Q4 2022 Report on Market Issues and Performance

March 16, 2023

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California Independent System Operator

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Executive summary

This report covers market performance during the fourth quarter of 2022 (October - December).

Key highlights during this quarter include the following:

- **Gas prices rose to extraordinarily high levels across the market footprint in December**, well above the Henry Hub price, the national index (Figure E.1). This resulted in higher system marginal energy prices across the California ISO and Western Energy Imbalance Market footprint.
- **Market prices were significantly higher** than the same quarter of 2021, on average (Figure E.2). Both day-ahead and real-time prices more than doubled in most areas due to higher natural gas prices. The average day-ahead price in December was more than four times that in December 2021.
- **Generation from imports decreased** during all hours and was 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**. Day-ahead congestion decreased SCE and SDG&E area prices and increased prices in the PG&E area. Total day-ahead congestion rent rose to $374 million, up from $155 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 $91 million and $17 million, respectively, during the quarter. The total $108 million cost for the quarter is more than triple the $35 million cost in 2021. About $79 million was paid to gas resources, followed by about $12 million to battery energy storage resources.
- **Real-time imbalance offset costs increased significantly to about $36 million,** up from $21 million in 2021, but lower than the extraordinarily high offsets in the second and third quarters.
- **Ancillary service costs totaled $35 million, a 10 percent increase** from the fourth quarter of 2021. Average requirements were lower for operating reserves, higher for regulation down, and nearly the same for regulation up compared to the fourth quarter of 2021.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by $26** million in the quarter, more than double losses $12 million losses in 2021. 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 $24 million** in Q4, up from $11 million in 2021.
- **Flexible ramping product system level prices** were zero for over 99 percent of intervals in the 15-minute market and in the 5-minute market. Implementation of nodal pricing for the product was implemented in February of 2023.
- **Imbalance conformance adjustments** averaged about 2,000 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

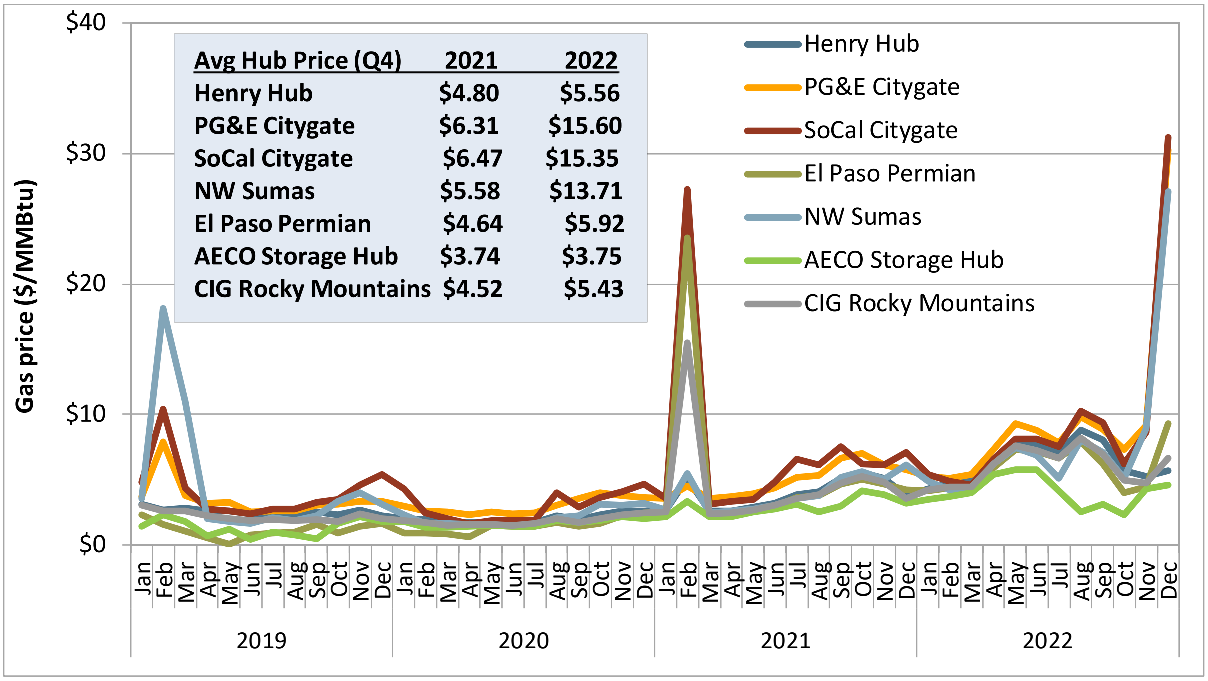
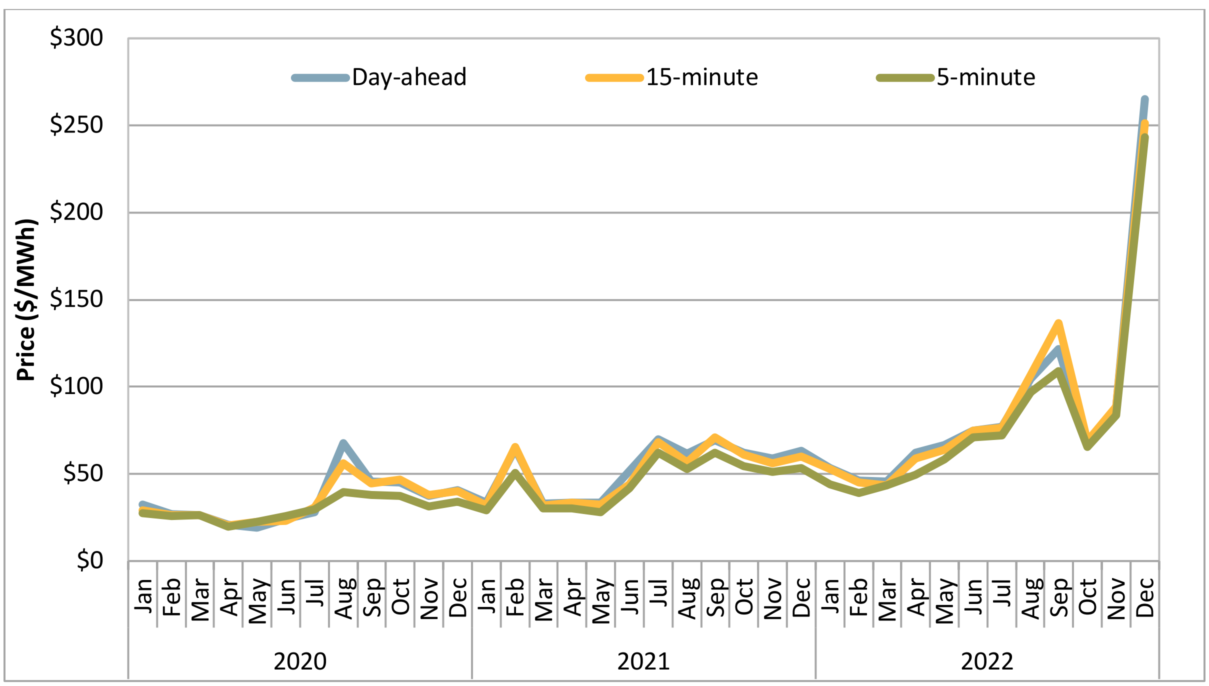


Figure E.2 Monthly load-weighted average energy prices California ISO (all hours)



Western Energy Imbalance Market

- **Natural gas prices rose across the WEIM**, resulting in higher energy prices in all balancing areas.
- **Prices in WEIM balancing areas within California were about $18/MWh higher than other regions**. Prices tend to be higher in California than the rest of the system due to both transfer constraint congestion and greenhouse gas compliance costs for energy that is delivered to California.
- **The California ISO 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 around 1,700 MW from neighboring areas including LADWP, Turlock Irrigation District, PacifiCorp West, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, and Tucson Electric Power.
- **The California ISO, Arizona Public Service, NV Energy and PacifiCorp East were major net exporters** during the mid-day period when solar generation is typically at its highest. These areas exported an average of about 1,500 MW to BANC, Idaho Power and areas in the Northwest.
- **Prices in the Northwest region 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. The Northwest region includes, Portland General Electric, Puget Sound Energy, Seattle City Light, Tacoma Power, PacifiCorp West, Powerex, NorthWestern, Avista Utilities, and Bonneville Power Administration.
- **Flow-based constraint congestion outside of the CAISO had a significant impact on prices** in both the 15-minute and 5-minute markets, lowering prices in Public Service Company of New Mexico and PacifiCorp East and raising prices in Southern California Edison, San Diego Gas & Electric, Los Angeles Department of Water and Power, NV Energy, Arizona Public Service, and Salt River Project.
- **The California ISO revised the loss sensitivity factor calculation** in August, reducing the impact on prices in WEIM areas that base scheduled the majority of their transfer capacity, especially those located in the Pacific Northwest.
- **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**.

1 Market performance

1.1 Supply conditions

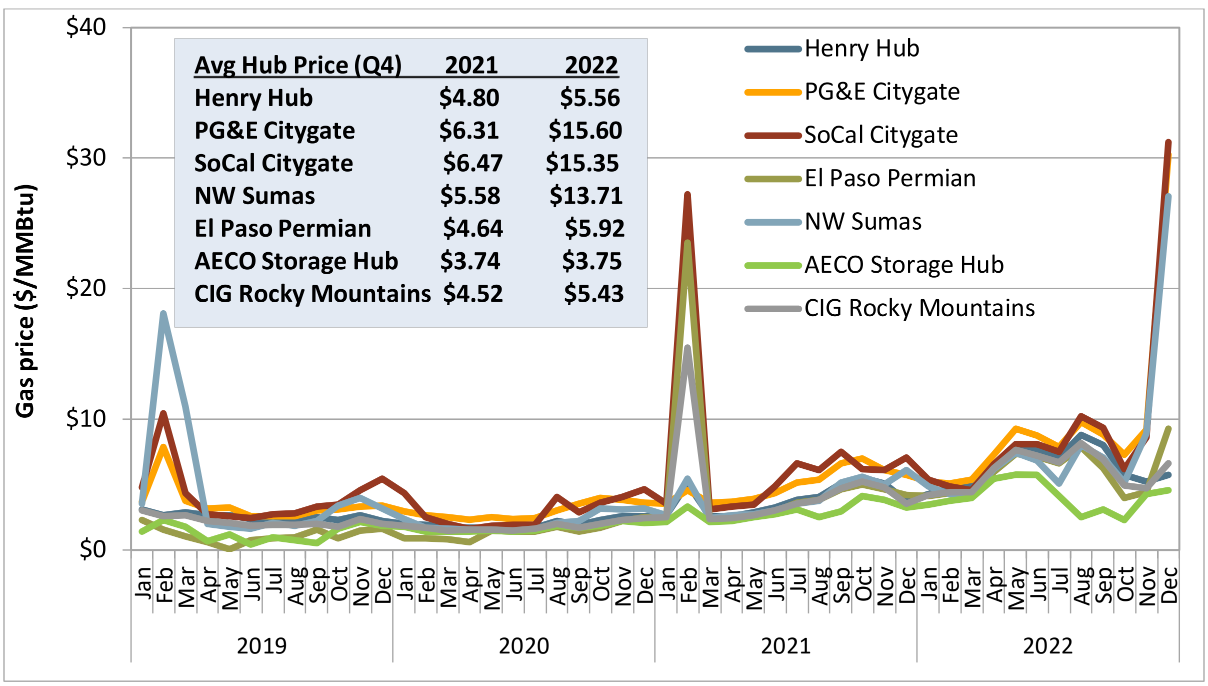
1.1.1 Natural gas prices

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. In December 2022, western gas hub prices traded at a significant premium over Henry Hub.

In the CAISO footprint, load-weighted average gas prices increased to $30.80/MMBtu in December 2022 compared to $6.46/MMBtu in December 2021. Overall for the fourth quarter, the load-weighted average gas price increased by 142 percent relative to the same quarter of 2021, from $6.39/MMBtu to $15.46/MMBtu. Elevated gas prices led to significantly higher system marginal energy prices in December.

Figure 1.1 shows monthly average natural gas prices at supply locations (Permian, AECO, and Rockies) and 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



Quarterly average prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) rose by 147 percent and 137 percent, respectively, compared to the fourth quarter of 2021. The Northwest Sumas gas hub price increased 145 percent, compared to last year. Prices at Henry Hub and supply locations were significantly below both California hubs and Northwest Sumas in December 2022.

Several factors contributed to persistent high gas prices in December, which on some days settled higher than $50/MMBtu in the western US:

1. High natural gas consumption in the residential and electric power sector. Below normal temperatures leading to increased demand for natural gas;[1]
2. Reduced natural gas deliveries into 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.[2,3] As of Dec 2, storage inventories were 18% below 2021 levels and nearly 24% below 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. [4]

In addition, 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 SDG&E service territories.[5] Until November 2022, SoCalGas declared 11 low OFOs, primarily stage 1. In December 2022, SoCalGas declared 10 low OFO's, primarily Stage 3.3 and above, with a starting non-compliance charge of $20/dth. In the PG&E service area, there were 25 low OFO's, primarily Stage 1 declared until November 2022. In December 2022, there were 8 Stage 3 and above low OFO's declared.

Figure 1.2 shows daily average natural gas prices for December 2022 and January 2023 at the same supply locations shown in Figure 1.1. 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.

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1 Daily regional average temperatures and departure from normal, EIA Natural Gas Storage Dashboard, page 4: https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20221215_natural_gas_storage_dashboard.pdf https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20221229_natural_gas_storage_dashboard.pdf

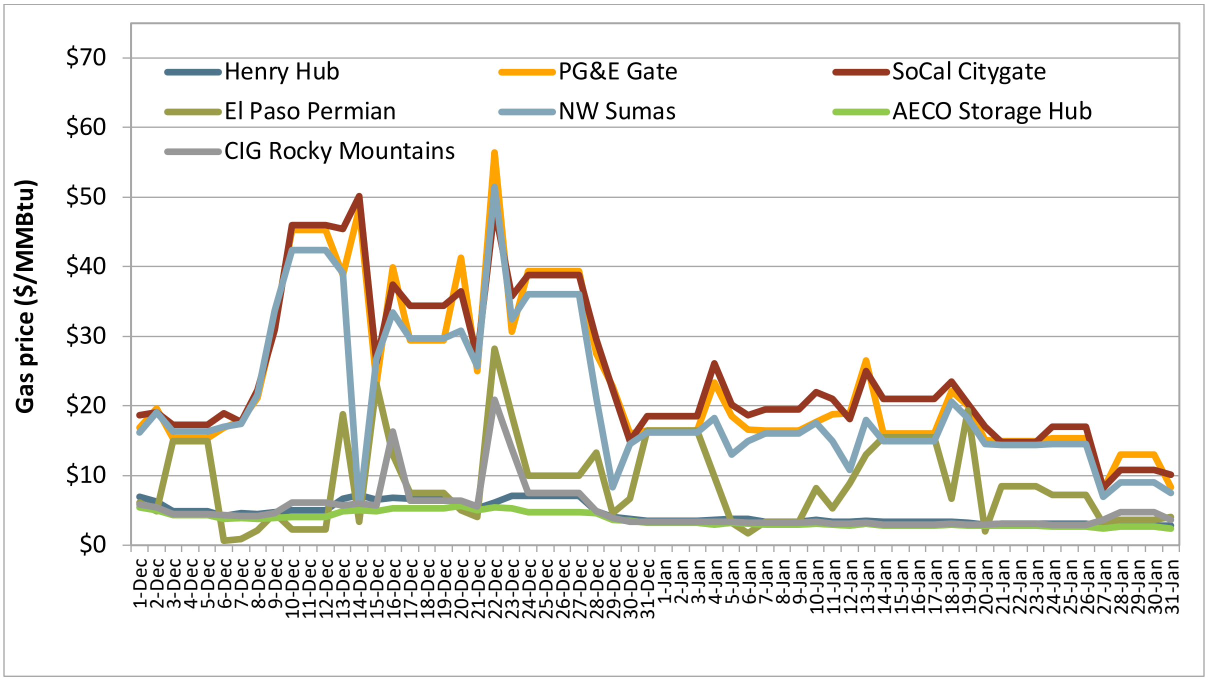
2 Pacific region weekly working gas in underground storage, EIA Natural Gas Storage Dashboard, page 3: https://www.eia.gov/naturalgas/storage/dashboard-api/archives/20221229_natural_gas_storage_dashboard.pdf

3 Southern California daily energy report: https://www.eia.gov/special/disruptions/socal/archive/winter/2022-12-31_winter_socal_energy_report.pdf

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

5 Proposed Decision for CPUC Docket No. R.20-01-007, *Decision Implementing Southern California Gas Company Rule 30 Operational Flow Order Winter Non-Compliance 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

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



1.1.2 Renewable generation

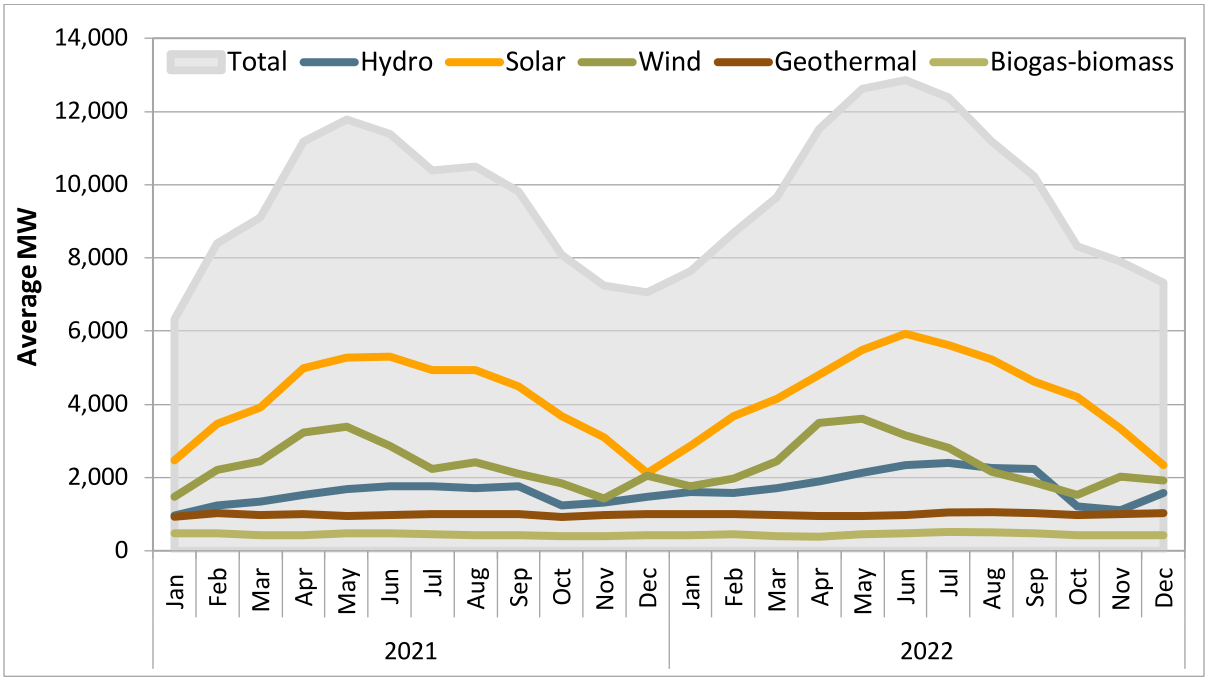
In the fourth quarter, the combined average monthly generation from renewable resources increased by about 400 MW (5 percent) compared to the same quarter of 2021.[6] Hydroelectric generation decreased 3 percent, while generation from solar, wind, geothermal, and biogas-biomass resources increased 7 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.[7] Solar and wind generation increased 325 MW (11 percent), while wind generation remained about the same. Generation from geothermal and biogas-biomass resources increased 40 MW and 14 MW (4 percent and 3 percent), respectively.

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

7 Hydroelectric generation greater than 30 MW is included.

Figure 1.3 Average monthly renewable generation



1.1.3 Generation by fuel type

In the fourth quarter, natural gas generation increased while generation from imports decreased. Average hourly generation by natural gas resources increased to 49 percent of total generation during peak net load hours. Nuclear and hydroelectric generation decreased 11 percent and 7 percent, respectively. Average hourly generation by batteries more than doubled relative to the fourth quarter of 2021.[8]

Figure 1.4 shows the average hourly generation by fuel type during the fourth quarter of 2022. Total hourly average generation peaked at about 26,425 MW during hour ending 19. Battery generation also peaked during hour end 19 at about 1,500 MW. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed to 16 percent of total generation during the peak net load hours of 17-21, up less than 1 percent from the same time last year.

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

Figure 1.4 Average hourly generation by fuel type (Q4 2022)

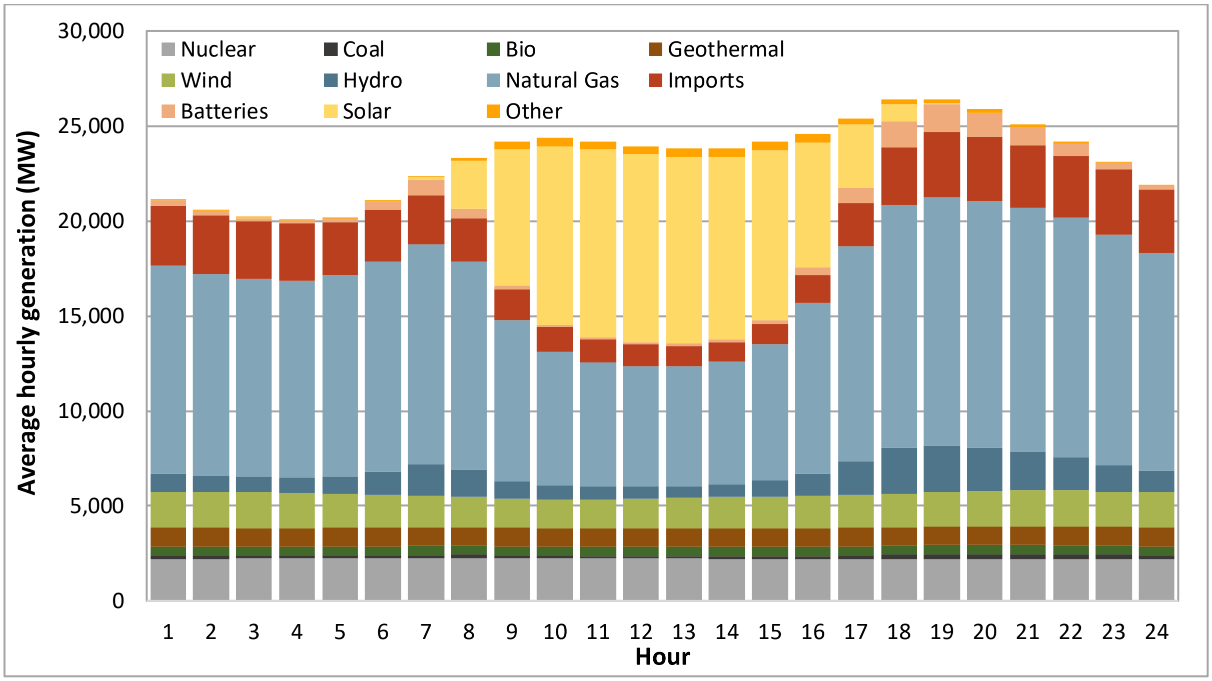


Figure 1.5 shows the change in hourly generation by fuel type between the fourth quarter of 2021 and the fourth quarter of 2022. In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

Overall, the net change shows that there was an increase in average hourly generation in the early morning hours and decrease during the peak net load hours. Generation from imports decreased during all hours and was primarily replaced by natural gas generation. This increase in natural gas generation, coupled with higher natural gas prices, help push overall energy prices higher. The "other" category was higher during the middle of the day alongside solar generation, likely due to an increase in hybrid resources.

Figure 1.6 shows the monthly average hydroelectric generation from 2019 to 2022. Hydroelectric generation in the fourth quarter of 2022 was 3 percent lower than the same time last year.

Figure 1.5 Change in average hourly generation by fuel type (Q4 2021 to Q4 2022)

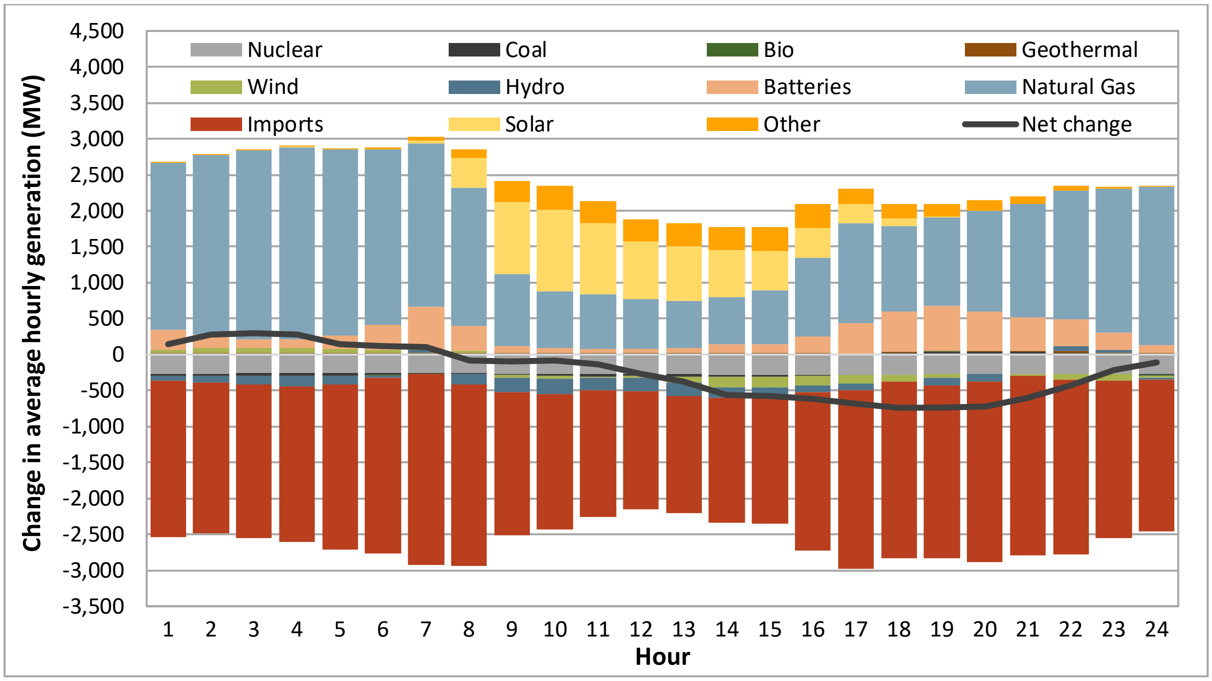
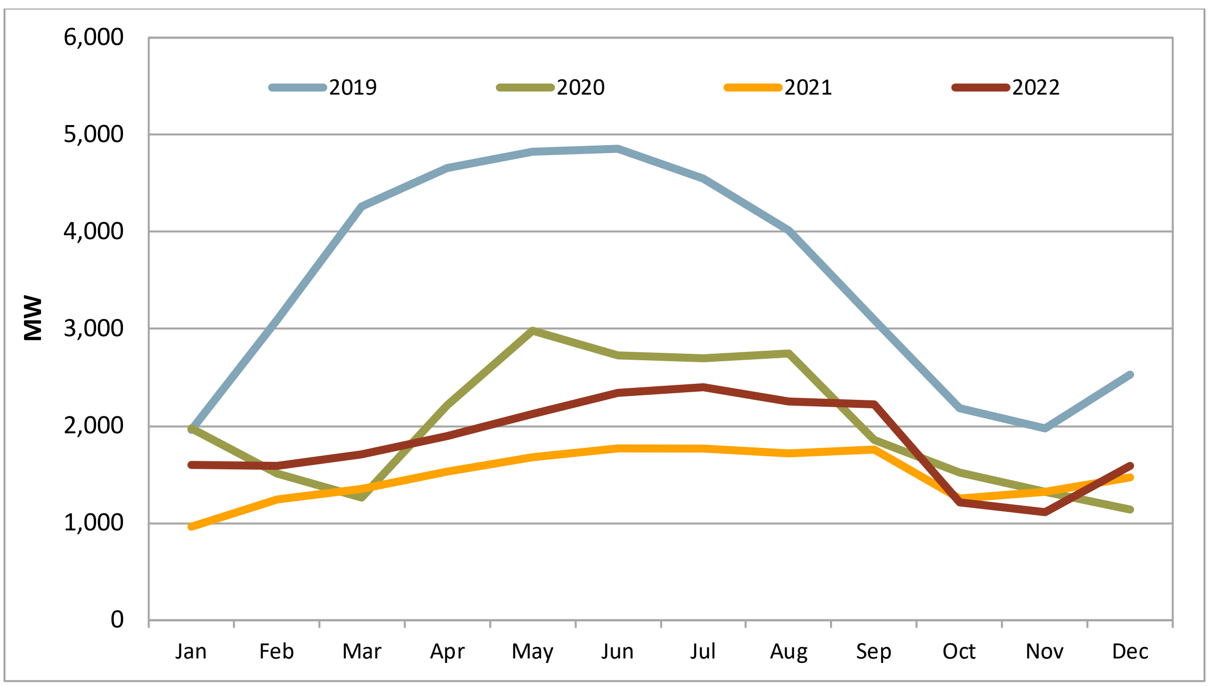


Figure 1.6 Monthly average hydroelectric generation by year



1.1.4 Generation outages

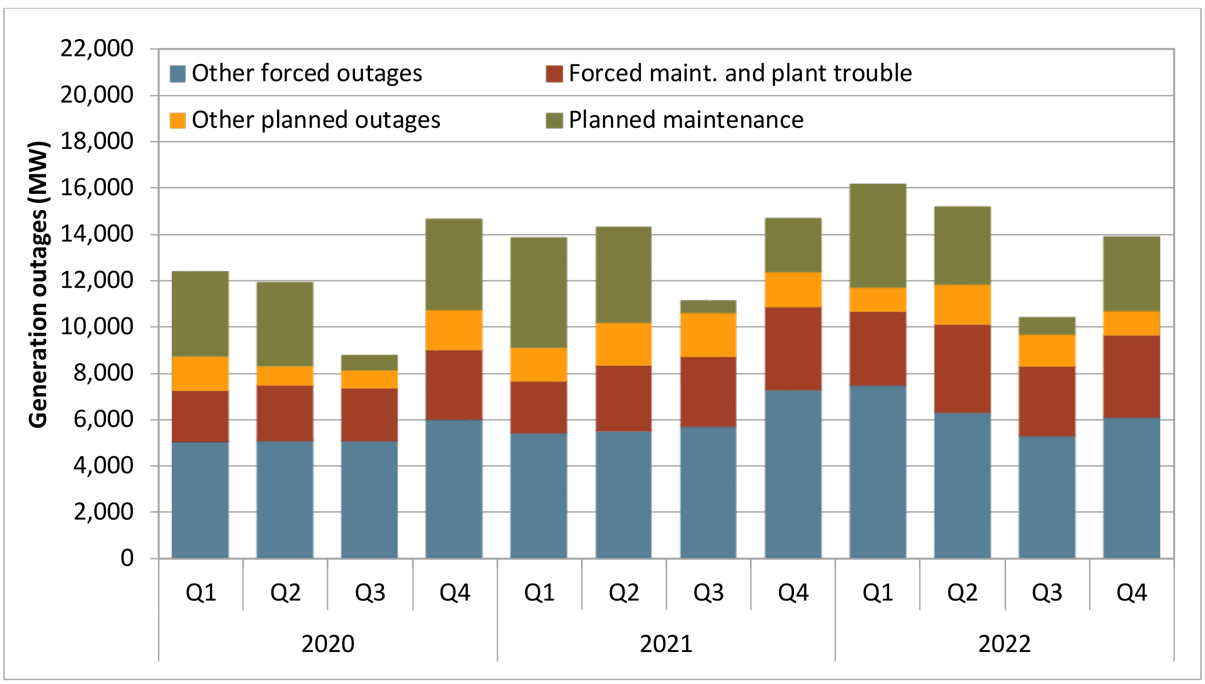
Total generation on outage in the California ISO balancing area averaged about 13,875 MW, 5 percent lower than the fourth quarter of 2021. This decrease was driven by forced outages, which decreased 11 percent relative to the same time last year.

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 2020 to 2022, respectively. 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 with planned maintenance outages decreasing over the second quarter, remaining low during the summer months, and increasing again in November and October.

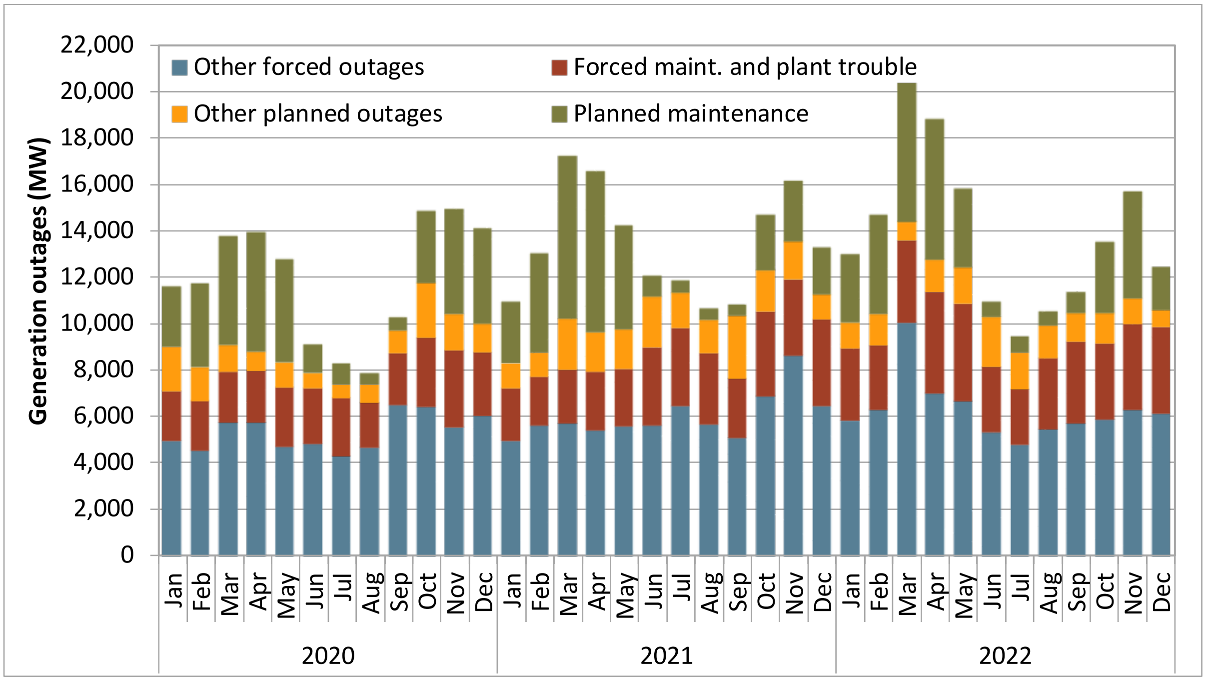
During the fourth quarter of 2022, the average total generation on outage in the California ISO balancing area was 13,875 MW, about 800 MW less than the fourth quarter of 2021, as shown in Figure 1.7.[9] There were 11 percent less forced outages compared to the time last year, which was largely offset by a 10 percent increase in planned outages.

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



[9] 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 1.8 Monthly average of maximum daily generation outages by type – peak hours



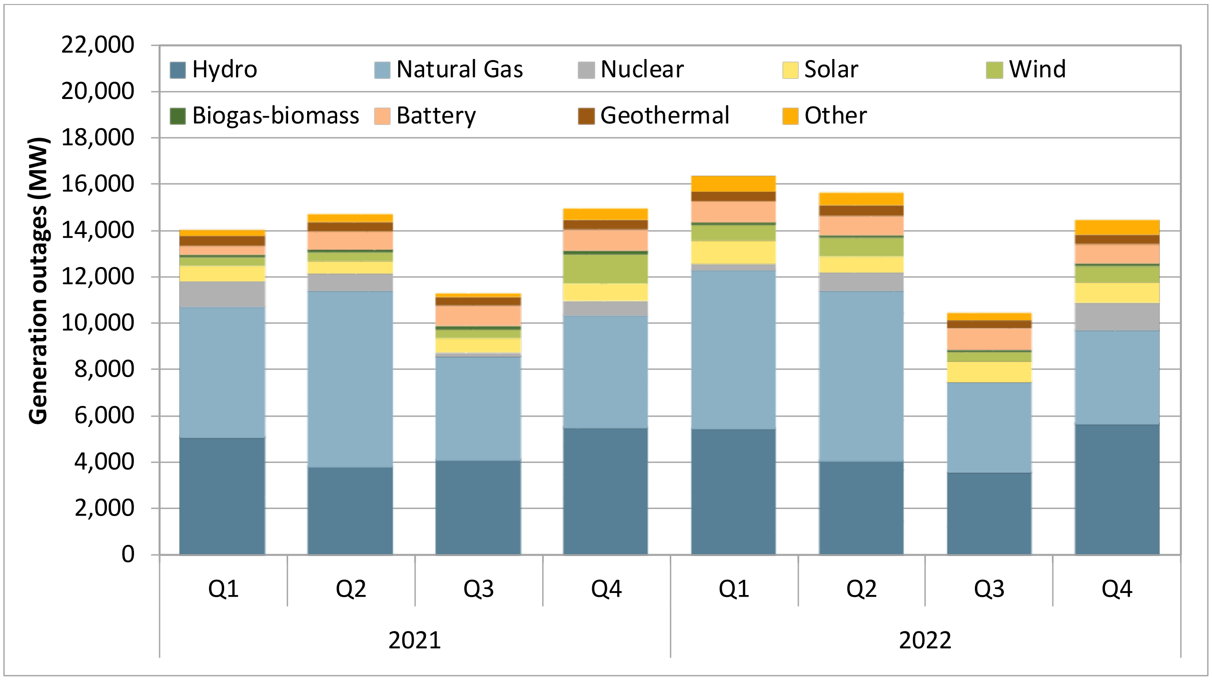
Generation outages by fuel type

Hydroelectric and natural gas generation on outage averaged about 5,650 MW and 4,075 MW during the fourth quarter, respectively. These two fuel types accounted for a combined 67 percent of the generation on outage for the quarter. The amount of hydroelectric generation on outage increased 3 percent relative to the fourth quarter of 2021, while natural gas generation on outage decreased 15 percent.

Figure 1.9 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[10] Most fuel types saw lower average amounts of generation on outage compared to the fourth quarter of 2021.

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

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



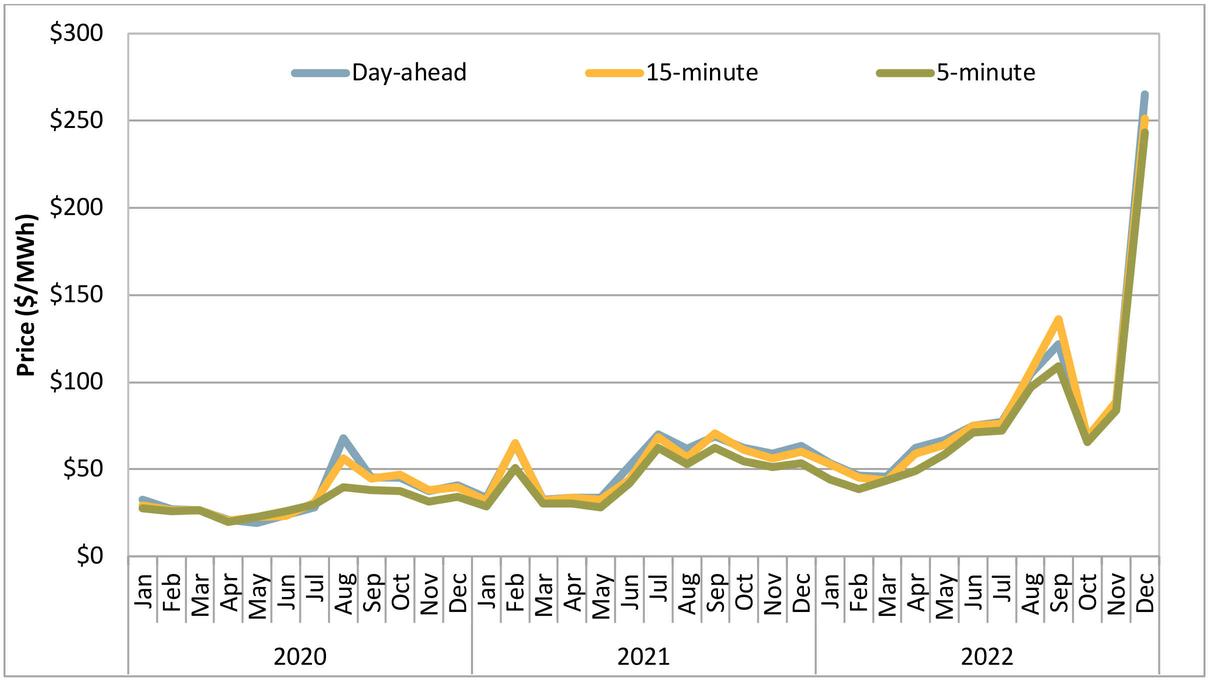
1.2 Energy market performance

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 2.3 times higher this quarter compared to the fourth quarter last year. The average price in December 2022 was about 4.7 times higher compared to that of December 2021.

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 2020 to December 2022.

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



Over the quarter, day-ahead prices averaged $140/MWh, 15-minute prices averaged $136/MWh, and 5-minute prices averaged $130/MWh. Prices across all three markets were about 134 percent higher than the fourth quarter last year. The average prices in all three markets were around $250/MWh in December alone; the highest monthly energy price since locational marginal price was introduced in 2009.

High gas prices drove the high energy prices seen in the fourth quarter. Figure 1.11 shows monthly average gas prices at SoCal Citygate and load weighted energy prices from July 2021 to December 2022. 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.[11] This 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. The average day-ahead price for December 2022 reached $265/MWh; the 15-minute price reached about $251/MWh; and the 5-minute price reached about $243/MWh.

[11] 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

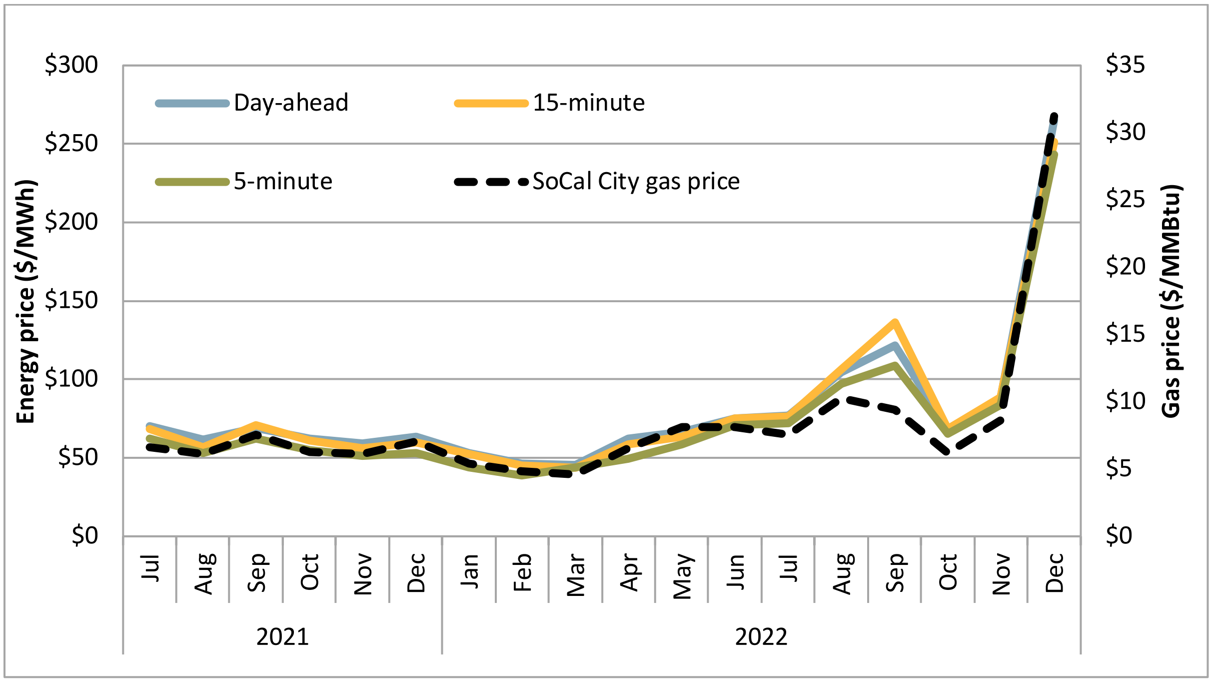
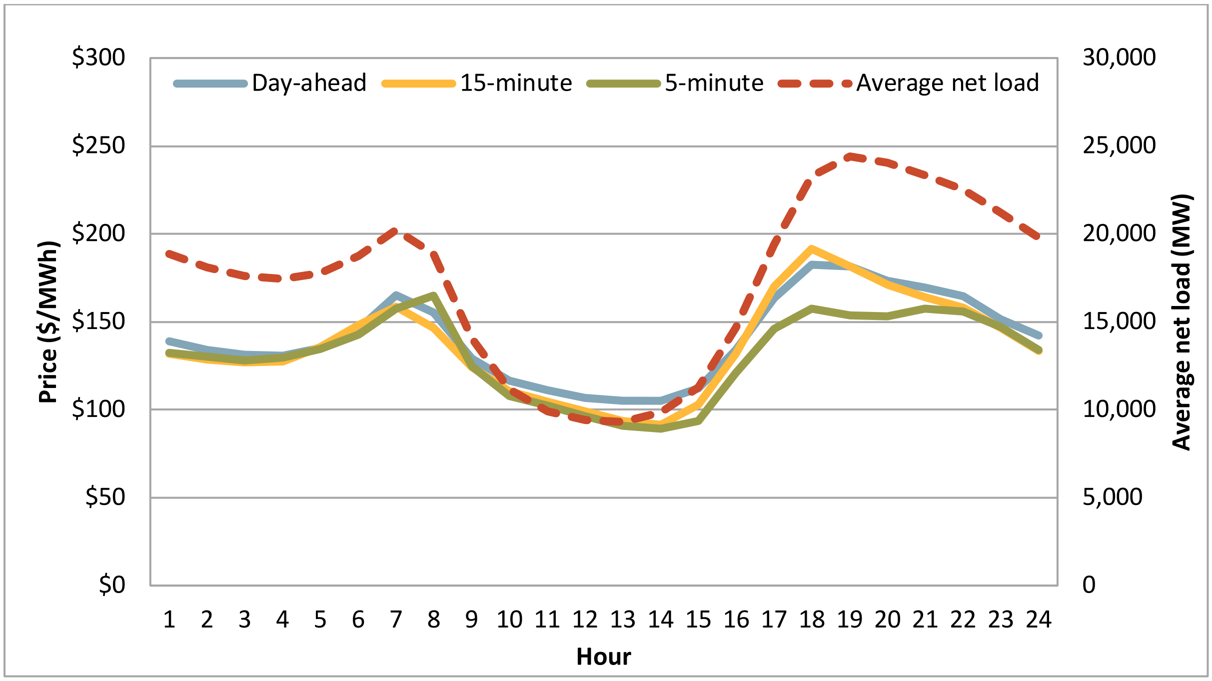


Figure 1.12 illustrates the hourly load-weighted average energy prices for the fourth quarter compared to the average hourly net load.[12] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) and are measured by the left axis, while the average hourly 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 7:00 pm when demand was still high but solar generation was substantially lower. The average net load in this quarter reached 24,405 MW at 7:00 pm. At this hour, the day-ahead load-weighted average energy price was $181/MWh, the 15-minute price was $181 /MWh, and the 5-minute price was $153/MWh.

[12] 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 (October - December)



1.2.2 Bilateral price comparison

Sustained high gas prices in December 2022 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.

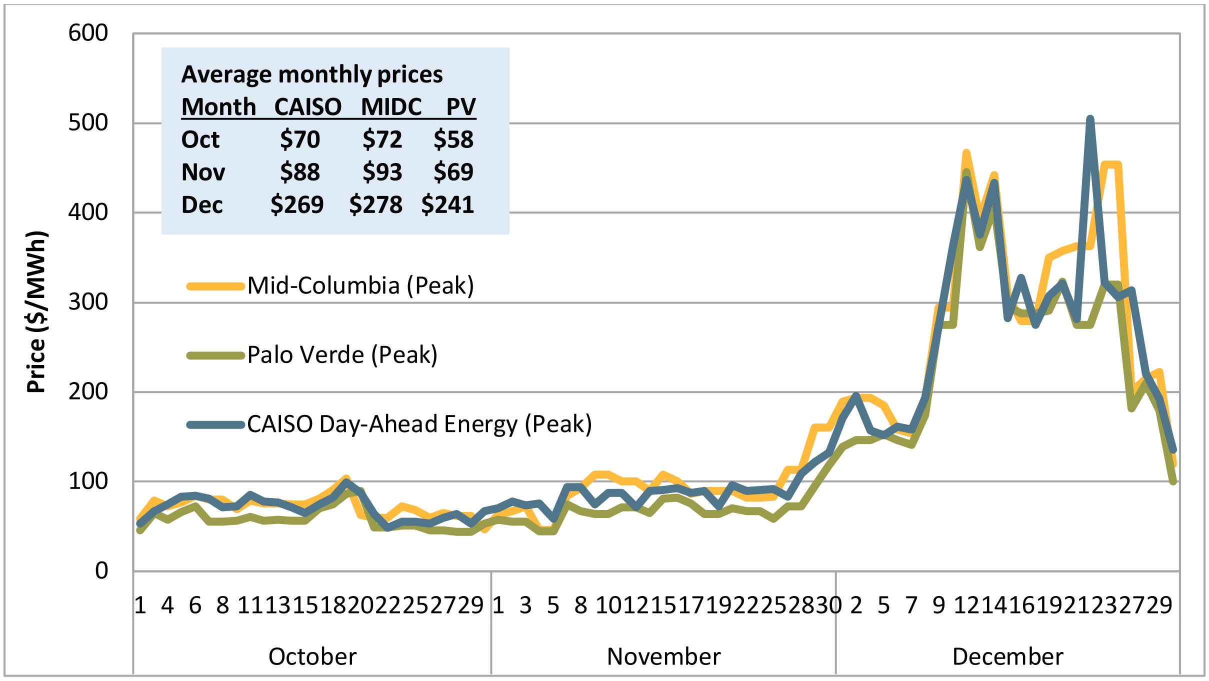
Figure 1.13 shows the CAISO day-ahead weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the 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 a significant increase in prices in the CAISO and at bilateral hubs during December when gas prices across the west were persistently high.

Figure 1.14 uses the same data underlying Figure 1.13 but on an average monthly basis for 2021 and 2022. 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 December at the Palo Verde and Mid-Columbia hubs were trending closer to prices in the California ISO.

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 $5/MWh and $3/MWh, respectively. Average day-ahead prices at Mid-Columbia were greater than average real-time prices (from Powerdex) by $5/MWh. At Palo Verde, average day-ahead prices (from ICE) were lower than average real-time prices (from Powerdex) by $18/MWh.

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.[13] 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.[14] FERC has yet to rule on some of the cost justification filings for June 2021, and has not begun to issue orders related to the August and September 2022 filings.

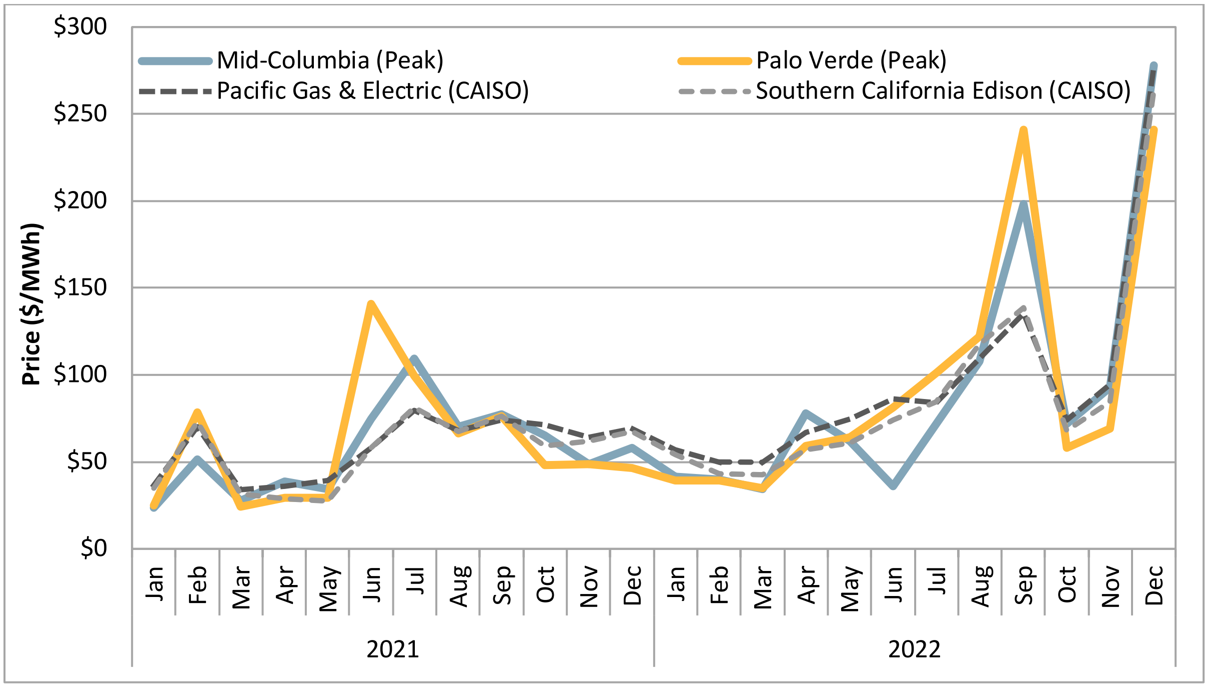
Figure 1.13 Day-ahead California ISO and bilateral market prices (October - December)



[13] 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

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

Figure 1.14 Monthly average day-ahead and bilateral market prices



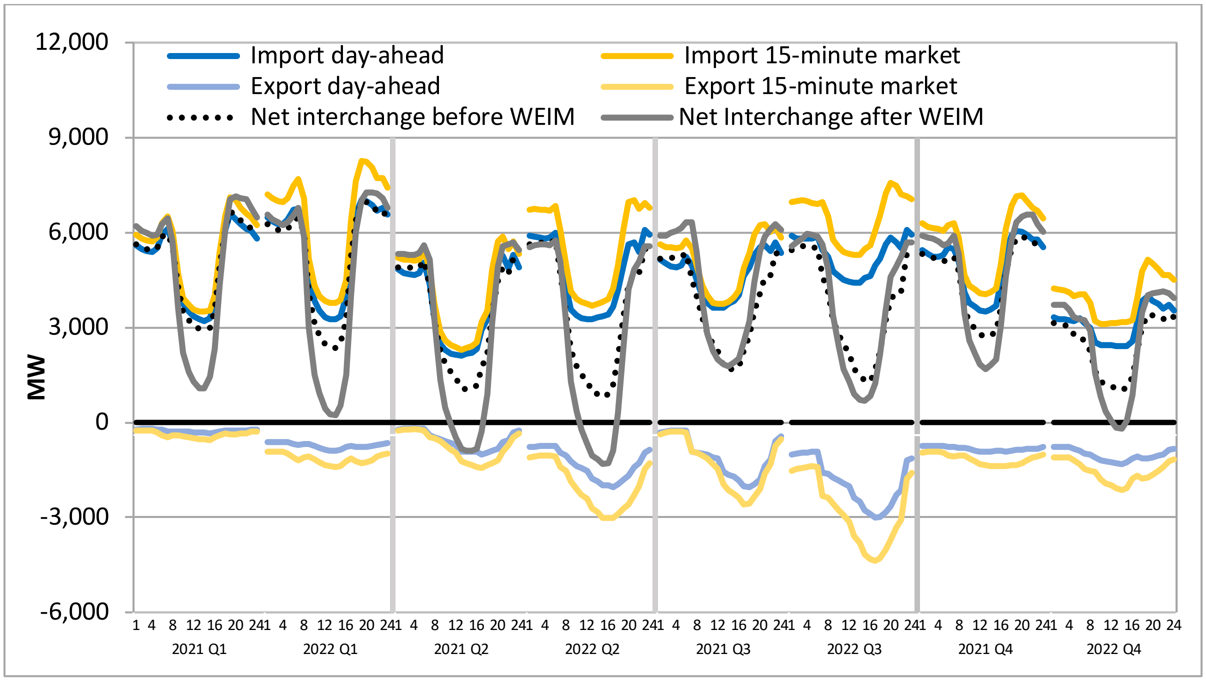
Imports and exports

Average imports decreased while exports increased slightly compared to the same quarter in 2021. As shown in Figure 1.15, peak imports in the day-ahead (dark blue line) decreased in all hours than compared to the same quarter of 2021, peaking at about 4,000 MW in hour-ending 19. Peak 15-minute cleared imports (dark yellow line) also decreased in all hours of the day and about 2,000 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 2021. The increases over the peak hours of 17 to 21 were between 300 MW and 400 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 1,700 MW and 1,900 MW on average by hour. During the solar ramp down period imports decreased both when excluding and including the WEIM, hourly average of 2,500 MW and 2,4000 MW, respectively. These values are based on meter data and averaged by hour and quarter.

The solid grey line, which adds incremental WEIM interchange, reached a low point of about negative 200 MW in hour ending 14. The greatest import transfer into the California ISO area from the WEIM occurred in hour ending 22, at about 900 MW, which is similar to the same quarter in the prior year. Export transfer from the California ISO to the WEIM primarily occurred between hour ending 9 to hour ending 17, with hour ending 13 topping out at about 1,200 MW. This is an increase from the same quarter of the previous year with a maximum export in hour ending 13 at about 1,000 MW.

Figure 1.15 Average hourly net interchange by quarter



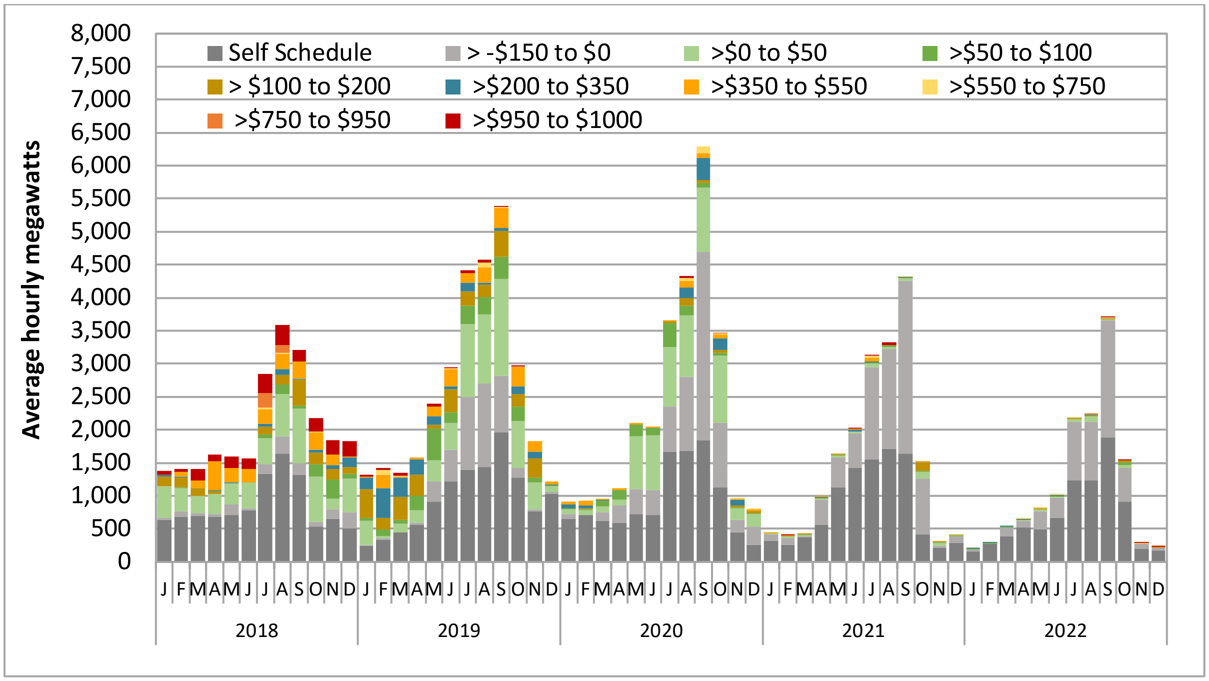
In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the CAISO markets at or below $0/MWh, at minimum in the availability assessment hours.[15] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices. An overall decline in volumes began in late 2020 and continued throughout 2021 as well as into the first half of 2022. 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, the 15-minute, and 5-minute markets compared to the same quarter last year. All three markets experienced a very high frequency of prices between $250/MWh and $500/MWh. No negative prices occurred in the day-ahead market and were rare in the real-time markets.

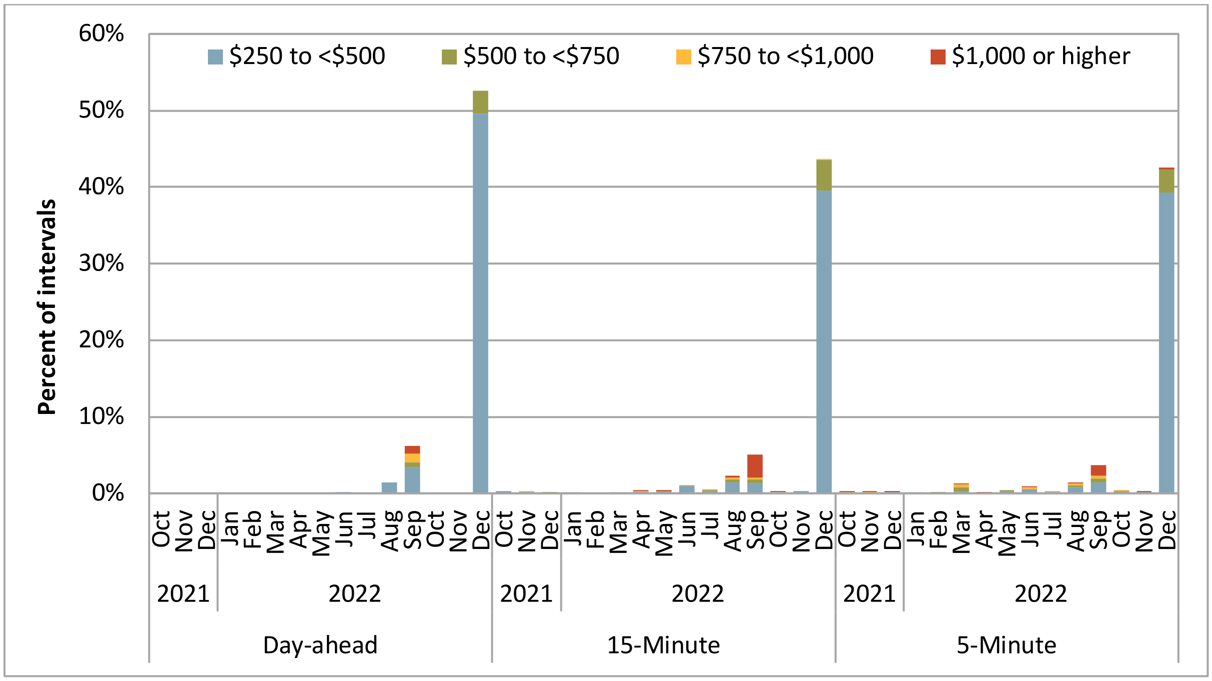
High prices

Figure 1.17 shows the frequency of high prices across all three markets for the three largest load aggregation points (LAP) by month between October 2021 and December 2022. In the day-ahead market, the frequency of high prices over $250/MWh significantly increased in the fourth quarter compared to the previous year. In 2021, no intervals had prices above $250/MWh between October and December. However, in 2022, 17 percent of intervals had prices above $250/MWh during the period. The majority of the high prices occurred during December where 52 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 15 percent from 0.2 percent in the fourth quarter compared to the same period last year. The majority of the high prices occurred during December where 43 percent of intervals had price above $250/MWh.

The 5-minute market also had more frequent price spikes this quarter. Prices above $250/MWh rose to 14 percent in the fourth quarter of 2022 from 1.8 percent in the same quarter last year. The majority of the high prices occurred during December where 42 percent of intervals had price above $250/MWh.

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



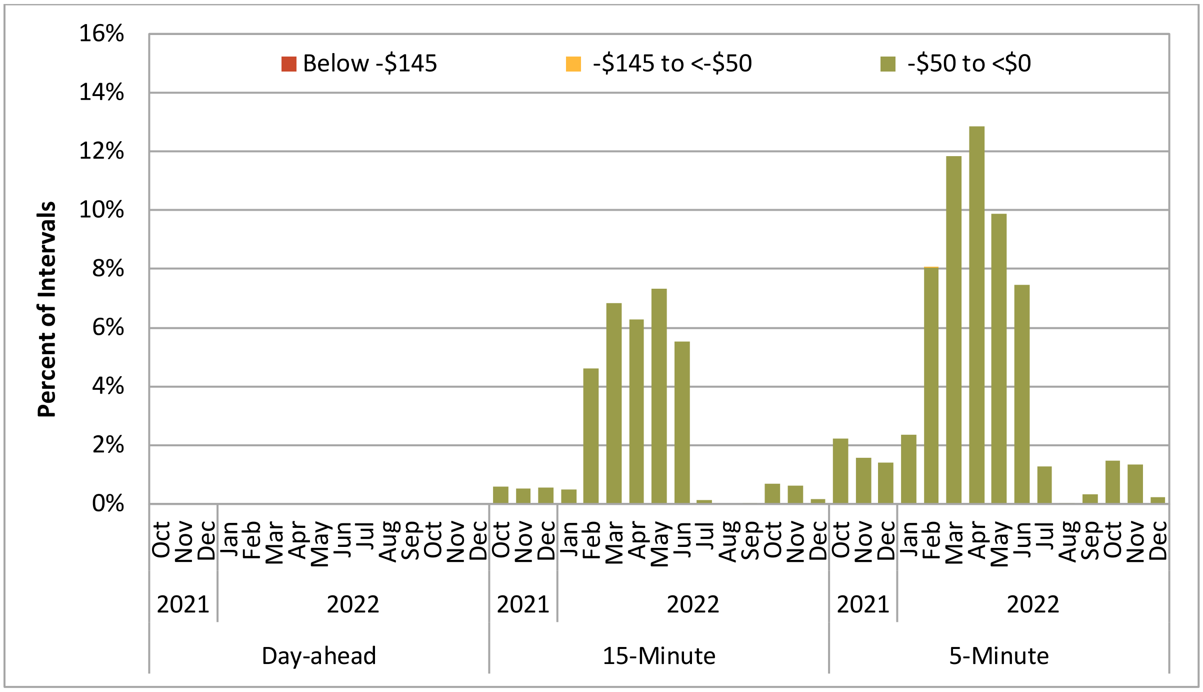
High natural gas prices in SoCal Citygate contributed to the greater frequency of high prices this quarter as illustrated in Figure 1.1. Natural gas-fired units are often the marginal energy source of generation in the CAISO balancing area, as well as other regional markets, and often results in higher 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 October 2021 and December 2022. The frequency of negative price intervals marginally decreased compared to the fourth quarter in 2021. Negative prices tend to be the most common when renewable production is high but 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 0.16 percent this quarter compared to 0.18 percent in the fourth quarter of last year. In the 5-minute markets, negative prices decreased to 0.34 percent this quarter compared to 0.58 percent in the fourth quarter of last year. There were no negative prices in the day-ahead market the fourth quarter of either 2021 or 2022.

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 fourth quarter of 2022. The majority of profits continue to be received by financial entities (69 percent) and marketers (29 percent), with about 2 percent going to entities with physical load and generation.

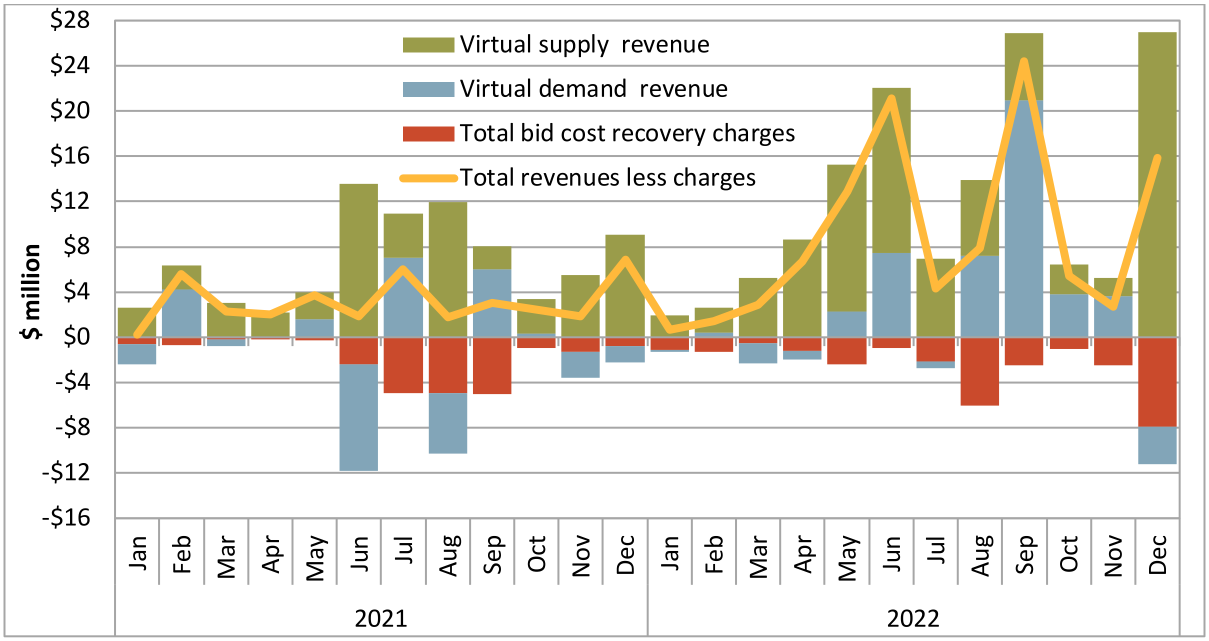
1.4.1 Convergence bidding revenues

Net revenues for convergence bidders were about $24 million for the fourth quarter, after inclusion of about $11.4 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 positive during all months of the quarter.
- Virtual demand revenues were about $3.8 million, $3.7 million, and -$3.3 million for October, November, and December, respectively.
- Virtual supply revenues were $2.7 million, $1.5 million, and $27 million for October, November, and December, respectively.

Convergence bidders received approximately $23.45 million after subtracting bid cost recovery charges during the fourth quarter. Bid cost recovery charges were about $1.0 million, $2.5 million, and $7.9 million in October, November, and December, 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 75 percent of volume and 69 percent of the settlement revenue. Marketers continue to have about 25 percent of volume and 29 percent of settlement revenue while generation owners and load serving entities represent about one percent of volumes and around two percent of settlement revenues.

Prices in the 15-minute market were consistently lower than day-ahead prices in the fourth quarter. This resulted in a decrease of virtual demand revenue to $4.2 million from $27.5 million in the previous quarter and -$3.3 million from the same quarter of the previous year.

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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 day) 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.

Table 1.1 Convergence bidding volumes and revenues by participant type (Q4 2022)

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	
Financial	1,470	1,923	3,393	$1.55	$22.96	-$7.42	$15.55	$17.10
Marketer	458	668	1,126	$2.57	$7.89	-$3.24	$4.65	$7.22
Physical load	0	19	19	$0.00	$0.34	-$0.75	-$0.41	-$0.41
Physical generation	15	0	15	$0.05	$0.00	$0.00	$0.00	$0.05
Total	**1,943**	**2,610**	**4,553**	**$4.18**	**$31.20**	**-$11.41**	**$19.79**	**$23.97**

1.5 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment process in the fourth quarter of 2022 was 63 percent higher than the same quarter of 2021. 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 capacity was primarily 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 31 percent lower in the fourth quarter than in the same quarter of 2021.

The figure also shows that residual unit commitment procurement was driven by operator adjustments in the fourth quarter. These manual adjustments increased significantly to about 576 MW per hour in the fourth quarter, compared to 57 MW per hour in the same quarter in 2021.

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 fourth quarter of 2022, averaging 282 MW per hour.

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

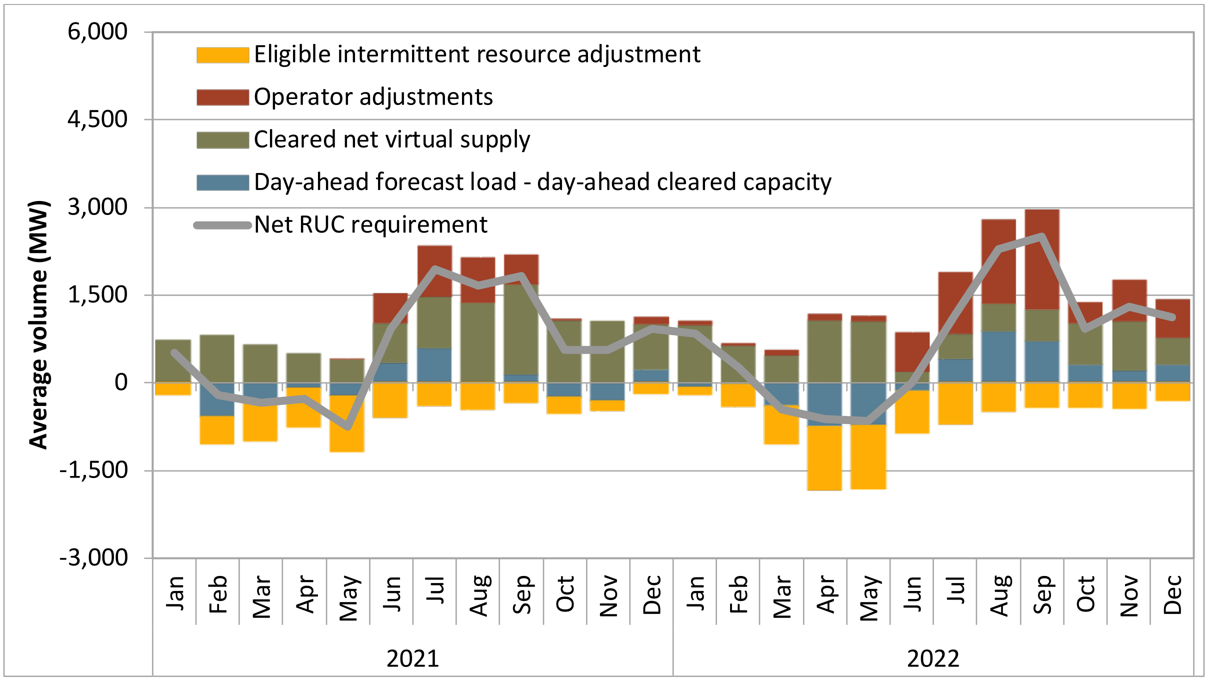
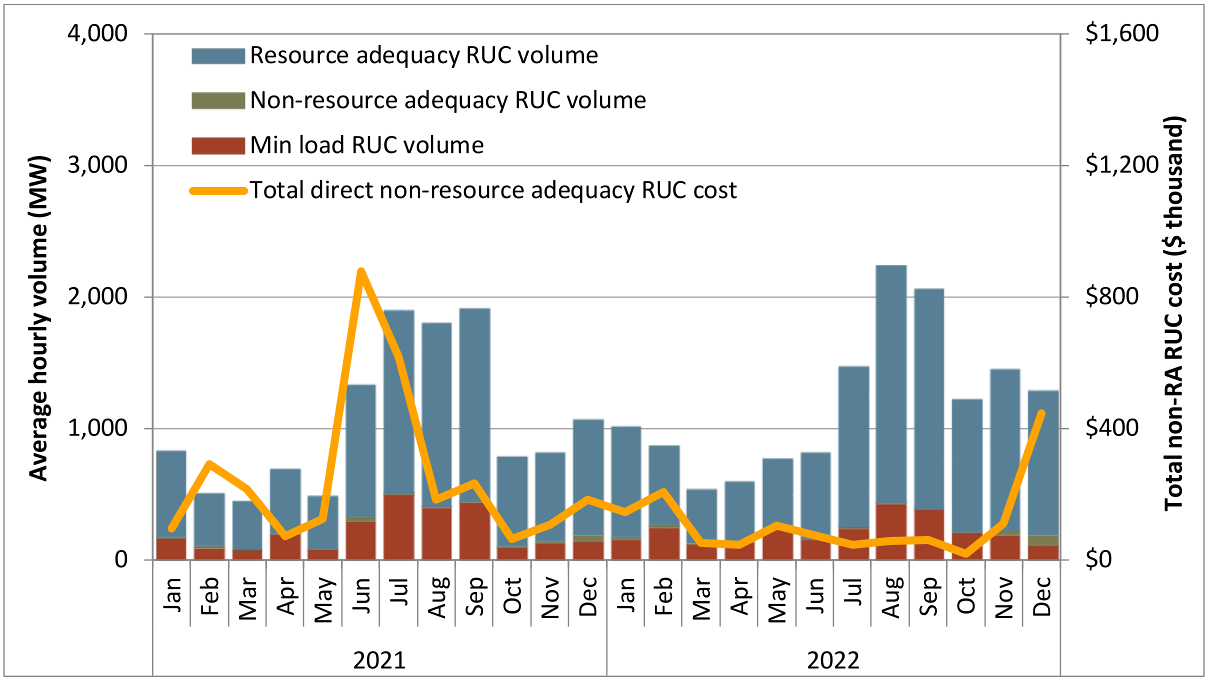


Figure 1.21 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased 47 percent to about 1,322 MW in the fourth quarter of 2022 from an average of 899 MW in the same quarter of 2021. Of the 1,322 MW capacity, the capacity committed to operate at minimum load averaged 173 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.[19] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.21. In the fourth quarter of 2022, these costs were about $0.2 million, almost twice the costs in the same quarter of 2021.

[19] 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 this quarter totaled $35.4 million, a 10 percent increase from the fourth quarter of 2021. Average requirements were lower for operating reserves, higher for regulation down, and nearly the same for regulation up compared to the fourth quarter of 2021.

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.

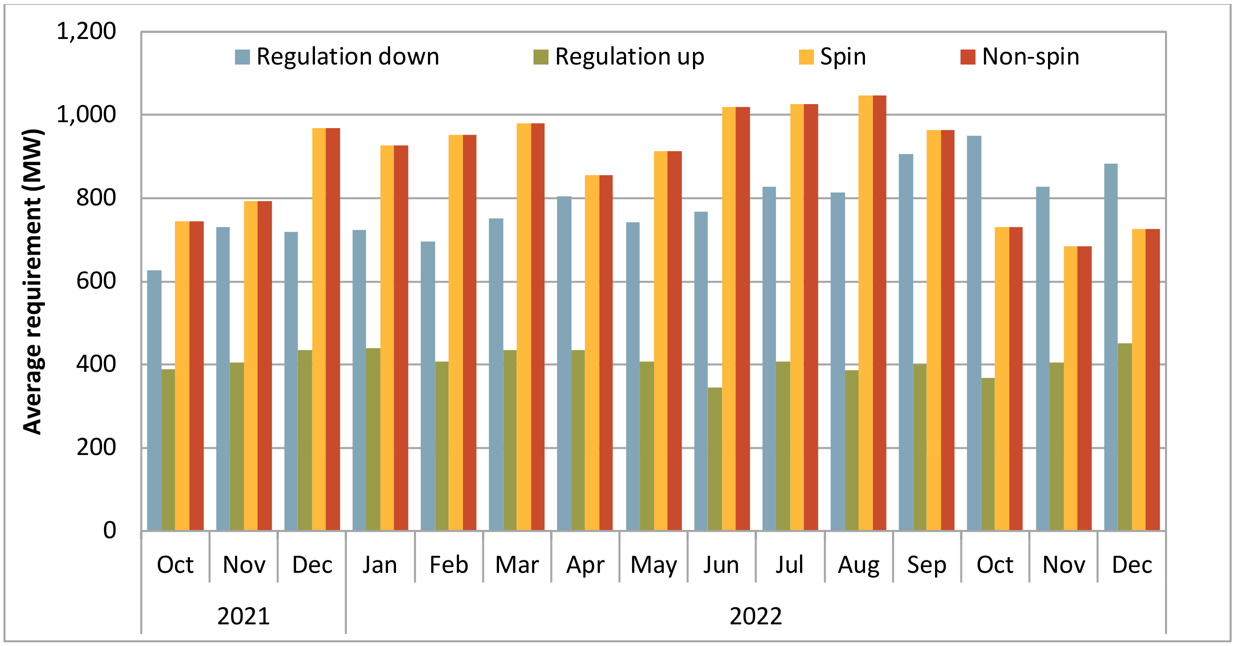
The California ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions.[20] Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency, and (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.

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 14 percent this quarter

[20] 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

compared to the fourth quarter of 2021. However, average regulation down requirements increased by 28 percent in the same period, with increased renewable penetration. Average regulation up requirements remained about the same.

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 fourth quarter of 2022. This was the second consecutive quarter where there were no ancillary service scarcity events.

1.6.3 Ancillary service costs

Ancillary service payments reached $35.4 million, around 10 percent more than the same quarter last year.

Figure 1.23 shows the total cost of procuring ancillary service products by quarter.[21] Regulation down procurement contributed the most to increased costs, with a $6.7 million increase, nearly 43 percent over what was paid in the fourth quarter of 2021. Over this same period, spinning reserve payments decreased 39 percent and non-spinning reserve payments increased 88 percent. Regulation up payments were similar to those in the fourth quarter of 2021.

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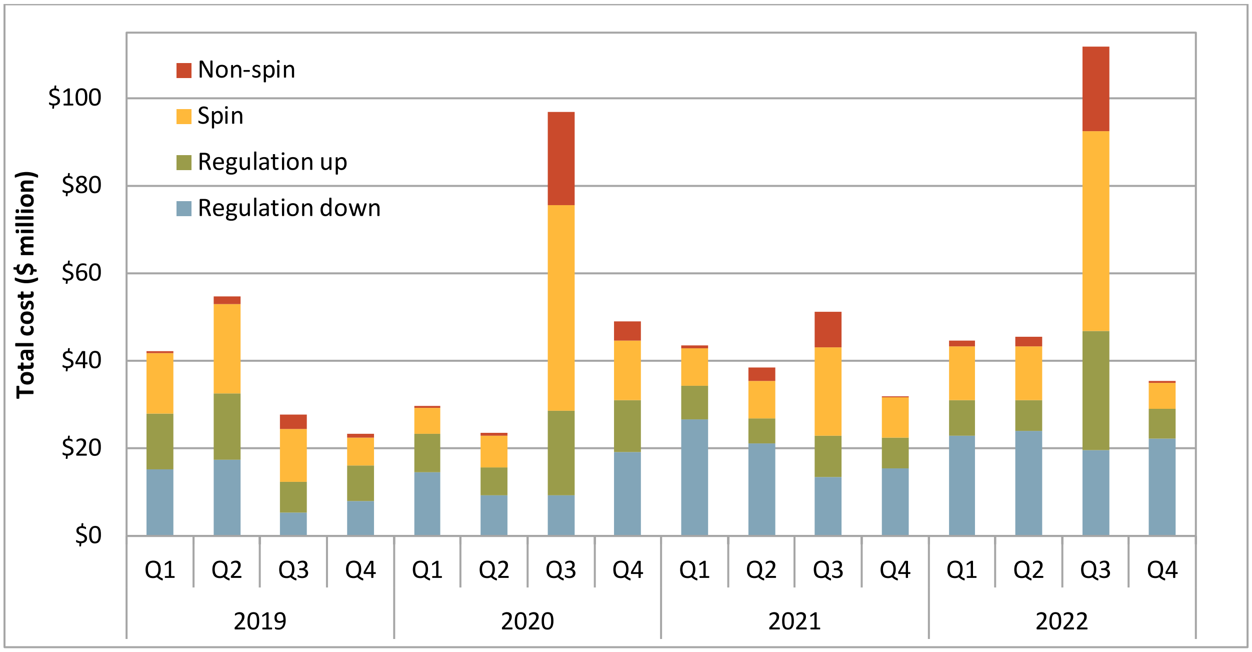
21 The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. As noted elsewhere in the report, settlements values are based on statements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

Figure 1.23 Ancillary service cost by product



1.7 Congestion

In the day-ahead market, congestion in the fourth 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.[22]

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.

[22] This approach does not include price differences that result from transmission losses.

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 fourth quarter of 2022, congestion rent and loss surplus was $374 million and $69 million, respectively. These respective amounts represent an increase of 141 percent and 65 percent relative to the same quarter of 2021.[23] Figure 1.24 shows the congestion rent and loss surplus by quarter for 2021 and 2022.

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 surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[24]

Figure 1.24 Day-ahead congestion rent and loss surplus by quarter (2021-2022)

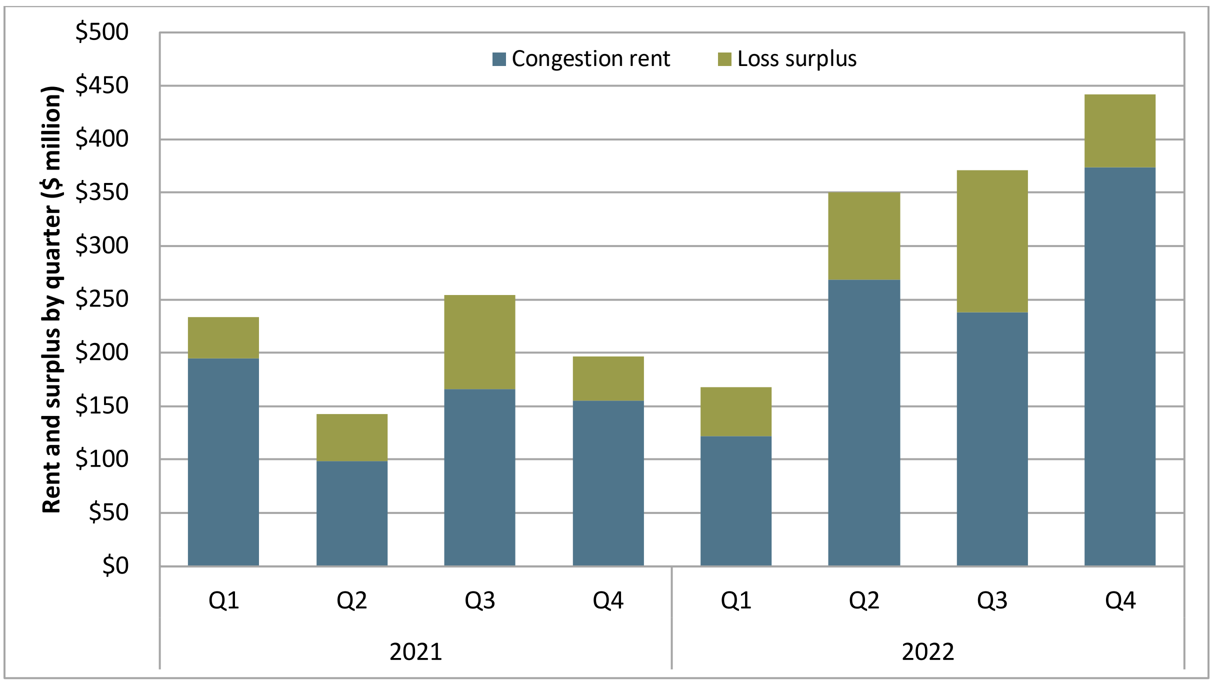


Figure 1.25 shows the overall impact of congestion on day-ahead prices in each load area in 2021 and 2022. Figure 1.26 shows the frequency of congestion. Highlights for this quarter include:

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23 Due to the availability of data, comparative analysis in Figure 1.28 and the day-ahead congestion rent and loss surplus in the third quarter of 2022 are preliminary.

24 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

- The overall impact of day-ahead congestion on price separation in the fourth quarter was higher than during same quarter last year. The impact during the fourth quarter of 2022 was stronger in PG&E and SCE compared to the fourth quarter of 2021.
- Day-ahead congestion increased quarterly average prices in PG&E by $2.57/MWh (1.8 percent), while it decreased average SCE and SDG&E prices by $1.51/MWh (1.1 percent) and $1.23/MWh (0.9 percent), respectively.
- The primary constraints impacting day-ahead market prices were the Panoche-Gates #2 230 kV line, Los Banos-Gates 500 kV line, and the Gates-Midway 230 kV line.

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

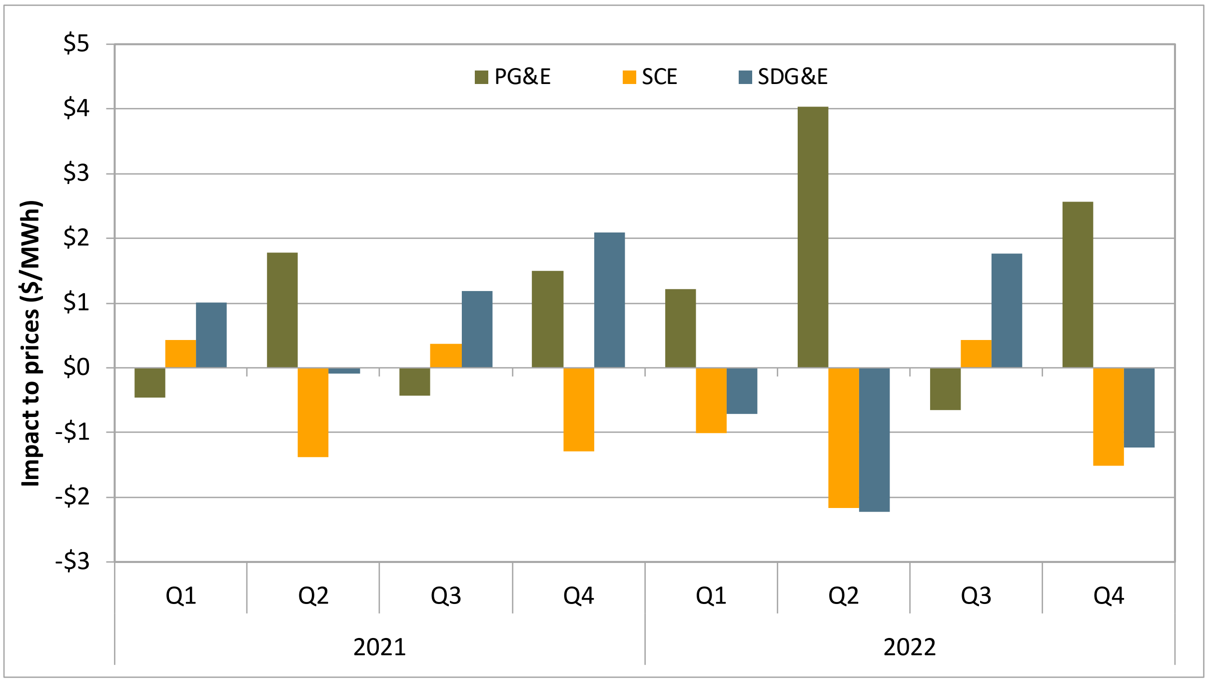
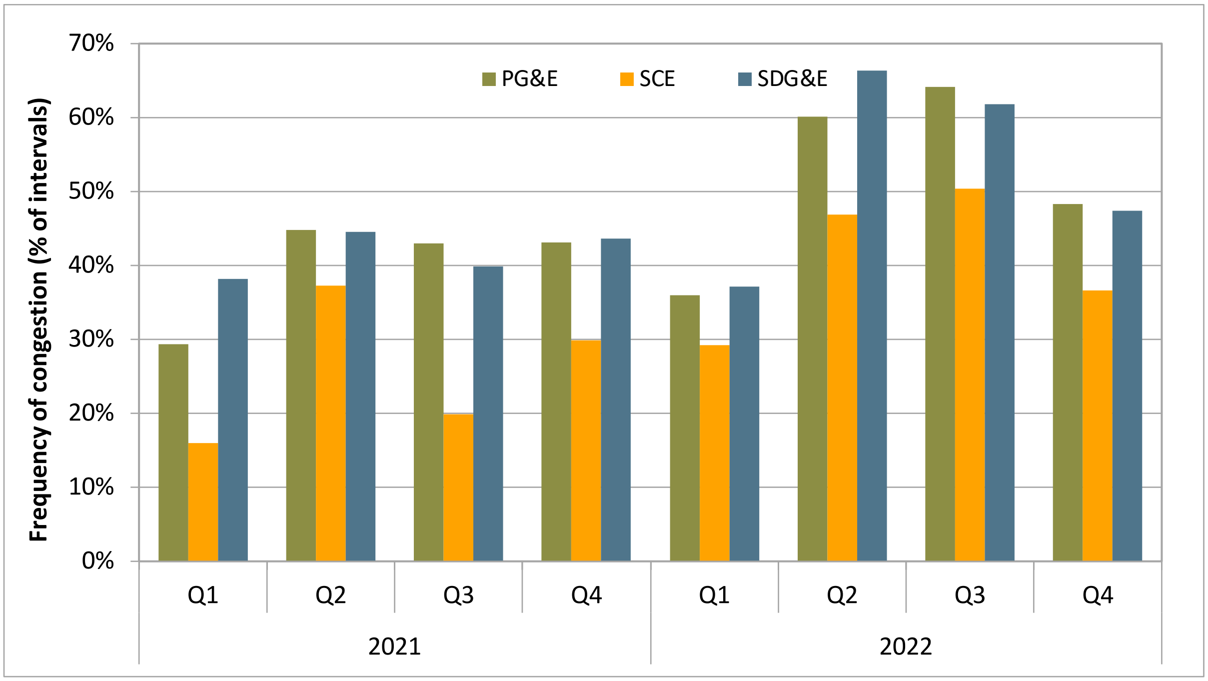


Figure 1.26 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation during the quarter by constraint.[25] 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, Los Banos-Gates 500 kV line, and the Gates-Midway 230 kV line.

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 fourth quarter. The line was congested during 14 percent of hours. When binding, it increased PG&E prices by $6.89/MWh, and decreased SCE and SDG&E prices by $4.59/MWh and $4.20/MWh, respectively. For the quarter, congestion on the line increased average PG&E prices by $0.98/MWh (0.7 percent), and decreased average SCE and SDG&E prices by $0.47/MWh (0.4 percent) and $0.41/MWh (0.3 percent). This line was frequently binding due to the contingency of the Los Banos-Gates #1 500 kV line.

Los Banos-Gates #1 500 kV line

The Los Banos-Gates 500 kV line (30050_LOSBANOS_500_30055_GATES1_500_BR_1_2) bound in 4 percent of hours over the quarter. When binding, it increased prices in PG&E by $9.32/MWh and decreased prices in SCE and SDG&E by $7.39/MWh and $6.70/MWh, respectively. For the quarter, congestion on the constraint increased average PG&E prices by $0.37/MWh (0.3 percent) and decreased average SCE and SDG&E prices by $0.30/MWh (0.2 percent) and $0.27/MWh (0.2 percent), respectively. This line was frequently mitigated for the contingency of the Los Banos-Midway #2 500 kV line.

[25] Details on constraints with shift factors less than 2 percent have been grouped in the "other" category.

Gates-Midway 230 kV line

The Gates-Midway 230 kV line (30900_GATES_230_30970_MIDWAY_230_BR_1_1) bound in about 6 percent of hours. When binding, it increased PG&E prices by $5.23/MWh and decreased SCE and SDG&E prices by $3.98/MWh and $3.74/MWh, respectively. For the quarter, the nomogram increased average PG&E prices by about $0.30/MWh (0.2 percent), and decreased average SCE and SDG&E prices by $0.23/MWh (0.2 percent) and $0.21/MWh (0.2 percent), respectively. This line was impacted by maintenance on the Gates-Midway 500 kV line.

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	$0.98	0.67%	-$0.47	-0.34%	-$0.41	-0.30%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.37	0.26%	-$0.30	-0.22%	-$0.27	-0.19%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.30	0.21%	-$0.23	-0.17%	-$0.21	-0.15%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.27	0.19%	-$0.20	-0.15%	-$0.18	-0.13%
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.22	0.15%	-$0.18	-0.13%	-$0.17	-0.12%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.20	0.13%	-$0.03	-0.02%	-$0.02	-0.01%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.19	0.13%	-$0.15	-0.11%	-$0.14	-0.10%
	7440_MetcalfImport_Tes-Metcalf	$0.04	0.03%	-$0.04	-0.03%	-$0.04	-0.03%
SCE	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.10	-0.07%
SDG&E	MIGUEL_BKs_MXFLW_NG	-$0.03	-0.02%	$0.00	0.00%	$0.23	0.17%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.10	0.08%
	OMS_12018815 ML_BK80_NG	-$0.02	-0.01%	$0.00	0.00%	$0.10	0.07%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-$0.01	-0.01%	$0.00	0.00%	$0.07	0.05%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.07	0.05%
	OMS_12018818 ML_BK80_NG	-$0.01	-0.01%	$0.00	0.00%	$0.07	0.05%
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.05	0.04%
	7820_TL 230S_OVERLOAD_NG	-$0.01	0.00%	$0.00	0.00%	$0.05	0.03%
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.02%
	OMS_12155335_TL13820_23004_NG	$0.00	0.00%	$0.00	0.00%	-$0.04	-0.03%
	7820_CP6_OMS_12313313_MS-SA	$0.00	0.00%	$0.01	0.01%	-$0.06	-0.04%
	7820_13810A_RAS_TL23004_NG	$0.00	0.00%	$0.00	0.00%	-$0.08	-0.06%
	7820_13810A_RAS_MS-SA_NG	$0.00	0.00%	$0.01	0.01%	-$0.33	-0.24%
Other		$0.09	0.06%	$0.05	0.04%	$0.03	0.02%
Total		**$2.57**	**1.77%**	**-$1.51**	**-1.10%**	**-$1.23**	**-0.89%**

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

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	14.2%	$6.89	-$4.59	-$4.20
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	8.8%	$2.22	-$2.48	-$2.72
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	8.6%	$3.15	-$2.34	-$2.08
	30055_GATES1 _500_30900_GATES _230_XF_12_P	8.1%	$2.65	-$2.14	-$2.04
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	5.7%	$5.23	-$3.98	-$3.74
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	4.0%	$9.32	-$7.39	-$6.70
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	3.1%	$5.96	-$4.81	-$4.43
	7440_MetcalfImport_Tes-Metcalf	0.6%	$6.94	-$6.01	-$5.75
SCE	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.3%	$0.00	$0.00	-$2.19
SDG&E	OMS_12018815 ML_BK80_NG	0.5%	-$3.56	$0.00	$19.24
	MIGUEL_BKs_MXFLW_NG	1.3%	-$2.51	$0.00	$17.82
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.5%	-$2.27	$0.00	$14.93
	OMS_12018818 ML_BK80_NG	0.5%	-$2.26	$0.00	$13.02
	7820_TL23040_IV_SPS_NG	1.0%	-$0.41	$0.00	$6.80
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	0.5%	$0.00	$0.00	$6.38
	7820_TL 230S_OVERLOAD_NG	1.2%	-$0.42	$0.00	$3.84
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	4.3%	$0.00	$0.00	$2.41
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	4.3%	$0.00	$0.00	$1.12
	7820_13810A_RAS_TL23004_NG	1.7%	$0.00	$0.00	-$4.93
	OMS_12155335_TL13820_23004_NG	0.5%	$0.00	$0.00	-$7.70
	7820_CP6_OMS_12313313_MS-SA	0.5%	$0.00	$2.11	-$10.86
	7820_13810A_RAS_MS-SA_NG	2.9%	$0.00	$2.46	-$11.55

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 very similar as congestion in the Four Corners area drove price separation in both markets.

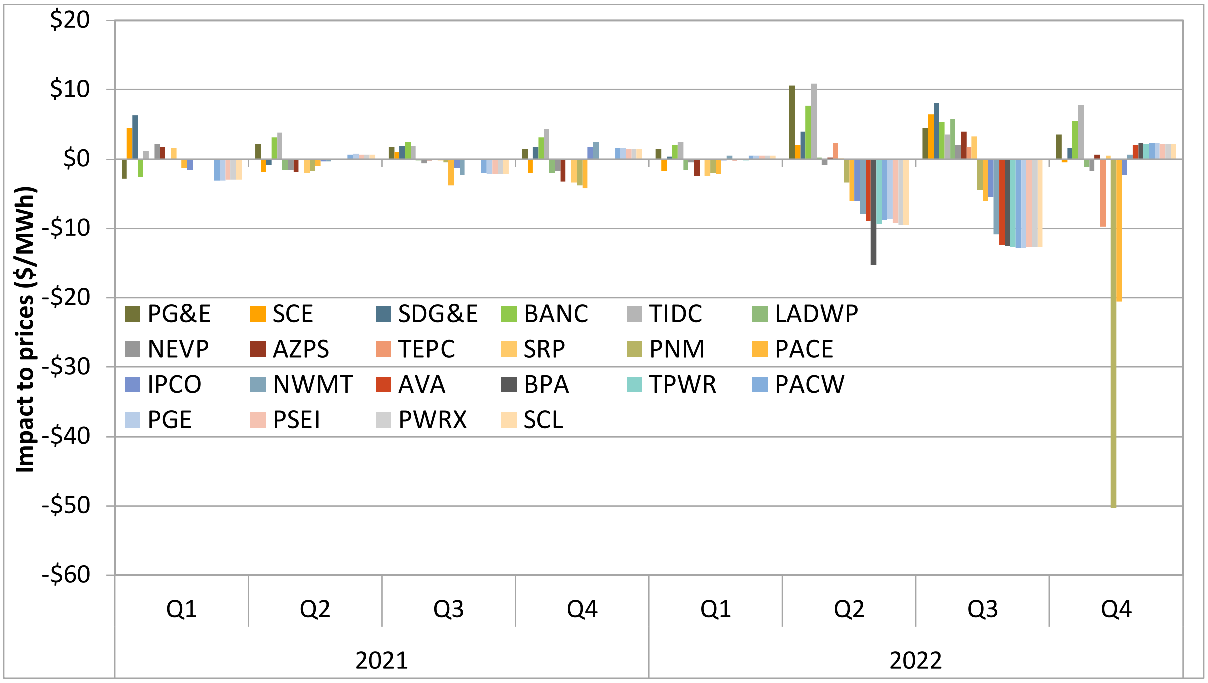
Impact of internal congestion to overall 15-minute prices in each load area

Figure 1.27 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2021 and 2022. Table 1.5 shows the frequency of this congestion. Highlights for this quarter include:

- The net impact of internal flow-based constraint congestion has significant impacts across the WEIM. Unlike previous quarters, congestion raised prices in the Pacific Northwest and lowered prices in the Southwest.
- The impact of internal congestion increased significantly in PNM and PACE compared to the fourth quarter of last year.
- The primary constraints creating price separation in the 15-minute market were the Four Corners-Cholla #2 345 kV line, the Four Corners-Cholla #1 345 kV line, and the Four Corners-Moenkopi 500 kV line.

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 fourth quarter, the constraints that had the greatest impact on price separation in the 15-minute market were the Four Corners-Cholla #2 345 kV line, the Four Corners-Cholla #1 345 kV line, and the Four Corners-Moenkopi 500 kV line.[26] These constraints were impacted by line maintenance in the area. This represents the first time internal constraints outside of the CAISO have had the largest impact on average prices over a quarter.

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.

[26] These constraints are shown as Line_FC-CH2_345KV, Line FC-CH1_345KV, and Line_FC-MK_500KV 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-CH2_345KV		$2.07	$2.83			$1.62	$0.37	$4.32	-$0.08	$4.35	-$20.89	-$4.83	-$1.33	-$0.40								
	Line_FC-CH1_345KV		$1.51	$1.87			$1.26	$0.23	$2.82	-$0.32	$2.75	-$13.70	-$3.12	-$0.87	-$0.36								
	Line_CH-MZZ_345KV		$0.01	$0.01			$0.01		$0.01	-$0.02	$0.01	-$0.06	-$0.01										
	Line_FC-MK_500KV	$0.45	$1.18	$0.71	$0.06	$0.34	$1.28	$1.33		-$2.95	$0.00	-$10.07	-$1.75	-$0.53	-$0.24								
IPCO	T501_xA	$0.00		$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PACE	PATH_C	-$0.01	$0.01	$0.01	-$0.01	-$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.05	-$0.04	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	SHERIDAN_YELLOWTA_230								$0.00	$0.00	$0.00	-$0.01	-$0.01		$0.02	$0.01	$0.00	$0.00			$0.00	$0.01	$0.00
	EAST_WYO_EXP												-$0.18										
	WINDSTAR EXPORT TCOR												-$1.31										
	TOTAL_WYOMING_EXPORT												-$8.37	$0.00									
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.59	-$1.01	-$0.96	$0.72	$0.75	-$0.98	-$0.51	-$0.85	-$0.83	-$0.85	-$0.74	-$0.11	$0.22	$0.40	$0.48	$0.51	$0.51	$0.53	$0.53	$0.51	$0.50	$0.51
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.46	-$1.11	-$1.05	$0.78	$0.81	-$1.07	-$0.55	-$0.93	-$0.90	-$0.93	-$0.79	-$0.15	$0.22	$0.48	$0.58	$0.63	$0.62	$0.66	$0.65	$0.62	$0.61	$0.62
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.32	-$0.39	-$0.37	$0.37	$0.38	-$0.37	-$0.14	-$0.31	-$0.28	-$0.30	-$0.24	-$0.02	$0.04	$0.15	$0.17	$0.19	$0.19	$0.21	$0.20	$0.19	$0.19	$0.19
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.24	-$0.14	-$0.14	$0.14	$0.16	-$0.14	-$0.08	-$0.12	-$0.12	-$0.12	-$0.11	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.02	$0.02	$0.02
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.18	-$0.99	-$0.94	$0.85	$1.03	-$0.96	-$0.05	-$0.83	-$0.80	-$0.83	-$0.37	-$0.01		$0.01	$0.03	$0.07	$0.07	$0.08	$0.08	$0.07	$0.06	$0.07
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.18	-$0.68	-$0.65	$0.98	$1.83	-$0.67	-$0.34	-$0.57	-$0.55	-$0.57	-$0.48	-$0.01	$0.14	$0.36	$0.42	$0.44	$0.44	$0.46	$0.46	$0.44	$0.44	$0.44
	6310_CP7_NG	$0.12	-$0.30	-$0.27	$0.23	$0.30	-$0.28	-$0.10	-$0.15	-$0.15	-$0.15	-$0.14	-$0.05	-$0.01	$0.08	$0.10	$0.11	$0.11	$0.12	$0.12	$0.11	$0.11	$0.11
	SUMMIT_BG	$0.11			$0.13	$0.01		-$0.33					-$0.01	-$0.02									
	ML_RM12_NS	$0.09	$0.06	$0.05	$0.09	$0.09	$0.05	$0.02	$0.04	$0.03	$0.04	$0.02	-$0.04	-$0.08	-$0.10	-$0.11	-$0.10	-$0.11	-$0.12	-$0.12	-$0.11	-$0.11	-$0.11
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	$0.01	-$0.06	-$0.06	$0.01	$0.01	-$0.05	-$0.03	-$0.05	-$0.05	-$0.05	-$0.05	-$0.02	-$0.02	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.01	$0.00		$0.02	$0.01								-$0.01	-$0.02	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	RM_TM12_NG	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$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	-$0.01
	7440_MetcalfImport_Tes-Metcalf	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.01	$0.00	$0.00	$0.00	$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	-$0.01
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.01	-$0.01	-$0.01	$0.00	$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.00	-$0.01	-$0.01	$0.01	$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00
	30790_PANOCHE _230_30900_GATES _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
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.01	$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	$0.00	-$0.07	-$0.07	$0.10	$0.18	-$0.07	$0.00	-$0.06	-$0.06	-$0.06	-$0.05			$0.00	$0.01	$0.04	$0.03	$0.04	$0.04	$0.03	$0.03	$0.03
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-$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	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1		-$0.12	-$0.11		$0.04	-$0.11		-$0.06	-$0.05	-$0.06	-$0.04											
	30805_BORDEN _230_30810_GREGG _230_BR_1 _1		$0.00	$0.00	$0.06	$0.03	$0.00																
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1		-$0.01	$0.00	$0.17	$0.08	$0.00																
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1				$0.01			-$0.07															
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1				$0.03			-$0.60															
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1							-$0.08															
SCE	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _4	$0.06	$0.07	-$0.03	$0.05	$0.06	$0.12	$0.12	-$0.33	-$0.34	-$0.32	-$0.50	-$0.06										
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.05	$0.05	$0.02	$0.04	$0.05	-$0.16	-$0.08	-$0.08	-$0.08	-$0.08	-$0.08	-$0.04	$0.00	$0.01	$0.02	$0.02	$0.02	$0.03	$0.02	$0.02	$0.02	$0.02
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1		$0.02	$0.02				-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01										
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	$0.01	$0.01	-$0.01	$0.01	$0.01	$0.01	$0.01	-$0.03	-$0.03	-$0.03	-$0.04	-$0.01										
	24219_PISGAH _230_24085_LUGO _230_BR_1 _1		$0.00				$0.00	-$0.08	-$0.06	-$0.07	-$0.06	-$0.07	$0.00										
	PATH26_BG	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$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	-$0.01			$0.00	$0.00	-$0.01	-$0.04	-$0.03	-$0.04	-$0.03											
	24384_EAST TS _500_24092_MIRALOMA_500_BR_1 _1	$0.06	-$0.04	-$0.11	$0.06	$0.06	-$0.04	-$0.08	-$0.12	-$0.12	-$0.12	-$0.11	-$0.04	$0.00	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
	6410_CP7_NG	$0.48	-$0.71	-$0.67	$0.45	$0.47	-$0.69	-$0.36	-$0.60	-$0.59	-$0.60	-$0.52	-$0.10	$0.13	$0.23	$0.28	$0.31	$0.31	$0.32	$0.32	$0.30	$0.30	$0.30
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	$0.00			$0.00	$0.00	$0.00	-$0.01	-$0.02	-$0.01	-$0.02	-$0.01	$0.00										
SDG&E	MIGUEL_BKs_MXFLW_NG			$0.56				-$0.01	-$0.17	-$0.17	-$0.18	-$0.14											
	OMS_12018815 ML_BK80_NG		$0.01	$0.50				-$0.08	-$0.18	-$0.17	-$0.18	-$0.14	-$0.06										
	7820_TL 230S_OVERLOAD_NG	$0.01	$0.04	$0.47	$0.00	$0.01	$0.00	-$0.04	-$0.10	-$0.11	-$0.11	-$0.09	-$0.03	$0.00									
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.03	$0.24				-$0.03	-$0.09	-$0.09	-$0.09	-$0.07	-$0.01										
	OMS 12618319_IV_NBUS_NG		$0.00	$0.17				$0.00	-$0.05	-$0.05	-$0.05	-$0.04											
	OMS 12455416_TL23055_NG		$0.02	$0.17				-$0.02	-$0.05	-$0.05	-$0.06	-$0.04	-$0.02										
	OMS_12685980_TL23055_NG		$0.01	$0.15					-$0.05	-$0.05	-$0.05	-$0.04											
	OMS 12212473 TL50005_NG		$0.01	$0.14				-$0.01	-$0.03	-$0.03	-$0.03	-$0.02	-$0.01	-$0.01									
	OMS_12018818 ML_BK80_NG		$0.00	$0.07				$0.00	-$0.03	-$0.03	-$0.03	-$0.02	$0.00										
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1		$0.03	$0.06					-$0.07	-$0.07	-$0.07	-$0.05											
	7820_13810A_RAS_TL6916_NG			-$0.01					-$0.02	-$0.02	-$0.02	-$0.01											
	OMS_12593475_TL6916_NG			-$0.01					-$0.02	-$0.02	-$0.02	-$0.01											
	7820_13810A_OVERLOAD_NG			-$0.02					-$0.01	-$0.01	-$0.01	-$0.01											
	7820_CP6_OMS_12313252_MS-SA		$0.00	-$0.03					-$0.02	-$0.02	-$0.02	-$0.01											
	7820_CP6_OMS_12226836_MS-SA		$0.00	-$0.05					-$0.03	-$0.02	-$0.03	-$0.01											
	7820_13810A_RAS_TL23004_NG			-$0.06					-$0.02	-$0.02	-$0.02	-$0.02											
	7820_CP6_OMS_12313277_MS-SA			-$0.08					-$0.04	-$0.04	-$0.04	-$0.02											
	7820_CP6_OMS_12313313_MS-SA			-$0.10					-$0.04	-$0.03	-$0.05	-$0.02											
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	$0.01	$0.02	-$0.12	$0.01	$0.01	$0.01	$0.00	-$0.03	-$0.02	-$0.03	-$0.02											
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.01	$0.02	-$0.15	$0.01	$0.01	$0.01		-$0.02	-$0.02	-$0.03	-$0.02	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_13810A_RAS_MS-SA_NG		$0.00	-$0.41					-$0.20	-$0.18	-$0.20	-$0.08											
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	$0.00				$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01											
TIDC	TID_NET_INT_BG					$0.99																	
	Other	$0.04	$0.01	$0.02	$0.08	-$0.01	$0.03	-$0.02	$0.03	-$0.06	-$0.11	-$0.36	-$0.11	-$0.03	$0.00	$0.01	$0.01	$0.01	$0.01	-$0.02	$0.01	$0.01	$0.01
	Internal Total	**$3.55**	**-$0.48**	**$1.57**	**$5.50**	**$7.78**	**-$1.21**	**-$1.68**	**$0.69**	**-$9.69**	**$0.47**	**-$50.36**	**-$20.48**	**-$2.22**	**$0.61**	**$2.01**	**$2.29**	**$2.22**	**$2.37**	**$2.31**	**$2.22**	**$2.17**	**$2.21**
	Transfers				-$0.09	$3.12	-$0.06	-$0.11	-$0.32	-$0.75	-$33.31	$0.65	$0.07	$1.57	$2.25	$1.54	$3.11	$1.57	$0.11	$1.05	$1.89	-$10.75	$1.82
	Grand Total	**$3.55**	**-$0.48**	**$1.57**	**$5.41**	**$10.90**	**-$1.27**	**-$1.79**	**$0.37**	**-$10.44**	**-$32.84**	**-$49.71**	**-$20.41**	**-$0.65**	**$2.86**	**$3.55**	**$5.40**	**$3.79**	**$2.48**	**$3.36**	**$4.11**	**-$8.58**	**$4.03**

Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals [27]

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
AZPS	Line_FC-CH2_345KV	11.9%		$25.10	$27.43			$23.72	$24.84	$36.30	-$13.25	$36.55	-$175.70	-$40.61	-$22.79	-$26.19								
	Line_FC-CH1_345KV	8.5%		$20.92	$25.00			$19.02	$16.43	$33.16	-$26.81	$32.33	-$161.14	-$36.72	-$18.19	-$13.95								
	Line_FC-MK_500KV	7.1%	$9.30	$16.59	$13.02	$5.03	$8.78	$17.95	$18.65		-$41.34	-$2.80	-$140.98	-$24.50	-$12.17	-$11.03								
PACE	PATH_C	0.6%	-$1.57	$1.19	$1.70	-$1.63	-$1.79	$1.54	$1.39	$2.59	$2.78	$2.61	$3.45	$9.03	-$6.94	-$3.95	-$3.79	-$2.76	-$3.59	-$3.42	-$3.47	-$3.59	-$3.63	-$3.61
	EAST_WYO_EXP	8.6%												-$2.12										
	WINDSTAR EXPORT TCOR	50.6%												-$2.58										
	TOTAL_WYOMING_EXPORT	74.1%												-$11.30	$0.12									
PG&E	ML_RM12_NS	0.5%	$16.86	$10.47	$9.22	$17.77	$17.38	$9.69	$3.03	$7.03	$6.53	$7.00	$4.58	-$7.14	-$14.63	-$19.17	-$20.57	-$18.22	-$21.21	-$21.74	-$21.64	-$21.20	-$21.07	-$21.17
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	3.6%	$16.33	-$27.91	-$26.53	$19.98	$20.83	-$27.20	-$14.28	-$23.65	-$22.98	-$23.66	-$20.56	-$3.57	$6.67	$11.01	$13.28	$14.25	$14.13	$14.84	$14.68	$14.11	$13.89	$14.08
	SUMMIT_BG	1.1%	$10.78			$12.01	$13.65		-$29.58					-$13.63	-$14.89									
	6310_CP7_NG	1.2%	$10.01	-$24.63	-$22.73	$19.12	$25.32	-$23.44	-$8.36	-$12.89	-$12.52	-$12.90	-$11.39	-$4.71	-$1.13	$6.33	$8.19	$9.20	$9.07	$9.71	$9.62	$9.06	$8.86	$9.03
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	4.7%	$9.83	-$23.44	-$22.16	$16.70	$17.18	-$22.80	-$11.75	-$19.70	-$19.09	-$19.72	-$16.88	-$3.48	$6.62	$10.18	$12.39	$13.42	$13.27	$14.02	$13.86	$13.26	$13.04	$13.22
	30055_GATES1 _500_30900_GATES _230_XF_12_P	3.4%	$7.27	-$4.28	-$4.08	$4.19	$4.79	-$4.16	-$2.50	-$3.71	-$3.60	-$3.71	-$3.26	-$0.90	$0.50	$1.32	$1.63	$1.77	$1.73	$1.82	$1.81	$1.72	$1.69	$1.72
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	6.3%	$7.01	-$15.76	-$14.95	$13.51	$16.46	-$15.40	-$8.86	-$13.33	-$12.82	-$13.32	-$9.66	-$11.60		$11.96	$7.19	$6.05	$6.26	$6.23	$6.18	$6.28	$6.39	$6.27
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	4.7%	$6.79	-$8.26	-$7.77	$7.79	$8.14	-$7.93	-$4.92	-$7.22	-$7.12	-$7.22	-$6.54	-$3.94	$3.11	$5.18	$6.06	$6.41	$6.36	$6.61	$6.64	$6.35	$6.28	$6.33
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	5.4%	$3.85	-$12.62	-$11.90	$18.03	$33.71	-$12.27	-$6.31	-$10.49	-$10.10	-$10.48	-$8.81	-$6.56	$3.42	$6.67	$7.71	$8.19	$8.13	$8.48	$8.40	$8.11	$8.03	$8.10
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.9%	$2.01	-$8.22	-$7.82	$10.95	$20.90	-$7.92	-$3.01	-$7.04	-$6.82	-$7.04	-$6.53			$2.68	$4.86	$6.10	$6.04	$6.46	$6.33	$6.08	$6.02	$6.04
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	1.6%	$0.89	-$3.62	-$3.50	$0.80	$0.90	-$3.43	-$2.00	-$3.44	-$3.34	-$3.47	-$3.17	-$2.99	-$1.36	-$0.27	$0.21	$0.42	$0.39	$0.50	$0.49	$0.38	$0.33	$0.38
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	2.8%				$10.01			-$21.66															
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1	2.3%		-$2.68	-$1.53	$7.37	$3.82	-$1.26																
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.3%		-$8.68	-$8.56		$30.11	-$8.65		-$12.72	-$13.02	-$12.72	-$13.27											
	30805_BORDEN _230_30810_GREGG _230_BR_1 _1	0.8%		-$3.47	-$2.91	$6.99	$3.34	-$2.96																
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	0.7%							-$12.27															
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	0.3%				$6.42			-$19.92															
SCE	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _4	0.8%	$8.85	$10.94	-$6.95	$8.18	$8.58	$14.34	$15.28	-$40.47	-$41.62	-$39.24	-$61.87	-$10.96										
	24219_PISGAH _230_24085_LUGO _230_BR_1 _1	0.5%		$3.75				-$3.93	-$14.73	-$11.76	-$12.01	-$11.55	-$12.03	-$4.65										
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.5%	$3.17	$3.63	$1.78	$2.93	$3.10	-$11.10	-$5.45	-$5.65	-$5.58	-$5.61	-$5.48	-$2.59	-$1.59	$0.74	$1.35	$1.58	$1.56	$1.73	$1.69	$1.55	$1.50	$1.55
	6410_CP7_NG	1.5%	$32.44	-$47.75	-$45.26	$30.57	$31.93	-$46.77	-$24.57	-$40.34	-$39.46	-$40.35	-$35.35	-$7.31	$8.45	$15.20	$19.12	$20.78	$20.59	$21.74	$21.45	$20.56	$20.16	$20.51
SDG&E	OMS_12018815 ML_BK80_NG	0.5%		$2.24	$91.36				-$14.39	-$32.46	-$31.36	-$32.96	-$26.59	-$14.11										
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.3%		$9.60	$72.89				-$9.09	-$27.79	-$26.86	-$28.73	-$21.41	-$8.13										
	MIGUEL_BKs_MXFLW_NG	1.1%			$51.38				-$4.03	-$15.46	-$15.17	-$15.95	-$12.66											
	OMS 12618319_IV_NBUS_NG	0.4%		$0.42	$45.93				-$4.95	-$13.31	-$12.78	-$13.78	-$10.13											
	OMS 12212473 TL50005_NG	0.3%		$3.61	$41.38				-$3.30	-$9.03	-$8.57	-$9.21	-$7.23	-$3.80	-$2.63									
	OMS_12018818 ML_BK80_NG	0.4%		$1.00	$19.98				-$1.08	-$7.69	-$7.31	-$7.82	-$6.07	-$0.93										
	7820_TL 230S_OVERLOAD_NG	2.9%	$0.89	$1.52	$16.18	$0.60	$0.85	$0.92	-$1.54	-$3.59	-$3.62	-$3.91	-$3.08	-$1.20	-$0.61									
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	0.8%		$6.68	$7.48					-$9.47	-$8.52	-$9.45	-$6.82											
	OMS_12593475_TL6916_NG	0.5%			-$2.89					-$3.44	-$3.42	-$3.53	-$2.76											
	7820_13810A_RAS_TL6916_NG	0.4%			-$3.70					-$4.59	-$4.54	-$4.70	-$3.69											
	7820_13810A_OVERLOAD_NG	0.3%			-$4.85					-$3.53	-$3.25	-$3.53	-$2.18											
	7820_CP6_OMS_12226836_MS-SA	0.5%		$3.07	-$9.84					-$5.11	-$4.87	-$5.22	-$2.54											
	7820_13810A_RAS_TL23004_NG	0.6%			-$10.79					-$4.17	-$3.93	-$4.18	-$3.30											
	7820_CP6_OMS_12313313_MS-SA	0.5%			-$18.48					-$7.34	-$5.10	-$8.97	-$3.56											
	7820_13810A_RAS_MS-SA_NG	2.2%		$1.14	-$18.60					-$8.87	-$8.24	-$9.18	-$3.67											
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	0.5%	$2.01	$3.59	-$22.52	$1.91	$1.96	$2.04	-$1.69	-$4.89	-$4.63	-$4.97	-$3.68											
	7820_CP6_OMS_12313277_MS-SA	0.3%			-$24.63					-$12.78	-$12.18	-$12.92	-$5.03											
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	0.4%	$2.10	$3.84	-$35.52	$1.96	$2.08	$2.18		-$5.72	-$5.66	-$5.95	-$4.39	-$0.17			$0.09	$0.27	$0.26	$0.26	$0.27	$0.27	$0.05	$0.27
TIDC	TID_NET_INT_BG	3.0%					$33.00																	

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 Salt River Project and Powerex 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 1.6. Transfer constraint congestion typically has the largest impact on prices; therefore, it is isolated here to better show its effects on the WEIM load areas. Table 1.6 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter.

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

Table 1.6 Quarterly average price impact and congestion frequency on WEIM transfer constraints (Q4 2022)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	0%	-$0.09	0%	-$0.08
L.A. Dept. of Water and Power	0%	-$0.06	0%	$0.12
NV Energy	1%	-$0.11	1%	$0.28
Arizona Public Service	1%	-$0.32	2%	$0.49
PacifiCorp East	1%	$0.07	2%	$0.03
Public Service Company of NM	1%	$0.65	2%	$1.07
Tucson Electric Power	3%	-$0.75	4%	-$0.75
Turlock Irrigation District	7%	$3.12	5%	$2.30
Idaho Power	9%	$1.57	7%	$0.44
Avista	10%	$1.54	7%	$0.94
NorthWestern Energy	10%	$2.25	7%	$2.93
PacifiCorp West	17%	$0.11	9%	-$0.75
Portland General Electric	18%	$1.05	10%	-$0.51
Bonneville Power Admin.	25%	$3.11	21%	$1.86
Salt River Project	27%	-$33.31	26%	-$32.42
Tacoma Power	29%	$1.57	28%	$0.98
Puget Sound Energy	30%	$1.89	29%	$1.53
Seattle City Light	30%	$1.82	29%	$1.08
Powerex	51%	-$10.75	72%	-$10.88

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. Figure 1.28 and Figure 1.29 shows the average impact to prices and the frequency of congestion on transfer constraints in the 15-minute market by quarter for 2021 and 2022, respectively.

There was an overall decrease in the frequency and an increase in impact of transfer constraint congestion in the fourth quarter of 2022 compared to the same quarter in 2021. The average frequency of transfer constraint congestion in the Pacific Northwest was 29 percent, down from 36 percent during the same time last year.[28]

[28] 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

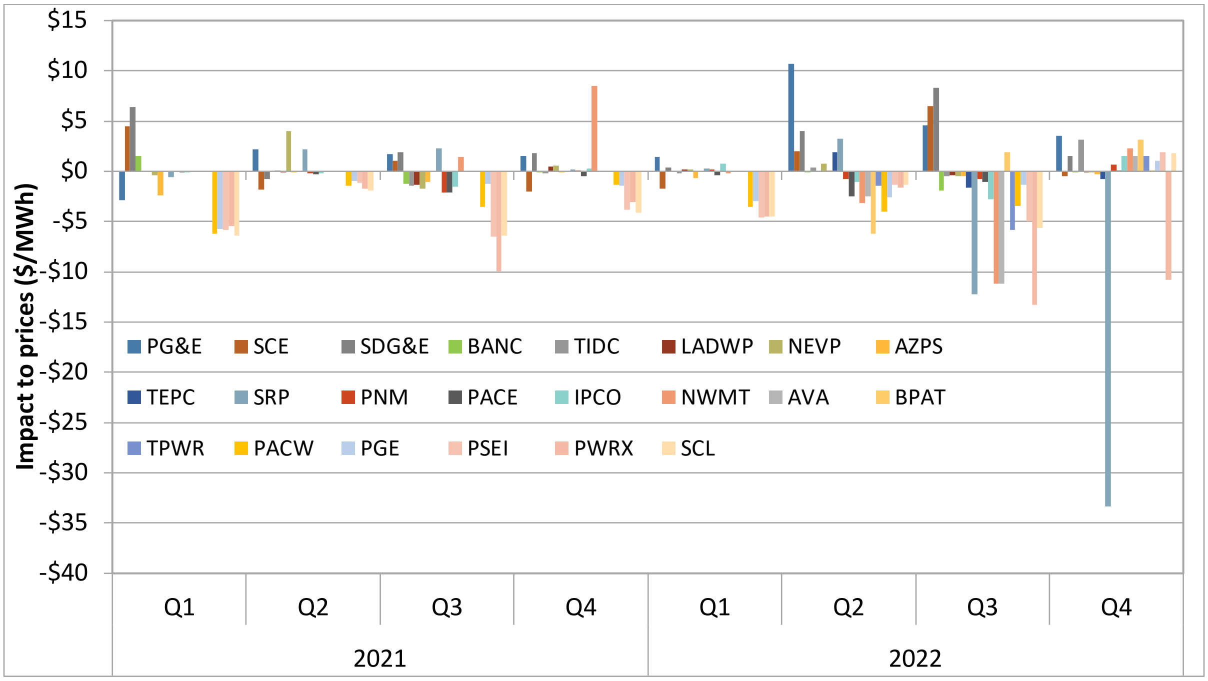
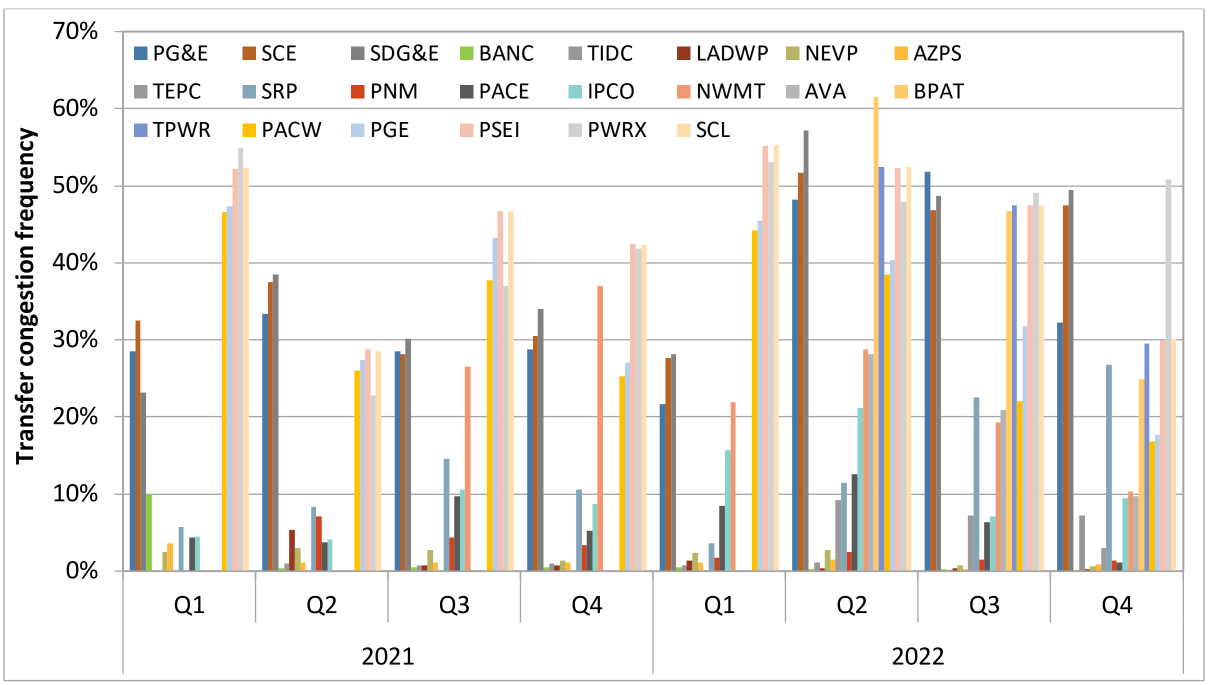


Figure 1.29 Transfer constraint congestion frequency in the 15-minute market



1.7.3 Congestion on interties

In the fourth quarter of 2022, the frequency and import congestion rent on the Malin 500 and NOB increased significantly relative to same time last year. Figure 1.30 shows total import congestion charges in the day-ahead market for 2021 and 2022. Figure 1.31 shows the frequency of congestion on five major interties. Table 1.7 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 fourth quarter of 2022 was 32 percent lower than the fourth quarter of 2021 at $13 million. The Malin 500 and Palo Verde interties were the primary drivers of congestion charges in the day-ahead market, while congestion on NOB decreased significantly.
- The frequency and impact of congestion on Palo Verde was elevated from the third quarter of 2021 to the first quarter of 2022. This changed in the second quarter of 2022 where it decreased significantly and later generated no congestion charges in the third quarter. In the fourth quarter, congestion returned on intertie and generated about $6.7 million in congestion charges.
- The frequency of congestion and magnitude of congestion charges was highest on the Malin 500, Palo Verde, which accounted for 89 percent of the total congestion charges for the quarter. Congestion on other interties continued to remain relatively low relative to these constraints, with the exception of IPP Utah, which generated $1 million in congestion charges.

Figure 1.30 Day-ahead import congestion charges on major interties

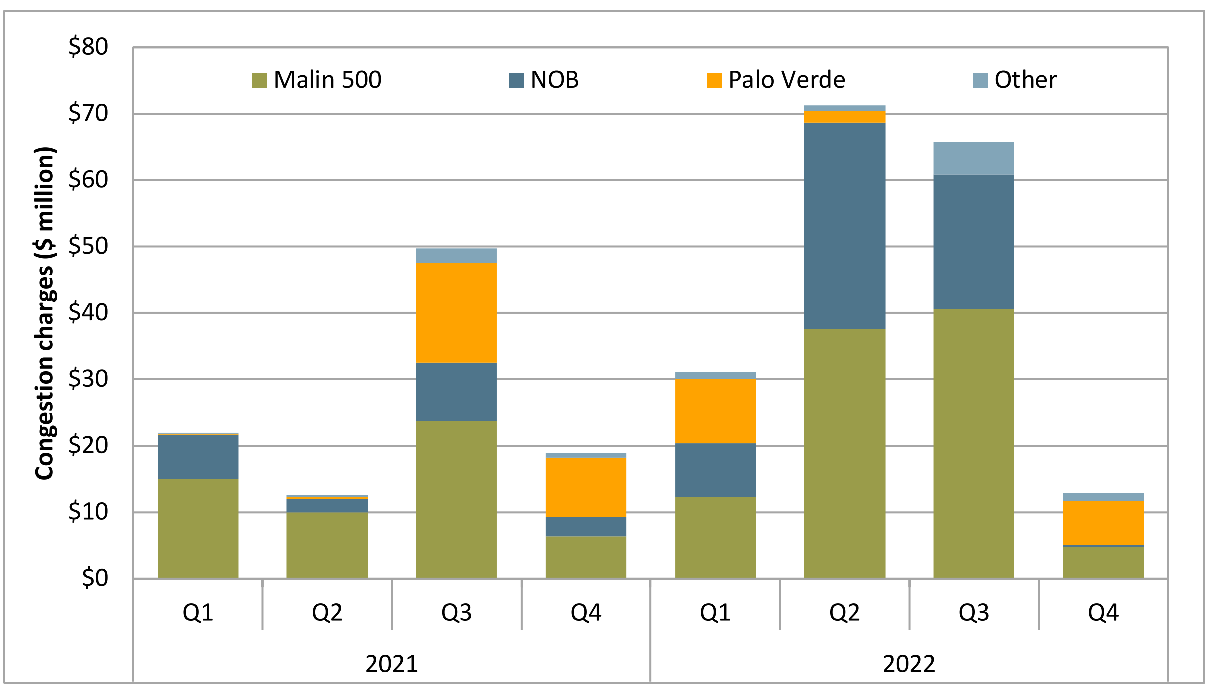


Figure 1.31 Frequency of import congestion on major interties in the day-ahead market

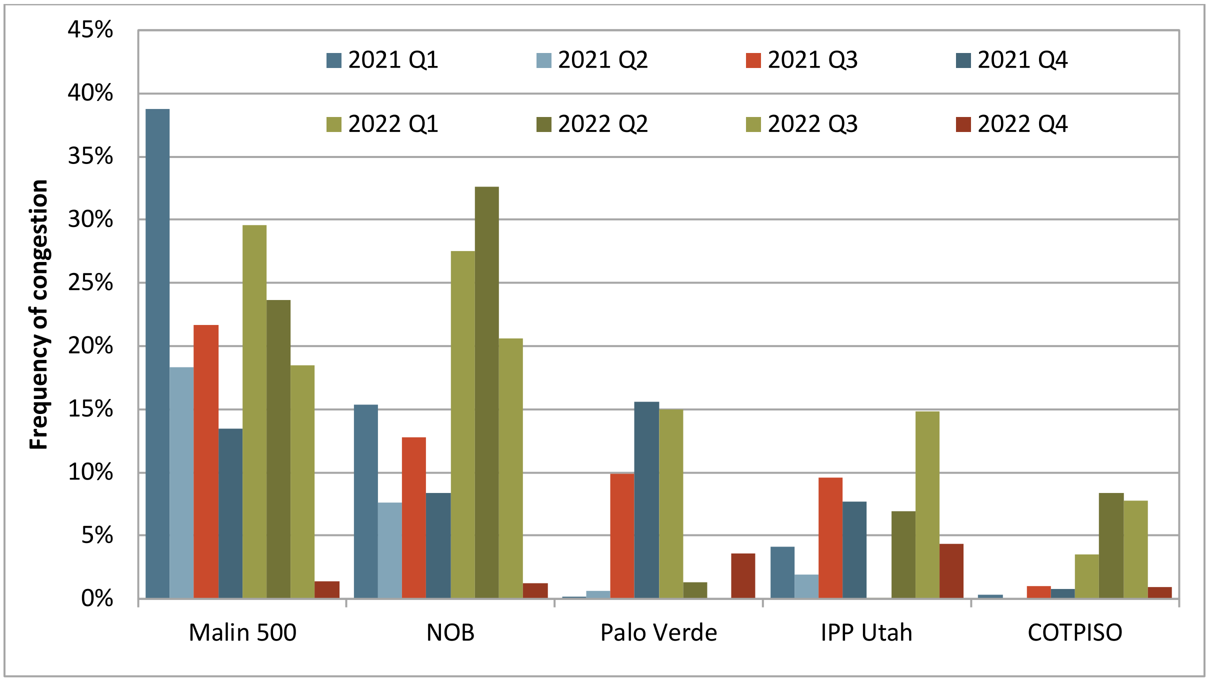


Table 1.7 Summary of import congestion in day-ahead market (2021-2022)

Area	Intertie	Frequency of import congestion								Import congestion charges ($ thousand)							
		2021				2022				2021				2022			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Northwest	Malin 500	39%	18%	22%	14%	30%	24%	18%	1%	15,055	9,920	23,650	6,302	12,221	37,557	40,646	4,786
	NOB	15%	8%	13%	8%	28%	33%	21%	1%	6,689	2,132	8,899	2,976	8,216	31,130	20,229	333
	COTPISO	0%		1%	1%	4%	8%	8%	1%	3	0	17	11	53	435	310	15
	Summit						0%	0%	1%						1	14	4
	Cascade					0%	2%	0%						5	61	7	
Southwest	Palo Verde	0%	1%	10%	16%	15%	1%		4%	35	178	15,005	8,910	9,694	1,643		6,663
	IPP Utah	4%	2%	10%	8%	0%	7%	15%	4%	65	16	1,278	266	0	480	4,092	1,084
	IPP Adelanto	1%		0%		6%		0%	0%	38		2		673		0	12
	Mead	0%		0%	0%	1%		0%		10		665	74	182		308	
	Merchant	1%						0%		150						101	
	Mercury					0%								10			

1.8 Congestion revenue rights

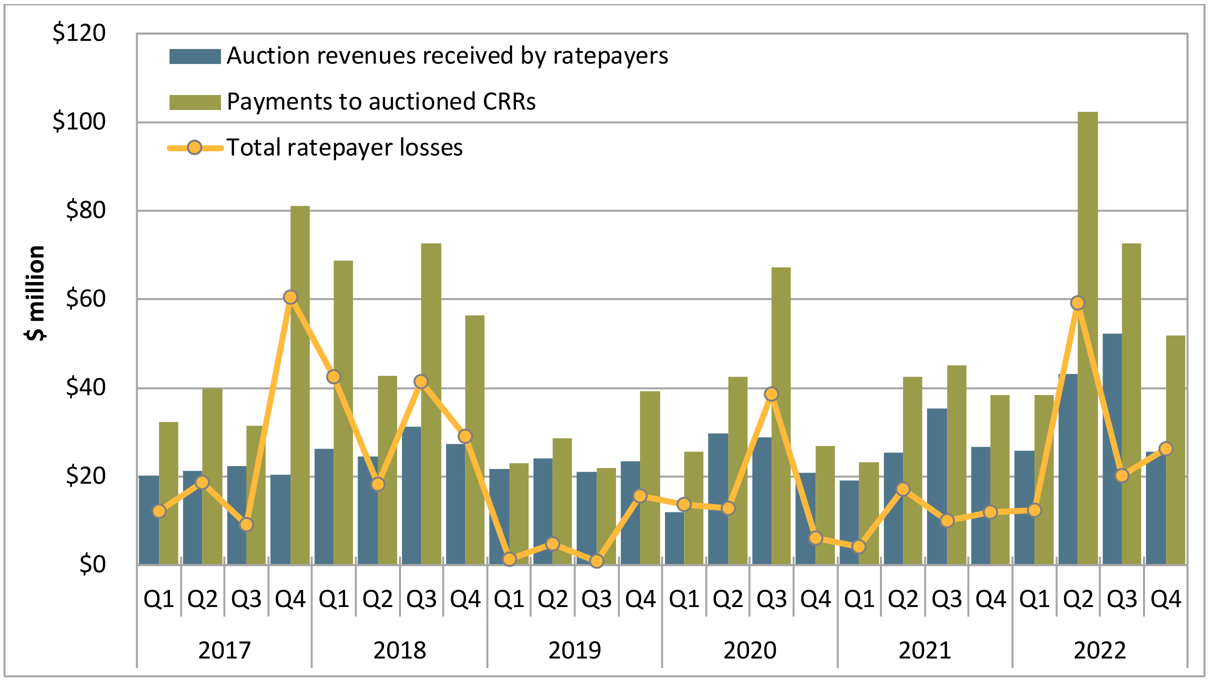
Congestion revenue right auction returns

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 $26 million during the fourth quarter of 2022 as payments to auctioned congestion revenue rights holders continued to exceed auction revenues.[29] This brings total losses to transmission ratepayers to about $118 million in 2022 significantly up from $43 million in 2021.

29 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.

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



During the fourth quarter of 2022:

- Financial entities received profits of nearly $18.6 million, significantly up from $7.7 million during the same quarter of 2021. Total revenue deficit offsets were about $10 million.[30]
- Marketers received profits of nearly $5.8 million from auctioned rights, up from a loss of $0.2 million in 2021. Total revenue deficit offsets were nearly $4.6 million.
- Physical generation entities received about $2 million in profits from auctioned rights, down from $4.4 million compared to 2021. Total revenue deficit offsets were about $2 million.

The $26 million in fourth quarter 2022 auction losses was about 7 percent of day-ahead congestion rent. This is slightly down from 8 percent in the previous quarter and in the fourth quarter of 2021. The losses as a 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).[31,32]

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

30 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 SC's with net flows on the constraint.

31 California ISO, Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1.pdf

32 California ISO, Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendumCongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

total payments to non-load serving entities by about $17 million in the fourth 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.

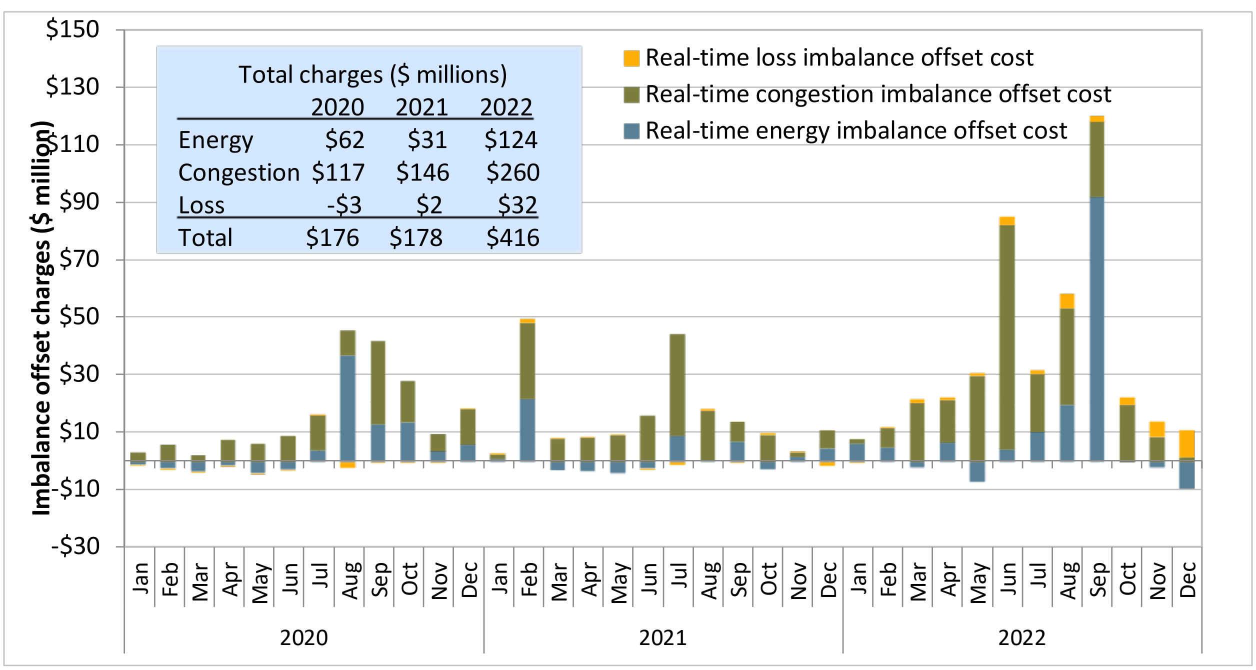
1.9 Real-time imbalance offset costs

Real-time imbalance offset costs increased to $36 million, up from $21 million in the fourth quarter of 2021, but lower than the extraordinarily high offsets in the second and third quarters. Real-time imbalance energy costs were $89 million in September alone; the highest monthly energy offset costs since locational marginal pricing was introduced in 2009. Congestion imbalance offset costs were $77 million in June alone; the highest monthly congestion imbalance recorded.

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).

Figure 1.33 Real-time imbalance offset costs



1.10 Bid cost recovery

During 2022, estimated bid cost recovery payments for units in the California ISO (CAISO) and Western Energy Imbalance Market (WEIM) balancing areas totaled about $258 million and $44 million, respectively.[33] These payments were the highest since 2011 and a significant increase from 2021 when total payments were $180 million.

In the fourth quarter of 2022, the CAISO and WEIM payments totaled $108 million, which were similar to the previous quarter ($109 million) and 209 percent higher than the same quarter of 2021 ($35 million). As shown in Figure 1.34, bid cost recovery payments were the highest during December 2022. These significantly higher payments can be attributed to the rise in gas prices at major trading hubs in the west during December 2022. As mentioned in Section 1.1.1, for the fourth quarter, the load-weighted average gas price increased by 147 percent relative to the same quarter of 2021.

The figure also shows that in the fourth quarter of 2022, bid cost recovery attributed to the day-ahead market totaled about $17 million, which was $9 million higher than fourth quarter of 2021. Bid cost recovery payments for residual unit commitment during the quarter totaled about $24 million, or about $17 million higher than the fourth quarter of 2021. Bid cost recovery attributed to the real-time market totaled about $67 million similar to payments in the previous quarter, and about $47 million higher than the same quarter of 2021. Out of the $67 million in real-time payments, about $17 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 fourth quarter, about 73 percent of these payments, or about $79 million, were made to gas resources, followed by about $12 million to battery energy storage resources.

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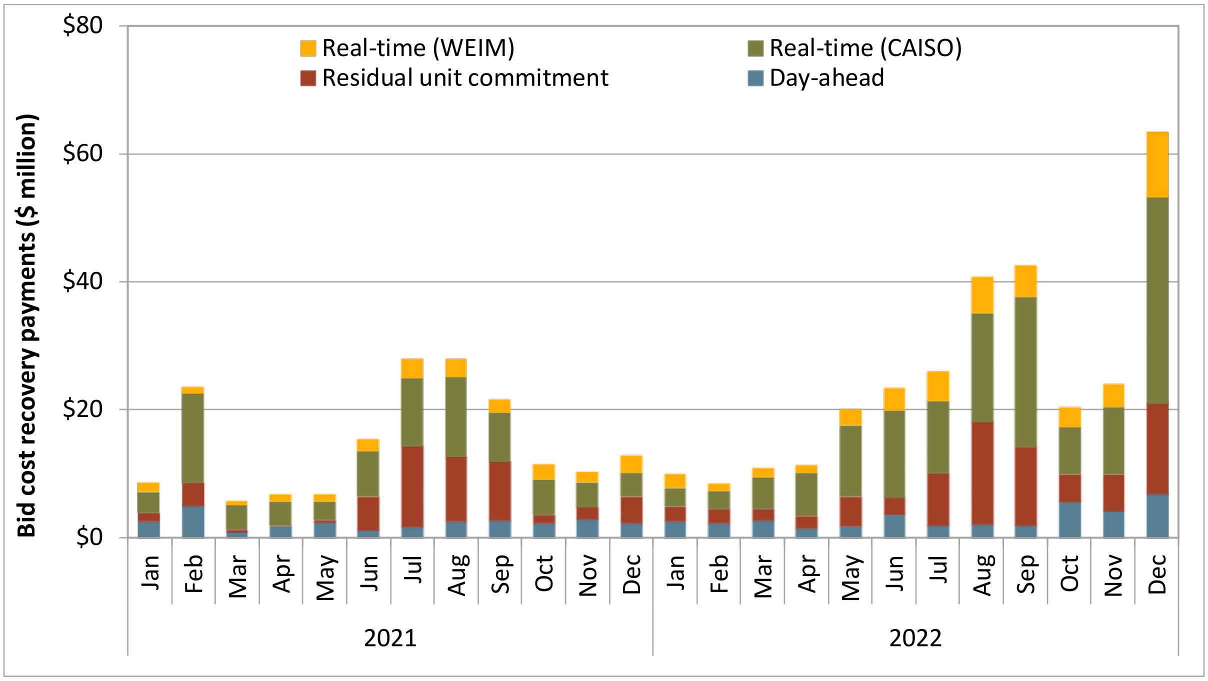
33 Settlement data for the fourth quarter of 2022 is preliminary. More final settlement statements are issued at trade day plus 70 business days. Settlements can change substantially between statements. For further information on settlement timeline changes see: California ISO, *Market Settlements Timeline Transformation*, July 20, 2020: http://www.caiso.com/Documents/Presentation-MarketSettlementsTimelineTransformationTraining.pdf

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 in both the morning solar ramp up and the afternoon peak solar ramp down period. Average hourly imbalance conformance adjustments in these markets peaked in the morning at about 600 MW, and at just over 2,000 MW in the afternoon, about a 50 MW decrease and 500 MW increase, respectively, over the same quarter peak periods of the previous year. Solar uncertainty contributed to the morning increase in imbalance conformance levels compared to previous quarters of the year.

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.

Outside of hours-ending 1-4 and 24, the 5-minute market adjustments in this quarter were consistently lower than 15-minute market imbalance conformance. 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 (Q4 2021 – Q4 2022)

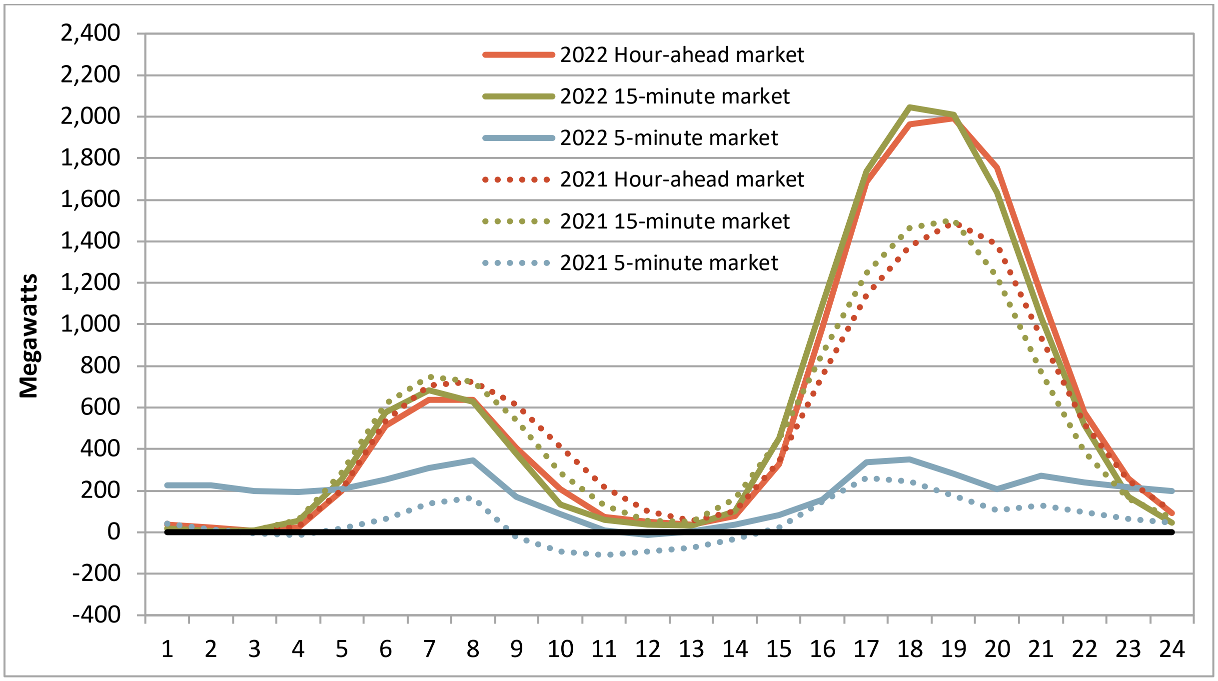


Figure 1.36 15-minute market hourly distribution of operator load adjustments (Q4 2022)

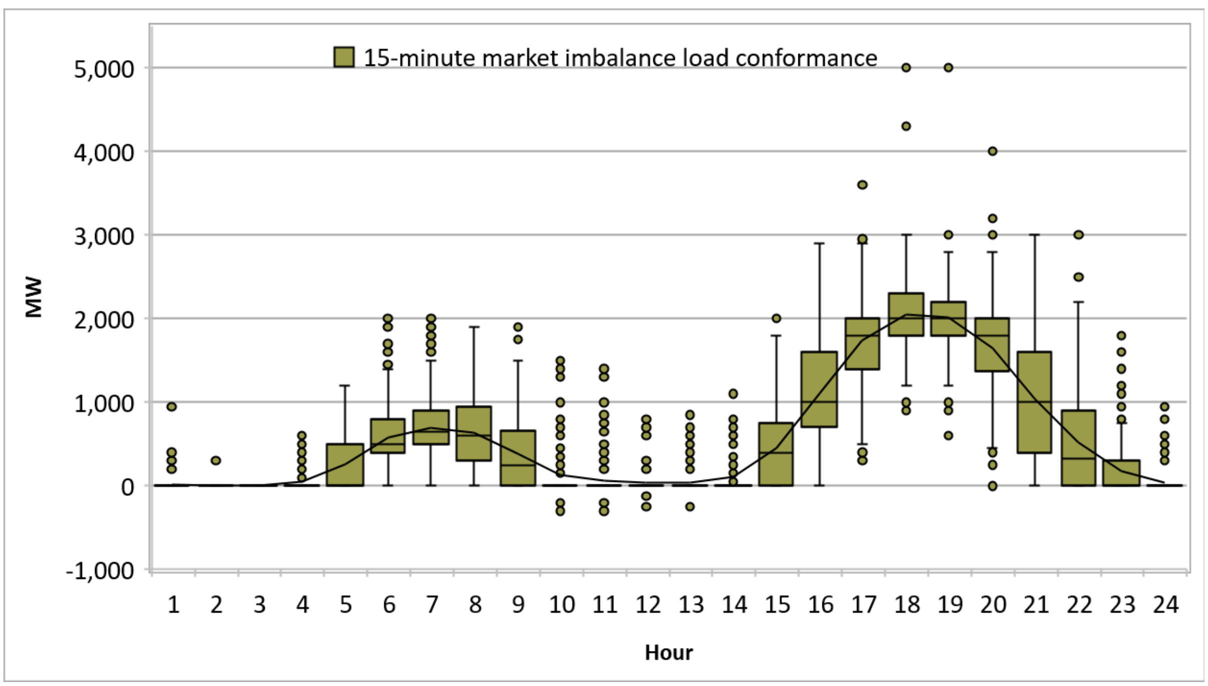


Figure 1.36 shows the distribution of the 15-minute market into quartiles for the load adjustment profile for the fourth quarter of 2022. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the filled 'dots. The outside whiskers do not include these

outliers. For the quarter, the major outliers above 3,000 MW occurred in hours-ending 17 through 20 on October 19, 2022 in response to an issue with the CAISO's market software data.

1.12 Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an out-of-market dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs not fully recovered through market prices, affect market prices, and create opportunities for the exercise of market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

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

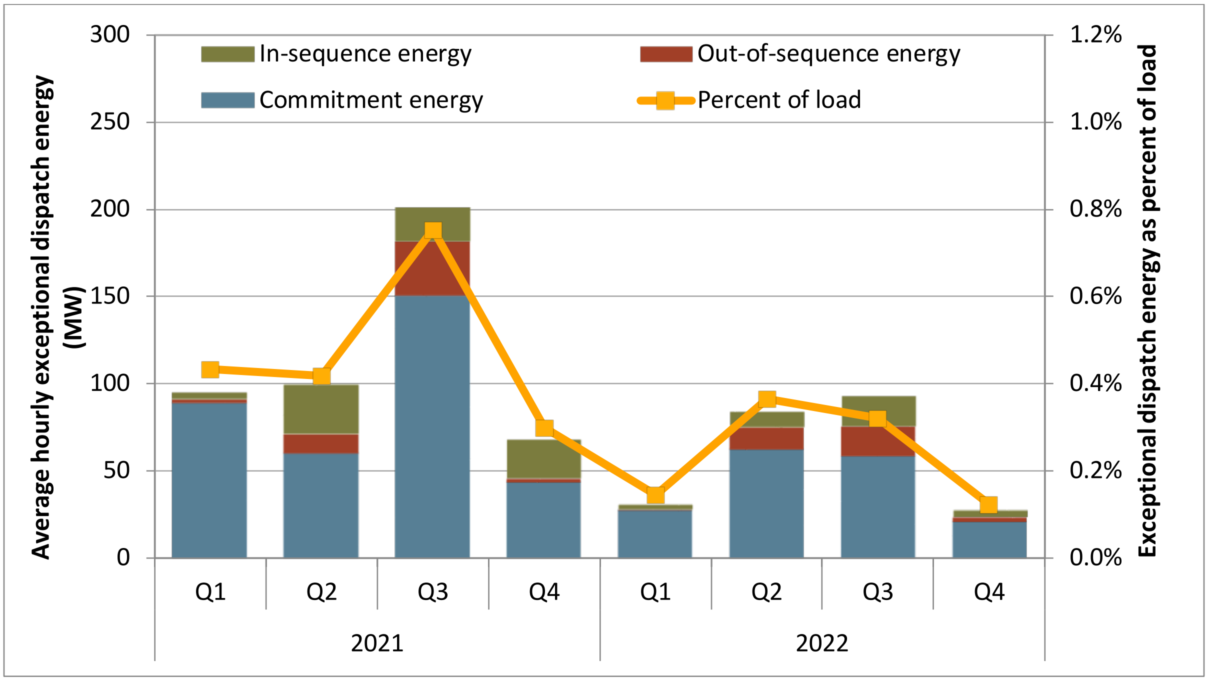
Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 1 percent of total load in the CAISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 28 MWh in the fourth quarter of 2022, down from 68 MWh in the same quarter of 2021.

As shown in Figure 1.37, exceptional dispatches for unit commitments accounted for about 77 percent of all exceptional dispatch energy in this quarter, about 10 percent was from out-of-sequence energy, and the remaining 13 percent was from in-sequence energy.[34]

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

Figure 1.37 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

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

Figure 1.38 Average minimum load energy from exceptional dispatch unit commitments

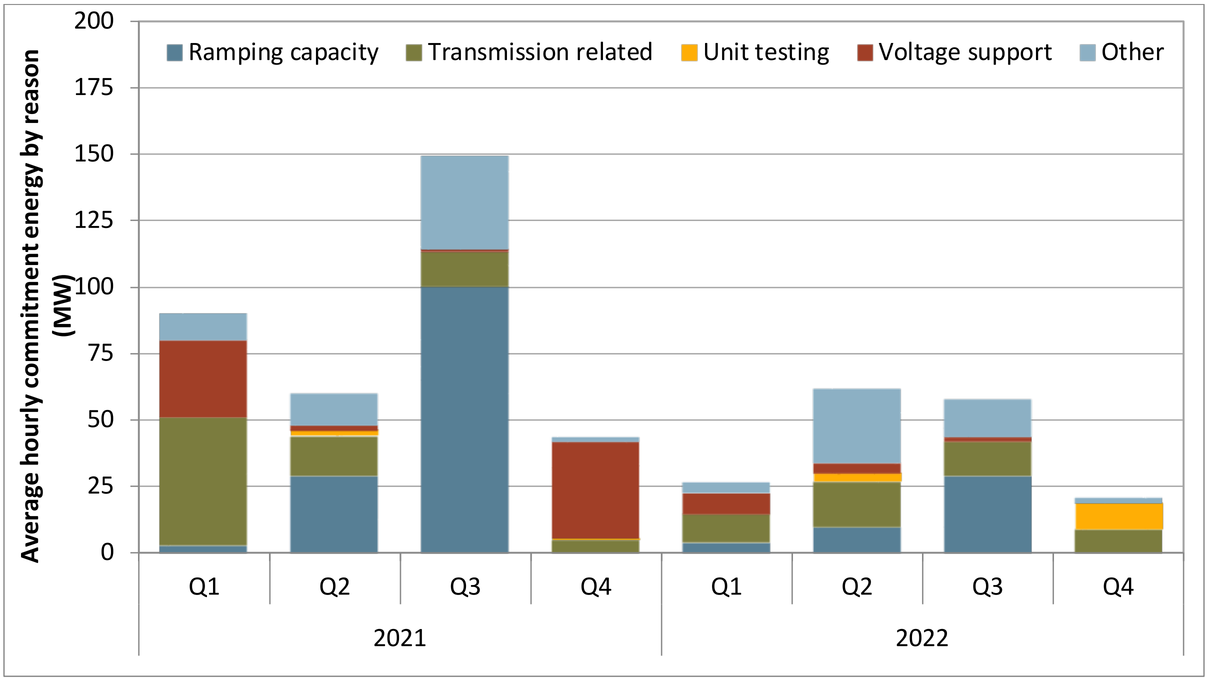
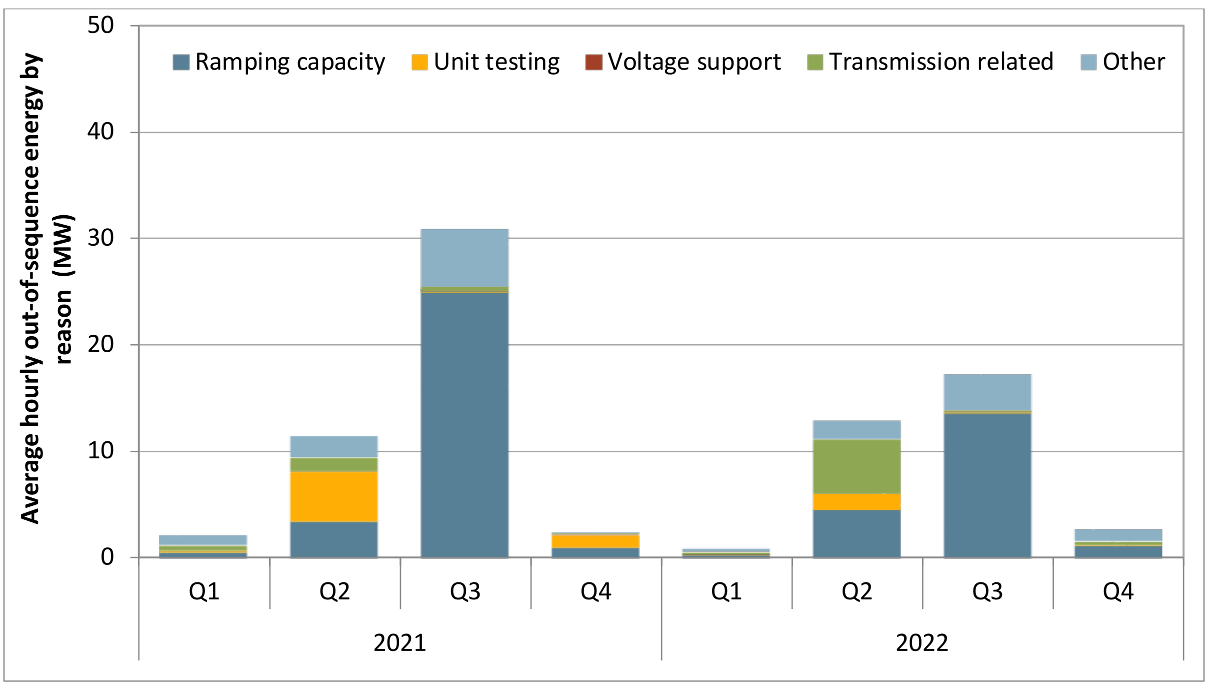


Figure 1.39 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatches for energy

As shown in Figure 1.38, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch in the fourth quarter of 2022 did not decrease from the same quarter in 2021, as it was zero in both quarters. Figure 1.39 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2021 and 2022. The primary reason logged for out-of-sequence energy in the fourth quarter of 2022 was "exceptional dispatches for unit testing." Unit testing is used to test the reliability of a resource.

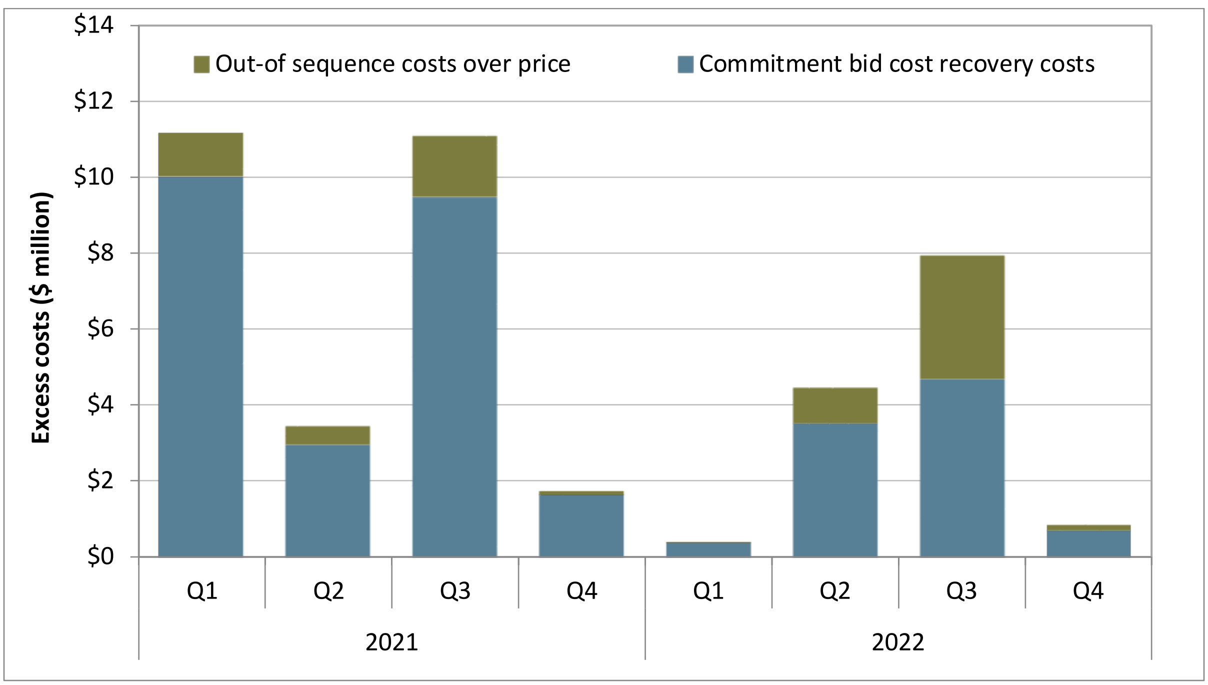
Exceptional dispatch costs

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

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

Figure 1.40 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. In the third quarter, out-of-sequence energy costs were $168,000, while commitment costs for exceptional dispatch paid through bid cost recovery were $711,000.

Figure 1.40 Above market exceptional dispatch costs



2 Chapter 2

This section covers Western Energy Imbalance Market (WEIM) performance during the fourth 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 2021 through 2022. The combined average of WEIM prices outside of California was lower than California area prices by $18.35/MWh on average over the fourth quarter. The combined average prices of these areas, which include the Balancing Area of Northern California, Turlock Irrigation District, and Los Angeles Department of Water and Power, was $0.82/MWh lower than Pacific Gas and Electric's average price of $141.90/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

	2021												2022											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$31	$61	$31	$33	$32	$42	$64	$54	$68	$61	$54	$57	$51	$44	$42	$59	$59	$55	$69	$97	$125	$69	$90	$246
PG&E (CAISO)	$33	$49	$34	$37	$37	$45	$70	$57	$72	$67	$58	$60	$54	$48	$47	$63	$68	$82	$74	$103	$136	$73	$95	$257
SCE (CAISO)	$31	$78	$30	$30	$28	$44	$67	$56	$70	$56	$55	$58	$52	$43	$40	$55	$60	$69	$78	$108	$135	$64	$83	$246
Avista Utilities															$35	$57	$41	$12	$36	$68	$72	$65	$86	$246
Arizona PS	$23	$63	$20	$23	$24	$37	$54	$44	$57	$42	$39	$41	$39	$34	$31	$45	$52	$64	$72	$97	$118	$56	$80	$251
BANC	$33	$48	$35	$38	$39	$44	$69	$56	$70	$71	$57	$60	$53	$48	$48	$65	$69	$68	$72	$106	$131	$75	$95	$252
BPA																	$46	$10	$46	$80	$91	$65	$86	$251
Idaho Power	$26	$51	$27	$28	$26	$36	$49	$45	$57	$55	$40	$46	$43	$41	$35	$57	$47	$32	$69	$82	$92	$63	$84	$237
LADWP				$30	$29	$42	$63	$52	$66	$56	$54	$57	$50	$42	$41	$55	$57	$63	$77	$108	$135	$67	$87	$256
NV Energy	$26	$63	$26	$29	$27	$41	$54	$42	$56	$45	$40	$45	$40	$38	$35	$49	$53	$55	$69	$93	$117	$58	$79	$243
NorthWestern						$37	$41	$41	$66	$79	$38	$44	$41	$37	$34	$57	$41	$15	$42	$69	$73	$64	$87	$243
PacifiCorp East	$24	$52	$25	$26	$24	$34	$47	$38	$51	$42	$37	$38	$37	$35	$32	$45	$43	$40	$65	$81	$99	$59	$72	$193
PacifiCorp West	$22	$34	$24	$29	$29	$30	$40	$42	$56	$53	$40	$44	$39	$35	$32	$59	$42	$13	$42	$76	$89	$64	$85	$244
Portland GE	$22	$34	$24	$30	$28	$31	$41	$46	$57	$53	$38	$43	$38	$35	$33	$59	$43	$16	$43	$77	$92	$65	$87	$244
Powerex	$22	$35	$26	$29	$27	$29	$35	$38	$44	$50	$40	$39	$36	$34	$32	$52	$46	$15	$37	$61	$69	$67	$82	$212
PSC New Mexico				$24	$23	$34	$51	$41	$54	$42	$38	$36	$37	$34	$30	$43	$47	$49	$67	$84	$102	$58	$64	$114
Puget Sound Energy	$21	$34	$26	$29	$29	$30	$39	$41	$48	$48	$39	$41	$37	$34	$31	$60	$44	$13	$41	$74	$81	$64	$85	$249
Seattle City Light	$21	$34	$24	$29	$28	$29	$39	$40	$50	$47	$38	$41	$37	$34	$31	$60	$45	$12	$40	$74	$80	$64	$85	$249
Salt River Project	$23	$66	$22	$25	$24	$41	$60	$50	$55	$42	$43	$37	$39	$34	$33	$47	$56	$67	$67	$88	$93	$56	$76	$157
Tucson Electric																	$54	$64	$72	$96	$111	$57	$76	$222
Turlock ID			$32	$38	$41	$45	$67	$56	$71	$75	$57	$61	$54	$49	$48	$69	$76	$68	$72	$100	$136	$76	$95	$266
Tacoma Power															$30	$59	$44	$13	$39	$74	$80	$64	$85	$248

Figure 2.1 Quarterly average 15-minute price by component (Q4 2022)

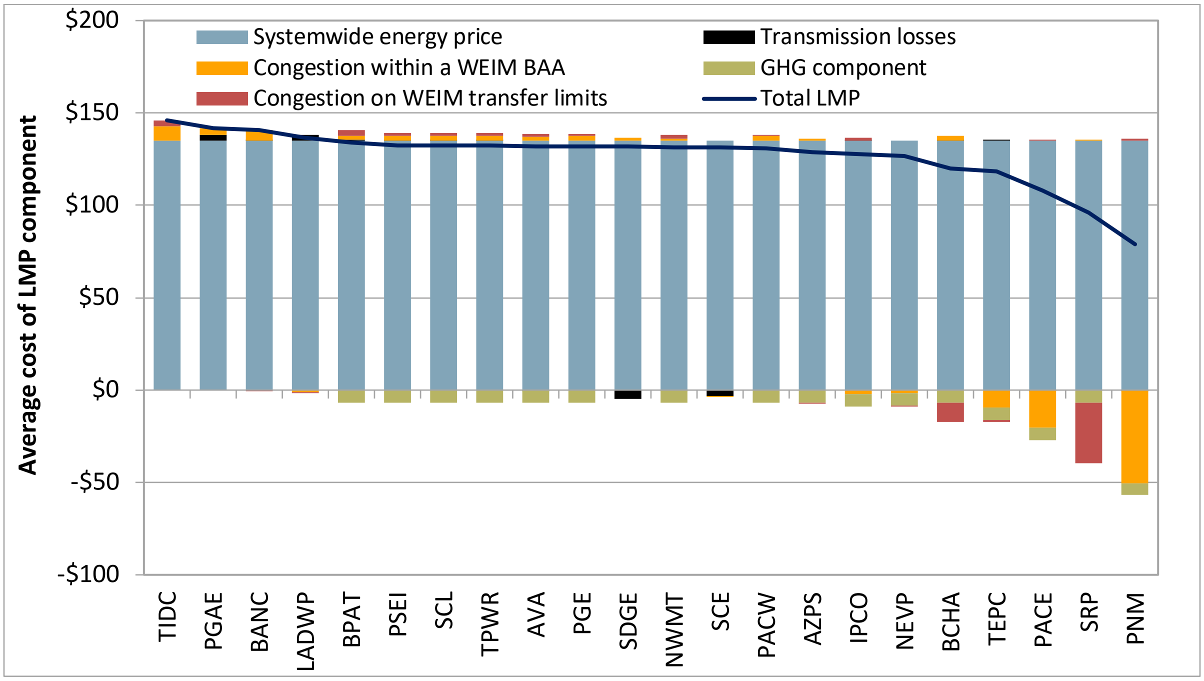


Figure 2.2 Quarterly average 5-minute price by component (Q4 2022)

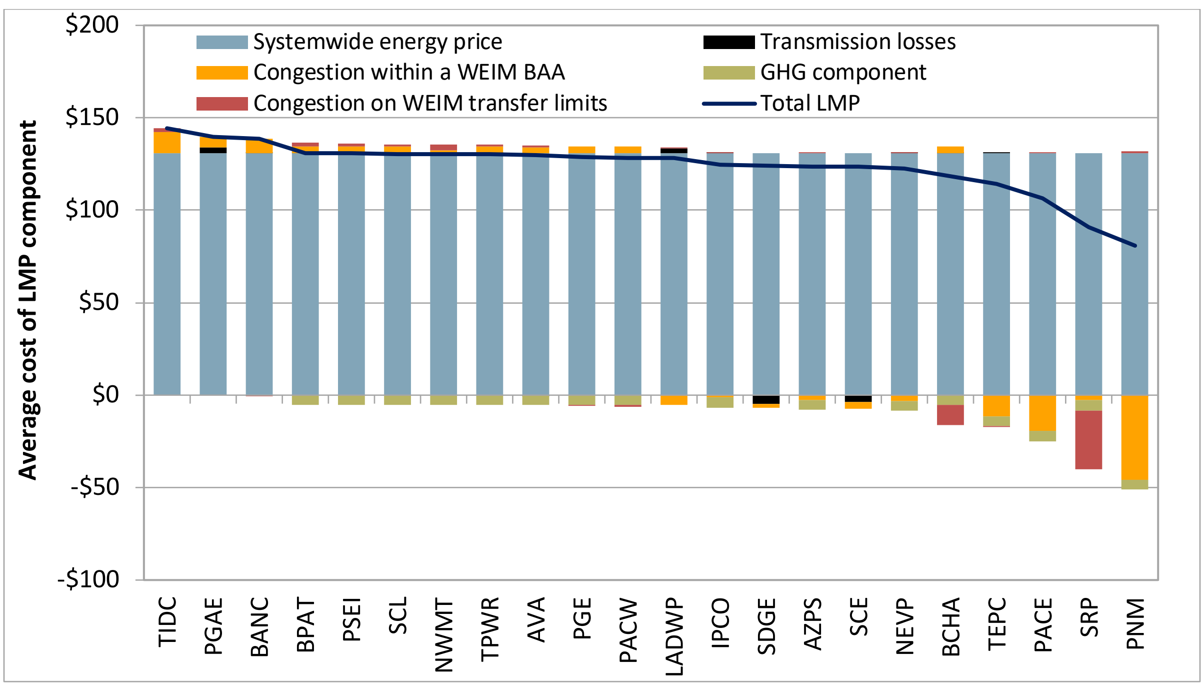


Figure 2.1 depicts the average 15-minute price by component for each balancing authority area.[35] The system marginal energy price is the same for all entities in each hour. The price difference between balancing authority areas is determined by area specific elements including transmission losses, 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 fourth quarter of 2022. 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.

Table 2.2 Hourly 15-minute market prices (October-December)

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	$128	$124	$123	$123	$132	$145	$155	$144	$124	$114	$109	$105	$99	$96	$107	$132	$167	$187	$176	$167	$160	$154	$143	$130
PG&E (CAISO)	$133	$129	$127	$128	$137	$150	$159	$151	$133	$126	$123	$119	$112	$109	$118	$139	$174	$192	$180	$173	$166	$159	$147	$134
SCE (CAISO)	$131	$128	$126	$127	$134	$147	$158	$143	$117	$98	$90	$83	$79	$77	$90	$126	$167	$190	$182	$170	$163	$157	$146	$133
BANC	$129	$126	$124	$125	$134	$147	$157	$148	$133	$129	$126	$122	$116	$113	$123	$139	$171	$187	$178	$169	$162	$155	$144	$131
Turlock ID	$133	$130	$128	$128	$136	$148	$158	$151	$141	$140	$138	$134	$130	$130	$135	$147	$173	$188	$180	$169	$162	$156	$146	$137
LADWP	$135	$131	$129	$130	$138	$151	$161	$146	$122	$104	$95	$90	$85	$83	$96	$133	$175	$196	$191	$177	$170	$164	$151	$137
NV Energy	$122	$118	$117	$119	$127	$139	$147	$133	$117	$107	$98	$95	$91	$87	$97	$126	$159	$176	$166	$156	$152	$146	$136	$124
Arizona PS	$128	$124	$123	$125	$133	$145	$155	$140	$120	$100	$92	$85	$80	$76	$88	$123	$161	$181	$173	$165	$160	$155	$144	$130
Tucson Electric	$115	$111	$110	$111	$122	$135	$145	$130	$109	$93	$84	$79	$74	$71	$85	$117	$149	$166	$167	$152	$146	$139	$131	$119
Salt River Project	$84	$83	$82	$84	$97	$112	$121	$109	$89	$78	$69	$69	$64	$61	$68	$89	$127	$144	$133	$122	$114	$108	$109	$96
PSC New Mexico	$68	$66	$67	$67	$78	$91	$105	$90	$85	$75	$57	$54	$51	$51	$65	$93	$107	$111	$107	$97	$93	$79	$73	$68
PacifiCorp East	$100	$96	$96	$95	$105	$117	$124	$115	$102	$95	$90	$86	$81	$79	$88	$110	$137	$150	$139	$132	$128	$121	$113	$102
Idaho Power	$117	$114	$113	$115	$124	$134	$143	$134	$121	$116	$117	$113	$109	$105	$109	$127	$156	$167	$158	$151	$147	$140	$131	$120
NorthWestern	$119	$116	$115	$116	$125	$136	$151	$137	$126	$131	$120	$116	$112	$109	$113	$127	$160	$170	$164	$154	$150	$143	$134	$121
Avista Utilities	$120	$117	$115	$117	$126	$136	$146	$138	$126	$123	$124	$119	$115	$111	$115	$130	$161	$172	$162	$156	$151	$144	$135	$123
BPA	$122	$117	$116	$117	$126	$135	$138	$135	$136	$132	$128	$130	$124	$118	$122	$134	$157	$167	$157	$154	$154	$148	$138	$125
Tacoma Power	$122	$117	$115	$117	$126	$134	$137	$134	$130	$132	$129	$131	$123	$119	$122	$134	$157	$163	$151	$149	$146	$142	$135	$124
PacifiCorp West	$120	$117	$115	$117	$125	$135	$139	$135	$127	$123	$124	$120	$116	$111	$115	$131	$158	$168	$156	$153	$150	$143	$135	$123
Portland GE	$120	$117	$115	$117	$125	$135	$140	$140	$127	$123	$124	$120	$116	$113	$115	$131	$162	$178	$157	$153	$150	$143	$136	$123
Puget Sound Energy	$122	$118	$115	$117	$126	$134	$137	$134	$132	$132	$130	$131	$124	$119	$122	$136	$157	$163	$151	$149	$146	$142	$135	$124
Powerex	$115	$113	$112	$111	$118	$122	$123	$116	$117	$113	$113	$113	$108	$105	$110	$125	$139	$140	$134	$135	$134	$129	$126	$120
Seattle City Light	$122	$117	$115	$117	$126	$132	$136	$134	$132	$132	$130	$131	$124	$119	$122	$136	$157	$163	$151	$148	$146	$146	$135	$124

35 The 'Congestion within CAISO' component represents all congestion on internal constraints, including those within the California ISO and the WEIM. California ISO-specific internal constraints typically make up the large majority of this category.

Table 2.3 Hourly 5-minute market prices (October-December)

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	$129	$127	$125	$126	$131	$140	$155	$162	$126	$115	$110	$105	$99	$97	$101	$122	$143	$152	$149	$149	$153	$152	$144	$131
PG&E (CAISO)	$136	$132	$131	$132	$137	$146	$161	$175	$140	$133	$127	$122	$115	$113	$116	$129	$148	$158	$154	$155	$160	$157	$149	$137
SCE (CAISO)	$130	$129	$126	$127	$132	$140	$154	$156	$112	$87	$81	$76	$72	$69	$75	$114	$144	$156	$153	$152	$155	$155	$146	$132
BANC	$132	$129	$127	$128	$134	$143	$158	$169	$137	$138	$133	$127	$121	$121	$123	$129	$147	$155	$151	$151	$156	$154	$145	$133
Turlock ID	$136	$132	$130	$131	$136	$144	$159	$173	$147	$151	$146	$140	$136	$137	$138	$139	$149	$156	$152	$151	$156	$155	$147	$138
LADWP	$134	$132	$129	$130	$136	$144	$158	$161	$118	$93	$87	$83	$78	$75	$81	$121	$151	$160	$158	$157	$160	$160	$151	$137
NV Energy	$122	$121	$118	$120	$126	$135	$148	$152	$119	$100	$96	$92	$87	$85	$88	$120	$140	$149	$143	$142	$146	$143	$138	$125
Arizona PS	$129	$125	$123	$126	$131	$140	$154	$157	$115	$90	$84	$79	$73	$70	$76	$116	$142	$153	$149	$150	$155	$158	$150	$132
Tucson Electric	$116	$113	$112	$114	$123	$132	$145	$148	$107	$84	$78	$71	$66	$66	$74	$110	$134	$144	$141	$139	$141	$139	$131	$120
Salt River Project	$80	$82	$85	$83	$98	$111	$129	$115	$77	$67	$65	$64	$58	$61	$58	$93	$115	$117	$109	$113	$111	$108	$97	$85
PSC New Mexico	$78	$74	$75	$73	$85	$96	$110	$122	$89	$71	$59	$56	$52	$53	$60	$87	$93	$91	$85	$92	$95	$86	$82	$83
PacifiCorp East	$103	$99	$98	$99	$106	$116	$125	$133	$105	$96	$91	$87	$82	$80	$84	$104	$119	$124	$119	$121	$124	$121	$116	$105
Idaho Power	$119	$117	$116	$118	$124	$132	$144	$148	$123	$119	$115	$111	$104	$102	$105	$120	$136	$141	$137	$139	$143	$139	$134	$121
NorthWestern	$121	$121	$123	$119	$127	$142	$152	$151	$133	$135	$120	$117	$122	$109	$109	$121	$139	$143	$146	$142	$145	$142	$136	$123
Avista Utilities	$122	$119	$118	$119	$126	$134	$146	$152	$128	$127	$130	$121	$112	$111	$113	$124	$140	$145	$142	$143	$146	$143	$137	$126
BPA	$123	$119	$118	$120	$125	$134	$142	$140	$131	$133	$131	$126	$119	$118	$117	$128	$140	$146	$146	$144	$148	$146	$139	$126
Tacoma Power	$122	$118	$116	$119	$125	$132	$141	$138	$132	$135	$132	$131	$121	$118	$119	$128	$139	$143	$140	$139	$143	$141	$137	$124
PacifiCorp West	$121	$119	$118	$119	$125	$134	$144	$147	$126	$127	$123	$118	$111	$110	$112	$124	$140	$144	$141	$142	$146	$143	$137	$124
Portland GE	$121	$119	$117	$119	$125	$134	$143	$147	$125	$127	$123	$118	$111	$110	$111	$124	$140	$152	$141	$142	$146	$143	$137	$124
Puget Sound Energy	$122	$119	$116	$119	$125	$132	$141	$138	$134	$135	$133	$132	$122	$119	$119	$131	$141	$142	$140	$139	$143	$141	$137	$126
Powerex	$114	$114	$112	$112	$115	$120	$121	$115	$113	$119	$115	$114	$105	$101	$107	$120	$131	$132	$128	$131	$133	$129	$126	$118
Seattle City Light	$121	$118	$117	$119	$123	$130	$141	$138	$132	$135	$133	$131	$121	$118	$119	$131	$141	$142	$140	$139	$143	$143	$137	$124

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.[36] 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.[37] 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.[38] 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 just over 800 MW, on average during these mid-day hours, out to neighboring areas including BANC, LADWP, Powerex, BPA, and Portland General Electric. The

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

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

38 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.

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 1,400 MW of exports out of LADWP, Turlock Irrigation District, 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). In particular, Arizona Public Service, NV Energy, and Salt River Project each exported around 300 MW on average out to CAISO during these peak hours.

Figure 2.3 Average 15-minute market WEIM exports (mid-day hours, October – December, 2022)

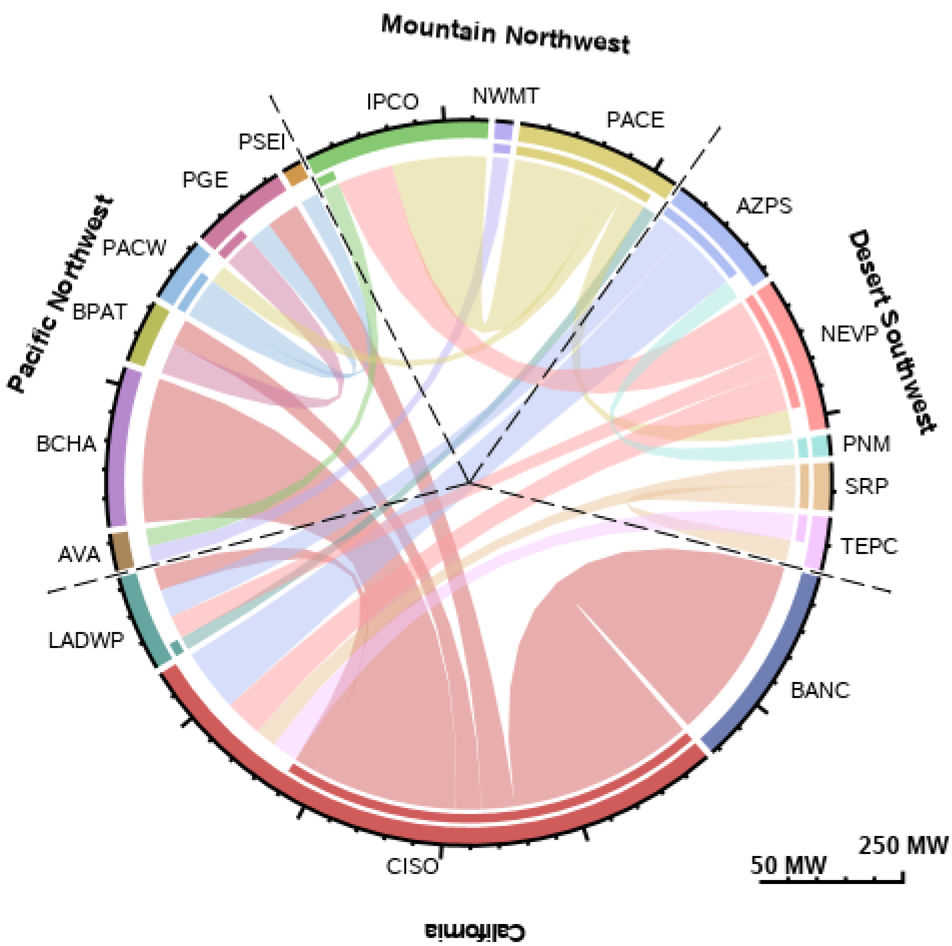
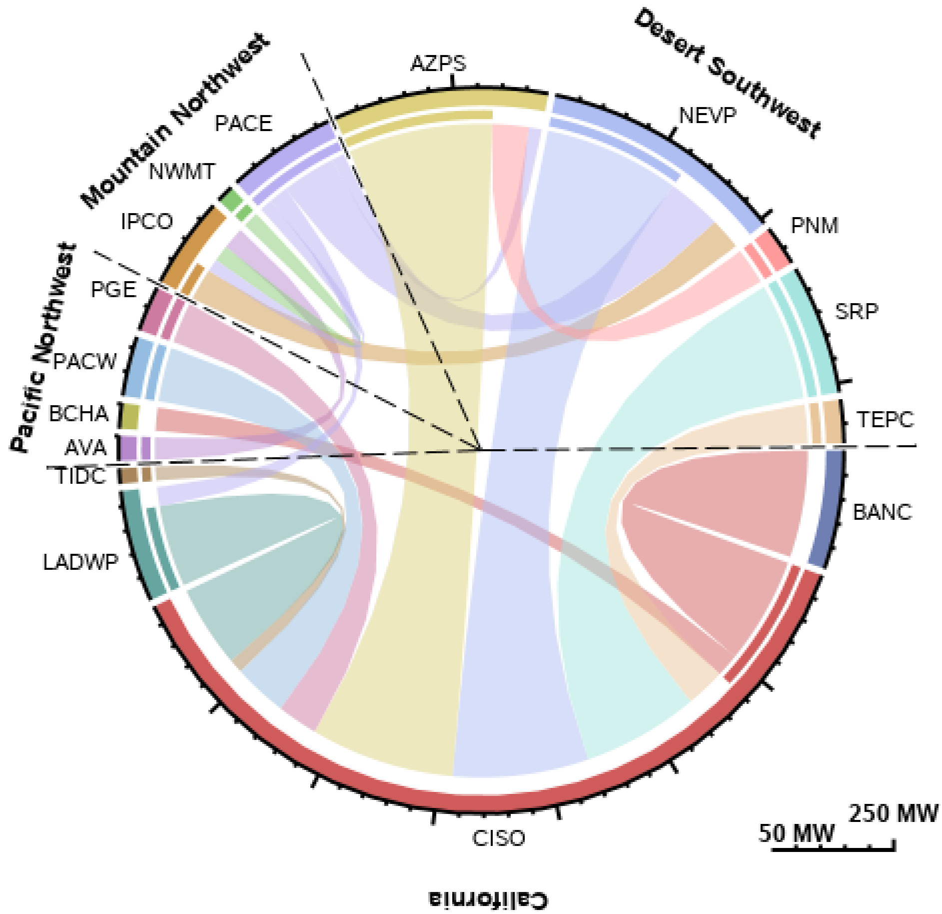


Figure 2.4 Average 15-minute market WEIM exports (peak load hours, October – December, 2022)



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, Avista Utilities, Tacoma Power, and Bonneville Power Administration) was around 5,025 MW of exports and 4,950 MW of imports on average during the quarter. There was an average of 32,400 MW of import and 33,950 MW of export transfer capacity in the east WEIM (including NV Energy, Arizona Public Service, Tucson Electric, Salt River Project, Public Service Company of New Mexico, PacifiCorp East, Idaho Power, and NorthWestern Energy). The lack of transfer capability out of the Pacific Northwest leads to price separation between the WEIM entities located within the Pacific Northwest and the rest of the WEIM.

Table 2.4 Average 15-minute market WEIM limits (October-December)

From Balancing Authority Area	To Balancing Authority Area																				*Total*
	CAISO	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	SCL	*export limit*
California ISO		3,650	1,280	3,850	3,720	1,540	320	1,840					0	100		80	100		370		16,850
BANC	3,560		570																		4,130
Turlock Irrig. District	1,290	730																			2,020
LADWP	7,800				1,610	330	290			170											10,200
NV Energy	4,060			990		310				720	350										6,430
Arizona Public Service	2,530			330	240		1,640	3,730	610	450											9,530
Tucson Electric	390			150		1,730		1,550	250	210											4,280
Salt River Project	3,010					3,050	1,160		50												7,270
PSC New Mexico						440	310	170													920
PacifiCorp East				130	510	410	170				480	180				110					1,990
Idaho Power					460					1,600		180	340	0		280				20	2,880
NorthWestern Energy										180	230		210	40	0						660
Avista Utilities	0										590	370		70	0	20					1,050
BPA	120										0	60	90		160	60	220	70	0	50	830
Tacoma Power												0	0	90			0	190			280
PacifiCorp West	200									0	170		20	40			360	70		10	870
Portland GE	200													210	0	380				10	800
Puget Sound Energy														70	190	50			50	350	710
Powerex	0													0				50			50
Seattle City Light											20			40		10	10	350			430
Total import limit	23,160	4,380	1,850	5,450	6,540	7,810	3,890	7,290	910	3,330	1,840	790	660	660	350	990	690	730	420	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.[39] In addition to the typical high frequency of transfer congestion in the Pacific Northwest, Salt River Project experience congestion out of the area in a quarter of 15-minute and 5-minute market intervals.

Table 2.6 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of a WEIM area. This is calculated as the frequency 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.[40] 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. The results of this section are the same as those found in Section 1.7.2 of this report on congestion. Section 1.7.2 focuses on the impact of congestion on prices, whereas this section describes the same information in terms of the impact to WEIM import or export capability.

Congestion in either direction for BANC, Los Angeles Department of Water and Power, NV Energy, Arizona Public Service, PacifiCorp East, and PSC New Mexico 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.

39 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.

40 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 of congestion in the WEIM (October-December)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
L.A. Dept. of Water and Power	0%	0%	0%	0%
NV Energy	1%	0%	0%	1%
Arizona Public Service	1%	0%	1%	1%
PacifiCorp East	0%	1%	1%	1%
Public Service Company of NM	1%	0%	1%	1%
Tucson Electric Power	2%	1%	2%	2%
Turlock Irrigation District	0%	7%	0%	5%
Idaho Power	1%	8%	1%	5%
Avista Utilities	1%	9%	2%	6%
NorthWestern Energy	2%	8%	2%	5%
PacifiCorp West	7%	9%	5%	4%
Portland General Electric	8%	10%	6%	5%
Bonneville Power Admin.	8%	16%	7%	14%
Salt River Project	26%	1%	25%	1%
Tacoma Power	12%	17%	14%	15%
Puget Sound Energy	12%	18%	14%	15%
Seattle City Light	12%	18%	14%	15%
Powerex	29%	22%	40%	31%

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

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.[42] The dash indicates the area did not fail the test during the month.

Net load uncertainty was removed from the bid-range capacity test on February 15, 2022.[43] Intertie uncertainty was removed on June 1, 2022. Net load uncertainty is proposed to return to the capacity test in the summer of 2023.[44] This is following the introduction of the new quantile regression methodology for calculating uncertainty that will be deployed as part of the *flexible ramping product enhancements* in February 2023.[45] The CAISO is also proposing to permanently remove intertie uncertainty from the capacity test.

WEIM participants failed the resource sufficiency evaluation infrequently in the fourth quarter. Both the capacity and flexibility tests were failed in less than 1 percent of intervals, across each area and direction.

41 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.

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

43 Net load uncertainty was originally added to the requirement of the bid-range capacity test on June 16, 2021.

44 California ISO, *EIM Resource Sufficiency Evaluation Enhancements Phase 2 Straw Proposal*, July 1, 2022. http://www.caiso.com/InitiativeDocuments/StrawProposal-WEIMResourceSufficiencyEvaluationEnhancementsPhase2.pdf

45 California ISO Market Notice: *Hybrid Resources Phase 2-B and Flexible Ramping Product Improvements activation rescheduled from 12/1/22 to 2/1/23*, November 30, 2022: http://www.caiso.com/Documents/hybrid-resources-phase-2b-and-flexible-ramping-product-improvements-activation-rescheduled-from-12122-to-2123.html

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

	2021			2022											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	—	0.3	0.0	—	—	0.0	0.0	—	—	—	—	—	—	—	0.1
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	0.3	0.2	0.1	—	—	—	—	—	—	0.0	—	—	—	—	—
NorthWestern	8.5	1.2	0.2	0.3	0.1	—	0.0	—	—	—	0.1	0.1	—	0.2	0.1
NV Energy	0.3	—	—	—	—	—	0.2	0.1	0.0	0.1	—	—	—	—	—
PacifiCorp East	0.1	—	—	—	—	—	—	—	—	—	—	0.1	—	—	0.3
PacifiCorp West	0.1	0.5	0.4	0.3	0.1	0.3	0.0	0.2	0.0	1.0	0.2	0.0	—	0.0	0.0
Portland GE	0.4	0.2	0.4	0.1	—	—	—	—	—	—	0.1	—	—	0.3	—
Powerex	0.5	0.2	0.2	0.2	—	—	0.1	—	—	—	0.2	—	—	0.0	—
PSC New Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Puget Sound En	1.0	0.6	0.3	—	—	—	0.0	0.0	0.2	—	—	0.2	0.1	0.0	—
Salt River Proj.	0.1	0.7	—	—	—	0.2	1.5	1.0	0.2	0.2	0.4	0.4	0.2	0.0	0.0
Seattle City Light	0.1	—	0.1	—	—	0.1	—	—	—	0.2	0.1	0.2	0.0	0.0	0.2
Tacoma Power						—	0.6	0.1	0.0	0.0	0.2	0.0	—	—	—
Tucson Elec.								—	—	—	0.1	—	—	—	—
Turlock ID	1.5	—	—	—	—	—	—	—	0.1	—	—	—	—	—	0.2

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

	2021			2022											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	—	0.3	0.0	0.0	0.2	0.1	—	—	—	0.0	0.1	—	—	0.1	0.4
Avista						—	0.2	0.5	1.0	0.5	0.1	—	0.1	—	0.1
BANC	—	—	—	—	—	—	—	—	—	—	—	0.3	—	—	—
BPA								0.9	3.1	3.3	1.0	1.1	0.2	0.1	0.4
California ISO	—	0.1	—	—	—	—	—	—	—	—	0.1	0.5	0.0	—	—
Idaho Power	—	—	0.0	—	0.2	—	—	—	—	0.2	0.2	0.5	—	0.1	—
LADWP	0.0	0.0	0.3	—	—	0.1	—	—	—	—	—	0.1	0.1	—	—
NorthWestern	8.3	0.5	0.5	—	0.1	0.1	0.3	—	0.1	0.3	1.0	0.2	—	0.5	0.8
NV Energy	0.3	0.0	0.0	0.0	0.7	0.4	1.0	0.8	0.2	—	0.1	0.1	0.1	0.2	0.0
PacifiCorp East	—	0.1	0.0	0.0	0.0	—	0.1	0.1	0.1	0.2	0.1	—	0.1	—	0.0
PacifiCorp West	—	0.6	0.2	0.0	0.0	0.1	0.2	0.1	0.0	—	0.1	0.1	—	0.1	—
Portland GE	0.0	—	0.2	0.3	0.0	—	—	—	0.0	0.4	0.1	0.1	0.2	1.0	0.1
Powerex	0.2	0.2	0.3	0.2	0.0	—	0.1	—	—	—	0.3	0.1	—	—	—
PSC New Mexico	—	0.1	—	—	—	0.1	0.0	0.1	—	0.4	—	0.0	0.2	0.1	0.8
Puget Sound En	—	0.1	—	—	—	0.0	0.1	—	0.1	0.4	0.2	0.3	—	0.0	—
Salt River Proj.	0.2	1.2	0.0	0.2	—	0.6	0.5	0.2	0.5	0.6	1.1	0.6	0.6	0.5	0.8
Seattle City Light	—	—	—	—	—	0.1	—	—	—	0.2	0.0	0.2	—	0.1	0.0
Tacoma Power						—	—	0.1	0.1	0.0	0.1	0.1	—	0.2	—
Tucson Elec.								0.1	—	—	—	0.4	0.0	—	0.2
Turlock ID	0.2	—	—	—	—	—	—	—	—	—	—	0.1	—	—	1.2

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

	2021			2022											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	—	0.2	—	0.3	—	—	—	0.0	0.0	—	—	—	—	—	0.1
Avista						—	—	—	—	0.2	—	—	0.0	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA								—	—	—	—	0.1	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	0.1	—	—	—	—	—	0.6	—	—	—	—	—	—	—
LADWP	0.2	—	—	0.3	—	—	—	0.2	—	—	—	—	—	—	—
NorthWestern	1.0	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NV Energy	—	—	—	—	—	—	—	0.1	0.5	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland GE	—	—	—	—	—	—	—	—	0.0	—	—	—	—	—	—
Powerex	0.3	0.0	—	0.1	—	0.1	—	0.1	—	—	0.0	—	—	0.0	—
PSC New Mexico	0.2	0.1	—	—	—	0.1	—	0.1	—	—	—	—	—	—	—
Puget Sound En	0.0	—	—	—	—	—	—	0.0	0.7	0.1	—	—	—	—	—
Salt River Proj.	—	—	0.0	—	0.2	0.3	—	0.4	0.5	0.1	0.2	1.1	0.2	0.3	—
Seattle City Light	—	0.2	0.2	—	—	0.1	—	—	0.0	0.1	—	0.2	—	—	—
Tacoma Power						—	0.8	0.1	—	0.6	0.3	—	0.1	—	0.2
Tucson Elec.								—	0.0	—	—	—	—	—	—
Turlock ID	0.7	0.1	0.0	0.1	0.0	—	0.1	—	—	—	—	—	—	—	—

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

	2021			2022											
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	0.1	0.5	0.4	1.4	0.4	0.8	0.3	0.5	0.2	—	—	0.1	0.2	0.2	0.1
Avista						—	—	—	0.1	—	—	0.1	0.2	—	0.0
BANC	—	—	0.1	—	—	0.1	0.0	0.1	0.1	—	—	—	—	—	—
BPA								0.1	0.2	—	0.0	0.3	—	0.2	0.2
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	0.3	0.0	—	0.0	—	0.3	0.4	—	—	0.0	—	—	—	—
LADWP	0.1	—	—	0.1	—	—	—	—	—	—	—	—	—	—	—
NorthWestern	2.3	0.1	0.0	—	—	—	—	0.5	1.9	0.2	—	—	—	0.0	0.1
NV Energy	1.1	0.4	0.4	0.6	4.1	1.7	3.2	1.3	2.0	0.6	0.2	0.5	0.5	0.6	0.1
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	0.0	—	—	—	0.0	0.0	0.1	0.4	0.5	—	—	0.1	—	0.0
Portland GE	—	—	—	—	—	—	—	—	0.2	—	—	—	—	—	—
Powerex	0.4	0.0	0.1	—	0.0	0.2	0.0	0.3	0.2	—	0.1	0.1	0.1	—	—
PSC New Mexico	0.4	0.7	0.1	0.3	0.0	1.2	0.3	1.8	0.7	0.0	0.0	0.2	0.2	0.1	—
Puget Sound En	—	0.0	—	—	—	—	—	0.2	2.3	0.1	—	—	0.1	—	—
Salt River Proj.	0.1	0.0	0.1	0.1	1.0	1.5	0.2	0.4	0.5	0.2	0.2	1.0	0.2	0.9	0.3
Seattle City Light	—	0.0	0.0	—	—	0.1	0.1	0.1	0.3	0.1	0.8	0.3	—	0.2	0.6
Tacoma Power						—	0.4	0.3	—	0.5	0.2	—	—	—	0.1
Tucson Elec.								—	—	—	—	—	—	0.0	—
Turlock ID	0.6	0.1	0.2	0.2	—	0.5	0.6	0.1	0.5	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.[46] 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. Seattle City Light used negative imbalance conformance during 69 percent of 5-minute market intervals, averaging 1.8 percent of total load adjustment. 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.

46 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 (October-December)

Balancing area	Market	Positive imbalance conformance: Percent of intervals	Positive imbalance conformance: Average MW	Positive imbalance conformance: Percent of total load	Negative imbalance conformance: Percent of intervals	Negative imbalance conformance: Average MW	Negative imbalance conformance: Percent of total load	Average hourly adjustment MW
California ISO	FMM	51%	1202	5.0%	0.2%	-262	1.2%	610
	RTD	74%	345	1.5%	10%	-279	1.3%	230
BANC	FMM	0.1%	62	3.8%	0.1%	-41	2.3%	0
	RTD	0.2%	67	4.1%	0.6%	-40	2.3%	0
Turlock Irrigation District	FMM	0.0%	N/A	N/A	0.0%	-50	20%	0
	RTD	0.0%	N/A	N/A	0.1%	-40	16%	0
LADWP	FMM	0.2%	47	2.0%	0.3%	-63	3.0%	0
	RTD	8.1%	46	1.9%	24%	-54	2.3%	-9
NV Energy	FMM	0.0%	100	2.7%	0.0%	N/A	N/A	0
	RTD	46%	94	2.5%	6.6%	-101	2.8%	37
Arizona Public Service	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	48%	78	2.6%	20%	-61	2.3%	26
Tucson Electric Power	FMM	0.0%	100	9.5%	0.3%	-48	4.0%	0
	RTD	5.2%	49	4.3%	18%	-54	4.8%	-7
Salt River Project	FMM	1.3%	58	1.9%	0.0%	-100	3.4%	1
	RTD	12%	64	2.1%	0.7%	-92	3.3%	7
Public Service Co. of New Mexico	FMM	0.1%	60	4.0%	0.0%	N/A	N/A	0
	RTD	40%	65	4.4%	3.0%	-85	5.9%	23
PacifiCorp East	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	13%	91	1.6%	30%	-110	2.0%	-21
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	20%	43	2.1%	12%	-48	2.4%	3
NorthWestern Energy	FMM	11%	14	0.9%	3.1%	-11	0.8%	1
	RTD	23%	15	1.0%	7.7%	-14	1.0%	2
Avista Utilities	FMM	0.0%	10	0.6%	0.3%	-44	2.7%	0
	RTD	1.2%	15	1.0%	39%	-21	1.4%	-8
Bonneville Power Administration	FMM	56%	32	0.4%	43%	-29	0.4%	5
	RTD	55%	32	0.4%	43%	-29	0.4%	5
Tacoma Power	FMM	0.2%	15	2.0%	0.0%	N/A	N/A	0
	RTD	5.0%	12	1.8%	4.0%	-13	2.1%	0
PacifiCorp West	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	8.2%	64	2.6%	6.6%	-48	1.8%	2
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	7.6%	30	1.0%	1.1%	-59	2.2%	2
Puget Sound Energy	FMM	1.0%	49	1.4%	2.2%	-48	1.4%	-1
	RTD	2.0%	47	1.4%	38%	-39	1.2%	-14
Seattle City Light	FMM	0.3%	16	1.0%	6.2%	-19	1.5%	-1
	RTD	4.5%	15	1.1%	69%	-22	1.8%	-15

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:

- The system marginal energy price (SMEC) was the largest contributor to the overall LMP in each area. Congestion within the CAISO had strong effects on PacifiCorp East and PSC New Mexico, but only a small impact elsewhere.
- Average quarterly transfers in the 15-minute and 5-minute markets have generally remained relatively consistent over recent quarters, but have been steadily increasing in BANC, BPA, NWMT, PNM, and TPWR.

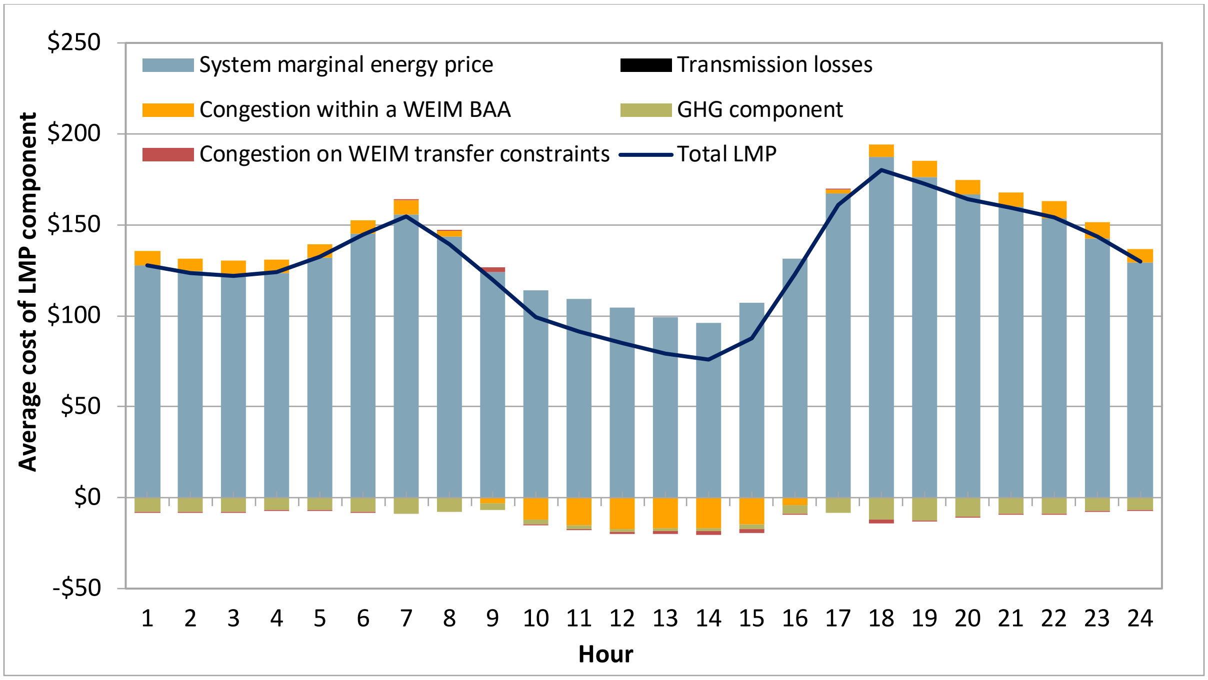
The hourly locational marginal price decomposition figures break down the price into five separate components. These components, listed below, can influence the prices in an area positively or negatively depending on the circumstances.

- **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 the CAISO** is the price impact from internal transmission constraints that are restricting the flow of energy within an area. While these constraints are located within a single balancing area, they can create price impacts across the WEIM. This LMP component is labeled 'within CAISO' as it is primarily transmission constraints within the CAISO area that are affecting prices. However, price impacts from internal constraints within other WEIM balancing areas are included in the category as well.
- **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.

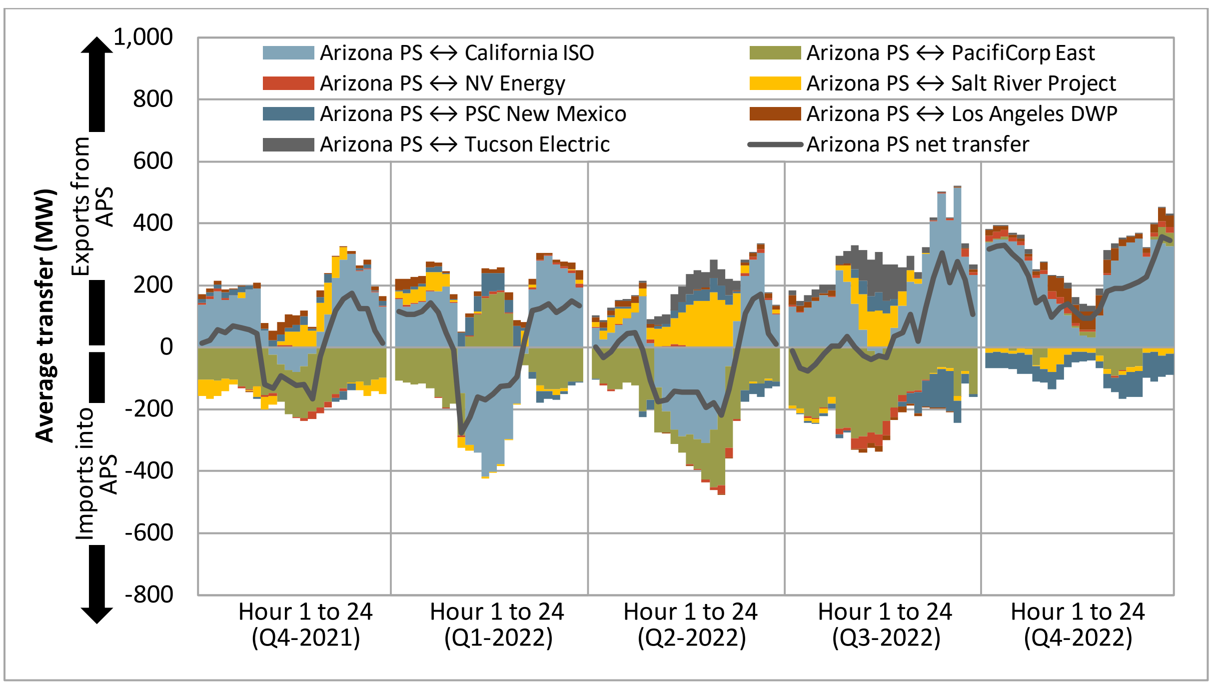
The transfer figures below show the hourly average imports and exports by WEIM area in the 15-minute and 5-minute markets by quarter. These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will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

A.1 Arizona Public Service

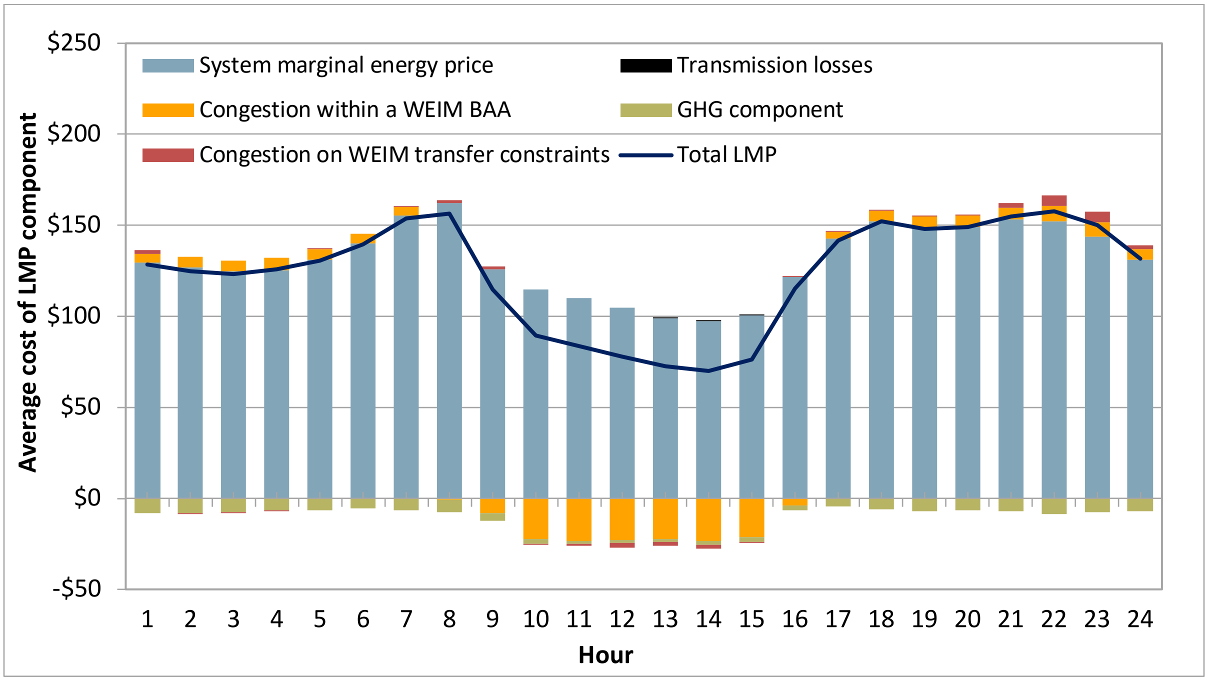
Appendix Figure A.1 Average hourly 15-minute price by component (Q4 2022)



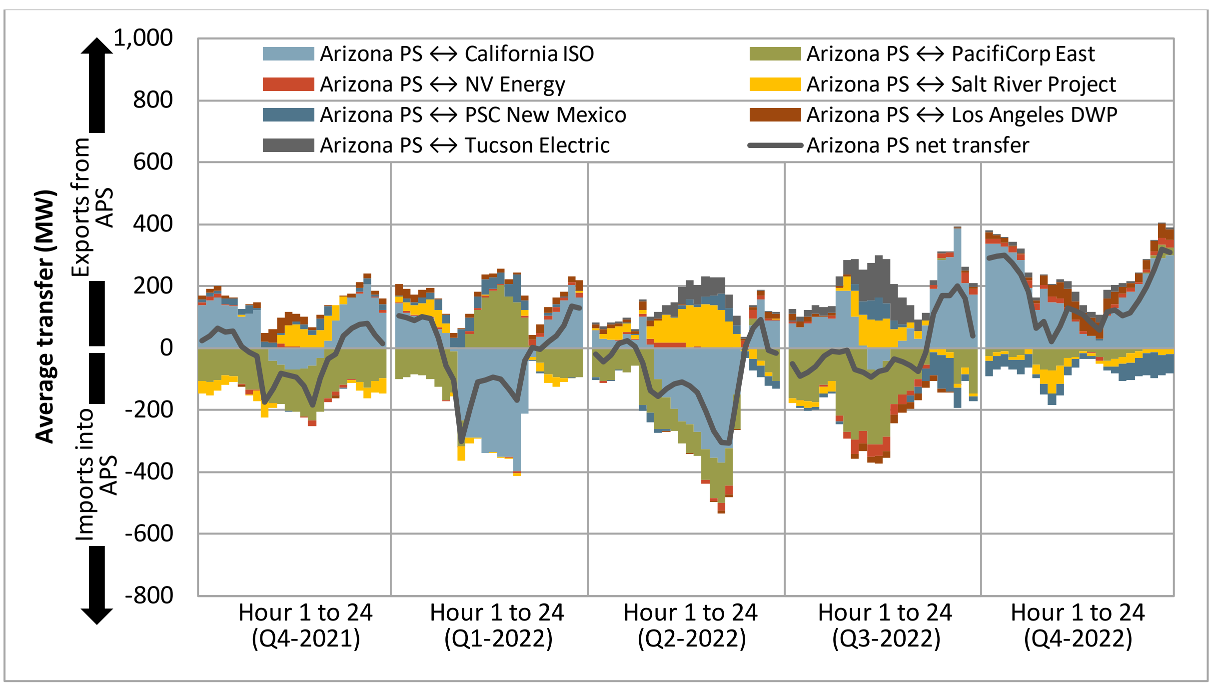
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q4 2022)

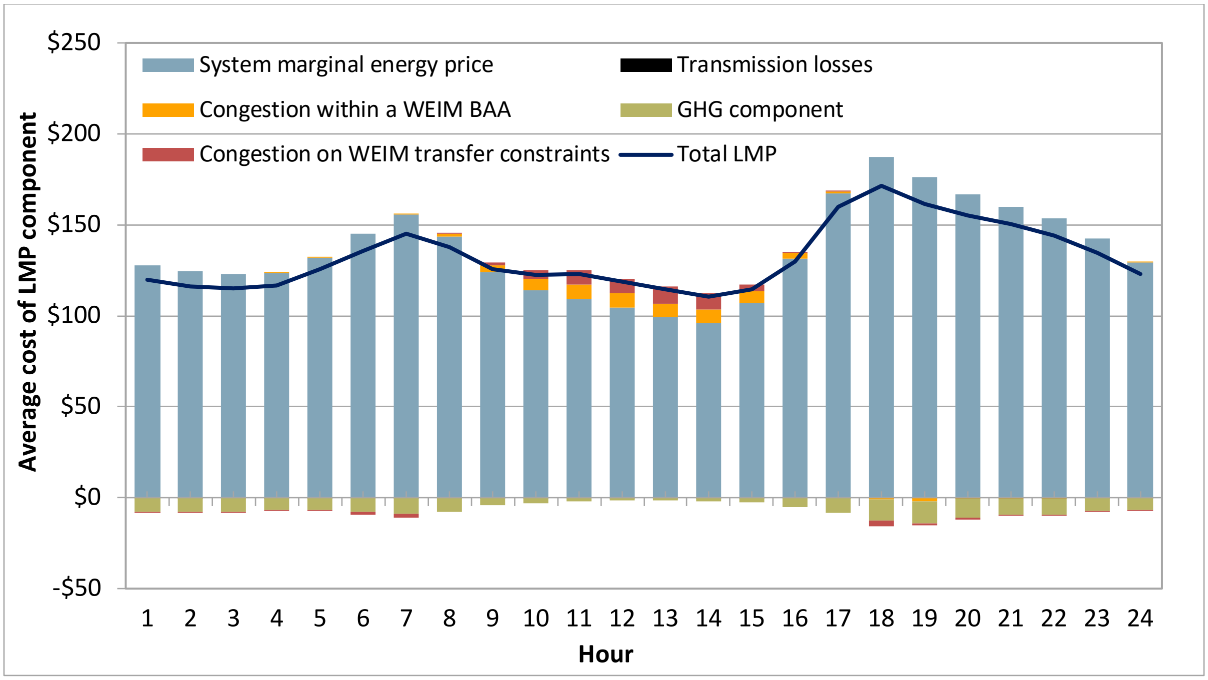


Appendix Figure A.4 Average hourly 5-minute market transfers

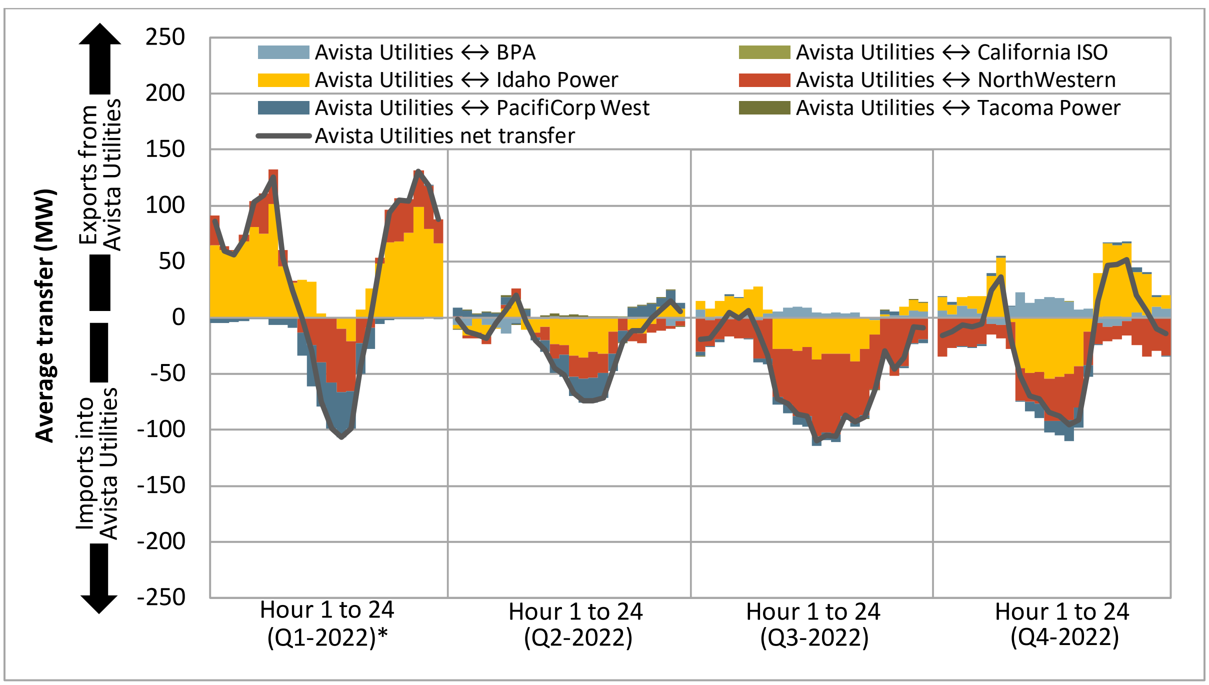


A.2 Avista Utilities

Appendix Figure A.5 Average hourly 15-minute price by component (Q4 2022)

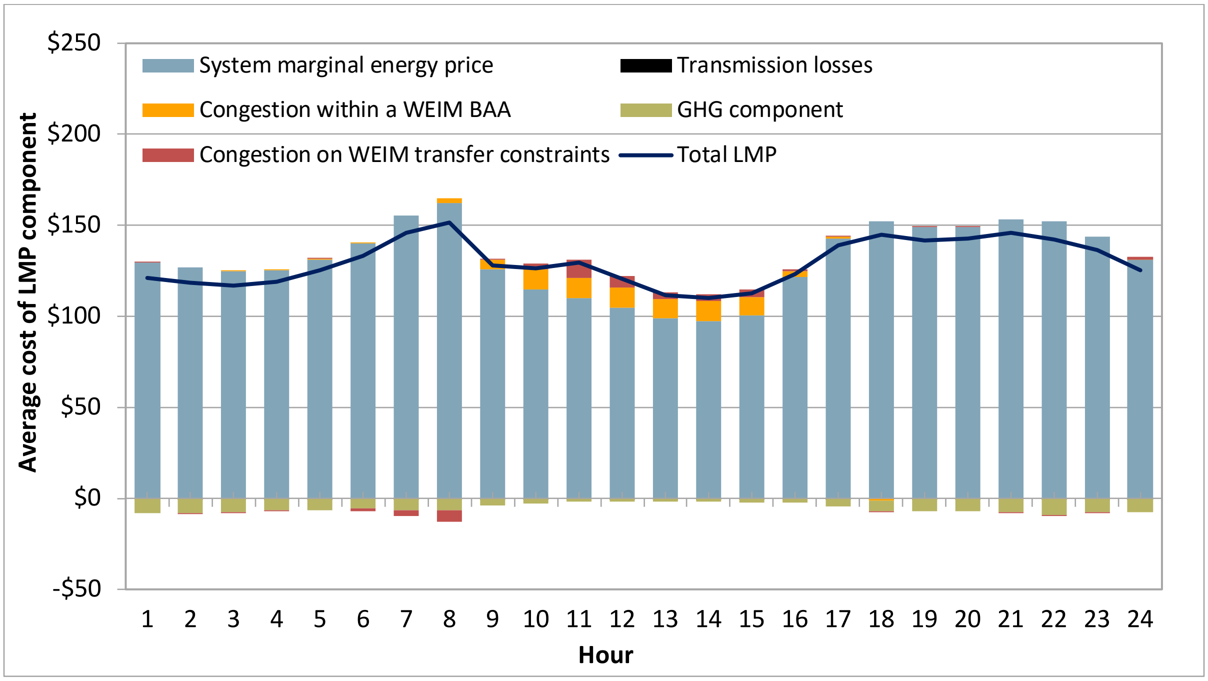


Appendix Figure A.6 Average hourly 15-minute market transfers

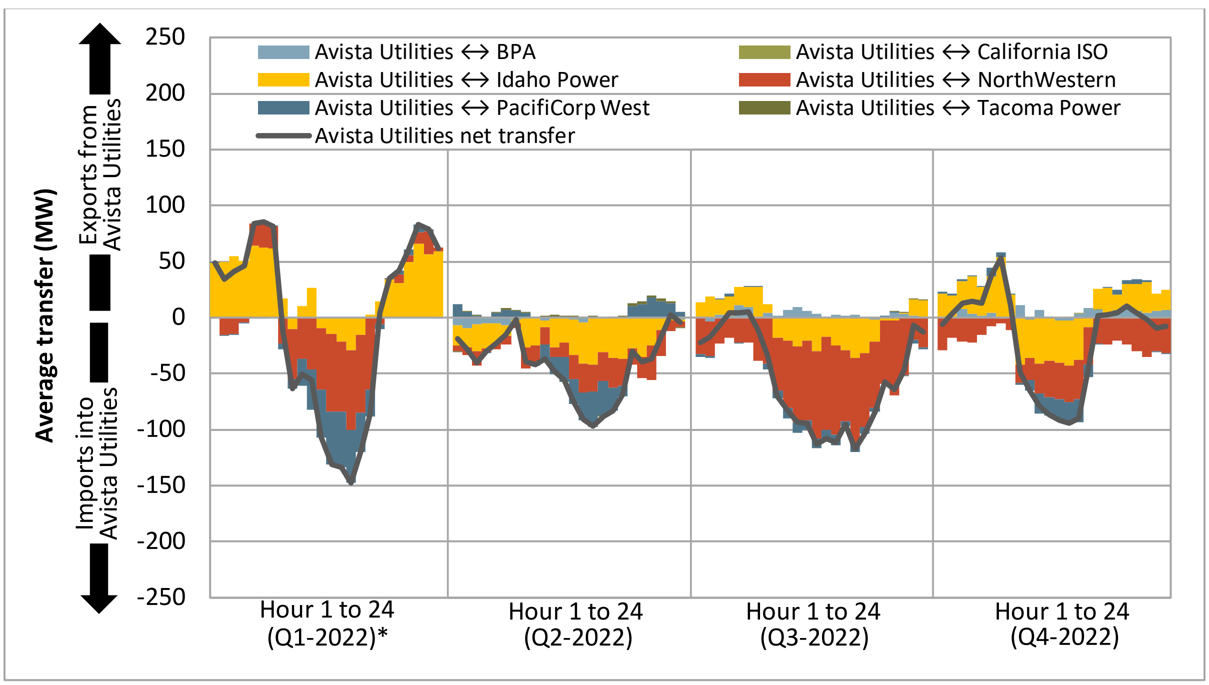


*Since joining the WEIM

Appendix Figure A.7 Average hourly 5-minute price by component (Q4 2022)



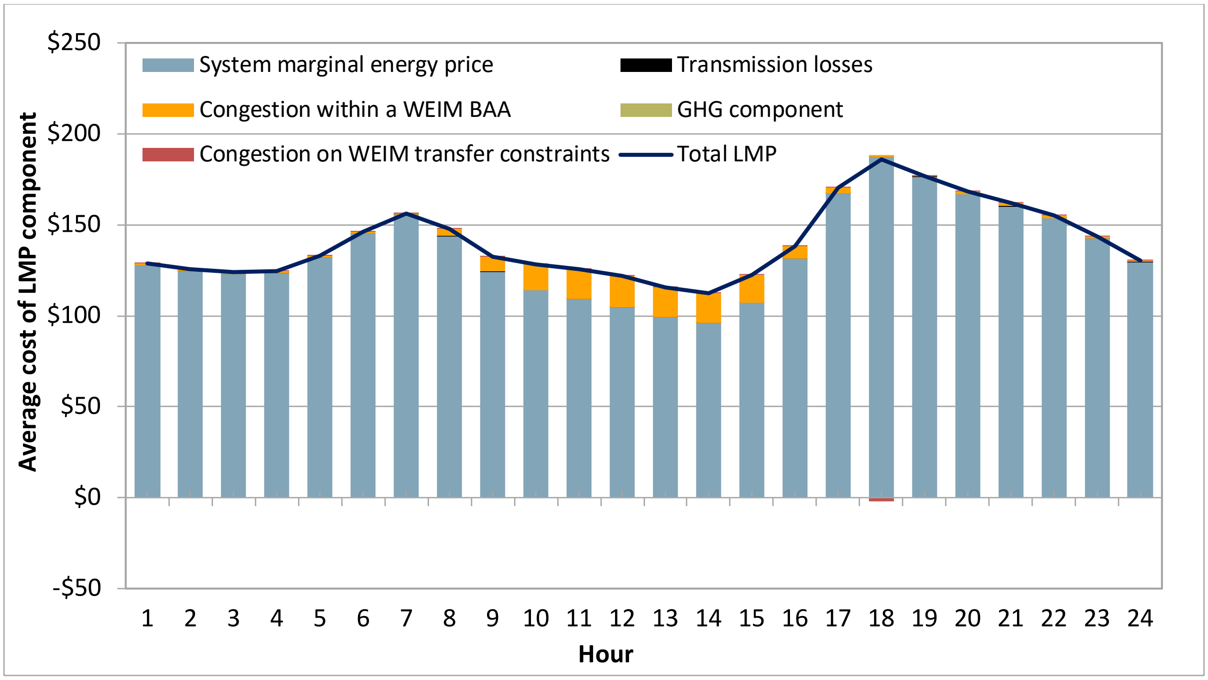
Appendix Figure A.8 Average hourly 5-minute market transfers



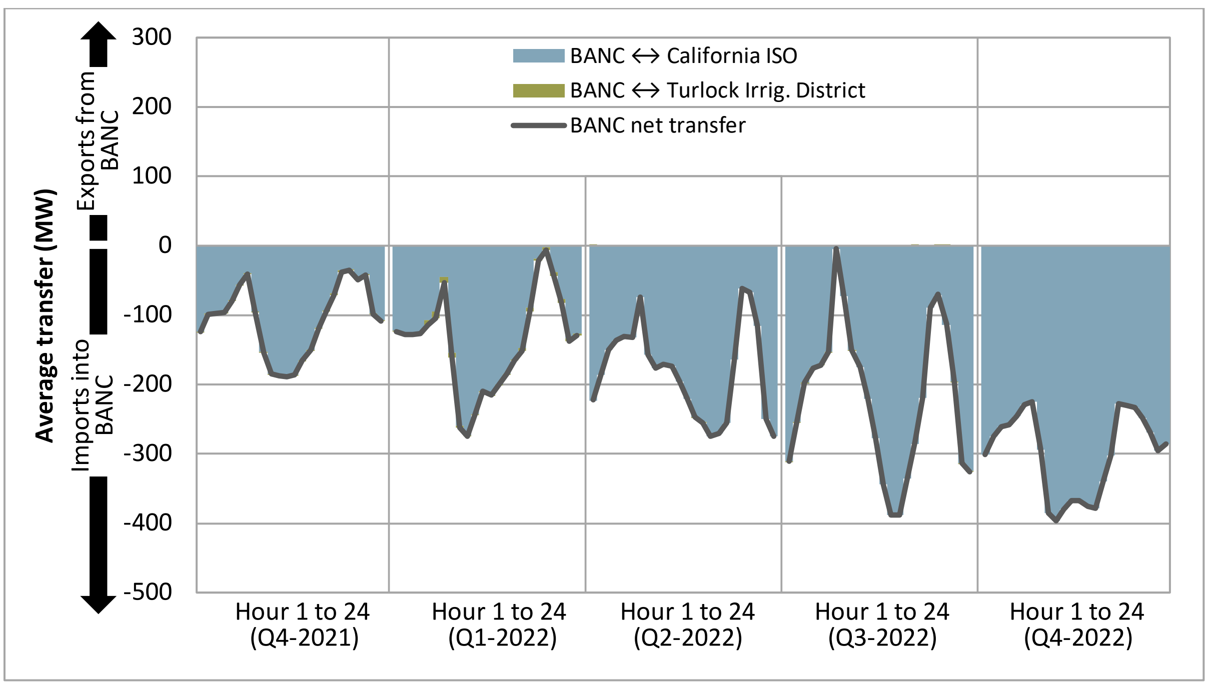
*Since joining the WEIM

A.3 Balancing Authority of Northern California

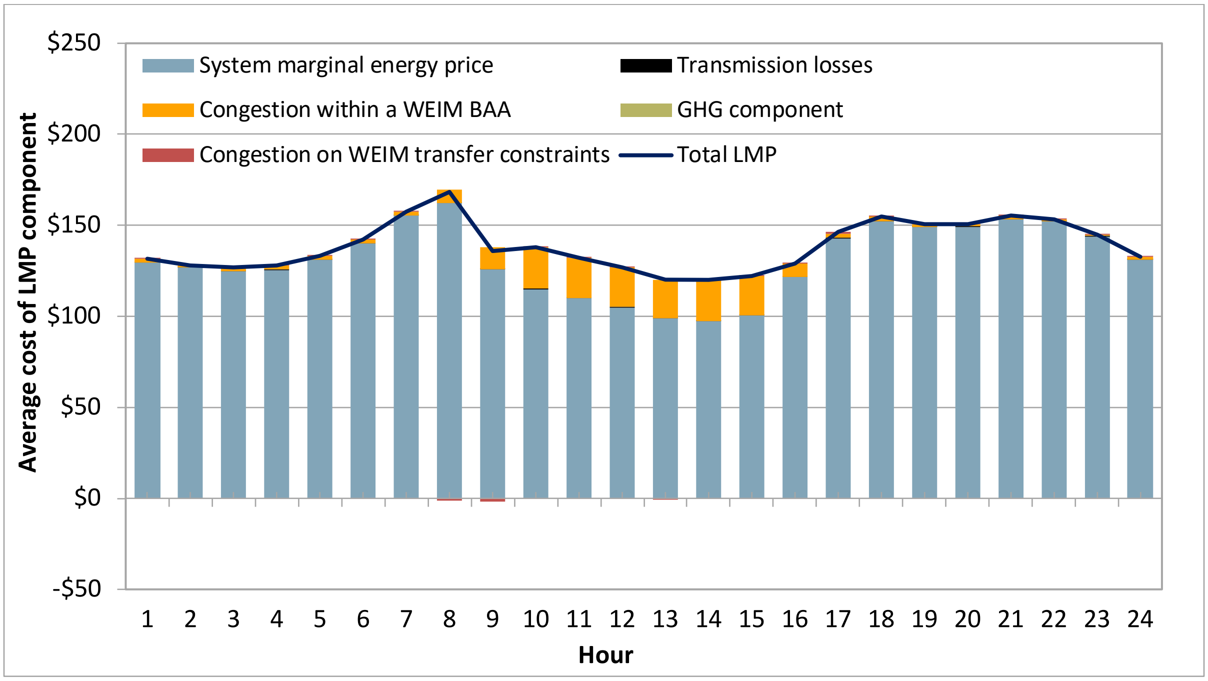
Appendix Figure A.9 Average hourly 15-minute price by component (Q4 2022)



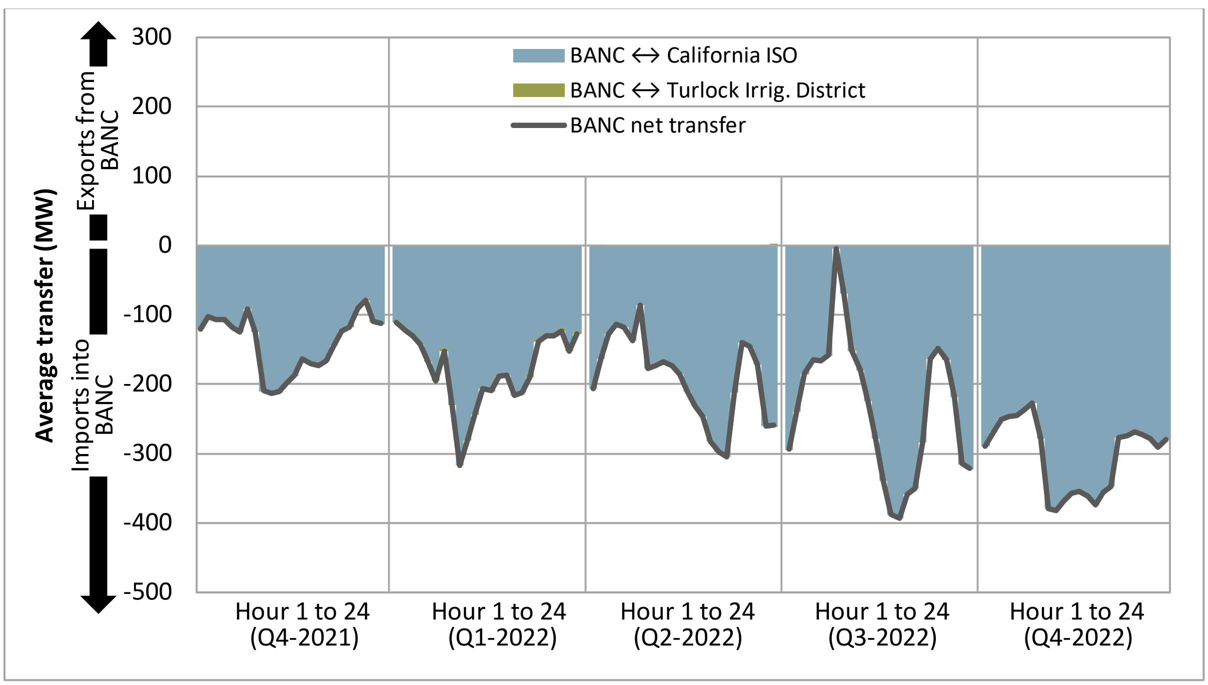
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q4 2022)

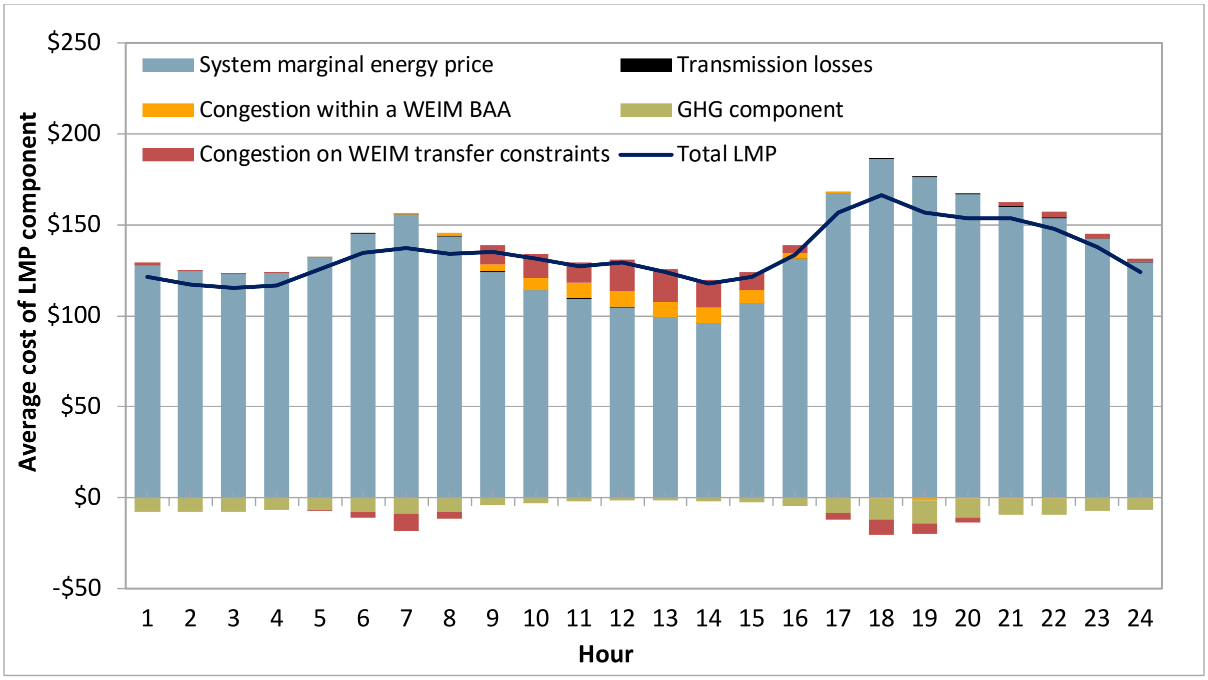


Appendix Figure A.12 Average hourly 5-minute market transfers

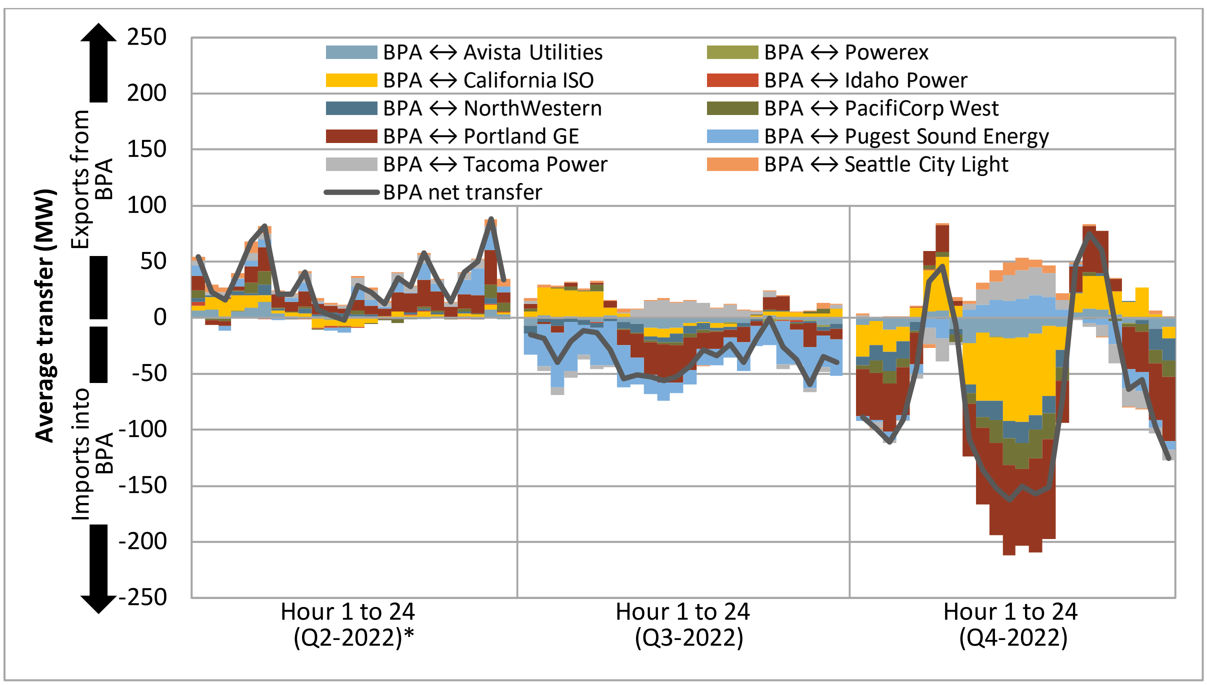


A.4 Bonneville Power Administration

Appendix Figure A.13 Average hourly 15-minute price by component (Q4 2022)

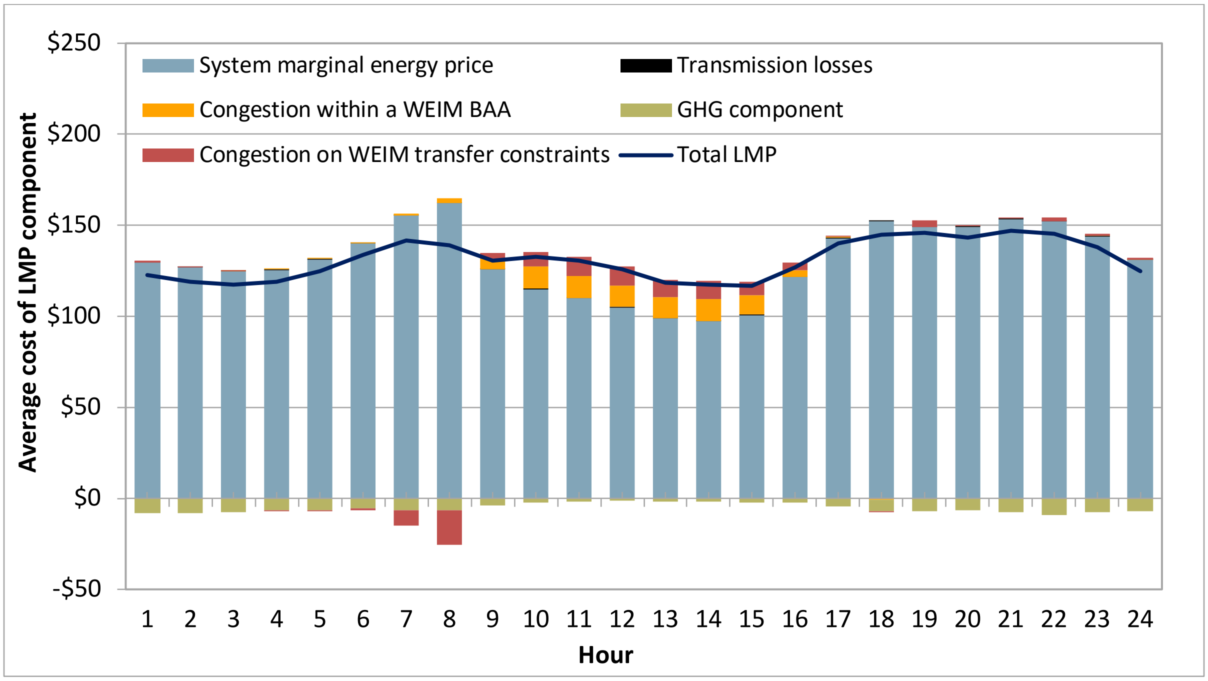


Appendix Figure A.14 Average hourly 15-minute market transfers

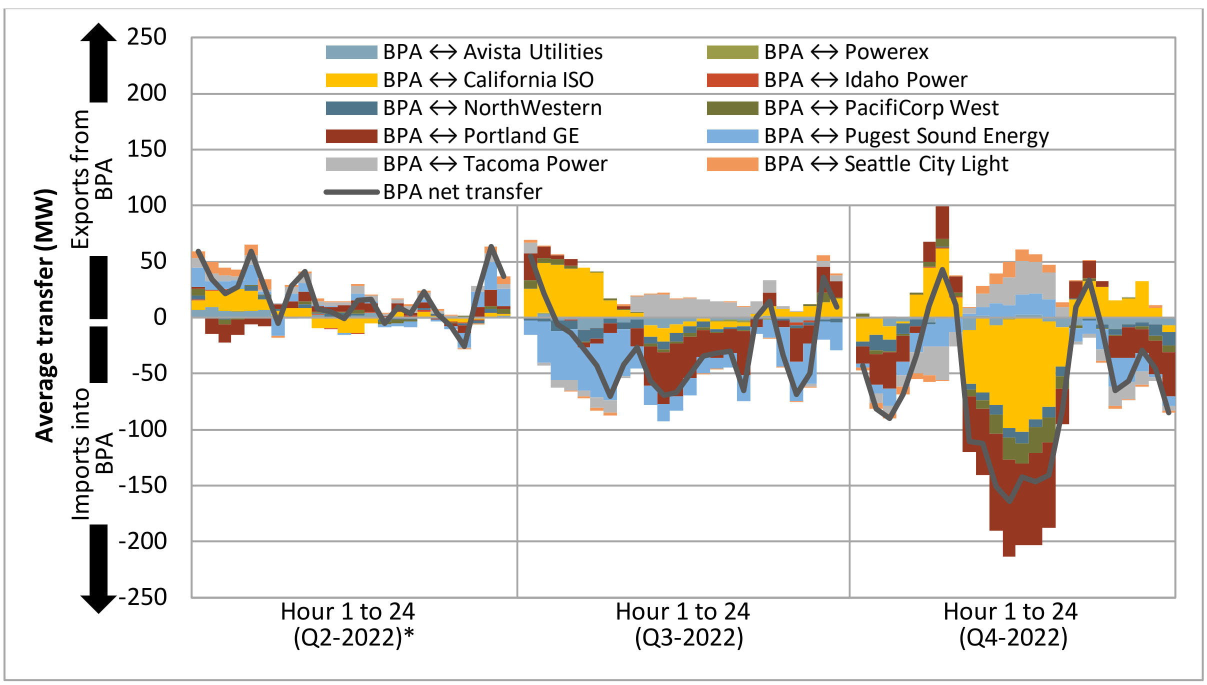


*Since joining the WEIM

Appendix Figure A.15 Average hourly 5-minute price by component (Q4 2022)



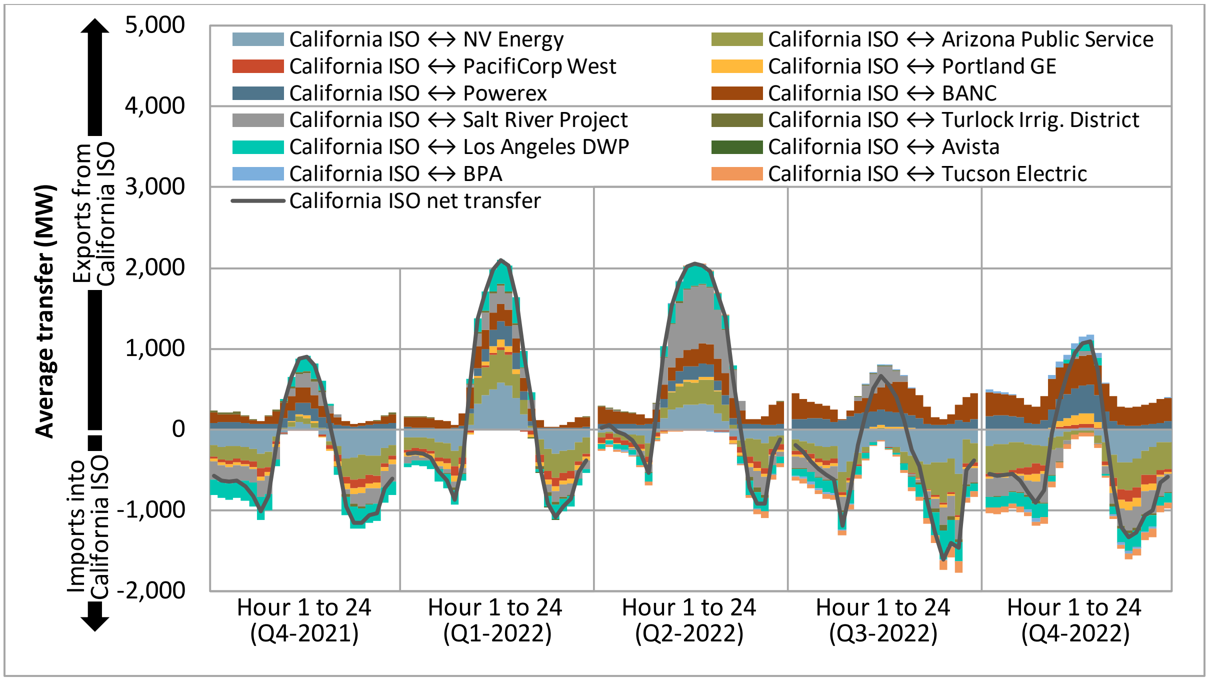
Appendix Figure A.16 Average hourly 5-minute market transfers



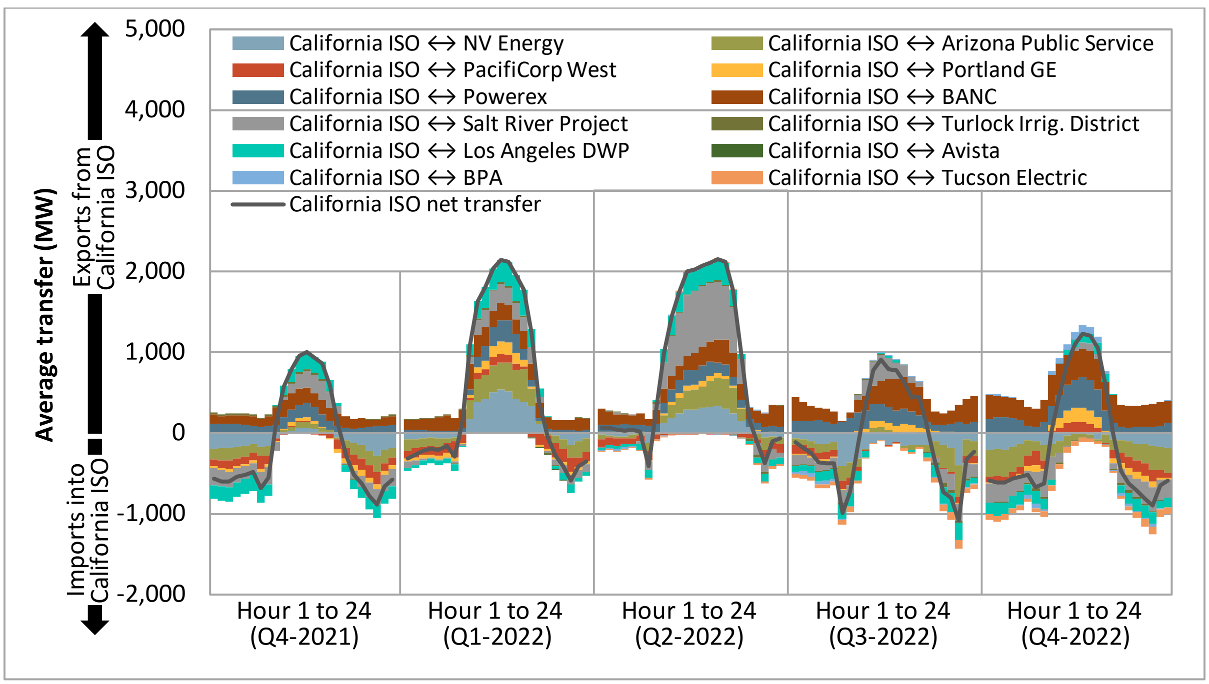
*Since joining the WEIM

A.5 California ISO

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

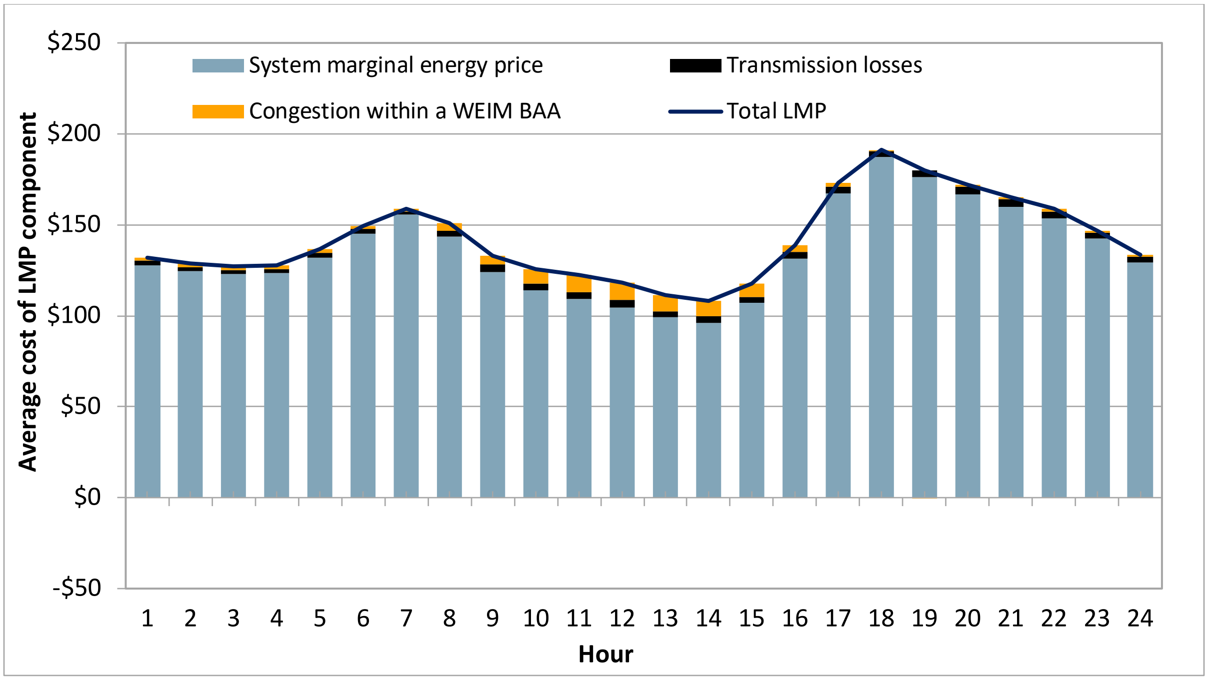


Appendix Figure A.18 Average hourly 5-minute market transfers

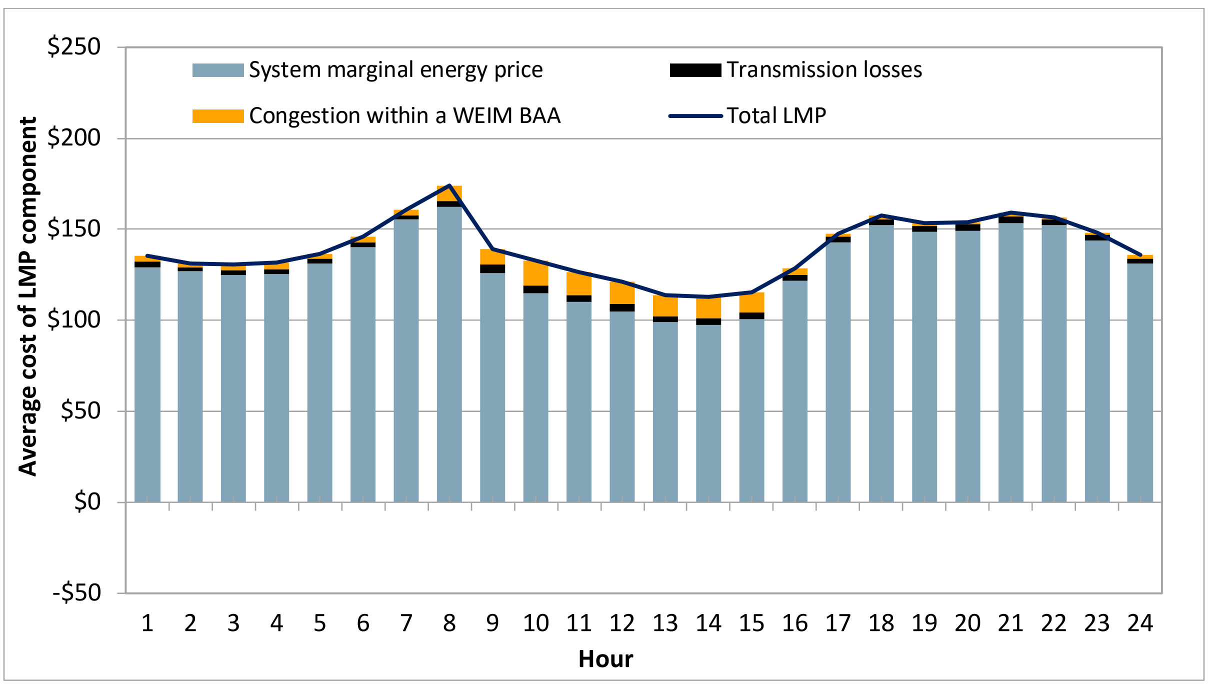


A.5.1 Pacific Gas and Electric

Appendix Figure A.19 Average hourly 15-minute price by component (Q4 2022)

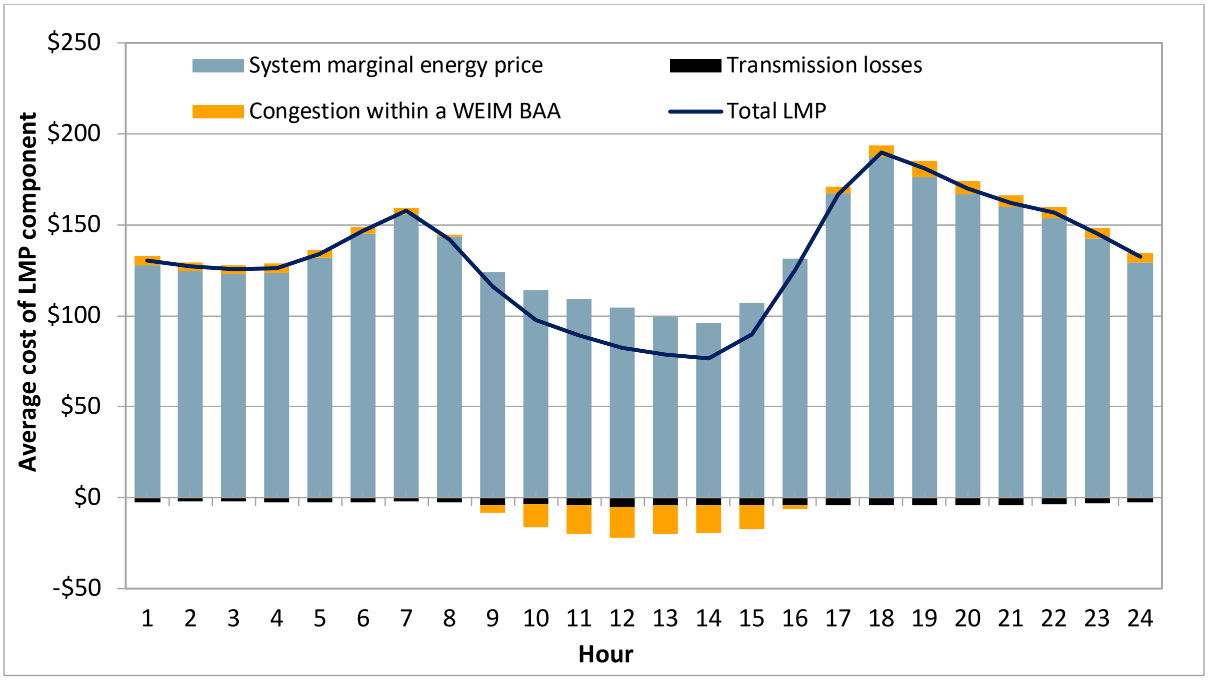


Appendix Figure A.20 Average hourly 5-minute price by component (Q4 2022)

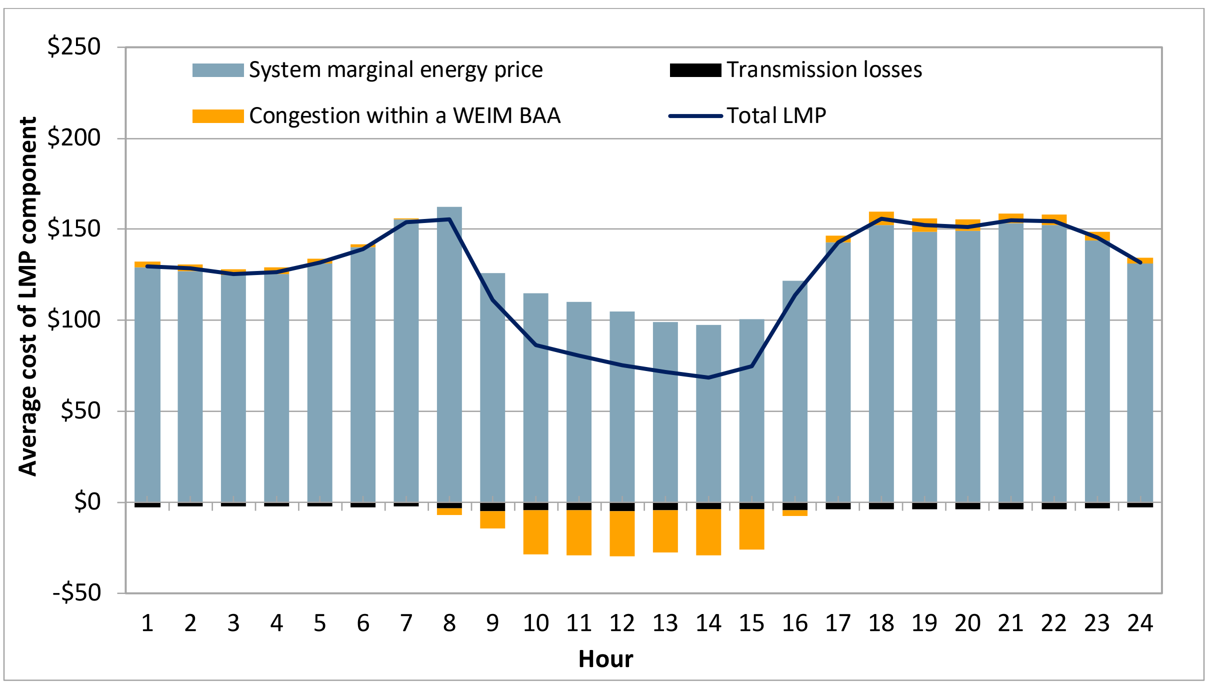


A.5.2 Southern California Edison

Appendix Figure A.21 Average hourly 15-minute price by component (Q4 2022)

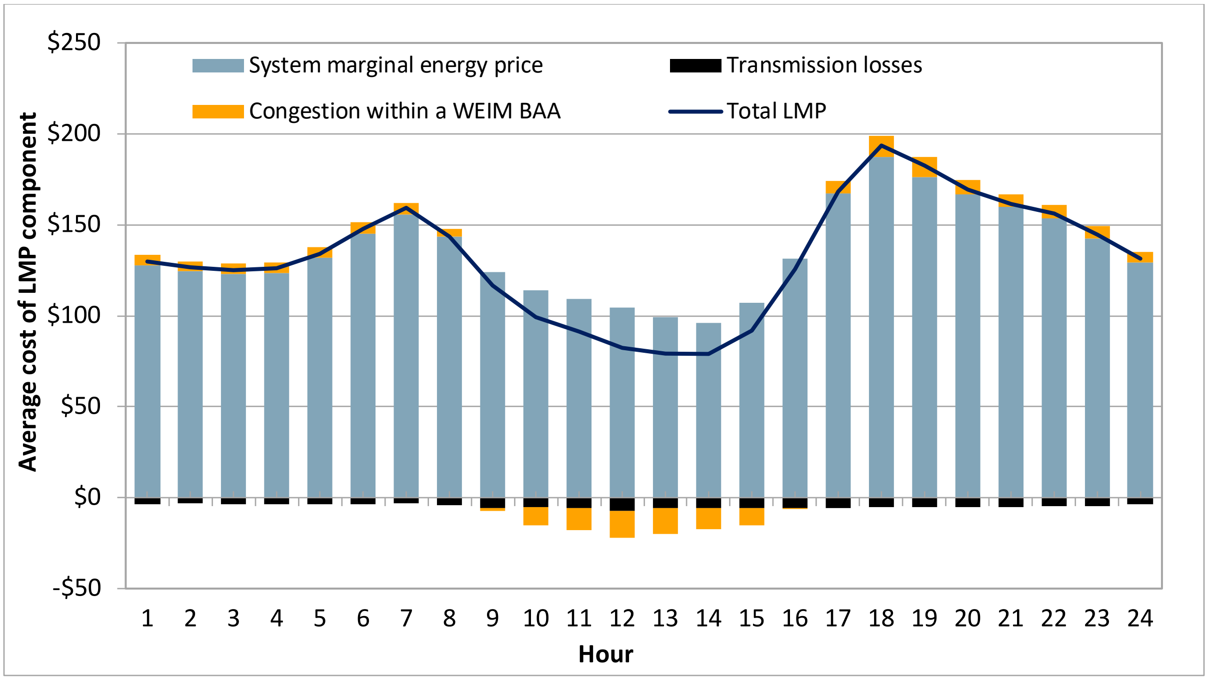


Appendix Figure A.22 Average hourly 5-minute price by component (Q4 2022)

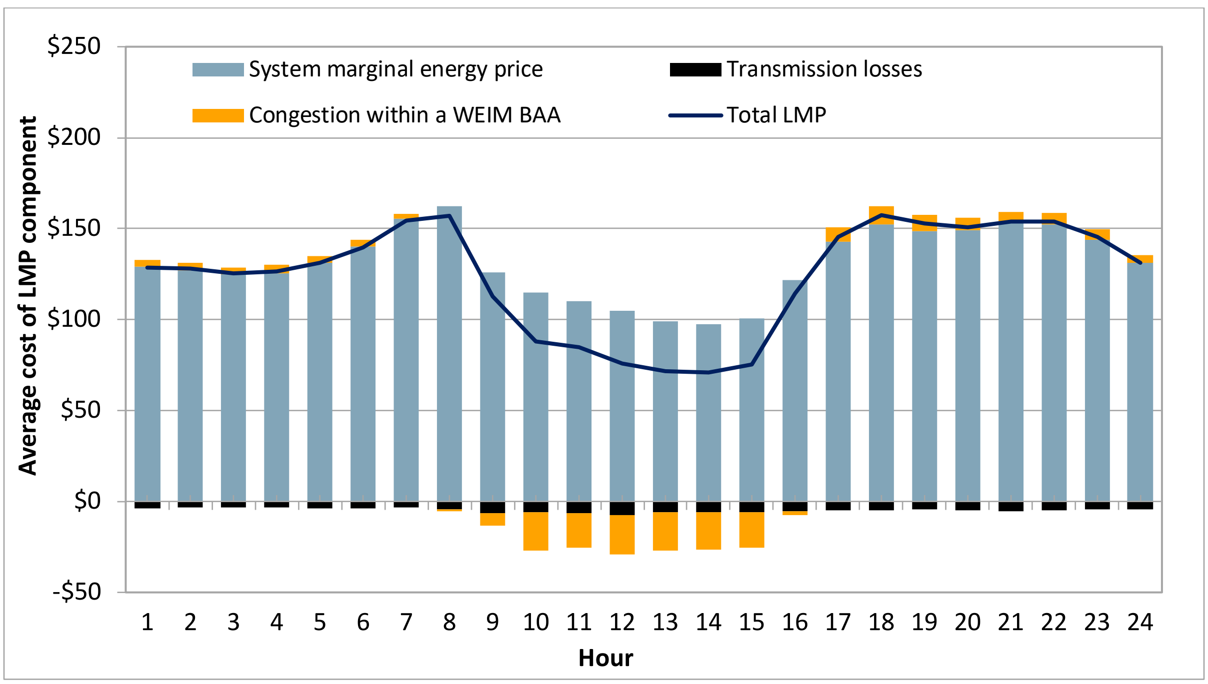


A.5.3 San Diego Gas & Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q4 2022)

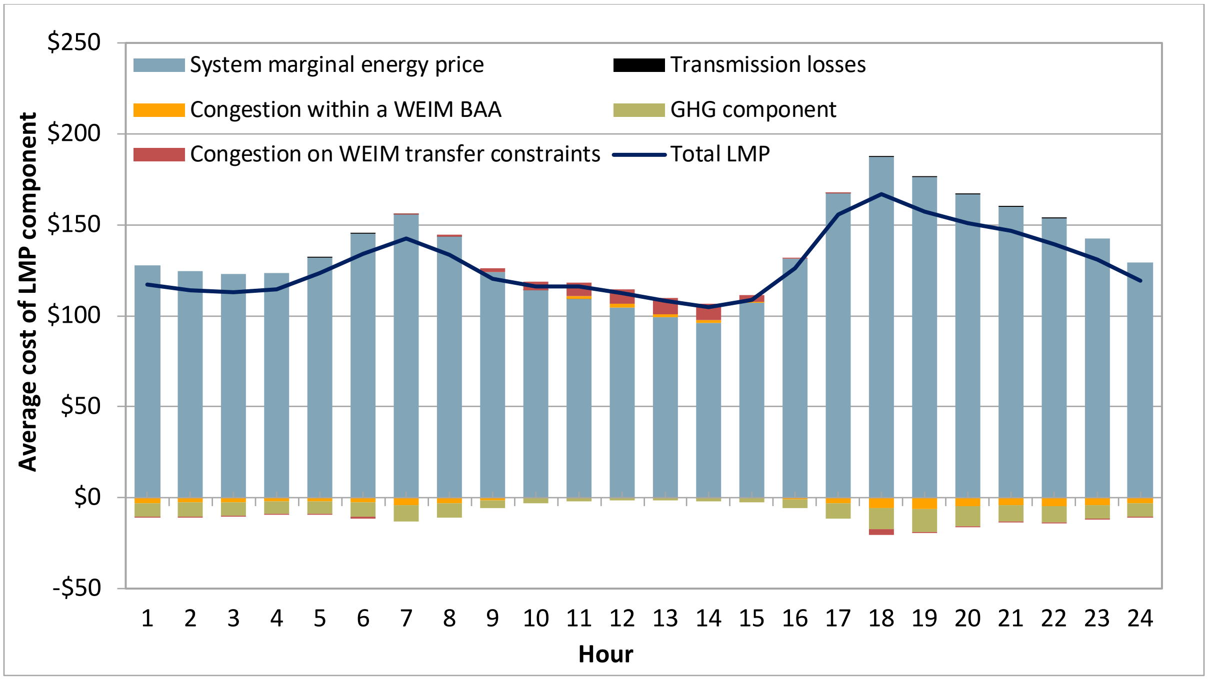


Appendix Figure A.24 Average hourly 5-minute price by component (Q4 2022)

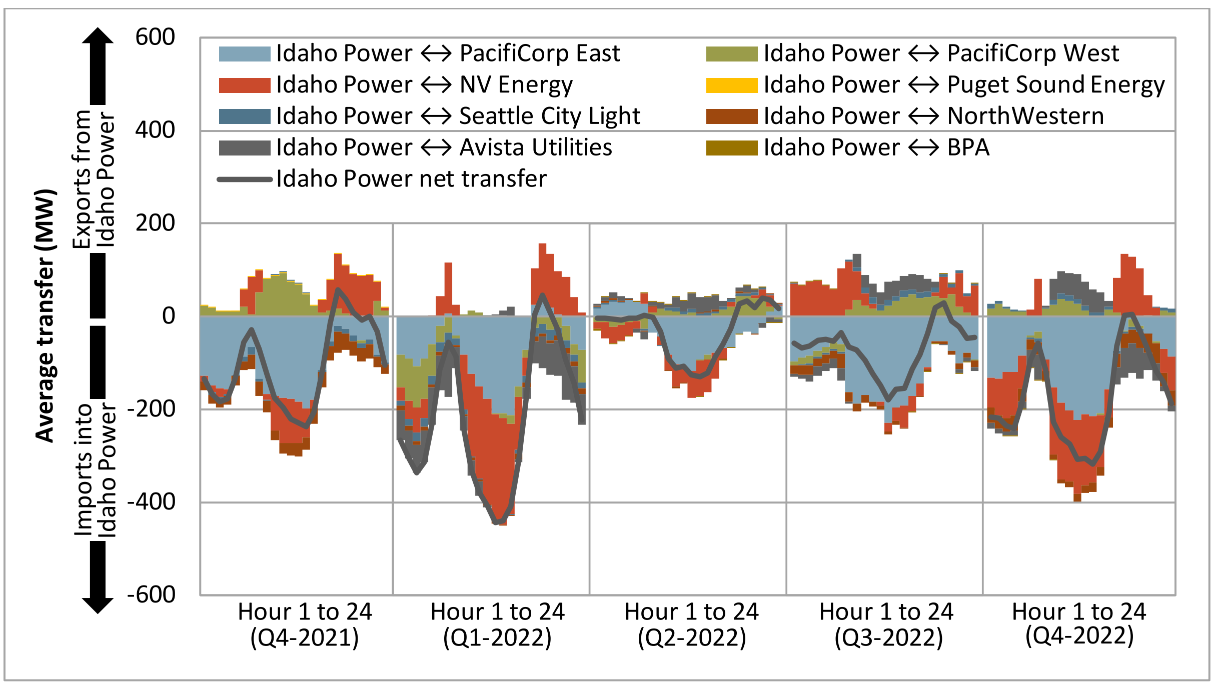


A.6 Idaho Power

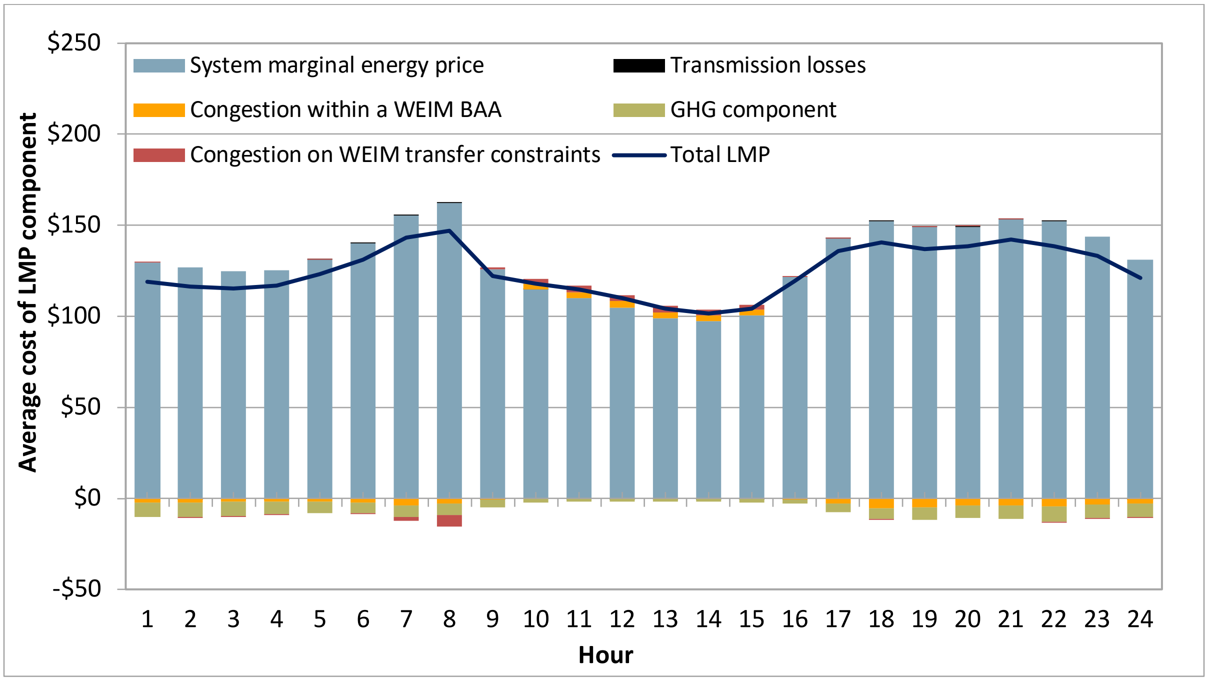
Appendix Figure A.25 Average hourly 15-minute price by component (Q4 2022)



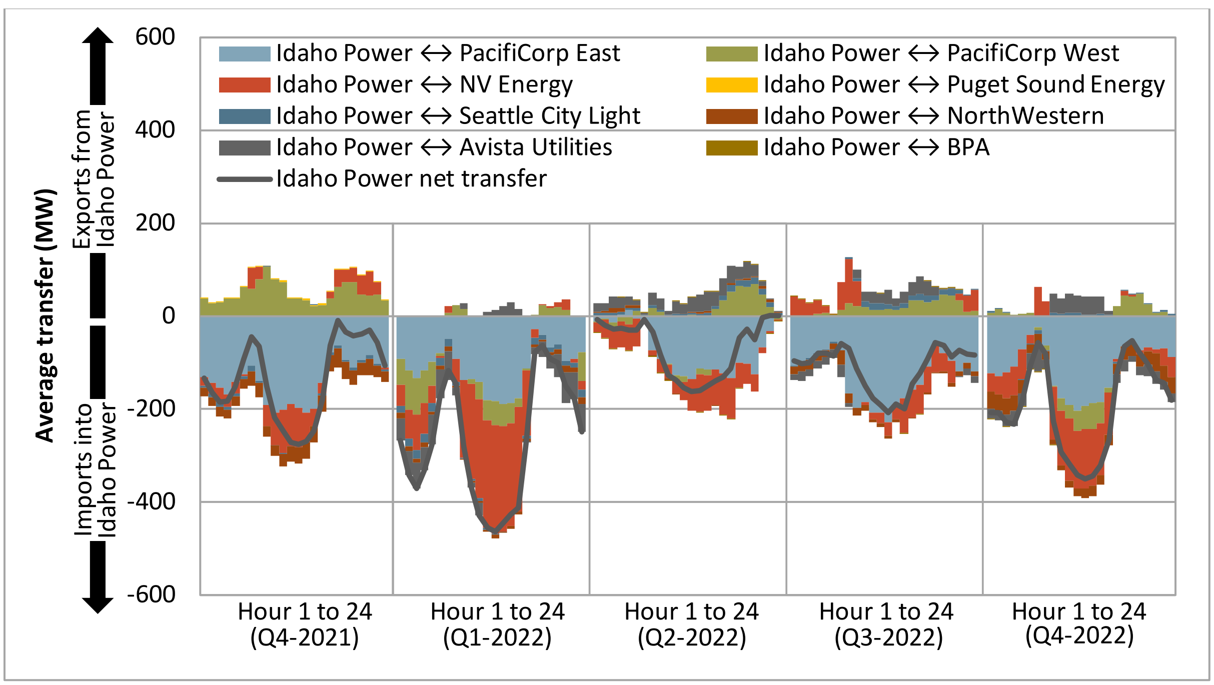
Appendix Figure A.26 Average hourly 15-minute market transfers



Appendix Figure A.27 Average hourly 5-minute price by component (Q4 2022)

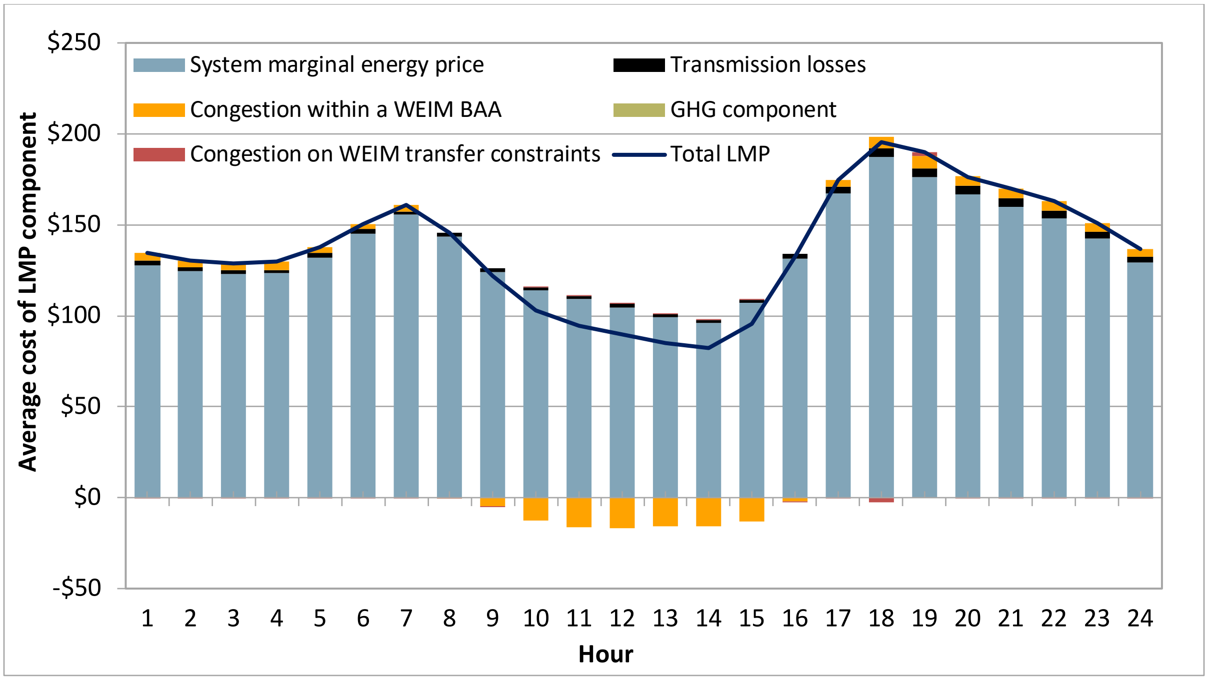


Appendix Figure A.28 Average hourly 5-minute market transfers

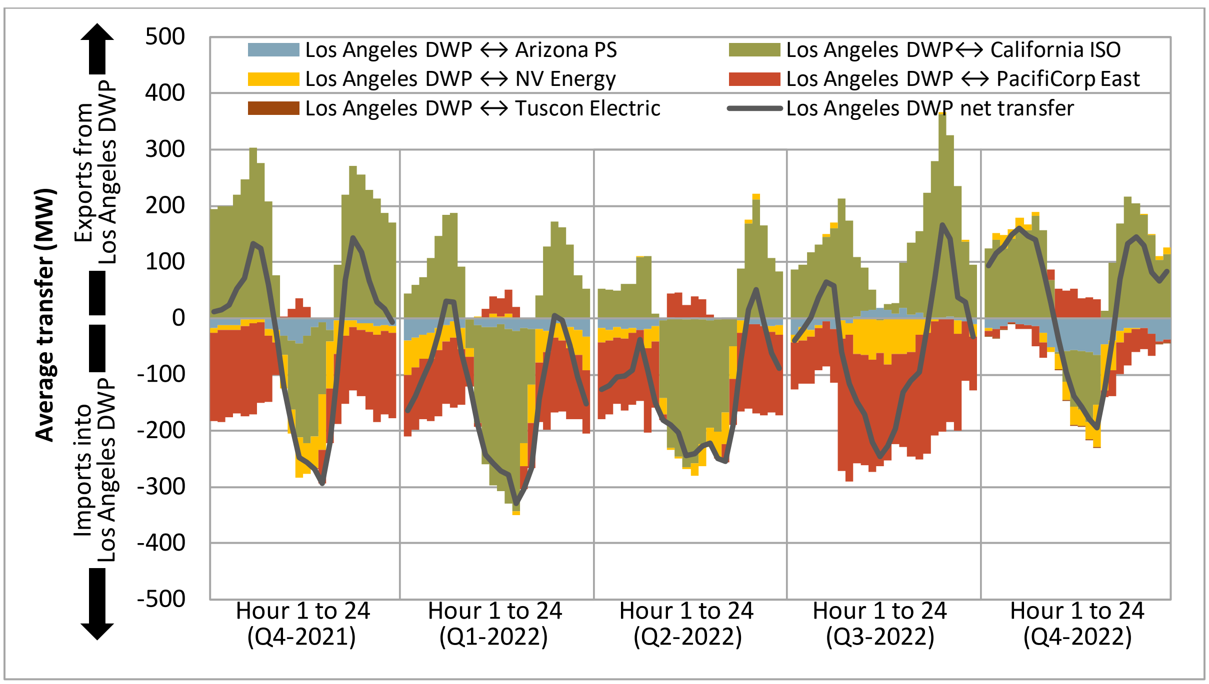


A.7 Los Angeles Department of Water and Power

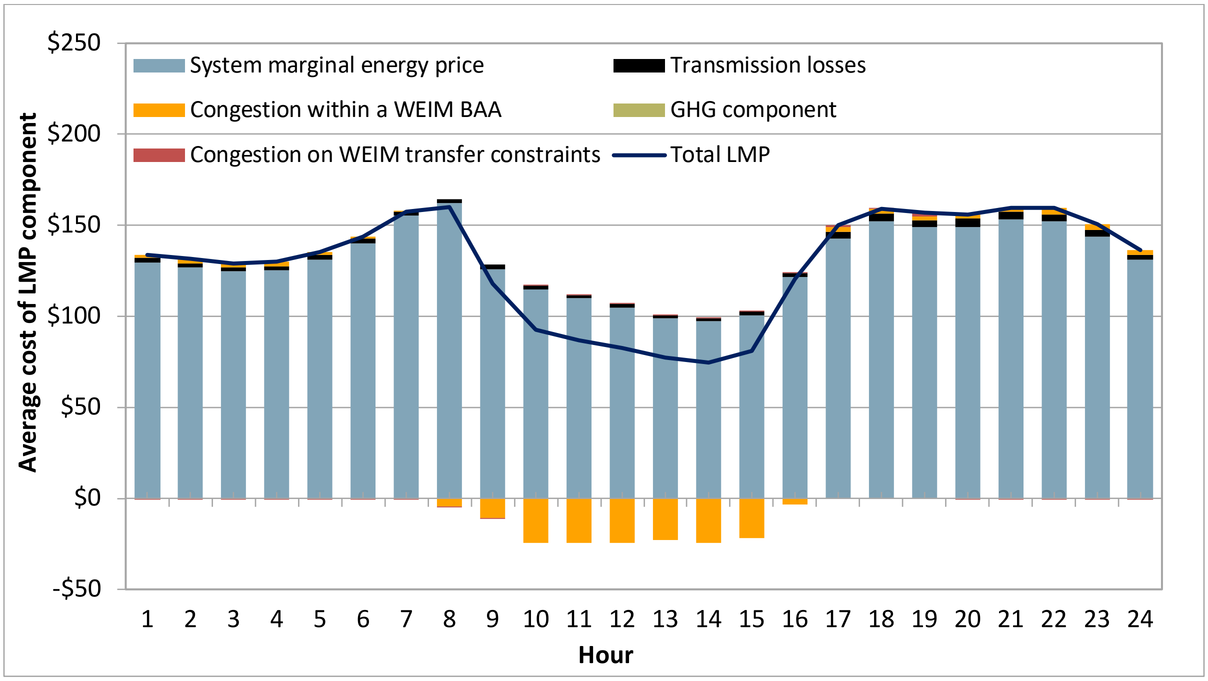
Appendix Figure A.29 Average hourly 15-minute price by component (Q4 2022)



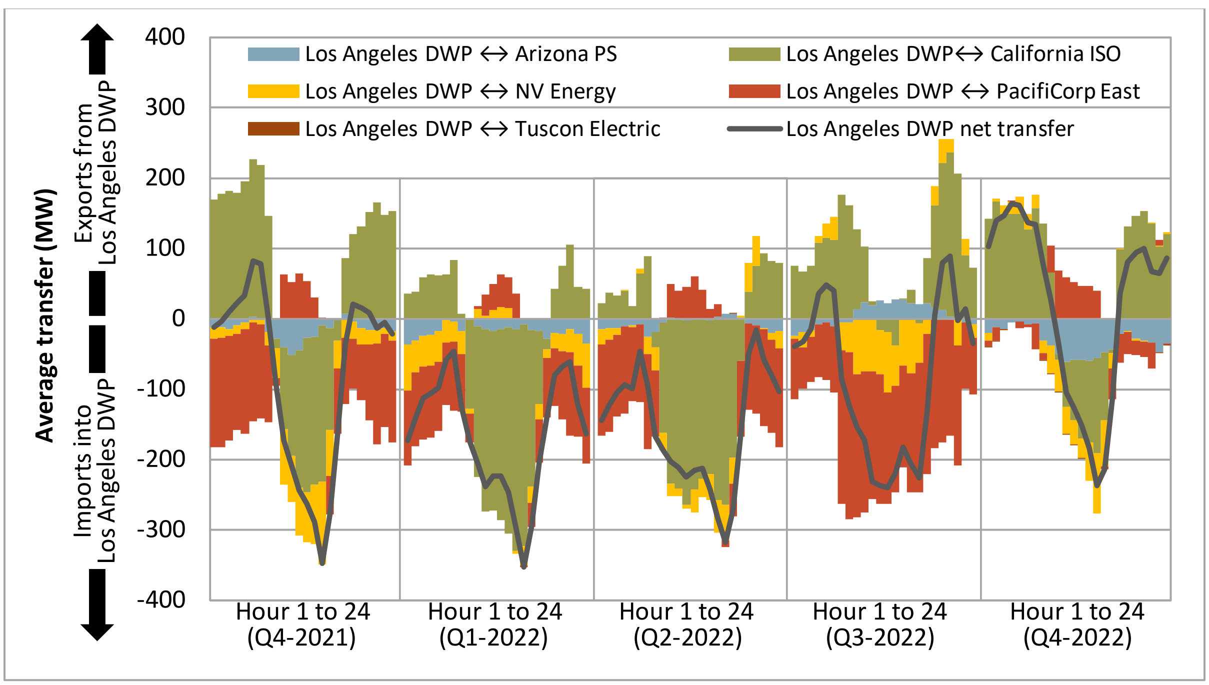
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q4 2022)

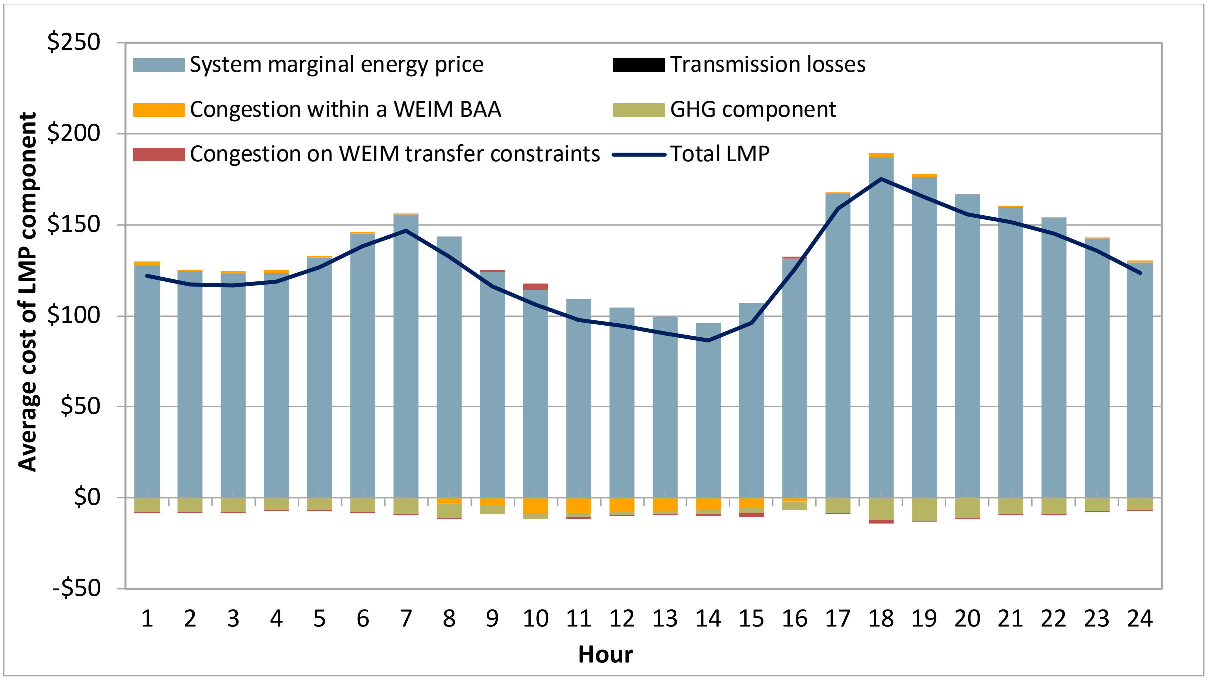


Appendix Figure A.32 Average hourly 5-minute market transfers

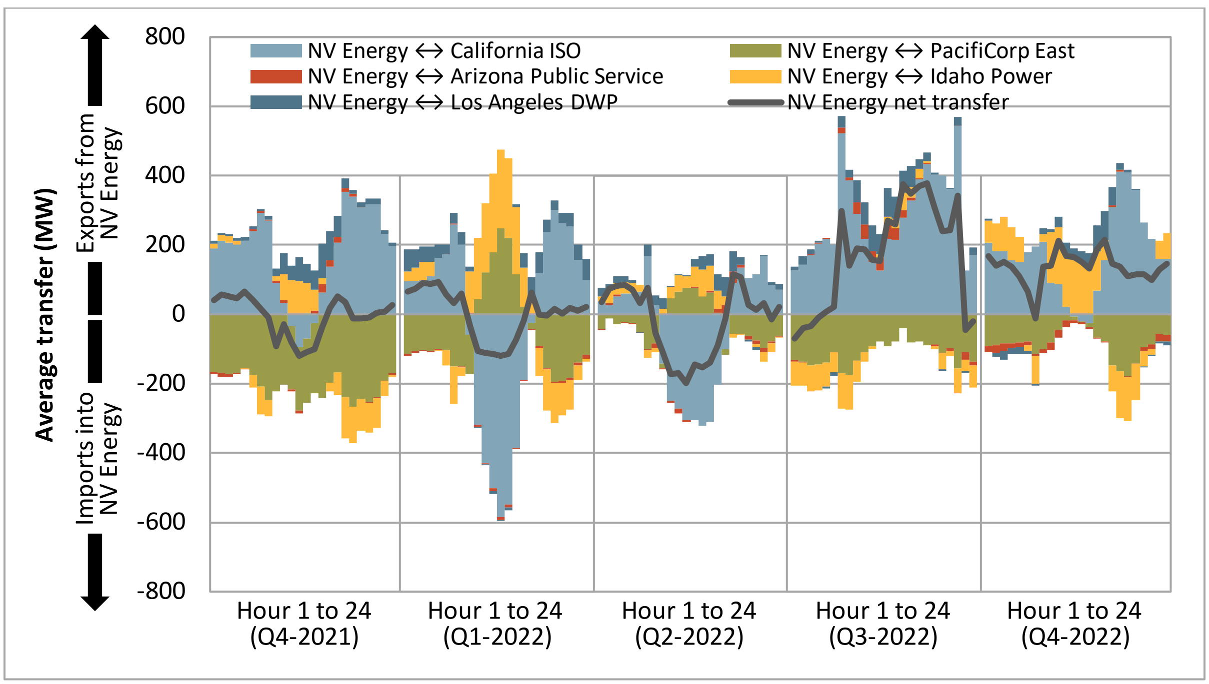


A.8 NV Energy

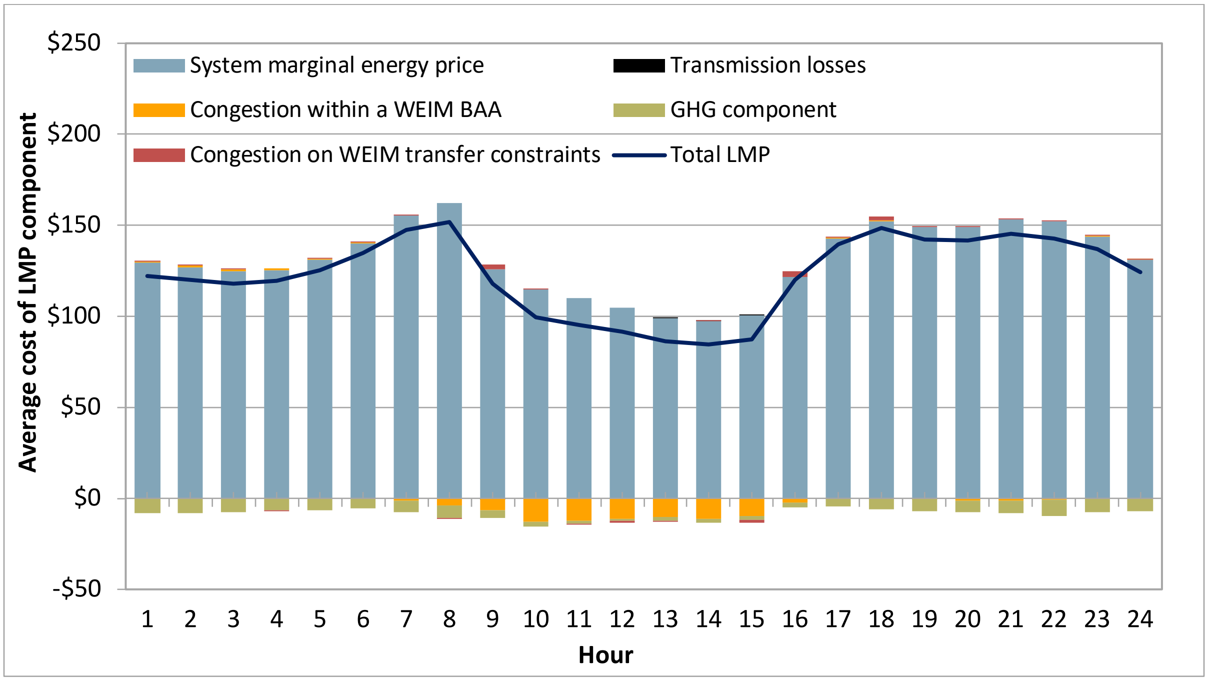
Appendix Figure A.33 Average hourly 15-minute price by component (Q4 2022)



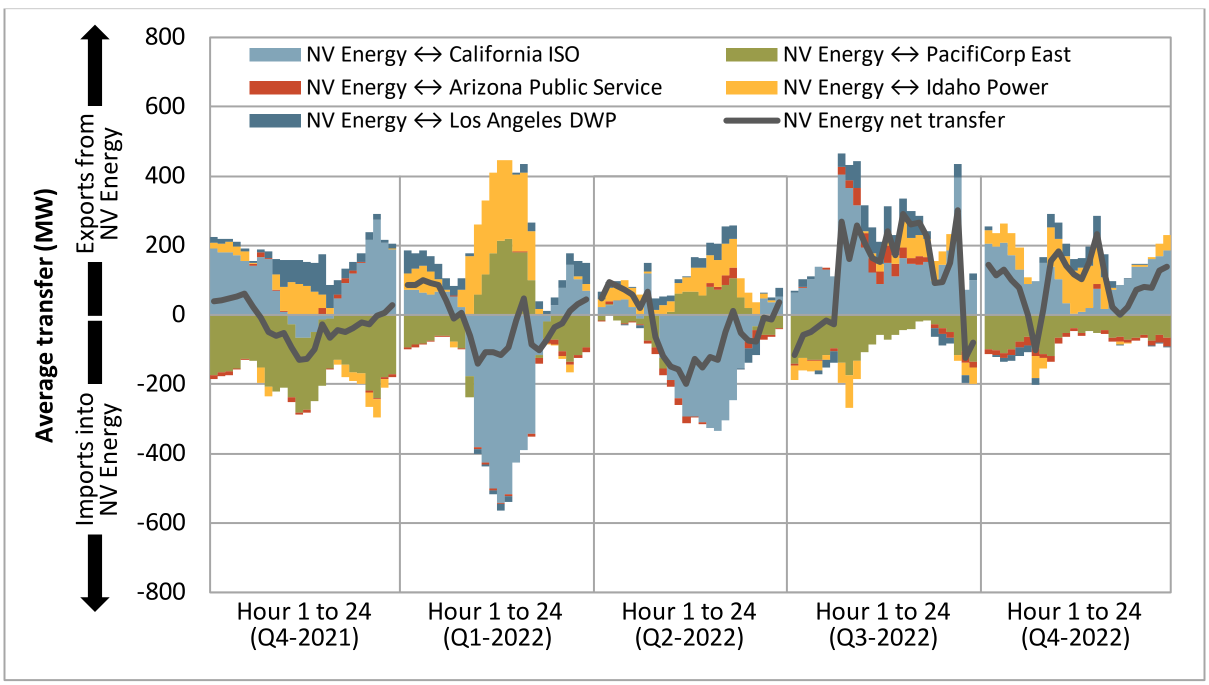
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q4 2022)

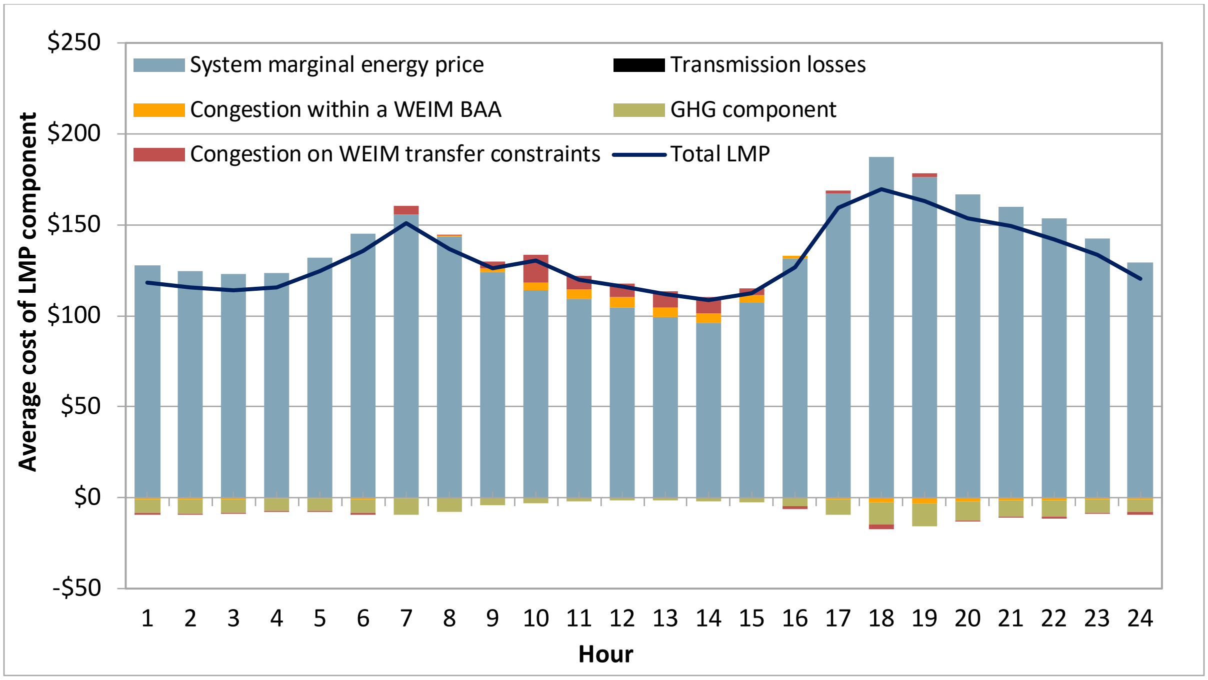


Appendix Figure A.36 Average hourly 5-minute market transfers

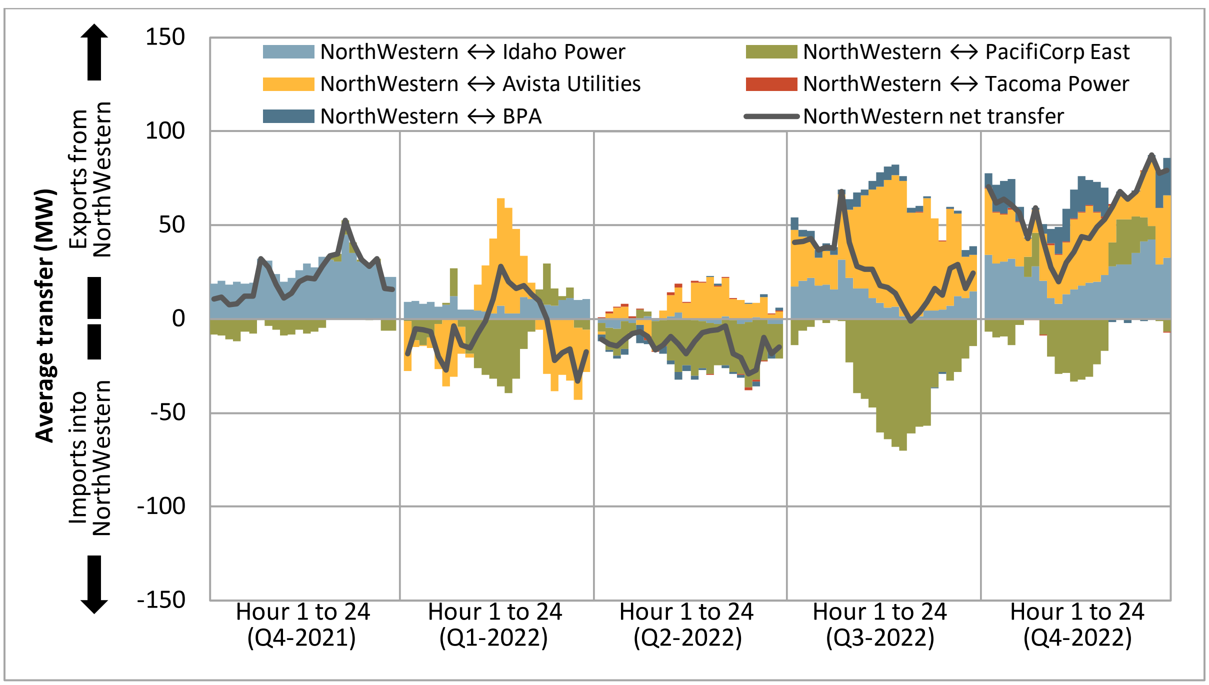


A.9 NorthWestern Energy

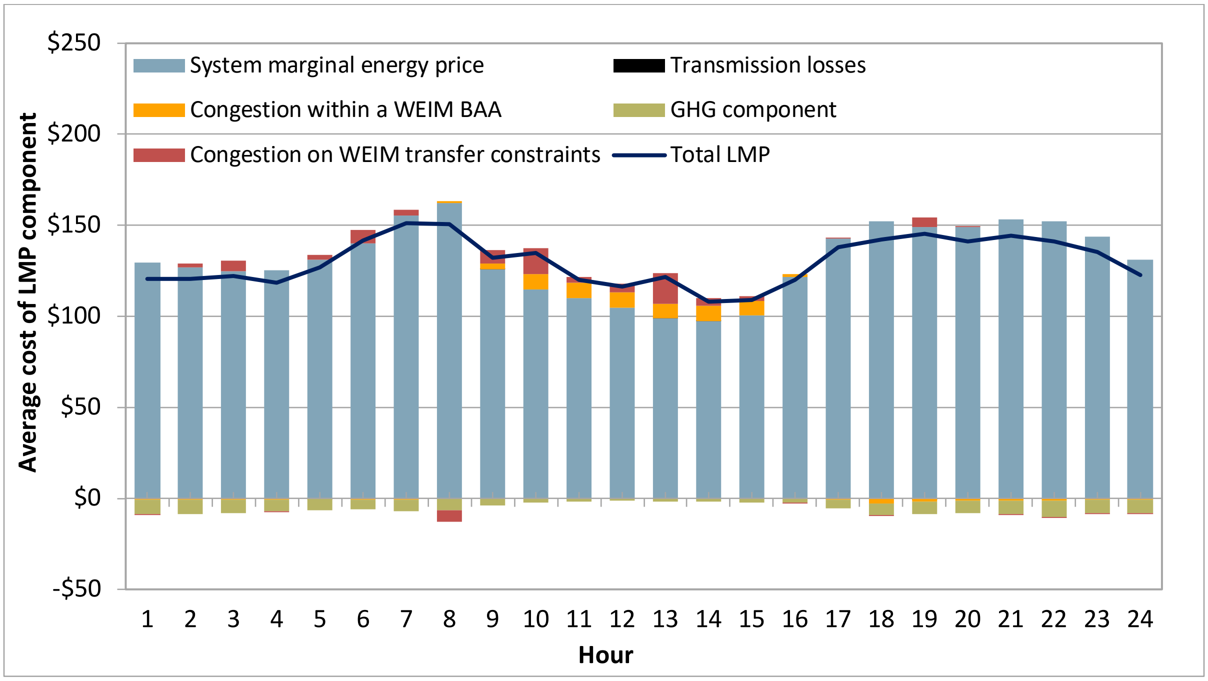
Appendix Figure A.37 Average hourly 15-minute price by component (Q4 2022)



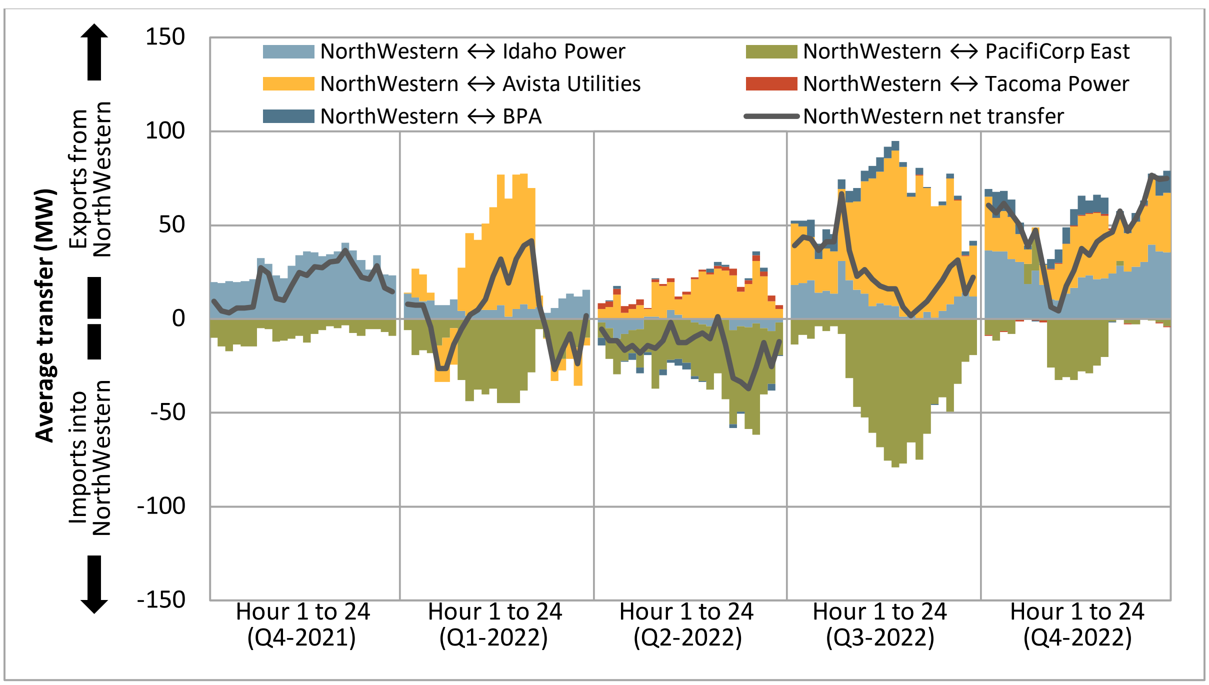
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q4 2022)

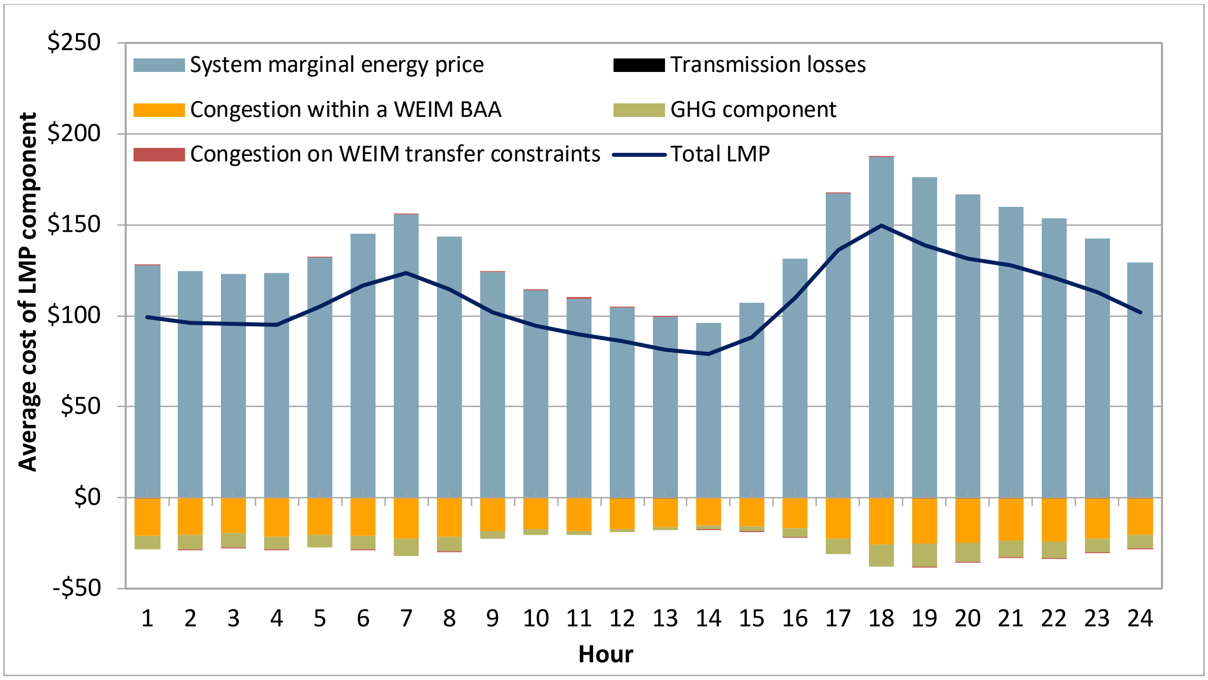


Appendix Figure A.40 Average hourly 5-minute market transfers

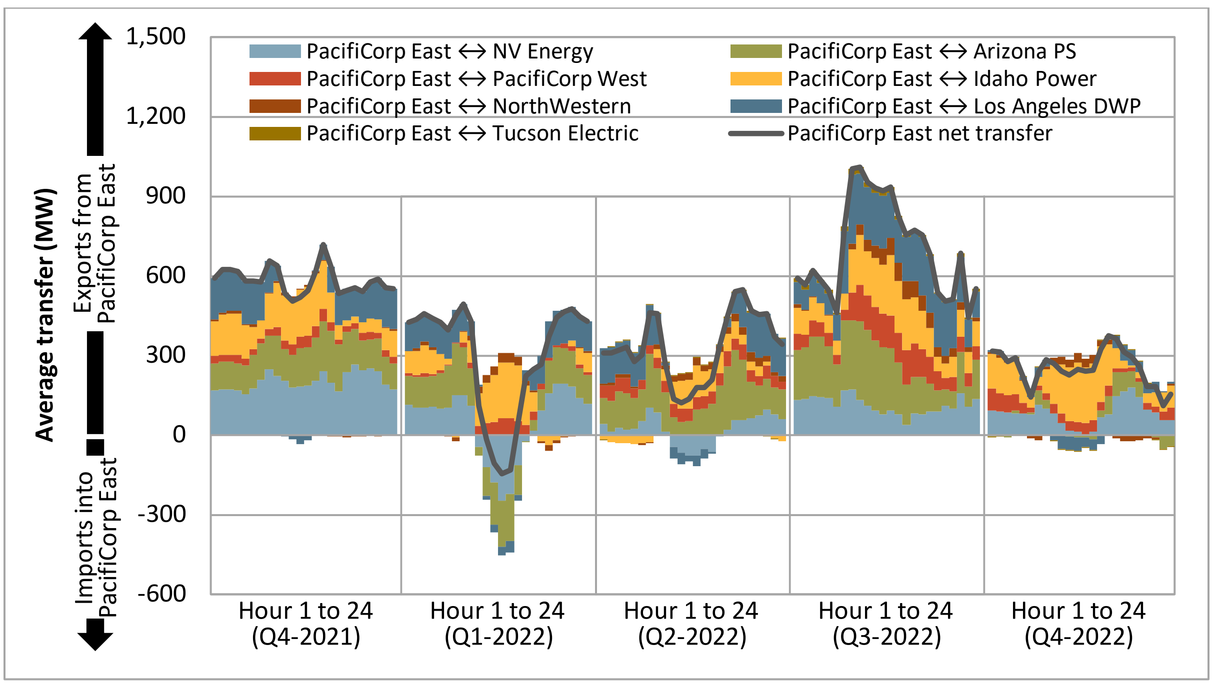


A.10 PacifiCorp East

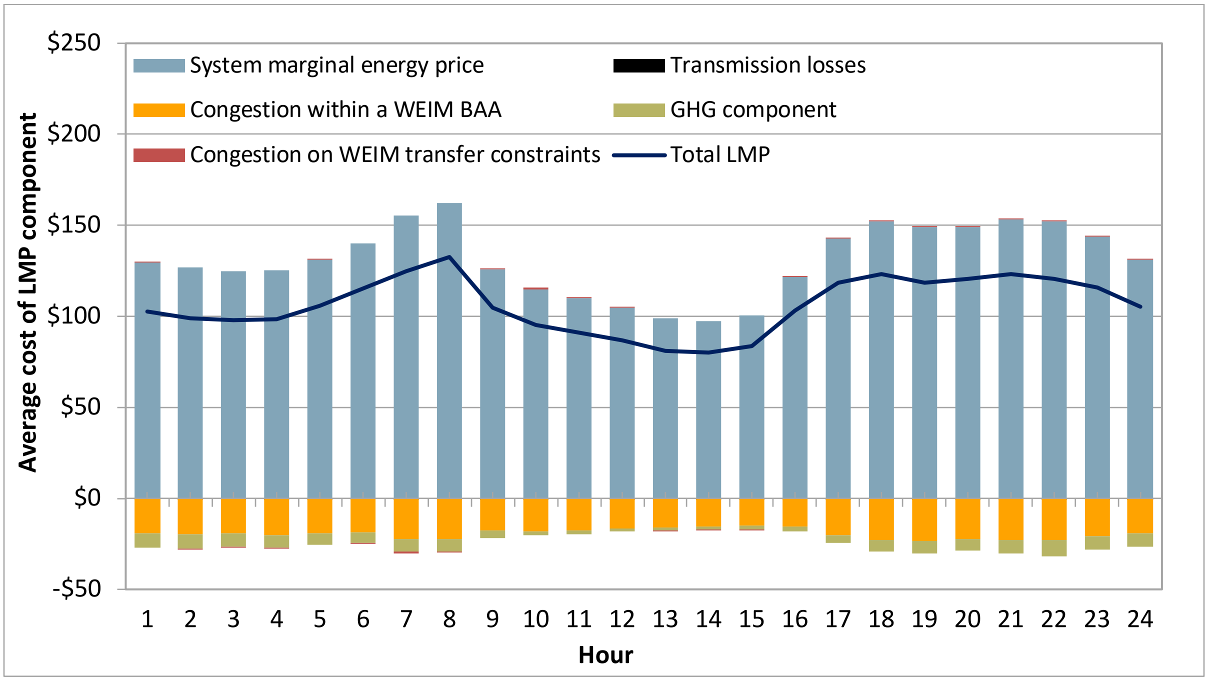
Appendix Figure A.41 Average hourly 15-minute price by component (Q4 2022)



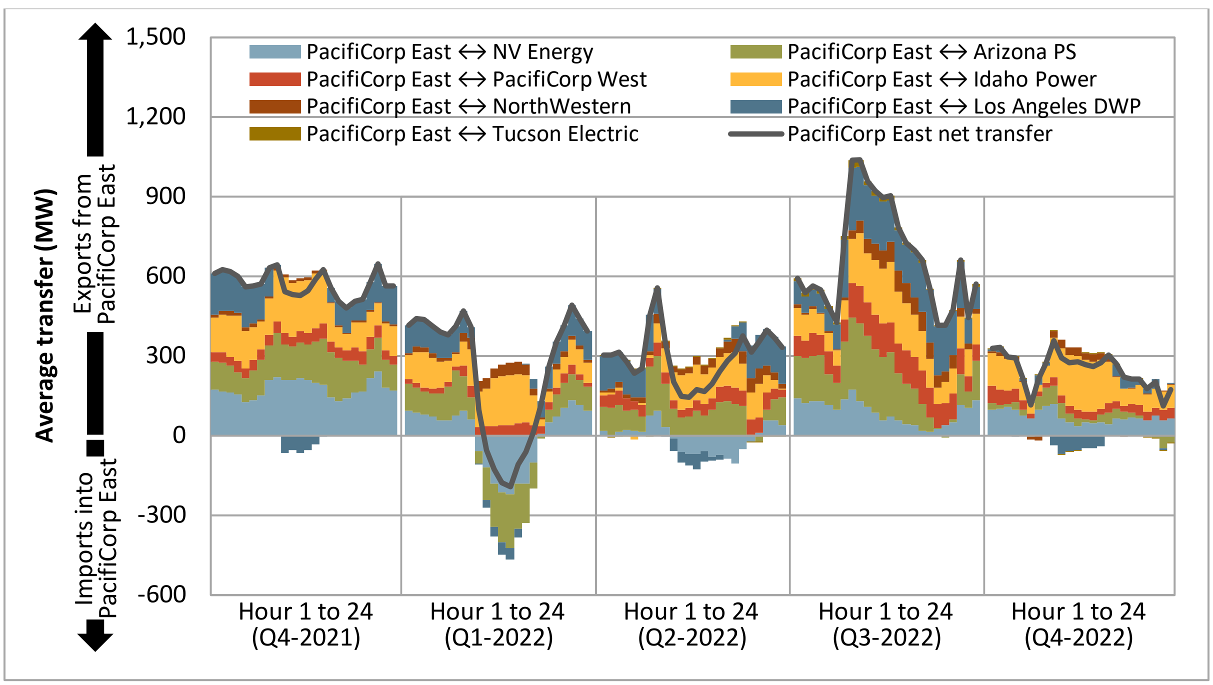
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q4 2022)

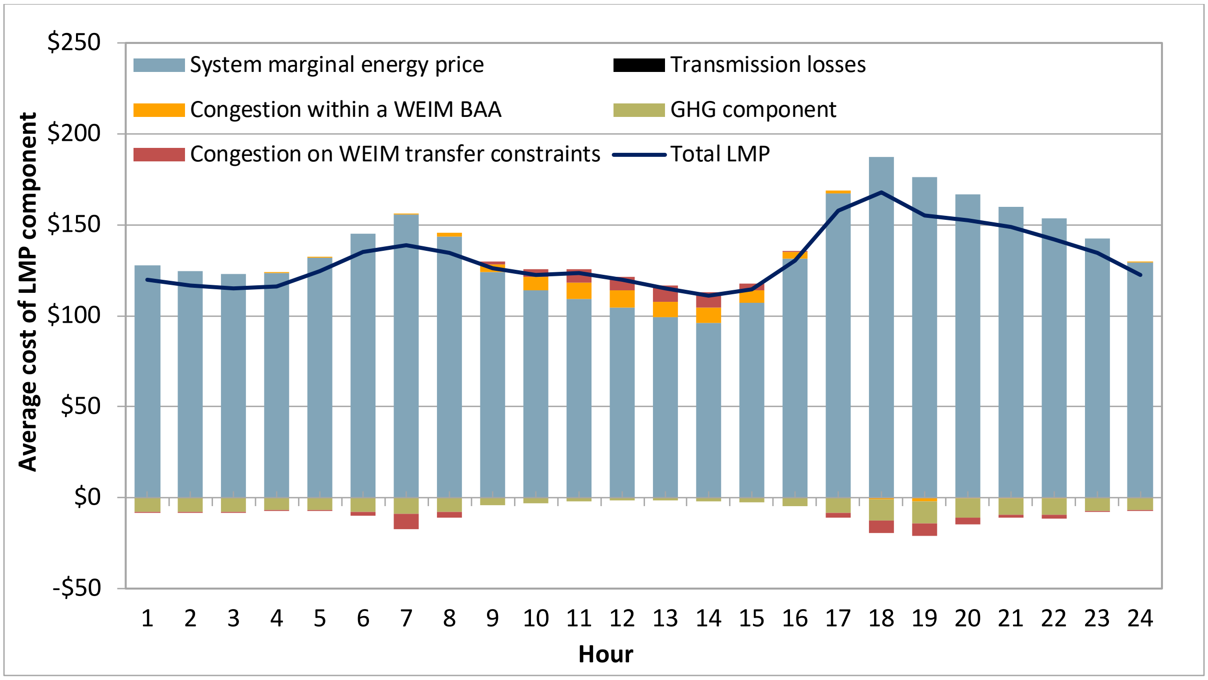


Appendix Figure A.44 Average hourly 5-minute market transfers

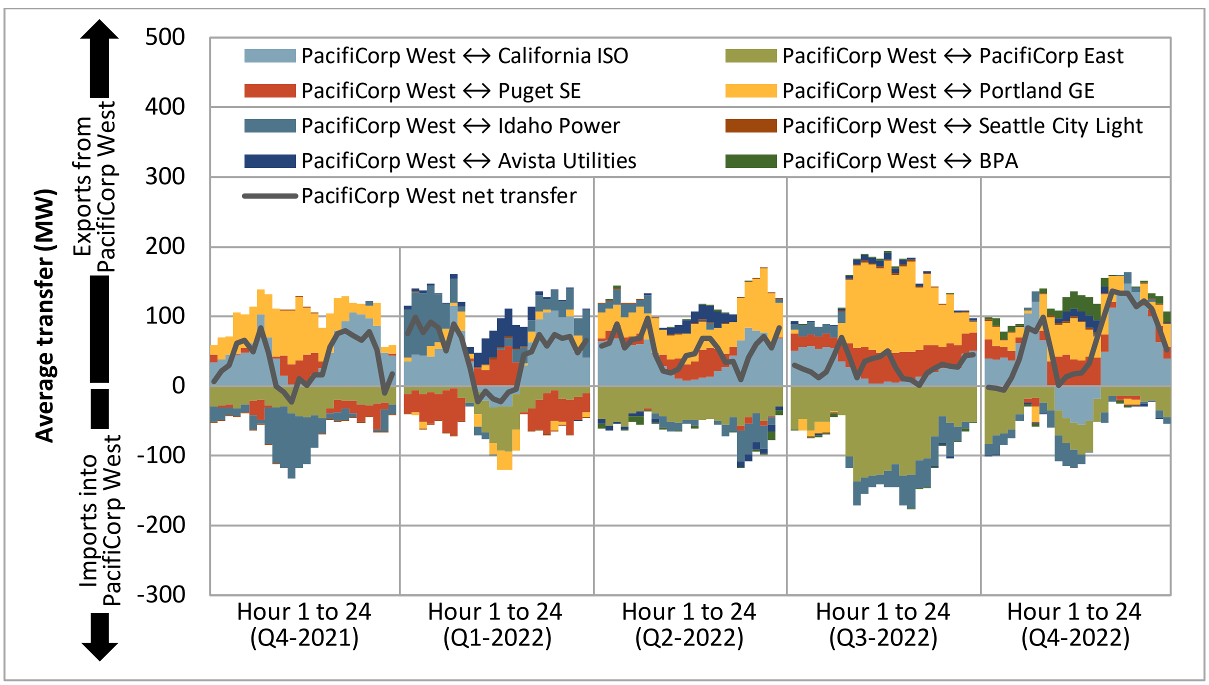


A.11 PacifiCorp West

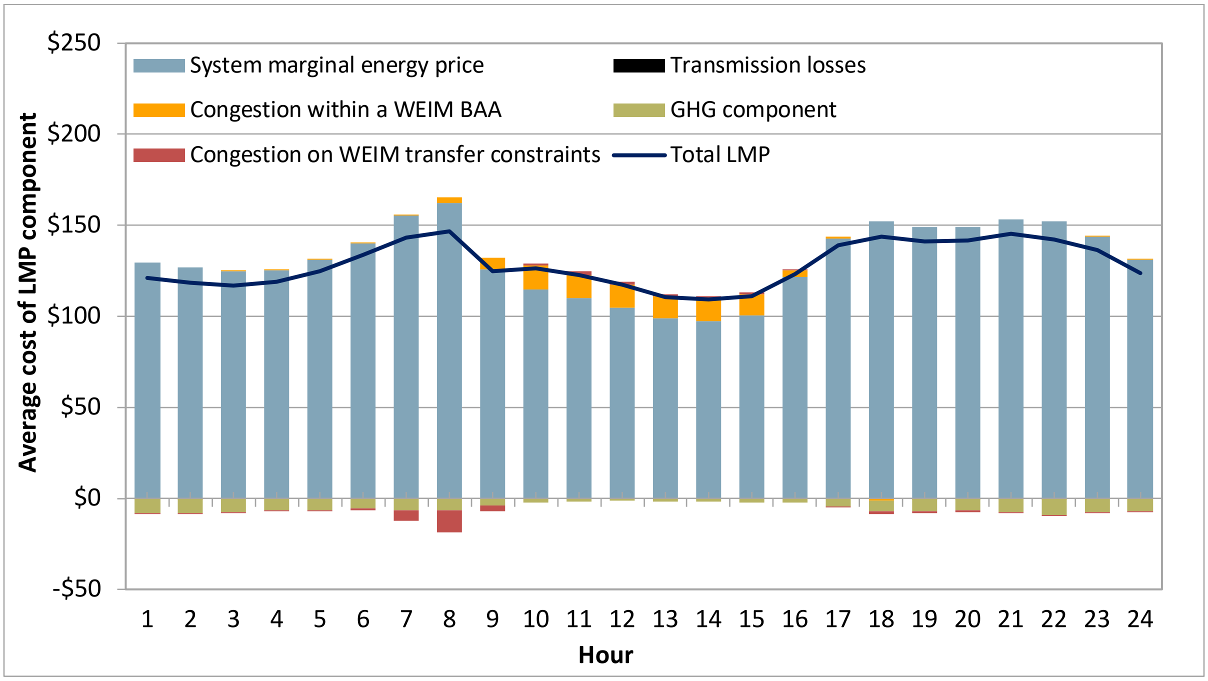
Appendix Figure A.45 Average hourly 15-minute price by component (Q4 2022)



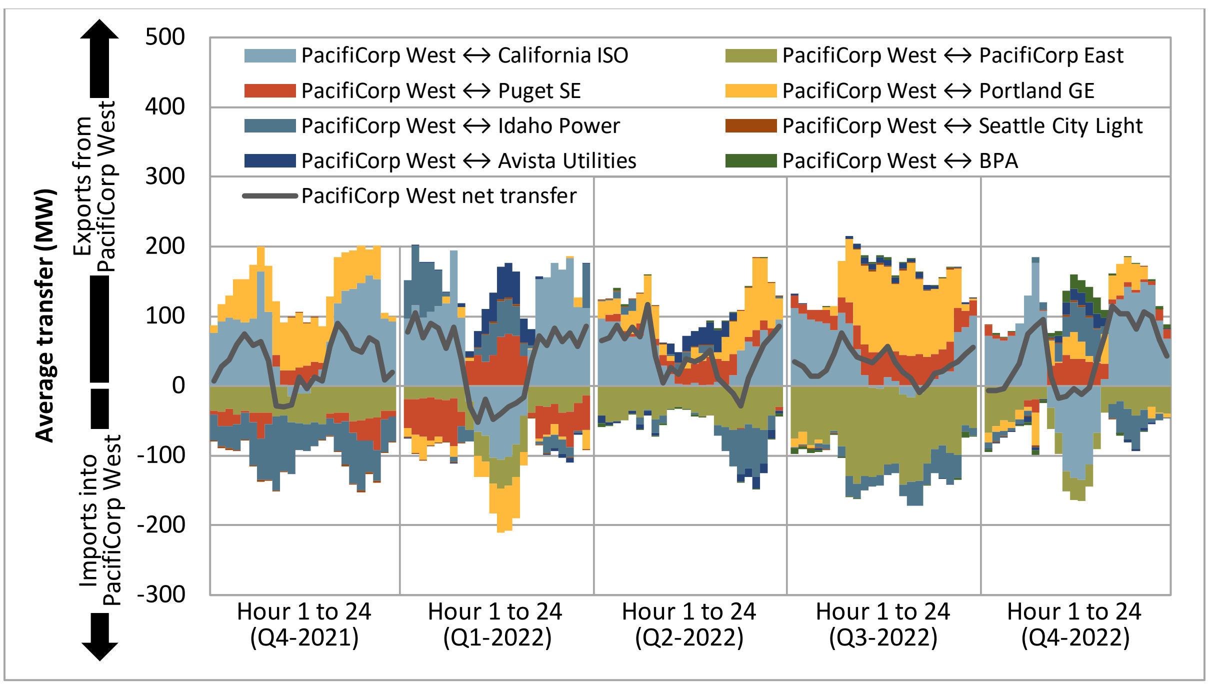
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q4 2022)

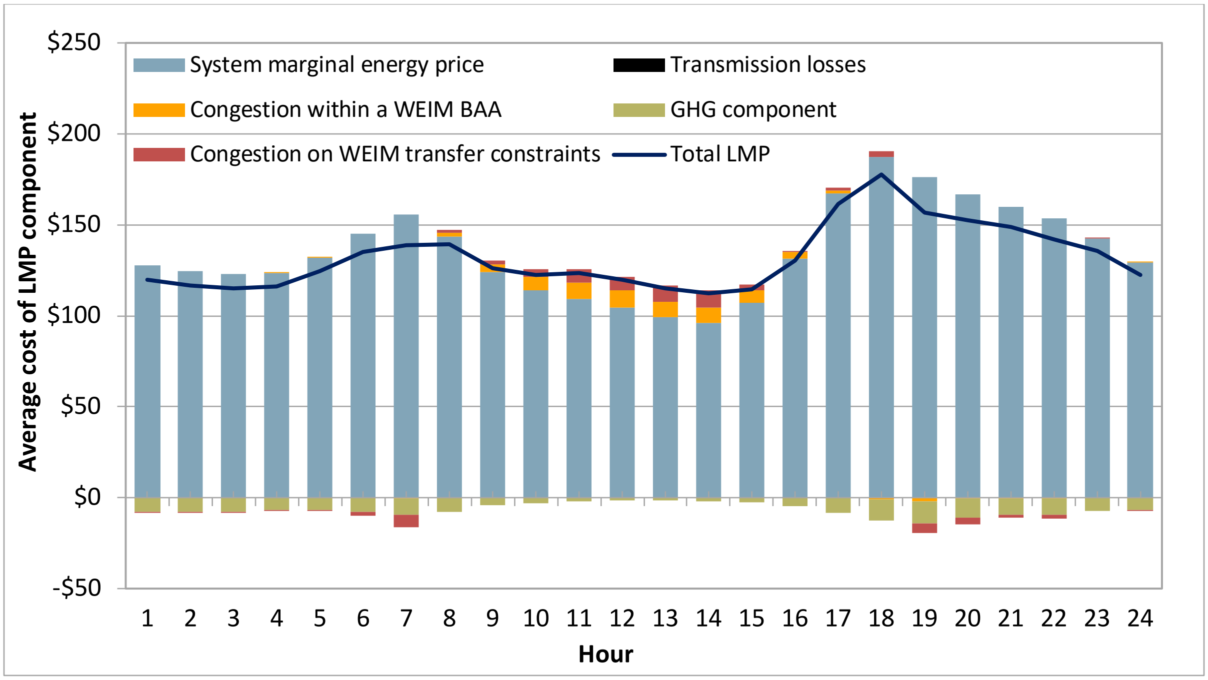


Appendix Figure A.48 Average hourly 5-minute market transfers

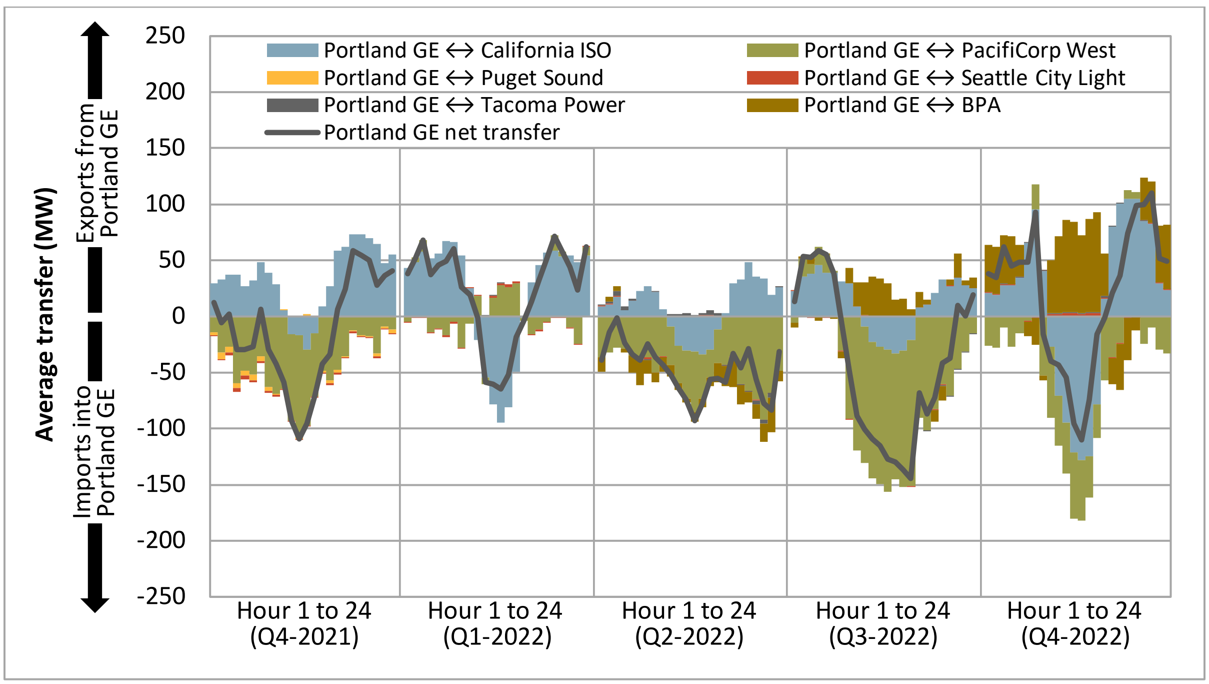


A.12 Portland General Electric

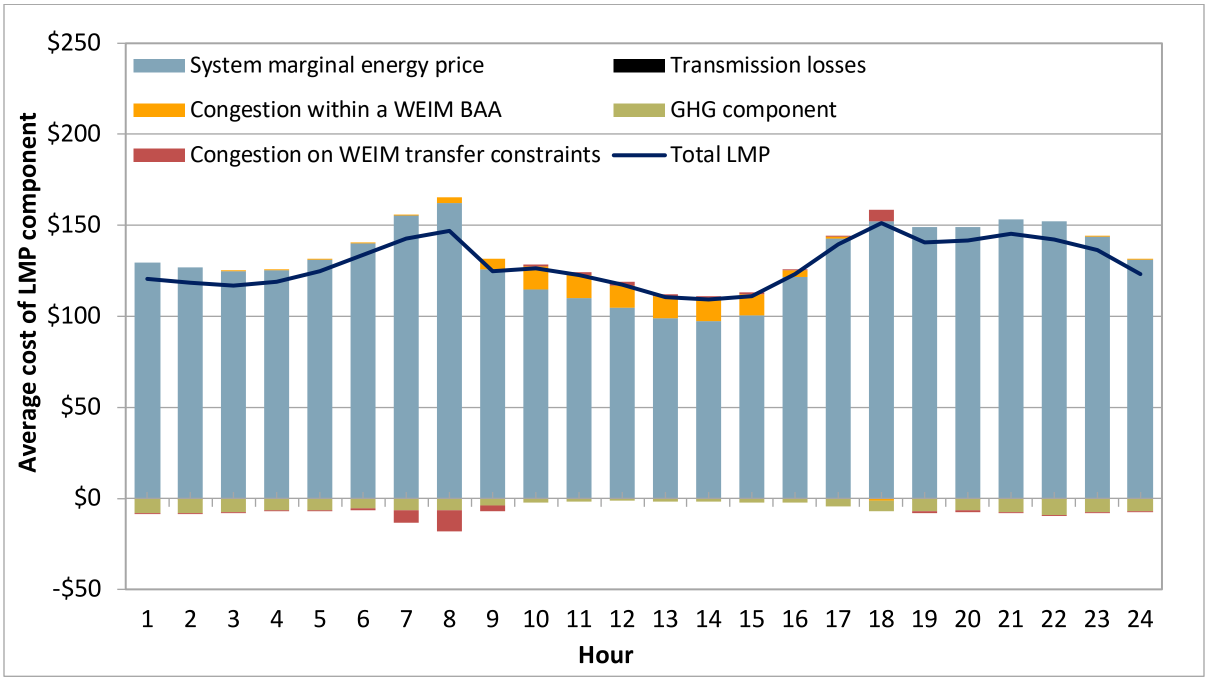
Appendix Figure A.49 Average hourly 15-minute price by component (Q4 2022)



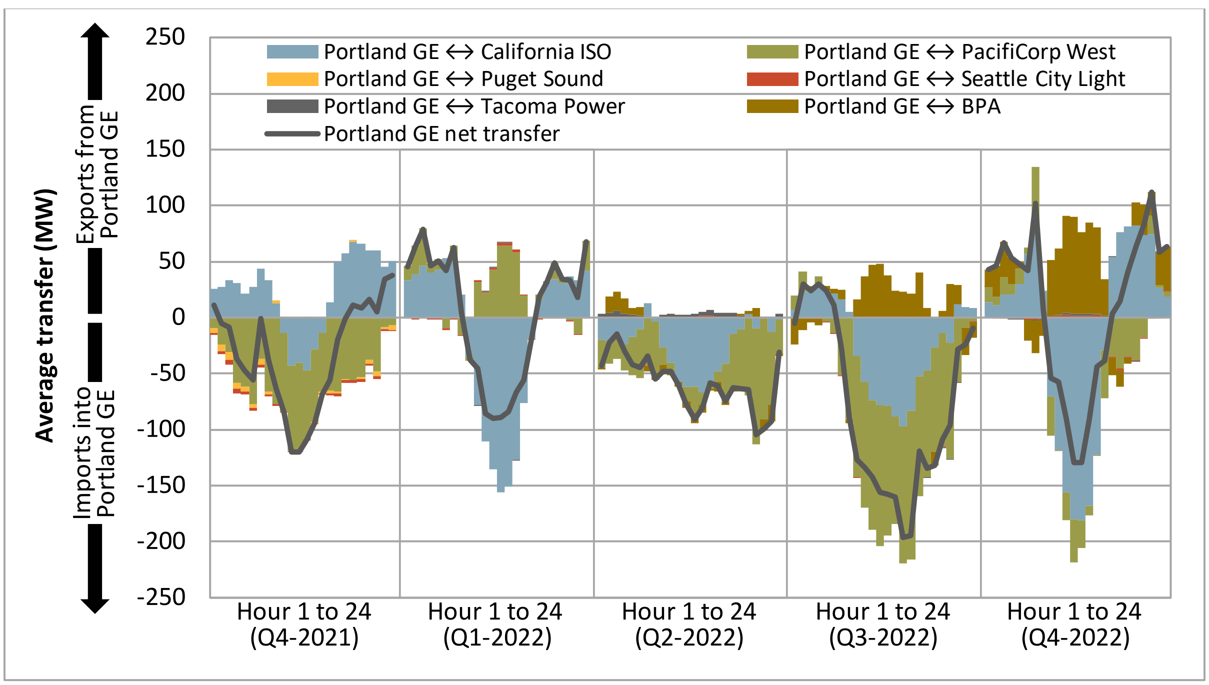
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q4 2022)

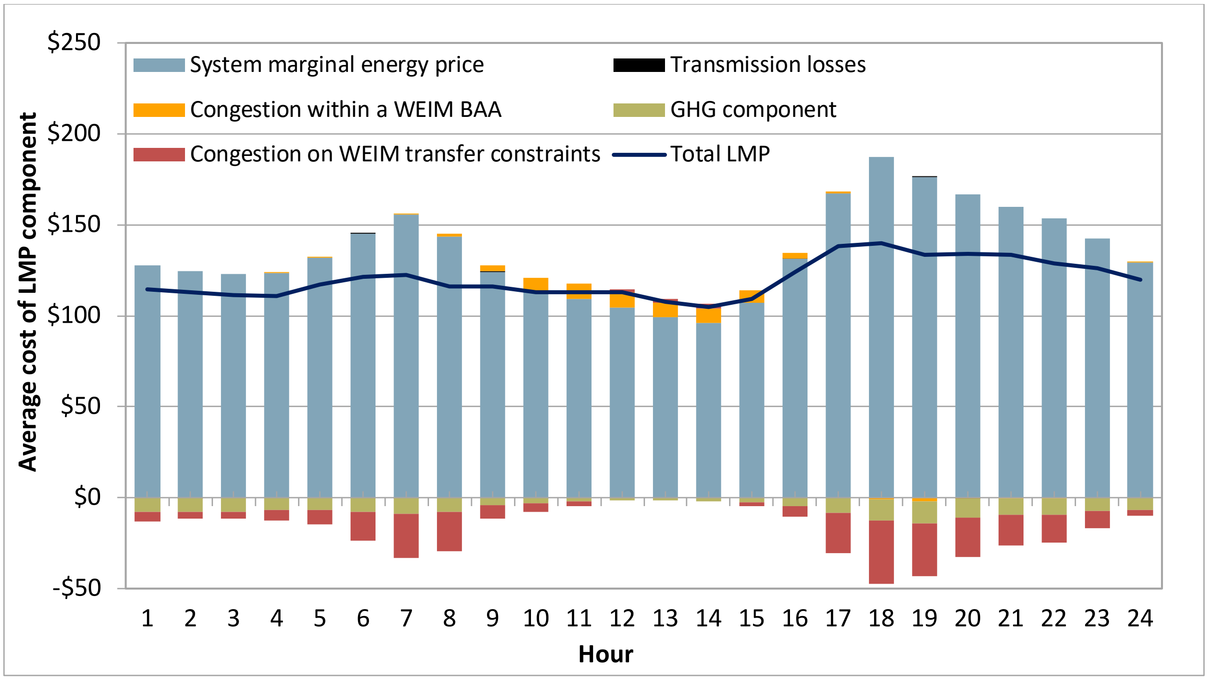


Appendix Figure A.52 Average hourly 5-minute market transfers

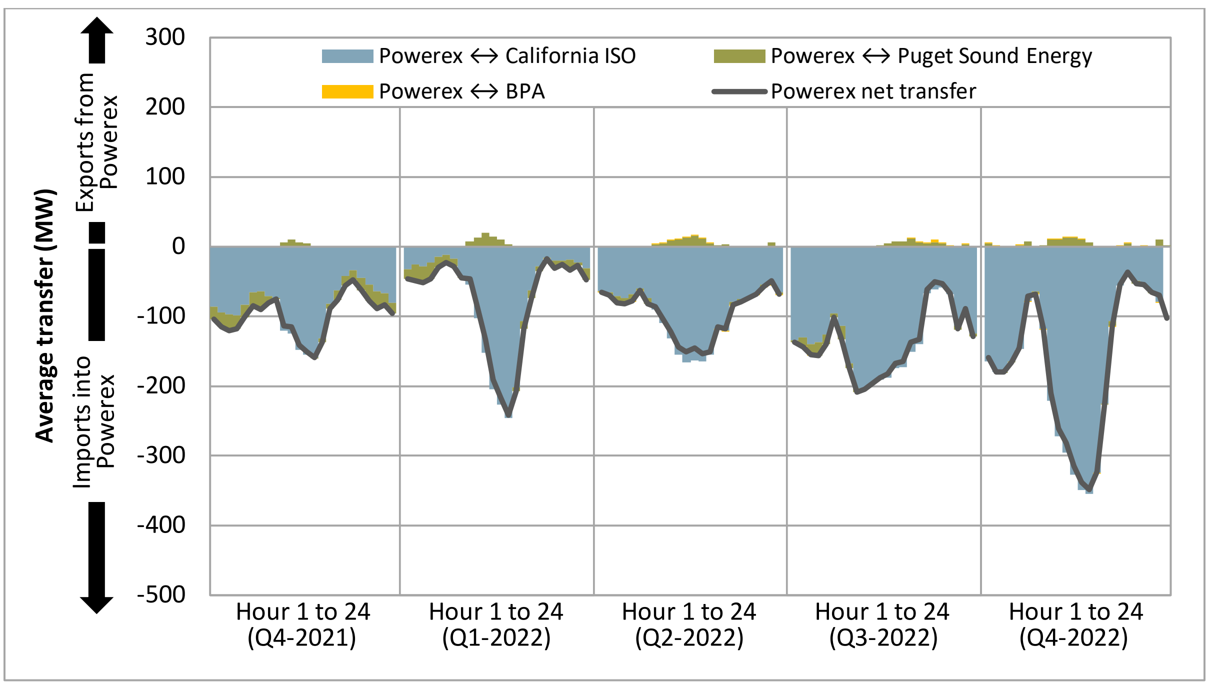


A.13 Powerex

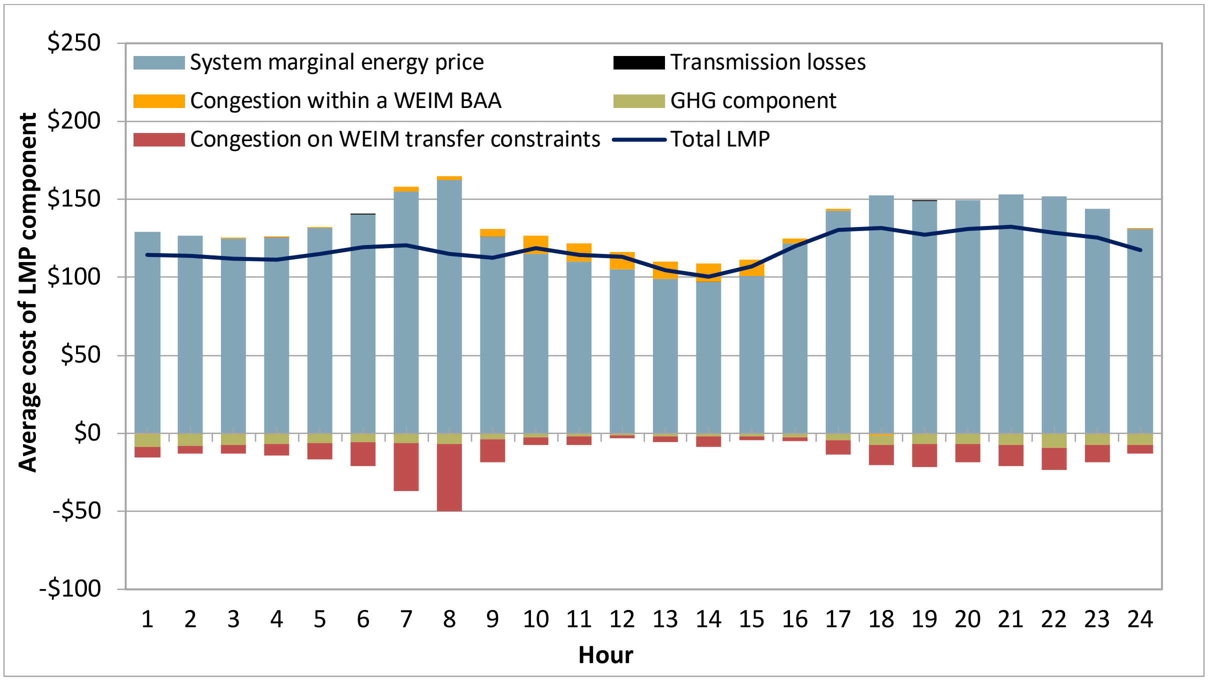
Appendix Figure A.53 Average hourly 15-minute price by component (Q4 2022)



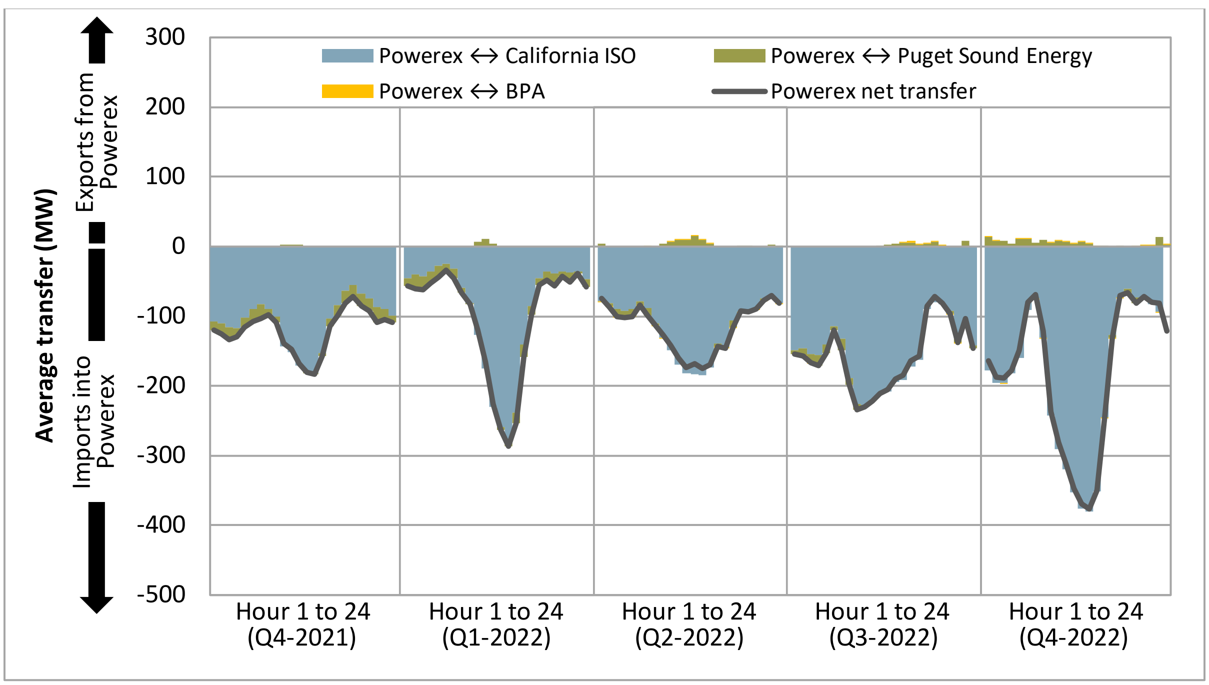
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q4 2022)

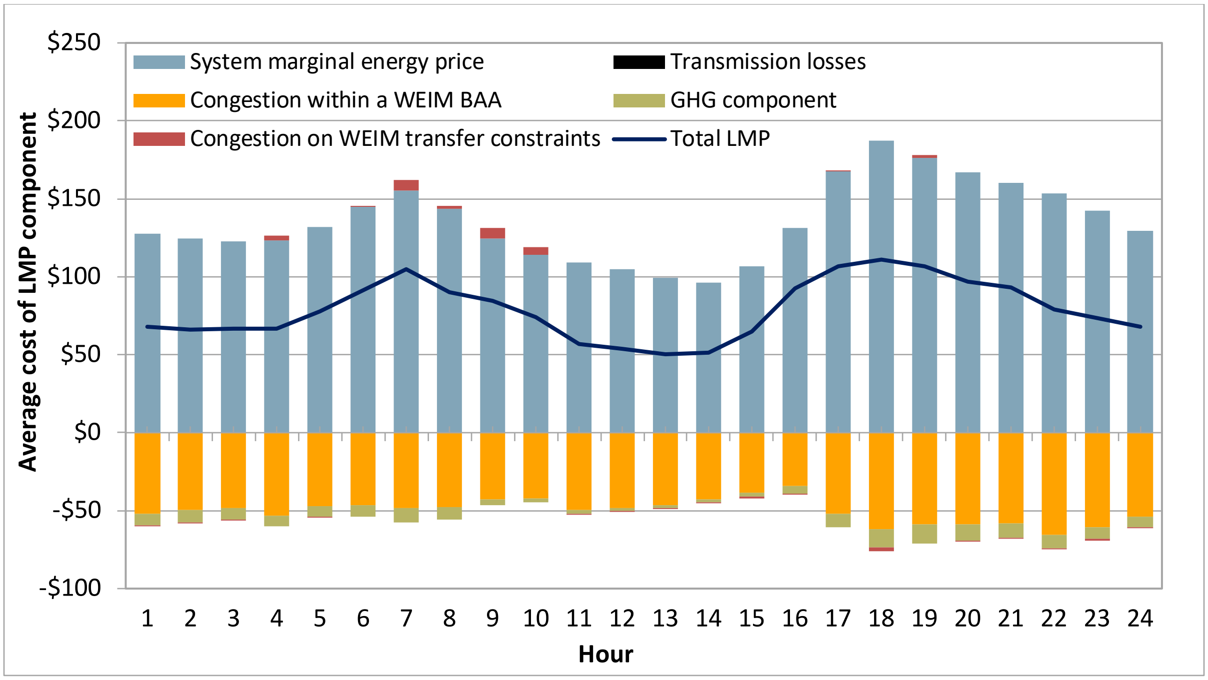


Appendix Figure A.56 Average hourly 5-minute market transfers

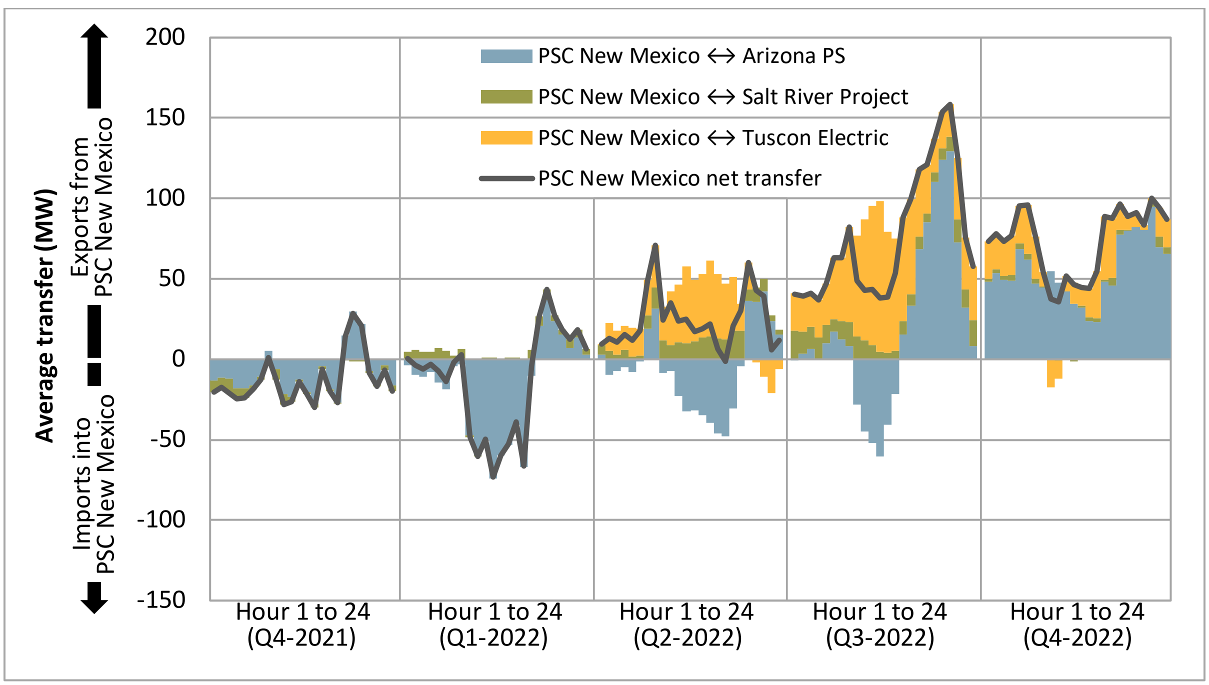


A.14 Public Service Company of New Mexico

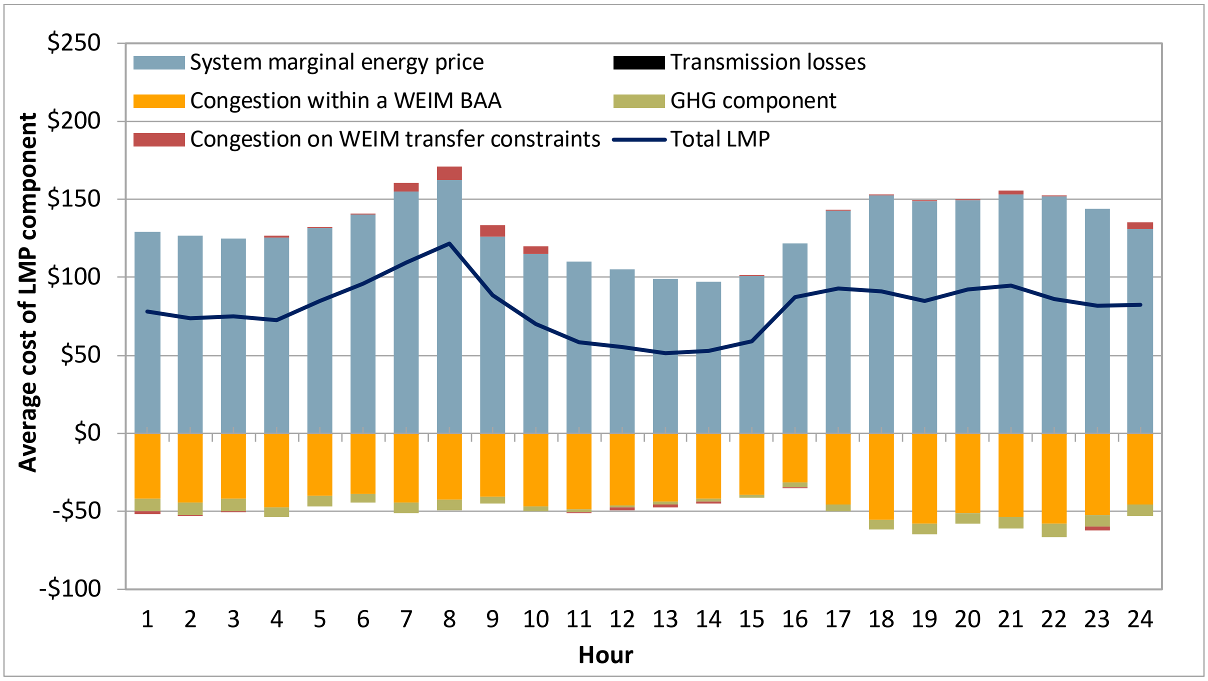
Appendix Figure A.57 Average hourly 15-minute price by component (Q4 2022)



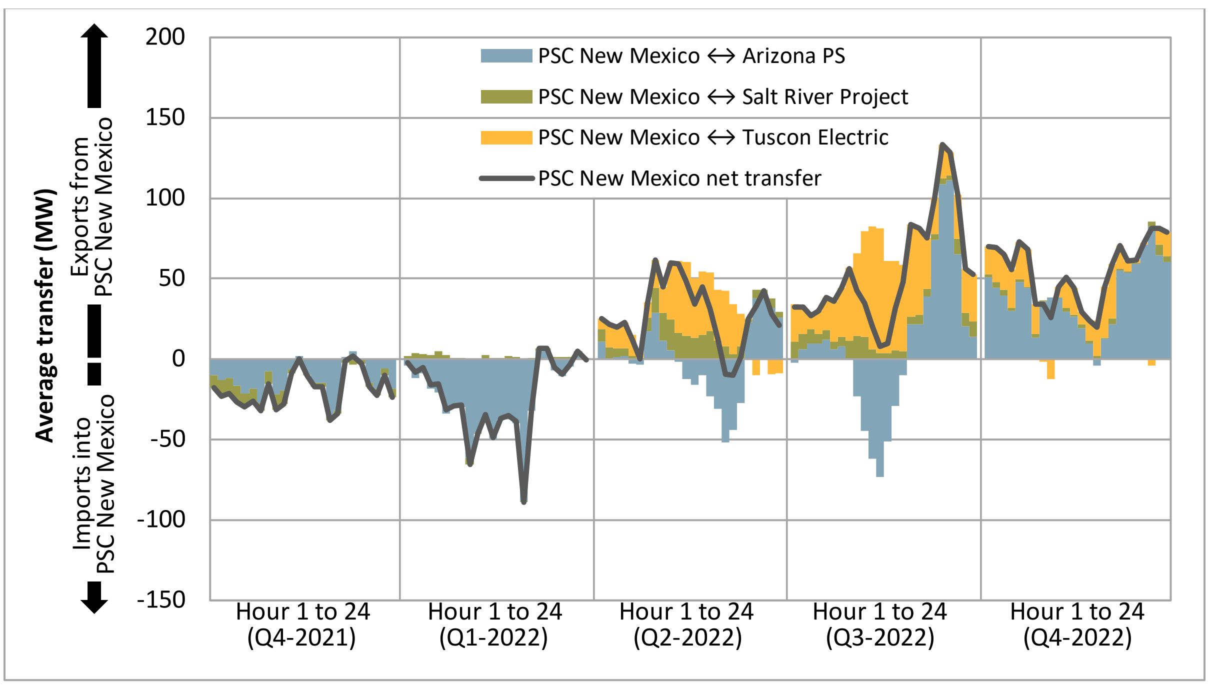
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q4 2022)

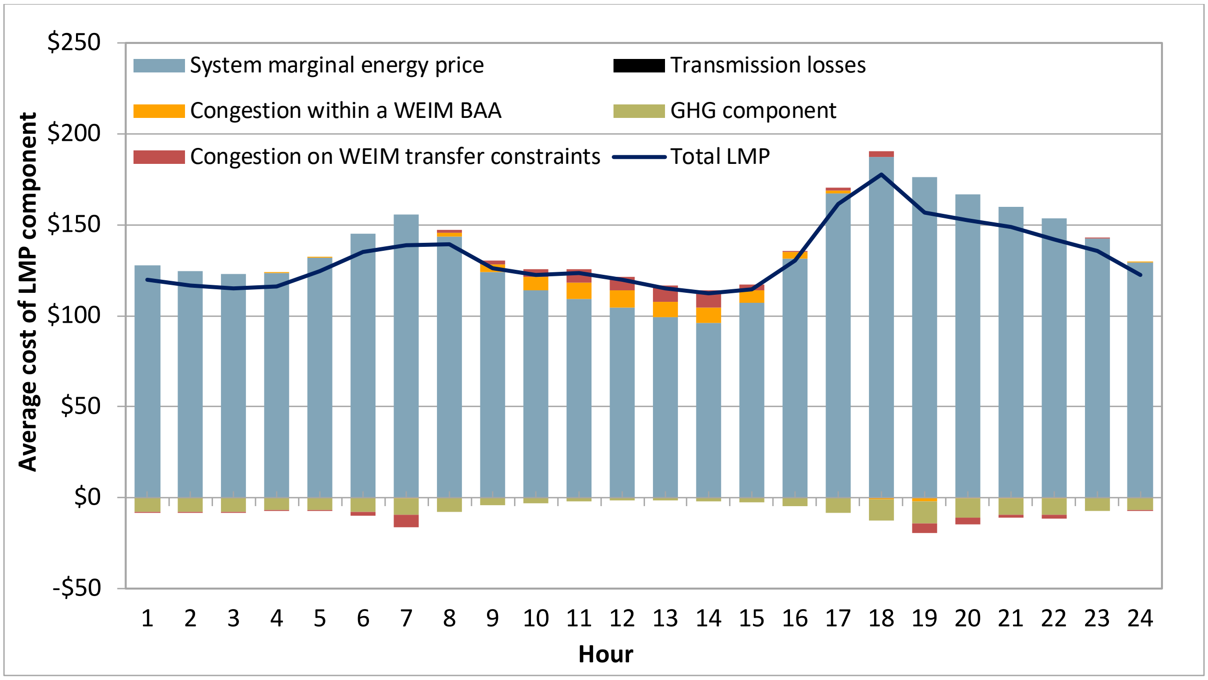


Appendix Figure A.60 Average hourly 5-minute market transfers

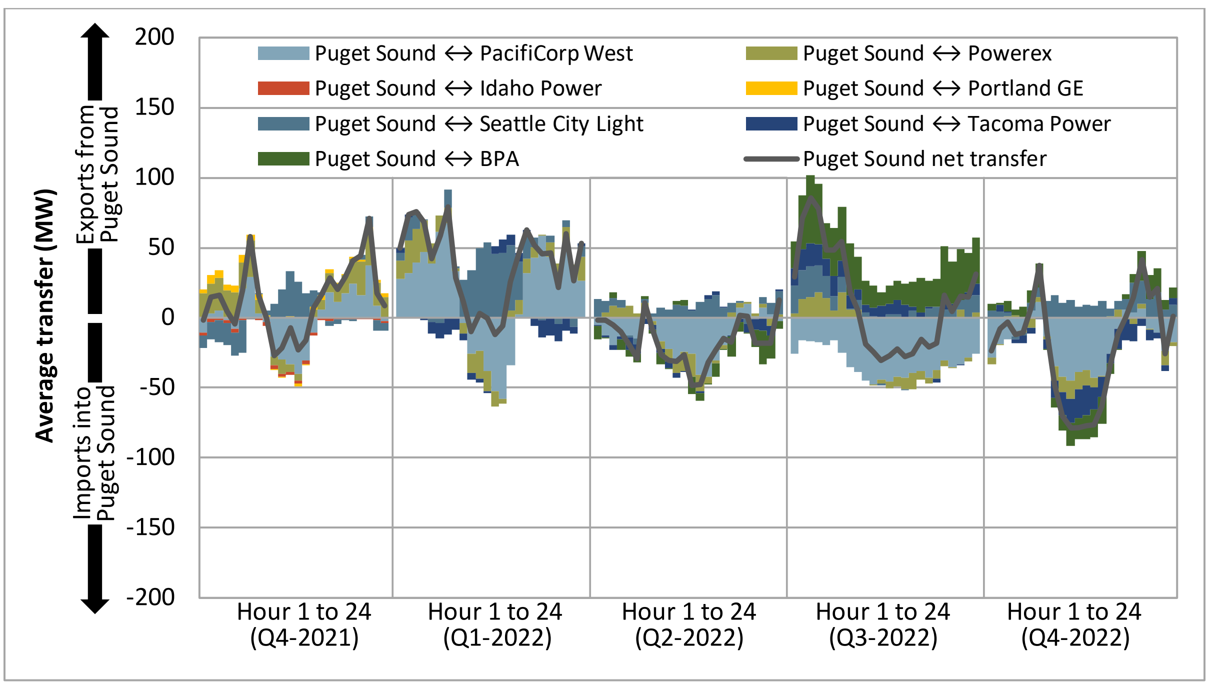


A.15 Puget Sound Energy

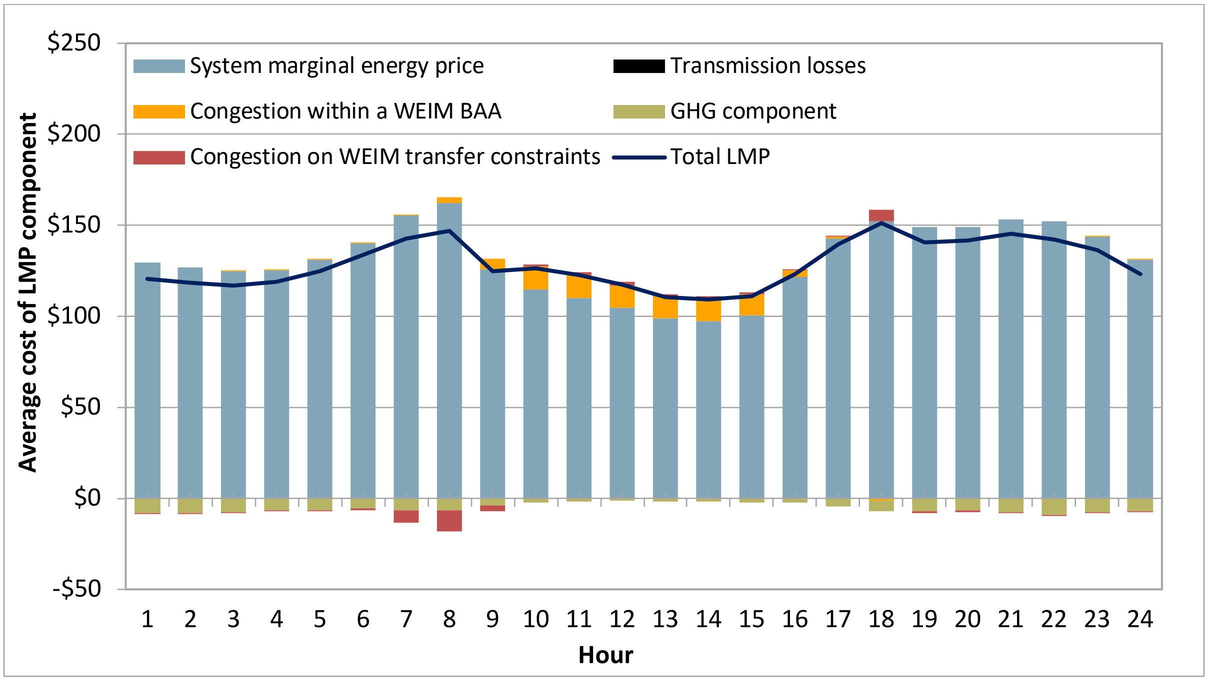
Appendix Figure A.61 Average hourly 15-minute price by component (Q4 2022)



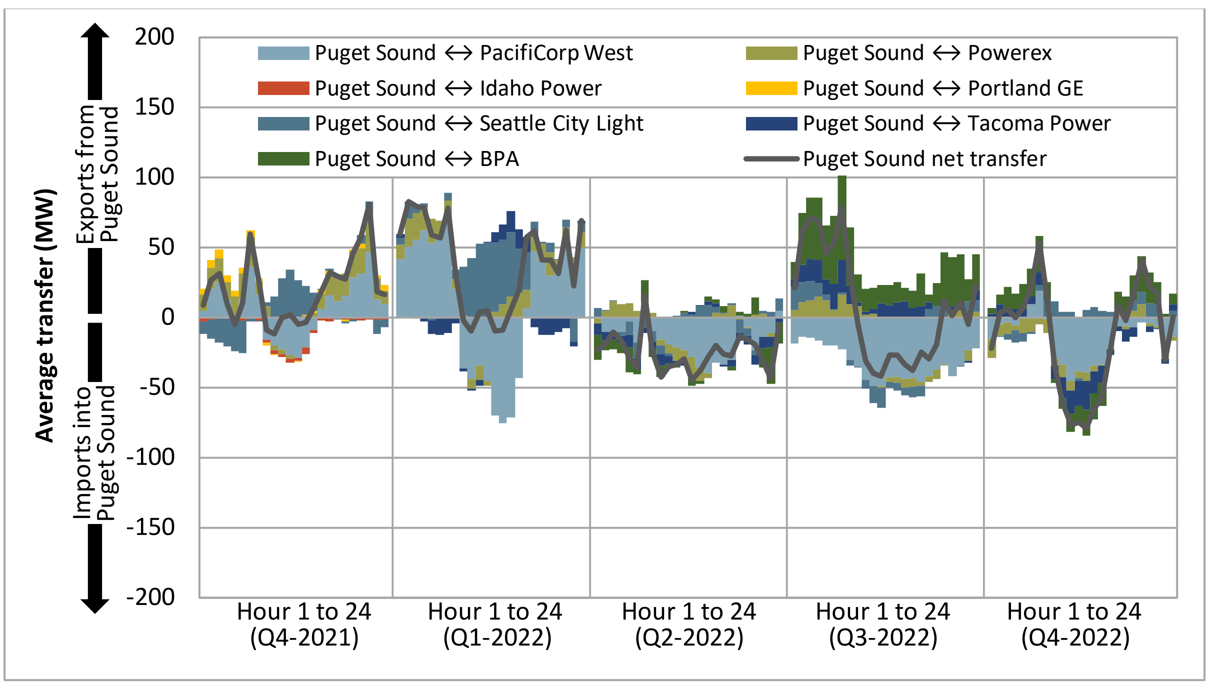
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q4 2022)

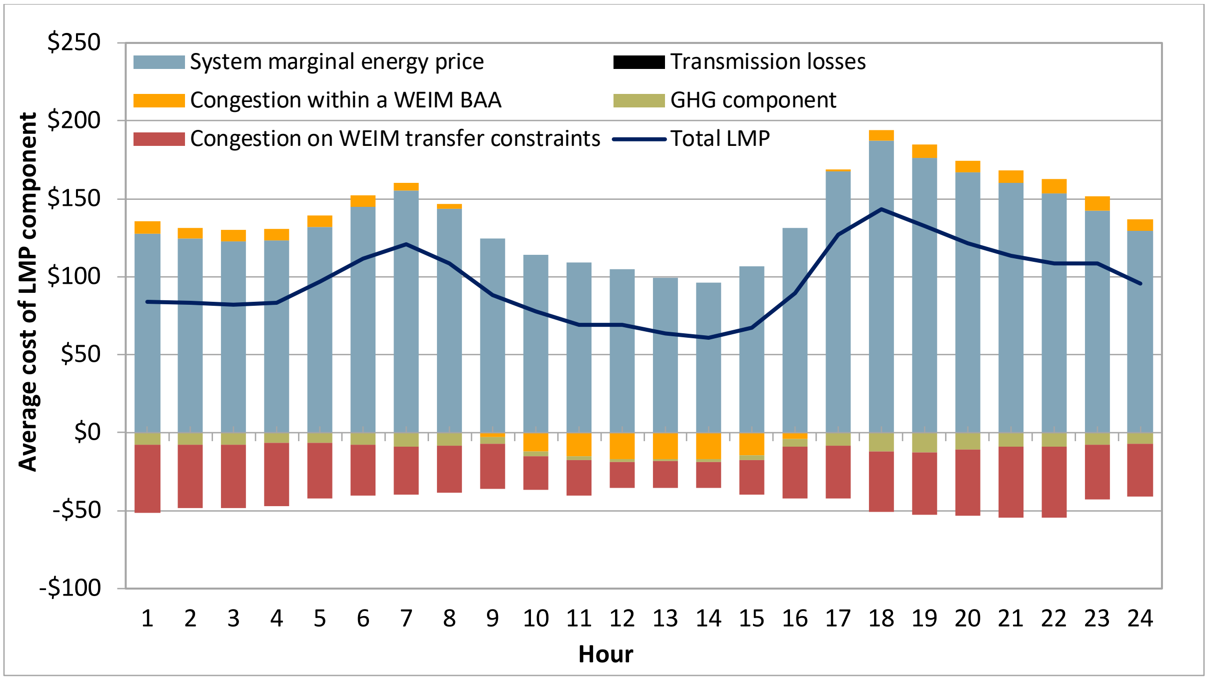


Appendix Figure A.64 Average hourly 5-minute market transfers

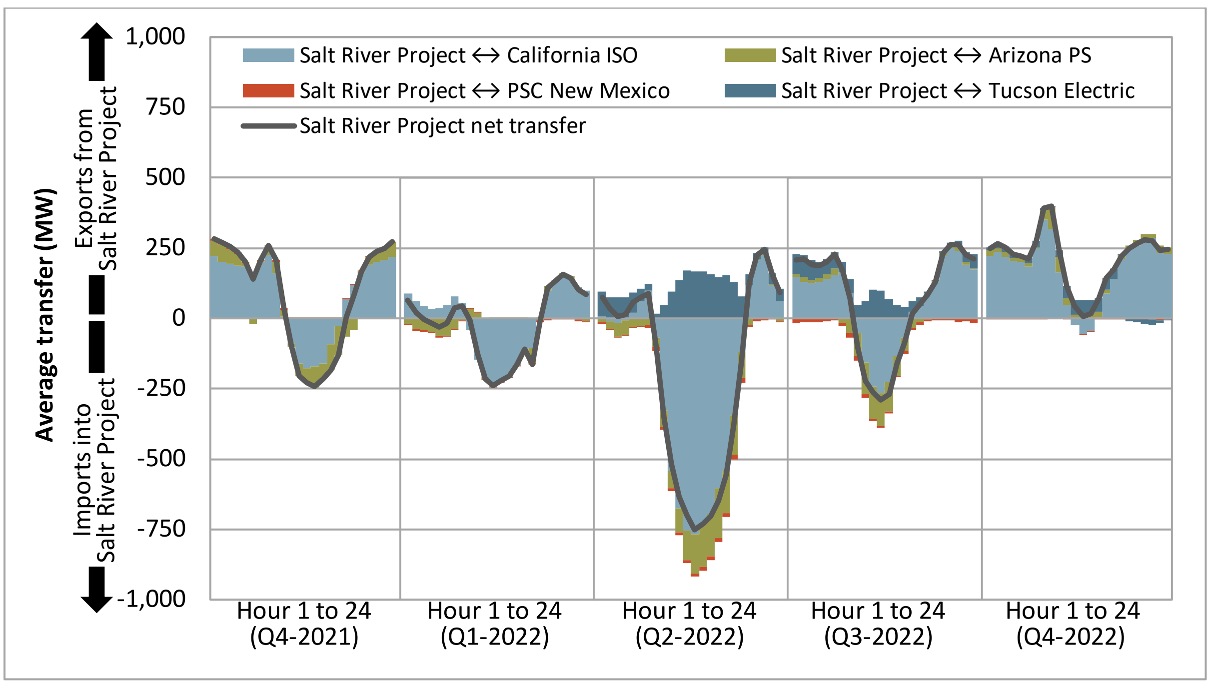


A.16 Salt River Project

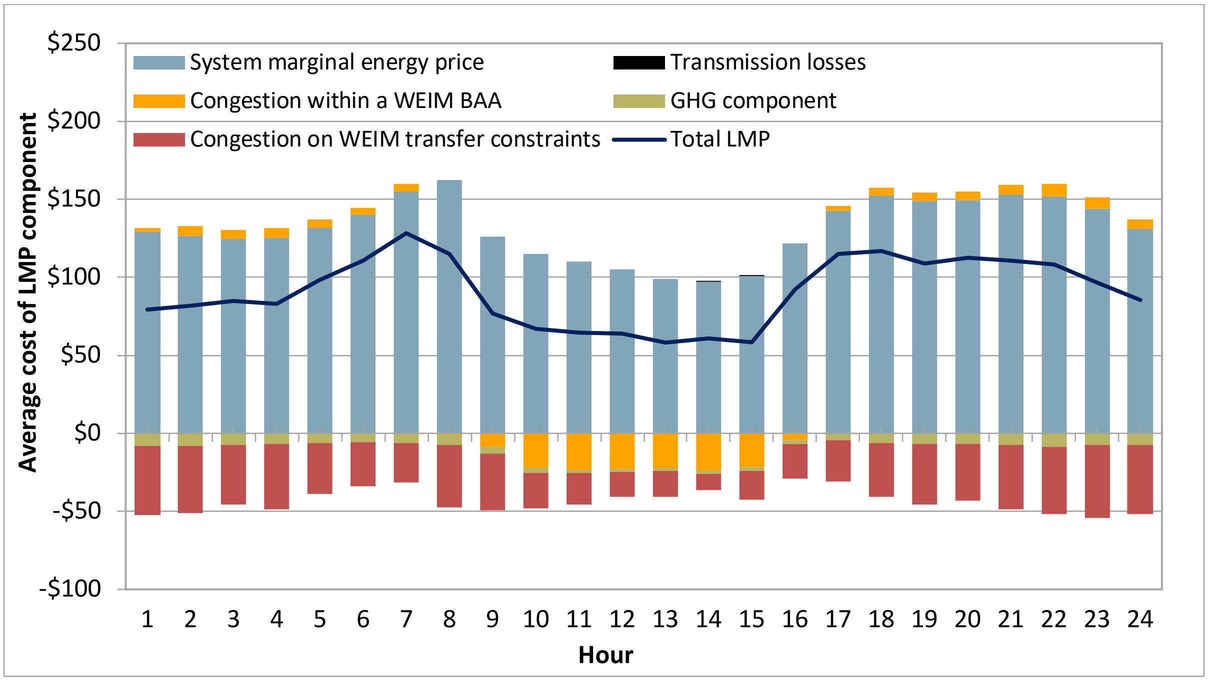
Appendix Figure A.65 Average hourly 15-minute price by component (Q4 2022)



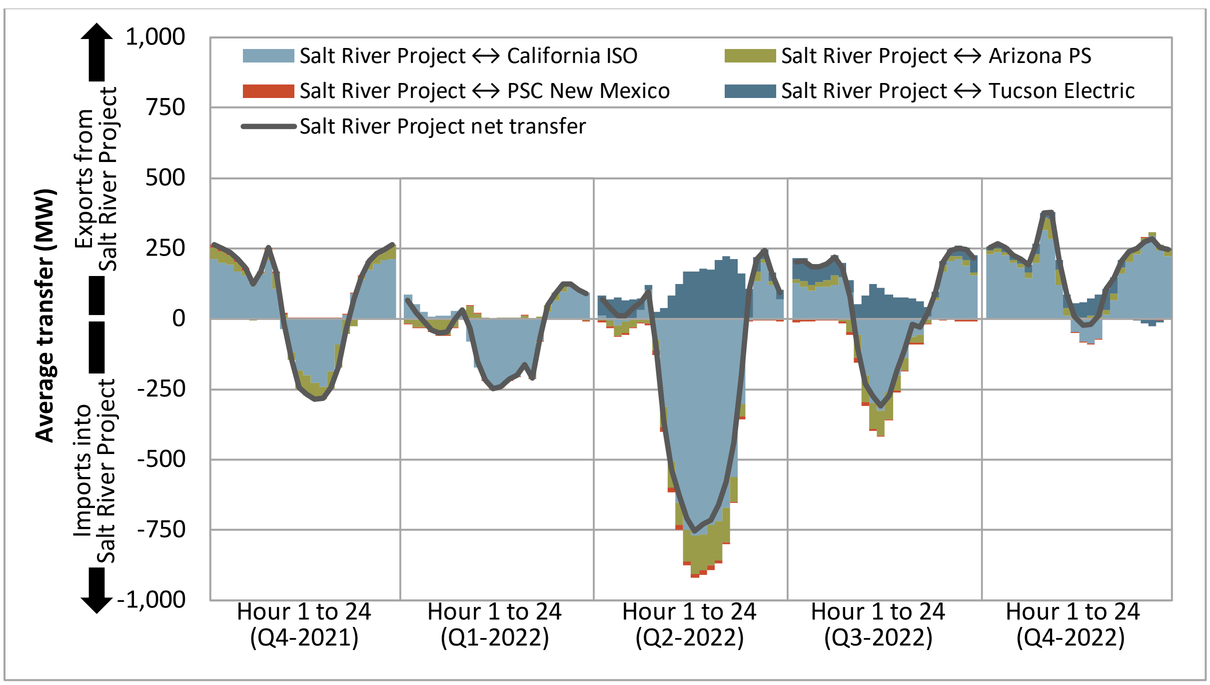
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q4 2022)

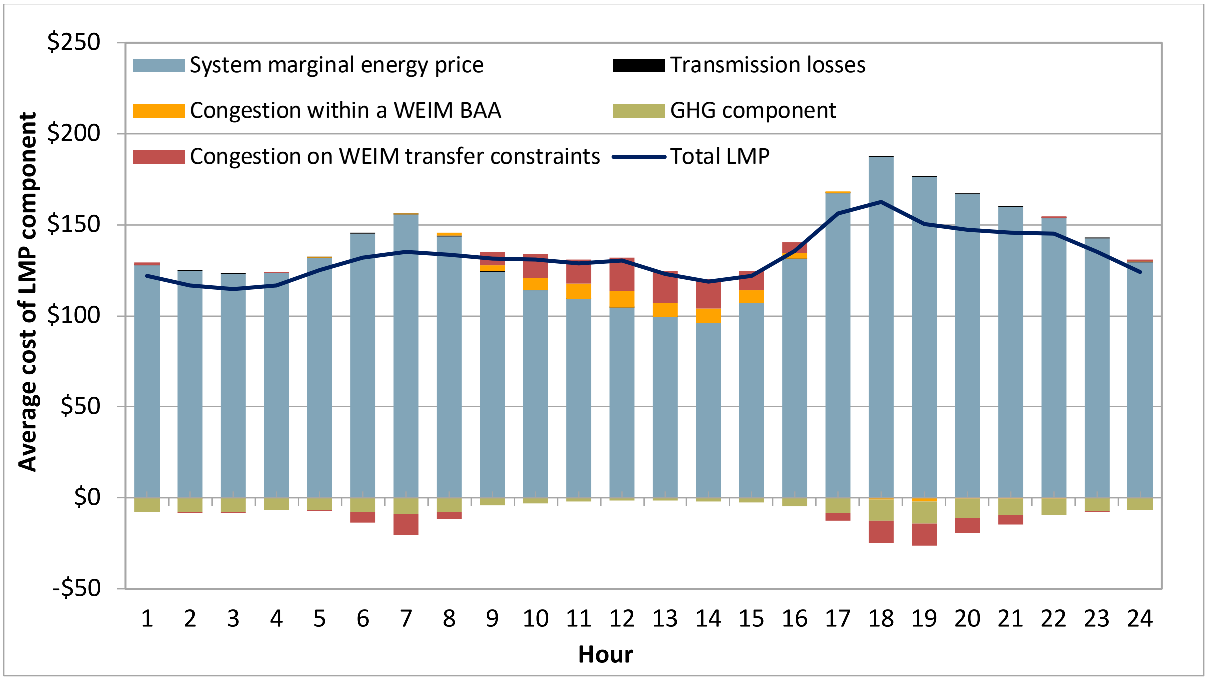


Appendix Figure A.68 Average hourly 5-minute market transfers

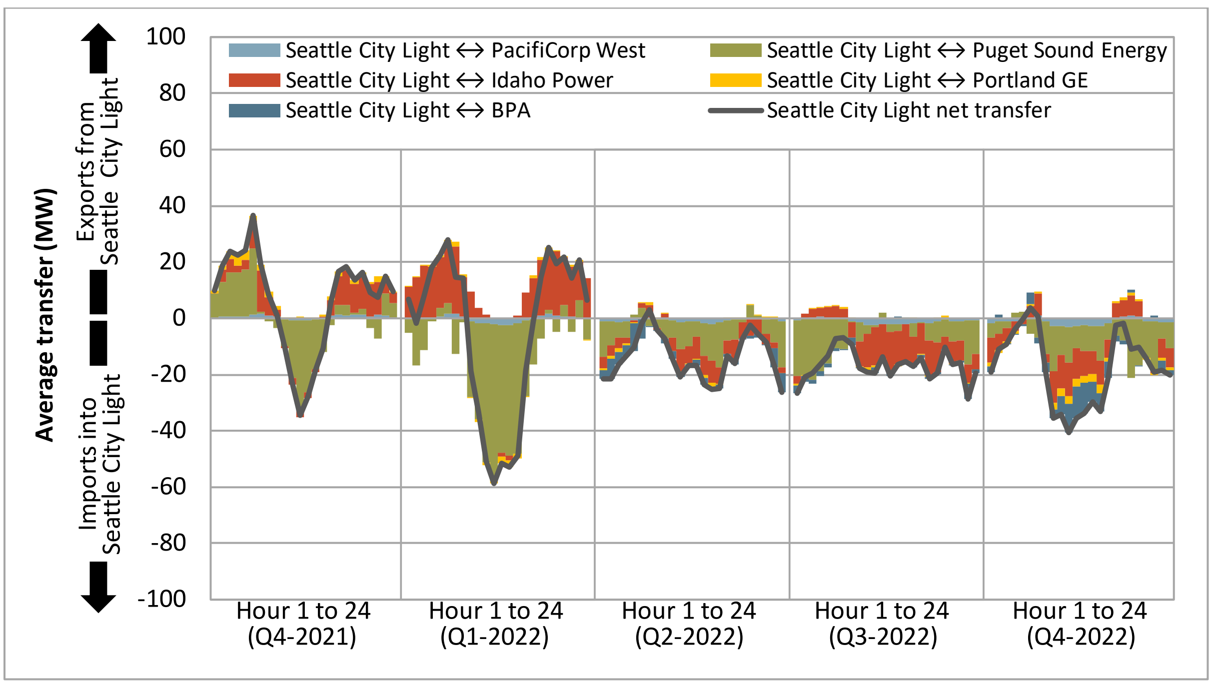


A.17 Seattle City Light

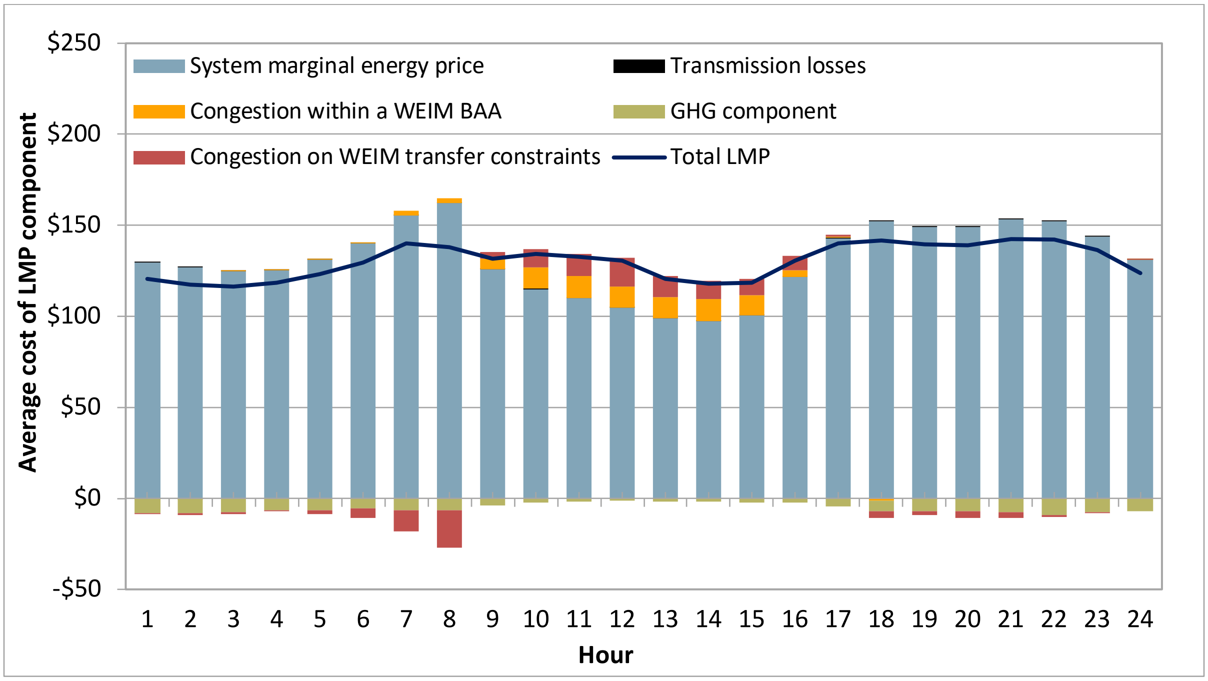
Appendix Figure A.69 Average hourly 15-minute price by component (Q4 2022)



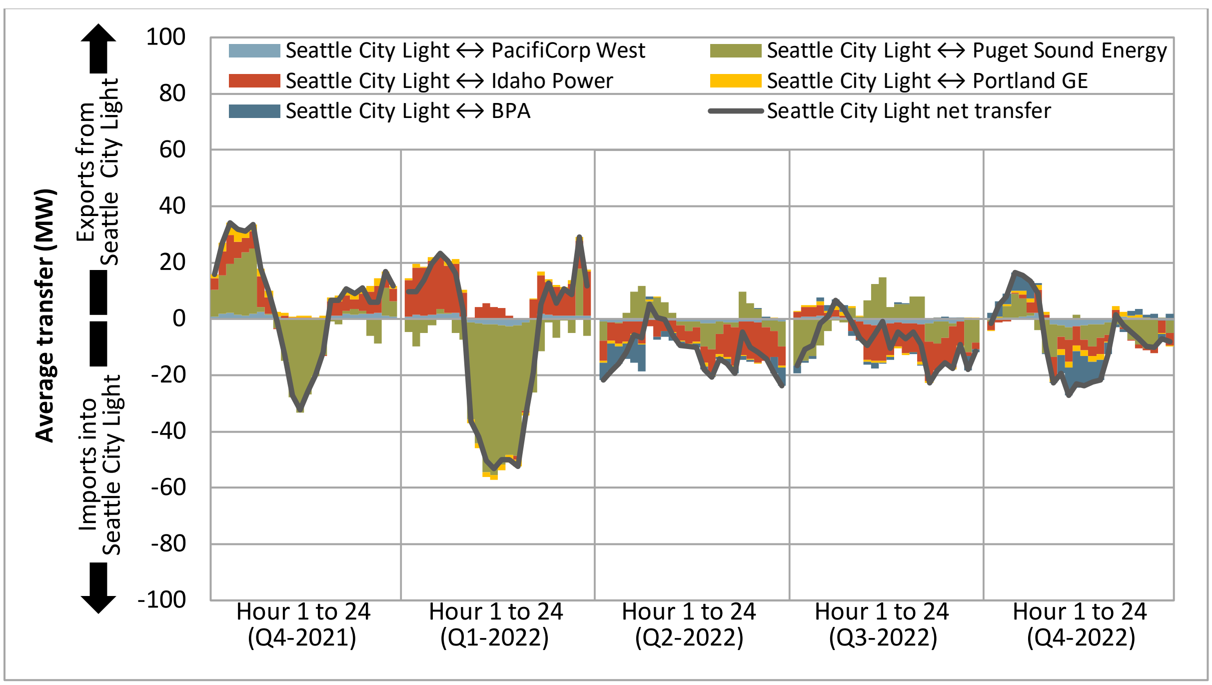
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q4 2022)

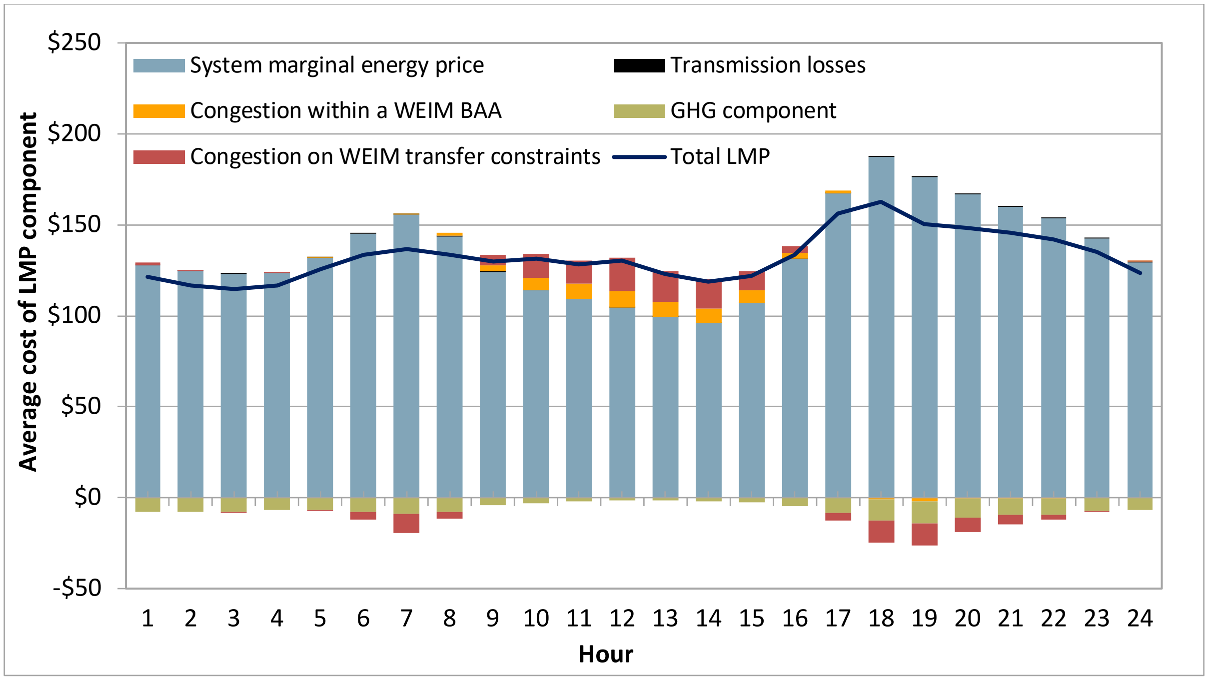


Appendix Figure A.72 Average hourly 5-minute market transfers

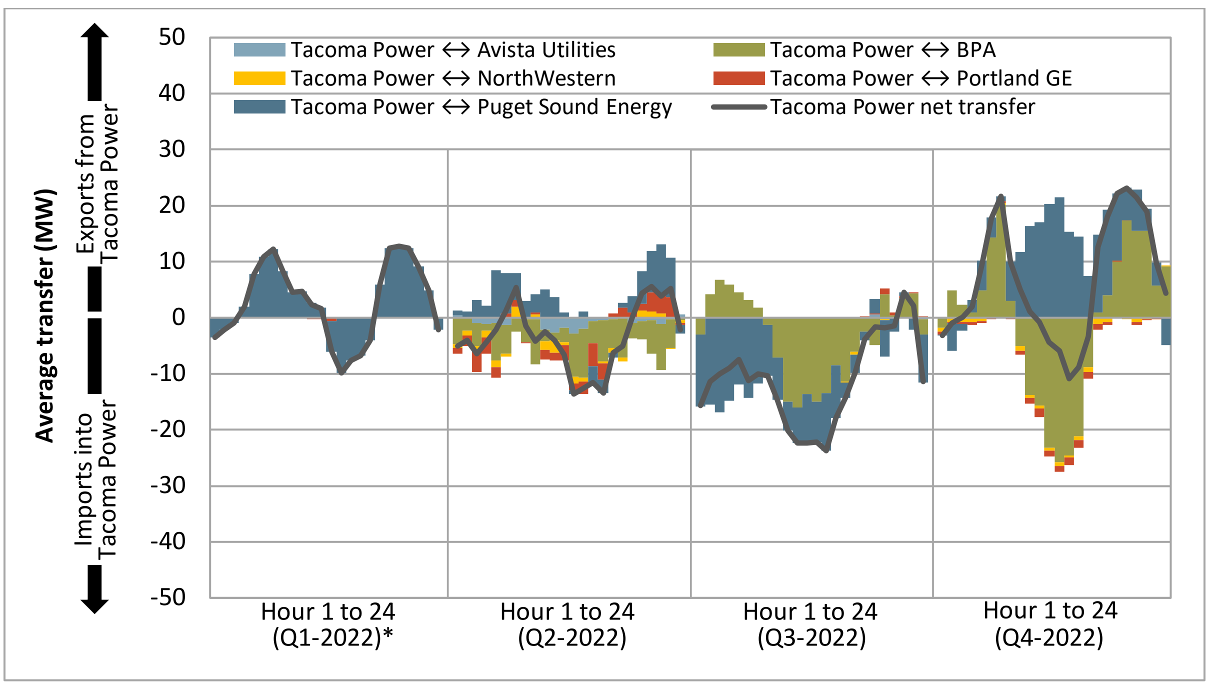


A.18 Tacoma Power

Appendix Figure A.73 Average hourly 15-minute price by component (Q4 2022)

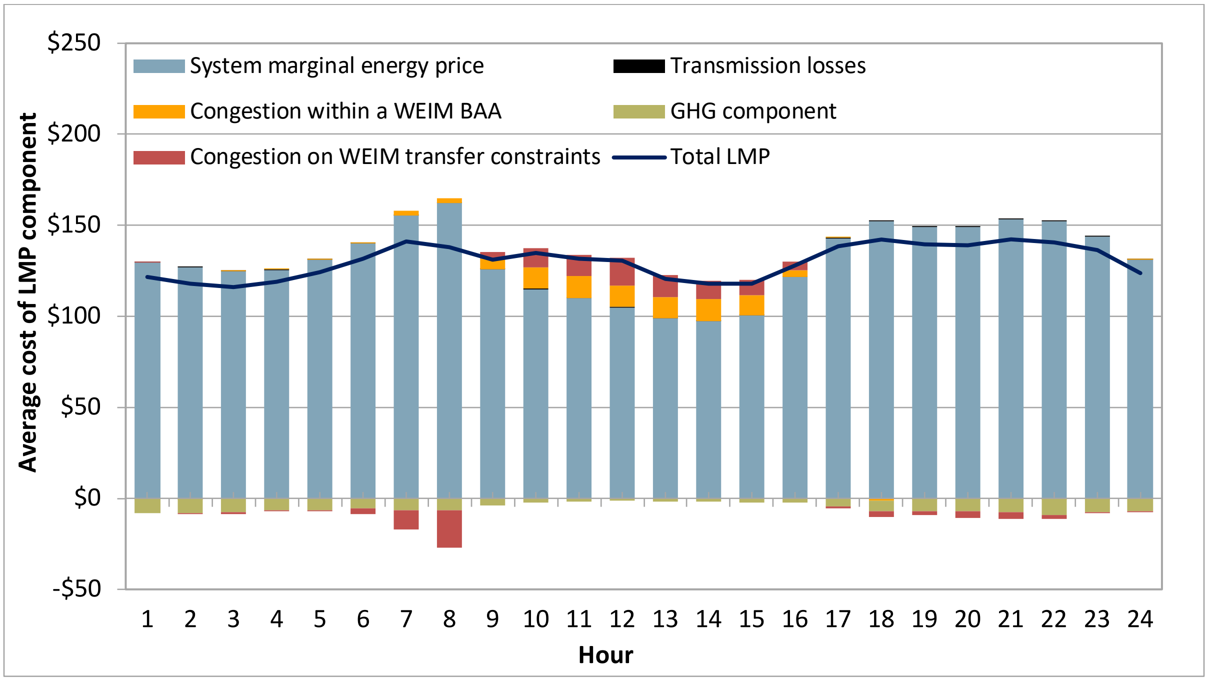


Appendix Figure A.74 Average hourly 15-minute market transfers

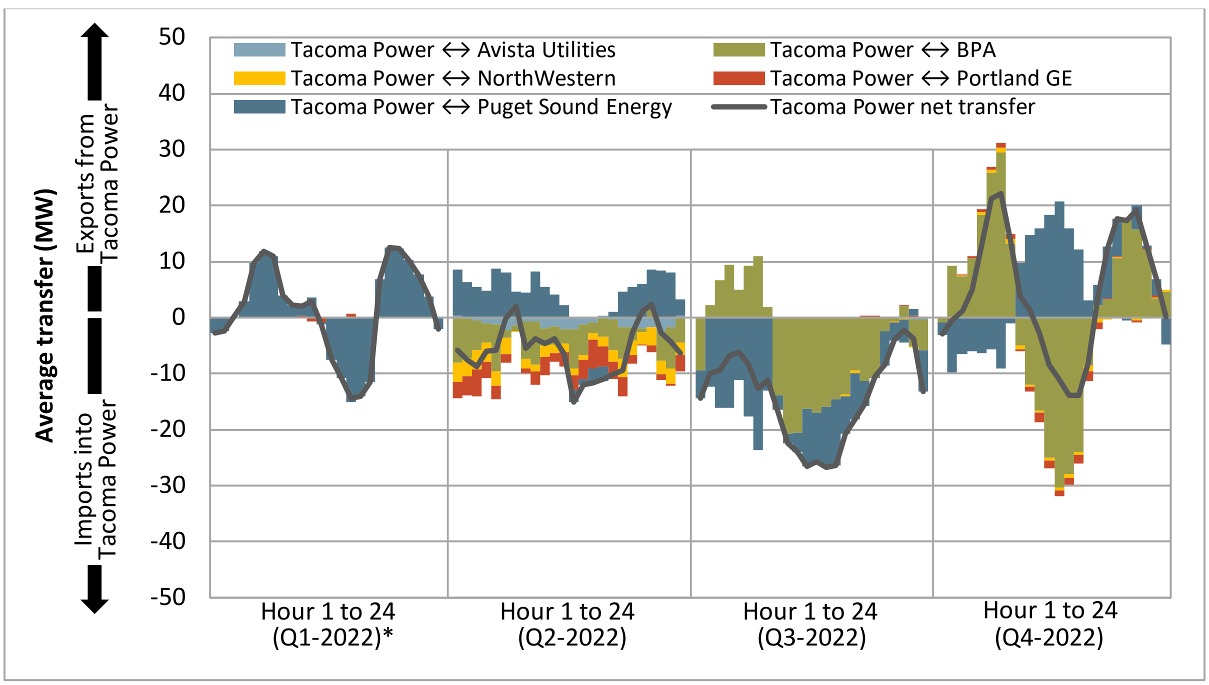


*Since joining the WEIM

Appendix Figure A.75 Average hourly 5-minute price by component (Q4 2022)



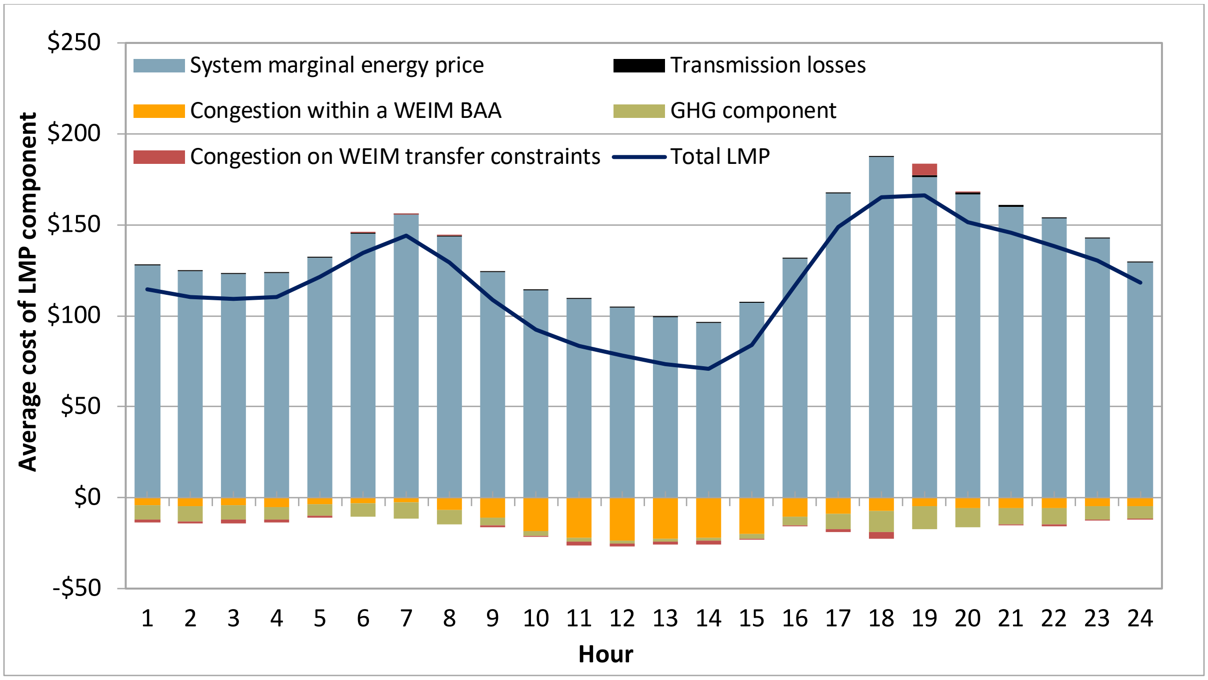
Appendix Figure A.76 Average hourly 5-minute market transfers



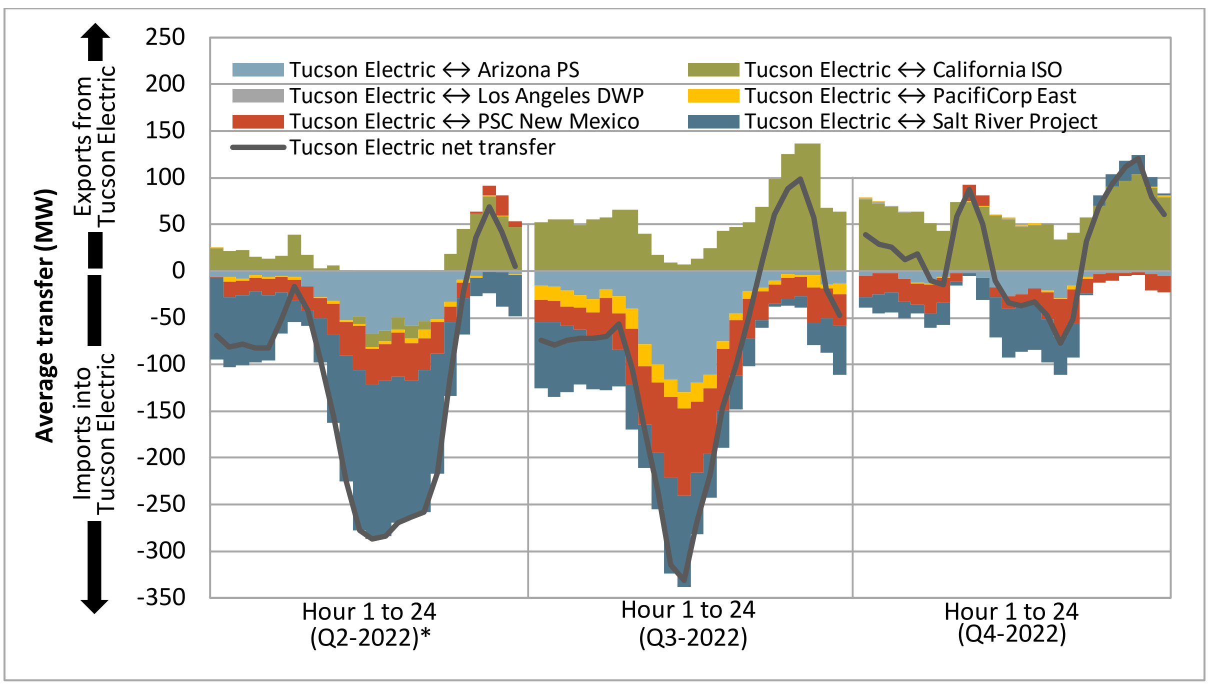
*Since joining the WEIM

A.19 Tucson Electric Power

Appendix Figure A.77 Average hourly 15-minute price by component (Q4 2022)

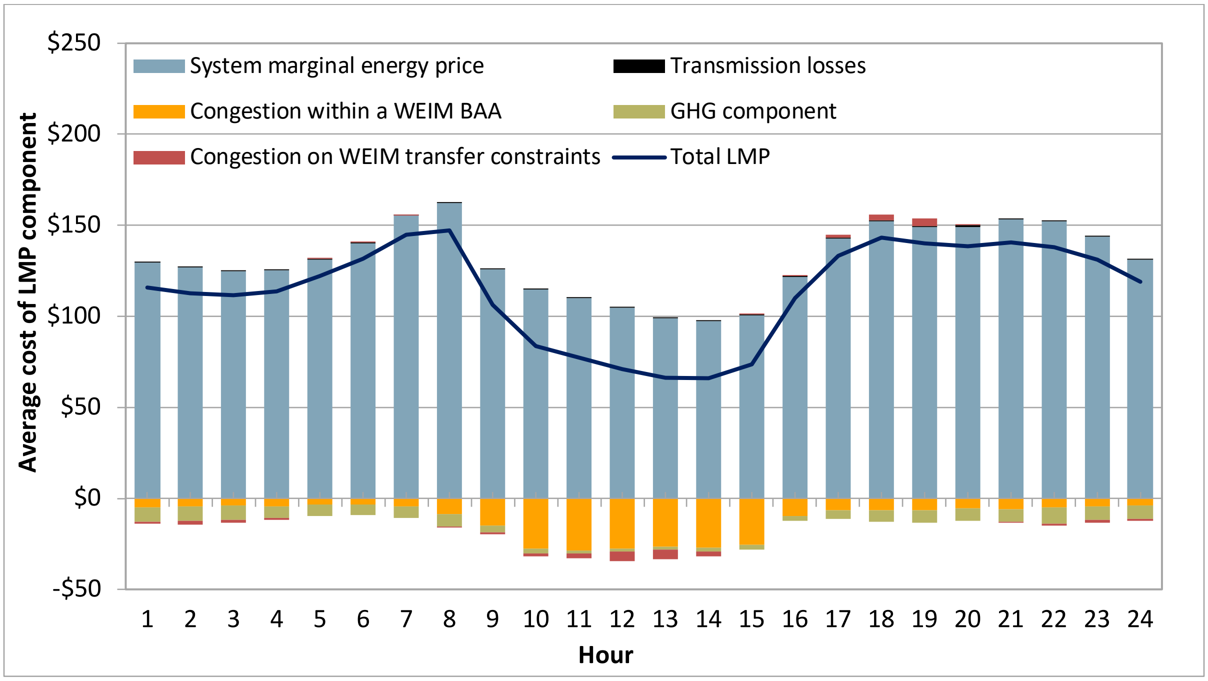


Appendix Figure A.78 Average hourly 15-minute market transfers

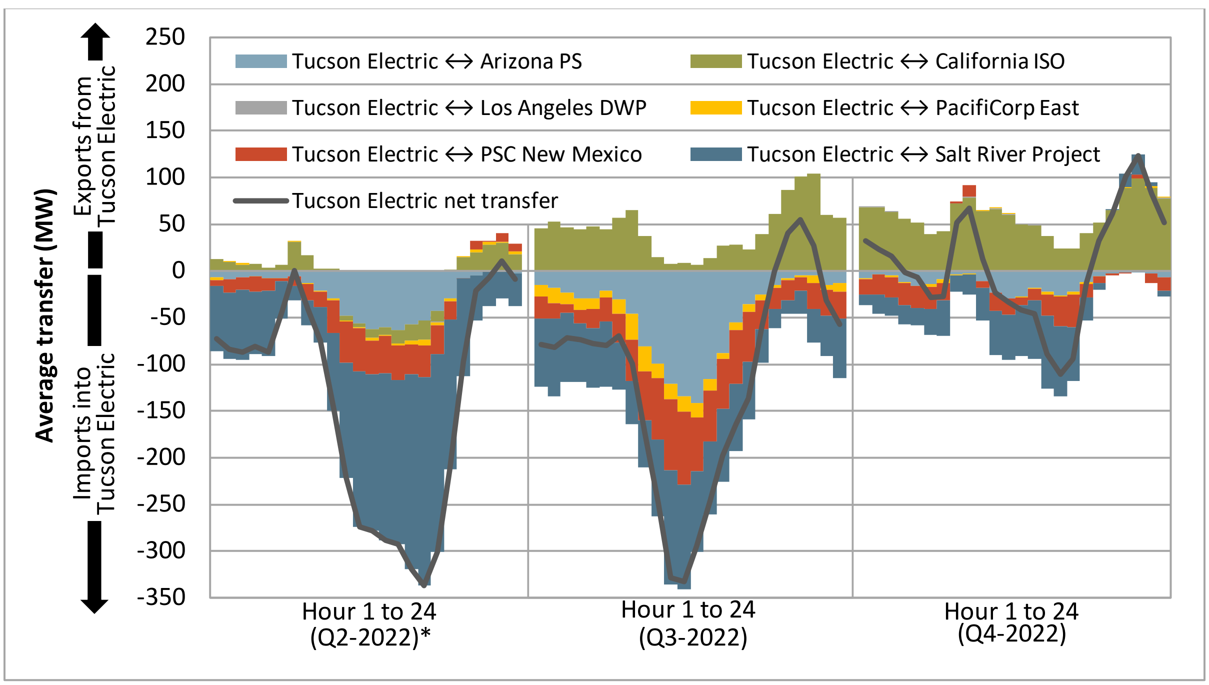


*Since joining the WEIM

Appendix Figure A.79 Average hourly 5-minute price by component (Q4 2022)



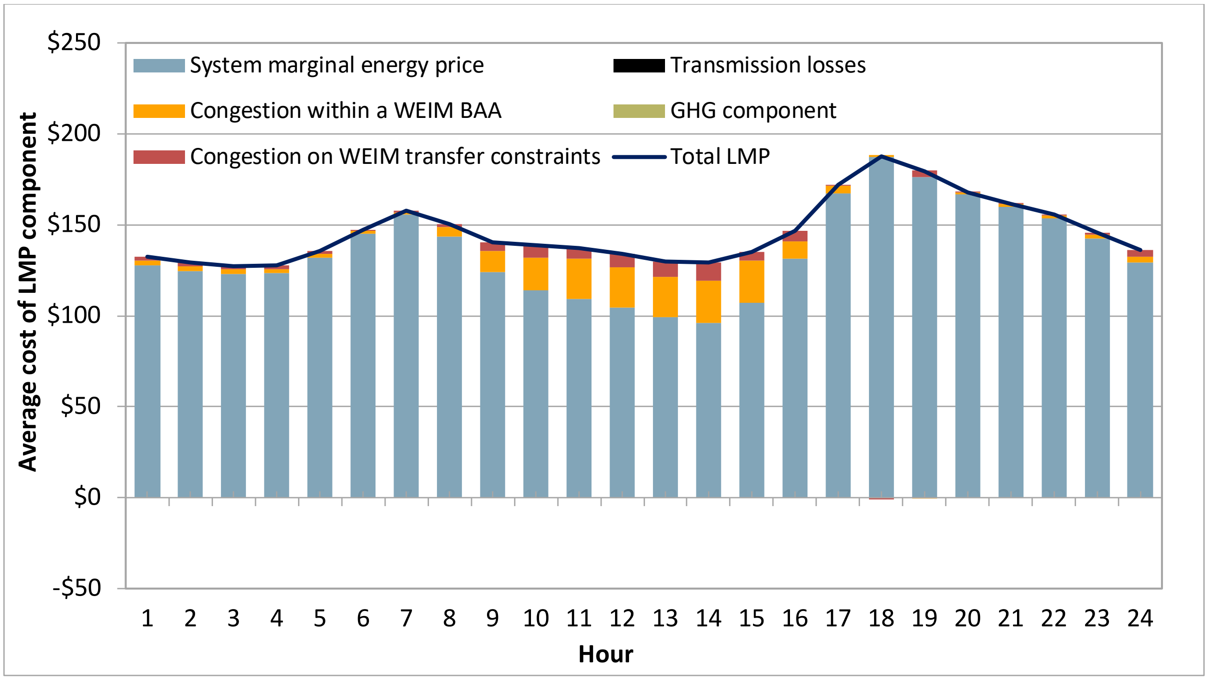
Appendix Figure A.80 Average hourly 5-minute market transfers



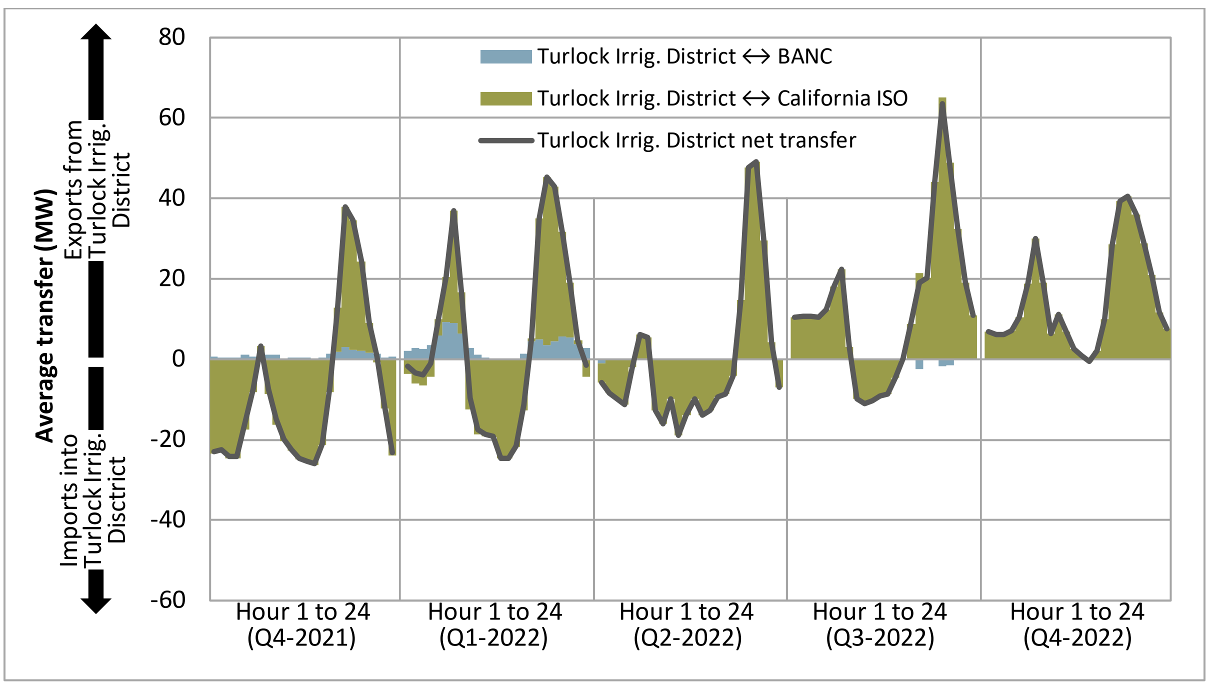
*Since joining the WEIM

A.20 Turlock Irrigation District

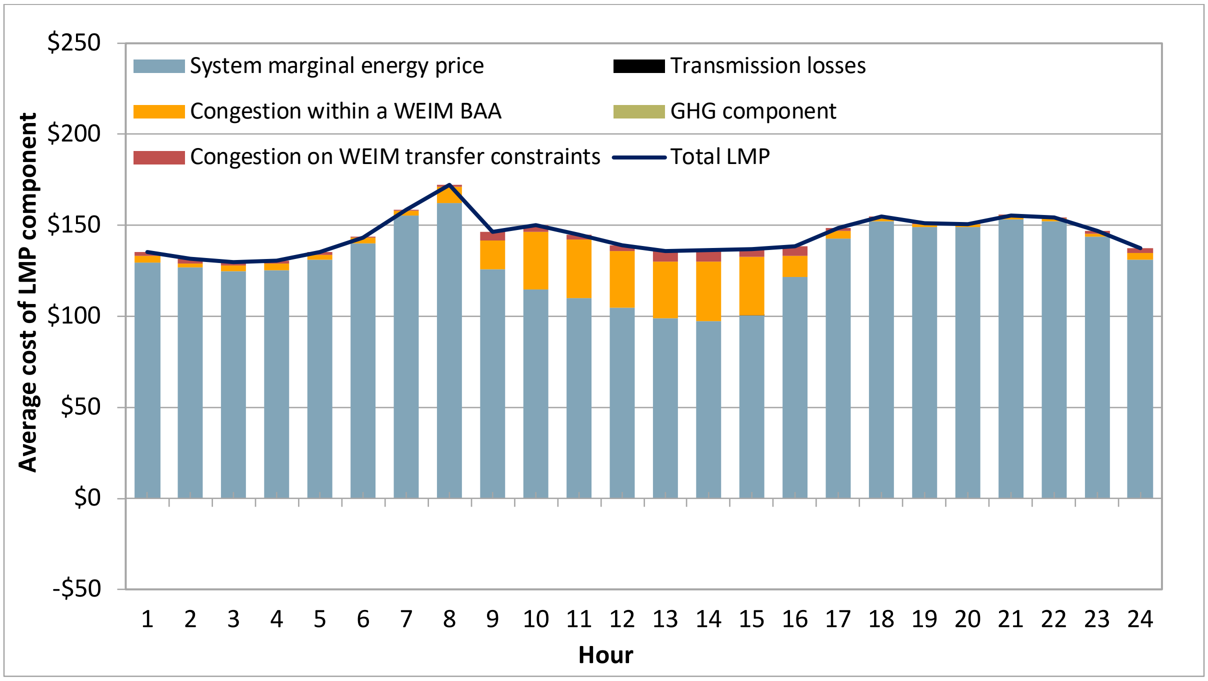
Appendix Figure A.81 Average hourly 15-minute price by component (Q4 2022)



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



Appendix Figure A.83 Average hourly 5-minute price by component (Q4 2022)



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