Q3 2024 Report on Market Issues and Performance

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California Independent System Operator

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Executive summary

This report covers market performance during the third quarter of 2024 (July–September). Key highlights during this quarter include the following:

- **Prices decreased substantially compared to the same quarter of 2023** (Figure E.1). Prices in the 15-minute market across the Western Energy Imbalance Market (WEIM) averaged about $40/MWh, down 31 percent due mainly to lower natural gas prices. Prices in the 5-minute market were down 32 percent and day-ahead market prices were down 28 percent compared to Q3 2023.
- **Natural gas prices in the West were significantly lower.** Average gas prices at Henry Hub, the national index, decreased by about 19 percent from the same quarter of 2023. Prices at PG&E Citygate and SoCal Citygate decreased 37 percent and 58 percent, respectively, while prices at Northwest Sumas were down 60 percent and prices at El Paso Permian decreased 104 percent compared to Q3 2023. This was the major driver of lower electricity prices across western markets.
- **Average hourly generation from renewable resources in the WEIM footprint increased by about 4,110 MW** (11 percent) compared to the third quarter of 2023. Over 60 percent of this growth was from solar generation, which increased in every region.[1] Hydroelectric generation represented 83 percent of all renewable generation in the Pacific Northwest and increased by 1,940 MW (15 percent) compared to Q3 2023.
- **Coal generation in the Intermountain West region decreased by 1,220 MW (27 percent) compared to the third quarter of 2023**, while natural gas generation increased by 810 MW (28 percent). Average hourly net imports into the Pacific Northwest region, excluding WEIM transfers, decreased by around 1,380 MW, due to a large increase in hydro production. The Pacific Northwest was a net exporter on average in all hours. Average hourly battery discharge in the California and Desert Southwest regions increased relative to the third quarter of 2023 by 550 MW (87 percent) and 310 MW (130 percent), respectively.
- **Load across the WEIM increased 4 percent compared to the same quarter of 2023.** Q3 2024 had more hours with high system load (over 110 GW) and less hours with low system load (below 80 GW) than Q3 2023.
- **Average day-ahead peak energy prices at the Mid-Columbia and Palo Verde bilateral trading hubs were significantly higher than prices in the 15-minute market for WEIM areas in the Pacific Northwest and Desert Southwest, respectively.** Prices at major load locations in the ISO's day-ahead market tracked much more closely with their corresponding 15-minute market prices.
- **Analysis of system supply and demand curves for a 15-minute market interval of a peak hour during the September heat wave** shows the supply curve being relatively flat at that interval's cleared load level, but very steep at higher load levels. Substituting cost-based bids for submitted market bids would not have significantly reduced this interval's system clearing price, but cost-based bids were significantly lower than submitted bids on parts of the supply curve that would be needed at higher load levels.
- **WEIM transfers averaged 4,560 MW, down about 10 percent from the third quarter of 2023.** During mid-day solar hours, the majority of regional transfers were from the CAISO area to the

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

Pacific Northwest and non-CAISO California areas. During morning and evening hours, the Desert Southwest was the major exporting region.

- **California ISO balancing area operators did not implement peak hour dynamic WEIM transfer restrictions into the CAISO area during any hours of the third quarter of 2024.** Operators had restricted most Western Energy Imbalance Market (WEIM) transfers into the CAISO area in the hour-ahead and 15-minute markets during peak net load hours from July 26 through November 15, 2023.
- **Transmission congestion impact on regional prices continued to be different during mid-day solar hours than during evening peak net load hours.** During solar hours, congestion contributed to higher prices in the Pacific Northwest, Intermountain West, and Northern California relative to the Desert Southwest and Southern California. During peak evening hours, congestion was instead from the Pacific Northwest and Intermountain West, into Northern and Southern California and the Desert Southwest.
- **Overall day-ahead market congestion rents on internal and intertie constraints was $112 million,** down 43 percent from the third quarter of 2023**.**
- **Transmission ratepayers made over $2 million from the congestion revenue rights auction during the third quarter of 2024**, as payments to auctioned congestion revenue rights holders were lower than auction revenues. This was the first time ratepayers made money in the auction on a quarterly basis since Q3 2016. Gains were driven by load serving entities trading in the auction, which earned them over $14 million.
- **Almost all WEIM balancing areas passed each type of resource sufficiency evaluation test in more than 99 percent of intervals.** Public Service Company of New Mexico (PNM) failed the upward flexibility test in around 1 percent of intervals.
- **Ten balancing areas opted in to the assistance energy transfer program on at least one day during the quarter.** Seven of these balancing areas received additional WEIM transfers during a resource sufficiency evaluation failure as a result of the program. Failures while opted in to receiving assistance energy transfers were not highly coincident across balancing areas.
- **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]
- **Real-time imbalance offsets for balancing areas participating only in the WEIM real-time markets were a $28 million credit** to WEIM entities, compared to a $115 million credit in the third quarter of 2023. The congestion portion of this offset, which is largely congestion rent from WEIM transfer constraints, was a $31 million credit.
- **Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $78 million in uplift in the third quarter of 2024.** This was a decrease from $106 million in the same quarter of 2023. During the third quarter of 2024, real-time *congestion* imbalance offset costs made up $48 million of these costs while real-time imbalance *energy* offset costs made up $29 million.

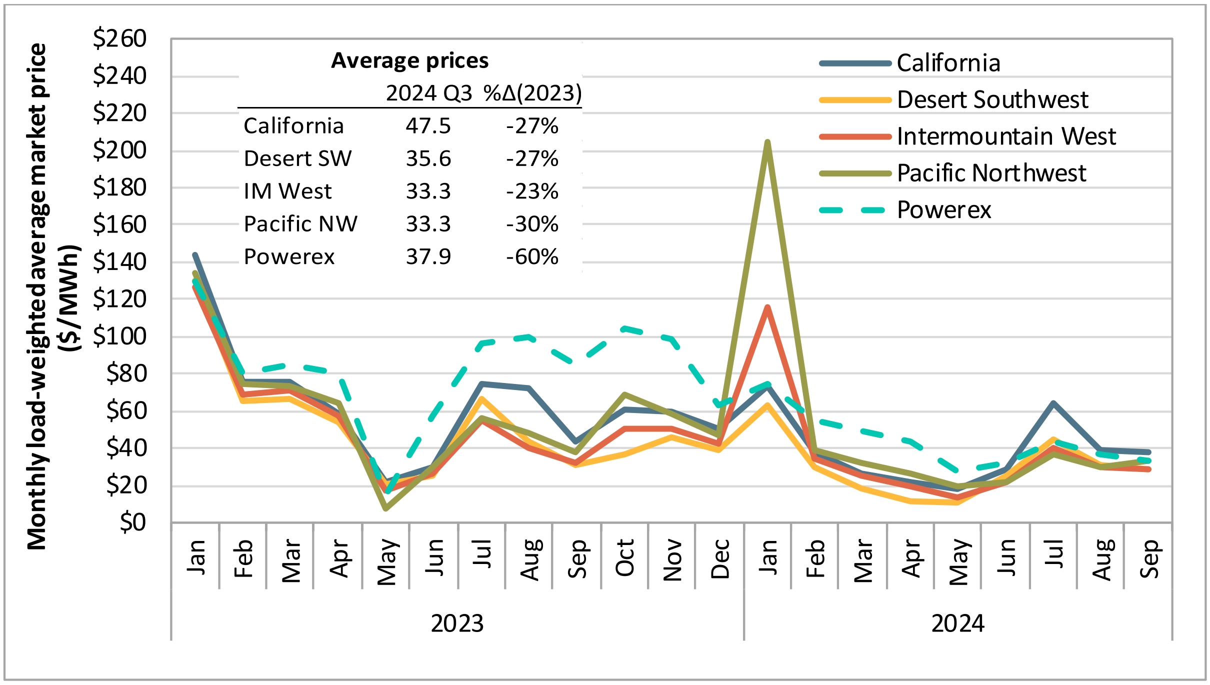
[2] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations#weim-resource

- **Bid cost recovery payments for units in balancing areas participating in both the day-ahead and real-time markets totaled about $28.5 million, down about 63 percent** from the $78.4 million in bid cost recovery in the third quarter of 2023. Bid cost recovery payments associated with the residual unit commitment market were about 82 percent, or $37.6 million, lower than in the third quarter of 2023.
- **Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM)** totaled about $4.1 million, down about 50 percent from Q3 2023.
- **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.
- **Upward flexible ramping product system level prices for the 15-minute market were non-zero in 1.7 percent of intervals in July.** System prices for the upward and downward product in the 15-minute and 5-minute markets were zero in more than 99.4 percent of intervals in all other months of the quarter. Battery and hydro resources made up 56 percent and 33 percent of upward flexible capacity, respectively. Wind and solar combined to provide 40 percent of downward flexible capacity. The CAISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 60 percent of each. Balancing areas in the Pacific Northwest made up 28 percent of upward flexible capacity and 15 percent of downward flexible capacity.
- **Mosaic quantile regression uncertainty requirements for the flexible ramping product and resource sufficiency evaluation were on average lower than requirements would have been using the previous histogram method.** For flexible ramping products, the coverage rate was 95 percent or higher, but the regression coefficients were statistically different from zero in only 32 percent of intervals. The coverage rate for the resource sufficiency evaluation varied across balancing areas between 75 percent and 91 percent, and only 41 percent of regression coefficients were statistically significant.
- **The ISO set the uncertainty adjustment to the residual unit commitment load forecast to cover the 97.5th percentile of net load uncertainty on only 15 percent of days in the quarter.** On all other days, the largest hourly load adjustment was set to cover only the 75th or 50th percentile of uncertainty. Average requirements using the 97.5th percentile target were roughly double those using the 75th percentile target. The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty, but the requirement will be set to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in which the ISO used the 97.5th percentile target in RUC indicates that the imbalance reserve product demand curve may be much too high during most hours.
- **The ISO adjusted the mosaic quantile regression method on August 14 to use observations from the past 90 days of this year and the next 90 days from the prior year**, rather than using the past 180 days of this year. In DMM's replications of the old and new sampling methods, requirements and coverage rates were down slightly, while rates of statistically significant regression coefficients were up about 5 percent.
- **The ISO made enhancements that significantly reduced the percent of intervals in which the mosaic quantile regression method for estimating the flexible ramping product uncertainty requirements used the wrong set of balancing areas to determine the regression coefficients.** The balancing area inconsistency fell to 6 percent of intervals, down from 18 percent of intervals in 2024 prior to the enhancements.
- **The regression model's predicted uncertainty for the resource sufficiency evaluation covered the realized uncertainty much less for intervals at the end of the hour than for intervals at the**

beginning of the hour. This is because the model is designed to predict uncertainty in forecasts that are produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, produced between 47.5 and 102.5 minutes before real-time.

- **In June, the ISO implemented its new policy to issue high priority wheeling-through rights based on its estimation of CAISO area transmission capacity available for these wheels.** In the third quarter, participants reserved most priority wheel-through capacity on the NOB and Round Mountain interties each month. Malin had the third largest quantity of reservations in July and August, but had none in September.
- **The CAISO balancing area underestimated native load needs on interties that had priority wheel-through reservations in the third quarter.** In reservation windows prior to final resource adequacy showings, the CAISO area underestimated native load needs for these interties by about 677 MW (or 19 percent) in July, 190 MW (6 percent) in August, and 144 MW (5 percent) in September. The CAISO area did not underestimate native load needs for all interties, but did in aggregate. This underestimation for the NOB intertie resulted in the sum of priority wheel through contracts and native load needs slightly exceeding available transmission capacity on NOB in September.
- **Resource adequacy bids from imports into the CAISO area increased 28 percent** compared to the third quarter of 2023.
- **The average total volume of capacity procured through the residual unit commitment (RUC) process in the third quarter of 2024 was 54 percent lower than the same quarter of 2023.** Operator adjustments to the RUC procurement target decreased by about 64 percent for the same period. This was in large part because of a change in the methodology for determining the adjustments on May 7, 2024.
- **Ancillary service payments in the CAISO balancing area totaled $49.9 million, a 20 percent decrease from the same quarter last year.**
- **Forced outages in the CAISO balancing area increased by 20 percent when compared to the same quarter last year**. The year-over-year increase in forced outages is consistent with a general trend of higher forced outages seen in the first and second quarters of 2024. The increase in forced outages is largely explained by the implementation of the Strategic Reliability Reserve (SRR) program, which uses outages to prevent the dispatching of SRR participating resources outside of dispatch instructions issued in the context of the SRR program.
- **Out-of-sequence exceptional dispatch energy due to ramping capacity in the CAISO balancing area decreased by 90 percent compared to the third quarter of 2023.** This decrease is largely due to the implementation of specific exceptional dispatch instructions for Long Start Strategic Reliability Reserve (LS-SRR) resources in 2024. With the use of specific LS-SRR dispatch instructions in 2024, these long-start gas units were only exceptionally dispatched during extreme conditions and system emergencies, rather than for non-transmission related ramping capacity.

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



1 Supply conditions

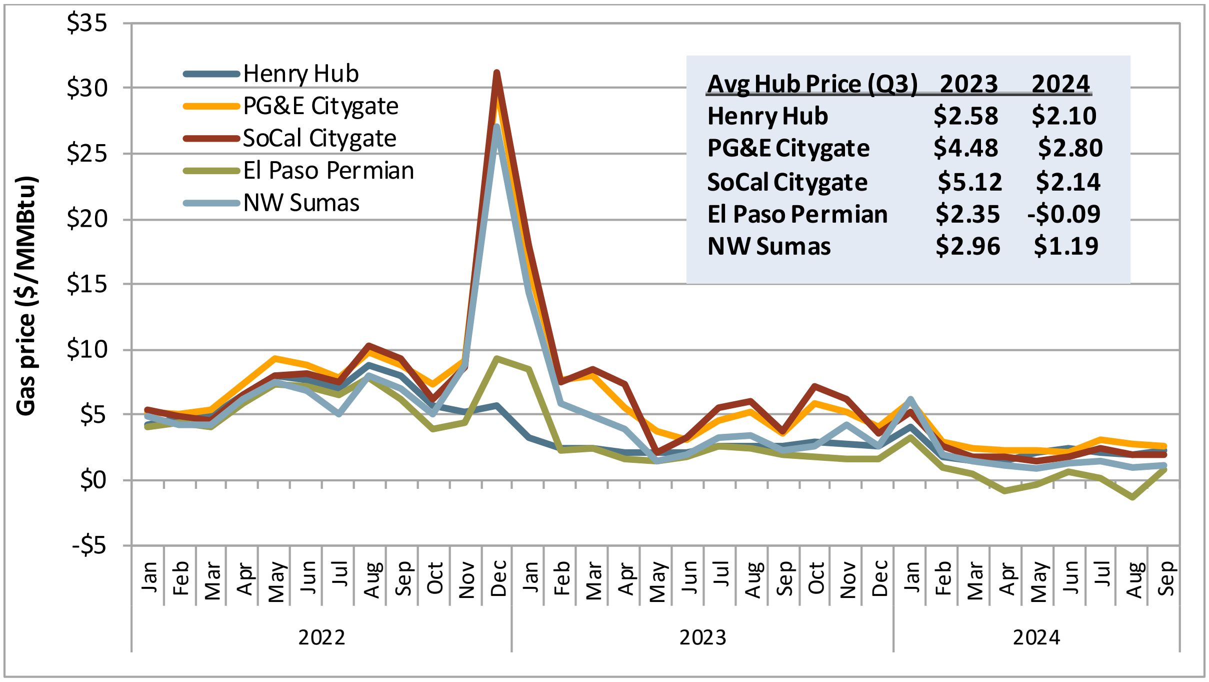
1.1 Natural gas prices

Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in Western Energy Imbalance Market (WEIM) balancing areas and other regional markets. Figure 1.1 shows monthly average natural gas prices at key delivery points across the West, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

Average natural gas prices at major Western U.S. trading hubs were down significantly in the third quarter of 2024 compared to the same quarter of 2023. Average third quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) decreased by 37 percent and 58 percent compared to the same quarter of the previous year, respectively. The Henry Hub, Northwest Sumas, and El Paso Permian gas prices decreased by 19 percent, 60 percent, and 104 percent, respectively, during the same time period.

Compared to the second quarter of 2024, natural gas prices at PG&E Citygate and SoCal Citygate increased by 27 percent and 26 percent, respectively. Henry Hub and Northwest Sumas prices increased by about 3 percent and 5 percent, respectively, compared to last quarter. Average natural gas prices at El Paso Permian were negative in August.

Figure 1.1 Monthly average natural gas prices



1.2 Renewable generation

In the third quarter, the average hourly generation from renewable resources in the WEIM footprint increased by about 4,110 MW (11 percent) compared to the same quarter of 2023.[3] Solar generation increased in every region.[4] The increase totaled 2,550 MW across the WEIM. The availability of variable energy resources, such as wind and solar resources, contributes to price patterns both seasonally and hourly due to their low marginal cost relative to other resources. Geothermal, biogas, and biomass resources provide a more constant and predictable availability, but represent a lower share of generation compared to the variable energy resources.

Figure 1.2 to Figure 1.5 show the average monthly renewable generation by fuel type.[5] Generation from solar resources made up 47 percent of all renewable output in the California region and increased by 1,220 MW (20 percent) compared to the third quarter of 2023. Solar generation represented 61 percent of the renewable fuel mix in the Desert Southwest region and increased by 1,040 MW (65 percent) from the third quarter of 2023. Overall, renewable generation in the Intermountain West region increased by 320 MW (8 percent) relative to the third quarter of 2023, with the largest increase coming from solar (230 MW). In the third quarter of 2024, hydroelectric generation represented 83 percent of all renewable generation in the Pacific Northwest and increased by 1,940 MW (15 percent) from the same

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

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

5 Hydroelectric generation greater than 30 MW is included.

quarter of the previous year. Wind generation in the WEIM footprint increased by 120 MW (2 percent) while geothermal and biogas-biomass generation decreased in all regions compared to the third quarter of 2023.

Figure 1.2 Average monthly renewable generation in the California region

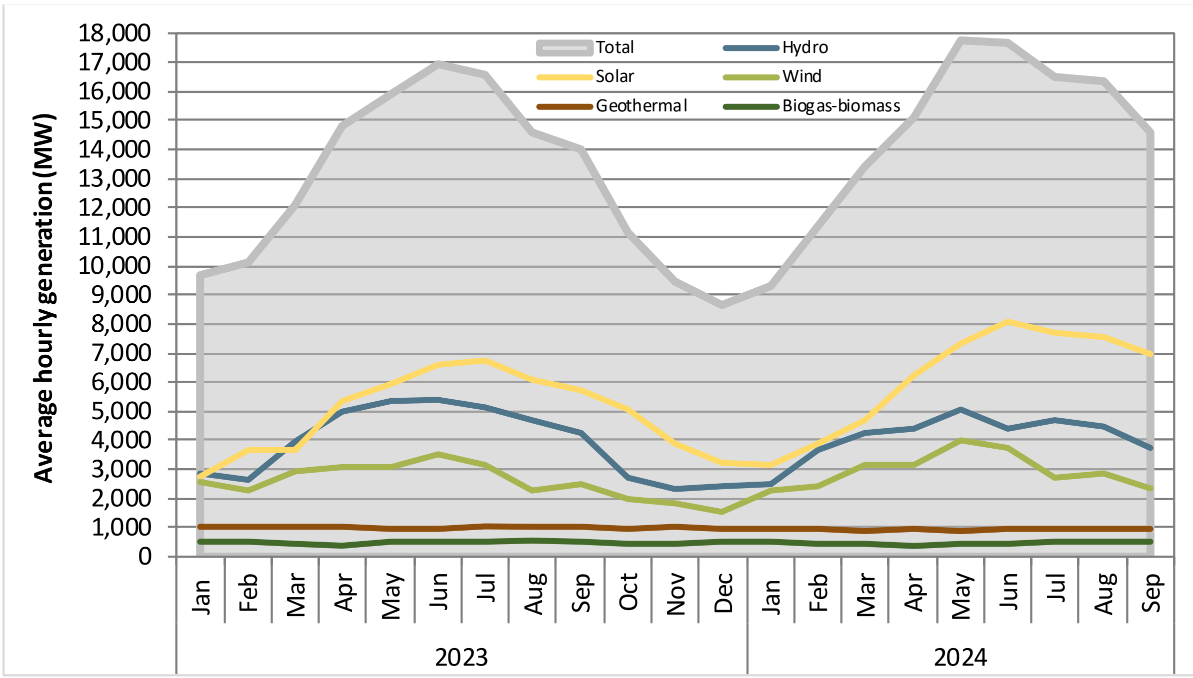


Figure 1.3 Average monthly renewable generation in the Desert Southwest region

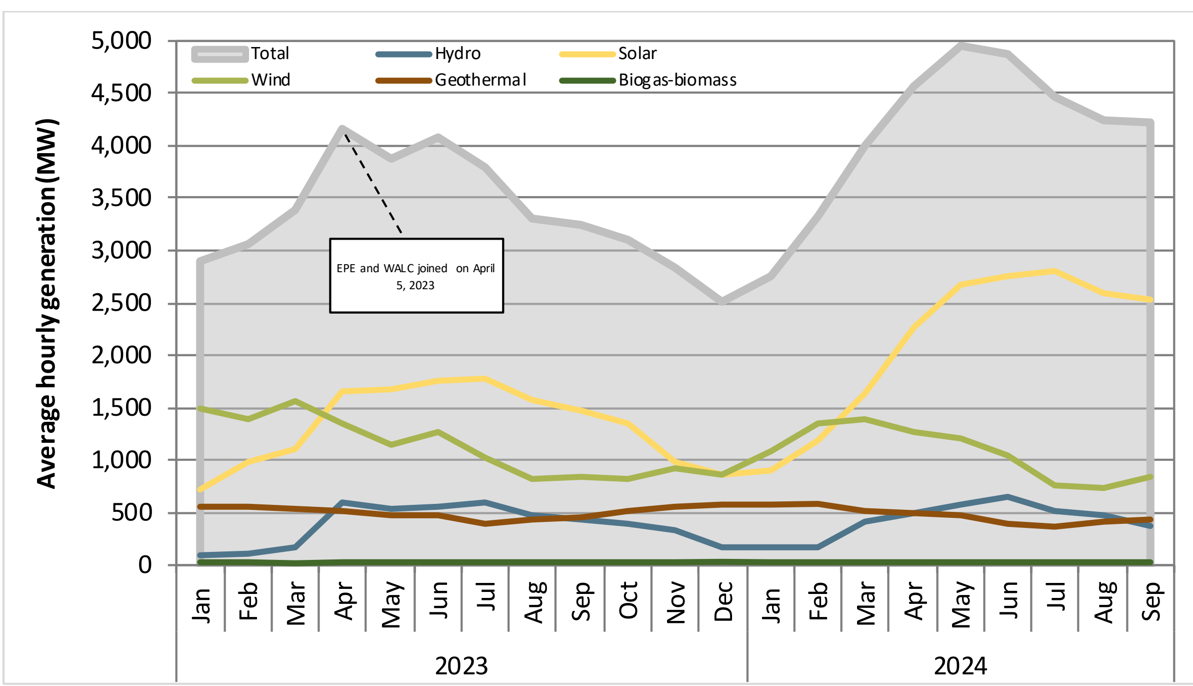


Figure 1.4 Average monthly renewable generation in the Intermountain West region

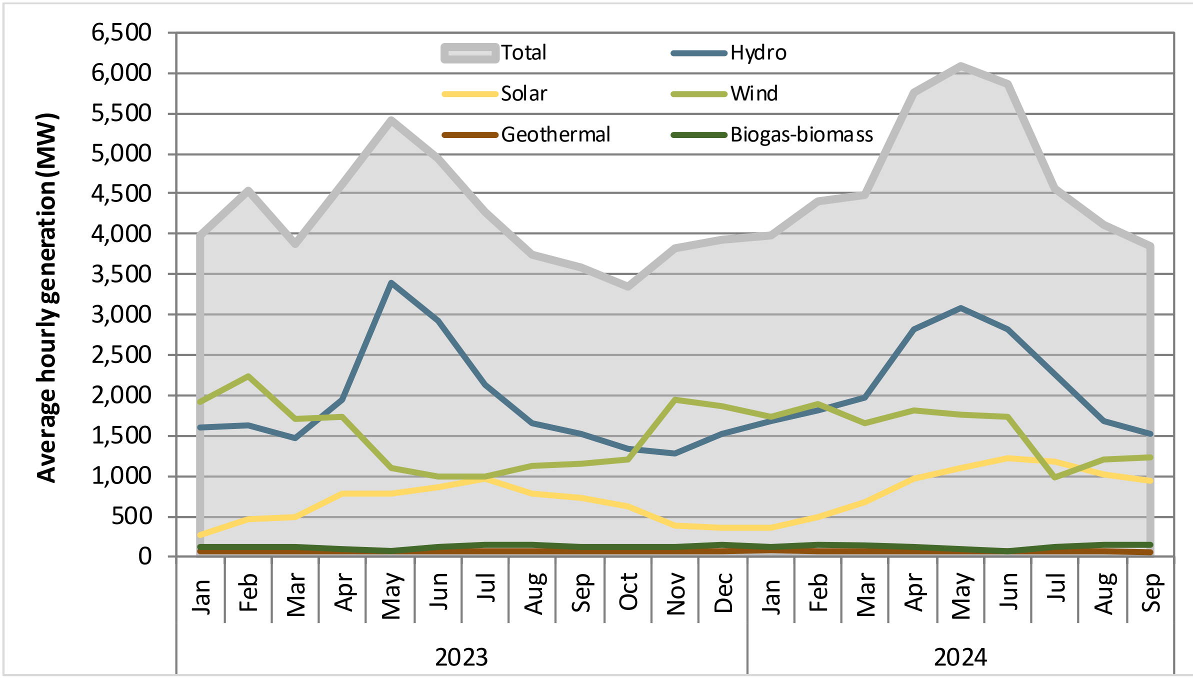
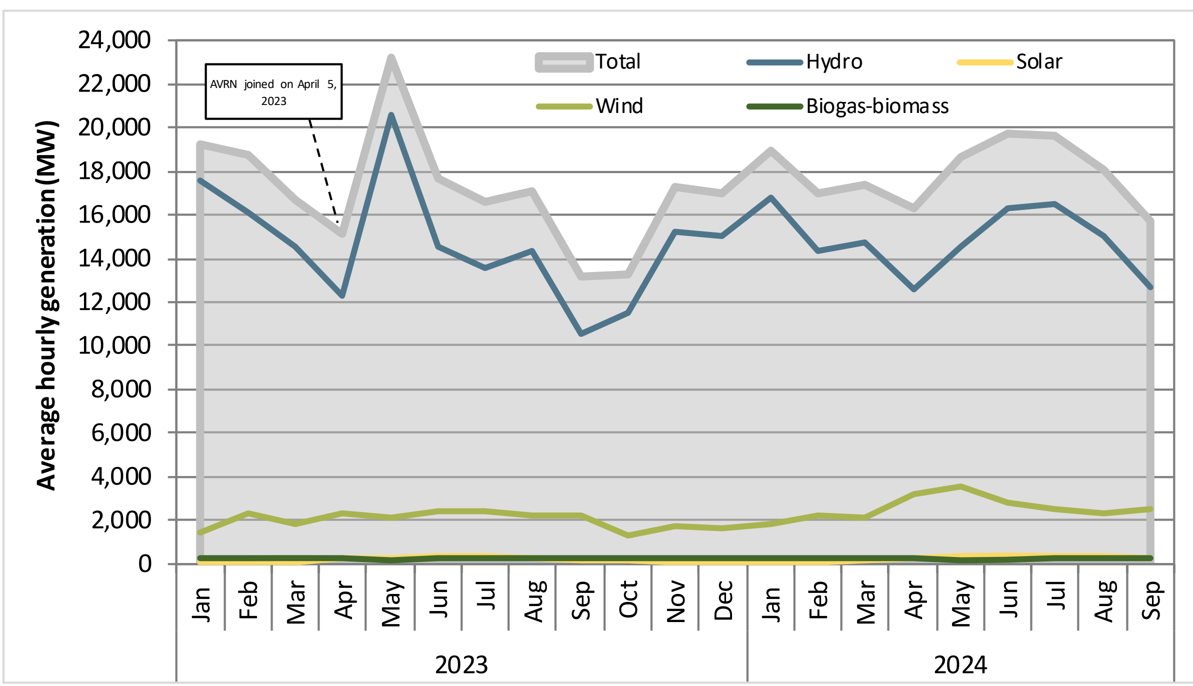


Figure 1.5 Average monthly renewable generation in the Pacific Northwest region

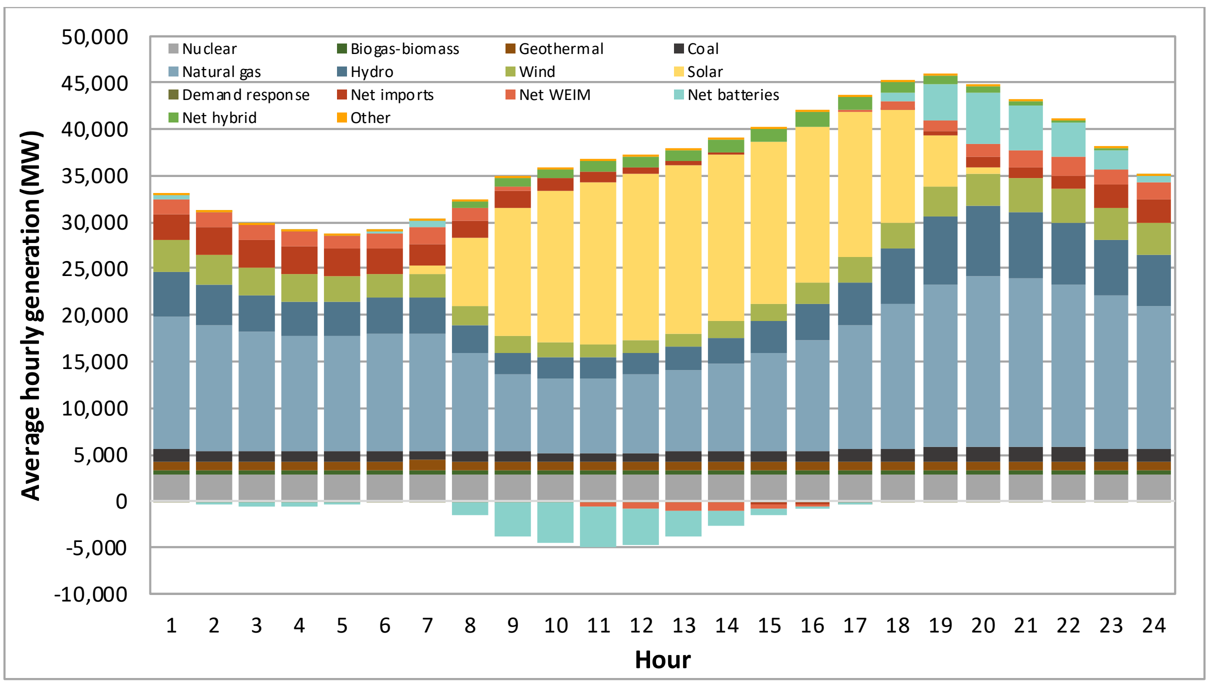


1.3 Generation by fuel type

Average hourly battery discharge in the California and Desert Southwest regions increased relative to the third quarter of 2023 by 550 MW (87 percent) and 310 MW (130 percent), respectively.[6] Coal generation in the Intermountain West region decreased by 1,220 MW (27 percent) while natural gas generation increased by 810 MW (28 percent). Average hourly net imports into the Pacific Northwest region, excluding WEIM transfers, decreased by around 1,380 MW. The Pacific Northwest was net exporting in all hours during the third quarter of 2024.

Figure 1.6 to Figure 1.9 show the average hourly generation by fuel type during the third quarter of 2024 for each region in the WEIM. The fuel mix of each region is distinct. Peak generation also varies by region. Total hourly average generation peaks at hour-ending 19 in the California and Pacific Northwest regions, while generation peaks at hour-ending 18 for the Intermountain West and Desert Southwest regions. Note that these figures also show net battery generation across all hours. During the mid-day hours, there is significant load from batteries charging, represented by the net negative points below the zero-axis. On average, net battery generation for the third quarter for 2024 was lowest during hour-ending 10, at around negative 5,700 MW. These figures also show dispatchable demand response resources represented as negative generation below the zero-axis.

Figure 1.6 Average hourly generation by fuel type in the California region (Q3 2024)



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

Figure 1.7 Average hourly generation by fuel type in the Desert Southwest region (Q3 2024)

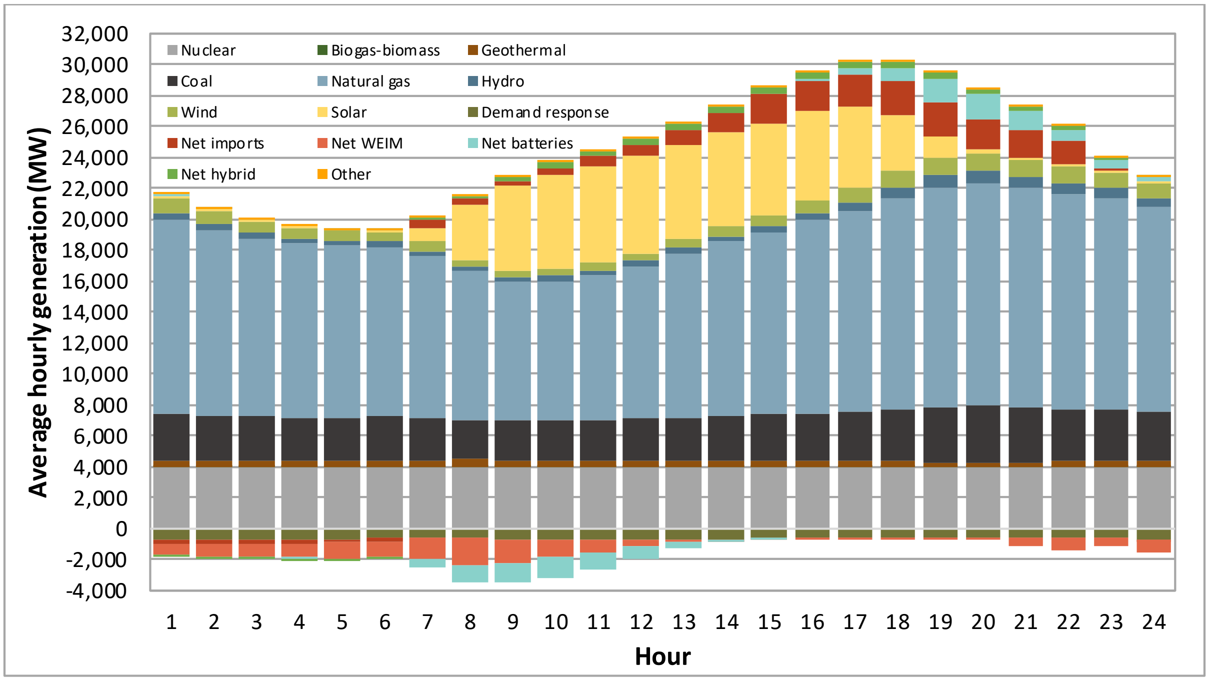


Figure 1.8 Average hourly generation by fuel type in the Intermountain West region (Q3 2024)

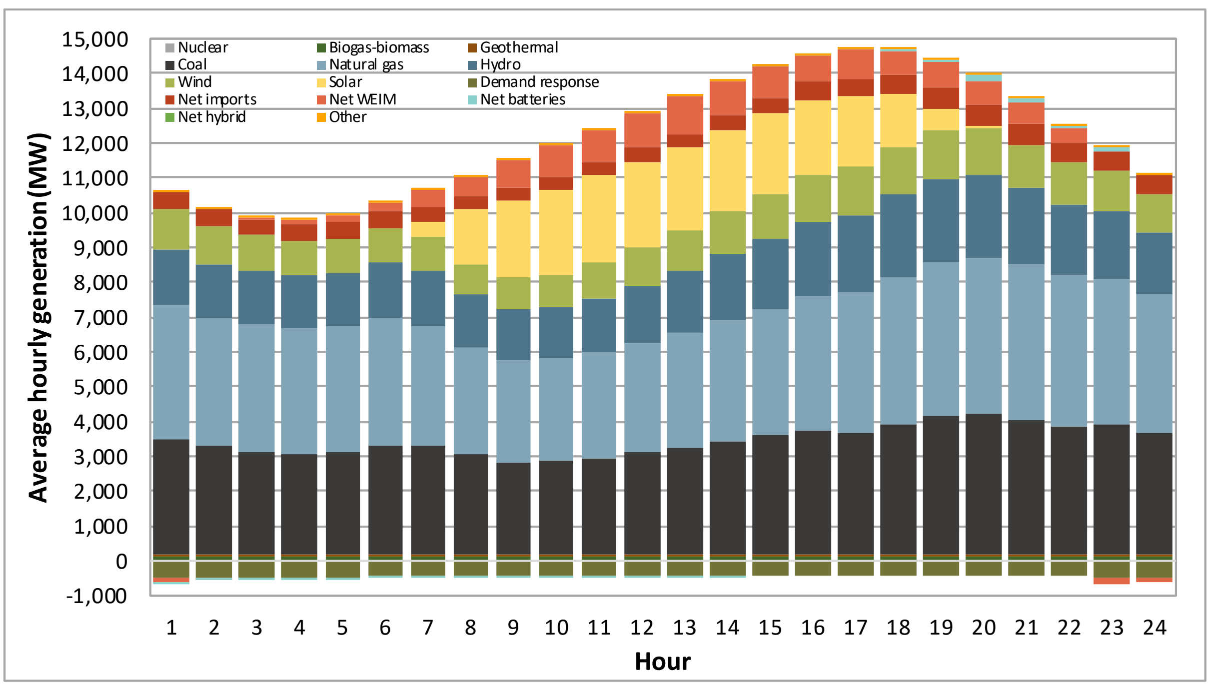


Figure 1.9 Average hourly generation by fuel type in the Pacific Northwest region (Q3 2024)

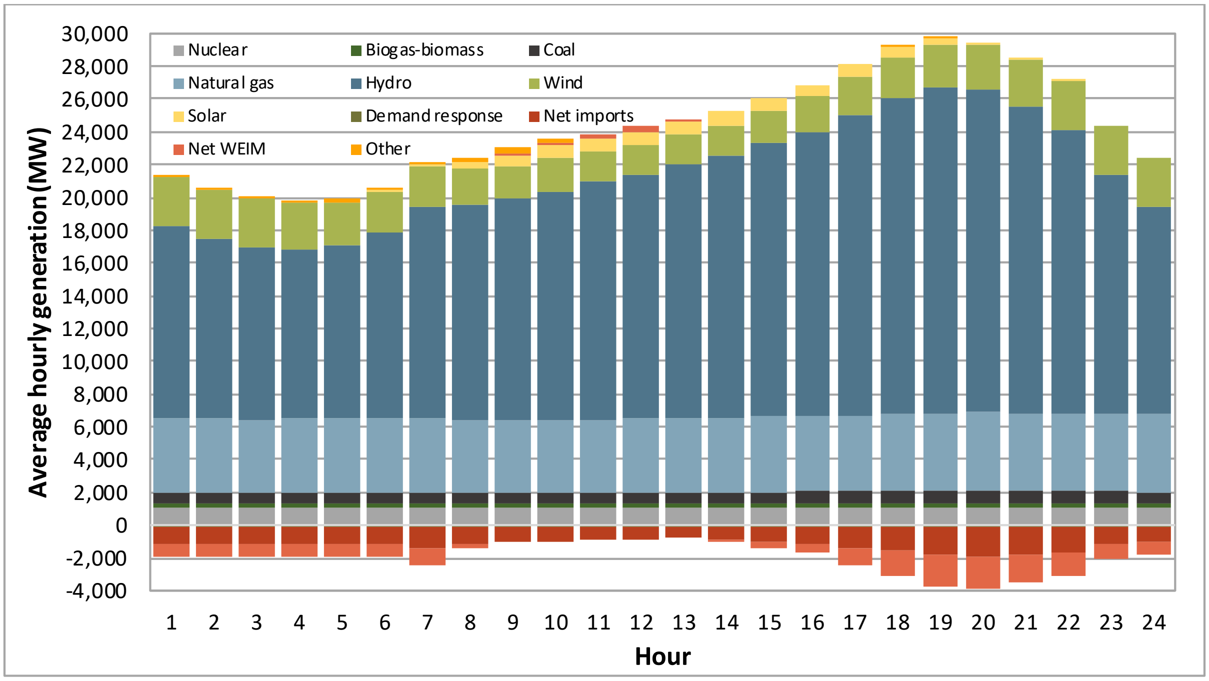


Figure 1.10 to Figure 1.13 show the change in hourly generation by fuel type between the third quarters of 2023 and 2024.[7] In the chart, positive values represent increased generation relative to the same time last year, and negative values represent a decrease in generation. Change in total load is denoted by the black line. Natural gas generation increased in the Desert Southwest and Intermountain West regions. In the Intermountain West, this can be attributed to coal-to-gas conversions of existing capacity. Batteries have been increasingly participating in energy arbitrage by charging during the high solar hours mid-day, and discharging during the high net-load periods in the evening. Increased mid-day battery charging was met largely by greater solar and hybrid production in the California and Desert Southwest regions. In the Pacific Northwest, increased hydro production led to significant decreases in net imports across all hours.

Figure 1.10 Change in average hourly generation by fuel type in the California region (Q3 2024 vs. Q3 2023)

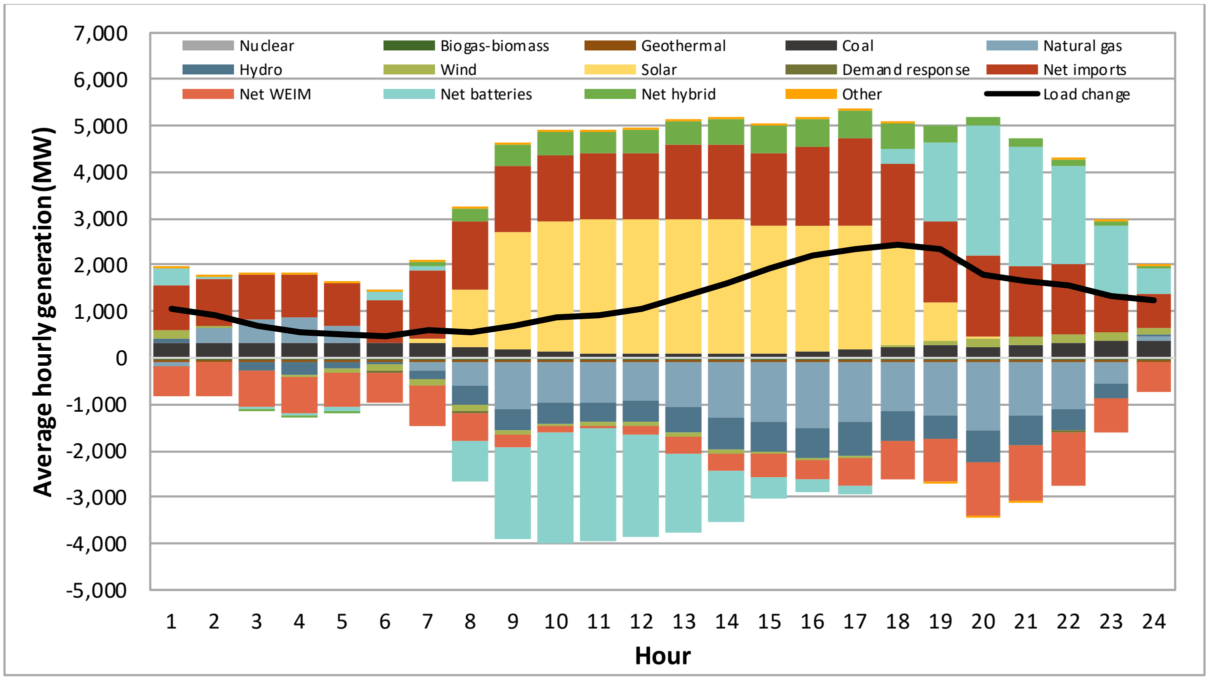


Figure 1.11 Change in average hourly generation by fuel type in the Desert Southwest region (Q3 2024 vs. Q3 2023)

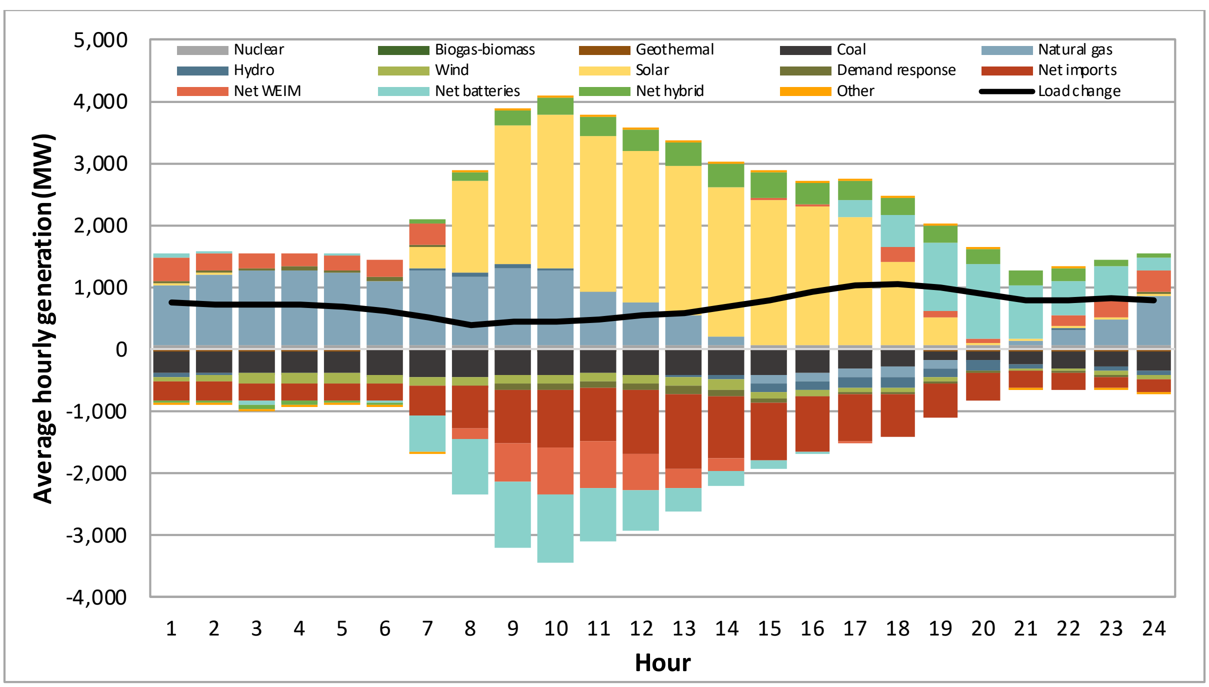


Figure 1.12 Change in average hourly generation by fuel type in the Intermountain West region (Q3 2024 vs. Q3 2023)

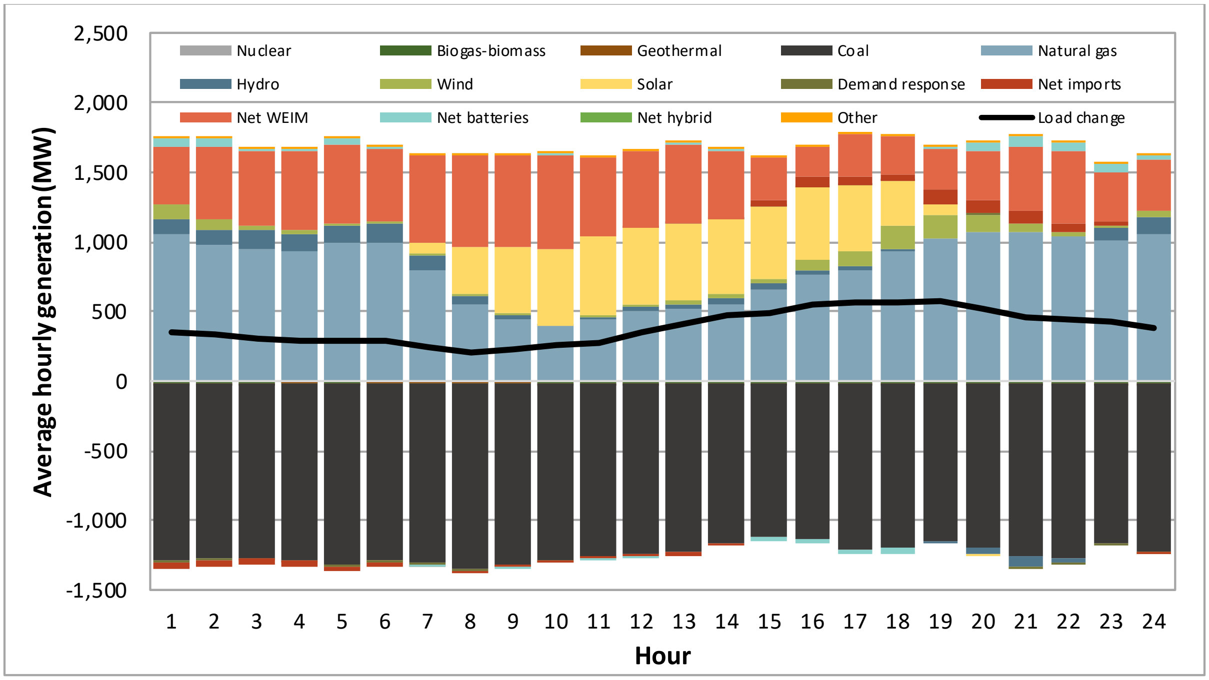


Figure 1.13 Change in average hourly generation by fuel type in the Pacific Northwest region (Q3 2024 vs. Q3 2023)

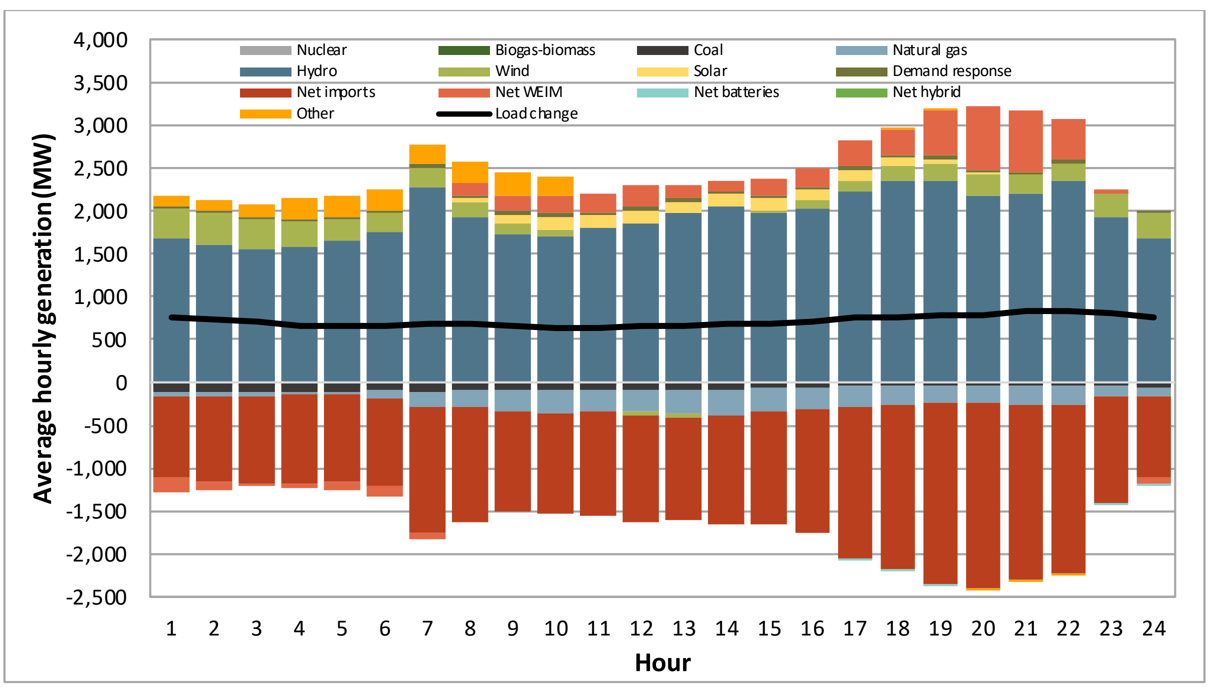
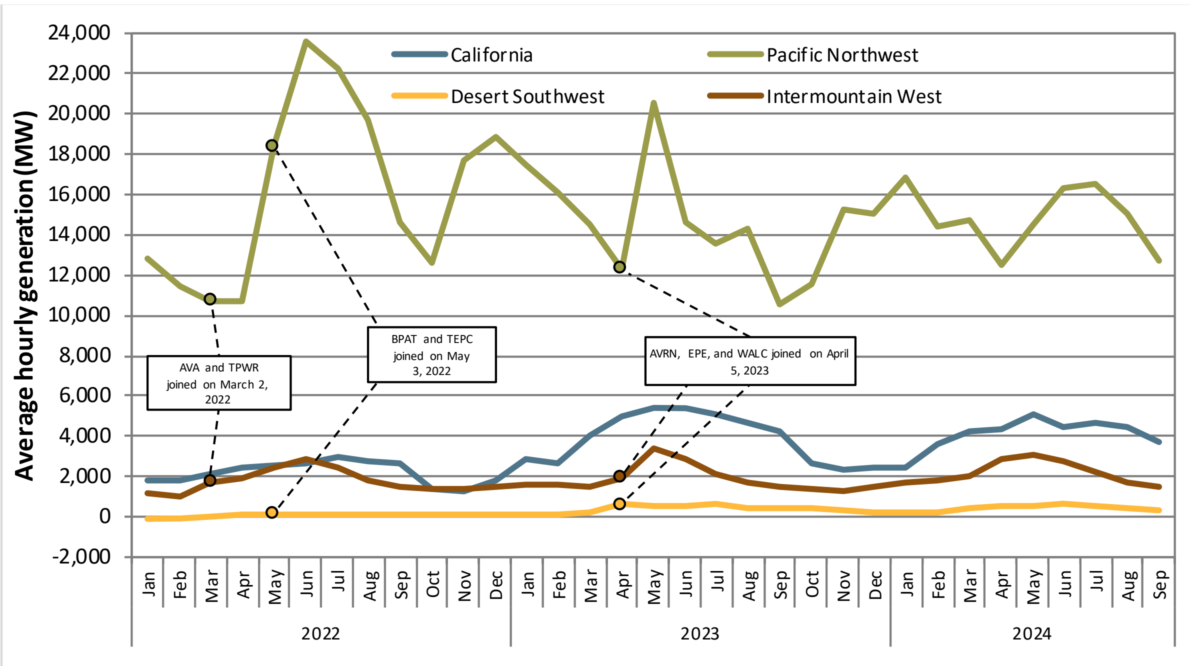


Figure 1.14 shows the monthly average hydroelectric generation from January 2022 to September 2024. In the Pacific Northwest, hydroelectric generation in the third quarter of 2024 tracked 1,940 MW (15 percent) higher than the same quarter of 2023, but fell short of the 2022 levels by 4,120 MW (22 percent). In the California region, hydroelectric generation decreased by 390 MW (8 percent) relative to the third quarter of 2023, but increased by 1,490 MW (53 percent) compared to 2022. Hydroelectric output in the Intermountain West was similar across the third quarters of 2022, 2023, and 2024. In the Desert Southwest, hydroelectric generation decreased by 50 MW (9 percent), but has increased by 330 MW (253 percent) from 2022.

Figure 1.14 Average monthly hydroelectric generation by region



2 Load conditions

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

The regions are divided into five categories:

1. **Desert Southwest**: includes Arizona Public Service, El Paso Electric, NV Energy, Public Service Company of New Mexico (PNM), Salt River Project, Tucson Electric, and WAPA-Desert Southwest.
2. **Intermountain West**: includes Avista Utilities, Idaho Power, NorthWestern Energy, and PacifiCorp East.
3. **Pacific Northwest**: includes Avangrid, BPA, PacifiCorp West, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, and Tacoma Power.

4. **CAISO**: represents the California ISO balancing authority.
5. **California**: includes all balancing areas in California except CAISO, such as BANC, LADWP, and Turlock ID.

2.1 Average load and load distribution

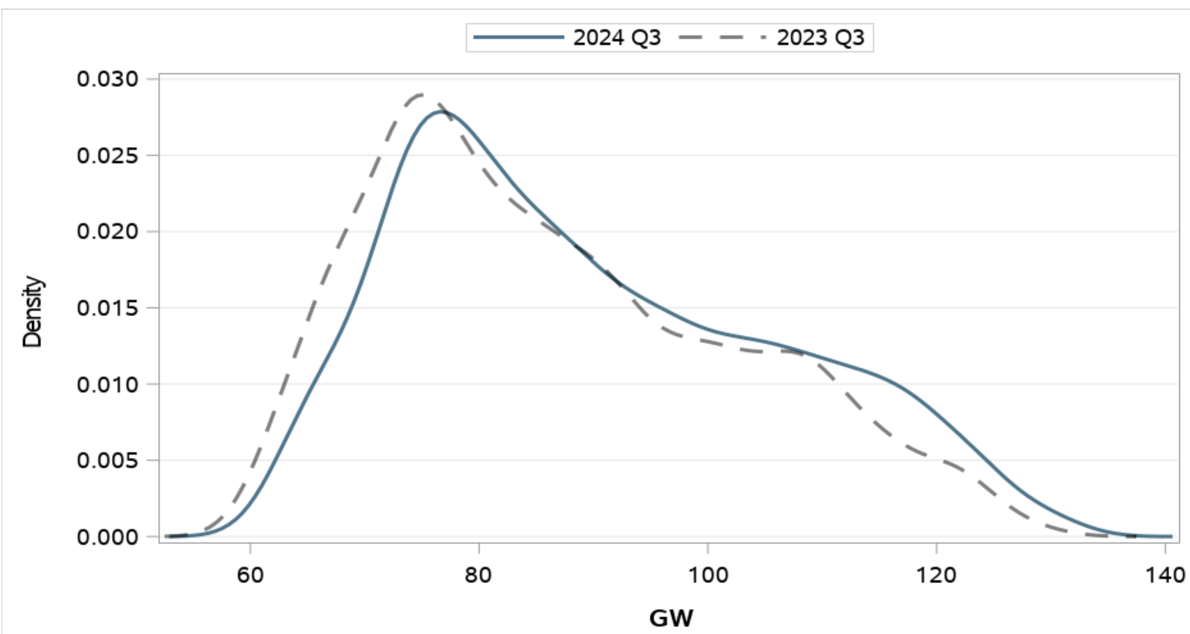
Figure 2.1 shows the total market load distribution in the 5-minute market.[8] The distribution incorporates all 5-minute load data for Q3 2024 (blue line) and Q3 2023 (grey dashed line).

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

The distribution shows how the load values are distributed. Higher points on the curve represent load levels that occurred more frequently during the quarter.[9] For instance, if the curve peaks around 70 GW, this indicates that 70 GW was a commonly observed load level.

The distribution shows more instances of high system loads—particularly above 110 GW—in the third quarter of 2024, compared to the same quarter last year. The blue line is generally above the grey dashed line above 110 GW, reflecting an increased frequency of high load intervals. Conversely, at the lower end of the load range, the blue line falls below the dashed line, indicating fewer instances of low-load intervals in Q3 2024, particularly below 80 GW.

Figure 2.1 Quarterly system-wide total load distribution



8 The total market load includes any load conformance.

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

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

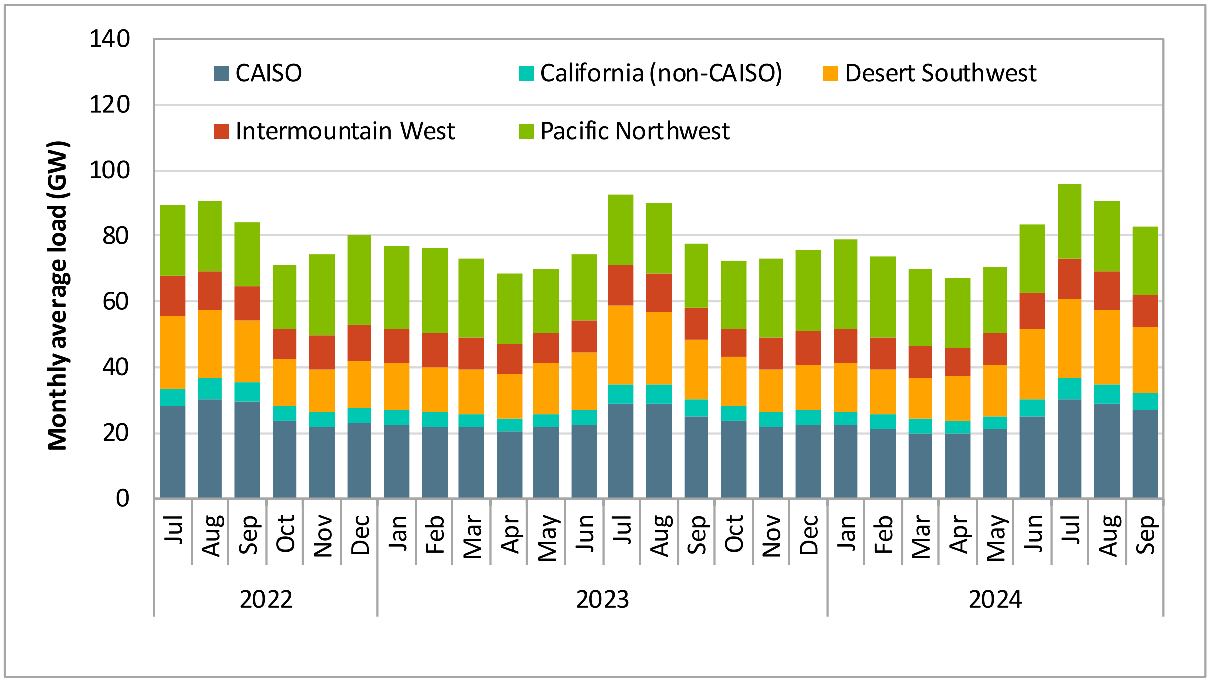


Figure 2.2 shows the monthly average 5-minute market load categorized by region from July 2022 to September 2024. In this quarter, on average:

- **CAISO** (dark blue) recorded the largest load, averaging nearly **28.7 GW**.
- **Desert Southwest** (yellow) followed with an average load of **22.4 GW**.
- **Pacific Northwest** (green) averaged **21.5 GW**.
- **Intermountain West** (red) had an average load of **11.4 GW**.
- **California** (light blue) recorded an average load of **5.8 GW**.

The total system load for this quarter averaged 89.8 GW, representing an approximately 4 percent increase compared to the same quarter last year. Each region's average load increased relative to the third quarter of 2023, ranging from 3 percent to 5 percent. The largest increase of 5 percent was observed in the California (non-CAISO) region.

The monthly load reveals a seasonal trend. The WEIM total market load tends to peak during the summer and drop to lows in April. At the regional level, the load patterns varied. Regions such as CAISO, California (non-CAISO), and Desert Southwest closely aligned with the overall seasonal trends of the total WEIM load, showing higher loads during the summer months. However, the Pacific Northwest exhibited a distinct pattern, with peak loads occurring in the winter months and comparatively low load during summer, particularly in May, June, and September. The Intermountain West displayed a hybrid trend, with peaks in the summer while also maintaining high loads during winter months.

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

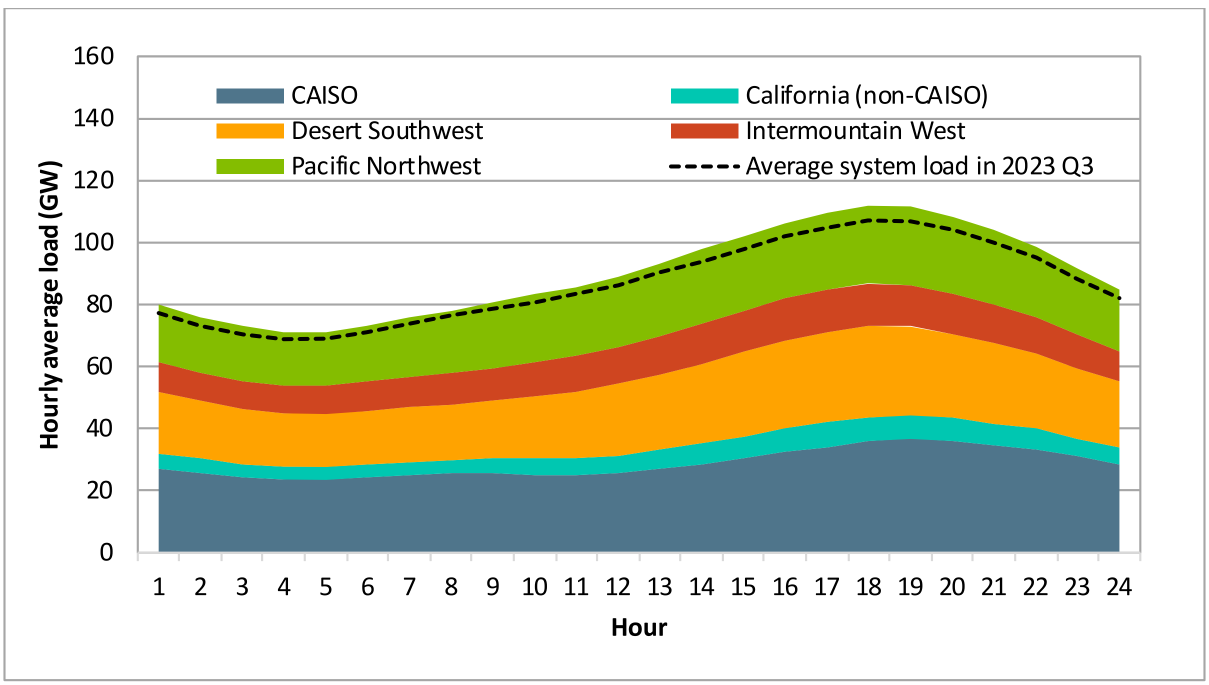
The total WEIM hourly average load peaked at hour-ending 18, reaching 111.9 GW, while the lowest load occurred at hour-ending 5, at 71.1 GW. CAISO consistently has the largest load across all hours. The Pacific Northwest has the second-highest load during the morning hours, from hour-ending 6 to hour-ending 11. However, starting from hour-ending 12 through hour-ending 24, the Desert Southwest was the region with the second-largest load.

The peak average hourly load for each region was:

- **CAISO:** peak load of 36.9 GW at hour-ending 19.
- **Desert Southwest**: peak load of 29.1 GW at hour-ending 18.
- **Pacific Northwest:** peak load of 25.2 GW at hour-ending 18.
- **Intermountain West**: peak load of 13.8 GW at hour-ending 17.
- **California (non-CAISO):** peak load of 7.8 GW at hour-ending 18.

In terms of variability, the California (non-CAISO) region exhibited the largest difference between its lowest and highest hourly load. The peak hourly load in California (non-CAISO) was 88 percent higher than its lowest point. The Desert Southwest region had a 70 percent difference between its peak and lowest hourly loads. The remaining regions displayed differences ranging from 47 percent to 57 percent.

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



2.2 Peak load

Figure 2.4 shows the highest 5-minute market *system* load forecast for each hour on July 10, 2024—the day with the highest system load during the quarter. The figure also shows corresponding load forecast data for each balancing area for the same 5-minute interval as the system peak for each hour. On this day, the WEIM system load peaked at 135.3 GW during hour-ending 18, interval 11. This was higher than the peak WEIM load during 2023 (131.6 GW).

This heatmap highlights the hour with the peak load for each balancing area on this day. Red indicates the hour of highest load for each balancing area and yellow indicates hours with above-average load for that day. Peak load for balancing areas varied across hours. While the system peak occurred during hour-ending 18, many balancing areas reached their peak at different times. Even within the same region, peaking hours varied among balancing areas.

In California, peaking hours ranged from hour-ending 18 to 20, while the Desert Southwest ranged from hour-ending 16 to 19. The Intermountain West balancing areas peaked at hour-ending 16 or 17, and the Pacific Northwest ranged from hour-ending 15 to 18. El Paso Electric, Idaho Power, and NorthWestern Energy hit peak load during hour-ending 16, while Seattle City Light was the only balancing area to have its peak load during hour-ending 15.

Figure 2.4 Hourly system and BAA load profiles (GW) on the system peak load day (5-minute market, July 10, 2024)

	12	13	14	15	16	17	18	19	20	21	22	23	24
SYSTEM	107.9	113.9	120.2	126.0	130.6	133.5	135.3	135.0	132.6	128.0	122.0	113.7	103.7
CAISO	29.5	31.6	34.1	36.6	39.0	40.8	42.4	42.5	42.5	41.3	40.0	37.6	34.0
BANC	2.81	3.13	3.53	3.87	4.14	4.27	4.32	4.29	4.23	4.02	3.78	3.41	2.98
Turlock ID	0.51	0.55	0.59	0.62	0.64	0.66	0.67	0.67	0.66	0.64	0.62	0.58	0.53
LADWP	3.71	3.93	4.18	4.42	4.61	4.69	4.69	4.68	4.50	4.20	4.06	3.76	3.38
NV Energy	7.65	8.20	8.70	9.13	9.34	9.57	9.67	9.69	9.27	8.83	8.47	7.85	7.25
Arizona PS	6.37	6.77	7.19	7.60	7.88	7.94	8.05	8.06	7.92	7.59	7.07	6.52	6.00
Tucson Electric	2.24	2.43	2.58	2.72	2.85	2.95	3.00	2.98	2.83	2.68	2.45	2.23	2.01
Salt River Project	6.84	7.25	7.53	7.73	7.90	7.94	7.91	7.94	7.68	7.42	6.93	6.35	5.88
PSC New Mexico	1.86	1.98	2.05	2.17	2.23	2.28	2.29	2.28	2.20	2.08	1.92	1.82	1.67
WAPA - Desert SW	1.27	1.37	1.44	1.52	1.54	1.59	1.55	1.55	1.48	1.40	1.31	1.24	1.13
El Paso Electric	1.63	1.75	1.85	1.95	1.99	1.89	1.76	1.71	1.58	1.50	1.36	1.25	1.15
PacifiCorp East	8.34	8.78	9.19	9.46	9.56	9.68	9.59	9.57	9.25	8.93	8.45	7.81	7.19
Idaho Power	3.66	3.69	3.96	4.11	4.18	4.08	4.06	4.05	4.03	3.94	3.72	3.46	3.19
NorthWestern	1.74	1.79	1.85	1.89	1.92	1.92	1.91	1.91	1.88	1.83	1.73	1.59	1.45
Avista Utilities	1.85	1.96	2.02	2.06	2.10	2.12	2.11	2.10	2.04	1.95	1.84	1.68	1.50
BPA	7.84	7.92	8.16	8.33	8.42	8.57	8.69	8.59	8.52	8.27	7.88	7.40	6.82
Tacoma Power	0.55	0.57	0.59	0.60	0.61	0.63	0.64	0.64	0.63	0.61	0.58	0.55	0.50
PacifiCorp West	3.34	3.50	3.63	3.73	3.78	3.83	3.86	3.85	3.76	3.64	3.41	3.17	2.85
Portland GE	3.33	3.50	3.66	3.79	3.87	3.99	3.98	3.98	3.91	3.76	3.53	3.29	2.99
Puget Sound Energy	3.23	3.37	3.46	3.58	3.68	3.73	3.78	3.76	3.68	3.54	3.40	3.20	2.88
Seattle City Light	1.21	1.25	1.26	1.32	1.31	1.31	1.30	1.29	1.26	1.23	1.19	1.13	1.05
Powerex	8.50	8.64	8.75	8.86	8.95	9.07	9.03	8.99	8.82	8.60	8.35	7.89	7.27

Hour

Table 2.1 shows the peak 5-minute market load and date for each balancing area (or region) during the third quarter. The California ISO and LADWP balancing areas experienced peak load during the first week of September while all other balancing areas experienced peak load in July or August. Each balancing area in the Pacific Northwest experienced peak load for the quarter on July 9, 2024. The table also shows each balancing area's load during the system peak load interval on July 10, 2024 (135.3 GW).

Table 2.1 Peak WEIM load (July–September 2024)

Region/ balancing area	Peak load (July - September, 2024)		Load during WEIM system peak (10-Jul-24)	
	Date	Load (MW)	Load (MW)	Percent
WEIM system	**10-Jul-24**	**135,299**	**135,299**	
California	**5-Sep-24**	**57,201**	**52,109**	**39%**
California ISO	5-Sep-24	46,830	42,428	31%
BANC	11-Jul-24	4,582	4,317	3%
LADWP	6-Sep-24	6,371	4,694	3%
Turlock Irrig. District	11-Jul-24	715	670	0.5%
Desert Southwest	**9-Jul-24**	**34,377**	**34,237**	**25%**
Arizona Public Service	4-Aug-24	8,309	8,052	6%
El Paso Electric	16-Aug-24	2,252	1,758	1%
NV Energy	11-Jul-24	9,702	9,670	7%
PSC New Mexico	20-Aug-24	2,645	2,288	2%
Salt River Project	4-Aug-24	8,314	7,914	6%
Tucson Electric	8-Jul-24	3,015	3,002	2%
WAPA - Desert SW	10-Jul-24	1,588	1,553	1%
Intermountain West	**11-Jul-24**	**17,867**	**17,672**	**13%**
Avista Utilities	10-Jul-24	2,120	2,108	2%
Idaho Power	10-Jul-24	4,229	4,058	3%
NorthWestern Energy	23-Jul-24	2,029	1,914	1%
PacifiCorp East	11-Jul-24	9,932	9,593	7%
Pacific Northwest	**9-Jul-24**	**33,317**	**31,281**	**23%**
BPA	9-Jul-24	9,204	8,688	6%
PacifiCorp West	9-Jul-24	4,030	3,863	3%
Portland General Electric	9-Jul-24	4,405	3,985	3%
Powerex	9-Jul-24	9,490	9,031	7%
Puget Sound Energy	9-Jul-24	4,183	3,778	3%
Seattle City Light	9-Jul-24	1,417	1,300	1%
Tacoma Power	9-Jul-24	694	636	0.5%

3 Energy market performance

3.1 Real-time energy market prices by region

This section analyzes real-time market prices across the Western Energy Imbalance Market (WEIM). The analysis focuses on monthly and hourly load-weighted average prices at the regional level.[10] Prices are calculated based on the load schedules and corresponding prices at Default Load Aggregation Points (DLAPs) and EIM Load Aggregation Points (ELAPs).[11]

Prices in the 15-minute market across the WEIM averaged about $40, down 31 percent due mainly to lower natural gas prices. Prices in the 5-minute market were down 32 percent compared to Q3 2023.

Figure 3.1 and Figure 3.2 display the weighted average monthly prices in the 15-minute and 5-minute markets by region from January 2023 to September 2024. In this quarter, California recorded the highest average price at $47.5/MWh, while other regions ranged between $33/MWh and $38/MWh. Greenhouse gas (GHG) costs contributed significantly to the higher prices in California compared to other regions. 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.

Compared to the third quarter of 2023, prices across the WEIM were lower despite higher loads, primarily due to significantly reduced natural gas prices. Figure 3.1 illustrates the substantial decline in natural gas prices across major Western U.S. trading hubs in Q3 2024 compared to Q3 2023. As gas-fired units frequently set electricity market prices, lower natural gas prices lead to lower real-time prices across the WEIM.

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

11 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 the monthly average, prices for each real-time interval are weighted by their respective loads and divided by the total monthly load for the region. For hourly averages over the quarter, each interval's price is weighted by its load relative to the total load during that hour for the region.

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

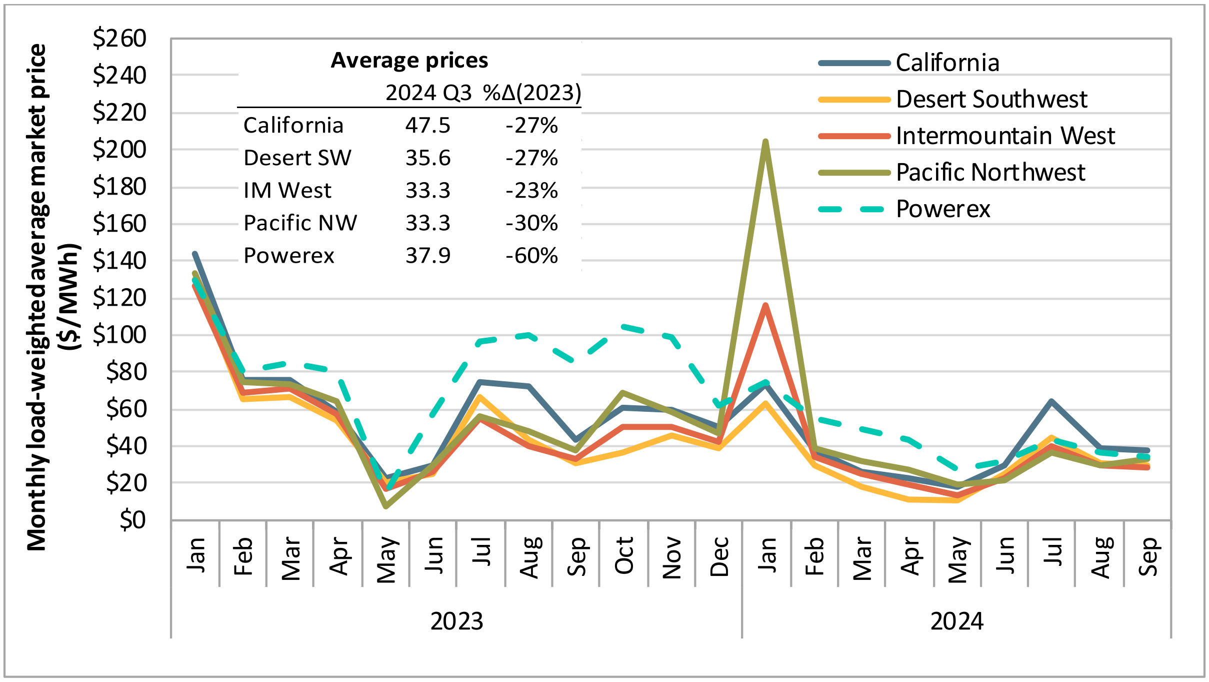


Figure 3.2 Weighted average monthly 5-minute market prices by region

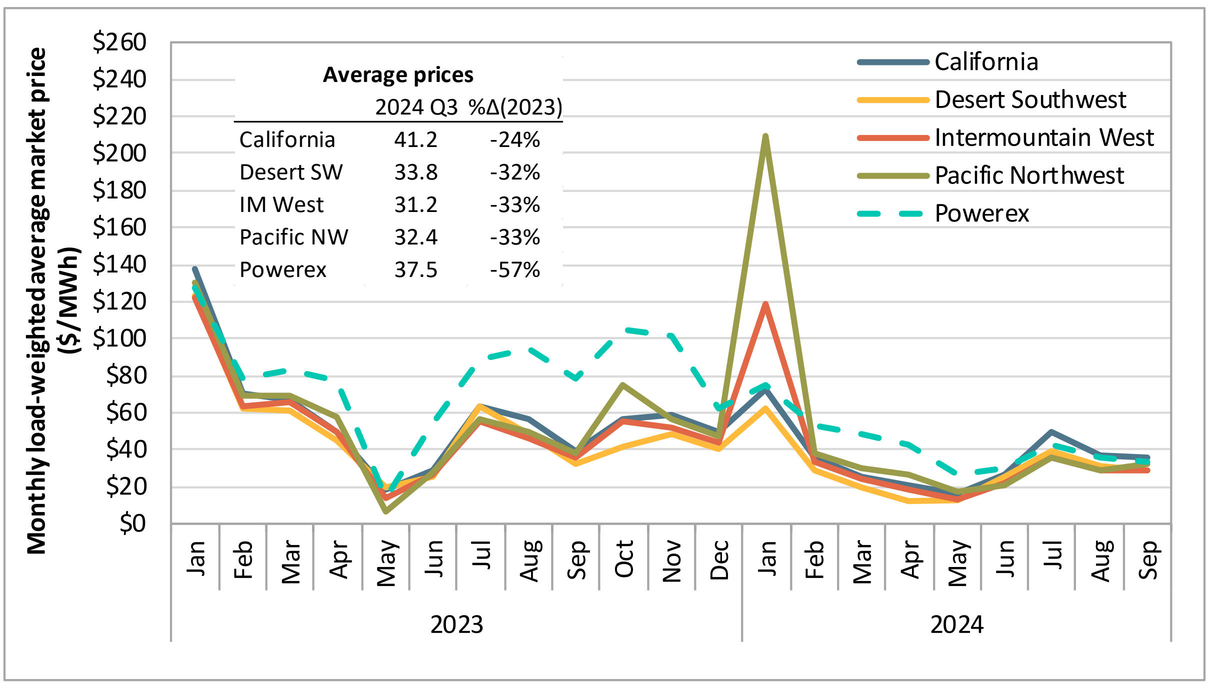


Figure 3.3 and Figure 3.4 illustrate the weighted average hourly prices for the 15-minute and 5-minute markets across regions. During the evening peak hours, 15-minute market prices were significantly higher than 5-minute market prices in the California, Intermountain West, and Desert Southwest regions. In the 15-minute market, the California region's peak average hourly price was $123/MWh during hour-ending 20. The Desert Southwest and Intermountain West peak average hourly prices were $89/MWh and $80/MWh, also during hour-ending 20. These 15-minute market peak prices were

approximately $30/MWh to $55/MWh higher than each region's corresponding 5-minute market prices. Significantly larger CAISO balancing area load conformance in the 15-minute market than in the 5-minute market likely contributed to this price discrepancy between the markets in these regions.

Figure 3.3 Weighted average hourly 15-minute market prices by region (July–September 2024)

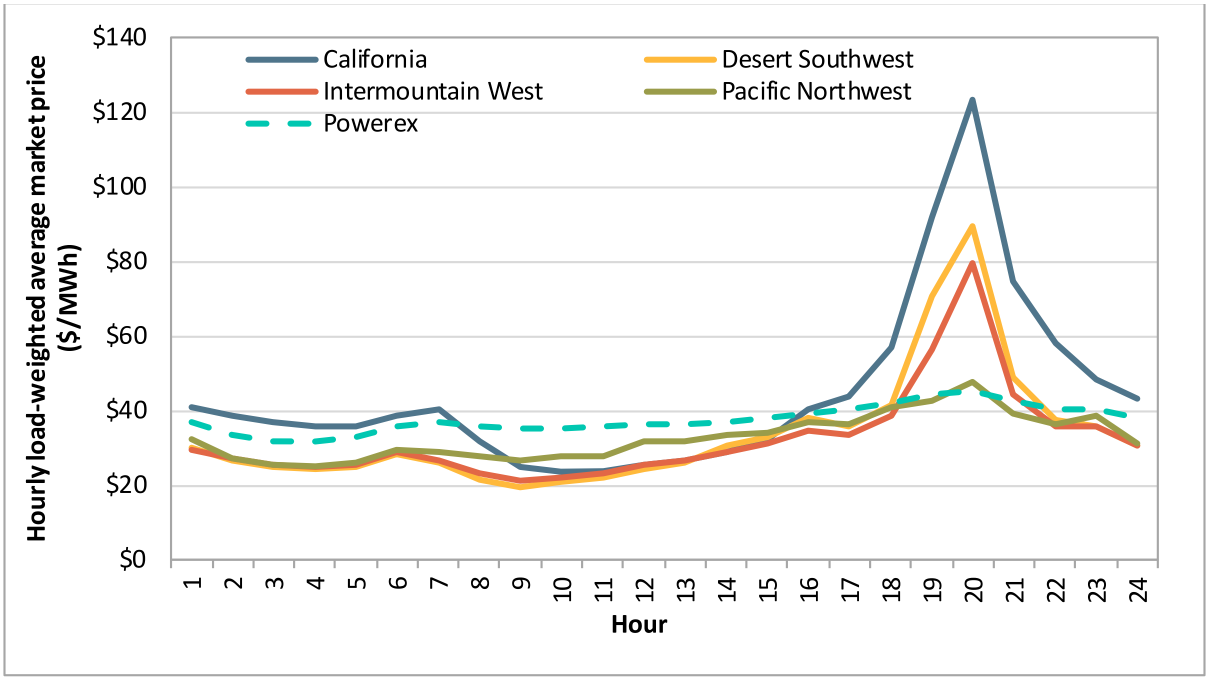
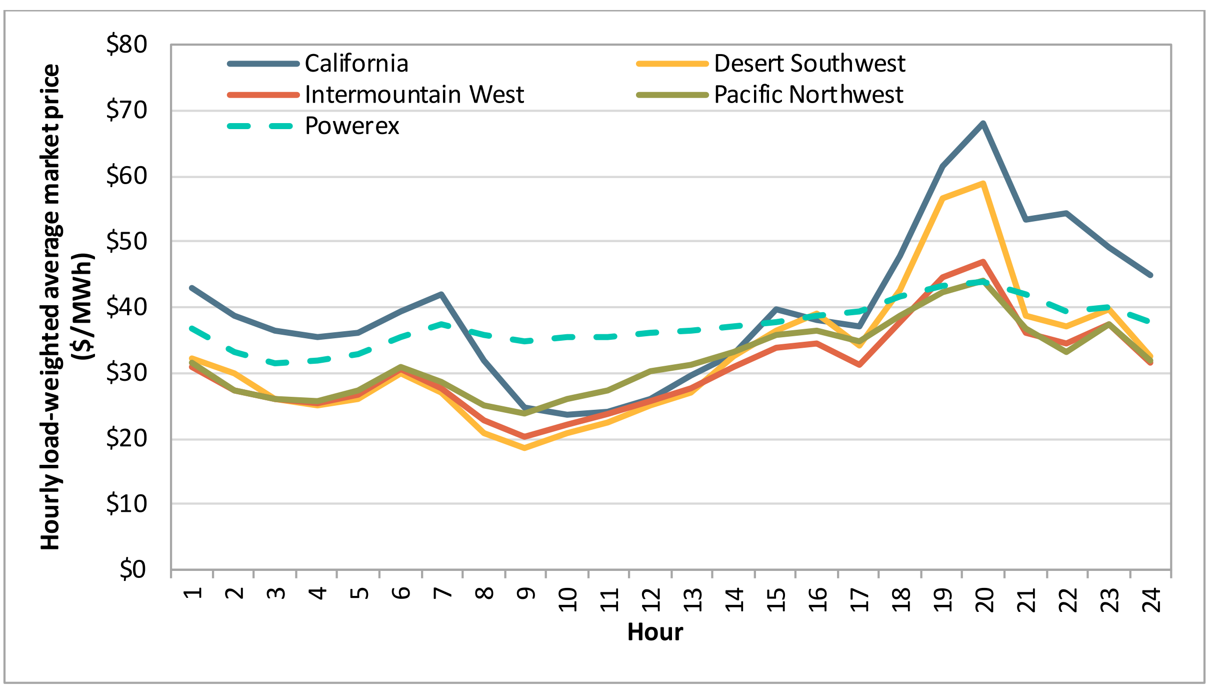


Figure 3.4 Weighted average hourly 5-minute market prices by region (July–September 2024)



3.2 Real-time market prices by balancing area

This section summarizes prices in each Western Energy Imbalance Market (WEIM) balancing area during the third quarter of 2024. Figure 3.5 and Figure 3.6 show the average 15-minute and 5-minute market price by component for each balancing authority area in this quarter. These figures highlight how price differences between regions are determined by differences in transmission losses, greenhouse gas compliance costs, and congestion. These components are listed below.

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

Significant factors impacting the locational marginal price (LMP) differences between balancing areas included congestion on WEIM transfer constraints and internal congestion from flow-based constraints. GHG costs also contributed to lowering prices in non-California balancing areas relative to California areas. These compliance costs are embedded within system marginal energy costs, but are reflected as negative costs (or payments) that are received by other WEIM areas making transfers into California areas through the WEIM. This indicates resources with non-zero GHG costs were often sending the last increment of power to California in the real-time markets.

In both the 5-minute and 15-minute markets, WEIM transfer constraints increased prices for BCHA, BPA, and LADWP relative to other balancing areas. Congestion on WEIM transfer constraints or congestion within the CAISO balancing area tended to decrease prices in many Desert Southwest, Intermountain West, and Pacific Northwest areas relative to balancing areas in California.

Figure 3.5 Average monthly 15-minute market prices by balancing area (July–September 2024)

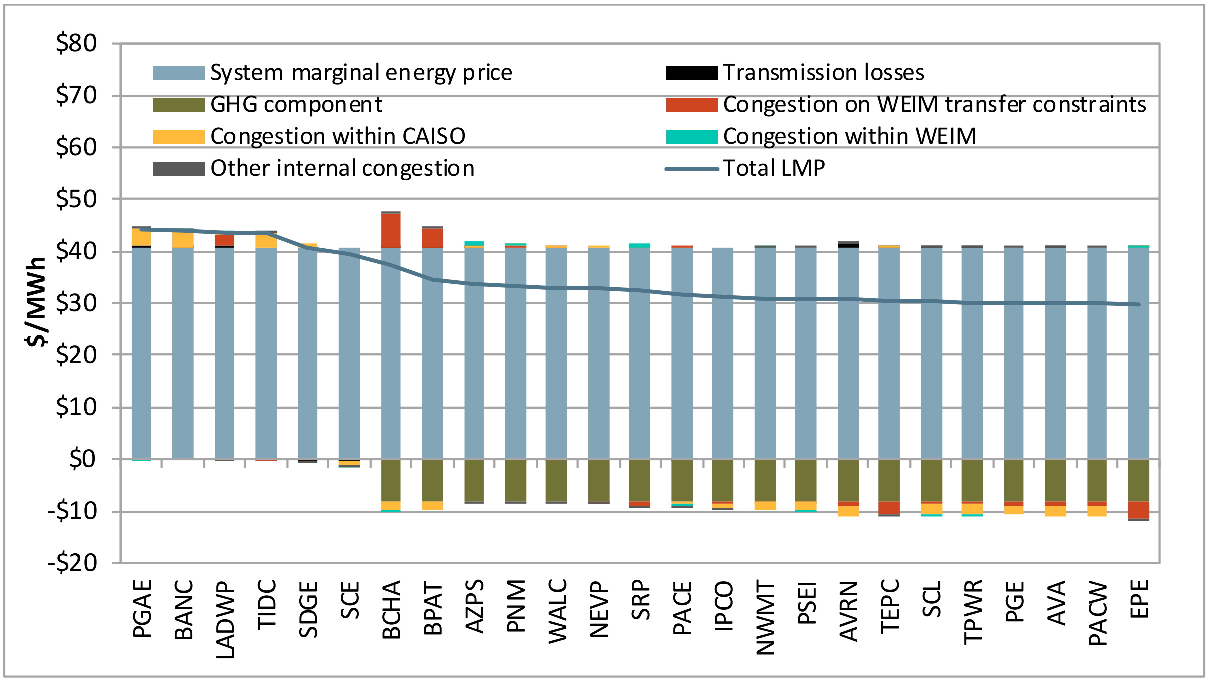


Figure 3.6 Average monthly 5-minute market prices by balancing area (July–September 2024)

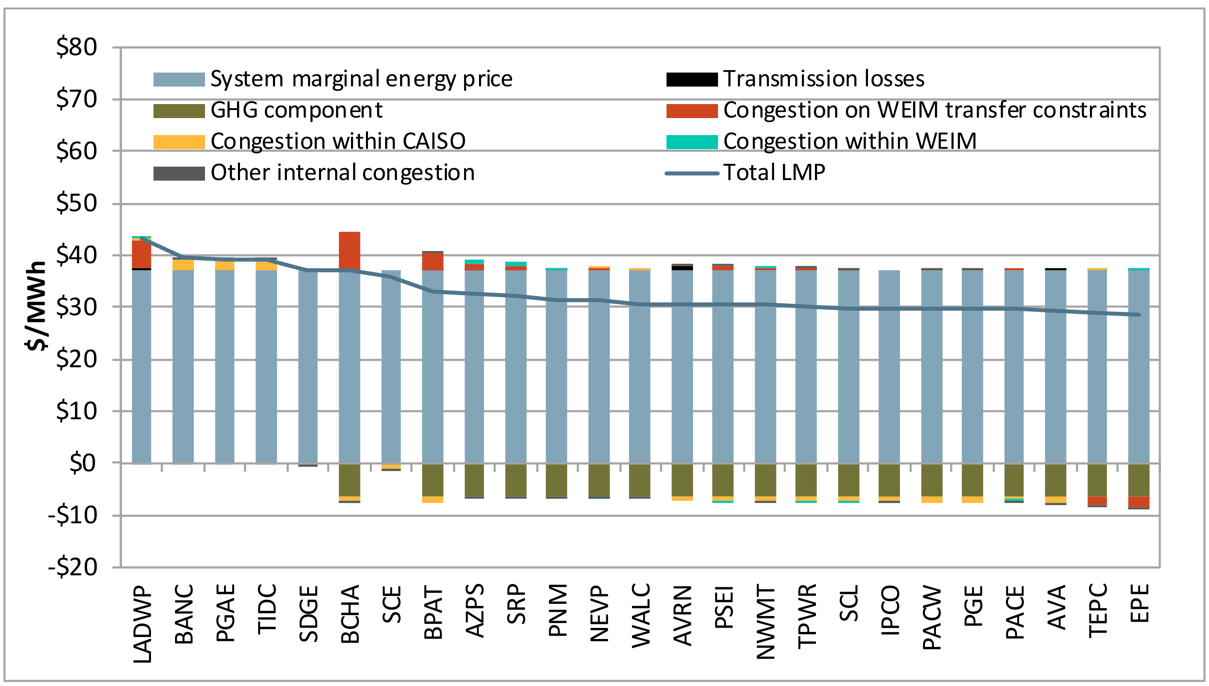


Table 3.1 and Table 3.2 show average 15-minute and 5-minute market prices by month for each balancing area. The color gradient highlights deviation from the average system marginal energy price (SMEC), shown in the top row. Here, blue indicates prices below that month's average system price and

orange indicates prices above. These tables show average prices in California balancing areas were generally higher than those in other regions in both the 15-minute and 5-minute markets over Q3 2024.

Table 3.3 and Table 3.4 show average hourly prices in the 15-minute and 5-minute markets during the third quarter. During mid-day solar hours, prices were generally higher in the Pacific Northwest and Northern California than in the Desert Southwest, Intermountain West, and Southern California. The mid-day price separation pattern was primarily driven by south-to-north congestion on WEIM transfer and internal flow-based constraints. When internal or transfer constraints limit the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply. Greenhouse gas compliance costs contribute to higher prices in California relative to the rest of the system. During non-solar hours, California balancing authority areas had higher prices compared to the rest of the WEIM due to congestion and California greenhouse house gas pricing.

In this quarter, 15-minute market prices frequently exceeded 5-minute market prices, especially during evening peak hours.

Table 3.1 Monthly 15-minute market prices

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

Table 3.2 Monthly 5-minute market prices

	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024	Jul 2024	Aug 2024	Sep 2024
SMEC	$66	$86	$241	$135	$68	$66	$47	$16	$27	$58	$53	$39	$53	$57	$49	$85	$35	$26	$20	$14	$24	$43	$34	$34
PG&E (CAISO)	$73	$92	$254	$136	$70	$68	$49	$16	$28	$52	$52	$42	$58	$62	$53	$79	$38	$28	$26	$19	$26	$49	$34	$35
SCE (CAISO)	$60	$77	$234	$133	$63	$58	$41	$16	$26	$62	$53	$35	$48	$52	$44	$63	$29	$16	$9	$8	$22	$42	$33	$32
BANC	$74	$92	$249	$138	$71	$68	$49	$16	$29	$54	$53	$42	$57	$62	$53	$79	$39	$30	$27	$20	$25	$48	$34	$36
Turlock ID	$77	$94	$263	$139	$72	$69	$52	$16	$30	$54	$53	$42	$58	$63	$54	$79	$40	$31	$29	$19	$24	$45	$35	$38
LADWP	$61	$81	$244	$134	$67	$59	$42	$16	$26	$62	$55	$37	$51	$53	$45	$66	$30	$17	$10	$10	$27	$50	$45	$35
NV Energy	$57	$76	$235	$126	$62	$60	$42	$14	$22	$56	$45	$34	$44	$50	$43	$65	$29	$19	$12	$9	$21	$37	$29	$28
Arizona PS	$54	$77	$240	$123	$66	$61	$42	$15	$24	$59	$45	$32	$40	$46	$40	$59	$26	$17	$8	$8	$21	$40	$32	$27
Tucson Electric	$54	$73	$215	$123	$60	$54	$40	$20	$26	$58	$44	$31	$38	$46	$40	$58	$28	$16	$10	$14	$24	$34	$26	$27
Salt River Project	$51	$72	$149	$109	$49	$54	$45	$23	$26	$61	$48	$27	$38	$49	$39	$53	$24	$17	$10	$13	$29	$37	$31	$29
PSC New Mexico	$57	$63	$123	$122	$60	$58	$53	$14	$24	$56	$44	$33	$46	$51	$42	$70	$34	$18	$16	$12	$25	$37	$28	$28
WAPA - Desert SW							$40	$19	$26	$58	$44	$33	$38	$47	$40	$59	$28	$14	$6	$9	$21	$37	$29	$27
El Paso Electric							$28	$16	$23	$47	$40	$30	$33	$23	$23	$52	$24	$15	$8	$18	$25	$36	$24	$26
PacifiCorp East	$57	$70	$192	$116	$59	$62	$45	$14	$25	$52	$43	$34	$44	$47	$40	$73	$30	$21	$15	$11	$20	$35	$27	$27
Idaho Power	$61	$80	$233	$127	$66	$68	$51	$13	$26	$52	$44	$35	$61	$54	$46	$119	$34	$25	$19	$13	$21	$34	$28	$28
NorthWestern	$64	$86	$241	$128	$67	$69	$56	$9	$27	$55	$46	$37	$67	$55	$48	$161	$37	$28	$26	$18	$20	$33	$28	$30
Avista Utilities	$64	$83	$242	$129	$67	$69	$56	$10	$27	$51	$44	$37	$68	$55	$48	$164	$37	$29	$27	$18	$20	$32	$28	$29
Avangrid							$56	$6	$27	$51	$44	$38	$68	$55	$48	$168	$37	$29	$24	$16	$20	$33	$28	$31
BPA	$63	$83	$247	$130	$68	$68	$57	$4	$28	$53	$48	$37	$69	$56	$47	$184	$37	$28	$26	$17	$22	$38	$29	$32
Tacoma Power	$62	$82	$246	$130	$67	$69	$56	$5	$28	$50	$45	$37	$69	$54	$47	$170	$37	$29	$26	$17	$20	$32	$27	$31
PacifiCorp West	$63	$83	$239	$129	$66	$68	$56	$6	$26	$50	$42	$37	$68	$54	$47	$171	$37	$28	$24	$16	$20	$32	$27	$31
Portland GE	$63	$84	$239	$129	$66	$68	$56	$9	$27	$50	$45	$37	$69	$54	$47	$169	$37	$29	$26	$16	$20	$32	$27	$31
Puget Sound Energy	$62	$83	$247	$131	$68	$69	$56	$7	$28	$61	$47	$38	$74	$56	$47	$175	$37	$29	$27	$16	$20	$33	$27	$31
Seattle City Light	$62	$82	$247	$130	$69	$68	$56	$5	$27	$50	$46	$37	$68	$55	$47	$171	$37	$28	$26	$16	$20	$31	$27	$31
Powerex	$65	$80	$209	$127	$77	$83	$77	$14	$52	$87	$94	$77	$102	$101	$61	$72	$53	$48	$43	$27	$30	$42	$36	$33

Table 3.3 Hourly 15-minute market prices (July–September)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$40	$38	$36	$35	$35	$38	$39	$31	$24	$24	$24	$25	$26	$28	$31	$37	$39	$50	$75	$102	$63	$51	$45	$42
PG&E (CAISO)	$40	$38	$36	$35	$35	$39	$40	$32	$27	$26	$25	$27	$27	$29	$31	$40	$45	$60	$91	$119	$75	$56	$46	$42
SCE (CAISO)	$40	$38	$36	$35	$35	$38	$40	$30	$21	$19	$20	$21	$23	$24	$27	$33	$36	$48	$77	$104	$65	$53	$45	$42
BANC	$40	$37	$36	$35	$35	$38	$39	$32	$27	$27	$27	$29	$30	$33	$36	$43	$45	$53	$82	$115	$71	$55	$45	$41
Turlock ID	$40	$38	$36	$35	$35	$38	$39	$32	$28	$29	$30	$32	$33	$36	$38	$43	$42	$50	$76	$107	$67	$53	$44	$41
LADWP	$43	$38	$37	$36	$36	$39	$42	$31	$23	$22	$23	$24	$26	$29	$32	$38	$41	$52	$87	$118	$67	$57	$59	$46
NV Energy	$29	$27	$26	$25	$26	$29	$27	$23	$20	$21	$22	$24	$25	$27	$29	$34	$33	$40	$63	$86	$48	$38	$36	$30
Arizona PS	$29	$27	$26	$25	$25	$29	$28	$23	$20	$21	$22	$23	$25	$30	$35	$39	$36	$41	$65	$88	$50	$38	$36	$33
Tucson Electric	$27	$23	$21	$19	$20	$23	$17	$14	$13	$16	$20	$22	$25	$33	$30	$35	$34	$40	$64	$86	$49	$36	$35	$28
Salt River Project	$29	$26	$25	$24	$24	$27	$27	$23	$19	$21	$22	$24	$25	$29	$33	$38	$35	$37	$82	$73	$42	$34	$33	$29
PSC New Mexico	$29	$28	$26	$25	$26	$30	$28	$21	$19	$18	$19	$23	$25	$27	$29	$34	$36	$46	$64	$91	$49	$38	$36	$31
WAPA - Desert SW	$29	$27	$26	$25	$25	$29	$28	$23	$20	$20	$21	$23	$25	$26	$29	$33	$33	$40	$64	$89	$50	$38	$36	$31
El Paso Electric	$30	$21	$19	$17	$18	$22	$13	$13	$15	$17	$20	$23	$31	$31	$29	$42	$35	$53	$60	$72	$45	$30	$33	$25
PacifiCorp East	$29	$26	$25	$24	$25	$29	$27	$23	$20	$21	$22	$24	$25	$27	$29	$33	$32	$38	$57	$79	$44	$35	$35	$30
Idaho Power	$29	$27	$25	$25	$25	$29	$27	$23	$21	$22	$23	$25	$26	$28	$30	$34	$33	$38	$52	$69	$43	$34	$35	$30
NorthWestern	$29	$27	$25	$24	$25	$29	$27	$23	$22	$22	$23	$25	$26	$28	$30	$33	$32	$37	$50	$68	$38	$33	$35	$30
Avista Utilities	$29	$26	$25	$24	$25	$29	$27	$23	$22	$23	$24	$25	$26	$28	$30	$33	$32	$36	$42	$57	$34	$32	$35	$30
Avangrid	$30	$27	$26	$25	$26	$30	$27	$25	$25	$26	$27	$30	$31	$33	$33	$36	$33	$36	$38	$41	$35	$31	$35	$31
BPA	$33	$27	$26	$25	$26	$30	$32	$31	$29	$30	$28	$33	$32	$34	$33	$37	$39	$49	$49	$51	$44	$43	$41	$32
Tacoma Power	$29	$27	$25	$25	$26	$29	$27	$25	$24	$26	$27	$30	$31	$31	$32	$35	$34	$35	$38	$41	$34	$31	$34	$30
PacifiCorp West	$29	$26	$25	$25	$26	$29	$26	$24	$24	$25	$27	$30	$30	$31	$33	$35	$32	$34	$37	$39	$34	$30	$35	$30
Portland GE	$29	$26	$25	$25	$26	$29	$26	$25	$24	$25	$27	$30	$30	$31	$32	$35	$32	$35	$38	$40	$34	$30	$35	$30
Puget Sound Energy	$36	$26	$25	$25	$26	$29	$26	$25	$24	$26	$27	$30	$31	$31	$32	$35	$33	$35	$38	$49	$34	$31	$36	$30
Seattle City Light	$29	$26	$25	$25	$24	$27	$25	$24	$25	$26	$28	$31	$31	$32	$34	$35	$35	$35	$38	$40	$34	$31	$37	$30
Powerex	$37	$33	$32	$32	$33	$36	$37	$36	$35	$35	$36	$36	$36	$37	$37	$39	$40	$42	$44	$45	$42	$40	$40	$38

Table 3.4 Hourly 5-minute market prices (July–September)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$42	$38	$36	$35	$36	$39	$41	$31	$24	$23	$24	$25	$27	$30	$33	$35	$33	$42	$53	$57	$47	$49	$46	$43
PG&E (CAISO)	$42	$38	$36	$35	$36	$39	$41	$33	$27	$26	$26	$27	$28	$31	$34	$37	$38	$49	$61	$66	$54	$52	$47	$43
SCE (CAISO)	$42	$38	$36	$35	$36	$39	$41	$30	$21	$19	$20	$22	$24	$26	$30	$31	$30	$41	$53	$58	$48	$51	$46	$44
BANC	$41	$38	$36	$35	$36	$39	$41	$32	$27	$27	$27	$29	$31	$34	$38	$41	$39	$45	$56	$63	$52	$51	$46	$43
Turlock ID	$41	$38	$36	$35	$36	$39	$41	$32	$28	$29	$30	$31	$33	$36	$40	$41	$36	$42	$52	$59	$48	$50	$46	$43
LADWP	$44	$39	$37	$36	$36	$39	$47	$31	$23	$22	$23	$25	$37	$42	$71	$39	$37	$45	$68	$82	$50	$54	$62	$49
NV Energy	$31	$28	$26	$26	$27	$31	$29	$22	$19	$21	$22	$24	$26	$29	$32	$37	$31	$40	$51	$52	$39	$37	$40	$32
Arizona PS	$36	$37	$26	$26	$27	$31	$29	$22	$19	$20	$22	$24	$26	$32	$37	$39	$33	$41	$54	$53	$39	$41	$41	$35
Tucson Electric	$27	$23	$22	$21	$21	$25	$18	$13	$13	$15	$19	$23	$25	$36	$37	$39	$33	$42	$51	$51	$38	$35	$37	$29
Salt River Project	$30	$27	$25	$24	$25	$28	$28	$24	$18	$21	$23	$24	$26	$32	$34	$38	$33	$44	$69	$69	$35	$32	$37	$30
PSC New Mexico	$31	$28	$27	$26	$28	$32	$29	$20	$18	$19	$20	$24	$26	$28	$32	$33	$35	$44	$50	$54	$38	$37	$38	$32
WAPA - Desert SW	$31	$28	$26	$26	$27	$31	$29	$21	$19	$20	$22	$24	$25	$28	$31	$33	$30	$40	$49	$52	$39	$37	$38	$32
El Paso Electric	$26	$22	$21	$19	$20	$24	$16	$12	$14	$17	$20	$24	$28	$34	$41	$41	$43	$46	$46	$47	$36	$29	$35	$27
PacifiCorp East	$30	$27	$25	$25	$26	$30	$27	$21	$19	$21	$22	$24	$26	$29	$32	$33	$30	$37	$45	$47	$36	$34	$36	$31
Idaho Power	$31	$27	$26	$25	$27	$30	$28	$22	$20	$22	$23	$25	$27	$29	$32	$33	$30	$37	$41	$43	$36	$34	$37	$31
NorthWestern	$31	$27	$26	$25	$27	$30	$28	$33	$21	$22	$24	$26	$27	$33	$32	$33	$30	$36	$44	$44	$34	$32	$36	$31
Avista Utilities	$30	$27	$26	$25	$27	$30	$27	$22	$21	$23	$24	$26	$27	$30	$33	$33	$30	$36	$38	$37	$33	$32	$38	$32
Avangrid	$31	$27	$26	$26	$27	$31	$28	$24	$23	$24	$26	$34	$30	$32	$35	$35	$31	$36	$38	$39	$34	$31	$37	$32
BPA	$32	$27	$26	$26	$28	$31	$30	$27	$25	$28	$28	$31	$32	$33	$36	$37	$38	$42	$47	$45	$41	$36	$37	$32
Tacoma Power	$30	$27	$26	$25	$27	$30	$28	$24	$23	$25	$27	$29	$30	$32	$34	$34	$32	$35	$37	$38	$33	$30	$36	$31
PacifiCorp West	$30	$27	$25	$25	$27	$31	$27	$23	$22	$24	$26	$29	$31	$32	$34	$34	$30	$35	$37	$37	$32	$30	$36	$31
Portland GE	$30	$27	$26	$25	$27	$31	$27	$23	$22	$24	$26	$28	$29	$31	$34	$34	$30	$35	$38	$38	$33	$30	$36	$31
Puget Sound Energy	$31	$27	$26	$25	$27	$31	$27	$24	$23	$24	$27	$29	$30	$32	$34	$34	$31	$35	$37	$50	$33	$30	$36	$31
Seattle City Light	$30	$27	$26	$25	$25	$28	$27	$23	$23	$25	$27	$29	$30	$32	$35	$34	$32	$35	$37	$38	$33	$30	$38	$31
Powerex	$37	$33	$31	$32	$33	$35	$37	$36	$35	$35	$35	$36	$36	$37	$37	$38	$39	$41	$43	$43	$42	$39	$39	$37

Hour

3.3 Day-ahead market price comparison

This section analyzes day-ahead and real-time market prices for balancing areas in the day-ahead market.

In 2024, the third quarter prices in the California ISO area's day-ahead, 15-minute, and 5-minute markets dropped by about 27 percent compared to the third quarter of the previous year. The average price of the three markets this quarter decreased to $45/MWh from $62/MWh in the same quarter of 2023.

Figure 3.7 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Prices are calculated based on the load schedules and corresponding prices at these aggregation points.[12] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets from October 2022 to September 2024.

Over the quarter, day-ahead prices averaged $48/MWh, 15-minute prices averaged $47/MWh, and 5-minute prices averaged $40/MWh. July had the highest prices, with an average over the three markets of about $57/MWh.

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

Figure 3.7 also shows monthly average gas prices at PG&E Citygate from October 2022 to September 2024. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. Over the past 27 months, both gas and energy prices exhibited similar fluctuations. The PG&E Citygate gas price has remained down after declining from its peak in December 2022, averaging about $2.8/MMBtu during the third quarter of 2024.

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

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

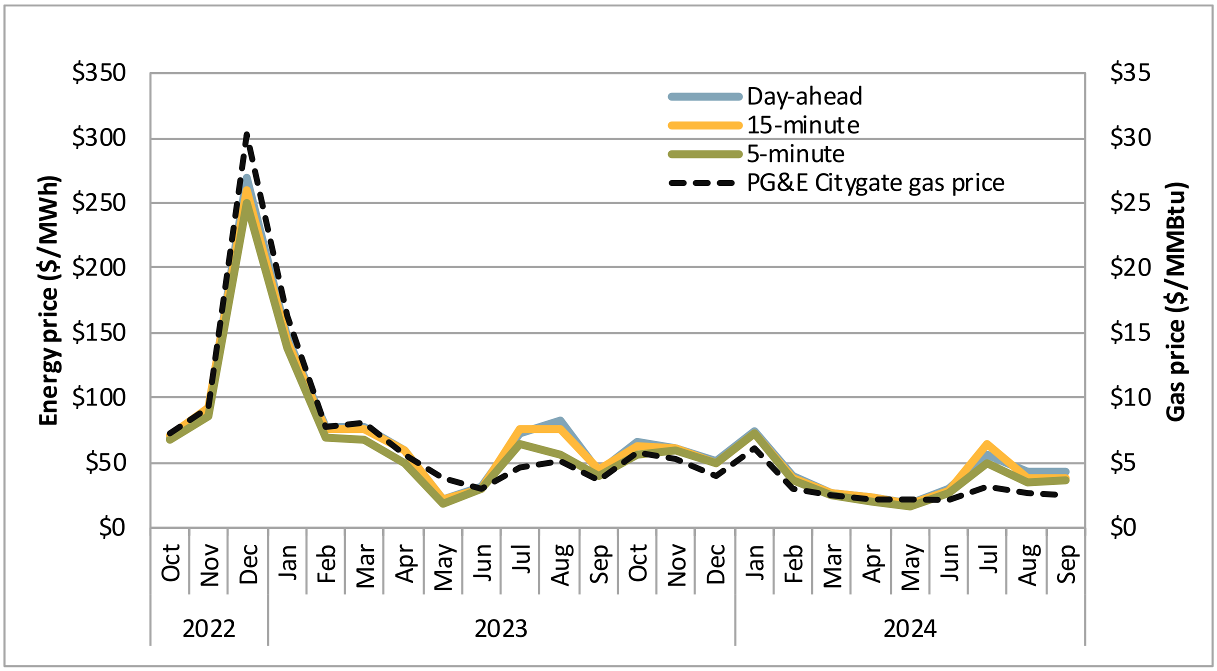


Figure 3.8 illustrates the hourly load-weighted average energy prices for the third quarter compared to the average hourly net load.[13] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) markets are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

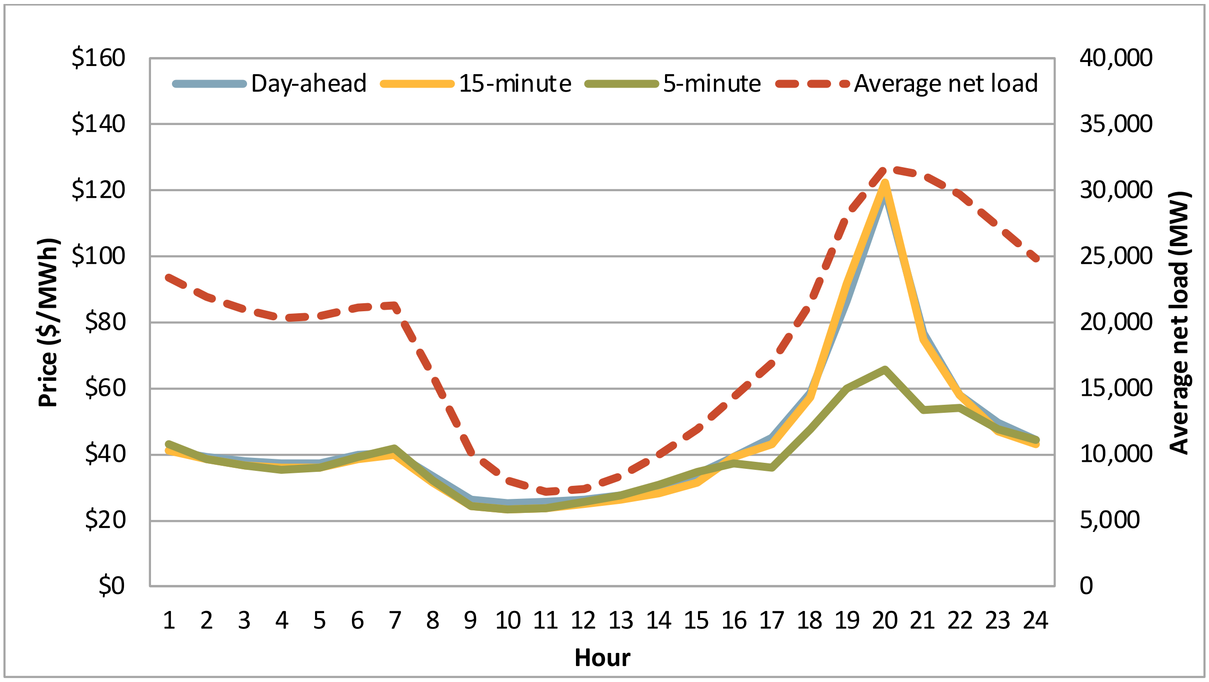
Average hourly prices continue to follow the net load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening. Prices peaked at hour-ending 20, when demand was still high but solar generation was substantially below its peak. The average net load in this quarter reached 31,688 MW at hour-ending 20.

13 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.

During hour-ending 20, the day-ahead load-weighted average energy price was $120/MWh, the 15-minute price was $122/MWh, and the 5-minute price was $66/MWh. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding.

One major cause of price separation between the 15-minute and 5-minute markets this quarter was load conformance during evening peak net load hours. California ISO operators typically adjust the load forecast up significantly more in the 15-minute market than in the 5-minute market over these hours.[14]

Figure 3.8 Hourly load-weighted average energy prices for balancing areas in day-ahead market (July–September)



3.4 Bilateral price comparison

Figure 3.9 and Figure 3.10 compare 15-minute prices in different regions of the WEIM during peak hours (hours-ending 7 to 22) to day-ahead prices for comparable markets. These figures show the monthly average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays.

As shown in these figures, average peak hour prices in the 15-minute market for WEIM areas in the Pacific Northwest and Desert Southwest were significantly lower than day-ahead prices in the Intercontinental Exchange for the Mid-Columbia and Palo Verde trading hubs, respectively. Prices in the 15-minute market for the two main areas in the California ISO area (Pacific Gas and Electric, and

[14] Please see Section 8 for a detailed discussion on load conformance.

Southern California Edison) tracked much more closely with day-ahead prices in the ISO's integrated forward market (IFM).

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

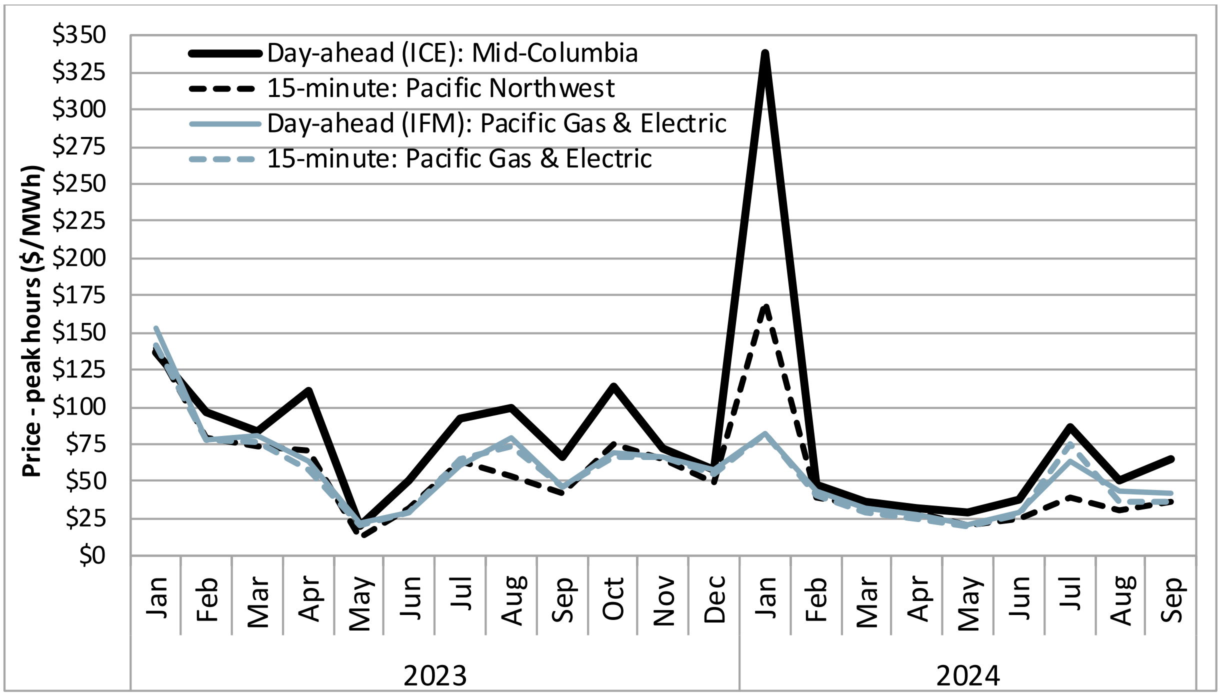


Figure 3.10 Palo Verde bilateral ICE vs. Desert Southwest 15-minute market prices (peak hours)

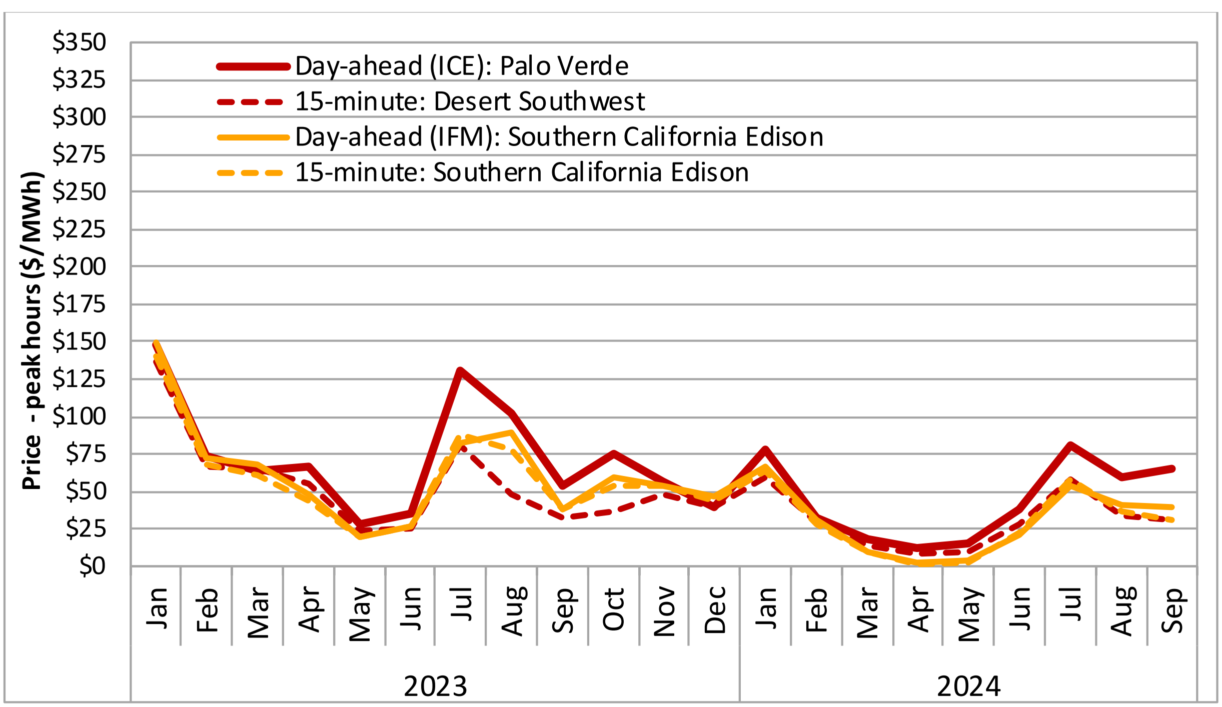


Figure 3.11 compares monthly average bilateral and ISO day-ahead market prices for 2023 through the third quarter of 2024. ISO market day-ahead prices are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). Average bilateral prices for Mid-Columbia (Peak) significantly exceeded ISO market day-ahead prices in January 2024. This was a result of a large arctic air mass in mid-January,[15] which covered much of the Pacific Northwest and Intermountain West regions. In all months of the third quarter, the Palo Verde (Peak) and Mid-Columbia (Peak) bilateral day-ahead prices exceed ISO day-ahead market prices. Palo Verde (Peak) prices were higher than Mid-Columbia (Peak) prices in August, but they were slightly lower than Mid-C prices in July and September.

Figure 3.11 Monthly average day-ahead and bilateral market prices

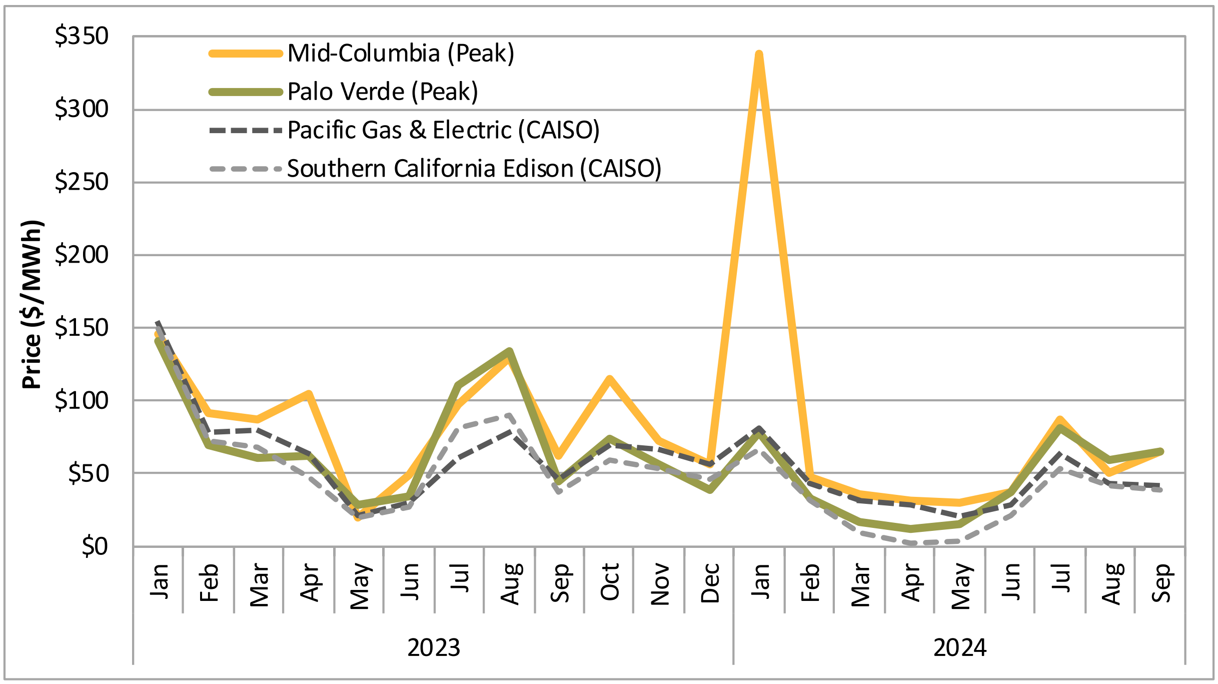


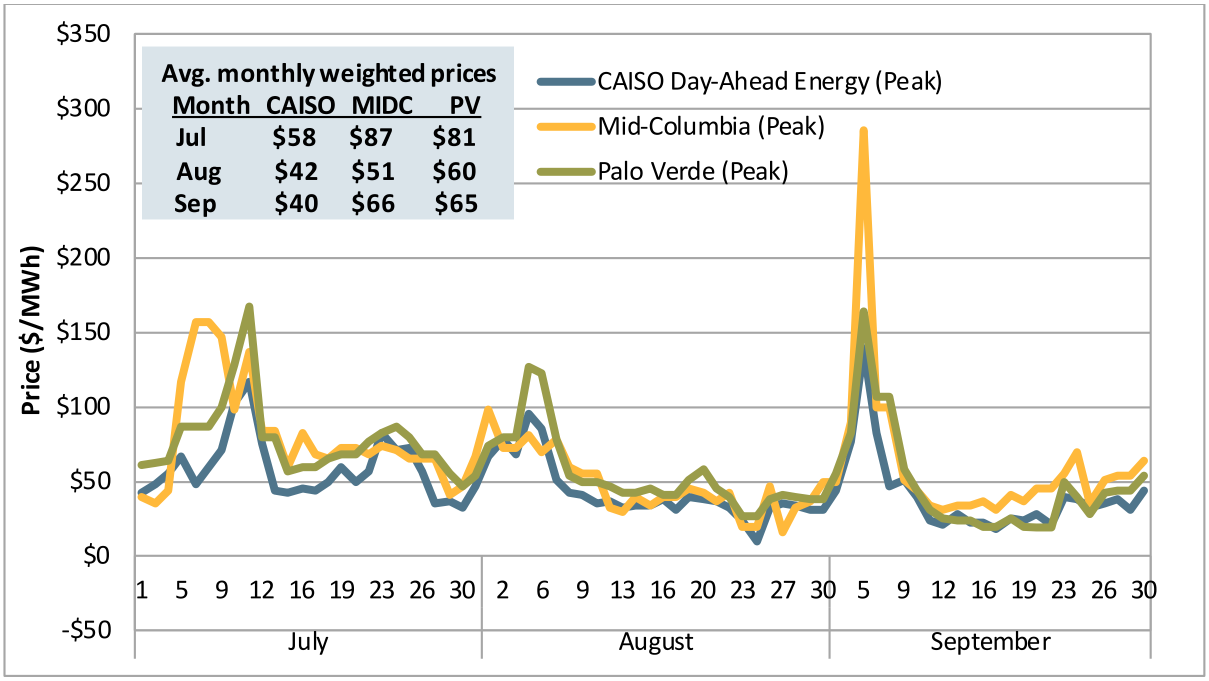
Figure 3.12 shows ISO market day-ahead load weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the average bilateral day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the ISO markets. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays. Prices at Mid-C were about 50 percent, 20 percent, and 65 percent higher than average ISO day-ahead market prices in July, August, and September, respectively.

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 raised its energy bid caps and penalty prices to

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

$2,000/MWh for hours-ending 19 and 20 in both the day-ahead and real-time markets on September 5, 2024.[16]

Figure 3.12 Day-ahead California ISO and bilateral market prices (July–September)



Average day-ahead prices in the California ISO balancing area and bilateral hubs (from the Intercontinental Exchange—or ICE) were also compared to real-time hourly energy prices traded at the Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average day-ahead hourly prices in the California ISO balancing area were similar to the average real-time prices at Mid-Columbia while about $1/MWh lower than Palo Verde. Average day-ahead prices at Mid-Columbia and Palo Verde were greater than the average real-time prices (from Powerdex) by about $12/MWh and $11/MWh, respectively.

3.5 Price variability

This section analyzes the frequency of prices exceeding $250/MWh and the occurrence of negative prices. Two groups of 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.[17] The second group comprises BAAs participating exclusively in the real-time market, which includes all WEIM entities aside from the California ISO balancing area.

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16 *Summer Market Performance Report for September 2024*, California ISO, October 31, 2024, p 80: https://www.caiso.com/documents/summer-market-performance-report-september-2024.pdf

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

High prices

Figure 3.13 shows the monthly frequency of high prices across all three markets for the balancing areas participating in both day-ahead and real-time markets from July 2023 to September 2024.[18] Figure 3.14 illustrates the monthly frequency of high prices for balancing areas participating only in the real-time market during the same period.[19]

In the day-ahead market, the frequency of high prices over $250/MWh decreased compared to the same quarter of 2023. In the third quarter of 2024, the day-ahead market recorded 0.6 percent of intervals with an average price exceeding $250/MWh. In the same quarter of the previous year, 1.3 percent of intervals had prices above $250/MWh.

In the 15-minute market, the frequency of high prices for balancing areas participating in the day-ahead market decreased by 34 percent, dropping from 1.1 percent in Q3 2023 to 0.7 percent in Q3 2024. This decline aligned with the CAISO balancing area having fewer high load hours, above 30-40 GW, this quarter compared to the same quarter last year.

Conversely, for BAAs participating exclusively in the real-time market, the frequency of high 15-minute market prices slightly increased from 0.39 percent to 0.4 percent in the 15-minute market. This trend reflects similar load profiles to the previous year.

In the 5-minute market, the frequency of high prices for balancing areas participating in the day-ahead market decreased by 32 percent, dropping from 0.34 percent to 0.23 percent. For balancing areas participating only in the real-time market, the frequency of high prices in the 5-minute market dropped by 57 percent, from 0.35 percent to 0.15 percent.

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

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

Figure 3.13 Monthly frequency of high prices ($/MWh) in BAAs participating in the day-ahead market (CAISO)

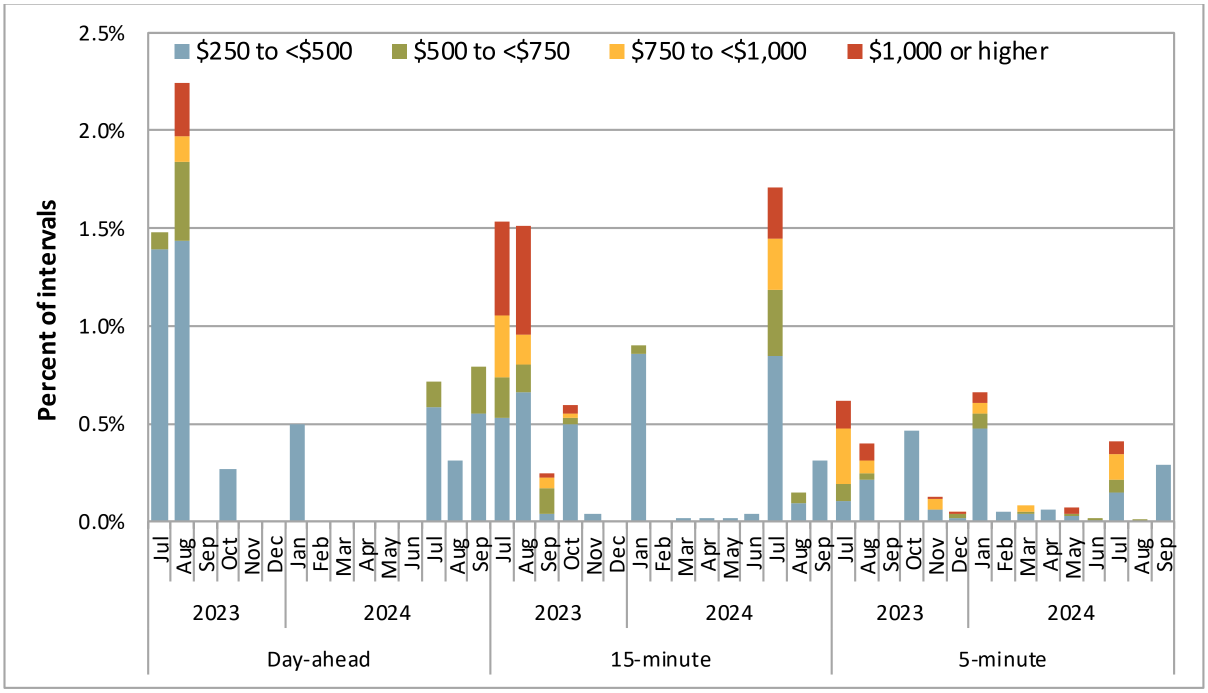
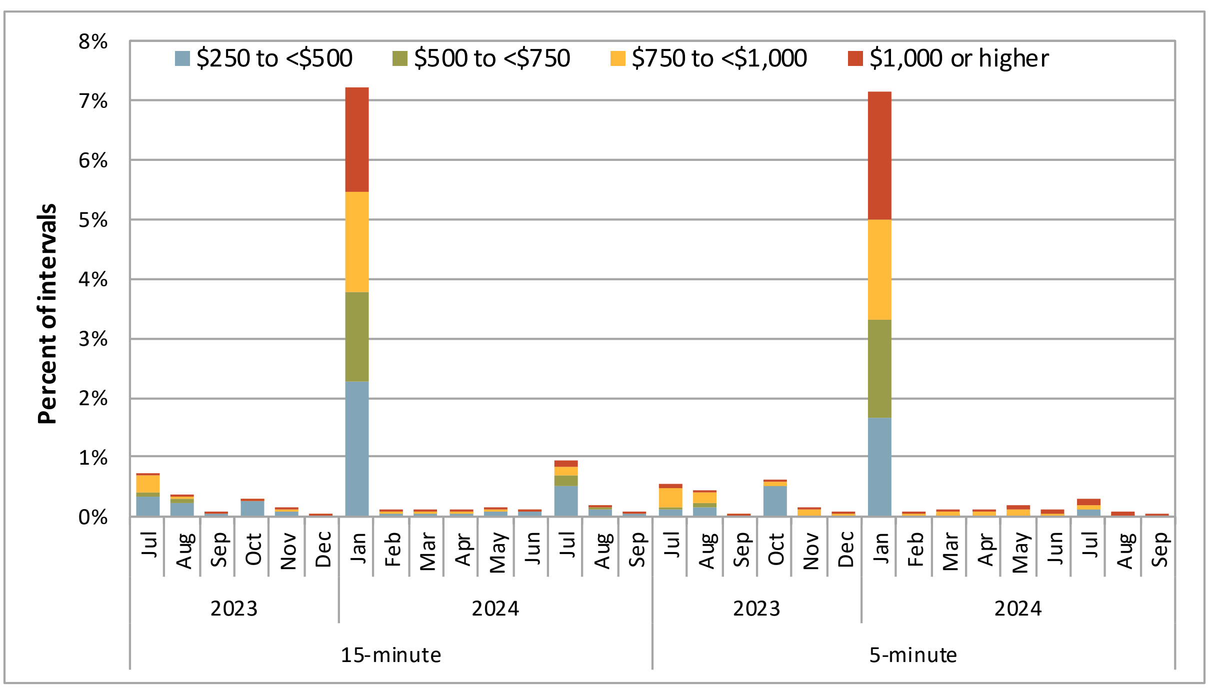


Figure 3.14 Monthly frequency of high prices ($/MWh) in BAAs participating only in the real-time markets



Negative prices

Figure 3.15 and Figure 3.16 show the frequency of negative prices across two groups: those participating in the day-ahead market and those participating only in the real-time markets, spanning the period from July 2023 to September 2024 for each market. Overall, the frequency of negative prices showed a continued increase across all markets during this quarter compared to the same quarter of the previous year.

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

For balancing areas participating in the day-ahead market—currently just the CAISO balancing area—the frequency of negative prices increased significantly across the day-ahead, 15-minute, and 5-minute markets, with an average rise of approximately 300 percent. For instance, in the day-ahead market, the frequency increased from 0.4 percent to 1.6 percent compared to the same quarter of the previous year. In the 15-minute market, it rose from 0.5 percent to 2.5 percent, and in the 5-minute market, it increased from 1 percent to 2.7 percent.

For the BAAs participating exclusively in the real-time markets—all balancing areas in WEIM besides ISO—the frequency of negative prices also showed a notable increase across the 15-minute and 5-minute markets, with an average rise of 106 percent compared to the same quarter of the previous year. For instance, in the 15-minute market, the frequency increased from 0.3 percent to 0.6 percent, while in the 5-minute market, it rose from 0.5 percent to 0.9 percent during this quarter.

One potential indicator of the frequency of negative pricing is the frequency of low-load conditions. System-wide, instances of load falling below 80 GW, which is below the median load level, decreased. However, some regions had more instances of low load in Q3 2024 compared to Q3 2023. In the California ISO balancing area, there was an increase in cases where the load dropped below 20 GW, a notably low level within the region's load distribution. Similarly, in the Desert Southwest, loads below 12 GW, representing the lower end of their load distribution, occurred more frequently. Additionally, the California region, excluding CAISO, experienced a higher frequency of load below 4 GW, reflecting the lower end of its load profile.

Figure 3.15 Monthly frequency of negative prices ($/MWh) in BAAs participating in the day-ahead market (CAISO)

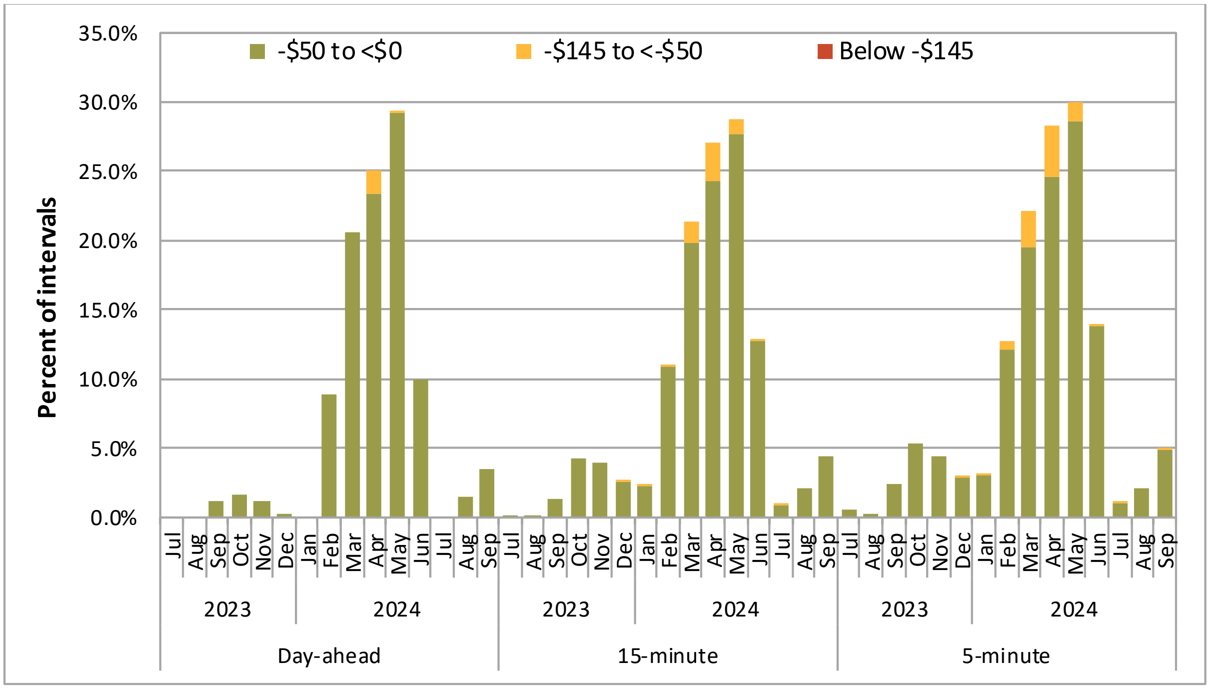
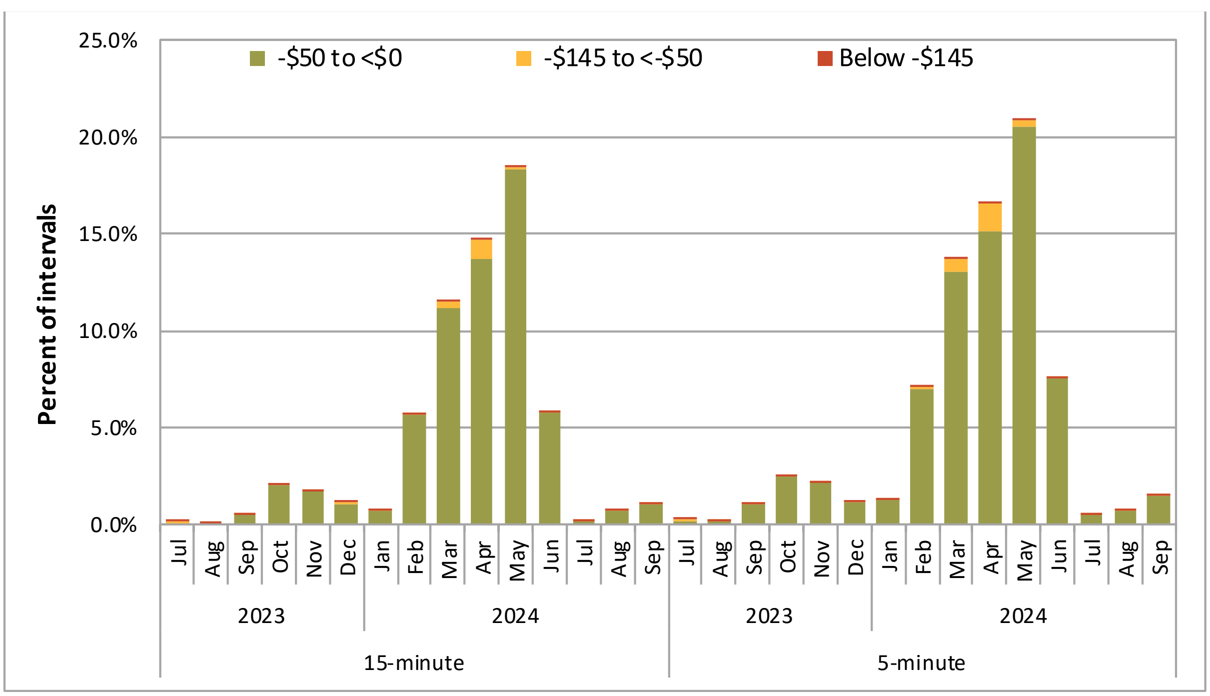


Figure 3.16 Monthly frequency of negative prices ($/MWh) in BAAs participating only in the real-time markets



3.6 Case study in bidding conduct

This section looks at bidding conduct and the composition of supply and demand in an example interval on September 6—during the early September heatwave that impacted much of the Southwest. Figure 3.17 shows the supply curve for the entire WEIM footprint in the 15-minute market at 18:15 on September 6.[20] During this interval, there was no WEIM transfer congestion such that transfers were able to optimally flow between balancing areas. Congestion on internal flow-based constraints was also minimal. As shown in Figure 3.17, the economic bids are relatively flat below $100/MWh and rise steeply between $100/MWh and $1,000/MWh.

Figure 3.18 shows the same information by fuel (or resource) type, while Figure 3.19 shows only the section of the supply curve with economic bid segments. In the 15-minute market, much of the supply that meets system-wide energy needs are self-scheduled (price-taking supply), including significant amounts from hydro generation and imports.[21] Looking instead at the economic portion of the curve, bid-in supply at or below $0/MWh was largely from wind, solar, and hydro resources. Moving up the supply stack, roughly half of the incremental bid-in supply in the range of $0/MWh to $100/MWh was from gas resources—while storage, coal, and hydro resources made up most of the remaining half. At the upper end of the supply stack (between $100/MWh and $1,000/MWh), bid-in supply was mostly from storage and hydro resources.

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20 The supply curve here considers all energy that balances against demand. For illustrative purposes, generation associated with the minimum operating level of online resources are shown at -$250/MWh and self-scheduled supply is shown at -$200/MWh. The economic segments include generation and imports that either cleared the market, or were bid above locational price and did not clear the market. Segments that were bid below locational price and did not clear the market (because of ancillary service obligation, resource constraint, etc.) were therefore not included.

21 Self-scheduled supply consists of any supply that does not have a price associated with it. This includes generation and imports that clear an earlier market process and are not re-bid in the real-time (such as California ISO balancing area imports that clear the hour-ahead scheduling process). This category also includes base-scheduled non-participating generation and imports in the WEIM.

Figure 3.17 15-minute market system supply (September 6, 2024 18:15)

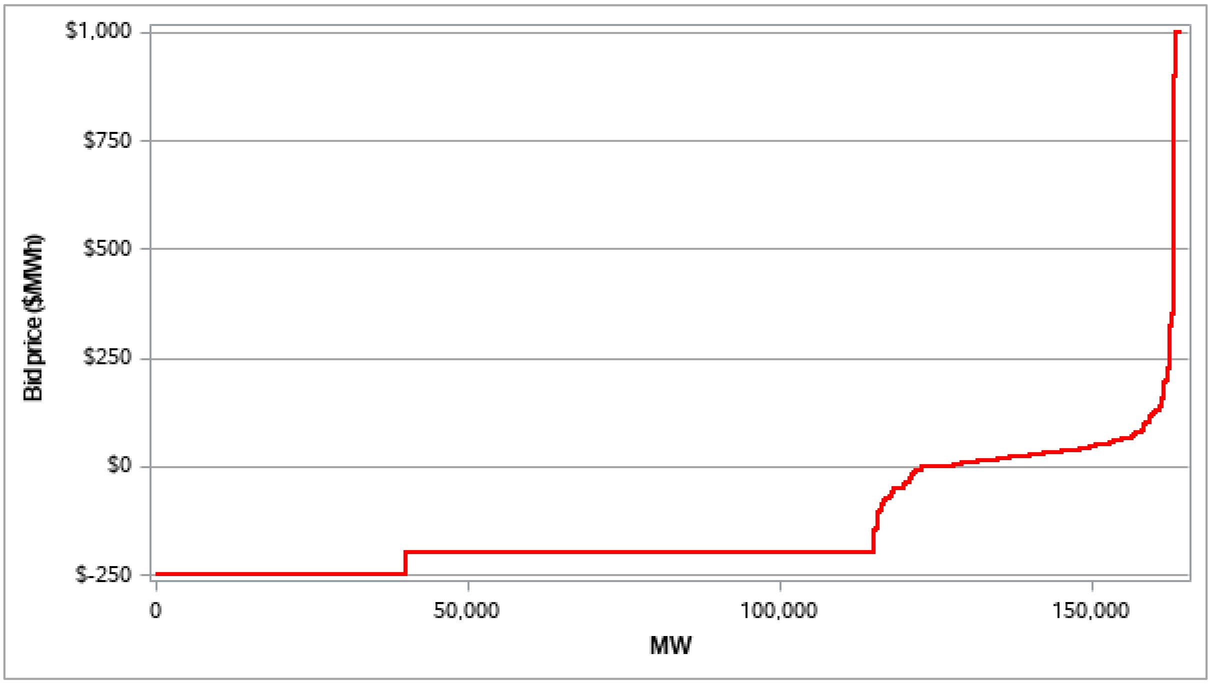


Figure 3.18 15-minute market system supply by fuel type (September 6, 2024 18:15)

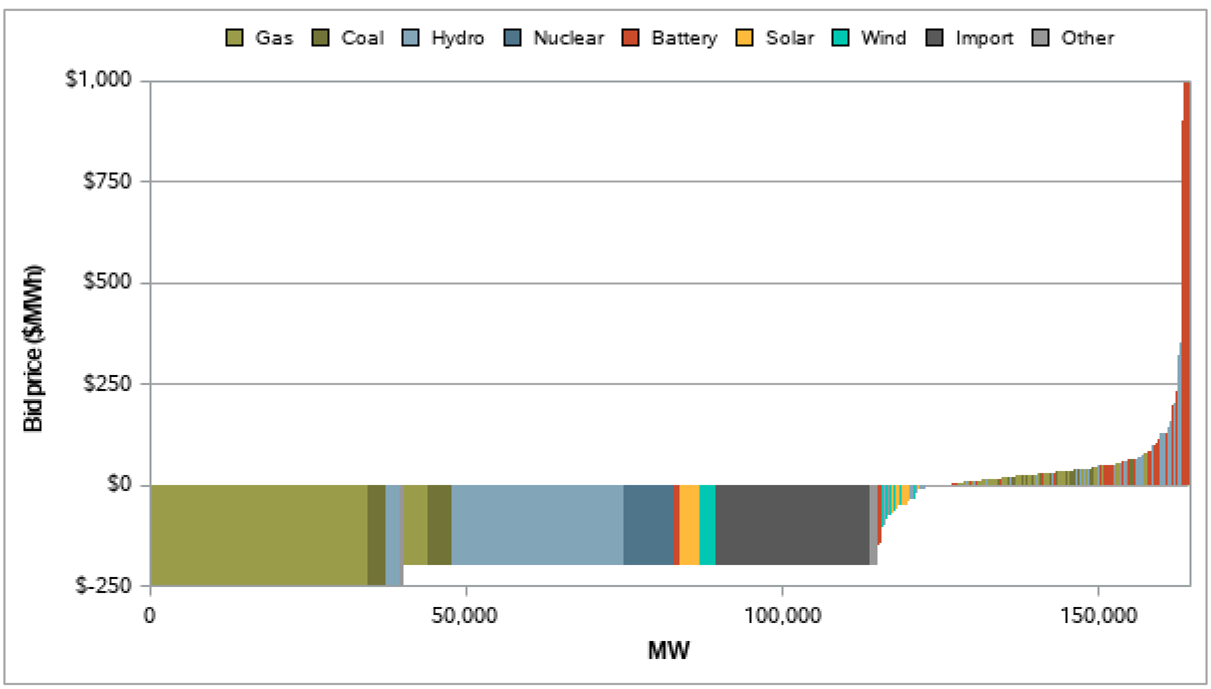


Figure 3.19 Economic 15-minute market supply by fuel type (September 6, 2024 18:15)

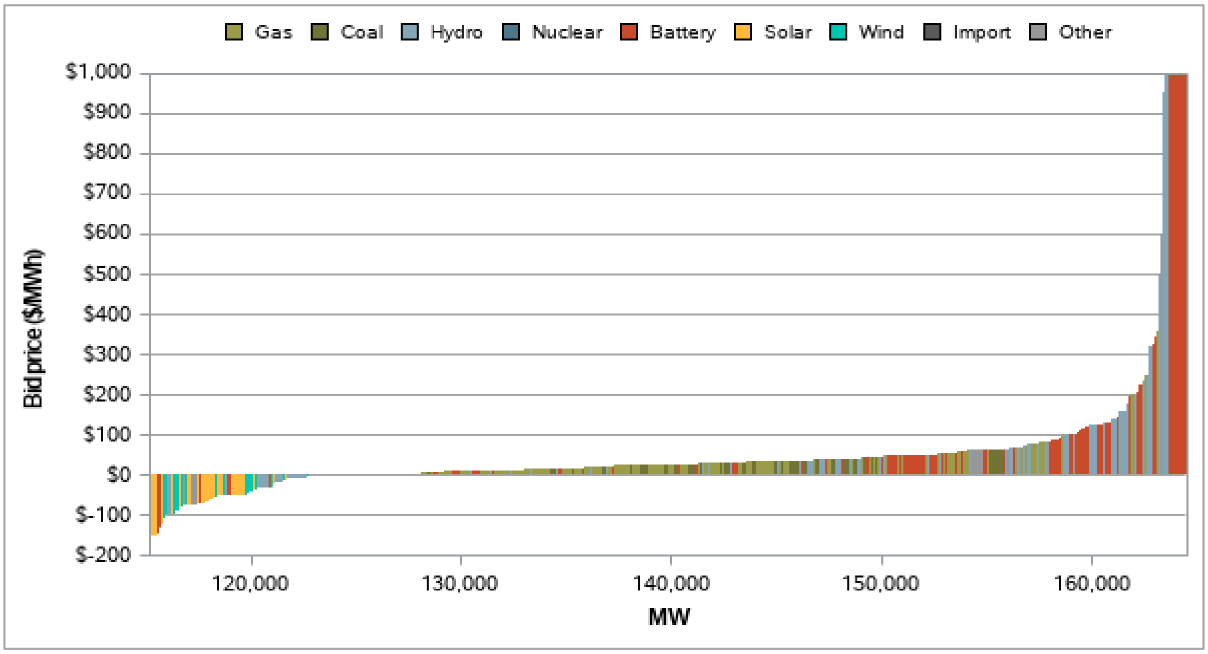


Figure 3.20 adds the demand curve, and shows the intersection of supply and demand during the example September interval.[22] In the 15-minute market, demand is mostly inelastic, illustrated by the near vertical line around 155,000 MW. The demand bids shown here instead between $0/MWh and $100/MWh were mostly from storage or hybrid resources (offers to charge). In this interval, the system marginal price equaled the intersection of the curves shown in this figure, at around $63/MWh. The price here was likely set by a gas resource.

Figure 3.21 shows the upper section of the supply and demand curves, including also a "competitive" supply curve with all generation set to the lower of their submitted market bid, or their *default energy bid* (DEB). The default energy bid is designed to reflect a unit's marginal energy cost.[23] As shown in the figure, market bids can significantly exceed competitive prices at the upper portion of the supply curve. However, this difference is largely from storage and hydro resources. In the example interval, moving all generation to competitive levels would have had a relatively small impact on the market clearing price based on the level of demand and flat nature of the supply at this price range. However, at higher levels of demand, resources bidding above competitive levels would be more likely to have a larger impact on prices.

[22] The demand curve here considers all energy that balances against supply. This includes forecasted load, pump-load, losses, exports, and battery-charging in the market. For illustrative purposes, forecasted load, pump-load, losses, and self-scheduled exports are shown at $1,100/MWh.

[23] Default energy bids are used in local market power mitigation.

Figure 3.20 15-minute market supply and demand (September 6, 2024 18:15)

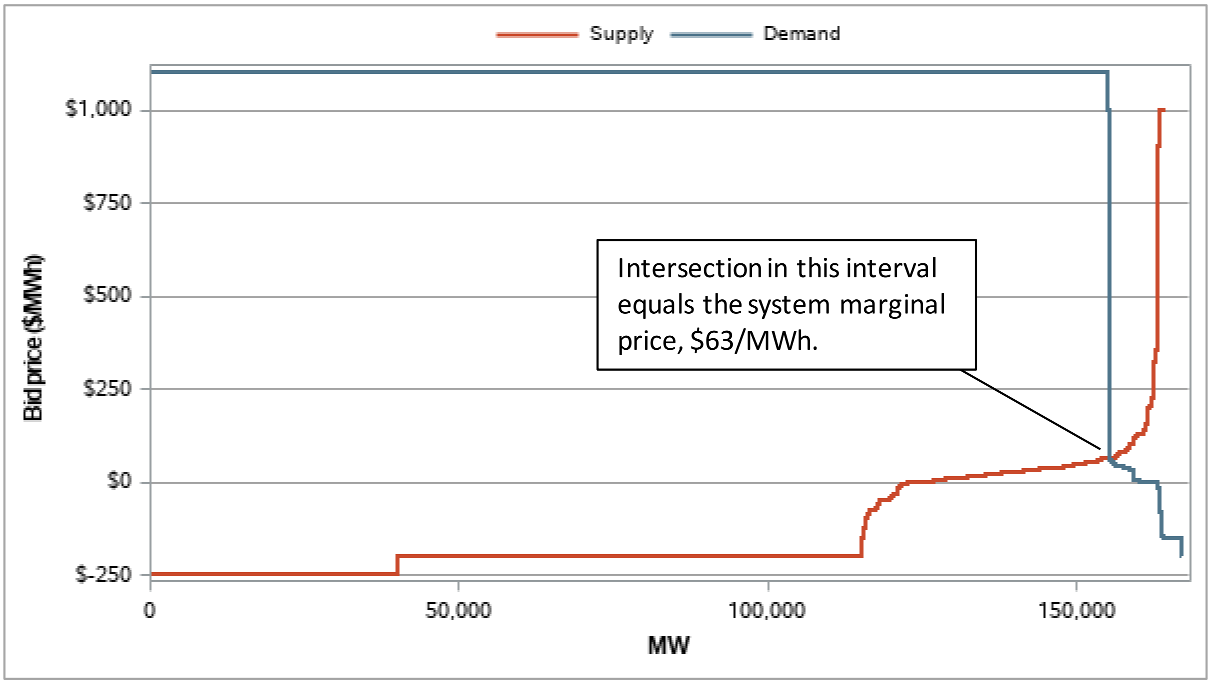
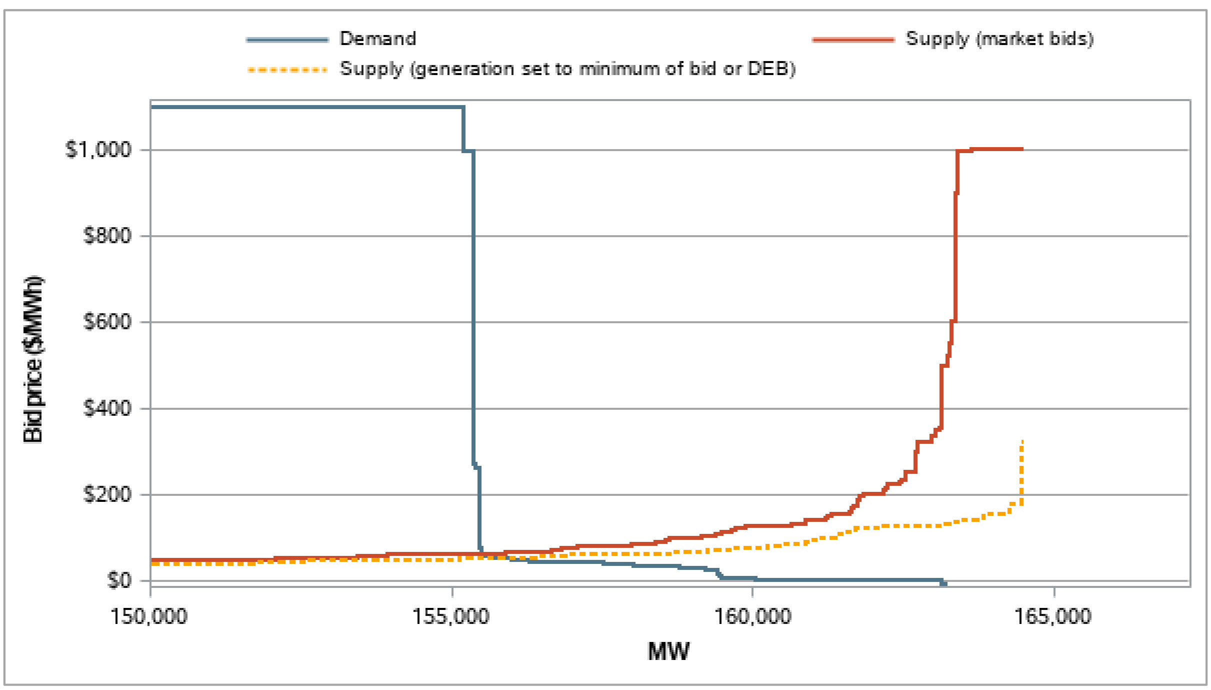


Figure 3.21 15-minute market supply and demand with generation at competitive reference levels (September 6, 2024 18:15)



3.7 WEIM transfers and transfer limits

Energy transfers

One of the key benefits of the WEIM is the ability to transfer energy between balancing areas in the 15-minute and 5-minute markets. These transfers are the result of regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint.

Figure 3.22 summarizes the average volume of WEIM transfers in the 5-minute market by hour during the last five quarters.[24] During the quarter, the average volume of transfers across the system was around 4,560 MW, compared to around 4,770 MW in the previous quarter, and around 5,080 MW from the same quarter of the previous year.

Figure 3.23 summarizes average inter-regional transfers during the quarter. The bars show *net* WEIM transfers for each region by hour.[25] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system. Net WEIM exports for a region are shown as positive and net WEIM imports for a region are shown as negative. The figure also highlights two key periods: mid-day and peak. During the mid-day hours, regional WEIM transfers are typically highest with significant levels of exports from the CAISO balancing area. During the peak hours—when net load in the WEIM system was highest—regional WEIM transfers were relatively low. Overall, balancing areas in the Desert Southwest and Intermountain West regions were exporting during this peak period, out to balancing areas in the California and Pacific Northwest regions.

Figure 3.24 and Figure 3.25 show average WEIM transfers in the 5-minute market by balancing area in the mid-day and peak periods during the quarter.[26] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area.

As shown in Figure 3.24, the CAISO balancing area exported on average around 1,840 MW out to neighboring balancing areas, during the mid-day hours. These hours typically contain the highest levels of exports out of the CAISO balancing area because of significant solar production. During the peak period (Figure 3.25), balancing areas in the Desert Southwest region exported on average around 880 MW to balancing areas outside the region (and 580 MW to balancing areas within the region).

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

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

[26] In Figure 3.24, each small tick is 100 MW, each large tick is 500 MW, and average WEIM transfer paths less than 50 MW are excluded. In Figure 3.25, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

Figure 3.22 Average dynamic WEIM transfer volume by hour and quarter (5-minute market)

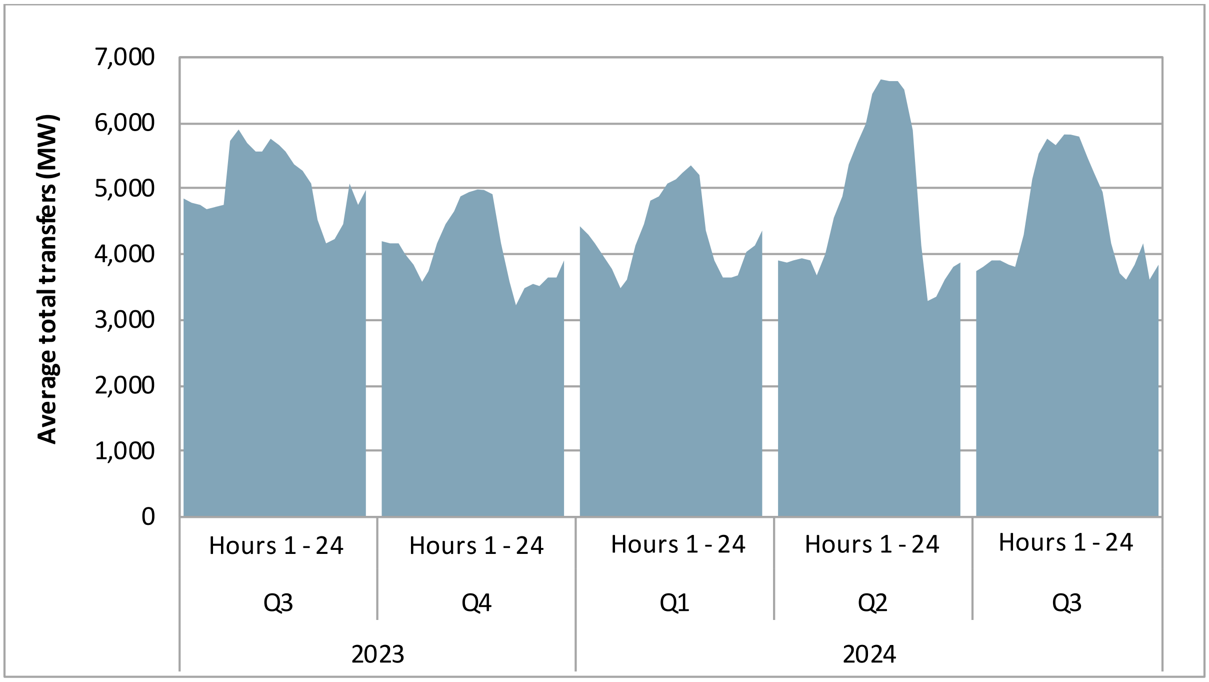


Figure 3.23 Average dynamic inter-regional WEIM transfers by hour (5-minute market, July–September 2024)

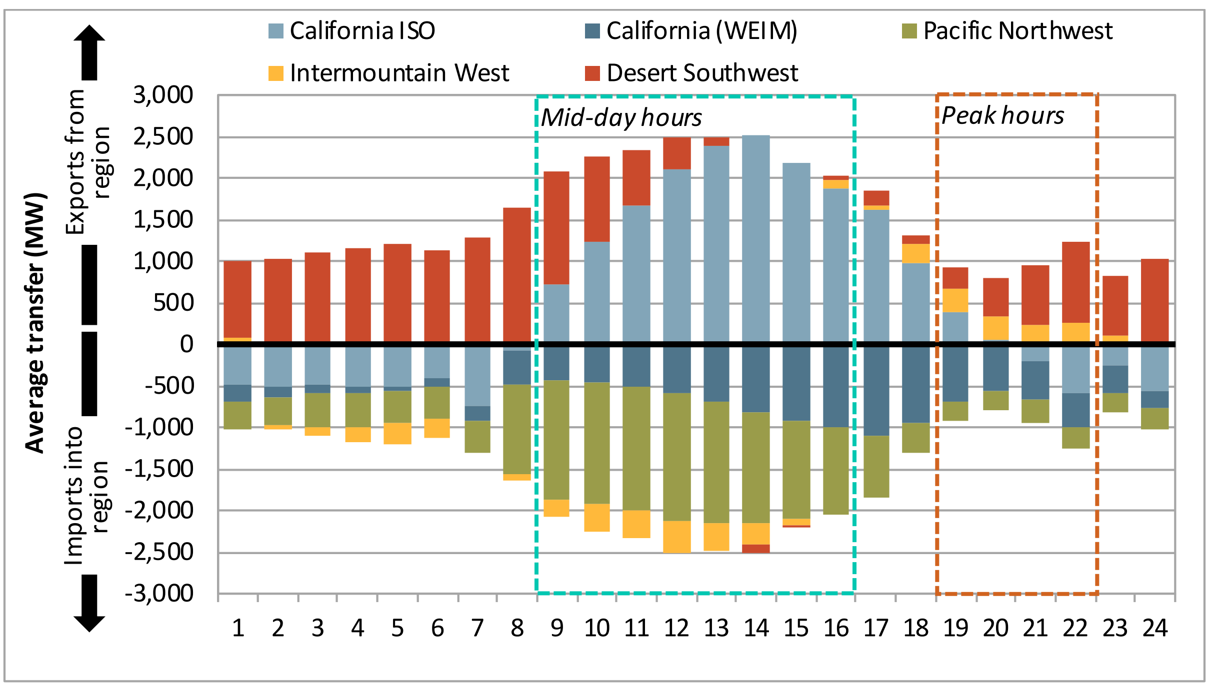


Figure 3.24 Average 5-minute market WEIM exports (mid-day hours, July–September 2024)

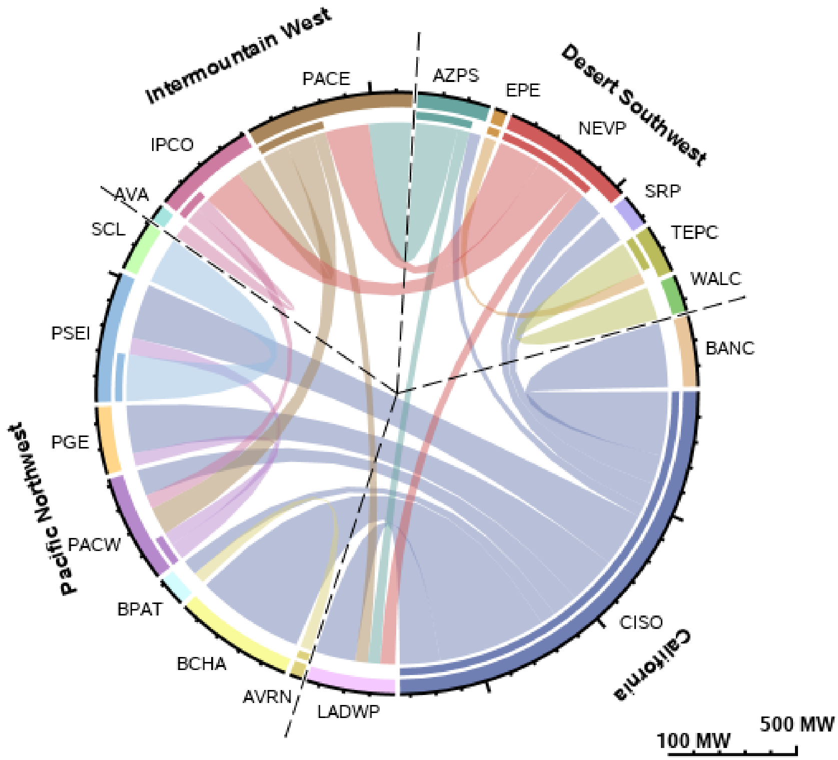
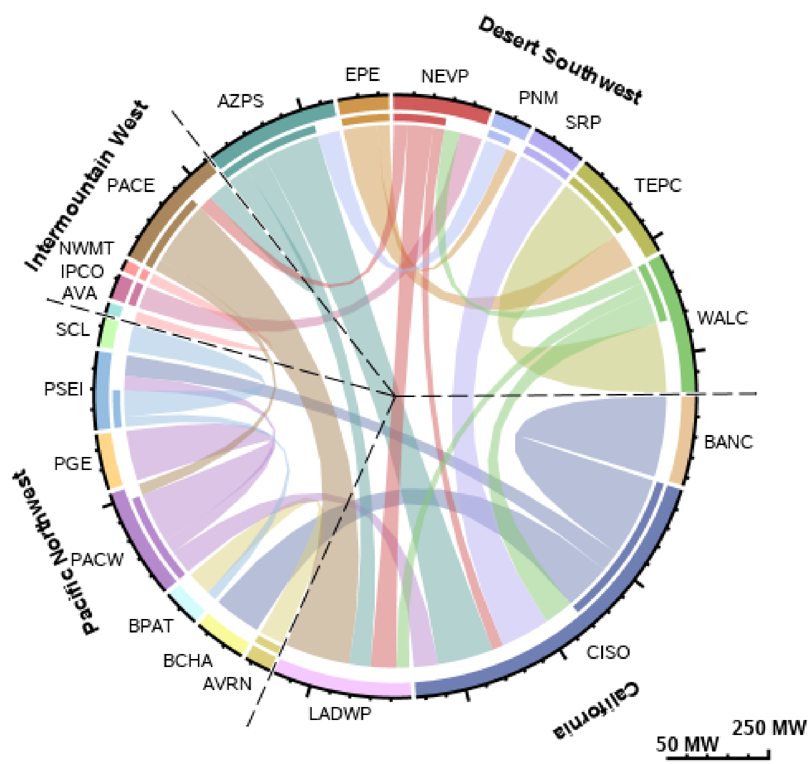


Figure 3.25 Average 5-minute market WEIM exports (peak load hours, July–September 2024)



Transfer limits

WEIM transfers between areas are constrained by transfer limits. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities. Table 3.5 shows average 5-minute market import and export limits for each balancing area, grouped by region. These amounts exclude base WEIM transfer schedules and therefore reflect transfer capability which is made available by WEIM entities to optimally transfer energy between areas. The last two columns in Table 3.5 show WEIM transfer limits between regions (out-of-region import and export limits).

Import and export transfer capacity into or out of the Desert Southwest region was around 29,100 MW and 34,600 MW, respectively. For the Pacific Northwest region, there was an average of around 1,600 MW of import and 600 MW of export transfer capacity into or out of the region. The lack of transfer capability out of the Pacific Northwest often leads to price separation between the region and the rest of the WEIM.

Table 3.5 Average 5-minute market WEIM limits (July–September 2024)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**33,254**	**28,245**
California ISO	42,685	33,071	29,848	23,828
BANC	4,122	3,957	0	0
LADWP	8,057	12,556	3,406	4,417
Turlock Irrig. District	1,769	2,041	0	0
Desert Southwest			**29,111**	**34,613**
Arizona Public Service	30,121	31,623	21,828	25,326
El Paso Electric	604	435	0	0
NV Energy	4,200	3,591	3,519	3,216
PSC New Mexico	1,032	1,248	0	0
Salt River Project	6,469	8,451	1,346	2,913
Tucson Electric	4,454	5,958	681	1,026
WAPA - Desert SW	4,356	5,433	1,737	2,133
Intermountain West			**2,521**	**2,983**
Avista Utilities	769	864	107	83
Idaho Power	2,170	3,072	566	866
NorthWestern Energy	795	574	32	16
PacifiCorp East	3,538	3,223	1,817	2,017
Pacific Northwest			**1,571**	**617**
Avangrid	830	733	20	18
Powerex	335	42	291	0
BPA	612	784	130	175
PacifiCorp West	1,949	1,643	662	370
Portland General Electric	737	534	190	10
Puget Sound Energy	1,278	1,180	274	43
Seattle City Light	439	410	5	0
Tacoma Power	347	248	0	0

4 Congestion

This section analyzes the impact of congestion from various constraint types in the real-time market and in the day-ahead market. Congestion in a nodal energy market occurs when the market model determines that flows have reached or exceeded the limit of a transmission constraint. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission-constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

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

4.1 WEIM transfer constraint congestion

When limits on constraints impacting WEIM transfers between balancing areas are reached, this can create congestion—resulting in higher or lower prices in the area relative to prevailing system prices. Table 4.1 shows the percent of intervals and price impact of 15-minute and 5-minute market transfer constraint congestion in each WEIM area during the quarter.[28] The congestion on the WEIM transfer constraints are measured relative to a reference price in the CAISO balancing area. *Congested from area* reflects that prices are lower in the balancing area because of limited export capability out of the area or region, relative to the CAISO (and connected WEIM system). *Congestion into area* reflects that prices are higher within an area or region, because of limited import capability into the area or region.[29]

Powerex was frequently import constrained relative to the CAISO balancing area because of WEIM transfer congestion. Powerex was congested into the area during around 64 percent of intervals in the 15-minute and 5-minute markets. On average for the quarter, prices in Powerex were around $9/MWh higher because of WEIM transfer congestion. BPA was also frequently import constrained, during around 23 percent of 15-minute and 5-minute market intervals.

The rest of the Pacific Northwest region was also frequently transfer constrained relative to the rest of the WEIM system. These balancing areas were *import* constrained in around 16 percent of 15-minute

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

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

29 When a balancing area has net WEIM transfer import congestion into the area, the market software triggers local market power mitigation procedures for resources in that area. If bid in supply after removing the three largest suppliers is less than the generation dispatched in the area in the market power mitigation run, bids in excess of the higher of default energy bids and the competitive LMP will be replaced by the higher of default energy bids and the competitive LMP.

intervals and 10 percent of 5-minute intervals. These balancing areas were also *export* constrained in around 6 percent of 15-minute and 5-minute market intervals.

El Paso Electric, Tucson Electric Power, and Salt River Project were also frequently export constrained during the quarter. El Paso Electric was export constrained in roughly 23 percent of 15-minute and 5-minute market intervals. Tucson Electric Power was export constrained in around 20 percent of intervals. Salt River Project was export constrained in around 11 percent of intervals. These balancing areas were frequently transfer constrained because of intertie constraints that these balancing areas use to manage WEIM transfers into or out of their system.

Table 4.1 Frequency and impact of transfer congestion in the WEIM (July–September 2024)

	15-minute market				5-minute market			
	Congested from area		Congested into area		Congested from area		Congested into area	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
Turlock Irrigation District	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00
BANC	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00
WAPA – Desert Southwest	0.0%	-$0.04	0.0%	$0.11	0.0%	-$0.01	0.0%	$0.02
NV Energy	0.2%	-$0.05	0.0%	$0.00	0.1%	-$0.03	0.1%	$0.42
Arizona Public Service	0.2%	-$0.01	0.1%	$0.11	0.0%	$0.00	0.2%	$1.19
Public Service Company of NM	0.3%	-$0.36	0.2%	$0.57	0.2%	-$0.31	0.2%	$0.56
L.A. Dept. of Water and Power	0.4%	-$0.19	2%	$1.97	0.4%	-$0.08	2%	$5.51
PacifiCorp East	0.1%	-$0.01	2%	$0.11	0.1%	-$0.03	1%	$0.07
Idaho Power	1%	-$0.56	3%	$0.15	0.6%	-$0.35	2%	$0.11
NorthWestern Energy	2%	-$0.59	3%	$0.27	1%	-$0.15	2%	$0.76
Avista Utilities	2%	-$1.28	4%	$0.23	1%	-$0.48	2%	$0.29
Salt River Project	11%	-$2.57	3%	$1.57	10%	-$1.58	3%	$2.67
PacifiCorp West	8%	-$2.75	15%	$1.69	5%	-$0.91	9%	$1.10
Avangrid Renewables	8%	-$2.76	15%	$1.67	5%	-$0.93	9%	$1.16
Tucson Electric Power	21%	-$3.11	1%	$0.55	19%	-$2.98	1%	$1.10
Puget Sound Energy	7%	-$2.56	16%	$2.44	5%	-$0.89	11%	$1.73
Tacoma Power	7%	-$2.68	16%	$1.93	5%	-$0.92	11%	$1.33
Seattle City Light	7%	-$2.87	16%	$2.21	5%	-$1.14	11%	$1.47
Portland General Electric	8%	-$2.71	16%	$1.82	5%	-$0.89	10%	$1.08
El Paso Electric Company	25%	-$5.59	0.7%	$2.33	22%	-$4.43	0.9%	$2.24
Bonneville Power Admin.	7%	-$2.42	24%	$6.09	5%	-$0.77	22%	$4.21
Powerex	4%	-$2.57	64%	$8.98	15%	-$1.61	64%	$9.01

4.2 Internal congestion in the real-time market

This section presents analysis of the effect of internal congestion on real-time markets across the WEIM.[30] This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas. The impact from transfer constraints are discussed above in Section 4.1.

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

The impact of congestion on each pricing node in the system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[31]

In this quarter, internal congestion in the real-time market was on average in the north-to-south direction. This trend was more pronounced during evening peak hours. This congestion contributed to increasing prices in the California and Desert Southwest areas relative to balancing areas in the Pacific Northwest and Intermountain West regions.[32]

Figure 4.1 illustrates the overall impact of internal congestion on prices at the default load aggregation points (DLAP) and EIM load aggregation points (ELAP) in the third quarter of 2024. The blue bars represent the 15-minute market price impact, and the yellow bars indicate the 5-minute market price impact from internal constraints.

Figure 4.1 Overall impact of internal congestion on price separation in the 15-minute and 5-minute markets (July–September 2024)

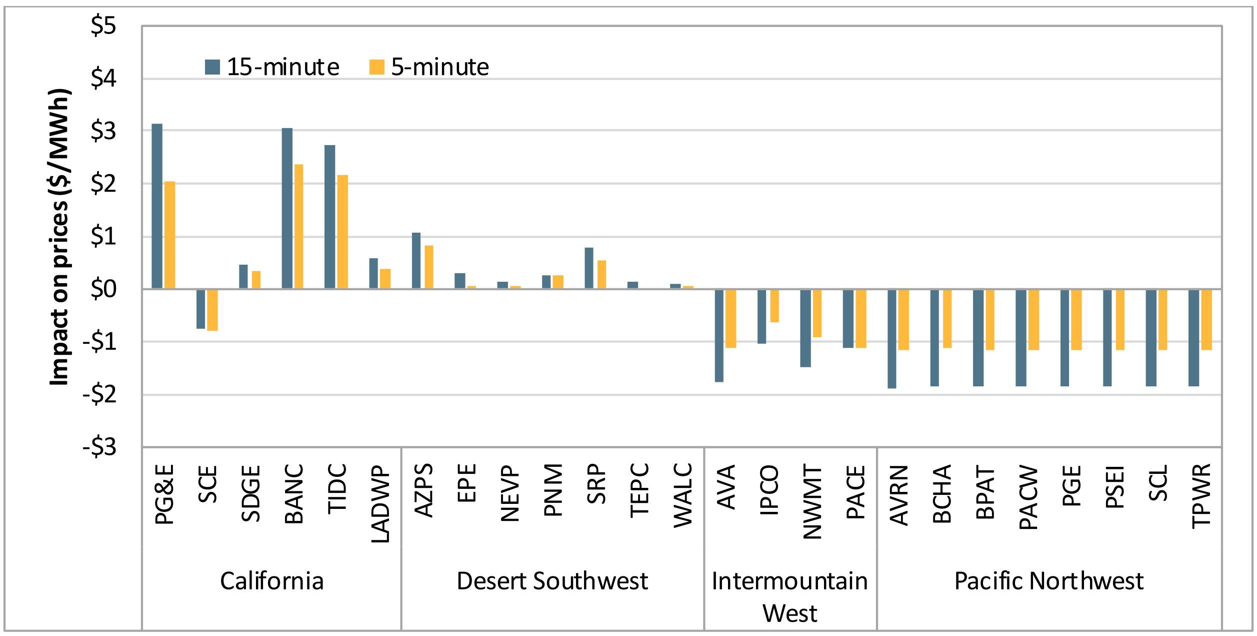


Figure 4.2 displays the average impact of internal congestion on prices in the third quarter of 2023 and 2024. The blue bars represent the impact for 2023, and the red bars show the impact for 2024. This

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

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

impact was calculated as the average of the 15-minute and 5-minute market price impacts of internal constraints for all intervals.

In both Q3 2023 and Q3 2024, congestion on internal paths was on average from the Pacific Northwest and Intermountain West, to the Desert Southwest. However, impacts of internal congestion on prices in California areas shifted year-over-year.

Figure 4.2 Average impact of internal congestion on real-time market price (2023-2024)

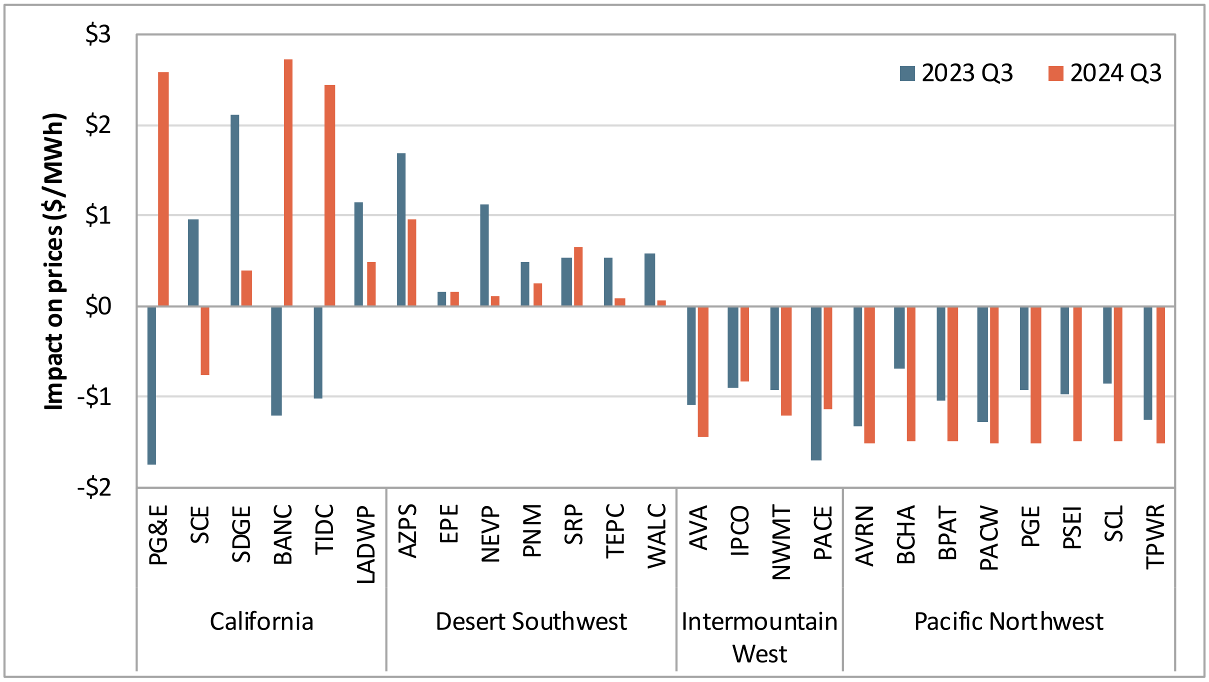


Figure 4.3 and Figure 4.4 display the hourly impact of internal congestion on the 15-minute market prices by DLAPs and ELAPs for the third quarter of 2024 and 2023, respectively. In 2023, south-to-north congestion was prevalent during solar hours, increasing prices in Northern California, the Pacific Northwest, and Intermountain West relative to Southern California and the Desert Southwest. This pattern shifted somewhat for the third quarter of 2024. The heaviest congestion was into specific balancing areas such as BANC and Turlock across the mid-day solar hours, and into Arizona Public Service and Salt River Project during the later solar hours.

During evening peak hours, congestion was from the Pacific Northwest and Intermountain West into all of California and the Desert Southwest. In Q3 2023, Northern California had been on the upstream side of the north-to-south evening peak hour congestion.

Figure 4.3 Overall impact of internal congestion on price separation in the 15-minute market by hour (July–September 2024)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	0.3	0.1	0.1	0.0	0.0	0.3	0.1	0.7	2.0	2.4	1.3	1.4	0.8	0.6	-0.2	2.2	5.0	10.1	14.8	16.7	11.4	4.7	0.6	0.0
BANC	-0.1	-0.1	0.0	0.0	0.0	0.1	0.1	0.7	2.8	3.0	3.7	4.1	3.9	4.5	4.6	6.0	5.6	3.7	7.0	13.6	7.8	3.2	0.0	-0.3
Turlock ID	-0.1	0.0	0.0	0.0	0.0	0.0	-0.1	0.7	3.9	5.1	6.5	6.8	7.1	7.6	6.8	6.5	3.0	0.8	1.0	5.5	3.8	1.6	-0.4	-0.5
SCE	0.2	0.5	0.4	0.3	0.2	0.2	0.5	-0.7	-3.0	-4.0	-3.4	-3.5	-2.8	-3.8	-3.9	-3.4	-2.3	-1.1	2.5	3.6	2.6	2.1	0.6	0.5
SDG&E	0.6	0.8	0.6	0.4	0.4	0.3	0.6	-0.4	-2.4	-3.3	-2.8	-2.8	-3.7	-5.4	-4.2	-2.2	0.3	4.4	7.4	7.1	7.1	6.8	1.0	0.8
LADWP	0.2	0.4	0.3	0.2	0.1	0.1	0.4	-0.4	-1.2	-1.2	-1.0	-0.9	-0.5	-0.5	-0.2	0.3	0.7	1.2	5.1	4.9	3.0	1.9	0.6	0.5
NV Energy	0.1	0.2	0.1	0.1	0.0	0.0	0.2	-0.2	-0.6	-0.7	-0.7	-0.5	-0.3	-0.3	-0.3	-0.1	0.2	0.4	2.3	1.7	0.9	0.5	0.3	0.3
Arizona PS	0.1	0.3	0.2	0.2	0.1	0.1	0.3	-0.3	-1.0	-1.0	-0.8	-0.7	-0.1	2.8	5.3	5.0	2.8	2.2	3.6	3.2	1.6	0.7	0.6	0.4
Tucson Electric	0.1	0.3	0.2	0.2	0.1	0.1	0.3	-0.3	-1.0	-1.0	-0.9	-0.8	-0.6	-0.9	-0.9	-0.7	0.0	0.5	3.3	2.9	1.4	0.5	0.5	0.4
Salt River Project	0.1	0.3	0.2	0.2	0.1	0.1	0.3	-0.3	-1.0	-1.1	-0.9	-0.8	-0.3	2.2	4.0	3.2	1.9	1.2	3.4	3.1	1.5	0.6	0.5	0.4
PSC New Mexico	0.4	0.6	0.6	0.6	0.7	1.1	1.6	0.2	-1.6	-1.3	-1.3	-1.1	-0.5	-0.6	-0.6	-0.5	0.2	0.5	2.7	2.1	1.0	0.5	0.6	0.5
WAPA - Desert SW	0.1	0.3	0.3	0.2	0.1	0.1	0.3	-0.3	-1.0	-1.1	-0.9	-0.8	-0.6	-0.8	-0.8	-0.7	0.1	0.5	3.5	1.1	1.6	0.7	0.5	0.4
El Paso Electric	-0.4	-0.4	-0.6	-0.9	-1.1	-1.3	-0.5	0.8	0.4	-0.1	0.5	0.7	-0.1	-0.2	0.0	0.1	0.6	0.7	3.3	2.9	1.5	0.7	0.6	0.0
PacifiCorp East	-0.6	-0.5	-0.4	-0.5	-0.4	-0.4	-0.6	-0.5	-0.6	-0.6	-0.5	-0.4	-0.3	-0.4	-0.6	-0.7	-0.7	-1.0	-3.6	-6.5	-3.5	-2.2	-0.8	-0.6
Idaho Power	-0.2	-0.4	-0.3	-0.2	-0.1	-0.2	-0.3	-0.1	0.1	0.2	0.2	0.1	0.0	0.0	0.0	-0.2	-0.4	-0.9	-5.8	-7.6	-5.0	-2.9	-0.4	-0.3
NorthWestern	-0.2	-0.5	-0.4	-0.3	-0.1	-0.2	-0.4	0.1	0.5	0.6	0.6	0.4	0.3	0.3	0.1	-0.5	-1.0	-1.9	-8.7	-11.4	-7.7	-4.4	-0.6	-0.3
Avista Utilities	-0.3	-0.6	-0.5	-0.3	-0.2	-0.2	-0.6	0.0	0.6	0.8	0.8	0.6	0.4	0.4	0.2	-0.6	-1.2	-2.4	-10.7	-13.4	-8.9	-5.2	-0.8	-0.5
Avangrid	-0.3	-0.7	-0.6	-0.4	-0.2	-0.3	-0.7	0.1	0.9	1.0	1.1	0.9	0.7	1.0	0.8	0.0	-1.1	-2.5	-12.1	-15.0	-10.0	-5.9	-0.9	-0.6
BPA	-0.3	-0.6	-0.5	-0.4	-0.2	-0.3	-0.6	0.1	0.7	0.9	0.9	0.7	0.5	0.4	0.3	-0.6	-1.3	-2.5	-11.2	-14.0	-9.4	-5.5	-0.8	-0.5
Tacoma Power	-0.3	-0.6	-0.5	-0.4	-0.2	-0.3	-0.6	0.0	0.7	0.9	0.9	0.7	0.5	0.4	0.3	-0.6	-1.3	-2.5	-11.2	-14.0	-9.3	-5.4	-0.8	-0.5
PacifiCorp West	-0.3	-0.6	-0.6	-0.4	-0.2	-0.3	-0.6	0.1	0.8	0.9	0.9	0.8	0.5	0.5	0.4	-0.5	-1.3	-2.5	-11.5	-14.3	-9.5	-5.6	-0.8	-0.5
Portland GE	-0.3	-0.6	-0.6	-0.4	-0.2	-0.3	-0.6	0.1	0.8	0.9	0.9	0.7	0.5	0.5	0.3	-0.6	-1.3	-2.5	-11.4	-14.2	-9.4	-5.5	-0.8	-0.5
Puget Sound Energy	-0.3	-0.6	-0.5	-0.4	-0.2	-0.3	-0.6	0.0	0.7	0.9	0.9	0.7	0.5	0.4	0.3	-0.6	-1.3	-2.5	-11.2	-14.0	-9.3	-5.4	-0.8	-0.5
Seattle City Light	-0.3	-0.6	-0.5	-0.4	-0.2	-0.3	-0.6	0.0	0.7	0.9	0.9	0.7	0.5	0.4	0.3	-0.6	-1.3	-2.5	-11.2	-14.0	-9.3	-5.4	-0.8	-0.5
Powerex	-0.3	-0.6	-0.5	-0.4	-0.2	-0.3	-0.6	0.0	0.7	0.8	0.8	0.7	0.4	0.4	0.3	-0.6	-1.3	-2.5	-11.0	-13.9	-9.2	-5.4	-0.8	-0.5

Hour

Figure 4.4 Overall impact of internal congestion on price separation in the 15-minute market by hour (July–September 2023)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PG&E	-1.4	-1.2	-1.2	-0.9	-0.8	-1.1	-0.9	0.9	3.4	3.1	2.5	2.9	2.6	1.9	-0.3	-2.1	-1.4	-6.0	-13.3	-19.6	-11.9	-9.5	-3.7	-1.8
BANC	-1.3	-1.2	-1.3	-1.3	-1.0	-1.1	-0.7	1.1	4.7	4.6	3.8	4.4	4.1	3.6	1.4	-0.9	-0.8	-5.8	-11.2	-20.7	-13.0	-9.3	-3.8	-1.9
Turlock ID	-1.4	-1.2	-1.3	-1.2	-1.0	-1.1	-0.7	1.2	4.8	5.0	4.4	5.1	4.8	4.1	1.7	-0.6	-0.4	-5.6	-13.0	-20.3	-12.3	-9.2	-3.8	-1.9
SCE	1.2	1.0	1.0	0.9	0.8	1.0	0.6	-1.3	-4.8	-5.2	-4.4	-4.4	-4.1	-3.0	-1.0	0.8	1.0	5.7	11.9	21.0	12.3	8.7	3.3	1.6
SDG&E	1.4	1.3	1.1	1.0	0.8	1.2	0.6	-0.8	-2.2	-2.6	-1.1	-1.9	-0.8	0.0	1.0	2.3	2.3	5.9	11.6	20.2	13.0	9.4	5.2	2.4
LADWP	1.2	1.1	1.1	0.9	0.8	1.0	0.6	-1.3	-4.6	-4.9	-4.1	-3.9	-3.4	-2.5	-0.6	1.3	1.1	5.6	12.1	21.1	12.7	9.0	3.3	1.6
NV Energy	0.7	0.3	0.3	0.4	0.3	0.5	1.1	-1.1	-2.6	-1.7	-1.4	-1.7	-0.9	-0.9	0.3	2.5	1.6	3.6	9.2	13.4	8.2	6.2	1.2	0.4
Arizona PS	1.0	0.8	0.9	0.7	0.6	0.8	0.5	-1.3	-4.6	-4.8	-4.4	-3.7	-2.2	0.9	5.9	7.7	4.9	6.7	10.5	17.6	10.5	7.3	2.4	1.4
Tucson Electric	1.0	0.8	0.9	0.7	0.6	0.8	0.5	-1.3	-4.5	-4.7	-4.3	-4.1	-3.7	-2.8	-1.0	0.5	0.3	3.5	9.7	16.9	10.1	7.0	2.2	1.2
Salt River Project	1.0	0.8	0.9	0.7	0.6	0.8	0.5	-1.3	-4.6	-4.8	-4.4	-4.2	-3.8	-3.0	-1.2	0.5	0.4	3.5	9.9	17.3	10.4	7.2	2.4	1.4
PSC New Mexico	0.2	0.3	0.4	0.3	0.2	0.4	0.2	-1.2	-4.1	-4.2	-3.9	-3.6	-3.1	-1.8	-0.6	1.5	0.8	4.1	10.0	15.1	8.7	5.9	1.3	-0.4
WAPA - Desert SW	1.0	0.8	0.9	0.7	0.6	0.8	0.5	-1.3	-4.6	-4.7	-4.3	-4.1	-3.7	-2.9	-0.9	0.6	0.4	3.7	10.0	17.3	10.4	7.2	2.3	1.2
El Paso Electric	-1.3	-1.0	-0.9	-0.5	-0.7	-0.5	-0.6	-1.6	-4.9	-4.3	-4.1	-3.9	-2.9	-1.9	-1.0	1.1	0.4	3.8	10.7	16.7	9.8	6.1	1.1	-1.2
PacifiCorp East	-1.4	-1.2	-1.1	-1.2	-1.2	-1.5	-1.4	-1.3	-1.2	-1.2	-1.2	-1.1	-1.2	-1.5	-1.5	-1.8	-1.9	-1.9	-1.9	-3.7	-2.6	-2.2	-2.2	-1.9
Idaho Power	-0.5	-0.4	-0.4	-0.4	-0.3	-0.4	-0.2	0.5	1.4	1.4	1.4	1.5	1.5	1.2	-0.1	-1.2	-1.0	-3.3	-6.7	-12.7	-7.6	-4.9	-1.7	-1.0
NorthWestern	-0.7	-0.6	-0.6	-0.5	-0.5	-0.6	-0.3	0.8	2.8	2.9	2.5	2.6	2.3	1.7	0.4	-0.9	-0.9	-4.0	-9.2	-16.9	-10.0	-6.5	-2.1	-1.0
Avista Utilities	-0.9	-0.8	-0.8	-0.6	-0.5	-0.7	-0.4	1.0	3.4	3.5	3.0	3.1	2.7	2.1	0.5	-1.0	-1.0	-4.8	-10.9	-20.0	-11.9	-7.7	-2.5	-1.2
Avangrid	-1.1	-0.9	-0.9	-0.7	-0.6	-0.8	-0.5	1.0	3.9	4.0	3.5	3.7	3.0	2.3	0.4	-1.4	-1.2	-5.8	-12.7	-23.1	-14.0	-9.2	-2.9	-1.4
BPA	-0.9	-0.8	-0.8	-0.7	-0.6	-0.7	-0.4	1.0	3.5	3.7	3.2	3.3	3.0	2.2	0.5	-1.3	-1.1	-4.8	-10.6	-19.4	-11.8	-7.9	-2.5	-1.2
Tacoma Power	-0.9	-0.8	-0.8	-0.7	-0.6	-0.7	-0.4	0.8	3.4	3.4	2.9	3.1	2.8	2.0	0.4	-1.4	-1.2	-5.3	-11.4	-21.0	-12.5	-8.3	-2.6	-1.3
PacifiCorp West	-1.0	-0.8	-0.8	-0.7	-0.6	-0.8	-0.4	0.9	3.5	3.6	3.1	3.3	2.8	2.1	0.4	-1.4	-1.2	-5.5	-11.8	-21.7	-13.1	-8.6	-2.7	-1.3
Portland GE	-1.0	-0.8	-0.8	-0.7	-0.6	-0.8	-0.4	0.8	3.4	3.5	3.0	3.2	5.2	2.1	1.7	0.6	0.4	-4.1	-11.3	-21.5	-13.0	-8.5	-2.7	-1.3
Puget Sound Energy	-0.9	-0.8	-0.8	-0.7	-0.6	-0.7	-0.4	1.3	3.8	4.3	3.7	3.5	3.2	2.4	0.7	-0.8	-0.9	-4.8	-11.4	-20.8	-12.4	-8.0	-2.6	-1.3
Seattle City Light	-0.9	-0.8	-0.8	-0.7	-0.6	-0.7	-0.4	1.5	4.0	4.6	3.9	3.7	3.4	2.6	0.9	-0.4	-0.8	-4.5	-11.4	-20.6	-12.3	-7.9	-2.6	-1.3
Powerex	-0.9	-0.8	-0.8	-0.6	-0.6	-0.7	-0.4	1.7	4.2	5.2	4.5	3.9	3.5	2.8	1.0	-0.1	-0.6	-4.1	-11.3	-20.3	-12.1	-7.6	-2.5	-1.2

Hour

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

Table 4.2 shows the quarterly impact of congestion from individual constraints on prices across the WEIM for the 15-minute market. The two constraints that had the greatest impact on price separation in the 15-minute market were Midway-Vincent #2 500kV line and the California-Oregon Intertie (COI) nomogram.

Midway-Vincent #2 500kV line

Midway-Vincent #2 500kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) increased prices in Southern California and the Desert Southwest, while it decreased prices in Northern California, Intermountain West, and the Pacific Northwest. This line typically experienced congestion during evening peak hours, from hour-ending 18 to 22.

California-Oregon Intertie (COI) nomogram

The California-Oregon Intertie nomogram (6110_COI_N-S) increased prices in California and the Desert Southwest, while it decreased prices in the Intermountain West and Pacific Northwest. This line experienced congestion during evening peak hours, from hour-ending 19 to 22.

Table 4.2 Impact of internal transmission constraint congestion on 15-minute market prices during all hours (WEIM, July–September 2024)

Constraint location	Constraint	Average quarter impact ($/MWh)																							
		California			Desert Southwest							Intermountain West				Pacific Northwest							
		BANC	TIDC	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	CCXFMR8A69KV	.	.	.	0.23	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	LSSXFMR10A230KV	.	.	.	0.04	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Line_OC-LSS_230KV	.	.	.	0.02	.	.	.	-0.01	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Line_CC-LSS_230KV	.	.	.	0.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
CISO	6110_COI_N-S	0.62	0.59	0.34	0.25	0.20	0.10	0.16	0.25	0.24	0.25	-0.94	-0.62	-0.81	-0.31	-1.05	-0.96	-0.97	-0.99	-0.99	-0.97	-0.97	-0.97
	30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	-0.48	-0.49	0.38	0.33	0.30	0.25	0.28	0.33	0.32	0.33	-0.31	-0.15	-0.26	0.01	-0.38	-0.33	-0.34	-0.35	-0.35	-0.34	-0.33	-0.34
	OMS_16244394_COI_DLO	0.22	0.21	0.12	0.09	0.07	0.04	0.06	0.09	0.09	0.09	-0.34	-0.22	-0.27	-0.10	-0.39	-0.35	-0.36	-0.37	-0.36	-0.36	-0.36	-0.36
	30105_COTTNWD_230_30245_ROUNDMT_230_BR_3_1	0.36	0.00	.	.	.	.	.	.	.	.	-0.29	.	-0.24	.	-0.31	-0.29	-0.30	-0.30	-0.30	-0.30	-0.30	-0.30
	30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	0.81	1.77	0.00	.	.	.	.	.	.	.	0.00	.	.	.	0.10	0.00	0.00	0.01	0.01	0.00	0.00	0.00
	30056_GATES2_500_30060_MIDWAY_500_BR_2_1	0.17	0.18	-0.15	-0.14	-0.13	-0.10	-0.12	-0.14	-0.14	-0.14	0.12	0.03	0.09	-0.03	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13
	COI_600N-S	0.09	0.08	0.05	0.04	0.03	0.01	0.02	0.04	0.03	0.04	-0.11	-0.07	-0.10	-0.03	-0.13	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
	30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	0.10	0.10	-0.08	-0.08	-0.07	-0.05	-0.07	-0.08	-0.07	-0.08	0.07	0.03	0.06	-0.01	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	30790_PANOCHE_230_30900_GATES_230_BR_2_1	0.14	0.27	-0.09	-0.05	-0.04	-0.01	-0.03	-0.05	-0.04	-0.05	0.04	.	0.03	.	0.08	0.05	0.05	0.06	0.06	0.05	0.05	0.05
	30055_GATES1_500_30060_MIDWAY_500_BR_1_1	0.08	0.08	-0.07	-0.06	-0.06	-0.05	-0.05	-0.06	-0.06	-0.06	0.05	0.01	0.04	-0.01	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.06
	7820_CP3_NG	.	0.00	0.00	-0.15	-0.14	-0.05	-0.12	-0.16	-0.15	-0.14	.	-0.01	.	-0.05	.	.	.	.	.	.	.	.
	30055_GATES1_500_30900_GATES_230_XF_11_P	-0.09	-0.09	0.06	0.05	0.05	0.03	0.04	0.05	0.05	0.05	-0.03	-0.02	-0.02	0.00	-0.04	-0.03	-0.03	-0.04	-0.04	-0.03	-0.03	-0.03
	7430_CP6_NG	0.87	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	99013_CALCAPS_500_24801_DEVERS_500_BR_1_1	0.02	0.02	0.02	-0.06	-0.05	-0.01	-0.04	-0.06	-0.05	-0.05	.	.	.	-0.01	0.00	.	.	0.00	0.00	.	.	.
	30005_ROUNDMT_500_30015_TABLEMT_500_BR_2_2	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.02	-0.01	-0.02	-0.01	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
	30885_MUSTANGS_230_30900_GATES_230_BR_2_1	0.03	0.02	-0.03	-0.03	-0.02	-0.02	-0.02	-0.03	-0.03	-0.03	.	.	.	.	.	.	.	.	.	.	.	.
	COI_600S-N	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	22846_SANJCP_230-22260_ESCNDO_230-BR1	.	.	.	-0.03	-0.03	.	-0.02	-0.03	-0.03	-0.03	.	.	.	.	.	.	.	.	.	.	.	.
	6410_CP1_NG	-0.01	-0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.01	0.00	-0.01	0.00	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	30975_MDWAYR11_230_30060_MIDWAY_500_XF_11_P	-0.01	-0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	.	.	.	.	.	.	.	.	.	.	.	.
	30330_RIOOSO_230_30335_ATLANTC_230_BR_1_1	0.13	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30114_DELEVAN_230_30450_CORTINA_230_BR_1_1	.	.	.	.	.	.	.	.	.	.	-0.01	0.00	0.00	.	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	30879_HENTAP1_230_30885_MUSTANGS_230_BR_1_1	0.02	0.01	-0.01	-0.01	-0.01	.	0.00	-0.01	-0.01	-0.01	.	.	.	.	.	.	.	.	.	.	.	.
	7820_TL23040_IV_SPS_NG	.	.	.	-0.01	-0.01	.	-0.01	-0.01	-0.01	-0.01	.	.	.	.	.	.	.	.	.	.	.	.
	22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3_1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1_1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30435_LAKEVILE_230_30440_TULUCAY_230_BR_1_1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	30440_TULUCAY_230_30460_VACA-DIX_230_BR_1_1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
PNM	115kvDL_Mi_Wm	.	.	.	.	0.28	.	0.07	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvPicFro	.	.	.	.	-0.18	.	0.08	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvML	.	.	.	.	0.05	.	0.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	LunaPNM345_115X	.	.	.	.	0.03	.	0.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	FRCE-PINT1	.	.	.	.	-0.01	.	-0.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvSOC_BeBe	.	.	.	.	0.03	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	115kvLK	.	.	.	.	-0.02	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
SRP	RUDT230H5003B	.	.	.	0.21	.	.	.	0.24	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	RUDT230H5001B	.	.	.	0.16	.	.	.	0.17	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	RUDT230H5001A	.	.	.	0.15	.	.	.	0.17	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	RUDT230H5003A	.	.	.	0.04	.	.	.	0.04	.	.	.	.	.	.	.	.	.	.	.	.	.	.
	Other	0.01	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	-0.09	-0.01	0.01	-0.02	0.00	-0.01	-0.02	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02
Total	Total	3.08	2.73	0.58	1.07	0.29	0.14	0.27	0.78	0.16	0.11	-1.78	-1.03	-1.49	-1.13	-1.87	-1.83	-1.84	-1.86	-1.86	-1.85	-1.84	-1.85

Table 4.3 Impact of internal transmission constraint congestion on 15-minute market prices during all hours – top 25 primary congestion constraints (CAISO, July–September 2024)

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	5.8%	-0.49	0.39	0.37
6110_COI_N-S	0.7%	0.58	0.35	0.32
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	13.3%	0.32	-0.36	-0.34
7820_CP3_NG	3.1%	0.00	0.03	0.81
32214_RIOOSO_115_30330_RIOOSO_230_XF_1	12.8%	0.79	0.00	0.00
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	12.5%	0.05	-0.38	-0.36
7430_CP6_NG	5.4%	0.21	-0.26	-0.25
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	7.9%	.	.	0.54
30733_VASONA_230_30735_METCALF_230_BR_1_1	1.2%	0.29	-0.10	-0.10
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	1.8%	0.14	-0.16	-0.15
OMS_16244394_COI_DLO	1.1%	0.20	0.13	0.11
30790_PANOCHE_230_30900_GATES_230_BR_2_1	9.4%	0.10	-0.15	-0.14
30105_COTTNWD_230_30245_ROUNDMT_230_BR_3_1	1.6%	0.20	0.10	0.08
22846_SANJCP_230-22260_ESCNDO_230-BR1	0.7%	0.02	0.03	-0.22
34366_SANGER_115_34370_MCCALL_115_BR_3_1	2.2%	0.14	-0.06	-0.06
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	1.1%	0.07	-0.09	-0.08
30055_GATES1_500_30900_GATES_230_XF_11_P	6.3%	-0.11	0.06	0.06
RUDT230H5003B	1.2%	-0.05	-0.07	-0.10
34116_LEGRAND_115_34115_ADRATAP_115_BR_1_1	44.5%	-0.16	-0.03	-0.02
34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1	1.8%	0.11	-0.05	-0.05
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	1.3%	0.07	-0.07	-0.07
COI_600N-S	0.9%	0.08	0.05	0.05
RUDT230H5001B	0.7%	-0.04	-0.05	-0.07
RUDT230H5001A	0.7%	-0.04	-0.05	-0.07
7820_TL23040_IV_SPS_NG	1.1%	0.00	0.01	0.12
Other	2.1%	0.69	-0.01	0.09
Total		3.15	-0.74	0.47

4.3 Congestion rent and loss surpluses

Figure 4.5 shows that in the third quarter of 2024, congestion rent and loss surpluses were $112 million and $46 million, respectively.[33] These amounts represent a decrease of 43 percent and a decrease of 27 percent relative to the same quarter of 2023. The reduction in the congestion component can be attributed to decreased congestion rent from internal constraints. The reduction in the loss component was due to lower energy prices in this quarter compared to the same period in 2023.

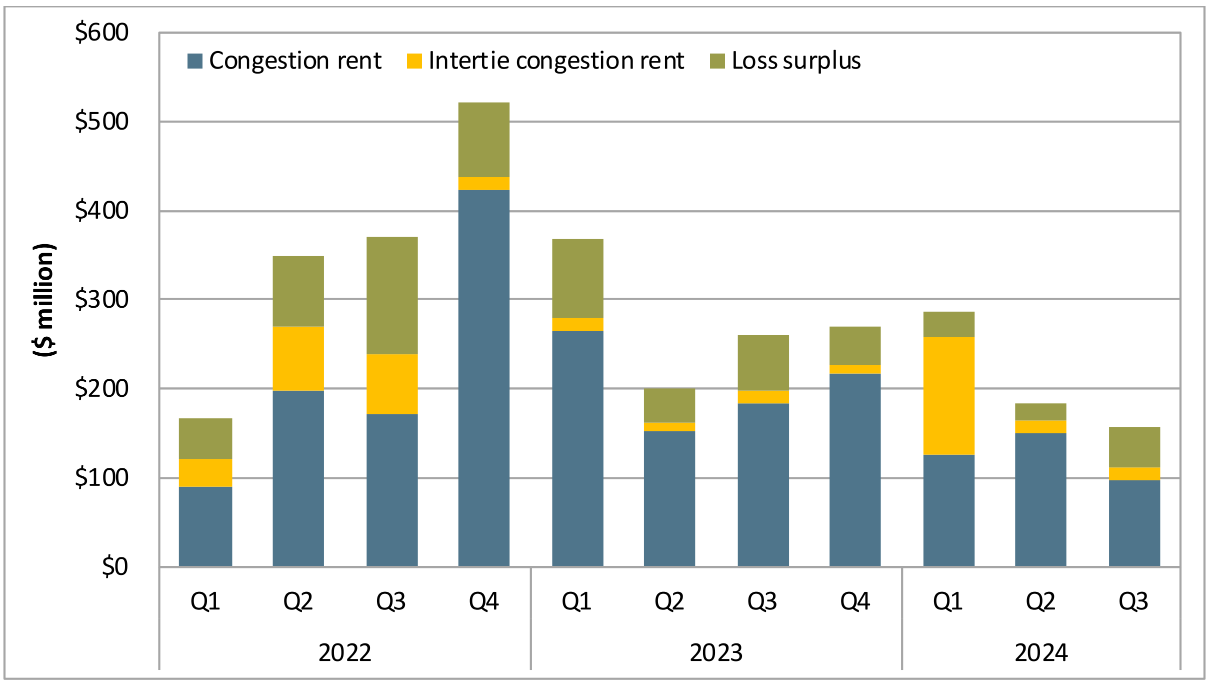
33 Information in this section is based on settlement values available at the time of drafting and will be updated in future reports. Updates can occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after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

Congestion rent consists of rents from internal constraints and interties. Intertie congestion increased slightly from $15 million to $16 million this quarter compared to the same quarter in 2023.

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 27 percent decrease in the loss surplus compared to Q3 2023 can largely be attributed to lower system energy costs. The loss surplus represents the difference between what load pays for the loss component of the locational marginal price (LMP) and what generation gets paid from the loss component of LMP in the day-ahead market. The magnitude of the loss component of LMP is directly proportional to the energy component of LMP, so the loss surplus values should correlate with electricity prices and load quantities over time. In settlements, the loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[34]

Figure 4.5 Day-ahead congestion rent and loss surplus by quarter (2022–2024)



4.4 Congestion on interties

Total intertie congestion rent in the day-ahead market was $16 million, up slightly from $15 million in the third quarter of 2023. The major driver was increased import congestion on Malin. The import congestion rent on this intertie rose by $5.6 million in this quarter compared to the same quarter in

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

2023. However, this increase was partially offset by a decrease in import congestion rent from other interties.

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

Figure 4.6 shows total intertie congestion charges in the day-ahead market from the third quarter of 2023 to the third quarter of 2024. This figure categorizes total congestion charges by interties and flow direction, distinguishing between imports and exports. Figure 4.7 shows the frequency of congestion on five major interties, categorized by import and export congestion. Table 4.4 provides a detailed summary of congestion rent and frequency over a broader set of interties distinguishing by imports and exports. As highlighted in these charts and table:

- Compared to the third quarter of 2023, import congestion rent increased from $12 million to $15 million, whereas export congestion rent decreased from $3 million to $0.8 million.
- The majority of import congestion rent was from the Malin and NOB interties. These two interties accounted for 94 percent of the total congestion rent during this quarter.
- Import congestion on Malin accounted for 56 percent of the total intertie congestion rent in this quarter. While the binding limits on this intertie slightly decreased, the shadow price and binding frequency in the import direction significantly increased compared to the same quarter of the previous year.

Figure 4.6 Day-ahead congestion charges on major interties

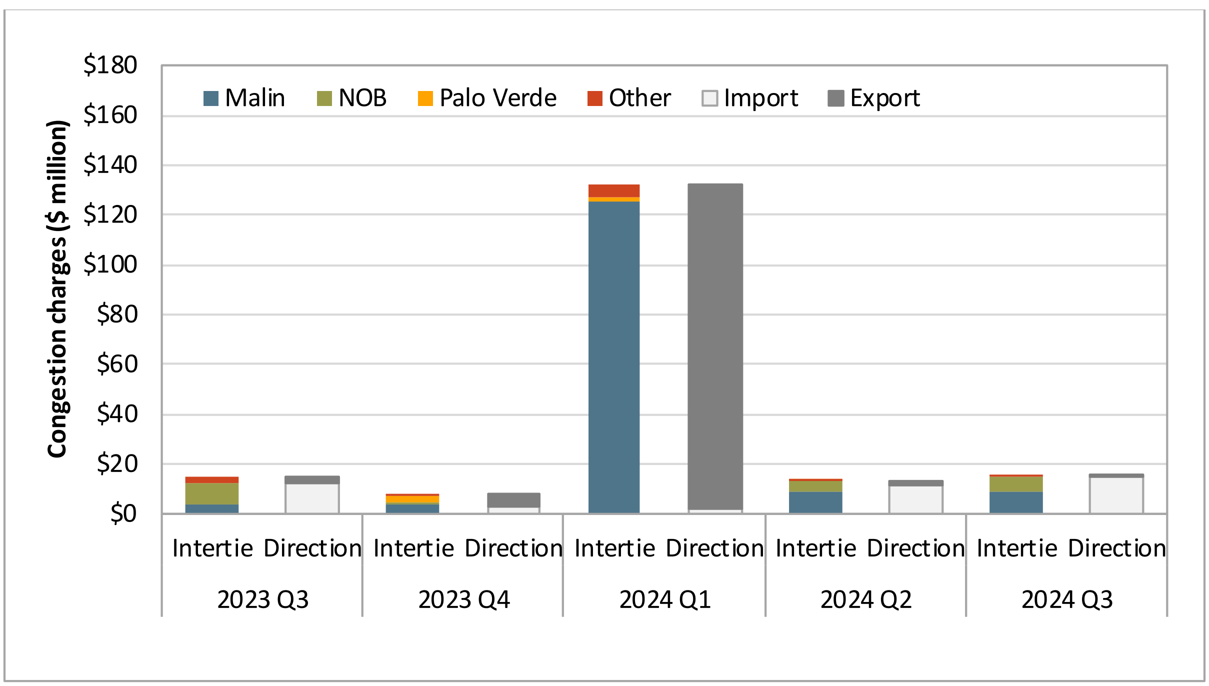


Figure 4.7 Frequency of congestion on major interties in the day-ahead market

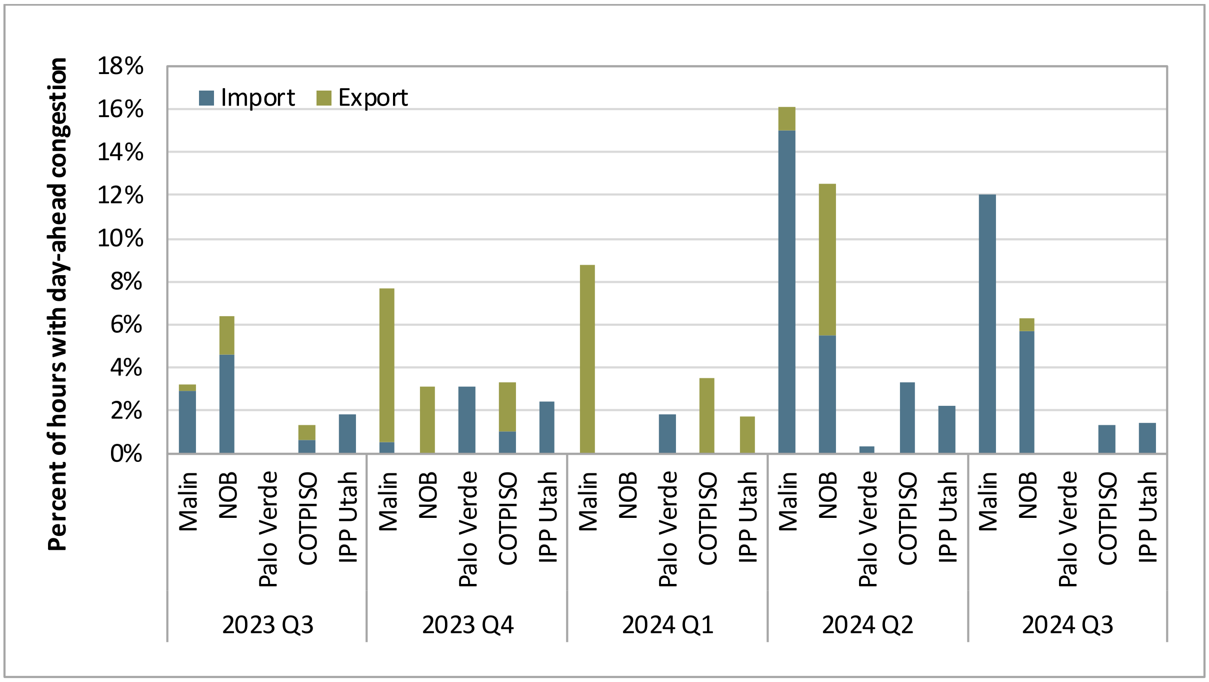


Table 4.4 Summary of intertie congestion in day-ahead market (2023–2024)

Intertie	Direction*	Congestion charges ($ thousand)					Frequency of congestion				
		2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3
Northwest											
Malin	I	$3,127	$243		$8,229	$8,805	2.9%	0.5%		15.0%	12.0%
	E	$339	$3,866	$125,571	$292		0.3%	7.2%	8.8%	1.1%	
NOB	I	$8,755			$2,608	$5,947	4.6%			5.5%	5.7%
	E	$252	$851		$1,665	$103	1.9%	3.1%		7.0%	0.6%
COTPISO	I	$16	$103	$1	$98	$14	0.6%	1.1%	0.0%	3.3%	1.3%
	E	$30	$55	$1,367			0.7%	2.2%	3.5%		
Cascade	I										
	E			$2,147					8.0%		
Summit	I	$42	$5		$14		1.4%	0.2%		0.8%	
	E										
Southwest											
Palo Verde	I		$2,593	$1,909	$61			3.1%	1.8%	0.3%	
	E										
IPP Utah	I	$59	$186		$141	$115	1.8%	2.4%		2.2%	1.4%
	E			$401					1.7%		
IPP DC Adelanto	I										
	E			$1,071					4.0%		
Mona	I					$19					0.2%
	E	$77	$143	$75	$180	$712	0.4%	0.7%	0.4%	2.2%	1.5%
Mead	I			$1	$23				0.0%	0.2%	
	E	$2,370					1.5%				
Merchant	I										
	E										
Silver Peak	I										
	E	$2					1.0%				
Mercury	I										
	E										
Other	I	$21	$81	$0	$8	$0					
	E	$0		$58	$70						
Import total (I)		$12,021	$3,213	$1,911	$11,182	$14,900					
Export total (E)		$3,071	$4,915	$130,690	$2,207	$815					
Total		$15,092	$8,128	$132,601	$13,389	$15,715					

* I: import, E: export

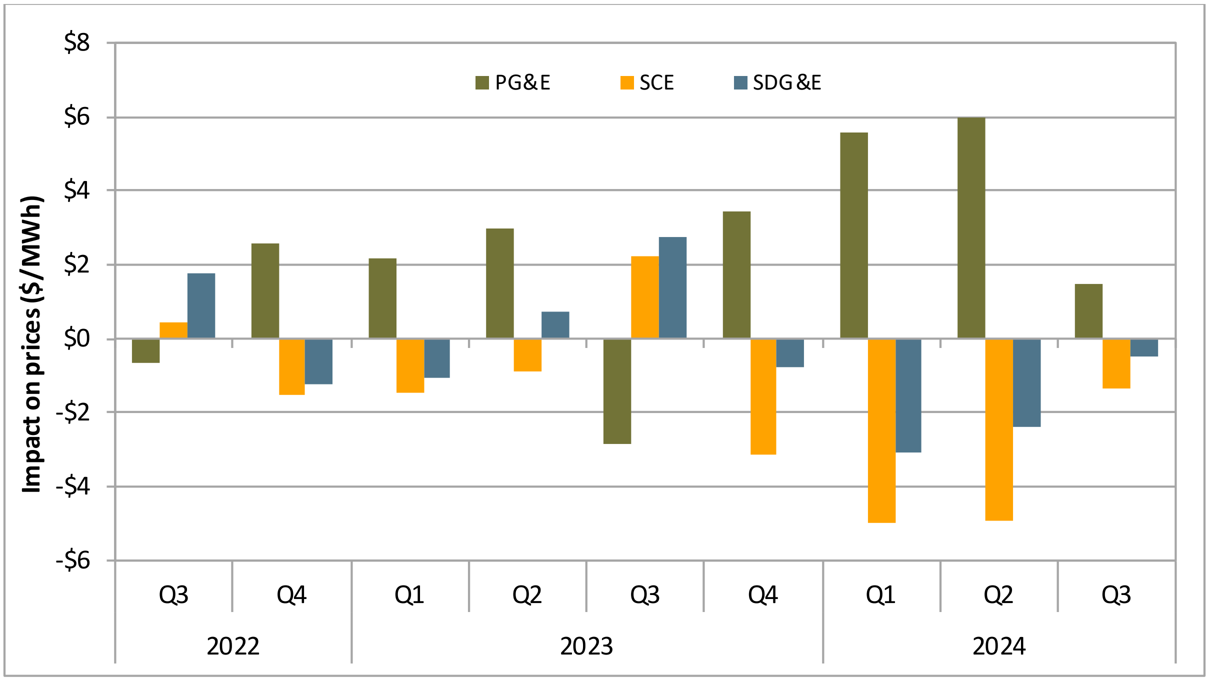
4.5 Internal congestion in the day-ahead market

Figure 4.8 shows the overall impact of congestion on day-ahead market prices in each load area from Q3 2022 to Q3 2024. Figure 4.9 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in this quarter was significantly lower than during the same quarter of 2023. This quarter exhibited an overall average south-to-north congestion pattern, but its impact on price separation was partially offset by north-to-south congestion on a major constraint during evening hours.

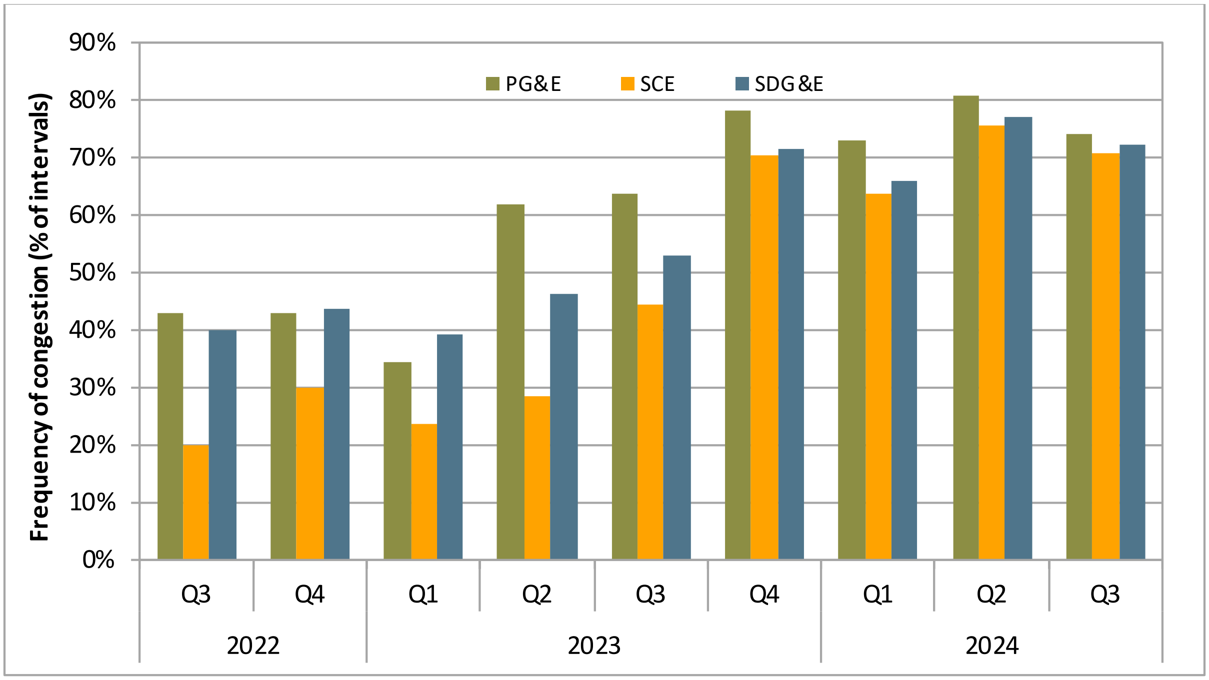
- Day-ahead congestion increased quarterly average prices in PG&E by $1.47/MWh, while it decreased average SCE and SDG&E prices by $1.34/MWh and $0.47/MWh, respectively.[35]
- The percentage of hours in which congestion impacts DLAP prices remained high this quarter, with PG&E experiencing congestion during an average of 74 percent of hours.
- The primary constraints affecting day-ahead market prices were the Midway-Vincent #2 500kV line, Moss Landing-Las Aguilas #1 230kV line, and Rio Oso 115/230kV transformer.

Figure 4.8 Overall impact of congestion on price separation in the day-ahead market



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

Figure 4.9 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 4.5 breaks down the congestion effect on price separation during the quarter by constraint.[36] The table presents the top 25 most congested lines, ranked by their impact, while the "Other" category shows the average impact of the remaining constraints. Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact—the stronger the shading, the greater the impact in either the positive or the negative direction.

The constraints with the greatest impact on day-ahead price separation for the quarter were Midway-Vincent #2 500kV line, Moss Landing-Las Aguilas #1 230kV line, and Rio Oso 115/230kV transformer.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) bound in 8.4 percent of hours over the quarter. For the quarter, congestion on the constraint decreased average PG&E prices by $0.86/MWh and increased average SCE and SDG&E prices by $0.59/MWh and $0.58/MWh, respectively. This transmission line was generally binding during evening peak hours, from hour-ending 18 through hour-ending 23.

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

Moss Landing-Las Aguilas #1 230 kV line

The Moss Landing-Las Aguilas #1 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in about 30 percent of hours. For the quarter, the constraint increased average PG&E prices by about $0.49/MWh, and decreased average SCE and SDG&E prices by $0.35/MWh and $0.33/MWh, respectively. This line was frequently binding during solar production hours, from hour-ending 9 through hour-ending 15.

Rio Oso 115/230kV transformer

The Rio Oso 115/230kV transformer (32214_RIOOSO_115_30330_RIOOSO_230_XF_1) bound in 36 percent of hours over the quarter. For the quarter, congestion on the constraint increased average PG&E prices by $0.49/MWh and decreased average SCE and SDG&E prices by $0.32/MWh and $0.31/MWh, respectively. This transmission line was generally binding during evening peak hours, from hour-ending 18 through hour-ending 21.

Table 4.5 Impact of congestion on overall day-ahead prices – top 25 primary congestion constraints

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30060_MIDWAY_500_24156_VINCENT_500_BR_2_3	8.4%	-0.86	0.59	0.58
30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1	30.0%	0.49	-0.35	-0.33
32214_RIOOSO_115_30330_RIOOSO_230_XF_1	35.9%	0.49	-0.32	-0.31
30765_LOSBANOS_230_30790_PANOCHE_230_BR_2_1	16.6%	0.19	-0.14	-0.13
7430_CP6_NG	14.8%	0.17	-0.14	-0.13
22208_ELCAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1	18.2%	0.00	0.00	0.43
32056_CORTINA_60.0_30451_CRTNAM_1.0_XF_1	11.3%	0.15	-0.14	-0.14
30733_VASONA_230_30735_METCALF_230_BR_1_1	2.3%	0.16	-0.13	-0.13
30056_GATES2_500_30060_MIDWAY_500_BR_2_1	1.8%	0.12	-0.10	-0.09
30055_GATES1_500_30900_GATES_230_XF_11_P	12.8%	-0.14	0.08	0.08
30790_PANOCHE_230_30900_GATES_230_BR_2_1	11.0%	0.11	-0.09	-0.08
30050_LOSBANOS_500_30055_GATES1_500_BR_1_2	4.4%	0.10	-0.08	-0.07
34366_SANGER_115_34370_MCCALL_115_BR_3_1	5.4%	0.09	-0.06	-0.06
30440_TULUCAY_230_30460_VACA-DIX_230_BR_1_1	1.0%	0.07	-0.06	-0.06
36851_NORTHERN_115_36852_SCOTT_115_BR_2_1	3.7%	0.05	-0.06	-0.06
33315_RAVENSWD_115_38028_PLOALTO_115_BR_1_1	5.4%	-0.04	-0.05	-0.05
30055_GATES1_500_30060_MIDWAY_500_BR_1_1	1.0%	0.06	-0.05	-0.04
OMSIV-SXOUTAGE_NG	0.5%	-0.01	-0.01	0.12
OMS50004IV-MLOUTAGE_NG	0.5%	-0.01	0.00	0.09
34418_KINGSBRG_115_34428_CONTADNA_115_BR_1_1	2.8%	0.04	-0.03	-0.03
34724_KRNOLJ_115_34736_MAGUNDEN_115_BR_1_1	5.3%	0.03	-0.02	-0.02
30114_DELEVAN_230_30450_CORTINA_230_BR_1_1	1.1%	0.02	-0.02	-0.02
7820_TL23040_IV_SPS_NG	1.0%	-0.01	0.00	0.05
38610_DELTAPMP_230_30580_ALTMMDW_230_BR_1_1	3.2%	0.01	-0.02	-0.02
33378_WTRSHTPA_60.0_33380_JEFFERSN_60.0_BR_1_1	1.4%	0.02	-0.01	-0.01
Other	1.3%	0.16	-0.13	-0.02
Total		1.47	-1.34	-0.47

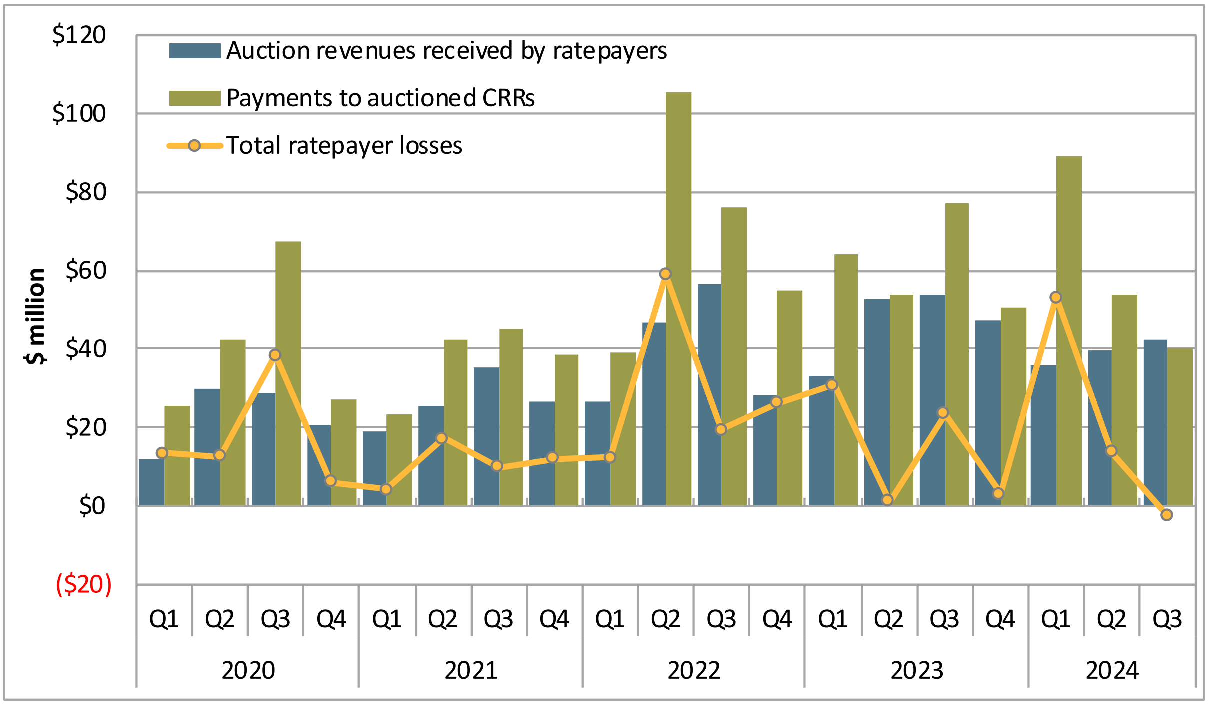
4.6 Congestion revenue rights

Congestion revenue right auction returns

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

As shown in Figure 4.10, transmission ratepayers made over $2 million during the third quarter of 2024, as payments to auctioned congestion revenue rights holders were lower than auction revenues. This was the first time ratepayers made money in the auction on a quarterly basis since Q3 2016. Gains were driven by load serving entities (LSEs) trading in the auction which earned LSEs over $14 million.

Figure 4.10 Auction revenues and payments to non-load serving entities



During the third quarter of 2024:

- Financial entities received profits of over $1 million, down from about $15 million during the same quarter of 2023. Total revenue deficit offsets were about $17 million.[37]
- Marketers lost about $2 million from auctioned rights, down from about an $8 million gain in Q3 2023. Total revenue deficit offsets were over $7 million.

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

- Physical generation entities lost about $1 million from auctioned rights, down from less than a half million dollar gain in Q3 2023. Total revenue deficit offsets were almost $1 million.

The $2 million in third quarter 2024 auction gains was about 2 percent of day-ahead congestion rent. This is down from 8 percent from the previous quarter. 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).[38,39]

The impact of track 1A changes, which limit the types of congestion revenue rights that can be sold in the auction, cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under track 1B reduced total payments to non-load serving entities by about $26 million in the third quarter. The track 1B effects on auction bidding behavior and reduced auction revenues are not known.

Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction consistently continues to cause millions of dollars in losses to transmission ratepayers each year, while exposing transmission ratepayers to a risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends the ISO convert the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers. DMM recently posted a whitepaper analyzing a potential option for this kind of alternative CRR auction design.[40]

5 Resource sufficiency evaluation

As part of the WEIM design, each area, including the California ISO balancing area, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize transfers between participating WEIM entities while deterring WEIM balancing areas from relying on other WEIM areas for capacity.

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

- **The bid range capacity test (capacity test)** requires that each area provide incremental bid-in capacity to meet the imbalance between load, intertie, and generation base schedules.

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

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

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

- **The flexible ramping sufficiency test (flexibility test)** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area that has not opted in to assistance energy transfers fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[41] If an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

5.1 Frequency of resource sufficiency evaluation failures

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

In the third quarter of 2024:

- Public Service Company of New Mexico (PNM) failed the upward flexibility test in around 1 percent of intervals.
- All other balancing areas failed each test type in less than one percent of intervals.

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

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

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

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

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

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

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

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

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

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

5.2 Assistance energy transfers

The assistance energy transfer (AET) option gives balancing areas access to excess WEIM supply that may not have been available otherwise following an upward resource sufficiency evaluation failure. Without AET, a balancing area failing either the upward flexibility or upward capacity test would have net WEIM imports limited to the greater of either the base transfer or the optimal transfer from the last 15-minute market interval. Balancing areas can voluntarily opt in to the AET program to prevent their WEIM transfers from being limited during an upward resource sufficiency evaluation failure, but will be subject to an ex-post surcharge. Balancing areas must opt in or opt out of the program in advance of the trade date.[43]

The assistance energy transfer surcharge is applied during any interval in which an opt-in balancing area fails the upward flexibility or capacity test. The surcharge is calculated as the *applicable real-time assistance energy transfer* times the real-time bid cap.[44] The applicable AET quantity is based on the lesser of either (1) the tagged dynamic WEIM transfers or (2) the amount by which the balancing area failed the resource sufficiency evaluation. If the tagged dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the ISO balancing area.

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

Table 5.1 shows the days in which a balancing area was opted in to receiving assistance energy transfers during the third quarter. Ten balancing areas were opted in to the program on at least one day during this period: Avangrid, CAISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PacifiCorp West, PNM, Portland General Electric, and WAPA Desert Southwest.[45] Avangrid, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, and PacifiCorp West were opted in to AET during all days during the quarter (92 days).

Table 5.2 summarizes all balancing areas that were opted in to assistance energy transfers on at least one day during the quarter and its impact following a resource sufficiency evaluation failure. First, the table shows the number of 15-minute intervals in which a balancing area failed the upward resource sufficiency evaluation after opting in to AET. These are the intervals in which the WEIM import limit

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

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

45 The CAISO balancing area can opt in to assistance energy transfers based on upcoming system conditions and operator experience. For more information, see the *Business Practice Manual for the Western Energy Imbalance Market*, section 11.3.2: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

following the test failure was removed—giving the WEIM entity access to WEIM supply that may not have been available otherwise. During the quarter, eight balancing areas (Avangrid, California ISO, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp East, PNM, and WAPA Desert Southwest) failed the resource sufficiency evaluation during at least one interval while opted in to the program. Table 5.2 also shows the percent of failure intervals in the 5-minute market in which the balancing area achieved additional WEIM imports due to opting in to AET. The table also shows the average and maximum WEIM imports added in the 5-minute market because of AET.

During the quarter, the Public Service Company of New Mexico (PNM) failed the resource sufficiency evaluation during 79 intervals while opted in to receiving assistance energy transfers. PNM achieved an additional 49 MW on average during these intervals (and maximum of 434 MW).

Table 5.1 Assistance energy transfer opt-in designations by balancing area (July–September 2024)

Balancing area	Period opted in to receiving assistance energy transfers	Days opted in to AET
Avangrid	Jul. 1 - Sep. 30	92
California ISO	Jul. 3, Jul. 8 - Jul. 11, Jul. 22 - Jul. 24, Aug. 5 - Aug. 7, Sep. 4 - Sep. 6, Sep. 9 - Sep. 10	16
Idaho Power	Jul. 1 - Sep. 30	92
NorthWestern Energy	Jul. 1 - Sep. 30	92
NV Energy	Jul. 1 - Sep. 30	92
PacifiCorp East	Jul. 1 - Sep. 30	92
PacifiCorp West	Jul. 1 - Sep. 30	92
PNM	Jul. 8 - Sep. 23	78
Portland General Electric	Jul. 4 - Jul. 10, Aug. 5 - Aug. 7	10
WAPA Desert Southwest	Jul. 8 - Sep. 30	85

Table 5.2 Resource sufficiency evaluation failures during assistance energy transfer opt-in (July–September 2024)

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	92	10	33%	23	151	58
California ISO	16	1	0%	0	0	0
Idaho Power	92	4	33%	11	42	11
NorthWestern Energy	92	19	40%	14	157	65
NV Energy	92	3	56%	104	336	78
PacifiCorp East	92	3	33%	61	203	45
PacifiCorp West	92	0	N/A	N/A	N/A	N/A
PNM	78	79	41%	49	434	973
Portland General Electric	10	0	N/A	N/A	N/A	N/A
WAPA Desert Southwest	85	9	56%	99	277	223

Table 5.3 summarizes the total cost from assistance energy transfers. AET is settled during any interval in which the balancing area both opted in to receiving assistance energy transfers and failed the

resource sufficiency evaluation. The applicable quantity that is settled for AET is based on the lower of the resource sufficiency evaluation insufficiency or the WEIM imports.[46] The price is the real-time bid cap, typically $1,000/MWh. Table 5.3 also shows the total cost per *WEIM imports added*. WEIM imports added are measured as net WEIM imports in the 5-minute market above what the limit would have been following the resource sufficiency evaluation failure without opting in to AET.

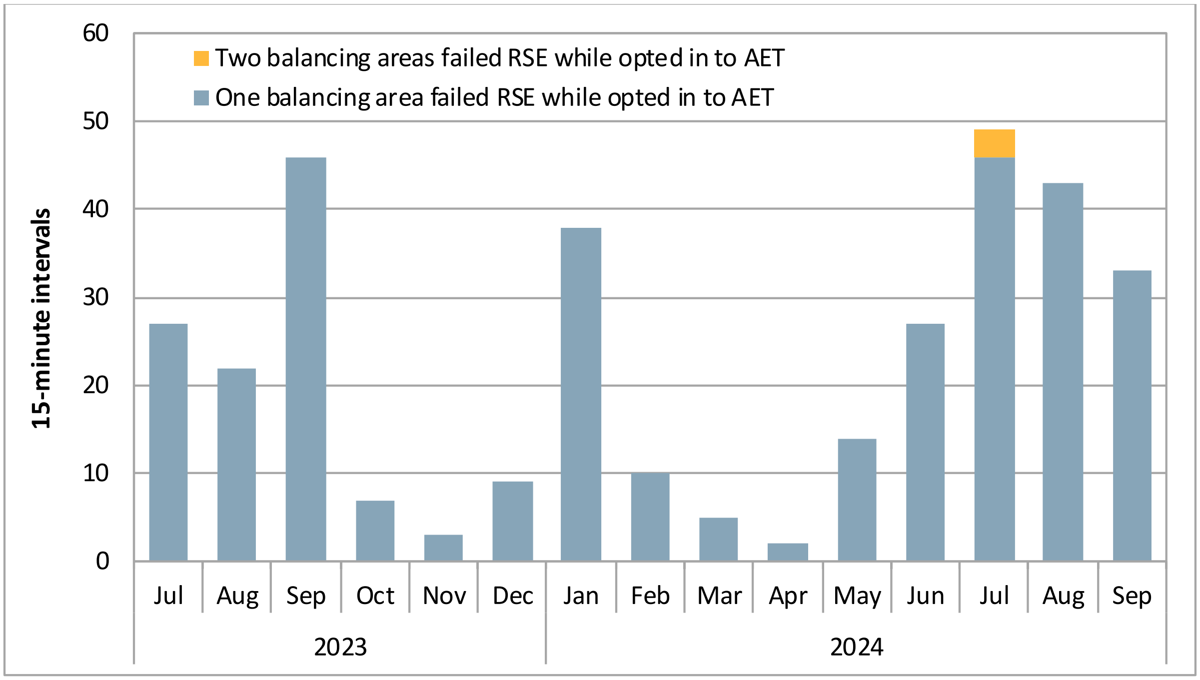
Table 5.3 Cost of assistance energy transfers (July-September 2024)

Balancing area	RSE failures under AET (15-min. intervals)	Total WEIM imports added (MWh)	Total cost of assistance energy transfers	Total cost per added WEIM imports
Avangrid	10	58	$8,223	$143
California ISO	1	0	$97,020	*
Idaho Power	4	11	$7,408	$645
NorthWestern Energy	19	65	$217,427	$3,352
NV Energy	3	78	$41,983	$539
PacifiCorp East	3	45	$6,963	$153
PacifiCorp West	0	N/A	N/A	N/A
PNM	79	973	$870,527	$895
Portland General Electric	0	N/A	N/A	N/A
WAPA Desert Southwest	9	223	$22,913	$103

WEIM entities have expressed concern that leaning on assistance energy transfers may cause multiple balancing areas to procure less in advance, therefore exacerbating more widespread scarcity conditions. If multiple balancing areas are frequently failing the resource sufficiency evaluation at the same time while opting in to receiving assistance energy transfers, that can be an indicator of extensive reliance on AET during tight west-wide conditions. If individual balancing areas are instead failing the resource sufficiency evaluation in isolated non-coincident events while opting in to receiving AET, that can reflect more localized and varied issues at the balancing area level. Figure 5.5 shows intervals when at least one balancing area failed the resource sufficiency evaluation while opted in to receiving AET. The blue bars indicate that only one balancing area failed the resource sufficiency evaluation while opted in to AET. The yellow bars indicate that two balancing areas failed the RSE while opted in to AET. There were no cases with three or more balancing areas. Failures while opted in to receiving AET were not highly coincident across balancing areas.

46 If the dynamic WEIM transfers are less than the amount by which the balancing area failed the resource sufficiency evaluation, then the applicable AET quantity is also reduced by a credit. The credit is either upward available balancing capacity for WEIM entities or cleared regulation up for the ISO balancing area.

Figure 5.5 Frequency of coincident resource sufficiency evaluation failures while opted in to receiving assistance energy transfers



5.3 Resource sufficiency evaluation enhancements phase 2 (track 2)

Phase 2 (track 2) of resource sufficiency evaluation enhancements was fully implemented on July 1, 2024. This included the following enhancements:

- **On April 16, 2024, the ISO implemented the "failed-to-start" exemption for counting offline short-start resources in the capacity test.** Phase 1 of resource sufficiency evaluation enhancements excluded offline long-start resources from the capacity test. It also created a check to determine if offline short-start resources with commitment instructions during the resource sufficiency evaluation horizon *failed-to-start*. If a committed short-start resource had zero or negative telemetry at the time of the test, it was excluded from consideration in the capacity test. However, this incorrectly excluded some fast-start resources or resources with negative telemetry (particularly pump hydro resources) that could actually be available in the resource sufficiency evaluation horizon. The enhancement created a flag to exempt these resources from the failed-to-start rule. Short-start resources that can have zero or negative telemetry at the time of a resource sufficiency evaluation—but be available and online for the next interval—can request the exemption.[47]
- **On July 1, 2024, the ISO implemented changes to improve visibility around the priority of export tags that are submitted.** As part of the enhancements, low-priority exports need to be tagged as *Firm Provisional Energy* along with the priority type (Day-Ahead Lower Price Taker [DALPT], Real-Time Lower Price Taker [RTLPT], or Real-Time Economic [RTECON]) so that all parties understand the

47 Resources can request an exemption to the failed-to-start rule in the capacity test by submitting an updated Generator Resource Data Template (GRDT).

quality and firmness of the market award. During stressed system conditions, the enhancement allows operators to make curtailment decisions more effectively.

Resource sufficiency evaluation reports

DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic.[48] 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.

6 Real-time imbalance offset costs

Real-time imbalance offset costs for balancing areas participating in the day-ahead market were $78 million in the third quarter of 2024.[49,50] This was a decrease from $106 million in the same quarter of 2023. During the third quarter of 2024, real-time *congestion* imbalance offset costs made up $48 million of these costs while real-time imbalance *energy* offset costs made up $29 million.

Real-time imbalance offset costs for balancing areas participating only in the WEIM real-time markets were a $28 million credit to WEIM entities, compared to a $115 million credit in the third quarter of 2023. The congestion portion of the offset, which is largely congestion rent from WEIM transfer constraints, was a $31 million credit. The energy and loss portions of the offset combined to be a $3 million charge.

The real-time imbalance offset cost is the difference between the total money *paid out* and the total money *collected* by the California ISO settlement process for energy in the real-time markets. This charge is calculated separately for each balancing area. Any revenue surplus or revenue shortfall within this charge is allocated to measured demand (for the California ISO balancing area) or the WEIM entity scheduling coordinator (for the WEIM balancing areas).[51]

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the congestion components of real-time energy settlement prices is collected through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the *loss* component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge,* while any remaining revenue imbalance is *recovered* through the *real-time imbalance energy offset charge* (RTIEO). Figure 6.1 shows monthly imbalance offset costs for balancing areas participating in the day-ahead market by component since 2022.

48 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

49 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.

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

51 Measured demand is physical load plus exports.

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

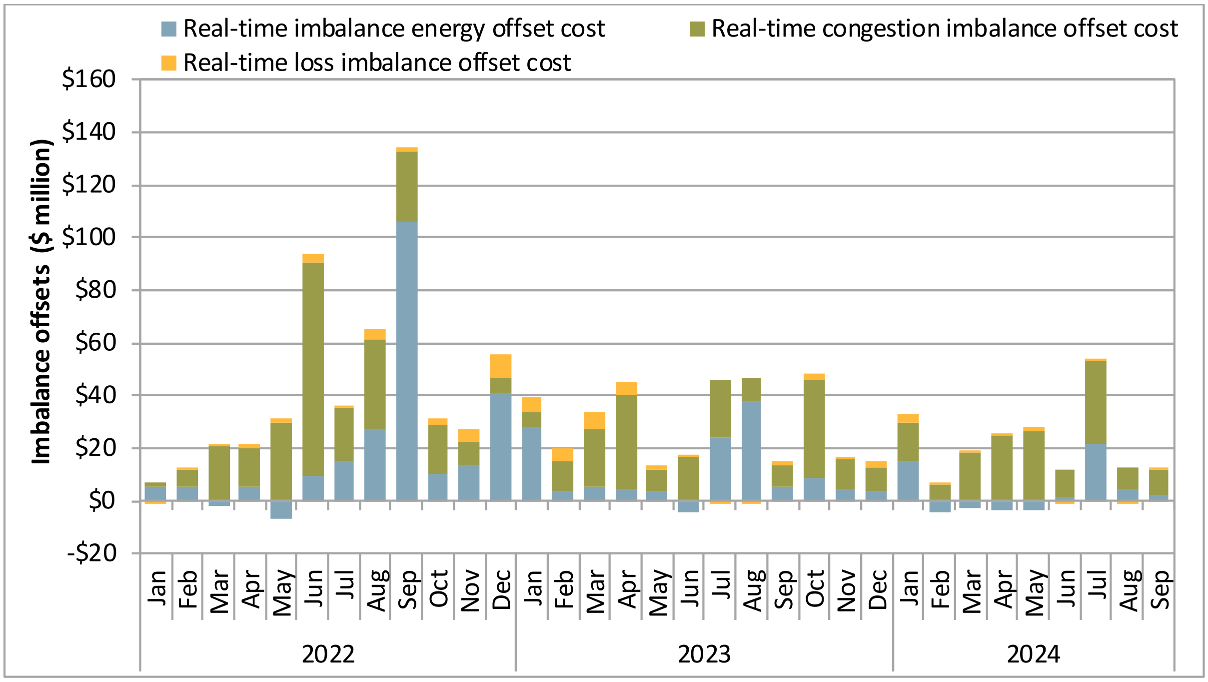


Figure 6.2 shows monthly imbalance offset costs for balancing areas only participating in the WEIM real-time markets. Offset amounts for each balancing area and charge type (energy, congestion, or losses) were assessed as positive or negative over the month, and shown collectively in the corresponding bars. The lighter-colored bars reflect positive amounts (or charges for revenue shortfall), while the darker bars reflect negative amounts (or credits for revenue surplus).

Figure 6.3 through Figure 6.5 show the quarterly real-time energy, congestion, or loss imbalance offsets for each balancing area participating only in the WEIM. Figure 6.6 shows the *total* real-time imbalance offset charges for each quarter and balancing area. Charges for revenue shortfall are shown in red, while credits for revenue surplus are shown in black. The color gradient highlights balancing areas with either greater revenue shortfall (orange) or revenue surplus (blue) over the period.

Of note in the third quarter:

- Revenue *surplus* from congestion imbalance offsets for PacifiCorp East was $7.1 million (credit).
- Revenue *surplus* from congestion imbalance offsets for Powerex was $5.9 million (credit).
- Revenue *shortfall* from imbalance energy offsets for Arizona Public Service was $3.9 million (charge).

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

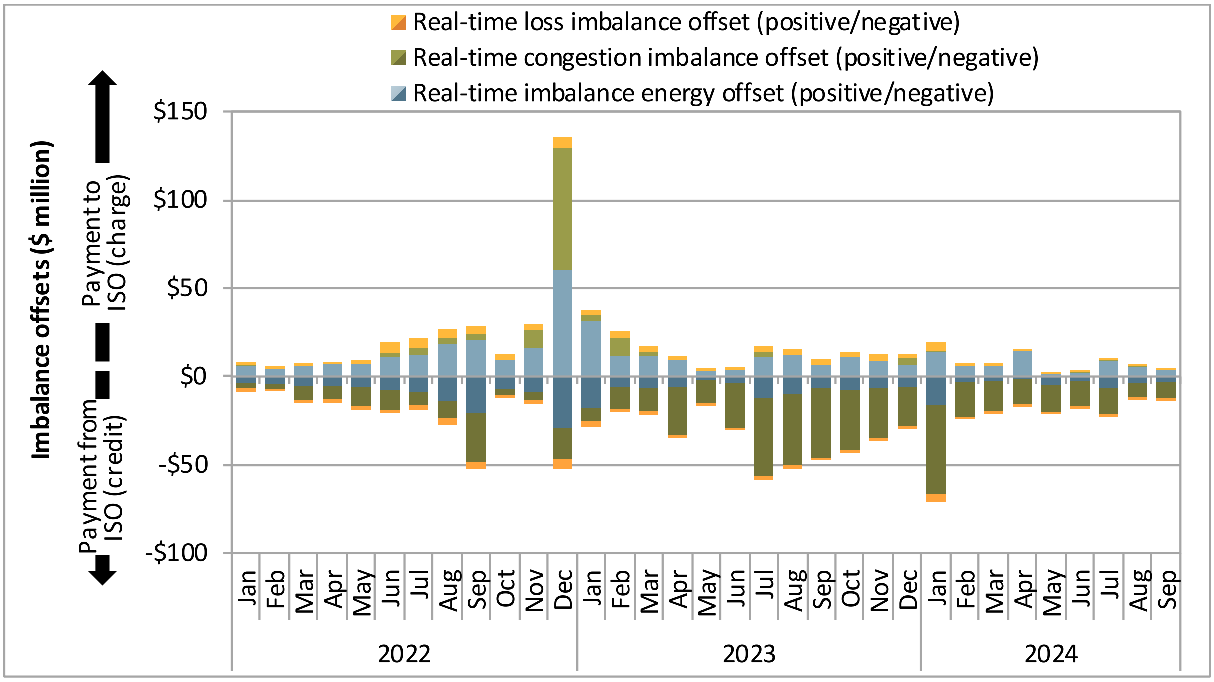


Figure 6.3 Real-time imbalance energy offsets by quarter and balancing area ($ millions)

	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3
Arizona Public Service	5	4	5	1	4
Avangrid	3	.1	3	8	.3
Avista	.2	.1	.1	.1	.1
BANC	.1	.3	.4	.1	1
Bonneville Power Administration	.8	.2	1	.3	.4
El Paso Electric	.6	.2	0	0	.3
Idaho Power	1	.6	3	.1	1
LADWP	.4	.2	.2	.2	2
NorthWestern Energy	4	6	5	1	3
NV Energy	.5	2	.9	.2	.6
PacifiCorp East	9	7	3	.7	3
PacifiCorp West	13	8	10	1	4
Portland General Electric	.6	.2	.1	0	.4
Powerex	.5	.7	.7	.2	.2
Public Service Company of NM	3	4	4	1	.9
Puget Sound Energy	6	6	7	2	4
Salt River Project	7	5	3	1	3
Seattle City Light	0	.1	.4	.1	.1
Tacoma Power	0	0	0	0	0
Tucson Electric Power	.3	.5	.4	.1	.1
Turlock Irrigation District	1	.5	.3	.4	.9
WAPA Desert Southwest	.4	.1	.1	.1	.2

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

	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3
Arizona Public Service	.3	.3	.1	.1	.7
Avangrid	.3	.1	.9	.4	.3
Avista	.2	.4	1	.3	.3
BANC	0	.1	0	.2	0
Bonneville Power Administration	1	1	1	.8	2
El Paso Electric	2	1	.3	.7	.8
Idaho Power	1	2	5	1	1
LADWP	4	1	2	1	4
NorthWestern Energy	.1	.3	1	.2	.1
NV Energy	.3	1	2	1	.2
PacifiCorp East	9	23	22	7	7
PacifiCorp West	3	2	9	1	1
Portland General Electric	5	3	6	2	1
Powerex	85	36	25	16	6
Public Service Company of NM	2	3	1	1	.5
Puget Sound Energy	5	4	5	2	2
Salt River Project	5	5	4	5	1
Seattle City Light	.3	.3	.3	.1	.2
Tacoma Power	.1	.1	.2	.1	.1
Tucson Electric Power	4	2	2	3	4
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	.3	0	.1	0	0

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

	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3
Arizona Public Service	1	.4	.4	.2	.8
Avangrid	.1	0	.3	.1	.2
Avista	0	0	0	0	.1
BANC	.1	0	.1	0	0
Bonneville Power Administration	.3	.1	.9	0	.1
El Paso Electric	.1	.1	.1	0	.2
Idaho Power	1	.8	.4	.2	.2
LADWP	.1	0	.5	0	0
NorthWestern Energy	0	.1	.1	0	.1
NV Energy	.3	.3	.4	0	.2
PacifiCorp East	2	2	2	.1	1
PacifiCorp West	.1	.4	0	.3	.3
Portland General Electric	.2	.1	2	0	.4
Powerex	8	7	3	1	1
Public Service Company of NM	.3	.1	0	.1	0
Puget Sound Energy	.1	.1	.5	0	.2
Salt River Project	.7	.7	.7	.1	.4
Seattle City Light	.2	.2	.4	.2	.5
Tacoma Power	0	0	.3	0	0
Tucson Electric Power	.6	.4	.3	.1	.4
Turlock Irrigation District	0	0	0	0	0
WAPA Desert Southwest	0	0	.2	0	0

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

	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3
Arizona Public Service	4	3	4	1	4
Avangrid	3	.1	2	8	.2
Avista	.1	.2	1	.2	.2
BANC	.1	.3	.5	0	.9
Bonneville Power Administration	.8	.6	1	.5	1
El Paso Electric	2	1	.4	.7	.7
Idaho Power	.9	.2	2	1	3
LADWP	4	1	3	1	2
NorthWestern Energy	4	6	4	1	3
NV Energy	.2	.5	1	1	.1
PacifiCorp East	2	18	21	6	6
PacifiCorp West	16	11	19	3	5
Portland General Electric	4	3	4	2	.3
Powerex	76	30	20	15	4
Public Service Company of NM	6	6	2	.1	.4
Puget Sound Energy	10	10	11	4	6
Salt River Project	13	10	7	6	4
Seattle City Light	.2	0	.4	0	.2
Tacoma Power	.1	.1	.5	.1	0
Tucson Electric Power	4	1	2	3	4
Turlock Irrigation District	1	.4	.3	.4	.8
WAPA Desert Southwest	.1	0	.1	.1	.2

7 Bid cost recovery

During the third quarter of 2024, estimated bid cost recovery payments for units in balancing areas participating in the day-ahead market totaled about $28.5 million.[52] This was a 63 percent decrease from the $78.4 million in bid cost recovery in the third quarter of 2023. Bid cost recovery for units in areas participating only in the Western Energy Imbalance Market (WEIM) totaled about $4.1 million. WEIM area bid cost recovery payments decreased about 50 percent from $8.4 million in Q3 2023.[53]

Figure 7.1 shows monthly bid cost recovery payments in the third quarter of 2024 for areas participating in the day-ahead market. Bid cost recovery payments associated with the day-ahead integrated forward market totaled about $5.3 million, which was less than the $5.8 million in the third quarter of 2023. Bid cost recovery payments associated with residual unit commitment during the quarter totaled about $8.4 million, or about $37.6 million lower than the third quarter of 2023. Bid cost recovery associated with the real-time market for areas that participate in the day-ahead market totaled about $23.2 million, which was about $49.4 million lower than the same quarter of 2023.

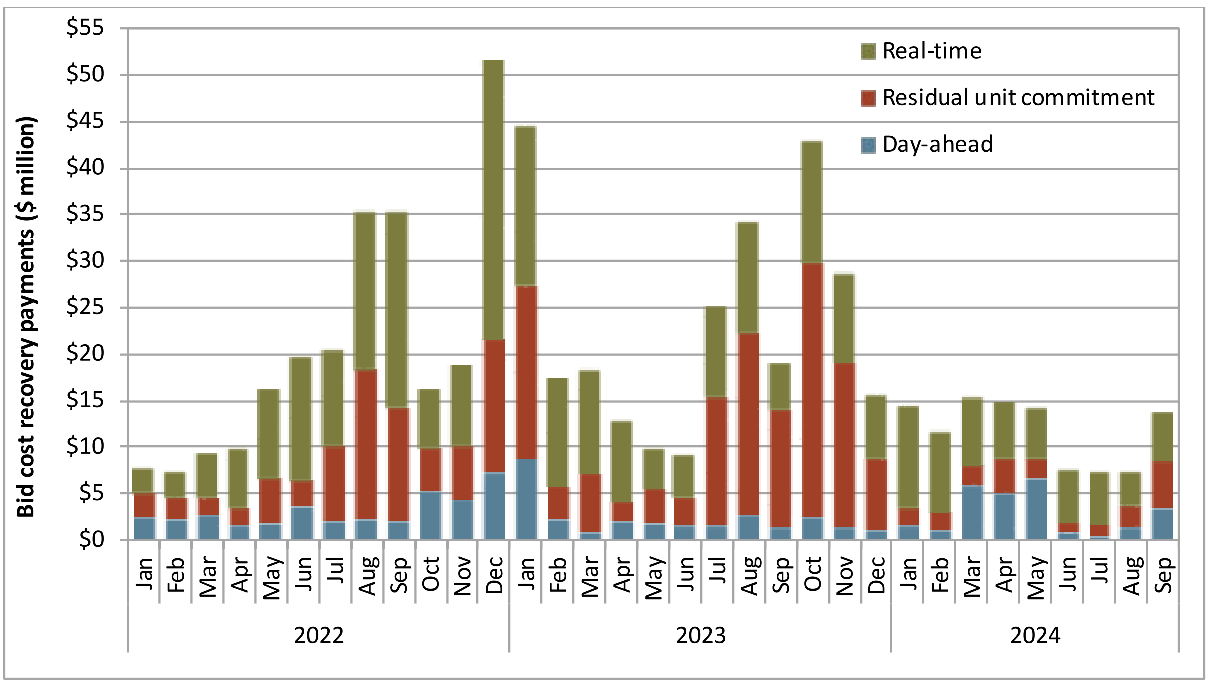
52 CAISO is the only balancing area currently participating in the day-ahead market.

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

Figure 7.2 shows monthly bid cost recovery payments paid to units in areas participating only in the WEIM. Bid cost recovery payments to these units were greatest in the Desert Southwest and California[54] regions at $2.5 million and $1.1 million, respectively. Bid cost recovery payments to the Intermountain West and Pacific Northwest regions totaled around $377,000 and $26,000, respectively.

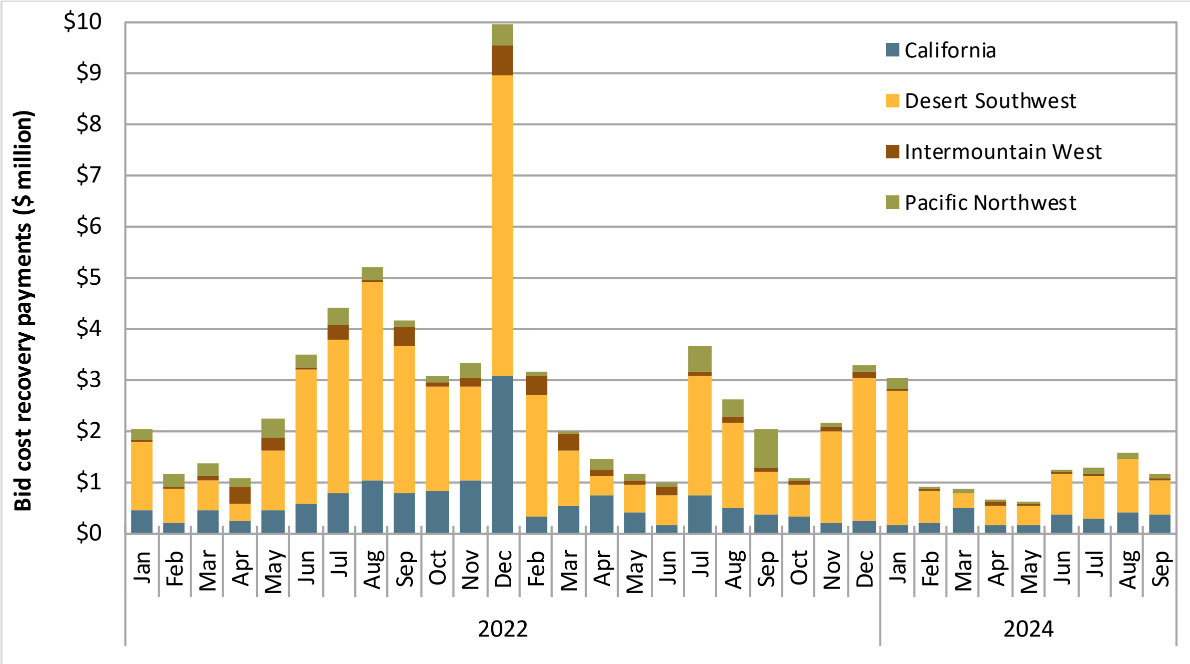
Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. In the third quarter of 2024, about $22 million of bid cost recovery payments were made to gas resources, 90 percent of which were paid to units participating in both the day-ahead market and the WEIM. About $4.9 million and $2.1 million of payments were made to battery and hybrid resources, respectively.

Figure 7.1 Monthly bid cost recovery payments for Day-Ahead Market area



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

Figure 7.2 Monthly bid cost recovery payments for the WEIM



8 Imbalance conformance

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

8.1 Imbalance conformance by balancing area

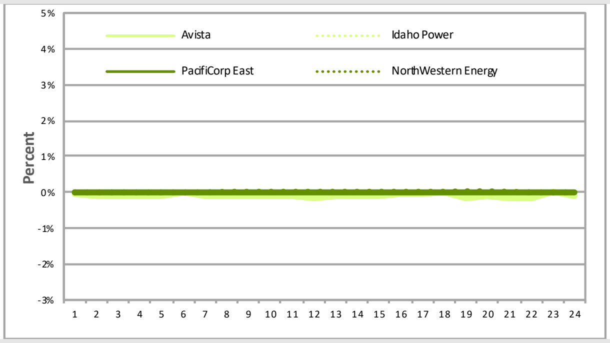
Table 8.1 shows each balancing area's 15-minute market and 5-minute market average hourly imbalance conformance as a percentage of that area's average load for the third quarter.[55] Generally, imbalance conformance levels were much higher in the 5-minute market than the 15-minute market, with exceptions being the CAISO balancing area and BPA.

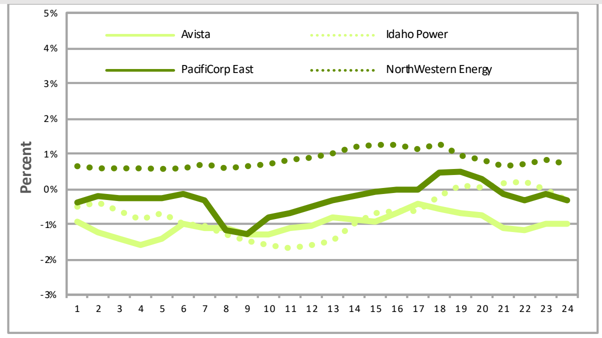
55 Avangrid Renewables and Powerex are not shown in this figure. Avangrid Renewables is a generation-only entity and therefore load conformance cannot be measured as a percent of load. Powerex is not a balancing authority area like other participating WEIM entities and instead uses residual capability of the BC Hydro system to participate in the WEIM. Powerex therefore does not have the ability to enter load bias in the market.

Table 8.1 Average hourly imbalance conformance as a percent of average load in the 15-minute and 5-minute markets by balancing area (Q3 2024)

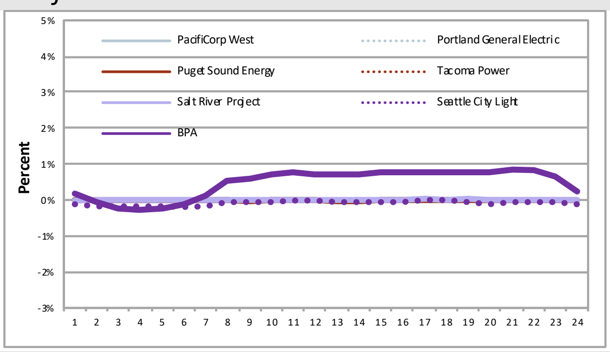
15-minute market	*5-minute market*

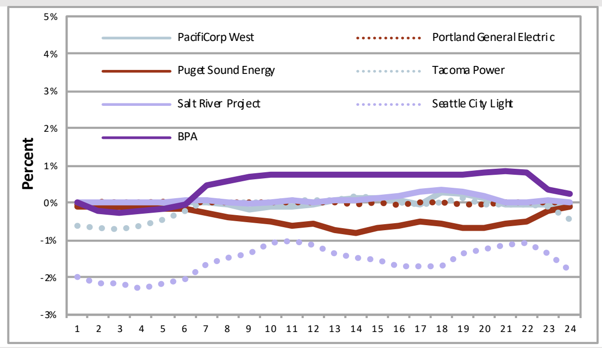
Intermountain West



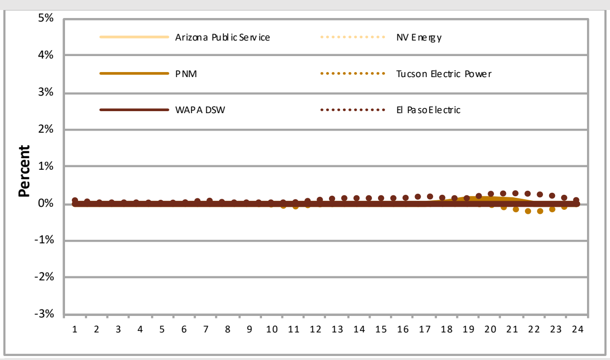


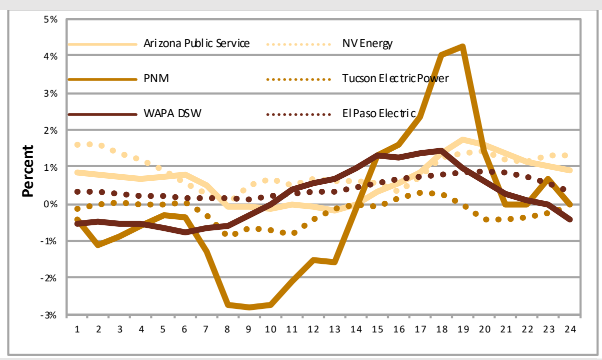
Pacific Northwest



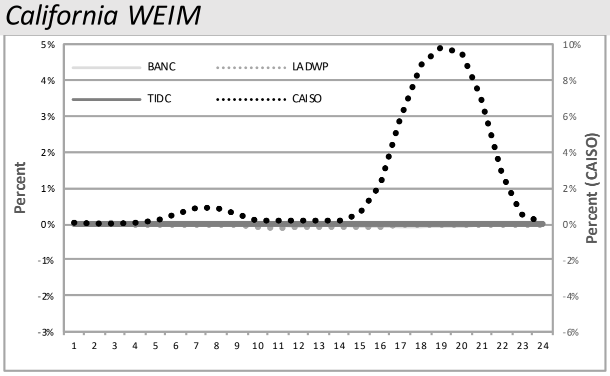


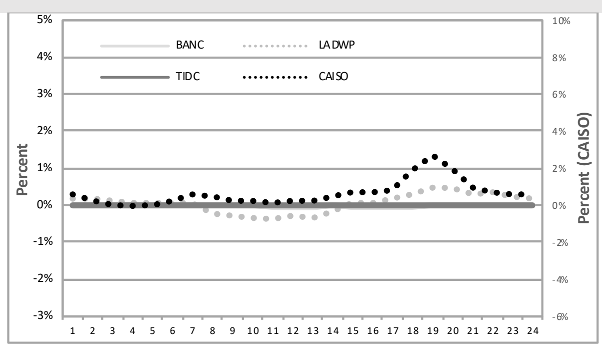
Desert Southwest





California WEIM





8.2 Imbalance conformance – special report on CAISO balancing area

The size and frequency of CAISO balancing area operators' use of imbalance conformance in the 15-minute market made it an outlier amongst WEIM areas in the third quarter of 2024. This section analyzes the use of imbalance conformance by CAISO balancing area operators.

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 8.1 shows CAISO area imbalance conformance adjustments in real-time markets for the third quarter of 2023 and 2024. Imbalance conformance over the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. This contributes to higher prices in the 15-minute market than in the 5-minute market over these hours.

Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets increased in the third quarter of 2024 relative to the same quarter of 2023, particularly in the evening ramp hours. During the morning hours, the highest average hourly adjustments were around 270 MW. This was an increase from a maximum of about 40 MW over the morning hours of Q3 2023. Imbalance conformance over the evening peak hours reached about 2,700 MW, about 700 MW higher than the largest average hourly evening adjustments over Q3 2023.

The 5-minute market adjustments increased in the third quarter of 2024 in all hours compared to the third quarter of 2023. These adjustments peaked in hour-ending 19 at about 750 MW.

Figure 8.1 Average CAISO balancing area hourly imbalance conformance adjustment (Q3 2023 and Q3 2024)

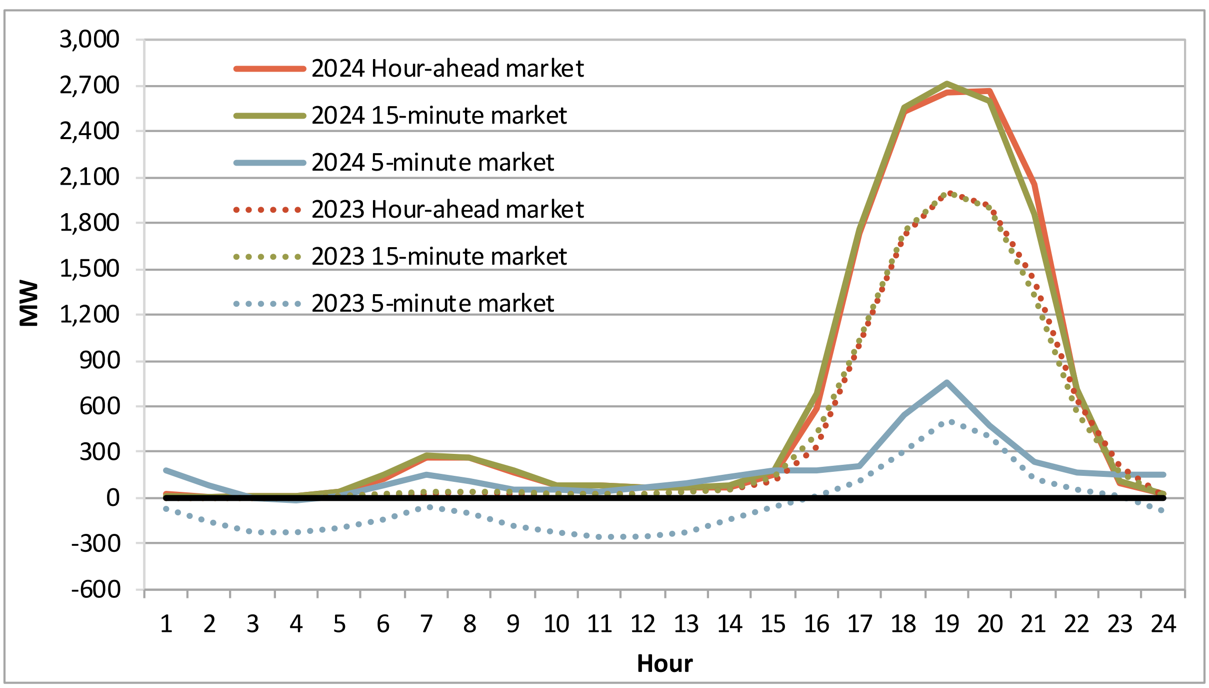
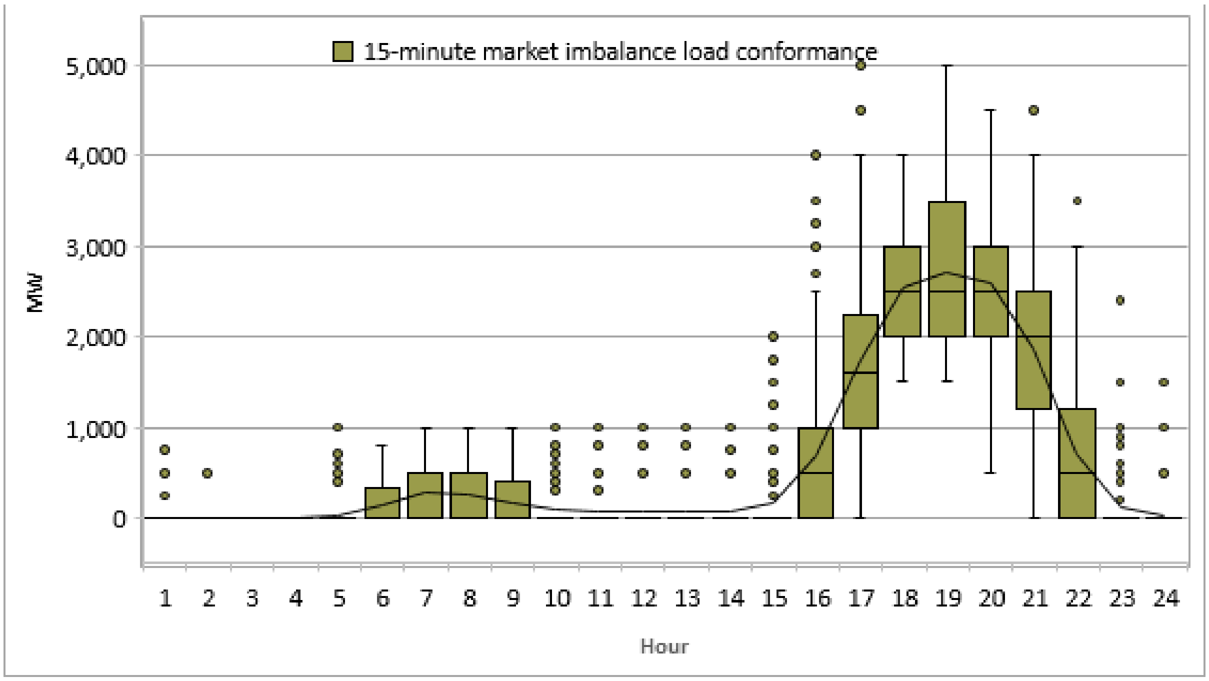


Figure 8.2 shows an hourly distribution of the 15-minute market load adjustments for the third quarter of 2024. This box and whisker graph highlights extreme outliers[56] (positive and negative), minimum excluding outliers, lower quartile, median, upper quartile, and maximum excluding outliers, as well as the mean (line). The extreme outliers are represented by the filled "dots". The outside whiskers do not include these outliers. For the quarter, the maximums and major outliers in hours-ending 17 to 22, e.g., 5,000 MW, occurred on July 24 and August 28, associated with rapid solar ramp down.

Figure 8.2 CAISO BA 15-minute market hourly distribution of operator load adjustments (Q3 2024)



9 Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market, to help manage volatility and uncertainty surrounding net load forecasts.[57] The amount of flexible capacity the product procures is derived from a demand curve, which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between

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

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

the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs. Flexible capacity is procured and priced at a nodal level to better ensure that sufficient transmission is available for the capacity to be utilized.

The flexible ramping product demand curves are implemented in the ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This "requirement" for rampable capacity reflects the upper end of uncertainty in each direction that might materialize.[58] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

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

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

9.1 Flexible ramping product prices

Flexible ramping product prices are determined locationally at each node. This nodal price can be made up of multiple components.[59] The first component is the shadow price associated with meeting the flexible ramp requirement either for the group of balancing areas that pass the resource sufficiency evaluation or the individual balancing areas that fail the tests.

The nodal price also includes components to reflect any congestion based on the dispatch of flexible capacity in the deployment scenarios. This accounts for any congestion on WEIM transfer constraints between balancing areas as well as congestion on transmission constraints.[60] These components can create price differences across nodes in the WEIM based on the demand for flexibility in the system and

58 Based on a 95 percent confidence interval.

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

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

the feasibility for flexible capacity at a node to meet that demand. For the transmission constraints, only base-case flow based constraints were modeled in the deployment scenarios at implementation of the enhancements on February 1, 2023. Nomogram constraints were later enforced for flexible ramping product procurement on September 7, 2023. Contingency flowgate constraints were activated on June 4, 2024 and de-activated on June 12 due to performance issues with the solution run-times.[61] Using the same constraints for both the real-time market and flexible ramping product deployment scenarios is important in order to prevent conditions in which procured flexible capacity is actually stranded behind transmission constraint congestion, and therefore not able to address materialized uncertainty.

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

The slack variables are implemented for each balancing area.[62] The cost associated with the slack variable (cost of relaxing the requirement) is reflected by a demand curve. The demand curves are based on each balancing area's expected cost of a power balance constraint violation for the level of flexible capacity forgone.[63] The more flexibility forgone, the greater the likelihood of a power balance constraint violation and therefore greater expected cost. For a balancing area in the pass-group, the slack variable (or end of the demand curve) is limited by its distributed share of the pass-group uncertainty requirement.

The shadow price on the constraint for procuring flexible capacity in the pass-group has frequently been zero. When the shadow price on this constraint is zero, this generally reflects that flexible capacity within the wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available.[64] Here, the flexible capacity requirement for the group of balancing areas that passed the resource sufficiency evaluation can be met by resources with zero opportunity cost for providing that flexibility.

Figure 9.1 shows the percent of intervals in which the shadow price on the pass-group constraint was non-zero (constraint binding) for upward and downward flexible capacity. This reflects more widespread prices for flexible capacity within the group of balancing areas that passed the resource sufficiency evaluation, but does not account for any congestion that may affect the price of flexible capacity at the

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

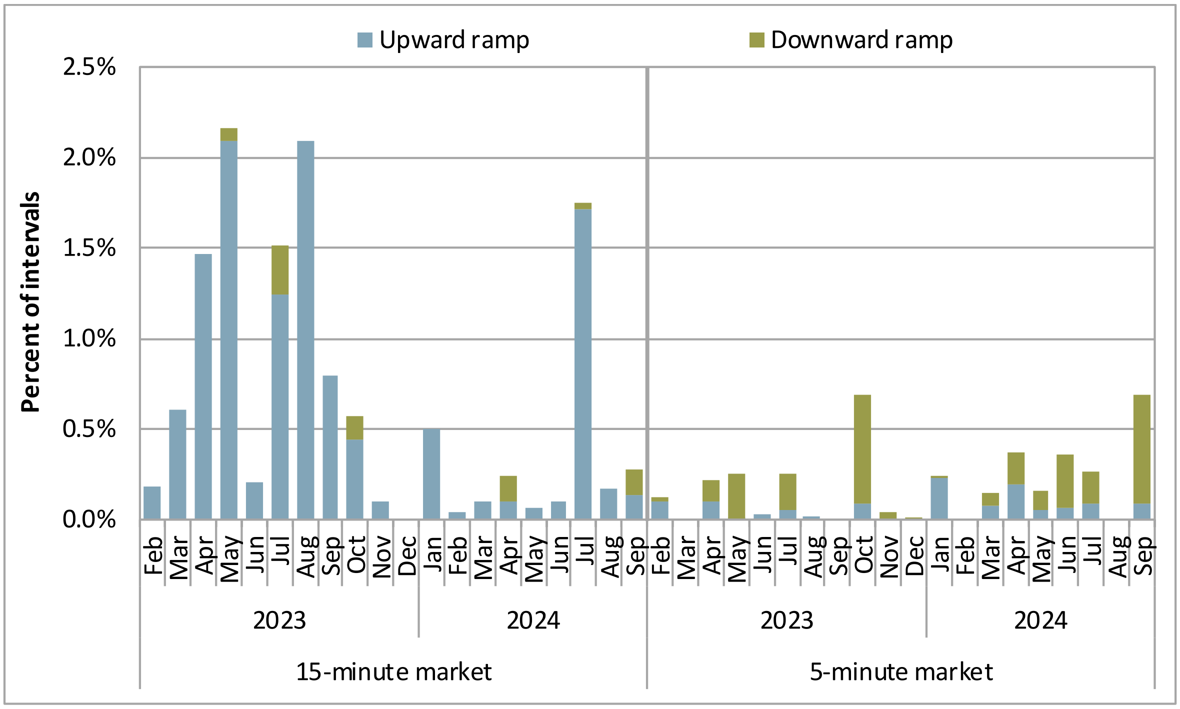
62 Or for each surplus zone in the case of the CAISO balancing area (by TAC area) and BANC (by custom load aggregation point).

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

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

nodal level.[65] The pass-group constraint for procuring *upward* flexible capacity in the 15-minute market was binding in 1.7 percent of intervals during July. These all occurred during the peak net load hours when supply conditions were tightest in the WEIM footprint. In August and September, the shadow price on this constraint was frequently zero. In the 5-minute market, the constraint for procuring flexible capacity within the pass-group was also binding infrequently.

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



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

Figure 9.2 summarizes the frequency of flexible ramping product prices in either the wider pass-group or transfer-constrained balancing areas within the pass-group. The blue bars are identical to the 15-minute market upward ramping capacity information shown in Figure 9.1, summarizing the frequency in which the constraint for meeting pass-group flexible capacity requirements was binding. The figure adds the percent of intervals in which the constraint that reflects WEIM transfer congestion in the deployment scenario was binding for one or more balancing areas in the pass-group—*and the pass-group constraint was not also binding*. This reflects additional flexible ramping product prices within at least one balancing area. In most cases, these prices were within one isolated balancing area in the pass-group

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

that was not able to meet its share of pass-group uncertainty. Localized flexible ramping product prices within the pass-group that are entirely driven by congestion on transmission constraints are not reflected in this figure.

Figure 9.2 Frequency of upward flexible ramping product prices from pass-group or WEIM transfer constraints (15-minute market)

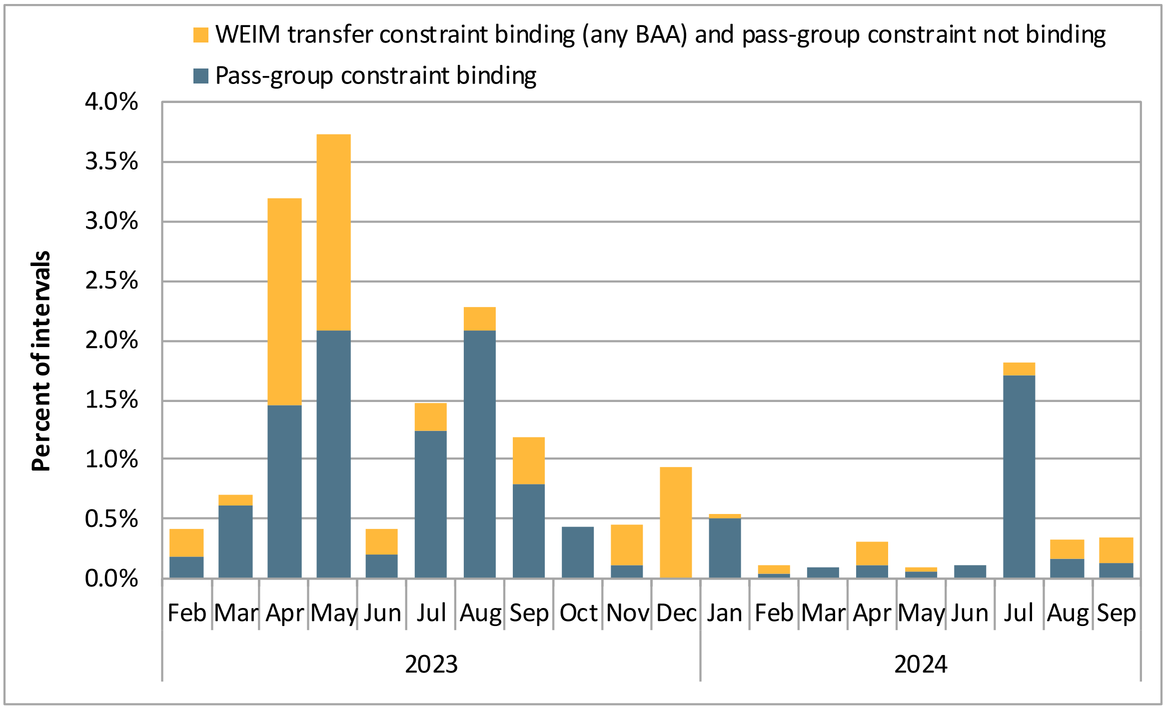


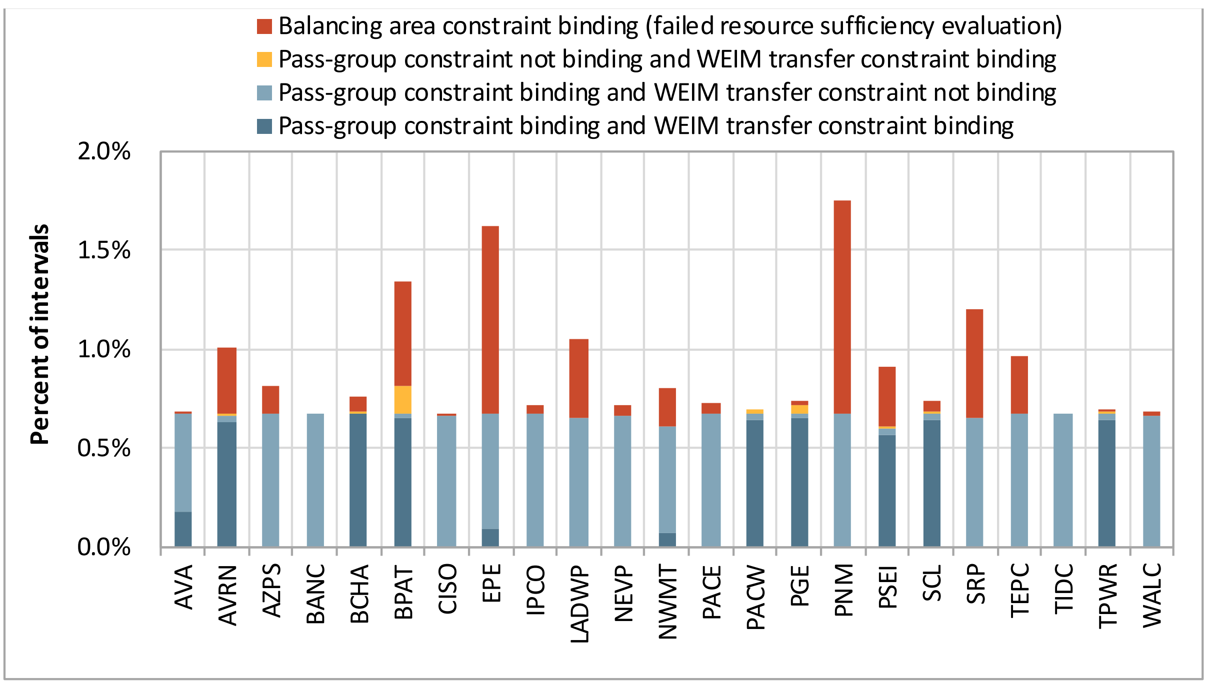
Figure 9.3 summarizes the frequency of upward flexible ramping product prices in the 15-minute market by balancing area in the quarter. These results are shown separately by the constraint contributing to that price:

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

During the quarter, the pass-group constraint was binding infrequently for upward flexible capacity in the 15-minute market, during around 0.7 percent of intervals. In most of these intervals, balancing areas in the Pacific Northwest region had sufficient flexible capacity, but because of congestion on WEIM transfer constraints out of the balancing area in the deployment scenario, flex ramp prices here were typically zero.

Figure 9.3 also summarizes flexible capacity prices that can exist following a resource sufficiency evaluation failure (red bars). When a balancing area fails the resource sufficiency evaluation, the area will not have access to any diversity benefit of reduced uncertainty over a larger footprint and will instead need to meet its uncertainty needs from flexible capacity within its area only. The Public Service Company of New Mexico (PNM) and El Paso Electric had prices for flexible capacity following a failure of the resource sufficiency evaluation during around 1 percent of intervals. Many of these were associated with failure of the second run of the resource sufficiency evaluation at 55 minutes prior to the hour, which impacts the first interval of each hour.[66]

Figure 9.3 Frequency of upward flexible ramping product prices by balancing area and constraint (15-minute market, July–September 2024)



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

9.2 Flexible ramping product procurement

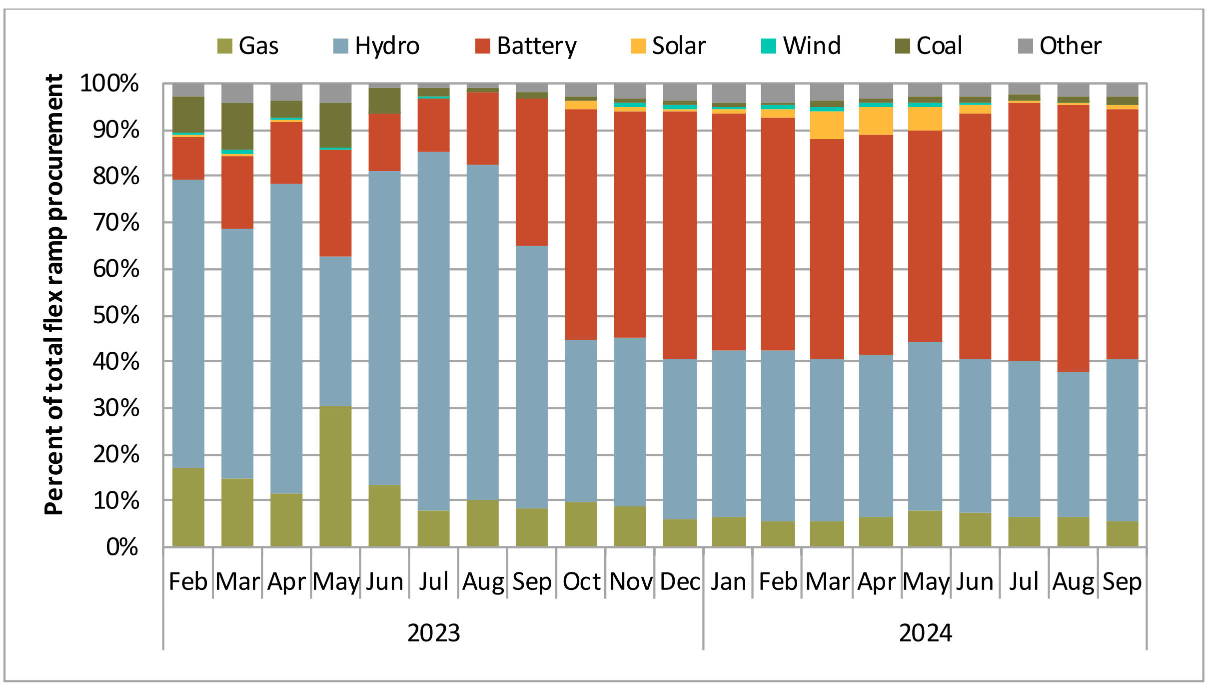
This section summarizes flexible capacity procured to meet the uncertainty needs of the group of WEIM balancing areas that pass the resource sufficiency evaluation. Figure 9.4 and Figure 9.5 show the percent of upward or downward flexible capacity that was procured from various fuel types.

The share of flexible capacity from various fuel types has been relatively stable in 2024. During the quarter, battery resources continued contributing to much of the upward and downward flexible capacity. Battery resources made up almost 56 percent of upward flexible capacity and 28 percent of downward flexible capacity. Hydro resources continued to supply a large portion of upward flexible capacity (33 percent). Wind and solar resources combined made up around 40 percent of downward flexible capacity.

Figure 9.6 and Figure 9.7 show the percent of upward or downward flexible capacity that was procured in various regions.[67] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained, along with one or more other balancing areas relative to the greater WEIM system.

During the quarter, the California ISO balancing area continued to make up the majority of upward and downward flexible capacity awards, at around 60 percent for both directions. Balancing areas in the Pacific Northwest made up 28 percent of upward flexible capacity and 15 percent of downward flexible capacity.

Figure 9.4 Percent of upward system or pass-group flexible ramp procurement by fuel type



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

Figure 9.5 Percent of downward system or pass-group flexible ramp procurement by fuel type

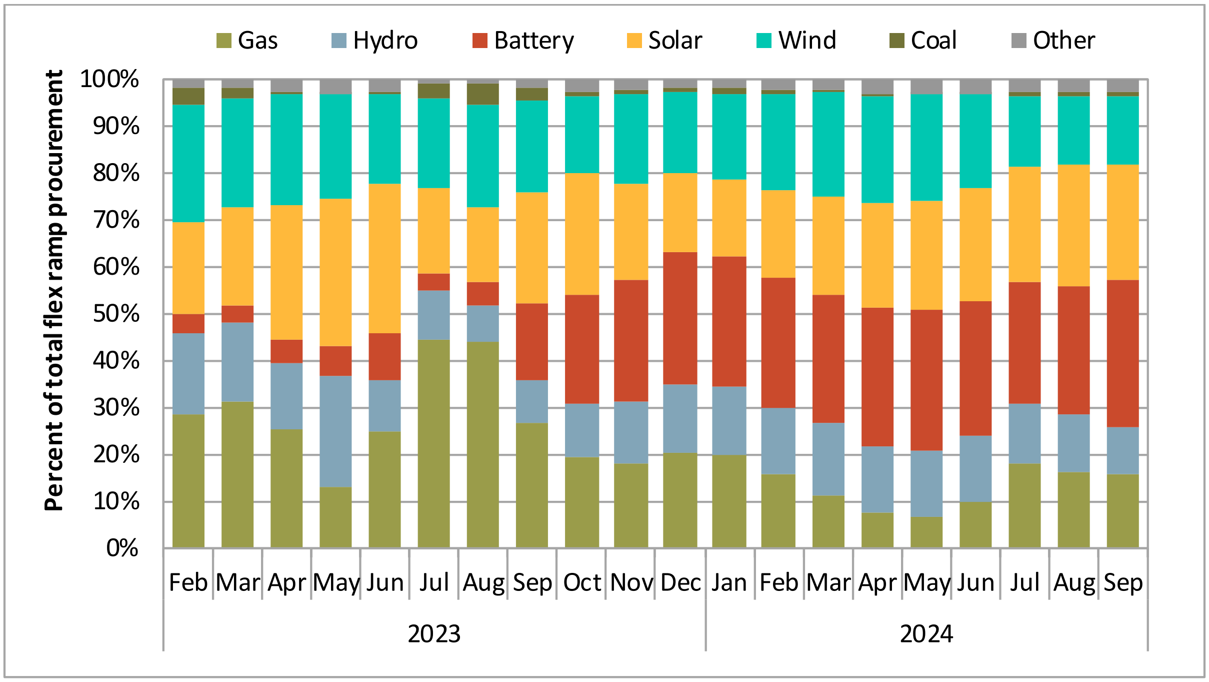


Figure 9.6 Percent of upward system or pass-group flexible ramp procurement by region

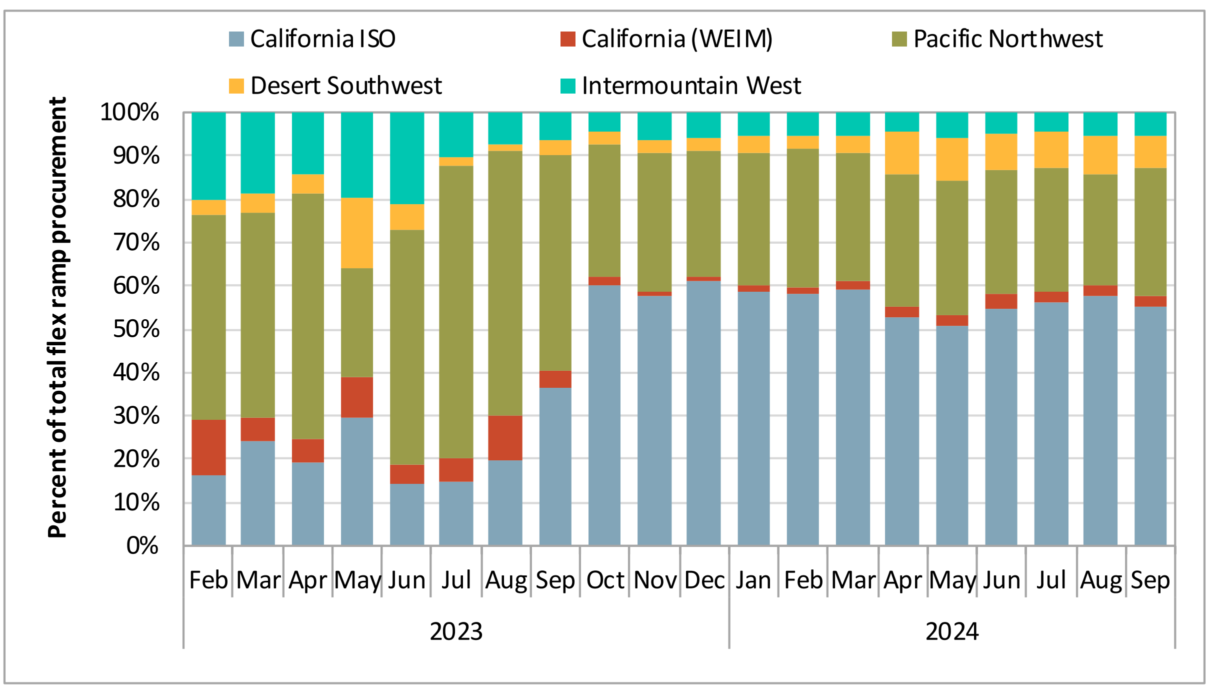
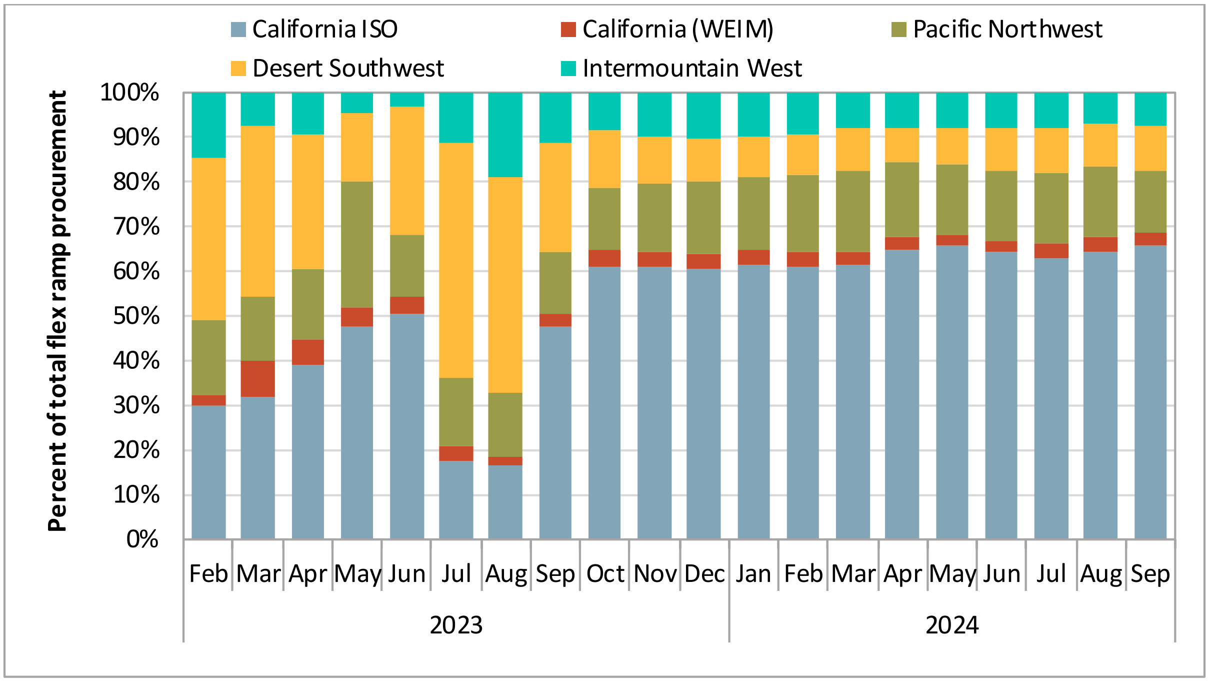


Figure 9.7 Percent of downward system or pass-group flexible ramp procurement by region



10 Uncertainty

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

Background defining the uncertainty analyzed in this section

The California ISO introduced a regression method to calculate uncertainty on February 1, 2023.[68] This methodology is a forecasting approach to manage uncertainty. Uncertainty in the market is defined as forecasting error. For example, the 15-minute and 5-minute markets utilize available forecasts for load, wind, and solar at the time when the market runs. If the target is hour-ending 18, both markets run for the same target hour, but calculations are made at different times. The 15-minute market runs earlier than the 5-minute markets, leading to differences in forecast data due to updates in weather and other variables in the interim period. This difference in forecast data is the uncertainty.

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

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

Uncertainty for an upcoming interval cannot be known in advance. For example, for the 15-minute market flexible ramping product, uncertainty is defined as the difference between the first advisory 15-minute forecast and the binding 5-minute forecasts.[69] At the start time of the advisory 15-minute market run, the 15-minute market uses a forecast of what net load is expected to be. However, at that time, the net load that the corresponding 5-minute markets will use when those market runs start 45-55 minutes later is not known. The uncertainty calculation uses historical data to forecast what the uncertainty might be. This allows for better preparation and adjustment in the market operations.

Background on calculating net load uncertainty

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

On February 1, 2023, the ISO began using a second method to calculate uncertainty. This was the mosaic quantile regression method. The regression approach adds another layer to the uncertainty calculation by incorporating the mosaic variable—a predictor constructed by the ISO. Unlike the first method that only considers historical uncertainty, this approach looks for patterns between uncertainty and the mosaic variable, and uses it for forecasting. For example, if uncertainty was high when the mosaic variable was high in the past, it suggests that high uncertainty might occur in future periods, when the mosaic variable is also high. The regression method quantifies the patterns observed in the past, providing exact numbers rather than just indicating high or low. Once the pattern is known, it can be applied to future scenarios. The variable is derived from a combination of load, solar, and wind forecasts.[70]

For a regression methodology to produce better forecasting results than a histogram methodology, there must be a strong pattern between the uncertainty and the mosaic variable. Also, this pattern should persist in the future period being forecasted. If the pattern does not persist over time, it may suggest the pattern is driven by noise in the past data, providing incorrect information for forecasting

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

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

uncertainty. This could result in less accurate and potentially erroneous forecasts. If the pattern is weak or nonexistent, the regression method essentially reverts to the histogram method, which relies solely on past uncertainty distributions without the added insight from the mosaic variable.[71]

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

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

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

Background on assessing performance of the mosaic quantile regression forecast

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

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

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

In addition to accuracy and efficiency, this section evaluates the model's validity by examining the statistical significance of its coefficients. These coefficients reflect patterns in historical data, and their statistical significance confirms whether these patterns are strong enough for forecasting. For example, in load forecasting, if temperature and load have a significant historical relationship, this can be useful

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

for future prediction, assuming the pattern holds. However, if the relationship is non-significant, the forecast is likely based on unreliable patterns, making the prediction questionable.

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

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

If in a larger percentage of intervals, the regression method produces statistically significant coefficients, the regression forecast results should have greater divergence from the histogram method results. This is because the regression incorporates the histogram method. When the pattern detected by regression is not statistically significant, one possibility is that the coefficient may be zero, causing the regression results to resemble the histogram.[72] Another possibility is that the coefficient is non-zero but unreliable, potentially leading to erroneous forecasts. In practice, mosaic regression often encounters a combination of these two issues.

In the following subsections, this report presents performance metrics for the mosaic quantile regression performed for the flexible ramping product, resource sufficiency evaluation, and the residual unit commitment market adjustment. Measurements of the uncertainty requirements and coverage in this section are based on actual market results. The statistical significance metrics are based on DMM's replication of the ISO's mosaic quantile regression method.[73]

10.1 Flexible ramping product uncertainty

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

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

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

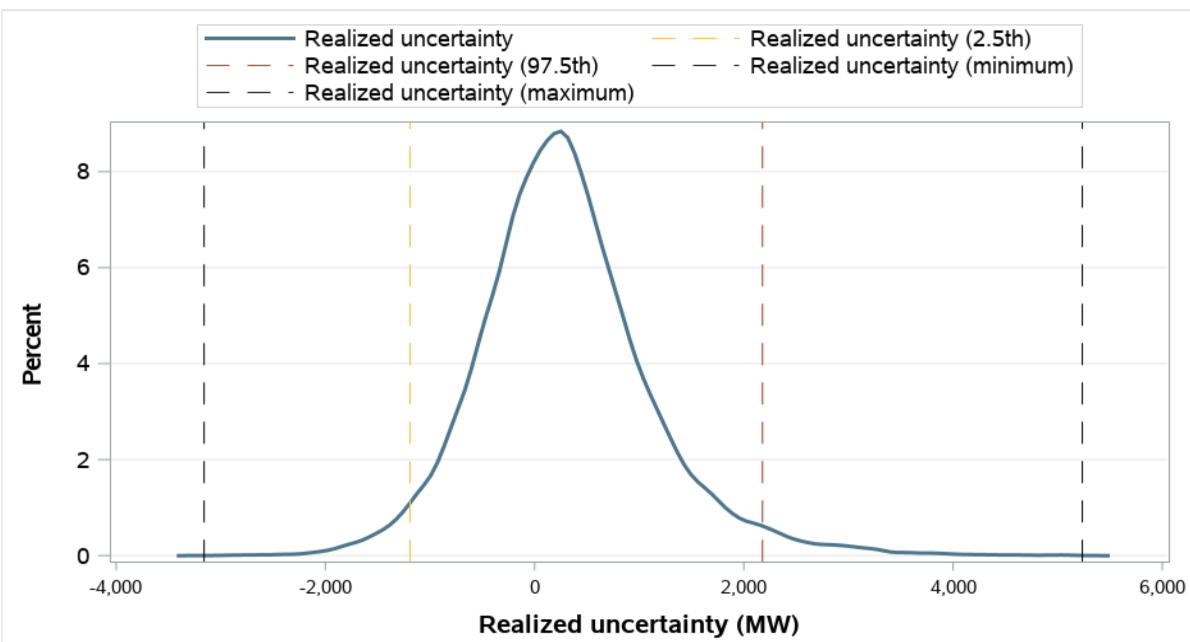
The flexible ramping product uses an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for instead the group of balancing areas that pass the resource sufficiency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

Figure 10.1 illustrates the distribution of realized uncertainty in the flexible ramping product (FRP) for the group of balancing areas that passed the resource sufficiency evaluation (RSE) for the third quarter of 2024. The distribution is depicted as a blue line, with the extreme percentiles highlighted: the lowest 2.5th percentile in yellow, the 97.5th percentile in red, and the black dashed lines indicating the minimum and maximum values.

The range from the upper 2.5 percent of uncertainty to its maximum spans from 2,000 MW to over 5,500 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 distribution was skewed upward, resulting in a longer tail on the upper end. This may indicate the influence of systematic patterns, rather than purely random variations. These factors may provide valuable information for forecasting uncertainty.

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

Figure 10.1 Distribution of realized uncertainty in FRP (pass-group, July–September 2024)



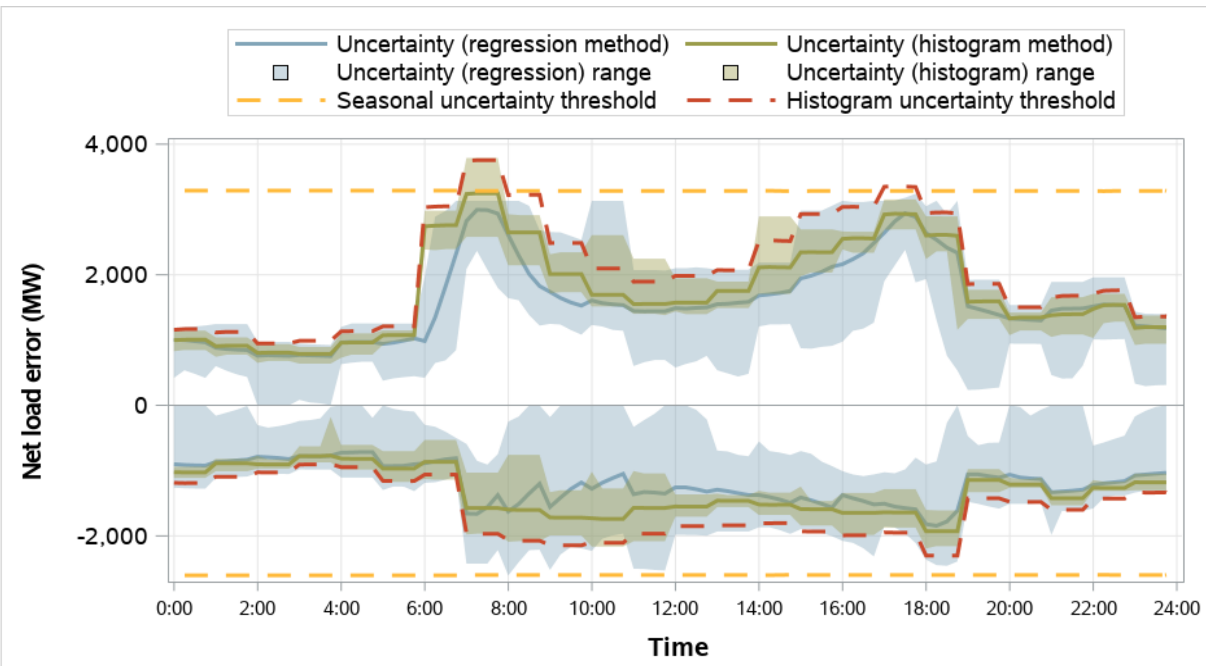
10.1.1 Results of flexible ramping product uncertainty calculation

Figure 10.2 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation, both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the historical 180-day period) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the quarter. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively, during the period.[74]

Figure 10.3 shows the same information for 5-minute market uncertainty, which reflects the difference between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach was typically lower or comparable to uncertainty calculated with the histogram approach. In hour-ending 7, the regression-based uncertainty in the 15-minute market was much lower on average, in comparison to the histogram-based uncertainty. However, results of the regression-based approach vary more widely, including periods with much lower uncertainty.

Figure 10.2 15-minute market pass-group uncertainty requirements (July–September 2024)



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

Figure 10.3 5-minute market pass-group uncertainty requirements (July–September 2024)

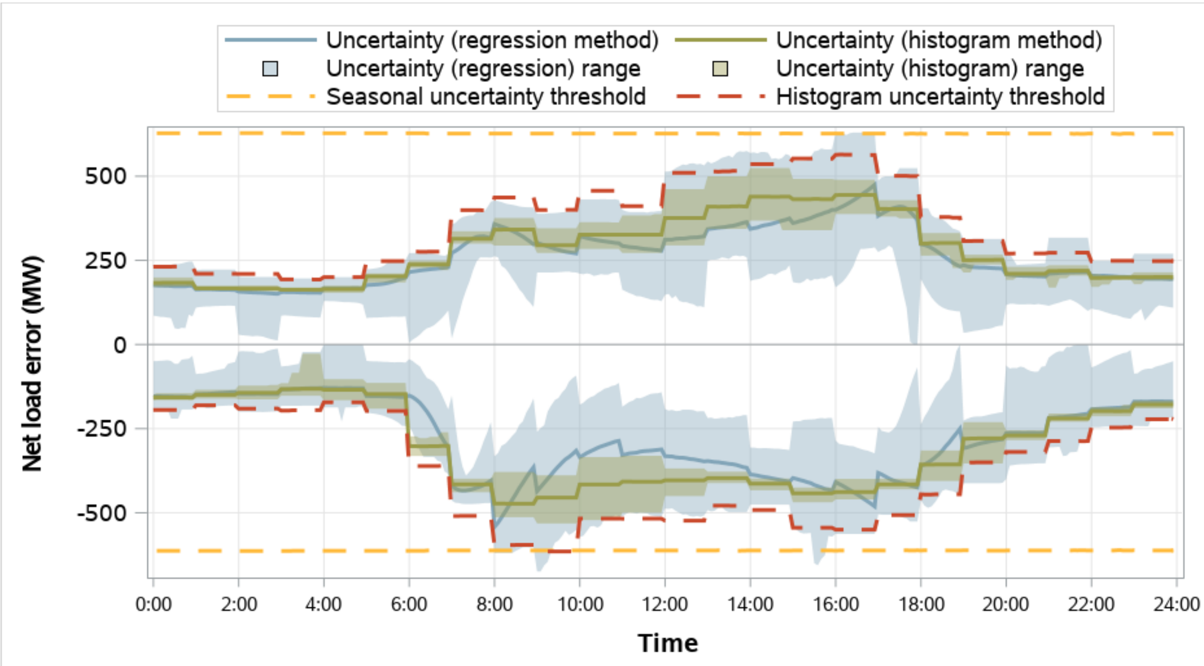


Table 10.1 summarizes the average uncertainty requirement and coverage for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. The *requirement* shows the average target for procuring flexible capacity within the pass-group (based on a 95 percent confidence interval). The *coverage* shows how often the realized uncertainty fell within the requirement for the same interval.[75] On average across all hours, 15-minute and 5-minute market uncertainty calculated from the regression method was less than the histogram method for both directions. The mosaic regression and histogram requirements also covered a similar percent of realized uncertainty across both real-time markets and directions (around 1 percent or less difference).

Table 10.1 Average pass-group uncertainty requirements (July–September 2024)

		Requirement			Coverage		
Market	Direction	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
15-minute market	Up	1,755	1,587	-168	96.4%	95.4%	-1.0%
	Down	1,333	1,195	-138	98.2%	97.1%	-1.1%
5-minute market	Up	282	262	-20	97.6%	96.9%	-0.7%
	Down	306	281	-25	97.8%	97.2%	-0.6%

75 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.

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

The mosaic regression is primarily designed to forecast net load uncertainty, with the mosaic variable serving as the main predictor in this regression. The three additional quantile regressions—load, solar, and wind—function as intermediate regressions used to construct the mosaic variable.[76]

The percentages in the table indicate the proportion of estimated coefficients that were statistically different from zero among all regression estimation in this quarter. Each regression includes two primary coefficients: a quadratic term and a linear term.[77] The percentages represent the proportion of regression where at least one of these coefficients was statistically significant. The significance level was set at 10 percent.

Table 10.2 Statistical significant test for mosaic quantile regression in FRP (July–September 2024)

Regression type	All hours	Peak hours(1)
Mosaic	32%	41%
Load	26%	40%
Solar	78%	92%
Wind	53%	60%

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

The coefficient for the mosaic variable was statistically significant during only 32 percent of intervals. This means that in 68 percent of cases, the mosaic variable does not show a strong pattern with historical uncertainty.[78] Whether the mosaic variable is high or low, the uncertainty does not consistently respond with similarly high or low levels of uncertainty. Consequently, when looking at future data, even if the mosaic variable is high, it is unclear whether the uncertainty will be high or low.

Low statistical significance suggests that the regression often fails to identify a meaningful relationship. This failure could stem from either no relationship or inconsistent relationship. While it is difficult to quantify the proportion of cases due to no relationship versus inconsistency, mathematically, if no

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

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

78 Quantile regression assesses patterns that may exist at a specific percentile of the sample. For the flexible ramping product, the 97.5th and 2.5th percentiles reflect the extreme upper or lower 2.5 percent of uncertainty relative to the mosaic variable. If the pattern is strong, it indicates a clear relationship at these extremes. Conversely, a weak pattern suggests that the relationship is less pronounced or not robust.

relationship exists, the quantile regression outcomes will converge to the histogram results.[79] Intuitively, this occurs because a no relationship implies that the mosaic variable provides no additional information for forecasting. As a result, the forecast relies solely on the historical net load uncertainty data, which is the histogram method.

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

10.1.2 Threshold for capping flexible ramping product uncertainty

Flexible ramping product and resource sufficiency evaluation uncertainty calculated from the quantile regressions is capped by the lesser of two ceiling thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from a 180 day period.[80] The seasonal threshold is updated each quarter and is calculated based on the 1st and 99th percentile using observations over the previous 90 days. For the upward seasonal threshold, the 99th percentile is calculated separately for each of the 24 hours in a day. The maximum value out of these 24 hours is used as the threshold for all hours.[81]

During the quarter, the ceiling thresholds capped *upward* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 12 percent of intervals in the 15-minute market and 2 percent of intervals in the 5-minute market. *Downward uncertainty* was capped by the ceiling thresholds in around 6 percent of intervals in the 15-minute market and 4 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the seasonal threshold.

The ceiling threshold implies that the requirement is set at the highest 1 percent of uncertainty over the past 90 or 180 days. The expected frequency of reaching this threshold is around 1 percent of the time. However, the observed frequency of 12 percent in the 15-minute market significantly exceeded this expectation.

A floor threshold is also in place that sets the floor for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. During the quarter, uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this threshold in less than 1 percent of intervals in both directions and in both the 15-minute and 5-minute markets.

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

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

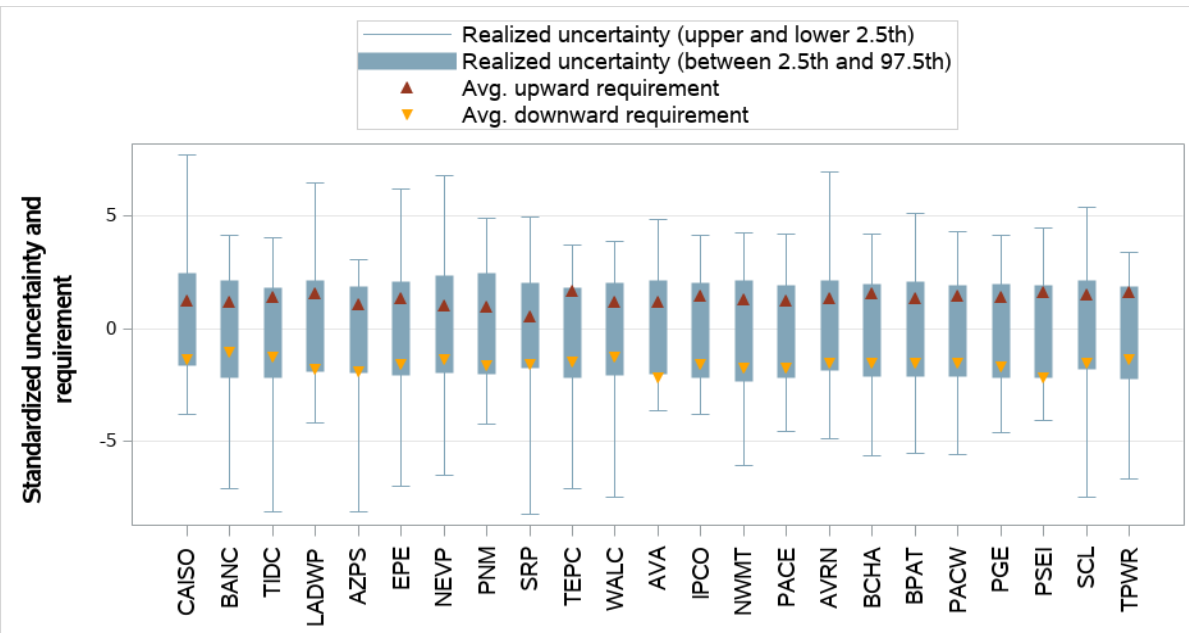
81 For the downward seasonal threshold, the 1st percentile is calculated separately for each of the 24 hours in a day. The minimum value out of these 24 is used as the threshold for all hours.

10.2 Resource sufficiency evaluation uncertainty

Uncertainty is included as an additional requirement in the flexible ramp sufficiency test (flexibility test) as part of the resource sufficiency evaluation (RSE). Here, balancing areas must show enough upward and downward ramping flexibility over an hour to meet both the forecasted change in demand *as well as uncertainty*.[82] This additional requirement in the flexibility test is also based on a 95 percent confidence interval for uncertainty that might materialize. This section analyzes the performance of the mosaic quantile regression in the resource sufficiency evaluation.

Figure 10.4 shows the distribution of realized 15-minute uncertainty in the RSE for each balancing authority area (BAA) for the third quarter of 2024. Here, realized uncertainty is defined as the net load forecast difference between the forecasts used in the resource sufficiency evaluation and those in the binding 5-minute market runs. To facilitate comparison across different BAAs, the realized uncertainty has been standardized by its mean and standard deviation.[83] This eliminates scale issues and allows for a clear assessment of relative volatility in realized uncertainty among BAAs. Additionally, the figure displays the standardized average upward and downward requirement imposed in the market, enabling a comparison of each BAA's requirement relative to its own uncertainty, as well as in relation to other areas.

Figure 10.4 Standardized realized uncertainty and requirement for RSE (July–September 2024)



[82] 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.

[83] 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 10.4 provides a comparison of the realized uncertainty across different BAAs for this quarter. The blue box represents the range of realized uncertainty between the 2.5th and 97.5th percentiles. The blue lines extend upward from the 97.5th percentile to the maximum value and downward from the 2.5th percentile to the minimum value of realized uncertainty. The triangle markers show the average upward and downward requirement applied in the market, based on the ISO estimates.

Key observations include:

- **Long tails**: Most BAAs exhibit a long tail distribution. The range of uncertainty beyond the 2.5th and 97.5th percentiles is wider than the main distribution of data.
- **Asymmetry in uncertainty:** Not all have symmetric uncertainty distributions. Some tend to have more positive uncertainty, while others skew more negative.
- **Requirement**: The requirements reflect the forecasted outcomes of the mosaic regression. Some BAAs exhibited a narrower range of requirements compared to others, which may indicate the regression model performed differently across BAAs.

10.2.1 Results of resource sufficiency evaluation uncertainty calculation

Table 10.3 summarizes the average requirements and coverage for uncertainty in the resource sufficiency evaluation using both the histogram and mosaic quantile regression methods. In this table, *requirement* shows the average uncertainty component considered in the upward and downward flexibility test requirements. *Coverage* measures how frequent realized uncertainty—as measured by the difference between binding 5-minute market net load forecasts and net load forecasts in the resource sufficiency evaluation—fell within the calculated uncertainty requirements for the same interval. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for almost all of the WEIM entities. The resource sufficiency evaluation uncertainty calculated from the regression method covered between 75 and 91 percent of realized uncertainty across all balancing areas.

Table 10.3 Average resource sufficiency evaluation uncertainty requirements and coverage (July–September 2024)

	Upward requirement			Downward requirement			Coverage		
Balancing area	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference	Histogram	Mosaic	Difference
Arizona Public Service	247	220	-27	235	216	-20	87%	84%	-3%
Avangrid	233	193	-40	173	144	-29	92%	89%	-3%
Avista	61	50	-11	77	71	-6	91%	87%	-5%
BANC	49	45	-5	46	42	-4	89%	87%	-2%
Bonneville Power Admin.	248	215	-33	240	213	-27	92%	90%	-2%
California ISO	1,215	1,036	-179	749	664	-85	92%	88%	-4%
El Paso Electric	44	43	0	42	40	-2	89%	88%	0%
Idaho Power	135	125	-11	152	134	-18	92%	89%	-3%
LADWP	169	152	-16	172	157	-15	93%	91%	-2%
NorthWestern Energy	75	59	-15	85	75	-10	92%	89%	-3%
NV Energy	294	259	-35	261	219	-42	89%	85%	-4%
PacifiCorp East	363	324	-39	552	490	-62	92%	88%	-4%
PacifiCorp West	95	89	-6	125	105	-20	92%	90%	-2%
Portland General Electric	146	132	-15	137	134	-4	90%	88%	-2%
Powerex	133	129	-4	141	135	-6	89%	88%	-1%
PNM	153	139	-14	175	166	-9	90%	88%	-2%
Puget Sound Energy	147	124	-23	145	137	-8	93%	90%	-3%
Salt River Project	161	151	-10	159	151	-9	78%	75%	-2%
Seattle City Light	20	19	-2	21	19	-2	93%	91%	-2%
Tacoma Power	11	10	-1	11	10	-1	92%	90%	-2%
Tucson Electric Power	109	102	-6	93	91	-1	91%	90%	-1%
Turlock Irrigation District	8	8	-1	8	8	0	89%	87%	-2%
WAPA Desert Southwest	25	25	0	27	26	-1	85%	84%	-1%

Table 10.4 summarizes the percentage of statistically significant coefficients during all hours and peak hours, based on DMM's replication of the regression. The balancing areas are listed in descending order, starting with those with the highest percentage of significant coefficients. Overall, 41 percent of regression coefficients were significant in Q3 2024, indicating that 59 percent of the regression estimations were based on either weak or inconsistent patterns.

Table 10.4 Statistical significant test for mosaic quantile regression in RSE (July–September 2024)

BAA	Percent of significant coefficients: All hours	Percent of significant coefficients: Peak hours(1)
Avangrid	84%	94%
BPA	65%	69%
PacifiCorp West	58%	57%
Avista Utilities	50%	45%
Idaho Power	47%	62%
NorthWestern	45%	42%
Portland GE	44%	46%
Arizona PS	41%	37%
CAISO	47%	50%
LADWP	39%	40%
PacifiCorp East	39%	46%
NV Energy	42%	59%
PSC New Mexico	38%	50%
Puget Sound Energy	36%	40%
Salt River Project	44%	45%
El Paso Electric	42%	56%
Powerex	24%	17%
Tucson Electric	37%	34%
WAPA - Desert SW	34%	35%
BANC	35%	27%
Seattle City Light	22%	24%
Turlock ID	21%	21%
Tacoma Power	20%	25%
Average	41%	45%

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

10.3 Residual unit commitment uncertainty

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

Figure 10.5 shows the average residual unit commitment adjustment on each day of 2023 (red) and through September of 2024 (blue). The arrows highlight key changes that occurred in 2023 and 2024.

1. On June 30, 2023, the ISO began using the *mosaic quantile regression* method to calculate the RUC adjustments. Between June 30 and December 20, this calculation was applied to all hours based on the 97.5th percentile of net load uncertainty that might materialize in real-time.

2. On December 21, 2023, the ISO implemented a new operating procedure that changed the methodology for calculating the RUC adjustments, effectively lowering the amounts. The procedure calls for selecting the percentile target for calculating the adjustment based on conditions in the system. Under periods with moderate operational uncertainty, the operating procedure calls for using an adjustment that will procure enough capacity 50 percent of the time (i.e., the 50th percentile of upward uncertainty). The ISO can adjust the calculation on any day to instead use the 75th or 97.5th percentile during periods of higher forecast uncertainty or in extreme conditions.

3. On May 7, 2024, the ISO made changes to the operating procedure that allowed the uncertainty adjustment to be applied to only select hours.[84] During periods with moderate uncertainty, the adjustment is typically applied only to the peak morning and peak evening hours (around six hours). During periods with more operational uncertainty, the adjustment is generally applied to either mid-day hours (around 16 hours) or all hours. During periods with low operational uncertainty, *no adjustment* can also be applied.[85]

Figure 10.5 Average residual unit commitment adjustment by day (2023 vs. January–September 2024)

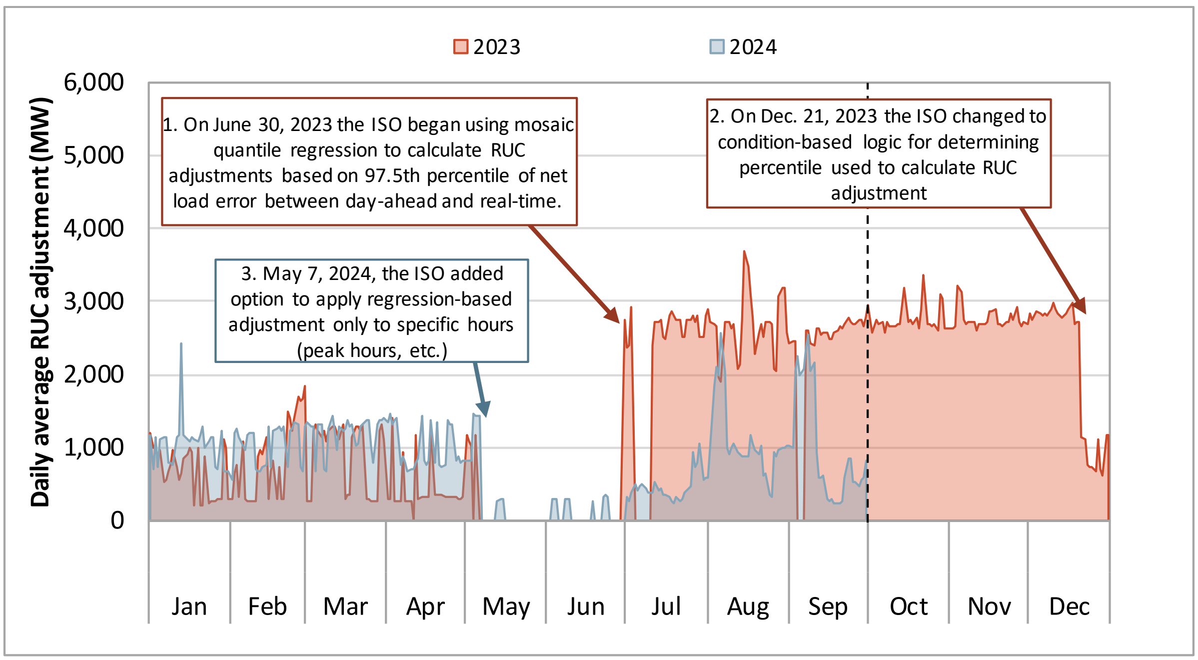


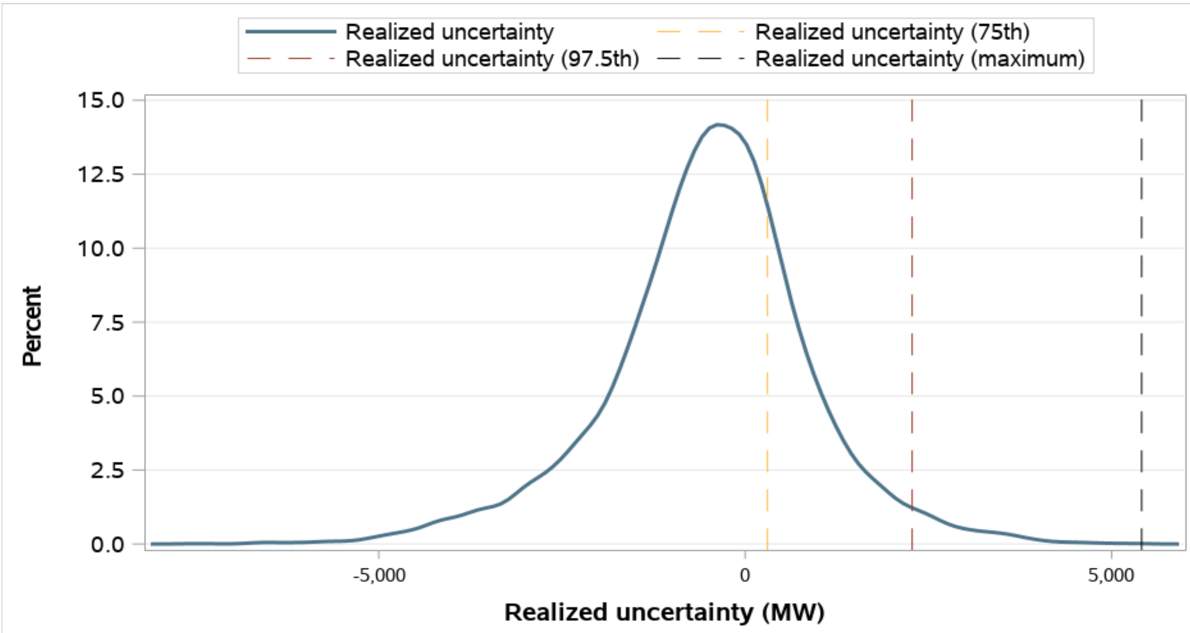
Figure 10.6 shows this quarter's distribution of realized uncertainty between the net load forecasts of the day-ahead market and the 15-minute market. This distribution represents all uncertainties observed in the 15-minute market intervals for this quarter and serves as the forecasting target. The first notable feature is that net load uncertainty in the day-ahead time horizon ranged from -7,600 MW to 5,400 MW. The distribution shows a long tail, with the area between the red dashed line and the black dashed line highlighting the range from the 97.5th percentile of uncertainty up to the maximum value. This area

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

[85] As noted in the day-ahead market operating procedure, dispatchable resources in the market, WEIM transfers, or regulating resources can instead manage uncertainty during periods with lower uncertainty.

ranged from 2,300 MW to 5,400 MW. A long tail could indicate rare but impactful events, such as unexpected weather changes or some other cause of a sudden shift in demand or renewable resource output.

Figure 10.6 Distribution of realized uncertainty between RUC and 15-minute market net load forecasts (July–September 2024)



10.3.1 Results of uncertainty calculation for residual unit commitment

Figure 10.7 shows the average RUC adjustment on each day since May 7, 2024 during the peak morning and evening hours (hours 7 to 9 and 19 to 21). The figure also shows the estimated percentile that was used to determine the additional requirements for the peak hours of each day.[86] During the third quarter, the 97.5th percentile target was applied on 15 percent of days. The 75th and 50th percentile targets were applied on 51 and 34 percent of days, respectively, during the quarter.

Figure 10.8 instead shows the average RUC adjustment for each day *across all hours*.[87] The dotted black line (right axis) shows the number of hours in which the adjustment was applied. During each day of the third quarter, the ISO applied an uncertainty-based operator adjustment to at least the peak hours. The adjustment was applied during all 24 hours using the 97.5th percentile target on one day (August 6).

The imbalance reserve product for the extended day-ahead market is intended to procure capacity to address the same uncertainty as this RUC adjustment, but the imbalance reserve up requirement will be set to cover the 97.5th percentile of uncertainty in all hours of all days. The low number of hours in

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

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

which the ISO used the 97.5th percentile target in RUC indicates that the imbalance reserve product demand curve may be much too high during most hours.

Figure 10.7 Average residual unit commitment adjustment by day (peak morning and evening hours, May 7–September 30, 2024)

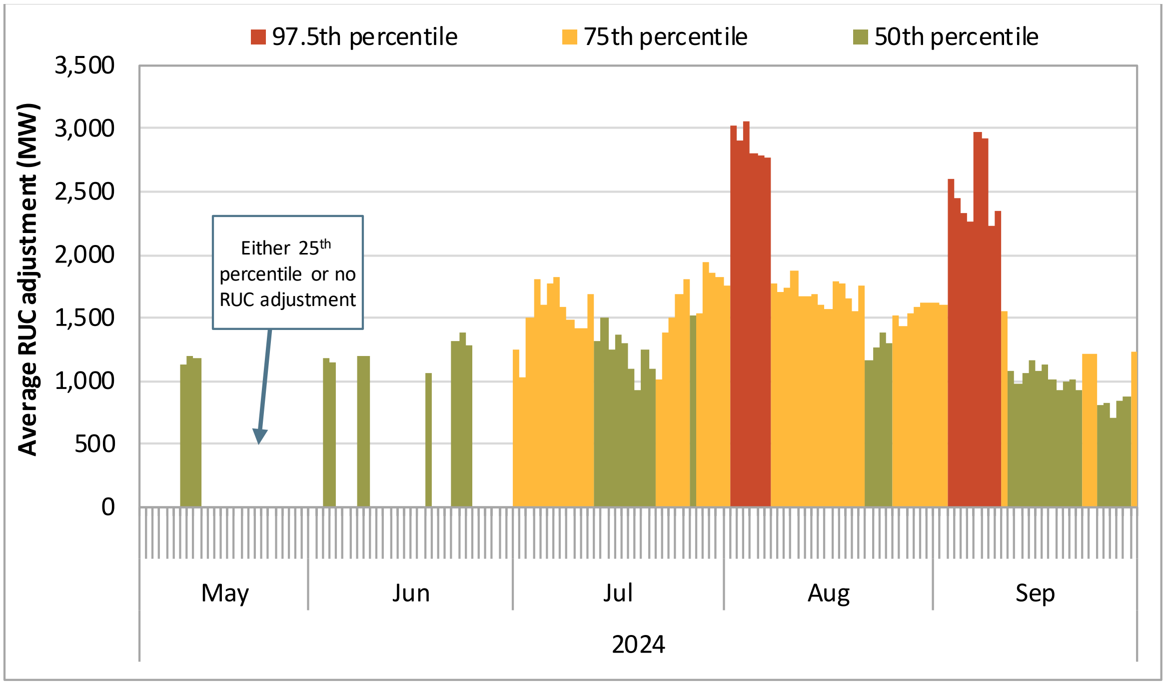


Figure 10.8 Average residual unit commitment adjustment by day (all hours, May 7–September 30, 2024)

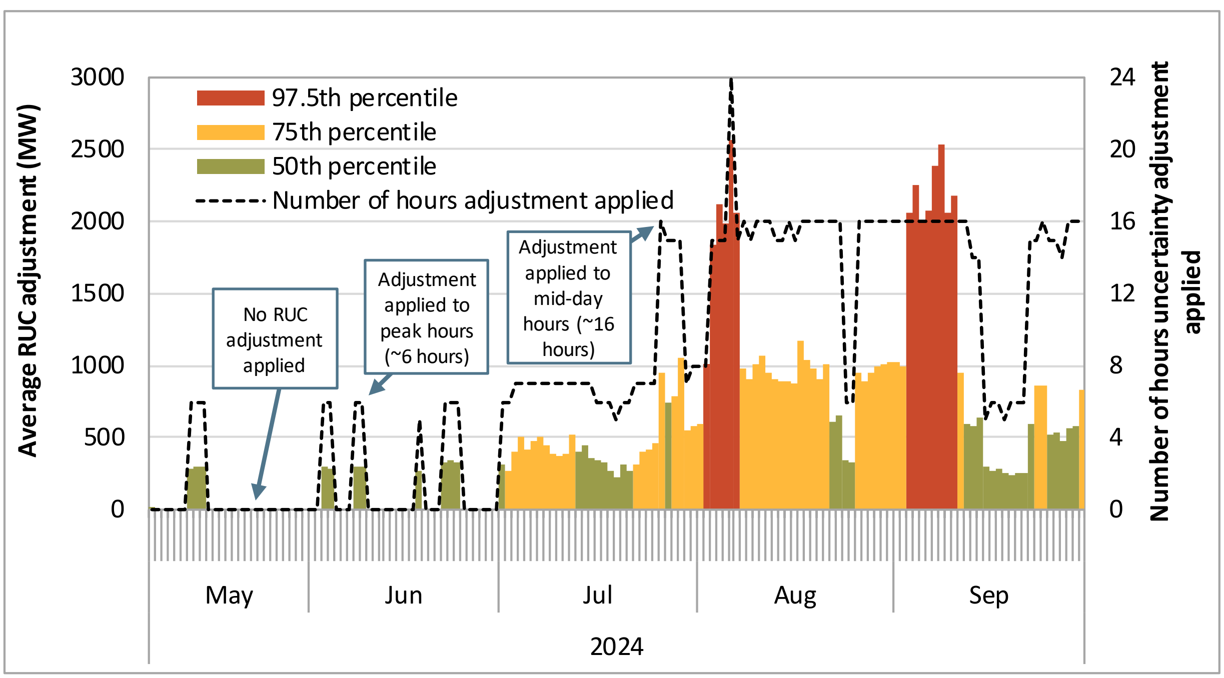


Table 10.5 summarizes the average requirement and coverage based on the percentile target that was selected and the hours it was applied (either all hours, mid-day hours, or peak hours). Coverage shows the percent of 15-minute market intervals in which realized uncertainty from the day-ahead market to the real-time market was below the RUC adjustment quantity. The average requirement and coverage were assessed only in hours the uncertainty adjustment was applied. Average requirements using the 97.5th percentile target were roughly double those using the 75th percentile target while coverage was higher (100 percent compared to 89 percent).

Table 10.5 Average residual unit commitment uncertainty adjustment and coverage (July–September 2024)

Percentile target	Hours applied	Percent of days	Average requirement (MW)	Coverage
97.5th percentile	All hours	1%	2,571	100%
	Midday hours	13%	3,261	100%
	Peak hours	1%	3,030	100%
75th percentile	Midday hours	32%	1,457	89%
	Peak hours	20%	1,509	89%
50th percentile	Midday hours	13%	935	85%
	Peak hours	21%	1,217	81%

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

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

The 97.5th percentile regression showed a zero rate of statistical significance, likely due to sample size. This specific percentile regression focuses on only 4 to 5 observations.[88] While an underlying pattern may exist, the small sample size of 4 to 5 observations is insufficient to find such a pattern, resulting in zero statistical significance.

The coverage rates for regression were notably inflated. For example, the 50th percentile regression, designed to capture 50 percent of realized uncertainty, showed coverage rates of 74 percent and 81 percent during peak hours. This inflation arises from two key factors. First, while the realized uncertainty represents the difference between day-ahead and 15-minute net load forecasts, available as four

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

uncertainty realizations per hour, the regression model forecasts the maximum uncertainty for each hour. This discrepancy inflated the result. As shown in Table 10.6, the realized uncertainty was centered around zero. However, the 50th percentile regression averaged around 920 MW during peak hours (as shown in Table 10.6). Second, the regression in RUC estimates only the upper bound of uncertainty, meaning any negative uncertainty is automatically covered, contributing to the inflated coverage rate.

Table 10.6 DMM simulation for RUC adjustment using mosaic quantile regression (July–September 2024)

	Requirement (MW)		Percent of significant coefficients		Coverage	
	All hours	Peak hours(1)	All hours	Peak hours	All hours	Peak hours
Replication (97.5th)	2,242	3,012	0%	0%	99%	99%
Replication (75th)	996	1,609	31%	45%	88%	91%
Replication (50th)	376	920	53%	63%	74%	81%
Replication (25th)	-221	199	44%	75%	55%	65%

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

10.4 Enhancements and issues with uncertainty calculation

This section summarizes recent enhancements as well as outstanding issues with the calculation of uncertainty in the market.

10.4.1 Change to symmetric sampling for calculating uncertainty

The regressions use a distribution of historical forecast observations from 180 days, separate for each hour, to calculate uncertainty. Prior to August 14, the historical observations were selected from the previous 180 days. On August 14, the ISO changed the methodology to instead select the observations from two periods (1) the previous 90 days and (2) the next 90 days minus one year.[89] This is known as symmetric sampling. This change impacted all calculations of uncertainty in the market.

The intent of this change was to improve the performance of the regression, particularly during seasonal transition periods (for example from spring to summer or summer to fall). By including historical observations from the following 90 days of the previous year, the historical data used to estimate uncertainty can be better representative of seasonal conditions in the present.

Table 10.7 presents the DMM simulation analyzing the impact of the policy change that introduced the symmetric sampling method compared to the previous methodology, which utilized the past 180 days. The performance metrics, including coverage, requirements, and the percentage of significant coefficients, were evaluated for the same period, from August 14 to September 30, using both sampling

89 Changes to Net-Demand Uncertainty Requirement Calculation Methodology in Flexible Ramping Product effective trade date 8/14/24: https://www.caiso.com/notices/changes-to-net-demand-uncertainty-requirement-calculation-methodology-in-flexible-ramping-product-effective-trade-date-8-14-24

methods.[90] All metrics in the table are based on DMM's replication. DMM conducted the analysis for the flexible ramping product (FRP) and RSE 15-minute market uncertainty calculations.

The overall impact of this change did not indicate significant shifts in performance. Both requirements and coverage showed slight decreases, while the percentage of significant coefficients increased by 5 percent. The areas significantly impacted by these changes were Arizona Public Service and the Public Service Company of New Mexico (PNM). For Arizona Public Service, the coverage rate decreased by about 3 percent and the requirement dropped by 7 percent compared to the previous method. For PNM, the coverage rate fell by 2.5 percent and the requirement decreased by 10 percent compared to the previous method.

90 The histogram method was calculated based on the symmetric sampling approach.

Table 10.7 Mosaic regression performance in FRP and RSE after policy update on new sampling method (DMM replication results, 15-minute uncertainty calculation, August 14–September 30, 2024)

BAA/Group	Percent of significant coefficients		Coverage			Requirement (MW)(3)		
	Current(1)	Past(2)	Current	Past	Histogram	Current	Past	Histogram
FRP:								
RSE passed-group	33%	38%	96%	96%	95%	1,468	1,504	1,450
RSE:								
Avangrid	80%	71%	92%	92%	93%	152	155	194
BPA	64%	52%	94%	94%	91%	206	206	229
PacifiCorp West	55%	61%	91%	92%	92%	92	89	106
CAISO	54%	38%	90%	91%	90%	898	908	888
Tucson Electric	53%	43%	92%	94%	93%	95	105	102
Salt River Project	53%	49%	86%	85%	85%	165	162	167
Portland GE	51%	33%	91%	92%	90%	131	134	143
El Paso Electric	51%	43%	93%	95%	93%	38	42	42
Avista Utilities	48%	53%	93%	95%	92%	66	72	65
Idaho Power	48%	55%	91%	93%	91%	125	140	135
WAPA - Desert SW	48%	43%	91%	92%	91%	26	27	26
NV Energy	47%	48%	92%	94%	95%	225	244	273
NorthWestern	47%	44%	94%	93%	94%	67	65	79
Arizona PS	45%	42%	89%	92%	87%	227	244	227
PacifiCorp East	44%	37%	94%	92%	93%	424	451	456
BANC	42%	44%	92%	94%	94%	39	41	46
Puget Sound Energy	42%	39%	96%	97%	96%	139	147	144
LADWP	42%	32%	96%	97%	97%	147	160	163
PSC New Mexico	40%	37%	87%	90%	88%	138	154	161
Tacoma Power	29%	16%	91%	92%	89%	10.2	10.7	9.5
Seattle City Light	28%	25%	94%	94%	94%	17.1	17.7	19.0
Powerex	27%	14%	92%	91%	89%	145	135	134
Turlock ID	22%	23%	94%	95%	94%	8.1	8.3	8.1
Average	**46%**	**41%**	**92%**	**93%**	**92%**	**210**	**218**	**219**

(1): The current sampling method, implemented on August 14, 2024, selects regression input samples using a symmetric 90 days sampling approach.

(2): The previous sampling methodology, used before the August 14th update, relied on data from the last 180 days.

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

10.4.2 Improvement for calculating uncertainty within the pass-group

On June 25, 2024, the ISO made an improvement for determining the group of balancing areas passing the resource sufficiency evaluation in advance of the regressions for calculating uncertainty for the pass-group. This enhancement impacted only the calculation of uncertainty for the flexible ramping product.

In some intervals, the regressions for calculating the uncertainty requirement for the pass-group must be performed before the final set of balancing areas in this group are known. Here, the set of balancing areas in this group is estimated from preliminary test results based on information available at the time of this process. Then in the present, when the current forecast information is combined with the regression information to calculate uncertainty, a different set of balancing areas in the pass-group may be used based on changes in the results of the later resource sufficiency evaluation runs.[91]

On June 25, 2024 the ISO made an improvement to the timing in which the resource sufficiency evaluation results are pushed in advance of the regressions that are performed to calculate pass-group uncertainty. The enhancement improved the consistency between (1) the group of balancing areas used to determine the regression coefficients for the pass-group and (2) the group of balancing areas whose forecast information gets combined with those coefficients to determine the uncertainty requirement.

Table 10.8 summarizes this inconsistency and the improvement made on June 25. The set of balancing areas in the pass-group for the current weather information that is ultimately combined with the regression results to calculate uncertainty and procure flexible capacity, is based on the second run of the resource sufficiency evaluation (T-55) for interval 1, and the final resource sufficiency evaluation (T-40) for intervals 2 through 4. However, prior to June 25, *the regressions* were based on the results from the earliest resource sufficiency evaluation (T-75) to define the pass-group for the first interval of each hour, while the results from the second resource sufficiency evaluation (T-55) were used to define the pass-group for the second interval of each hour.

Starting on June 25, 2024 the set of balancing areas in the pass-group between the regression information and the current forecast information became more consistent. For the second interval of each hour, the regressions now use the results from the final resource sufficiency evaluation (consistent with forecast information). For the first interval of each hour, the regressions now use the results from the first or second resource sufficiency evaluation depending on the timing of various market processes (sometimes consistent with forecast information). DMM recommends that additional improvements be made to resolve inconsistencies in the set of balancing areas in the pass-group for the first interval of each hour.

[91] There are three runs of the resource sufficiency evaluation, at 75 minutes (first run), 55 minutes (second run), and 40 minutes (final run) prior to each evaluation hour. The first and second runs are sometimes considered the *advisory runs*, with the results of the final evaluation at 40 minutes prior considered the *binding run*.

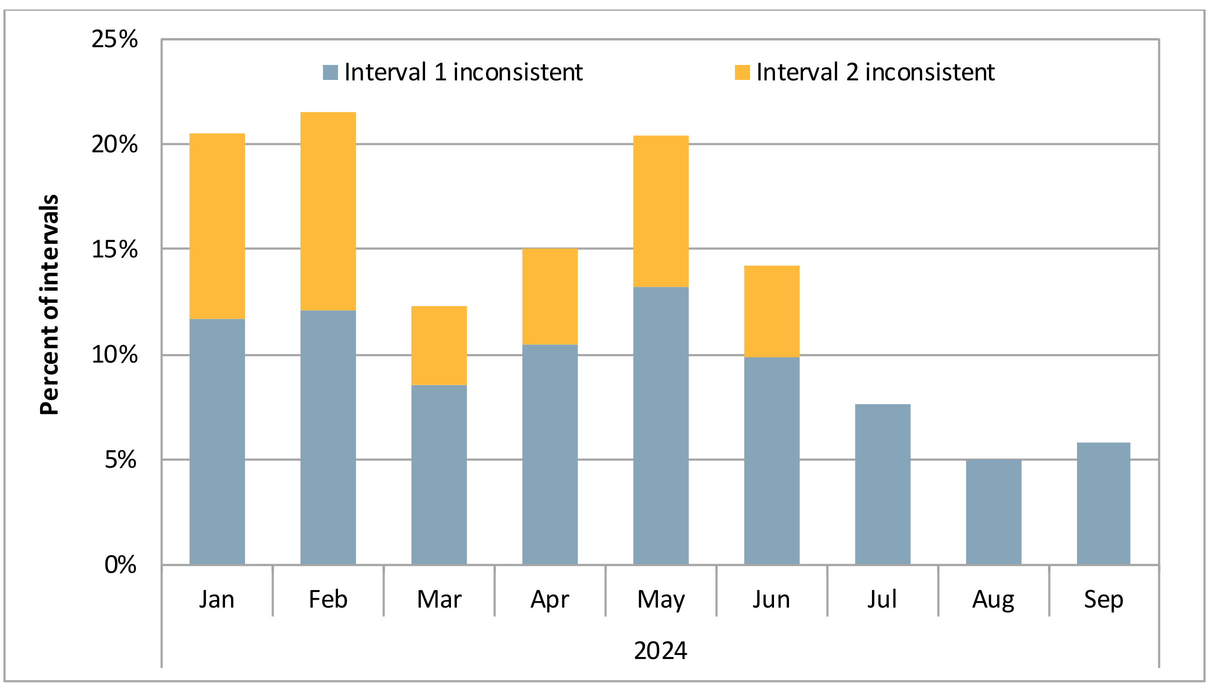
Table 10.8 Source of pass-group for determining regression parameters and for calculating uncertainty for flexible ramping capacity (prior to and after June 25, 2024)

15-minute market interval	Regression inputs and outputs (*prior to* June 25, 2024)	Regression inputs and outputs (*after* June 25, 2024)	Current weather information for calculating flexible ramping product uncertainty
1	First run (T-75)	First run (T-75) or second run (T-55)	Second run (T-55)
2	Second run (T-55)	Final run (T-40)	Final run (T-40)
3	Final run (T-40)	Final run (T-40)	Final run (T-40)
4	Final run (T-40)	Final run (T-40)	Final run (T-40)

Using one set of balancing areas in the pass-group when determining the regression parameters, and then using a different set of balancing areas in the pass-group when actually calculating uncertainty using those regression parameters, can create significant swings in the calculated uncertainty for the final pass-group. For example, if you have a regression model to predict uncertainty based on forecast information of all but one balancing area passing the test (based on earlier test results), but then combine this with current forecast information of all balancing areas (based on later test results), then the calculated uncertainty can be disconnected from any of the historical data.

Figure 10.9 shows the percent of intervals by month in which the set of balancing areas in the pass-group differed between the regression information and current forecast information. The figure also shows whether it was the first or second interval of the hour that had the inconsistency. The enhancement removed the potential for inconsistency in interval 2 and improved the consistency in interval 1. Following the enhancements, the set of balancing areas in the pass-group differed in around 6 percent of intervals, compared to around 18 percent of intervals prior to the enhancements in 2024.

Figure 10.9 Percent of intervals in which the set of balancing areas in the pass-group differed between the current forecast information and regression information



10.4.3 RSE uncertainty special issue — time horizon for predicting uncertainty

The regression model used for the resource sufficiency evaluation is currently designed to predict uncertainty in forecasts produced only 45 to 55 minutes before real-time. However, the time horizon of the resource sufficiency evaluation includes four intervals, typically produced between 47.5 and 102.5 minutes before real-time.

The resource sufficiency evaluation uses exactly the same underlying historical data to perform the regressions and calculate uncertainty as the flexible ramping product in the 15-minute market.[92] This data is based on the difference from advisory forecasts in the 15-minute market to the corresponding binding forecasts in the 5-minute market. The regressions use this data to produce hourly coefficients that define the relationship between the forecasts and uncertainty. This calculation reflects 45 to 55 minutes in which uncertainty may materialize between the applicable 15-minute and 5-minute market runs.

However, the resource sufficiency evaluation occurs over a different timeframe than what is considered for procuring 15-minute market flexible capacity. Figure 10.10 illustrates the timeframe of uncertainty considered for the flexible ramping product in the 15-minute market, and how it compares with the timeframe of the resource sufficiency evaluation.[93] For the flexible ramping product, the calculation is designed to capture uncertainty that may materialize around a single upcoming (advisory) interval. However, the resource sufficiency evaluation considers forecast information from *four* 15-minute intervals within an hour. When comparing the forecast values used in each interval of the resource sufficiency evaluation to corresponding 5-minute market intervals, there exists a larger gap of time for uncertainty to materialize.

In comparing the first 15-minute test interval of the RSE to corresponding 5-minute market intervals, the timeframe and potential for net load uncertainty to materialize is similar to the timeframe of the 15-minute market flexible ramping product uncertainty calculation. However, in the later test intervals, the gap between the predicted forecasts at the time of the resource sufficiency evaluation and the real-time forecasts widens, reaching above 100 minutes. The current determination of the regression coefficients for predicting net load uncertainty for the resource sufficiency evaluation (based on short-term historical data) does not capture the increased net load uncertainty associated with the longer-term horizon of this market process.[94]

This inconsistency results in lower performance in the rate of coverage provided by the uncertainty component in the resource sufficiency evaluation. Figure 10.11 shows the average coverage rate across all balancing areas by interval. Here, coverage is measured as the percent of intervals when realized uncertainty from the forecasts considered in the resource sufficiency evaluation to the 5-minute market

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

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

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

forecasts fell within the calculated uncertainty requirement for the same interval. The calculated uncertainty covered the realized uncertainty much less for intervals at the end of the hour compared to the beginning of the hour because the current calculation is not designed to capture uncertainty that can realize over a longer-term horizon.

Figure 10.10 Comparison of timeframe considered for the flexible ramping product and resource sufficiency evaluation

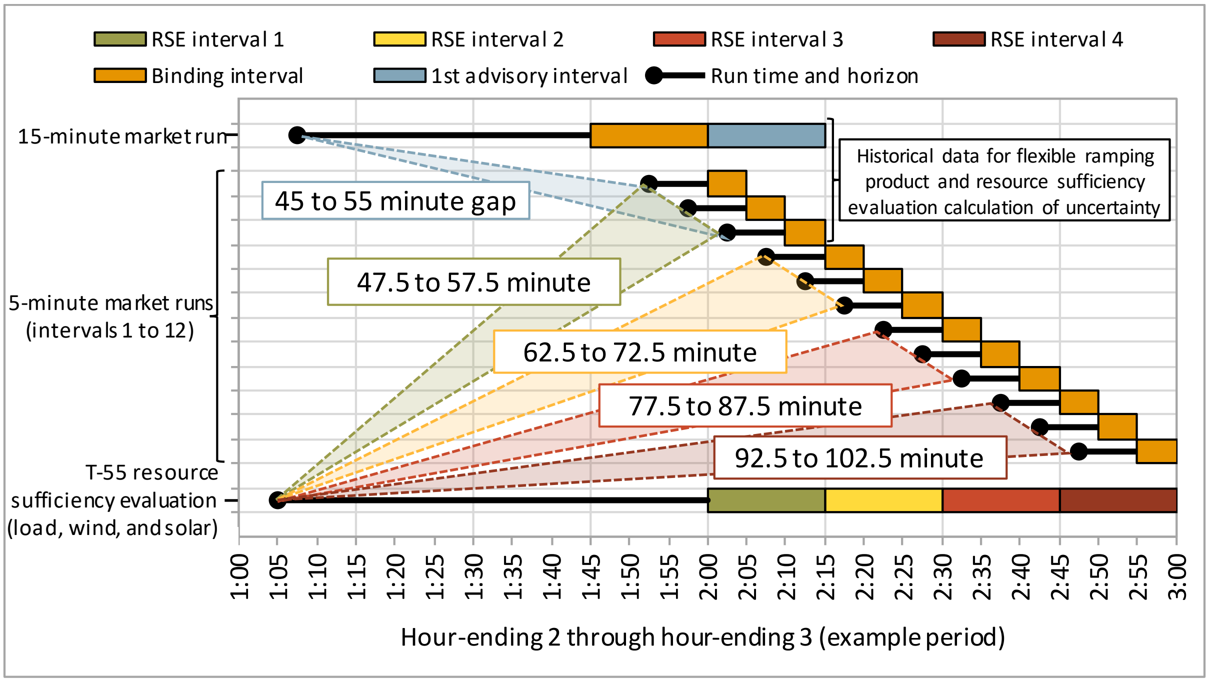
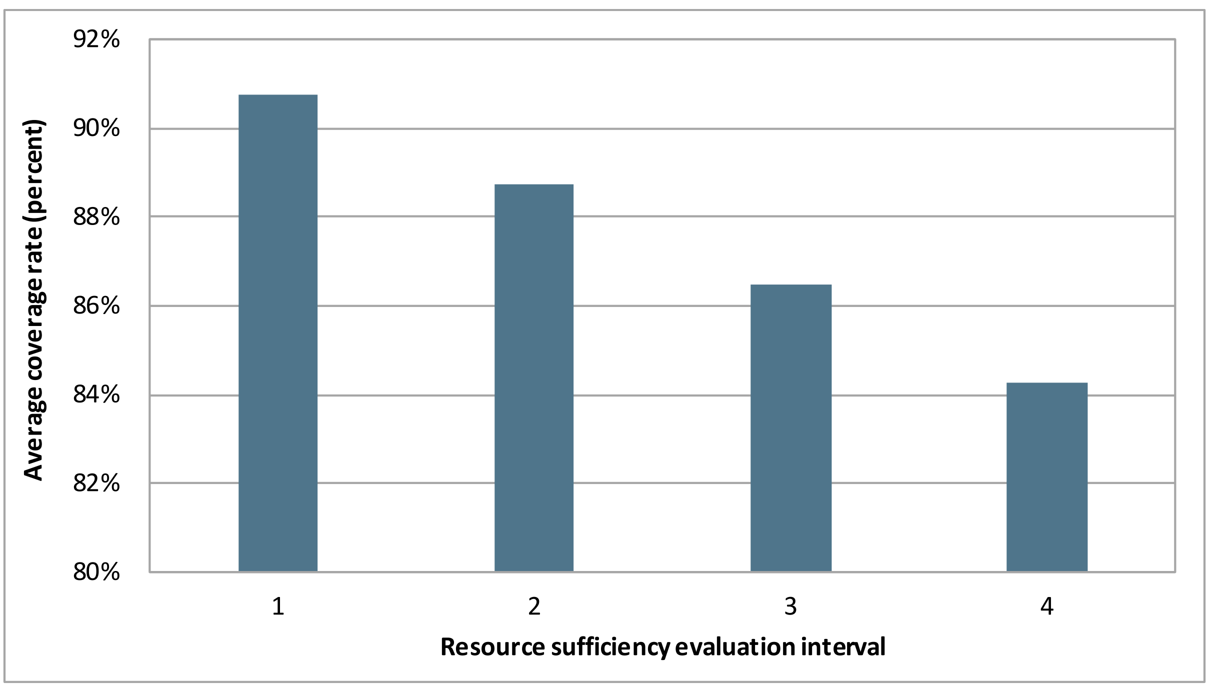


Figure 10.11 Average coverage rate by resource sufficiency evaluation interval (July–September 2024)



11 Wheeling rights

The ISO began developing a framework that establishes high-priority wheeling through scheduling priorities in the CAISO balancing area following the power outages in the summer of 2020. In July 2021, the ISO started the Transmission Service and Market Scheduling Priorities (TSMSP) initiative that had two phases: an interim phase to establish wheeling-through priorities for the challenging system conditions in the summer of 2022, and a longer-term framework that started in 2024. External suppliers and load serving entities can now reserve the capacity to self-schedule wheel-through transactions that have the same scheduling priority as CAISO demand in advance of the market runs on rolling monthly and daily timeframes.[95]

11.1 Transmission capacity reservations and usage

The following analysis shows the reserved priority wheel-through (PWT) capacity, native load need estimates, and the actual market usage of the reserved capacity on interties that experienced demand for reservations, as well as a more focused look at the Malin (MALIN500), Nevada-Oregon Border (NOB), and Round Mountain (RDM230) interties. The analysis uses data as of December 2024.

Table 11.1 shows all of the priority wheel-through reservations made in the second and third quarters by constraint. Schedulers reserved slightly more PWT capacity, and on additional interties, in the third quarter compared to June. Participants reserved most priority wheel-through capacity on the NOB and Round Mountain constraints each month. Malin also had a significant amount of reservations, except for September.

95 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

Table 11.1 2024 monthly high priority wheel-through reservations by constraint[96]

Quarter	Month	Constraint	Monthly PWT
Q2	Jun	MALIN500_ISL	72
		NOB_ITC	378
		RDM230_ITC	225
Q3	Jul	MALIN500_ISL	77
		NOB_ITC	378
		PALOVRDE_ITC	10
		RDM230_ITC	225
	Aug	IPP	25
		MALIN500_ISL	97
		NOB_ITC	378
		PALOVRDE_ITC	10
		RDM230_ITC	225
	Sep	IPP	25
		NOB_ITC	250
		PALOVRDE_ITC	10
		RDM230_ITC	225

Figure 11.1 to Figure 11.4 show monthly capacity categories for all interties with priority wheel-through reservations in aggregate, as well as for Malin, NOB, and RDM230 individually for the second and third quarters. The red lines show the available transmission capacity (ATC), which is the total transmission capacity leftover after accounting for outages and existing transmission rights (TTC – outages – ETC/TORs). Scheduling coordinators can reserve available priority wheel-through capacity (grey bars) at interties if there is leftover ATC after accounting for native load need (green bars), a transmission reliability margin (yellow bars), and any previously reserved priority wheel-through capacity (turquoise bars). The stacked capacity bars can total more than the available capacity of an intertie if outage conditions or native load need values change between reservation windows. For example, the final capacity values for June could total more than the final available transmission capacity if the ISO underestimates the native load need before the final resource adequacy (RA) showings, or if new intertie outages lower intertie availability below values the ISO assumed would be available for the month in previous reservation windows.

Figure 11.1 shows the monthly transmission capacity categories for all interties with priority wheel-through reservations in aggregate. Scheduling coordinators reserved 690 MW of PWT capacity in July, 735 MW in August, and 510 MW in September. The July and August priority wheel-through reservations were a marginal increase from the June reservations of 675 MW. Scheduling coordinators did not reserve all available priority wheel-through capacity in the third quarter. There was an additional 1,615 MW, 2,136 MW, and 159 MW of available PWT capacity in July, August, and September, respectively. While Figure 11.1 aggregates the capacity of all interties with priority wheel-through reservations to

96 Table 1 reports PWT reservations for the IPP tie point, rather than for each of IPPCADLN_ITC, ADLANTO-SP_ITC, and ADLANTOVICTVL-SP_ITC constraints. Each of these constraints affect the flows over the IPP tie point and, therefore, OASIS reports the same PWT amount for each constraint in addition to the other transmission capacity category amounts. This section reports transmission and PWT capacity for IPPCADLN_ITC, and not for ADLANTO-SP_ITC and ADLANTOVICTVL-SP_ITC, to avoid double counting.

present a high level view of how much available capacity scheduling coordinators reserved, it is important to note that the aggregated available capacity (red lines) are not simultaneously deliverable.

Figure 11.1 Monthly transmission capacity values at all interties with PWT reservations

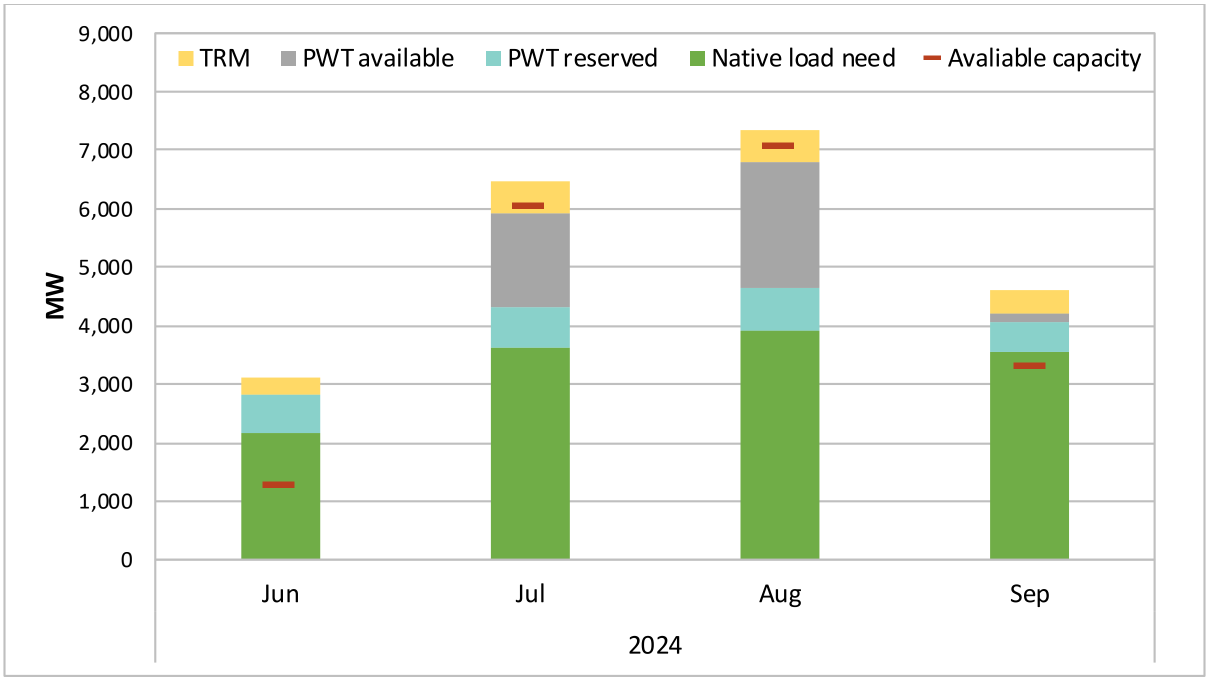


Figure 11.2 shows the monthly transmission capacity reservations at Malin. Priority wheel-through reservations marginally increased from 72 MW in the second quarter (June) to 77 MW and 97 MW in July and August, respectively. There were no priority wheel-through reservations on Malin for September. Native load needs also increased from 1,192 MW in June to 1,425 MW in July, and 1,495 MW in August, however the transmission reliability margin capacity covered any changes in intertie availability and native load needs during the monthly time horizon.

Figure 11.2 Monthly transmission capacity values at MALIN500

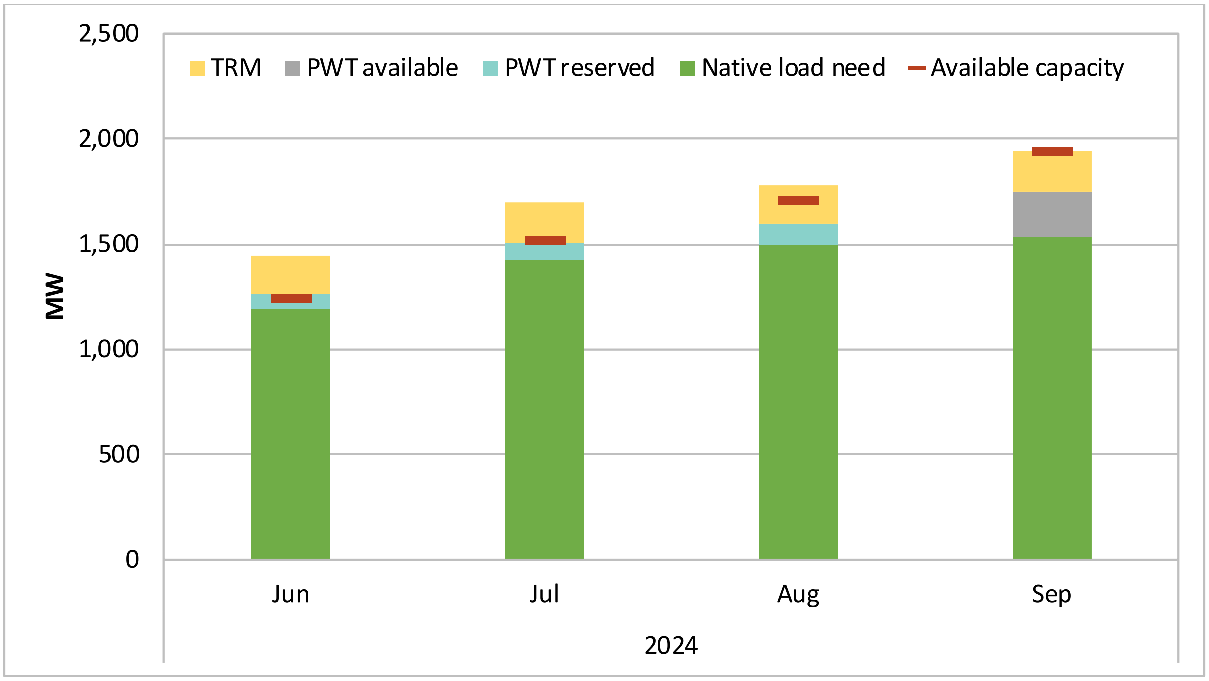


Figure 11.3 shows the monthly transmission capacity reservations at NOB. Priority wheel-through reservations did not increase from the June level of 378 MW for the first two months of the third quarter. Reservations decreased to 250 MW in September. There was an additional 191 MW of available capacity that scheduling coordinators could have reserved as priority wheel-through capacity in August. The NOB intertie was oversubscribed relative to the anticipated transmission availability in September. In earlier reservation windows, the ISO underestimated the native load needs on the NOB intertie. Final resource adequacy showings on NOB for September exceeded the ISO's earlier estimates. As a result, the ISO made more capacity on NOB available for priority wheel-through capacity in earlier reservation windows than NOB could ultimately accommodate.

Figure 11.3 Monthly transmission capacity values at NOB

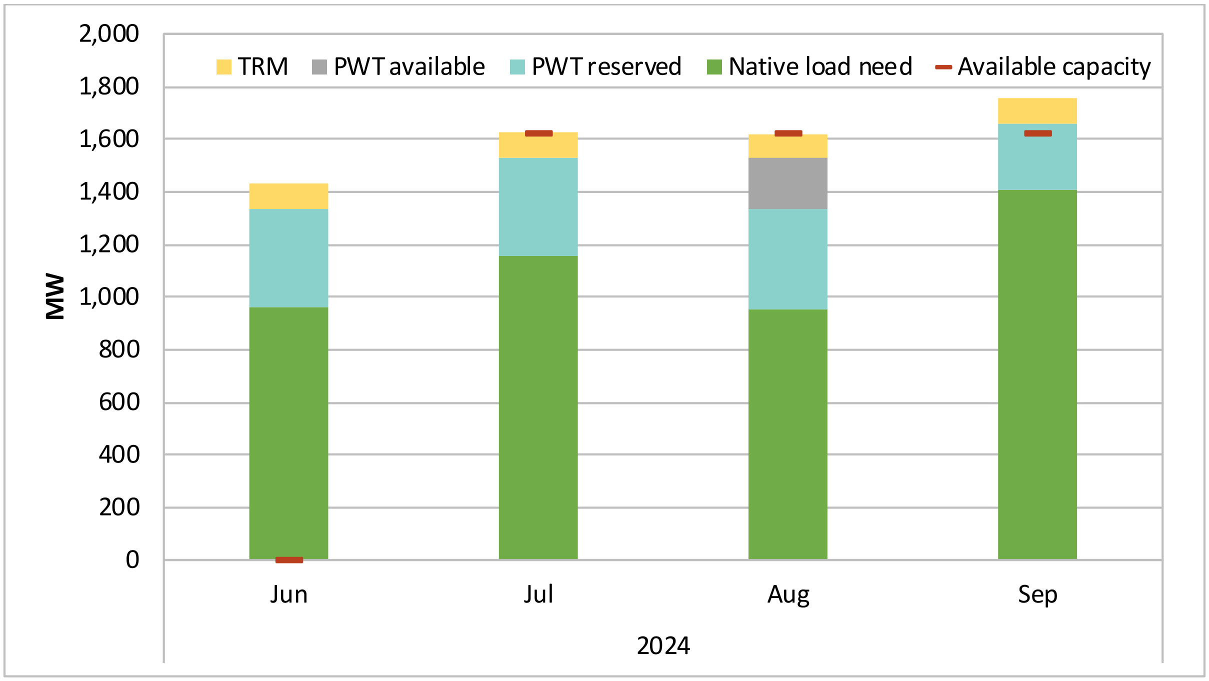


Figure 11.4 shows the monthly transmission capacity reservations at RDM230. RDM230 had priority wheel-through reservations of 225 MW for June and each of the months in the third quarter. Each month also had a transmission reliability margin of 20 MW. RDM230 is a special case where the intertie is almost entirely dedicated to ETC/TOR capacity, which is why the intertie appears oversubscribed with an available transmission capacity of 0 MW for each month. A market participant utilized TORs to reserve for priority wheel-throughs at RDM230, which is why the PWT reserved (grey bars) are above the indicated transmission availability (red lines). RDM230 does not have a native load need component.

Figure 11.4 Monthly transmission capacity values at RDM230

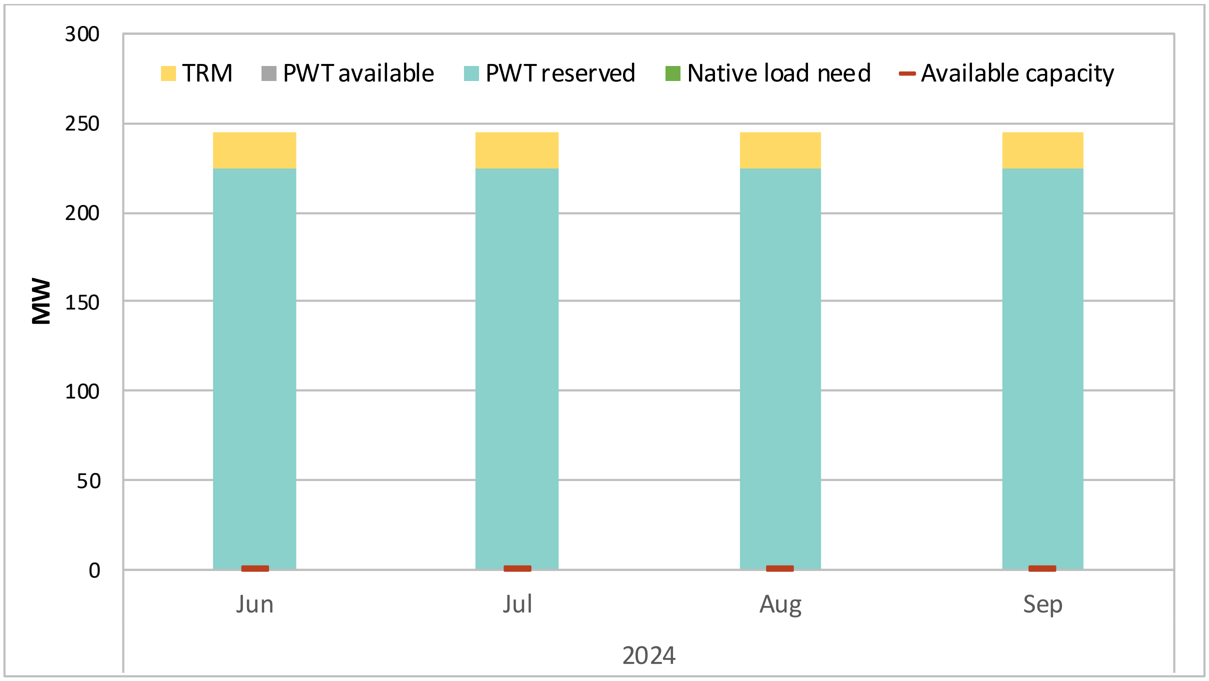
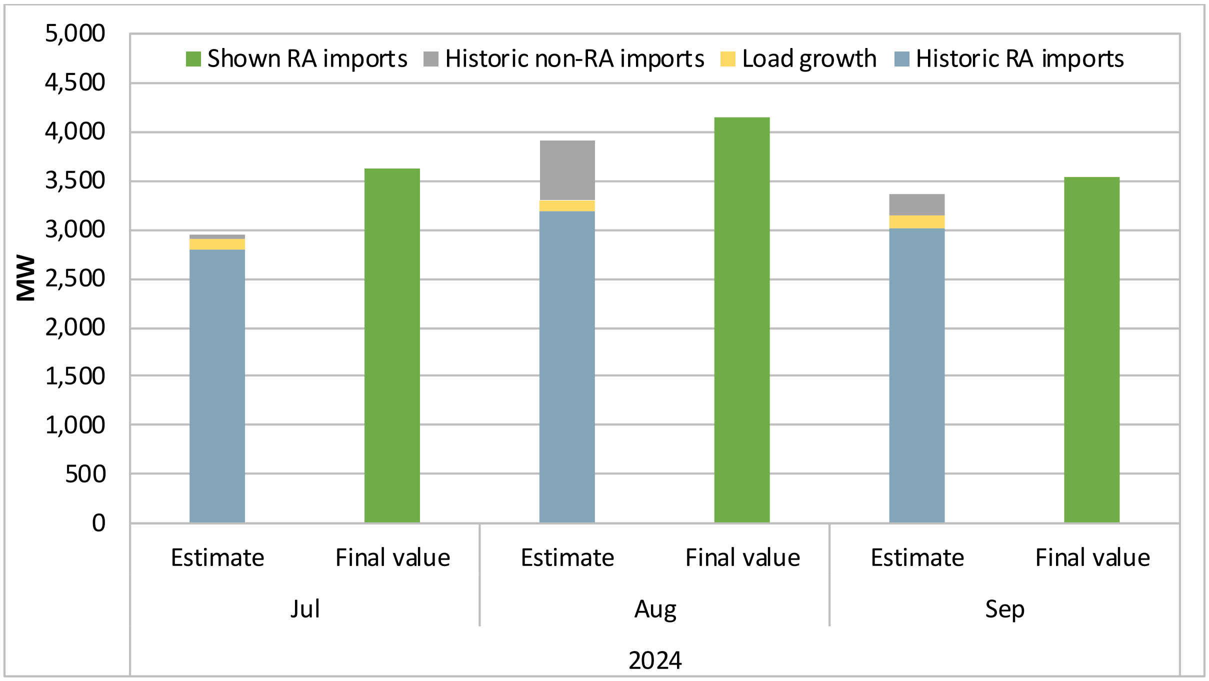


Figure 11.5 to Figure 11.7 show how native load need estimates compare to final import showings from load serving entities. In calculating available transmission capacity for priority wheel-throughs for future months, the ISO sets aside transmission capacity by estimating what native load needs will be. Ultimately, the amount of native load need capacity on interties is the sum of shown import resource adequacy, as well as non-resource adequacy contracts that load serving entities may show the ISO. Final resource adequacy plans are due 30 days prior to the relevant month. Before T-30, the ISO estimates how much intertie transmission capacity native loads will need by taking the maximum amount of shown import RA and non-RA contracted imports delivered on that intertie for the same month over the previous two years. In addition, the ISO accounts for the impact load growth may have on native load needs by calculating a load growth value from the California Energy Commission load forecast. This is because loads may have increased over the value that determined maximum resource adequacy obligations over the past two years. The ISO updates these native load need numbers after load serving entities submit their final resource adequacy plans.

Figure 11.5 shows the cumulative native load need estimates and final values on all of the interties that had priority wheel-through reservations in the third quarter. The ISO estimated native load needs for these interties would be about 2,955 MW in July, 3,909 MW in August, and 3,360 MW in September. This underestimated native load needs by about 677 MW (or 19 percent) in July, 190 MW (6 percent) in August, and 144 MW (5 percent) in September. The ISO did not underestimate native load needs for all interties, but did in aggregate. This suggests load serving entities are currently more dependent on imports to fulfill capacity obligations than in previous years, and at a rate that is outpacing load growth.

Figure 11.5 Native load need capacity set aside vs. final import RA at all relevant interties



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

Figure 11.6 shows the native load need estimate and final value for the Malin intertie. The ISO estimated native loads would need about 1,250 MW of transmission capacity in July, 1,495 MW in August, and 1,960 MW in September. This underestimated actual native load needs by 175 MW (or 12 percent) in June, overestimated August native load need by 95 MW (7 percent) in August, and overestimated September native load need by 421 MW (27 percent).

Figure 11.6 Native load need estimate vs. final import RA at MALIN500

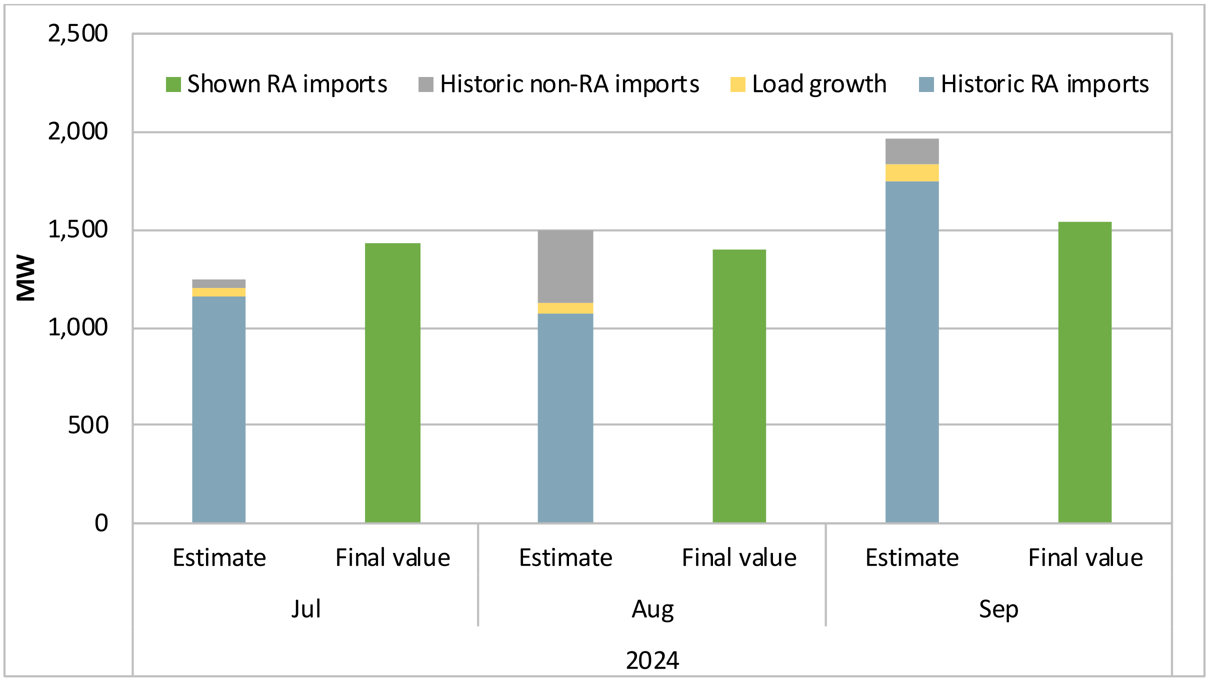


Figure 11.7 shows the native load need estimates and final values for the NOB intertie. The ISO estimated native loads would need 797 MW in July, 956 MW in August, and 1,260 MW in September. This underestimated actual native load needs by 357 MW (or 31 percent) in July, 190 MW (17 percent) in August, and 299 MW (21 percent) in September.

Figure 11.7 Native load need estimate vs. final import RA at NOB

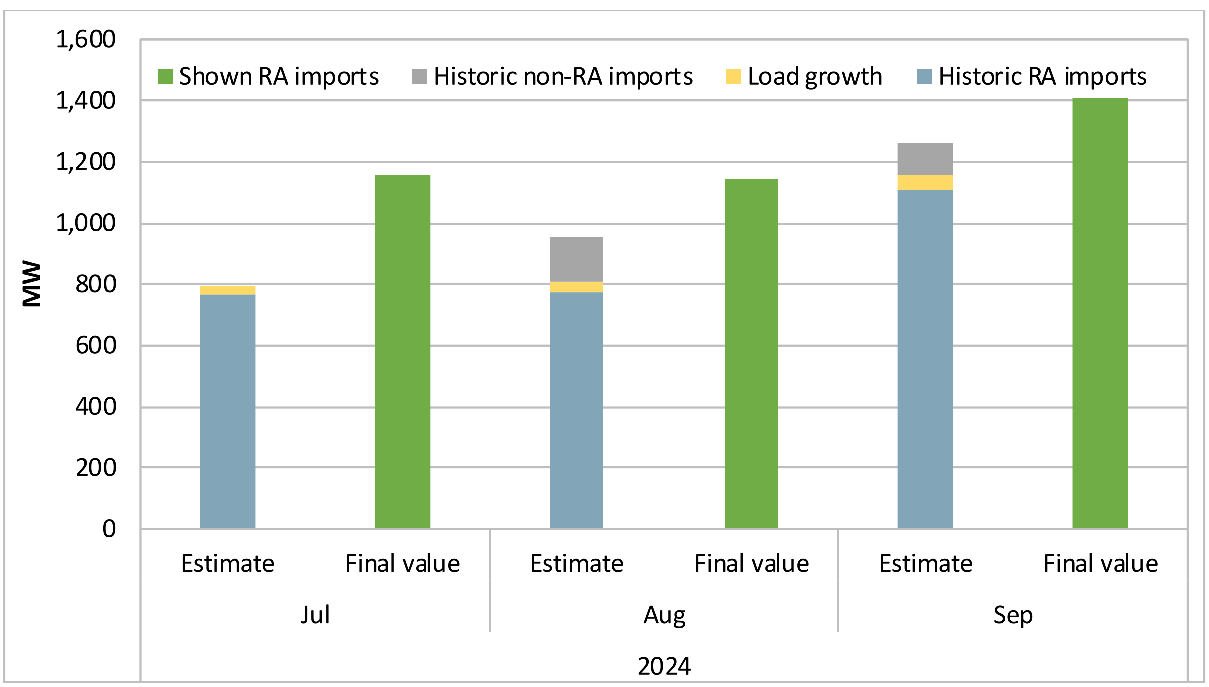


Figure 11.8 to Figure 11.15 show how scheduling coordinators used priority wheel-through reservations on all interties with priority wheel-through reservations in general, as well as for Malin, NOB, and RDM230 individually in the third quarter. Priority wheel-through reservation values, or awards, (blue lines) are dependent on the contract parameters that scheduling coordinators submit to the ISO. These priority wheel-through awards can vary by hour. For example, a scheduling coordinator may show a contract with an outside load entity for a 16-hour block. In this case, the ISO would award the contract amount for 16 hours and zero MW for the other 8 hours. IFM self-schedules (green bars) show how often, and to what extent, scheduling coordinators used their priority wheel-through awards. This analysis aggregates awards and schedules by intertie.

Figure 11.8 shows the hourly priority wheel-through awards and associated average hourly IFM self-schedules for all interties with PWT awards in the third quarter. Cumulative priority wheel-through awards had similar profiles in each month of the quarter, albeit at different levels. Scheduling coordinators requested most reservation capacity during peak net load hours between hour-ending (HE) 18 and HE22. Net load ramping hours between HE15 and HE17 had slightly lower reservations. Middle of the day solar hours between HE7 and HE14 had roughly half the amount of reservations as the peak net load hours. Off-peak hours between HE1 and HE6, as well as HE23 and HE24, had the fewest priority wheel-through reservation capacity awards. The figure shows that, on an hourly basis, scheduling coordinators used their priority wheel-through reservations, although not to the full extent during each month.

Figure 11.8 Average hourly PWT reservations vs. IFM self-schedules at all relevant interties

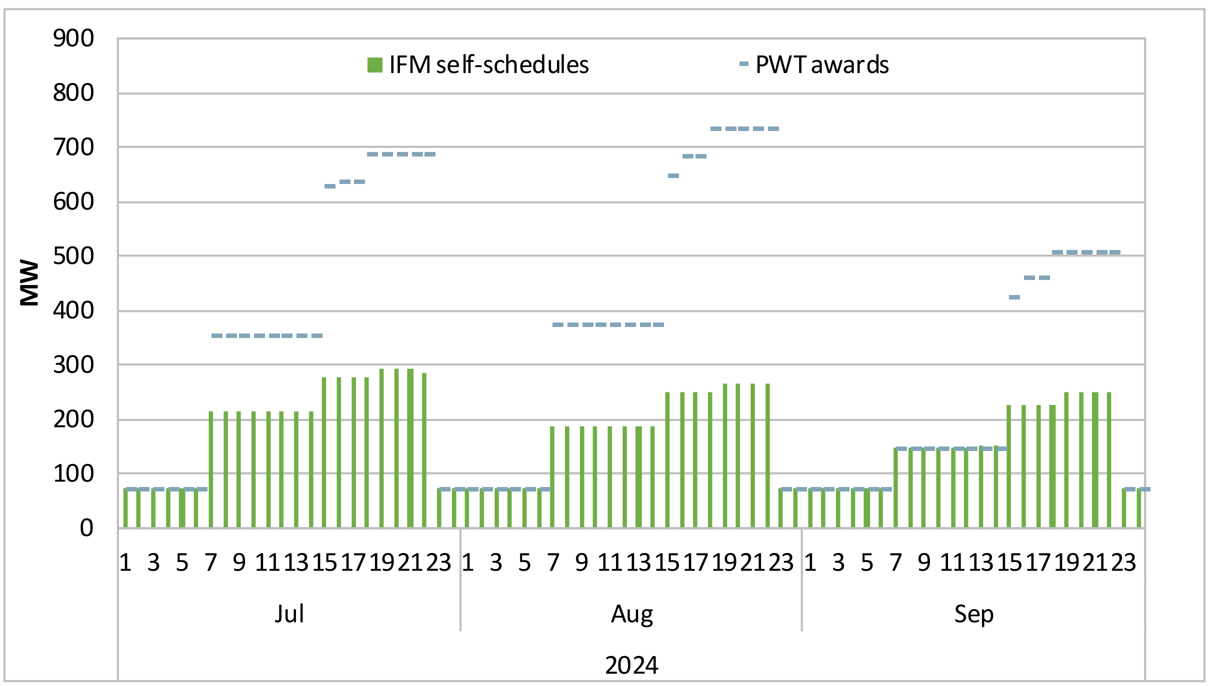


Figure 11.9 uses HE19 as a representative hour to show whether bidding infrequency or bidding amount caused low average IFM self-schedules relative to awards during the peak net load hours. Cumulatively, scheduling coordinators bid at least some of their reservations in the IFM during hour-ending 19 on every day of the quarter. There were a few days (July 10, August 6, and September 5 to 7) where scheduling coordinators bid nearly all priority wheel-through reservations into the market during the hour.

Figure 11.9 Hour-ending 19 PWT reservations vs. IFM self-schedules at all relevant interties

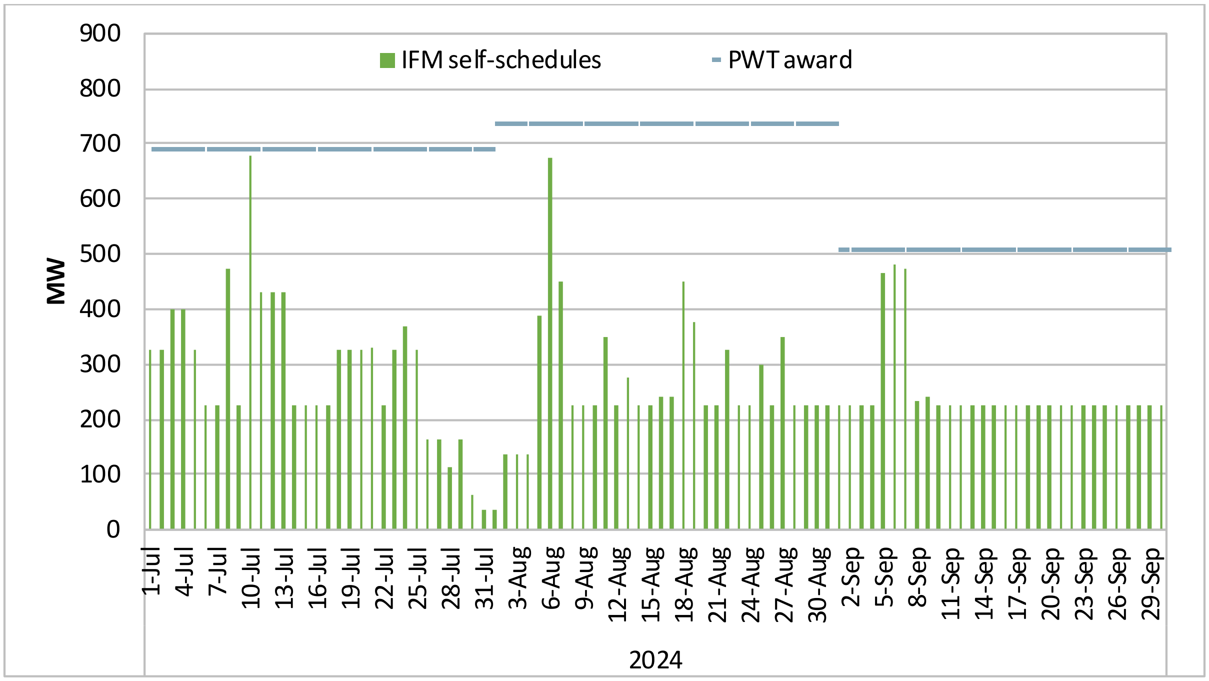


Figure 11.10 shows the hourly priority wheel-through awards and associated hourly IFM self-schedules for Malin. The ISO awarded 77 MW of priority wheel-throughs for HE7 to HE22 in July and 97 MW for the same hours in August. Malin did not have any PWT awards in September. On average, scheduling coordinators self-scheduled about 43 MW (or 56 percent) of priority wheel-through capacity into the IFM during the awarded hours in July. Scheduling coordinators self-scheduled about 26 MW (or 27 percent) of priority wheel-through capacity in August.

Figure 11.10 Average hourly PWT reservations vs. IFM self-schedules at MALIN500

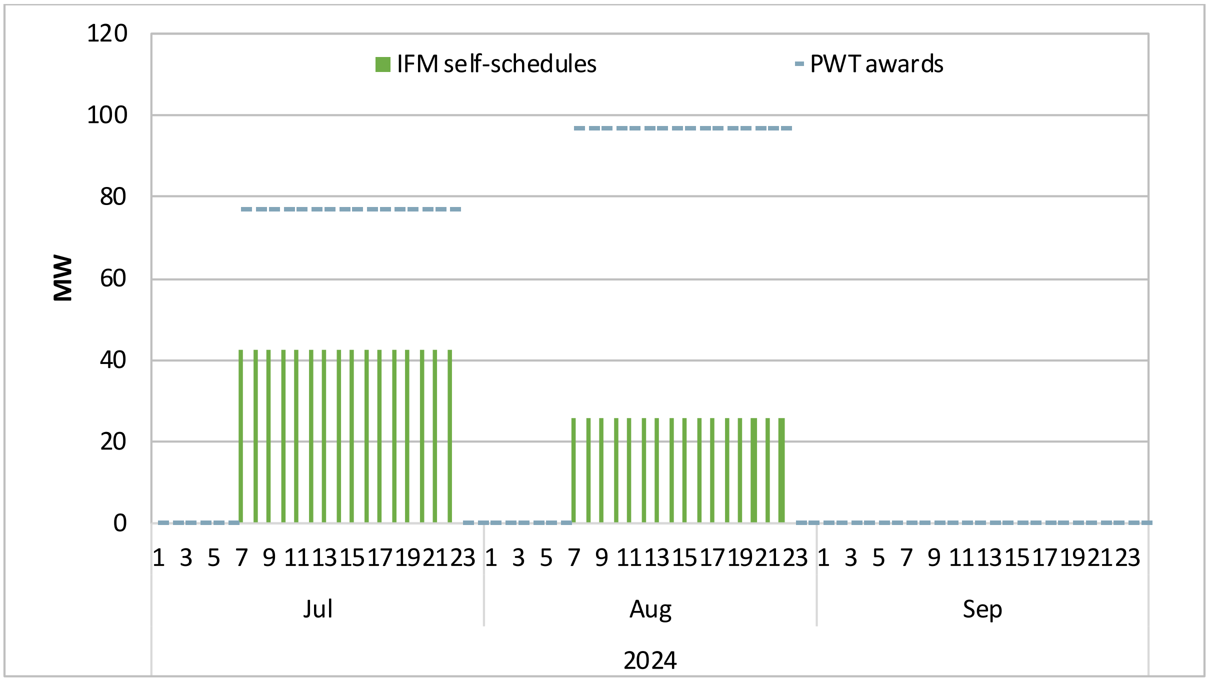


Figure 11.11 uses hour-ending 19 as a representative hour to show whether bidding infrequency or bidding amount caused low average IFM self-schedules relative to awards during the peak net load hours at Malin. The figure shows that bidding infrequency is what drove down hourly averages. However, scheduling coordinators bid all, or nearly all, of the reserved capacity when they did bid into the market, at least for hour-ending 19.

Figure 11.11 Hour-ending 19 PWT reservations vs. IFM self-schedules at MALIN500

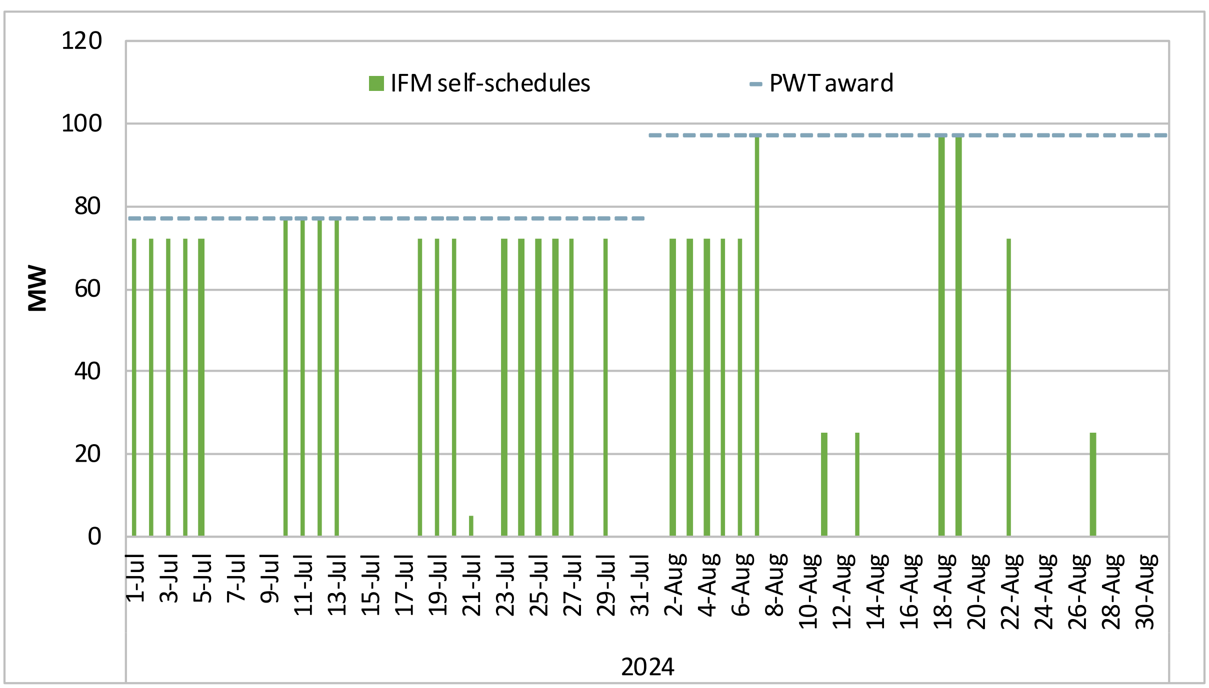


Figure 11.12 shows the hourly priority wheel-through awards and associated hourly IFM self-schedules for NOB. The ISO awarded the same amount of hourly awards in July and August. This included 378 MW of reservations from hour-ending 19 to hour-ending 22, 328 MW from hour-ending 16 to hour-ending 18, and 128 MW from hour-ending 8 to hour-ending 15. Scheduling coordinators did not utilize much of this capacity, and bid less than 56 MW each awarded hour, on average.

Figure 11.12 Average hourly PWT reservations vs. IFM self-schedules at NOB

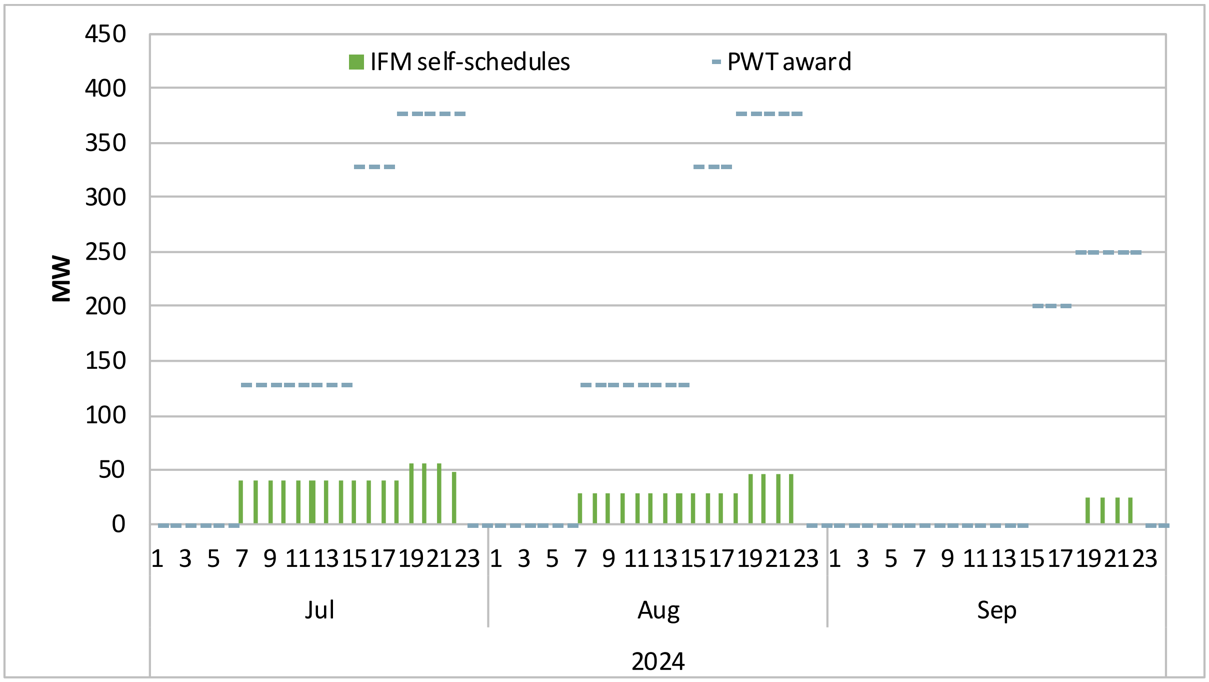


Figure 11.13 uses hour-ending 19 as a representative hour to show whether bidding infrequency or bidding amount caused low average IFM self-schedules relative to awards at NOB. The figure shows that bidding infrequency and low bid amounts drove down hourly averages. However, scheduling coordinators bid all, or nearly all, of the reserved capacity during a few days in the third quarter.

Figure 11.13 Hour-ending 19 PWT reservations vs. IFM self-schedules at NOB

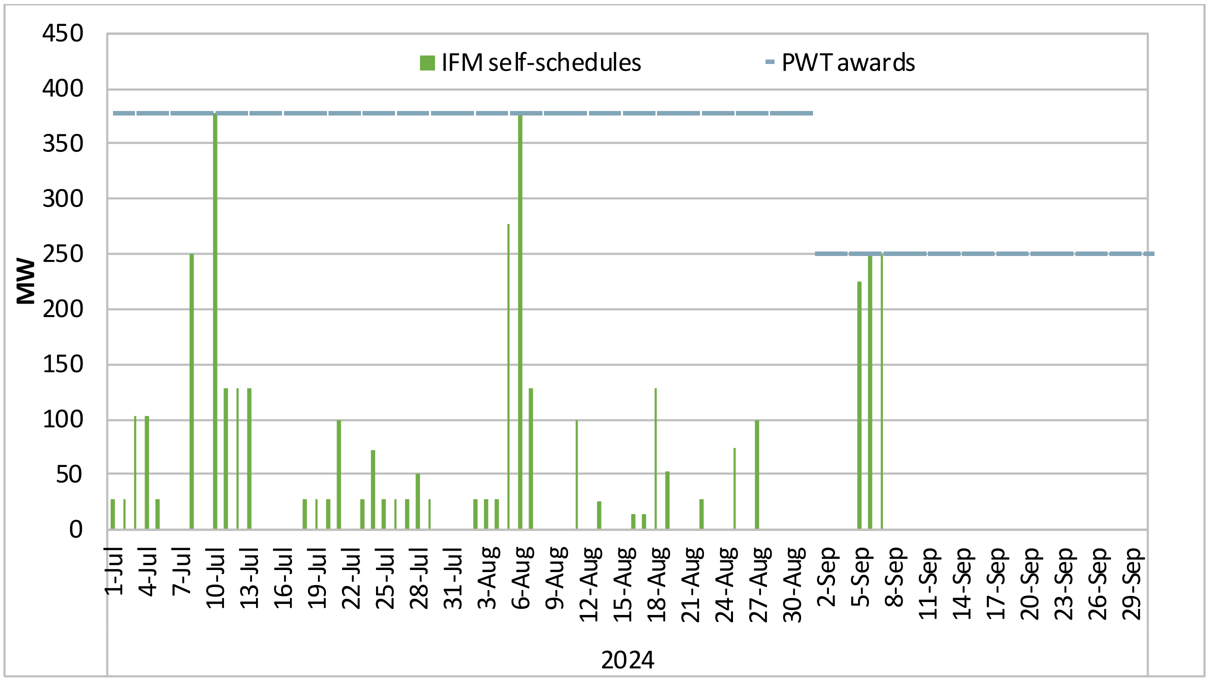


Figure 11.14 shows the hourly priority wheel-through awards and associated hourly IFM self-schedules for RDM230. The ISO awarded the same amount of hourly awards in July, August, and September. This included 225 MW of reservations from hour-ending 15 to hour-ending 22, 150 MW from hour-ending 16 to hour-ending 18, 128 MW from hour-ending 8 to hour-ending 15, and 75 MW from hour-ending 1 to hour-ending 6, hour-ending 23, and hour-ending 24. The scheduling coordinators utilized almost all of the reserved capacity during each hour on average.

Figure 11.14 Average hourly PWT reservations vs. IFM self-schedules at RDM230

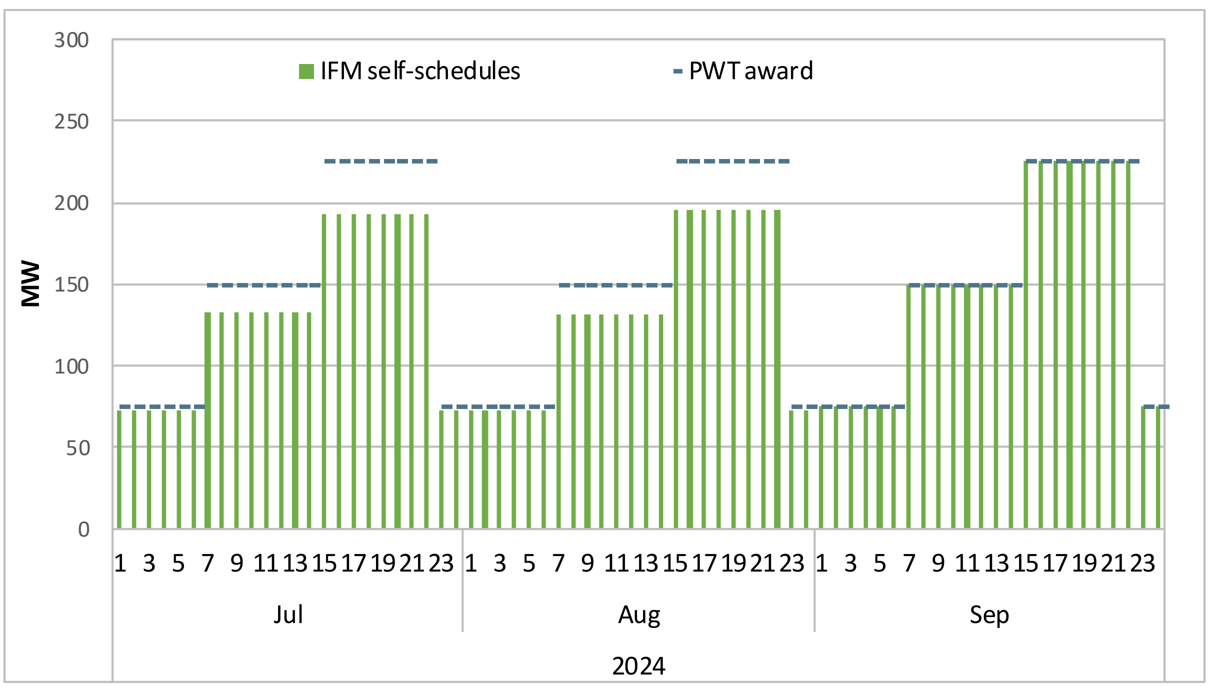
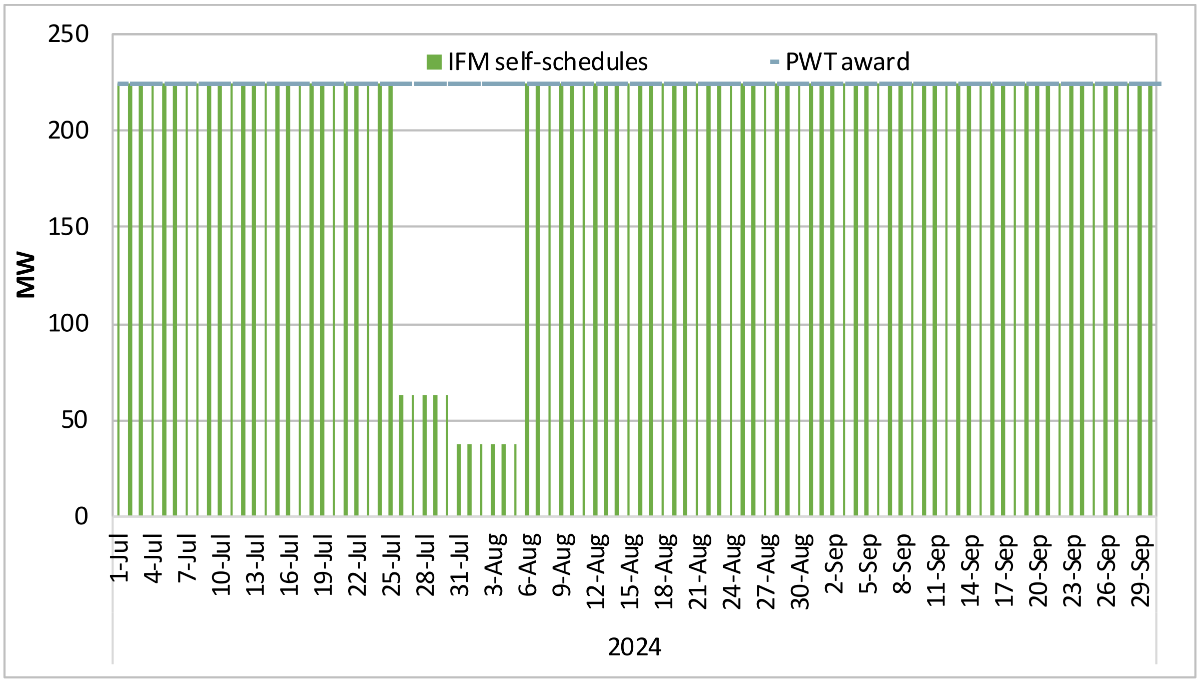


Figure 11.15 uses hour-ending 19 as a representative hour to show whether bidding infrequency or bidding amount caused IFM self-schedules to be less than priority wheel-through awards at RDM230 for most hours in July and August. The scheduling coordinator bid in the full priority wheel-through reservation capacity into the IFM market every day, except for a few weeks in July and August when they consistently bid between 38 MW (or 17 percent of reservations) and 63 MW (28 percent).

Figure 11.15 HE19 PWT reservations vs. IFM self-schedules at RDM230



12 Import resource adequacy bids

In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource specific import resource adequacy resources must bid into the California ISO markets at or below $0/MWh during the availability assessment hours.[97] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices of imports. An overall decline in volumes began in late 2020 and continued throughout 2021, but appear to have stabilized since then. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

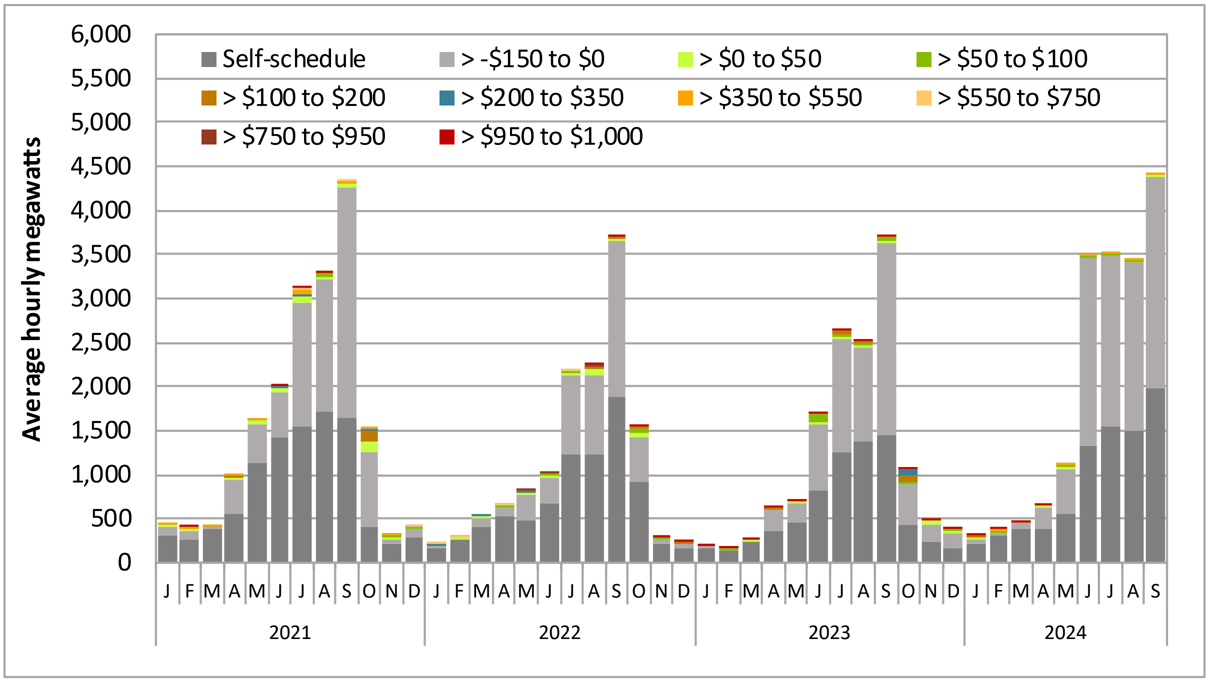
Figure 12.1 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[98] The dark grey bars reflect import capacity that was self-scheduled. The light grey bars show imports bid at or below $0/MWh. The

97 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.

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

remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market bid above $0/MWh. Overall bid-in levels of resource adequacy imports increased in July, August, and September compared to the same month of 2023, by 33 percent, 37 percent, and 19 percent, respectively.

Figure 12.1 Average hourly resource adequacy imports by price bin



13 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the third quarter of 2024 was 54 percent lower than the same quarter of 2023. Operator adjustments to the RUC procurement target decreased by about 64 percent for the same period. This was in large part because of a change in the methodology for determining the adjustments on May 7, 2024. CAISO balancing area methods for determining operator adjustments are discussed in detail in Section 10 above on uncertainty.

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

13.1 Residual unit commitment requirement

The quantity of residual unit commitment procured is determined by several automatically calculated components, as well as any adjustments that operators make to increase residual unit commitment requirements for reliability purposes. Figure 13.1 shows the average incremental residual unit commitment requirement by component relative to the integrated forward market component of the day-ahead market.

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

The blue bars in Figure 13.1 depict the day-ahead forecasted load versus cleared day-ahead capacity, which includes both physical supply and net virtual supply. This represents the difference between the CAISO day-ahead load forecast and the physical load that cleared the integrated forward market (IFM). On average, this factor contributed towards increasing residual unit commitment requirements by about 610 MW per hour in the third quarter of 2024, down from about 850 MW in 2023.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market, illustrated by the yellow bars in Figure 13.1

Lastly, operators will often increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply. The red bars in Figure 13.1 show the average adjustment to the residual unit commitment requirement. During 2023 and 2024, there were significant changes to how these amounts were determined. The operator adjustments and the changes in the methodology are described above in Section 10.

Figure 13.2 shows the hourly distribution of these operator adjustments during the second quarter of 2024. The black line shows the average adjustment quantity in each hour and the red dots highlight outliers in each hour.

Figure 13.1 Average incremental residual unit commitment requirement by component

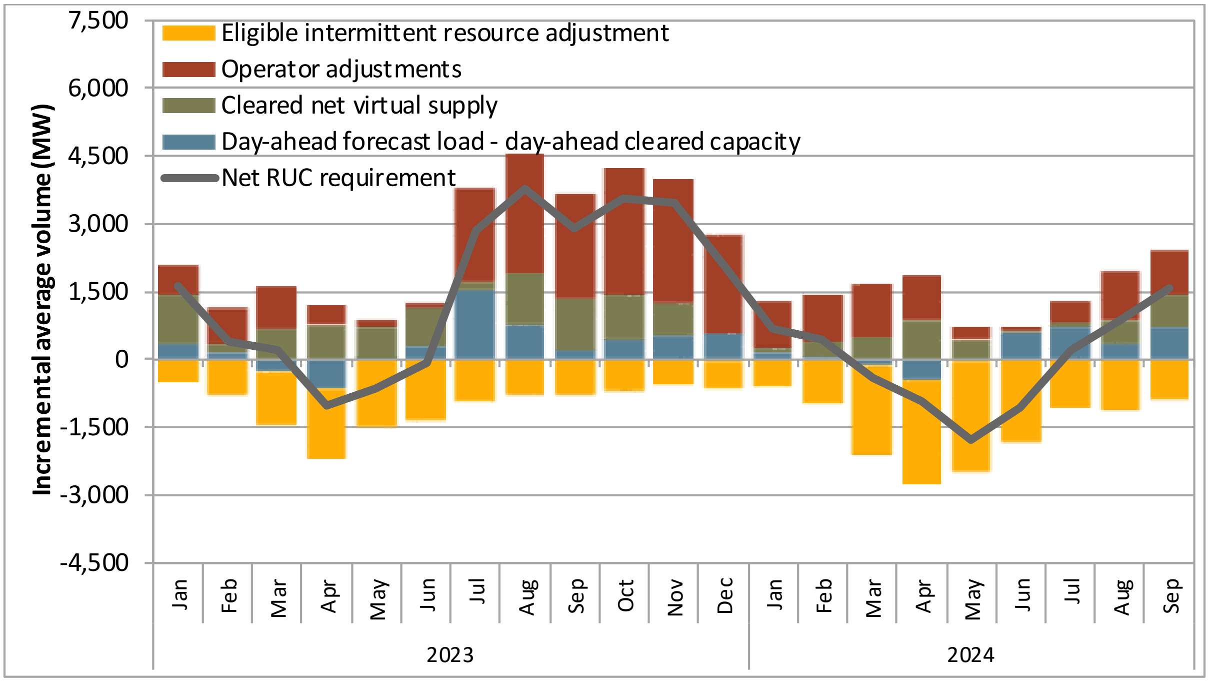
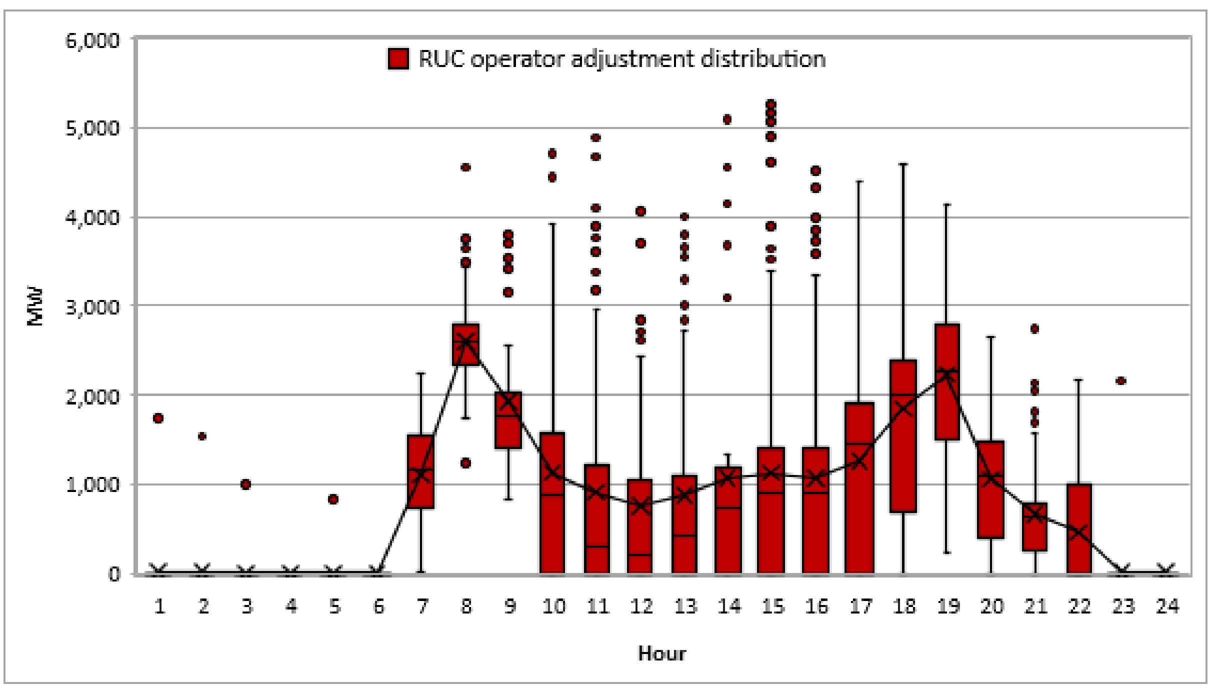


Figure 13.2 Hourly distribution of residual unit commitment operator adjustments (July–September 2024)

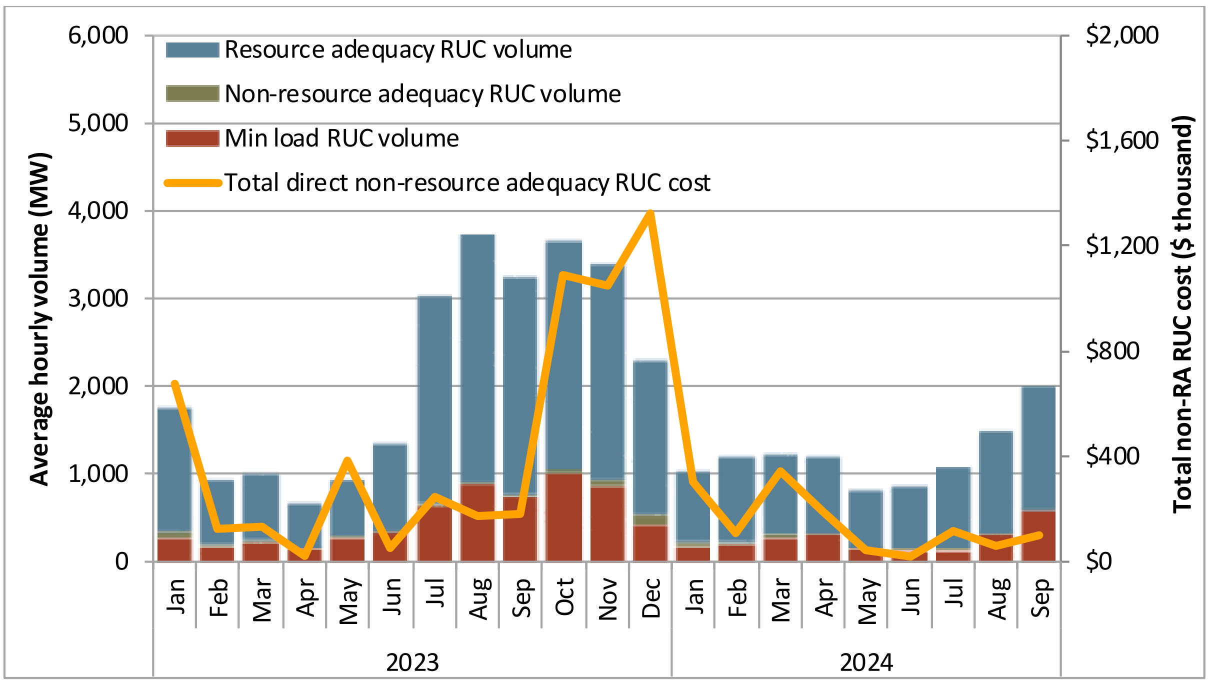


13.2 Residual unit commitment procurement and costs

Figure 13.3 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. The average residual unit commitment procurement for the quarter decreased by 54 percent to about 1,500 MW in the third quarter of 2024, from an average of about 3,350 MW in the same quarter of 2023. Of the 1,500 MW capacity, the capacity committed to operate at minimum load averaged about 200 MW.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units receiving awards in this process receive RUC capacity payments.[99] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 13.3. In the third quarter of 2024, these costs were about $258,000, about 47 percent of the costs in the same quarter of 2023.

Figure 13.3 Residual unit commitment costs and volume



14 Convergence bidding

Convergence bidding is designed to align day-ahead and 15-minute market prices by allowing financial arbitrage between the two markets. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. In the third quarter, financial entities received the vast majority of profits from convergence bidding, while load serving entities were the only others to profit.

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

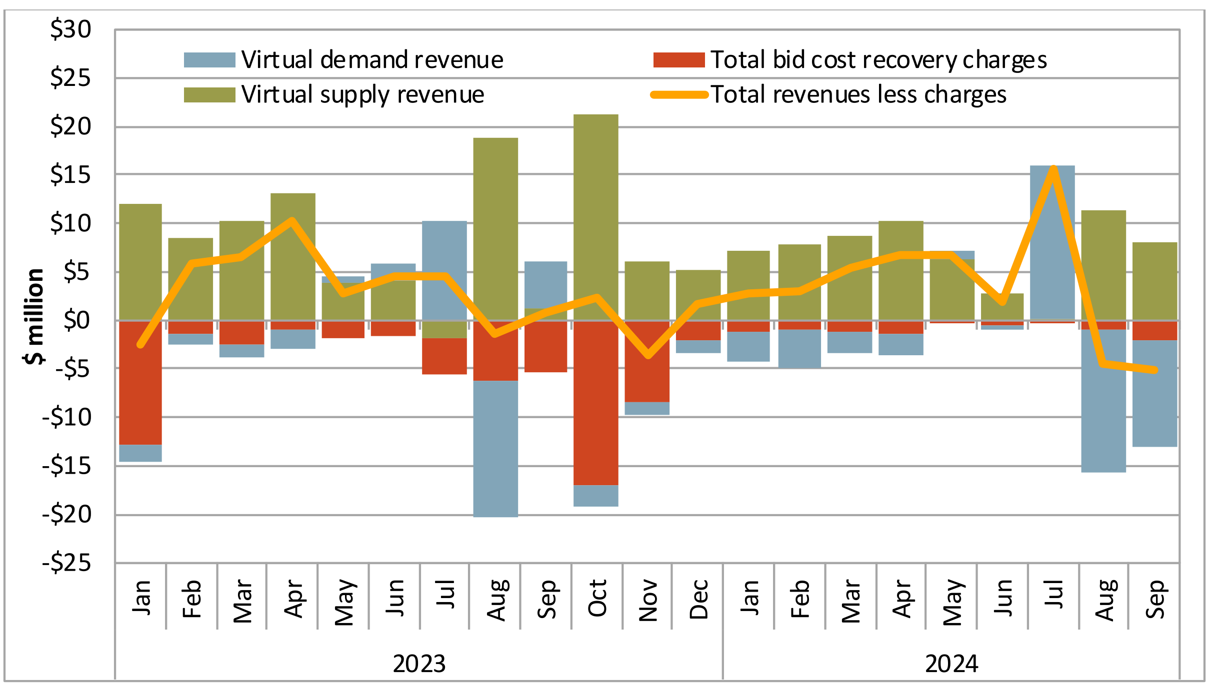
14.1 Convergence bidding revenues

Net revenues for convergence bidders were about $6.2 million for the third quarter, after inclusion of about $3.2 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply.[100] Figure 14.1 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

- Total market revenues for July were positive, and negative for August and September. Net revenues for the quarter overall represent a 48 percent increase compared to the third quarter of 2023.
- Virtual demand revenues were about $15.8 million, -$14.8 million, and -$11.1 million for July, August, and September, respectively.
- Before accounting for bid cost recovery, virtual supply revenues were about $170,000, $11.4 million, and $8 million for July, August, and September, respectively.

Bid cost recovery charges allocated to virtual bids were about $360,000, $930,000, and $1.9 million for July, August, and September, respectively. The majority of bid cost recovery allocated to virtual bidding participants in this quarter was charged to the residual unit commitment (RUC) tier 1 allocation, which helps offset costs related to periods with net virtual supply. Virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in RUC. When market revenues do not cover the commitment costs of resources committed in RUC, the resources receive bid cost recovery payments, and some of this bid cost recovery is allocated to virtual supply during periods with net virtual supply.

Figure 14.1 Convergence bidding revenues and bid cost recovery charges



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

Net revenues and volumes by participant type

Table 14.1 compares the distribution of convergence bidding cleared volumes and revenues, before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.[101,102]

After accounting for bid cost recovery, financial entities received nearly 98 percent of the total revenue earned from convergence bidding. Financial entities and marketers accounted for about 79 percent and 19 percent, respectively, of the cleared volume of virtual trades in the third quarter.

Table 14.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2024 Q3								
Financial	2,819	3,082	5,901	-$5.36	$16.45	-$2.30	$14.15	$8.79
Marketer	641	771	1,412	-$2.80	$2.58	-$0.66	$1.92	-$0.89
Physical load	14	85	98	-$0.13	$0.52	-$0.25	$0.27	$0.14
Physical generation	39	21	60	-$1.79	-$0.04	-$0.03	-$0.07	-$1.86
Total	**3,513**	**3,959**	**7,471**	**-$10.08**	**$19.51**	**-$3.24**	**$16.27**	**$6.18**

15 Ancillary services

Ancillary service payments totaled $49.9 million, a 20 percent decrease from the same quarter last year. Average requirements for regulation up increased compared to the third quarter of 2023. Average regulation down requirements decreased and operating reserve requirements remained the same compared to the third quarter of 2023.

15.1 Ancillary service requirements

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

101 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

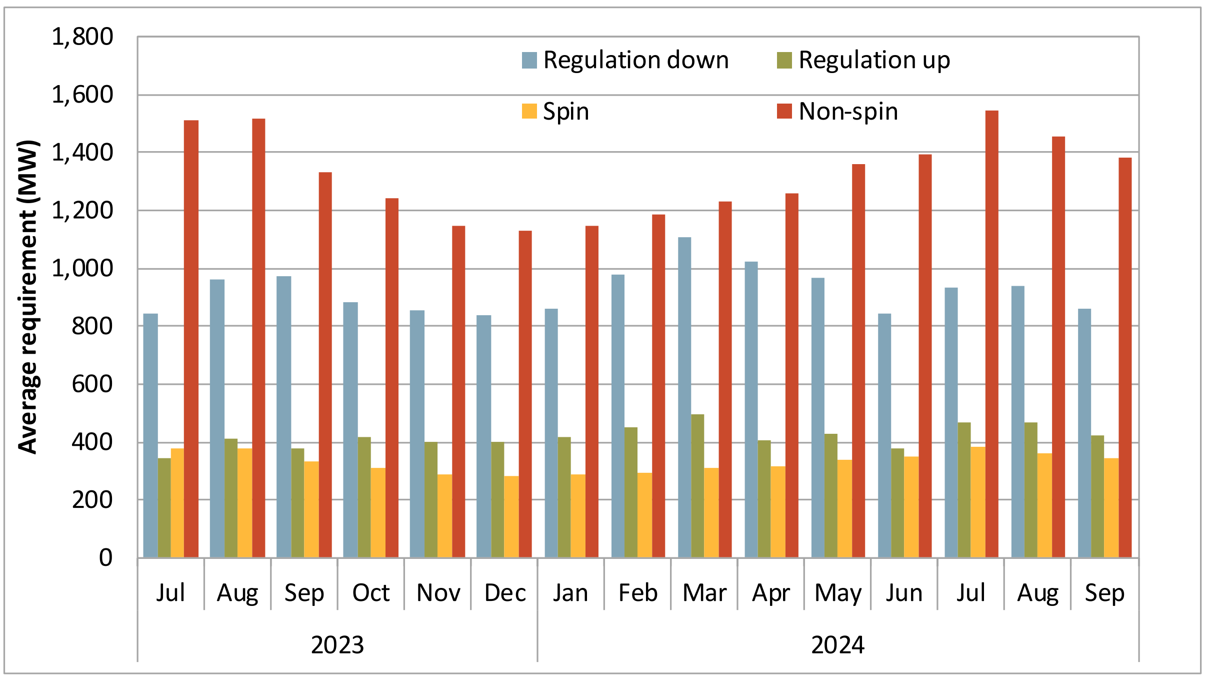
102 DMM has defined financial entities as participants who do not own physical power, and only participate in the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the California ISO markets as physical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

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.[103] 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.[104] Operating reserve requirements in real-time are calculated similarly, except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

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

Figure 15.1 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation up requirements increased 20 percent compared to the third quarter of 2023. Regulation down requirements decreased 2 percent compared to the third quarter of 2023. Average requirements for operating reserves did not change significantly year-over-year.

Figure 15.1 Average monthly day-ahead ancillary service requirements



103 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

104 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.

15.2 Ancillary service scarcity

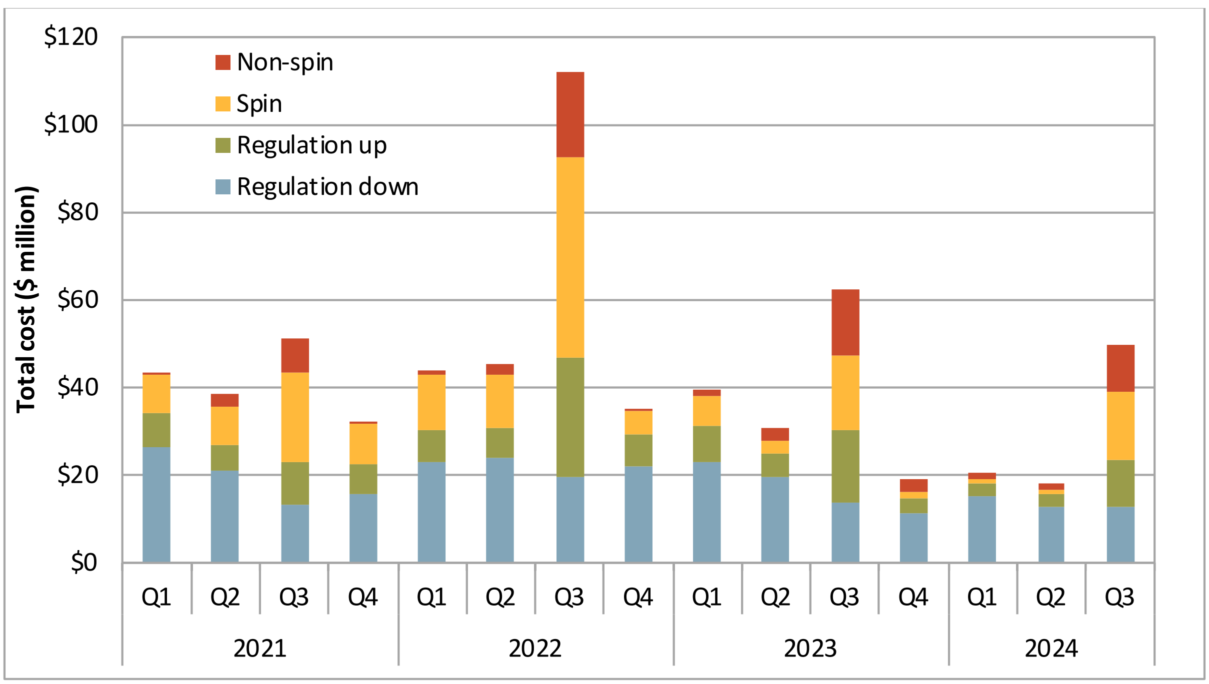
Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California ISO balancing area pays a predetermined scarcity price for ancillary services procured during scarcity events. The scarcity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

15.3 Ancillary service costs

Ancillary service payments totaled $49.9 million in the third quarter of 2024, around $12.3 million less than the same quarter of the previous year.

Figure 15.2 shows the total cost of procuring ancillary service products by quarter.[105] Payments for regulation down, regulation up, spinning reserve, and non-spinning reserve decreased 7 percent, 34 percent, 9 percent, and 28 percent, respectively, compared to the third quarter of 2023. Regulation up payments had the largest absolute decrease, at around $5.6 million.

Figure 15.2 Ancillary service cost by product



[105] 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.

16 Generation outages

This section covers information on generation outages in the California ISO balancing area.[106] Total generation on outage in the California ISO balancing area averaged about 13,490 MW in the third quarter of 2024. This was an overall increase of 18 percent from the third quarter of 2023, with forced outages increasing by 20 percent and planned outages increasing by four percent.

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

Figure 16.1 and Figure 16.2 show the quarterly and monthly averages, respectively, of maximum daily outages during peak hours by type from the first quarter of 2022 through the third quarter of 2024.[107] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period. Looking at the monthly outages, there are usually a higher number of outages in the fall, winter, and early spring than in the summer months. This trend continued in 2024, with planned maintenance outages falling by 85 percent in the third quarter from the second quarter of 2024.

During the third quarter of 2024, the average total generation on outage in the California ISO balancing area was 13,490 MW, about 2,100 MW greater than the third quarter of 2023, as shown in Figure 16.2. Forced outages increased by 20 percent when compared to the same quarter last year, while planned outages increased by four percent. The year-over-year increase in forced outages is consistent with a general trend of higher forced outages seen in the first and second quarters of 2024. The increase in forced outages is largely explained by the implementation of the Strategic Reliability Reserve (SRR) program which uses outages to prevent the dispatching of SRR participating resources outside of dispatch instructions issued in the context of the SRR program.

[106] DMM is developing public metrics on outages for WEIM balancing areas to include in future reports.

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

Figure 16.1 Quarterly average of maximum daily generation outages by type – peak hours

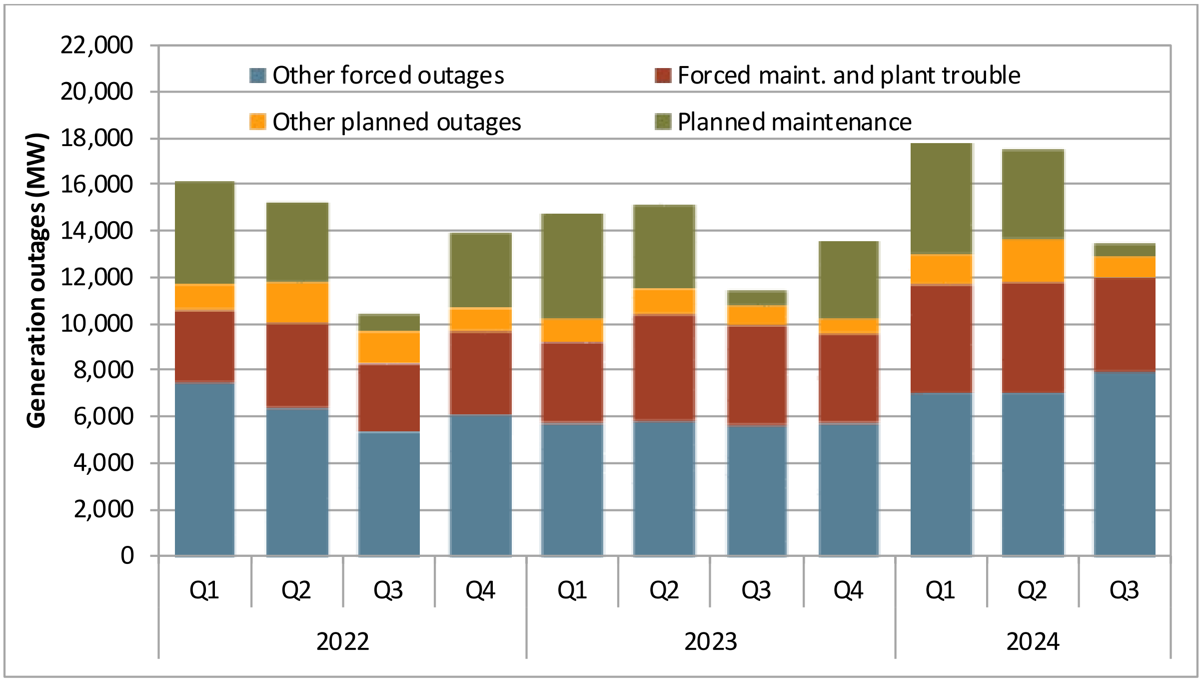
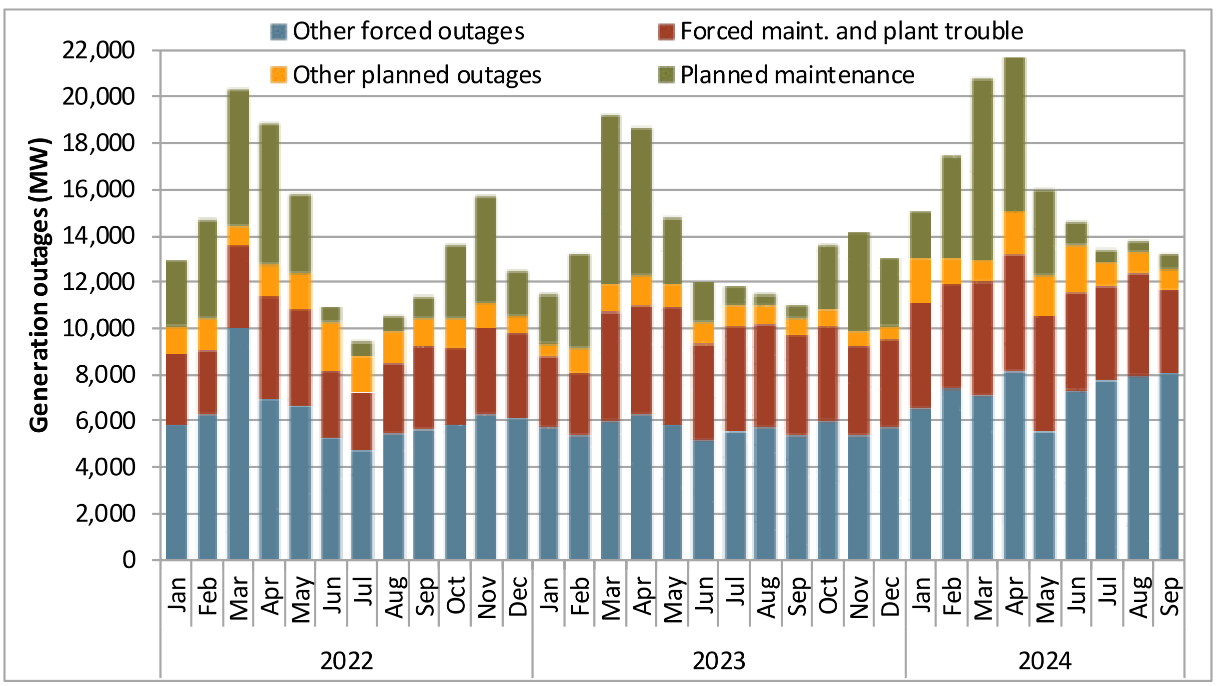


Figure 16.2 Monthly average of maximum daily generation outages by type – peak hours



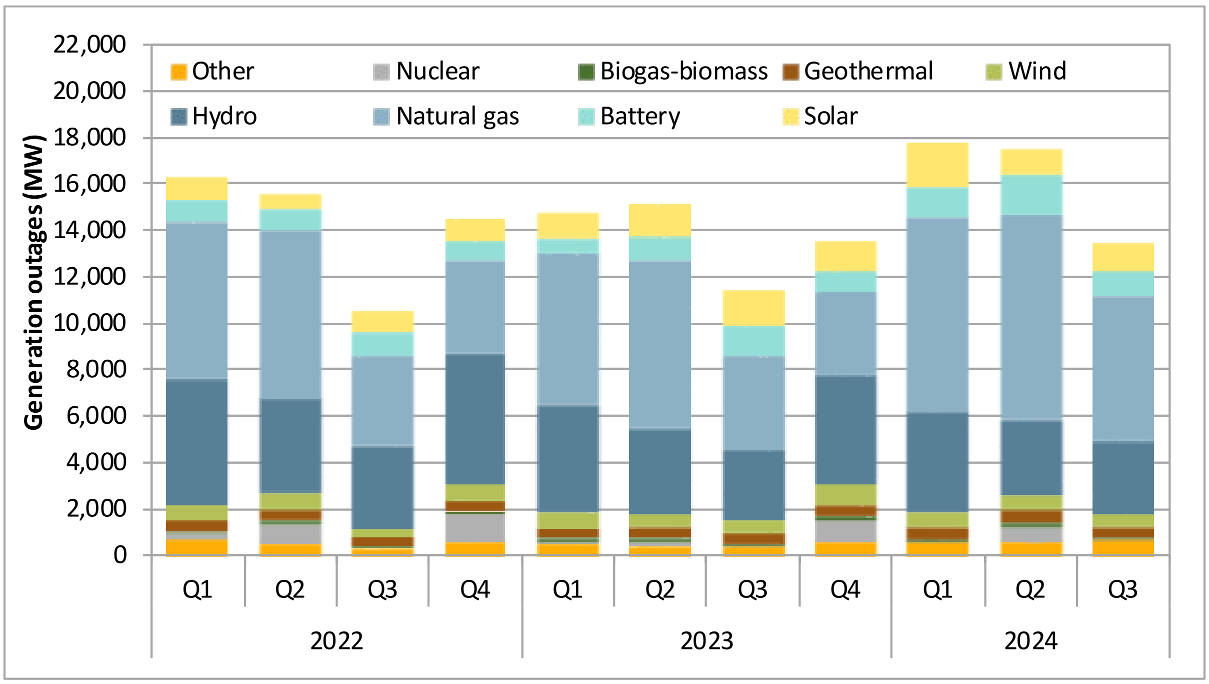
Generation outages by fuel type

Natural gas and hydroelectric generation had the largest volume of outages in the third quarter of 2024 and averaged about 8,360 MW and 4,290 MW during the third quarter of 2024, respectively. These two fuel types accounted for a combined 70 percent of the generation outages for the quarter. The amount of natural gas generation outages increased 55 percent relative to the third quarter of 2023.

The quarterly average megawatts of battery storage resources on outage fell by 13 percent in the third quarter of 2024 when compared to the third quarter of 2023. This is a reversal of the trend seen in the first two quarters of 2024 which saw significant year-over-year increases in the average megawatts of battery storage on outage. It is also worth noting that the fall in storage related outages occurred as the total battery capacity in the CAISO footprint continued to grow.

Figure 16.3 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[108] Solar, battery storage, and wind outages decreased compared to the third quarter of 2023, while outages for all other resource types increased.

Figure 16.3 Quarterly average of maximum daily generation outages by fuel type – peak hours



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

17 Exceptional dispatch

This section analyzes exceptional dispatches for the California ISO balancing area.[109] Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an *out-of-market* or *manual* dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs because out-of-market payments to the resources may exceed market prices. Manual dispatch compensation may also create opportunities for the exercise of temporal market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

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

Energy from exceptional dispatch

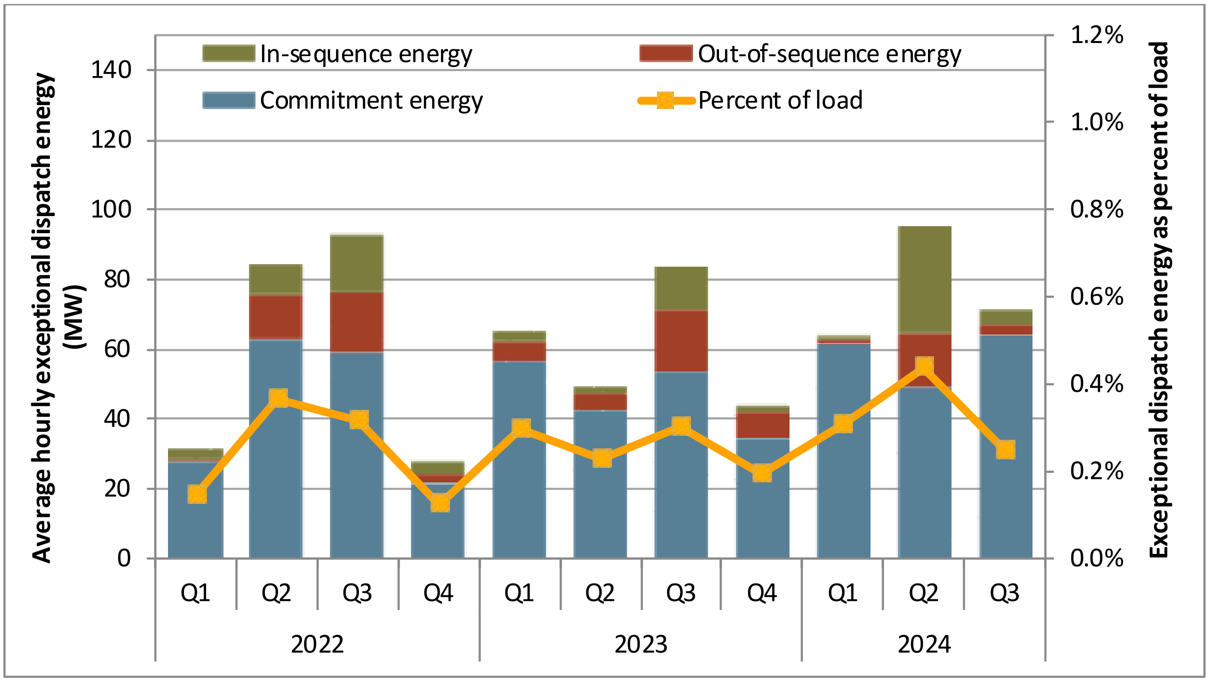
Energy from exceptional dispatches continued to account for under 1 percent of total load in the California ISO balancing area, represented by the yellow line in Figure 17.1. As shown in Figure 17.1, the average hourly total energy from exceptional dispatches—including minimum load energy from unit commitments—was 71 MW in the third quarter of 2024, which is a 15 percent decrease from the third quarter of 2023.[110]

In the third quarter of 2024, exceptional dispatches for unit commitments (blue) accounted for about 90 percent of all exceptional dispatch energy—about 5 percent was from out-of-sequence energy (red), and the remaining 5 percent was from in-sequence energy (green), as shown in Figure 17.1.

[109] For future reports, DMM is developing public metrics on manual dispatches made by operators in balancing areas only participating in the WEIM real-time markets.

[110] 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 17.1 Average hourly energy from exceptional dispatch



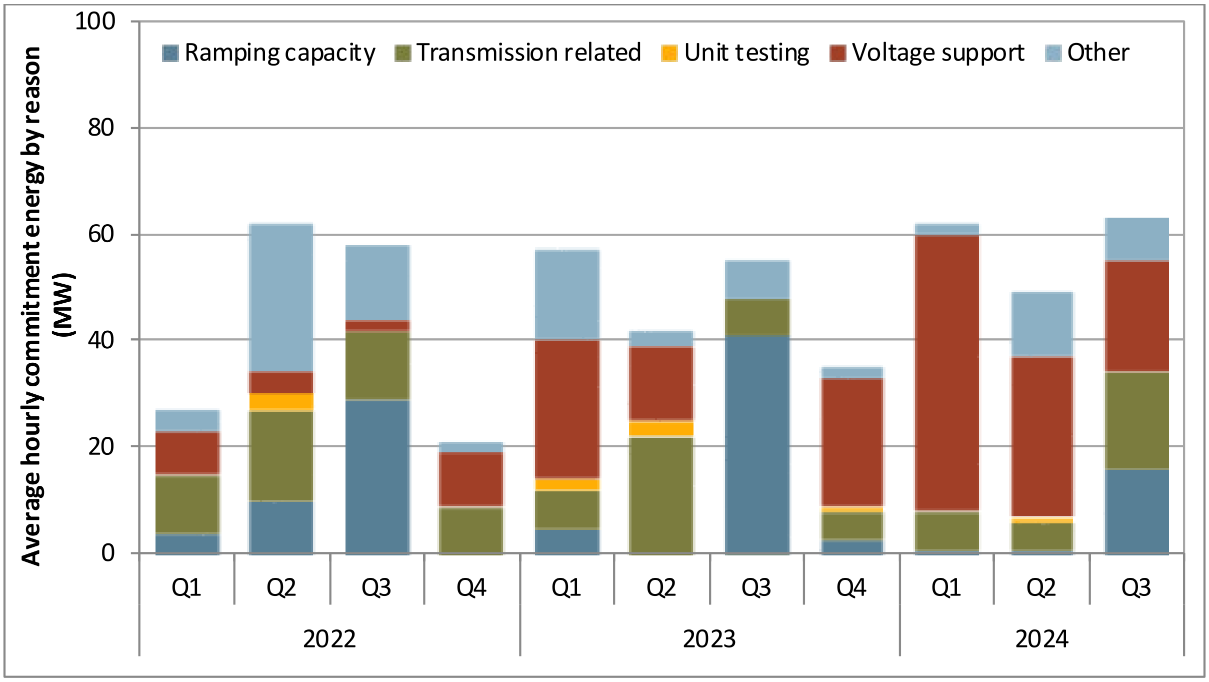
Exceptional dispatches for unit commitment

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

Figure 17.2 shows the reasons for minimum load energy exceptional dispatches: ramping capacity (dark blue), transmission related (green), unit testing (yellow), voltage support (red), and other (light blue). The average minimum load energy from unit commitment exceptional dispatches in the third quarter of 2024 was 63 MW, which was above the 53 MW of average minimum load energy from unit commitment in the third quarter of 2023.

Minimum load energy from unit commitment exceptional dispatches to provide voltage support (red bars) in the third quarter of 2024 increased to 21 MW from 0 MW in the same quarter of 2023. Meanwhile, minimum load energy from transmission related unit commitment exceptional dispatches (green bars) in the third quarter of 2024 increased by 157 percent from the same quarter in 2023.

Figure 17.2 Average minimum load energy from exceptional dispatch unit commitments



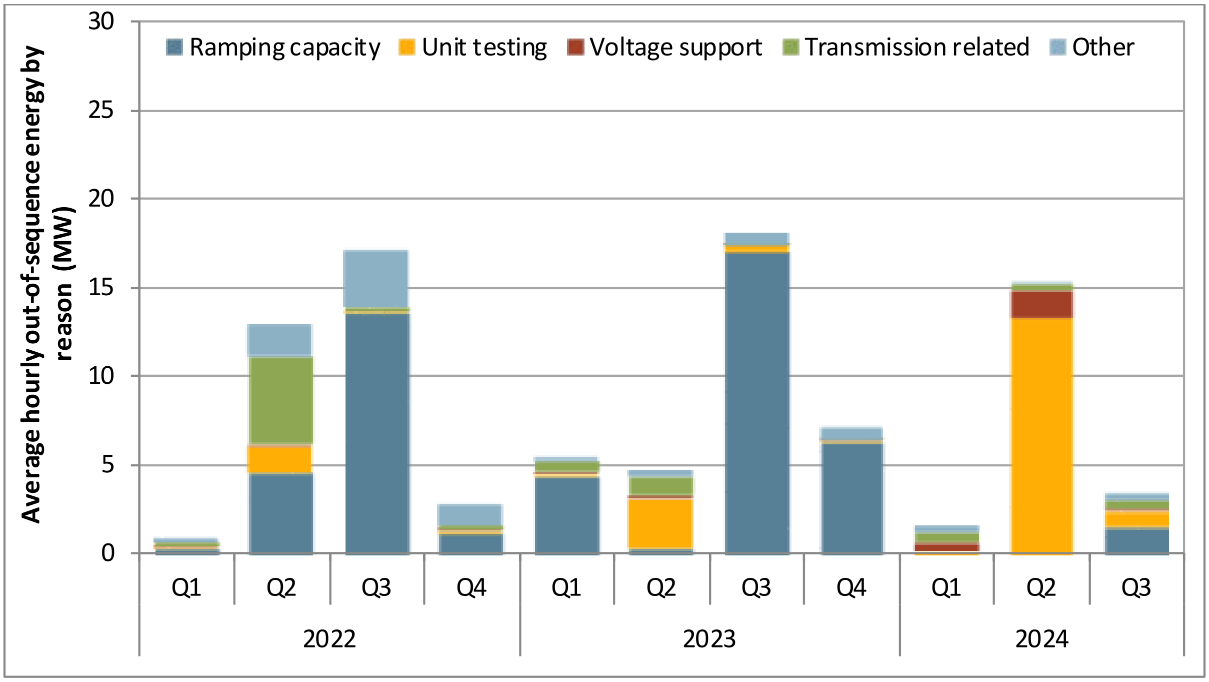
Exceptional dispatches for energy

Figure 17.3 shows the average out-of-sequence exceptional dispatch energy by quarter for 2022, 2023, and 2024. The primary reasons logged for out-of-sequence energy in the third quarter of 2024 were ramping capacity and unit testing. Ramping capacity exceptional dispatches are issued to support system ramping requirements, net peak load, or congestion management. Unit testing exceptional dispatches are issued for general reliability testing or for unit-specific purposes, such as pre-commercial or post-outage operational testing.

Out-of-sequence exceptional dispatch energy due to ramping capacity (blue bars) decreased by 90 percent in the third quarter of 2024 when compared to the third quarter of 2023. This decrease is largely due to the implementation of specific exceptional dispatch instructions for Long Start Strategic Reliability Reserve (LS-SRR) resources in 2024.[111] In the third quarter of 2023, a majority of out-of-sequence exceptional dispatch energy due to ramping capacity came from long-start gas units in response to load forecast uncertainty and system capacity needs. However, with the use of specific LS-SRR dispatch instructions in 2024, these long-start gas units were only exceptionally dispatched during extreme conditions and system emergencies, rather than for non-transmission related ramping capacity. This not only reduced the frequency of dispatch for these resources, but also significantly reduced the amount of out-of-sequence exceptional dispatch energy due to ramping capacity in the third quarter of 2024.

[111] California ISO Operating Procedure No. 4420, Section 3.2.3. Long Start Strategic Reliability Reserve Resources (LS-SRR)

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



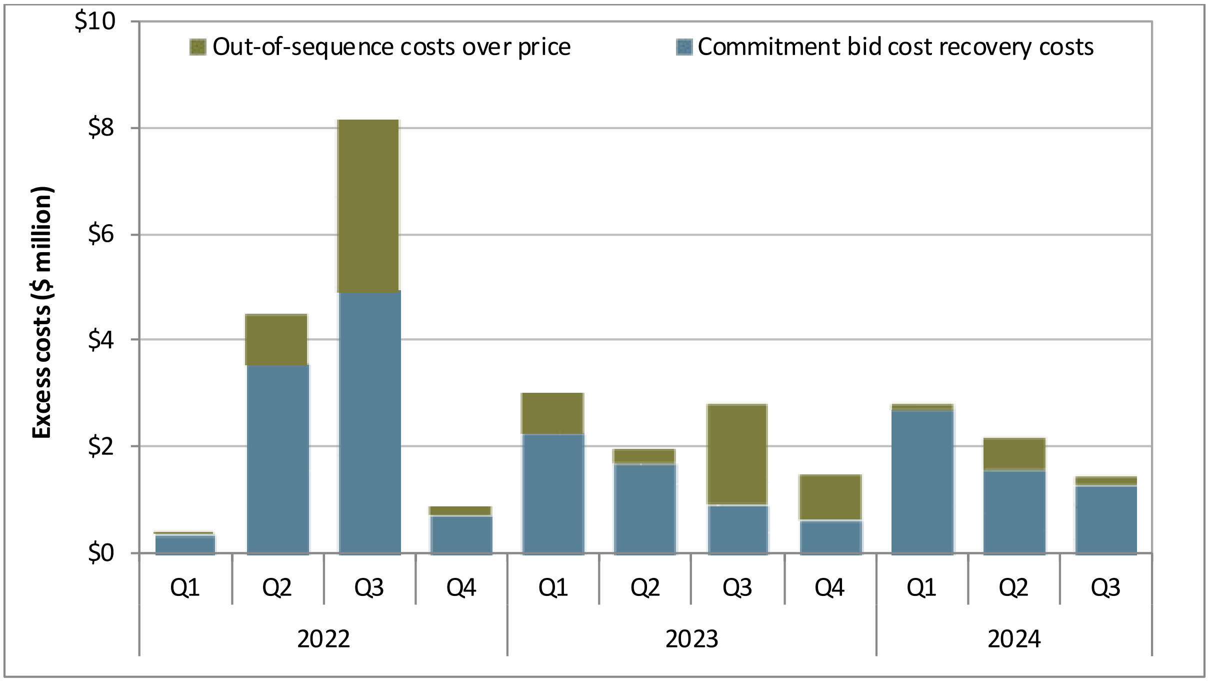
Exceptional dispatch costs

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

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

Figure 17.4 shows the estimated costs for unit commitment and exceptional dispatch for energy above minimum load whose bid price exceeded the resource's locational marginal price. In the third quarter of 2024, out-of-sequence energy costs were $0.16 million, a 92 percent decrease from the third quarter of 2023. The bid cost recovery payments awarded to resources that were committed via exceptional dispatch in the third quarter were $1.3 million, a 38 percent increase from the third quarter of 2023. Overall, the additional costs associated with the exceptional dispatches in the third quarter of 2024 decreased by 49 percent when compared to the third quarter of 2023.

Figure 17.4 Excess exceptional dispatch cost by type



APPENDIX

Appendix A | Western Energy Imbalance Market area specific metrics

Sections A.1 to A.23 include figures by WEIM area on the hourly locational marginal price (LMP) and dynamic transfers.[112] These figures are included for both the 15-minute and 5-minute markets. Key highlights of the quarter include:

- In this quarter, internal flow-based congestion generally increased prices in balancing authority areas (BAAs) in the California region. WEIM transfer congestion raised prices for Powerex, Bonneville Power Administration, and Los Angeles Department of Water and Power. The most significant component was greenhouse gas (GHG), which lowers prices for non-California BAAs.
- In this quarter, WEIM dynamic transfers exhibited distinct patterns across regions as well as BAAs. CAISO generally displayed a trend of net exporting during solar hours and net importing during non-solar hours. Non-CAISO California BAAs typically showed net imports during solar hours. In the Desert Southwest, the general trend was net exporting across all hours. However, exceptions included PNM and SRP, which showed net imports during the solar hours. In the Intermountain West, the region generally exhibited net imports during solar hours, with the exception of NWMT, which consistently showed net exports across all hours. The Pacific Northwest region generally showed net imports during both solar and evening peak hours, with exception of PSEI and PACW, which transitioned to net exports during the evening peak hours.

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

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for energy at a reference location. The SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is the greenhouse gas price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.
- **Congestion within the California ISO** is the price impact from transmission constraints within the California ISO area that are restricting the flow of energy. While these constraints are located within the California ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within the WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other internal congestion.** DMM calculates the congestion impact from constraints within the California ISO or within WEIM by replicating the nodal congestion component of the price from

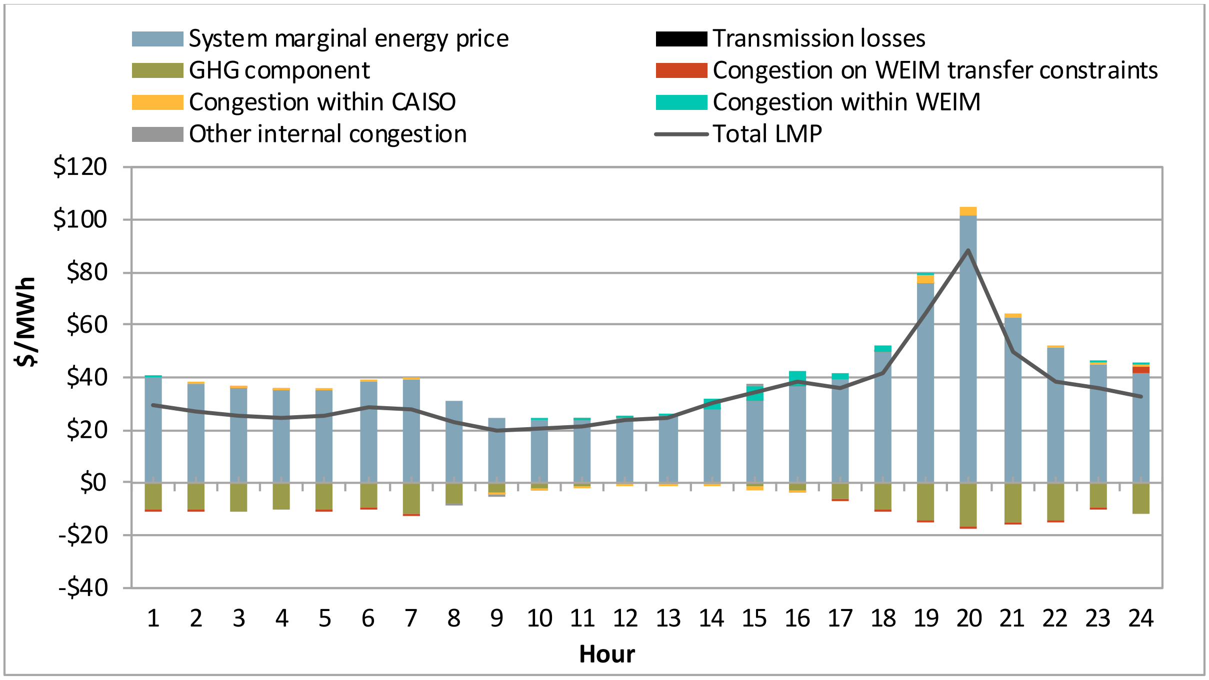
[112] These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the congestion component from individual constraints such that the remainder is flagged as *Other internal congestion.*

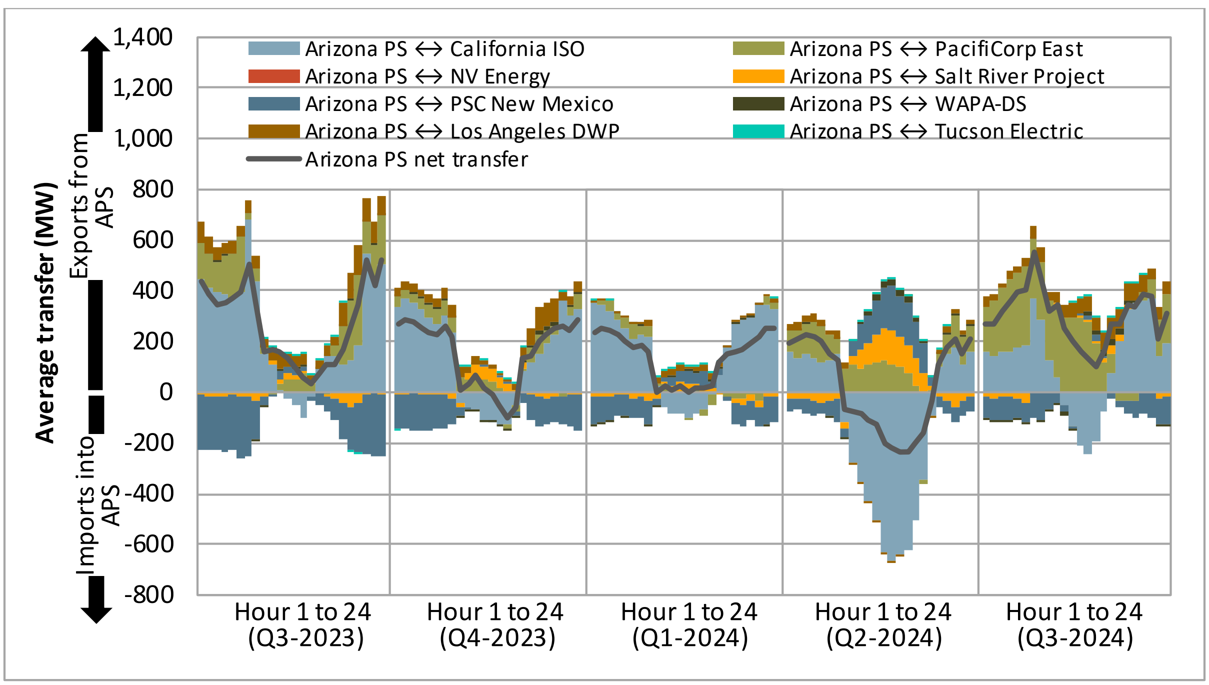
- **Congestion on WEIM transfer constraints** is the price impact from any constraint that limits WEIM transfers between balancing areas. This includes congestion from (1) scheduling limits on individual WEIM transfers, (2) total scheduling limits following a resource sufficiency evaluation failure,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

A.1 Arizona Public Service

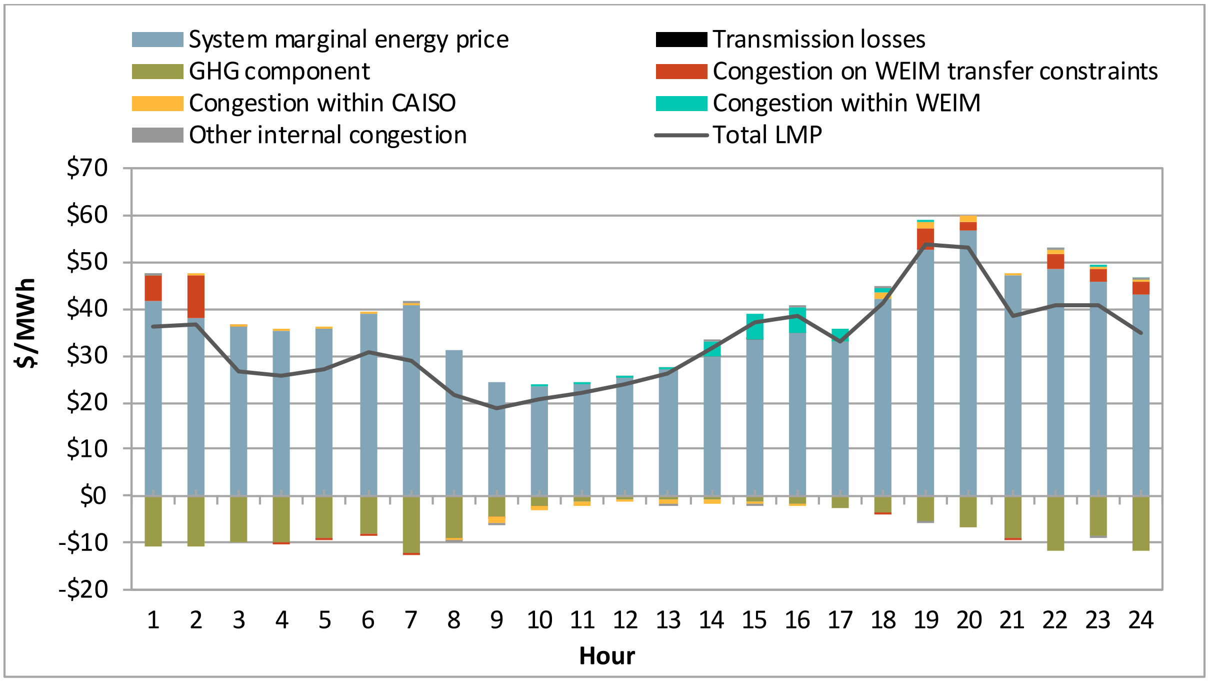
Appendix Figure A.1 Average hourly 15-minute price by component (Q3 2024)



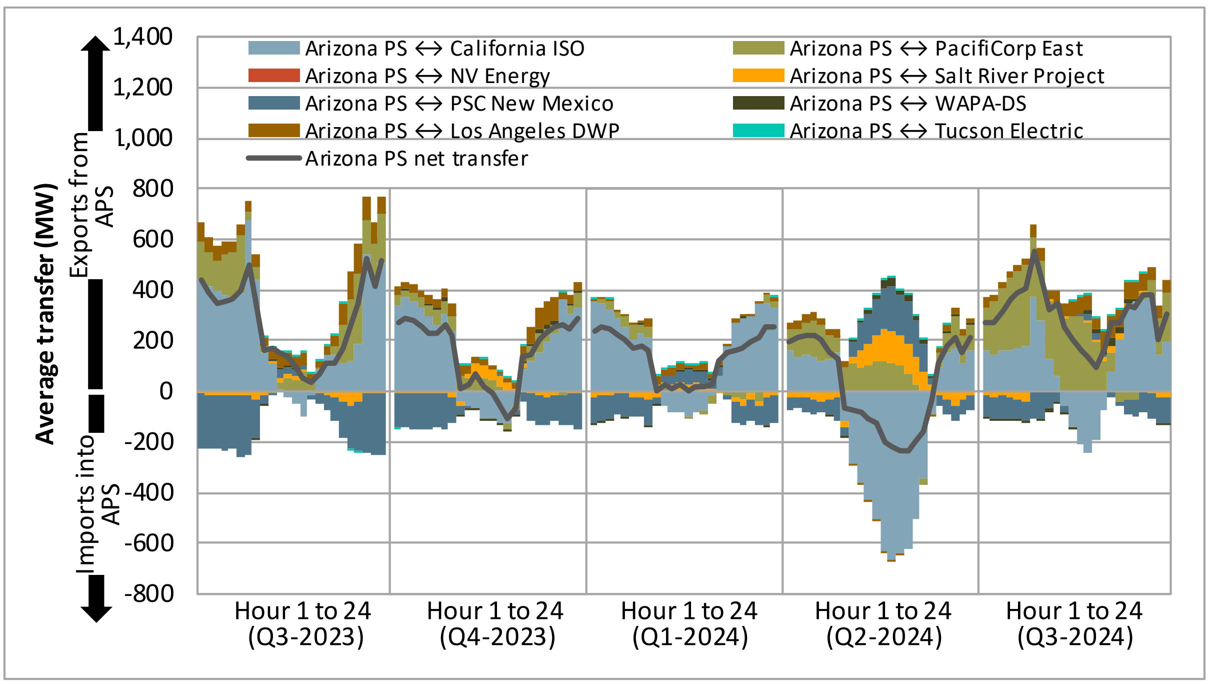
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q3 2024)

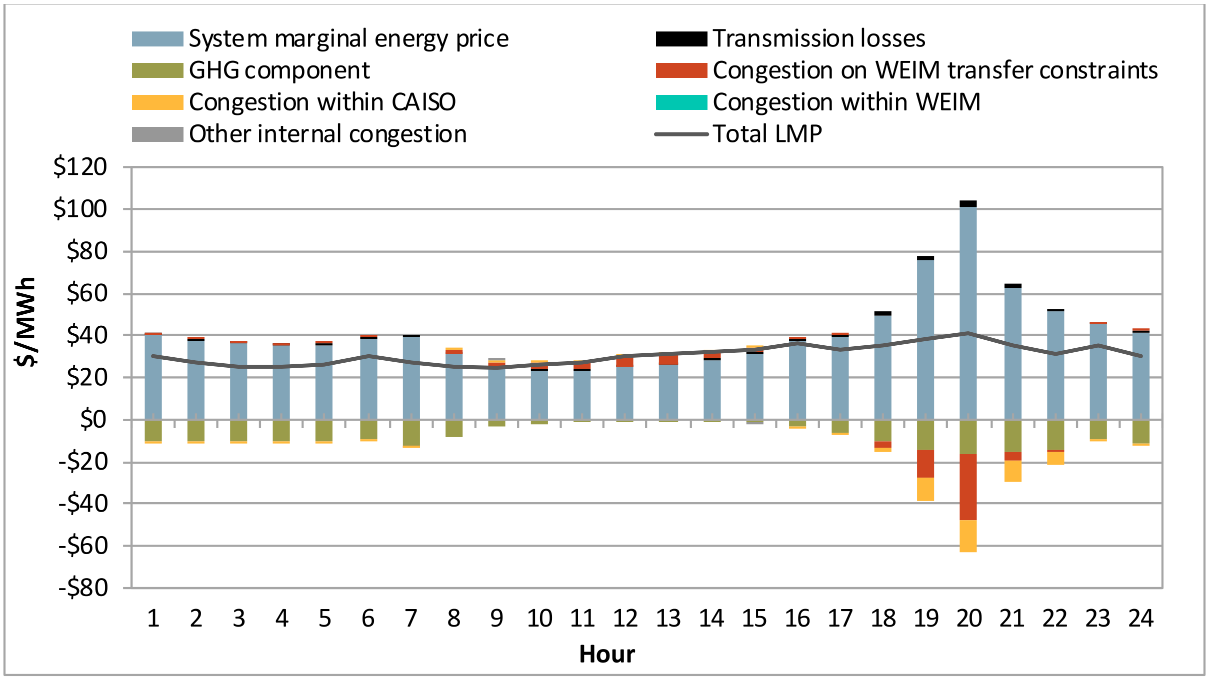


Appendix Figure A.4 Average hourly 5-minute market transfers

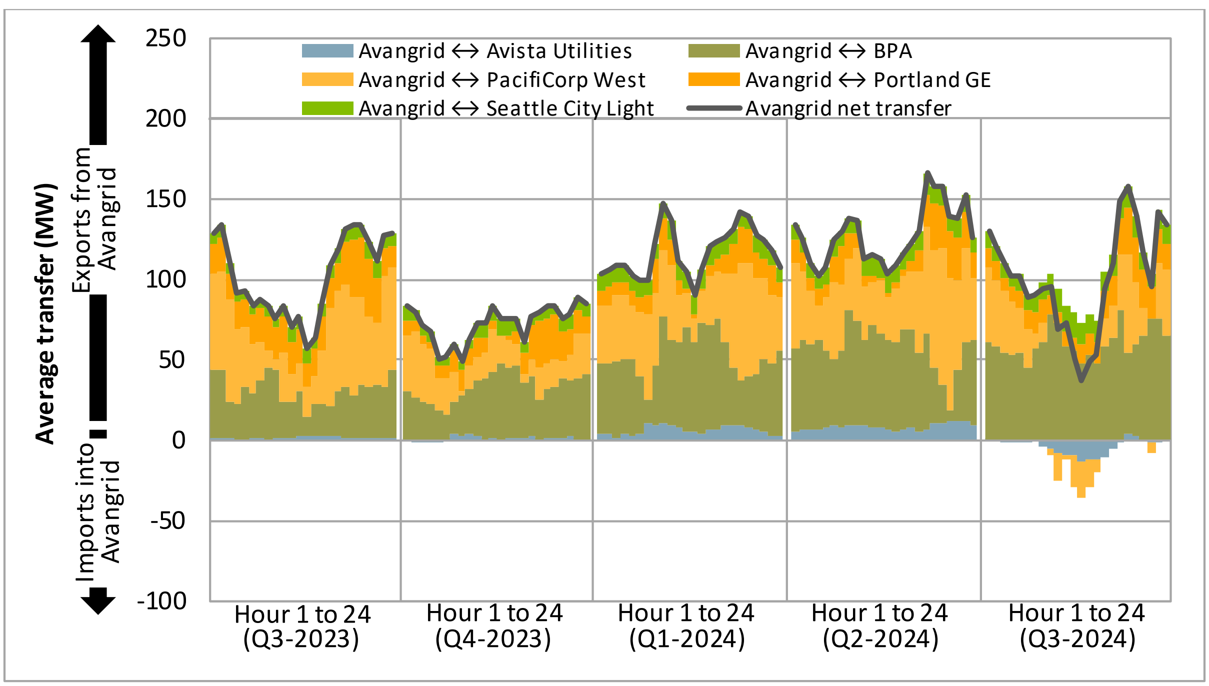


A.2 Avangrid

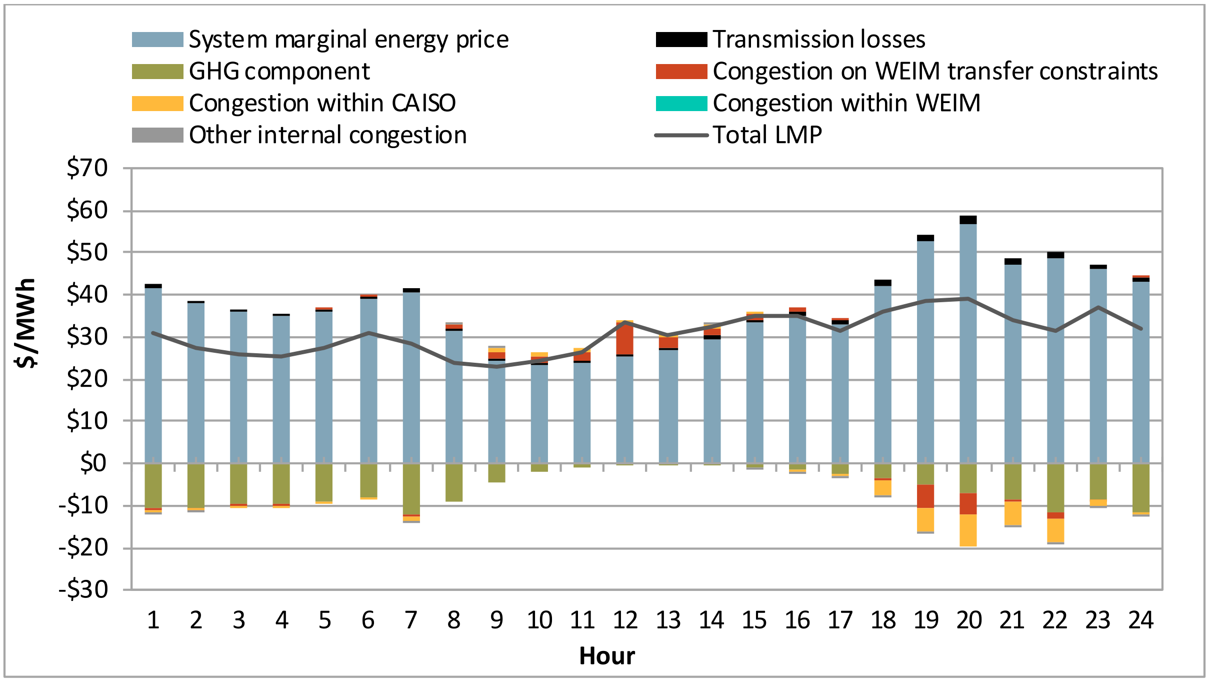
Appendix Figure A.5 Average hourly 15-minute price by component (Q3 2024)



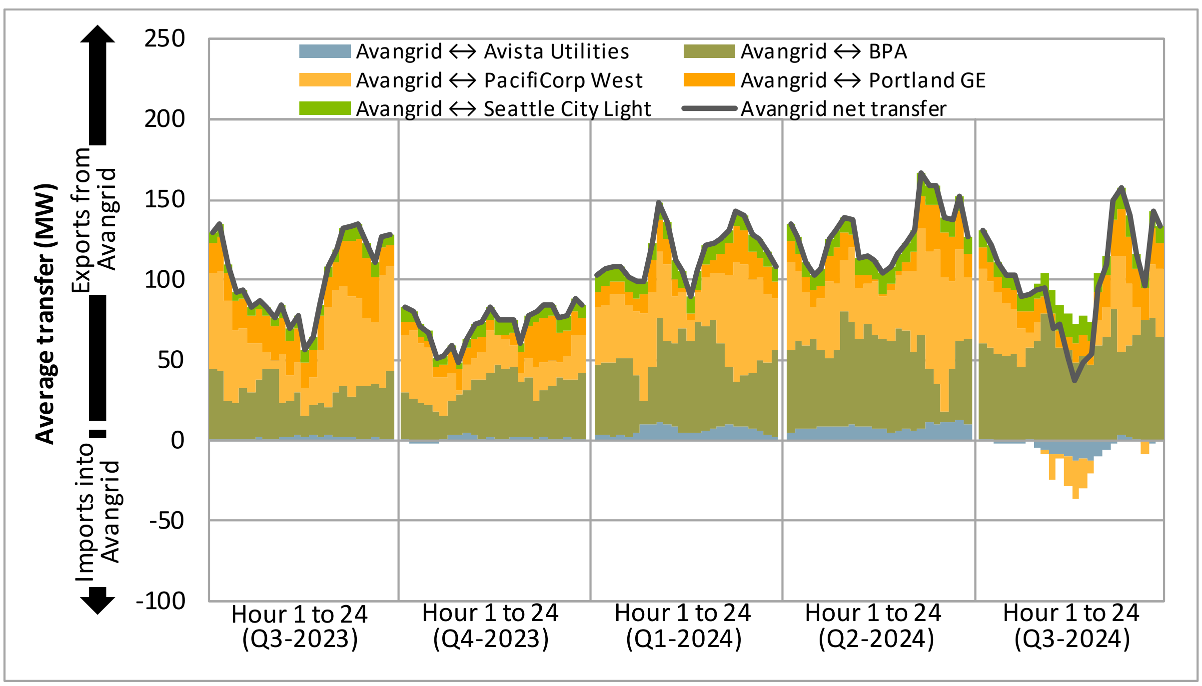
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q3 2024)

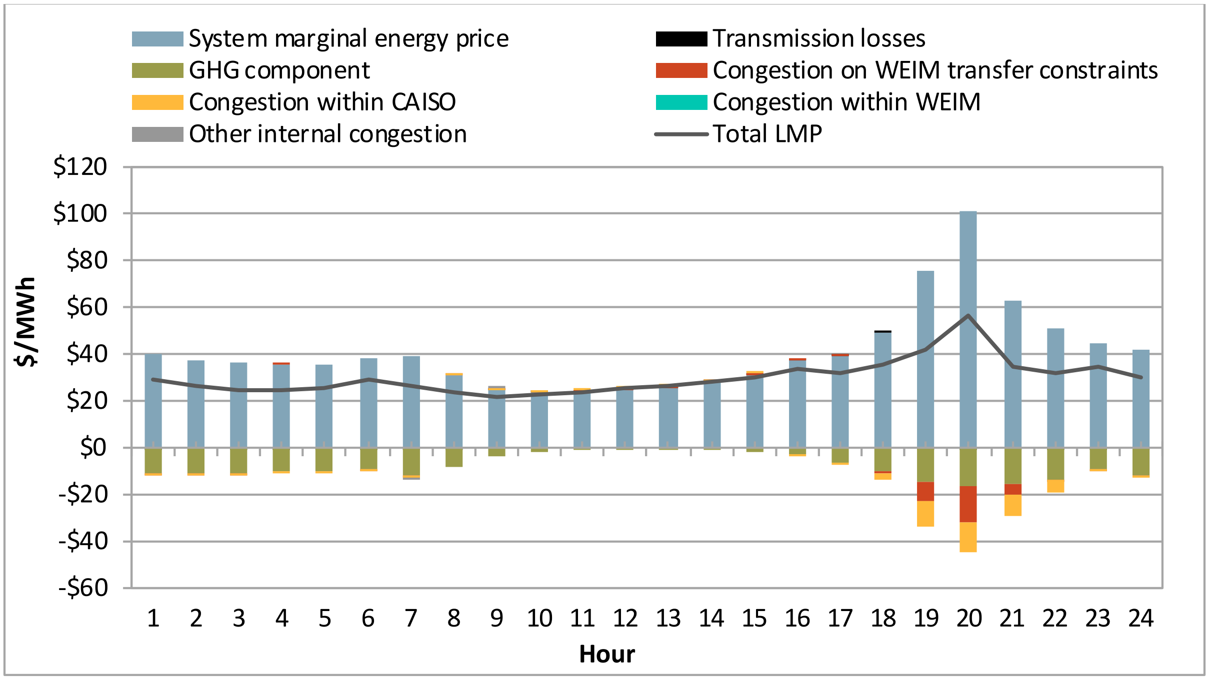


Appendix Figure A.8 Average hourly 5-minute market transfers

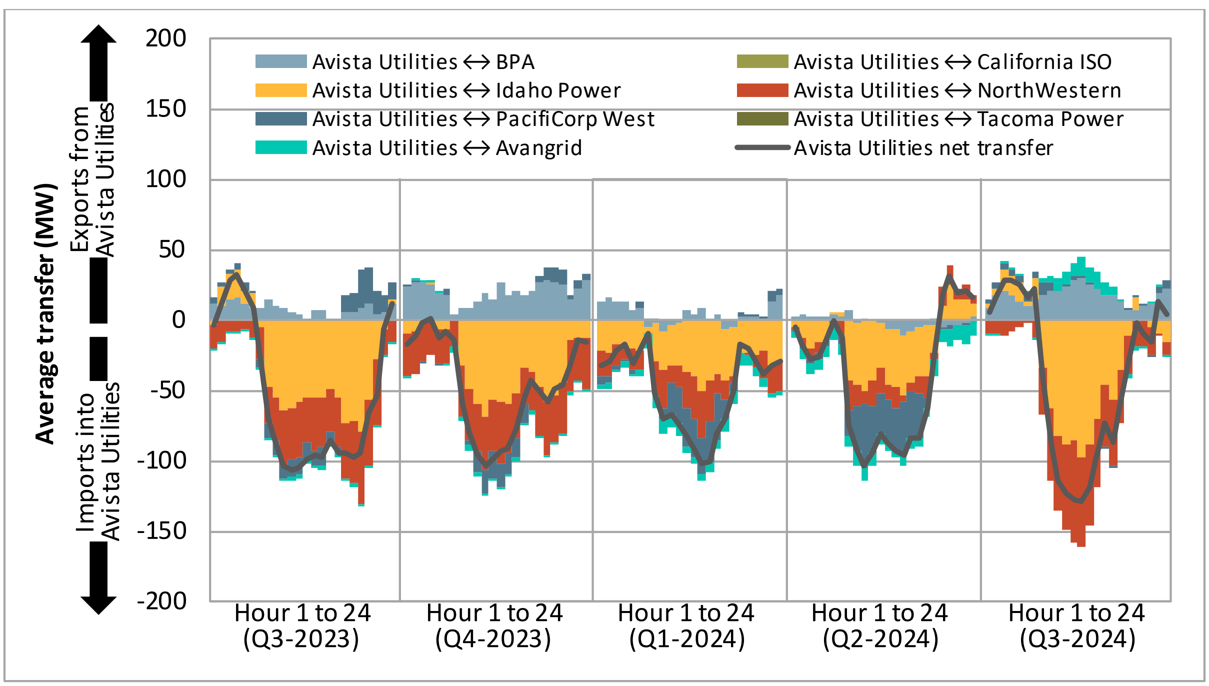


A.3 Avista Utilities

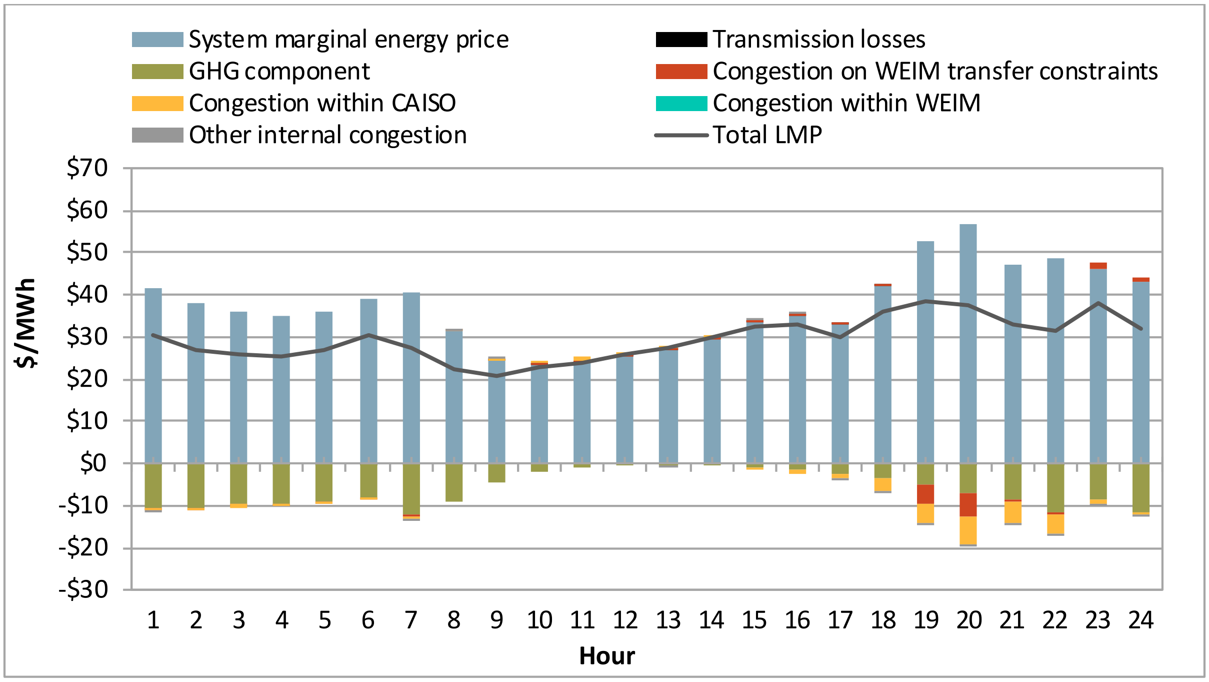
Appendix Figure A.9 Average hourly 15-minute price by component (Q3 2024)



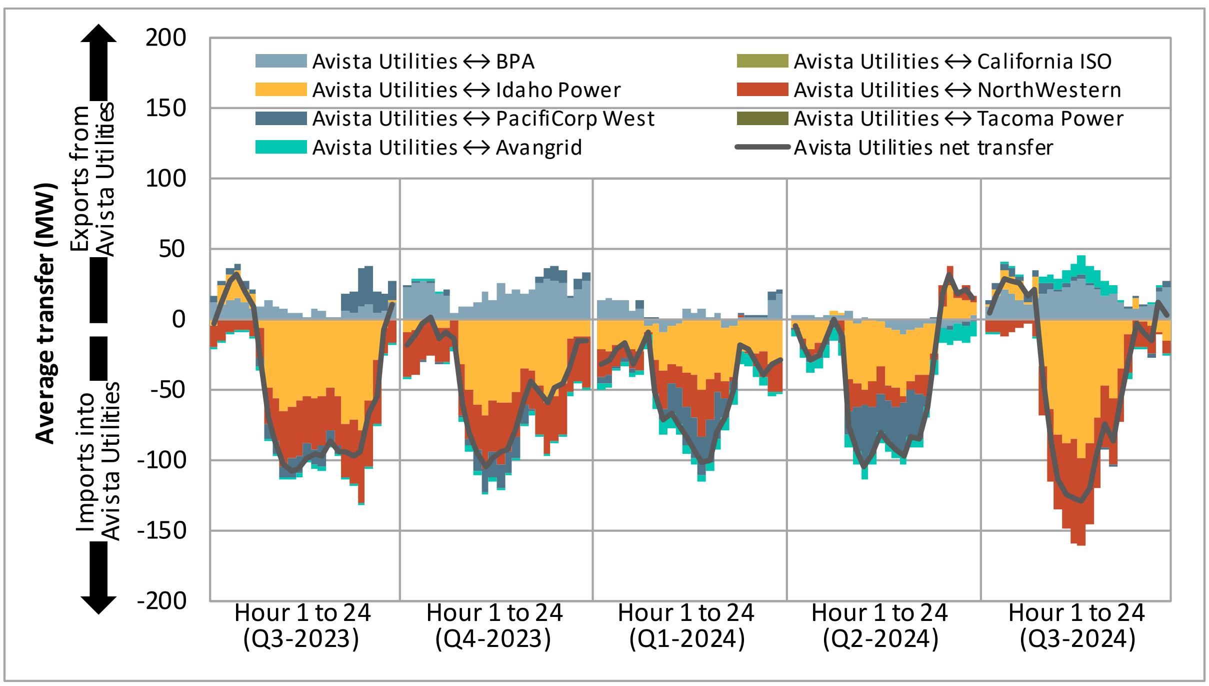
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q3 2024)

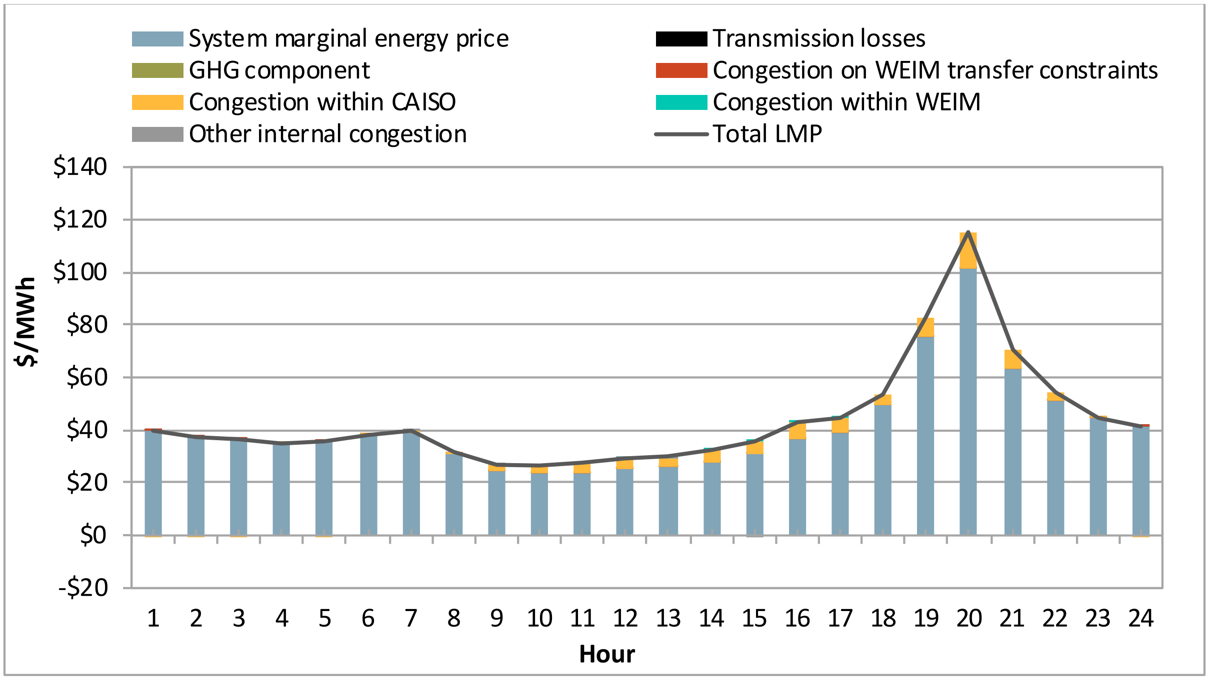


Appendix Figure A.12 Average hourly 5-minute market transfers

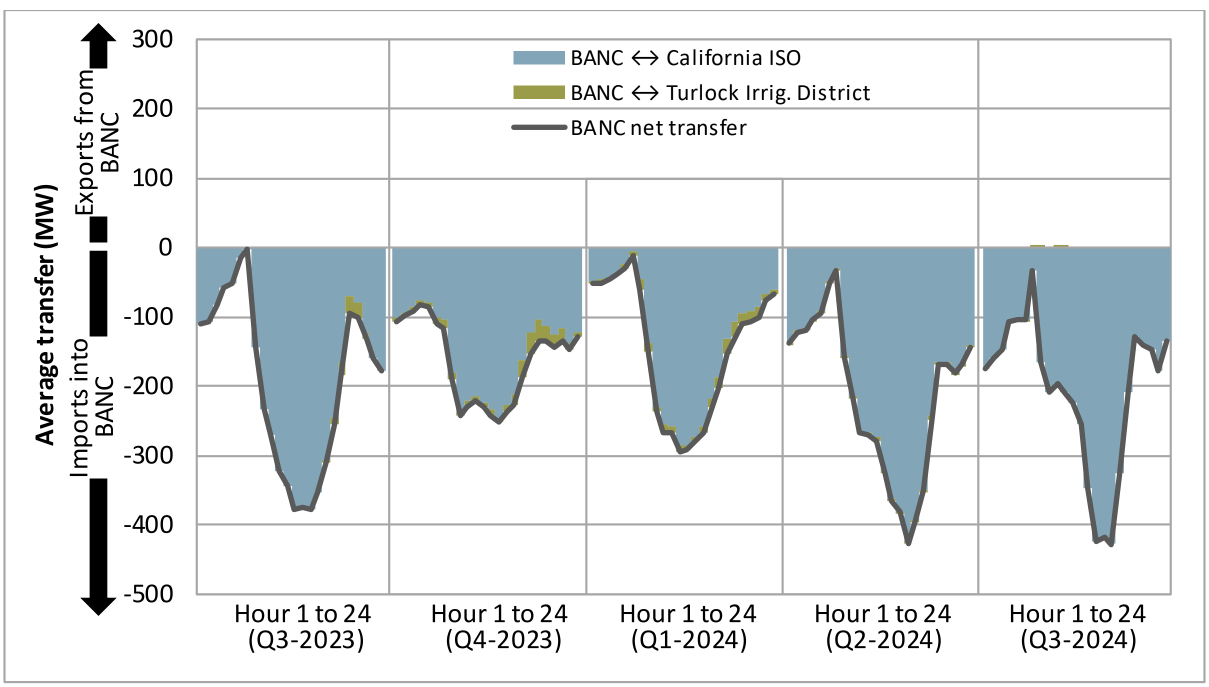


A.4 Balancing Authority of Northern California

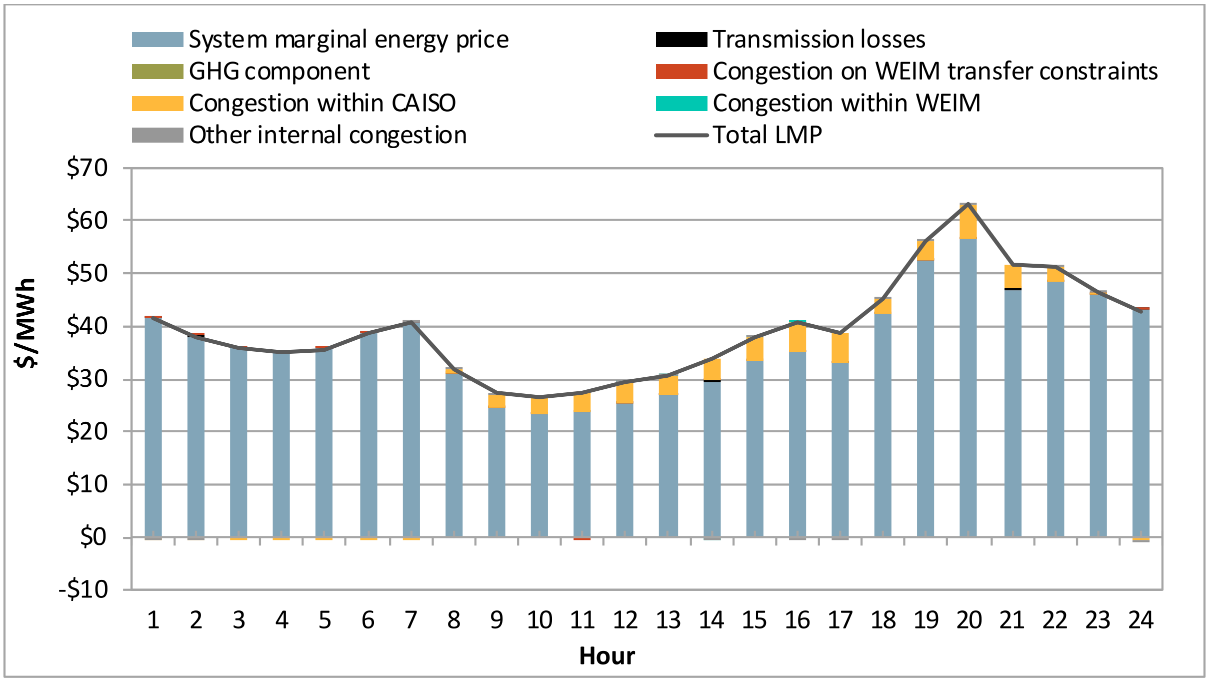
Appendix Figure A.13 Average hourly 15-minute price by component (Q3 2024)



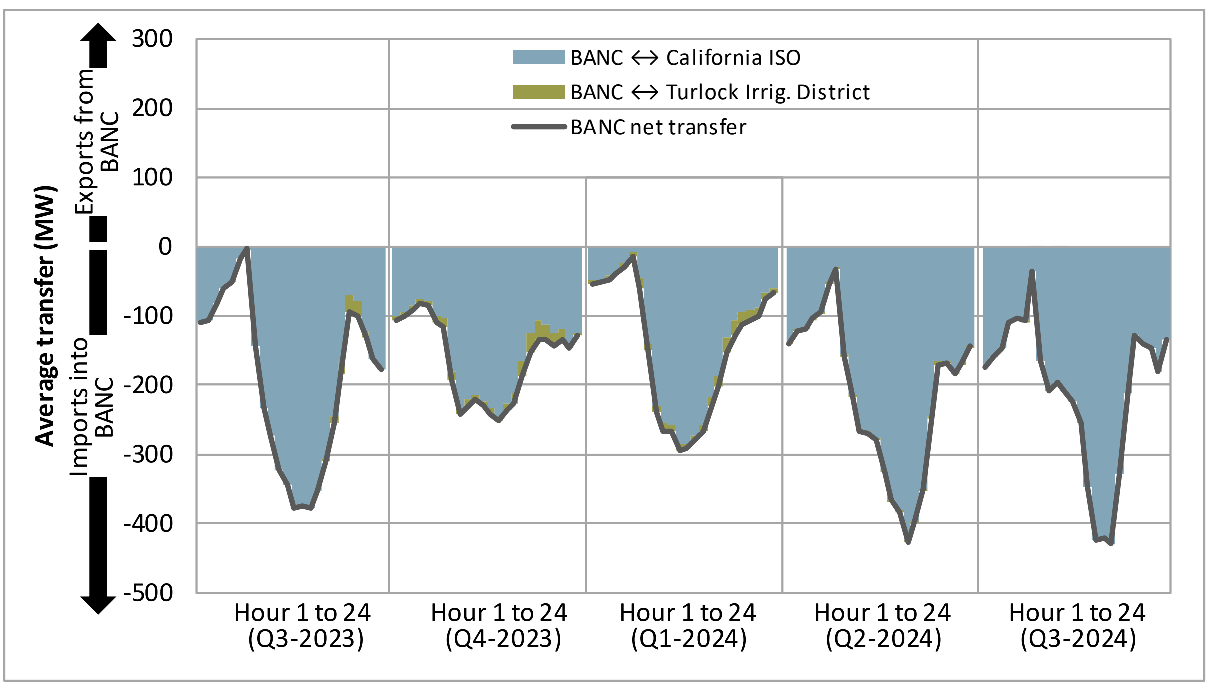
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q3 2024)

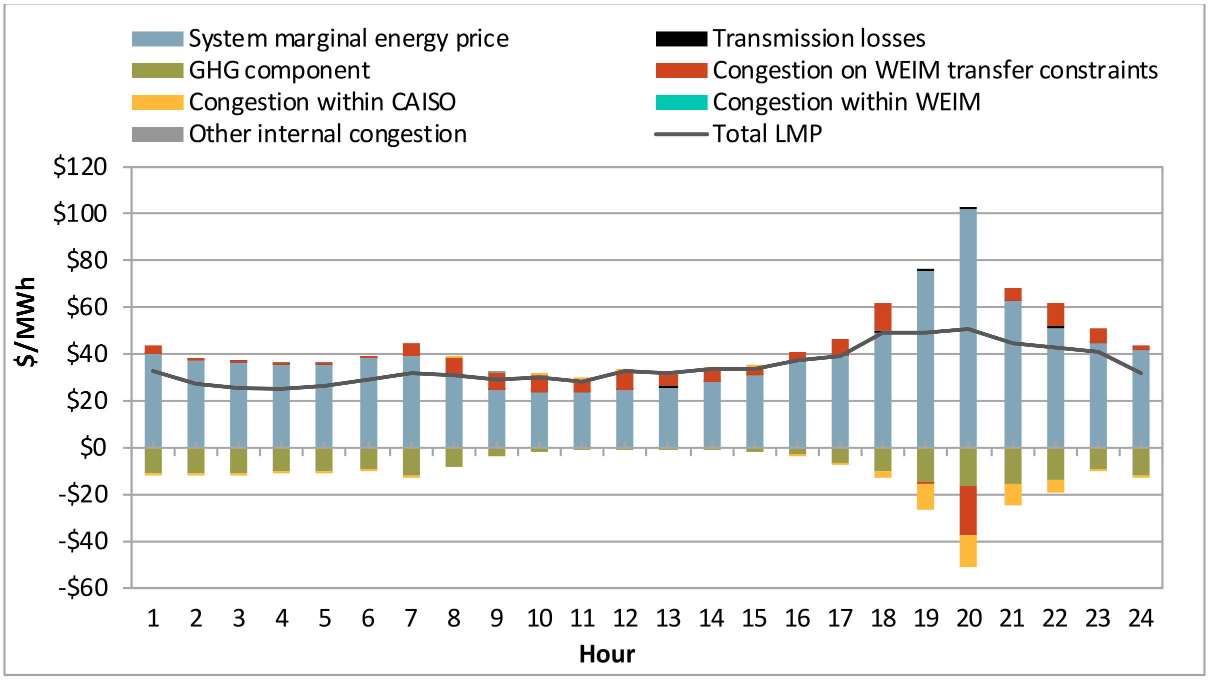


Appendix Figure A.16 Average hourly 5-minute market transfers

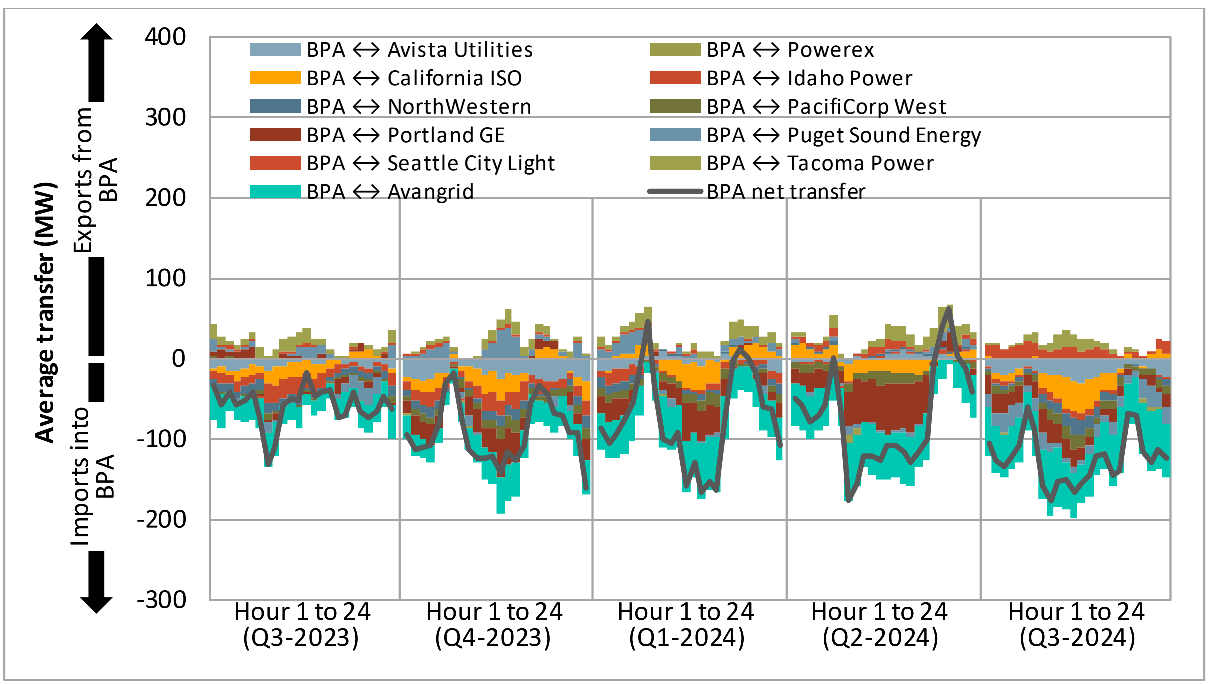


A.5 Bonneville Power Administration

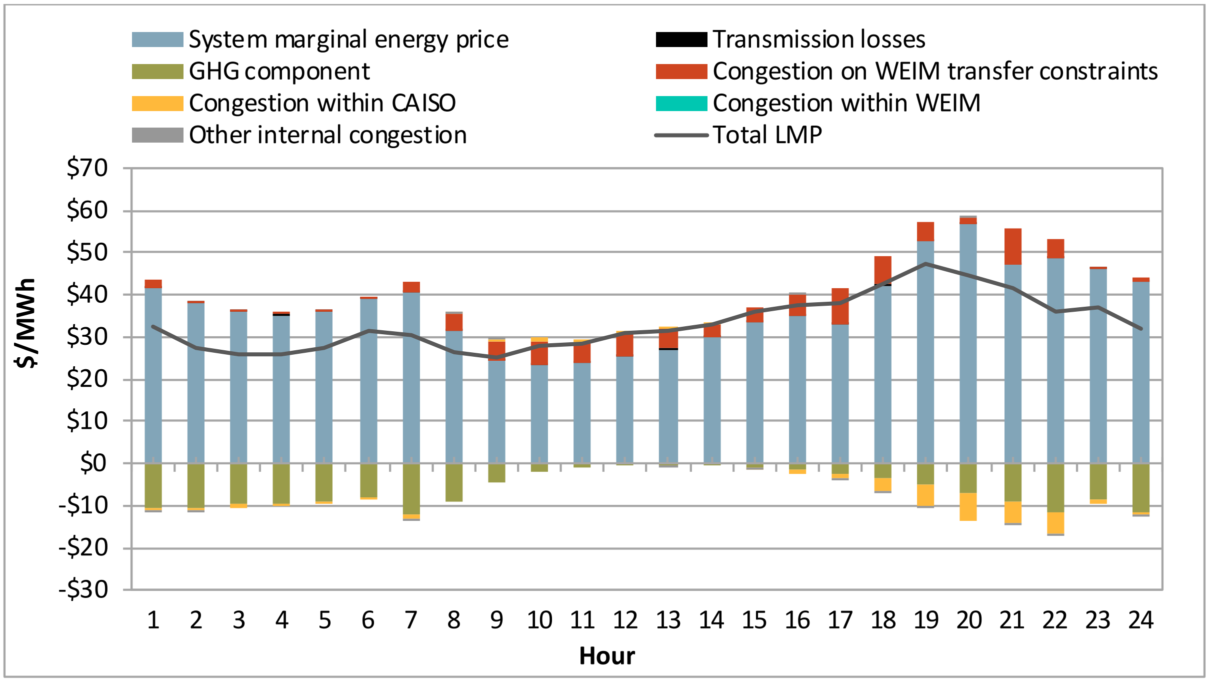
Appendix Figure A.17 Average hourly 15-minute price by component (Q3 2024)



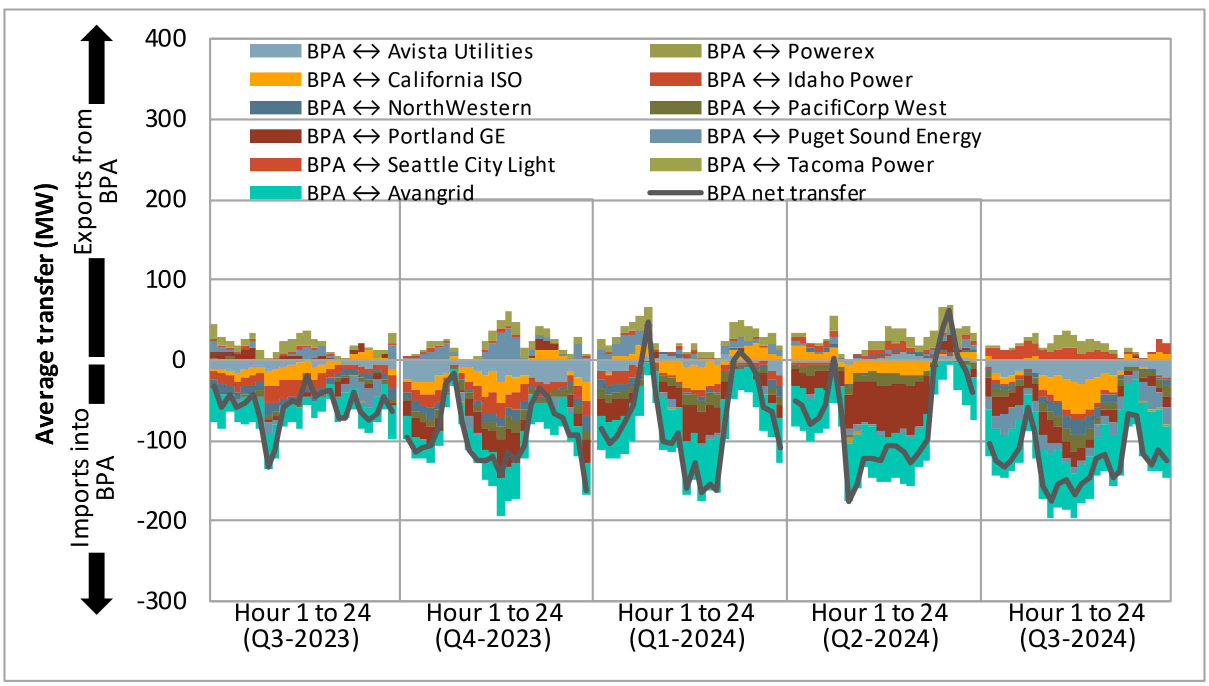
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q3 2024)

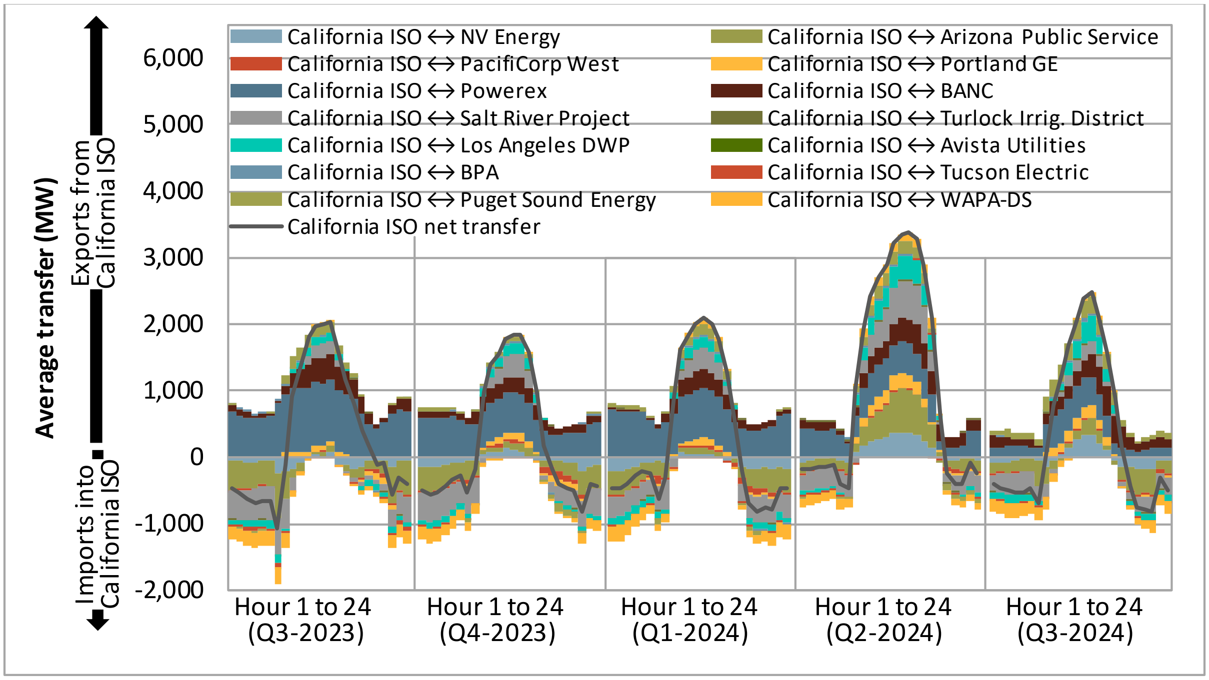


Appendix Figure A.20 Average hourly 5-minute market transfers

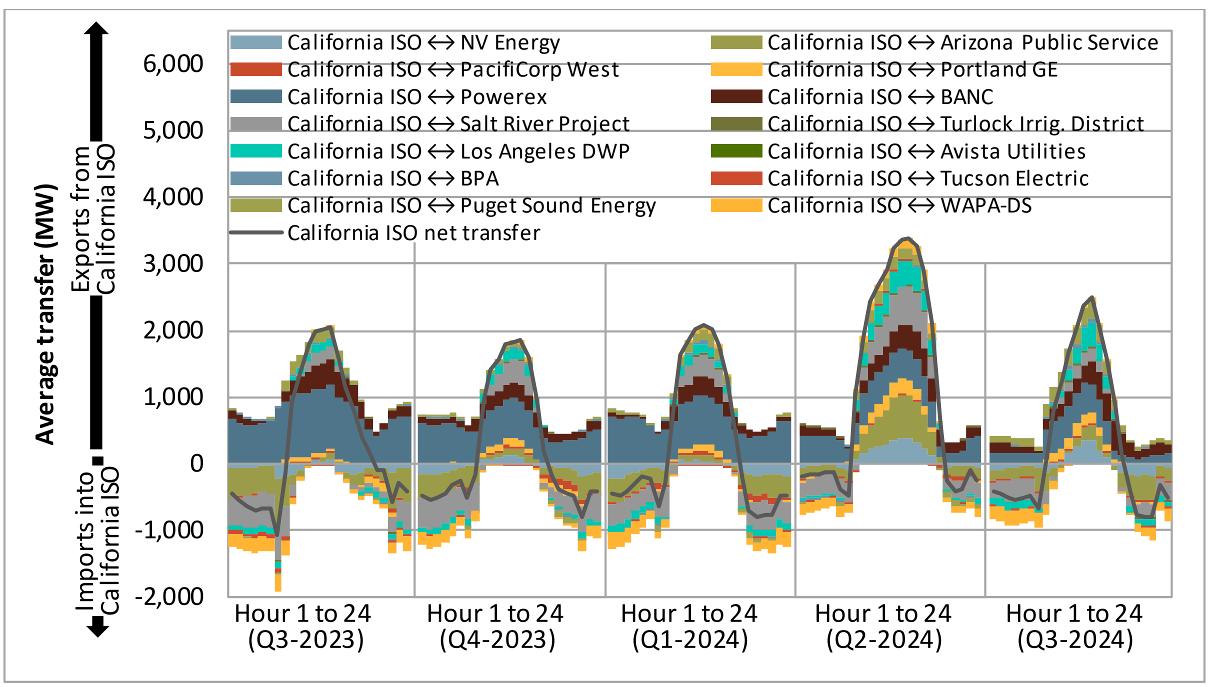


A.6 California ISO

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

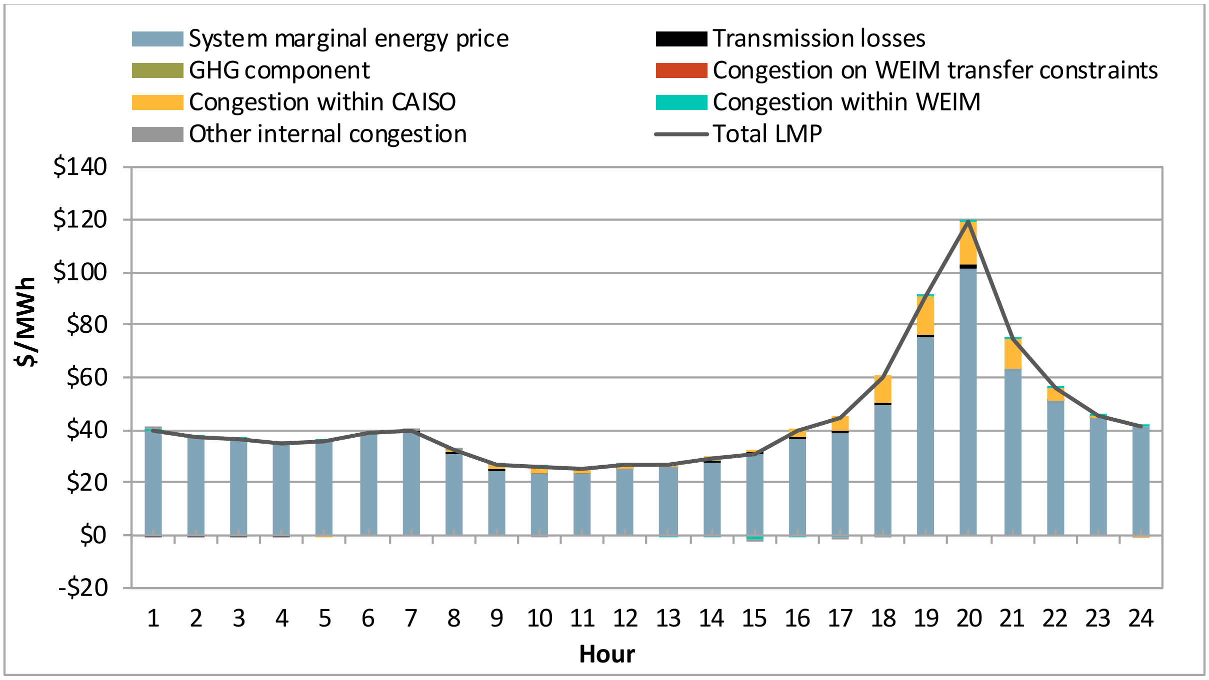


Appendix Figure A.22 Average hourly 5-minute market transfers

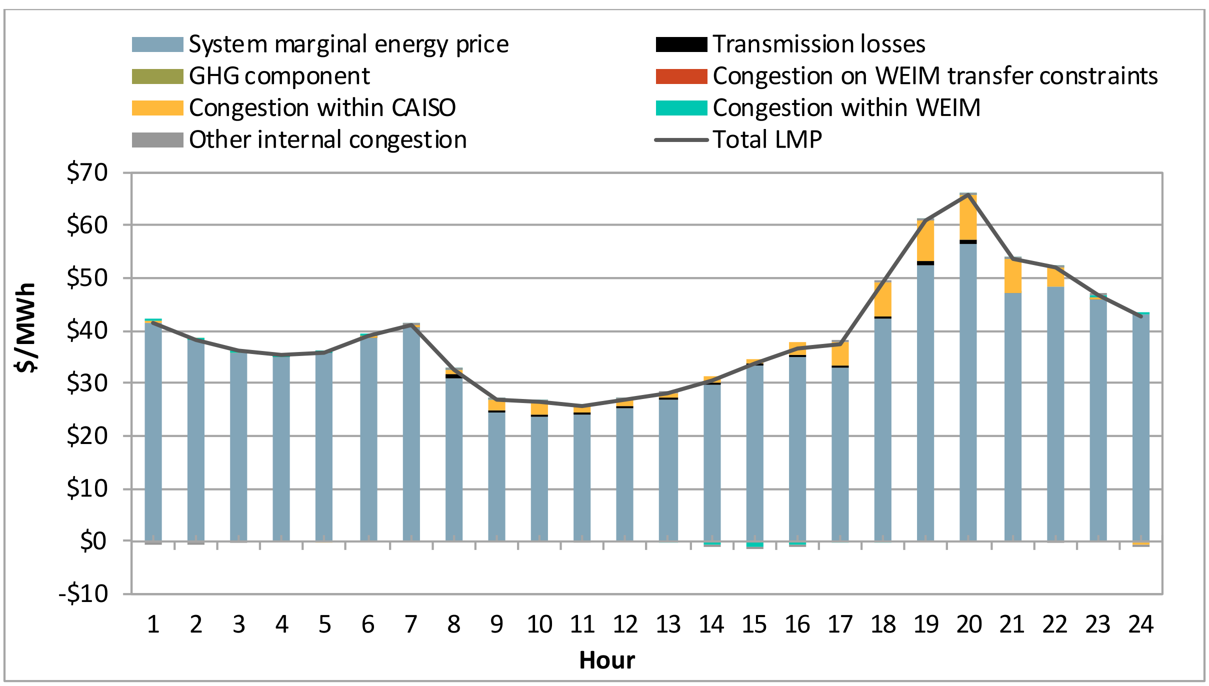


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q3 2024)

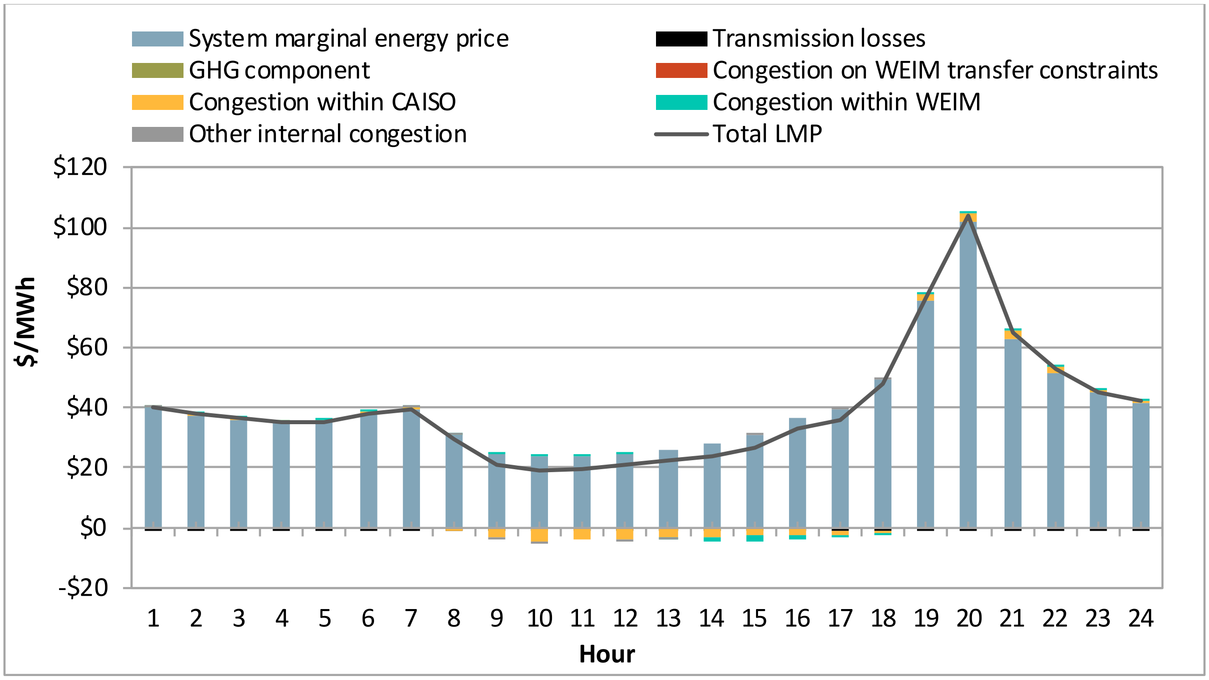


Appendix Figure A.24 Average hourly 5-minute price by component (Q3 2024)

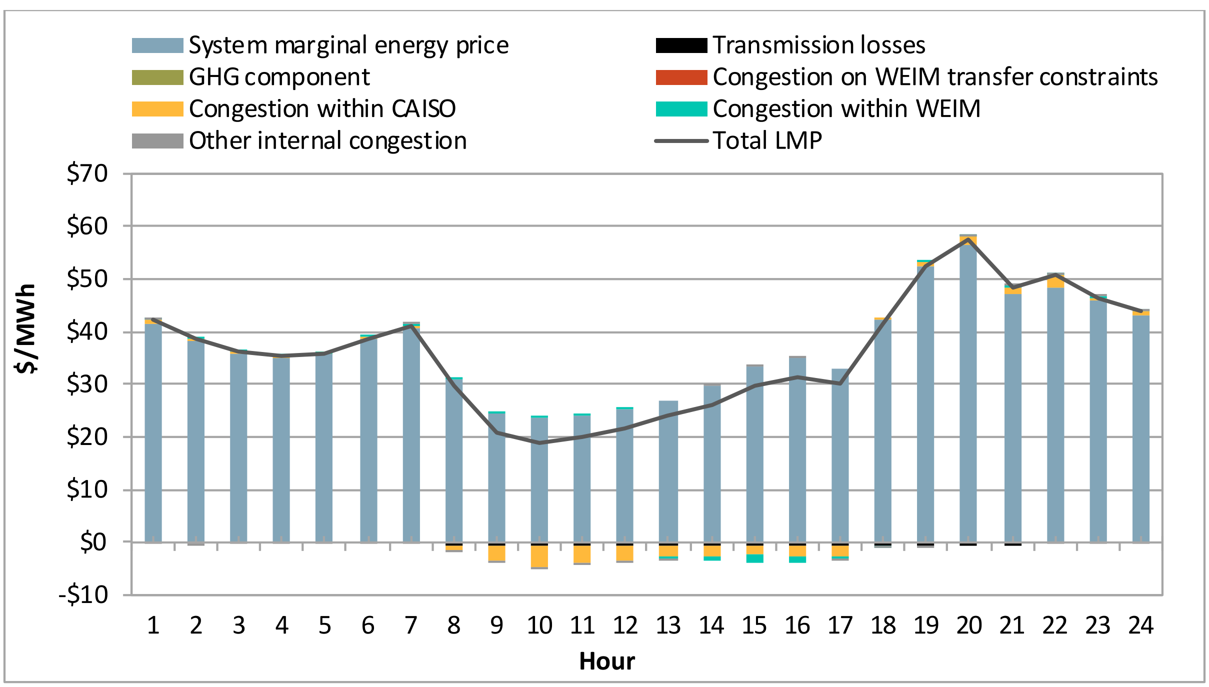


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q3 2024)

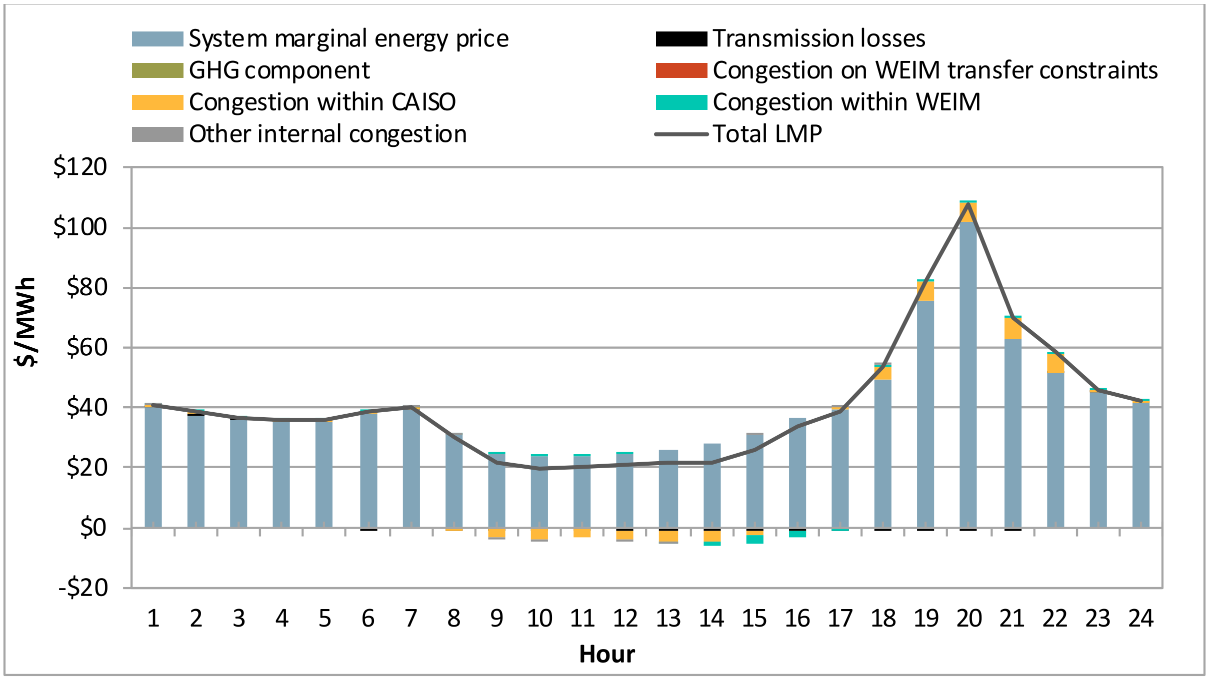


Appendix Figure A.26 Average hourly 5-minute price by component (Q3 2024)

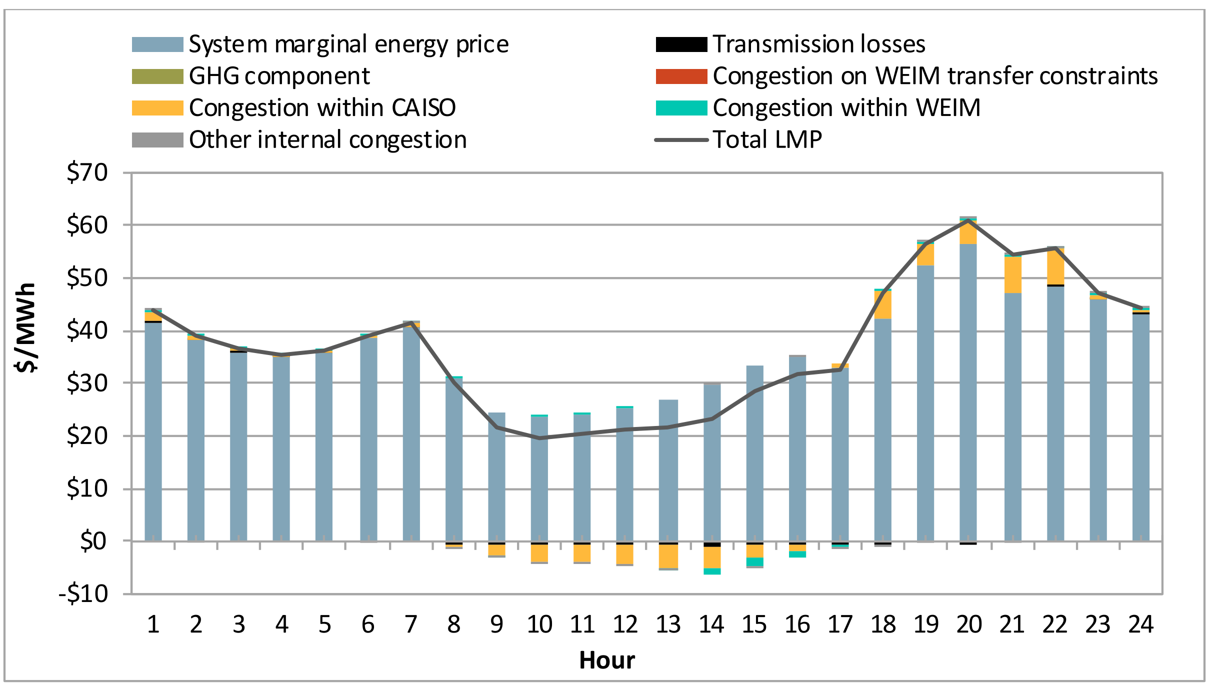


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q3 2024)

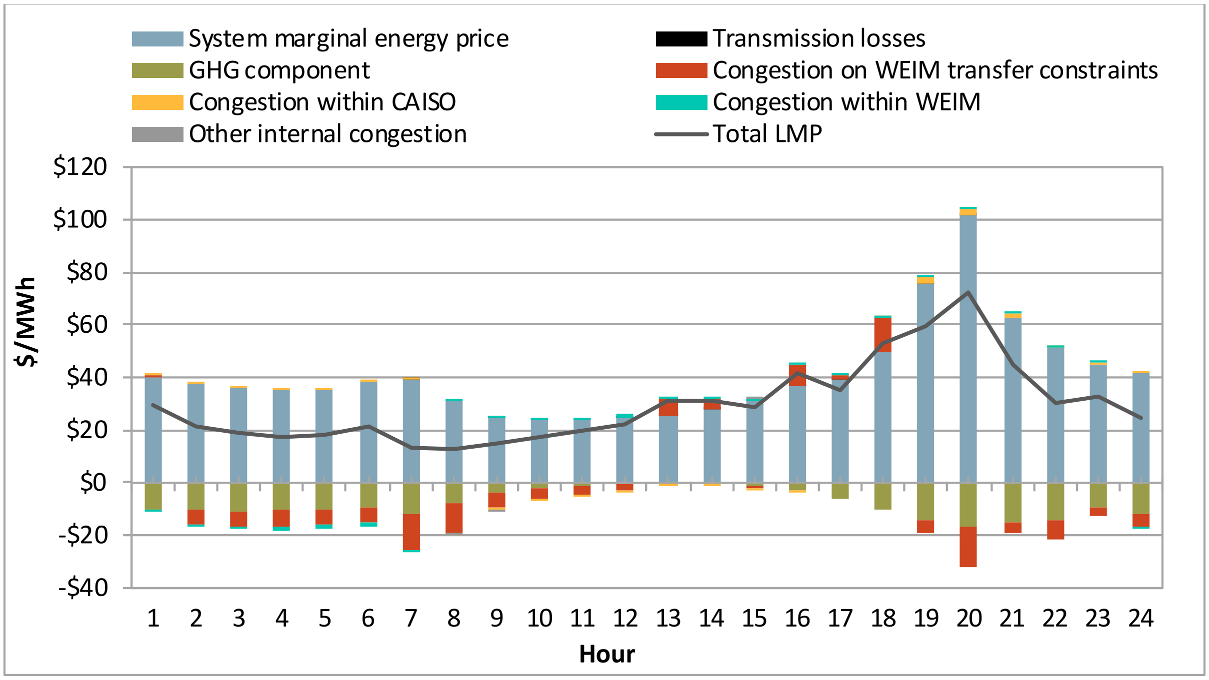


Appendix Figure A.28 Average hourly 5-minute price by component (Q3 2024)

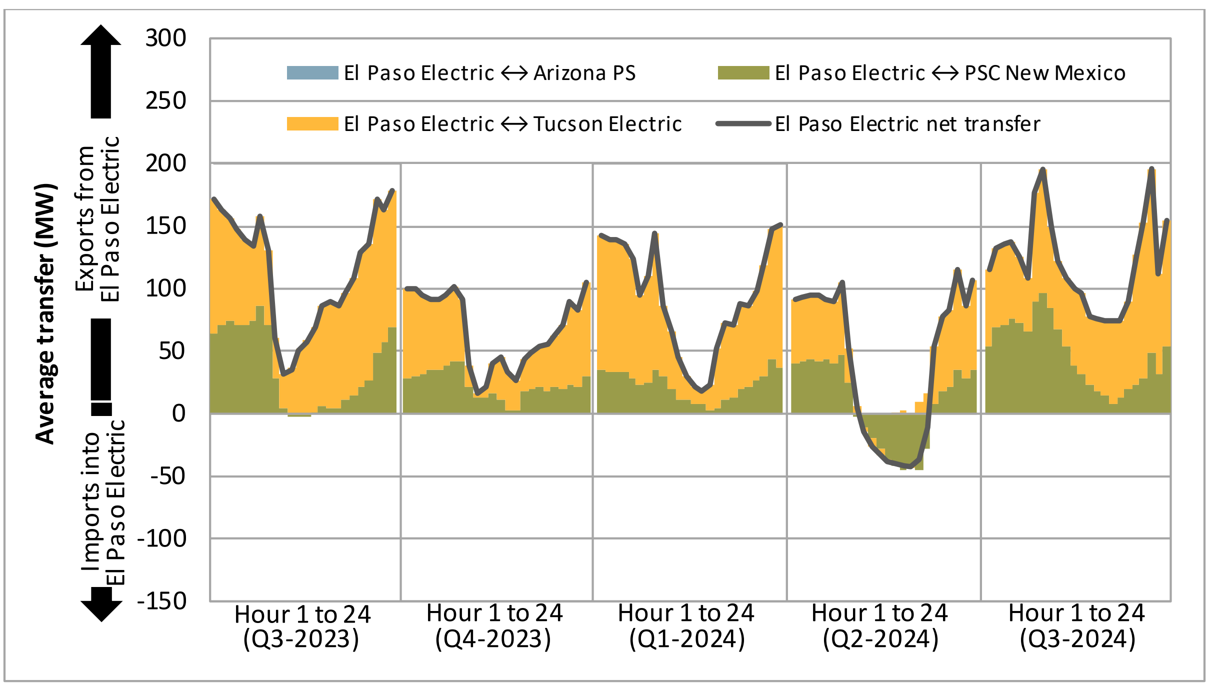


A.7 El Paso Electric

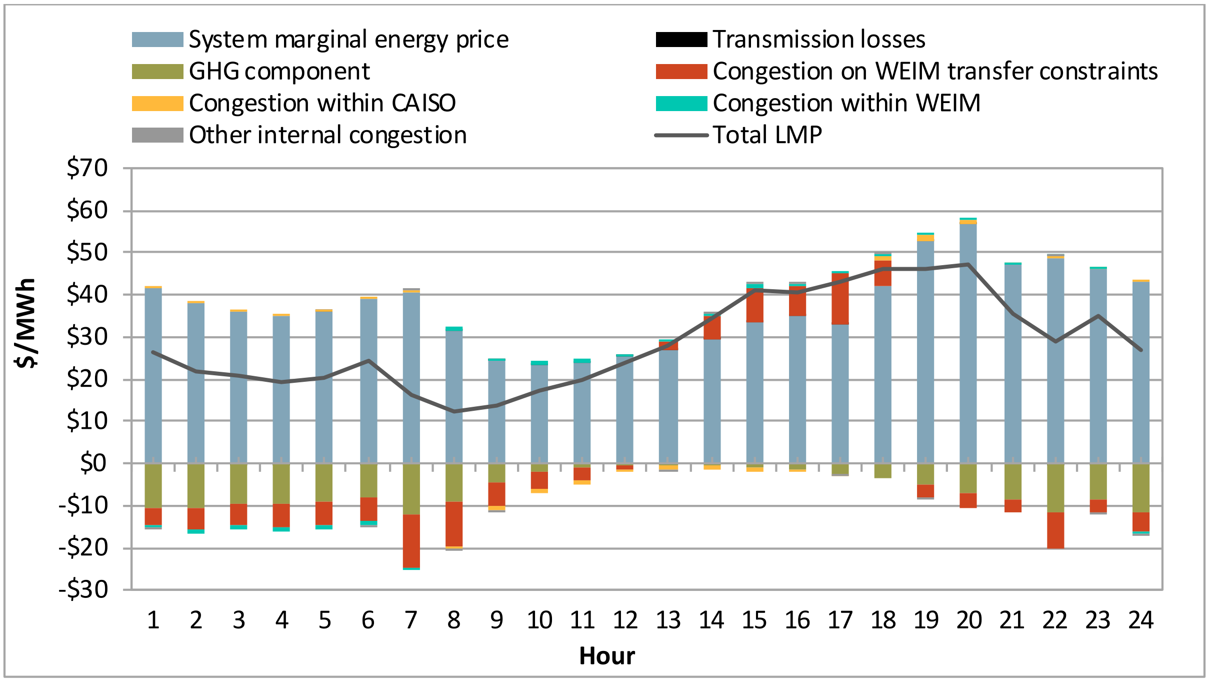
Appendix Figure A.29 Average hourly 15-minute price by component (Q3 2024)



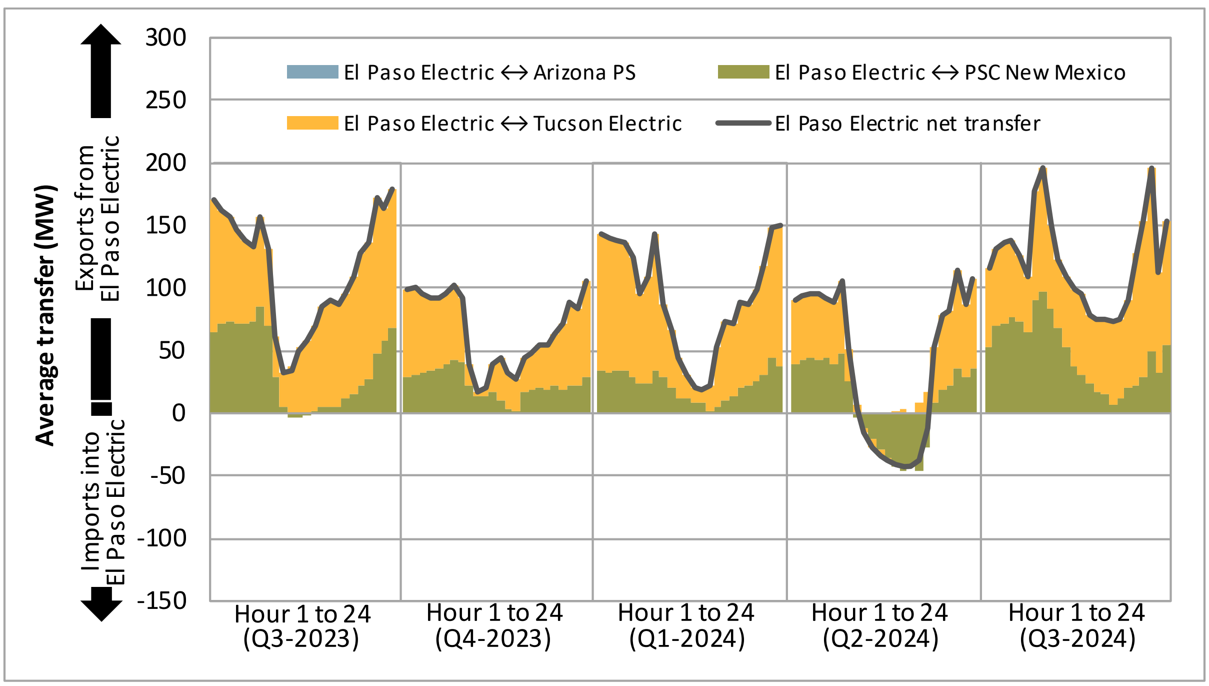
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q3 2024)

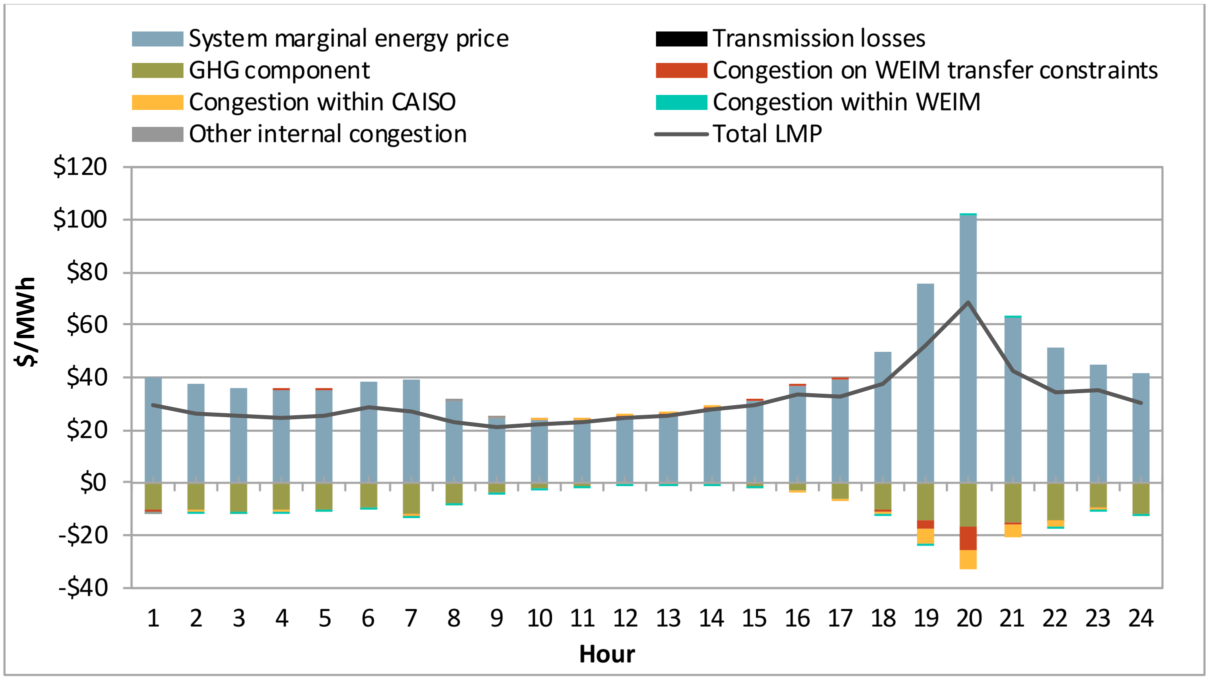


Appendix Figure A.32 Average hourly 5-minute market transfers

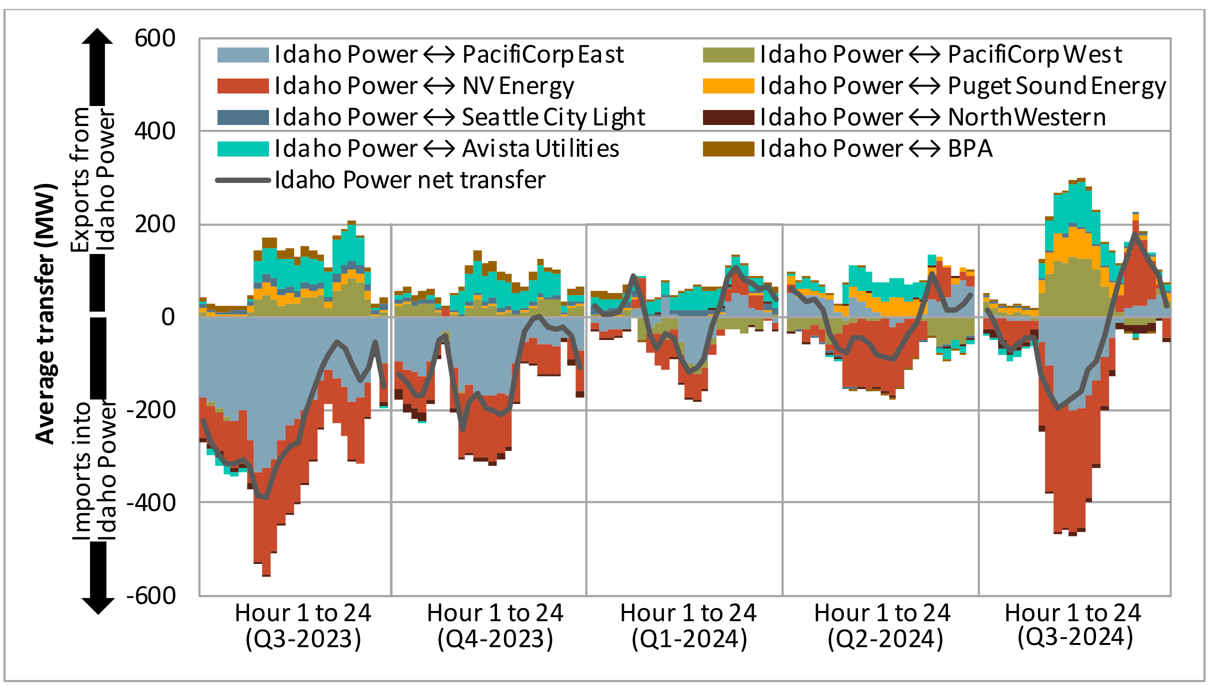


A.8 Idaho Power

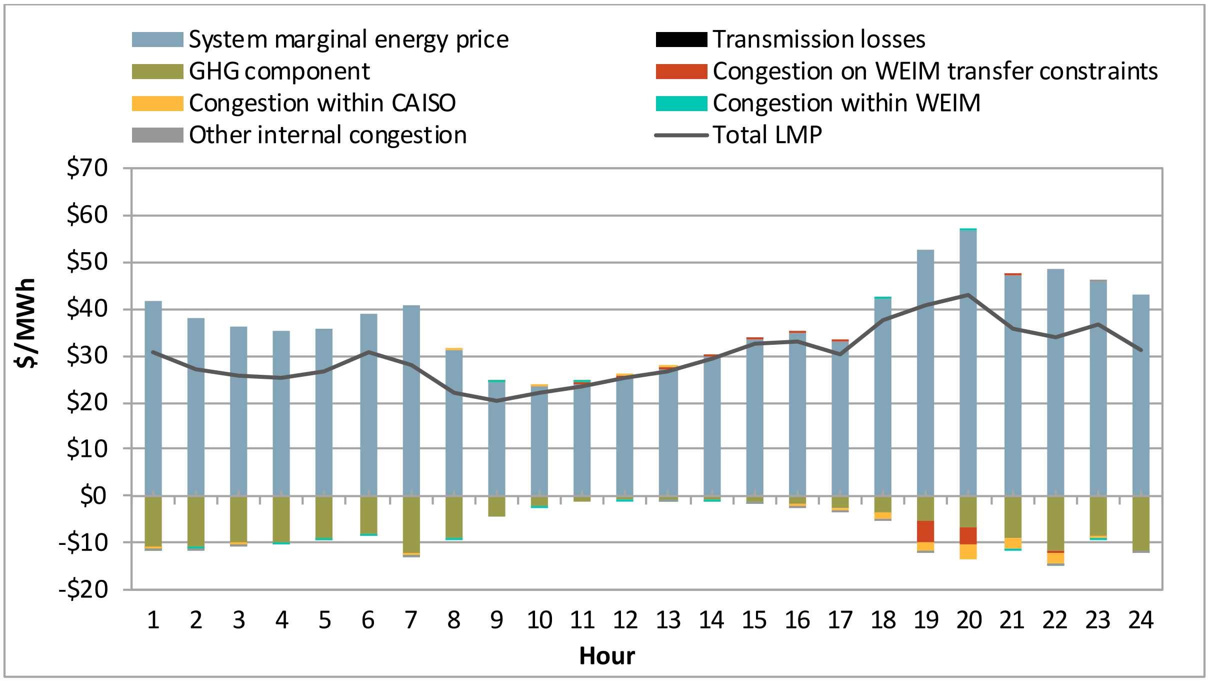
Appendix Figure A.33 Average hourly 15-minute price by component (Q3 2024)



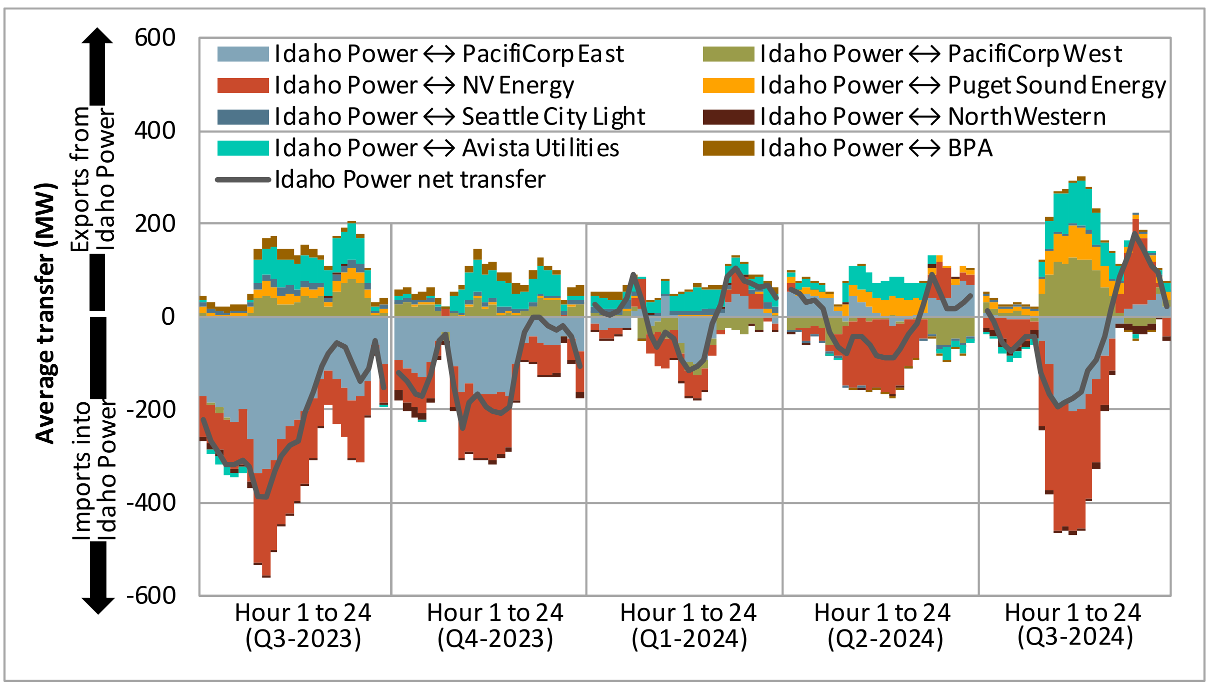
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q3 2024)

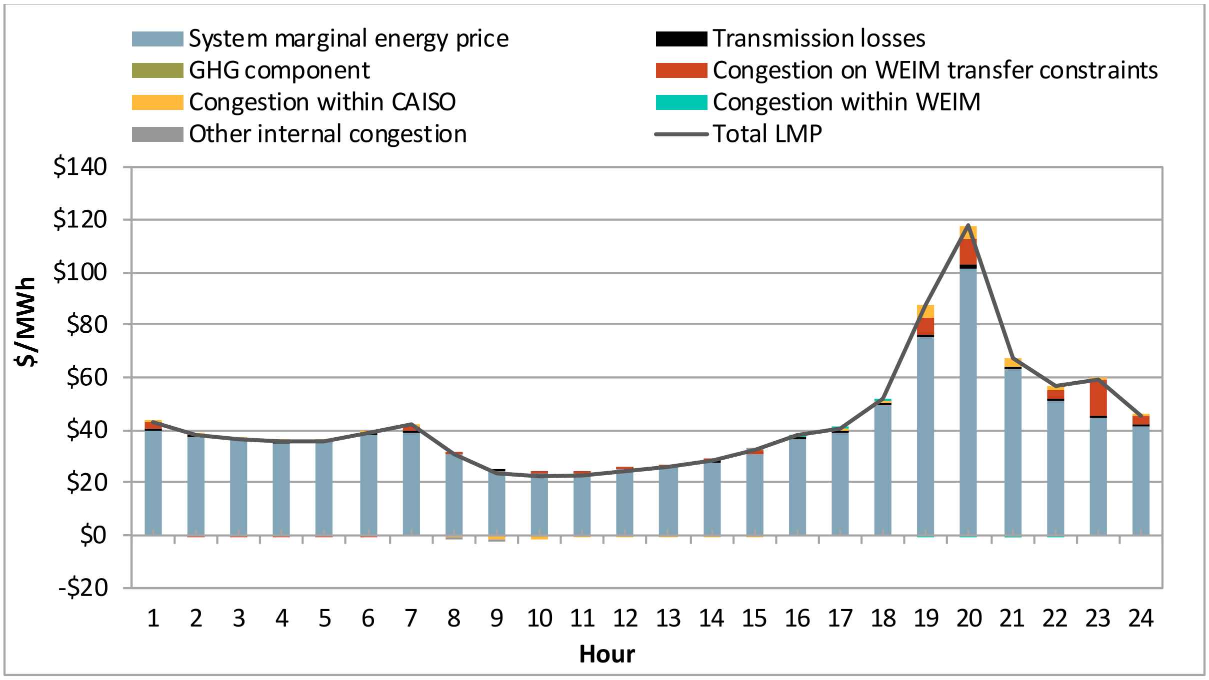


Appendix Figure A.36 Average hourly 5-minute market transfers

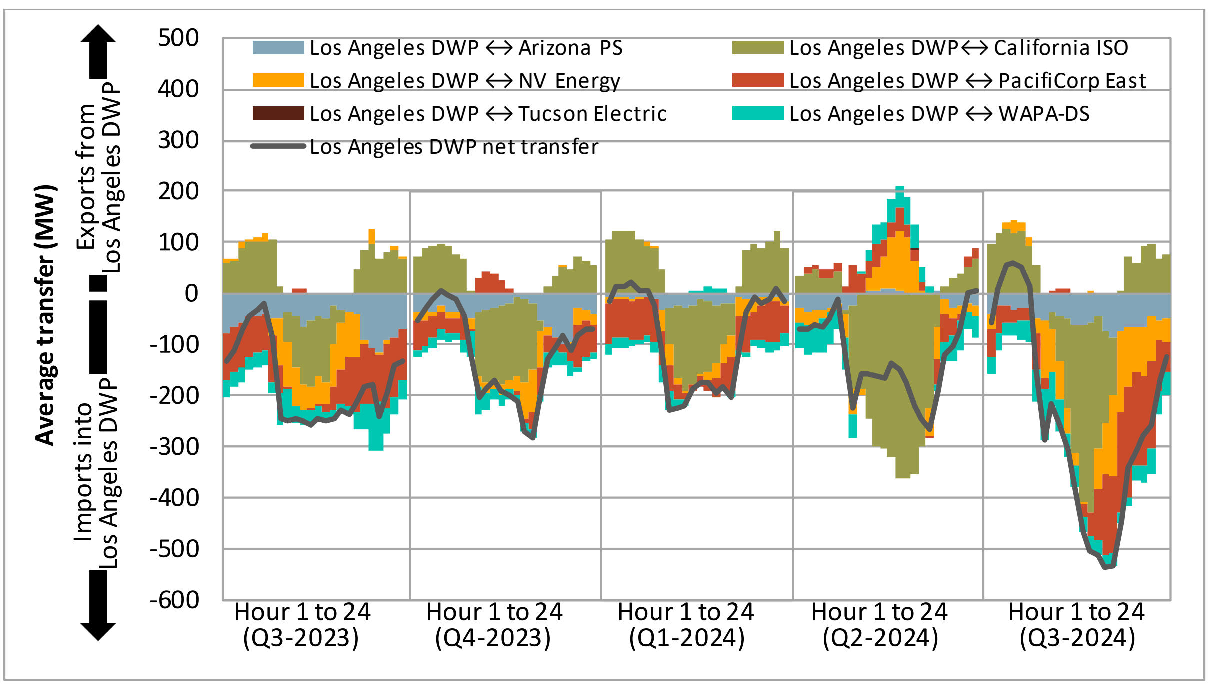


A.9 Los Angeles Department of Water and Power

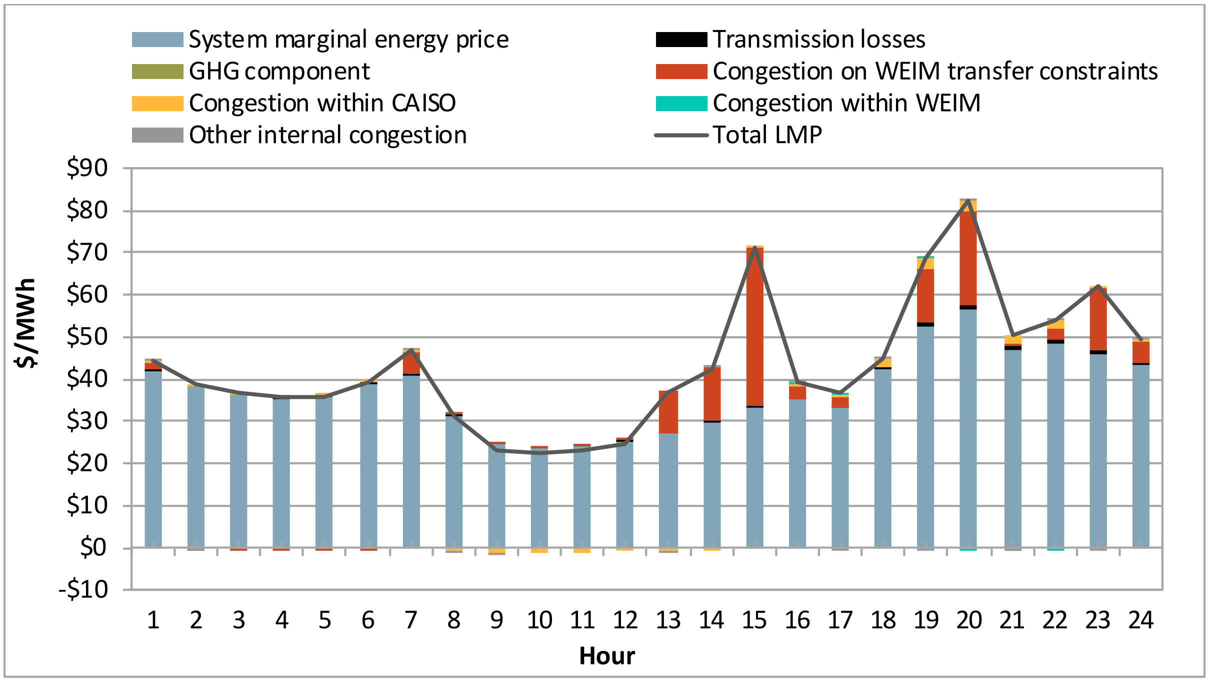
Appendix Figure A.37 Average hourly 15-minute price by component (Q3 2024)



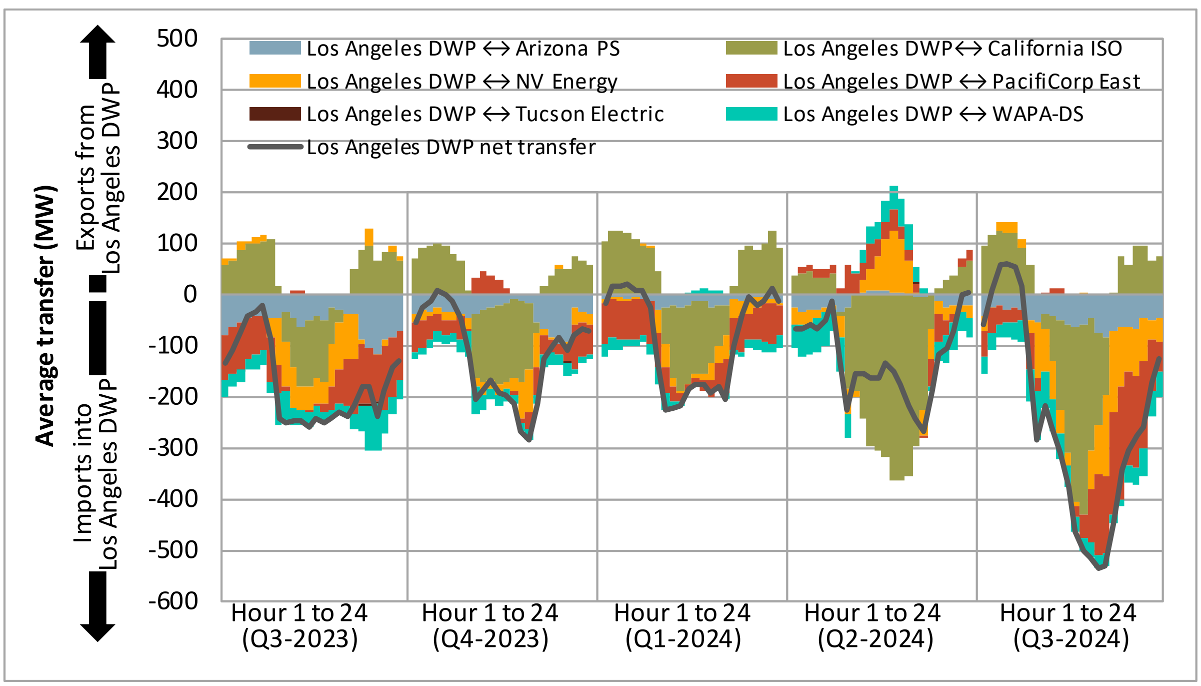
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q3 2024)

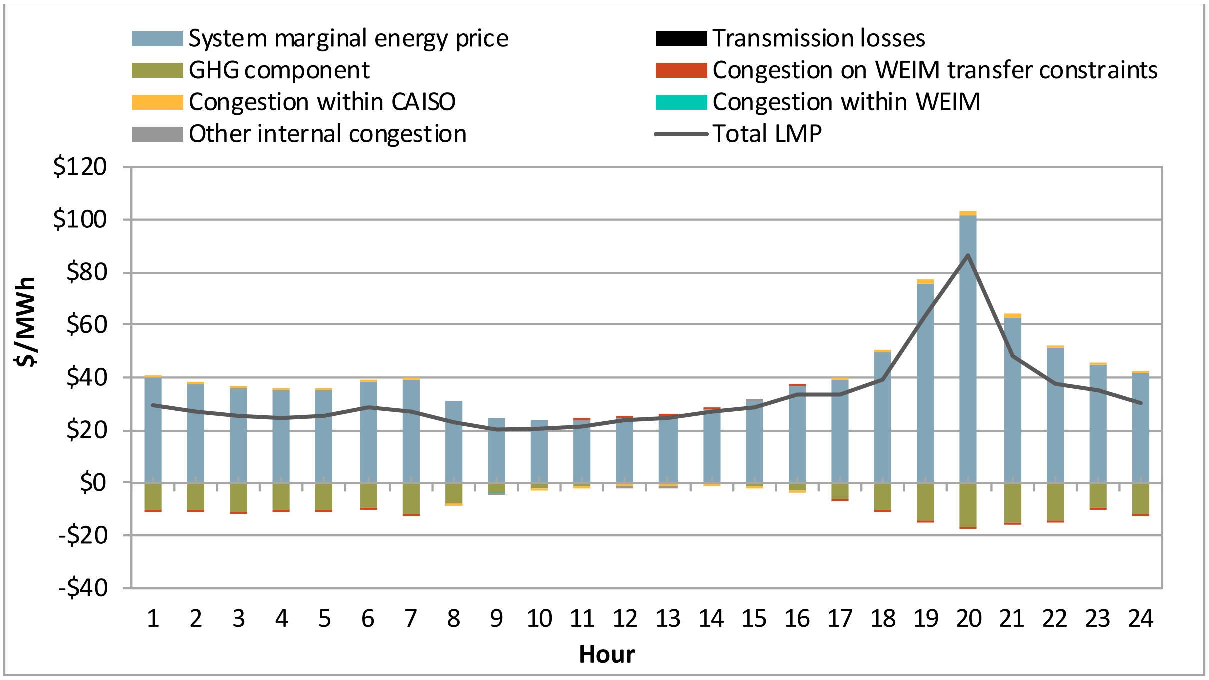


Appendix Figure A.40 Average hourly 5-minute market transfers

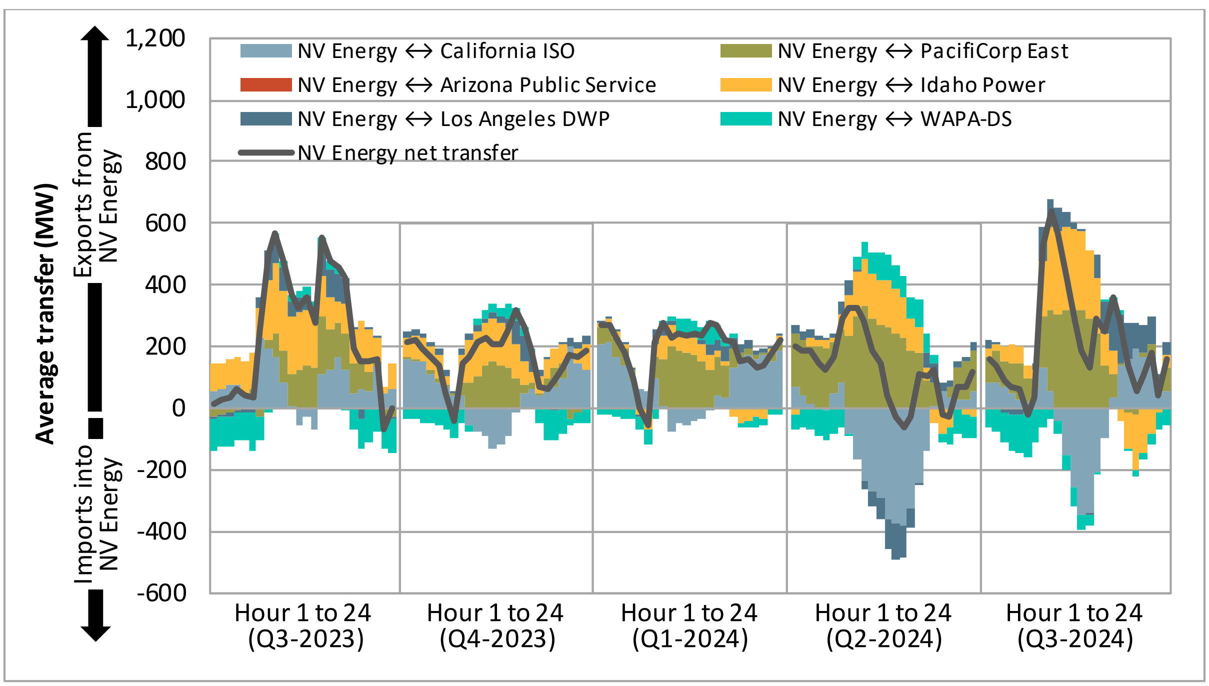


A.10 NV Energy

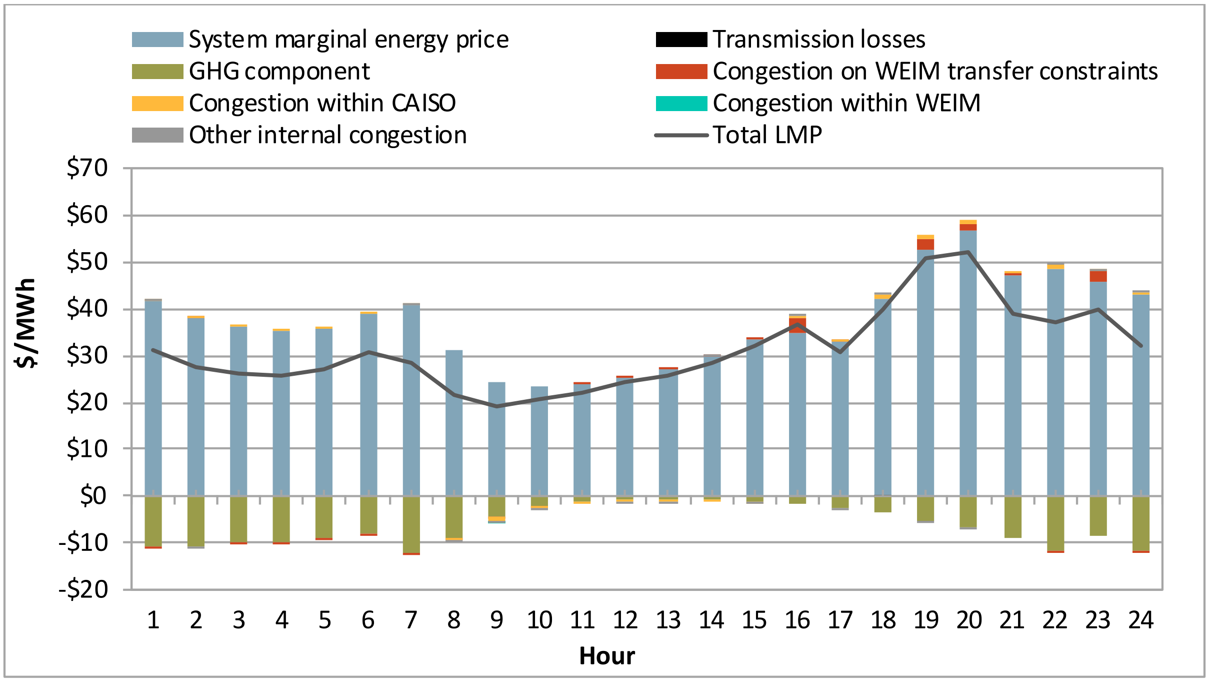
Appendix Figure A.41 Average hourly 15-minute price by component (Q3 2024)



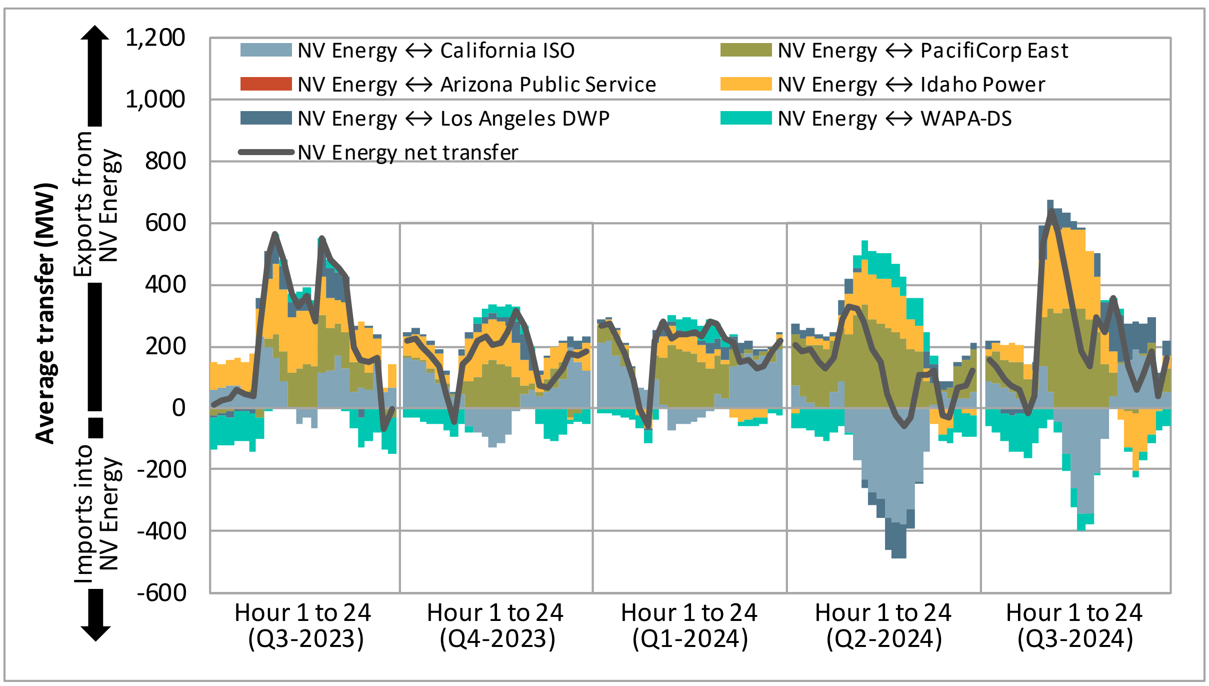
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q3 2024)

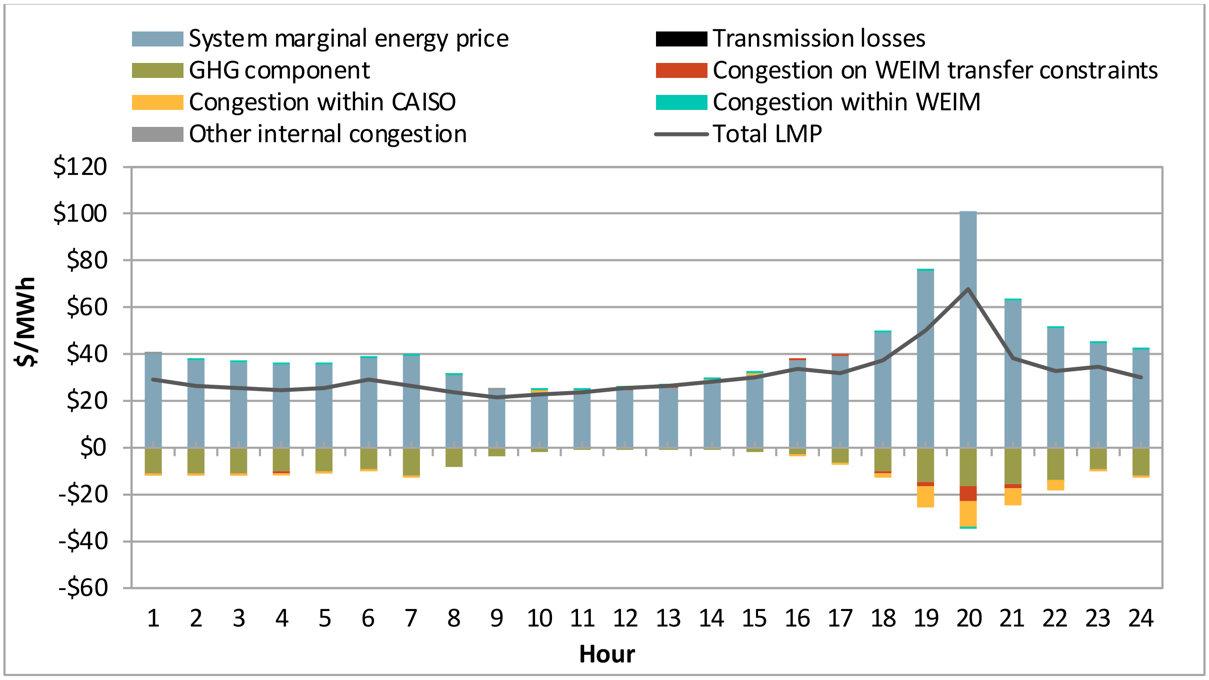


Appendix Figure A.44 Average hourly 5-minute market transfers

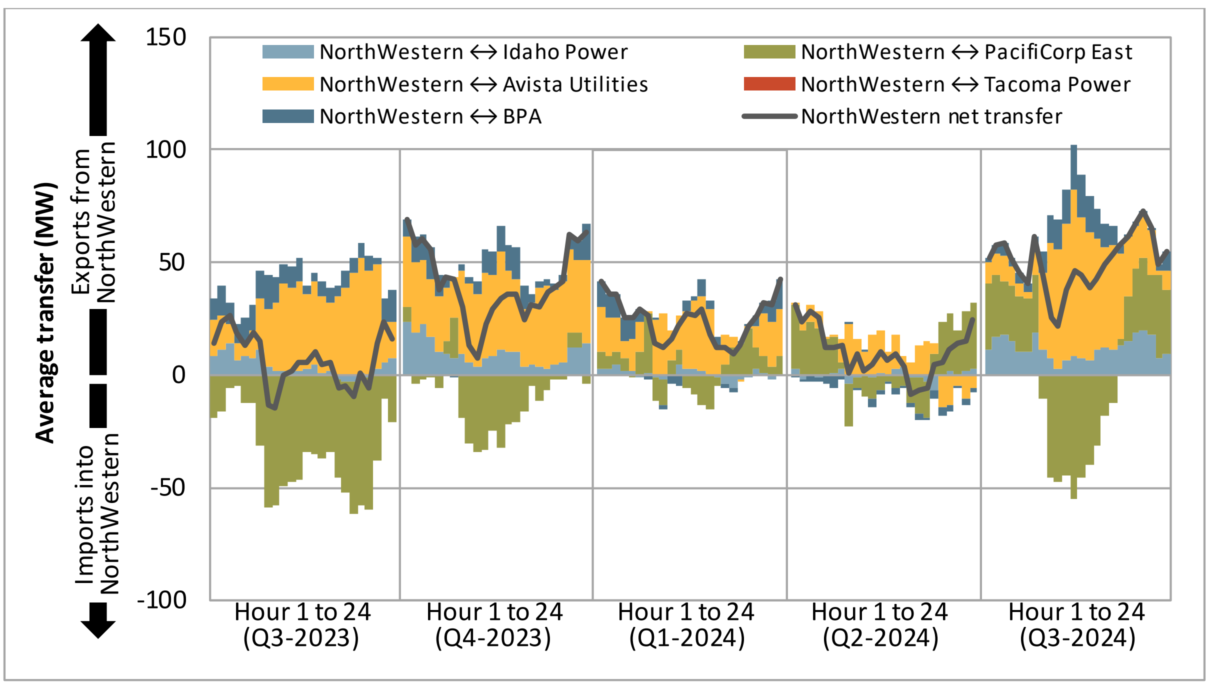


A.11 NorthWestern Energy

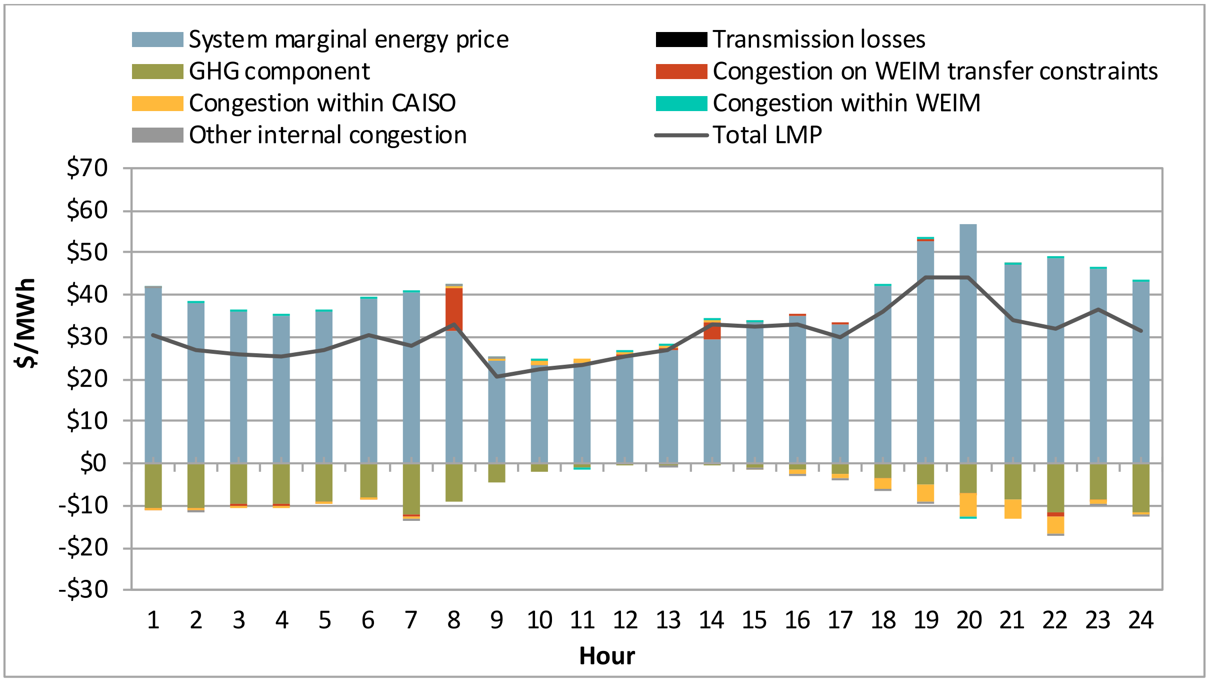
Appendix Figure A.45 Average hourly 15-minute price by component (Q3 2024)



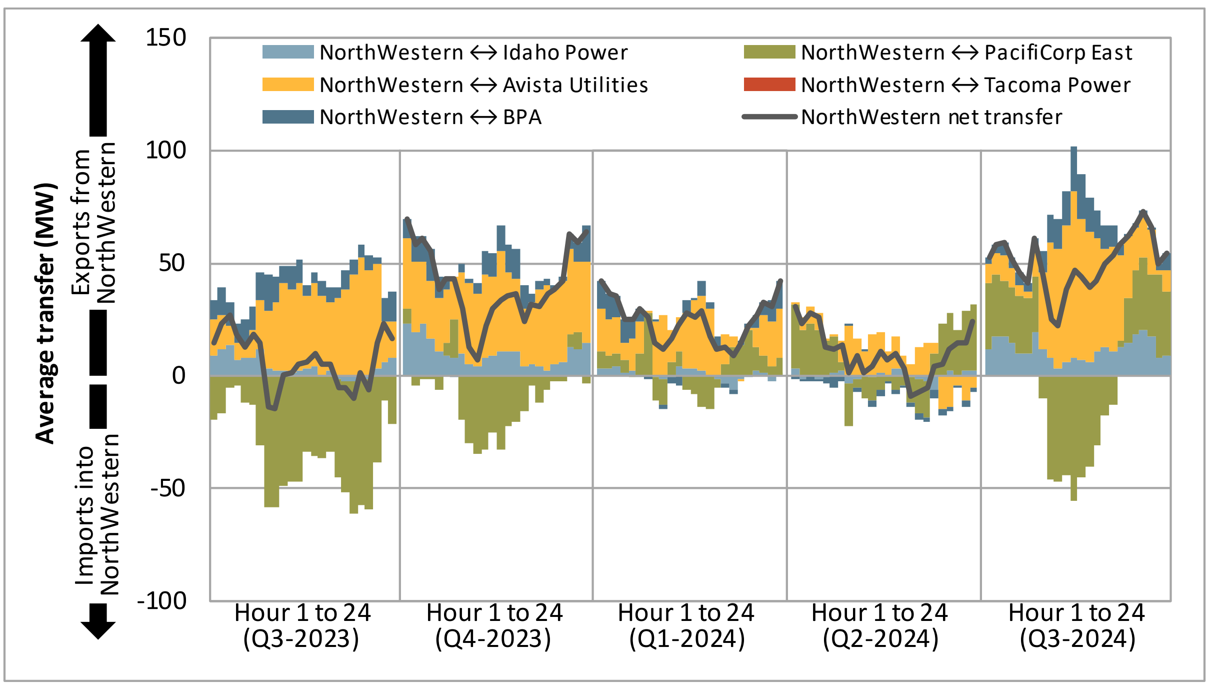
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q3 2024)

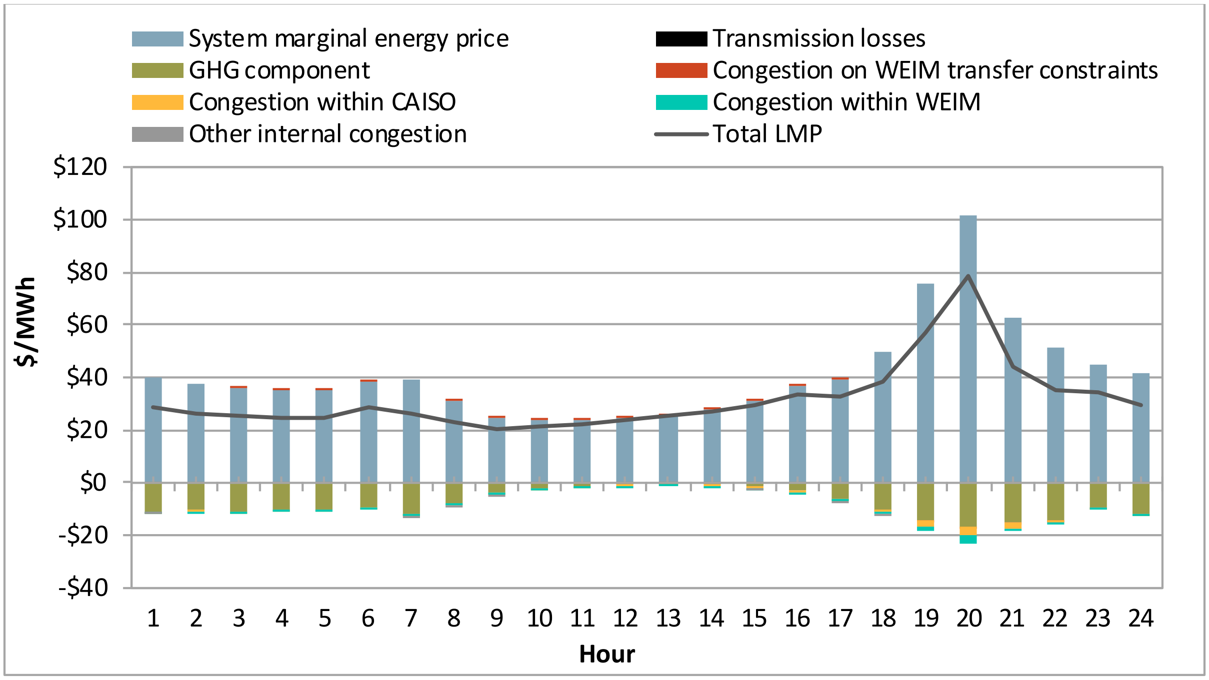


Appendix Figure A.48 Average hourly 5-minute market transfers

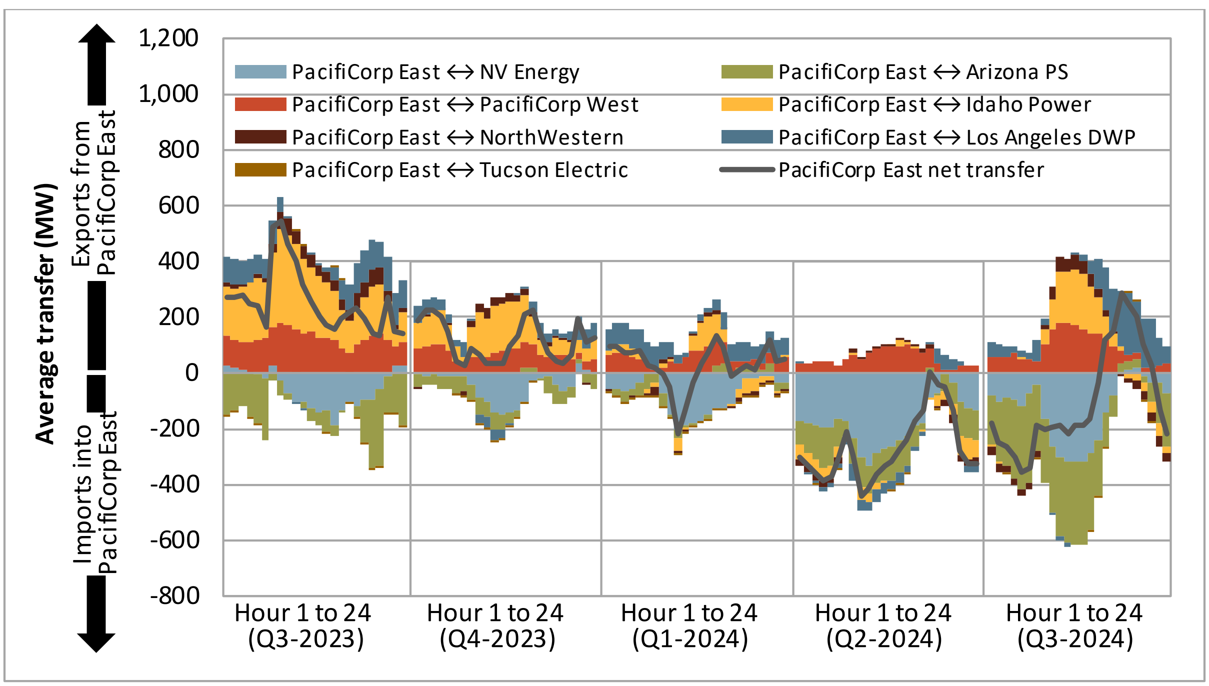


A.12 PacifiCorp East

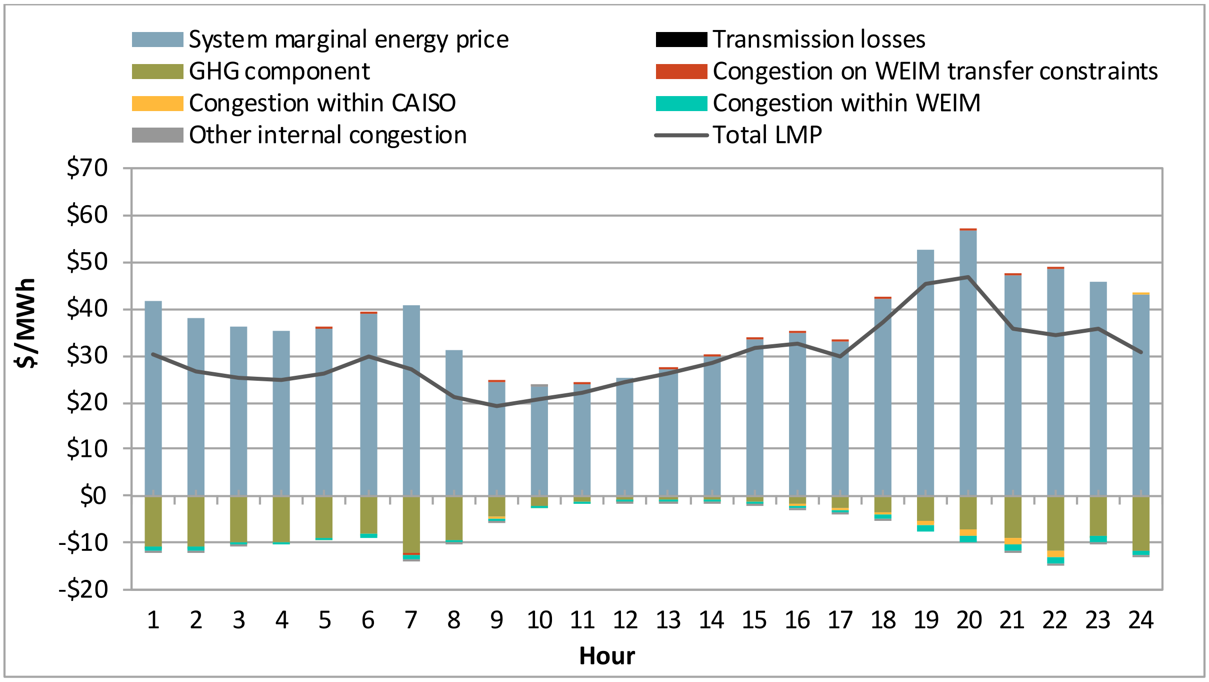
Appendix Figure A.49 Average hourly 15-minute price by component (Q3 2024)



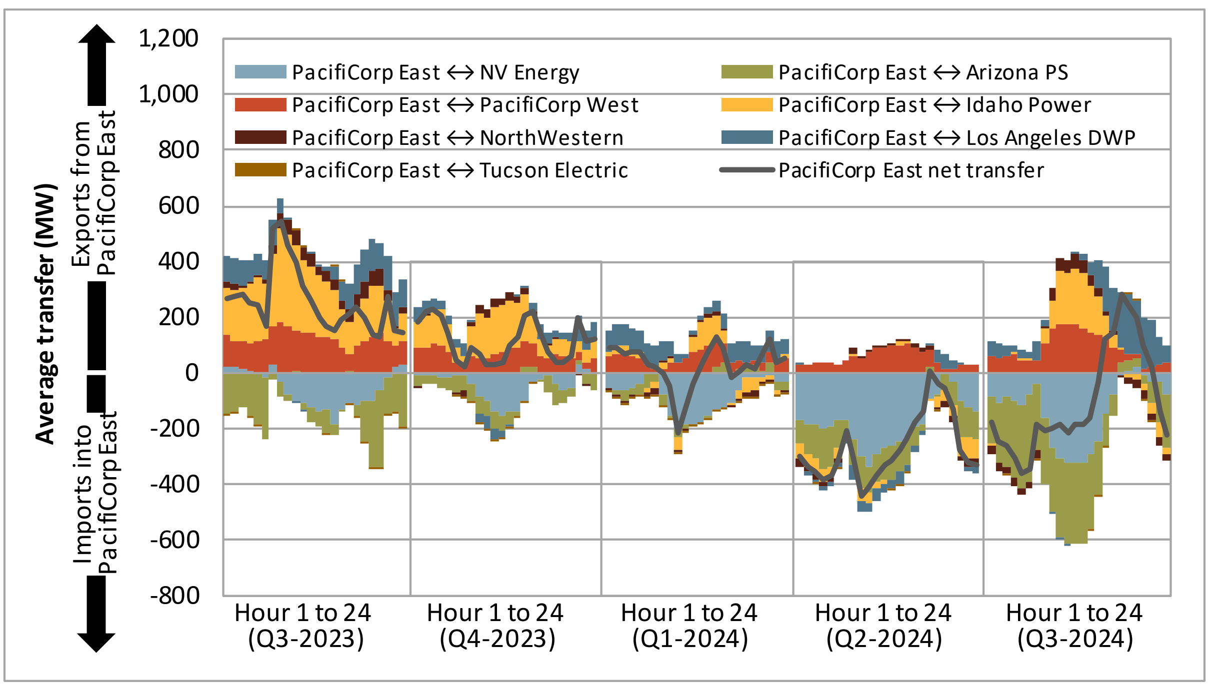
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q3 2024)

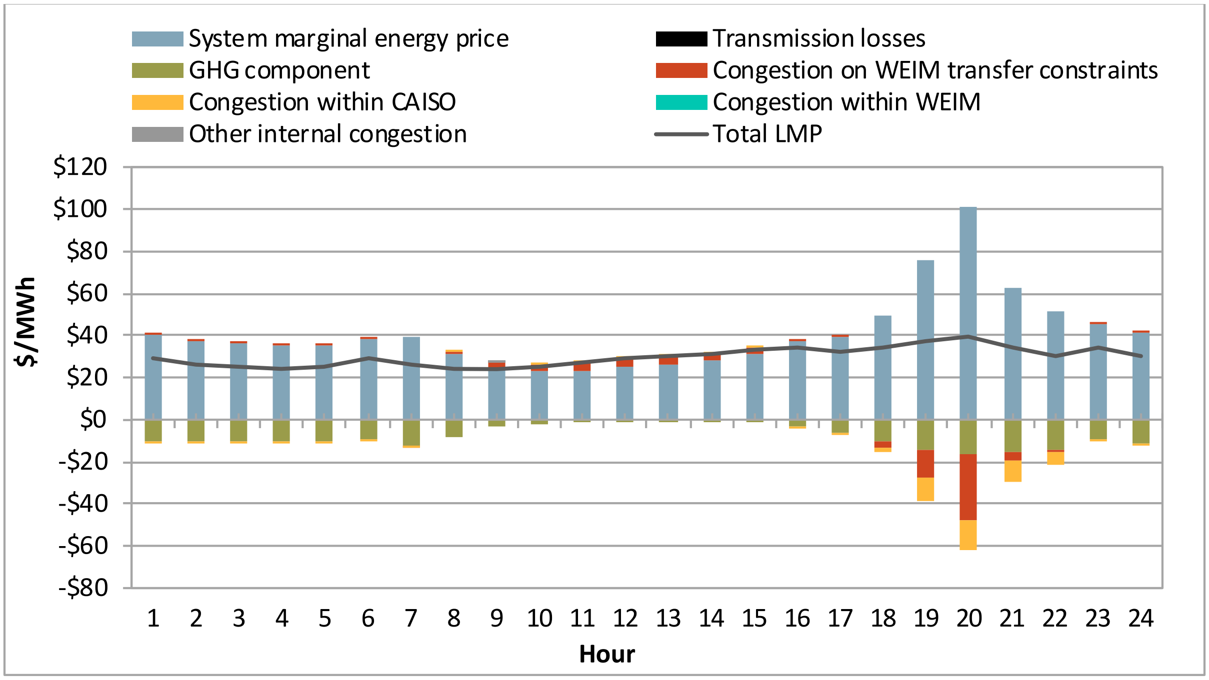


Appendix Figure A.52 Average hourly 5-minute market transfers

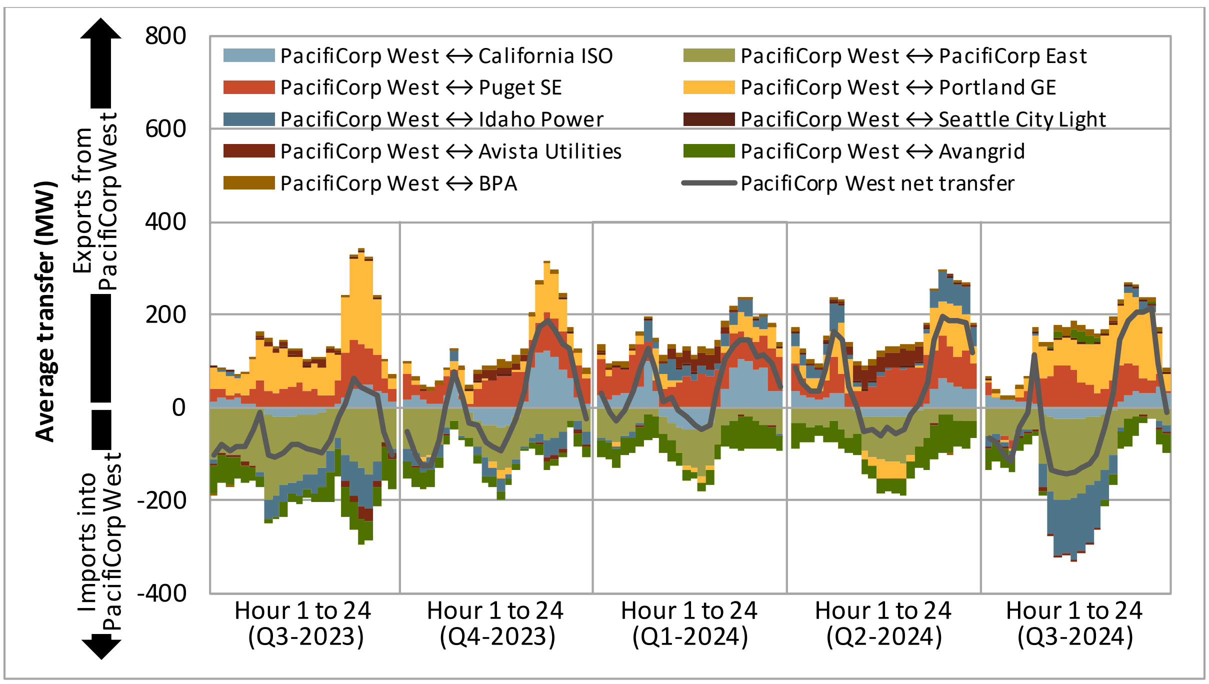


A.13 PacifiCorp West

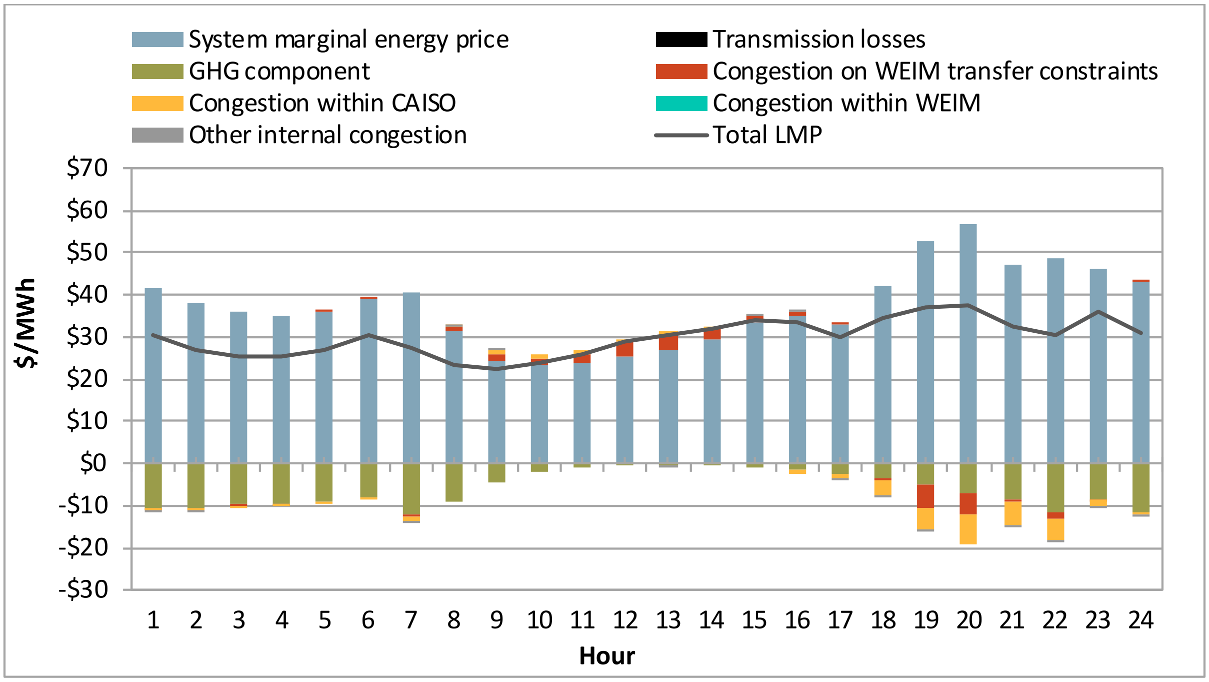
Appendix Figure A.53 Average hourly 15-minute price by component (Q3 2024)



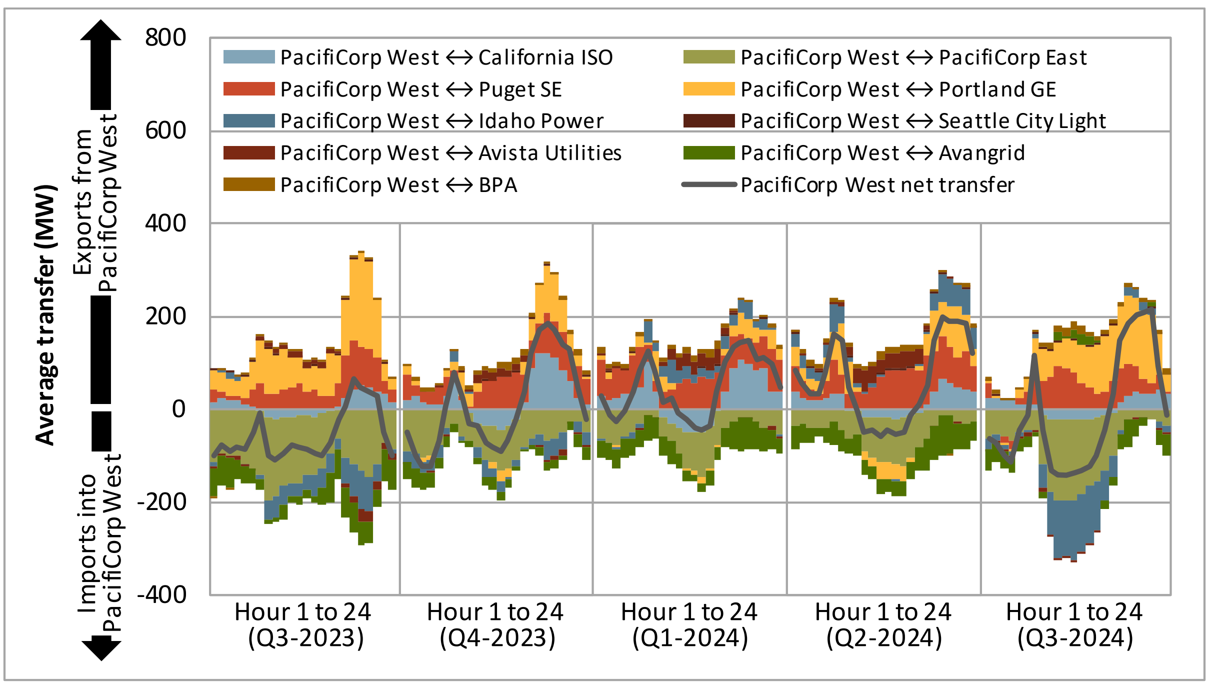
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q3 2024)

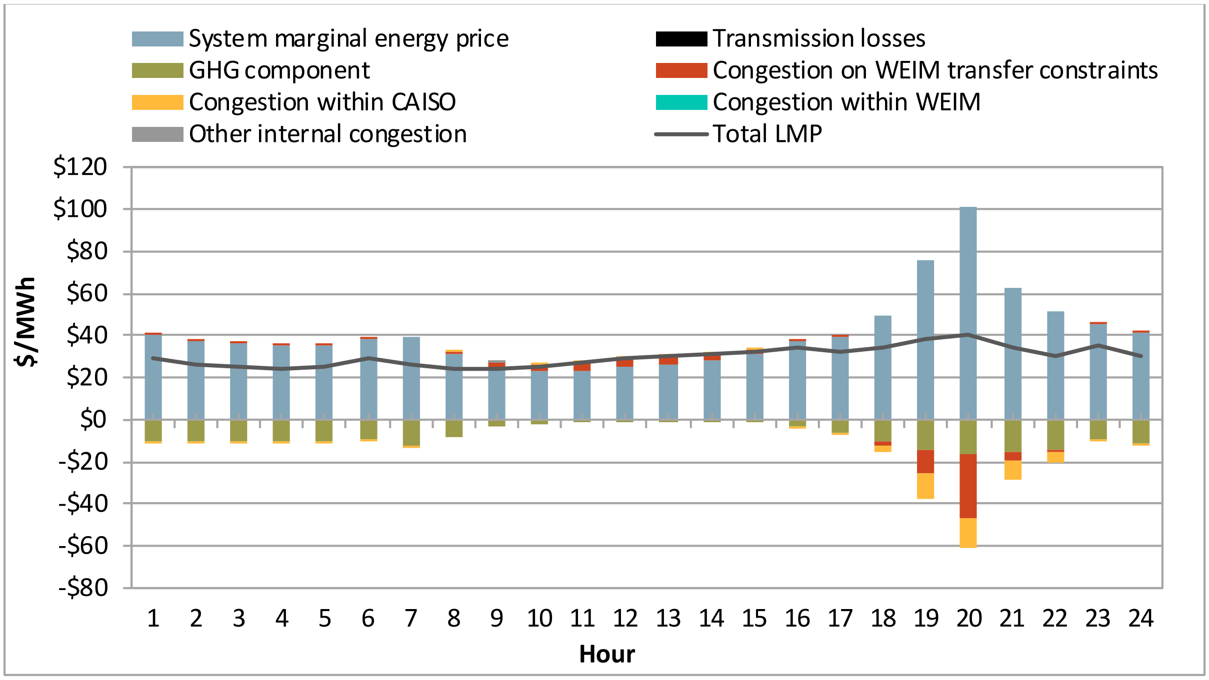


Appendix Figure A.56 Average hourly 5-minute market transfers

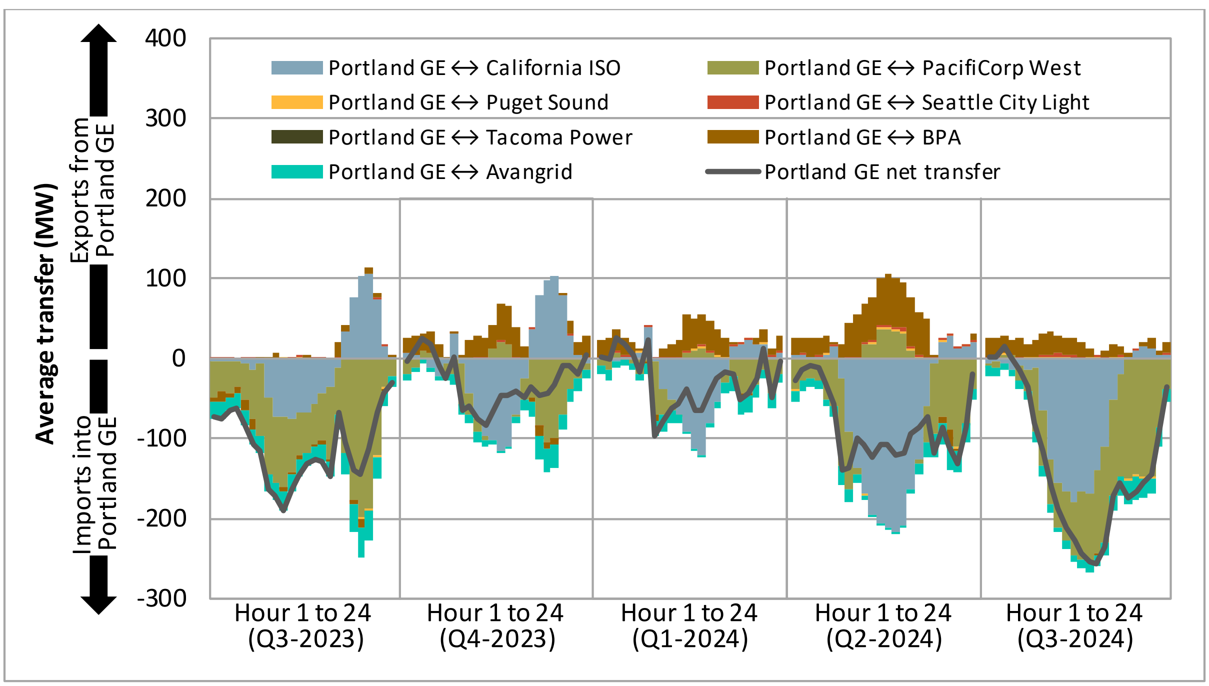


A.14 Portland General Electric

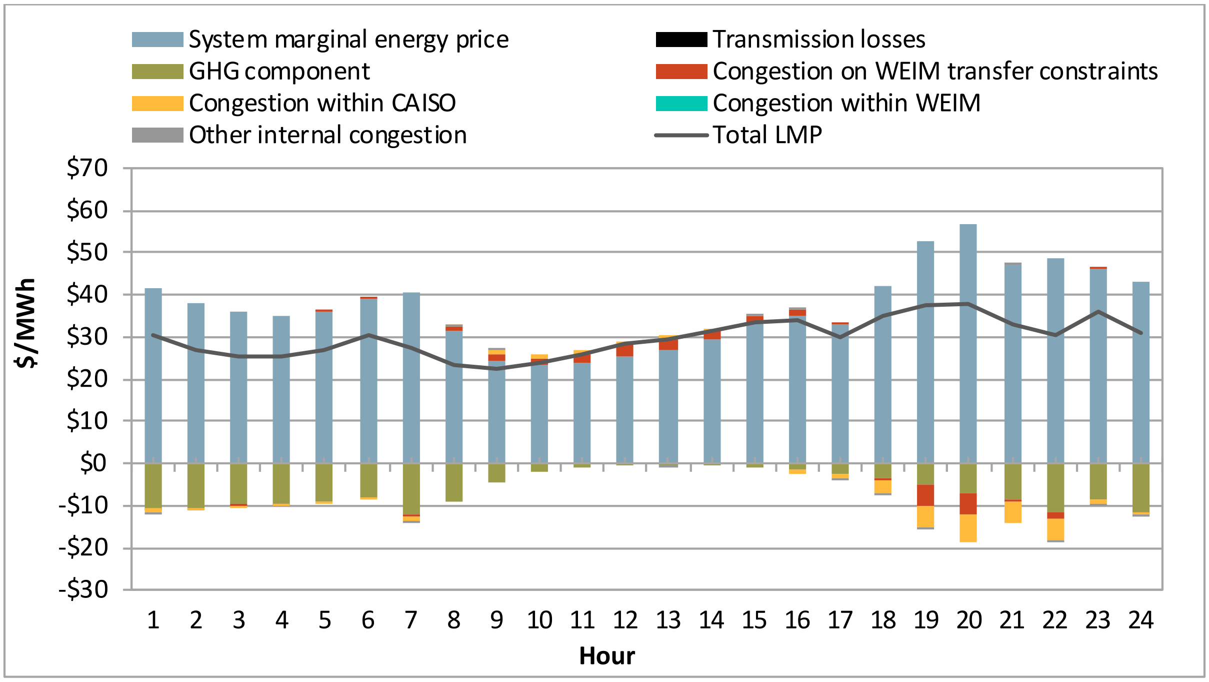
Appendix Figure A.57 Average hourly 15-minute price by component (Q3 2024)



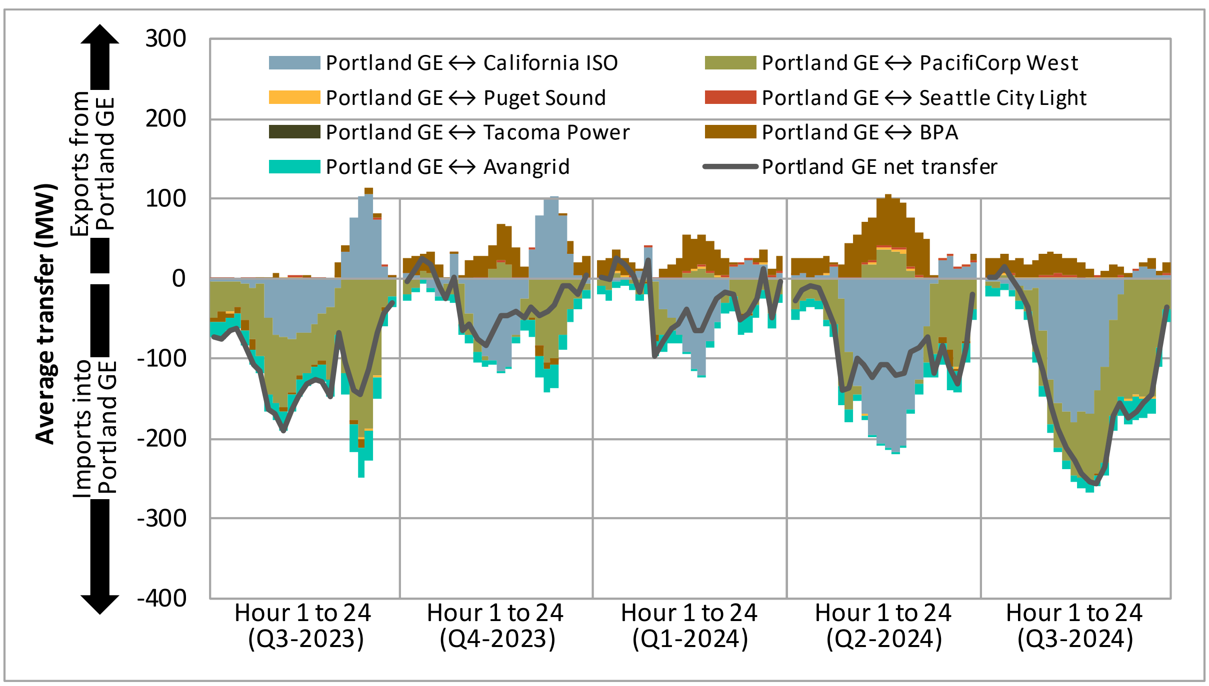
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q3 2024)

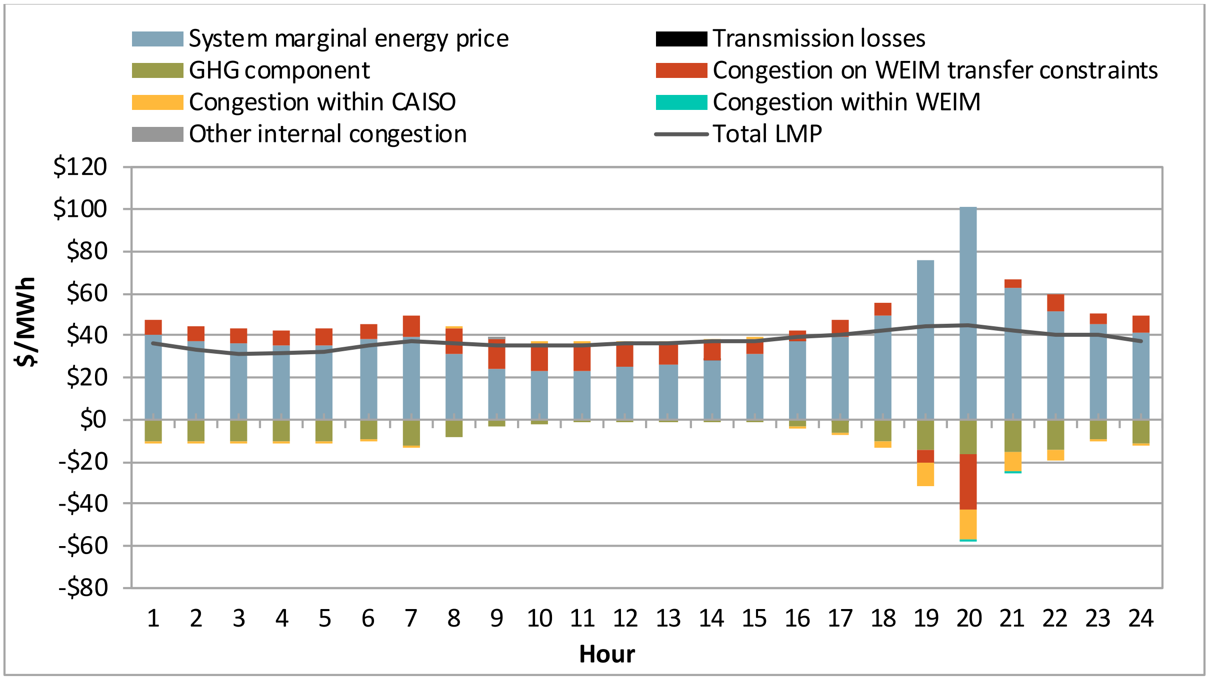


Appendix Figure A.60 Average hourly 5-minute market transfers

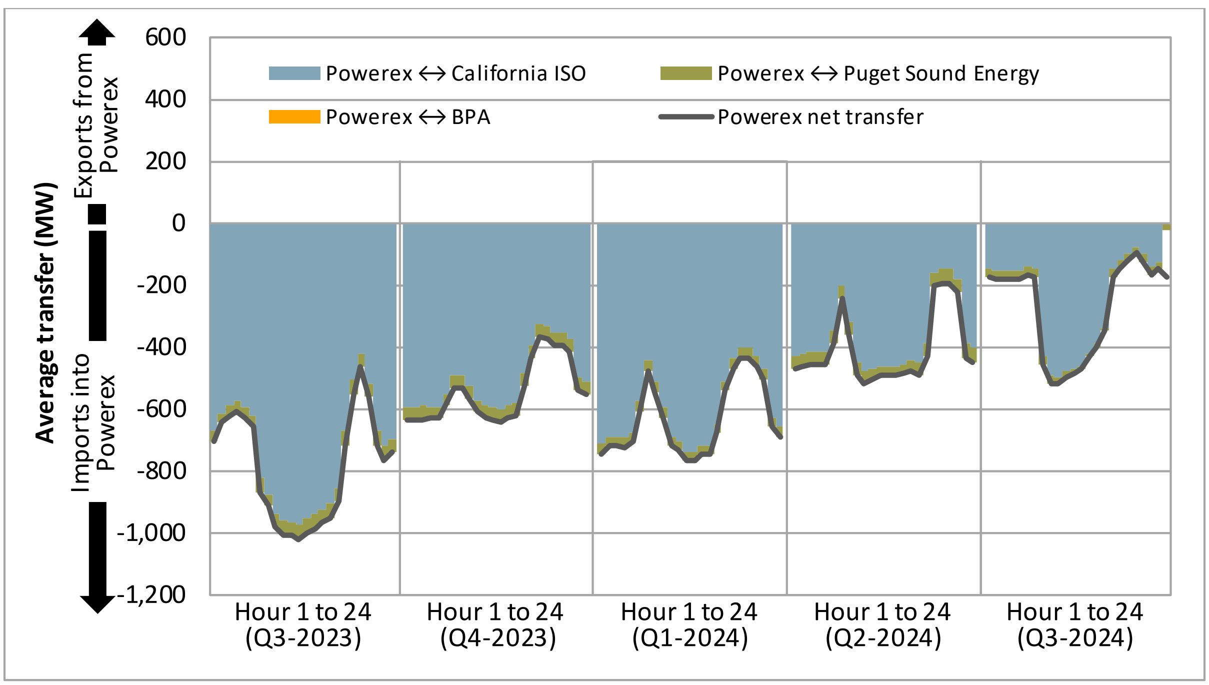


A.15 Powerex

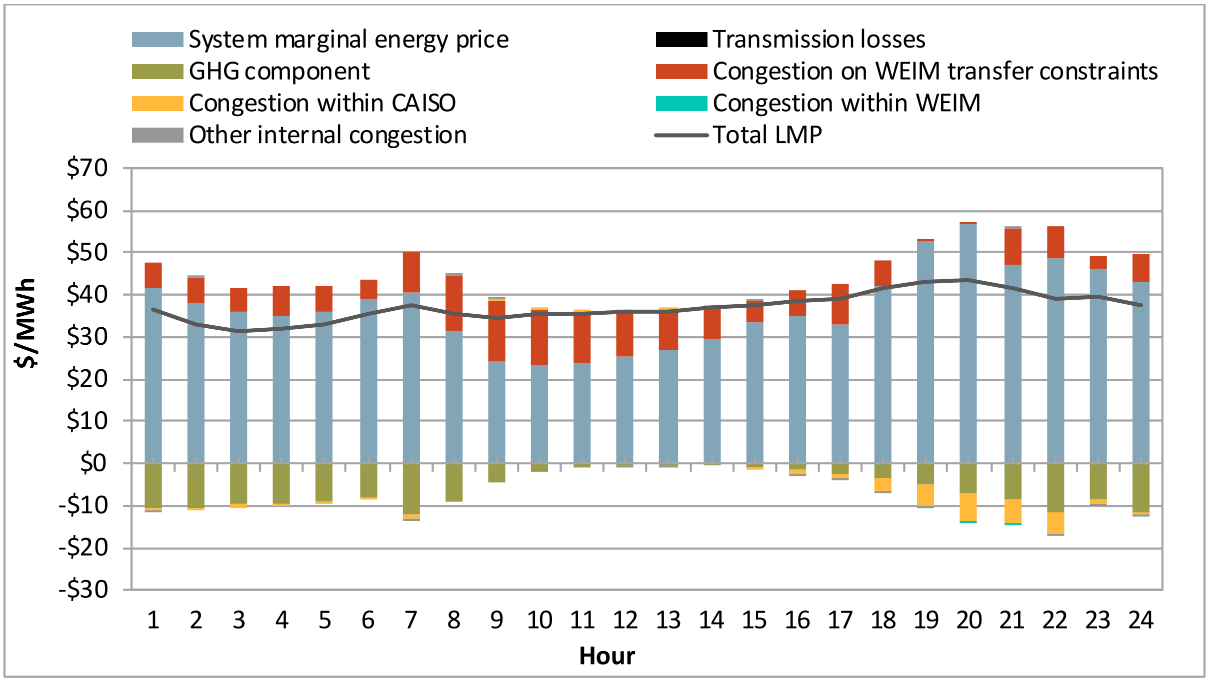
Appendix Figure A.61 Average hourly 15-minute price by component (Q3 2024)



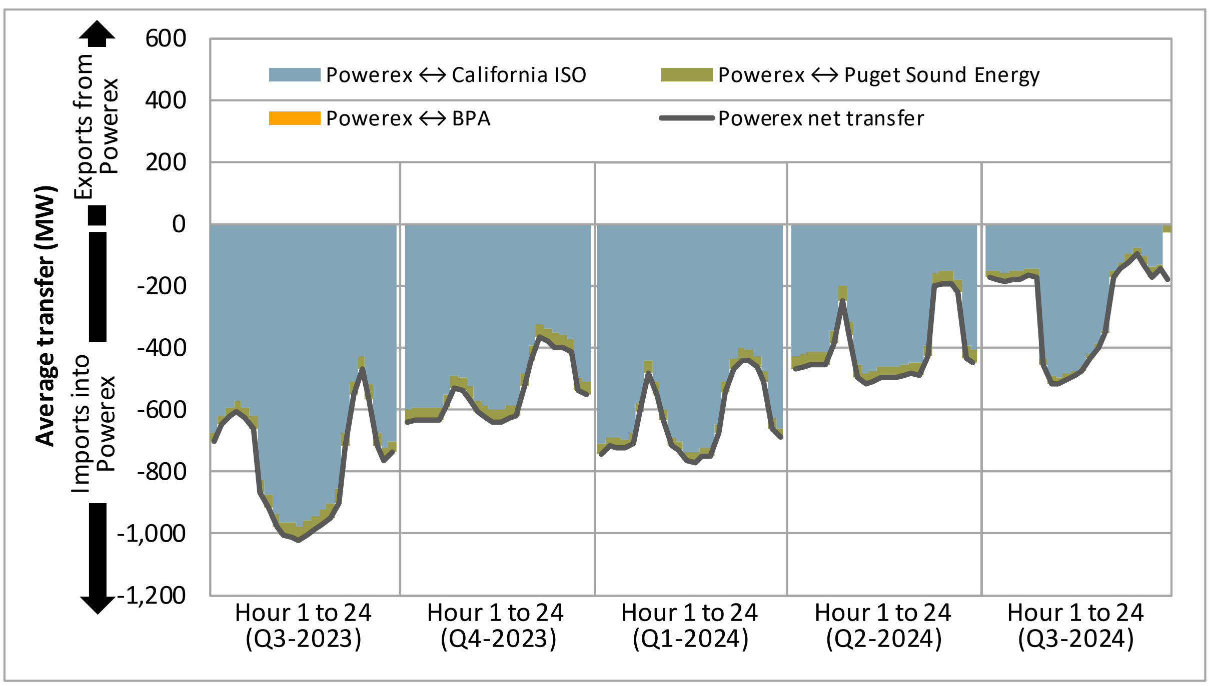
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q3 2024)

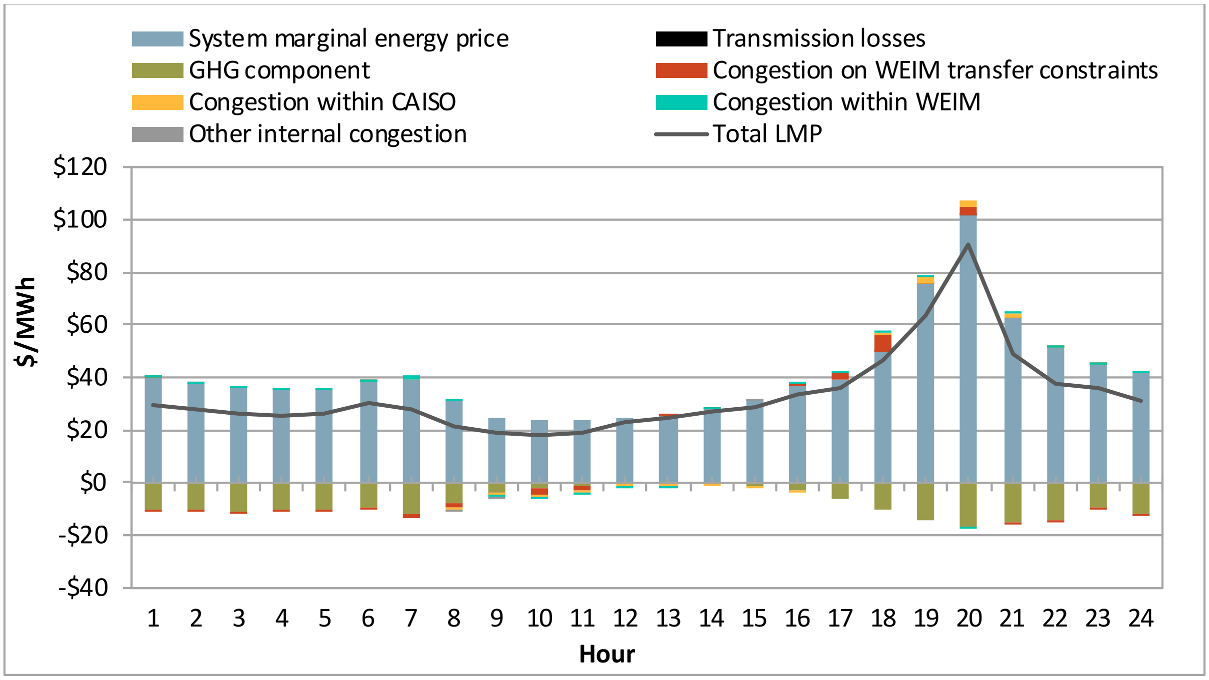


Appendix Figure A.64 Average hourly 5-minute market transfers

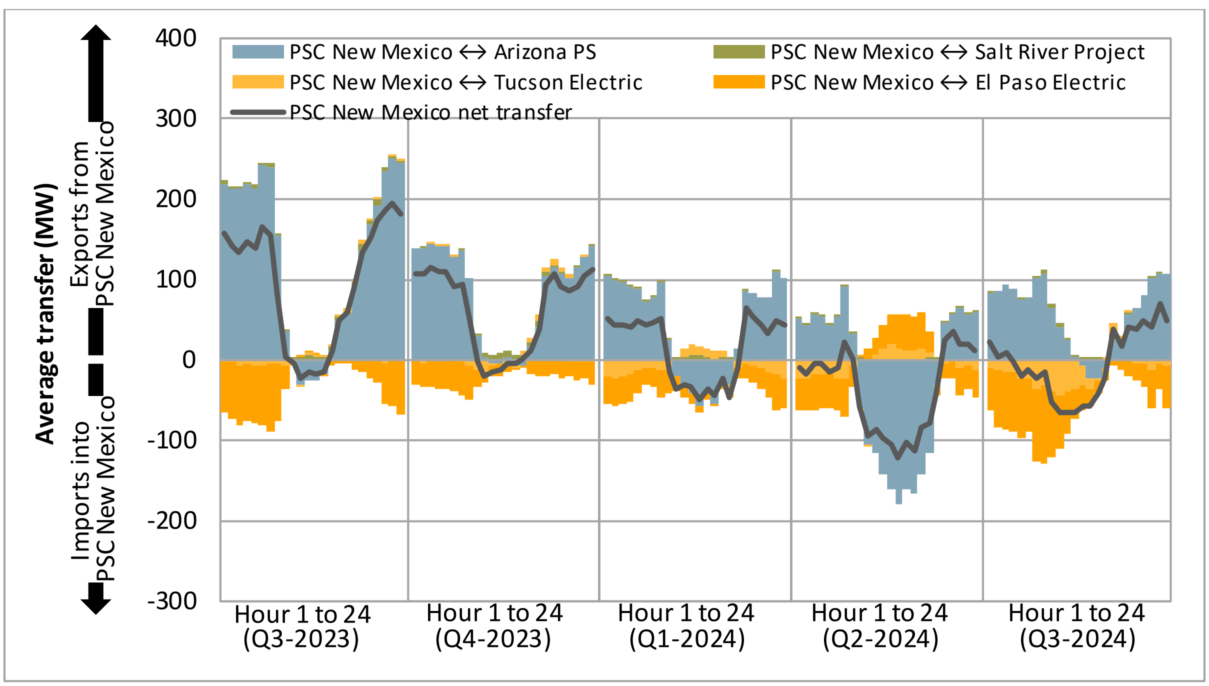


A.16 Public Service Company of New Mexico

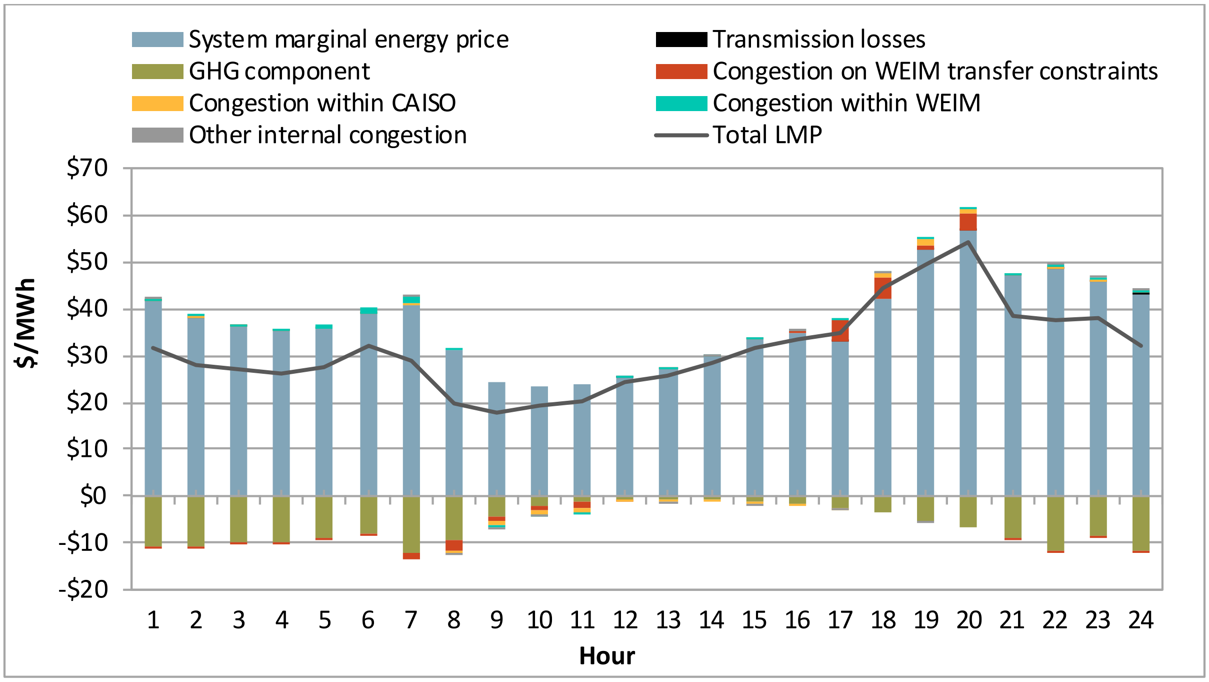
Appendix Figure A.65 Average hourly 15-minute price by component (Q3 2024)



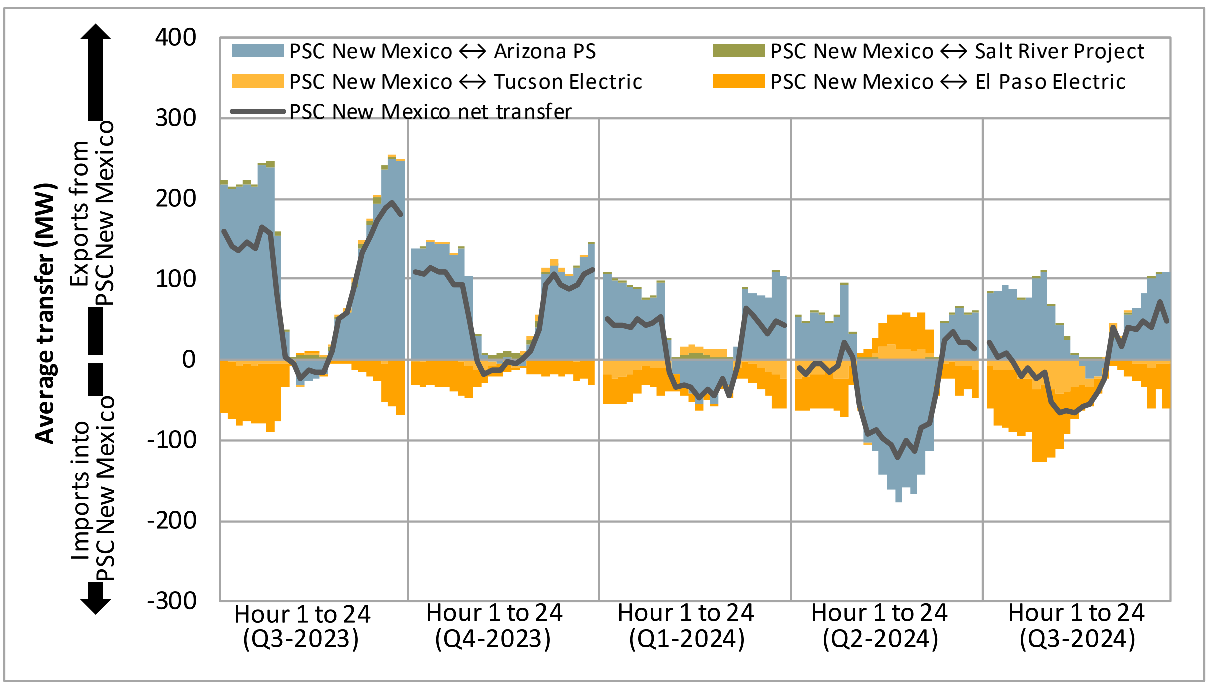
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q3 2024)

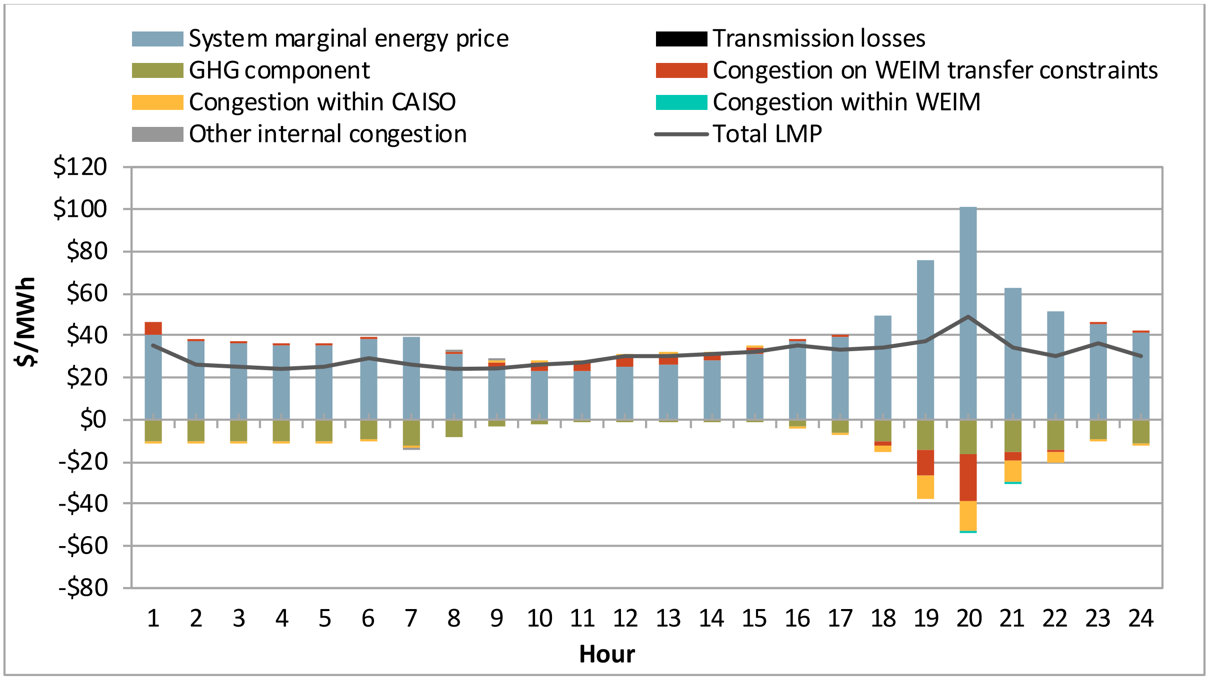


Appendix Figure A.68 Average hourly 5-minute market transfers

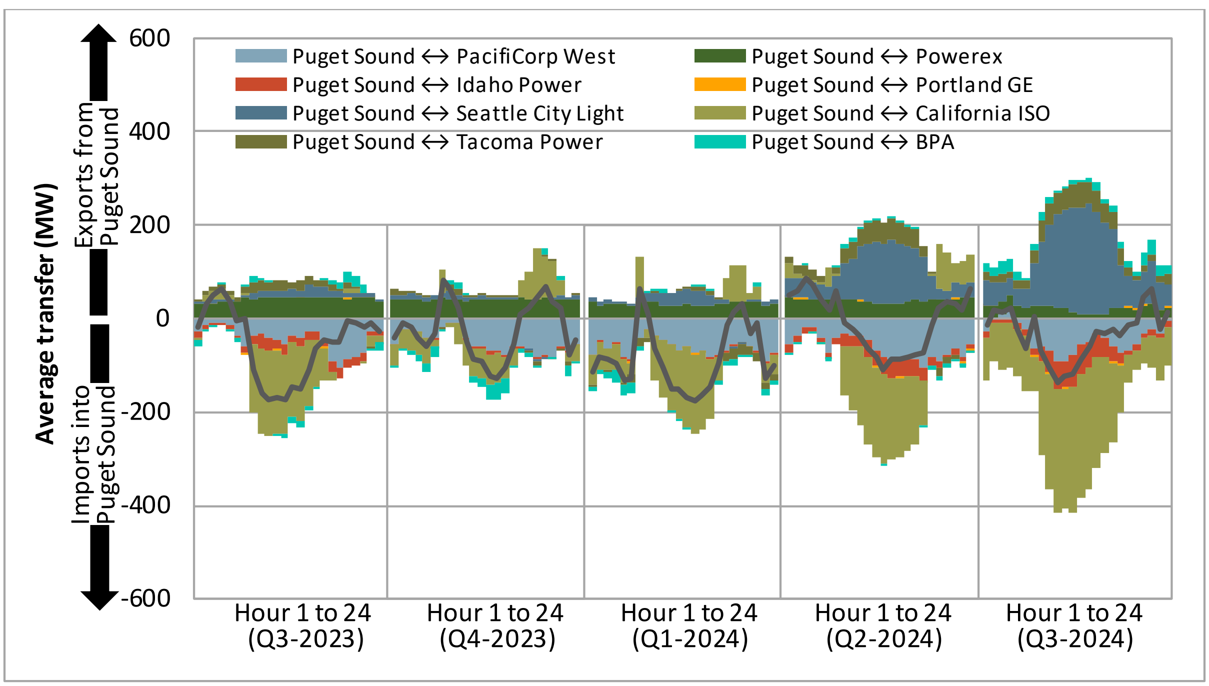


A.17 Puget Sound Energy

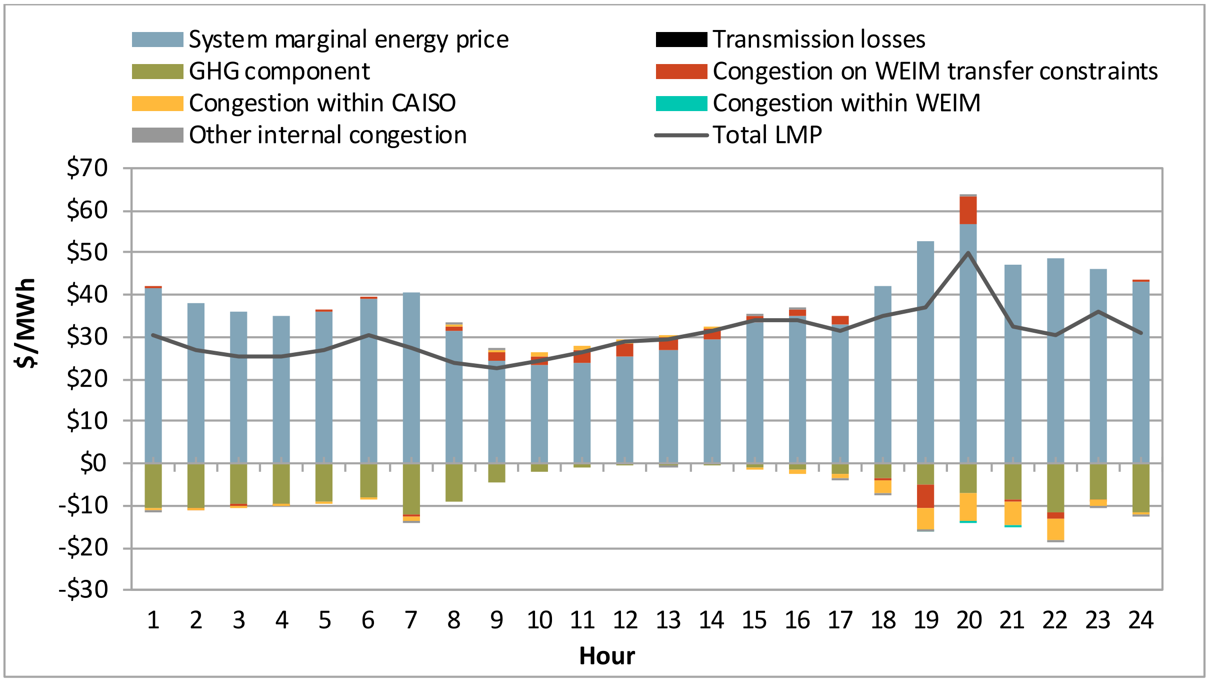
Appendix Figure A.69 Average hourly 15-minute price by component (Q3 2024)



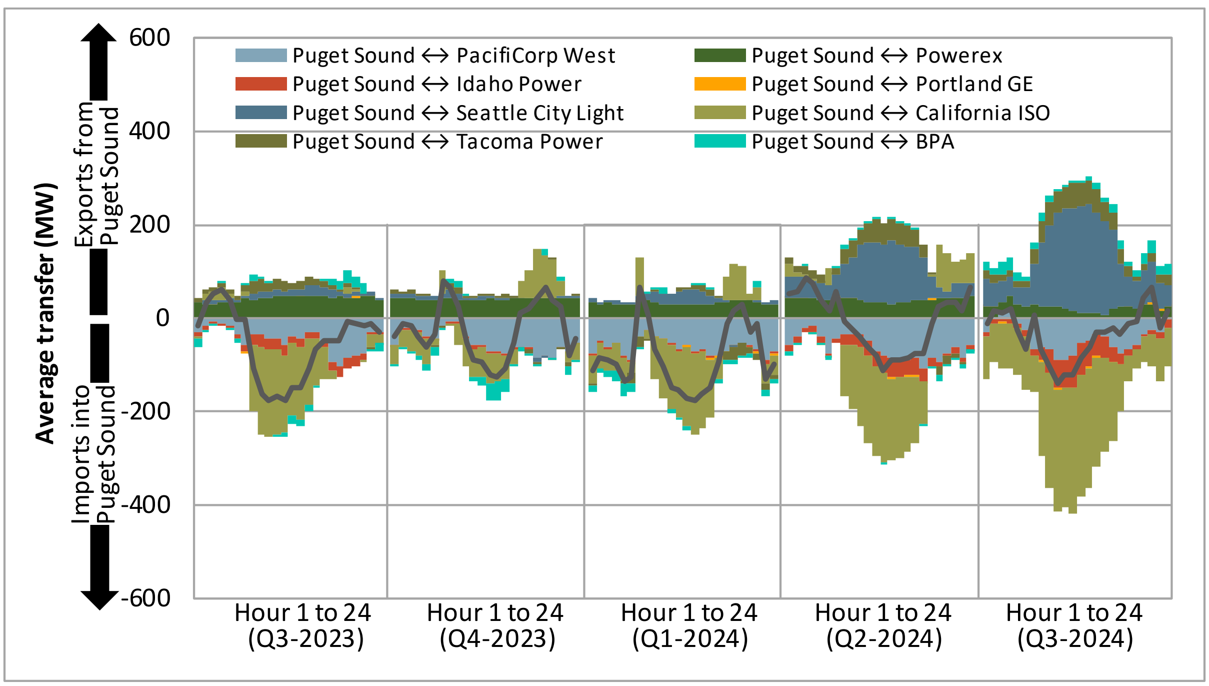
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q3 2024)

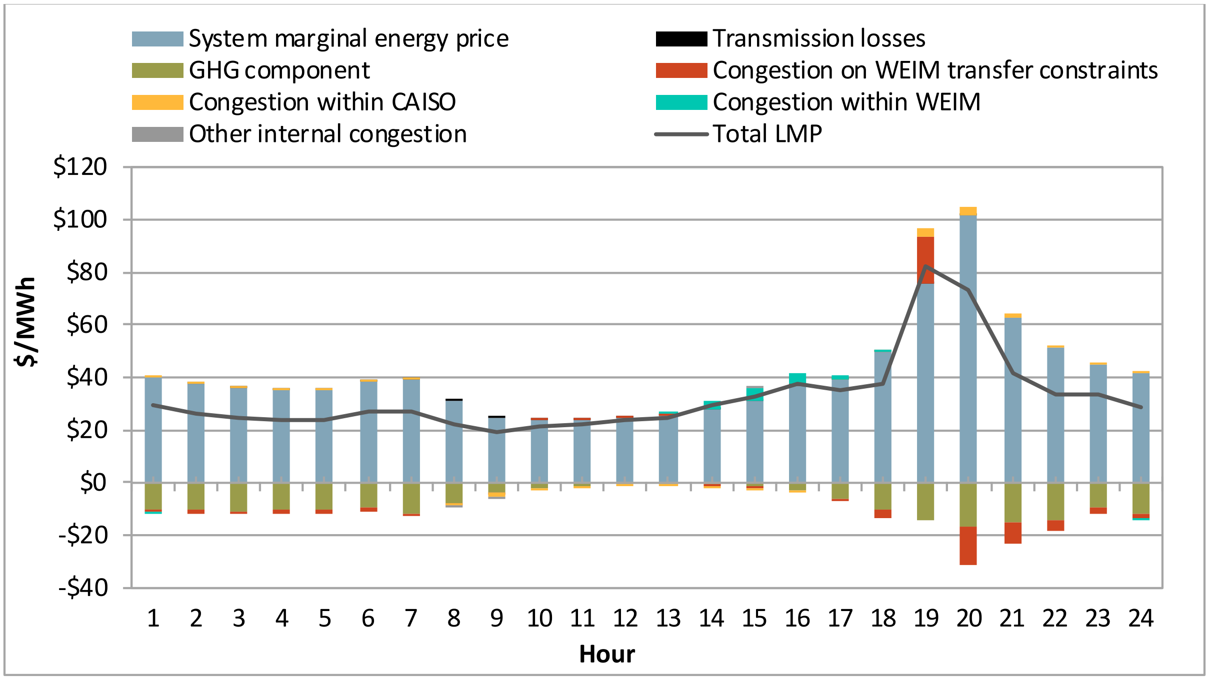


Appendix Figure A.72 Average hourly 5-minute market transfers

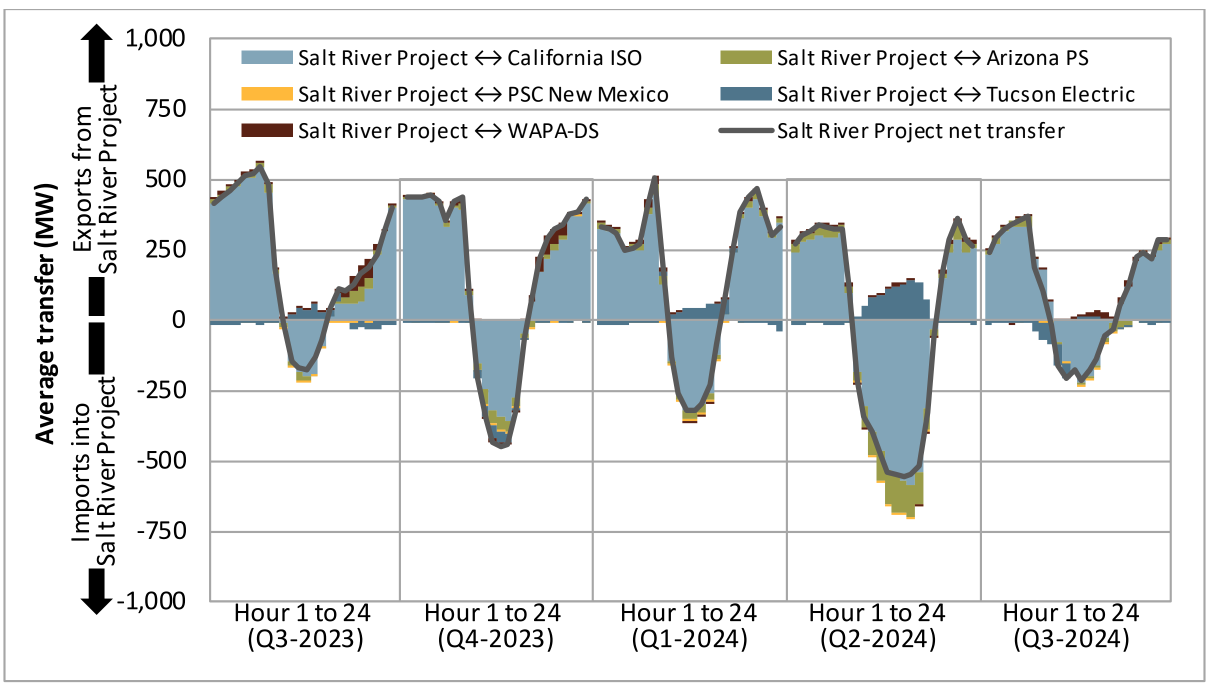


A.18 Salt River Project

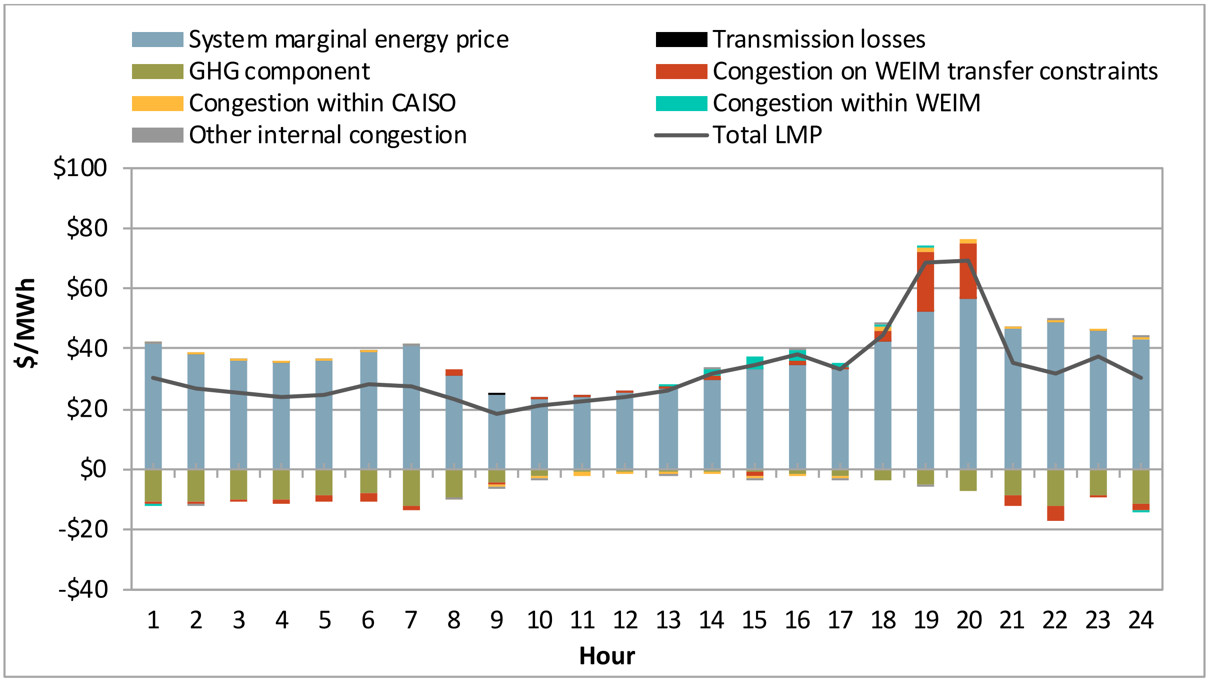
Appendix Figure A.73 Average hourly 15-minute price by component (Q3 2024)



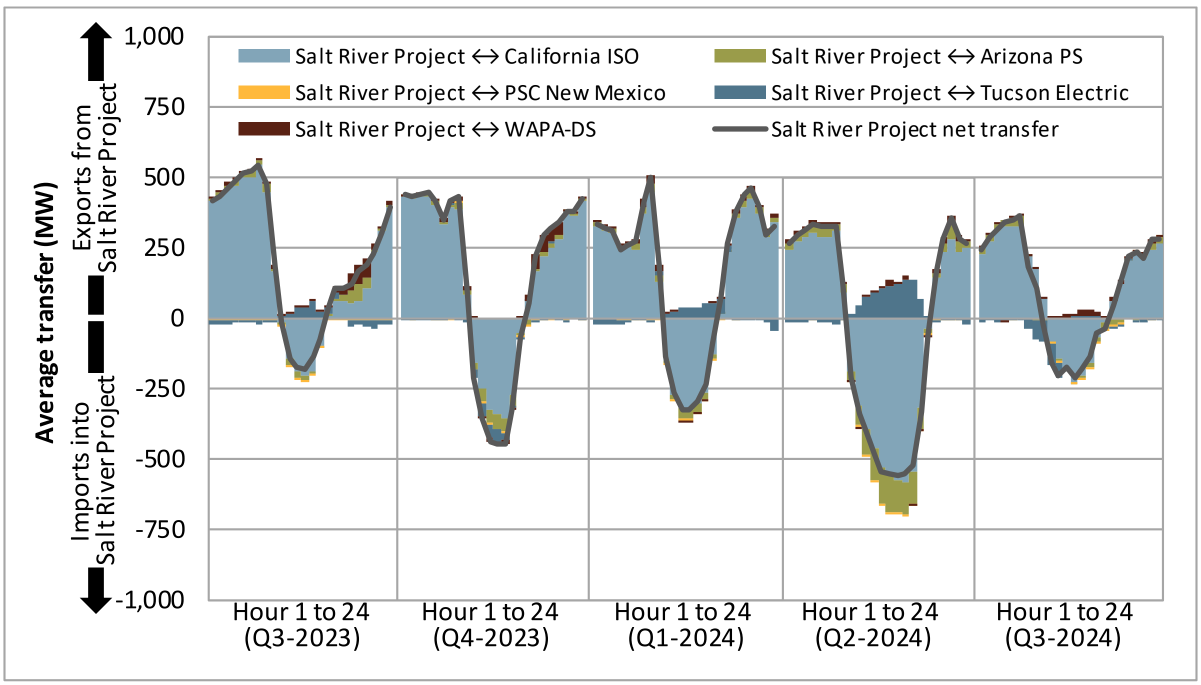
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q3 2024)

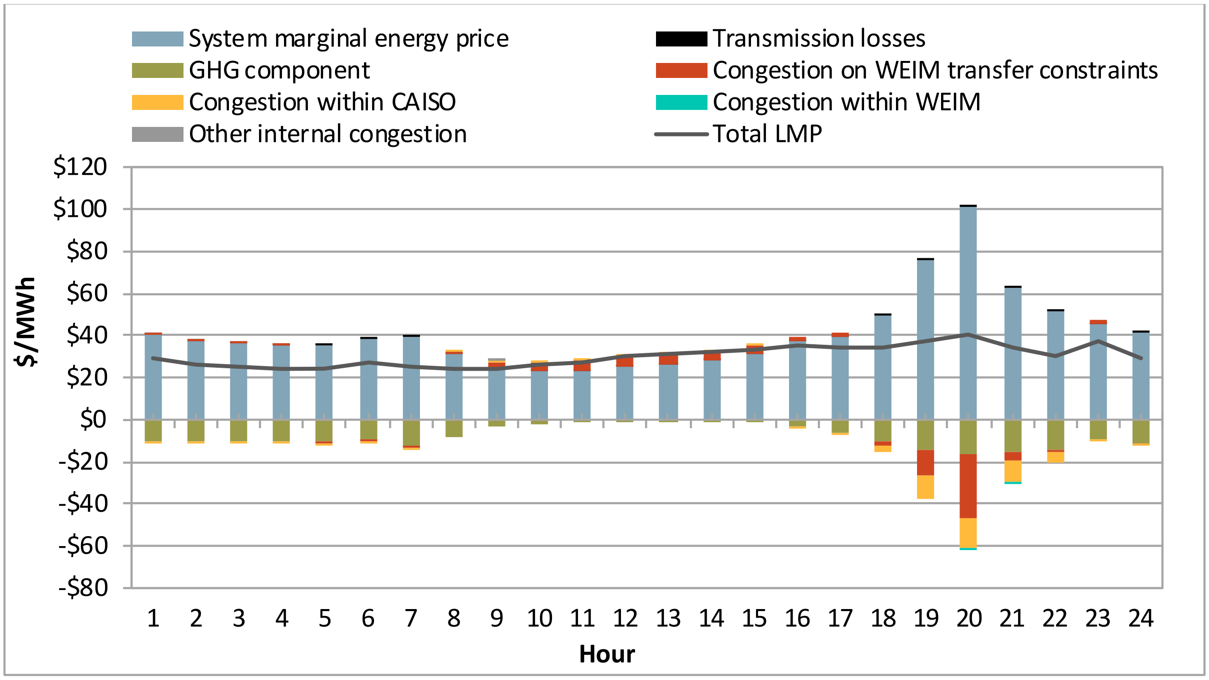


Appendix Figure A.76 Average hourly 5-minute market transfers

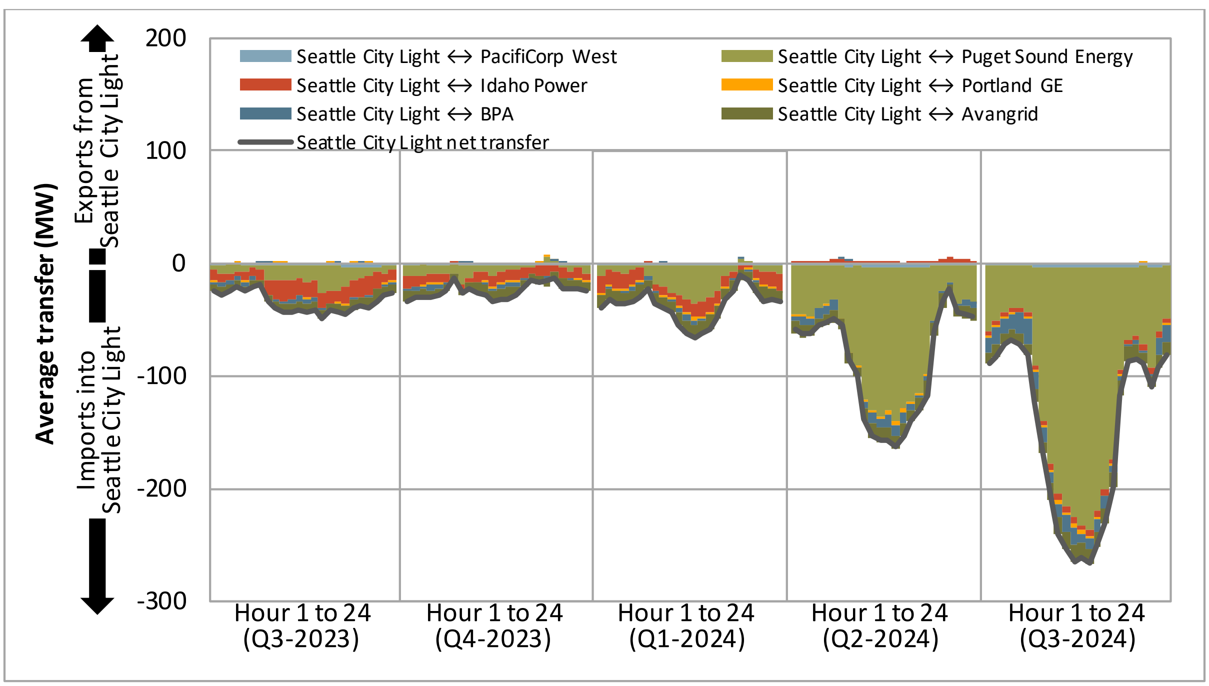


A.19 Seattle City Light

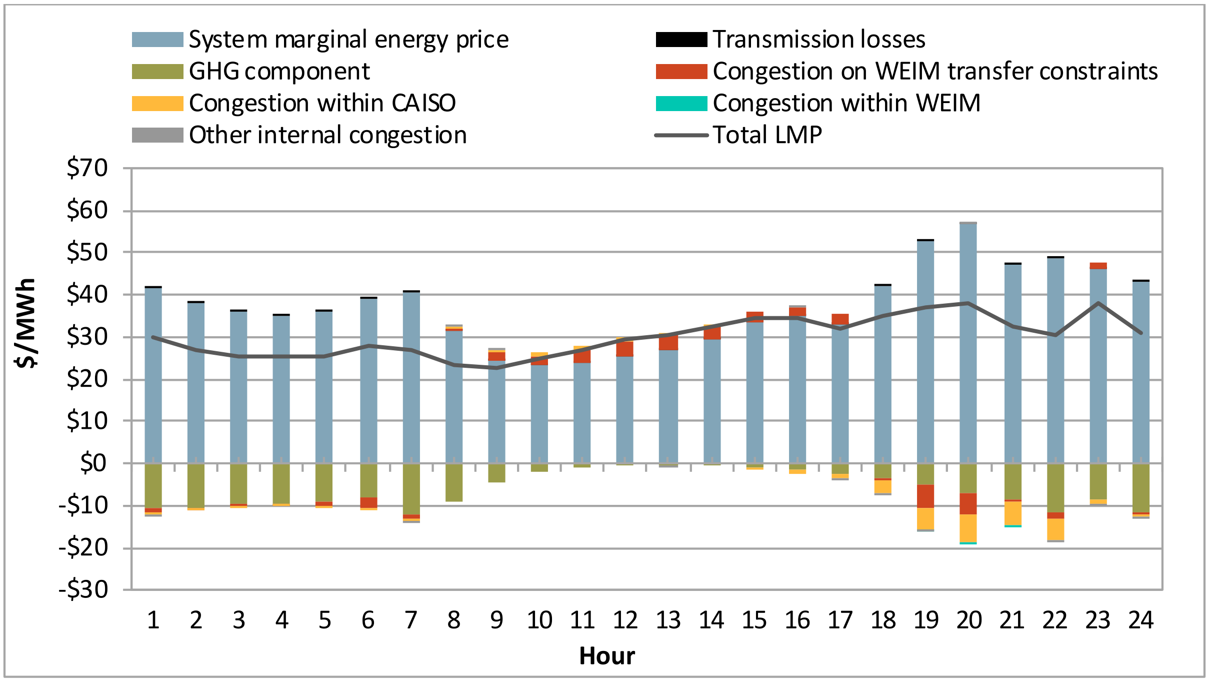
Appendix Figure A.77 Average hourly 15-minute price by component (Q3 2024)



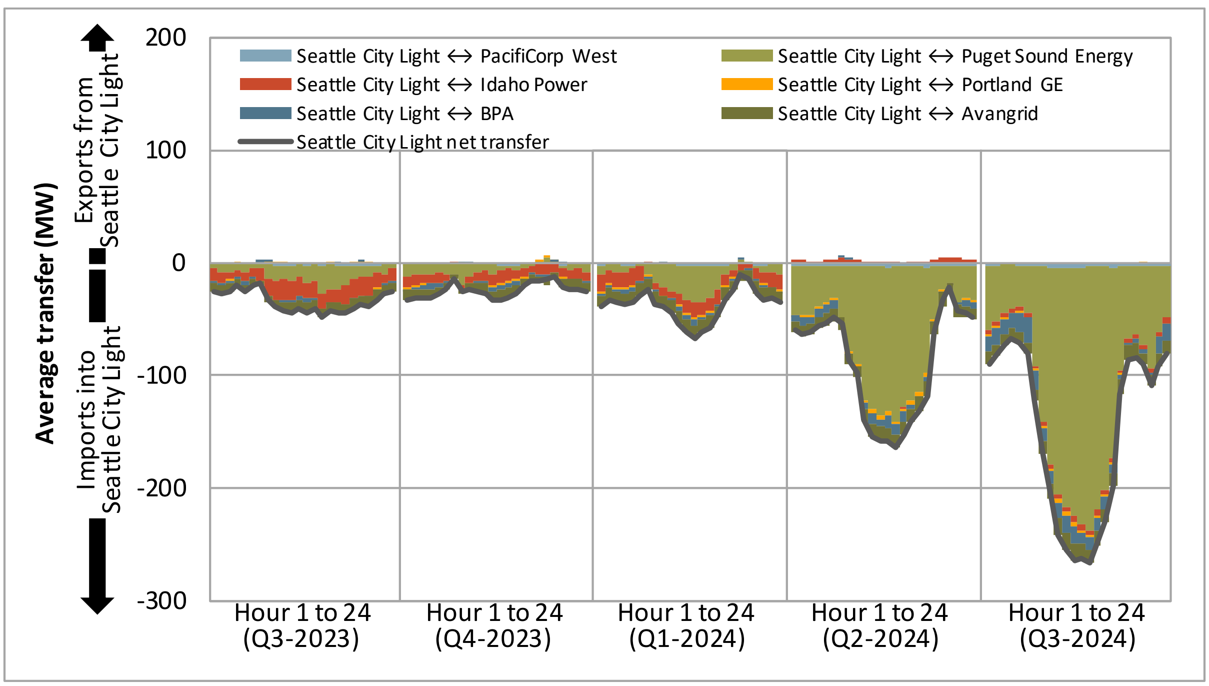
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q3 2024)

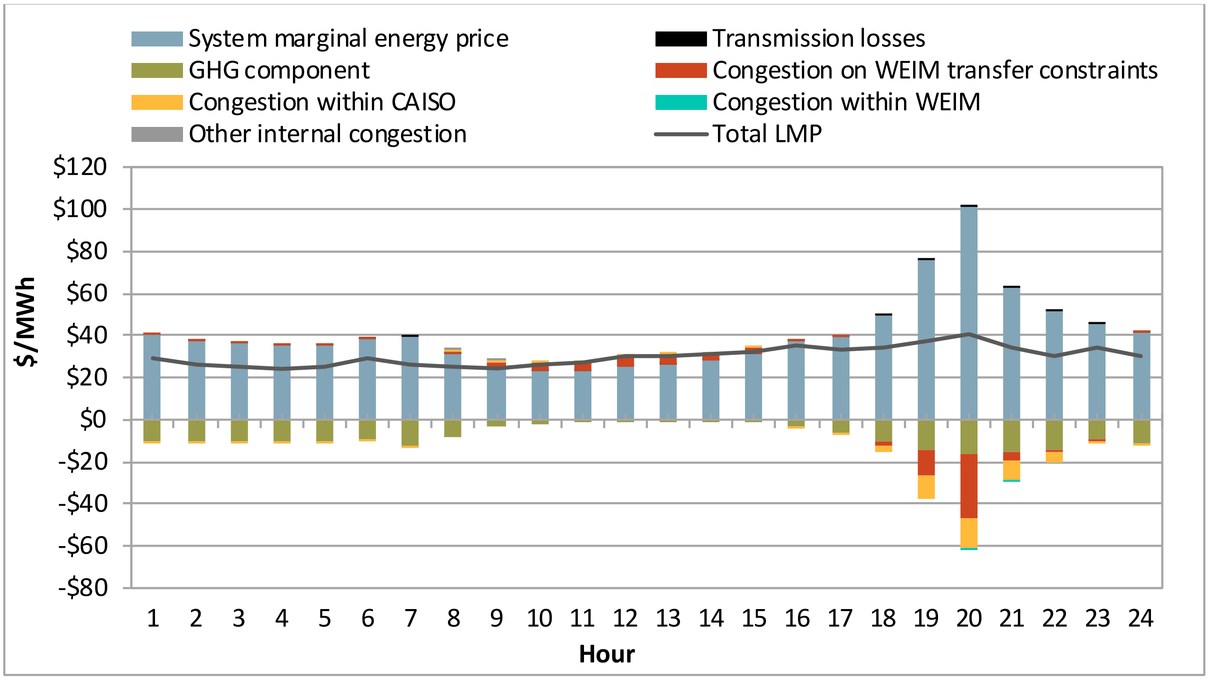


Appendix Figure A.80 Average hourly 5-minute market transfers

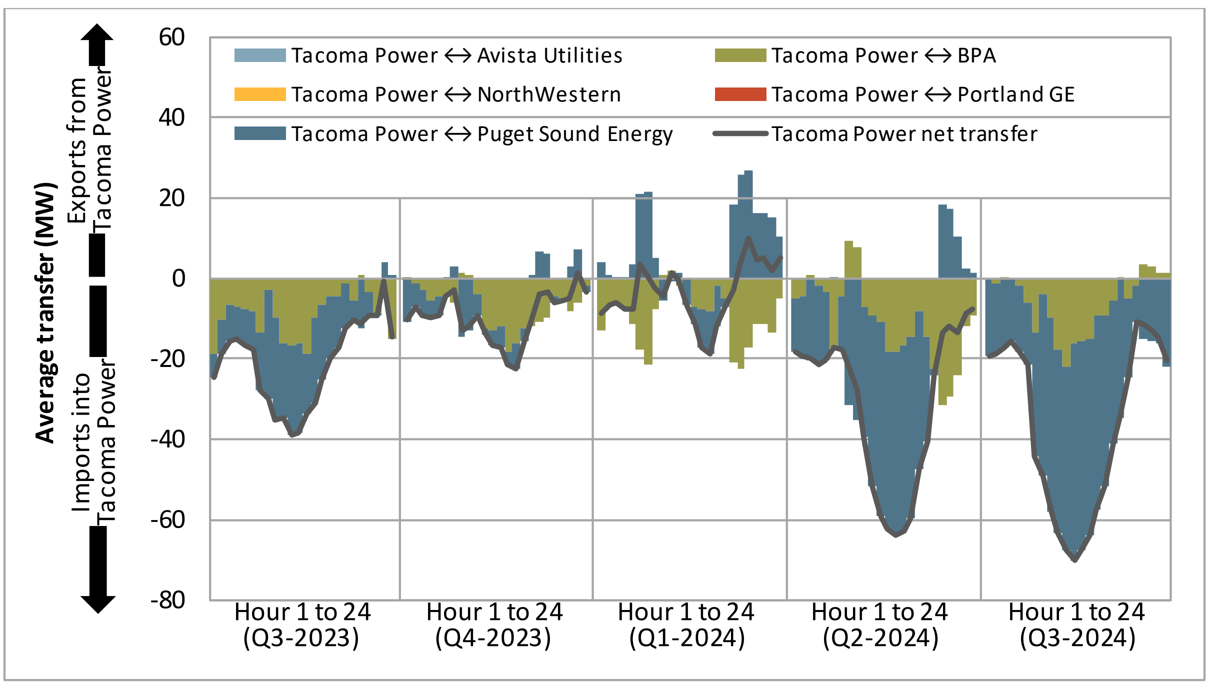


A.20 Tacoma Power

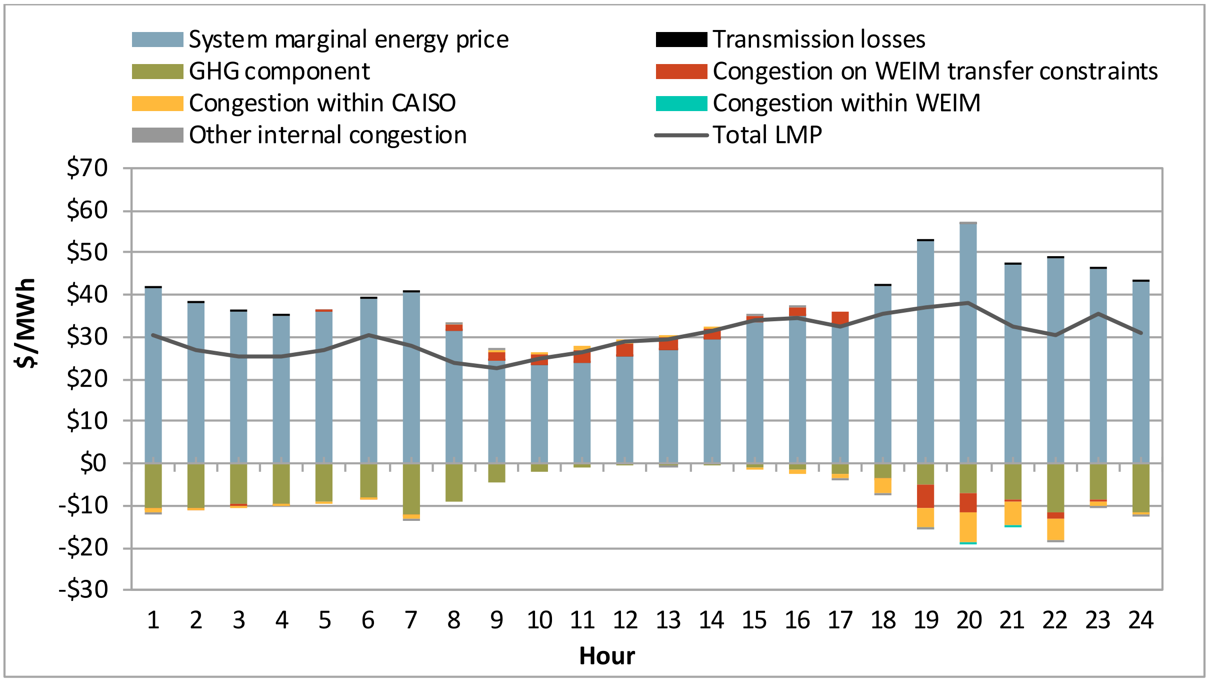
Appendix Figure A.81 Average hourly 15-minute price by component (Q3 2024)



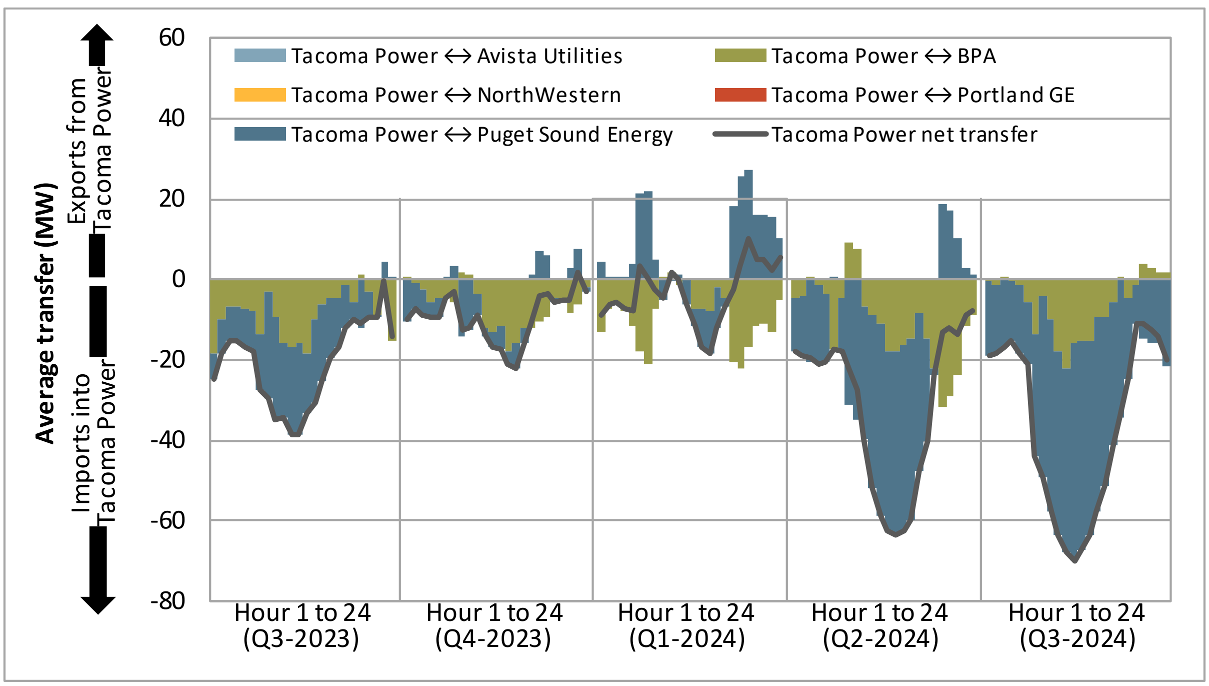
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q3 2024)

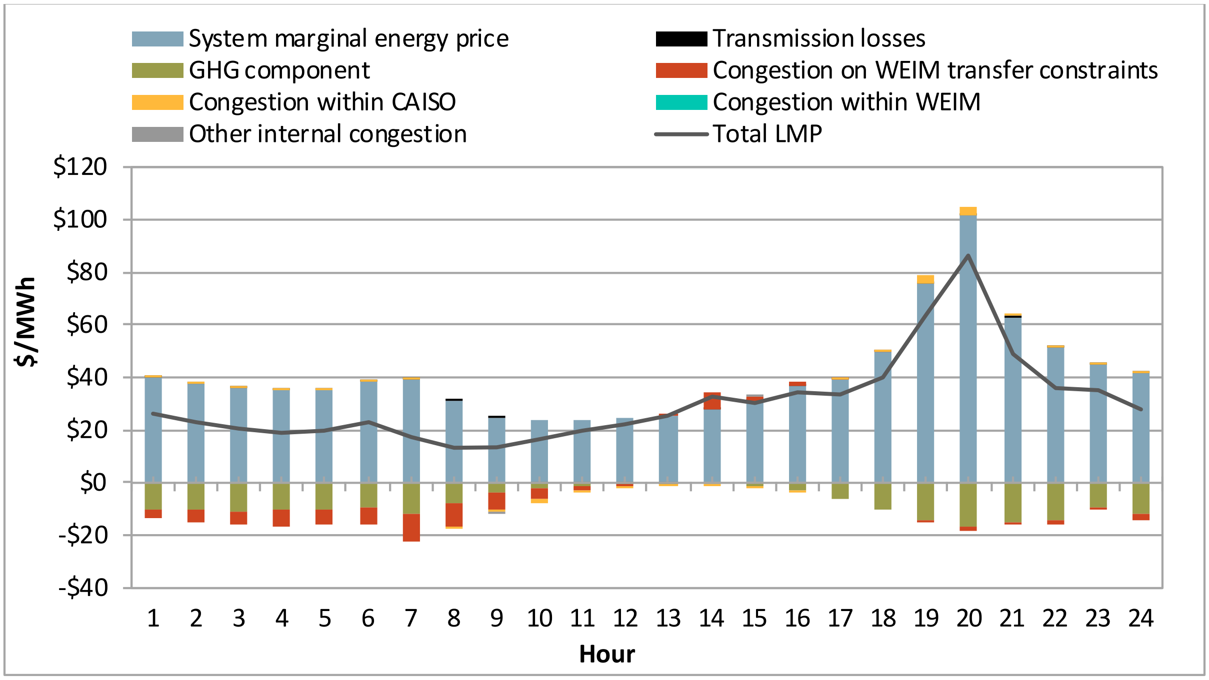


Appendix Figure A.84 Average hourly 5-minute market transfers

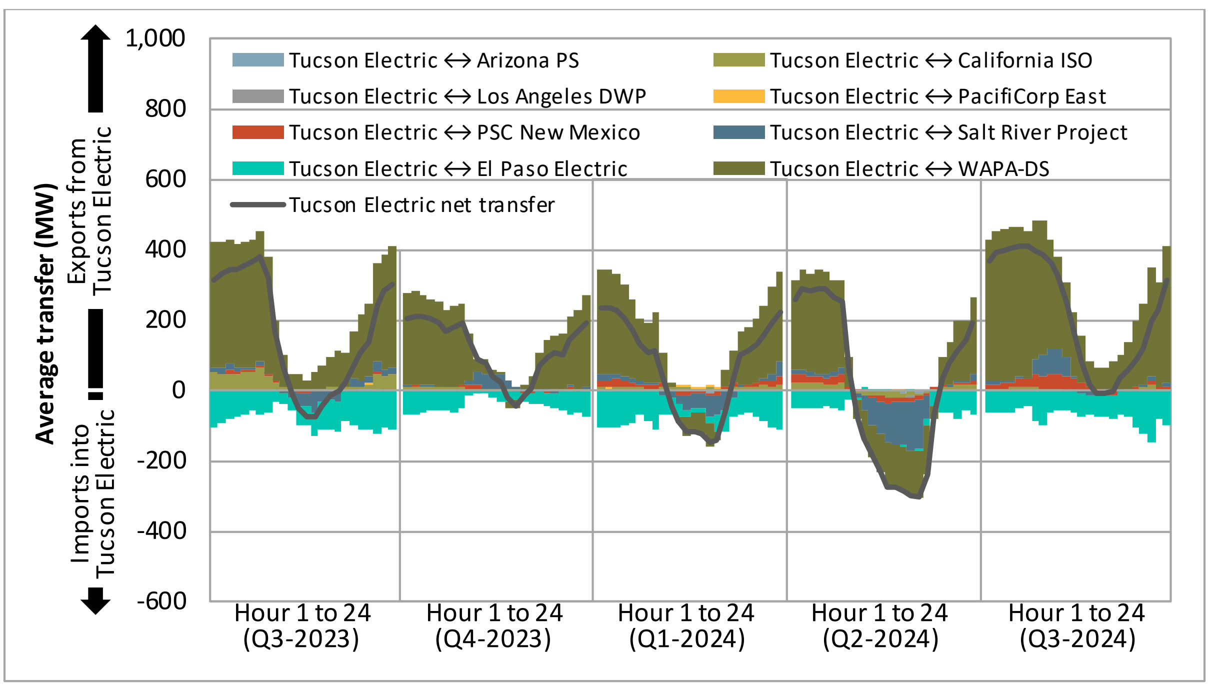


A.21 Tucson Electric Power

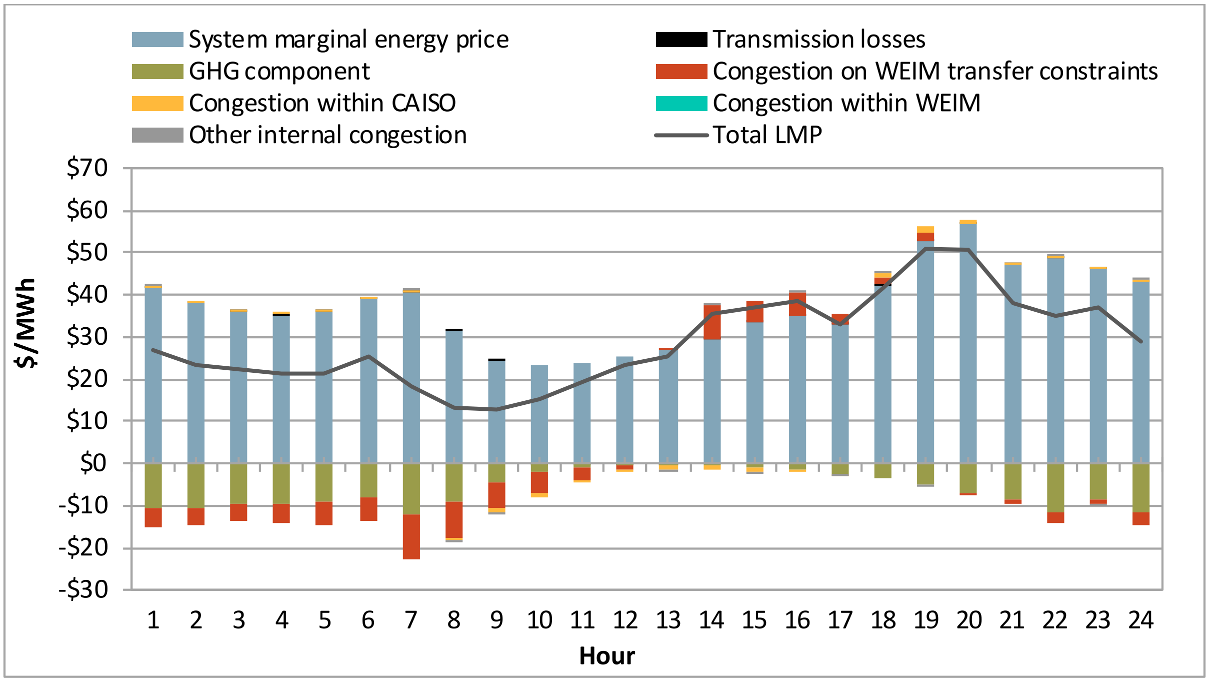
Appendix Figure A.85 Average hourly 15-minute price by component (Q3 2024)



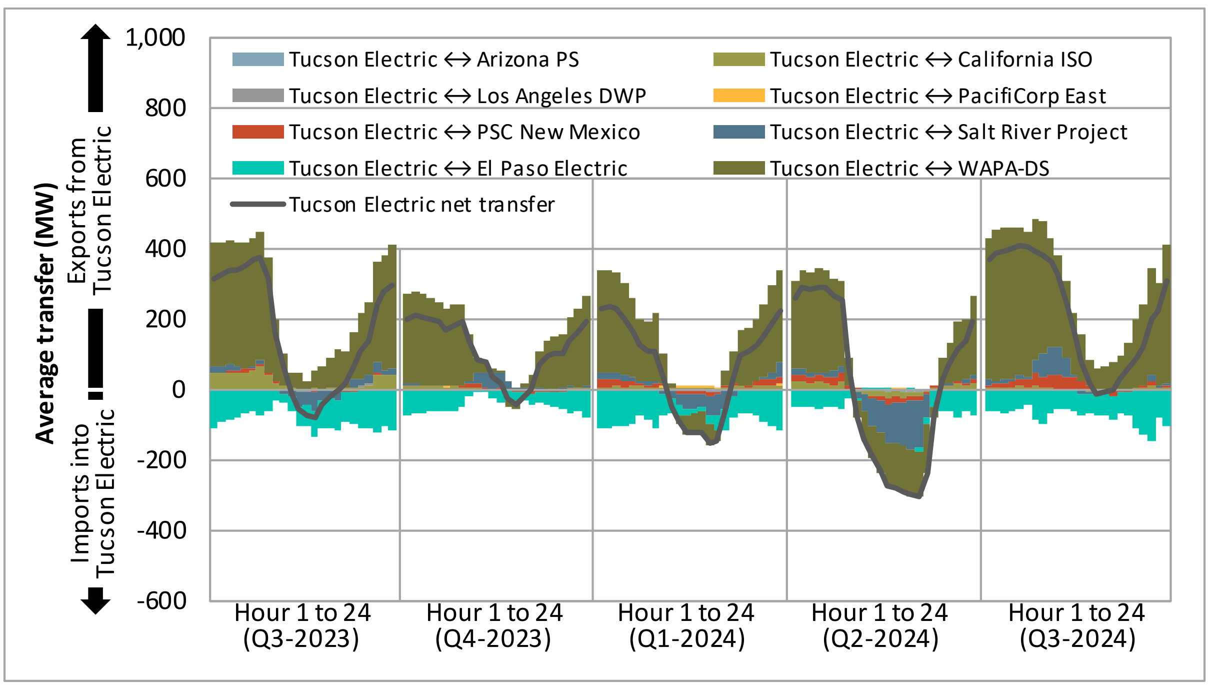
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q3 2024)

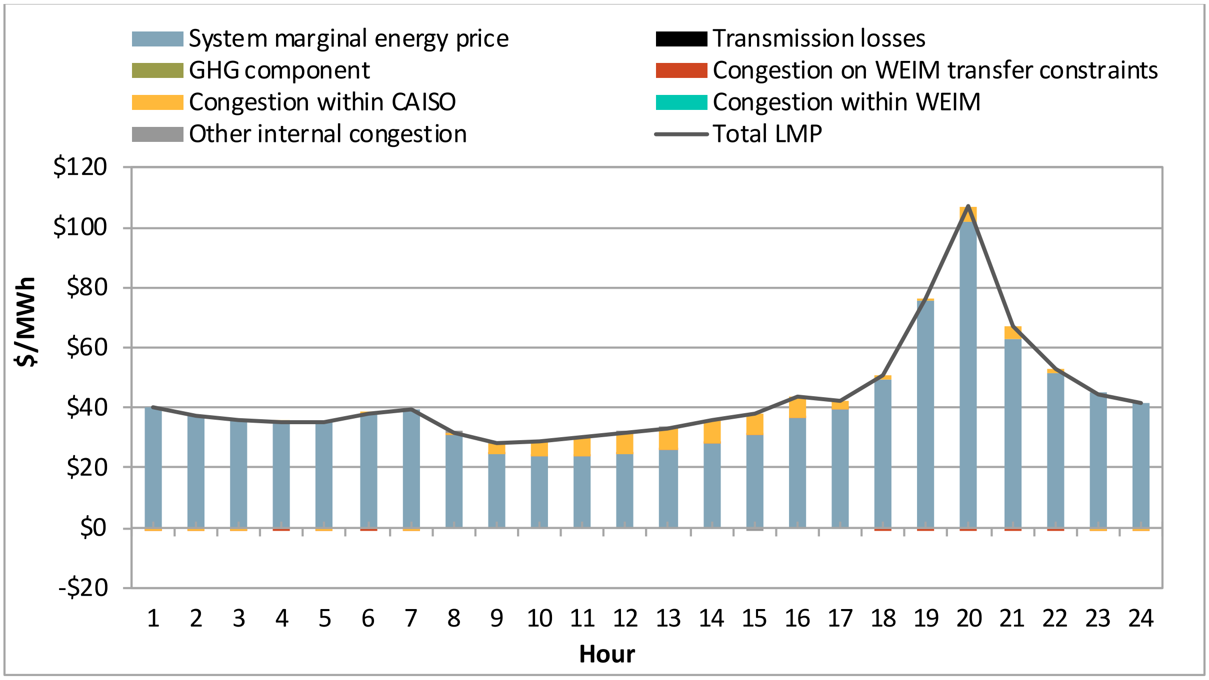


Appendix Figure A.88 Average hourly 5-minute market transfers

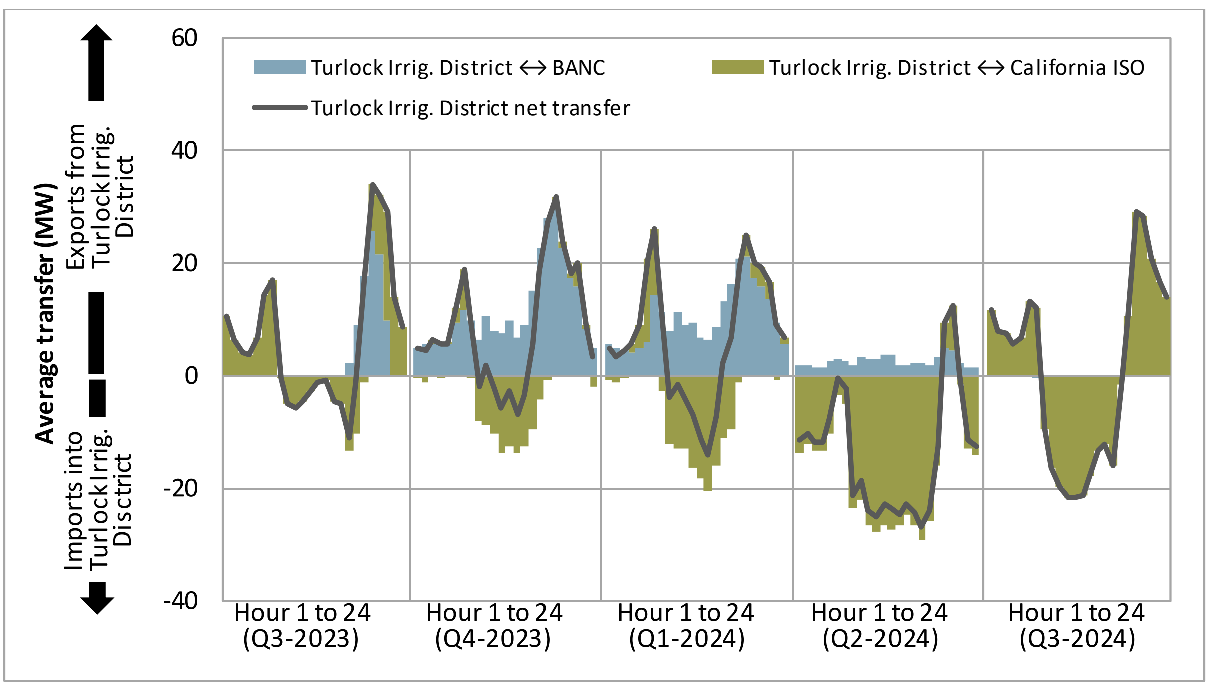


A.22 Turlock Irrigation District

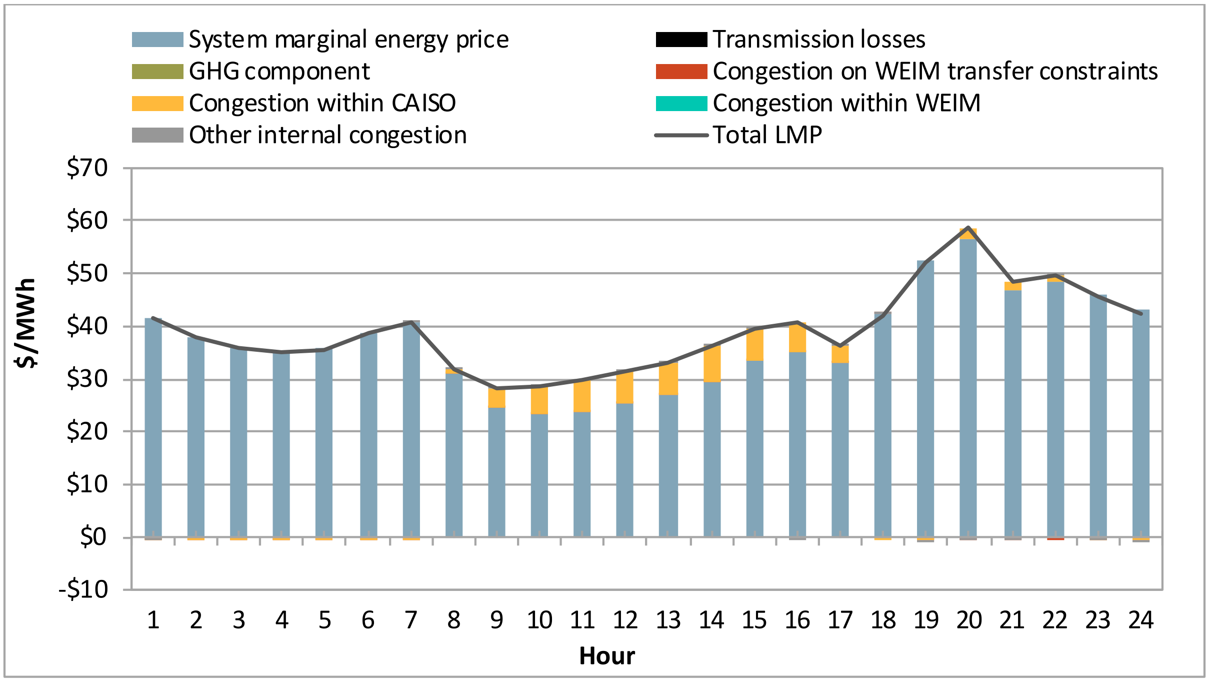
Appendix Figure A.89 Average hourly 15-minute price by component (Q3 2024)



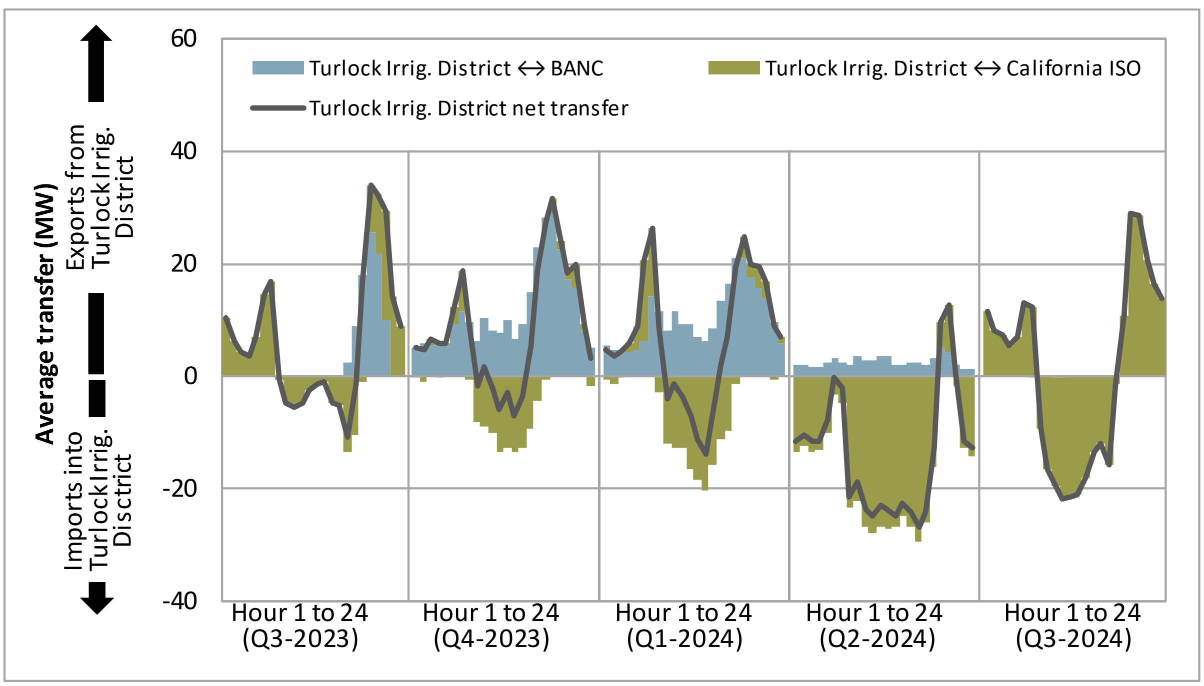
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q3 2024)

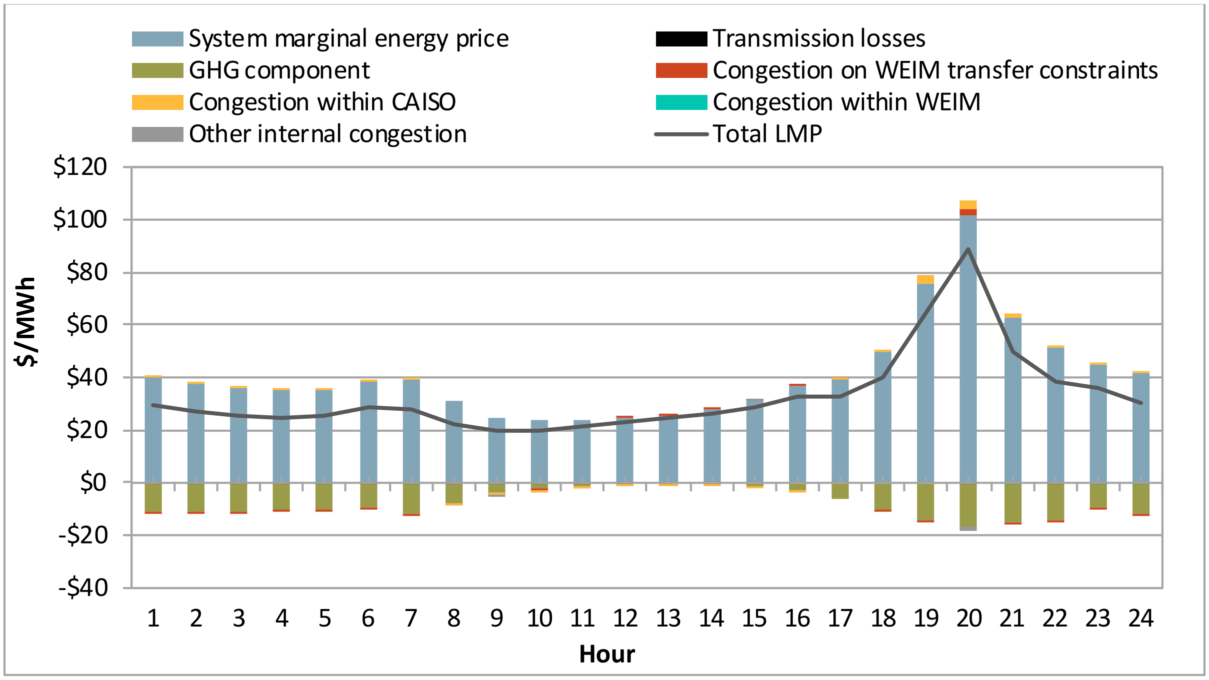


Appendix Figure A.92 Average hourly 5-minute market transfers

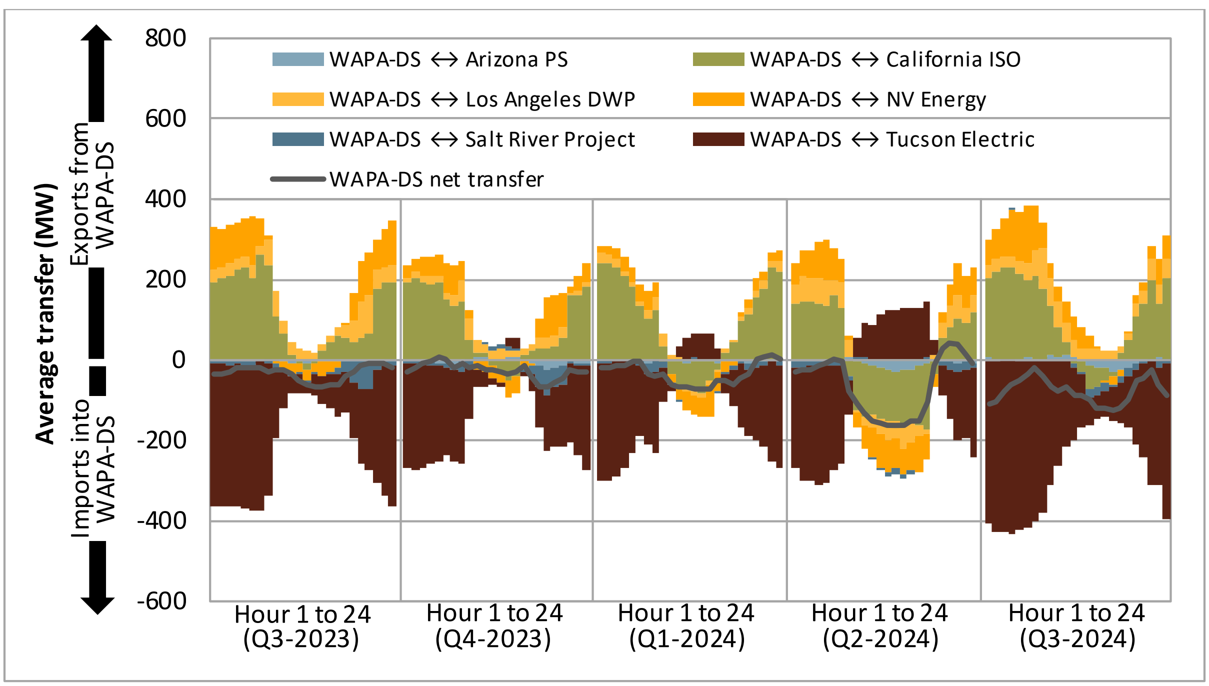


A.23 Western Area Power Administration Desert Southwest

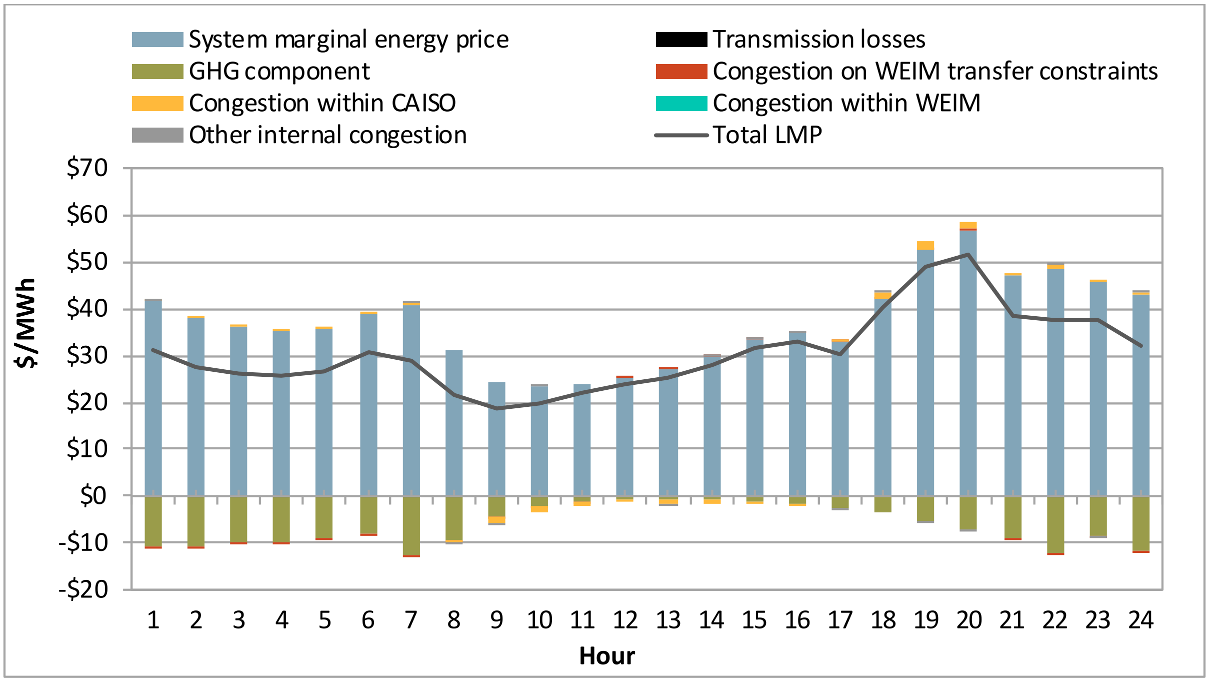
Appendix Figure A.93 Average hourly 15-minute price by component (Q3 2024)



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



Appendix Figure A.95 Average hourly 5-minute price by component (Q3 2024)



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