Q1 2023 Report on Market Issues and Performance

September 19, 2023

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California Independent System Operator

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Executive summary

This report covers market performance during the first quarter of 2023 (January - March).

Key highlights during this quarter include the following:

- **Although gas prices fell from extraordinarily high levels in December, gas prices remained high.** Average gas prices were double prices in the same quarter of last year at both California hubs, well above the Henry Hub price, the national index (Figure E.1). This resulted in higher system marginal energy prices across the market.
- **Market prices were significantly higher than the same quarter of 2022** (Figure E.2). Both day-ahead and real-time prices doubled in most areas due to higher natural gas prices, rising to an average of $93/MWh from $46/MWh.
- **Imports were lower during all hours and were primarily replaced by natural gas generation**, in the California ISO. This increase in natural gas generation, coupled with higher natural gas prices, help push overall energy prices higher.
- **Congestion increased in both the day-ahead and real-time markets** for non WEIM transfer constraints. Day-ahead congestion in the south to north direction decreased SCE and SDG&E area prices and increased prices in the PG&E area. Total day-ahead congestion rent rose to $280 million, up from $122 million in the same quarter of the previous year.
- **Estimated bid cost recovery payments increased** for units in the California ISO and WEIM balancing areas, totaling about $84 million and $13 million, respectively, during the quarter. The total $97 million cost for the quarter is more than triple the $29 million cost in 2022.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by $29 million** in the quarter, more than double losses from $12 million losses in 2022. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. DMM continues to recommend further changes to eliminate or at least reduce these losses.
- **Net revenues for convergence bidders were about $10 million** in Q1, up from $5 million in 2022.
- **Imbalance conformance adjustments** averaged over 2,300 MW in the peak net load ramp hours in the California ISO. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributed to the price difference between these markets.

Figure E.1 Average monthly natural gas prices by hub

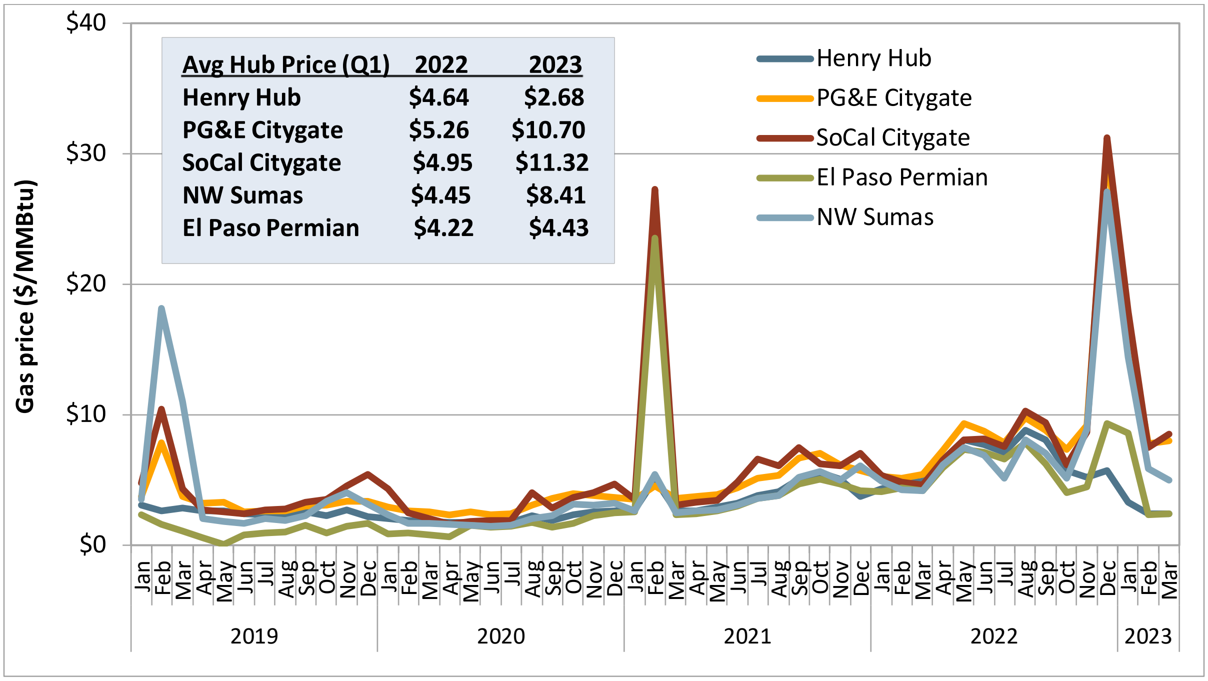
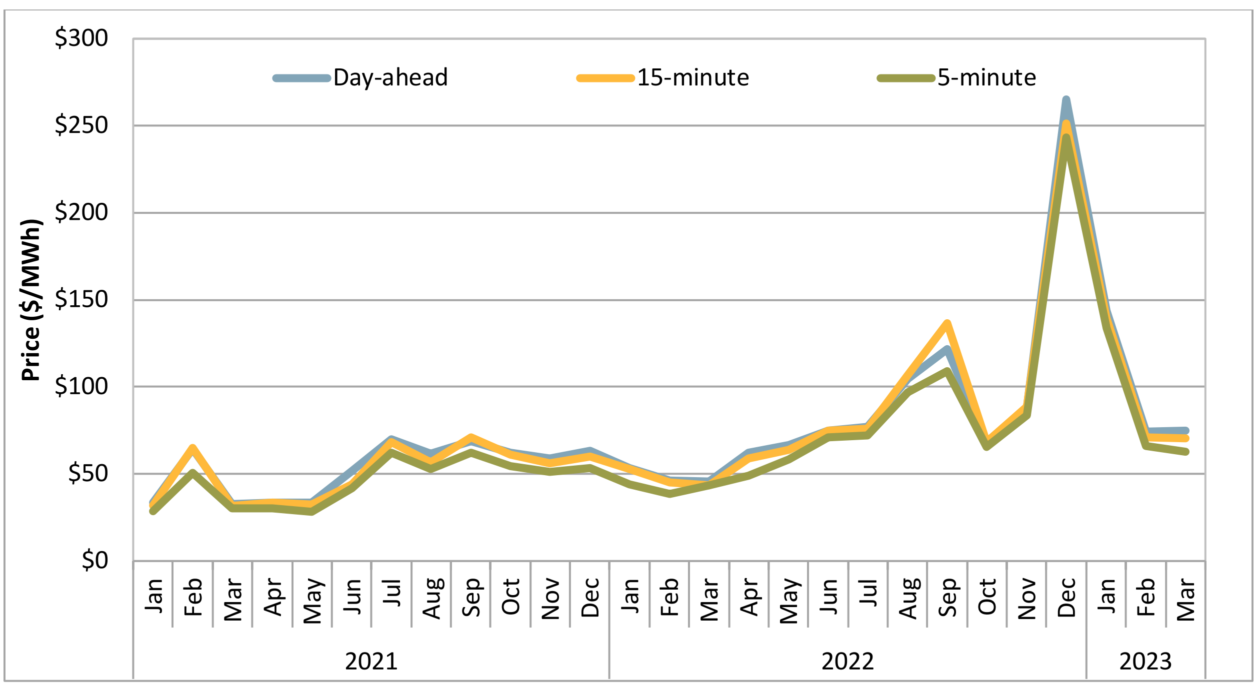


Figure E.2 Monthly load-weighted average energy prices California ISO (all hours)



Western Energy Imbalance Market

- **Natural gas prices rose in the Desert Southwest and in California**, resulting in higher energy prices.
- **Prices in WEIM balancing areas within California were about $7/MWh higher than other regions**. Prices tend to be higher in California than the rest of the system due to greenhouse gas compliance costs for energy that is delivered to California.
- **The California ISO, PacifiCorp East, Powerex and the Balancing Authority of Northern California (BANC) were major net importers** during peak net load hours. During these hours, these areas imported an average of about 1,500 MW from neighboring areas.
- **The California ISO and areas in the Desert Southwest were major net exporters** during the mid-day period when solar generation is typically at its highest. These areas exported an average of about 1,750 MW to BANC, LADWP, Powerex and other areas in the Northwest.
- **Prices in the Pacific Northwest and Mountain Northwest regions and in Salt River Project** were frequently separated from system prices by congestion on WEIM transfer constraints. Transfer congestion lowered prices in Salt River Project, reflecting constraints from this region to the rest of the system when marginal system costs were relatively high. In the Northwest, this congestion typically increased prices in mid-day hours, preventing these areas from importing lower marginal cost system power.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in monthly 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.
- **Appendix A includes hourly price and transfer figures for each WEIM area**.

Special issues: Flexible ramping product enhancements and quantile regression review

On February 1, 2023, the CAISO implemented enhancements to the flexible ramping product. This introduced two significant changes. The first of these improves flexible ramping product deliverability by procuring and pricing flexible capacity at a nodal level to better ensure that sufficient transmission is available for this capacity to be utilized.

The second significant change adjusted the calculation of the uncertainty requirement by incorporating current load, solar, and wind forecast information using a method called mosaic quantile regression. This calculated uncertainty is included in both flexible ramping product demand curves and in the flexible ramping sufficiency test, part of the WEIM resource sufficiency evaluation.

Key highlights include the following:

- **The flexible ramping product demand curves were implemented incorrectly on February 1, 2023.** The result is that the prices on the demand curve are too low relative to the expected cost of a power balance constraint relaxation for the level of flexible capacity procured. This made it appear inappropriately cheap for the market optimization to forgo flexible ramping capacity. The CAISO implemented a correction to the calculation of the flexible ramping product demand curves effective August 8, 2023.
- **Flexible capacity prices for the larger system continued to be low following the enhancements**. During February and March the 15-minute market prices for flexible capacity within the pass-group

were non-zero in less than 1 percent of intervals for upward capacity and never for downward capacity. 5-minute market prices were also infrequent, in less than 0.1 percent of intervals.

- **The balancing areas included in the pass-group for performing the uncertainty regressions can be inconsistent from the balancing areas included in the pass-group used to determine weather information used in the regressions.** The current weather information is ultimately combined with the regression results to calculate uncertainty. This discrepancy can create significant swings in the calculated uncertainty.
- **DMM's review of the performance of this new methodology indicates that it is not a clear improvement over the prior method**. Although uncertainty values calculated with this method are generally lower while covering uncertainty (an improvement), they fluctuate more significantly and are likely to be more difficult for balancing areas to reproduce or predict in advance. A more comprehensive review will be provided in a forthcoming special report.

1 Market performance

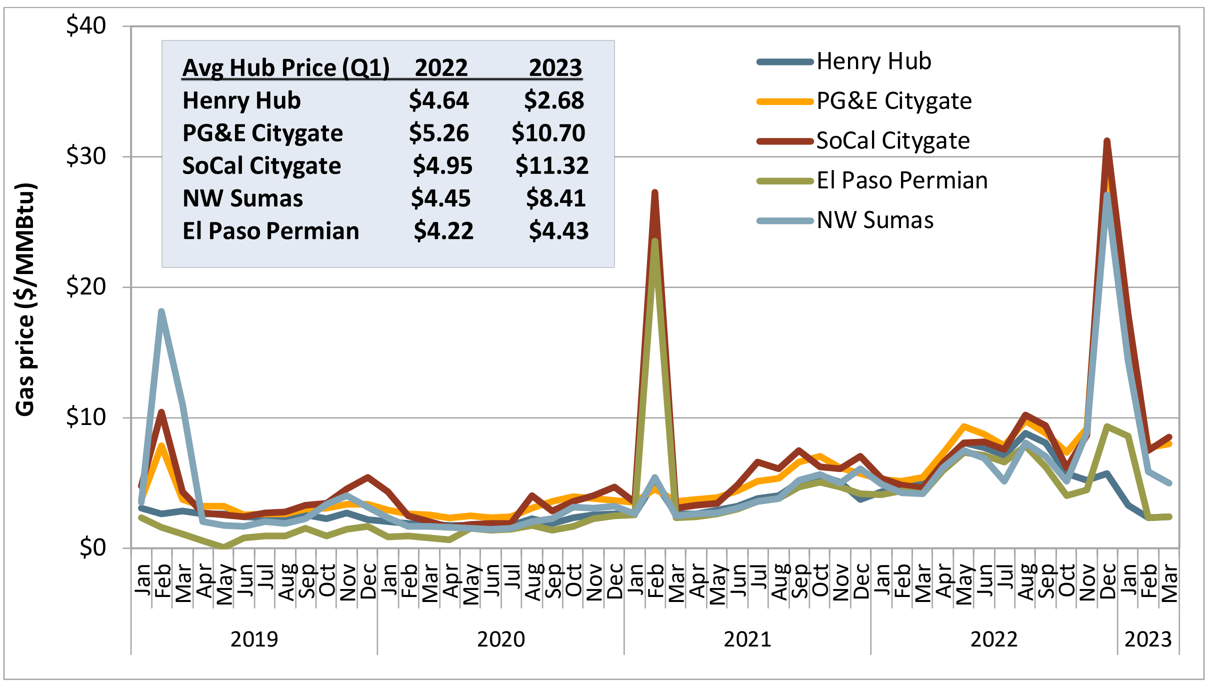
1.1 Supply conditions

1.1.1 Natural gas prices

Electricity prices in western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in the California ISO (CAISO) balancing area and other regional markets. By January 2023, gas prices at PG&E Citygate, SoCal Citygate and Northwest Sumas declined by more than 40 percent from record high levels in December 2022. Elevated gas prices led to higher system marginal energy prices in January.

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

Figure 1.1 Monthly average natural gas prices



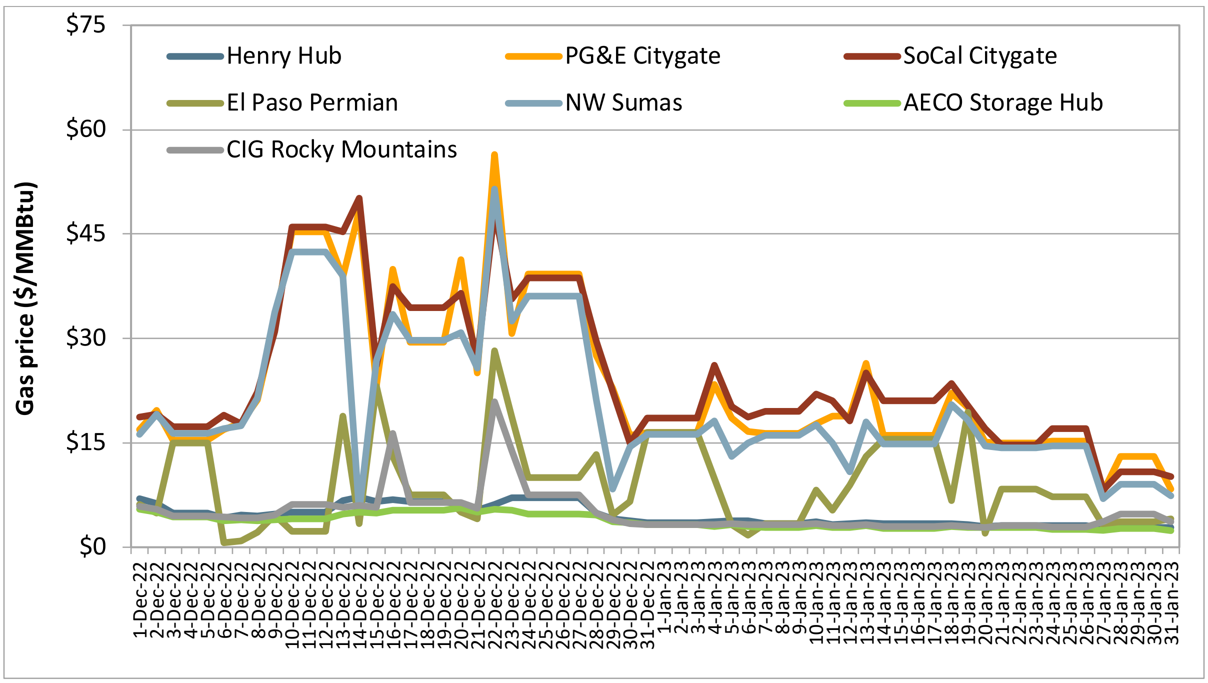
Average first quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) declined by 31 percent and 26 percent compared to the previous quarter, respectively. The Northwest Sumas gas hub price declined 39 percent during the same time period. Prices at Henry Hub and Permian basin also decreased by 52 percent and 25 percent, respectively. When compared to the first quarter of 2022, prices at PG&E Citygate, SoCal Citygate, and Northwest Sumas increased significantly, rising by 104 percent, 129 percent, and 89 percent, respectively. Prices at Henry Hub declined 42 percent and increasing slightly by 5 percent at Permian basin during the same time period.

Figure 1.2 shows daily average natural gas prices for December 2022 and January 2023 and also includes supply locations (Permian, AECO, and Rockies). The high monthly average prices were not the result of a short period of high prices. Instead, prices at both PG&E Citygate and SoCal Citygate traded at a significant premium over Henry Hub for the entire two month period.

Several factors contributed to persistent high gas prices in December 2022 and January 2023[1]:

1. High natural gas consumption in the residential and electric power sector. Below normal temperatures leading to increased demand for natural gas;
2. Reduced natural gas deliveries into the Pacific Northwest and California from supply regions. Pipeline constraints on the El Paso Natural Gas pipeline system restricting Permian Basin flows into Southern California; and
3. Low natural gas storage inventory levels in the Pacific region. As of March 31, 2023, storage inventories were down by more than 50 percent from 2022 levels and the five-year average. After the 2022 summer heatwave, PG&E's injections to rebuild natural gas inventories have not kept pace with previous summers.[2]

Figure 1.2 Daily natural gas prices, December 2022 - January 2023



On March 18, 2022, the CPUC issued a proposed decision to extend SoCalGas's 8-stage winter operational flow order (OFO) penalty structure year-round and made it applicable to the PG&E and

1 End-of-winter natural gas storage stocks in the Pacific region dip to record low, EIA Natural Gas Storage Dashboard, April 27, 2023: https://www.eia.gov/naturalgas/storage/dashboard/commentary/20230427

2 California natural gas storage levels are much lower in the north than in the south: https://www.eia.gov/todayinenergy/detail.php?id=53259

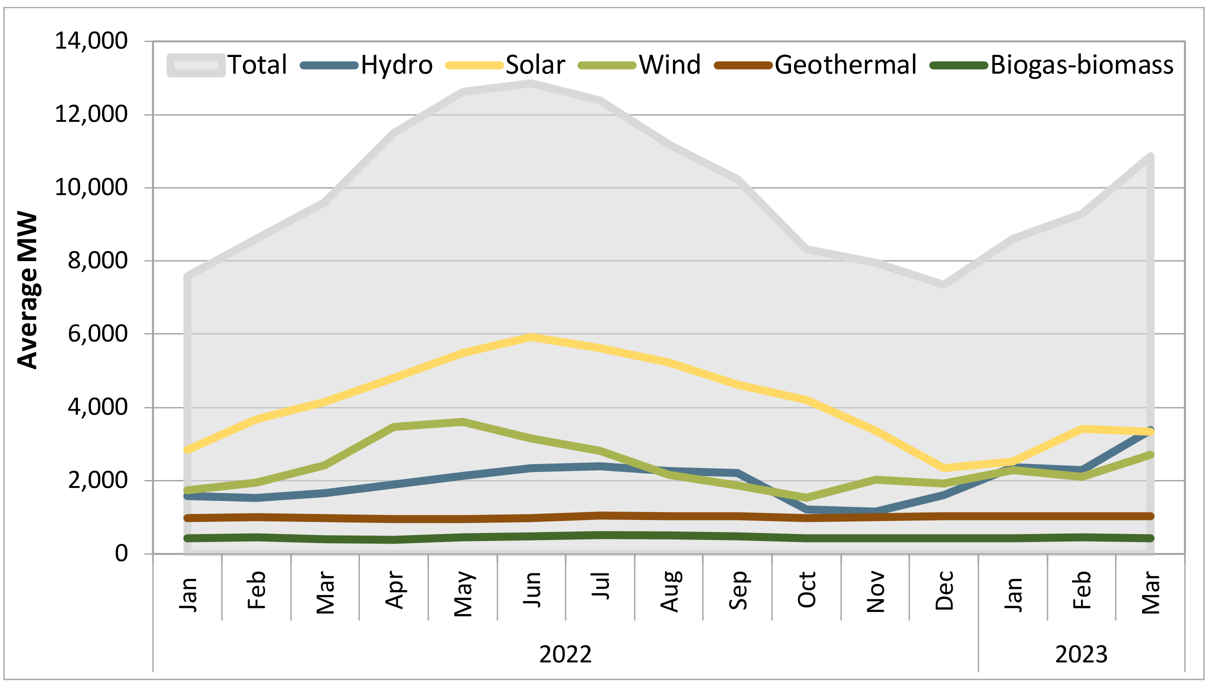
SDG&E service territories.[3] During the first quarter of 2023, SoCalGas declared 40 low OFO's, primarily Stage 3, compared to 11 low OFO's during the same quarter last year, which were primarily Stage 1. In the PG&E service area, there were 32 low OFO's, primarily Stage 3, compared to 7 low OFO's during the same quarter in 2022.

1.1.2 Renewable generation

In the first quarter, the combined average monthly generation from renewable resources increased by about 975 MW (11 percent) compared to the same quarter of 2022.[4] Hydroelectric generation increased 68 percent, while generation from solar, wind, geothermal, and biogas-biomass resources decreased 1 percent. The availability of variable energy resources contributes to price patterns, both seasonally and hourly, due to their low marginal cost relative to other resources.

Figure 1.3 shows the average monthly renewable generation by fuel type.[5] Wind generation increased 325 MW (16 percent), while solar generation decreased by about 475 MW (13 percent). Generation from geothermal generation increased 34 MW (4 percent), while biogas-biomass generation remained relatively unchanged.

Figure 1.3 Average monthly renewable generation



3 Proposed Decision for CPUC Docket No. R.20-01-007, *Decision Implementing Southern California Gas Company Rule 30 Operational Flow Order Winter Noncompliance Penalty Structure Year-Round for Southern California Gas Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company,* March 18, 2022: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M460/K301/460301154.PDF

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

5 Hydroelectric generation greater than 30 MW is included.

1.1.3 Generation by fuel type

In the first quarter, natural gas and hydroelectric generation increased while generation from net imports decreased. Average hourly generation by natural gas resources increased to 36 percent of total generation during peak net load hours. Hydroelectric generation increased 65 percent and battery generation doubled compared to the first quarter of 2022.[6]

Figure 1.4 shows the average hourly generation by fuel type during the first quarter of 2023 as measured by preliminary meter data. Total hourly average generation peaked at about 28,925 MW during hour ending 19. Battery generation also peaked during hour end 19 at about 1,550 MW. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed to 18 percent of total generation during the peak net load hours of 17-21, up from 15 percent during the same time last year.

Figure 1.4 Average hourly generation by fuel type (Q1 2023)

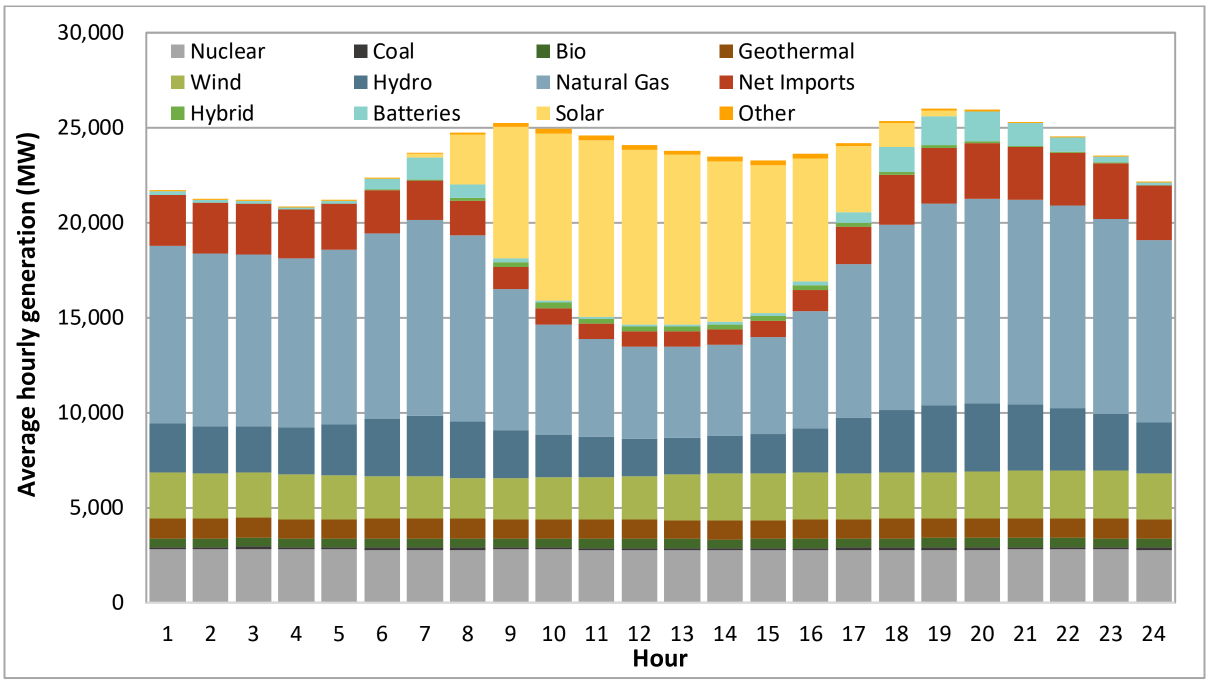


Figure 1.5 shows the change in hourly generation by fuel type between the first quarter of 2022 and the first quarter of 2023.[7] In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

Overall, the net change shows that there was an increase in average hourly generation in the early morning and mid-day hours and a decrease during the peak net load hours. Generation from net imports decreased during all hours and was primarily replaced by natural gas and hydroelectric

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

7 Hybrid generation was included in the "Other" category in Q1 2022 but is identified as 'Hybrid' in Q1 2023. Therefore, reductions in 'Other' generation are offset by the additional 'Hybrid' generation.

generation. Hybrid resource generation is now split out from 'Other' generation, and primarily appears in the mid-day and net peak hours.

Figure 1.6 shows the monthly average hydroelectric generation from 2019 to 2023. Hydroelectric generation in the first quarter of 2023 was higher than the last three years and tracked most similarly to 2019.

Figure 1.5 Change in average hourly generation by fuel type (Q1 2022 to Q1 2023)

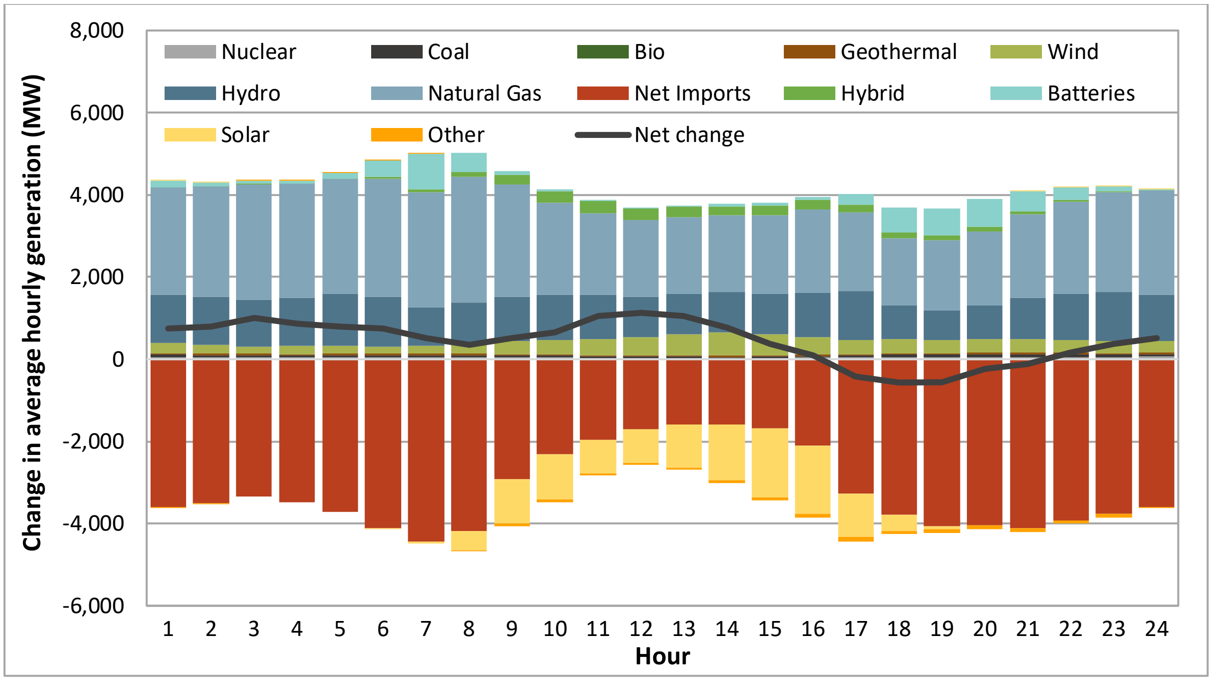
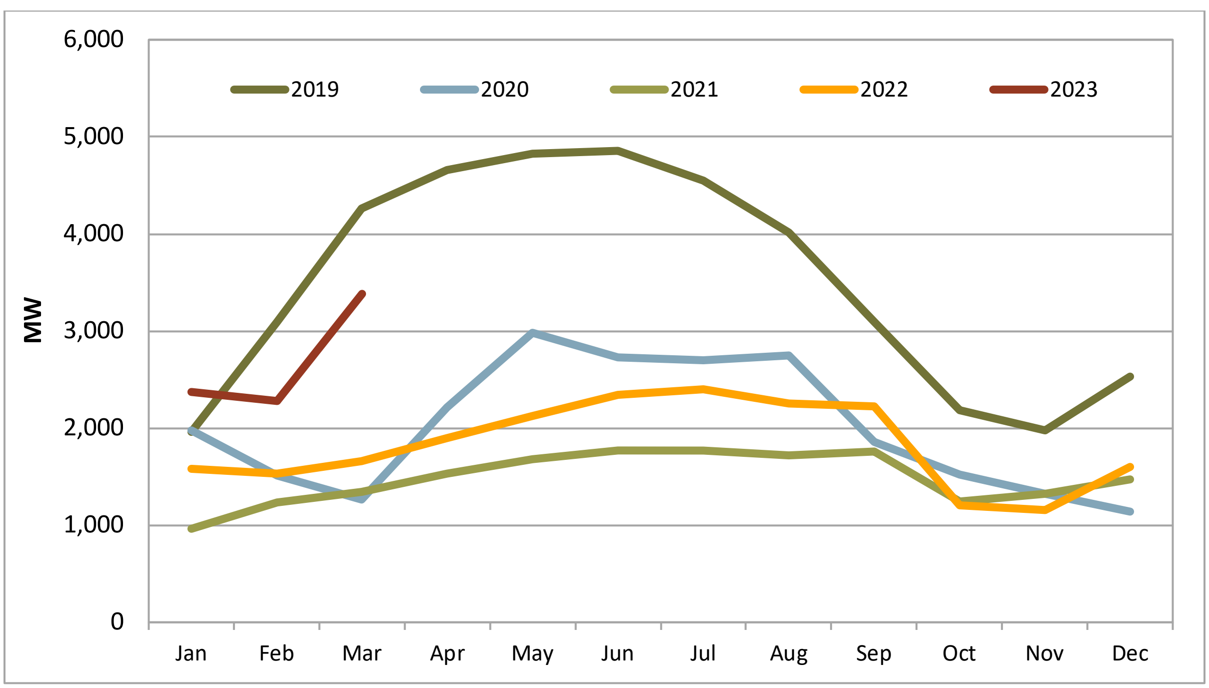


Figure 1.6 Monthly average hydroelectric generation by year



1.1.4 Generation outages

Total generation on outage in the California ISO balancing area averaged about 14,775 MW, 8 percent lower than the first quarter of 2022. This decrease was driven by forced outages, which decreased 13 percent relative to the same time last year.

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

Figure 1.7 and Figure 1.8 show the quarterly and monthly averages of maximum daily outages during peak hours by type from 2021 to 2023, respectively.[8] 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 is usually a high number of outages in the spring months. This year followed this trend thus far with planned maintenance outages increasing over the first quarter, reaching an average of 19,225 MW in March.

During the first quarter of 2023, the average total generation on outage in the California ISO balancing area was 14,775 MW, about 1,375 MW less than the first quarter of 2022, as shown in Figure 1.7. There were 13 percent less forced outages compared to the same time last year, and the same amount of planned outages.

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

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

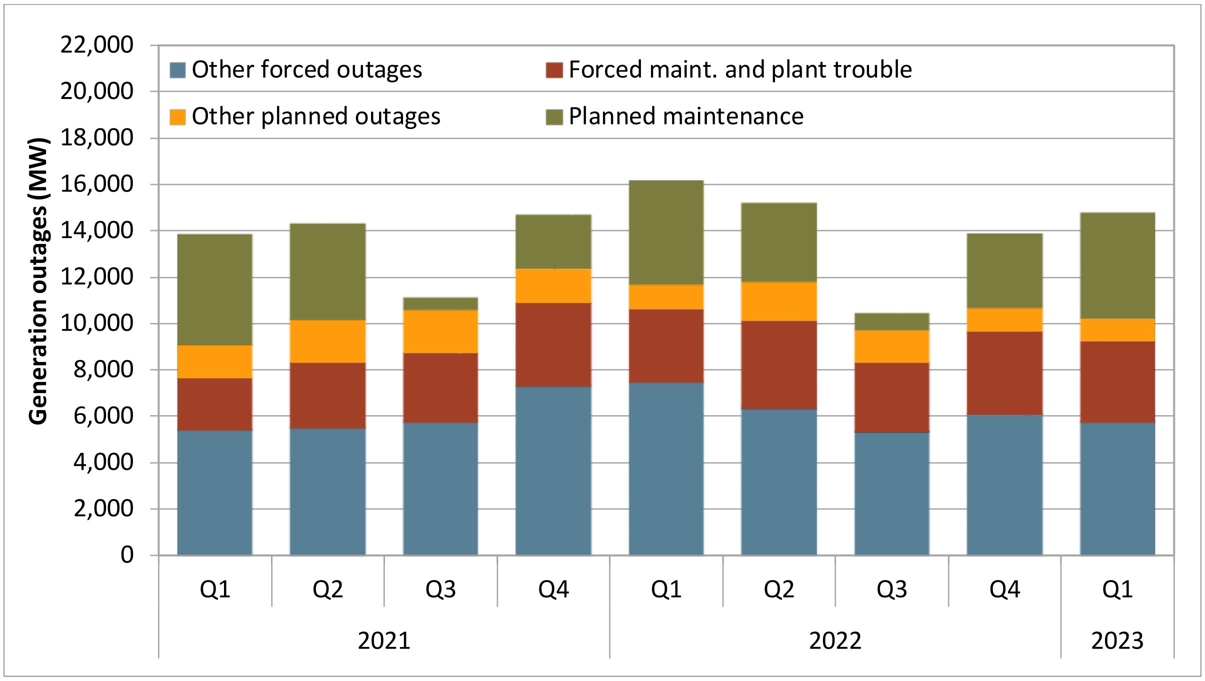
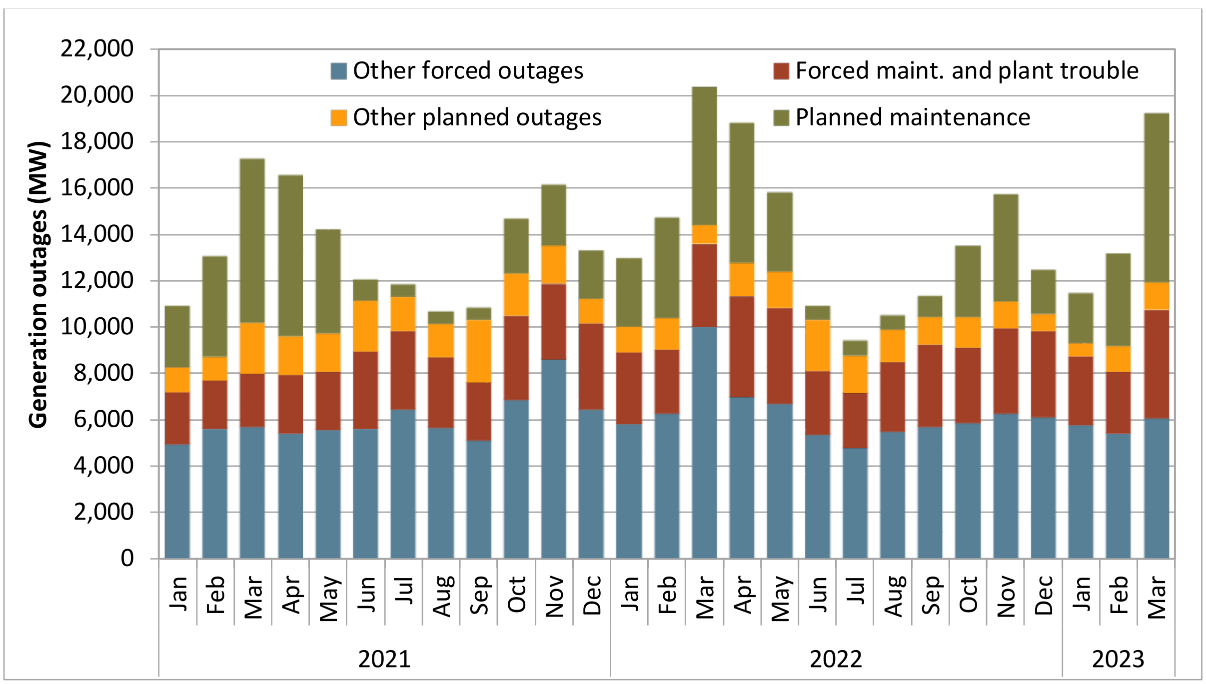


Figure 1.8 Monthly average of maximum daily generation outages by type – peak hours

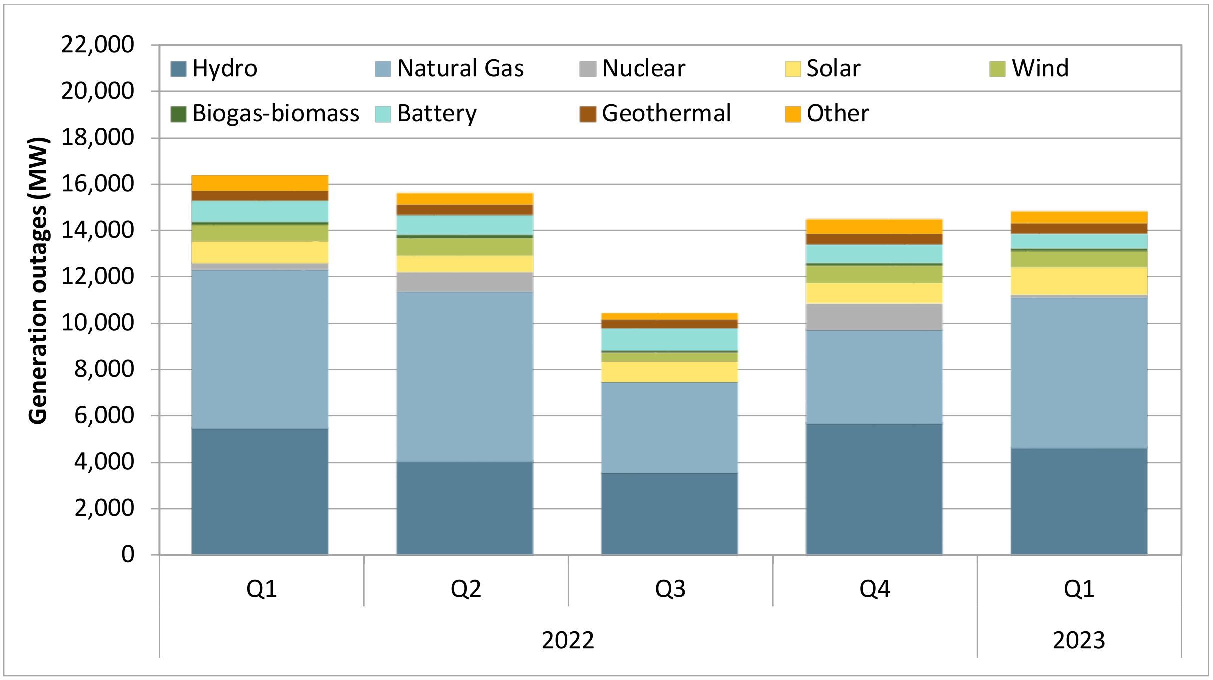


Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 6,475 MW and 4,625 MW during the first quarter, respectively. These two fuel types accounted for a combined 75 percent of the generation on outage for the quarter. The amount of hydroelectric generation on outage decreased 15 percent relative to the same time last year.

Figure 1.9 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[9] Solar, wind, and geothermal generation had an increase in average capacity on outage, while all other fuel types saw a decrease compared to the first quarter of 2022.

Figure 1.9 Quarterly average of maximum daily generation outages by fuel type – peak hours



1.2 Energy market performance

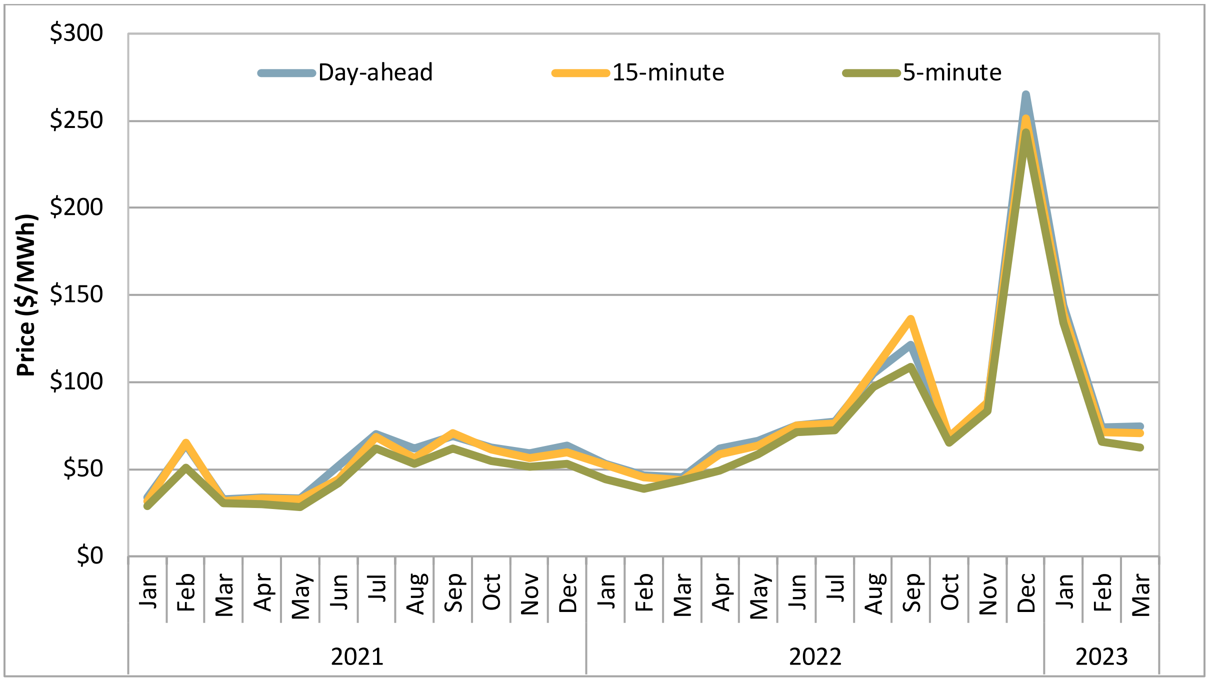
1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Prices in all three markets were about 2 times higher this quarter compared to the first quarter last year. The average price in all three markets this quarter increased to $93/MWh from $46/MWh in the same quarter last year.

Figure 1.10 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2021 to March 2023.

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

Figure 1.10 Monthly load-weighted average energy prices for California ISO (all hours)



Over the quarter, day-ahead prices averaged $97/MWh, 15-minute prices averaged $93/MWh, and 5-minute prices averaged $87/MWh. Prices across all three markets were about 2 times higher than the first quarter last year. In January, the average prices in all three markets stood at around $140/MWh, reflecting a significant drop from December 2022's figure of $253/MWh, yet still maintaining a relatively high level. In March 2023, the prices in all three markets stabilized around $70/MWh.

High gas prices drove the high energy prices seen in the first quarter. Figure 1.11 shows monthly average gas prices at SoCal Citygate and load-weighted energy prices from October 2021 to March 2023. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. In December 2022, the gas price surged to $31/MMBtu while energy prices surged to $253/MWh.[10] In 2023, energy prices decreased in line with falling gas prices. While January's energy prices remained high compared to the previous year, by February both energy and gas prices had returned to levels comparable to those of the same month in the previous year. This strong correlation between energy and gas prices can be attributed to gas-fired units often serving as the price-setting units within the market. A high gas price increased the marginal cost of generation for gas-fired units and non-gas-fired resources with opportunity costs indexed to gas prices. Market bids reflected these higher marginal costs.

[10] See Section 1.1.1 for more information on natural gas prices during this time period.

Figure 1.11 Monthly average SoCal City gas price and load-weighted average energy price for California ISO

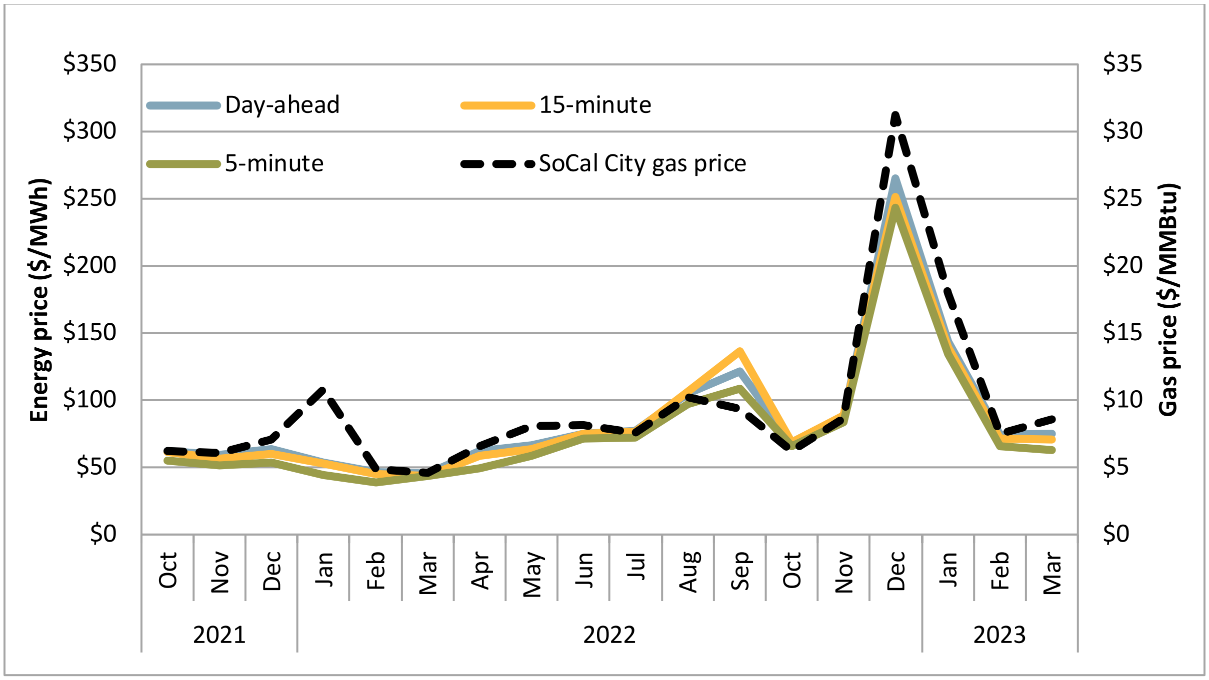
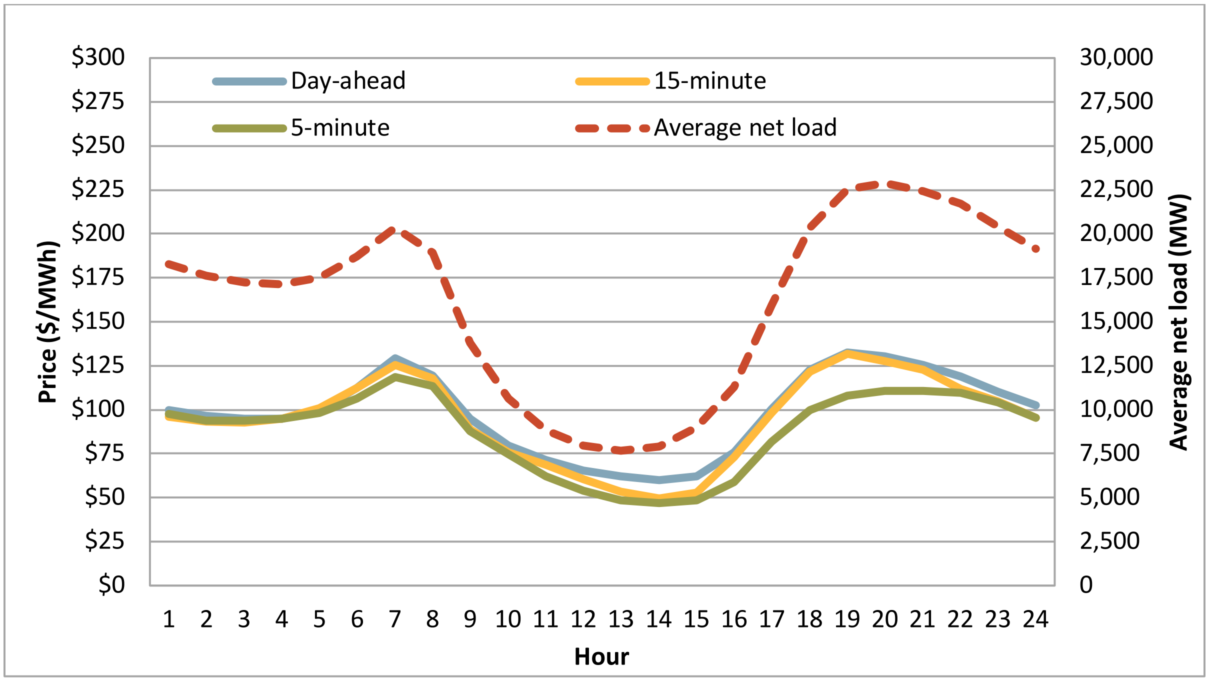


Figure 1.12 illustrates the hourly load-weighted average energy prices for the first quarter compared to the average hourly net load.[11] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening, and peaked at 8:00 p.m. when demand was still high but solar generation was substantially lower. The average net load in this quarter reached 22,883 MW at 8:00 p.m. At this hour, the day-ahead load-weighted average energy price was $130/MWh, the 15-minute price was $127/MWh, and the 5-minute price was $110/MWh.

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

Figure 1.12 Hourly load-weighted average energy prices (January - March)



1.2.2 Bilateral price comparison

Elevated gas prices in January 2023 led to high energy prices in the California ISO (CAISO) balancing area and at the Mid-Columbia and Palo Verde bilateral hubs. Regional differences in prices reflect transmission constraints and greenhouse gas compliance costs.

Figure 1.13 shows the CAISO day-ahead weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours ending 7 through 22) for all days, excluding Sundays and holidays. The figure shows higher than normal prices in the CAISO and at bilateral hubs during January when gas prices across the west were persistently high.

Figure 1.13 Day-ahead California ISO and bilateral market prices (January - March)

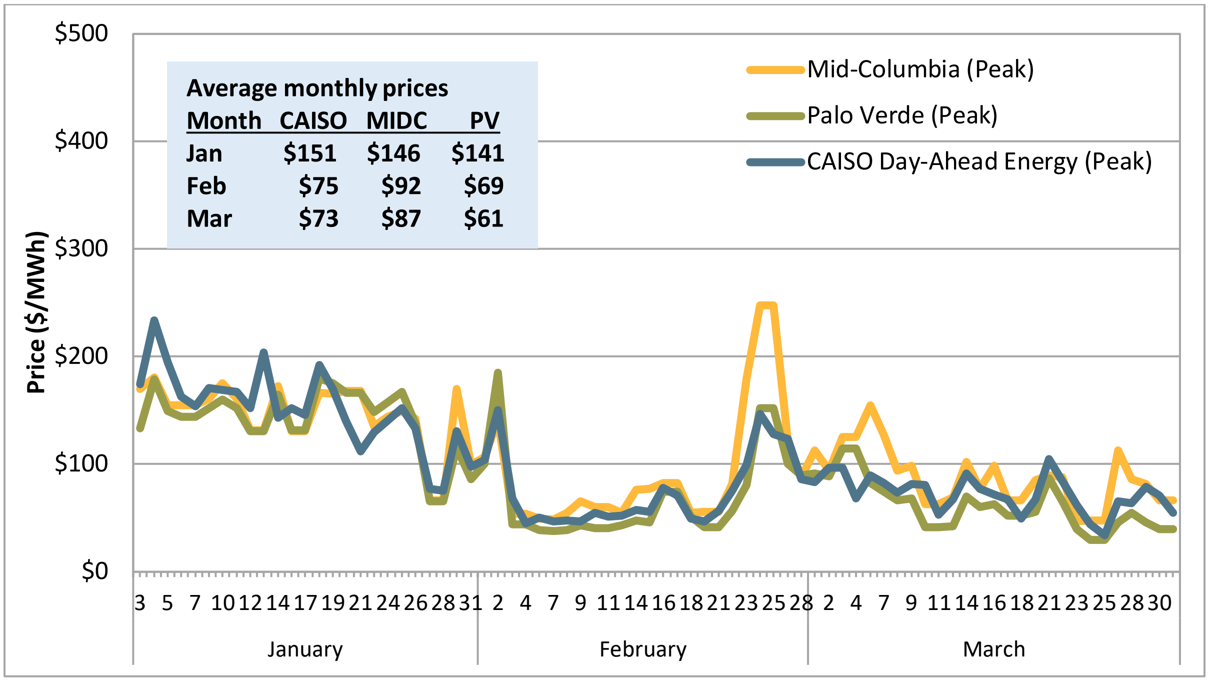
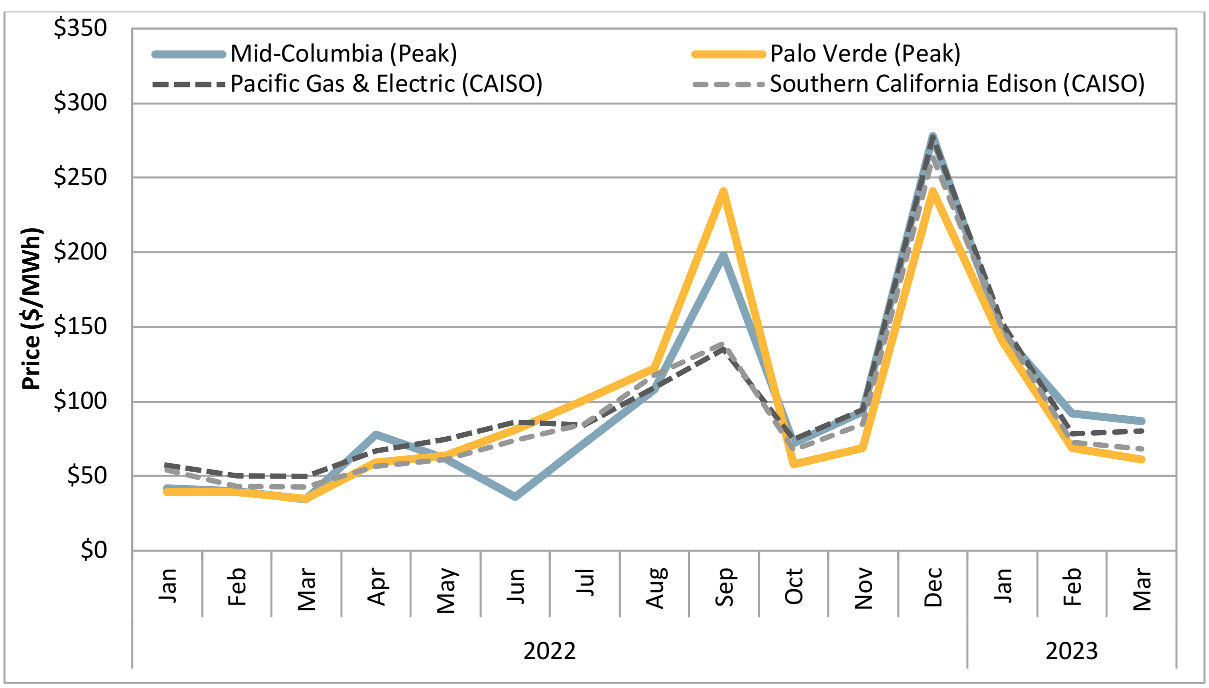


Figure 1.14 uses the same data underlying Figure 1.13 but on an average monthly basis for 2022 and 2023. Prices in the CAISO balancing area are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). As shown in this figure, average prices in January at the Palo Verde and Mid-Columbia hubs were trending closer to prices in the California ISO.

Figure 1.14 Monthly average day-ahead and bilateral market prices



Average day-ahead prices in the California ISO balancing area and bilateral hubs (from 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 greater than average real-time prices at Mid-Columbia and Palo Verde by $4/MWh and $9/MWh, respectively. Average day-ahead prices at Mid-Columbia were greater than average real-time prices (from Powerdex) by $11/MWh. At Palo Verde, average day-ahead prices (from ICE) were similar to average real-time prices (from Powerdex).

Beginning on April 8, 2022, FERC started issuing orders in response to cost justification filings from sellers who made sales above the WECC soft offer cap during the August 2020 heat wave event. In particular, FERC has ordered some sellers to refund the premium they charged above the index price, for sellers whose sales were above the prevailing index price.[12] DMM estimates the refunds to be about $5.1 million out of $90 million in bilateral sales exceeding the WECC soft offer cap during August 2020.[13] Based on FERC rulings on the cost justification filings for June 2021, DMM estimates the refunds to be about $1.6 million out of $34 million in bilateral sales exceeding the WECC soft offer cap. FERC has yet to rule on some of the cost justification filings for June 2021, and has not begun issuing orders related to the August and September 2022 filings. A motion is pending at FERC to raise the soft offer cap from $1,000/MWh to $2,000/MWh for spot sales in WECC's bilateral markets.[14]

Imports and exports

During the first quarter, average imports decreased while exports increased slightly compared to the same quarter in 2022. As shown in Figure 1.15, peak imports in the day-ahead (dark blue line) decreased in all hours when compared to the same quarter of 2022, peaking at about 3,400 MW in hour-ending 19. Peak 15-minute cleared imports (dark yellow line) also decreased in all hours of the day, peaking around 4,400 MW over the peak hours of 17 to 21. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased in both the day-ahead and 15-minute markets compared to the same quarter of 2022. These increases over the peak hours of 17 to 21 were between 200 MW and 300 MW.

Compared to the same quarter in the previous year, the average net interchange when exporting increased in the middle of the day, both excluding (dashed black line) and including (solid grey line) WEIM transfers, at about 1,800 MW and 1,300 MW on average by hour. During the solar ramp down period, imports decreased both when excluding and including the WEIM, to an hourly average of 3,800 MW and 3,500 MW, respectively. These values are based on meter data and averaged by hour and quarter.

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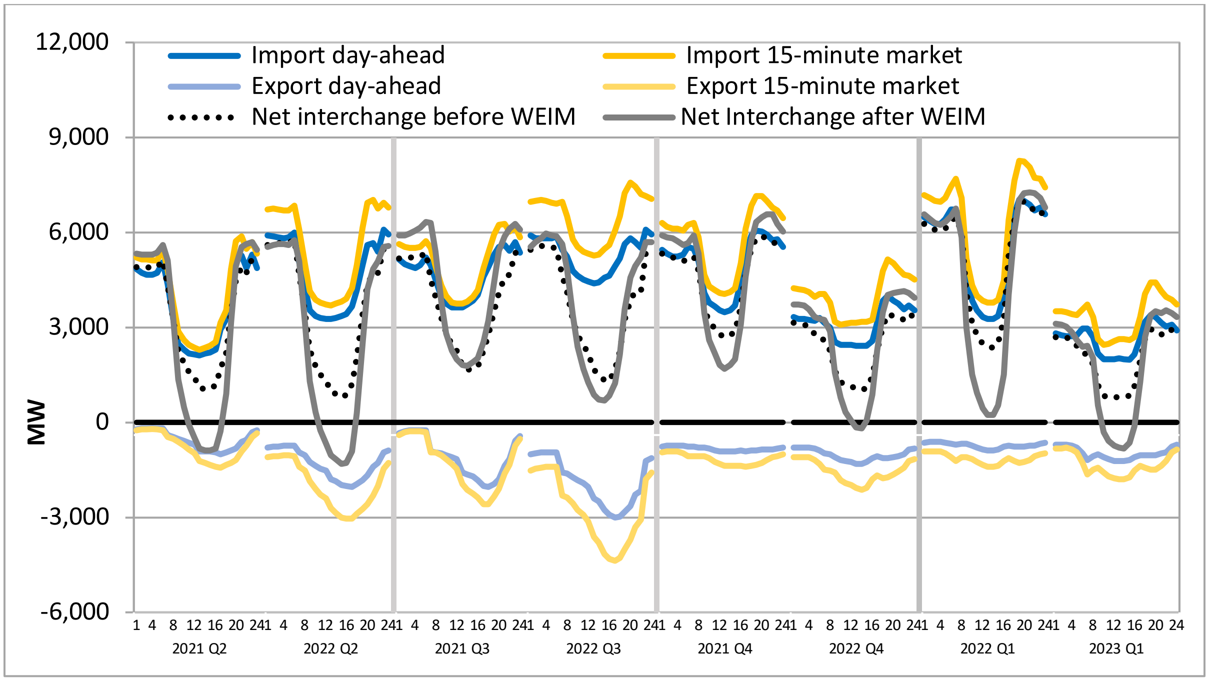
12 FERC issued orders on a number of sellers and directing them to refunds for sales during August 2020. Following order directing refunds re Mercuria Energy America, LLC under ER21-46: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220422-3059&optimized=false

13 DMM estimates are based on public FERC cost justification filings and FERC electric quarterly report (EQR) data.

14 FERC Docket No. ER21-64*, Macquarie Energy, LLC submits Explanation for Bilateral Spot Sales in Western Electricity Coordinating Council*: eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. ER21-46, *Mercuria Energy America, LLC submits Tariff Filing per 35: Explanation for Bilateral Spot Sales in the West*: eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. EL10-56*, Macquarie Energy and Mercuria Energy filings, July 19, 2021*: eLibrary | Docket Search Results (ferc.gov)

The solid grey line, which adds incremental WEIM interchange, reached a low point of about negative 800 MW in hour ending 13 and 14. The greatest import transfer into the California ISO area from the WEIM occurred in hour ending 22, at about 800 MW, about 200 MW more than in the same quarter of 2022. Export transfer from the California ISO to the WEIM primarily occurred between hours ending 9 to 17, with hour ending 16 topping out at about 1,600 MW. This is a decrease from the same quarter of the previous year where maximum exports in hour ending 13 were 2,100 MW.

Figure 1.15 Average hourly net interchange by quarter



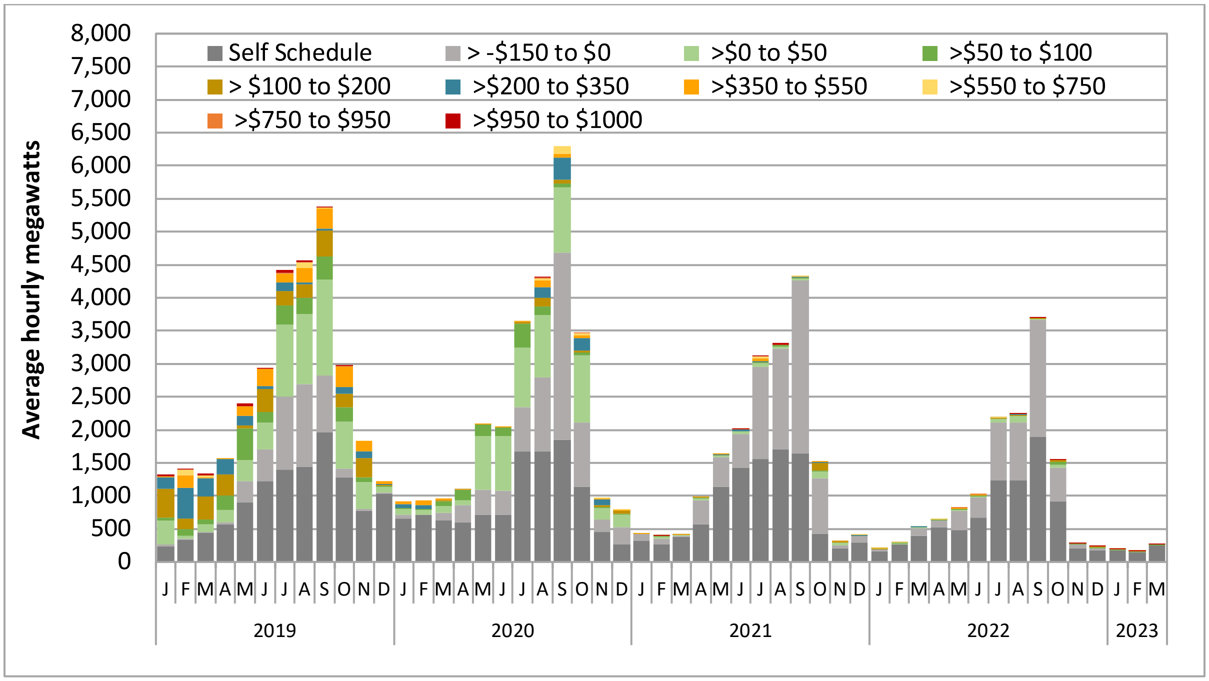
In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the CAISO markets at or below $0/MWh, at minimum in the availability assessment hours.[15] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices. An overall decline in volumes began in late 2020 and continued through the first quarter of 2023. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 1.16 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[16] The grey bars reflect import capacity that was self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market.

15 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 CAISO 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 MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

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

Figure 1.16 Average hourly resource adequacy imports by price bin



1.3 Price variability

Price variability this quarter significantly increased in the day-ahead, 15-minute, and 5-minute markets compared to the same quarter last year. All three markets experienced a minor rise in the frequency of high prices between $250/MWh and $500/MWh. The frequency of negative prices in all three markets showed a marginal decrease in the first quarter of 2023.

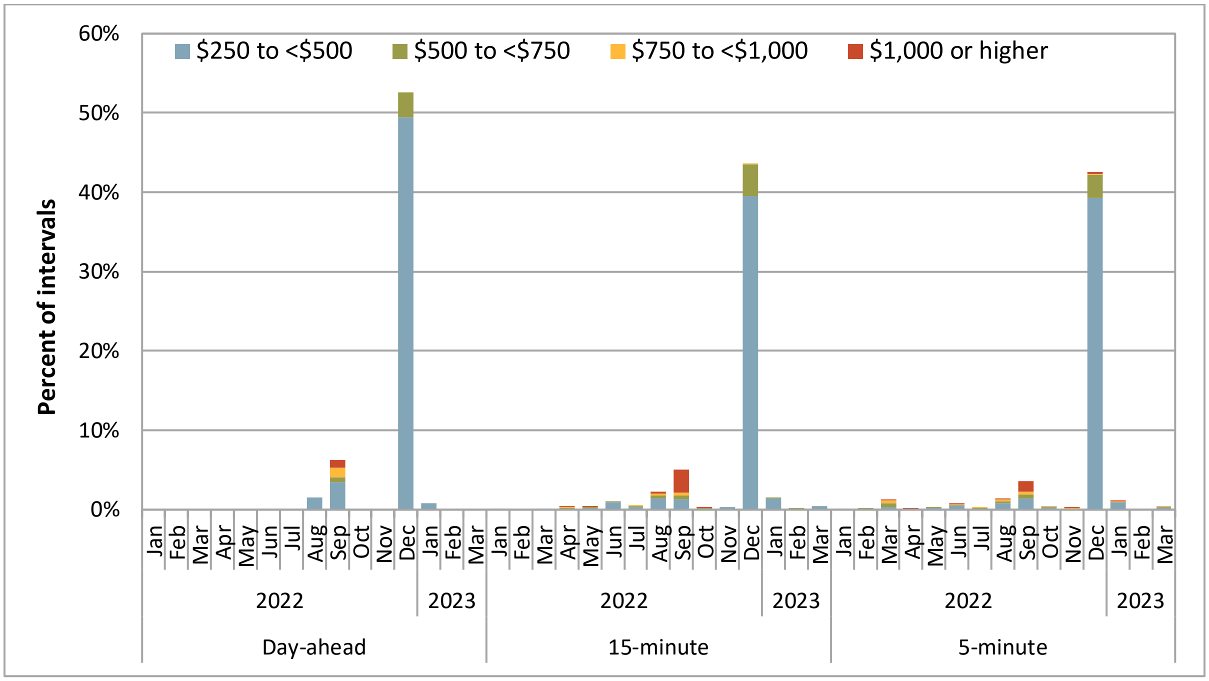
High prices

Figure 1.17 shows the frequency of high prices across all three markets for the three largest load aggregation points (LAP) by month between January 2022 and March 2023. In the day-ahead market, the frequency of high prices over $250/MWh slightly increased in the first quarter compared to the previous year. In 2022, no intervals had prices above $250/MWh between January and March. However, in 2023, 0.3 percent of intervals had prices above $250/MWh during the period. The majority of the high prices occurred during January where 0.9 percent of intervals had price above $250/MWh.

The 15-minute market had a higher frequency of price spikes in this quarter compared to previous periods. Prices above $250/MWh rose to 0.7 percent from 0.3 percent in the first quarter compared to the same period last year. The majority of the high prices occurred during January where 1.4 percent of intervals had price above $250/MWh.

The 5-minute market also had slightly more frequent price spikes this quarter. Prices above $250/MWh rose to 0.5 percent in the first quarter of 2022 from 0.4 percent in the same quarter last year. The majority of the high prices occurred during January where 1.0 percent of intervals had prices above $250/MWh.

Figure 1.17 Frequency of high prices ($/MWh) by month



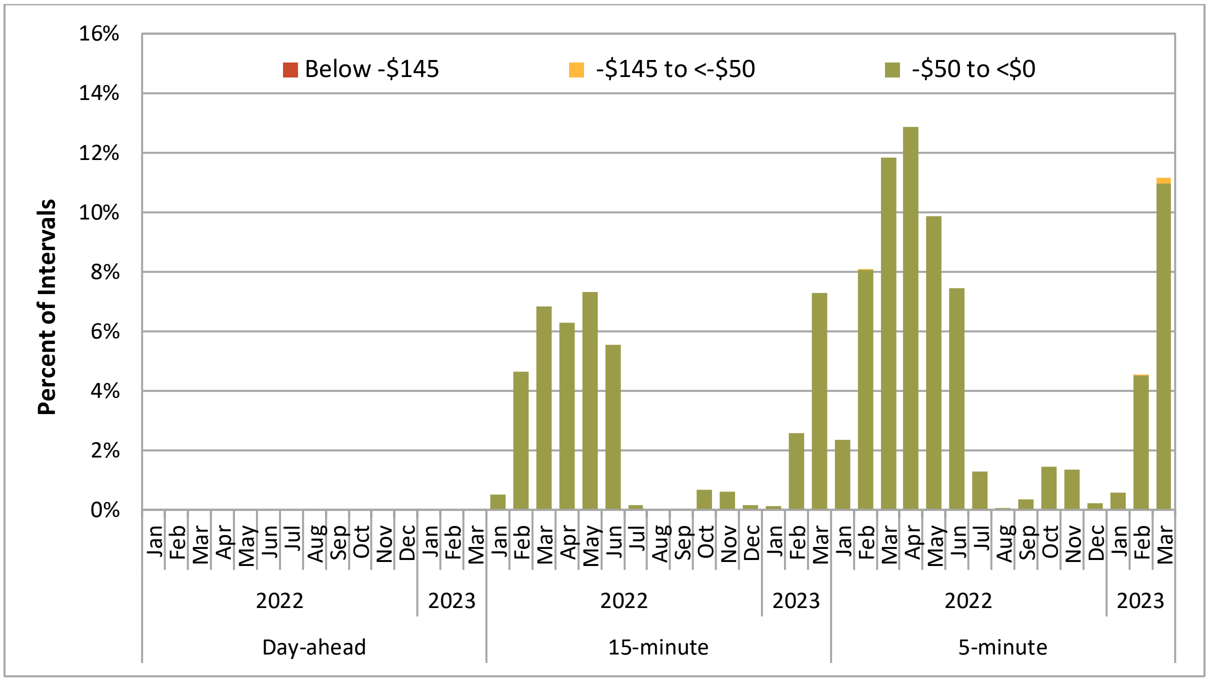
High natural gas prices in SoCal Citygate contributed to the higher frequency of high prices this January as illustrated in Figure 1.1. Natural gas-fired units are often the marginal energy source of generation in the CAISO balancing area, as well as other regional markets, and often result in higher system marginal energy prices across the CAISO footprint.

Negative prices

Figure 1.18 shows the frequency of negative prices across all three markets for the three largest load aggregation points (LAP) by month between January 2022 and March 2023. The frequency of negative price intervals marginally decreased compared to the first quarter in 2022. Negative prices tend to be most common when renewable production is high and demand is low. Low-cost renewable resources often bid at or below zero, increasing the potential of becoming the marginal energy source for that period. This leads to a higher frequency of negative prices in the real-time markets, which experience more negative prices than the day-ahead market.

In the 15-minute market, negative prices decreased to 1.1 percent this quarter compared to 1.3 percent in the first quarter of last year. In the 5-minute market, negative prices decreased to 1.8 percent this quarter compared to 2.5 percent in the first quarter of last year. There were no negative prices in the day-ahead market during the first quarters of 2022 or 2023.

Figure 1.18 Frequency of negative prices ($/MWh) by month



1.4 Convergence bidding

Convergence bidding is designed to align day-ahead and real-time prices by allowing financial arbitrage between the two markets. During most hours, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. Convergence bidding continued to be profitable overall for most entities engaged in virtual bidding during the first quarter of 2023. The majority of profits continue to be received by financial entities (80 percent) and marketers (11 percent), with about 9 percent going to entities with physical load and generation.

1.4.1 Convergence bidding revenues

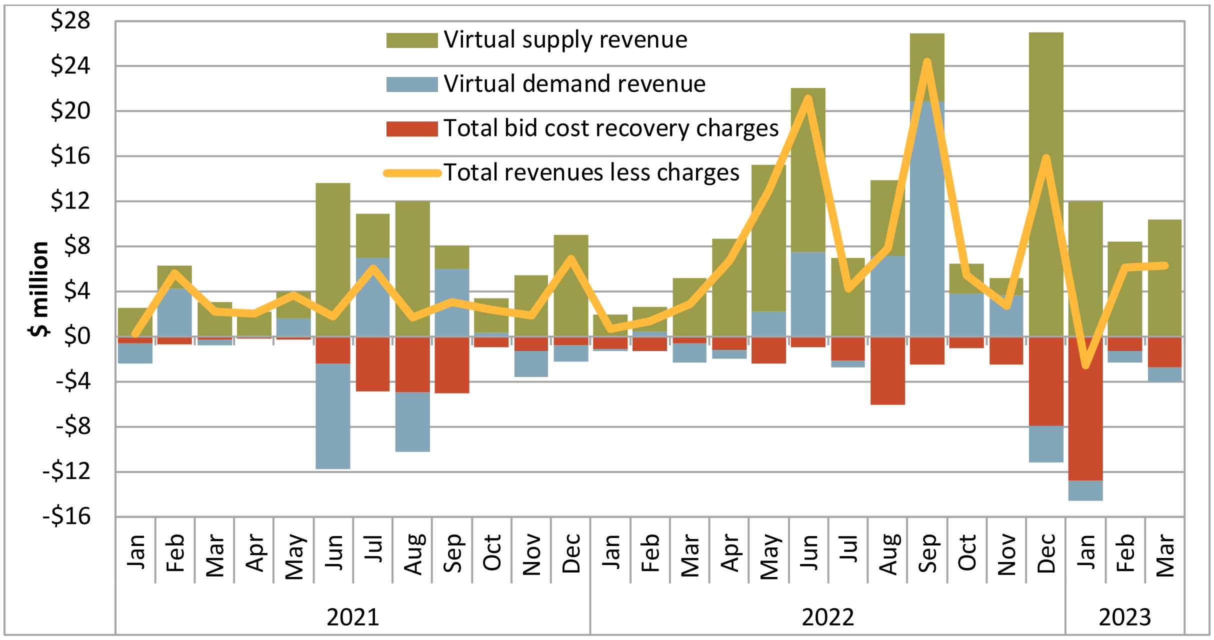
Net revenues for convergence bidders were about $9.9 million for the first quarter, after inclusion of about $16.9 million of virtual bidding bid cost recovery charges which are primarily associated with virtual supply. Figure 1.19 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

- Total market revenues were negative for January and positive for March and April of the quarter. The high level of bid cost recovery costs pushed market revenues negative in January. These higher costs are associated with virtual supply sharing the costs of higher levels of residual unit commitment quantities and costs.
- Virtual demand revenues were negative in total for all months of the quarter, about -$1.8 million, -$1.0 million, and -$1.3 million for January, February, and March, respectively.

- Virtual supply revenues were positive in total for all months of the quarter, $12.0 million, $8.4 million, and $10.4 million for January, February, and March, respectively.

Convergence bidders received approximately $9.9 million after subtracting bid cost recovery charges during the first quarter. Bid cost recovery charges were about $12.8 million, $1.3 million, and $2.8 million for January, February, and March, respectively.

Figure 1.19 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.1 compares the distribution of convergence bidding cleared volumes and revenues before and after taking into account bid cost recovery, in millions of dollars, among different groups of convergence bidding participants.[17,18]

Financial entities represented the largest segment of the virtual bidding market for the current quarter, with 79 percent of volume and 80 percent of the settlement revenue. Marketers held about 20 percent of volume and 11 percent of settlement revenue while generation owners and load serving entities represented about one percent of volumes and around nine percent of settlement revenues.

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17 This table summarizes data from the CAISO settlements database and is based on a snapshot on 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

18 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.

In general, prices in the 15-minute market were consistently lower than day-ahead prices in the first quarter. This resulted in overall negative virtual demand revenues for each month of the quarter. However, virtual supply experienced a number of days[19] in the quarter with major negative revenue when market prices in the 15-minute were consistently below the day-ahead prices.

Table 1.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2023 Q1								
Financial	1,775	2,302	4,077	-$3.05	$24.39	-$11.84	$12.55	$9.50
Marketer	438	571	1,010	-$1.11	$6.31	-$3.90	$2.41	$1.30
Physical load	0	20	20	$0.00	$0.11	-$1.07	-$0.96	-$0.96
Physical generation	23	3	26	$0.05	$0.04	$0.00	$0.03	$0.08
Total	**2,236**	**2,897**	**5,133**	**-$4.12**	**$30.85**	**-$16.82**	**$14.03**	**$9.92**

1.5 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the first quarter of 2023 was 50 percent higher than the same quarter of 2022. High levels of RUC capacity procurement, especially on some days in January, was driven by increased cleared virtual supply, manual operator adjustments, and under-scheduling for load in the integrated forward market (IFM). This led to virtual supply sharing the cost of these increased RUC commitments and resulted in overall negative market revenues for virtual bidders in January 2023.[20]

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

Figure 1.20 shows that residual unit commitment procurement was primarily driven by operator adjustments in the first quarter. These manual adjustments increased significantly to about 807 MW per hour in the first quarter, compared to 74 MW per hour in the same quarter in 2022.

The figure also shows that residual unit commitment capacity was procured by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 9 percent lower in the first quarter than in the same quarter of 2022.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar in Figure 1.20) represent the difference in cleared supply (both physical and virtual) compared to the CAISO load forecast. On average, this factor contributed towards increasing residual unit commitment requirements in the first quarter of 2023, averaging 98 MW per hour.

19 Dates include: January 2, 4, 22, 29, and 30, February 14 and 15, and March 1, 2, 7, and 29.

20 For more information, refer to Section 1.4.1.

Lastly, 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 bar in Figure 1.20.

Figure 1.20 Determinants of residual unit commitment procurement

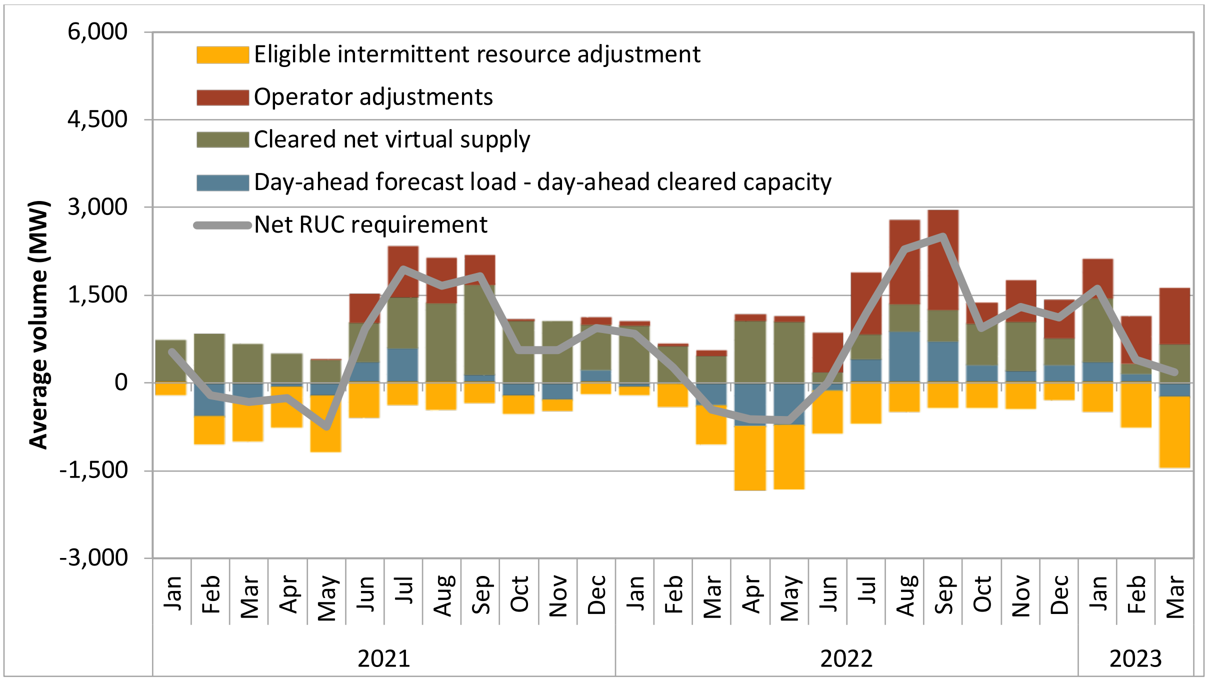
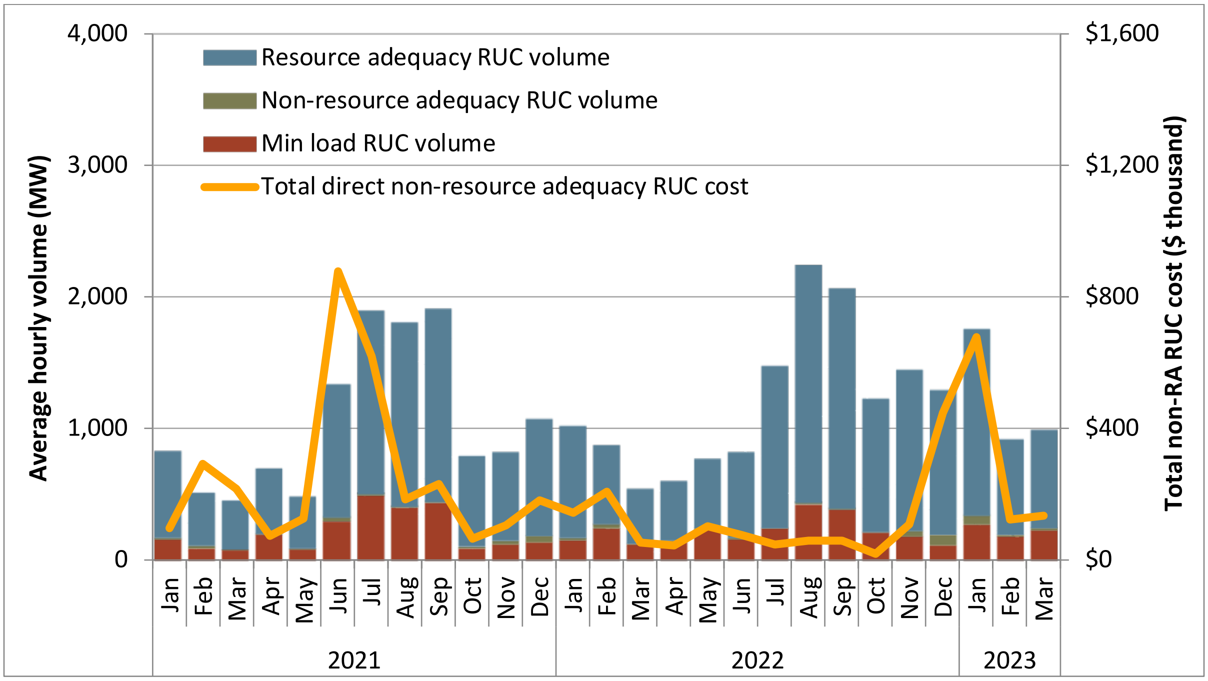


Figure 1.21 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased about 50 percent to about 1,223 MW in the first quarter of 2023 from an average of about 817 MW in the same quarter of 2022. Of the 1,223 MW capacity, the capacity committed to operate at minimum load averaged 227 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 committed in this process receive capacity payments.[21] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.21. In the first quarter of 2023, these costs were about $0.9 million, more than twice the costs in the same quarter of 2022.

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

Figure 1.21 Residual unit commitment costs and volume



1.6 Ancillary services

Ancillary service payments totaled $39.7 million, a 10 percent decrease from the same quarter last year. Average requirements were higher for regulation up and regulation down, and lower for operating reserves compared to the first quarter of 2022.

1.6.1 Ancillary service requirements

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

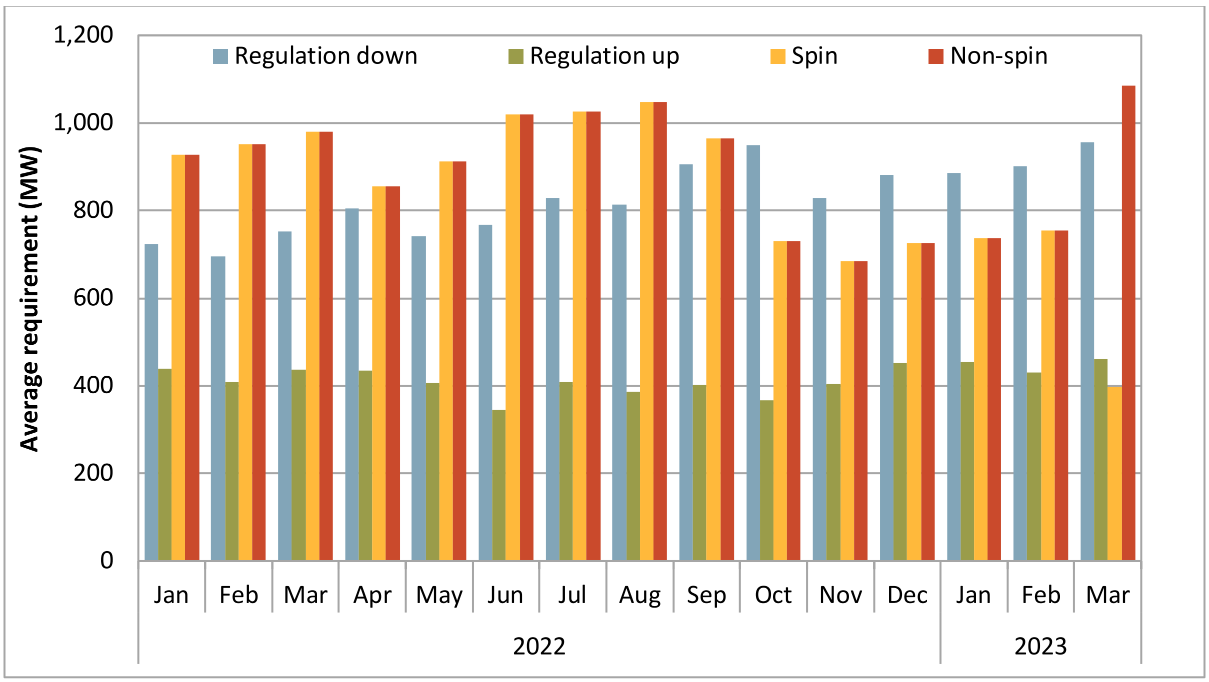
The California ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions.[22] Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency, or (3) 15 percent of forecasted solar production. 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.

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

Figure 1.22 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Average requirements for operating reserves decreased 22 percent this quarter compared to the first quarter of 2022. 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. In March, spinning reserve accounted for 27 percent operating reserves requirements on average.

Regulation down and regulation up requirements increased 22 percent and 5 percent, respectively, compared to the first quarter of 2022.

Figure 1.22 Average monthly day-ahead ancillary service requirements



1.6.2 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 pays a pre-determined 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 first quarter of 2023. This was the third consecutive quarter where there were no ancillary service scarcity events.

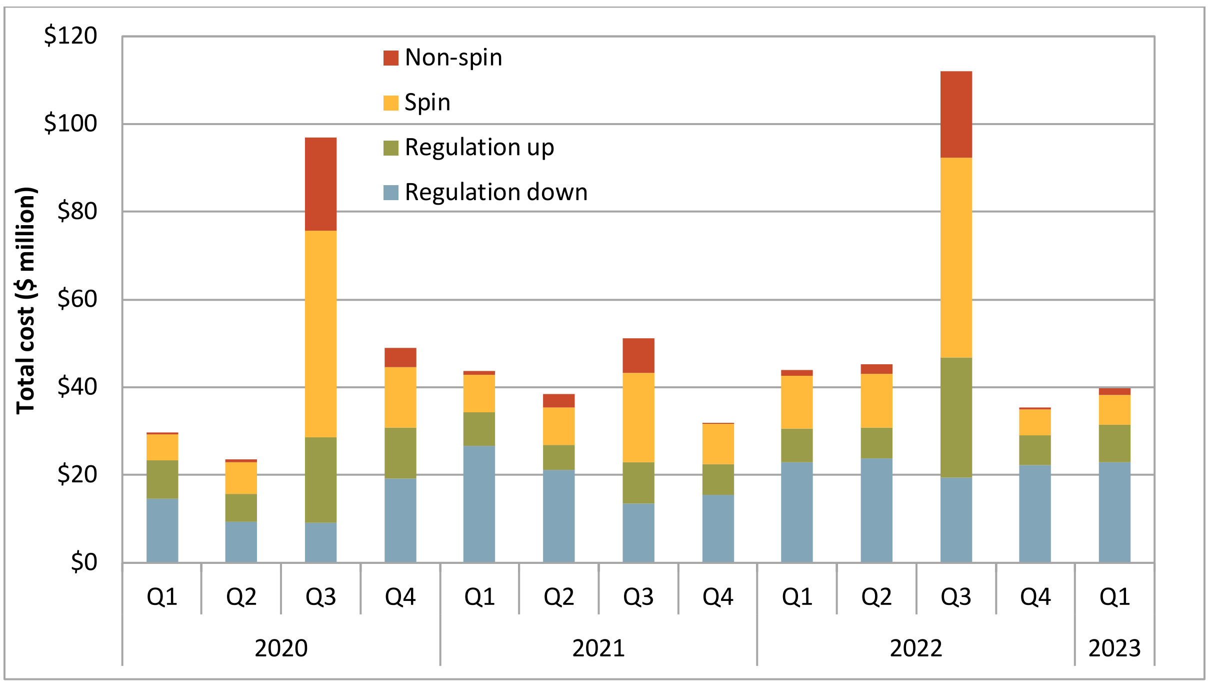
The lack of scarcity events in recent quarters can be attributed in part to the rapidly increasing participation of battery storage resources. However, the CAISO has reported on an increasing frequency of resources – especially batteries – that fail to deliver awarded regulation in real-time.[23] These failures are not reflected in the market results that generate scarcity alerts.

1.6.3 Ancillary service costs

Ancillary service payments totaled $39.7 million, compared to $35.3 million in the previous quarter. Ancillary service payments were $4.3 million less than in the first quarter of 2022.

Figure 1.23 shows the total cost of procuring ancillary service products by quarter.[24] Payments for spinning reserve had the largest year-over-year decrease as a result of lower requirements relative to total operating reserve requirements. The remaining operating reserve requirements were fulfilled by non-spinning reserves, which are cheaper to procure. Spinning reserve payments decreased $5.5 million, or 45 percent, compared to 2022.

Figure 1.23 Ancillary service cost by product



[23] California ISO, *Market Performance and Planning Forum*, March 16, 2023, slides 42-47: Presentation-MarketPerformancePlanningForum-Mar16-2023.pdf (caiso.com)

[24] 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.

1.7 Congestion

In the day-ahead market, congestion in the first quarter was more impactful than the same quarter last year, raising prices in PG&E while lowering prices in SCE and SDG&E. In the 15-minute and 5-minute markets, the impact of internal congestion generally raised prices in the Pacific Northwest and lowered prices in the Southwest.

The following sections provide an assessment of the frequency and impact of congestion on prices in the day-ahead and 15-minute markets. It assesses the impact of congestion on local areas in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric) as well as on WEIM entities.

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.

The impact of congestion on each pricing node in the CAISO 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.[25]

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.

1.7.1 Congestion in the day-ahead market

Day-ahead market congestion frequency tends to be higher than in the 15-minute market, but price impacts to load tend to be lower. The congestion pattern in this quarter reflects this overall trend.

Congestion rent and loss surplus

In the first quarter of 2023, congestion rent and loss surplus was $280 million and $89 million, respectively. These respective amounts represent an increase of 129 percent and 94 percent relative to the same quarter of 2022.[26] Figure 1.24 shows the congestion rent and loss surplus by quarter for 2022 and 2023.

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

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

26 Due to the availability of data, comparative analysis in Figure 1.24 and the day-ahead congestion rent and loss surplus in the first quarter of 2023 are preliminary.

surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[27]

Figure 1.24 Day-ahead congestion rent and loss surplus by quarter (2022-2023)

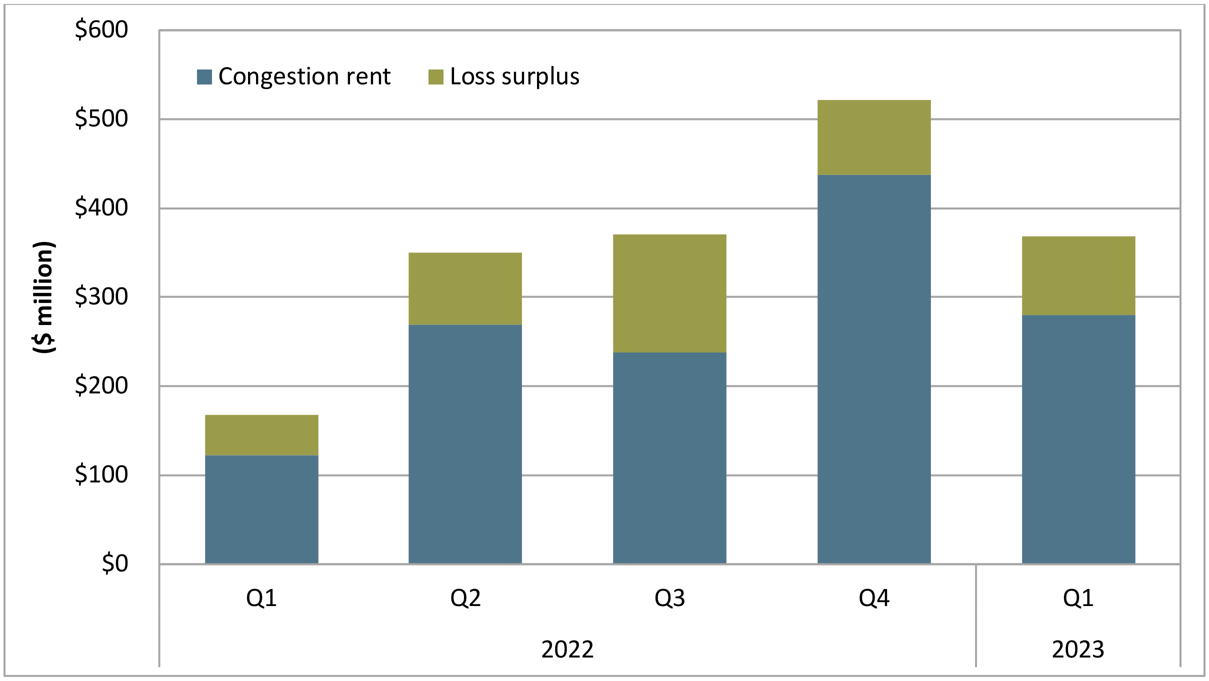


Figure 1.25 shows the overall impact of congestion on day-ahead prices in each load area in 2022 and 2023. Figure 1.26 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in the first quarter was higher than during same quarter last year. The impact during the first quarter of 2023 was slightly less than during the fourth quarter of 2022.
- Day-ahead congestion increased quarterly average prices in PG&E by $2.15/MWh (2.1 percent), while it decreased average SCE and SDG&E prices by $1.44/MWh (1.5 percent) and $1.05/MWh (1.1 percent), respectively.
- The primary constraints impacting day-ahead market prices were the Panoche-Gates #2 230 kV line, Moss Landing-Las Aguilas 230 kV line, and Metcalf 500/230 kV transformer Bank 13.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion on constraints that had the largest impact on price separation is provided below.

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

Figure 1.25 Overall impact of congestion on price separation in the day-ahead market

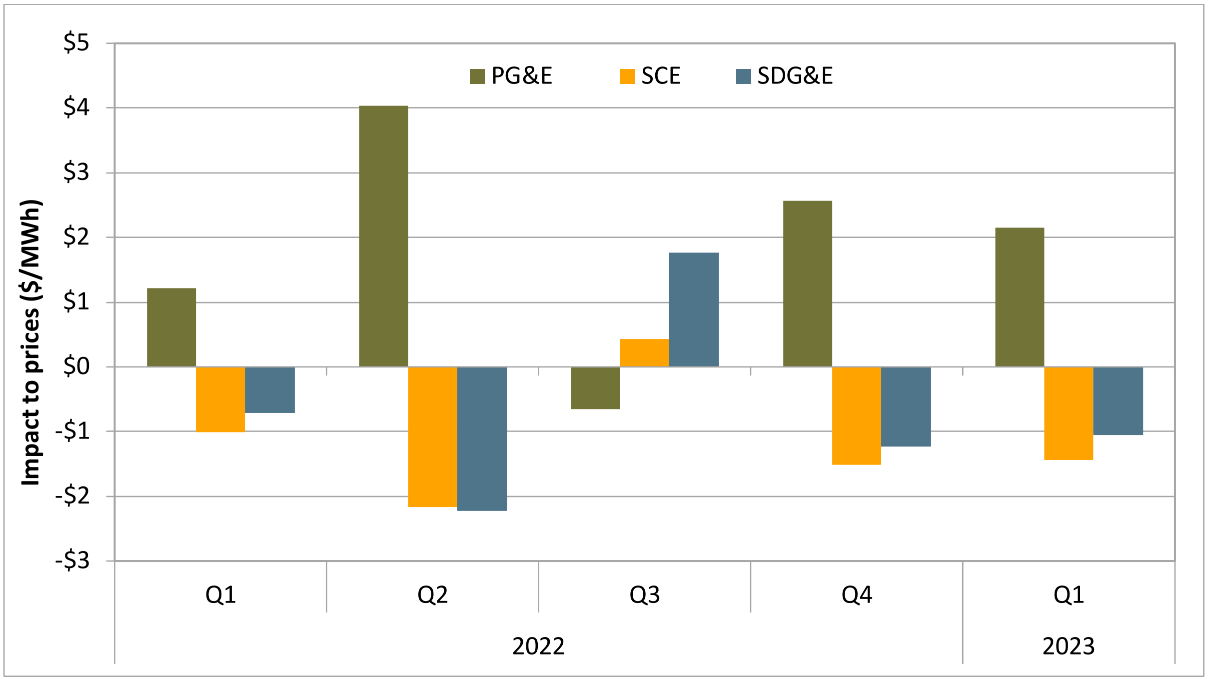
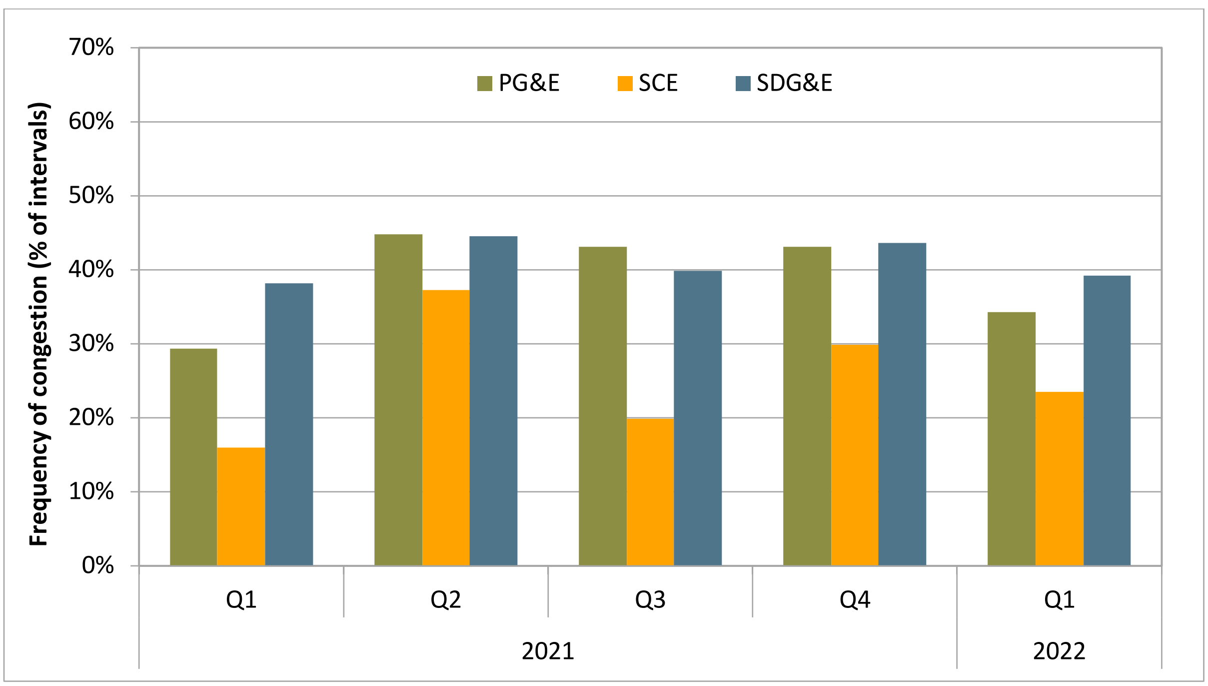


Figure 1.26 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation during the quarter by constraint.[28] Table 1.3 shows the impact of congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The constraints with the greatest impact on day-ahead price separation for the quarter were the Panoche-Gates #2 230 kV line, Moss Landing-Las Aguilas 230 kV line, and Metcalf 500/230 kV transformer Bank 13.

Panoche-Gates #2 230 kV line

The Panoche-Gates #2 230 kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) had the greatest impact on day-ahead prices during the first quarter. The line was congested during 12 percent of hours. When binding, it increased PG&E prices by $10.52/MWh, and decreased SCE and SDG&E prices by $11.78/MWh and $11.82/MWh, respectively. For the quarter, congestion on the line increased average PG&E prices by $1.29/MWh (1.3 percent), and decreased average SCE and SDG&E prices by $0.88/MWh (0.9 percent) and $0.75/MWh (0.8 percent). This line was frequently binding due to loss of the Moss Landing-Los Banos #1 500 kV line.

Moss Landing-Las Aguilas 230 kV line

The Moss Landing-Las Aguilas 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1 _1) bound in 8 percent of hours over the quarter. When binding, it increased prices in PG&E by $4.03/MWh and decreased prices in SCE and SDG&E by $3.69/MWh and $3.92/MWh, respectively. For the quarter, congestion on the constraint increased average PG&E prices by $0.33/MWh (0.3 percent) and decreased average SCE and SDG&E prices by $0.19/MWh (0.2 percent) and $0.15/MWh (0.2 percent), respectively. This line was frequently mitigated for the loss of the Moss Landing-Los Banos 500 kV line.

Metcalf 500/230 kV transformer

The Metcalf 500/230 kV transformer Bank 13 (30735_METCALF_230_30042_METCALF _500_XF_13) bound in about 2 percent of hours. When binding, it increased PG&E prices by $8.97/MWh and decreased SCE and SDG&E prices by $6.22/MWh and $6.14/MWh, respectively. For the quarter, the constraint increased average PG&E prices by about $0.20/MWh (0.2 percent), and decreased average SCE and SDG&E prices by $0.14/MWh (0.1 percent) and $0.14/MWh (0.1 percent), respectively. This constraint was impacted by maintenance on the Metcalf 500/230 kV transformer Bank 12.

[28] Details on constraints with shift factors less than 2 percent have been grouped in the ‘Other’ category.

Table 1.2 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$1.29	1.28%	-$0.88	-0.91%	-$0.75	-0.77%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.33	0.32%	-$0.19	-0.19%	-$0.15	-0.16%
	30735_METCALF _230_30042_METCALF _500_XF_13	$0.20	0.20%	-$0.14	-0.15%	-$0.14	-0.14%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.12	0.12%	-$0.11	-0.11%	-$0.10	-0.10%
	7440_MetcalfImport_Tes-Metcalf	$0.11	0.11%	-$0.08	-0.08%	-$0.08	-0.08%
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_2 _1	$0.11	0.11%	-$0.08	-0.09%	-$0.08	-0.08%
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	$0.05	0.05%	-$0.05	-0.05%	-$0.04	-0.04%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.03	0.03%	-$0.02	-0.02%	-$0.02	-0.02%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.02	0.02%	-$0.02	-0.02%	-$0.02	-0.02%
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	$0.02	0.02%	-$0.02	-0.02%	-$0.01	-0.01%
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.01	-0.01%	$0.01	0.01%	$0.01	0.01%
SCE	6410_CP5_NG	-$0.12	-0.12%	$0.10	0.11%	$0.09	0.10%
	SYLMAR-AC_BG_NG	-$0.02	-0.02%	$0.02	0.02%	-$0.05	-0.05%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.01	-0.01%	$0.01	0.01%	$0.04	0.05%
	6410_CP7_NG	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
SDG&E	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.20	0.21%
	OMS_13175630_SUNCREST BK81_NG	-$0.01	-0.01%	$0.00	0.00%	$0.14	0.15%
	OMS_13175637_SUNCREST BK80_NG	-$0.01	-0.01%	$0.00	0.00%	$0.09	0.09%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.07	0.07%
	22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.04	0.04%
	OMS 13108255_TL50003_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.03%
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.02%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.02%
	22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.02%
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	$0.00	0.00%	$0.00	0.00%	-$0.02	-0.02%
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	$0.00	0.00%	$0.00	0.00%	-$0.40	-0.41%
Other		$0.03	0.03%	$0.01	0.01%	$0.05	0.06%
Total		**$2.15**	**2.13%**	**-$1.44**	**-1.50%**	**-$1.05**	**-1.08%**

Table 1.3 Impact of congestion on day-ahead prices during congested hours

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	1.0%	$12.53	-$10.81	-$9.91
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	12.2%	$10.52	-$11.78	-$11.82
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	0.6%	$9.41	-$8.09	-$7.39
	30735_METCALF _230_30042_METCALF _500_XF_13	2.3%	$8.97	-$6.22	-$6.14
	7440_MetcalfImport_Tes-Metcalf	1.3%	$8.73	-$6.27	-$5.98
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.1%	$5.90	-$5.05	-$4.44
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.5%	$4.68	-$3.70	-$3.41
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_2 _1	2.4%	$4.45	-$3.49	-$3.32
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	0.5%	$4.05	-$3.24	-$2.96
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	8.1%	$4.03	-$3.69	-$3.92
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	1.8%	$1.44	-$1.25	-$1.13
	30735_METCALF _230_30042_METCALF _500_XF_12	0.9%	$1.39	-$1.12	-$1.11
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.1%	-$9.74	$8.55	$7.88
SCE	6410_CP5_NG	1.0%	-$12.04	$10.70	$9.63
	SYLMAR-AC_BG_NG	0.8%	-$2.79	$2.81	-$6.40
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	6.5%	-$0.74	$0.72	$0.68
	6410_CP7_NG	0.2%	$3.29	-$2.88	-$2.68
SDG&E	OMS_13175637_SUNCREST BK80_NG	0.4%	-$1.61	$0.00	$20.72
	MIGUEL_BKs_MXFLW_NG	1.1%	$0.00	$0.00	$17.95
	OMS_13175630_SUNCREST BK81_NG	1.1%	-$0.96	$0.00	$12.98
	OMS 13108255_TL50003_NG	0.5%	-$0.92	$0.00	$6.39
	22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1	0.7%	$0.00	$0.00	$5.40
	7820_TL23040_IV_SPS_NG	1.3%	-$0.27	$0.00	$5.04
	22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1	0.5%	$0.00	$0.00	$4.24
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	0.6%	$0.00	$0.00	$3.38
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	0.7%	$0.00	$0.00	$3.29
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	15.9%	$0.00	$0.00	-$2.51
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	0.7%	$0.00	$0.00	-$3.15

1.7.2 Congestion in the real-time market

Congestion frequency in the real-time market is typically lower than in the day-ahead market, but has higher price impacts on load area prices. The congestion pattern in this quarter reflects this overall trend. Congestion patterns in the 15-minute and 5-minute markets were similar.

Impact of internal congestion to overall 15-minute prices in each load area

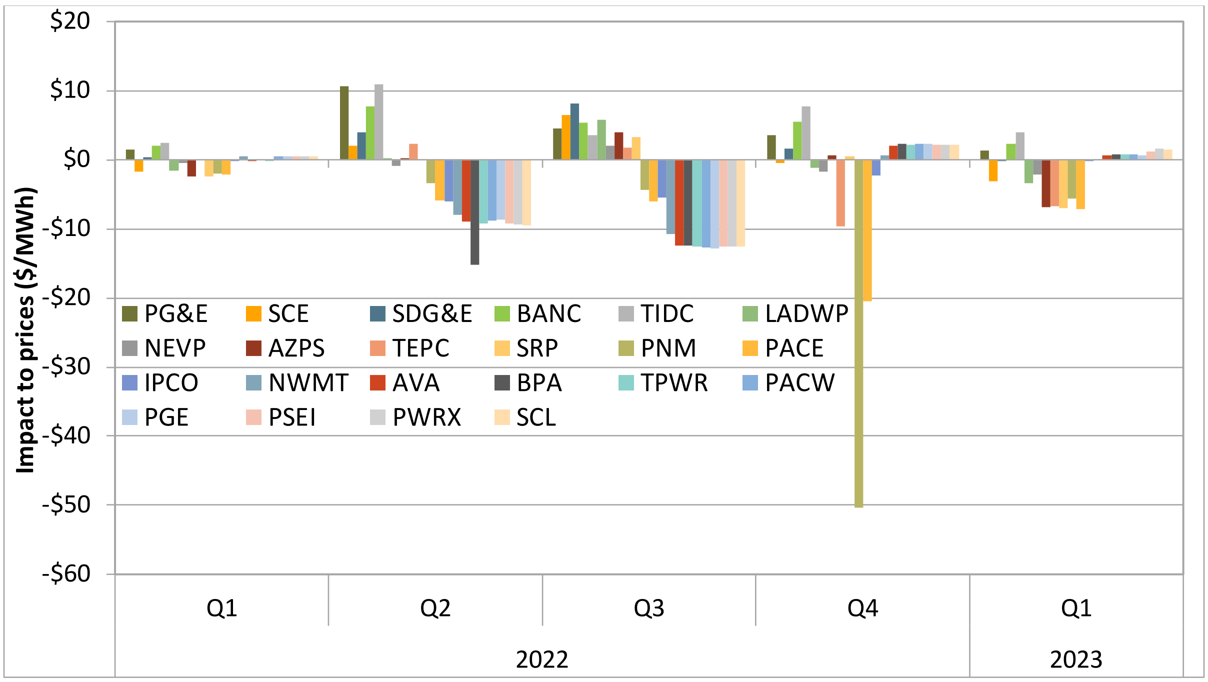
Figure 1.27 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2022 and 2023. Table 1.5 shows the frequency of this congestion. Highlights for this quarter include:

- The net impact of internal flow-based constraint congestion had varied impacts across the WEIM. Similar to the fourth quarter of 2022, congestion raised prices in the Pacific Northwest and lowered prices in the Southwest.

- Internal congestion was most impactful in the AZPS, TEPC, SRP, PNM, and PACE where it decreased prices in these areas by an average of $6.70/MWh.
- The primary constraints creating price separation in the 15-minute market were the Panoche-Gates #2 230 kV line, Devers 500/230 kV transformer, and a BPA constraint 'INTNEL'.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion on constraints that had the largest impact on price separation is provided below.

Figure 1.27 Overall impact of internal congestion on price separation in the 15-minute market



Impact of internal congestion from individual constraints in the 15-minute market

This section focuses on individual flow-based constraints. In the first quarter, the constraints that had the greatest impact on price separation in the 15-minute market were the Panoche-Gates #2 230 kV line, Devers 500/230 kV transformer, and a BPA constraint 'INTNEL'.[29] These constraints were impacted by maintenance in their respective areas.

Table 1.4 shows the overall impact (during all intervals) of internal congestion on average 15-minute prices in each load area. Table 1.5 shows the impact of internal congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The color scales in the table below apply only to the individual constraints and the "other" category in Table 1.4. The "other" category includes the impact of constraints not listed and power balance constraint (PBC) violations, which often have an impact on price separation. These topics are discussed in greater depth in Chapter 2.

[29] These constraints are shown as 30790_PANOCHE_230_30900_GATES_230_BR_2_1, 24801_DEVERS_500_24804_DEVERS_230_XF_1_P, and INTNEL in the tables, respectively.

Table 1.4 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	SCL
AZPS	Line_FC-MK_500KV	$0.01	$0.02	$0.01	$0.00	$0.01	$0.02	$0.02	-$0.01	-$0.04	-$0.01	-$0.14	-$0.03	-$0.01									
	Line_CH-LW_230KV									-$0.03		-$0.05											
BPA	NWACI_NS	$0.01	$0.01	$0.01	$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	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	INTNEL	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.18	-$0.18	-$0.18	-$0.18	-$0.18	-$0.16	-$0.17				-$0.07	-$0.20	-$0.23	$0.36	$0.92	$0.67
CAISO	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.77	-$2.23	-$2.01	$1.66	$1.98	-$2.16	-$0.62	-$1.67	-$1.57	-$1.67	-$1.18				$0.38	$0.44	$0.43	$0.54	$0.49	$0.43	$0.40	$0.42
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	$0.42	$0.00	$0.15	$0.37	$0.40	$0.46	-$0.41	-$1.76	-$1.68	-$1.93	-$1.41	-$0.41										
	6410_CP1_NG	-$0.37	$0.42	$0.41	-$0.35	-$0.36	$0.43	$0.22	$0.35	$0.34	$0.35	$0.29	$0.00	-$0.12	-$0.18	-$0.22	-$0.24	-$0.24	-$0.25	-$0.25	-$0.24	-$0.23	-$0.24
	6410_CP5_NG	-$0.33	$0.40	$0.36	-$0.31	-$0.32	$0.38	$0.20	$0.31	$0.30	$0.31	$0.27	$0.05	-$0.08	-$0.16	-$0.20	-$0.22	-$0.22	-$0.23	-$0.23	-$0.22	-$0.21	-$0.22
	7440_MetcalfImport_Tes-Metcalf	$0.37	-$0.35	-$0.34	$0.25	$0.54	-$0.34	-$0.20	-$0.30	-$0.30	-$0.30	-$0.26	-$0.05			$0.03	$0.09	$0.09	$0.10	$0.10	$0.08	$0.08	$0.08
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	$0.14	-$0.35	-$0.33	$0.25	$0.32	-$0.35	-$0.17	-$0.29	-$0.28	-$0.29	-$0.24	-$0.01	$0.07	$0.12	$0.15	$0.16	$0.16	$0.17	$0.17	$0.16	$0.16	$0.16
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.15	$0.21	$0.26	$0.14	$0.15	-$0.44	-$0.29	-$0.37	-$0.36	-$0.37	-$0.34	-$0.15	-$0.02	$0.00	$0.05	$0.06	$0.06	$0.07	$0.07	$0.06	$0.06	$0.06
	ML_RM12_SN	-$0.27	-$0.19	-$0.18	-$0.27	-$0.28	-$0.18	-$0.08	-$0.14	-$0.13	-$0.14	-$0.10	$0.05	$0.14	$0.18	$0.21	$0.22	$0.21	$0.22	$0.22	$0.21	$0.21	$0.21
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	$0.14	-$0.26	-$0.24	$0.17	$0.18	-$0.25	-$0.13	-$0.21	-$0.20	-$0.21	-$0.18	-$0.03	$0.05	$0.09	$0.11	$0.12	$0.12	$0.13	$0.12	$0.12	$0.12	$0.12
	OMS_13175637_SUNCREST BK80_NG		$0.06	$1.13				-$0.05	-$0.38	-$0.39	-$0.41	-$0.32	-$0.05										
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.07	-$0.41	-$0.38	$0.00	$0.39	-$0.40		-$0.32	-$0.31	-$0.32	-$0.09											
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.08	-$0.16	-$0.15	$0.11	$0.11	-$0.15	-$0.08	-$0.13	-$0.13	-$0.13	-$0.11	-$0.02	$0.03	$0.05	$0.07	$0.07	$0.07	$0.08	$0.07	$0.07	$0.07	$0.07
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	$0.04	$0.06	$0.07	$0.04	$0.04	$0.07	$0.04	-$0.21	-$0.21	-$0.21	-$0.27	-$0.06										
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.04	$0.07	-$0.44	$0.03	$0.04	$0.04	-$0.02	-$0.13	-$0.12	-$0.13	-$0.09	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1		-$0.09	-$0.09	$0.11	$0.21	-$0.09	-$0.04	-$0.08	-$0.07	-$0.08	-$0.06		$0.01	$0.03	$0.04	$0.05	$0.04	$0.05	$0.05	$0.04	$0.04	$0.04
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1		-$0.11		$0.20	$0.46	-$0.09																
	6410_CP7_NG	$0.07	-$0.09	-$0.08	$0.06	$0.06	-$0.08	-$0.04	-$0.07	-$0.07	-$0.07	-$0.06	-$0.01	$0.01	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1		$0.07	$0.11					-$0.15	-$0.14	-$0.15	-$0.12											
	30050_LOSBANOS_500_30055_GATES1 _500_BR_3 _1	$0.02	-$0.06	-$0.06	$0.04	$0.04	-$0.06	-$0.03	-$0.05	-$0.05	-$0.05	-$0.04	-$0.01	$0.01	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_2 _1		-$0.12	-$0.11	$0.00	$0.01	-$0.12	$0.00	-$0.10	-$0.10	-$0.10	-$0.01											
	MIGUEL_BKs_MXFLW_NG			$0.23					-$0.08	-$0.07	-$0.08	-$0.06											
	ML_RM12_NS	$0.04	$0.02	$0.02	$0.04	$0.04	$0.02	$0.01	$0.02	$0.02	$0.02	$0.01	-$0.01	-$0.03	-$0.03	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	99254_J.HINDS2_230_24806_MIRAGE _230_BR_1 _1		$0.10					-$0.06	-$0.11	-$0.11	-$0.10	-$0.06											
	OMS_13175630_SUNCREST BK81_NG		$0.01	$0.19				-$0.01	-$0.07	-$0.07	-$0.07	-$0.05	-$0.01										
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	$0.02			$0.02	$0.02	$0.02	-$0.02	-$0.07	-$0.06	-$0.07	-$0.05	-$0.02										
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.09	-$0.03	-$0.03		$0.08	-$0.03		-$0.02	-$0.02	-$0.02	-$0.01											
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	$0.02	-$0.03	-$0.03	$0.02	$0.02	-$0.03	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30055_GATES1 _500_30900_GATES _230_XF_12 _P	-$0.02	-$0.02	-$0.02	$0.00	$0.01	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.01	-$0.02	-$0.02	$0.01	$0.01	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.01	-$0.02	-$0.02	$0.01	$0.01	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	24056_ETIWANDA_230_24132_SANBRDNO_230_BR_1 _1	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	-$0.03	-$0.03	-$0.03	-$0.02	$0.00										
	30735_METCALF _230_30042_METCALF _500_XF_13	$0.02	-$0.01	-$0.01		$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00										
	Line_Wilo-EOX_500KV	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00						$0.00				
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				$0.00			-$0.05															
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1							-$0.05															
	7820_TL 230S_OVERLOAD_NG	$0.00	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00									
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LADWP	Victorville_Los_Angeles		$0.00	-$0.01			$0.08	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00
PACE	EAST_WYO_EXP												-$0.04										
	TOTAL_WYOMING_EXPORT												-$2.92										
	WINDSTAR EXPORT TCOR												-$3.12										
SRP	CO T345H500 9B		$0.00	$0.02					$0.03	-$0.08	$0.03	-$0.15	-$0.02										
	Other	$0.01	$0.10	$0.10	-$0.11	-$0.08	$0.04	-$0.02	$0.03	$0.02	$0.02	-$0.01	-$0.05	$0.00	$0.00	$0.01	$0.00	$0.01	$0.00	$0.00	$0.01	$0.01	$0.01
	Internal Total	**$1.35**	**-$3.14**	**-$1.63**	**$2.33**	**$3.94**	**-$3.45**	**-$2.13**	**-$6.29**	**-$6.23**	**-$6.49**	**-$5.20**	**-$7.12**	**-$0.10**	**$0.15**	**$0.66**	**$0.80**	**$0.72**	**$0.73**	**$0.65**	**$1.14**	**$1.67**	**$1.45**
	Transfers				$0.00	-$1.00	$0.55	-$0.05	$3.17	-$0.17	-$6.16	$0.63	$0.83	$2.19	$3.26	$2.40	$2.93	$2.34	$1.06	$1.53	$2.43	$6.97	$2.06
	Grand Total	**$1.35**	**-$3.14**	**-$1.63**	**$2.33**	**$2.94**	**-$2.90**	**-$2.18**	**-$3.12**	**-$6.40**	**-$12.65**	**-$4.57**	**-$6.29**	**$2.09**	**$3.41**	**$3.06**	**$3.73**	**$3.06**	**$1.79**	**$2.18**	**$3.57**	**$8.64**	**$3.51**

Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals [30]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	SCL
CAISO	ML_RM12_SN	1.0%	-$28.62	-$19.48	-$18.28	-$28.00	-$28.66	-$19.15	-$8.52	-$14.23	-$13.49	-$14.22	-$10.65	$4.92	$14.61	$18.73	$21.37	$22.41	$22.29	$22.92	$22.82	$22.28	$22.01	$22.25
	6410_CP5_NG	1.4%	-$23.92	$28.88	$26.46	-$22.50	-$23.37	$27.81	$14.21	$22.78	$21.88	$22.70	$19.31	$3.43	-$6.08	-$11.82	-$14.71	-$15.97	-$15.85	-$16.75	-$16.53	-$15.83	-$15.52	-$15.79
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	1.2%	$11.26	-$28.77	-$27.24	$20.53	$25.87	-$28.19	-$13.81	-$23.73	-$22.96	-$23.75	-$19.79	-$4.56	$5.97	$9.73	$12.28	$13.37	$13.23	$13.96	$13.75	$13.21	$12.94	$13.17
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	11.1%	$15.10	-$20.01	-$20.07	$17.88	$19.71	-$19.64	-$16.81	-$18.81	-$18.43	-$18.81	-$18.91				$15.34	$16.49	$16.17	$17.11	$16.86	$16.14	$15.97	$16.07
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.6%	$13.24	-$25.31	-$24.02	$17.59	$18.54	-$24.93	-$12.79	-$21.02	-$20.39	-$21.04	-$17.86	-$3.39	$5.14	$8.55	$10.85	$11.77	$11.66	$12.34	$12.15	$11.63	$11.40	$11.60
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	1.1%	$13.69	-$24.73	-$23.15	$16.60	$17.49	-$24.05	-$12.19	-$20.13	-$19.46	-$20.14	-$17.03	-$3.10	$5.01	$8.37	$10.55	$11.46	$11.33	$11.98	$11.80	$11.30	$11.10	$11.28
	7440_MetcalfImport_Tes-Metcalf	1.5%	$24.80	-$23.73	-$22.69	$17.11	$36.44	-$23.28	-$13.36	-$20.46	-$19.95	-$20.49	-$17.55	-$8.08			$3.99	$6.51	$6.47	$6.79	$6.67	$6.44	$6.09	$6.42
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.7%		-$13.78	-$13.04	$17.05	$31.59	-$13.53	-$6.68	-$11.38	-$11.00	-$11.37	-$9.47		$26.32	$5.06	$6.35	$6.88	$6.78	$7.14	$7.08	$6.78	$6.64	$6.76
	OMS_13175637_SUNCREST BK80_NG	1.3%		$4.73	$86.32				-$5.23	-$29.43	-$29.87	-$31.34	-$24.53	-$5.52										
	6410_CP1_NG	3.1%	-$11.85	$13.48	$13.19	-$11.15	-$11.61	$13.82	$7.01	$11.31	$10.85	$11.27	$9.46	$0.16	-$3.90	-$5.87	-$7.16	-$7.69	-$7.63	-$8.02	-$7.92	-$7.63	-$7.50	-$7.61
	ML_RM12_NS	0.3%	$11.00	$7.01	$6.41	$10.83	$11.25	$6.82	$2.81	$5.02	$4.60	$4.97	$3.26	-$3.83	-$8.45	-$10.38	-$11.63	-$12.11	-$12.06	-$12.34	-$12.30	-$12.06	-$11.93	-$12.03
	99254_J.HINDS2_230_24806_MIRAGE _230_BR_1 _1	0.4%		$23.80					-$32.50	-$27.01	-$27.78	-$25.65	-$35.62											
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	0.8%	$5.33	$8.33	$8.46	$4.85	$5.16	$8.64	$4.91	-$26.62	-$27.19	-$26.60	-$34.36	-$7.51										
	6410_CP7_NG	0.9%	$7.21	-$9.43	-$8.92	$6.65	$6.95	-$9.26	-$4.80	-$7.82	-$7.55	-$7.82	-$6.58	-$1.25	$1.60	$2.88	$3.69	$4.04	$3.99	$4.24	$4.16	$3.98	$3.90	$3.97
	MIGUEL_BKs_MXFLW_NG	0.4%			$51.52					-$17.16	-$15.37	-$17.84	-$13.39											
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.3%	$4.70	$6.39	$8.12	$4.24	$4.55	-$13.37	-$8.71	-$11.12	-$10.90	-$11.17	-$10.24	-$4.53	-$1.03	$0.52	$1.59	$1.85	$1.80	$2.09	$2.01	$1.80	$1.74	$1.79
	30055_GATES1 _500_30900_GATES _230_XF_12_P	1.0%	-$2.25	-$6.23	-$5.85	$0.43	$5.14	-$6.08	-$4.09	-$6.27	-$6.03	-$6.27	-$5.33	-$9.65	$15.17	$3.05	$3.69	$4.06	$4.03	$4.26	$4.20	$4.03	$3.92	$4.01
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	1.2%	$3.16	$6.22	-$38.20	$2.88	$3.10	$3.56	-$2.24	-$11.07	-$9.98	-$11.48	-$8.04	-$2.47	-$0.48	-$0.48	-$0.48	-$0.42	-$0.42	$0.80	$0.47	-$0.42	-$0.42	-$0.42
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	4.2%	$14.01	-$9.66	-$9.88	$5.33	$11.88	-$9.49		-$9.13	-$8.88	-$9.13	-$9.41											
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	0.8%		$8.74	$13.86					-$18.57	-$17.91	-$19.34	-$15.02											
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	1.1%		-$14.90		$17.82	$41.57	-$16.05																
	OMS_13175630_SUNCREST BK81_NG	0.7%		$1.63	$29.50				-$2.37	-$10.00	-$10.15	-$10.63	-$8.32	-$2.49										
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.3%	$3.32	-$5.80	-$5.38	$4.04	$4.21	-$5.63	-$2.77	-$4.67	-$4.49	-$4.66	-$3.95	-$0.68	$1.26	$2.03	$2.54	$2.75	$2.73	$2.88	$2.84	$2.72	$2.67	$2.72
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	14.4%	$3.15	$0.06	$6.64	$2.81	$3.02	$3.43	-$3.14	-$12.25	-$11.69	-$13.36	-$9.80	-$3.10										
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_2 _1	1.2%		-$10.28	-$9.83	$1.64	$3.38	-$10.21	-$0.92	-$8.62	-$8.31	-$8.62	-$3.49											
	24056_ETIWANDA_230_24132_SANBRDNO_230_BR_1 _1	0.3%	$2.89	-$1.49	$5.10	$5.37	$4.30	$2.66	-$3.45	-$8.95	-$8.34	-$8.98	-$6.82	-$5.75										
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	0.7%	$2.60			$2.29	$2.46	$2.80	-$2.87	-$9.25	-$8.86	-$10.06	-$7.48	-$2.64										
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.8%	$2.42	-$3.39	-$3.28	$2.23	$2.35	-$3.40	-$1.67	-$2.78	-$2.69	-$2.78	-$2.35	-$0.54	$0.61	$0.99	$1.27	$1.38	$1.37	$1.45	$1.42	$1.36	$1.34	$1.36
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	0.5%				$10.71			-$11.56															
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	0.5%							-$12.03															
PACE	TOTAL_WYOMING_EXPORT	25.2%												-$11.55										
	WINDSTAR EXPORT TCOR	79.8%												-$3.91										
	EAST_WYO_EXP	1.4%												-$3.00										
SRP	CO T345H500 9B	0.4%		$4.91	$5.57					$6.69	-$20.22	$8.29	-$40.13	-$6.25										

30 Details on constraints binding in less than 0.3 percent of the intervals have not been reported.

Impact of congestion from transfer constraints

This section focuses on price impacts from congestion on schedule-based transfer constraints. The highest frequency generally occurred either into or away from the WEIM load areas located in the Pacific Northwest, where the transfer congestion increased prices in the majority of the areas. Transfer constraint congestion generally raised prices in the 15-minute and 5-minute markets, but significantly decreased prices in the Turlock Irrigation District and Salt River Project areas.

In the real-time market, the total impact of congestion on a specific WEIM area is equal to the sum of the price impact of flow-based constraints shown in Figure 1.27 and Table 1.4, and schedule-based constraints listed in Table 1.5. Transfer constraint congestion typically has a large impact on prices. Figure 1.28 and Figure 1.29 in the next section show the frequency and impact of transfer congestion in the WEIM.[31]

Transfer constraint congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market occurs with vastly different frequencies and price impacts across the WEIM. Transfer congestion in the 5-minute market was similar to the 15-minute market.[32] For most areas, 5-minute market transfer congestion had similar frequencies and slightly lower price impacts to that of the 15-minute market. Powerex congestion frequency increased to 74 percent in the 5-minute market, up from 51 percent in the 15-minute market. Figure 1.28 and Figure 1.29 show the average impact to prices and the frequency of congestion on transfer constraints in the 15-minute market by quarter for 2022 and 2023, respectively.

There was an overall decrease in the frequency and an increase in impact of transfer constraint congestion in the first quarter of 2023 compared to the same quarter in 2022. The average frequency of transfer constraint congestion in the Pacific Northwest was 30 percent, down from 51 percent during the same time last year.[33]

31 Table 2.5 in Section 2.2 shows the transfer congestion frequency and average price impact from transfer constraint congestion into and out of each WEIM area in the 15-minute and 5-minute markets during the quarter.

32 Appendix A shows average hourly 15-minute and 5-minute market transfers by area, not including base transfers.

33 The Pacific Northwest in this comparison only includes PacifiCorp West, Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light, as these areas were participating in the WEIM during both quarters.

Figure 1.28 Transfer constraint congestion average impact on prices in the 15-minute market

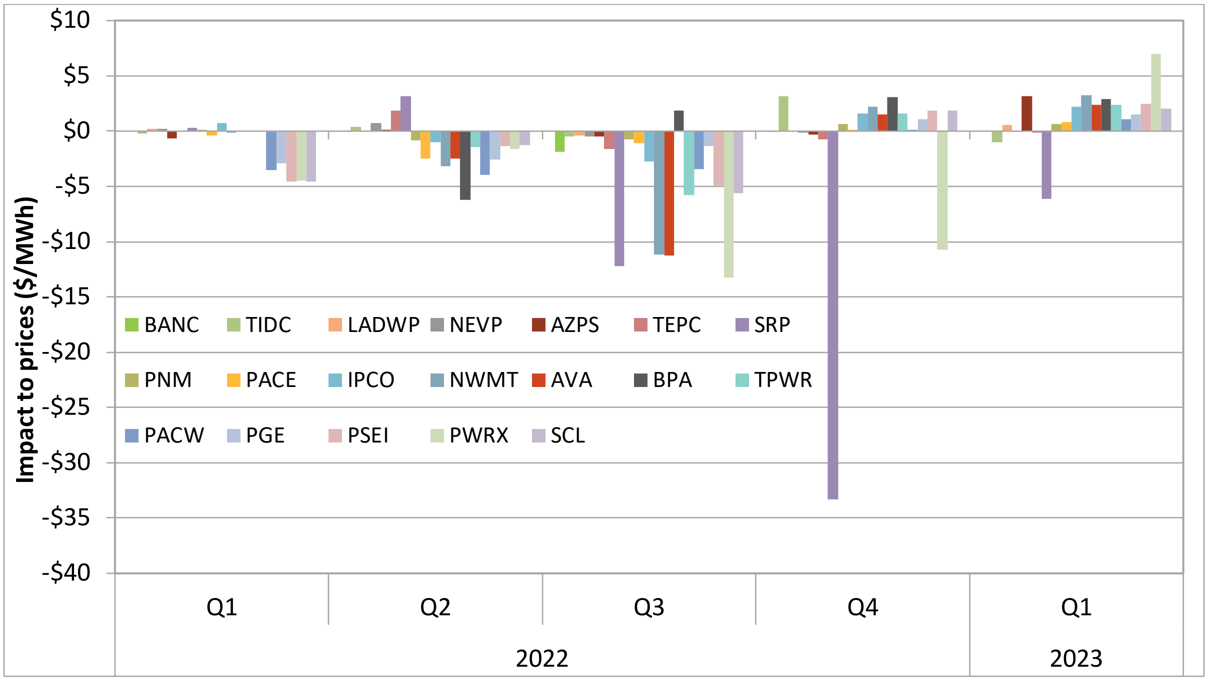
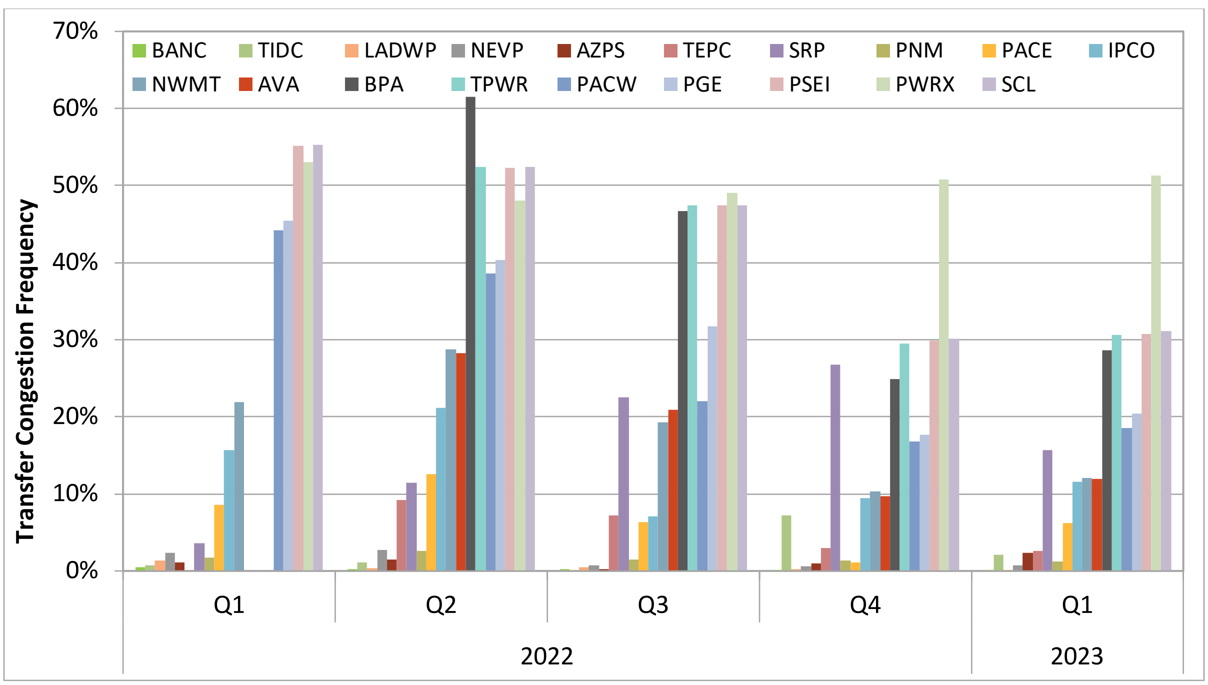


Figure 1.29 Transfer constraint congestion frequency in the 15-minute market



1.7.3 Congestion on interties

In the first quarter of 2023, the frequency and import congestion rent on the Malin 500 and NOB decreased significantly relative to the same time last year. The Palo Verde intertie generated 60 percent of the total import congestion charges for the quarter. Figure 1.30 shows total import congestion charges in the day-ahead market for 2022 and 2023. Figure 1.31 shows the frequency of congestion on five major interties. Table 1.6 provides a detailed summary of this data over a broader set of interties.

The total import congestion charges reported are 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 a congested intertie, assuming a radial line, the congestion price represents the difference between the higher price of the import on the CAISO side of the intertie and the lower price outside of the CAISO 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. The charts and table below highlight the following:

- Total import congestion charges for the first quarter of 2023 was 56 percent lower than the first quarter of 2022 at $14 million. The Palo Verde intertie was the primary driver of congestion charges in the day-ahead market, while congestion on the Malin 500 continued to decrease.
- The frequency and impact of congestion on Palo Verde continued to increase from the fourth quarter of 2022 to the first quarter of 2023, where it was congested during 10 percent of intervals and generated $8 million in congestion charges.
- The frequency of congestion and magnitude of congestion charges was highest on the Palo Verde, IPP Adelanto, and Malin 500 interties, which accounted for 90 percent of the total congestion charges for the quarter. Congestion on other interties was relatively low relative to these constraints, with the exception of Westwing Mead, which generated $1 million in congestion charges.

Figure 1.30 Day-ahead import congestion charges on major interties

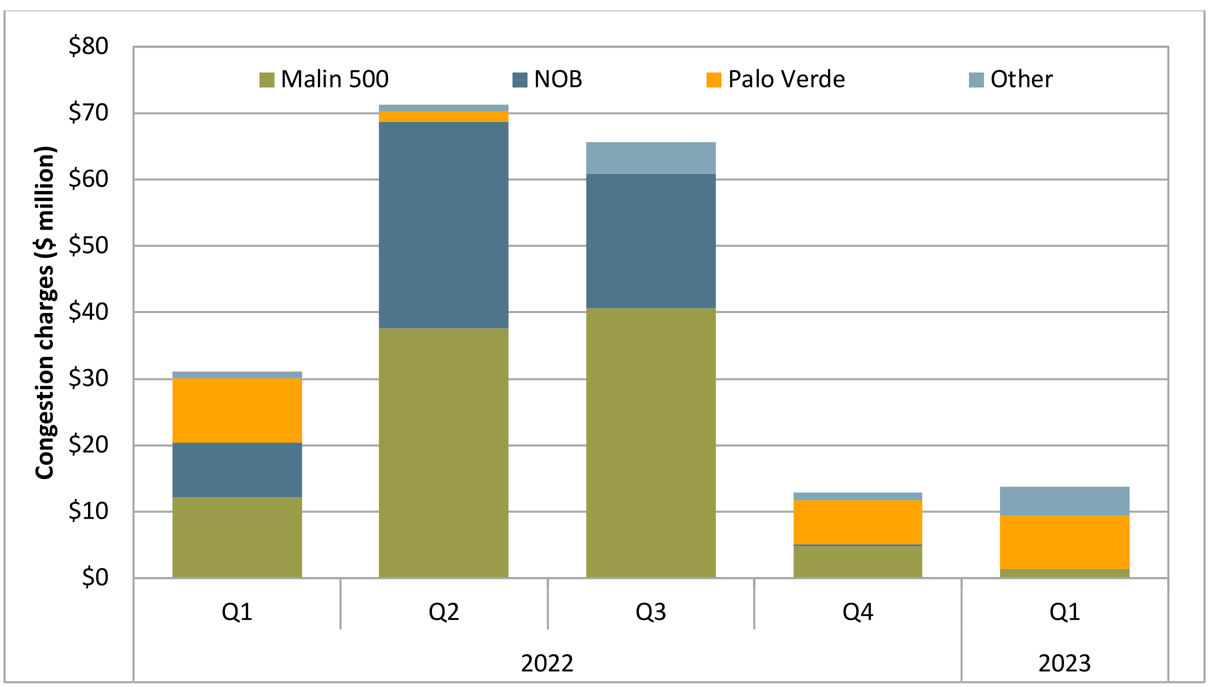


Figure 1.31 Frequency of import congestion on major interties in the day-ahead market

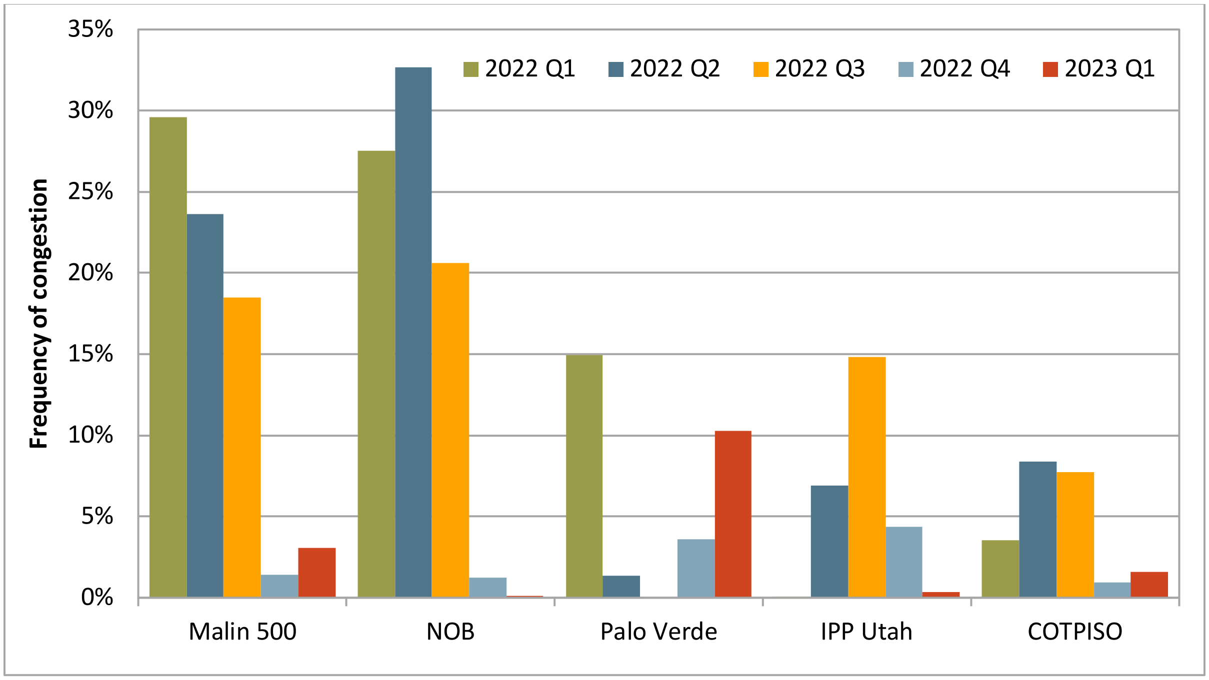


Table 1.6 Summary of import congestion in day-ahead market (2022-2023)

Area	Intertie	Frequency of import congestion					Import congestion charges ($ thousand)				
		2022				2023	2022				2023
		Q1	Q2	Q3	Q4	Q1	Q1	Q2	Q3	Q4	Q1
Northwest	Malin 500	30%	24%	18%	1%	3%	12,221	37,557	40,646	4,786	1,183
	NOB	28%	33%	21%	1%	0%	8,216	31,130	20,229	333	68
	COTPISO	4%	8%	8%	1%	2%	53	435	310	15	39
	Summit		0%	0%	1%	0%		1	14	4	10
Southwest	Palo Verde	15%	1%		4%	10%	9,694	1,643		6,663	8,199
	IPP Adelanto	6%		0%	0%	7%	673		0	12	2,996
	Westwing Mead					2%					1,013
	IID-SCE					1%					150
	Mead	1%		0%		0%	182		308		75
	IPP Utah	0%	7%	15%	4%	0%	0	480	4,092	1,084	18

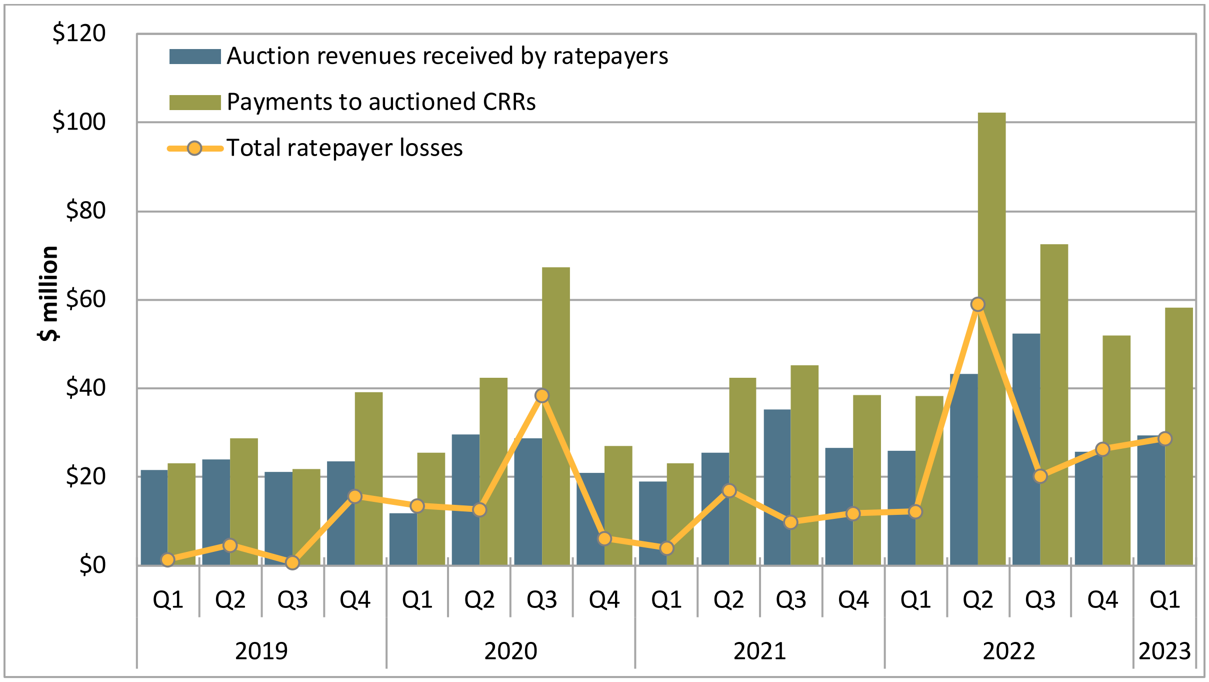
1.8 Congestion revenue rights

Congestion revenue right auction returns

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

As shown in Figure 1.32, transmission ratepayers lost about $29 million during the first quarter of 2023 as payments to auctioned congestion revenue rights holders continued to exceed auction revenues.[34] These losses were more than double compared to the first quarter of 2022 when losses were about $12 million.

Figure 1.32 Auction revenues and payments to non-load serving entities



During the first quarter of 2023:

- Financial entities received profits of nearly $20.6 million, significantly up from $6.3 million during the same quarter of 2022. Total revenue deficit offsets were about $16 million.[35]
- Marketers received profits of nearly $6.1 million from auctioned rights, up from $3.8 million in 2022. Total revenue deficit offsets were nearly $6.6 million.
- Physical generation entities received about $2 million in profits from auctioned rights, similar to 2022. Total revenue deficit offsets were about $1.6 million.

The $29 million in first quarter 2023 auction losses was about 10 percent of day-ahead congestion rent. This is similar to the first quarter of 2022 and up from 7 percent in the previous quarter. The losses as a

[34] The third quarter congestion revenue rights results are based on preliminary settlement data. More final settlement statements are issued at trade day plus 70 business days.

[35] 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.

percent of day-ahead congestion rent were below the average of 28 percent during the three years before the track 1A and 1B changes (2016 through 2018).[36,37]

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

Rule changes made by the California ISO reduced losses from sales of congestion revenue rights significantly in 2019, particularly in the first three quarters following their implementation. DMM continues to recommend that the California ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction consistently continues to cause millions of dollars of losses to transmission ratepayers each year, while exposing transmission ratepayers to risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the California ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends the California ISO convert the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

1.9 Real-time imbalance offset costs

Real-time imbalance offset costs increased to $91 million, up from $39 million in the first quarter of 2022. Real-time imbalance energy costs were $37 million in January alone, three times higher than the same time last year. Congestion imbalance offset costs were $23 million in March alone, 10 percent higher than in March 2022.

The real-time imbalance offset cost is the difference between the total money *paid out* by the CAISO and the total money *collected* by the CAISO for energy settled in the real-time energy markets. Within the CAISO system, the charge is allocated as an uplift to measured demand (physical load plus exports).

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).

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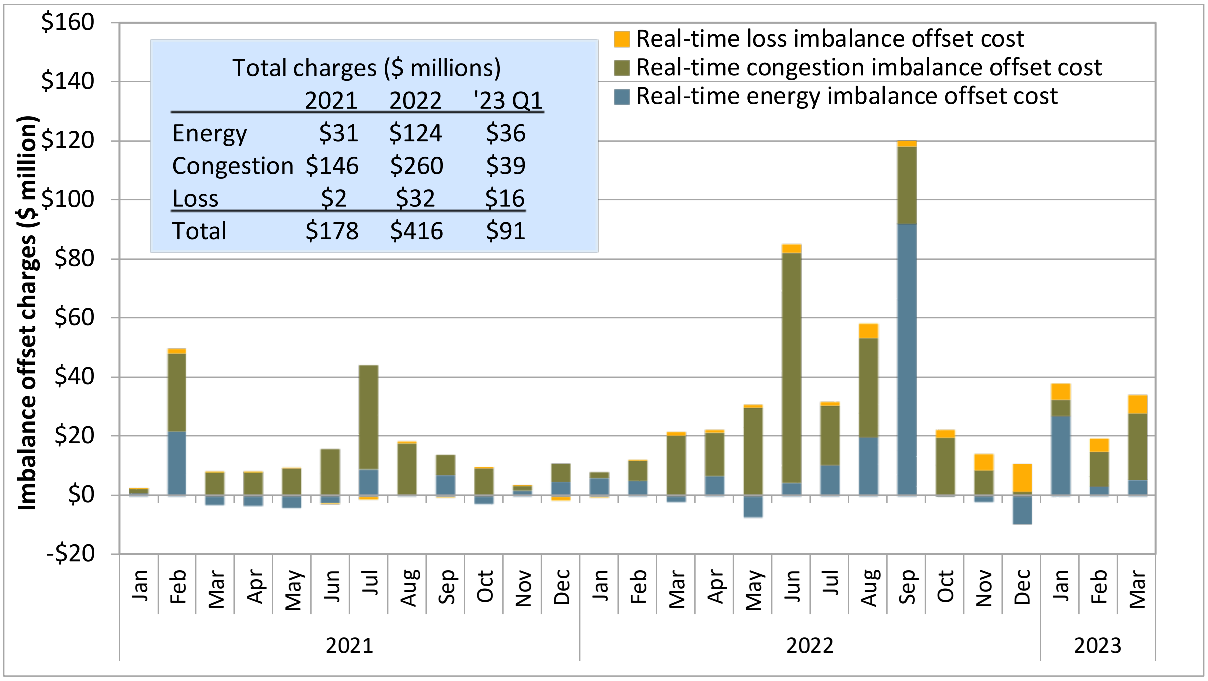
36 California ISO, Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

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

Figure 1.33 Real-time imbalance offset costs



1.10 Bid cost recovery

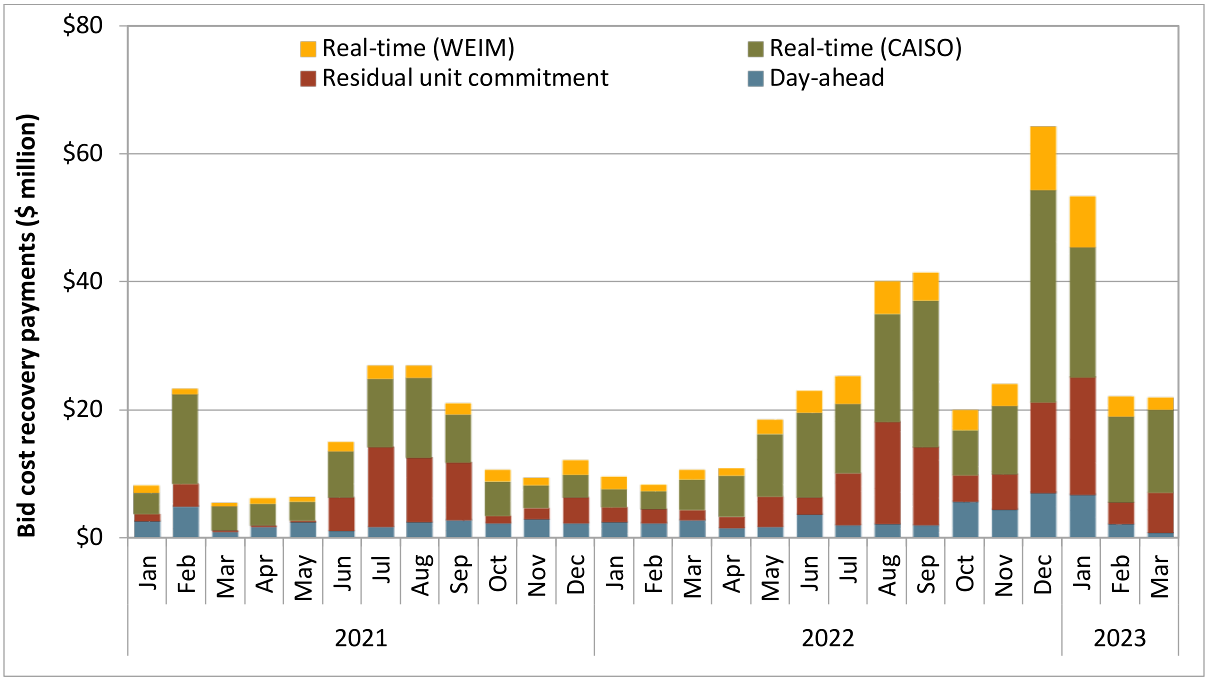
During the first quarter of 2023, estimated bid cost recovery payments for units in the California ISO (CAISO) and Western Energy Imbalance Market (WEIM) balancing areas totaled about 84 million and $13 million, respectively. These payments are significantly higher than the first quarter of 2022 when payments totaled $29 million in the CAISO ($24.5 million) and WEIM ($4.5 million) areas.

As shown in Figure 1.34, bid cost recovery payments were the highest during December 2022 and January 2023. These significantly higher payments can be attributed to the rise in gas prices at major trading hubs in the West during the same time period.

The figure also shows that in the first quarter of 2023, bid cost recovery attributed to the day-ahead market totaled about $10 million, which was $2 million higher than first quarter of 2022. Bid cost recovery payments for residual unit commitment during the quarter totaled about $28 million, or about $22 million higher than the first quarter of 2022. Bid cost recovery attributed to the real-time market totaled about $60 million, $7 million lower than the payments in the previous quarter, and about $45 million higher than the same quarter of 2022. Out of the $60 million in real-time payments, about $13 million was allocated to non-California ISO resources participating in the WEIM.

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. In the first quarter, about 75 percent of these payments, or about $73 million, were made to gas resources, followed by about $13 million to battery energy storage resources.

Figure 1.34 Monthly bid cost recovery payments



1.11 Imbalance conformance

Operators in the California ISO and the WEIM balancing areas can manually adjust the amount of imbalance demand used in the market to balance supply and demand conditions to maintain system reliability. The CAISO refers to this as *imbalance conformance*. These adjustments are used to account for potential modeling inconsistencies and inaccuracies, and to create additional unloaded ramping capacity in the real-time market.

Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO hour-ahead and 15-minute markets. This large increase continued to a lesser extent in the morning solar ramp up, and, to a slightly greater extent, the afternoon peak solar ramp down period. Average hourly imbalance conformance adjustments in these markets peaked in the morning at about 900 MW, and at just over 2,300 MW in the afternoon, about a 500 MW decrease and 200 MW increase, respectively, over the same quarter peak periods of the previous year. Solar uncertainty contributed to both the morning and evening imbalance conformance levels.

Figure 1.35 shows that imbalance conformance adjustments in real-time markets tend to follow a similar shape, with increases during the morning and evening net load ramp periods, and the lowest adjustments during the early morning pre-ramp, mid-day, and post-evening ramp periods.

The 5-minute market adjustments in this quarter were consistently higher the previous year. The wider gap between the 15-minute and 5-minute imbalance conformance contributed to the greater deviation between 15-minute and 5-minute prices this quarter.

Figure 1.35 Average hourly imbalance conformance adjustment (Q1 2022 - Q1 2023)

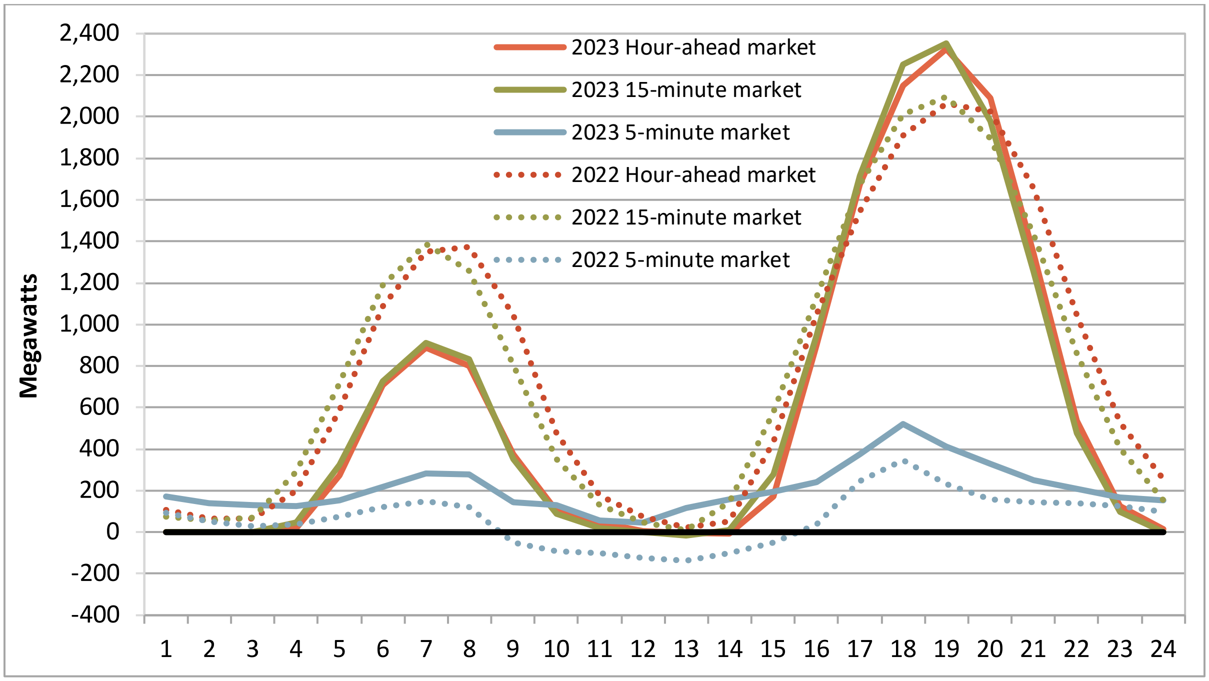
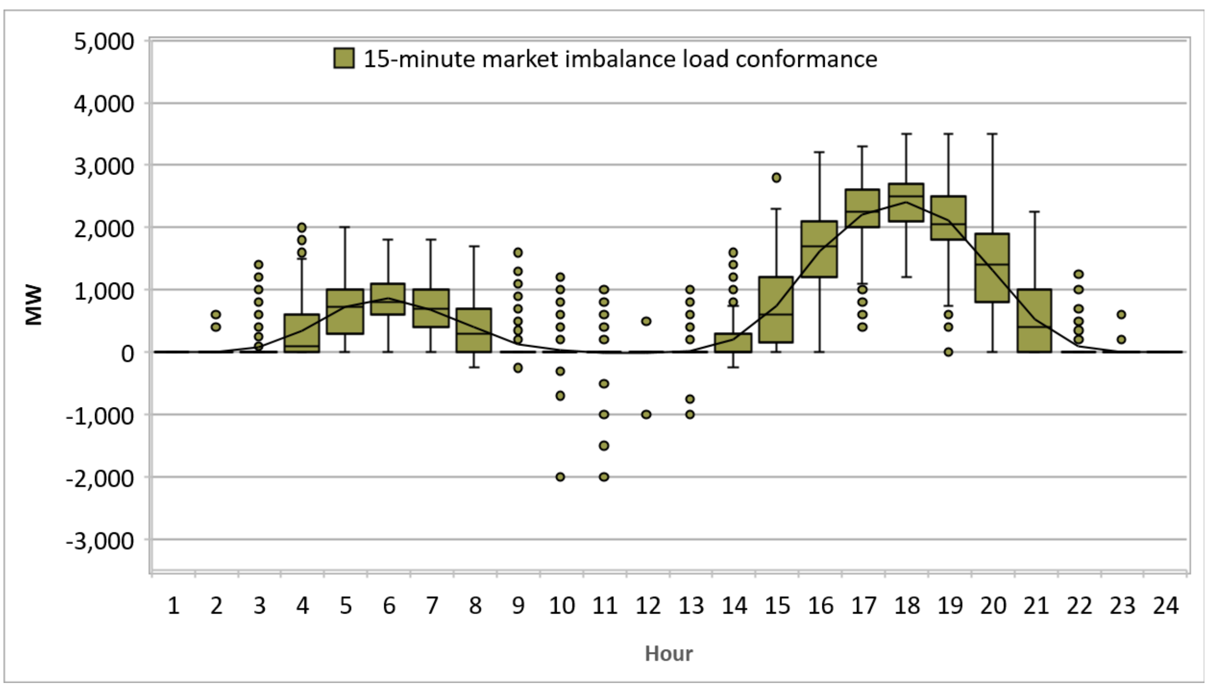


Figure 1.36 shows the distribution of the 15-minute market into quartiles for the load adjustment profile for the first quarter of 2023. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the filled 'dots. The outside whiskers do not include these outliers. For the quarter, the major outliers between 750 MW and 2,000 MW in the mid-day hours occurred on March 17, 2023 in response to an issue with the CAISO's market software data.

Figure 1.36 15-minute market hourly distribution of operator load adjustments (Q1 2023)



2 Western Energy Imbalance Market

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

2.1 Performance

The Western Energy Imbalance Market benefits participating areas by committing lower-cost resources across all areas to balance fluctuations in the supply and demand in the real-time energy market. Since dispatch decisions are determined across the whole WEIM footprint, prices within each balancing area diverge from the system price when transfer constraints are binding, when greenhouse gas compliance costs are enforced for imports into California, or if power balance constraint violations within a single area are assigned penalty prices.

Table 2.1 shows average monthly prices for the 15-minute market by area for 2022 through 2023. The combined average of WEIM prices outside of California was lower than California area prices by $7.04/MWh on average over the first quarter. The combined average prices of these California areas, which include the Balancing Area of Northern California, Turlock Irrigation District, and Los Angeles Department of Water and Power, was $0.20/MWh lower than Pacific Gas and Electric's average price of $97.00/MWh.

Price separation between balancing authorities occurs for several reasons. California area prices are typically higher than the rest of the WEIM due to greenhouse gas compliance cost for energy that is delivered to California. In addition, average prices in the Pacific Northwest are typically lower than other balancing areas because of limited transfer capability out of the region.

Table 2.1 Monthly 15-minute market prices

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023
SMEC	$51	$44	$42	$59	$59	$55	$69	$97	$125	$69	$90	$246	$140	$73	$73
PG&E (CAISO)	$54	$48	$47	$63	$68	$82	$74	$103	$136	$73	$95	$257	$140	$75	$76
SCE (CAISO)	$52	$43	$40	$55	$60	$69	$78	$108	$135	$64	$83	$246	$140	$68	$65
BANC	$53	$48	$48	$65	$69	$68	$72	$106	$131	$75	$95	$252	$142	$75	$76
Turlock ID	$54	$49	$48	$69	$76	$68	$72	$100	$136	$76	$95	$266	$142	$76	$77
LADWP	$50	$42	$41	$55	$57	$63	$77	$108	$135	$67	$87	$256	$142	$73	$68
NV Energy	$40	$38	$35	$49	$53	$55	$69	$93	$117	$58	$79	$243	$131	$66	$66
Arizona PS	$39	$34	$31	$45	$52	$64	$72	$97	$118	$56	$80	$251	$130	$66	$64
Tucson Electric					$54	$64	$72	$96	$111	$57	$76	$222	$129	$63	$60
Salt River Project	$39	$34	$33	$47	$56	$67	$67	$88	$93	$56	$76	$157	$119	$52	$60
PSC New Mexico	$37	$34	$30	$43	$47	$49	$67	$84	$102	$58	$64	$114	$127	$64	$64
PacifiCorp East	$37	$35	$32	$45	$43	$40	$65	$81	$99	$59	$72	$193	$120	$63	$67
Idaho Power	$43	$41	$35	$57	$47	$32	$69	$82	$92	$63	$84	$237	$132	$71	$73
NorthWestern	$41	$37	$34	$57	$41	$15	$42	$69	$73	$64	$87	$243	$133	$72	$75
Avista Utilities			$35	$57	$41	$12	$36	$68	$72	$65	$86	$246	$133	$72	$74
BPA					$46	$10	$46	$80	$91	$65	$86	$251	$133	$73	$73
Tacoma Power			$30	$59	$44	$13	$39	$74	$80	$64	$85	$248	$134	$72	$73
PacifiCorp West	$39	$35	$32	$59	$42	$13	$42	$76	$89	$64	$85	$244	$132	$71	$72
Portland GE	$38	$35	$33	$59	$43	$16	$43	$77	$92	$65	$87	$244	$133	$71	$72
Puget Sound Energy	$37	$34	$31	$60	$44	$13	$41	$74	$81	$64	$85	$249	$133	$73	$74
Seattle City Light	$37	$34	$31	$60	$45	$12	$40	$74	$80	$64	$85	$249	$133	$75	$72
Powerex	$36	$34	$32	$52	$46	$15	$37	$61	$69	$67	$82	$212	$129	$79	$84

Figure 2.1 and Figure 2.2 depict the average 15-minute and 5-minute prices by component for each balancing authority area, respectively. The system marginal energy price is the same for all entities in each hour. The price difference between balancing authority areas is determined by area specific elements, including transmission losses, greenhouse gas compliance costs, congestion, and power balance constraint (PBC) violations.

Congestion on WEIM transfer constraints often drives price separation between areas. Here, prices are higher on one side of the constraint with less access to supply and limited energy flow from the lower priced region to the higher priced region. In some cases, the power balance constraint may be relaxed within the constrained region at a high penalty parameter. The red segments reflect price differences caused by congestion on transfer constraints, including any PBC relaxations that increase the price in a single area.

Table 2.2 and Table 2.3 show the variation in prices throughout the day in the first quarter of 2023. In these tables, the colors change based on the deviation from the average system marginal energy price (SMEC). Therefore, blue represents prices below that hour's average system price and orange indicates prices above. Prices in balancing areas outside of California tend to be lower than prices in California for most hours, particularly during hours when California areas are typically importing energy subject to greenhouse gas compliance costs. Other differences in prices reflect transfer limitations between the different areas and congestion within BAAs.

Figure 2.1 Quarterly average 15-minute price by component (Q1 2023)

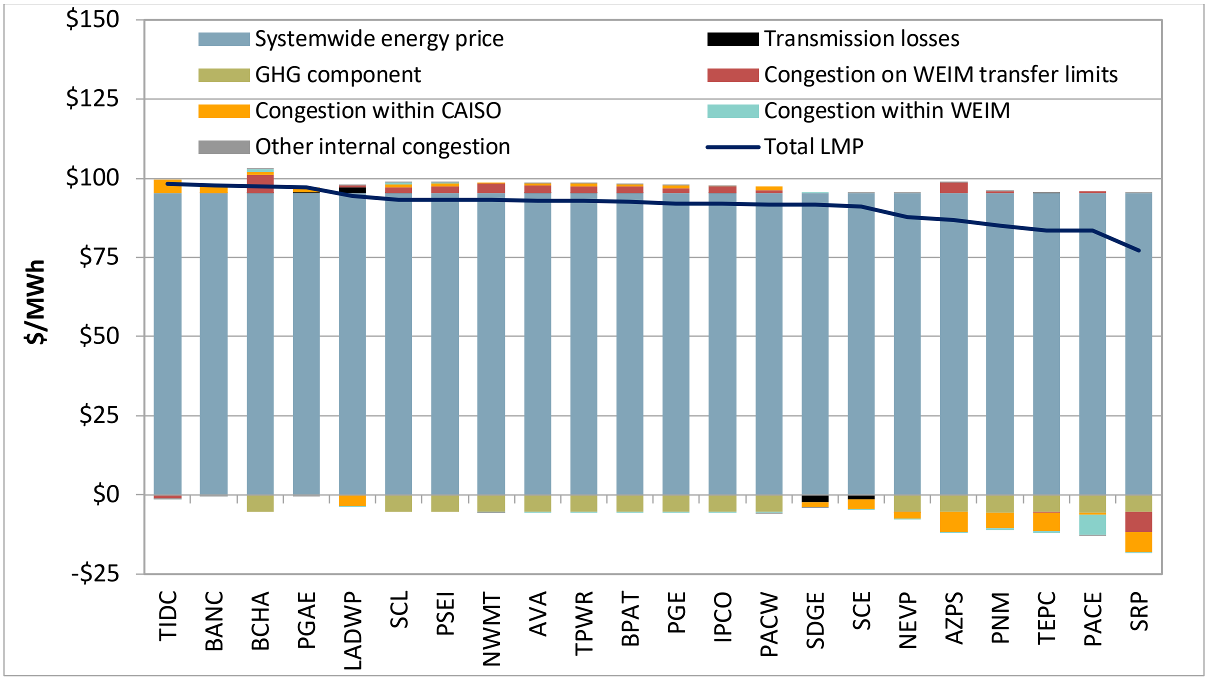


Figure 2.2 Quarterly average 5-minute price by component (Q1 2023)

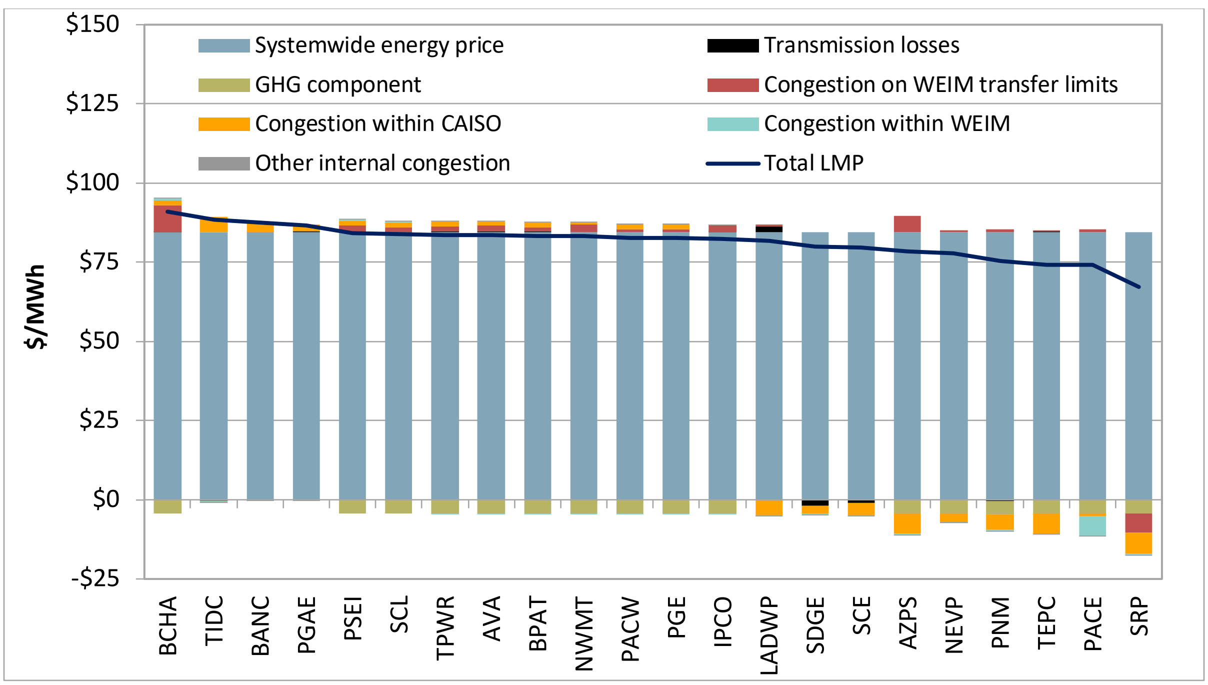


Table 2.2 Hourly 15-minute market prices (January-March)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$95	$93	$92	$94	$100	$111	$125	$117	$89	$78	$72	$66	$60	$56	$59	$76	$98	$121	$130	$127	$120	$111	$104	$95
PG&E (CAISO)	$96	$94	$93	$95	$100	$110	$121	$119	$94	$85	$80	$74	$67	$61	$65	$81	$101	$121	$132	$127	$121	$110	$104	$95
SCE (CAISO)	$96	$93	$93	$95	$101	$114	$129	$116	$84	$68	$59	$50	$42	$40	$43	$65	$95	$122	$131	$128	$123	$113	$105	$96
BANC	$96	$93	$93	$95	$100	$110	$122	$118	$93	$87	$82	$77	$70	$65	$68	$82	$101	$122	$131	$127	$121	$110	$104	$95
Turlock ID	$96	$93	$92	$93	$100	$109	$121	$118	$94	$91	$86	$81	$74	$68	$71	$82	$101	$121	$130	$126	$121	$110	$104	$96
LADWP	$102	$95	$94	$97	$103	$116	$131	$120	$89	$72	$63	$52	$46	$45	$47	$69	$98	$124	$134	$131	$126	$115	$110	$103
NV Energy	$89	$87	$87	$89	$95	$108	$121	$111	$83	$72	$66	$58	$51	$48	$51	$67	$90	$115	$116	$116	$112	$103	$99	$90
Arizona PS	$93	$84	$86	$89	$95	$120	$133	$127	$98	$80	$52	$43	$38	$32	$35	$64	$85	$104	$116	$115	$117	$106	$98	$92
Tucson Electric	$88	$86	$86	$89	$95	$110	$122	$110	$78	$62	$53	$46	$39	$35	$38	$59	$87	$108	$115	$115	$115	$103	$97	$88
Salt River Project	$76	$75	$73	$77	$89	$104	$123	$113	$83	$60	$52	$45	$31	$29	$28	$42	$75	$100	$110	$106	$107	$101	$94	$79
PSC New Mexico	$88	$86	$86	$97	$94	$117	$122	$109	$78	$70	$55	$47	$42	$39	$42	$61	$87	$113	$115	$115	$111	$102	$97	$87
PacifiCorp East	$83	$81	$81	$82	$89	$101	$112	$104	$80	$73	$66	$59	$53	$49	$52	$67	$87	$103	$109	$109	$105	$96	$92	$84
Idaho Power	$90	$88	$88	$90	$96	$107	$118	$113	$90	$84	$78	$72	$67	$62	$63	$76	$95	$111	$117	$116	$112	$103	$99	$91
NorthWestern	$90	$88	$88	$89	$96	$116	$117	$113	$97	$85	$79	$74	$69	$65	$68	$78	$95	$112	$116	$115	$112	$102	$100	$91
Avista Utilities	$90	$88	$88	$90	$96	$106	$117	$113	$91	$86	$80	$76	$71	$67	$68	$79	$95	$111	$116	$115	$111	$103	$99	$91
BPA	$91	$88	$88	$90	$96	$106	$110	$105	$93	$92	$87	$81	$77	$72	$71	$81	$93	$103	$108	$111	$107	$101	$101	$91
Tacoma Power	$90	$88	$88	$90	$96	$105	$109	$105	$92	$90	$90	$84	$77	$76	$72	$81	$95	$102	$107	$109	$105	$99	$104	$91
PacifiCorp West	$90	$88	$88	$89	$95	$108	$111	$107	$90	$86	$82	$76	$71	$66	$67	$79	$95	$109	$112	$112	$107	$100	$99	$90
Portland GE	$90	$88	$88	$89	$95	$105	$111	$107	$91	$88	$84	$78	$73	$67	$68	$79	$95	$109	$112	$112	$108	$100	$99	$90
Puget Sound Energy	$90	$88	$88	$90	$96	$105	$110	$105	$93	$100	$86	$83	$80	$76	$75	$83	$93	$103	$108	$110	$105	$100	$99	$90
Powerex	$93	$93	$91	$93	$97	$102	$107	$105	$97	$93	$92	$91	$89	$87	$87	$94	$103	$111	$113	$112	$109	$104	$101	$95
Seattle City Light	$98	$88	$88	$90	$96	$106	$107	$105	$93	$90	$87	$82	$81	$78	$77	$83	$92	$103	$108	$109	$105	$100	$100	$91

Table 2.3 Hourly 5-minute market prices (January-March)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$92	$89	$88	$90	$92	$100	$110	$105	$83	$73	$64	$57	$52	$48	$48	$58	$77	$94	$103	$105	$106	$105	$100	$91
PG&E (CAISO)	$98	$94	$94	$95	$98	$105	$116	$115	$94	$87	$75	$69	$63	$60	$62	$67	$84	$99	$107	$109	$111	$109	$104	$96
SCE (CAISO)	$98	$94	$94	$95	$99	$107	$121	$112	$82	$64	$51	$41	$37	$36	$37	$51	$79	$100	$109	$112	$112	$111	$105	$95
BANC	$98	$94	$94	$95	$98	$106	$117	$115	$94	$89	$78	$73	$67	$64	$65	$69	$84	$100	$107	$110	$111	$109	$104	$96
Turlock ID	$97	$93	$93	$94	$98	$105	$116	$114	$95	$93	$82	$78	$71	$67	$68	$70	$85	$100	$107	$110	$111	$109	$104	$96
LADWP	$105	$95	$95	$96	$100	$109	$122	$117	$86	$67	$55	$44	$41	$38	$41	$54	$83	$101	$109	$112	$113	$111	$106	$100
NV Energy	$90	$87	$87	$89	$94	$103	$115	$110	$81	$69	$60	$51	$46	$44	$46	$54	$87	$95	$99	$107	$101	$100	$97	$88
Arizona PS	$92	$85	$87	$88	$98	$110	$118	$135	$119	$68	$45	$33	$31	$29	$33	$59	$73	$93	$102	$106	$111	$108	$98	$87
Tucson Electric	$88	$86	$86	$88	$93	$106	$116	$111	$74	$60	$47	$38	$37	$32	$35	$50	$74	$95	$102	$103	$103	$100	$96	$87
Salt River Project	$75	$74	$72	$75	$86	$95	$115	$110	$77	$55	$44	$41	$27	$27	$28	$31	$62	$82	$93	$93	$94	$94	$93	$76
PSC New Mexico	$89	$85	$86	$97	$94	$111	$117	$106	$75	$62	$50	$43	$38	$36	$38	$50	$74	$98	$99	$102	$102	$101	$95	$86
PacifiCorp East	$84	$80	$81	$83	$87	$99	$107	$101	$78	$69	$62	$54	$50	$47	$48	$56	$75	$88	$94	$97	$97	$94	$91	$82
Idaho Power	$91	$88	$88	$90	$95	$103	$117	$113	$88	$81	$73	$67	$62	$59	$58	$63	$81	$95	$101	$104	$104	$101	$97	$89
NorthWestern	$91	$88	$88	$90	$95	$109	$113	$110	$97	$82	$75	$68	$64	$62	$61	$67	$81	$95	$101	$104	$104	$101	$98	$89
Avista Utilities	$91	$88	$88	$90	$95	$102	$113	$110	$90	$84	$77	$71	$67	$64	$64	$68	$82	$95	$102	$104	$104	$101	$97	$90
BPA	$90	$88	$88	$90	$95	$103	$108	$106	$90	$84	$79	$74	$72	$70	$69	$73	$80	$91	$97	$103	$100	$101	$98	$90
Tacoma Power	$91	$88	$88	$90	$95	$102	$107	$105	$91	$84	$81	$76	$75	$73	$70	$73	$80	$90	$96	$101	$99	$98	$103	$89
PacifiCorp West	$91	$88	$88	$90	$94	$104	$110	$105	$89	$82	$76	$70	$66	$63	$65	$69	$82	$95	$99	$103	$102	$100	$97	$89
Portland GE	$91	$88	$88	$90	$94	$102	$110	$105	$89	$82	$75	$70	$67	$64	$64	$69	$82	$95	$99	$103	$103	$100	$97	$89
Puget Sound Energy	$90	$88	$88	$90	$95	$103	$108	$105	$91	$95	$82	$75	$76	$75	$72	$74	$80	$90	$96	$104	$98	$98	$97	$88
Powerex	$93	$91	$90	$92	$94	$101	$105	$105	$95	$89	$90	$90	$87	$86	$87	$92	$100	$104	$110	$110	$107	$104	$100	$94
Seattle City Light	$91	$88	$88	$90	$95	$103	$108	$105	$91	$84	$80	$75	$77	$76	$74	$74	$79	$90	$96	$101	$99	$98	$97	$88

2.2 Transfers, limits, and congestion

Energy transfers

One of the key benefits of the WEIM is the ability to transfer energy between balancing areas in the 15-minute and 5-minute markets. These transfers are the result of regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint.[38] WEIM transfers are constrained by *transfer limits* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 2.3 and Figure 2.4 highlight typical transfer patterns during two key periods that produce a high volume of transfers.[39] Figure 2.3 shows average dynamic 15-minute market exports out of each area during mid-day hours (between hours 10 and 17) during the quarter.[40] 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. Each small tick is 50 MW and each large tick is 250 MW.

Figure 2.3 shows that the CAISO exported on average just over 1,250 MW during these mid-day hours, out to neighboring areas including BANC, LADWP, Powerex, BPA, PacifiCorp West, Portland General Electric, and NV Energy. Almost half of these CAISO exports were to Powerex at just over 600 MW on average during these hours. The mid-day typically contains the highest levels of exports out of the CAISO area because of significant solar production.

Figure 2.4 shows average dynamic transfers during peak net load hours (between hours 19 and 22) in the quarter. During these hours, imports into the CAISO are often highest. The figure shows an average of around 1,300 MW of exports out of LADWP, Turlock Irrigation District, BPA, PacifiCorp West, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, and Tucson Electric Power, going into the CAISO during these hours (CAISO import). Arizona Public Service, NV Energy, and Salt River Project exported the most during these hours, with almost 900 MW on average out to the CAISO in total during these peak hours.

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

39 WEIM transfer paths less than 25 MW, on average, are excluded from the figures.

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

Figure 2.3 Average 15-minute market WEIM exports (mid-day hours, January - March, 2023)

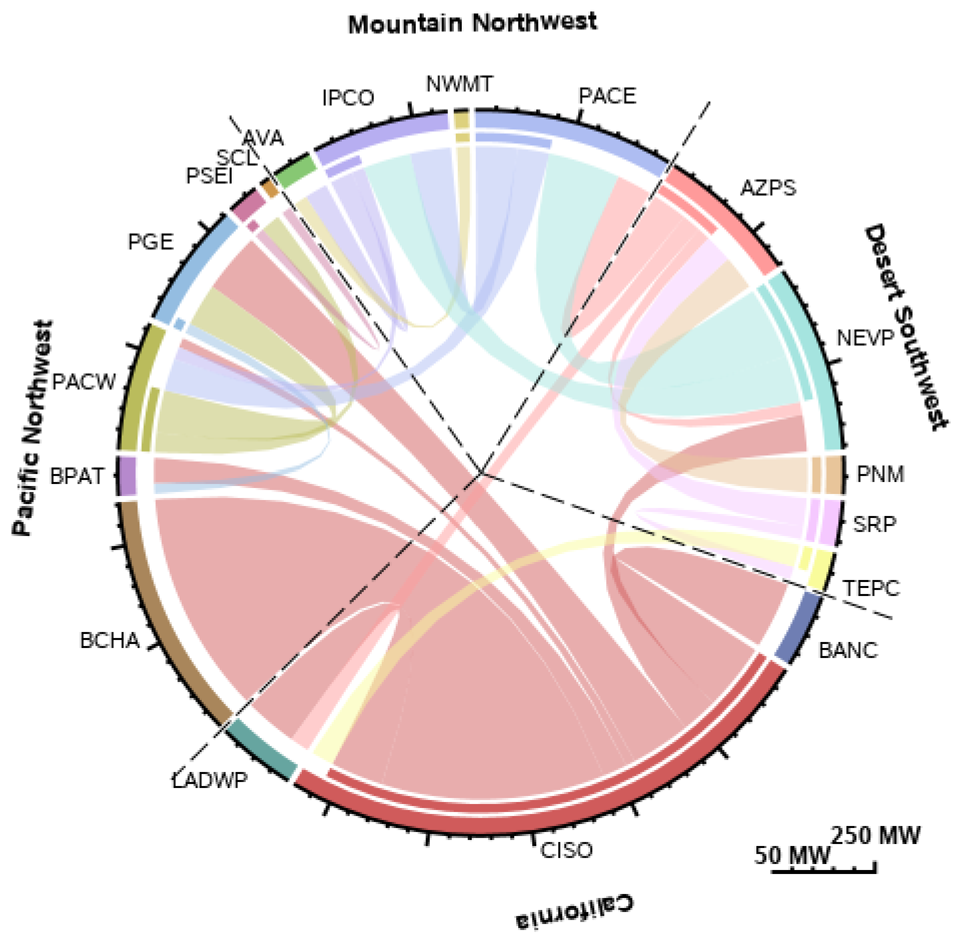
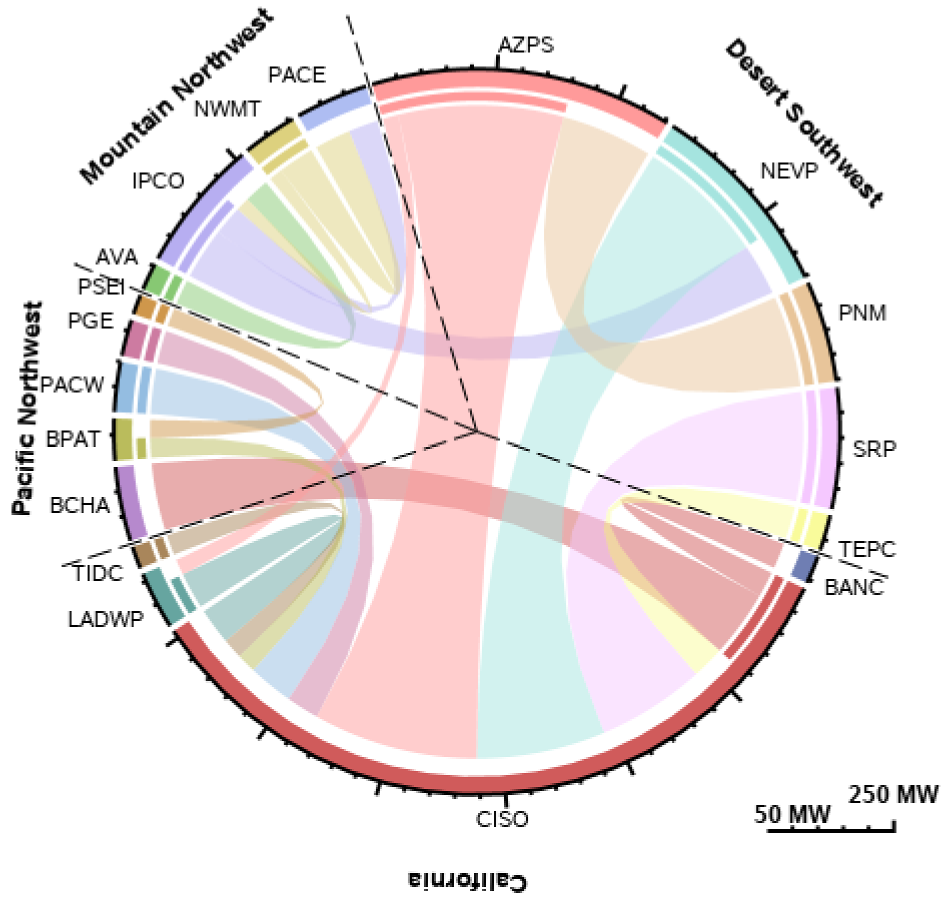


Figure 2.4 Average 15-minute market WEIM exports (peak load hours, January - March, 2023)



Transfer limits

WEIM transfers between areas are constrained by transfer limits. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities. Table 2.4 shows average 15-minute market limits between each of the areas over the quarter. 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 sum of each column reflects the average total import limit into each balancing area, while the sum of each row reflects the average total export limit from each area.

Transfer capacity into or out of the Pacific Northwest (including PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, Powerex, Tacoma Power, and Bonneville Power Administration) was around 1,620 MW of imports and 860 MW of exports on average during the quarter. There was an average of 20,130 MW of import and 15,130 MW of export transfer capacity in the Desert Southwest (including NV Energy, Arizona Public Service, Tucson Electric Power, Salt River Project, and Public Service Company of New Mexico). The lack of transfer capability out of the Pacific Northwest leads to price separation between the region and the rest of the WEIM.

Table 2.4 Average 15-minute market WEIM limits (January - March)

From Balancing Authority Area \ To Balancing Authority Area	CAISO	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	SCL	*Total export limit*
California ISO		3,640	970	3,210	3,540	9,650	290	1,940					0	100		70	140		630		24,180
BANC	3,490		630																		4,120
Turlock Irrig. District	980	670																			1,650
LADWP	6,990				1,710	680	280			140											9,800
NV Energy	4,230			800		460				700	330										6,520
Arizona Public Service	5,480			490	420		1,620	4,240	600	480											13,330
Tucson Electric	370			160		1,820		1,510	170	170											4,200
Salt River Project	1,920					4,220	1,170		10												7,320
PSC New Mexico						510	300	100													910
PacifiCorp East				80	560	770	190				540	150				170					2,460
Idaho Power					520					1,600		160	350	10		300		50		30	3,020
NorthWestern Energy										220	300		290	30	0						840
Avista Utilities	0										630	380		50	0	40					1,100
BPA	150										20	50	80		180	50	230	120	0	40	920
Tacoma Power												0	0	70			0	190			260
PacifiCorp West	160									0	140		30	30			390	100		10	860
Portland GE	160													200	0	410		50		10	830
Puget Sound Energy											40			210	190	40	50		50	350	930
Powerex	0													0				50			50
Seattle City Light											30			30		10	10	350			430
Total import limit	23,930	4,310	1,600	4,740	6,750	18,110	3,850	7,790	780	3,310	2,030	740	750	730	370	1,090	820	910	680	440	

Congestion on transfer constraints

Congestion between a WEIM area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an area, the market software triggers local market power mitigation for resources in that area.[41] Areas located in the Pacific Northwest continued to experience congestion into or out of the region during a high number of intervals. In particular, Powerex saw transfer congestion during 51 percent of 15-minute market intervals and 74 percent of 5-minute market intervals.

Table 2.5 shows the frequency and price impact of 15-minute and 5-minute transfer constraint congestion in each WEIM area. 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.[42] When prices are lower relative to the system, this indicates congestion out of an area (or region) and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for outside energy to serve that area's load.

Congestion in either direction for BANC, Los Angeles Department of Water and Power, NV Energy, PSC New Mexico, Turlock Irrigation District, Arizona Public Service, and Tucson Electric Power was infrequent during the quarter. Congestion that did occur between these areas and the larger WEIM was often the result of a failed upward or downward resource sufficiency evaluation, which limited transfer capability.

41 Structural market power may exist if the demand for imbalance energy within a balancing area exceeds the transfer capacity into that balancing area from the California ISO or other competitive markets. The California ISO area is not subject to market power mitigation under these conditions.

42 Greenhouse gas prices can contribute to lower prices relative to those inside CAISO. This calculation uses the WEIM greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only.

Table 2.5 Frequency and impact of transfer congestion in the WEIM (January - March)

	15-minute market				5-minute market			
	Congested from area		Congested into area		Congested from area		Congested into area	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.01
L.A. Dept. of Water and Power	0.1%	-$0.01	0.1%	$0.55	0.0%	$0.00	0.1%	$0.62
NV Energy	0.7%	-$0.30	0.1%	$0.25	0.6%	-$0.45	1.5%	$1.06
Public Service Company of NM	1.0%	-$0.67	0.2%	$1.30	1.0%	-$0.56	1.6%	$1.41
Turlock Irrigation District	2.1%	-$1.00	0.0%	$0.00	1.9%	-$0.48	0.0%	$0.00
Arizona Public Service	1.4%	-$1.31	1.0%	$4.48	1.3%	-$1.46	2.4%	$6.47
Tucson Electric Power	1.8%	-$0.56	0.8%	$0.39	2.1%	-$0.69	2.1%	$1.21
Idaho Power	0.1%	-$0.09	11%	$2.28	0.2%	-$0.17	10%	$2.18
NorthWestern Energy	0.1%	-$0.07	12%	$3.34	0.2%	-$0.07	10%	$2.66
Avista Utilities	0.1%	-$0.03	12%	$2.43	0.3%	-$0.07	11%	$2.08
Salt River Project	14%	-$9.98	1.8%	$3.82	13%	-$8.82	2.5%	$2.78
PacifiCorp West	6.6%	-$1.48	12%	$2.54	4.2%	-$1.03	9.2%	$1.95
Bonneville Power Admin.	10%	-$2.67	19%	$5.61	8.7%	-$2.27	17%	$3.82
Tacoma Power	12%	-$2.98	19%	$5.32	11%	-$2.86	18%	$4.77
Puget Sound Energy	12%	-$2.87	19%	$5.30	11%	-$2.82	18%	$4.97
Seattle City Light	12%	-$3.05	19%	$5.11	11%	-$2.94	18%	$4.40
Powerex	14%	-$3.69	37%	$10.66	21%	-$5.74	53%	$14.42
Puget Sound Energy	12%	-$2.87	19%	$5.30	11%	-$2.82	18%	$4.97
Powerex	14%	-$3.69	37%	$10.66	21%	-$5.74	53%	$14.42

2.3 Resource sufficiency evaluation

As part of the WEIM design, each area, including the California ISO, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize transfers between participating WEIM entities while preventing leaning by one area on another. The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation is made up of four tests: the power flow feasibility test, the balancing test, the bid range capacity test, and the flexible ramping sufficiency test. Failures of two of the tests can constrain transfer capability:

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

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[43] Similarly, if an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

43 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 prior to the hour.

Figure 2.5 and Figure 2.6 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.7 and Figure 2.8 provide the same information for the downward direction.[44] The dash indicates the area did not fail the test during the month.

In the first quarter of 2023:

- Salt River Project failed the upward flexibility test in 2.1 percent of intervals and the downward flexibility test in 1.9 percent of intervals.
- Arizona Public Service failed the upward flexibility test in 1.7 percent of intervals and the downward flexibility test in 1.2 percent of intervals.
- No balancing area failed the upward or downward capacity test in more than 1 percent of intervals.

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

	2022												2023		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	—	—	0.0	0.0	—	—	—	—	—	—	—	0.1	0.4	0.5	0.7
Avista			—	0.0	—	0.2	0.2	0.0	—	—	—	0.1	—	—	—
BANC	—	—	—	—	—	—	—	0.0	0.3	—	—	—	—	—	—
BPA					—	0.1	—	0.0	0.5	—	—	0.4	—	—	—
California ISO	—	—	—	—	—	—	—	—	0.1	—	—	—	—	—	—
Idaho Power	—	0.1	—	—	—	—	—	0.2	0.2	—	—	—	—	—	—
LADWP	—	—	—	—	—	—	0.0	—	—	—	—	—	0.1	—	—
NorthWestern En.	0.3	0.1	—	0.0	—	—	—	0.1	0.1	—	0.2	0.1	0.3	0.1	—
NV Energy	—	—	—	0.2	0.1	0.0	0.1	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	0.1	—	—	0.3	—	—	—
PacifiCorp West	0.3	0.1	0.3	0.0	0.2	0.0	1.0	0.2	0.0	—	0.0	0.0	0.1	0.1	—
Portland Gen. Elec.	0.1	—	—	—	—	—	—	0.1	—	—	0.3	—	—	0.0	0.0
Powerex	0.2	—	—	0.1	—	—	—	0.2	—	—	0.0	—	—	—	—
PSC of New Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.7
Puget Sound En.	—	—	—	0.0	0.0	0.2	—	—	0.2	0.1	0.0	—	—	0.0	0.2
Salt River Proj.	—	—	0.2	1.5	1.0	0.2	0.2	0.4	0.4	0.2	0.0	0.0	1.0	0.4	1.1
Seattle City Light	—	—	0.1	—	—	—	0.2	0.1	0.2	0.0	0.0	0.2	0.0	0.1	—
Tacoma Power			—	0.6	0.1	0.0	0.0	0.2	0.0	—	—	—	0.0	0.1	0.1
Tucson Elec. Pow.					—	—	—	0.1	—	—	—	—	0.1	0.0	—
Turlock Irrig. Dist.	—	—	—	—	—	0.1	—	—	—	—	—	0.2	—	—	—

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

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

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023
Arizona Publ. Serv.	0.0	0.2	0.1	—	—	—	0.0	0.1	—	—	0.1	0.4	0.9	1.8	2.5
Avista			—	0.2	0.5	1.0	0.5	0.1	—	0.1	—	0.1	—	0.0	0.0
BANC	—	—	—	—	—	—	—	—	0.3	—	—	—	—	—	—
BPA					0.9	3.1	3.3	1.0	1.1	0.2	0.1	0.4	—	0.1	0.6
California ISO	—	—	—	—	—	—	—	0.1	0.5	0.0	—	—	—	—	—
Idaho Power	—	0.2	—	—	—	—	0.2	0.2	0.5	—	0.1	—	0.0	0.1	0.3
LADWP	—	—	0.1	—	—	—	—	—	0.1	0.1	—	—	—	0.3	—
NorthWestern En.	—	0.1	0.1	0.3	—	0.1	0.3	1.0	0.2	—	0.5	0.8	0.3	0.1	0.2
NV Energy	0.0	0.7	0.4	1.0	0.8	0.2	—	0.1	0.1	0.1	0.2	0.0	0.1	0.3	0.0
PacifiCorp East	0.0	0.0	—	0.1	0.1	0.1	0.2	0.1	—	0.1	—	0.0	0.1	—	0.0
PacifiCorp West	0.0	0.0	0.1	0.2	0.1	0.0	—	0.1	0.1	—	0.1	—	0.1	0.1	—
Portland Gen. Elec.	0.3	0.0	—	—	—	0.0	0.4	0.1	0.1	0.2	1.0	0.1	0.0	0.1	0.0
Powerex	0.2	0.0	—	0.1	—	—	—	0.3	0.1	—	—	—	—	0.2	—
PSC of New Mexico	—	—	0.1	0.0	0.1	—	0.4	—	0.0	0.2	0.1	0.8	0.2	—	1.2
Puget Sound En.	—	—	0.0	0.1	—	0.1	0.4	0.2	0.3	—	0.0	—	—	0.1	0.8
Salt River Proj.	0.2	—	0.6	0.5	0.2	0.5	0.6	1.1	0.6	0.6	0.5	0.8	3.5	1.2	1.7
Seattle City Light	—	—	0.1	—	—	—	0.2	0.0	0.2	—	0.1	0.0	—	0.1	—
Tacoma Power			—	—	0.1	0.1	0.0	0.1	0.1	—	0.2	—	0.2	0.1	0.2
Tucson Elec. Pow.					0.1	—	—	—	0.4	0.0	—	0.2	0.3	0.3	0.3
Turlock Irrig. Dist.	—	—	—	—	—	—	—	—	0.1	—	—	1.2	—	—	—

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

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023
Arizona Publ. Serv.	0.3	—	—	—	0.0	0.0	—	—	—	—	—	0.1	—	—	0.6
Avista			—	—	—	—	0.2	—	—	0.0	—	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA					—	—	—	—	0.1	—	—	—	—	0.1	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	0.6	—	—	—	—	—	—	—	—	—	—
LADWP	0.3	—	—	—	0.2	—	—	—	—	—	—	—	0.1	—	—
NorthWestern En.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	—	—	—	—	0.1	0.5	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland Gen. Elec.	—	—	—	—	—	0.0	—	—	—	—	—	—	—	—	—
Powerex	0.1	—	0.1	—	0.1	—	—	0.0	—	—	0.0	—	—	—	—
PSC of New Mexico	—	—	0.1	—	0.1	—	—	—	—	—	—	—	—	—	0.1
Puget Sound En.	—	—	—	—	0.0	0.7	0.1	—	—	—	—	—	—	—	—
Salt River Proj.	—	0.2	0.3	—	0.4	0.5	0.1	0.2	1.1	0.2	0.3	—	0.4	1.5	0.2
Seattle City Light	—	—	0.1	—	—	0.0	0.1	—	0.2	—	—	—	—	0.1	—
Tacoma Power			—	0.8	0.1	—	0.6	0.3	—	0.1	—	0.2	—	0.2	0.1
Tucson Elec. Pow.					—	0.0	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	0.1	0.0	—	0.1	—	—	—	—	—	—	—	—	—	0.1	—

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

	2022												2023		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona Publ. Serv.	1.4	0.4	0.8	0.3	0.5	0.2	—	—	0.1	0.2	0.2	0.1	0.9	0.5	2.1
Avista			—	—	—	0.1	—	—	0.1	0.2	—	0.0	—	—	0.1
BANC	—	—	0.1	0.0	0.1	0.1	—	—	—	—	—	—	—	—	—
BPA					0.1	0.2	—	0.0	0.3	—	0.2	0.2	—	0.0	0.1
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	0.0	—	0.3	0.4	—	—	0.0	—	—	—	—	—	—	0.9
LADWP	0.1	—	—	—	—	—	—	—	—	—	—	—	0.1	—	—
NorthWestern En.	—	—	—	—	0.5	1.9	0.2	—	—	—	0.0	0.1	—	0.0	—
NV Energy	0.6	4.1	1.7	3.2	1.3	2.0	0.6	0.2	0.5	0.5	0.6	0.1	0.1	0.1	0.1
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	0.0	0.0	0.1	0.4	0.5	—	—	0.1	—	0.0	—	—	—
Portland Gen. Elec.	—	—	—	—	—	0.2	—	—	—	—	—	—	—	—	—
Powerex	—	0.0	0.2	0.0	0.3	0.2	—	0.1	0.1	0.1	—	—	0.1	0.1	—
PSC of New Mexico	0.3	0.0	1.2	0.3	1.8	0.7	0.0	0.0	0.2	0.2	0.1	—	0.0	—	0.4
Puget Sound En.	—	—	—	—	0.2	2.3	0.1	—	—	0.1	—	—	—	—	—
Salt River Proj.	0.1	1.0	1.5	0.2	0.4	0.5	0.2	0.2	1.0	0.2	0.9	0.3	1.4	3.3	1.0
Seattle City Light	—	—	0.1	0.1	0.1	0.3	0.1	0.8	0.3	—	0.2	0.6	0.1	0.2	0.0
Tacoma Power			—	0.4	0.3	—	0.5	0.2	—	—	—	0.1	—	0.2	0.1
Tucson Elec. Pow.					—	—	—	—	—	—	0.0	—	—	—	—
Turlock Irrig. Dist.	0.2	—	0.5	0.6	0.1	0.5	0.1	0.1	—	—	0.1	—	0.1	0.1	0.1

Resource sufficiency evaluation monthly reports

DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic.[45] 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.

2.4 Imbalance conformance

Frequency and size of imbalance conformance

Table 2.6 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM and CAISO for the 15-minute and 5-minute markets during the quarter. PacifiCorp East and BANC infrequently used negative imbalance conformance in the 15-minute market, but conformed an average of 9 percent and 15 percent of load when they did, respectively. Similar to previous quarters, nearly all WEIM entities had a greater frequency of imbalance conformance in the 5-minute market than in the 15-minute market.

45 Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports*: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

Table 2.6 Average frequency and size of imbalance conformance (January - March)

Balancing area	Market	Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
		Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO	FMM	45%	1350	5.8%	0.4%	-692	3.7%	611
	RTD	63%	395	1.8%	16%	-255	1.2%	208
BANC	FMM	0.3%	40	2.5%	0.1%	-204	15%	0
	RTD	0.8%	35	2.2%	0.3%	-115	8.1%	0
Turlock Irrigation District	FMM	0.1%	17	6.6%	0.0%	N/A	N/A	0
	RTD	0.1%	16	6.0%	0.0%	-18	6%	0
LADWP	FMM	0.2%	44	1.8%	2.4%	-95	3.6%	-2
	RTD	10%	49	2.0%	21%	-59	2.4%	-8
NV Energy	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	44%	79	2.1%	9.5%	-112	3.2%	24
Arizona Public Service	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	47%	69	2.2%	23%	-70	2.6%	17
Tucson Electric Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	3.4%	68	5.8%	32%	-55	4.9%	-15
Salt River Project	FMM	2.8%	77	2.7%	0.0%	N/A	N/A	2
	RTD	25%	70	2.4%	0.7%	-112	3.8%	17
Public Service Co. of New Mexico	FMM	0.0%	N/A	N/A	0.1%	-80	6.0%	0
	RTD	33%	61	4.2%	3.1%	-59	4.2%	19
PacifiCorp East	FMM	0.0%	N/A	N/A	0.1%	-578	9.1%	0
	RTD	11%	86	1.6%	34%	-102	1.8%	-25
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	13%	53	2.6%	19%	-57	2.9%	-4
NorthWestern Energy	FMM	4.8%	15	1.1%	2.9%	-14	1.0%	0
	RTD	13%	16	1.1%	7.5%	-17	1.2%	1
Avista Utilities	FMM	0.1%	20	1.9%	1.5%	-33	2.5%	0
	RTD	2.7%	19	1.4%	41%	-22	1.6%	-9
Bonneville Power Administration	FMM	44%	32	0.5%	56%	-35	0.5%	-5
	RTD	44%	33	0.5%	55%	-35	0.5%	-5
Tacoma Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	2.2%	12	1.9%	2.6%	-12	2.1%	0
PacifiCorp West	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	5.1%	47	1.8%	20%	-55	2.1%	-9
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	7.9%	30	1.1%	0.5%	-40	1.4%	2
Puget Sound Energy	FMM	0.1%	47	1.2%	0.4%	-44	1.3%	0
	RTD	5.2%	31	0.9%	40%	-37	1.1%	-13
Seattle City Light	FMM	0.4%	19	1.4%	7.3%	-23	1.9%	-2
	RTD	3.1%	17	1.3%	72%	-24	2.0%	-17

3 Special issues

On February 1, 2023, the CAISO implemented enhancements to the flexible ramping product. This introduced two significant changes. The first of these improves the deliverability by procuring and pricing flexible capacity at a nodal level to better ensure that sufficient transmission is available for this capacity to be utilized. The second significant change adjusted the calculation of the uncertainty requirement by incorporating current load, solar, and wind forecast information using a method called mosaic quantile regression.

This section summarizes the changes that were implemented and the performance of the flexible ramping product and quantile regression of uncertainty. Key highlights include the following:

- **The flexible ramping product demand curves were implemented incorrectly on February 1, 2023**. The result is that the prices on the demand curve are too low relative to the expected cost of a power balance constraint relaxation for the level of flexible capacity procured. This made it appear inappropriately cheap for the market optimization to forgo flexible ramping capacity. The CAISO implemented a correction to the calculation of the flexible ramping product demand curves effective August 8, 2023.
- **Flexible capacity prices for the larger system continued to be low following the enhancements**. During February and March the 15-minute market prices for flexible capacity within the pass-group were non-zero in less than 1 percent of intervals for upward capacity and never for downward capacity. 5-minute market prices were also infrequent, in less than 0.1 percent of intervals.
- **The balancing areas included in the pass-group for performing the uncertainty regressions can be inconsistent from the balancing areas included in the pass-group used to determine weather information used in the regressions**. The current weather information is ultimately combined with the regression results to calculate uncertainty. This discrepancy can create significant swings in the calculated uncertainty.
- **DMM's review of the performance of the new mosaic quantile regression uncertainty estimation methodology indicates that it is not a clear improvement over the prior method**. Although uncertainty values calculated with this method are generally lower while covering uncertainty (an improvement), they fluctuate more significantly and are likely to be more difficult for balancing areas to reproduce or predict in advance. A more comprehensive review will be provided in a forthcoming special report.

3.1 Flexible ramping product enhancements

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.[46] 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

46 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.

3.1.1 Flexible ramping product deliverability enhancements and market outcomes

On February 1, 2023, the CAISO implemented enhancements to the flexible ramping product. This introduced two significant changes. The first of these improves the deliverability by procuring and pricing flexible capacity at a nodal level to better ensure that sufficient transmission is available for this capacity to be utilized. The second significant change adjusted the calculation of the uncertainty requirement by incorporating current load, solar, and wind forecast information using a method called mosaic quantile regression.

Flexible ramping product requirement and deliverability enhancements

The end of the demand curve is implemented in the California 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.[47] 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, which 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 are pooled together to meet the uncertainty requirement for the rest of the system. As part of flexible ramping product enhancements, deliverable flexible capacity awards are now 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. Here, the uncertainty requirement is distributed at a nodal level to load, solar, and wind resources based on allocation factors that reflect the estimated contribution of these resources to potential uncertainty. The result is more deliverable upward and downward flexible capacity awards that do not violate transmission or transfer constraints.

Flexible ramping product demand curves and implementation error

The prices on the demand curves should reflect the expected cost of a power balance constraint violation for the level of flexible ramping capacity procured. When the uncertainty requirement is met and flexible capacity is readily available, the price is zero. However, as this requirement is relaxed and less flexible capacity is procured (below the upper end of uncertainty that might materialize) the likelihood of a power balance constraint relaxation — and therefore the expected cost of this outcome — both increase.

For example, assume there is a 20 percent probability of an under-supply power balance constraint violation associated with procuring 100 MW less flexible capacity than the upward uncertainty requirement. Since the penalty price for relaxing the power balance constraint is $1,000/MWh, the expected cost of the shortage is then $200/MWh (20 percent multiplied by $1,000/MWh).[48] Therefore,

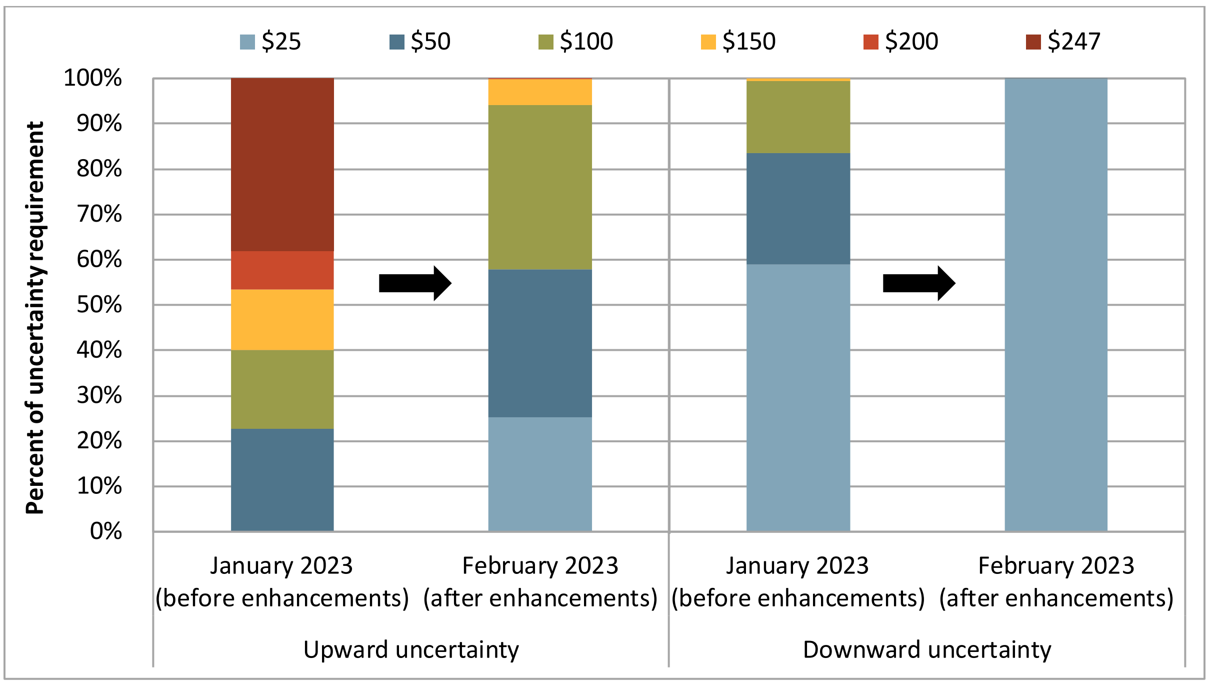
[47] Based on a 95 percent confidence interval.

[48] The penalty price for an undersupply infeasibility can be scaled above $1,000/MWh when a bid over $1,000/MWh is cost-justified prior to market operations (up to a maximum of $2,000/MWh). The penalty price for an over-supply infeasibility (excess energy) is -$155/MWh.

the flexible ramping product price (or willingness-to-pay for an additional megawatt of flexible capacity) at this particular point is $200/MWh.

Prices on the flexible ramping product demand curves have been consistently low across all balancing areas, markets, and directions since the enhancements were implemented on February 1. This made it appear cheaper for the market optimization to forego flexible ramping capacity. Figure 3.1 shows the average percent of each upward or downward uncertainty requirement that can be relaxed at various price points in January 2023 (prior to the enhancements) and February 2023 (following the enhancements).[49] For example, at $150/MWh, around 54 percent of the upward uncertainty requirements could be relaxed on average in January, compared to nearly all of the upward uncertainty requirements in February.

Figure 3.1 Average percent of uncertainty that can be relaxed at various price points



Uncertainty might materialize higher or lower than expected around a net load forecast. If the likelihood that net load uncertainty is higher actually materializes (i.e. actual net load is higher than expected) is 50 percent, then the expected cost of a power balance constraint relaxation with zero upward flexible capacity procured would be $500/MWh. In practice, the upward demand curves are capped at $247 such that the price for relaxing the final segment of the demand curve (or procuring zero upward flexible capacity) is typically $247/MWh.[50] However, the price for relaxing the final segment of the upward demand curve was $87/MWh on average during February. This inappropriately implies an 8.7 percent likelihood for a shortage with zero flexible capacity procured.

49 These amounts reflect an average across all balancing areas and intervals. However, this trend is similar across all areas.

50 The caps on the demand curves for flexible ramping capacity are intended to prevent flexible ramping procurement from replacing ancillary service or energy procurement.

DMM has released a special report covering this implementation error including the cause of the issue and its impact.[51] The California ISO has implemented a correction to the calculation of the flexible ramping product demand curves effective August 8, 2023.

Flexible ramping product prices

As part of flexible ramping product enhancements, flexible ramping product prices are now determined locationally at each node. This price can be made up of two components. The first component is the shadow price associated with meeting the uncertainty 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 can also include a congestion component. This reflects the shadow price on transmission constraints and relative contribution to that congestion which is expected based on the dispatch of all flexible capacity in the deployment scenarios. As of implementation of the enhancements on February 1, only a subset of transmission constraints are modeled in the deployment scenarios. This included only base-case flow-based transmission constraints. Contingency flowgate and nomogram constraints are expected to be implemented at a future date.

Flexible ramping product prices for the group of balancing areas that pass the resource sufficiency evaluation have frequently been zero since the enhancements were implemented on February 1. When the shadow price on this constraint is zero, this reflects that flexible capacity within this wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available. Here, the upper end of the uncertainty requirement can be met by resources with zero opportunity cost for providing that flexibility. Low or zero prices for upward flexible capacity during February and March are expected based on seasonally low loads and sufficient supply conditions in these months. DMM will continue to monitor flexible ramping product prices as system load conditions increase during the summer.

Figure 3.2 shows the percent of intervals since implementation of the enhancements in which the 15-minute market price for flexible capacity was non-zero for the *group of balancing areas that pass the tests*.[52] This is compared against the frequency of non-zero prices on the constraint for *system*-wide flexible capacity that was in place prior to the enhancements. Flexible capacity prices for the larger system continued to be low following the enhancements. During February and March, 15-minute market prices for flexible capacity within the pass-group were non-zero in less than 1 percent of intervals for upward capacity, and never for downward capacity. In these first two months, 5-minute market prices were also infrequent, in less than 0.1 percent of intervals.

51 Department of Market Monitoring, *Flexible ramping product enhancements demand curve implementation error,* July 20, 2023: http://www.caiso.com/Documents/Flexible-Ramping-Product-Enhancements-Demand-Curve-Implementation-Error-Jul-20-2023.pdf

52 For the group of balancing areas that pass the resource sufficiency evaluation, the demand curves for flexible capacity are distributed out to *surplus zones.* These surplus zones are separate for each balancing areas (or by LAP in the case of CAISO and BANC). The upper end of the demand curve for each surplus zone is equal to its share of the total pass-group uncertainty. In some cases, a balancing area may be transfer constrained from the rest of the system and unable to meet its share of pass-group uncertainty. This figure will only capture shadow prices for the greater pass-group region and will not include prices associated with local insufficiency.

Figure 3.2 Frequency of non-zero system or pass-group flexible ramping product shadow price

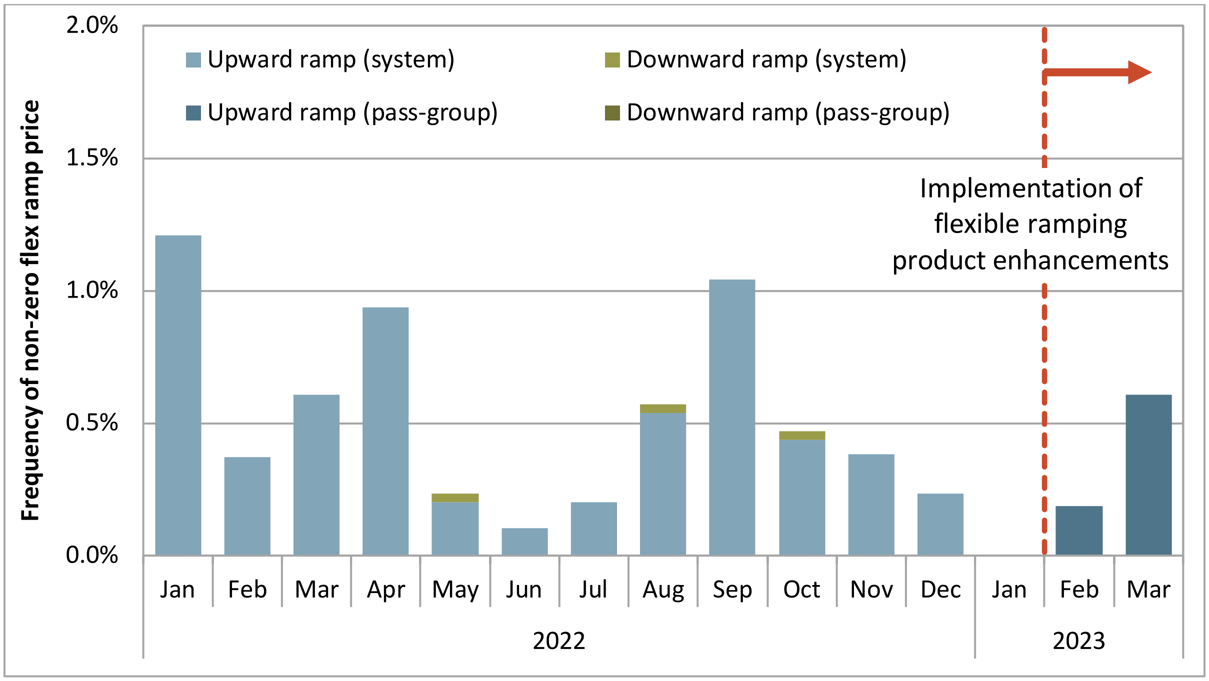
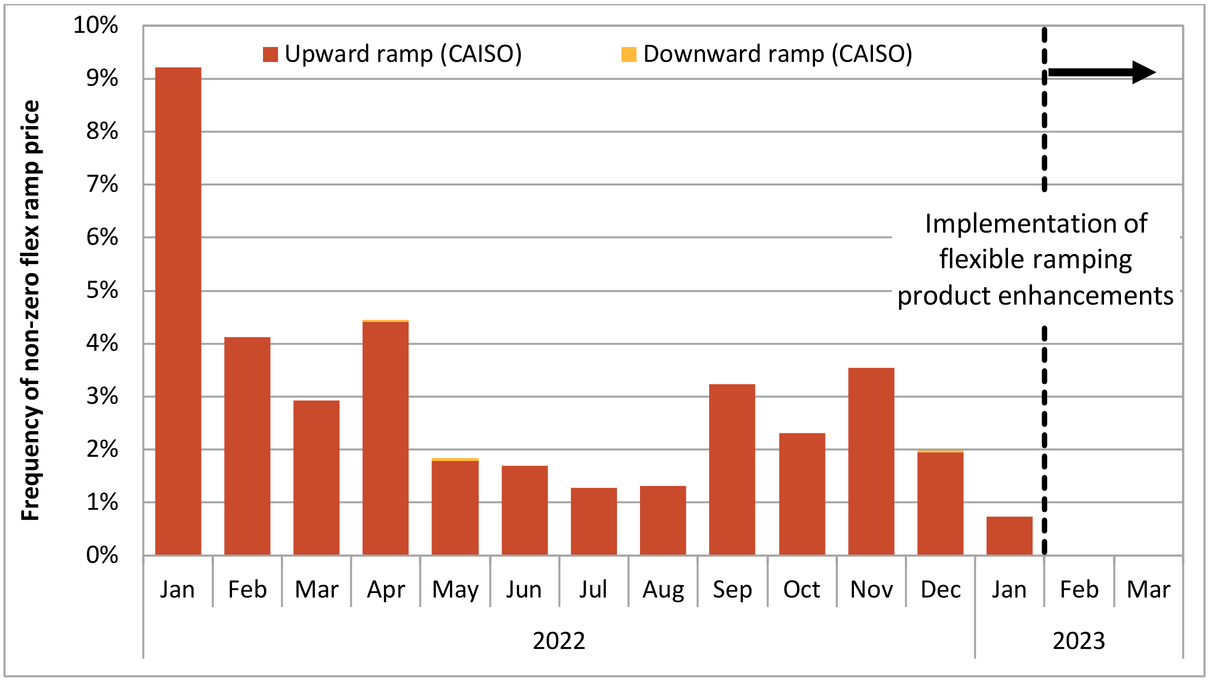


Figure 3.3 shows the frequency in which the area-specific constraint to procure flexible capacity within CAISO was binding at a non-zero price. Prior to the enhancements, a minimum requirement was in place to help procure flexible capacity within a balancing area that contributed to a large portion of system-wide uncertainty.[53] This was typically only the CAISO area, which had a minimum upward and downward uncertainty requirement enforced in most intervals. The result of this was greater flexible ramping capacity procurement from CAISO resources and frequent non-zero prices for flexible capacity within the CAISO area. This minimum requirement was removed as part of the enhancements on February 1 as nodal procurement can instead ensure that flexible capacity procured elsewhere in the system is deliverable. Flexible ramping product prices within CAISO are now driven by the shadow price on the constraint for procuring flexible capacity for the group of balancing areas that passed the resource sufficiency evaluation.

53 If a balancing area requirement was greater than 60 percent of the system requirement, then a minimum would be enforced equal to the balancing area's share of the diversity benefit. The minimum requirement was implemented in November 2020 as a short-term measure to help mitigate some of the issues surrounding procurement of stranded flexible capacity prior to nodal procurement.

Figure 3.3 Frequency of non-zero CAISO-specific flexible ramping product shadow price



Flexible ramping product procurement and impact of the enhancements

This section summarizes flexible capacity procured to meet the uncertainty needs of the greater WEIM system and the impact from flexible ramping product enhancements. Figure 3.4 shows the percent of upward or downward flexible capacity that was procured from various fuel types, both before and after the enhancements that were implemented at the start of February. Prior to the enhancements, these amounts reflect the percent of *system-wide* uncertainty. After the enhancements, these amounts instead reflect the percent of *pass-group* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation.

As shown in Figure 3.4, upward flexible capacity procured from hydro resources increased while upward capacity procured from batteries decreased following the enhancements. This is largely because of the elimination of the *minimum requirement.* As discussed in the last section, the minimum requirement was a temporary measure which often required that a portion of system-wide flexible capacity be procured within CAISO to help mitigate issues with stranded flexible capacity elsewhere in the system.

Since nodal procurement can instead better ensure that flexible capacity is deliverable, the minimum requirement is no longer needed, and a greater share of flexible capacity can be procured outside of the CAISO. Figure 3.5 shows the percent of upward or downward flexible capacity that was procured in various regions. These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system.

The balancing areas that were defined in each region are shown in Table 3.1. As shown in Figure 3.5, the percent of upward capacity procured from balancing areas in the Pacific Northwest region increased following the enhancements. Downward capacity procured from balancing areas in the Desert Southwest region also increased.

Figure 3.4 Percent of system or pass-group flexible capacity procurement by fuel type

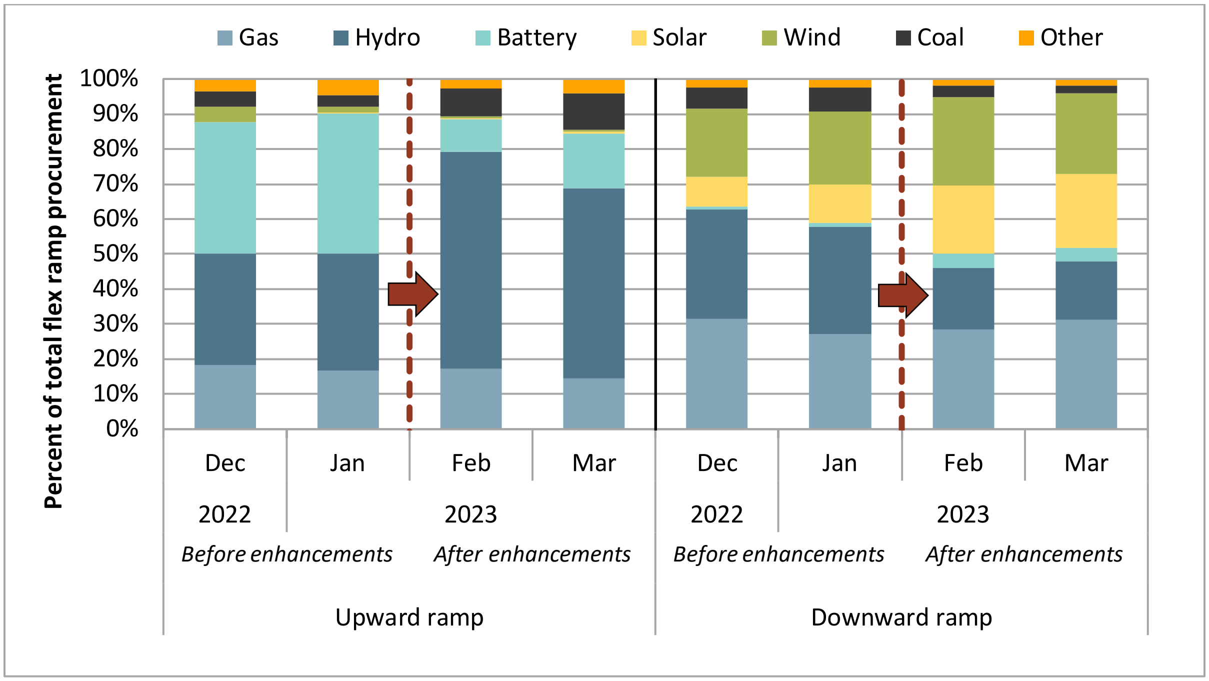


Figure 3.5 Percent of system or pass-group flexible capacity procurement by region

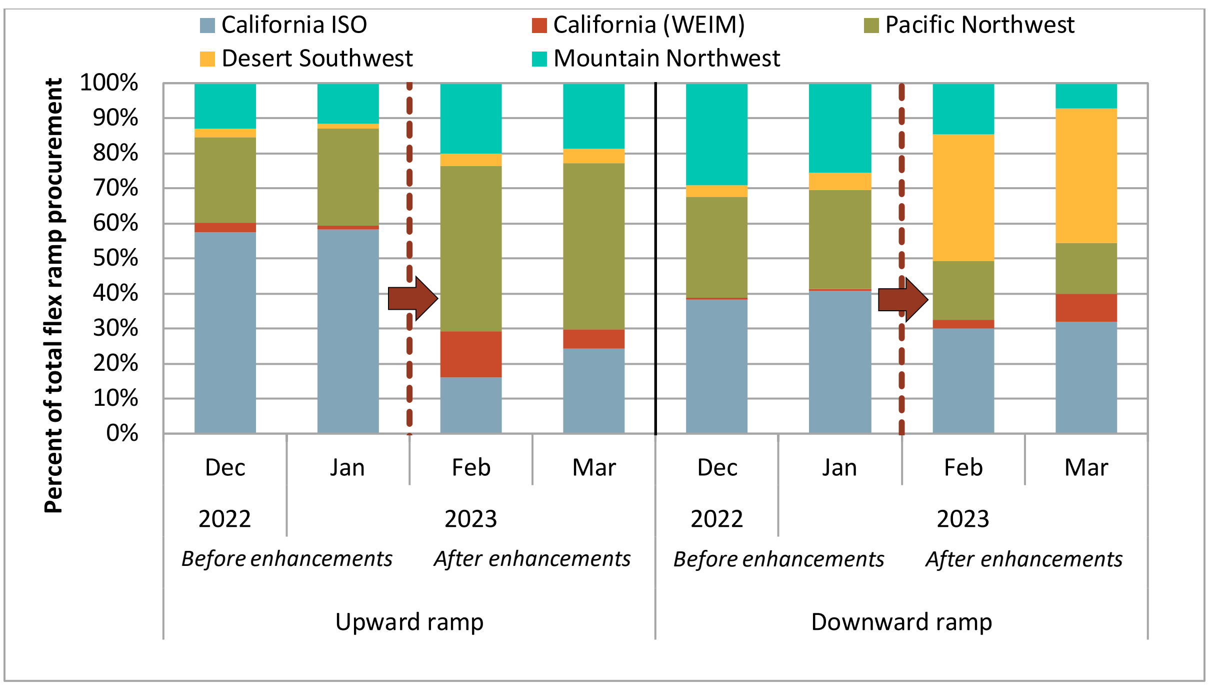


Table 3.1 WEIM balancing areas by region

Pacific Northwest	Mountain Northwest
Bonneville Power Administration	Idaho Power Company
PacifiCorp West	Avista
Portland General Electric	NorthWestern Energy
Powerex	PacifiCorp East
Puget Sound Energy	
Seattle City Light	
Tacoma Power	
California	**Desert Southwest**
California ISO	Arizona Public Service
Balancing Authority of Northern California	NV Energy
Los Angeles Department of Water and Power	Public Service Company of New Mexico
Turlock Irrigation District	Salt River Project
	Tucson Electric Power

3.1.2 Net load uncertainty for the flexible ramping product

The uncertainty requirement is used as part of the flexible ramping product design to capture the extreme ends of net load uncertainty, such that it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. Net load uncertainty is also included in the requirement of the flexible ramp sufficiency test (flexibility test) to capture additional flexibility needs that may be required in the evaluation hour due to variation in either load, solar, or wind forecasts. The calculation of uncertainty was adjusted on February 1 using a method called *mosaic quantile regression*. This section summarizes how uncertainty is currently calculated, the results of the uncertainty calculation, and DMM's recommendation for future refinement of this calculation.

Calculating net load uncertainty

Histogram method

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.[54]

Prior to February 1, 2023 the weekday distributions used data for the same hour from the previous 40 weekdays while weekend distributions instead used same-hour observations from the previous 20

[54] 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 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.

weekend days. The histogram approach did not factor in any current load, solar, or wind forecast information. Under this approach, uncertainty could have been set by historical outlier observations uncorrelated with current market conditions such as an extreme historical observation in which wind forecasts were significant while wind forecasts in the evaluation hour were minimal.

Mosaic quantile regression method

The calculation for net load uncertainty was adjusted on February 1, 2023 as part of flexible ramping enhancements. The uncertainty was adjusted to incorporate current load, solar, and wind forecast information using a method called *mosaic quantile regression*.

Regression is a statistical method used to study the relationship between two or more variables, such as the relationship between the load or renewable forecasts (independent variables) and uncertainty (dependent variable). Ordinary Least Squares is widely used to estimate the *mean* relationship between these variables (i.e. the average value of the dependent variable as a function of the independent variable). In contrast, quantile regression is a variation of regression that is useful when interested in the relationship between the independent variable(s) and different *percentiles* of the dependent variable. For example, the relationship between the load or renewable forecasts and the 97.5th percentile of uncertainty.

The new regression method employed by the CAISO is a two-step procedure to forecast the lower and upper extremes of net load uncertainty that might materialize. The initial quantile regressions determine the relationship between the forecasts (load, solar, and wind) and the extremes of each type of uncertainty (load, solar, and wind). In a simple linear regression, the relationship between the dependent variable Y and the independent variable X takes the basic form of $Y = bX$ where the outcome of the regression, b, explains how much Y changes for every one unit increase in X (e.g. If b is two, then y is predicted to be twice X). For calculating uncertainty as a function of the forecast, the quantile regressions are instead defined in the quadratic form ($Y = aX^2 + bX + c$). The initial regressions are shown below for 15-minute market upward net load uncertainty.[55]

Equation 1 Initial quantile regressions for upward net load uncertainty

$$Load\ uncertainty^{max} = a_l^{97.5}(load)^2 + b_l^{97.5}(load) + c_l^{97.5} + \varepsilon \qquad (\tau = 0.975)$$
$$Solar\ uncertainty^{min} = a_s^{2.5}(solar)^2 + b_s^{2.5}(solar) + c_s^{2.5} + \varepsilon \qquad (\tau = 0.025)$$
$$Wind\ uncertainty^{min} = a_w^{2.5}(wind)^2 + b_w^{2.5}(wind) + c_w^{2.5} + \varepsilon \qquad (\tau = 0.025)$$

Dependent variable: load, solar, and wind uncertainty — minimum or maximum difference between binding 5-minute market forecasts and advisory 15-minute market forecasts in each 15-minute market interval

Independent variable: advisory 15-minute market forecasts for load, solar, and wind in each interval

Error term (ε): variation in dependent variable that is not explained by independent variable

Quantile parameter (τ): determines the level of the quantile regression being estimated (high: 97.5 percentile, low: 2.5 percentile)

55 Equations 1 to 5 are for calculating *15-minute market upward* net load uncertainty. *Downward* net load uncertainty is instead based on the lower end of load uncertainty, and upper end of solar and wind uncertainty that might materialize. *5-minute market* net load uncertainty is instead based on the difference between a binding and advisory 5-minute market net load forecast.

The uncertainty regressions use a distribution of historical forecast observations from the previous 180 days — separate for each balancing area, hour, and day-type (weekday or weekend/holiday). For the 15-minute product and resource sufficiency evaluation, uncertainty in the distributions is the difference between binding 5-minute market forecasts and corresponding advisory 15-minute market forecasts.[56] The outcome of these regressions are the coefficients *a*, *b*, and *c*, that define the relationships between these forecasts and the extreme percentile of uncertainty that might materialize.[57] These coefficients can then be combined with the historical forecast data to create a distribution of predicted values for load, solar, and wind uncertainty which is needed for the second step of the calculation. This is shown below for upward net load uncertainty.

Equation 2 Predicted values for upward net load uncertainty

$$\hat{L}_Q^{97.5} = a_l^{97.5}(load)^2 + b_l^{97.5}(load) + c_l^{97.5}$$
$$\hat{S}_Q^{2.5} = a_s^{2.5}(solar)^2 + b_s^{2.5}(solar) + c_s^{2.5}$$
$$\widehat{W}_Q^{2.5} = a_w^{2.5}(wind)^2 + b_w^{2.5}(wind) + c_w^{2.5}$$

Predicted values: predicted 97.5th percentile of load uncertainty and 2.5th percentile of solar and wind uncertainty based on regression coefficients and historical distribution

Regression coefficients: parameters "a", "b", and "c" that define the relationship between the forecasts and the extreme end of uncertainty that might materialize

The *mosaic* element of the regression combines the predicted forecasts above with the histogram method. For the histogram estimates, the 180-day distributions are again used to calculate the lower and upper ends of uncertainty, based on the 2.5th and 97.5th percentiles in the distribution. The combination of the predicted values and the histogram extremes in the mosaic variable are intended to capture the incremental weather effect of using predicted information relative to the histogram approach. Here, the calculation modifies the histogram net load by adding the predicted values and subtracting the histogram outcomes for each uncertainty type individually.[58] This is shown below for upwards net load uncertainty:

56 In comparing the 15-minute observation to the three corresponding 5-minute observations, the maximum load errors and minimum wind and solar errors are used to calculate upward net load uncertainty. Or, minimum load errors and maximum wind and solar errors for downward net load uncertainty.

57 The coefficient *c* is also known as the intercept. It shows the value of the dependent variable when all independent variables are equal to zero.

58 The mosaic variable can be thought of as the modified net load.

Equation 3 Mosaic variable for upward net load uncertainty

$$\underbrace{mosaic^{97.5}} = \underbrace{NL_H^{97.5}} + \left(\left(\hat{L}_Q^{97.5} - L_H^{97.5}\right) - \left(\hat{S}_Q^{2.5} - S_H^{2.5}\right) - \left(\hat{W}_Q^{2.5} - W_H^{2.5}\right)\right)$$

Upward mosaic variable: intermediate variable for final regression

97.5th percentile of net load uncertainty from histogram

Predicted values: predicted load, solar, and wind uncertainty from initial quantile regressions (using historical distribution)

Load, solar, and wind uncertainty from histograms

Once the mosaic variable is calculated for each interval in the distribution, the software runs a final regression to predict net load uncertainty. Again, the quantile regression method looks for the extreme values of the data (at the 2.5th and 97.5th percentiles) such that the output reflects the upper and lower boundaries of the future uncertainty. Therefore, the predicted values obtained from the quantile regression models are expected to estimate the range in which net load uncertainty is likely to materialize. The final regression is shown below:

Equation 4 Mosaic regression for upward net load uncertainty

$$\underbrace{Net\ load\ uncertainty^{max}} = a_m^{97.5}(mosaic^{97.5})^2 + b_m^{97.5}(mosaic^{97.5}) + c_m^{97.5} + \underbrace{\varepsilon} \qquad \underbrace{(\tau = 0.975)}$$

Dependent variable: net load uncertainty — maximum difference between binding 5-minute market forecasts and advisory 15-minute market forecasts in each 15-minute market interval

Independent variable: mosaic variable in each 15-minute market interval (from previous step)

Error term (ε): variation in dependent variable that is not explained by independent variable

Quantile parameter (τ): determines the level of the quantile regression being estimated (high: 97.5th percentile)

Once all the regressions are complete, the regression output coefficients can be combined with current forecast information to calculate uncertainty for each interval. The 15-minute market product and resource sufficiency evaluation use the same regression coefficients but are combined with slightly different forecast information from each time horizon. The flexibility test uses the same load, solar, and wind forecasts which are considered in the resource sufficiency evaluation for calculating ramping capacity and test requirements.[59] The 15-minute and 5-minute market uncertainty calculations for the flexible ramping product instead use the advisory forecasts in the next interval — the same interval in which the deployment scenarios are run to determine feasible flexible capacity awards. The final equations for combining the current forecast information with the regression coefficients and histogram extremes to calculate upward uncertainty for each interval are shown below.

59 The latest forecasts at the time of the second pass of the resource sufficiency evaluation at 55 minutes prior to the evaluation hour, are held constant for the final test at 40 minutes prior to the hour.

Equation 5 Calculation of upward uncertainty from current forecast information

$$\hat{L}^{97.5}_{current} = a_l^{97.5}(load_{current})^2 + b_l^{97.5}(load_{current}) + c_l^{97.5}$$
$$\hat{S}^{2.5}_{current} = a_s^{2.5}(solar_{current})^2 + b_s^{2.5}(solar_{current}) + c_s^{2.5}$$
$$\widehat{W}^{2.5}_{current} = a_w^{2.5}(wind_{current})^2 + b_w^{2.5}(wind_{current}) + c_w^{2.5}$$

$$mosaic^{97.5}_{current} = NL_H^{97.5} + \left(\left(\hat{L}^{97.5}_{current} - L_H^{97.5}\right) - \left(\hat{S}^{2.5}_{current} - S_H^{2.5}\right) - \left(\widehat{W}^{2.5}_{current} - W_H^{2.5}\right)\right)$$

$$Net\ load\ uncertainty^{97.5}_{current} = a_m^{97.5}\left(mosaic^{97.5}_{current}\right)^2 + b_m^{97.5}\left(mosaic^{97.5}_{current}\right) + c_m^{97.5}$$

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

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

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

However, the current weather information that is ultimately combined with the regression results to calculate uncertainty are instead consistent with the group of balancing areas in the pass-group for flexible ramping capacity procurement. This is based on the second run of the resource sufficiency evaluation (T-55) for interval 1 and the final resource sufficiency evaluation (T-40) for intervals 2 through 4. Table 3.2 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

Table 3.2 Source of pass-group for calculating uncertainty and procuring flexible ramping capacity

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

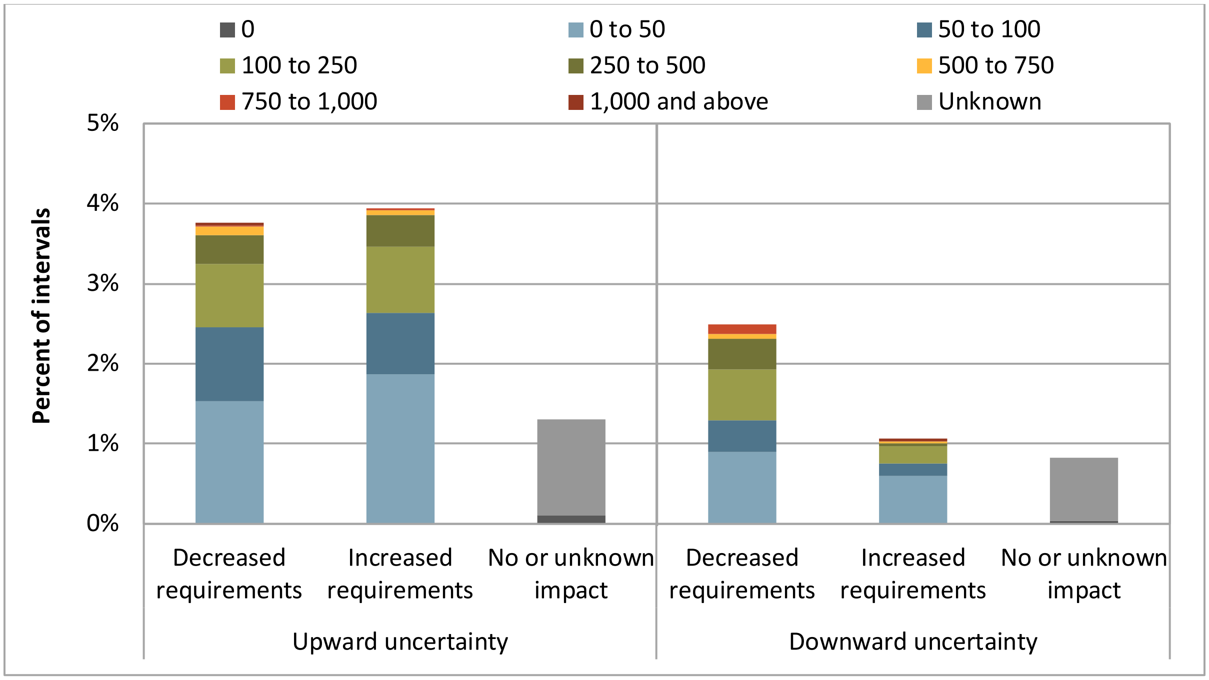
Using an inconsistent composition of balancing areas in the pass-group between the forecast and regression information can create significant swings in the calculated uncertainty for this group. For example, if you have a model to predict uncertainty based on forecast information of all but one balancing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

During about 12 percent of intervals during February and March, the composition of balancing areas in the pass-group between the current forecast information and regression information were inconsistent for either upward or downward uncertainty. Figure 3.6 summarizes the impact of this inconsistency on pass-group uncertainty requirements in cases when the composition of balancing areas differed between the two sets of data. The figure shows the percent of intervals in which the market uncertainty requirements (with inconsistent balancing areas in the pass-group) were higher or lower than counterfactual uncertainty requirements with a consistent composition of balancing areas in the pass-group.[60] These results are shown separately for the following categories to highlight the impact of this inconsistency on uncertainty requirements.

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

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

Figure 3.6 Impact of pass-group inconsistency on uncertainty requirements (February - March 2023)



Threshold for capping uncertainty

Uncertainty calculated from the quantile regressions are capped by the lesser of two thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from the previous 180 days.[61] The *mosaic* (or seasonal) threshold is updated each quarter and is calculated based on the 1st and 99th percentile using the quantile regression method and observations over the previous 90 days. Here, each hour is calculated separately and the greatest upward and downward uncertainty across all hours sets the mosaic threshold for each hour of the same direction.

During February and March, the thresholds capped upward and downward uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 11 percent of intervals in the 15-minute market and 7 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the mosaic threshold — during around 93 percent of cases in which pass-group uncertainty was capped by one of the two thresholds.

A threshold is also in place that sets the floor for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. During February and March, the 15-minute market uncertainty calculated for the group of balancing that passed the resource sufficiency evaluation was set near zero by this threshold in around 0.4 percent of intervals for each of upward and downward uncertainty.

[61] The histogram threshold is updated every day. The distributions are separate for each hour and day type (weekday or weekend/holiday).

Results of quantile regression uncertainty calculation

Figure 3.7 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation, both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the previous 180 days) and with the mosaic quantile regression method. The green and blue lines show the average upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the month. The dashed red and yellow lines show the average histogram and mosaic thresholds, respectively, during the period.

Figure 3.8 instead summarizes actual error between binding net load forecasts in the 5-minute market and advisory net load forecasts in the 15-minute market — for the group of balancing areas that passed the tests. Here, a higher net load error reflects higher load (or lower renewables) in the binding 5-minute market interval, relative to the advisory 15-minute market interval. For comparison the blue lines show the average upward and downward uncertainty used in the market during the same period per the mosaic quantile regression method. Again, the blue areas around the lines show the minimum and maximum amounts for each hour. This metric highlights how well actual pass-group net load error in each interval fits within the calculated uncertainty requirements.

Figure 3.9 and Figure 3.10 show the same information for instead 5-minute market uncertainty. 5-minute market uncertainty reflects the error between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach were often comparable to those calculated with the histogram approach on average. However, the quantile regression approach was more-often subject to periods of decreased uncertainty.

Figure 3.7 15-minute market pass-group uncertainty requirements (weekdays, February - March 2023)

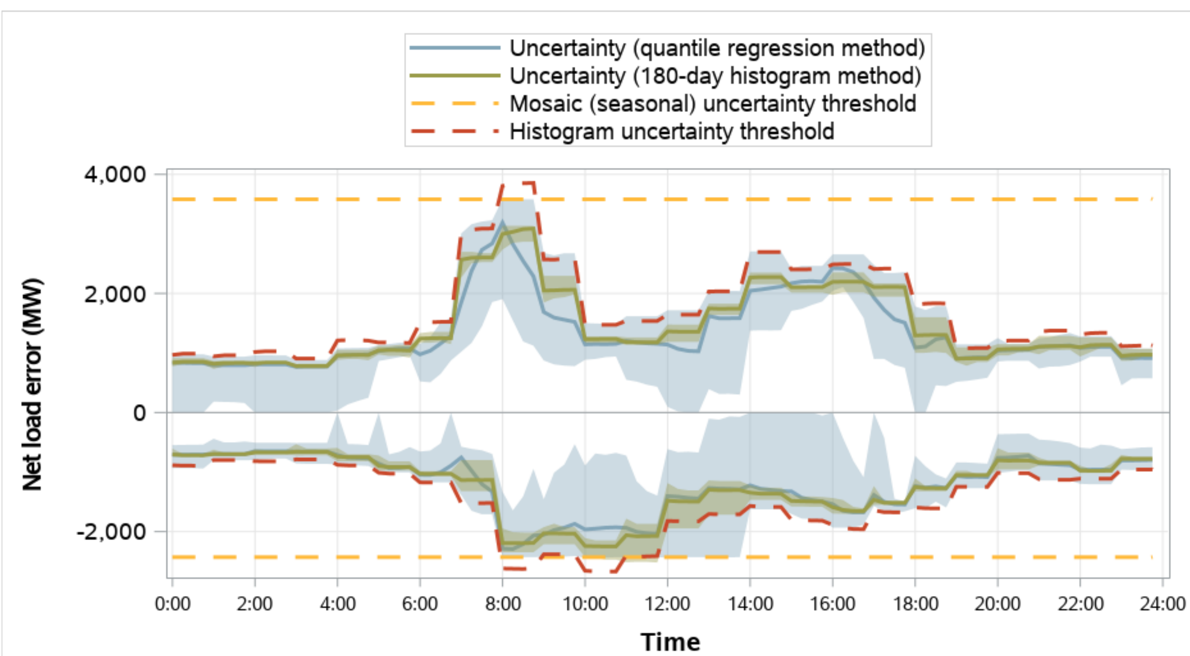


Figure 3.8 15-minute market distribution of actual pass-group net load error compared to uncertainty requirements (weekdays, February - March 2023)

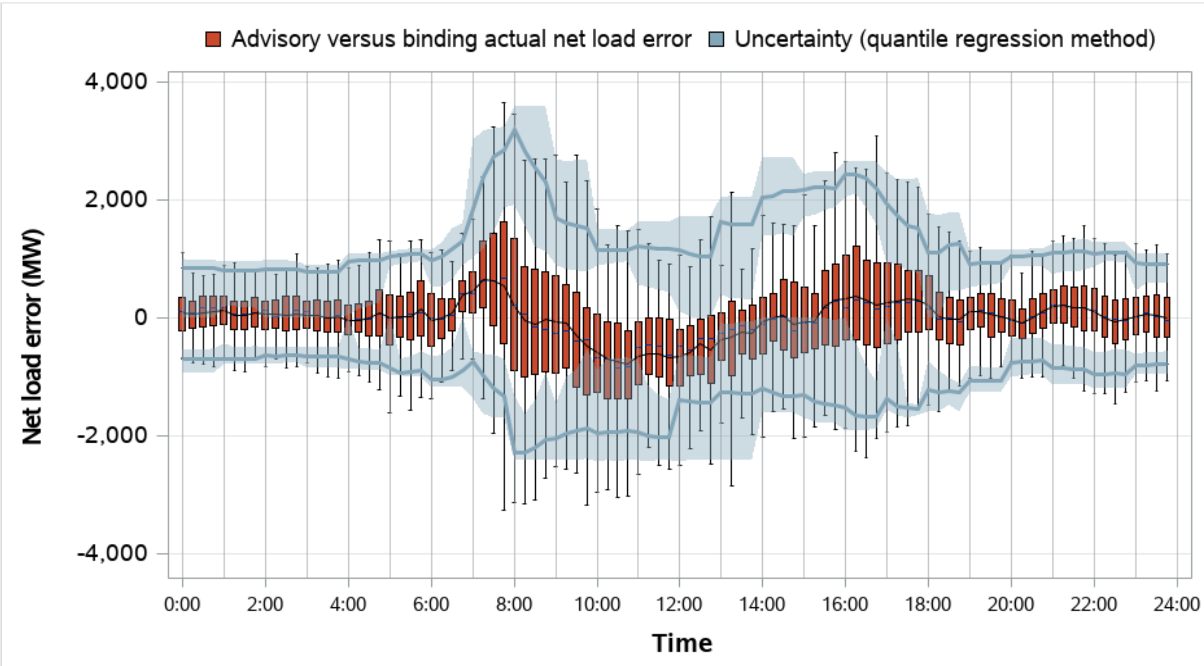


Figure 3.9 5-minute market pass-group uncertainty requirements (weekdays, February - March 2023)

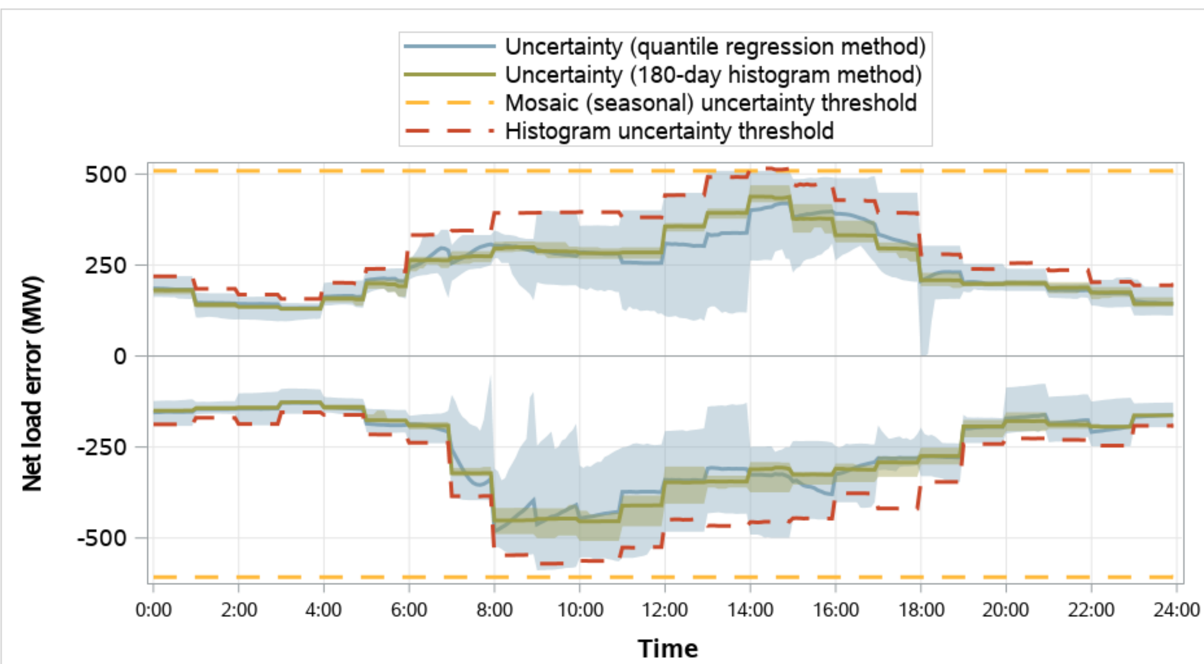


Figure 3.10 5-minute market distribution of actual pass-group net load error compared to uncertainty requirements (weekdays, February - March 2023)

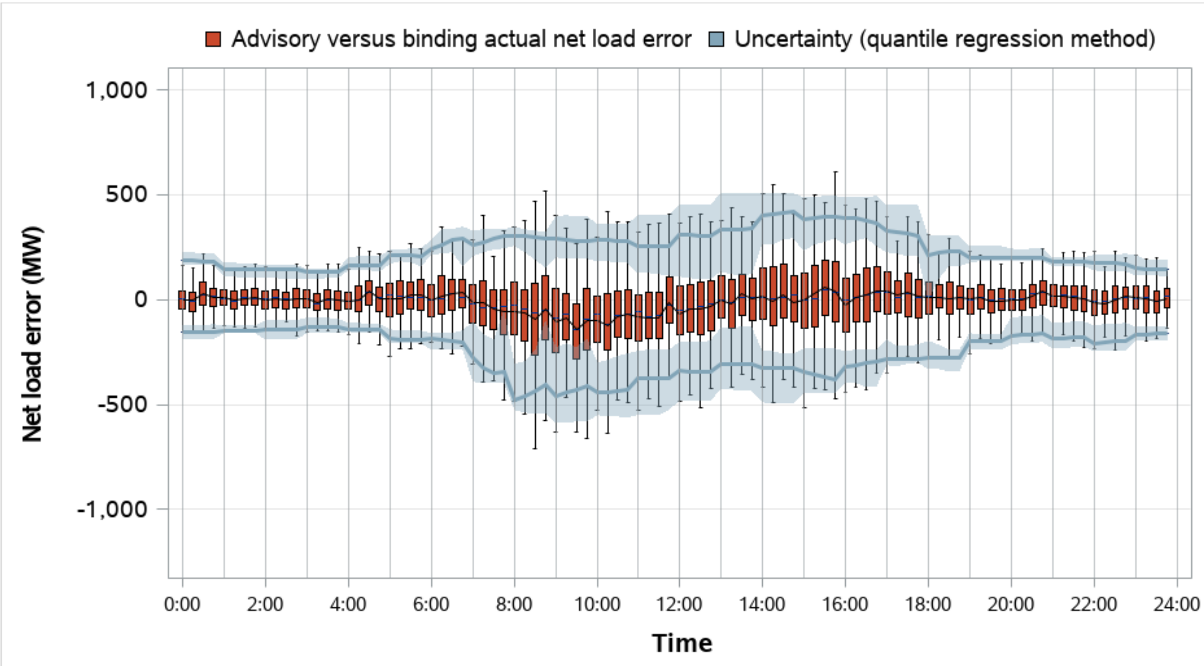


Table 3.3 summarizes the average uncertainty requirement for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. On average across all hours, the 15-minute uncertainty calculated from the regression method was less than the histogram method for both directions. In the 5-minute market, calculated uncertainty from both methods were nearly the same on average.

Table 3.4 summarize the actual net load error for the pass-group and how that compares to the mosaic regression uncertainty requirements for the same interval.[62] The left side of the table summarizes the closeness of the actual net load error to the pass-group uncertainty requirements when the actual net load error was within (or covered) by the upward or downward requirements. The mosaic regression requirements covered between 93 and 97 percent of actual net load errors across all markets and directions. The right side of the table summarizes when the actual net load error instead exceeded upward or downward uncertainty requirements.

Table 3.5 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was more than the mosaic regression method, but by less than 6 percent across all areas.

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

For more information on the calculated uncertainty used in the resource sufficiency evaluation for each balancing area, see DMM's February 2023 resource sufficiency evaluation report.[63]

Table 3.3 Average pass-group uncertainty requirements (February - March 2023)

Market	Uncertainty type	Pass-group uncertainty		
		Histogram	Mosaic	*Difference*
15-minute market	Upward	1,456	1,341	-115.2
	Downward	1,197	1,154	-43.5
5-minute market	Upward	245	245	-0.03
	Downward	257	254	-3.2

Table 3.4 Actual net load error compared to mosaic regression pass-group uncertainty requirements (February - March 2023)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*		*Actual net load error exceeds requirement*	
		Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	97%	1,415	3%	290
	Downward	93%	1,243	7%	426
5-minute market	Upward	97%	267	3%	87
	Downward	96%	257	4%	98

Table 3.5 Actual net load error compared to histogram regression pass-group uncertainty requirements (February - March 2023)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*		*Actual net load error exceeds requirement*	
		Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	97%	1,530	3%	311
	Downward	95%	1,260	5%	403
5-minute market	Upward	96%	268	4%	92
	Downward	96%	260	4%	102

DMM's review of the performance of this new methodology indicates that it is not a clear improvement over the prior method. Although uncertainty values calculated with this method are generally lower

[63] Department of Market Monitoring, *Western Energy Imbalance Market Resource Sufficiency Evaluation Metrics Report covering February 2023*, May 3, 2023: http://www.caiso.com/Documents/Feb-2023-Metrics-Report-on-Resource-Sufficiency-Evaluation-in-WEIM-May-3-2023.pdf

while covering uncertainty (an improvement), they fluctuate more significantly and are likely to be more difficult for balancing areas to reproduce or predict in advance.

Therefore, DMM continues to recommend that the ISO and stakeholders consider developing much simpler and more transparent uncertainty adders in the next phase of this initiative. A forthcoming paper will focus on specific recommendations and issues in need of resolution. The coefficients estimated with the quantile regression technique, as currently used, are not statistically different from zero in most instances in DMM's replication and uncertainty is set at non-regression based caps between 5 and 10 percent of intervals. This lack of statistical significance and need to set uncertainty with non-regression based values suggests improved forecasting performance may be possible. Using a forecasting technique that is more extensively studied and used in other applications could also increase transparency for market participants.

Monthly summaries of uncertainty as used in the resource sufficiency evaluation are available by balancing area in DMM's monthly resource sufficiency evaluation reports.[64] The July report includes new metrics summarizing both the intra-hour and inter-hour variability, which have both increased following the introduction of the quantile regression technique. Prior to the introduction of this method, uncertainty did not vary within an hour and could be calculated in advance of the trade day. DMM continues to recommend that the ISO and stakeholders consider developing a simpler, more transparent uncertainty adder.

64 Monthly resource sufficiency evaluation reports are posted on DMM's website here: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

APPENDIX

Appendix A | Western Energy Imbalance Market Area specific metrics

Sections A.1 to A.20 include figures by WEIM area on the hourly locational marginal price (LMP) and dynamic transfers. These figures are included for both the 15-minute and 5-minute markets. Key highlights of the quarter include:

- Average quarterly transfers in the 15-minute and 5-minute markets have generally increased in the first quarter of 2023. The hourly differences between import and exports in each area are more pronounced, with larger swings between importing and exporting around solar hours.
- The impact of 'Congestion within WEIM' is most apparent in PacifiCorp East where it decreases average prices in the area throughout the day. During the first quarter of 2023, PacifiCorp East shifted from primarily exporting to importing during all hours.

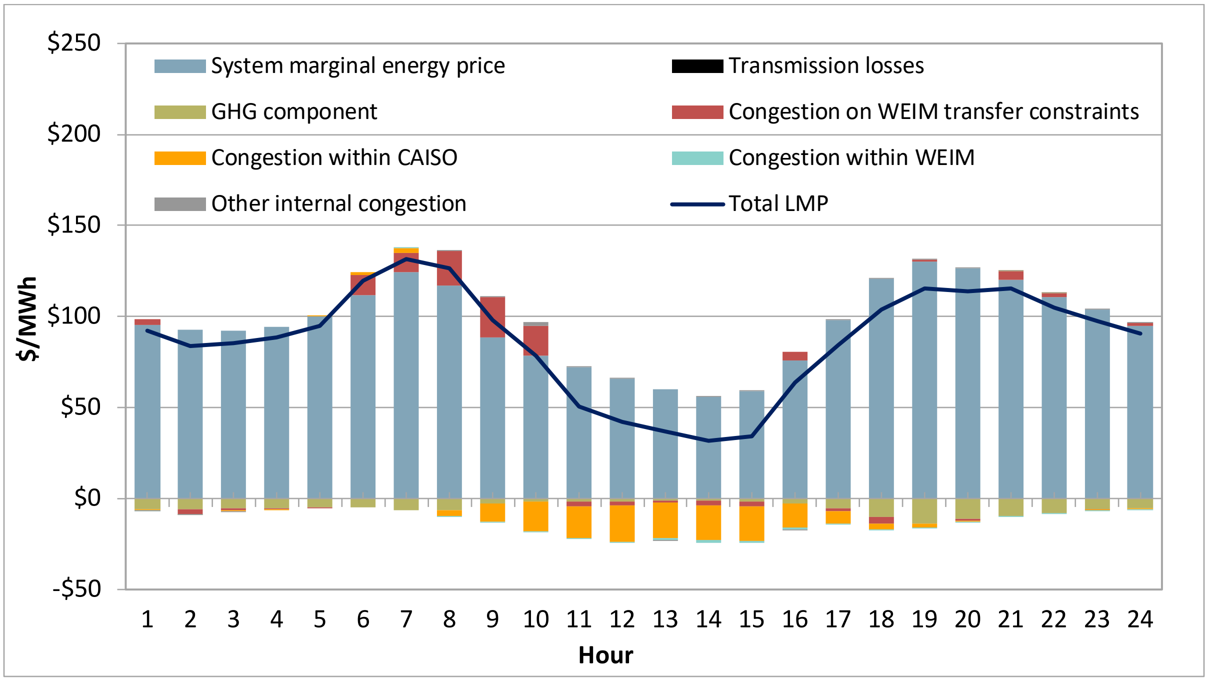
The hourly locational marginal price decomposition figures break down the price into seven separate components. These components, listed below, can influence the prices in an area positively or negatively depending on the circumstances.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for electricity in the WEIM footprint. Therefore, 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.
- **Congestion within CAISO** is the price impact from transmission constraints within the CAISO area that are restricting the flow of energy. While these constraints are located within CAISO's 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** is the price impact from internal transmission constraints that are restricting the flow of energy within an area. These are internal congestion impacts that are not captured within the CAISO and WEIM congestion categories.
- **Congestion on WEIM transfer constraints** is the price impact from intertie transmission constraints that link two balancing areas together. Price impacts from failed resource sufficiency evaluation (RSE) tests are included in this category as failed tests limit transfer capabilities.
- **Greenhouse gas price** is the 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.

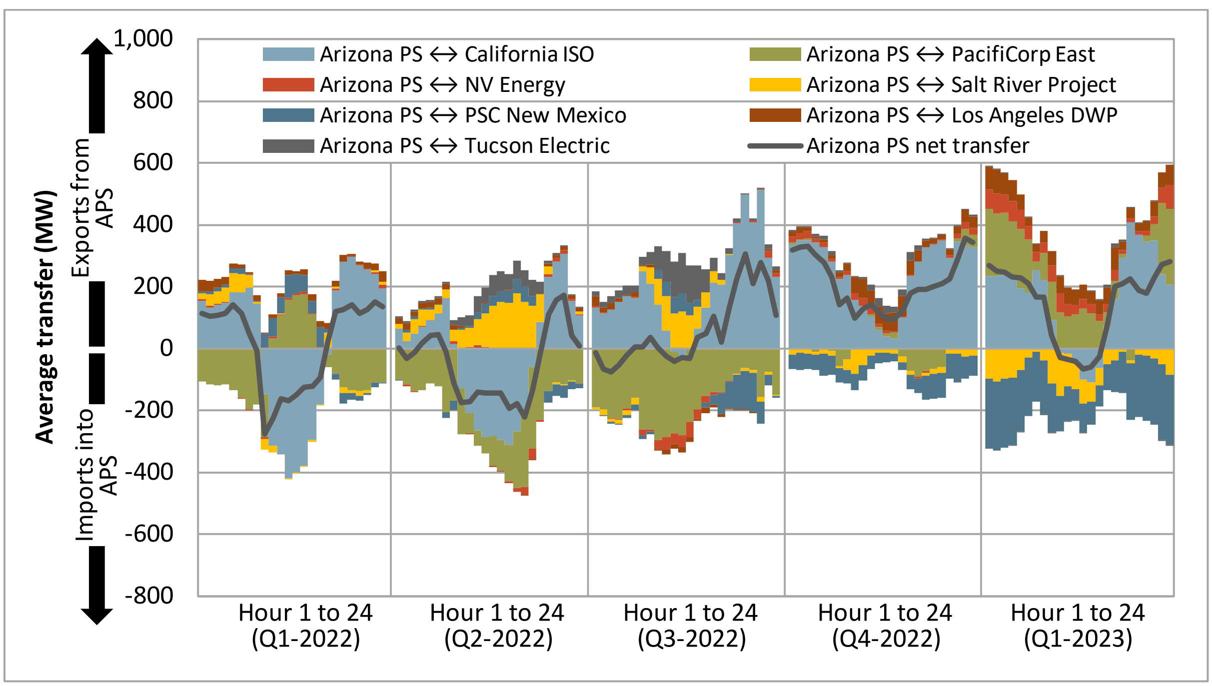
The transfer figures below show the hourly average imports and exports by WEIM area in the 15-minute and 5-minute markets by quarter. These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will not appear in the figures.

A.1 Arizona Public Service

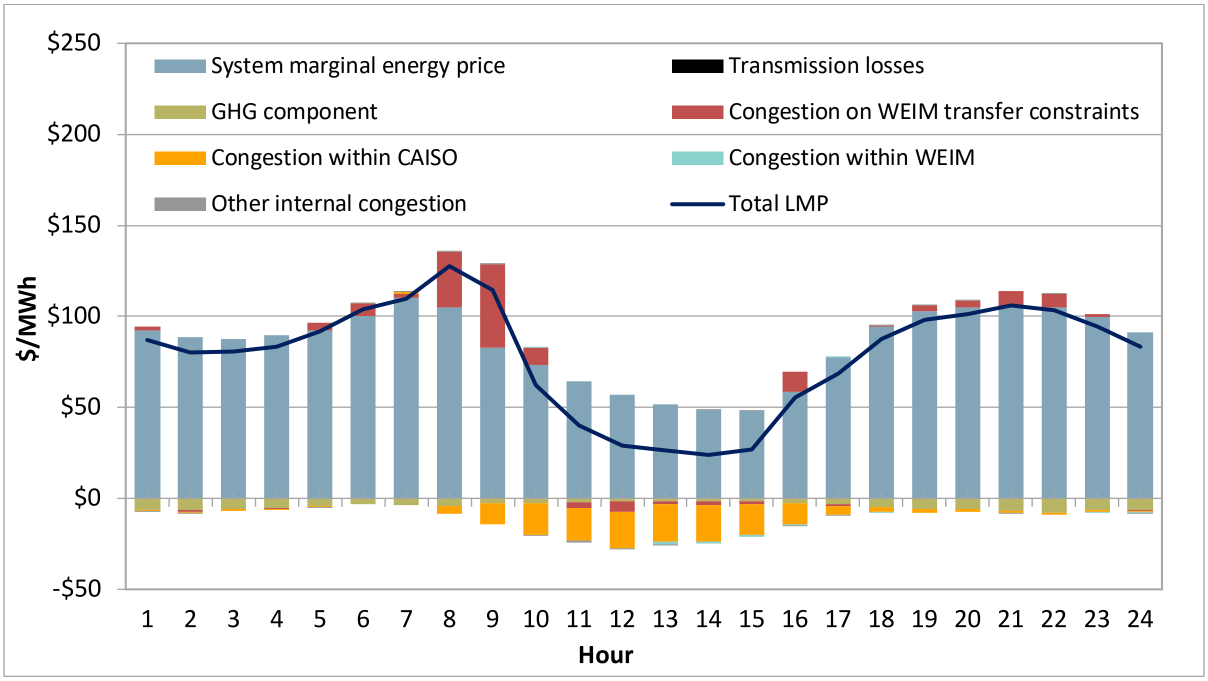
Appendix Figure A.1 Average hourly 15-minute price by component (Q1 2023)



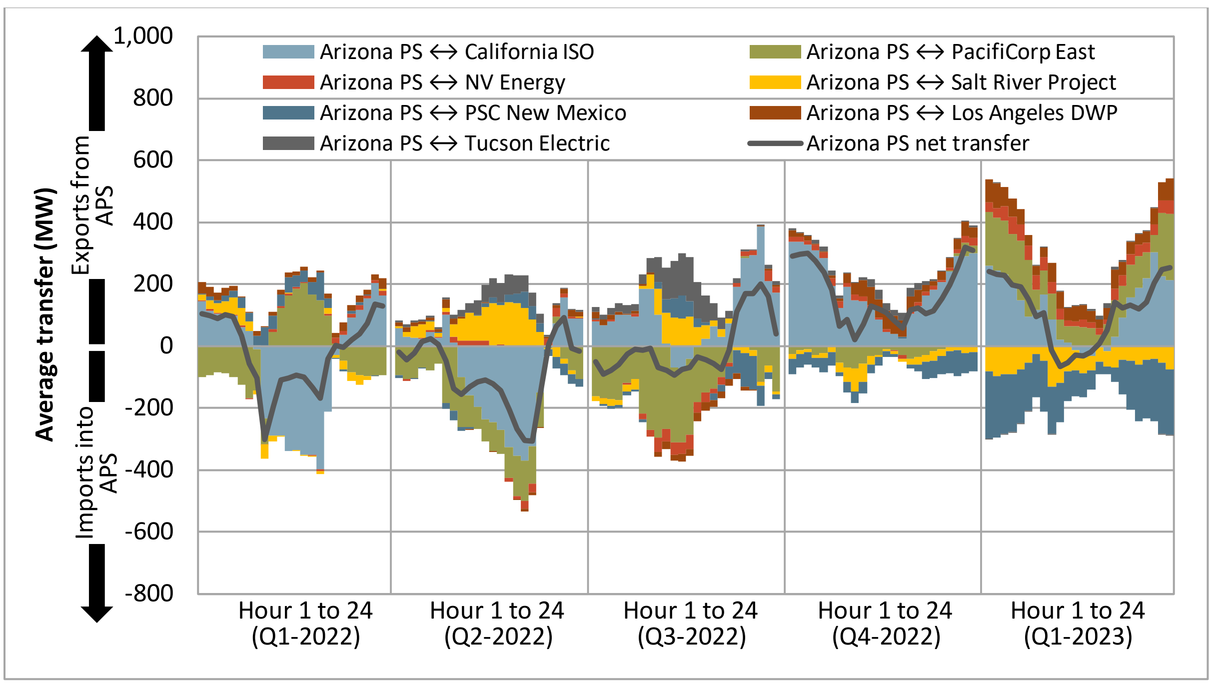
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q1 2023)

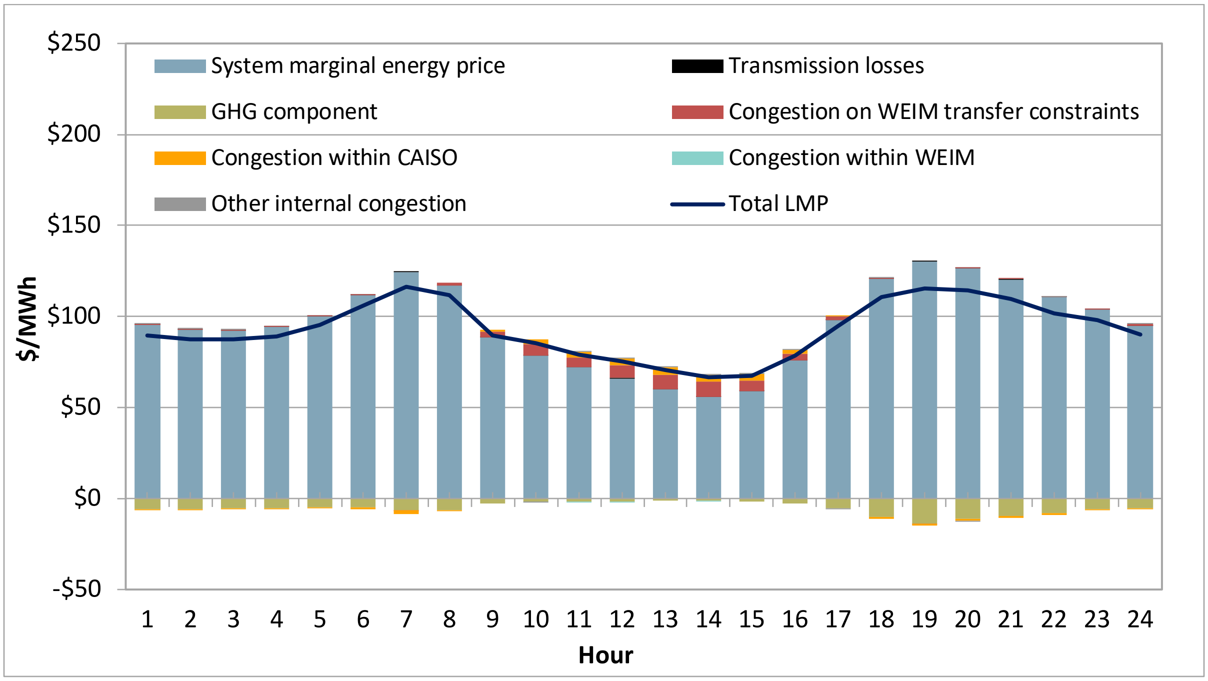


Appendix Figure A.4 Average hourly 5-minute market transfers

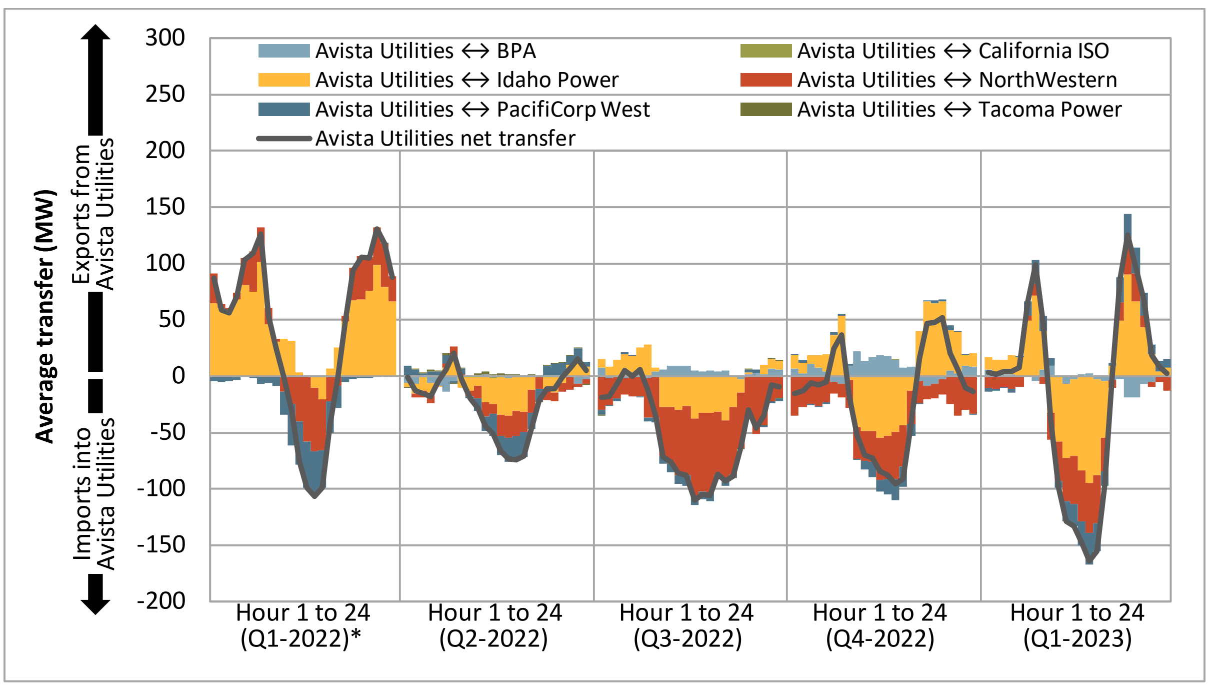


A.2 Avista Utilities

Appendix Figure A.5 Average hourly 15-minute price by component (Q1 2023)

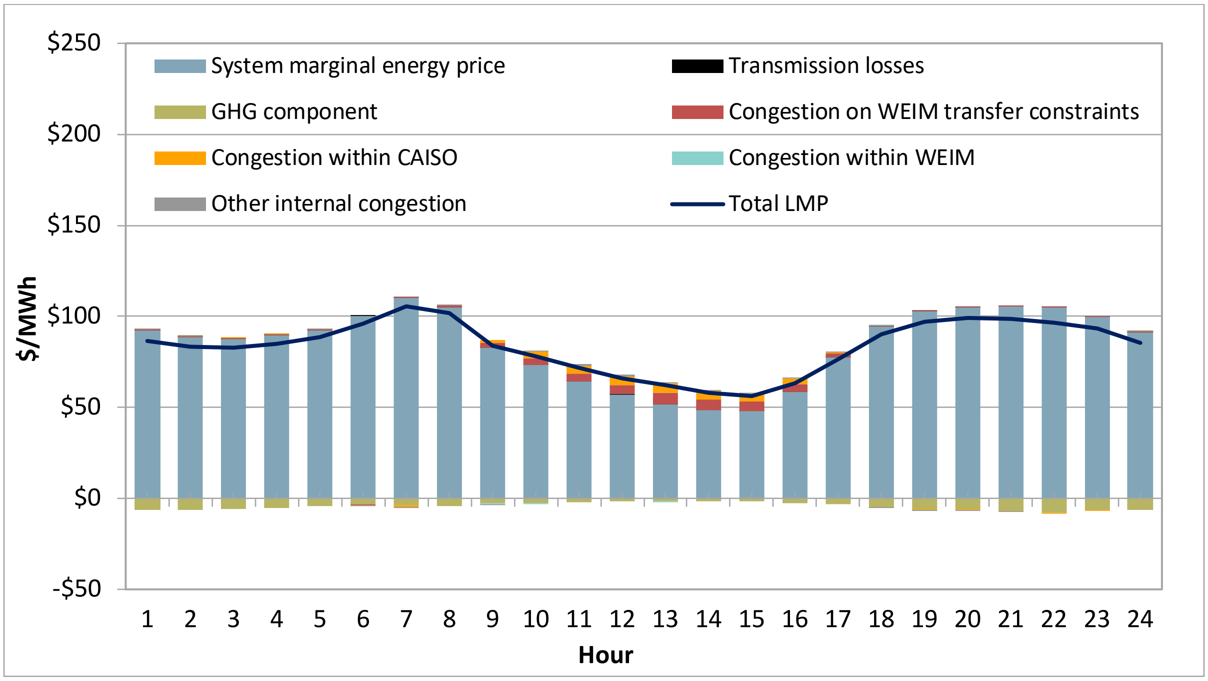


Appendix Figure A.6 Average hourly 15-minute market transfers

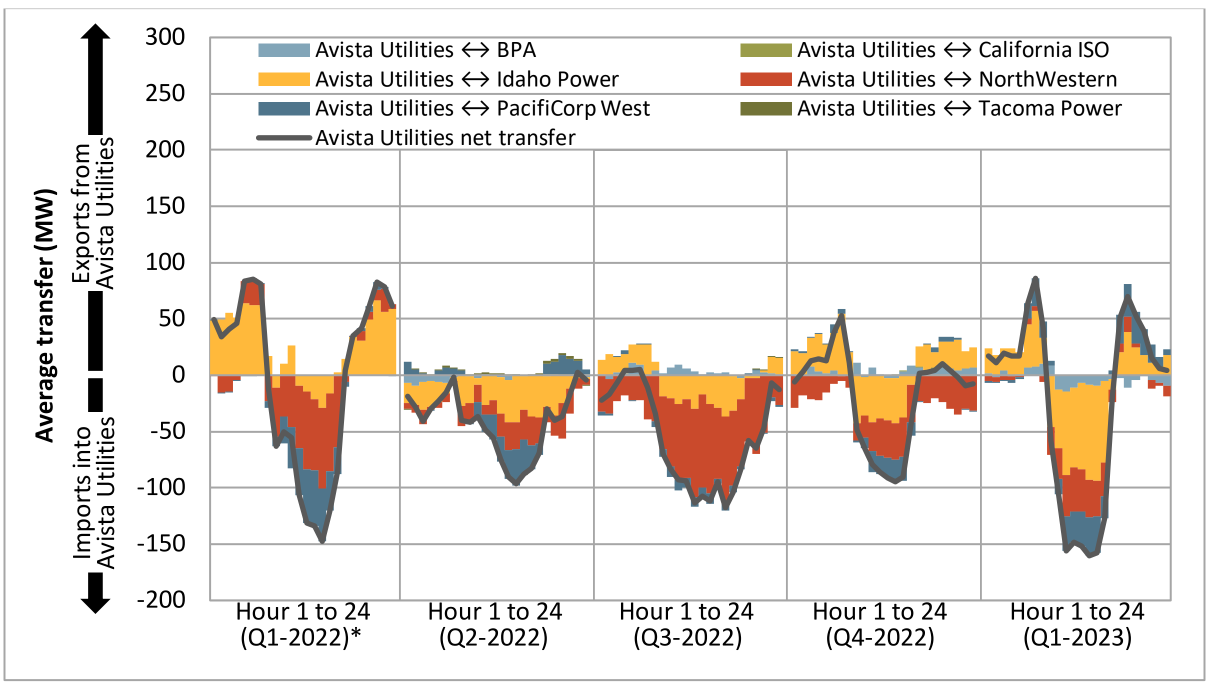


*Since joining the WEIM

Appendix Figure A.7 Average hourly 5-minute price by component (Q1 2023)



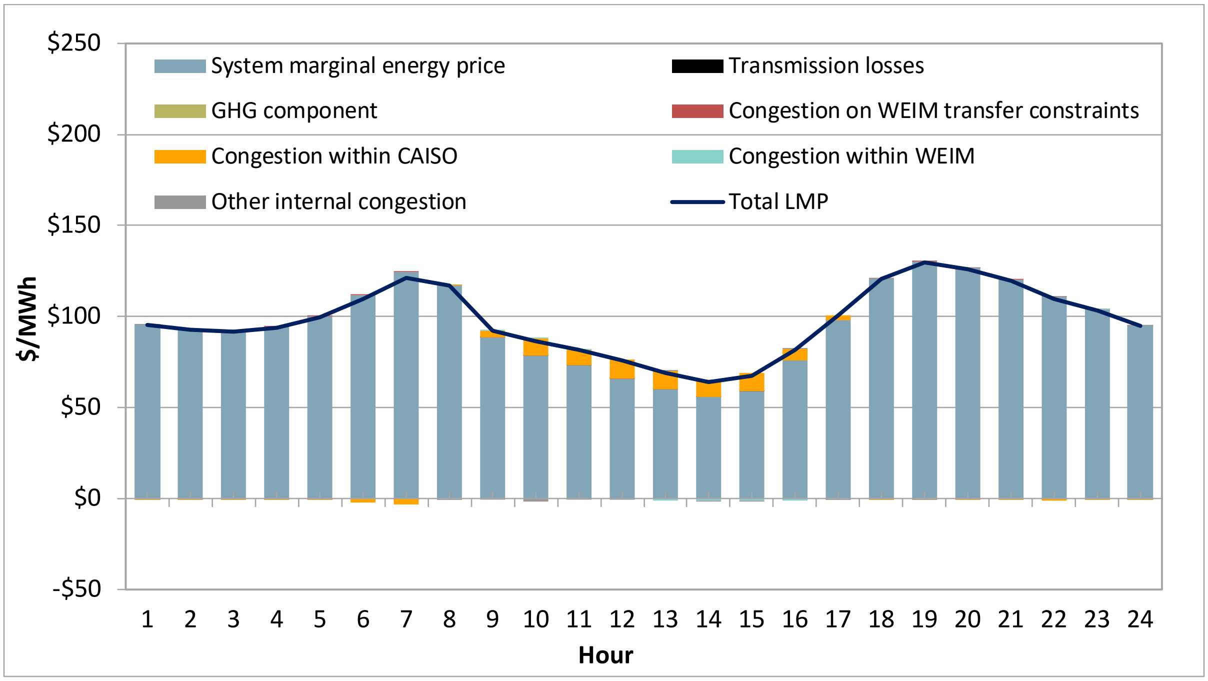
Appendix Figure A.8 Average hourly 5-minute market transfers



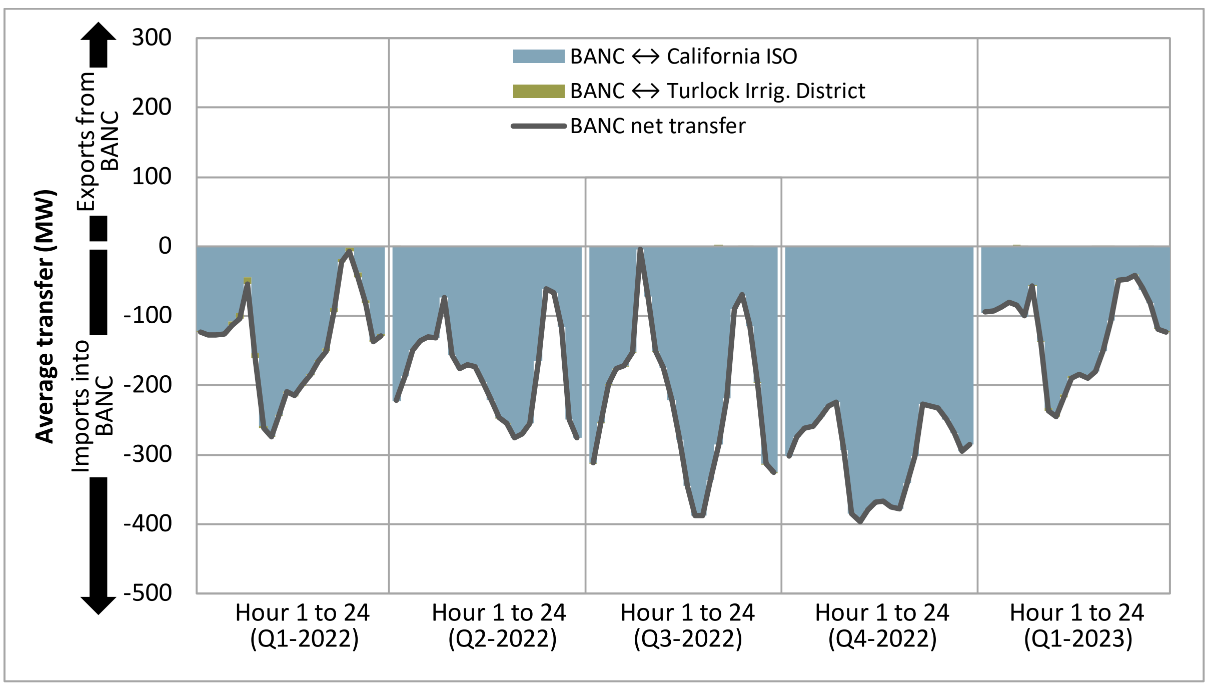
*Since joining the WEIM

A.3 Balancing Authority of Northern California

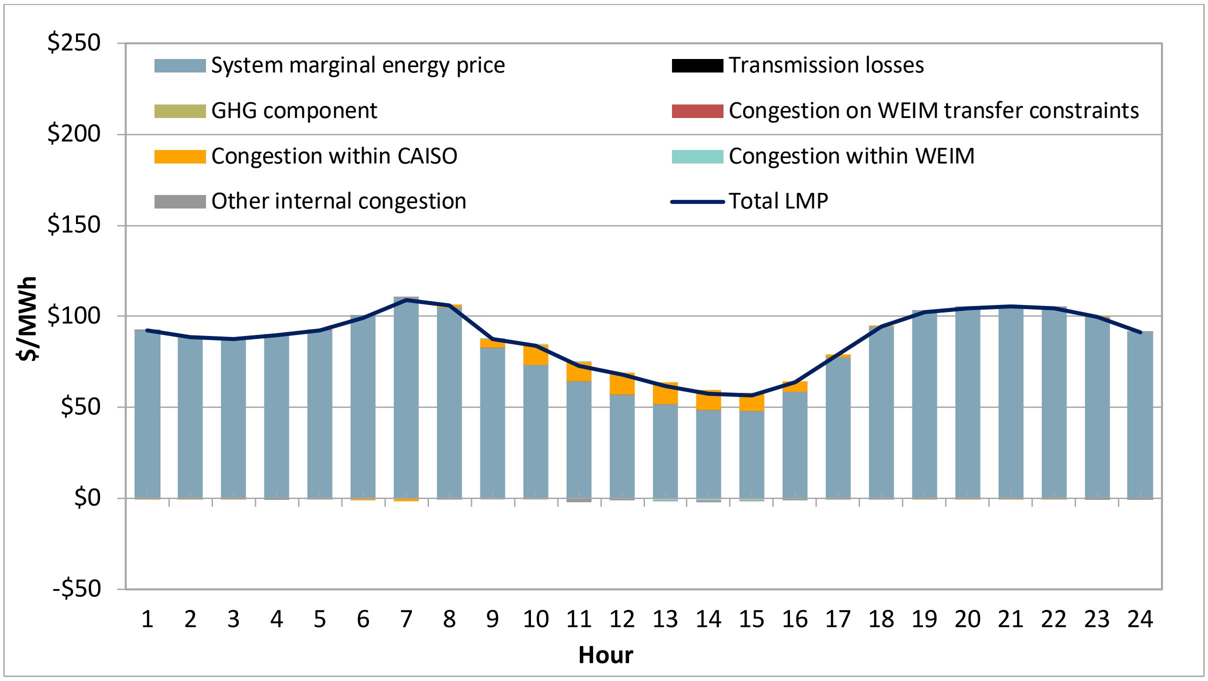
Appendix Figure A.9 Average hourly 15-minute price by component (Q1 2023)



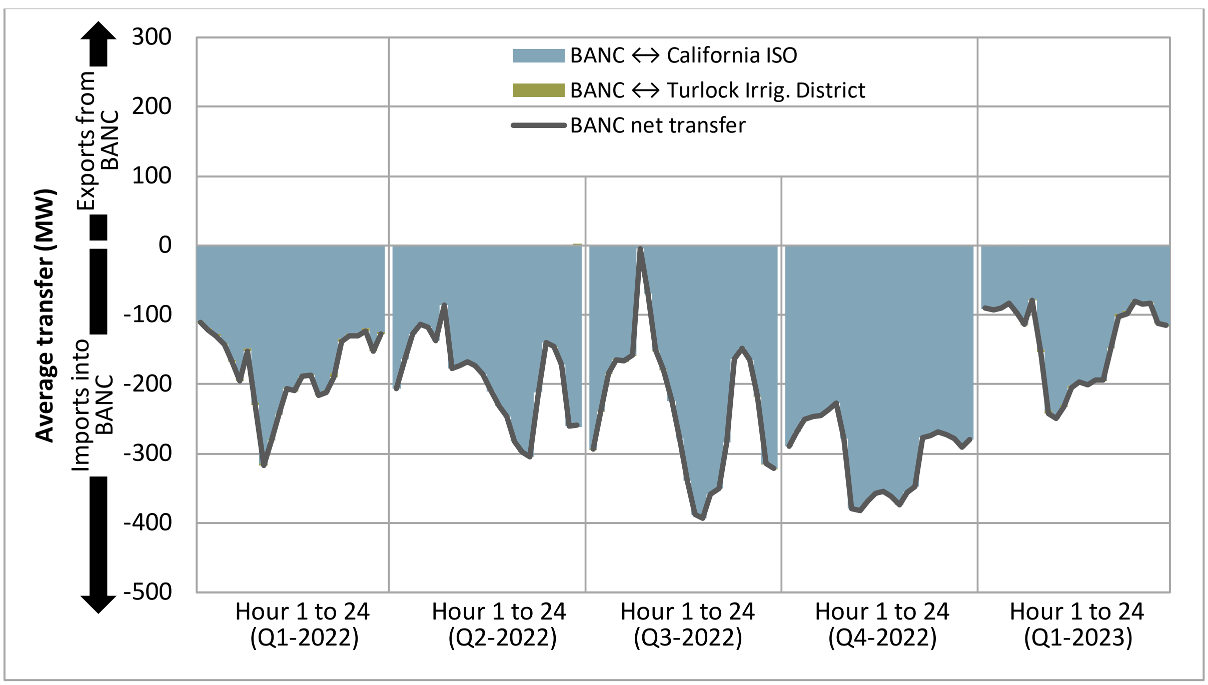
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q1 2023)

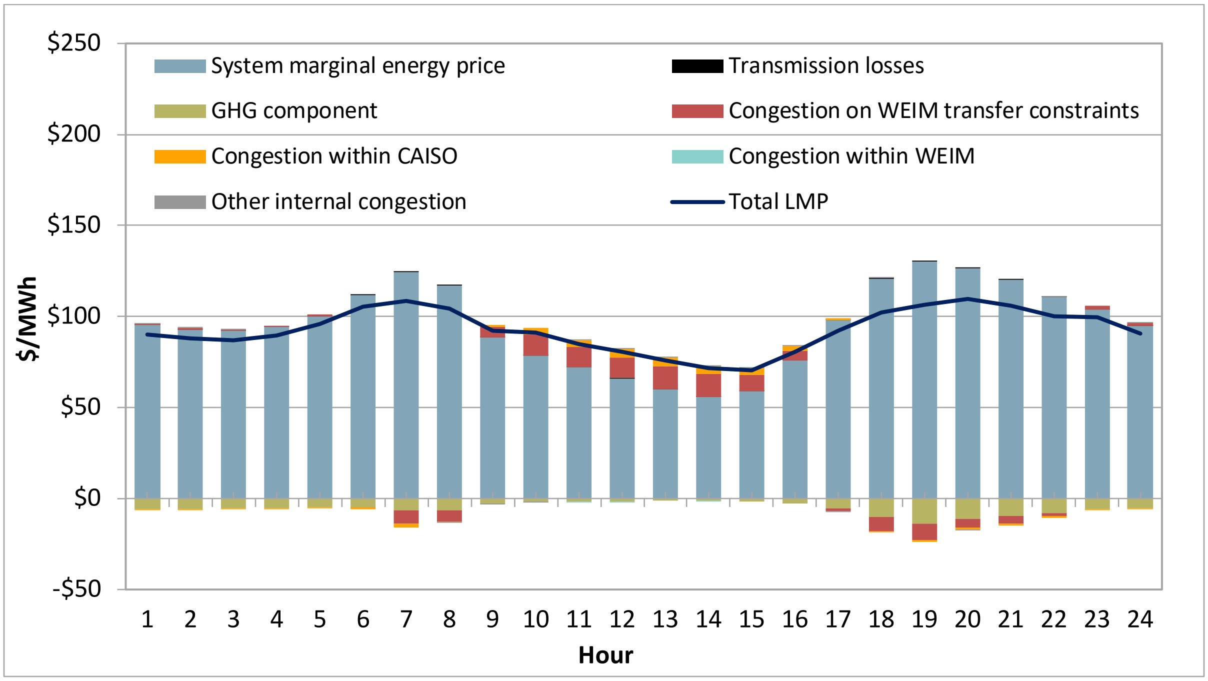


Appendix Figure A.12 Average hourly 5-minute market transfers

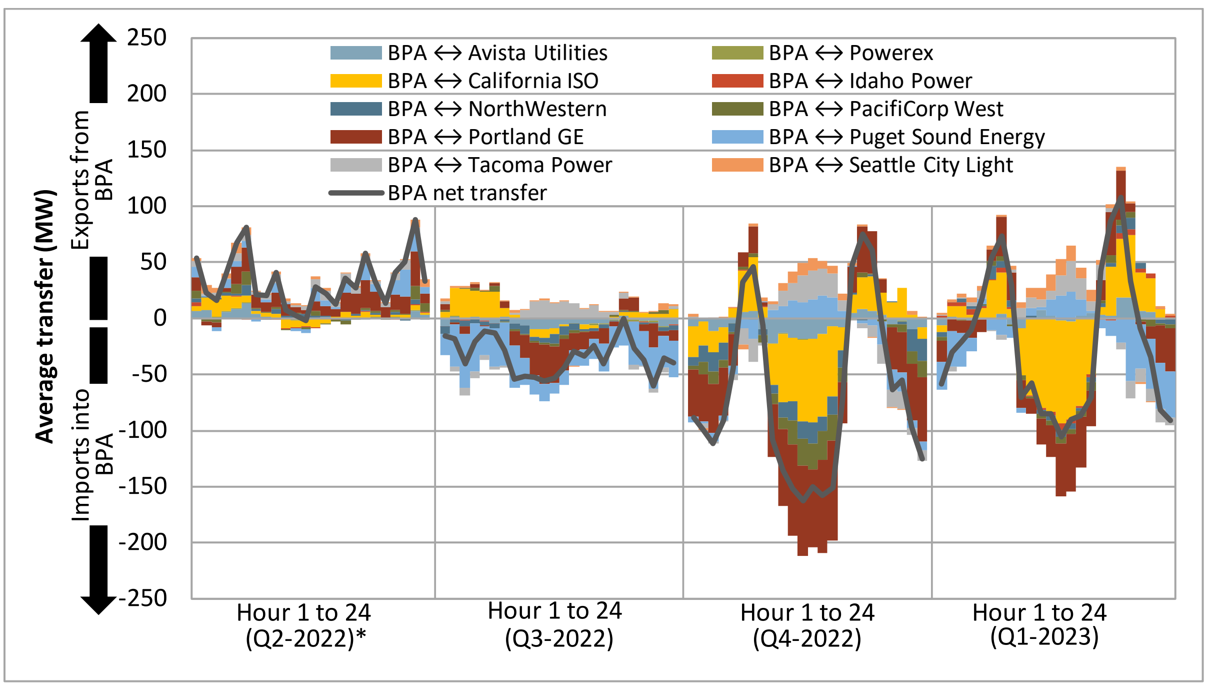


A.4 Bonneville Power Administration

Appendix Figure A.13 Average hourly 15-minute price by component (Q1 2023)

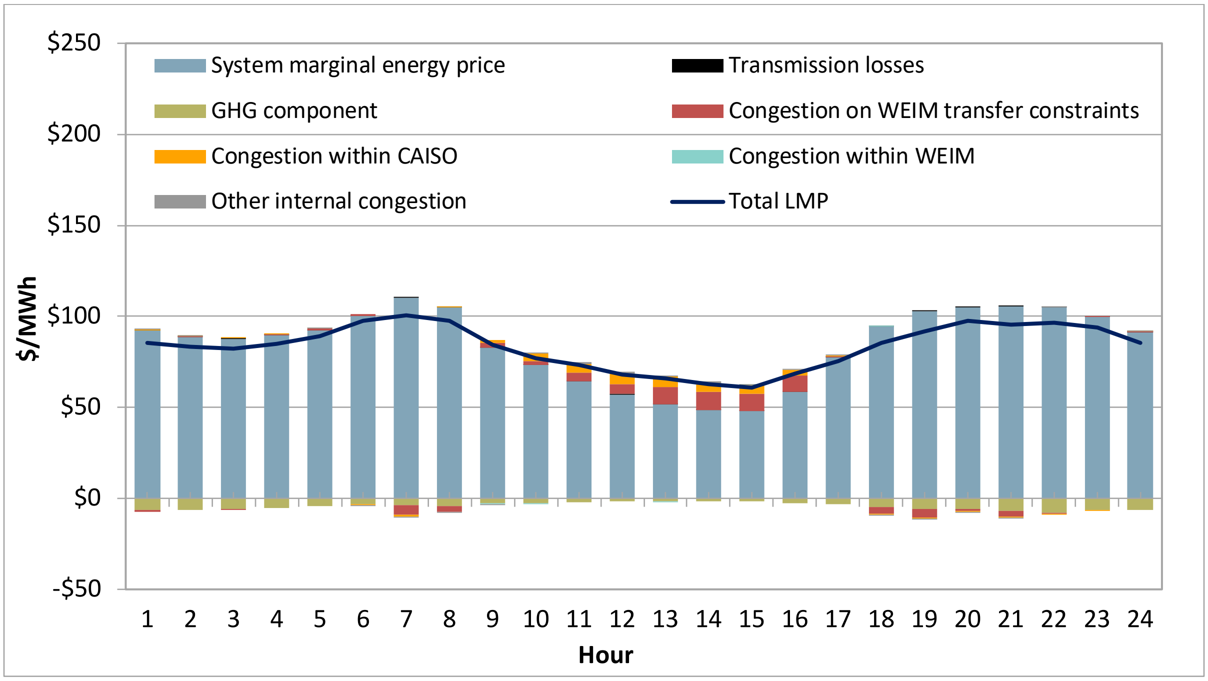


Appendix Figure A.14 Average hourly 15-minute market transfers

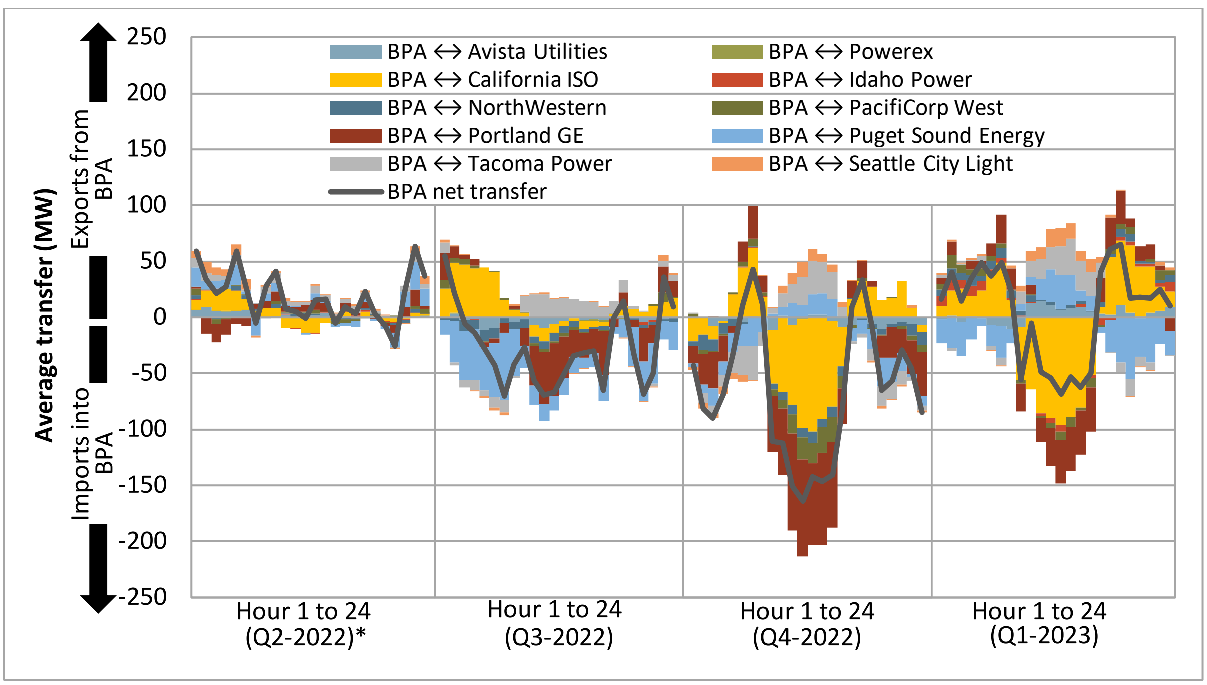


*Since joining the WEIM

Appendix Figure A.15 Average hourly 5-minute price by component (Q1 2023)



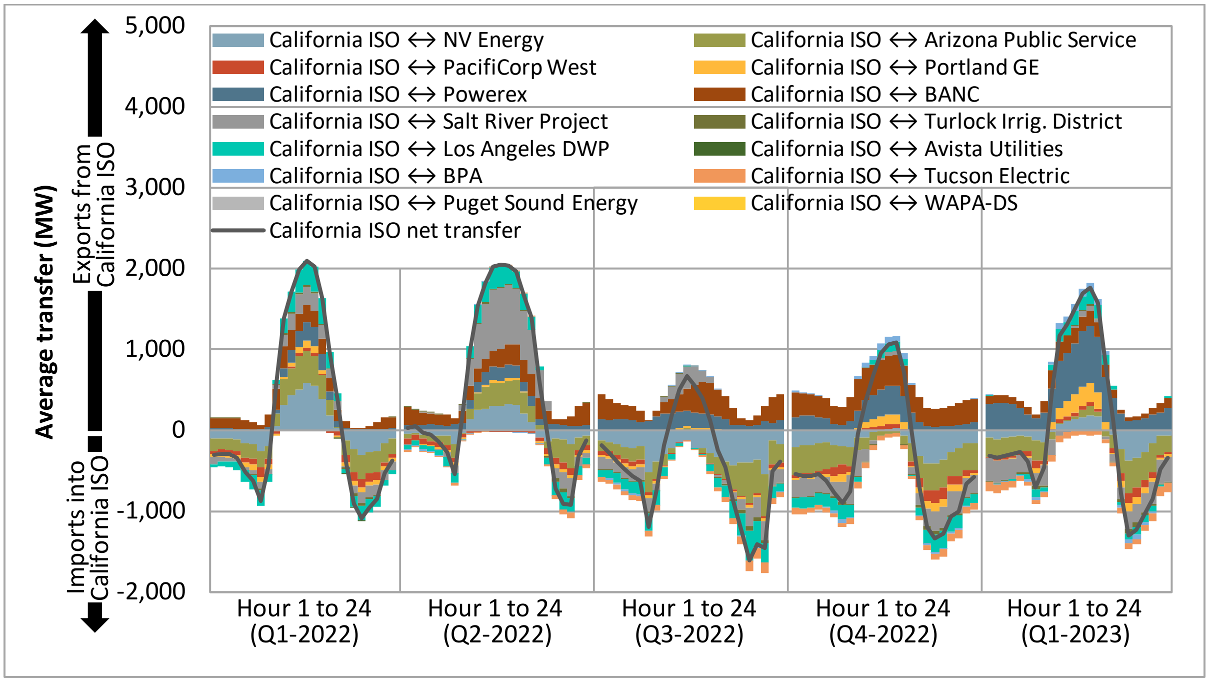
Appendix Figure A.16 Average hourly 5-minute market transfers



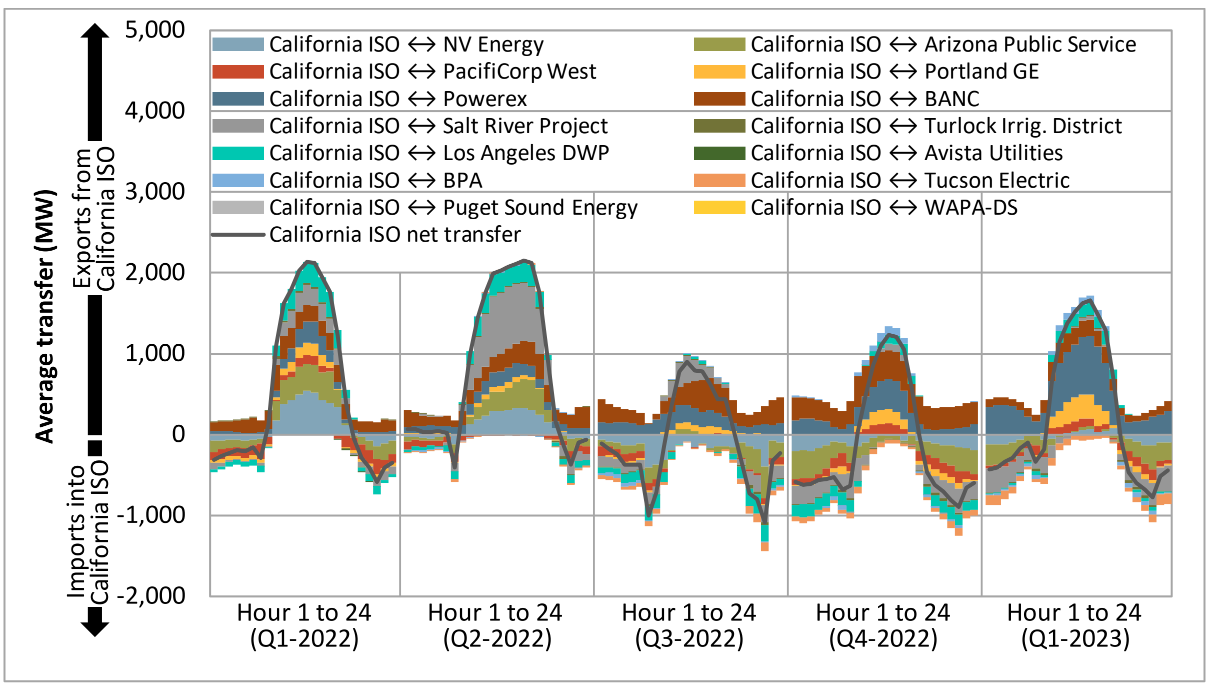
*Since joining the WEIM

A.5 California ISO

Appendix Figure A.17 Average hourly 15-minute market transfers

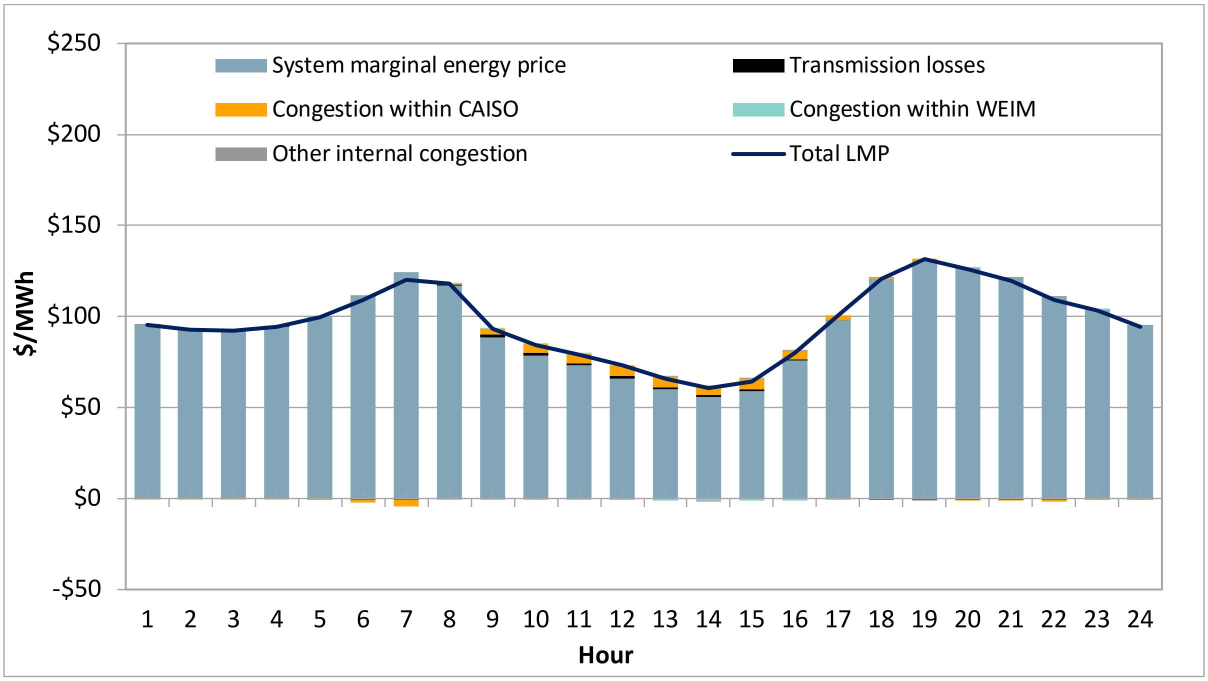


Appendix Figure A.18 Average hourly 5-minute market transfers

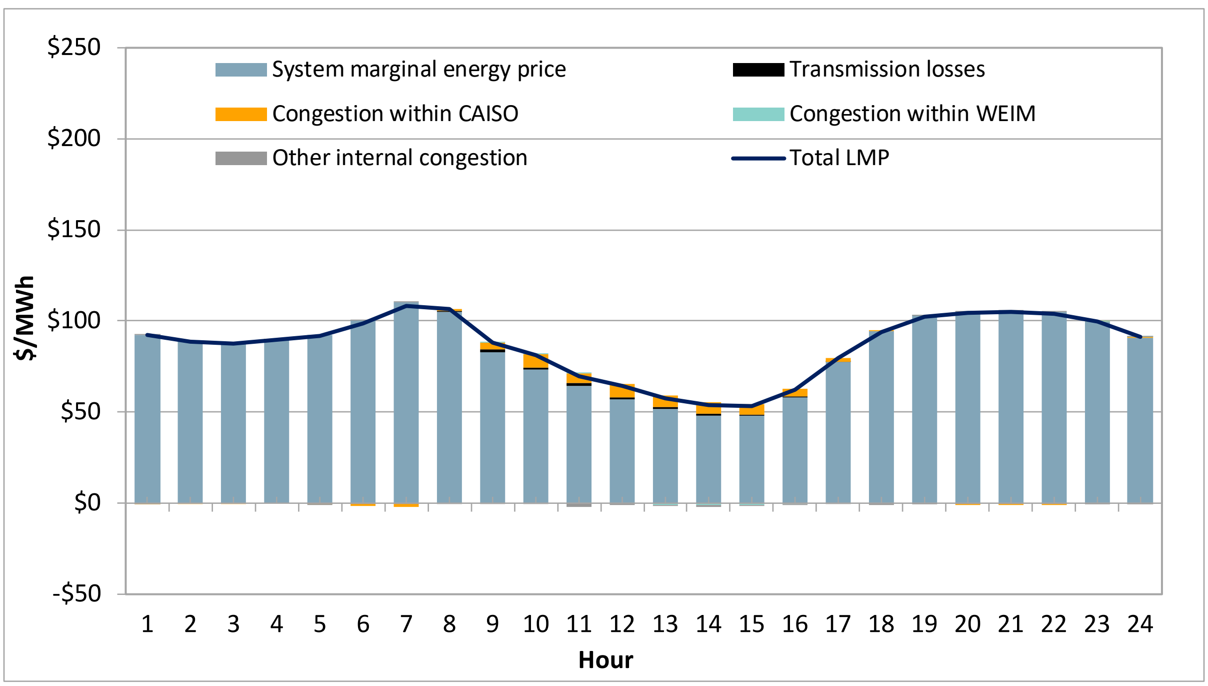


A.5.1 Pacific Gas and Electric

Appendix Figure A.19 Average hourly 15-minute price by component (Q1 2023)

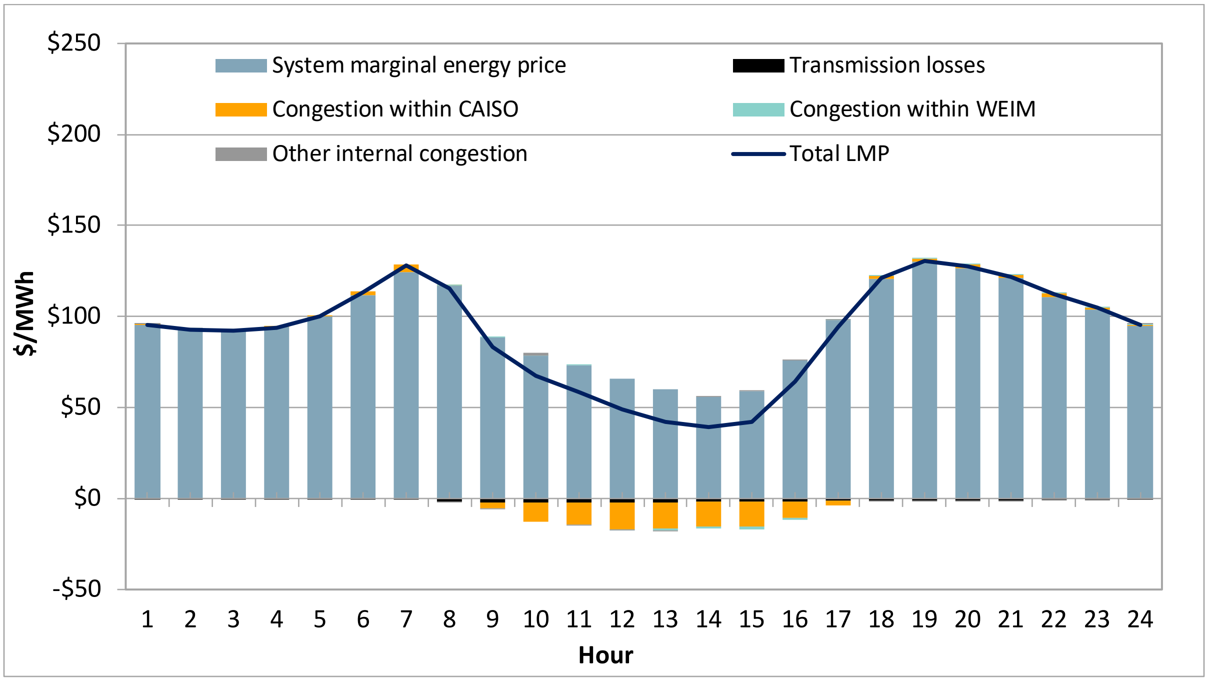


Appendix Figure A.20 Average hourly 5-minute price by component (Q1 2023)

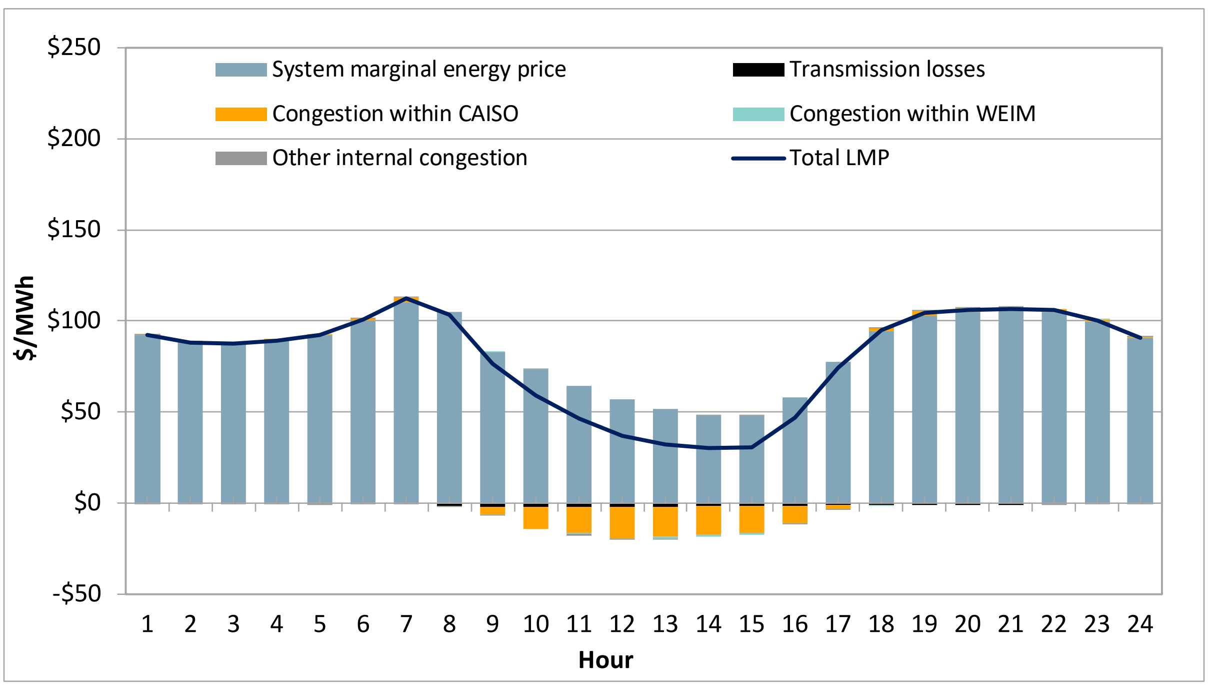


A.5.2 Southern California Edison

Appendix Figure A.21 Average hourly 15-minute price by component (Q1 2023)

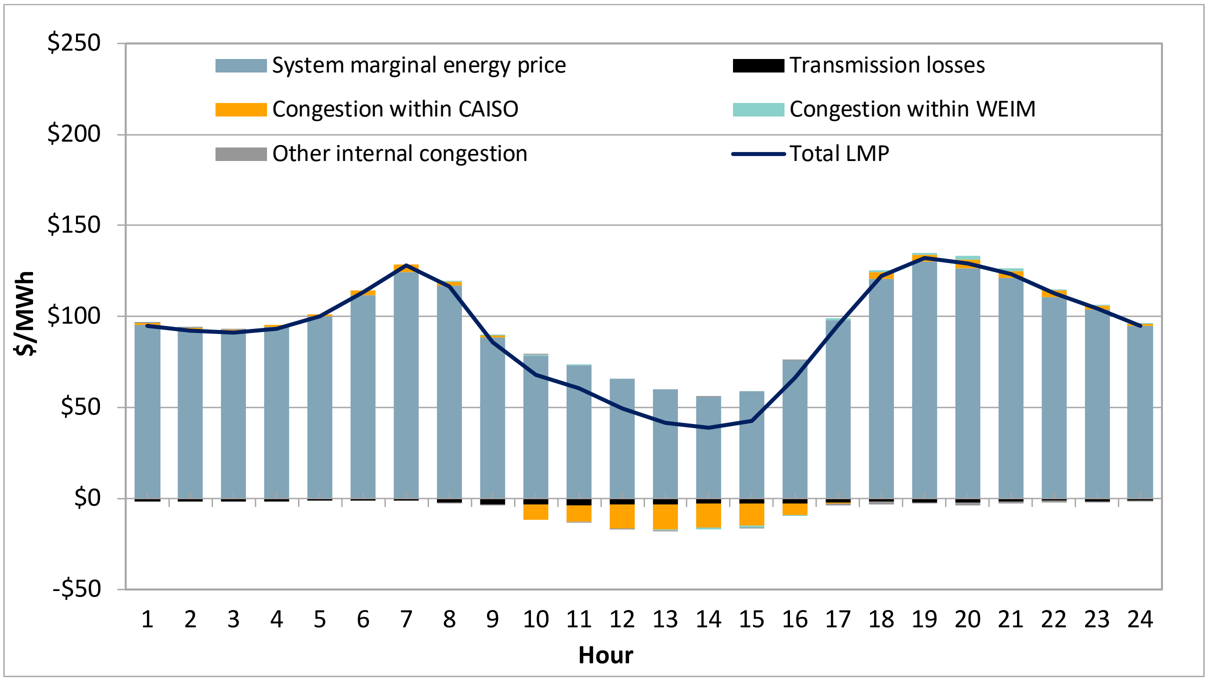


Appendix Figure A.22 Average hourly 5-minute price by component (Q1 2023)

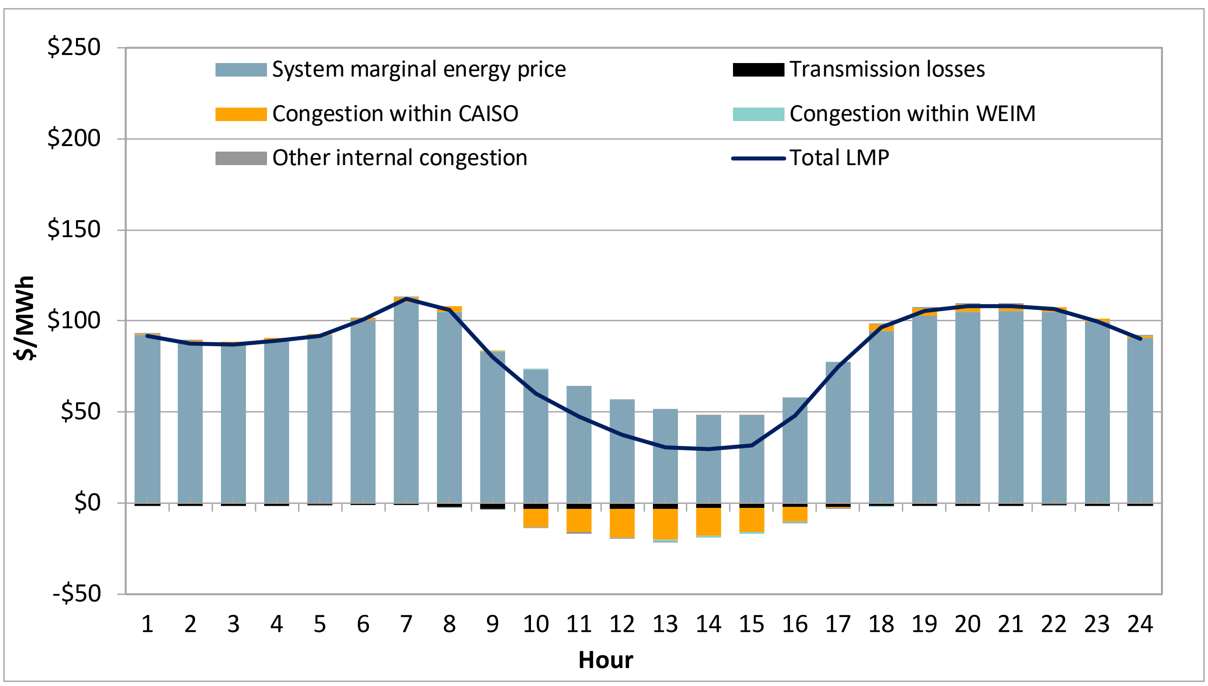


A.5.3 San Diego Gas & Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q1 2023)

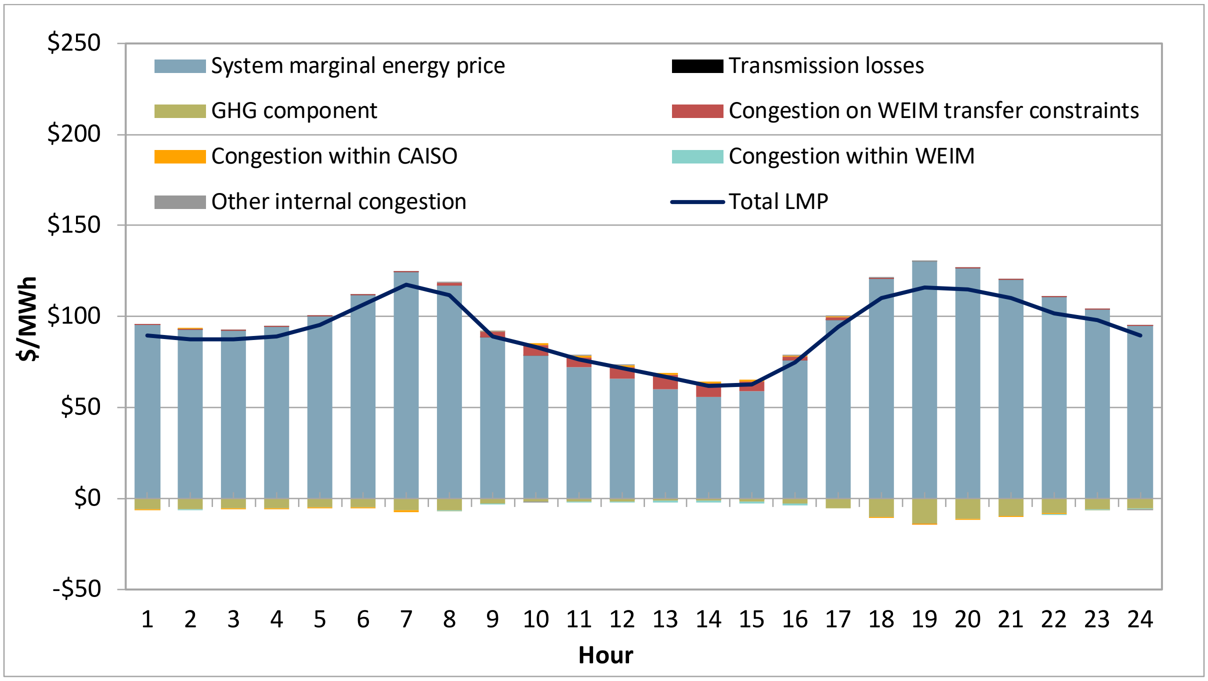


Appendix Figure A.24 Average hourly 5-minute price by component (Q1 2023)

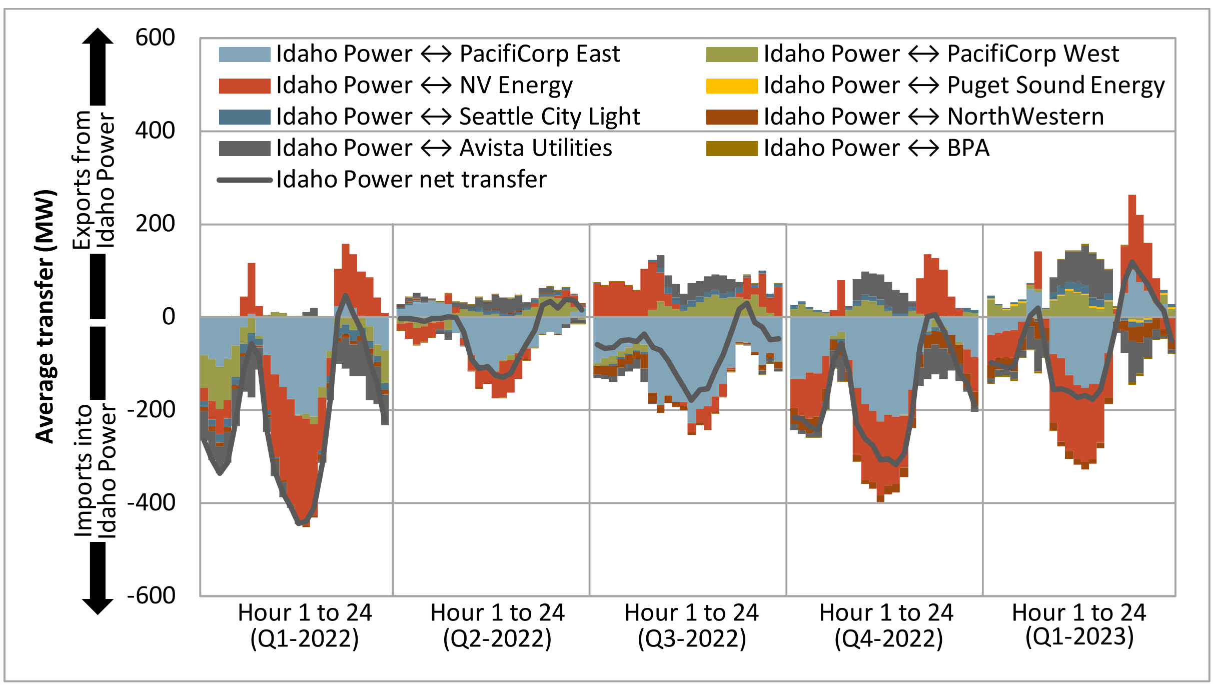


A.6 Idaho Power

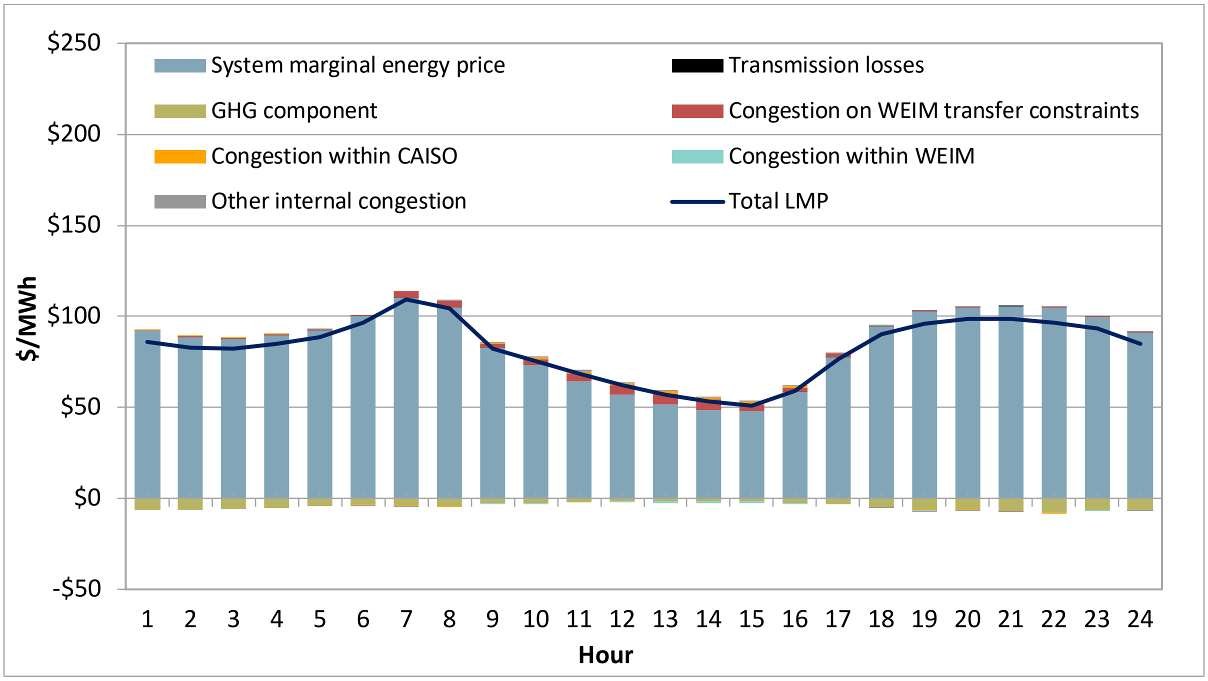
Appendix Figure A.25 Average hourly 15-minute price by component (Q1 2023)



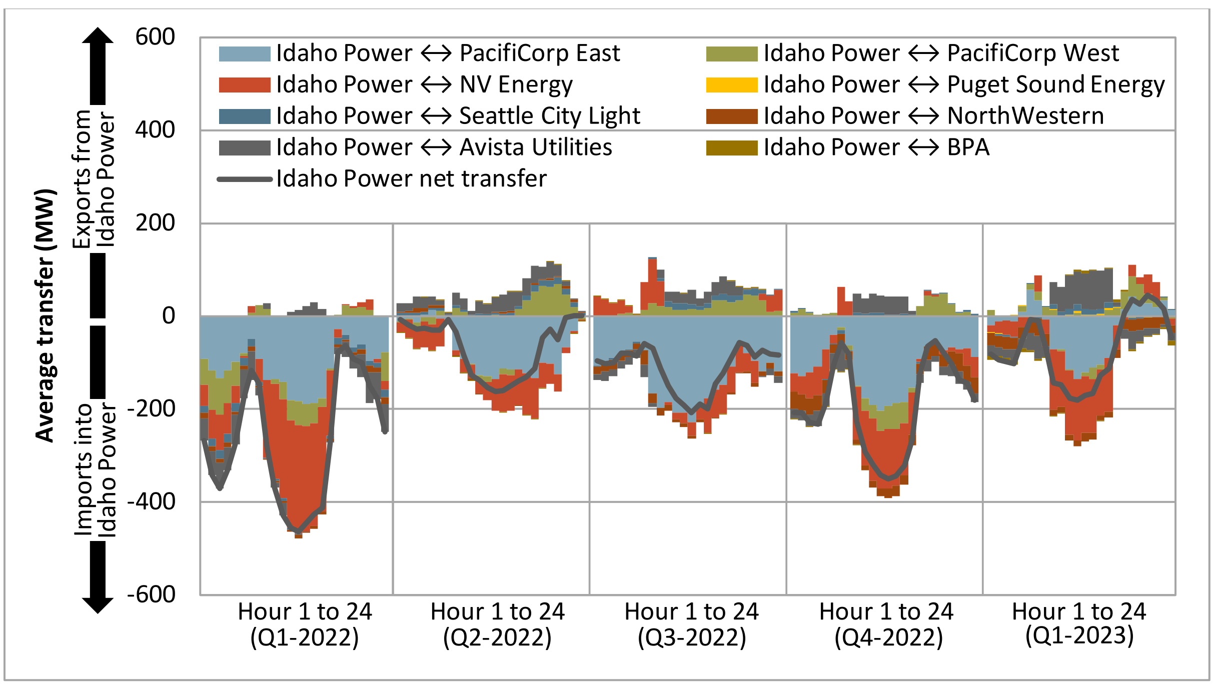
Appendix Figure A.26 Average hourly 15-minute market transfers



Appendix Figure A.27 Average hourly 5-minute price by component (Q1 2023)

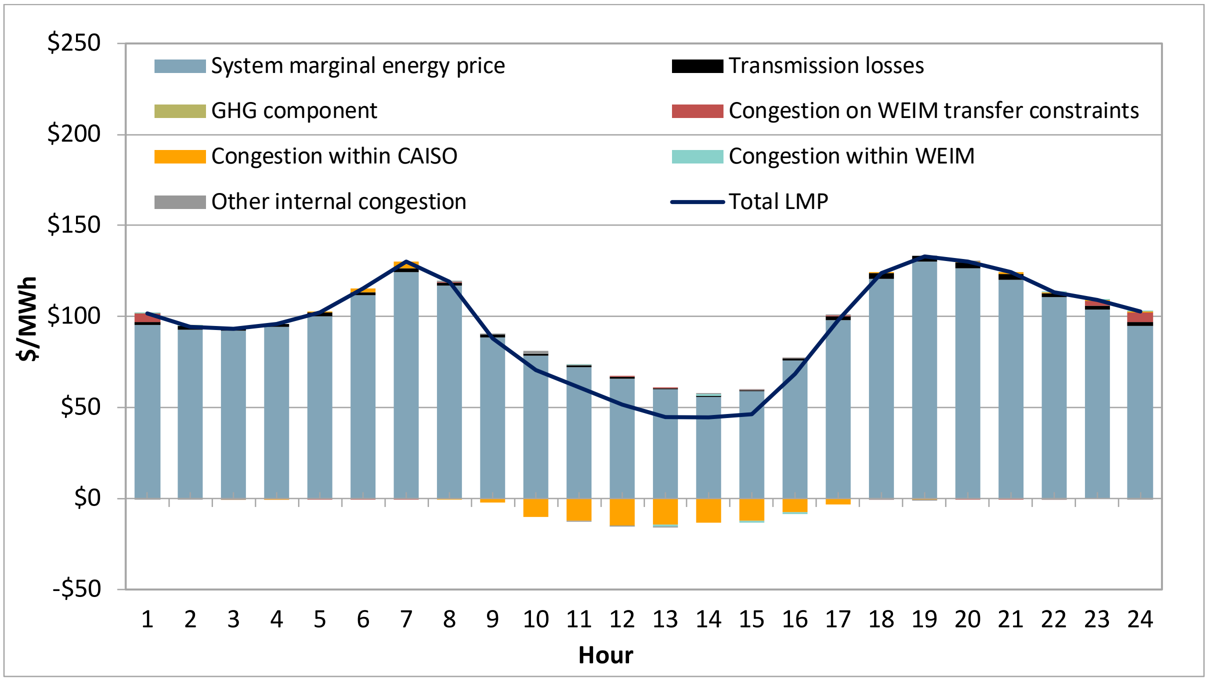


Appendix Figure A.28 Average hourly 5-minute market transfers

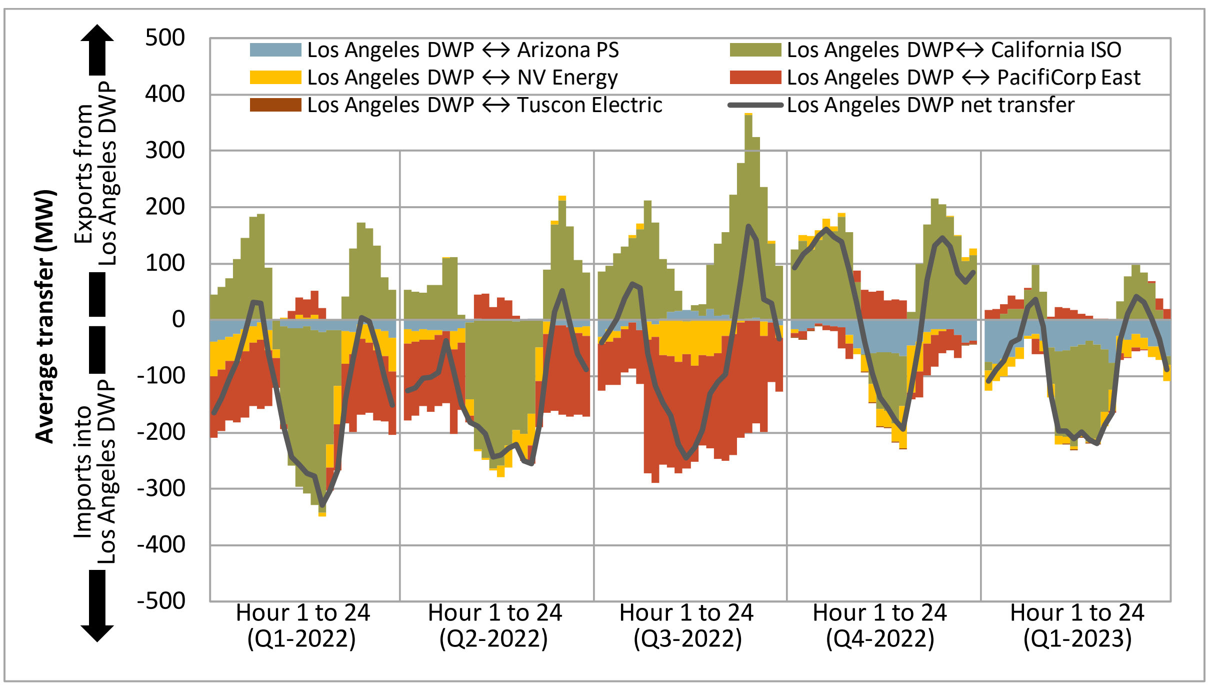


A.7 Los Angeles Department of Water and Power

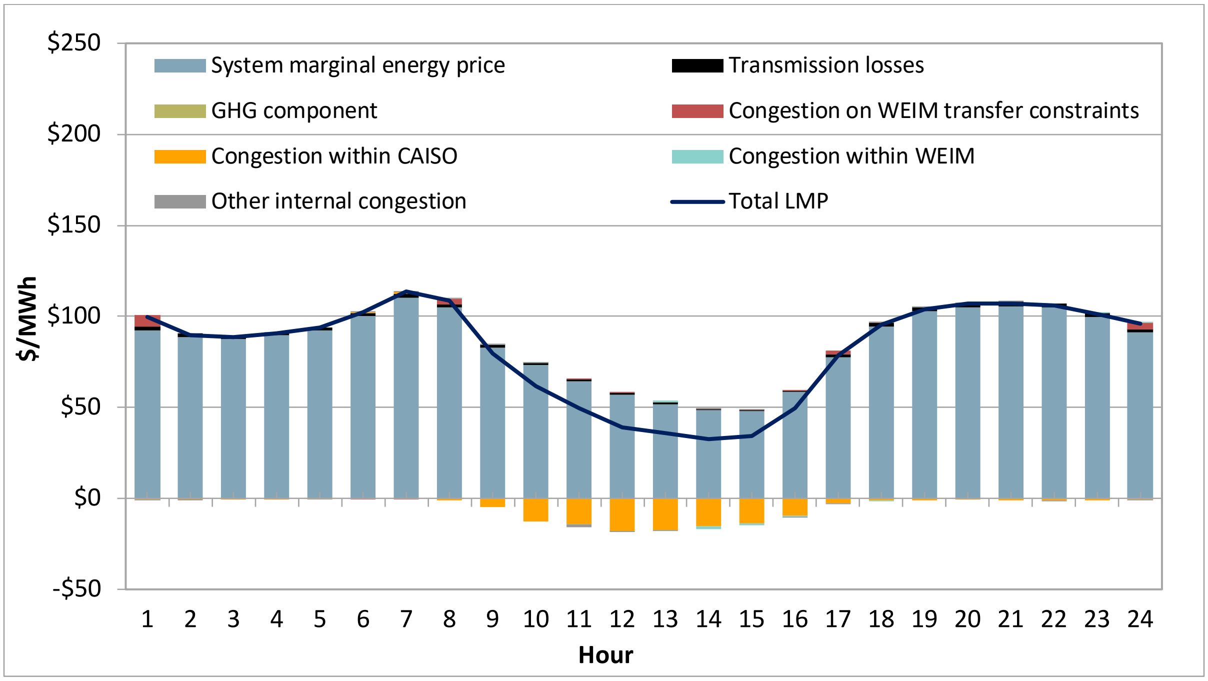
Appendix Figure A.29 Average hourly 15-minute price by component (Q1 2023)



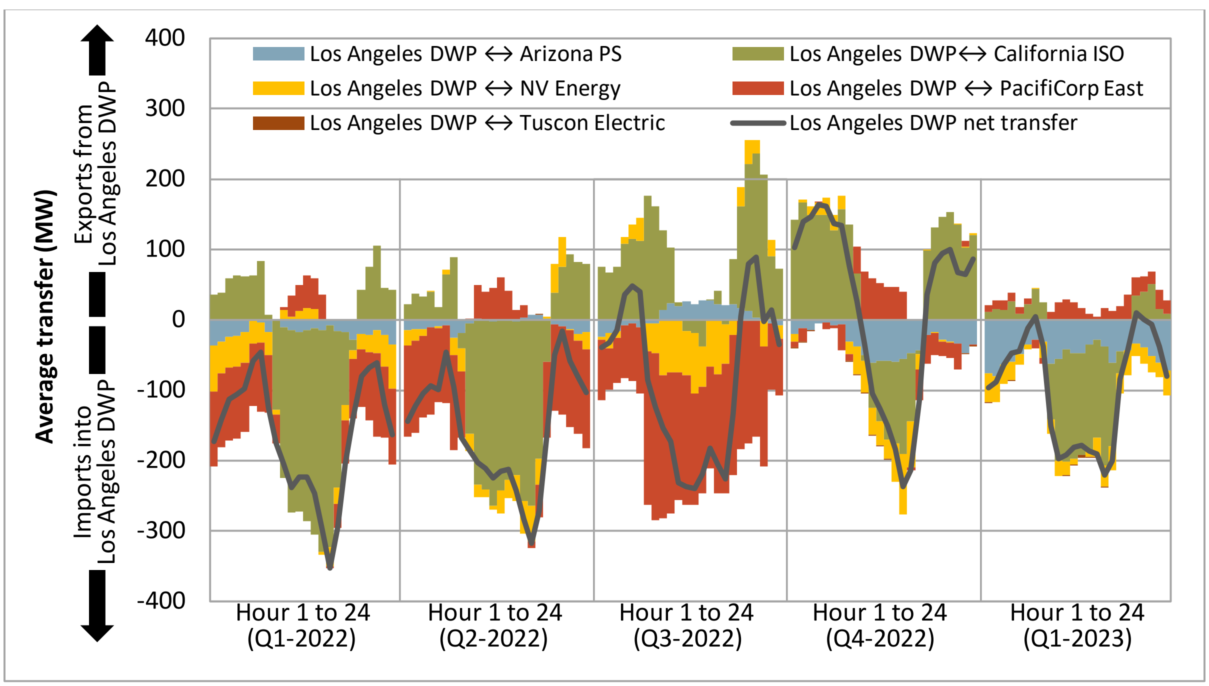
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q1 2023)

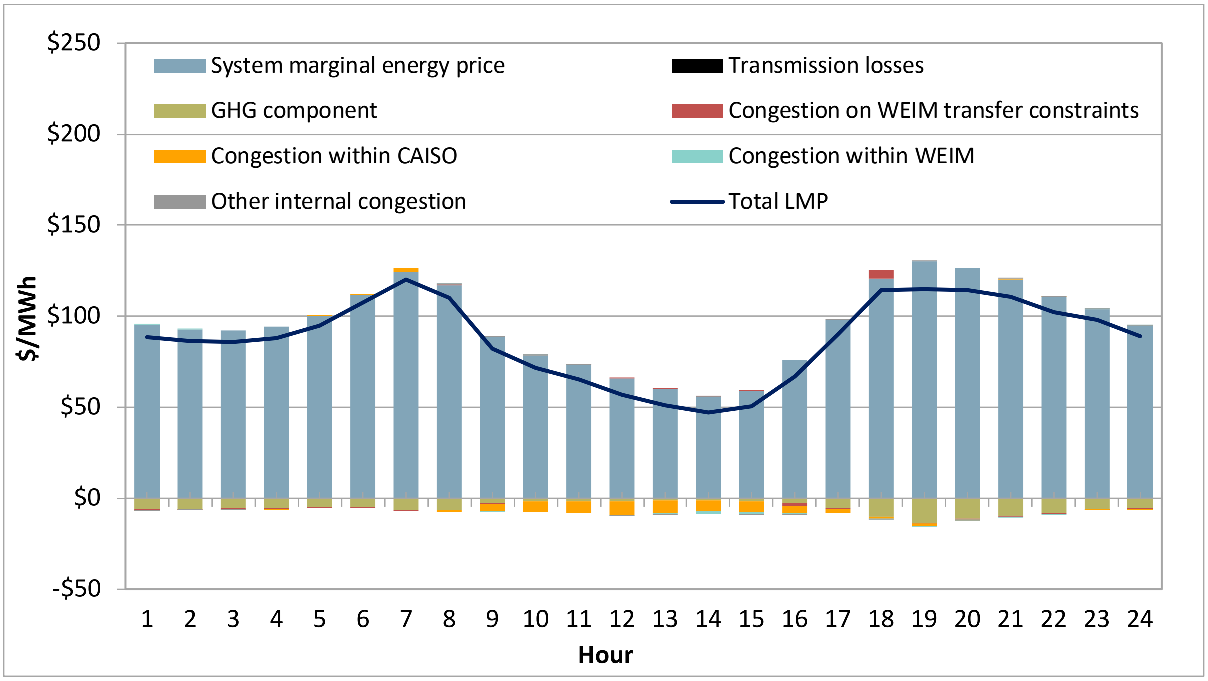


Appendix Figure A.32 Average hourly 5-minute market transfers

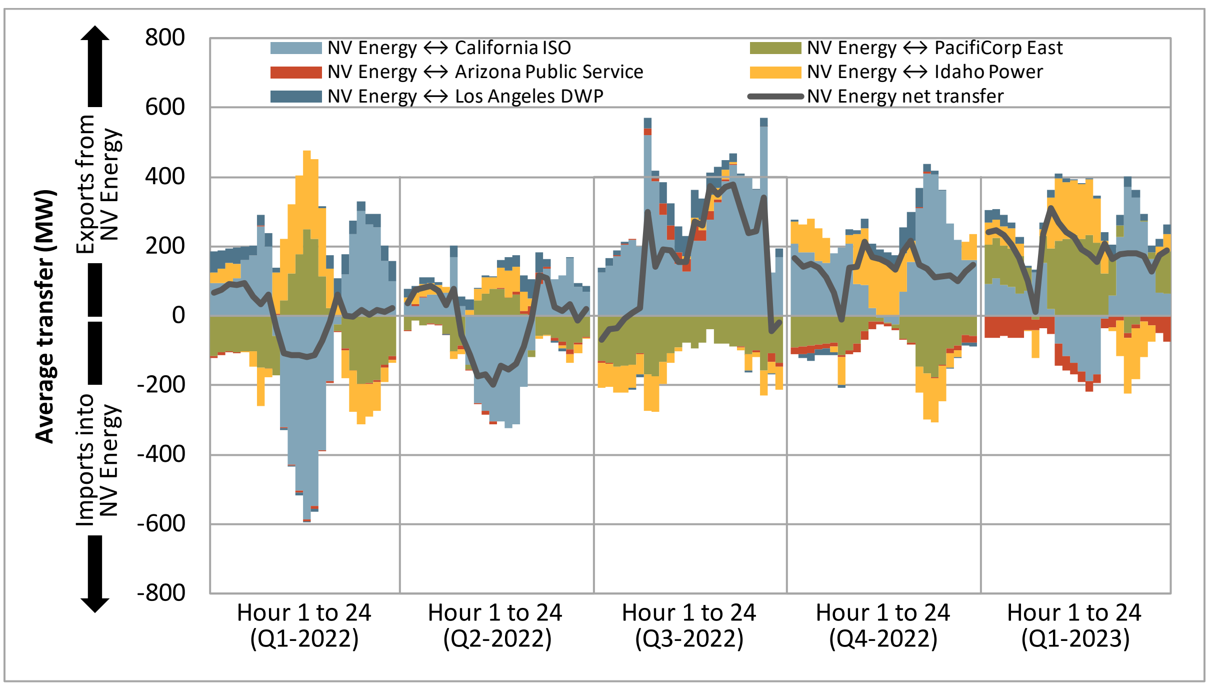


A.8 NV Energy

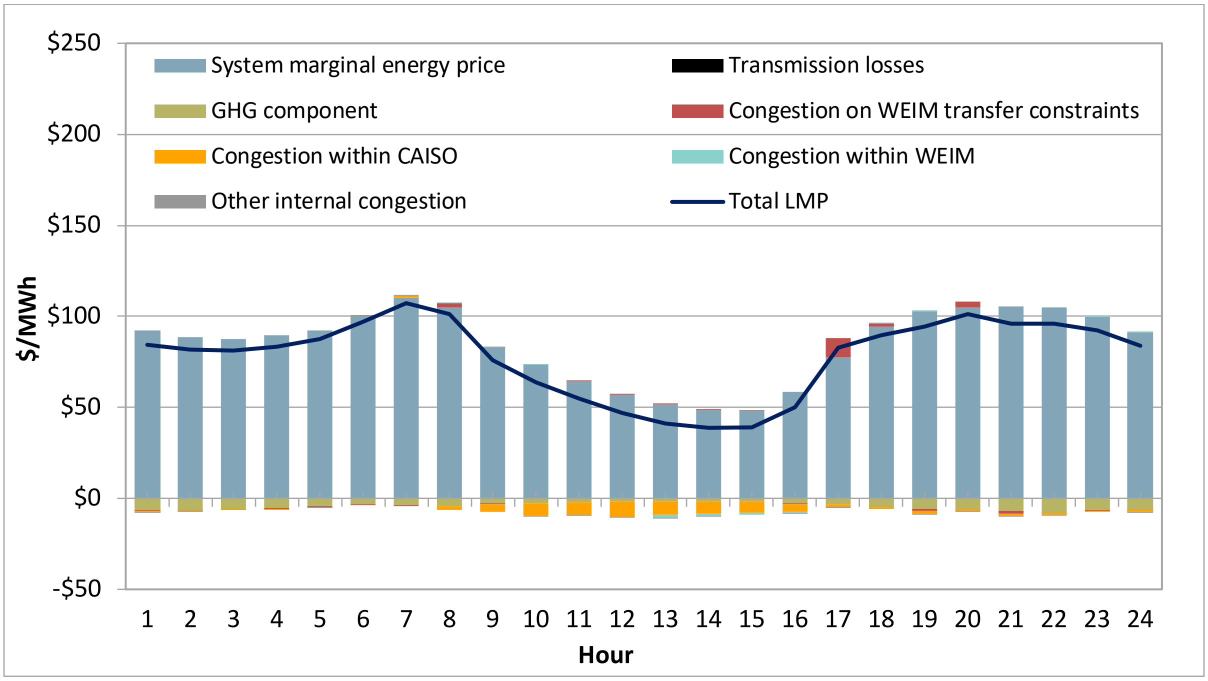
Appendix Figure A.33 Average hourly 15-minute price by component (Q1 2023)



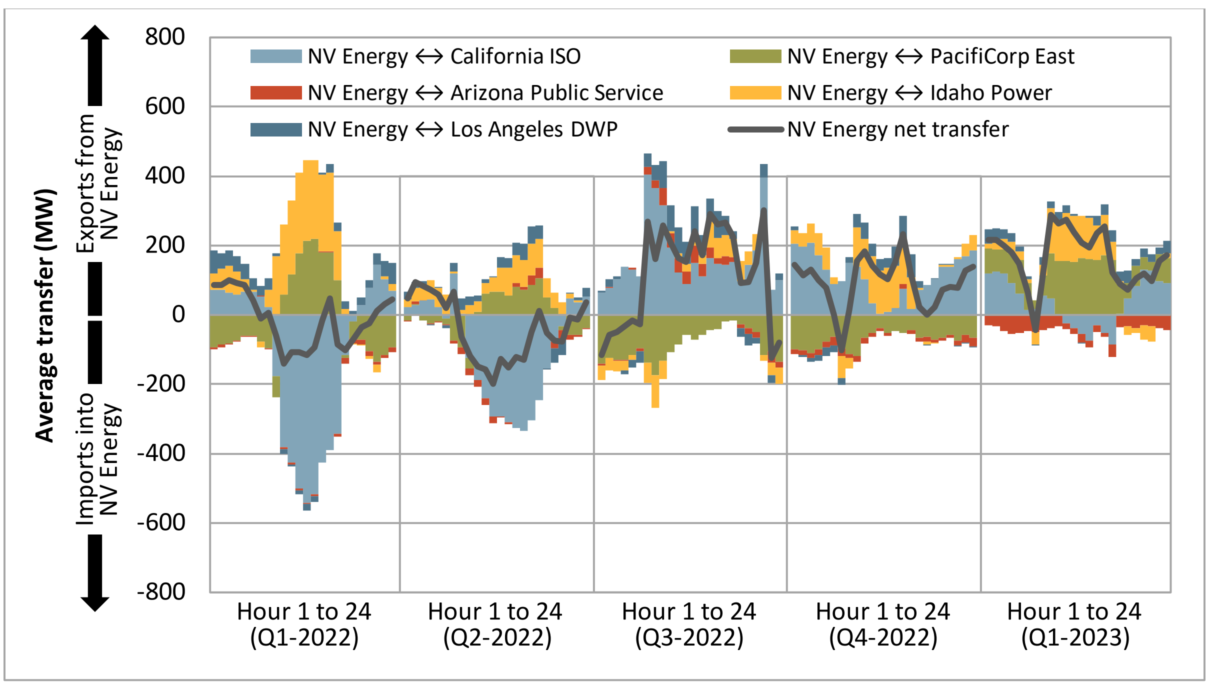
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q1 2023)

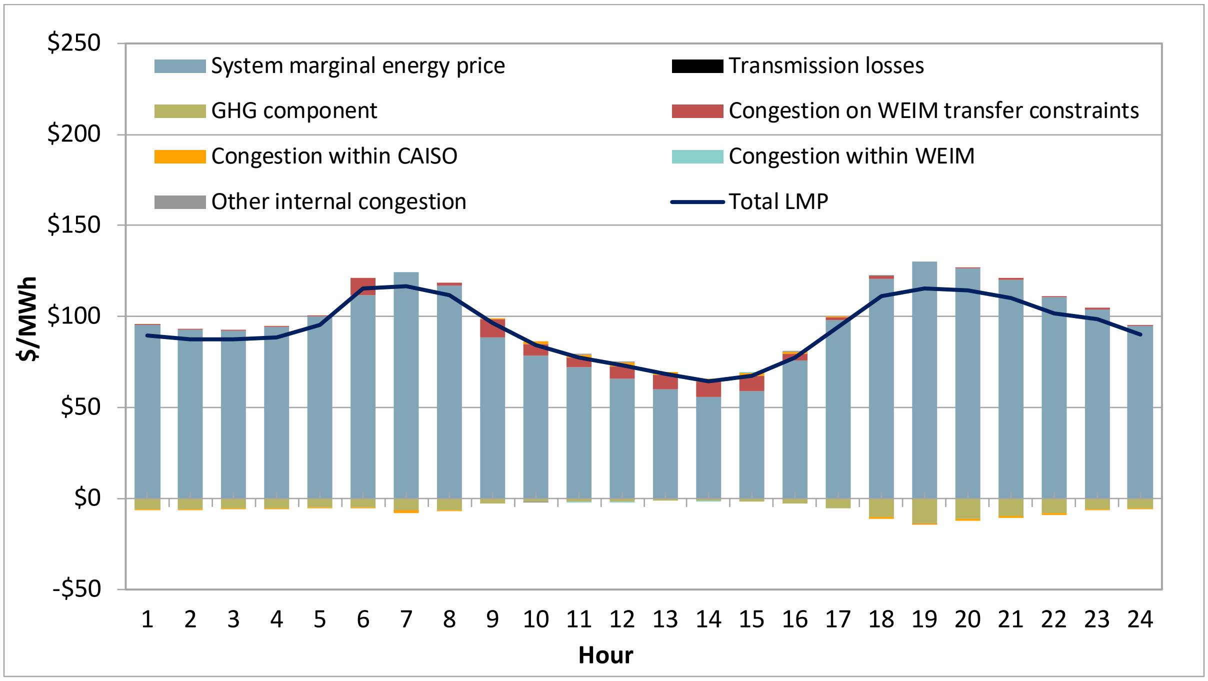


Appendix Figure A.36 Average hourly 5-minute market transfers

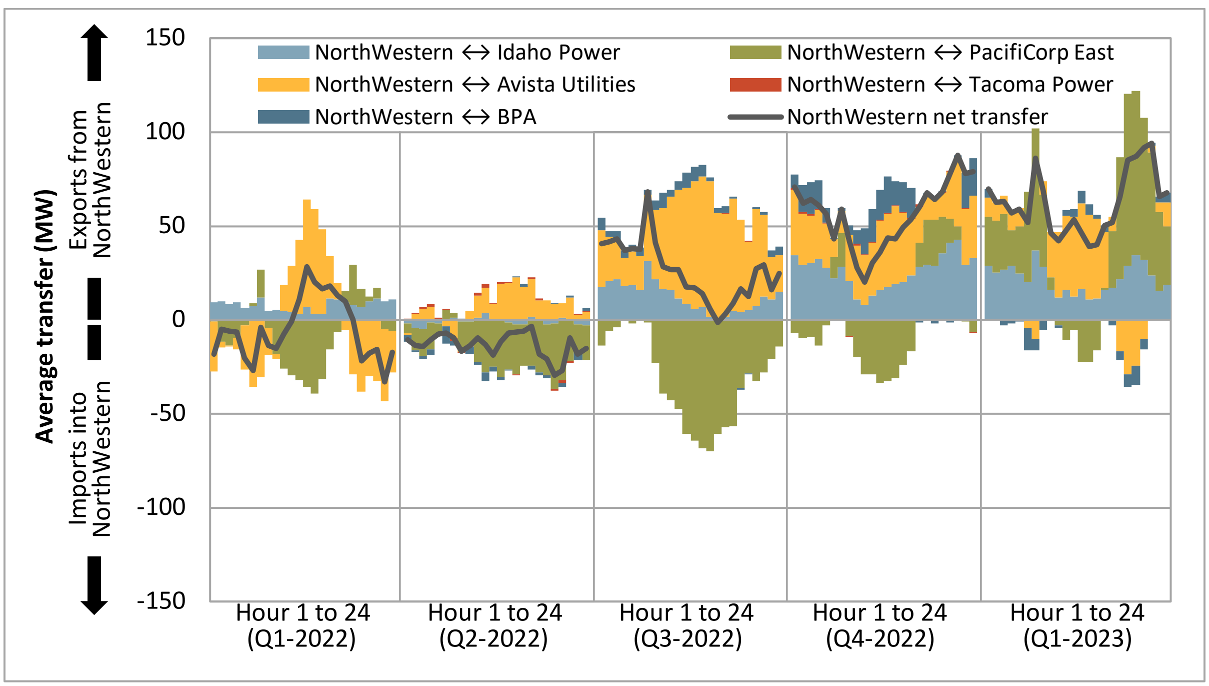


A.9 NorthWestern Energy

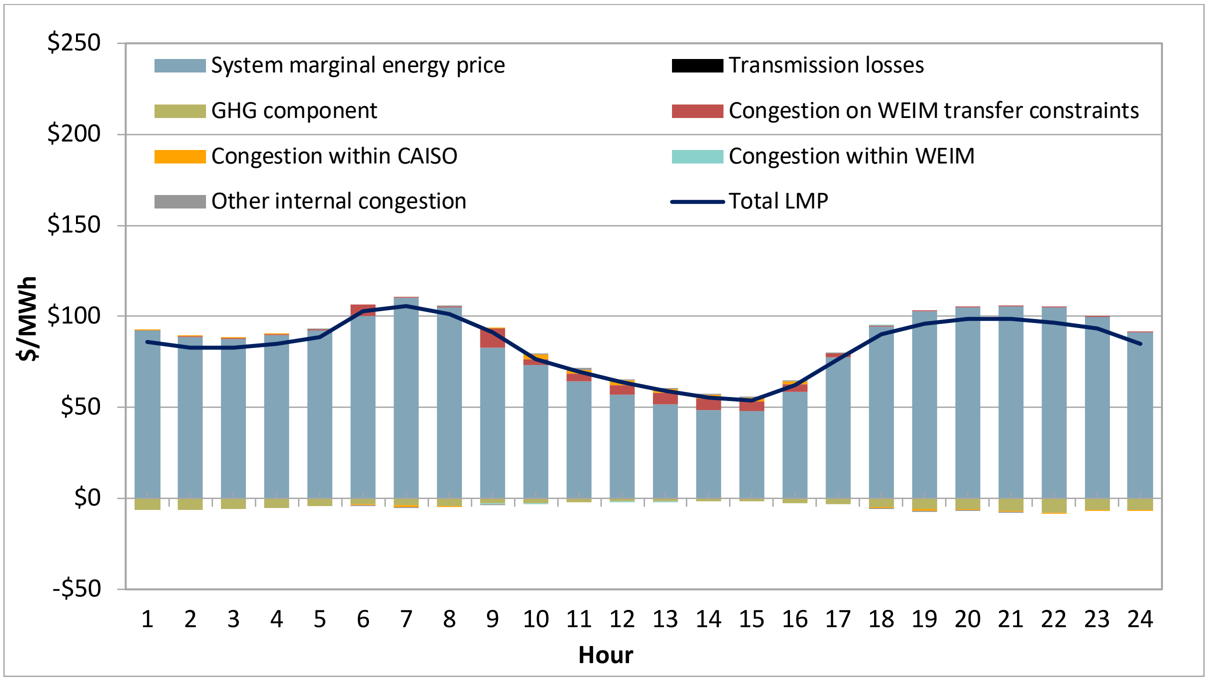
Appendix Figure A.37 Average hourly 15-minute price by component (Q1 2023)



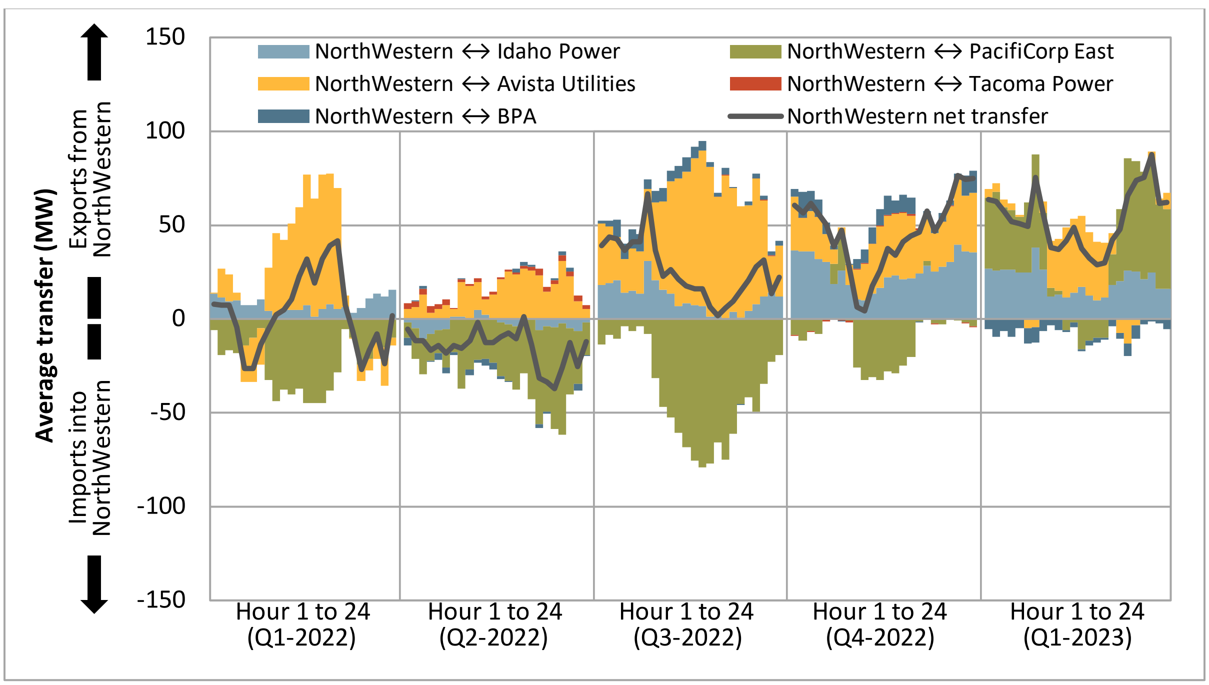
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q1 2023)

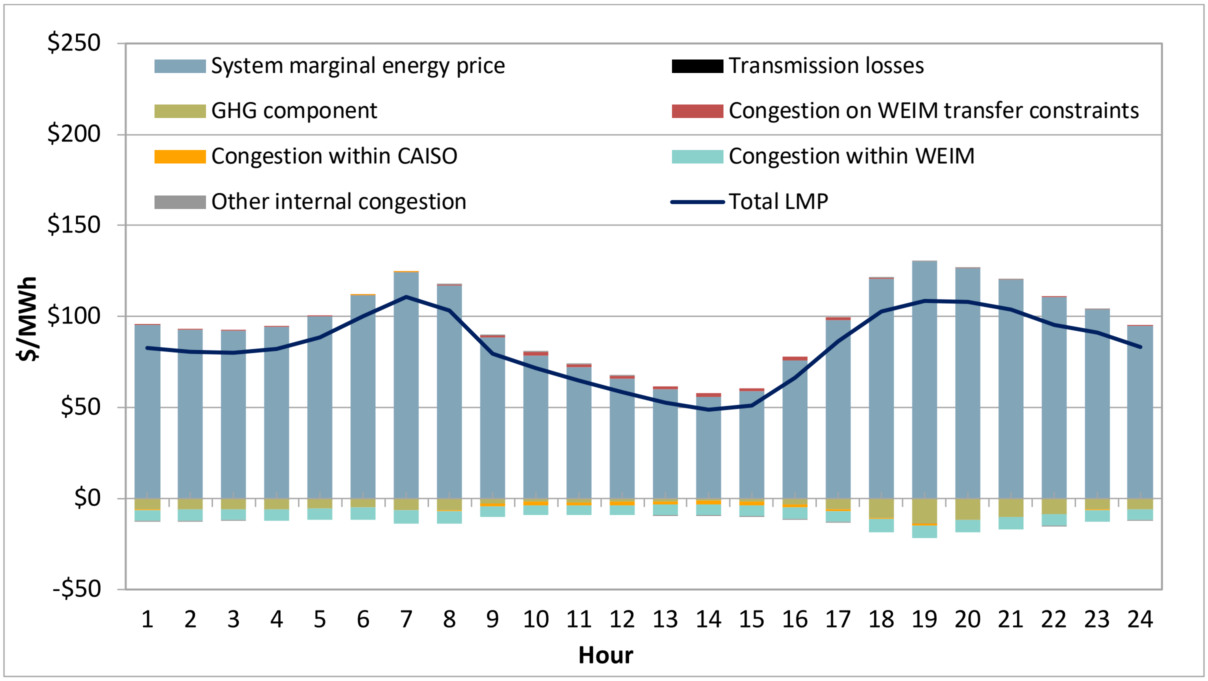


Appendix Figure A.40 Average hourly 5-minute market transfers

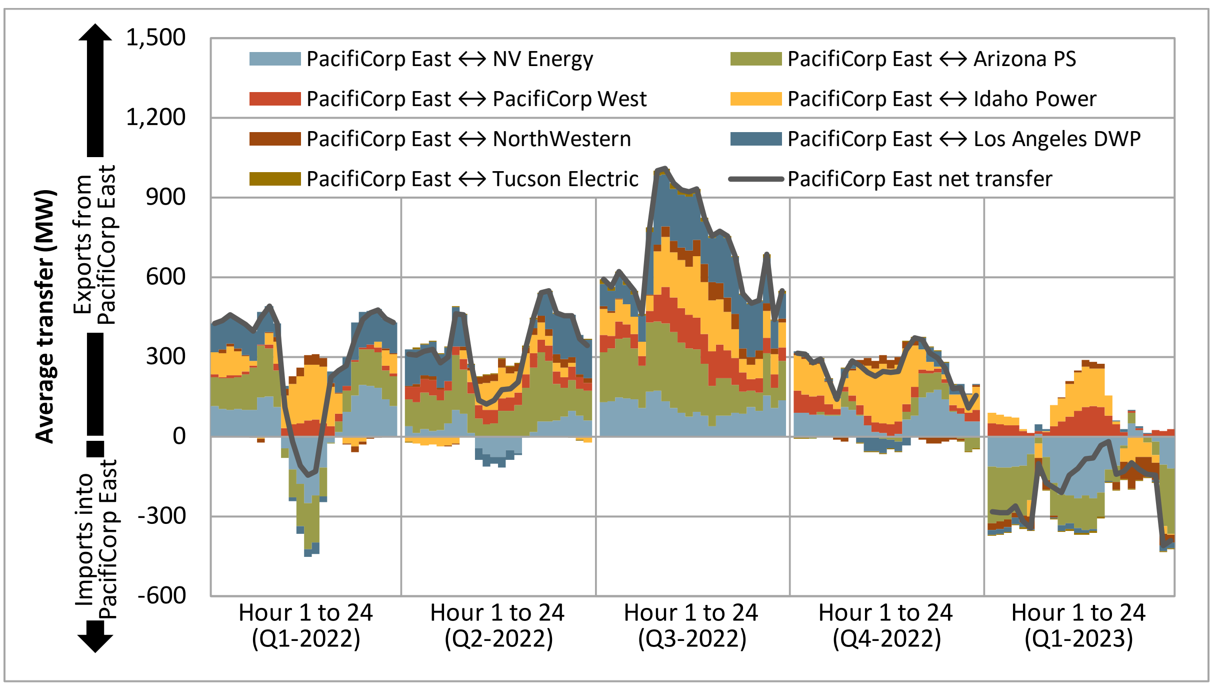


A.10 PacifiCorp East

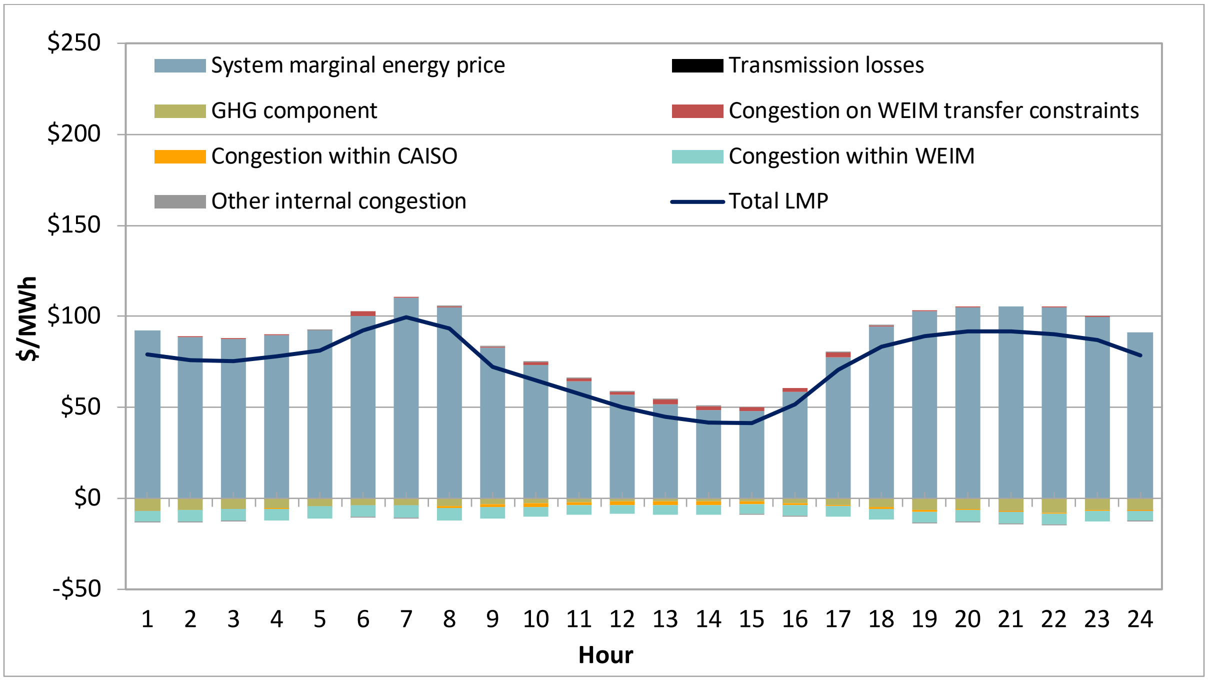
Appendix Figure A.41 Average hourly 15-minute price by component (Q1 2023)



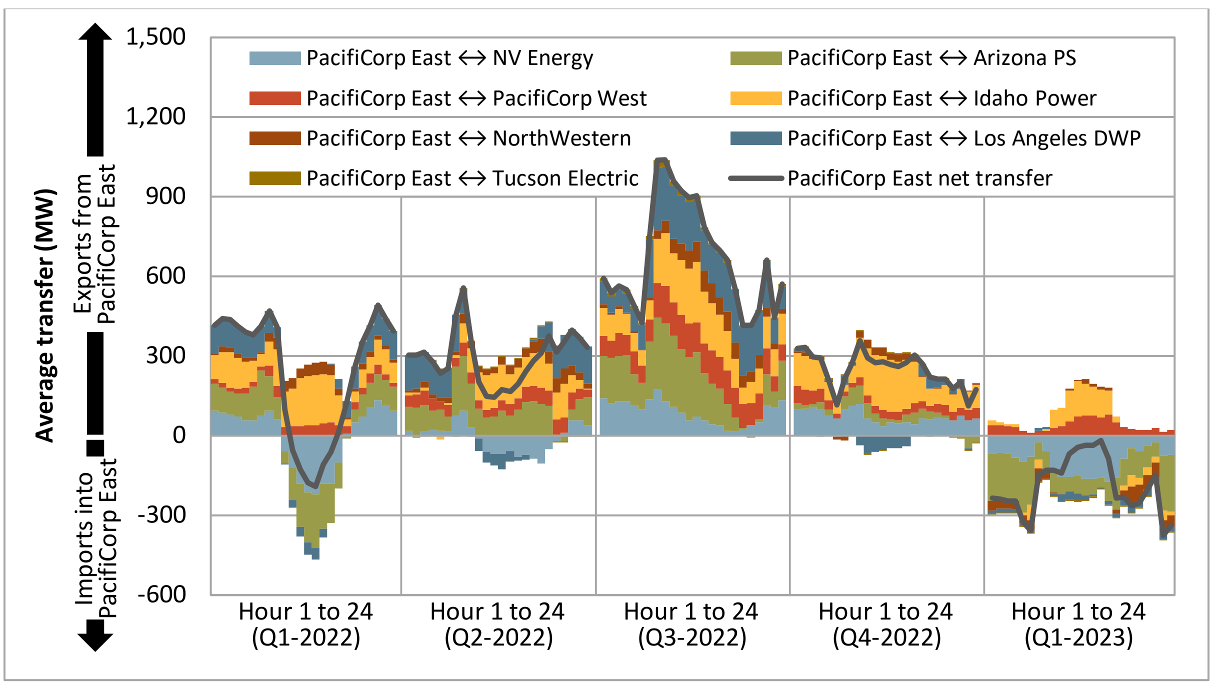
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q1 2023)

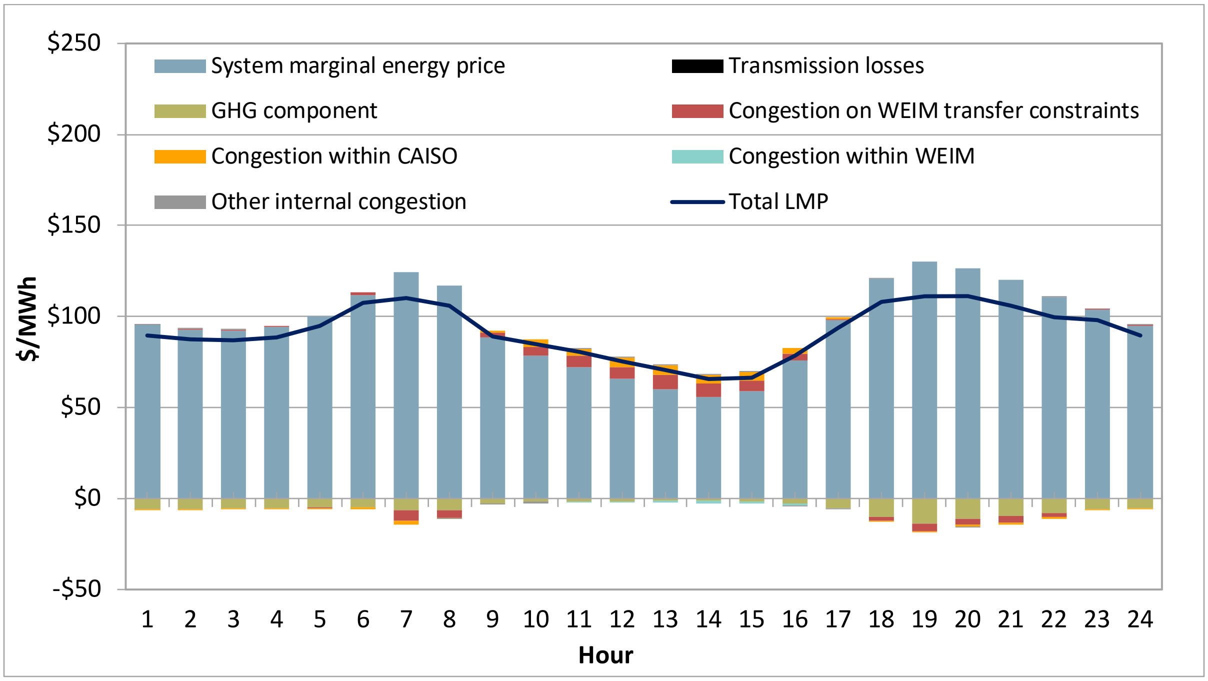


Appendix Figure A.44 Average hourly 5-minute market transfers

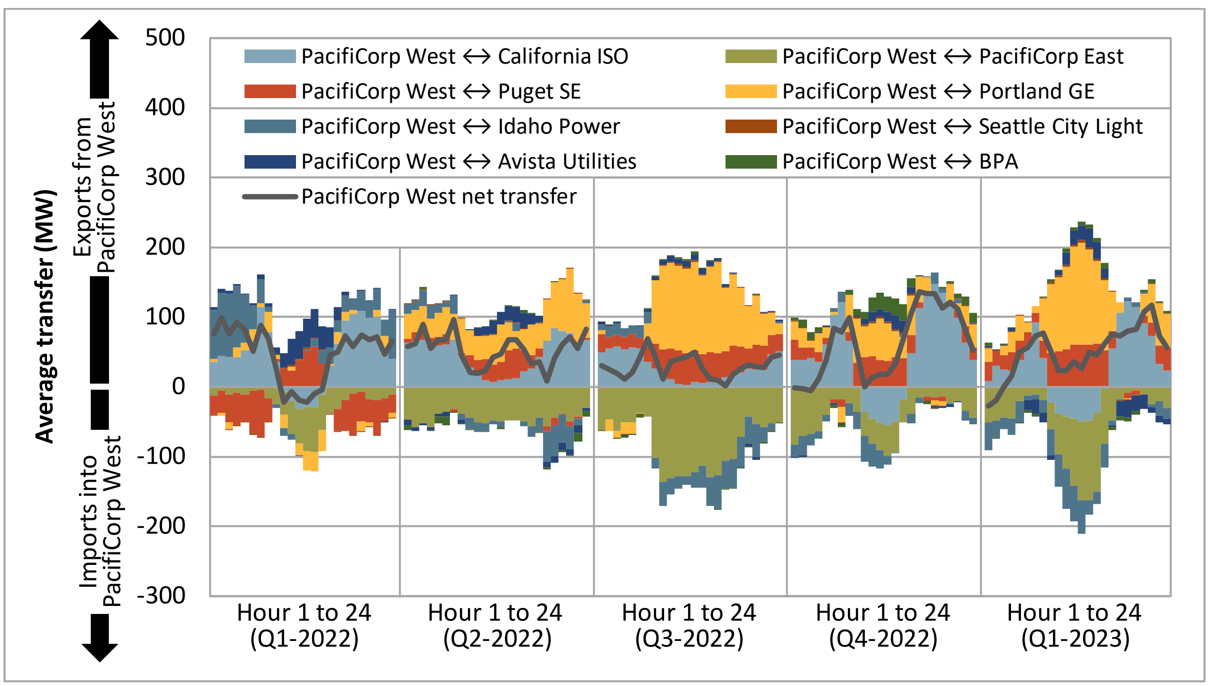


A.11 PacifiCorp West

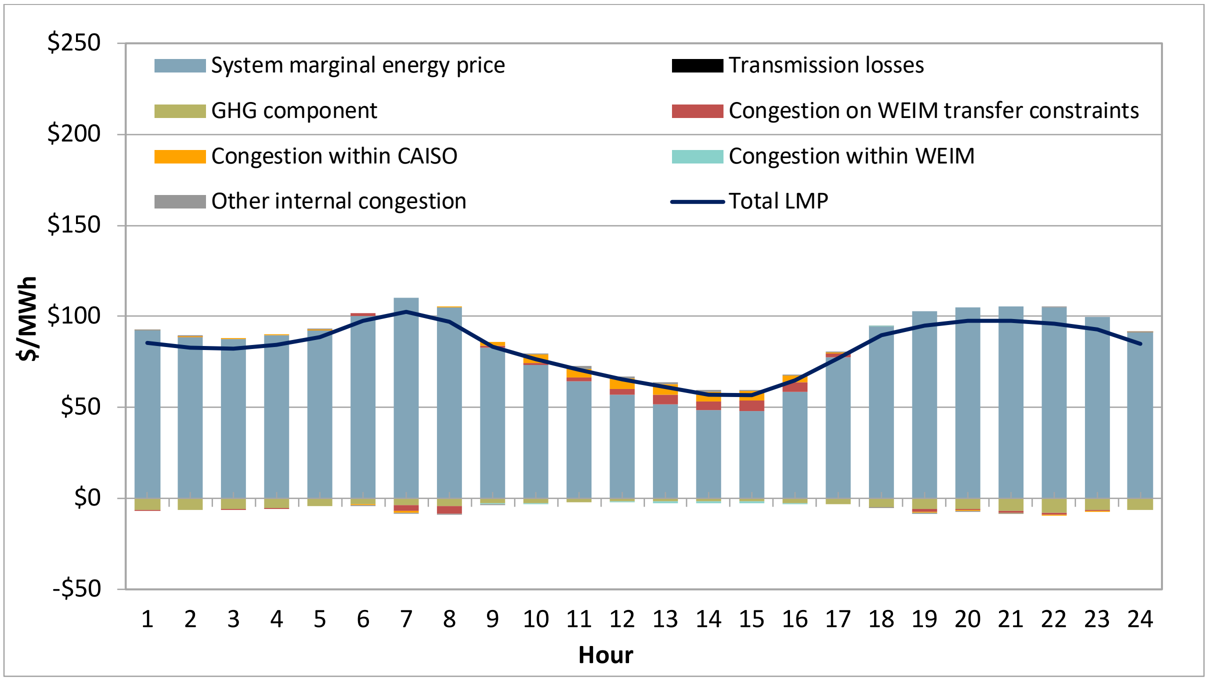
Appendix Figure A.45 Average hourly 15-minute price by component (Q1 2023)



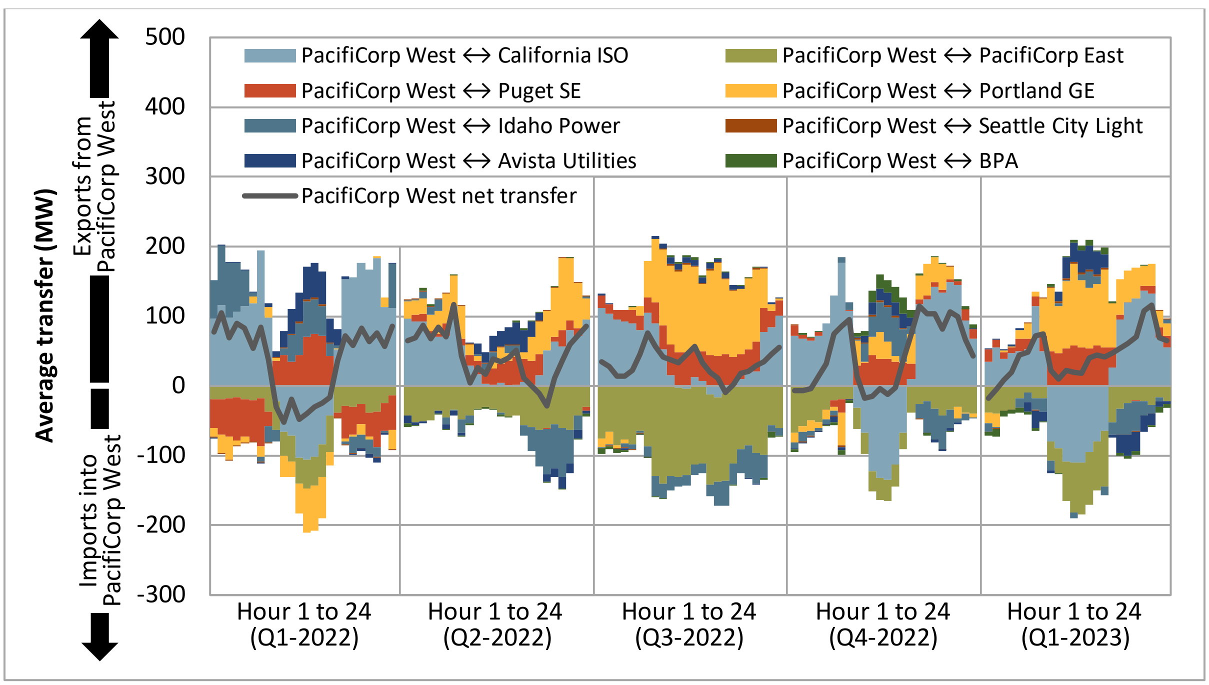
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q1 2023)

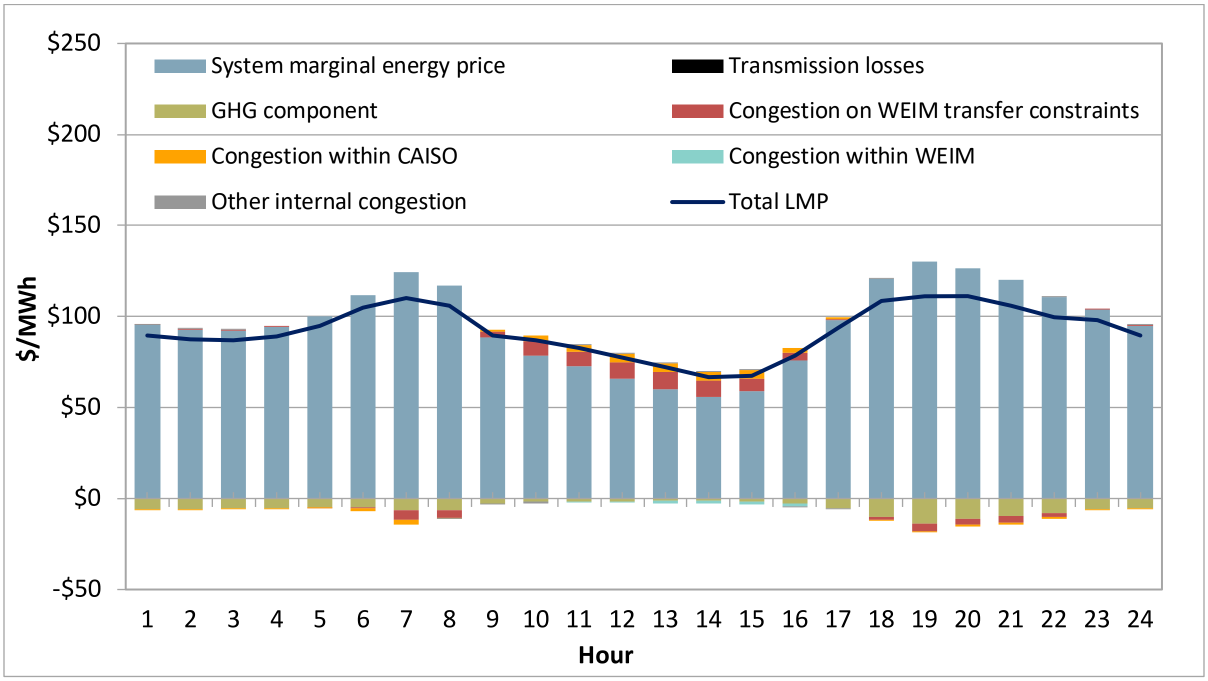


Appendix Figure A.48 Average hourly 5-minute market transfers

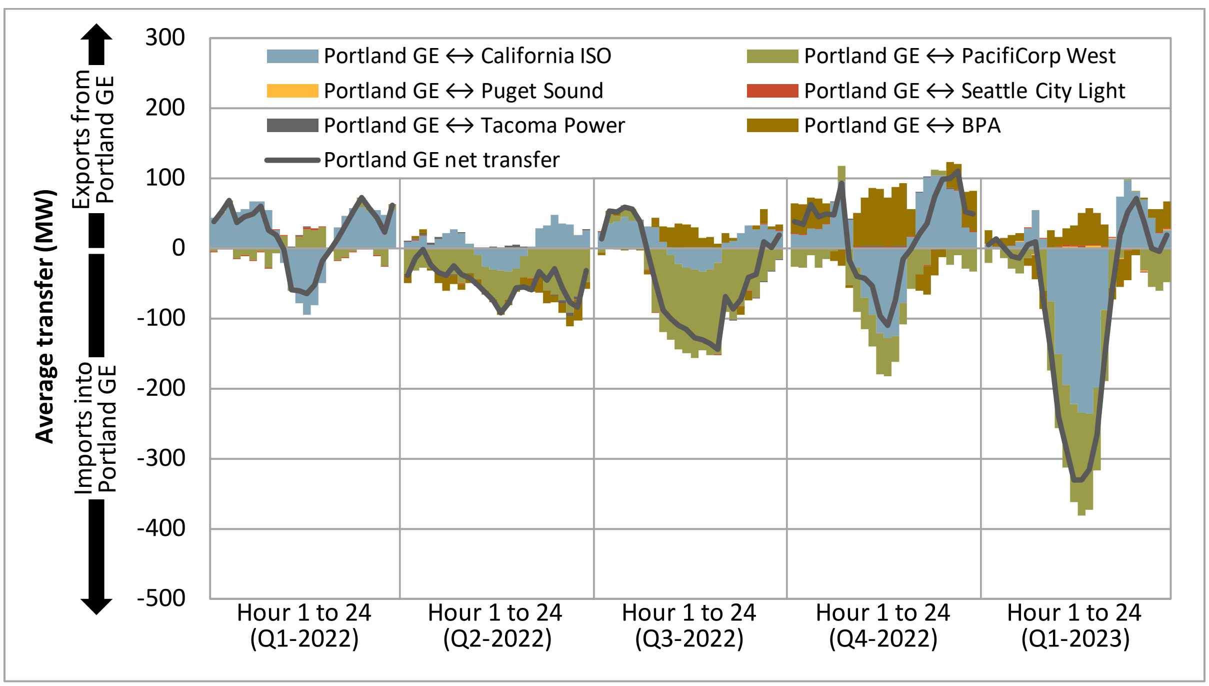


A.12 Portland General Electric

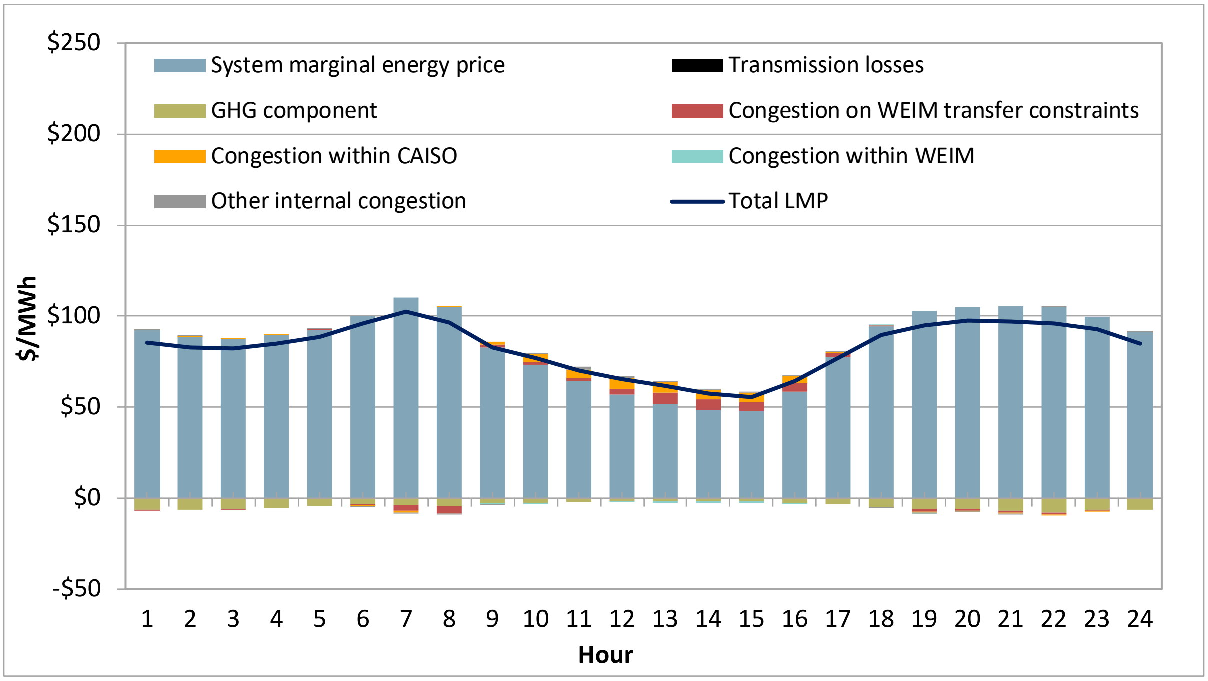
Appendix Figure A.49 Average hourly 15-minute price by component (Q1 2023)



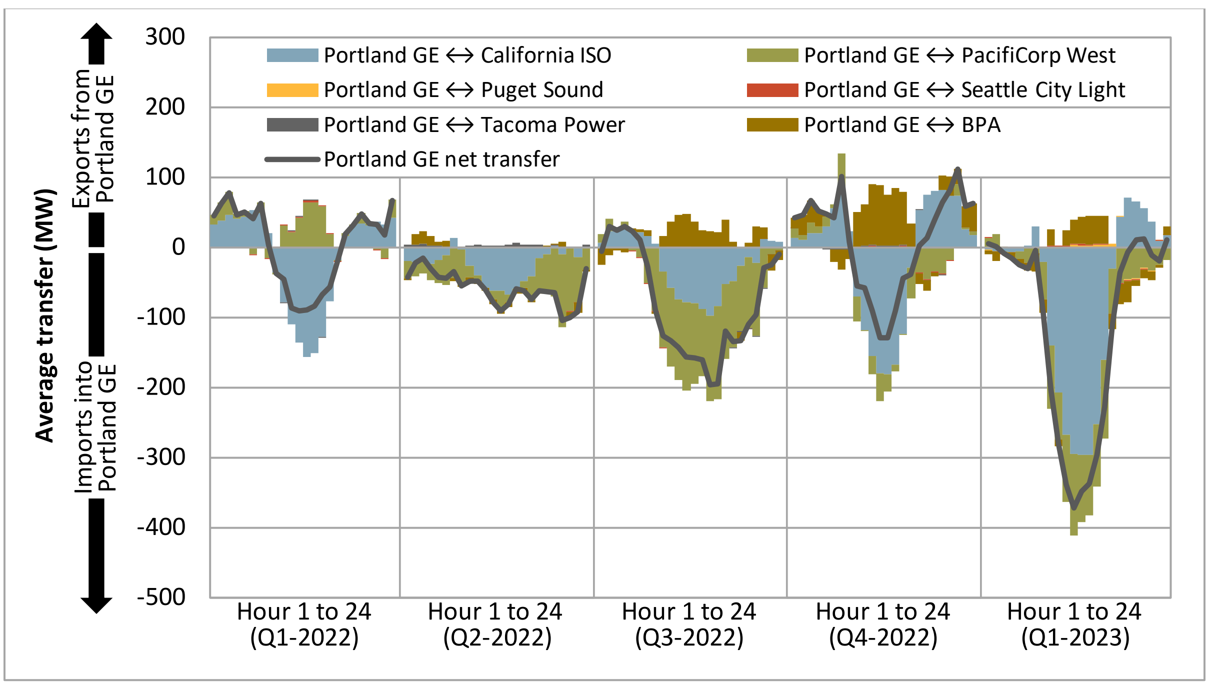
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q1 2023)

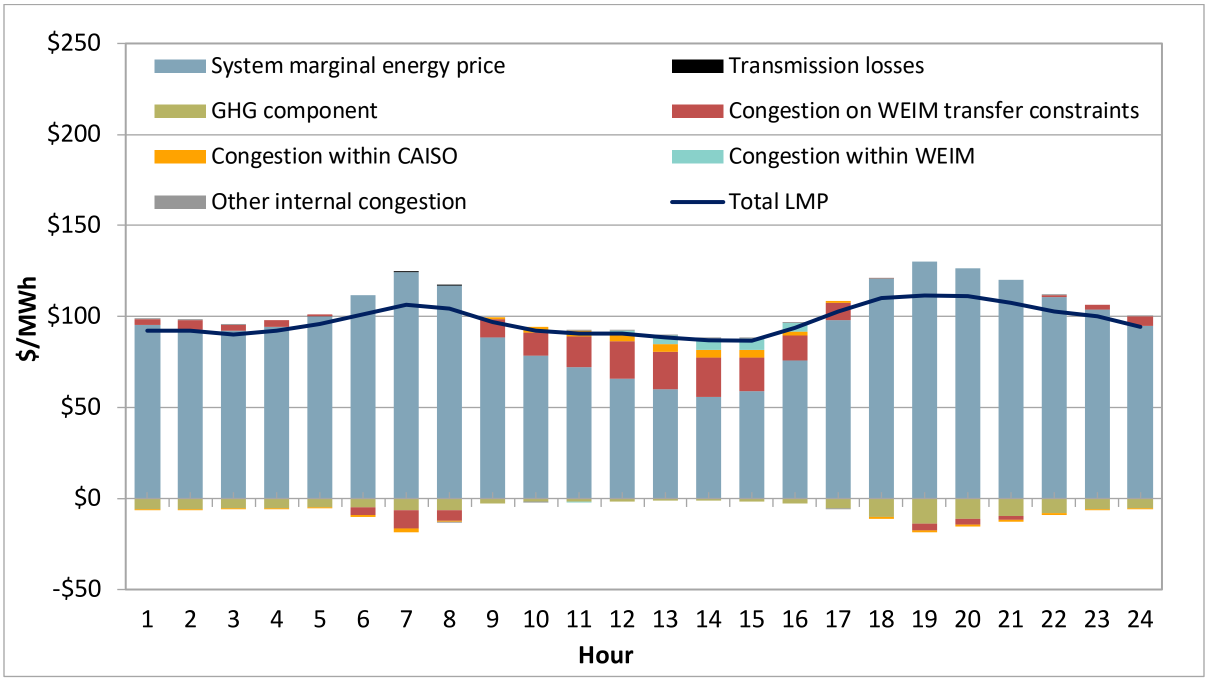


Appendix Figure A.52 Average hourly 5-minute market transfers

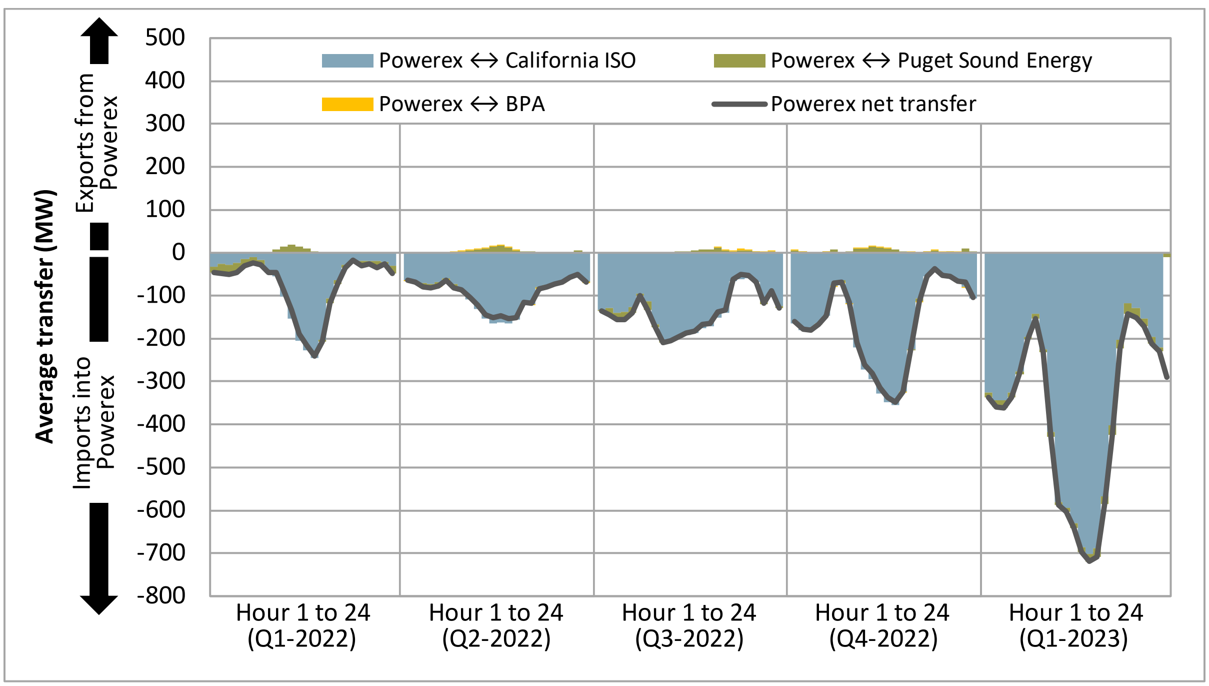


A.13 Powerex

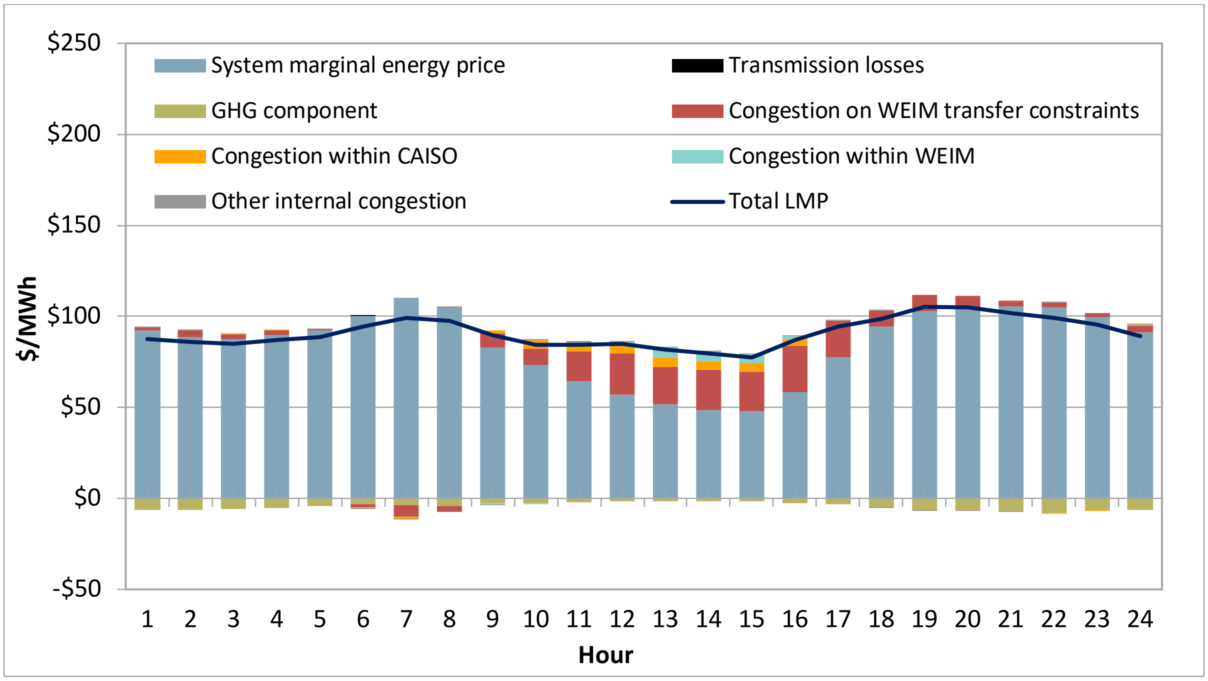
Appendix Figure A.53 Average hourly 15-minute price by component (Q1 2023)



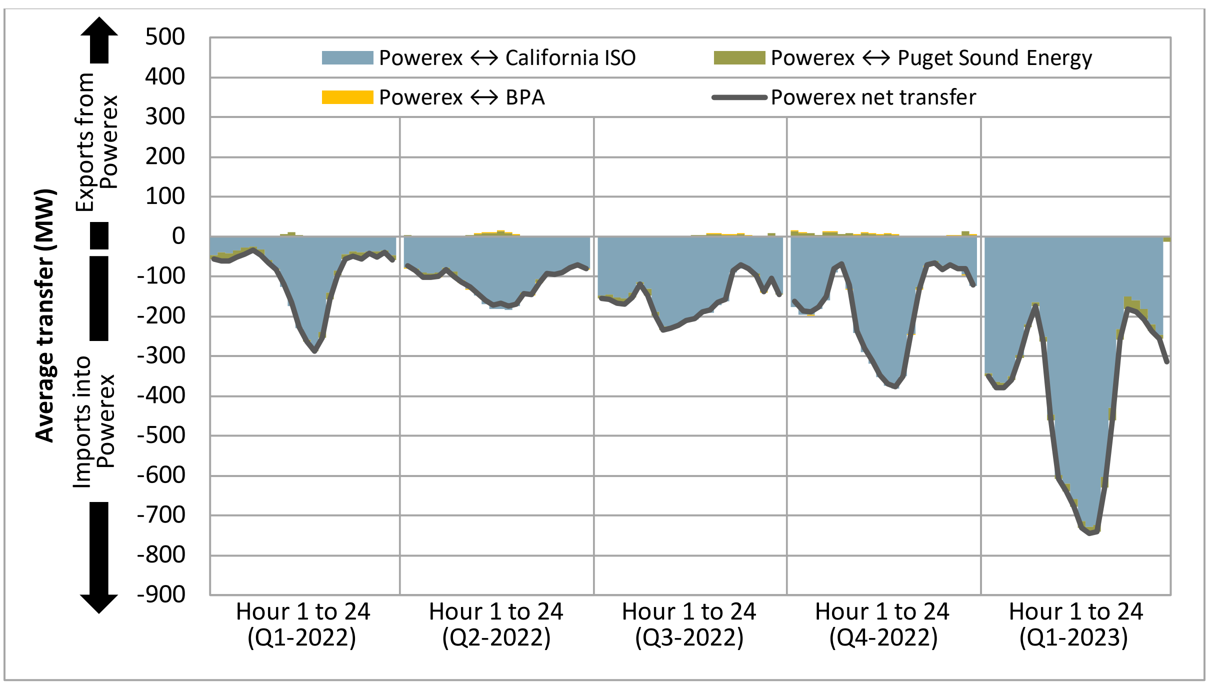
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q1 2023)

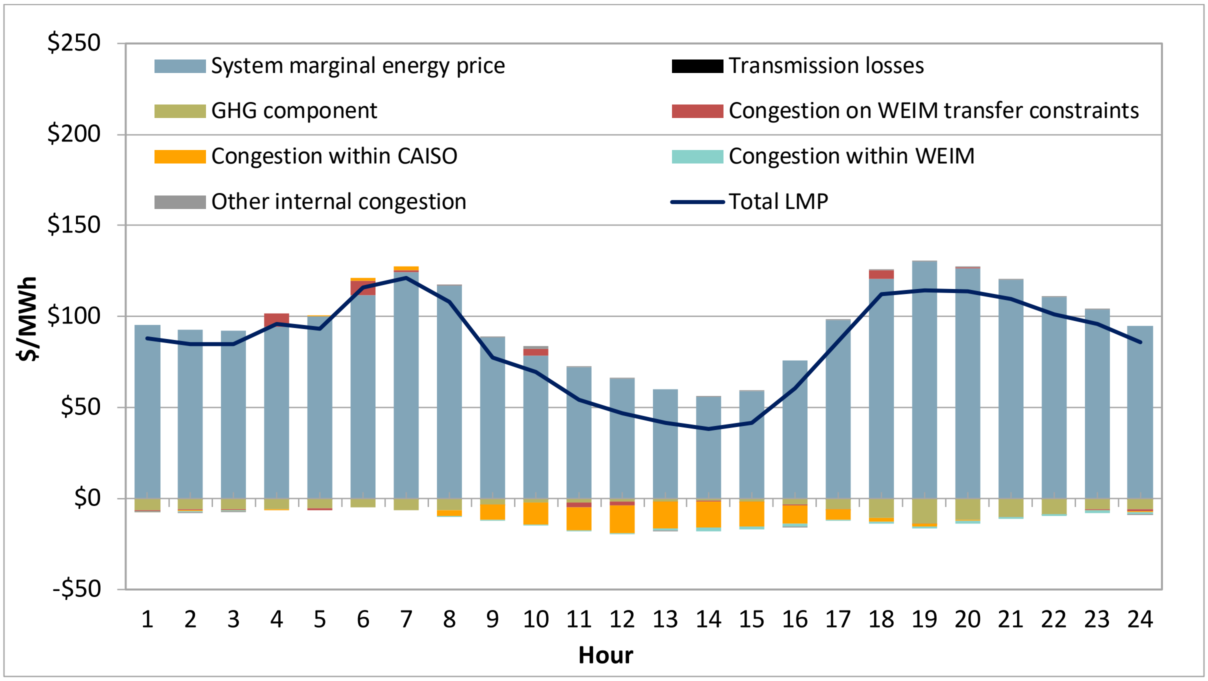


Appendix Figure A.56 Average hourly 5-minute market transfers

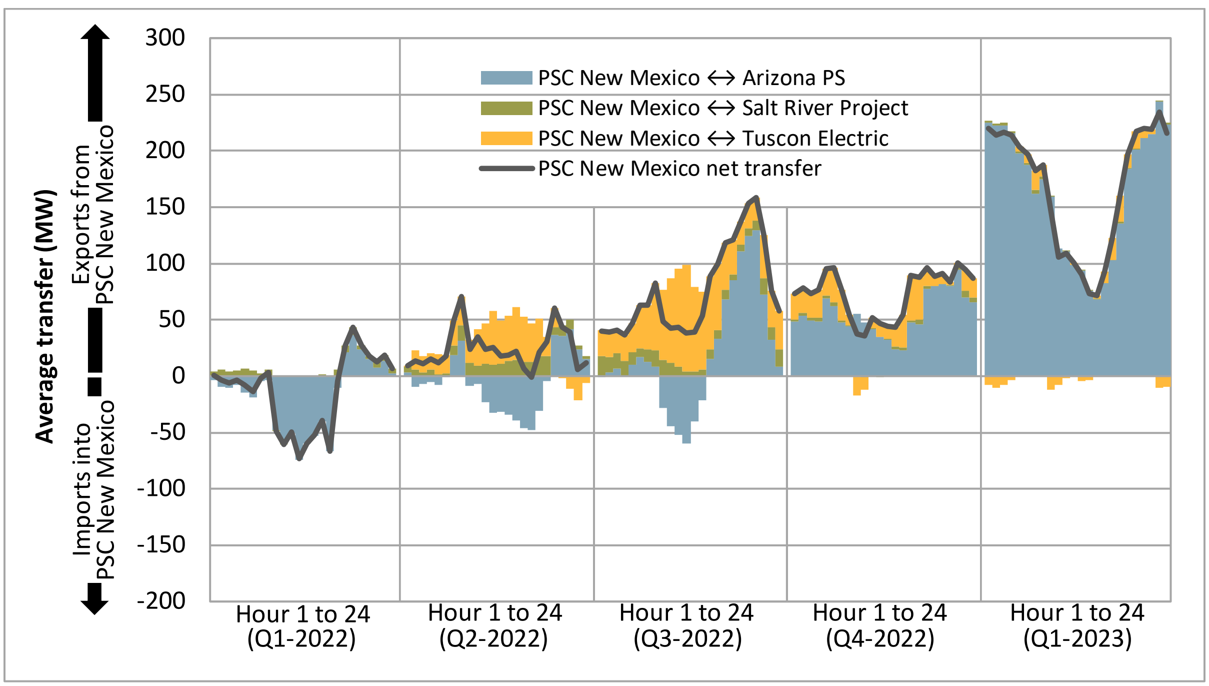


A.14 Public Service Company of New Mexico

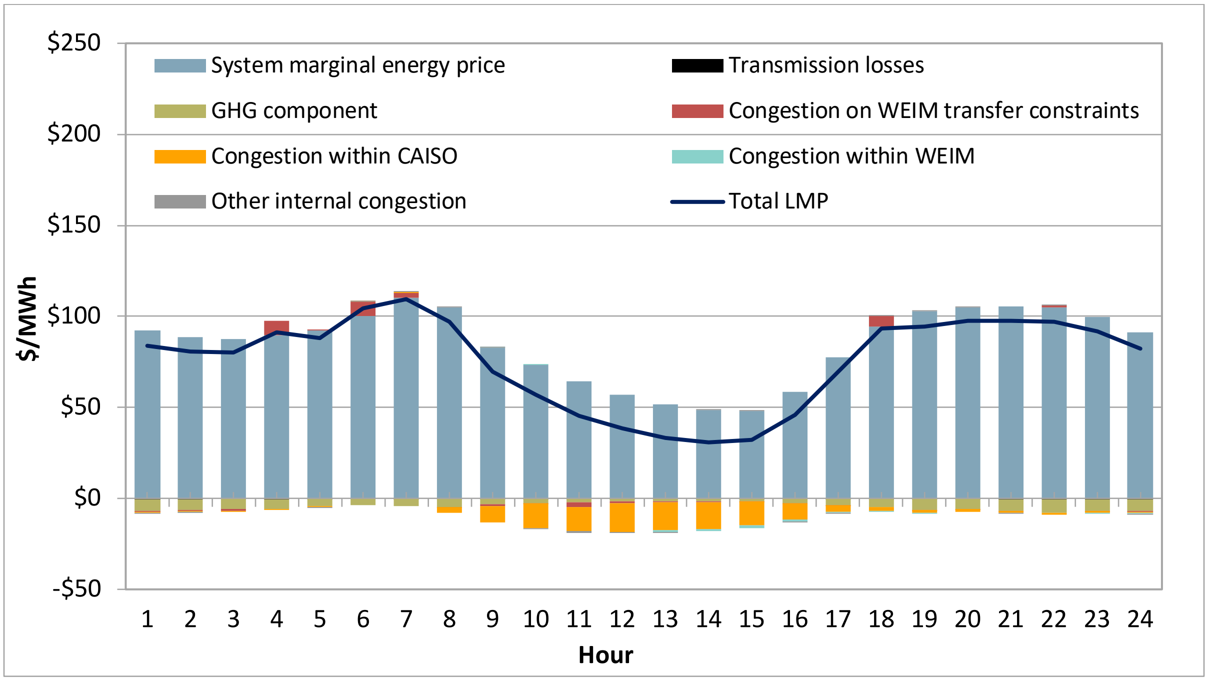
Appendix Figure A.57 Average hourly 15-minute price by component (Q1 2023)



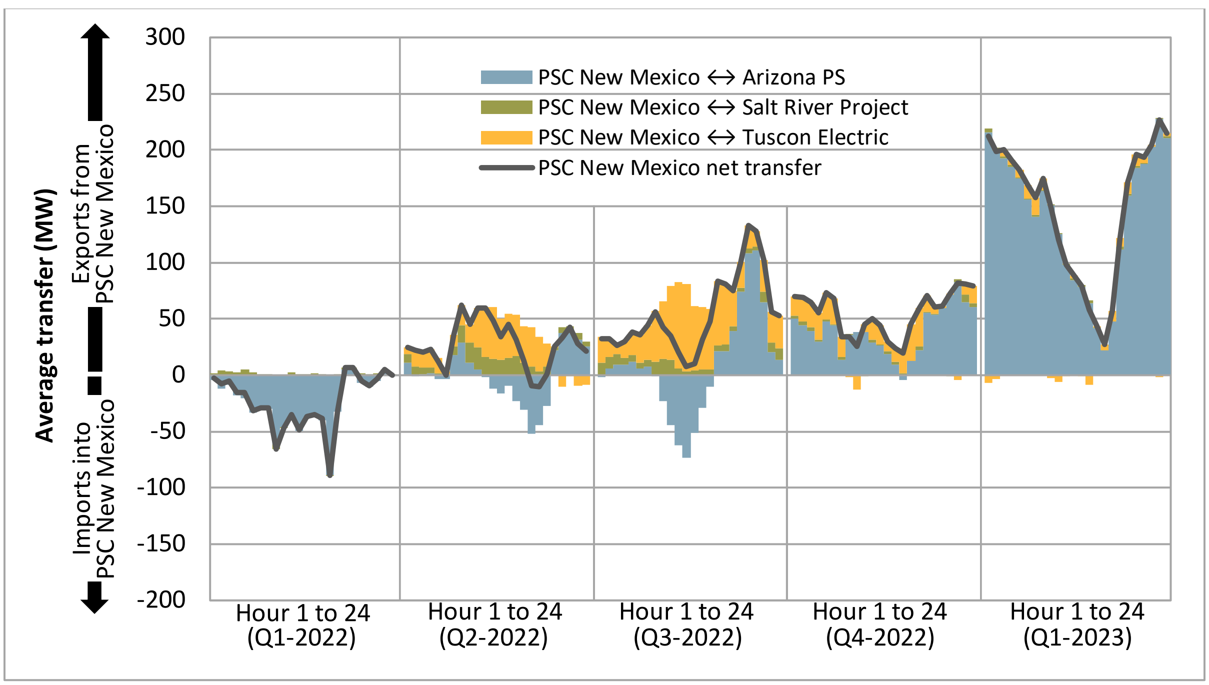
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q1 2023)

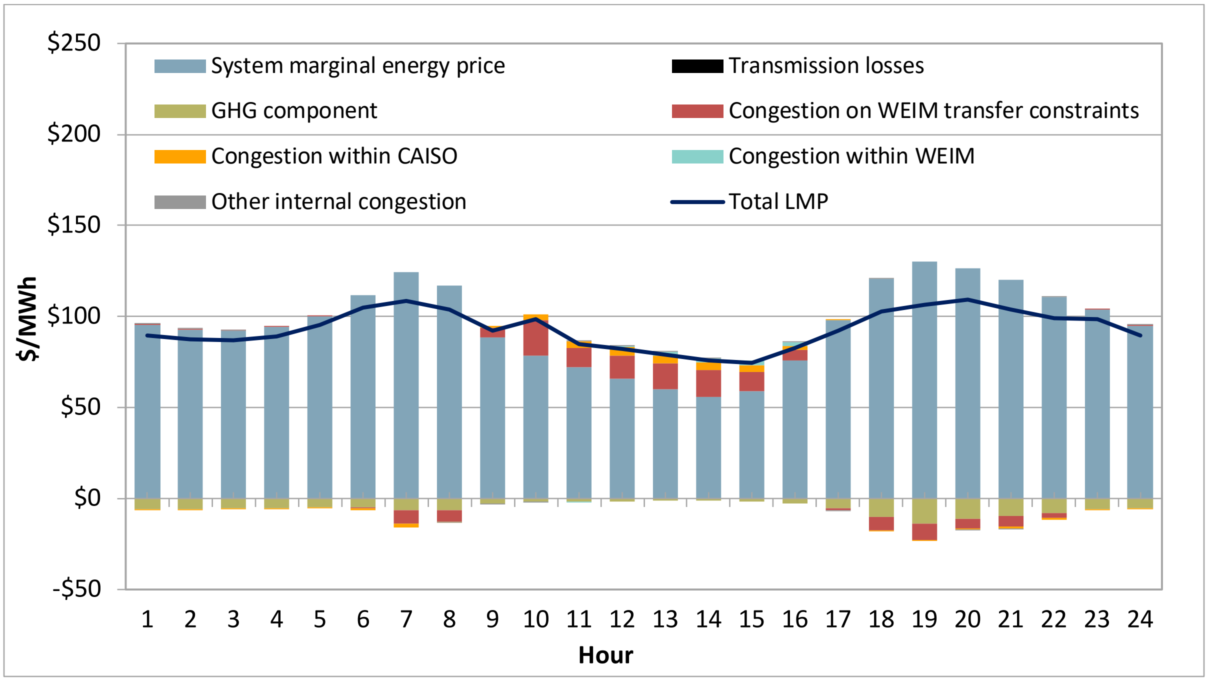


Appendix Figure A.60 Average hourly 5-minute market transfers

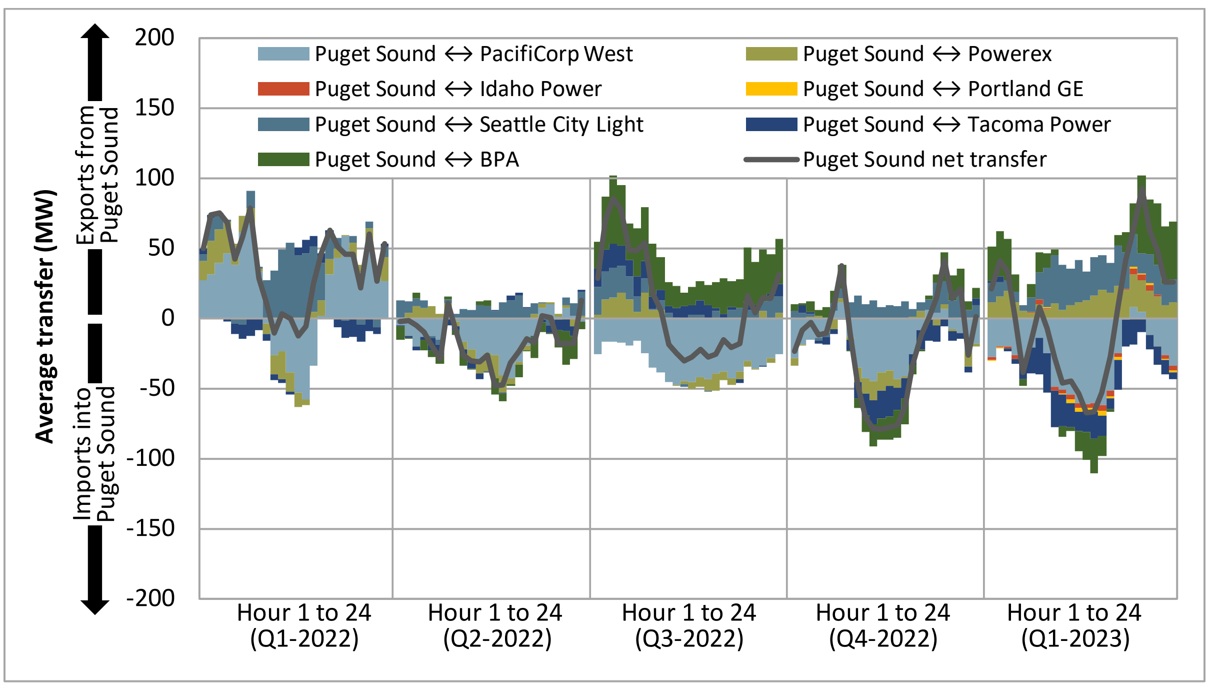


A.15 Puget Sound Energy

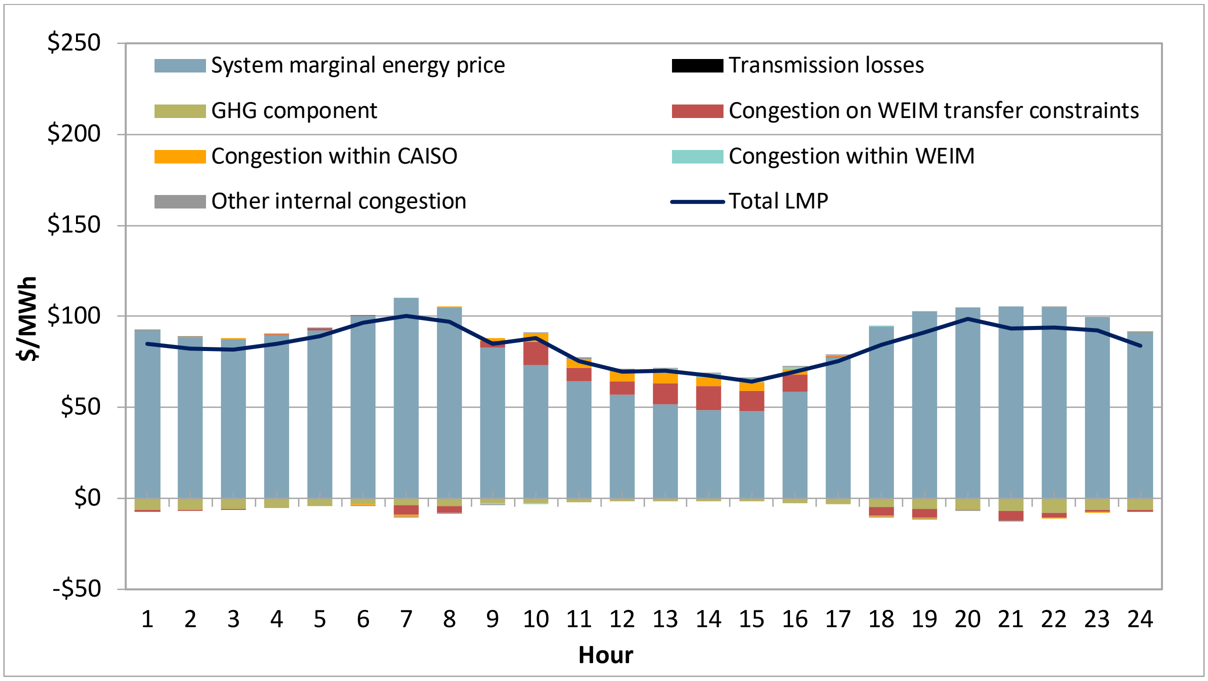
Appendix Figure A.61 Average hourly 15-minute price by component (Q1 2023)



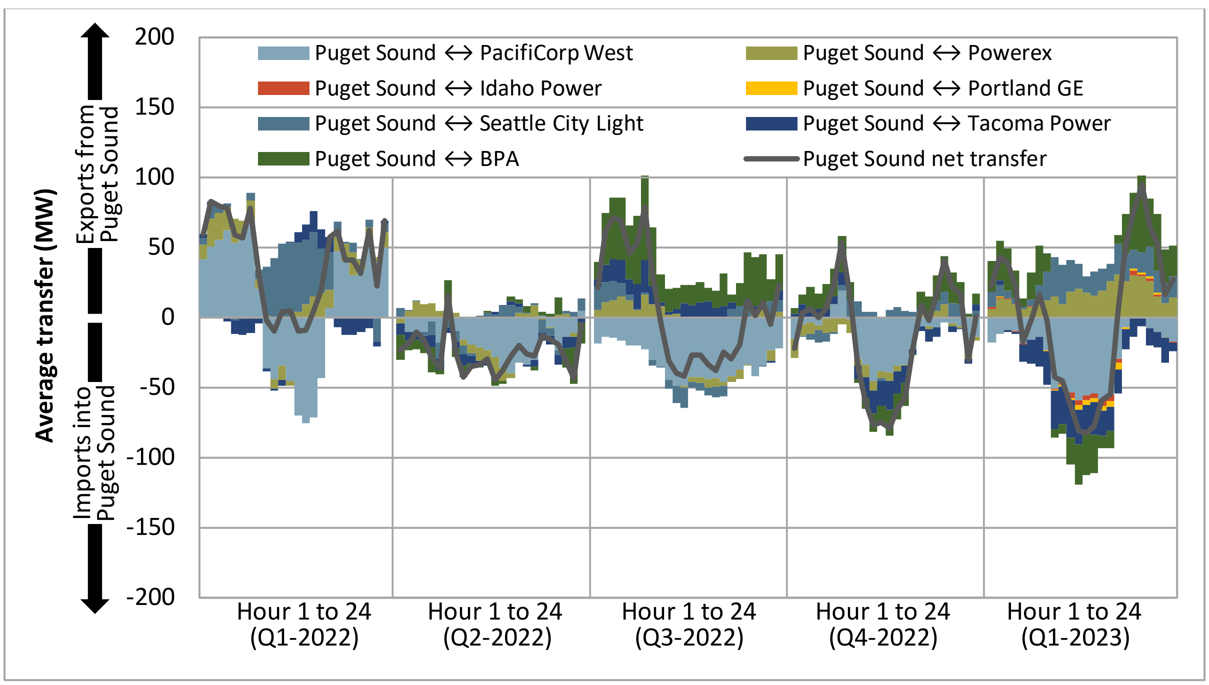
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q1 2023)

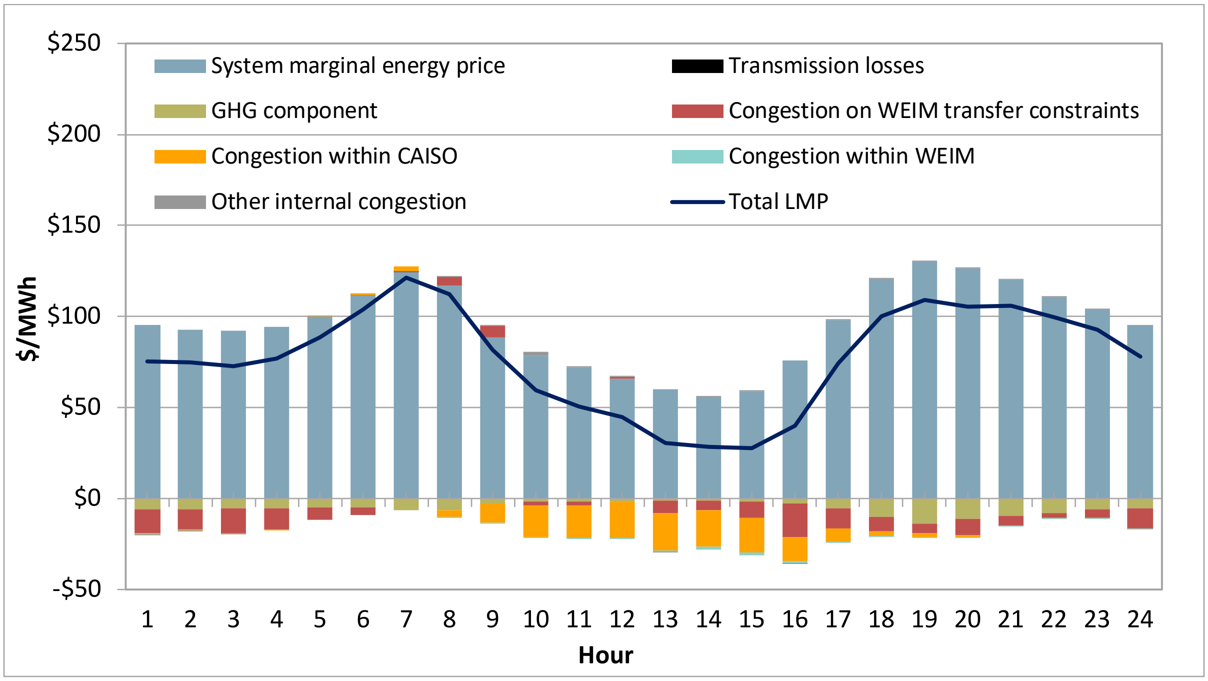


Appendix Figure A.64 Average hourly 5-minute market transfers

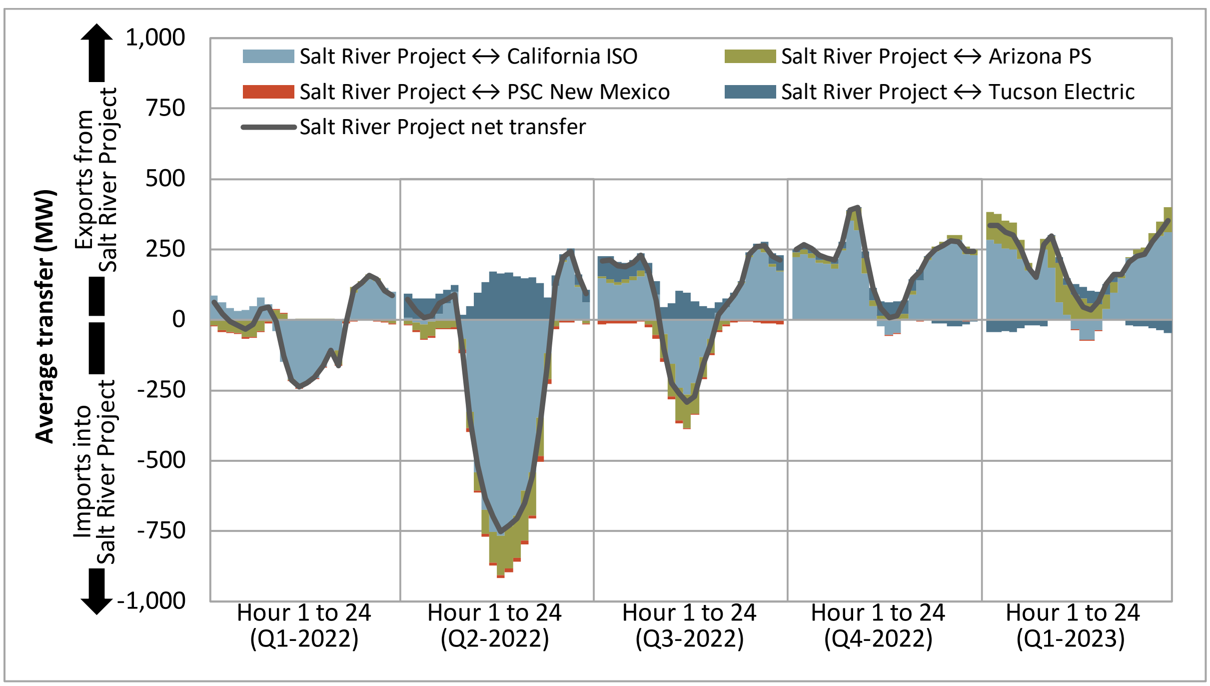


A.16 Salt River Project

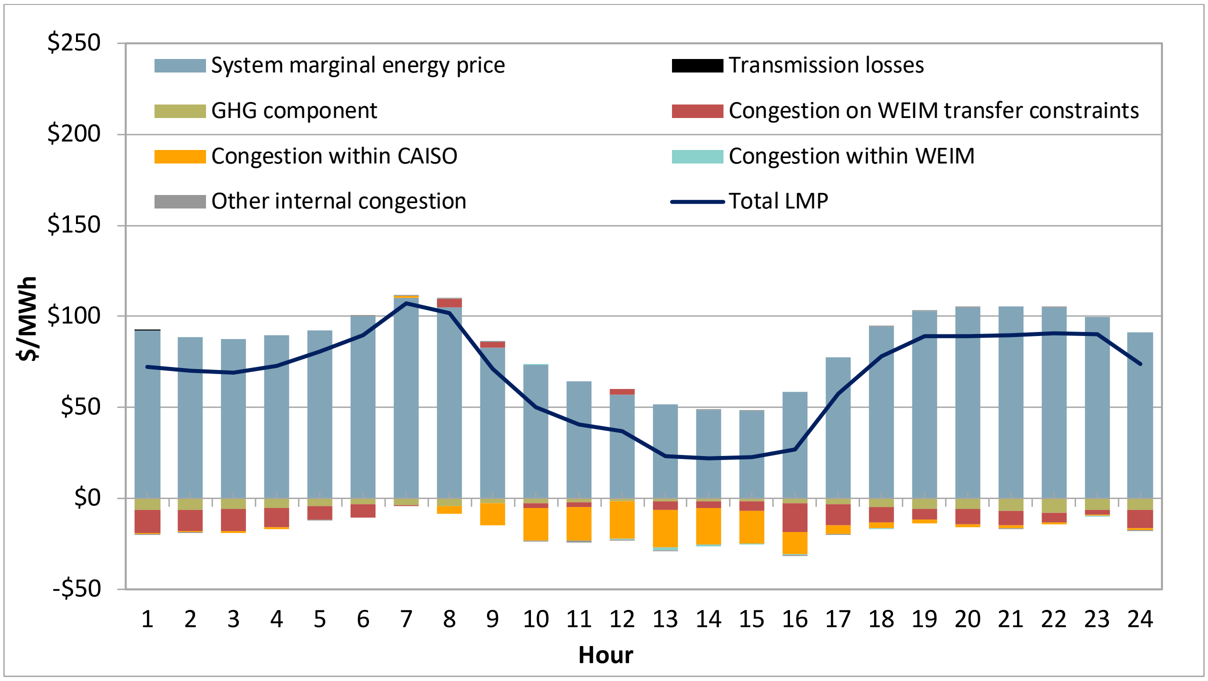
Appendix Figure A.65 Average hourly 15-minute price by component (Q1 2023)



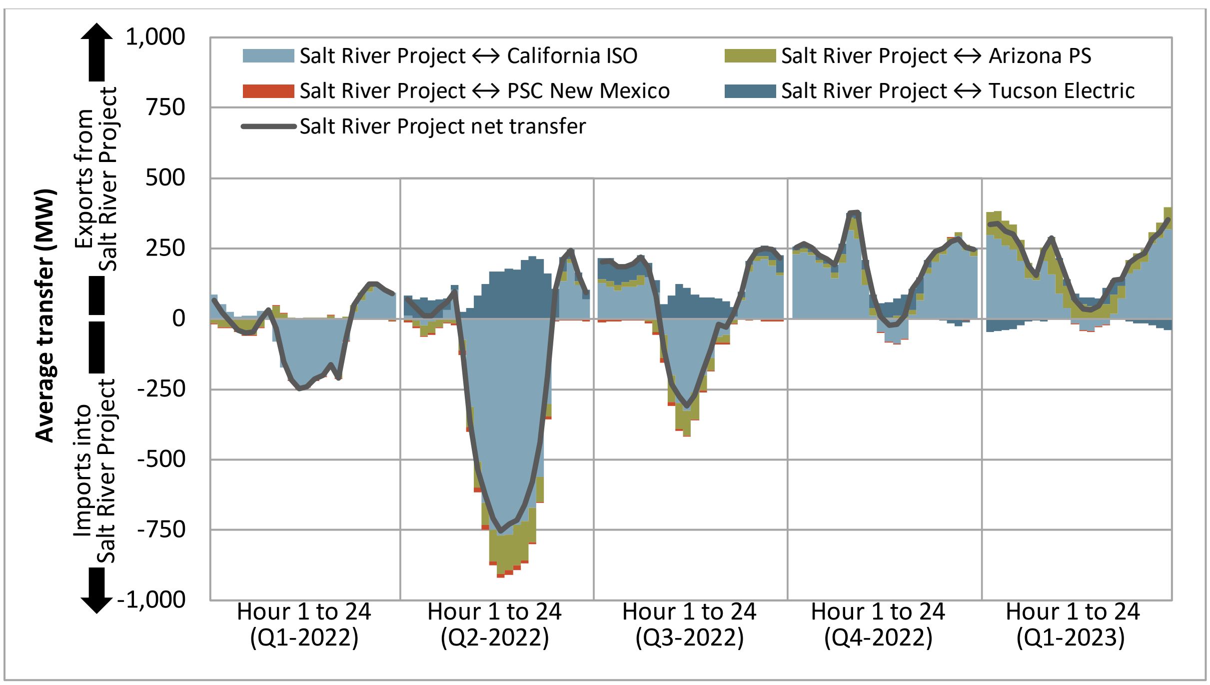
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q1 2023)

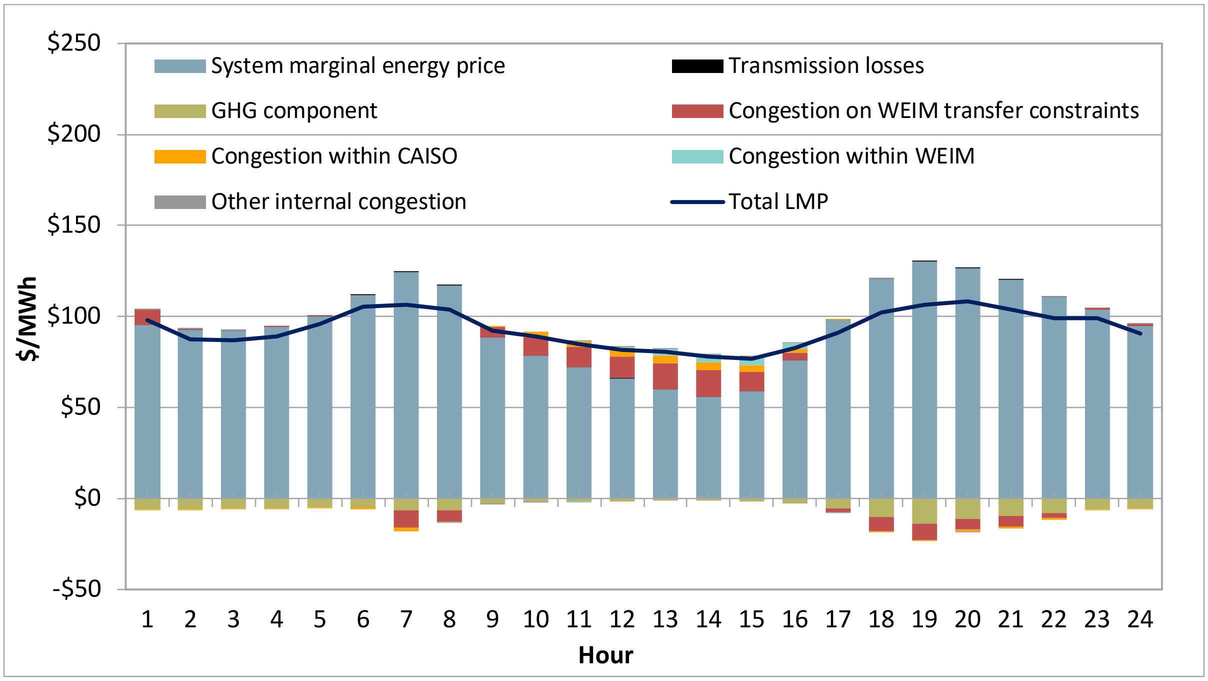


Appendix Figure A.68 Average hourly 5-minute market transfers

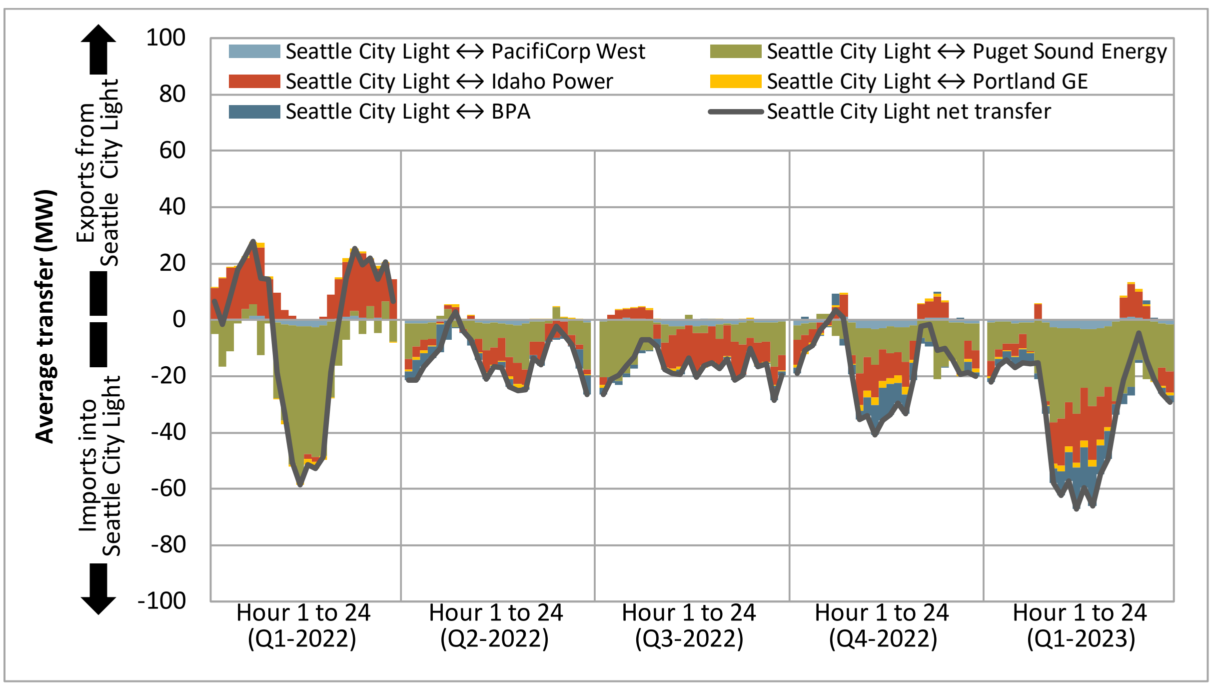


A.17 Seattle City Light

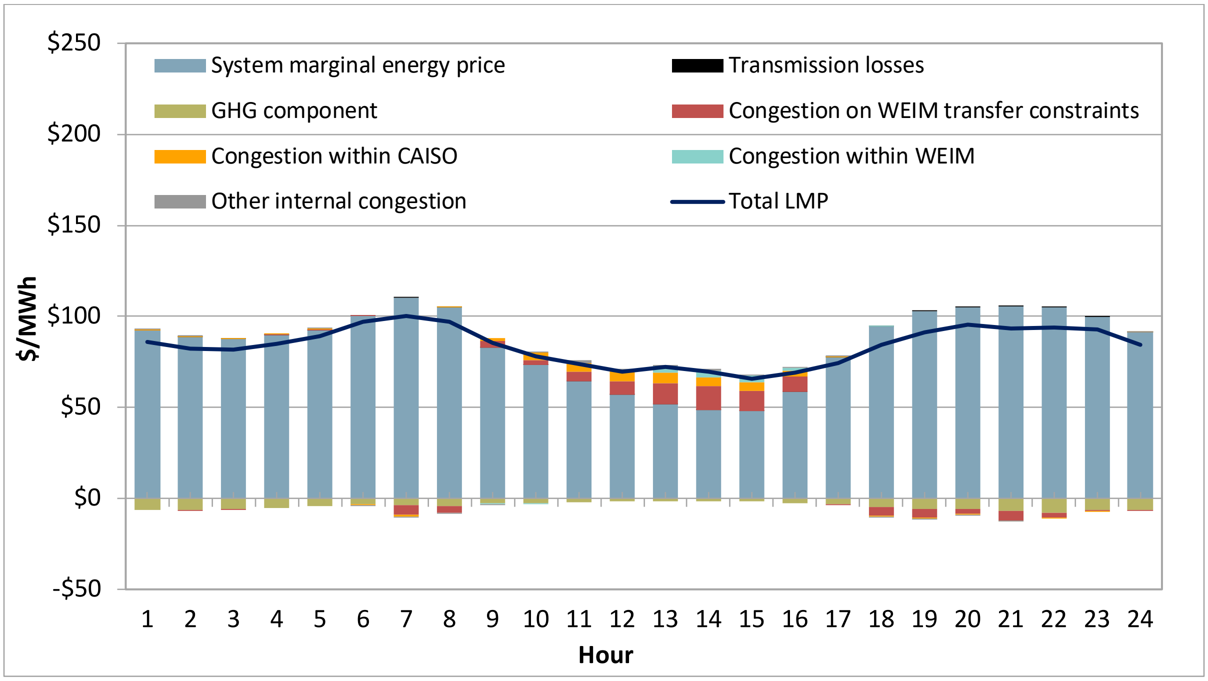
Appendix Figure A.69 Average hourly 15-minute price by component (Q1 2023)



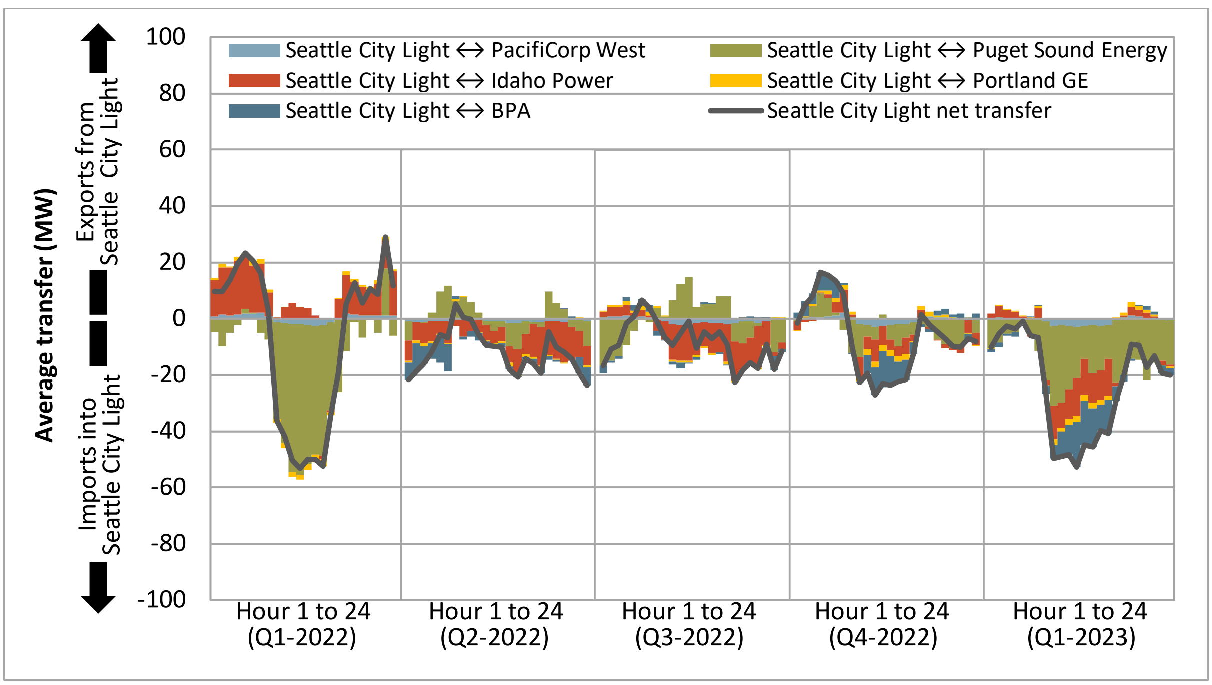
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q1 2023)

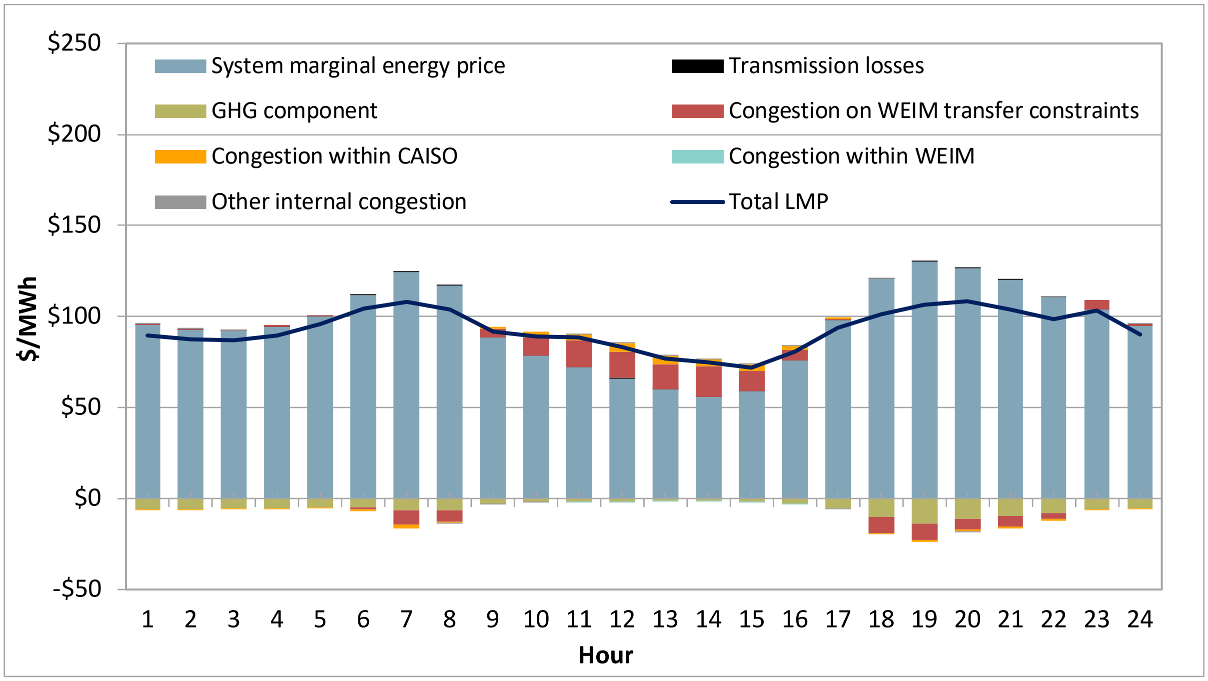


Appendix Figure A.72 Average hourly 5-minute market transfers

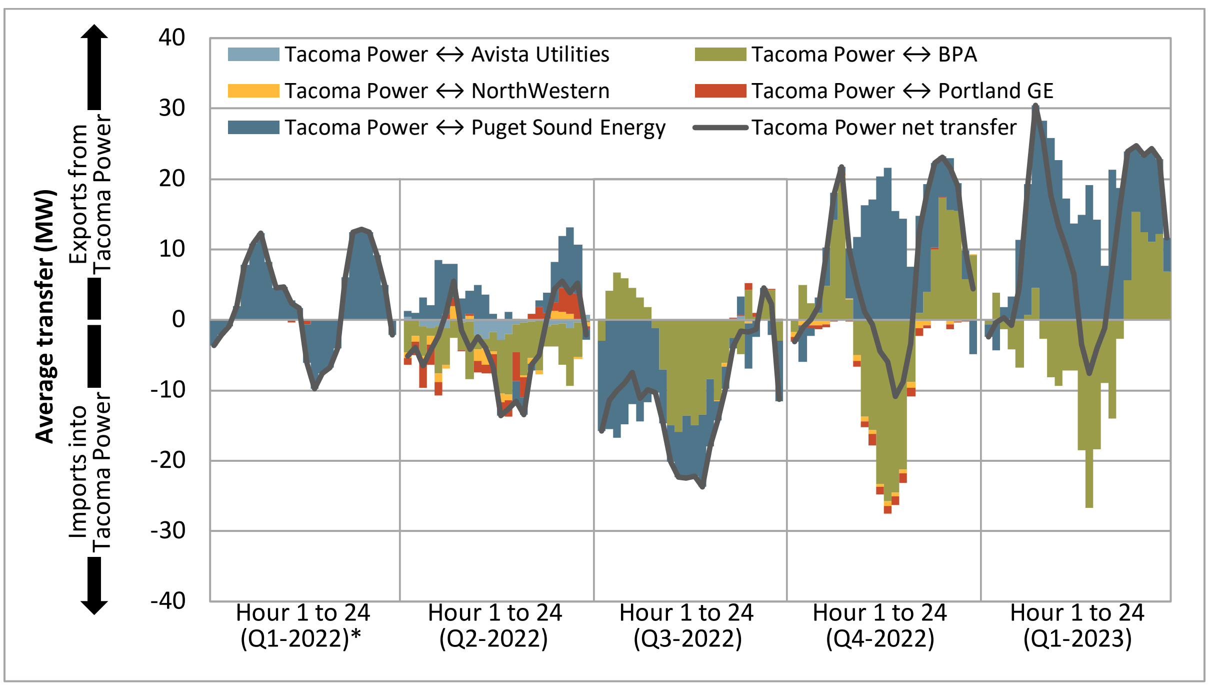


A.18 Tacoma Power

Appendix Figure A.73 Average hourly 15-minute price by component (Q1 2023)

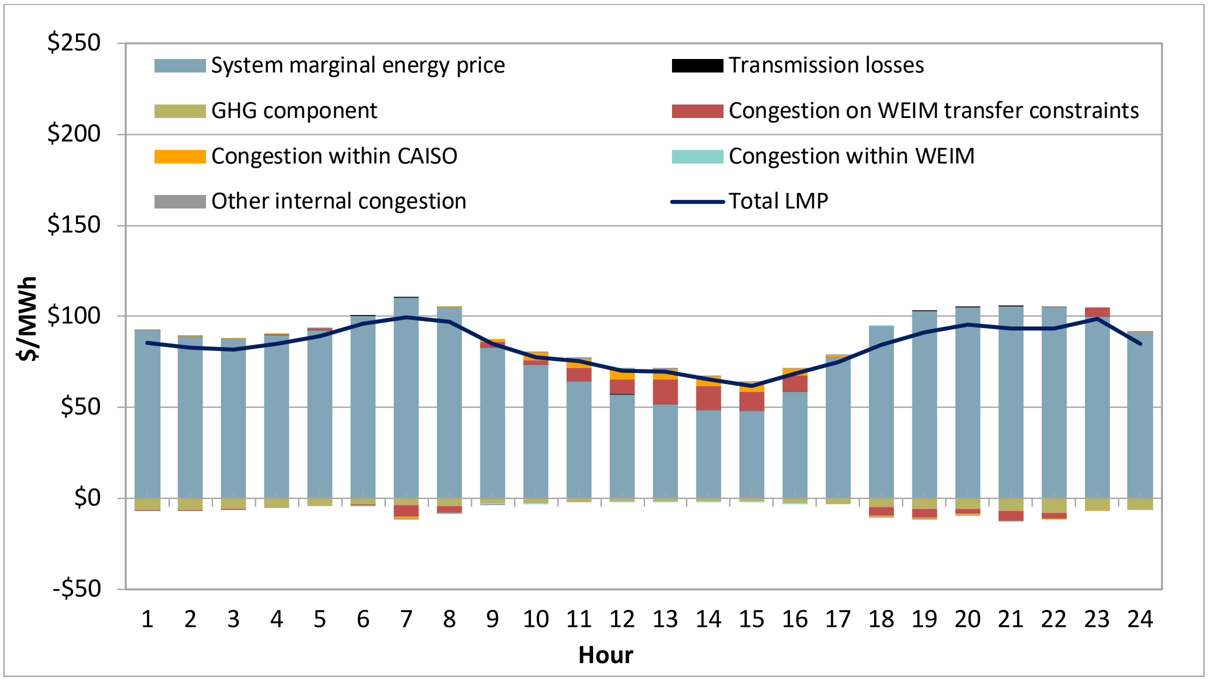


Appendix Figure A.74 Average hourly 15-minute market transfers

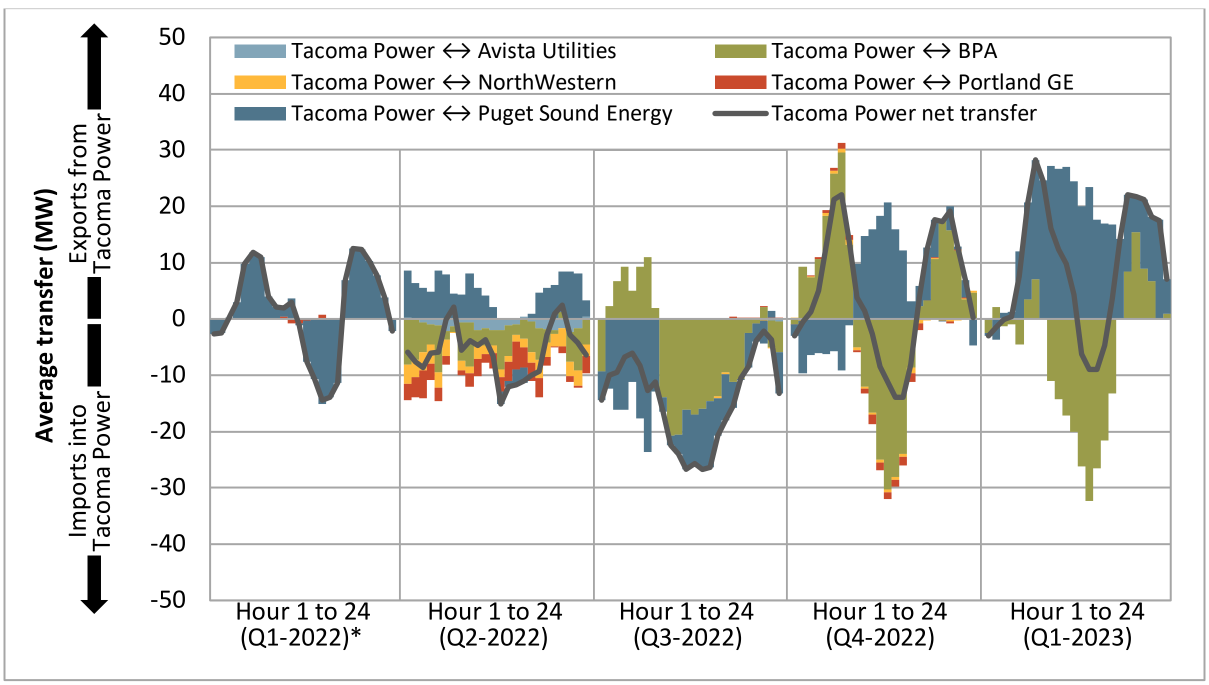


*Since joining the WEIM

Appendix Figure A.75 Average hourly 5-minute price by component (Q1 2023)



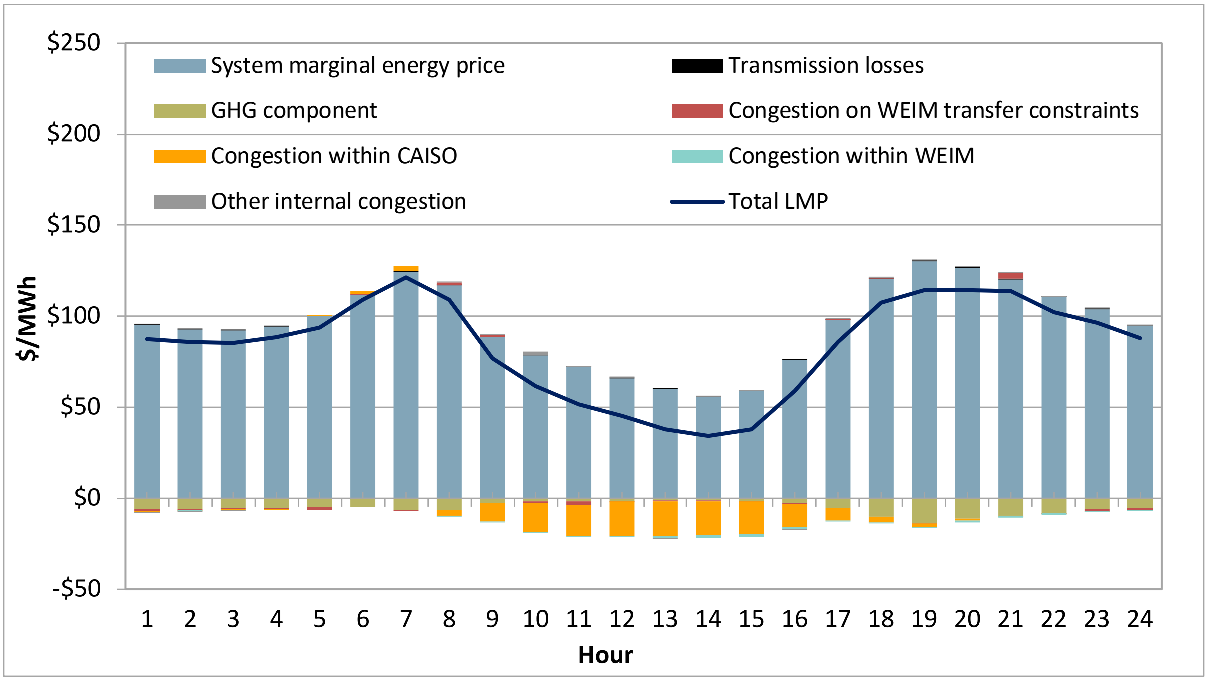
Appendix Figure A.76 Average hourly 5-minute market transfers



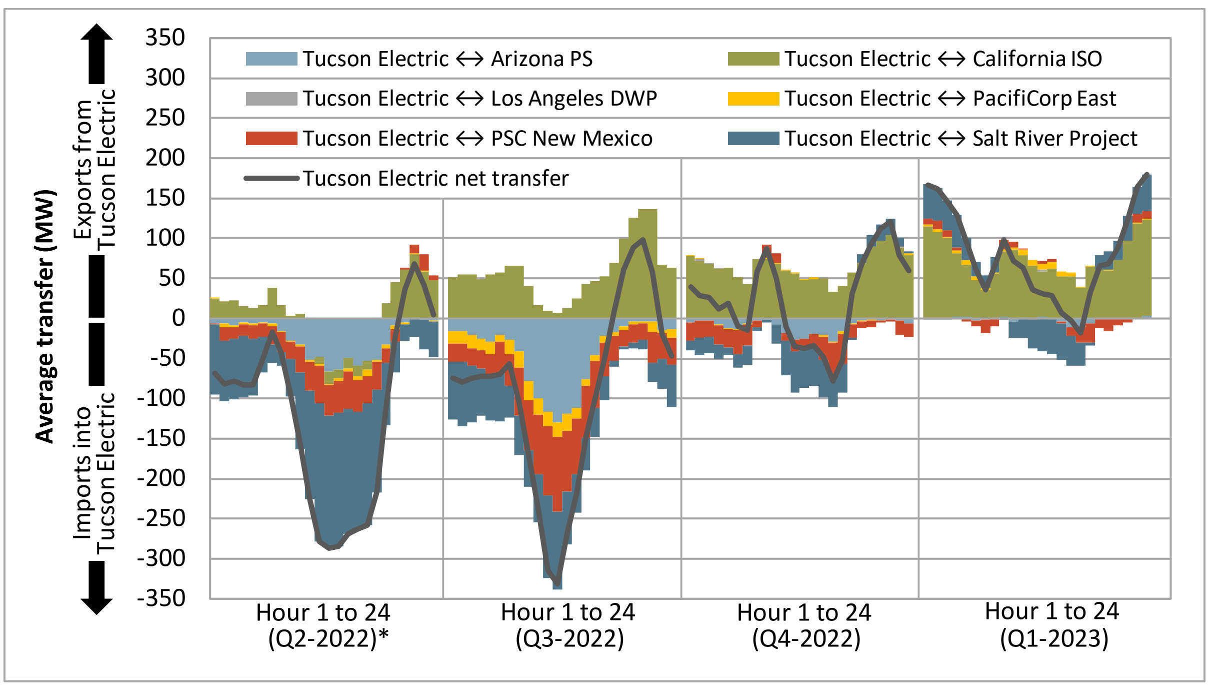
*Since joining the WEIM

A.19 Tucson Electric Power

Appendix Figure A.77 Average hourly 15-minute price by component (Q1 2023)

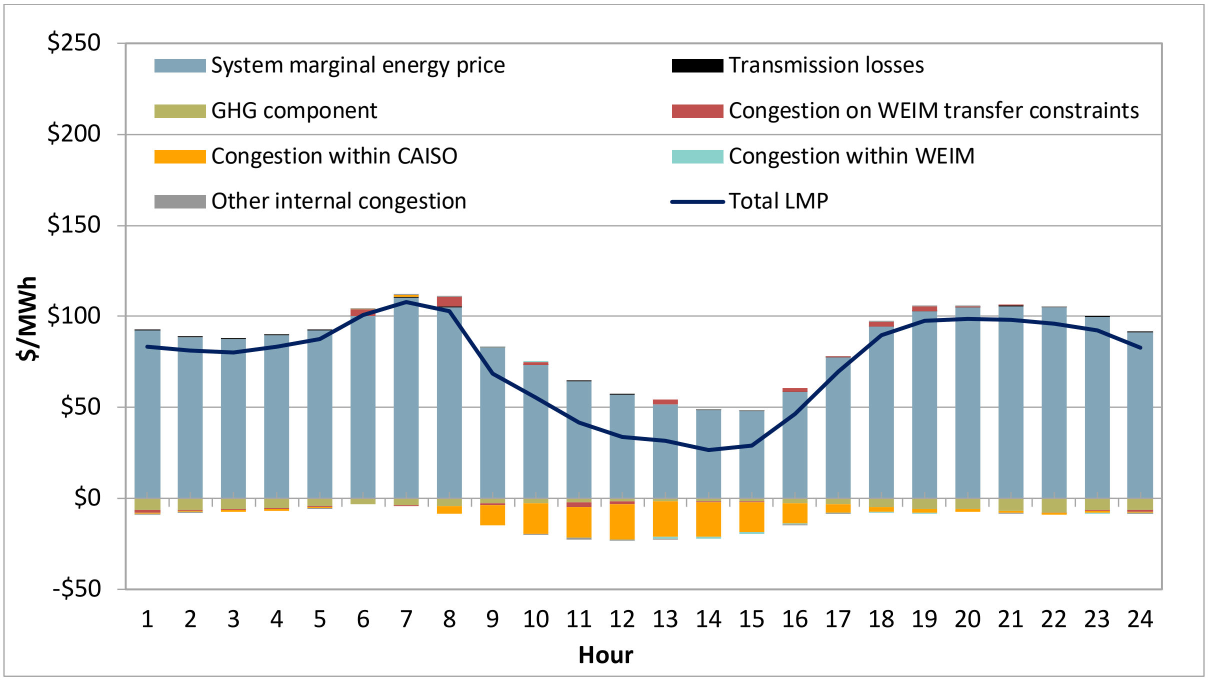


Appendix Figure A.78 Average hourly 15-minute market transfers

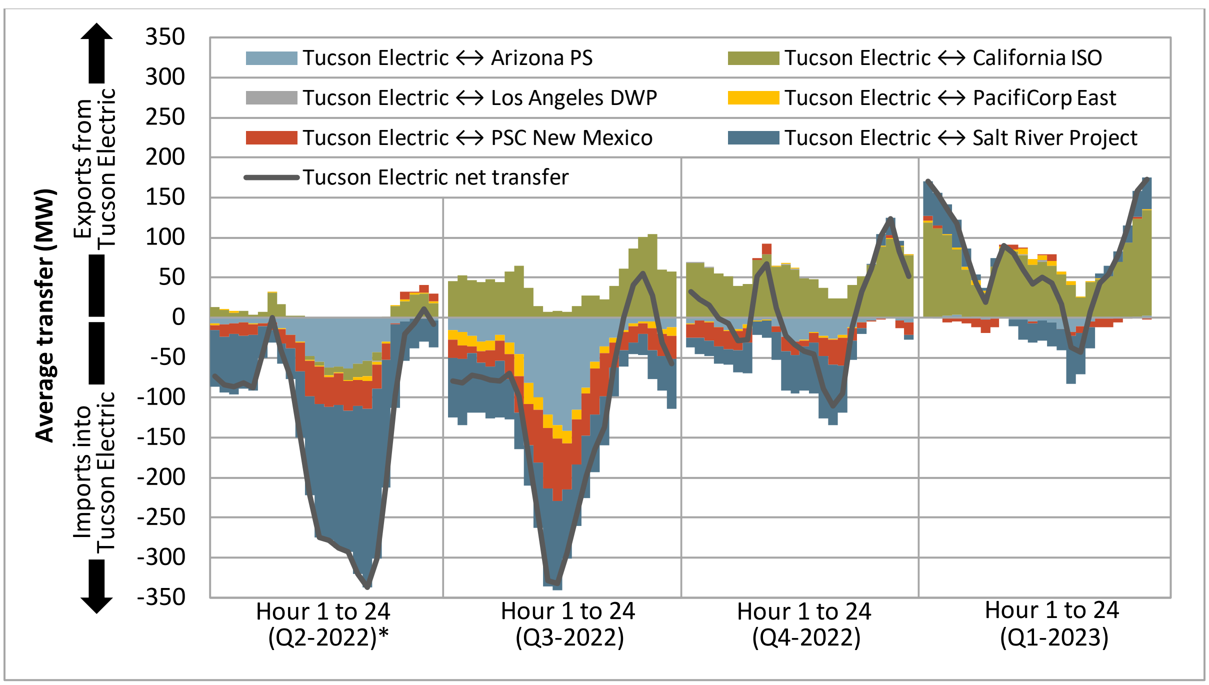


*Since joining the WEIM

Appendix Figure A.79 Average hourly 5-minute price by component (Q1 2023)



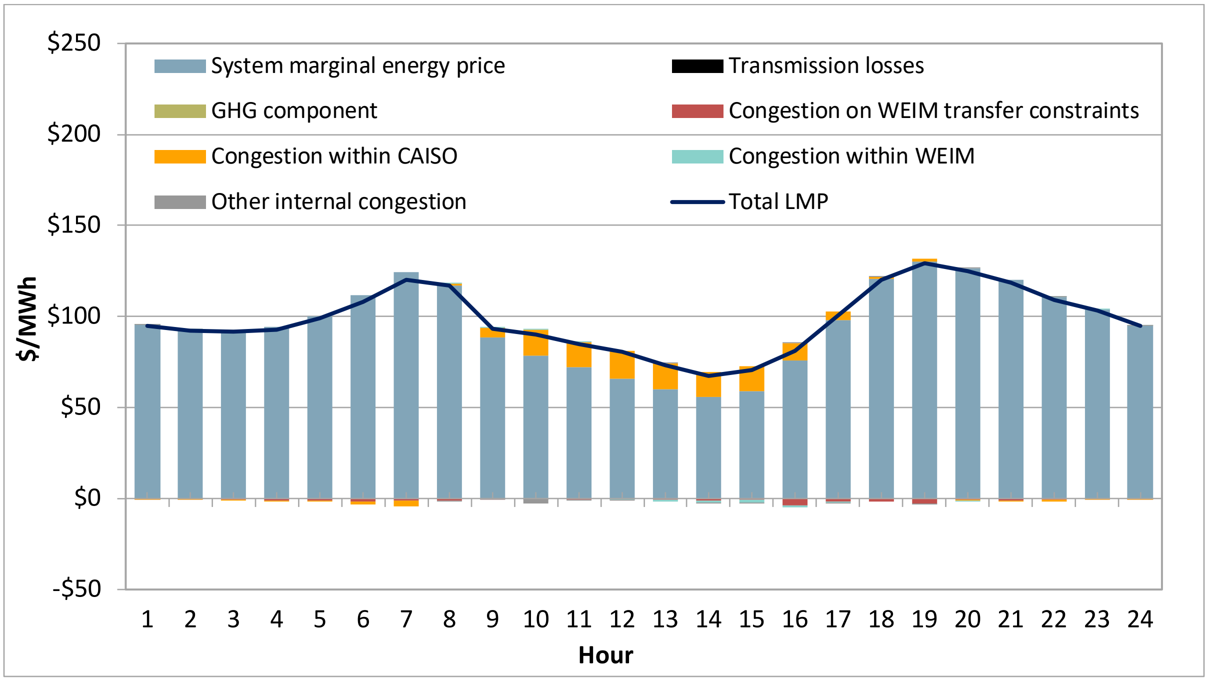
Appendix Figure A.80 Average hourly 5-minute market transfers



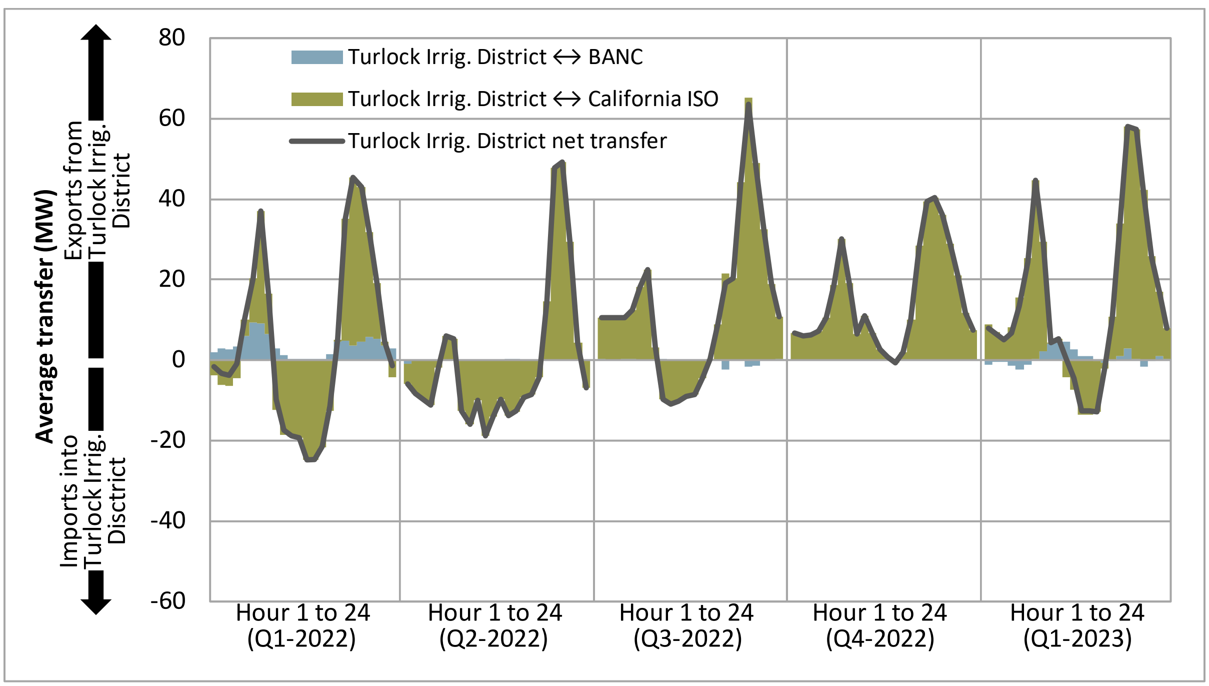
*Since joining the WEIM

A.20 Turlock Irrigation District

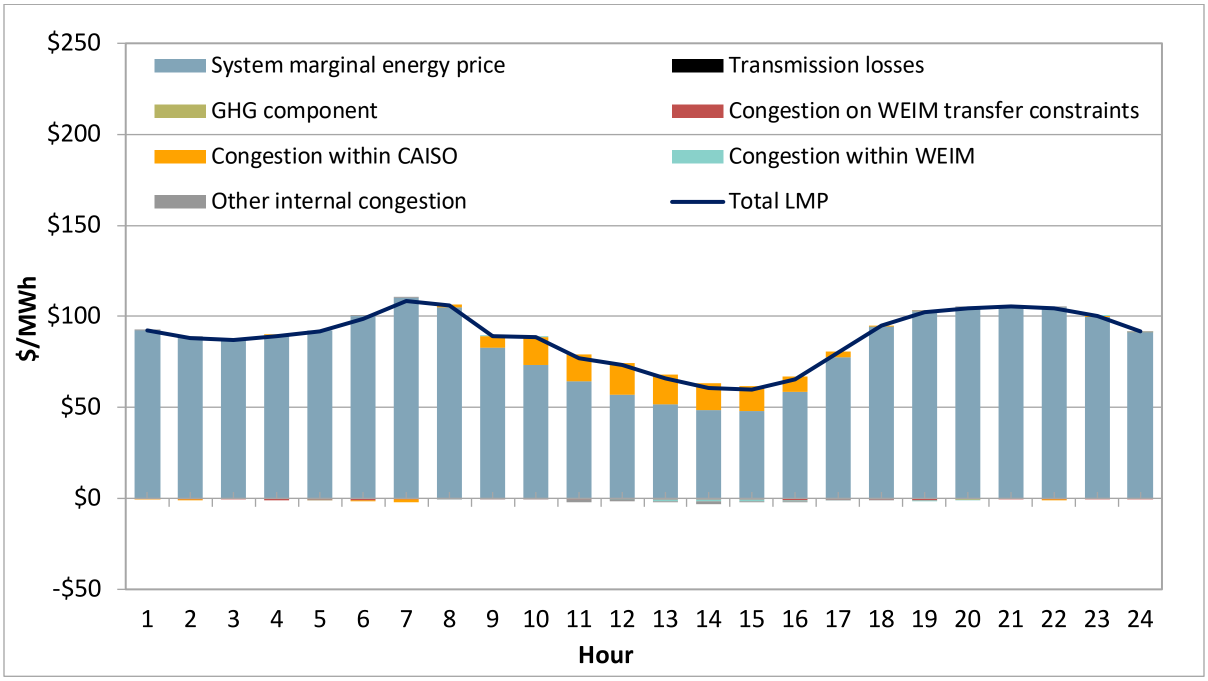
Appendix Figure A.81 Average hourly 15-minute price by component (Q1 2023)



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



Appendix Figure A.83 Average hourly 5-minute price by component (Q1 2023)



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