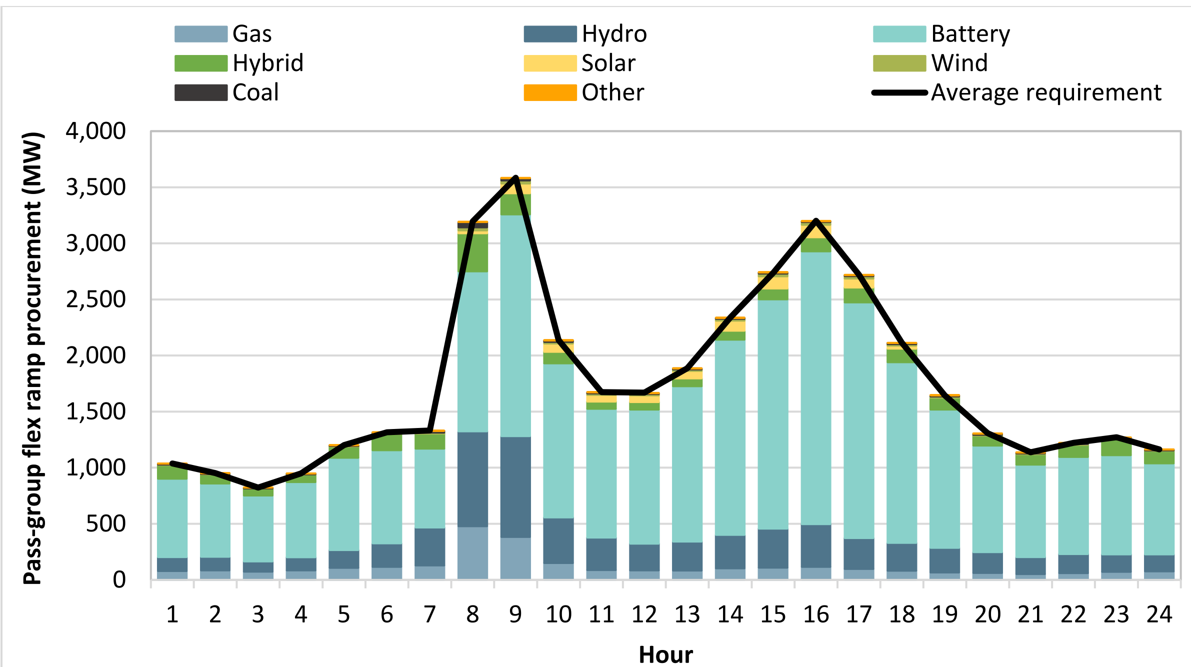


Figure 10.5 Average downward pass-group flexible ramp procurement by fuel type (15-minute market, Q1 2026)

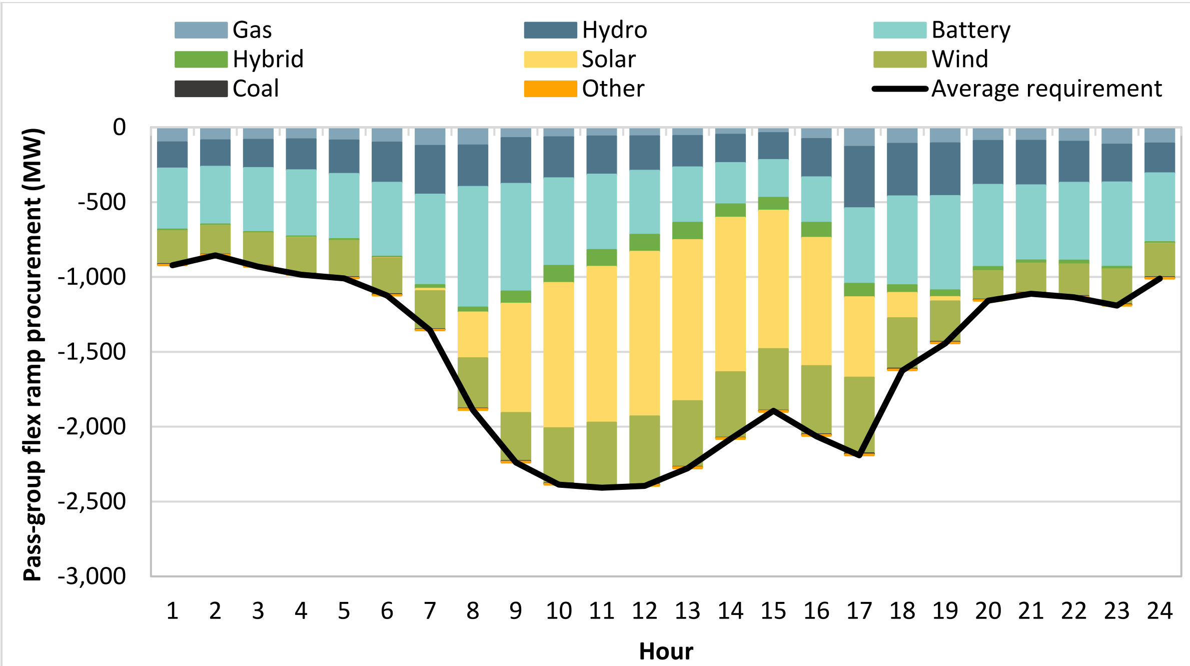


Figure 10.6 and Figure 10.7 show the average upward or downward flexible capacity that was procured in various regions.[80] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export 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 58 percent in the upward direction and 54 percent in the downward direction. Balancing areas in the Pacific Northwest made up 16 percent of upward flexible capacity and 18 percent of downward flexible capacity. The Desert Southwest and Intermountain West made up about 11 percent of flexible capacity each in the upward direction, and 11 and 14 percent in the downward direction, respectively.

[80] 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 10.6 Average upward pass-group flexible ramp procurement by region (15-minute market, Q1 2026)

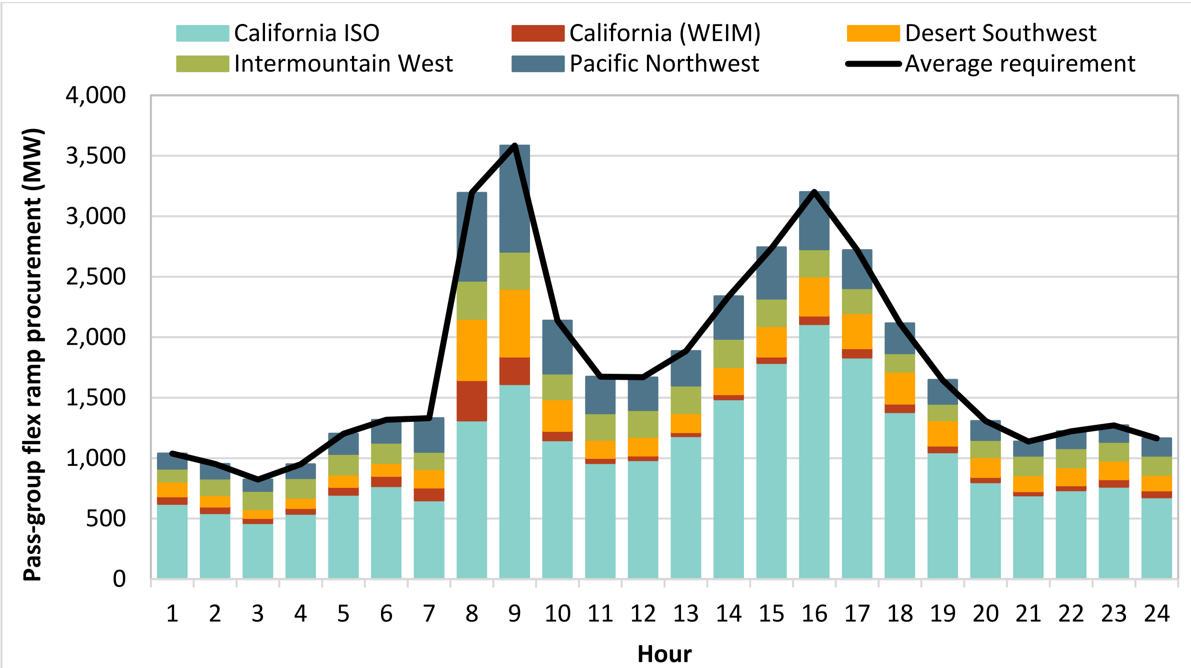
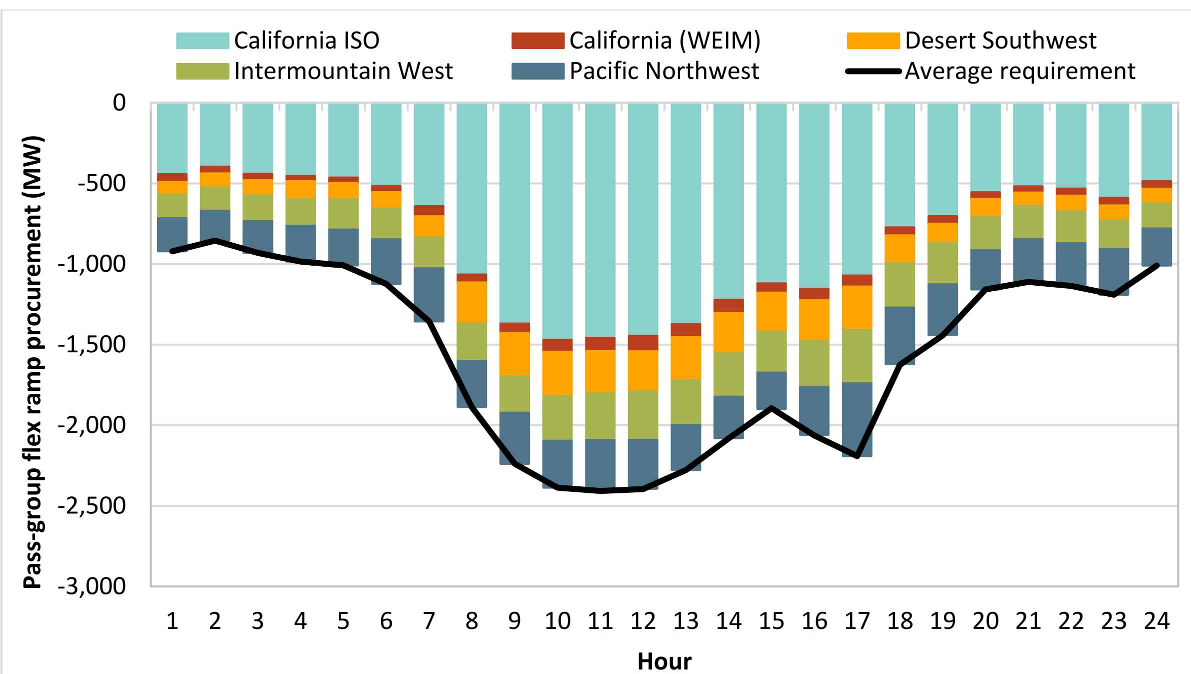


Figure 10.7 Average downward pass-group flexible ramp procurement by region (15-minute market, Q1 2026)



11 Uncertainty calculation assessment

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 uses a method called *mosaic quantile regression* to calculate and account for uncertainty that may materialize.[81] This chapter reviews the results of the uncertainty calculation and assesses the regression method.

DMM evaluates the performance of this model using three main criteria:

- **Accuracy:** accuracy is measured using the coverage rate, which reflects the percentage of realized uncertainties that falls within the forecast prediction interval.
- **Efficiency:** a forecast is considered efficient if it maintains the target coverage (e.g., 95 percent) while producing a relatively narrow prediction interval (requirement).
- **Validity:** DMM tests whether regression coefficients are statistically different from zero at the 10 percent significance level ($p<0.1$).[82]

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.[83]

11.1 Flexible ramping product uncertainty results and special issues

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.

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81 For further details on the regression methodology, a simplified explanation is available in chapter 11 of DMM's 2024 annual report, pp 240–243: https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf

For a more technical review, see the DMM special report, *Review of mosaic quantile regression for estimating net lad uncertainty*, November 20, 2023: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

82 Statistical testing is used to determine whether a regression coefficient is significantly different from zero, which suggests the presence of a non-random pattern in historical data. This relationship may be useful for forecasting—if the historical pattern continues into the future. However, statistical significance alone does not guarantee forecast accuracy; if the pattern does not persist, the model may still perform poorly despite showing past significance. If a coefficient is not statistically significant, it may indicate either no meaningful pattern or an unstable pattern that could result in inaccurate forecasts. The model produces two main coefficients (a linear and a quadratic term), and DMM evaluates model validity based on whether either is statistically significant at the 10 percent level.

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

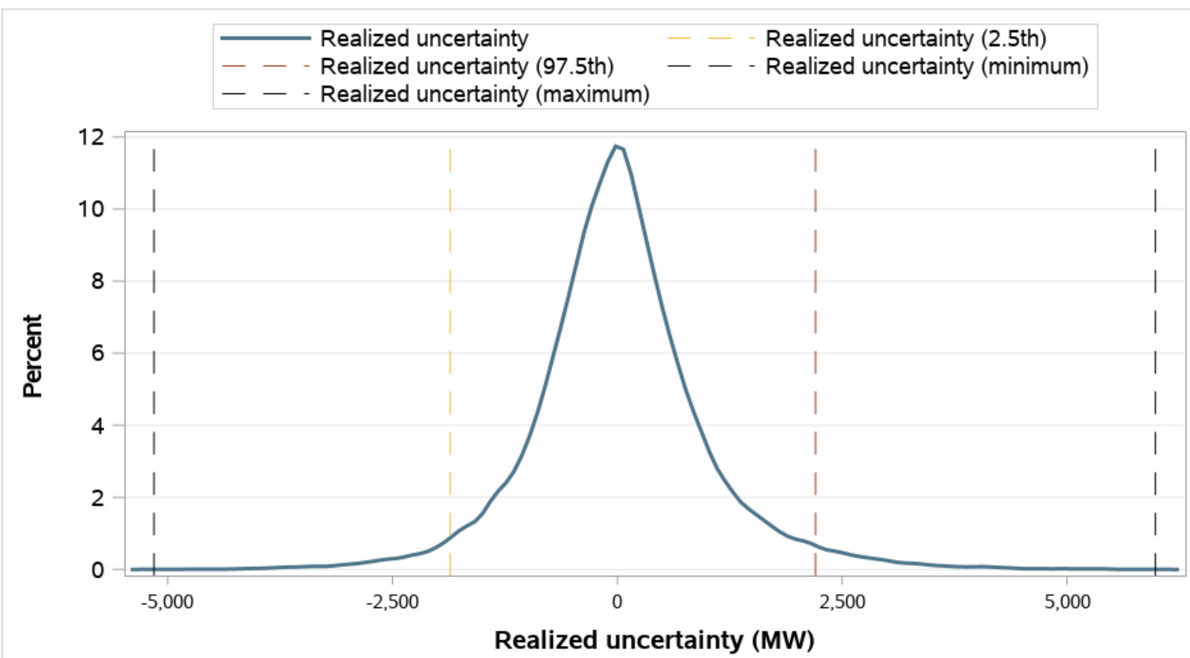
The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. For the group of balancing areas that instead pass the resource sufficiency evaluation (known as the pass-group), flexible capacity is pooled together to meet the group's uncertainty requirement.

Figure 11.1 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 2026. 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 2,200 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.

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

Figure 11.1 Distribution of realized uncertainty in FRP (pass-group, January–March 2026)



11.1.1 Results of flexible ramping product uncertainty calculation

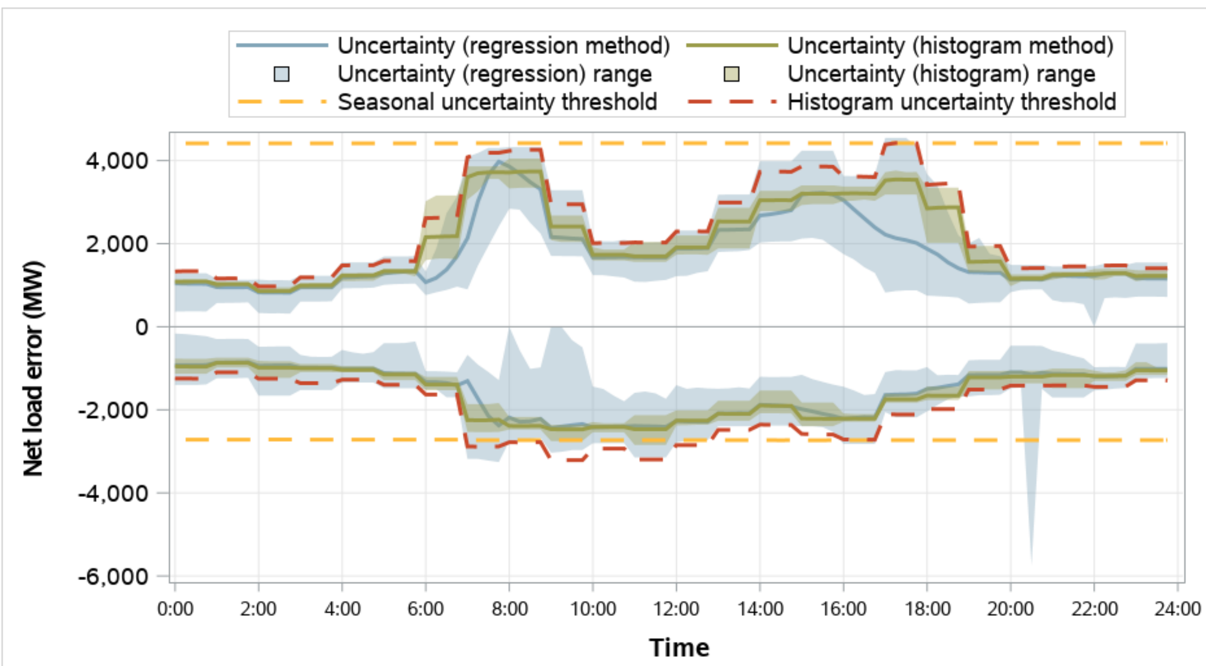
Figure 11.2 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), both with the histogram method (pulled from the 2.5th and 97.5th

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.[84]

Figure 11.3 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. However, results of the regression-based approach vary more widely, including periods with much lower uncertainty. DMM has also identified a number of cases where the final pass-group uncertainty from the regression method exceeds one or both of the thresholds (for example, the observation depicted in hour-ending 21 in Figure 11.2 below). DMM has requested that the ISO review and correct any issues associated with this outcome.

Figure 11.2 15-minute market pass-group uncertainty requirements (January–March 2026)



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

Figure 11.3 5-minute market pass-group uncertainty requirements (January–March 2026)

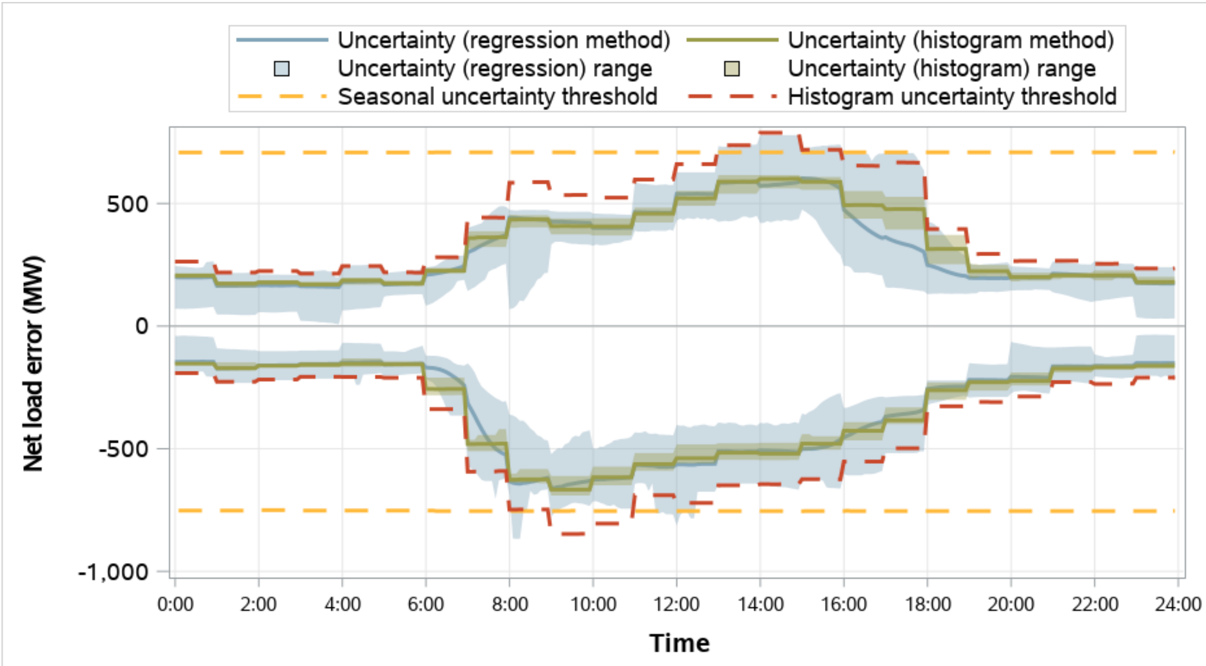


Table 11.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the 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.[85]

In the 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.[86] In both markets and directions, uncertainty forecasted by mosaic regression generally had lower coverage and lower requirements.

85 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.

86 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.

Table 11.1 Average pass-group uncertainty requirements (January–March 2026)

Market	Direction	Requirement			Coverage		
		Histogram	Mosaic	*Difference*	Histogram	Mosaic	*Difference*
15-minute market	Up	2,033	1,775	-258	98.7%	97.9%	-0.7%
	Down	1,635	1,570	-65	96.4%	96.1%	-0.2%
5-minute market	Up	333	316	-17	97.7%	97.4%	-0.3%
	Down	343	335	-8	97.7%	97.6%	-0.1%

Table 11.2 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.[87]

The percentages in the table indicate the proportion of estimated coefficients that were statistically different from zero among all regression estimations in this quarter. Each regression includes two primary coefficients: a quadratic term and a linear term.[88] The percentages represent the proportion of regression where at least one of these coefficients was statistically significant. The significance level was set at 10 percent.

Table 11.2 Test for statistical significance of the mosaic quantile regression in FRP (January–March 2026)[89]

Regression type	All hours	Peak hours(1)
Mosaic	29%	41%
Load	26%	41%
Solar	69%	80%
Wind	38%	41%

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

87 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 mosaic quantile regression for estimating net load uncertainty*, November 20, 2023, pp 6-10: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

88 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.

89 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.

The coefficient for the mosaic variable was statistically significant during only 29 percent of intervals. This means that in 71 percent of cases, the mosaic variable did not show a strong pattern with historical uncertainty.[90] 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 an 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.[91] 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 Table 11.2 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.

11.2 Resource sufficiency evaluation uncertainty results

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*.[92] 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 11.4 shows the distribution of realized 15-minute uncertainty in the RSE for each balancing authority area (BAA) for the first quarter of 2026. 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

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90 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.

91 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 mosaic quantile regression for estimating net load uncertainty*, Nov 20, 2023, p 5 and pp 31-33: https://www.caiso.com/documents/review-of-the-mosaic-quantile-regression-nov-20-2023.pdf

92 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.[93] 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 11.4 Standardized realized uncertainty and requirement for RSE (January–March 2026)

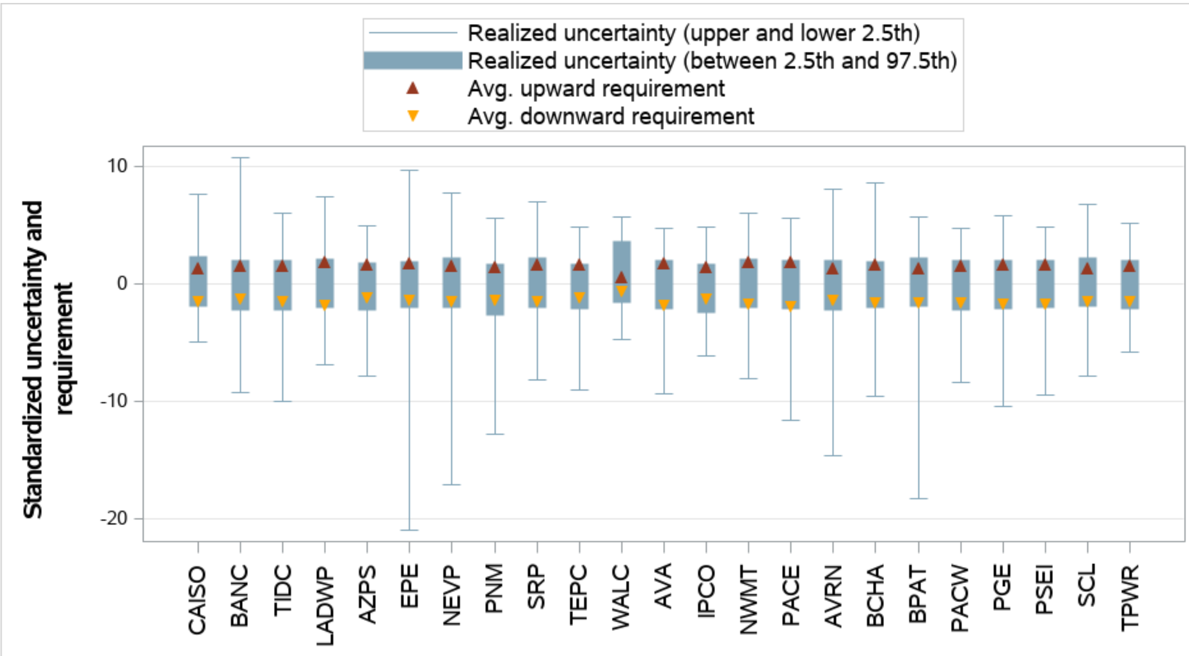

Figure 11.4 provides a comparison of the realized uncertainty across different BAAs for this quarter. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 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's 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.

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93 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.

- **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.

11.2.1 Results of resource sufficiency evaluation uncertainty calculation

Table 11.3 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 that 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, the mosaic regression method resulted in coverage levels largely below the 95 percent target. This is mostly 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 almost all of the WEIM entities. The resource sufficiency evaluation uncertainty calculated from the regression method covered between 84 and 95 percent of realized uncertainty across all balancing areas.

Table 11.3 Average resource sufficiency evaluation uncertainty requirements and coverage (January–March 2026)

	Upward uncertainty			Downward uncertainty			Coverage		
Balancing area	**Histogram**	**Mosaic**	**Difference**	**Histogram**	**Mosaic**	**Difference**	**Histogram**	**Mosaic**	**Difference**
Arizona Public Service	378	274	-104	328	284	-44	91%	88%	-2%
Avangrid	217	154	-63	199	126	-73	94%	90%	-4%
Avista	61	56	-5	65	61	-4	93%	91%	-1%
BANC	46	45	-1	46	43	-3	92%	91%	0%
Bonneville Power Admin.	253	197	-56	284	211	-73	93%	89%	-3%
California ISO	1,428	1,143	-285	939	865	-74	94%	92%	-2%
El Paso Electric	55	45	-11	50	39	-11	95%	92%	-3%
Idaho Power	135	117	-18	175	144	-31	93%	89%	-4%
LADWP	167	157	-10	152	150	-2	94%	94%	-1%
NorthWestern Energy	87	84	-3	80	73	-7	93%	93%	0%
NV Energy	264	226	-38	232	211	-21	96%	95%	-1%
PacifiCorp East	500	466	-34	692	660	-32	95%	94%	-1%
PacifiCorp West	104	91	-13	164	122	-41	93%	92%	-2%
Portland General Electric	124	112	-12	122	116	-6	93%	92%	-1%
Powerex	155	156	1	160	160	1	91%	91%	0%
PNM	246	174	-72	214	203	-11	95%	94%	-2%
Puget Sound Energy	165	160	-4	155	152	-3	90%	89%	-1%
Salt River Project	141	137	-4	126	124	-2	92%	92%	-1%
Seattle City Light	21	21	0	21	22	1	88%	89%	1%
Tacoma Power	12	13	0	13	13	0	89%	90%	0%
Tucson Electric Power	123	115	-7	98	84	-14	94%	92%	-2%
Turlock Irrigation District	8	7	0	8	8	0	91%	90%	-1%
WAPA Desert Southwest	45	41	-4	34	29	-5	86%	84%	-2%

Table 11.4 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, led by those with the highest percentage of significant coefficients. Overall, 36 percent of regression coefficients were significant in Q1 2026, indicating that 64 percent of the regression estimations were based on either weak or inconsistent patterns.

Table 11.4 Test for statistical significance of mosaic quantile regression in RSE (January–March 2026)[94]

BAA	Percent of significant coefficients	
	All hours	Peak hours(1)
Avangrid	85%	85%
PacifiCorp West	71%	71%
BPA	68%	62%
Arizona PS	49%	45%
NorthWestern	47%	55%
Idaho Power	45%	62%
CAISO	44%	66%
Tucson Electric	41%	42%
PSC New Mexico	39%	45%
NV Energy	37%	59%
Salt River Project	35%	43%
LADWP	35%	42%
PacifiCorp East	31%	39%
Portland GE	31%	31%
El Paso Electric	30%	47%
Avista Utilities	29%	32%
WAPA - Desert SW	28%	40%
BANC	20%	28%
Puget Sound Energy	19%	14%
Powerex	12%	9%
Seattle City Light	9%	11%
Turlock ID	8%	10%
Tacoma Power	6%	7%
Average	36%	41%

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

94 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.

11.2.2 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.

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.[95] 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 11.5 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.[96] 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.[97]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the resource sufficiency evaluation. Figure 11.6 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized

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

96 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.

97 The resource sufficiency evaluation and flexible ramping product uncertainty calculations for a single balancing area use the same hourly regression coefficients (produced from the 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.

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.

Figure 11.5 Comparison of timeframe considered for the flexible ramping product and resource sufficiency evaluation

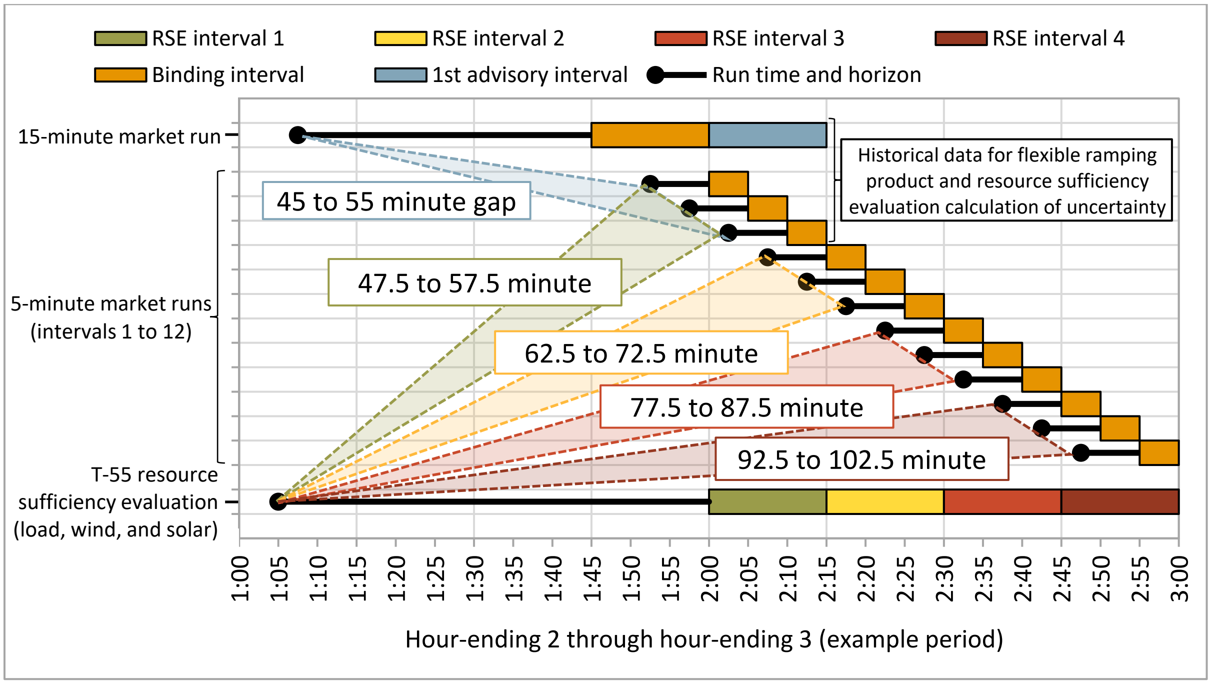
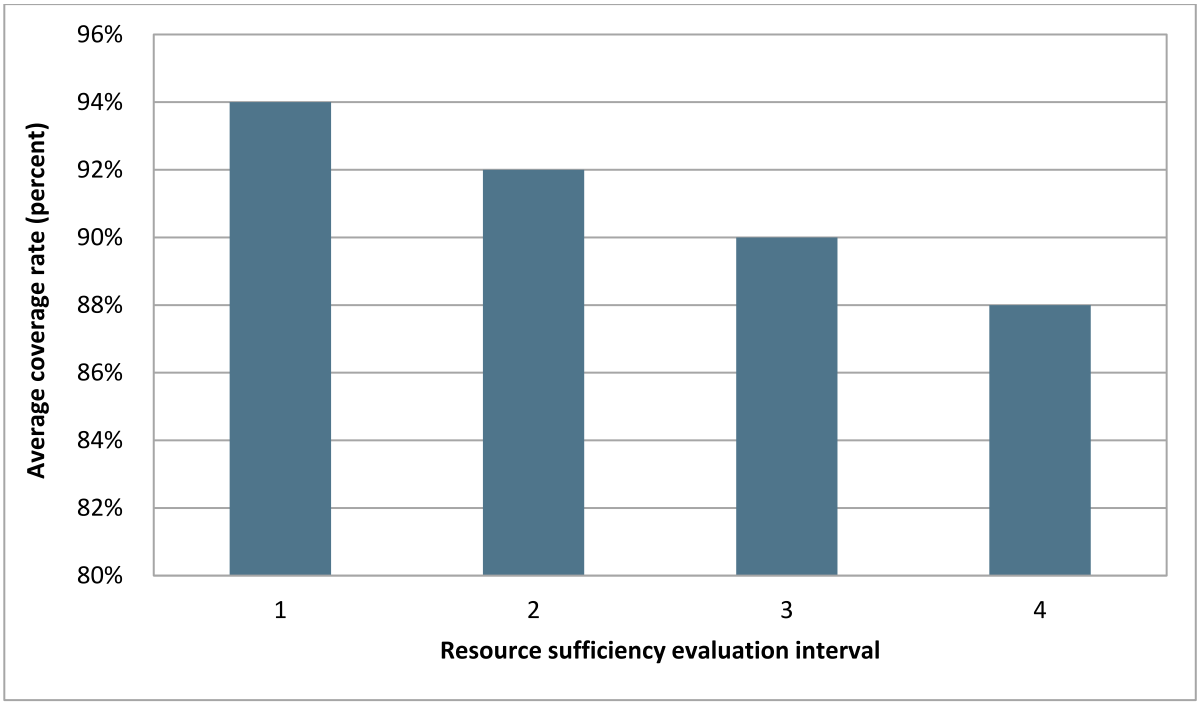


Figure 11.6 Average coverage rate by resource sufficiency evaluation interval (January–March 2026)



11.3 Residual unit commitment uncertainty results

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 the *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).[98] The ISO can adjust the calculation on any day to instead use the 75th or 97.5th percentile during periods of higher loads, higher forecast uncertainty, or in extreme conditions. During periods with low operational uncertainty, the 25th percentile or no adjustment can also be applied.

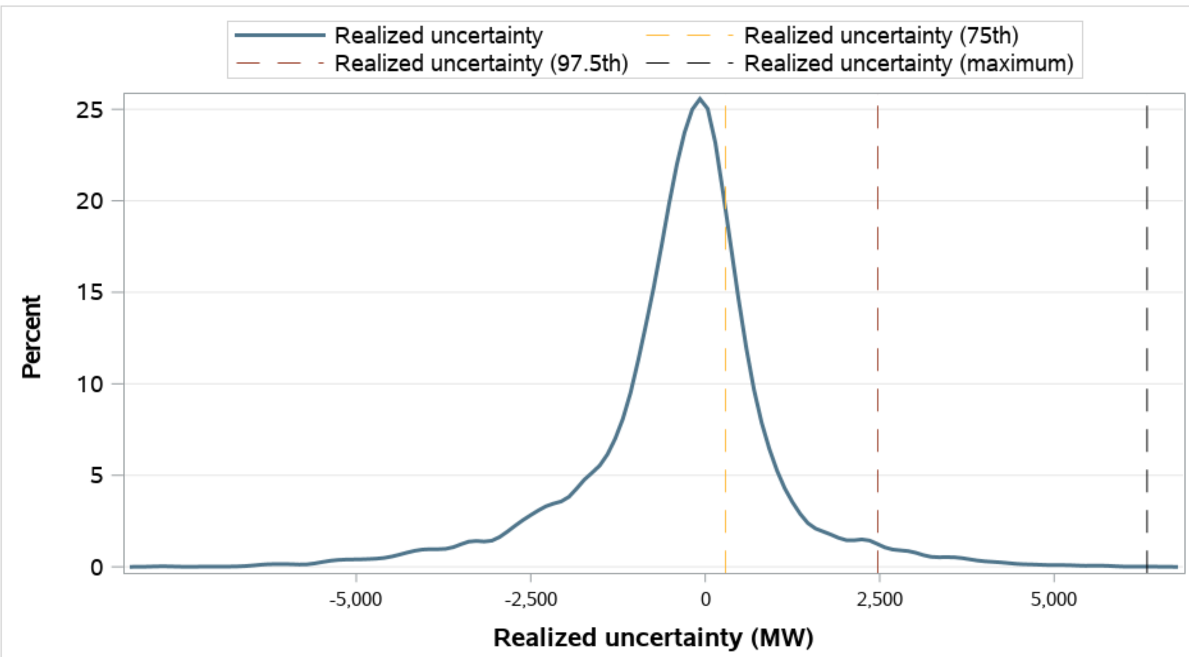
The adjustment can also be applied to only select hours. During periods with moderate uncertainty, the adjustment is typically applied only to the peak morning and peak evening hours (around six or seven

98 See CAISO Operating Procedure 1210, October 1, 2025, pp 12-13: https://www.caiso.com/Documents/1210.pdf

hours). During periods with more operational uncertainty, the adjustment is generally applied to either mid-day hours (around 16 hours) or all hours.

Figure 11.7 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 -7,800 MW to 6,300 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 2,500 MW to 6,300 MW. A long tail could indicate rare but impactful events, such as unexpected weather changes or some other cause of a sudden shift in demand or renewable resource output.

Figure 11.7 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (January–March 2026)



11.3.1 Results of uncertainty calculation for residual unit commitment

RUC adjustments in the first quarter of 2026 were low and similar to the same quarter of the previous year. Figure 11.8 shows the average RUC adjustment on each day, across all hours.[99] The figure also

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

shows the estimated percentile that was used to determine the additional requirements for each day.[100] During the first quarter, the 97.5th percentile target was not applied. The 75th percentile target was applied on two days and the 50th percentile target was applied on 6 days. No adjustment was applied on the remaining days.

The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty as this RUC adjustment. The extended day-ahead market launched on May 1, with the imbalance reserve up requirement set to cover all hours at the 90th percentile of uncertainty—down from the original 97.5th percentile target. The low number of hours in which the ISO uses the 97.5th (or 75th) percentile target in RUC indicates that the imbalance reserve product demand curve may still be too high during most hours. DMM has been highlighting this concern in its public reports for over a year. DMM appreciates that the ISO has lowered the target for the launch but recommends that the ISO consider reducing it further if imbalance reserve prices exceed the true value of the product.

Figure 11.8 Average residual unit commitment adjustment by day (all hours)

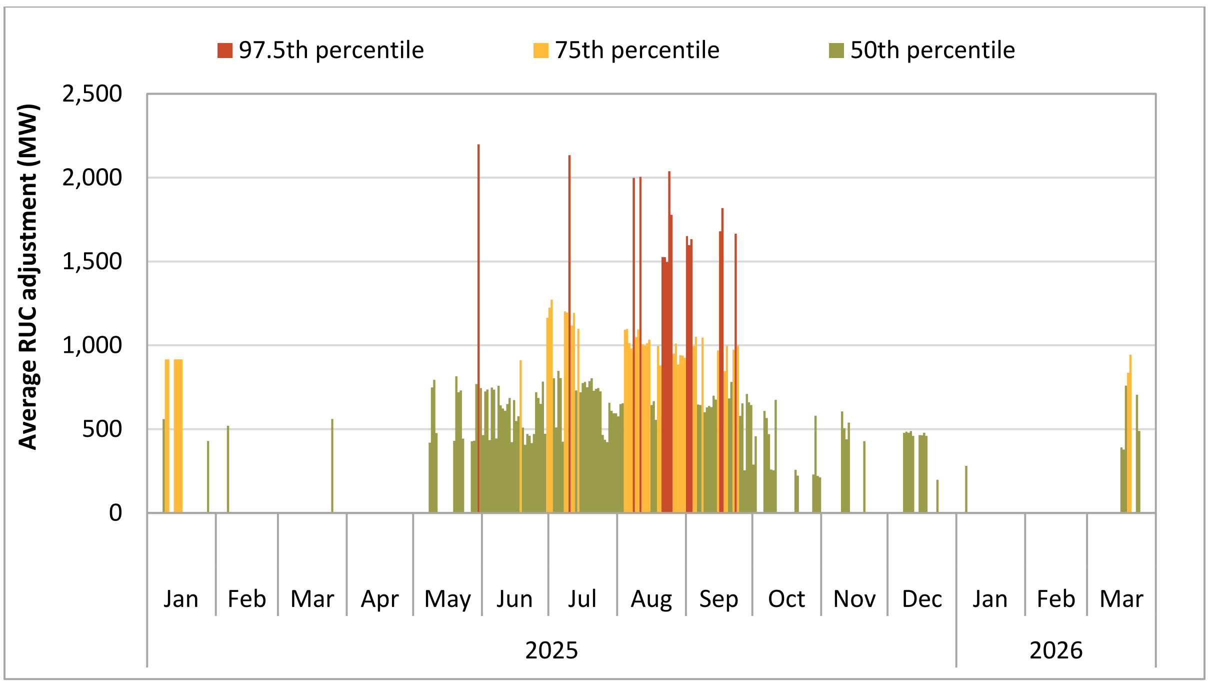


Table 11.5 summarizes the average requirement and coverage based on the estimated percentile target that was selected and the hours it was applied (either mid-day hours or peak hours).[101] Coverage shows the percent of 15-minute market intervals in which realized uncertainty from the day-ahead market to

[100] 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.

[101] The exact hours considered for the “mid-day” or “peak” hours can vary during the year. Typically, the peak morning and evening hours include the morning hours 7 to 9 as well as 3-4 hours in the evening (total of around 6-7 hours). The mid-day hours typically start in hour 7 and go through hour 22.

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 11.5 Average residual unit commitment uncertainty adjustment and coverage (Q1 2026)

Percentile target	Hours applied	Number of days	Percent of days	Average requirement (MW)	Coverage
75th percentile	Mid-day hours	2	2.2%	1,582	89%
50th percentile	Mid-day hours	3	3.3%	1,196	80%
	Peak hours	3	3.3%	1,327	89%

Table 11.6 represents DMM's simulation of the RUC adjustment using the mosaic quantile regression. Unlike the current market practice, this simulation estimates RUC adjustments for all hours in the quarter. 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 across all hours of the quarter.

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 a 3 percent rate of statistical significance, likely due to sample size. This specific percentile regression focuses on only 4 to 5 observations.[102] While an underlying pattern may exist, the small sample size of 4 to 5 observations is insufficient to find such a pattern, resulting in no 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 76 percent.

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 11.7, the realized uncertainty distribution indicated the 50th percentile value was around -210 MW, meaning that a -210 MW requirement would effectively achieve 50 percent coverage. However, the 50th percentile regression averaged around 624 MW (as shown in Table 11.6). This means that the regression is producing over 834 MW more than ideal, due to the practice of forecasting the maximum uncertainty per hour. Second, the regression in RUC estimates only the upper

102 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.

bound of uncertainty, meaning any negative uncertainty is automatically covered, contributing to the inflated coverage rate.

Table 11.6 DMM simulation for RUC adjustment using mosaic quantile regression (all hours: January–March 2026)[103]

	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Peak hours[(1)]	All hours	Peak hours	All hours	Peak hours
Replication (97.5th)	2,233	2,538	3%	9%	99%	99%
Replication (75th)	1,174	1,641	28%	60%	91%	89%
Replication (50th)	624	1,149	42%	70%	76%	76%
Replication (25th)	61	578	42%	65%	56%	58%

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

103 This simulation includes DMM's replication of RUC adjustment using all hours from this quarter, unlike the current market practice which applies RUC adjustment only during selected hours.

12 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. Exceptional dispatches in the CAISO balancing area are covered separately from those in other WEIM areas due to significant differences in settlement procedures.

12.1 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 issued by individual WEIM entities for their respective balancing authority areas and not by CAISO. 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 12.1 through Figure 12.4 summarize the 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 2026 to the first quarter of 2025, incremental manual dispatch energy from participating resources (yellow bars) decreased in all regions except California. The Desert Southwest, Intermountain West, and Pacific Northwest decreased by 36 percent, 51 percent, and 28 percent, respectively, while the California region increased by 12 percent. Similarly, when comparing the first quarter of 2026 to the same quarter in 2025, incremental manual dispatch energy from non-participating resources (red bars) decreased in the Desert Southwest and Intermountain West regions by 67 percent and 24 percent, respectively, while the Pacific Northwest region increased by 84 percent.

From the first quarter of 2025 to the first quarter of 2026, decremental manual dispatch energy from participating resources (green bars) decreased in all regions. The California, Desert Southwest, Intermountain West, and Pacific Northwest regions decreased by 75 percent, 18 percent, 31 percent, and 83 percent, respectively. When comparing the first quarter of 2026 to the same quarter in 2025, decremental manual dispatch energy from non-participating resources (blue bars) decreased in the Desert Southwest and Intermountain West regions by 71 percent and 9 percent, respectively, while the Pacific Northwest increased by 84 percent.

Overall, combined incremental and decremental manual dispatch energy decreased in the California (non-CAISO), Desert Southwest and the Intermountain West regions by 63 percent, 28 percent, and 39 percent, respectively, and increased in the Pacific Northwest by 78 percent.

Figure 12.1 WEIM manual dispatches – California

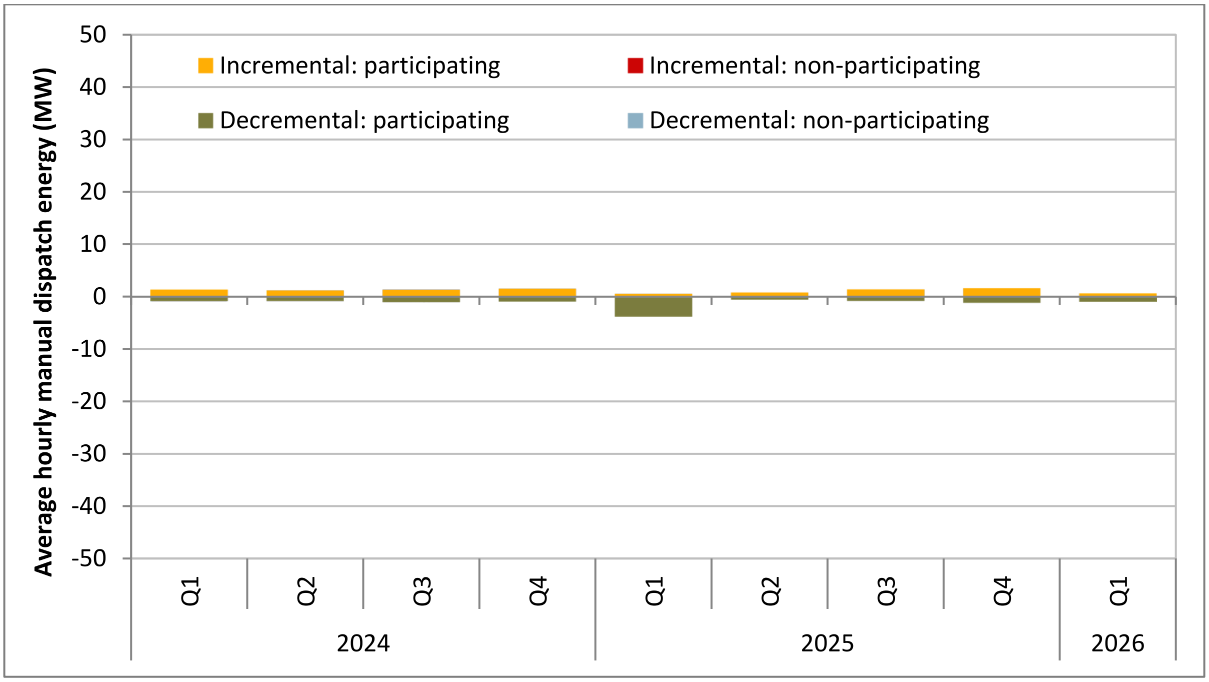


Figure 12.2 WEIM manual dispatches – Desert Southwest

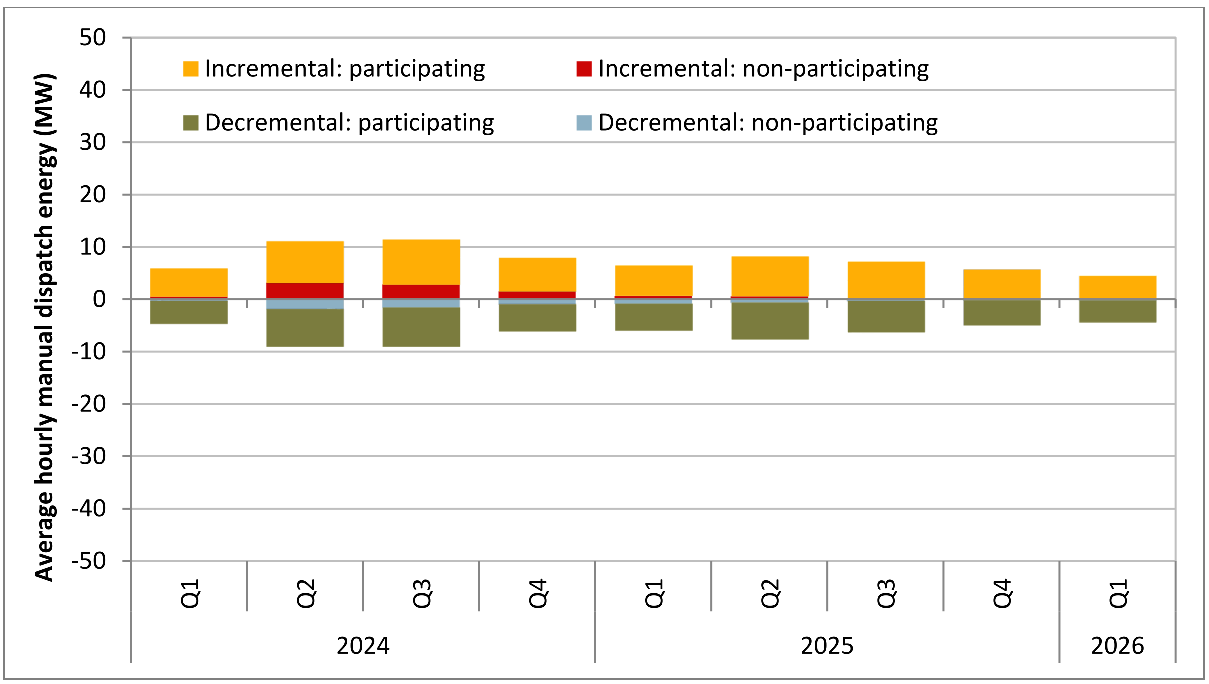


Figure 12.3 WEIM manual dispatches – Intermountain West

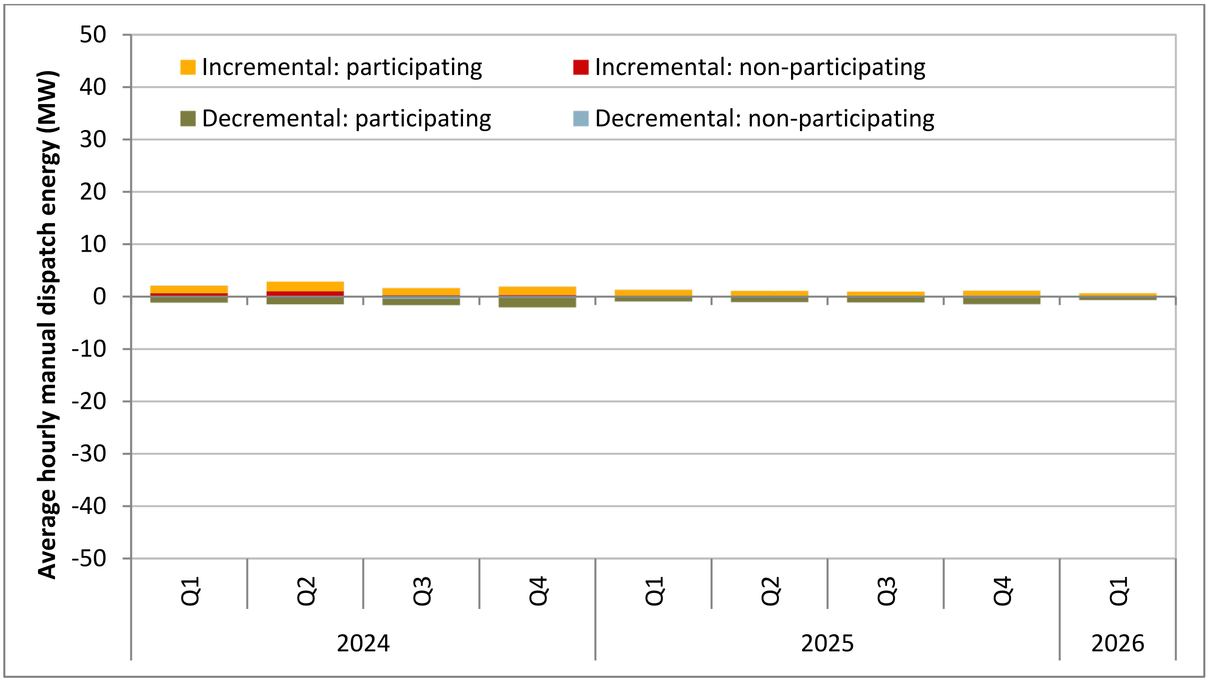
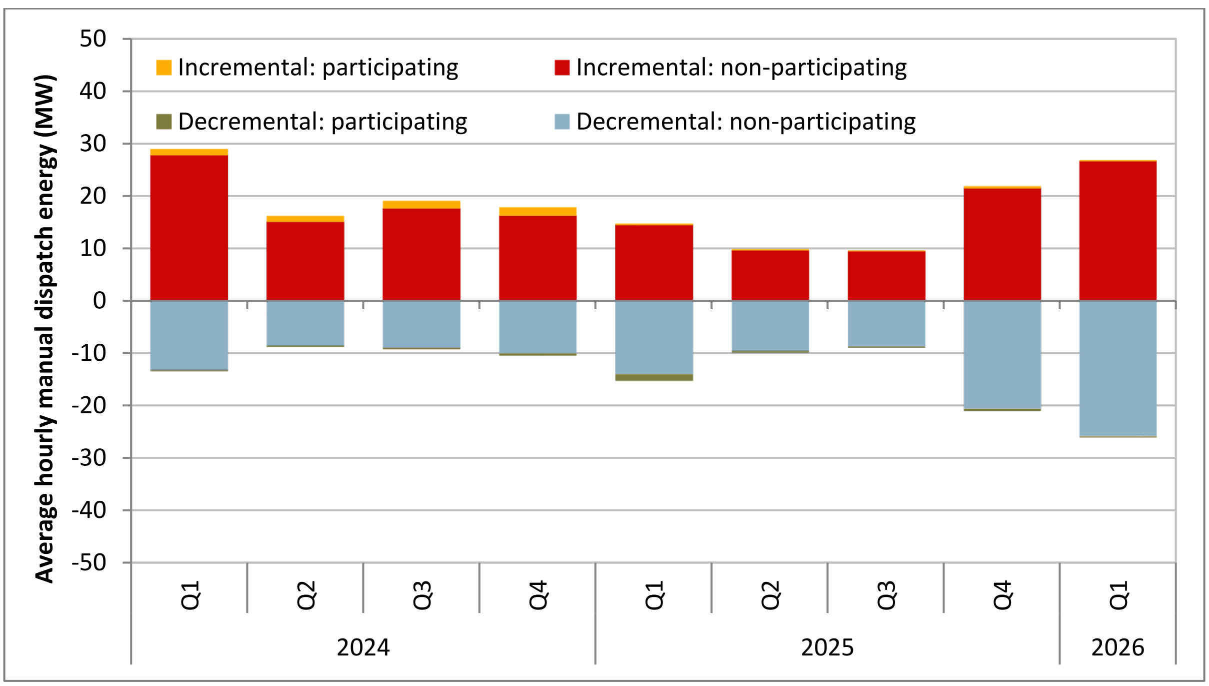


Figure 12.4 WEIM manual dispatches – Pacific Northwest



12.2 California ISO balancing area 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.

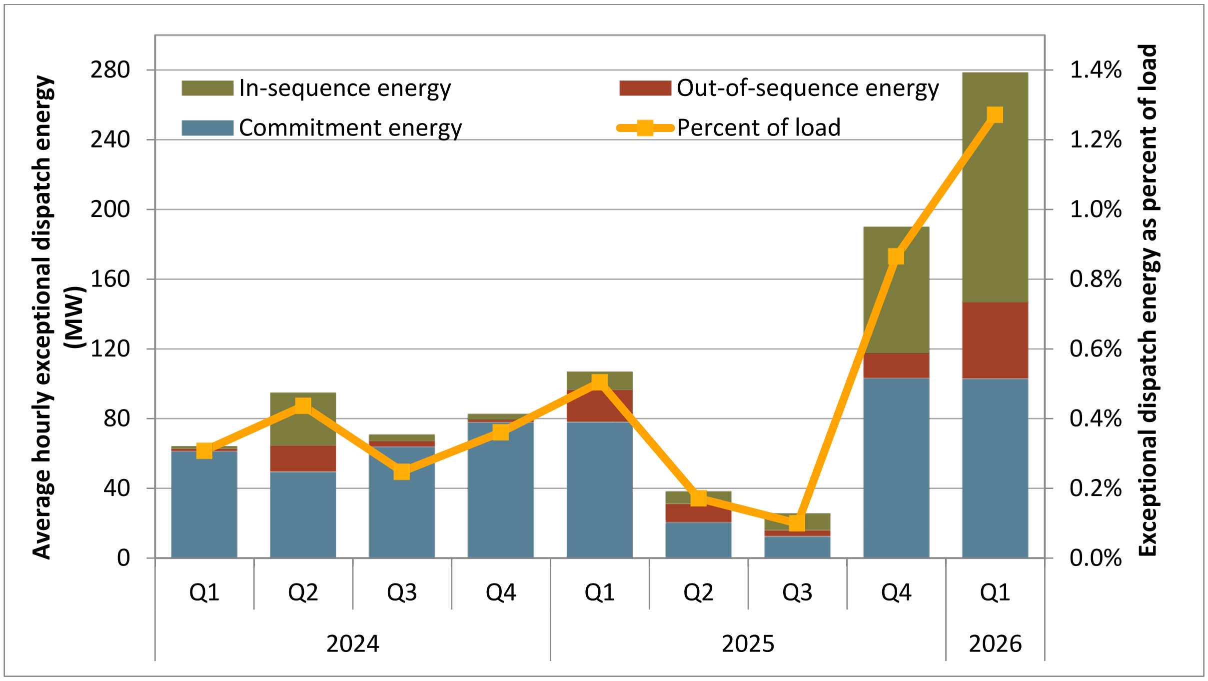
Energy from exceptional dispatch

Energy from exceptional dispatches reached the highest level in three years, accounting for about 1.3 percent of total load in the California ISO balancing area, represented by the yellow line in Figure 12.5. As shown in Figure 12.5, the average hourly total energy from exceptional dispatches—including minimum load energy from unit commitments—was 280 MW in the first quarter of 2026, which more than doubled, marking a 160 percent increase from the first quarter of 2025.[104]

In the first quarter of 2026, exceptional dispatches for unit commitments (blue) accounted for about 37 percent of all exceptional dispatch energy; about 16 percent was from out-of-sequence energy (red), and the remaining 47 percent was from in-sequence energy (green), as shown in Figure 12.5.

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

Figure 12.5 Average hourly energy from exceptional dispatch

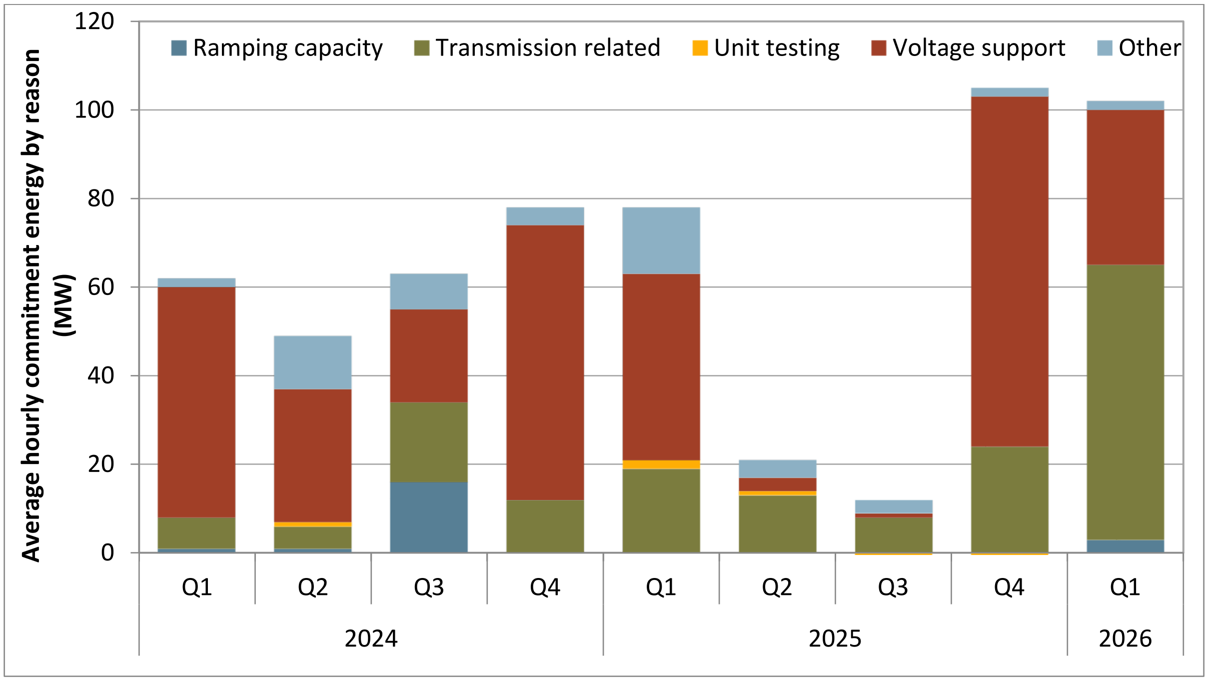


Exceptional dispatches for unit commitment

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 12.6 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 2026 was 102 MW, above the 78 MW average minimum load energy from unit commitment in the first quarter of 2025. These were largely due to exceptional dispatches to mitigate transmission outages in Northern California.

Figure 12.6 Average minimum load energy from exceptional dispatch unit commitments

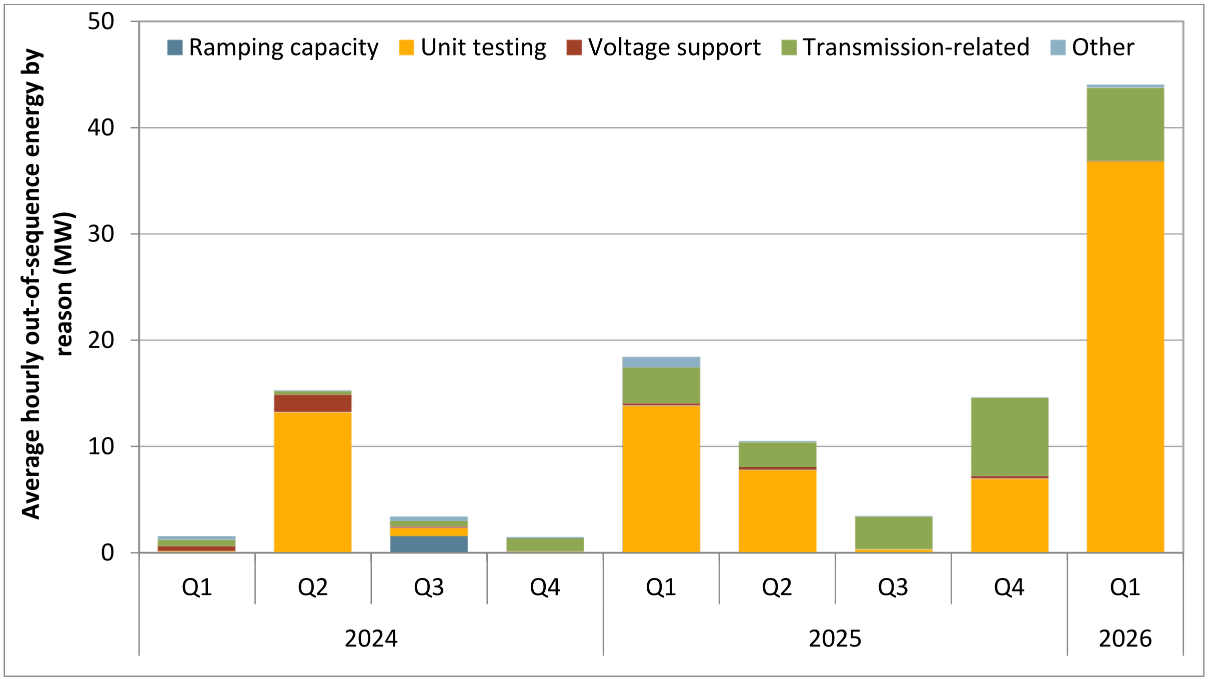


Exceptional dispatches for energy

Figure 12.7 shows the average hourly out-of-sequence exceptional dispatch energy by reason for each quarter from Q1 2024 through Q1 2026. The two primary reasons logged for out-of-sequence energy in the first quarter of 2026 were transmission-related (green bars) and unit testing (yellow bars). 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. Out-of-sequence energy due to transmission-related exceptional dispatches (green bars) slightly decreased in the first quarter of 2026 compared to the fourth quarter of 2025 while nearly doubling from the same period in 2025.

Average hourly out-of-sequence energy due to unit testing (yellow bars) increased in the first quarter of 2026 compared to the same quarter in 2025. This increase is largely due to exceptional dispatches related to unit testing in March associated with wind resources.

Figure 12.7 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

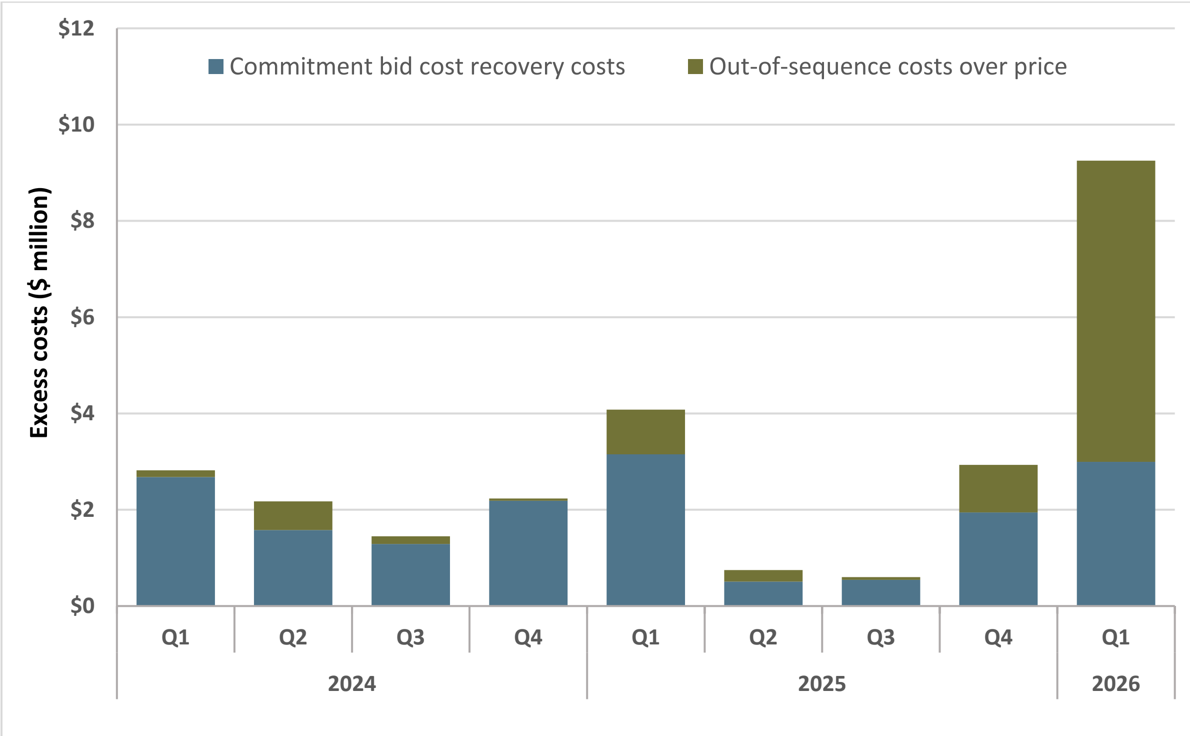
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

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 between their market bid price and their locational marginal energy price.

Figure 12.8 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 2026, out-of-sequence energy costs were $6.3 million, an increase from $925,000 in the first quarter of 2025. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the first quarter were $3 million, a 5 percent decrease from the first quarter of 2025. Overall, the additional costs associated with exceptional dispatches in the first quarter of 2026 increased by 127 percent compared to the first quarter of 2025. This increase was related to the testing of wind resources.

Figure 12.8 Excess exceptional dispatch cost by type



13 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. Financial entities and marketers continued to receive the vast majority of profits from convergence bidding. Net revenues for convergence bidders were about $9.5 million for the first quarter, after inclusion of about $6.9 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[105]

13.1 Convergence bidding revenues

Figure 13.1 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 (black line).

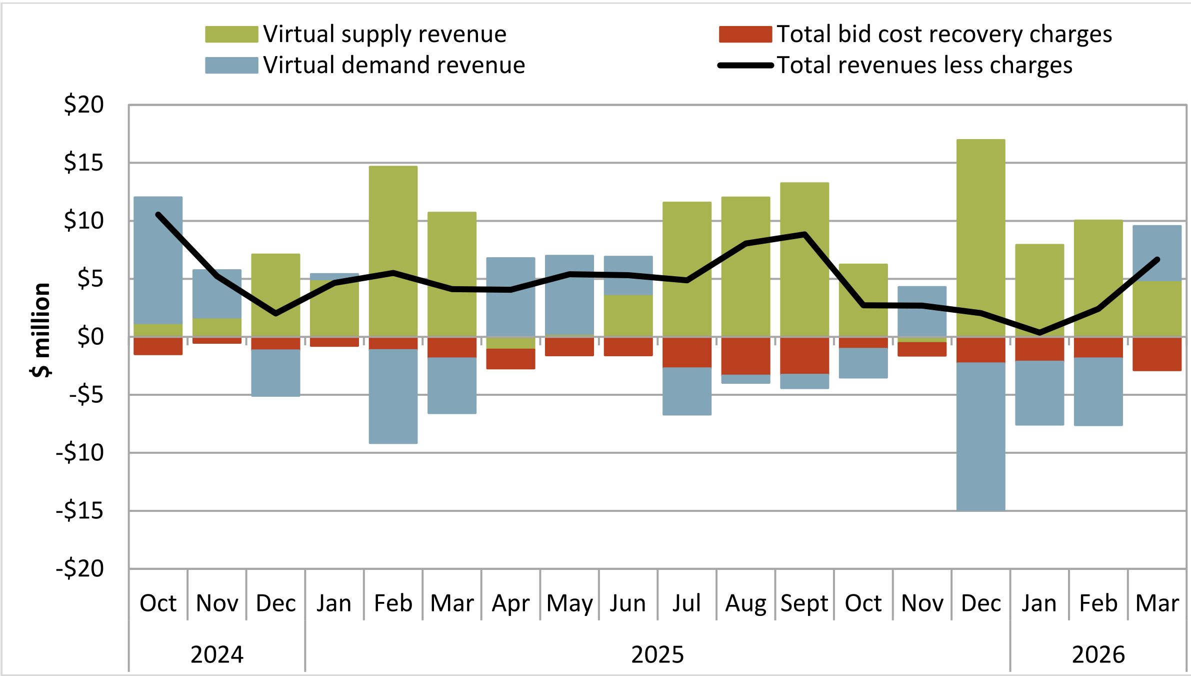
Before accounting for bid cost recovery, virtual supply revenues were about $7.9 million, $10.0 million, and $4.9 million for January, February, and March, respectively. Virtual demand revenues were about -$5.4 million, -$5.7 million, and $4.7 million for January, February, and March, respectively.

Bid cost recovery charges allocated to virtual bids were about -$2.1 million, -$1.9 million, and -$2.9 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.

Net convergence bidding revenues were positive during all months of the quarter, totaling $9.5 million. In comparison, net market revenues were around $14.3 million in the first quarter of 2025.

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

Figure 13.1 Convergence bidding revenues and bid cost recovery charges



13.2 Net revenues and volumes by participant type

Figure 13.2 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.[106,107]

After accounting for bid cost recovery, financial entities received about 88 percent of the total revenue earned from convergence bidding. Financial entities and marketers accounted for about 77 percent and 15 percent, respectively, of the cleared volume of virtual trades in the first quarter.

106 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

107 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, as well as participants whose portfolios are not primarily focused on physical or financial participation in the California ISO market.

Figure 13.2 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	
2026 Q1								
Financial	2,812	3,900	6,712	-$4.47	$17.72	-$4.94	$12.78	$8.31
Marketer	554	676	1,230	-$1.25	$2.78	-$0.59	$2.19	$0.94
Physical load	15	77	93	-$0.10	$0.31	-$0.31	$0.01	-$0.09
Physical generation	291	567	859	-$0.69	$2.02	-$1.04	$0.98	$0.29
BAA	0	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**3,672**	**5,220**	**8,894**	**-$6.51**	**$22.83**	**-$6.88**	**$15.96**	**$9.45**

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	-$9.90	$24.78	-$2.28	$22.50	$12.60
Marketer	450	576	1,026	-$1.34	$3.42	-$0.36	$3.07	$1.73
Physical load	39	186	226	-$0.12	$0.57	-$0.38	$0.19	$0.07
Physical generation	171	438	609	-$0.92	$1.55	-$0.75	$0.80	-$0.13
BAA	0	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**4,357**	**5,426**	**9,783**	**-$12.28**	**$30.32**	**-$3.77**	**$26.56**	**$14.27**

14 Ancillary services and available balancing capacity

Between January and early March 2026, the CAISO balancing area initiated a pilot program[108] designed to increase regulation up requirements in order to reduce uncertainty and minimize the use of load conformance in the real-time markets.[109]

While ancillary service requirements increased from the first quarter of 2026 compared to 2025, ancillary service payments decreased. Average requirements for regulation up and operating reserves increased 250 MW (54 percent) and 200 MW (14 percent), respectively, and regulation down decreased 90 MW (9 percent). Ancillary service payments totaled $17.0 million, a 53 percent decrease from the same quarter of the previous year.

Available balancing capacity up and down was dispatched to address power balance infeasibilities in 1.0 percent of intervals for NV Energy in both the 15-minute and 5-minute markets. Available balancing capacity was dispatched in less than 0.1% of intervals for all other WEIM balancing areas.[110]

14.1 Ancillary service requirements

The California ISO procures four ancillary services for the CAISO balancing area in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves. 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.[111] 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.[112] 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

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108 *Market Performance and Planning Forum Q2*, California ISO, April 27, 2026: caiso.com/documents/presentation-market-performance-planning-forum-q2-apr-27-2026.pdf. *Market performance update*, Joint ISO Board of Governors and WEM Governing Body meeting - General Session, California ISO, March 4, 2026: https://www.caiso.com/documents/market-performance-update-mar-2026.pdf.

109 Also see Section 3.2.

110 Figures and data provided in this chapter are preliminary and may be subject to change.

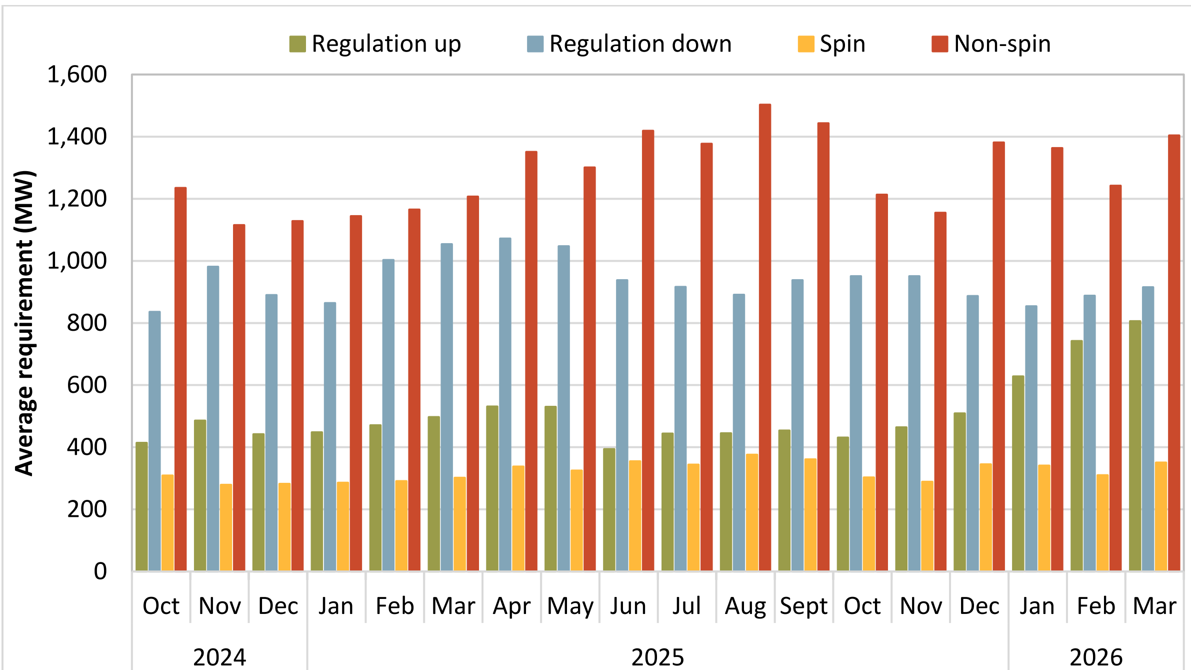
111 More information on ancillary services requirements and procurement for internal and expanded regions is available in *2020 Annual Report on Market Issues & Performance*, Department of Market Monitoring, August 2021, p 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

112 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.

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 14.1 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation up requirements increased about 250 MW (54 percent) compared to the first quarter of 2025, and regulation down requirements decreased about 90 MW (9 percent). Average operating reserve requirements increased about 200 MW (14 percent) compared to the first quarter of 2025.

Figure 14.1 Average monthly day-ahead ancillary service requirements



14.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. No scarcity events occurred in the first quarter of 2026.

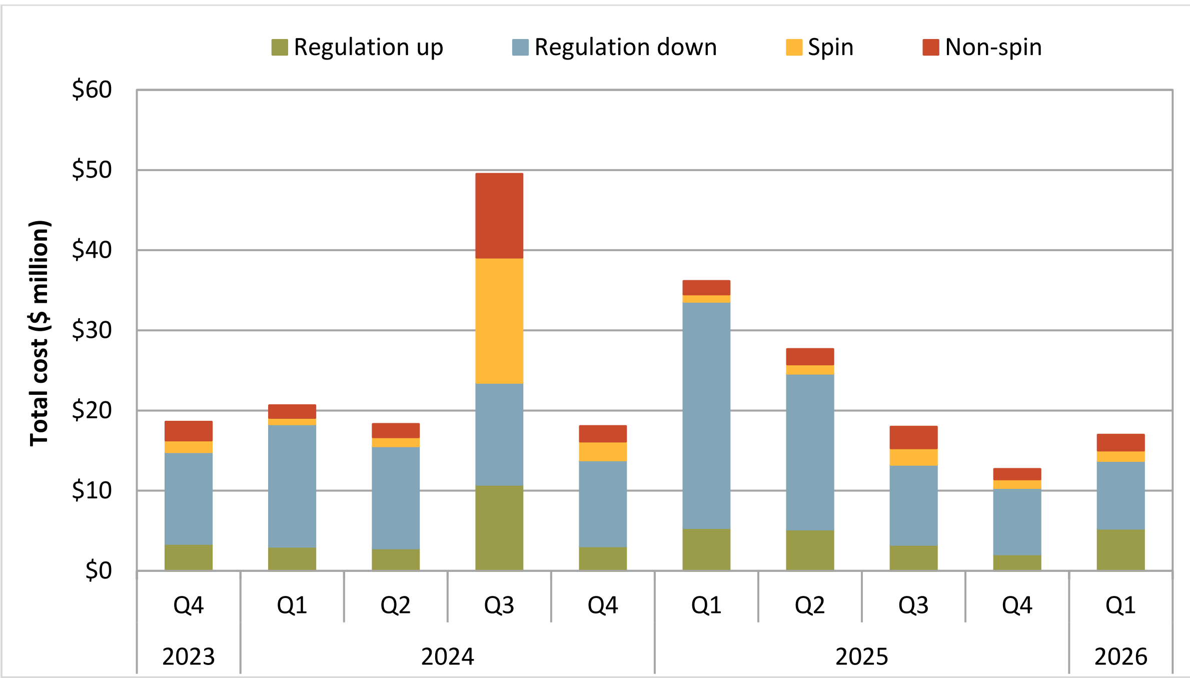
Under the ancillary service scarcity price mechanism, the California ISO balancing area pays a predetermined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

14.3 Ancillary service costs

Ancillary service payments totaled $17.0 million in the first quarter of 2026, around $19.2 million (or 53 percent) less than the same quarter of the previous year due in part to lower gas prices.[113]

Figure 14.2 shows the total cost of procuring ancillary service products by quarter.[114] Payments for regulation up and regulation down decreased by 2 and 70 percent, respectively, and increased for spinning and non-spinning reserve by 39 and 17 percent, respectively, compared to the first quarter of 2025.

Figure 14.2 Ancillary service cost by product



14.4 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 that 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.

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113 See Section 1.1.

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

Figure 14.3[115] summarizes the frequency of upward and downward available balancing capacity offered in each area in the first quarter. Available balancing capacity up and down was dispatched to address power balance infeasibilities in 1.0 percent of intervals for NV Energy in both the 15-minute and 5-minute markets. Available balancing capacity was dispatched in less than 0.1% of intervals for all other WEIM balancing areas.

Figure 14.3 Frequency of available balancing capacity offered (Q1 2026)

		ABC Up				ABC Down			
		Offered		Scheduled		Offered		Scheduled	
		Percent of hours	Average MW	Percent of intervals (15-min.)	Percent of intervals (5-min.)	Percent of hours	Average MW	Percent of intervals (15-min.)	Percent of intervals (5-min.)
California	BANC	100.0%	85	.0%	.0%	100.0%	111	.0%	.0%
	LADWP	34.0%	50	.0%	.0%	.0%	N/A	.0%	.0%
	Turlock Irrigation District	100.0%	14	.0%	.0%	100.0%	5	.0%	.0%
Desert Southwest	Arizona Public Service	100.0%	83	.0%	.0%	100.0%	82	.0%	.0%
	El Paso Electric	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	NV Energy	99.0%	70	1.0%	1.0%	85.0%	66	1.0%	1.0%
	PSC New Mexico	.0%	50	.0%	.0%	31.0%	48	.0%	.0%
	Salt River Project	100.0%	99	.0%	.0%	88.0%	49	.0%	.0%
	Tucson Electric	100.0%	29	.0%	.0%	100.0%	30	.0%	.0%
	WAPA - Desert Southwest	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
Intermountain West	Avista Utilities	100.0%	10	.0%	.0%	100.0%	10	.0%	.0%
	Idaho Power	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	NorthWestern Energy	100.0%	5	.0%	.0%	100.0%	5	.0%	.0%
	PacifiCorp East	98.0%	82	.0%	.0%	100.0%	177	.0%	.0%
Pacific Northwest	Avangrid	100.0%	42	.0%	.0%	.0%	N/A	.0%	.0%
	Powerex	100.0%	1,068	.0%	.0%	100.0%	600	.0%	.0%
	Bonneville Power Admin.	100.0%	325	.0%	.0%	100.0%	332	.0%	.0%
	PacifiCorp West	51.0%	21	.0%	.0%	98.0%	63	.0%	.0%
	Portland General Electric	99.0%	30	.0%	.0%	.0%	N/A	.0%	.0%
	Puget Sound Energy	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	Seattle City Light	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	Tacoma Power	63.0%	3	.0%	.0%	91.0%	4	.0%	.0%

115 Previous versions of this table published in the Department of Market Monitoring 2024 Q4 Report and the 2025 Q1 Report on Market Issues and Performance contained incorrect values in ABC Down Offered categories: https://www.caiso.com/documents/2024-fourth-quarter-report-on-market-issues-and-performance-mar-26-2025.pdf

https://www.caiso.com/documents/2025-first-quarter-report-on-market-issues-and-performance-jun-23-2025.pdf

15 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the first quarter of 2026 was about 40 percent higher than the same quarter of 2025. This increase occurred despite operator adjustments to the RUC procurement target decreasing by about 37 percent for the same period. CAISO balancing area methods for determining operator adjustments are discussed in detail in Chapter 11 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.

15.1 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 15.1 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 15.1 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 raising the residual unit commitment requirements by about 80 MW per hour in the first quarter of 2026.

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 15.1. Eligible intermittent resource adjustments dropped by an average of 1,100 MW, marking a 40 percent decrease from Q1 2025.

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 15.1 show the average adjustment to the residual unit commitment requirement. On average, operator adjustments were about 50 MW per hour in Q1 2026, which is a 37 percent decrease from Q1 2025.

Figure 15.2 shows the hourly distribution of these operator adjustments during the first quarter of 2026. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour.

Figure 15.1 Average incremental residual unit commitment requirement by component

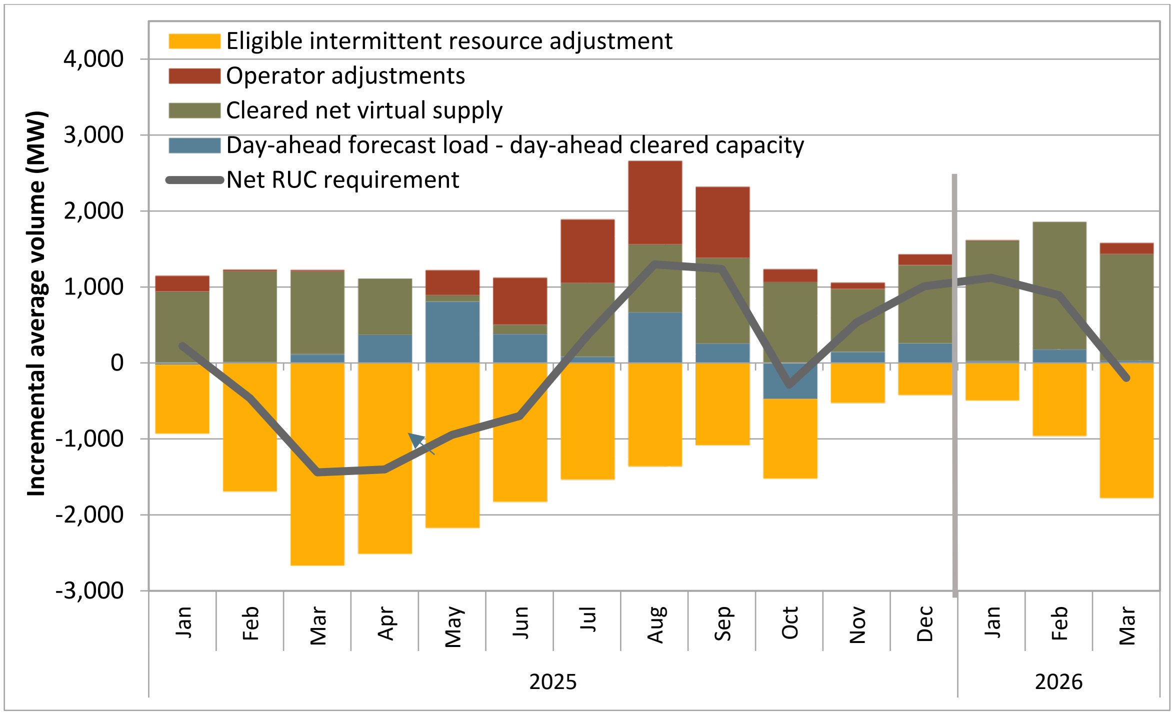
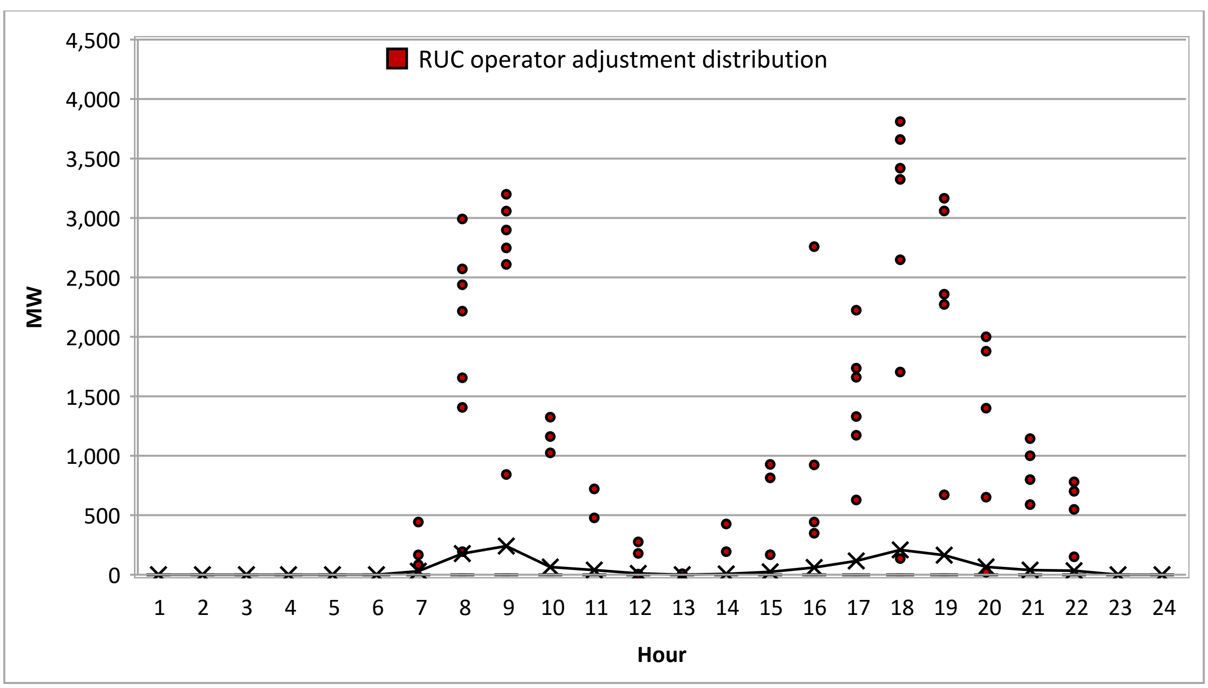


Figure 15.2 Hourly distribution of residual unit commitment operator adjustments (January–March 2026)

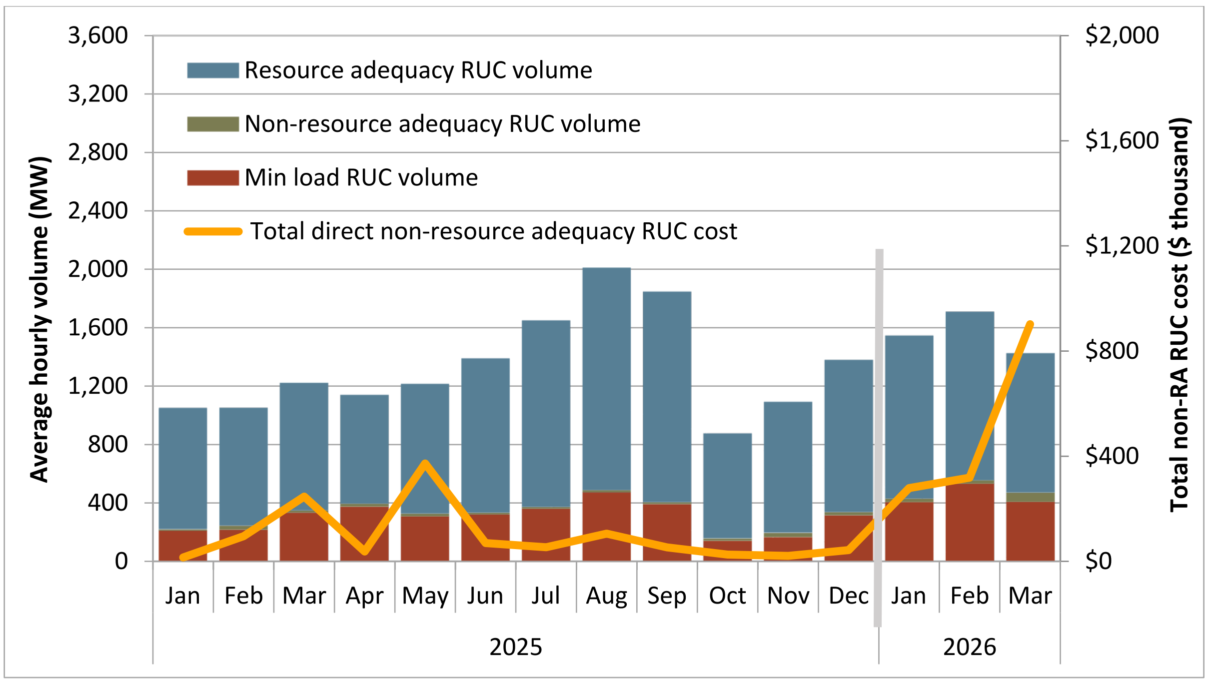


15.2 Residual unit commitment procurement and costs

Figure 15.3 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 2026 increased by 40 percent to about 1,550 MW, from an average of about 1,100 MW in the same quarter of 2025. Of the 1,550 MW capacity, the capacity committed to operate at minimum load averaged about 450 MW.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments, as only non-resource adequacy units receiving awards in this process receive RUC capacity payments.[116] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 15.3. In the first quarter of 2026, these costs were about $1.5 million.

Figure 15.3 Residual unit commitment costs and volume



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

16 Congestion revenue rights

Congestion revenue right auction returns

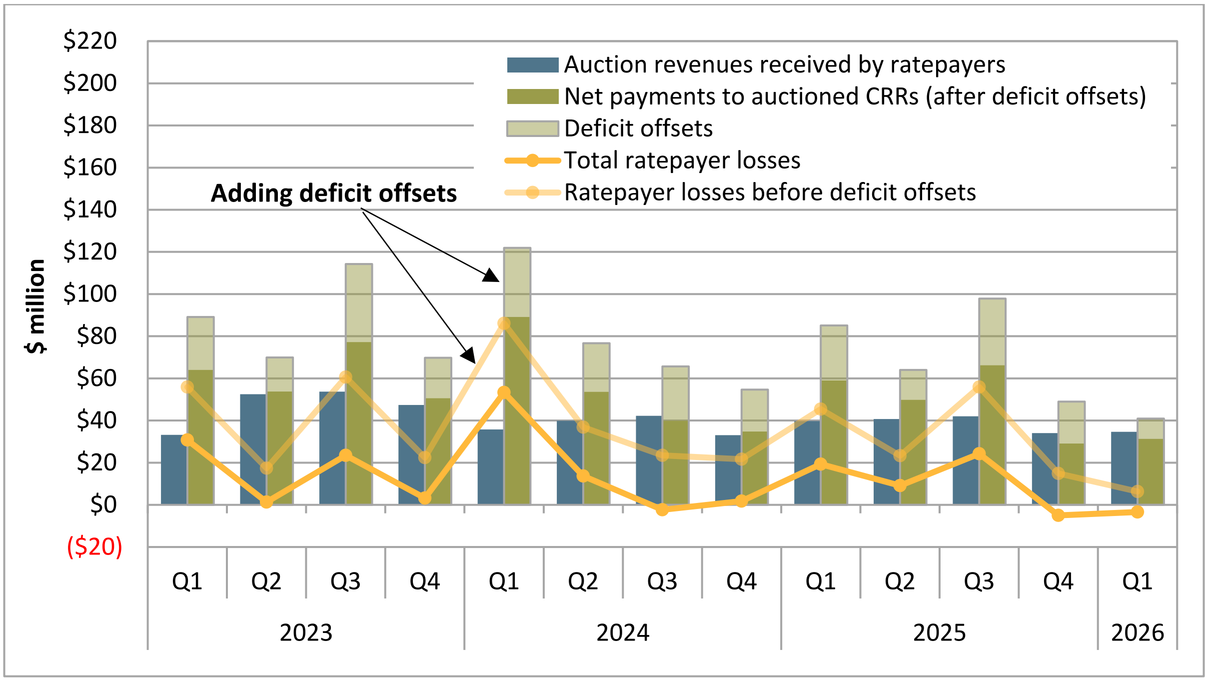
Profits from the congestion revenue rights (CRR) auction by non-load serving entities are calculated by summing revenue paid out to congestion revenue rights purchased by these entities, and then subtracting the auction price paid for these rights. While this represents a profit to entities purchasing rights in the auction, it represents a loss to transmission ratepayers. Figure 16.1 compares the following for each of the last several quarters:

- Auction revenues received by ratepayers from congestion revenue rights sold in the auction (blue bars).[117]
- Net payments, based on day-ahead market congestion rents, made to the non-load serving entities purchasing congestion revenue rights in the auction (green bars).
- Deficiency offsets are the reduction in payments to CRR holders as implemented under Track 1B reforms (transparent portion of green bars and yellow line). Deficiency offsets occur when day-ahead market congestion rents are not sufficient to cover "nominal payments" to auctioned CRRs. Nominal payments are those that would be made to CRRs based only on the quantity of CRRs over a path and the difference between source and sink congestion prices.
- Total ratepayer losses are the difference between auction revenues received by load serving entities and payments made to non-load serving entities (yellow line).

Transmission ratepayers made $3.4 million during the first quarter of 2026, as payments to auctioned congestion revenue rights holders were lower than auction revenues. This was the first time since 2012 that ratepayers earned a profit from CRRs in two consecutive quarters. Auction revenue remained relatively stable, while net payments to auction CRR holders declined sharply. Average net payments in the first quarter of 2024 and 2025 were about $71 million, compared with $31 million this quarter, a decline of 56 percent. By contrast, average auction revenue in the first quarter of 2024 and 2025 was about $38 million, similar to $35 million this quarter. This aligns with the decline in day-ahead congestion rent shown in Chapter 6 and Figure 6.11.

117 The auction revenues received by ratepayers are the auction revenues from congestion revenue rights paying into the auction less the revenues paid to "counter-flow" rights. Similarly, day-ahead payments made by ratepayers are net of payments by "counter-flow" rights.

Figure 16.1 Auction revenues and payments to non-load serving entities



During the first quarter of 2026:

- Financial entities earned a $1.2 million profit from auction rights, compared to a $3.1 million loss in Q4 2025 and the larger $16 million profit in Q1 2025. Total revenue deficit offsets were about $8.8 million in this quarter.[118]
- Marketers lost $4.6 million from auctioned rights, a reversal from a $3 million profit in the same quarter of 2025. Total revenue deficit offsets were over $0.9 million.
- Physical generation entities earned only $3,000 from auctioned rights, a decline from a $0.1 million in profit in Q1 2025. Total revenue deficit offsets were $6,000.

The $3.4 million auction profit in the first quarter of 2026 was about 4 percent of day-ahead congestion rent. This was a reversal from Q1 2025, when ratepayers experienced net loss equal to 14 percent of total congestion rent. The average ratepayer losses were 28 percent of day-ahead congestion rent during the three years before the track 1A and 1B changes (2016 through 2018).[119,120]

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[118] 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.

[119] *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

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

The impact of track 1A changes, which limit the types of congestion revenue rights that can be sold in the auction, cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under track 1B reduced total payments to non-load serving entities by about $9.7 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 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.[121]

[121] *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

17 Transmission service and market scheduling priorities

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.[122]

No monthly reservations were made for CAISO balancing area high priority wheel-through rights for the first quarter of 2026. Incremental daily reservations of 1 MW were made for two days in the first quarter, with the import portion of the wheel-through at the Palo Verde intertie. To use this reserved capacity, entities may self-schedule up to the reserved amount in the day-ahead market. The reserved wheel-through rights were used at the full 1 MW limit in four hours on March 5.

[122] 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

18 Resource adequacy

18.1 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.

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. As a result, in this metric assessing resource adequacy availability, DMM counts the quantity of real-time bids from non-resource adequacy capacity that displaces resource adequacy that had bid into the day-ahead market but did not have a real-time must offer obligation.

Real-time resource adequacy bids, including bids from variable energy resources (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.

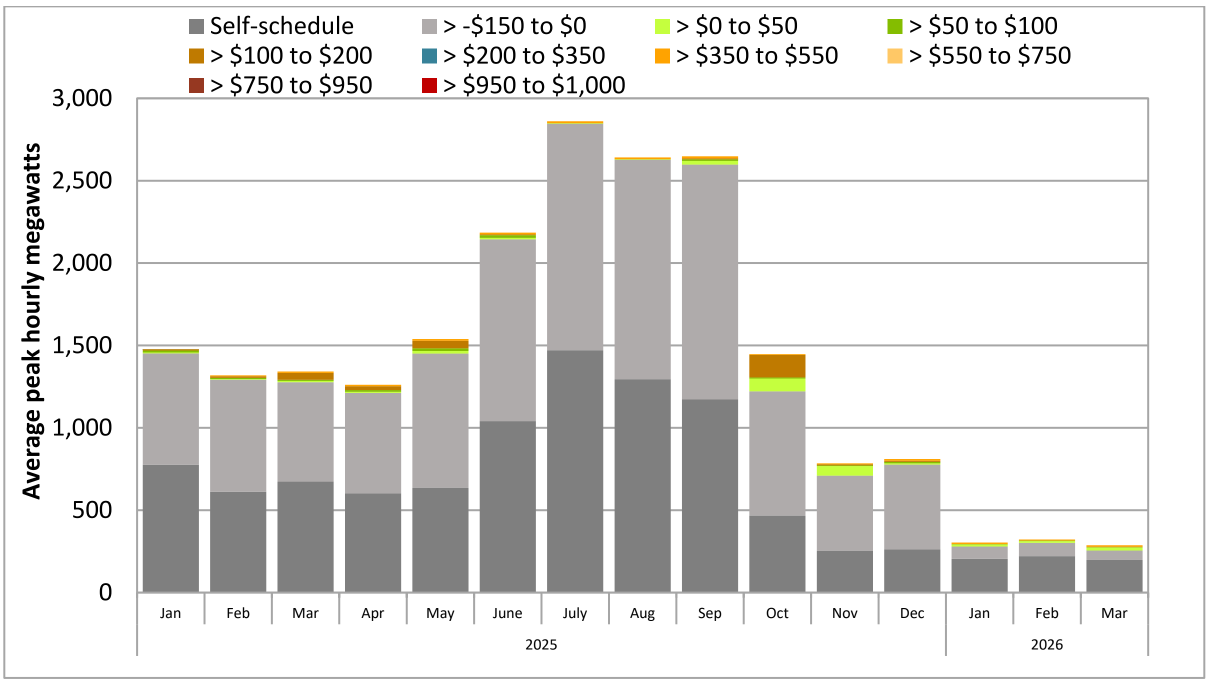
18.2 Resource adequacy import bids

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.[123] These rules became effective at the beginning of 2021.

Figure 18.1 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[124] 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 decreased in January, February, and March by 79 percent, 76 percent, and 79 percent, respectively, compared to the same months of 2025. Overall, resource adequacy import bids in Q1 2026 decreased 78 percent from Q1 2025.

Figure 18.1 Average hourly resource adequacy imports by price bin



123 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.

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

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.[125] These figures are included for both the 15-minute and 5-minute markets.

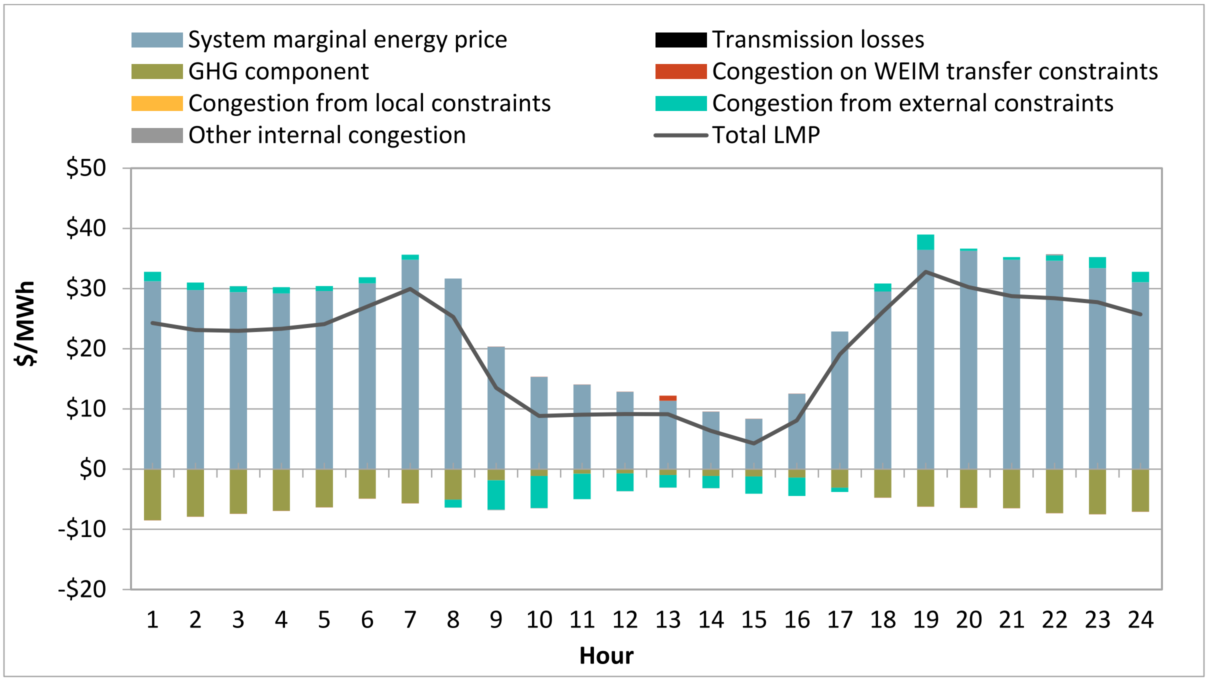
The hourly locational marginal price decomposition figures break down the price into seven separate components. These components, listed below, can influence the prices in an area positively or negatively, depending on the circumstances.

- **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 from local constraints** is the price impact from transmission constraints within its own balancing area that are restricting the flow of energy. While these constraints are located locally, they can create price impacts across the WEIM and show up as external constraints in the figures below to other balancing areas.
- **Congestion from external constraints** is the price impact from transmission constraints in an outside WEIM balancing 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 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).

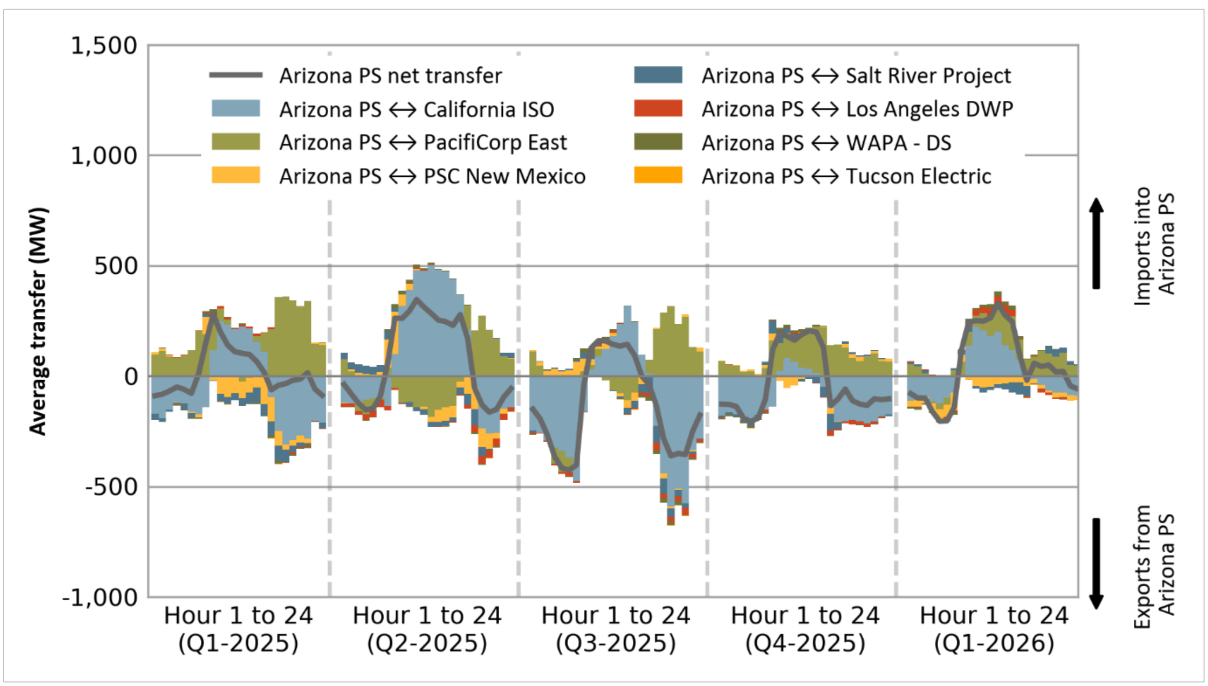
[125] These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

A.1 Arizona Public Service

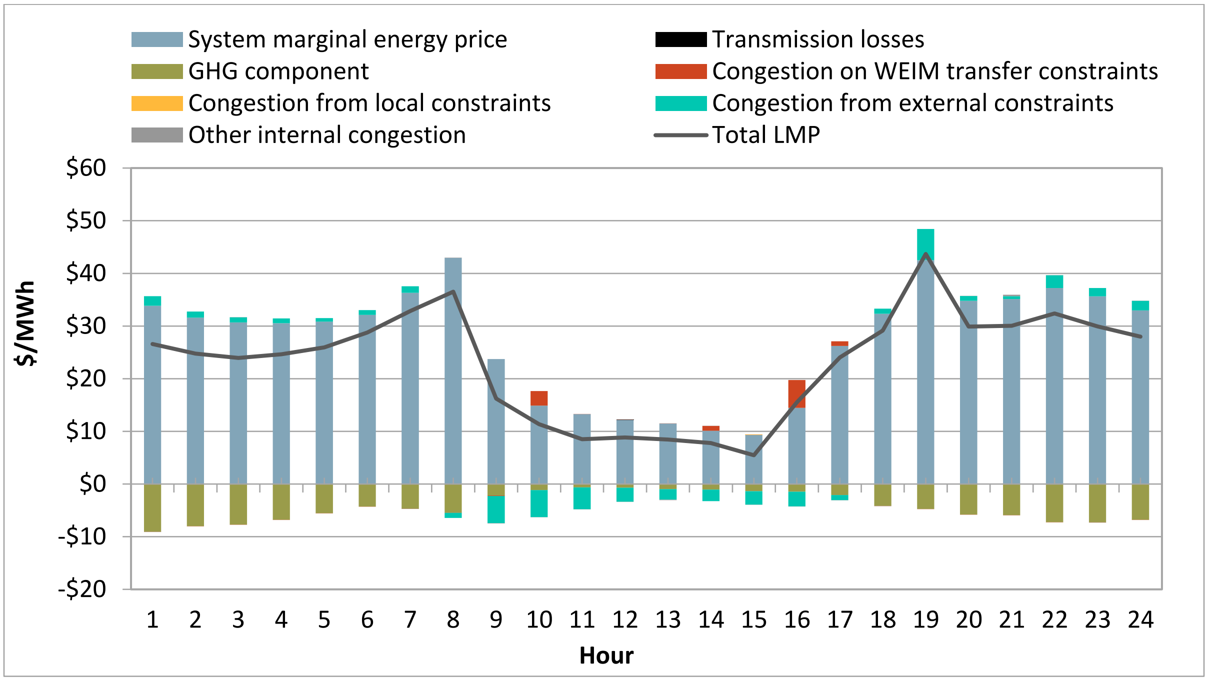
Appendix Figure A.1 Average hourly 15-minute price by component (Q1 2026)



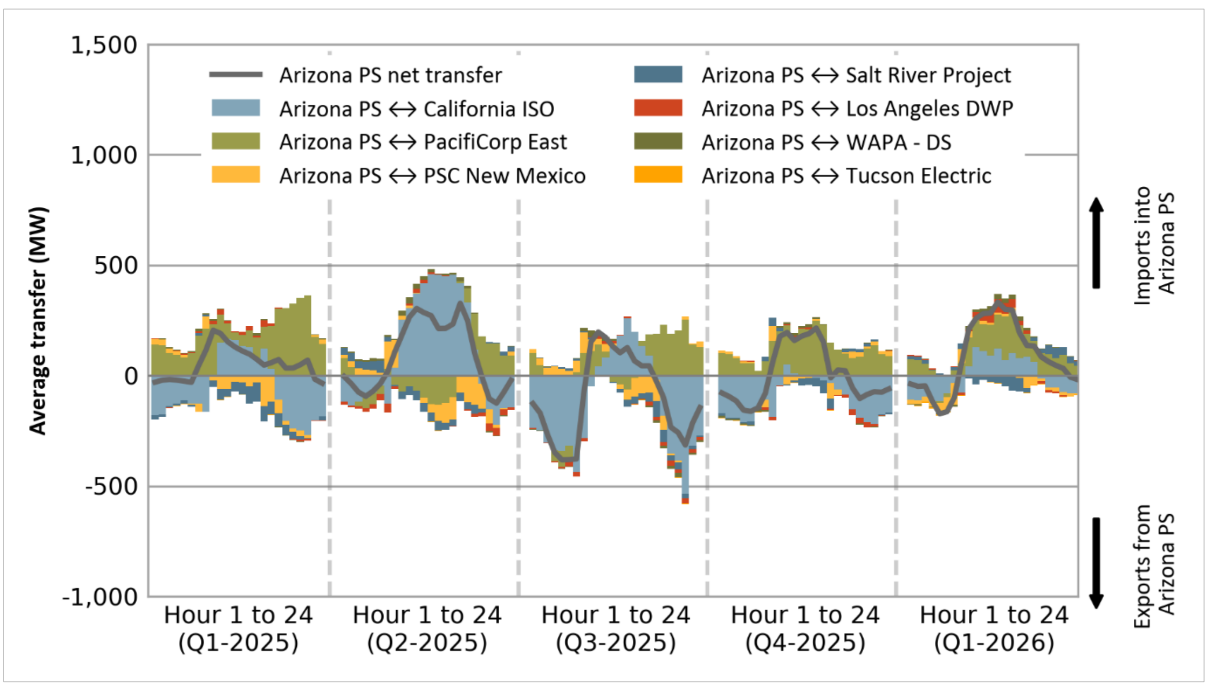
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q1 2026)

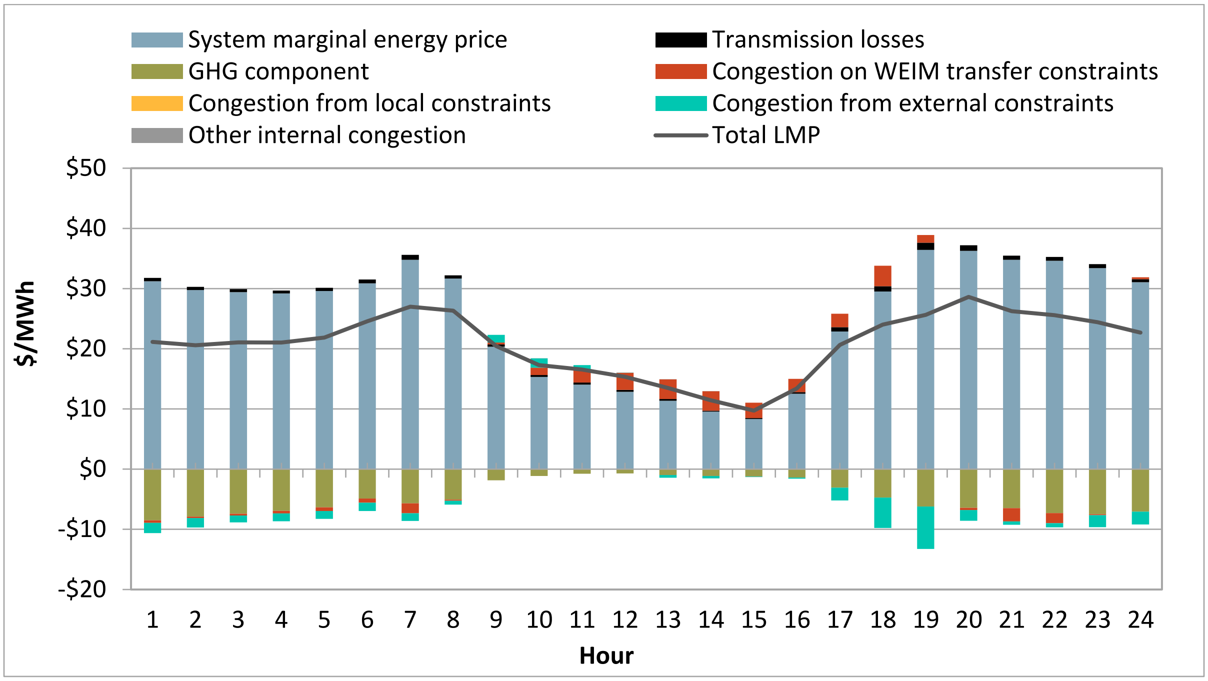


Appendix Figure A.4 Average hourly 5-minute market transfers

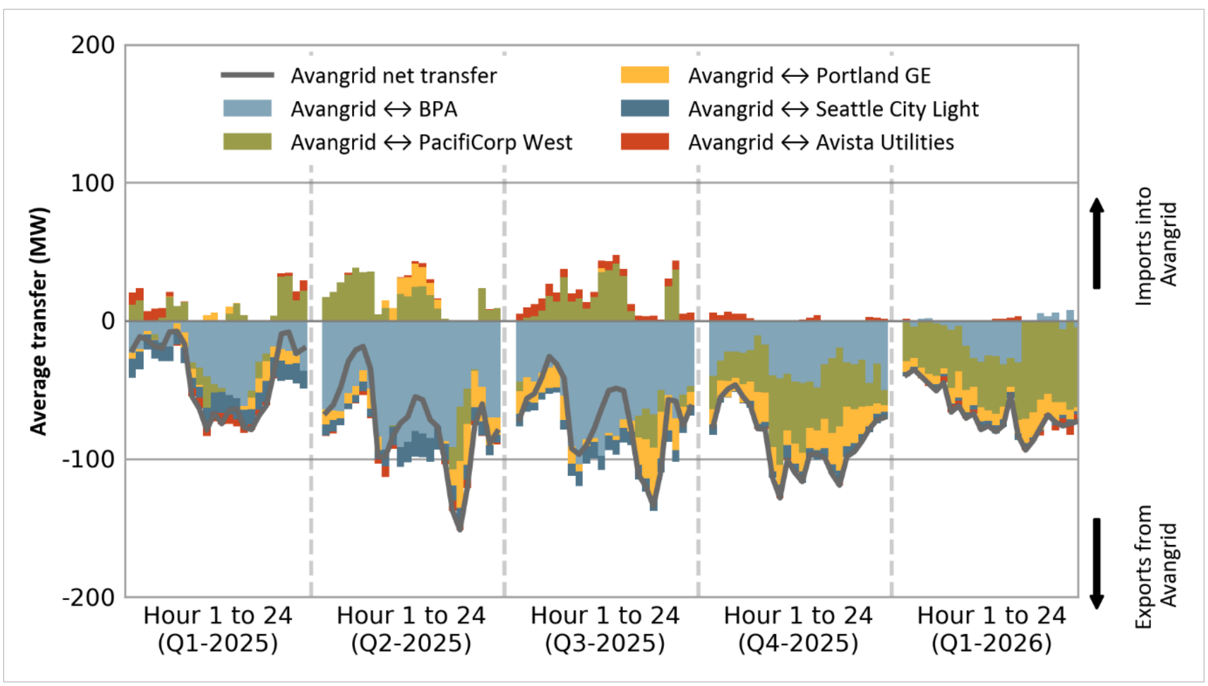


A.2 Avangrid

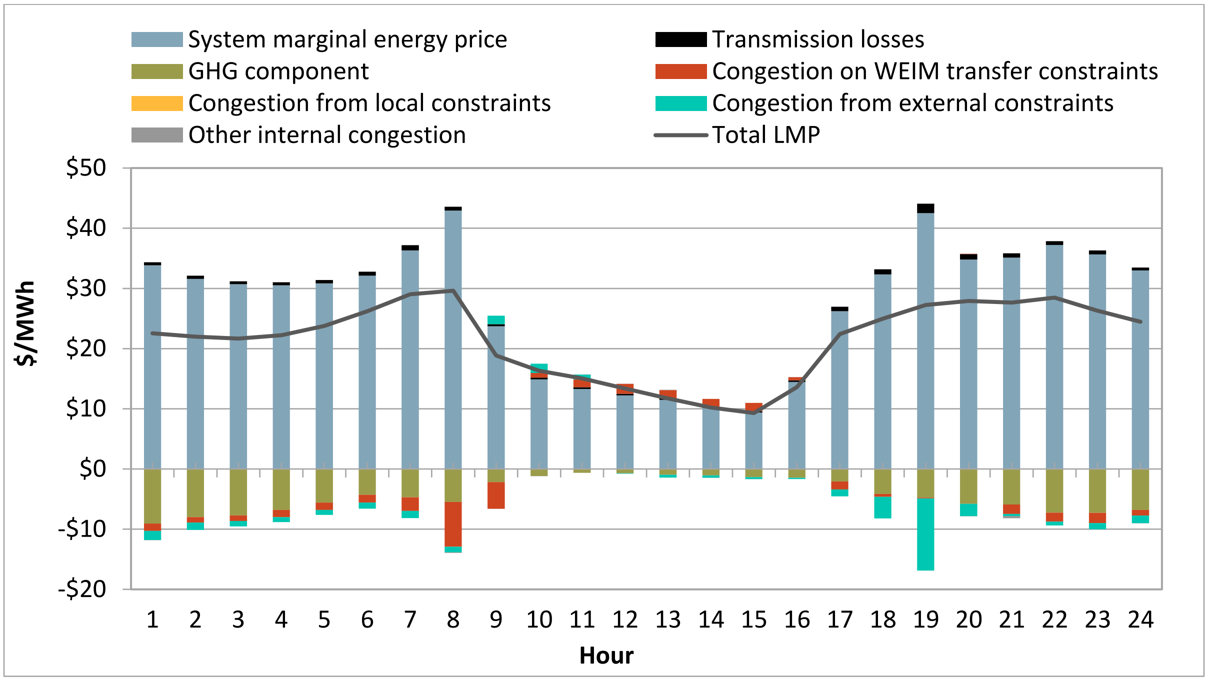
Appendix Figure A.5 Average hourly 15-minute price by component (Q1 2026)



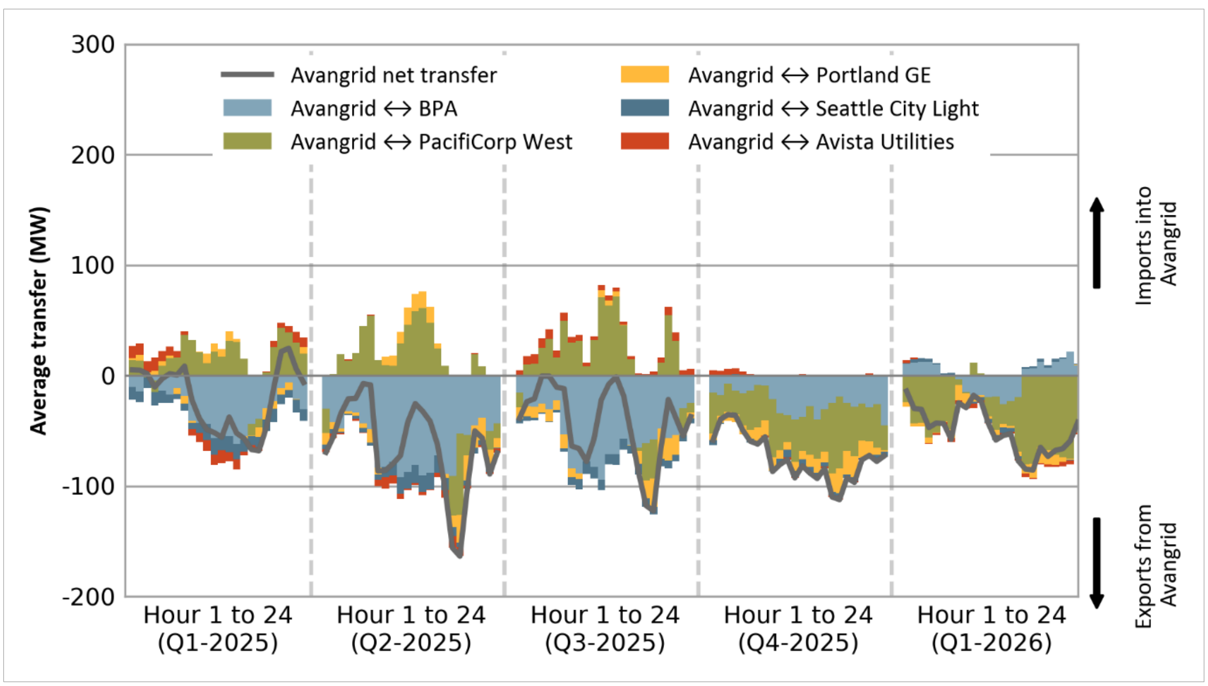
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q1 2026)

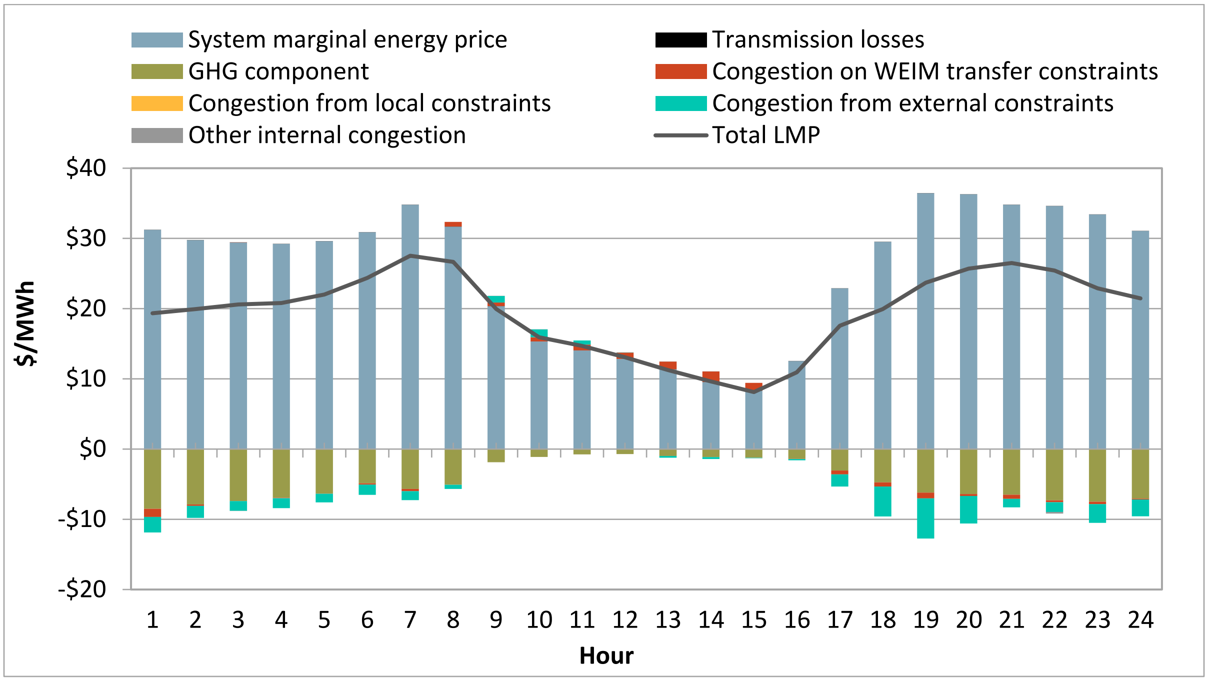


Appendix Figure A.8 Average hourly 5-minute market transfers

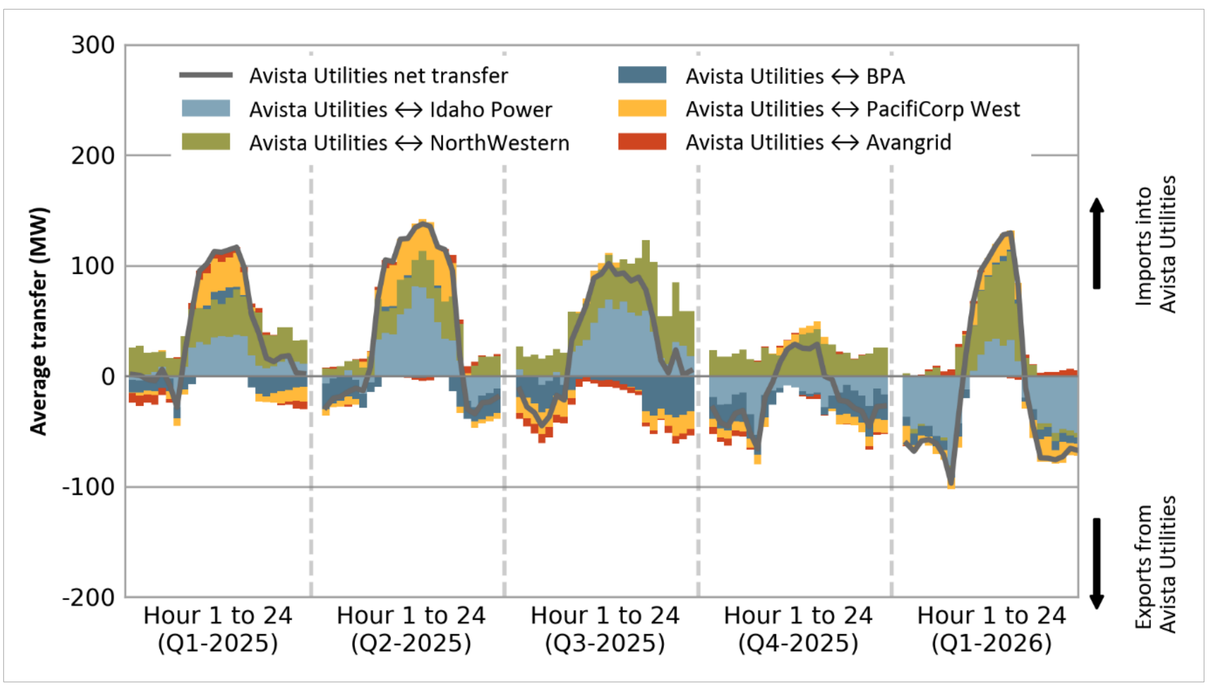


A.3 Avista Utilities

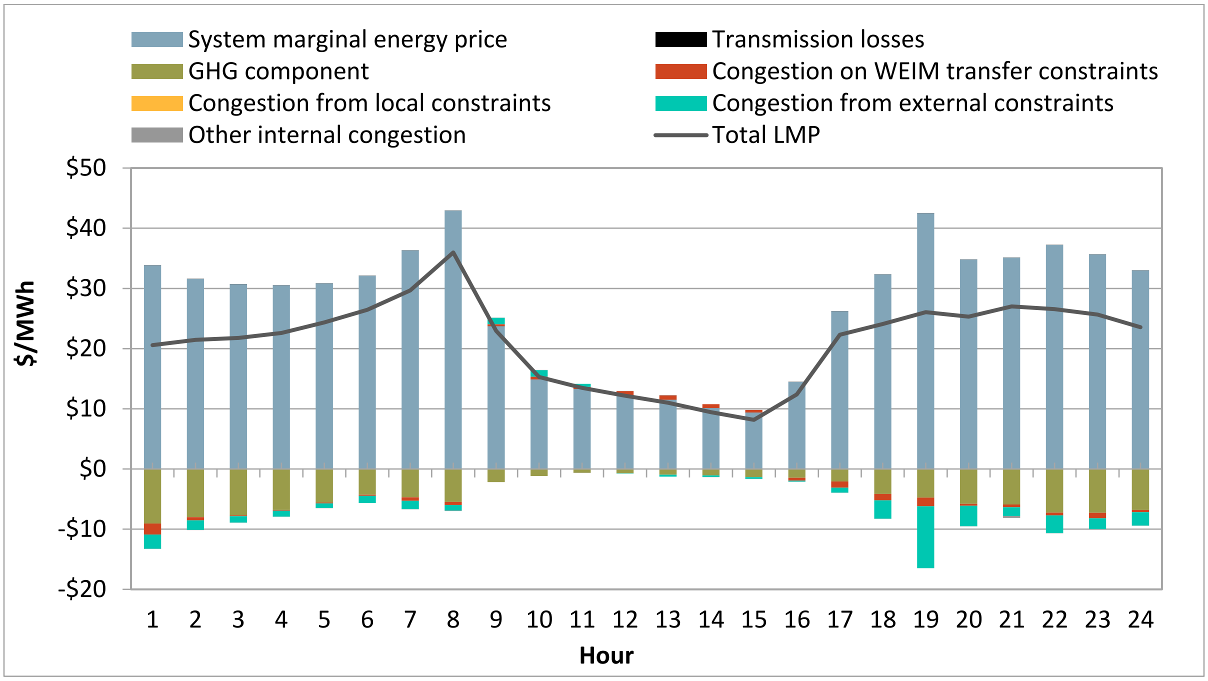
Appendix Figure A.9 Average hourly 15-minute price by component (Q1 2026)



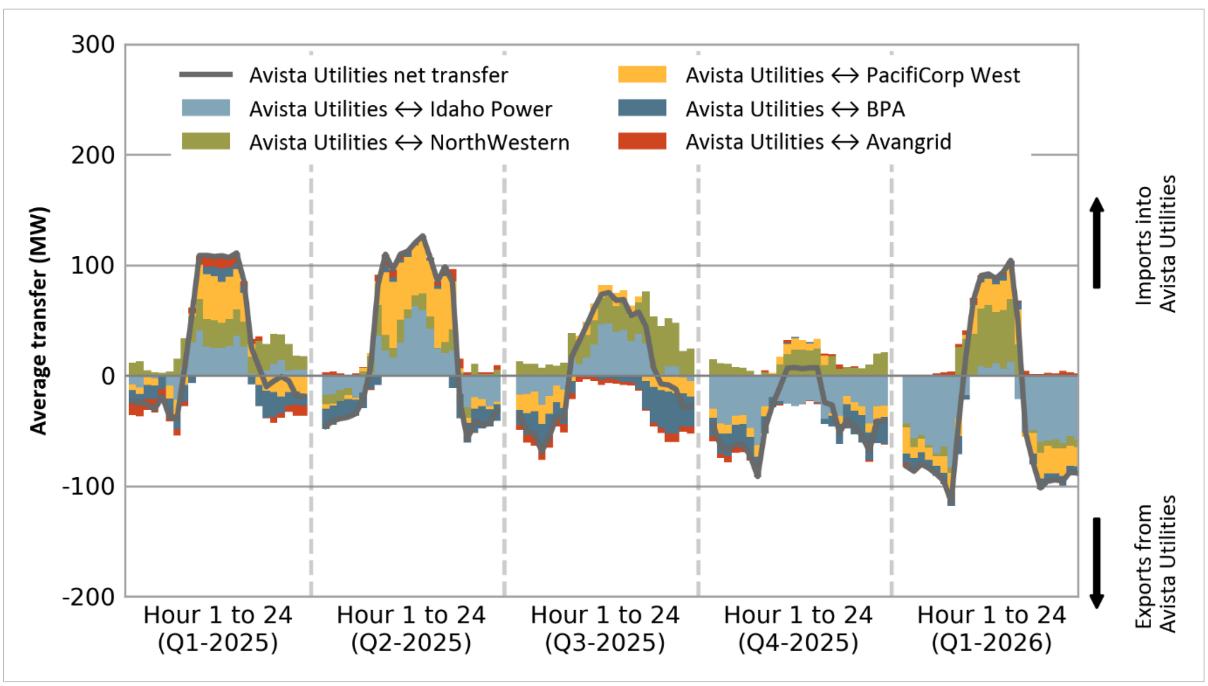
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q1 2026)

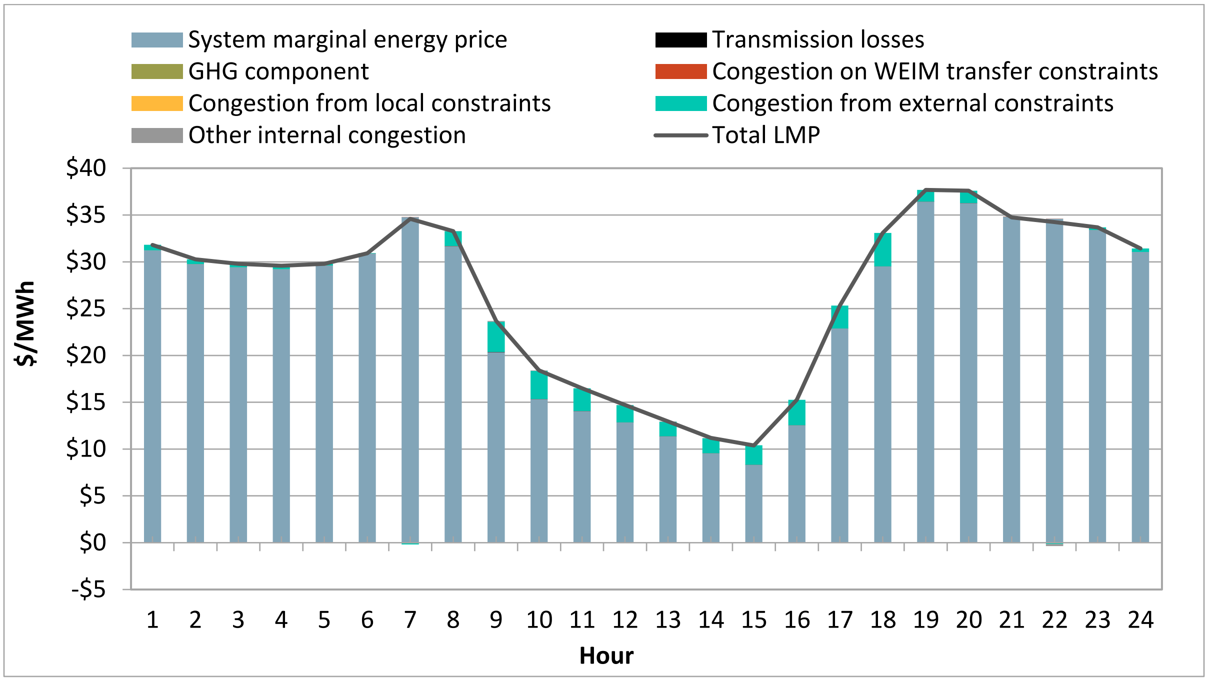


Appendix Figure A.12 Average hourly 5-minute market transfers

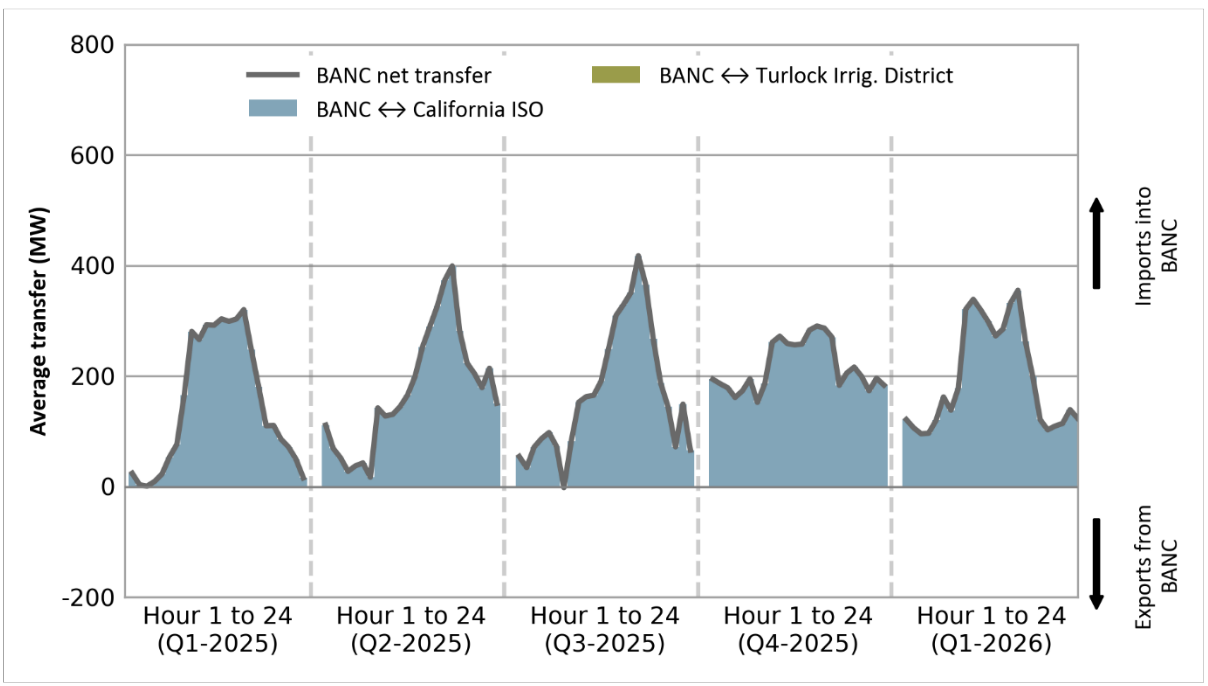


A.4 Balancing Authority of Northern California

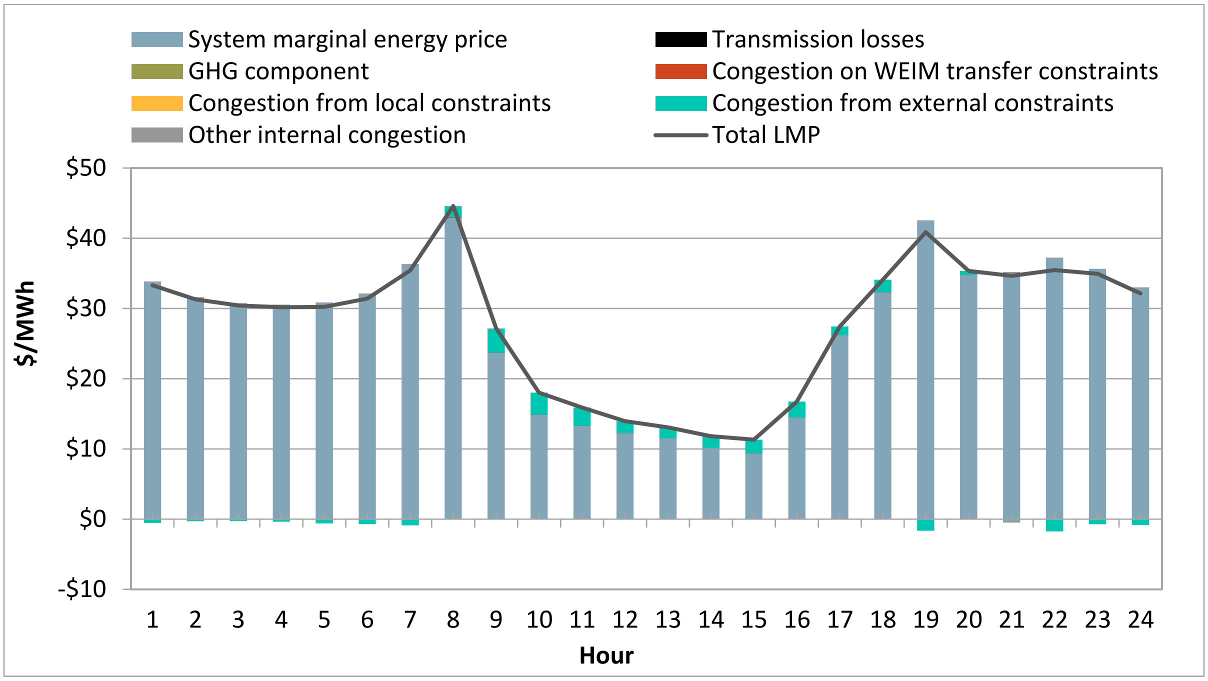
Appendix Figure A.13 Average hourly 15-minute price by component (Q1 2026)



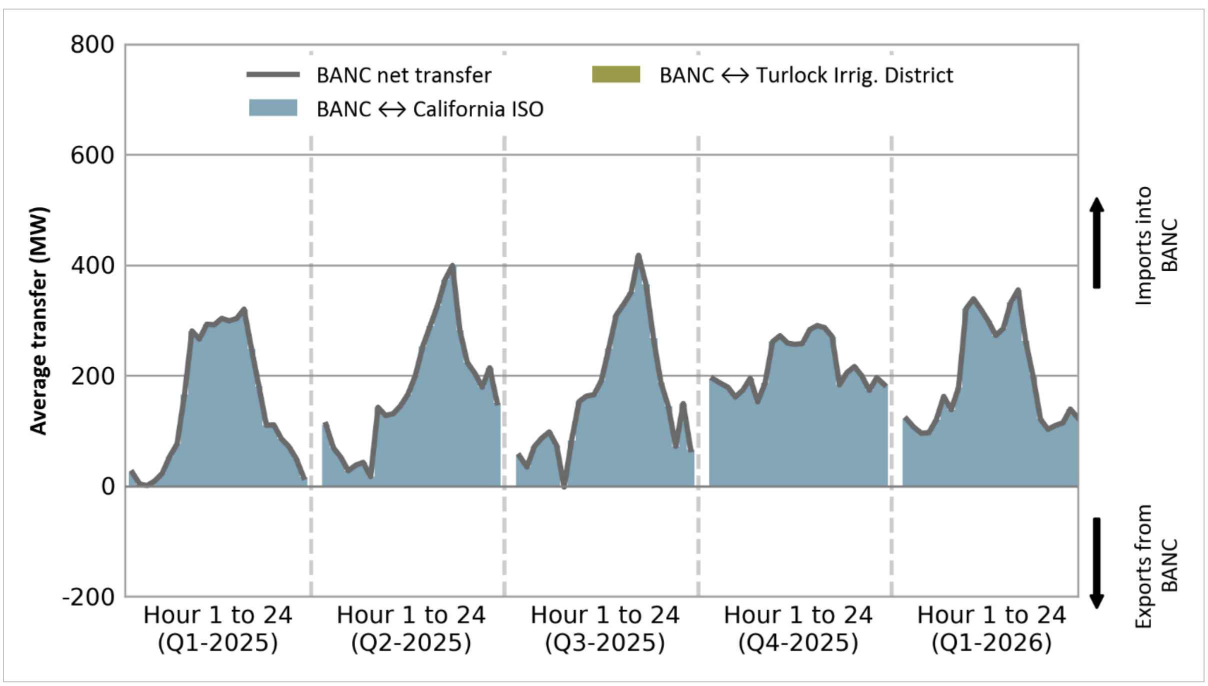
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q1 2026)

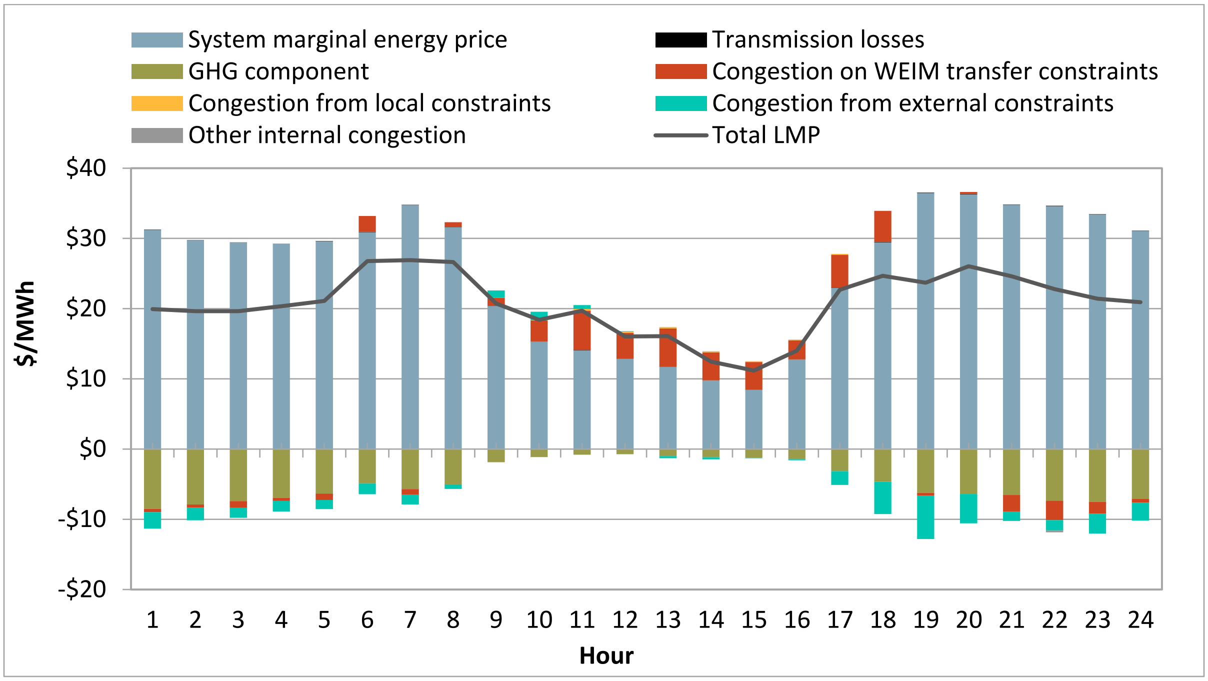


Appendix Figure A.16 Average hourly 5-minute market transfers

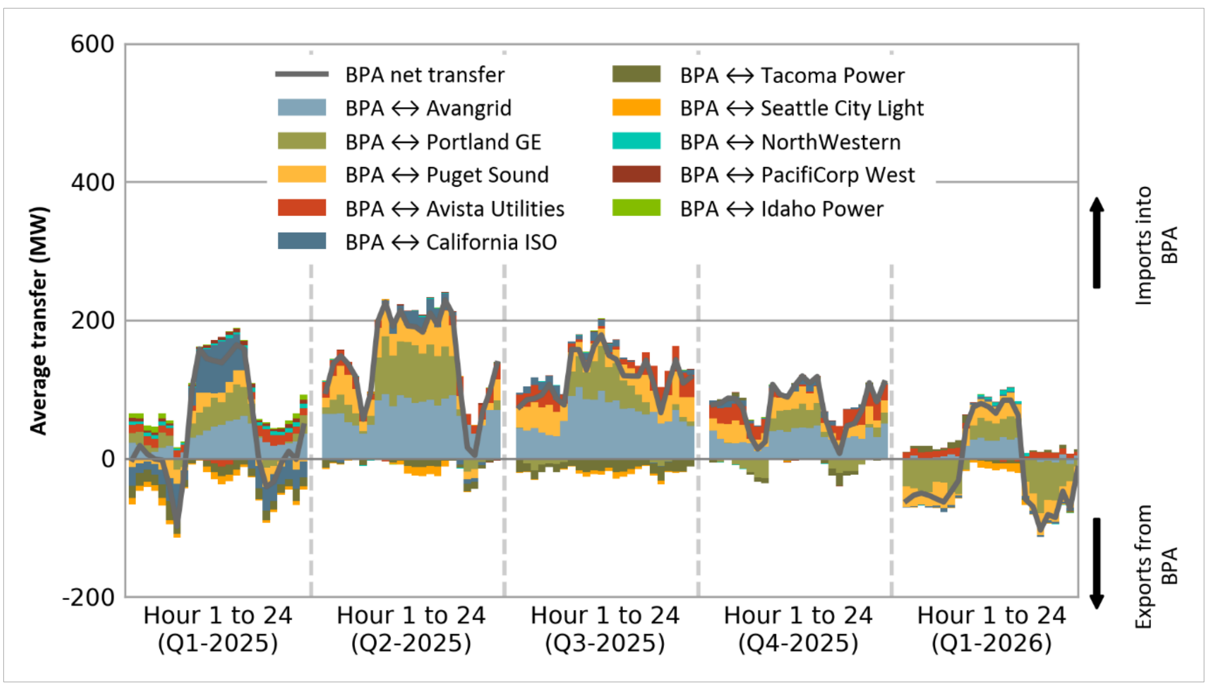


A.5 Bonneville Power Administration

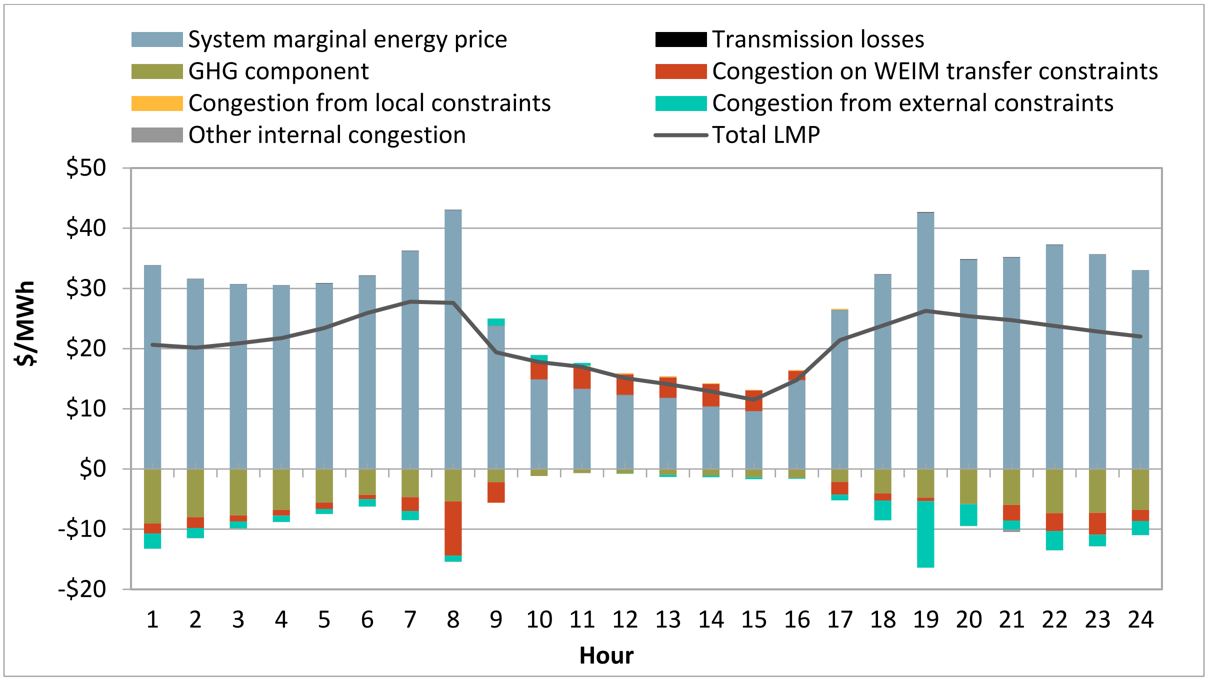
Appendix Figure A.17 Average hourly 15-minute price by component (Q1 2026)



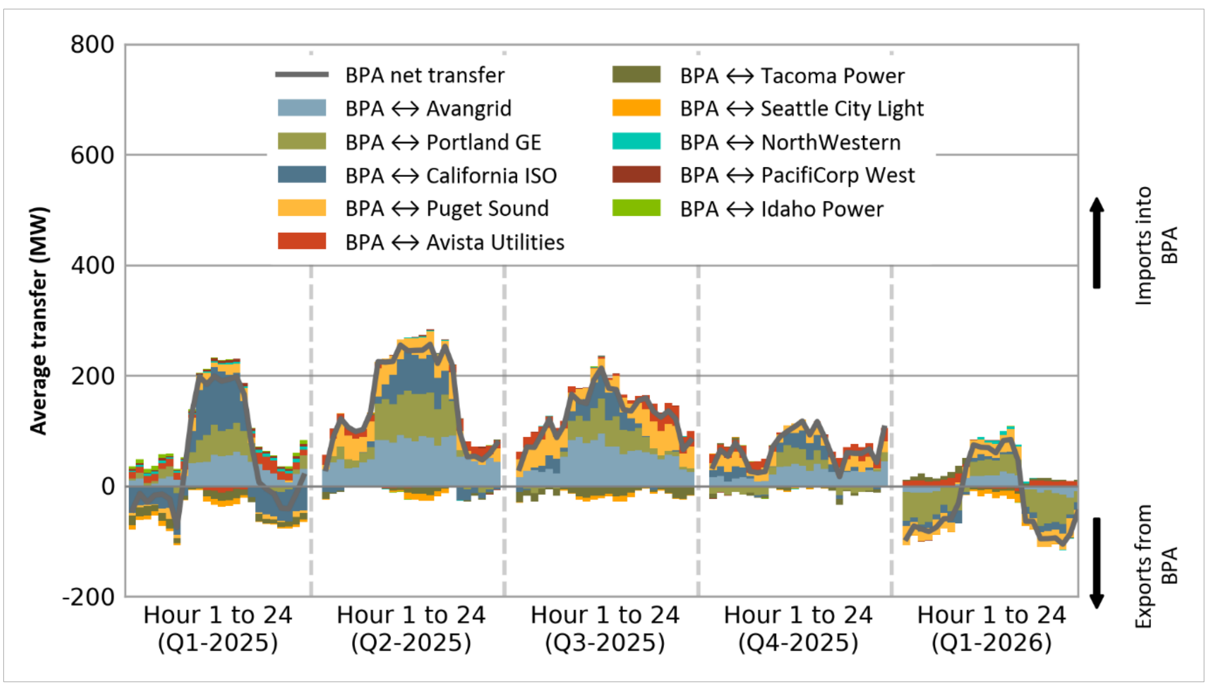
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q1 2026)

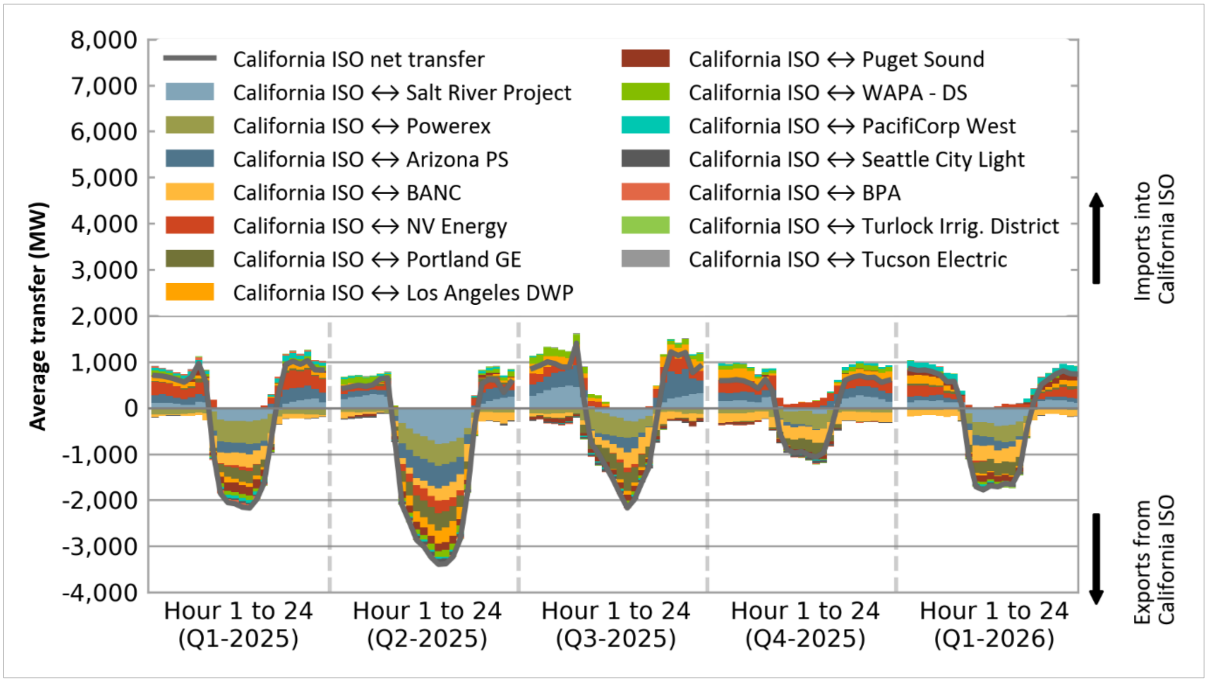


Appendix Figure A.20 Average hourly 5-minute market transfers

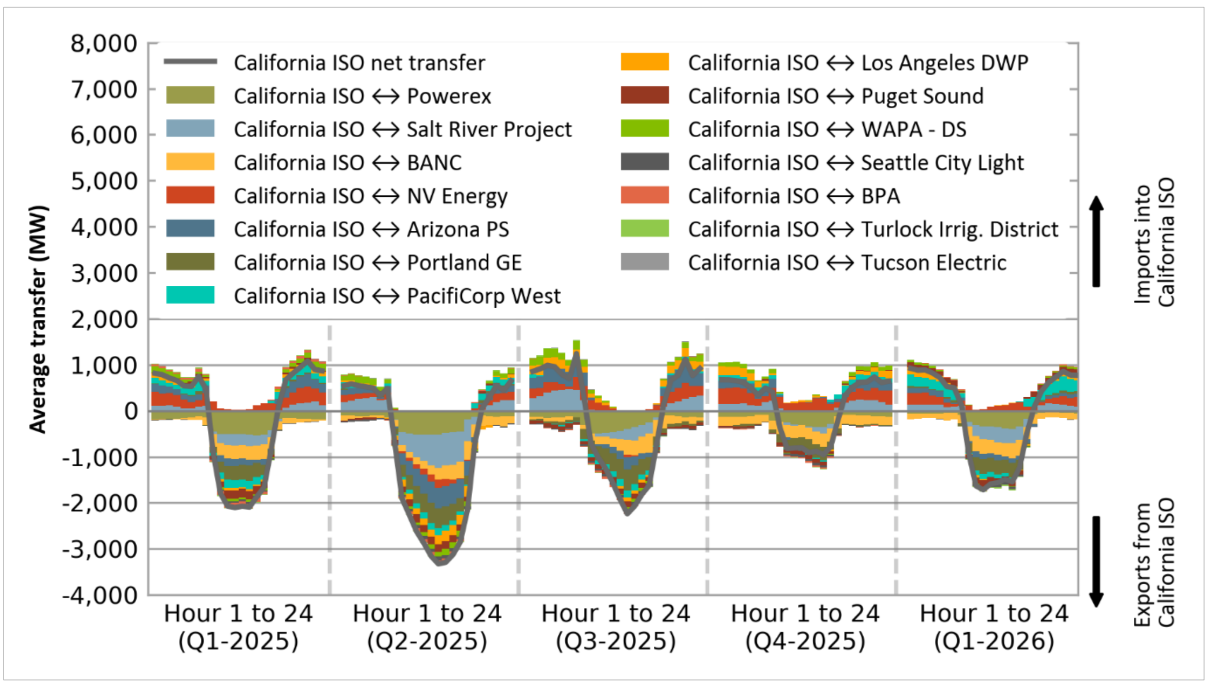


A.6 California ISO

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

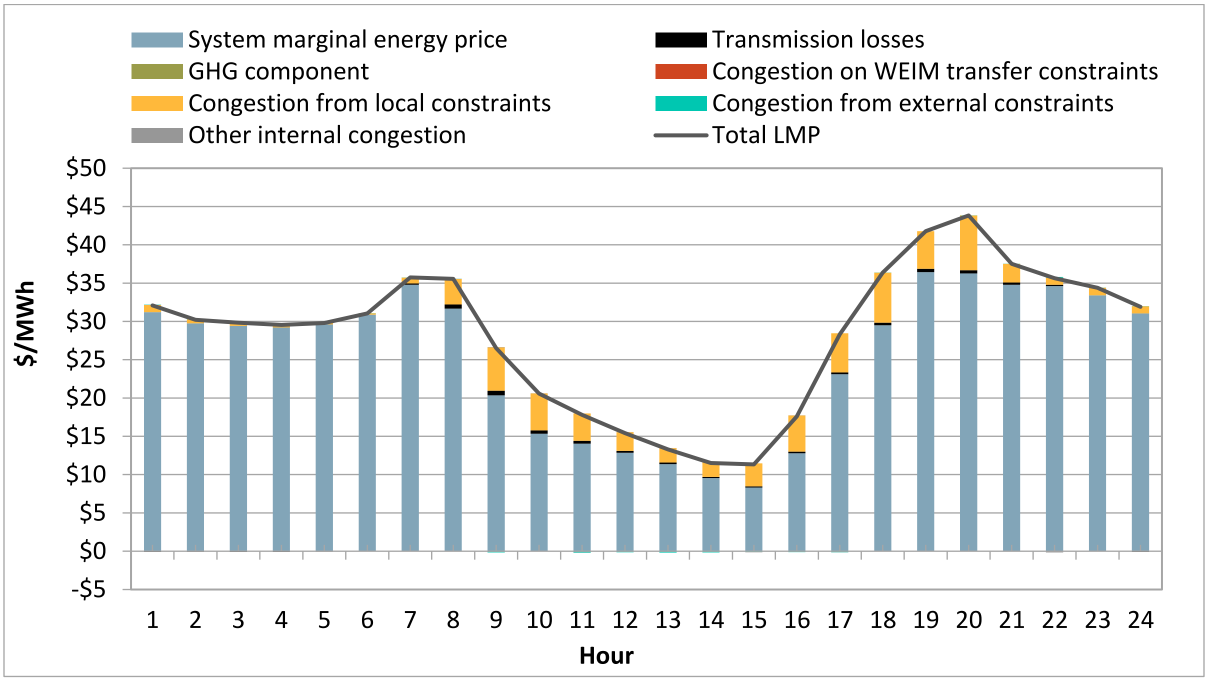


Appendix Figure A.22 Average hourly 5-minute market transfers

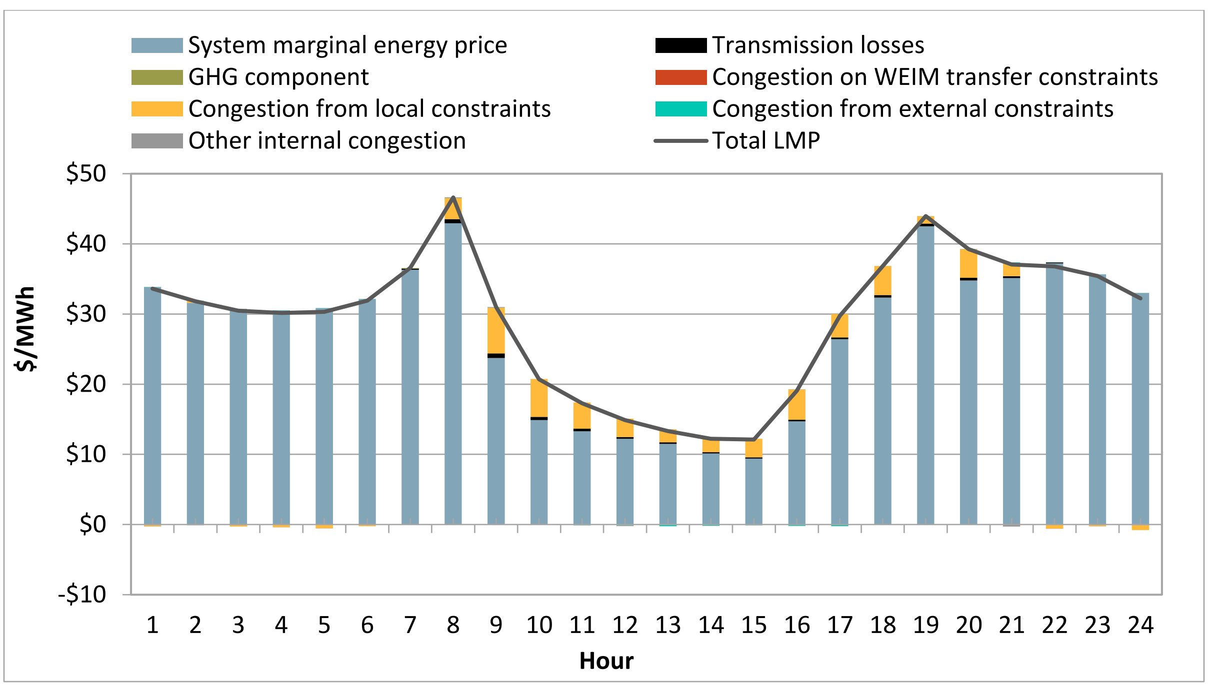


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q1 2026)

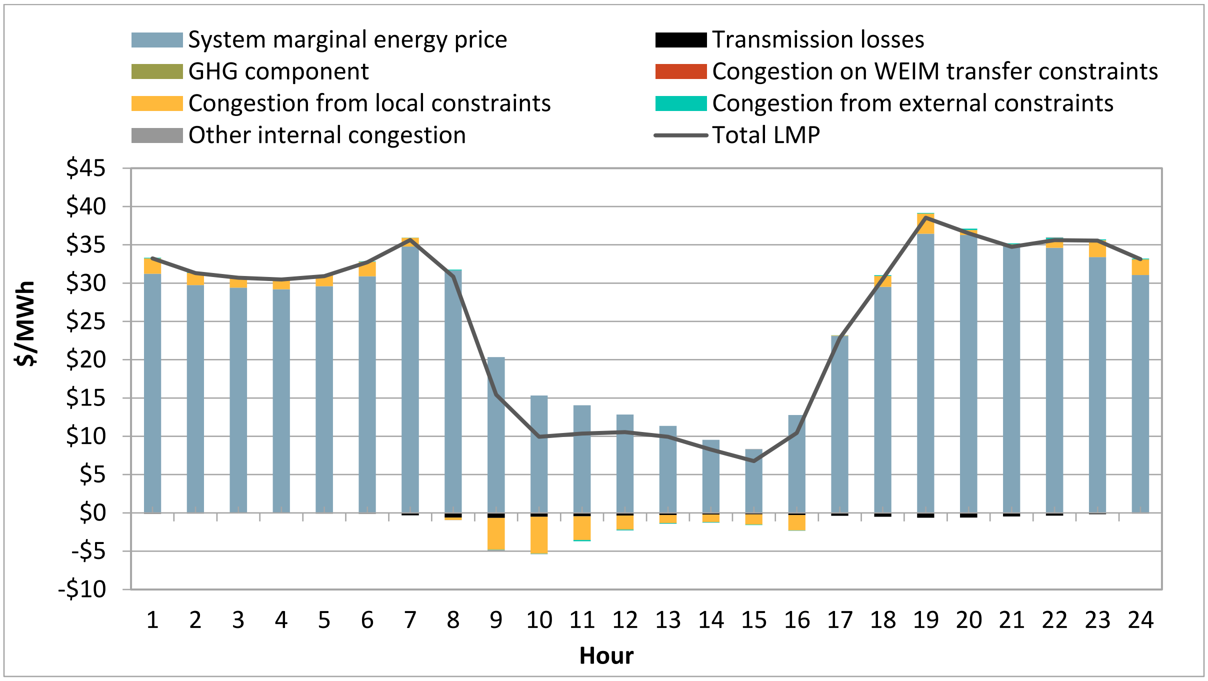


Appendix Figure A.24 Average hourly 5-minute price by component (Q1 2026)

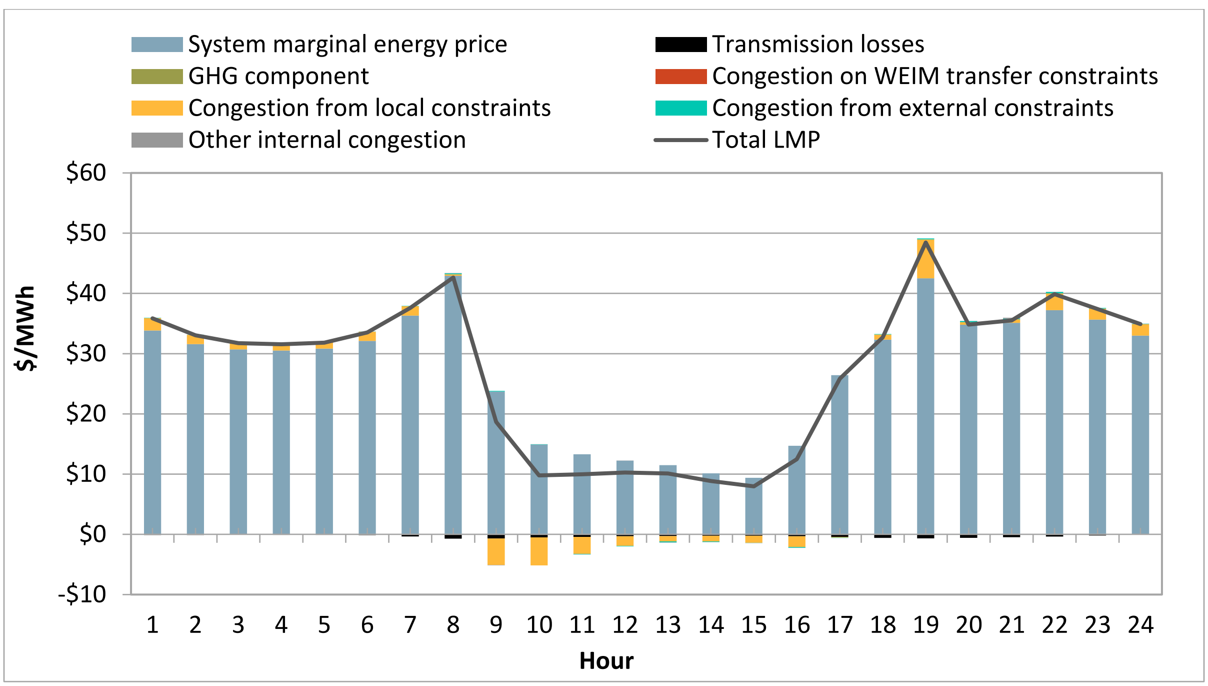


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q1 2026)

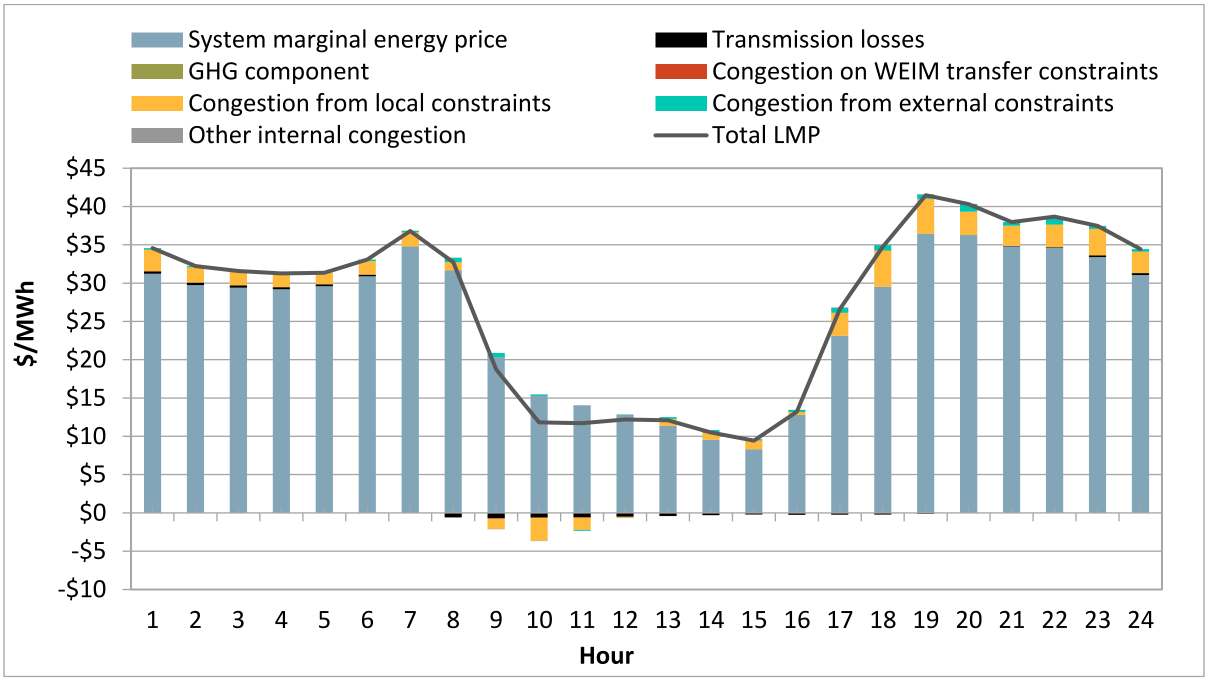


Appendix Figure A.26 Average hourly 5-minute price by component (Q1 2026)

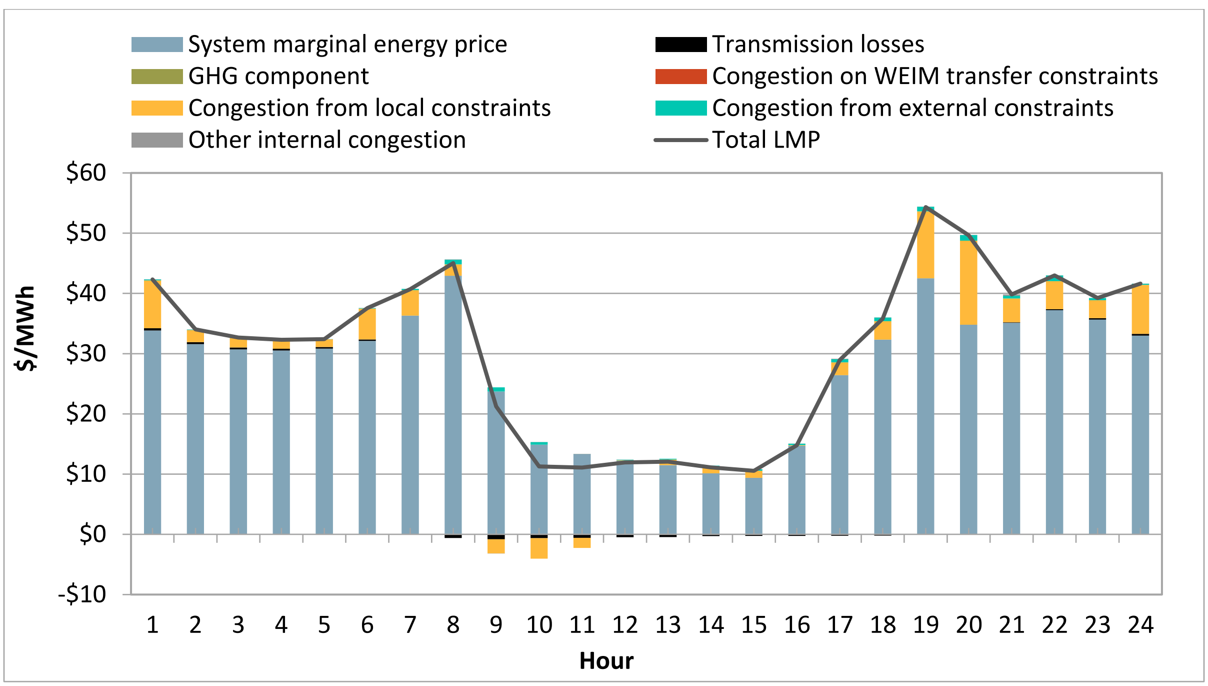


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q1 2026)

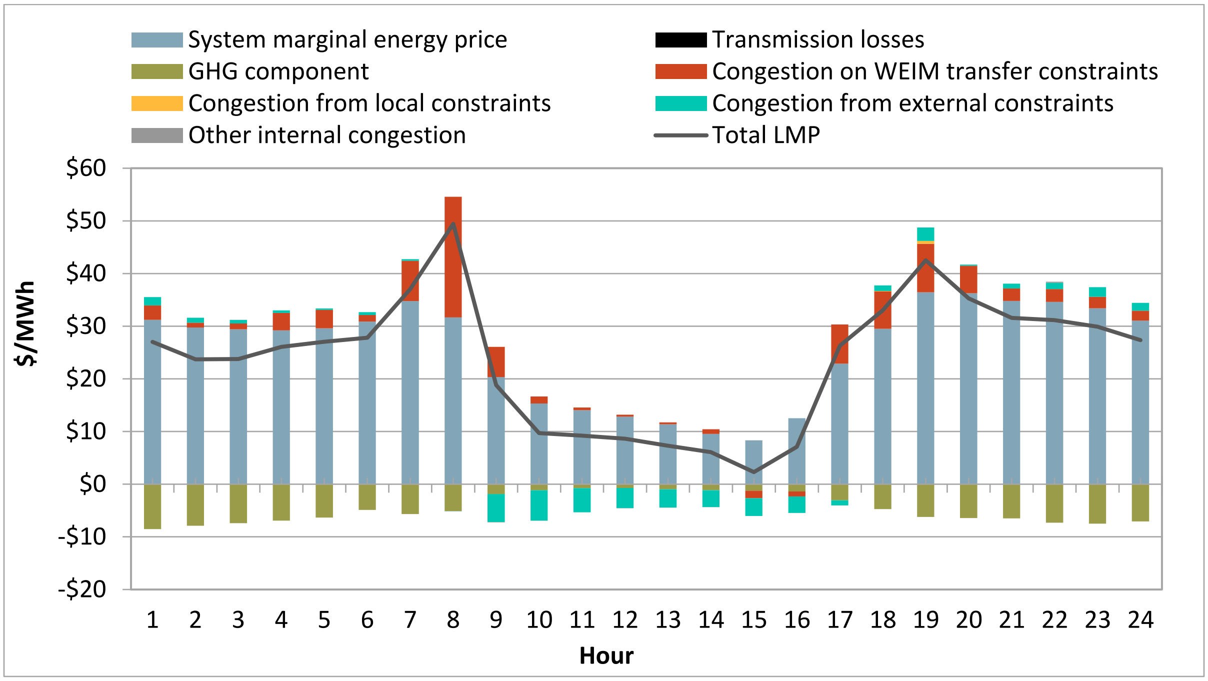


Appendix Figure A.28 Average hourly 5-minute price by component (Q1 2026)

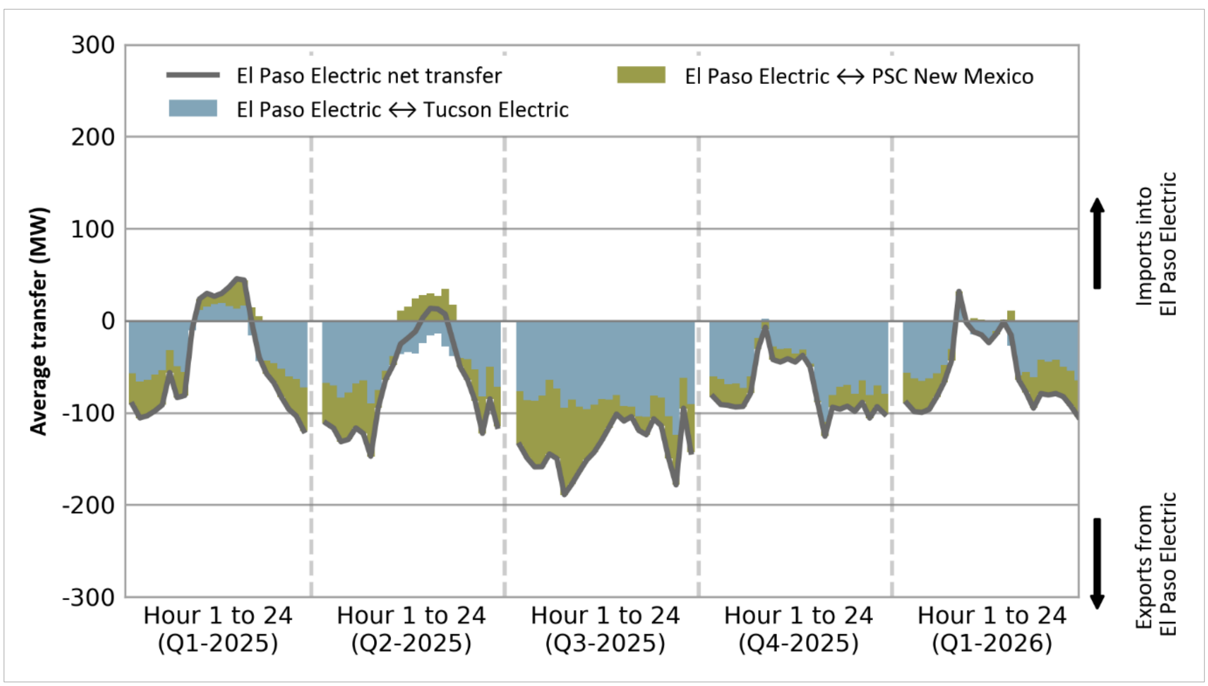


A.7 El Paso Electric

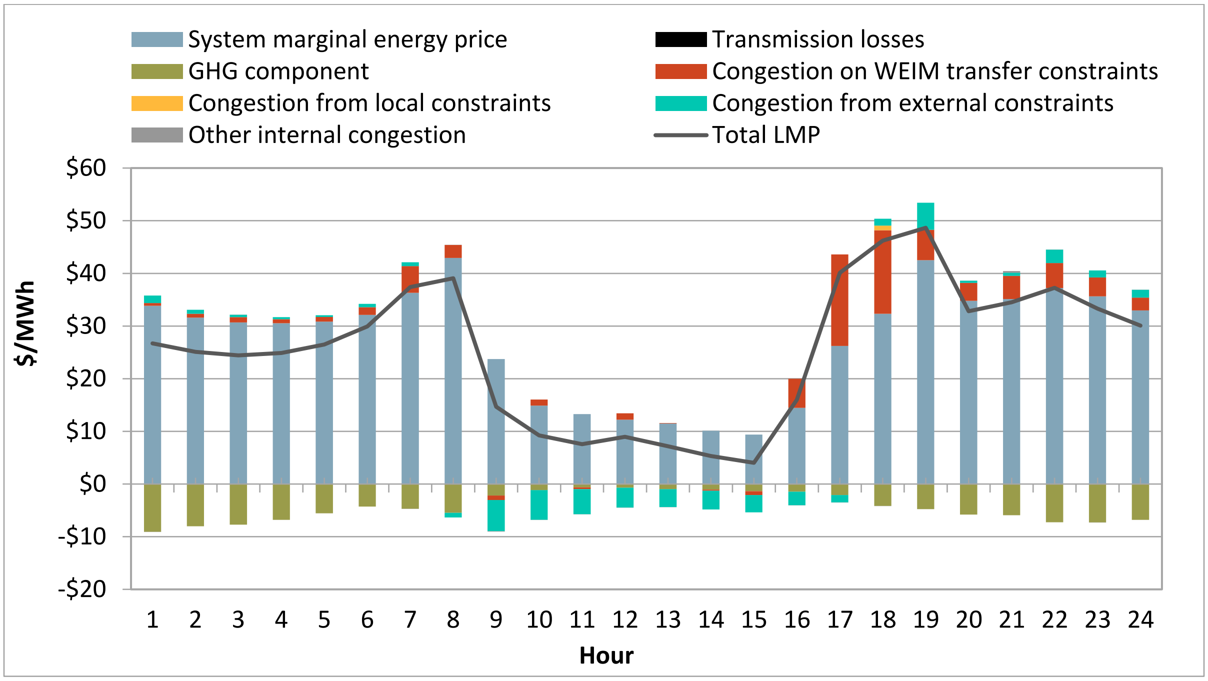
Appendix Figure A.29 Average hourly 15-minute price by component (Q1 2026)



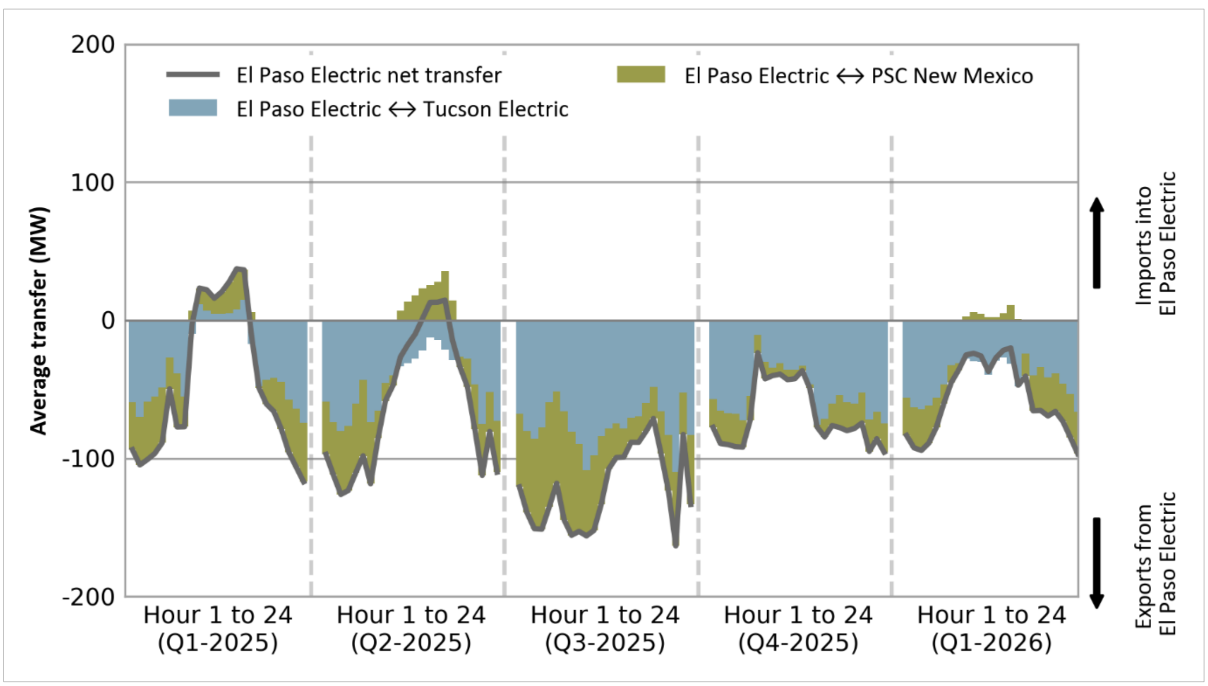
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q1 2026)

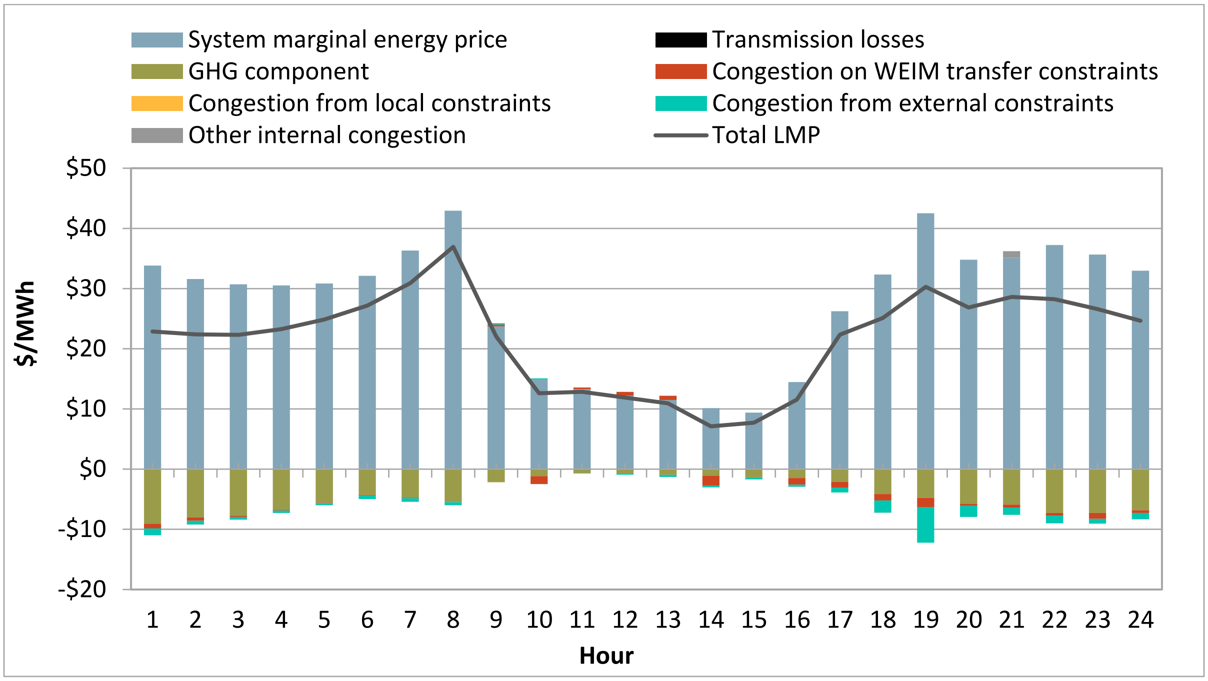


Appendix Figure A.32 Average hourly 5-minute market transfers

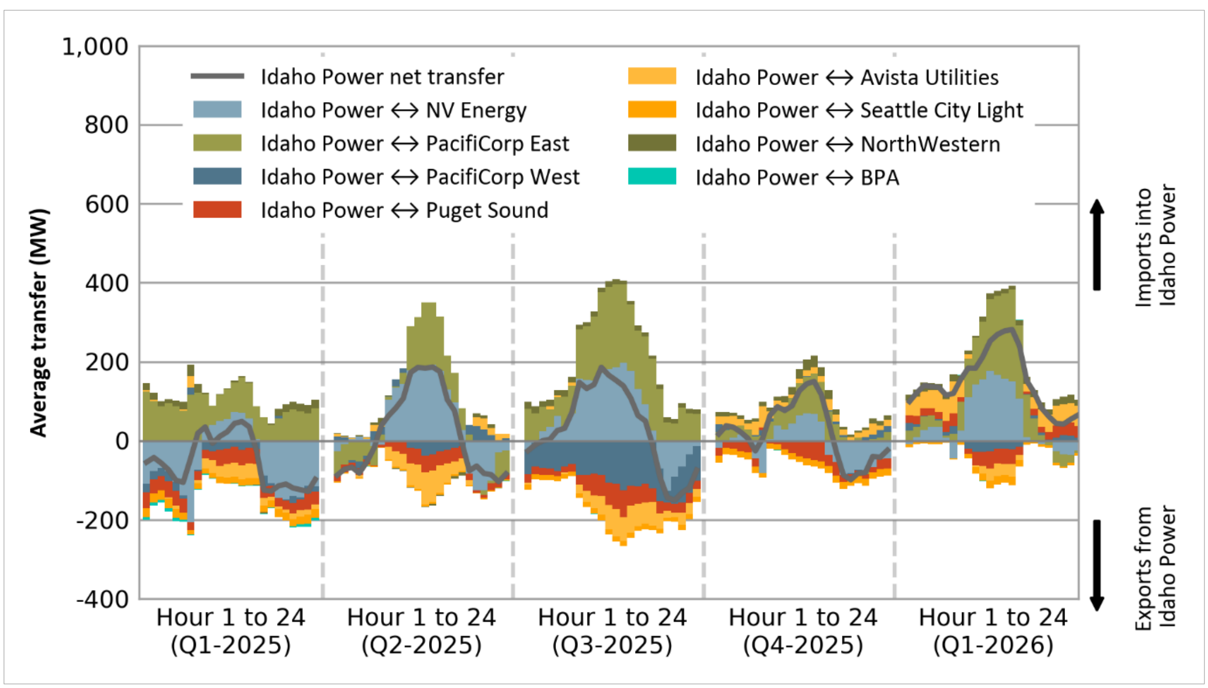


A.8 Idaho Power

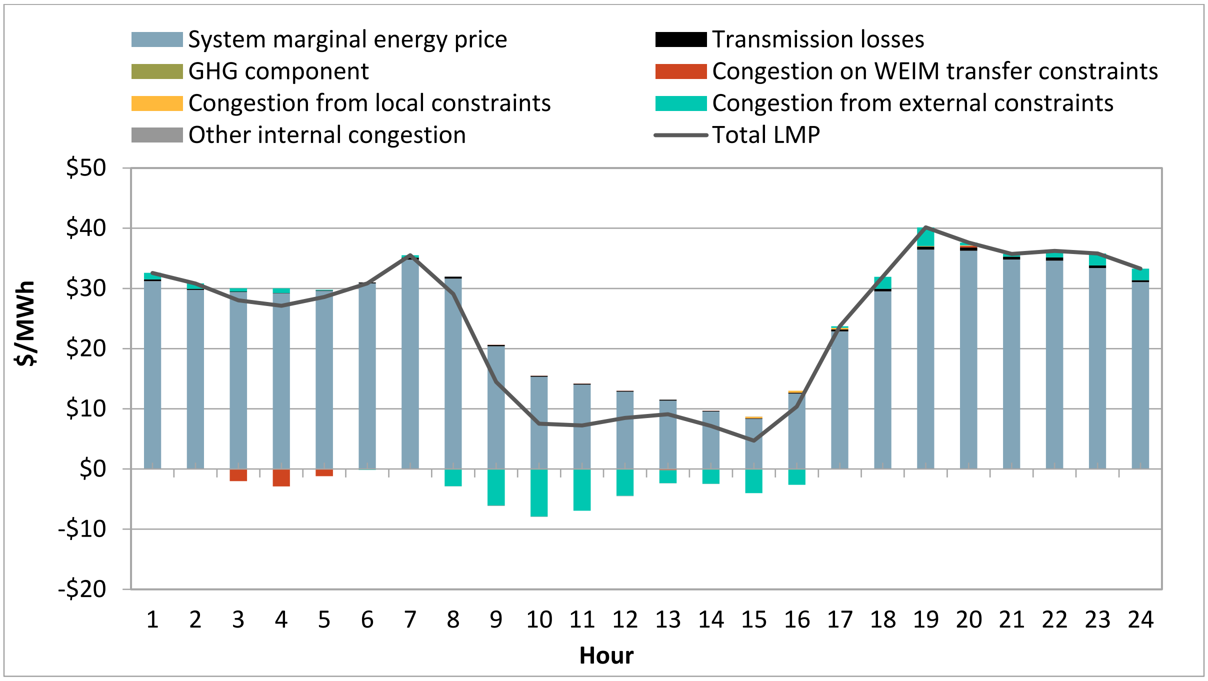
Appendix Figure A.33 Average hourly 15-minute price by component (Q1 2026)



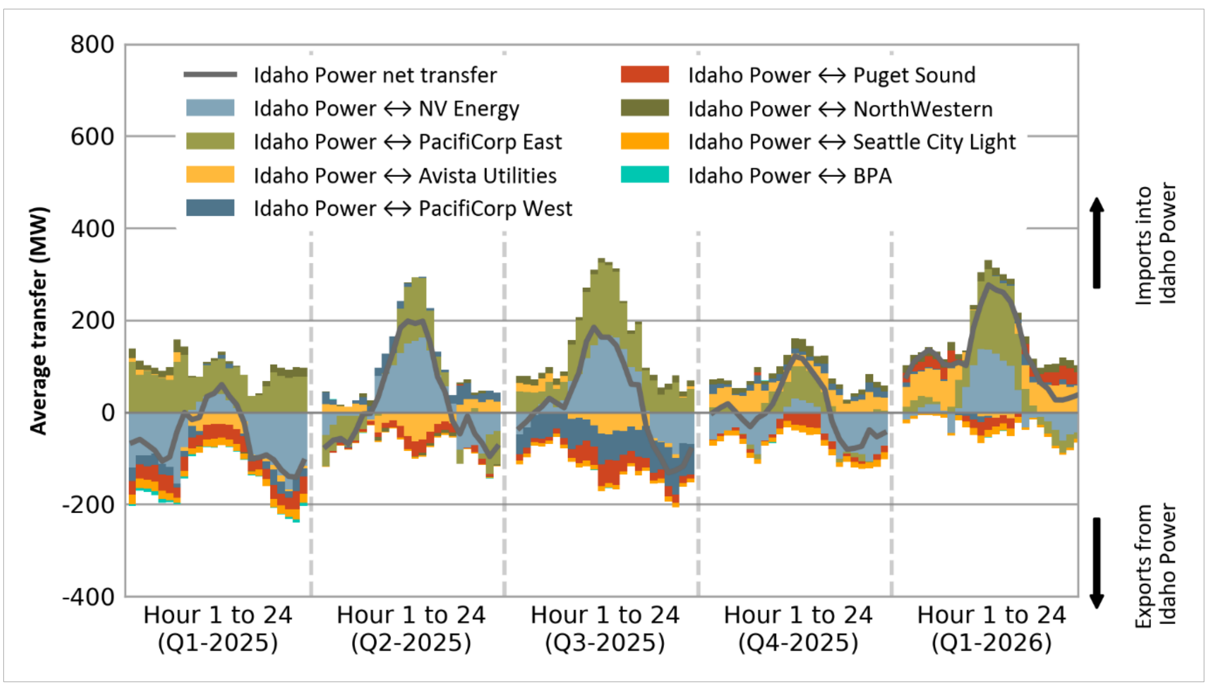
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q1 2026)

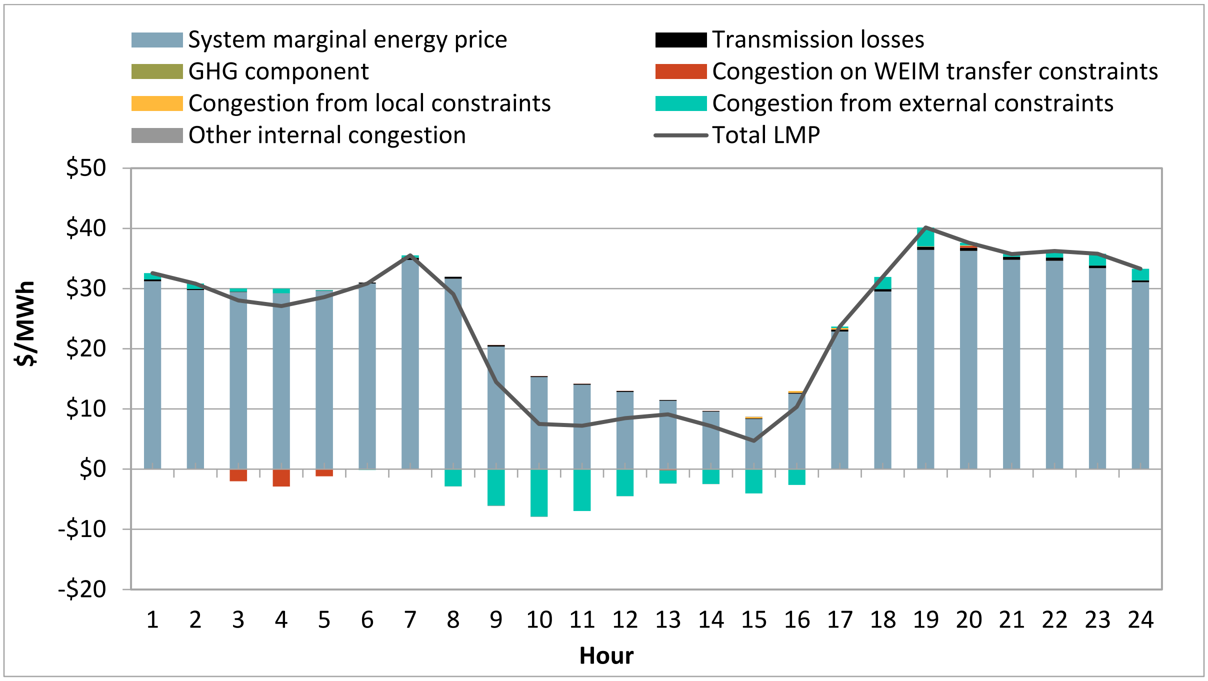


Appendix Figure A.36 Average hourly 5-minute market transfers

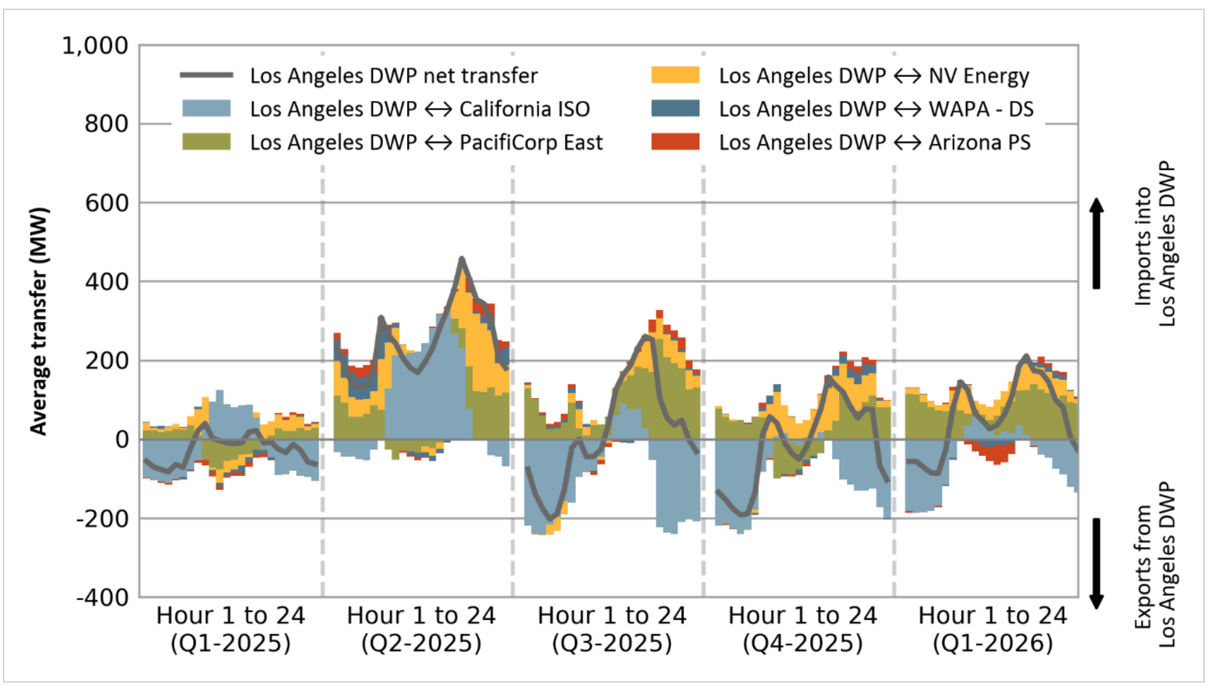


A.9 Los Angeles Department of Water and Power

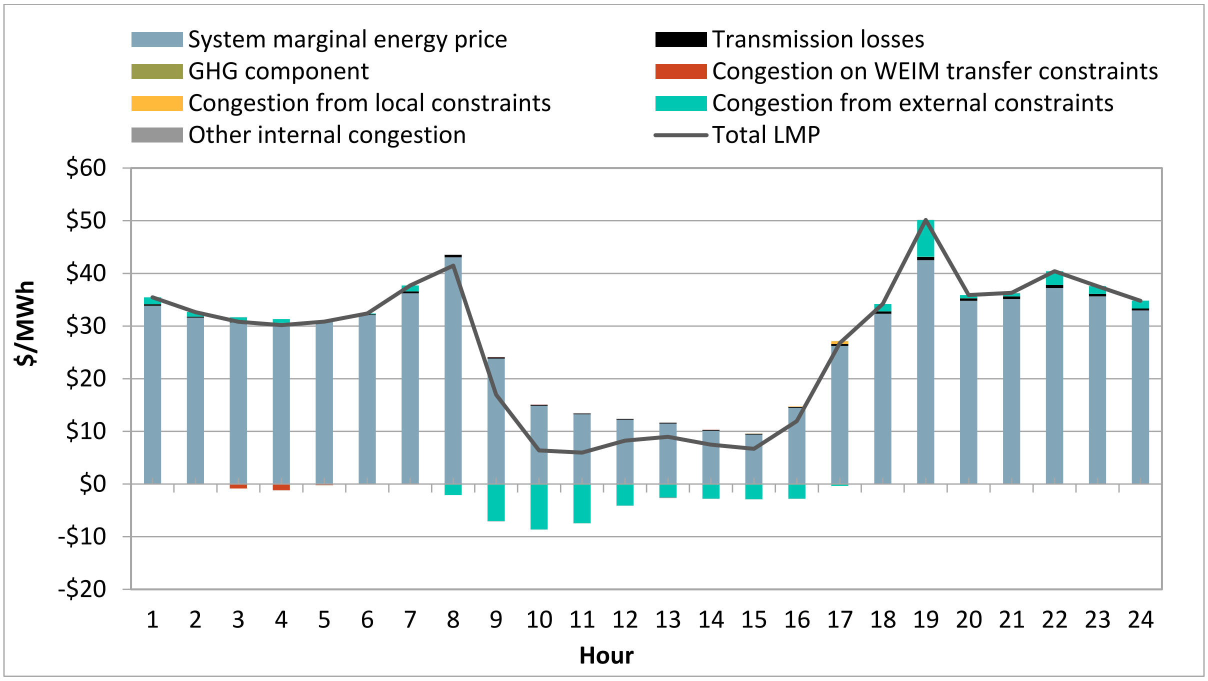
Appendix Figure A.37 Average hourly 15-minute price by component (Q1 2026)



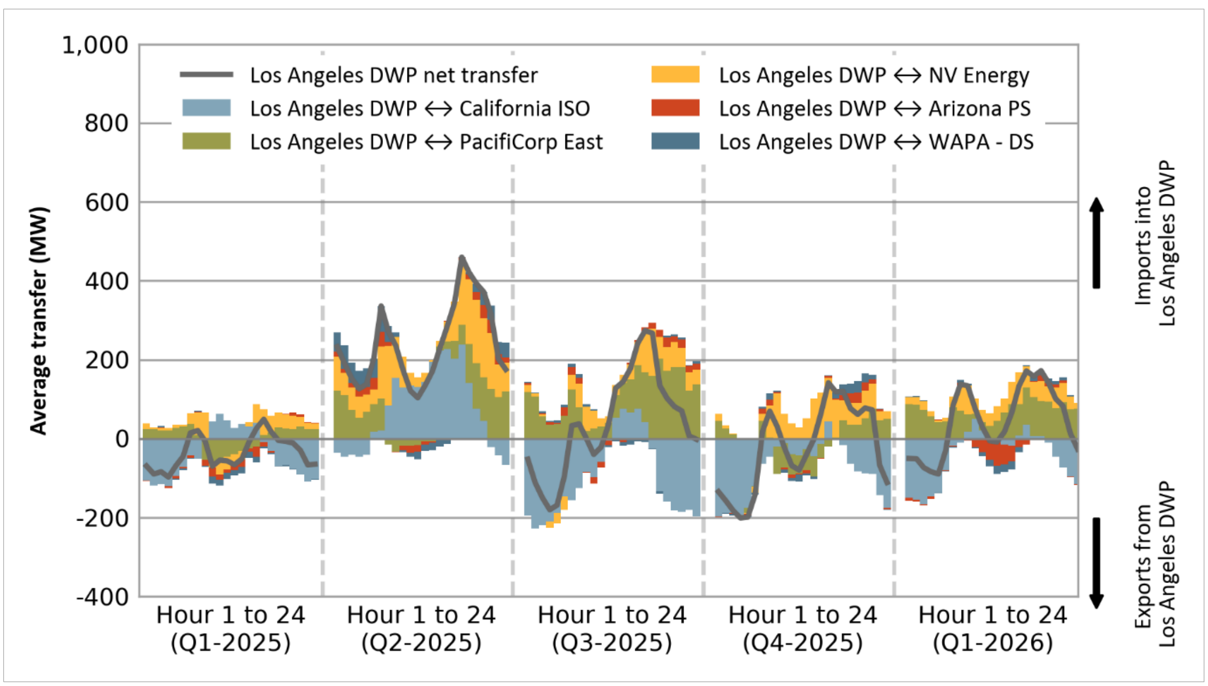
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q1 2026)

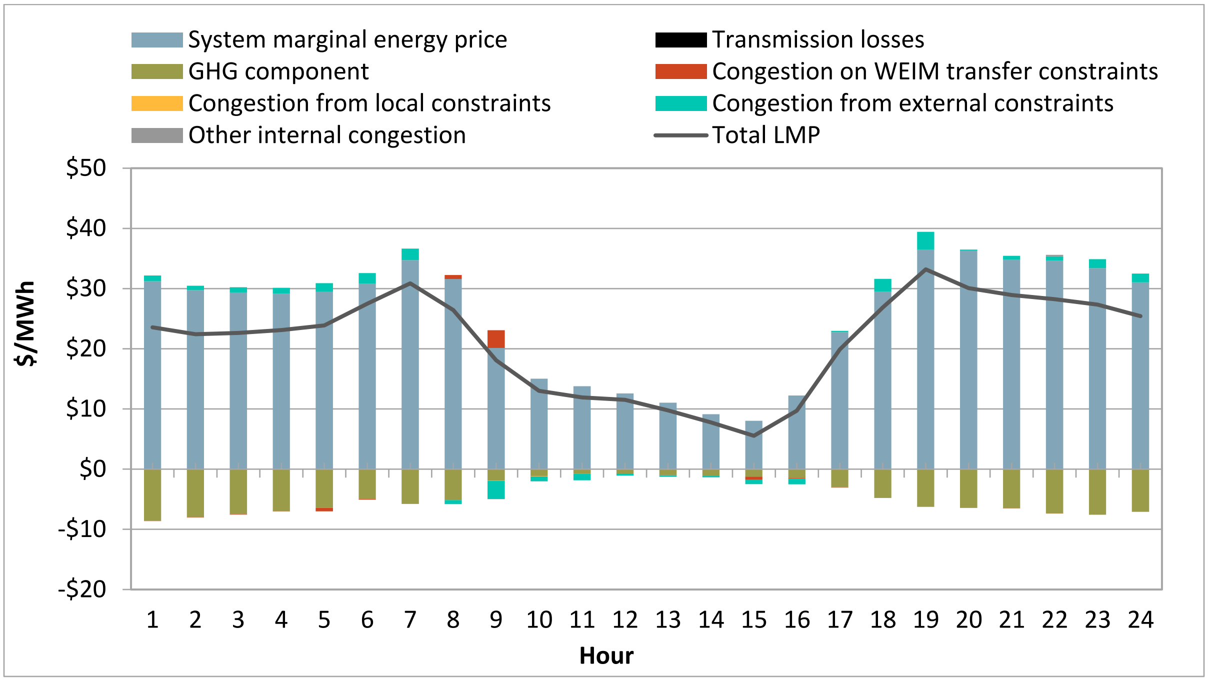


Appendix Figure A.40 Average hourly 5-minute market transfers

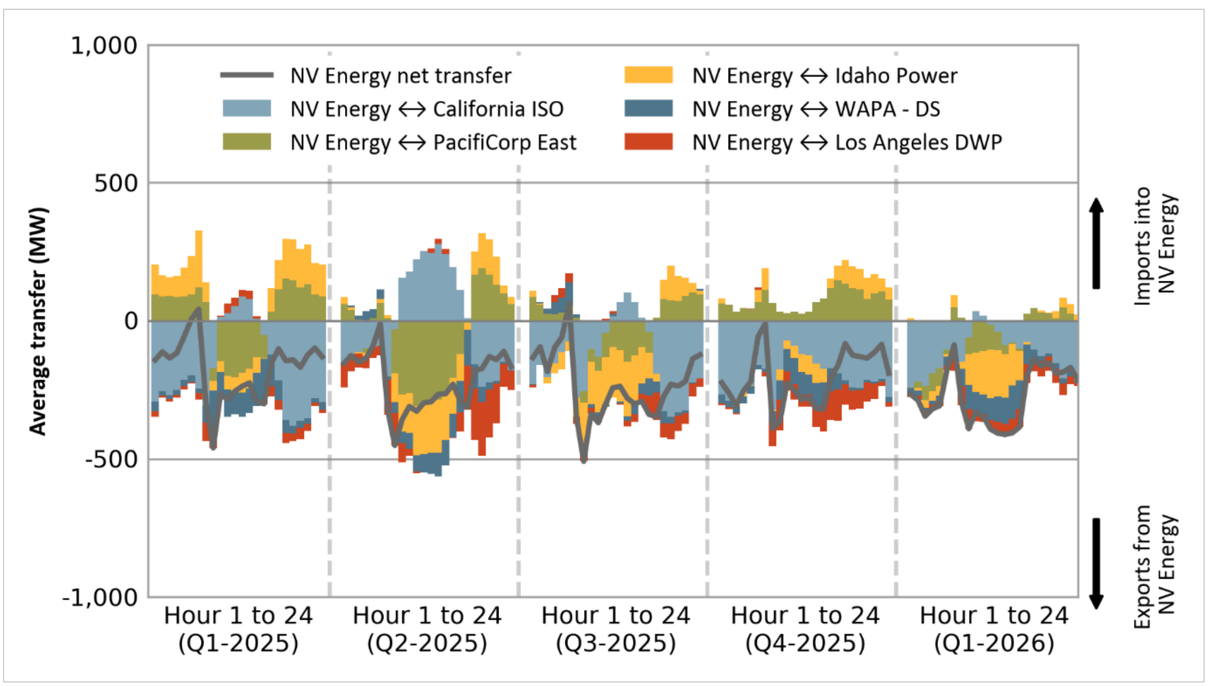


A.10 NV Energy

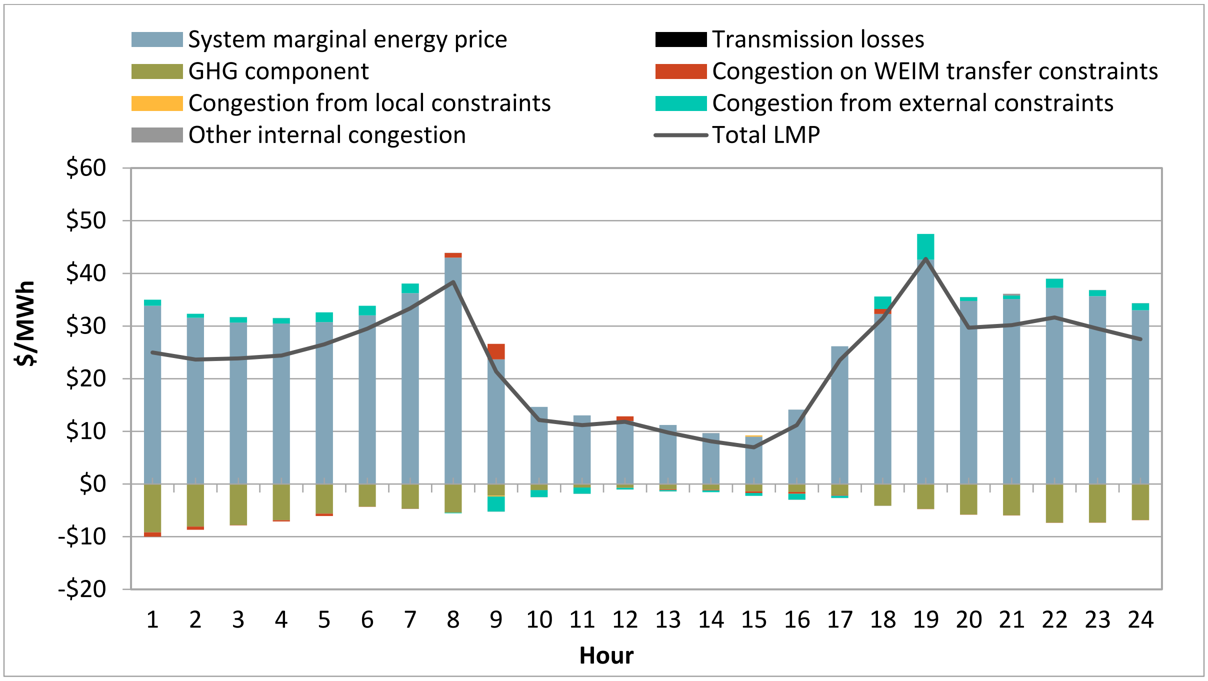
Appendix Figure A.41 Average hourly 15-minute price by component (Q1 2026)



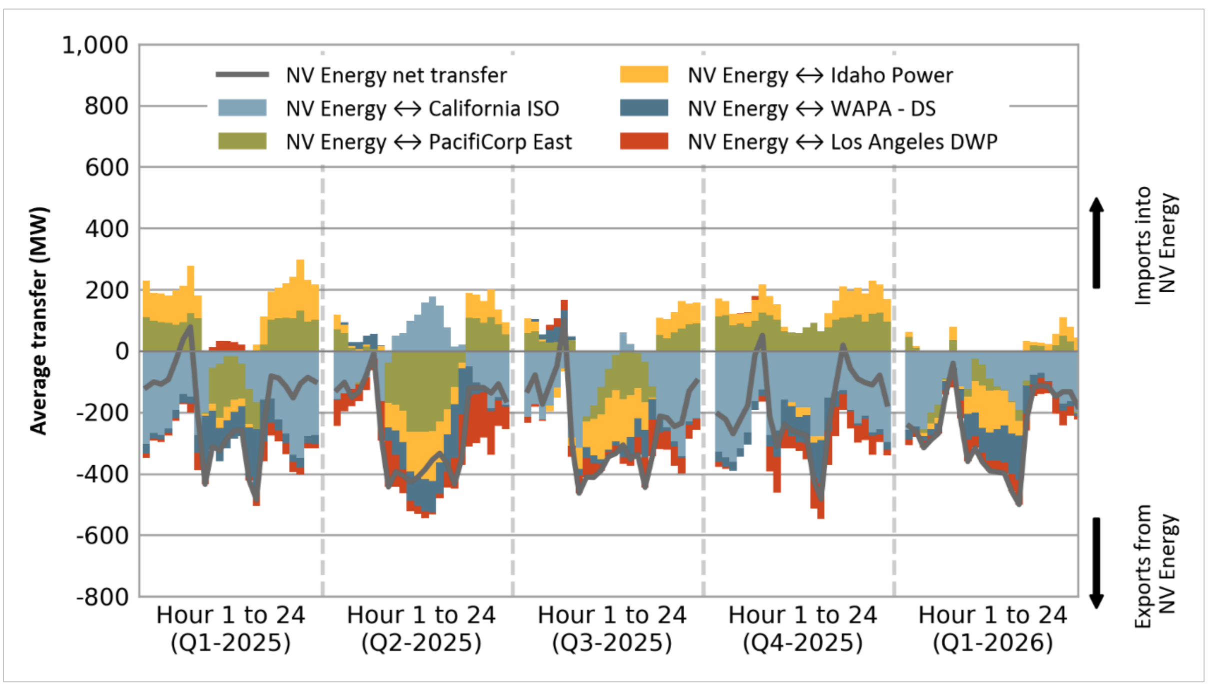
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q1 2026)

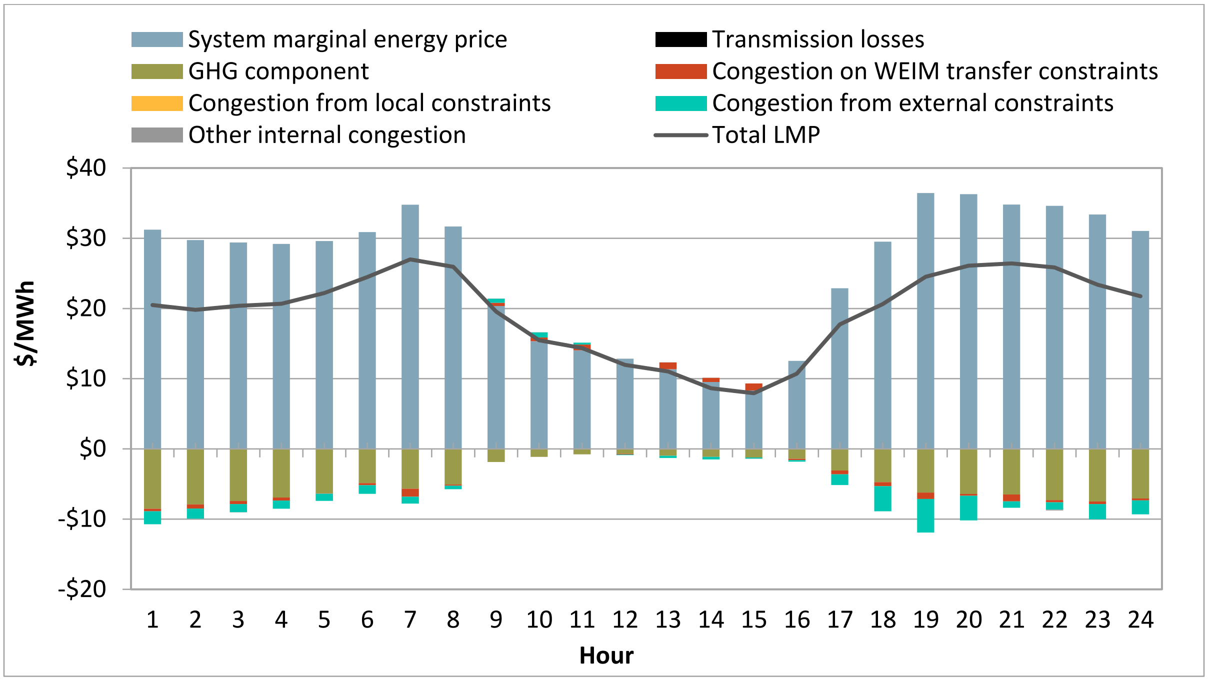


Appendix Figure A.44 Average hourly 5-minute market transfers

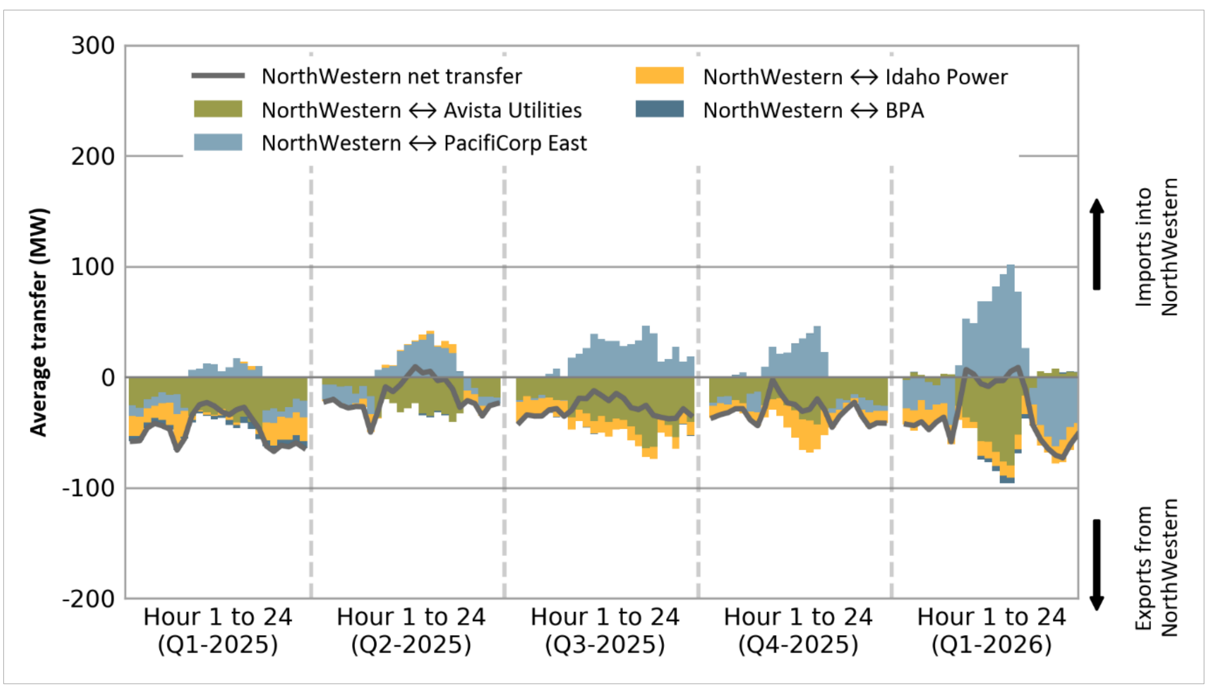


A.11 NorthWestern Energy

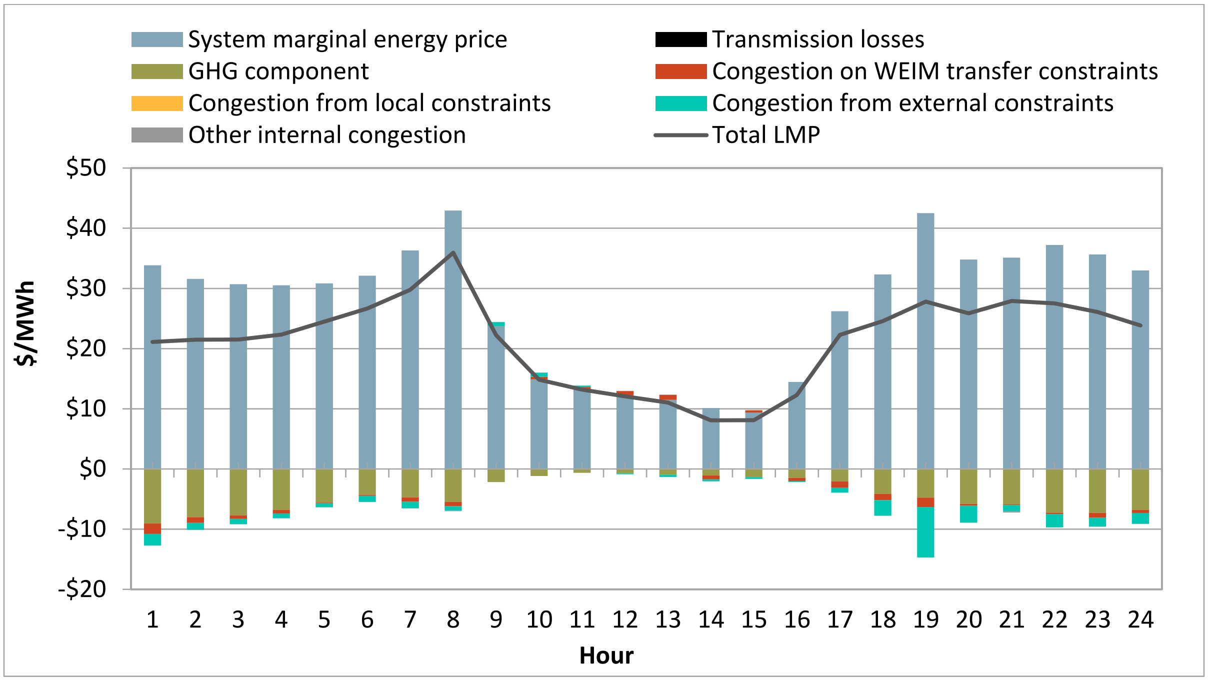
Appendix Figure A.45 Average hourly 15-minute price by component (Q1 2026)



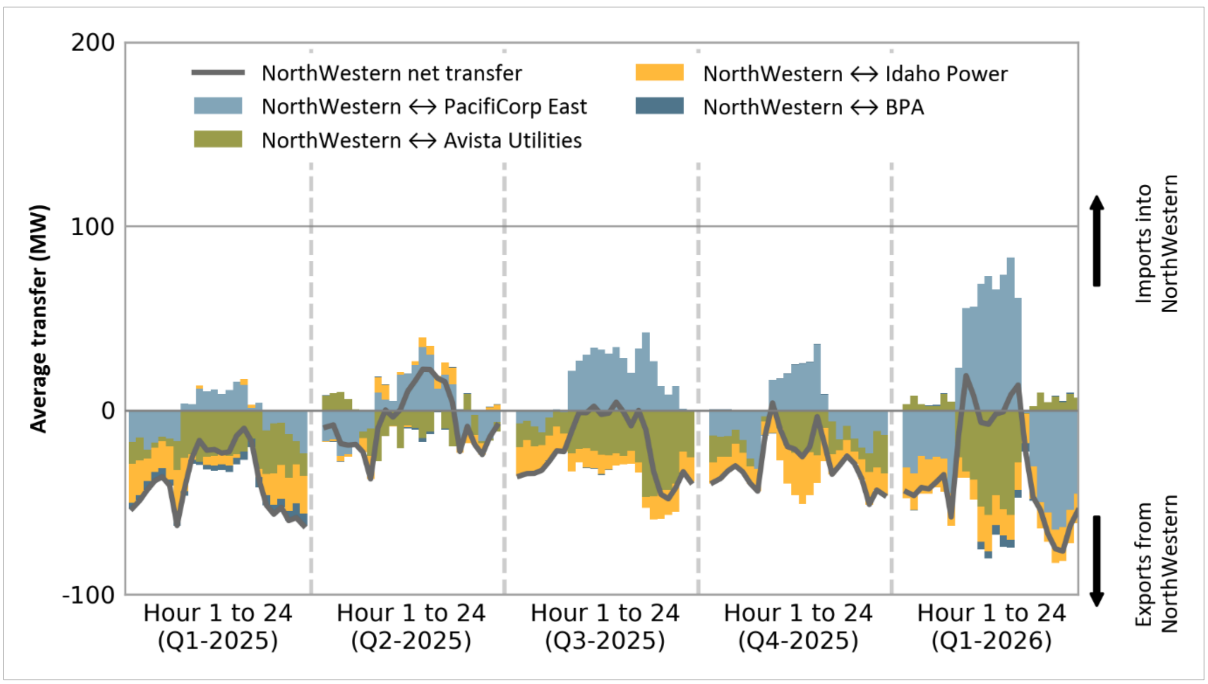
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q1 2026)

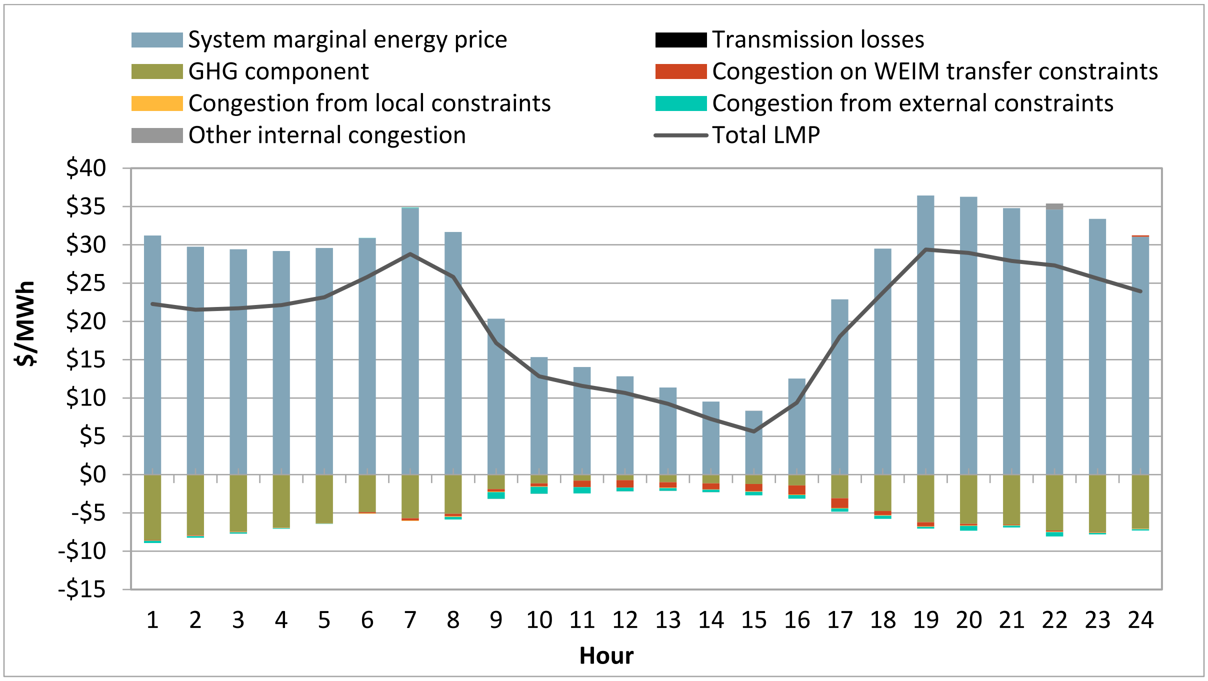


Appendix Figure A.48 Average hourly 5-minute market transfers

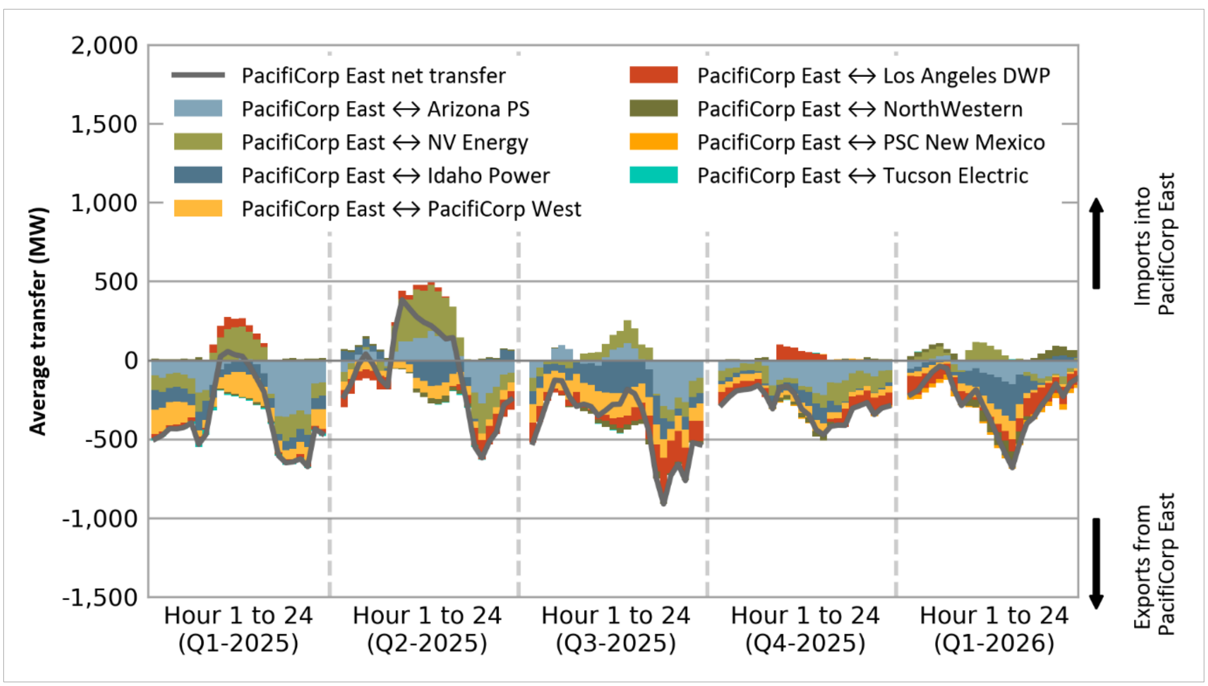


A.12 PacifiCorp East

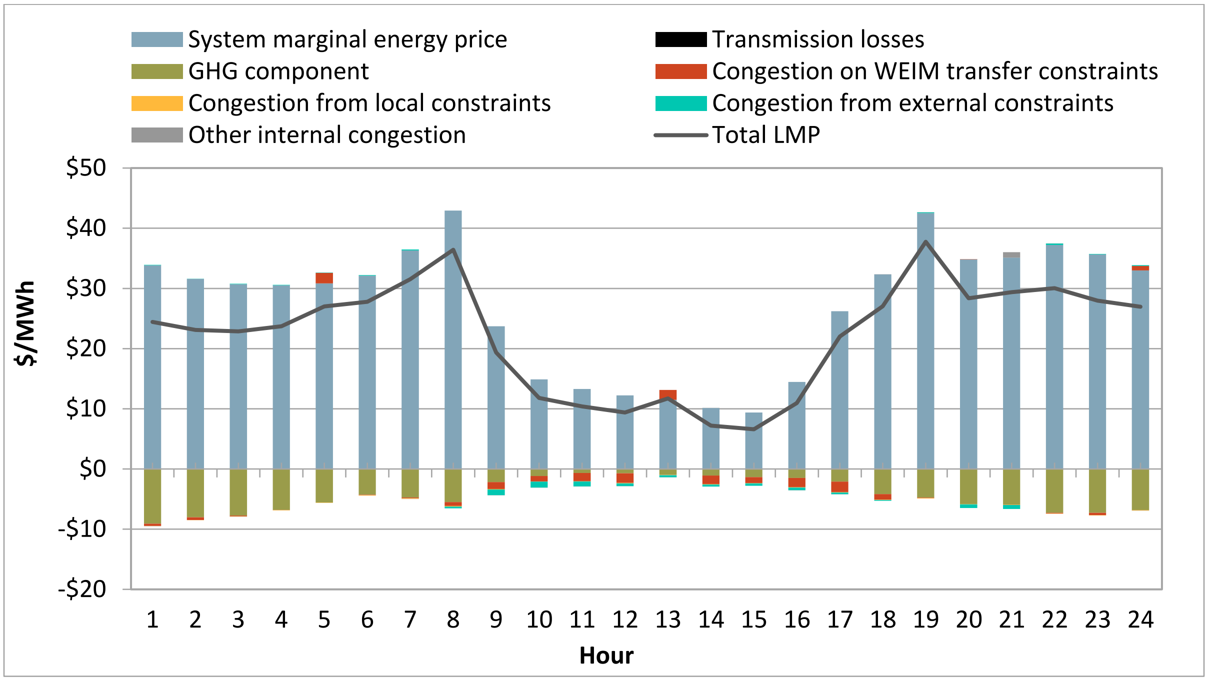
Appendix Figure A.49 Average hourly 15-minute price by component (Q1 2026)



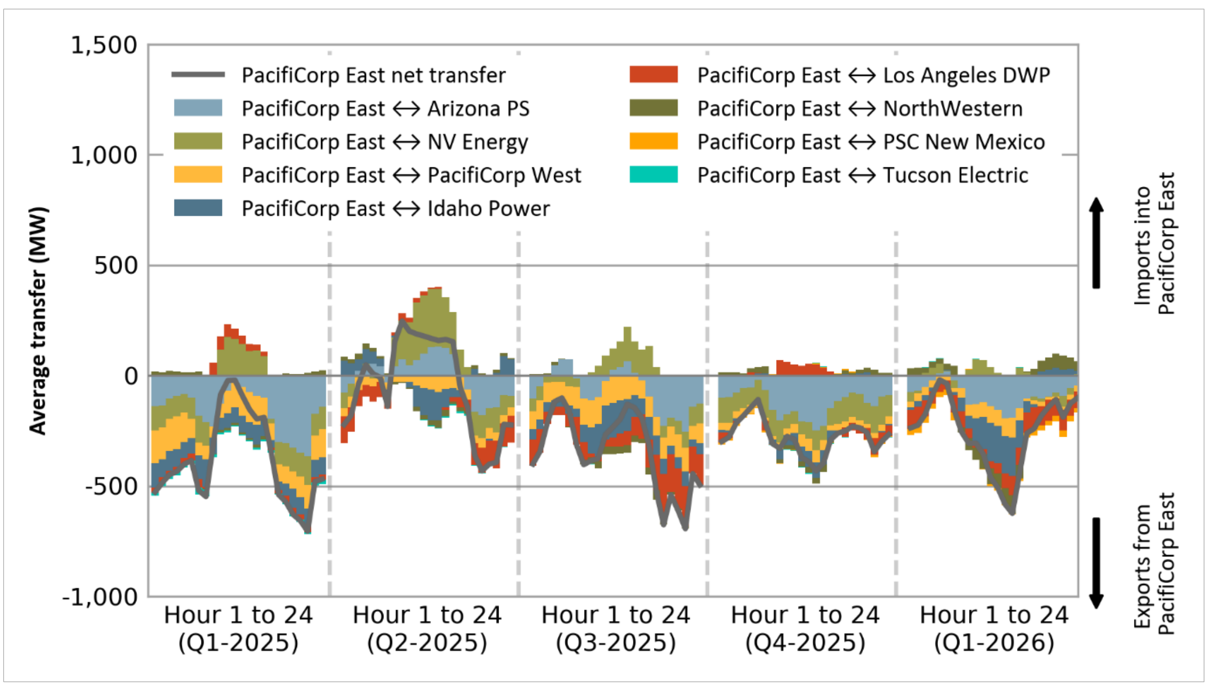
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q1 2026)

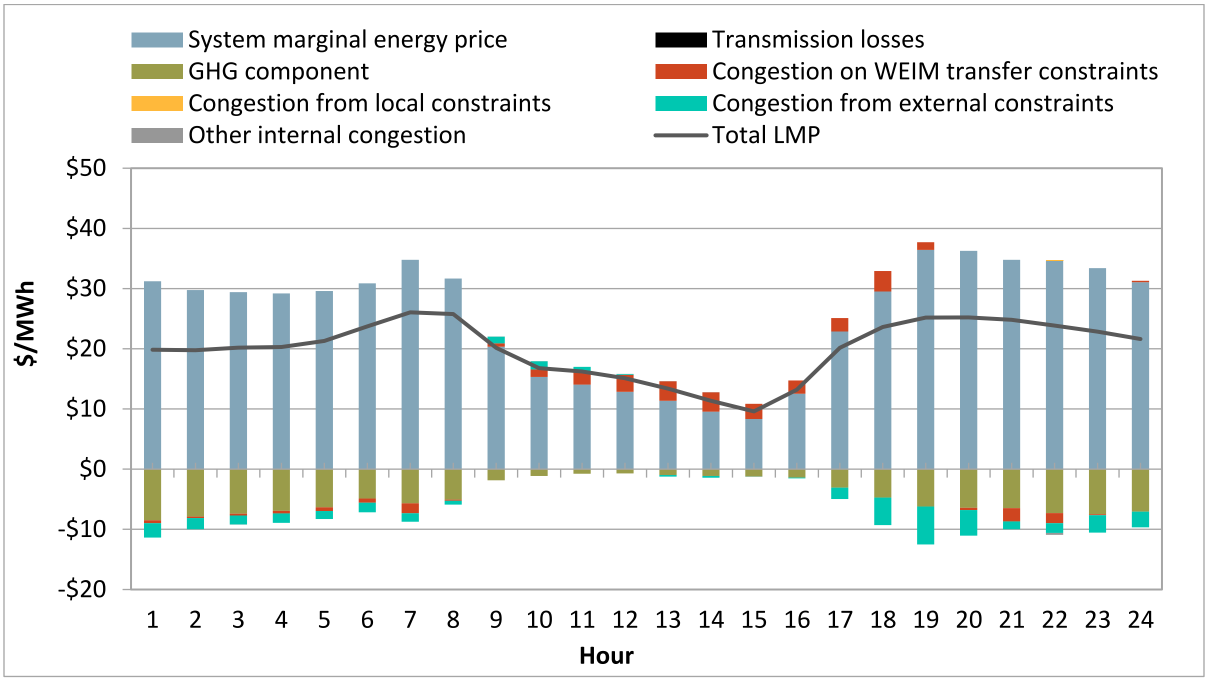


Appendix Figure A.52 Average hourly 5-minute market transfers

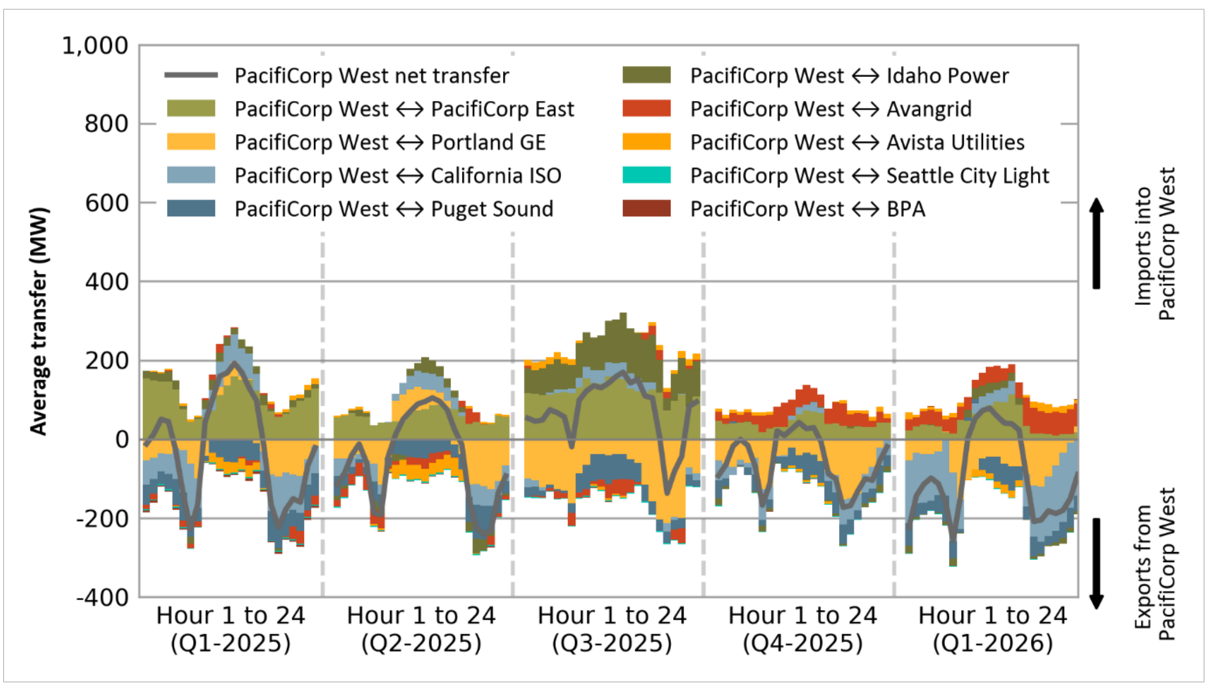


A.13 PacifiCorp West

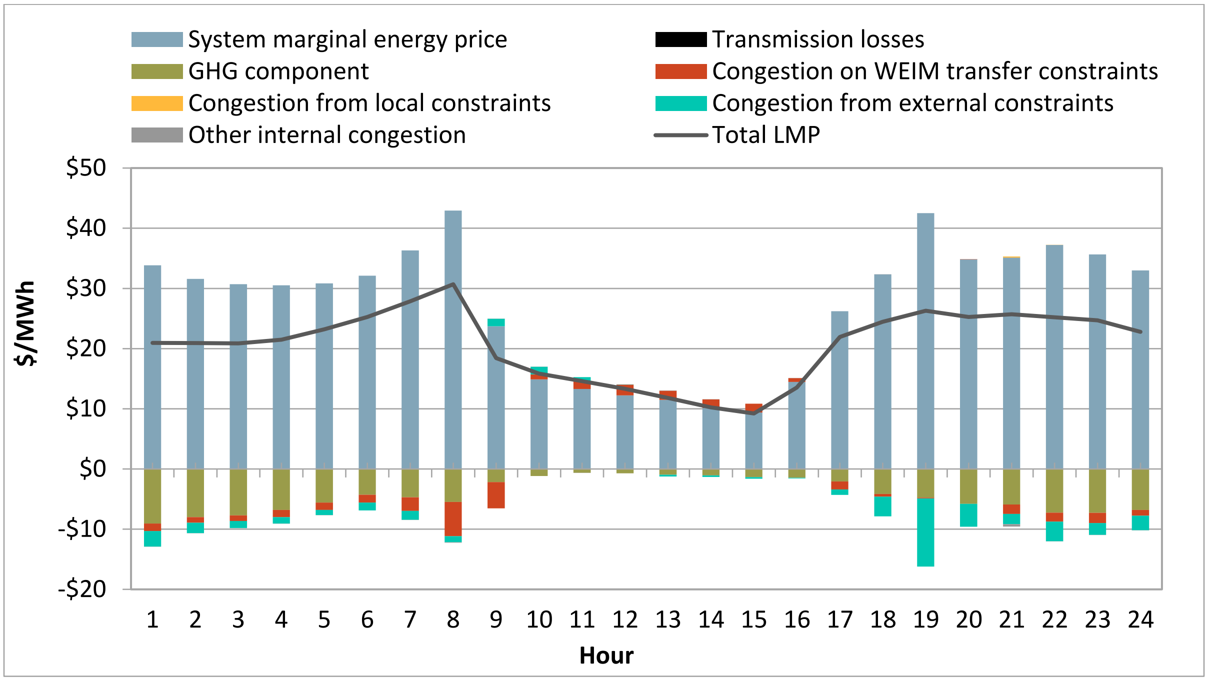
Appendix Figure A.53 Average hourly 15-minute price by component (Q1 2026)



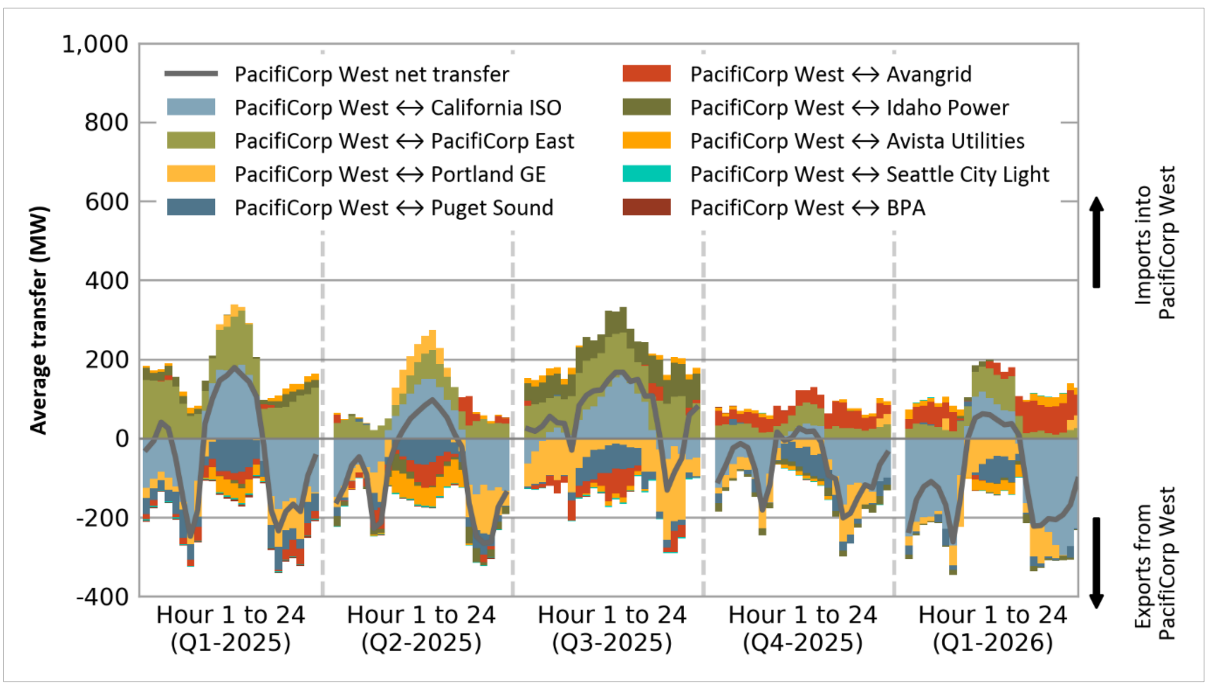
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q1 2026)

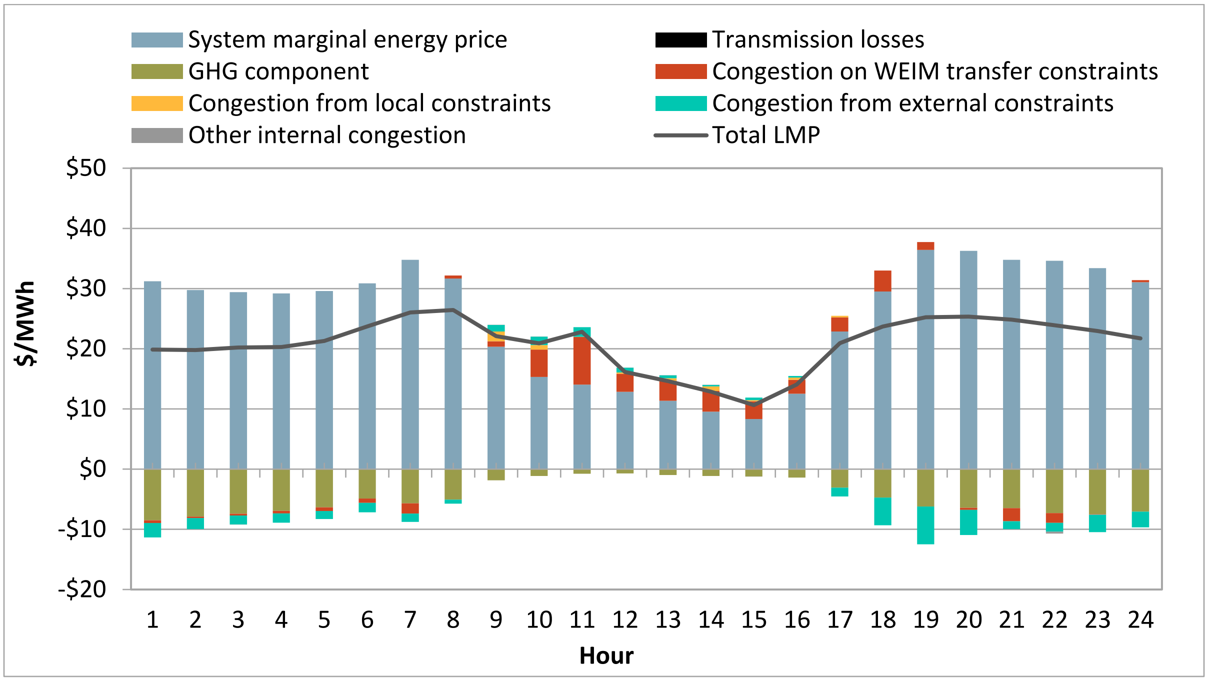


Appendix Figure A.56 Average hourly 5-minute market transfers

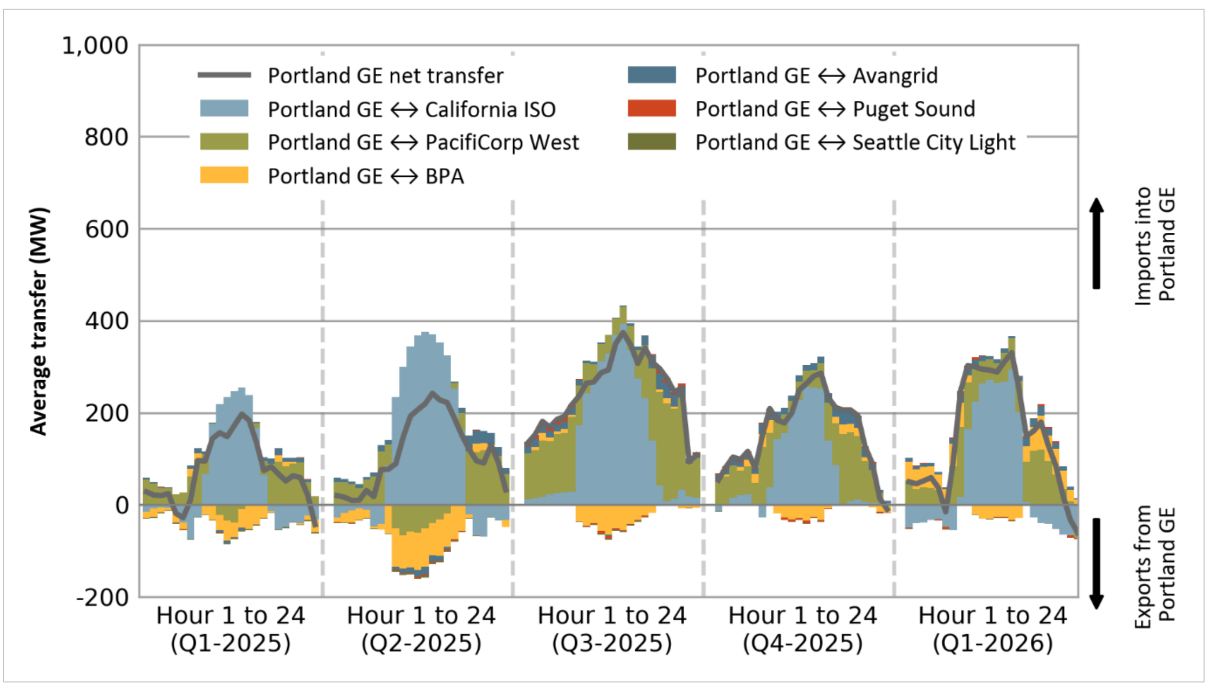


A.14 Portland General Electric

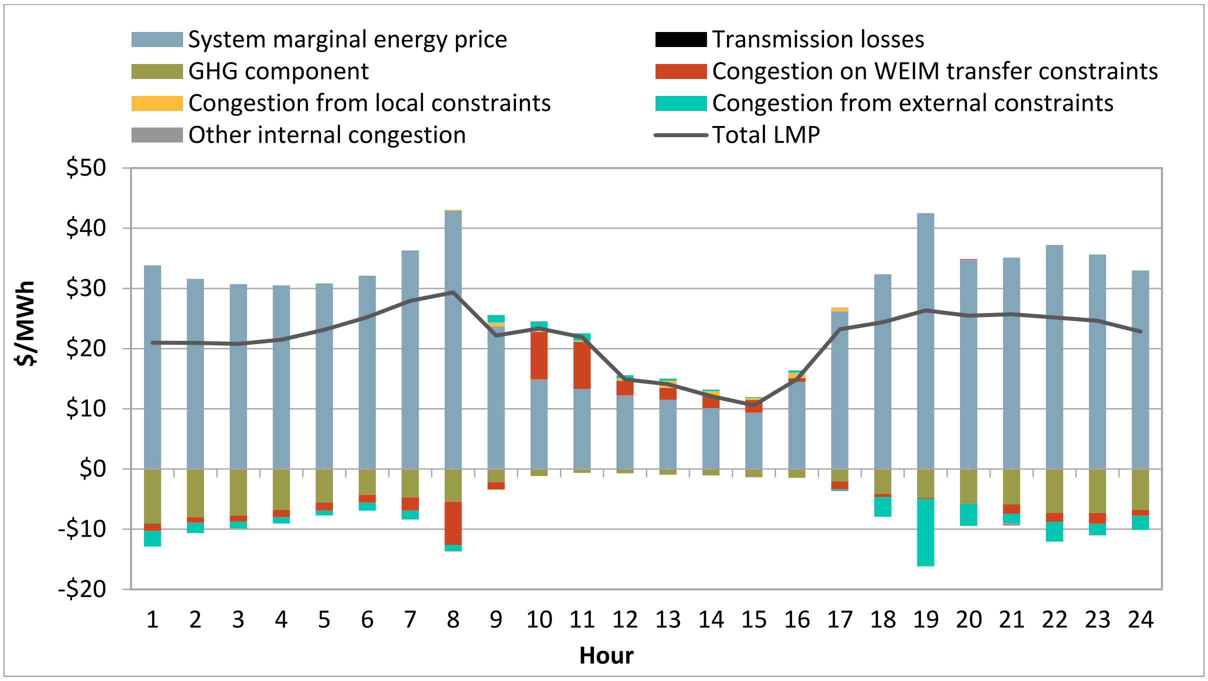
Appendix Figure A.57 Average hourly 15-minute price by component (Q1 2026)



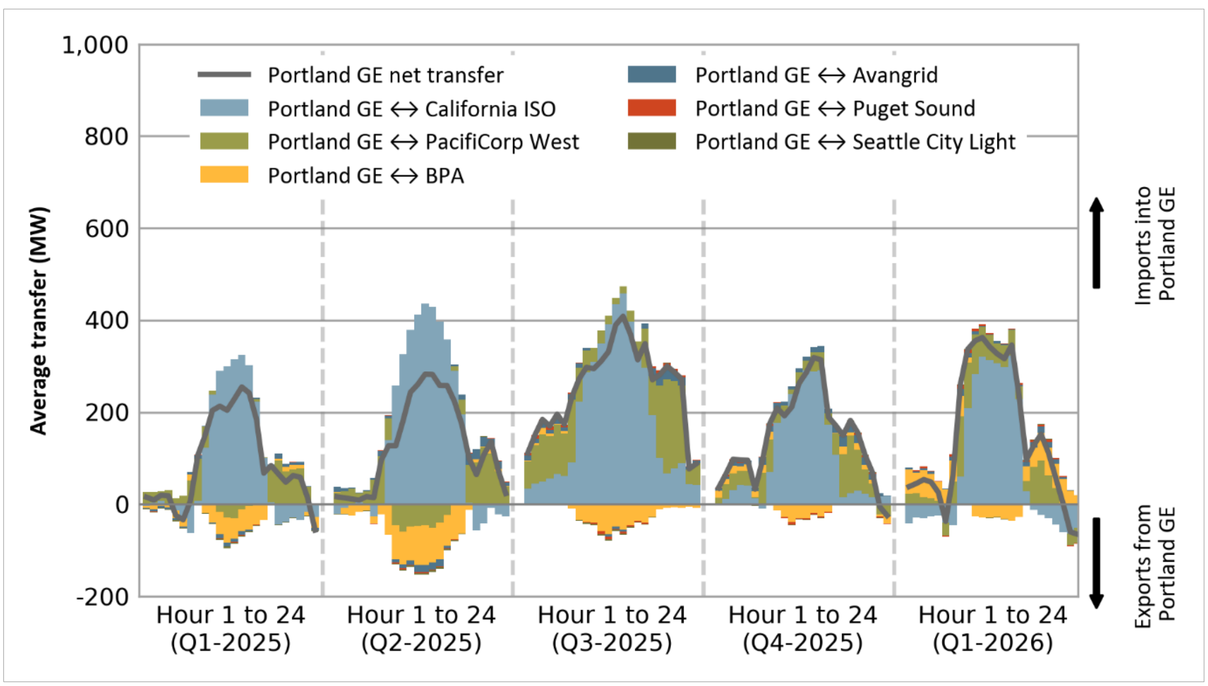
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q1 2026)

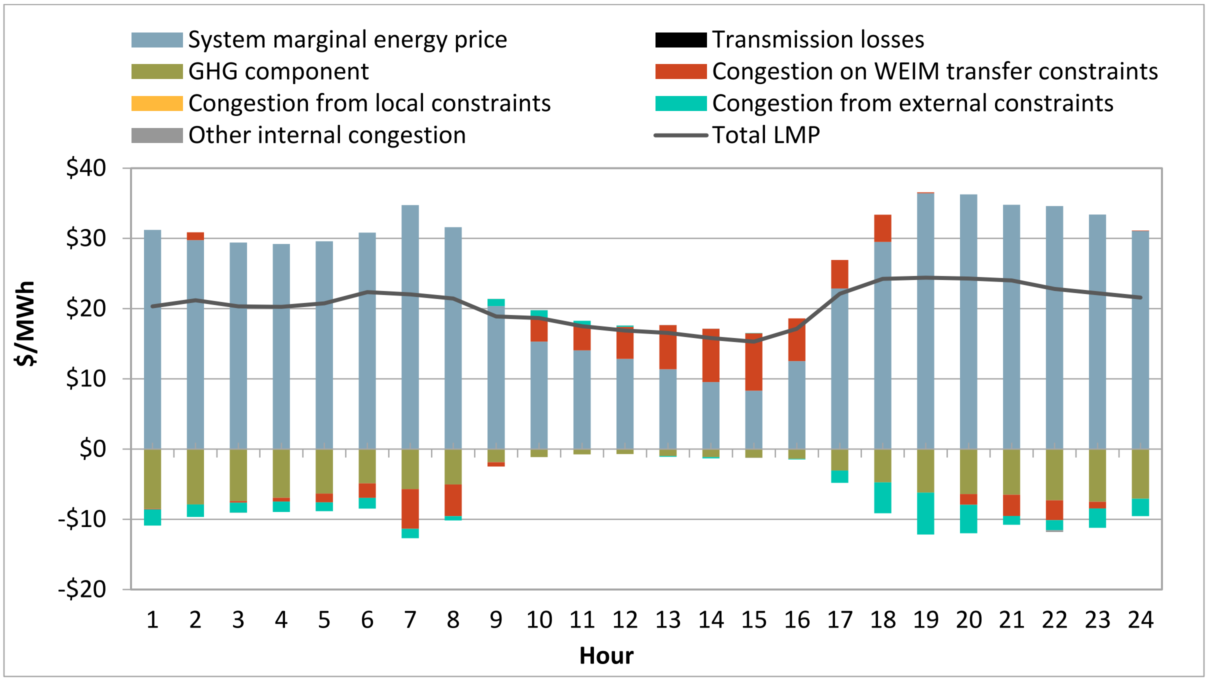


Appendix Figure A.60 Average hourly 5-minute market transfers

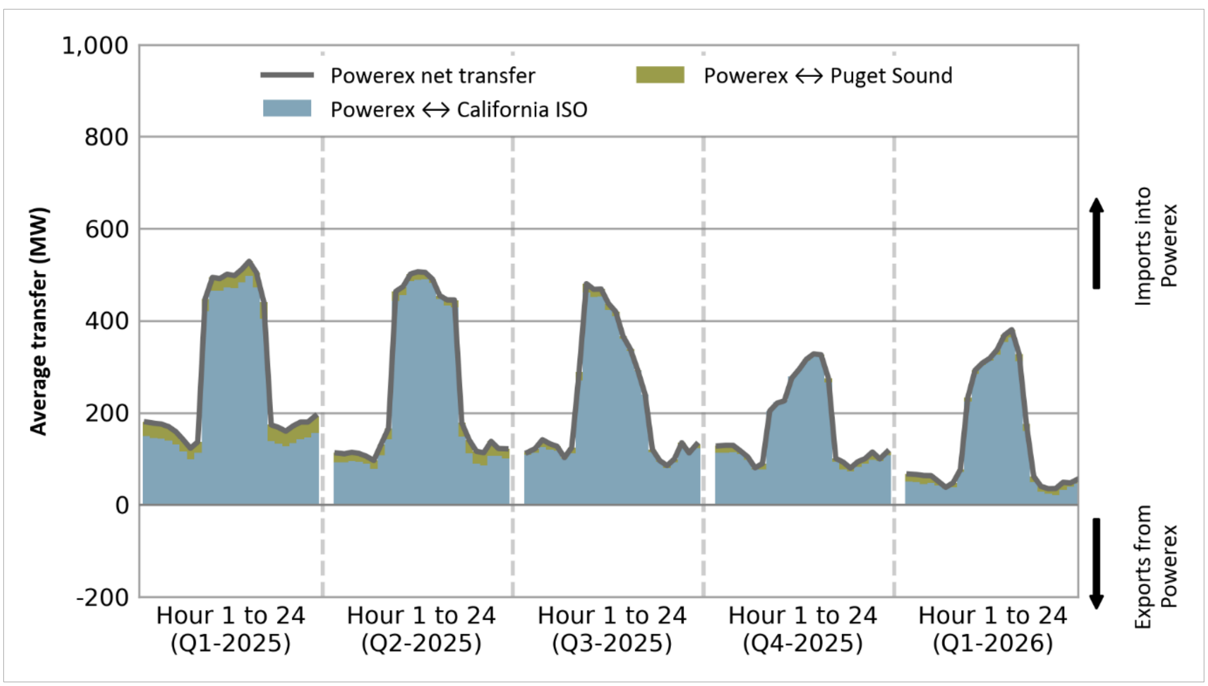


A.15 Powerex

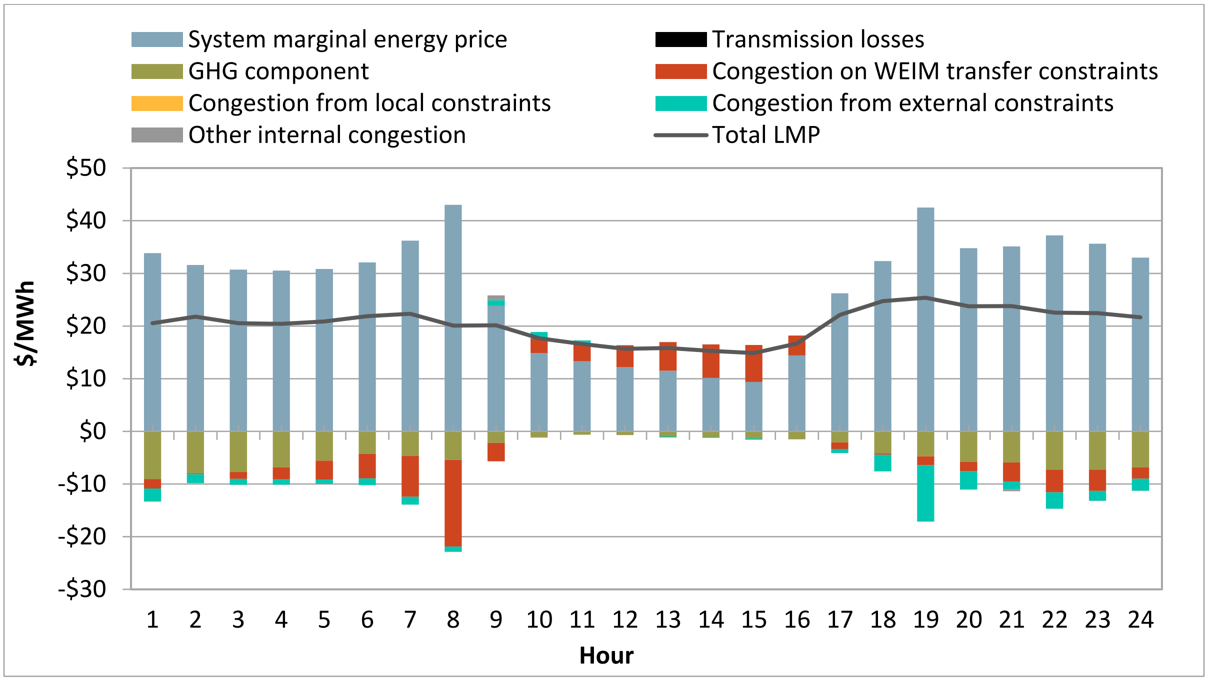
Appendix Figure A.61 Average hourly 15-minute price by component (Q1 2026)



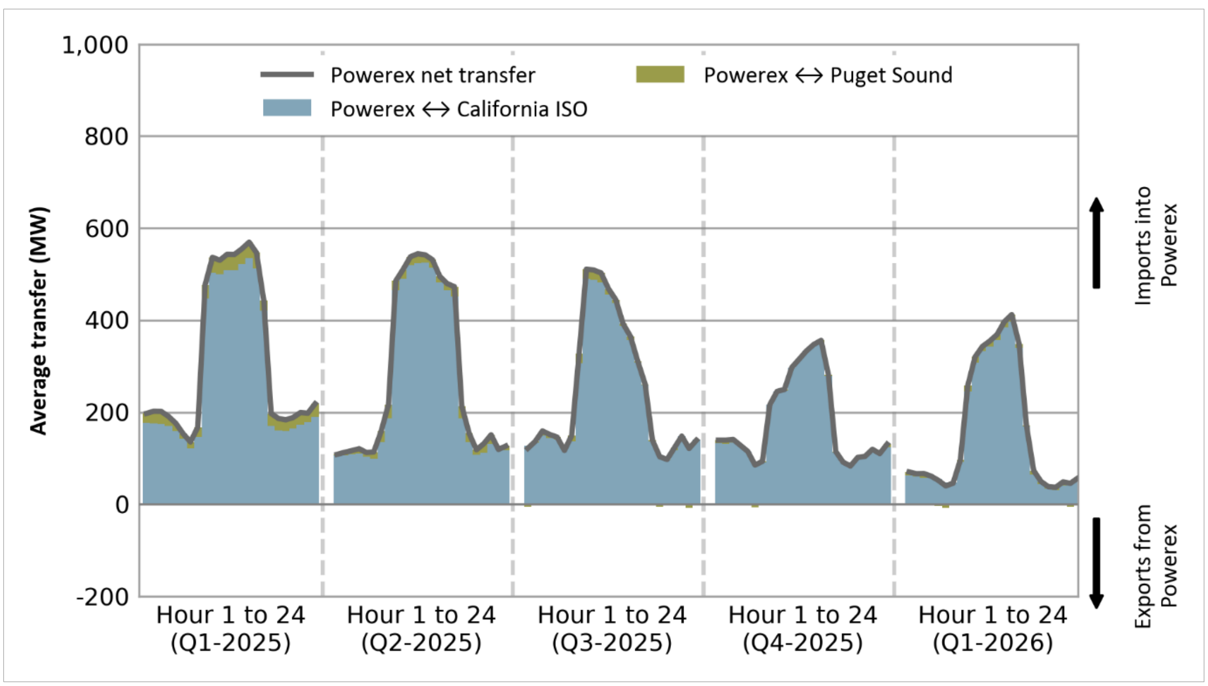
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q1 2026)

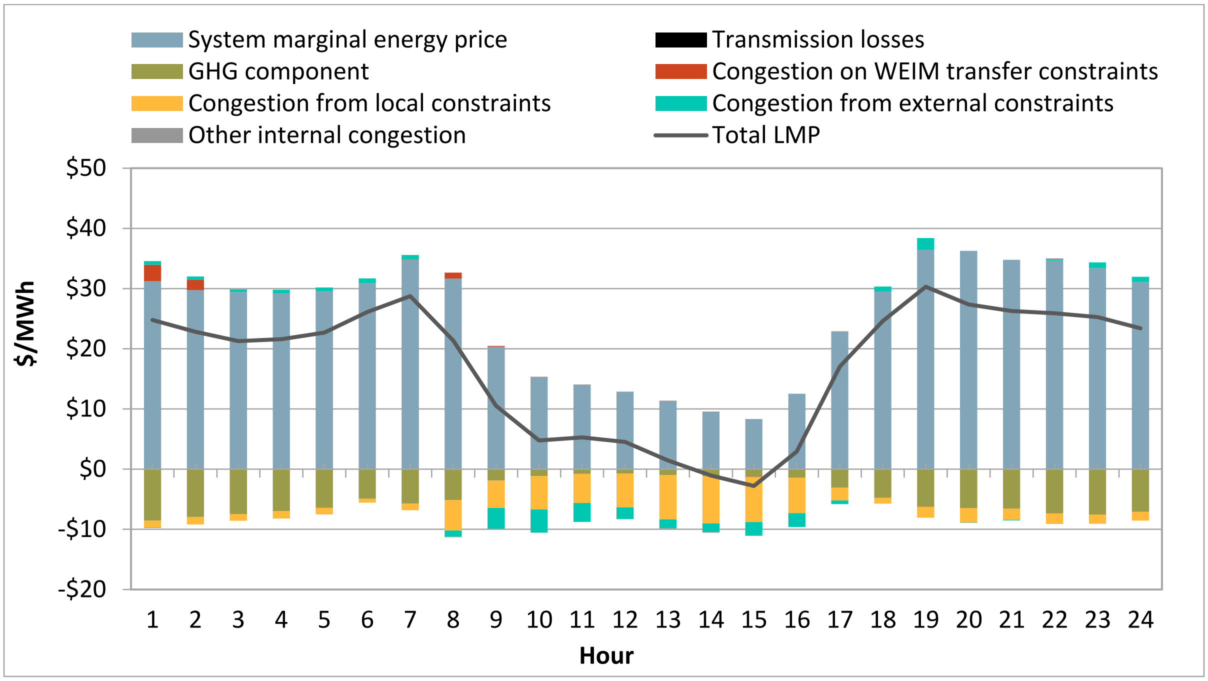


Appendix Figure A.64 Average hourly 5-minute market transfers

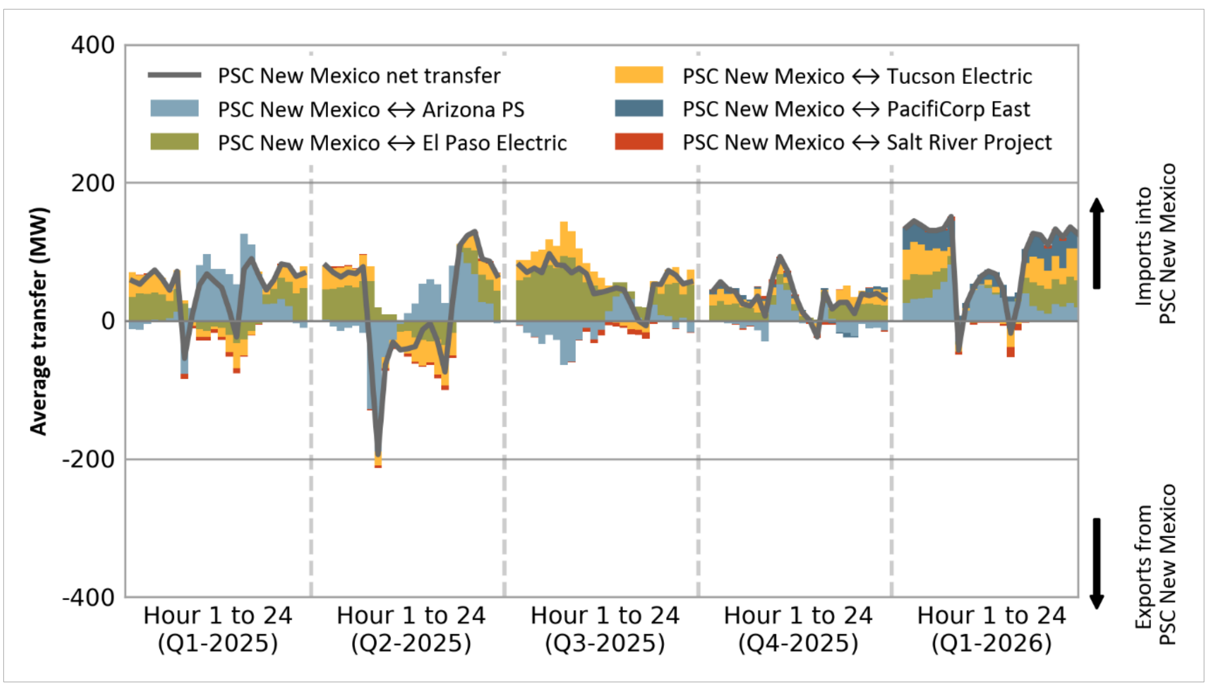


A.16 Public Service Company of New Mexico

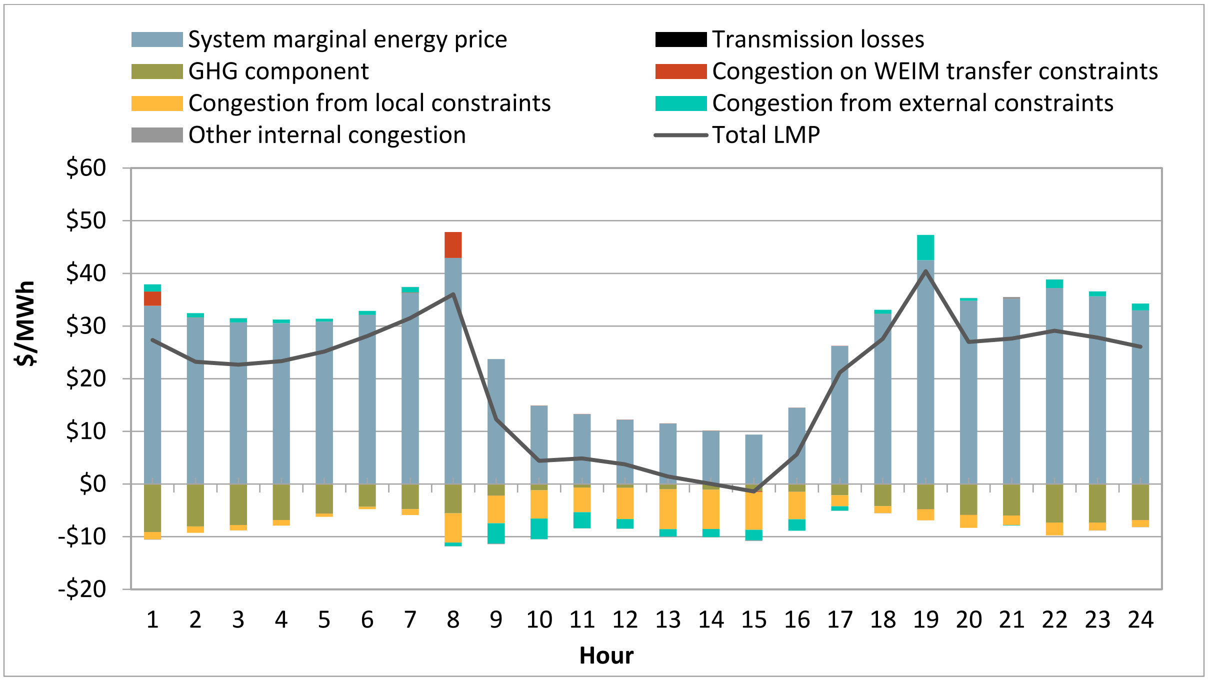
Appendix Figure A.65 Average hourly 15-minute price by component (Q1 2026)



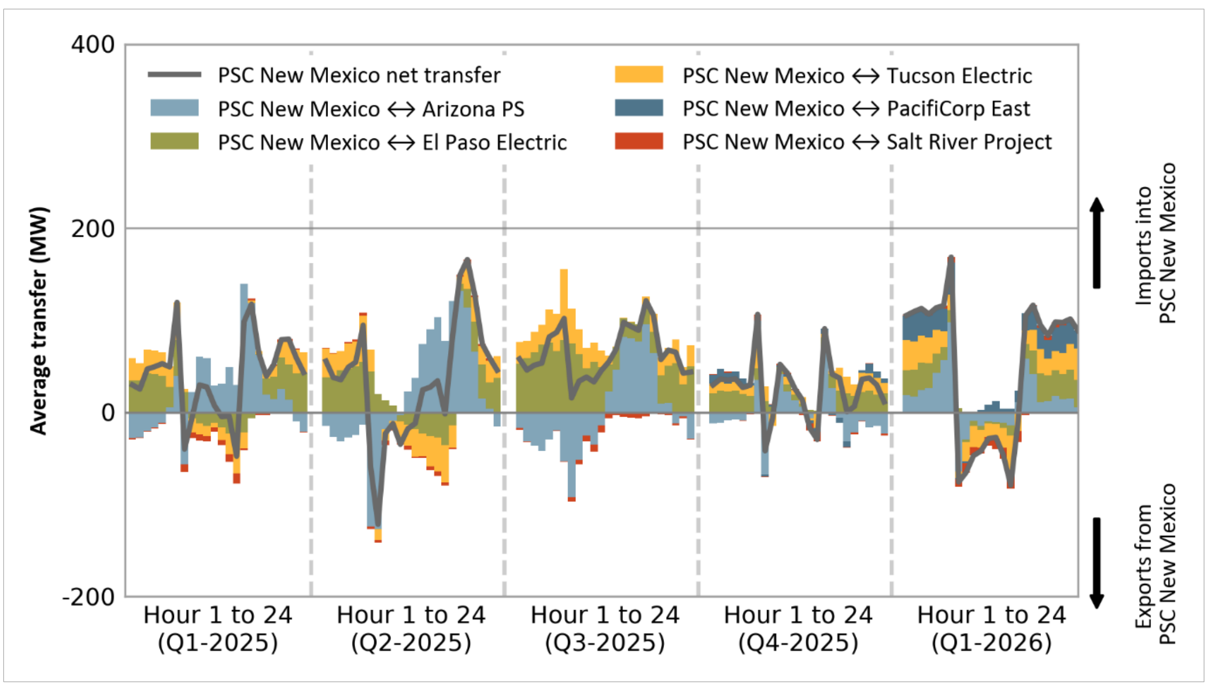
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q1 2026)

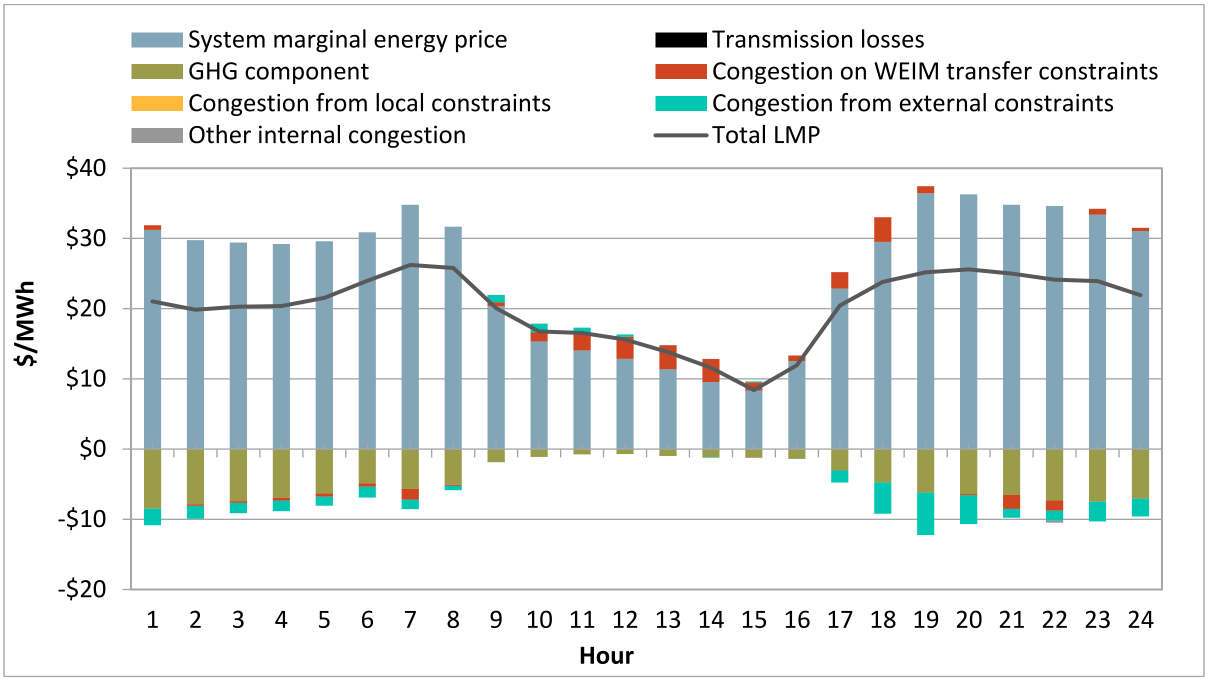


Appendix Figure A.68 Average hourly 5-minute market transfers

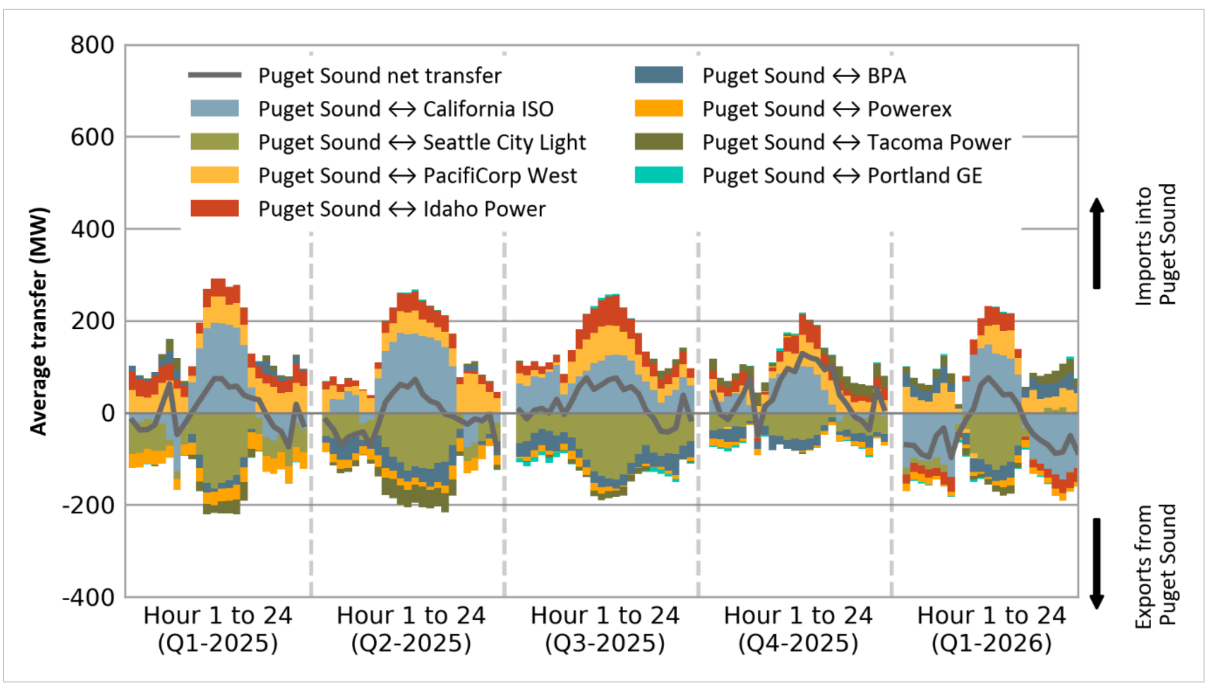


A.17 Puget Sound Energy

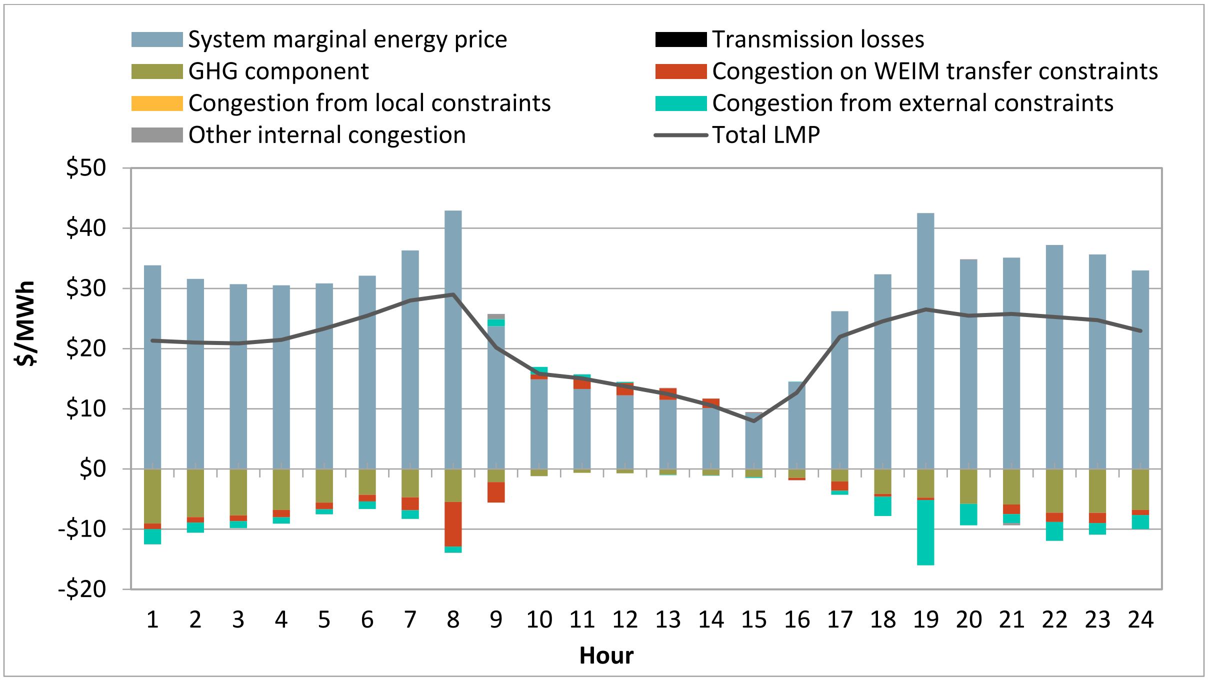
Appendix Figure A.69 Average hourly 15-minute price by component (Q1 2026)



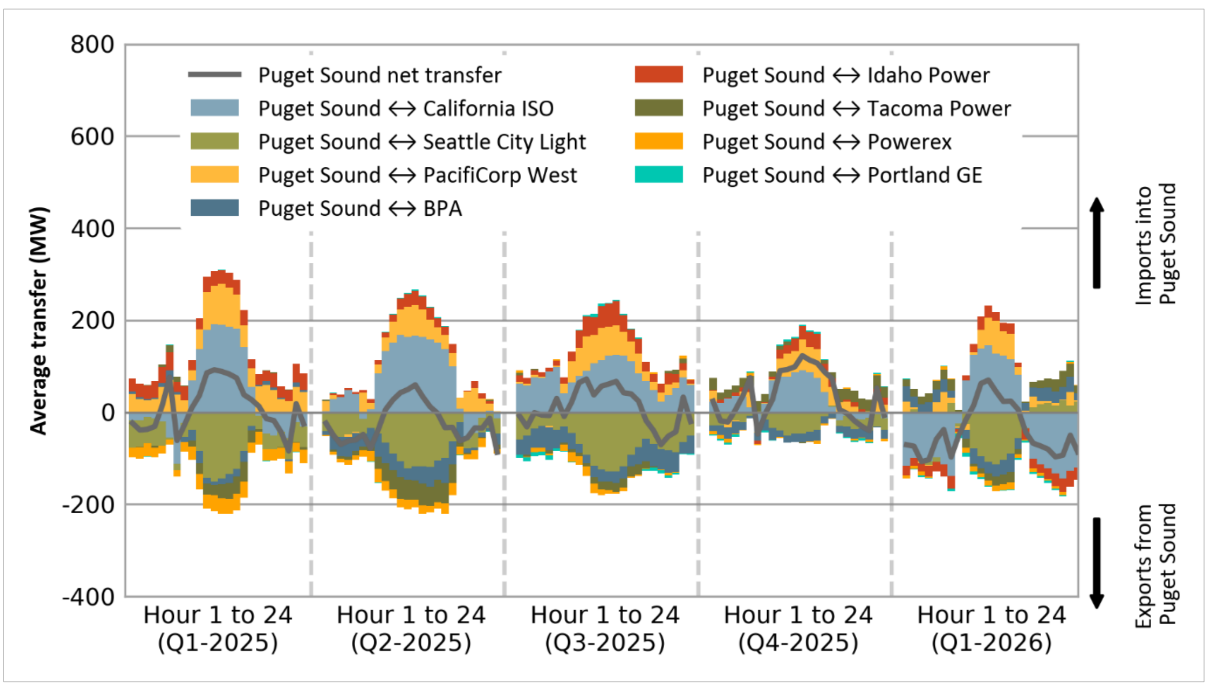
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q1 2026)

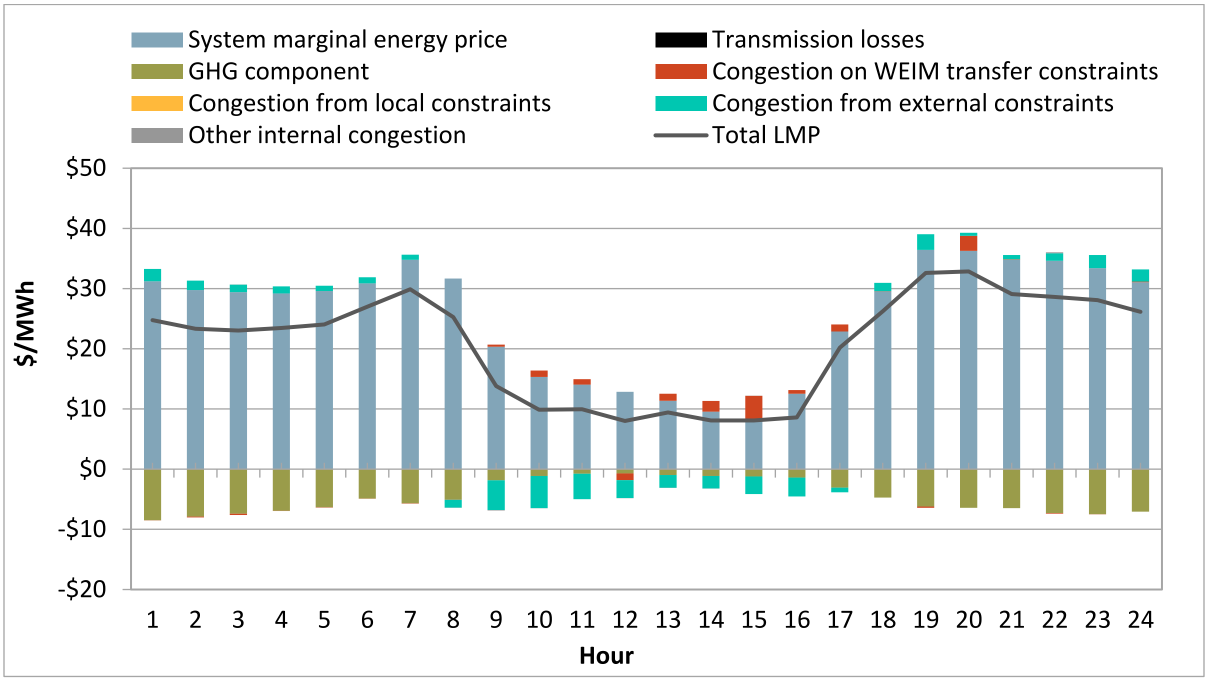


Appendix Figure A.72 Average hourly 5-minute market transfers

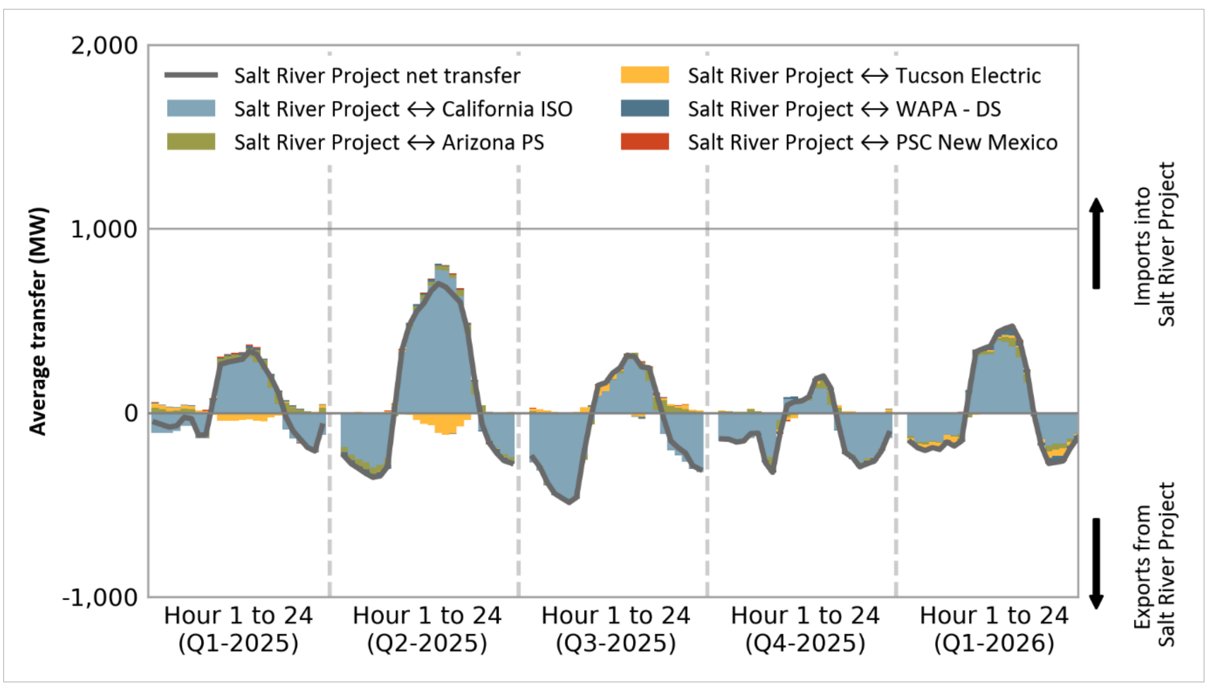


A.18 Salt River Project

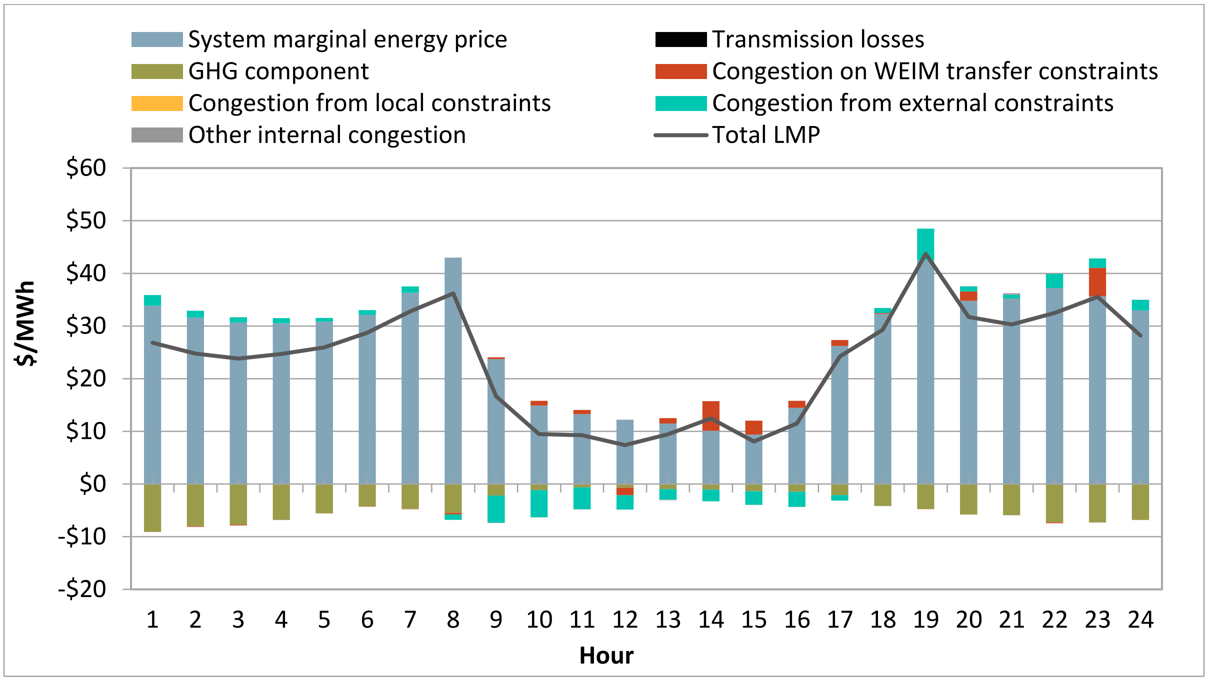
Appendix Figure A.73 Average hourly 15-minute price by component (Q1 2026)



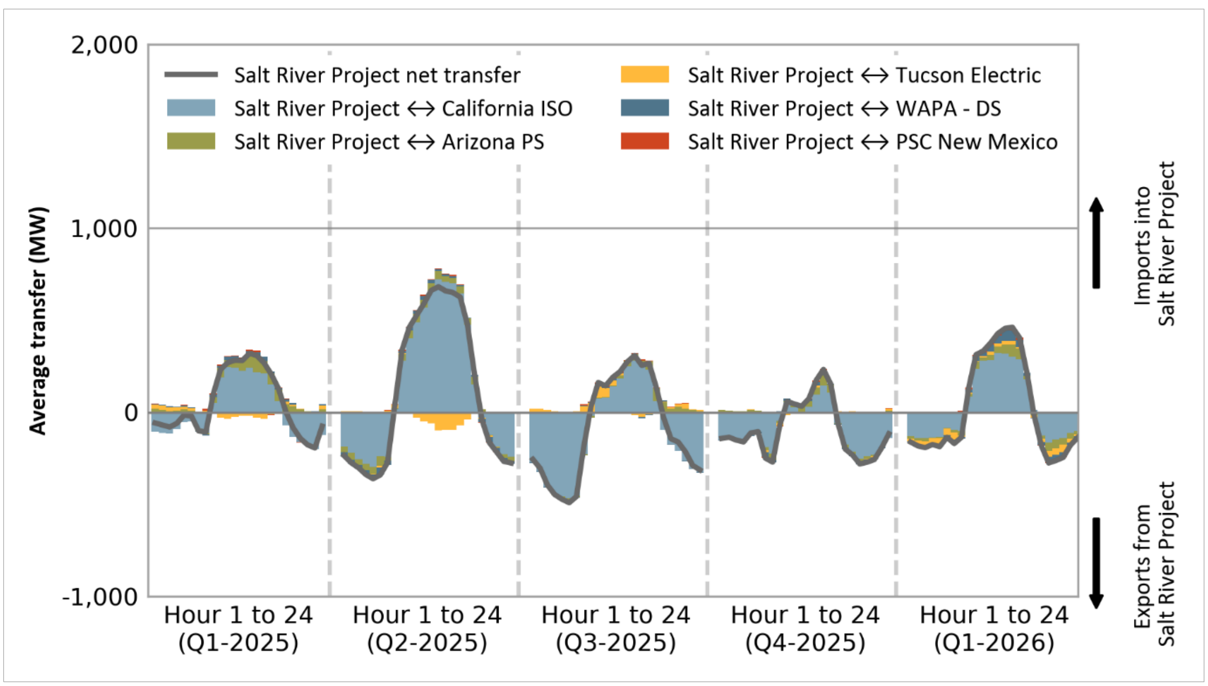
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q1 2026)

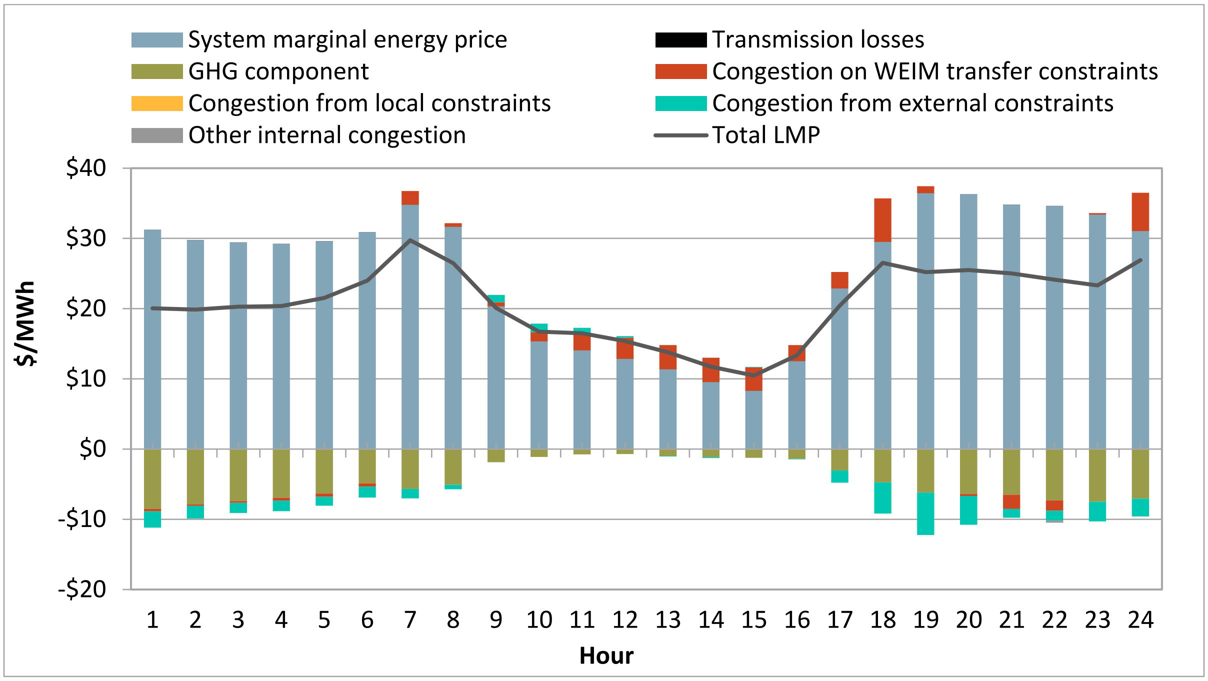


Appendix Figure A.76 Average hourly 5-minute market transfers

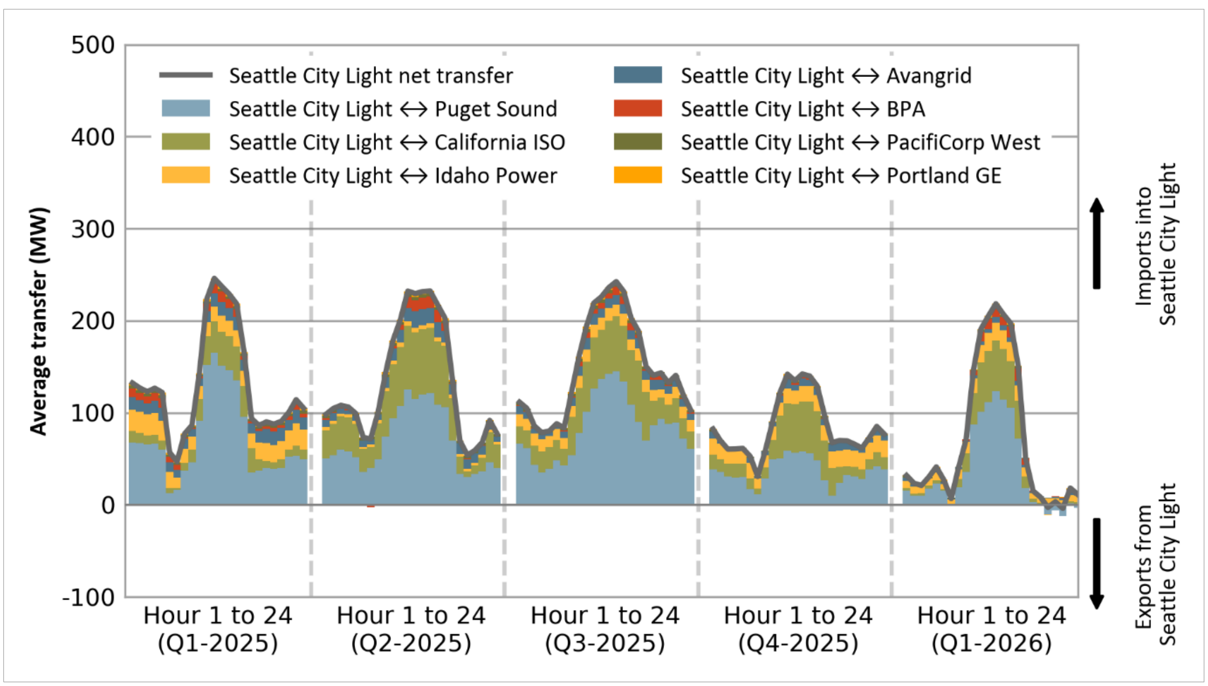


A.19 Seattle City Light

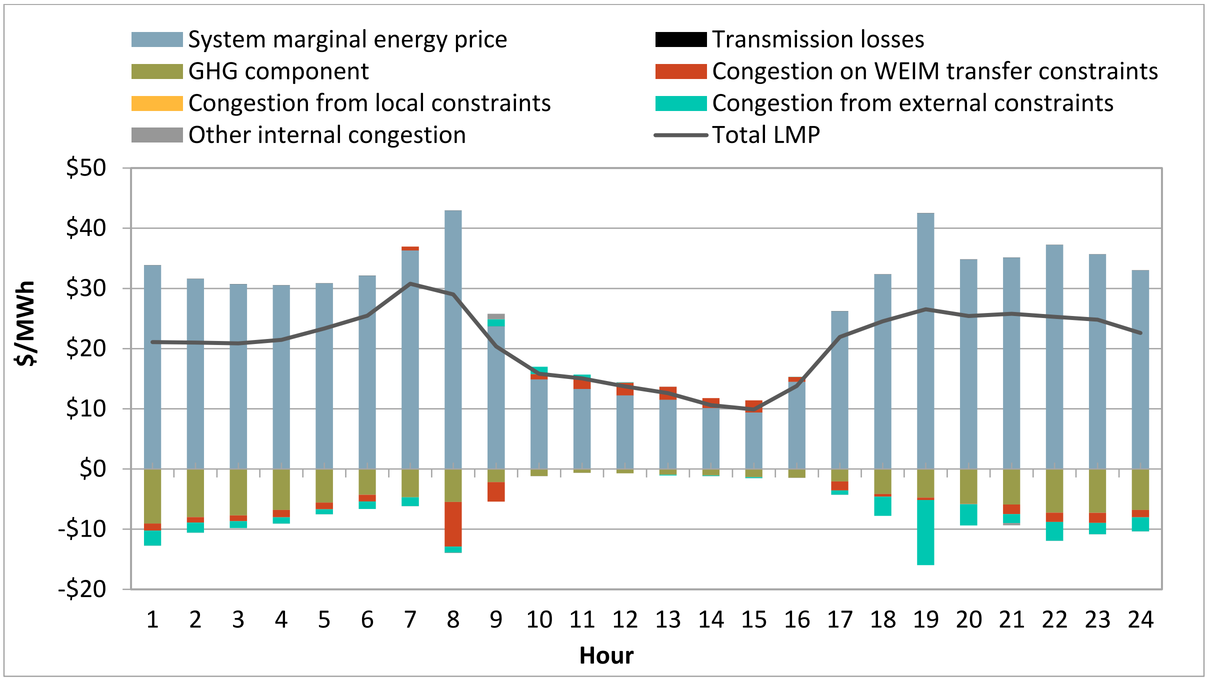
Appendix Figure A.77 Average hourly 15-minute price by component (Q1 2026)



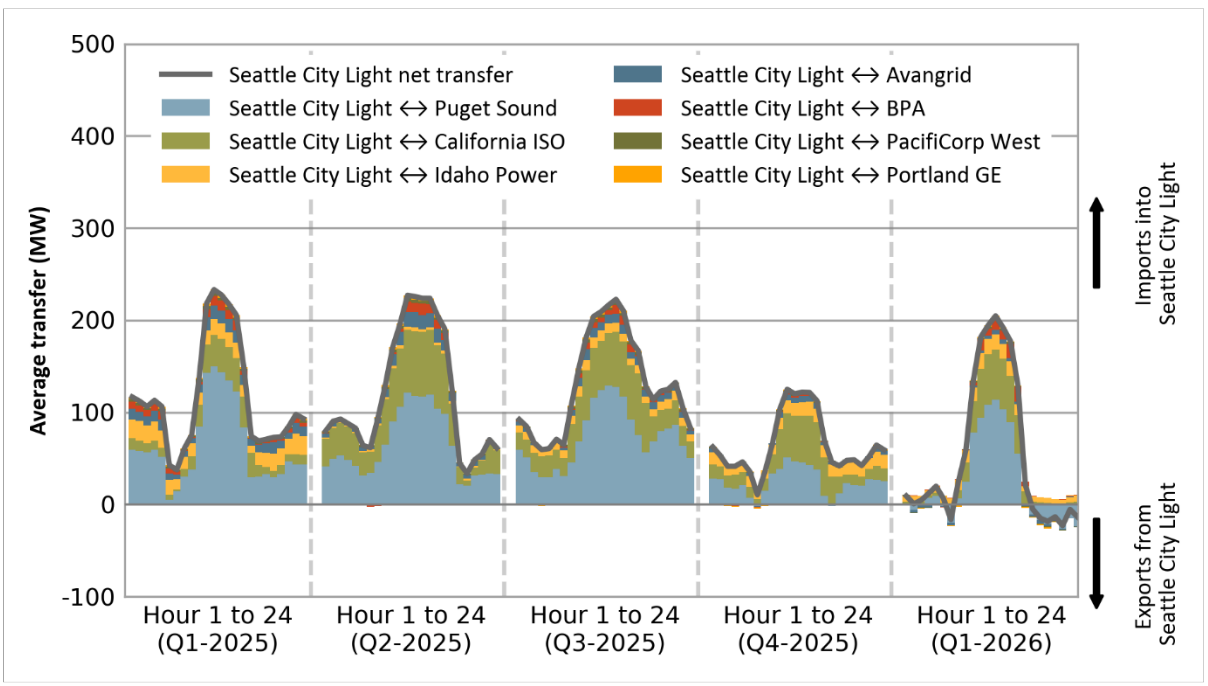
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q1 2026)

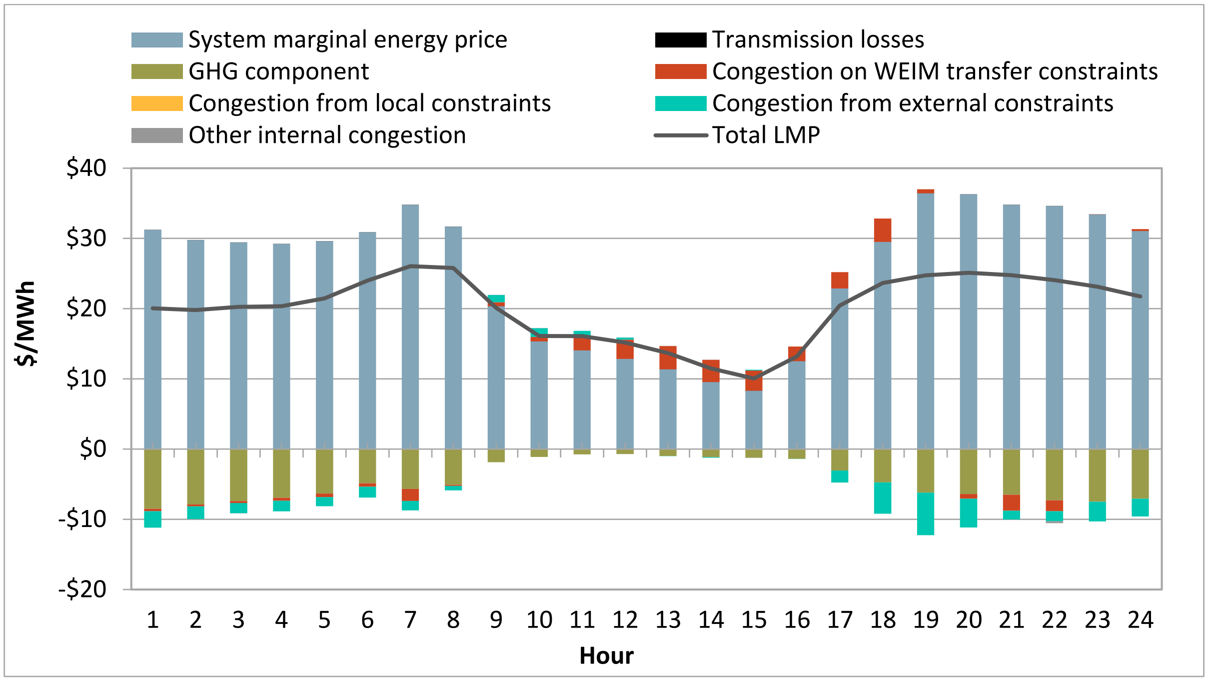


Appendix Figure A.80 Average hourly 5-minute market transfers

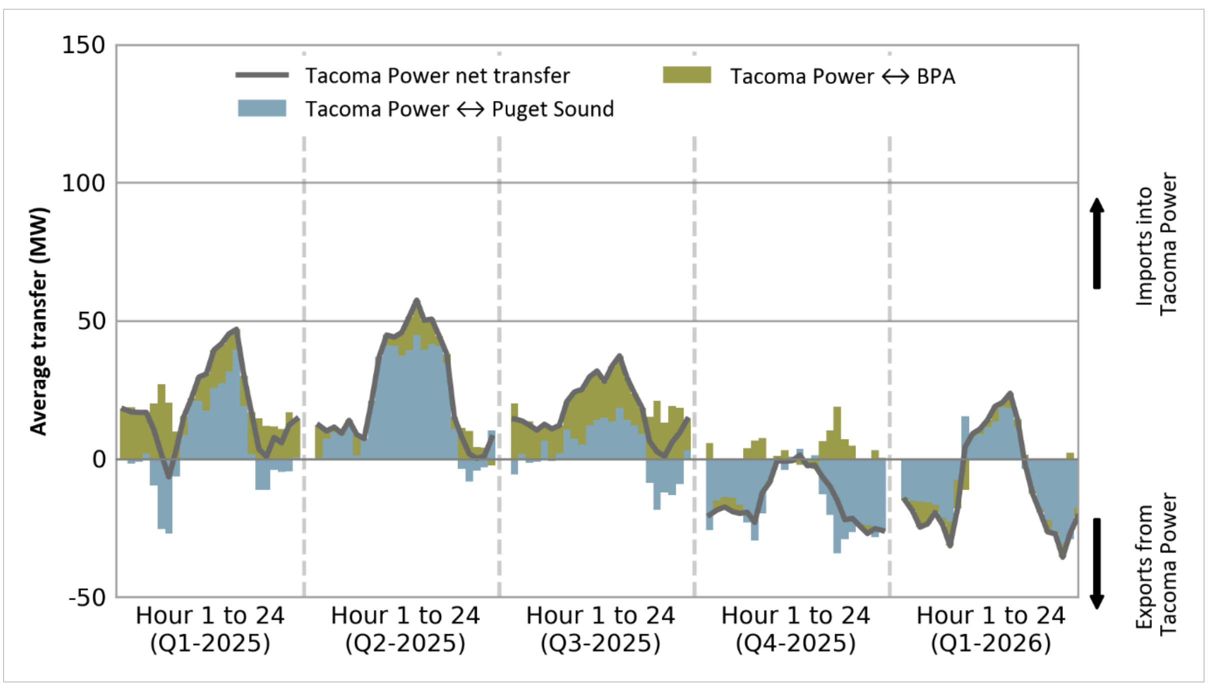


A.20 Tacoma Power

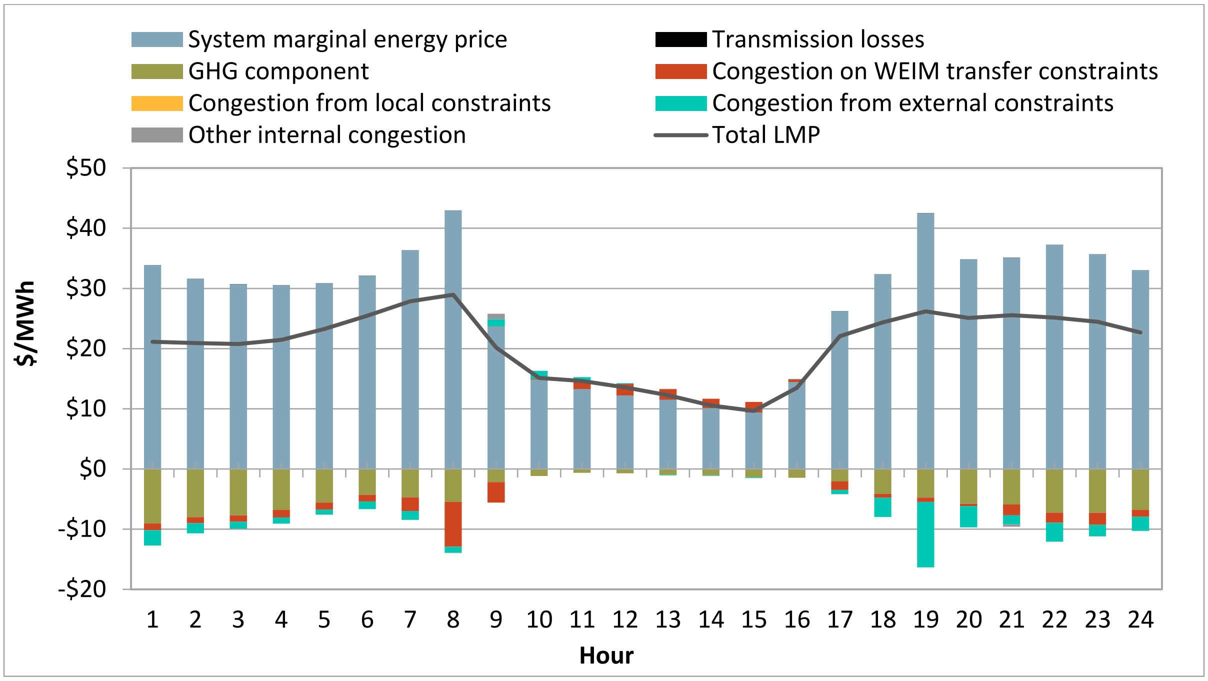
Appendix Figure A.81 Average hourly 15-minute price by component (Q1 2026)



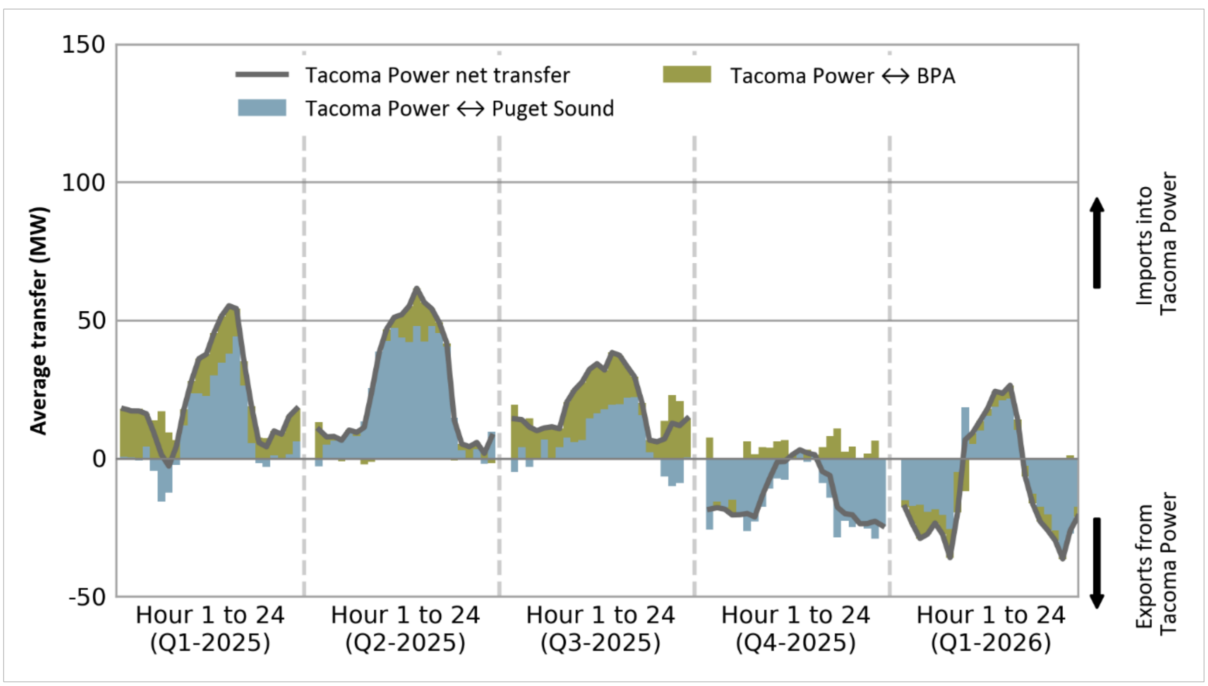
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q1 2026)

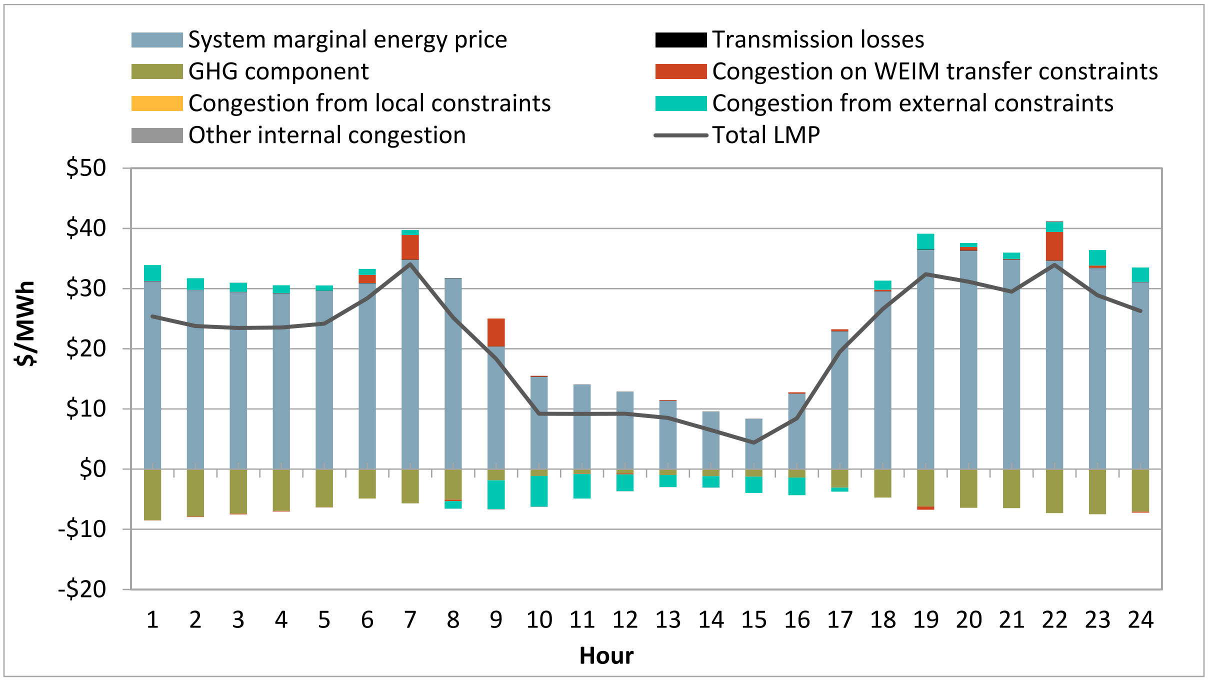


Appendix Figure A.84 Average hourly 5-minute market transfers

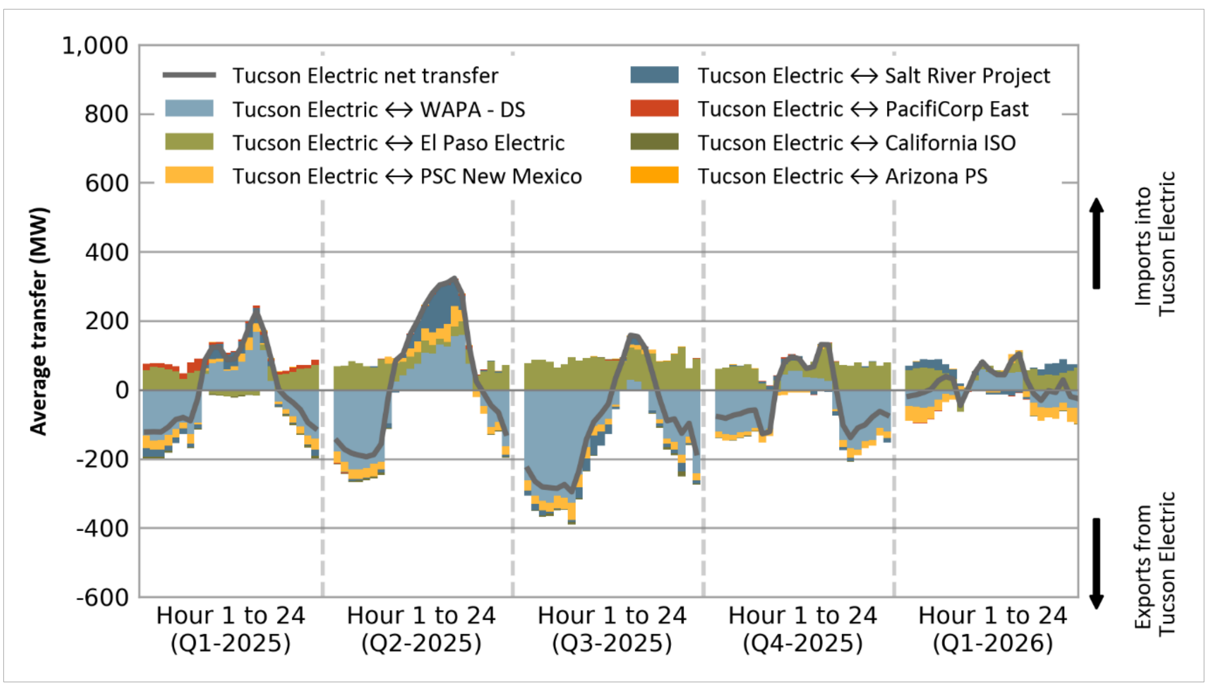


A.21 Tucson Electric Power

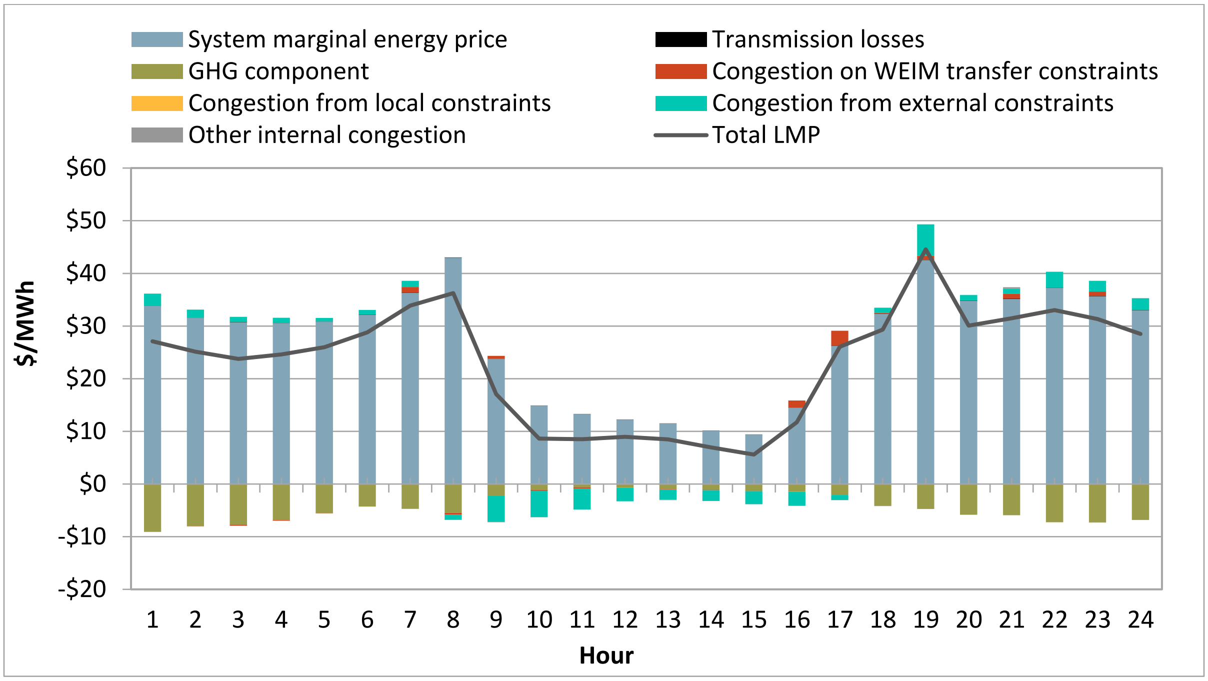
Appendix Figure A.85 Average hourly 15-minute price by component (Q1 2026)



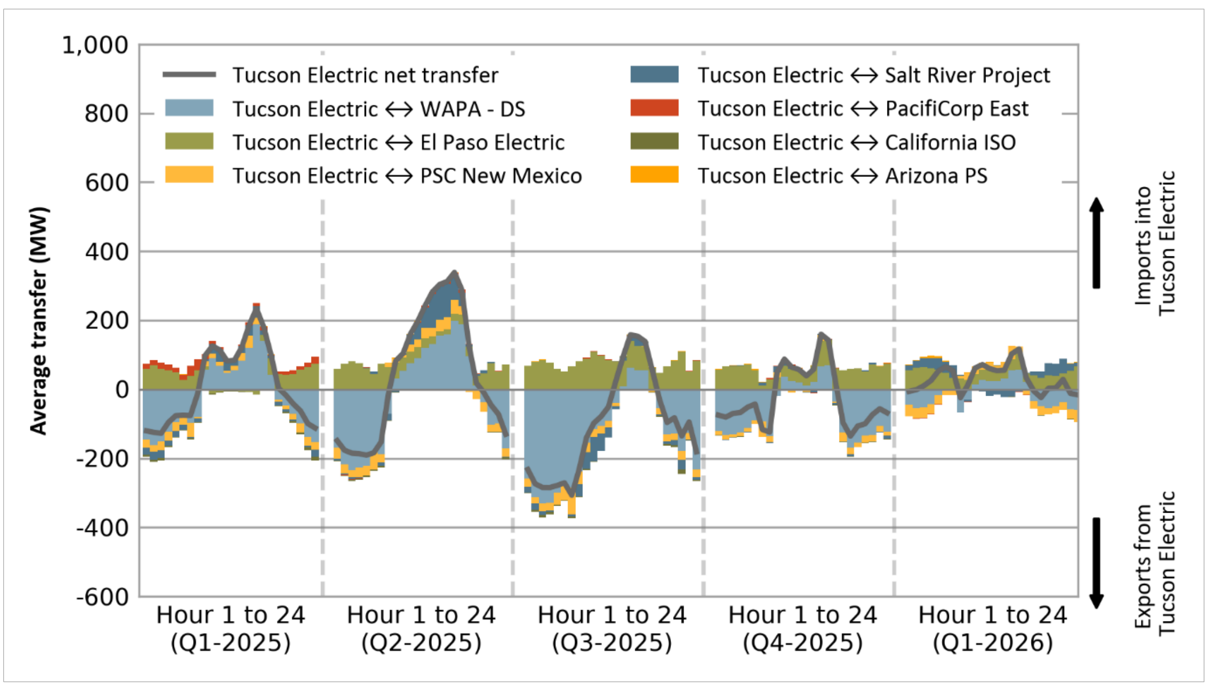
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q1 2026)

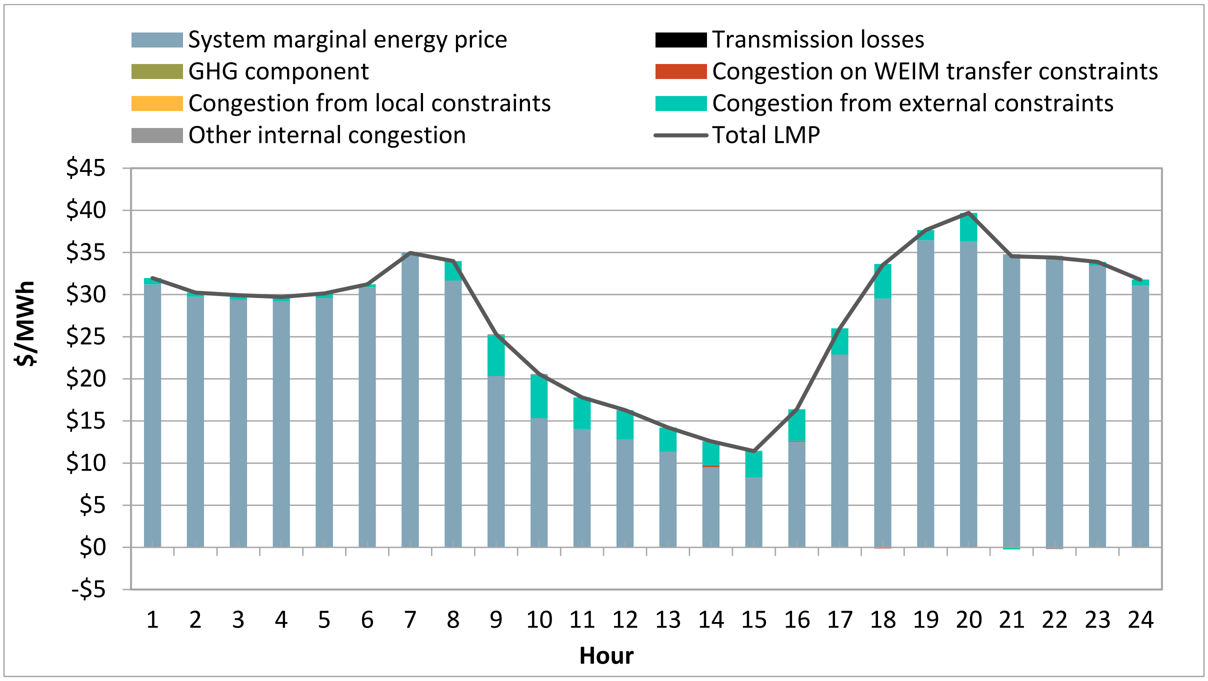


Appendix Figure A.88 Average hourly 5-minute market transfers

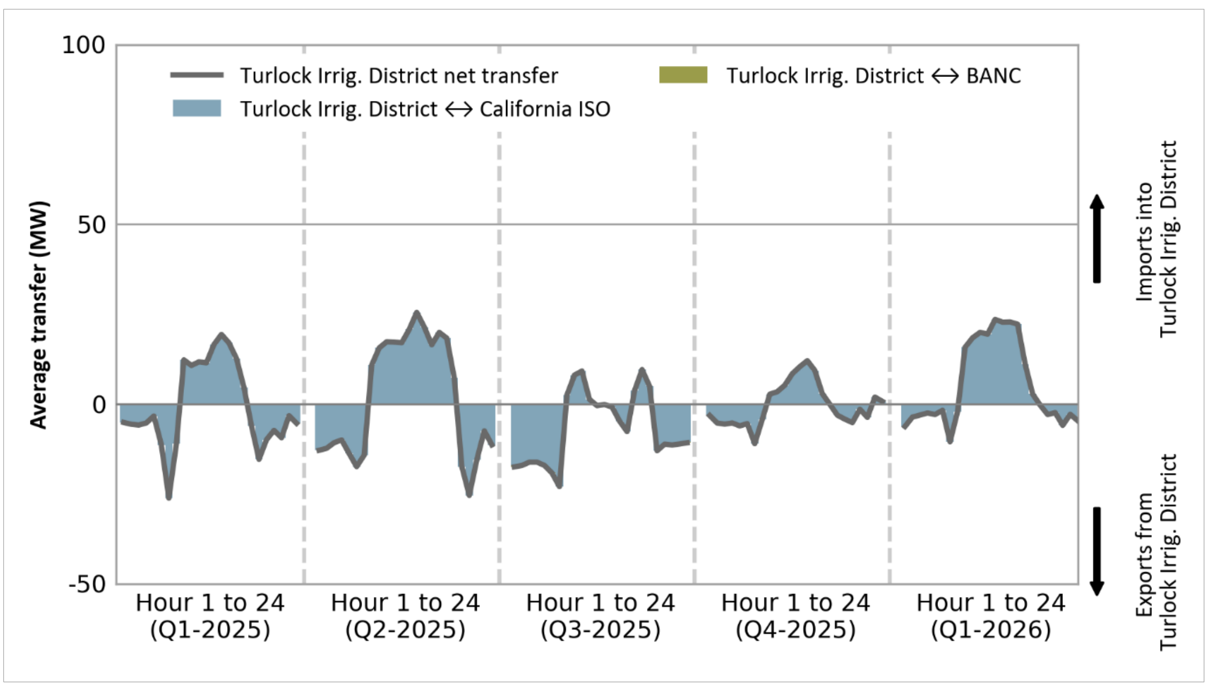


A.22 Turlock Irrigation District

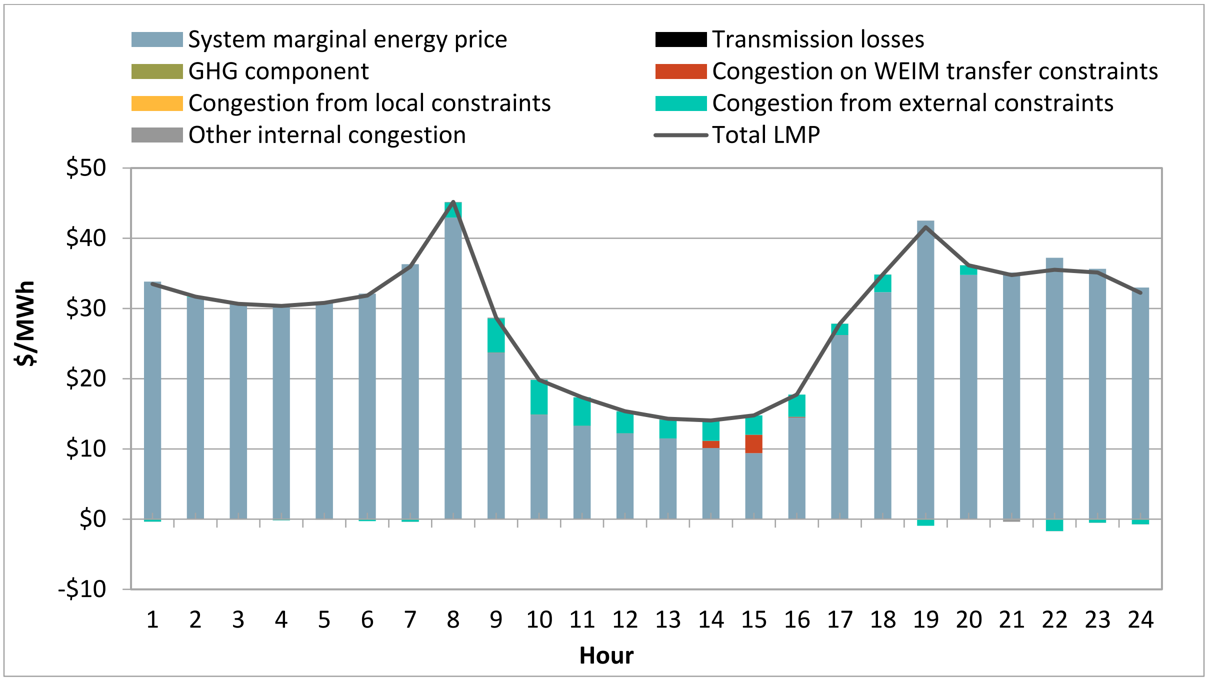
Appendix Figure A.89 Average hourly 15-minute price by component (Q1 2026)



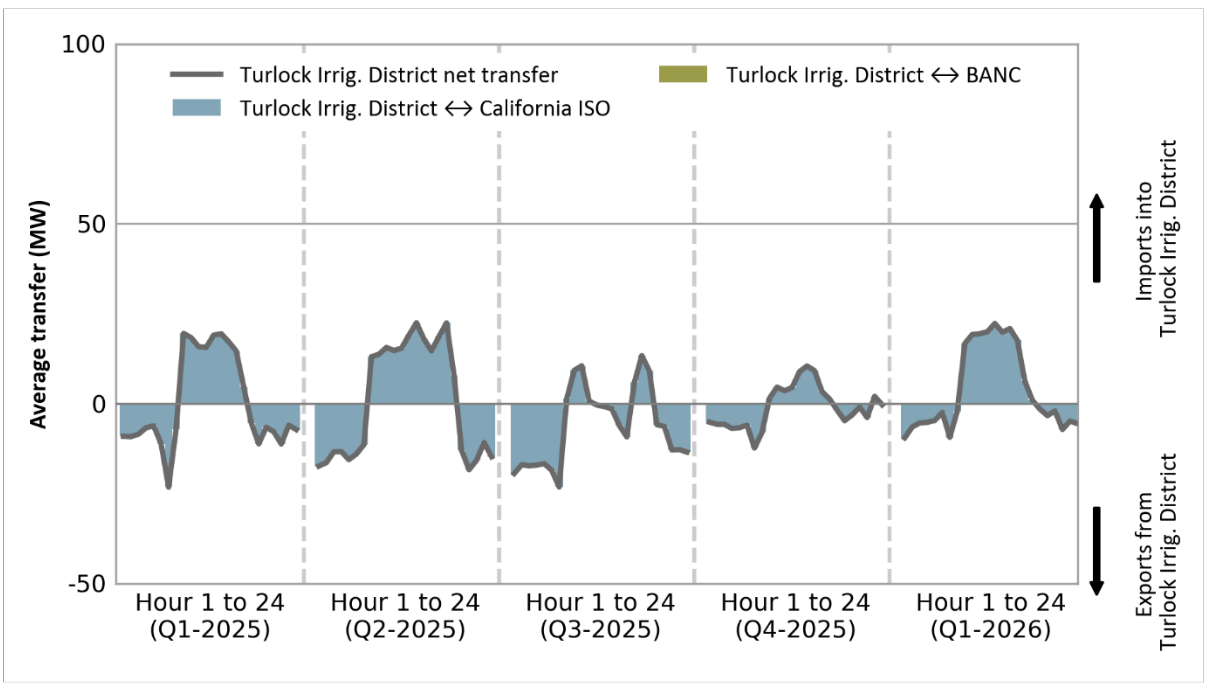
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q1 2026)

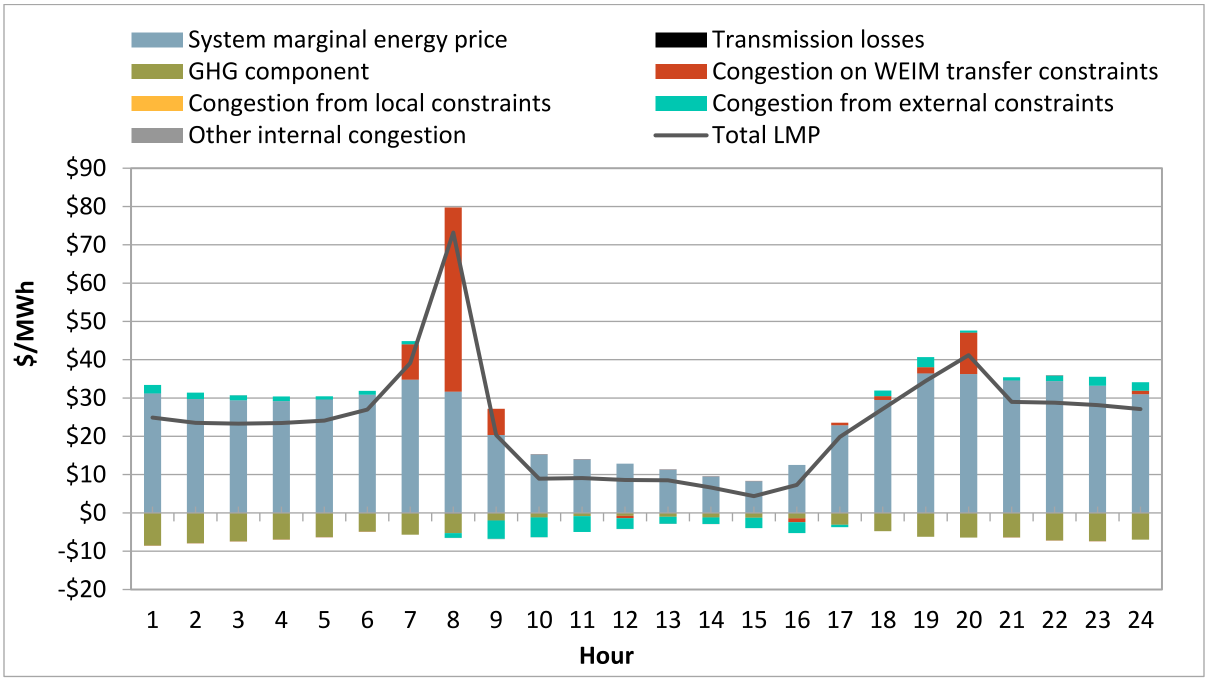


Appendix Figure A.92 Average hourly 5-minute market transfers

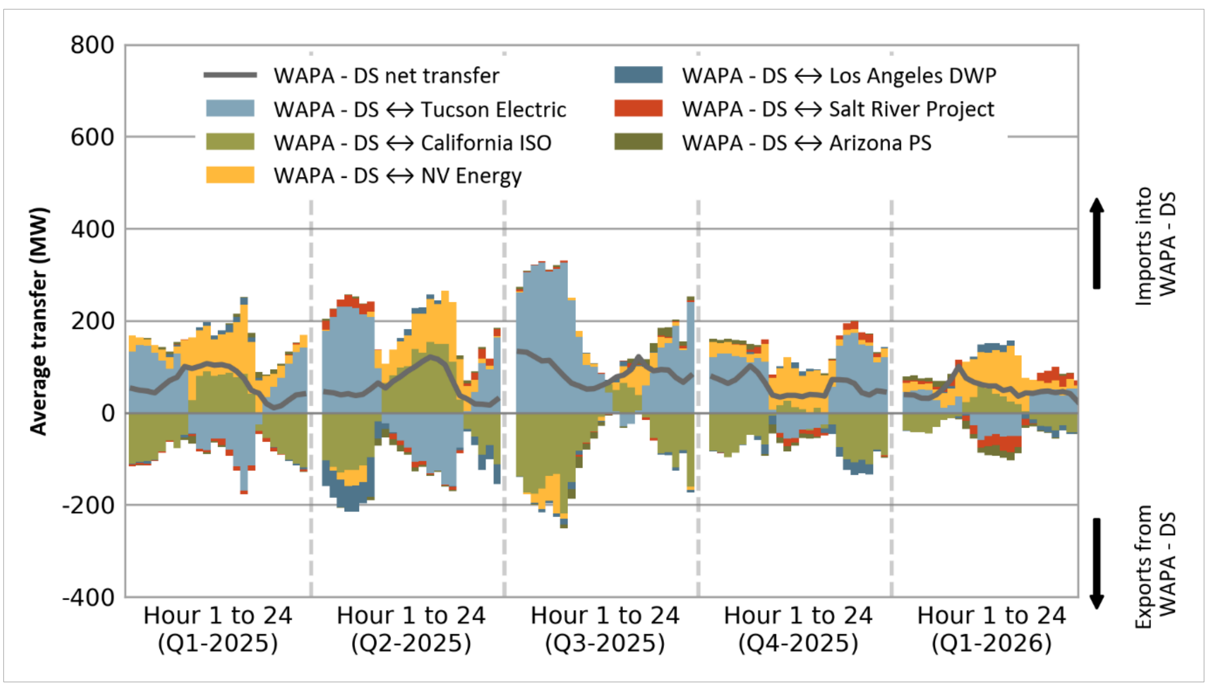


A.23 Western Area Power Administration Desert Southwest

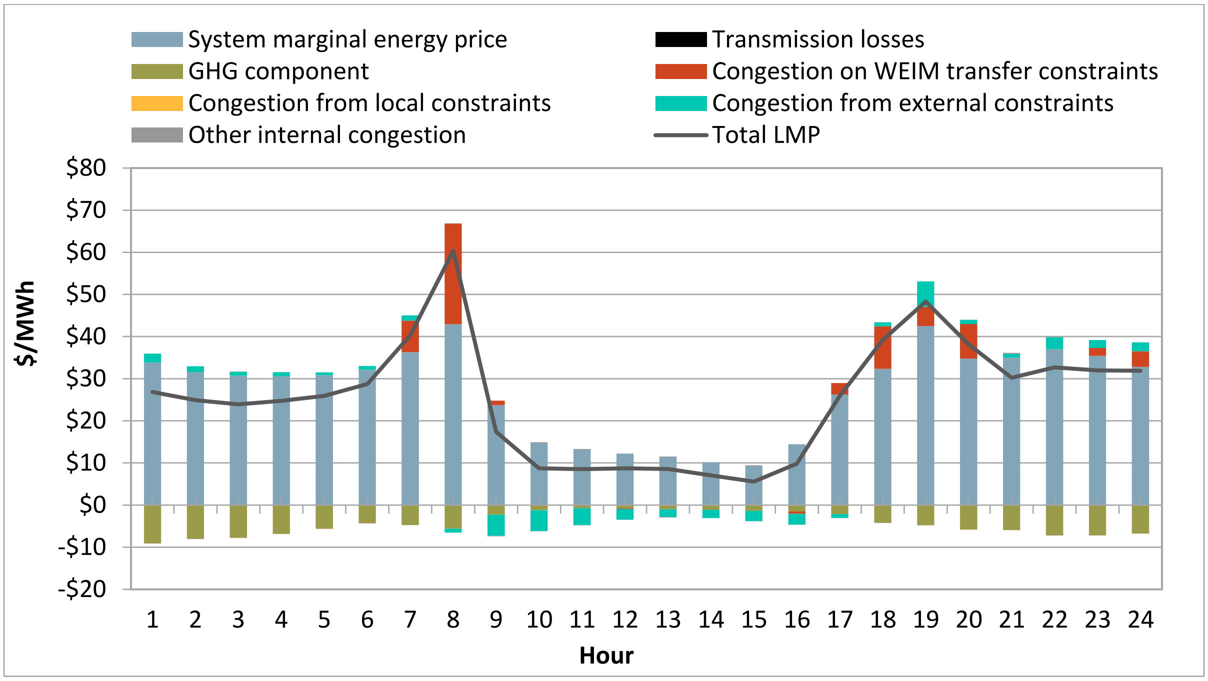
Appendix Figure A.93 Average hourly 15-minute price by component (Q1 2026)



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



Appendix Figure A.95 Average hourly 5-minute price by component (Q1 2026)



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