



California ISO

Q2 2026 Report on Market Issues and Performance

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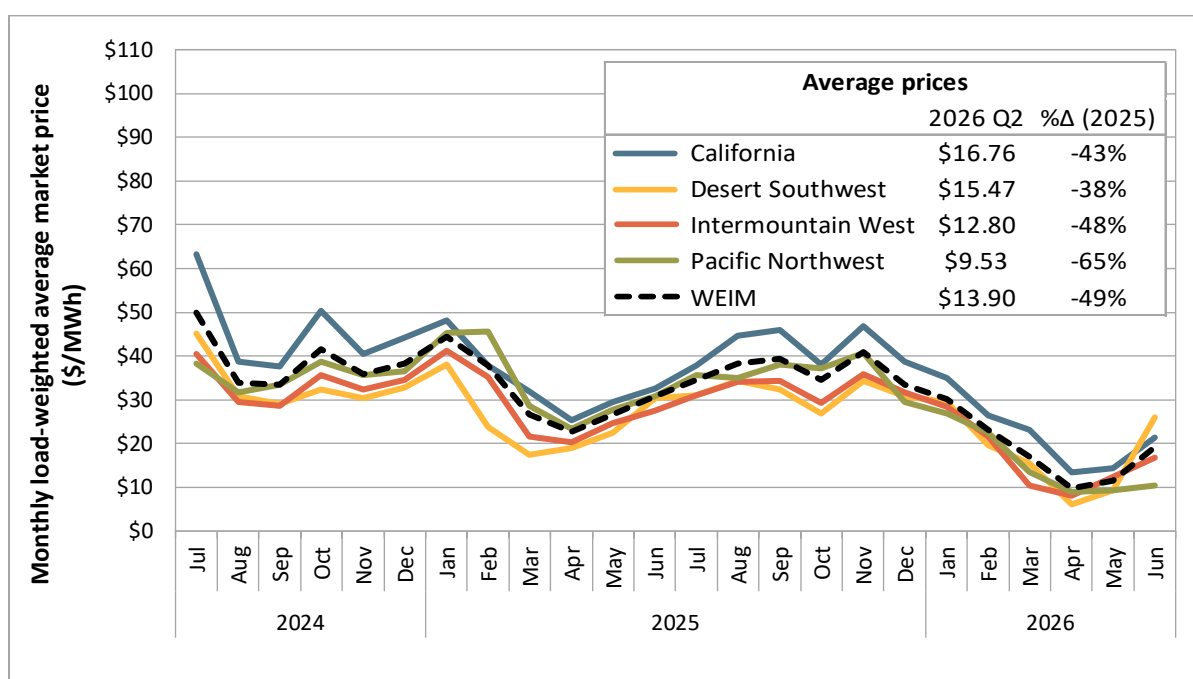
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Executive summary

This report covers market performance during the second quarter of 2026 (April–June). Overall 15-minute market prices across the Western Energy Imbalance Market (WEIM) averaged \$14/MWh, down 49 percent compared to the second quarter of 2025, due to lower natural gas prices and increased renewable energy production (Figure E. 1).

The extended day-ahead market (EDAM) launched May 1, 2026. EDAM prices averaged \$16/MWh across May and June, which was approximately equal to average 15-minute market prices of the three balancing areas participating in EDAM. The impact of transfer congestion on PacifiCorp East and PacifiCorp West prices was substantially different in the day-ahead market compared to the real-time markets due to less transfer capacity with neighboring areas in the day-ahead market.

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 Q2 2026**, with Henry Hub, PG&E Citygate, SoCal Citygate, and NW Opal Wyoming falling 7 percent, 45 percent, 23 percent, and 41 percent, respectively, compared to Q2 2025. El Paso Permian prices decreased to -\$1.74/MMBtu compared with \$1.30/MMBtu in the second quarter of 2025. Northwest Sumas prices increased slightly from very low second quarter 2025 prices.
- **Renewable output increased significantly across the WEIM footprint, with average hourly renewable generation up 5,900 MW (12 percent)** from Q2 2025. This included increases of 2,700 MW (12 percent) in hydro, 1,000 MW (8 percent) in solar, and 2,300 MW (25 percent) in wind.

- **Renewable patterns varied by region** with California having a rare decrease in solar production while solar increased significantly in the Desert Southwest and Intermountain West compared to Q2 2025.¹ Hydro generation increased significantly in the Pacific Northwest. Each region saw a large increase in wind production.
- **Changes in regional fuel-mix patterns reflected the year-over-year changes in renewable production.** The large increase in Pacific Northwest hydro production led to more exports out of the region, more imports into the Intermountain West and California regions, and decreased natural gas generation in all three regions. Higher solar and wind production supported larger load in most regions and contributed to increased battery charging during solar hours and increased battery discharging during morning and evening non-solar hours across the WEIM.
- **Black Hills Energy and Power Watch (formerly BHE Montana) joined the WEIM on May 6, 2026.** Power Watch joined with roughly 260 MW of dynamic transfer capacity with NorthWestern Energy, on average. Its generation capacity consists of about 400 MW of wind and 75 MW of batteries. Black Hills joined with around 250 MW of dynamic transfer capacity with PacifiCorp East. Its generation capacity consists of about 800 MW of coal resources, 370 MW of natural gas, and 230 MW each of wind and solar capacity.
- **PacifiCorp West was a net importer of EDAM transfers on average in all hours.** During the high solar production hours between hours-ending 8 and 18, the CAISO balancing area exported on average around 300 MW to PacifiCorp West in the day-ahead market. In the remaining hours, PacifiCorp East exported on average around 140 MW to PacifiCorp West.
- **The average volume of EDAM energy transfers across the system was around 670 MW during May and June.**
- **WEIM transfers averaged 4,800 MW over May and June, slightly lower compared to the same period of 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 the CAISO balancing area to other WEIM regions. During non-solar hours, transfers were lower and were largely into California from the rest of the WEIM.
- **Load across the WEIM averaged 77.1 GW, an increase of about 3.1 percent compared to the same quarter of 2025.** Average load in California decreased by 1.1 percent, whereas average load in the Pacific Northwest, Desert Southwest, and Intermountain West regions increased by 3.0 percent, 7.4 percent, and 7.3 percent, respectively. Black Hills Energy load averaged about 590 MW from May 6 through the end of the quarter. Peak 5-minute market load for the second quarter was 120.8 GW on June 15, 2026, hour-ending 18, interval 11, down slightly from the Q2 2025 peak load of about 123.0 GW.

Prices and congestion

- **Real-time prices decreased significantly across the WEIM.** WEIM prices averaged \$14/MWh in both the 15-minute and 5-minute markets, down 49 percent and 48 percent, respectively, from Q2 2025. Prices were highest in California at \$17/MWh in the 15-minute market, primarily due to greenhouse gas costs during non-solar hours. Prices were lowest in the Pacific Northwest at \$10/MWh, brought

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, PACE, Black Hills, and Power Watch. Pacific Northwest includes AVRN, BCHA, BPAT, PACW, PGE, PSEI, SCL, and TPWR.

down by low prices in Powerex across all hours. Hourly 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 \$16/MWh, down about 44 percent compared to Q2 2025.** Average 15-minute market prices were \$16/MWh and 5-minute market prices were \$17/MWh 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 \$20/MWh over the quarter, \$9/MWh higher than ISO 15-minute market prices in the Desert Southwest.** Day-ahead ICE prices for the Mid-Columbia trading hub averaged about \$12/MWh, \$2/MWh lower than ISO 15-minute market prices in the Pacific Northwest.
- **Transfer congestion out of Powerex separated its prices from the larger WEIM system in about 77 percent of intervals** in the 5-minute market. Salt River Project, Tucson Electric, and El Paso Electric were the balancing areas most frequently separated from the larger WEIM system by transfer congestion into their areas. Import transfer congestion occurred into their areas in 21 percent, 19 percent, and 12 percent of 5-minute market intervals, respectively.
- **There was no local market power mitigation in any real-time markets in the CAISO balancing area from May 1 through July 17, 2026 due to a software error associated with EDAM implementation.** The error in the real-time markets prevented the Dynamic Competitive Path Assessment (DCPA) process from calculating non-competitive congestion components stemming from flowgate constraints. The issue did not impact bid mitigation triggered when a WEIM balancing area is deemed non-competitive, so there was minimal impact on bid mitigation in WEIM areas. The impact on CAISO balancing area prices was limited due to mild conditions over the time period.
- **Day-ahead congestion rent totaled \$124 million, down \$5.6 million (4 percent) from Q2 2025.** The CAISO balancing area received about \$122 million of the congestion rent, compared with \$1.9 million for PACE and about \$0.03 million for PACW.
- **DMM estimates that congestion rent allocated to PacifiCorp balancing areas from congestion on CAISO constraints totaled about \$390,000 (credit) in May and -\$160,000 (charge) in June.** Initially, an error in the ISO's settlements process resulted in congestion revenue allocation credit payments of \$1.34 million in May and \$1.33 million in June. The ISO expects these payments to decrease at the 70-business-day resettlement, resulting in figures that are closer to DMM's estimates.

Resource sufficiency evaluation

- **Day-ahead resource sufficiency evaluation failures occurred on two days in the second quarter. None of these failures resulted in exclusion from the EDAM pool for real-time resource sufficiency evaluations.** On May 4, PacifiCorp West failed the imbalance reserve test in the upward direction in eight hours and in the downward direction during one hour. On June 17, PacifiCorp East failed the imbalance reserve test in the downward direction during one hour due to a software issue that the ISO subsequently fixed.
- **On two occasions, EDAM-participating balancing areas were excluded from the EDAM pool for real-time resource sufficiency evaluations.** On May 12, in hour-ending 19, PacifiCorp East was

evaluated separately in the real-time upward sufficiency test, and on June 15, in hour-ending 10, PacifiCorp West was evaluated separately in the real-time downward sufficiency test.

- **Resource sufficiency test failures remained rare across the WEIM** in Q2 2026, with all areas except El Paso Electric, WAPA Desert Southwest and Power Watch failing fewer than 1 percent of intervals across all test types and directions. El Paso Electric failed the downward flexibility test in 1.2 percent of intervals. WAPA Desert Southwest failed the upward flexibility test in 1.4 percent of intervals, and Power Watch failed the upward flexibility test in 3.4 percent of intervals.
- **Eleven 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 (529 MW). WAPA Desert Southwest received the largest amount of additional transfer energy over the quarter (585 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

Uplift costs and credits

- **Real-time imbalance offsets for balancing areas participating only in the WEIM real-time markets were a \$15 million charge** to WEIM entities. The energy portion of the offset was a \$19 million charge, almost all in May and June following the launch of the extended day-ahead market. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a \$4 million credit.
- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market were \$71 million in uplift** in the second quarter of 2026. Real-time congestion imbalance offset costs made up the large majority of these costs at \$76 million. The energy portion of the offset was a \$7 million credit. In May and June—since the launch of EDAM—the CAISO balancing area received around a \$26 million credit for the energy portion of the offset.
- **The ISO has reported a significant day-ahead energy offset since the launch of EDAM.** This credit back to EDAM balancing areas can accrue if the energy portion of prices paid into the day-ahead market by demand exceeds the energy portion of prices paid out to supply. The ISO reported a total day-ahead energy offset credit paid back to EDAM balancing areas of about \$16.5 million over May and June. The ISO is investigating the cause of this day-ahead energy revenue imbalance.
- **Bid cost recovery payments for units in balancing areas participating in both the day-ahead and real-time markets totaled about \$32.8 million** in the second quarter of 2026, up 25 percent from \$26.3 million in the second quarter of 2025.
- **Bid cost recovery for units in areas participating only in the WEIM totaled about \$1.8 million**, a 44 percent decrease from Q2 2025.

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>

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 Q2 2025. The much lower discrepancy between CAISO balancing area 15-minute market and 5-minute market load adjustments during peak morning and evening hours contributed to better overall convergence between 15-minute and 5-minute market prices.
- **There were no operator adjustments to the residual unit commitment process (RUC) procurement target in PacifiCorp East or PacifiCorp West in the second quarter of 2026.** RUC operator adjustments in the CAISO balancing area decreased by over 99 percent compared to the same quarter of 2025. The CAISO balancing area used RUC adjustments on only two days in Q2 2026—June 11 and 12—due to higher peak loads.
- **Manual dispatch energy trends were divergent across WEIM regions.** Compared to Q2 2025, manual dispatch energy decreased in the Pacific Northwest and Desert Southwest regions by 14 percent and 3 percent, respectively, and increased in the California (non-CAISO) region and the Intermountain West by 55 percent and 7 percent, respectively. The average hourly total energy from exceptional dispatches in the CAISO balancing area was 560 MW in the second quarter of 2026, up from only 40 MW in the second quarter of 2025. This increase was due to unit testing of a large quantity of new wind capacity.

Imbalance reserve and flexible ramping products

- **Gas resources made up around 51 percent of upward imbalance reserve schedules.** Wind and solar resources combined made up around 82 percent of downward imbalance reserve schedules.
- **PacifiCorp West was a net importer of both upward and downward imbalance reserve.** The CAISO balancing area was a net exporter of upward imbalance reserve on average. PacifiCorp East was a net importer of upward imbalance reserve and net exporter of downward imbalance reserve.
- **Prices for imbalance reserve have frequently been low or zero.** For the CAISO and PacifiCorp East balancing areas, prices have been less than \$5/MWh in more than 89 percent of hours. Imbalance reserve prices in PacifiCorp West were more frequently higher—above \$5/MWh in more than 35 percent of hours.
- **Between May and June, payments for upward imbalance reserve were around \$5 million while payments for downward imbalance reserve were around \$2.2 million—or around \$7.2 million combined.**
- **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 17.8 percent of intervals** in the second quarter of 2026, up significantly from 0.2 percent in the same quarter of 2025. The increase coincided with the implementation of EDAM, as these prices were greater than zero during about 0.9 percent of intervals in April 2026, 32.1 percent of intervals in May 2026, and 20.4 percent in June 2026. Most of this increase occurred in the Intermountain West and Pacific Northwest regions. DMM has notified the ISO of the increase in flexible ramping product prices and will continue to work with the ISO to understand the underlying causes.
- **Battery and hydro resources made up 65 percent and 17 percent of upward flexible capacity, respectively.** Wind and solar combined to provide 45 percent of downward flexible capacity, and

batteries provided 33 percent of downward flexible capacity. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 59 percent in the upward direction and 56 percent in the downward direction. Balancing areas in the Pacific Northwest made up 19 percent of flexible capacity in each direction.

Residual Unit Commitment

- **Average hourly residual unit commitment procurement** in May 2026 was 1,600 MW of reliability capacity up (RCU) and 500 MW of reliability capacity down (RCD), resulting in total procurement of 2,100 MW and net procurement of 1,100 MW. June was lower, at approximately 1,050 MW of RCU and 800 MW of RCD. Both months are comparable to the average of 1,500 MW observed between May 2025 and April 2026.
- **The CAISO balancing area accounted for 95 percent of both total RCU and RCD procurement**, PACE accounted for 4 percent of each, and PACW accounted for 1 percent of each.
- **Total RUC costs were approximately \$14 million in May 2026 and \$6 million in June 2026.** Between May 2025 and April 2026, RUC costs averaged about \$10 million per month, but actual payments to non-resource adequacy resources averaged only \$0.2 million per month. CAISO balancing area resources received about 91 percent of RUC payments in May and 98 percent in June.
- **Between May 2025 and April 2026, the average RUC price was about \$9/MWh, compared to \$9/MWh in May 2026 and \$4/MWh in June 2026.**

Ancillary services and available balancing capacity

- **Regulation up requirements increased 220 MW (45 percent) on average compared to Q2 2025 due largely to a CAISO balancing area program** initiated in Q1 2026 designed to increase regulation up requirements in order to address uncertainty and minimize the use of load conformance in the real-time markets. Regulation up costs increased to \$6.6 million, 27 percent higher than Q2 2025.
- **Ancillary service payments totaled \$20.0 million in the second quarter of 2026, down 28 percent from the same quarter of the previous year.**
- **Available balancing capacity was dispatched to address power balance infeasibilities in 0.4 percent or less of intervals for all areas except Nevada Energy** in the 15-minute and 5-minute markets. Available balancing capacity was dispatched in about 2.2 percent of intervals for Nevada Energy in the 15- and 5-minute markets and in both upward and downward directions.

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

- **Transmission ratepayers lost roughly \$12 million from the congestion revenue rights (CRR) auction** in the second quarter of 2026, as payments to auctioned congestion revenue rights holders were higher than auction revenues. This was an increase from \$9 million in the second quarter of 2025.
- **No monthly reservations were made for CAISO balancing area high priority wheel-through rights** for the second quarter of 2026.
- **Real-time resource adequacy bids were not sufficient to cover the market requirements for energy and upward ancillary services in the CAISO balancing area in four intervals during peak net load hours on May 11, 2026.**
- **Resource adequacy import bids decreased 67 percent from the second quarter of 2025.**

1 Supply conditions

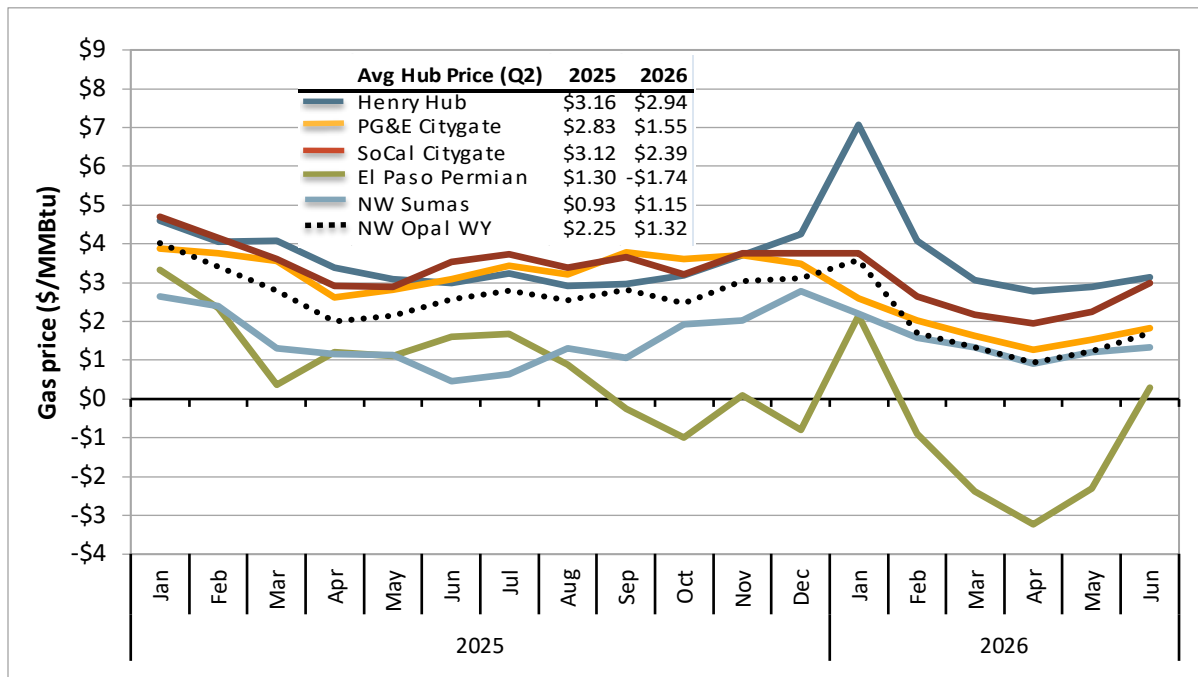
1.1 Natural gas prices

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. In the second quarter of 2026, average natural gas prices decreased relative to the same quarter of 2025 at most major Western trading hubs and approached historic lows.³ Average second quarter prices at Henry Hub, PG&E Citygate, SoCal Citygate, and NW Opal Wyoming decreased by 7 percent, 45 percent, 23 percent, and 41 percent, respectively, compared to the second quarter of 2025. El Paso Permian prices declined into negative territory in the second quarter of 2026, averaging -\$1.74/MMBtu compared with \$1.30/MMBtu in the same period in 2025.

Northwest Sumas was an exception to the broader decline in average prices, with natural gas prices increasing slightly from very low second quarter 2025 prices. Prices at Northwest Sumas were up \$0.22/MMBtu (24 percent).

Compared to the first quarter of 2026, natural gas prices at most major Western trading hubs decreased in the second quarter of 2026. Henry Hub, PG&E Citygate, SoCal Citygate, Northwest Sumas, and Northwest Opal Wyoming decreased about 36 percent, 24 percent, 16 percent, 31 percent, and 40 percent, respectively. El Paso Permian prices fell further into negative territory, declining from -\$0.52/MMBtu in the first quarter to -\$1.74/MMBtu in the second quarter.

³ *California natural gas prices reach historic lows in early 2026*, U.S. Energy Information Administration (EIA), 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 second quarter of 2026, the average hourly generation from renewable resources in the WEIM footprint increased by about 5,900 MW (12 percent) compared to the same quarter of 2025.^{4,5} Hydroelectric, solar, and wind generation increased by approximately 2,700 MW (12 percent), 1,000 MW (8 percent), and 2,300 MW (25 percent), respectively, across the WEIM footprint. Average hourly generation from geothermal and biogas-biomass resources decreased by about 100 MW (7 percent) and 26 MW (4 percent), respectively, across the WEIM footprint compared to the second 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 46 percent of all renewable output in the California region and decreased by 170 MW (2 percent) compared to the second quarter of 2025. Hydroelectric generation decreased by about 450 MW (11 percent), while wind generation increased by about 1,050 MW (31 percent), year-over-year, overtaking hydroelectric generation to be the second largest type of renewable generation in the California region.

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

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

- The Desert Southwest region saw increases in solar (730 MW or 22 percent) and wind (470 MW or 45 percent), contributing to an overall increase in renewable generation of 1,200 MW (22 percent) compared to the second quarter of 2025.
- Renewable generation in the Intermountain West increased by approximately 880 MW (15 percent) compared to the second quarter of 2025, with the largest increases attributed to solar and wind generation (420 MW or 34 percent, and 530 MW or 30 percent, respectively).
- In the second quarter of 2026, hydroelectric generation represented 84 percent of all renewable generation in the Pacific Northwest, with an increase of 3,230 MW (20 percent) from the same quarter of the previous year. Solar and wind generation increased by about 45 MW (10 percent) and 220 MW (8 percent), respectively.

Figure 1.2 California - Average monthly renewable generation

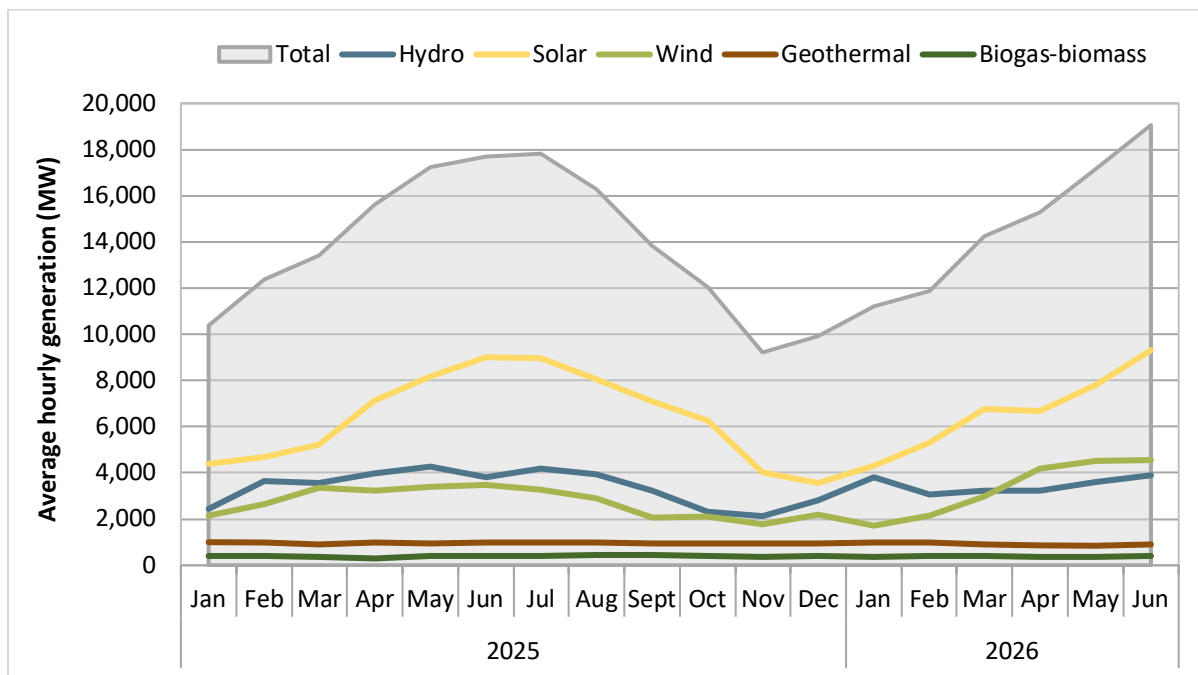


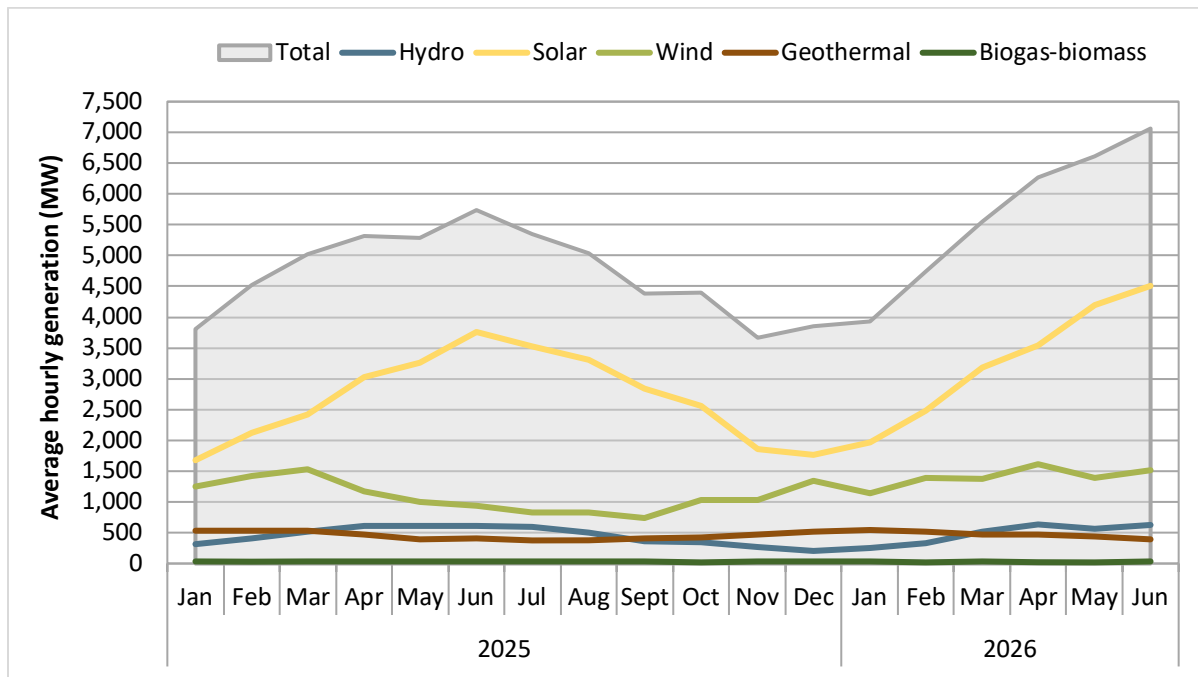
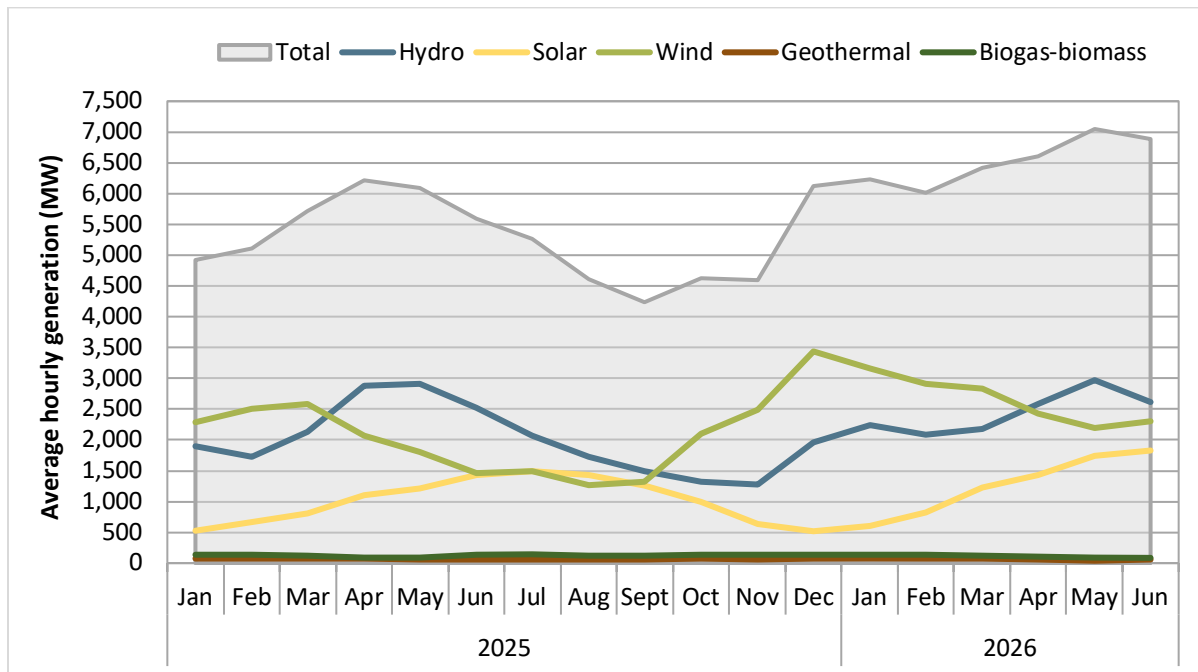
Figure 1.3 Desert Southwest - Average monthly renewable generation**Figure 1.4 Intermountain West - Average monthly renewable generation**

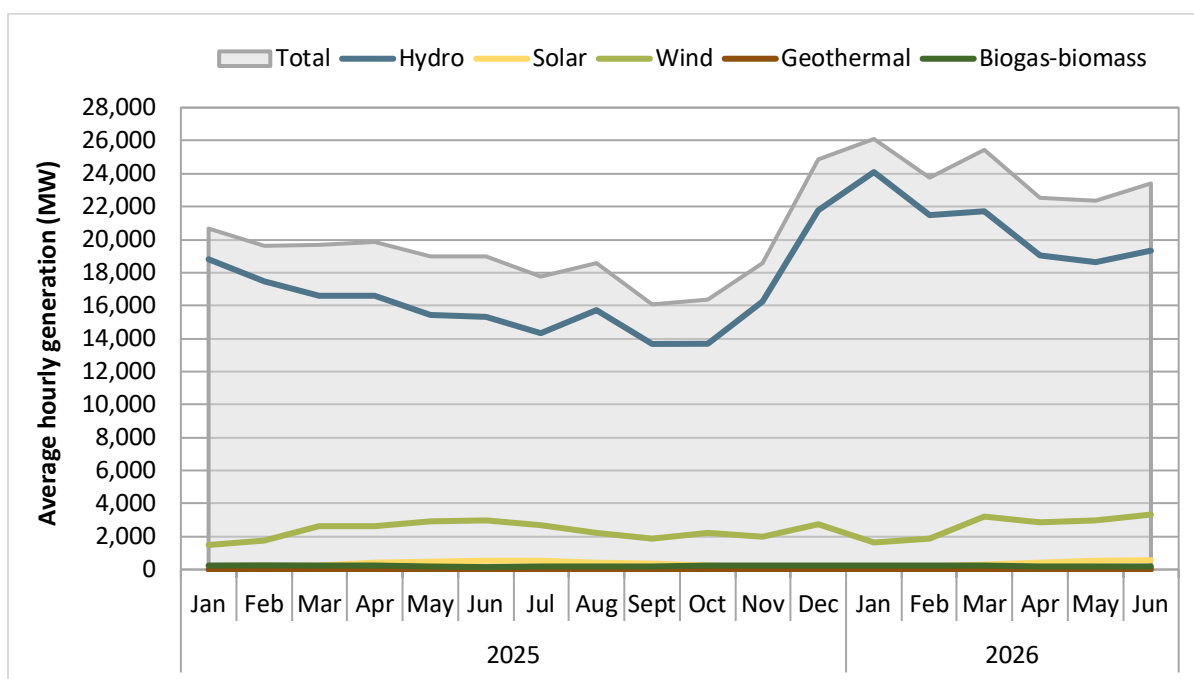
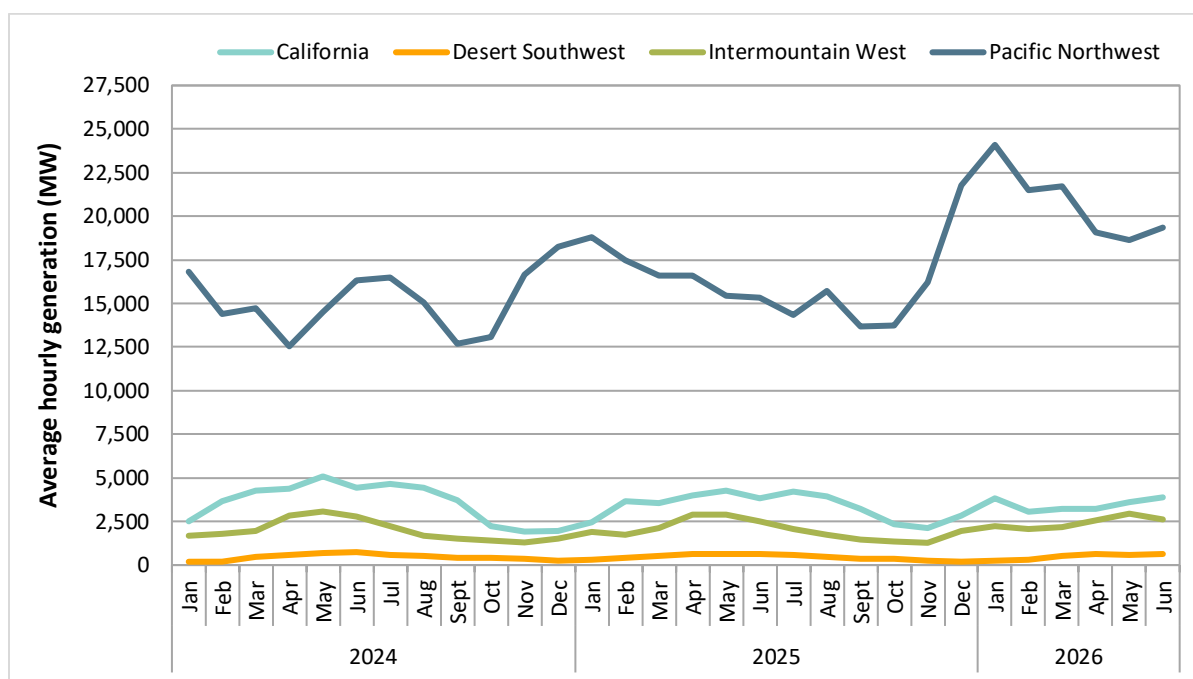
Figure 1.5 Pacific Northwest - Average monthly renewable generation

Figure 1.6 shows the monthly average hydroelectric generation from January 2024 to June 2026.

- In the California region, hydroelectric generation decreased by 440 MW (11 percent) compared to the second quarter of 2025.
- In the Desert Southwest, hydroelectric generation remained the same compared to the second quarter of 2025.
- Hydroelectric output in the Intermountain West decreased by 50 MW (2 percent) compared to the second quarter of 2025.
- In the Pacific Northwest, hydroelectric generation in the second quarter of 2026 increased 3,230 (20 percent) compared to the same quarter of 2025, and increased 4,560 MW (32 percent) compared to the second 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 second 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 second 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 peaked at hour-ending 18 in the Desert Southwest, hour-ending 19 in the Intermountain West and Pacific Northwest, and hour-ending 20 in the California region.

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, as shown in Figure 1.8. This was partially due to higher wind generation from the SunZia Wind and Transmission project which added approximately 3,500 MW of wind capacity.⁶ Imports increased across all hours as well, and battery discharge increased during morning and evening hours.

Natural gas remained the largest source of generation in the Desert Southwest in the second quarter of 2026. 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, as well as increases in wind in all hours. Net dynamic transfers, i.e., imports and exports that are optimized in the WEIM, increased into the region in all hours. Net imports into the region, i.e., energy schedules made prior to

⁶ See <https://patternenergy.com/projects/sunzia/> for more information.

the market optimization, decreased in all hours. This reflected the Desert Southwest exporting more hourly schedules out of the region before the WEIM market optimization runs, but then transferring more power during solar hours and transferring less power out via the WEIM market optimization.

In the Intermountain West, coal, natural gas, hydro, and wind generation continued to contribute about equally to the region's generation mix. Wind and solar generation increased by an hourly average of 580 MW (33 percent) and 450 MW (36 percent), respectively, compared to the second quarter of 2025. Imports increased by 270 MW (130 percent). Coal generation decreased in all hours by an average of 190 MW (7 percent).

Hydroelectric generation dominated the generation mix in the Pacific Northwest, accounting for about 89 percent of total generation, as shown in Figure 1.7, and increasing by about 3,230 MW (20 percent) in each hour year-over-year. Nuclear generation increased in all hours year-over-year. Natural gas generation and net imports decreased across all hours, with the Pacific Northwest shifting from being a net importer in most hours of the second quarter of 2025 to a net exporter in all hours of the second quarter of 2026.

Figure 1.7 California - Average hourly generation by fuel type (Q2 2026)

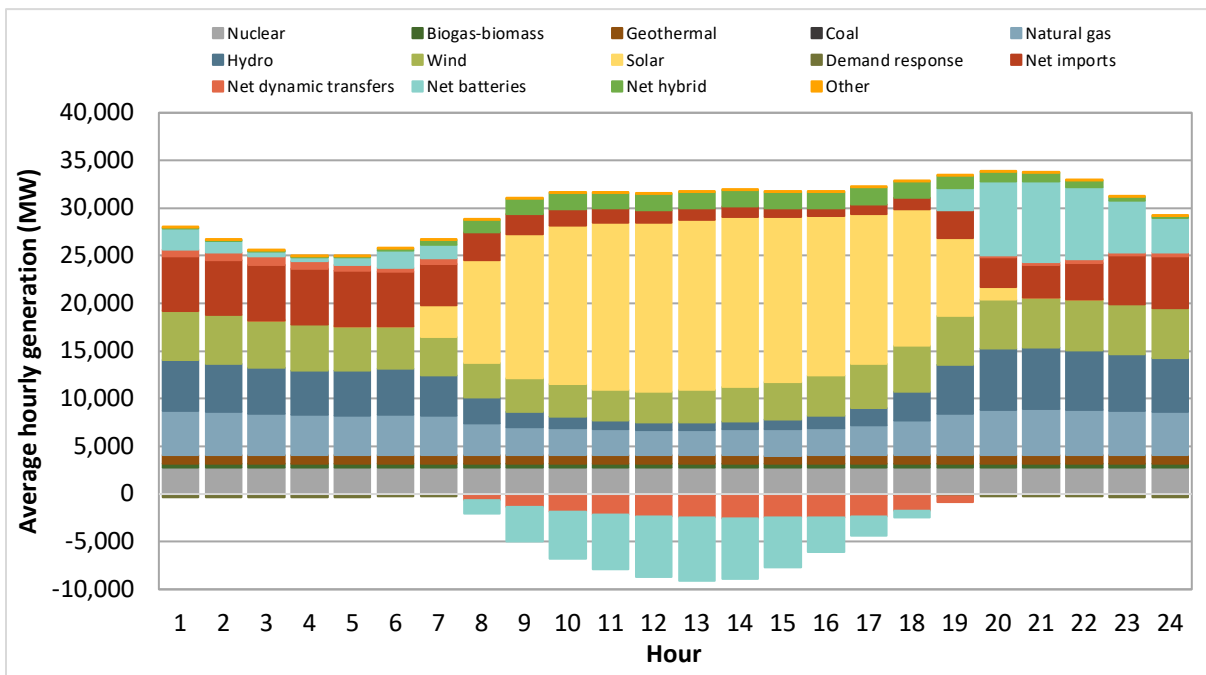


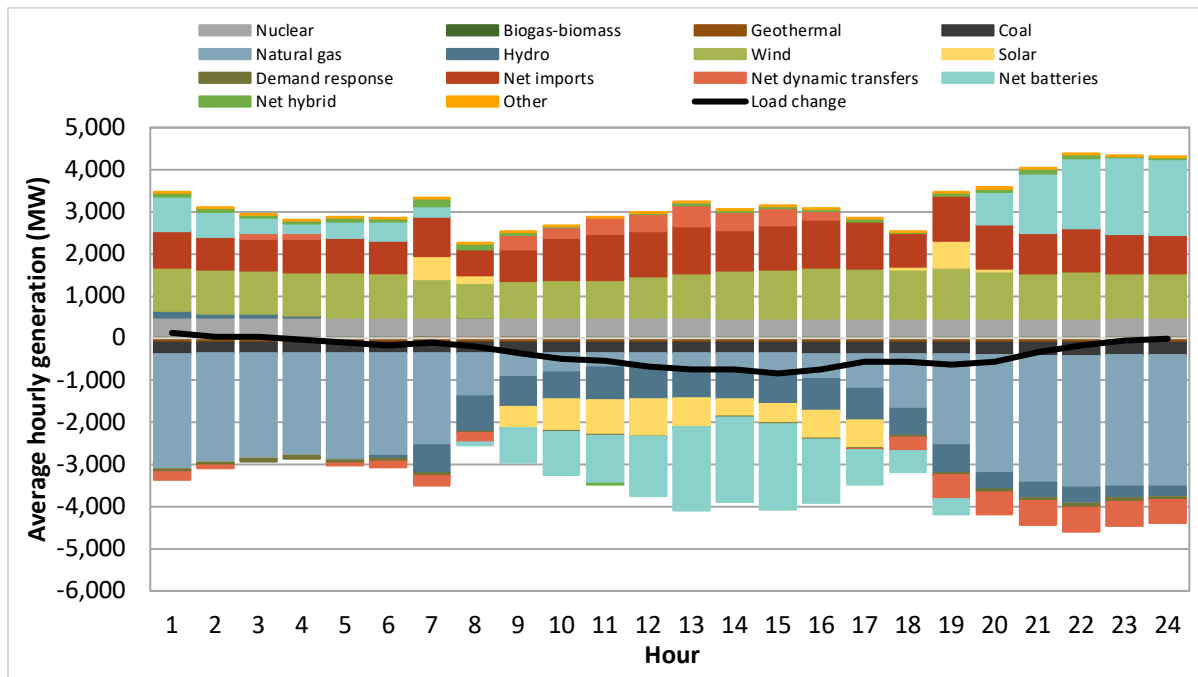
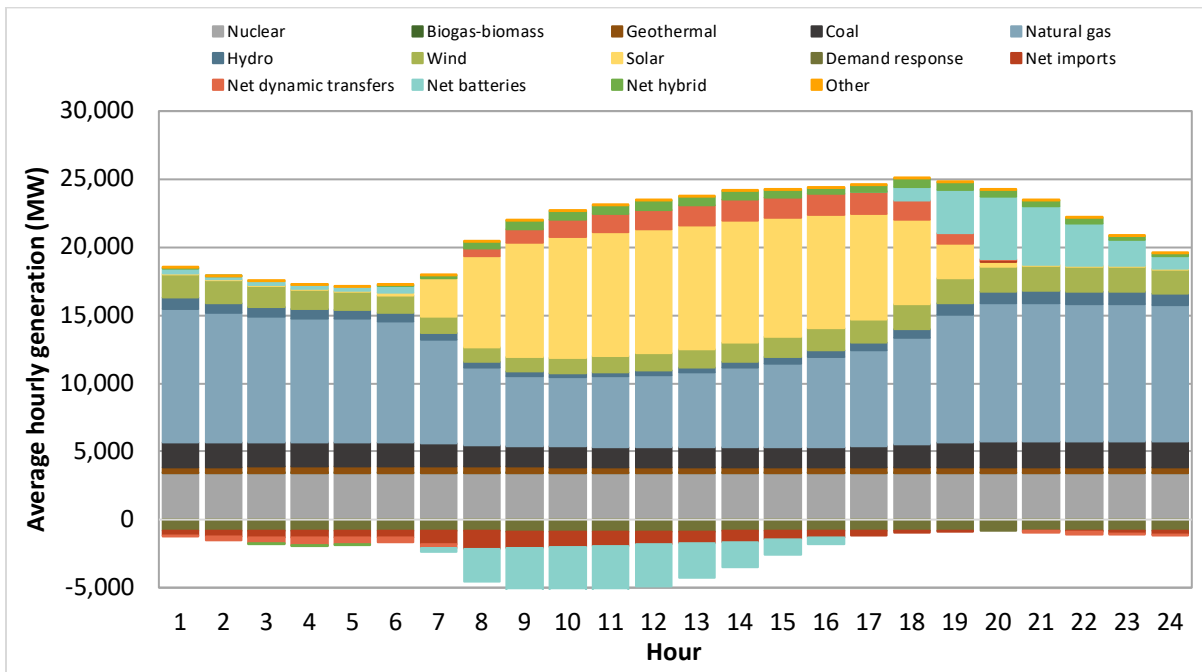
Figure 1.8 California - Change in average hourly generation by fuel type (Q2 2026 vs. Q2 2025)**Figure 1.9 Desert Southwest - Average hourly generation by fuel type (Q2 2026)**

Figure 1.10 Desert Southwest - Change in average hourly generation by fuel type (Q2 2026 vs. Q2 2025)

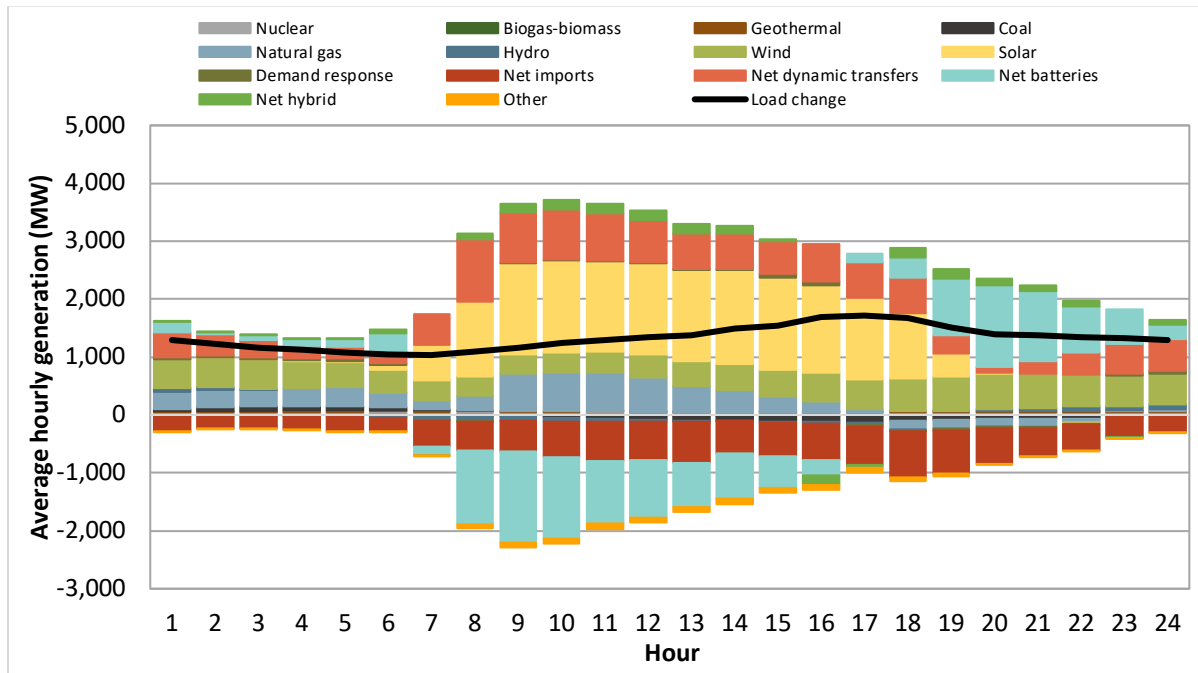


Figure 1.11 Intermountain West - Average hourly generation by fuel type (Q2 2026)

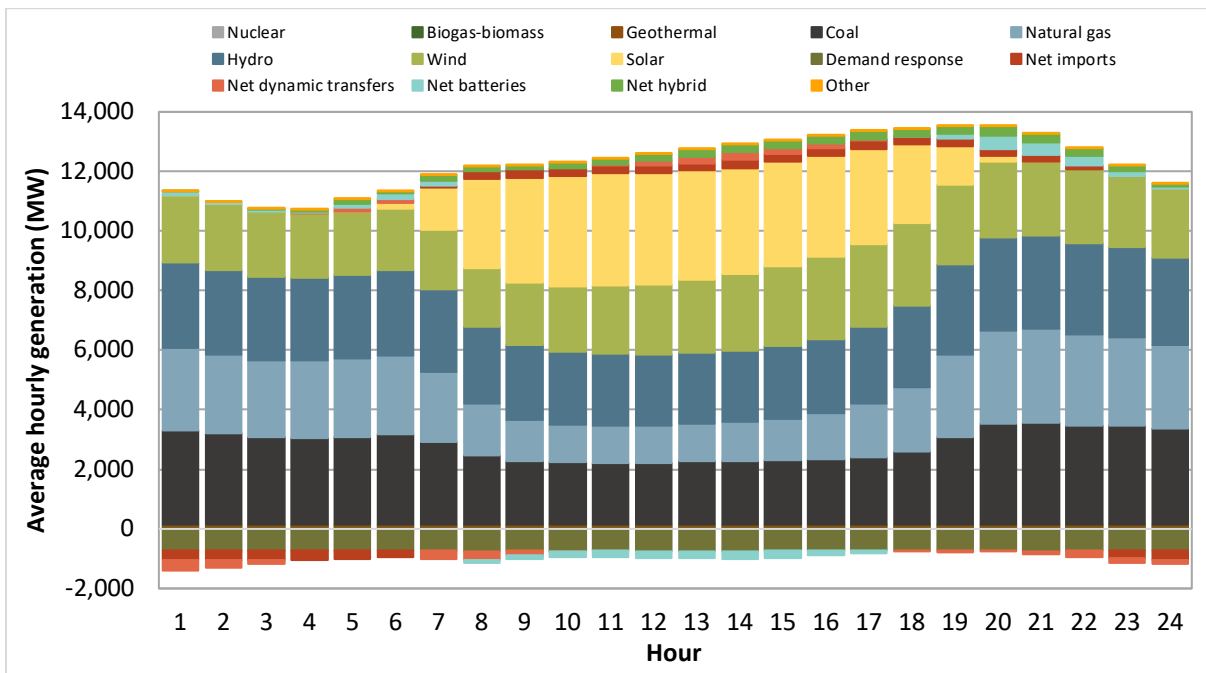


Figure 1.12 Intermountain West - Change in average hourly generation by fuel type (Q2 2026 vs. Q2 2025)

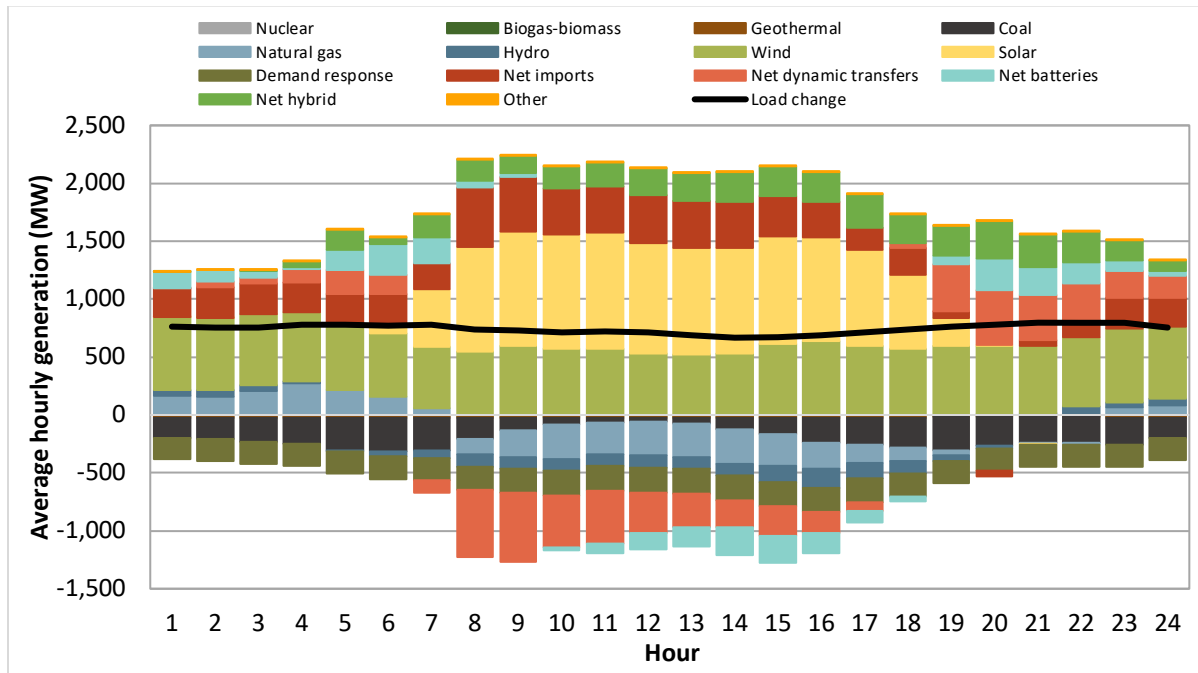


Figure 1.13 Pacific Northwest - Average hourly generation by fuel type (Q2 2026)

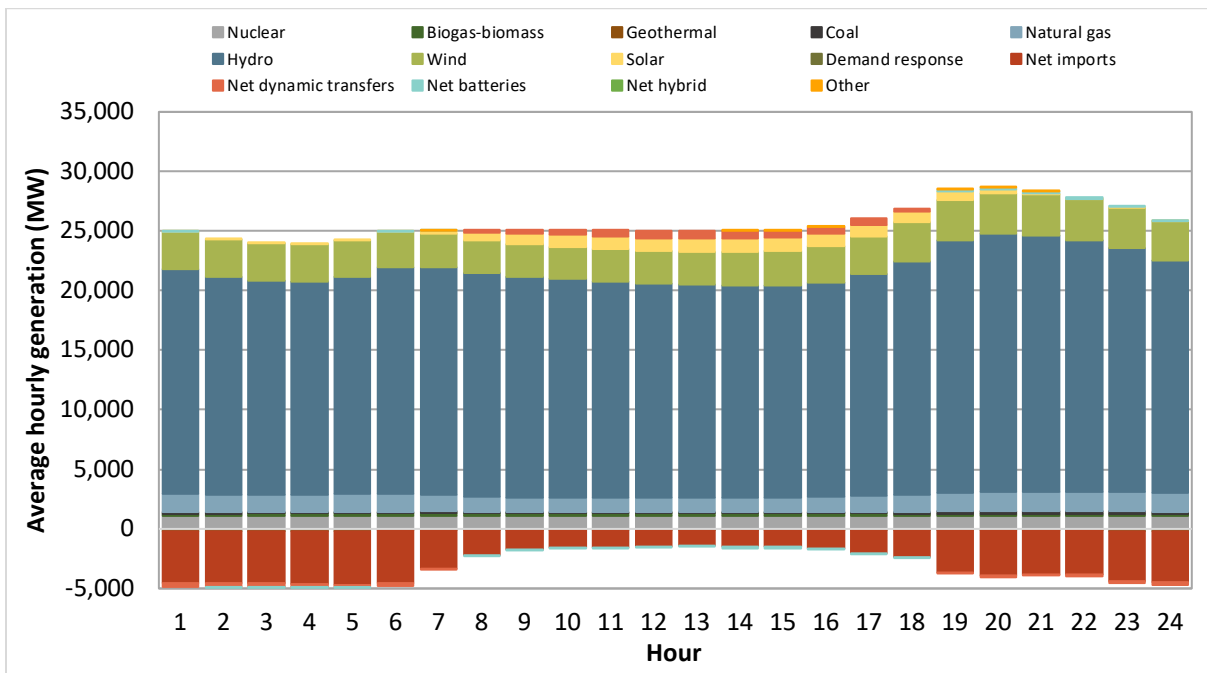
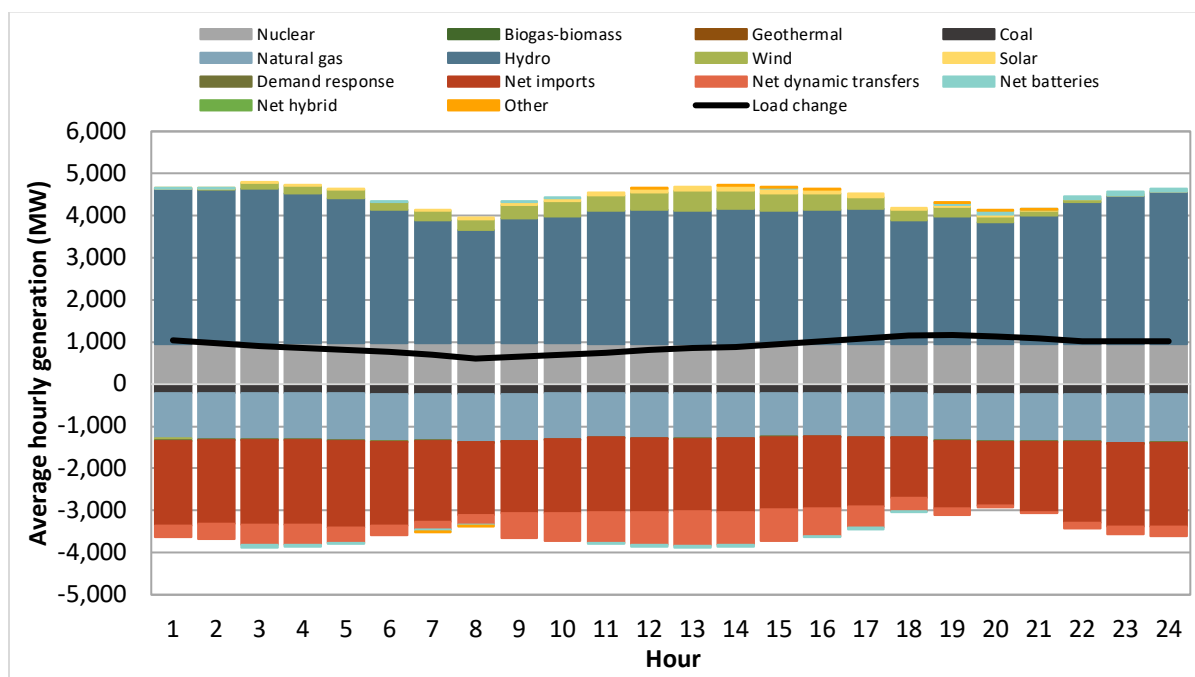
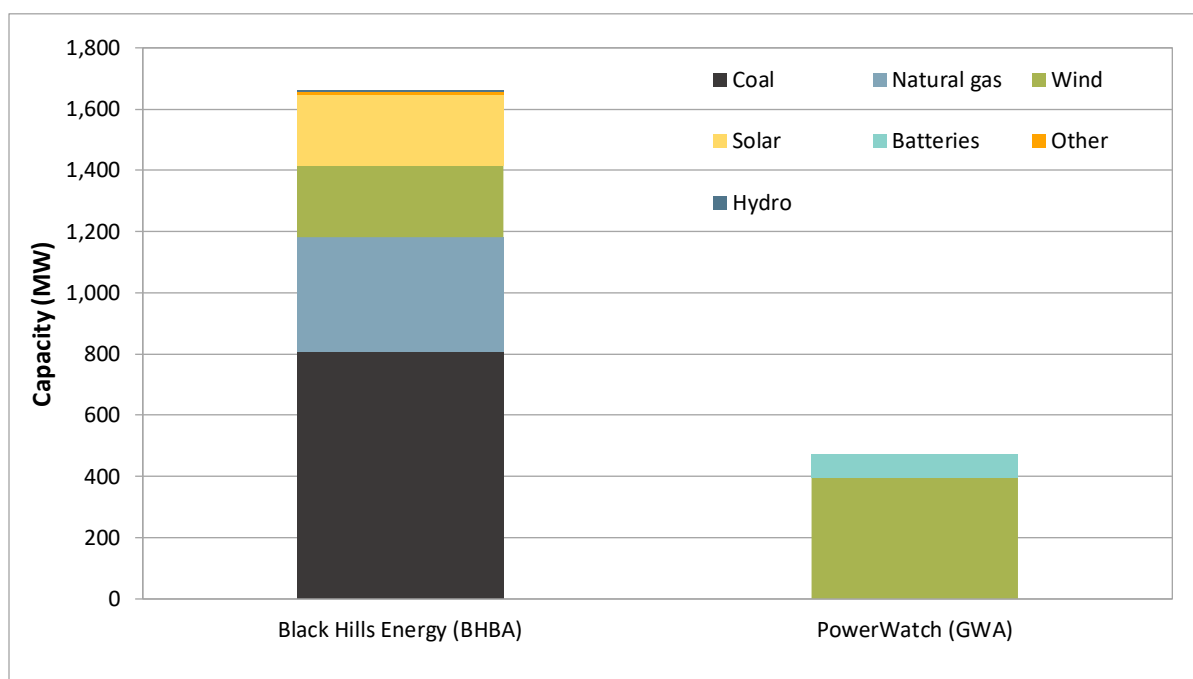


Figure 1.14 Pacific Northwest - Change in average hourly generation by fuel type (Q2 2026 vs. Q2 2025)



Black Hills Energy and Power Watch (formerly BHE Montana) joined the WEIM on May 6, 2026.⁷ Figure 1.15 shows the total capacity of the newly participating entities. Black Hills Energy capacity consists of about 800 MW of coal resources, 370 MW of natural gas, and 230 MW each of wind and solar capacity. Power Watch capacity consists of about 400 MW of wind and 75 MW of batteries. These amounts include capacity from WEIM participating resources as well as non-participating resources, which are neither bid nor optimized in the market.

⁷ See here for more information:
<https://www.westernenergymarkets.com/news-notice/news-releases/black-hills-corp-s-south-dakota-and-wyoming-electric-utility-subsidaries-join-western-energy-imbalance-market>
<https://www.westernenergymarkets.com/news-notice/news-releases/bhe-montana-joins-the-western-energy-imbalance-market>

Figure 1.15 Total capacity of new WEIM entities by fuel type (as of June 30, 2026)

1.4 Interchanges between WEIM regions

Figure 1.16 to Figure 1.23 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.
 - **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.

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.

- **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 second quarters of 2025 and 2026, net interchange after dynamic transfers (red line) increased in California, the Desert Southwest, and the Intermountain West by approximately 950 MW (53 percent), 20 MW (38 percent), and 260 MW (127 percent), respectively. Net interchange after dynamic transfers decreased (i.e., net exports increased) in the Pacific Northwest by roughly 2,380 MW (397 percent). This decrease in the Pacific Northwest reflects a significant shift toward net exports, consistent with Figure 1.14, which shows an increase in net exports in every hour in the second quarter of 2026. The increase in net exports in the Pacific Northwest was largely due to increases in hydroelectric generation during all hours in the region.

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.

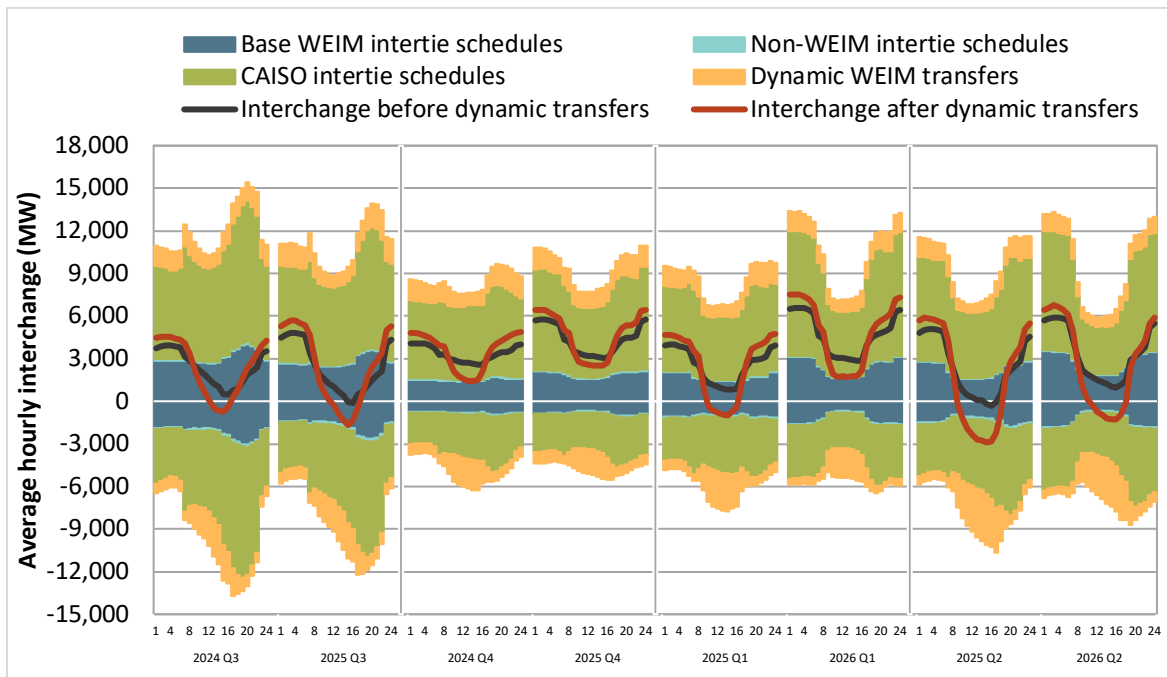
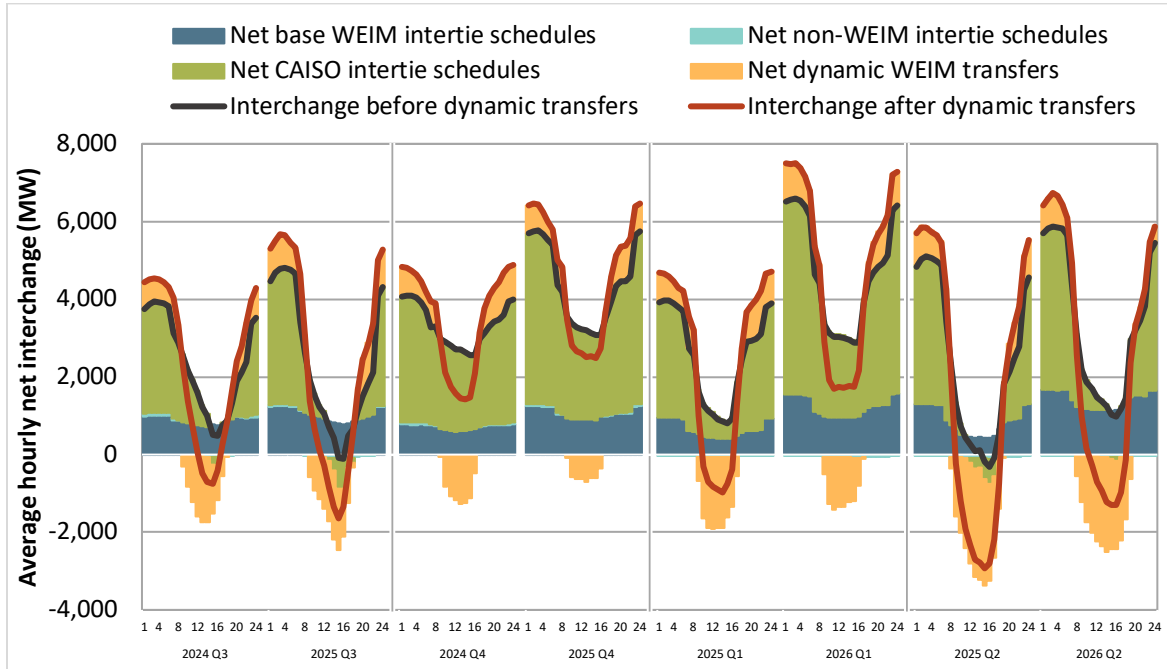
Figure 1.16 California - Average hourly interchange by quarter**Figure 1.17 California - Average hourly net interchange by quarter**

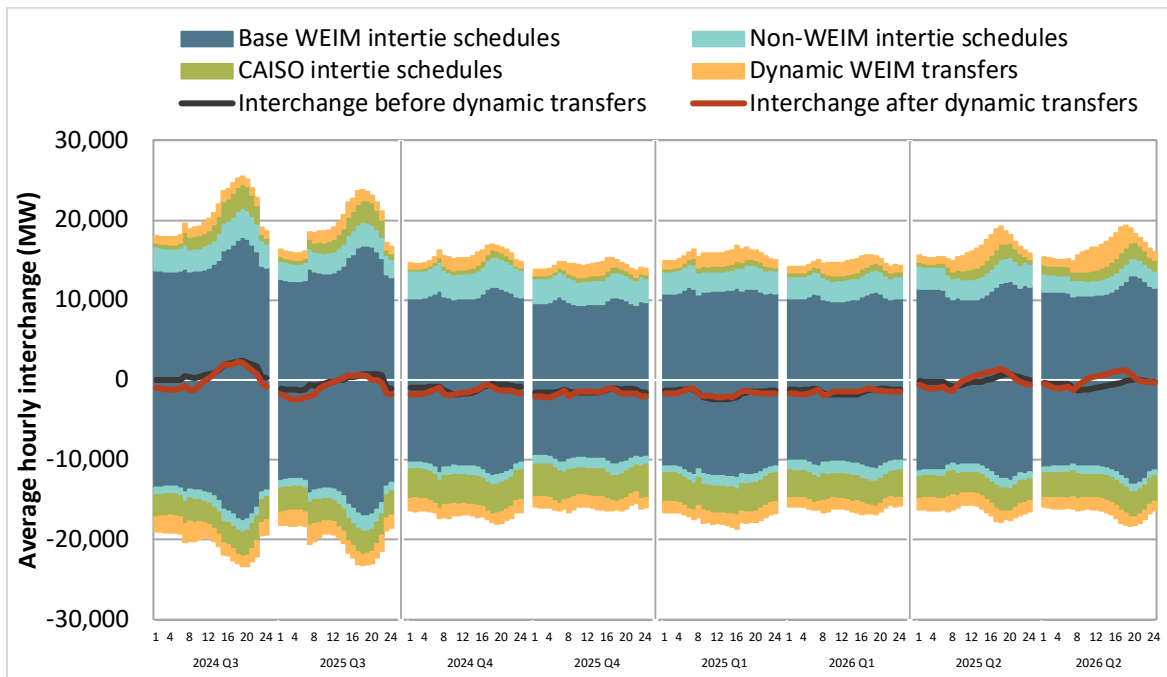
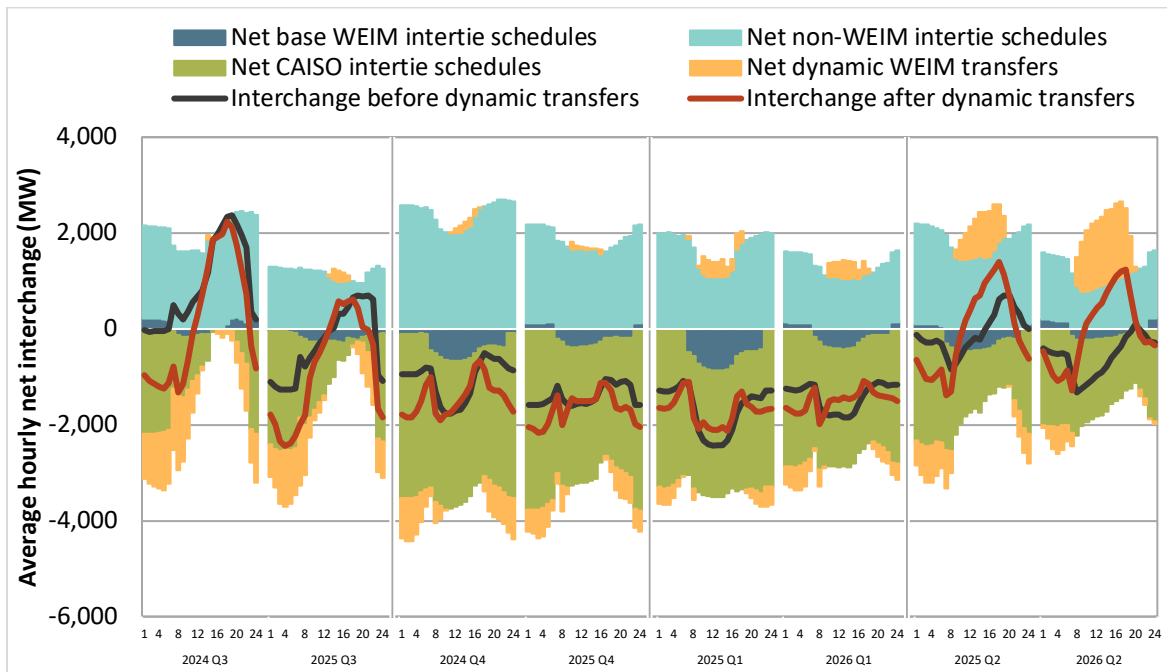
Figure 1.18 Desert Southwest - Average hourly interchange by quarter**Figure 1.19 Desert Southwest - Average hourly net interchange by quarter**

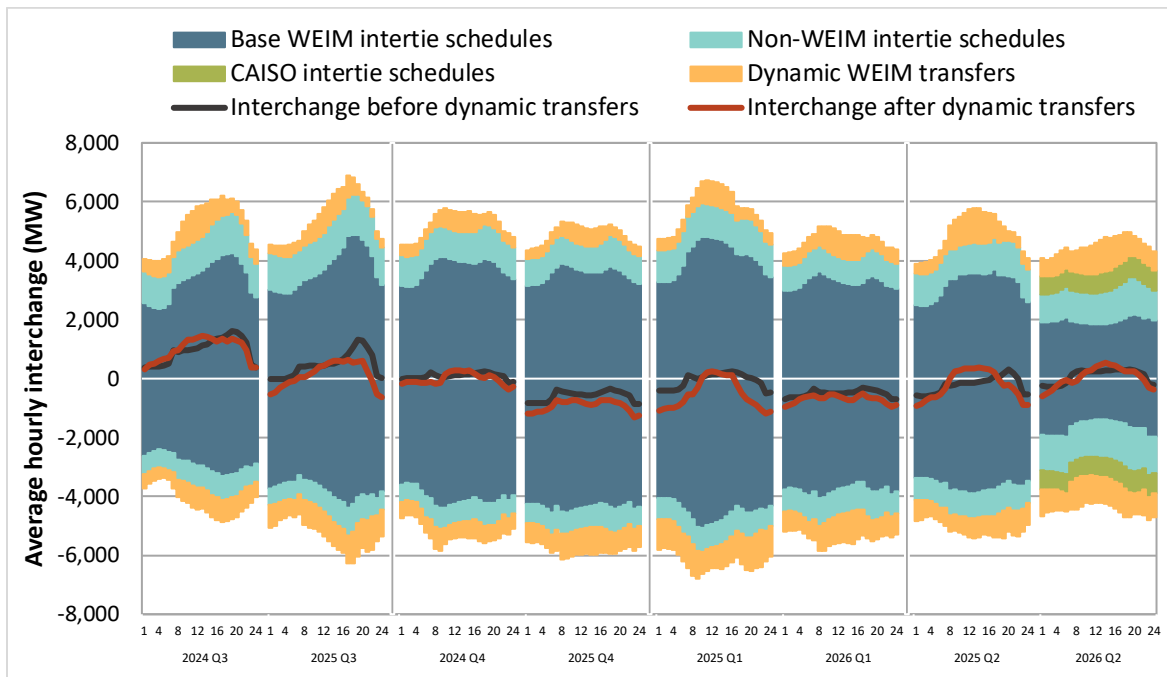
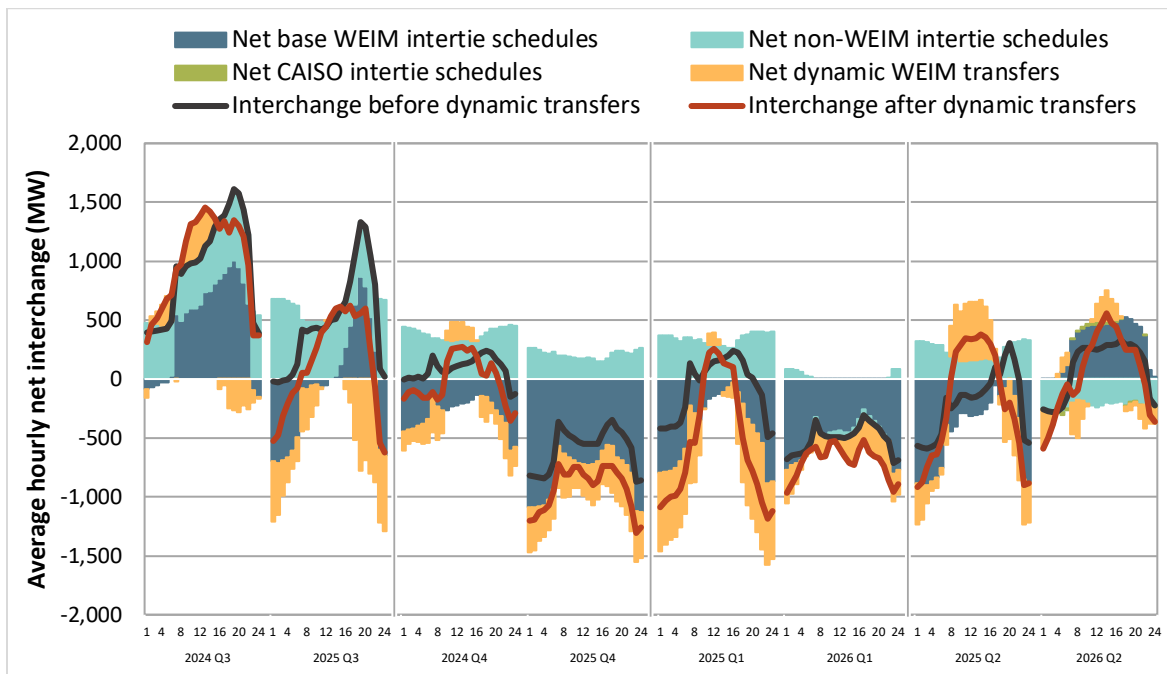
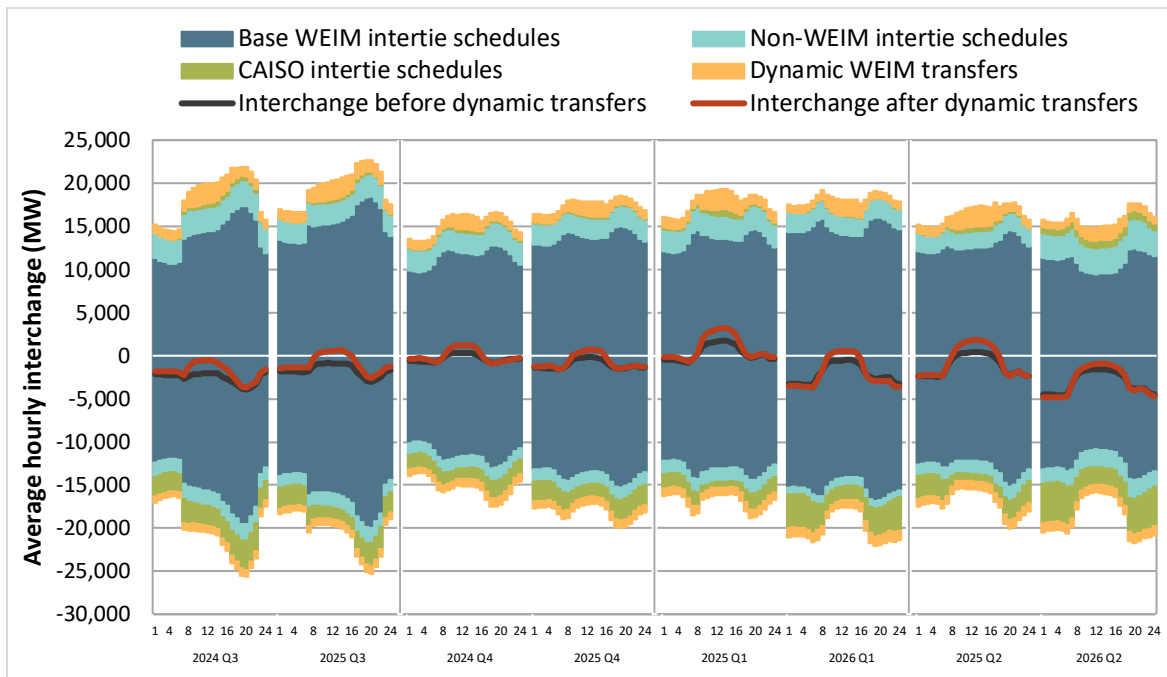
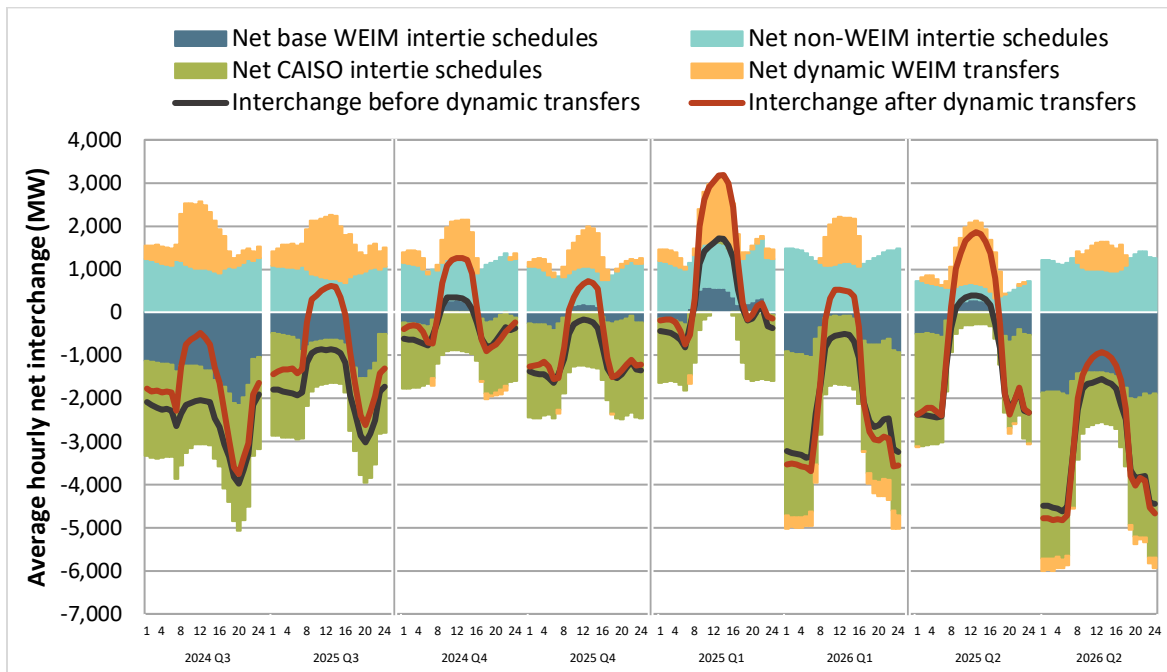
Figure 1.20 Intermountain West - Average hourly interchange by quarter**Figure 1.21 Intermountain West - Average hourly net interchange by quarter**

Figure 1.22 Pacific Northwest - Average hourly interchange by quarter**Figure 1.23 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 19,900 MW in the second quarter of 2026, about a 17 percent increase compared to the second quarter of 2025.¹⁴ In the California (non-CAISO) region of the WEIM, outages averaged about 4,500 MW, a decrease of about 470 MW from the second quarter of 2025. The Desert Southwest region averaged about 12,300 MW of total generation outages, a 17 percent increase from the second quarter of 2025. The Intermountain West region averaged about 4,350 MW of total generation outages, a 15 percent increase from the second quarter of 2025. The Pacific Northwest region averaged about 3,400 MW of total generation outages, a decrease of about 13 percent from the second 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 1.24 and Figure 1.25 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 second 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, there are usually more outages in the late fall, winter, and early spring than in the summer months, and this trend continued in the second quarter of 2026.

During the second quarter of 2026, the average total generation on outage in the California ISO balancing area was about 19,900 MW, which is an increase of about 17 percent compared to the second quarter of 2025, as shown in Figure 1.24. Other forced outages increased by about 31 percent, an increase of about 2,000 MW. Forced maintenance and plant trouble outages increased by about 27 percent when compared to the same quarter last year, an increase of about 1,500 MW. Compared to

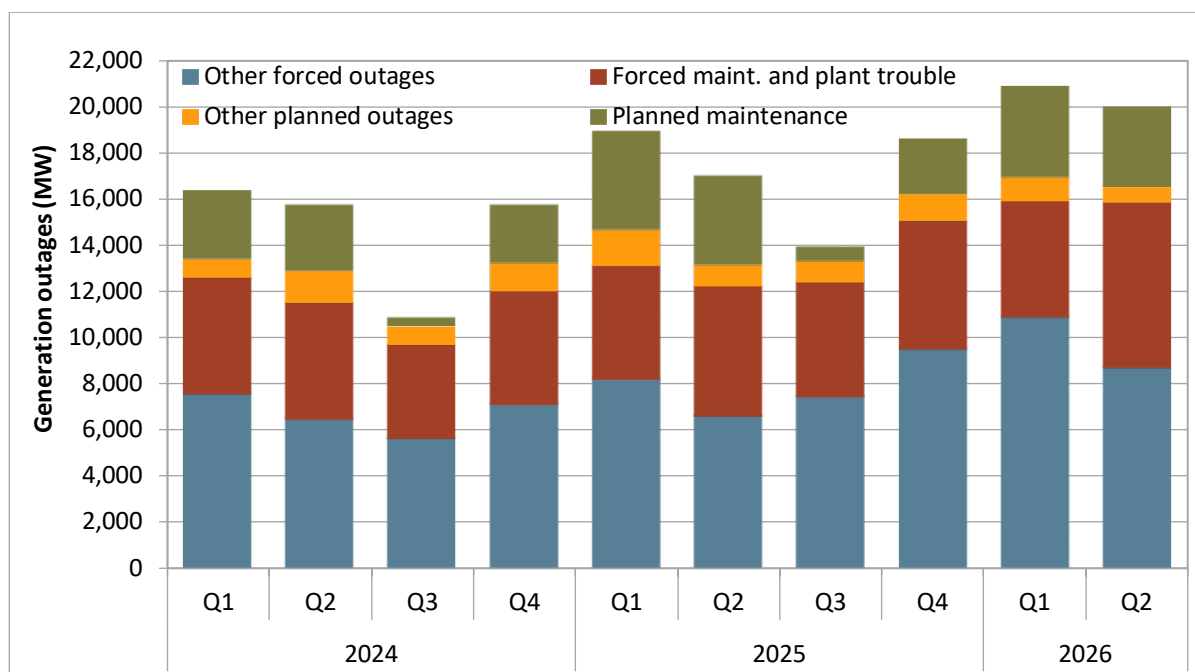
¹² The data for 2024 has been updated from 2024 quarterly reports to reflect the new accounting method used to exclude outages of available California Strategic Reliability Reserve participating resource capacity that were submitted to prevent these units from being committed and dispatched by the market. 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, PACE, Black Hills, and Power Watch. 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.

the second quarter of 2025, planned maintenance outages decreased by 11 percent (about 420 MW) on average, and other planned outages decreased by 23 percent (about 210 MW).

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



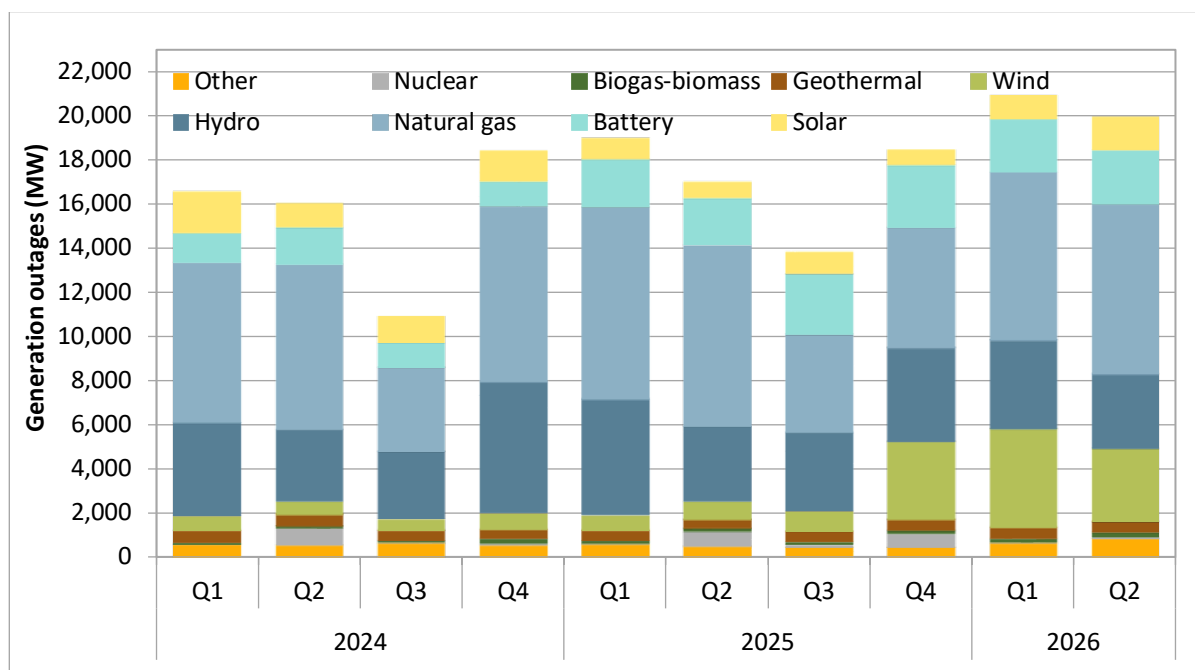
Natural gas, hydroelectric generation, wind, and batteries had the largest volume of outages in the second quarter of 2026 and averaged about 7,700 MW, 3,400 MW, 3,200 MW, and 2,400 MW, respectively. These four fuel types accounted for a combined 84 percent of the generation outages for the quarter. The amount of natural gas generation outages decreased six percent relative to the second quarter of 2025.

The quarterly average megawatts of wind resources on outage increased by about 300 percent in the second quarter of 2026 compared to the second quarter of 2025 due to testing of a large new wind resource.

Figure 1.25 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.¹⁵ Outages for most fuel types other than natural gas increased compared to the second quarter of 2025.

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

Figure 1.25 CAISO balancing area quarterly average of maximum daily generation outages by fuel type – peak hours



California (non-CAISO) region

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 second 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 generation outages in the second quarter were about 4,500 MW, about a nine percent decrease compared to the second quarter of 2025. Total forced outages decreased by about 13 percent and total planned maintenance was essentially flat. Outages from natural gas resources decreased by about 5 percent.

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

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

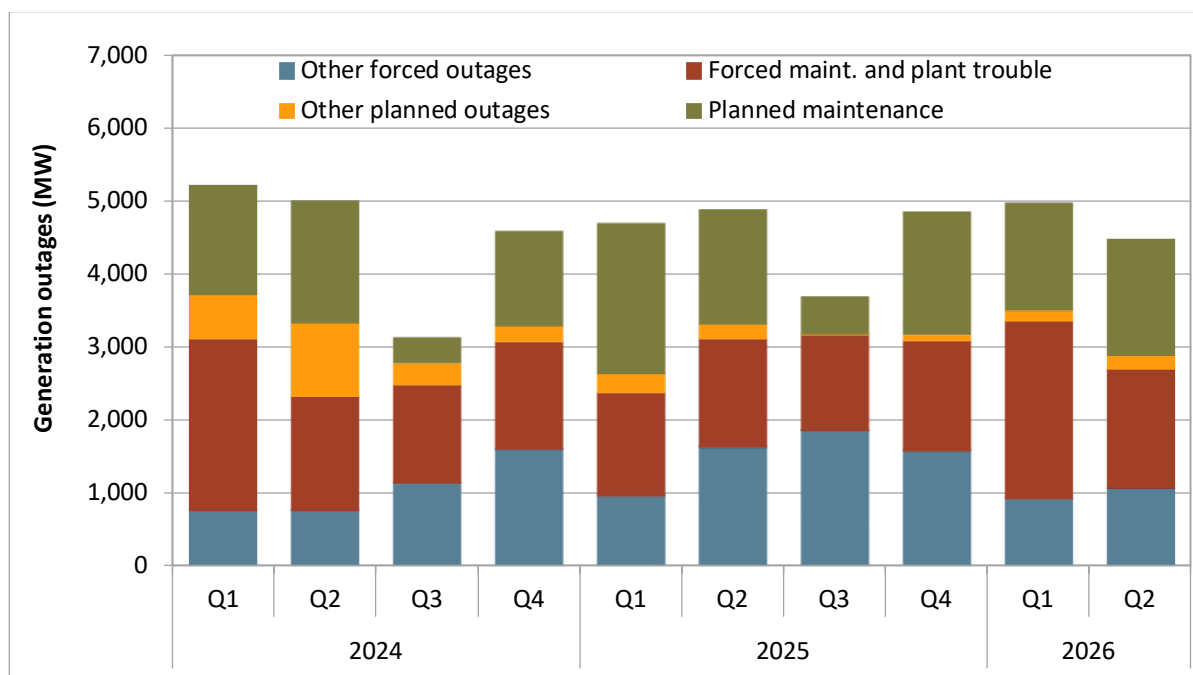
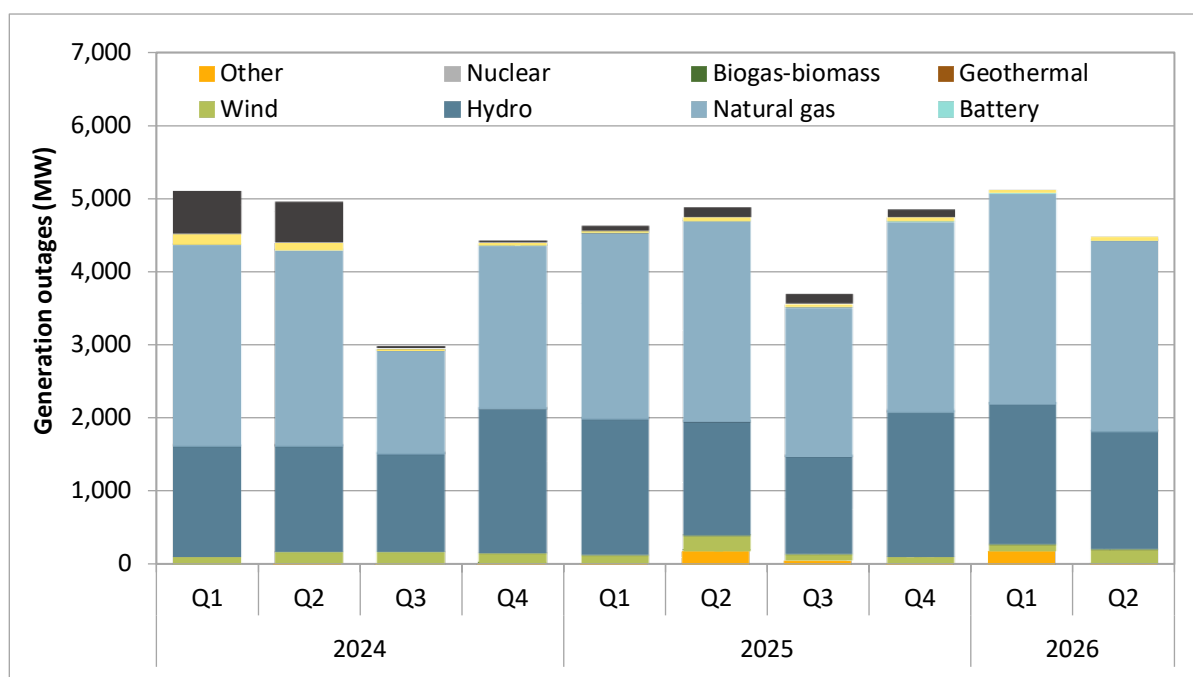


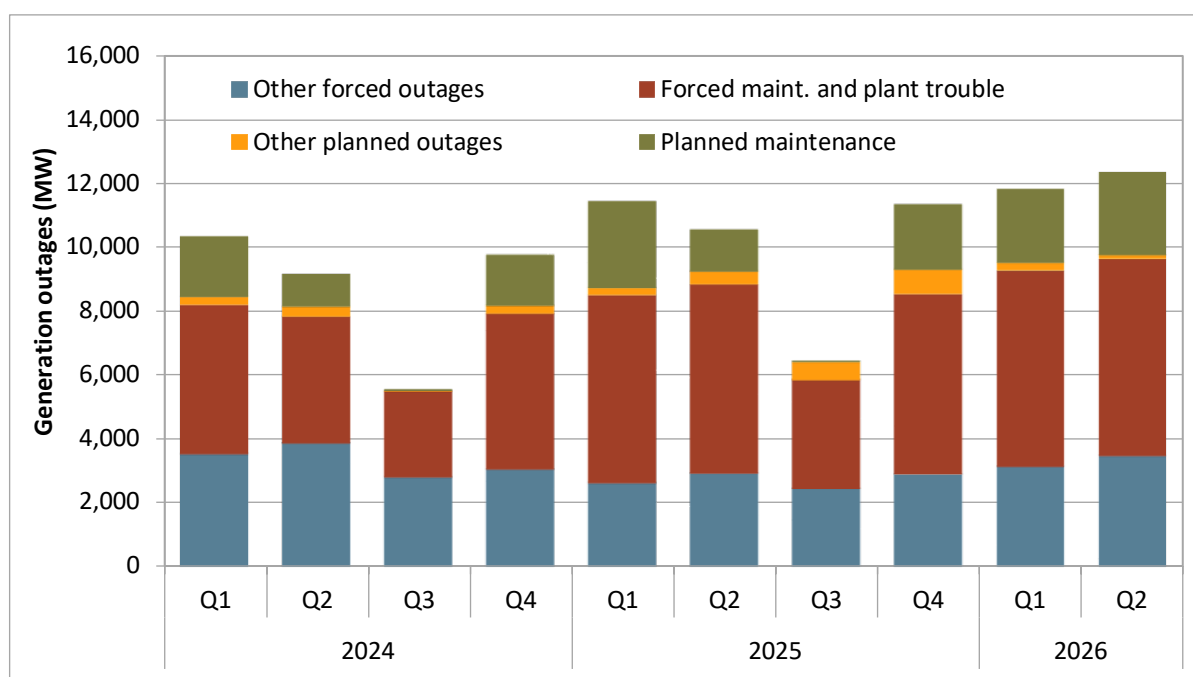
Figure 1.27 California WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Desert Southwest

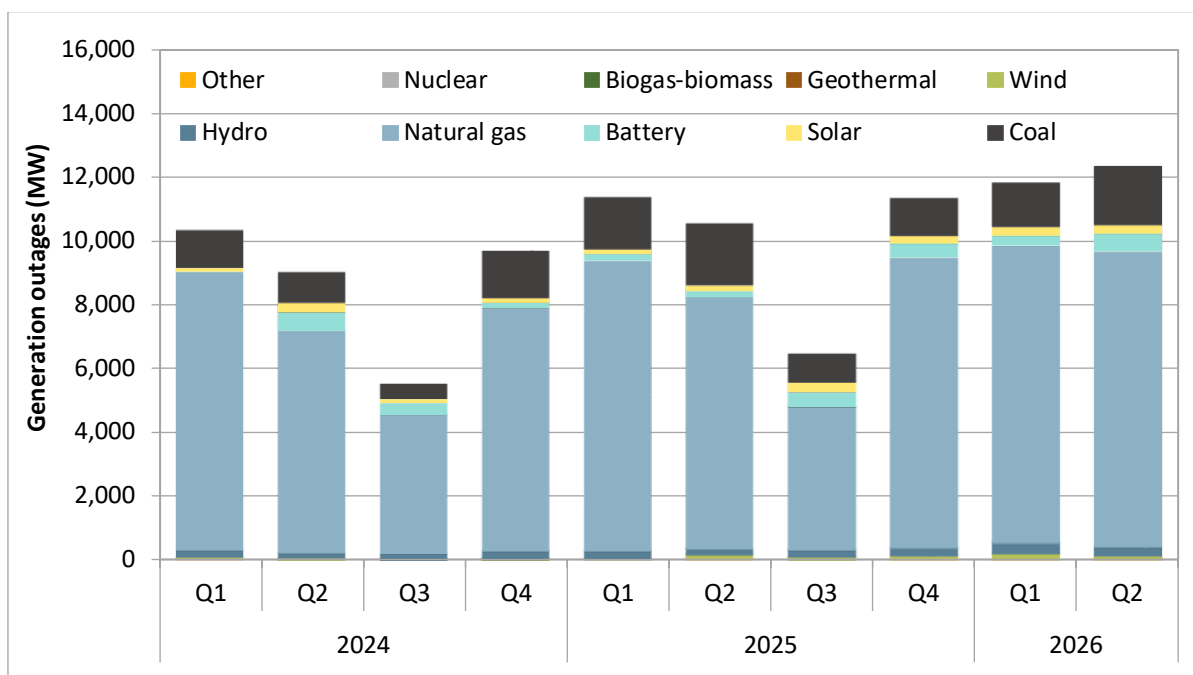
Figure 1.29 and Figure 1.30 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the second quarter of 2026 for entities in the Desert Southwest WEIM region.¹⁷ The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period, and this trend continued in the second quarter of 2026. Average total generation outages increased by about 1,800 MW, or approximately 17 percent, compared to the second quarter of 2025. Total forced outages increased by about 10 percent while total planned outages by about 57 percent. Outages from natural gas resources increased by about 17 percent.

Figure 1.28 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 1.29 Desert Southwest WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Intermountain West

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 second 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. Average total generation outages increased by approximately 580 MW, or 15 percent, driven by increases in coal, solar, wind, and hydro generation outages in the second quarter of 2026 compared to the second quarter of 2025. Outages from natural gas resources decreased by about 12 percent, or about 250 MW.

¹⁸ The Intermountain West region includes AVA, IPCO, NWMT, PACE, Black Hills, and Power Watch.

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

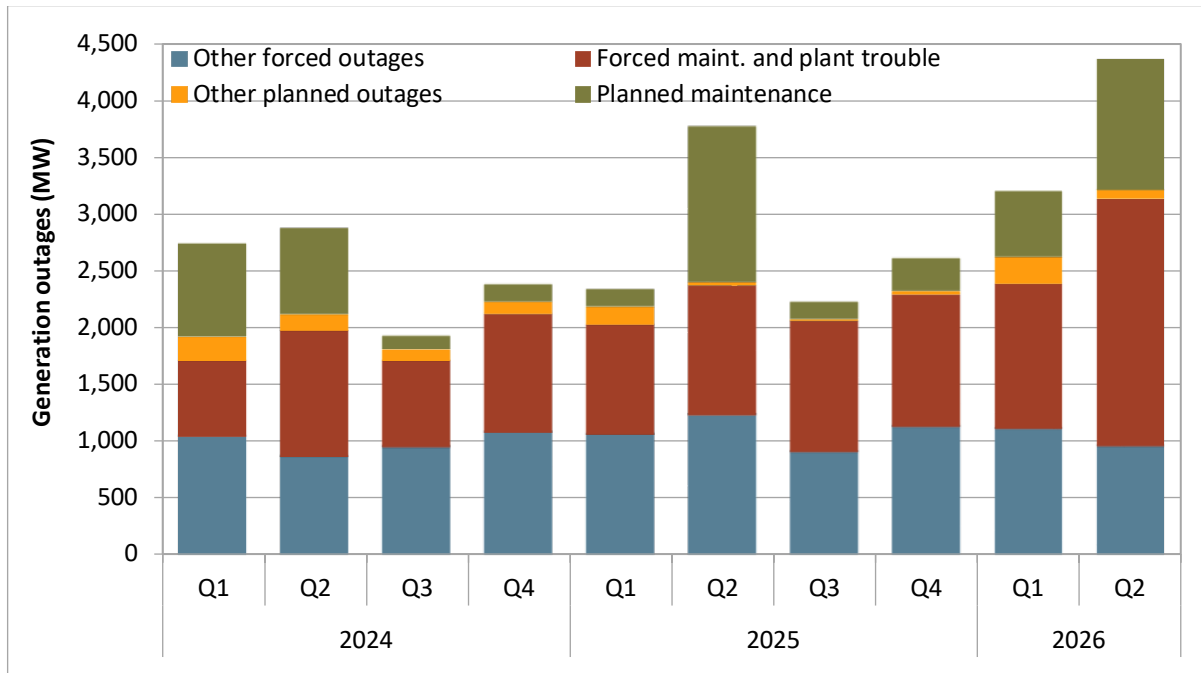
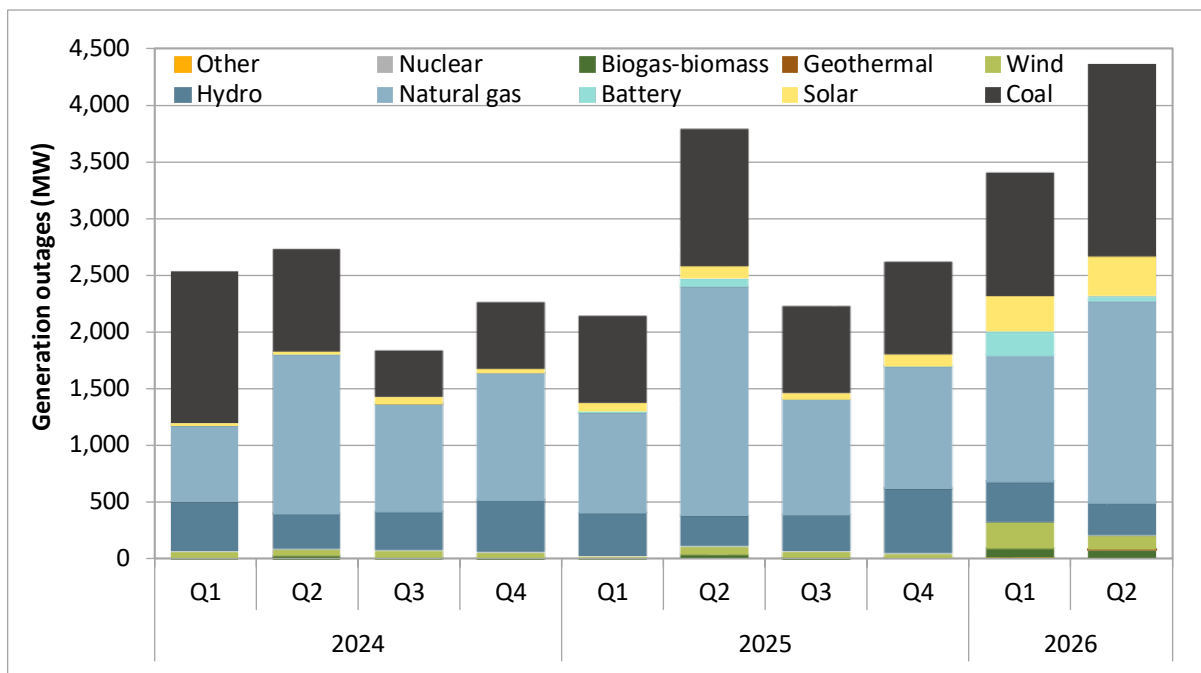


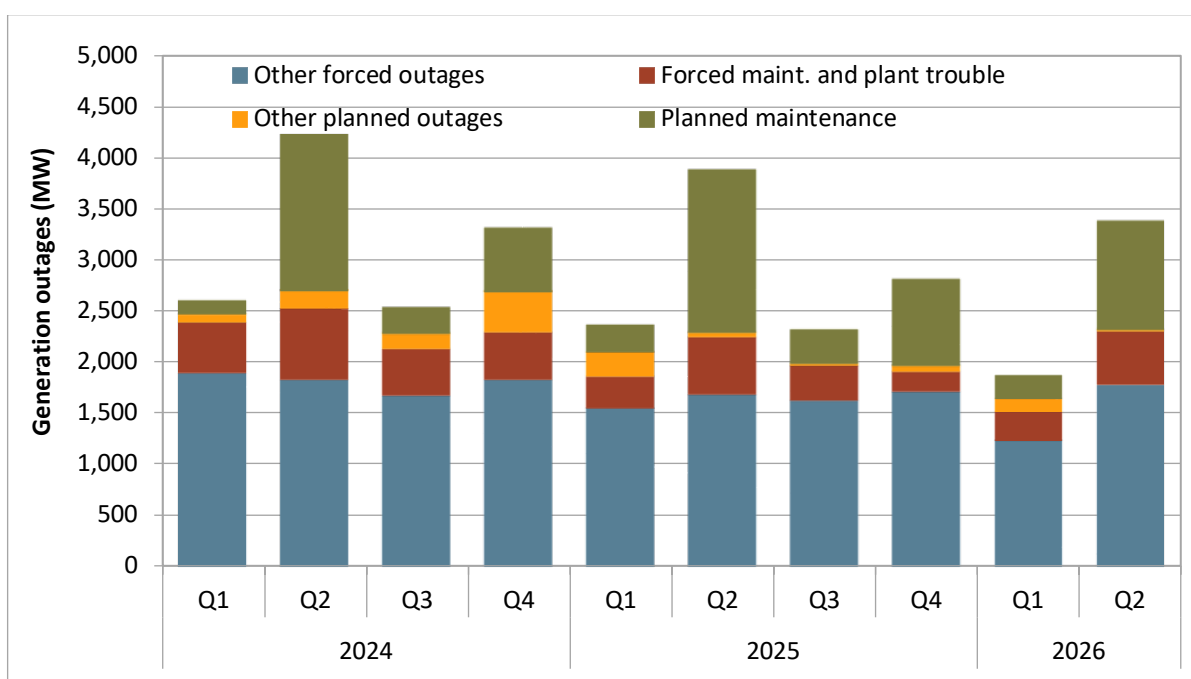
Figure 1.31 Intermountain West WEIM region quarterly average of maximum daily generation outages by fuel type – peak hours



Pacific Northwest

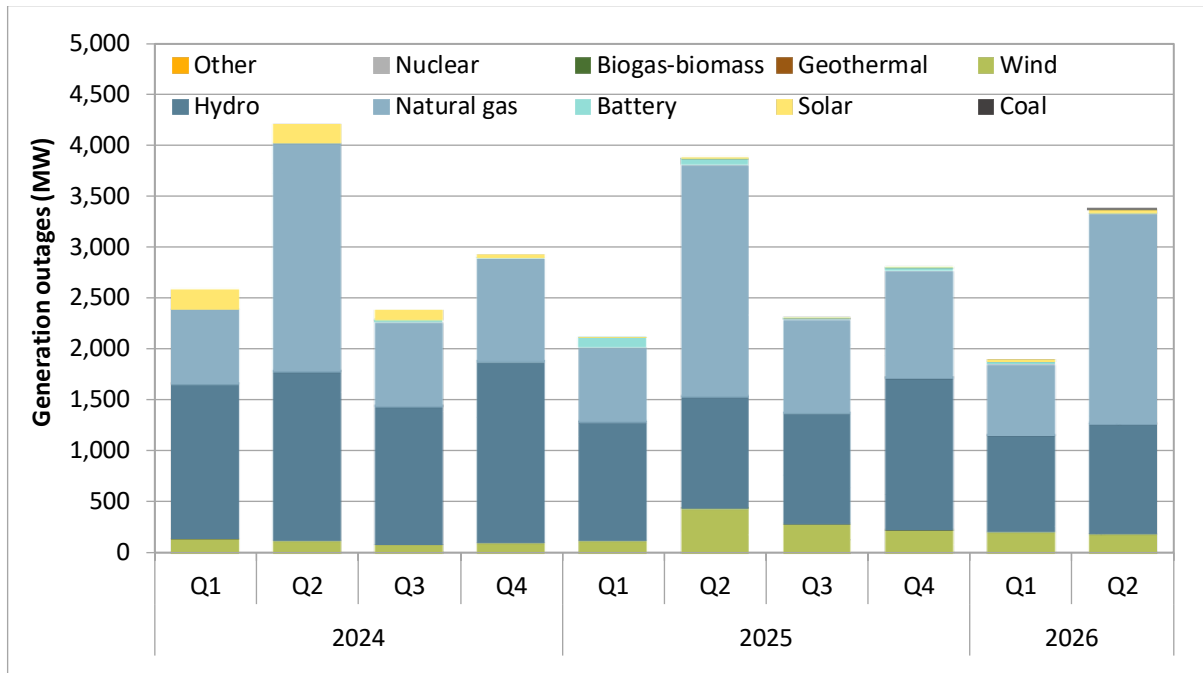
Figure 1.33 and Figure 1.33 show the quarterly averages of maximum daily outages during peak hours by outage type and fuel type, respectively, from the first quarter of 2024 through the second quarter of 2026 for resources in the Pacific Northwest WEIM region.¹⁹ The typical seasonal outage pattern for 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. Average total generation outages decreased, driven primarily by reductions in wind and natural gas outages, along with modest reductions in hydro outages, which more than offset increases in coal and solar outages during the second quarter of 2026.

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



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

Figure 1.33 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 (NWM), and PacifiCorp East (PACE). On May 6, 2026, the Black Hills Energy (BHBA) balancing area, located in the Intermountain West, joined the WEIM system.
- **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 Q2 2026 (blue line) and Q2 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 second quarter is 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 Q2 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 second quarter of 2026 largely resembles that of the same quarter last year. However, relative to Q2 2025, the Q2 2026 system load distribution is shifted slightly to the right, indicating slightly higher load levels but similar load profile. This was due, in part, to the Black Hills

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).

Energy balancing area joining the Western Energy Imbalance Market in Q2 2026. Black Hills Energy load averaged about 590 MW from May 6 through the end of the quarter.

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

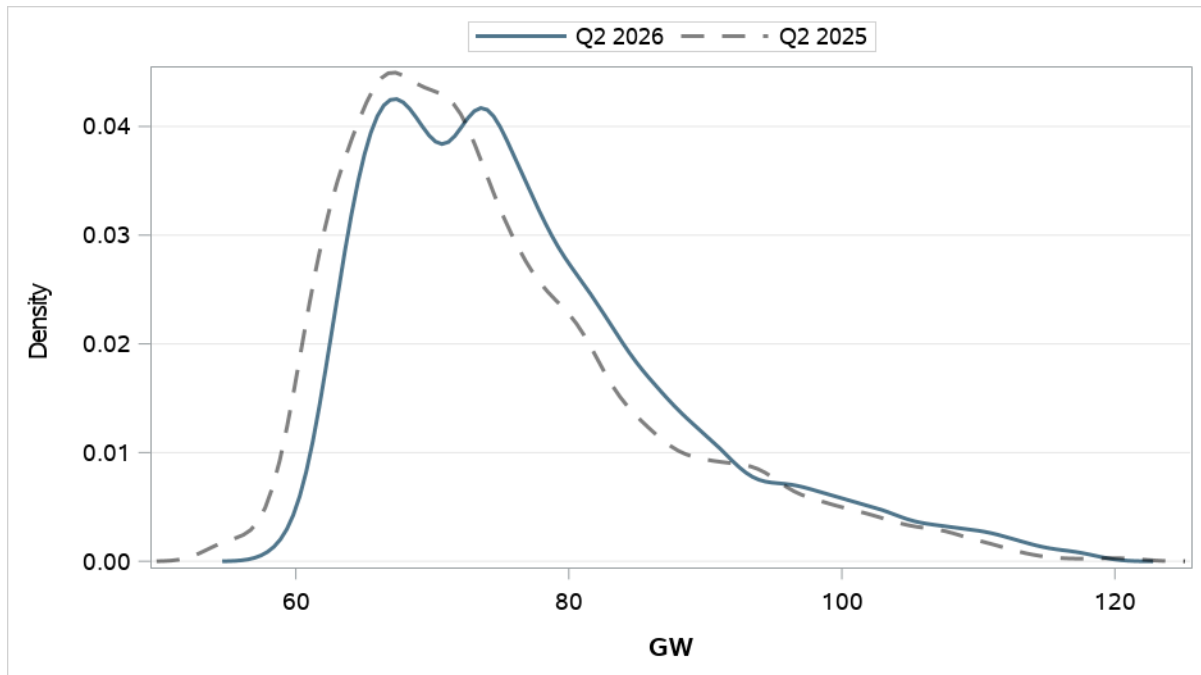


Figure 2.2 shows the monthly average 5-minute market load categorized by region from April 2024 through June 2026. The total system load for this quarter averaged 77.1 GW, representing an approximately 3.1 percent increase compared to the same quarter of 2025. This large relative increase in load between Q2 2025 and Q2 2026 is driven in part by Black Hills Energy joining the WEIM system, but average load in the second quarter of 2026 increased in all regions except for California:

- **Pacific Northwest** (green) averaged **21.5 GW**, a 3.0 percent increase.
- **California** (blue) averaged **26.5 GW**, a 1.1 percent decrease.
- **Desert Southwest** (yellow) averaged **18.4 GW**, a 7.4 percent increase.
- **Intermountain West** (red) averaged **10.7 GW**, a 7.3 percent increase.

The WEIM total market load tends to be lowest in April and tends to peak in July. Regions such as CAISO, California (non-CAISO), and 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.

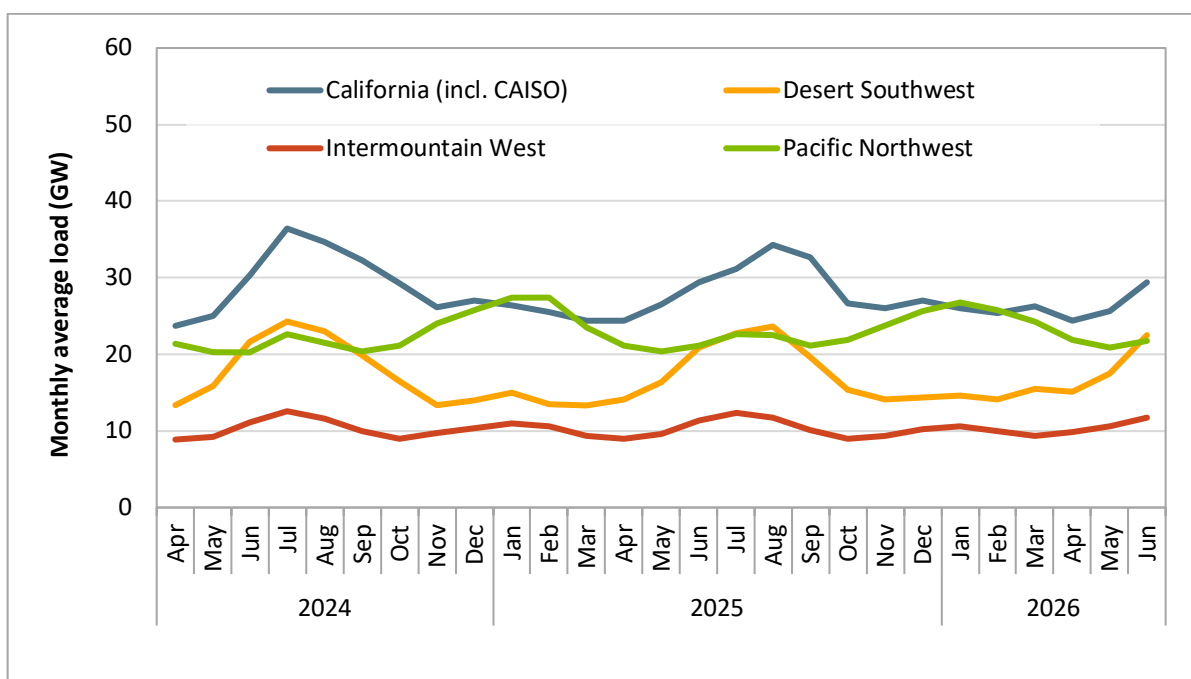
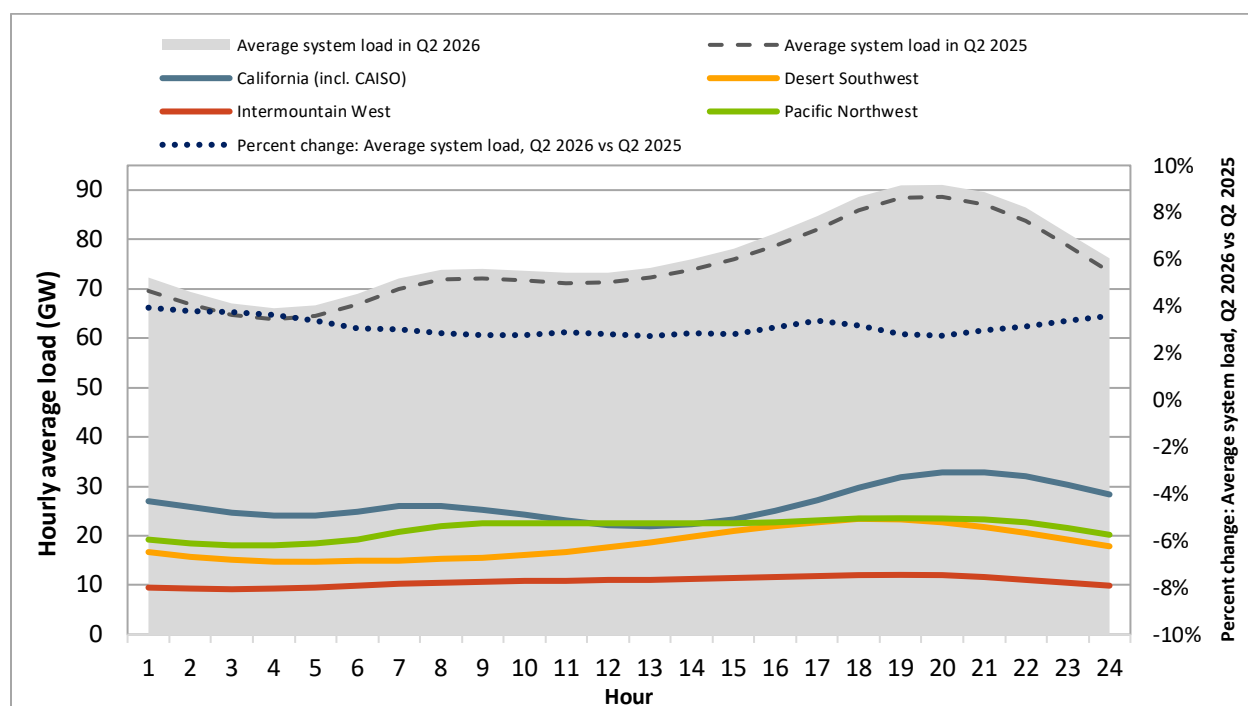
Figure 2.2 Monthly average 5-minute market load by region (GW)

Figure 2.3 displays the hourly average 5-minute market load across different regions in Q2 2026. Each color represents a specific region. The gray area represents the average WEIM system-wide total load for the second quarter of 2026 while the gray dashed line represents the same for the second quarter of 2025. The navy blue dotted line represents the percent change of load between Q2 2025 and Q2 2026, computed for each hour by taking the difference in average system load levels between Q2 2026 and Q2 2025, and then dividing the difference by the average system load level in Q2 2025. The percent change for each hour measures how the average system load has changed in Q2 2026 relative to Q2 2025, expressed as a percentage.

The WEIM system-wide hourly average load peaked at hour-ending 20, recording a load of 91.1 GW, while the lowest load occurred at hour-ending 4, at 66.2 GW. In Q2 of 2026, all regions recorded peak hourly average loads during the evening hours, between hours-ending 18 and 20. The peak average hourly load for each region is given below:

- **Pacific Northwest:** peak load of 23.5 GW at hour-ending 19.
- **California:** peak load of 32.8 GW at hour-ending 20.
- **Desert Southwest:** peak load of 23.4 GW at hour-ending 18.
- **Intermountain West:** peak load of 12.1 GW at hour-ending 19.

Figure 2.3 Hourly average 5-minute market load by region (Q2 2026)

2.2 Peak load

Figure 2.4 shows the highest 5-minute market *system* load forecast for each hour on June 15, 2026, the day with the highest system load during the second quarter of 2026. The figure also shows load forecast data for each balancing authority area (BAA) during the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 120.8 GW during hour-ending 18, interval 11. This was slightly lower than the peak WEIM load during Q2 2025 (123.0 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 18, and all balancing areas recorded peak loads during the evening hours, between hours-ending 16 and 20.

Figure 2.4 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, June 15, 2026)

SYSTEM	89.6	93.0	96.7	101.2	106.5	111.4	115.7	119.0	120.8	120.6	118.9	114.7	110.4	103.5	95.4
CAISO	23.5	23.9	24.2	25.2	27.2	29.0	30.9	32.8	34.7	34.8	35.3	34.4	33.8	32.1	29.8
BANC	2.04	2.19	2.42	2.65	2.91	3.17	3.39	3.50	3.51	3.49	3.36	3.09	2.86	2.57	2.28
Turlock ID	.38	.40	.43	.47	.50	.54	.56	.58	.59	.60	.59	.56	.53	.49	.44
LADWP	2.79	2.90	3.02	3.14	3.31	3.48	3.66	3.76	3.77	3.72	3.55	3.34	3.21	3.01	2.77
NV Energy	5.90	6.31	6.73	7.17	7.64	8.00	8.30	8.56	8.62	8.61	8.39	7.99	7.62	7.11	6.58
Arizona PS	5.59	5.88	6.24	6.56	6.88	7.32	7.58	7.60	7.36	7.33	7.42	7.29	6.84	6.33	5.79
Tucson Electric	1.59	1.59	1.57	1.68	1.86	2.07	2.32	2.38	2.36	2.33	2.24	2.18	2.04	1.85	1.67
Salt River Project	5.87	6.25	6.68	7.05	7.41	7.74	7.89	7.93	7.69	7.67	7.33	7.13	6.80	6.28	5.76
PSC New Mexico	1.61	1.73	1.85	1.95	2.05	2.13	2.21	2.24	2.30	2.28	2.20	2.13	1.96	1.80	1.66
WAPA - Desert SW	.98	1.05	1.11	1.17	1.30	1.26	1.38	1.44	1.39	1.37	1.34	1.26	1.18	1.10	.99
El Paso Electric	1.31	1.37	1.43	1.53	1.61	1.69	1.77	1.78	1.77	1.75	1.65	1.56	1.45	1.31	1.20
PacifiCorp East	6.62	6.86	7.12	7.48	7.74	8.06	8.31	8.44	8.41	8.43	8.16	7.71	7.33	6.78	6.28
Idaho Power	2.81	2.90	3.01	3.15	3.26	3.36	3.45	3.53	3.58	3.56	3.49	3.37	3.23	2.98	2.76
Black Hills Energy	0.65	0.65	0.65	0.65	0.66	0.66	0.67	0.67	0.66	0.66	0.66	0.66	0.64	0.60	0.57
NorthWestern	1.31	1.33	1.37	1.39	1.42	1.46	1.48	1.49	1.51	1.52	1.49	1.44	1.43	1.32	1.24
Avista Utilities	1.28	1.34	1.42	1.47	1.53	1.59	1.62	1.66	1.64	1.63	1.58	1.51	1.45	1.34	1.21
BPA	7.58	7.90	8.29	8.59	8.77	8.94	9.02	9.16	9.23	9.17	9.03	8.73	8.39	8.01	7.52
Tacoma Power	.52	.55	.58	.61	.61	.64	.65	.64	.65	.64	.62	.60	.57	.54	.49
PacifiCorp West	2.57	2.73	2.88	3.04	3.20	3.31	3.39	3.45	3.52	3.52	3.45	3.32	3.17	2.94	2.63
Portland GE	3.05	3.21	3.43	3.66	3.83	4.00	4.10	4.17	4.14	4.11	4.05	3.99	3.82	3.56	3.23
Puget Sound Energy	2.99	3.09	3.28	3.39	3.53	3.63	3.73	3.73	3.73	3.71	3.61	3.46	3.31	3.11	2.79
Seattle City Light	1.18	1.21	1.25	1.27	1.30	1.31	1.34	1.34	1.33	1.32	1.26	1.21	1.17	1.13	1.03
Powerex	7.46	7.68	7.75	7.91	8.00	8.05	8.04	8.17	8.35	8.32	8.07	7.78	7.55	7.24	6.75
	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Hour														

Table 2.1 shows the peak 5-minute market load and date for each balancing area (or region) during the second quarter. Nearly all BAAs recorded quarterly peak load in June. Powerex and Tacoma Power, both in the Pacific Northwest, recorded quarterly peak loads in April. The table also shows each balancing area's load during the system peak load interval on June 15, 2026 (120,791 MW).

Table 2.1 Peak WEIM load (April–June 2026)

Region/balancing area	Peak load (April–June, 2026)		Load during WEIM system peak (15-Jun-2026)	
	Date	Load (MW)	Load (MW)	Percent
WEIM system	15-Jun-26	120,791	120,791	
California	12-Jun-26	46,010	42,540	35%
California ISO	12-Jun-26	37,670	34,668	29%
BANC	12-Jun-26	3,945	3,512	3%
LADWP	12-Jun-26	4,166	3,765	3%
Turlock Irrig. District	12-Jun-26	615	594	.5%
Desert Southwest	23-Jun-26	34,229	31,491	26%
Arizona Public Service	16-Jun-26	8,325	7,363	6%
El Paso Electric	24-Jun-26	2,391	1,768	1.5%
NV Energy	16-Jun-26	9,001	8,621	7%
PSC New Mexico	24-Jun-26	2,677	2,297	2%
Salt River Project	16-Jun-26	8,304	7,693	6%
Tucson Electric	25-Jun-26	2,799	2,359	2%
WAPA - Desert SW	16-Jun-26	1,538	1,390	1.2%
Intermountain West	23-Jun-26	17,019	15,814	13%
Avista Utilities	24-Jun-26	1,730	1,644	1%
Black Hills Energy	7-Jun-26	839	657	0.5%
Idaho Power	24-Jun-26	3,922	3,584	3%
NorthWestern Energy	16-Jun-26	1,683	1,515	1%
PacifiCorp East	23-Jun-26	9,395	8,414	7%
Pacific Northwest	23-Jun-26	31,060	30,946	26%
BPA	15-Jun-26	9,232	9,231	8%
PacifiCorp West	15-Jun-26	3,524	3,524	3%
Portland General Electric	15-Jun-26	4,201	4,140	3%
Powerex	1-Apr-26	9,267	8,349	7%
Puget Sound Energy	23-Jun-26	3,785	3,729	3%
Seattle City Light	15-Jun-26	1,368	1,327	1%
Tacoma Power	16-Apr-26	672	646	.5%

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

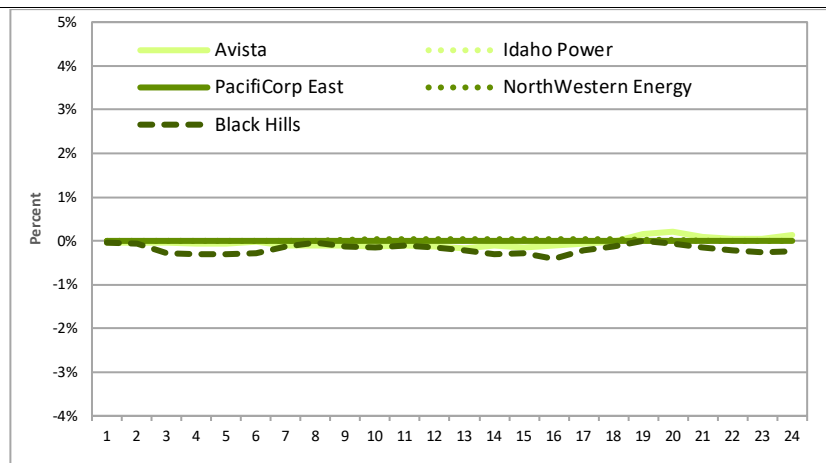
3.1 Load forecast adjustments - all balancing areas

The figures below show second quarter average hourly load forecast adjustments in the 15-minute and 5-minute markets for each balancing area, as a percentage of the balancing area's average load.²³ The magnitudes of average hourly 5-minute market load adjustments made by most balancing areas were a non-negligible percentage of their load forecasts. The CAISO balancing area and BPA also made significant hourly average load adjustments in the 15-minute market.

²³ Avangrid Power, Power Watch and Powerex are not shown in these figures. Avangrid Power and Power Watch are generation-only entities 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 load forecast adjustment as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q2 2026)

15-minute market



5-minute market

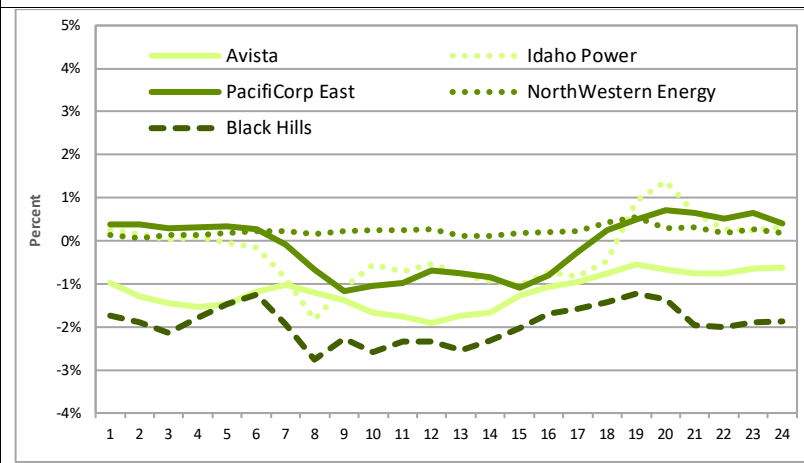
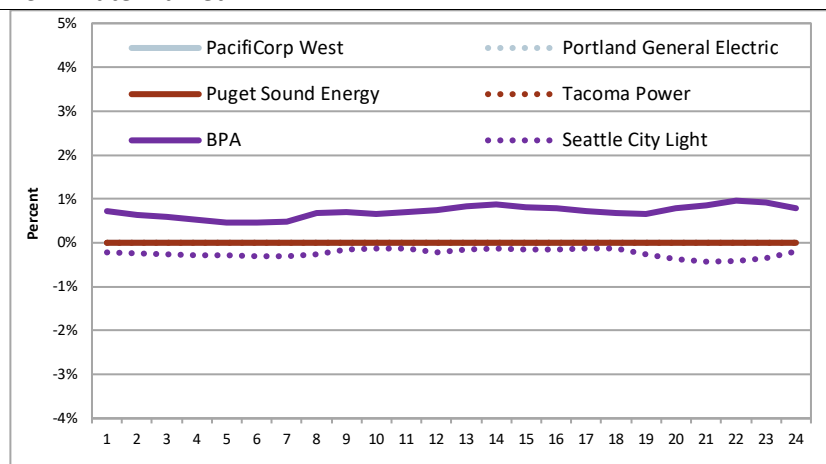


Figure 3.2 Pacific Northwest: Average hourly load forecast adjustments as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q2 2026)

15-minute market



5-minute market

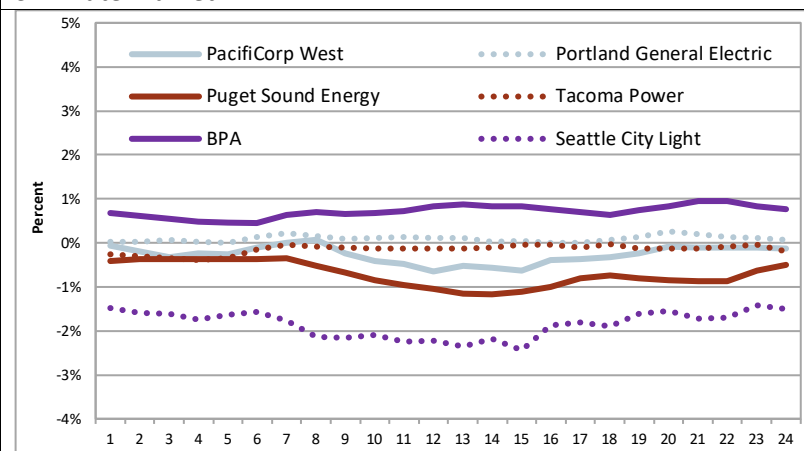
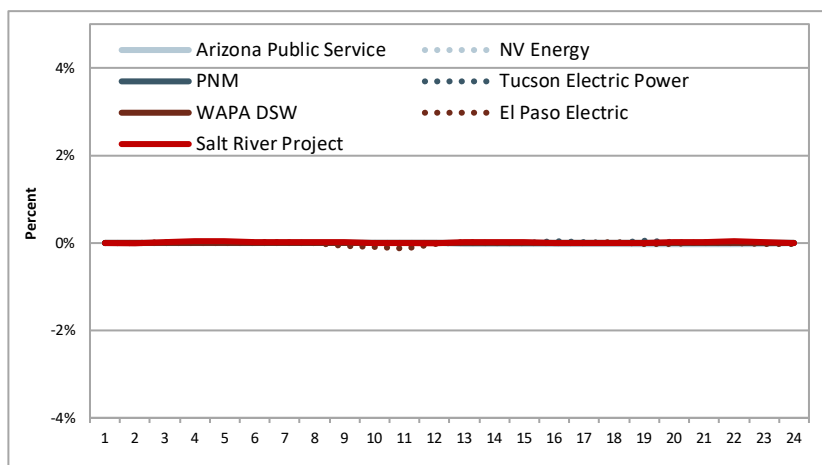


Figure 3.3 Desert Southwest: Average hourly load forecast adjustments as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q2 2026)

15-minute market



5-minute market

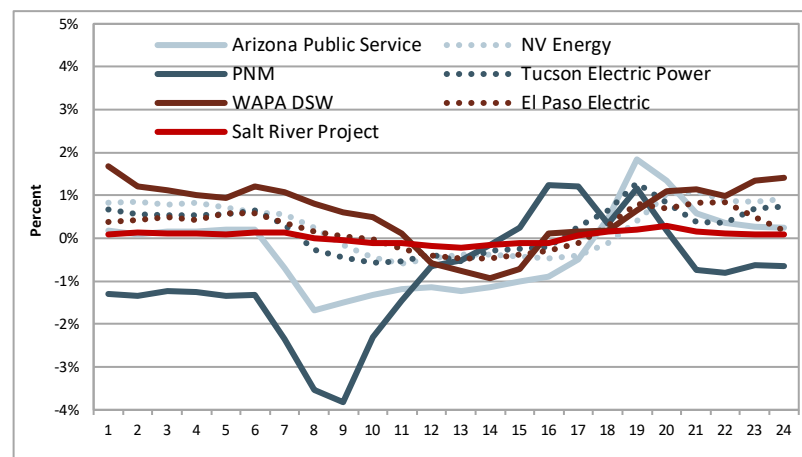
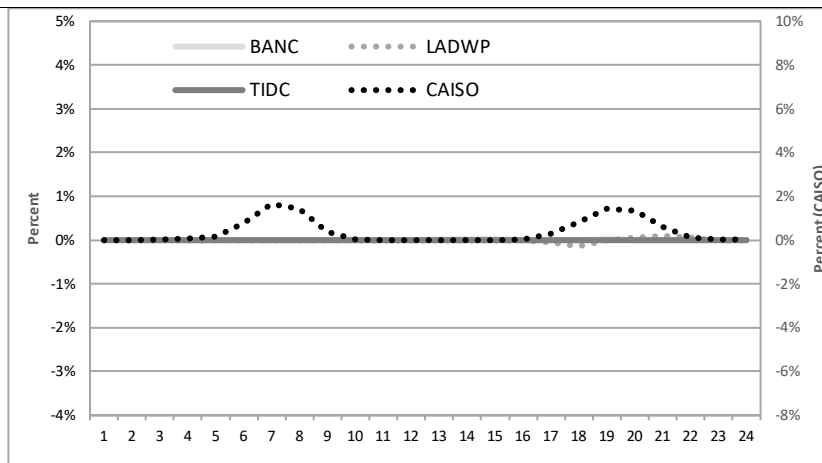
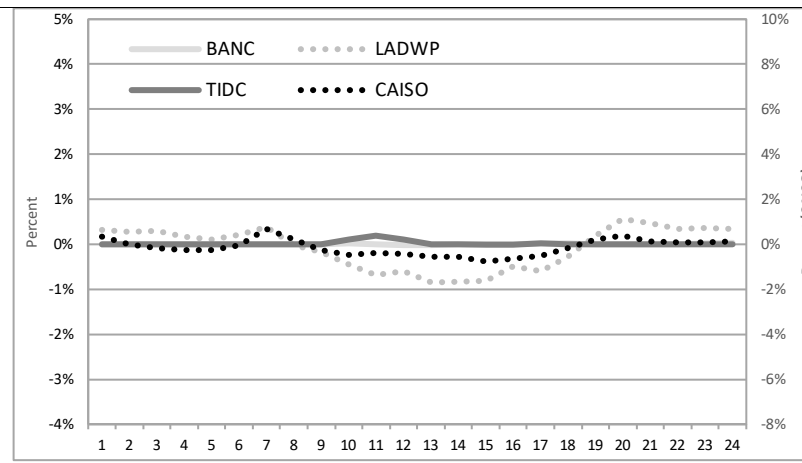


Figure 3.4 California: Average hourly load forecast adjustments as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q2 2026)

15-minute market



5-minute market



3.2 Real-time load forecast adjustments in CAISO balancing area

Between January and early March 2026, the CAISO initiated a pilot program²⁴ designed to minimize the use of load conformance in the real-time markets. Lessons learned from this pilot program appear to have continued into the second quarter and may have contributed to the reduction in imbalance conformance adjustments observed in the second quarter of 2026 compared to the second quarter of 2025. The lower discrepancy between 15-minute market and 5-minute market load adjustments in Q2 2026 compared to Q2 2025 contributed to greater convergence between prices in these markets during this period.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets declined significantly during the morning and evening ramp periods in the second quarter of 2026 compared to the same period in 2025. The largest average morning hourly adjustment in the 15-minute market was in hour-ending 7 and was approximately 750 MW lower in Q2 2026 than in Q2 2025. The maximum average evening hourly adjustment occurred in hour-ending 20 and was approximately 1,500 MW lower than the corresponding adjustment observed in Q2 2025.

The 5-minute market adjustments were similar in the morning ramp hours for the second quarter of 2026 compared to the second quarter of 2025. Evening 5-minute market adjustments peaked in hour-ending 20 at about 85 MW and were about 525 MW lower than in the second 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](https://www.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 (Q2 2025 and Q2 2026)

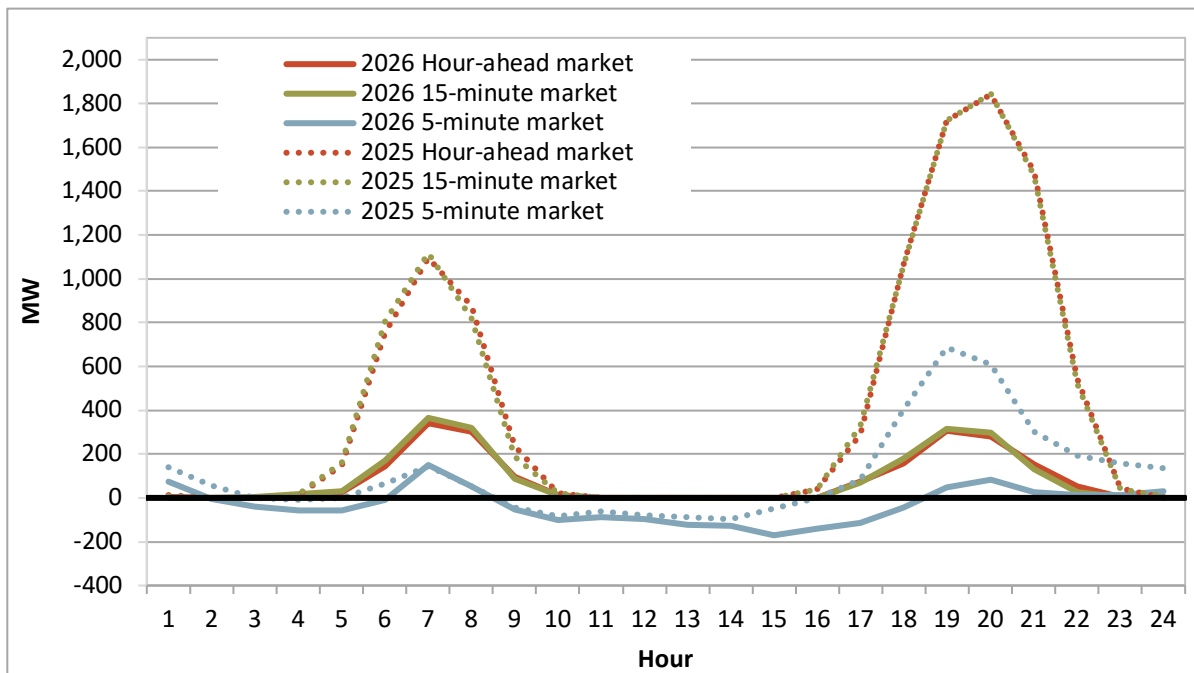
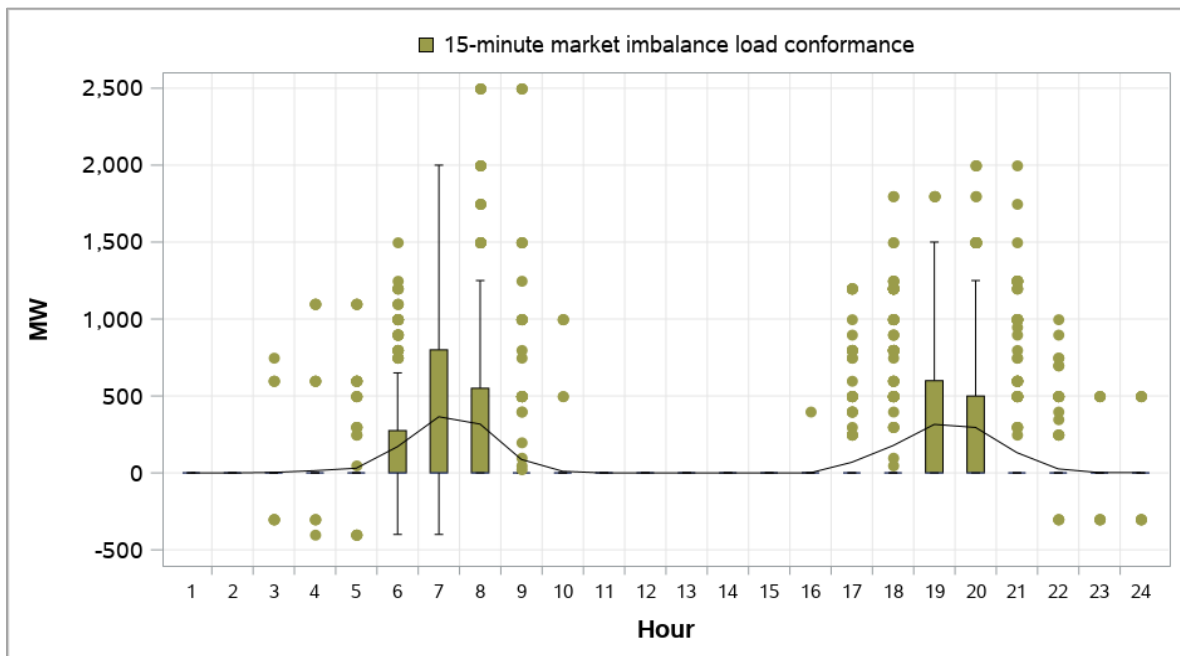


Figure 3.6 shows an hourly distribution of the 15-minute market load adjustments for the second quarter of 2026. This box and whisker graph highlights extreme outliers²⁵ (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well 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 few days in April and May.

²⁵ The upper outliers are greater than the 3rd quartile + $1.5 \times$ Interquartile Range (IQR), while the lower outliers are less than the 1st quartile – $1.5 \times$ IQR. The whiskers extend to the most extreme data values that are still within these limits. Observations beyond these limits are displayed individually as outliers.

Figure 3.6 CAISO BA 15-minute market hourly distribution of operator load adjustments (Q2 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.²⁶ Prices are calculated based on the load schedules and corresponding prices at all Aggregated Pricing Nodes (APnodes).²⁷

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 July 2024 to June 2026. Prices in the 15-minute market across the WEIM averaged about \$14/MWh in the second quarter of 2026, down 49 percent from the same quarter of last year. Prices in the 5-minute market were \$14/MWh, a 48 percent decrease compared to Q2 2025.

In the 15-minute market, California recorded the highest average price at \$17/MWh, followed by the Desert Southwest at \$15/MWh. Average prices in these regions were slightly higher than prices in the Pacific Northwest (\$10/MWh) and Intermountain West regions (\$13/MWh). Greenhouse gas (GHG) costs during non-solar hours contributed to higher average prices in California compared to other regions.²⁸

²⁶ 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 BHBA (Black Hills), GWA (Power Watch), PACE, IPCO, NWMT, and AVA. The Pacific Northwest includes AVRN, BPA, BCHA, TWPR, PGE, PSEI, and SCL.

²⁷ 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.

²⁸ 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.

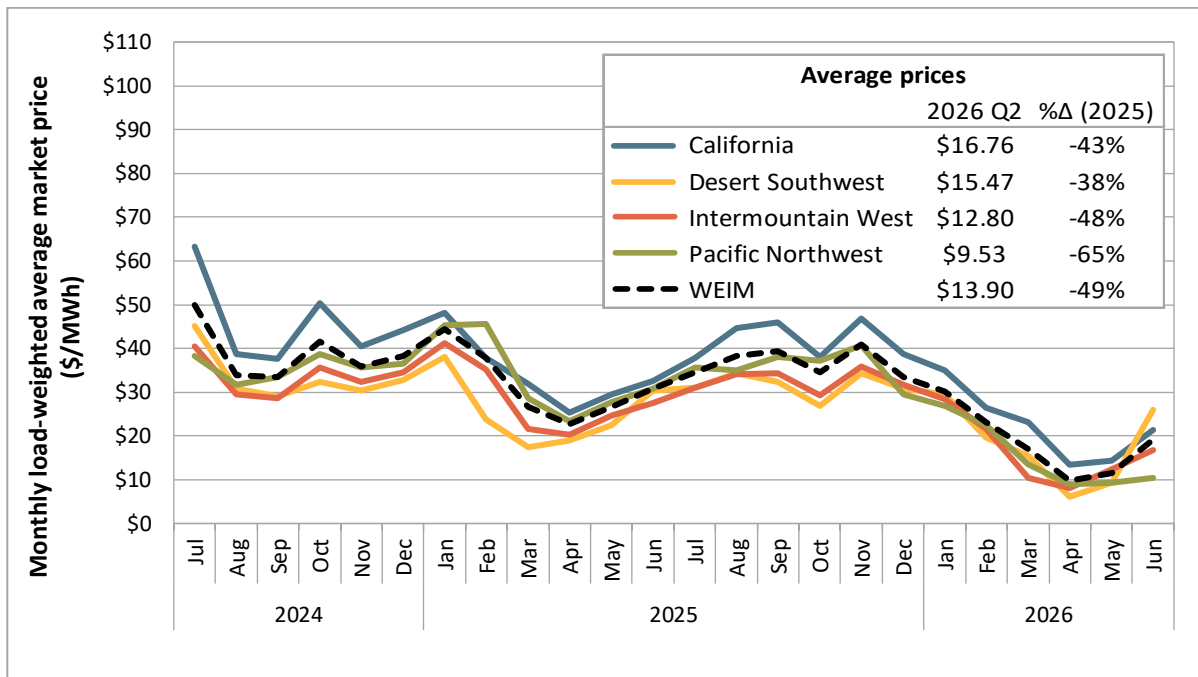
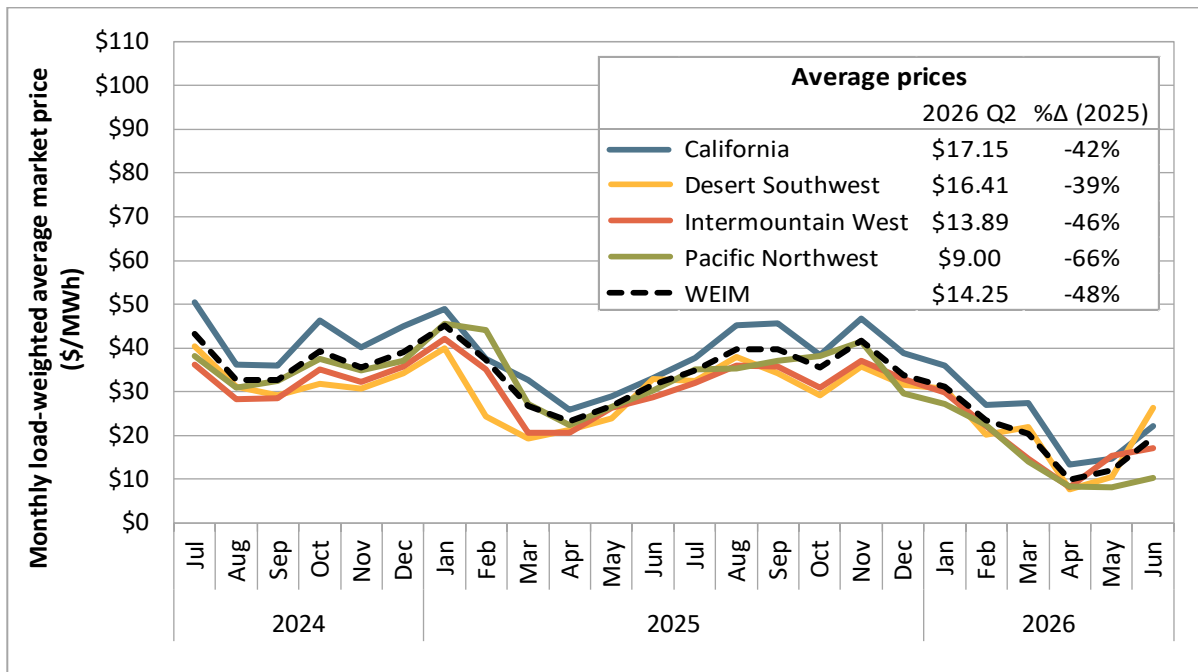
Figure 4.1 Weighted average monthly 15-minute market prices by region**Figure 4.2 Weighted average monthly 5-minute market prices by region**

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 second 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 21 in both the 15-minute and 5-minute markets, reaching 77.7 GW and 77.8 GW, respectively. In the 15-minute market, all four regions experienced peak average prices in hour-ending 20. In the 5-minute market, the California, Desert Southwest, and Pacific Northwest regions experienced peak average prices at hour-ending 20, while the Intermountain West region experienced peak prices in hour-ending 19.

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. Low prices in Powerex brought down the average price of the Pacific Northwest across all hours.

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.

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

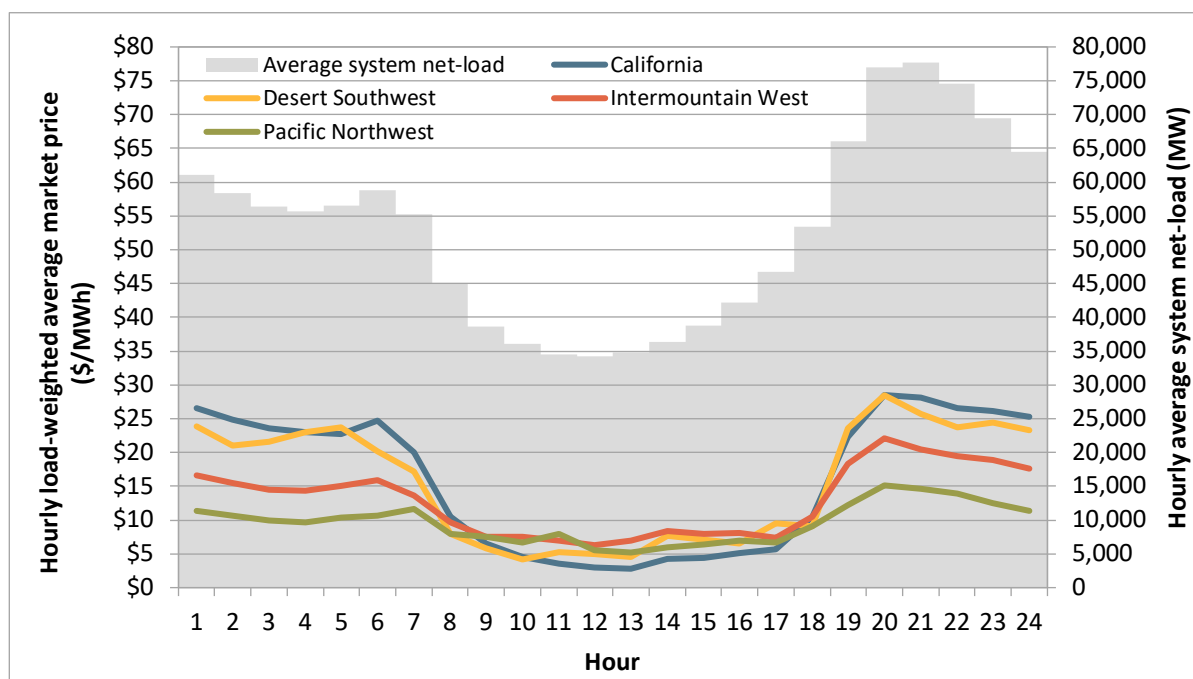
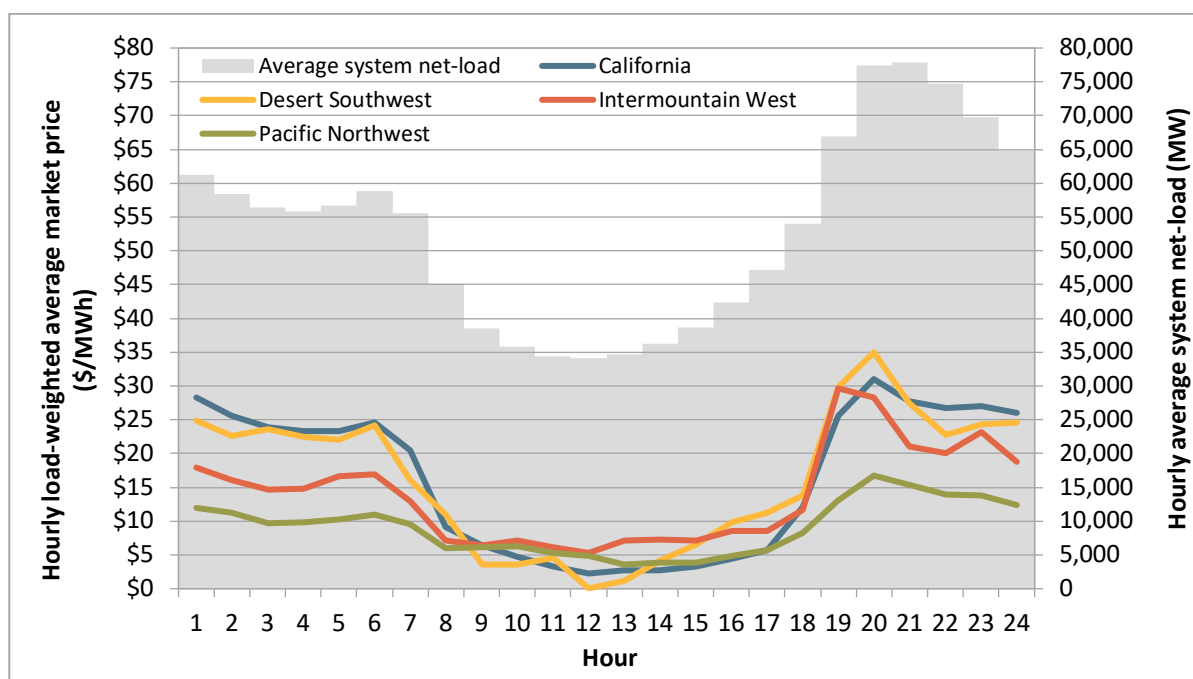


Figure 4.4 Weighted average hourly 5-minute market prices by region (April–June 2026)

4.2 Real-time market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during the second quarter of 2026. Figure 4.6, Figure 4.8, Figure 4.7, and Figure 4.8 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.

- **Marginal energy cost**, referred to as MEC, is the marginal clearing price for energy in a balancing authority area (BAA). The difference in MEC between balancing areas reflects any transfer congestion between one another.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the price impact from greenhouse gas (GHG) regulation. It represents the marginal cost of a net import transfer into the GHG regulation area (currently only balancing authority areas in California) determined within the optimization using the GHG bid adders of resources located outside of the GHG regulation area. This contributes to price differences between the GHG regulation area and the regions outside of it.²⁹
- **Congestion from local constraints** is the price impact on a balancing area from transmission constraints within its own balancing area. While these constraints are located locally, they can

²⁹ Previously, the GHG component was represented as a negative price impact in all non-California balancing areas. Going forward with EDAM, GHG costs are added as a positive price impact on the GHG regulation area.

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 on a balancing area from transmission constraints in a different WEIM balancing area. 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 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*.

Significant factors impacting the locational marginal price (LMP) differences between balancing areas included internal congestion from flow-based constraints. GHG costs were previously embedded within the system marginal energy costs and subtracted from non-California balancing areas. These costs are now added onto the GHG regulation area which currently consists of balancing areas in California.

Internal flow-based constraints in the CAISO balancing area impacted prices in both the 15-minute and 5-minute markets. Congestion on these constraints mainly during mid-day solar hours contributed to prices in Northern California and the Pacific Northwest being relatively higher than prices in Southern California and the Desert Southwest.

Figure 4.5 to Figure 4.8 in this report are separated into pre-EDAM (April 2026) and post-EDAM (May – June 2026) due to changes in the LMP components. In the post-EDAM figures, system marginal energy price is replaced by marginal energy cost (MEC) and the marginal GHG cost is now represented as a positive price component for the California balancing areas.

Figure 4.5 Average 15-minute market prices by balancing area (April 2026)

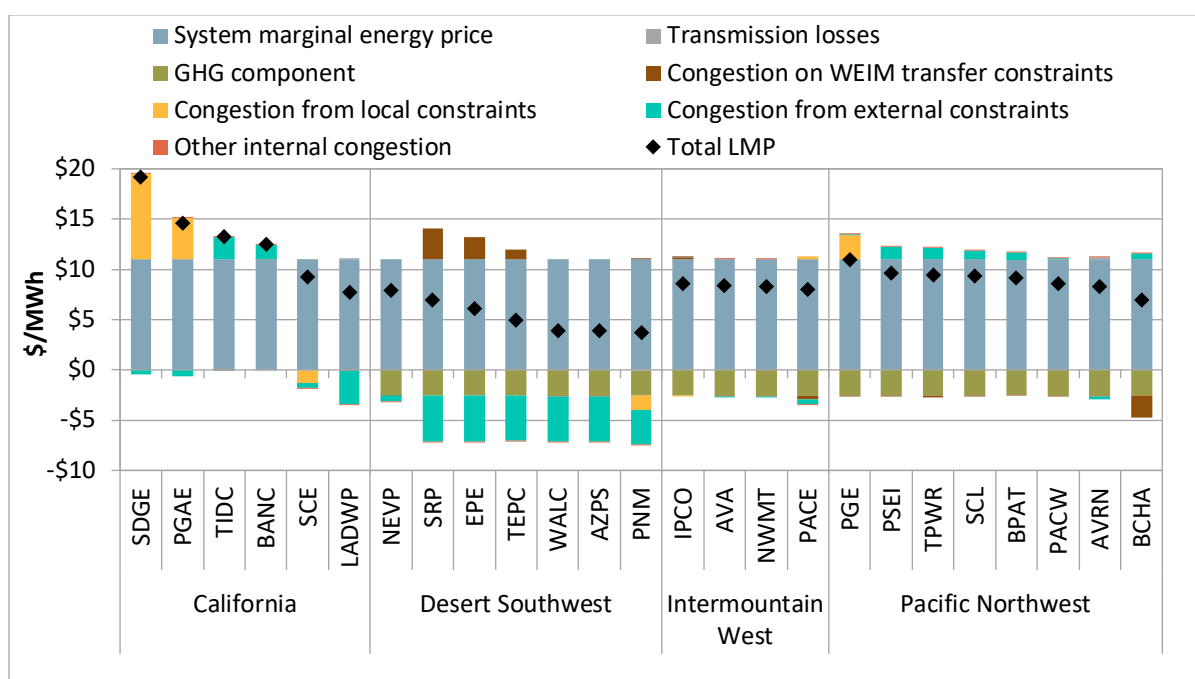


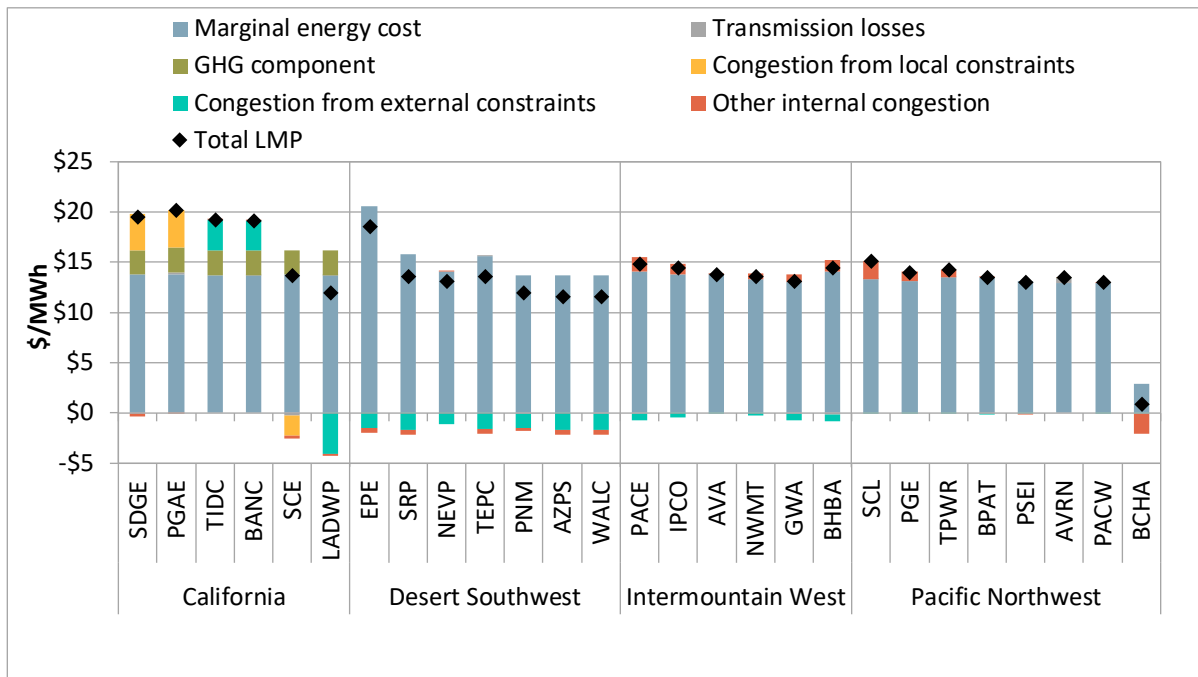
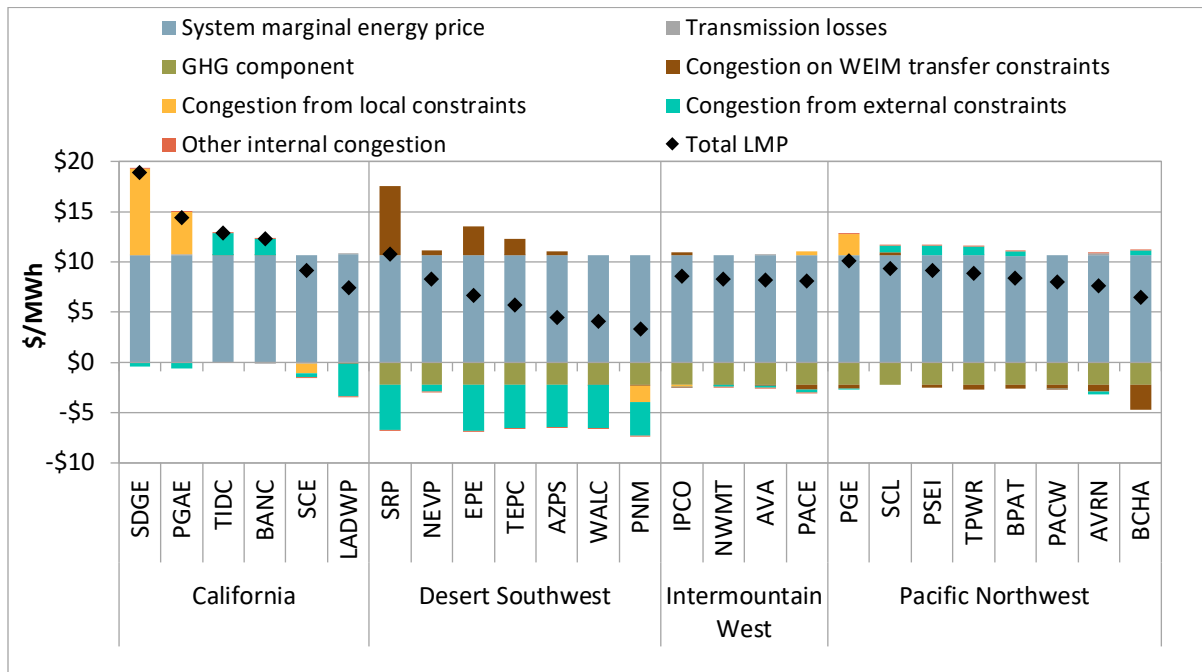
Figure 4.6 Average 15-minute market prices by balancing area (May and June 2026)**Figure 4.7 Average 5-minute market prices by balancing area (April 2026)**

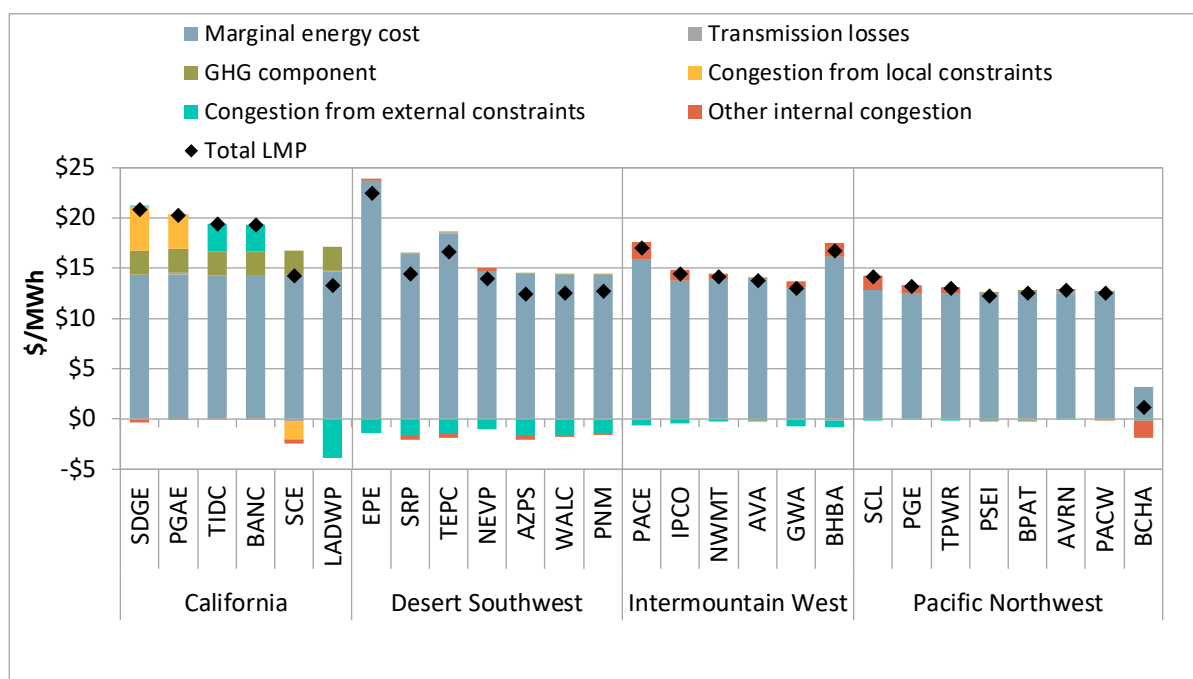
Figure 4.8 Average 5-minute market prices by balancing area (May and June 2026)

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 load weighted average marginal energy cost (MEC) across all BAAs, shown in the top row. Blue indicates prices below that month's average MEC 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 Q2 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 second 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

Average MEC	\$56	\$38	\$36	\$48	\$41	\$43	\$47	\$41	\$30	\$25	\$29	\$33	\$38	\$43	\$44	\$38	\$46	\$36	\$34	\$26	\$18	\$11	\$11	\$16		
PG&E (CAISO)	\$61	\$36	\$36	\$56	\$46	\$46	\$49	\$40	\$31	\$27	\$30	\$34	\$38	\$43	\$48	\$42	\$50	\$37	\$34	\$28	\$23	\$15	\$18	\$22		
SCE (CAISO)	\$50	\$35	\$33	\$38	\$35	\$40	\$43	\$30	\$25	\$18	\$24	\$28	\$35	\$42	\$39	\$32	\$42	\$34	\$34	\$23	\$18	\$9	\$10	\$17		
SDGE (CAISO)	\$50	\$36	\$37	\$40	\$38	\$43	\$49	\$35	\$27	\$21	\$25	\$29	\$38	\$47	\$45	\$33	\$44	\$37	\$37	\$25	\$20	\$19	\$17	\$22		
BANC	\$58	\$37	\$37	\$56	\$46	\$45	\$49	\$40	\$31	\$25	\$29	\$35	\$39	\$43	\$48	\$43	\$49	\$36	\$33	\$27	\$20	\$12	\$17	\$22		
Turlock ID	\$54	\$37	\$39	\$61	\$47	\$45	\$51	\$40	\$32	\$28	\$30	\$36	\$41	\$44	\$51	\$46	\$49	\$36	\$33	\$28	\$21	\$13	\$17	\$22		
LADWP	\$55	\$40	\$35	\$40	\$37	\$38	\$45	\$30	\$28	\$21	\$27	\$31	\$37	\$43	\$42	\$34	\$44	\$36	\$34	\$23	\$16	\$8	\$5	\$19		
NV Energy	\$42	\$29	\$28	\$33	\$29	\$31	\$38	\$26	\$20	\$18	\$24	\$28	\$31	\$33	\$33	\$28	\$35	\$30	\$29	\$20	\$14	\$8	\$10	\$16		
Arizona PS	\$45	\$30	\$27	\$30	\$26	\$31	\$35	\$22	\$18	\$15	\$19	\$25	\$30	\$33	\$31	\$26	\$34	\$29	\$29	\$19	\$13	\$4	\$8	\$15		
Tucson Electric	\$39	\$26	\$26	\$28	\$27	\$31	\$36	\$22	\$18	\$16	\$20	\$26	\$30	\$32	\$31	\$27	\$34	\$30	\$29	\$20	\$15	\$5	\$10	\$17		
Salt River Project	\$38	\$31	\$28	\$30	\$26	\$30	\$35	\$22	\$19	\$24	\$20	\$30	\$30	\$33	\$32	\$26	\$34	\$29	\$28	\$19	\$15	\$7	\$10	\$18		
PSC New Mexico	\$43	\$29	\$28	\$27	\$57	\$29	\$37	\$14	-\$1	\$14	\$19	\$43	\$31	\$40	\$32	\$24	\$31	\$25	\$26	\$15	\$11	\$4	\$9	\$15		
WAPA - Desert SW	\$42	\$29	\$27	\$32	\$26	\$32	\$36	\$22	\$19	\$15	\$19	\$25	\$30	\$33	\$31	\$28	\$33	\$28	\$29	\$23	\$19	\$4	\$8	\$15		
El Paso Electric	\$38	\$25	\$26	\$27	\$27	\$30	\$34	\$19	\$8	\$17	\$26	\$32	\$31	\$33	\$33	\$26	\$34	\$29	\$37	\$19	\$14	\$6	\$18	\$20		
PacifiCorp East	\$39	\$28	\$27	\$35	\$31	\$33	\$39	\$30	\$19	\$18	\$23	\$27	\$30	\$34	\$33	\$26	\$34	\$29	\$28	\$21	\$11	\$8	\$13	\$17		
Idaho Power	\$37	\$28	\$28	\$37	\$34	\$35	\$42	\$35	\$22	\$26	\$25	\$28	\$31	\$34	\$34	\$33	\$36	\$30	\$28	\$21	\$10	\$9	\$13	\$16		
NorthWestern	\$36	\$28	\$29	\$30	\$33	\$33	\$41	\$39	\$25	\$21	\$24	\$28	\$31	\$33	\$34	\$32	\$38	\$30	\$28	\$22	\$9	\$8	\$13	\$15		
PowerWatch																								\$11	\$15	
Black Hills Energy																									\$12	\$16
Avista Utilities	\$33	\$28	\$29	\$39	\$36	\$35	\$43	\$41	\$26	\$21	\$24	\$28	\$31	\$33	\$35	\$34	\$38	\$30	\$28	\$22	\$9	\$8	\$13	\$15		
Avangrid	\$32	\$28	\$33	\$40	\$37	\$36	\$44	\$44	\$26	\$21	\$27	\$30	\$33	\$34	\$38	\$38	\$40	\$28	\$27	\$23	\$13	\$8	\$12	\$15		
BPA	\$40	\$31	\$33	\$40	\$37	\$35	\$43	\$45	\$26	\$22	\$28	\$33	\$36	\$36	\$41	\$39	\$40	\$28	\$27	\$23	\$13	\$9	\$12	\$15		
Tacoma Power	\$32	\$27	\$32	\$38	\$36	\$36	\$43	\$43	\$26	\$22	\$26	\$29	\$35	\$34	\$38	\$36	\$39	\$28	\$27	\$22	\$12	\$9	\$14	\$15		
PacifiCorp West	\$31	\$27	\$32	\$39	\$36	\$36	\$43	\$43	\$25	\$20	\$26	\$29	\$31	\$33	\$37	\$37	\$39	\$27	\$27	\$22	\$12	\$9	\$12	\$14		
Portland GE	\$32	\$27	\$32	\$39	\$36	\$35	\$43	\$43	\$25	\$20	\$26	\$29	\$32	\$34	\$38	\$37	\$39	\$28	\$27	\$22	\$14	\$11	\$14	\$14		
Puget Sound Energy	\$33	\$28	\$32	\$38	\$35	\$36	\$43	\$43	\$26	\$23	\$27	\$29	\$37	\$34	\$39	\$36	\$39	\$28	\$27	\$22	\$12	\$10	\$12	\$14		
Seattle City Light	\$31	\$27	\$32	\$40	\$36	\$37	\$43	\$43	\$26	\$22	\$26	\$29	\$37	\$34	\$39	\$36	\$39	\$29	\$27	\$22	\$13	\$9	\$16	\$14		
Powerex	\$42	\$36	\$33	\$36	\$35	\$34	\$48	\$46	\$33	\$27	\$29	\$31	\$36	\$33	\$34	\$36	\$39	\$29	\$25	\$22	\$14	\$7	\$2	-\$1		
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun		
	2024						2025												2026							

Table 4.2 Average monthly 5-minute market prices

Average MEC	\$46	\$35	\$35	\$45	\$41	\$43	\$48	\$40	\$30	\$25	\$28	\$33	\$38	\$43	\$44	\$38	\$47	\$37	\$35	\$27	\$23	\$11	\$12	\$17
PG&E (CAISO)	\$49	\$34	\$35	\$51	\$45	\$46	\$50	\$39	\$32	\$28	\$29	\$34	\$38	\$43	\$48	\$43	\$50	\$38	\$35	\$28	\$25	\$14	\$18	\$23
SCE (CAISO)	\$42	\$33	\$32	\$37	\$35	\$41	\$44	\$30	\$26	\$19	\$24	\$29	\$35	\$43	\$40	\$33	\$42	\$35	\$35	\$24	\$23	\$9	\$11	\$18
SDGE (CAISO)	\$42	\$34	\$36	\$38	\$38	\$43	\$49	\$35	\$29	\$21	\$25	\$30	\$38	\$49	\$45	\$33	\$44	\$38	\$38	\$25	\$28	\$19	\$19	\$23
BANC	\$48	\$34	\$36	\$52	\$45	\$45	\$50	\$39	\$32	\$26	\$29	\$35	\$39	\$43	\$48	\$44	\$49	\$37	\$34	\$28	\$22	\$12	\$17	\$22
Turlock ID	\$45	\$35	\$38	\$57	\$46	\$46	\$51	\$39	\$33	\$30	\$30	\$36	\$41	\$44	\$51	\$46	\$49	\$37	\$34	\$29	\$23	\$13	\$17	\$22
LADWP	\$50	\$45	\$35	\$39	\$37	\$38	\$45	\$30	\$28	\$21	\$27	\$32	\$38	\$45	\$43	\$34	\$44	\$36	\$35	\$24	\$20	\$7	\$7	\$20
NV Energy	\$37	\$29	\$28	\$33	\$30	\$32	\$40	\$25	\$21	\$22	\$25	\$29	\$32	\$35	\$34	\$30	\$37	\$32	\$30	\$21	\$20	\$8	\$11	\$17
Arizona PS	\$40	\$32	\$27	\$30	\$27	\$33	\$37	\$23	\$19	\$16	\$20	\$27	\$32	\$37	\$32	\$29	\$35	\$31	\$30	\$20	\$19	\$4	\$9	\$16
Tucson Electric	\$34	\$26	\$27	\$27	\$28	\$32	\$38	\$23	\$21	\$18	\$23	\$27	\$32	\$35	\$33	\$28	\$35	\$31	\$30	\$20	\$19	\$6	\$14	\$20
Salt River Project	\$37	\$31	\$29	\$30	\$27	\$32	\$37	\$23	\$20	\$26	\$23	\$34	\$32	\$36	\$33	\$28	\$35	\$30	\$30	\$20	\$21	\$11	\$10	\$19
PSC New Mexico	\$37	\$28	\$28	\$27	\$50	\$30	\$39	\$15	\$3	\$15	\$20	\$44	\$32	\$43	\$34	\$27	\$32	\$25	\$28	\$15	\$16	\$3	\$10	\$16
WAPA - Desert SW	\$37	\$29	\$27	\$32	\$27	\$32	\$37	\$22	\$20	\$16	\$20	\$27	\$31	\$36	\$32	\$29	\$34	\$30	\$30	\$21	\$24	\$4	\$9	\$16
El Paso Electric	\$36	\$24	\$26	\$27	\$27	\$32	\$36	\$19	\$10	\$17	\$27	\$33	\$32	\$39	\$34	\$27	\$33	\$32	\$36	\$20	\$20	\$7	\$19	\$26
PacifiCorp East	\$35	\$27	\$27	\$34	\$31	\$34	\$40	\$30	\$18	\$18	\$25	\$28	\$32	\$36	\$34	\$27	\$36	\$30	\$30	\$22	\$15	\$8	\$17	\$17
Idaho Power	\$34	\$28	\$28	\$36	\$34	\$35	\$43	\$34	\$21	\$25	\$27	\$29	\$32	\$35	\$35	\$35	\$37	\$31	\$29	\$22	\$14	\$9	\$13	\$16
NorthWestern	\$33	\$28	\$30	\$31	\$34	\$34	\$42	\$39	\$25	\$22	\$25	\$29	\$32	\$35	\$35	\$33	\$39	\$35	\$29	\$23	\$13	\$8	\$14	\$14
PowerWatch																							\$11	\$15
Black Hills Energy																							\$17	\$17
Avista Utilities	\$32	\$28	\$29	\$37	\$36	\$36	\$43	\$41	\$25	\$22	\$25	\$29	\$32	\$34	\$36	\$36	\$39	\$30	\$29	\$23	\$12	\$8	\$13	\$15
Avangrid	\$33	\$28	\$31	\$39	\$37	\$37	\$44	\$42	\$24	\$20	\$26	\$30	\$33	\$35	\$37	\$38	\$40	\$29	\$28	\$23	\$14	\$8	\$11	\$14
BPA	\$38	\$29	\$32	\$38	\$35	\$36	\$44	\$43	\$24	\$20	\$26	\$31	\$35	\$36	\$40	\$38	\$40	\$28	\$27	\$22	\$14	\$8	\$11	\$14
Tacoma Power	\$32	\$27	\$31	\$37	\$35	\$36	\$43	\$42	\$24	\$21	\$26	\$29	\$34	\$35	\$37	\$36	\$39	\$29	\$27	\$22	\$13	\$9	\$13	\$14
PacifiCorp West	\$32	\$27	\$31	\$38	\$36	\$36	\$43	\$41	\$23	\$19	\$25	\$29	\$32	\$34	\$36	\$37	\$39	\$29	\$28	\$22	\$12	\$8	\$12	\$13
Portland GE	\$32	\$27	\$31	\$38	\$35	\$36	\$43	\$41	\$24	\$19	\$25	\$29	\$32	\$34	\$37	\$37	\$39	\$28	\$27	\$22	\$15	\$10	\$13	\$14
Puget Sound Energy	\$33	\$27	\$31	\$37	\$34	\$36	\$43	\$41	\$24	\$22	\$26	\$29	\$36	\$35	\$37	\$36	\$39	\$28	\$27	\$22	\$13	\$9	\$11	\$13
Seattle City Light	\$31	\$27	\$31	\$38	\$35	\$36	\$45	\$41	\$24	\$21	\$25	\$29	\$36	\$35	\$37	\$36	\$39	\$29	\$27	\$22	\$13	\$9	\$14	\$14
Powerex	\$42	\$36	\$33	\$36	\$35	\$34	\$47	\$45	\$33	\$27	\$28	\$30	\$36	\$33	\$34	\$36	\$39	\$29	\$25	\$22	\$14	\$6	\$2	\$1
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
	2024					2025												2026						

Table 4.3 Average hourly 15-minute market prices (April–June)

Average MEC	\$20	\$18	\$17	\$16	\$17	\$18	\$16	\$9	\$7	\$5	\$4	\$4	\$4	\$5	\$5	\$6	\$6	\$9	\$19	\$22	\$22	\$20	\$20	\$19
PG&E (CAISO)	\$26	\$25	\$23	\$23	\$22	\$25	\$21	\$15	\$15	\$12	\$9	\$8	\$7	\$8	\$7	\$8	\$9	\$14	\$23	\$30	\$29	\$27	\$26	\$25
SCE (CAISO)	\$26	\$25	\$23	\$23	\$23	\$25	\$19	\$5	-\$3	-\$4	-\$3	-\$4	-\$3	-\$2	-\$2	-\$1	\$4	\$19	\$25	\$25	\$24	\$25	\$25	
SDGE (CAISO)	\$38	\$32	\$30	\$29	\$29	\$31	\$25	\$14	\$5	\$4	\$6	\$4	\$2	\$2	\$3	\$3	\$5	\$12	\$27	\$32	\$33	\$32	\$33	\$33
BANC	\$25	\$24	\$23	\$22	\$22	\$24	\$20	\$13	\$11	\$9	\$7	\$6	\$6	\$7	\$6	\$7	\$8	\$12	\$21	\$27	\$27	\$26	\$25	\$25
Turlock ID	\$25	\$24	\$23	\$23	\$22	\$24	\$20	\$13	\$12	\$9	\$8	\$7	\$6	\$8	\$8	\$8	\$9	\$13	\$22	\$27	\$27	\$26	\$25	\$24
LADWP	\$21	\$19	\$18	\$20	\$19	\$14	\$14	\$5	\$0	-\$2	-\$3	-\$3	-\$2	-\$1	-\$1	-\$2	-\$1	\$5	\$20	\$23	\$24	\$22	\$21	\$22
NV Energy	\$19	\$17	\$16	\$16	\$16	\$17	\$13	\$6	\$4	\$3	\$2	\$2	\$2	\$3	\$4	\$3	\$4	\$7	\$18	\$22	\$21	\$20	\$21	\$20
Arizona PS	\$17	\$16	\$15	\$16	\$16	\$17	\$13	\$4	\$0	-\$1	-\$2	-\$2	-\$2	-\$2	-\$1	-\$3	\$0	\$4	\$16	\$20	\$20	\$18	\$19	\$18
Tucson Electric	\$17	\$16	\$15	\$16	\$16	\$17	\$13	\$5	\$1	\$0	\$0	\$1	\$1	\$2	\$3	\$3	\$5	\$8	\$17	\$20	\$21	\$19	\$21	\$19
Salt River Project	\$17	\$16	\$15	\$16	\$16	\$17	\$13	\$5	\$2	\$2	\$2	\$2	\$4	\$5	\$6	\$6	\$7	\$10	\$18	\$20	\$20	\$18	\$20	\$18
PSC New Mexico	\$17	\$16	\$15	\$16	\$16	\$17	\$13	\$5	\$1	\$0	-\$2	-\$2	-\$2	-\$2	-\$1	-\$1	-\$1	\$5	\$16	\$20	\$20	\$19	\$19	\$18
WAPA - Desert SW	\$17	\$16	\$15	\$15	\$16	\$17	\$13	\$4	\$0	-\$1	-\$2	-\$2	-\$2	-\$2	-\$1	-\$1	\$0	\$5	\$16	\$20	\$20	\$18	\$19	\$18
El Paso Electric	\$31	\$16	\$15	\$18	\$29	\$19	\$29	\$9	\$8	\$1	\$11	\$3	\$13	\$8	\$0	\$3	\$3	\$4	\$30	\$22	\$19	\$17	\$19	\$18
PacifiCorp East	\$18	\$16	\$15	\$16	\$16	\$17	\$14	\$8	\$6	\$6	\$6	\$5	\$6	\$7	\$6	\$6	\$5	\$9	\$19	\$23	\$21	\$19	\$20	\$19
Idaho Power	\$17	\$15	\$14	\$14	\$15	\$15	\$13	\$12	\$8	\$8	\$7	\$6	\$6	\$8	\$7	\$6	\$6	\$9	\$18	\$21	\$20	\$19	\$18	\$17
NorthWestern	\$14	\$14	\$13	\$13	\$14	\$15	\$14	\$10	\$8	\$8	\$7	\$6	\$6	\$7	\$7	\$7	\$7	\$9	\$16	\$19	\$19	\$19	\$17	\$15
PowerWatch	\$16	\$15	\$13	\$14	\$15	\$17	\$11	\$7	\$9	\$10	\$8	\$7	\$9	\$9	\$9	\$10	\$10	\$13	\$15	\$19	\$22	\$20	\$19	\$17
Black Hills Energy	\$19	\$17	\$15	\$15	\$16	\$17	\$12	\$7	\$8	\$10	\$10	\$9	\$10	\$10	\$11	\$11	\$10	\$13	\$20	\$25	\$22	\$20	\$20	\$19
Avista Utilities	\$16	\$14	\$13	\$13	\$13	\$17	\$14	\$10	\$9	\$8	\$6	\$6	\$6	\$8	\$6	\$7	\$7	\$10	\$16	\$20	\$19	\$18	\$17	\$16
Avangrid	\$16	\$15	\$13	\$12	\$14	\$15	\$13	\$10	\$8	\$7	\$7	\$6	\$5	\$6	\$6	\$7	\$7	\$9	\$16	\$19	\$19	\$19	\$18	\$16
BPA	\$16	\$14	\$12	\$12	\$12	\$13	\$15	\$10	\$9	\$8	\$8	\$7	\$7	\$7	\$8	\$9	\$8	\$11	\$16	\$18	\$18	\$17	\$17	\$16
Tacoma Power	\$16	\$15	\$13	\$13	\$13	\$14	\$13	\$10	\$9	\$8	\$8	\$7	\$7	\$8	\$7	\$16	\$9	\$11	\$16	\$19	\$19	\$18	\$18	\$16
PacifiCorp West	\$15	\$14	\$13	\$12	\$13	\$14	\$13	\$10	\$9	\$8	\$7	\$7	\$6	\$7	\$7	\$7	\$8	\$10	\$15	\$18	\$17	\$17	\$16	\$15
Portland GE	\$15	\$14	\$13	\$12	\$13	\$14	\$13	\$11	\$13	\$11	\$10	\$9	\$9	\$9	\$10	\$10	\$10	\$12	\$16	\$19	\$19	\$18	\$17	\$15
Puget Sound Energy	\$15	\$14	\$12	\$12	\$12	\$14	\$13	\$10	\$9	\$8	\$8	\$7	\$7	\$8	\$8	\$8	\$9	\$10	\$15	\$19	\$18	\$18	\$17	\$15
Seattle City Light	\$18	\$16	\$15	\$14	\$14	\$16	\$15	\$10	\$9	\$8	\$8	\$7	\$7	\$7	\$10	\$8	\$8	\$12	\$17	\$21	\$21	\$19	\$19	\$17
Powerex	\$3	\$4	\$5	\$5	\$6	\$3	\$5	\$2	\$2	\$2	\$1	\$1	\$1	\$1	\$1	\$0	\$1	\$3	\$2	\$6	\$6	\$5	\$2	\$2
	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 (April–June)

	\$21	\$18	\$17	\$17	\$17	\$18	\$14	\$7	\$6	\$5	\$4	\$3	\$4	\$4	\$4	\$5	\$6	\$11	\$23	\$26	\$22	\$21	\$22	\$20
Average MEC	\$28	\$26	\$24	\$23	\$23	\$24	\$22	\$16	\$15	\$12	\$8	\$6	\$6	\$5	\$5	\$7	\$9	\$14	\$27	\$32	\$29	\$27	\$27	\$25
PG&E (CAISO)	\$29	\$26	\$24	\$24	\$23	\$25	\$19	\$3	-\$3	-\$4	-\$4	-\$4	-\$4	-\$3	-\$2	-\$2	-\$1	\$5	\$22	\$27	\$25	\$24	\$26	\$26
SCE (CAISO)	\$39	\$32	\$30	\$29	\$28	\$33	\$26	\$12	\$9	\$11	\$10	\$3	\$2	\$2	\$2	\$2	\$4	\$12	\$30	\$34	\$32	\$34	\$35	\$33
SDGE (CAISO)	\$27	\$25	\$23	\$23	\$22	\$23	\$20	\$12	\$11	\$8	\$6	\$5	\$5	\$5	\$5	\$7	\$8	\$13	\$25	\$30	\$27	\$26	\$26	\$25
BANC	\$27	\$25	\$23	\$23	\$23	\$24	\$20	\$12	\$12	\$9	\$7	\$6	\$6	\$6	\$6	\$7	\$9	\$14	\$24	\$29	\$27	\$25	\$26	\$25
Turlock ID	\$24	\$20	\$20	\$21	\$20	\$18	\$15	\$3	-\$1	-\$2	-\$4	-\$4	-\$3	-\$3	-\$2	-\$4	\$0	\$11	\$24	\$26	\$24	\$22	\$22	\$22
LADWP	\$21	\$18	\$16	\$17	\$17	\$18	\$13	\$4	\$4	\$3	\$1	\$1	\$1	\$2	\$2	\$2	\$4	\$8	\$23	\$25	\$22	\$20	\$25	\$21
NV Energy	\$19	\$17	\$18	\$17	\$17	\$18	\$13	\$2	-\$1	-\$2	-\$3	-\$3	-\$3	-\$3	-\$2	-\$3	\$4	\$6	\$21	\$24	\$21	\$19	\$20	\$19
Arizona PS	\$19	\$17	\$16	\$17	\$17	\$18	\$12	\$3	\$1	\$0	\$0	\$2	\$1	\$3	\$11	\$18	\$13	\$15	\$22	\$24	\$21	\$19	\$23	\$20
Tucson Electric	\$20	\$17	\$16	\$17	\$17	\$18	\$12	\$5	\$1	\$2	\$1	\$2	\$3	\$4	\$12	\$14	\$10	\$12	\$29	\$24	\$23	\$19	\$21	\$19
Salt River Project	\$19	\$17	\$16	\$17	\$17	\$18	\$13	\$2	\$0	-\$2	-\$3	-\$3	-\$3	-\$3	-\$3	-\$2	-\$1	\$6	\$21	\$24	\$21	\$19	\$21	\$20
PSC New Mexico	\$19	\$18	\$16	\$17	\$17	\$18	\$13	\$2	-\$1	-\$2	-\$3	-\$2	-\$3	-\$2	-\$2	-\$2	-\$1	\$0	\$6	\$21	\$24	\$21	\$19	\$20
WAPA - Desert SW	\$39	\$17	\$16	\$16	\$25	\$21	\$12	\$6	\$2	-\$1	\$3	-\$1	\$9	\$2	\$10	\$19	\$18	\$18	\$47	\$50	\$23	\$22	\$21	\$19
El Paso Electric	\$20	\$18	\$16	\$16	\$17	\$18	\$13	\$5	\$5	\$6	\$5	\$4	\$6	\$6	\$5	\$6	\$7	\$11	\$36	\$30	\$22	\$20	\$26	\$20
PacifiCorp East	\$18	\$16	\$14	\$14	\$18	\$16	\$13	\$9	\$7	\$7	\$5	\$5	\$7	\$6	\$6	\$4	\$5	\$10	\$20	\$23	\$21	\$20	\$19	\$18
Idaho Power	\$15	\$13	\$13	\$13	\$14	\$16	\$12	\$8	\$7	\$7	\$6	\$5	\$6	\$5	\$5	\$12	\$9	\$10	\$19	\$23	\$20	\$19	\$19	\$15
NorthWestern	\$18	\$15	\$12	\$14	\$15	\$16	\$10	\$5	\$8	\$9	\$7	\$6	\$9	\$8	\$8	\$9	\$10	\$12	\$18	\$23	\$22	\$21	\$20	\$19
PowerWatch	\$20	\$18	\$16	\$16	\$18	\$18	\$12	\$6	\$8	\$9	\$9	\$7	\$10	\$10	\$11	\$13	\$15	\$15	\$50	\$36	\$23	\$21	\$22	\$21
Black Hills Energy	\$17	\$15	\$13	\$13	\$14	\$18	\$12	\$8	\$7	\$6	\$6	\$5	\$5	\$5	\$4	\$5	\$6	\$10	\$19	\$25	\$20	\$20	\$18	\$17
Avista Utilities	\$16	\$14	\$13	\$13	\$13	\$15	\$12	\$8	\$7	\$6	\$5	\$5	\$4	\$4	\$3	\$5	\$5	\$9	\$17	\$21	\$20	\$19	\$18	\$17
Avangrid	\$15	\$14	\$12	\$12	\$12	\$13	\$11	\$7	\$8	\$7	\$6	\$6	\$5	\$5	\$5	\$6	\$7	\$10	\$16	\$20	\$18	\$17	\$17	\$16
BPA	\$16	\$14	\$12	\$12	\$13	\$14	\$12	\$7	\$7	\$7	\$6	\$6	\$5	\$5	\$5	\$9	\$7	\$10	\$17	\$22	\$20	\$18	\$18	\$16
Tacoma Power	\$15	\$17	\$13	\$12	\$13	\$14	\$11	\$8	\$7	\$7	\$6	\$5	\$4	\$4	\$4	\$6	\$6	\$9	\$16	\$20	\$18	\$17	\$17	\$15
PacifiCorp West	\$16	\$14	\$12	\$12	\$13	\$14	\$12	\$8	\$9	\$11	\$8	\$7	\$7	\$7	\$7	\$9	\$8	\$11	\$17	\$21	\$19	\$18	\$17	\$16
Portland GE	\$16	\$14	\$12	\$12	\$12	\$13	\$11	\$8	\$7	\$7	\$6	\$6	\$5	\$5	\$6	\$7	\$7	\$10	\$16	\$21	\$19	\$18	\$17	\$16
Puget Sound Energy	\$18	\$15	\$14	\$14	\$14	\$15	\$17	\$8	\$7	\$7	\$6	\$6	\$5	\$5	\$6	\$7	\$7	\$16	\$19	\$23	\$21	\$18	\$19	\$16
Seattle City Light	\$5	\$5	\$5	\$6	\$6	\$5	\$4	\$1	\$2	\$1	\$0	-\$1	-\$1	\$0	-\$1	-\$1	\$1	\$2	\$4	\$6	\$7	\$6	\$5	\$5
Powerex	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. PacifiCorp (PACE and PACW) joined the CAISO balancing area in the day-ahead market on May 1, 2026.

Load weighted average day-ahead market prices were about \$16/MWh in the second quarter of 2026, down 44 percent from \$29/MWh in the second quarter of 2025. Average prices in the CAISO balancing area's 15-minute and 5-minute markets both decreased by about 43 and 42 percent, respectively, compared to the second quarter of the previous year. The average price of the three markets this quarter decreased to \$16/MWh from \$29/MWh in the same quarter of 2025.

Figure 4.9 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 July 2024 to June 2026.

Over the quarter, prices in the day-ahead market averaged \$16/MWh, and prices in the 15-minute and 5-minute markets averaged \$16/MWh and \$17/MWh, respectively. June had the highest prices, with an average over the three markets of about \$21/MWh.

Figure 4.9 also shows monthly average gas prices at PG&E Citygate from July 2024 to June 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 \$1.55/MMBtu this quarter, down from \$2.84/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 4.9 Monthly average PG&E Citygate gas price and load-weighted average electricity prices for balancing areas in day-ahead market

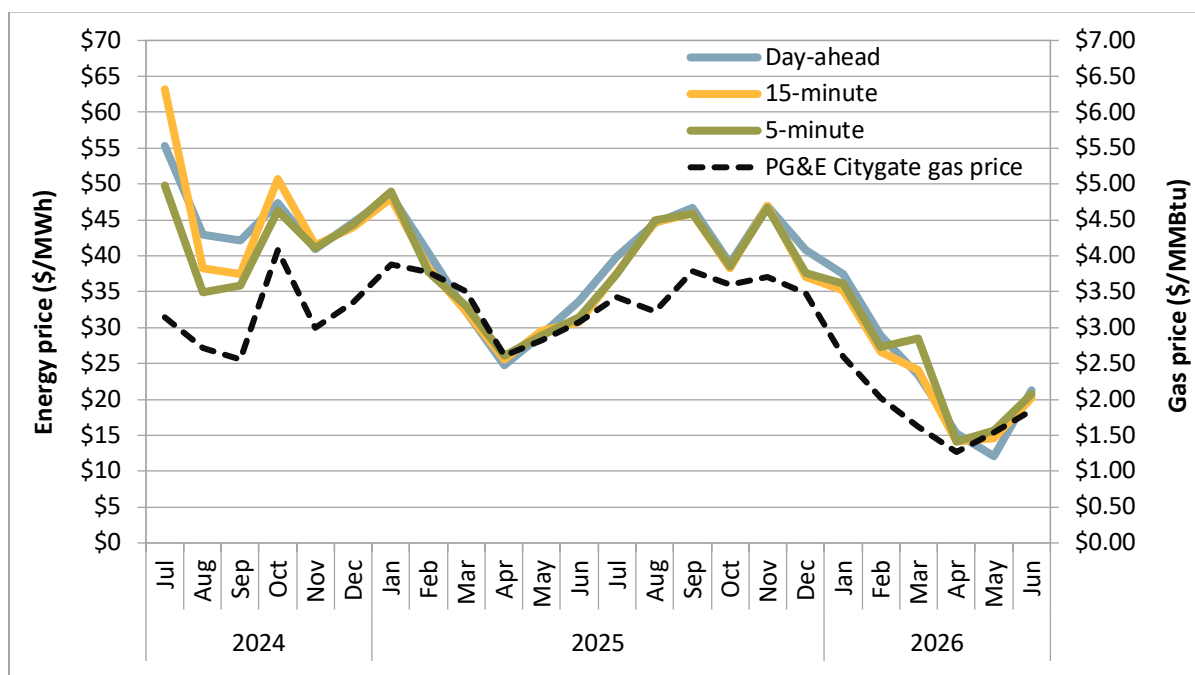


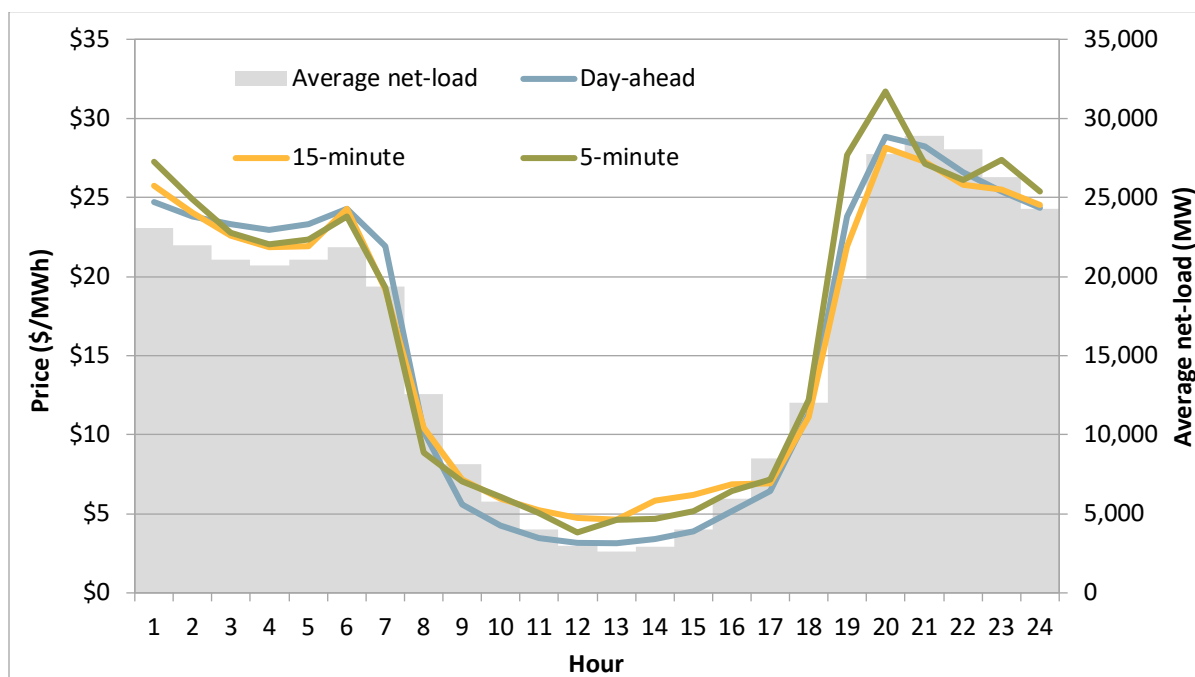
Figure 4.10 illustrates the hourly load-weighted average electricity prices for the second quarter compared to the average hourly net-load for balancing areas participating in the day-ahead market.³¹ Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green 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 continued 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 20, at around \$30/MWh, while average net-load peaked at hour-ending 21, reaching 28,900 MW.

During hour-ending 20, the day-ahead load-weighted average electricity price was \$29/MWh, the 15-minute price was \$28/MWh, and the 5-minute price was \$32/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 4.10 Hourly load-weighted average energy prices for balancing areas in day-ahead market (April–June 2026)



4.4 Bilateral price comparison

Figure 4.11 and Figure 4.12 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 ISO markets. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

As shown in Figure 4.11, day-ahead prices in the Intercontinental Exchange for the Mid-Columbia trading hub averaged \$12/MWh in Q2 2026, lower than the ISO 15-minute market prices in the Pacific Northwest (\$14/MWh). Day-ahead Mid-Columbia ICE prices were also lower than average ISO day-ahead market prices at the Pacific Gas and Electric load node (\$18/MWh).

As shown in Figure 4.12, day-ahead prices in the Intercontinental Exchange for the Palo Verde trading hub averaged about \$20/MWh over the quarter, about \$9/MWh higher than the ISO 15-minute market prices in the Desert Southwest (\$11/MWh). Day-ahead Palo Verde ICE prices were also higher than average ISO day-ahead market prices at the Southern California Edison load node (\$8/MWh).

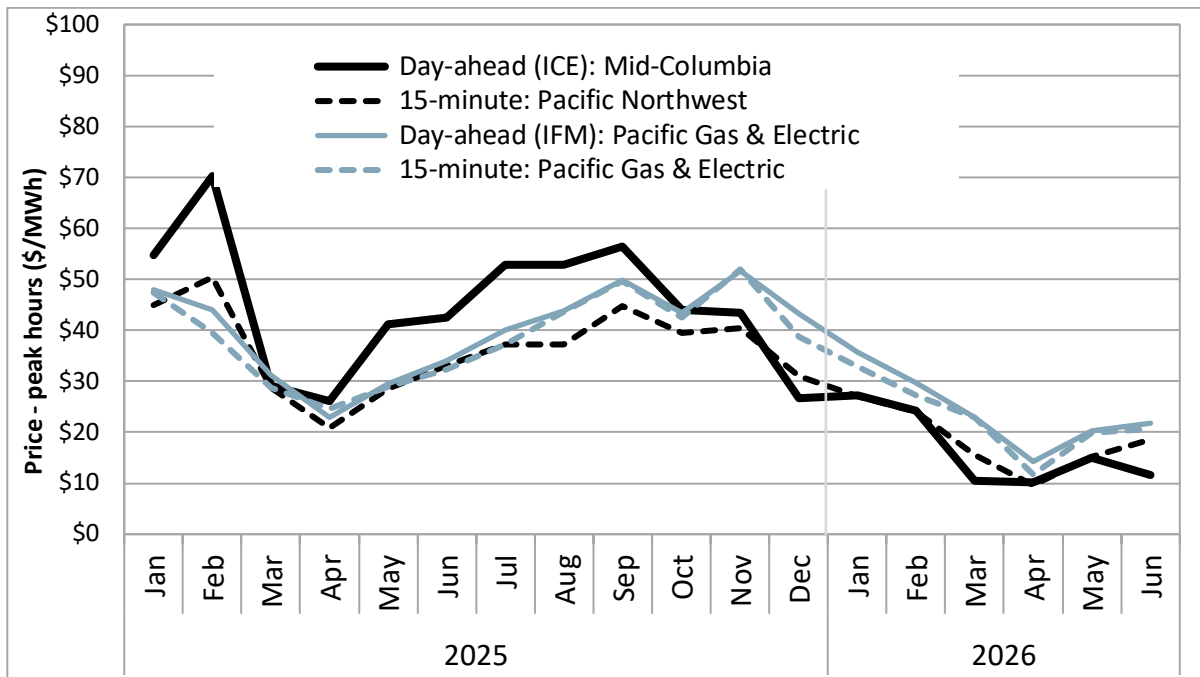
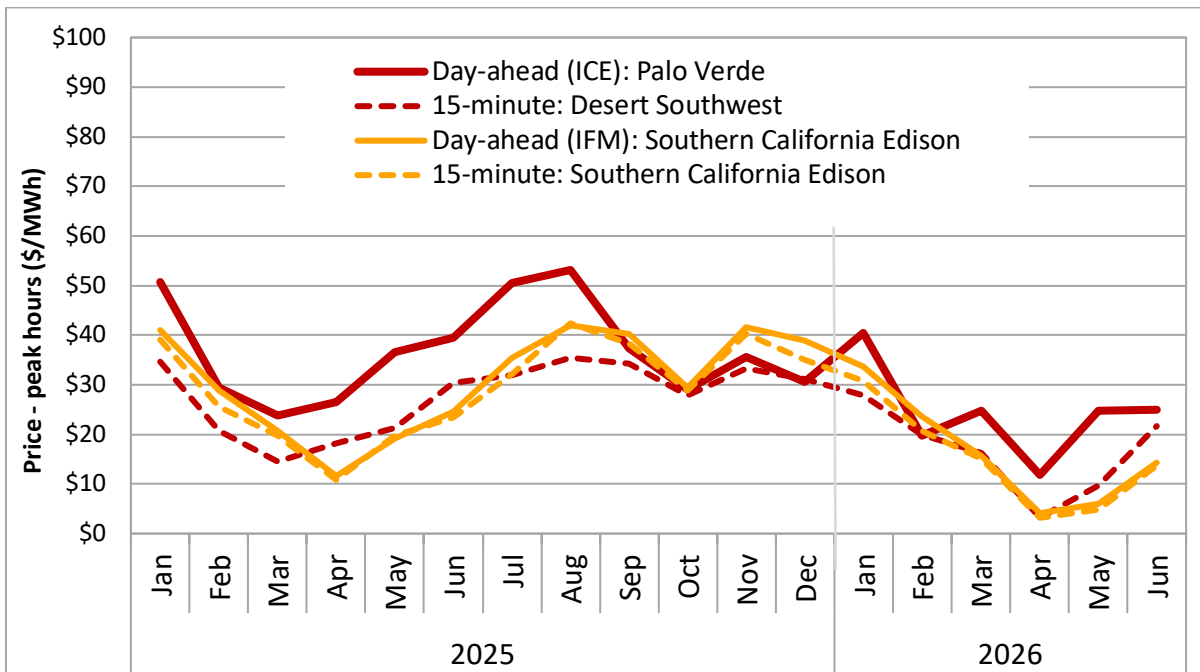
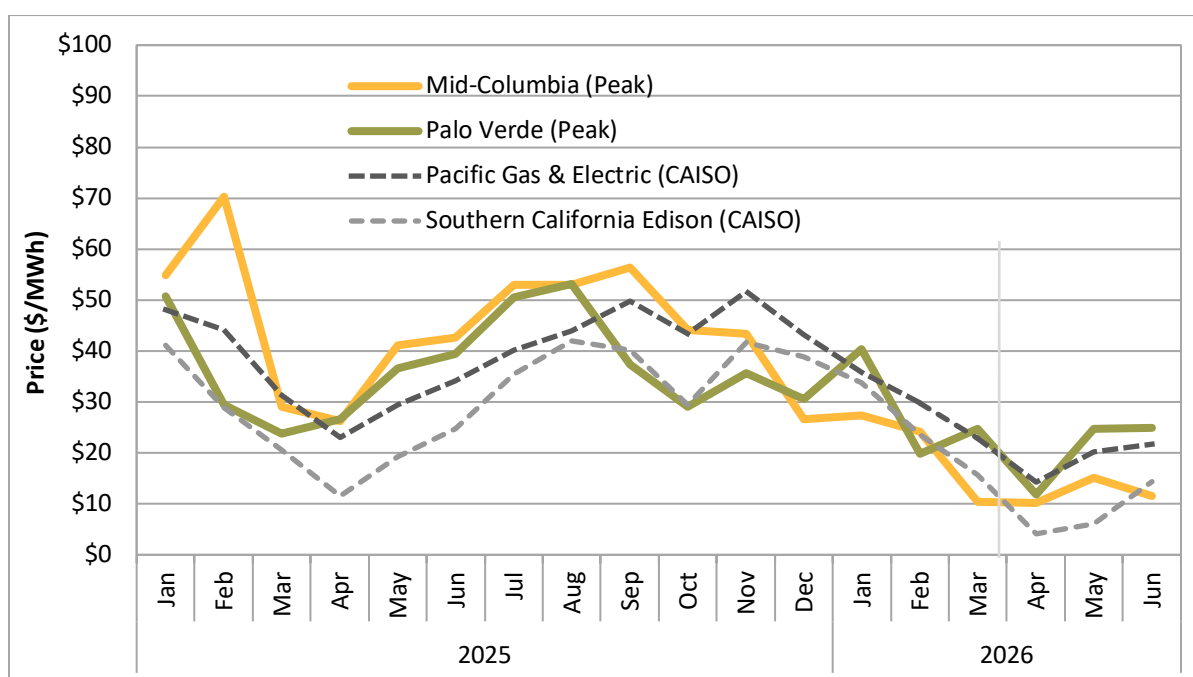
Figure 4.11 Mid-C bilateral ICE vs. Pacific Northwest 15-minute market prices (peak hours)**Figure 4.12 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)**

Figure 4.13 compares monthly average prices in the bilateral and ISO day-ahead markets for 2025 through the second 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 \$12/MWh and \$20/MWh, respectively, while ISO day-ahead prices at Pacific Gas and Electric and Southern California Edison averaged around \$19/MWh and \$8/MWh, respectively. Prices at Mid-Columbia were lower than those at Palo Verde in each month of the quarter. In April, May, and June, Mid-Columbia prices were approximately 14 percent, 39 percent, and 54 percent lower than Palo Verde prices, respectively.

Figure 4.13 Monthly average day-ahead and bilateral market prices



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, 2024.³² The ISO did not raise the energy bid cap and penalty prices to \$2,000/MWh in the second quarter of 2026.

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

³² 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\(BPM\)](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))

average real-time prices (from Powerdex) by about \$1.16/MWh. At the Palo Verde hub, average day-ahead prices were higher than average real-time prices (from Powerdex) by about \$2.16/MWh.

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 in April and adds PACE and PACW in May and June.³³ The second group comprises balancing areas participating exclusively in the real-time market, which includes all WEIM entities aside from the day-ahead participating balancing authorities. Black Hills Energy (BHBA) and Power Watch (GWA) joined the WEIM in May, and their price data were included for May and June.

High prices

Figure 4.14 shows the monthly frequency of high prices across all three markets for balancing areas participating in both the day-ahead and real-time markets from April 2025 to June 2026.³⁴ Figure 4.15 illustrates the monthly frequency of high prices for balancing areas participating only in the real-time market during the same period.³⁵ Day-ahead market prices never reached \$250/MWh in the second quarter, similar to 2025.

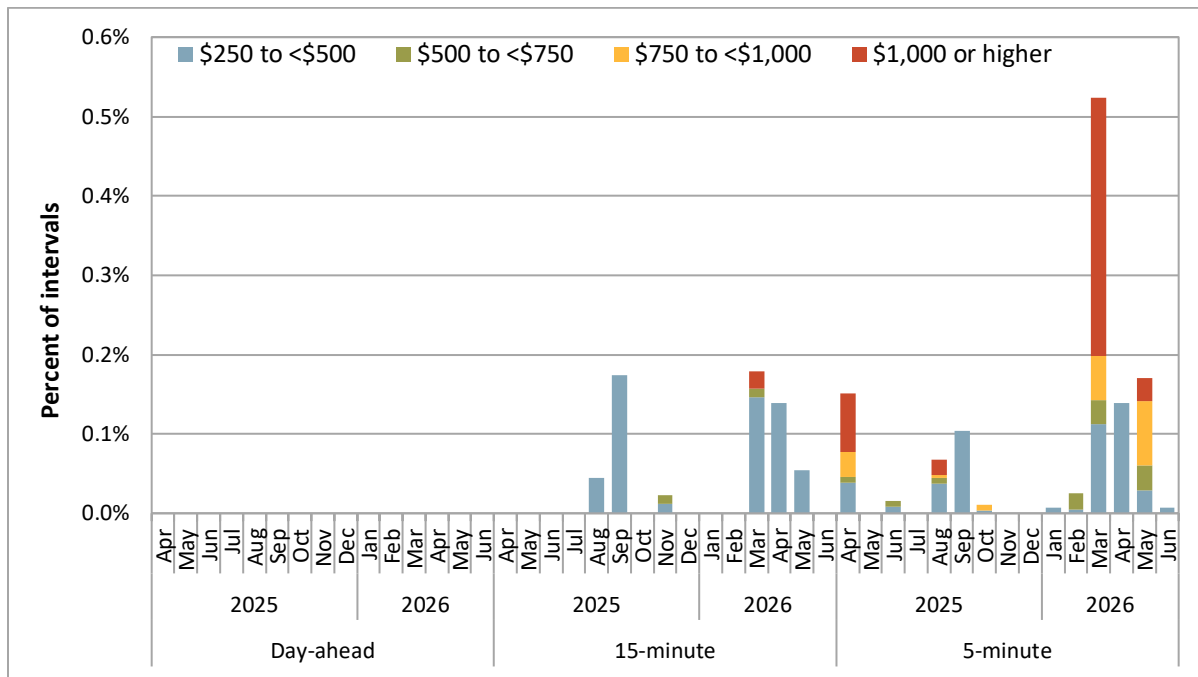
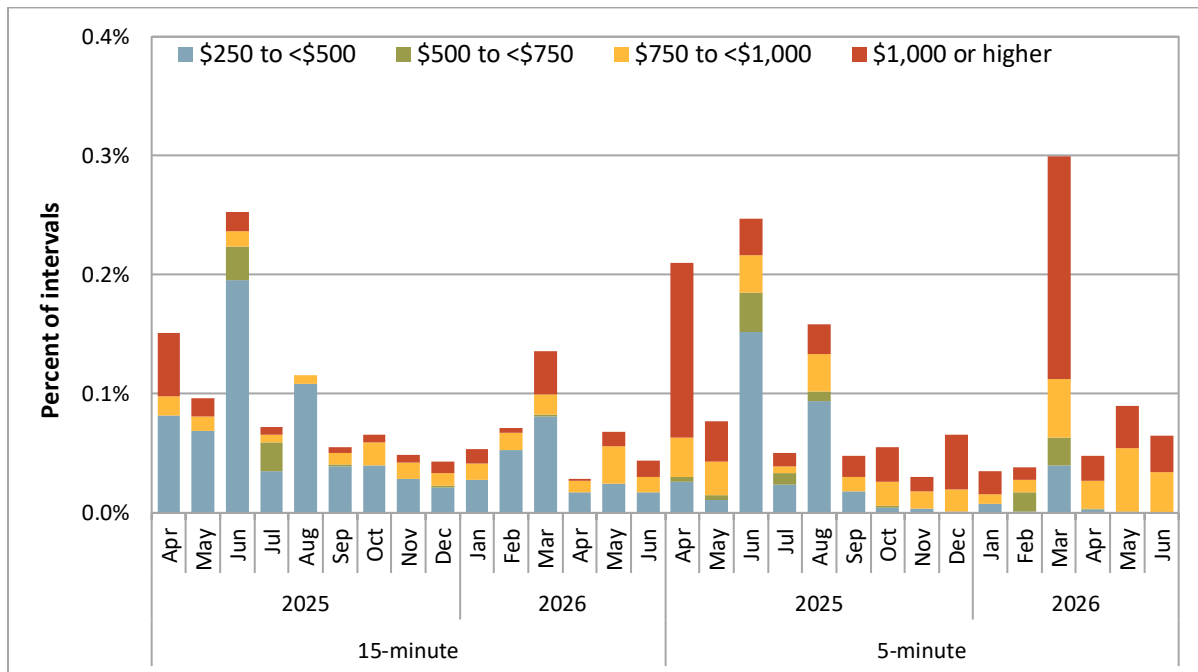
In the 15-minute market, the frequency of high prices for balancing areas participating in the day-ahead market increased from zero percent in Q2 2025 to 0.05 percent in Q2 2026. For balancing areas participating exclusively in the real-time market, the frequency of high 15-minute market prices decreased, from 0.17 percent in Q2 2025 to 0.05 percent in Q2 2026.

In the 5-minute market, the frequency of high prices for balancing areas participating in the day-ahead market increased from 0.05 percent in Q2 2025 to 0.1 percent in Q2 2026. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market decreased from 0.18 percent to 0.07 percent.

³³ 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, the EIM Load Aggregation Point (ELAP) for PACE and PACW, and the ELAP for 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.

³⁴ 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. For PACE and PACW, the frequency was measured at their respective ELAPs.

³⁵ The frequency of high prices was measured at EIM Load Aggregation Points (ELAPs).

Figure 4.14 Frequency of high prices in BAAs participating in the day-ahead market (EDAM)**Figure 4.15 Frequency of high prices in BAAs participating only in the real-time markets**

Negative prices

Figure 4.16 and Figure 4.17 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 April 2025 to June 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, the frequency of negative prices increased in the three markets. In the day-ahead market, the frequency increased from 14 percent to 17 percent compared to the same quarter of the previous year. In the 15-minute market, it increased from 14 percent to 20 percent, and in the 5-minute market, it increased from 14 percent to 22 percent.

For the BAAs participating exclusively in the real-time markets, the frequency of negative prices showed a significant increase across the 15-minute and 5-minute markets, with an average increase of 170 percent compared to the same quarter of the previous year. For instance, in the 15-minute market, the frequency increased from 7 percent to 20 percent. In the 5-minute market, it increased from 8 percent to 22 percent during this quarter.

Figure 4.16 Frequency of negative prices in BAAs participating in the day-ahead market (EDAM)

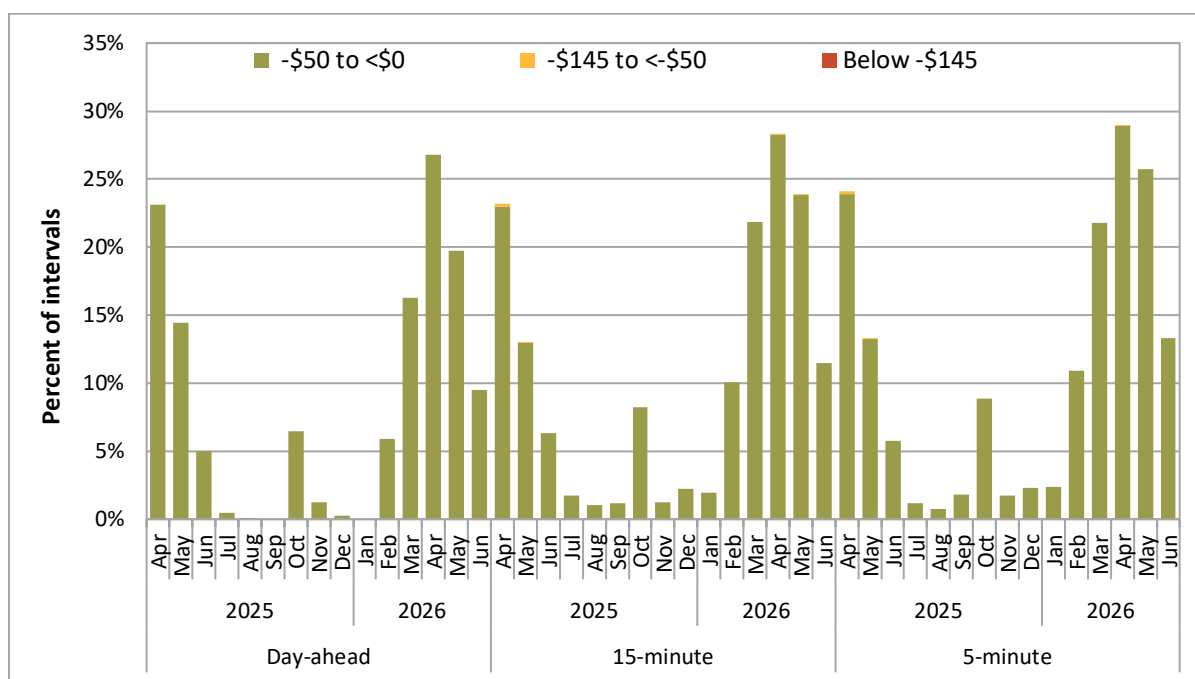
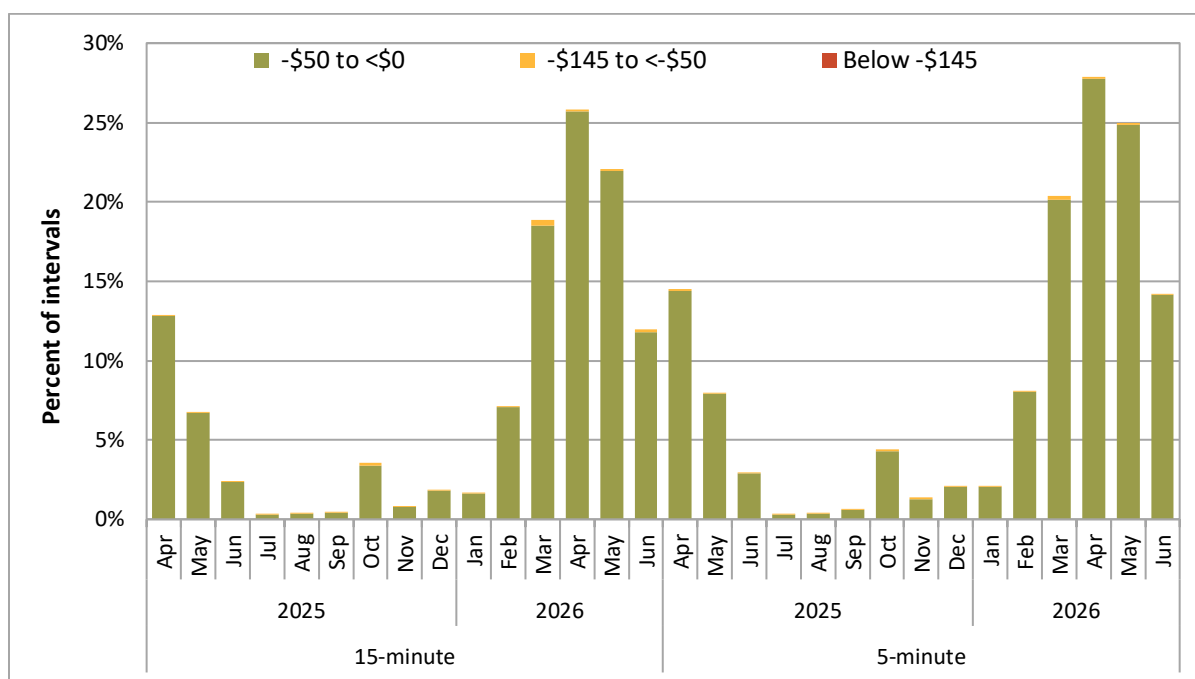


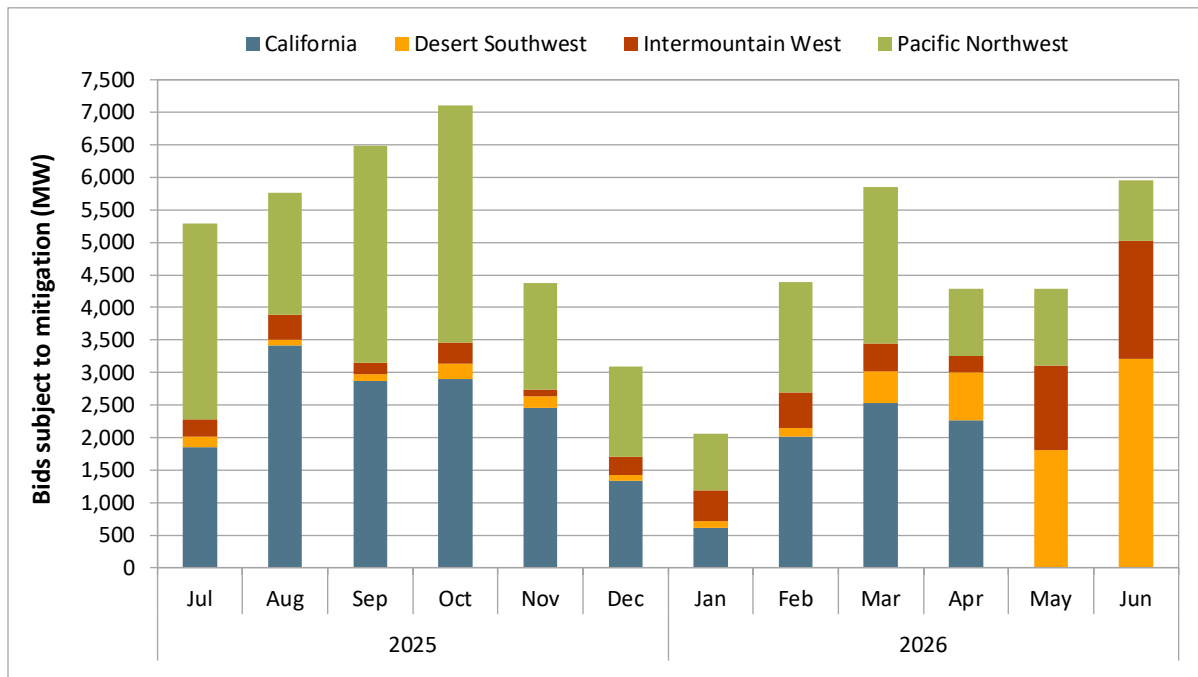
Figure 4.17 Frequency of negative prices in BAAs participating only in the real-time markets

4.6 Local market power mitigation in the real-time market

A software error in the real-time markets (RTM) prevented the Dynamic Competitive Path Assessment (DCPA) process from calculating non-competitive congestion components stemming from flowgate constraints starting May 1, 2026. This issue did not impact BAA-level mitigation, and resources in WEIM BAAs outside of the CAISO balancing area GHG regulation area were still deemed to have a positive non-congestion component when the DCPA flagged a balancing area to be non-competitive. This resulted in no bid segments in the CAISO balancing area to be subject to mitigation from May 1 through July 17. The ISO identified the issue and implemented a fix in the market software effective for trade date July 17.³⁶

Figure 4.18 shows the monthly average energy bids subject to mitigation in the 15-minute market by regions. Most mitigation in the California region is typically driven by the California ISO balancing area. There were no bids subject to mitigation in the CAISO BAA during May and June 2026.

³⁶ Extended day-ahead market Performance July Report, California ISO, August 24, 2026, p 211: [monthly-extended-day-ahead-market-edam-performance-report-for-jul-2026.pdf](#)

Figure 4.18 Average incremental energy subject to mitigation in the 15-minute market

5 EDAM and WEIM transfers

This section provides an overview of transfers between EDAM or WEIM balancing areas as well as constraints impacting those transfers. Key observations from the quarter include the following:

The extended day-ahead market launched on May 1, 2026. The average volume of EDAM transfers across the system was around 670 MW during May and June.

The average volume of WEIM transfers was 4,800 MW during the same period, slightly lower compared to May and June of the previous year. These transfers helped to displace expensive generation and meet load across the footprint.

Power Watch and Black Hills Energy joined the Western Energy Imbalance Market on May 6, 2026. Power Watch joined with roughly 260 MW on average in dynamic transfer capacity with NorthWestern Energy. Black Hills joined with around 250 MW on average in dynamic transfer capacity with PacifiCorp East.

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 balancing area 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.

Total transfers for Salt River Project were frequently 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 23 percent of intervals at 1,050 MW because of this constraint.

5.1 Energy transfers

One of the key benefits of the Western Energy Imbalance Market (WEIM) is the ability to transfer energy between balancing areas in the real-time 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. The extended day-ahead market (EDAM) was launched on May 1, 2026, extending this benefit to participating balancing areas in the longer timeframe of the day-ahead market.

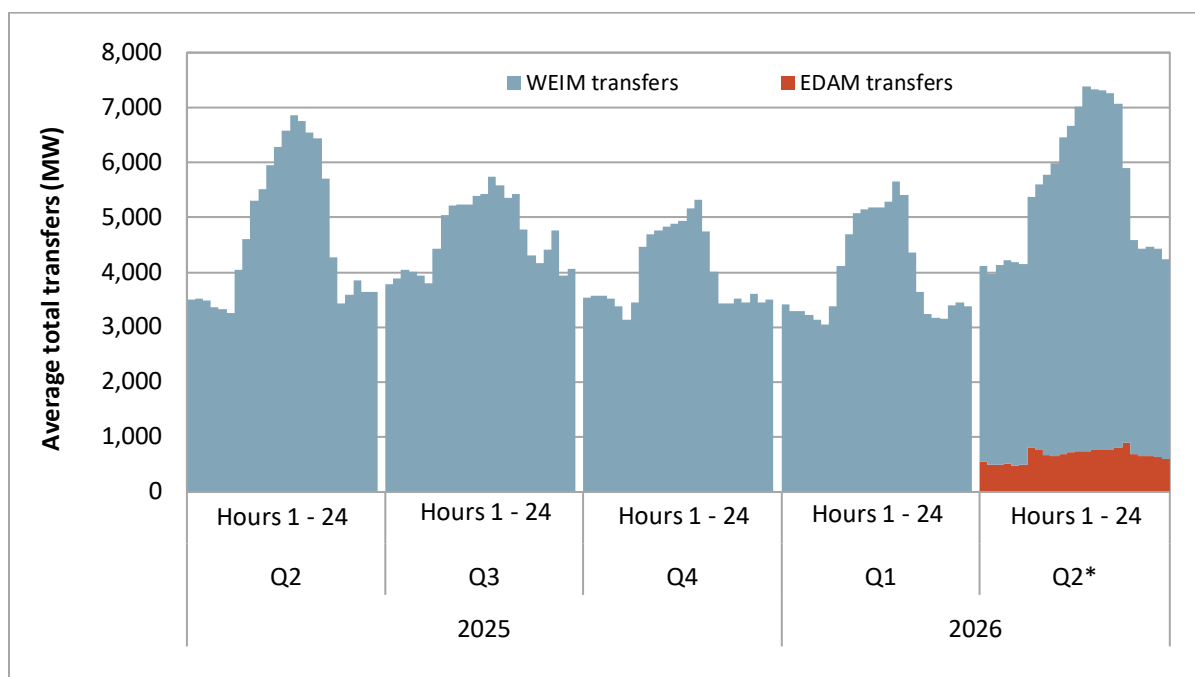
WEIM transfers for the real-time markets are defined as either base, dynamic, or static. Base WEIM transfers are fixed bilateral transactions between WEIM entities and are not optimized in the market. Dynamic WEIM transfers are optimized in all markets. Static WEIM transfers are a smaller set of transfers 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 EDAM and WEIM transfers — as optimized in the day-ahead and 5-minute markets, respectively — during the last five quarters.³⁷ The transfer volume

³⁷ Average transfer volume for April 2026, prior to the launch of EDAM in Q2 are not shown.

summarizes how much transfer activity there is in each period, by looking at only exports in the system. The average volume of EDAM transfers across the system was around 670 MW during May and June. The average volume of WEIM transfers was 4,800 MW during the same period, slightly lower compared to May and June of the previous year. These transfers helped to displace expensive generation and meet load across the footprint.

Figure 5.1 Average 5-minute market WEIM transfer volume by hour and quarter (Day-ahead and 5-minute market, Q2 2025 – Q2 2026)



*WEIM transfers for Q2 2026 are May and June only for comparison to EDAM

Figure 5.2 summarizes *net* EDAM transfers as optimized in the day-ahead market during May and June. At the time of the launch on May 1, the EDAM included participation from the California ISO, PacifiCorp East, and PacifiCorp West balancing areas. EDAM transfers leverage resource diversity and transfer capability between these balancing areas. PacifiCorp West was a net importer on average in all hours. During the high solar production hours between hours-ending 8 and 18, the CAISO balancing area exported on average around 300 MW to PacifiCorp West. In the remaining hours, PacifiCorp East exported on average around 140 MW to PacifiCorp West.

Figure 5.3 summarizes average inter-regional transfers by hour during the last five quarters.³⁸ Figure 5.4 summarizes average inter-regional transfers since the launch of EDAM, during May and June, compared to the same period of the previous year. The bars show *net* WEIM transfers for each region by hour and do not include EDAM transfers that were scheduled in the day-ahead market.³⁹ WEIM transfers between

³⁸ See Appendix A for figures on the average hourly transfers by quarter for each WEIM balancing area.

³⁹ 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.

regions continued to be significantly different during mid-day (solar) hours than during evening and early morning (non-solar) hours. During May and June, net WEIM imports into the Desert Southwest region during the mid-day hours were higher compared to the same period of the previous year, while net transfers for each of the other regions were generally lower in the mid-day hours.

Figure 5.2 Average day-ahead market EDAM transfers by hour (May–June 2026)

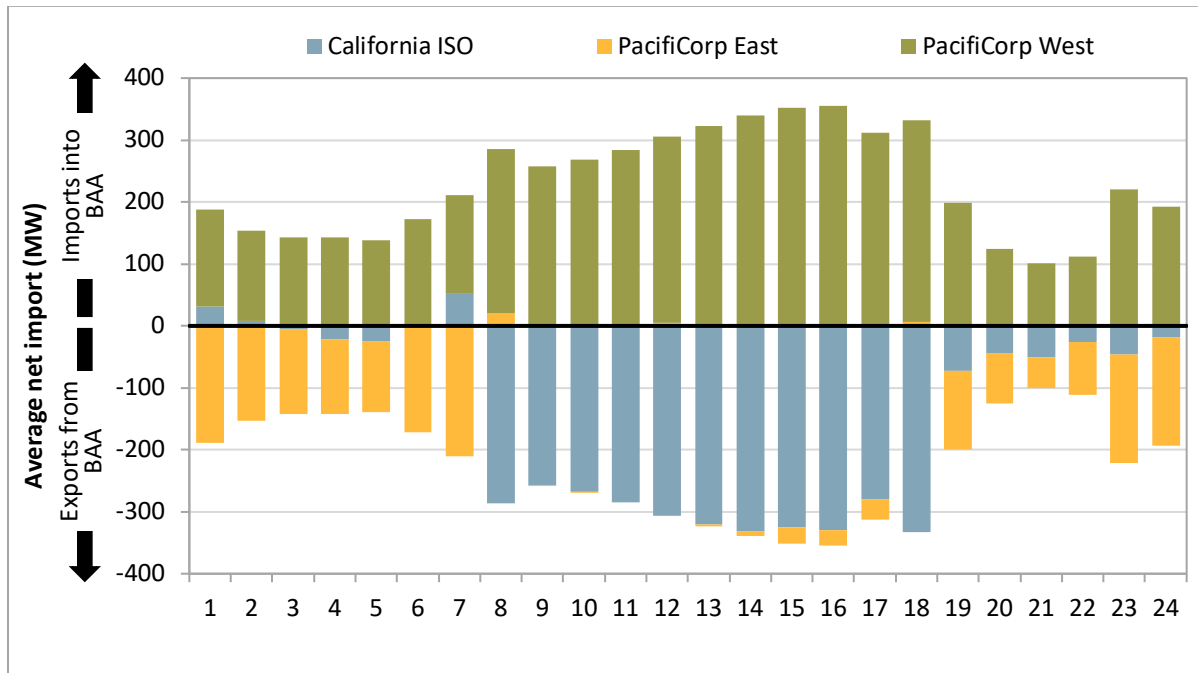
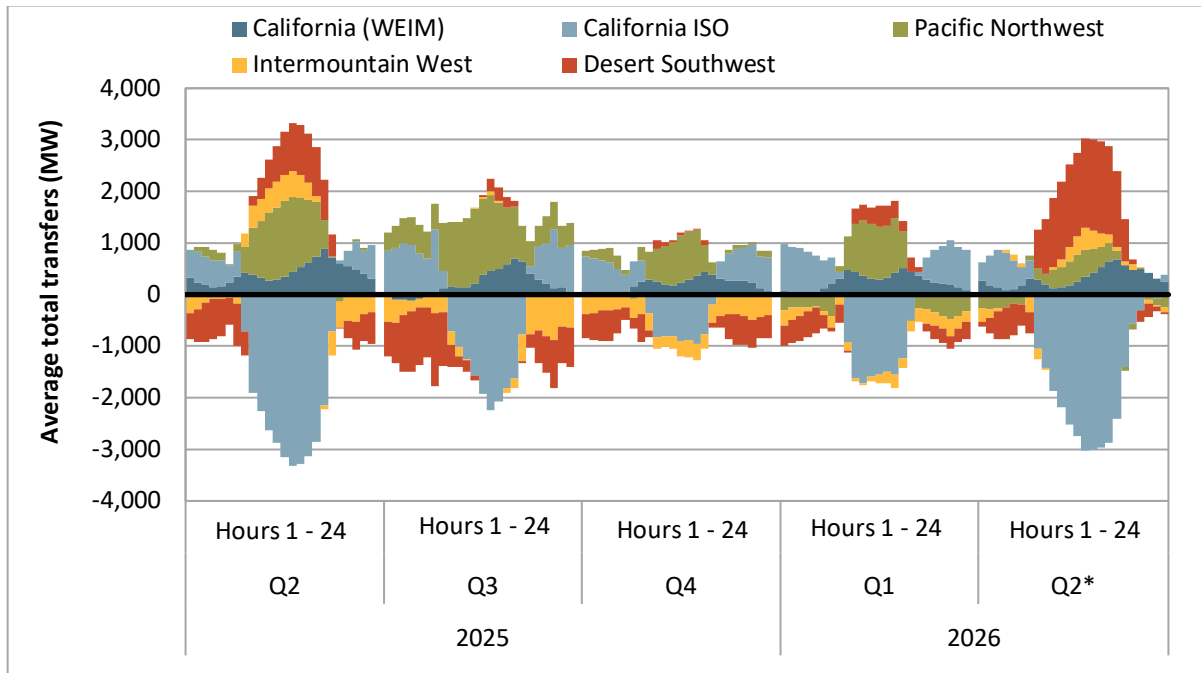


Figure 5.3 Average 5-minute market inter-regional WEIM transfers by hour (Q2 2025 – Q2 2026)



*WEIM transfers for Q2 2026 are May and June only for comparison to EDAM

Figure 5.4 Average 5-minute market inter-regional WEIM transfers by hour (May–June, 2025 vs. 2026)

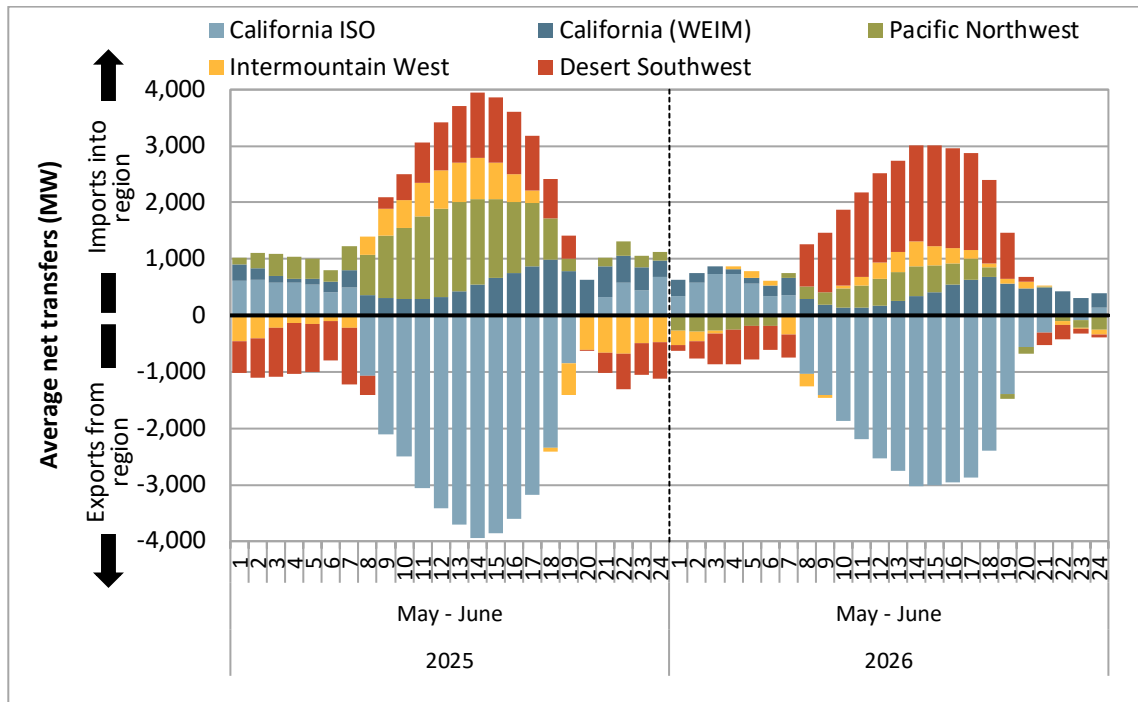
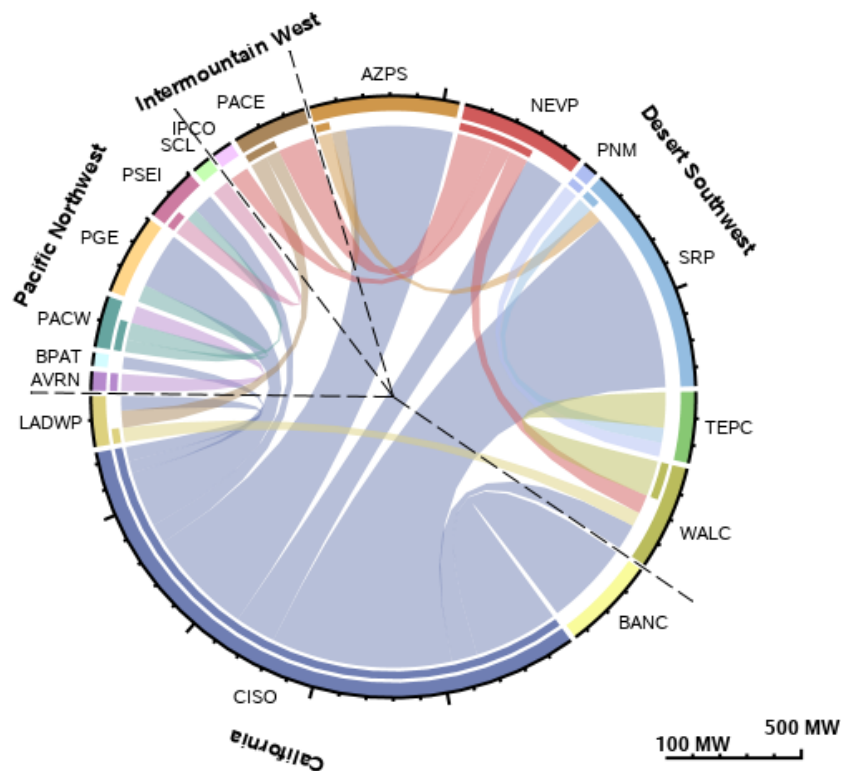


Figure 5.5 shows average WEIM transfers in the 5-minute market by balancing area in the mid-day hours when solar generation is highest.⁴⁰ Figure 5.6 shows the same information except in the remaining off-solar hours. The curves show the path and size of exports where the color corresponds to the area the transfer is coming from.⁴¹ 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 5.5, the CAISO balancing area exported on net over 2,300 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 remaining non-solar hours (Figure 5.6), balancing areas in the Intermountain West, Desert Southwest, and Pacific Northwest regions exported on net around 500 MW on average out to balancing areas in California.

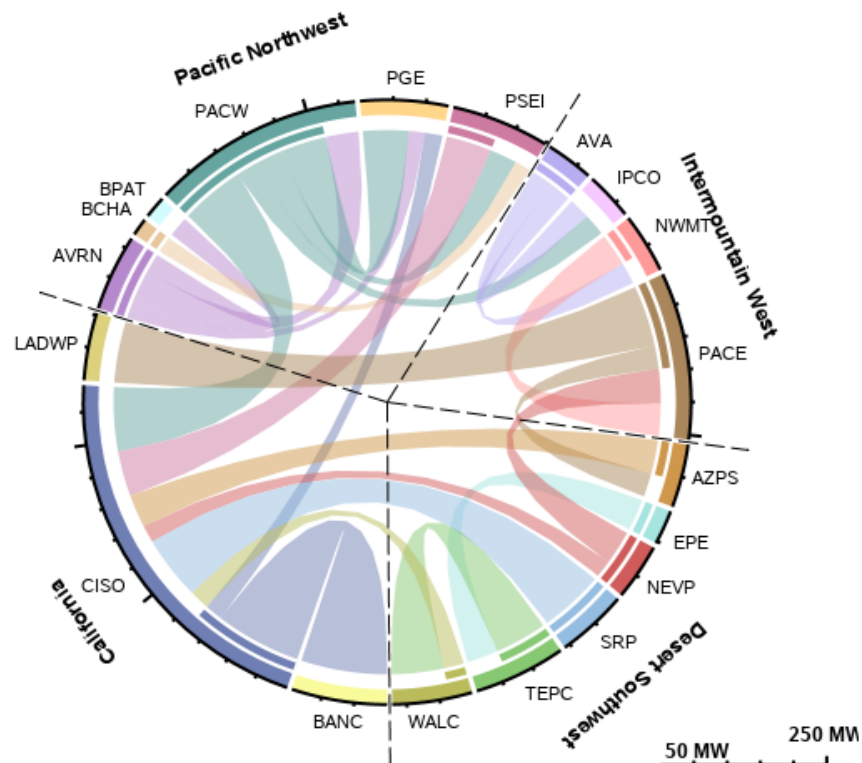
**Figure 5.5 Average 5-minute market WEIM exports in mid-day solar hours
(May–June 2026)**



⁴⁰ Mid-day solar hours in this figure are the twelve hours in the middle of the day when solar generation is highest, while the off-solar hours are the remaining twelve hours in the early morning and late evening.

⁴¹ In the first figure, each small tick is 100 MW, each large tick is 500 MW, and average WEIM transfer paths less than 50 MW are excluded. In the second figure, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 5.6 **Average 5-minute market WEIM exports in off-solar hours
(May–June 2026)**



5.2 EDAM and WEIM transfer limits

EDAM and WEIM transfers between areas are constrained by *transfer limits*. These limits largely reflect transmission and interchange rights made available to the market by participating EDAM and WEIM entities.

Figure 5.7 summarizes average transfer limits (or transfer capacity) made available to transfer energy between participating EDAM balancing areas in the day-ahead market during May and June.

Figure 5.7 Average day-ahead market EDAM transfer limits between balancing areas (May–June 2026)

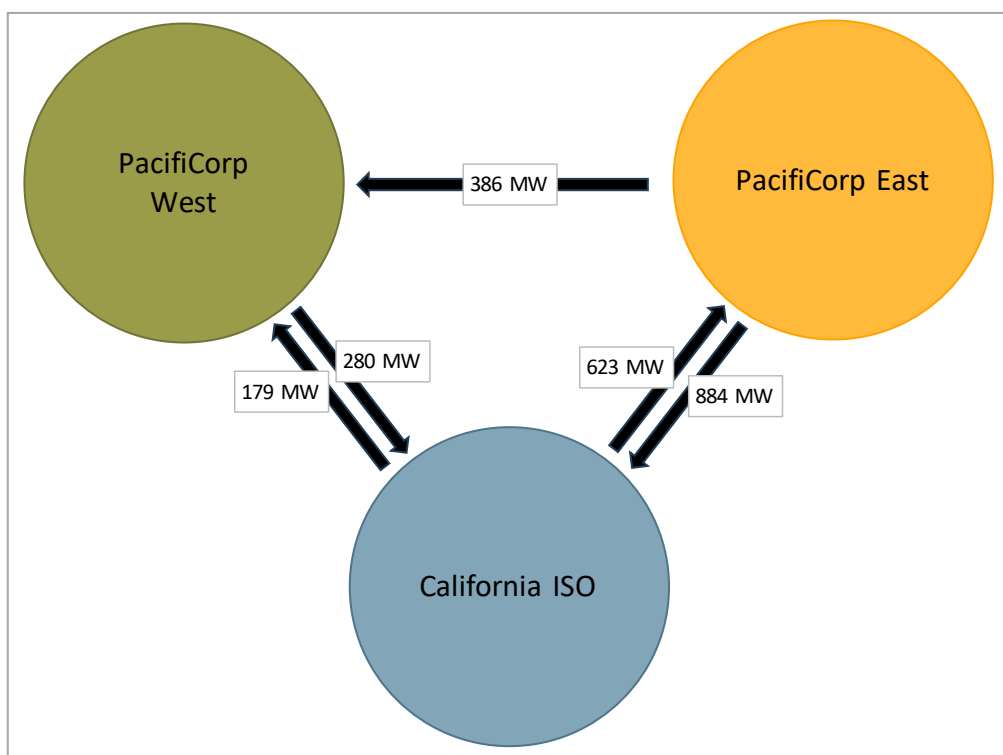


Figure 5.8 shows WEIM transfer capacity (or transfer limits) available in the 5-minute market to support the transfer of energy between balancing areas and regions in the Western Energy Imbalance Market.⁴² The width of each path reflects the size of the WEIM transfer capacity. WEIM transfer capacity 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. Of note, much more transfer capacity between balancing areas is available in the real-time market relative to the day-ahead market. This can contribute to different pricing outcomes for each EDAM balancing area between the day-ahead and real-time markets.

On May 6, 2026, Power Watch (GWA) and Black Hills Energy (BHBA) joined the Western Energy Imbalance Market. Power Watch joined with roughly 260 MW on average in dynamic transfer capacity with NorthWestern Energy. Black Hills joined with around 250 MW on average in dynamic transfer capacity with PacifiCorp East.

⁴² Transfer capacity (limits) were categorized by the average limit from both the import and export direction. Transfer paths with 5 MW or less of transfer capacity on average for the quarter are not shown.

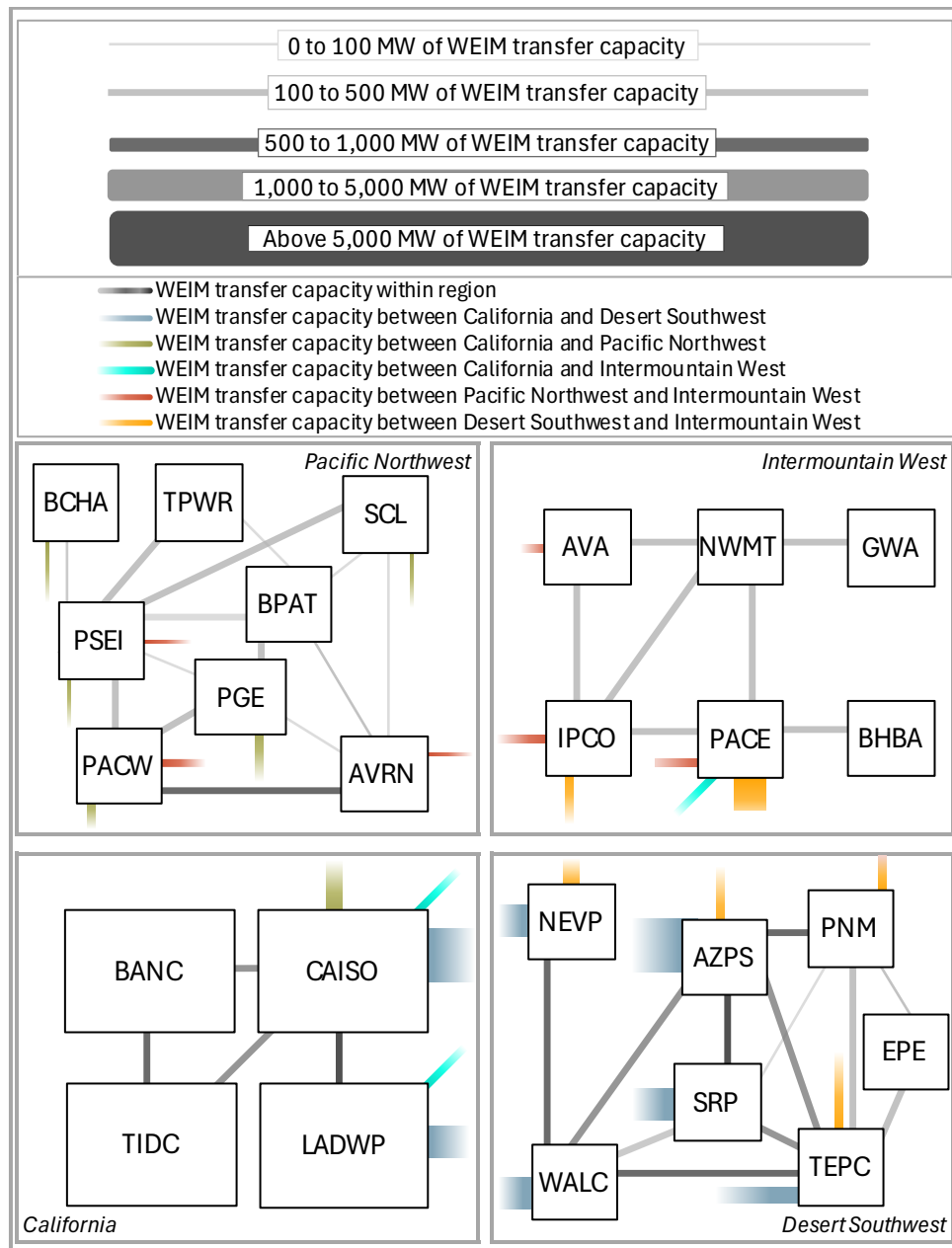
Figure 5.8 Average 5-minute market WEIM transfer limits by balancing area (May–June 2026)

Table 5.1 summarizes average regional transfer capacity in the WEIM.⁴³ 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-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 1,473 MW of import transfer capacity and 871 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 (May–June 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				Total out-of-region	
		California	Desert Southwest	Intermountain West	Pacific Northwest	export limit
	California	23,240	27,358	152	1,038 / 332	28,636 / 332
	Desert Southwest	32,968	55,085	1,735		34,703
	Intermountain West	319	1,806	4,305	435	2,615
	Pacific Northwest	590 / 127		281	5,165	871 / 127
	Total out-of-region import limit	33,931 / 127	29,165	2,256	1,473 / 332	

EDAM transfer system resource types

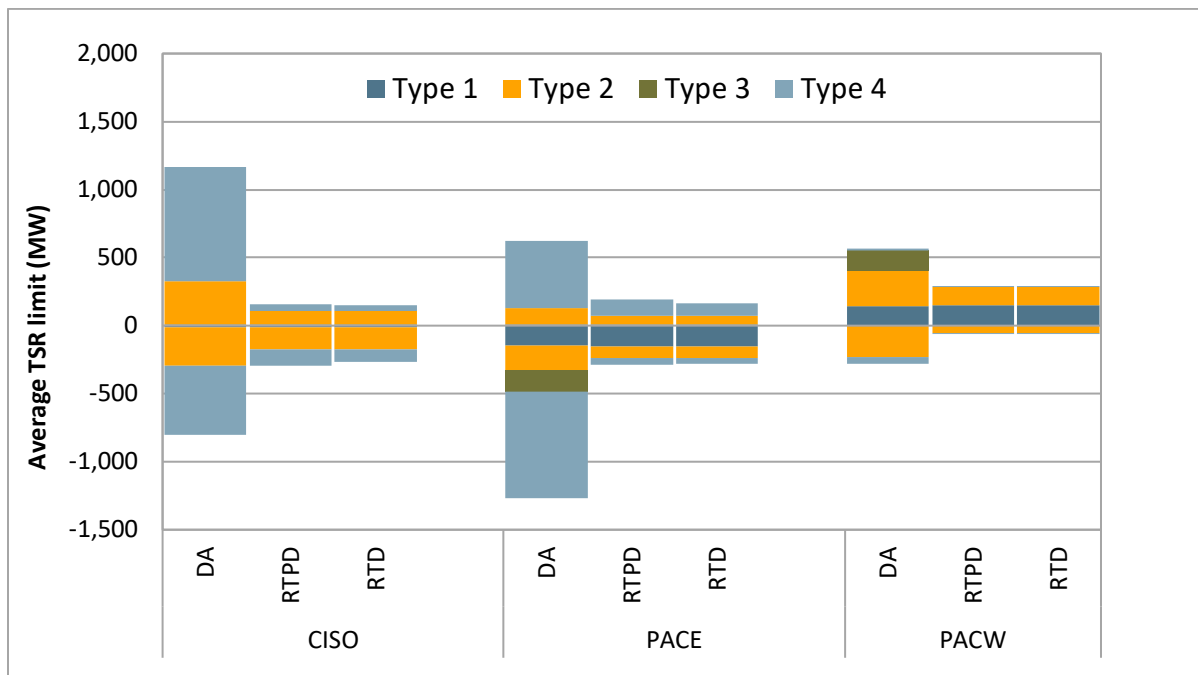
Day-ahead transfers between EDAM balancing areas are modeled using one of four categories of transfer system resource (TSR). Type 1 TSRs represent bilateral transfers between EDAM balancing areas and are self-scheduled into the day-ahead market. Type 1 TSRs are the only TSR type that may re-bid capacity into the real-time market. Type 2 and type 4 TSRs are similar in that they represent released transmission rights that are available to the day-ahead market to optimize transfers. For type 2 TSRs, the transmission customer (the EDAM scheduling coordinator) releases the transmission capacity for optimization, whereas for type 4 TSRs, the capacity is released by the EDAM BA. Type 3 TSRs represent

⁴³ 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) inertia constraints that can limit WEIM transfers.

resource-specific capacity used to support balancing area load. Type 1 and type 3 TSRs are eligible to be counted in the day-ahead resource sufficiency evaluation.

Besides type 1 TSR resources rebidding into the real-time market, changes to day-ahead TSR schedules in real-time may only be caused by derates in the TSRs' maximum capacity. Figure 5.9 shows average EDAM TSR limits by type and market for the second quarter. Most decreases in TSR limits from the day-ahead to the real-time market are for type 2 and type 4 resources, which are ineligible to be counted towards the day-ahead RSE. On average, type 1 limits either increased or stayed near day-ahead levels going into the real-time market across all EDAM balancing areas. Type 3 day-ahead import limits in PACW consistently decreased to 0 in the real-time market. However, no type 3 transfers were cleared in the day-ahead market in Q2.

Figure 5.9 EDAM transfer system resource limits by type and market (2026 Q2)



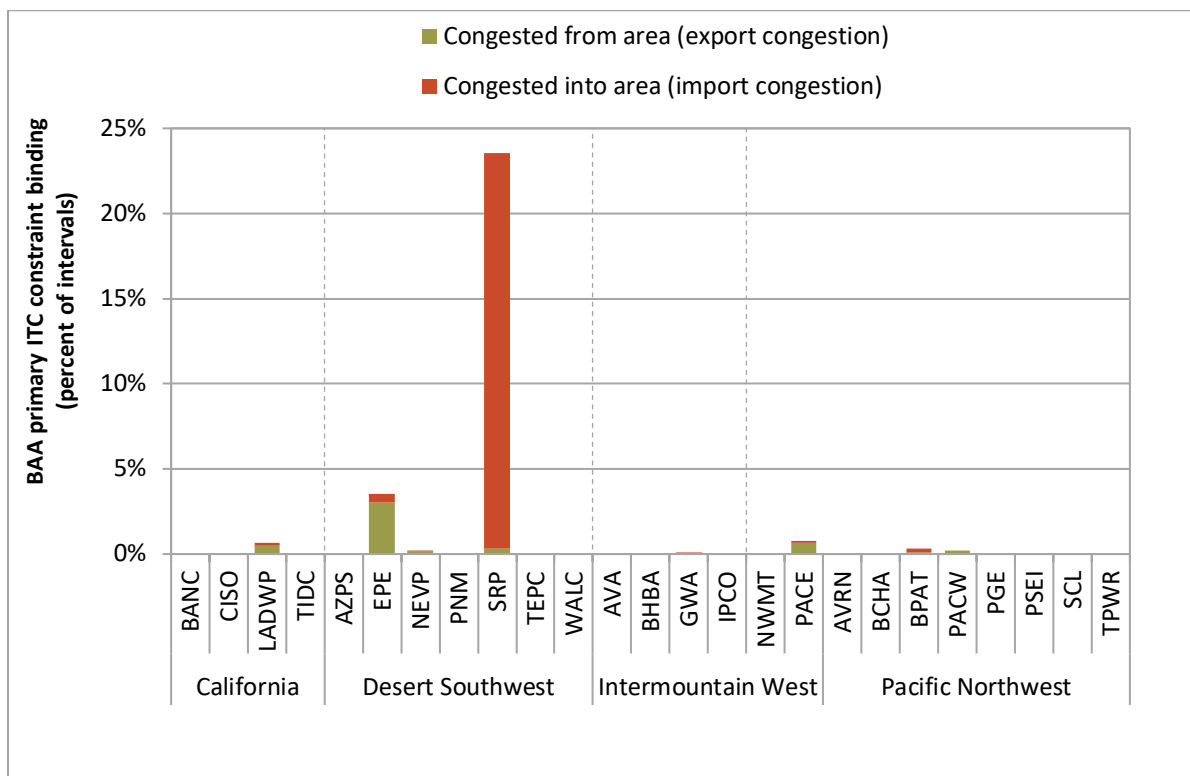
5.3 WEIM inertia constraints

An inertia constraint (ITC) is a scheduling limit applied to a specified set of scheduling points or inertia 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* inertia 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 5.10 shows the percent of intervals in the 5-minute market in which the primary inertia 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 23 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 5.10 Frequency of primary ITC constraint binding for net WEIM transfers (5-minute market, Q2 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 an intertie constraint for total WEIM imports that was binding in around 15 percent at around 500 MW on average.

5.4 Intertie transfers for EDAM entities

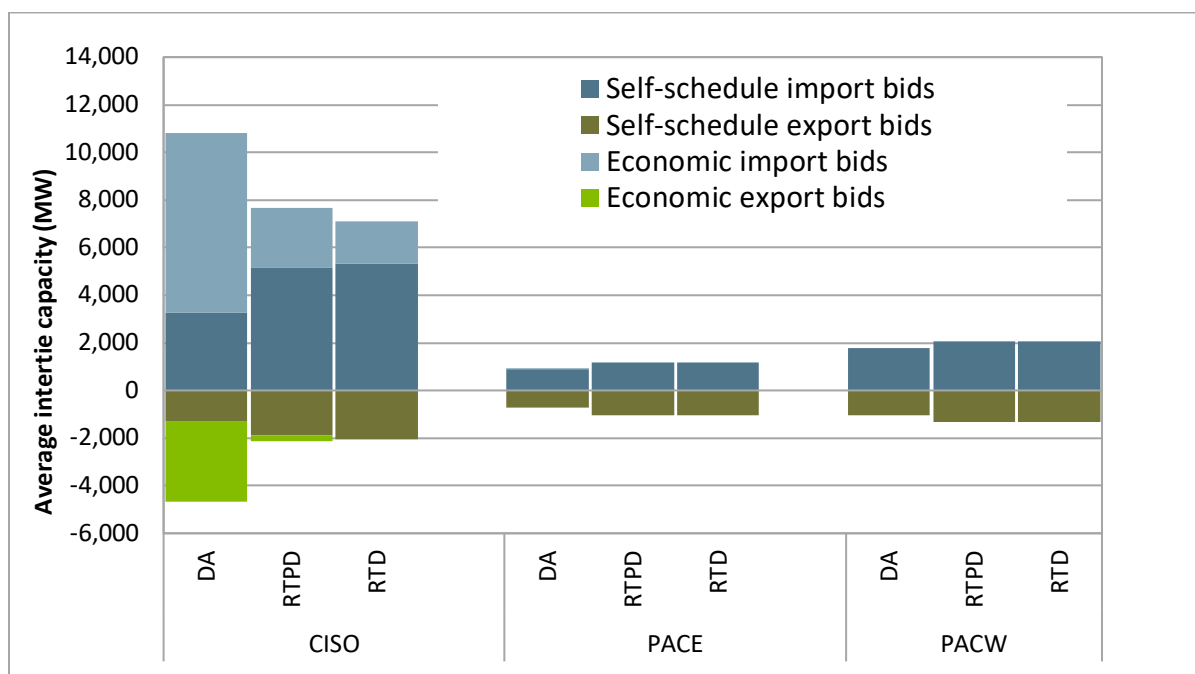
In the extended day-ahead market (EDAM), the ISO's market software continues to support intertie transfers at EDAM external interties, i.e., interties between an EDAM balancing area and non-EDAM balancing area. CAISO interties continue to support intertie resources' ability to submit self-schedules or economic bids. However, at non-CAISO external interties, entities may submit self-schedules for imports and exports but economic bids are limited to imports from designated network resources specified in the terms of the EDAM entity Open Access Transmission Tariff (OATT).

Except for the Mona and Crag View interties, the market software does not support day-ahead intertie bidding to facilitate bilateral transactions between two EDAM balancing areas. The ISO made exceptions for these locations on an interim basis to support imports into the CAISO balancing area related to either

resource adequacy or Renewable Portfolio Standard contracts. Under the EDAM design, all such bilateral transactions are modeled as TSR type 1, described in more detail in Section 5.2 of this report.

Figure 5.11 shows average intertie resource capacity bid into the market for day-ahead balancing areas in the second quarter, broken out by whether capacity was self-scheduled or bid in economically. The majority of intertie bids for the CAISO balancing area were economic bids, with 73 percent of exports and 70 percent of imports being bid economically. PACE had economically bid day-ahead import quantities of 100 MW or less on four days in May 2026.

Figure 5.11 Average bid-in intertie resource capacity for day-ahead balancing areas (Q2 2026)



Intertie transfers are considered in the new day-ahead market resource sufficiency evaluation (RSE), with imports counting towards additional supply for a balancing area and exports counting towards additional demand. Figure 5.12 shows average cleared intertie resource capacity by balancing area for the day-ahead RSE and all market runs for the second quarter. In the second quarter, CAISO was the only day-ahead balancing area that cleared less intertie capacity (both imports and exports) in the day-ahead RSE compared to the day-ahead market. Intertie bids are not counted towards the day-ahead RSE for the CAISO balancing area unless they meet the deliverability requirements outlined under the CAISO tariff.⁴⁴

Figure 5.13 compares average intertie import capacity that counted towards the day-ahead RSE, with day-ahead market awards and 5-minute market bids from those same resources. On average, these resources bid more import capacity into the real-time market compared to their day-ahead market awards in all areas and months except PACE in May, which had a slight shortfall of 12 MW.

⁴⁴ California ISO Tariff Section 33.30.8.2
<https://www.caiso.com/documents/section-33-extended-day-ahead-market-as-of-may-1-2026.pdf>

Figure 5.14 highlights this difference between 5-minute market bids and day-ahead awards for resources counted in the day-ahead RSE. In addition to changes in supply shown by the blue bars (with negative values indicating real-time supply shortfalls resulting from lower import bid quantities), Figure 5.14 also shows changes in demand, represented by the yellow bars (with negative values indicating increased export bids). The red diamonds indicate the net shortfall resulting from changes in either real-time import bids, export bids, or both, relative to day-ahead market awards.

Figure 5.12 Average cleared inertia resource capacity for day-ahead balancing areas (2026 Q2)

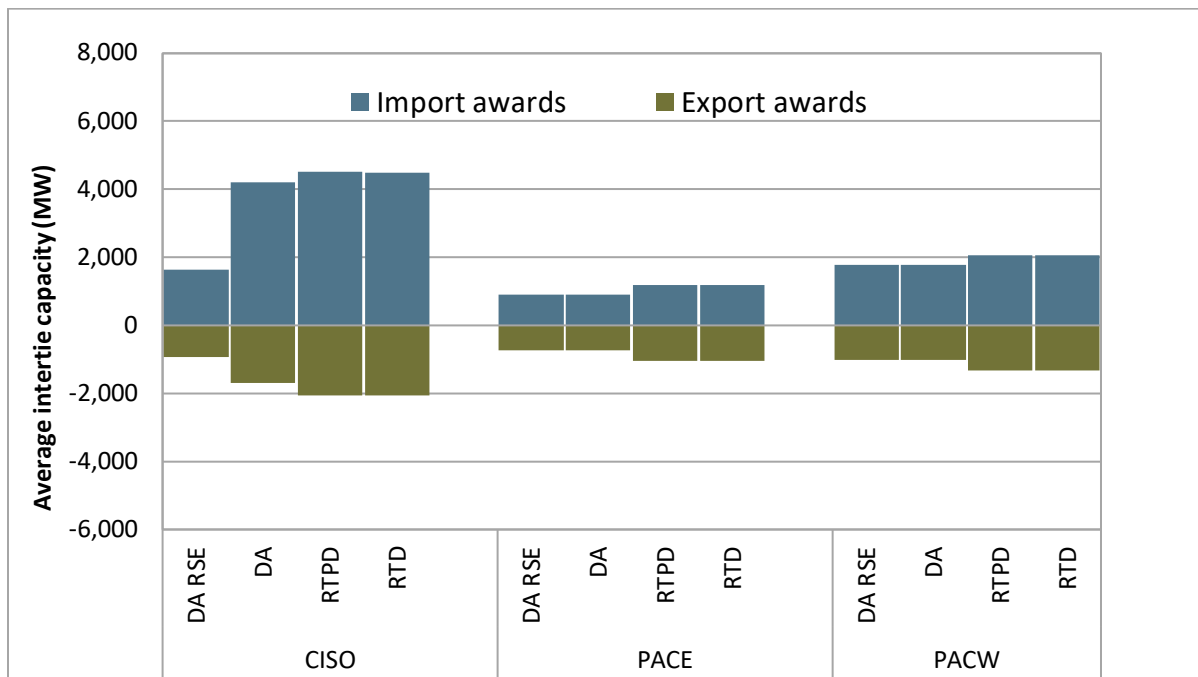
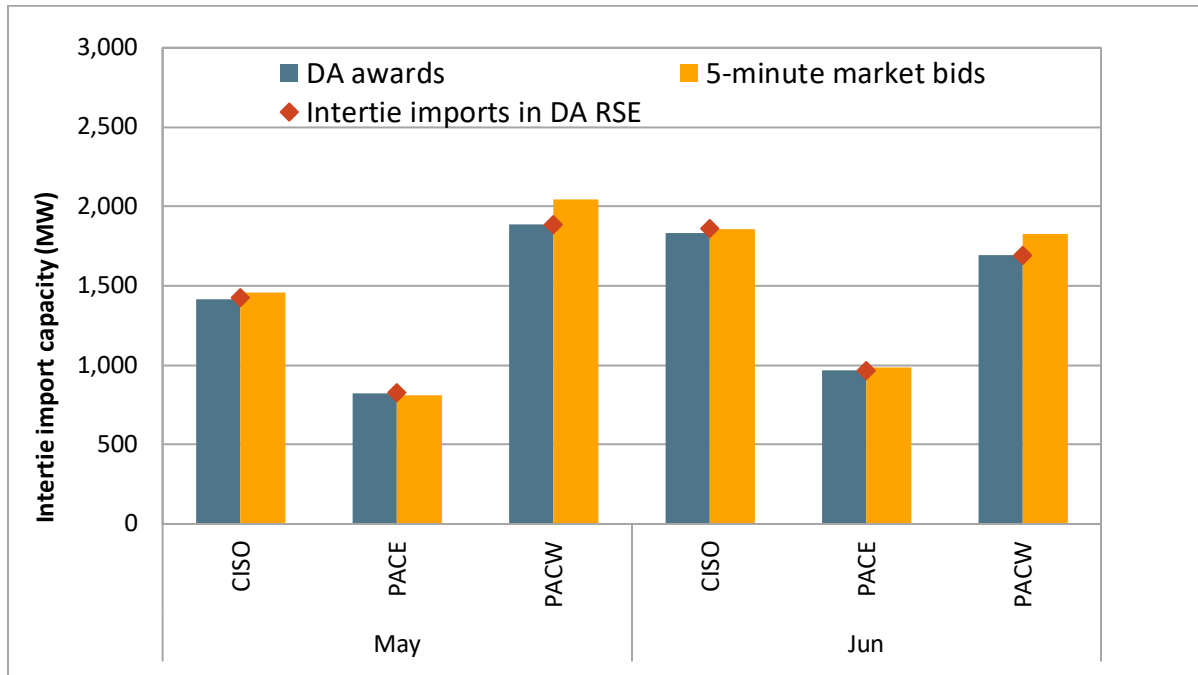
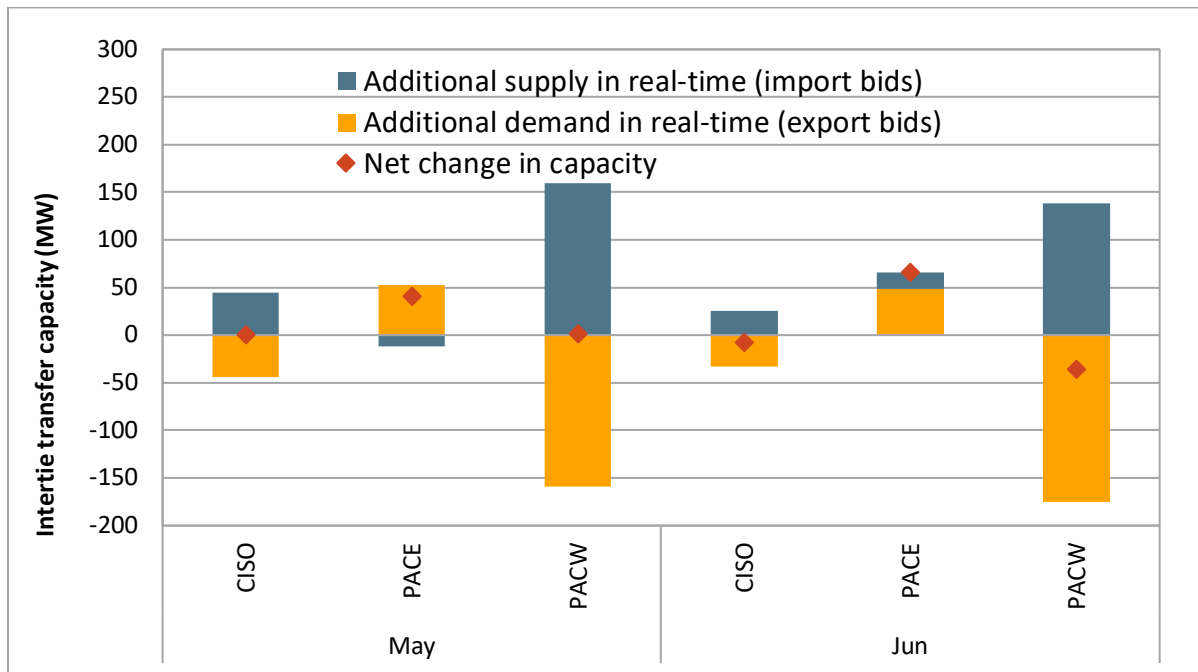


Figure 5.13 Day-ahead and real-time market comparison of intertie import capacity (2026)**Figure 5.14 Real-time bid changes for resources counted toward the day-ahead RSE (Q2 2026)**

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.

Beginning May 1, the extended day-ahead market (EDAM) launched, covering two of the three months in this quarter. This section presents a mix of April data that was pre-EDAM and May–June data under EDAM, with results highlighted separately where applicable. Before EDAM, the marginal cost of congestion (MCC) included both internal and transfer congestion components. After EDAM, transfer congestion is reflected in differences in the marginal energy cost (MEC) across BAAs, and MCC only represents internal congestion.

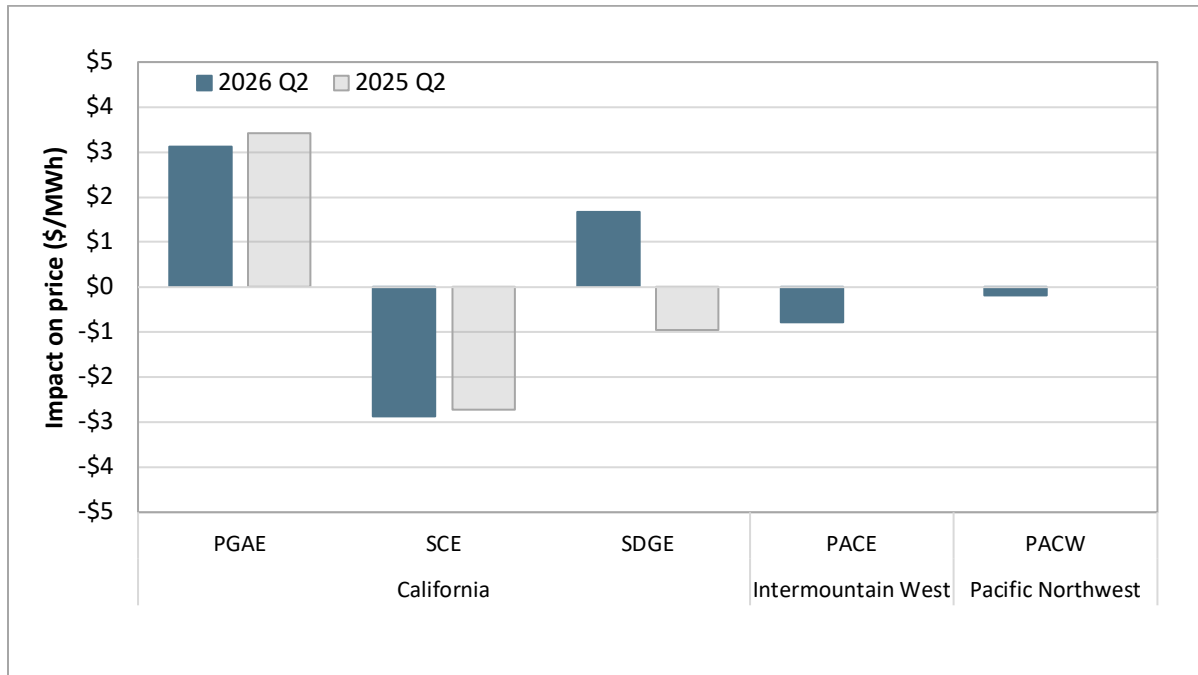
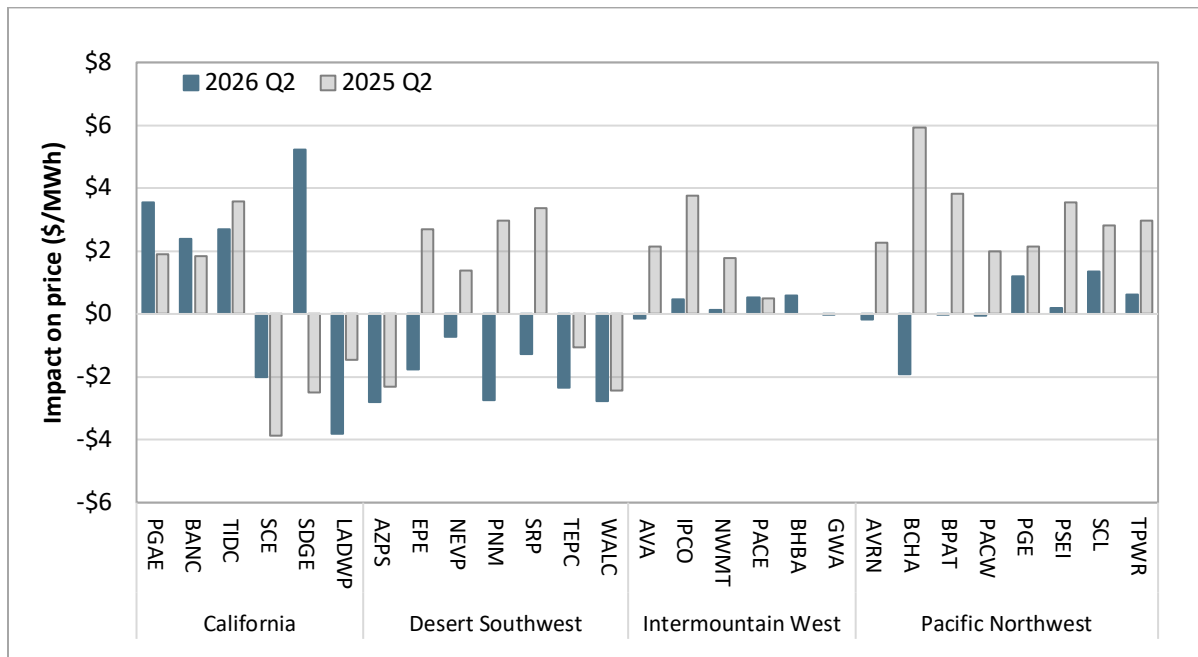
Figure 6.1 and Figure 6.2 show the average impact of congestion on day-ahead and real-time market prices, respectively, in Q2 of 2025 and 2026. Blue bars represent the 2026 impact, while gray bars represent the 2025 values. The congestion impact in real-time was calculated as the average price impact across both the 15-minute and 5-minute markets for all intervals during the quarter.

Total congestion in these figures reflects the applicable market design for each period: both internal and transfer congestion for April, and internal congestion only for May and June. Several balancing areas newly joined in May including PACE and PACW in the day-ahead market and Black Hills Energy (BHBA) and Power Watch (GWA) in the real-time market, with data reflected for May and June only.

In the day-ahead market this quarter, prices in PG&E and SDG&E were higher due to congestion, while prices in SCE, PACE, and PACW were lower.

In the real-time market, the south-to-north congestion pattern was pronounced in this quarter. Prices in Northern California, the Pacific Northwest, and the Intermountain West were generally higher, while prices in Southern California were lower.

Compared with the same quarter last year, congestion impacts shifted notably in the Desert Southwest, the Pacific Northwest, and SDG&E showing a reversal in price impact. In the Desert Southwest, for example, prices were higher by congestion last year but were generally lower this quarter. BHBA and GWA, which joined in May, experienced relatively small congestion price impacts during May and June.

Figure 6.1 Average impact of total congestion on day-ahead market price (Q2 2026)**Figure 6.2 Average impact of total 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 EDAM and WEIM transfers between balancing areas. Section 6.2 addresses real-time market internal congestion.⁴⁵ Section 6.3 analyzes day-ahead market congestion rent and loss surpluses. Section 6.5 addresses intertie constraint congestion in the day-ahead market. Lastly, Section 6.6 addresses the impact of internal congestion on the day-ahead market.

6.1 EDAM and WEIM transfer constraint congestion

When limits on constraints impacting EDAM or 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. With the launch of the EDAM on May 1, the marginal energy cost (MEC) is now calculated separately for each balancing area and differences in the MEC between balancing areas reflects any EDAM or WEIM transfer congestion. Figure 6.3 shows the percent of intervals and overall price difference for EDAM participating balancing areas in each market between May and June. The EDAM or WEIM transfer congestion is measured as the difference in the marginal energy cost (MEC) for each balancing area relative to the CAISO balancing area.⁴⁶ 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 balancing area (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.⁴⁷

Much more transfer capacity between balancing areas is available in the real-time markets relative to the day-ahead market. This can contribute to different price outcomes for each EDAM balancing area between the day-ahead and real-time markets. PacifiCorp East was transfer constrained (either direction) in 76 percent of intervals in the day-ahead market, compared to 12 percent of intervals in the 5-minute market. PacifiCorp West was transfer constrained in 70 percent of intervals in the day-ahead market, compared to 33 percent of intervals in the 5-minute market.

For the CAISO balancing area, convergence bidding helps to align day-ahead and 15-minute market prices by allowing financial bids on internal nodes to arbitrage price differences between the two markets. At the launch of the extended day-ahead market, PacifiCorp East and PacifiCorp West have opted *not* to enable convergence bidding in their balancing areas.⁴⁸ Substantial differences in transfer

⁴⁵ 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.

⁴⁶ Differences in the marginal energy cost between balancing areas accounts for any constraint that can limit EDAM or WEIM transfers between balancing areas, including (1) scheduling limits on individual EDAM or WEIM transfers, (2) total scheduling limits, or (3) intertie constraint and intertie scheduling limits.

⁴⁷ 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.

⁴⁸ EDAM participating balancing areas can choose to enable convergence bidding or not in their balancing area at the onset of participation. The ISO intends to derive a more permanent EDAM convergence bidding policy after two years of EDAM operation.

capacity between the day-ahead and real-time markets can contribute to very different price outcomes in these balancing areas.

Figure 6.3 Frequency and impact of EDAM or WEIM transfer congestion — EDAM balancing areas (May–June 2026)

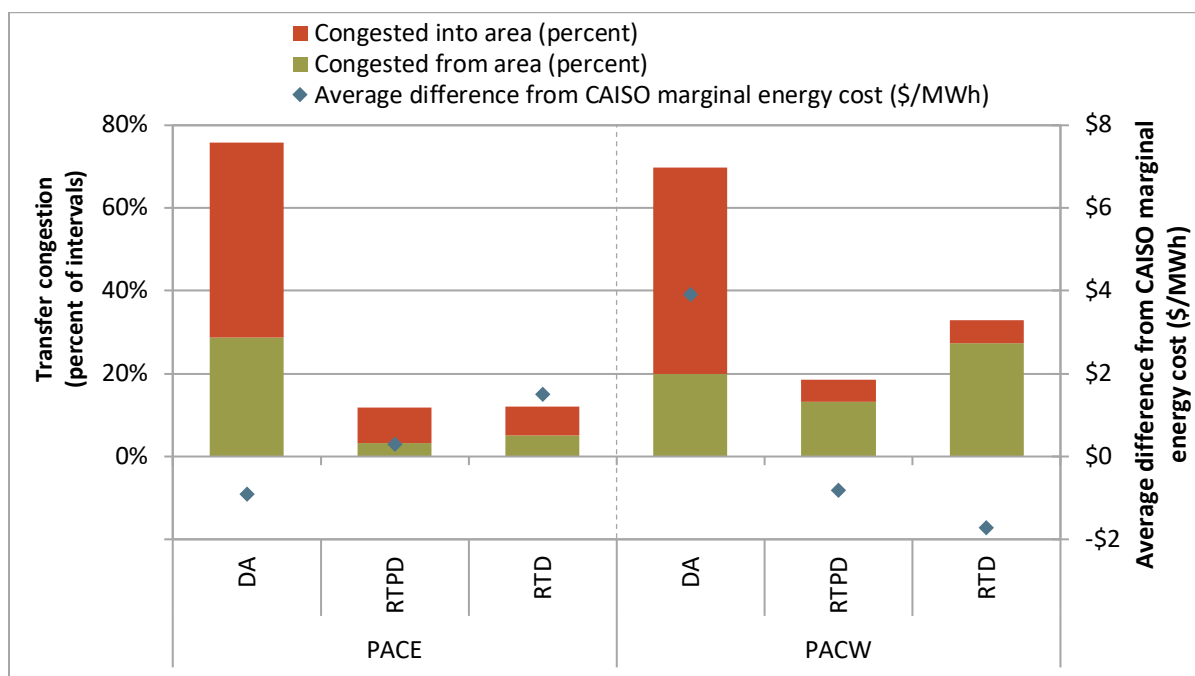


Figure 6.4 and Figure 6.5 shows the same information for all WEIM participating balancing areas in the 15-minute and 5-minute markets.

Powerex (BCHA) was frequently export constrained relative to the CAISO balancing area because of WEIM transfer congestion between May and June. In the 5-minute market, Powerex was export constrained during around 77 percent of intervals. On average for May and June, Powerex prices were \$10.79/MWh lower because of WEIM transfer congestion in the 15-minute market, and \$11.30/MWh lower in the 5-minute market.

WEIM transfer congestion was also high for other balancing areas in the Pacific Northwest. In the 5-minute market, these balancing areas were import constrained in around 27 percent of intervals and export constrained in around 6 percent of intervals. Prices in the Pacific Northwest were about \$1.73 lower in the 5-minute market relative to the CAISO balancing area because of WEIM transfer congestion.

El Paso Electric, Salt River Project, and Tucson Electric Power were frequently transfer constrained. This transfer congestion was often the result of intertie constraints that each balancing area can use to manage total or net WEIM transfers into or out of their system. Salt River Project and Tucson Electric Power were import constrained in around 20 percent of intervals. El Paso Electric was export constrained in 6 percent of intervals and import constrained in 12 percent of intervals. For El Paso Electric, the average difference above the CAISO marginal energy cost because of WEIM transfer congestion was \$6.84 in the 15-minute market and \$9.39 in the 5-minute market.

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

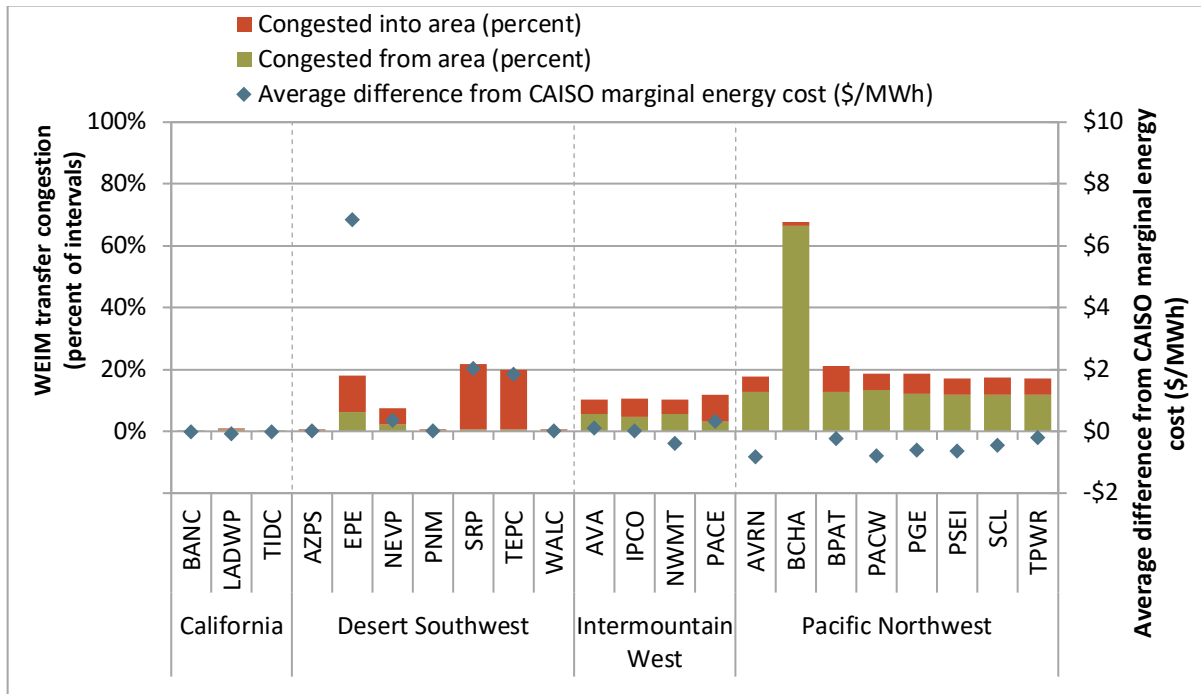
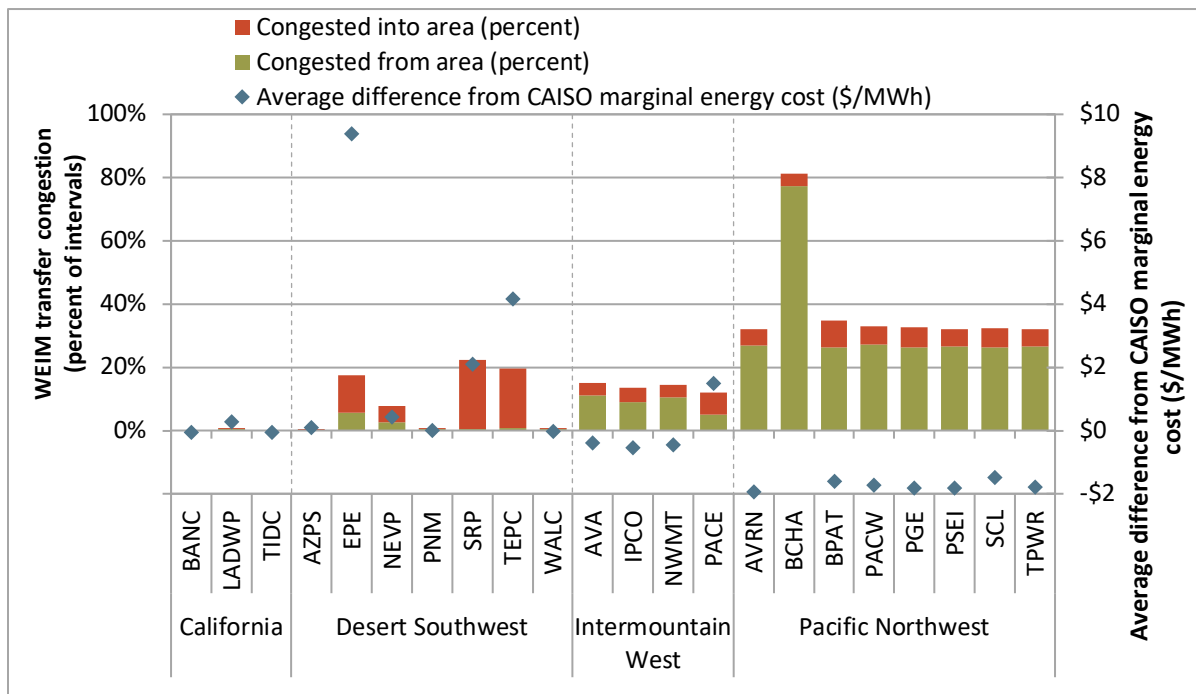


Figure 6.5 Frequency and impact of WEIM transfer congestion in the 5-minute market (May–June 2026)



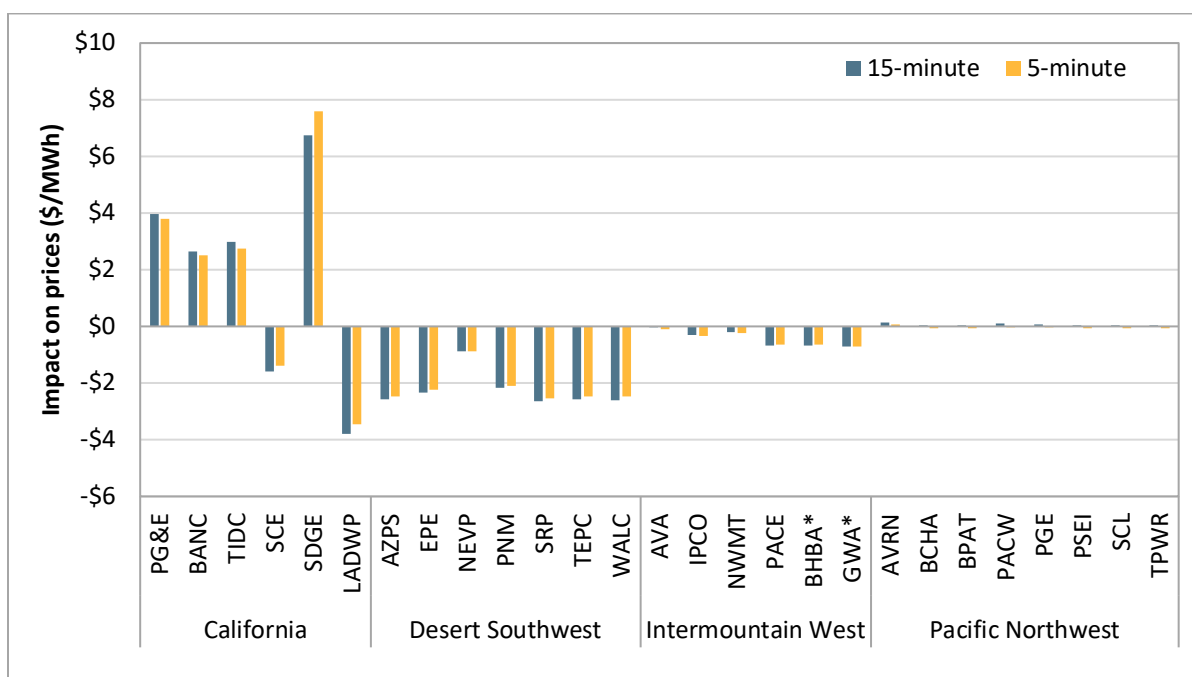
6.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM.⁴⁹ 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.⁵⁰

The EDAM launch was coupled with several changes affecting the real-time market, including the addition of two new BAAs and the introduction of the marginal energy cost (MEC). This quarter can therefore be divided into two periods around these market changes: April represents the pre-EDAM period, while May and June represent the post-EDAM period.

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



⁴⁹ 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.

⁵⁰ This approach does not include price differences that result from transmission losses.

Figure 6.6 and Figure 6.7 illustrate the overall impact of internal congestion on prices at the default load aggregation points (DLAPs) and EIM load aggregation points (ELAPs) across these periods in the second 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.

In April, prices were elevated in Northern California and SDG&E relative to prices in the Desert Southwest and the Intermountain West regions. A similar pattern continued in May and June in California and the Desert Southwest. In the Intermountain West, congestion contributed to decreasing prices relative to other areas in April, while contributing to increasing prices relative to other areas in May and June. In the Pacific Northwest, congestion had a bigger impact on prices in May and June than in April.

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 (April 2026)

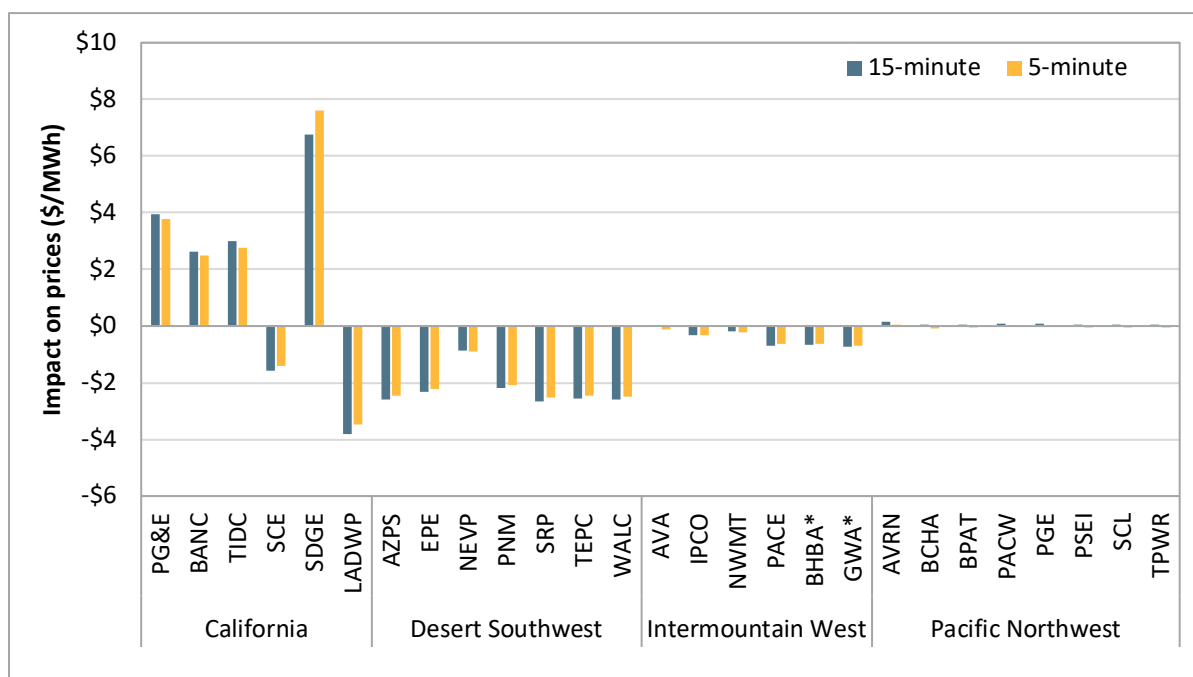


Figure 6.7 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (May–June 2026)

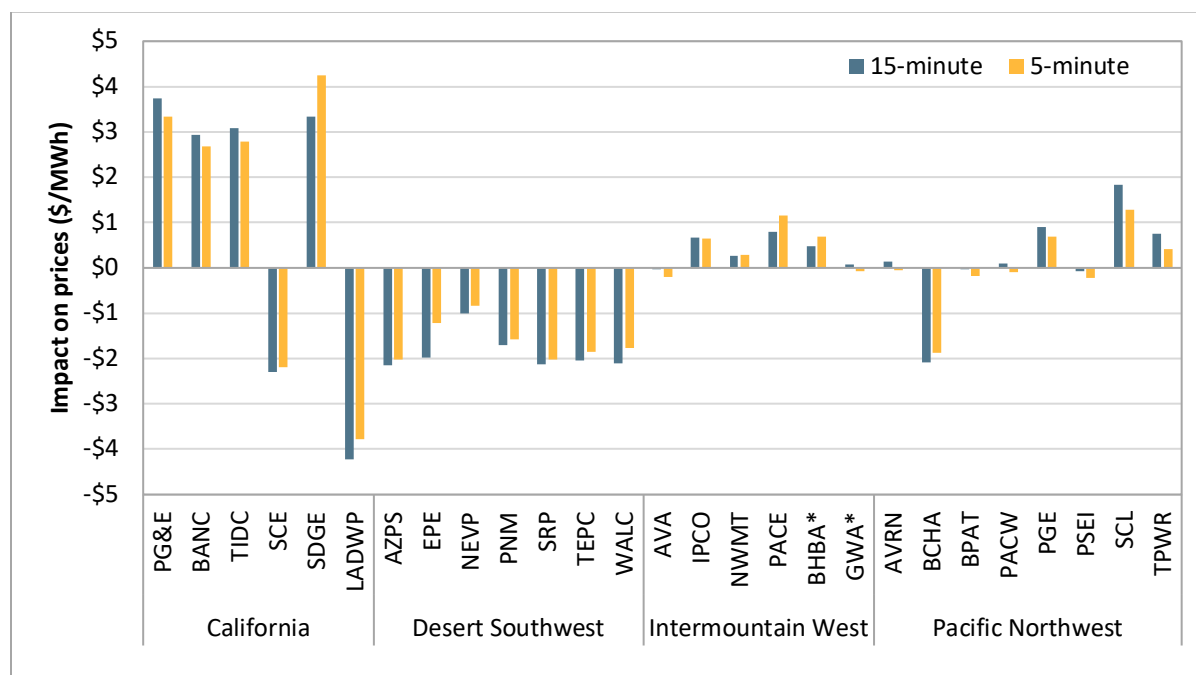


Figure 6.8, Figure 6.9, and Figure 6.10 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the second quarter of 2026 and 2025, respectively. The 2026 quarter is further divided into pre- and post-EDAM periods. Congestion patterns were generally similar across the two 2026 periods. In addition to the south-to-north congestion during solar hours, substantial congestion into California occurred during non-solar hours. LADWP was an exception, as congestion out of LADWP reduced prices there relative to other areas. This differed from the same quarter in 2025, when non-solar-hour congestion into California was limited and stronger congestion into the Desert Southwest was observed.

The two newly joined BAAs, Black Hills Energy (BHBA) and Power Watch (GWA), generally followed congestion patterns similar to other BAAs in their region, with south-to-north congestion during solar hours and congestion out of the region during non-solar hours.

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

PG&E	2.3	3.0	2.5	2.1	1.9	3.1	3.0	5.3	6.0	5.0	3.6	3.8	3.1	3.5	3.0	4.4	4.9	5.7	4.8	4.9	4.7	3.6	3.5	1.9
BANC	1.6	2.2	1.8	1.5	1.2	2.2	1.8	3.1	3.8	3.1	3.2	3.2	3.0	3.3	3.4	4.3	5.2	5.0	3.1	3.1	3.3	3.2	2.9	1.9
Turlock ID	1.8	2.4	1.9	1.6	1.3	2.5	1.7	2.9	3.6	3.2	3.8	4.0	3.9	4.2	4.4	4.9	6.1	5.7	2.9	2.3	2.6	2.3	2.4	1.5
SCE	2.7	2.6	2.4	2.2	2.4	4.1	0.5	-6.0	-8.3	-8.2	-7.5	-7.6	-7.5	-7.1	-6.4	-6.9	-6.2	-4.9	-0.9	0.7	0.6	0.6	1.6	1.9
SDG&E	8.2	7.3	7.3	7.7	8.3	9.3	4.5	2.7	-2.0	-0.9	1.3	-0.5	-2.0	-2.3	-2.0	-2.0	-0.1	2.4	5.0	5.2	6.0	5.7	5.5	5.5
LADWP	-3.9	-5.8	-4.7	-2.4	-3.7	-13.4	-6.3	-4.8	-5.4	-5.2	-5.2	-5.6	-4.8	-4.1	-4.6	-6.1	-4.9	-4.1	-0.7	0.0	-0.2	-1.8	-2.0	-1.7
NV Energy	0.1	-0.4	-0.2	0.4	0.2	-1.4	-2.6	-3.9	-2.0	-2.0	-2.1	-1.9	-1.5	-1.3	-0.8	-1.9	-2.2	-1.7	0.2	0.4	0.2	0.0	0.2	0.4
Arizona PS	0.5	0.1	0.3	0.9	0.7	-0.6	-1.1	-3.8	-4.4	-5.1	-5.5	-5.5	-5.2	-5.0	-5.0	-5.2	-4.7	-3.8	-0.5	0.2	0.1	-0.3	0.5	0.9
Tucson Electric	0.4	0.0	0.2	0.8	0.7	-0.6	-1.1	-3.6	-4.3	-4.8	-5.1	-5.1	-4.7	-4.8	-4.8	-5.0	-4.5	-3.5	-0.5	0.2	0.0	-0.3	0.5	0.9
Salt River Project	0.5	0.1	0.3	0.9	0.7	-0.5	-1.1	-3.8	-4.4	-5.1	-5.5	-5.5	-5.0	-5.0	-5.0	-5.3	-4.7	-3.7	-0.5	0.2	0.1	-0.3	0.5	0.9
PSC New Mexico	0.3	-0.1	0.1	0.7	0.5	-0.8	-1.3	-3.1	-3.2	-3.6	-4.0	-4.1	-3.5	-3.7	-3.9	-4.3	-4.2	-3.3	-0.4	0.1	0.0	-0.3	0.4	0.7
WAPA - Desert SW	0.5	0.0	0.2	0.8	0.7	-0.7	-1.2	-3.8	-4.4	-5.0	-5.5	-5.5	-5.1	-5.0	-4.9	-5.2	-4.6	-3.4	-0.4	0.2	0.1	-0.3	0.5	0.9
El Paso Electric	0.4	0.0	0.2	0.7	0.6	-0.7	-1.2	-3.3	-3.7	-4.3	-4.9	-4.8	-4.4	-4.2	-4.3	-4.7	-5.0	-4.6	-0.5	0.1	0.0	-0.3	0.4	0.8
PacifiCorp East	-0.3	-0.5	-0.5	0.1	0.1	-0.9	-0.5	0.2	0.9	2.5	2.9	2.8	3.4	2.7	3.1	2.4	0.9	0.5	0.4	0.3	-0.2	-0.5	-0.2	-0.1
Idaho Power	-0.8	-0.9	-1.1	-0.8	-1.1	-1.4	-0.3	1.1	1.6	3.0	3.3	3.4	3.8	3.5	3.6	3.9	2.6	1.2	-1.1	-1.7	-1.6	-1.2	-1.5	-1.1
NorthWestern	-1.5	-1.6	-2.0	-1.6	-2.0	-1.9	-0.4	1.7	2.3	2.8	3.2	3.0	3.2	3.0	3.0	3.2	2.6	1.4	-1.6	-2.3	-2.2	-1.6	-2.3	-1.9
Avista Utilities	-1.6	-1.7	-2.2	-2.0	-2.5	-1.9	-0.3	1.9	2.2	2.1	2.2	2.2	2.2	2.4	2.5	3.1	3.0	1.9	-2.0	-2.9	-2.7	-1.8	-2.7	-2.2
Black Hills Corp*	-0.8	-1.0	-1.0	-0.4	-0.6	-1.5	-0.9	0.1	1.0	2.9	3.4	2.8	3.5	2.5	2.8	1.8	0.5	0.3	-0.1	-0.4	-0.7	-1.0	-0.9	-0.7
Power Watch*	-0.9	-1.1	-1.5	-1.3	-1.6	-0.8	-0.2	1.3	1.6	1.9	2.1	2.1	2.3	2.2	2.1	2.5	2.1	0.4	-1.4	-2.4	-2.2	-1.7	-2.0	-1.6
Avangrid	-1.1	-1.0	-1.2	-1.2	-1.2	-1.2	0.0	1.4	1.9	1.6	1.7	1.9	1.6	1.9	2.1	2.5	2.6	2.0	-1.7	-2.9	-2.4	-1.2	-1.4	-1.3
BPA	-1.7	-1.7	-2.1	-2.0	-2.5	-1.8	-0.2	1.9	2.3	2.1	2.2	2.2	2.0	2.4	2.6	3.2	3.2	2.1	-2.0	-2.9	-2.7	-1.9	-2.7	-2.3
Tacoma Power	-0.1	-0.2	-0.7	-0.7	-1.3	-0.4	0.9	2.2	2.3	2.0	2.2	2.2	2.0	2.4	2.6	3.2	3.2	3.0	-0.5	-1.2	-1.1	-1.3	-1.2	-1.5
PacifiCorp West	-1.5	-1.2	-1.6	-1.5	-2.0	-1.2	0.2	2.1	2.4	2.2	2.3	2.3	2.0	2.4	2.5	3.1	3.2	2.2	-2.2	-3.1	-2.9	-2.0	-2.9	-2.3
Portland GE	-1.1	-1.0	-1.4	-1.4	-1.8	-1.1	0.3	2.6	2.7	3.0	3.7	4.2	3.4	4.0	4.3	4.7	3.9	3.4	-0.6	-2.3	-2.1	-1.7	-2.1	-2.0
Puget Sound Energy	-1.7	-1.8	-2.4	-2.2	-2.7	-2.0	-0.2	1.9	2.3	2.0	2.2	2.2	2.0	2.5	2.6	3.2	3.2	2.0	-2.0	-2.9	-2.7	-1.9	-2.7	-2.3
Seattle City Light	2.1	2.0	1.4	1.1	0.5	1.7	2.4	2.6	2.3	2.0	2.2	2.2	2.0	2.5	2.6	3.2	3.2	4.2	1.5	1.2	1.1	-0.6	1.0	-0.4
Powerex	-5.7	-5.8	-6.4	-5.6	-6.0	-6.0	-3.0	1.2	2.2	2.0	2.1	2.2	2.1	2.4	2.6	3.2	3.1	-0.3	-5.8	-7.3	-6.7	-3.1	-6.6	-4.3
	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																							

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

PG&E	2.3	1.4	1.2	0.9	0.9	1.2	1.5	4.8	11.0	9.7	7.1	4.8	2.2	5.4	2.7	3.1	3.2	4.3	2.2	3.8	3.0	2.8	1.8	2.3
BANC	1.5	1.0	1.0	0.7	0.7	1.1	1.3	3.3	4.9	4.2	2.2	1.5	0.7	1.6	-0.3	0.6	0.4	1.7	0.7	1.5	1.4	1.3	1.1	1.8
Turlock ID	1.1	0.9	0.8	0.7	0.7	0.9	1.1	3.8	7.7	6.3	4.6	3.3	1.4	3.9	2.1	2.1	2.1	2.8	1.4	1.7	1.5	1.3	1.1	1.2
SCE	3.5	1.8	1.4	1.2	1.2	1.4	1.4	-2.0	-10.7	-10.1	-6.6	-6.1	-5.3	-7.0	-4.5	-4.5	-4.9	-3.9	0.8	2.6	1.6	2.0	2.3	3.0
SDG&E	26.6	12.7	9.7	7.4	7.4	8.3	10.4	7.5	-1.6	-1.8	2.1	1.0	-0.4	-0.6	0.5	1.4	3.0	5.0	13.0	13.8	15.0	15.3	18.3	20.3
LADWP	0.9	0.9	0.9	0.9	0.9	0.8	0.1	-4.9	-11.0	-10.2	-8.3	-7.5	-7.9	-8.6	-6.1	-7.6	-5.7	-2.2	-0.1	-4.8	-0.6	-2.1	0.5	0.7
NV Energy	0.5	0.8	0.7	0.9	0.8	0.6	0.2	-1.2	-4.0	-4.1	-4.0	-2.4	-3.4	-2.1	0.8	-0.1	1.3	-0.5	1.3	0.2	0.1	-0.1	0.7	0.5
Arizona PS	-5.9	-2.1	-1.3	-0.7	-0.7	-1.0	-2.2	-4.8	-9.6	-9.0	-7.8	-6.2	-6.2	-8.4	-6.0	-5.5	-4.7	-3.5	-2.8	-3.5	-3.7	-3.9	-3.8	-3.9
Tucson Electric	-6.2	-2.3	-1.4	-0.7	-0.8	-1.1	-2.3	-5.0	-9.4	-8.9	-7.8	-6.1	-6.1	-8.4	-5.8	-5.5	-4.6	-3.5	-2.7	-3.5	-3.8	-4.0	-4.0	-4.1
Salt River Project	-6.4	-2.4	-1.5	-0.8	-0.9	-1.2	-2.4	-5.1	-9.8	-9.2	-8.0	-6.2	-6.3	-8.5	-6.0	-5.6	-4.7	-3.6	-2.9	-3.7	-4.0	-4.1	-4.1	-4.3
PSC New Mexico	-4.5	-1.5	-0.8	-0.2	-0.4	-0.7	-2.3	-5.0	-8.5	-9.4	-9.9	-9.7	-9.1	-11.7	-8.0	-7.7	-6.8	-3.7	-2.9	-3.6	-3.1	-3.0	-2.8	-2.9
WAPA - Desert SW	-6.0	-2.2	-1.4	-0.8	-0.8	-1.1	-2.3	-5.0	-9.6	-9.1	-7.9	-6.2	-6.3	-8.4	-6.0	-5.6	-4.7	-3.5	-2.8	-3.5	-3.8	-4.0	-3.9	-4.0
El Paso Electric	-5.2	-1.8	-1.1	-0.4	-0.5	-0.9	-2.2	-4.7	-8.6	-8.7	-8.6	-7.9	-7.9	-10.3	-6.7	-6.1	-5.4	-3.6	-2.7	-3.5	-3.4	-3.4	-3.4	-3.4
PacifiCorp East	0.2	0.9	0.9	1.3	1.1	0.4	-0.2	-0.8	-2.1	-1.7	-1.2	-0.9	0.1	2.0	0.3	0.1	-1.4	-0.3	0.0	-0.2	-0.3	-0.2	-0.1	0.2
Idaho Power	-1.0	-1.1	-0.9	-1.0	-0.9	-0.8	-0.5	-0.2	0.7	0.8	0.6	0.6	0.8	2.1	1.1	0.4	0.4	-0.1	-0.6	-0.7	-0.6	-0.6	-0.8	-1.0
NorthWestern	-1.2	-1.2	-1.1	-1.1	-1.0	-1.0	-0.8	0.0	1.6	1.8	1.4	1.2	1.0	1.2	1.0	1.1	1.2	0.1	-0.8	-1.0	-0.8	-0.7	-1.0	-1.3
Avista Utilities	-1.7	-1.8	-1.7	-1.8	-1.6	-1.4	-0.9	0.1	2.4	2.6	2.0	1.7	1.4	1.7	1.4	1.6	1.7	0.5	-0.9	-1.3	-1.0	-0.9	-1.3	-1.8
Black Hills Corp*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Watch*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avangrid	-1.3	-1.5	-1.4	-1.5	-1.4	-1.3	-1.1	0.4	1.9	2.5	1.3	1.1	0.0	1.1	0.6	1.0	0.6	-0.4	-1.0	-0.9	-0.8	-0.6	-1.2	-1.1
BPA	-1.9	-2.1	-1.9	-2.0	-1.8	-1.6	-1.1	0.4	4.7	4.3	3.8	3.3	4.1	3.4	3.1	3.8	4.0	1.9	-0.9	-1.1	-0.9	-0.8	-1.4	-1.9
Tacoma Power	-1.8	-1.9	-1.7	-1.9	-1.7	-1.5	-1.0	0.8	4.1	4.2	4.7	4.2	5.7	4.8	4.3	5.2	5.6	3.0	-0.9	-1.1	-0.9	-0.8	-1.4	-1.9
PacifiCorp West	-1.8	-2.0	-1.8	-1.9	-1.7	-1.5	-1.0	0.6	3.2	3.3	2.5	2.1	1.8	2.4	1.9	2.0	2.1	0.6	-1.0	-1.1	-1.0	-0.8	-1.4	-1.9
Portland GE	-1.8	-1.9	-1.8	-1.9	-1.7	-1.5	-1.0	1.2	14.5	10.5	6.3	5.8	8.5	6.8	6.7	7.3	7.8	4.3	-0.9	-1.1	-1.0	-0.8	-1.4	-1.9
Puget Sound Energy	-1.8	-1.9	-1.7	-1.9	-1.7	-1.5	-1.0	0.8	4.2	4.3	4.9	4.3	6.0	5.0	4.5	5.4	5.8	3.1	-0.9	-1.1	-0.9	-0.8	-1.4	-1.9
Seattle City Light	-1.8	-1.9	-1.7	-1.9	-1.7	-1.5	-1.0	0.7	3.8	3.9	4.2	3.6	4.8	4.2	3.7	4.5	4.8	2.5	-0.9	-1.1	-0.9	-0.8	-1.4	-1.9
Powerex	-1.7	-1.9	-1.7	-1.8	-1.6	-1.5	-1.0	0.5	3.4	3.5	3.6	3.1	3.8	3.5	3.1	3.7	4.0	1.9	-0.9	-1.1	-0.9	-0.8	-1.4	-1.8
	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																							

Figure 6.10 Overall impact of internal congestion on price separation in the 15-minute market by hour (April–June 2025)

PG&E	-0.7	-0.6	-0.8	-0.8	-0.9	-0.6	0.6	4.8	8.9	8.9	3.7	3.2	2.1	2.5	1.9	3.8	4.7	5.9	0.9	0.4	0.3	0.0	-0.6	-1.2
BANC	-0.1	-0.2	-0.1	-0.2	-0.1	0.0	0.3	3.2	5.3	4.4	3.3	2.7	2.1	2.0	1.9	3.3	4.7	3.9	1.2	3.3	3.0	0.4	-0.2	-0.7
Turlock ID	-0.2	-0.2	-0.2	-0.2	-0.2	0.0	0.3	3.7	8.8	7.4	8.5	8.4	7.7	7.8	7.9	9.5	10.0	6.7	1.4	0.3	0.5	0.0	-0.5	-0.8
SCE	0.1	0.1	0.1	0.1	0.1	-0.1	-0.1	-4.7	-10.8	-12.1	-8.1	-8.5	-7.2	-7.8	-8.4	-8.8	-7.5	-5.5	-1.2	-1.8	-1.6	-0.4	0.3	0.6
SDG&E	0.3	0.3	0.2	0.2	0.2	0.0	0.6	-0.7	-6.2	-9.4	-5.8	-6.6	-5.6	-5.9	-6.4	-7.1	-5.8	-3.1	0.6	-0.5	-0.2	0.5	0.6	0.8
LADWP	0.2	0.2	0.2	0.2	0.2	0.1	-0.1	-3.3	-5.7	-5.7	-4.9	-4.7	-3.7	-3.5	-3.2	-2.2	-2.4	-0.7	0.4	0.2	-0.4	0.1	0.6	0.8
NV Energy	1.0	0.4	1.2	1.2	1.3	0.9	0.1	-1.2	-2.0	-2.4	-1.4	-0.6	-0.9	-0.2	1.4	0.8	0.3	0.5	2.7	4.3	3.2	2.7	1.9	2.0
Arizona PS	0.1	0.0	0.0	0.1	0.1	0.0	-0.5	-4.0	-6.3	-5.8	-5.3	-5.1	-4.4	-4.5	-4.9	-5.2	-5.9	-4.2	-1.0	-0.3	-0.7	-0.3	0.4	0.5
Tucson Electric	0.1	0.0	0.0	0.1	0.1	0.0	-0.5	-3.9	-5.9	-5.3	-5.0	-4.9	-4.3	-4.5	-5.1	-5.5	-5.8	-4.4	-1.0	-0.3	-0.7	-0.3	0.3	0.5
Salt River Project	0.0	0.0	0.0	0.1	0.1	0.0	-0.5	-4.1	-6.3	-5.8	-5.3	-5.1	-4.4	-4.6	-5.2	-5.6	-6.0	-4.5	-1.0	-0.3	-0.7	-0.3	0.3	0.5
PSC New Mexico	6.7	6.3	8.3	7.9	8.2	8.7	-0.4	-6.6	-8.0	-5.6	-3.4	-2.2	-2.4	-0.6	-1.1	-1.1	-1.5	1.2	9.4	15.8	9.5	8.6	8.4	5.6
WAPA - Desert SW	0.1	0.0	0.0	0.1	0.1	0.0	-0.5	-4.0	-6.2	-5.7	-5.2	-5.0	-4.3	-4.5	-5.0	-5.5	-5.8	-4.3	-1.0	-0.3	-0.7	-0.3	0.3	0.5
El Paso Electric	3.5	3.0	1.9	0.6	2.8	0.8	2.1	-2.3	-3.3	-0.7	-1.9	-1.2	-1.3	-1.6	-1.9	-1.6	-2.5	-0.3	3.0	3.9	4.0	4.7	3.1	3.2
PacifiCorp East	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.7	-0.9	-0.6	-0.4	0.1	0.5	0.6	2.7	2.0	1.2	0.7	0.0	-0.1	-0.1	-0.1	0.0	0.0
Idaho Power	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.7	0.8	1.0	1.3	1.4	1.6	3.0	2.7	2.0	1.1	0.0	-0.1	0.0	-0.1	-0.2	-0.2
NorthWestern	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.2	2.2	2.2	2.4	2.4	2.2	2.3	2.1	2.5	2.5	1.2	-0.1	-0.1	0.1	-0.1	-0.4	-0.5
Avista Utilities	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.6	2.9	2.8	3.0	3.1	2.8	2.9	2.7	3.2	3.1	1.5	-0.1	-0.1	0.2	-0.1	-0.5	-0.6
Black Hills Corp*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Watch*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avangrid	-0.2	-0.2	-0.1	-0.2	-0.1	-0.1	-0.1	2.1	3.6	3.6	4.0	4.1	3.8	4.0	4.0	4.6	4.4	2.1	-0.1	-0.2	0.2	-0.1	-0.6	-0.7
BPA	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.8	3.1	3.1	3.3	3.4	3.0	3.2	2.9	3.5	3.4	1.7	-0.1	-0.2	0.2	-0.1	-0.5	-0.6
Tacoma Power	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.8	3.1	3.0	3.2	3.3	3.0	3.1	2.9	3.5	3.4	1.7	-0.1	-0.2	0.2	-0.1	-0.5	-0.6
PacifiCorp West	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.9	3.3	3.2	3.4	3.5	3.2	3.3	3.3	4.0	3.8	1.8	-0.1	-0.2	0.2	-0.1	-0.5	-0.7
Portland GE	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.8	3.2	3.2	3.4	3.4	3.1	3.3	3.1	3.8	3.6	1.7	-0.1	-0.2	0.2	-0.1	-0.5	-0.6
Puget Sound Energy	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.8	3.1	3.0	3.2	3.3	3.0	3.1	2.9	3.5	3.4	1.7	-0.1	-0.2	0.2	-0.1	-0.5	-0.6
Seattle City Light	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.8	3.1	3.0	3.2	3.3	3.0	3.1	2.9	3.5	3.4	1.7	-0.1	-0.2	0.2	-0.1	-0.5	-0.6
Powerex	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	1.7	3.0	3.0	3.2	3.3	2.9	3.0	2.8	3.4	3.3	1.6	-0.1	-0.1	0.2	-0.1	-0.5	-0.6
	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																							

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 Gates-Midway #2 500 kV line, Sylmar Transformer Banks nomogram, and California-Oregon Intertie (COI) nomograms.

Gates-Midway #2 500 kV line

The Gates-Midway #2 500 kV line (30056_GATES2_500_30060_MIDWAY_500_BR_2_1) contributed to south-to-north congestion. As a result, prices in Northern California and the Pacific Northwest were elevated relative to prices in Southern California and the Desert Southwest. This line typically experienced congestion during solar hours.

Sylmar Transformer Banks nomogram

The Sylmar Transformer Banks nomogram (8610_SylmarBNK_N-S_Import_NG) contributed to south-to-north congestion. As a result, prices in Northern California and the Pacific Northwest were elevated

relative to prices in Southern California and the Desert Southwest. LADWP was affected the most, with prices significantly reduced by congestion. This line was typically congested from hour-ending 2 through hour-ending 13.

California-Oregon Intertie (COI) nomogram

The California-Oregon Intertie (COI) nomograms (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.

For BHBA and GWA, which joined in May, congestion patterns were similar to other BAAs in the Intermountain West region.

Table 6.1 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 50 primary constraints (WEIM, April–June)⁵¹

BAA	Constraint	Average quarter impact (\$/MWh)																										
		California					Desert Southwest					Intermountain West					Pacific Northwest											
		PG&E	BANC	TIDC	SCE	SOGBE	LADWP	ADPS	EPE	NEVP	PJMW	SPP	TIPC	WALC	AVA	IFCO	NWMT	PACE	BHBA*	GWA*	AVRN	BCHA	BAT	PACW	PE	PSD	SCL	TPWR
CISO	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	.53	.70	.72	-.70	-.67	-.68	-.61	-.57	-.38	-.55	-.61	-.60	-.61	.48	.12	.35	-.15	-.09	.04	.49	.51	.52	.55	.54	.52	.52	.52
	8610_SylmarBKN_N-S_Import_NG	.31	.29	.31	.39	.01	-2.46	-.32	-.32	-.37	-.33	-.31	-.32	-.33	.12	-.01	.01	-.15	-.18	.00	.07	.14	.15	.17	.16	.15	.14	.15
	6110_COI_N-S	.30	.32	.31	.19	.17	.19	.15	.12	.07	.11	.14	.14	.14	-.38	-.23	-.32	-.11	-.20	-.54	-.29	-.39	-.39	-.40	-.40	-.39	-.39	-.39
	30005_ROUNDMT_500_30015_TABLEMT_500_BR_1_6	.26	.18	.26	.17	.16	.17	.14	.12	.07	.11	.14	.13	.14	-.34	-.17	-.29	-.06	-.15	-.23	-.30	-.35	-.35	-.36	-.36	-.35	-.35	-.35
	OMS19791504ML_BK80_NG	.11	-	-	.27	2.22	-	-.60	-.53	-	-.46	-.64	-.63	-.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	.10	.18	.14	-.19	-.18	-.18	-.16	-.15	-.11	-.14	-.16	-.16	-.16	.15	.06	.11	-.02	-.01	.11	.13	.16	.17	.17	.17	.16	.16	.16
	COI_600N-S	.15	.15	.15	.10	.10	.10	.08	.07	.05	.07	.08	.08	.08	-.17	-.09	-.14	-.02	-	-	-.20	-.18	-.18	-.19	-.19	-.18	-.18	-.18
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	.09	.15	.15	-.16	-.15	-.15	-.14	-.13	-.09	-.12	-.14	-.13	-.14	.11	.03	.08	-.04	.00	.01	.12	.12	.12	.12	.12	.12	.12	.12
	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	.13	.13	.13	-.15	-.14	-.15	-.15	-.14	-.09	-.13	-.15	-.15	-.15	.10	.02	.07	-.04	-.02	-	.14	.10	.10	.11	.11	.10	.10	.10
	SDGE_RT_Import_NG	-.05	-.07	-.07	-.05	1.91	-.05	-.03	-.04	-	-.04	-.03	-.03	-.03	-.05	-	.00	-	-	-	-.04	-.05	-.05	-.05	-.05	-.05	-.05	-.05
	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	.69	.00	.01	-.81	-.77	-.17	-.06	-.03	-	-.01	-.06	-.04	-.06	-	-	-	-	-	-	.01	-	-	.01	.00	-	-	-
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	.05	-	-	.12	1.04	-	-.18	-.16	-	-.14	-.19	-.18	-.18	-	-	-.02	-	-	-	-	-	-	-	-	-	-	-
	OMS_200801765NCRSTBK80_NG	.07	-	-	.16	1.19	-	-.10	-.09	-	-.08	-.10	-.10	-.10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MIGUEL_BKs_MKFLW_NG	.03	-	-	.08	.67	-	-.16	-.14	-	-.12	-.17	-.16	-.16	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7440_MetcalImport_Mossld-Metdfr	.30	.06	.15	-.11	-.10	-.10	-.10	-.09	-.08	-.09	-.10	-.10	-.10	-	.00	-	-.06	-	-	.03	.02	.02	.03	.03	.02	.02	.02
	30790_PANOCH_230_30900_GATES_230_BR_1_1	.06	.07	.12	-.08	-.08	-.06	-.05	-.04	.00	-.04	-.05	-.05	-.05	.01	-	-	-	-	-	.03	.02	.02	.03	.03	.02	.02	.02
	30797_LASAGUIL_230_30790_PANOCH_230_BR_1_1	.15	-	-	-.15	-.15	-.15	-.07	-.03	-	-.02	-.07	-.06	-.07	-	-	-	-	-	-	.02	-	-	.00	-	-	-	-
	30105_COTTNRD_230_30245_ROUNDMT_230_BR_2_1	.05	.09	.04	.02	.02	-	-	-	-	-	-	-	-	-.05	-.02	-.04	-	-	-.10	-.05	-.05	-.05	-.05	-.05	-.05	-.05	-.05
	30735_METCALF_230_30042_METCALF_500_XF_12	.16	-	.07	-.05	-.05	-.05	-.05	-.05	-.03	-.05	-.05	-.05	-.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-.04	-.04	-.04	.03	.03	.03	.03	.03	.02	.03	.03	.03	.03	-.02	.00	-.02	.01	.01	-.01	-.02	-.02	-.03	-.03	-.03	-.03	-.03	-.03
	OMS19234900_IV-SXOUTAGE_NG	.01	-	-	.03	.29	-	-.05	-.04	-.01	-.04	-.05	-.05	-.05	-	-	-.02	-	-	-	-	-	-	-	-	-	-	-
	30790_PANOCH_230_30900_GATES_230_BR_2_1	.06	.08	.10	-.07	-.07	-.05	-.03	-.02	-	-.01	-.03	-.03	-.03	.00	-	-	-	-	-	.01	.00	.00	.01	.00	.00	.00	.00
	30765_LOSBANOS_230_30790_PANOCH_230_BR_2_1	.02	.13	.30	-.06	-.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	.01	-	-	.04	.44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6110_SOLIO_NG	.04	.05	.02	.02	.02	.01	.01	.01	.01	.01	.01	.01	.01	-.02	-.01	-.02	-	-	-	-.01	-.02	-.02	-.02	-.02	-.02	-.02	-.02
	22208_ELCAJON_69.0_22408_LOSCOSCHS_69.0_BR_1_1	-	-	-	.42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7820_TL2305_OVERLOAD_NG	.01	.00	.00	.01	.19	.00	-.02	-.02	.00	-.02	-.03	-.03	-.02	-	.00	-	-.01	-.01	-	.00	-	-	-	-	-	-	-
	7690_CONTRL-INYOKN_EXP_NG	-	-	-	-.35	-.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P	.01	.01	.01	.01	.01	.01	-.03	-.03	-	-.02	-.03	-.03	-.02	.01	-	.00	-.01	.00	-	.01	.01	.01	.01	.01	.01	.01	.01
	OMSIV-MLOUTAGE_NG	.01	-	-	.02	.15	-	-.02	-.02	.00	-.01	-.02	-.02	-.02	-	-	.00	.00	-	-	-	-	-	-	-	-	-	-
	7430_CPE_NG	.03	.14	.00	-.05	-.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6410_CPT_NG	.01	.01	.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	-.01	.01	.00	.01	.00	.00	.00	.01	.01	.01	.01	.01	.01	.01	.01
	32218_DRUM_115_32220_DTCHFL1_115_BR_1_1	-.05	-.05	-.03	.00	.00	-	-	-	-.11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	30765_LOSBANOS_230_38625_SNLSPPT_230_BR_1_1	.01	.05	.10	-.02	-.02	.00	-	-	-	-	-	-	-	-	-	-	-	-	-	.01	.00	.00	.00	.00	.00	.00	.00
	22136_CLAIRMTNT_69.0_22140_CLAIRMTNT_69.0_BR_1_1	-	-	-	.20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	36850_KIFER_115_35615_FWC_115_BR_1_1	.05	-	-	-.05	-.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	35618_SNUSEA_115_35616_SNUSEB_115_BR_1_1	.06	-	-	-.04	-.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	32218_DRUM_115_32244_BRNSWKT2_115_BR_2_1	.04	.00	-	-	-	-	-	-	-.10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	30765_LOSBANOS_230_30766_PDRFLT_230_BR_1_1	-.03	.00	.04	-.01	-.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	24084_UTHEIPE_230_24091_MESACAL_230_BR_1_1	-.01	-.01	-.01	.03	.01	.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-.01	-	.00	-	-	-	-	-
	32220_DTCHFL1_115_32224_CHCGOPK_115_BR_1_1	-.02	-.02	-.01	-	-	-	-	-	.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	35352_WHISMAN_115_35356_MNTAVSA_115_BR_1_1	.04	-	-	-.03	-.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	OMS_19695948_DEV_RDB_AUS	-	.00	.00	-	-	.01	.00	.00	.00	.00	.00	.00	.00	.00	-	.00	.00	.00	.00	.00	.01	.01	.01	.01	.01	.01	.01
	22773_BAYBLVD_69.0_22352_IMPRLBCH_69.0_BR_1_1	-	-	-	.08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	OMS_19682561_Cielo_Azul	-	-.01	-.01	-	-	-.01	.00	.00	.00	.00	.00	.00	.00	.00	-	.01	-	-	-	-.01	.00	.00	.00	.00	.00	.00	.00
	32214_RIDOSO_115_32244_BRNSWKT2_115_BR_2_1	-.01	-.01	-	-	-	-	-	-	.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	33020_MORAGA_115_32780_CLAIRMTNT_115_BR_2_1	.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1_1	-	-	-	.00	.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	OMS_18894306_VACA-TSL	.03	-	-	-.01	-.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	OMS19220258IV-MLOUTAGE_NG	.00	-	-	.00	.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other	-.17	-.12	-.16	-.65	-1.86	-.21	-.42	.18	.01	-.62	.66	.00	-.37	-.03	.78	.33	1.05	1.14	.79	-.14	-1.94	.12	-.02	1.34	.30	1.49	.79
	Total	3.65	2.46	2.81	-2.11	4.92	-3.96	-2.95	-2.12	-.86	-2.72	-1.94	-2.54	-2.92	-.07	.48	.13	.37	.48	.07	-.02	-1.92	0.16	.08	1.40	0.33	1.51	1.51

⁵¹ 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.

6.3 Congestion rent and loss surpluses

Figure 6.11 shows that in the second quarter of 2026, EDAM congestion rent and loss surpluses were \$124 million and \$20.5 million, respectively.⁵² The congestion rent surplus was down \$5.6 million, or 4 percent, compared to the second quarter of 2025. The loss surplus was down about \$8 million compared to Q2 2025.

Total EDAM congestion rent was concentrated in CAISO, which accounted for about \$122 million, compared with \$1.9 million in PACE and about \$0.03 million in PACW.⁵³ The congestion revenue allocation (CRA) credit allocated to non-CAISO BAAs totaled \$0.2 million and are discussed further in the next section.

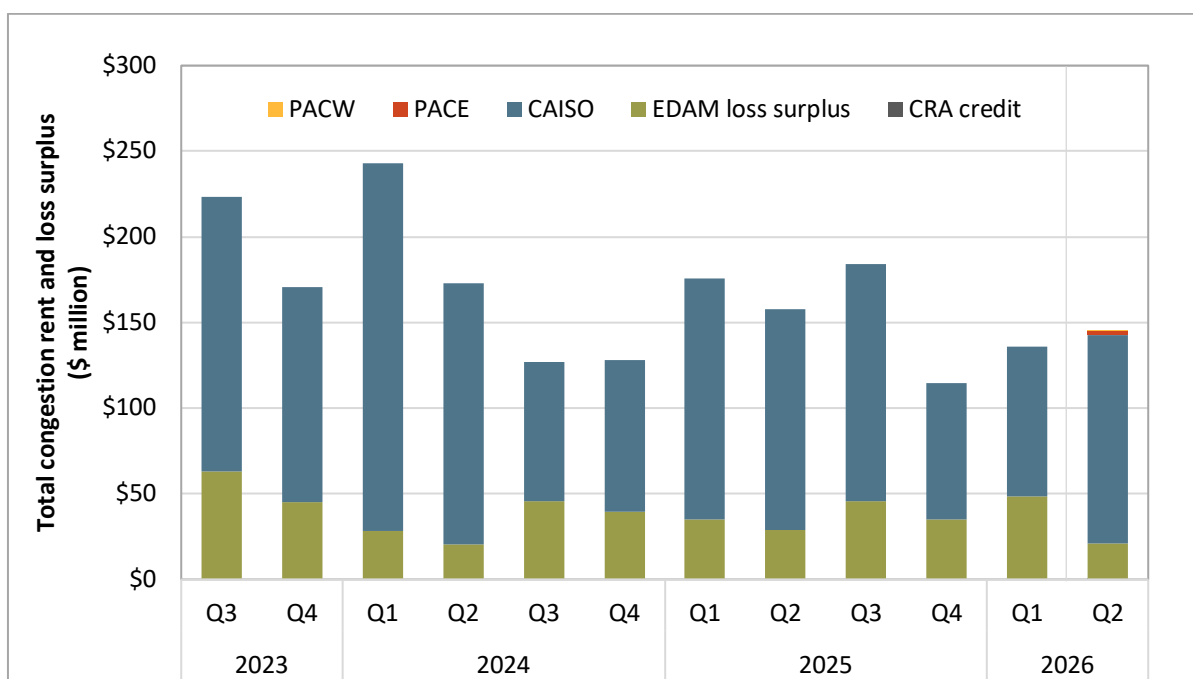
In the day-ahead market, hourly congestion rent collected on a constraint is roughly equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day.

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 BAA-specific marginal energy cost (MEC) and the marginal loss factor, which measures the sensitivity of total system losses to an incremental injection at that location.⁵⁴ Changes in the total loss surplus can be driven by changes in BAA-specific MEC 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.

⁵² 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.

⁵³ These values reflect each balancing area's day-ahead congestion rent net of ETC, TOR, and OATT credits, including CRA-related deductions. DMM separately calculate total EDAM CRA credit received by non-CAISO balancing areas, shown in dark gray in Figure 6.11.

⁵⁴ See CAISO Tariff, Appendix C, Section A.4, Marginal Losses Component Calculation:
<https://www.caiso.com/library/current-tariff-appendices-a-z>

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

6.4 Extended day-ahead market congestion revenue allocation

Under the EDAM design initially approved by the Federal Energy Regulatory Commission (FERC), the ISO would allocate congestion revenue to the balancing authority area (BAA) where the binding transmission constraint causing congestion is located. After stakeholders raised concerns that this design would limit EDAM BAAs' ability to hedge congestion costs by exercising transmission rights, FERC approved an amended design that would return congestion revenues resulting from binding external constraints to BAAs with eligible self-scheduled transmission rights. Eligible transmission rights, also referred to as open access transmission tariff (OATT) rights, include point-to-point (PTP) service and network integration transmission service (NITS). The CAISO balancing area does not offer PTP nor NITS, so this congestion revenue allocation (CRA) credit is currently only settled with PacifiCorp areas.

Figure 6.12 compares DMM's estimate of each PacifiCorp balancing area's CRA credit with all other congestion revenue paid to entities within the balancing area. In May 2026, DMM estimates that CRA credits represented 11 percent of congestion revenues for PACE entities and nearly 100 percent of congestion revenues for PACW entities. CRA credits were negative for both PacifiCorp areas in June 2026. Figure 6.12 also includes congestion revenue related to OATT self-schedules where, due to missing data, the location of the binding transmission constraint could not be determined. This "unknown constraint OATT revenue" category represented less than one percent of congestion revenue in the second quarter.

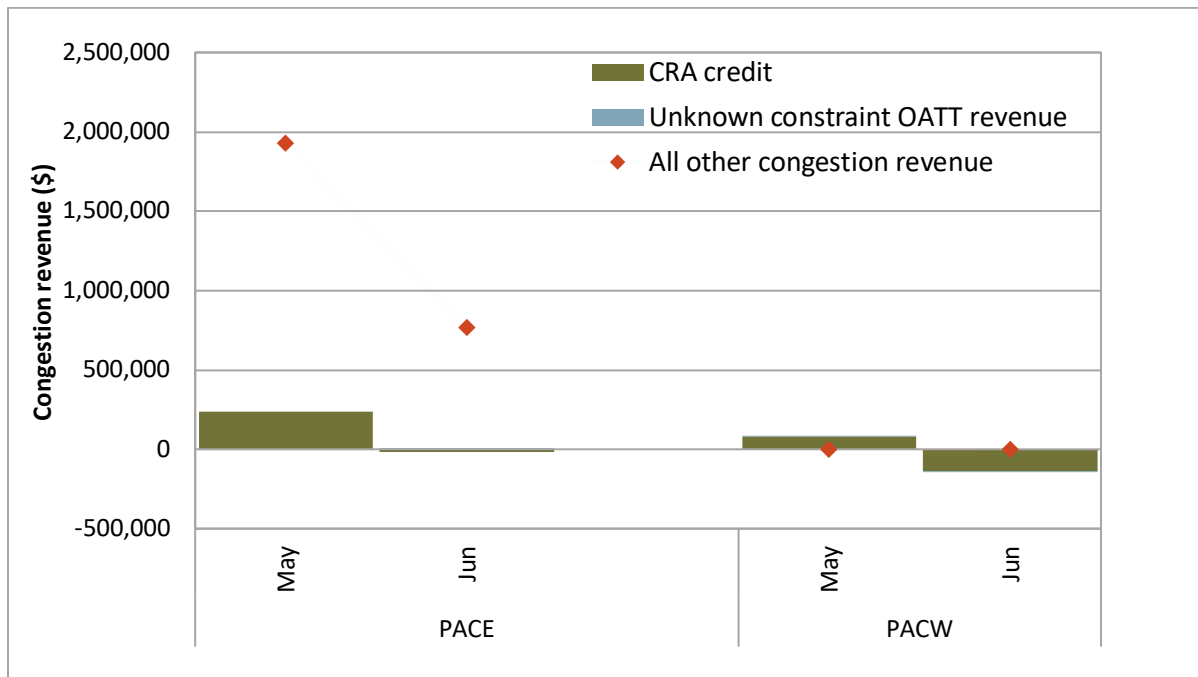
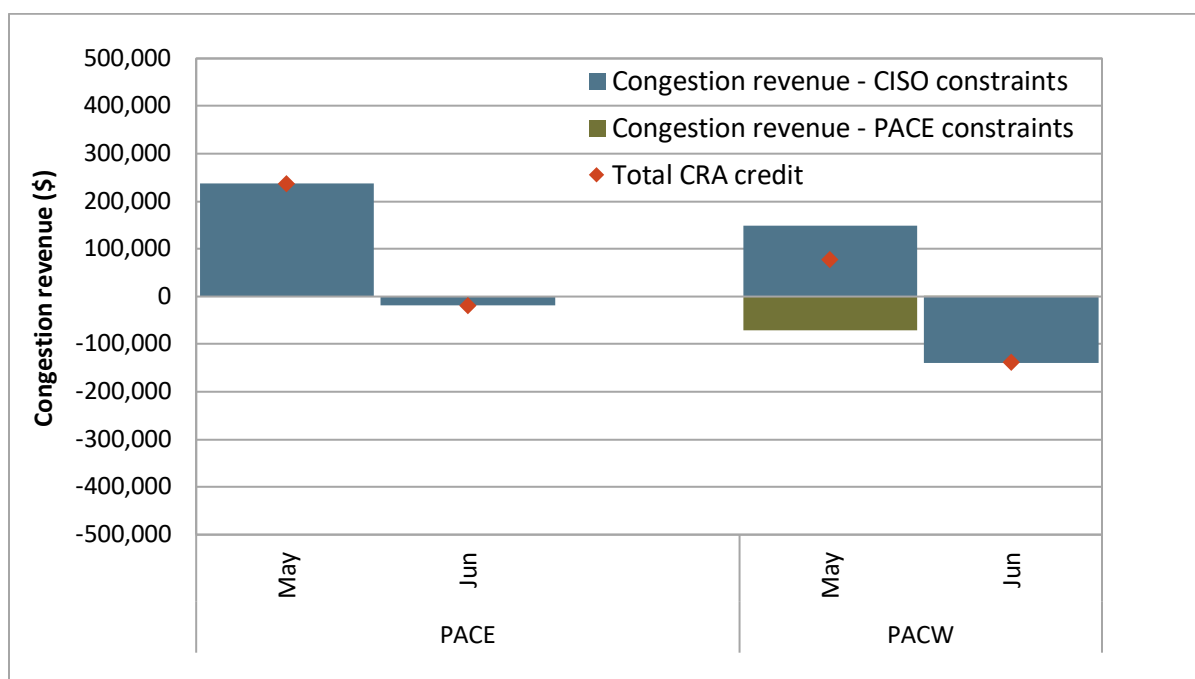
Figure 6.12 EDAM congestion revenue allocation credit and total congestion revenue

Figure 6.13 breaks out the CRA credit paid (or charged in the case of negative values) to a balancing area by which other balancing areas' binding constraints resulted in the credit. DMM estimates the CRA credit at approximately \$390,000 for PacifiCorp entities in May and -\$160,000 in June. Initially, an error in the ISO's settlements process resulted in CRA credit payments of \$1.34 million in May and \$1.33 million in June. The ISO expects these payments to decrease at the 70-business-day resettlement, resulting in figures that are closer to DMM's estimates.

Figure 6.13 EDAM congestion revenue allocation credit by balancing area

6.5 Congestion on interties

Total intertie congestion rent in the day-ahead market was \$9.8 million, up from \$6.7 million in the second quarter of 2025. The major driver was increased import congestion rent on Malin, NOB, IPP Utah, and IPP DC Adelanto by \$4.8 million in this quarter compared to the same quarter of 2025. The increase was partly offset by lower congestion on Palo Verde and Mona. No congestion rent was collected on PACE intertie constraints. Congestion rent was collected on PACW's COI constraint on June 2 and June 3, but the total was less than \$.01 million.

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 EDAM side of the intertie and the lower price of import bids outside of the EDAM area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO balancing area at points corresponding to interties.

Figure 6.14 shows total intertie congestion charges in the day-ahead market from the second quarter of 2025 to the second quarter of 2026. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 6.15 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 second quarter of 2025, the total intertie congestion rent increased from \$6.7 million to \$9.8 million.

- The majority of congestion occurred at Malin and NOB. These two interties accounted for 71 percent of total congestion rent this quarter.
- A notable change in congestion included a significant increase in export-direction congestion on IPP DC Adelanto. This intertie was congested in 21 percent of hours and accounted for \$1.4 million in congestion rent this quarter, up significantly from \$0.03 million in the same quarter last year. Congestion began in May with the EDAM launch and persisted through the remainder of the quarter.

Figure 6.14 Day-ahead congestion charges on major interties

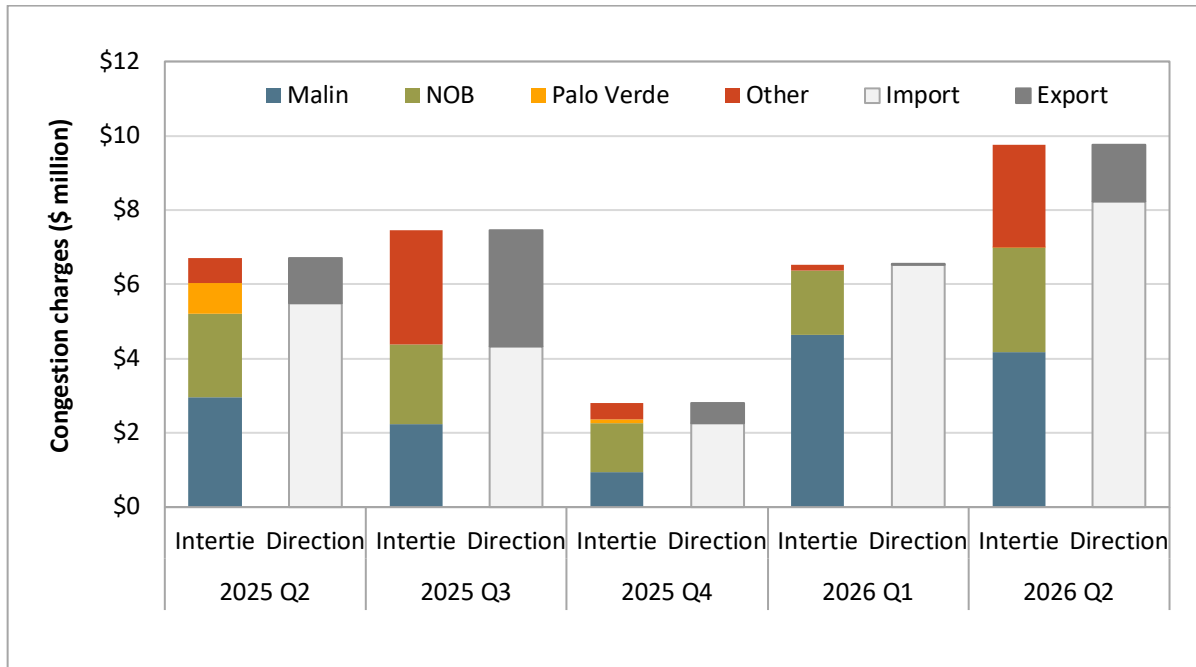


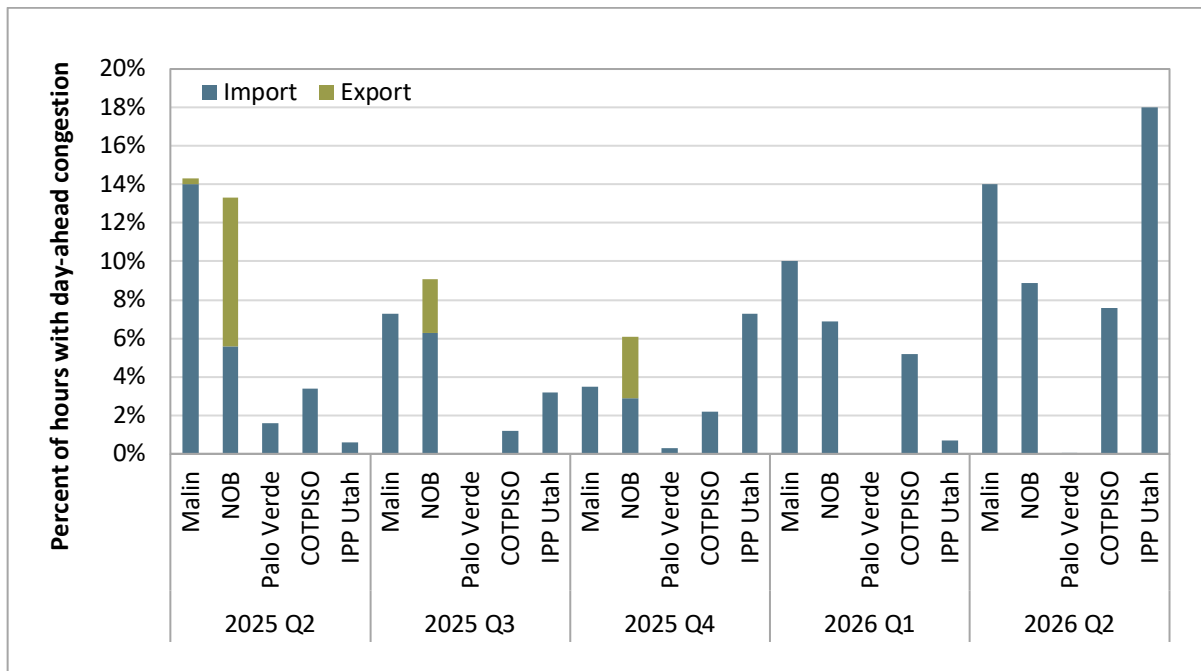
Figure 6.15 Frequency of congestion on major interties in the day-ahead market

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

Intertie	Direction*	Congestion charges (\$ thousand)					Frequency of congestion				
		2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2
Northwest											
Malin	I	\$2,904	\$2,223	\$949	\$4,650	\$4,178	14.0%	7.3%	3.5%	10.0%	14.0%
	E	\$53					0.3%				
NOB	I	\$1,600	\$1,983	\$781	\$1,725	\$2,802	5.6%	6.3%	2.9%	6.9%	8.9%
	E	\$661	\$180	\$530			7.7%	2.8%	3.2%		
COTPISO	I	\$29	\$11	\$92	\$122	\$311	3.4%	1.2%	2.2%	5.2%	7.6%
	E										
Cascade	I										
	E										
Summit	I	\$23	\$11				0.5%	.1%			
	E										
Southwest											
Palo Verde	I	\$828		\$92		\$12	1.6%		0.3%		.0%
	E										
IPP Utah	I	\$13	\$103	\$354	\$33	\$915	0.6%	3.2%	7.3%	0.7%	18.0%
	E										
IPP DC Adelanto	I					\$9					0.3%
	E	\$33	\$92			\$1,420	0.7%	0.8%			21.0%
Mona	I										
	E	\$238	\$2,856			\$29	2.2%	3.7%			1.1%
Mead	I										
	E	\$155				\$2	0.2%				0.1%
Merchant	I										
	E										
Silver Peak	I										
	E	\$11	\$1		\$0	\$0	1.3%	0.5%		0.3%	0.0%
Mercury	I										
	E										
Other	I	\$104				\$0					
	E	\$50				\$87					
Import total (I)		\$5,501	\$4,332	\$2,268	\$6,530	\$8,226					
Export total (E)		\$1,200	\$3,128	\$530	\$0	\$1,538					
Total		\$6,701	\$7,460	\$2,798	\$6,531	\$9,764					

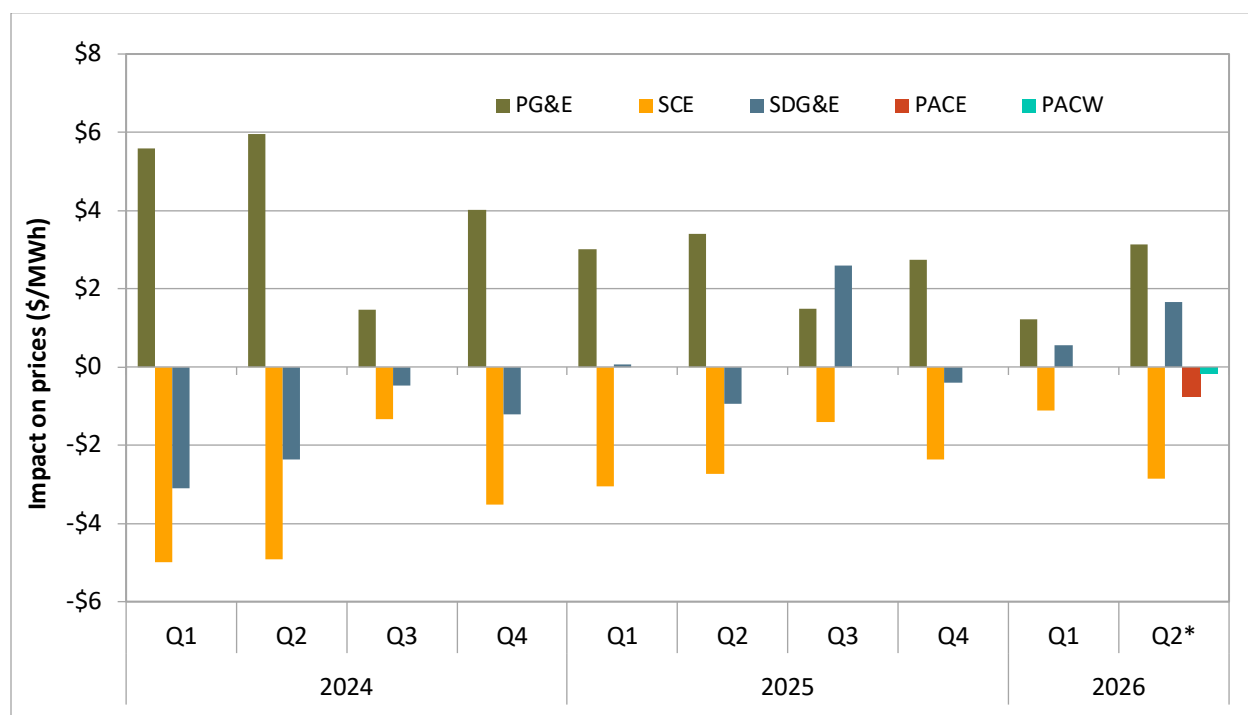
* I: import, E: export

6.6 Internal congestion in the day-ahead market

Figure 6.16 shows the overall impact of congestion on day-ahead market prices in each load area from Q1 2024 to Q2 2026. Figure 6.17 shows the frequency of congestion. Highlights for this quarter include:

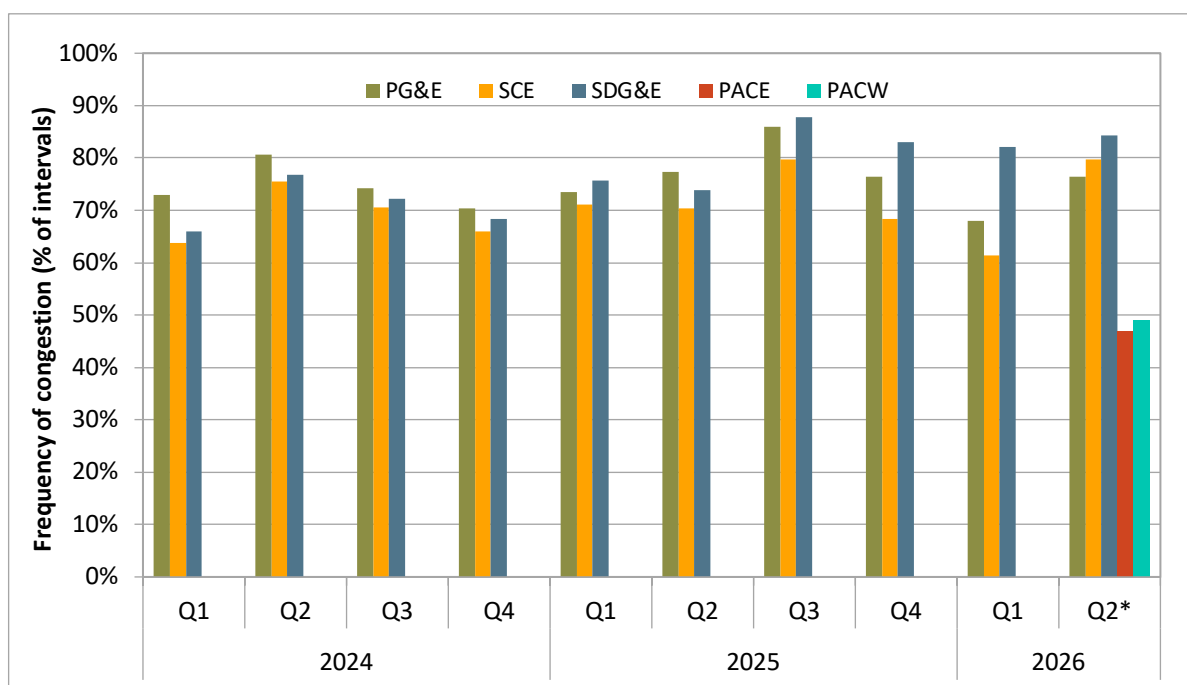
- Prices in PG&E and SDG&E were elevated by \$3.1/MWh and \$1.7/MWh, respectively, while prices in SCE, PACE, and PACW were reduced by \$2.9/MWh, \$0.8/MWh, and \$0.2/MWh, respectively, due to internal congestion.⁵⁵
- The percentage of hours in which congestion impacted DLAP prices remained high this quarter, with SDG&E experiencing congestion during 84 percent of hours on average. For PACE and PACW, the congestion frequency averaged about 48 percent in May and June.

Figure 6.16 Overall impact of congestion on price separation in the day-ahead market⁵⁶



⁵⁵ 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.

⁵⁶ Data for PACE and PACW reflect May and June after the EDAM launch, while the remaining data cover the full second quarter.

Figure 6.17 Hours with congestion impacting day-ahead prices by load area (>\$0.05/MWh)⁵⁷

Impact of congestion from individual constraints

Table 6.3 breaks down the congestion effect on price separation during the quarter by constraint.⁵⁸ 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, Metcalf 230/500 kV transformer, and SDG&E import nomogram.

Moss Landing-Las Aguilas #1 230 kV

The Moss Landing-Las Aguilas #1 230 kV (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) line bound in 30 percent of hours over the quarter. For the quarter, on average, prices in PG&E were pushed upward, while prices on the SCE and SDG&E were pushed downward. No price impact was observed in

⁵⁷ Data for PACE and PACW reflect May and June after the EDAM launch, while the remaining data cover the full second quarter.

⁵⁸ 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”.

PACE and PACW. The constraints generally bound during solar hours, and were congested in all three months of the quarter.

Metcalfe 230/500 kV transformer

The Metcalfe 230/500 #13 transformer (30735_METCALF_230_30042_METCALF_500_XF_13) bound in 14 percent of hours over the quarter. For the quarter, on average, prices in PG&E were elevated, while prices in the rest of EDAM were reduced due to this constraint. This transmission line was generally binding during the evening peak hours.

SDG&E import nomogram

The SDG&E import nomogram (SDGE_RT_Import_NG) bound in 5 percent of hours over the quarter. For the quarter, on average, prices in SDG&E were raised, while prices in the rest of EDAM were reduced due to this constraint. This transmission line was generally binding across all hours and was mainly congested in May during this quarter.

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 constraints⁵⁹

BAA	Constraint	Frequency	Average quarter impact (\$/MWh)				
			PG&E	SCE	SDG&E	PACE*	PACW*
CISO	30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	30.1%	.9	-.71	-.67	.	.
	30735_METCALF_230_30042_METCALF_500_XF_13	14.3%	.57	-.28	-.27	-.26	-.23
	SDGE_RT_Import_NG	5.3%	-.08	-.08	1.1	-.11	-.06
	30005_ROUNDMT_500_30015_TABLEMT_500_BR_1_6	7.1%	.13	.05	.04	-.31	-.68
	OMS_20219806_SDGE_RT_Import_NG	2.1%	-.03	-.04	.5	-.05	-.03
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	7.0%	.14	-.13	-.12	-.01	.21
	30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2	8.3%	.12	-.11	-.10	-.02	.12
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	5.5%	.08	-.07	-.07	-.02	.11
	30790_PANOCHE_230_30900_GATES_230_BR_1_1	11.4%	.1	-.09	-.08	.	.04
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	12.8%	.05	-.07	-.07	.	.11
	30797_LASAGUIL_230_30790_PANOCHE_230_BR_1_1	6.8%	.11	-.08	-.08	.	.
	22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	32.1%	.	.	.25	.	.
	30056_GATES2_500_30060_MIDWAY_500_BR_2_3	0.8%	.05	-.04	-.04	-.01	.07
	7820_TL230S_OVERLOAD_NG	8.6%	-.01	.	.13	-.02	-.01
	30040_TESLA_500_30050_LOSBANOS_500_BR_1_1	0.8%	.03	-.03	-.03	.	.06
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_3	1.7%	.03	-.03	-.03	.	.05
	35618_SNJSEA_115_35616_SNJOSEB_115_BR_1_1	11.5%	.06	-.03	-.03	.	.
	8610_SylmarBNK_N-S_Import_NG	4.9%	.01	.02	-.02	-.07	.
	6410_CP10_NG	1.0%	.03	-.02	-.02	.0	.03
	22468_MIGUEL_500_22472_MIGUELMP_1.0_XF_80	1.8%	.	.	.07	-.02	.
	OMS_18894306_VACA-TSL	5.0%	.03	-.01	-.01	-.01	-.02
	7430_CP6_NG	8.1%	.02	-.03	-.03	.	.
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P	1.2%	.	.	.06	-.02	.0
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	2.7%	.02	-.02	-.01	.0	.02
	24801_DEVERS_500_24804_DEVERS_230_XF_1_P	1.5%	.01	.01	-.01	-.05	.
	Other		.76	-1.07	1.2	.21	.01
Total			3.13	-2.86	1.66	-.77	-.2

⁵⁹ Data for PACE and PACW reflect May and June after the EDAM launch, while the remaining data cover the full second quarter.

7 Resource sufficiency evaluation

Beginning on May 1, 2026, all extended day-ahead market (EDAM) participants are subject to an EDAM Resource sufficiency evaluation (EDAM RSE). Before engaging in economic transfers with other EDAM balancing areas in the day-ahead market, the EDAM RSE tests if each EDAM-participating balancing area has procured sufficient supply and reserves to meet their own forecasted demand, ancillary services, and uncertainty. The EDAM RSE considers whether a unit commitment optimization problem can be solved without relaxing (1) the power balance constraint, (2) the imbalance reserve up/down procurement constraints, or (3) the ancillary services procurement constraints. Each condition is assessed independently, and an entity passes the test only if all three can be satisfied without relaxation. The evaluation is performed hourly for both upward and downward directions.

Any balancing area that fails any test has the opportunity to cure the insufficiency in the integrated forward market with appropriate surcharges assessed on the procurement, and if the insufficiency is appropriately cured, the balancing area will remain on track to be in the EDAM pool for the real-time resource sufficiency evaluation on the trade day. If the balancing area fails to cure the insufficiency, the balancing area will be ejected from, or evaluated separately from, the EDAM pool in real-time.

In the real-time, as part of the WEIM design, each 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, inertia, 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.⁶⁰ If an area fails either test in the downward direction, transfers out of that area cannot be increased.

7.1 Frequency of EDAM resource sufficiency evaluation failures

Day-ahead or EDAM resource sufficiency evaluation failures occurred on two days in the second quarter. On May 4, PacifiCorp West failed the imbalance reserve test in the upward direction in eight hours and

⁶⁰ 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.

in the downward direction during one hour. On June 17, PacifiCorp East failed the imbalance reserve test in the downward direction during one hour due to a software issue that the ISO subsequently fixed. None of these failures resulted in exclusion from the EDAM pool. Table 7.1 provides a full summary of EDAM resource sufficiency evaluation failure rates.

Table 7.1 Frequency of EDAM resource sufficiency evaluation failures (May–June 2026)

	Imbalance Reserve Up	Imbalance Reserve Down	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve
CAISO	0%	0%	0%	0%	0%	0%
PacifiCorp East	.1%	0%	0%	0%	0%	0%
PacifiCorp West	.5%	.1%	0%	0%	0%	0%

7.2 Exclusion from the EDAM pool in real-time resource sufficiency evaluations

On two occasions, EDAM-participating balancing areas were excluded from the EDAM pool for real-time resource sufficiency evaluations. On May 12, in hour-ending 19, PacifiCorp East was evaluated separately in the real-time upward sufficiency test, and on June 15, in hour-ending 10, PacifiCorp West was similarly evaluated separately in the real-time downward sufficiency test. This is potentially because the balancing areas were found to not adequately comply with e-tagging requirements; specifically, EDAM-participating balancing areas are required to tag, by the start of the short-term unit commitment (STUC) run, all imports used to pass the EDAM resource sufficiency evaluation.

7.3 Frequency of real-time 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 in real-time, while Figure 7.3 and Figure 7.4 provide the same information for the downward direction.⁶¹ The dash indicates the area did not fail the test during the month. A gray-shaded cell indicates that the given test was not applicable to the WEIM area during that month. For example, both Power Watch and Black Hills Energy joined the WEIM in May 2026. Accordingly, all months preceding their participation are shown as gray-shaded cells for each test in Figures 7.1-7.4.

Each row in Figures 7.1-7.4 represents a WEIM area, and areas are grouped by geographical region. The first four rows represent EDAM-participating balancing areas. As part of the market design, beginning on May 1, 2026, the EDAM balancing areas are jointly evaluated in the real-time resource sufficiency evaluation. EDAM balancing areas may be excluded from this “EDAM pool” if they fail the day-ahead resource sufficiency evaluation or if an EDAM area is found to not adequately comply with e-tagging protocols. For this reason, Figures 7.1-7.4 include separate rows for the EDAM pool and for each EDAM-participating balancing area. Gray cells indicate that an EDAM-participating balancing area was evaluated as part of the EDAM pool and therefore was not tested separately in the real-time resource sufficiency evaluations. However, in Q2 2026, there were two instances when an EDAM-participating balancing area was ejected from the EDAM pool and evaluated separately: PacifiCorp East on May 12, 2026, for the real-time upward flexibility test, and PacifiCorp West on June 15, 2026, for the real-time

⁶¹ Results exclude known invalid test failures. These can occur because of a market disruption, software defect, or other error.

downward flexibility test. In both instances, the balancing area passed the test, and the corresponding month is denoted by a blue-shaded cell and a dashed line.

EDAM balancing areas are no longer subject to the real-time capacity test, either jointly, as a pool, or individually, when excluded from the pool, and so the EDAM pool is not represented in the capacity test in Figure 7.1 and Figure 7.3.⁶²

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

- WAPA Desert Southwest failed the flexibility test in the upward direction in 1.4 percent of intervals. WAPA Desert Southwest failed all other tests in all directions in under one percent of intervals.
- Power Watch failed the flexibility test in the upward direction in 3.4 percent of intervals. Many of these failures occurred close to the date of Power Watch's entry into the WEIM system on May 6, 2026. Power Watch failed all other tests in all directions in under one percent of intervals.
- El Paso Electric failed the flexibility test in the downward direction in 1.2 percent of intervals. El Paso Electric failed all other tests in all directions in under one percent of intervals.
- All other balancing areas failed the capacity and flexibility tests in less than one percent of intervals.

⁶² *Business Requirements Specification, Extended Day-Ahead Market*, California ISO, version dated March 26, 2026, p 128: <https://www.caiso.com/documents/business-requirements-specification-extended-day-ahead-market.pdf>. Feasibility or capacity real-time tests will no longer run for EDAM-participating balancing areas, either jointly, in the pool, or individually, when excluded from the pool. Further, the real-time balancing test will no longer apply to *any* balancing area in the WEIM system.

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

CAISO	—	—	—	—	—	—	—	—	—	—	—	—	—		
PacifiCorp East	—	—	—	—	—	.0	.0	—	—	—	—	—	—		
Pacificorp West	.0	.1	.0	.1	.1	.7	.4	.2	.7	.1	.4	.2	.5		
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	—	—	—	—	—	—	.1	—	—	—	—	—	—	—	—
LADWP	—	.1	—	—	—	—	—	—	—	—	—	.1	.0	—	—
NV Energy	—	—	—	.0	.1	—	—	—	—	—	—	—	—	—	.7
Arizona PS	—	—	—	—	—	—	—	—	—	—	—	—	.1	—	—
Tucson Electric	—	—	—	—	.0	—	—	—	—	—	—	.2	—	.1	—
Salt River Project	.7	—	.3	—	.2	.0	.1	.0	—	—	—	.1	—	—	—
PSC New Mexico	.1	—	—	—	—	—	.1	—	.1	—	—	—	—	—	—
WAPA - Desert SW	.1	.1	.1	.0	.1	1.1	—	—	—	.1	.1	1.8	2.4	.1	.0
El Paso Electric	.3	—	.2	.1	.0	—	.1	.1	—	—	.0	.1	.1	1.1	.1
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PowerWatch														.7	—
Black Hills Energy														.1	—
NorthWestern	—	—	—	—	—	.2	.0	—	.1	—	—	—	—	—	—
Avista Utilities	—	.1	—	—	—	.1	—	—	—	—	—	—	—	.1	—
Avangrid	—	—	—	—	.3	—	—	—	—	—	.0	—	—	—	—
BPA	—	—	—	—	.0	—	—	—	—	—	—	—	—	—	.1
Tacoma Power	—	.1	—	.2	—	—	—	—	—	—	—	—	—	—	.1
Portland GE	—	—	.1	—	.1	—	—	—	—	—	.1	.1	—	—	.0
Puget Sound Energy	.1	.2	—	.1	.0	—	.1	—	—	—	.2	—	—	—	—
Seattle City Light	—	—	.1	.0	—	—	.0	—	.2	.1	.1	.2	.3	.2	.1
Powerex	—	—	—	—	—	.0	—	—	—	—	—	.1	—	—	—
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
	2025									2026					

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

EDAM Pool														—	—
CAISO	—	—	—	—	—	—	—	—	—	—	—	—	—		
PacifiCorp East	.0	—	—	.0	.2	.2	.4	.1	.1	.0	.1	.1	.1		
Pacificorp West	.1	.2	.0	—	.0	.5	.2	.3	.5	.5	.1	.3	.0		
BANC	—	.0	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	—	—	—	—	—	.0	—	—	—	—	—	—	—	—	—
LADWP	.1	.0	—	—	.0	—	—	—	—	—	—	—	—	—	—
NV Energy	.0	.0	—	—	.1	.0	—	—	—	.1	—	—	—	—	1.1
Arizona PS	—	—	—	—	—	—	—	.0	—	—	.1	—	.1	—	—
Tucson Electric	.0	.2	.0	—	—	.0	.1	.2	.1	—	.3	.7	.1	.1	.1
Salt River Project	1.8	.0	.6	—	.2	.3	.0	.1	—	—	—	.2	.1	—	—
PSC New Mexico	.8	—	.0	.1	—	.0	.7	.3	.4	.3	.1	.2	.2	.0	—
WAPA - Desert SW	.1	.2	—	.0	—	—	—	—	—	.0	1.7	2.3	3.5	.6	.1
El Paso Electric	.2	.3	.2	.4	.1	.0	.6	1.2	.6	.4	1.0	.8	.7	1.6	.5
Idaho Power	2.9	.6	.0	—	.1	—	.1	—	—	—	.0	—	.3	.2	—
PowerWatch														4.4	2.4
Black Hills Energy														.3	—
NorthWestern	—	—	.0	—	—	.0	.0	—	—	—	—	—	—	.1	—
Avista Utilities	—	.3	—	—	—	—	—	—	—	—	—	.2	.1	.4	.0
Avangrid	.1	.0	—	.2	—	.0	—	.1	.1	.1	.4	.2	.1	.1	.1
BPA	.1	.0	.0	—	—	—	.1	.1	.3	.3	.2	.4	.3	.1	.1
Tacoma Power	.0	—	—	—	—	—	—	.1	.0	—	—	—	—	.1	.2
Portland GE	.1	—	.0	—	—	—	—	.0	.1	—	.1	.1	—	.0	—
Puget Sound Energy	.7	1.0	.0	.1	.0	.1	—	—	—	.0	.1	.1	.0	.1	—
Seattle City Light	—	—	—	—	—	—	—	—	.1	—	.0	.1	.2	.3	—
Powerex	—	—	—	—	—	.0	—	—	.0	—	.1	.3	.1	.0	.0
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
	2025									2026					

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

CAISO	—	—	—	—	—	—	—	—	—	—	—	—	—		
PacifiCorp East	—	—	—	—	.1	—	—	—	—	—	—	—	—		
Pacificorp West	.1	.1	.3	.0	—	.2	—	.6	.0	.2	.1	—	—		
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	—	—	—	—	—	—	—	—	—	—	—	—	—	.1	.0
LADWP	—	.0	—	—	—	.1	—	—	—	—	—	—	—	—	—
NV Energy	—	—	—	—	—	—	—	—	—	—	—	—	—	—	.4
Arizona PS	—	—	—	—	—	—	—	—	—	—	—	—	.1	—	—
Tucson Electric	—	—	—	—	—	—	—	—	—	—	—	—	—	.0	—
Salt River Project	—	—	.1	—	—	—	—	—	—	—	—	—	—	—	—
PSC New Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
WAPA - Desert SW	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric	.2	.0	.2	.3	.1	.2	.2	.4	.3	.0	.1	.1	.1	.4	.5
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PowerWatch														.5	.3
Black Hills Energy														.2	—
NorthWestern	.0	—	—	—	—	.1	—	—	—	—	—	.4	.1	.3	—
Avista Utilities	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Avangrid	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	—	—	—	—	—	—	—	—	—	—	—	—	.1	—
Tacoma Power	—	—	—	.1	—	—	—	—	—	—	—	—	—	—	.0
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound Energy	—	—	—	—	—	—	—	—	—	—	—	.3	—	—	—
Seattle City Light	—	—	—	—	—	—	—	—	—	—	—	.0	—	.2	—
Powerex	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
	2025									2026					

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

EDAM Pool														—	—
CAISO	—	—	—	—	—	—	—	—	—	—	—	—	—		
PacifiCorp East	—	.0	—	.0	.4	—	—	—	—	—	—	—	.0		
PacifiCorp West	.0	.0	.0	.1	.1	.0	—	.5	—	.1	—	—	.2		—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Turlock ID	.1	.1	—	.3	.1	—	—	—	.0	—	—	.2	—	.2	.1
LADWP	—	—	—	—	—	—	.2	.0	.1	.1	.4	—	—	.1	—
NV Energy	—	—	—	—	—	—	—	—	—	—	—	—	—	—	1.1
Arizona PS	.1	.0	.0	—	—	—	.1	.0	.1	.0	—	—	.2	—	—
Tucson Electric	—	—	.1	—	—	—	—	—	—	.2	—	.2	.0	.1	—
Salt River Project	—	—	.1	—	.0	—	—	.0	.0	.3	—	—	—	—	—
PSC New Mexico	—	—	—	.0	—	—	—	—	—	—	—	—	—	—	—
WAPA - Desert SW	—	—	—	—	—	—	—	.7	1.5	.3	.1	—	.0	—	—
El Paso Electric	.6	.5	.0	—	—	.0	.8	1.0	2.2	1.0	1.1	.6	.7	2.5	.6
Idaho Power	—	.1	—	—	—	—	.0	—	—	—	.6	.2	.2	—	.9
PowerWatch														1.1	—
Black Hills Energy														.3	—
NorthWestern	—	.1	.0	.0	—	.1	.2	—	.8	.1	—	.8	.0	.4	.6
Avista Utilities	—	—	—	—	.1	—	—	—	—	—	—	—	—	—	—
Avangrid	—	—	.1	—	—	—	—	—	—	.2	—	.0	—	.6	—
BPA	—	.1	—	—	—	.3	.1	—	.2	.0	.0	—	.1	.4	—
Tacoma Power	—	.1	—	.3	—	—	—	.1	—	—	—	—	—	.0	.1
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound Energy	—	—	—	—	—	—	—	—	—	—	—	.1	—	—	—
Seattle City Light	.0	—	.1	.3	—	—	.1	.0	—	—	—	.0	.1	.2	—
Powerex	.0	—	—	—	—	—	—	—	—	.1	—	.1	—	—	.0
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
	2025									2026					

7.4 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 in real-time. 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.⁶³

⁶³ 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>

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.⁶⁴ 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 7.2 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the quarter. Eleven balancing areas were opted in to the program on at least one day during this period: Avangrid, the Balancing Area of Northern California, Black Hills Energy, California ISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, PSC of New Mexico, and WAPA Desert Southwest. Avangrid, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, and WAPA Desert Southwest were opted in to AET on all days during the quarter.

Table 7.2 Assistance energy transfer opt-in designations by balancing area (April–June 2026)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Apr. 1 - Jun. 30	91
Balancing Area of Northern California	Jun. 1 - Jun. 30	30
Black Hills Energy	May 22 - May 27	6
California ISO	May 1 - Jun. 30	61
Idaho Power	Jun. 1 - Jun. 30	30
NorthWestern Energy	Apr. 1 - Jun. 30	91
NV Energy	Apr. 1 - Jun. 30	91
PacifiCorp East	Apr. 1 - Jun. 30	91
PacifiCorp West	Apr. 1 - Jun. 30	91
PSC of New Mexico	Jun. 15 - Jun. 30	16
WAPA Desert Southwest	Apr. 1 - Jun. 30	91

Table 7.3 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the quarter and the resulting 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

⁶⁴ The soft bid cap is \$1,000/MWh and can increase to the hard bid cap of \$2,000/MWh under certain conditions.

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, six balancing areas (Avangrid, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, and WAPA Desert Southwest) failed the resource sufficiency evaluation during at least one interval while opted in to the program. Only NorthWestern Energy, PacifiCorp East, PacifiCorp West, and WAPA Desert Southwest received additional imports due to assistance energy transfer opt-in.

Table 7.3 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, WAPA Desert Southwest failed the resource sufficiency evaluation in the most intervals while opted in to receiving assistance energy transfers (132 intervals). WAPA Desert Southwest achieved an additional 18 MW on average during these intervals (and maximum of 135 MW). WAPA Desert Southwest also achieved the most additional imports from assistance energy transfers during the quarter (585 MWh).

Table 7.3 Resource sufficiency evaluation failures during assistance energy transfer opt-in (April–June 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	91	11	0%	N/A	N/A	N/A
Balancing Area of Northern California	30	0	N/A	N/A	N/A	N/A
Black Hills Energy	6	0	N/A	N/A	N/A	N/A
California ISO	61	0	N/A	N/A	N/A	N/A
Idaho Power	30	0	N/A	N/A	N/A	N/A
NorthWestern Energy	91	4	42%	16	71	16
NV Energy	91	28	0%	N/A	N/A	N/A
PacifiCorp East	91	4	25%	99	529	99
PacifiCorp West	91	15	33%	20	182	76
PSC of New Mexico	16	0	N/A	N/A	N/A	N/A
WAPA Desert Southwest	91	132	37%	18	135	585

Table 7.4 summarizes the total cost from assistance energy transfers.⁶⁵ 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.⁶⁶ The price is the real-time bid cap, typically \$1,000/MWh. Table 7.4 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.

⁶⁵ 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.

⁶⁶ 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.

Table 7.4 Cost of assistance energy transfers (April–June 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	91	N/A	N/A	N/A
Balancing Area of Northern California	30	N/A	N/A	N/A
Black Hills Energy	6	N/A	N/A	N/A
California ISO	61	N/A	N/A	N/A
Idaho Power	30	N/A	N/A	N/A
NorthWestern Energy	91	16	\$21,590	\$1,377
NV Energy	91	N/A	N/A	N/A
PacifiCorp East	91	99	\$166,277	\$1,680
PacifiCorp West	91	76	\$65,297	\$859
PSC of New Mexico	16	N/A	N/A	N/A
WAPA Desert Southwest	91	585	\$416,252	\$712

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.⁶⁷ 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.

⁶⁷ 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>

8 Real-time imbalance offset costs

Total real-time imbalance offset costs for balancing areas participating in the day-ahead market were \$71 million in the second quarter of 2026.^{68,69} The congestion portion of the offset made up a large majority of the cost at around \$76 million. The energy portion of the offset was a \$7 million credit while the loss portion was a \$2 million charge.

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a \$15 million charge to WEIM entities. The energy portion of the offset was around \$19 million (charge), almost all in May and June following the launch of the extended day-ahead market. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a \$4 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).⁷⁰

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 *real-time imbalance energy offset charge* (RTIEO).

Figure 8.1 shows monthly imbalance offset costs since the second quarter of 2024 for balancing areas participating in the day-ahead market. 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). In May and June—since the launch of EDAM—the CAISO balancing area received around \$26 million (credit) for the energy portion of the offset.

Figure 8.2 shows the same information for balancing areas only participating in the WEIM real-time markets. Total charges (positive) for the energy portion of the offset increased for these balancing areas in May and June, at around \$19 million in these months. DMM has requested that the ISO review and correct any issues with the real-time imbalance offset calculation.

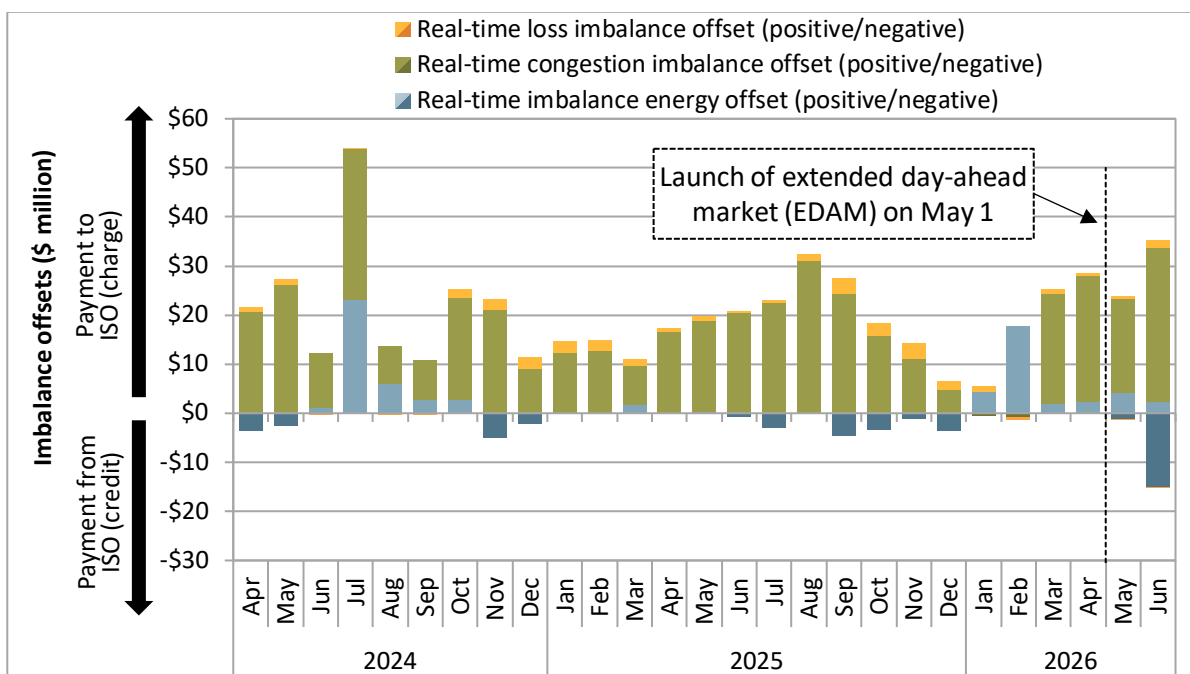
⁶⁸ Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date.

⁶⁹ This includes PacifiCorp East and PacifiCorp West since May, following the launch of the extended day-ahead market (EDAM) on May 1. Prior to May, CAISO was the only balancing area participating in the day-ahead market.

⁷⁰ Measured demand is physical load plus exports.

The ISO has reported a significant day-ahead energy offset since the launch of EDAM.⁷¹ This credit back to EDAM balancing areas can accrue if the energy portion of prices paid into the day-ahead market by demand exceeds the energy portion of prices paid out to supply. The ISO reported a total day-ahead energy offset credit paid back to EDAM balancing areas of about \$16.5 million over May and June. The ISO is investigating the cause of this day-ahead energy revenue imbalance.

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



⁷¹ *Extended Day-Ahead Market Performance August Report*, California ISO, September 28, 2026, pp. 204-5: [monthly-extended-day-ahead-market-edam-performance-report-for-aug-2026.pdf](#)

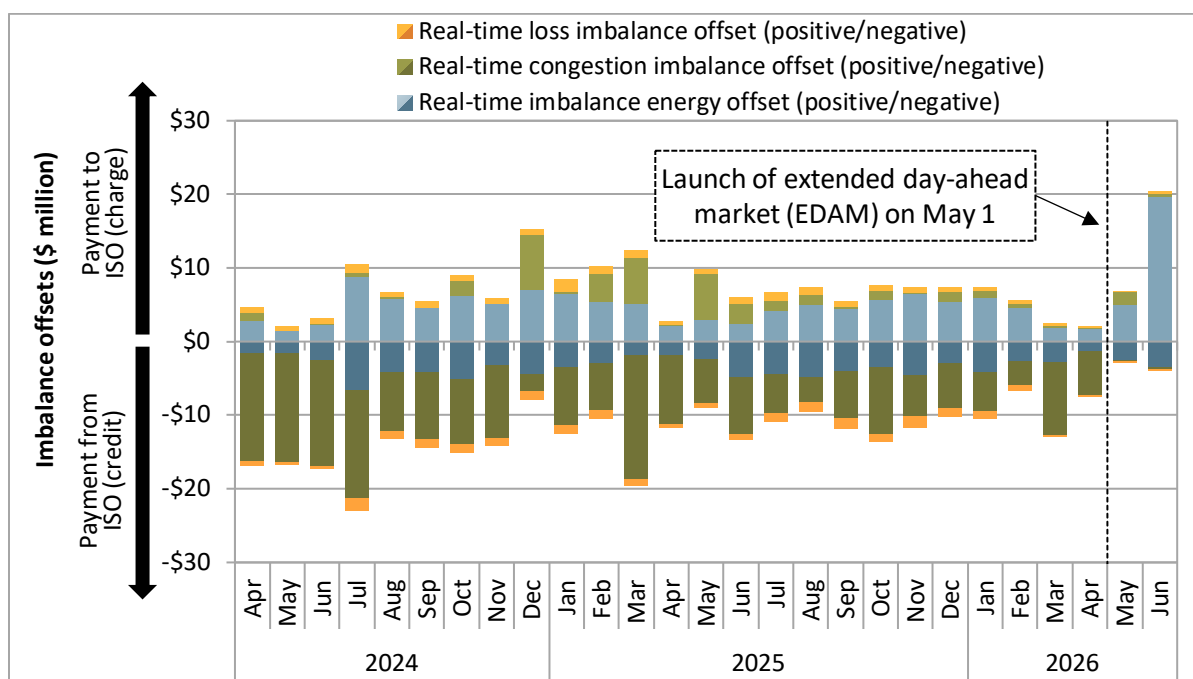
Figure 8.2 Monthly real-time imbalance offset costs (balancing areas participating only in WEIM)

Figure 8.3 through Figure 8.5 show the quarterly real-time energy, congestion, or loss imbalance offsets from Q2 2025 through Q2 2026 for each balancing area.⁷² 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 orange, while credits for revenue surplus are shown in blue. Of note in the second quarter:

- Revenue *shortfall* from imbalance energy offsets for Arizona Public Service was \$4.3 million (charge).
- Revenue *shortfall* from imbalance energy offsets for Black Hills was \$3.3 million (charge).
- Revenue *shortfall* from imbalance energy offsets for Salt River Project was \$6.6 million (charge), while revenue *surplus* from congestion imbalance offsets was \$2.8 million (credit).

⁷² The nature of real-time imbalance offset costs differs between balancing areas in the day-ahead market and balancing areas participating in only the Western Energy Imbalance Market (WEIM). PacifiCorp East and PacifiCorp West joined the extended day-ahead market (EDAM) on May 1. Black Hills and Power Watch joined the WEIM on May 6.

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

	Charge (revenue shortfall)		Credit (revenue surplus)		
Arizona Public Service	1	4	3	1	4
Avangrid	0	.1	.3	.2	.7
Avista	0	0	0	0	.5
BANC	.5	.6	.8	.1	.2
Black Hills					3
BPA	.4	.4	.2	.1	.6
California ISO	.5	7	8	24	8
El Paso Electric	.3	.1	.1	.1	.2
Idaho Power	0	.9	.8	1	.7
LADWP	.2	.1	.1	.2	.2
NorthWestern Energy	2	3	5	2	.8
NV Energy	1	3	4	3	2
PacifiCorp East	.6	.9	.3	1	.9
PacifiCorp West	2	3	2	2	.9
Portland General Electric	.1	0	0	0	1
Powerex	.2	.2	.2	.3	1
PowerWatch					0
PNM	.8	1	2	2	.3
Puget Sound Energy	2	4	4	3	.4
Salt River Project	3	3	2	2	7
Seattle City Light	.3	1	1	1	.5
Tacoma Power	0	0	0	0	.2
Tucson Electric Power	0	0	.1	.3	1
Turlock Irrigation District	.4	.7	.7	.2	.5
WAPA Desert Southwest	.1	.7	.2	.6	1
	Q2	Q3	Q4	Q1	Q2
	2025			2026	

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

	Charge (revenue shortfall)		Credit (revenue surplus)		
Arizona Public Service	.1	1	.5	.4	0
Avangrid	.4	.5	.3	.1	0
Avista	.3	.2	.3	.2	0
BANC	0	0	0	0	0
Black Hills					0
BPA	1	.3	.9	.8	0
California ISO	56	78	32	21	75
El Paso Electric	.4	.9	.8	1	.3
Idaho Power	.9	.7	1	.6	.2
LADWP	.1	.3	1	.4	.2
NorthWestern Energy	.2	0	.5	.3	.1
NV Energy	.8	.4	.5	.4	.4
PacifiCorp East	.4	2	7	5	1
PacifiCorp West	2	1	2	2	.3
Portland General Electric	3	2	2	2	.5
Powerex	6	3	2	3	.4
PowerWatch					0
PNM	9	.6	2	.8	0
Puget Sound Energy	2	1	.9	1	.3
Salt River Project	4	.6	.2	1	3
Seattle City Light	.5	.5	.3	.2	1
Tacoma Power	.1	.1	.1	.1	0
Tucson Electric Power	2	1	.7	.2	.3
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	0	0	.1	.2	0
	Q2	Q3	Q4	Q1	Q2
	2025			2026	

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

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

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

	Charge (revenue shortfall)			Credit (revenue surplus)	
Arizona Public Service	1	4	3	2	4
Avangrid	.5	.6	.3	0	.7
Avista	.3	.2	.3	.2	.5
BANC	.5	.5	.7	.1	.3
Black Hills					3
BPA	.8	.8	.7	1	.7
California ISO	57	75	31	47	69
El Paso Electric	.2	1	.8	.9	.2
Idaho Power	1	2	.2	.7	.6
LADWP	.1	.5	1	.4	.1
NorthWestern Energy	1	3	4	2	.6
NV Energy	.2	2	3	3	2
PacifiCorp East	.3	3	9	4	2
PacifiCorp West	4	4	4	4	.5
Portland General Electric	2	2	1	2	2
Powerex	5	1	.8	2	.5
PowerWatch					0
PNM	9	2	5	2	.3
Puget Sound Energy	4	5	5	4	.1
Salt River Project	7	4	3	3	4
Seattle City Light	.4	1	1	1	.9
Tacoma Power	.1	.1	.1	.1	.1
Tucson Electric Power	2	1	.8	.1	1
Turlock Irrigation District	.4	.7	.7	.1	.5
WAPA Desert Southwest	.1	.7	.1	.4	1
	Q2	Q3	Q4	Q1	Q2
	2025			2026	

9 Bid cost recovery

During the second quarter of 2026, estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market totaled about \$32.8 million.⁷³ This was a 25 percent increase from the \$26.3 million in bid cost recovery in the second quarter of 2025. Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM) totaled about \$1.8 million. WEIM area bid cost recovery payments decreased 44 percent from Q2 2025.⁷⁴

Figure 9.1 shows monthly bid cost recovery payments in the second quarter of 2026 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market (blue bars) totaled about \$8.1 million, up from \$7 million in the second quarter of 2025. Bid cost recovery payments associated with residual unit commitment (red bars) during the quarter totaled about \$6.7 million, or about \$4.9 million lower than the second 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 \$18 million, which was about \$10.3 million higher than the same quarter of 2025.

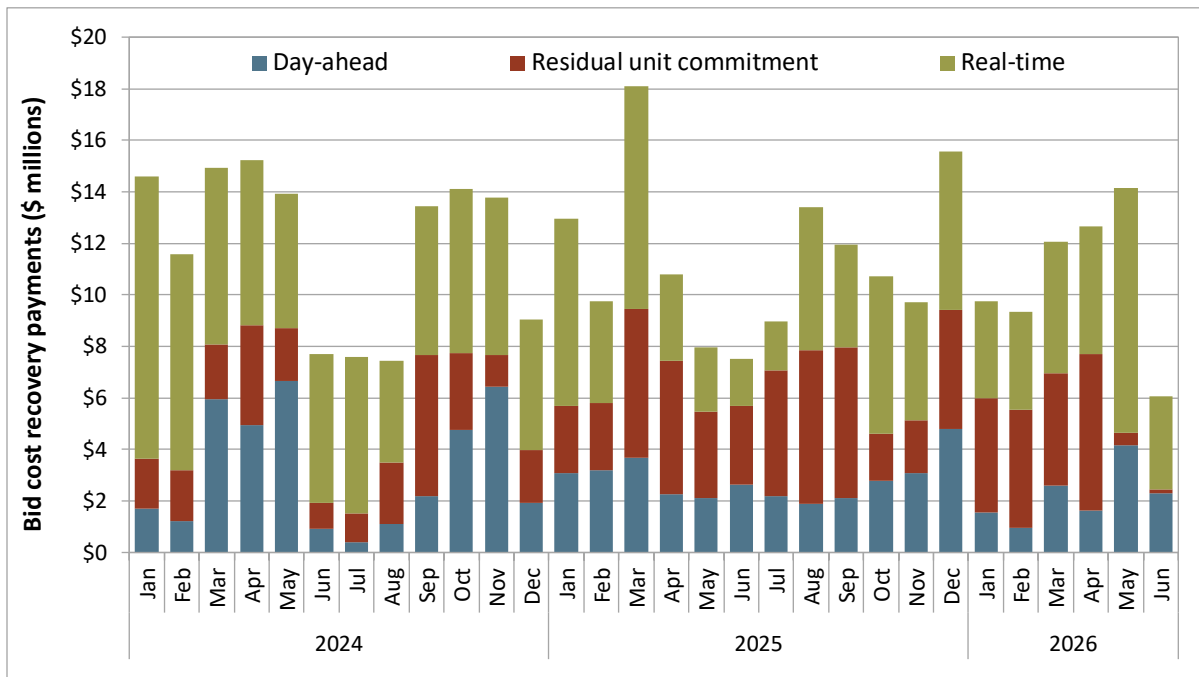
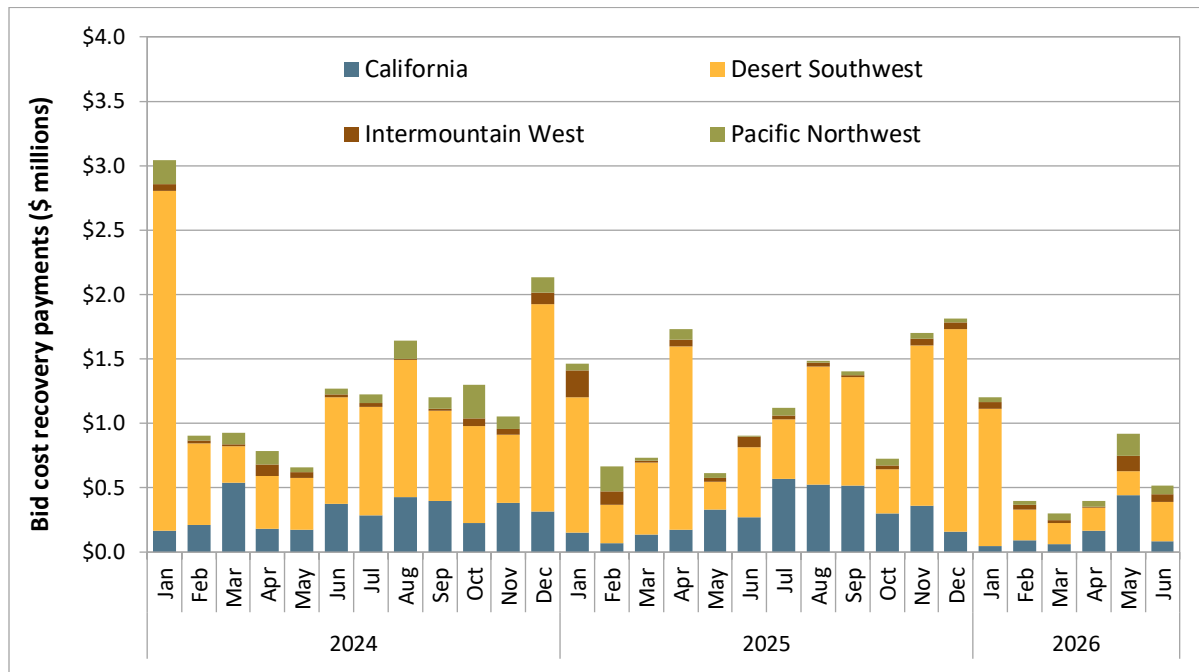
Figure 9.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM.⁷⁵ Bid cost recovery payments to these units were greatest in the California and Desert Southwest regions at \$690,000 and \$678,000, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around \$185,000 and \$274,000, 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 second quarter of 2026, about \$24.3 million of bid cost recovery payments were made to gas resources. About \$3.4 million and \$2.4 million of payments were made to hybrid and battery resources, respectively. Solar resources were paid \$2.1 million in bid cost recovery payments.

⁷³ CAISO was the only balancing area participating in the day-ahead market until PacifiCorp (PACW and PACE) joined on May 1, 2026.

⁷⁴ The bid cost recovery payment amounts in this report are different than what is reported in previous reports due to resettlements.

⁷⁵ Figure 9.2 only shows non-EDAM balancing authority areas.

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 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the second quarter of 2026 was about 20 percent lower than the same quarter of 2025. Operator adjustments to the RUC procurement target decreased by about 99 percent for the same period.

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.

10.1 Residual unit commitment requirement

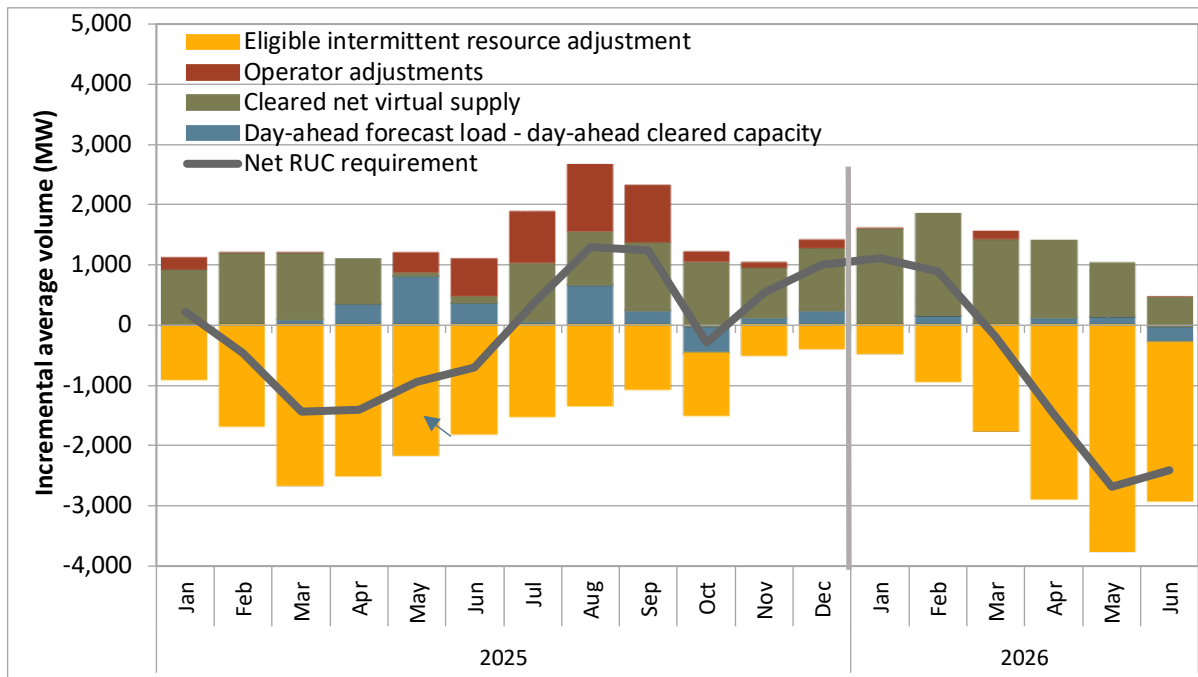
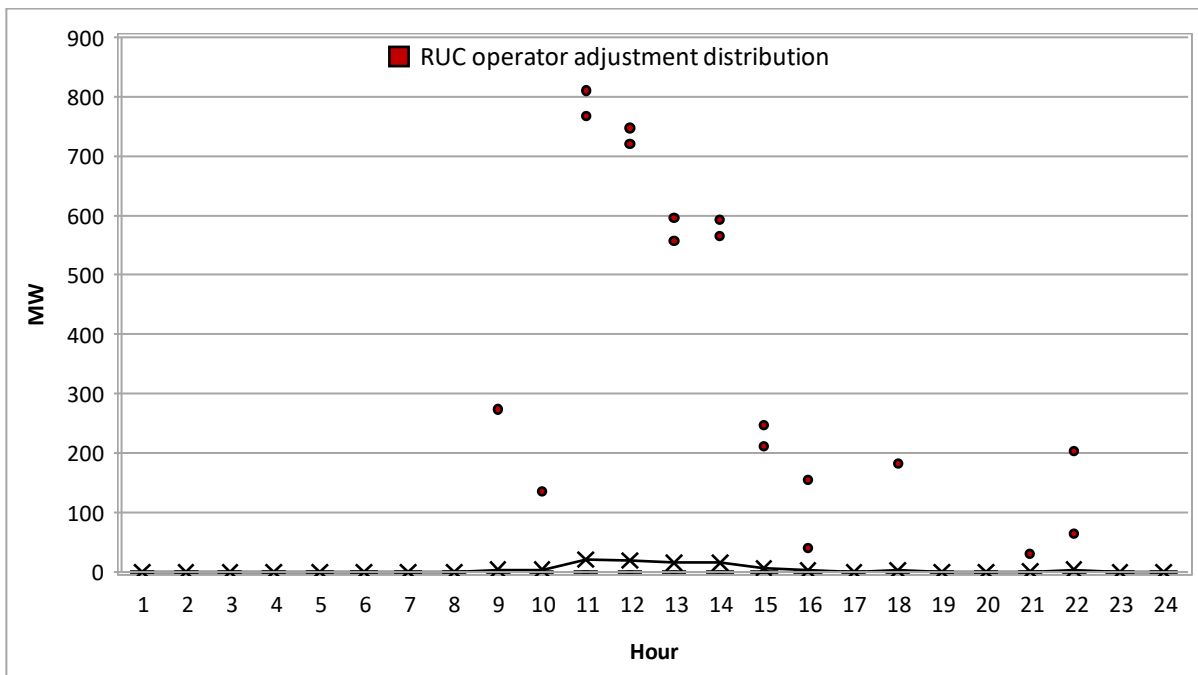
The quantity of residual unit commitment procured is determined by several automatically calculated components, as well as any adjustments that operators make to increase residual unit commitment requirements for reliability purposes. Figure 15.1 shows the average incremental residual unit commitment 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 ISO's day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed to raising the residual unit commitment requirements by about 10 MW per hour in the second 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. The magnitude of these downward eligible intermittent resource adjustments increased by an average of 3,100 MW, which is 42 percent larger than adjustments in Q2 2025.

Lastly, operators can 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. Figure 15.2 shows the hourly distribution of these operator adjustments during the second quarter of 2026. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour. The operator adjustments and changes to the methodology are described in more detail in the following section.

Figure 10.1 Average incremental residual unit commitment requirement by component**Figure 10.2 Hourly distribution of residual unit commitment operator adjustments (April–June 2026)**

Residual unit commitment operator adjustments

The residual unit commitment (RUC) adjustments are added to the forecasted load in the RUC process and are intended to address uncertainty and provide extra capacity for a balancing area beyond what is accounted for in the integrated forward market.

Day-ahead market enhancements (DAME) and the extended day-ahead market (EDAM) were launched on May 1, 2026. This includes the implementation of the *imbalance reserve product*. Imbalance reserves are bid into the market, co-optimized with energy and ancillary services, and are intended to address much of the same net load uncertainty as the former RUC adjustments. However, there are several key differences with imbalance reserve. The imbalance reserve requirement is 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 flexibility. The imbalance reserve product was also implemented at launch with the requirement set to cover all hours at the 90th percentile of uncertainty.

With the implementation of the imbalance reserve product, RUC adjustments can still be entered to address any uncertainty not covered by imbalance reserve, but the amount is now *incremental* and tied to the 97.5th percentile of uncertainty.⁷⁶ RUC adjustments may be entered in addition to procurement of imbalance reserve for a number of reasons. First, the imbalance reserve requirement is based on the 90th percentile instead of the 97.5th percentile. Next, there can be relaxation of the imbalance reserve requirement. Last, there can be additional sources of operational uncertainty not covered by the imbalance reserve product (outages, fire risk, weather events, etc.). Any RUC adjustment is calculated minus upward imbalance reserve procured in the day-ahead market to capture only incremental uncertainty that may need to be accounted for to be sufficient between the day-ahead and real-time markets.⁷⁷

The CAISO operating procedure for setting the RUC adjustments within the CAISO balancing area recommends to use a particular percent of the 97.5th percentile of uncertainty, considering the level of operational uncertainty or load.^{78,79} During days with moderate operational uncertainty or load, the operating procedure recommends to use 4 percent of this uncertainty for either the peak morning and evening hours or the mid-day hours. During days with higher operational uncertainty or load, the procedure recommends using 50 percent for the mid-day hours. Last, during the days with the highest operational uncertainty or load, the procedure recommends using 100 percent for the mid-day hours.

Figure 15.3 shows the average residual unit commitment adjustment on each day during the first half of the year, comparing 2025 (red) and 2026 (blue). There were no RUC adjustments applied for PacifiCorp East or PacifiCorp West such that these amounts are for the CAISO balancing area only. Following the launch of day-ahead market enhancements, RUC adjustments in May and June were down significantly

⁷⁶ The RUC uncertainty is calculated using the same mosaic quantile regression method as the imbalance reserve product, except using the 97.5th percentile. 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 high percentile of uncertainty that might materialize. These coefficients are then combined with RUC forecast information at the time of each market run to determine the uncertainty.

⁷⁷ The imbalance reserve procured here also accounts for imports and exports of imbalance reserve for the balancing area.

⁷⁸ See CAISO Operating Procedure 1210, July 1, 2026, pp 12-13: <https://www.caiso.com/Documents/1210.pdf>

⁷⁹ Prior to the implementation of Day-Ahead Market Enhancements, the percentile target of uncertainty for the RUC adjustments was selected at either the 50th percentile, 75th percentile, or 97.5th percentile, based on conditions in the system.

in 2026 compared to the previous year. No RUC adjustments occurred in April or May of 2026. CAISO balancing area RUC adjustments in June 2026 only occurred on two days—June 11 and 12—due to higher peak loads. Figure 15.4 shows the calculation of these RUC adjustments. On these days, RUC adjustments were applied above imbalance reserve schedules up to 50 percent of the 97.5th percentile of uncertainty. These adjustments were applied in the mid-day hours.

Figure 10.3 Average residual unit commitment adjustment by day (first half 2025 vs. 2026)

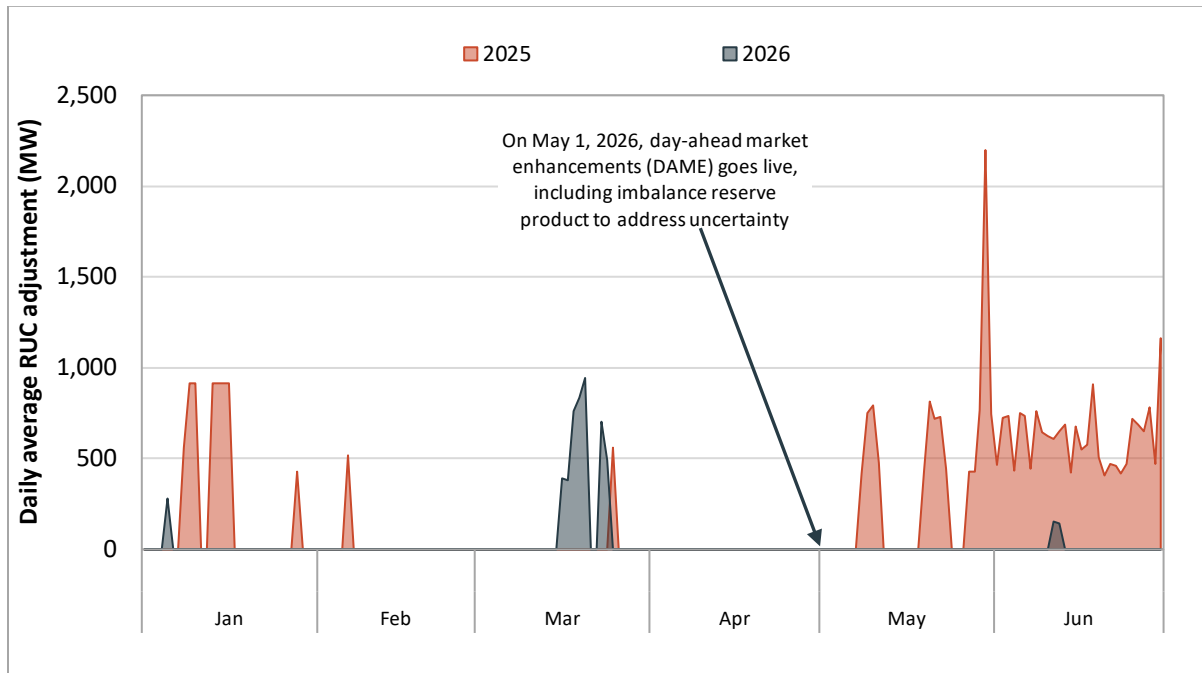
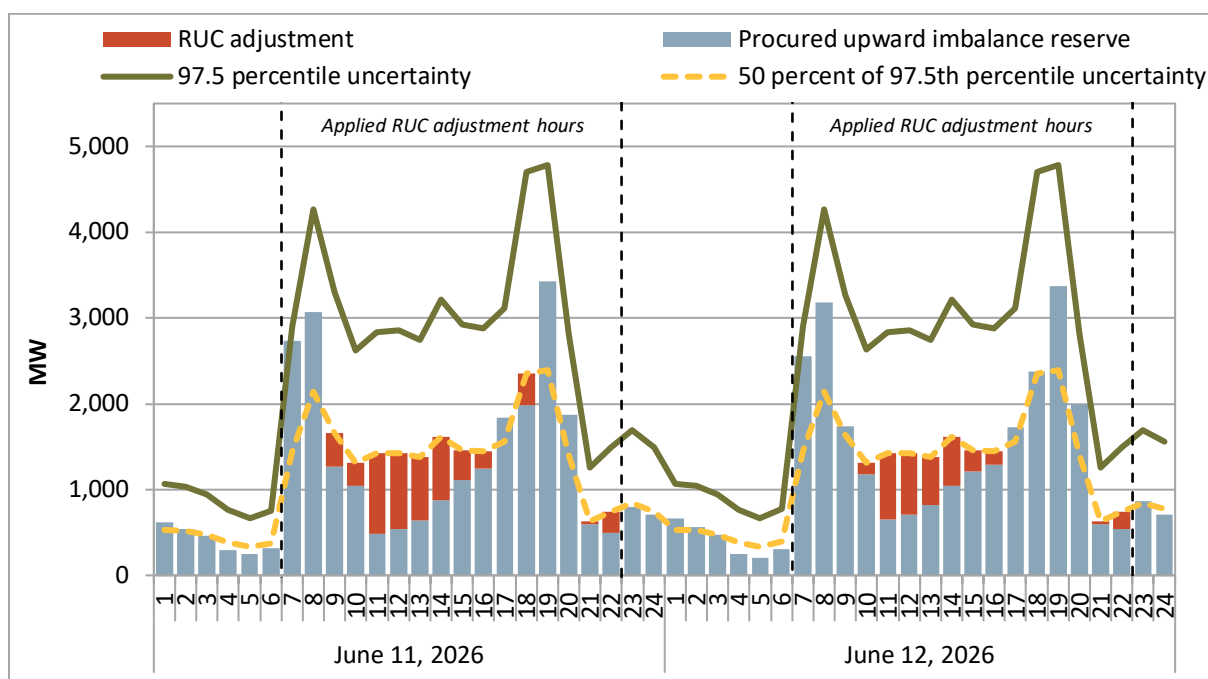


Figure 10.4 CAISO residual unit commitment adjustment calculation (June 11 and June 12, 2026)

10.2 Residual unit commitment procurement and costs

In May 2026, the ISO implemented day-ahead market enhancements (DAME) and the extended day-ahead market (EDAM), which introduced significant changes to the residual unit commitment (RUC) process. Under the prior design, RUC procured capacity in the upward direction only. Under DAME, RUC procures both upward capacity (reliability capacity up, or RCU) and downward capacity (reliability capacity down, or RCD), with separate locational prices for each. Resources submit RCU and RCD availability bids as part of the day-ahead market submission, with bid prices between \$0/MWh and \$250/MWh. A resource can only receive an RCU or RCD award in a given hour. Under EDAM, the RUC process extends to EDAM entity balancing authority areas, each with its own procurement target. Reliability capacity can transfer between balancing authority areas.

DAME transitional measures and resource adequacy revenue allocation

A significant financial change is to resource adequacy (RA) resource compensation. Under the prior design, RA resources were required to bid \$0/MWh into RUC and were excluded from RUC availability payments. The RUC settlement system only compensated non-RA capacity, while RA resources received no market payment for their RUC awards. Starting with DAME/EDAM, resources with RCU and or RCD awards—including RA resources—receive availability payment at the market clearing price. This change created new market revenue for RA resources that did not exist under the prior design. The tariff includes optional DAME transitional measures under Section 11.2.6, through which resource and load

serving entity (LSE) scheduling coordinators can mutually elect to have the RA capacity portion of RCU and RCD revenue credited back to the LSE. If neither party elects, the resource retains all revenue.^{80, 81}

The tariff specifies that the overlapping RA capacity—the portion used to determine how much revenue flows back to the LSE—is based on the higher of generic RA capacity or flexible RA capacity on the monthly supply plan (section 11.2.6.2). This is why the effective RA capacity shown in the first grouping may differ from the generic or flexible RA values individually. The generic and flexible RA values are calculated based on shown RA capacity including capacity procurement mechanism designations.

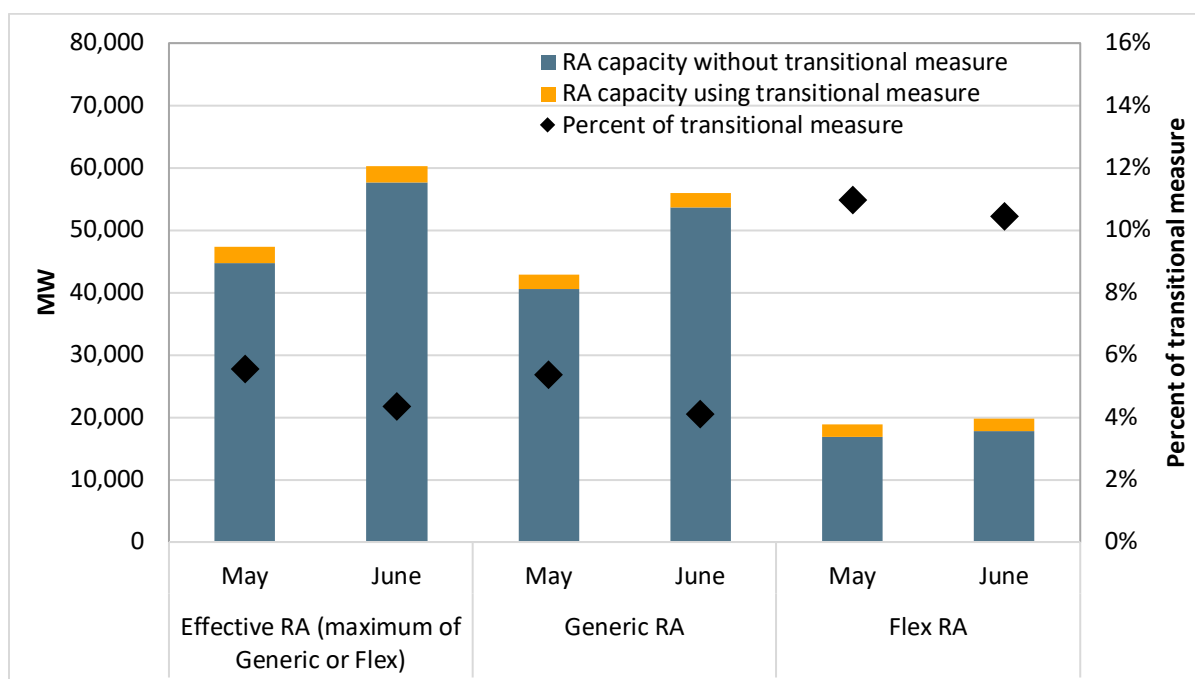
The transitional measures data shown for May and June is based on the July 2026 election records rather than the May or June records. This is because the tariff provides a 60-day grace period following DAME implementation on May 1, 2026. During this window, resource/LSE pairs could elect transitional measures at any point through late June and have the election applied retroactively to May 1 through settlement resettlement. For resource/LSE pairs that elected transitional measures during the 60-day grace period, the ISO resettled May and June to transfer the RA overlap revenue from the resource to the LSE.

Figure 15.5 shows total RA capacity split by resources with and without DAME transitional measures elections for May and June 2026, displaying across three groupings: the effective RA capacity (the higher of generic or flexible RA on the monthly supply plan for each resource), generic RA only, and flexible RA only.

The relative size of the transitional measures portion in each group indicates the degree to which the revenue clawback is in effect. Based on July election records, approximately 2,600 MW of RA capacity was subject to transitional measures, representing about 6 percent of May effective RA capacity and 4 percent of June effective RA capacity.

⁸⁰ For additional tariff detail, see *California ISO Settlement and Billing, Section 11, effective May 1, 2026*, available at: <https://www.caiso.com/library/tariff-sections>. DAME transitional measures are specified in Section 11.2.6

⁸¹ For RCU, if the day-ahead energy schedule plus upward ancillary service awards and imbalance reserve up award is below the RA capacity, part of the upward awards falls within the RA capacity range. That portion is credited to the LSE. Any RCU award above the RA capacity level stays with the resource. For RCD, if the day-ahead energy schedule minus regulation down and imbalance reserve down awards is above the RA capacity, part of the downward award brings the resource back down to the RA capacity level. That portion is credited to the LSE. Any award that takes the resource below the RA capacity level stays with the resource (tariff section 11.2.6.2)

Figure 10.5 RA capacity and DAME transitional measures elections (May–June 2026)

Residual unit commitment costs and procurement under DAME and EDAM

As discussed above, DAME introduced RCU and RCD as separate products replacing the prior single upward RUC schedules, with RA resources now receiving revenues at the market clearing price. Under EDAM, PacificCorp East (PACE) and PacificCorp West (PACW) participate in the RUC process with their own procurement targets, and reliability capacity can transfer between BAAs.

Figure 15.6 shows average hourly RUC MW from May 2025 through June 2026, calculated as total monthly RUC MW divided by the number of hours in each month. Prior to May 2026, bars show only CAISO RUC MW, of which 98 percent on average came from RA resources. Beginning in May 2026, bars show RCU as positive values and RCD as negative values for each EDAM BAA.

Average hourly procurement in May 2026 was 1,600 MW of RCU and 500 MW of RCD, resulting in total procurement of 2,100 MW and net procurement of 1,100 MW. June was lower, at approximately 1,050 MW of RCU and 800 MW of RCD, with total procurement of 1,850 MW and net procurement of approximately 250 MW. Both months are comparable to the average of 1,500 MW observed between May 2025 and April 2026.

The CAISO BAA accounted for 95 percent of both total RCU and RCD procurement, PACE accounted for 4 percent of each, and PACW accounted for 1 percent of each.

Total RUC procurement in May and June 2026 remained broadly consistent with pre-EDAM levels despite the two additional balancing areas under EDAM.

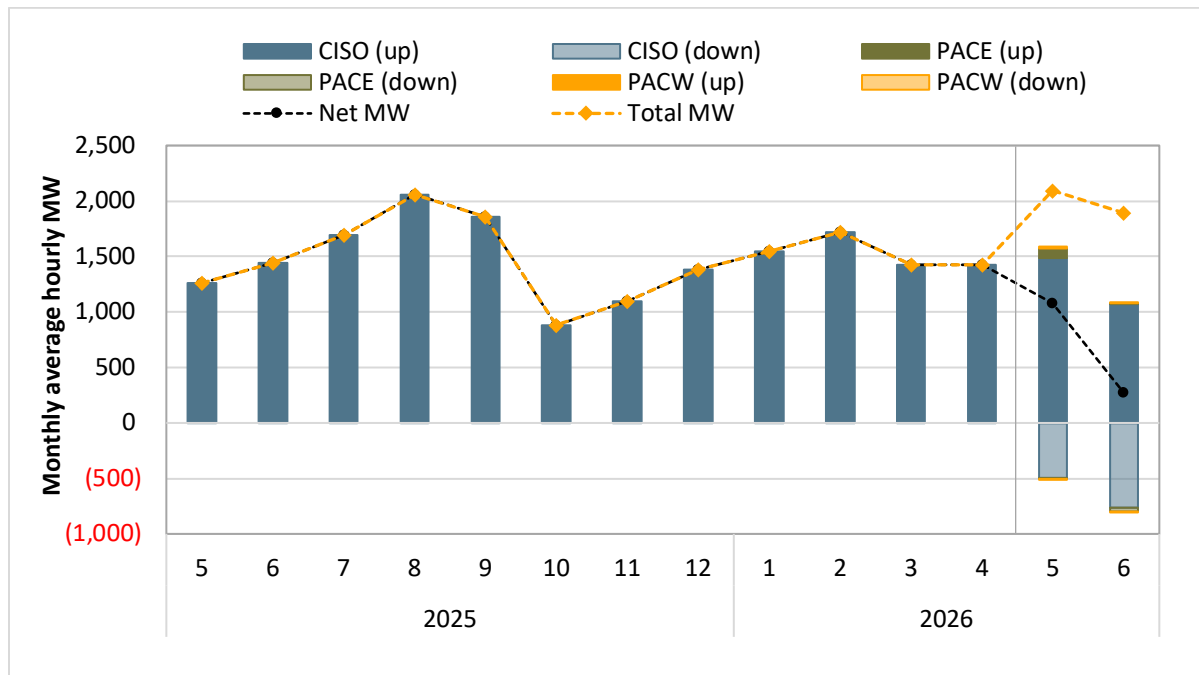
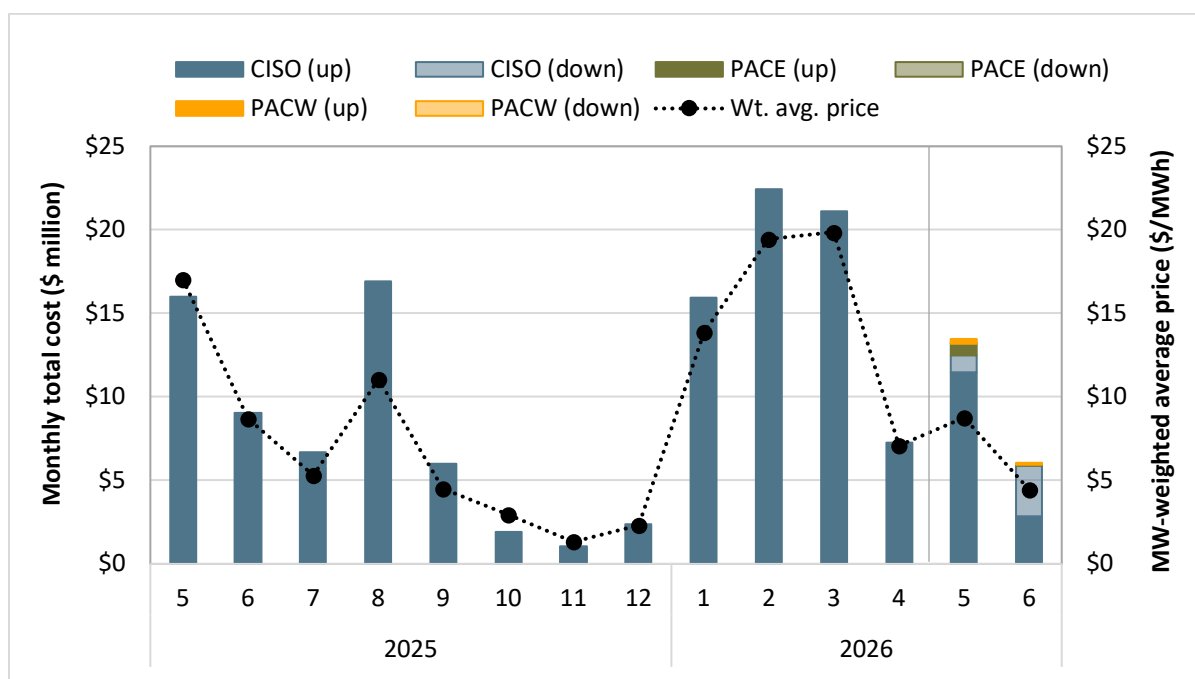
Figure 10.6 Monthly hourly average RUC procurement (May 2025 – June 2026)

Figure 15.7 shows monthly total RUC payment costs and MW-weighted average RUC prices from May 2025 through June 2026. Prior to May 2026, the bars (blue) represent the imputed cost of RA and non-RA capacity in RUC, calculated as RA and non-RA resource schedules multiplied by their locational RUC prices. This amount was not an actual market payment—under the prior design, RA resources were excluded from RUC payments and received no compensation. The imputed value reflects the cost that would have been incurred if the market had to procure this capacity at market prices rather than through bilateral RA contracts. Beginning in May 2026 under DAME, RA capacity could be scheduled for both upward and downward reliability capacity and received settlement payments. About 5 percent of RA capacity was subjected to the transitional measure election. Costs for this capacity are included in the chart and averaged about \$0.2 million per month in May and June.

The secondary axis displays the MW-weighted average RUC price, calculated across all resource RUC schedules weighted by their locational RUC prices.

Figure 10.7 Monthly RUC costs and weighted average price (May 2025 – June 2026)

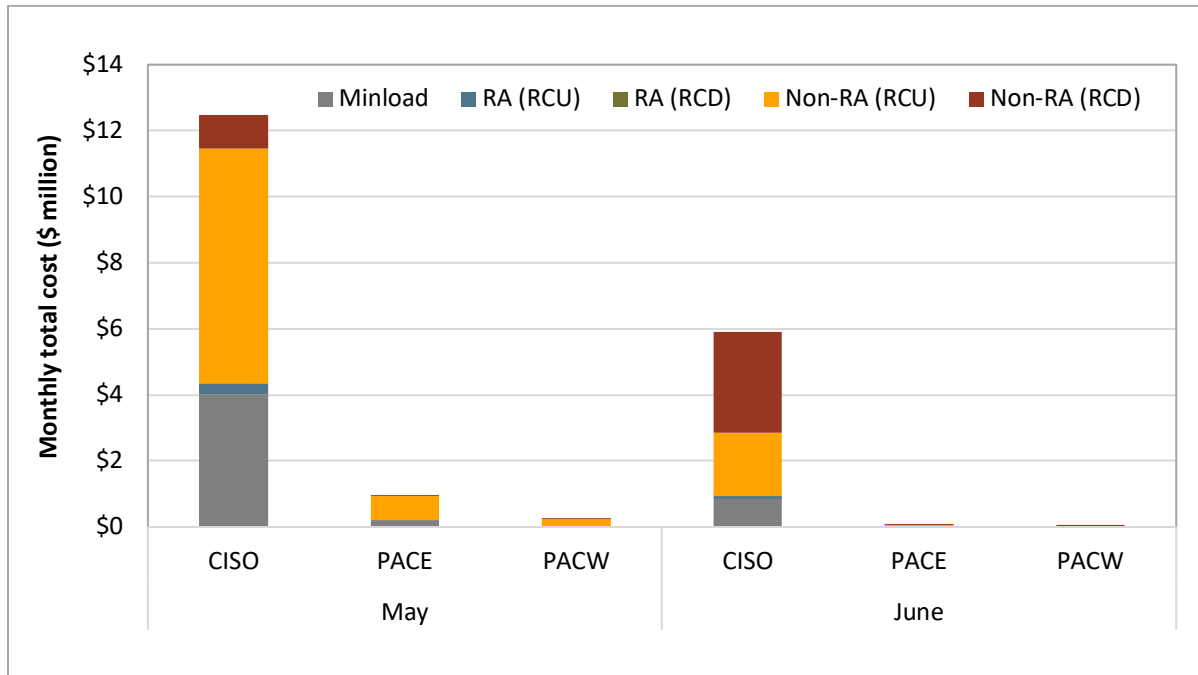
Total RUC costs were approximately \$14 million in May 2026 and \$6 million in June 2026, compared to an average of \$10 million per month between May 2025 and April 2026, of which actual payments to non-RA resources averaged only \$0.2 million per month. The MW-weighted average RUC price fluctuated over the period. Between May 2025 and April 2026, the average price was about \$9/MWh. It remained at \$9/MWh in May 2026 and fell to \$4/MWh in June.

Total RUC cost increased from April to May 2026, immediately before and after the EDAM/DAME launch, while the average price remained similar. The increase in cost was mainly driven by the addition of 700 MW of procurement in May compared with April.

Figure 15.8 shows the total RUC cost breakdown for May and June 2026 by balancing area and category: minimum load, RA RCU, RA RCD, non-RA RCU, and non-RA RCD. The RA designation reflects resources with DAME transitional measures elections, where the RA capacity portion of RCU and RCD revenue is credited back to the LSE. Non-RA includes both non-RA resources and RA resources without elections.

Of the total \$14 million in May 2026, about \$7 million reflected RCU payments to non-RA resources and RA resources not subject to the transitional measure in the CAISO balancing area, while approximately \$4 million reflected CAISO minimum-load payments. Of the resource adequacy resource payments, about \$0.3 million was subject to the transitional measure and credited back to LSEs in May and \$0.1 million in June. Total RUC payments were about \$1 million for PACE and \$0.3 million for PACW. RCU accounted for most RUC payments across all balancing areas in May.

Total RUC payments declined to \$6 million in June. This amount included about \$3 million in CAISO RCD payments and \$2 million in CAISO RCU payments. Payments totaled about \$0.1 million for PACE and \$0.06 million for PACW.

Figure 10.8 Monthly RUC cost breakdown (May–June 2026)

11 Uncertainty products

This chapter analyzes the imbalance reserve product in the day-ahead market and the flexible ramping product in the real-time market. These products are designed to enhance reliability and market performance as well as support renewable integration by procuring upward and downward flexibility to meet net load uncertainty. Key findings in this chapter include:

- Gas resources made up around 51 percent of upward imbalance reserve schedules. Wind and solar resources combined made up around 82 percent of downward imbalance reserve schedules.
- The California ISO balancing area was a net exporter of upward imbalance reserve on average. PacifiCorp East was a net importer of upward imbalance reserve and net exporter of downward imbalance reserve. PacifiCorp West was a net importer of both upward and downward imbalance reserve.
- Prices for imbalance reserve have frequently been very low or zero. For the CAISO and PacifiCorp East balancing areas, prices have been less than \$5/MWh in more than 89 percent of hours. Imbalance reserve prices in PacifiCorp West were more frequently higher—above \$5/MWh in more than 35 percent of hours.
- Between May and June, payments for upward imbalance reserve were around \$5 million while payments for downward imbalance reserve were around \$2.2 million—or around \$7.2 million combined.
- 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 17.8 percent of intervals in the second quarter of 2026, up significantly from 0.2 percent in the same quarter of 2025. The increase coincided with the implementation of EDAM, as these prices were greater than zero during about 0.9 percent of intervals in April 2026, 32.1 percent of intervals in May 2026, and 20.4 percent in June 2026. Most of this increase occurred in the Intermountain West and Pacific Northwest regions. DMM has notified the ISO of the increase in flexible ramping product prices and will continue to work with the ISO to understand the underlying causes.
- Battery and hydro resources made up 65 percent and 17 percent of upward flexible capacity, respectively. Wind and solar combined to provide 45 percent of downward flexible capacity, and batteries provided 33 percent of downward flexible capacity.
- The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 59 percent in the upward direction and 56 percent in the downward direction. Balancing areas in the Pacific Northwest made up 19 percent of flexible capacity in each direction.

The imbalance reserve product is procured in the day-ahead market—reserving flexible ramping capacity to cover uncertainty that may materialize between the day-ahead and real-time markets. The flexible ramping product is procured in the real-time market—covering uncertainty that may materialize within the next real-time market interval.

The amount of flexibility the imbalance reserve and flexible ramping product procures are each derived from a demand curve which reflects a calculation of the optimal willingness-to-pay for that flexibility. The demand curves allow the market optimization to consider the trade-off between the cost of

procuring additional flexibility and the expected reduction in cost associated with power balance constraint infeasibilities.

The imbalance reserve and 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 flexibility. This “requirement” reflects the upper end of uncertainty in each direction that might materialize.⁸² This is sometimes referred to as the uncertainty requirement.

The uncertainty is 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 high percentile of uncertainty that might materialize. These coefficients are then combined with current forecast information for each interval to determine the uncertainty requirement.

11.1 Imbalance reserve

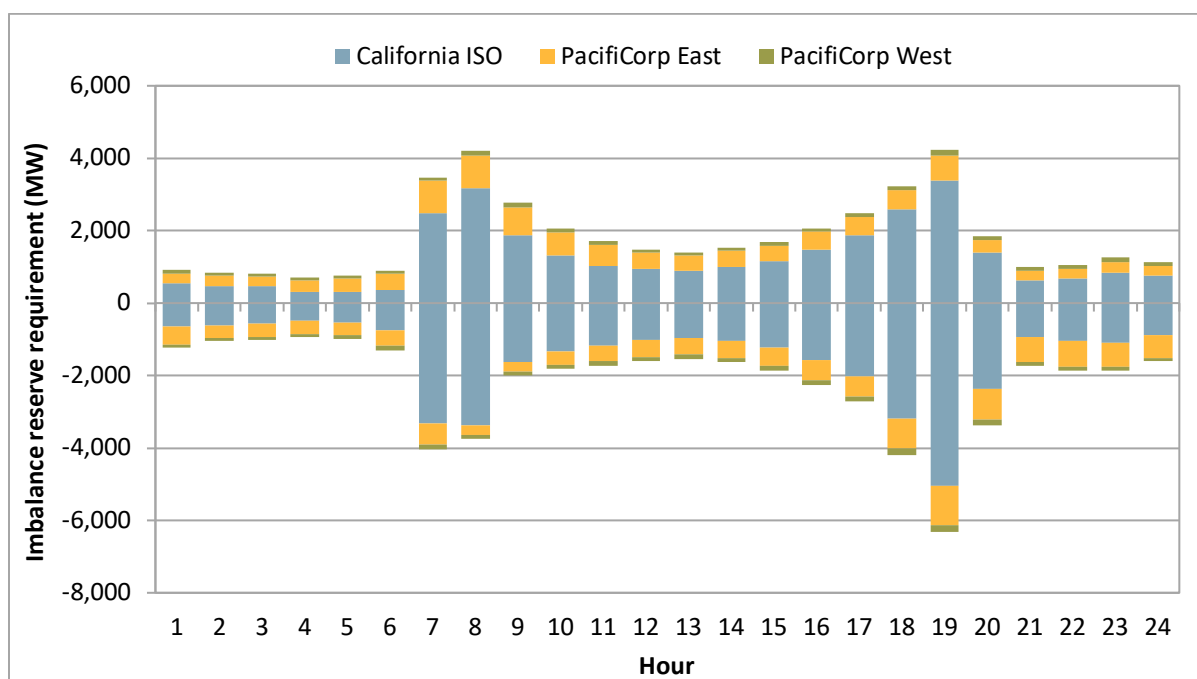
The imbalance reserve product was implemented on May 1, 2026 as part of day-ahead market enhancements (DAME) alongside the launch of the extended day-ahead market (EDAM). These reserves are bid into the market and co-optimized with energy and ancillary services in the day-ahead market to cover net load uncertainty that may materialize. This allows the market to optimally position and compensate resources that are able to provide flexibility to cover variation in load, wind, or solar forecasts.

11.1.1 Imbalance reserve requirements

Figure 11.1 shows average imbalance reserve requirements for each balancing area participating in the day-ahead market. These requirements are calculated based on the 10th and 90th percentile of net load uncertainty that may materialize between the day-ahead market and real-time markets.⁸³ Between May and June, the California ISO balancing area accounted for roughly 70 percent of total imbalance reserve requirements. Total imbalance reserve requirements were highest in hours 7, 8, 18, and 19. These hours include the morning and evening solar ramp, which typically has the highest levels of uncertainty.

⁸² For imbalance reserve, the requirement is calculated based on the 10th and 90th percentile of net load uncertainty. For the flexible ramping product, the requirement is calculated based on the 2.5th and 97.5th percentile of net load uncertainty.

⁸³ The 10th and 90th percentile for the uncertainty requirements were set as a transitional measure for the launch of the extended day-ahead market (EDAM) and implementation of day-ahead market enhancements (DAME). These levels may be adjusted at a later date.

Figure 11.1 Imbalance reserve requirements by hour and balancing area (May–June 2026)

11.1.2 Imbalance reserve procurement

Figure 11.2 and Figure 11.3 summarize schedules for upward and downward imbalance reserve by fuel type across all EDAM participating balancing areas. The black line shows the combined California ISO, PacifiCorp East, and PacifiCorp West imbalance reserve requirement. For *upward* imbalance reserves, gas resources made up around 51 percent of the schedules. Coal and solar resources each made up around 15.5 percent of upward imbalance reserve schedules.⁸⁴ For *downward* imbalance reserves, wind and solar resources combined made up around 82 percent of schedules.

Figure 11.4 shows average transfers of upward and downward imbalance reserve between EDAM participating balancing areas. Net import of imbalance reserve is shown as negative and net export of imbalance reserve is shown as positive. On average, the California ISO balancing area was a net exporter of upward imbalance reserve. PacifiCorp East was a net importer of upward imbalance reserve and net exporter of downward imbalance reserve. PacifiCorp West was a net importer of both upward and downward imbalance reserve. Imports made up around 61 percent of PacifiCorp West upward imbalance reserve requirements.

⁸⁴ The upward imbalance reserve awards to solar resources were to solar resources that were decrementally dispatched below forecast to provide energy, but can provide upward reserve capacity up to forecast.

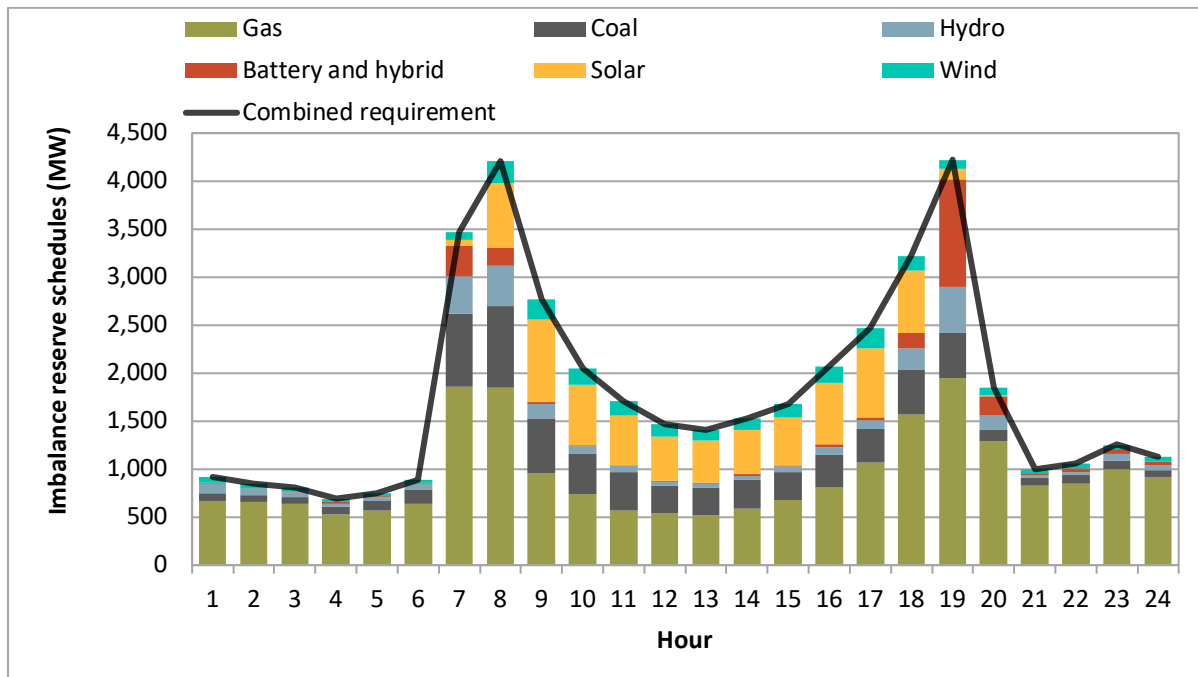
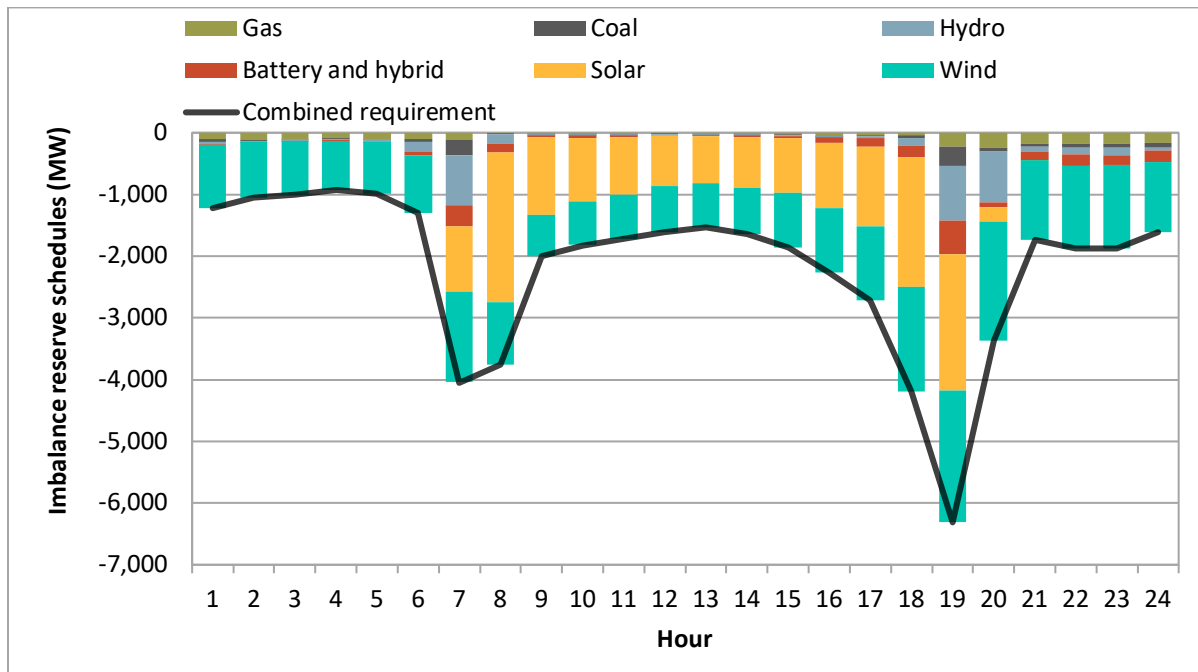
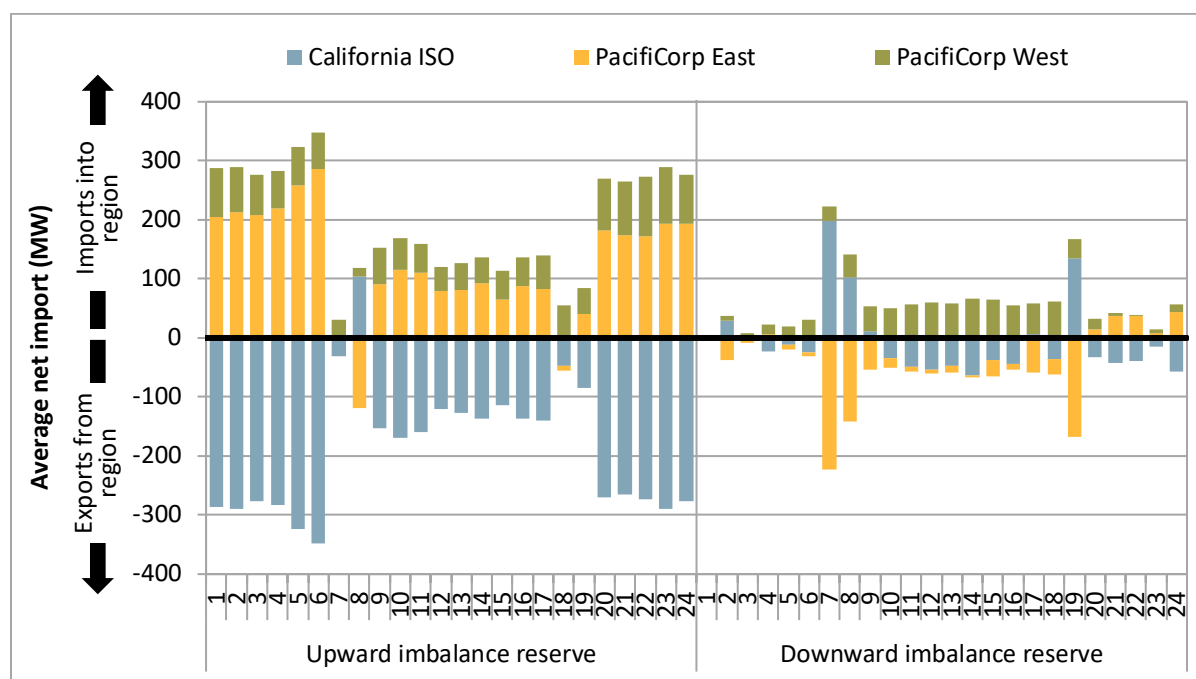
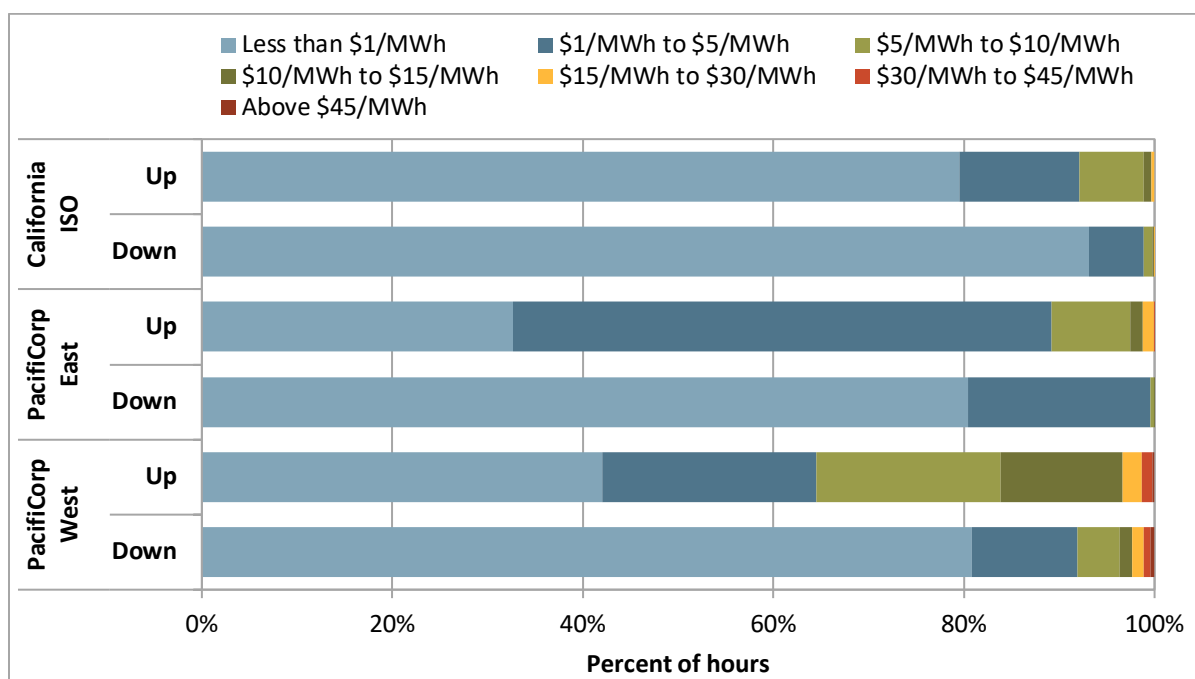
Figure 11.2 Average upward imbalance reserve procurement by fuel type (May–June 2026)**Figure 11.3 Average downward imbalance reserve procurement by fuel type (May–June 2026)**

Figure 11.4 Average imbalance reserve transfers by balancing area (May–June 2026)

11.1.3 Imbalance reserve prices

For imbalance reserves, the offer cap and demand curve (for any relaxation of the uncertainty requirement) are both capped at \$55/MWh. Figure 11.5 summarizes the frequency of imbalance reserve prices by price range for each balancing area.⁸⁵ Prices for imbalance reserve have frequently been low or zero. For the CAISO and PacifiCorp East balancing areas, prices have been less than \$5/MWh in more than 89 percent of hours. Imbalance reserve prices in PacifiCorp West were more frequently higher—above \$5/MWh in more than 35 percent of hours.

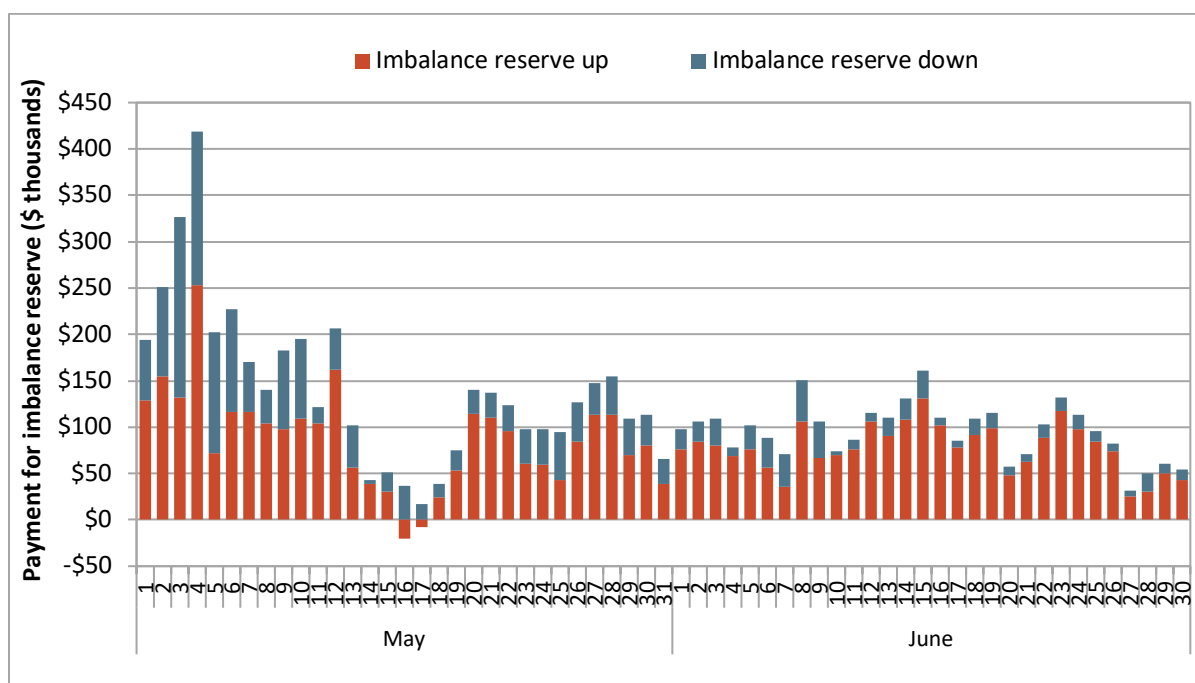
⁸⁵ This figure summarizes the shadow price on each balancing area's constraint for procuring imbalance reserve up or down, and does not consider prices that may exist at the nodal level that are the result of internal congestion.

Figure 11.5 Frequency of imbalance reserve prices by price range (May–June 2026)

11.1.4 Imbalance reserve settlement

Figure 11.6 shows total daily payments for imbalance reserve, in thousands of dollars.⁸⁶ Between May and June, payments for upward imbalance reserve were around \$5 million while payments for downward imbalance reserve were around \$2.2 million—or around \$7.2 million combined. Total daily payments for imbalance reserve were highest in the first week following the implementation of day-ahead market enhancements (DAME) on May 1, but were otherwise relatively stable towards the end of May and June.

⁸⁶ This information is based on settlement values available at the time of drafting. Settlement information is subject to updates that can occur within the settlements timeline.

Figure 11.6 Total daily payments for imbalance reserve by direction (May–June 2026)

11.2 Flexible ramping product

The flexible ramping product procures and prices flexible capacity in the real-time market. 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.

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.

11.2.1 Flexible ramping product requirements

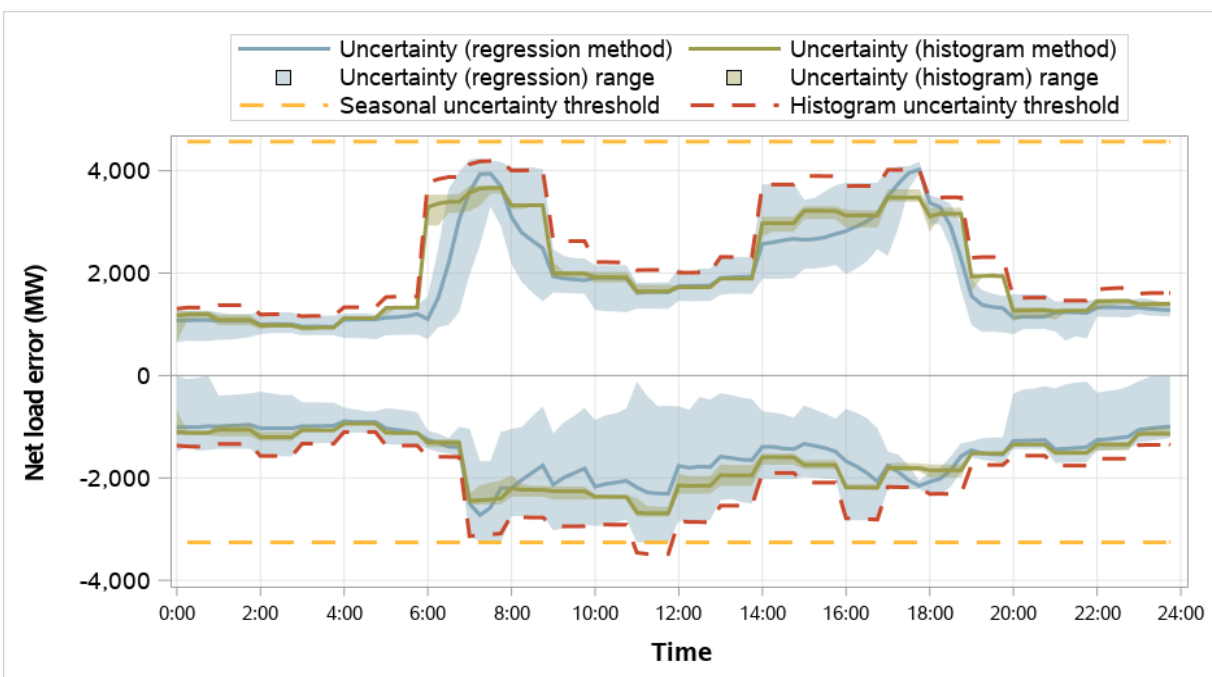
Figure 11.7 shows 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation (RSE), comparing the *mosaic quantile regression* method that is used currently and a simpler *histogram* method (pulled from the 2.5th and 97.5th percentile of observations in

the hour from the historical 180-day period).⁸⁷ 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.⁸⁸

Figure 11.8 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.

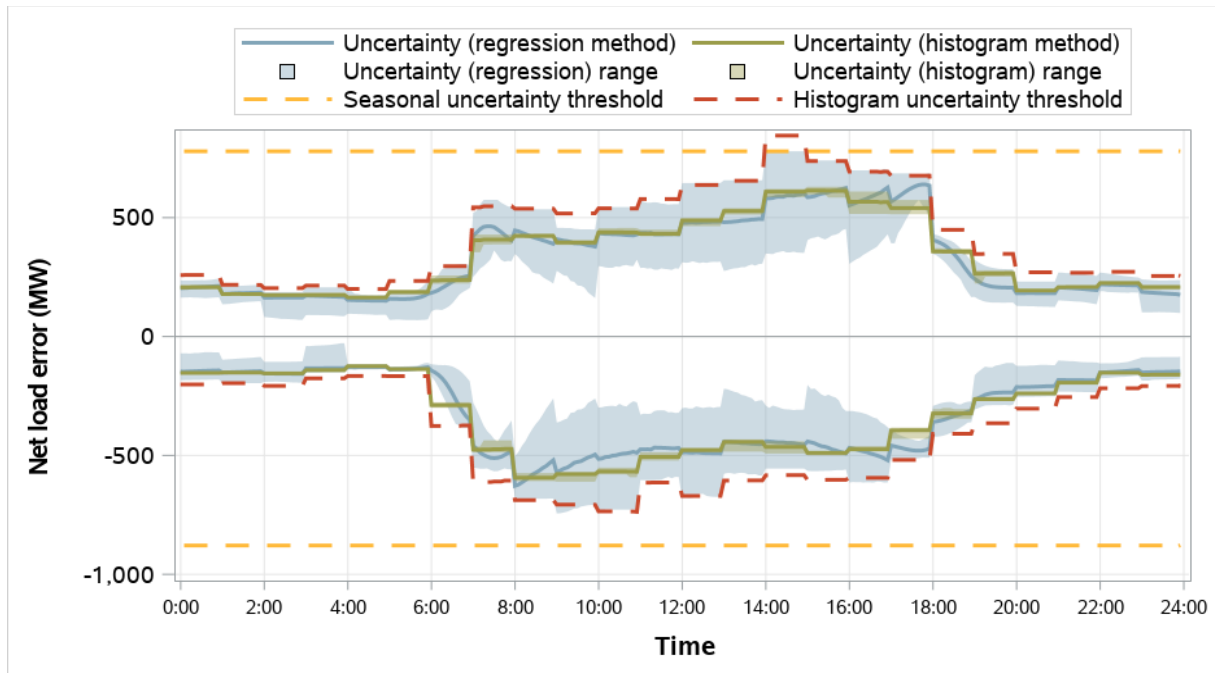
Figure 11.7 15-minute market pass-group uncertainty requirements (April–June 2026)



⁸⁷ The ISO uses *mosaic quantile regression* to calculate uncertainty. This applies regression techniques on historical data to produce outputs that are dependent on current forecast conditions. This is compared against the *histogram* method which simply selects the 2.5th and 97.5th percentile observations from the historical data. The histogram method was used prior to the implementation of the regression-based method.

⁸⁸ Two ceiling thresholds are applied to help prevent extreme outlier results from impacting the final uncertainty.

Figure 11.8 5-minute market pass-group uncertainty requirements (April–June 2026)



11.2.2 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.⁸⁹ 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.⁹⁰ 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-

⁸⁹ 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/businessrequirements12-flexiblerampingproduct-deliverability.pdf>

⁹⁰ 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.

activated on June 12 due to performance issues with the solution run-times.⁹¹ Using the same constraints for both the real-time market and flexible ramping product deployment scenarios is important in order to prevent conditions in which procured flexible capacity is actually stranded behind transmission constraint congestion, and therefore not able to address materialized uncertainty.

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

The slack variables are implemented for each balancing area.⁹² 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.⁹³ 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.⁹⁴ 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 11.9 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.⁹⁵ The pass-group constraint for procuring *upward* flexible capacity in both the 15-minute and 5-minute markets was binding in about 0.3 percent or less of intervals on average during the

⁹¹ *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>

⁹² 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).

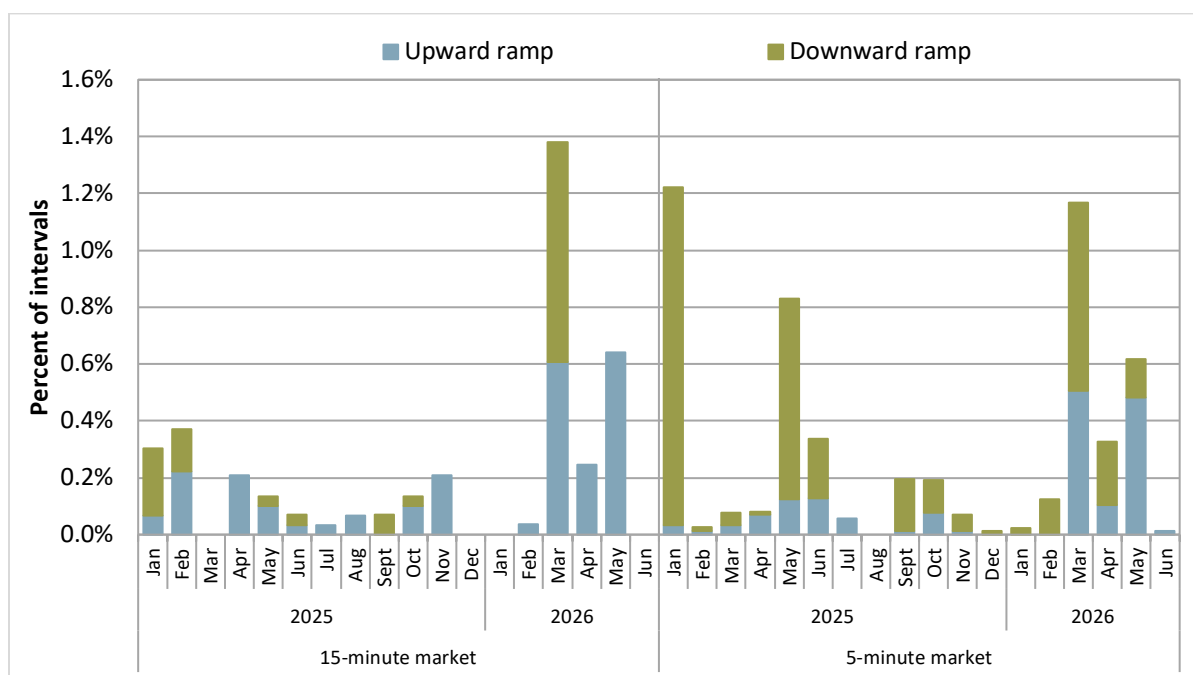
⁹³ For upward flexible capacity, the demand curves are capped at \$247/MWh.

⁹⁴ 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.

⁹⁵ 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.

quarter. The pass-group constraint for procuring *downward* flexibility in the 15- and 5-minute markets was also binding very infrequently, in less than 0.1 percent of intervals on average.

Figure 11.9 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 11.10⁹⁶ 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 11.9, 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.

⁹⁶ Localized flexible ramping product prices within the pass-group that are entirely driven by congestion on transmission constraints are not reflected in this figure.

The frequency of upward flexible ramping product prices has been very low across the pass-group until May of this year. 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 about 0.9 percent of intervals in April 2026, 32.1 percent of intervals in May 2026, and 20.4 percent in June 2026. This represents an average of 17.8 percent of intervals in the second quarter of 2026, up from 0.2 percent in the same quarter of 2025. DMM has notified the ISO of the increase in flexible ramping product prices and will continue to work with the ISO to understand the underlying causes.

Figure 11.10 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

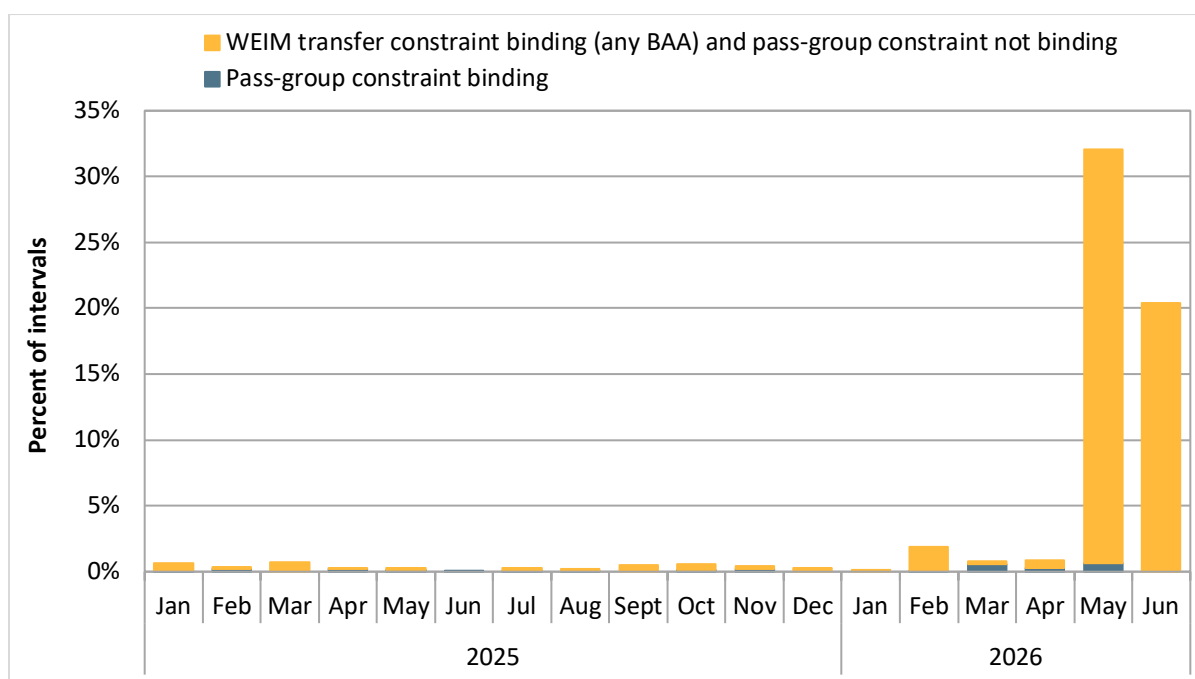


Figure 11.11 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

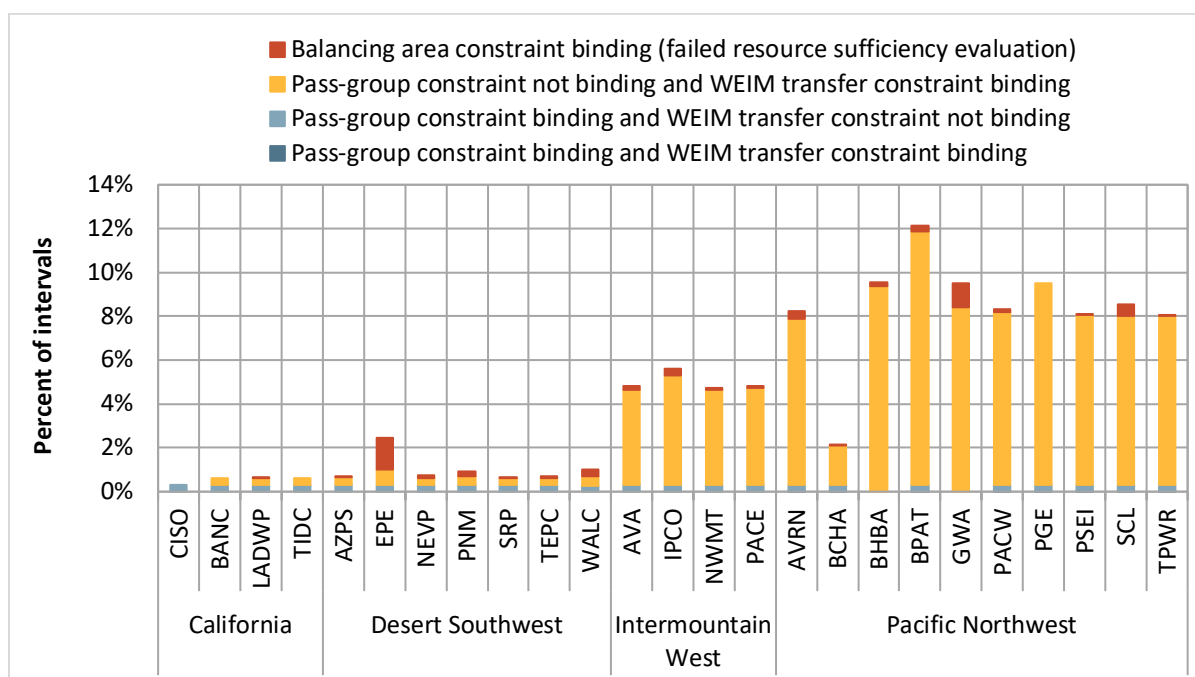
- **Balancing area constraint binding (failed resource sufficiency evaluation)** indicates that the balancing area failed the resource sufficiency evaluation and there is a price for upward flexible capacity within the balancing area. When a balancing area fails the resource sufficiency evaluation, the 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 11.11.
- **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 0.3 percent of intervals. Balancing areas across the WEIM failed the resource sufficiency evaluation during around 0.2 percent of intervals overall. 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.⁹⁷

Balancing areas in the Intermountain West and Pacific Northwest experienced an increase in the frequency of flexible ramping product prices due to the WEIM transfer constraint binding. Balancing areas in the Intermountain West had prices for flexible capacity due to the WEIM transfer constraint binding in about 4.5 percent of intervals in the second quarter of 2026, up from 0.0 percent of intervals of the same quarter in 2025. Balancing areas in the Pacific Northwest had prices for flexible capacity due to the WEIM transfer constraint binding in about 7.9 percent of intervals in the second quarter of 2026, up from 0.02 percent of intervals of the same quarter in 2025.

⁹⁷ There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each evaluation. The first and second runs are sometimes considered the advisory runs, with the final evaluation occurring at 40 minutes prior to the hour. For procuring and pricing flexible capacity in the first 15-minute market interval of each hour, the market uses the results from the second run of the resource sufficiency evaluation. This is based on the latest information available at the time of this market run.

Figure 11.11 Frequency of upward flexible ramping product prices by balancing area and constraint

11.2.3 Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that passed the resource sufficiency evaluation. Figure 11.12 and Figure 11.13 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 65 percent of upward flexible capacity and 33 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (17 percent). Wind and solar resources combined made up around 45 percent of downward flexible capacity.

Figure 11.12 Average upward pass-group flexible ramp procurement by fuel type (15-minute market, Q2 2026)

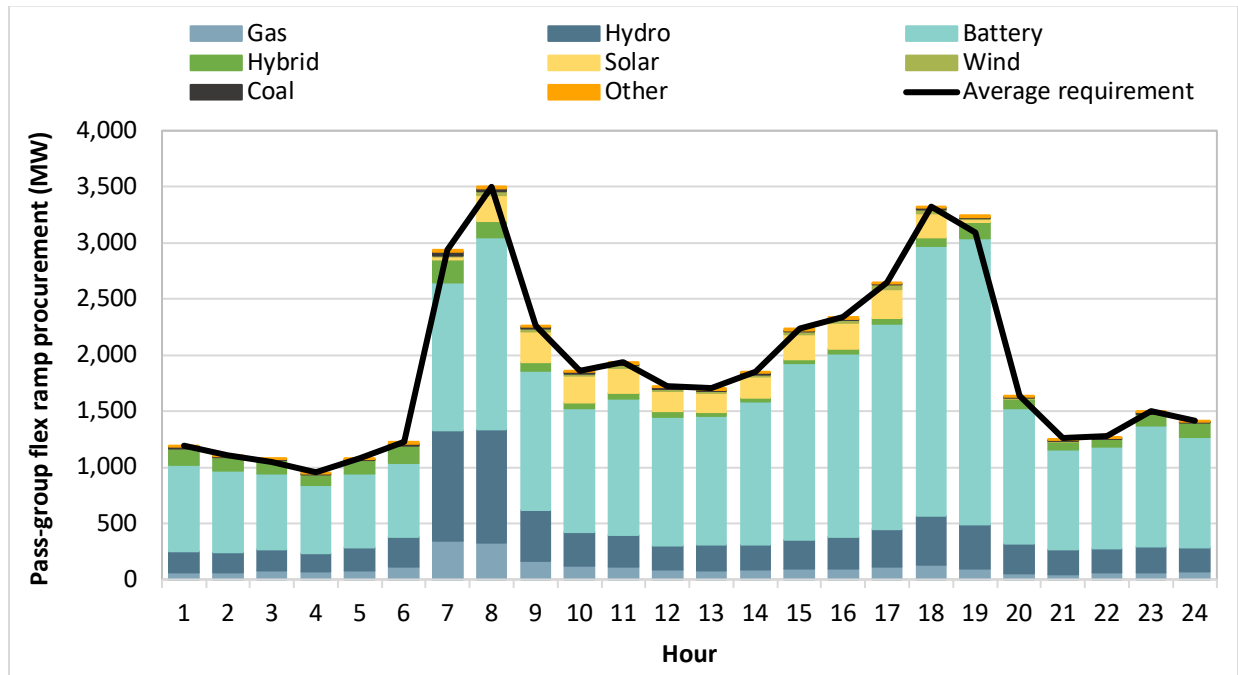


Figure 11.13 Average downward pass-group flexible ramp procurement by fuel type (15-minute market, Q2 2026)

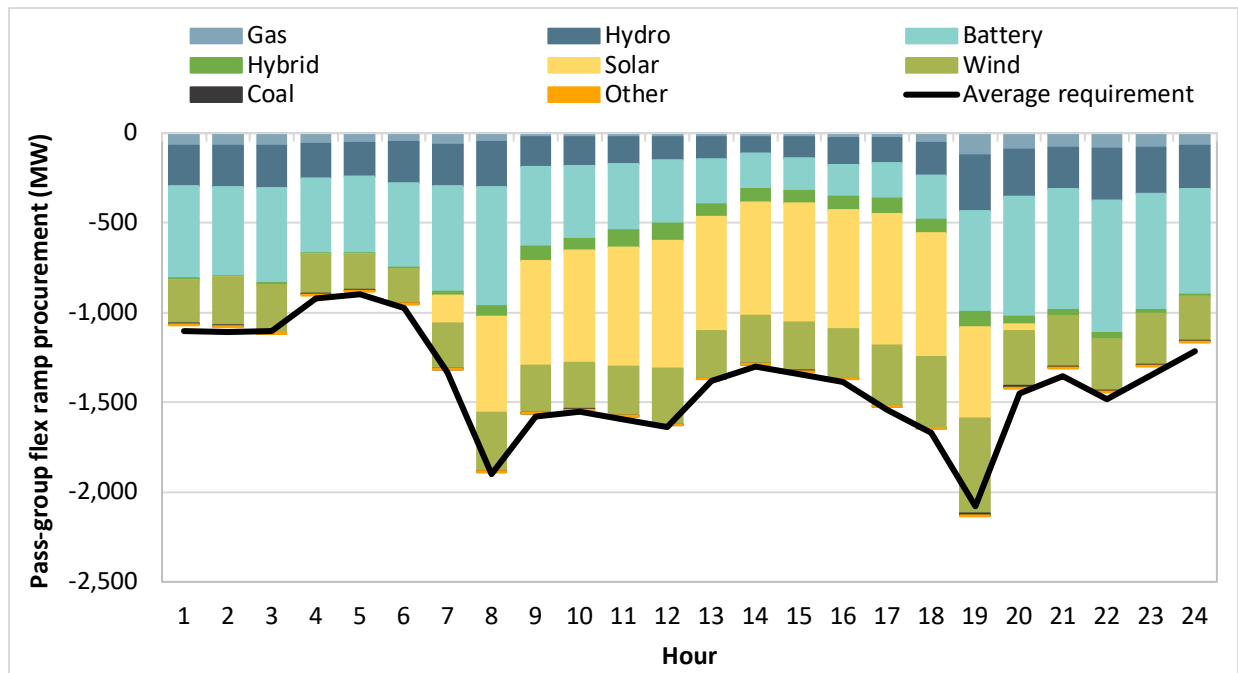
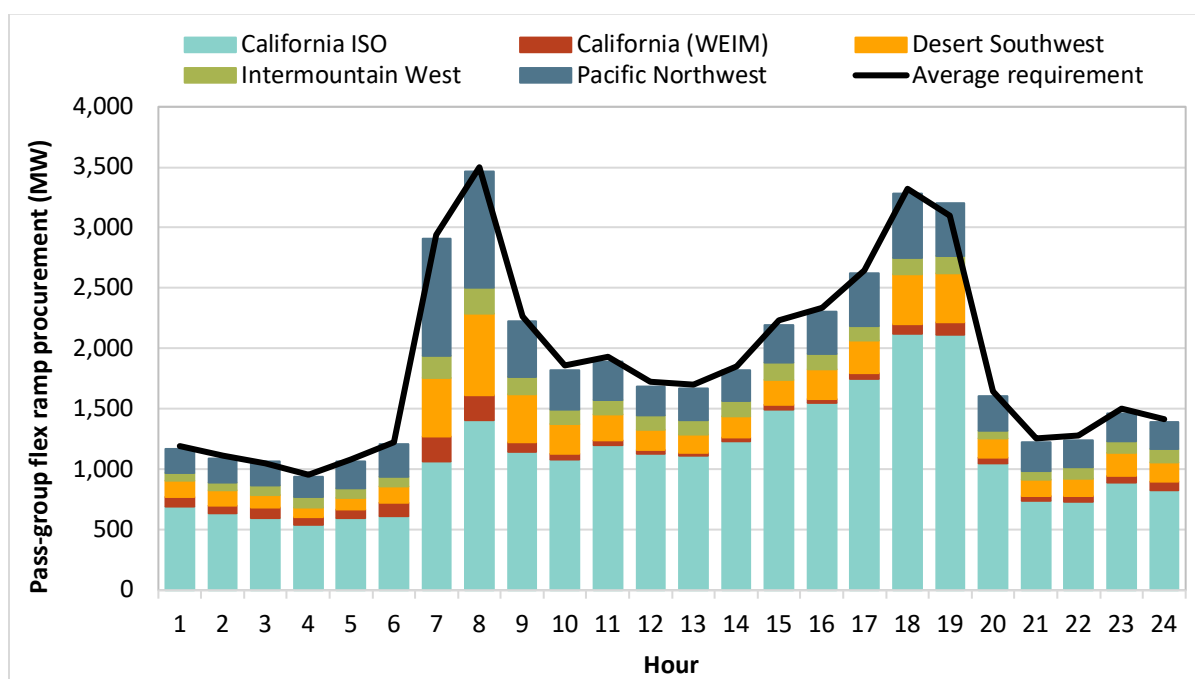


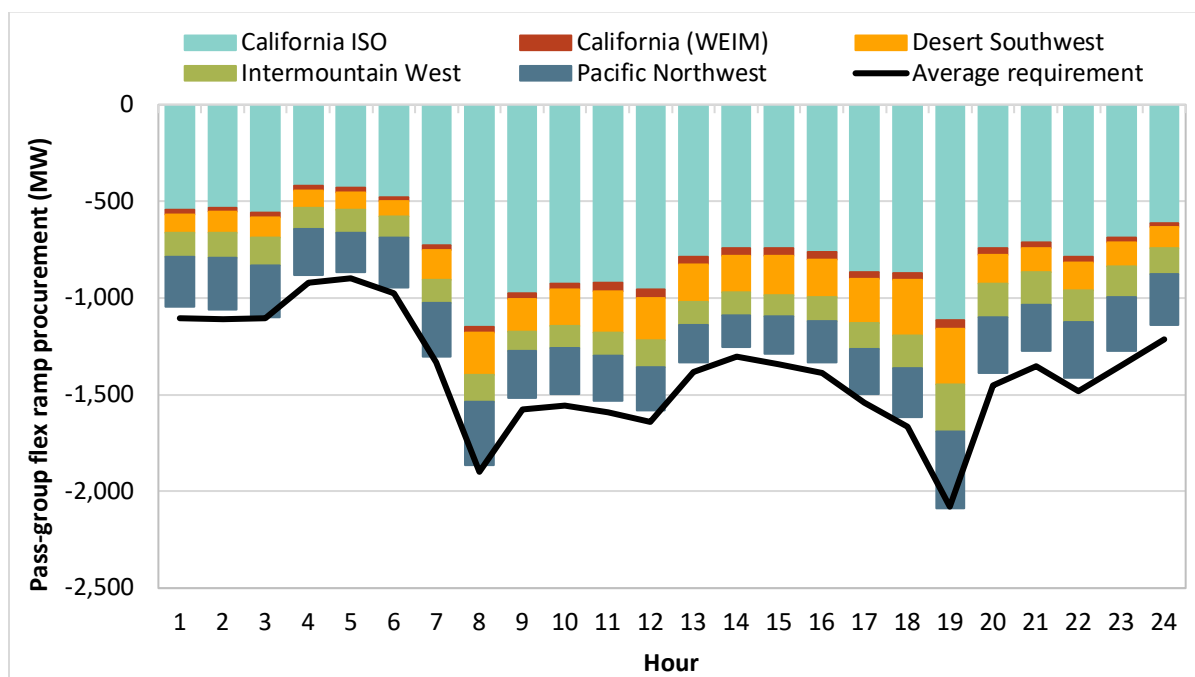
Figure 11.14 and Figure 11.15 show the average upward or downward flexible capacity that was procured in various regions.⁹⁸ These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export 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 59 percent in the upward direction and 56 percent in the downward direction. Balancing areas in the Desert Southwest made up 12 percent of flexible capacity in each direction, while balancing areas in the Pacific Northwest made up 19 percent of flexible capacity in each direction. Balancing areas in the Intermountain West made up 6 percent of upward flexible capacity and 10 percent in the downward direction.

Figure 11.14 Average upward pass-group flexible ramp procurement by region (15-minute market, Q2 2026)



⁹⁸ 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, Avista, Black Hills, and Power Watch. Pacific Northwest includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Figure 11.15 Average downward pass-group flexible ramp procurement by region (15-minute market, Q2 2026)



11.3 Uncertainty calculation and assessments

This section discusses uncertainty considered in different applications of the market. This includes the EDAM resource sufficiency evaluation (EDAM RSE) and imbalance reserve product in the day-ahead market, and the WEIM resource sufficiency evaluation (WEIM RSE) and flexible ramping products (FRP) in the real-time markets. Because net load uncertainty can be highly variable and difficult to interpret directly, this section presents basic statistics and distributions to provide context for the characteristics of uncertainty observed in the market.⁹⁹

11.3.1 Imbalance reserve and EDAM resource sufficiency evaluation uncertainty

The imbalance reserve product procures flexible capacity in the day-ahead market to cover net-load uncertainty that may materialize in the real-time market. Uncertainty is measured as the difference

⁹⁹ Uncertainty represents conditions that are not known at the time of the market run and only materialize in future operating intervals. To account for this uncertainty, the ISO uses Mosaic Quantile regression to estimate the range of uncertainty that may materialize.

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

between the 15-minute market net-load forecast and the corresponding day-ahead net-load forecast, where net load is demand minus wind and solar generation. Upward and downward requirements reflect the upper and lower portions of the forecast-error: imbalance reserve up addresses the higher-end of the uncertainty while imbalance reserve down addresses the lower-end of the uncertainty. The same definition of uncertainty is also used to determine the additional reliability capacity that may need to be procured through the residual unit commitment process.

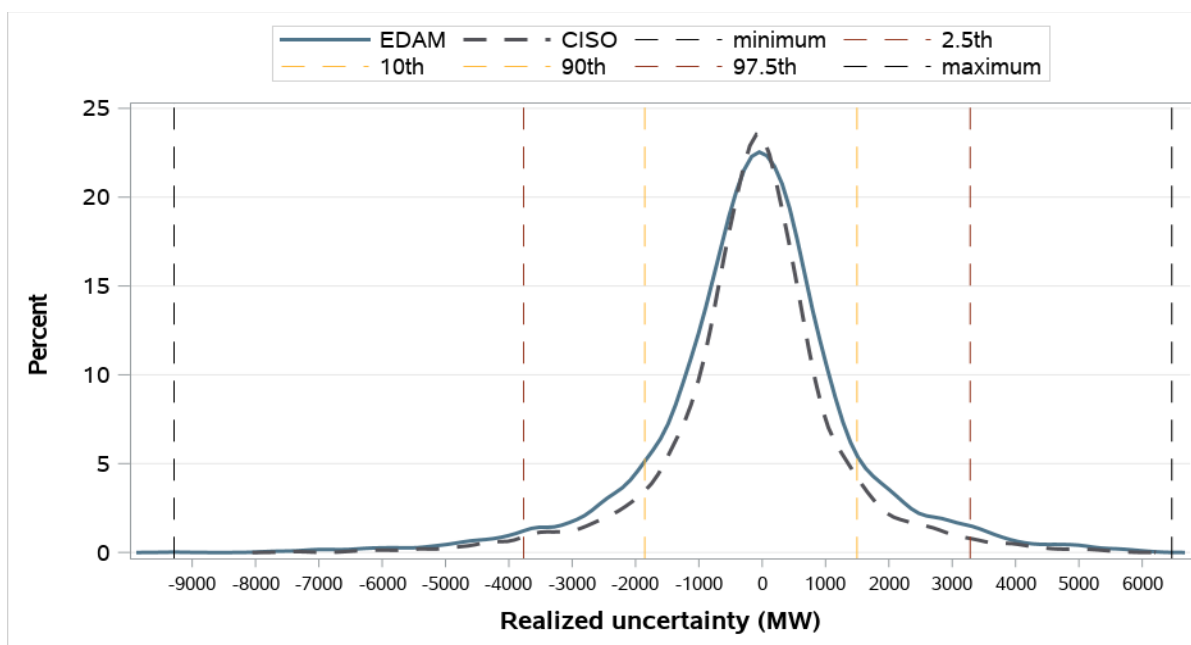
Because the actual uncertainty is not known at the time of the market run, the ISO uses the mosaic quantile regression to estimate the uncertainty in advance and establish the imbalance reserve requirement. The EDAM resource sufficiency evaluation requirement includes an uncertainty component in addition to each balancing area's load forecast. The ISO uses the same definition of uncertainty and regression method to determine both the EDAM RSE uncertainty component and the upward imbalance reserve product uncertainty. Figure 11.16 shows the uncertainty that ultimately materialized in the market, which is the uncertainty the imbalance reserve and EDAM RSE requirement is intended to cover.

Figure 11.16 shows the distribution of realized uncertainty between the net-load forecasts of the day-ahead market and the 15-minute market in May and June 2026. This distribution represents all uncertainties observed in the 15-minute market intervals for this quarter and serves as the forecasting target. The blue line represents aggregate uncertainty across all EDAM entities, while the black dashed line represents the CAISO balancing area only, illustrating the change in uncertainty following EDAM implementation. Vertical reference lines indicate the minimum, maximum, and selected percentiles of EDAM uncertainty.

The first notable feature is the shape of the EDAM and CAISO uncertainty distributions. EDAM uncertainty is more dispersed, with a higher frequency of non-zero values, particularly between -4,000 MW and 4,000 MW. By contrast, the CAISO-only distribution is more concentrated near zero. This suggests that forecast uncertainty across the three EDAM BAAs often moves in the same direction rather than offsetting across areas, increasing aggregate uncertainty in either the positive or negative direction.

The EDAM net-load uncertainty in the day-ahead time horizon ranged from -9,300 MW to 6,500 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 and from the 2.5th percentile to the minimum value. These areas ranged from 3,300 MW to 6,500 MW on the positive side and from about -3,800 MW to -9,300 MW on the negative side. The distribution is strongly skewed downward. This indicates that 15-minute net-load came in below the day-ahead forecast. 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 11.16 Distribution of realized uncertainty between RUC and 15-minute market net-load forecasts (May–June 2026)



11.3.2 Flexible ramping product uncertainty

The flexible ramping product procures flexible capacity to cover uncertainty that may materialize in the real-time market. By design, the *uncertainty requirement* captures the extreme ends of net-load uncertainty and it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. For the 15-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 15-minute market net-load forecast and the binding 5-minute market forecasts. For the 5-minute market flexible ramping product, uncertainty is defined as the difference between the advisory 5-minute market forecast and the binding 5-minute market forecast.

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

Figure 11.17 illustrates the distribution of realized uncertainty in the flexible ramping product (FRP) for the group of balancing areas that passed the resource sufficiency evaluation (RSE) for the second quarter of 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 2,300 MW to over 6,100 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 11.17 Distribution of realized uncertainty in FRP (pass-group, April–June 2026)

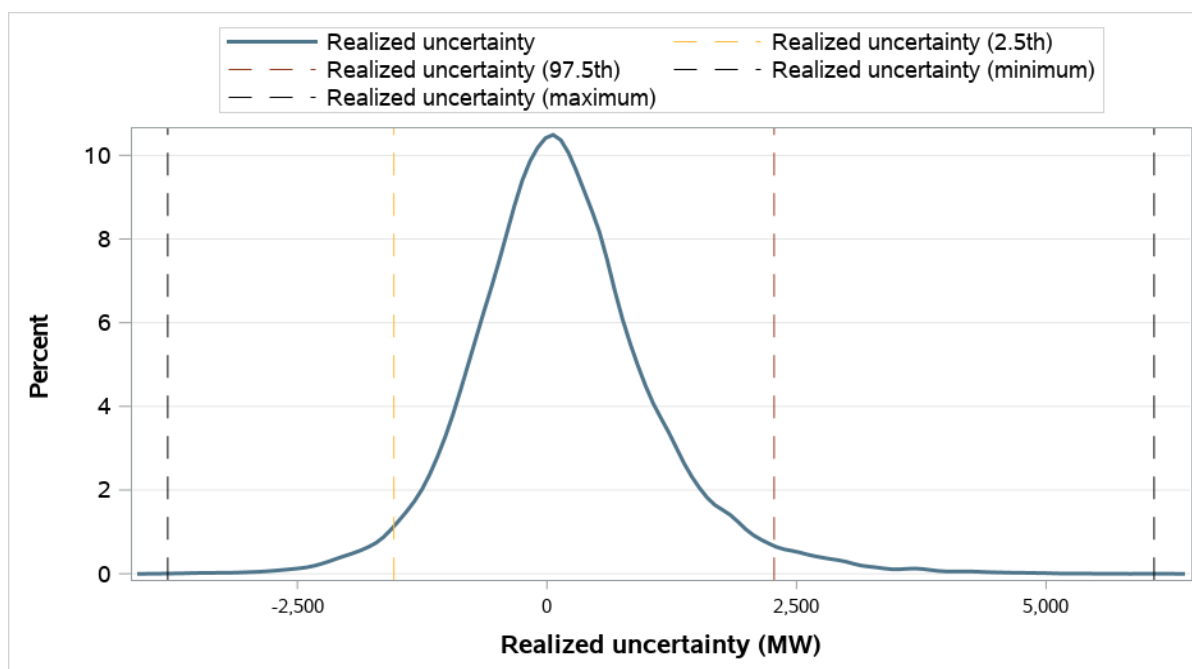


Table 11.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the 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.¹⁰⁰

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.¹⁰¹ In the 15-minute

¹⁰⁰ 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.

¹⁰¹ 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 25 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.

market, uncertainty forecasted by mosaic regression generally had lower coverage and lower requirements in both markets. In the 5-minute market, coverage was around the same.

Table 11.1 Average pass-group uncertainty requirements (April–June 2026)

Market	Direction	Requirement			Coverage		
		Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
15-minute market	Up	2,056	1,890	-166	98.2%	98.0%	-0.2%
	Down	1,661	1,518	-143	97.1%	95.8%	-1.3%
5-minute market	Up	342	336	-6	96.3%	96.3%	0.0%
	Down	330	321	-9	97.2%	97.2%	0.0%

11.3.3 WEIM resource sufficiency evaluation uncertainty

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the WEIM 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.¹⁰² 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 WEIM resource sufficiency evaluation.

Figure 11.18 shows the distribution of realized 15-minute uncertainty in the WEIM RSE for each balancing authority area (BAA) for the second quarter of 2026. Here, realized uncertainty is defined as the net-load forecast difference between the forecasts used in the WEIM resource sufficiency evaluation and those in the binding 5-minute market runs. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation.¹⁰³ 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.

¹⁰² 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.

¹⁰³ 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.

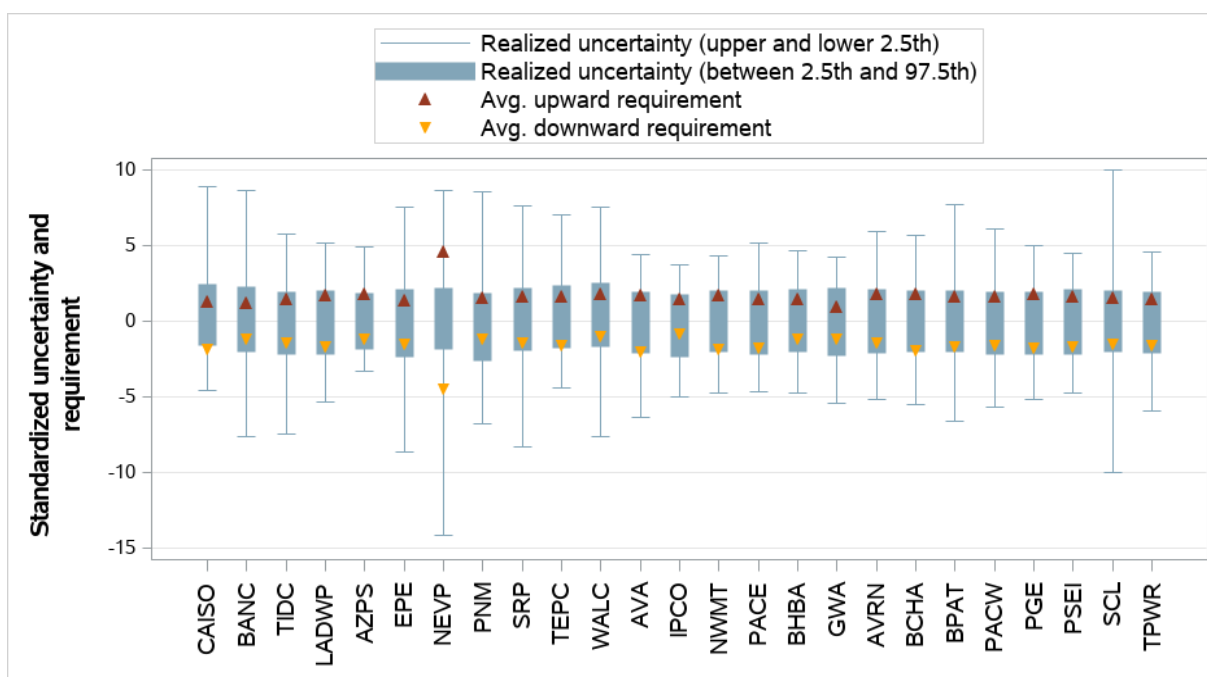
Figure 11.18 Standardized realized uncertainty and requirement for RSE (April–June 2026)

Figure 11.18 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.
- **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.

Table 11.2 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 WEIM 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 all of the WEIM entities. The WEIM resource sufficiency evaluation uncertainty calculated from the regression method covered between 84 and 93 percent of realized uncertainty across all balancing areas.

Table 11.2 Average resource sufficiency evaluation uncertainty requirements and coverage (April–June 2026)

Balancing area	Upward uncertainty			Downward uncertainty			Coverage		
	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
Arizona Public Service	353	333	-20	452	401	-51	91%	90%	-1%
Avangrid	218	187	-31	180	144	-36	93%	92%	-1%
Avista	57	56	0	67	63	-5	93%	92%	-2%
BANC	45	40	-5	45	37	-8	90%	87%	-3%
Black Hills	69	66	-3	71	65	-5	83%	80%	-3%
Bonneville Power Admin.	256	219	-37	238	204	-33	94%	92%	-2%
California ISO	1,435	1,318	-117	909	817	-92	91%	90%	-1%
El Paso Electric	51	48	-3	52	50	-2	91%	90%	-2%
Idaho Power	138	136	-2	183	164	-19	85%	84%	-1%
LADWP	168	157	-11	155	147	-8	93%	92%	-1%
NorthWestern Energy	79	76	-3	80	75	-5	93%	92%	-1%
NV Energy	280	227	-53	235	179	-56	94%	91%	-3%
PacifiCorp East	525	489	-36	702	648	-54	94%	91%	-3%
PacifiCorp West	110	92	-17	147	103	-44	95%	92%	-3%
Portland General Electric	122	116	-6	134	128	-6	93%	92%	-1%
Powerex	140	131	-9	153	143	-10	94%	93%	-1%
Power Watch	59	41	-18	56	53	-3	83%	81%	-2%
PNM	233	212	-21	254	216	-37	92%	92%	0%
Puget Sound Energy	160	148	-12	155	147	-8	91%	90%	-1%
Salt River Project	165	159	-6	144	118	-26	93%	92%	-1%
Seattle City Light	19	16	-3	18	16	-2	94%	91%	-3%
Tacoma Power	11	10	-1	11	10	-1	93%	90%	-3%
Tucson Electric Power	123	121	-2	104	82	-22	92%	91%	-1%
Turlock Irrigation District	7	7	0	8	8	0	90%	89%	-1%
WAPA Desert Southwest	61	61	0	33	25	-8	87%	85%	-2%

WEIM RSE uncertainty special issue — time horizon for predicting uncertainty

The regression model used for the WEIM 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 WEIM resource sufficiency evaluation includes four intervals, typically produced between 47.5 and 102.5 minutes before real-time.

The WEIM 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.¹⁰⁴ 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

¹⁰⁴ A balancing-area-specific flexible ramping product uncertainty requirement will be enforced for any balancing area that failed the WEIM resource sufficiency evaluation.

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 WEIM resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 11.19 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 WEIM resource sufficiency evaluation.¹⁰⁵ For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the WEIM 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 WEIM 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 WEIM 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 WEIM 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.¹⁰⁶

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the WEIM resource sufficiency evaluation. Figure 11.20 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized uncertainty from the forecasts considered in the WEIM 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.

¹⁰⁵ The figure shows the time horizon for the WEIM 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.

¹⁰⁶ The WEIM 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 WEIM resource sufficiency evaluation is combined with the short-term regression coefficients.

Figure 11.19 Comparison of timeframe considered for the flexible ramping product and WEIM resource sufficiency evaluation

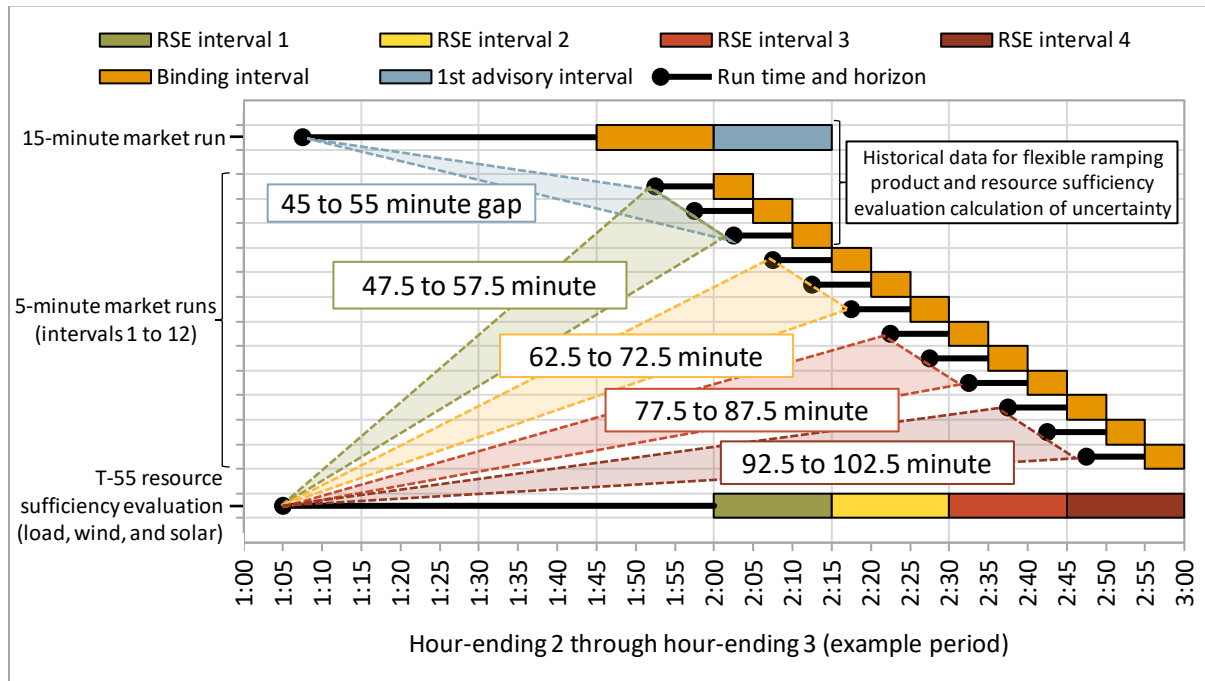
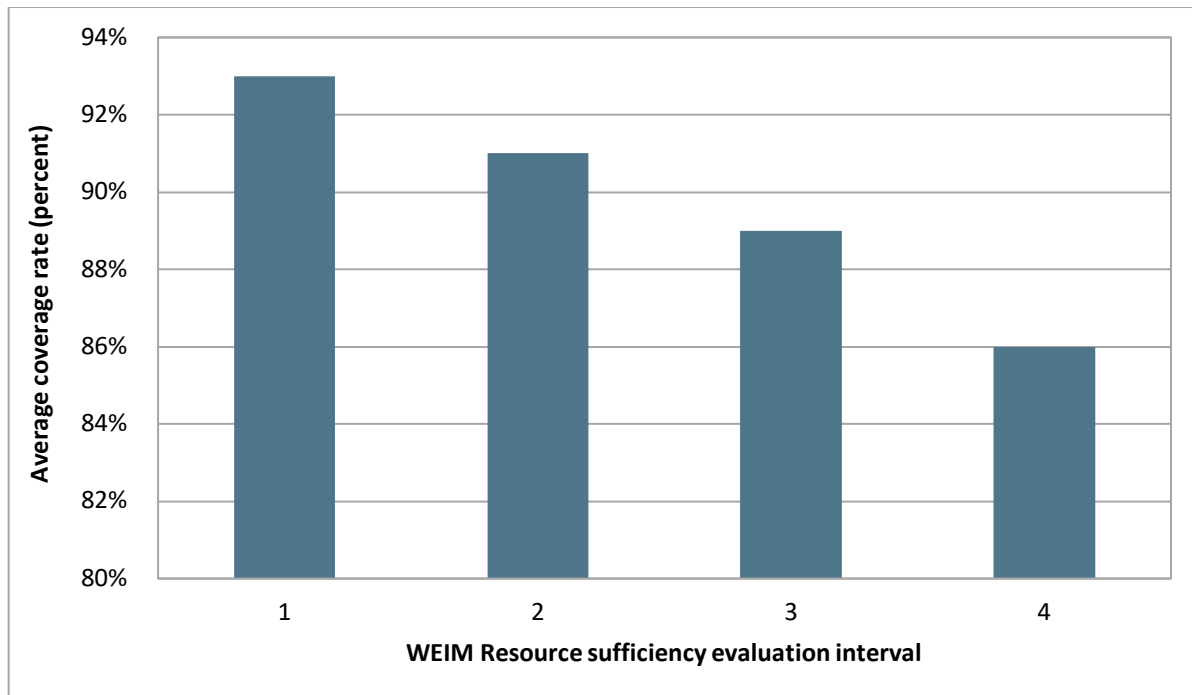


Figure 11.20 Average coverage rate by WEIM resource sufficiency evaluation interval (April–June 2026)



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 second quarter of 2026 to the second quarter of 2025, incremental manual dispatch energy from participating resources (yellow bars) increased in all regions except the Desert Southwest. The California region, Pacific Northwest, and Intermountain West increased by 60 percent, 30 percent, and six percent, respectively, while the Desert Southwest region decreased by three percent. Similarly, when comparing the second 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 Pacific Northwest regions by 62 percent and 11 percent, respectively, while the Intermountain West region increased by 67 percent.

From the second quarter of 2025 to the second quarter of 2026, decremental manual dispatch energy from participating resources (green bars) increased in both the California and Desert Southwest regions, 49 percent and nine percent, respectively. The Pacific Northwest and Intermountain West regions decreased by 27 percent and 3 percent, respectively. When comparing the second 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 Pacific Northwest regions by 67 percent and 27 percent, respectively, while the Intermountain West increased by 19 percent.

Overall, combined incremental and decremental manual dispatch energy increased by 55 percent in the California (non-CAISO) region and seven percent in the Intermountain West region. Manual dispatch energy decreased in the Pacific Northwest by 14 percent and three percent in the Desert Southwest region.

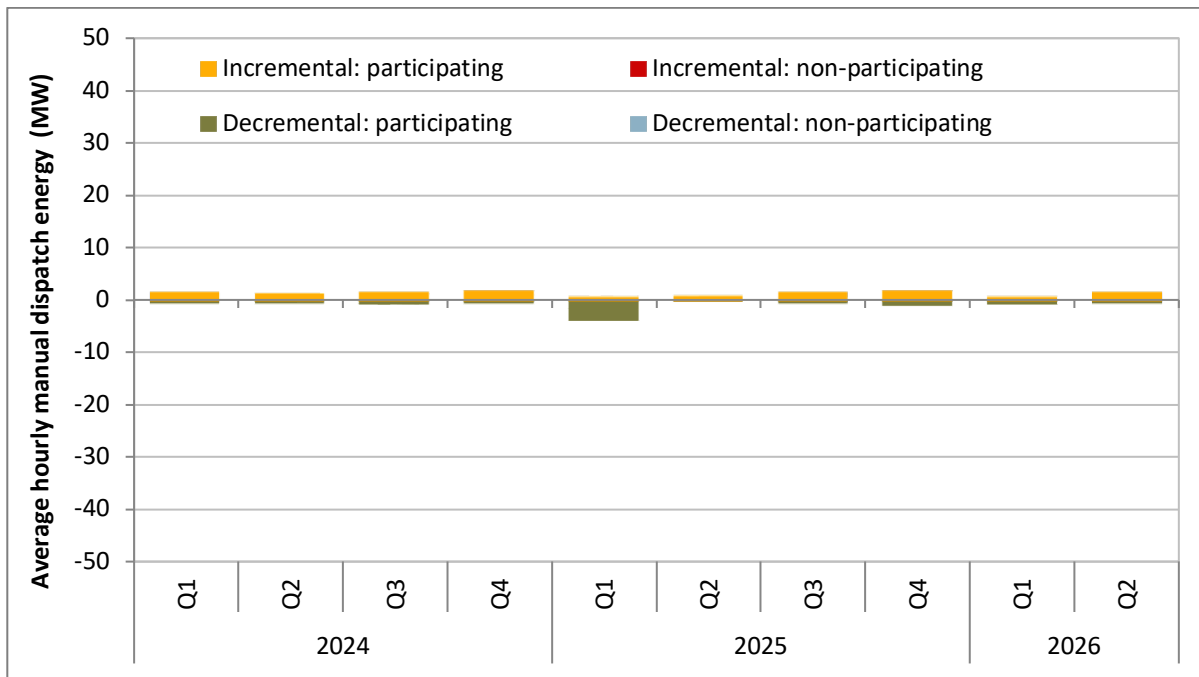
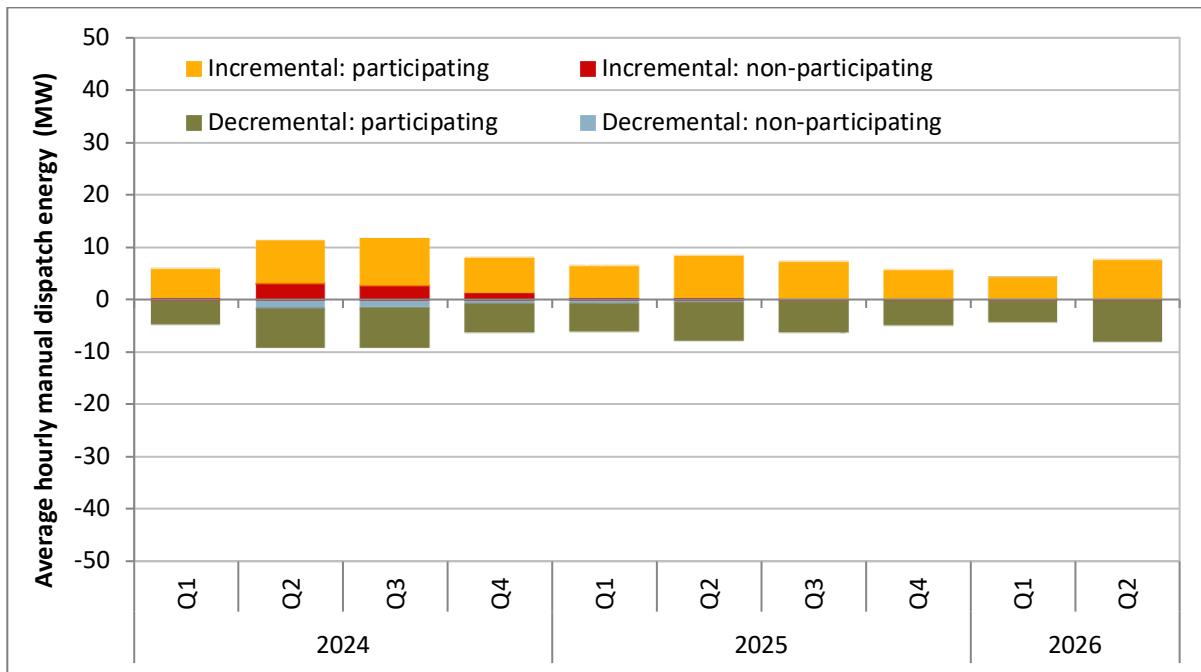
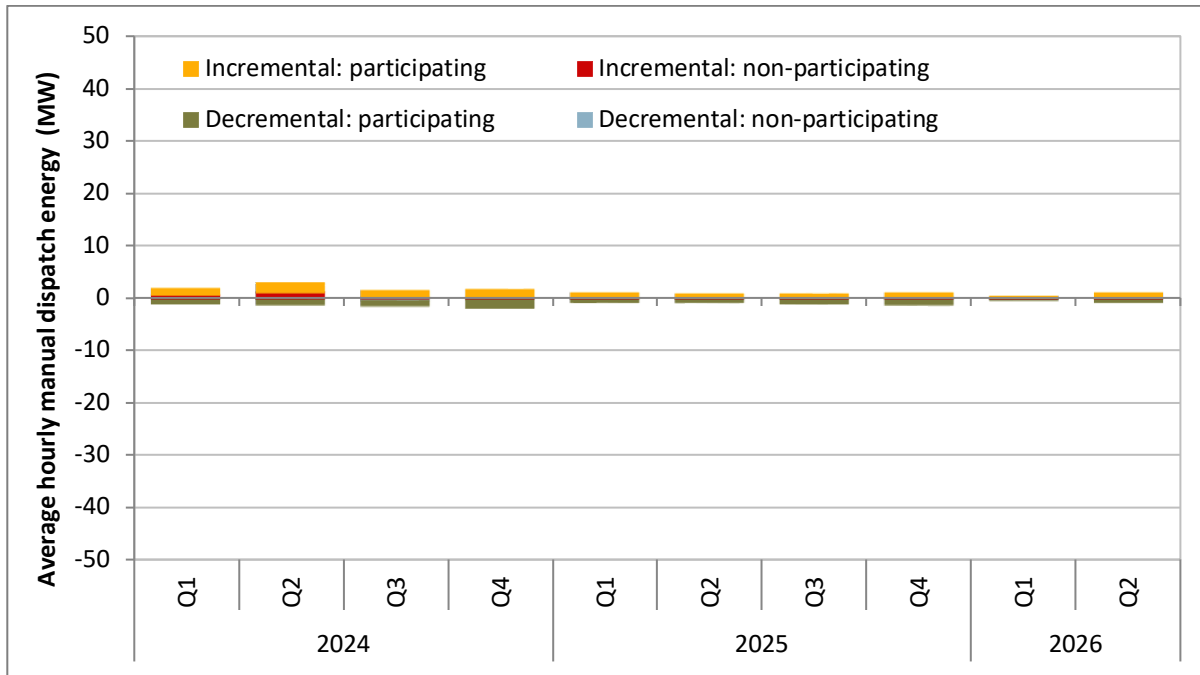
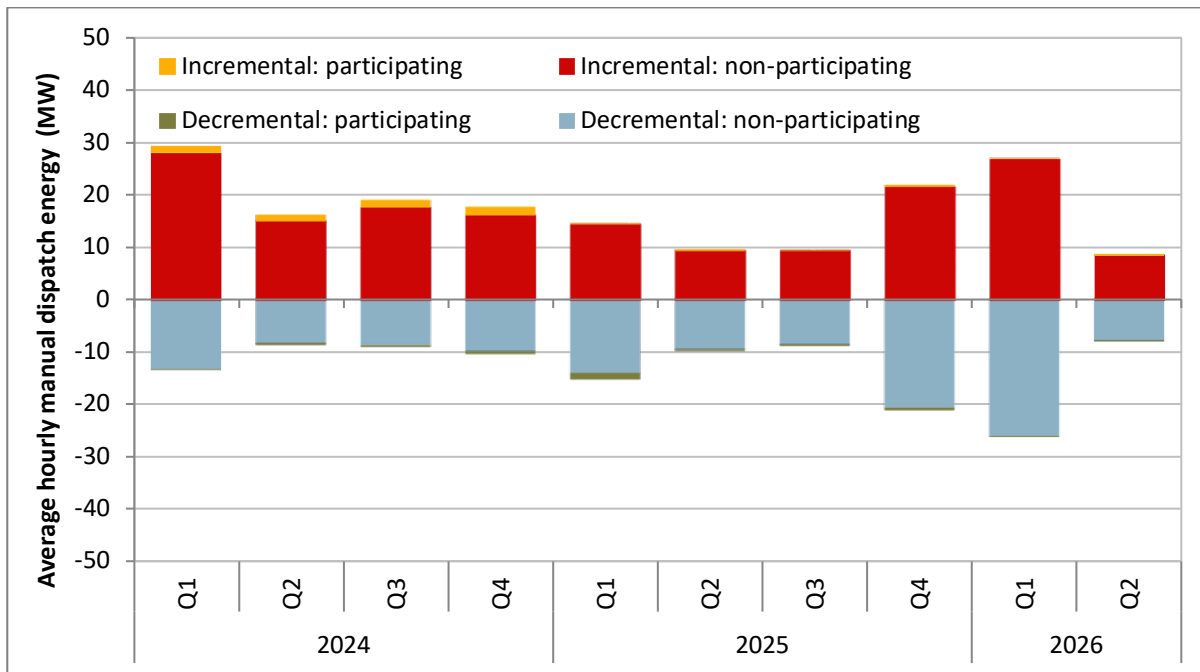
Figure 12.1 WEIM manual dispatches – California**Figure 12.2 WEIM manual dispatches – Desert Southwest**

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:

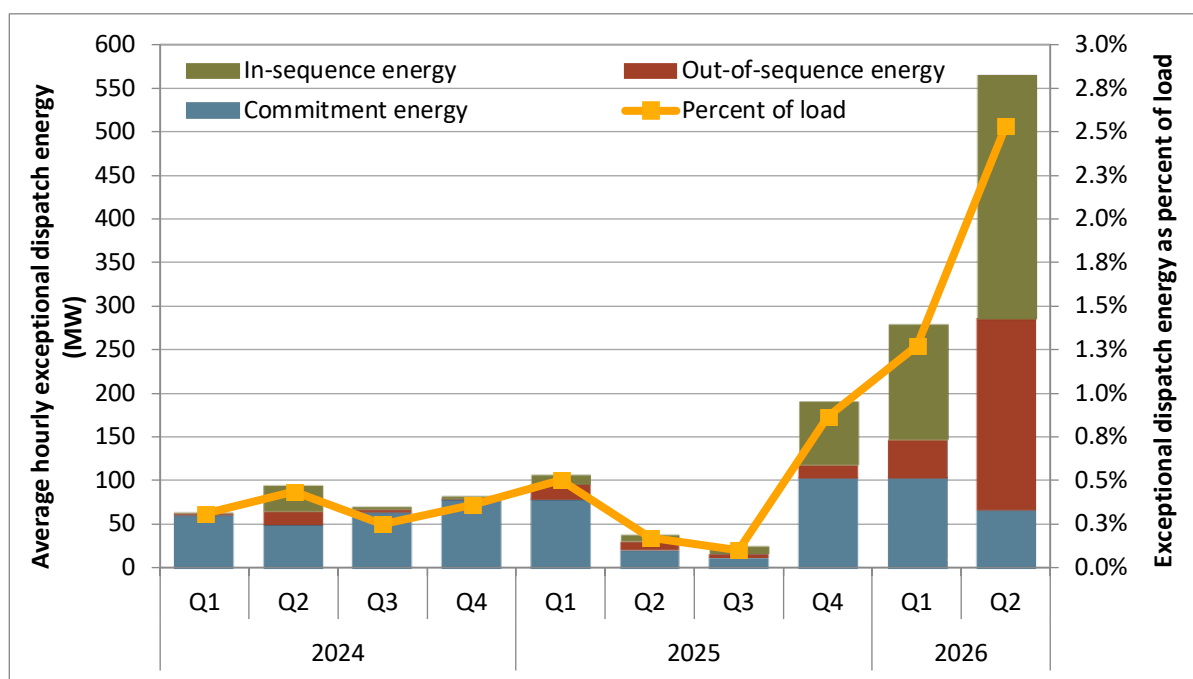
- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments 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 2.5 percent of total load in the California ISO balancing area, represented by the yellow line in Figure 12.5. The elevated level of exceptional dispatch energy was associated with the addition of new wind resources to the market. As shown in Figure 12.5, the average hourly total energy from exceptional dispatches—including minimum load energy from unit commitments—was 560 MW in the second quarter of 2026, which is a considerable increase from about 40 MW in the second quarter of 2025.¹⁰⁷

In the second quarter of 2026, exceptional dispatches for unit commitments (blue) accounted for about 12 percent of all exceptional dispatch energy; about 39 percent was from out-of-sequence energy (red), and the remaining 49 percent was from in-sequence energy (green), as shown in Figure 12.5.

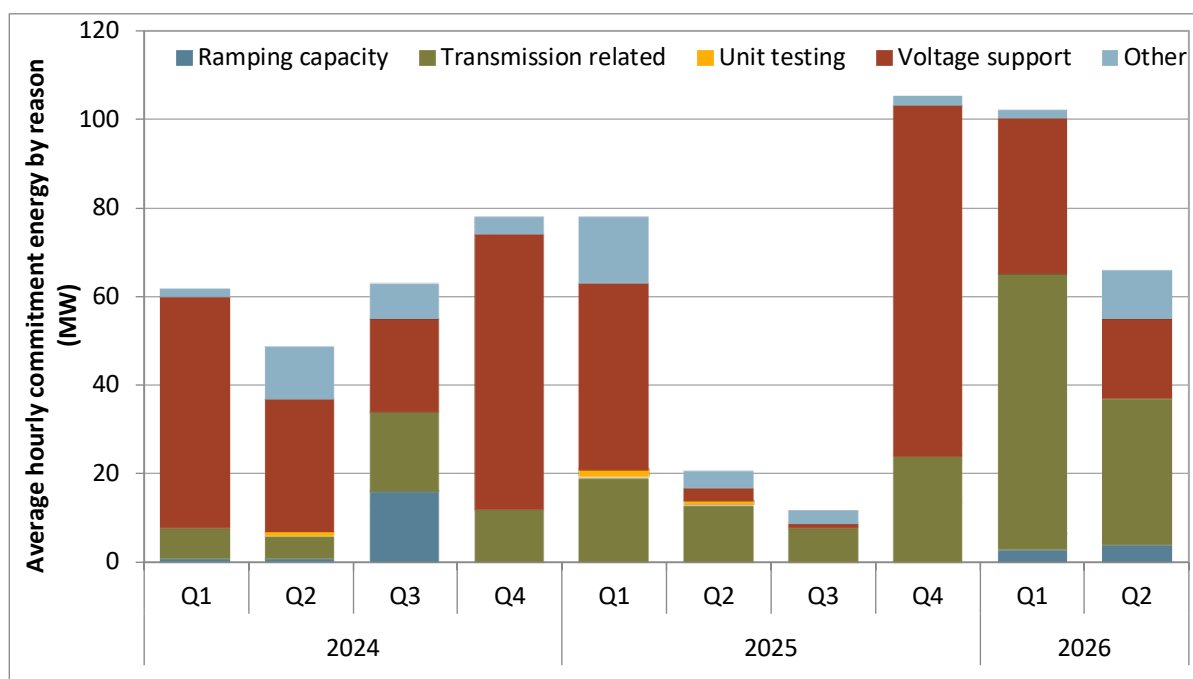
¹⁰⁷ All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional 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 second quarter of 2026 was 66 MW, above the 21 MW average minimum load energy from unit commitment in the second quarter of 2025. The increase was largely due to exceptional dispatches issued to mitigate transmission outages in Northern California.

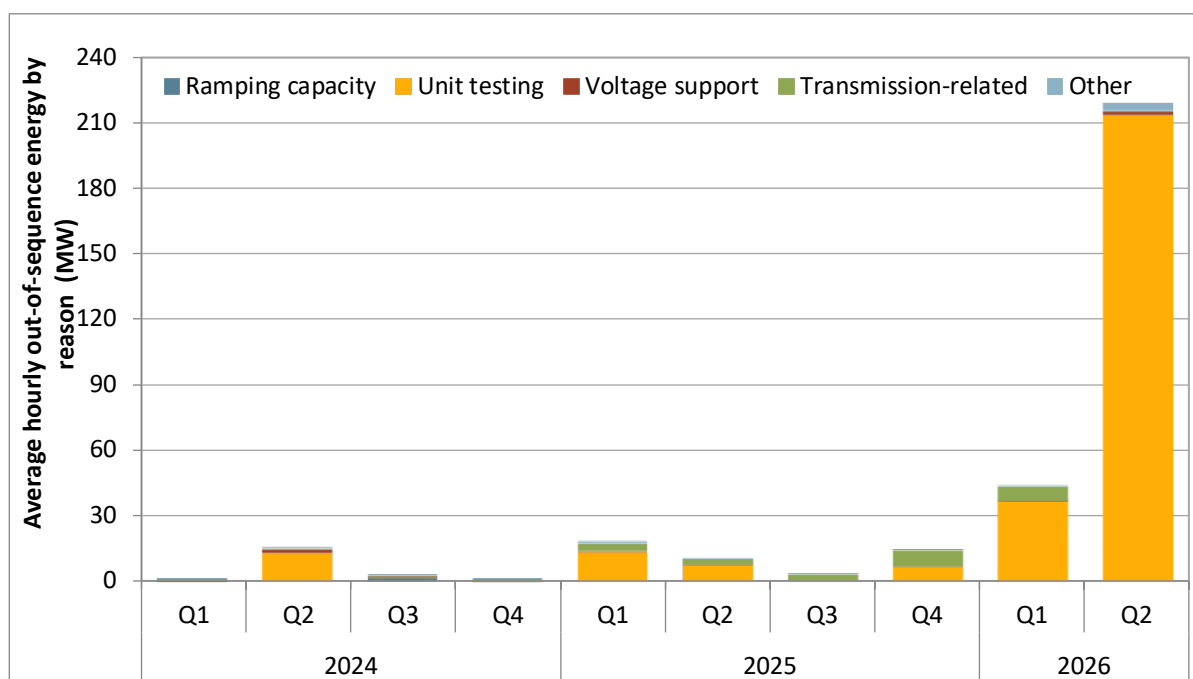
Figure 12.6 Average minimum load energy from exceptional dispatch unit commitments

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 Q2 2026. The two primary reasons logged for out-of-sequence energy in the second quarter of 2026 were unit testing (yellow bars) and transmission-related (green 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) decreased in the second quarter of 2026 compared to the second quarter of 2025.

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

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

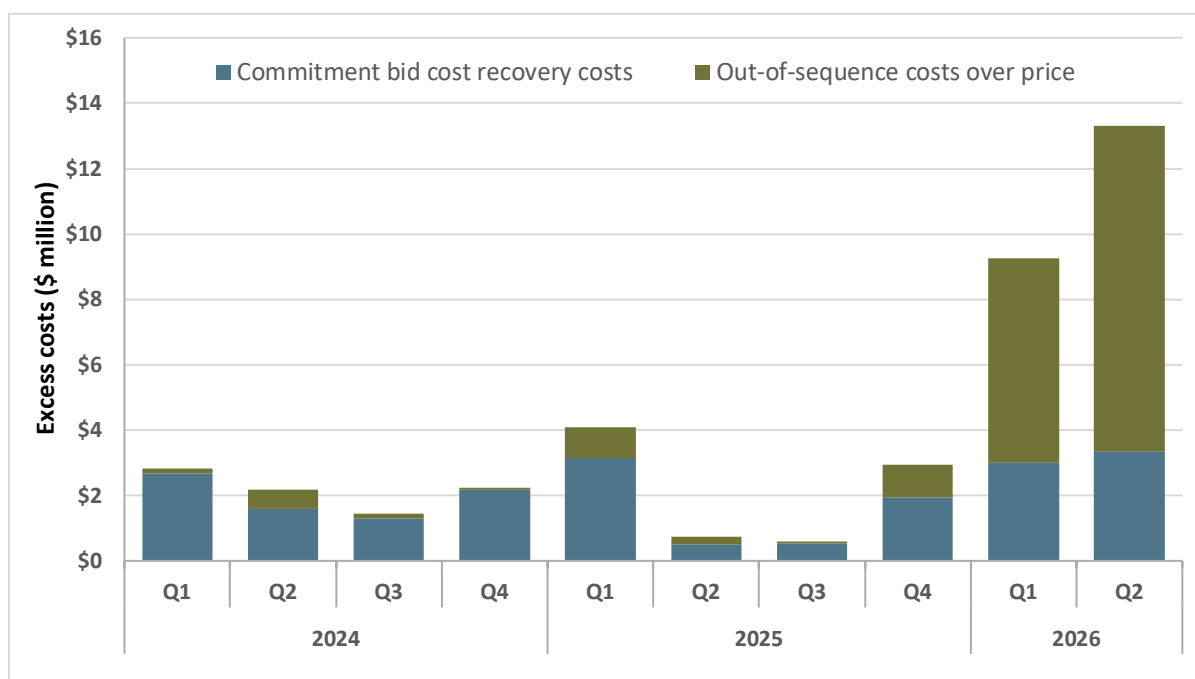
Exceptional dispatch costs

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 second quarter of 2026, out-of-sequence energy costs were about \$10 million, an increase from about \$240,000 in the second quarter of 2025. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the second quarter were \$3.3 million, up from about \$510,000 from the second quarter of 2025. Overall, the additional costs associated with exceptional dispatches in the second quarter of 2026 increased to \$13.3 million from \$750,000 in the second quarter of 2025. The higher costs were primarily attributable to out-of-sequence energy associated with voltage support requirements and planned transmission outages.

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 \$8.2 million for the second quarter, after inclusion of about \$12.3 million of virtual bidding bid cost recovery charges.¹⁰⁸

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 \$11.1 million, \$5.2 million, and \$12.7 million for April, May, and June, respectively. Virtual demand revenues were about -\$3.1 million, -\$0.5 million, and -\$2.8 million, for April, May, and June, respectively.

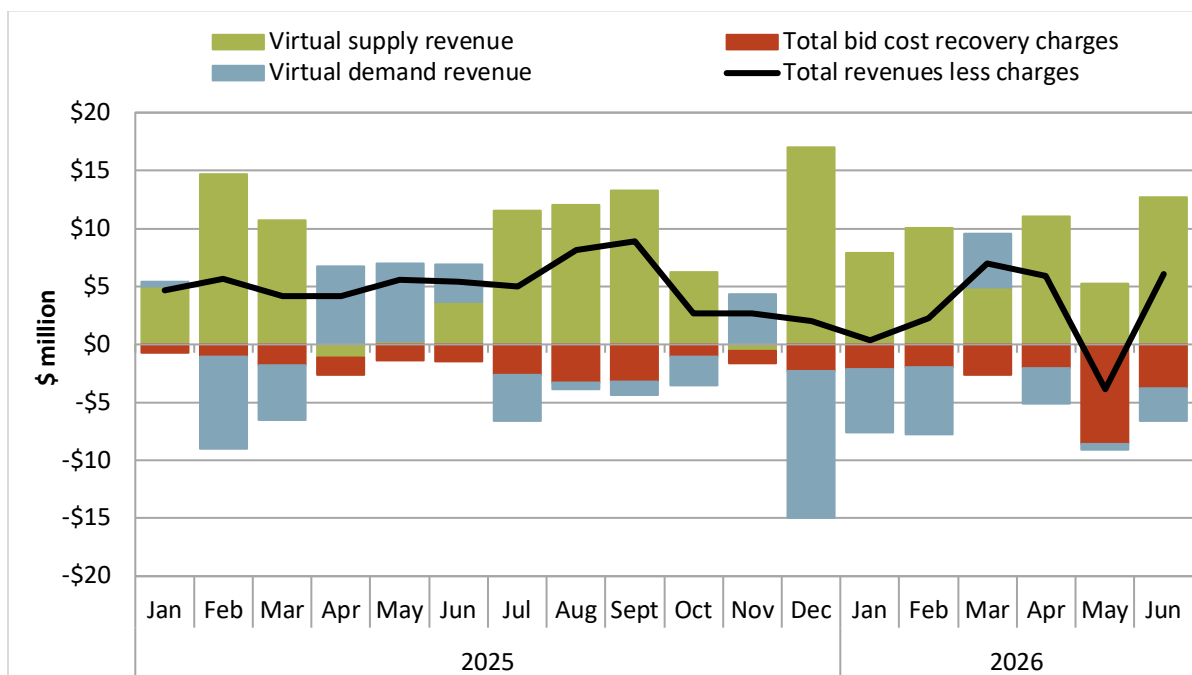
Bid cost recovery charges allocated to virtual bids were about -\$2.1 million, -\$8.6 million, and -\$3.8 million for April, May, and June, respectively.

Much of the bid cost recovery allocated to virtual bidding participants during the quarter was associated with reliability commitment costs. In April, these charges were primarily allocated through the residual unit commitment (RUC) tier 1 allocation. In May and June, following the implementation of EDAM, equivalent costs were allocated through the reliability capacity up (RCU) and reliability capacity down (RCD) tier 1 allocations.

These allocations help offset reliability commitment costs associated with virtual bids clearing in the day-ahead market. Virtual supply leads to decreased unit commitment in the day-ahead market while increasing 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. During periods of net virtual supply, a portion of this bid cost recovery is allocated to virtual supply. Since the launch of EDAM, virtual demand also receives a surcharge to help offset the costs of RCD related to periods with net virtual demand.

Net convergence bidding revenues totaled \$8.2 million in the second quarter of 2026. In comparison, net revenues were around \$15.2 million in the second quarter of 2025.

¹⁰⁸ 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

Table 13.1 compares the distribution of convergence bidding cleared volumes and revenues, before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.^{109,110,111}

After accounting for bid cost recovery, financial and marketing entities were the only participants who profited from convergence bidding overall. Before accounting for bid cost recovery, nearly all virtual bidding revenue was split between financial entities and marketers, at around 80 percent and 15

¹⁰⁹ 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>

¹¹⁰ 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.

¹¹¹ BCR allocated to virtual supply includes the virtual-allocated portion of charge codes 6636 and 6806 before EDAM implementation, and the virtual-allocated portion of charge codes 6636 and 8806 after EDAM implementation. BCR allocated to virtual demand includes the virtual-allocated portion of charge code 8816, which was introduced with the implementation of EDAM.

percent, respectively. Financial entities and marketers accounted for about 78 percent and 17 percent, respectively, of the cleared volume of virtual trades in the second quarter.

Table 13.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues/losses (\$ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand before BCR	Virtual supply before BCR	Virtual demand BCR	Virtual supply BCR	
2026 Q2								
Financial	3,499	3,963	7,462	-\$4.4	\$22.4	-\$1.9	-\$8.9	\$7.1
Marketer	750	854	1,604	-\$1.6	\$5.1	\$0.0	-\$1.0	\$2.4
Physical load	14	33	47	-\$0.2	\$0.2	\$0.0	-\$0.1	-\$0.1
Physical generation	95	402	497	-\$0.2	\$1.3	-\$0.2	-\$2.2	-\$1.2
BAA	0	0	0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total	4,357	5,252	9,609	-\$6.4	\$29.0	-\$2.2	-\$12.3	\$8.2

Trading entities	Total hourly megawatts			Revenues/losses (\$ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand before BCR	Virtual supply before BCR	Virtual demand BCR	Virtual supply BCR	
2025 Q2								
Financial	4,353	4,408	8,761	\$13.0	\$2.4	\$0.0	-\$2.8	\$12.6
Marketer	626	674	1,299	\$2.5	-\$0.2	\$0.0	-\$0.4	\$2.0
Physical load	45	110	155	\$0.0	-\$0.1	\$0.0	-\$0.2	-\$0.3
Physical generation	277	418	696	\$1.2	\$0.6	\$0.0	-\$0.9	\$0.9
BAA	0	3	3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total	5,301	5,612	10,913	\$16.7	\$2.8	\$0.0	-\$4.3	\$15.2

14 Ancillary services and available balancing capacity

While ancillary service requirements increased from the second quarter of 2026 compared to 2025, ancillary service payments decreased. Average requirements for regulation up and operating reserves increased 220 MW (45 percent) and 80 MW (5 percent), respectively, and regulation down decreased 120 MW (11 percent). Ancillary service payments totaled \$20.0 million, a 28 percent decrease from the same quarter of the previous year. Available balancing capacity was dispatched to address power balance infeasibilities in 0.4 percent or less of intervals for all areas except Nevada Energy in the 15-minute and 5-minute markets. Available balancing capacity was dispatched in about 2.2 percent of intervals for Nevada Energy in the 15- and 5-minute markets and in both upward and downward directions.¹¹²

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.¹¹³ 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.¹¹⁴ Operating reserve requirements in real-time are calculated similarly, except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

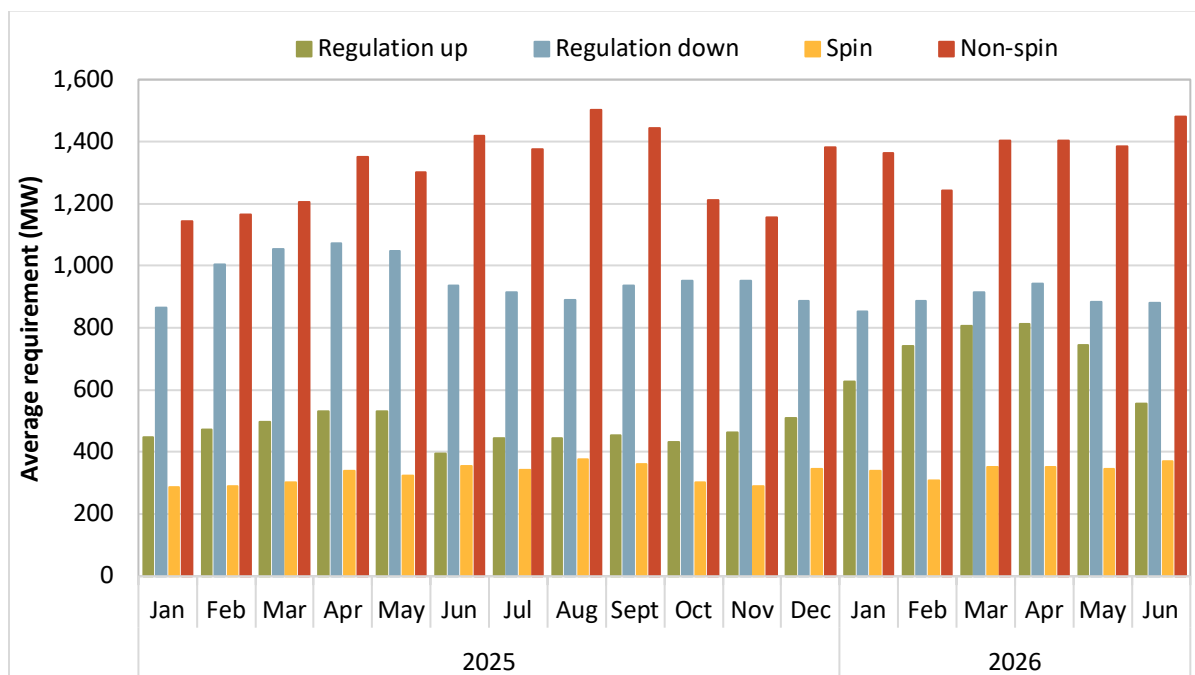
Starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. Since the second quarter of 2023, CAISO operators have procured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

Figure 14.1 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation up requirements increased about 220 MW (45 percent) compared to the second quarter of 2025, and regulation down requirements decreased about 120 MW (11 percent). Average operating reserve requirements increased about 80 MW (5 percent) compared to the second quarter of 2025.

¹¹² Figures and data provided in this chapter are preliminary and may be subject to change.

¹¹³ 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>

¹¹⁴ As of April 2024, CAISO operators lowered the contribution of forecasted solar production in determining day-ahead operating reserve requirements from 15 percent to 10 percent. CAISO operators determined they could change the requirement because of the growing fleet of new solar resources that can respond quickly to voltage issues.

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

No scarcity events occurred in the second quarter of 2026.

14.3 Ancillary service costs

Ancillary service payments totaled \$20.0 million in the second quarter of 2026, around \$7.7 million (or 28 percent) less than the same quarter of the previous year due in part to lower gas prices.¹¹⁵

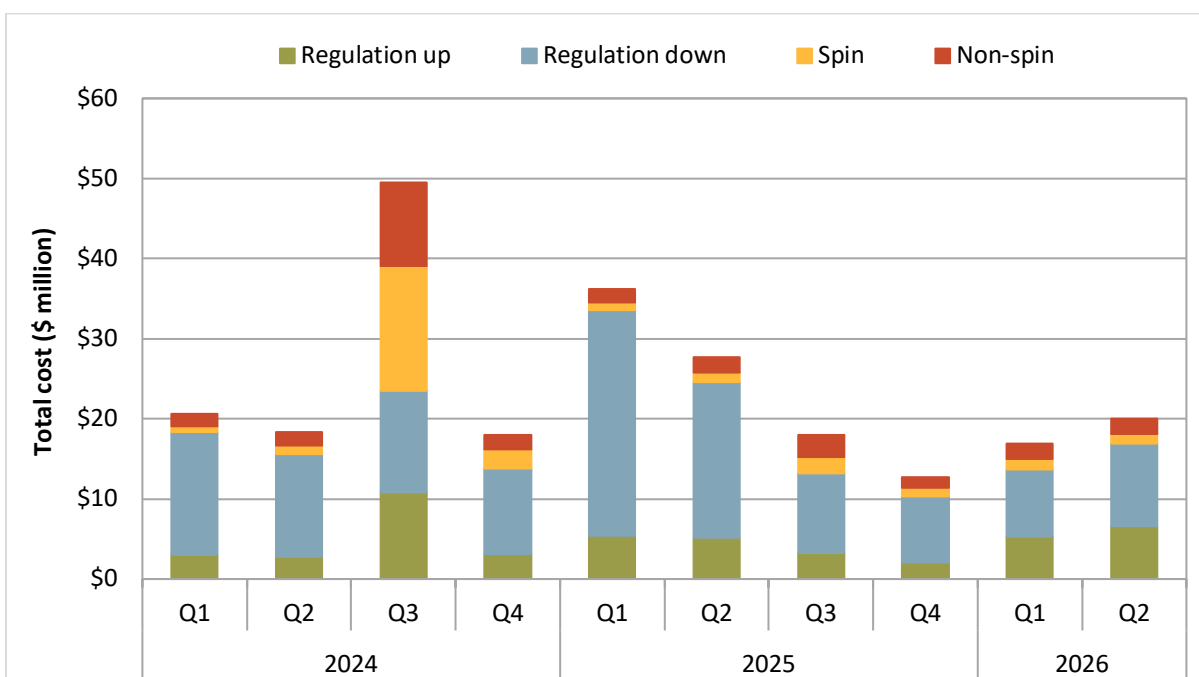
Figure 14.2 shows the total cost of procuring ancillary service products by quarter.¹¹⁶ Payments for regulation up and spinning reserves increased by 27 and 1 percent, respectively, and decreased for

¹¹⁵ See Section 1.1.

¹¹⁶ The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. As noted elsewhere in the report, settlements values are based on statements available at the time of drafting and will be updated in future reports.

regulation down and non-spinning reserves by 47 and 2 percent, respectively, compared to the second 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.

Table 14.1 summarizes the frequency of upward and downward available balancing capacity offered in each area in the second quarter. Available balancing capacity was dispatched in 0.4 percent or less of intervals for all areas except Nevada Energy in the 15-minute and 5-minute markets. Available balancing capacity was dispatched in about 2.2 percent of intervals for Nevada Energy in the 15- and 5-minute markets and in both upward and downward directions.

Table 14.1 Frequency of available balancing capacity offered (Q2 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	99.5%	86	.0%	.0%	99.5%	104	.0%	.0%
	LADWP	38.8%	50	.0%	.0%	.0%	N/A	.0%	.0%
	Turlock Irrigation District	99.5%	15	.0%	.0%	99.0%	5	.0%	.0%
Desert Southwest	Arizona Public Service	99.5%	78	.1%	.0%	99.5%	76	.1%	.1%
	El Paso Electric	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	NV Energy	96.7%	67	2.2%	2.2%	75.3%	65	2.2%	2.1%
	PSC New Mexico	.0%	N/A	.0%	.0%	15.4%	51	.0%	.0%
	Salt River Project	99.5%	99	.1%	.1%	98.9%	50	.0%	.0%
	Tucson Electric	99.5%	38	.3%	.4%	99.5%	39	.0%	.0%
	WAPA - Desert Southwest	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
Intermountain West	Avista Utilities	99.5%	10	.0%	.0%	99.5%	10	.0%	.0%
	Black Hills	61.3%	45	.0%	.0%	61.3%	23	.1%	.1%
	Idaho Power	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
	NorthWestern Energy	99.4%	5	.0%	.0%	98.4%	5	.1%	.1%
	PacifiCorp East	32.2%	102	.0%	.0%	32.5%	159	.0%	.0%
	PowerWatch	.0%	N/A	.0%	.0%	.0%	N/A	.0%	.0%
Pacific Northwest	Avangrid	99.5%	46	.0%	.1%	.0%	N/A	.0%	.0%
	Powerex	97.8%	974	.0%	.0%	99.5%	600	.0%	.0%
	Bonneville Power Admin.	99.5%	328	.0%	.1%	99.5%	336	.0%	.1%
	PacifiCorp West	11.4%	15	.0%	.0%	32.0%	49	.0%	.0%
	Portland General Electric	99.1%	30	.0%	.0%	.3%	17	.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	95.7%	5	.0%	.0%	84.4%	3	.0%	.0%

15 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the second quarter of 2026 was about 20 percent lower than the same quarter of 2025. Operator adjustments to the RUC procurement target decreased by about 99 percent for the same period.

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

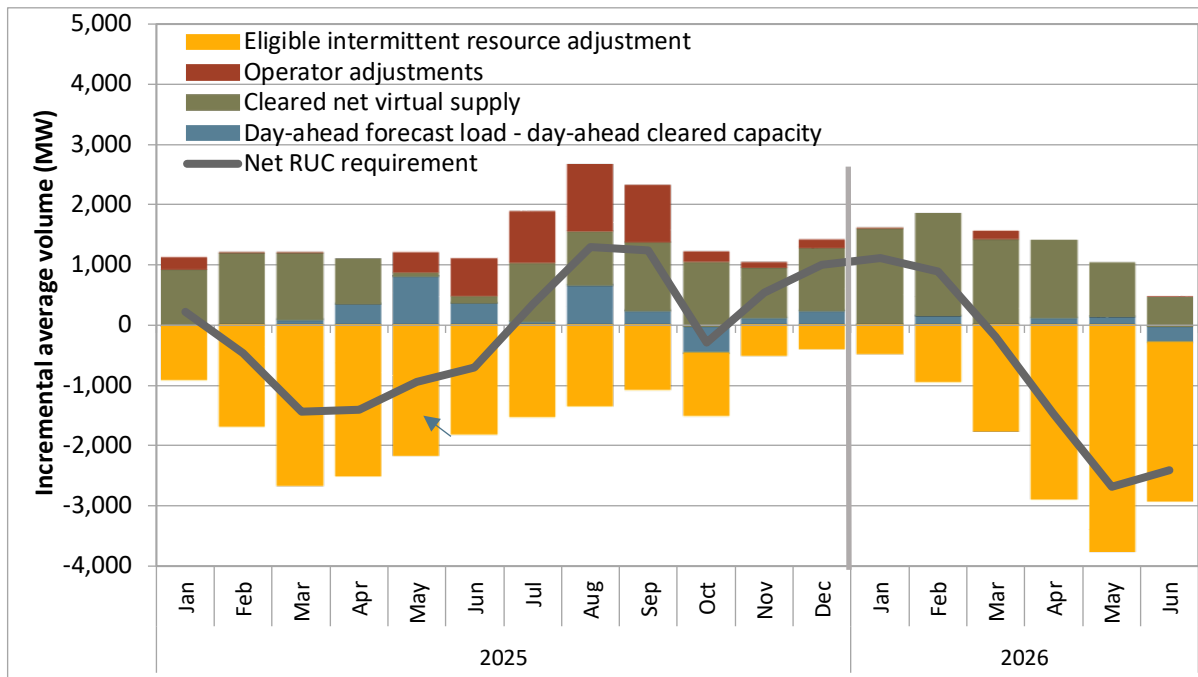
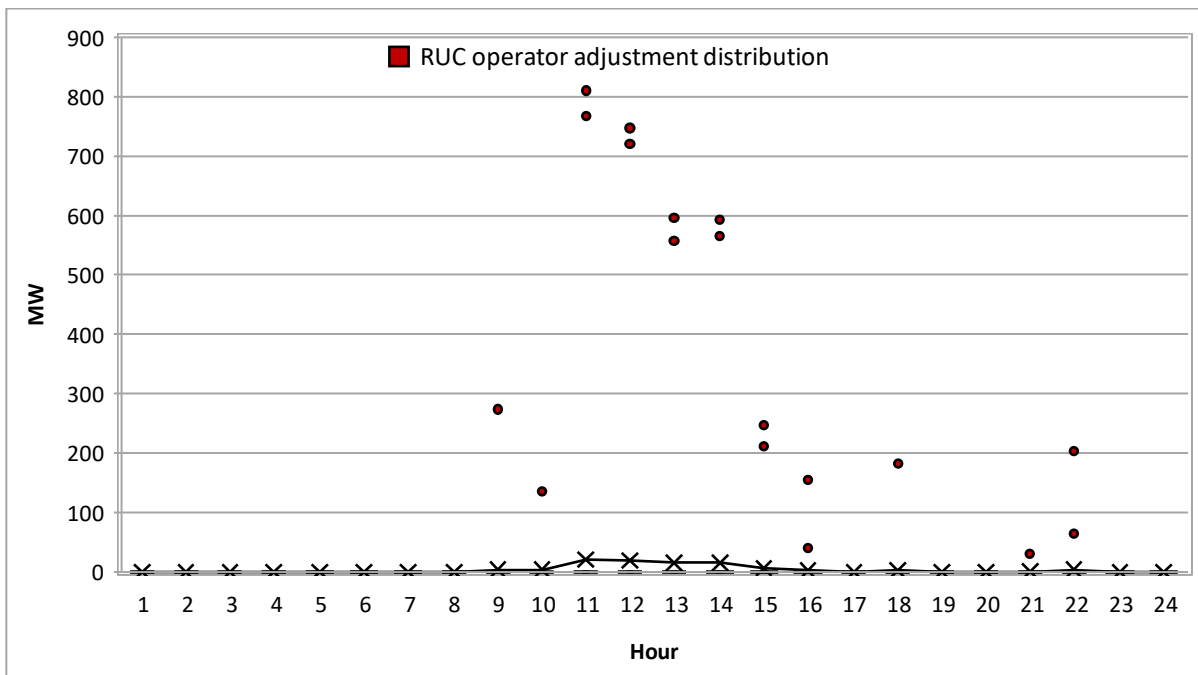
The quantity of residual unit commitment procured is determined by several automatically calculated components, as well as any adjustments that operators make to increase residual unit commitment requirements for reliability purposes. Figure 15.1 shows the average incremental residual unit commitment 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 ISO's day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed to raising the residual unit commitment requirements by about 10 MW per hour in the second 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. The magnitude of these downward eligible intermittent resource adjustments increased by an average of 3,100 MW, which is 42 percent larger than adjustments in Q2 2025.

Lastly, operators can 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. Figure 15.2 shows the hourly distribution of these operator adjustments during the second quarter of 2026. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour. The operator adjustments and changes to the methodology are described in more detail in the following section.

Figure 15.1 Average incremental residual unit commitment requirement by component**Figure 15.2 Hourly distribution of residual unit commitment operator adjustments (April–June 2026)**

Residual unit commitment operator adjustments

The residual unit commitment (RUC) adjustments are added to the forecasted load in the RUC process and are intended to address uncertainty and provide extra capacity for a balancing area beyond what is accounted for in the integrated forward market.

Day-ahead market enhancements (DAME) and the extended day-ahead market (EDAM) were launched on May 1, 2026. This includes the implementation of the *imbalance reserve product*. Imbalance reserves are bid into the market, co-optimized with energy and ancillary services, and are intended to address much of the same net load uncertainty as the former RUC adjustments. However, there are several key differences with imbalance reserve. The imbalance reserve requirement is 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 flexibility. The imbalance reserve product was also implemented at launch with the requirement set to cover all hours at the 90th percentile of uncertainty.

With the implementation of the imbalance reserve product, RUC adjustments can still be entered to address any uncertainty not covered by imbalance reserve, but the amount is now *incremental* and tied to the 97.5th percentile of uncertainty.¹¹⁷ RUC adjustments may be entered in addition to procurement of imbalance reserve for a number of reasons. First, the imbalance reserve requirement is based on the 90th percentile instead of the 97.5th percentile. Next, there can be relaxation of the imbalance reserve requirement. Last, there can be additional sources of operational uncertainty not covered by the imbalance reserve product (outages, fire risk, weather events, etc.). Any RUC adjustment is calculated minus upward imbalance reserve procured in the day-ahead market to capture only incremental uncertainty that may need to be accounted for to be sufficient between the day-ahead and real-time markets.¹¹⁸

The CAISO operating procedure for setting the RUC adjustments within the CAISO balancing area recommends to use a particular percent of the 97.5th percentile of uncertainty, considering the level of operational uncertainty or load.^{119,120} During days with moderate operational uncertainty or load, the operating procedure recommends to use 4 percent of this uncertainty for either the peak morning and evening hours or the mid-day hours. During days with higher operational uncertainty or load, the procedure recommends using 50 percent for the mid-day hours. Last, during the days with the highest operational uncertainty or load, the procedure recommends using 100 percent for the mid-day hours.

Figure 15.3 shows the average residual unit commitment adjustment on each day during the first half of the year, comparing 2025 (red) and 2026 (blue). There were no RUC adjustments applied for PacifiCorp East or PacifiCorp West such that these amounts are for the CAISO balancing area only. Following the launch of day-ahead market enhancements, RUC adjustments in May and June were down significantly

¹¹⁷ The RUC uncertainty is calculated using the same mosaic quantile regression method as the imbalance reserve product, except using the 97.5th percentile. 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 high percentile of uncertainty that might materialize. These coefficients are then combined with RUC forecast information at the time of each market run to determine the uncertainty.

¹¹⁸ The imbalance reserve procured here also accounts for imports and exports of imbalance reserve for the balancing area.

¹¹⁹ See CAISO Operating Procedure 1210, July 1, 2026, pp 12-13: <https://www.caiso.com/Documents/1210.pdf>

¹²⁰ Prior to the implementation of Day-Ahead Market Enhancements, the percentile target of uncertainty for the RUC adjustments was selected at either the 50th percentile, 75th percentile, or 97.5th percentile, based on conditions in the system.

in 2026 compared to the previous year. No RUC adjustments occurred in April or May of 2026. CAISO balancing area RUC adjustments in June 2026 only occurred on two days—June 11 and 12—due to higher peak loads. Figure 15.4 shows the calculation of these RUC adjustments. On these days, RUC adjustments were applied above imbalance reserve schedules up to 50 percent of the 97.5th percentile of uncertainty. These adjustments were applied in the mid-day hours.

Figure 15.3 Average residual unit commitment adjustment by day (first half 2025 vs. 2026)

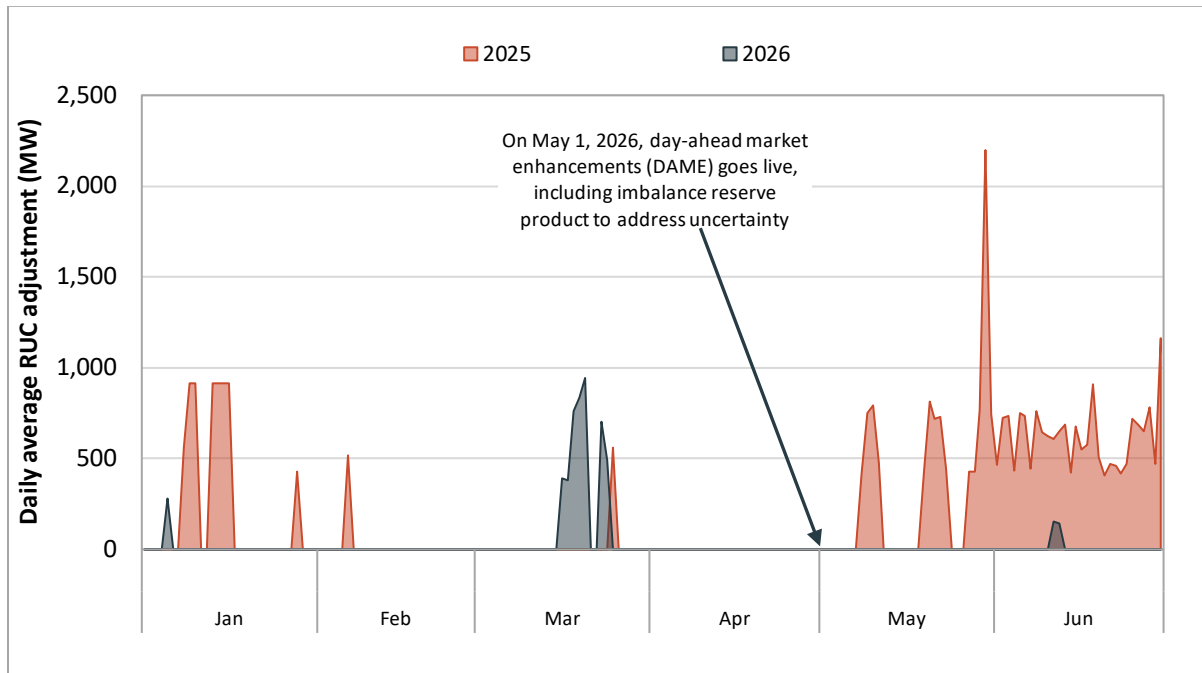
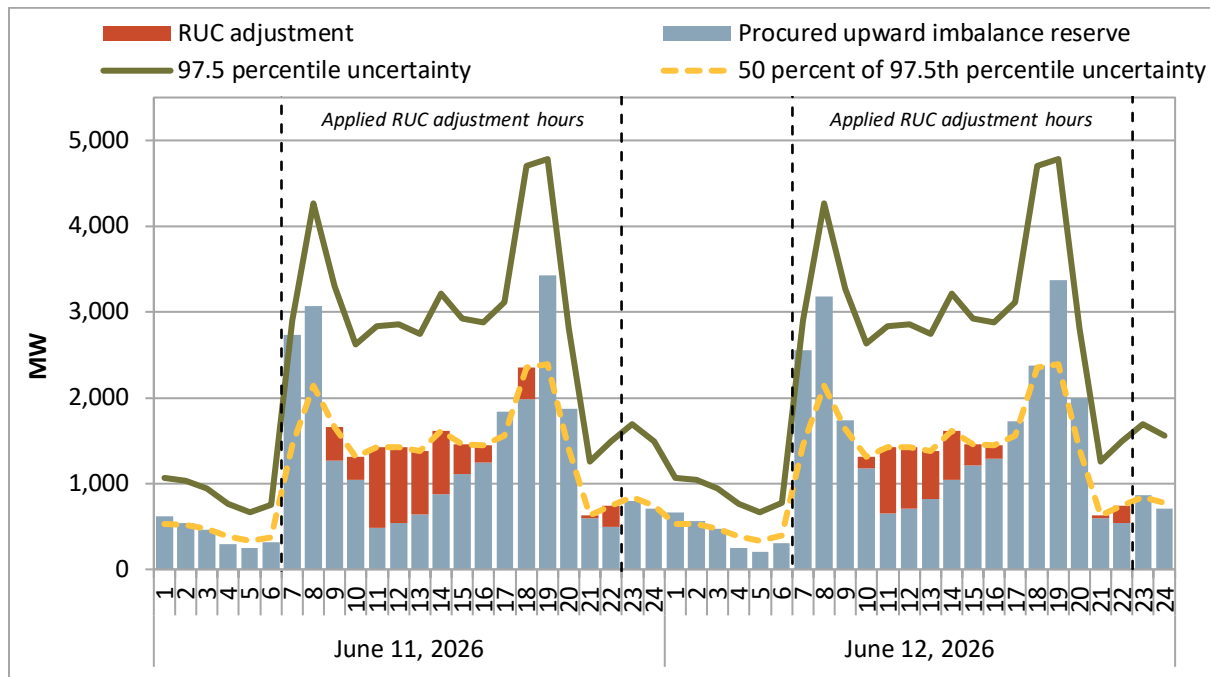


Figure 15.4 CAISO residual unit commitment adjustment calculation (June 11 and June 12, 2026)

15.2 Residual unit commitment procurement and costs

In May 2026, the ISO implemented day-ahead market enhancements (DAME) and the extended day-ahead market (EDAM), which introduced significant changes to the residual unit commitment (RUC) process. Under the prior design, RUC procured capacity in the upward direction only. Under DAME, RUC procures both upward capacity (reliability capacity up, or RCU) and downward capacity (reliability capacity down, or RCD), with separate locational prices for each. Resources submit RCU and RCD availability bids as part of the day-ahead market submission, with bid prices between \$0/MWh and \$250/MWh. A resource can only receive an RCU or RCD award in a given hour. Under EDAM, the RUC process extends to EDAM entity balancing authority areas, each with its own procurement target. Reliability capacity can transfer between balancing authority areas.

DAME transitional measures and resource adequacy revenue allocation

A significant financial change is to resource adequacy (RA) resource compensation. Under the prior design, RA resources were required to bid \$0/MWh into RUC and were excluded from RUC availability payments. The RUC settlement system only compensated non-RA capacity, while RA resources received no market payment for their RUC awards. Starting with DAME/EDAM, resources with RCU and or RCD awards—including RA resources—receive availability payment at the market clearing price. This change created new market revenue for RA resources that did not exist under the prior design. The tariff includes optional DAME transitional measures under Section 11.2.6, through which resource and load

serving entity (LSE) scheduling coordinators can mutually elect to have the RA capacity portion of RCU and RCD revenue credited back to the LSE. If neither party elects, the resource retains all revenue.^{121, 122}

The tariff specifies that the overlapping RA capacity—the portion used to determine how much revenue flows back to the LSE—is based on the higher of generic RA capacity or flexible RA capacity on the monthly supply plan (section 11.2.6.2). This is why the effective RA capacity shown in the first grouping may differ from the generic or flexible RA values individually. The generic and flexible RA values are calculated based on shown RA capacity including capacity procurement mechanism designations.

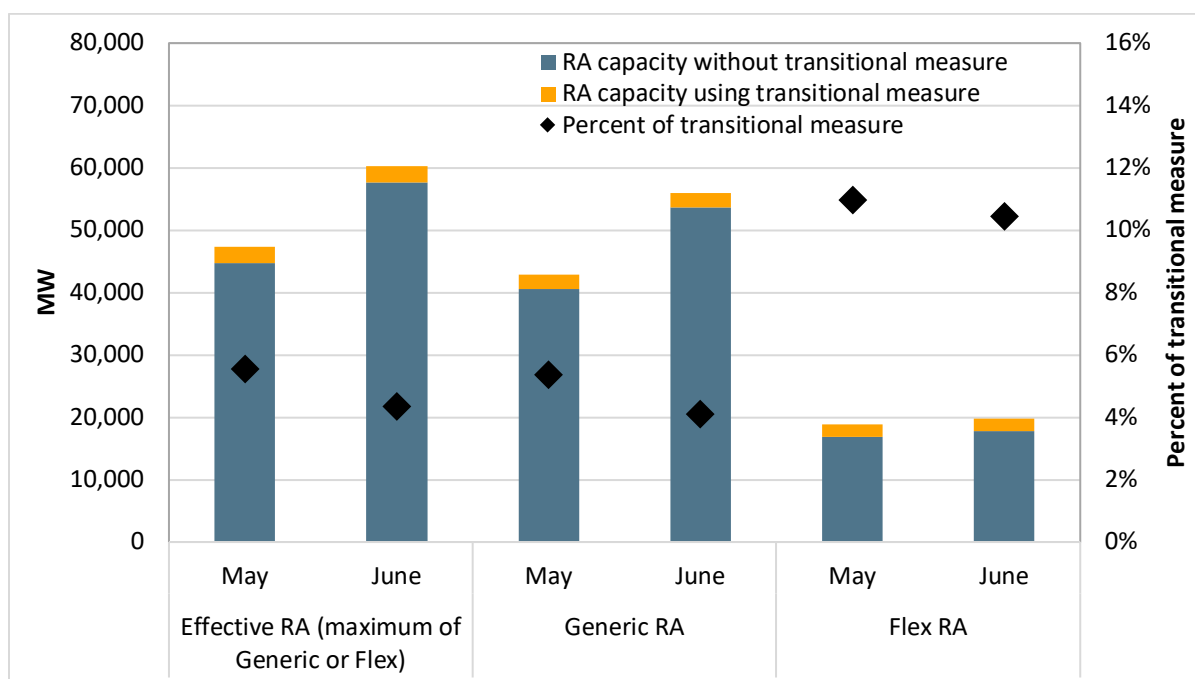
The transitional measures data shown for May and June is based on the July 2026 election records rather than the May or June records. This is because the tariff provides a 60-day grace period following DAME implementation on May 1, 2026. During this window, resource/LSE pairs could elect transitional measures at any point through late June and have the election applied retroactively to May 1 through settlement resettlement. For resource/LSE pairs that elected transitional measures during the 60-day grace period, the ISO resettled May and June to transfer the RA overlap revenue from the resource to the LSE.

Figure 15.5 shows total RA capacity split by resources with and without DAME transitional measures elections for May and June 2026, displaying across three groupings: the effective RA capacity (the higher of generic or flexible RA on the monthly supply plan for each resource), generic RA only, and flexible RA only.

The relative size of the transitional measures portion in each group indicates the degree to which the revenue clawback is in effect. Based on July election records, approximately 2,600 MW of RA capacity was subject to transitional measures, representing about 6 percent of May effective RA capacity and 4 percent of June effective RA capacity.

¹²¹ For additional tariff detail, see *California ISO Settlement and Billing, Section 11, effective May 1, 2026*, available at: <https://www.caiso.com/library/tariff-sections>. DAME transitional measures are specified in Section 11.2.6

¹²² For RCU, if the day-ahead energy schedule plus upward ancillary service awards and imbalance reserve up award is below the RA capacity, part of the upward awards falls within the RA capacity range. That portion is credited to the LSE. Any RCU award above the RA capacity level stays with the resource. For RCD, if the day-ahead energy schedule minus regulation down and imbalance reserve down awards is above the RA capacity, part of the downward award brings the resource back down to the RA capacity level. That portion is credited to the LSE. Any award that takes the resource below the RA capacity level stays with the resource (tariff section 11.2.6.2)

Figure 15.5 RA capacity and DAME transitional measures elections (May–June 2026)

Residual unit commitment costs and procurement under DAME and EDAM

As discussed above, DAME introduced RCU and RCD as separate products replacing the prior single upward RUC schedules, with RA resources now receiving revenues at the market clearing price. Under EDAM, PacificCorp East (PACE) and PacificCorp West (PACW) participate in the RUC process with their own procurement targets, and reliability capacity can transfer between BAAs.

Figure 15.6 shows average hourly RUC MW from May 2025 through June 2026, calculated as total monthly RUC MW divided by the number of hours in each month. Prior to May 2026, bars show only CAISO RUC MW, of which 98 percent on average came from RA resources. Beginning in May 2026, bars show RCU as positive values and RCD as negative values for each EDAM BAA.

Average hourly procurement in May 2026 was 1,600 MW of RCU and 500 MW of RCD, resulting in total procurement of 2,100 MW and net procurement of 1,100 MW. June was lower, at approximately 1,050 MW of RCU and 800 MW of RCD, with total procurement of 1,850 MW and net procurement of approximately 250 MW. Both months are comparable to the average of 1,500 MW observed between May 2025 and April 2026.

The CAISO BAA accounted for 95 percent of both total RCU and RCD procurement, PACE accounted for 4 percent of each, and PACW accounted for 1 percent of each.

Total RUC procurement in May and June 2026 remained broadly consistent with pre-EDAM levels despite the two additional balancing areas under EDAM.

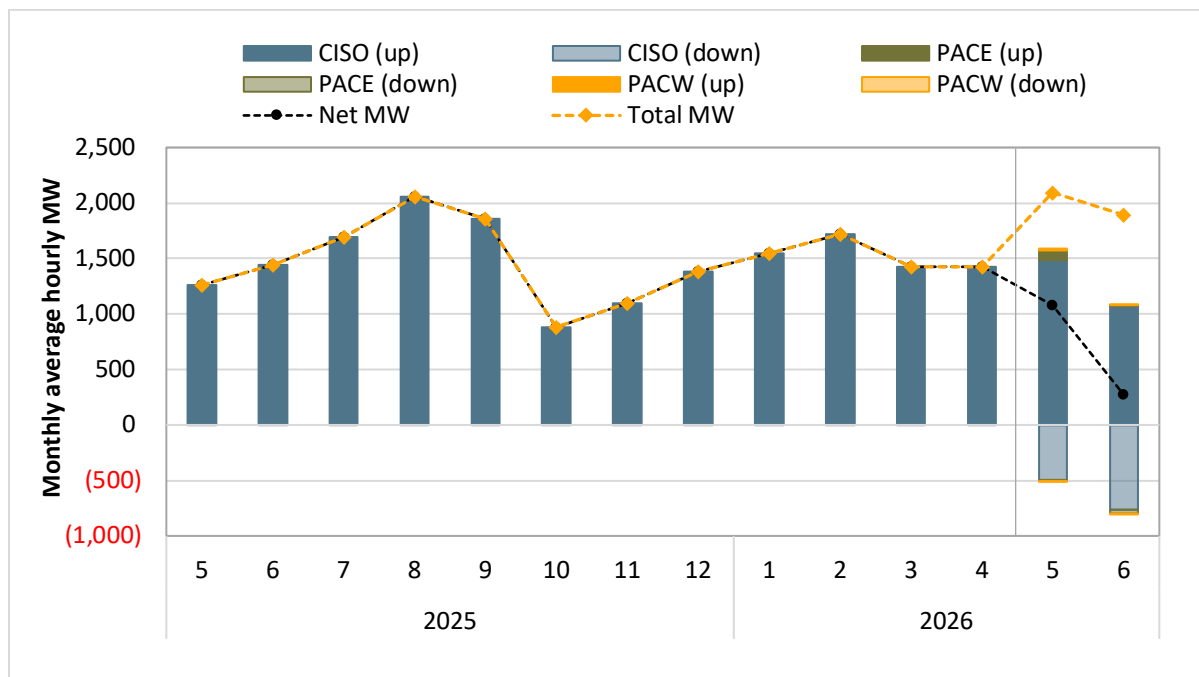
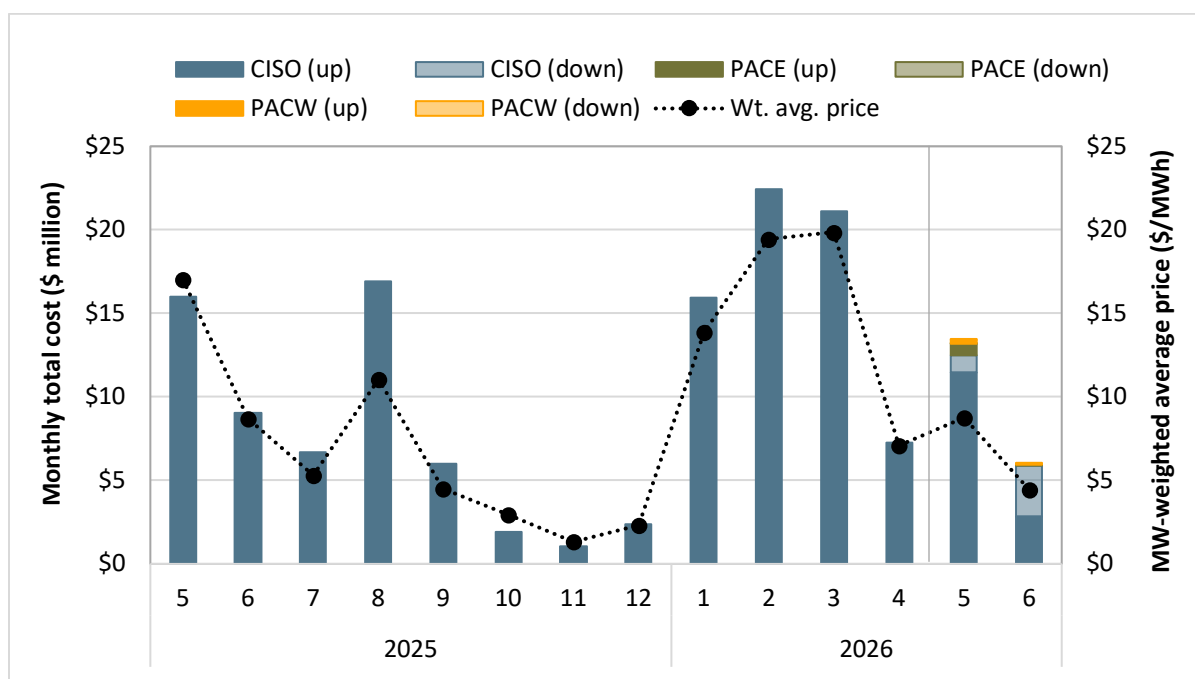
Figure 15.6 Monthly hourly average RUC procurement (May 2025 – June 2026)

Figure 15.7 shows monthly total RUC payment costs and MW-weighted average RUC prices from May 2025 through June 2026. Prior to May 2026, the bars (blue) represent the imputed cost of RA and non-RA capacity in RUC, calculated as RA and non-RA resource schedules multiplied by their locational RUC prices. This amount was not an actual market payment—under the prior design, RA resources were excluded from RUC payments and received no compensation. The imputed value reflects the cost that would have been incurred if the market had to procure this capacity at market prices rather than through bilateral RA contracts. Beginning in May 2026 under DAME, RA capacity could be scheduled for both upward and downward reliability capacity and received settlement payments. About 5 percent of RA capacity was subjected to the transitional measure election. Costs for this capacity are included in the chart and averaged about \$0.2 million per month in May and June.

The secondary axis displays the MW-weighted average RUC price, calculated across all resource RUC schedules weighted by their locational RUC prices.

Figure 15.7 Monthly RUC costs and weighted average price (May 2025 – June 2026)

Total RUC costs were approximately \$14 million in May 2026 and \$6 million in June 2026, compared to an average of \$10 million per month between May 2025 and April 2026, of which actual payments to non-RA resources averaged only \$0.2 million per month. The MW-weighted average RUC price fluctuated over the period. Between May 2025 and April 2026, the average price was about \$9/MWh. It remained at \$9/MWh in May 2026 and fell to \$4/MWh in June.

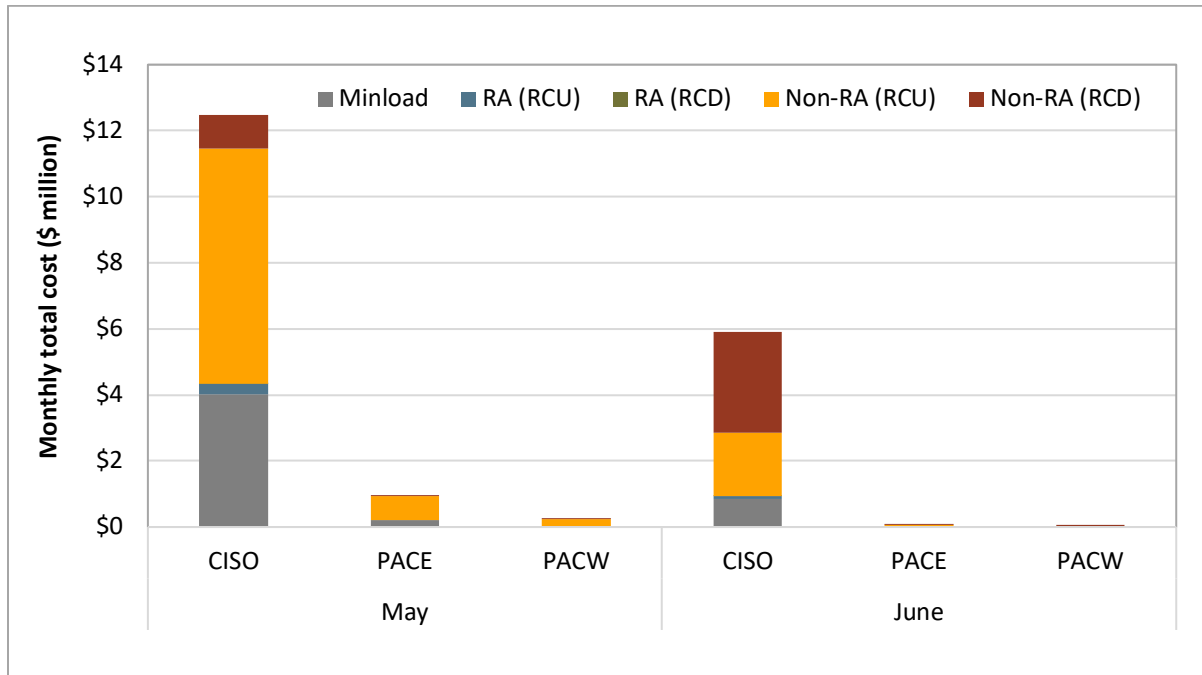
Total RUC cost increased from April to May 2026, immediately before and after the EDAM/DAME launch, while the average price remained similar. The increase in cost was mainly driven by the addition of 700 MW of procurement in May compared with April.

Figure 15.8 shows the total RUC cost breakdown for May and June 2026 by balancing area and category: minimum load, RA RCU, RA RCD, non-RA RCU, and non-RA RCD. The RA designation reflects resources with DAME transitional measures elections, where the RA capacity portion of RCU and RCD revenue is credited back to the LSE. Non-RA includes both non-RA resources and RA resources without elections.

Of the total \$14 million in May 2026, about \$7 million reflected RCU payments to non-RA resources and RA resources not subject to the transitional measure in the CAISO balancing area, while approximately \$4 million reflected CAISO minimum-load payments. Of the resource adequacy resource payments, about \$0.3 million was subject to the transitional measure and credited back to LSEs in May and \$0.1 million in June. Total RUC payments were about \$1 million for PACE and \$0.3 million for PACW. RCU accounted for most RUC payments across all balancing areas in May.

Total RUC payments declined to \$6 million in June. This amount included about \$3 million in CAISO RCD payments and \$2 million in CAISO RCU payments. Payments totaled about \$0.1 million for PACE and \$0.06 million for PACW.

Figure 15.8 Monthly RUC cost breakdown (May–June 2026)



16 Congestion revenue rights

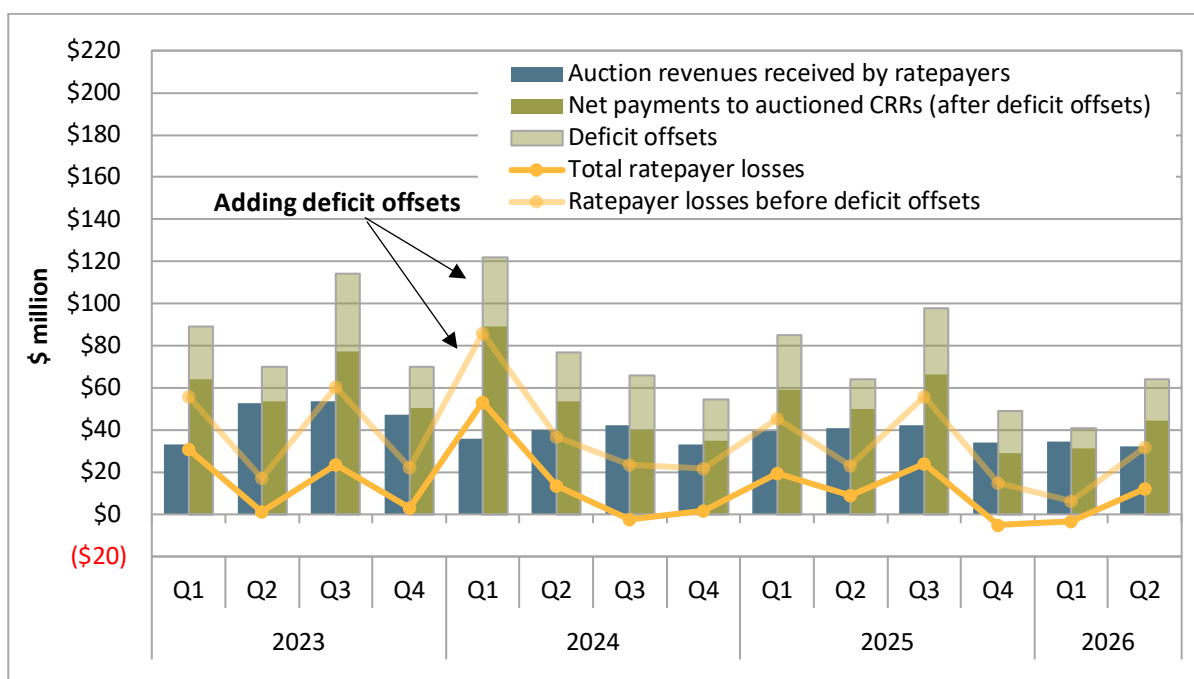
Congestion revenue right auction returns

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).¹²³
- 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 lost \$12 million during the second quarter of 2026, as payments to auctioned congestion revenue rights holders were lower than auction revenues. This was an increase from ratepayer losses of \$9 million in the second quarter of 2025.

¹²³ 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 an \$11 million profit from auction rights, up from about \$6.4 million during the same quarter of 2025. Total revenue deficit offsets were about \$16 million.¹²⁴
- Marketers earned \$0.2 million from auctioned rights, similar to a \$0.4 million profit in the same quarter of 2025. Total revenue deficit offsets were over \$3.9 million.
- Physical generation entities earned \$0.7 million from auctioned rights, a decline from a \$2.3 million in profit in Q2 2025. Total revenue deficit offsets were \$0.9 million.

The \$12 million auction loss in the second quarter of 2026 was about 10 percent of CAISO day-ahead congestion rent. This was an increase from 7 percent of CAISO total congestion rent in the second

¹²⁴ 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.

quarter of 2025.¹²⁵ 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).^{126,127}

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 \$20 million in the second 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.¹²⁸

¹²⁵ 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. Therefore, the share of auction losses in total congestion rent may differ from values reported in the previous reports, due to updates in the source data.

¹²⁶ *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>

¹²⁷ *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>

¹²⁸ *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.¹²⁹

No reservations were made for CAISO balancing area high priority wheel-through rights for the second quarter of 2026.

¹²⁹ 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

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.

Table 18.1 shows the hours during the second quarter of 2026 where real-time bids from resource adequacy resources, including bids from variable energy resources (VERs) above their resource adequacy capacity were not sufficient to cover the load forecast for energy and upward ancillary service awards. Available resource adequacy capacity was not sufficient to meet CAISO balancing area load requirements in 4 intervals during the peak load hours on May 11, 2026.

Table 18.1 Resource adequacy bids vs. market requirement

Date	Hour	Interval	Real-time requirement			Real-time resource adequacy bids			Total available RA - Total requirement
			Fifteen-minute load forecast	+ Regulation	+ Reserves	Resource adequacy + Above RA VERs	RA bids	Above RA VERs	
5/11/2026	20	2	32,989	34,129	36,234	36,073	35,150	923	-160
5/11/2026	20	3	32,952	34,092	36,179	35,523	35,095	427	-657
5/11/2026	20	4	33,023	34,162	36,251	35,282	34,937	346	-969
5/11/2026	21	1	32,998	33,308	35,362	34,993	34,648	345	-369

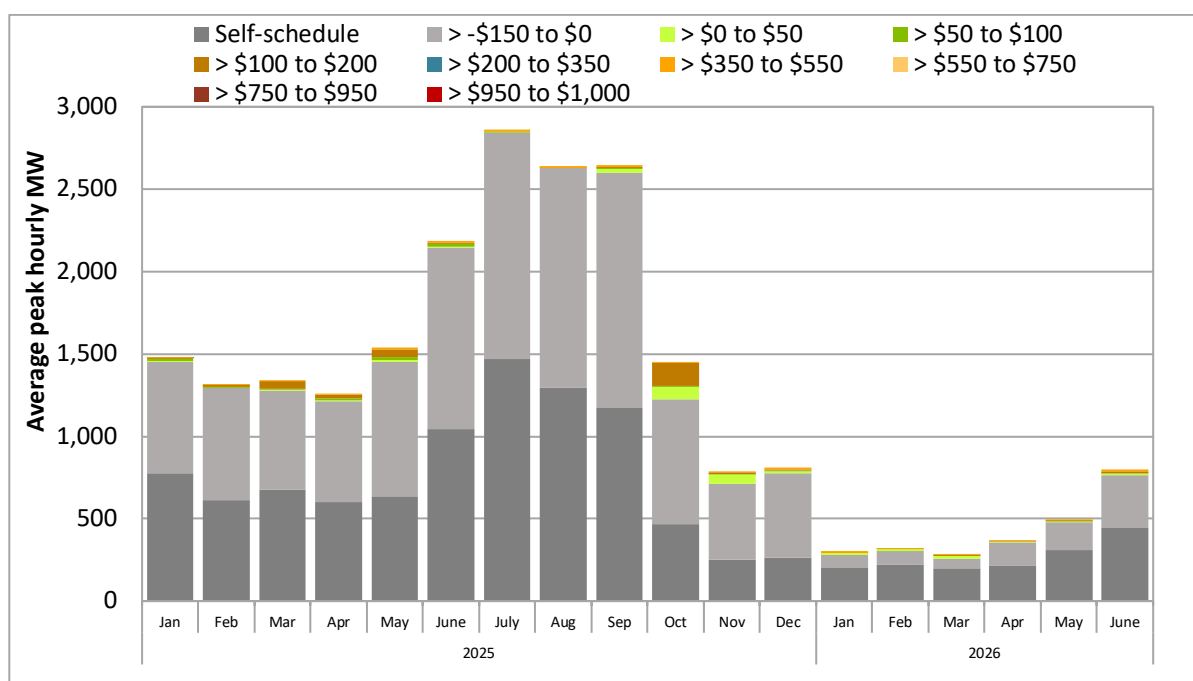
18.2 Resource adequacy import bids

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.¹³⁰ 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.¹³¹ 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 April, May, and June by 71 percent, 68 percent, and 64 percent, respectively, compared to the same months of 2025. Resource adequacy import bids in Q2 2026 decreased 67 percent from Q2 2025.

Figure 18.1 Average hourly resource adequacy imports by price bin



¹³⁰ 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.

¹³¹ 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.25 include figures for each WEIM area showing hourly locational marginal price (LMP) and dynamic transfers.¹³² 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.

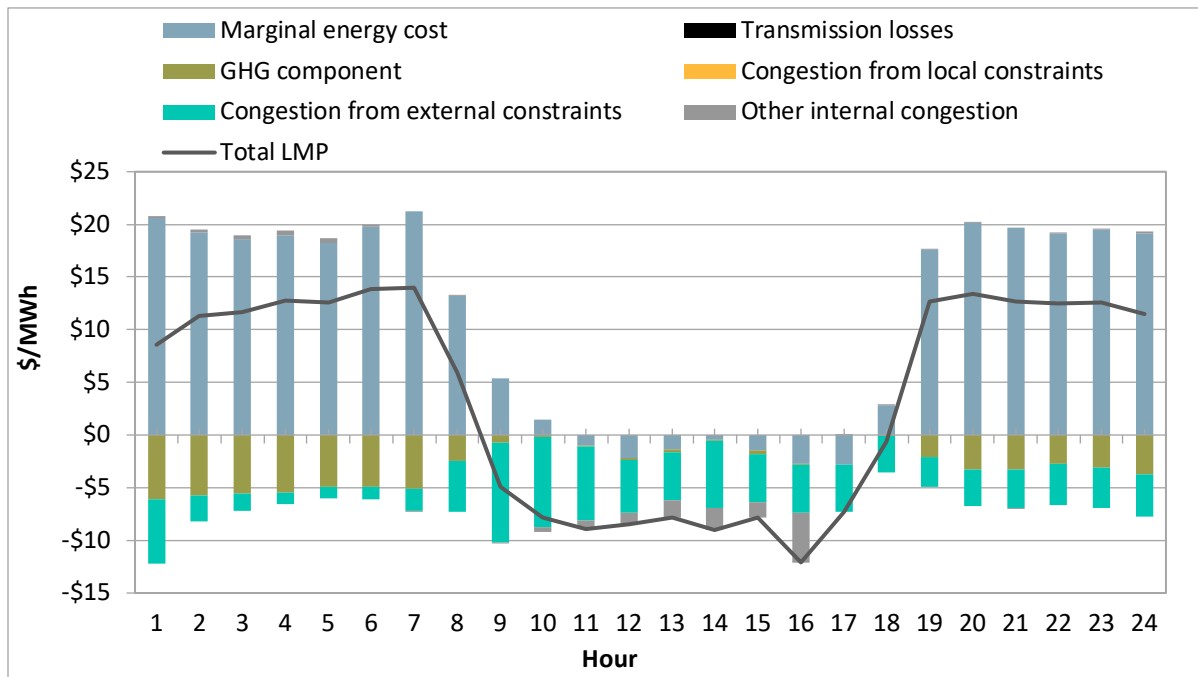
- **Marginal energy cost**, referred to as MEC, is the marginal clearing price for energy in a balancing authority area (BAA). The difference in MEC between balancing areas reflects any transfer congestion between one another.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the price impact from greenhouse gas (GHG) regulation. It represents the marginal cost of a net import transfer into the GHG regulation area (currently only balancing authority areas in California) determined within the optimization using the GHG bid adders of resources located outside of the GHG regulation area. This contributes to price differences between the GHG regulation area and the regions outside of it.¹³³
- **Congestion from local constraints** is the price impact on a balancing area from transmission constraints within its own balancing area. While these constraints are located locally, they can create price impacts across the WEIM and show up as external constraints to other balancing areas
- **Congestion from external constraints** is the price impact on a balancing area from transmission constraints in a different WEIM balancing area. 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*.

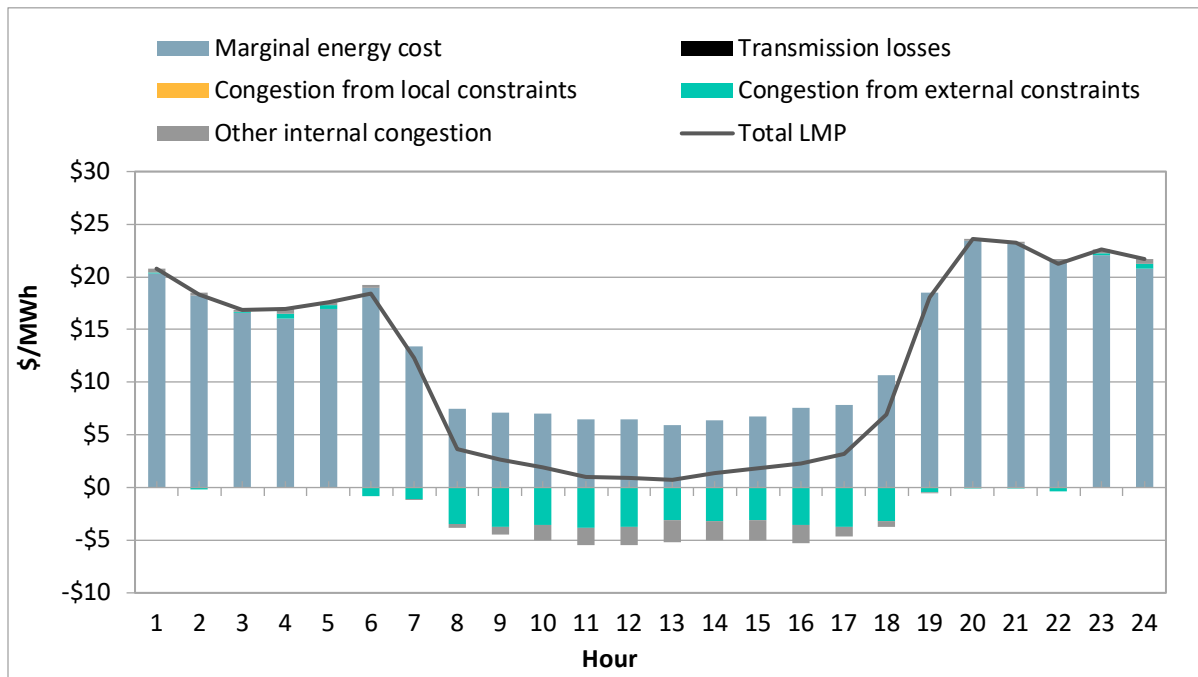
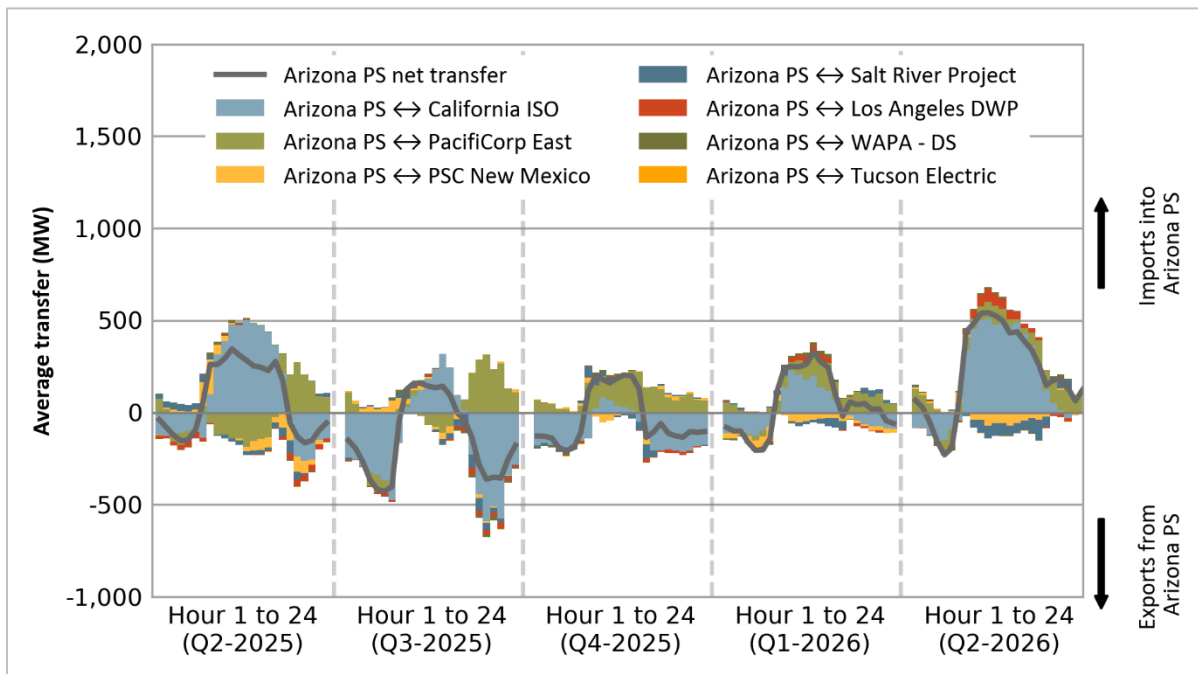
The LMP components figures in this report are separated into pre-EDAM (April 2026) and post-EDAM (May–June 2026) due to changes in how the components are broken out. In the post-EDAM figures, system marginal energy price is replaced by marginal energy cost (MEC) and the marginal GHG cost is now represented as a positive price component for the California balancing areas.

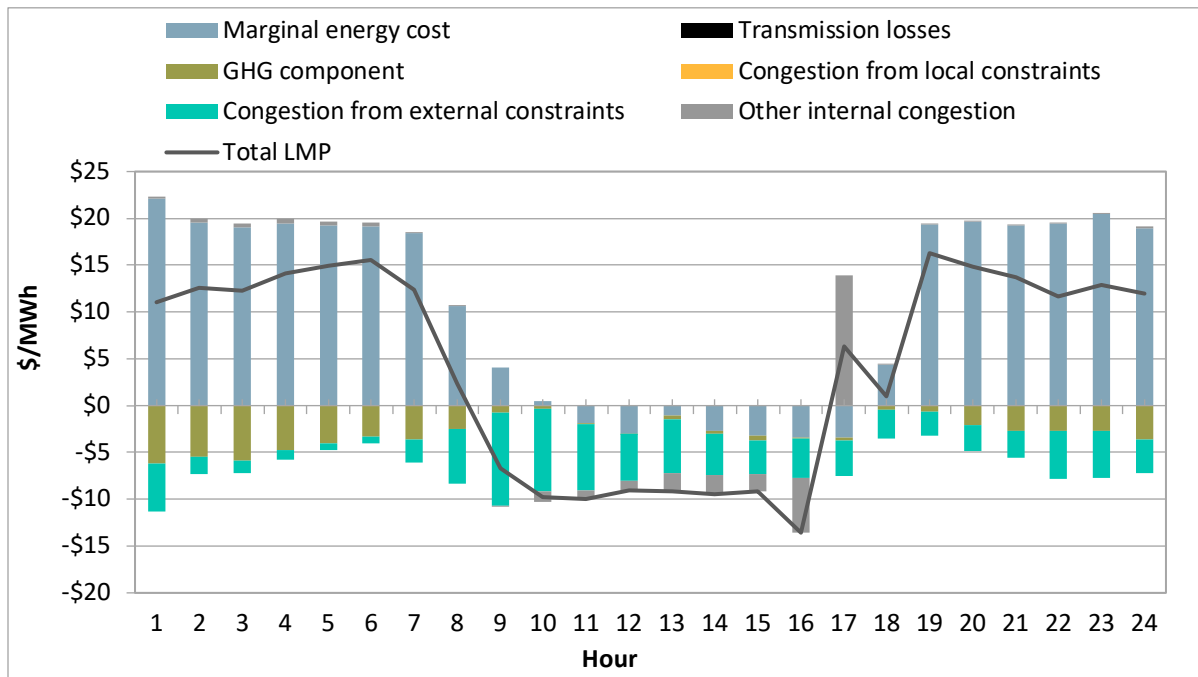
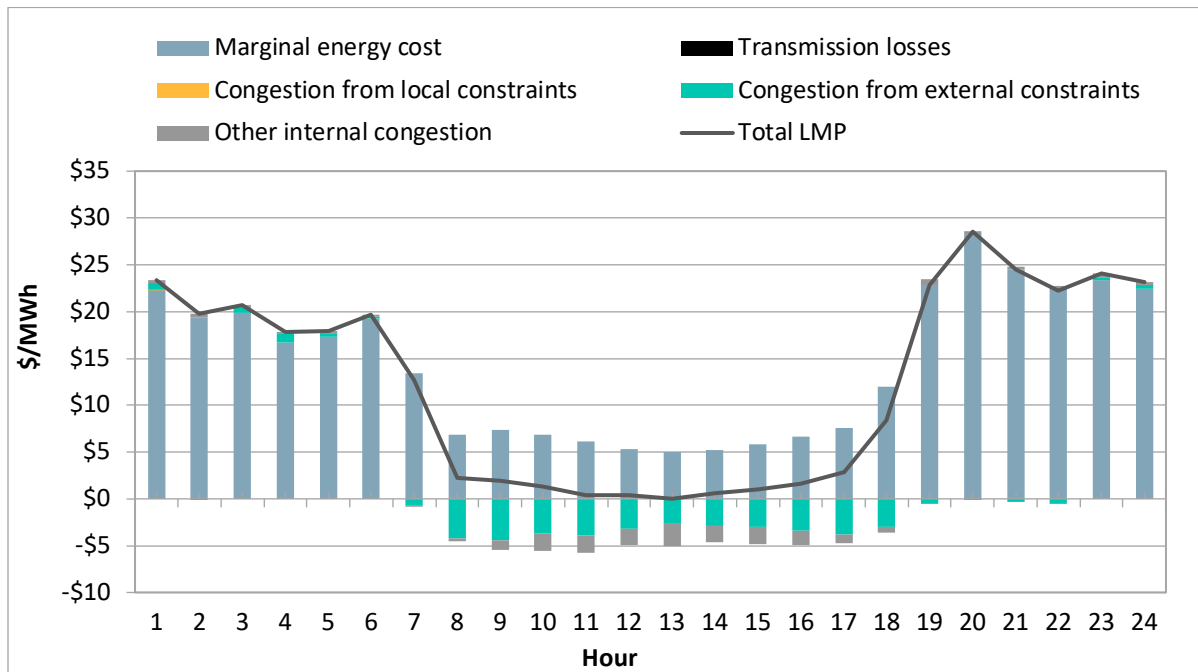
¹³² These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

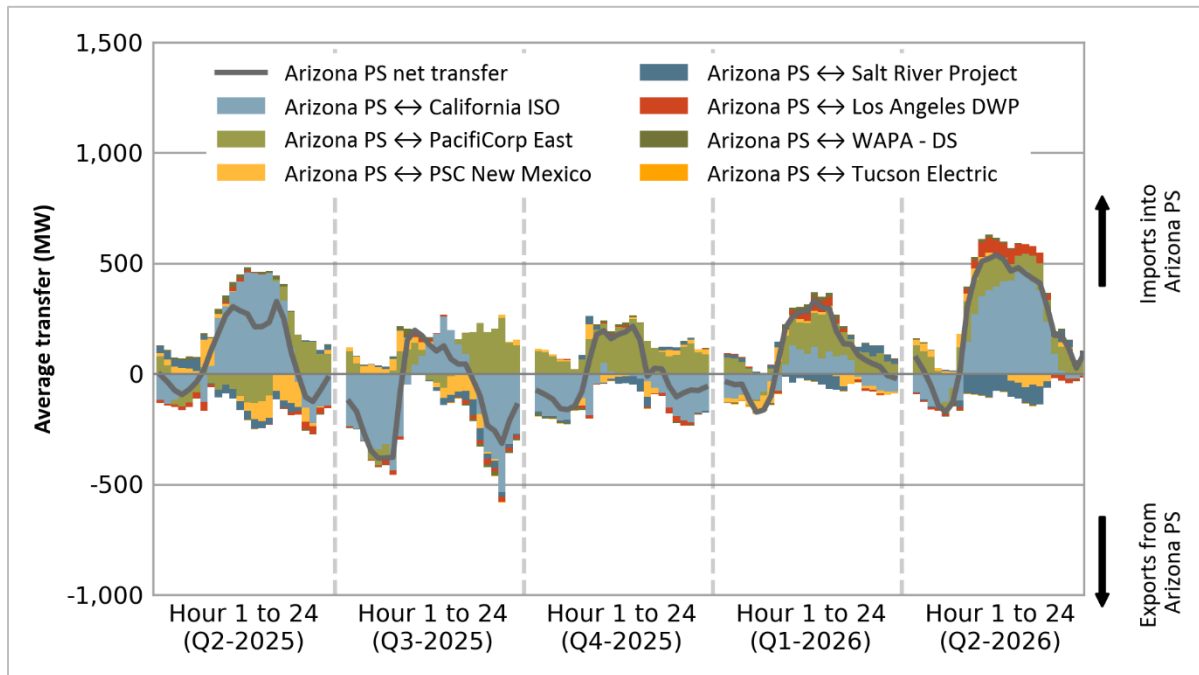
¹³³ Previously, the GHG component was represented as a negative price impact in all non-California balancing areas. Going forward with EDAM, GHG costs are added as a positive impact on the GHG regulation area.

A.1 Arizona Public Service

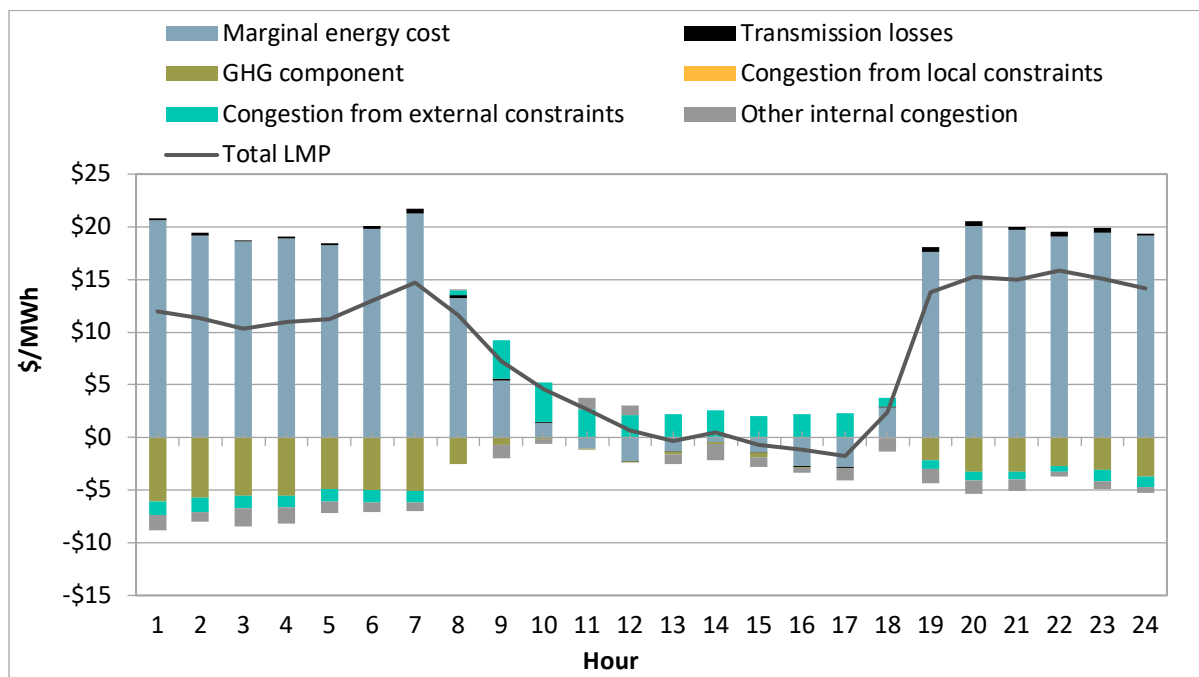
Appendix Figure A.1 Average hourly 15-minute price by component (April 2026)

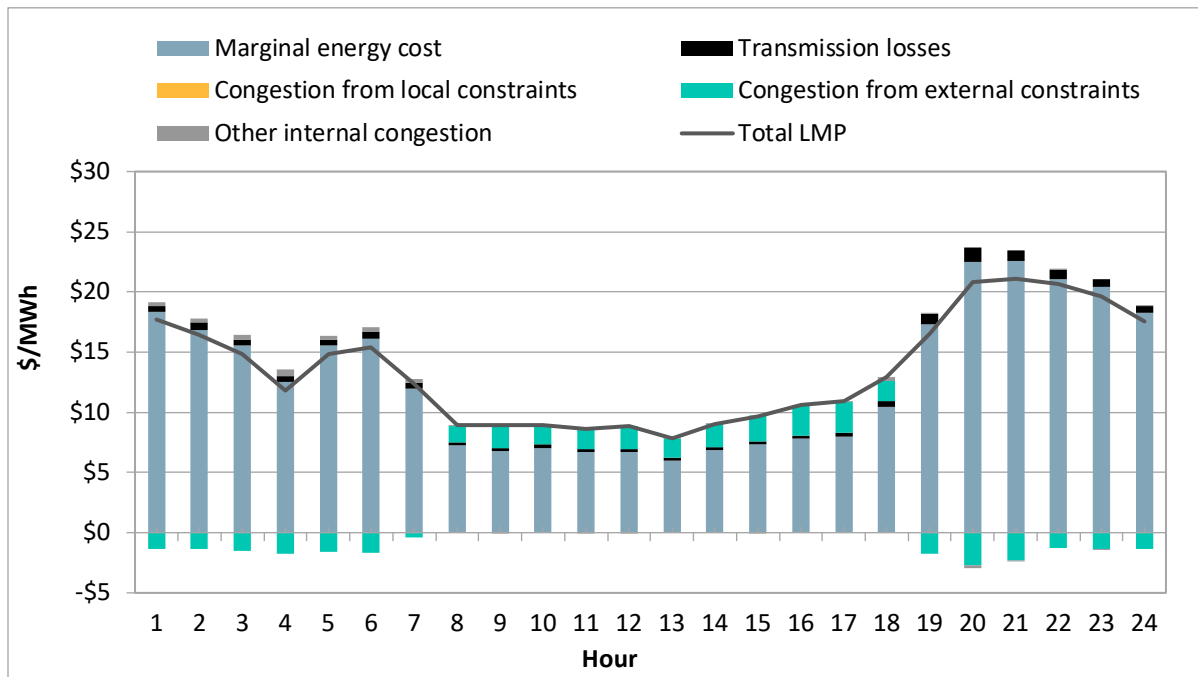
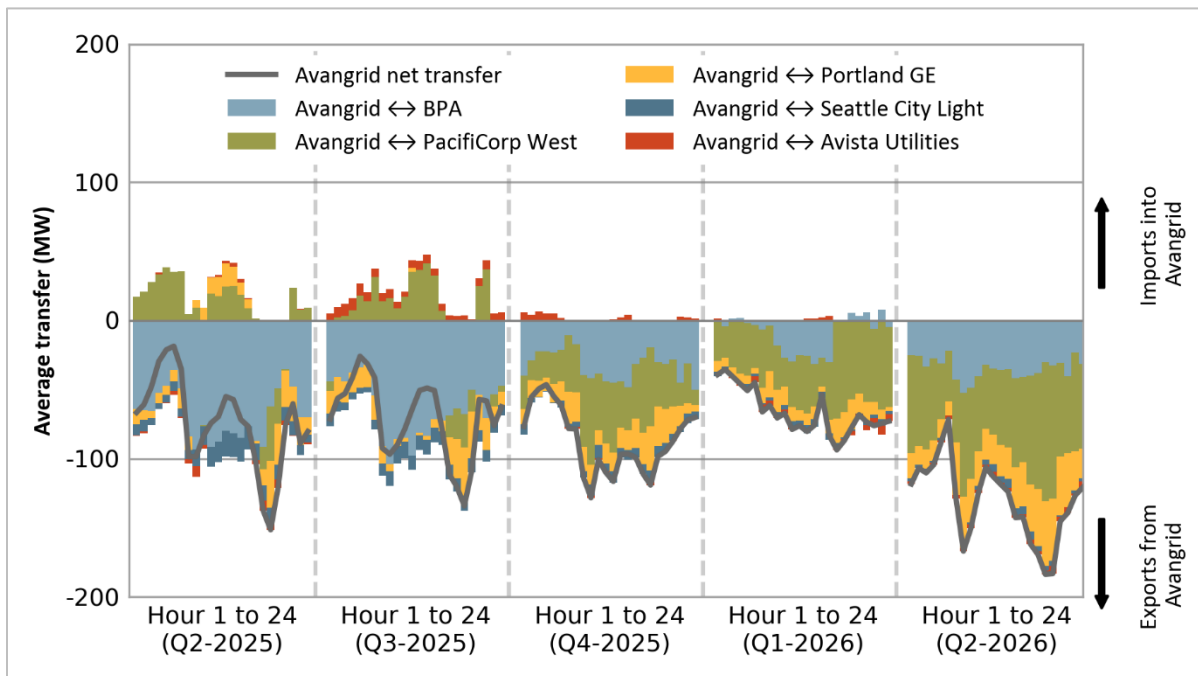
Appendix Figure A.2 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.3 Average hourly 15-minute market transfers**

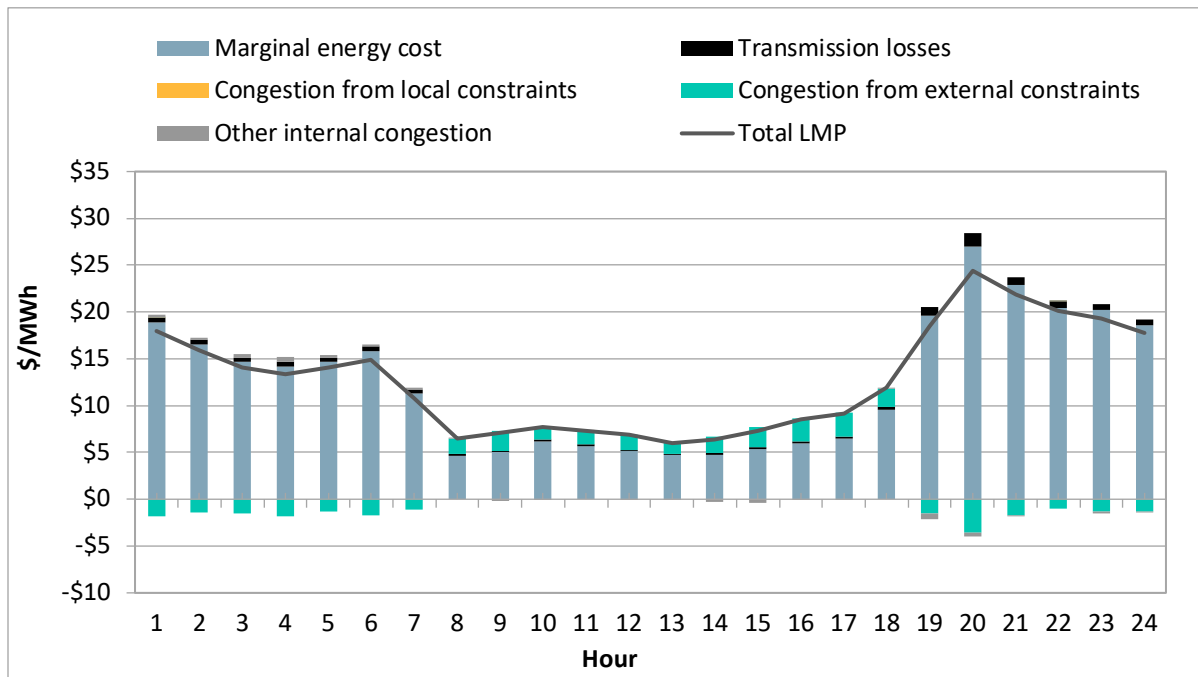
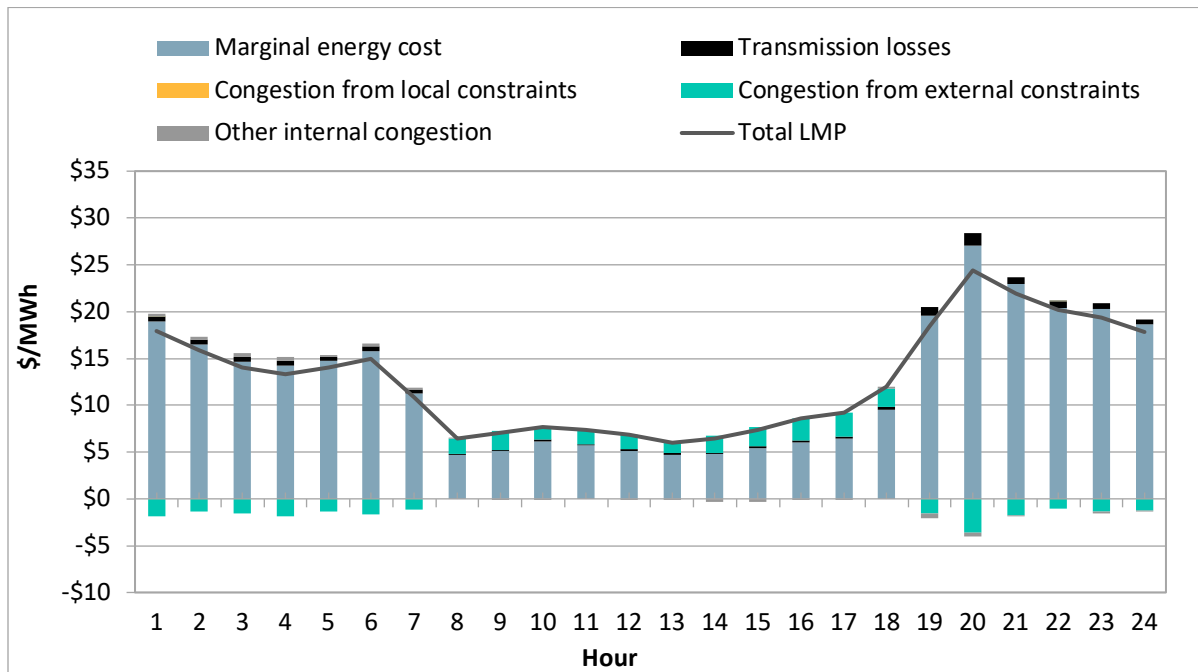
Appendix Figure A.4 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.5 Average hourly 5-minute price by component (May–June 2026)**

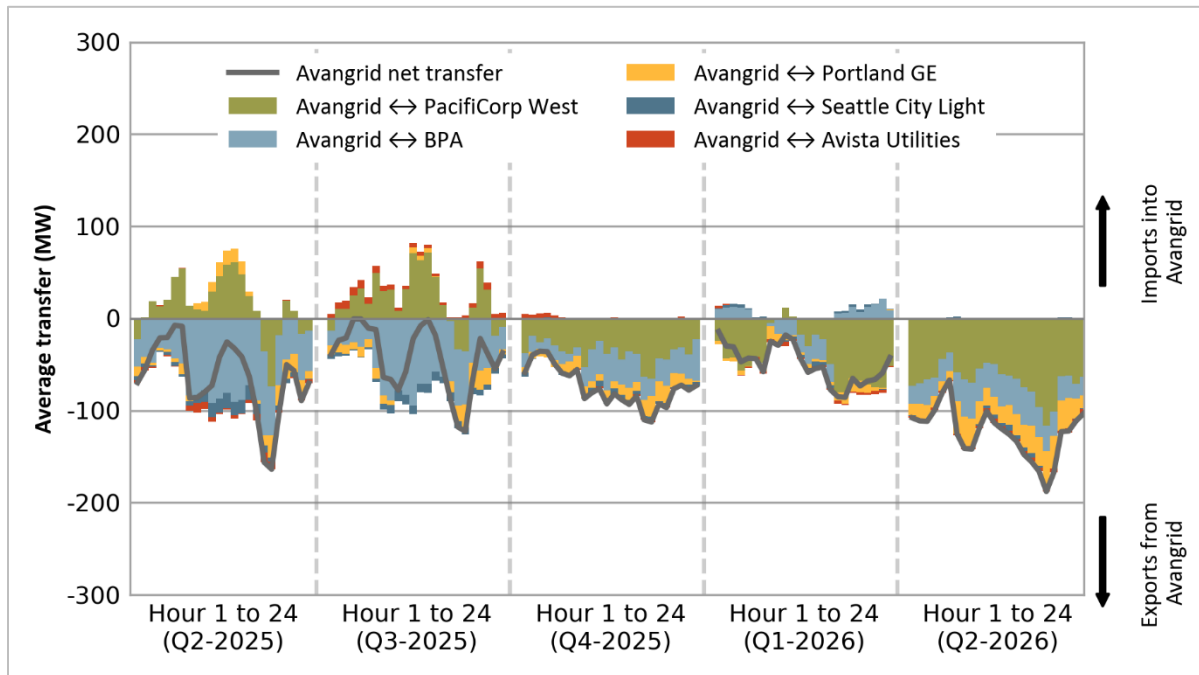
Appendix Figure A.6 Average hourly 5-minute market transfers

A.2 Avangrid

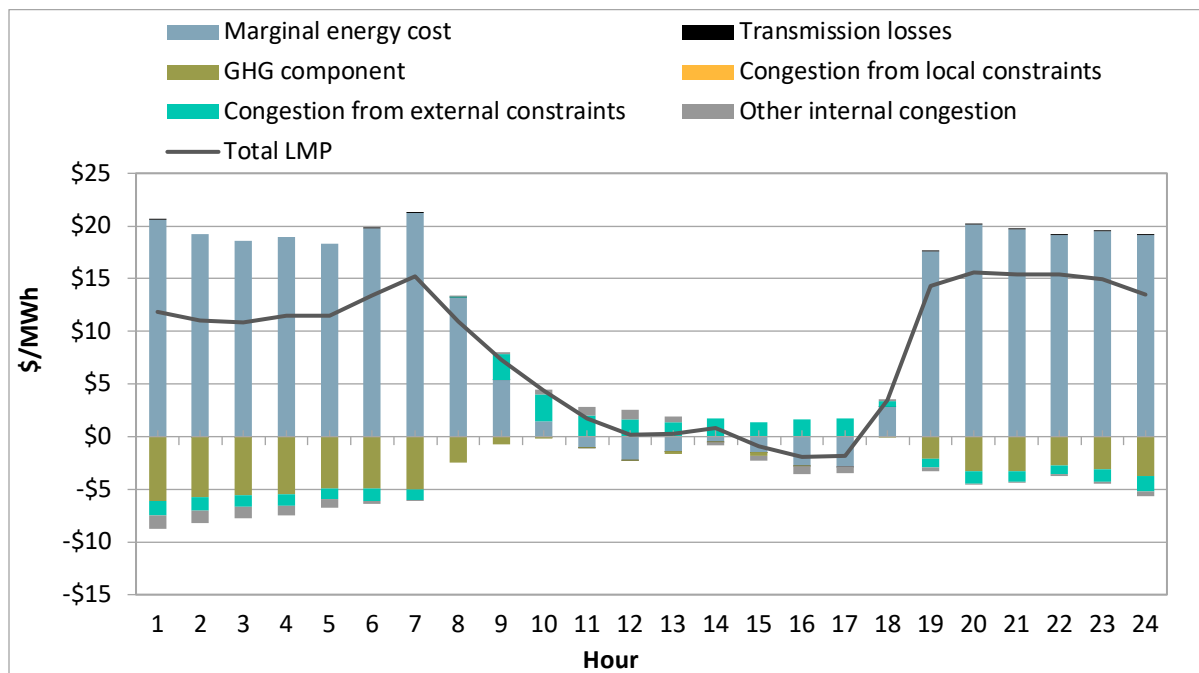
Appendix Figure A.7 Average hourly 15-minute price by component (April 2026)

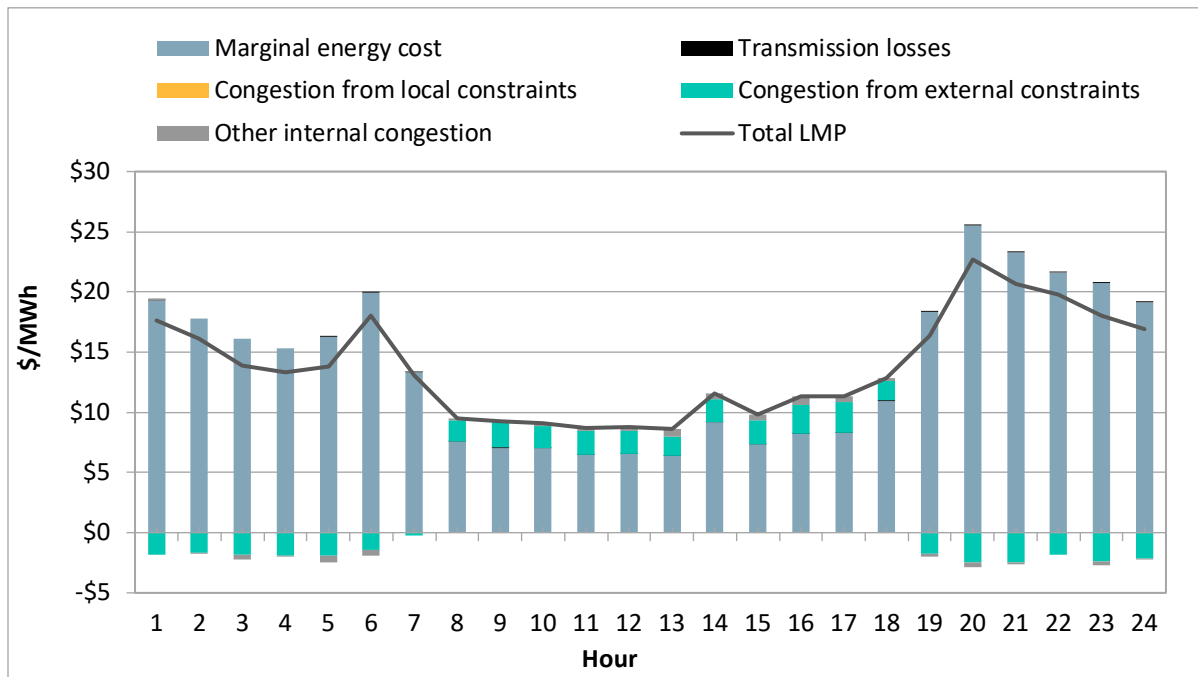
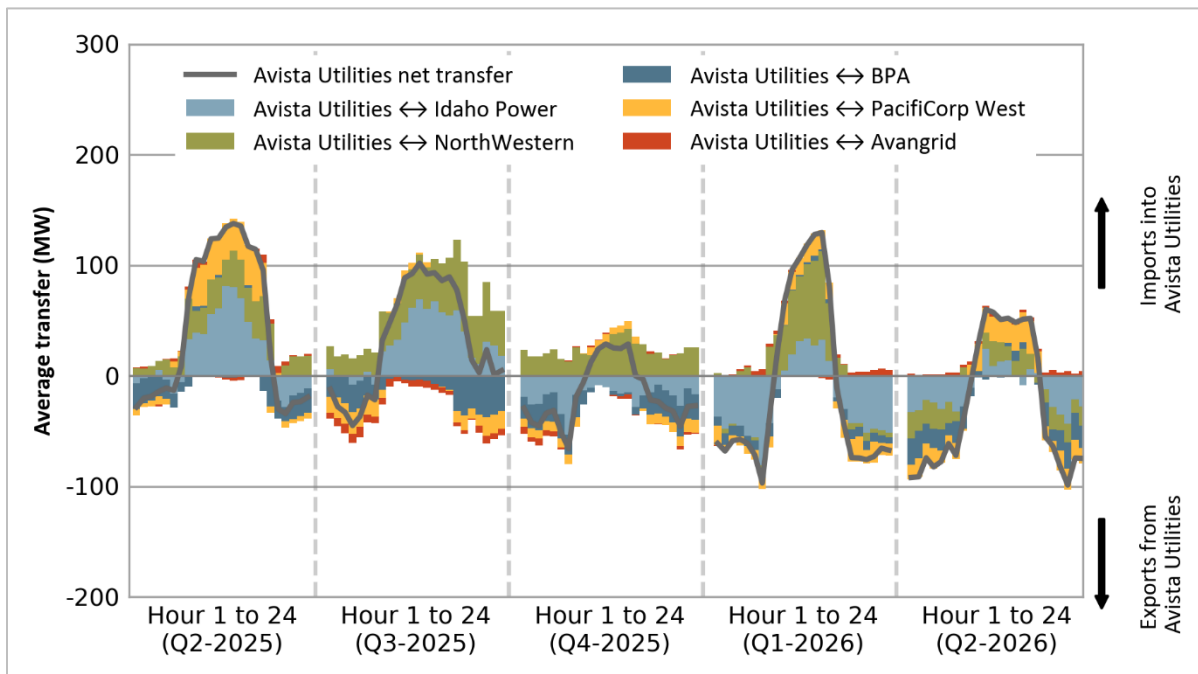
Appendix Figure A.8 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.9 Average hourly 15-minute market transfers**

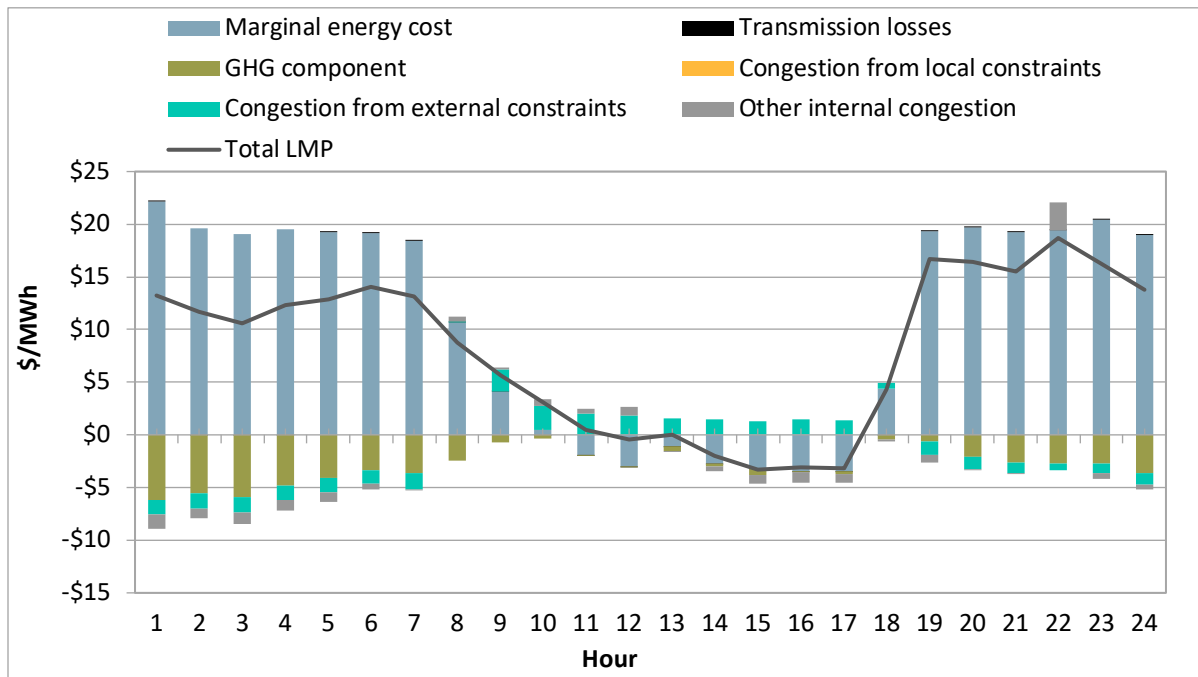
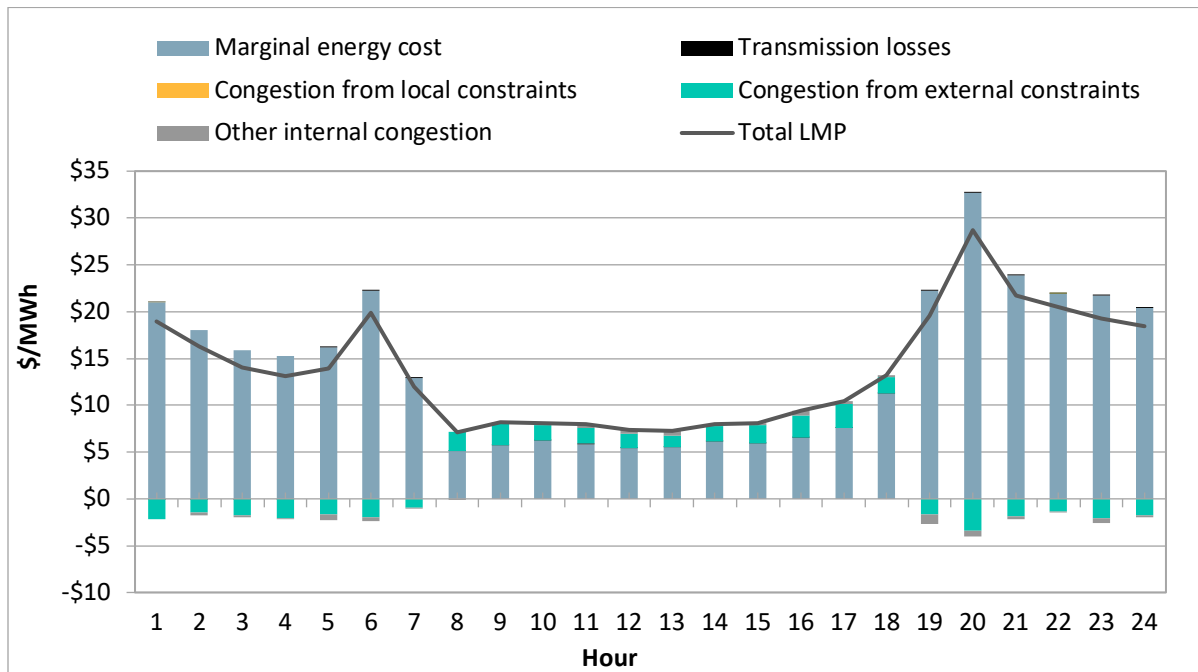
Appendix Figure A.10 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.11 Average hourly 5-minute price by component (May–June 2026)**

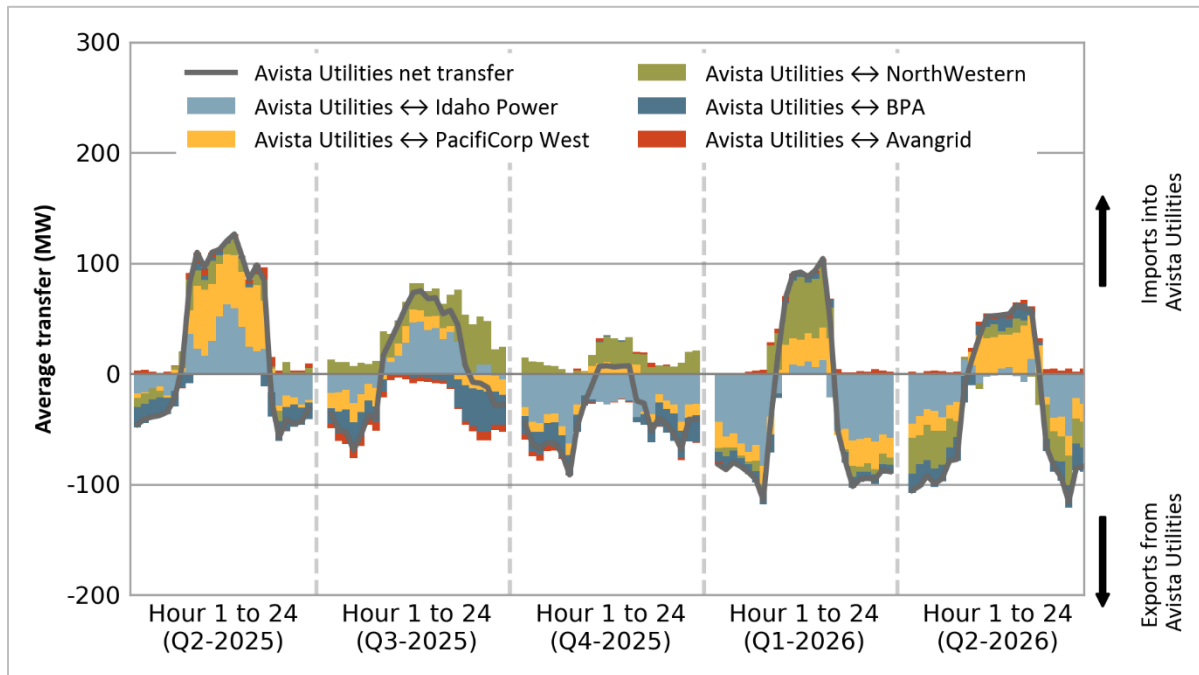
Appendix Figure A.12 Average hourly 5-minute market transfers

A.3 Avista Utilities

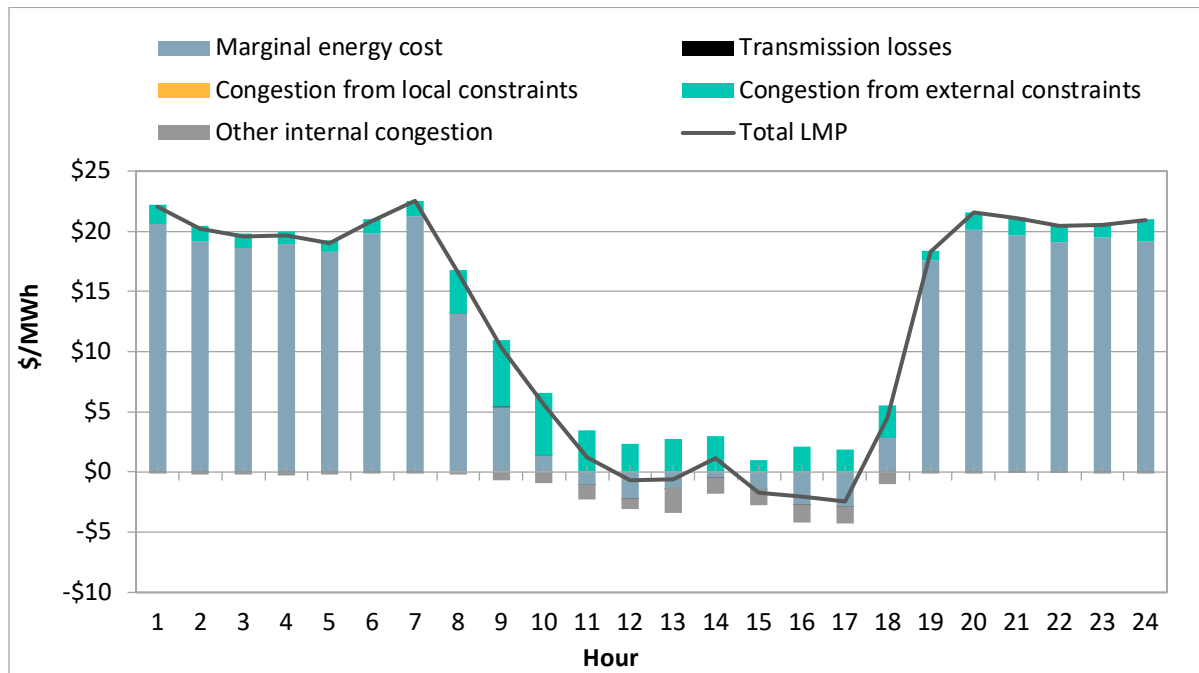
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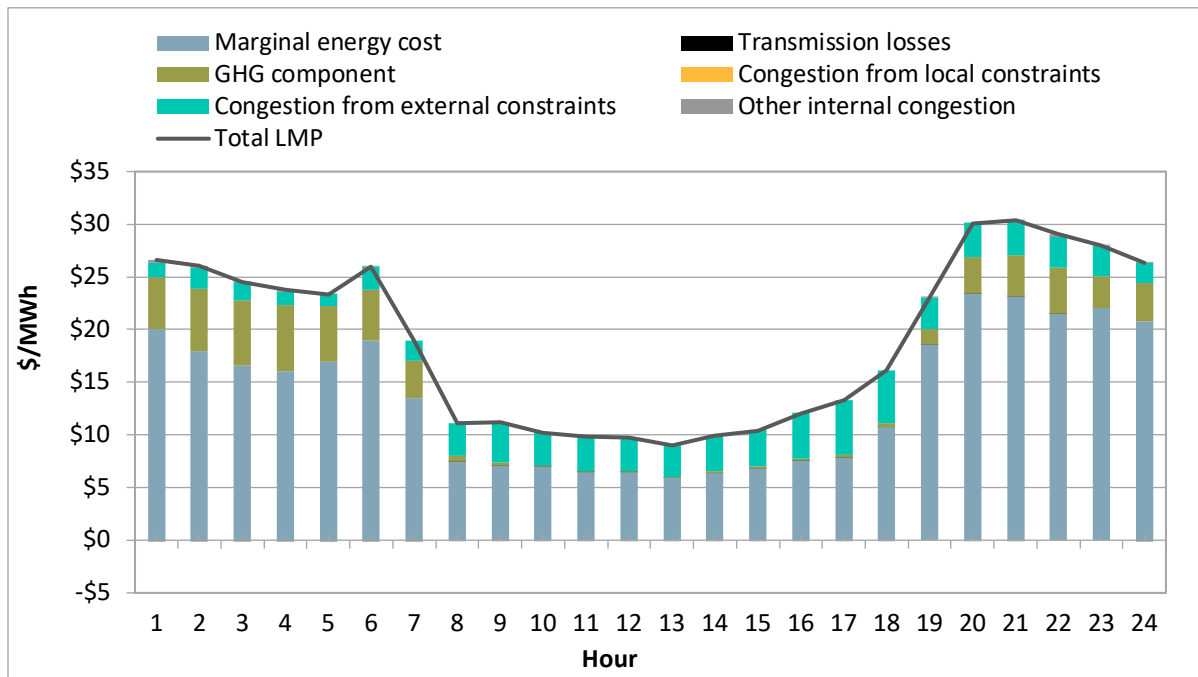
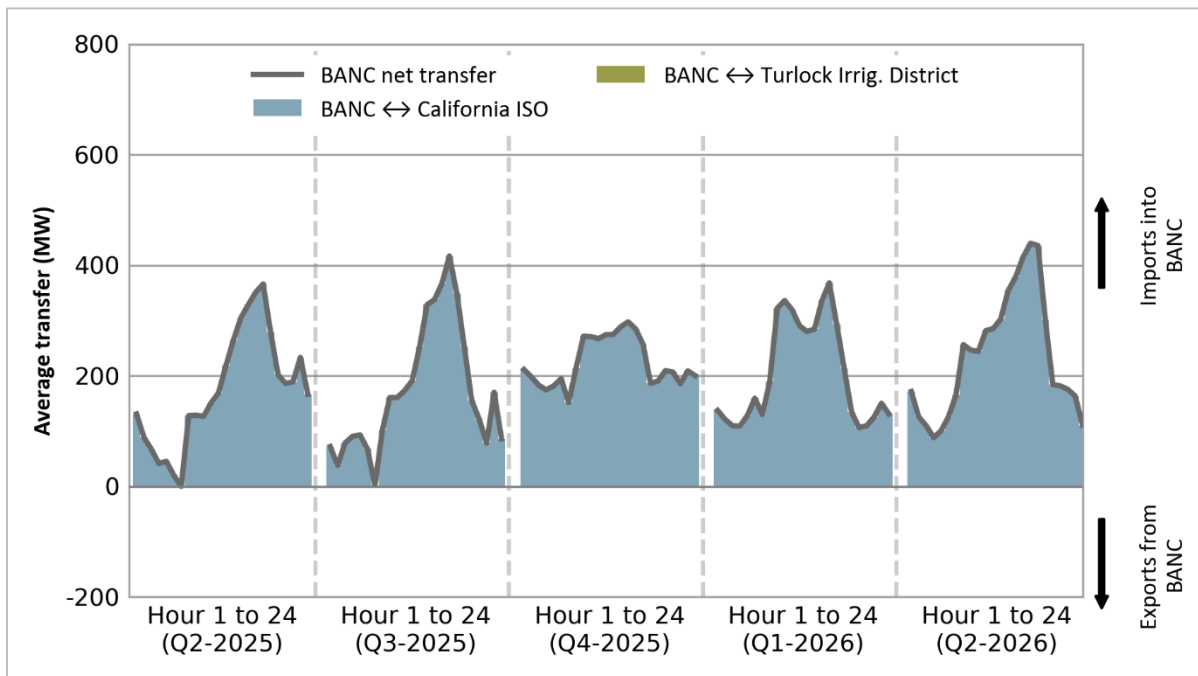
Appendix Figure A.14 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.15 Average hourly 15-minute market transfers**

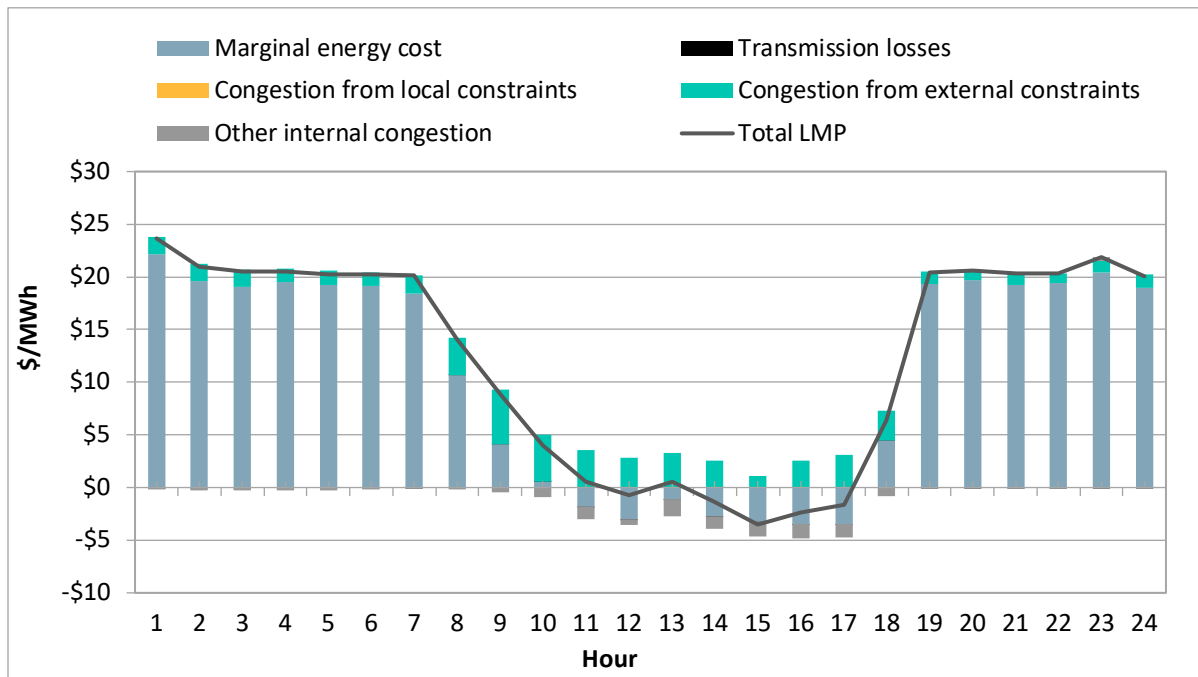
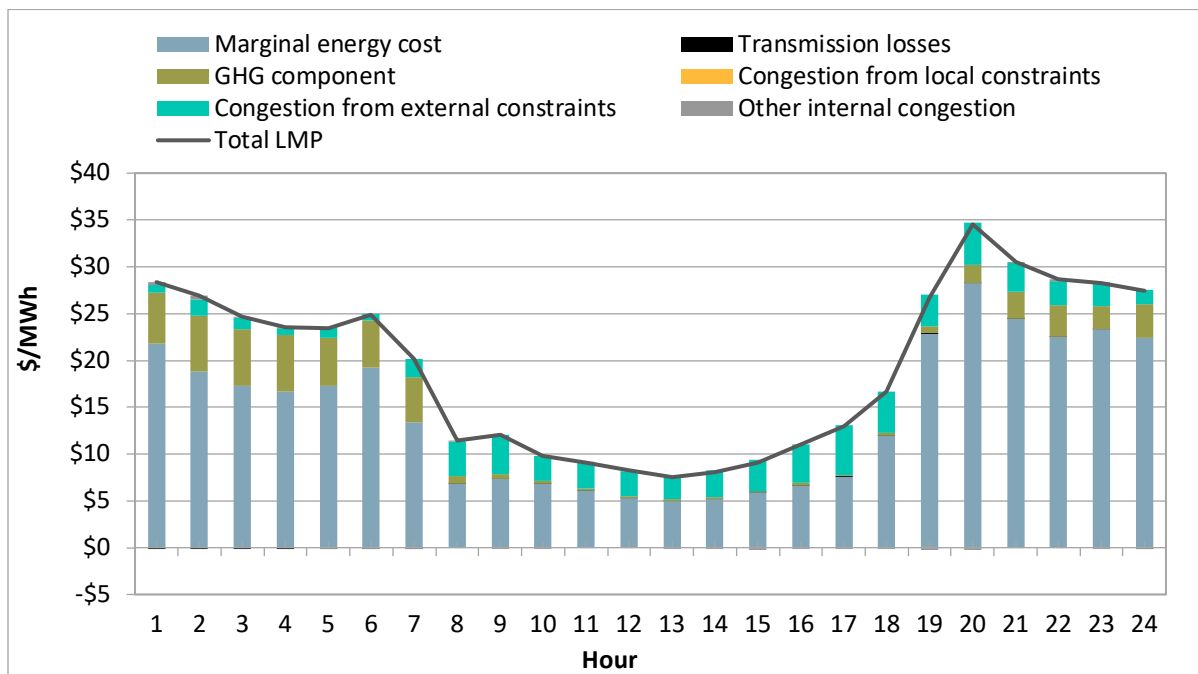
Appendix Figure A.16 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.17 Average hourly 5-minute price by component (May–June 2026)**

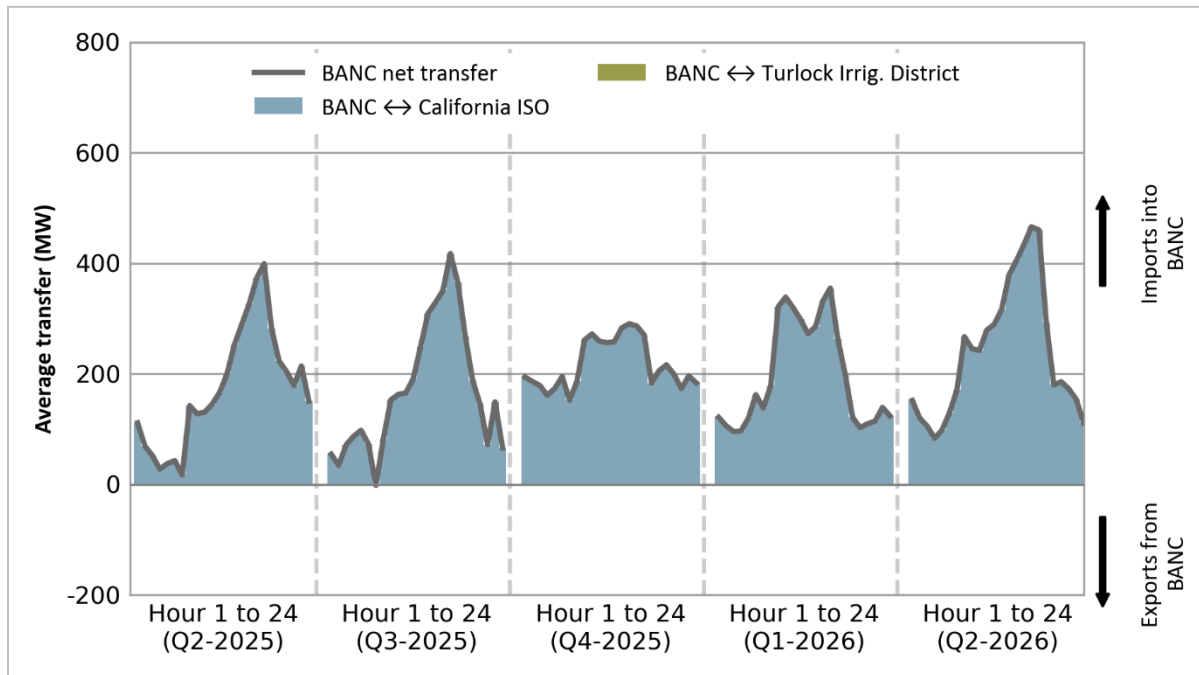
Appendix Figure A.18 Average hourly 5-minute market transfers

A.4 Balancing Authority of Northern California

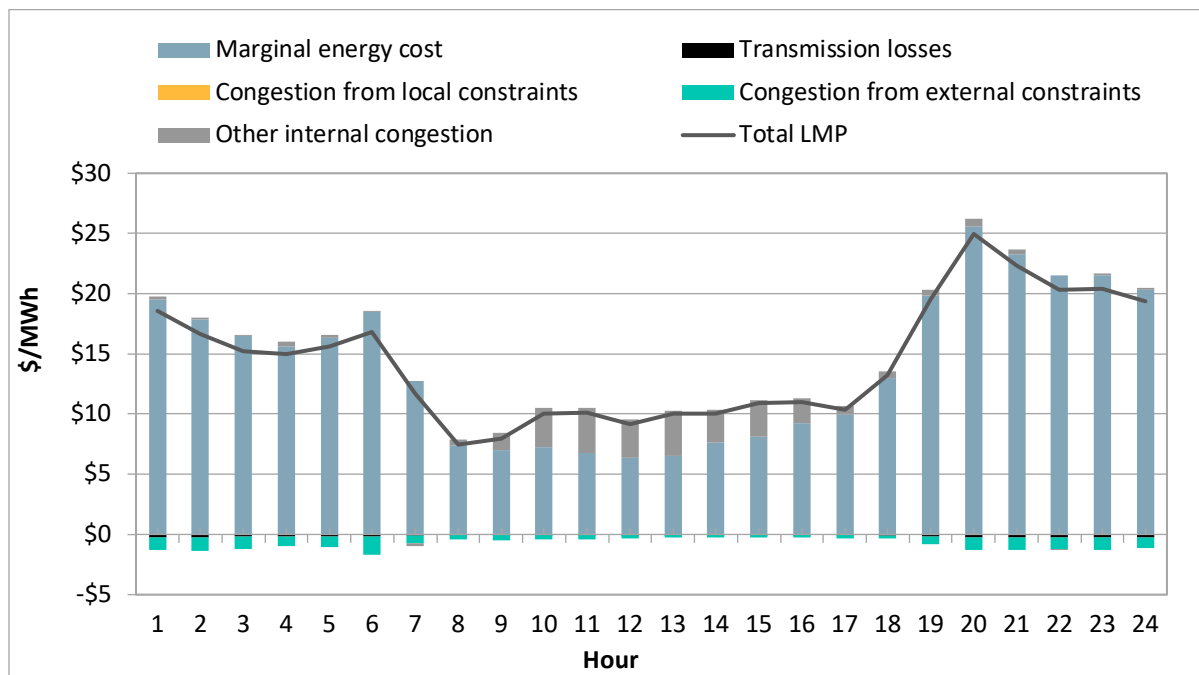
Appendix Figure A.19 Average hourly 15-minute price by component (April 2026)

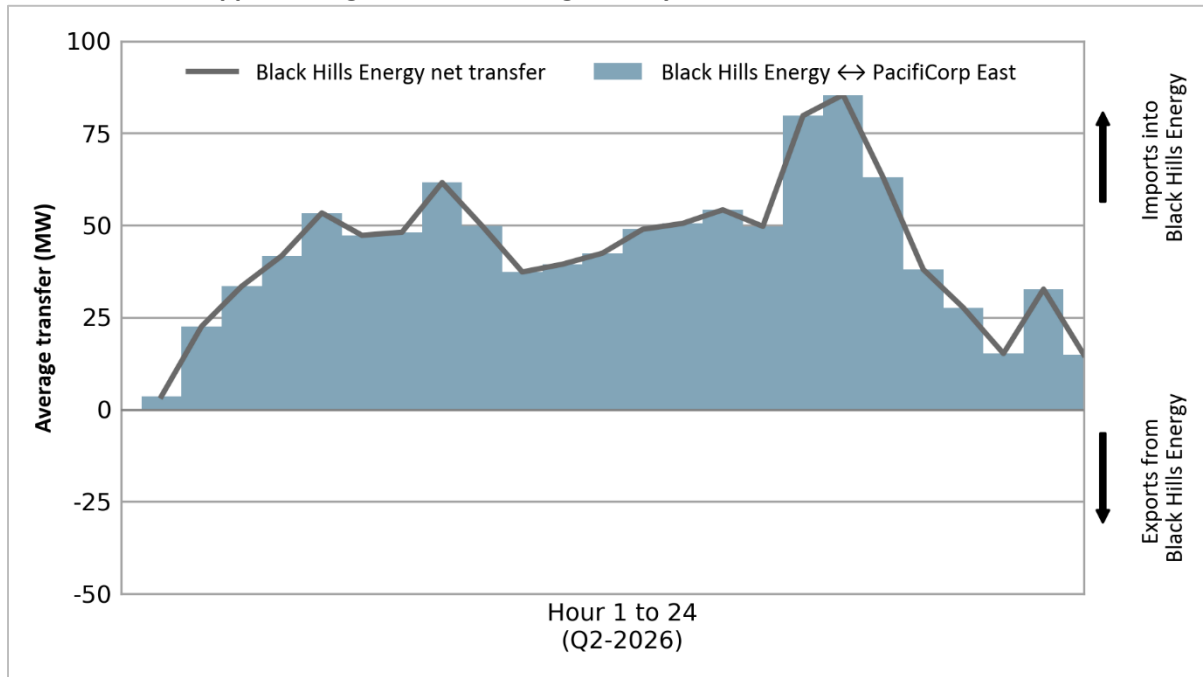
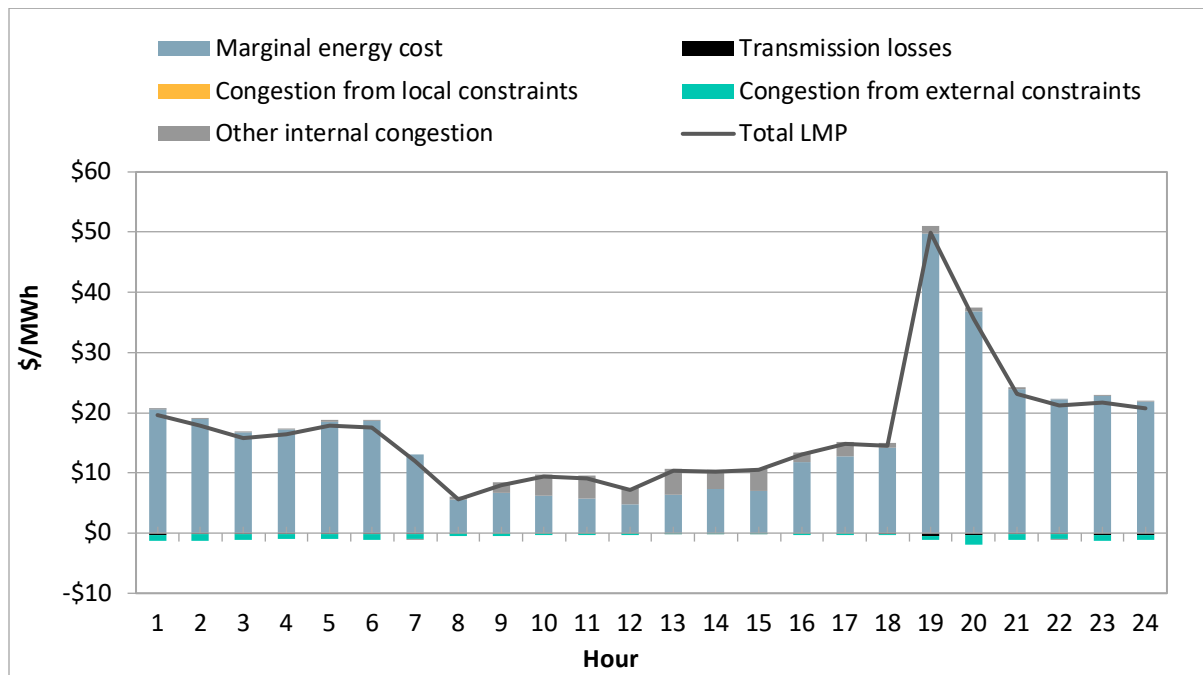
Appendix Figure A.20 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.21 Average hourly 15-minute market transfers**

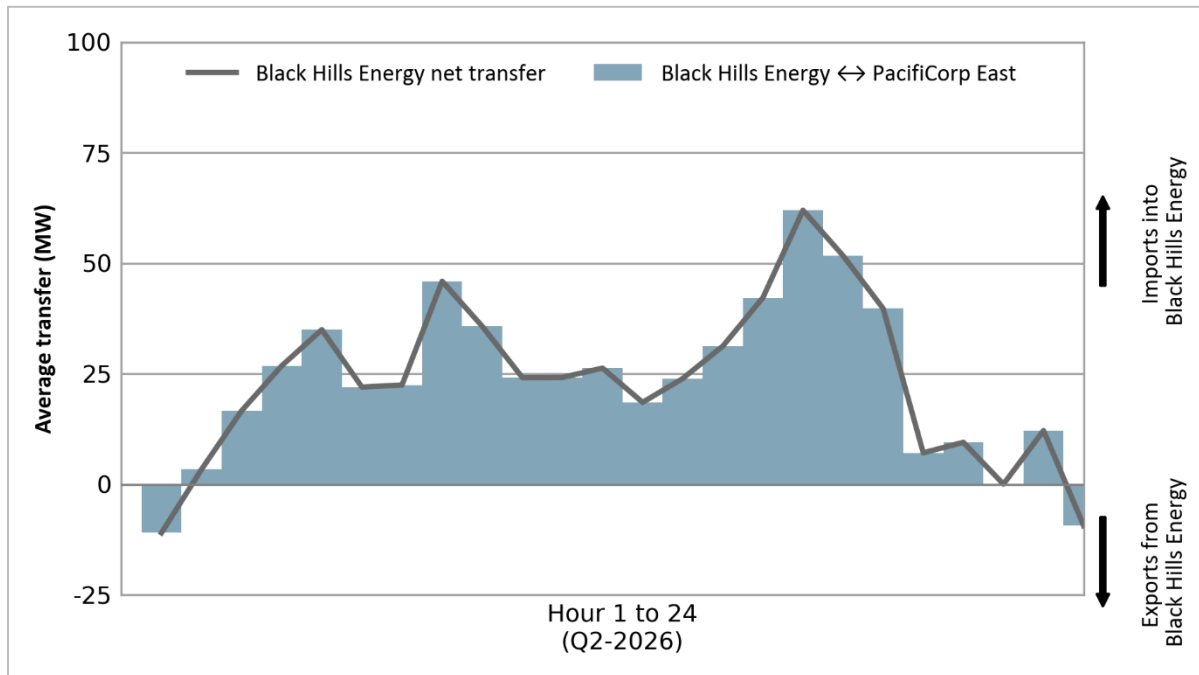
Appendix Figure A.22 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.23 Average hourly 5-minute price by component (May–June 2026)**

Appendix Figure A.24 Average hourly 5-minute market transfers

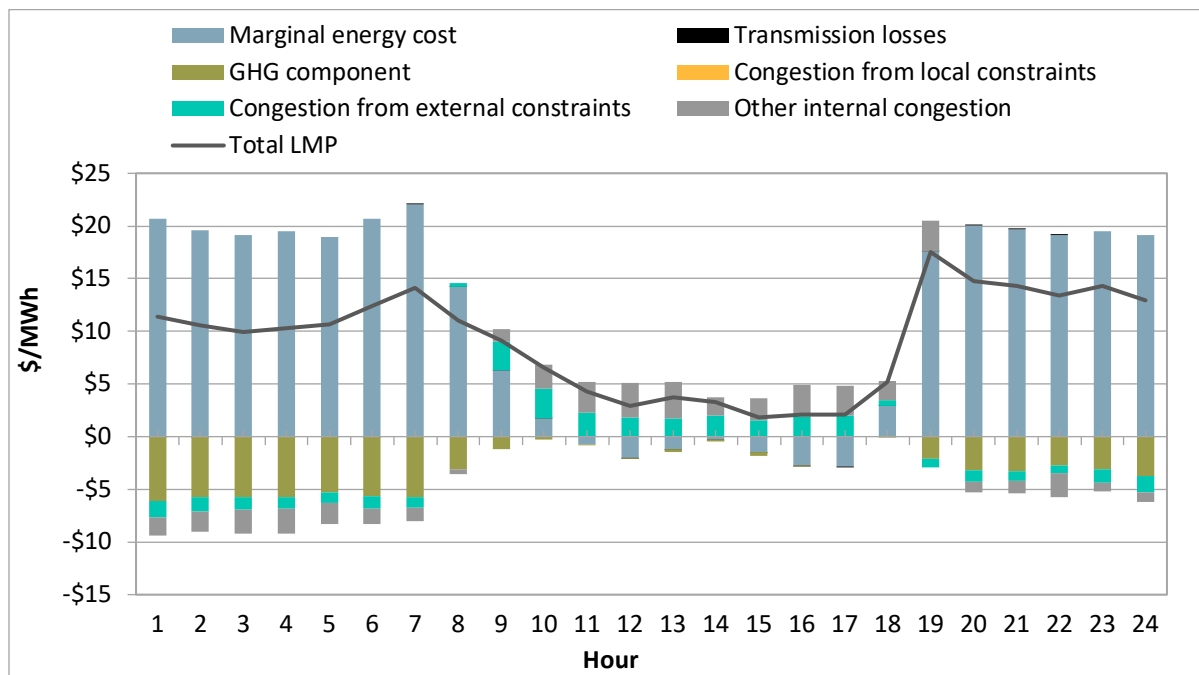
A.5 Black Hills Energy

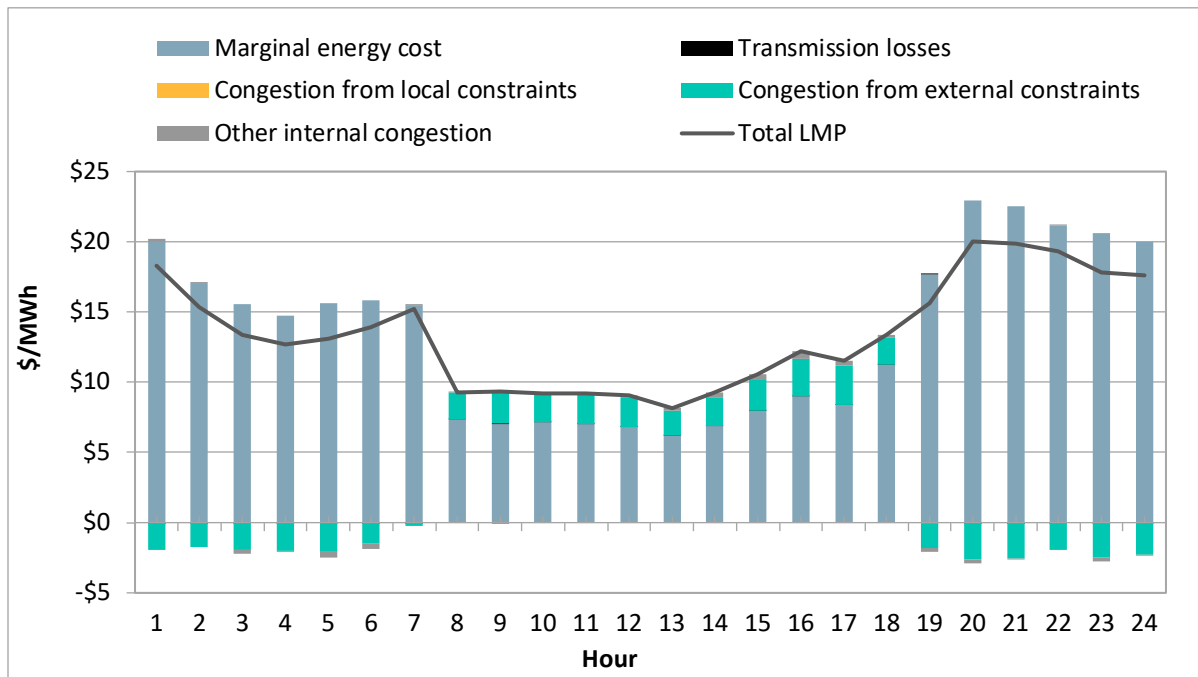
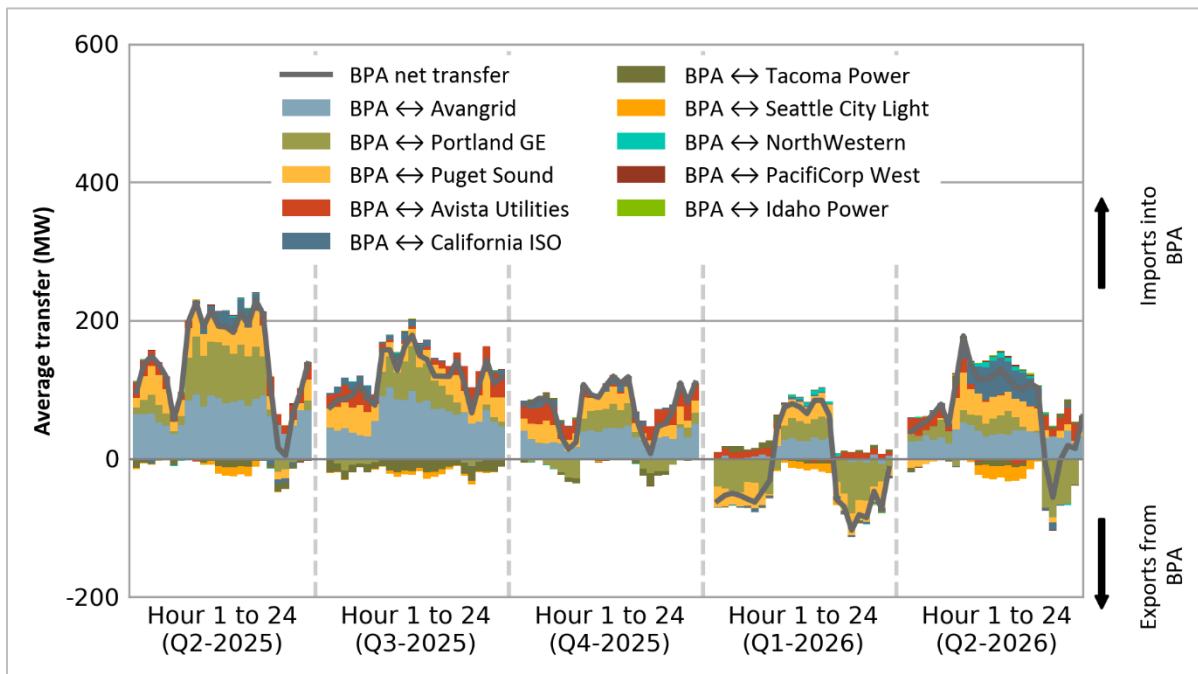
Appendix Figure A.25 Average hourly 15-minute price by component (May–June 2026)

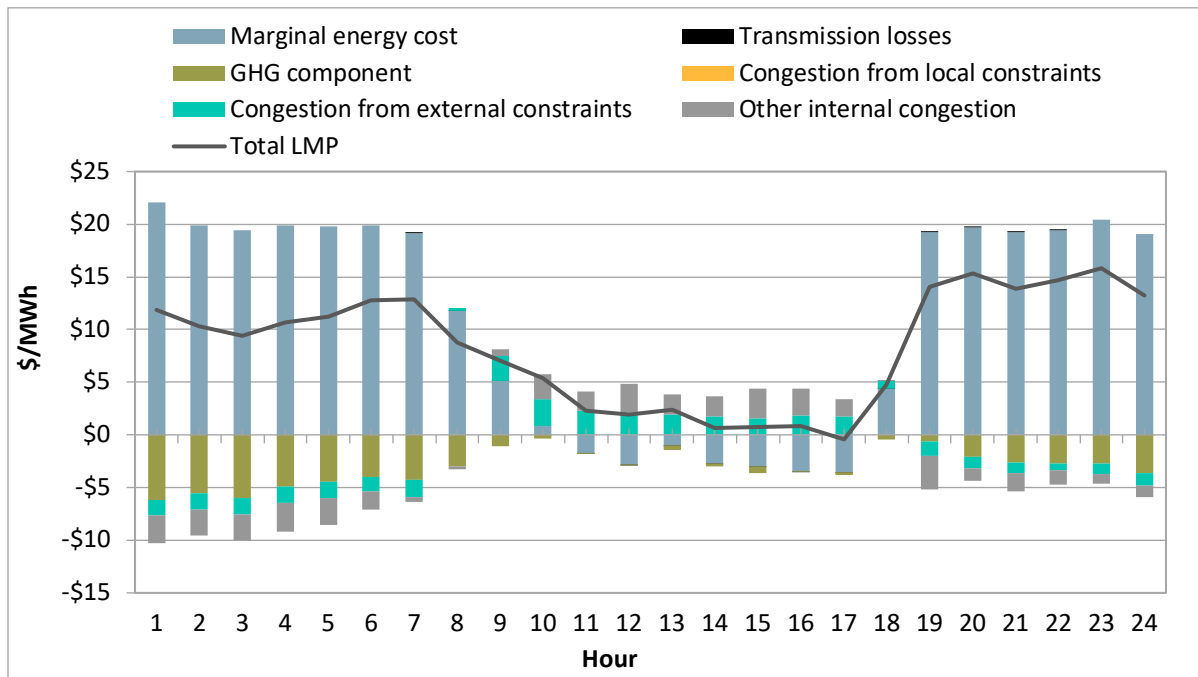
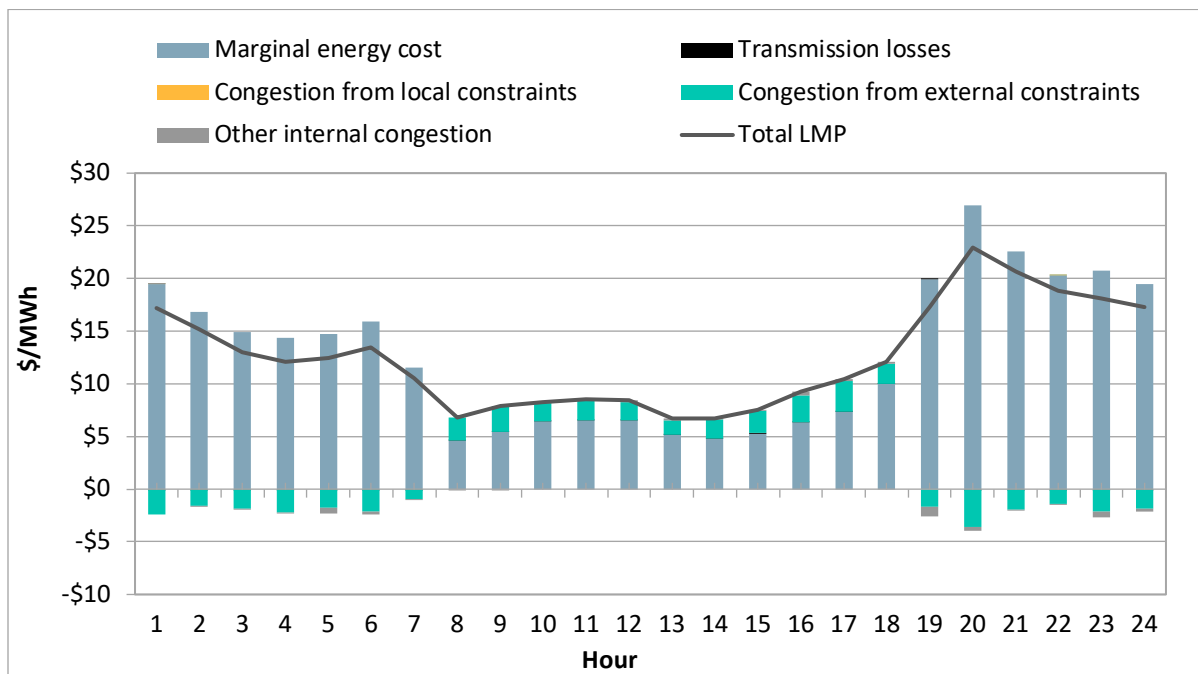
Appendix Figure A.26 Average hourly 15-minute market transfers**Appendix Figure A.27 Average hourly 5-minute price by component (May–June 2026)**

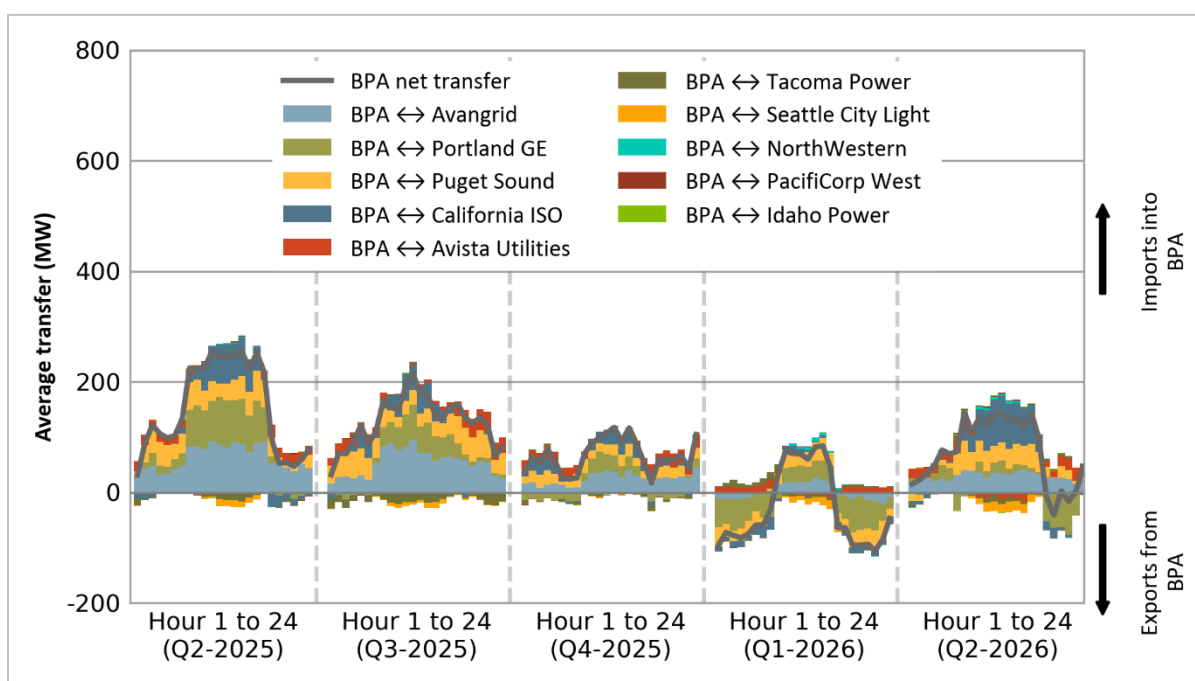
Appendix Figure A.28 Average hourly 5-minute market transfers

A.6 Bonneville Power Administration

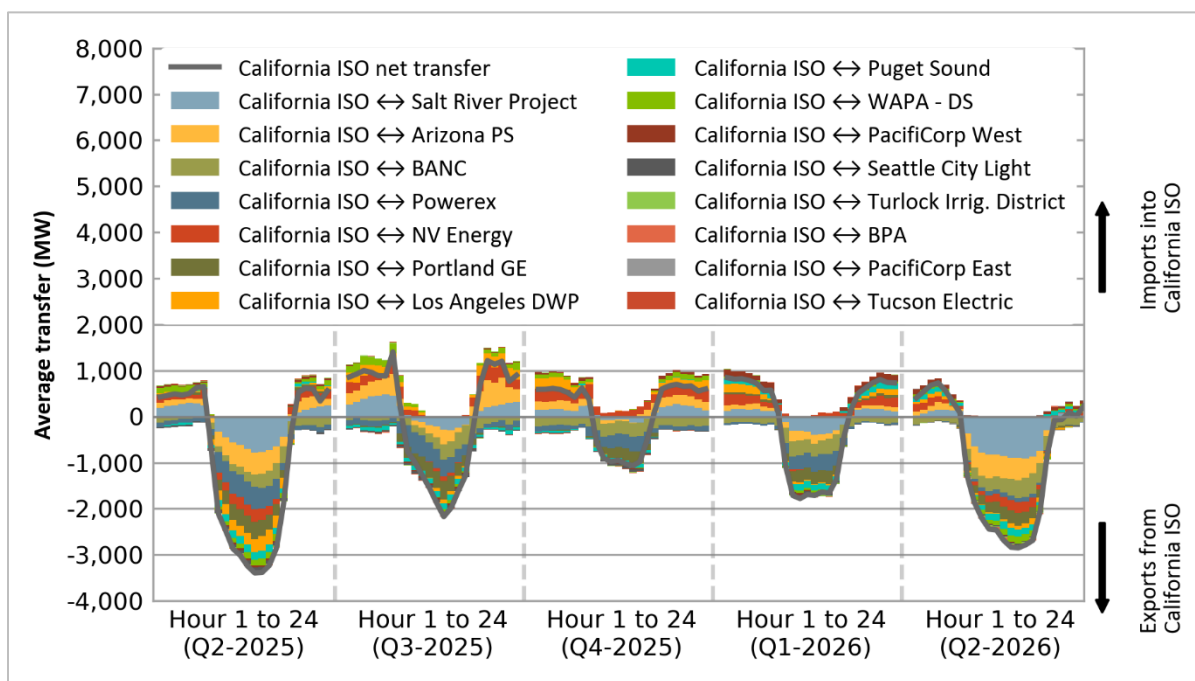
Appendix Figure A.29 Average hourly 15-minute price by component (April 2026)

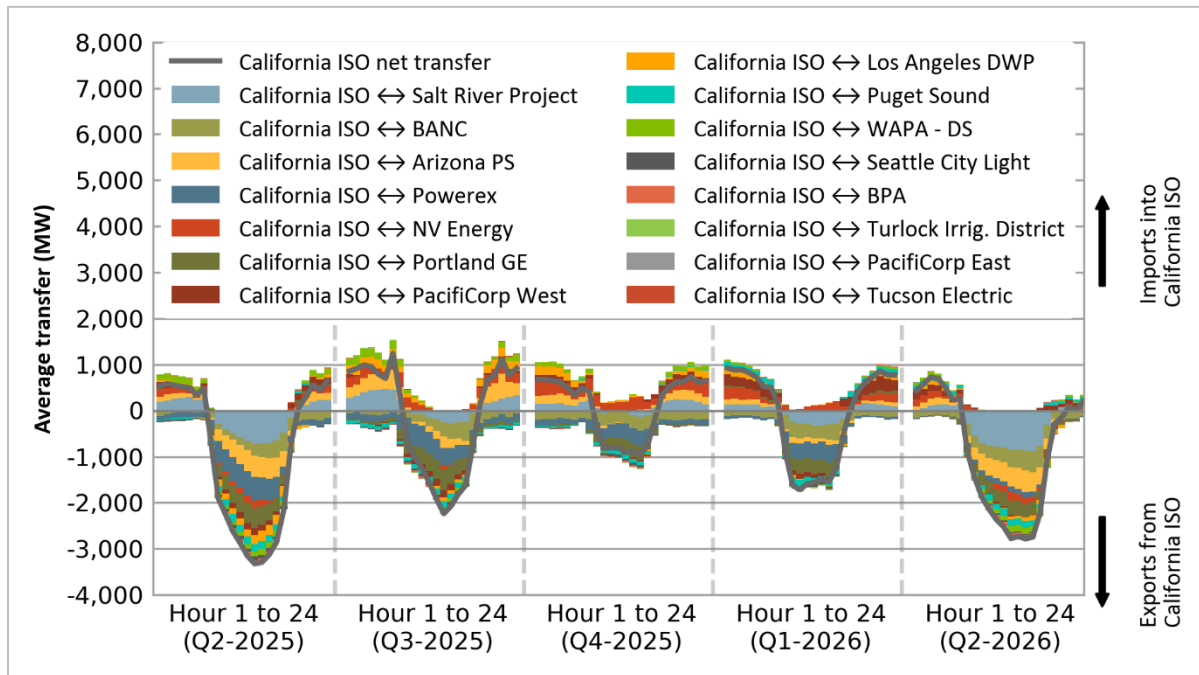
Appendix Figure A.30 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.31 Average hourly 15-minute market transfers**

Appendix Figure A.32 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.33 Average hourly 5-minute price by component (May–June 2026)**

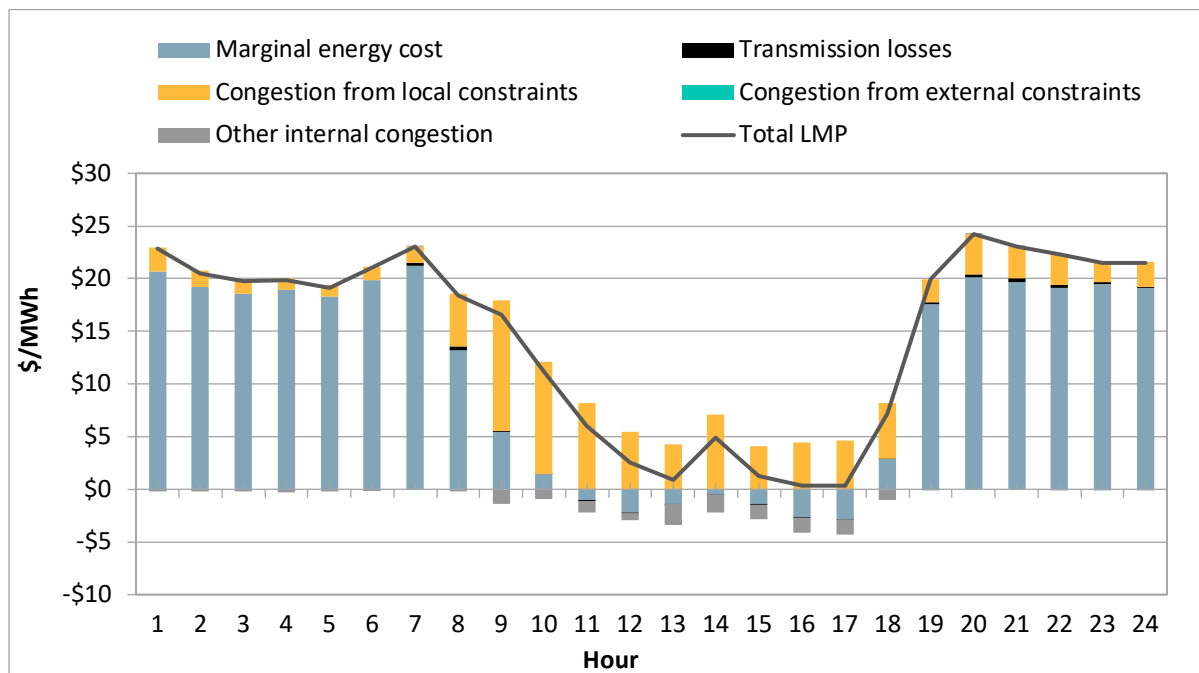
Appendix Figure A.34 Average hourly 5-minute market transfers

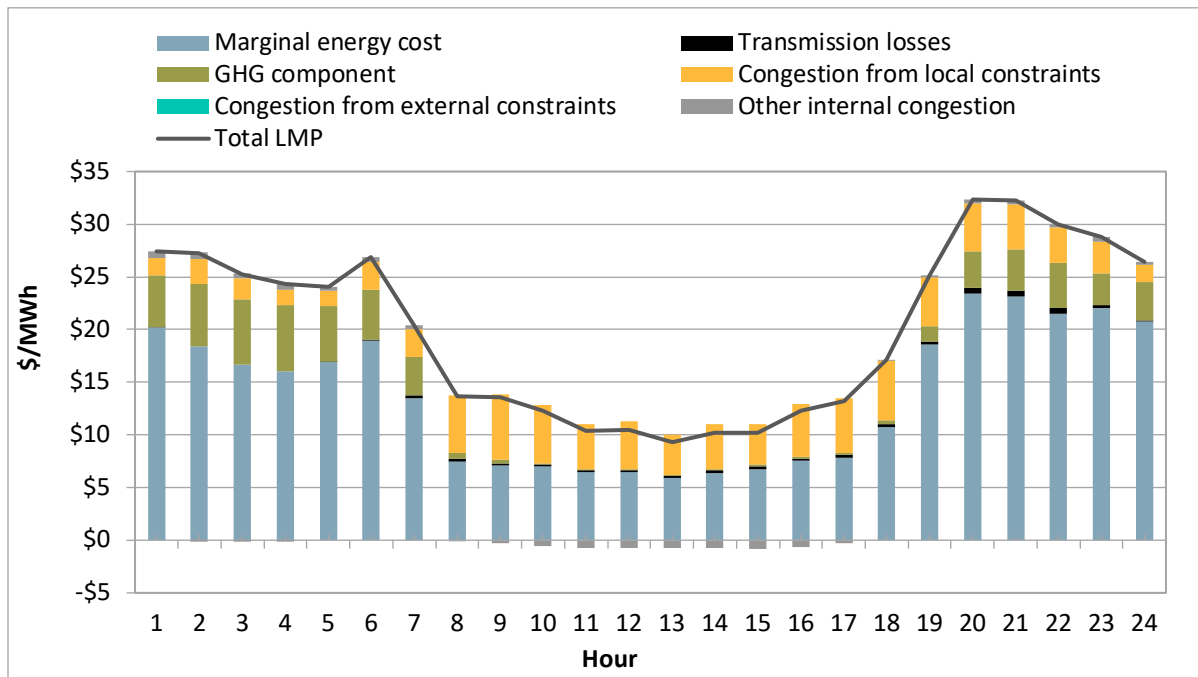
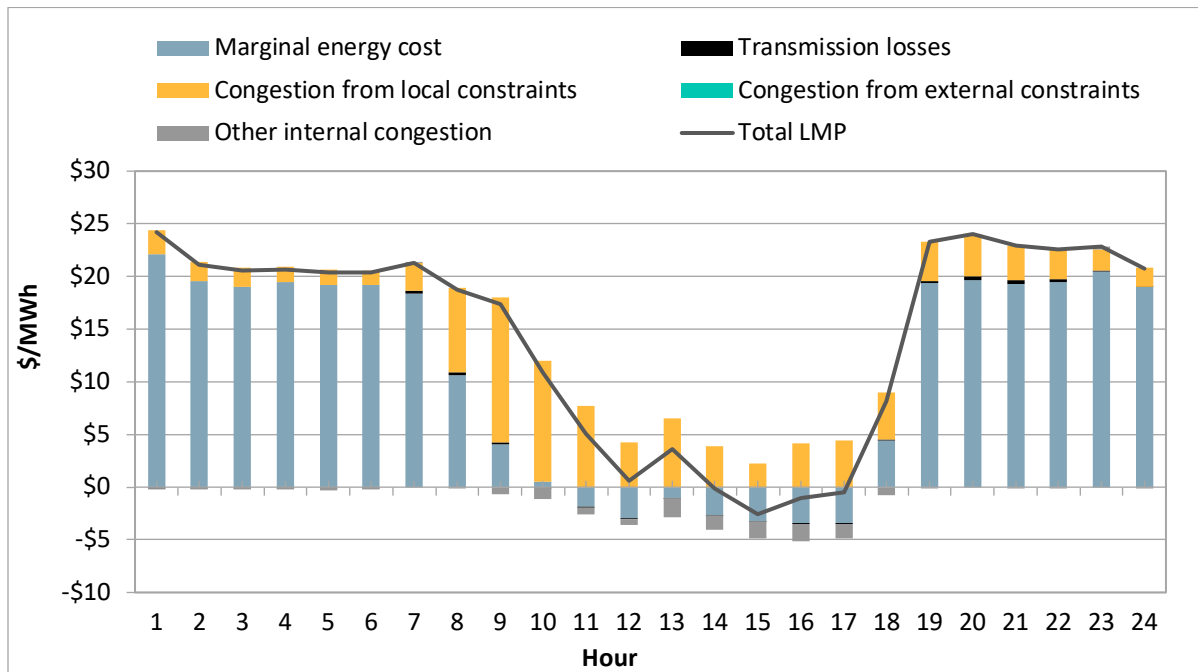
A.7 California ISO

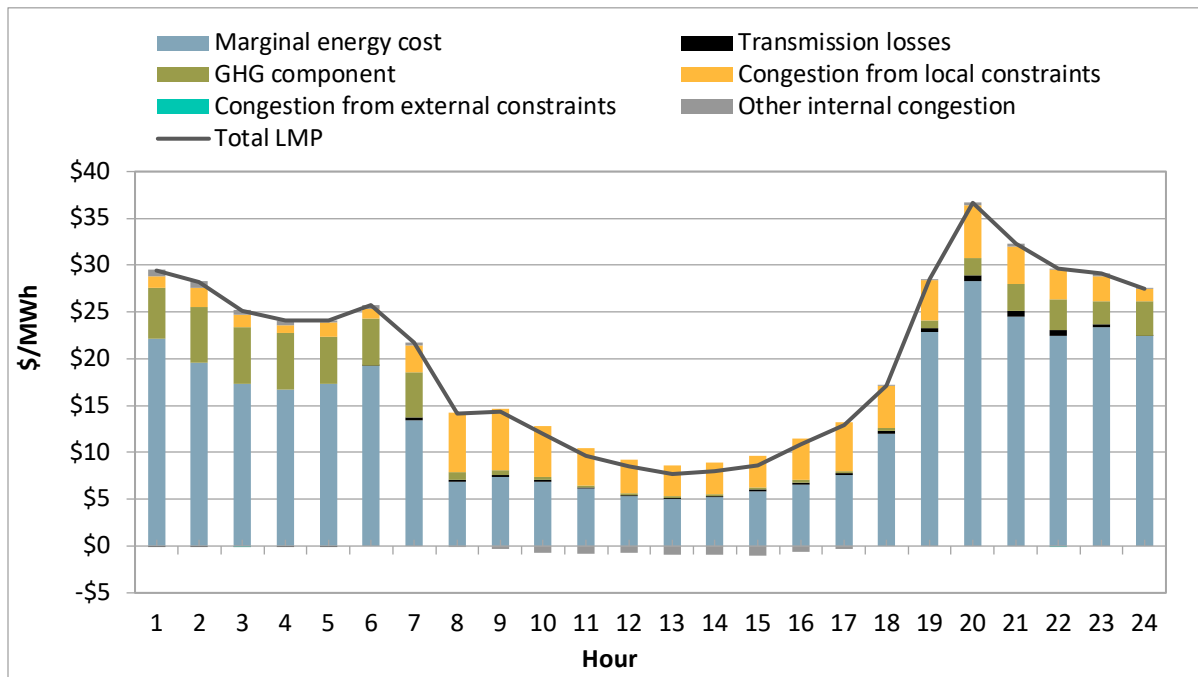
Appendix Figure A.35 Average hourly 15-minute market transfers

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

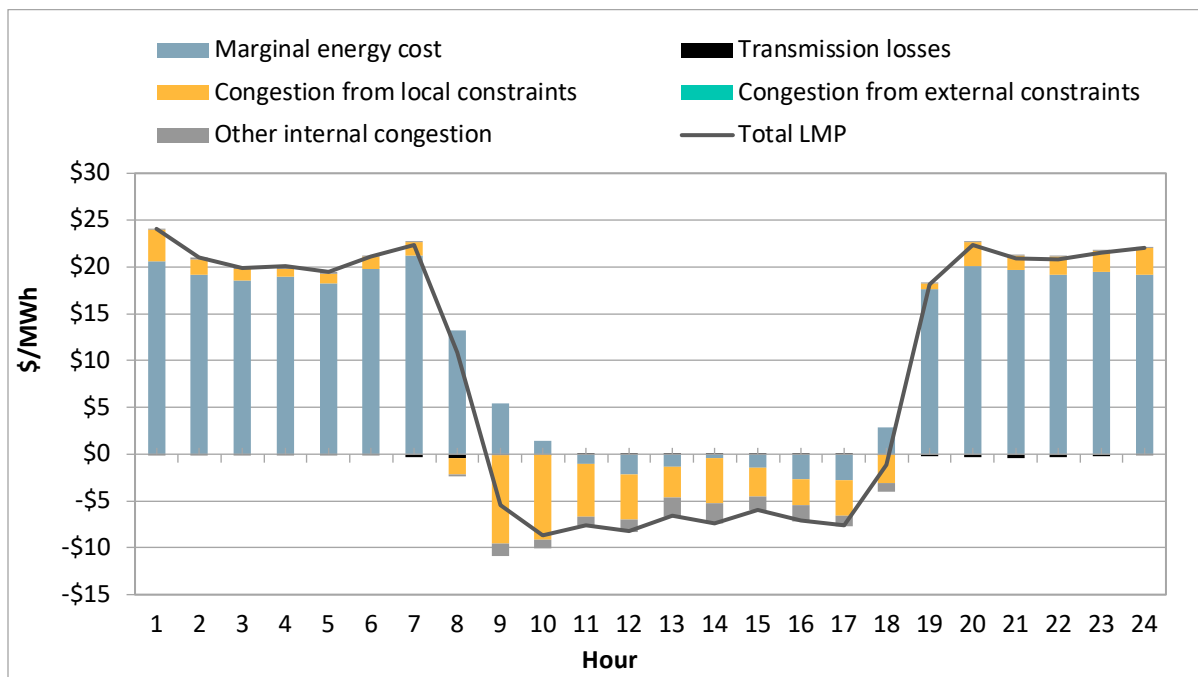
A.7.1 Pacific Gas and Electric

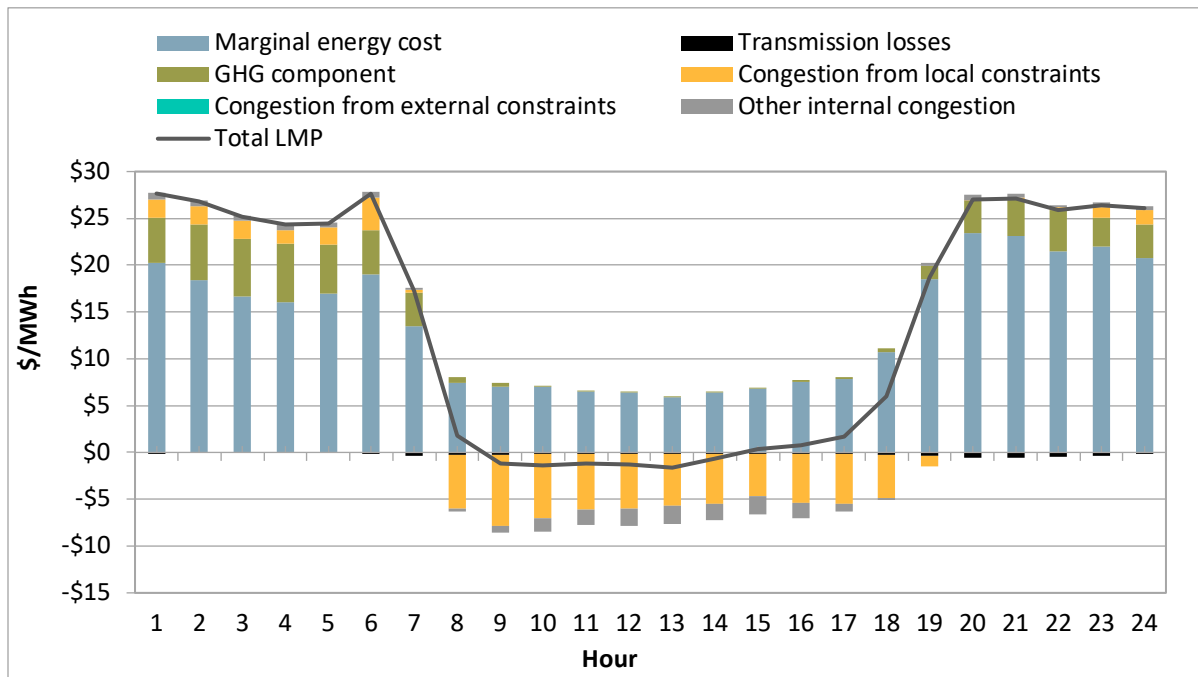
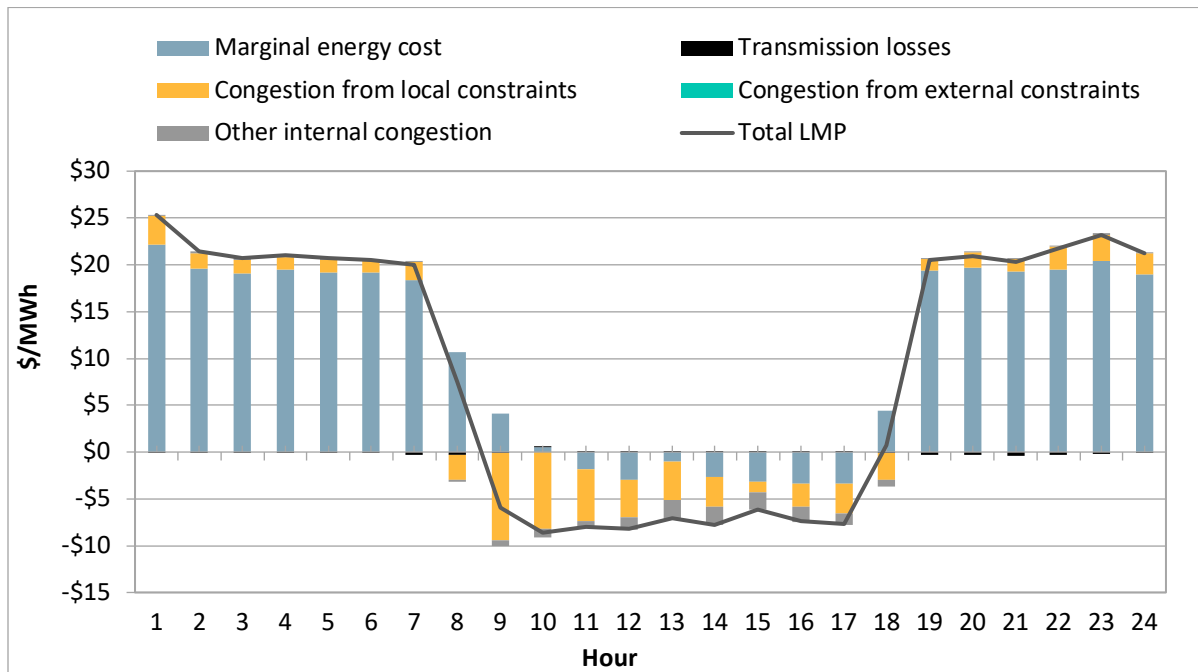
Appendix Figure A.37 Average hourly 15-minute price by component (April 2026)

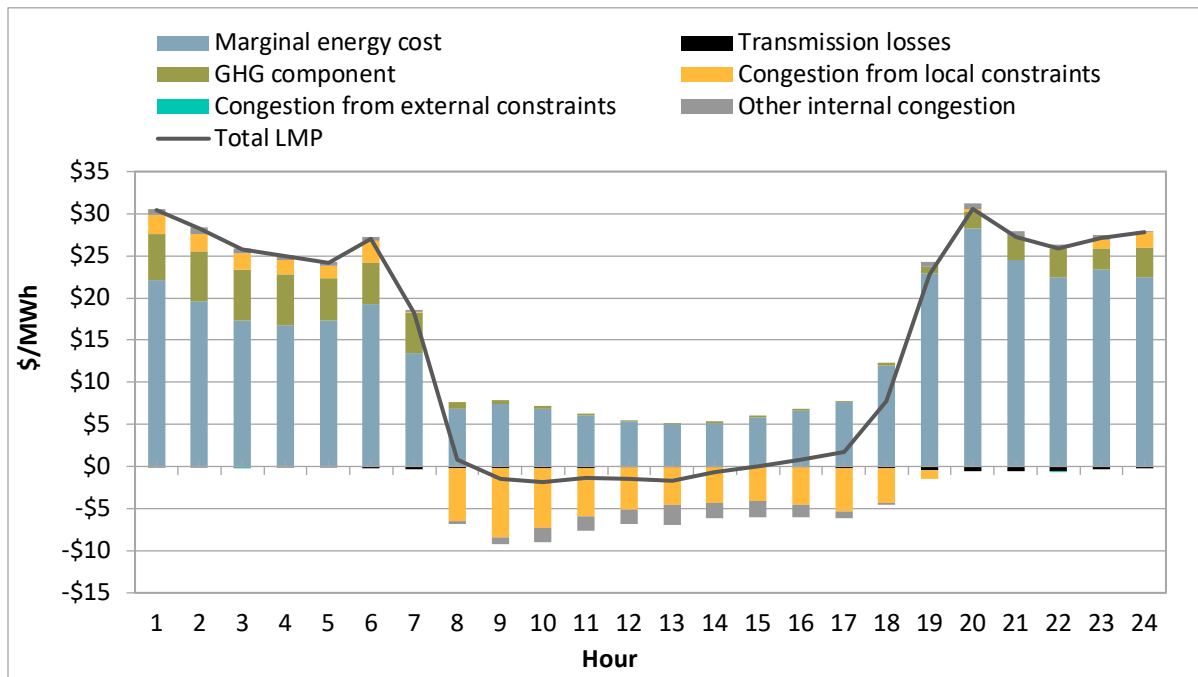
Appendix Figure A.38 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.39 Average hourly 5-minute price by component (April 2026)**

Appendix Figure A.40 Average hourly 5-minute price by component (May–June 2026)

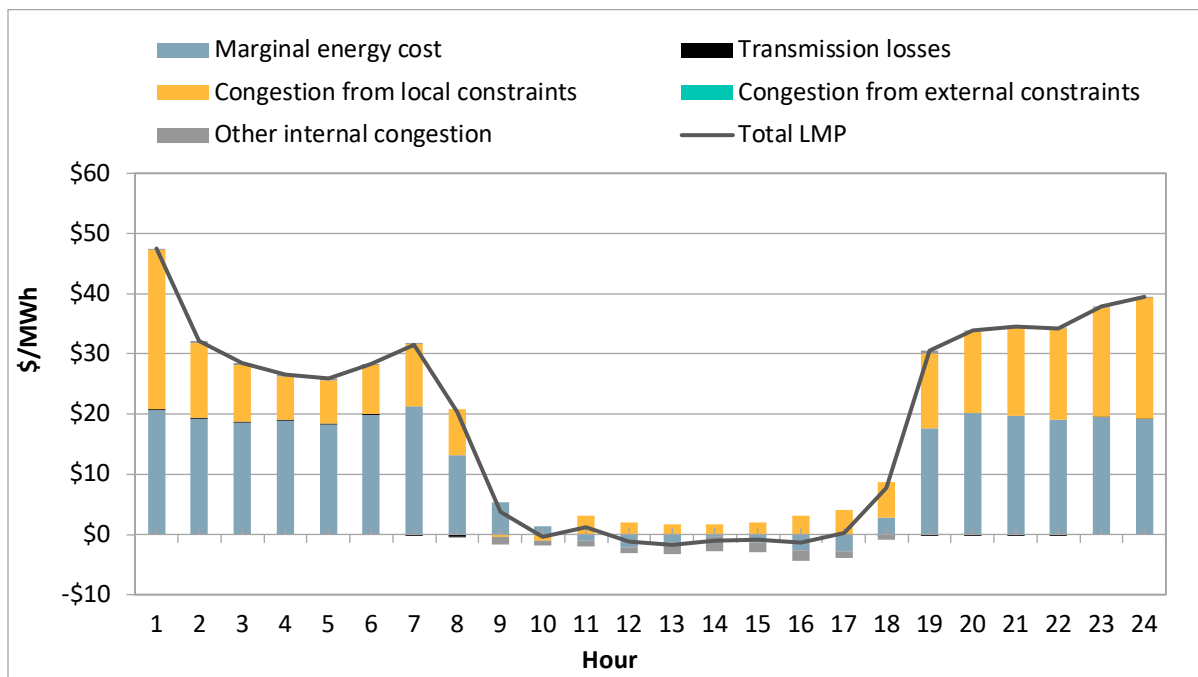
A.7.2 Southern California Edison

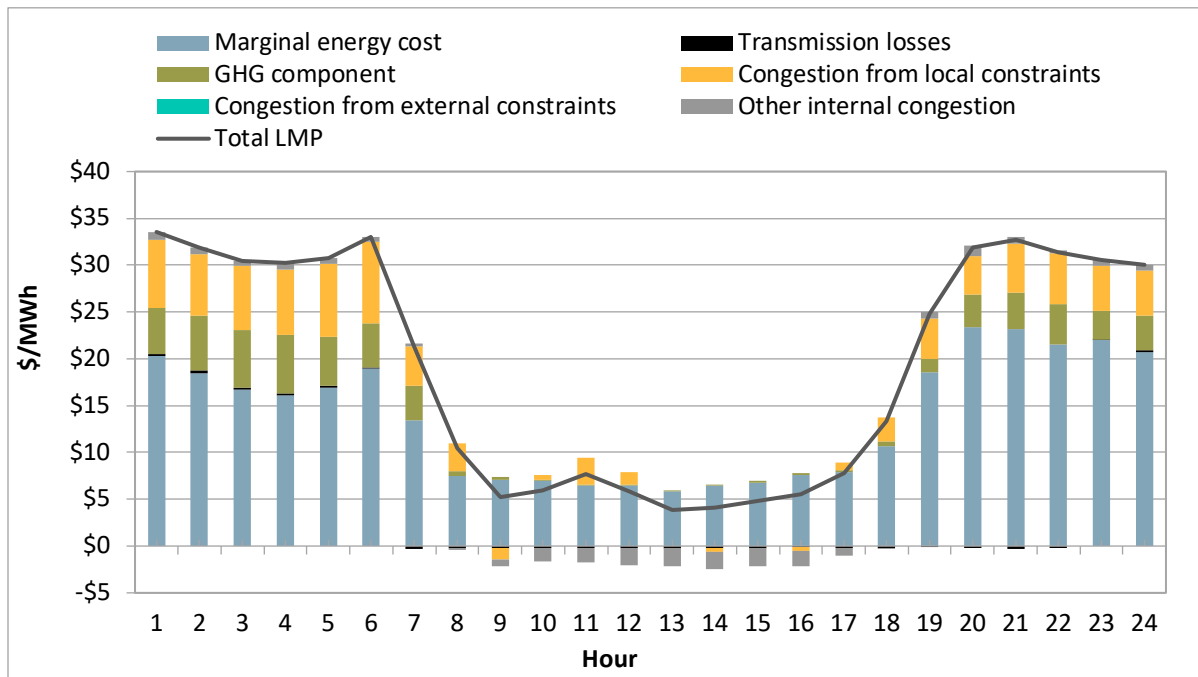
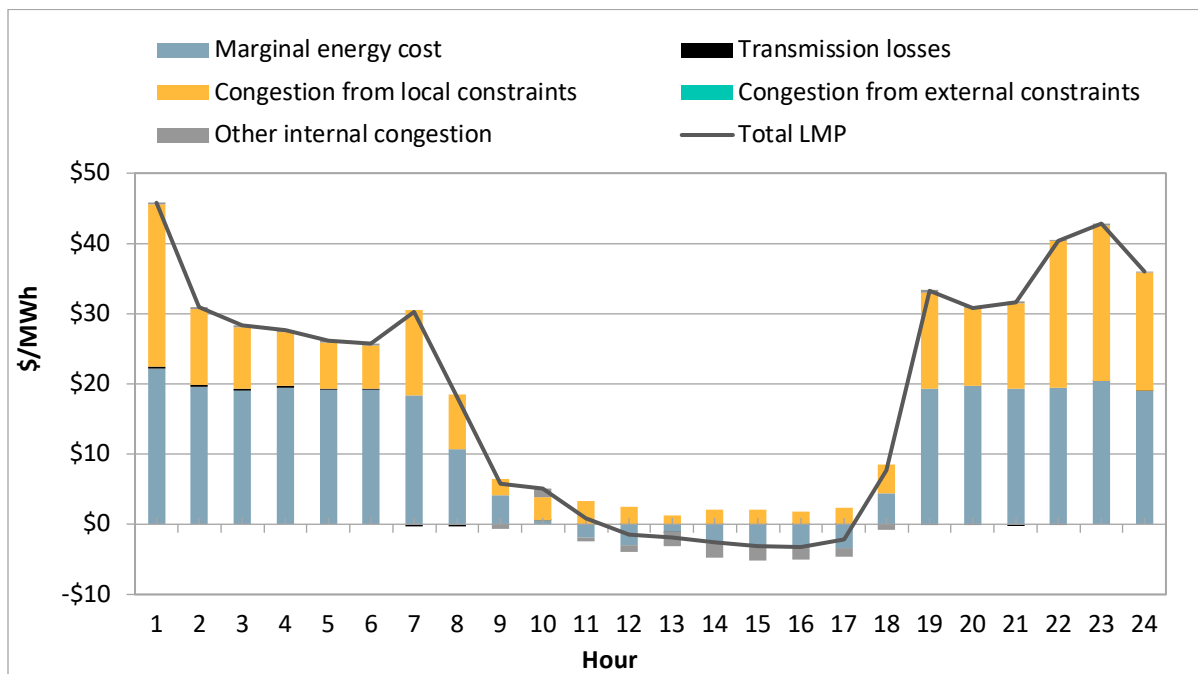
Appendix Figure A.41 Average hourly 15-minute price by component (April 2026)

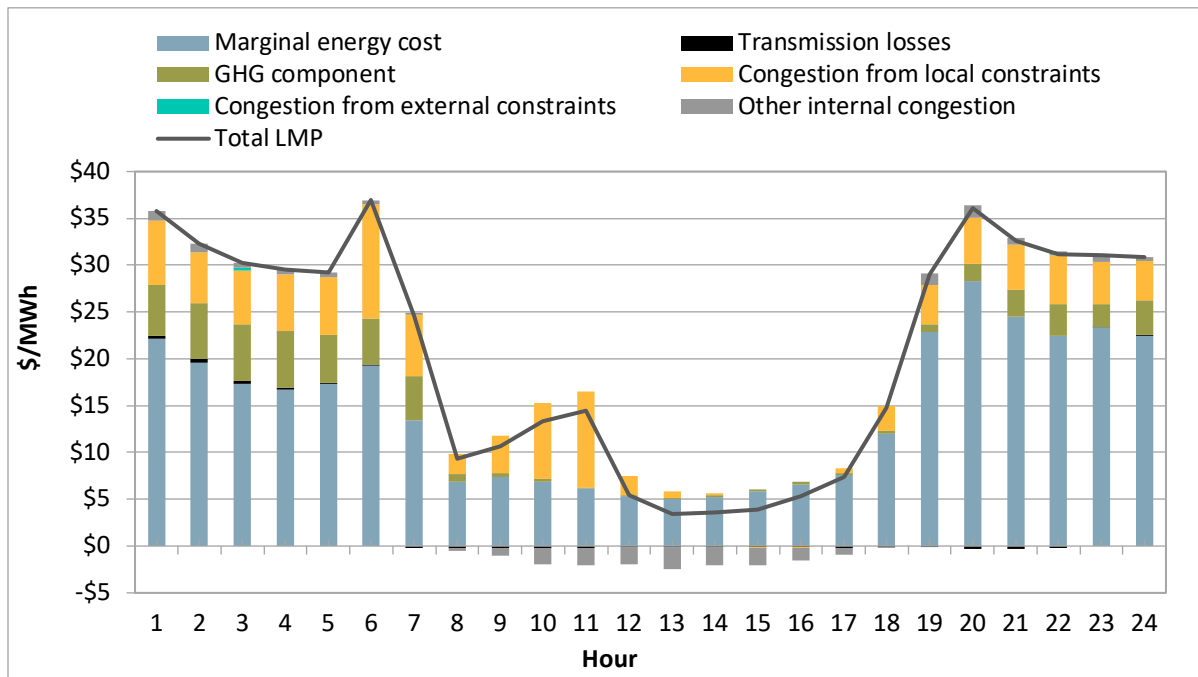
Appendix Figure A.42 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.43 Average hourly 5-minute price by component (April 2026)**

Appendix Figure A.44 Average hourly 5-minute price by component (May–June 2026)

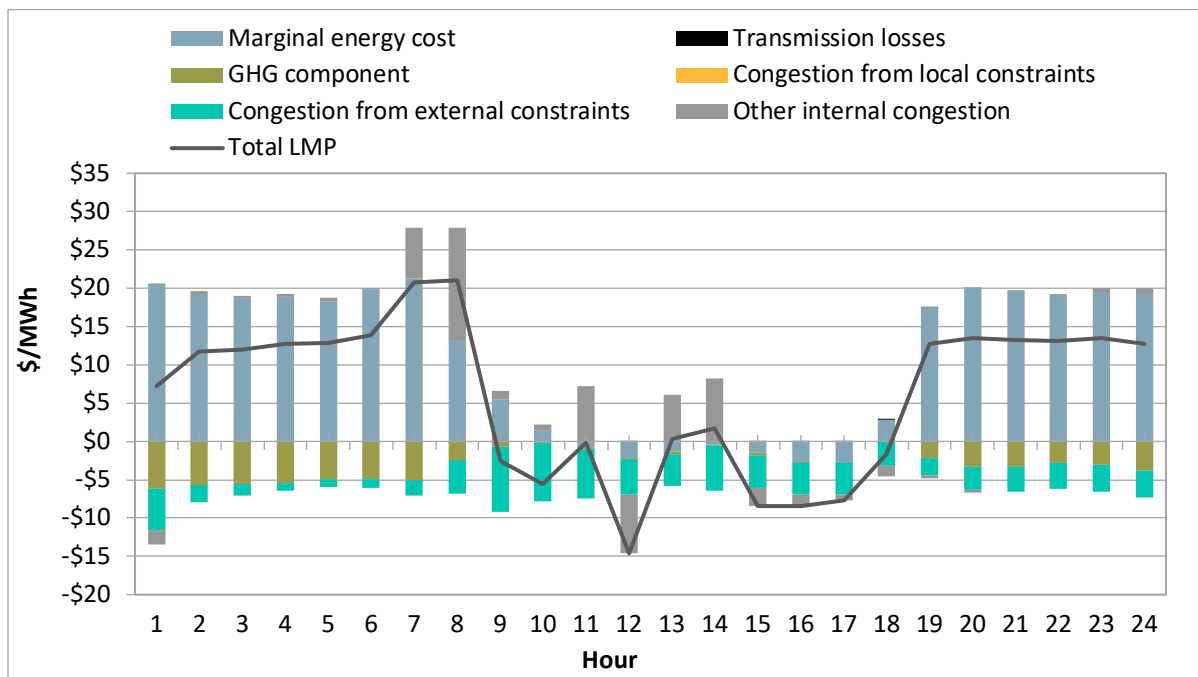
A.7.3 San Diego Gas & Electric

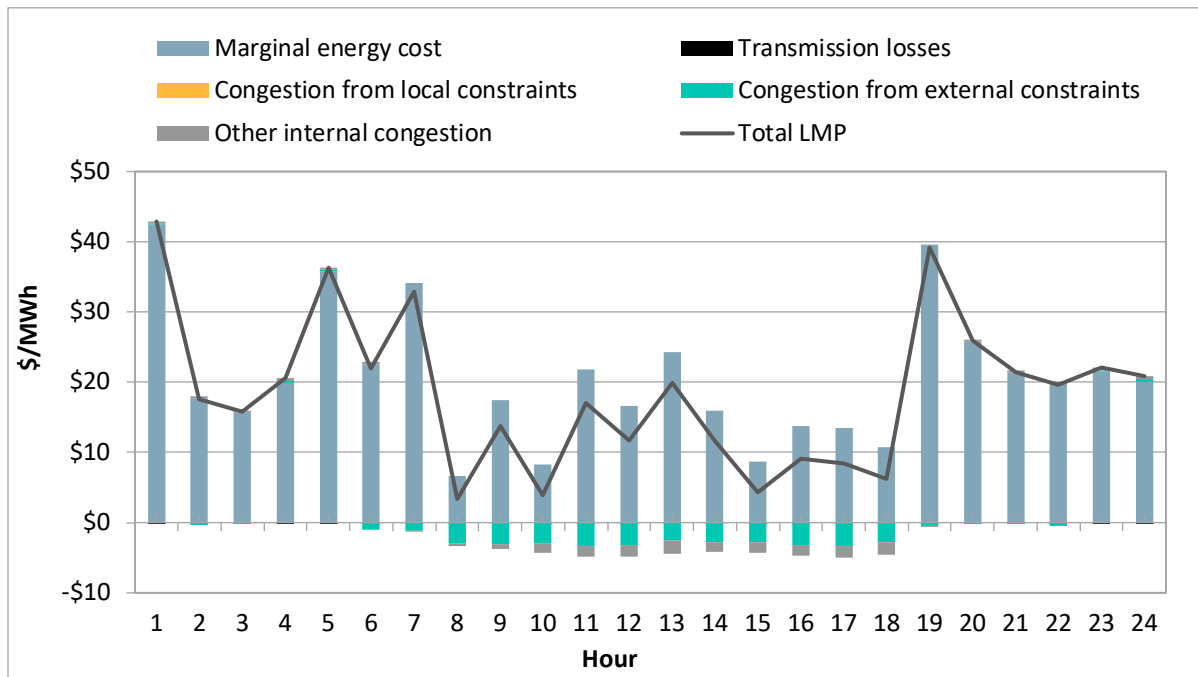
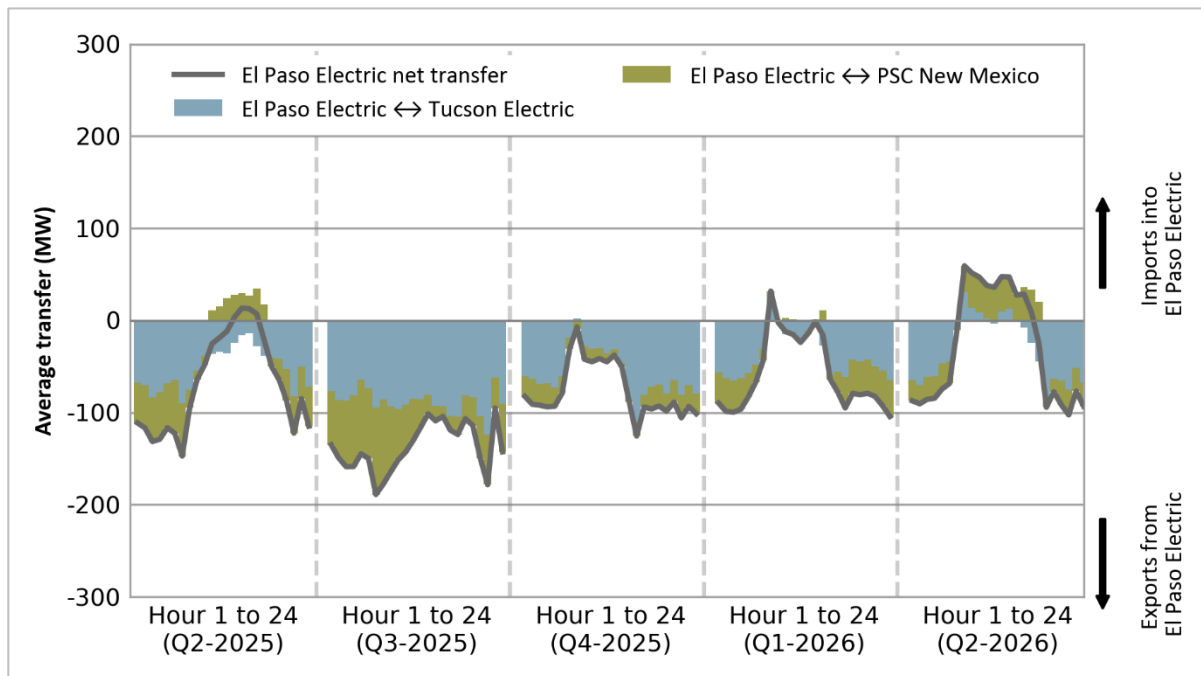
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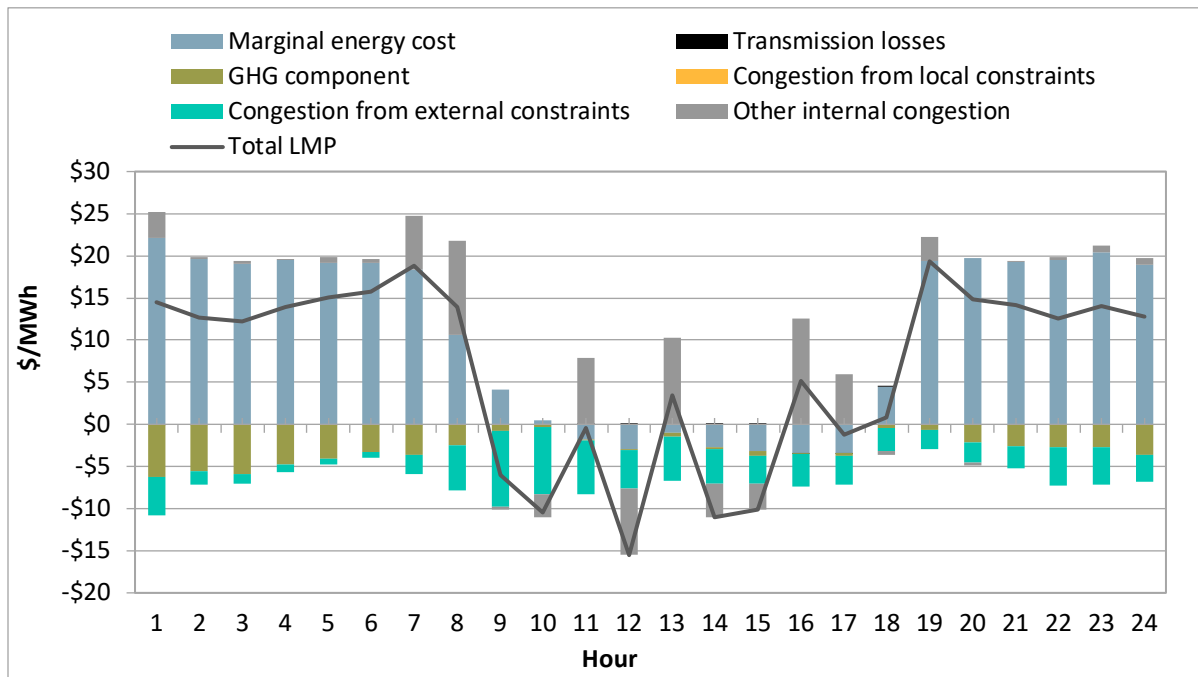
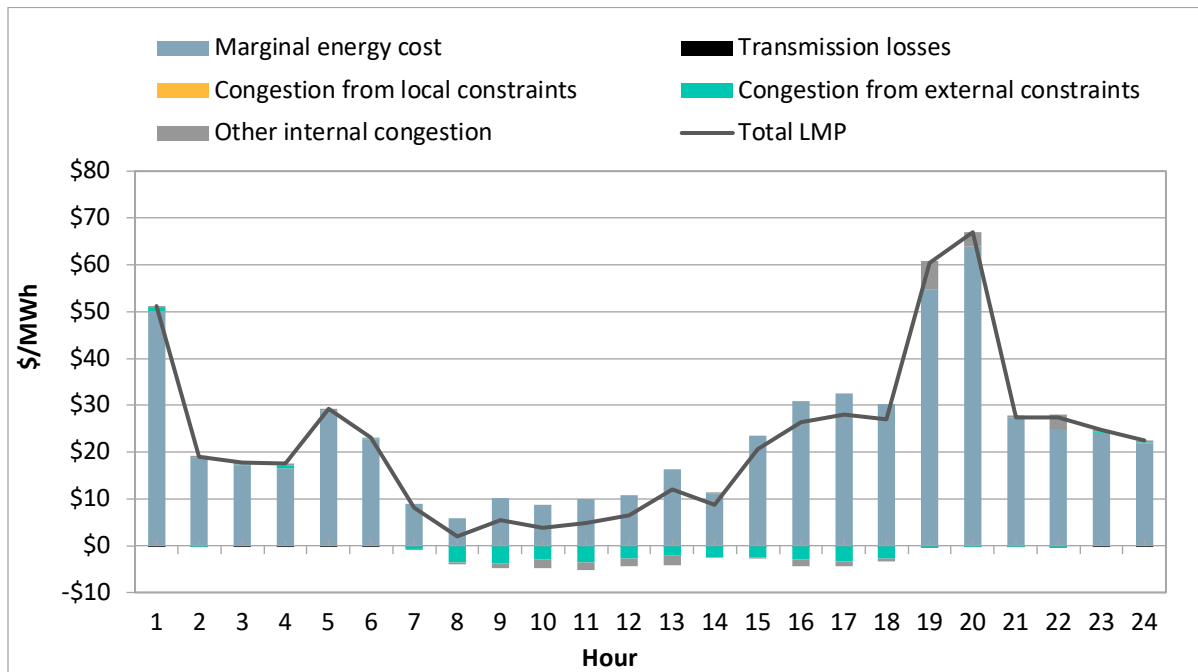
Appendix Figure A.46 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.47 Average hourly 5-minute price by component (April 2026)**

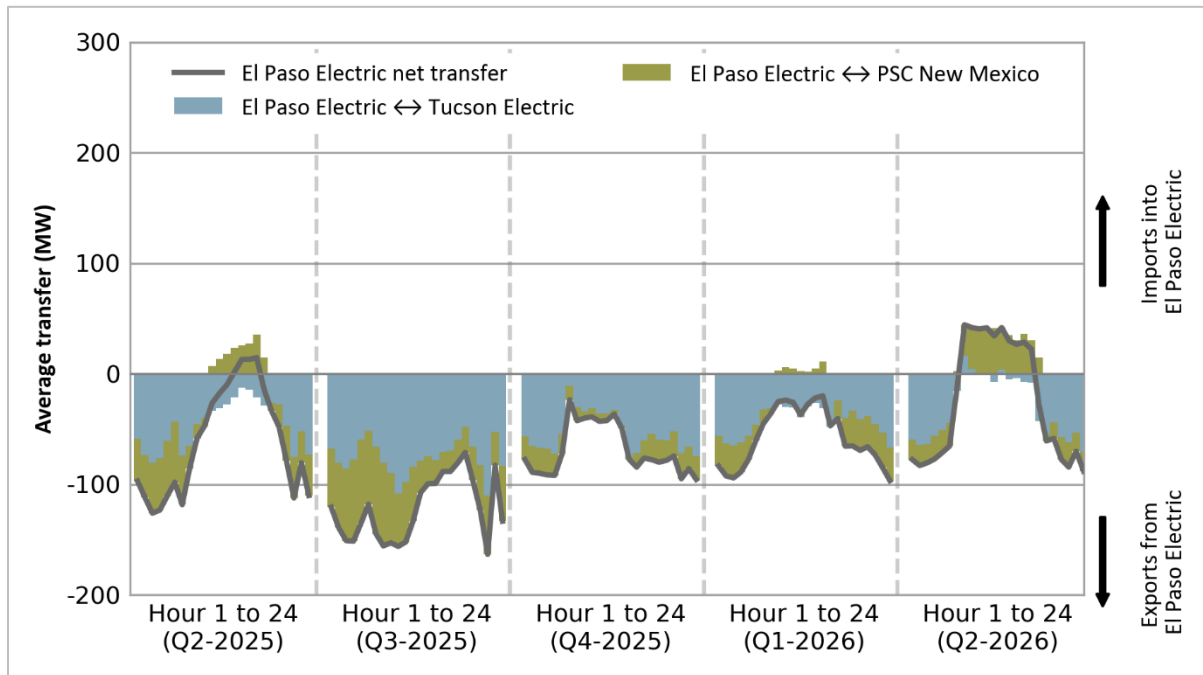
Appendix Figure A.48 Average hourly 5-minute price by component (May–June 2026)

A.8 El Paso Electric

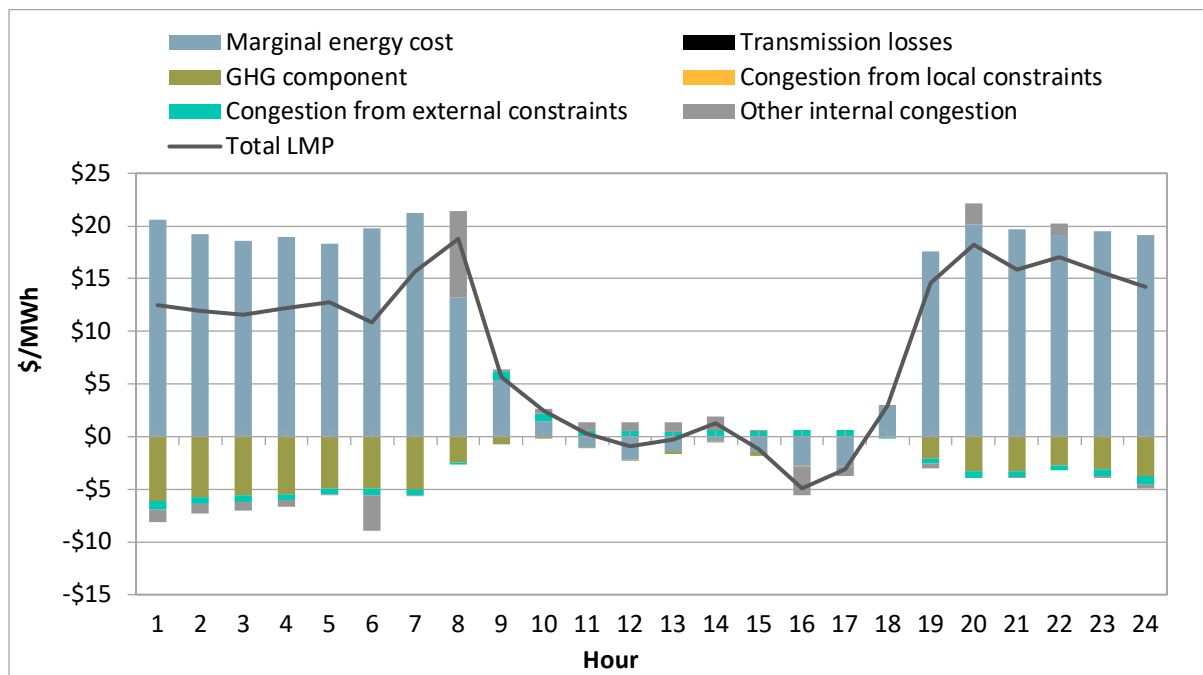
Appendix Figure A.49 Average hourly 15-minute price by component (April 2026)

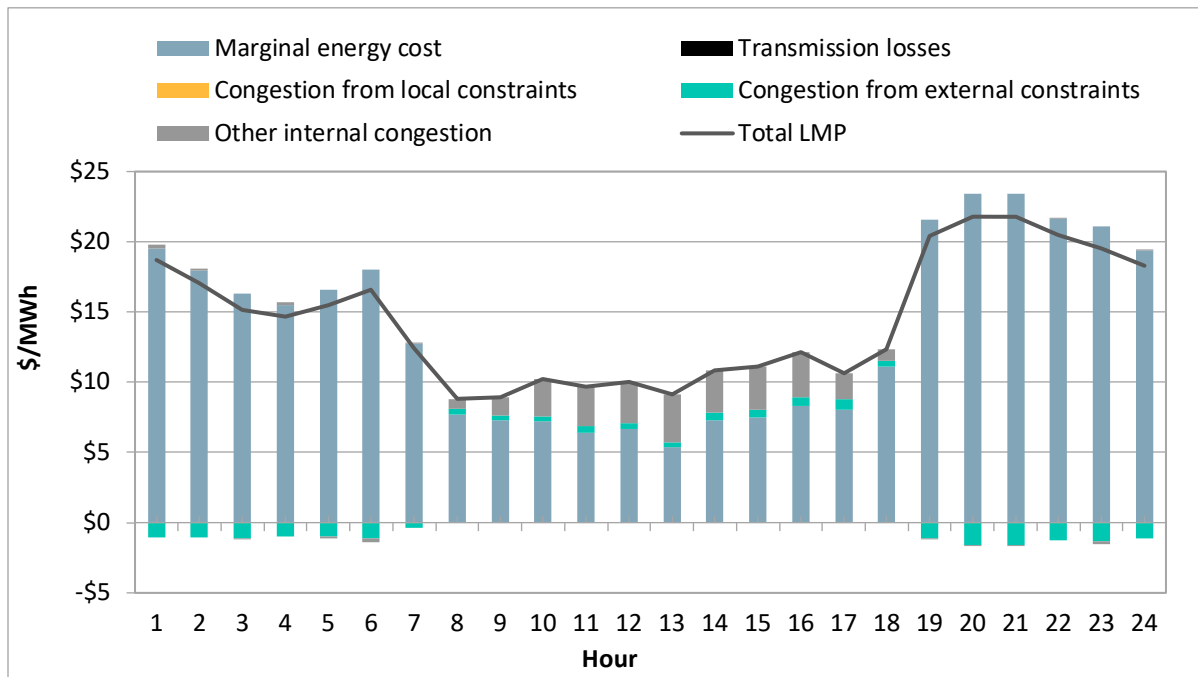
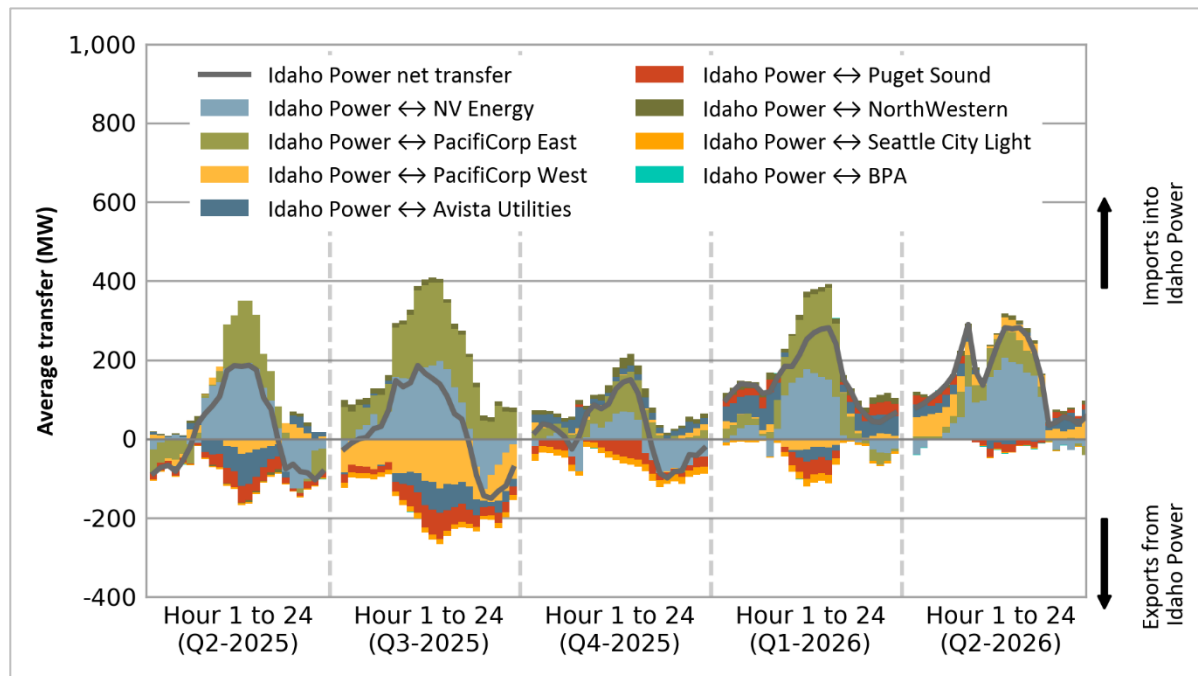
Appendix Figure A.50 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.51 Average hourly 15-minute market transfers**

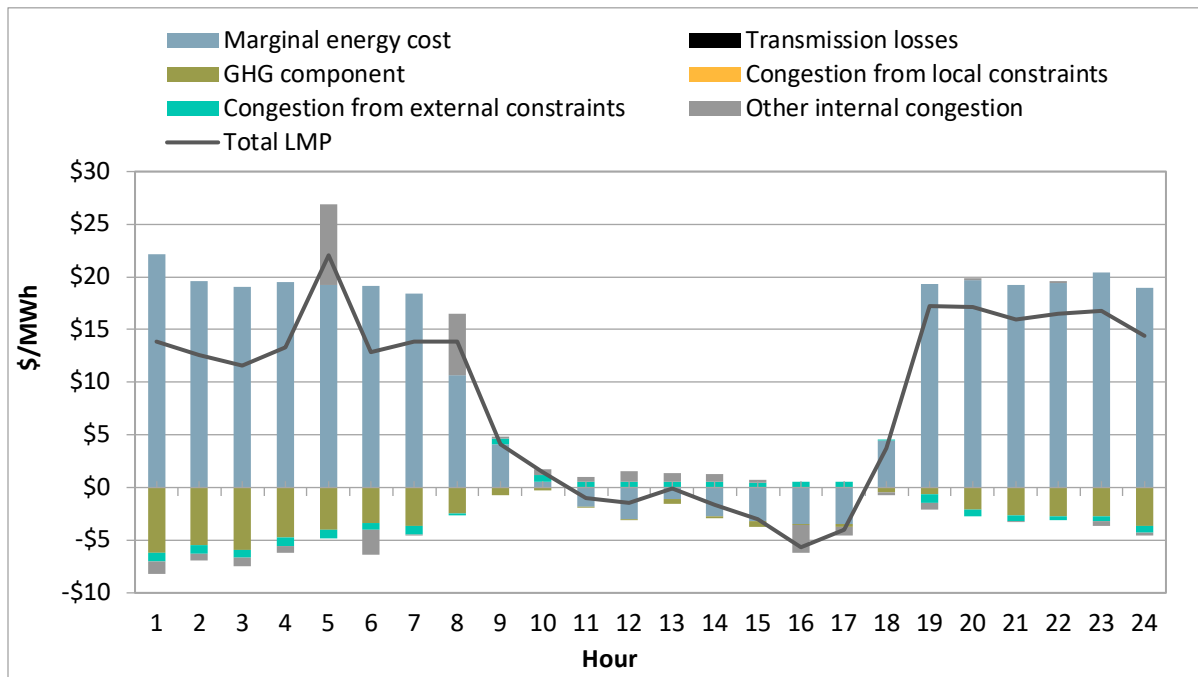
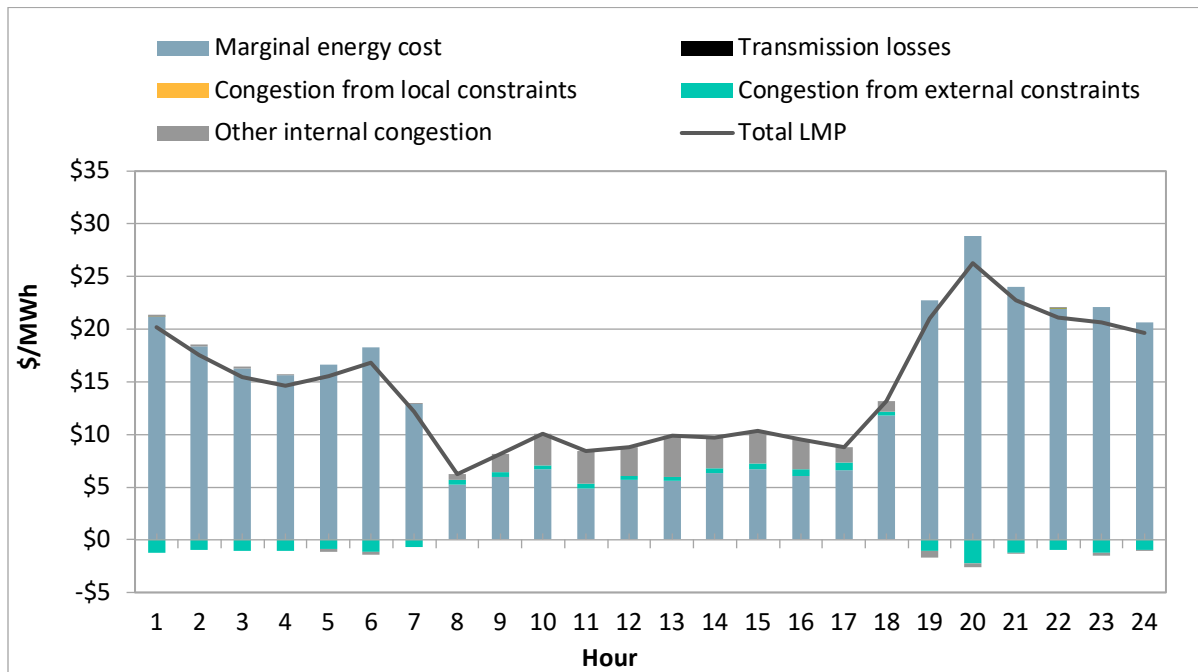
Appendix Figure A.52 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.53 Average hourly 5-minute price by component (May–June 2026)**

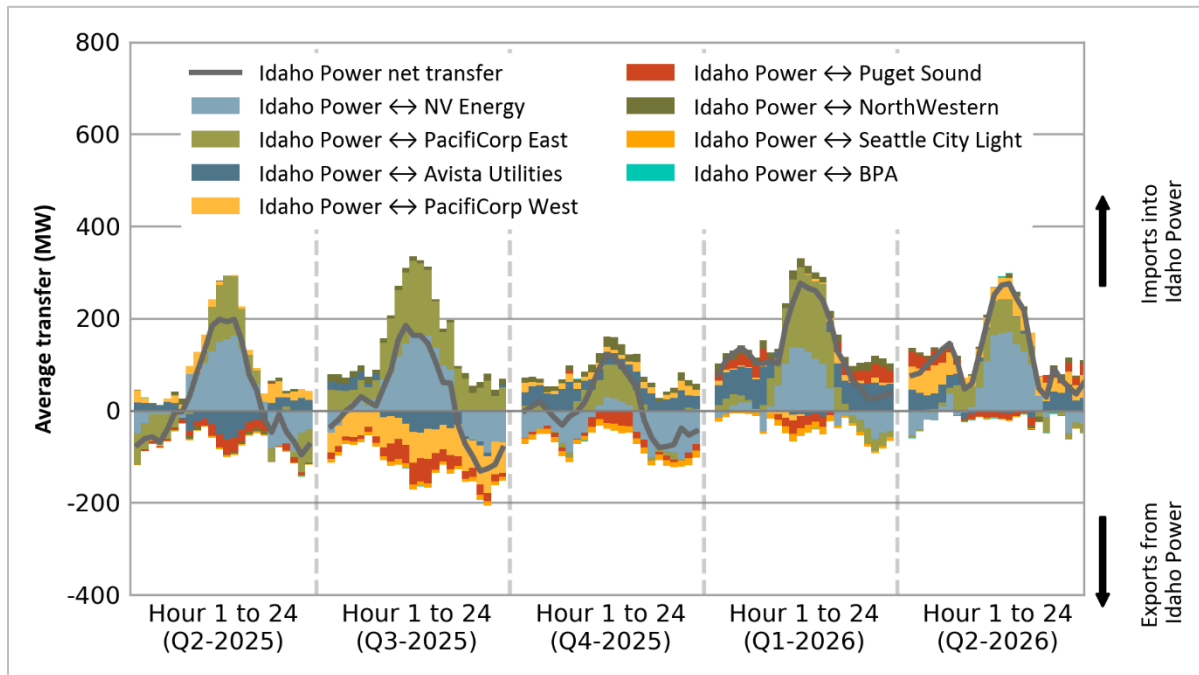
Appendix Figure A.54 Average hourly 5-minute market transfers

A.9 Idaho Power

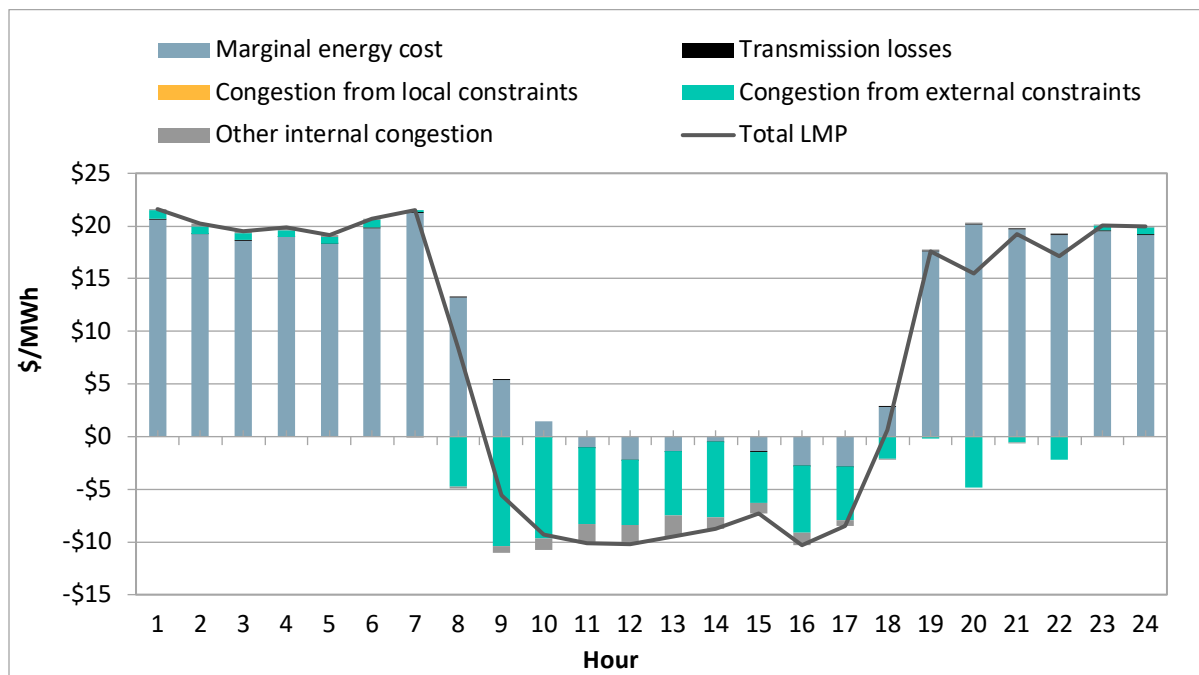
Appendix Figure A.55 Average hourly 15-minute price by component (April 2026)

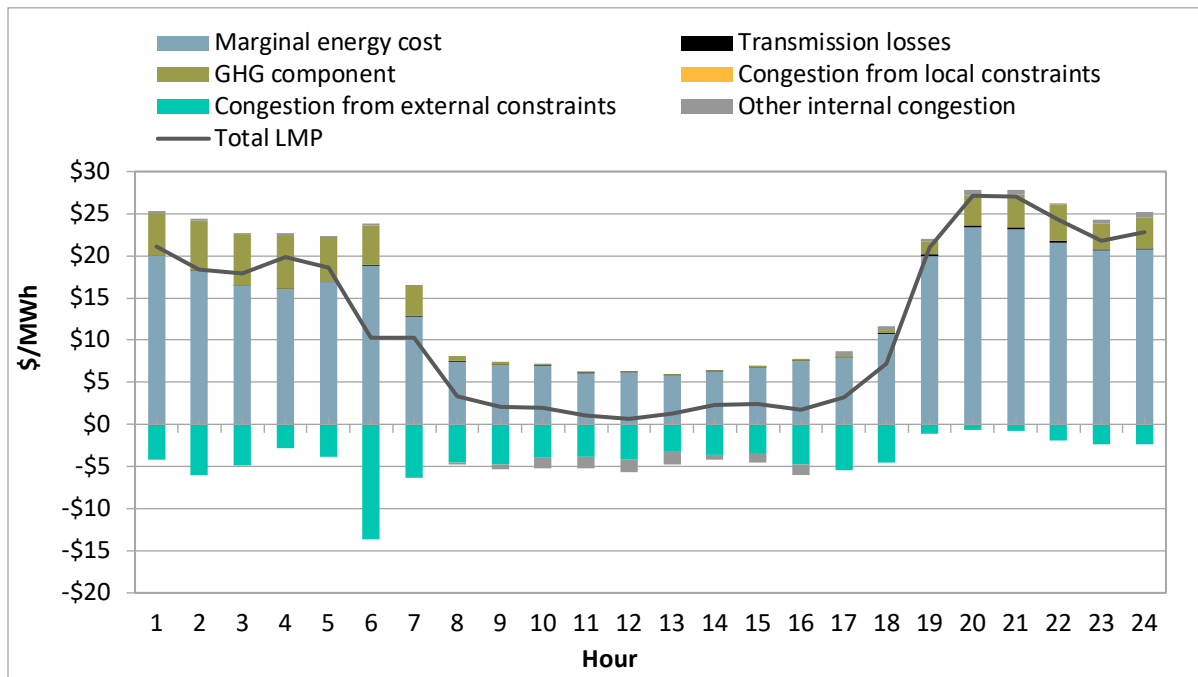
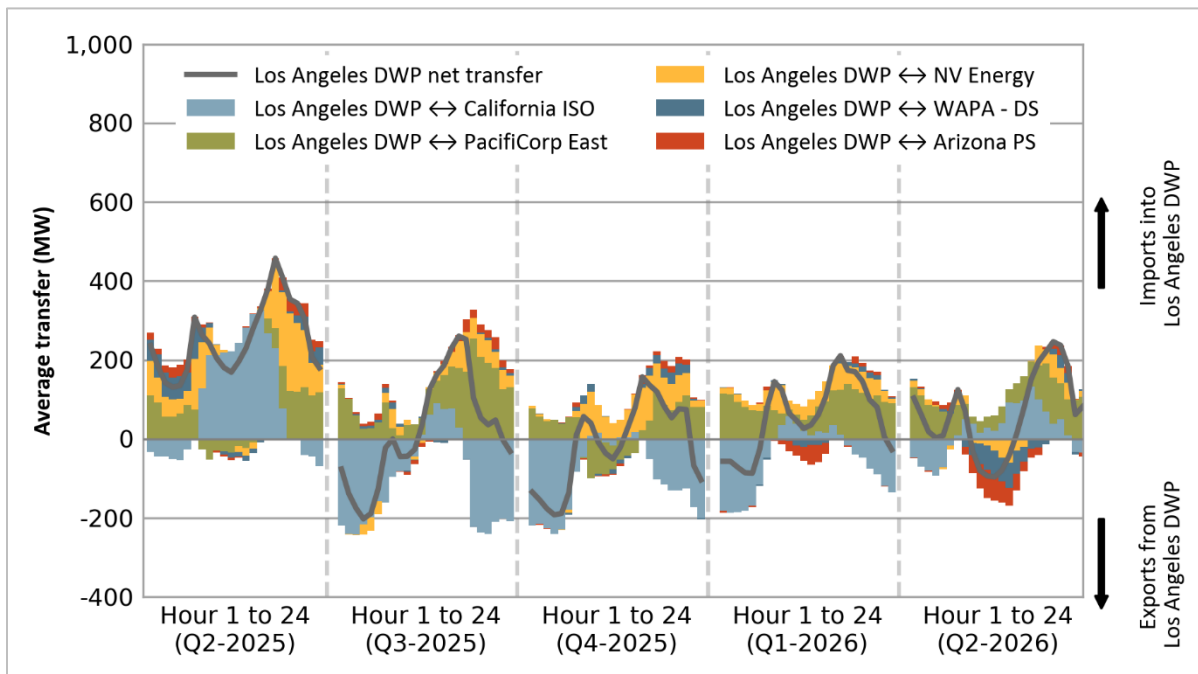
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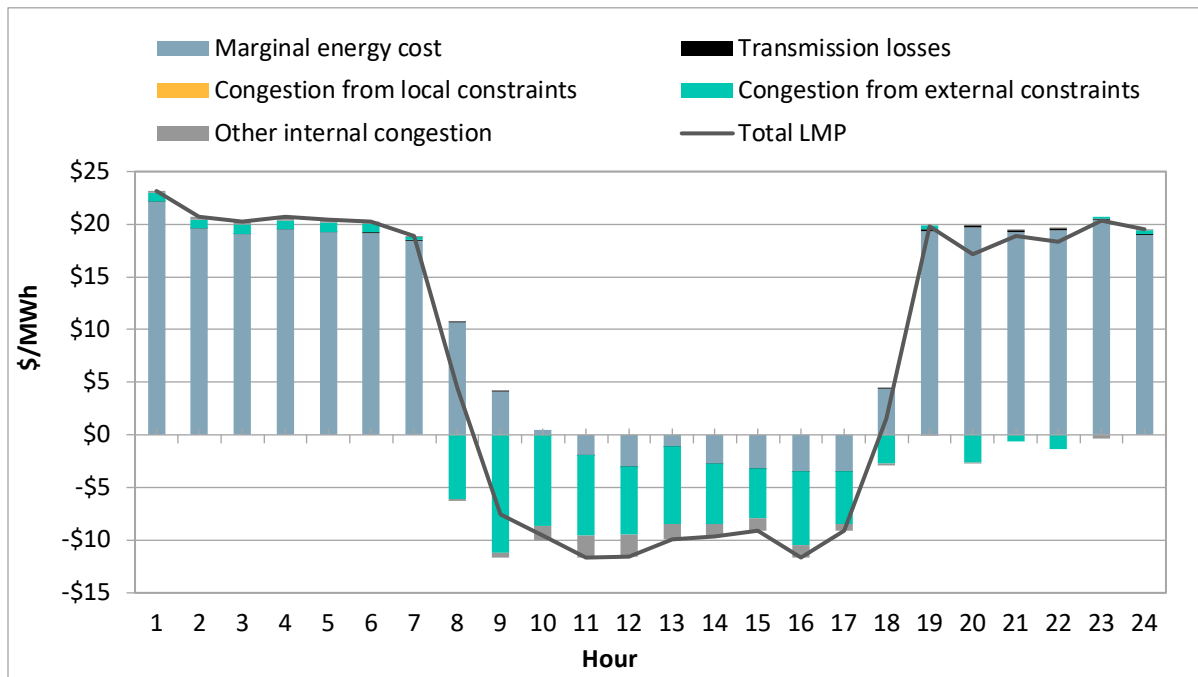
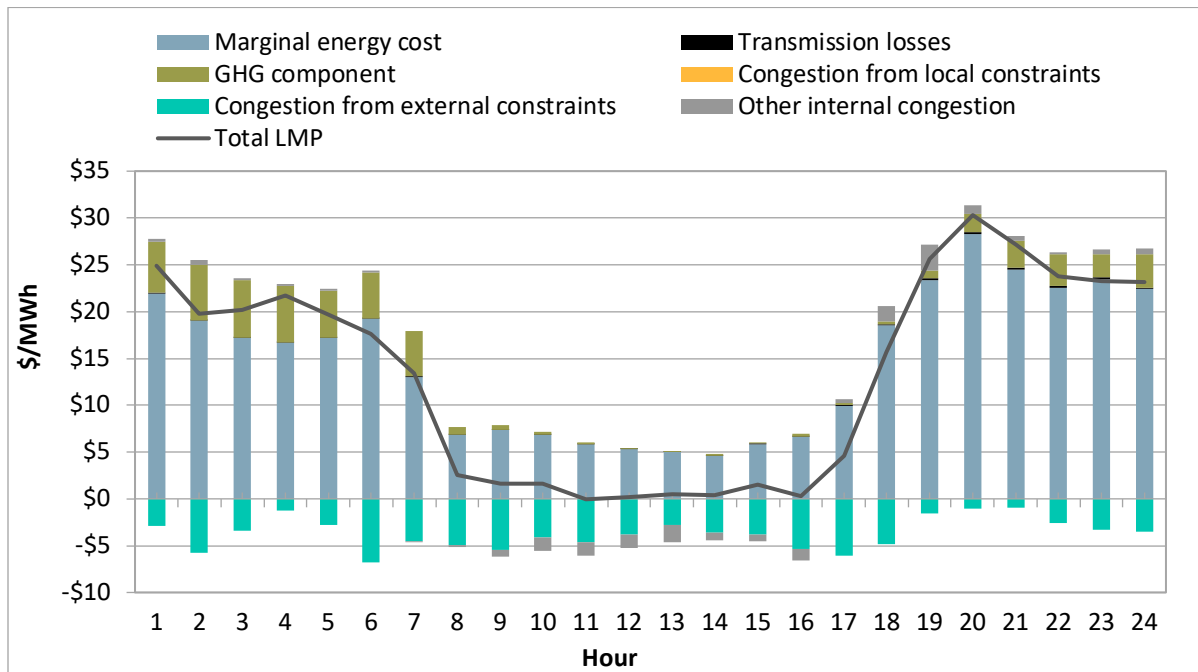
Appendix Figure A.58 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.59 Average hourly 5-minute price by component (May–June 2026)**

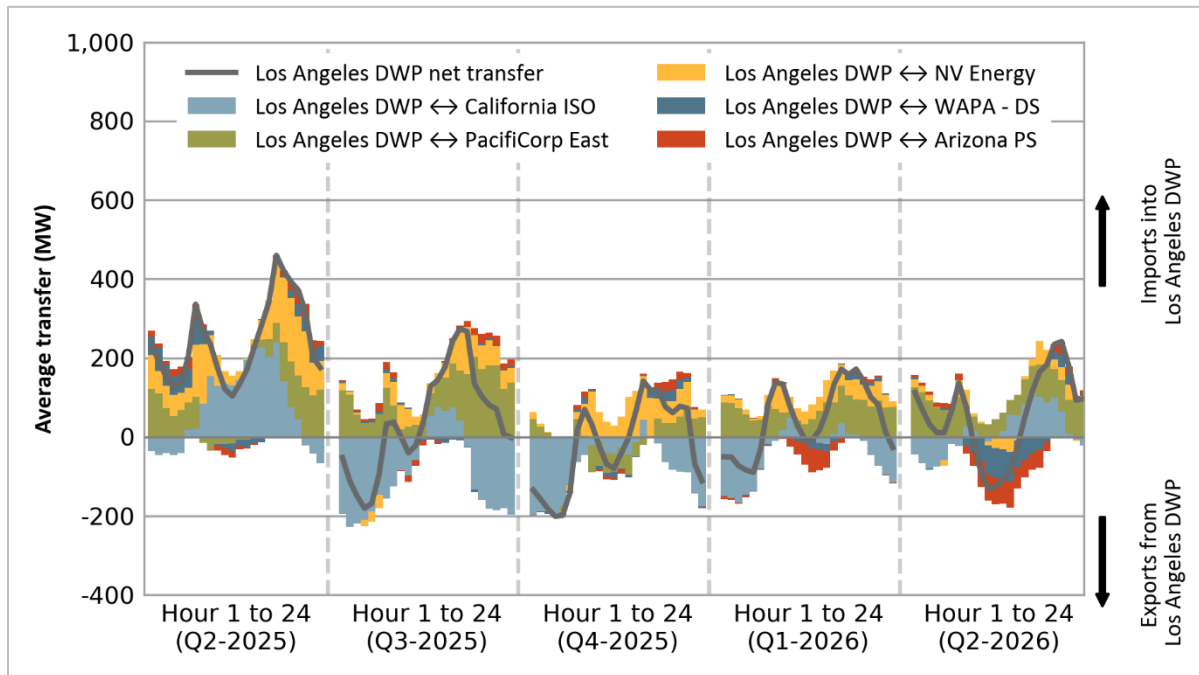
Appendix Figure A.60 Average hourly 5-minute market transfers

A.10 Los Angeles Department of Water and Power

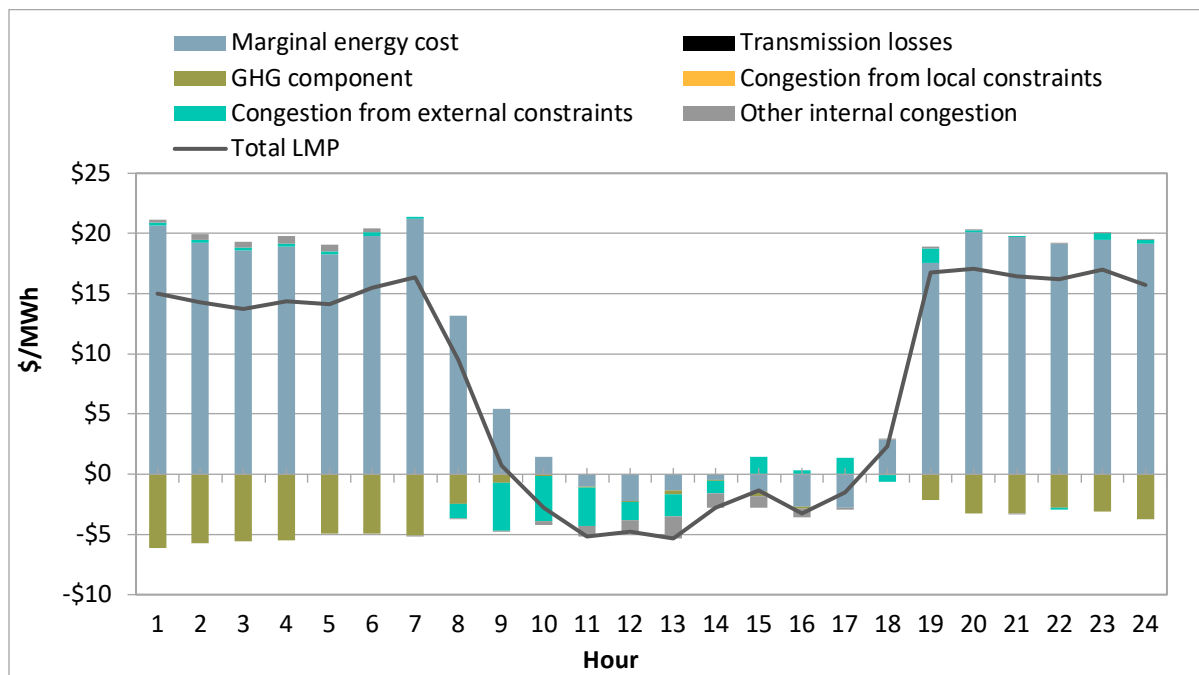
Appendix Figure A.61 Average hourly 15-minute price by component (April 2026)

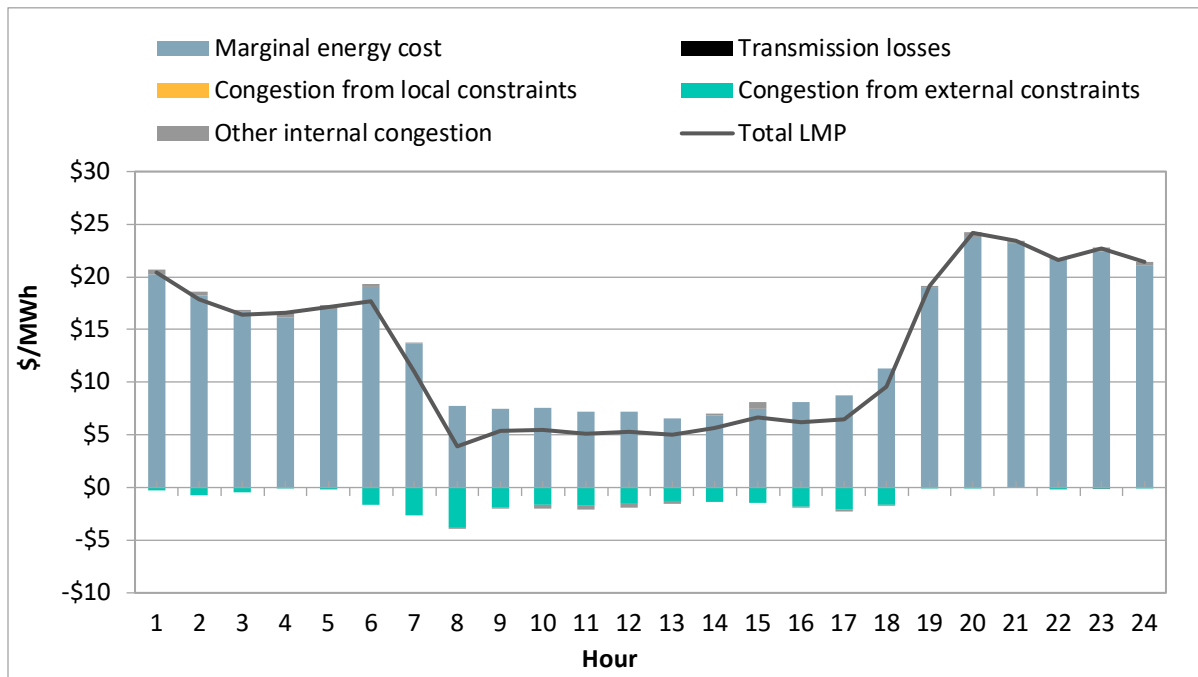
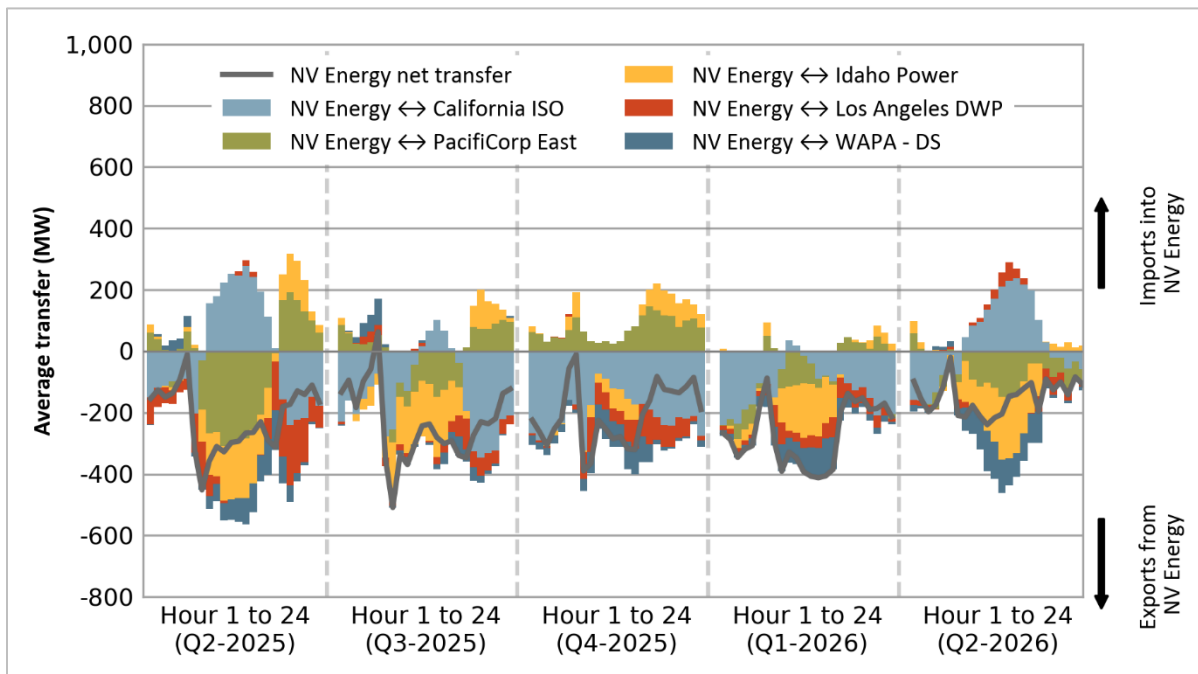
Appendix Figure A.62 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.63 Average hourly 15-minute market transfers**

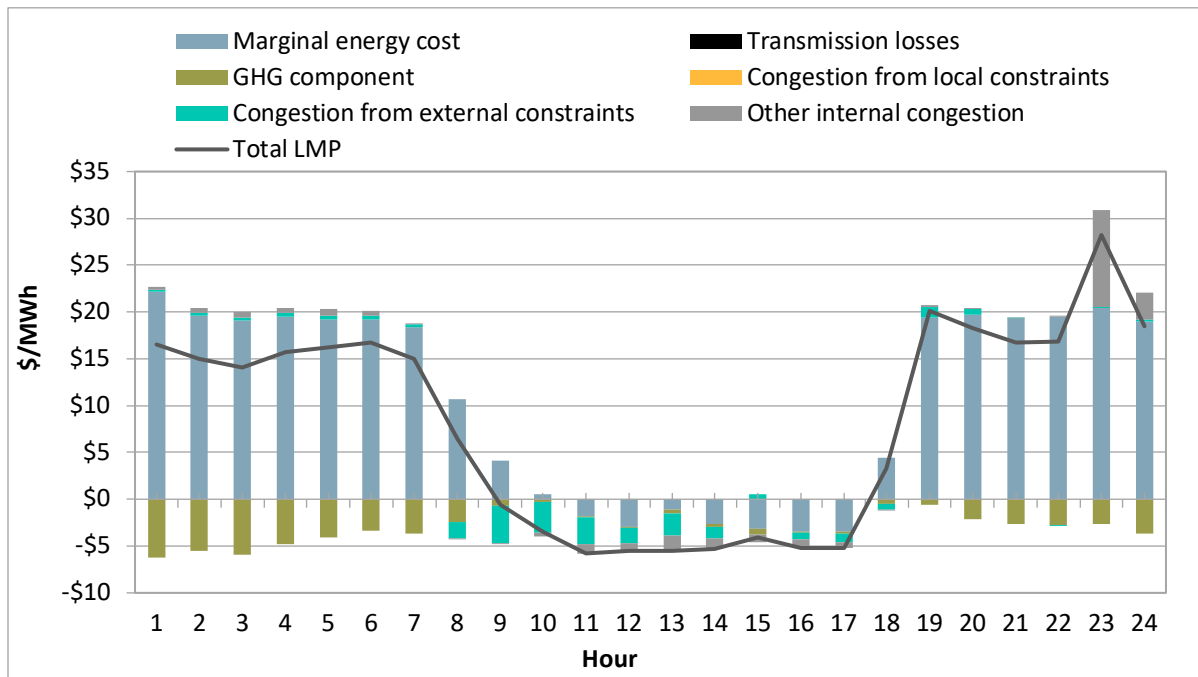
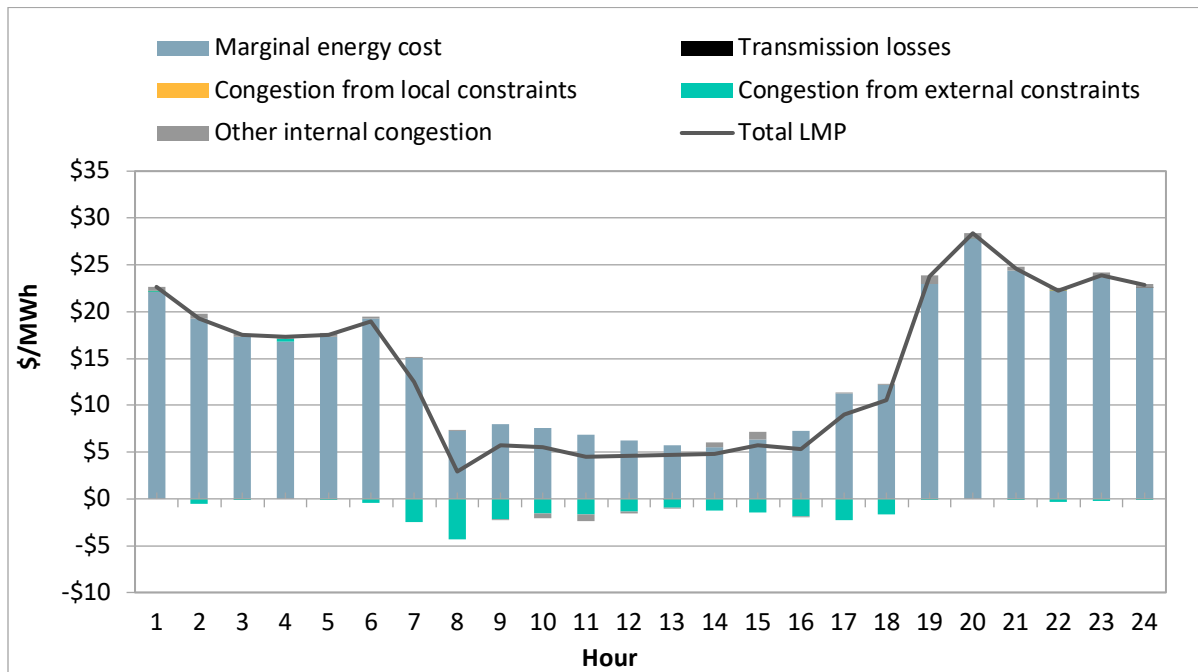
Appendix Figure A.64 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.65 Average hourly 5-minute price by component (May–June 2026)**

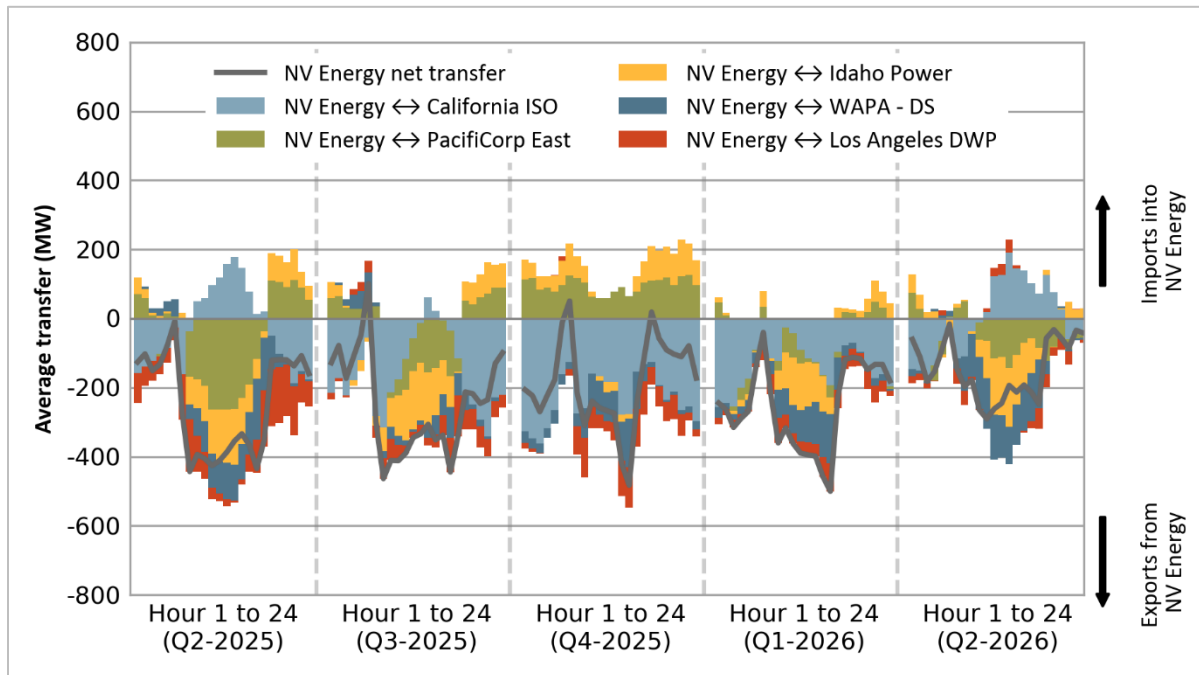
Appendix Figure A.66 Average hourly 5-minute market transfers

A.11 NV Energy

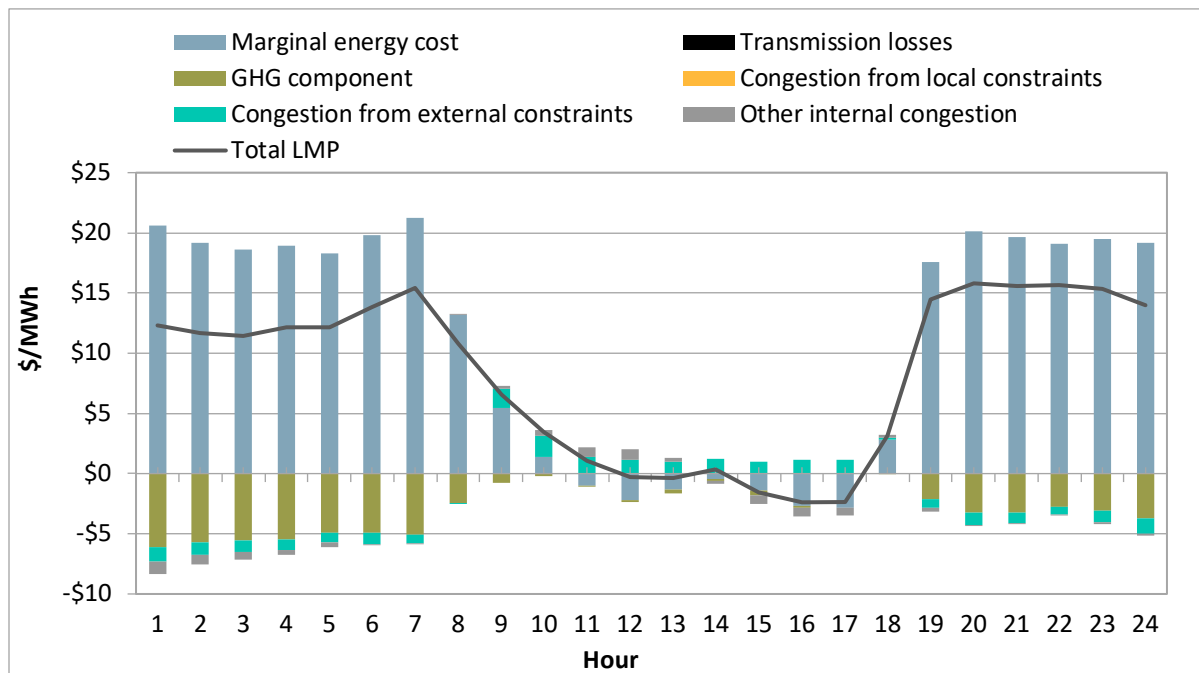
Appendix Figure A.67 Average hourly 15-minute price by component (April 2026)

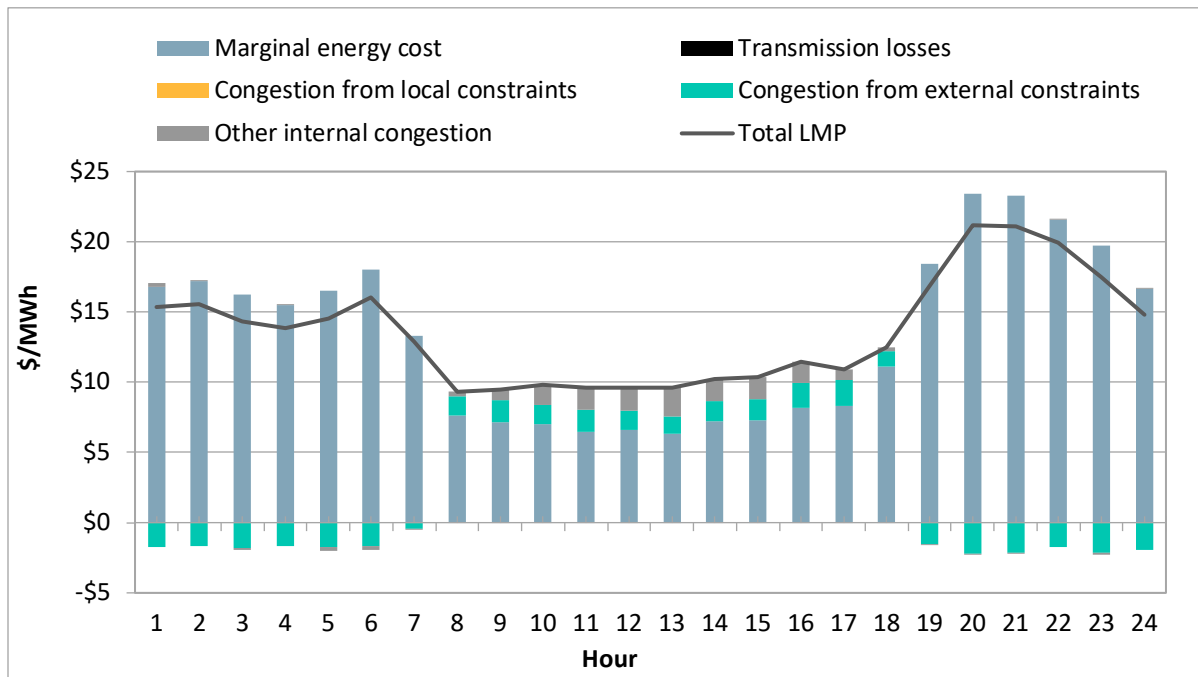
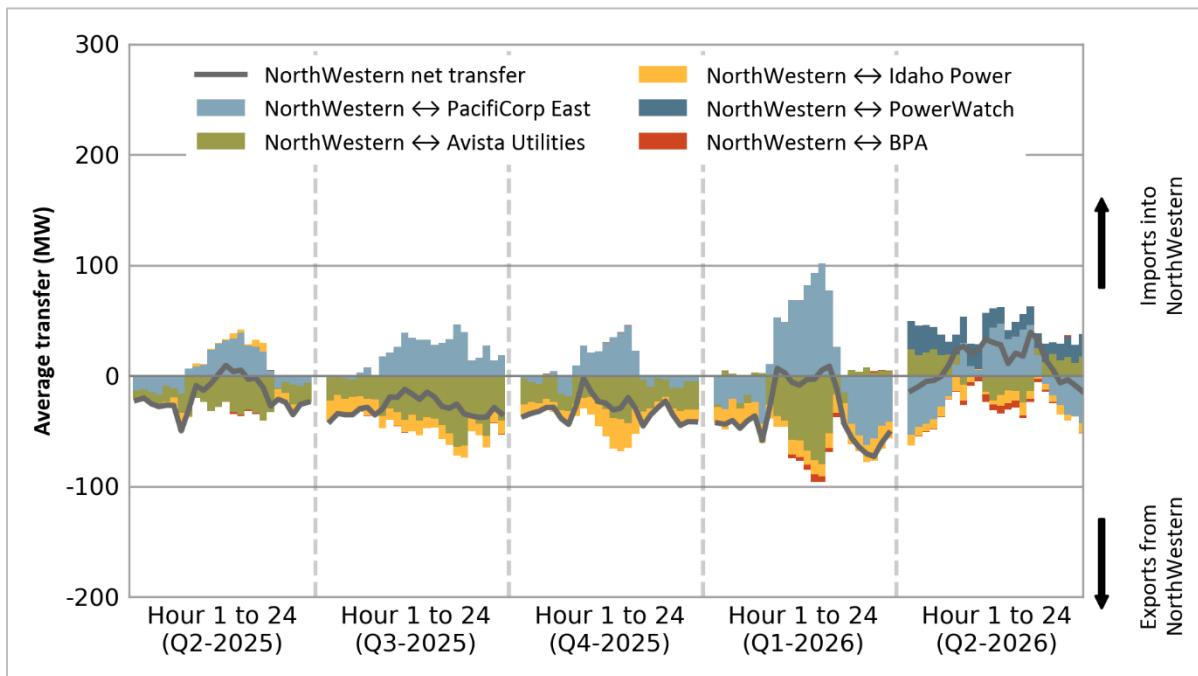
Appendix Figure A.68 Average hourly 15-minute price by component (May - June 2026)**Appendix Figure A.69 Average hourly 15-minute market transfers**

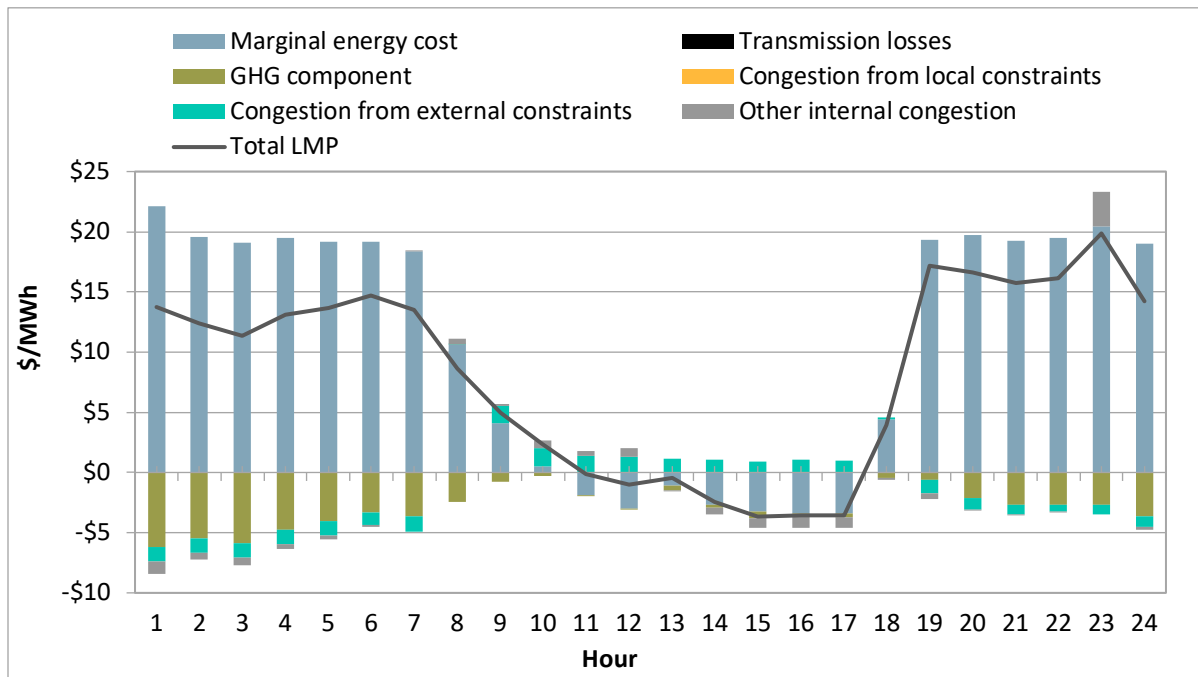
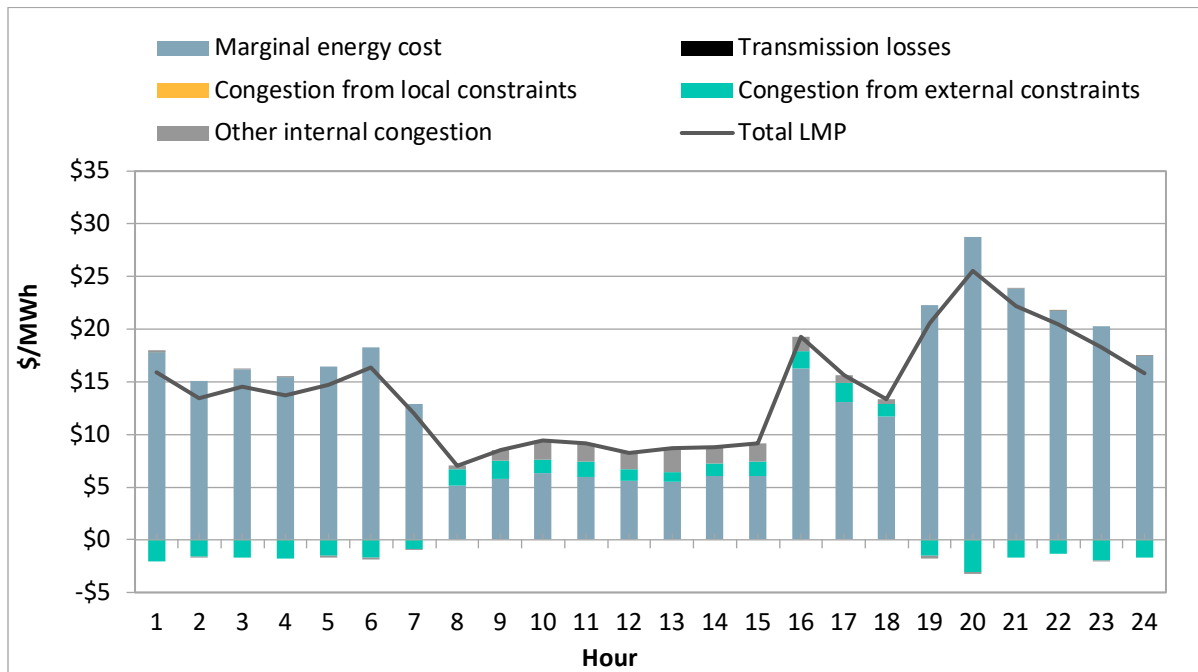
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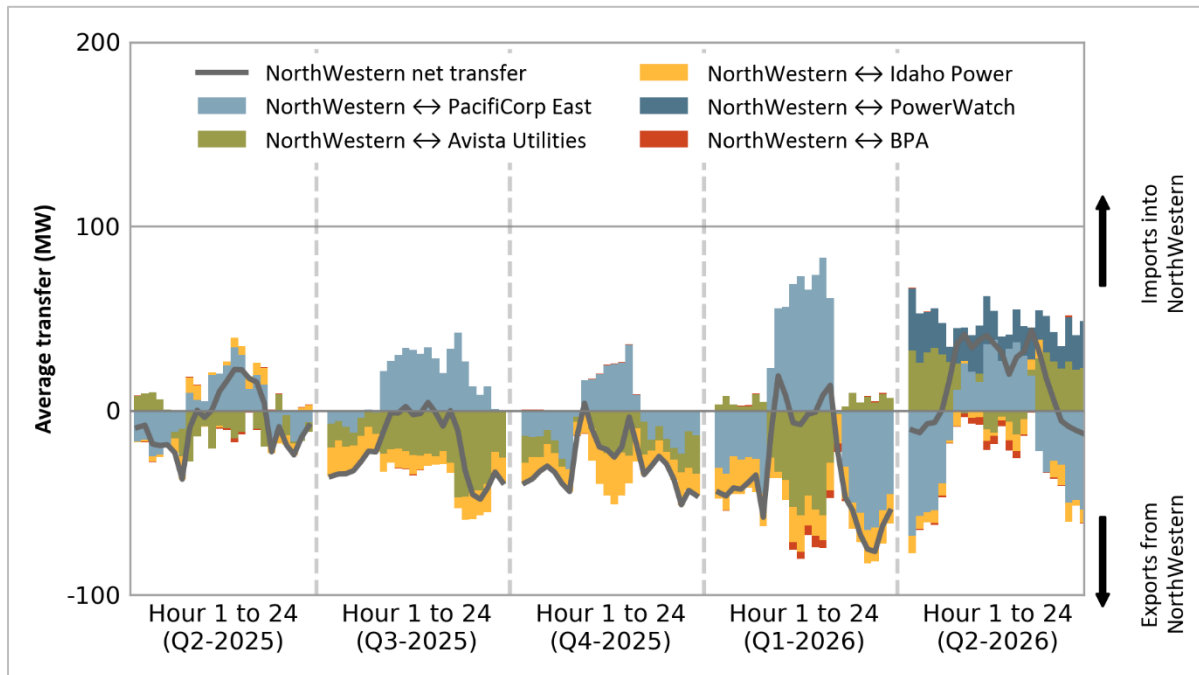
Appendix Figure A.72 Average hourly 5-minute market transfers

A.12 NorthWestern Energy

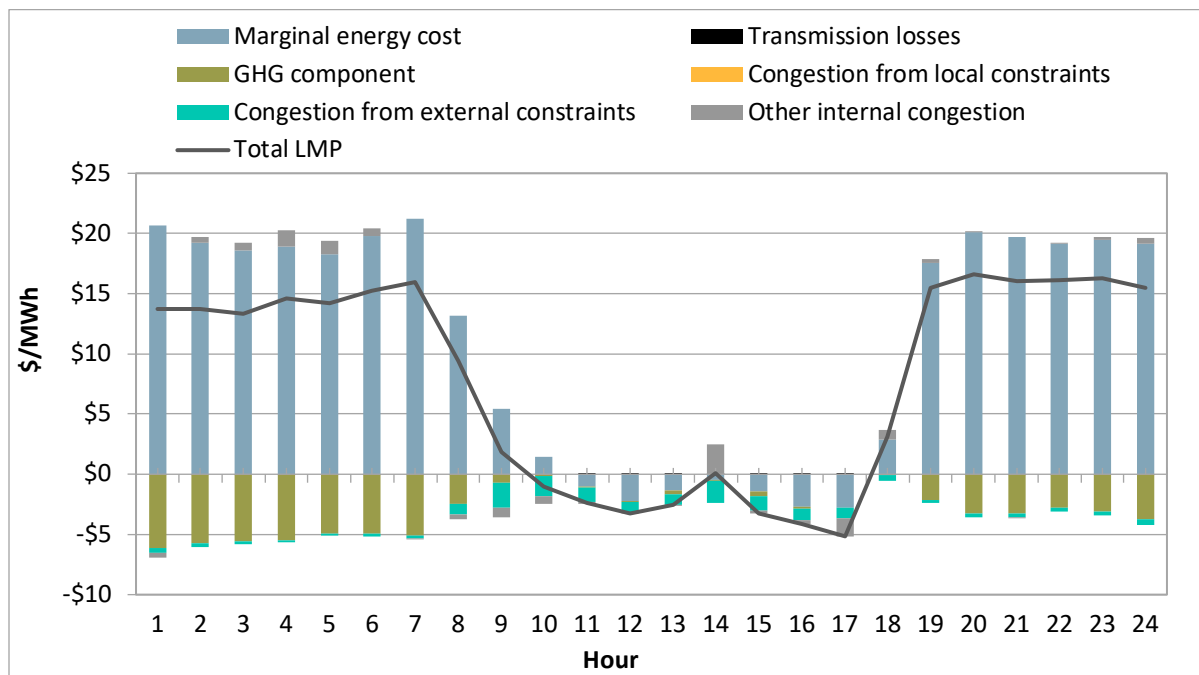
Appendix Figure A.73 Average hourly 15-minute price by component (April 2026)

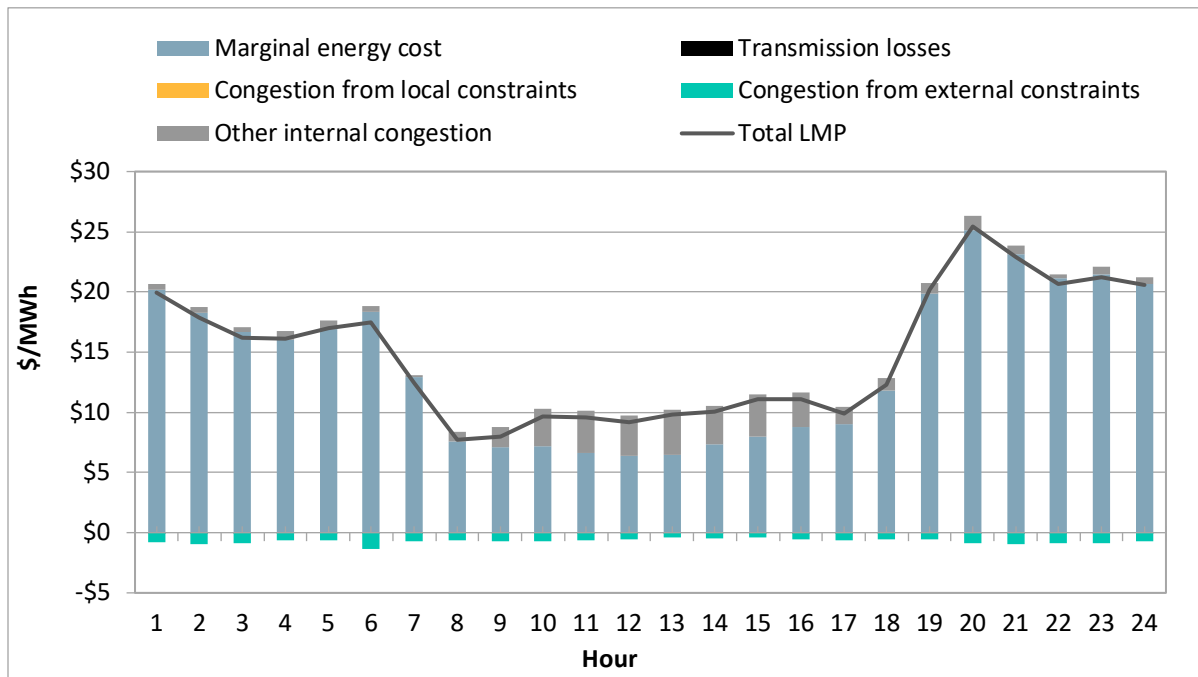
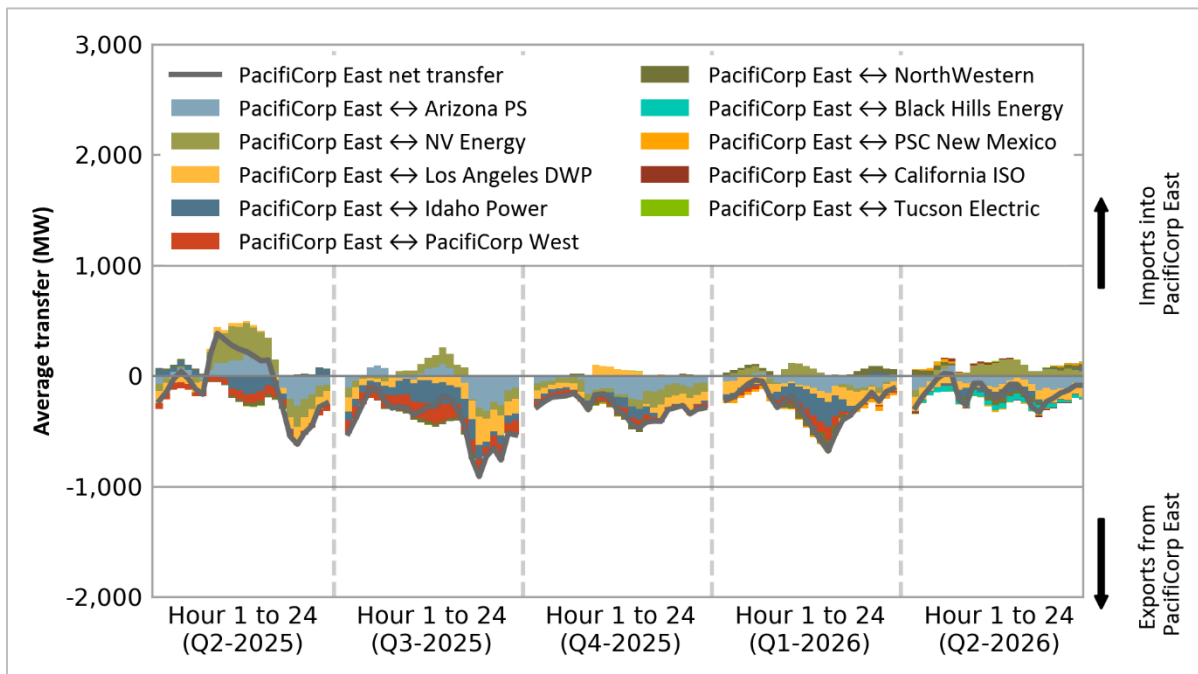
Appendix Figure A.74 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.75 Average hourly 15-minute market transfers**

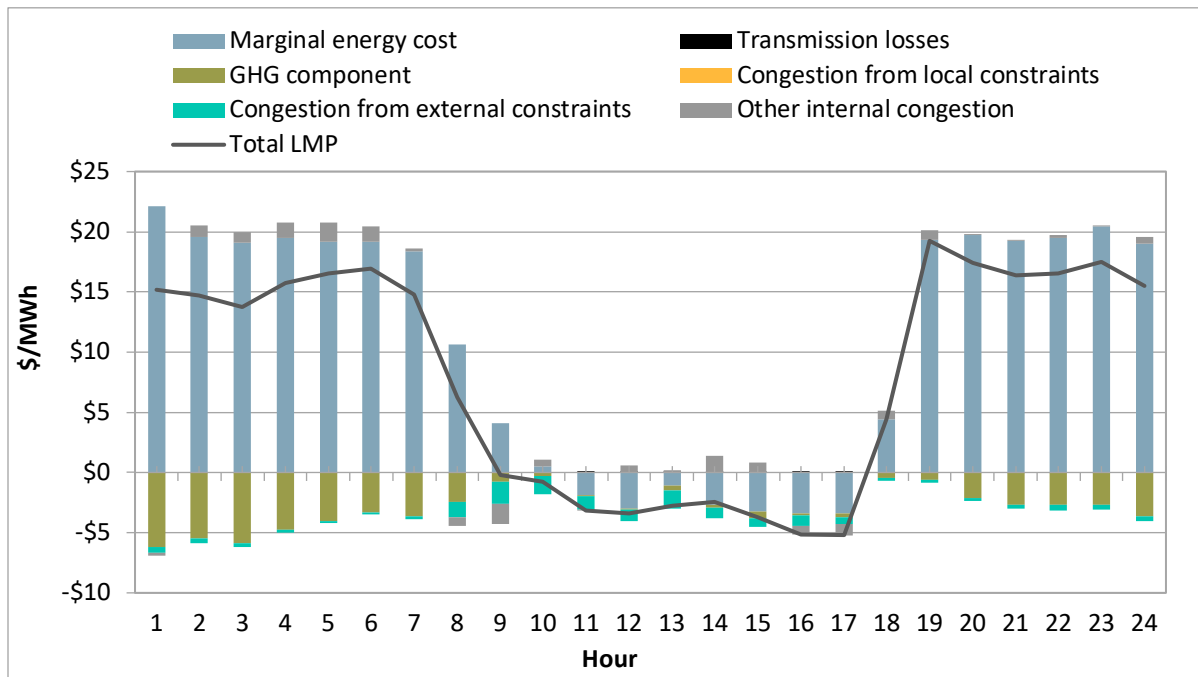
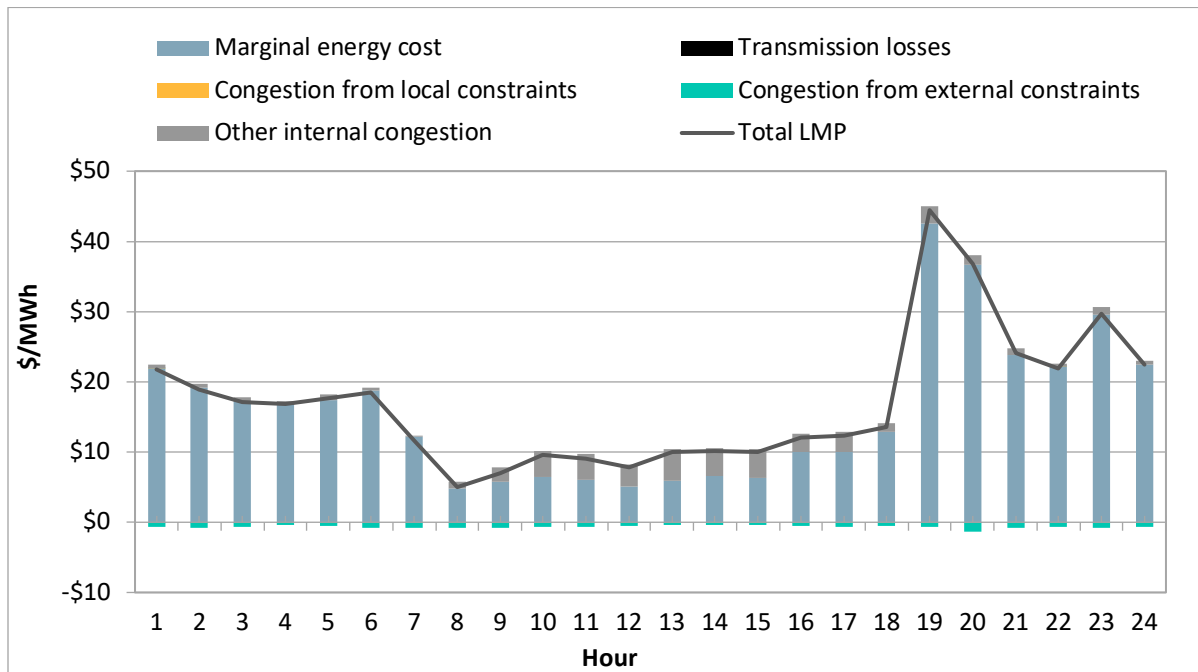
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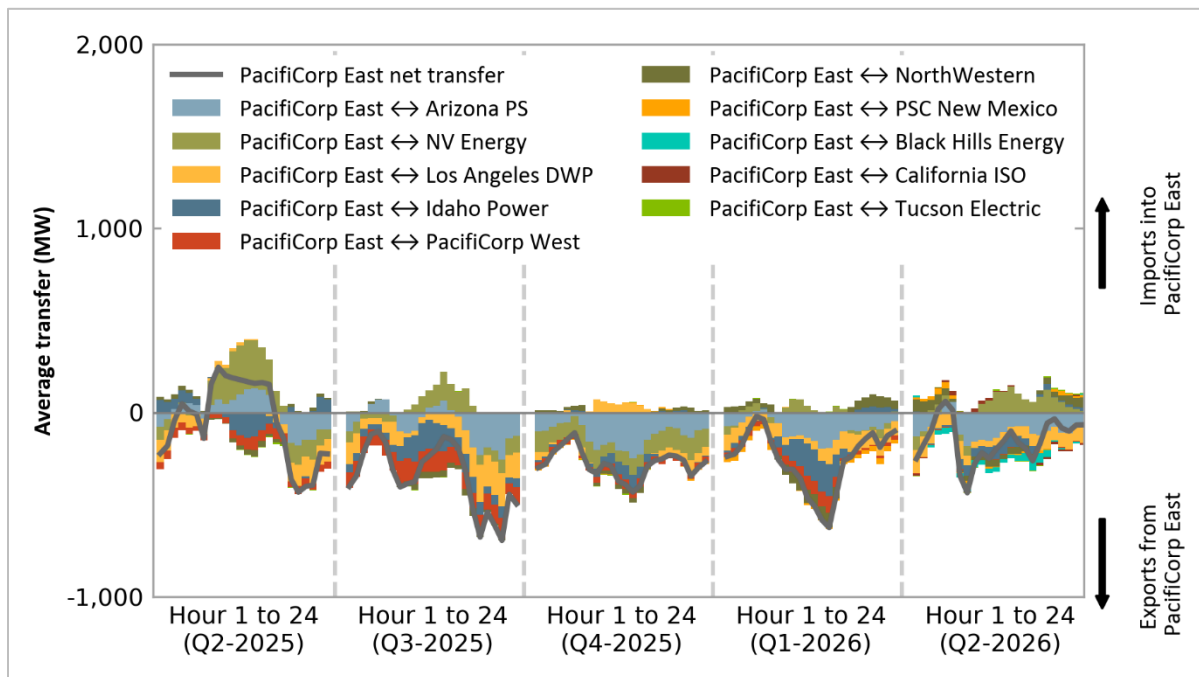
Appendix Figure A.78 Average hourly 5-minute market transfers

A.13 PacifiCorp East

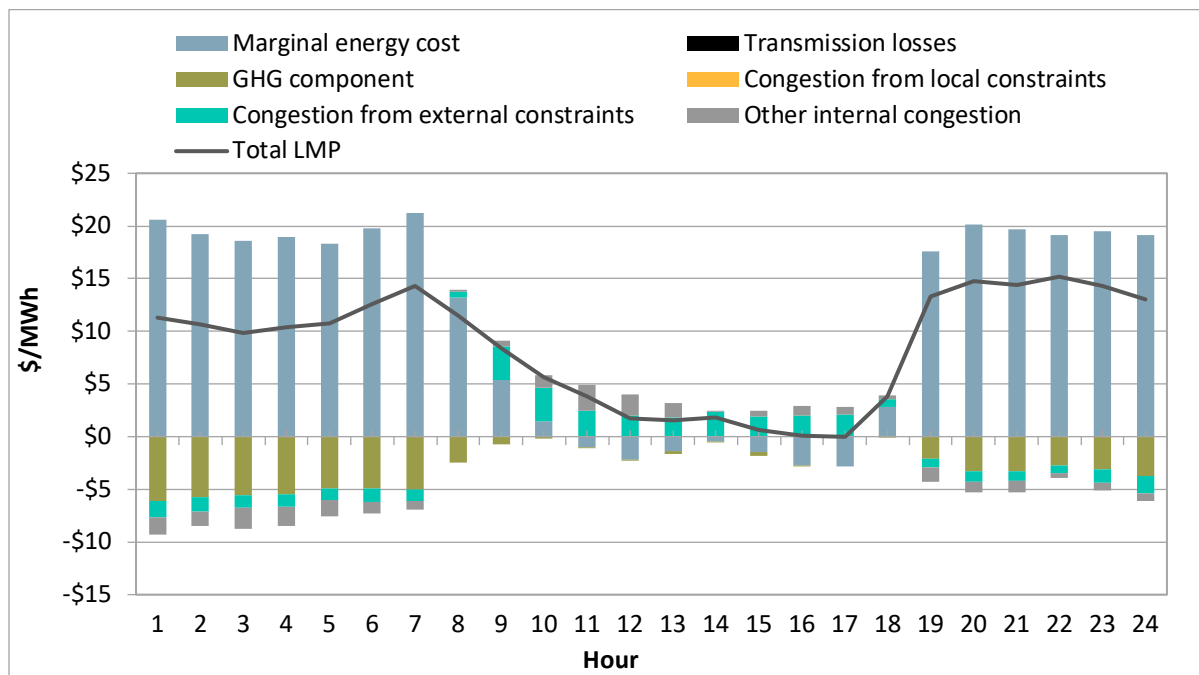
Appendix Figure A.79 Average hourly 15-minute price by component (April 2026)

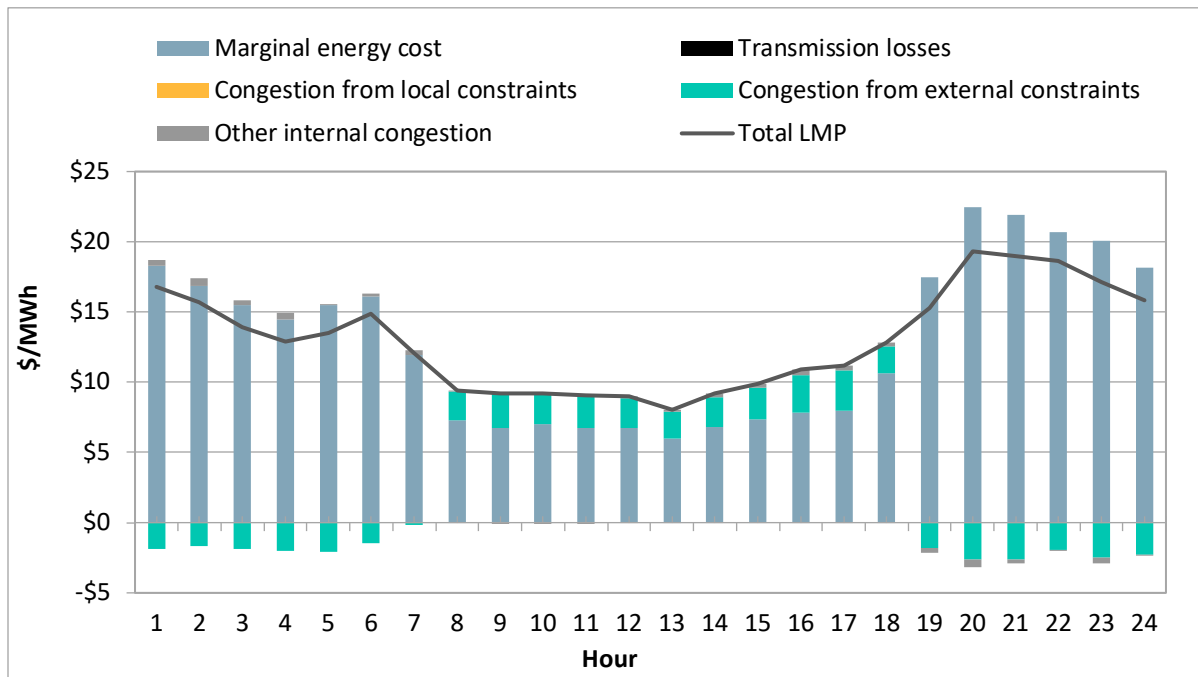
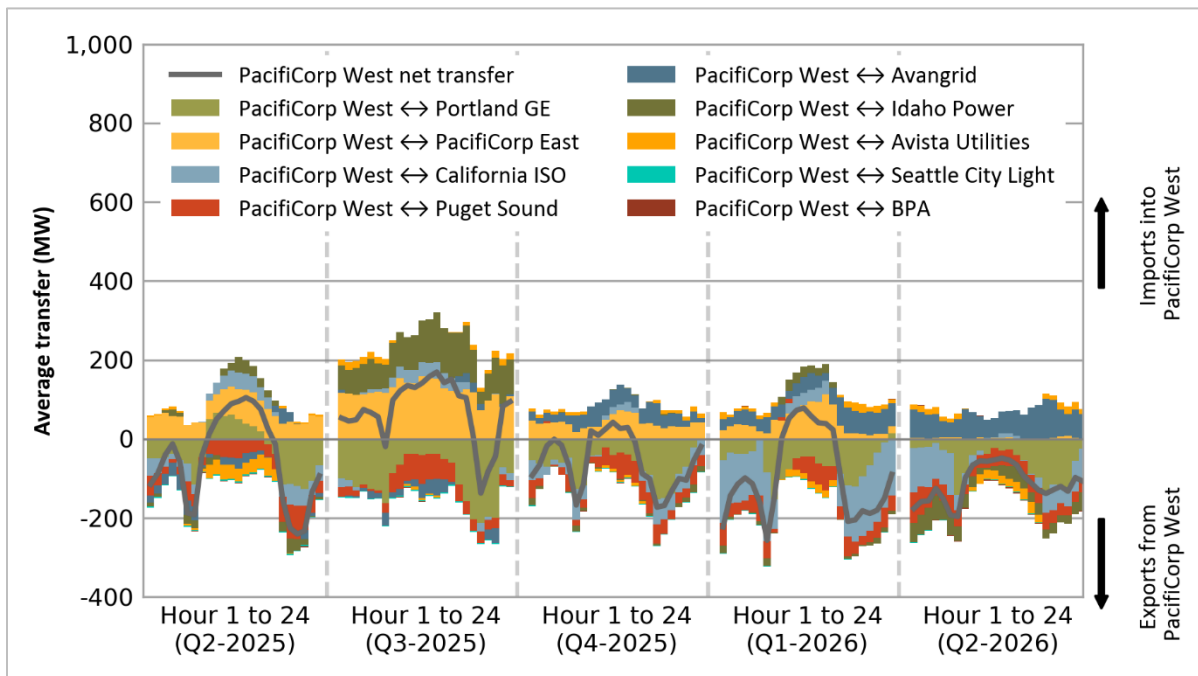
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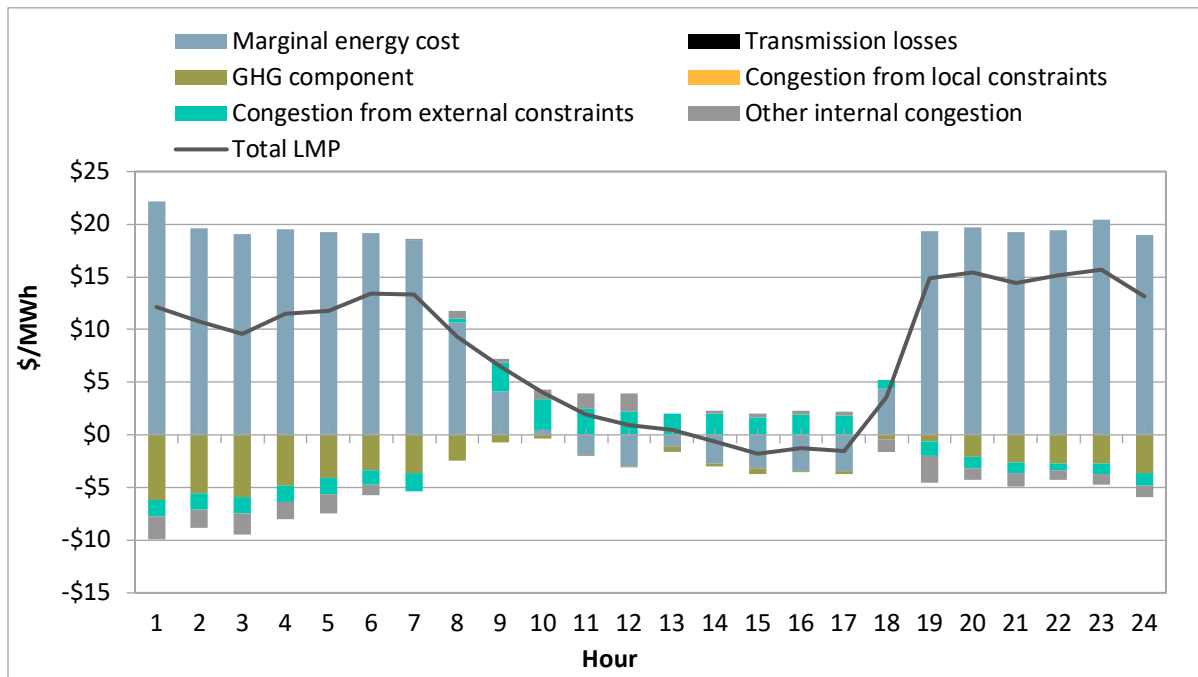
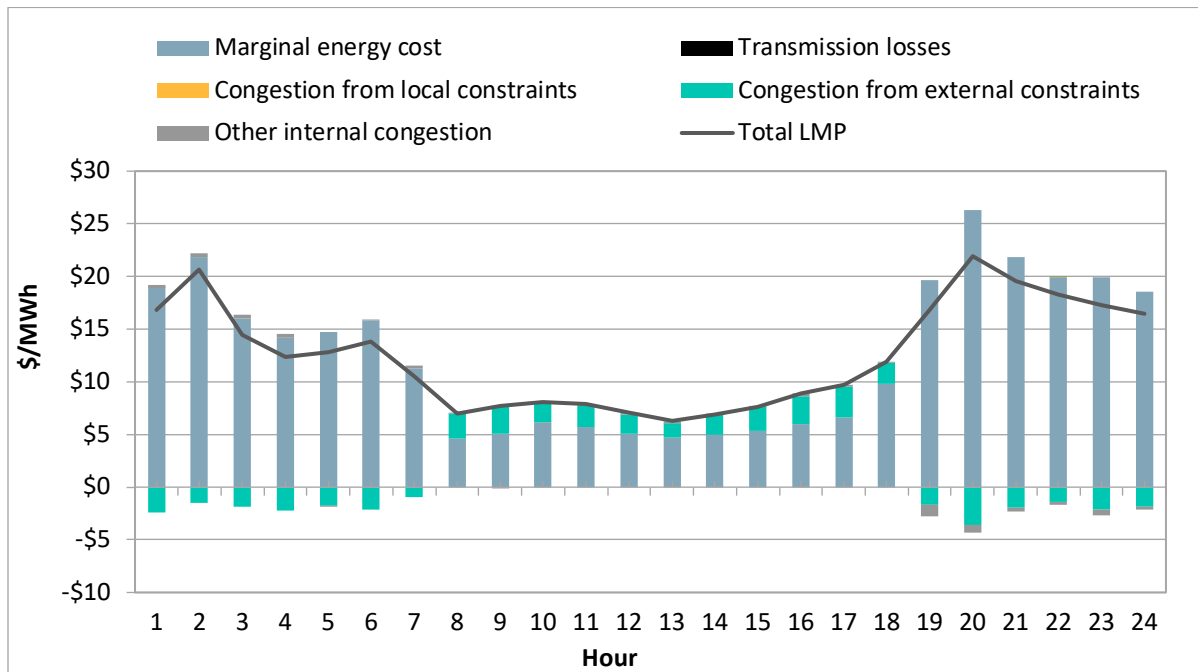
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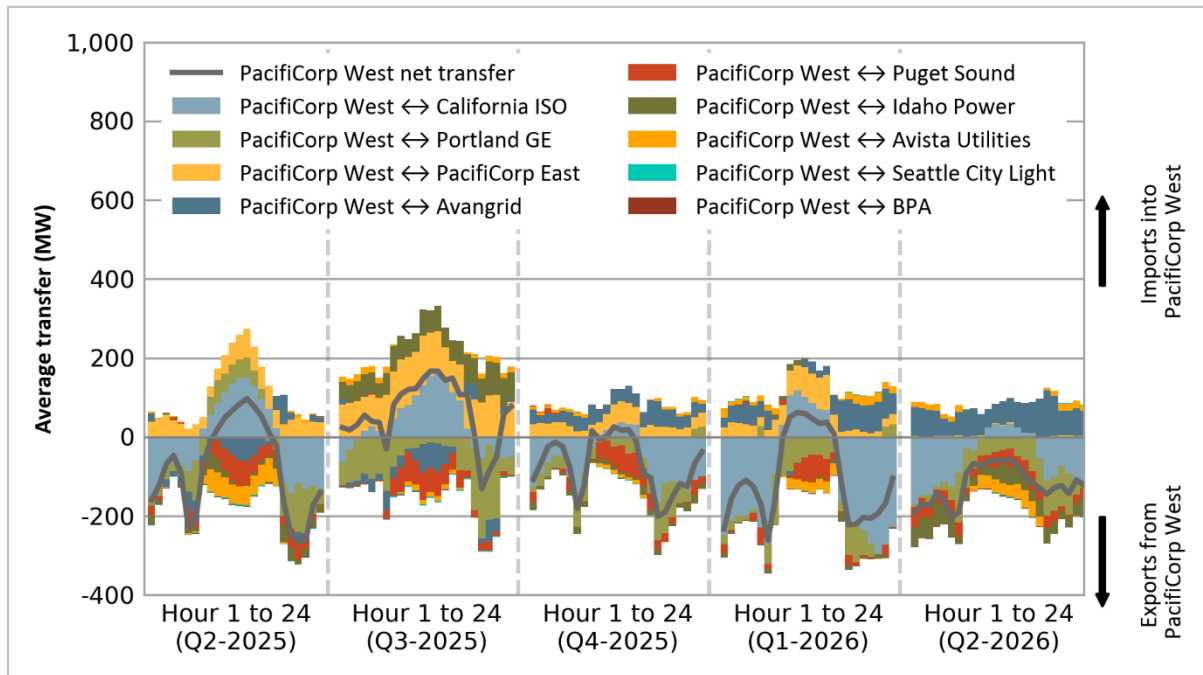
Appendix Figure A.84 Average hourly 5-minute market transfers

A.14 PacifiCorp West

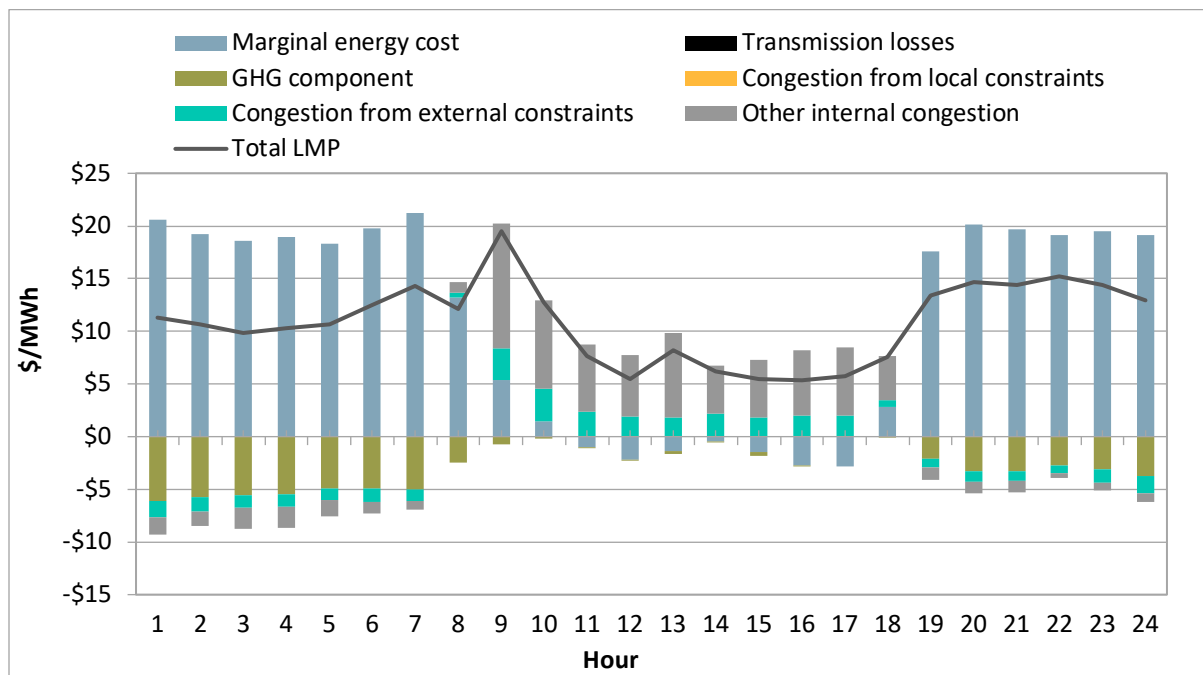
Appendix Figure A.85 Average hourly 15-minute price by component (April 2026)

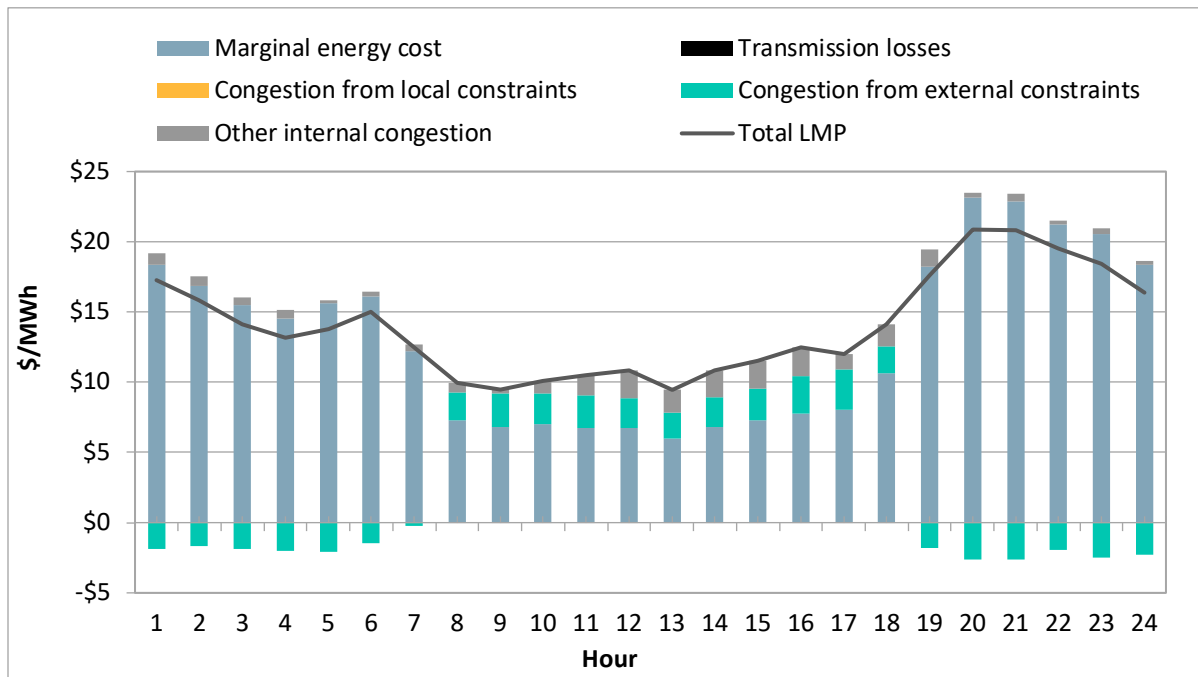
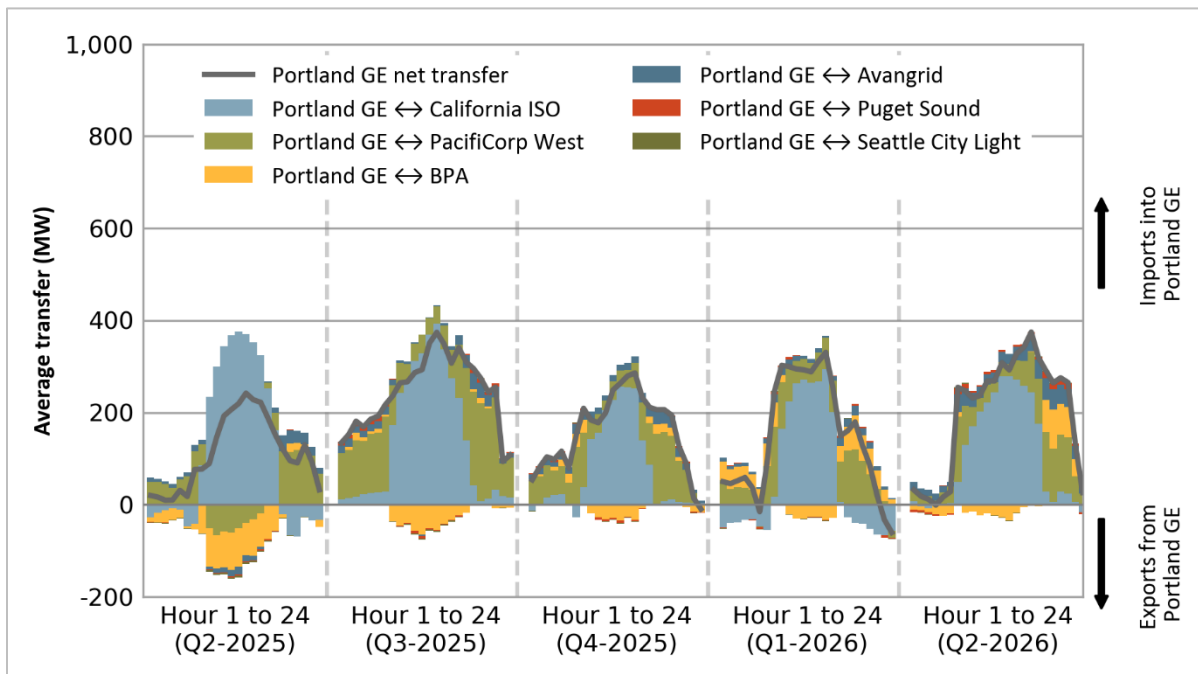
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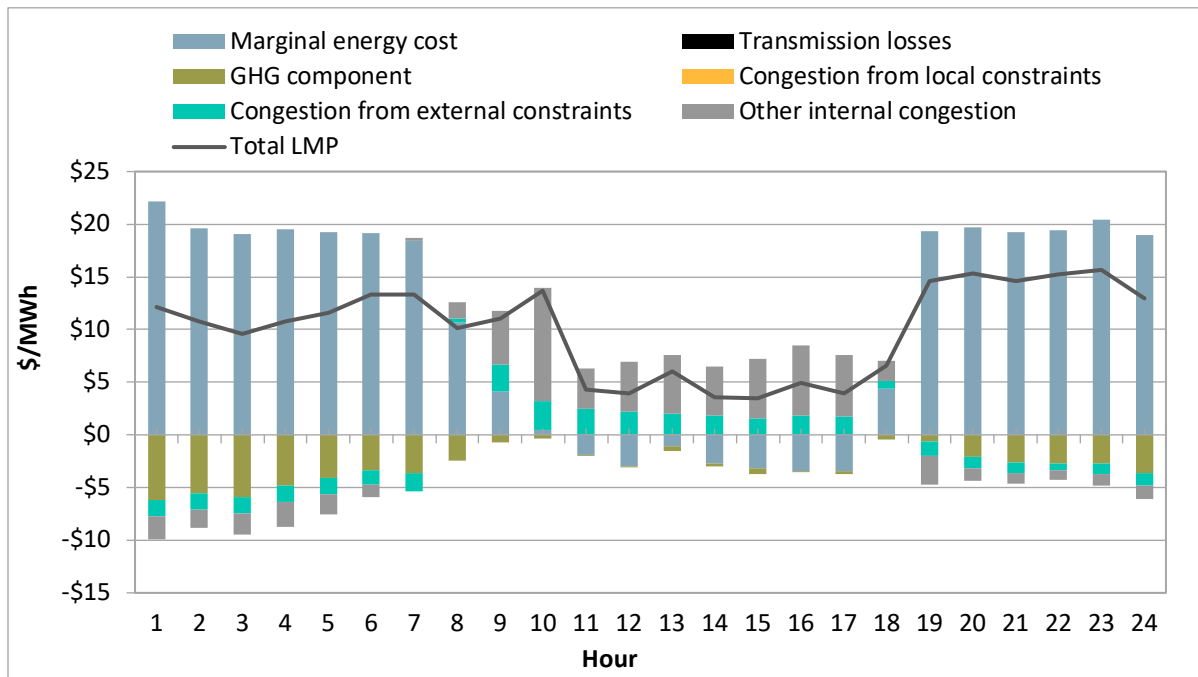
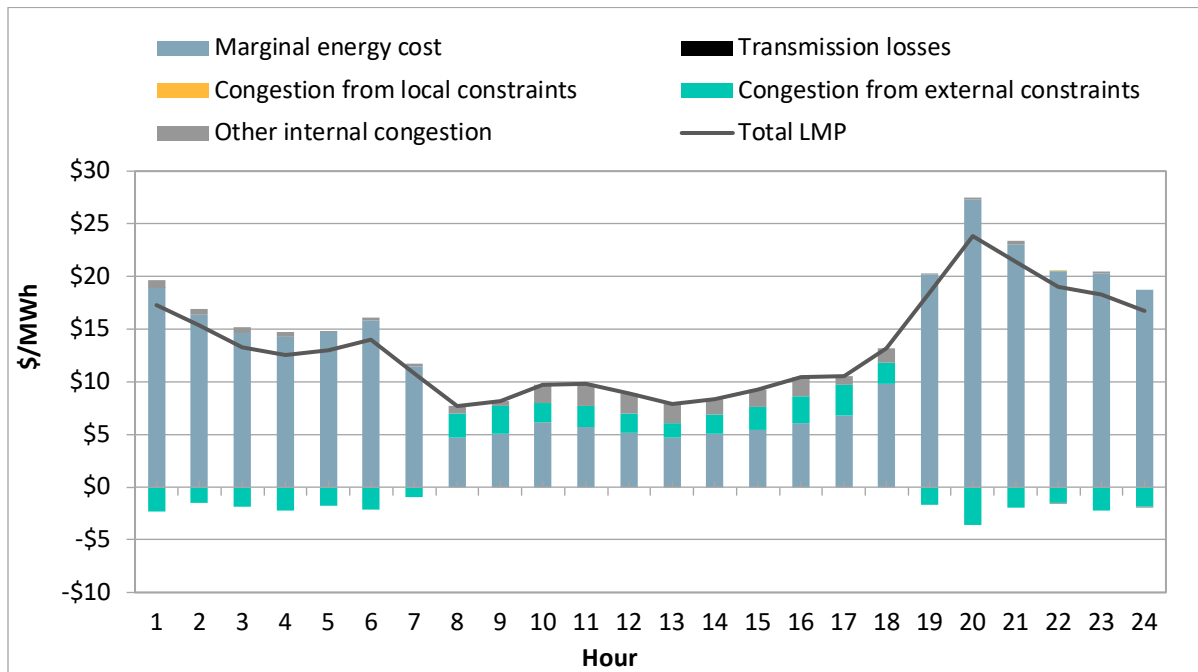
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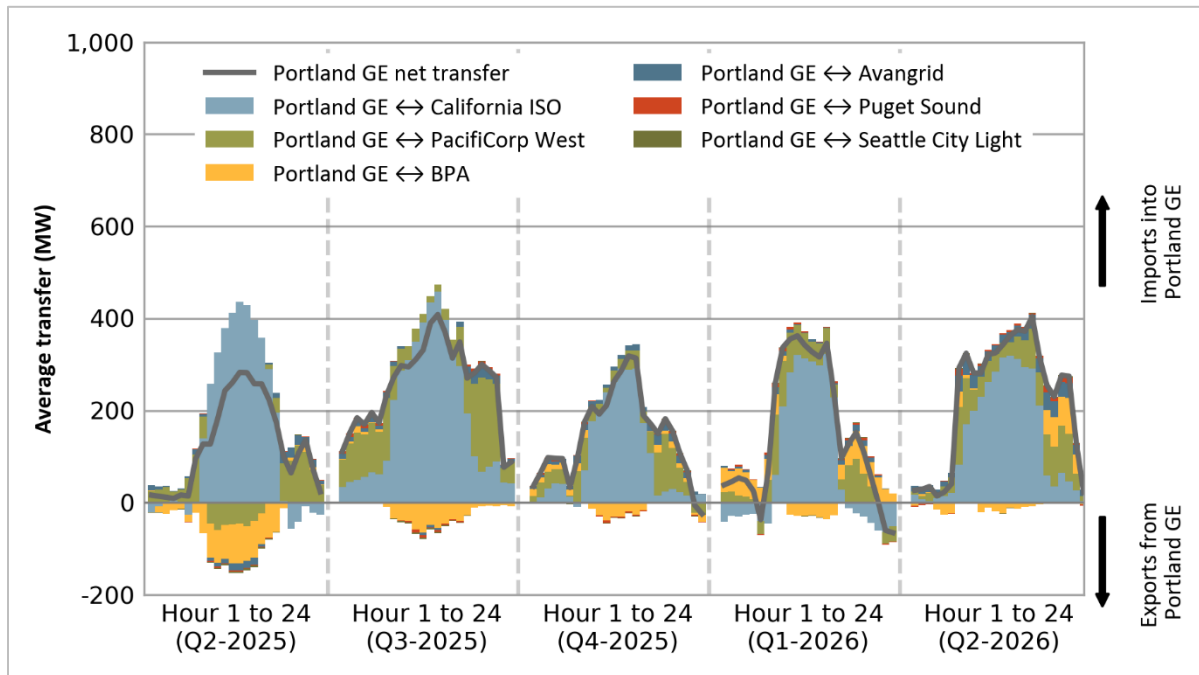
Appendix Figure A.90 Average hourly 5-minute market transfers

A.15 Portland General Electric

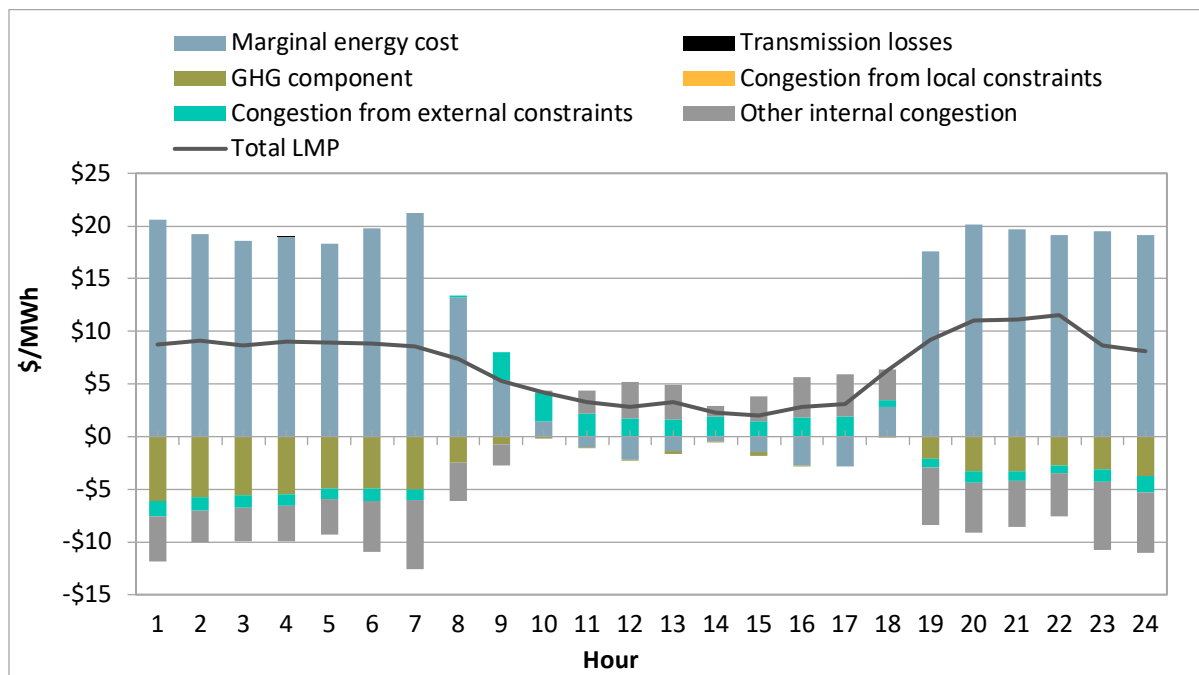
Appendix Figure A.91 Average hourly 15-minute price by component (April 2026)

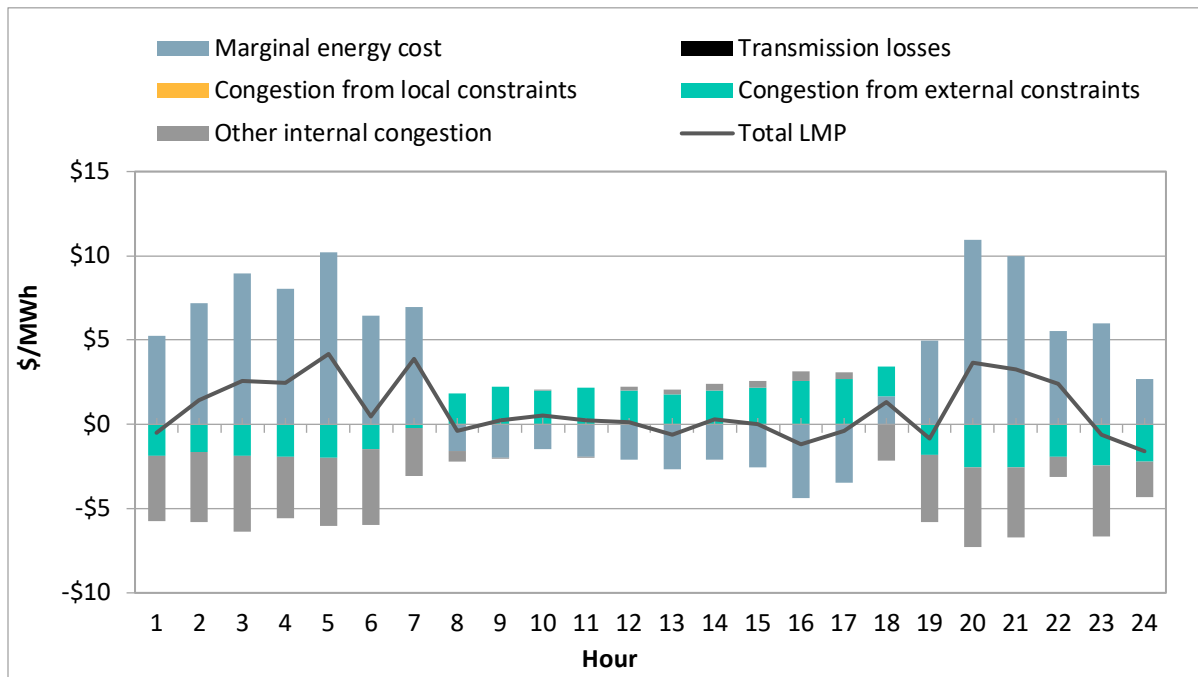
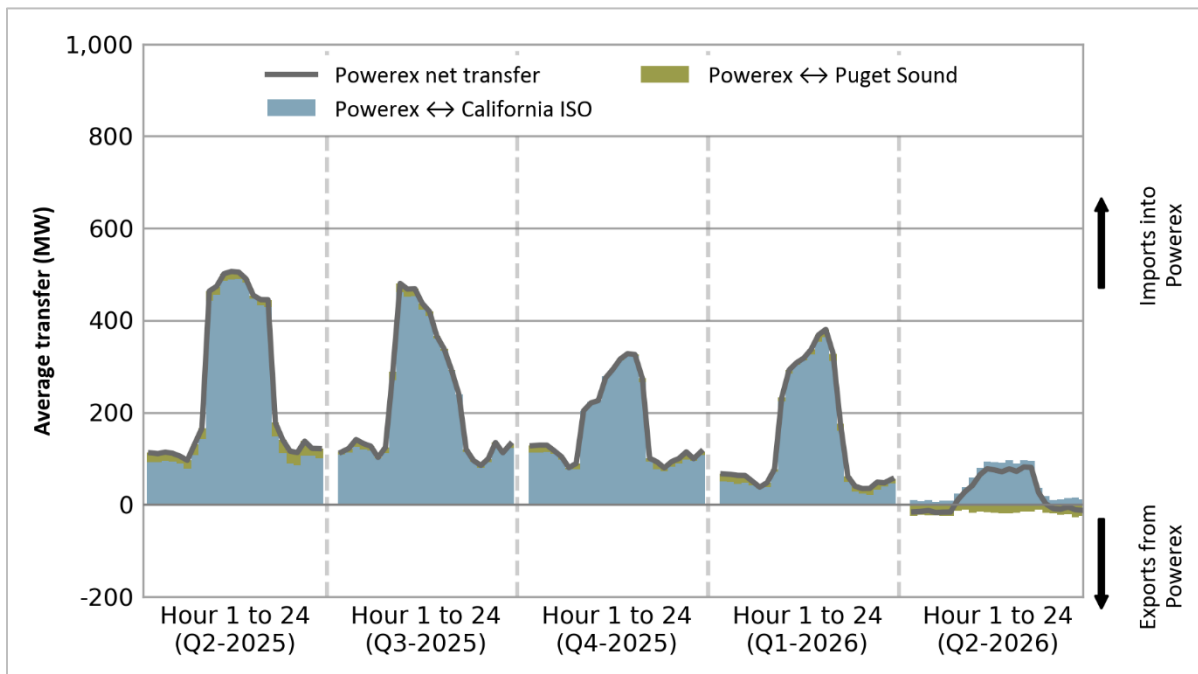
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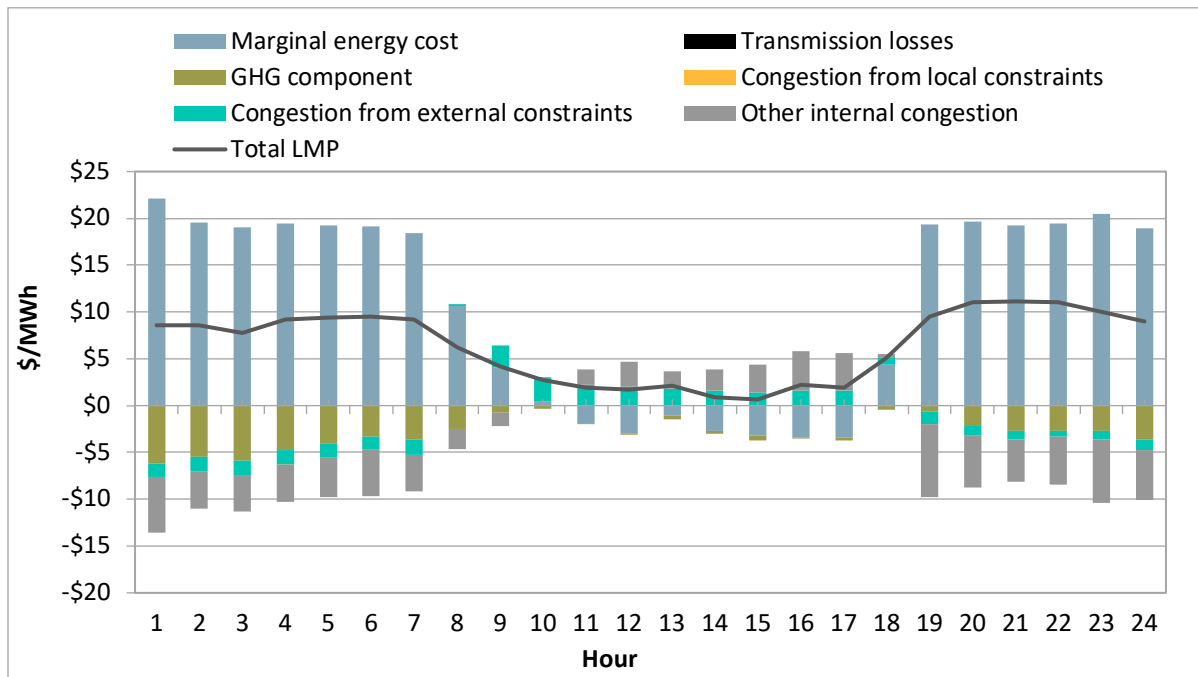
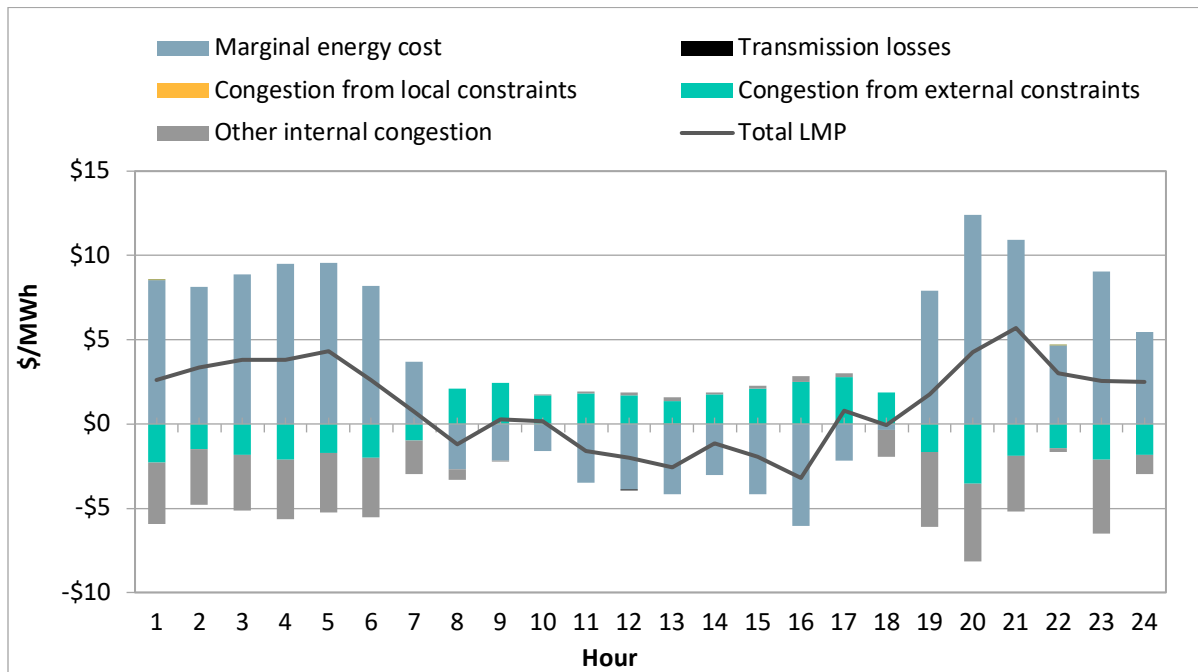
Appendix Figure A.94 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.95 Average hourly 5-minute price by component (May–June 2026)**

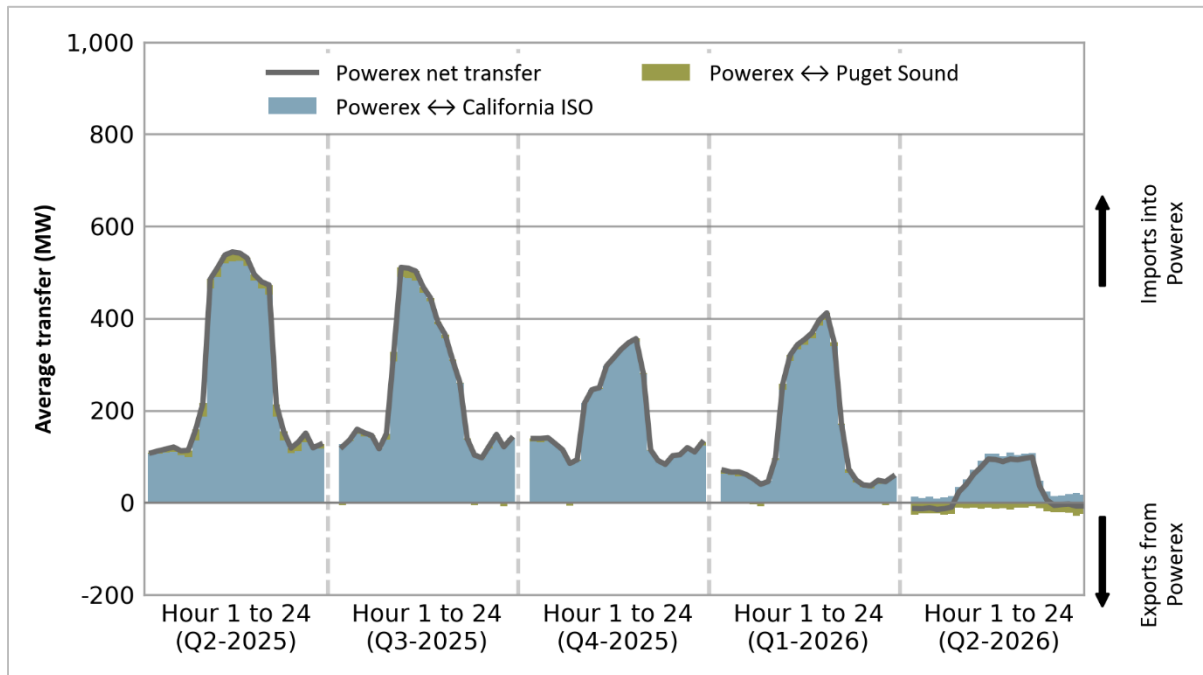
Appendix Figure A.96 Average hourly 5-minute market transfers

A.16 Powerex

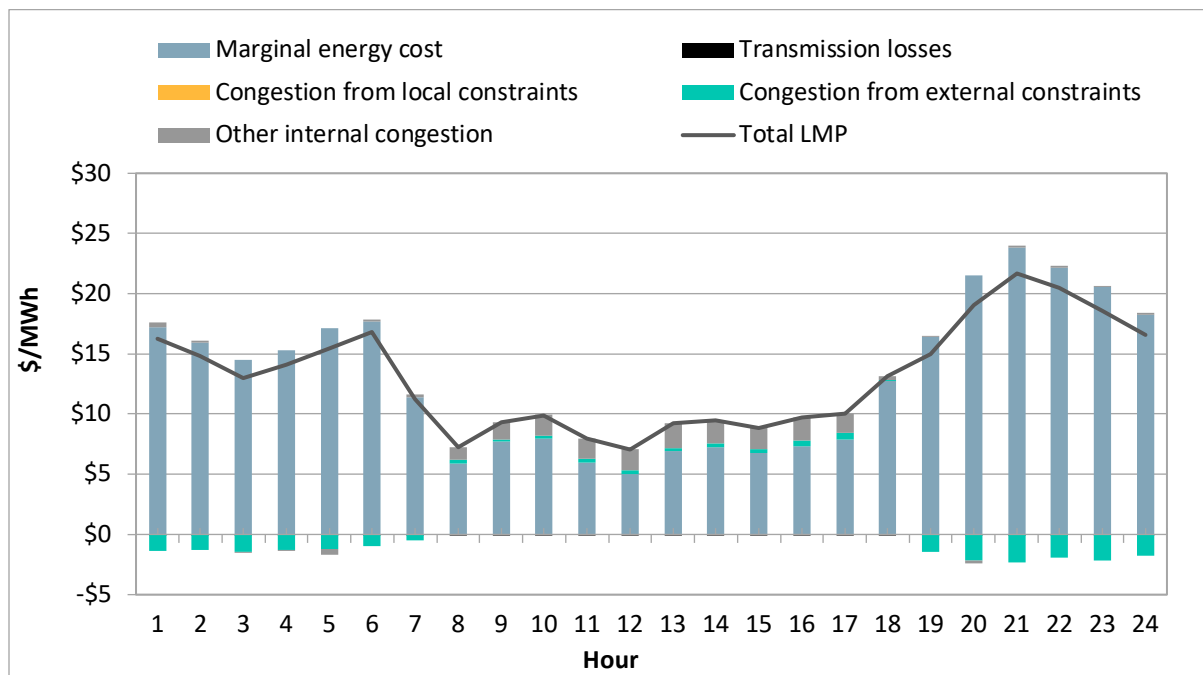
Appendix Figure A.97 Average hourly 15-minute price by component (April 2026)

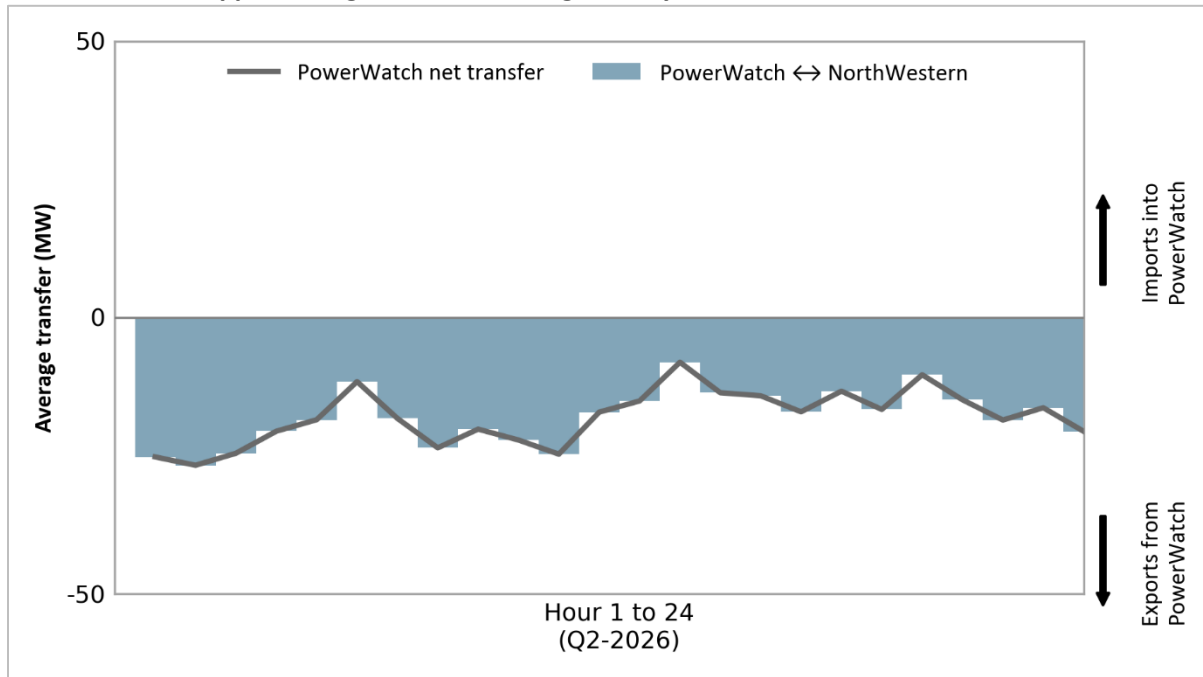
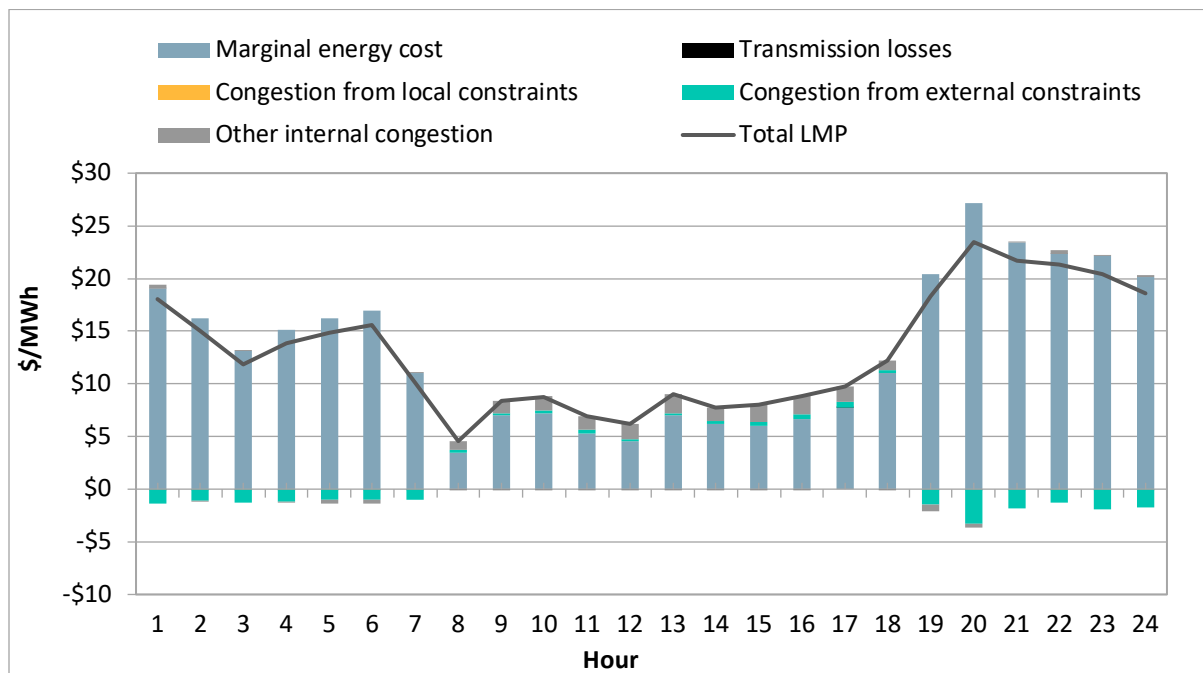
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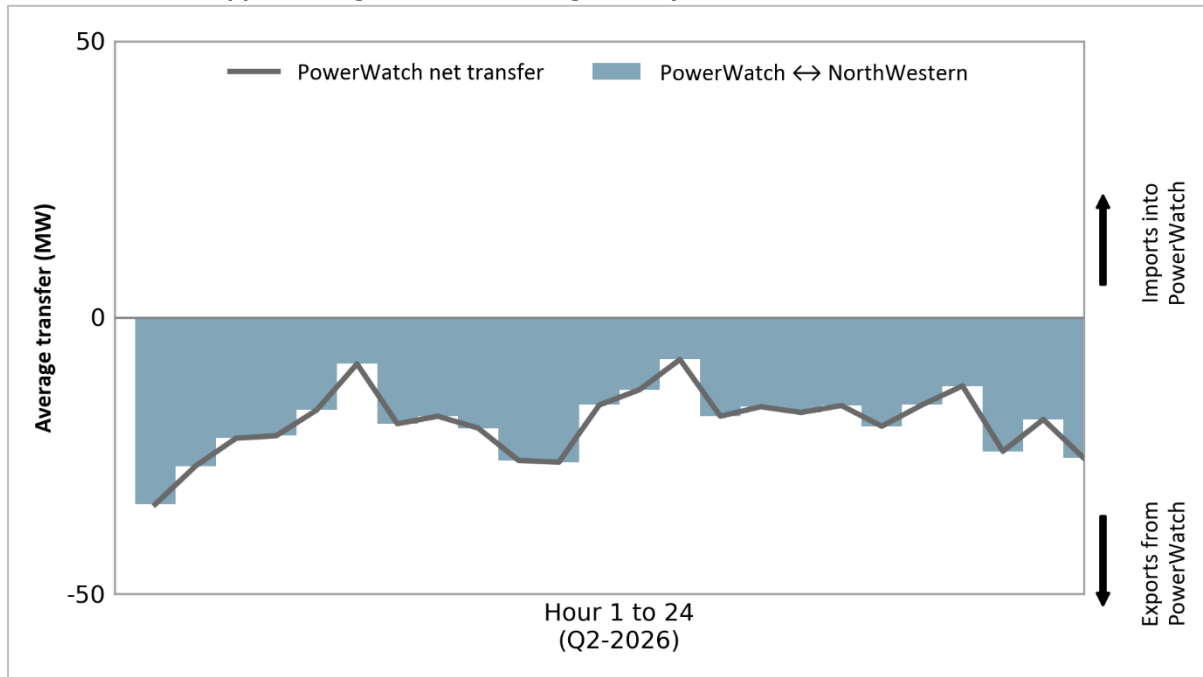
Appendix Figure A.100 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.101 Average hourly 5-minute price by component (May–June 2026)**

Appendix Figure A.102 Average hourly 5-minute market transfers

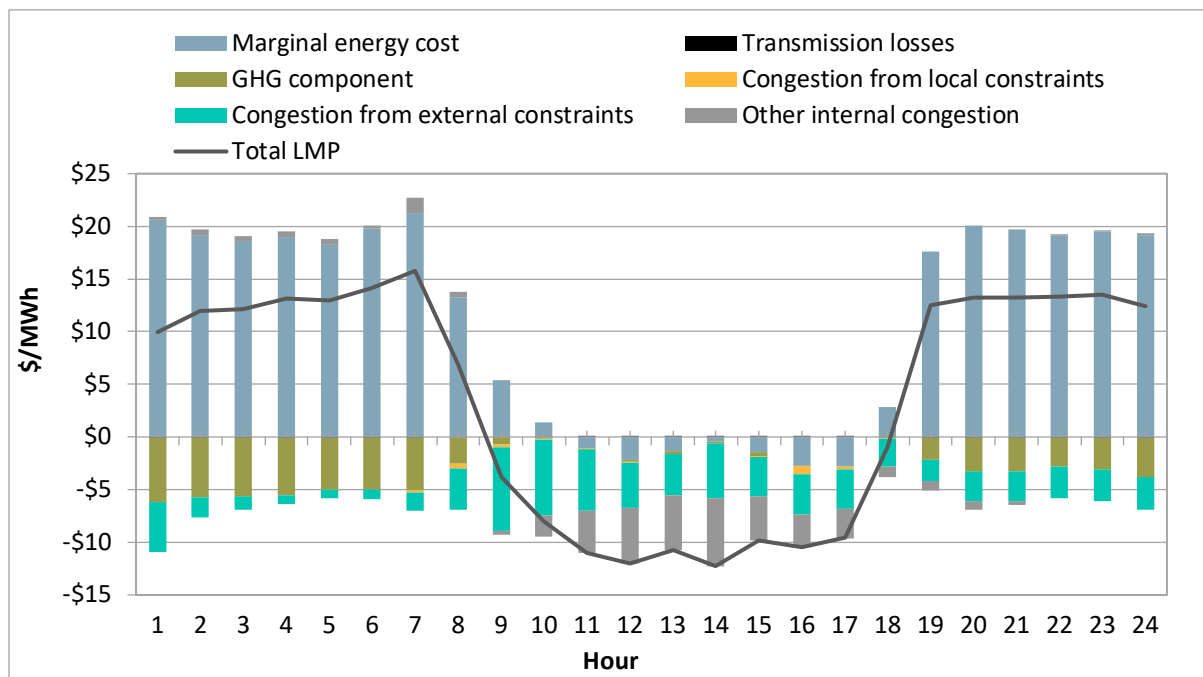
A.17 Power Watch

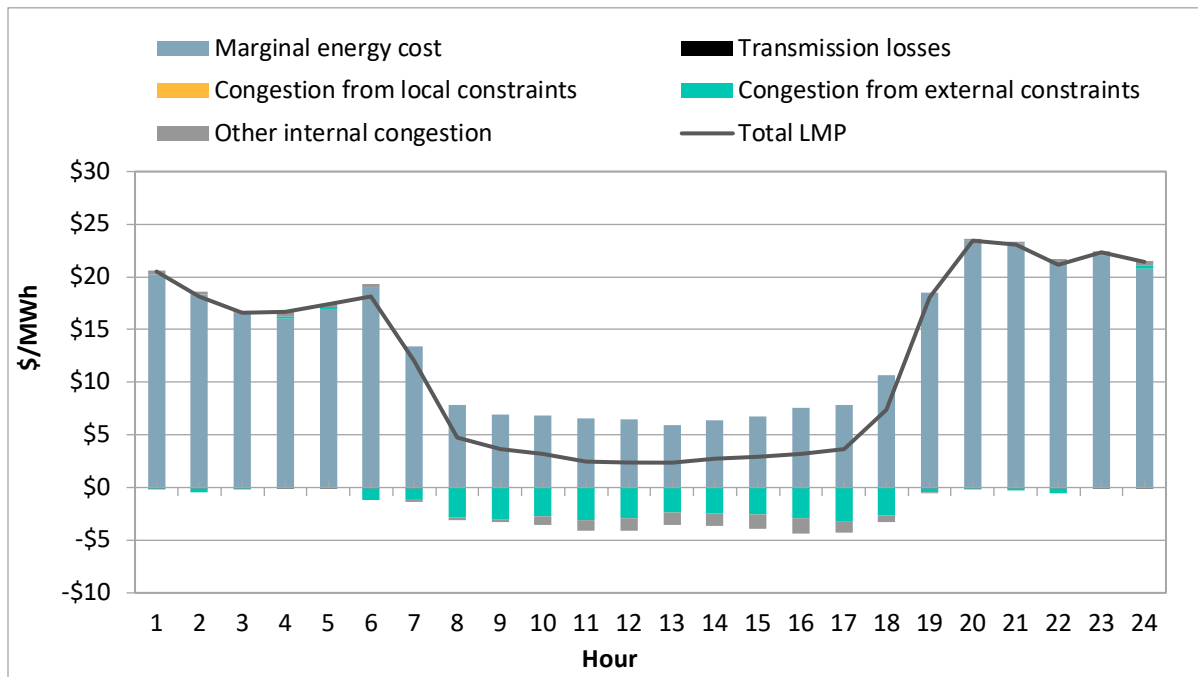
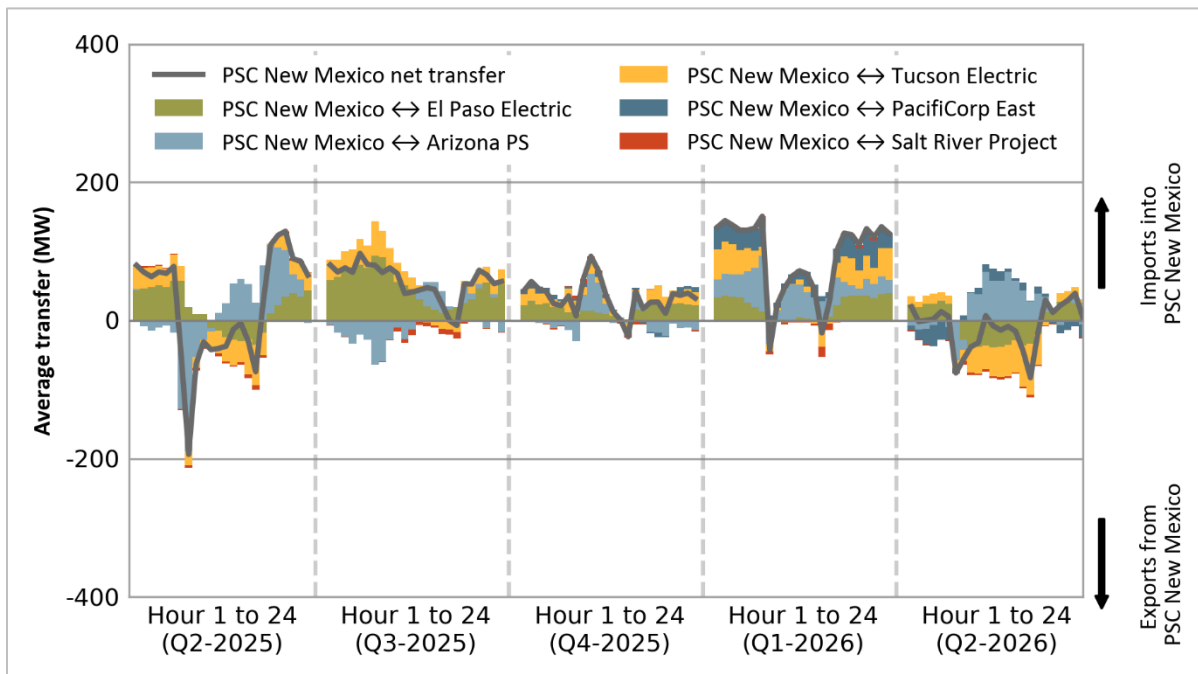
Appendix Figure A.103 Average hourly 15-minute price by component (May–June 2026)

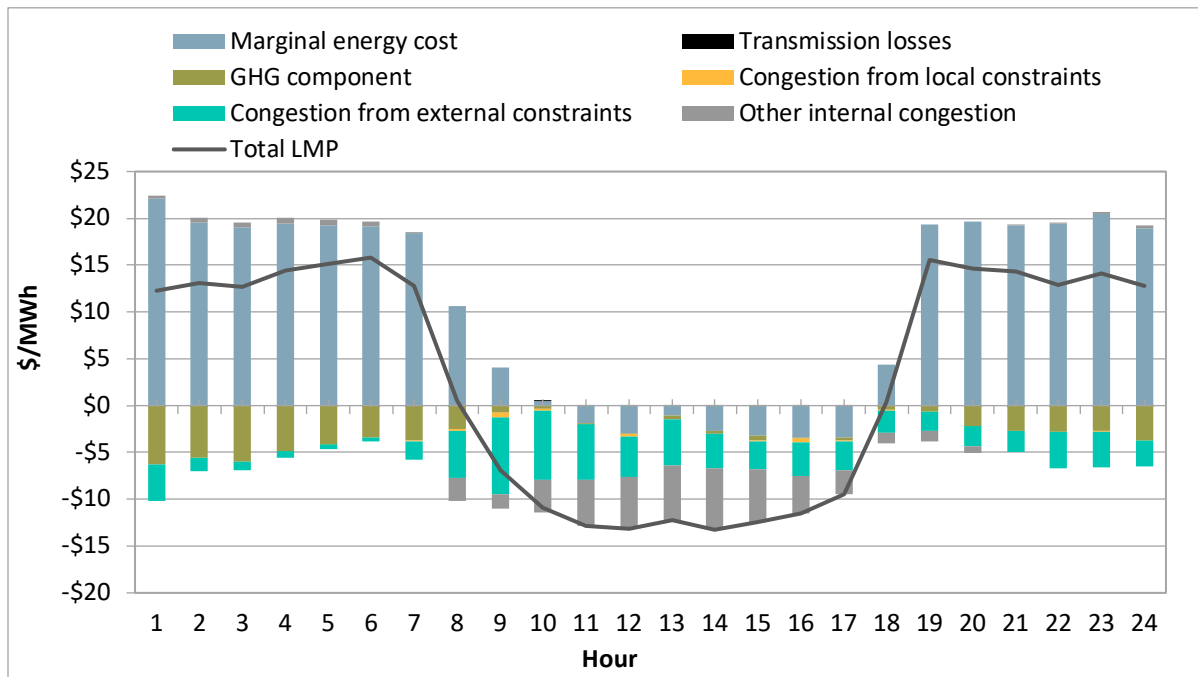
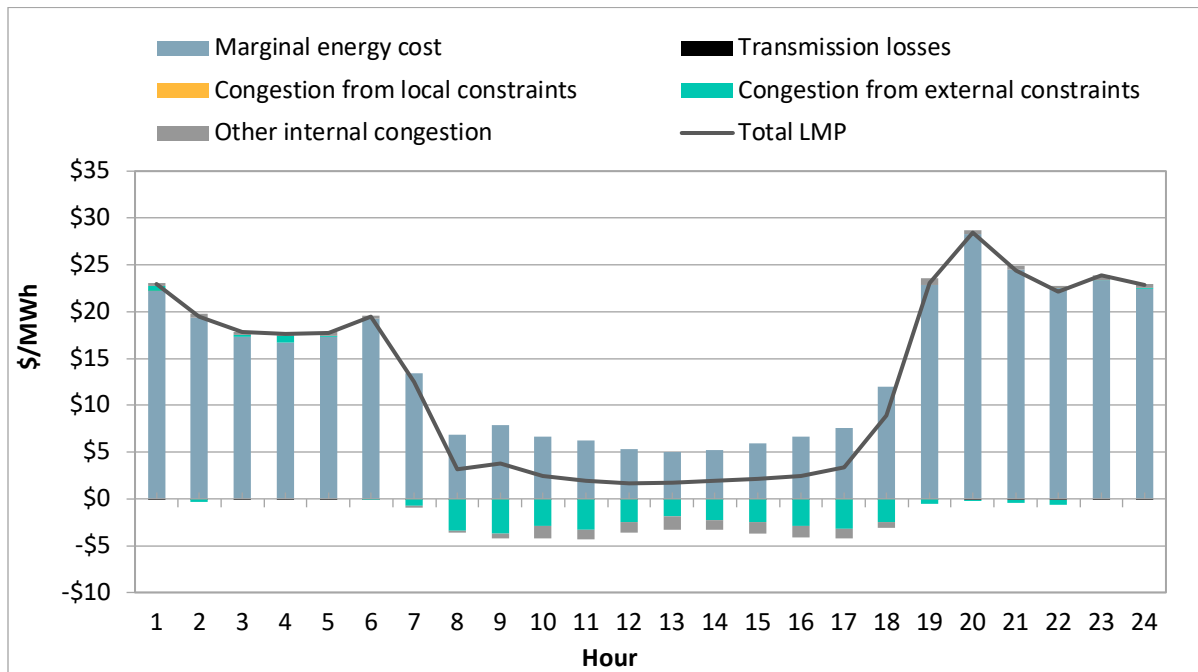
Appendix Figure A.104 Average hourly 15-minute market transfers**Appendix Figure A.105 Average hourly 5-minute price by component (May–June 2026)**

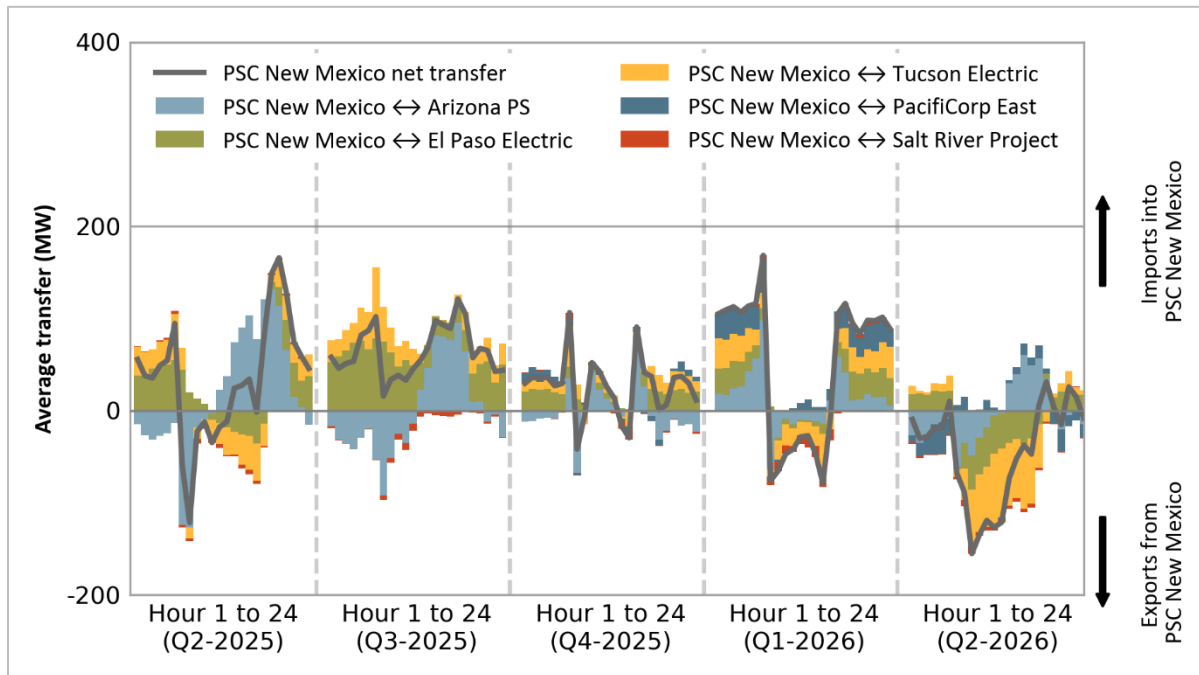
Appendix Figure A.106 Average hourly 5-minute market transfers

A.18 Public Service Company of New Mexico

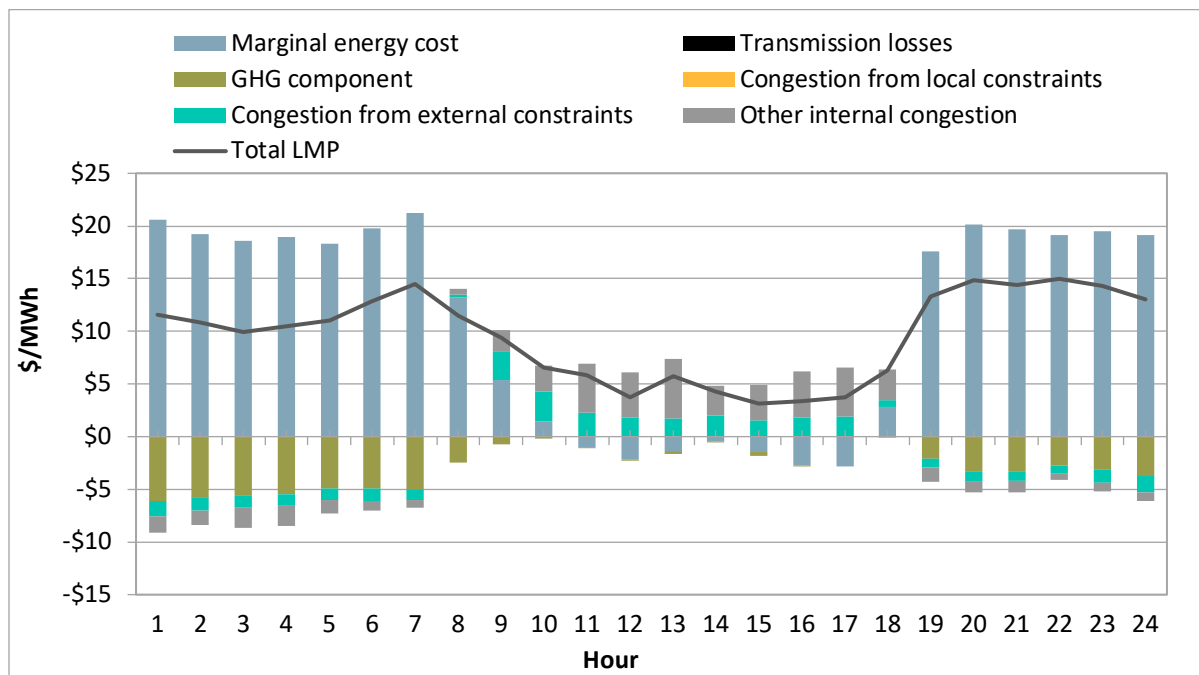
Appendix Figure A.107 Average hourly 15-minute price by component (April 2026)

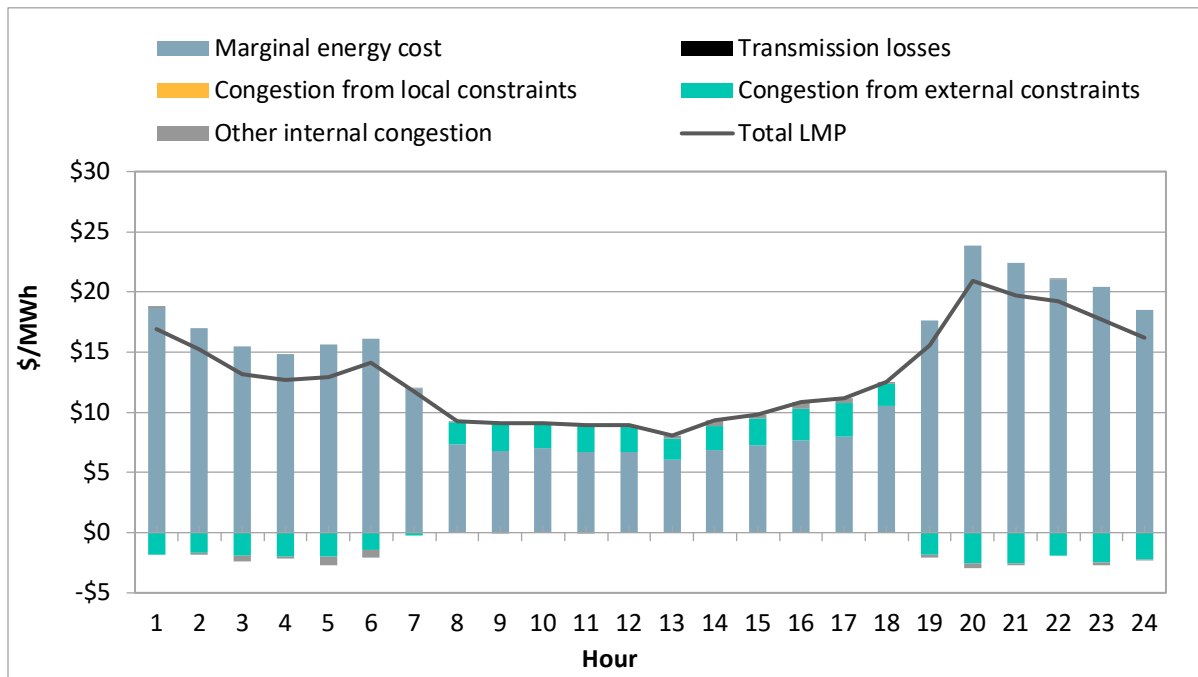
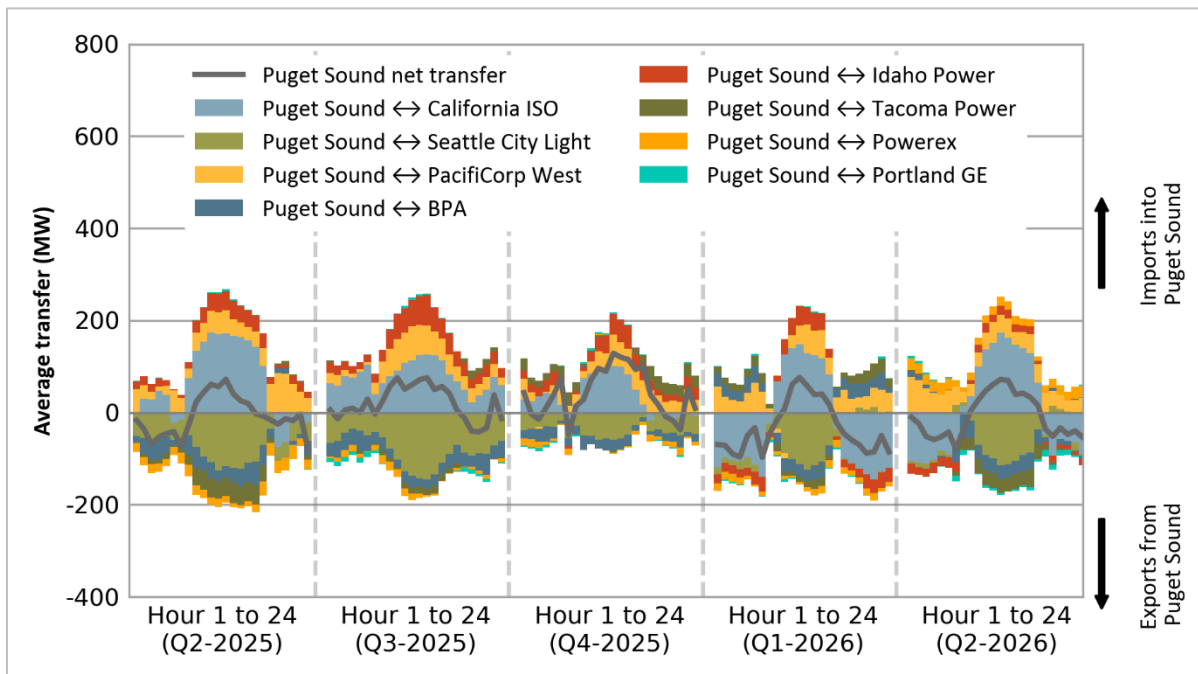
Appendix Figure A.108 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.109 Average hourly 15-minute market transfers**

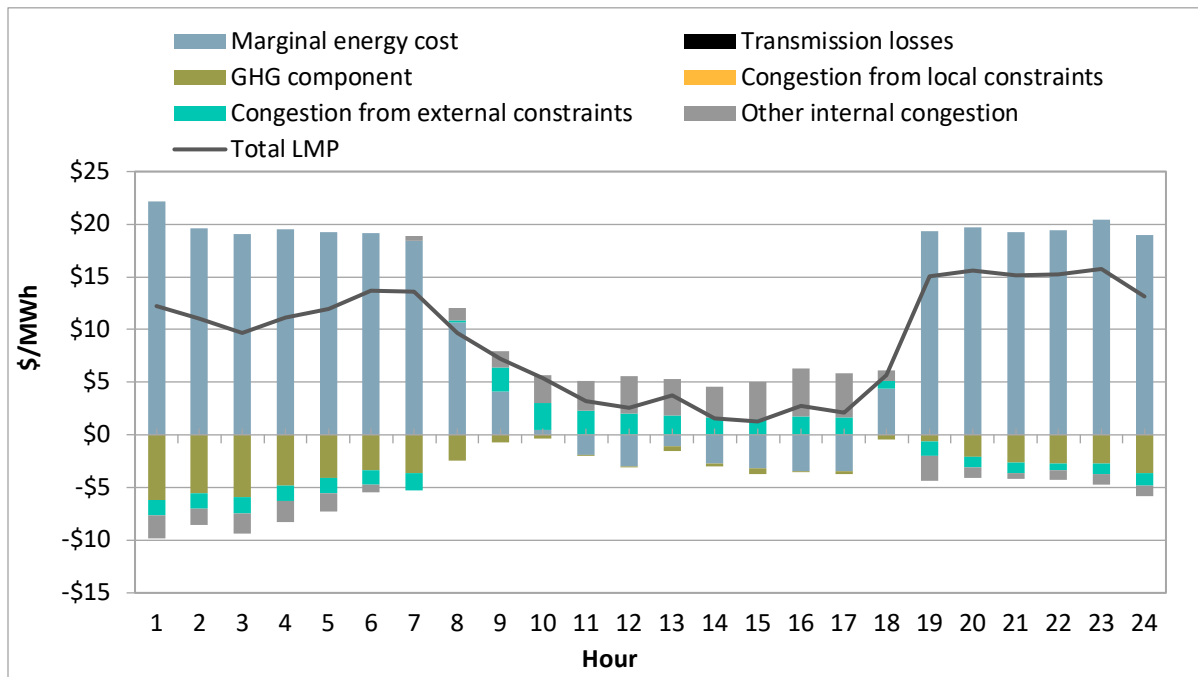
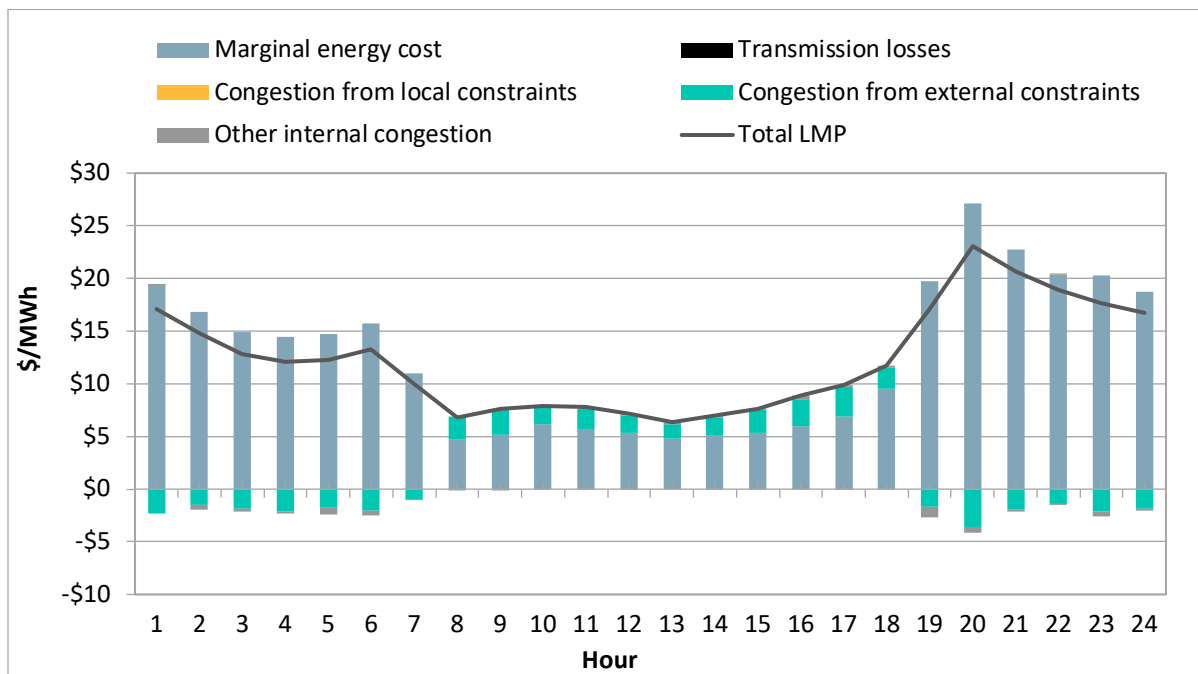
Appendix Figure A.110 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.111 Average hourly 5-minute price by component (May–June 2026)**

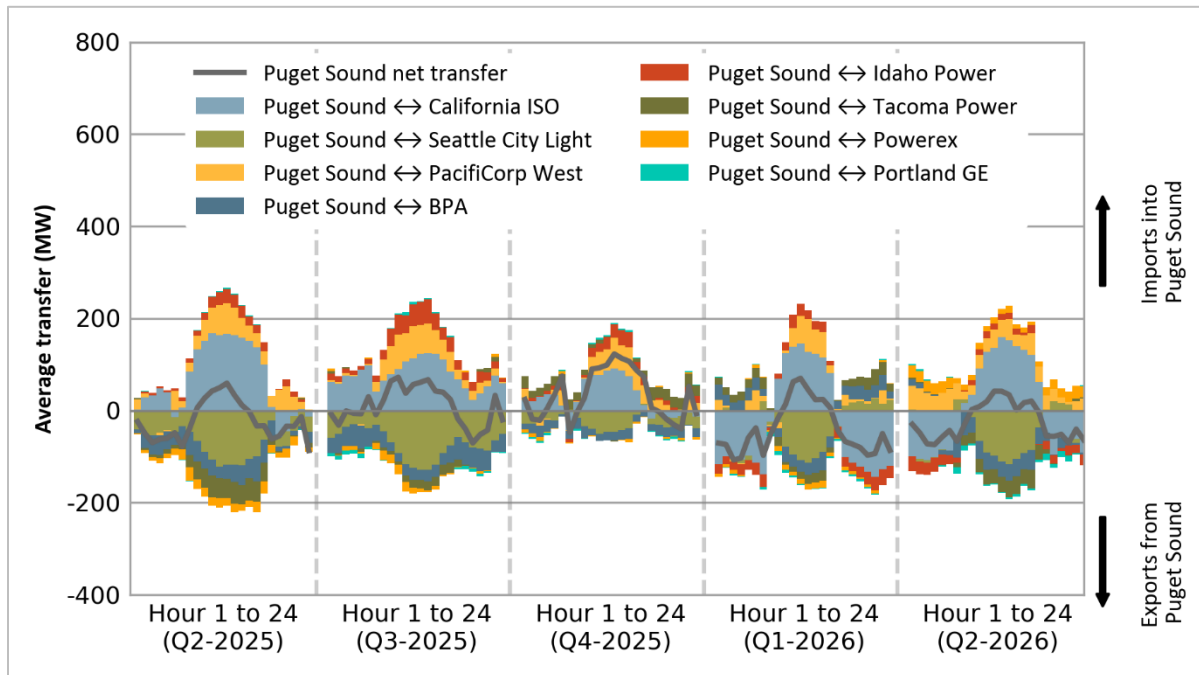
Appendix Figure A.112 Average hourly 5-minute market transfers

A.19 Puget Sound Energy

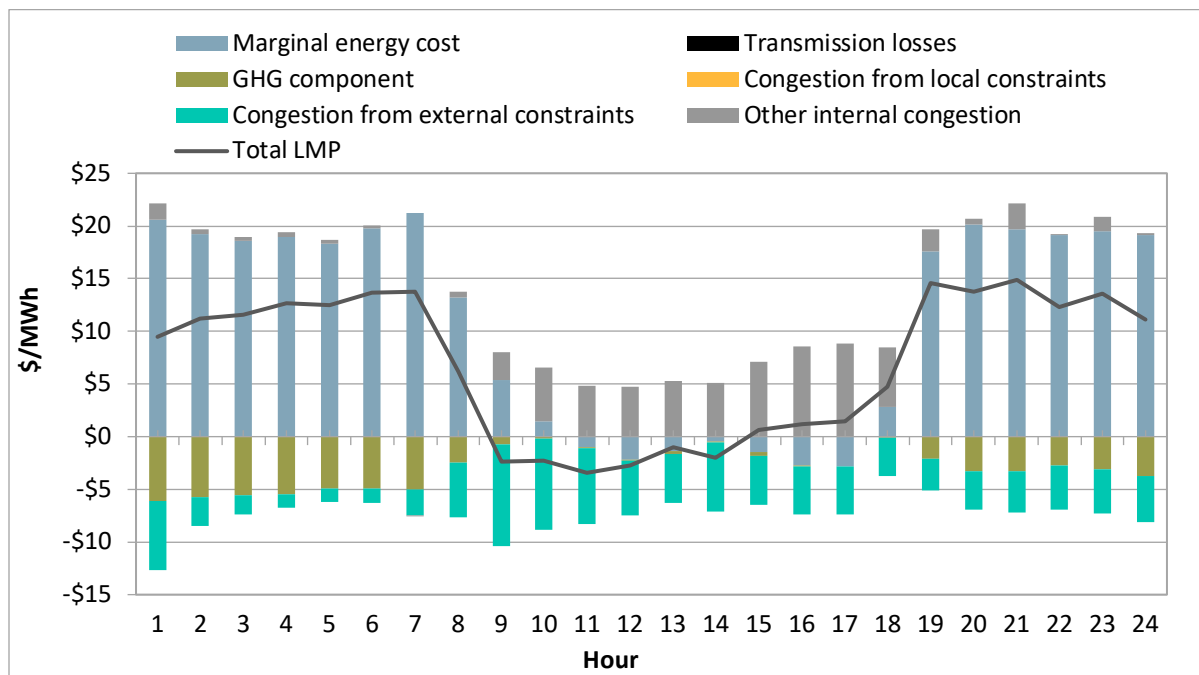
Appendix Figure A.113 Average hourly 15-minute price by component (April 2026)

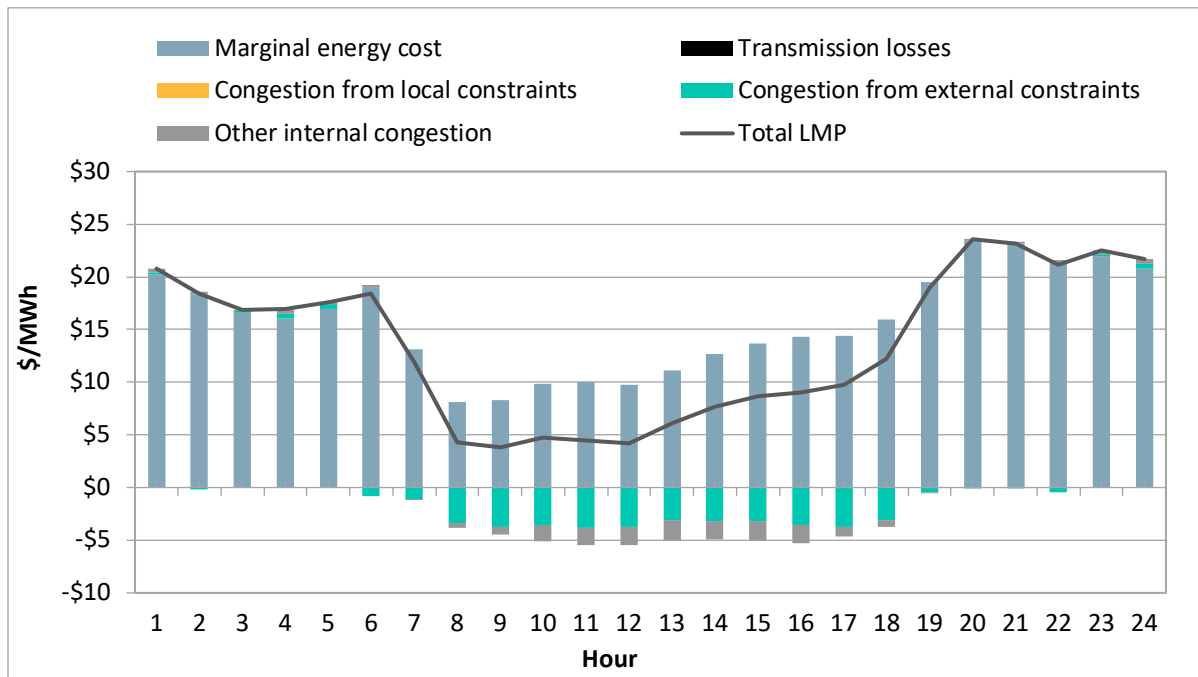
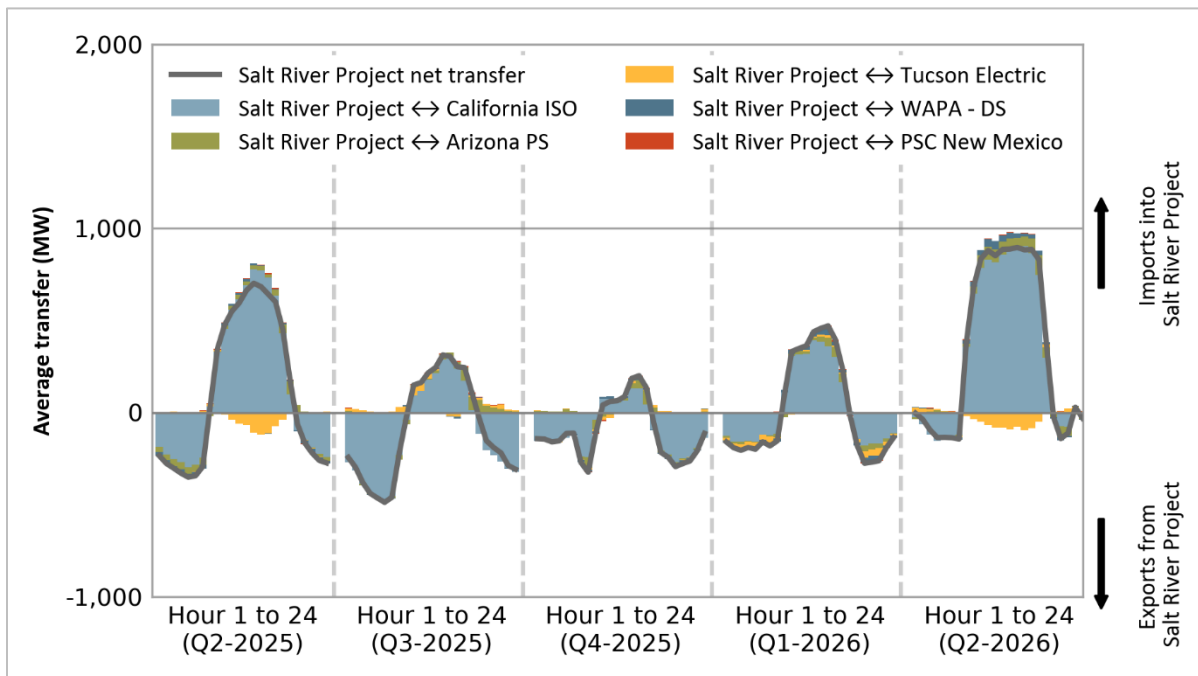
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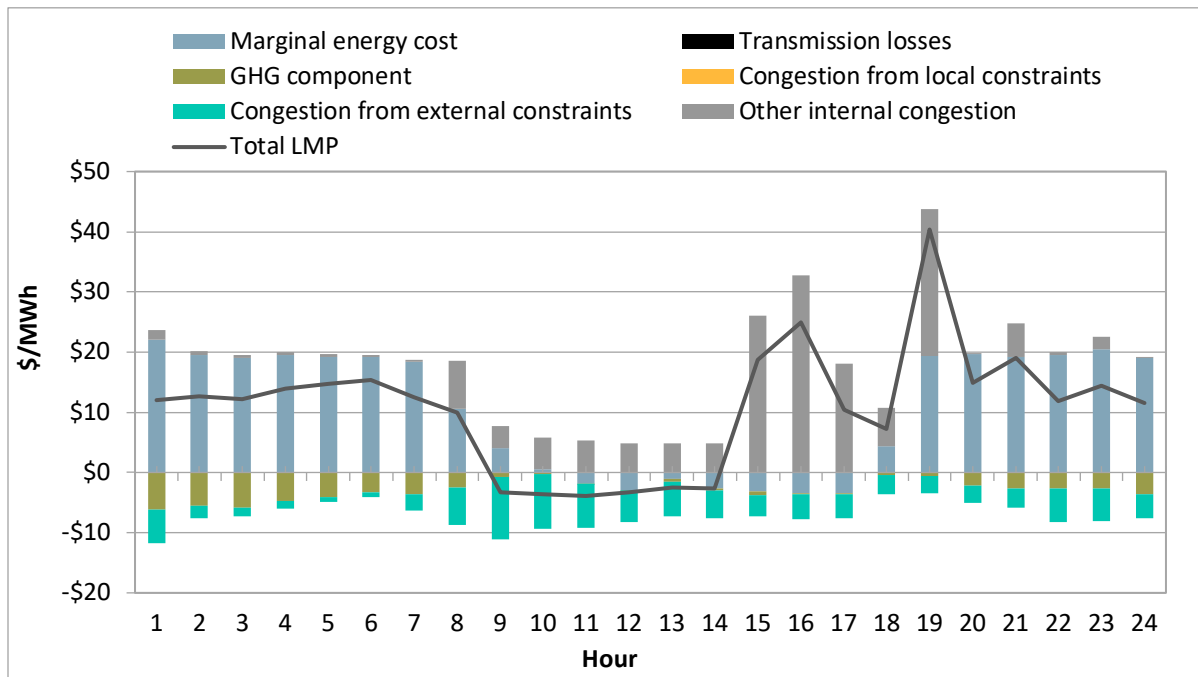
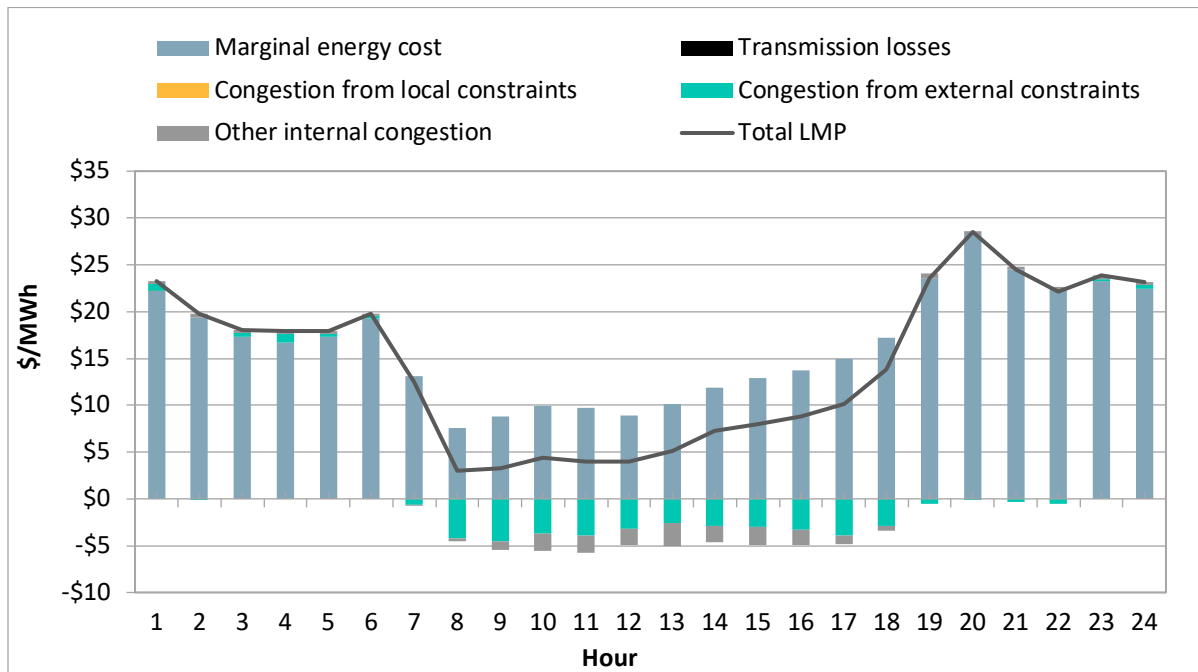
Appendix Figure A.116 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.117 Average hourly 5-minute price by component (May–June 2026)**

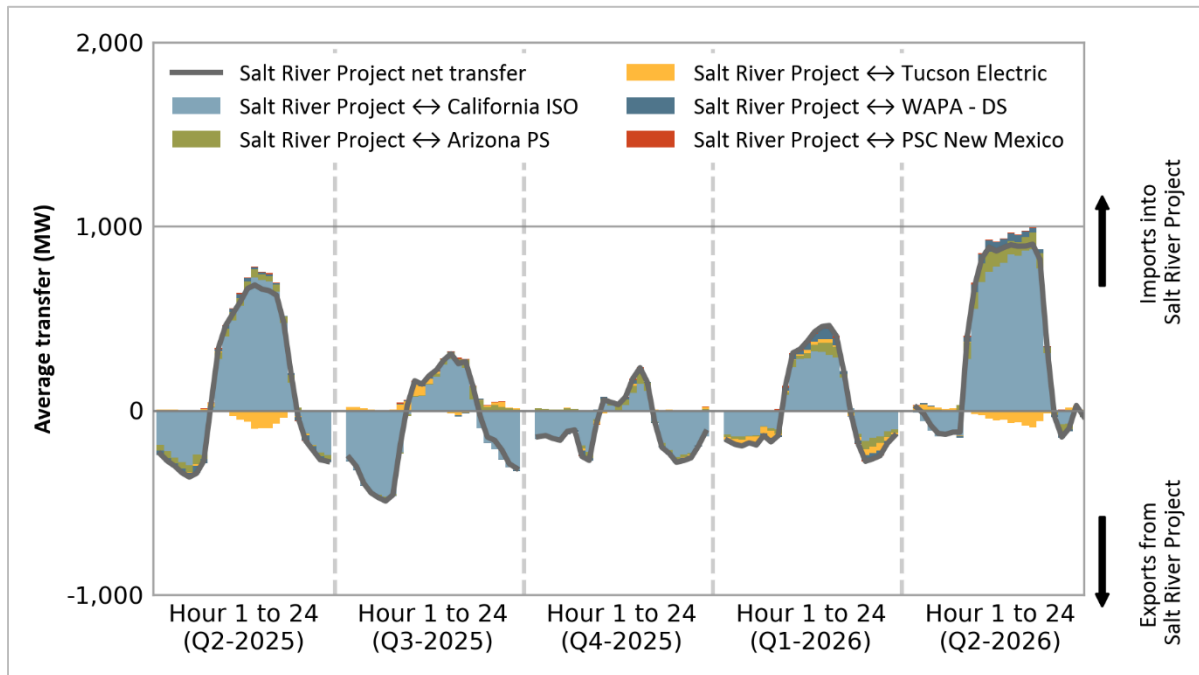
Appendix Figure A.118 Average hourly 5-minute market transfers

A.20 Salt River Project

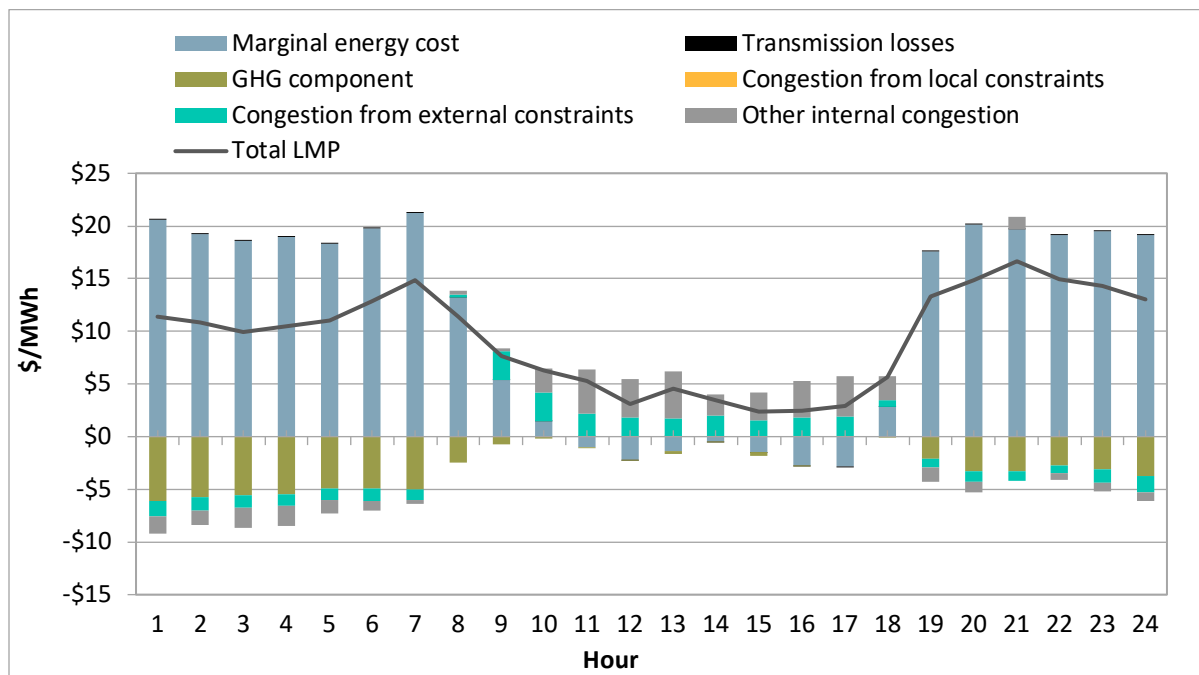
Appendix Figure A.119 Average hourly 15-minute price by component (April 2026)

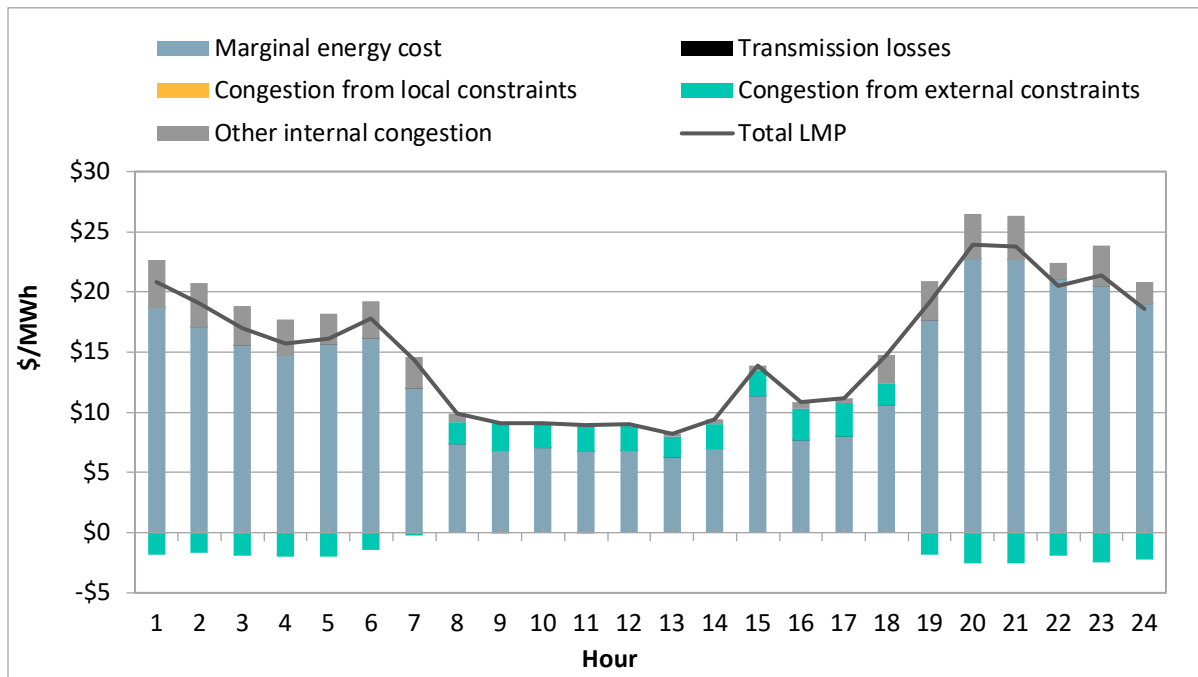
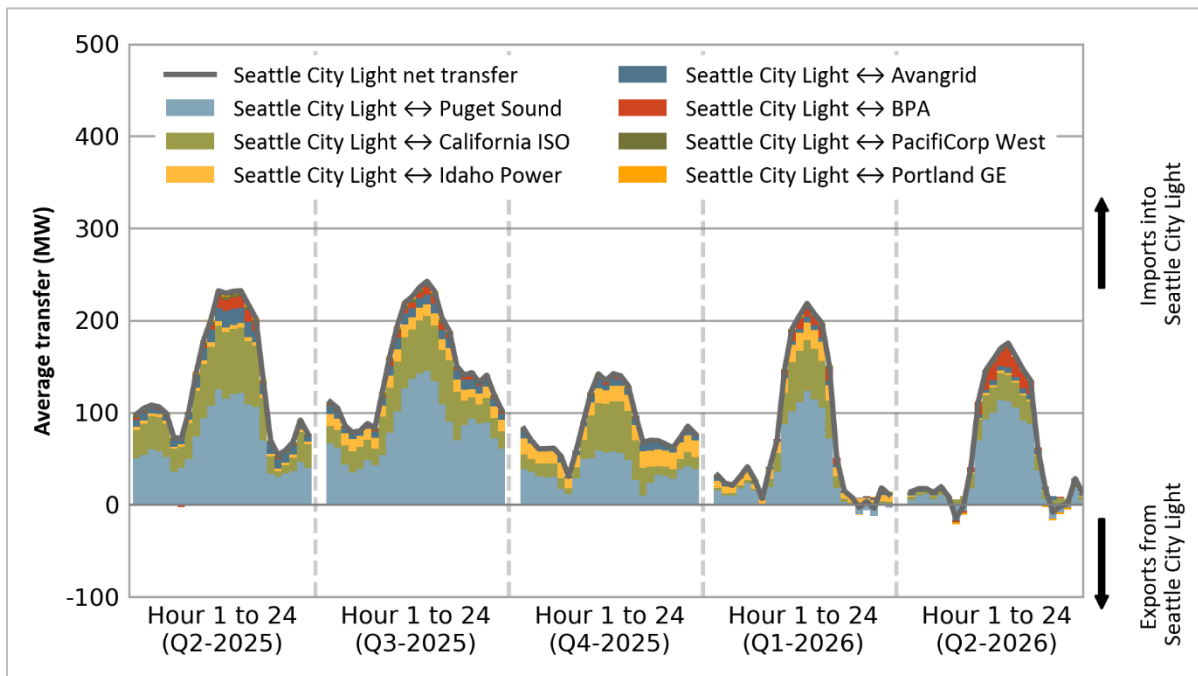
Appendix Figure A.120 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.121 Average hourly 15-minute market transfers**

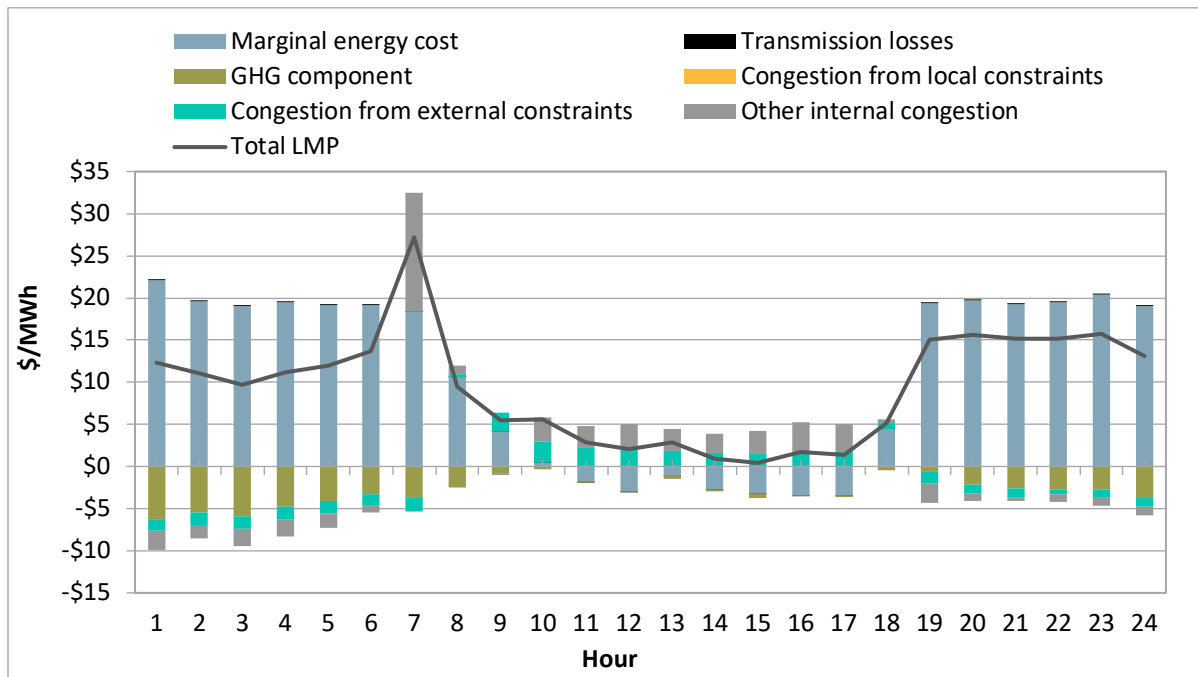
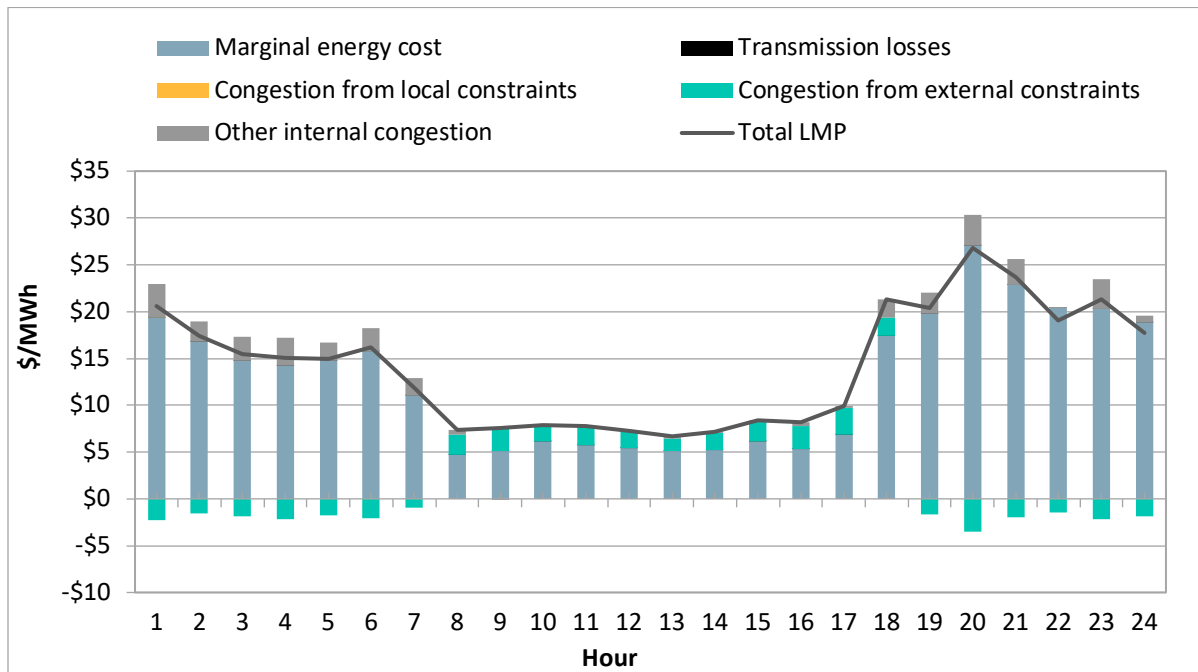
Appendix Figure A.122 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.123 Average hourly 5-minute price by component (May–June 2026)**

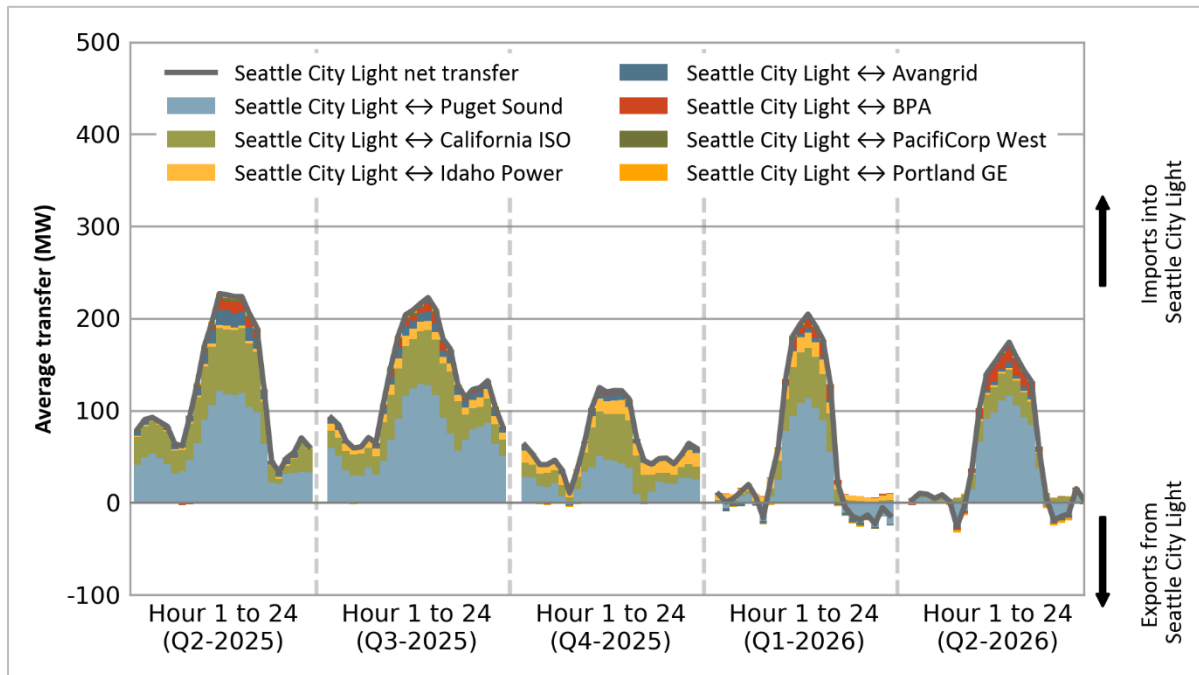
Appendix Figure A.124 Average hourly 5-minute market transfers

A.21 Seattle City Light

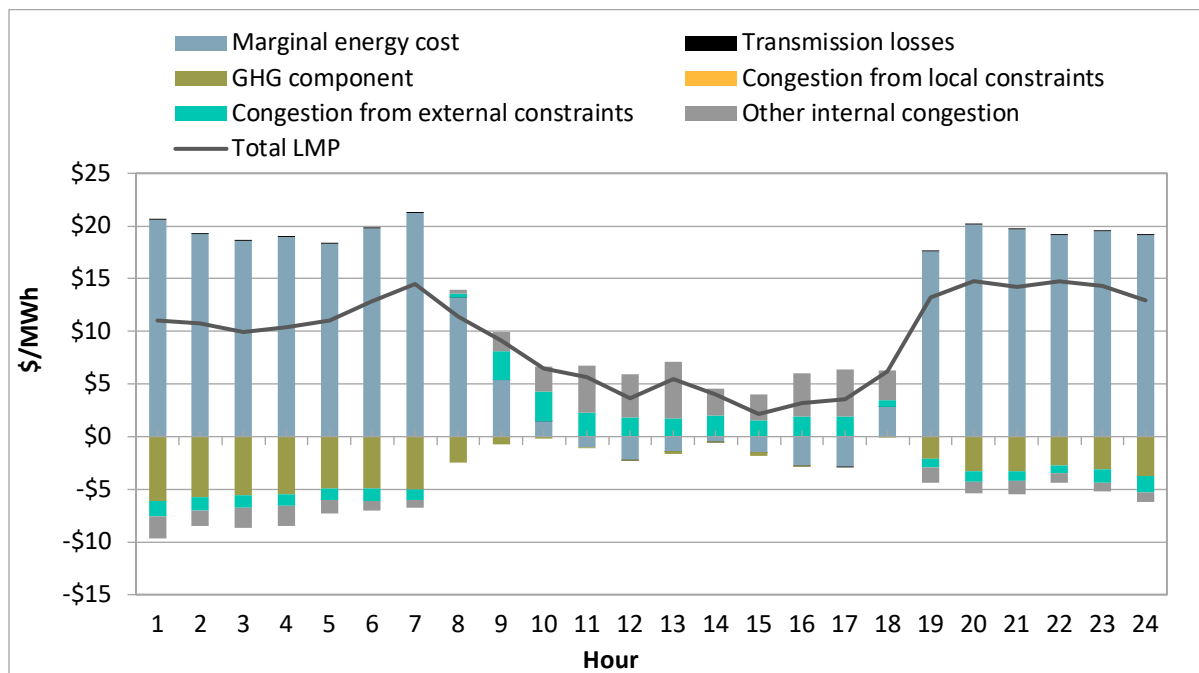
Appendix Figure A.125 Average hourly 15-minute price by component (April 2026)

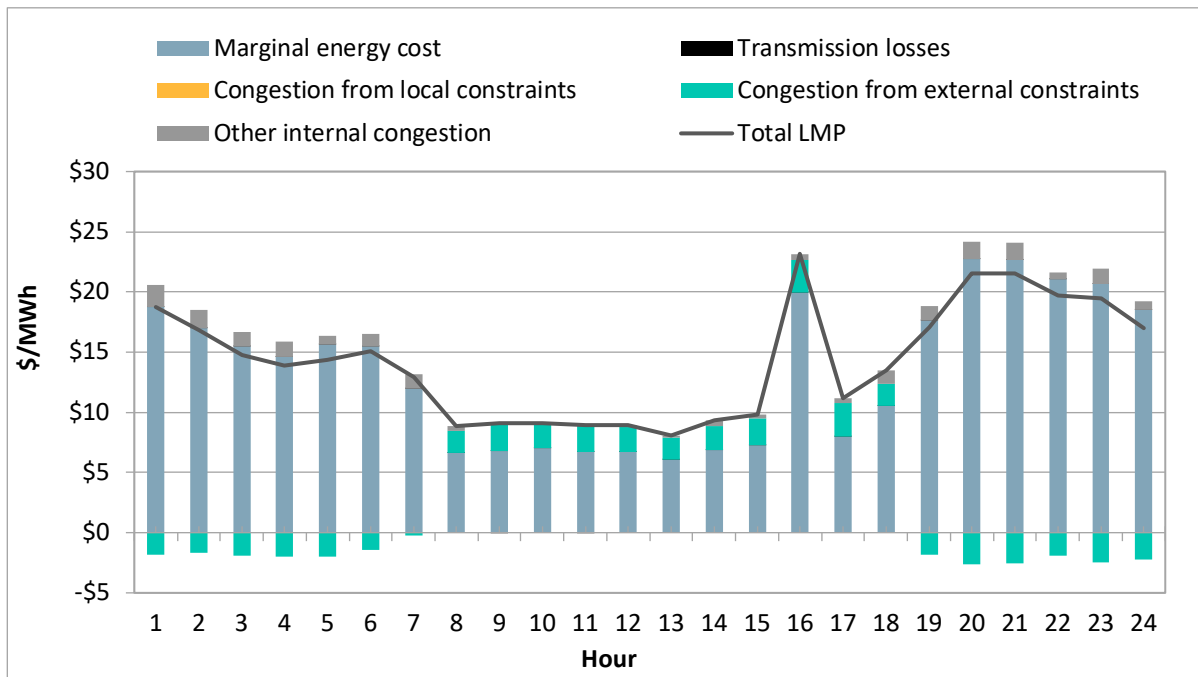
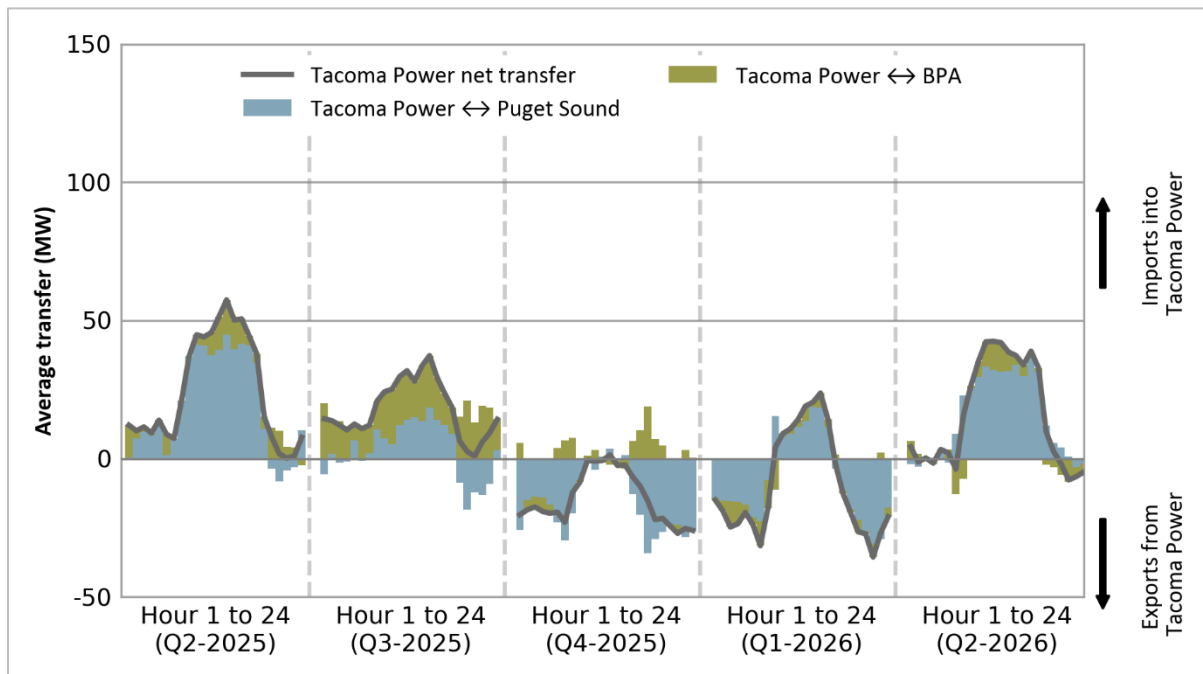
Appendix Figure A.126 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.127 Average hourly 15-minute market transfers**

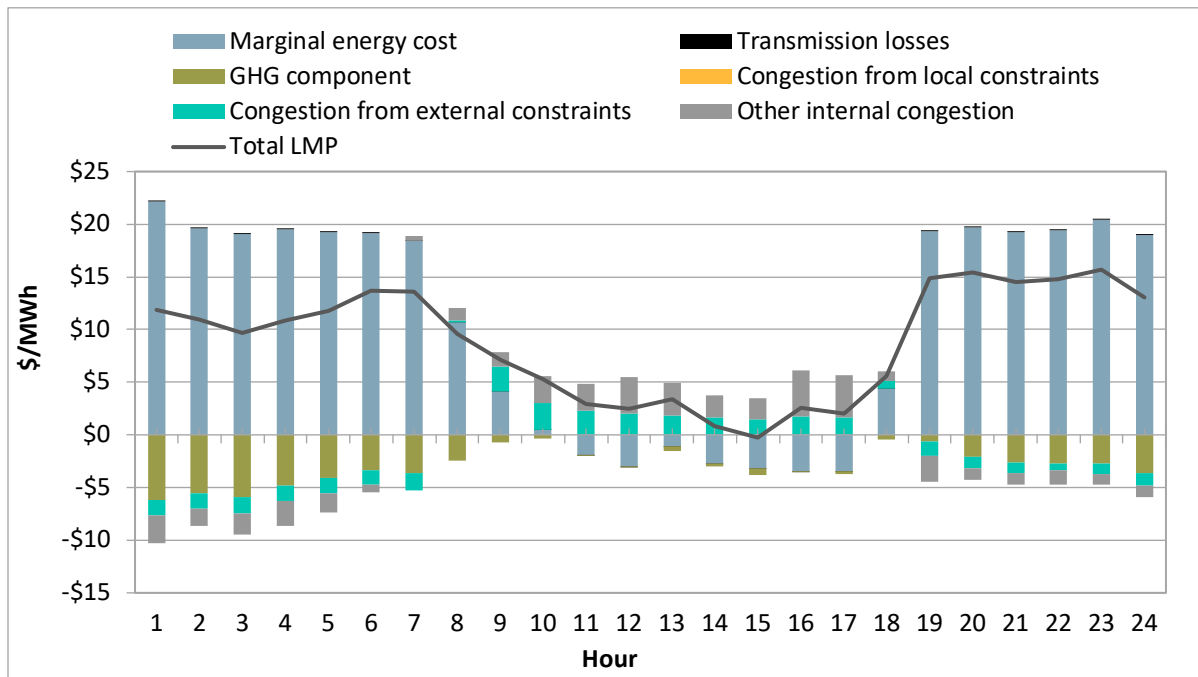
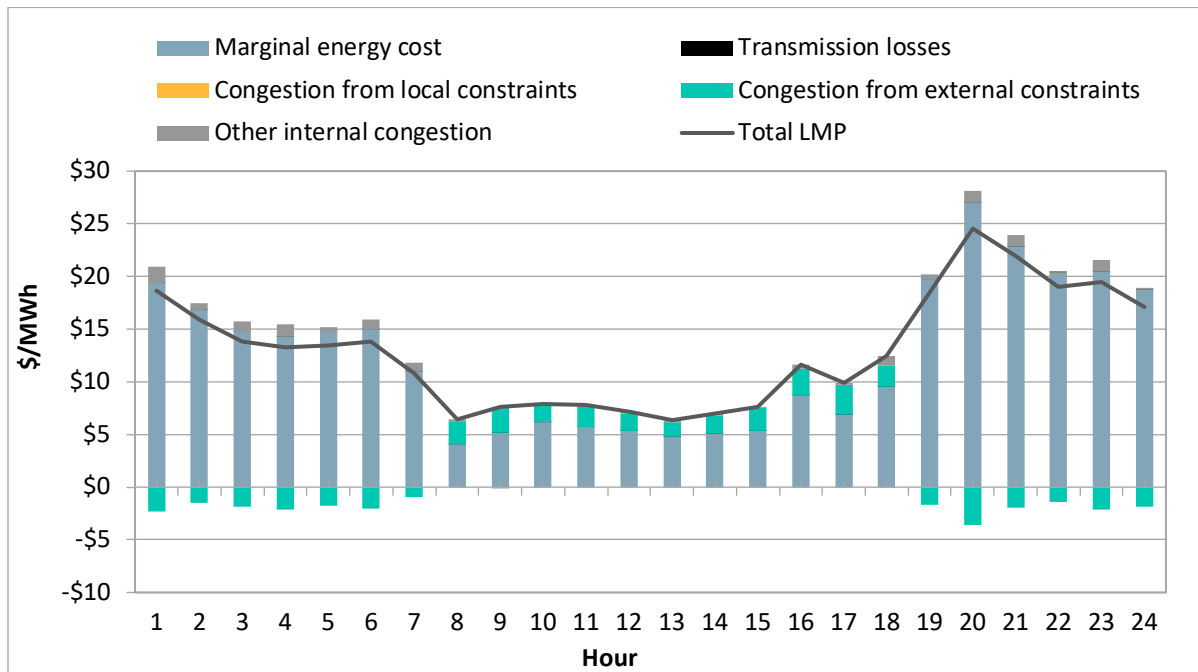
Appendix Figure A.128 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.129 Average hourly 5-minute price by component (May–June 2026)**

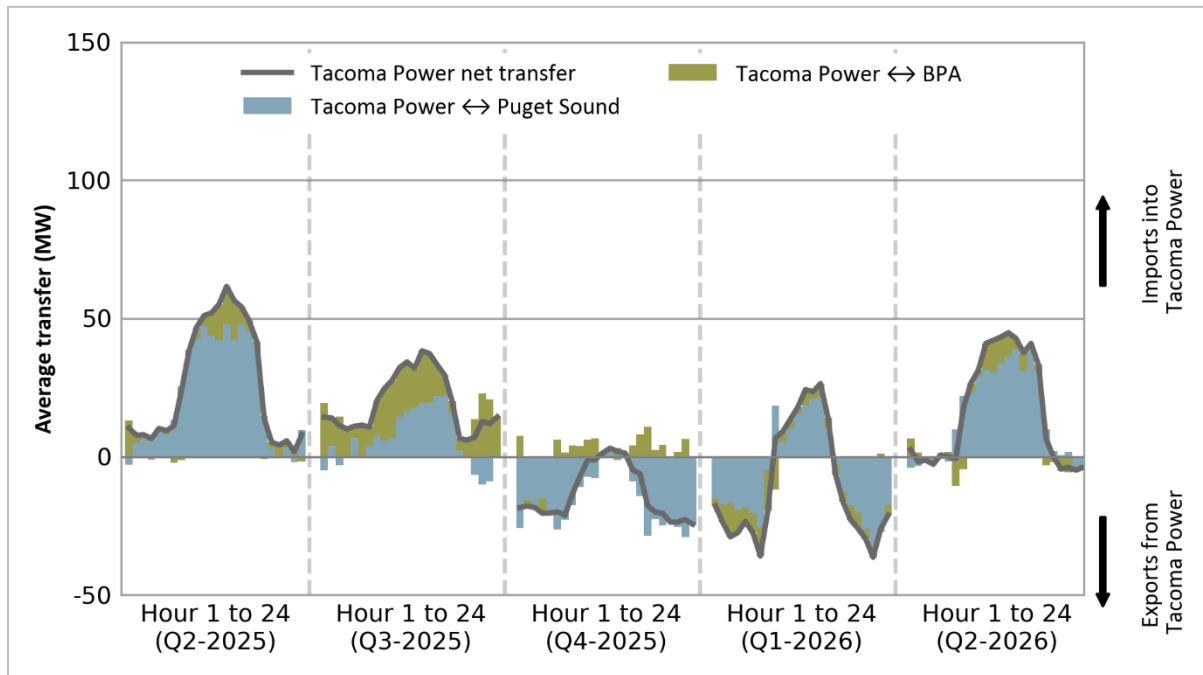
Appendix Figure A.130 Average hourly 5-minute market transfers

A.22 Tacoma Power

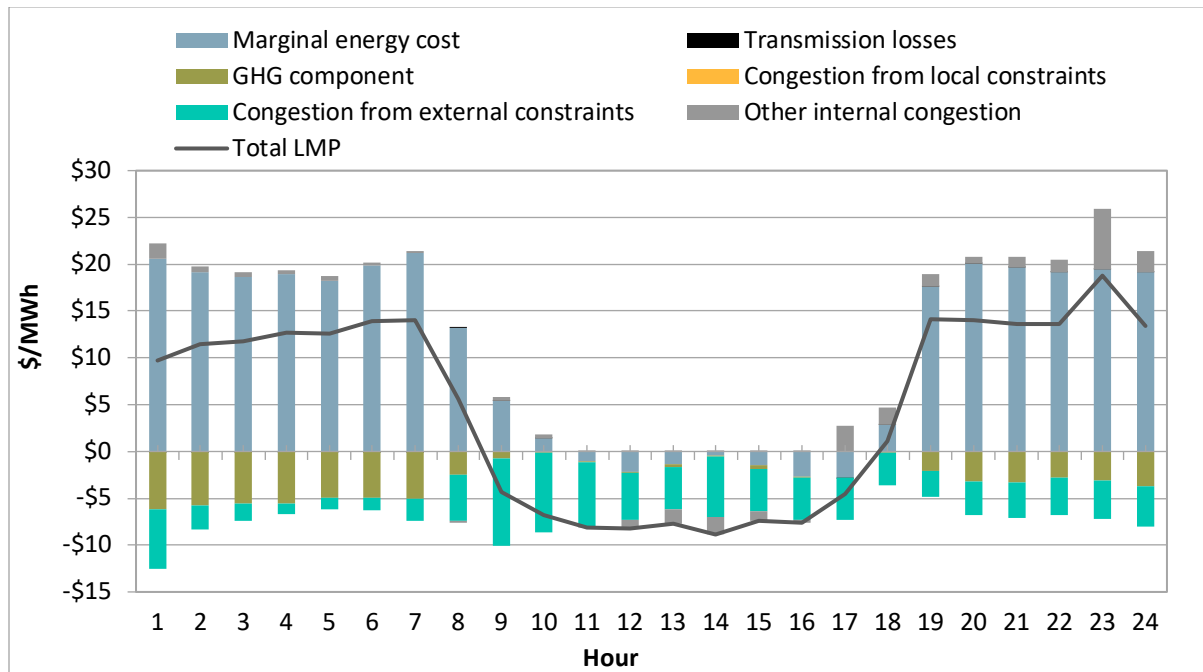
Appendix Figure A.131 Average hourly 15-minute price by component (April 2026)

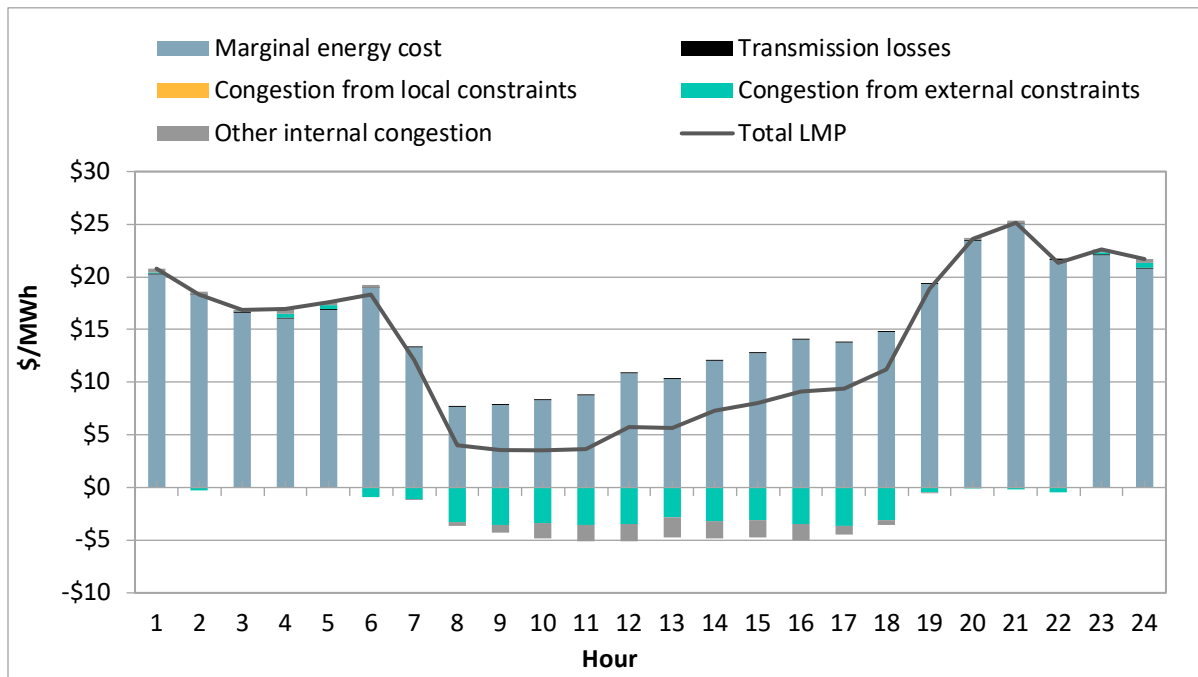
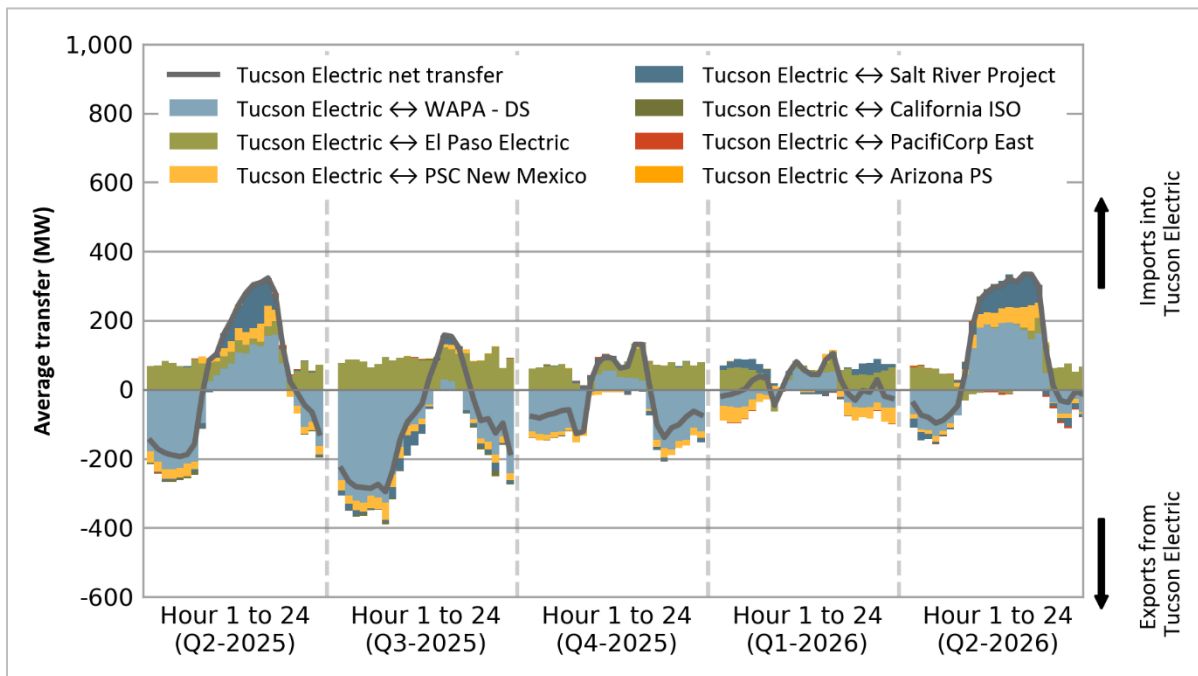
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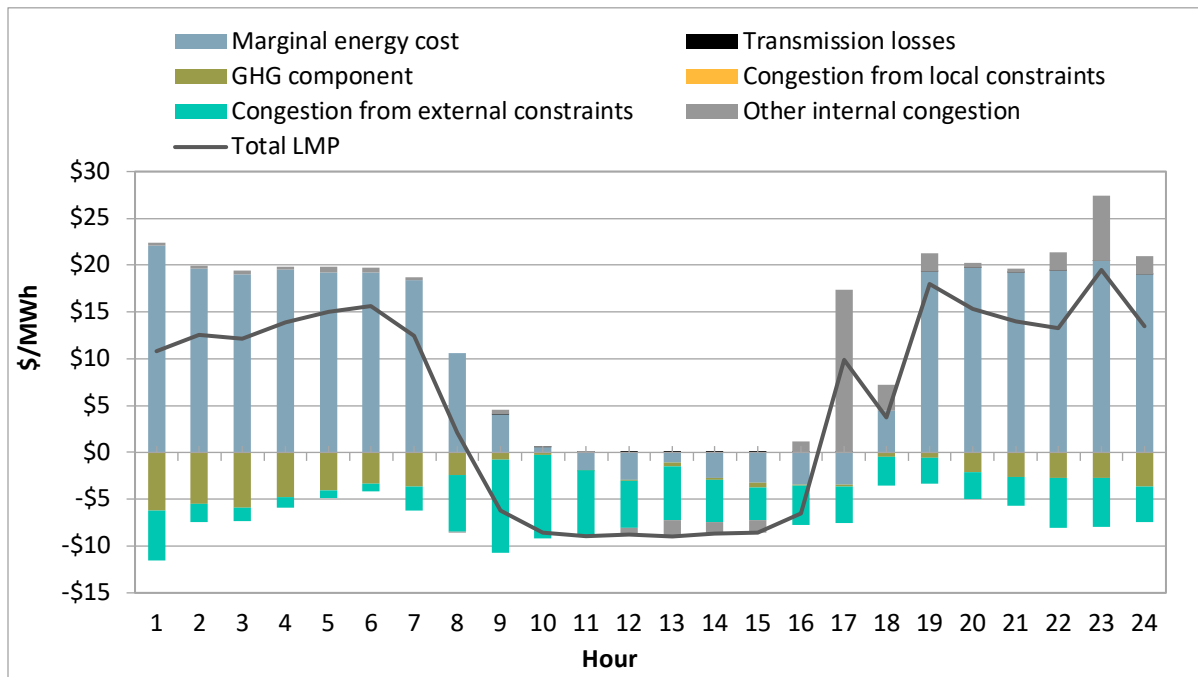
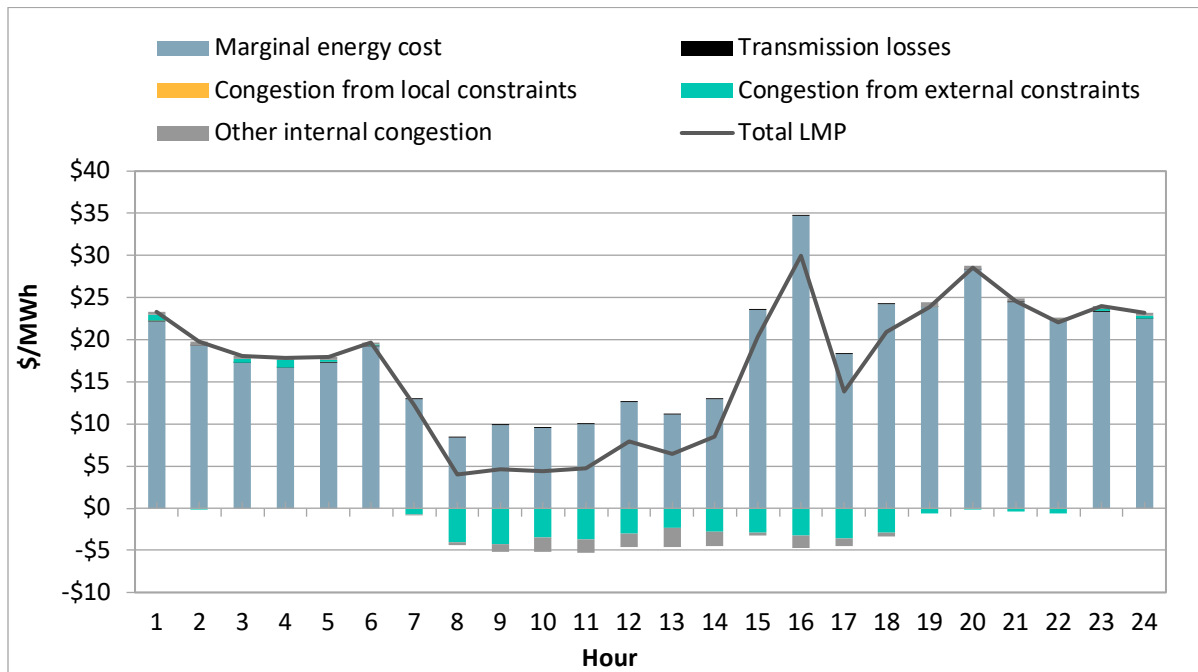
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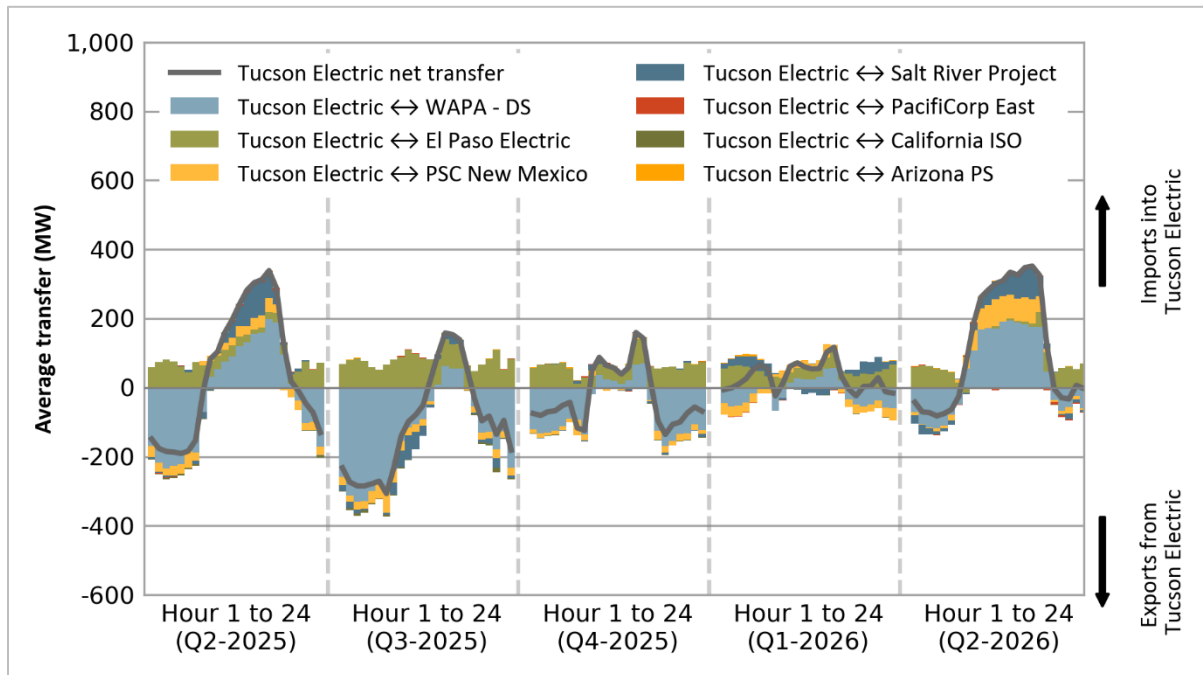
Appendix Figure A.136 Average hourly 5-minute market transfers

A.23 Tucson Electric Power

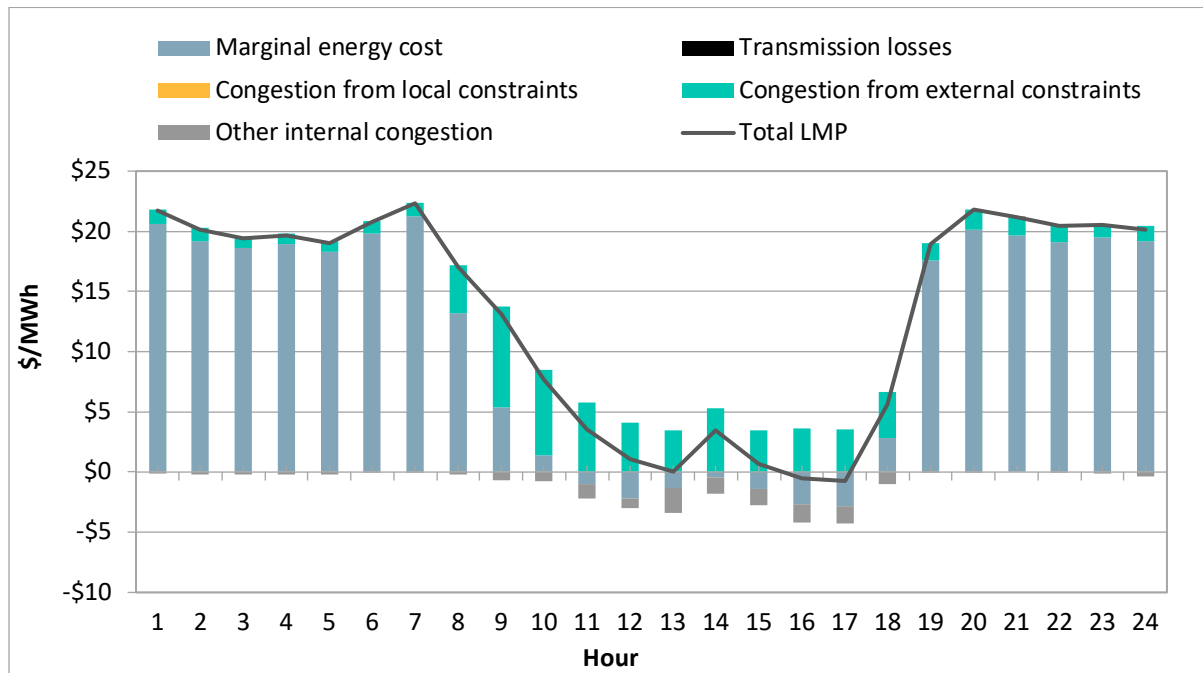
Appendix Figure A.137 Average hourly 15-minute price by component (April 2026)

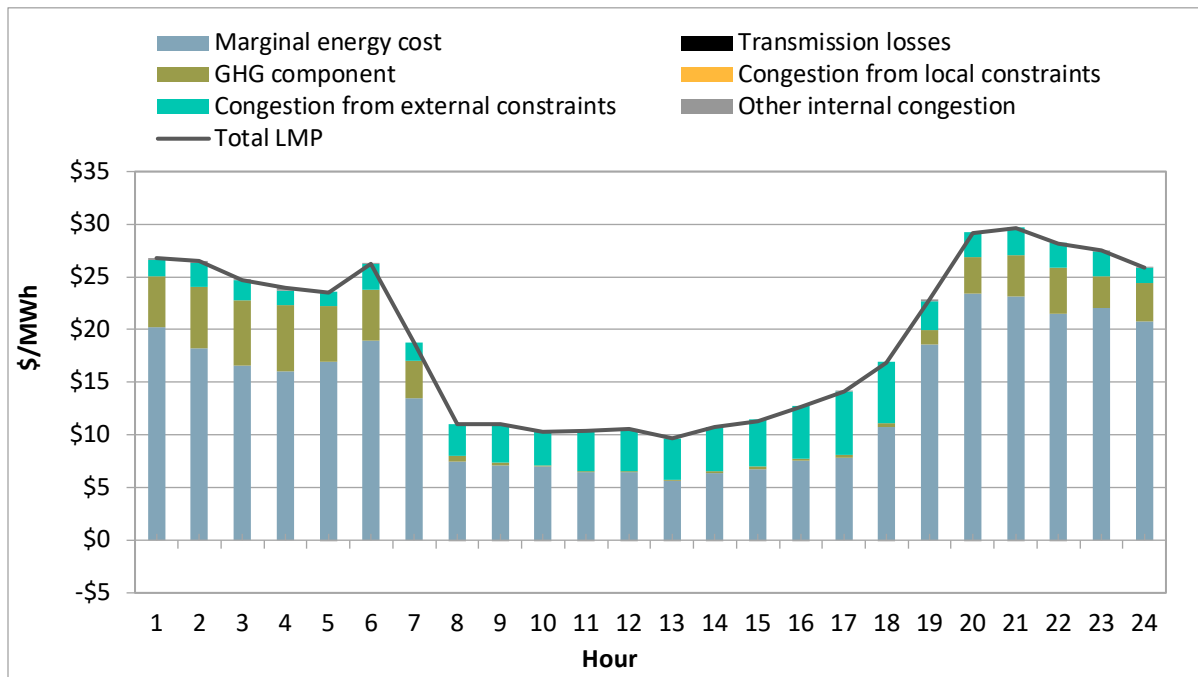
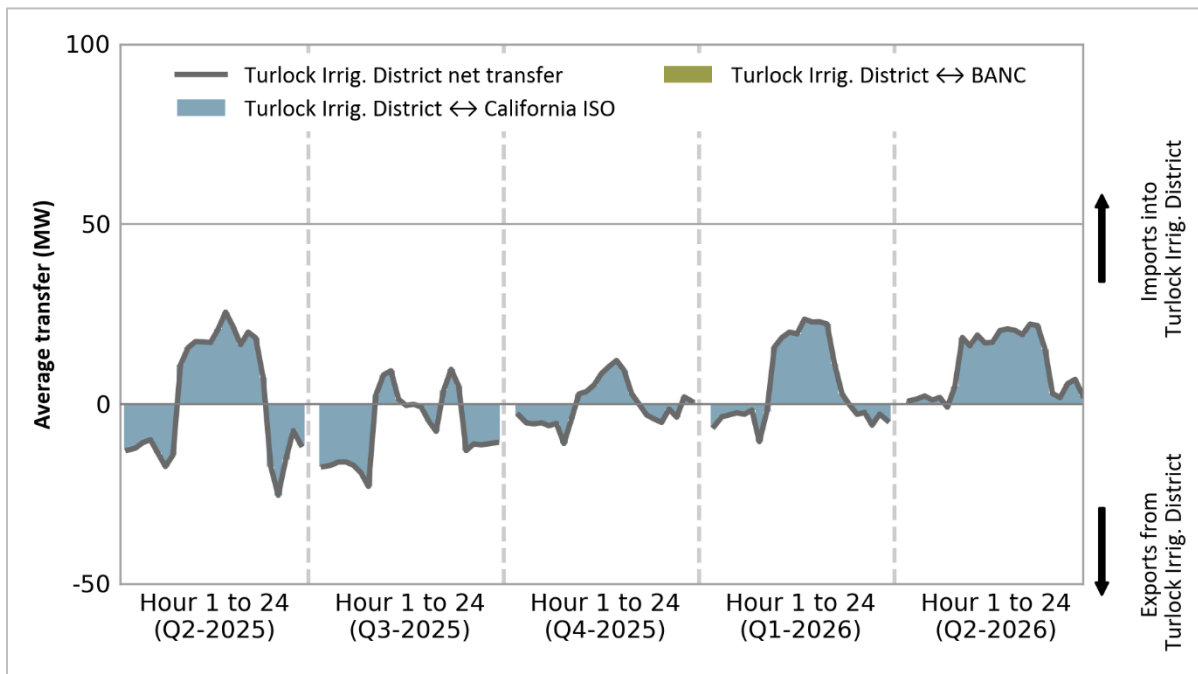
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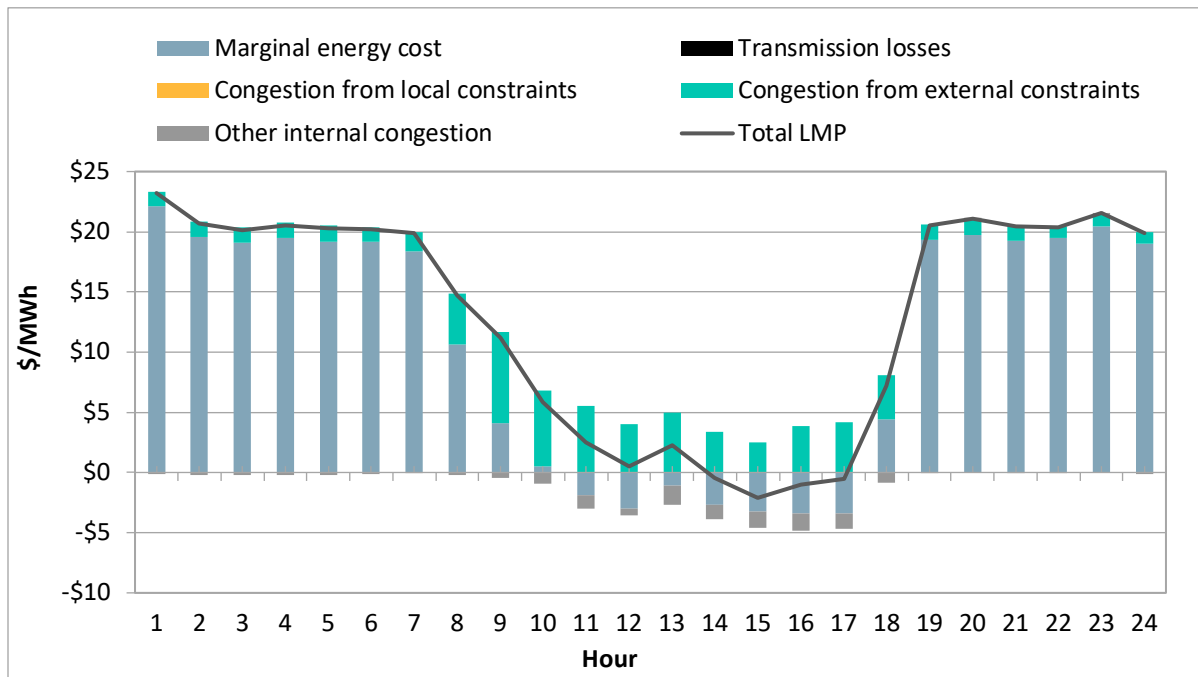
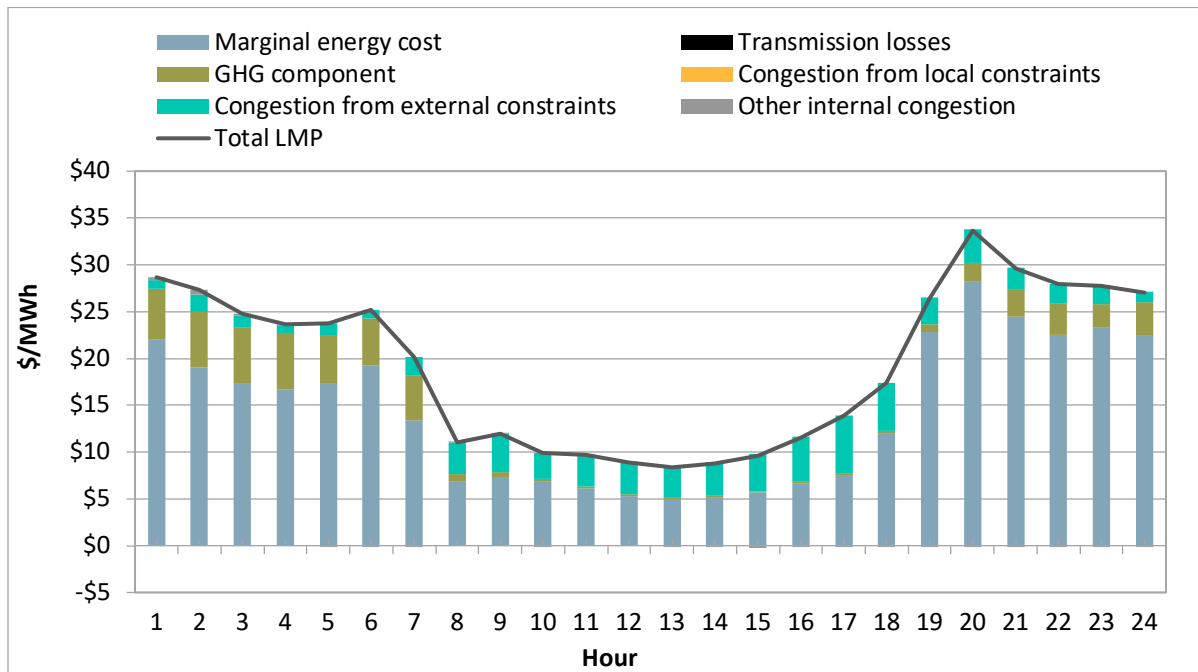
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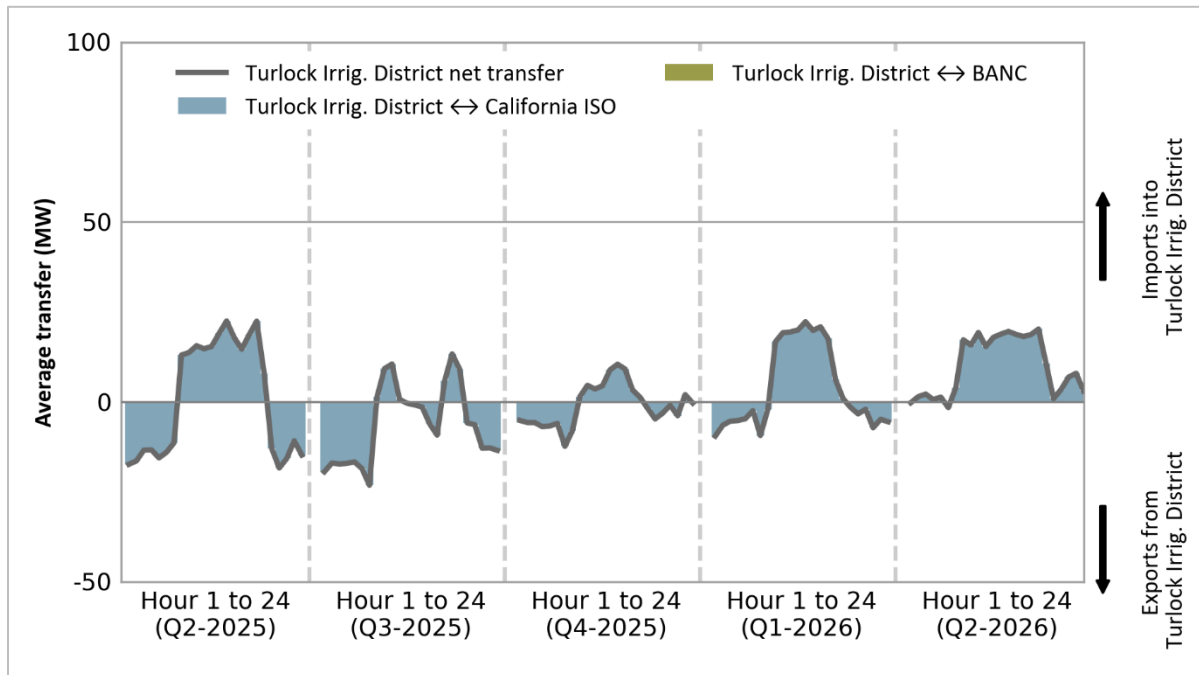
Appendix Figure A.142 Average hourly 5-minute market transfers

A.24 Turlock Irrigation District

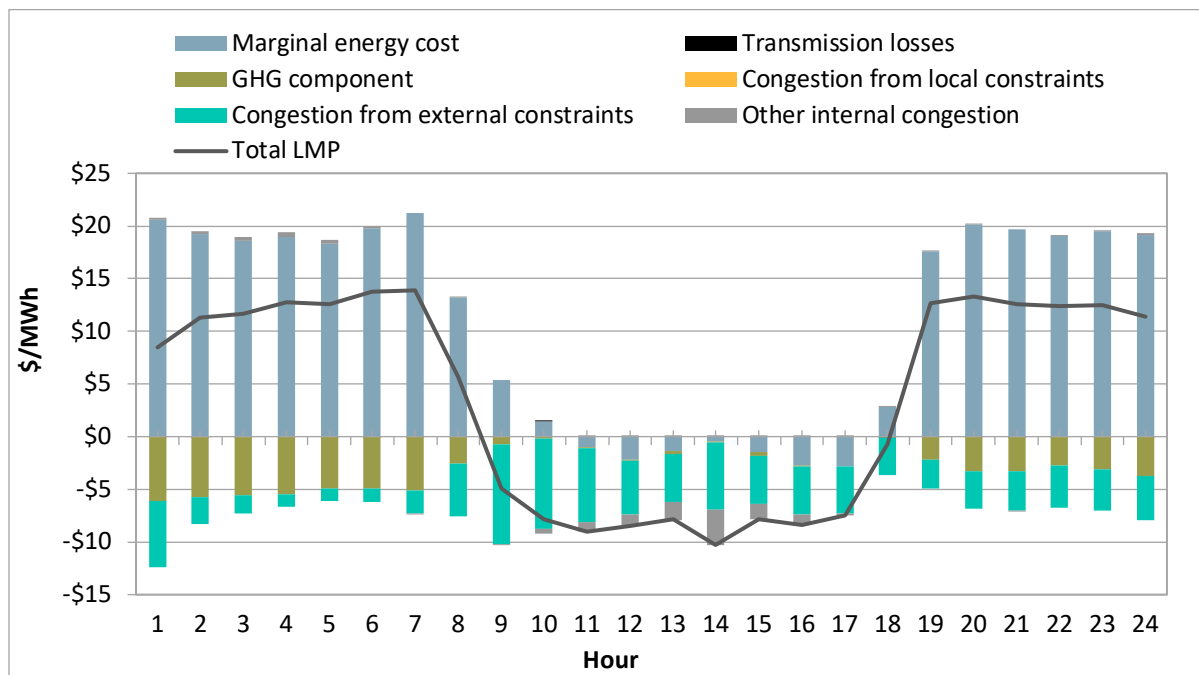
Appendix Figure A.143 Average hourly 15-minute price by component (April 2026)

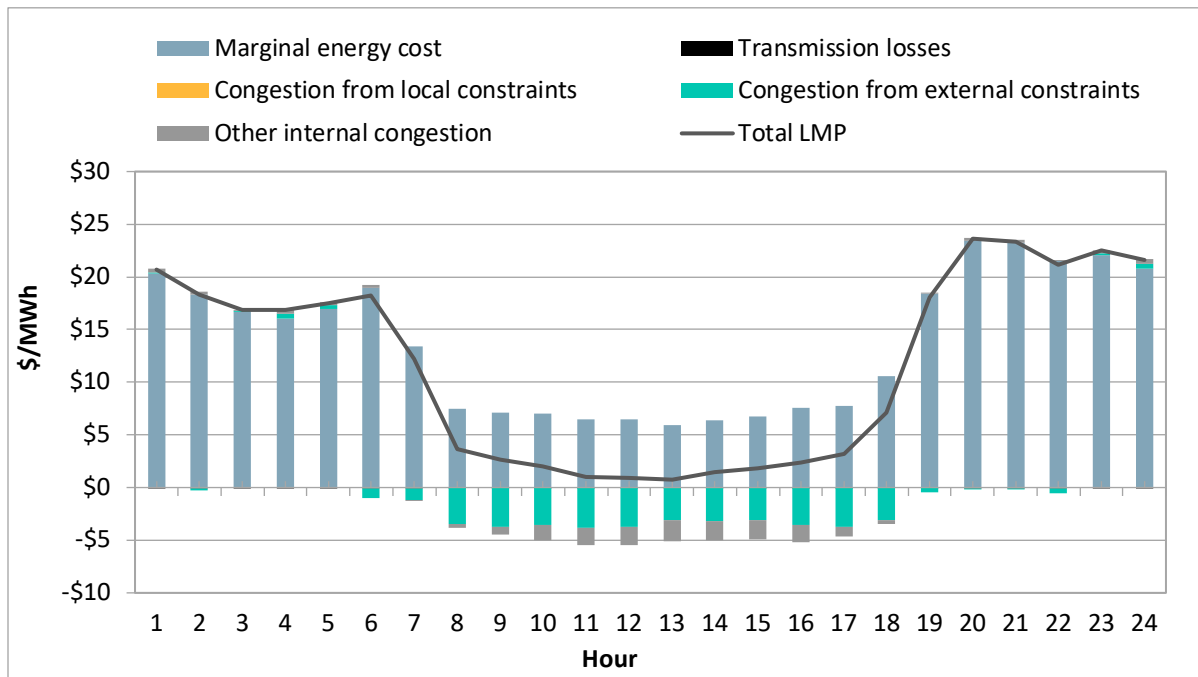
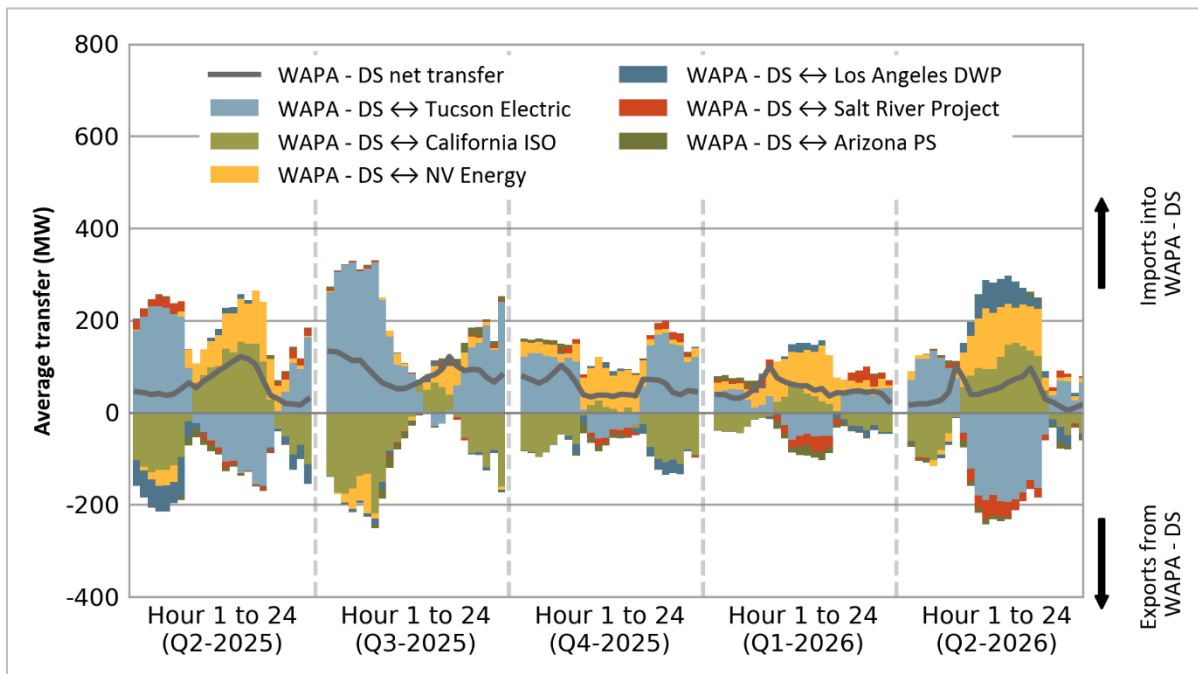
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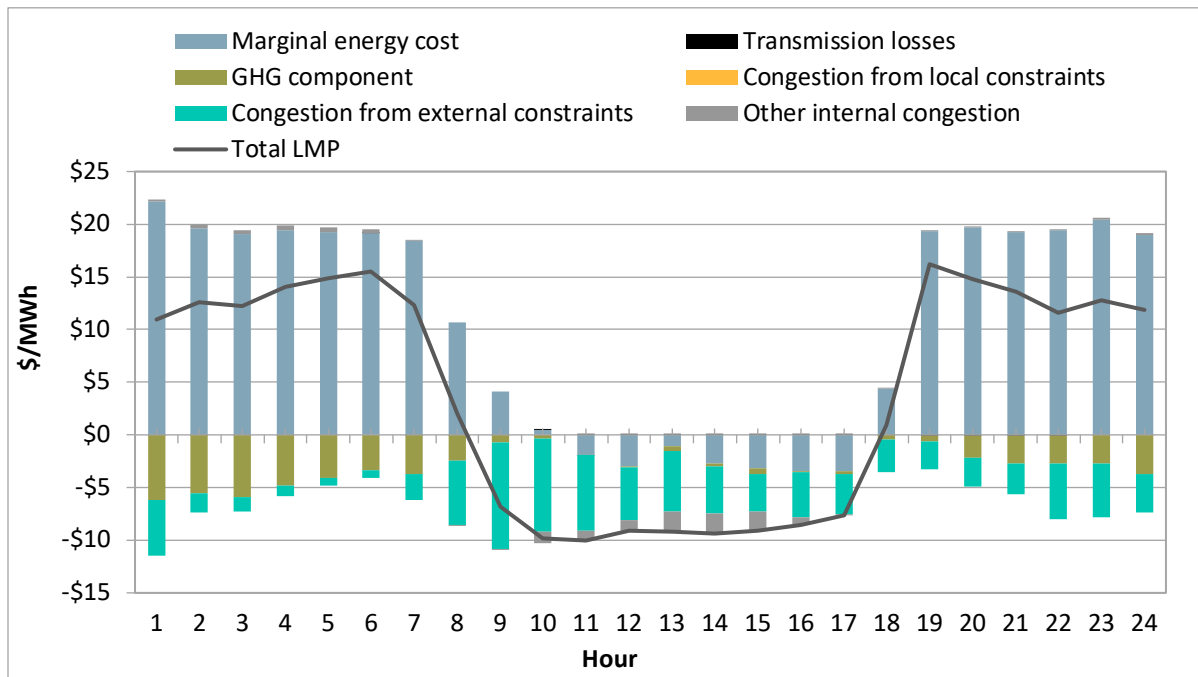
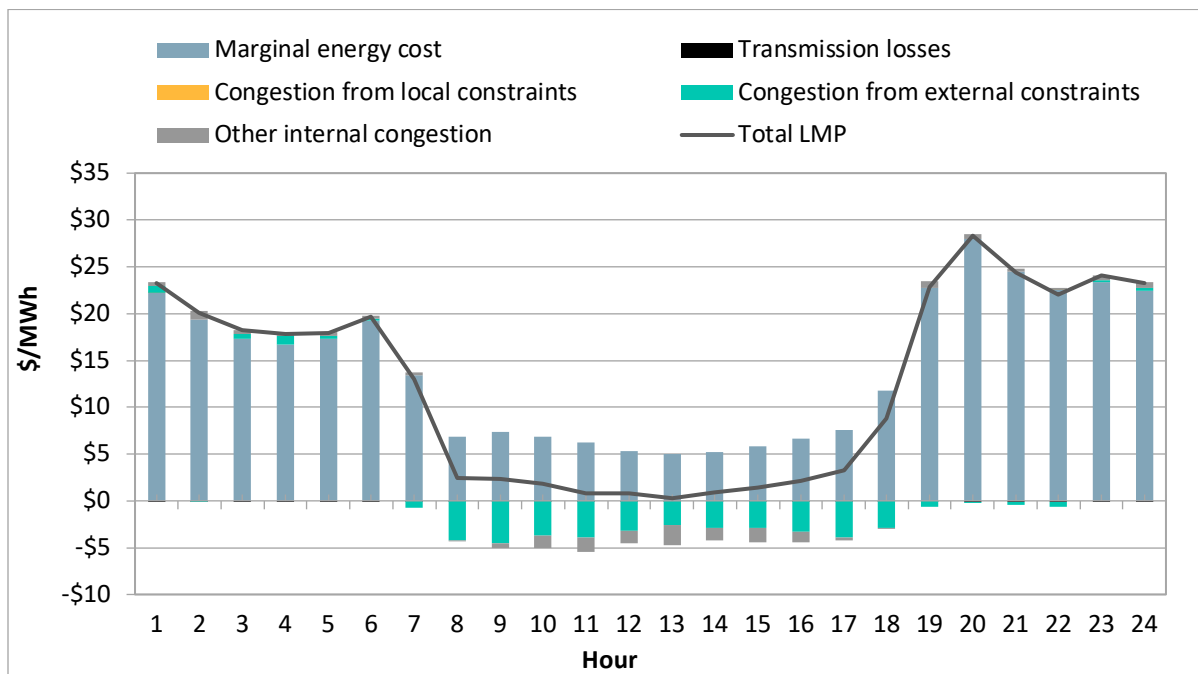
Appendix Figure A.146 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.147 Average hourly 5-minute price by component (May–June 2026)**

Appendix Figure A.148 Average hourly 5-minute market transfers

A.25 Western Area Power Administration Desert Southwest

Appendix Figure A.149 Average hourly 15-minute price by component (April 2026)

Appendix Figure A.150 Average hourly 15-minute price by component (May–June 2026)**Appendix Figure A.151 Average hourly 15-minute market transfers**

Appendix Figure A.152 Average hourly 5-minute price by component (April 2026)**Appendix Figure A.153 Average hourly 5-minute price by component (May–June 2026)**

Appendix Figure A.154 Average hourly 5-minute market transfers