Q2 2023 Report on Market Issues and Performance

November 16, 2023

Prepared by: Department of Market Monitoring

California Independent System Operator

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Executive summary

This report covers market performance during the second quarter of 2023 (April-June).

Key highlights during this quarter include the following:

- **Natural gas prices fell from extraordinarily high levels in December, averaging less than Q2 2022**. Average gas prices at Henry Hub, the national index, were less than one third of prices in the same quarter of last year, while prices at both California hubs fell to less than 60 percent (Figure E.1). This resulted in lower system marginal energy prices across the market.
- **Prices were significantly lower than the same quarter of 2022** (Figure E.2). Day-ahead and real-time prices fell by half in most areas due to lower natural gas prices and higher renewable generation.
- **Hydroelectric generation almost doubled**, substituting for both natural gas generation and lower net imports. Hydroelectric generation was higher than 2020, 2021, or 2022.
- **Imports were lower during all hours**, falling by more than 1,000 MW on average, in the California ISO. The ISO was a net exporter, on average, in hours ending 11 through 17.
- **Congestion decreased in both the day-ahead and real-time markets**. Day-ahead congestion in the south to north direction decreased SCE and SDG&E area prices and increased prices in the PG&E area. Total day-ahead congestion rent fell to $151 million, down from $269 million in the same quarter of the previous year.
- **Real-time imbalance offset costs remained high**, but decreased to about $71 million, down from $130 million in 2022. Real-time *congestion* imbalance offset costs made up the majority of these costs, at $60 million.
- **Estimated bid cost recovery payments increased** for units in the California ISO and WEIM balancing areas, totaling about $32 million and $4 million, respectively, during the quarter, about two thirds of the total for 2022. About $27.5 million was paid to gas resources, followed by about $5 million to battery energy storage resources.
- **Ancillary service costs totaled $31 million, about two thirds of costs in** Q2 2022. Costs fell both due to replacement of spinning reserves with lower cost non-spinning reserves, and because of the rapidly increasing participation of battery storage resources, which provide a substantial proportion of ISO ancillary services.
- **Net revenues for convergence bidders were about $17 million**, down from $40 million in 2022.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by $1 million** in the quarter. 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.
- **Flexible ramping product system level prices** were zero for over 98 percent of intervals in the 15-minute market and in the 5-minute market. Nodal pricing and a new uncertainty calculation for the product were implemented in February of 2023. Before implementation, prices were zero in over 99 percent of intervals. Errors in implementation of product demand curves lowered prices in non-zero intervals. These errors were resolved in August and October.
- **Imbalance conformance adjustments** averaged about 1,600 MW in the peak net load ramp hours in the California ISO, lower than Q2 2022. The 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

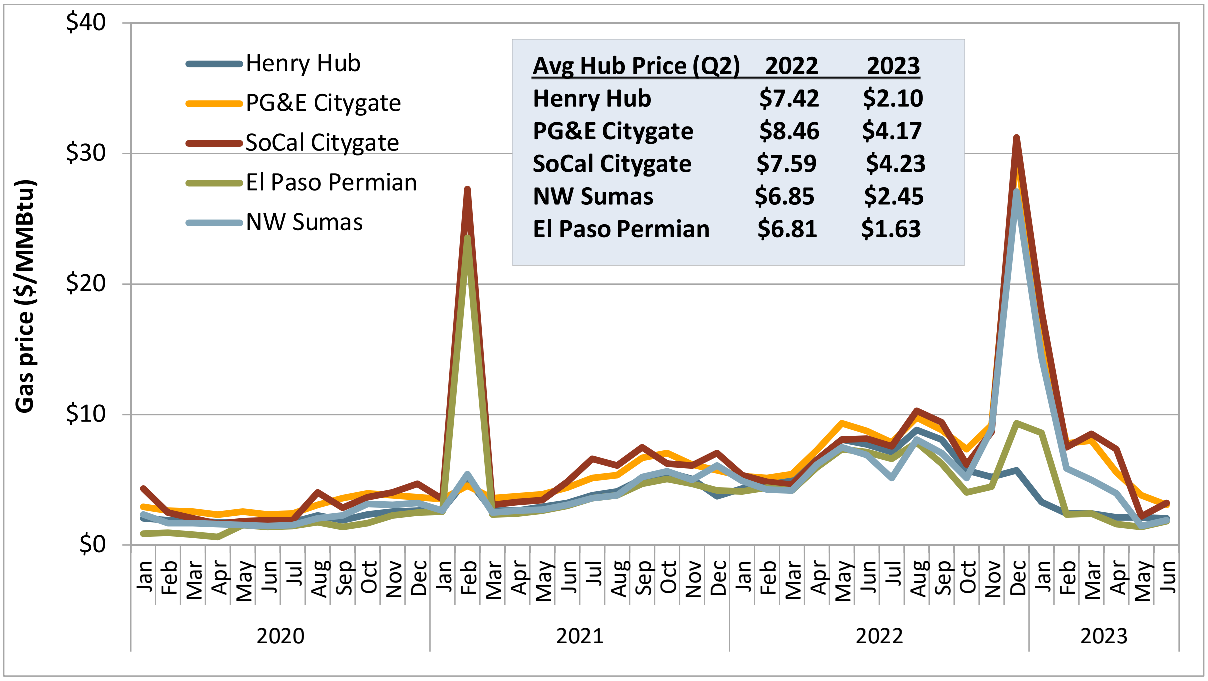
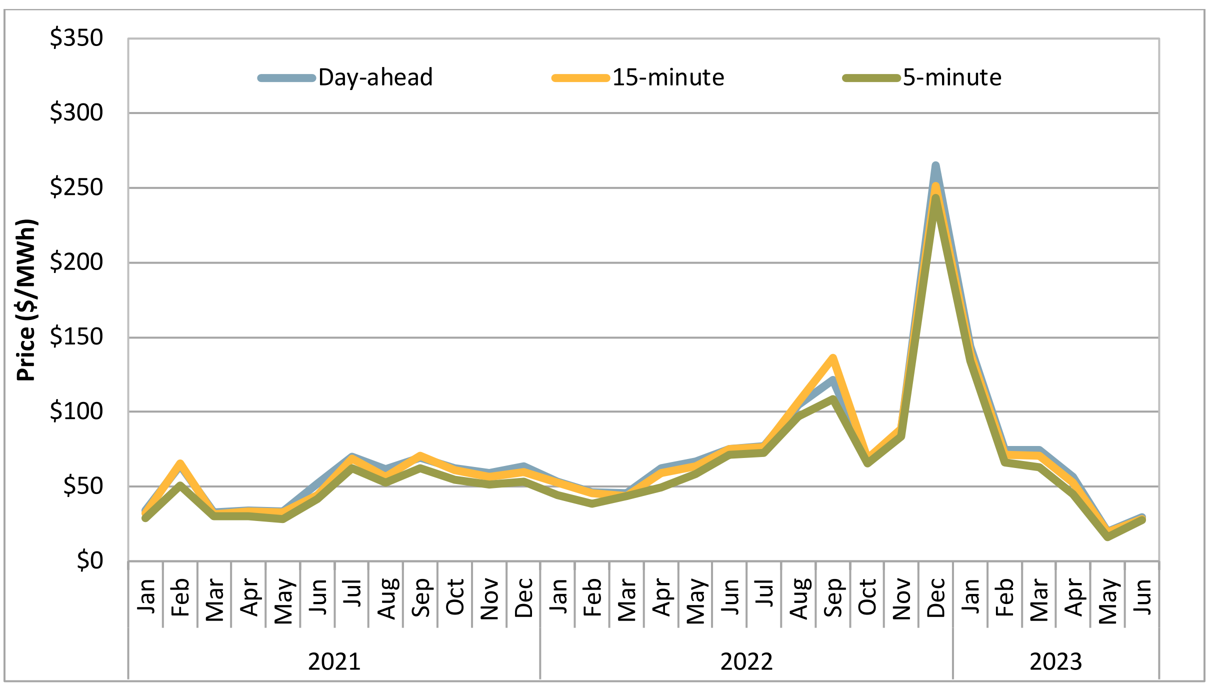


Figure E.2 Monthly load-weighted average energy prices California ISO (all hours)



Western Energy Imbalance Market

- **Natural gas prices fell across the WEIM**, resulting in lower energy prices in all balancing areas.
- **Avangrid Renewables (AVRN), El Paso Energy (EPE), and the Western Area Power Authority – Desert South West (WALC)**, **joined** the Western Energy Imbalance Market in April, bringing the total number of participants up to 22.
- **Prices in WEIM balancing areas within California were about $2/MWh higher than other regions**. Prices tend to be higher in California than the rest of the system due to greenhouse gas compliance costs for energy that is delivered to California.
- **The California ISO was a major net importer** during peak net load hours, importing an average of about 750 MW from neighboring areas in the 15-minute market.
- **The California ISO was the major net exporter** during the mid-day period when solar generation is typically at its highest, exporting over 3,000 MW to areas in the Northwest and Southwest.
- **Prices in the Northwest region** were frequently separated from system prices by congestion on WEIM transfer constraints. 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.
- **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

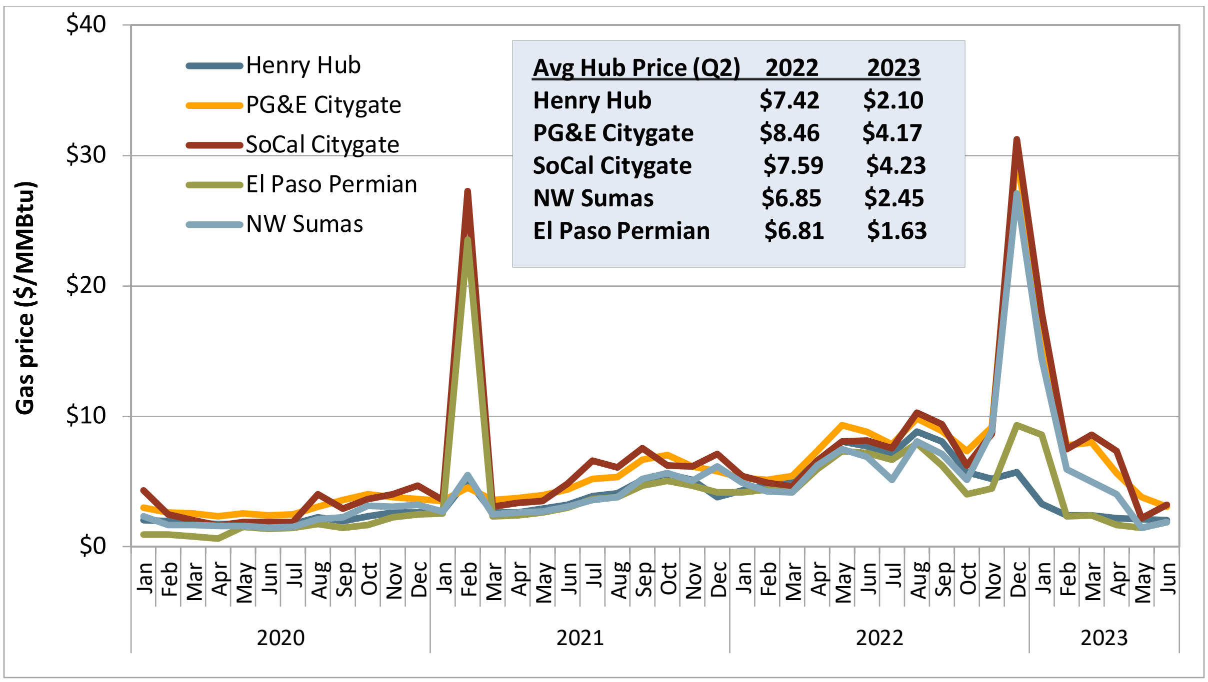
1.1 Supply conditions

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 ISO balancing area and other regional markets. During the second quarter of 2023, average gas prices at major western gas trading hubs declined by more than 60 percent from record high levels in December 2022 and January 2023.

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

Figure 1.1 Monthly average natural gas prices



Average second quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) declined by 61 percent and 63 percent, respectively, compared to the previous quarter. The Northwest Sumas gas hub price declined 71 percent during the same time period. Prices at Henry Hub and Permian Basin also decreased by 22 percent and 63 percent, respectively.

When compared to the second quarter of 2022, prices at PG&E Citygate, SoCal Citygate, and Northwest Sumas decreased by 51 percent, 44 percent, and 64 percent, respectively. Prices at Henry Hub and Permian also declined by more than 70 percent during the same time period.

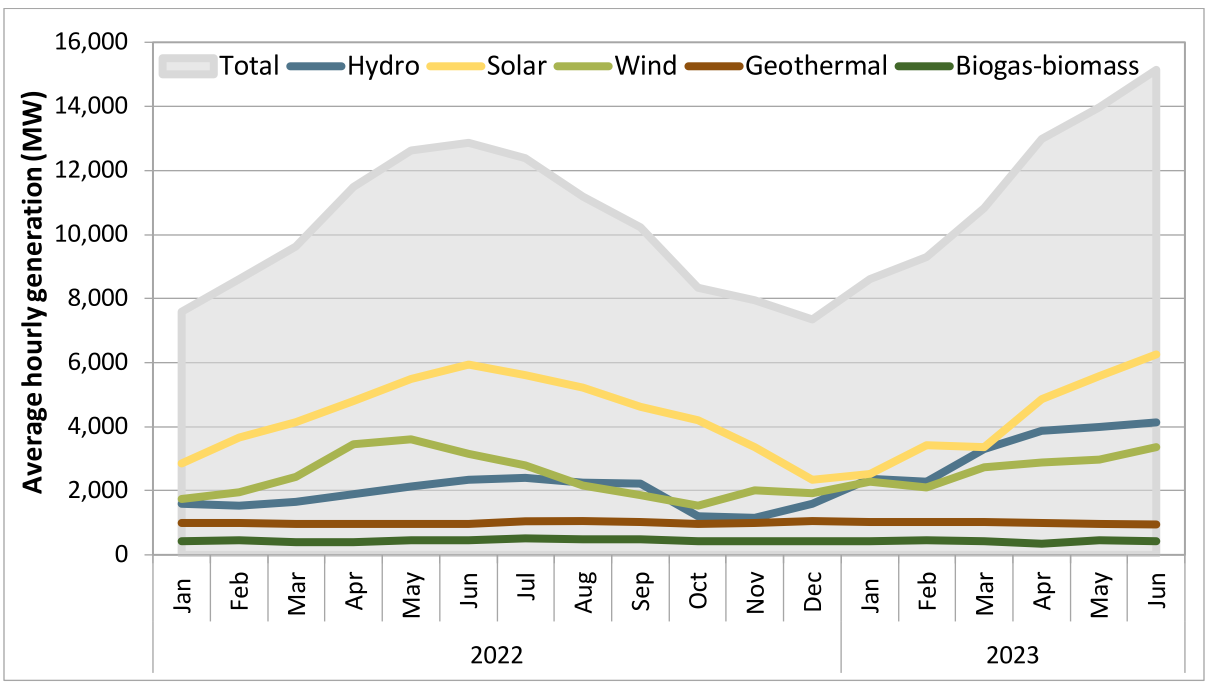
On August 31, 2023, the CPUC issued an order increasing the inventory limit for the Aliso Canyon storage facility from 41.16 Bcf to 68.6 Bcf.[1] This action increases the SoCalGas total authorized storage inventory capacity from 84.9 Bcf to 119.5 Bcf.

1.1.2 Renewable generation

In the second quarter, the combined average monthly generation from renewable resources increased by about 1,700 MW (14 percent) compared to the same quarter of 2022.[2] Hydroelectric generation increased 88 percent, while generation from other renewables (including solar, wind, geothermal, and biogas-biomass resources) decreased 2 percent year-over-year. 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 1.2 shows the average monthly renewable generation by fuel type.[3] Wind generation decreased by 326 MW (10 percent), while solar generation increased by about 162 MW (3 percent) compared to the same quarter last year on average. Generation from geothermal generation increased 14 MW (1 percent), and biogas-biomass generation decreased by 17 MW (4 percent) on average. Average hydroelectric generation had the largest year-over-year growth of all renewables, at around 88 percent, largely due to historically high precipitation levels in late 2022 and early 2023 which also filled reservoirs to historically high levels in California.

Figure 1.2 Average monthly renewable generation



[1] CPUC Proposed Decision to Protect Against Natural Gas Price Spikes in Southern California (I.17-02-002): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/ac-storage-level-pd-0722823.pdf

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

[3] Hydroelectric generation greater than 30 MW is included.

1.1.3 Generation by fuel type

In the second quarter, average daily natural gas generation decreased year-over-year by around 1,600 MW, or 27 percent. Net imports had the next largest year-over-year decrease at around 1,200 MW, or 27 percent. Moreover, on average the ISO balancing area switched from importing on net to exporting from hours-ending 11 through 17. Average hourly generation by natural gas resources decreased from 27 percent to 22 percent of total generation during peak net load hours since the second quarter of 2022. Battery generation increased 51 percent compared to the second quarter of 2022.[4]

Figure 1.3 shows the average hourly generation by fuel type during the second quarter of 2023 as measured by preliminary meter data. Total hourly average generation peaked at about 26,600 MW during hour-ending 21. Battery generation peaked during hour-ending 20 at about 2,360 MW. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed to 39 percent of total generation during the peak net load hours of 17-21, up from 33 percent during the same time last year.

Figure 1.3 Average hourly generation by fuel type (Q2 2023)

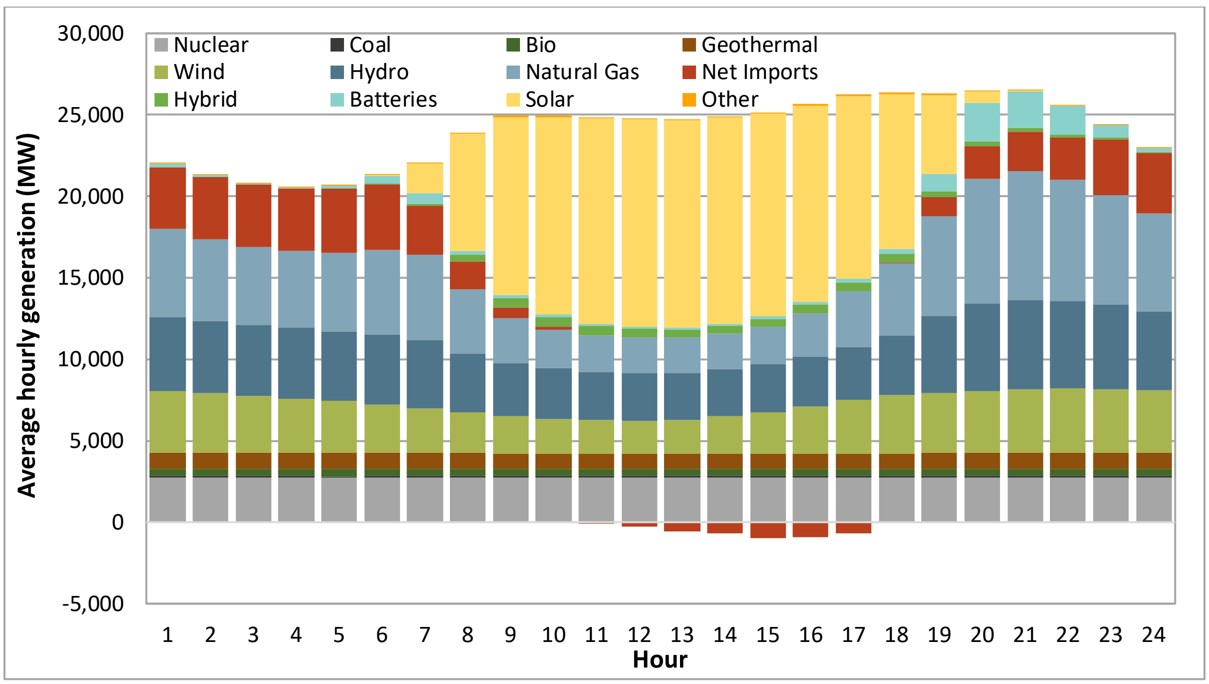


Figure 1.4 shows the change in hourly generation by fuel type between the second quarter of 2022 and the second quarter of 2023.[5] In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

Overall, the net change shows that there was a decrease in average hourly generation in all hours of the day.

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

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

Figure 1.5 shows the monthly average of hydroelectric generation from 2019 to 2023. Hydroelectric generation in the second quarter of 2023 was higher than the last three years and tracked most similarly to 2019.

Figure 1.4 Change in average hourly generation by fuel type (Q2 2022 to Q2 2023)

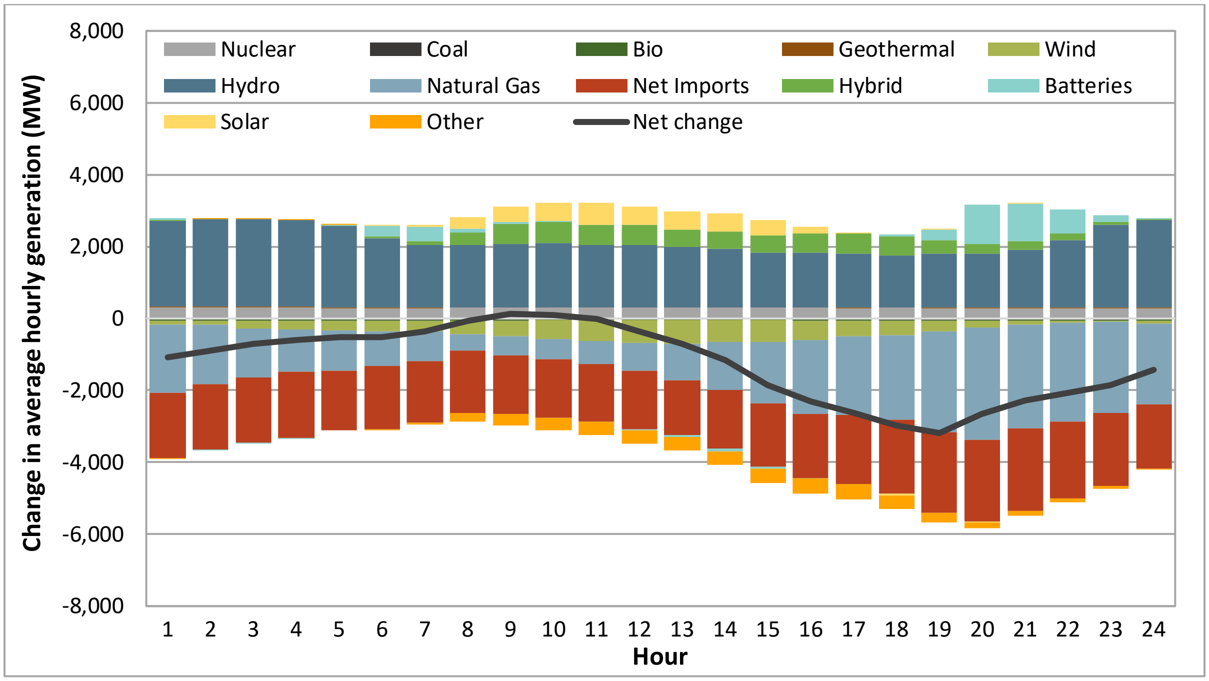
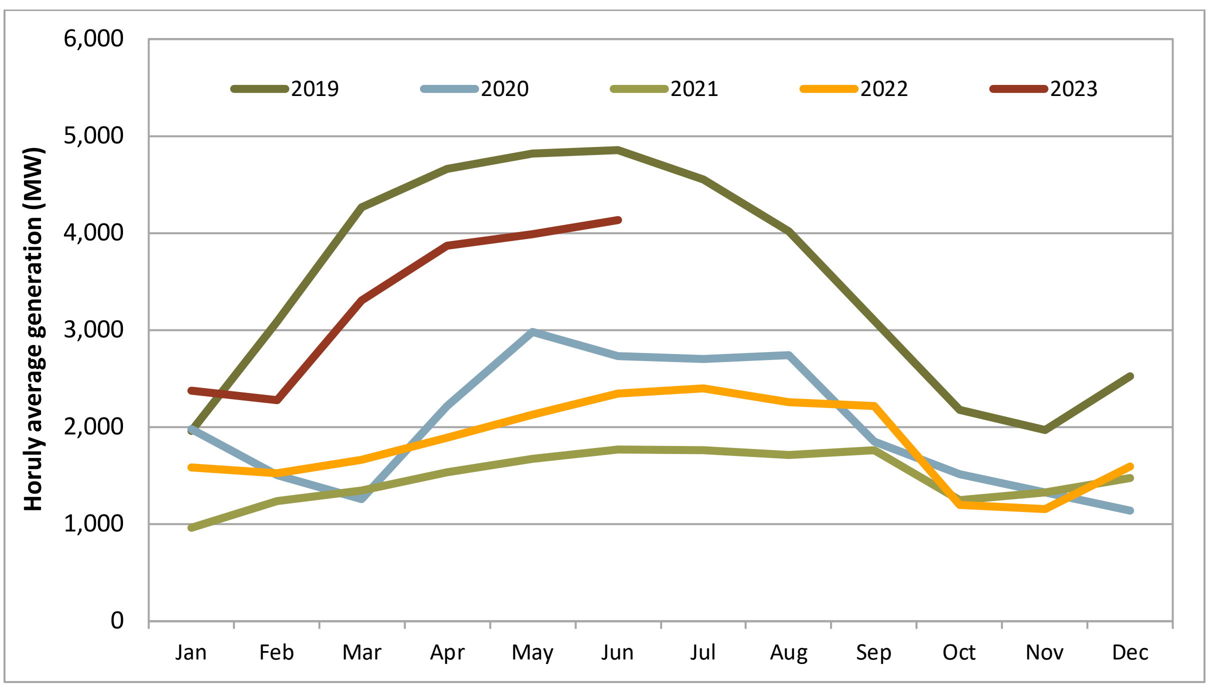


Figure 1.5 Monthly average hydroelectric generation by year



1.1.4 Generation outages

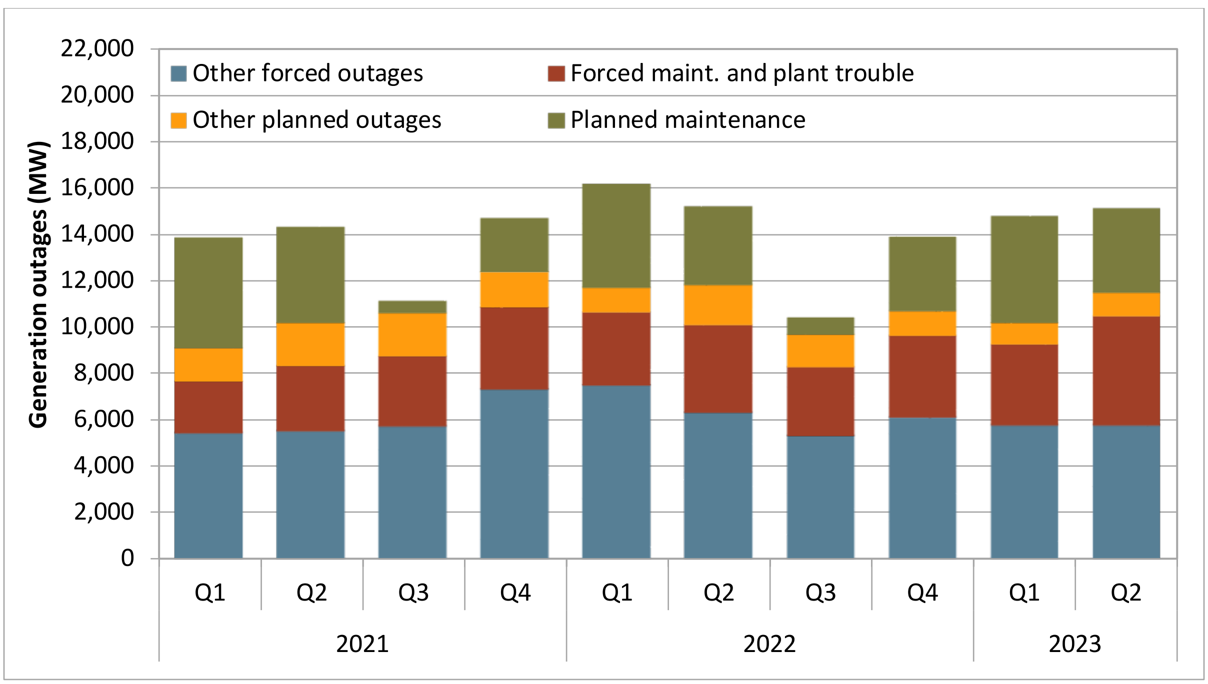
Total generation on outage in the ISO balancing area averaged about 15,089 MW, 1 percent lower than the second quarter of 2022. This decrease was driven by planned outages not due to maintenance, which fell 38 percent relative to the same time last year.

Under the 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 1.6 and Figure 1.7 show the quarterly and monthly averages of maximum daily outages during peak hours by type from 2021 to 2023, respectively.[6] 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, this year followed that trend with planned maintenance outages decreasing over the second quarter, reaching an average total of 12,012 MW in June.

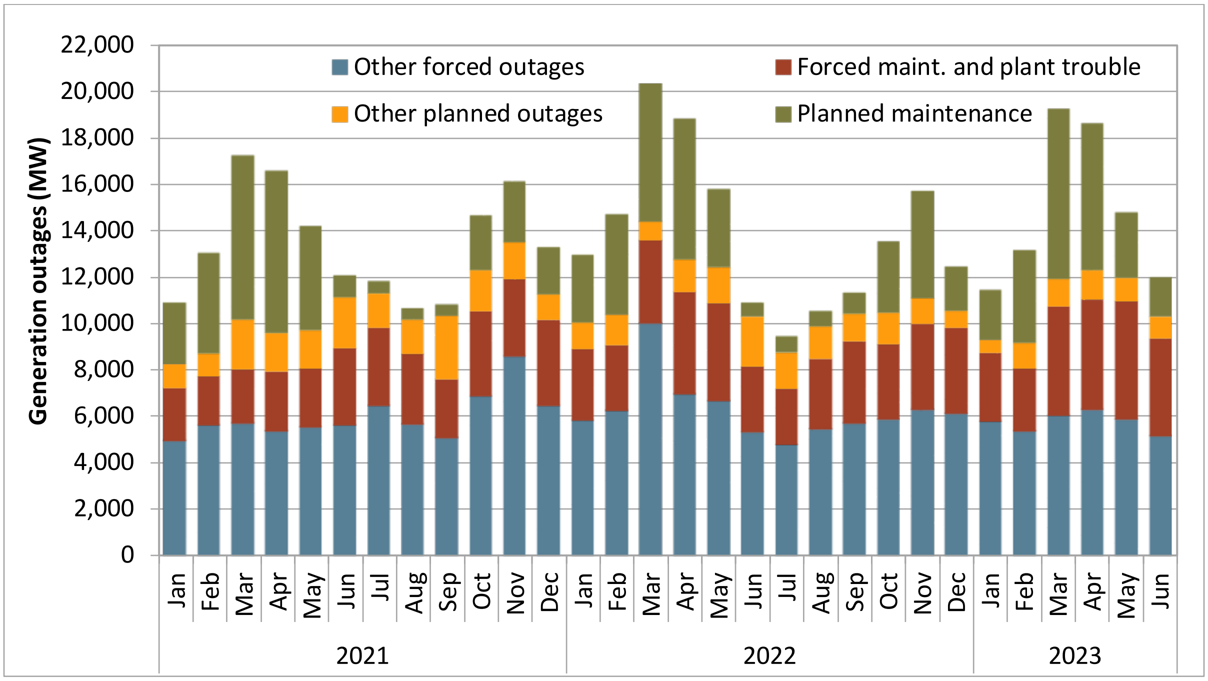
During the second quarter of 2023, the average total daily maximum generation on outage in the ISO balancing area was 15,089 MW, about 91 MW less than the second quarter of 2022, as shown in Figure 1.6. There were 3 percent more forced outages compared to the same time last year, and an 8 percent decline in planned outages.

Figure 1.6 Quarterly average of maximum daily generation outages by type – peak hours



[6] 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 ISO balancing area and do not include outages in the Western Energy Imbalance Market.

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



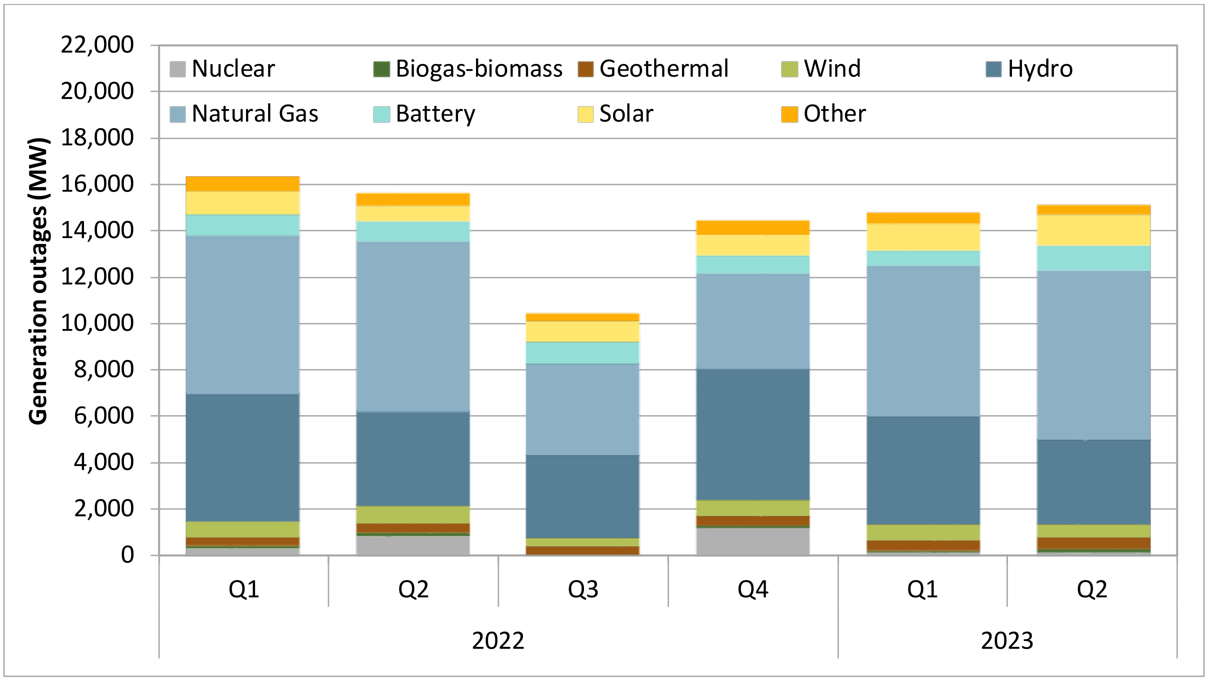
Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 7,270 MW and 4,066 MW during the second quarter, respectively. These two fuel types accounted for a combined 74 percent of the generation on outage for the quarter. The amount of hydroelectric generation on outage decreased 11 percent relative to the same time last year, with natural gas staying the same.

Figure 1.8 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[7] Battery and solar generation had an increase in average capacity on outage, while all other fuel types saw a decrease compared to the second quarter of 2022.

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

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



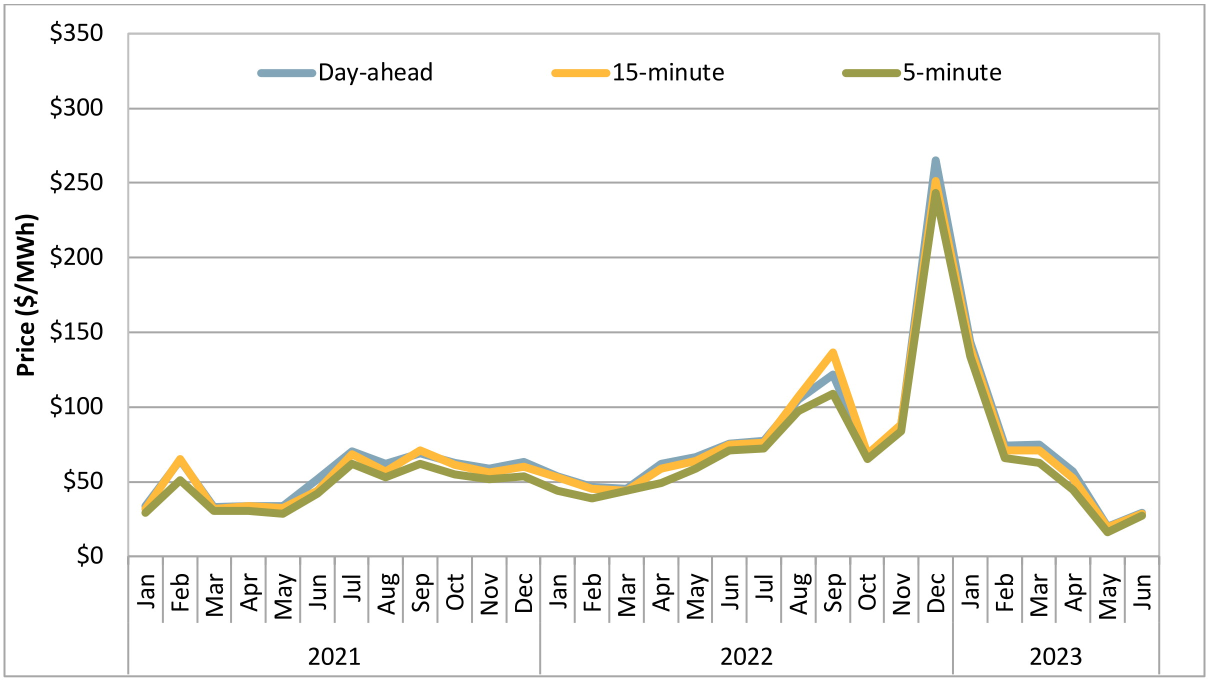
1.2 Energy market performance

1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. In 2023, the second quarter prices in all three markets dropped by half compared to the previous year. The average price in all three markets this quarter decreased to $33/MWh from $64/MWh in the same quarter last year.

Figure 1.9 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2021 to June 2023.

Figure 1.9 Monthly load-weighted average energy prices for California ISO (all hours)



Over the quarter, day-ahead prices averaged $35/MWh, 15-minute prices averaged $33/MWh, and 5-minute prices averaged $29/MWh. Prices across all three markets were half of those in the second quarter of the prior year. In May, the market showed the lowest price, with an average price of $18/MWh across all three markets.

Relatively low natural gas prices contributed to the decrease in energy prices observed this quarter. Figure 1.10 shows monthly average gas prices at SoCal Citygate, and load-weighted energy prices from January 2022 to June 2023. The chart shows that the monthly variation of the energy prices is highly correlated with natural gas prices. The black dashed line shows the monthly average natural gas price at SoCal Citygate, complemented by the colored lines illustrating energy prices. Over the past 18 months, both natural gas and energy prices exhibited similar fluctuations. After reaching its peak in December 2022, the price of natural gas has consistently declined, approximating $4/MMBtu this quarter.

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

Figure 1.10 Monthly average SoCal City natural gas price and load-weighted average energy price for California ISO

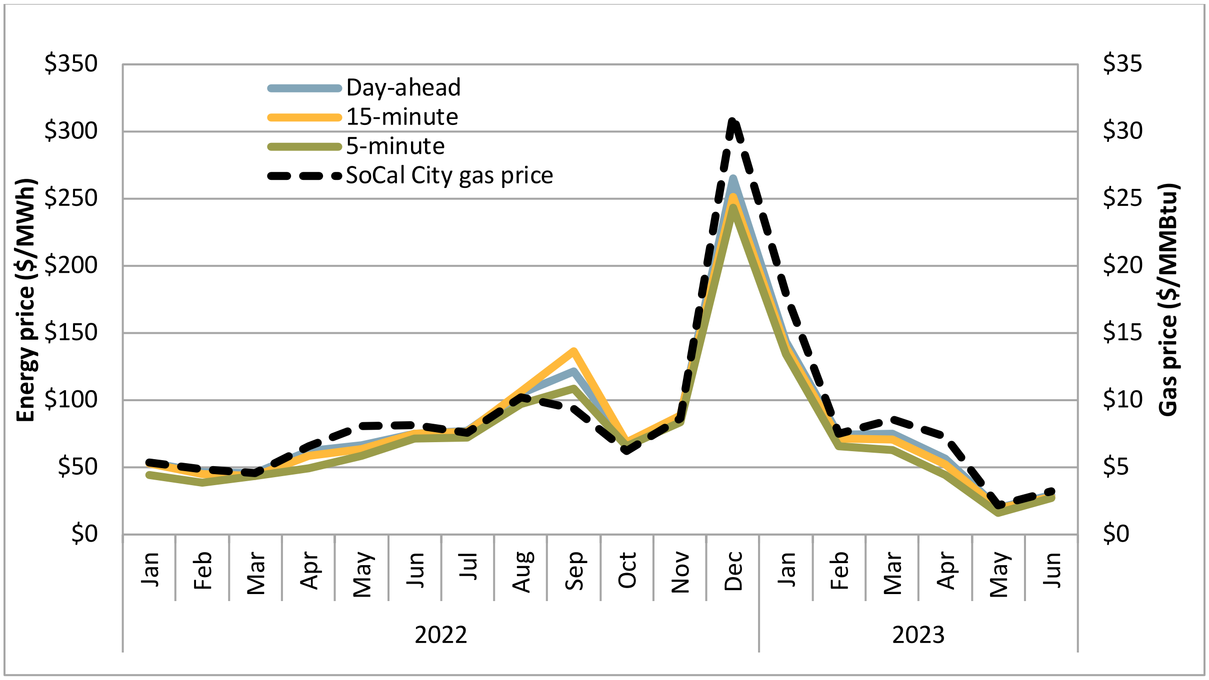


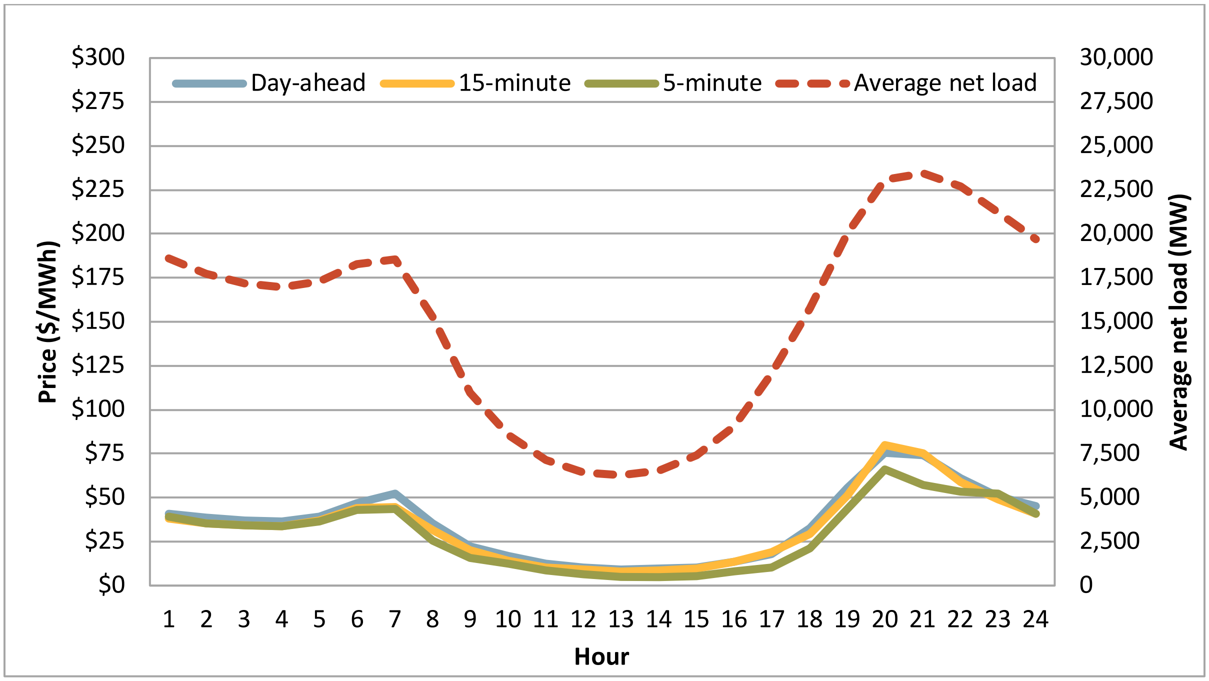
Figure 1.11 illustrates the hourly load-weighted average energy prices for the second quarter compared to the average hourly net load.[8] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net load pattern, with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening, and peaked at hour-ending 21 when demand was still high but solar generation was substantially lower. The average net load in this quarter reached 23,444 MW at hour-ending 21.

The average price peaked at hour-ending 20, an hour before the average net load reached its maximum. At this hour, the day-ahead load-weighted average energy price was $76/MWh, the 15-minute price was $80/MWh, and the 5-minute price was $66/MWh.

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

Figure 1.11 Hourly load-weighted average energy prices (April-June)



1.2.2 Bilateral price comparison

Figure 1.12 shows the ISO 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 ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays. The figure shows consistently higher prices at Mid-Columbia in April and June compared to the ISO and Palo Verde prices. Regional differences in prices reflect transmission constraints and greenhouse gas compliance costs.

Figure 1.12 Day-ahead California ISO and bilateral market prices (April-June)

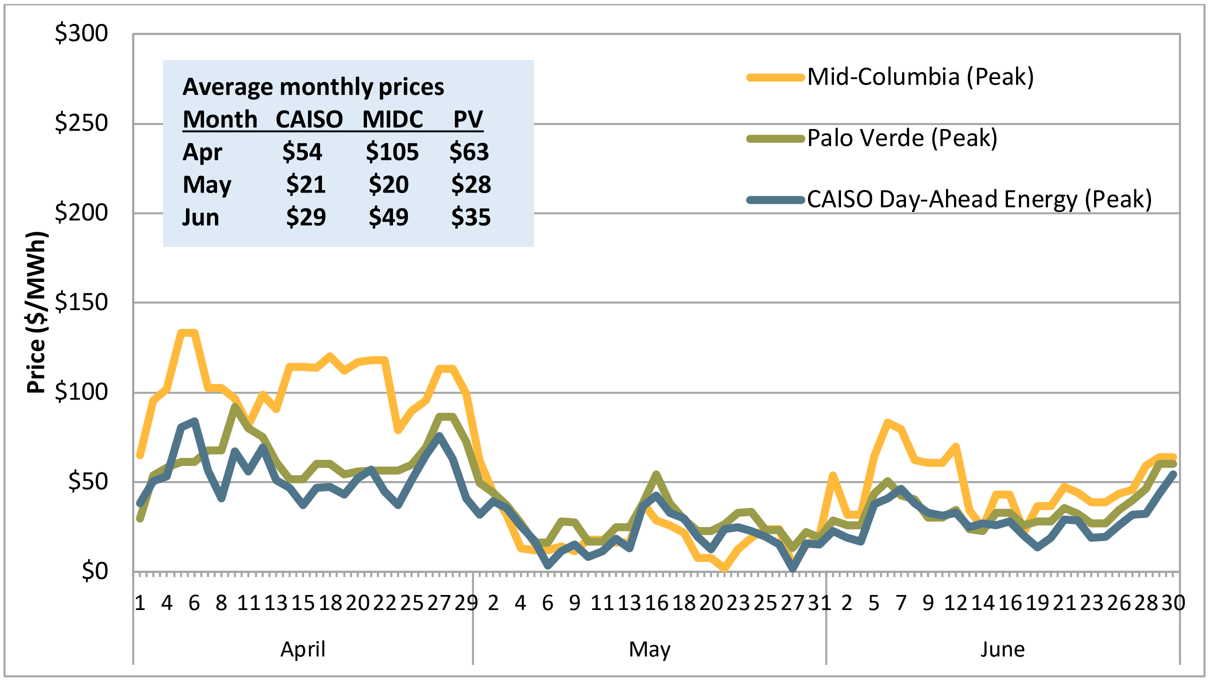
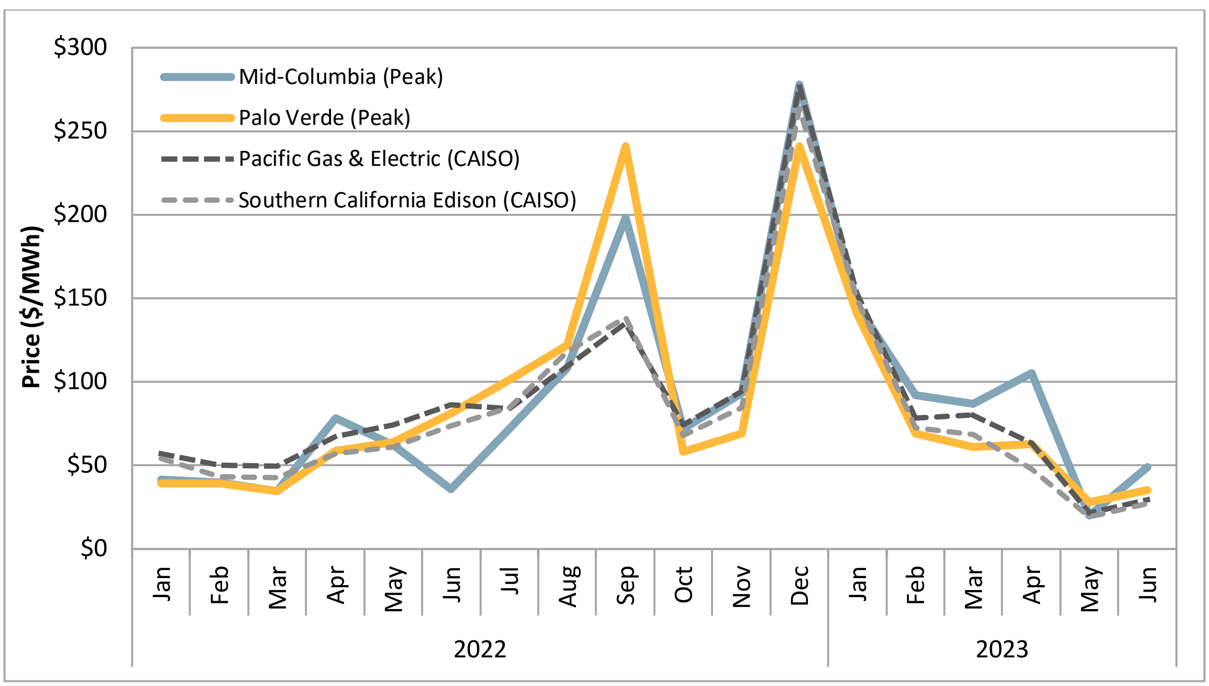


Figure 1.13 uses the same data underlying Figure 1.12 but on an average monthly basis for 2022 and 2023. Prices in the ISO balancing area are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). As shown in this figure, average prices in April and June at the Mid-Columbia hub exceeded prices in the ISO and at the Palo Verde hub.

Figure 1.13 Monthly average day-ahead and bilateral market prices



Average day-ahead prices in the 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 ISO balancing area were lower than average real-time prices at Mid-Columbia and Palo Verde by $5/MWh and $7/MWh, respectively. Average day-ahead prices at Mid-Columbia were greater than average real-time prices (from Powerdex) by $11/MWh. At Palo Verde, average day-ahead prices (from ICE) were similar to average real-time prices (from Powerdex).

Beginning on April 8, 2022, FERC started issuing orders in response to cost justification filings from sellers who made sales above the WECC soft offer cap during the August 2020 heat wave event. In particular, FERC has ordered some sellers to refund the premium they charged above the index price, for sellers whose sales were above the prevailing index price.[9] 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.[10] Based on FERC rulings on the cost justification filings for June 2021, DMM estimates the refunds to be about $1.6 million out of $34 million in bilateral sales exceeding the WECC soft offer cap. FERC has yet to rule on some of the cost justification filings for June 2021, and has not begun issuing orders related to the August/September 2022 and August 2023 filings. A motion is pending at FERC to raise the soft offer cap from $1,000/MWh to $2,000/MWh for spot sales in WECC's bilateral markets.[11]

Imports and exports

During the second quarter, average imports decreased while exports increased slightly compared to the same quarter in 2022. As shown in Figure 1.14, peak imports in the day-ahead (dark blue line) decreased in all hours when compared to the same quarter of 2022, peaking at about 4,400 MW in both the morning and evening ramp hours. Peak 15-minute cleared imports (dark yellow line) also decreased in all hours of the day, peaking in the morning and evening ramp hours at around 5,000 MW. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased in both the day-ahead and 15-minute markets compared to the same quarter of 2022. These increases over the peak hours of 17 to 21 were between 200 MW and 400 MW.

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9 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

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

11 FERC Docket No. ER21-64*, Macquarie Energy, LLC submits Explanation for Bilateral Spot Sales in Western Electricity Coordinating Council*: https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=er21-64&sub_docket=000&dt_from=1960-01-01&dt_to=2022-06-20&chklegadata=false&pagenm=dsearch&date_range=custom&search_type=docket&date_type=filed_date&sub_docket_q=allsub

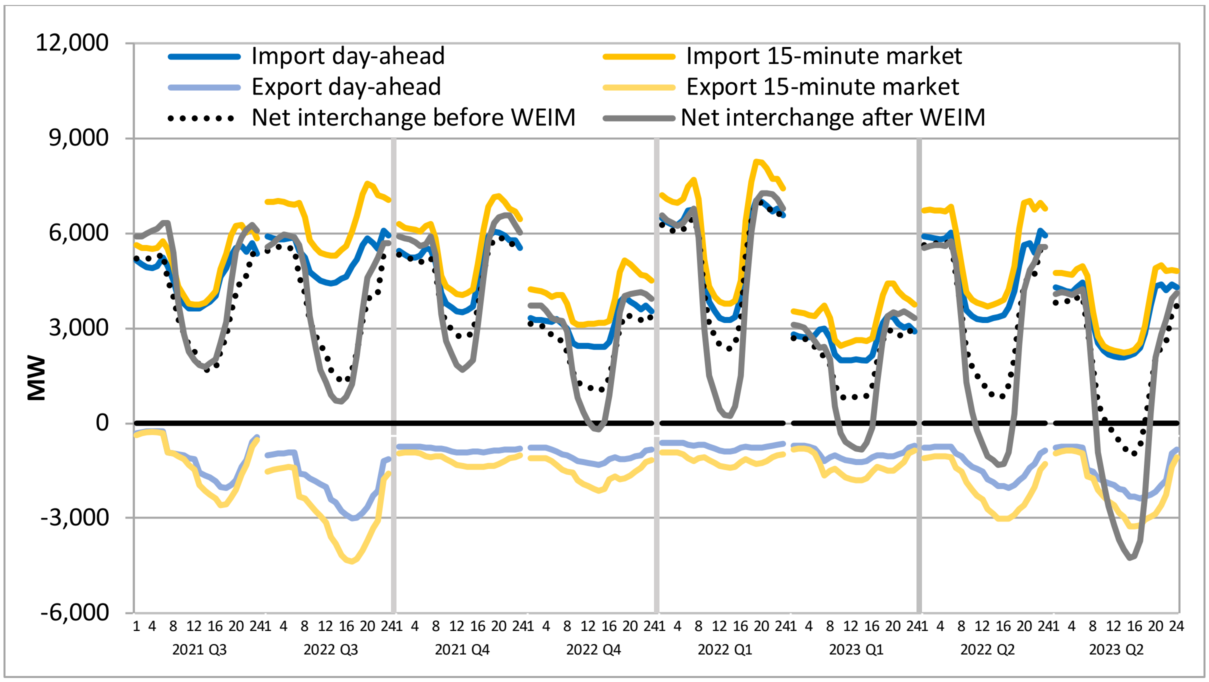
FERC Docket No. ER21-46, *Mercuria Energy America, LLC submits Tariff Filing per 35: Explanation for Bilateral Spot Sales in the West*: https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=er21-46&sub_docket=000&dt_from=1960-01-01&dt_to=2022-06-20&chklegadata=false&pagenm=dsearch&date_range=custom&search_type=docket&date_type=filed_date&sub_docket_q=allsub

FERC Docket No. EL10-56*, Macquarie Energy and Mercuria Energy filings, July 19, 2021*: https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=el10-56&sub_docket=all&dt_from=1960-01-01&dt_to=2022-06-20&chklegadata=false&pagenm=dsearch&date_range=custom&search_type=docket&date_type=filed_date&sub_docket_q=allsub

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 1,600 MW and 2,500 MW, respectively, on average by hour. During the solar ramp down period, imports decreased both when excluding and including the WEIM, to an hourly average of 2,200 MW and 2,300 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 4,300 MW in hour-ending 15. The greatest import transfer into the ISO balancing area from the WEIM occurred in hour-ending 21, at about 700 MW, about 300 MW more than in the same quarter of 2022. Export transfer from the ISO to the WEIM primarily occurred between hours-ending 8 and 18, with hour-ending 14 topping out at about 3,300 MW. This is an increase from the same quarter of the previous year where maximum exports in hour-ending 16 were 2,200 MW.

Figure 1.14 Average hourly net interchange by quarter

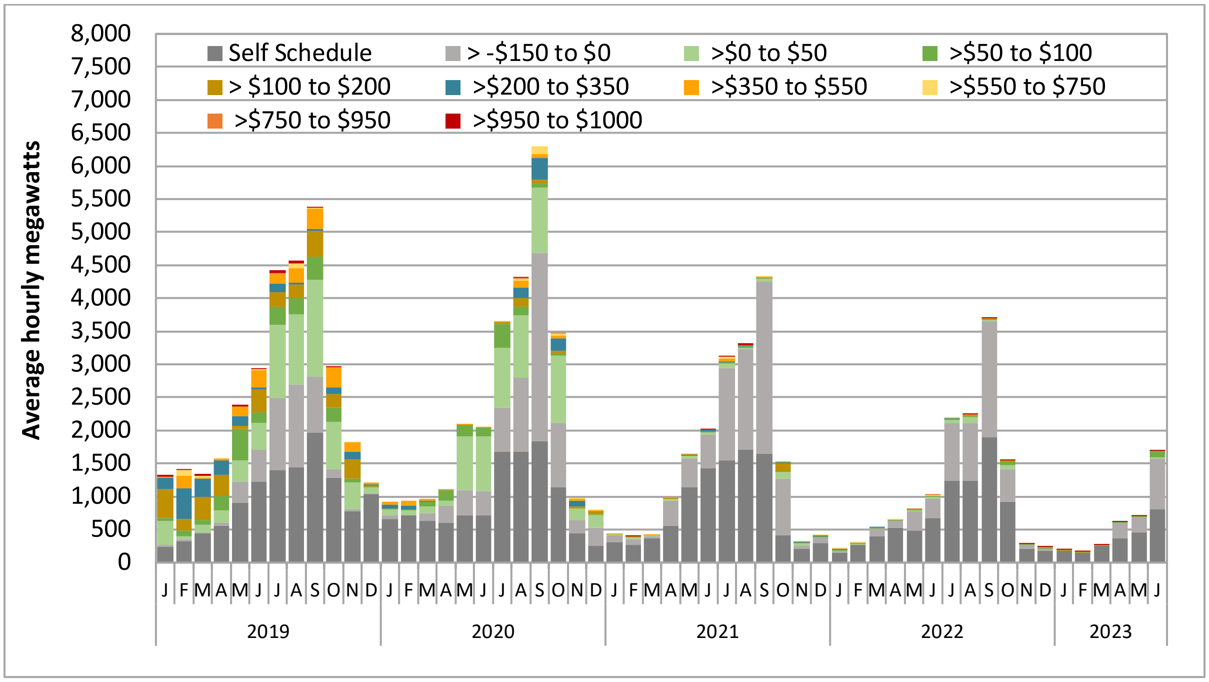


In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the ISO markets at or below $0/MWh, at minimum in the availability assessment hours.[12] These rules became effective at the beginning of 2021. They appear 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 2022 and 2023. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

12 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 ISO has accepted a cost-verified bid over $1,000/MWh. Phase 2 imposed bidding rules capping resource adequacy import bids over $1,000/MWh at the greater of MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

Figure 1.15 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[13] 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.

Figure 1.15 Average hourly resource adequacy imports by price bin



1.3 Price variability

In this quarter, instances of prices exceeding $250/MWh decreased to 0.15 percent from 0.3 percent when compared to the same quarter of the previous year. Meanwhile, the proportion of intervals with zero or negative prices increased to 3 percent from 1.8 percent.

High prices

Figure 1.16 shows the frequency of high prices across all three markets for the three largest load aggregation points (LAP) by month between April 2022 and June 2023. In the day-ahead market, the frequency of high prices over $250/MWh decreased in this second quarter compared to the previous year.

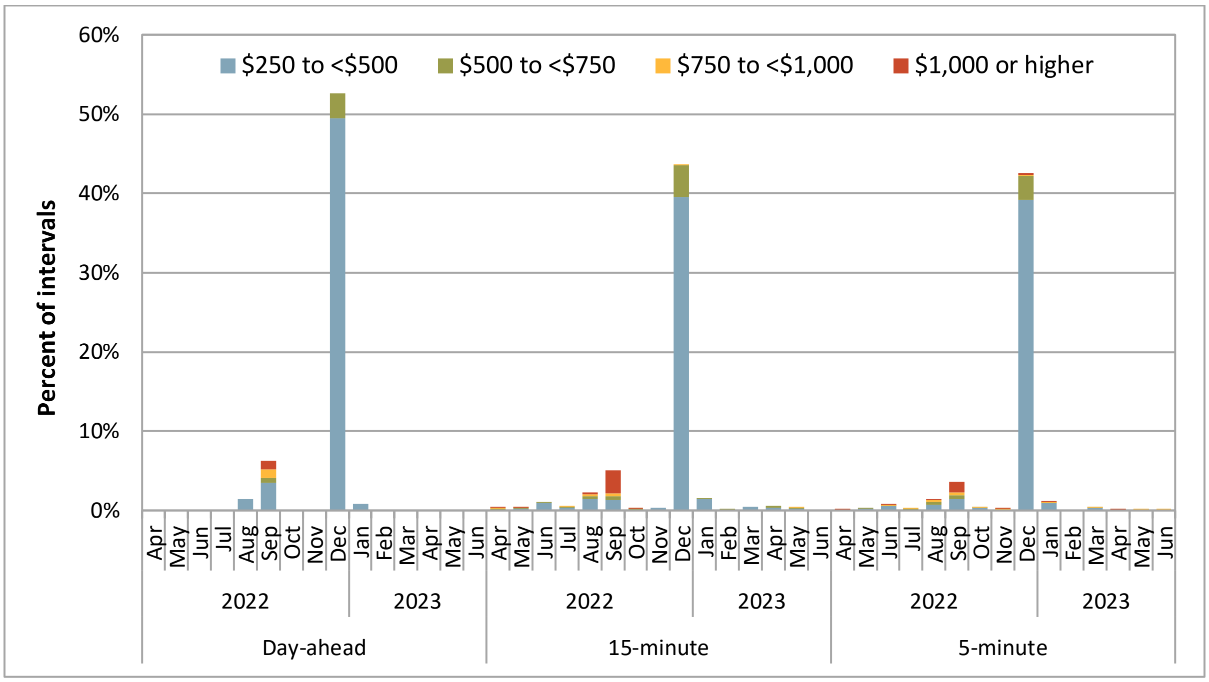
In the second quarter of 2023, the day-ahead market recorded no intervals with an average price exceeding $250/MWh. In the same quarter of the previous year, 0.05 percent of intervals had prices above $250/MWh.

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

The 15-minute market had a lower frequency of price spikes in this quarter compared to previous periods. Prices above $250/MWh decreased to 0.3 percent from 0.6 percent in the second quarter compared to the same period last year.

The 5-minute market also had a reduced frequency of high prices this quarter. Prices above $250/MWh decreased to 0.14 percent in the second quarter of 2022 from 0.37 percent in the same quarter last year.

Figure 1.16 Frequency of high prices ($/MWh) by month



Low natural gas prices in SoCal Citygate contributed to the low frequency of prices above $250/MWh in this quarter as illustrated in Figure 1.1. Natural gas-fired units are often the marginal energy source of generation in the ISO balancing area, as well as other regional markets, and often result in influencing system marginal energy prices across the ISO's footprint.

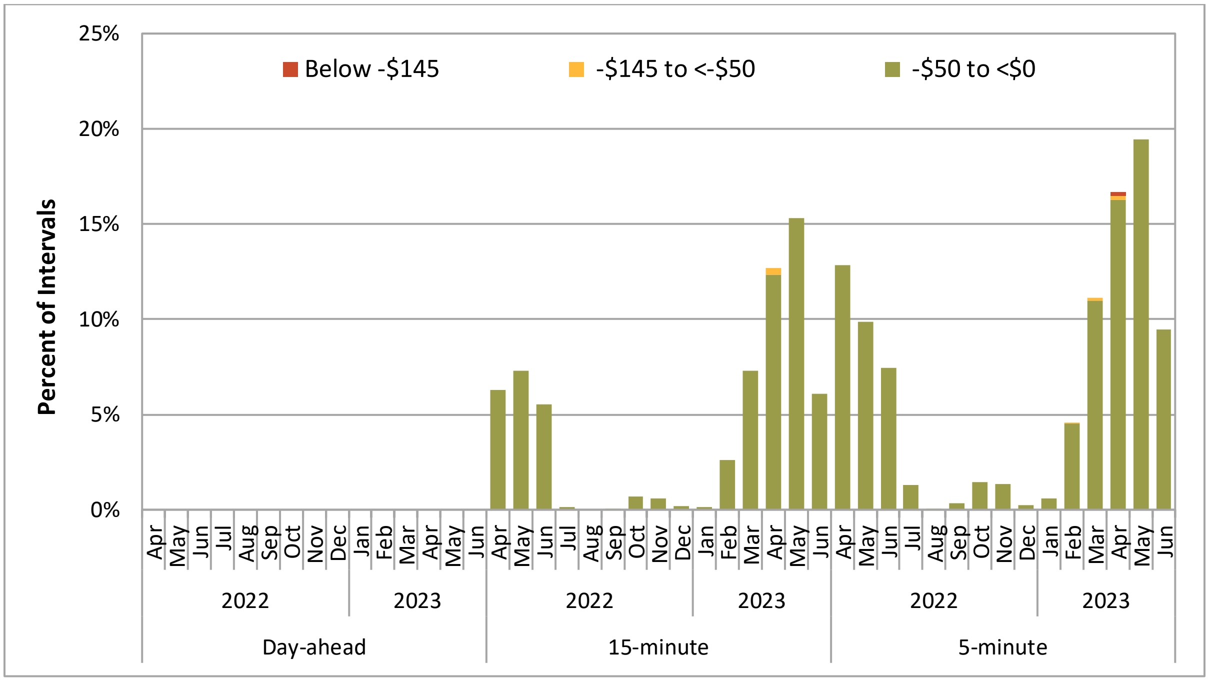
Negative prices

Figure 1.17 shows the frequency of negative prices across all three markets for the three largest load aggregation points (LAP) by month between April 2022 and June 2023. The frequency of negative price intervals increased compared to the first quarter of 2022.

Negative prices tend to be most common when renewable production is high and demand is low. Low-cost renewable resources often bid at or below zero, increasing the potential of becoming the marginal energy source for that period. This leads to a higher frequency of negative prices in the real-time markets, which experience more negative prices than the day-ahead market.

In the 15-minute market, the frequency of negative prices increased to 11.4 percent this quarter compared to 6.4 percent in the second quarter of last year. In the 5-minute market, negative prices increased to 15.2 percent this quarter compared to 10.1 percent in the second quarter of last year. There were no negative prices in the day-ahead market during the second quarters of 2022 or 2023.

Figure 1.17 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. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. Convergence bidding continued to be profitable in the first quarter of 2023, with the majority of profits being received by financial entities (79 percent) and marketers (21 percent).

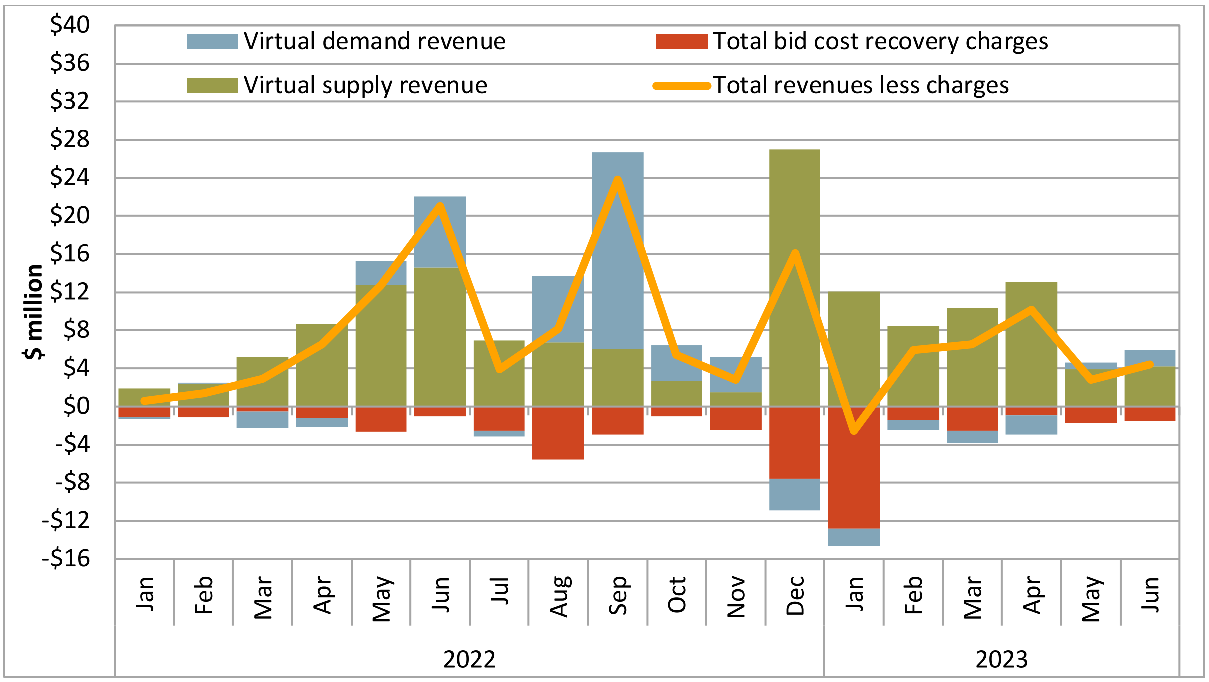
1.4.1 Convergence bidding revenues

Net revenues for convergence bidders were about $17.5 million for the first quarter, after inclusion of about $4.16 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply. Figure 1.18 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. Net revenues for the quarter overall represent a 61 percent decrease compared to the same quarter from the previous year, and a 75 percent increase compared to the previous quarter.

- Virtual demand revenues were about -$2 million, $0.7 million, and $1.7 million for April, May, and June, respectively.
- Virtual supply revenues were positive in total for all months of the quarter, $13.1 million, $3.9 million, and $4.2 million for April, May, and June, respectively.
- Bid cost recovery charges were about $0.9 million, $1.8 million, and $1.5 million for April, May, and June, respectively.

Figure 1.18 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.[14,15]

Financial entities represented the largest segment of the virtual bidding market for the current quarter, with 79 percent of volume and 79 percent of the settlement revenue. Marketers held about 18 percent

[14] This table summarizes data from the ISO settlements database and is based on a snapshot on a given day after the end of the period. DMM strives to provide the most up-to-date data before publishing. Updates occur regularly within the settlements timeline, starting with T+9B (trade date plus nine business days) and T+70B, as well as others up to 36 months after the trade date. More detail on the settlement cycle can be found on the ISO settlements page: http://www.caiso.com/market/Pages/Settlements/Default.aspx

[15] 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 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 ISO market.

of volume and 21 percent of settlement revenue. Generation owners and load serving entities together represented about 3 percent of volumes, and neither profited from convergence bidding this quarter.

Table 1.1 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2023 Q2								
Financial	2,383	2,831	5,215	$0.34	$16.34	-$2.80	$13.54	$13.88
Marketer	486	700	1,186	$0.10	$4.36	-$0.82	$3.54	$3.64
Physical load	0	32	32	$0.00	$0.14	-$0.21	-$0.06	-$0.06
Physical generation	39	112	151	-$0.01	$0.35	-$0.33	$0.01	$0.00
Total	**2,908**	**3,675**	**6,584**	**$0.43**	**$21.19**	**-$4.16**	**$17.03**	**$17.46**

1.5 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the second quarter of 2023 was 34 percent higher than the same quarter of 2022. 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 1.19 shows that residual unit commitment procurement was primarily driven 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 similar when compared to the same quarter of 2022.

The figure also shows that residual unit commitment capacity was procured through operator adjustments in the second quarter. These manual adjustments decreased to about 218 MW per hour in the second quarter, compared to 303 MW per hour in the same quarter in 2022.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar in Figure 1.19) represent the difference in cleared supply (both physical and virtual) compared to the ISO load forecast. On average, this factor contributed towards lowering residual unit commitment requirements by 98 MW per hour in the second quarter of 2023.

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 1.19.

Figure 1.19 Determinants of residual unit commitment procurement

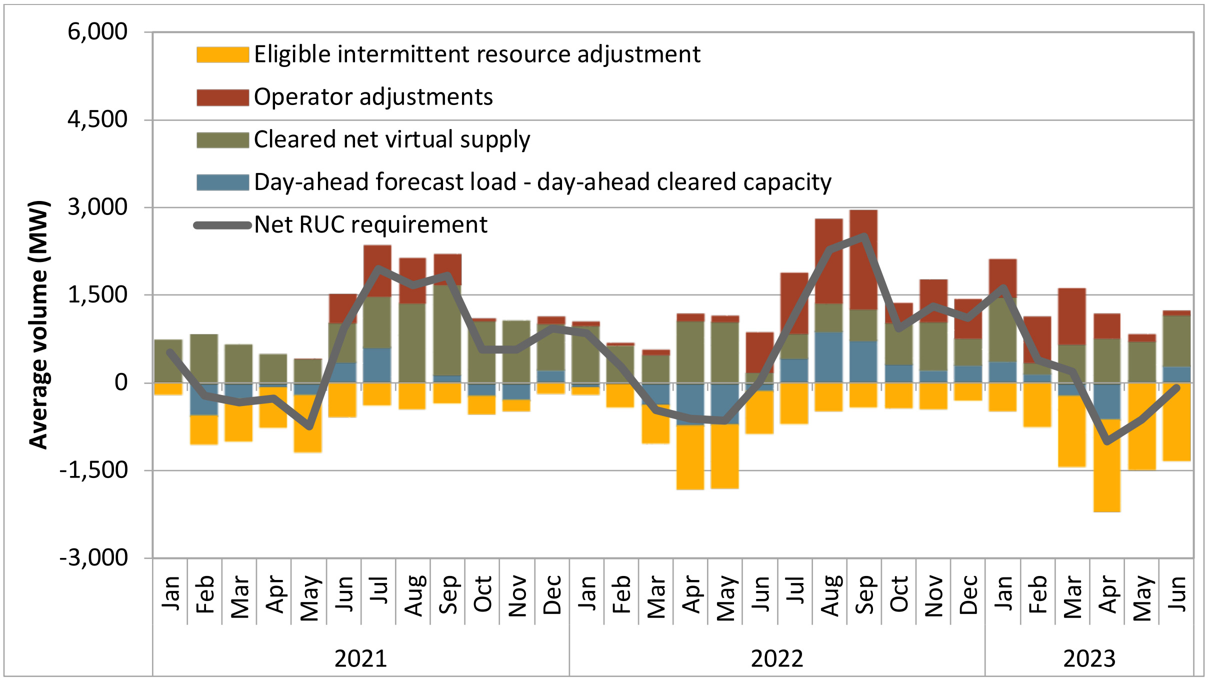
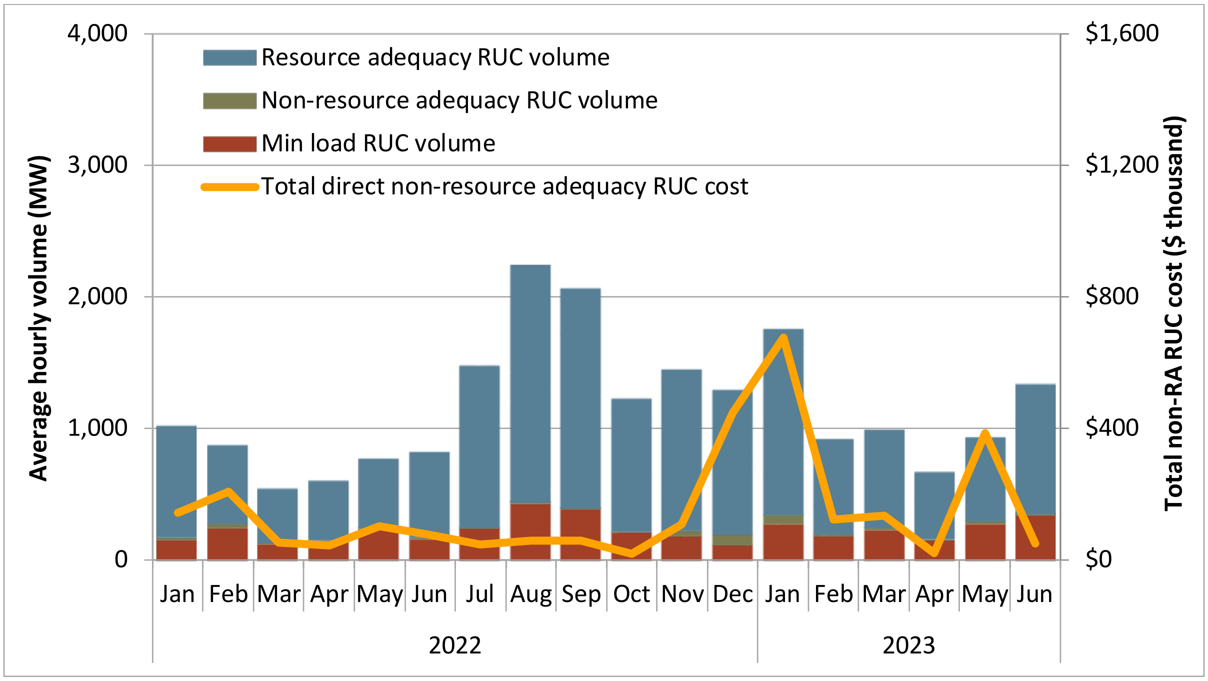


Figure 1.20 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased about 34 percent to about 982 MW in the second quarter of 2023 from an average of about 735 MW in the same quarter of 2022. Of the 982 MW capacity, the capacity committed to operate at minimum load averaged 253 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.[16] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.20. In the second quarter of 2023, these costs were about $0.5 million, more than twice the costs in the same quarter of 2022.

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

Figure 1.20 Residual unit commitment costs and volume



1.6 Ancillary services

Ancillary service payments totaled $30.7 million, a 32 percent decrease from the same quarter last year. Average requirements were higher for regulation down, and lower for operating reserves and regulation up compared to the second quarter of 2022.

1.6.1 Ancillary service requirements

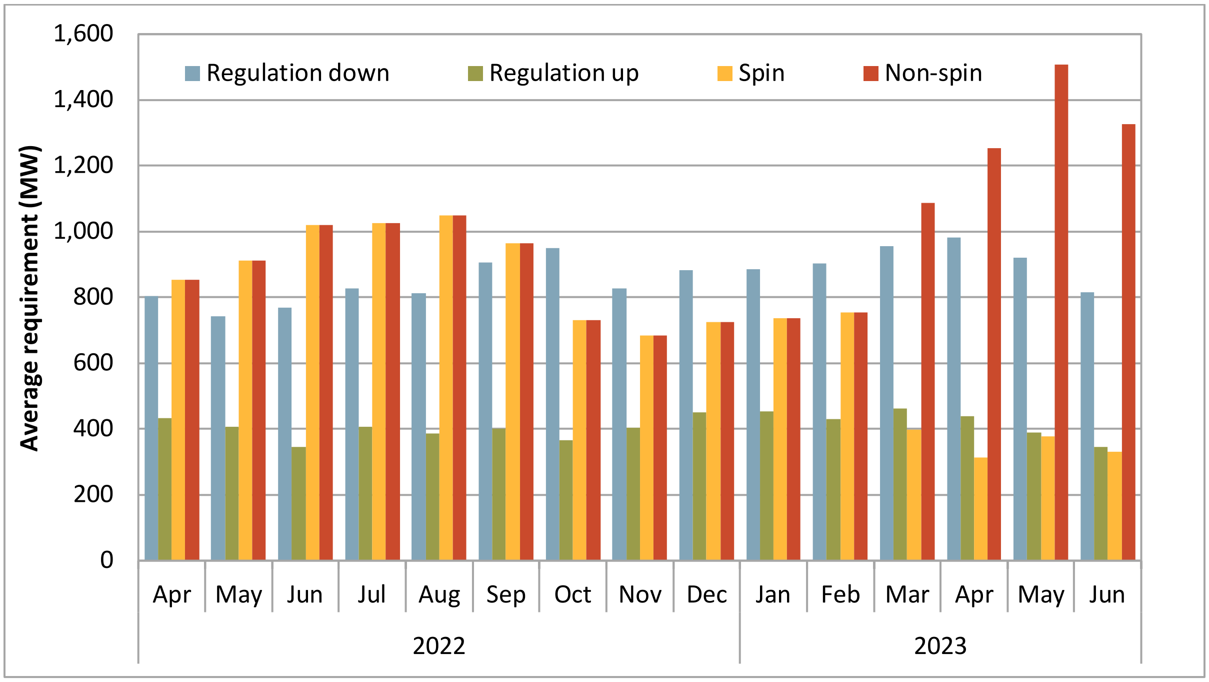
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum operating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

The 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.[17] Operating reserve requirements in the day-ahead market are typically set by the maximum of: (1) 6.3 percent of the load forecast, (2) the most severe single contingency, or (3) 15 percent of forecasted solar production. Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

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

Figure 1.21 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation down requirements increased 17 percent compared to the second quarter of 2022. Requirements for regulation up and operating reserves decreased by one percent and 8 percent, respectively.

Figure 1.21 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 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 second quarter of 2023. This was the fourth consecutive quarter where there were no ancillary service scarcity events.

The lack of scarcity events in recent quarters can be attributed in part to the rapidly increasing participation of battery storage resources, which provide a substantial proportion of ISO ancillary services.

The ISO has noted that resources occasionally fail to deliver awarded regulation in real-time.[18] These failures are not reflected in the market results that generate scarcity alerts.

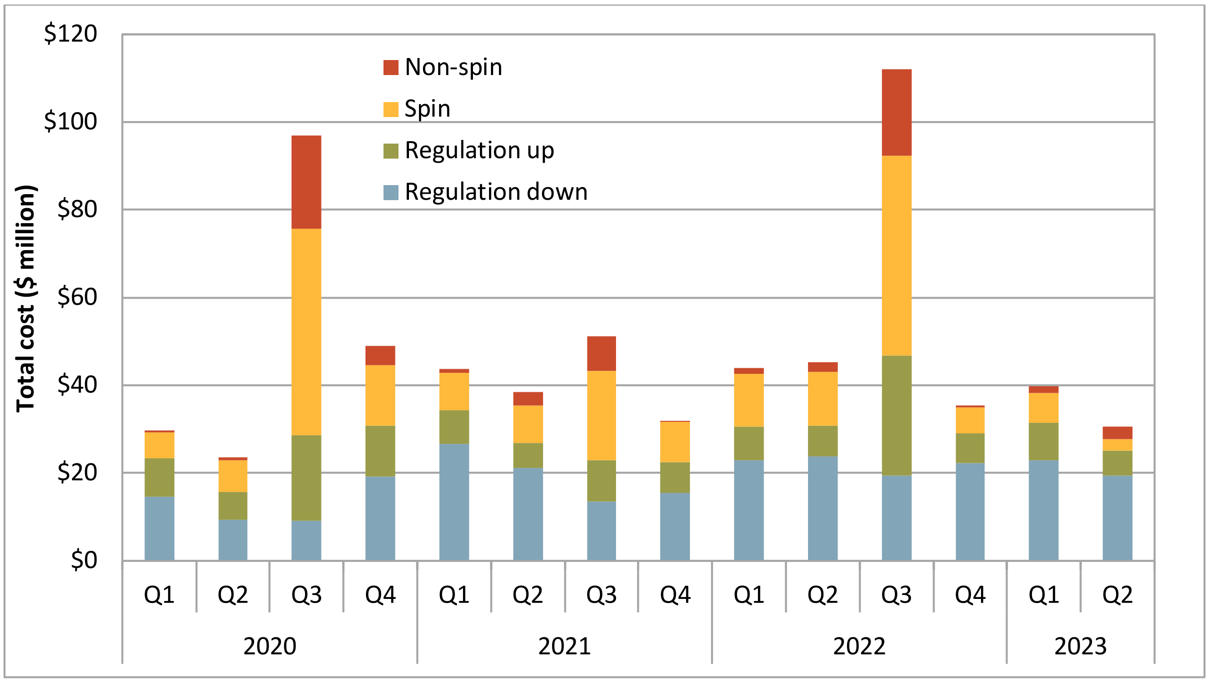
[18] California ISO, Market Performance and Planning Forum, March 16, 2023, slides 42-47: https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Mar16-2023.pdf

1.6.3 Ancillary service costs

Ancillary service payments totaled $30.7 million, compared to $39.7 million in the previous quarter. Ancillary service payments were $14.7 million less than in the second quarter of 2022.

Figure 1.22 shows the total cost of procuring ancillary service products by quarter.[19] Similarly to the first quarter of 2022, payments for spinning reserve had the largest year-over-year decrease as a result of lower requirements relative to total operating reserve requirements.[20] The remaining operating reserve requirements were fulfilled by non-spinning reserves, which are cheaper to procure. Spinning reserve payments decreased $9.4 million, or 78 percent, compared to the second quarter of 2022. Payments for regulation up and regulation down both decreased by 19 percent, and payments for non-spinning reserves increased by 23 percent compared to the second quarter of 2022.

Figure 1.22 Ancillary service cost by product



19 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.

20 Department of Market Monitoring, *Q1 2023 Report on Market Issues and Performance*, July 11, 2023, p. 26: https://www.caiso.com/Documents/2023-First-Quarter-Report-on-Market-Issues-and-Performance-Sep-19-2023.pdf

1.7 Congestion

In the day-ahead market, congestion in the second quarter was less impactful than the same quarter last year, raising prices in PG&E and SDG&E, while lowering prices in SCE. 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 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 ISO 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.[21]

Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact – the stronger the shading, the greater the impact in either the positive or the negative direction.

1.7.1 Congestion in the day-ahead market

Day-ahead market congestion frequency tends to be higher than in the 15-minute market, but price impacts to load tend to be lower. The congestion pattern in this quarter deviates from this overall trend with day-ahead market congestion being slightly more impactful and more frequent than 15-minute market congestion in the ISO.

Congestion rent and loss surplus

In the second quarter of 2023, congestion rent and loss surplus was $151 million and $36 million, respectively. These respective amounts represent decreases of 44 percent and 56 percent relative to the same quarter of 2022.[22] Figure 1.23 shows the congestion rent and loss surplus by quarter for 2022 and 2023.

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

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

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

surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[23]

Figure 1.23 Day-ahead congestion rent and loss surplus by quarter (2022-2023)

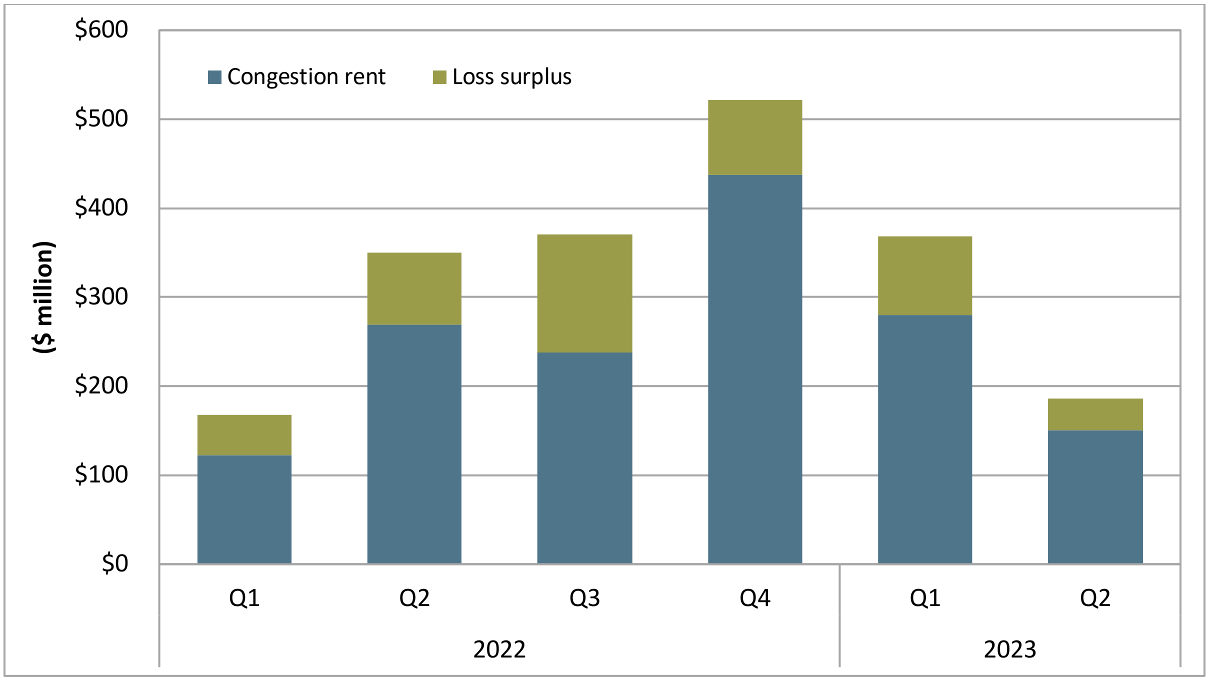


Figure 1.24 shows the overall impact of congestion on day-ahead prices in each load area in 2022 and 2023. Figure 1.25 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in the second quarter was lower than during same quarter last year. The impact during the second quarter compared to the first quarter of 2023 was higher in PG&E and slightly lower in SCE, while it changed from negative to positive in SDG&E.
- Day-ahead congestion increased quarterly average prices in PG&E and SDG&E by $2.99/MWh (8.1 percent) and $0.75/MWh (2.1 percent), respectively, while it decreased average SCE prices by $0.86/MWh (2.6 percent).
- The primary constraints impacting day-ahead market prices were the Moss Landing-Las Aguilas 230 kV line, Gates-Midway #2 500 kV line, and the Los Banos-Gates 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.

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

Figure 1.24 Overall impact of congestion on price separation in the day-ahead market

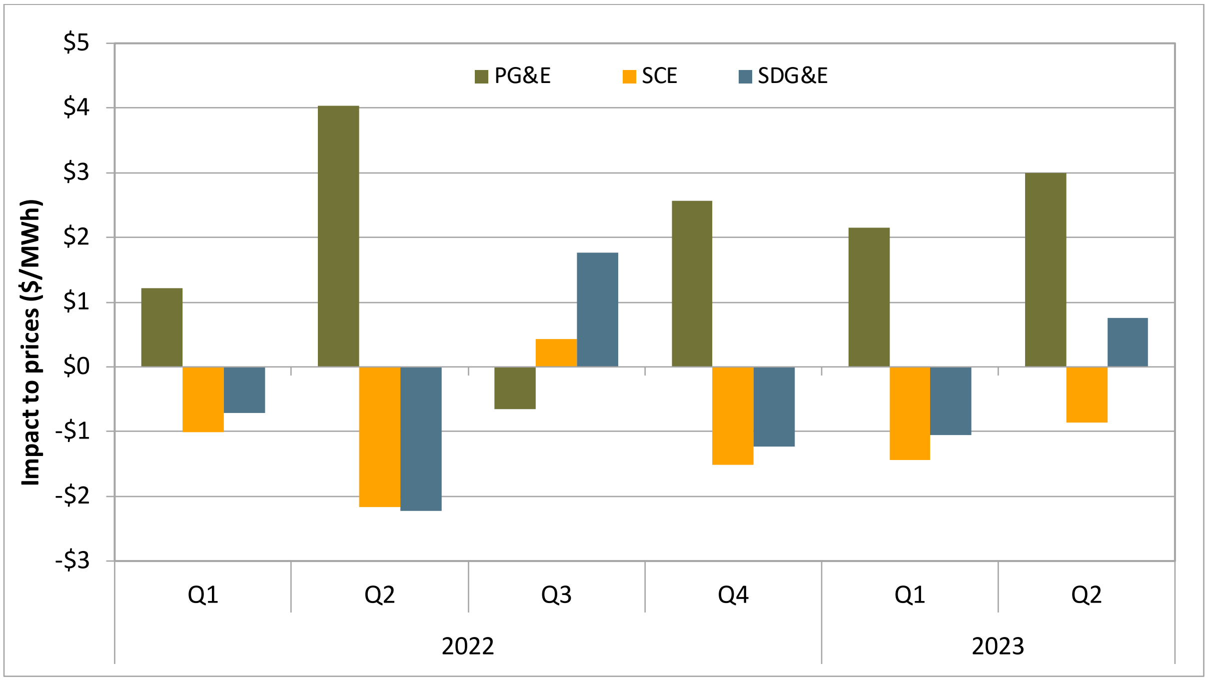
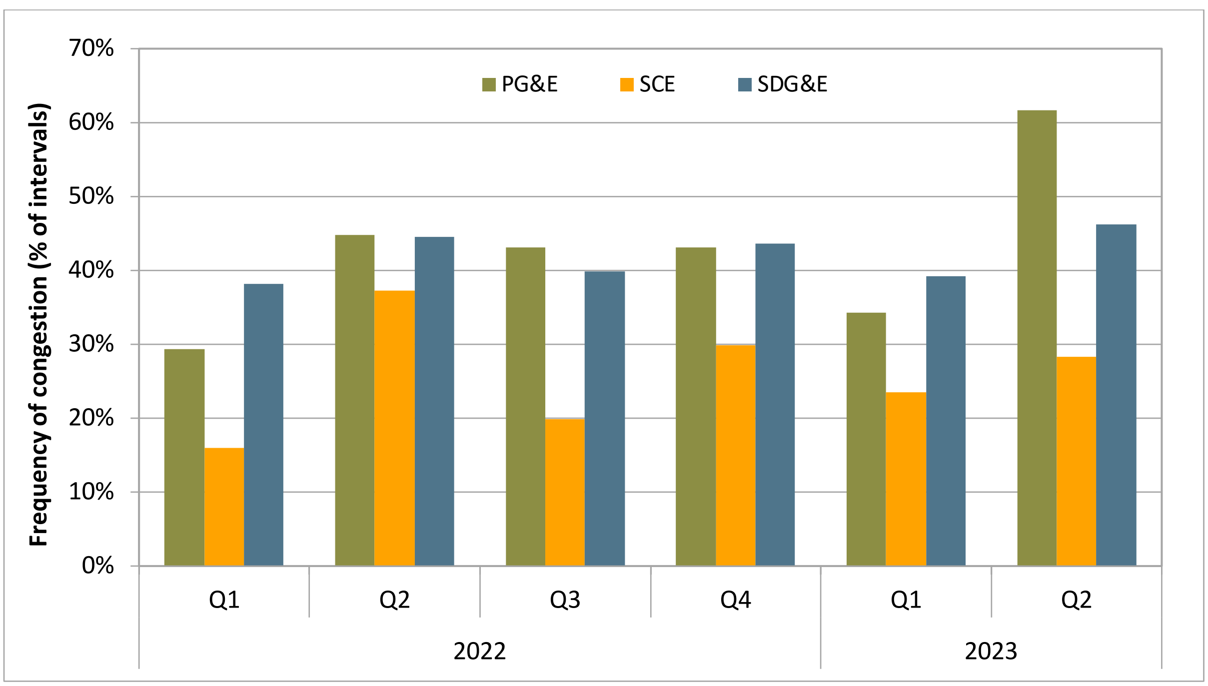


Figure 1.25 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation during the quarter by constraint.[24] 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 Moss Landing-Las Aguilas 230 kV line, Gates-Midway #2 500 kV line, and the Los Banos-Gates 500 kV line.

Moss Landing-Las Aguilas 230 kV line

The Moss Landing-Las Aguilas 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1 _1) had the greatest impact on day-ahead prices during the second quarter. The line was congested during 34 percent of hours over the quarter. When binding, it increased prices in PG&E by $5.85/MWh and decreased prices in SCE and SDG&E by $5.41/MWh and $5.15/MWh, respectively. For the quarter, congestion on the constraint increased average PG&E prices by $2.01/MWh (5.4 percent) and decreased average SCE and SDG&E prices by $0.31/MWh (0.9 percent) and $0.10/MWh (0.3 percent), respectively. This line was frequently mitigated for the loss of the Moss Landing-Los Banos 500 kV line.

Gates-Midway #2 500 kV line

The Gates-Midway #2 500 kV line (30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1) was congested during 4 percent of hours. When binding, it increased PG&E prices by $7.83/MWh, and decreased SCE and SDG&E prices by $5.41/MWh and $5.06/MWh, respectively. For the quarter, congestion on the line increased average PG&E prices by $0.34/MWh (0.9 percent), and decreased average SCE and SDG&E prices by $0.24/MWh (0.7 percent) and $0.22/MWh (0.6 percent).

Los Banos-Gates 500 kV line

The Los Banos-Gates 500 kV line (30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2) bound in about 5 percent of hours. When binding, it increased PG&E prices by $5.72/MWh and decreased SCE and SDG&E prices by $4.30/MWh and $3.97/MWh, respectively. For the quarter, the line increased average PG&E prices by about $0.26/MWh (0.7 percent), and decreased average SCE and SDG&E prices by $0.20/MWh (0.6 percent) and $0.18/MWh (0.5 percent), respectively.

24 Details on constraints with shift factors less than 2 percent have been grouped in the "Other" category.

Table 1.2 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$2.01	5.41%	-$0.31	-0.92%	-$0.10	-0.29%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.34	0.93%	-$0.24	-0.72%	-$0.22	-0.63%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.26	0.71%	-$0.20	-0.60%	-$0.18	-0.52%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.16	0.44%	-$0.04	-0.12%	-$0.04	-0.10%
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.15	0.42%	-$0.12	-0.36%	-$0.12	-0.34%
	7440_MetcalfImport_Tes-Metcalf	$0.15	0.39%	-$0.11	-0.32%	-$0.10	-0.29%
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.09	0.24%	-$0.02	-0.05%	-$0.01	-0.02%
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	$0.07	0.18%	-$0.05	-0.14%	-$0.04	-0.12%
	30735_METCALF _230_30042_METCALF _500_XF_13	$0.02	0.06%	-$0.02	-0.05%	-$0.02	-0.05%
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.02	0.05%	-$0.01	-0.04%	-$0.01	-0.04%
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	7440_MetcalfImport_Mossld-Metclf	$0.01	0.02%	$0.00	-0.01%	$0.00	-0.01%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.01	-0.04%	$0.01	0.04%	$0.01	0.04%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.23	-0.62%	$0.19	0.58%	$0.18	0.52%
SCE	6410_CP1_NG	-$0.02	-0.05%	$0.02	0.05%	$0.02	0.05%
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.00	0.00%	$0.00	0.00%	-$0.05	-0.14%
SDG&E	MIGUEL_BKs_MXFLW_NG	$0.00	-0.01%	$0.00	0.00%	$0.27	0.77%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-$0.04	-0.10%	$0.00	0.00%	$0.25	0.71%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.22	0.62%
	OMS 13108255_TL50003_NG	-$0.01	-0.02%	$0.00	0.00%	$0.11	0.31%
	OMS 13410364_50001_OOS_NG	-$0.01	-0.02%	$0.00	0.00%	$0.07	0.21%
	OMS 13368679_50001_OOS_NG	-$0.01	-0.01%	$0.00	0.00%	$0.07	0.20%
	OMS 13410435_50001_OOS_NG	-$0.01	-0.02%	$0.00	0.00%	$0.07	0.18%
	OMS 13593700_TL50003_NG	-$0.01	-0.01%	$0.00	0.00%	$0.06	0.16%
	OMS 13398667_50001_OOS_NG	$0.00	-0.01%	$0.00	0.00%	$0.05	0.14%
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.05	0.14%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.04	0.11%
	22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.09%
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.00	-0.01%	$0.00	-0.01%	$0.03	0.09%
	OMS 13581743_TL50003_NG	$0.00	-0.01%	$0.00	0.00%	$0.03	0.08%
	OMS 13593678_TL50003_NG	$0.00	-0.01%	$0.00	0.00%	$0.02	0.06%
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	22856_TOREYPNS_69.0_22864_UCM _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS_13632484_13810A_NG	$0.00	0.00%	$0.00	0.00%	-$0.01	-0.04%
	OMS_13632463_13810A_NG	$0.00	0.00%	$0.00	0.00%	-$0.03	-0.08%
	OMS_13632437_13810A_NG	$0.00	0.00%	$0.00	0.00%	-$0.03	-0.09%
Other		$0.05	0.13%	$0.03	0.10%	$0.12	0.34%
Total		**$2.99**	**8.06%**	**-$0.86**	**-2.58%**	**$0.75**	**2.13%**

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

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	7440_MetcalfImport_Tes-Metcalf	1.6%	$9.09	-$6.65	-$6.43
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	4.4%	$7.83	-$5.41	-$5.06
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	2.4%	$6.36	-$4.93	-$4.91
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	34.3%	$5.85	-$5.41	-$5.15
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	4.6%	$5.72	-$4.30	-$3.97
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	0.5%	$4.00	-$2.69	-$2.69
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	4.3%	$3.85	-$6.16	-$6.85
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	2.4%	$2.78	-$1.92	-$1.83
	30735_METCALF _230_30042_METCALF _500_XF_13	1.0%	$2.40	-$1.71	-$1.72
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	4.5%	$1.99	-$1.36	-$0.77
	7440_MetcalfImport_Mossld-Metclf	0.4%	$1.68	-$1.18	-$1.17
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	0.6%	$1.23	-$0.89	-$0.89
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.3%	-$4.51	$4.11	$3.86
SCE	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	4.5%	-$5.05	$4.27	$4.04
	6410_CP1_NG	0.9%	-$2.27	$1.98	$2.02
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	2.8%	$0.00	$0.00	-$1.71
	OMS 13410435_50001_OOS_NG	0.4%	-$1.56	$0.00	$17.80
SDG&E	OMS 13410364_50001_OOS_NG	0.5%	-$1.08	$0.00	$14.56
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	1.5%	$0.00	$0.00	$14.49
	OMS 13593700_TL50003_NG	0.5%	-$1.09	$0.00	$12.15
	OMS 13108255_TL50003_NG	0.9%	-$0.98	$0.00	$12.04
	MIGUEL_BKs_MXFLW_NG	2.7%	-$2.23	$0.00	$10.07
	OMS 13398667_50001_OOS_NG	0.5%	-$0.71	$0.00	$9.26
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	2.9%	-$1.33	$0.00	$8.76
	OMS 13581743_TL50003_NG	0.4%	-$0.70	$0.00	$8.16
	OMS 13368679_50001_OOS_NG	1.2%	-$0.41	$0.00	$5.83
	OMS 13593678_TL50003_NG	0.5%	-$0.42	$0.00	$4.60
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	1.0%	$0.00	$0.00	$3.87
	22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1	1.0%	$0.00	$0.00	$3.32
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	1.6%	$0.00	$0.00	$3.19
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	1.0%	-$0.35	-$0.36	$3.09
	22856_TOREYPNS_69.0_22864_UCM _69.0_BR_1 _1	0.4%	$0.00	$0.00	$2.77
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	2.0%	$0.00	$0.00	$0.55
	OMS_13632484_13810A_NG	0.4%	$0.00	$0.41	-$3.11
	OMS_13632463_13810A_NG	0.4%	$0.00	$0.00	-$7.13
	OMS_13632437_13810A_NG	0.4%	$0.00	$1.15	-$7.70

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 deviates from this overall trend with day-ahead market congestion being slightly more impactful and more frequent than 15-minute market congestion in the ISO. Congestion patterns in the 15-minute and 5-minute markets were similar.

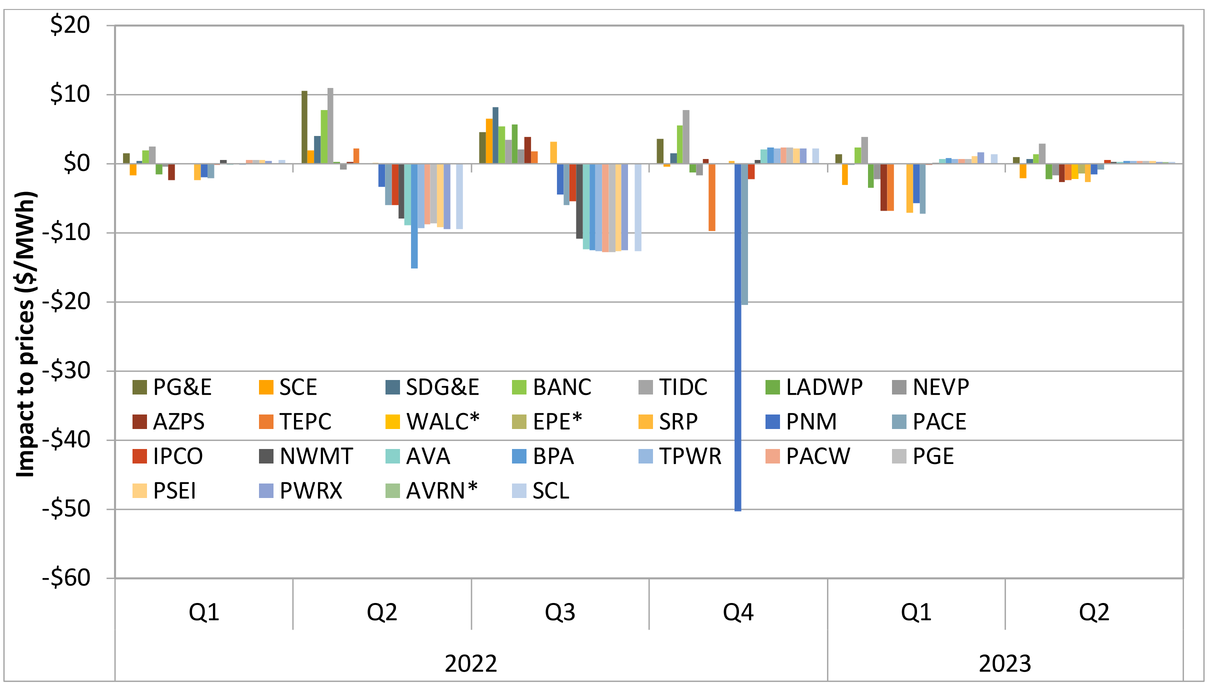
Impact of internal congestion to overall 15-minute prices in each load area

Figure 1.26 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2022 and 2023. Table 1.5 shows the frequency of this congestion. Highlights for this quarter include:

- The net impact of internal flow-based constraint congestion had a generally low impact across the WEIM. Congestion slightly raised prices in the Pacific Northwest, a sharp contrast to the second quarter of 2022, when it significantly lowered prices in the region.
- Internal congestion was most impactful in the TIDC and BANC where it increased prices in by $2.86/MWh and $1.41/MWh, as well as in LADWP, NEVP, AZPS, TEPC, WALC, EPE, SRP, and PNM, where it decreased prices by an average of $2.09/MWh.
- The primary constraints creating price separation in the 15-minute market were the Tesla-Los Banos 500 kV line, Moss Landing-Las Aguilas, and the Los Banos-Gates 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 1.26 Overall impact of internal congestion on price separation in the 15-minute market



*Since joining the WEIM

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

This section focuses on individual flow-based constraints. In the second quarter, the constraints that had the greatest impact on price separation in the 15-minute market were the Tesla-Los Banos 500 kV line, Moss Landing-Las Aguilas, and the Los Banos-Gates 500 kV line.[25]

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. These topics are discussed in greater depth in Section 2.

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

Table 1.4 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	WALC*	EPE*	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	AVRN*	SCL
AZPS	CC XFMR8 A 69KV								$0.02																	
BANC	XFMR1 500.TRY	$0.08	$0.05	$0.05	$0.07	$0.12	$0.05		$0.04	$0.04	$0.04	$0.03	$0.04		-$0.04	-$0.08	-$0.09	-$0.11	-$0.11	-$0.11	-$0.11	-$0.11	-$0.11	-$0.11	-$0.12	-$0.11
	COR_HED				$0.04																					
	XFMR2 500.TRY	$0.03	$0.02	$0.02	$0.03	$0.05	$0.02		$0.02	$0.01	$0.02	$0.01	$0.02		-$0.02	-$0.03	-$0.04	-$0.04	-$0.05	-$0.04	-$0.05	-$0.05	-$0.04	-$0.04	-$0.05	-$0.04
CAISO	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	$0.31	-$1.00	-$0.96	$0.82	$0.83	-$0.99	-$0.51	-$0.85	-$0.82	-$0.78	-$0.69	-$0.85	-$0.71		$0.28	$0.43	$0.54	$0.60	$0.60	$0.63	$0.62	$0.60	$0.59	$0.65	$0.60
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.02	-$1.10	-$1.05	$0.15	$1.21	-$1.07		-$0.84	-$0.65	-$0.63	-$0.05	-$0.83	-$0.05							$0.00				$0.00	
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.28	-$0.44	-$0.42	$0.43	$0.44	-$0.43	-$0.24	-$0.37	-$0.36	-$0.37	-$0.33	-$0.37	-$0.31	$0.00	$0.18	$0.27	$0.32	$0.34	$0.34	$0.35	$0.35	$0.34	$0.33	$0.38	$0.34
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.18	-$0.34	-$0.33	$0.25	$0.26	-$0.34	-$0.18	-$0.29	-$0.28	-$0.13	-$0.12	-$0.29	-$0.25	-$0.04	$0.08	$0.13	$0.16	$0.17	$0.17	$0.18	$0.18	$0.17	$0.17	$0.10	$0.17
	6410_CP1_NG	-$0.25	$0.25	$0.25	-$0.23	-$0.24	$0.26	$0.16	$0.22	$0.22	$0.22	$0.20	$0.22	$0.19	$0.01	-$0.08	-$0.12	-$0.15	-$0.16	-$0.16	-$0.17	-$0.17	-$0.16	-$0.16	-$0.19	-$0.16
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.22	$0.23	$0.22	-$0.20	-$0.21	$0.22	$0.13	$0.19	$0.18	$0.19	$0.16	$0.19	$0.15	$0.00	-$0.08	-$0.11	-$0.14	-$0.15	-$0.15	-$0.15	-$0.15	-$0.15	-$0.14	-$0.17	-$0.15
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.20	$0.21	$0.20	-$0.19	-$0.20	$0.21	$0.13	$0.18	$0.18	$0.18	$0.17	$0.18	$0.16	$0.02	-$0.05	-$0.10	-$0.12	-$0.13	-$0.13	-$0.14	-$0.14	-$0.13	-$0.13	-$0.15	-$0.13
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.10	$0.75				-$0.02	-$0.21	-$0.21	-$0.21	-$0.19	-$0.22	-$0.16	-$0.02											
	OMS 13368679_50001_OOS_NG		$0.05	$0.90				-$0.03	-$0.12	-$0.12	-$0.13	-$0.11	-$0.13	-$0.10	-$0.03											
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.11	-$0.13	-$0.12	$0.12	$0.13	-$0.12	-$0.07	-$0.11	-$0.10	-$0.11	-$0.10	-$0.11	-$0.09	$0.00	$0.04	$0.07	$0.08	$0.09	$0.08	$0.09	$0.09	$0.08	$0.08	$0.10	$0.08
	SYLMAR-AC_BG_NG	$0.05	$0.07	$0.00	$0.04	$0.04	-$0.63	-$0.09	-$0.09	-$0.09	-$0.09	-$0.09	-$0.09	-$0.09	-$0.04						$0.00				$0.00	
	ML_RM12_NS	$0.11	$0.07	$0.06	$0.10	$0.10	$0.06	$0.03	$0.05	$0.05	$0.05	$0.04	$0.05	$0.03	-$0.03	-$0.08	-$0.11	-$0.13	-$0.10	-$0.13	-$0.13	-$0.13	-$0.13	-$0.13	-$0.14	-$0.13
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.06	-$0.11	-$0.10	$0.10	$0.11	-$0.11	-$0.04	-$0.09	-$0.08	-$0.03	-$0.01	-$0.09	-$0.05				$0.00	$0.03	$0.03	$0.04	$0.04	$0.03	$0.03		$0.03
	MIGUEL_BKs_MXFLW_NG			$0.43					-$0.13	-$0.12	-$0.10	-$0.09	-$0.13	-$0.10												
	OMS 13108255_TL50003_NG		$0.03	$0.43				-$0.02	-$0.07	-$0.07	-$0.02	-$0.02	-$0.07	-$0.05	-$0.02											
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1				$0.00			-$0.66																		
	ML_RM12_SN	-$0.05	-$0.03	-$0.03	-$0.05	-$0.05	-$0.03	-$0.01	-$0.03	-$0.02	-$0.03	-$0.02	-$0.03	-$0.02	$0.01	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
	24801_DEVERS _500_99014_CALCAPS2_500_BR_2 _1	$0.01	$0.03	$0.01	$0.01	$0.01	$0.02	-$0.01	-$0.05	-$0.05	-$0.05	-$0.05	-$0.06	-$0.04	-$0.01				$0.00	$0.00	$0.00	$0.00	$0.00		$0.01	
	RM_TM12_NG	$0.03	$0.02	$0.02	$0.02	$0.03	$0.02	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.01	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	30765_LOSBANOS_230_38625_SN LS PP_230_BR_1 _1				$0.09	$0.21																				
	7820_TL 50002_IV-NG-OUT_TDM			$0.20					-$0.04		-$0.05															
	OMS 13352412_50004_OOS_NG		$0.01	$0.14				-$0.01	-$0.03	-$0.03	-$0.03	-$0.02	-$0.03	-$0.02	-$0.01											
	7440_MetcalfImport_Tes-Metcalf	$0.04	-$0.02	-$0.02	$0.02	$0.03	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02				$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1							-$0.25																		
	33020_MORAGA _115_30550_MORAGA _230_XF_3 _P	$0.25																								
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.24																								
	SDGE_OMS 13521394+13521372_NG		$0.02	-$0.05					-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.02												
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1				-$0.13	-$0.07																				
	7820_TL 230S_OVERLOAD_NG	$0.00	$0.01	$0.09	$0.00	$0.00	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01	-$0.01											
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	$0.00	-$0.03	-$0.03	$0.01	$0.03	-$0.03	$0.00	-$0.02	-$0.02	-$0.02	-$0.01	-$0.02	-$0.01					$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00
	38206_COTTLE A_230_37563_MELONES _230_BR_1 _1		-$0.01	$0.00	$0.14	$0.03	-$0.01																			
	7820_13810A_RAS_MS-SA_NG		$0.01	-$0.06					-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01												
	OMS_13632484_13810A_NG		$0.02	-$0.06					-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01												
	30015_TABLE MT_500_30068_TB MT 5M_ 1.0_XF_5	-$0.06			-$0.07	-$0.03		$0.00										$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00
	OMS 13357976_50004_OOS_NG		$0.00	$0.07				$0.00	-$0.02	-$0.02	-$0.02	-$0.01	-$0.02	-$0.01	$0.00											
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				-$0.07			-$0.08																		
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01	$0.01	$0.01	$0.00	$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.01	-$0.02	-$0.01	$0.01	$0.02	-$0.02		-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00												
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1				$0.06	$0.00											$0.00	-$0.02	-$0.02	-$0.02	-$0.02	-$0.03	-$0.02	-$0.02	-$0.02	-$0.02
	30050_LOSBANOS_500_30055_GATES1 _500_BR_3 _1	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01		$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.01	$0.01	$0.01	-$0.02	-$0.02	$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	-$0.01
	OMS 13198220_SENTNL_NG										-$0.11															
	OMS_13632463_13810A_NG		$0.01	-$0.03					-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01												
	64229_SUMMIT 2_115_32218_DRUM _115_BR_1 _1	$0.00			-$0.01			$0.07																		
	30015_TABLE MT_500_30030_VACA-DIX_500_BR_1 _3	$0.01	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30763_QUINTO_230_30765_LOSBNS_230_BR_1A _1	$0.00	$0.01	$0.00	-$0.01	-$0.02	$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	$0.00	$0.00	$0.00
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1							-$0.07																		
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1							-$0.07																		
	7430_MEL_COT_NG				$0.06	$0.00																				
	24091_MESA CAL_230_24076_LAGUBELL_230_BR_2 _1	-$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
	30500_BELLOTA _230_38206_COTTLE A_230_BR_1 _1		$0.00		$0.04	$0.01																				
	30622_EIGHT MI_230_30495_STAGG _230_BR_1 _1				-$0.04	$0.01																				
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30055_GATES1 _500_30900_GATES _230_XF_12_P	-$0.05	$0.00		$0.00		$0.00																			
	30337_GOLDHILL_230_30622_EIGHT MI_230_BR_1 _1				-$0.05																					
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1				$0.00	$0.03																				
	32950_PITSBURG_115_30527_PITSBRG _230_XF_13	$0.03																								
	35616_SNJOSEB _115_35612_TRIMBLE _115_BR_1 _1					$0.03																				
	30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1				-$0.02	$0.01																				
	37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1	$0.00	$0.00	$0.00	-$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
	7430_MEL_WIL_NG				-$0.02																					
IPCO	PATH_55	$0.00	$0.01	$0.03	$0.00	$0.00	$0.02	$0.05	$0.04	$0.04	$0.04	$0.04	$0.04	$0.05	$0.11	$0.26	-$0.07	-$0.12	-$0.09	-$0.09	-$0.07	-$0.08	-$0.09	-$0.09	-$0.03	-$0.09
	PATH_14	-$0.03	$0.00	$0.01	-$0.04	-$0.04	$0.01	$0.04	$0.03	$0.03	$0.03	$0.04	$0.03	$0.04	$0.13	$0.24	-$0.01	-$0.06	-$0.07	-$0.07	-$0.07	-$0.07	-$0.07	-$0.06	-$0.06	-$0.07
	BLPR-HCPR1_A							$0.00				$0.00		$0.00	$0.05	$0.12		-$0.04	-$0.04	-$0.04	-$0.04	-$0.01	-$0.04	-$0.04	-$0.01	-$0.04
	Midpoint_West	-$0.01	$0.00	$0.00	-$0.01	-$0.01	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.03	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	T341.MPSN			$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
	T342.MPSN			$0.00				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00
LADWP	TAR BK E						$0.02																			
	SYL_SS BK G	$0.00	$0.03				-$0.23	-$0.04	-$0.03	-$0.03	-$0.04	-$0.03	-$0.03	-$0.03												
PACE	TOTAL_WYOMING_EXPORT														-$0.03											
	EAST_WYO_EXP														-$0.08											
	WINDSTAR EXPORT TCOR														-$0.75											
PGE	MCL_PE_SHW_V682	$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		$0.01	$0.00		$0.00	$0.00
PNM	115kv LK											-$0.29		-$0.06												
	115kv EB Fron											$0.14														
	115kv KC_TNP											-$0.02														
	Other	-$0.07	-$0.10	$0.00	-$0.06	-$0.06	$0.81	$0.15	$0.09	$0.09	-$0.02	$0.02	$0.09	$0.08	-$0.06	-$0.23	$0.06	$0.11	$0.09	$0.09	$0.07	$0.08	$0.09	$0.09	$0.04	$0.09
	Internal Total	**$0.93**	**-$2.04**	**$0.62**	**$1.41**	**$2.86**	**-$2.28**	**-$1.66**	**-$2.60**	**-$2.35**	**-$2.28**	**-$1.46**	**-$2.61**	**-$1.51**	**-$0.84**	**$0.53**	**$0.29**	**$0.26**	**$0.37**	**$0.34**	**$0.37**	**$0.39**	**$0.34**	**$0.33**	**$0.32**	**$0.34**
	Transfers				$0.20	-$0.17	$0.02	$0.07	$1.32	$2.02	$4.54	-$4.93	$3.13	$6.13	$1.26	$1.76	$1.67	$2.23	$0.15	$0.03	-$0.57	$1.38	$1.03	$17.40	-$1.38	-$0.25
	Grand Total	**$0.93**	**-$2.04**	**$0.62**	**$1.61**	**$2.69**	**-$2.26**	**-$1.59**	**-$1.28**	**-$0.33**	**$2.26**	**-$6.39**	**$0.52**	**$4.62**	**$0.42**	**$2.29**	**$1.96**	**$2.49**	**$0.52**	**$0.37**	**-$0.20**	**$1.77**	**$1.37**	**$17.73**	**-$1.06**	**$0.09**

*Since joining the WEIM

Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals[26]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	WALC*	EPE*	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	AVRN*	SCL
CAISO	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	1.9%	$16.29	-$53.16	-$50.94	$43.27	$43.93	-$52.24	-$27.25	-$45.22	-$43.42	-$44.68	-$39.20	-$45.12	-$37.33		$15.05	$23.01	$28.55	$31.89	$31.72	$33.44	$32.85	$31.66	$30.98	$37.22	$31.58
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	1.9%	$9.70	-$18.37	-$17.54	$13.38	$14.10	-$17.97	-$9.69	-$15.70	-$15.19	-$10.00	-$8.88	-$15.70	-$13.20	-$3.16	$4.08	$6.77	$8.52	$9.32	$9.23	$9.74	$9.58	$9.21	$9.03	$7.66	$9.19
	ML_RM12_NS	0.9%	$12.23	$7.59	$6.92	$12.10	$12.06	$7.29	$3.58	$5.63	$5.33	$5.55	$4.60	$5.58	$3.99	-$4.02	-$9.28	-$12.94	-$14.61	-$11.44	-$15.24	-$15.47	-$15.60	-$15.22	-$15.05	-$16.20	-$15.20
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	2.0%	-$10.60	$11.20	$10.55	-$9.98	-$10.34	$10.85	$6.29	$9.29	$8.99	$9.20	$8.03	$9.23	$7.56	-$0.01	-$4.13	-$5.61	-$6.73	-$7.23	-$7.17	-$7.49	-$7.39	-$7.17	-$7.06	-$8.07	-$7.16
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	4.2%	$6.72	-$10.48	-$9.86	$10.27	$10.39	-$10.20	-$5.72	-$8.70	-$8.45	-$8.65	-$7.79	-$8.67	-$7.25	-$0.95	$4.42	$6.50	$7.59	$8.07	$8.00	$8.37	$8.25	$7.98	$7.88	$9.08	$7.98
	6410_CP1_NG	2.6%	-$9.30	$9.40	$9.50	-$8.74	-$9.00	$9.74	$5.86	$8.47	$8.21	$8.38	$7.54	$8.42	$7.10	$1.49	-$3.36	-$4.59	-$5.72	-$6.18	-$6.12	-$6.45	-$6.34	-$6.11	-$6.00	-$7.04	-$6.10
	RM_TM12_NG	0.3%	$8.94	$5.87	$5.35	$7.37	$9.34	$5.59	$4.03	$4.21	$3.91	$4.10	$3.30	$4.17	$2.84	-$3.09	-$6.72	-$8.09	-$9.17	-$9.54	-$9.50	-$9.70	-$9.69	-$9.50	-$9.39	-$10.00	-$9.49
	SYLMAR-AC_BG_NG	1.2%	$3.86	$6.28	-$0.72	$3.47	$3.60	-$53.64	-$7.80	-$7.69	-$7.62	-$7.70	-$7.41	-$7.63	-$7.30	-$3.47						$0.00				$1.43	
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.6%	-$7.64	$8.15	$7.81	-$7.24	-$7.53	$7.92	$5.06	$6.99	$6.82	$6.93	$6.36	$6.97	$6.00	$1.03	-$2.41	-$3.68	-$4.71	-$5.04	-$5.03	-$5.31	-$5.23	-$5.02	-$4.93	-$5.81	-$5.01
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	1.6%	$6.75	-$6.64	-$6.35	$5.88	$6.48	-$6.57	-$9.25	-$6.33	-$6.50	-$2.67	-$2.38	-$6.32	-$12.68				$6.19	$8.94	$8.86	$9.45	$9.28	$8.86	$8.66		$8.86
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	1.8%		$5.59	$42.94				-$3.55	-$11.91	-$11.83	-$11.94	-$10.58	-$12.29	-$9.34	-$3.77											
	MIGUEL_BKs_MXFLW_NG	1.0%			$44.77					-$13.20	-$13.08	-$13.00	-$11.47	-$13.74	-$10.44												
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	1.9%	$5.68	-$6.71	-$6.34	$6.57	$6.84	-$6.53	-$3.70	-$5.62	-$5.47	-$5.58	-$5.07	-$5.60	-$4.74	-$0.55	$2.35	$3.54	$4.25	$4.53	$4.49	$4.72	$4.64	$4.48	$4.41	$5.16	$4.47
	7440_MetcalfImport_Tes-Metcalf	0.3%	$10.74	-$7.03	-$6.77	$5.41	$8.47	-$6.89	-$4.33	-$6.08	-$5.94	-$7.68	-$7.10	-$6.08	-$5.31				$2.58	$2.81	$2.79	$2.96	$2.91	$2.78	$2.71	$4.27	$2.78
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	13.0%	$4.81	-$8.52	-$8.15	$7.85	$9.32	-$8.38		-$7.95	-$8.17	-$7.46	-$11.68	-$8.01	-$10.23							$2.24				$2.46	
	OMS 13368679_50001_OOS_NG	2.0%		$2.77	$45.53				-$2.09	-$6.29	-$6.24	-$6.66	-$5.59	-$6.47	-$4.94	-$2.00											
	OMS 13108255_TL50003_NG	1.1%		$2.39	$38.12				-$1.98	-$6.14	-$6.14	-$8.08	-$6.90	-$6.40	-$4.89	-$2.03											
	OMS 13352412_50004_OOS_NG	0.4%		$2.43	$33.06				-$2.13	-$5.99	-$6.00	-$6.04	-$5.36	-$6.25	-$4.80	-$1.94											
	30015_TABLE MT_500_30068_TB MT 5M_ 1.0_XF_5	0.4%	-$12.78			-$15.43	-$12.60		-$1.12										$1.76	$4.10	$4.10	$4.09	$4.09	$4.10	$3.18	$6.39	$4.10
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	0.5%				$12.32	$0.33											-$0.35	-$7.40	-$7.75	-$7.75	-$7.49	-$8.24	-$7.75	-$7.72	-$7.75	-$7.75
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.9%	$4.00	-$4.08	-$5.16	$3.60	$2.33	-$4.55		-$4.60	-$4.60	-$4.58	-$4.40	-$4.60	-$8.84												
	24801_DEVERS _500_99014_CALCAPS2_500_BR_2 _1	1.0%	$1.50	$3.31	$3.85	$1.35	$1.40	$1.65	-$1.47	-$5.15	-$5.13	-$4.68	-$4.64	-$5.68	-$4.22	-$1.31				$1.05	$1.96	$0.99	$1.02	$2.13		$0.99	
	7820_TL 50002_IV-NG-OUT_TDM	0.6%			$32.70					-$7.22		-$7.92															
	OMS 13357976_50004_OOS_NG	0.4%		$1.05	$17.41				-$0.93	-$4.80	-$5.26	-$5.18	-$2.43	-$5.67	-$2.17	-$0.87											
	OMS_13632484_13810A_NG	0.4%		$4.01	-$13.86					-$4.93	-$4.97	-$4.90	-$4.24	-$5.11	-$3.61												
	SDGE_OMS 13521394+13521372_NG	0.5%		$3.26	-$9.44					-$5.75	-$5.68	-$5.77	-$5.04	-$5.92	-$4.42												
	7820_13810A_RAS_MS-SA_NG	0.5%		$4.16	-$13.61					-$4.26	-$4.35	-$4.24	-$3.69	-$4.85	-$3.10												
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	1.1%	$1.54	-$2.41	-$2.52	$2.63	$2.68	-$2.51	-$2.23	-$2.56	-$2.77	-$2.55	-$2.53	-$2.55	-$2.51					$1.61	$1.58	$1.83	$1.76	$1.58	$0.93	$2.37	$1.58
	7430_MEL_COT_NG	0.4%				$15.03	$23.86																				
	64229_SUMMIT 2_115_32218_DRUM _115_BR_1_1	0.6%	-$11.45			-$8.52			$11.77																		
	38206_COTTLE A_230_37563_MELONES _230_BR_1 _1	1.6%		-$4.08	-$3.47	$9.09	$7.02	-$4.82																			
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	0.8%				-$15.95	-$10.53																				
	OMS 13198220_SENTNL_NG	0.4%										-$25.98															
	33020_MORAGA _115_30550_MORAGA _230_XF_3 _P	1.1%	$23.37																								
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	1.2%				-$16.03			-$6.33																		
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	1.1%	$21.73																								
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	3.3%				-$0.71			-$19.88																		
	7820_TL 230S_OVERLOAD_NG	1.2%	$0.49	$0.75	$7.60	$0.73	$0.49	$0.53	-$0.45	-$1.50	-$1.58	-$1.47	-$1.44	-$1.68	-$1.26	-$0.46											
	30765_LOSBANOS_230_38625_SN LS PP_230_BR_1 _1	1.5%				$6.07	$13.58																				
	30622_EIGHT MI_230_30495_STAGG _230_BR_1 _1	0.3%				-$12.49	$5.96																				
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	1.8%							-$13.72																		
	30500_BELLOTA _230_38206_COTTLE A_230_BR_1 _1	0.7%		-$2.66		$5.79	$3.19																				
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	0.6%							-$10.27																		
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	0.8%							-$9.01																		
	30055_GATES1 _500_30900_GATES _230_XF_12_P	1.0%	-$5.27	$0.51		-$0.41		$0.51																			
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1	1.2%				$1.79	$2.82																				
IPCO	PATH_14	0.9%	-$3.68	$0.57	$1.59	-$4.38	-$3.98	$1.15	$4.46	$3.07	$3.37	$3.15	$4.21	$3.11	$4.85	$14.90	$26.74	-$1.47	-$6.96	-$7.66	-$7.45	-$7.77	-$7.72	-$7.40	-$7.11	-$7.22	-$7.40
	Midpoint_West	0.4%	-$1.32	$0.83	$1.21	-$1.67	-$1.46	$1.05	$2.61	$1.91	$2.06	$1.93	$2.45	$1.94	$2.77	$7.64	-$0.92	-$0.32	-$2.91	-$3.24	-$3.14	-$3.30	-$3.27	-$3.12	-$2.98	-$3.02	-$3.12
PACE	TOTAL_WYOMING_EXPORT	2.0%														-$1.71											
	WINDSTAR EXPORT TCOR	31.7%														-$2.37											
	EAST_WYO_EXP	2.9%														-$2.58											
PNM	115kv LK	0.7%											-$42.76		-$12.21												
	115kv EB Fron	0.9%											$16.23														

*Since joining the WEIM

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 transfer congestion increased prices in the majority of the areas on average. Transfer constraint congestion generally raised prices in the 15-minute and 5-minute markets, but significantly increased prices in the Powerex area and sharply decreased prices in the El Paso Electric area.

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 1.26 and Table 1.4, and schedule-based constraints listed in Table 2.5. Transfer constraint congestion typically has a large impact on prices. Figure 1.27 and Figure 1.28 in the next section show the frequency and impact of transfer congestion in the WEIM.[27]

Transfer constraint congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market occurs with different frequencies and price impacts across the WEIM. Transfer congestion in the 5-minute market was similar to the 15-minute

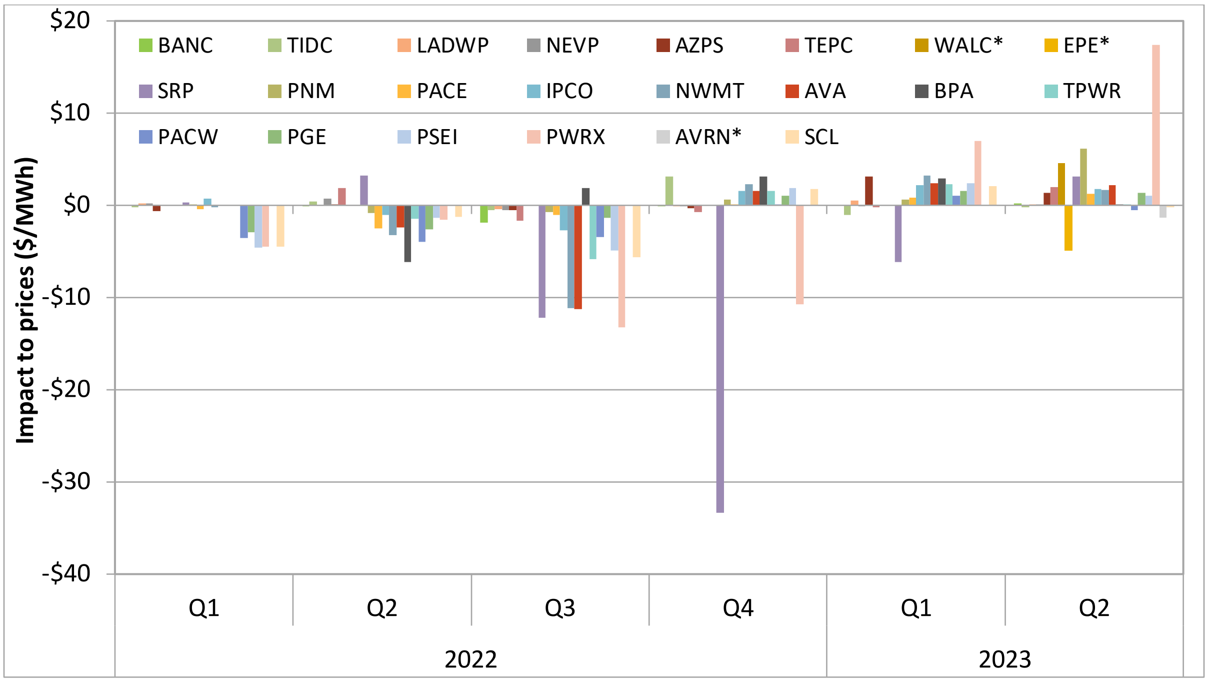
26 Details on constraints binding in less than 0.3 percent of the intervals have not been reported.

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

market.[28] Figure 1.27 and Figure 1.28 show the average impact to prices and the frequency of congestion on transfer constraints in the 15-minute market by quarter for 2022 and 2023, respectively.

There was an overall increase in the frequency and an increase in impact of transfer constraint congestion in the second quarter of 2023 compared to the same quarter in 2022. The average frequency of transfer constraint congestion in the Pacific Northwest was 44 percent, down from 47 percent during the same time last year.[29]

Figure 1.27 Transfer constraint congestion average impact on prices in the 15-minute market

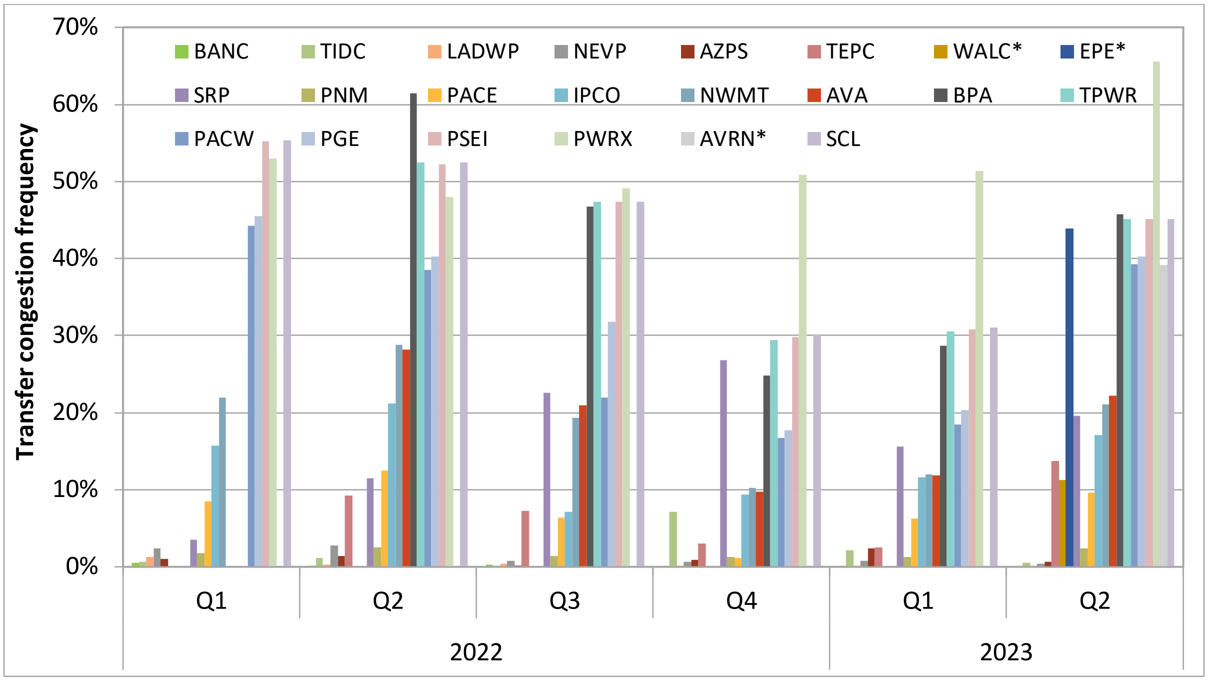


*Since joining the WEIM

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

[29] The Pacific Northwest in this comparison only includes Avista Utilities, Bonneville Power Administration, Tacoma Power, 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 frequency in the 15-minute market



*Since joining the WEIM

1.7.3 Congestion on interties

In the second quarter of 2023, the frequency and import congestion rent on the Malin 500 and NOB decreased significantly relative to the same time last year. Figure 1.29 shows total import congestion charges in the day-ahead market for 2022 and 2023. Figure 1.30 shows the frequency of congestion on five major interties. Table 1.6 provides a detailed summary of this data over a broader set of interties.

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

- Total import congestion charges for the second quarter of 2023 were 87 percent lower than the second quarter of 2022 at $9.5 million. The Malin 500 and NOB interties accounted for 98 percent of the total import congestion rent during the quarter.
- The frequency and impact of congestion on the Malin 500 was significantly lower than during the second quarter of 2022, falling 56 percent and 83 percent, respectively. This was the case for NOB as well, where the frequency and impact over the intertie fell 76 percent and 90 percent, respectively.

Figure 1.29 Day-ahead import congestion charges on major interties

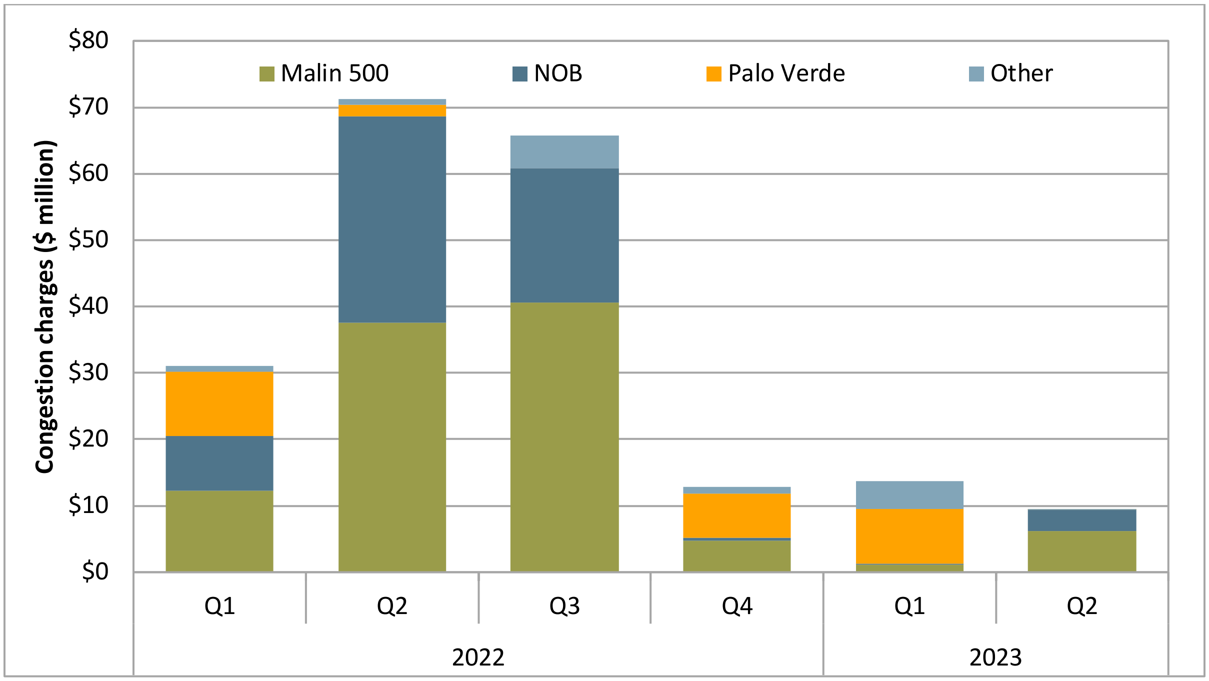


Figure 1.30 Frequency of import congestion on major interties in the day-ahead market

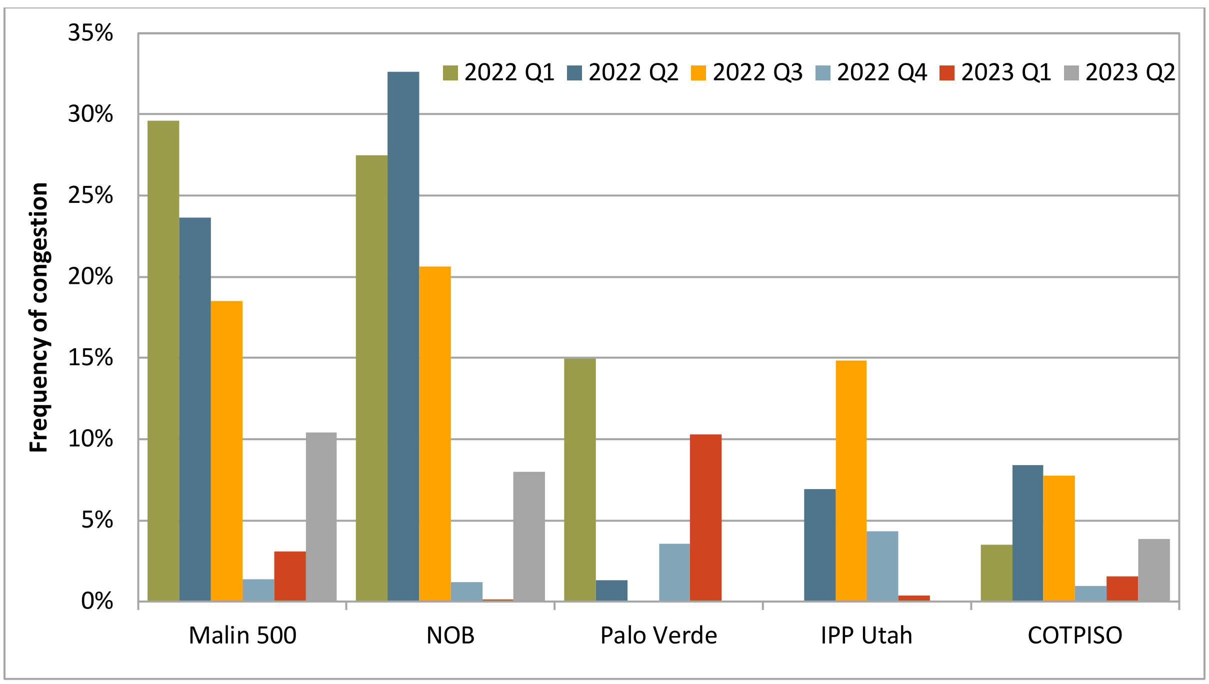


Table 1.6 Summary of import congestion in day-ahead market (2022-2023)

Area	Intertie	Frequency of import congestion						Import congestion charges ($ thousand)					
		2022				2023		2022				2023	
		Q1	Q2	Q3	Q4	Q1	Q2	Q1	Q2	Q3	Q4	Q1	Q2
Northwest	Malin 500	30%	24%	18%	1%	3%	10%	12,221	37,557	40,646	4,786	1,183	6,266
	NOB	28%	33%	21%	1%	0%	8%	8,216	31,130	20,229	333	68	3,075
	COTPISO	4%	8%	8%	1%	2%	4%	53	435	310	15	39	77
	Summit		0%	0%	1%	0%			1	14	4	10	
Southwest	IID-SCE					1%	1%					150	91
	Palo Verde	15%	1%		4%	10%	0%	9,694	1,643		6,663	8,199	33
	IPP Adelanto	6%		0%	0%	7%		673		0	12	2,996	
	Westwing Mead					2%						1,013	
	Mead	1%		0%		0%		182		308		75	
	IPP Utah	0%	7%	15%	4%	0%		0	480	4,092	1,084	18	

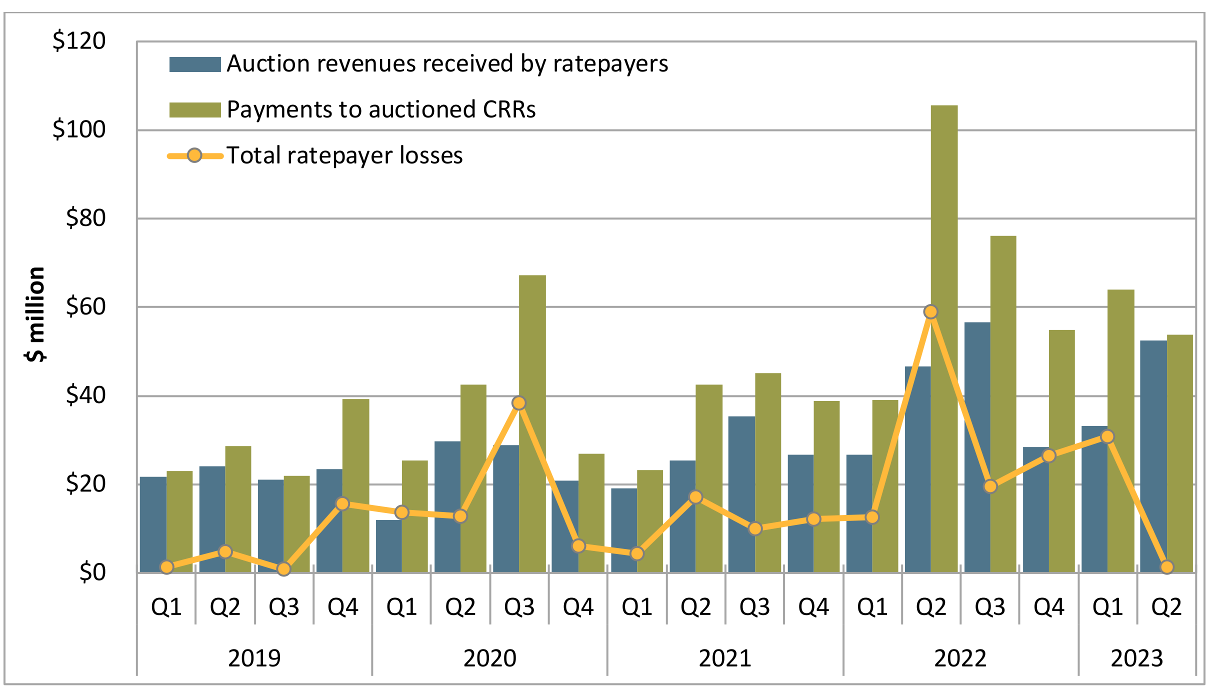
1.8 Congestion revenue rights

Congestion revenue right auction returns

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

As shown in Figure 1.31, transmission ratepayers lost about $1 million during the second quarter of 2023 as payments to auctioned congestion revenue rights holders were slightly higher than auction revenues. In the same quarter of 2022, the ratepayers lost a record $59 million.

Figure 1.31 Auction revenues and payments to non-load-serving entities



During the second quarter of 2023:

- Financial entities received profits of nearly $4.6 million, significantly down from $34 million during the same quarter of 2022. Total revenue deficit offsets were about $10.4 million.[30]
- Marketers lost about $3.3 million from auctioned rights, down from $18.6 million in 2022. Total revenue deficit offsets were nearly $4.4 million.
- Physical generation entities lost about $0.3 million from auctioned rights, down from $6.5 million in 2022. Total revenue deficit offsets were about $1.1 million.

The $1 million second quarter 2023 auction loss was less than 1 percent of day-ahead congestion rent. This is significantly down from 21 percent in the second quarter of 2022 and down from 10 percent in the previous quarter. 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 total payments to non-load serving entities by about $16 million in the second quarter. The track 1B effects on auction bidding behavior and reduced auction revenues are not known.

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

1.9 Real-time imbalance offset costs

Real-time imbalance offset costs decreased to $71 million, down from $130 million in the second quarter of 2022, as shown in Figure 1.32. Real-time *congestion* imbalance offset costs made up the majority of these costs in the second quarter of 2023, at $60 million. In comparison, congestion imbalance offset costs were $77 million in June of 2022 alone.

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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 SCs 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-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

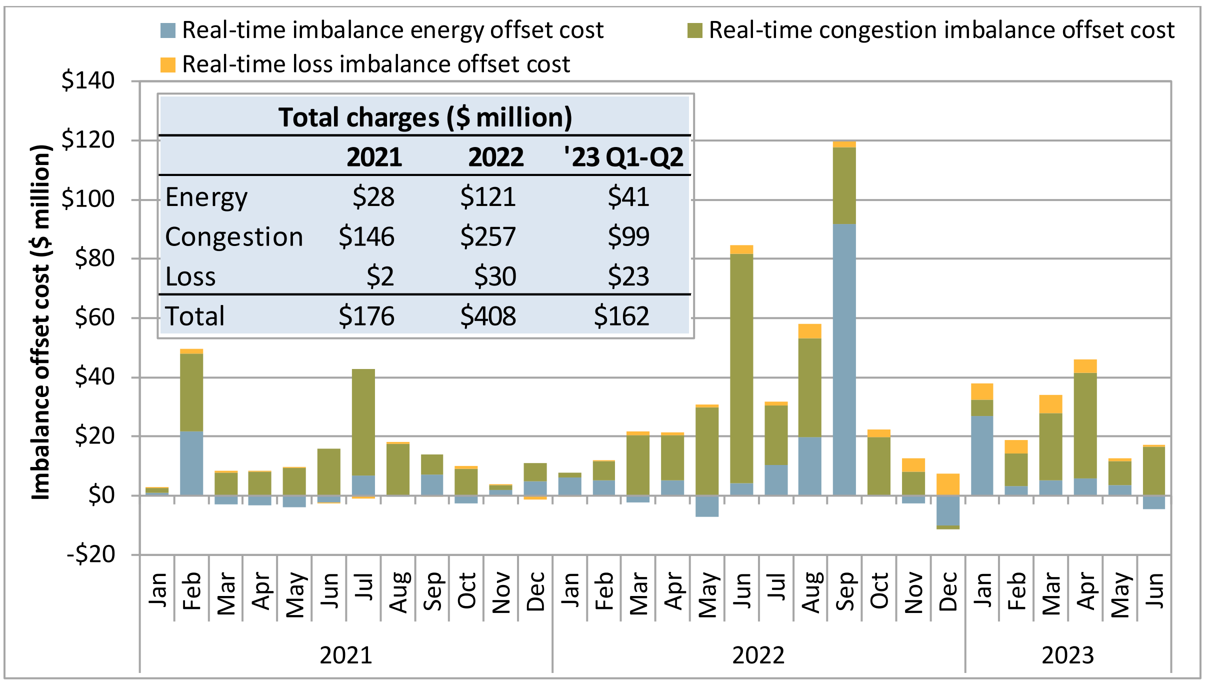
32 California ISO, Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

The real-time imbalance offset cost is the difference between the total money *paid out* by the ISO and the total money *collected* by the ISO for energy settled in the real-time energy markets. Within the ISO 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).

A structural inconsistency in the settlement of real-time market demand and generation can create real-time revenue shortfalls that are recovered through real-time revenue imbalance offset charges.[33] DMM recommends that the ISO settle real-time load incrementally in each market directly using market prices.

Figure 1.32 Real-time imbalance offset costs



	2021	2022	'23 Q1-Q2
Energy	$28	$121	$41
Congestion	$146	$257	$99
Loss	$2	$30	$23
Total	$176	$408	$162

1.10 Bid cost recovery

During the second quarter of 2023, estimated bid cost recovery payments for units in the ISO and Western Energy Imbalance Market (WEIM) balancing areas totaled about $32 million and $4 million,

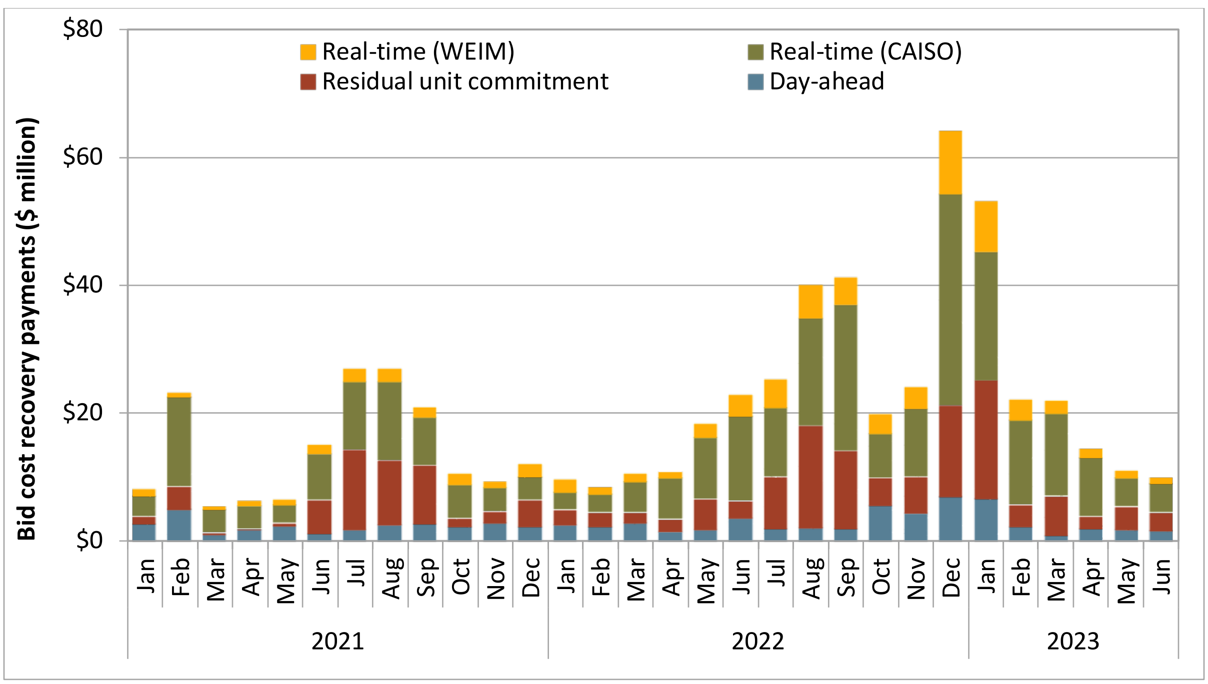
[33] For more information, see DMM's special report: Department of Market Monitoring, *Real-time load settlement price calculation causing revenue imbalances*, August 30, 2023: http://www.caiso.com/Documents/Real-Time-Load-Settlements-and-Revenue-Imbalances-Aug-30-2023.pdf

respectively. These payments are lower than the second quarter of 2022 when payments totaled $53 million in the ISO ($46 million) and WEIM ($7 million) areas.

As shown in Figure 1.33, bid cost recovery attributed to the day-ahead market in the second quarter totaled about $5.5 million, which was about $2 million lower than second quarter of 2022. Bid cost recovery payments for residual unit commitment during the quarter totaled about $8 million, or about $1 million lower than the second quarter of 2022. Bid cost recovery attributed to the real-time market totaled about $22 million, $38 million lower than the payments in the previous quarter, and about $14 million lower than the same quarter of 2022. Out of the $22 million in real-time payments, about $4 million was allocated to non-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 second quarter, about 76 percent of these payments, or about $27.5 million, were made to gas resources, followed by about $5 million to battery energy storage resources.

Figure 1.33 Monthly bid cost recovery payments



1.11 Imbalance conformance

Operators in the 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 ISO refers to this as *imbalance conformance or as load conformance* in the Summer Monthly Performance Reports.[34] 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 ISO hour-ahead and 15-minute markets. This large increase continued to a lesser extent in the morning solar ramp up and, to a slightly greater extent, the afternoon peak solar ramp down period.

Following record high levels of imbalance conformance in the summer of 2022, the ISO initiated a pilot program to assess the use, drivers, and impacts of imbalance conformance on supply changes in the market.[35] Beginning May 6, 2023 California ISO operators began to limit the use of operator adjustment in the day-ahead residual unit commitment to days with peak load forecast greater than 35,000 MW. The pilot program also resulted in lower levels of hour-ahead and fifteen-minute imbalance conformance from May through late July.[36]

Average hourly imbalance conformance adjustments in these markets peaked in the morning at about 300 MW and at just about 1,600 MW in the afternoon, about a 300 MW and 500 MW decrease, respectively, over the same quarter peak periods of the previous year. Solar uncertainty contributed to both the morning and evening imbalance conformance levels.

Figure 1.34 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.

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

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34 Market Performance Reports https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=BA9489A9-1B4A-4D56-8AB2-DBE56269893D

35 Market Performance and Planning Forum, June 29, 2023. https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun29-2023.pdf, pp 16-30.

36 Market Performance and Planning Forum, September 27, 2023. https://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Sep27-2023.pdf pp 210-227.

Figure 1.34 Average hourly imbalance conformance adjustment (Q2 2022-Q2 2023)

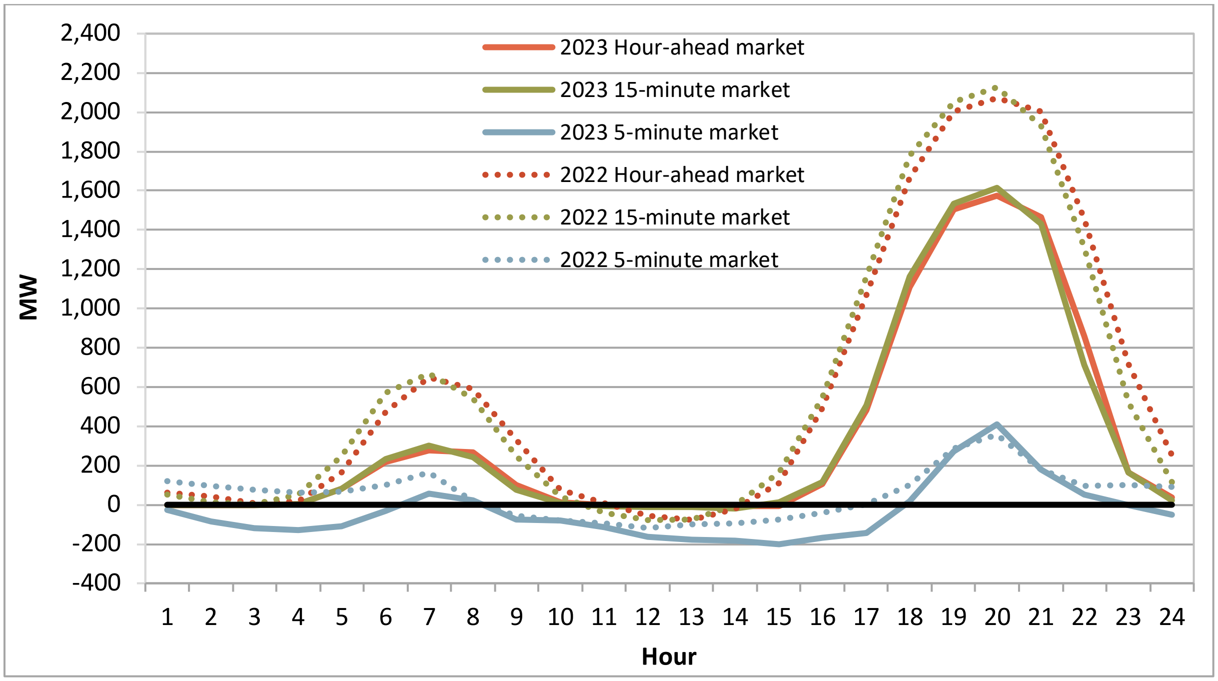
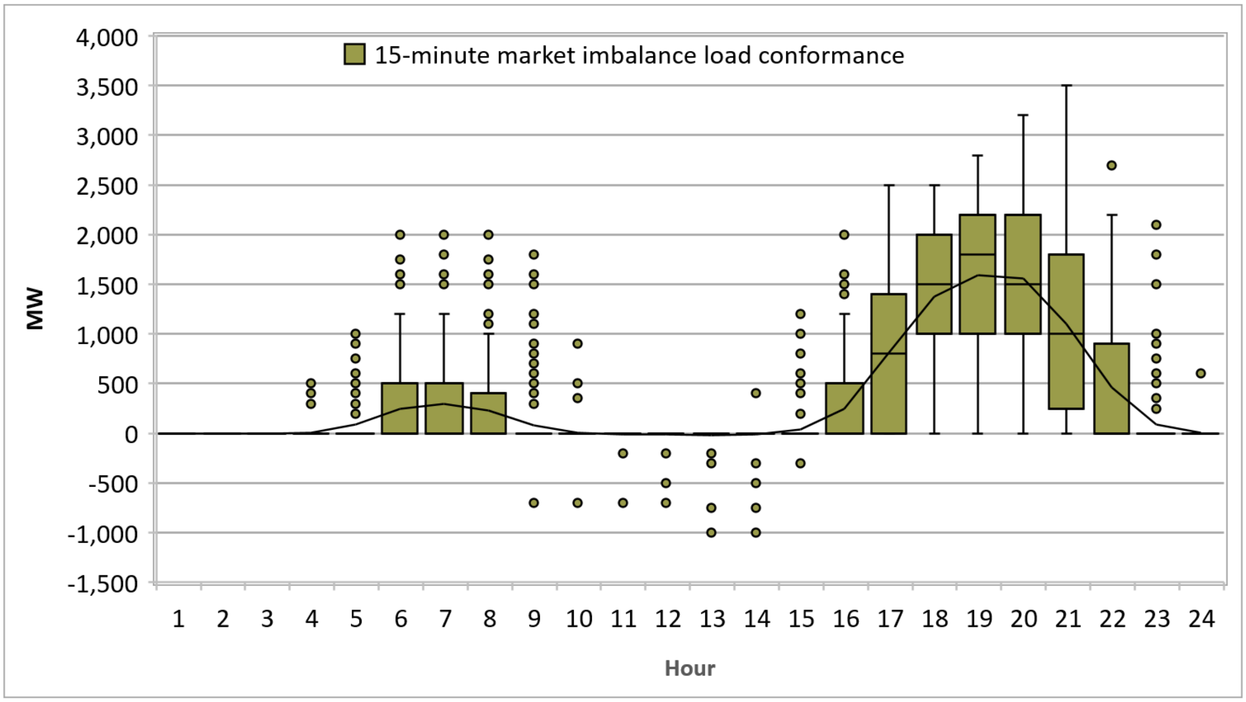


Figure 1.35 shows the distribution of the 15-minute market into quartiles for the load adjustment profile for the second quarter of 2023. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the filled dots. The outside whiskers do not include these outliers. For the quarter, the major positive outliers in the morning and late evening hours occurred in a few intervals in April and May while the negative 1,000 MW occurred on May, 19, 2023.

Figure 1.35 15-minute market hourly distribution of operator load adjustments (Q2 2023)



1.12 Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring upward and downward flexible ramping capacity in the real-time market to help manage volatility and uncertainty surrounding net load forecasts.[37] The amount of flexible capacity the product procures is derived from a demand curve, which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs.

1.12.1 Flexible ramping product deliverability enhancements and market outcomes

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

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

Flexible ramping product requirement and deliverability enhancements

The end of the demand curve is implemented in the ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This requirement for rampable capacity reflects the upper end of uncertainty in each direction that might materialize.[38] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation, which can only be met by flexible capacity within that area. Flexible capacity for instead the group of balancing areas that pass the resource sufficiency evaluation are pooled together to meet the uncertainty requirement for the rest of the system. As part of flexible ramping product enhancements, deliverable flexible capacity awards are now produced through two deployment scenarios that adjust the expected net load forecast in the following interval by the lower and upper ends of uncertainty that might materialize. Here, the uncertainty requirement is distributed at a nodal level to load, solar, and wind resources based on allocation factors that reflect the estimated contribution of these resources to potential uncertainty. The result is more deliverable upward and downward flexible capacity awards that do not violate transmission or transfer constraints.

Flexible ramping product demand curves and implementation error

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

The prices on the flexible ramping product demand curves were implemented incorrectly as part of the other enhancements on February 1. The result was that the prices on the demand curve were too low relative to the expected cost of a power balance constraint relaxation for the level of flexible capacity procured. The ISO implemented a correction to the demand curves effective August 8, 2023. For more information on the implementation error including the cause of the issue and its impact, see DMM's special report on the topic.[39]

Flexible ramping product prices

As part of flexible ramping product enhancements, flexible ramping product prices are now determined locationally at each node. This price can be made up of two components. The first component is the shadow price associated with meeting the uncertainty requirement — either for the group of balancing areas that pass the resource sufficiency evaluation or the individual balancing areas that fail the tests. The nodal price can also include a congestion component. This reflects the shadow price on transmission constraints and relative contribution to that congestion, which is expected based on the dispatch of all flexible capacity in the deployment scenarios. At the implementation of the enhancements on February

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[38] Based on a 95 percent confidence interval.

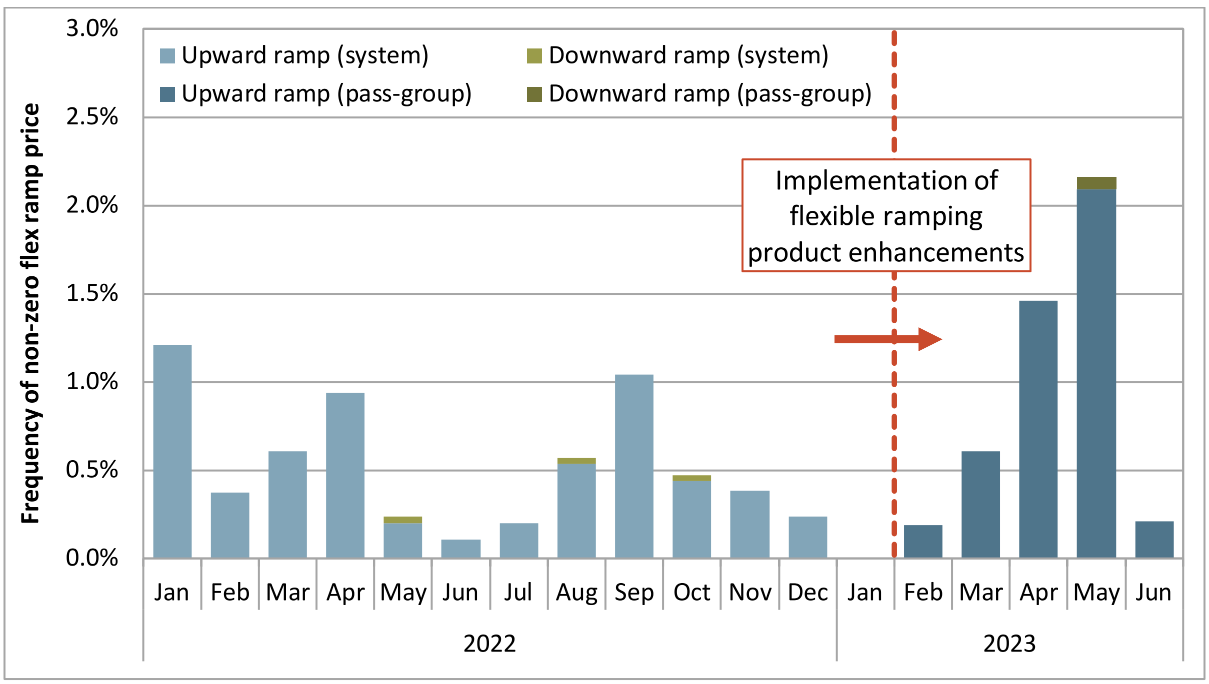
[39] Department of Market Monitoring, *Flexible ramping product enhancements demand curve implementation error,* July 20, 2023: http://www.caiso.com/Documents/Flexible-Ramping-Product-Enhancements-Demand-Curve-Implementation-Error-Jul-20-2023.pdf

1, only the base-case flow-based transmission constraints were modeled in the deployment scenarios. Nomogram constraints have since been activated as of September 13. Contingency flow-based constraints are being assessed for activation at a future date.

Flexible ramping product prices for the group of balancing areas that pass the resource sufficiency evaluation have frequently been zero since the enhancements were implemented on February 1. When the shadow price on this constraint is zero, this reflects that flexible capacity within this wider footprint of balancing areas that passed the resource sufficiency evaluation is readily available. Here, the upper end of the uncertainty requirement can be met by resources with zero opportunity cost for providing that flexibility.

Figure 1.36 shows the percent of intervals since implementation of the enhancements in which the 15-minute market price for flexible capacity was non-zero for the *group of balancing areas that pass the tests*.[40] This is compared against the frequency of non-zero prices on the constraint for *system*-wide flexible capacity that was in place prior to the enhancements. The frequency of non-zero prices were slightly higher in April and May but remained low overall. For the quarter, 15-minute market prices for upward flexible capacity within the pass-group were non-zero in around 1.3 percent of intervals. The frequency of non-zero prices in the 5-minute market were more infrequent, in less than 0.2 percent of intervals.

Figure 1.36 Frequency of non-zero system or pass-group flexible ramping product shadow price



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

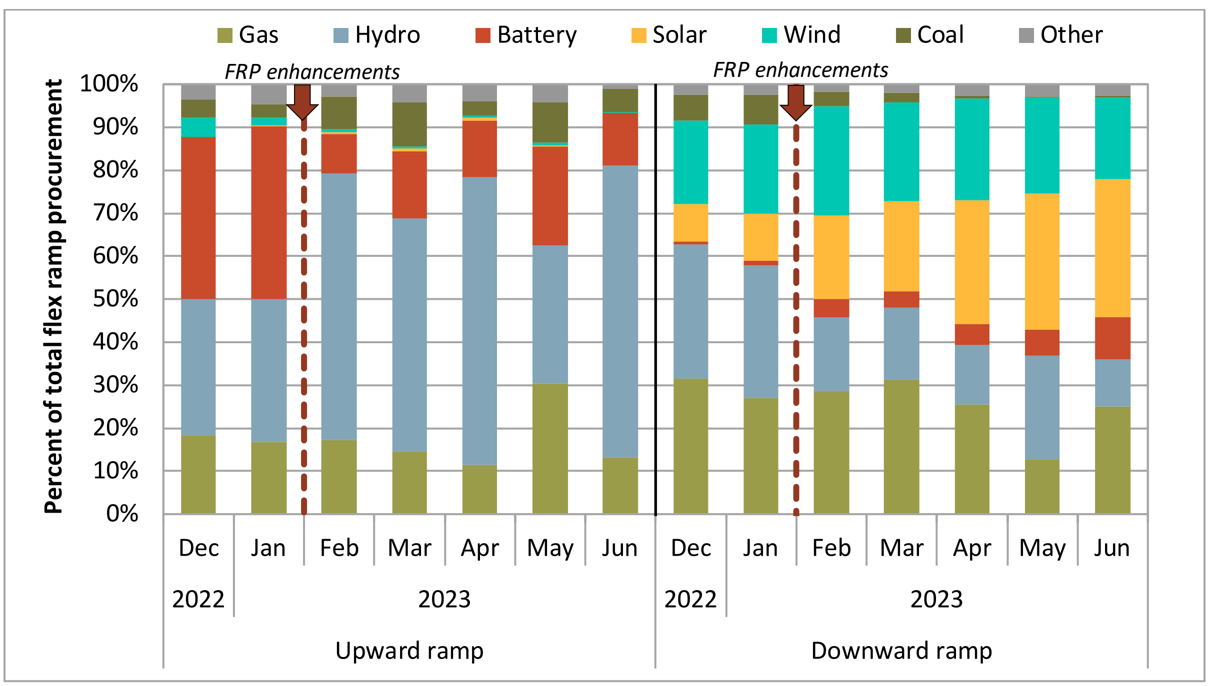
Flexible ramping product procurement

This section summarizes flexible capacity procured to meet the uncertainty needs of the greater WEIM system and the impact from flexible ramping product enhancements. Figure 1.37 shows the percent of upward or downward flexible capacity that was procured from various fuel types, both before and after the enhancements that were implemented at the start of February. Prior to the enhancements, these amounts reflect the percent of *system-wide* uncertainty. After the enhancements, these amounts instead reflect the percent of *pass-group* uncertainty for the group of balancing areas that passed the resource sufficiency evaluation.

During the second quarter, most upward flexible capacity continued to come from hydro resources (56 percent). Gas resources made up 21 percent of upward flexible capacity while battery resources were 16 percent. For the downward direction, wind and solar resources made up most of the flexible capacity at around 53 percent.

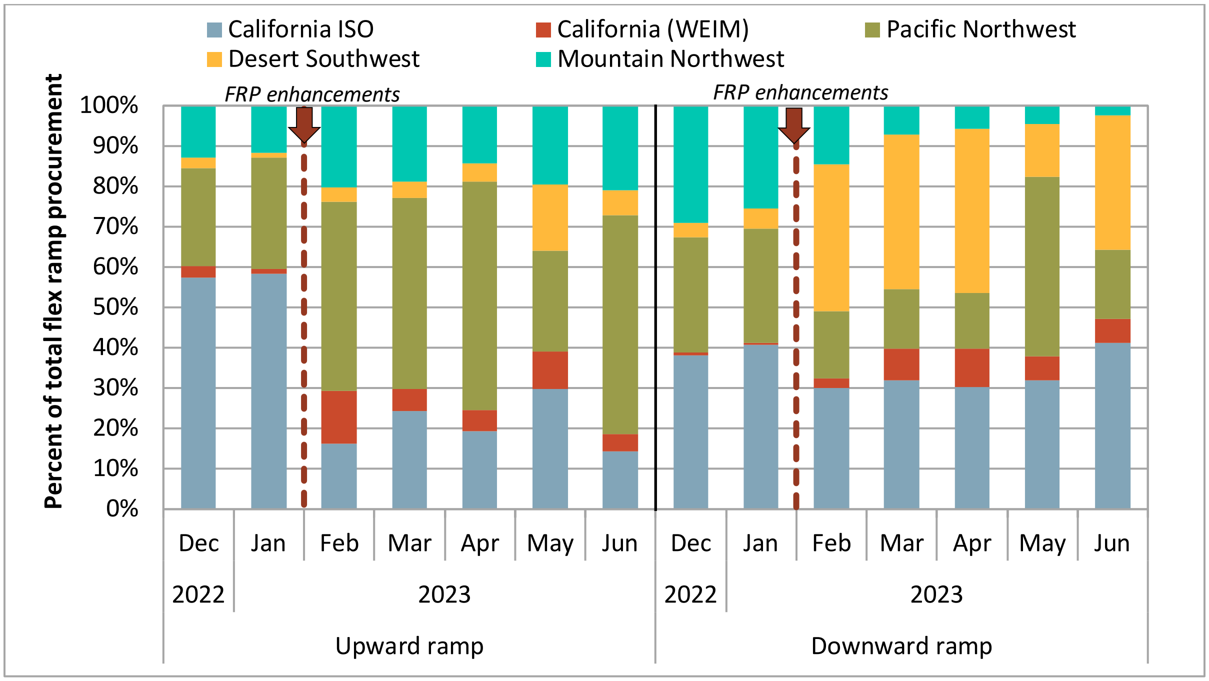
Figure 1.38 shows the percent of upward or downward flexible capacity that was procured in various regions.[41] These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system. As shown in Figure 1.38, the percent of upward capacity procured from balancing areas in the Pacific Northwest region continued to have the largest share of upward flexible capacity in the second quarter (45 percent)

Figure 1.37 Percent of system or pass-group flexible capacity procurement by fuel type



41 For a list of the balancing areas in each region, see Section 2.2.

Figure 1.38 Percent of system or pass-group flexible capacity procurement by region



1.12.2 Net load uncertainty for the flexible ramping product

The uncertainty requirement is used as part of the flexible ramping product design to capture the extreme ends of net load uncertainty, such that it can be optimally relaxed based on the trade-off between the cost of procuring additional flexible ramping capacity and the expected cost of a power balance relaxation. Net load uncertainty is also included in the requirement of the flexible ramp sufficiency test (flexibility test) to capture additional flexibility needs that may be required in the evaluation hour due to variation in either load, solar, or wind forecasts.

The calculation of uncertainty was adjusted on February 1 using a method called mosaic quantile regression. This method applies regression techniques on historical data to produce a series of coefficients that define the relationship between forecast information (load, solar, or wind) and the extreme percentile of uncertainty that might materialize (95 percent confidence interval).[42]

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

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation which can only be met by flexible capacity within that area. Here, the regressions can be performed in advance and local uncertainty targets can be readily determined based on current forecast information when a balancing area fails the test. However, for instead the group of

[42] For a detailed explanation of the mosaic quantile regression calculation, see the *Q1 2023 Report on Market Issues and Performance,* Department of Market Monitoring, September 19, 2023, pp. 66-70: http://www.caiso.com/Documents/2023-First-Quarter-Report-on-Market-Issues-and-Performance-Sep-19-2023.pdf

balancing areas that pass the resource sufficiency evaluation (known as the pass-group), the uncertainty calculation needs to first know which balancing areas make up this group so that it can perform the regression using historical data accordingly for that group.

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

However, the current weather information that is ultimately combined with the regression results to calculate uncertainty are instead consistent with the group of balancing areas in the pass-group for flexible ramping capacity procurement. This is based on the second run of the resource sufficiency evaluation (T-55) for interval 1 and the final resource sufficiency evaluation (T-40) for intervals 2 through 4. Table 1.7 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

Table 1.7 Source of pass-group for calculating uncertainty and procuring flexible ramping capacity

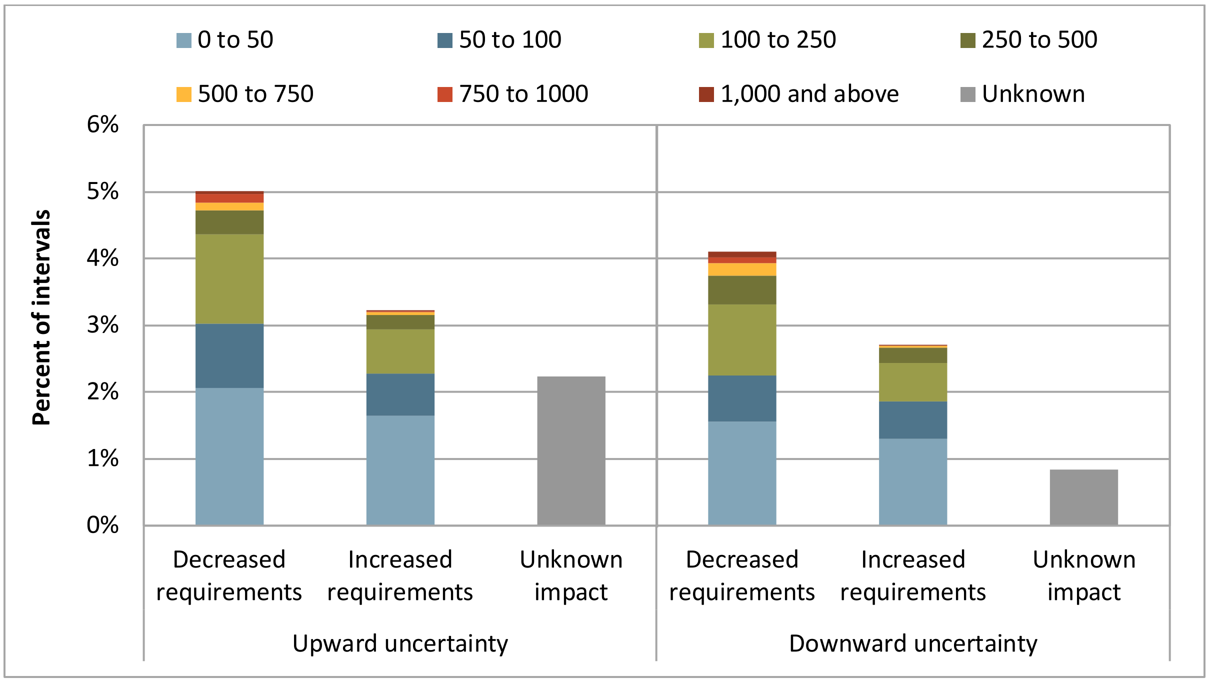
15-minute market interval	Current weather information for calculating uncertainty and flex ramp procurement	Regression inputs and outputs
1	Second run (T-55)	First run (T-75)
2	Final run (T-40)	Second run (T-55)
3	Final run (T-40)	Final run (T-40)
4	Final run (T-40)	Final run (T-40)

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

During about 16 percent of intervals during April and June, the composition of balancing areas in the pass-group between the current forecast information and regression information were inconsistent for either upward or downward uncertainty. Figure 1.39 summarizes the impact of this inconsistency on pass-group uncertainty requirements in cases when the composition of balancing areas differed between the two sets of data. The figure shows the percent of intervals in which the market uncertainty requirements (with inconsistent balancing areas in the pass-group) were higher or lower than counterfactual uncertainty requirements with a consistent composition of balancing areas in the pass-group.[43] These results are shown separately for the following categories to highlight the impact of this inconsistency on uncertainty requirements.

- **Decreased requirements** indicate that market uncertainty requirements for the pass-group were lower as a result of inconsistent balancing areas in the pass-group.
- **Increased requirements** indicate that market uncertainty requirements for the pass-group were higher as a result of inconsistent balancing areas in the pass-group.
- **Unknown impact** indicates that there was an inconsistent composition of balancing areas in the pass-group but data was not available to calculate the impact.

Figure 1.39 Impact of pass-group inconsistency on uncertainty requirements (April-June 2023)



Results of quantile regression uncertainty calculation

Figure 1.40 compares 15-minute market uncertainty for the group of balancing areas that passed the resource sufficiency evaluation, both with the histogram method (pulled from the 2.5th and 97.5th percentile of observations in the hour from the previous 180 days) and with the mosaic quantile regression method. The green and blue lines show the *average* upward and downward uncertainty from each method while the areas around the lines show the minimum and maximum amount over the month (range of uncertainty in each interval).

Uncertainty calculated from the quantile regressions are capped by the lesser of two thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The dashed red and yellow lines show the average histogram and seasonal thresholds, respectively,

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

during the period. The histogram threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from the previous 180 days. The seasonal threshold is updated each quarter and is calculated from the 1st and 99th percentile using observations over the previous 90 days. Here, each hour is calculated separately and the greatest upward and downward uncertainty across all hours sets the mosaic threshold for each hour of the same direction. A threshold is also in place that sets the *floor* for uncertainty near zero when the resulting uncertainty calculated from the quantile regression method would be in the opposite direction.[44]

Figure 1.41 instead summarizes actual error between binding net load forecasts in the 5-minute market and advisory net load forecasts in the 15-minute market – for the group of balancing areas that passed the tests. Here, a higher net load error reflects higher load (or lower renewables) in the binding 5-minute market interval, relative to the advisory 15-minute market interval. For comparison, the blue lines show the average upward and downward uncertainty used in the market during the same period per the mosaic quantile regression method. Again, the blue areas around the lines show the minimum and maximum amounts for each hour. This metric highlights how well actual pass-group net load error in each interval fits within the calculated uncertainty requirements.

Figure 1.42 and Figure 1.43 show the same information for 5-minute market uncertainty. 5-minute market uncertainty reflects the error between the binding and advisory net load forecasts in the 5-minute market.

Overall, pass-group uncertainty calculated from the quantile regression approach were often lower than those calculated with the histogram approach on average – particularly during midday hours. However, the regression approach had greater variability including instances with low or zero uncertainty.

44 Negative upward net load uncertainty would instead be set as 0.1 MW. Positive downward net load uncertainty would instead be set at -0.1 MW.

Figure 1.40 15-minute market pass-group uncertainty requirements (weekdays, April-June 2023)

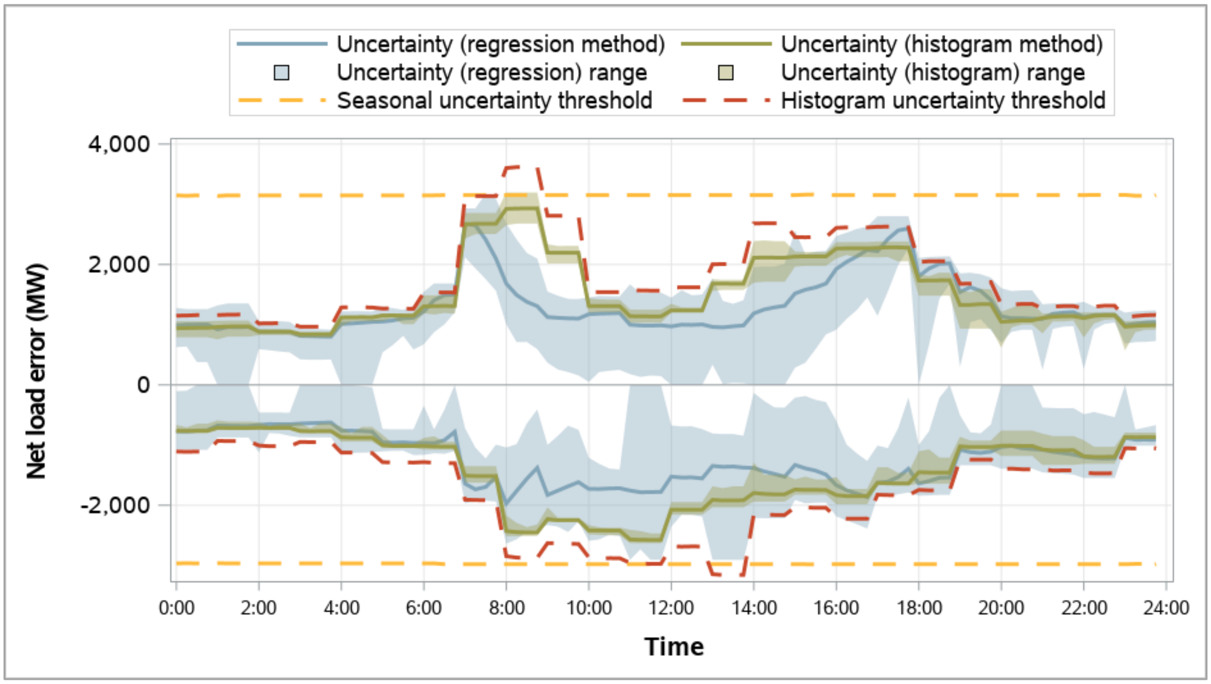


Figure 1.41 15-minute market distribution of actual pass-group net load error compared to uncertainty requirements (weekdays, April-June 2023)

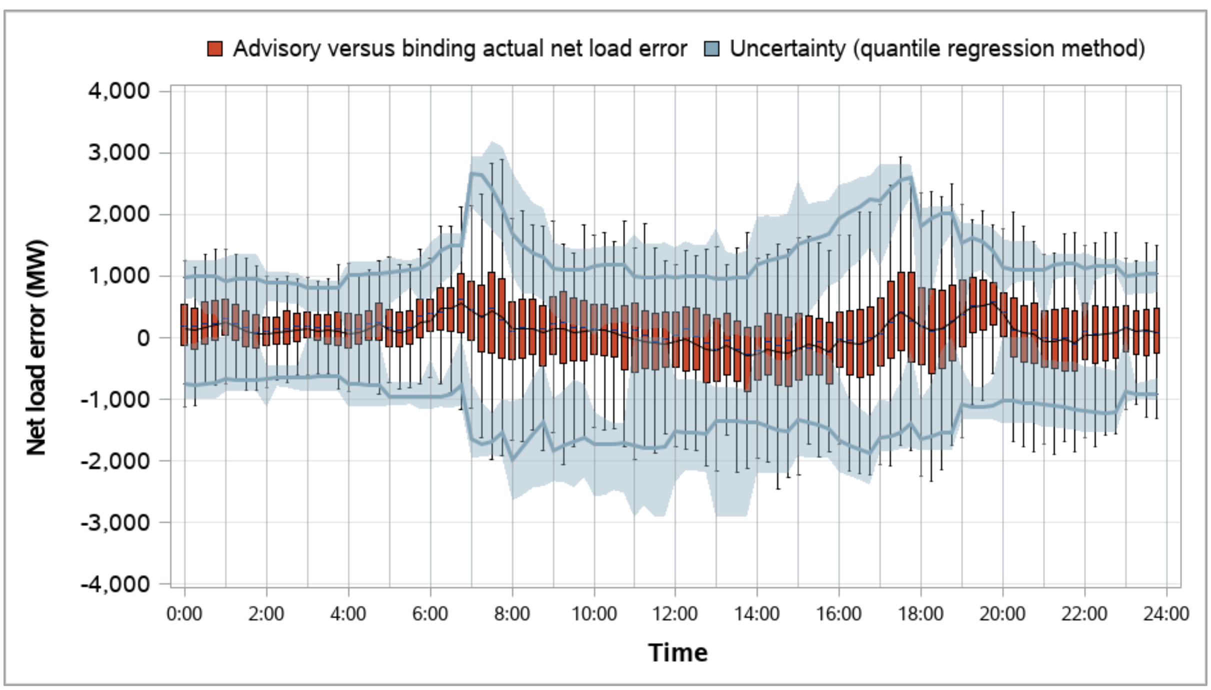


Figure 1.42 5-minute market pass-group uncertainty requirements (weekdays, April-June 2023)

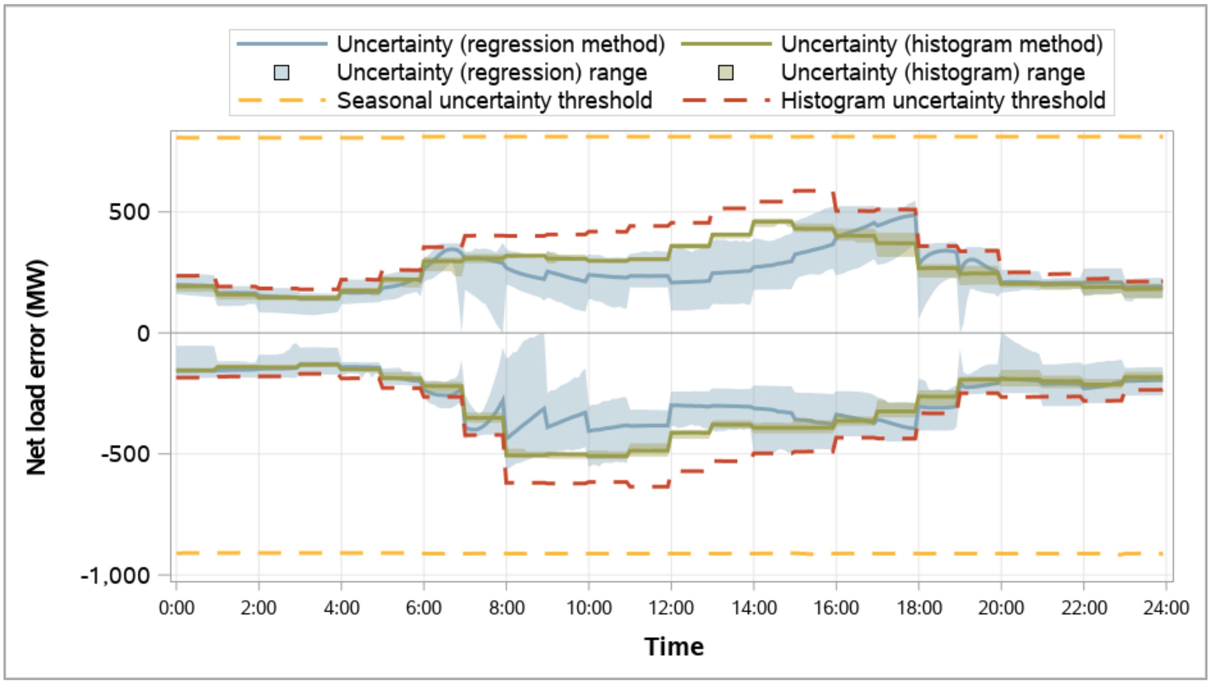


Figure 1.43 5-minute market distribution of actual pass-group net load error compared to uncertainty requirements (weekdays, April-June 2023)

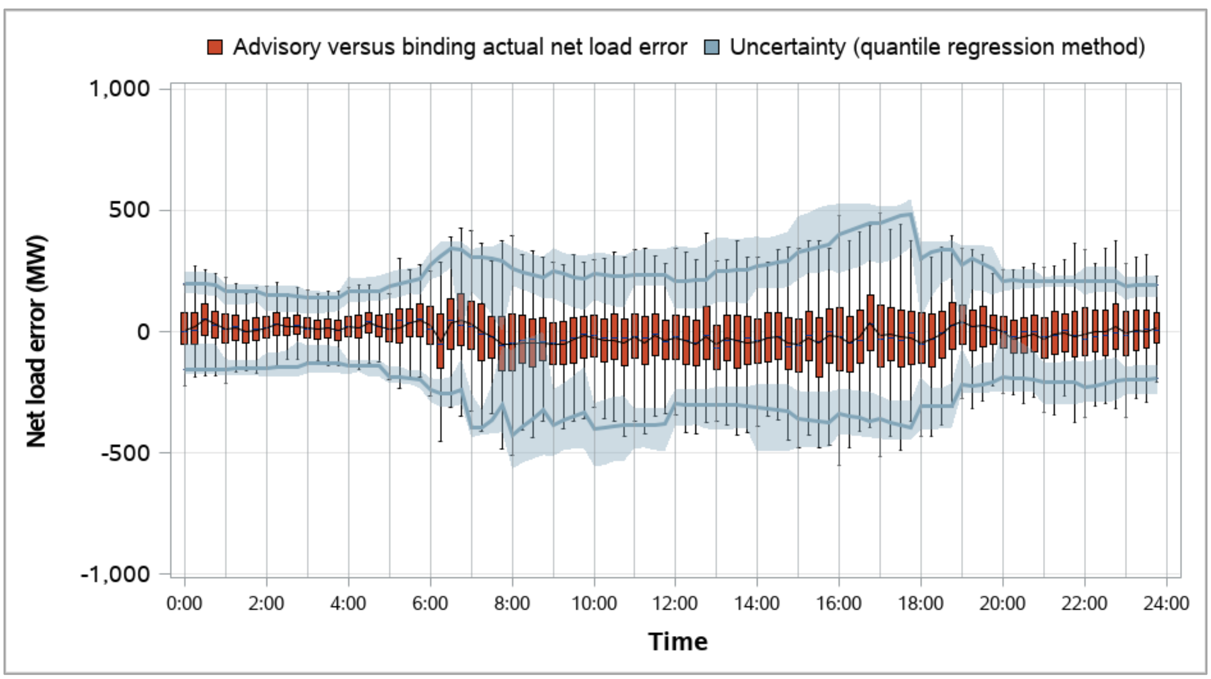


Table 1.8 summarizes the average uncertainty requirement for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. On average across all hours, the uncertainty calculated from the regression method was less than the histogram method for both directions and markets.

Table 1.9 summarizes the actual net load error for the pass-group and how that compares to the mosaic regression uncertainty requirements for the same interval.[45] The left side of the table summarizes the closeness of the actual net load error to the pass-group uncertainty requirements when the actual net load error was within (or covered) by the upward or downward requirements. The mosaic regression requirements covered between 95 and 97 percent of actual net load errors across all markets and directions. The right side of the table summarizes when the actual net load error instead exceeded upward or downward uncertainty requirements.

Table 1.10 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was slightly more than the mosaic regression method, but by less than 2 percent across all directions and markets.

For more information on the calculated uncertainty used in the resource sufficiency evaluation for each balancing area, see DMM's monthly WEIM resource sufficiency evaluation reports.[46]

Table 1.8 Average pass-group uncertainty requirements (April-June 2023)

		Pass-group uncertainty		
Market	**Uncertainty type**	**Histogram**	**Mosaic**	***Difference***
15-minute market	Upward	1,526	1,298	-227
	Downward	1,417	1,234	-183
5-minute market	Upward	270	245	-25
	Downward	287	263	-24

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

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

Table 1.9 Actual net load error compared to mosaic regression pass-group uncertainty requirements (April-June 2023)

		Actual net load error falls within calculated uncertainty requirements		*Actual net load error exceeds requirement*	
Market	**Uncertainty type**	**Percent of intervals**	**Average distance to requirement (MW)**	**Percent of intervals**	**Average amount (MW)**
15-minute market	Upward	95%	1,291	5%	289
	Downward	97%	1,388	3%	671
5-minute market	Upward	97%	267	3%	70
	Downward	96%	265	4%	77

Table 1.10 Actual net load error compared to histogram regression pass-group uncertainty requirements (April-June 2023)

		Actual net load error falls within calculated uncertainty requirements		*Actual net load error exceeds requirement*	
Market	**Uncertainty type**	**Percent of intervals**	**Average distance to requirement (MW)**	**Percent of intervals**	**Average amount (MW)**
15-minute market	Upward	97%	1,497	3%	286
	Downward	98%	1,560	2%	688
5-minute market	Upward	97%	291	3%	68
	Downward	97%	288	3%	77

DMM's review of the performance of this new methodology indicates that it is not a clear improvement over the prior method. Although uncertainty values calculated with this method are generally lower while covering uncertainty (an improvement), they fluctuate more significantly and are likely to be more difficult for balancing areas to reproduce or predict in advance.

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

2 Western Energy Imbalance Market

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

2.1 Performance

New WEIM balancing authority areas

On April 5, 2023, Avangrid, El Paso Electric, and Western Area Power Administration (WAPA) - Desert Southwest joined the Western Energy Imbalance Market, bringing the total number of participants up to 22.[47] Avangrid joined as the first generation-only entity, with 3,300 MW in participating capacity. WAPA Desert Southwest and El Paso Electric joined the WEIM with 2,300 MW and 2,000 MW of participating capacity, respectively.

Prices

The Western Energy Imbalance Market benefits participating areas by committing lower-cost resources across all areas to balance fluctuations in 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.

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. Limited transfer capability into the Pacific Northwest can also result in higher prices, as occurred on average in April. In the Northwest, this congestion typically increased prices in mid-day hours, preventing these areas from importing lower marginal cost system power.

Table 2.1 shows average monthly prices for the 15-minute market by area for 2022 through the first half of 2023. The combined average of WEIM prices outside of California was lower than California area prices by $1.68/MWh on average over the second quarter.

47 Total participants in the WEIM including the ISO is 22. PacifiCorp includes two balancing areas, PacifiCorp East and PacifiCorp West.

Table 2.1 Monthly 15-minute market prices

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023
SMEC	$51	$44	$42	$59	$59	$55	$69	$97	$125	$69	$90	$246	$140	$73	$73	$55	$19	$28
PG&E (CAISO)	$54	$48	$47	$63	$68	$82	$74	$103	$136	$73	$95	$257	$140	$75	$76	$57	$18	$29
SCE (CAISO)	$52	$43	$40	$55	$60	$69	$78	$108	$135	$64	$83	$246	$140	$68	$65	$48	$20	$27
BANC	$53	$48	$48	$65	$69	$68	$72	$106	$131	$75	$95	$252	$142	$75	$76	$58	$19	$30
Turlock ID	$54	$49	$48	$69	$76	$68	$72	$100	$136	$76	$95	$266	$142	$76	$77	$61	$19	$30
LADWP	$50	$42	$41	$55	$57	$63	$77	$108	$135	$67	$87	$256	$142	$73	$68	$49	$20	$27
NV Energy	$40	$38	$35	$49	$53	$55	$69	$93	$117	$58	$79	$243	$131	$66	$66	$50	$17	$23
Arizona PS	$39	$34	$31	$45	$52	$64	$72	$97	$118	$56	$80	$251	$130	$66	$64	$50	$17	$24
Tucson Electric					$54	$64	$72	$96	$111	$57	$76	$222	$129	$63	$60	$47	$21	$26
Salt River Project	$39	$34	$33	$47	$56	$67	$67	$88	$93	$56	$76	$157	$119	$52	$60	$50	$22	$24
PSC New Mexico	$37	$34	$30	$43	$47	$49	$67	$84	$102	$58	$64	$114	$127	$64	$64	$67	$17	$24
WAPA - Desert SW*																$57	$20	$24
El Paso Electric*																$33	$18	$23
PacifiCorp East	$37	$35	$32	$45	$43	$40	$65	$81	$99	$59	$72	$193	$120	$63	$67	$52	$18	$26
Idaho Power	$43	$41	$35	$57	$47	$32	$69	$82	$92	$63	$84	$237	$132	$71	$73	$59	$16	$27
NorthWestern	$41	$37	$34	$57	$41	$15	$42	$69	$73	$64	$87	$243	$133	$72	$75	$62	$13	$27
Avista Utilities			$35	$57	$41	$12	$36	$68	$72	$65	$86	$246	$133	$72	$74	$64	$12	$27
Avangrid*																$61	$7	$28
BPA					$46	$10	$46	$80	$91	$65	$86	$251	$133	$73	$73	$62	$5	$29
Tacoma Power			$30	$59	$44	$13	$39	$74	$80	$64	$85	$248	$134	$72	$73	$62	$6	$29
PacifiCorp West	$39	$35	$32	$59	$42	$13	$42	$76	$89	$64	$85	$244	$132	$71	$72	$61	$6	$28
Portland GE	$38	$35	$33	$59	$43	$16	$43	$77	$92	$65	$87	$244	$133	$71	$72	$62	$9	$29
Puget Sound Energy	$37	$34	$31	$60	$44	$13	$41	$74	$81	$64	$85	$249	$133	$73	$74	$62	$8	$29
Seattle City Light	$37	$34	$31	$60	$45	$12	$40	$74	$80	$64	$85	$249	$133	$75	$72	$61	$6	$28
Powerex	$36	$34	$32	$52	$46	$15	$37	$61	$69	$67	$82	$212	$129	$79	$84	$79	$14	$55

*Since joining the WEIM

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

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

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

Figure 2.1 Quarterly average 15-minute price by component (Q2 2023)

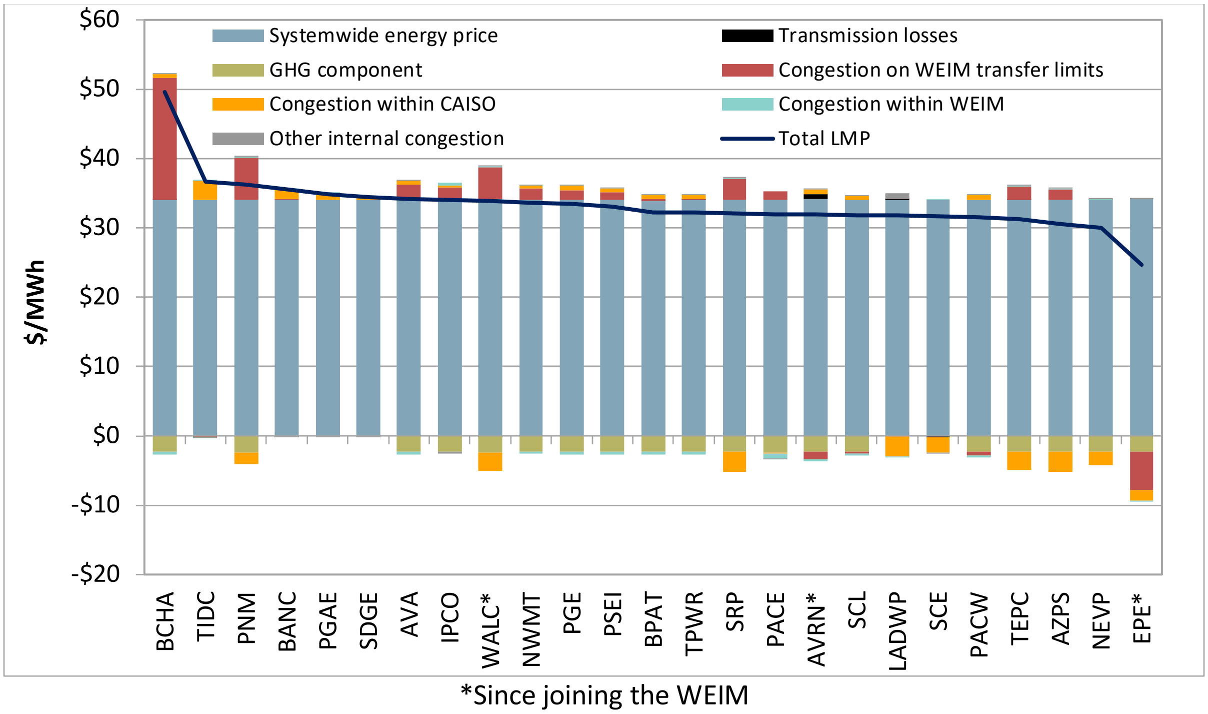


Figure 2.2 Quarterly average 5-minute price by component (Q2 2023)

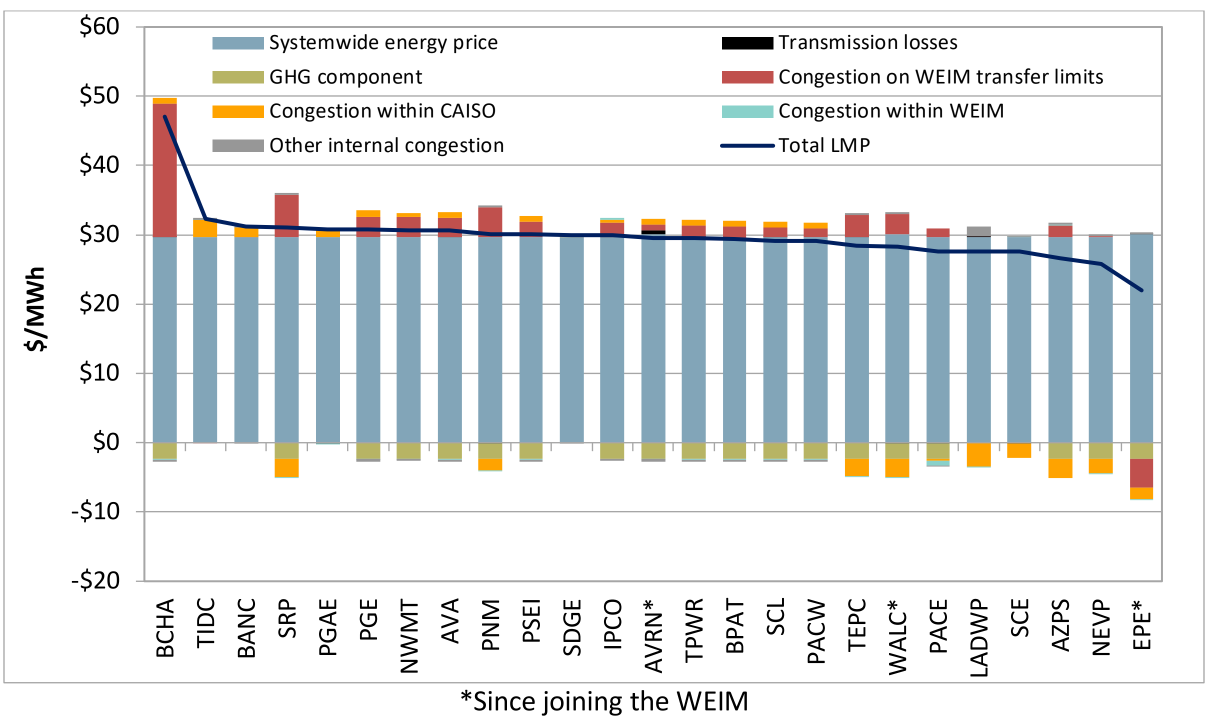


Table 2.2 Hourly 15-minute market prices (April-June)

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	$38	$35	$34	$34	$37	$44	$45	$32	$23	$18	$14	$12	$12	$11	$12	$16	$21	$31	$50	$77	$73	$58	$49	$41
PG&E (CAISO)	$37	$34	$33	$33	$35	$44	$45	$35	$28	$22	$17	$15	$13	$13	$14	$17	$22	$32	$50	$75	$72	$57	$48	$40
SCE (CAISO)	$39	$36	$35	$35	$38	$44	$44	$27	$12	$7	$5	$4	$3	$4	$6	$10	$15	$27	$52	$84	$78	$60	$50	$42
BANC	$36	$34	$33	$32	$35	$42	$44	$35	$29	$23	$19	$17	$16	$15	$15	$19	$24	$35	$51	$80	$73	$57	$48	$40
Turlock ID	$37	$34	$33	$33	$35	$42	$44	$36	$33	$27	$22	$19	$18	$18	$19	$22	$27	$36	$51	$74	$71	$57	$48	$40
LADWP	$39	$36	$35	$35	$38	$45	$45	$28	$14	$7	$5	$4	$3	$4	$6	$10	$16	$27	$52	$83	$78	$60	$49	$41
NV Energy	$36	$31	$30	$30	$34	$40	$38	$24	$16	$12	$9	$9	$8	$9	$10	$15	$19	$31	$47	$74	$67	$49	$42	$36
Arizona PS	$37	$32	$31	$31	$42	$56	$39	$27	$11	$6	$2	$1	$4	$4	$6	$10	$16	$26	$51	$78	$70	$51	$50	$50
Tucson Electric	$34	$32	$31	$30	$33	$40	$39	$24	$12	$9	$9	$9	$9	$12	$16	$20	$23	$32	$51	$77	$71	$51	$45	$37
Salt River Project	$32	$30	$27	$27	$31	$41	$42	$24	$20	$10	$10	$13	$12	$13	$17	$21	$21	$34	$57	$80	$74	$51	$46	$36
PSC New Mexico	$41	$58	$37	$38	$34	$60	$57	$43	$16	$10	$7	$3	$6	$7	$8	$13	$16	$31	$61	$83	$84	$52	$45	$54
WAPA - Desert SW*	$39	$39	$38	$34	$36	$44	$46	$27	$10	$10	$5	$8	$14	$15	$9	$13	$20	$31	$54	$78	$69	$54	$48	$42
El Paso Electric*	$25	$22	$22	$21	$23	$28	$21	$15	$12	$12	$13	$13	$15	$16	$17	$19	$20	$27	$44	$63	$45	$31	$32	$26
PacifiCorp East	$35	$31	$30	$30	$33	$41	$39	$29	$23	$19	$15	$14	$15	$15	$15	$18	$21	$30	$47	$71	$65	$49	$43	$37
Idaho Power	$34	$31	$29	$29	$33	$42	$41	$33	$27	$23	$20	$19	$20	$19	$21	$21	$25	$33	$50	$71	$64	$48	$43	$36
NorthWestern	$32	$29	$27	$27	$31	$38	$38	$34	$29	$25	$24	$23	$25	$23	$23	$22	$26	$30	$44	$65	$62	$46	$43	$34
Avista Utilities	$33	$29	$28	$27	$31	$43	$37	$33	$30	$27	$25	$24	$26	$24	$24	$24	$27	$33	$43	$60	$59	$46	$45	$35
Avangrid*	$29	$26	$25	$25	$29	$35	$32	$27	$24	$25	$23	$23	$25	$24	$23	$24	$28	$34	$40	$51	$49	$40	$38	$31
BPA	$31	$27	$26	$22	$29	$39	$34	$30	$27	$27	$27	$24	$28	$31	$25	$28	$29	$35	$43	$49	$48	$37	$38	$31
Tacoma Power	$32	$27	$26	$27	$30	$36	$34	$29	$27	$27	$26	$25	$28	$26	$25	$26	$29	$34	$40	$50	$49	$41	$39	$32
PacifiCorp West	$31	$28	$27	$26	$29	$35	$32	$28	$26	$26	$25	$25	$26	$25	$24	$25	$28	$33	$39	$49	$49	$40	$41	$32
Portland GE	$33	$28	$27	$26	$29	$35	$34	$29	$26	$27	$25	$25	$27	$26	$25	$31	$30	$42	$46	$57	$56	$43	$39	$32
Puget Sound Energy	$32	$27	$26	$26	$30	$35	$34	$31	$27	$27	$30	$25	$27	$34	$25	$29	$29	$36	$43	$53	$50	$43	$39	$32
Seattle City Light	$32	$28	$27	$26	$28	$35	$33	$28	$27	$27	$26	$25	$27	$26	$25	$26	$29	$34	$40	$50	$49	$41	$38	$31
Powerex	$39	$36	$34	$37	$38	$42	$45	$49	$50	$51	$52	$49	$49	$50	$51	$54	$58	$60	$59	$64	$63	$56	$52	$41

*Since joining the WEIM

Table 2.3 Hourly 5-minute market prices (April-June)

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	$39	$35	$34	$34	$36	$43	$43	$26	$18	$16	$11	$9	$8	$7	$7	$10	$12	$22	$43	$61	$56	$52	$51	$40
PG&E (CAISO)	$39	$35	$33	$33	$36	$43	$44	$29	$22	$20	$15	$12	$10	$10	$9	$11	$13	$23	$42	$64	$55	$53	$51	$40
SCE (CAISO)	$39	$36	$34	$34	$37	$43	$43	$23	$10	$6	$3	$2	$1	$1	$2	$5	$8	$19	$45	$67	$59	$54	$53	$42
BANC	$38	$34	$33	$32	$35	$42	$43	$28	$22	$21	$16	$14	$12	$11	$10	$13	$15	$25	$43	$66	$55	$52	$51	$39
Turlock ID	$39	$35	$33	$33	$35	$42	$43	$29	$26	$25	$19	$16	$15	$14	$13	$15	$17	$26	$42	$64	$54	$52	$51	$39
LADWP	$39	$35	$35	$34	$37	$43	$43	$24	$11	$6	$3	$2	$1	$1	$2	$5	$8	$20	$45	$65	$59	$54	$52	$41
NV Energy	$33	$30	$30	$29	$33	$39	$35	$18	$11	$10	$7	$6	$5	$5	$4	$8	$10	$23	$42	$60	$51	$44	$49	$38
Arizona PS	$36	$31	$30	$30	$38	$51	$37	$22	$8	$2	$0	-$1	$0	$1	$5	$7	$7	$18	$45	$63	$60	$54	$47	$48
Tucson Electric	$36	$31	$30	$30	$34	$39	$37	$20	$9	$7	$6	$6	$7	$10	$17	$23	$17	$34	$43	$63	$53	$46	$47	$37
Salt River Project	$34	$29	$29	$26	$30	$38	$38	$17	$13	$7	$9	$32	$36	$15	$21	$20	$28	$25	$56	$69	$55	$45	$45	$34
PSC New Mexico	$41	$40	$35	$37	$34	$40	$40	$25	$11	$8	$4	$2	$3	$3	$3	$7	$13	$32	$56	$75	$62	$50	$53	$51
WAPA - Desert SW*	$37	$34	$32	$30	$34	$43	$47	$17	$6	$9	$1	$3	$9	$9	$6	$10	$11	$22	$42	$66	$55	$48	$53	$39
El Paso Electric*	$24	$22	$21	$20	$23	$28	$21	$13	$10	$10	$11	$13	$14	$15	$16	$16	$17	$22	$38	$51	$38	$27	$29	$25
PacifiCorp East	$34	$31	$29	$29	$33	$38	$37	$23	$17	$15	$12	$11	$11	$10	$10	$11	$13	$22	$42	$58	$49	$44	$46	$37
Idaho Power	$33	$30	$29	$29	$33	$41	$38	$26	$21	$20	$18	$16	$16	$14	$15	$14	$17	$26	$45	$61	$53	$45	$46	$35
NorthWestern	$35	$29	$28	$30	$31	$40	$36	$27	$23	$23	$21	$20	$20	$19	$17	$17	$19	$25	$41	$60	$51	$44	$45	$34
Avista Utilities	$33	$28	$28	$28	$31	$42	$36	$27	$26	$24	$22	$21	$22	$20	$19	$19	$21	$26	$39	$50	$47	$44	$47	$34
Avangrid*	$28	$26	$25	$26	$29	$35	$33	$24	$23	$23	$22	$20	$21	$19	$19	$19	$21	$27	$38	$48	$44	$39	$41	$31
BPA	$30	$31	$27	$25	$29	$33	$34	$27	$25	$25	$27	$22	$22	$24	$21	$20	$22	$27	$40	$45	$42	$36	$40	$33
Tacoma Power	$31	$27	$26	$27	$30	$35	$33	$27	$24	$25	$24	$23	$23	$22	$21	$21	$22	$27	$38	$47	$43	$39	$38	$32
PacifiCorp West	$30	$27	$27	$27	$30	$35	$33	$26	$24	$24	$23	$22	$22	$20	$20	$20	$21	$26	$38	$47	$43	$39	$40	$31
Portland GE	$31	$27	$27	$27	$30	$35	$34	$26	$24	$25	$24	$22	$22	$21	$20	$23	$22	$34	$49	$60	$45	$41	$41	$31
Puget Sound Energy	$31	$27	$26	$27	$30	$35	$33	$27	$24	$25	$24	$22	$22	$32	$21	$21	$23	$28	$40	$48	$44	$40	$39	$31
Seattle City Light	$31	$27	$27	$27	$27	$35	$33	$26	$24	$25	$24	$22	$22	$22	$21	$21	$22	$27	$37	$47	$43	$40	$38	$30
Powerex	$38	$33	$33	$36	$37	$42	$44	$45	$49	$50	$52	$48	$48	$50	$51	$51	$52	$52	$56	$62	$59	$54	$49	$39

*Since joining the WEIM

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.[48] 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.[49] 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 average dynamic 15-minute market exports out of each area during mid-day hours (between hours 10 and 17) during the quarter.[50] The ISO exported on average over 2,800 MW during these mid-day hours, out to neighboring areas. The mid-day typically contains the highest levels of exports out of the ISO 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 ISO are often highest. The figure shows an average of over 700 MW of exports from LADWP, PacifiCorp West, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, Tucson Electric Power, and WAPA Desert Southwest going into the ISO during these hours (CAISO import).

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

49 In Figure 2.3, each small tick is 100 MW, each large tick is 500 MW, and average WEIM transfer paths less than 50 MW are excluded. In Figure 2.4, each small tick is 50 MW, each large tick is 250 MW, and average WEIM transfer paths less than 25 MW are excluded.

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

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

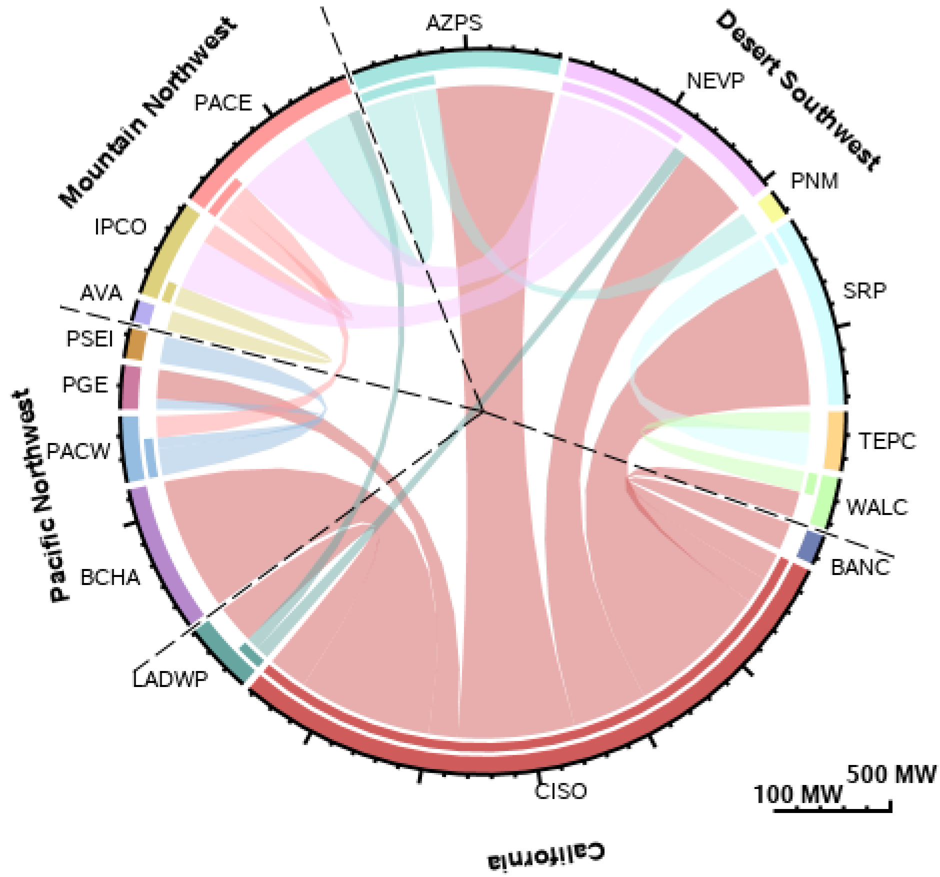
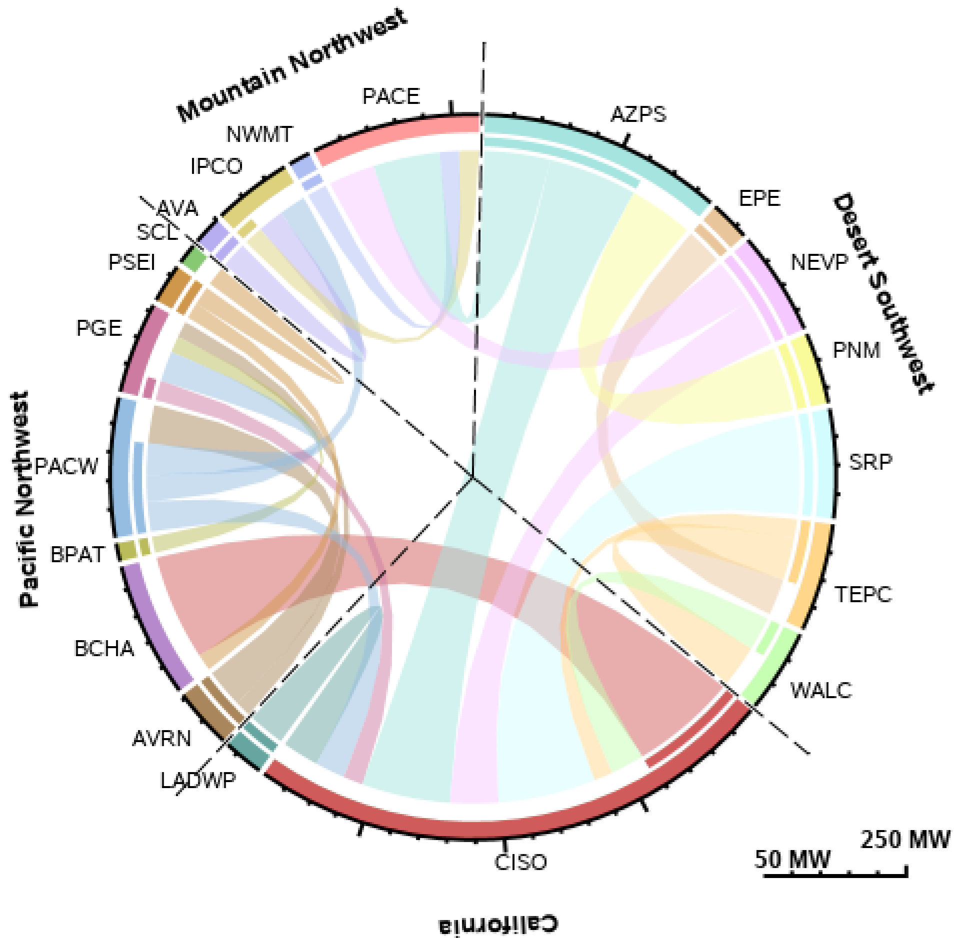


Figure 2.4 Average 15-minute market WEIM exports (peak load hours, April-June 2023)



Transfer limits

WEIM transfers between areas are constrained by transfer limits. These limits largely reflect transmission and interchange rights made available to the market by participating WEIM entities. Table 2.4 shows average 15-minute market import and export limits for each balancing area. 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.

On April 5, 2023, Avangrid, El Paso Electric, and Western Area Power Administration (WAPA) - Desert Southwest joined the Western Energy Imbalance Market. WAPA Desert Southwest added significant import and export capacity at around 6,400 MW (average for the second quarter). Avangrid joined with around 700 MW on average in dynamic export capacity to neighboring areas in the Pacific Northwest. Dynamic import and export transfer capacity for El Paso Electric during the quarter was low, at around 440 MW.

The balancing areas in Table 2.4 are grouped in one of four regions: California, Desert Southwest, Mountain Northwest, and Pacific Northwest. These regions reflect a combination of general geographic location as well as common price-separated groupings that can exist when a balancing area is collectively import or export constrained along with one or more other balancing areas relative to the greater WEIM system. The last two columns in Table 2.4 shows WEIM transfer limits between these regions (out-of-region import and export limits).

Import and export transfer capacity into or out of the Desert Southwest region was around 33,590 MW and 28,250 MW, respectively. For the Pacific Northwest region, there was an average of around 1,450 MW of import and 620 MW of export transfer capacity into or out of the region. The lack of transfer capability out of the Pacific Northwest leads to price separation between the region and the rest of the WEIM.

Table 2.4 Average 15-minute market WEIM limits (April-June)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**26,792**	**32,684**
California ISO	34,764	35,930	23,595	28,250
BANC	3,528	3,449	0	0
LADWP	7,257	11,936	3,197	4,434
Turlock Irrig. District	1,393	1,518	0	0
Desert Southwest			**33,589**	**28,253**
Arizona Public Service	36,249	28,335	25,495	19,339
El Paso Electric*	463	415	0	0
NV Energy	4,903	4,818	3,470	3,156
PSC New Mexico	1,001	1,213	0	0
Salt River Project	8,419	9,879	1,775	2,610
Tucson Electric	4,498	5,666	732	874
WAPA - Desert SW*	6,434	6,305	2,116	2,274
Mountain Northwest			**2,366**	**2,637**
Avista Utilities	679	967	106	87
Idaho Power	2,443	2,768	691	709
NorthWestern Energy	736	696	25	8
PacifiCorp East	3,307	3,006	1,544	1,833
Pacific Northwest			**1,446**	**618**
Avangrid*	679	703	0	0
Powerex	610	50	560	0
BPA	683	915	136	148
PacifiCorp West	1,535	1,348	484	300
Portland General Electric	726	675	137	85
Puget Sound Energy	1,230	1,065	98	56
Seattle City Light	431	420	30	30
Tacoma Power	338	227	0	0

*Since joining the WEIM

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.[51] Areas located in the Pacific Northwest continued to experience congestion into or out of the region during a high number of intervals. El Paso Electric Company also saw a high frequency of transfer congestion, occurring in 44 percent of 15-minute and 5-minute market intervals.

Table 2.5 shows the frequency and price impact of 15-minute and 5-minute transfer constraint congestion in each WEIM area. The frequency is calculated as the number of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices.[52] When prices are lower relative to the system, this indicates congestion out of an area (or region) and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for outside energy to serve that area's load.

Congestion in either direction for BANC, Los Angeles Department of Water and Power, Turlock Irrigation District, NV Energy, Arizona Public Service, 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.

[51] 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.

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

Table 2.5 Frequency and impact of transfer congestion in the WEIM (April-June)

	15-minute market				5-minute market			
	Congested from area		Congested into area		Congested from area		Congested into area	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.1%	$0.06
L.A. Dept. of Water and Power	0.1%	-$0.02	0.0%	$0.04	0.2%	-$0.05	0.1%	$0.13
Turlock Irrigation District	0.5%	-$0.17	0.0%	$0.00	0.4%	-$0.08	0.0%	$0.01
NV Energy	0.3%	-$0.28	0.1%	$0.35	0.3%	-$0.38	0.2%	$0.53
Arizona Public Service	0.5%	-$0.44	0.2%	$1.76	0.5%	-$0.57	0.4%	$2.34
Public Service Company of NM	1.1%	-$1.08	1.3%	$7.22	0.8%	-$0.74	1.2%	$5.07
PacifiCorp East	0.1%	-$0.01	10%	$1.26	0.0%	$0.00	7.1%	$1.29
WAPA – Desert Southwest*	3.6%	-$1.56	7.7%	$6.10	4.9%	-$2.10	6.4%	$4.86
Tucson Electric Power	2.5%	-$0.34	11%	$2.36	1.9%	-$0.17	13%	$3.48
Idaho Power	6.1%	-$1.10	11%	$2.86	4.7%	-$0.81	9.1%	$2.97
NorthWestern Energy	8.2%	-$1.69	13%	$3.36	6.4%	-$1.19	12%	$4.08
Salt River Project	6.9%	-$1.63	13%	$4.76	7.9%	-$1.99	12%	$8.12
Avista Utilities	8.1%	-$1.59	14%	$3.82	6.4%	-$1.24	13%	$4.05
Avangrid Renewables*	23%	-$4.66	16%	$3.28	17%	-$3.14	13%	$3.39
PacifiCorp West	23%	-$4.40	17%	$3.83	16%	-$2.73	14%	$3.84
Portland General Electric	22%	-$4.32	18%	$5.71	16%	-$2.68	15%	$5.57
Seattle City Light	23%	-$4.64	22%	$4.39	18%	-$3.31	20%	$4.56
Puget Sound Energy	23%	-$4.43	22%	$5.45	18%	-$3.17	20%	$5.16
Tacoma Power	23%	-$4.44	22%	$4.47	18%	-$3.12	20%	$4.64
Bonneville Power Admin.	23%	-$5.73	23%	$5.87	18%	-$4.00	21%	$5.50
El Paso Electric Company*	27%	-$7.07	17%	$2.14	24%	-$6.49	20%	$2.88
Powerex	16%	-$3.10	50%	$20.50	20%	-$3.28	58%	$22.31

*Since joining the WEIM

2.3 Resource sufficiency evaluation

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

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

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[53] Similarly, if an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

53 If an area fails either test in the upward direction, net WEIM imports during the hour cannot exceed the greater of either the base transfer or the optimal transfer from the last 15-minute interval prior to the hour.

Figure 2.5 and Figure 2.6 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.7 and Figure 2.8 provide the same information for the downward direction.[54] The dash indicates the area did not fail the test during the month.

In the second quarter of 2023:

- The Public Service Company of New Mexico (PNM) failed the upward flexibility test in 2.2 percent of intervals and downward flexibility test in 1.2 percent of intervals.
- Bonneville Power Administration (BPA) failed the downward flexibility test in 2 percent of intervals.
- In the first three months of WEIM participation, WAPA Desert Southwest failed the upward flexibility and capacity test in around 1.3 percent of intervals. The balancing area also failed the downward flexibility test in 1.3 percent of intervals.

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

	2022									2023					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	0.0	—	—	—	—	—	—	—	0.1	0.4	0.5	0.7	0.2	0.0	0.1
Avangrid													0.0	—	—
Avista	0.0	—	0.2	0.2	0.0	—	—	—	0.1	—	—	—	0.1	0.0	—
BANC	—	—	—	—	0.0	0.3	—	—	—	—	—	—	—	—	—
BPA		—	0.1	—	0.0	0.5	—	—	0.4	—	—	—	0.2	—	0.3
California ISO	—	—	—	—	—	0.1	—	—	—	—	—	—	—	—	—
El Paso Electric													0.0	0.1	0.3
Idaho Power	—	—	—	—	0.2	0.2	—	—	—	—	—	—	0.0	0.1	—
LADWP	—	—	—	0.0	—	—	—	—	—	0.1	—	—	—	—	—
NorthWestern En.	0.0	—	—	—	0.1	0.1	—	0.2	0.1	0.3	0.1	—	—	—	—
NV Energy	0.2	0.1	0.0	0.1	—	—	—	—	—	—	—	—	—	0.0	—
PacifiCorp East	—	—	—	—	—	0.1	—	—	0.3	—	—	—	—	—	—
PacifiCorp West	0.0	0.2	0.0	1.0	0.2	0.0	—	0.0	0.0	0.1	0.1	—	—	—	—
Portland Gen. Elec.	—	—	—	—	0.1	—	—	0.3	—	—	0.0	0.0	0.1	0.4	0.1
Powerex	0.1	—	—	—	0.2	—	—	0.0	—	—	—	—	—	0.1	—
PSC of New Mexico	—	—	—	—	—	—	—	—	—	—	—	0.7	0.3	0.2	0.0
Puget Sound En.	0.0	0.0	0.2	—	—	0.2	0.1	0.0	—	—	0.0	0.2	—	0.1	0.5
Salt River Proj.	1.5	1.0	0.2	0.2	0.4	0.4	0.2	0.0	0.0	1.0	0.4	1.1	0.9	0.2	0.0
Seattle City Light	—	—	—	0.2	0.1	0.2	0.0	0.0	0.2	0.0	0.1	—	—	—	—
Tacoma Power	0.6	0.1	0.0	0.0	0.2	0.0	—	—	—	0.0	0.1	0.1	—	0.1	—
Tucson Elec. Pow.		—	—	—	0.1	—	—	—	—	0.1	0.0	—	—	—	—
Turlock Irrig. Dist.	—	—	0.1	—	—	—	—	—	0.2	—	—	—	0.0	—	—
WAPA DSW													2.3	0.8	0.7

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

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

	2022									2023					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona Publ. Serv.	—	—	—	0.0	0.1	—	—	0.1	0.4	0.9	1.8	2.5	1.1	0.2	0.1
Avangrid													1.0	0.7	0.1
Avista	0.2	0.5	1.0	0.5	0.1	—	0.1	—	0.1	—	0.0	0.0	0.2	0.2	0.0
BANC	—	—	—	—	—	0.3	—	—	—	—	—	—	—	0.1	—
BPA		0.9	3.1	3.3	1.0	1.1	0.2	0.1	0.4	—	0.1	0.6	0.2	1.2	0.3
California ISO	—	—	—	—	0.1	0.5	0.0	—	—	—	—	—	—	—	—
El Paso Electric													0.8	0.7	0.3
Idaho Power	—	—	—	0.2	0.2	0.5	—	0.1	—	0.0	0.1	0.3	0.3	0.5	0.1
LADWP	—	—	—	—	—	0.1	0.1	—	—	—	0.3	—	0.1	0.0	0.1
NorthWestern En.	0.3	—	0.1	0.3	1.0	0.2	—	0.5	0.8	0.3	0.1	0.2	0.8	0.3	0.2
NV Energy	1.0	0.8	0.2	—	0.1	0.1	0.1	0.2	0.0	0.1	0.3	0.0	0.1	0.1	0.0
PacifiCorp East	0.1	0.1	0.1	0.2	0.1	—	0.1	—	0.0	0.1	—	0.0	0.1	—	0.0
PacifiCorp West	0.2	0.1	0.0	—	0.1	0.1	—	0.1	—	0.1	0.1	—	0.1	0.6	0.0
Portland Gen. Elec.	—	—	0.0	0.4	0.1	0.1	0.2	1.0	0.1	0.0	0.1	0.0	0.1	1.5	0.7
Powerex	0.1	—	—	—	0.3	0.1	—	—	—	—	0.2	—	—	—	—
PSC of New Mexico	0.0	0.1	—	0.4	—	0.0	0.2	0.1	0.8	0.2	—	1.2	5.1	0.9	0.6
Puget Sound En.	0.1	—	0.1	0.4	0.2	0.3	—	0.0	—	—	0.1	0.8	0.2	1.0	0.6
Salt River Proj.	0.5	0.2	0.5	0.6	1.1	0.6	0.6	0.5	0.8	3.5	1.2	1.7	2.0	0.6	0.2
Seattle City Light	—	—	—	0.2	0.0	0.2	—	0.1	0.0	—	0.1	—	—	—	—
Tacoma Power	—	0.1	0.1	0.0	0.1	0.1	—	0.2	—	0.2	0.1	0.2	—	0.1	—
Tucson Elec. Pow.		0.1	—	—	—	0.4	0.0	—	0.2	0.3	0.3	0.3	0.1	0.1	—
Turlock Irrig. Dist.	—	—	—	—	—	0.1	—	—	1.2	—	—	—	0.0	—	—
WAPA DSW													2.7	0.7	0.8

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

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

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

	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023
Arizona Publ. Serv.	0.3	0.5	0.2	—	—	0.1	0.2	0.2	0.1	0.9	0.5	2.1	0.7	1.2	0.1
Avangrid													0.1	—	—
Avista	—	—	0.1	—	—	0.1	0.2	—	0.0	—	—	0.1	0.1	0.1	—
BANC	0.0	0.1	0.1	—	—	—	—	—	—	—	—	—	—	—	—
BPA		0.1	0.2	—	0.0	0.3	—	0.2	0.2	—	0.0	0.1	0.6	5.5	0.0
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric													0.2	0.9	1.9
Idaho Power	0.3	0.4	—	—	0.0	—	—	—	—	—	—	0.9	0.2	—	—
LADWP	—	—	—	—	—	—	—	—	—	0.1	—	—	—	—	—
NorthWestern En.	—	0.5	1.9	0.2	—	—	—	0.0	0.1	—	0.0	—	—	0.2	0.2
NV Energy	3.2	1.3	2.0	0.6	0.2	0.5	0.5	0.6	0.1	0.1	0.1	0.1	0.0	0.1	0.4
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	0.0	0.1	0.4	0.5	—	—	0.1	—	0.0	—	—	—	0.0	0.2	0.0
Portland Gen. Elec.	—	—	0.2	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.0	0.3	0.2	—	0.1	0.1	0.1	—	—	0.1	0.1	—	0.2	—	—
PSC of New Mexico	0.3	1.8	0.7	0.0	0.0	0.2	0.2	0.1	—	0.0	—	0.4	1.6	2.1	—
Puget Sound En.	—	0.2	2.3	0.1	—	—	0.1	—	—	—	—	—	—	0.8	—
Salt River Proj.	0.2	0.4	0.5	0.2	0.2	1.0	0.2	0.9	0.3	1.4	3.3	1.0	0.3	0.1	0.1
Seattle City Light	0.1	0.1	0.3	0.1	0.8	0.3	—	0.2	0.6	0.1	0.2	0.0	0.3	0.0	0.3
Tacoma Power	0.4	0.3	—	0.5	0.2	—	—	—	0.1	—	0.2	0.1	—	—	—
Tucson Elec. Pow.		—	—	—	—	—	—	0.0	—	—	—	—	—	—	—
Turlock Irrig. Dist.	0.6	0.1	0.5	0.1	0.1	—	—	0.1	—	0.1	0.1	0.1	0.1	0.4	—
WAPA DSW													2.7	0.5	0.7

Resource sufficiency evaluation monthly reports

DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic.[55] 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 the ISO for the 15-minute and 5-minute markets during the quarter. About a third of the balancing areas infrequently used positive imbalance conformance, e.g. PacifiCorp East, Arizona Public Service, Public Service Company of New Mexico, Idaho Power, Tacoma Power, Portland General Electric, and Avangrid Renewables. Negative imbalance conformance was infrequently used by about half of all the balancing areas.

55 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 (April-June)

		Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
Balancing area	Market	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO	FMM	27.4%	1,252	5.2%	0.5%	-525	2.4%	341
	RTD	30.0%	317	1.4%	39.8%	-327	1.6%	-35
Avangrid Renewables*	FMM	0.0%	N/A	N/A	0.0%	-30	N/A	0
	RTD	37.9%	42	N/A	17.3%	-39	N/A	9
BANC	FMM	0.1%	34	1.6%	0.5%	-72	4.5%	0
	RTD	0.6%	41	2.0%	0.9%	-70	4.4%	0
Turlock Irrigation District	FMM	0.0%	23	5.3%	0.0%	N/A	N/A	0
	RTD	0.1%	20	6.3%	0.0%	-34	10.2%	0
LADWP	FMM	0.5%	55	2.3%	3.0%	-219	9.3%	-6
	RTD	15.0%	44	2.0%	22.2%	-75	3.3%	-10
NV Energy	FMM	1.0%	102	2.1%	0.0%	N/A	N/A	1
	RTD	36.8%	103	2.4%	15.2%	-109	2.7%	22
Arizona Public Service	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	38.1%	65	1.7%	36.2%	-70	2.2%	0
Tucson Electric Power	FMM	0.0%	80	6.1%	0.0%	-50	2.9%	0
	RTD	10.9%	48	3.7%	18.9%	-48	4.2%	-4
WAPA - Desert Southwest	FMM	5.8%	27	3.9%	0.1%	-25	3.4%	2
	RTD	53.3%	26	3.5%	4.5%	-23	3.4%	13
El Paso Electric	FMM	10.5%	15	1.2%	10.4%	-15	1.4%	0
	RTD	12.9%	18	1.4%	18.7%	-19	1.8%	-1
Salt River Project	FMM	22.9%	84	2.1%	0.5%	-49	1.7%	19
	RTD	52.7%	82	2.1%	0.9%	-71	2.3%	43
Public Service Co. of New Mexico	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	33.1%	75	5.4%	21.1%	-114	8.7%	1
PacifiCorp East	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	12.5%	110	2.1%	47.8%	-117	2.3%	-42
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	12.7%	60	2.9%	23.3%	-59	3.1%	-6
NorthWestern Energy	FMM	19.0%	14	1.1%	8.5%	-12	1.0%	2
	RTD	42.1%	15	1.3%	16.6%	-14	1.1%	4
Avista Utilities	FMM	0.2%	32	2.5%	1.8%	-32	2.8%	-1
	RTD	3.6%	19	1.7%	33.7%	-21	1.9%	-6
Bonneville Power Administration	FMM	40.8%	28	0.5%	58.4%	-33	0.6%	-8
	RTD	40.9%	28	0.5%	58.2%	-33	0.6%	-8
Tacoma Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	3.4%	18	3.9%	6.4%	-16	4.0%	0
PacifiCorp West	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	7.7%	41	1.8%	21.9%	-47	2.2%	-7
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	10.0%	45	1.8%	2.1%	-49	2.2%	3
Puget Sound Energy	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	7.1%	47	2.0%	45.1%	-37	1.5%	-14
Seattle City Light	FMM	0.8%	21	2.1%	7.2%	-17	1.7%	-1
	RTD	6.7%	17	1.8%	55.7%	-22	2.2%	-11

*Avangrid Renewables is a generation-only entity and therefore load conformance cannot be measured as a percent of load

APPENDIX

Appendix A | Western Energy Imbalance Market Area specific metrics

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

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

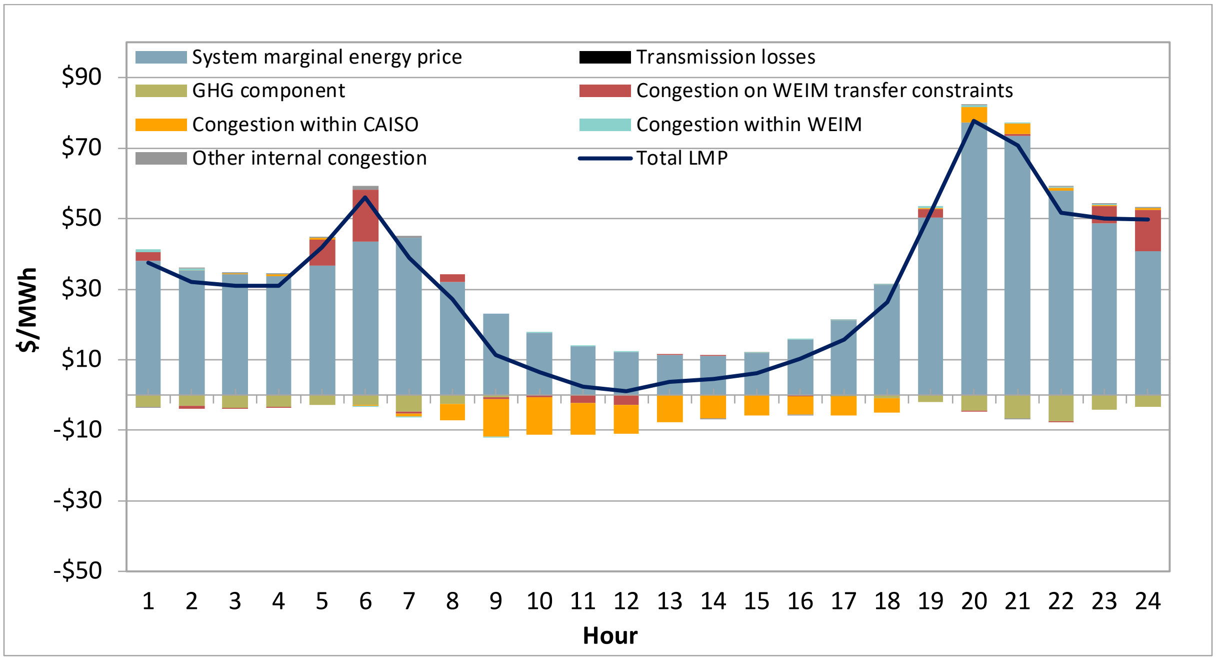
The hourly locational marginal price decomposition figures break down the price into seven separate components. These components, listed below, can influence the prices in an area positively or negatively depending on the circumstances.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for electricity in the WEIM footprint. Therefore, the SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **Congestion within the ISO** is the price impact from transmission constraints within the ISO area that are restricting the flow of energy. While these constraints are located within the ISO balancing area, they can create price impacts across the WEIM.
- **Congestion within WEIM** is the price impact from transmission constraints within a WEIM area that are restricting the flow of energy. While these constraints are located within a single balancing area, they can create price impacts across the WEIM.
- **Other Internal Congestion** is the price impact from internal transmission constraints that are restricting the flow of energy within an area. These are internal congestion impacts that are not captured within the ISO and WEIM congestion categories.
- **Congestion on WEIM transfer constraints** is the price impact from intertie transmission constraints that link two balancing areas together. Price impacts from failed resource sufficiency evaluation (RSE) tests are included in this category as failed tests limit transfer capabilities.
- **Greenhouse gas price** is the price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.

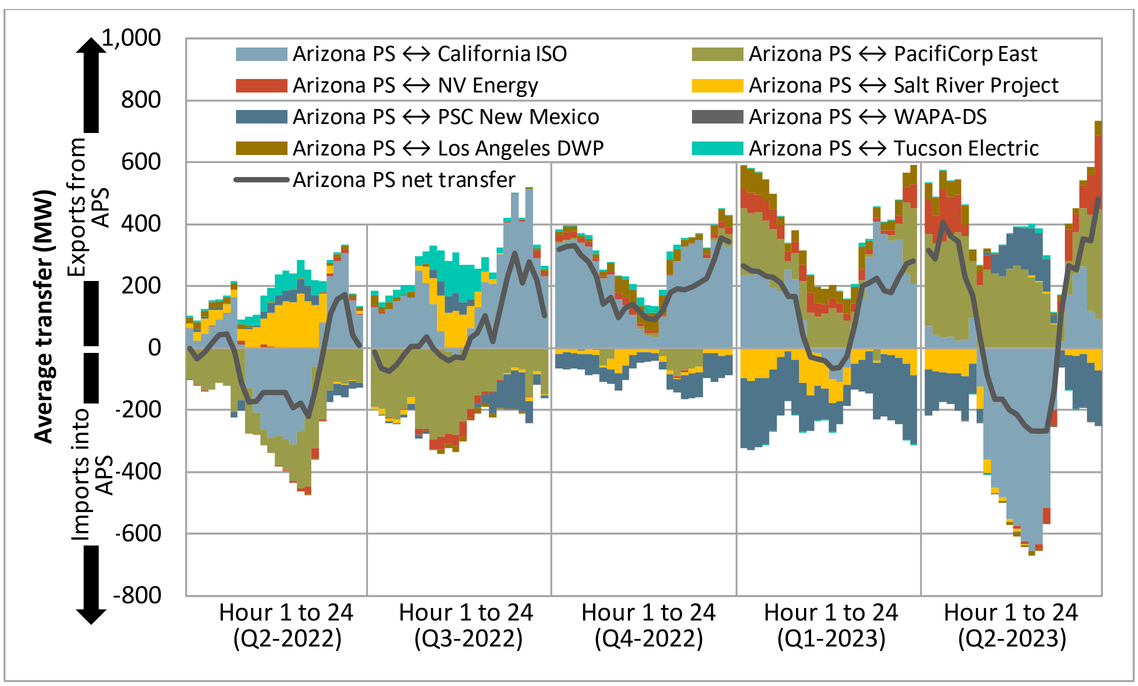
The transfer figures below show the hourly average imports and exports by WEIM area in the 15-minute and 5-minute markets by quarter. These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will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

A.1 Arizona Public Service

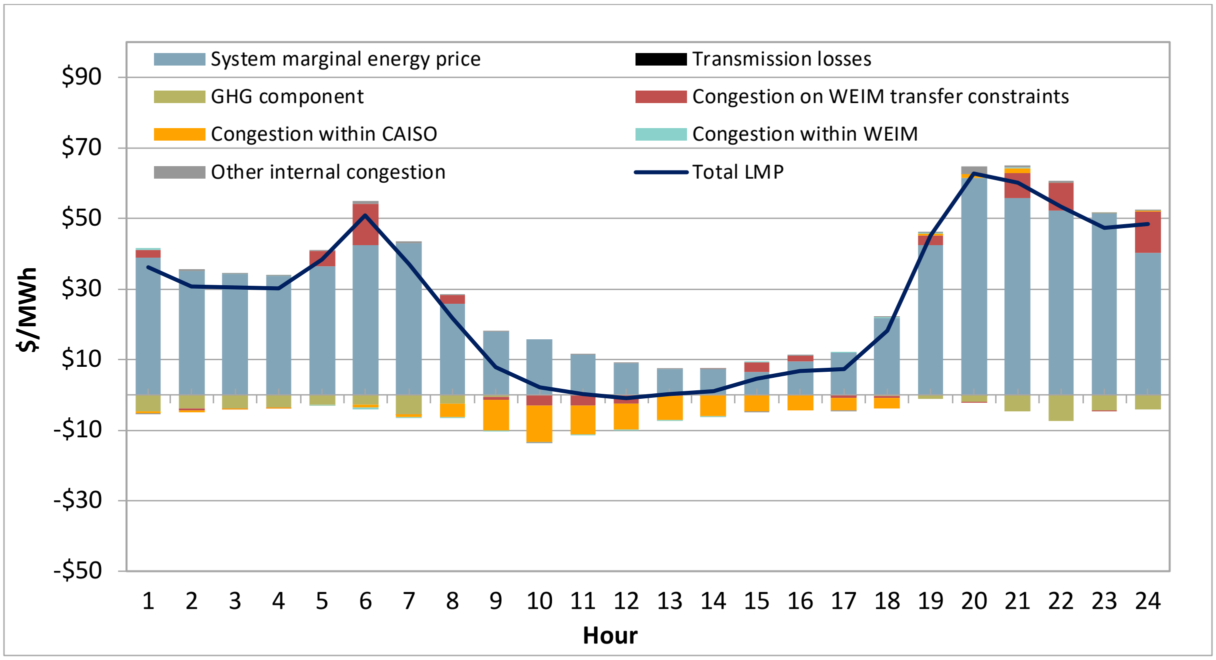
Appendix Figure A.1 Average hourly 15-minute price by component (Q2 2023)



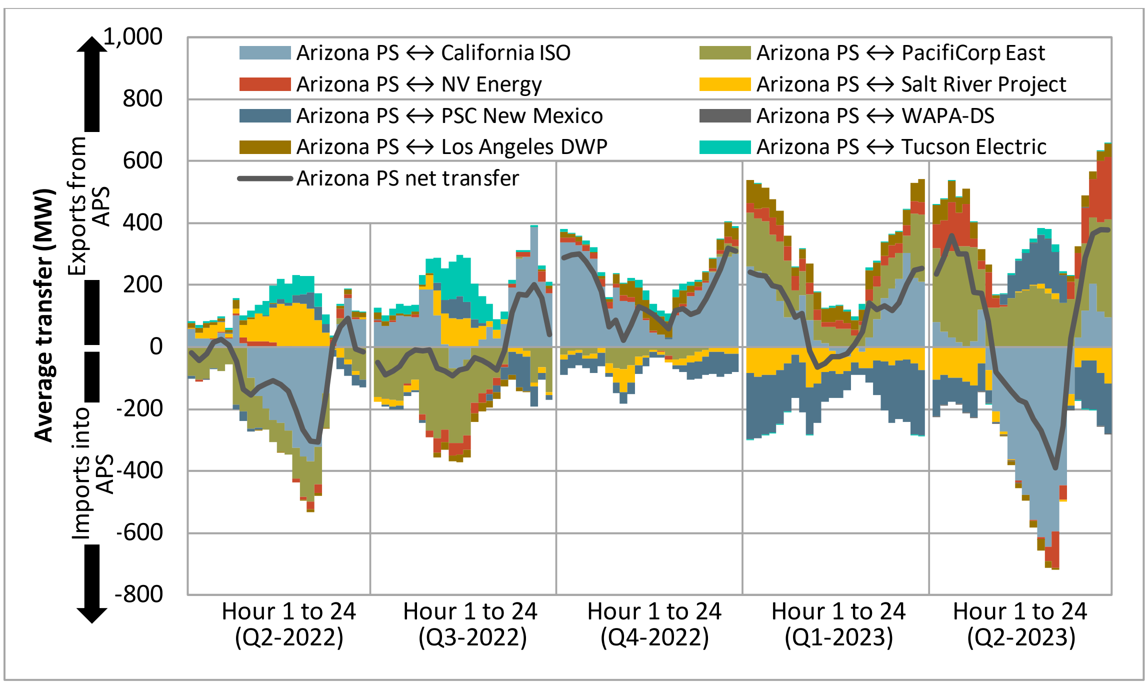
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q2 2023)

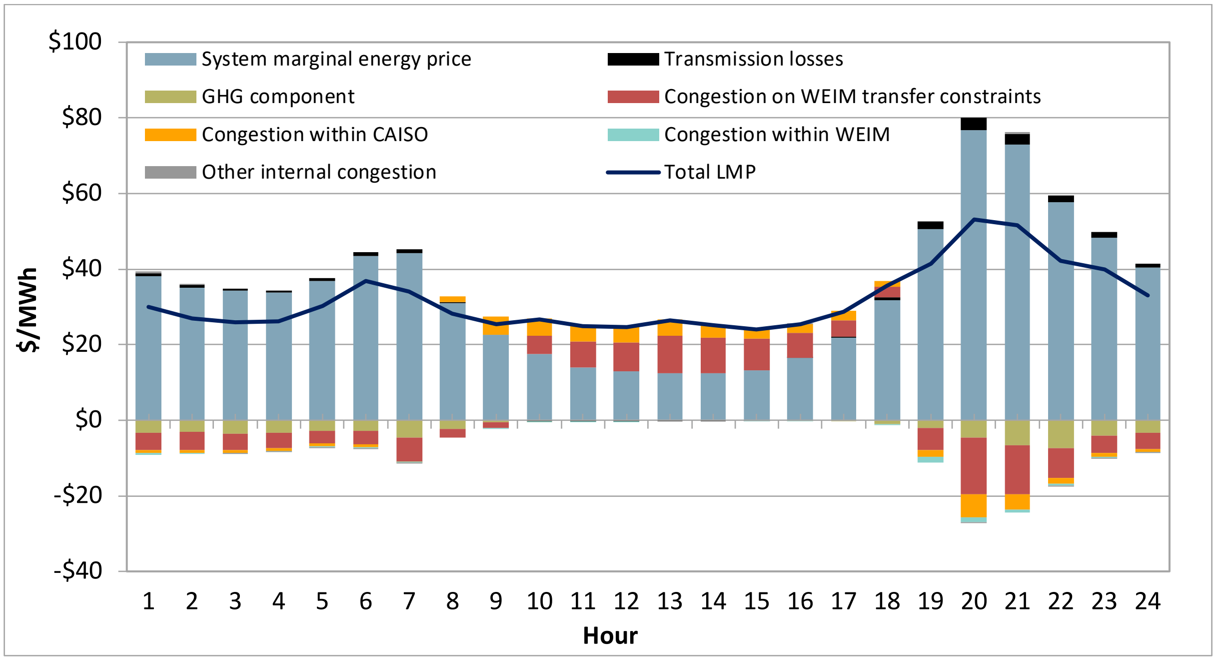


Appendix Figure A.4 Average hourly 5-minute market transfers



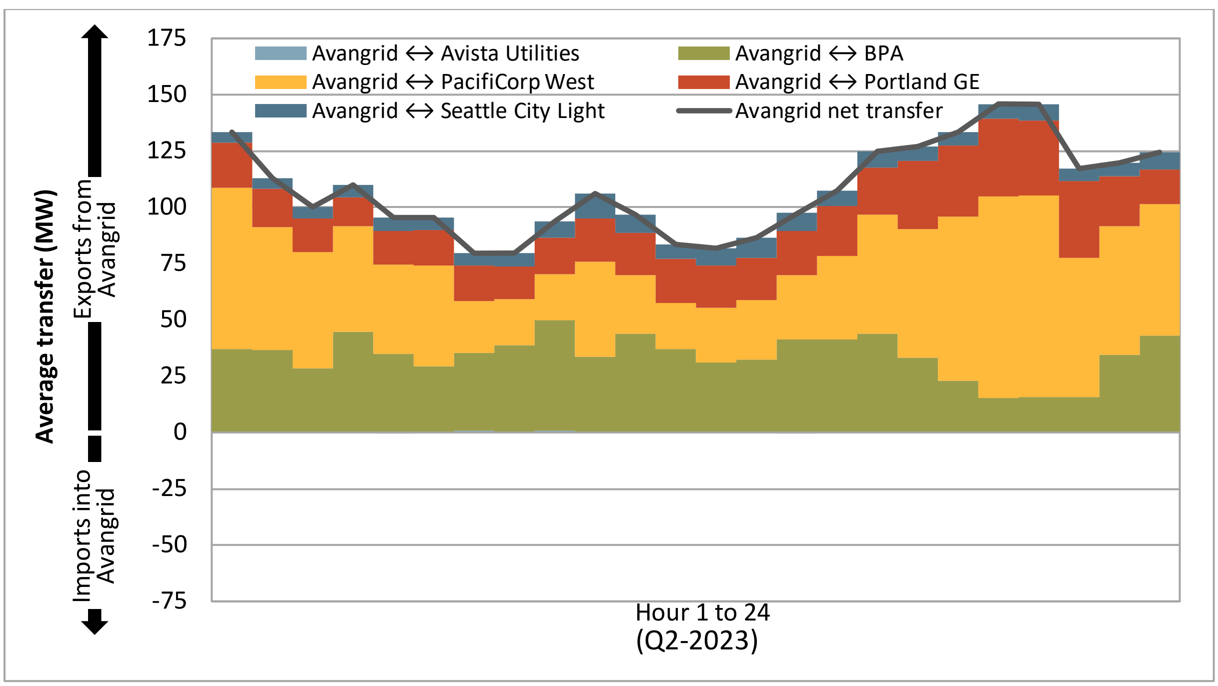
A.2 Avangrid

Appendix Figure A.5 Average hourly 15-minute price by component (Q2 2023)



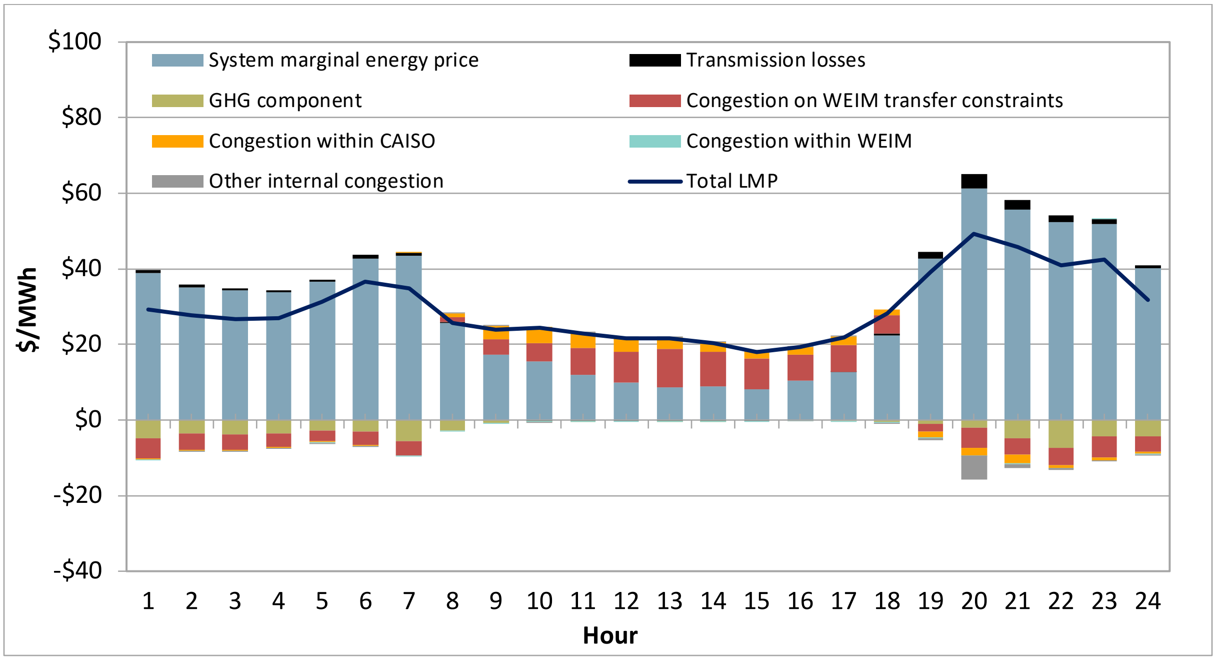
*Since joining the WEIM

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



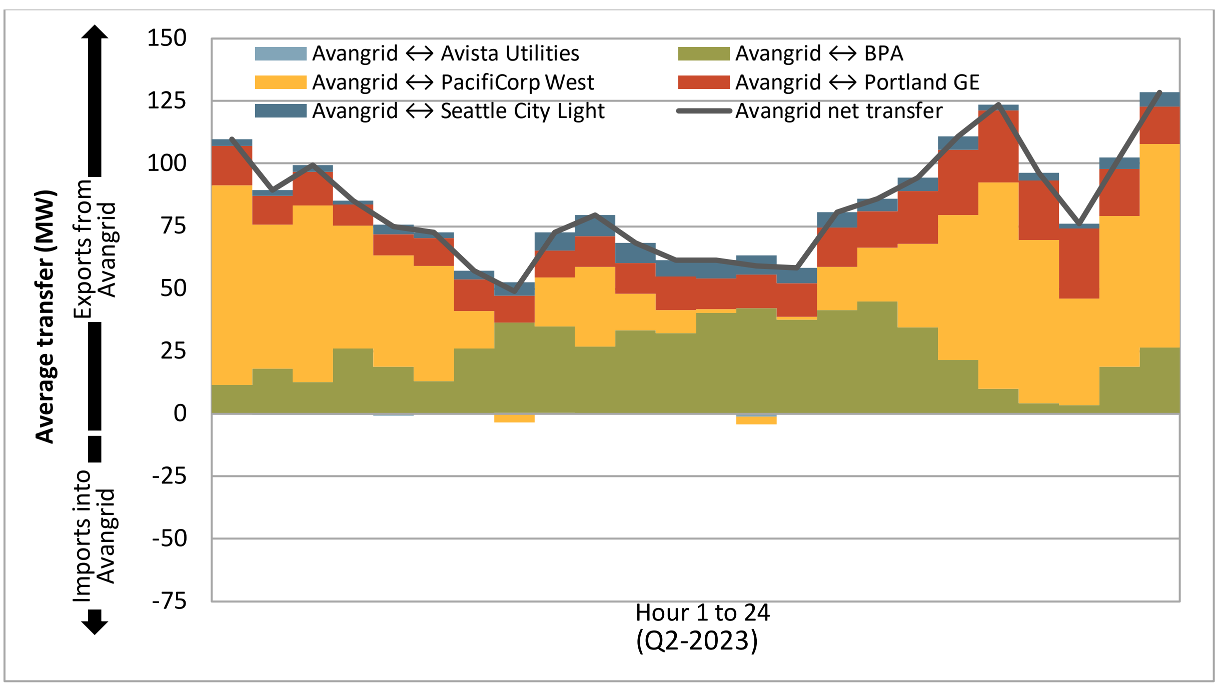
*Since joining the WEIM

Appendix Figure A.7 Average hourly 5-minute price by component (Q2 2023)



*Since joining the WEIM

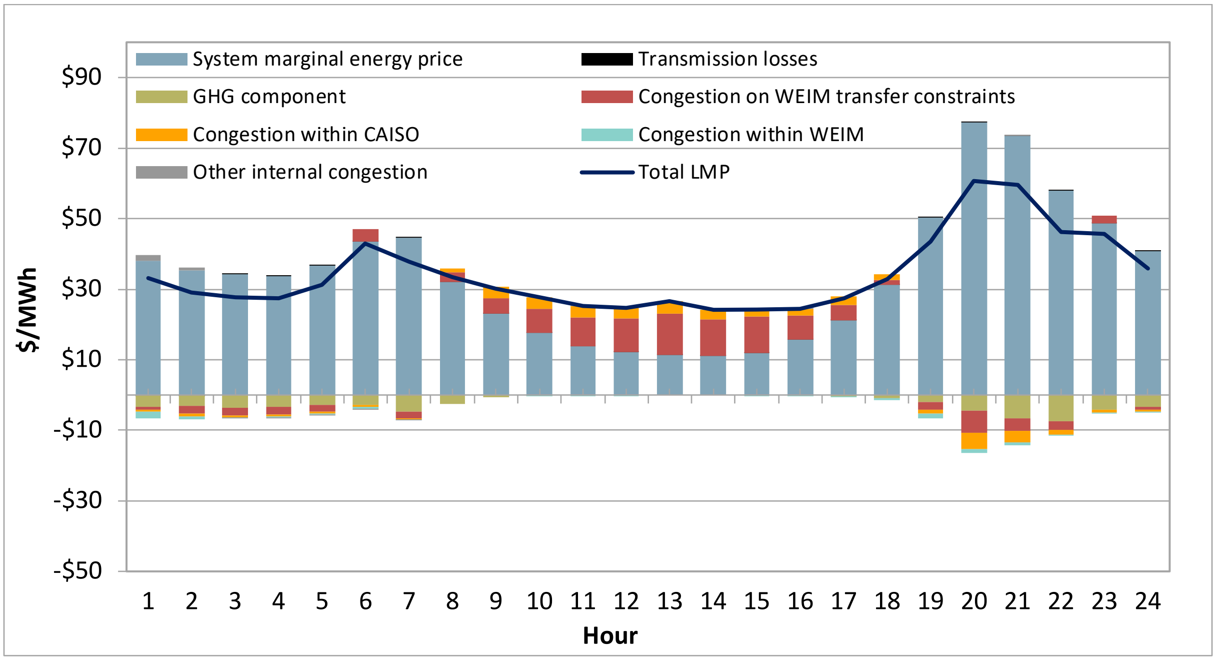
Appendix Figure A.8 Average hourly 5-minute market transfers



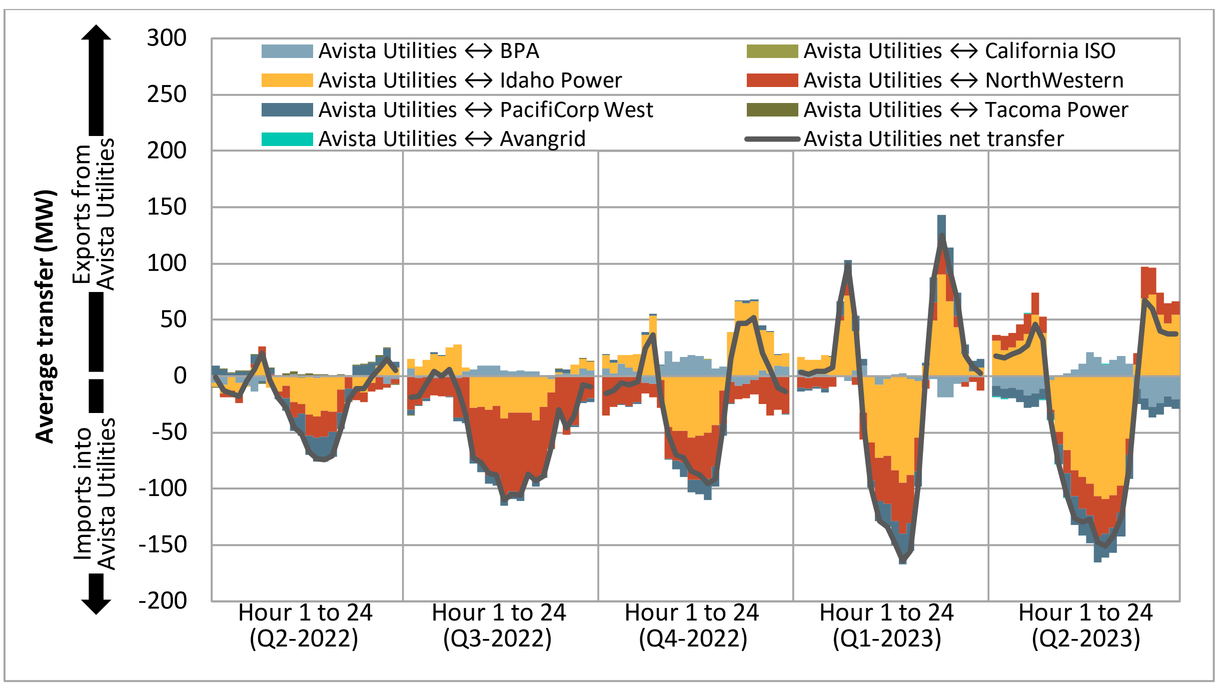
*Since joining the WEIM

A.3 Avista Utilities

Appendix Figure A.9 Average hourly 15-minute price by component (Q2 2023)

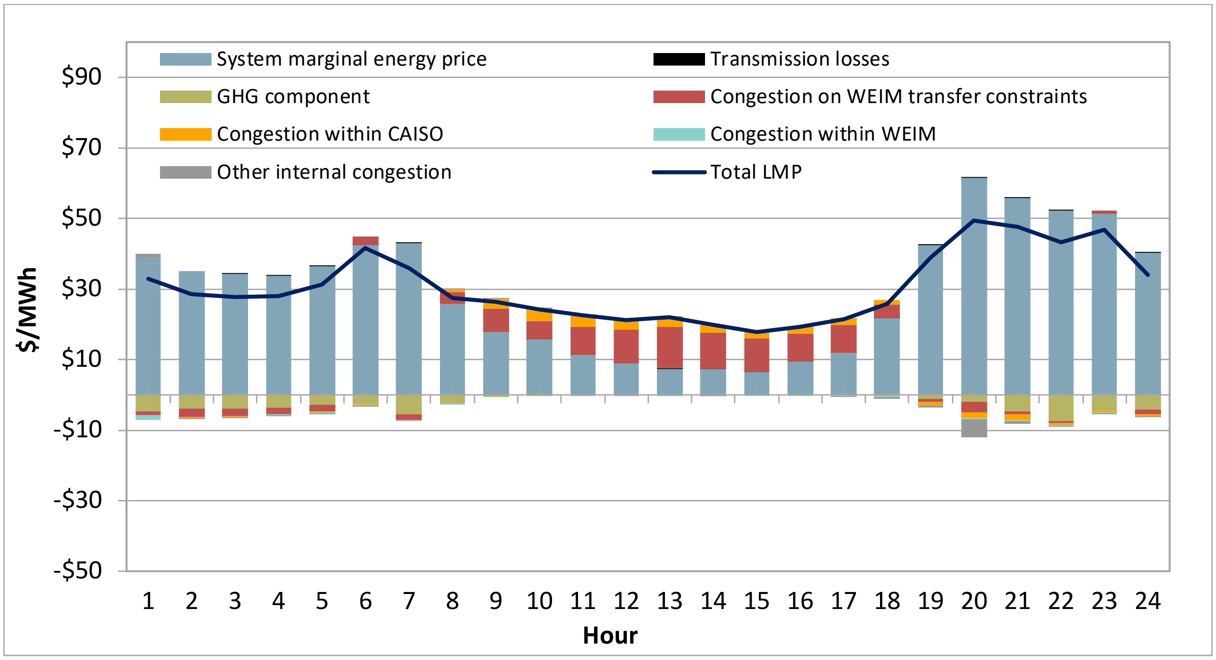


Appendix Figure A.10 Average hourly 15-minute market transfers

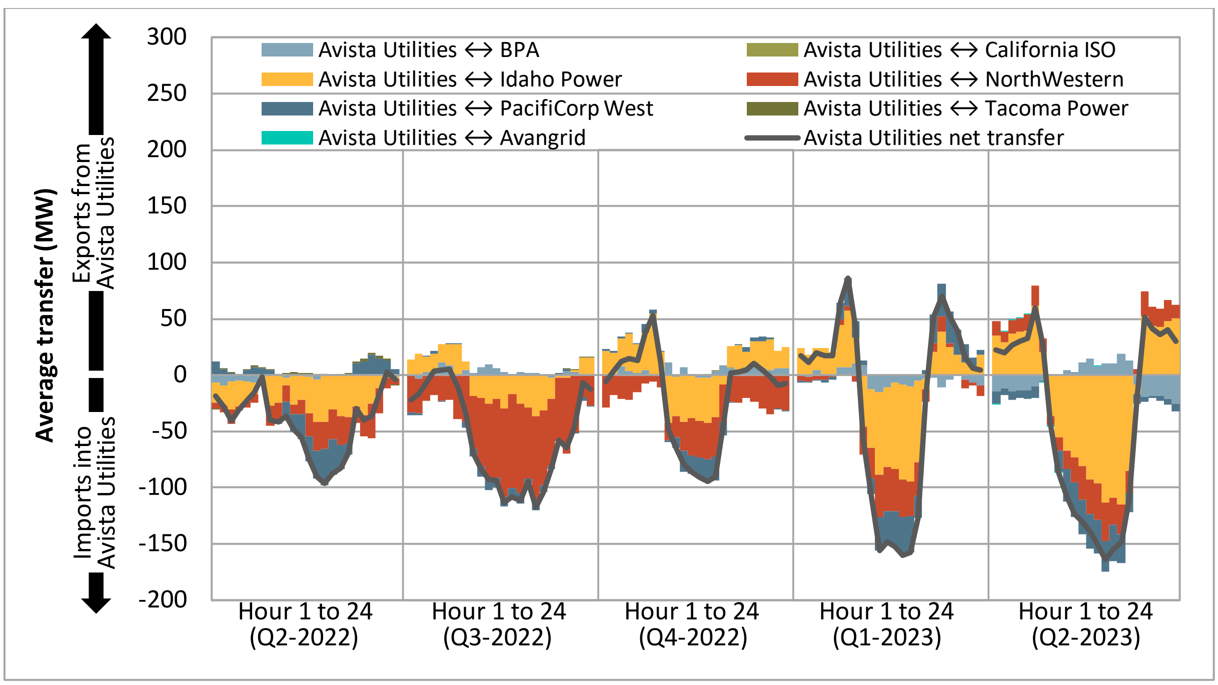


*Since joining the WEIM

Appendix Figure A.11 Average hourly 5-minute price by component (Q2 2023)



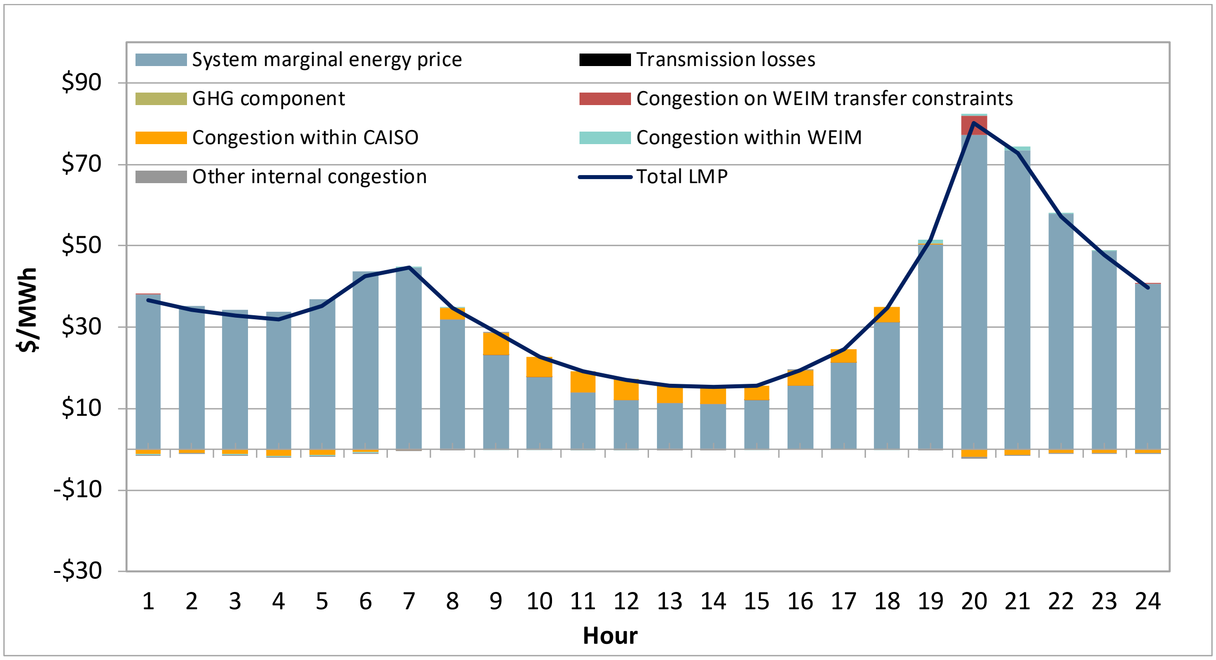
Appendix Figure A.12 Average hourly 5-minute market transfers



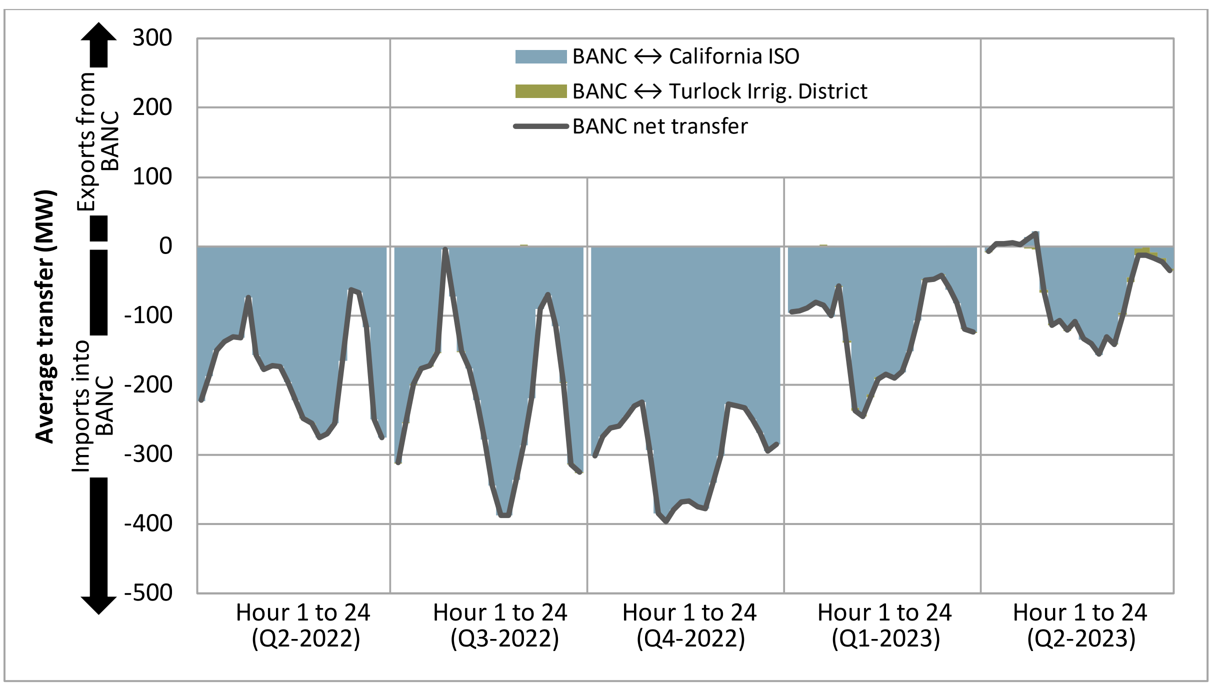
*Since joining the WEIM

A.4 Balancing Authority of Northern California

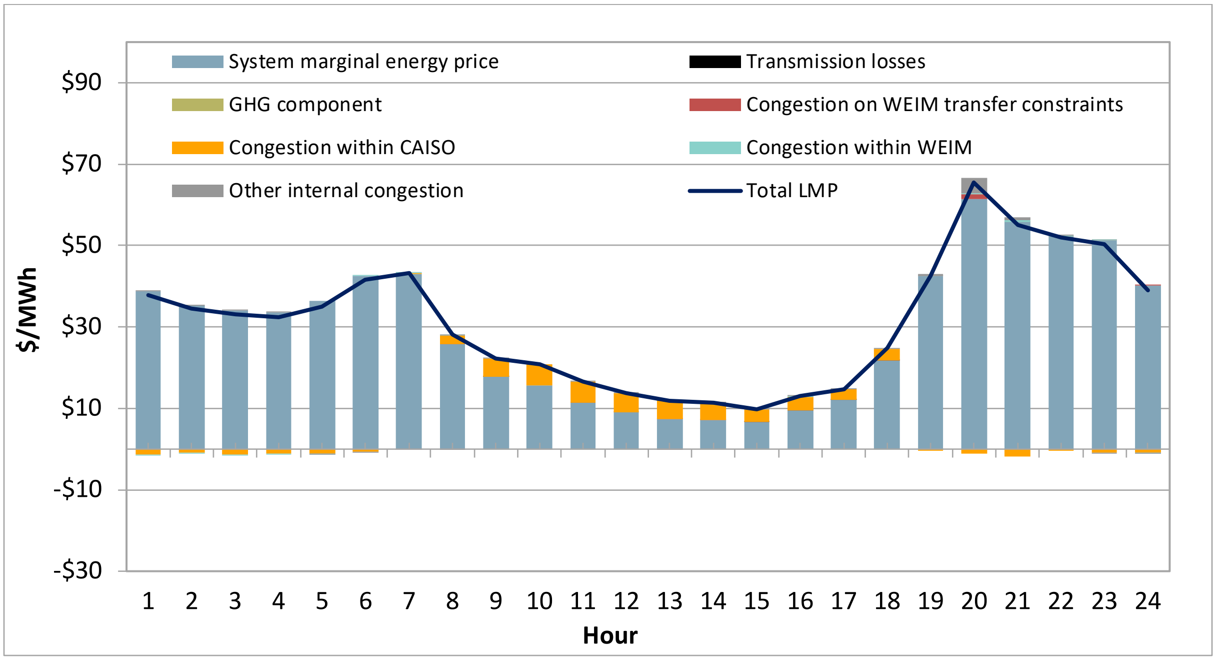
Appendix Figure A.13 Average hourly 15-minute price by component (Q2 2023)



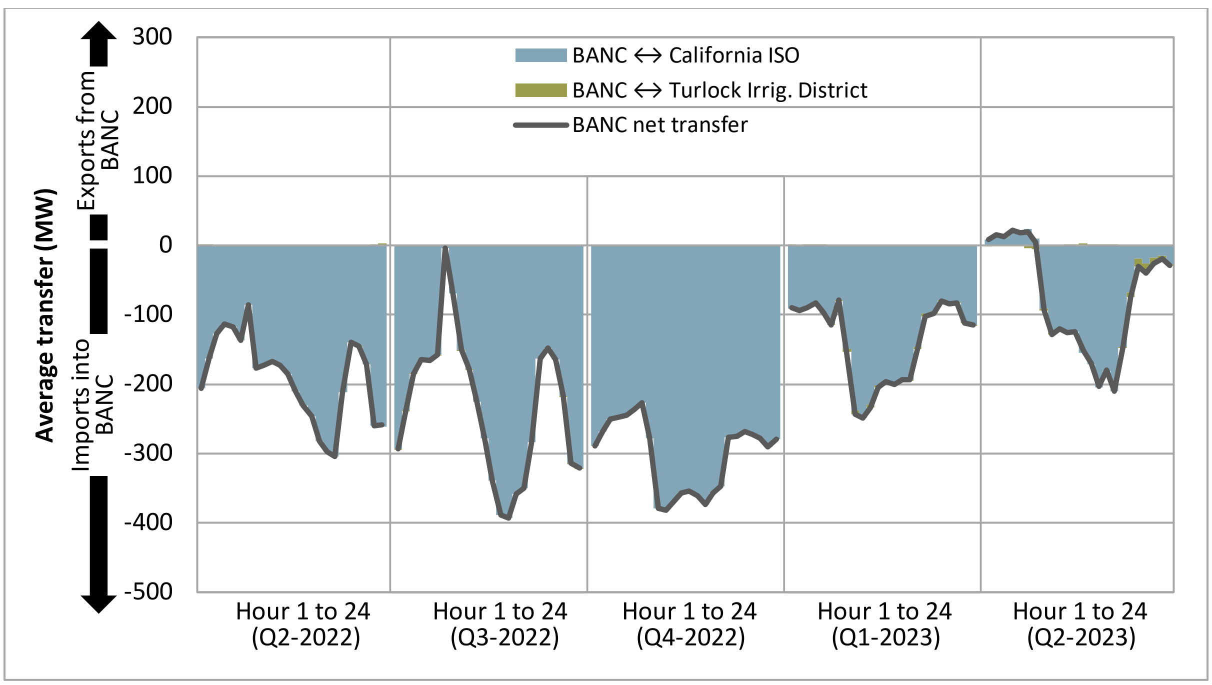
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q2 2023)

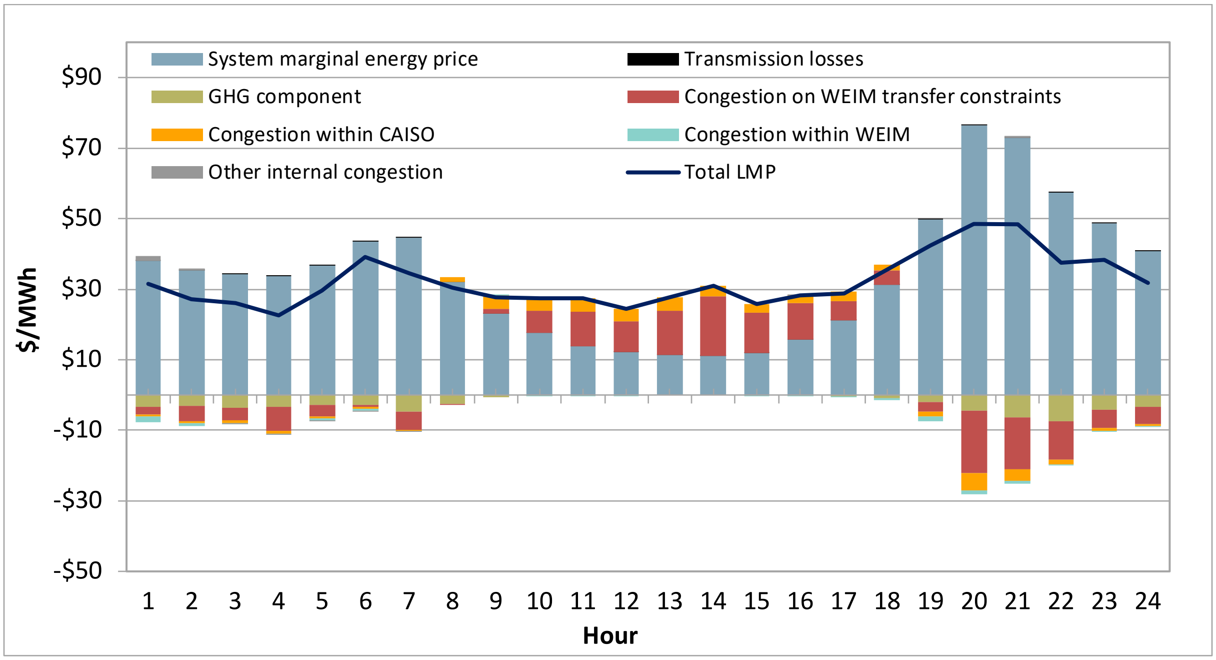


Appendix Figure A.16 Average hourly 5-minute market transfers

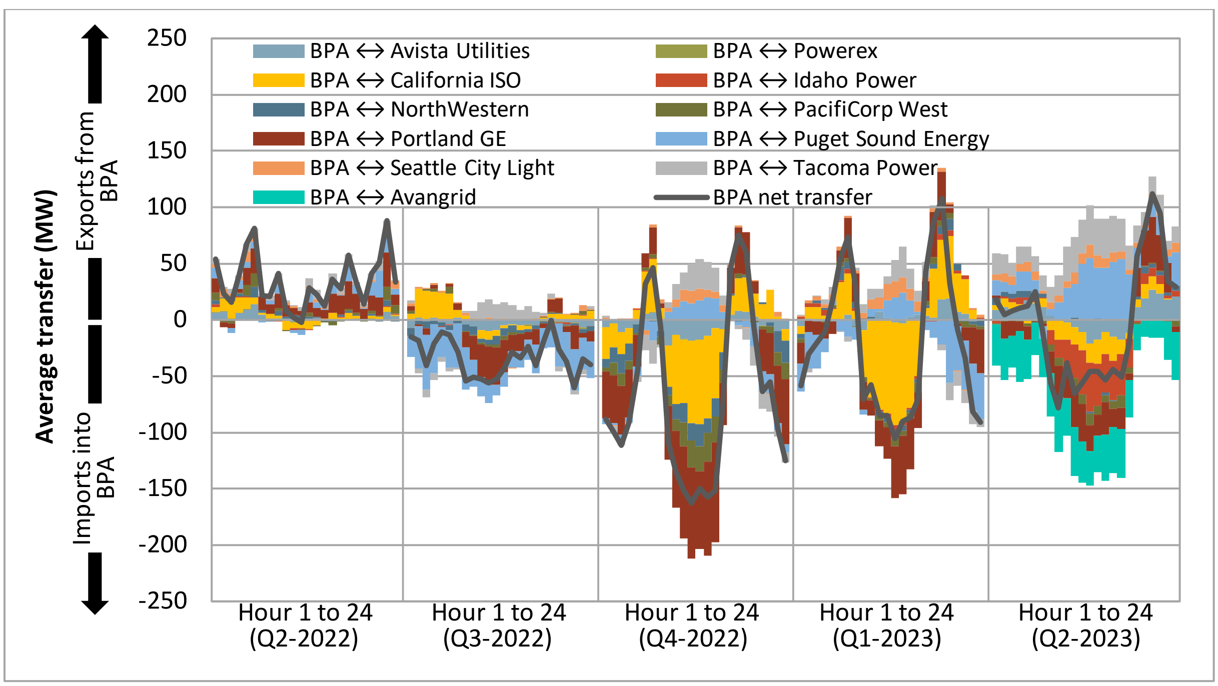


A.5 Bonneville Power Administration

Appendix Figure A.17 Average hourly 15-minute price by component (Q2 2023)

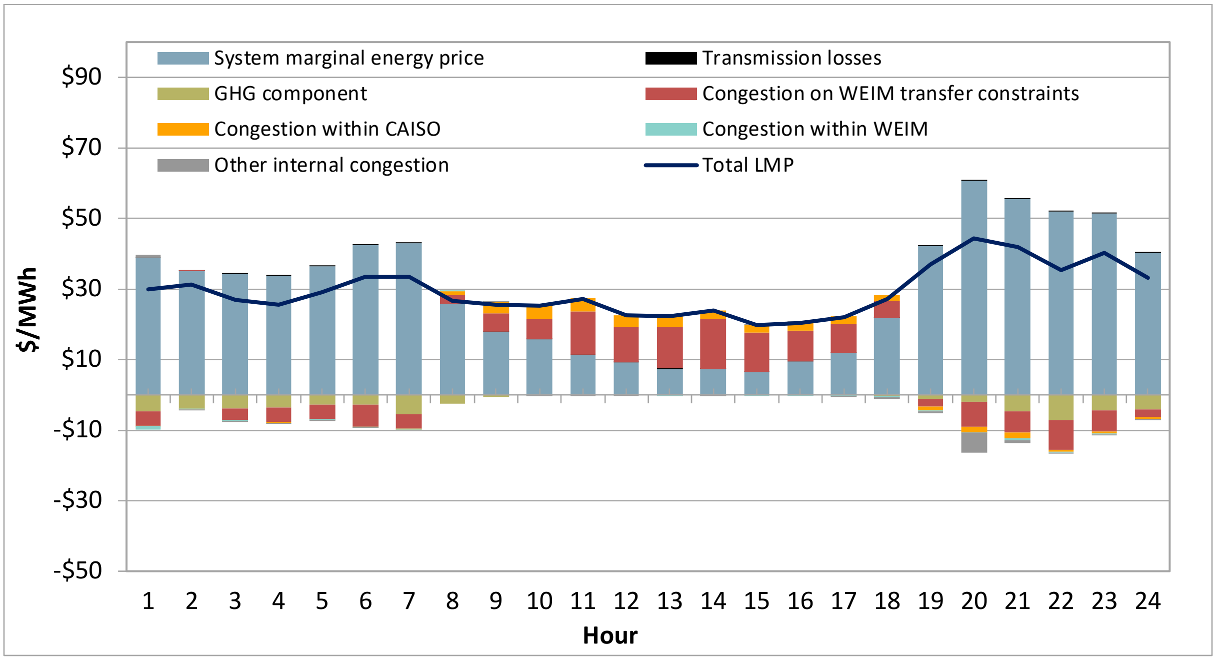


Appendix Figure A.18 Average hourly 15-minute market transfers

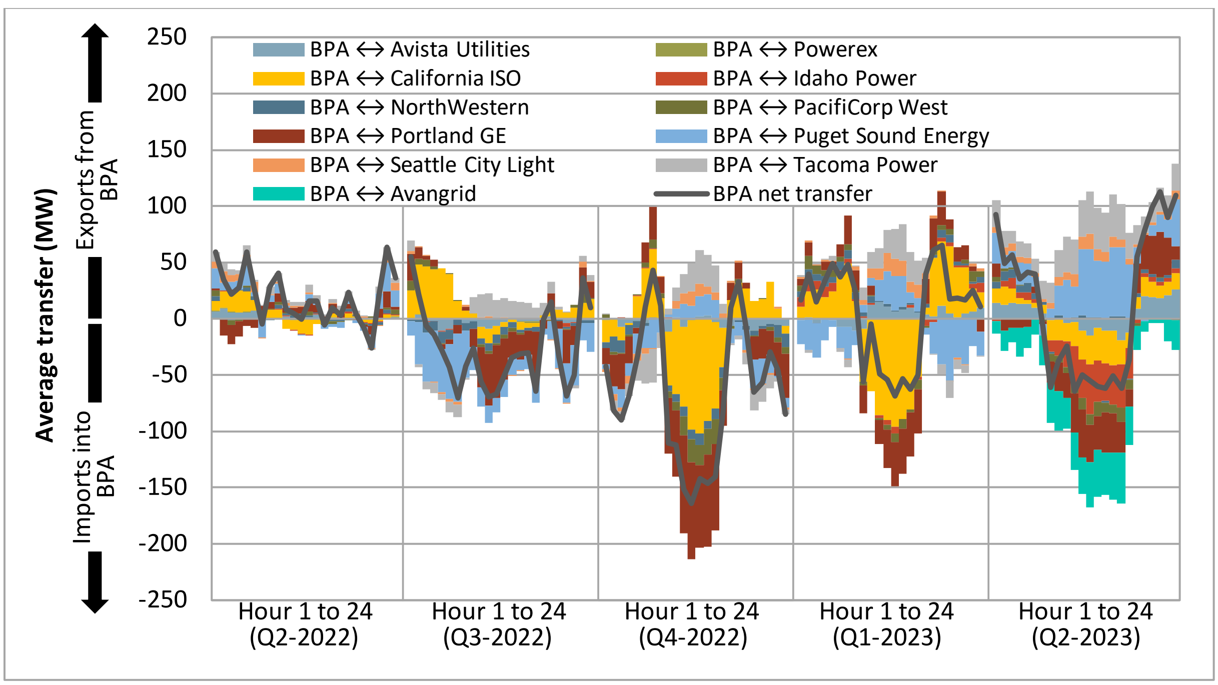


*Since joining the WEIM

Appendix Figure A.19 Average hourly 5-minute price by component (Q2 2023)

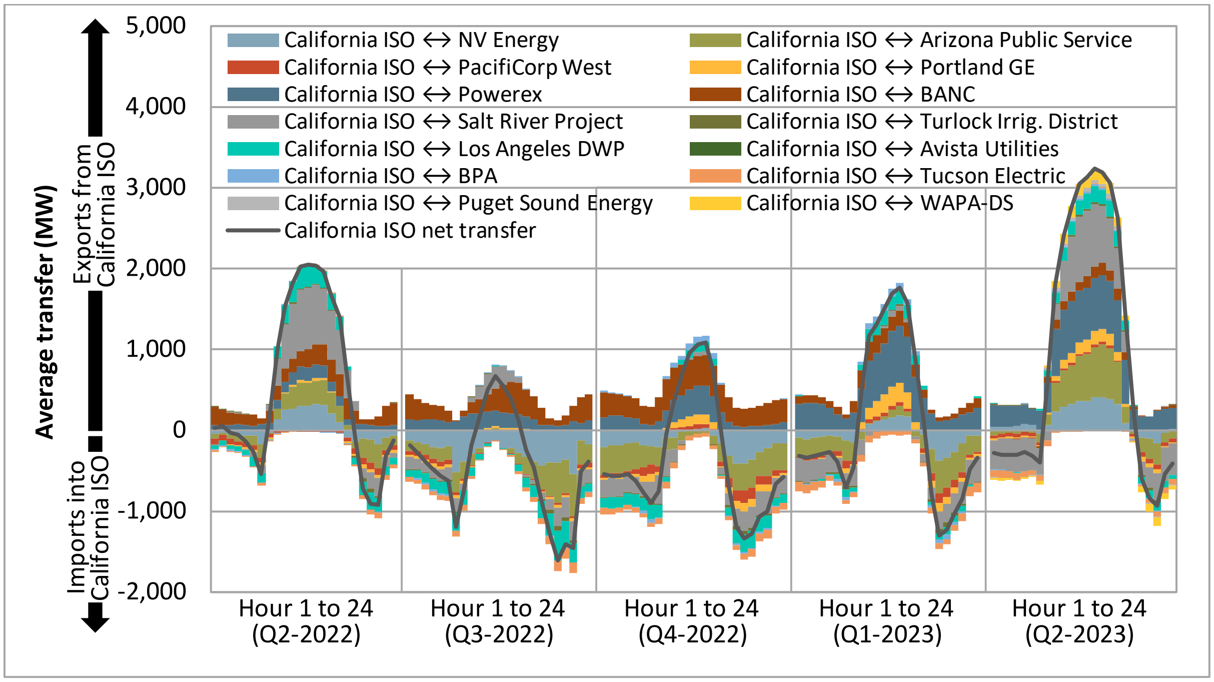


Appendix Figure A.20 Average hourly 5-minute market transfers

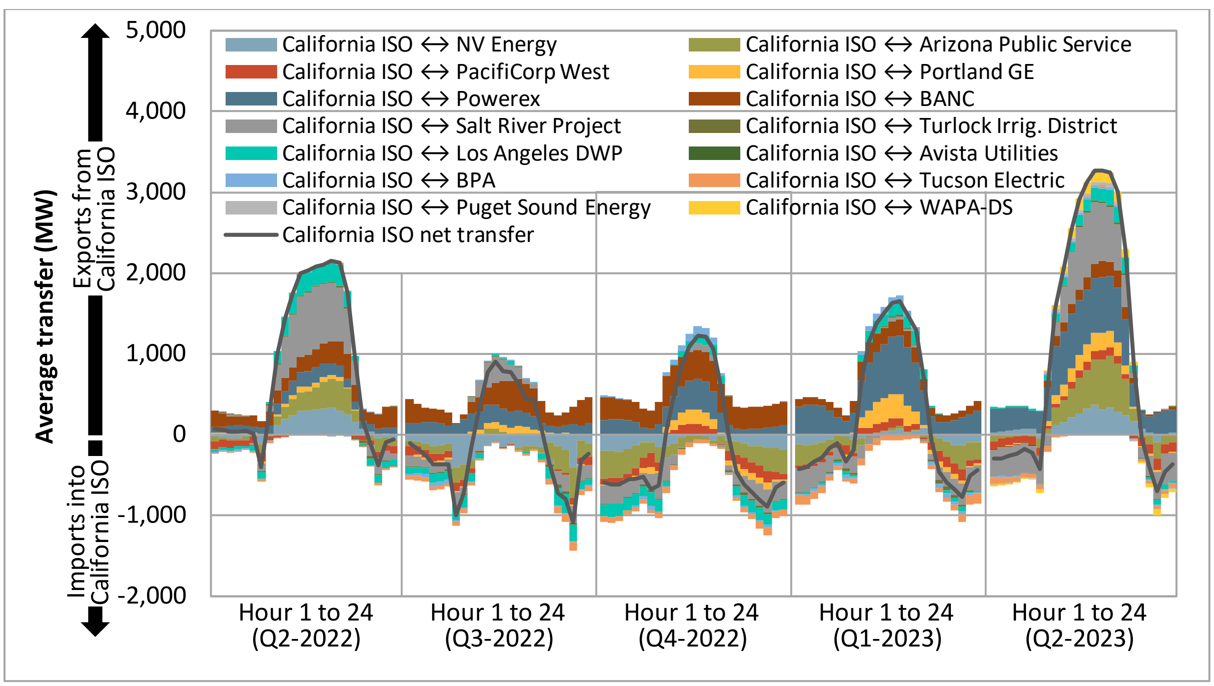


A.6 California ISO

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

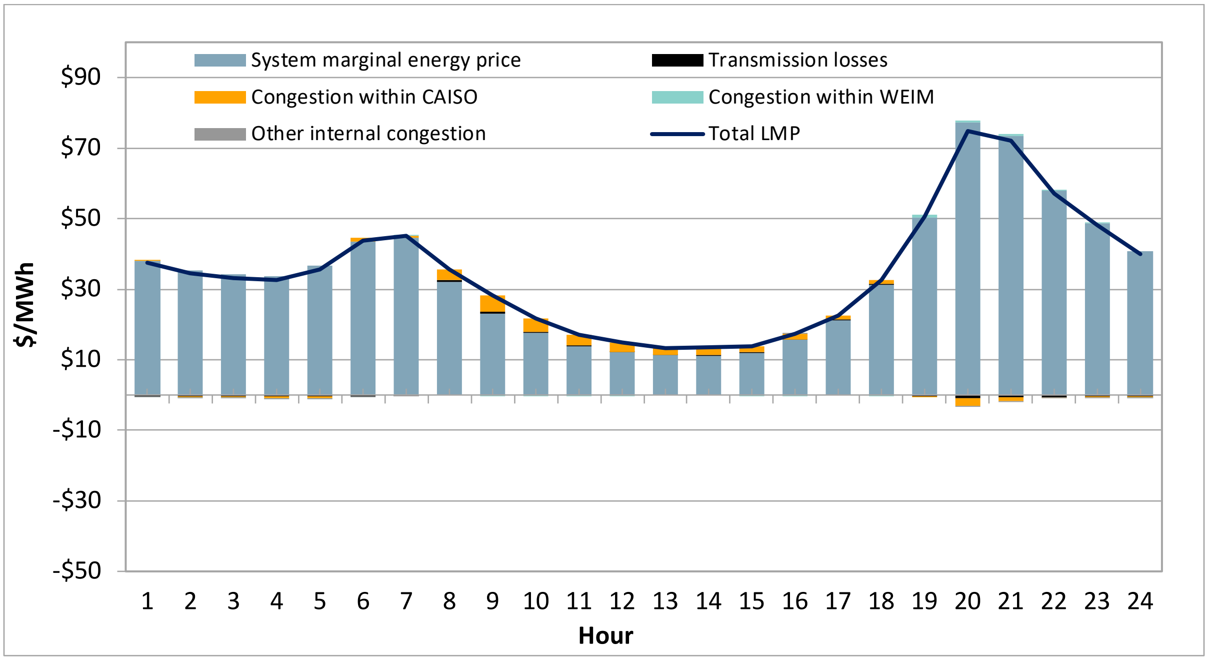


Appendix Figure A.22 Average hourly 5-minute market transfers

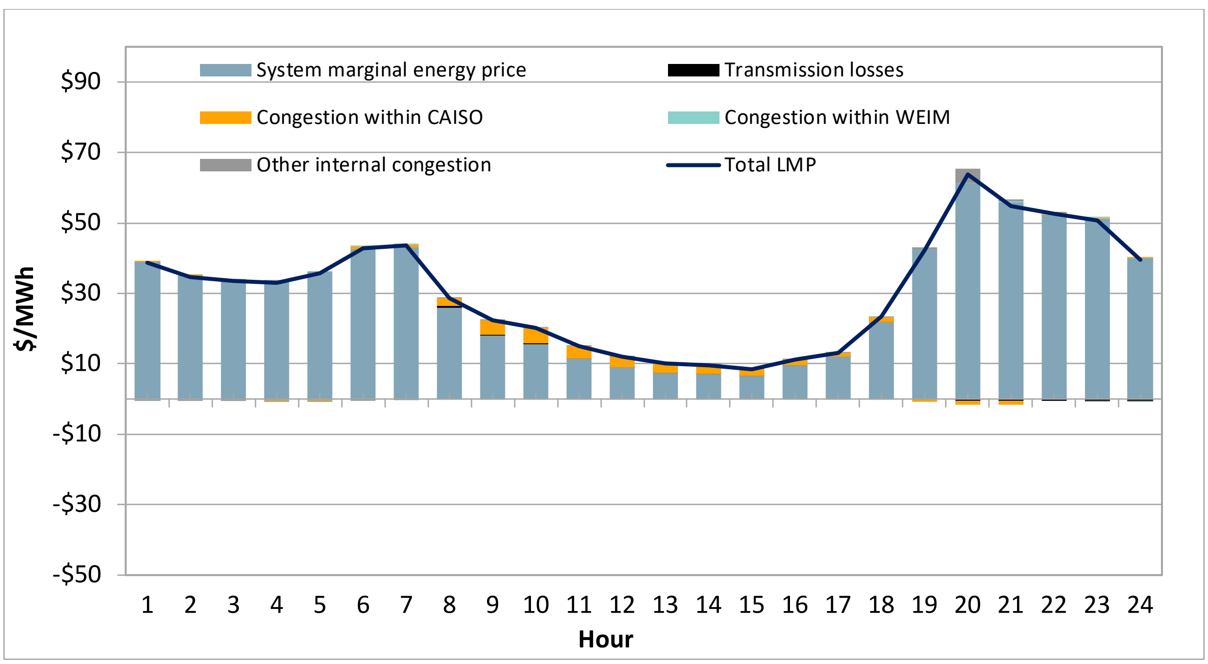


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q2 2023)

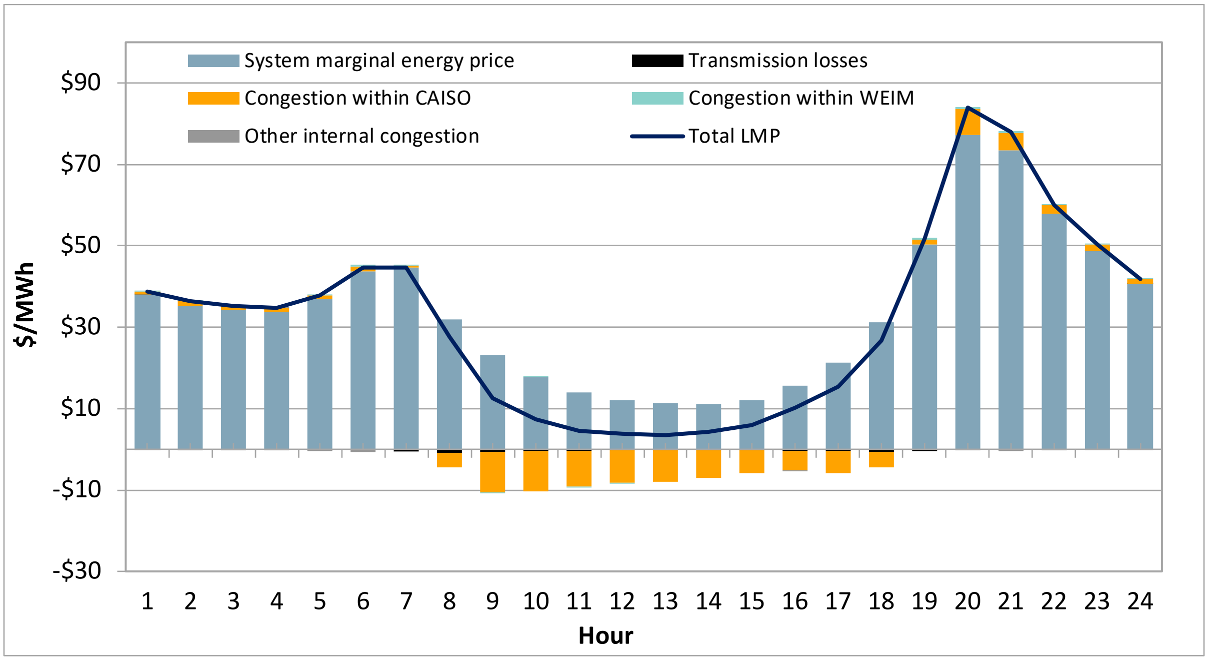


Appendix Figure A.24 Average hourly 5-minute price by component (Q2 2023)

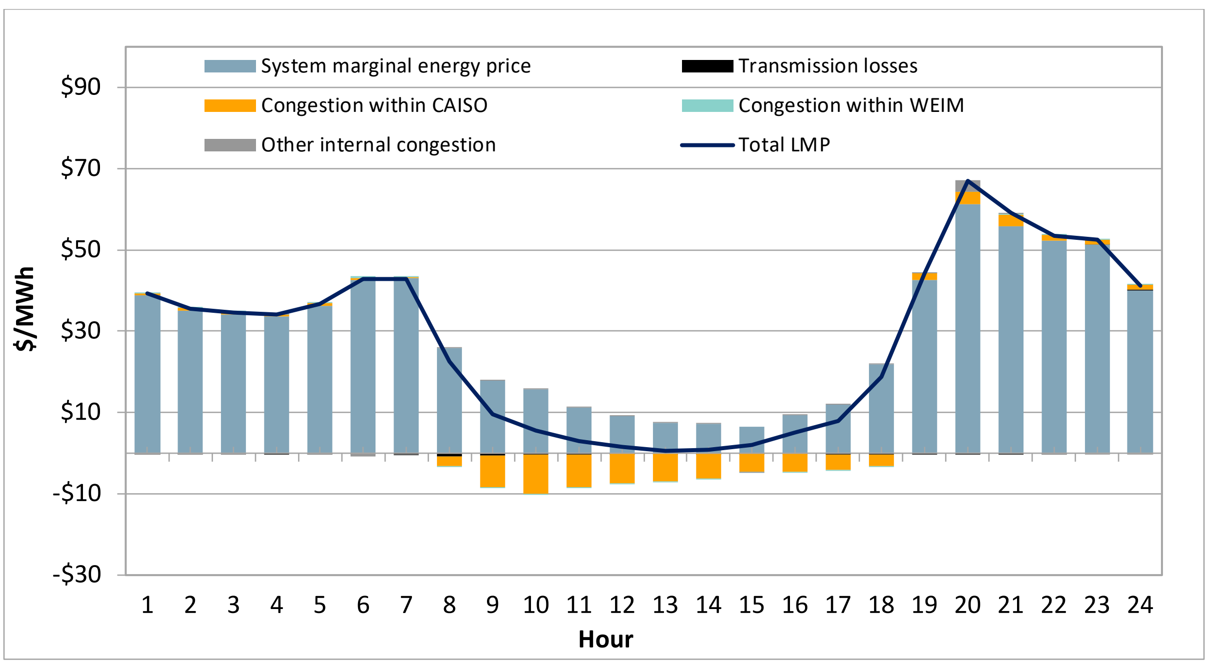


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q2 2023)

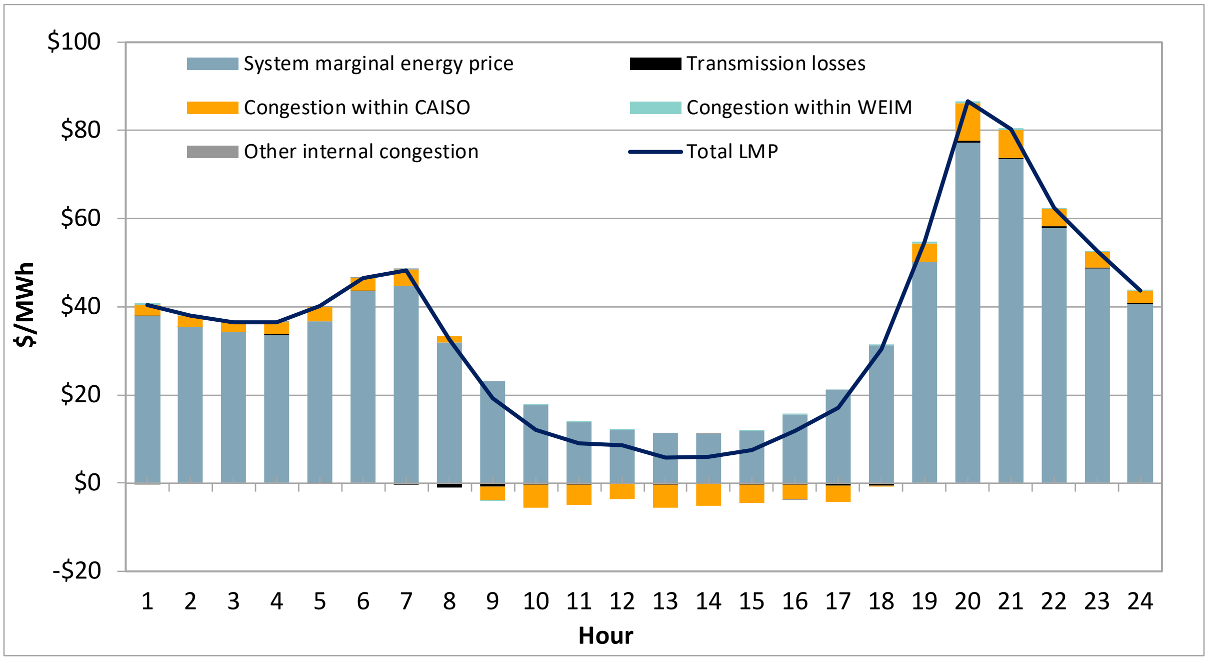


Appendix Figure A.26 Average hourly 5-minute price by component (Q2 2023)

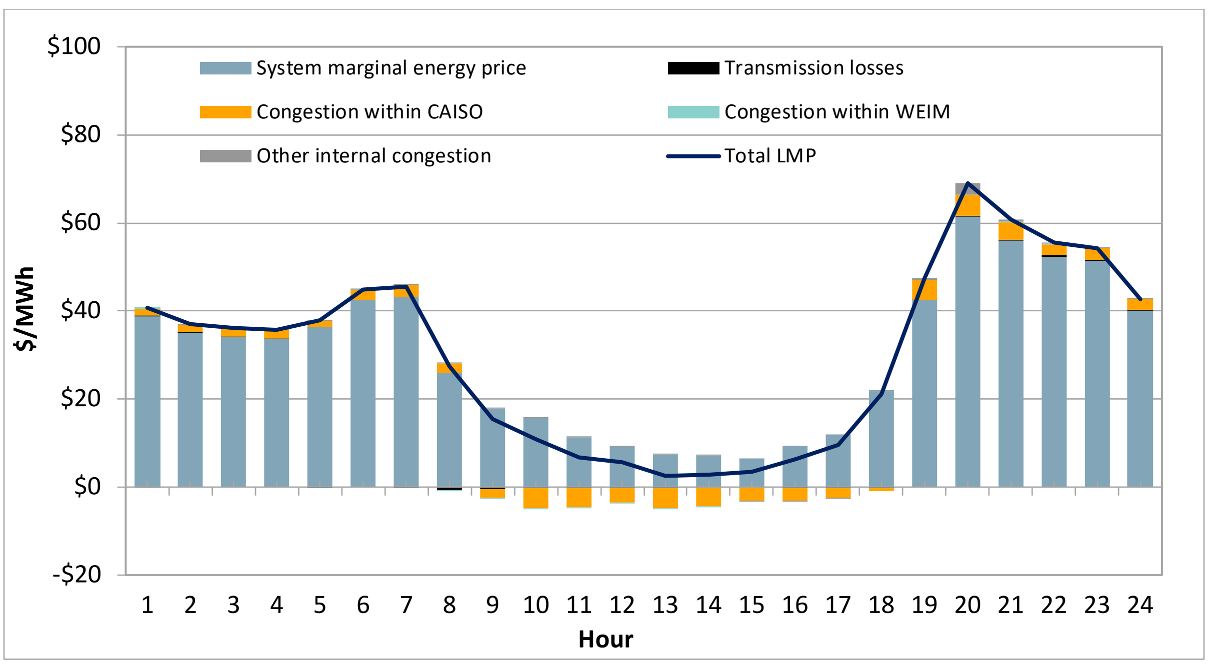


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q2 2023)

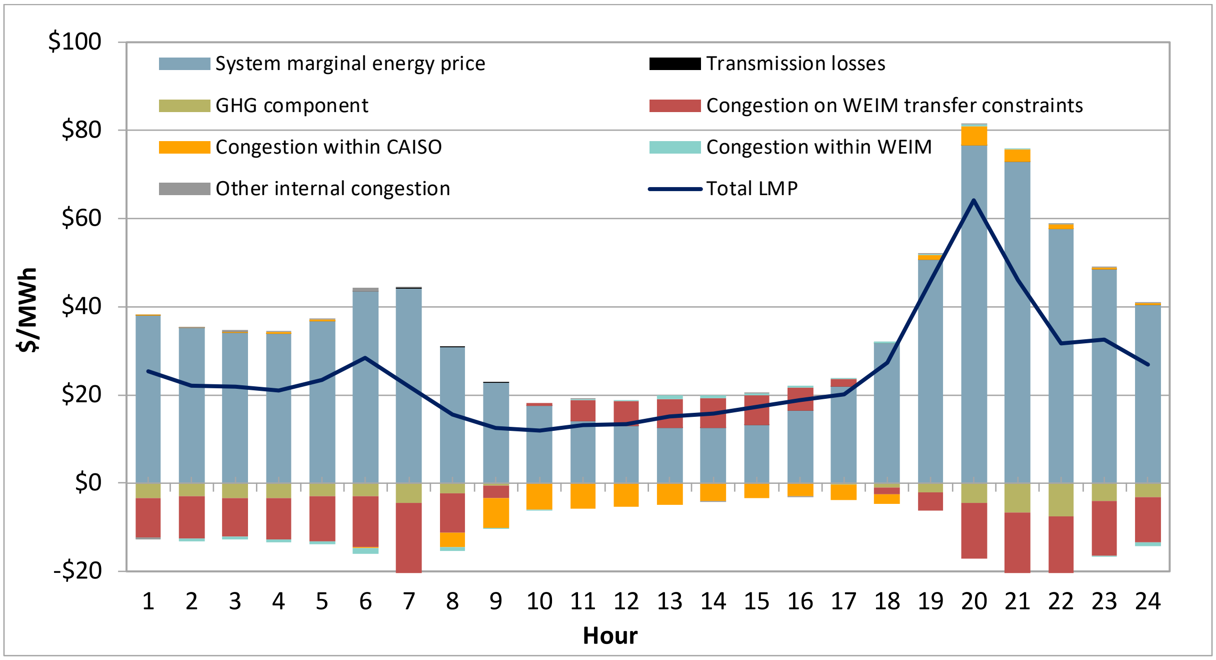


Appendix Figure A.28 Average hourly 5-minute price by component (Q2 2023)



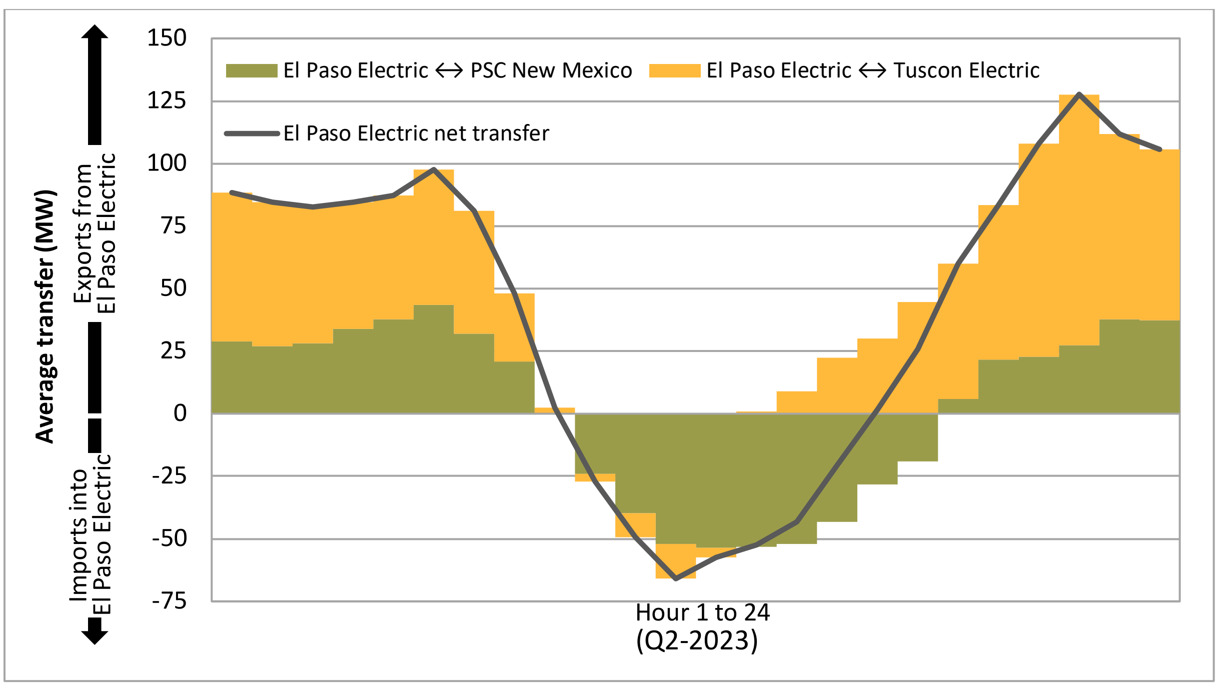
A.7 El Paso Electric

Appendix Figure A.29 Average hourly 15-minute price by component (Q2 2023)



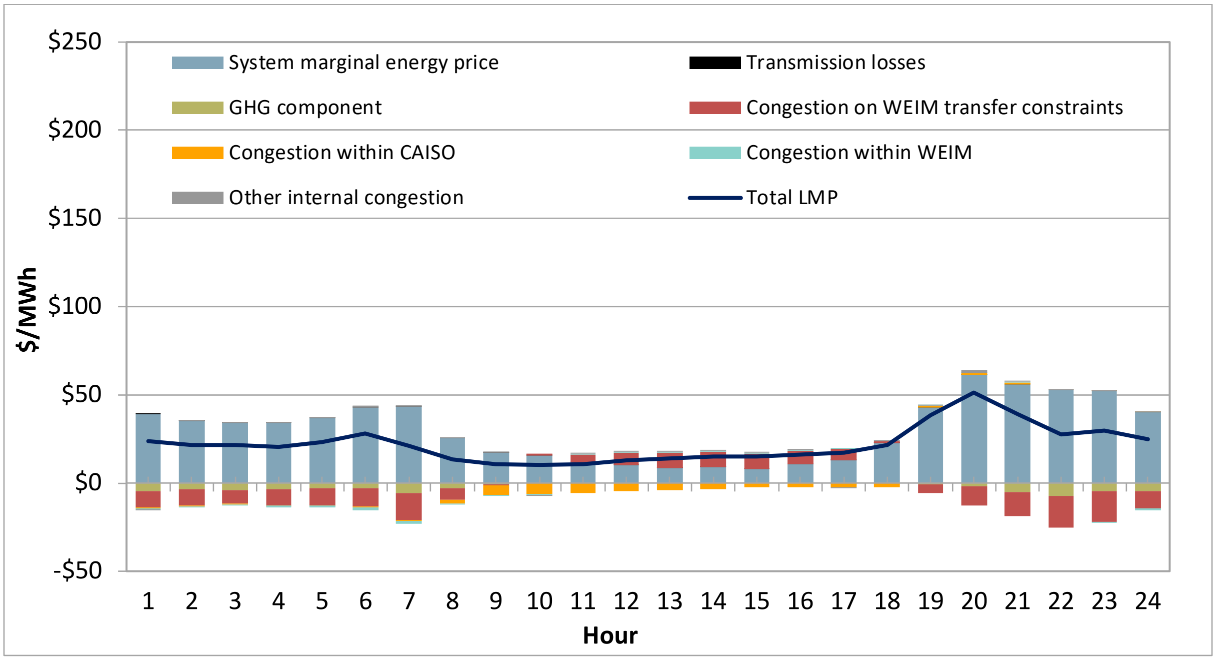
*Since joining the WEIM

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



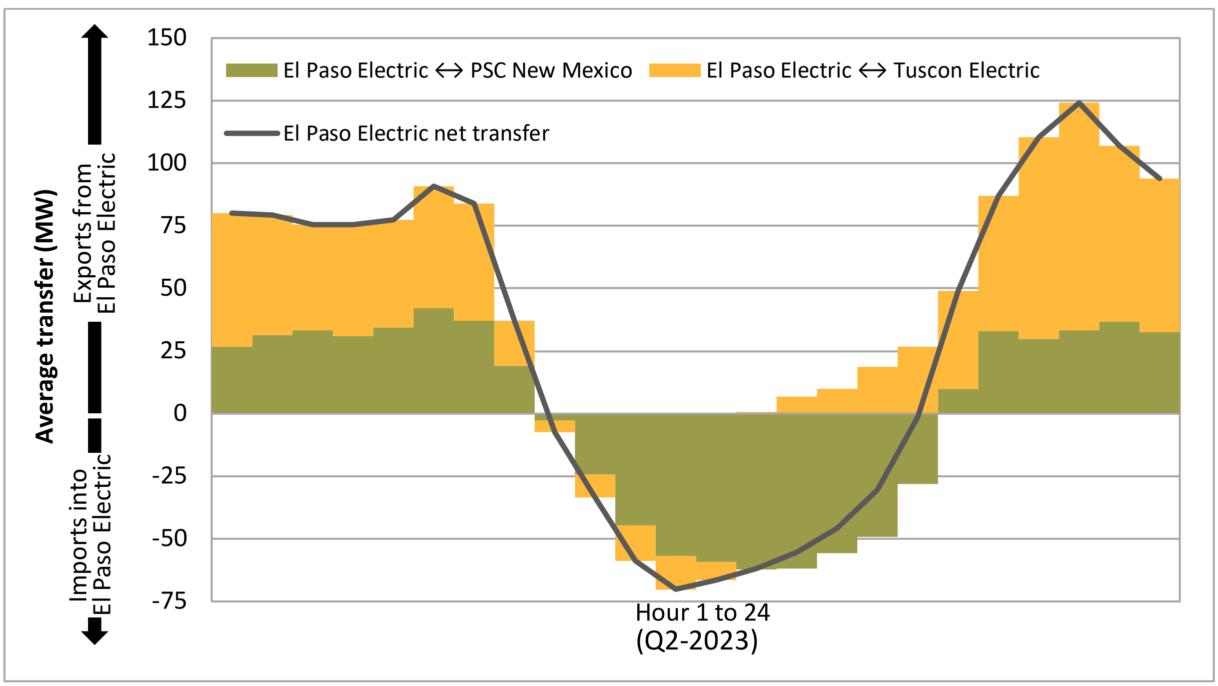
*Since joining the WEIM

Appendix Figure A.31 Average hourly 5-minute price by component (Q2 2023)



*Since joining the WEIM

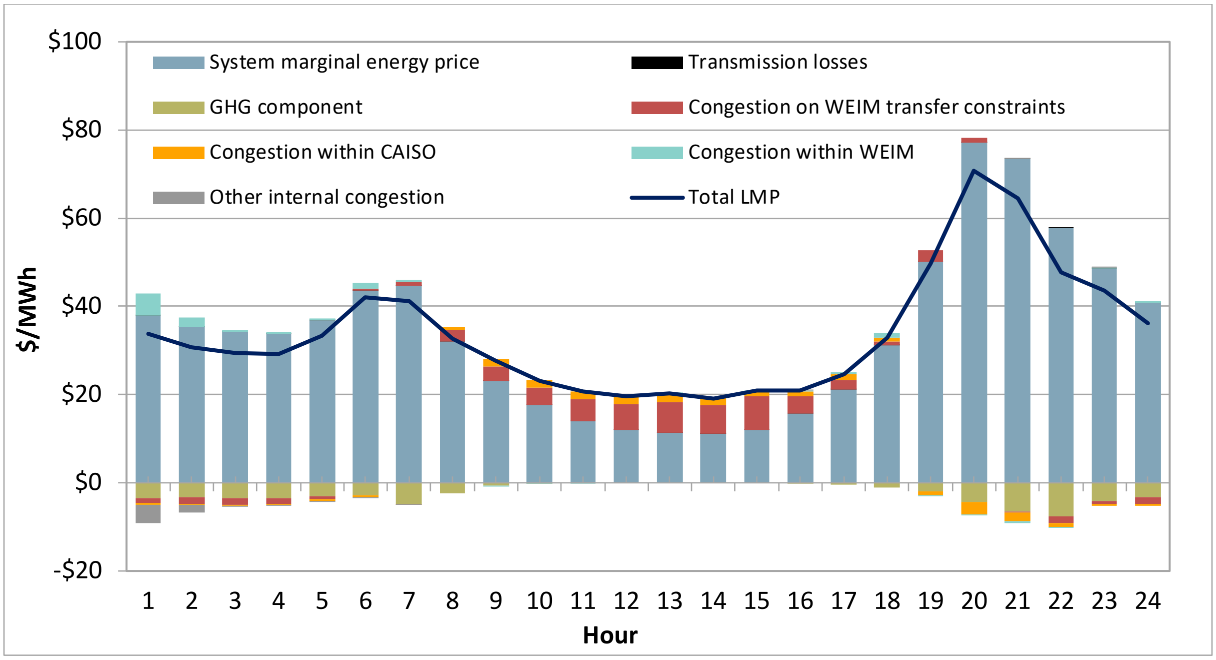
Appendix Figure A.32 Average hourly 5-minute market transfers



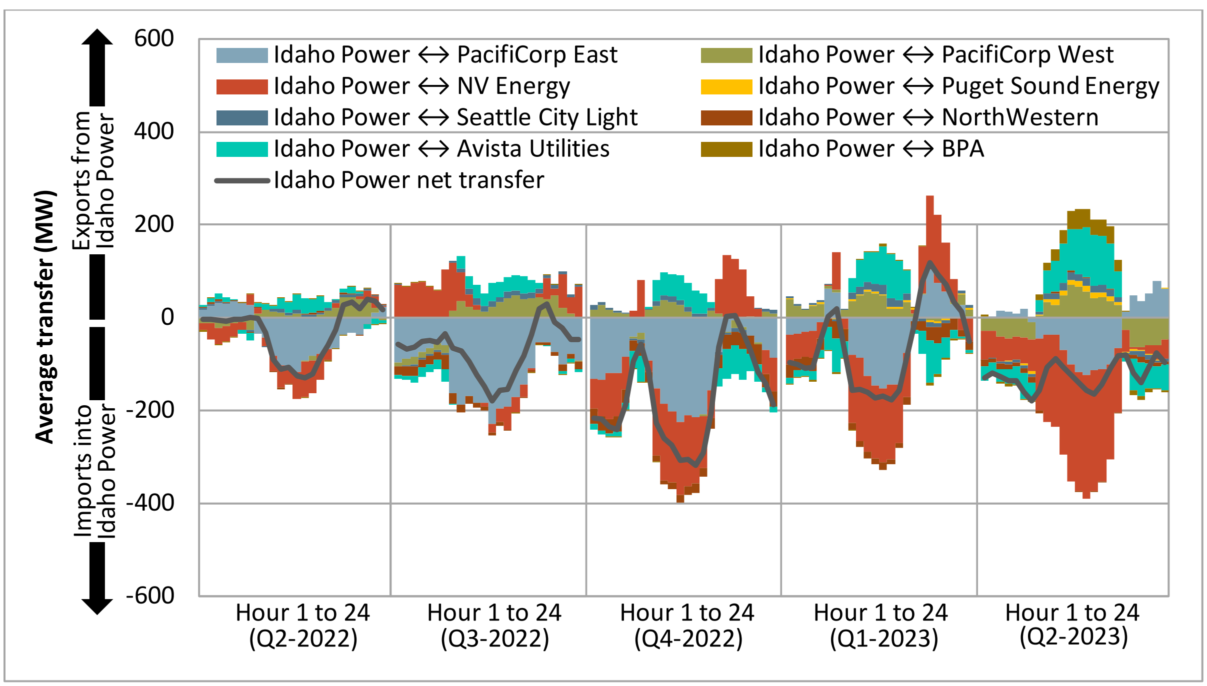
*Since joining the WEIM

A.8 Idaho Power

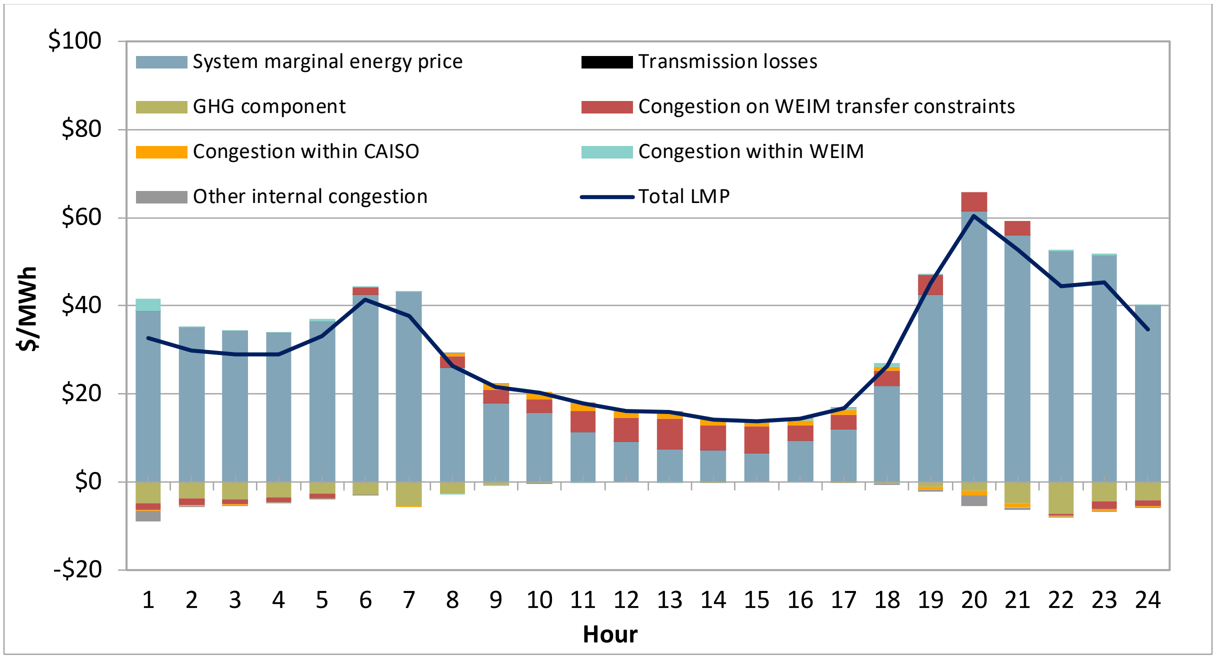
Appendix Figure A.33 Average hourly 15-minute price by component (Q2 2023)



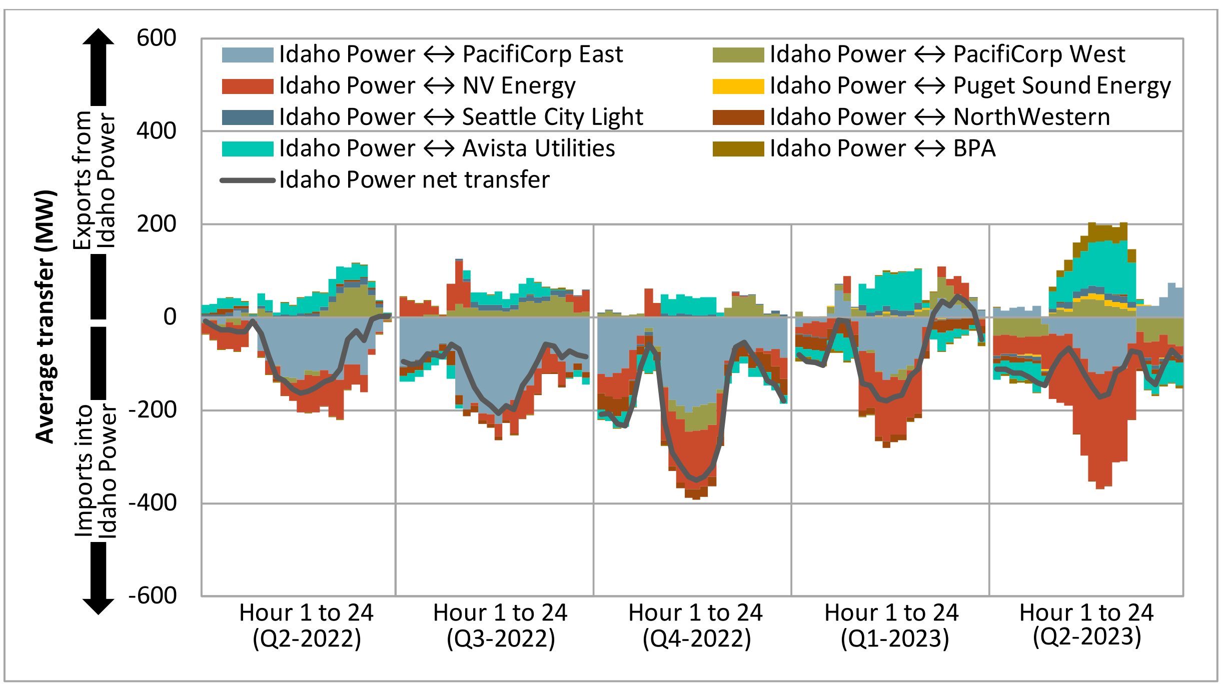
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q2 2023)

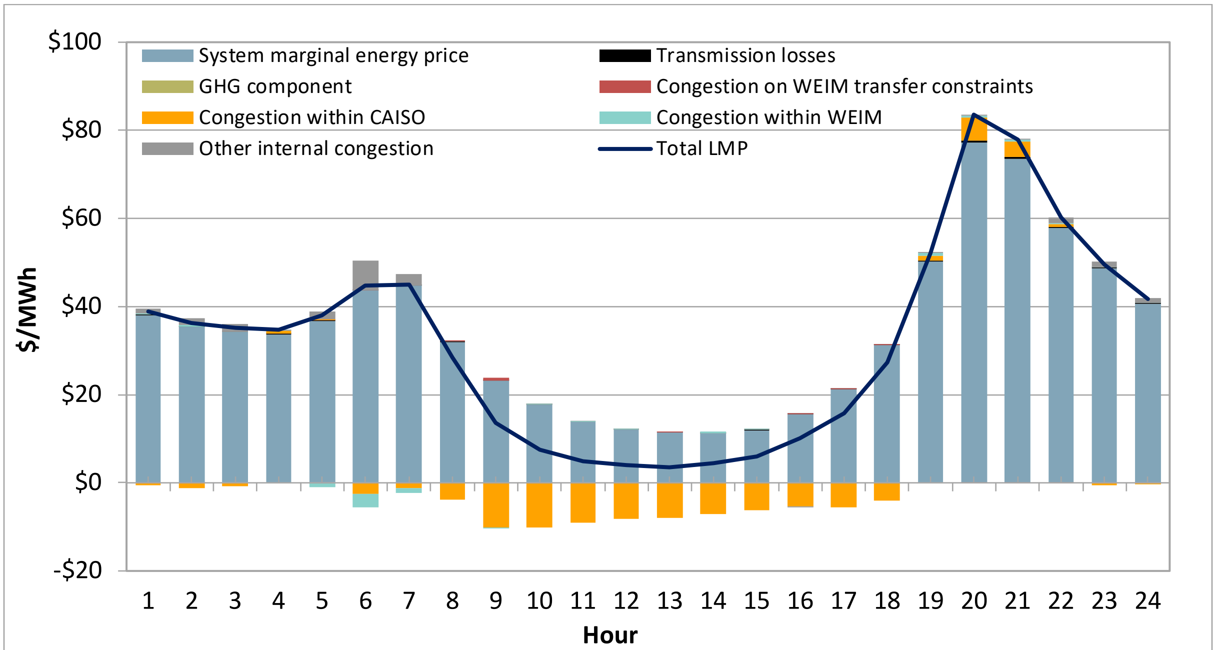


Appendix Figure A.36 Average hourly 5-minute market transfers

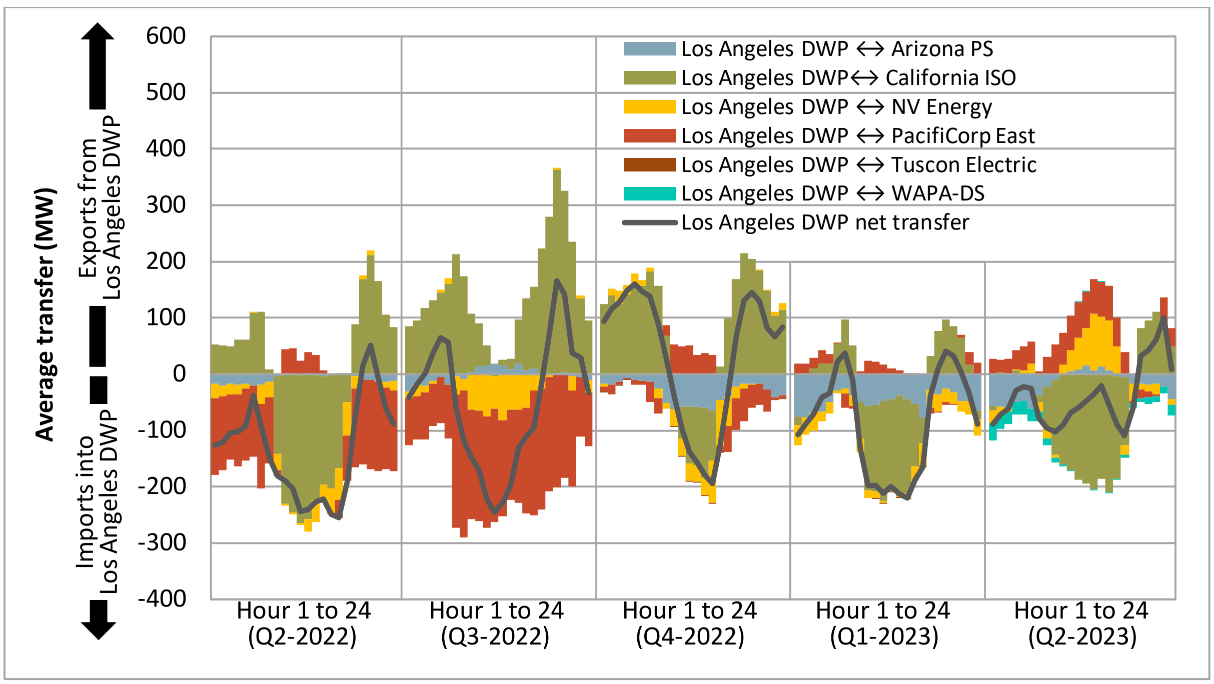


A.9 Los Angeles Department of Water and Power

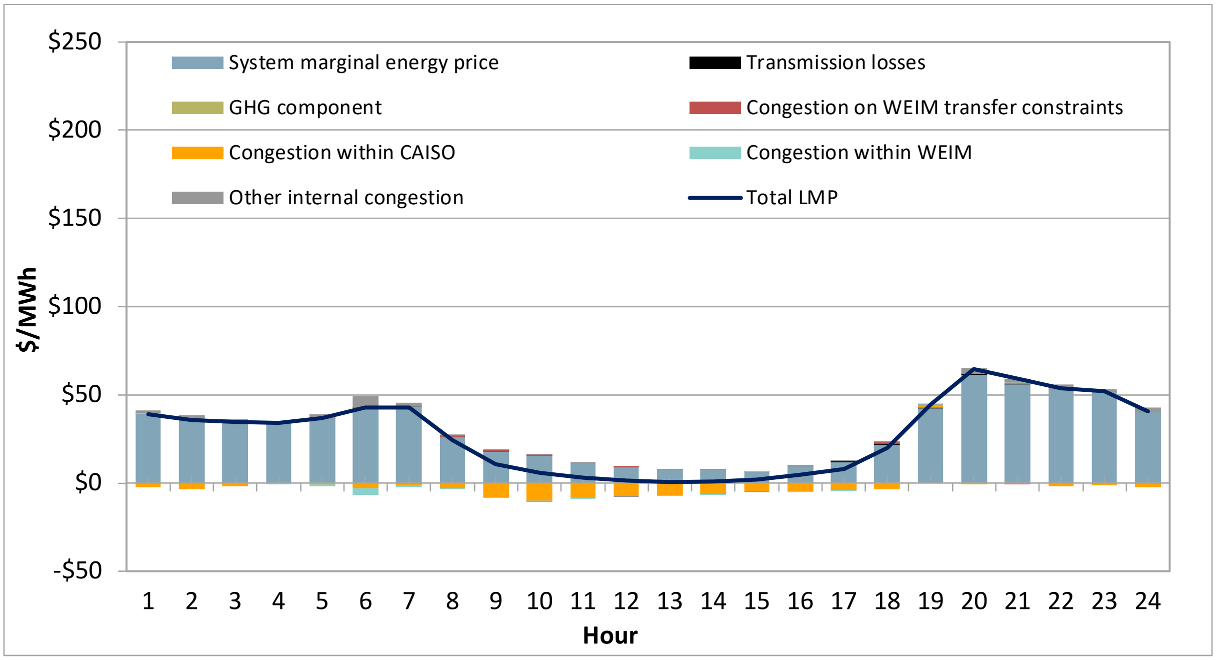
Appendix Figure A.37 Average hourly 15-minute price by component (Q2 2023)



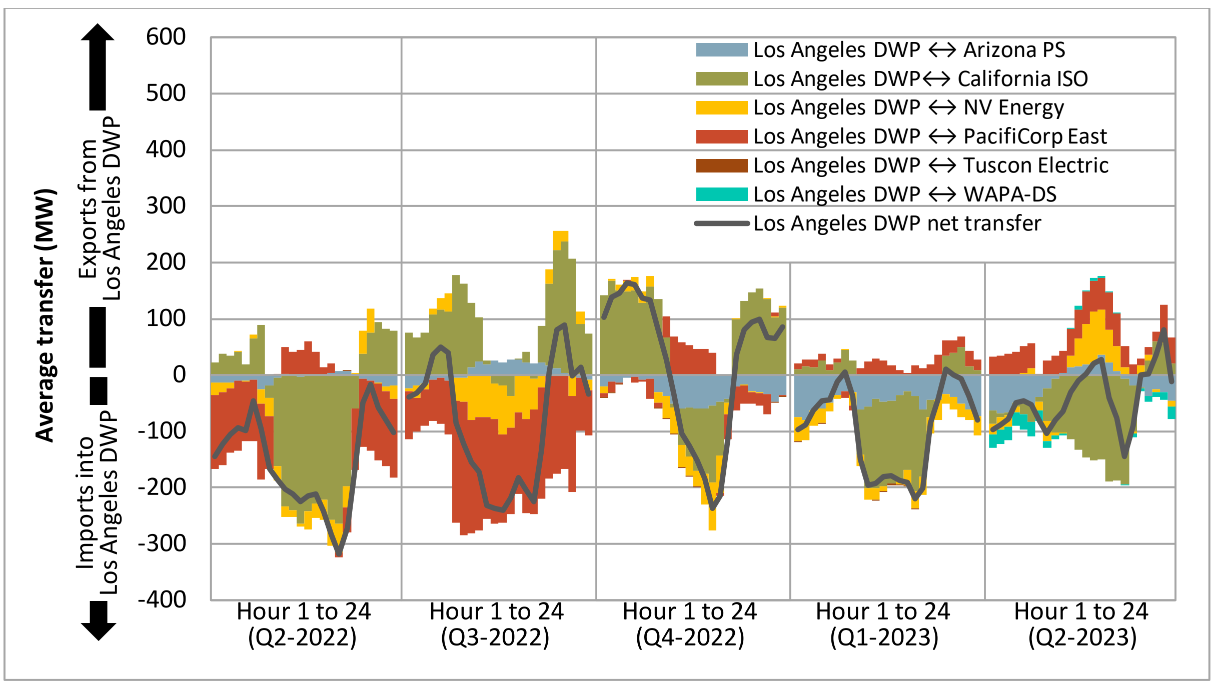
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q2 2023)

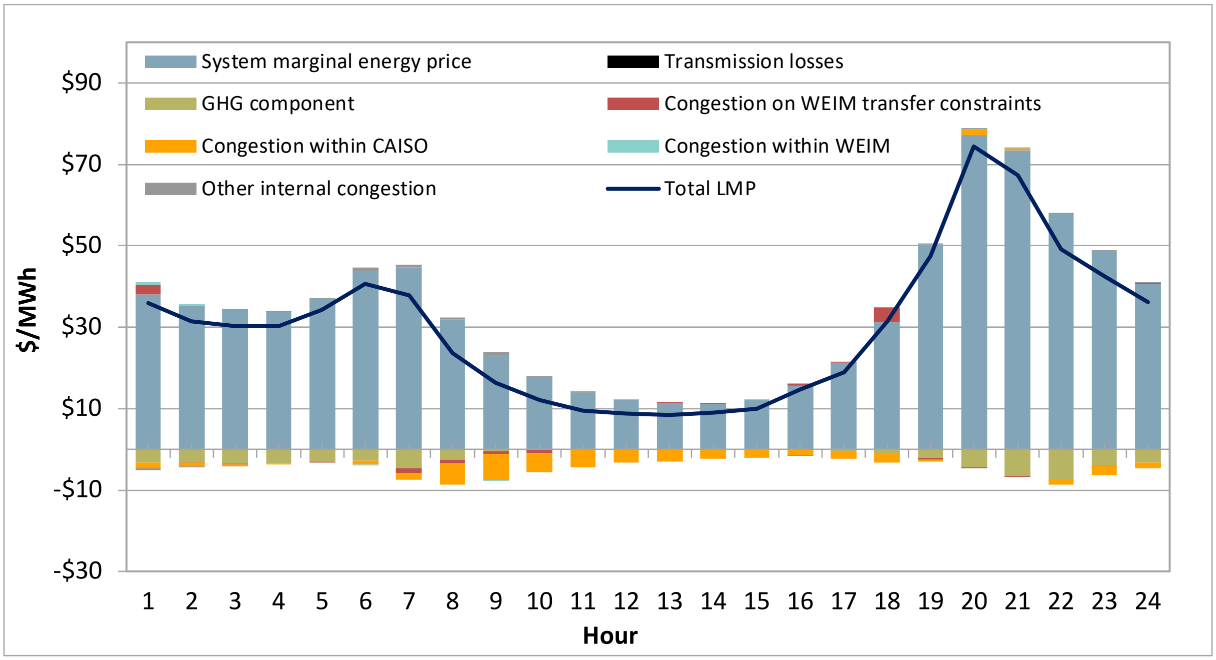


Appendix Figure A.40 Average hourly 5-minute market transfers

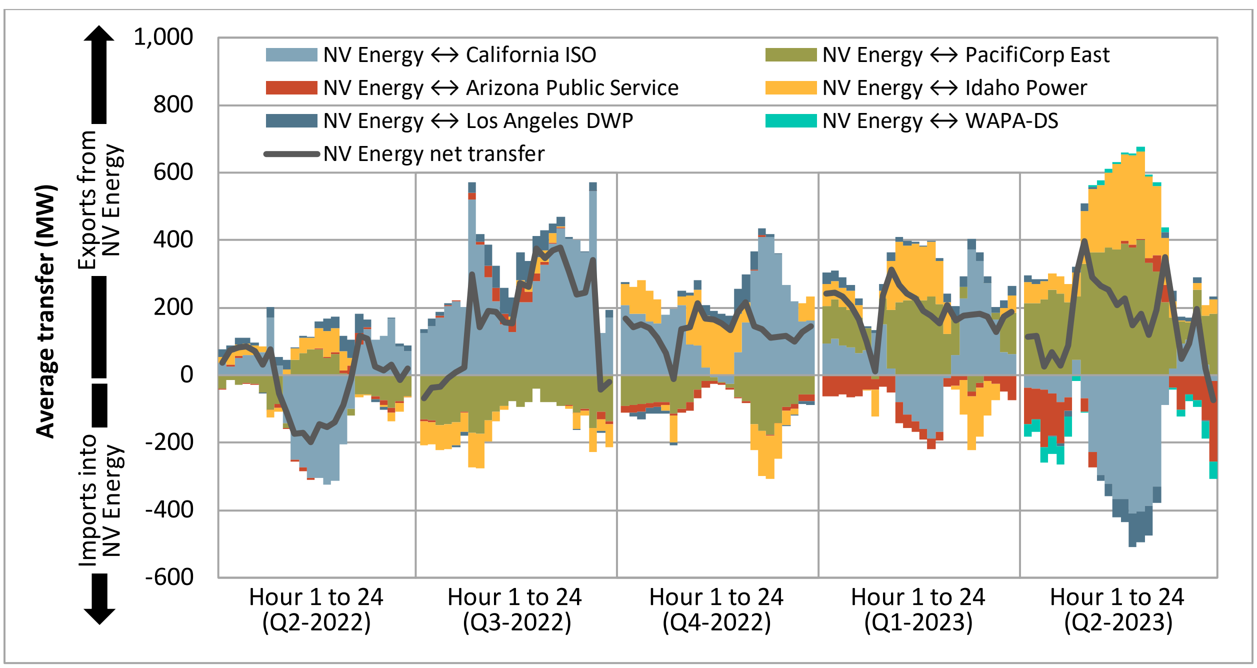


A.10 NV Energy

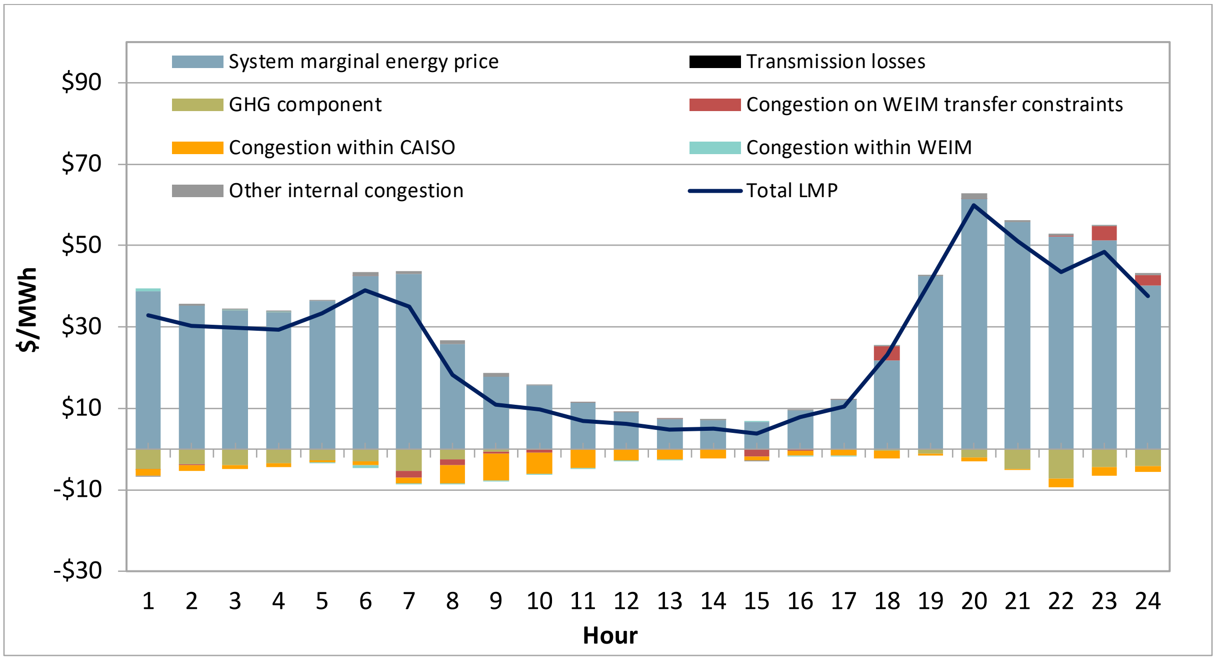
Appendix Figure A.41 Average hourly 15-minute price by component (Q2 2023)



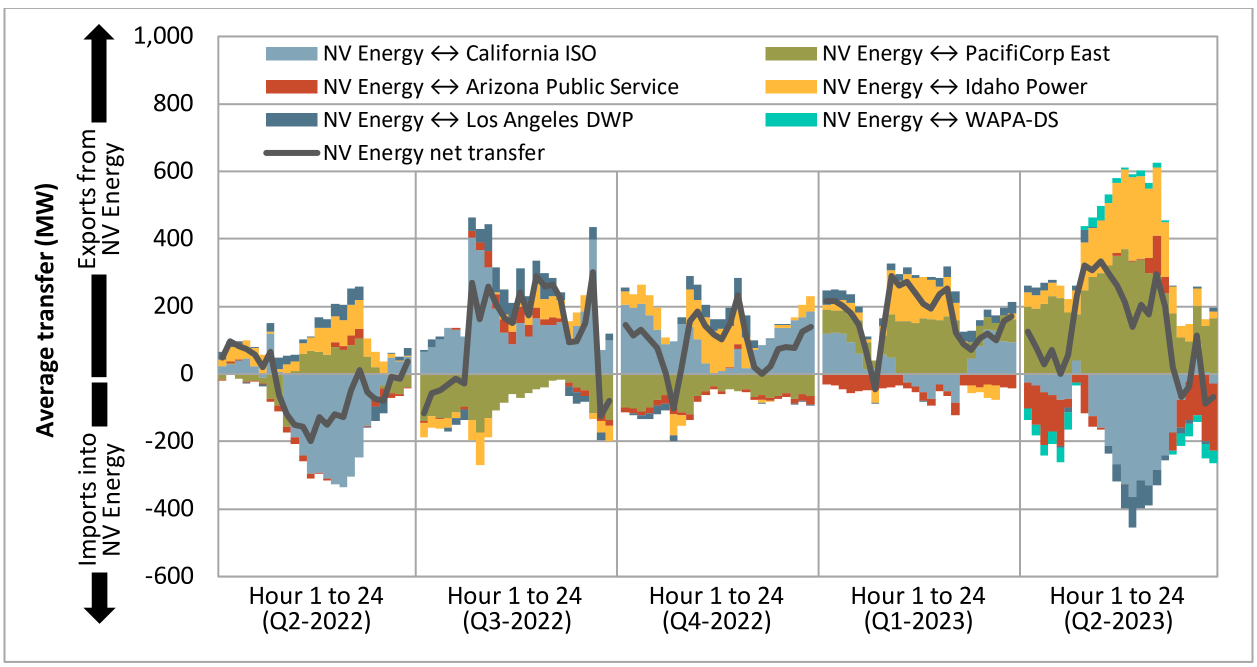
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q2 2023)

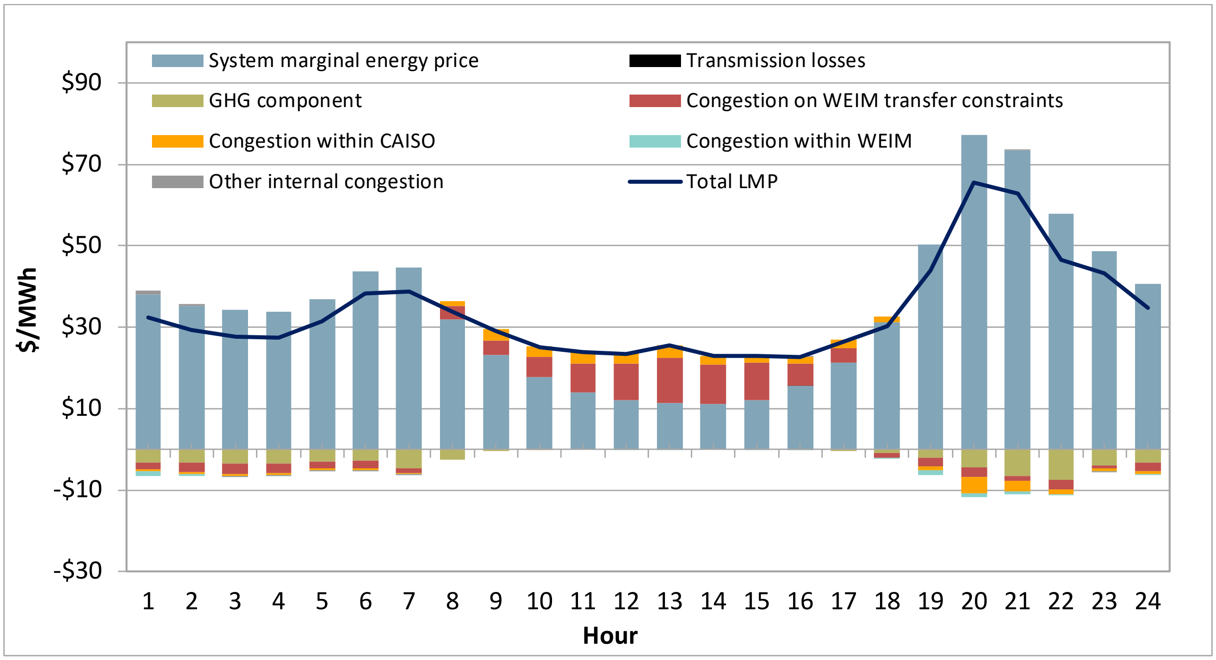


Appendix Figure A.44 Average hourly 5-minute market transfers

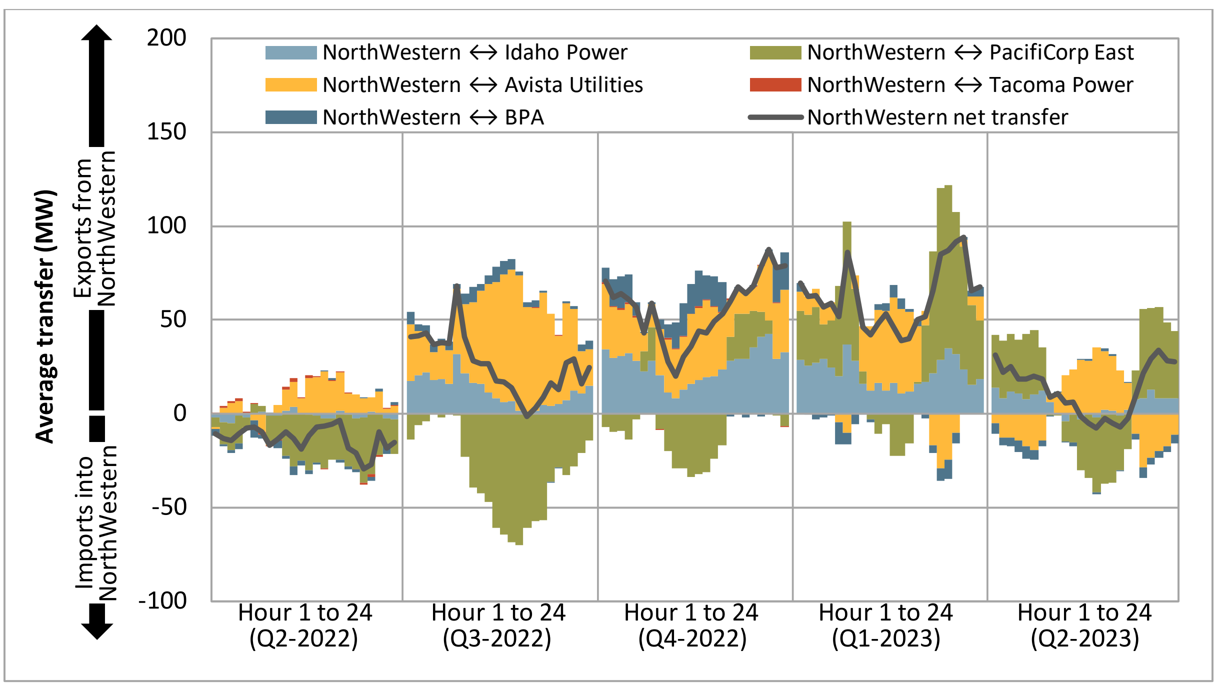


A.11 NorthWestern Energy

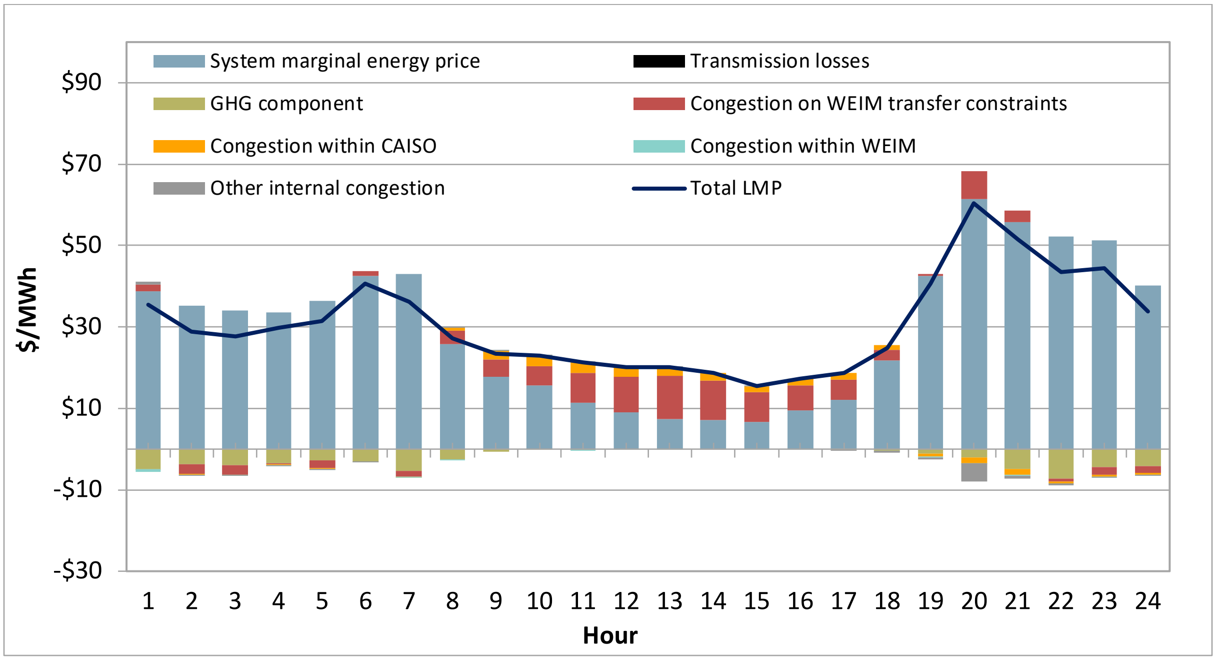
Appendix Figure A.45 Average hourly 15-minute price by component (Q2 2023)



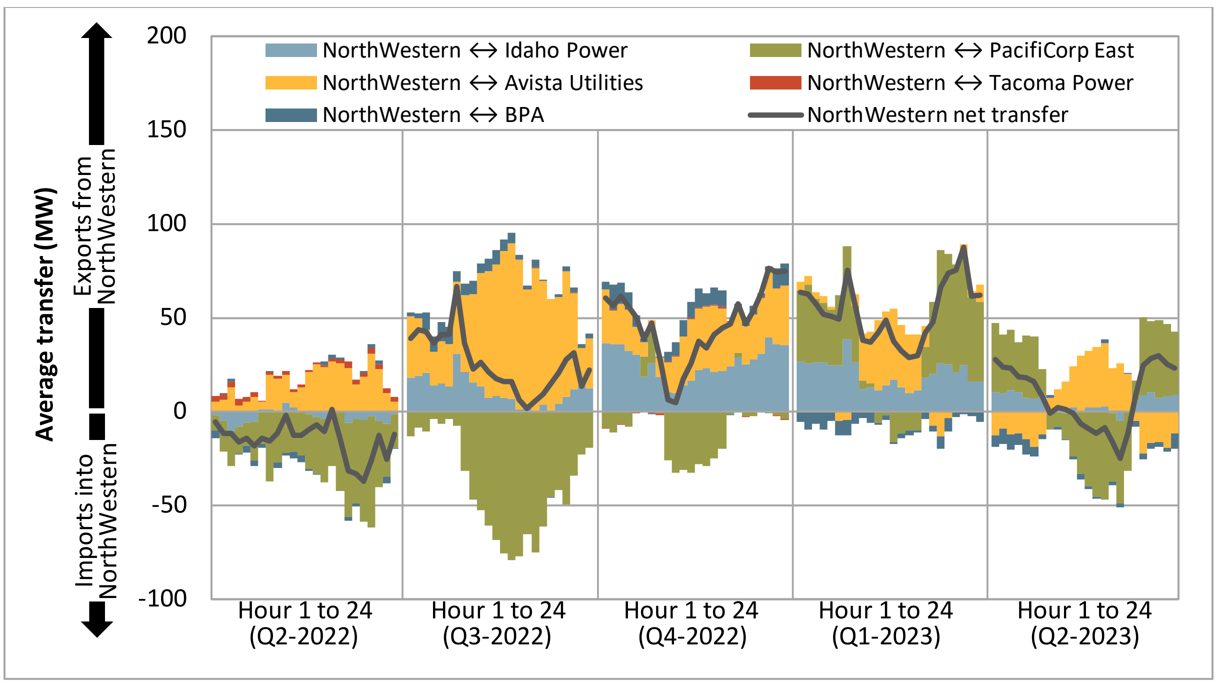
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q2 2023)

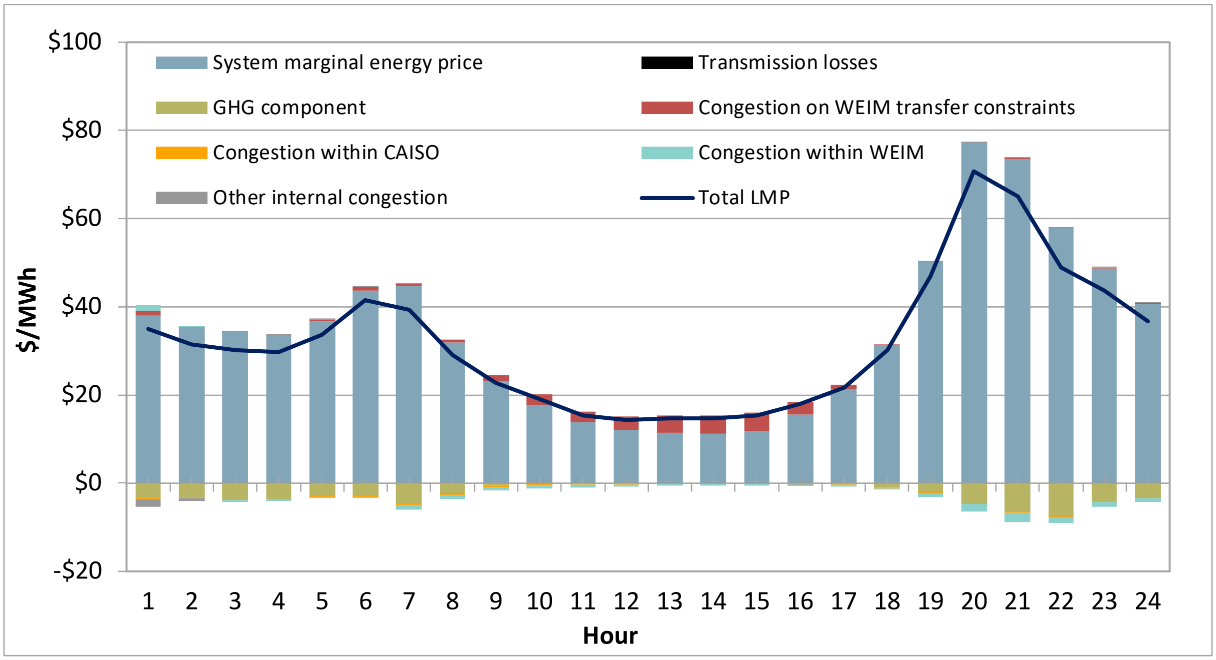


Appendix Figure A.48 Average hourly 5-minute market transfers

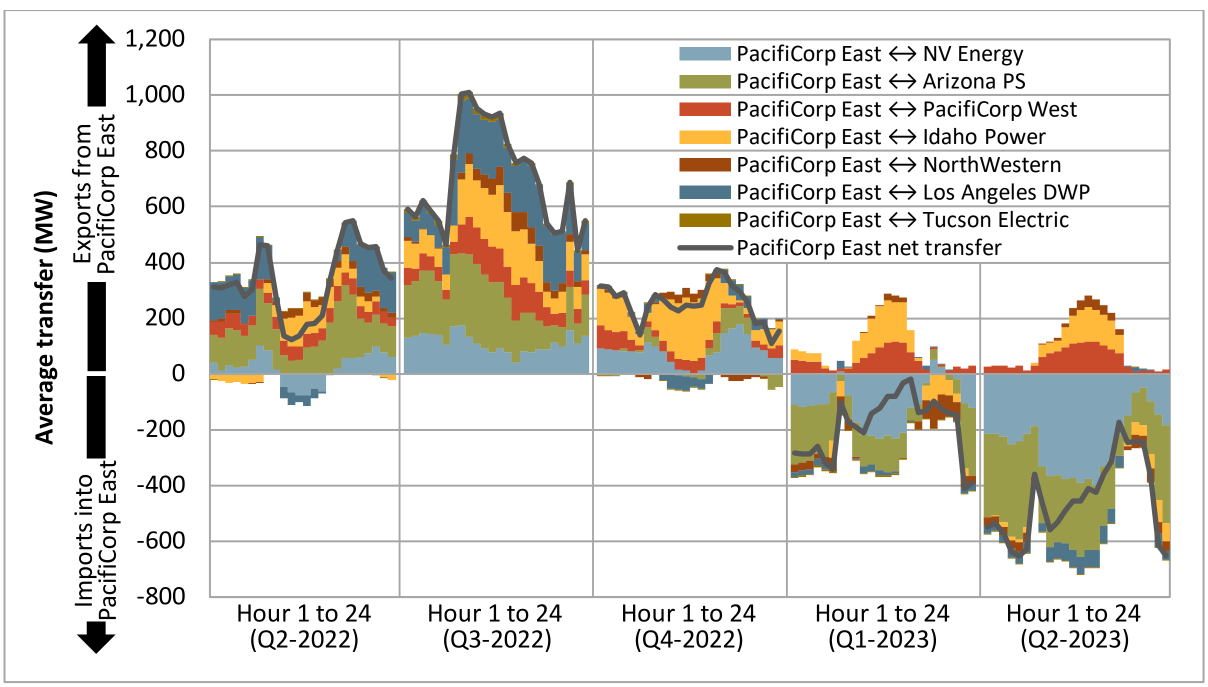


A.12 PacifiCorp East

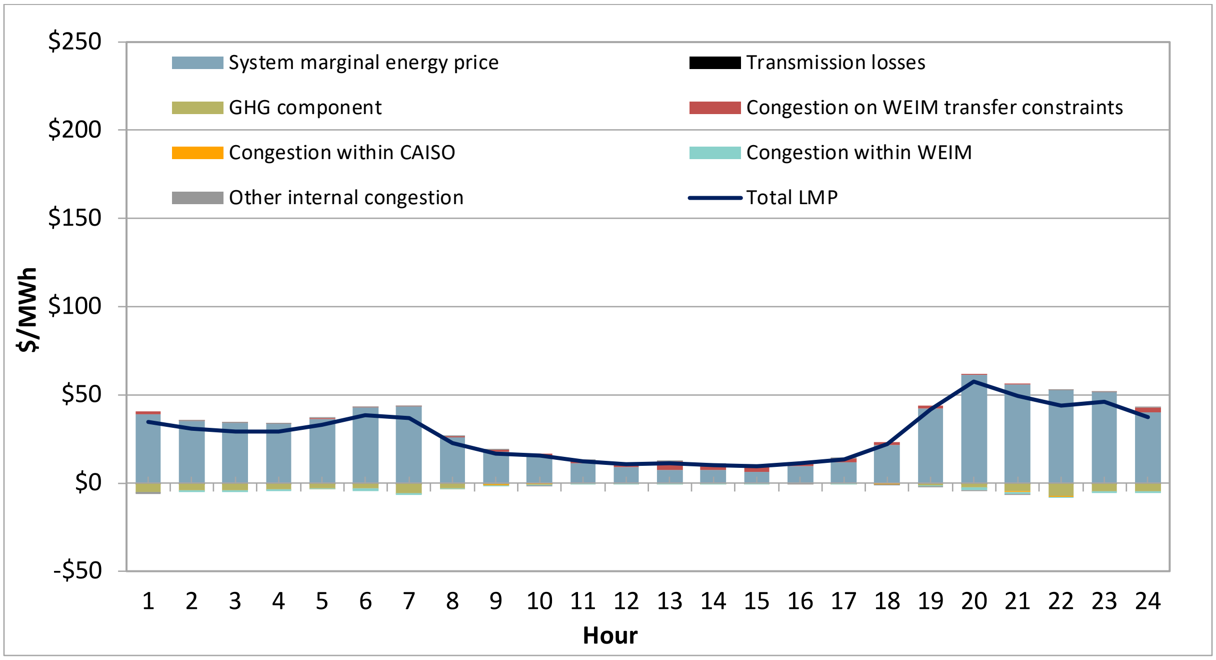
Appendix Figure A.49 Average hourly 15-minute price by component (Q2 2023)



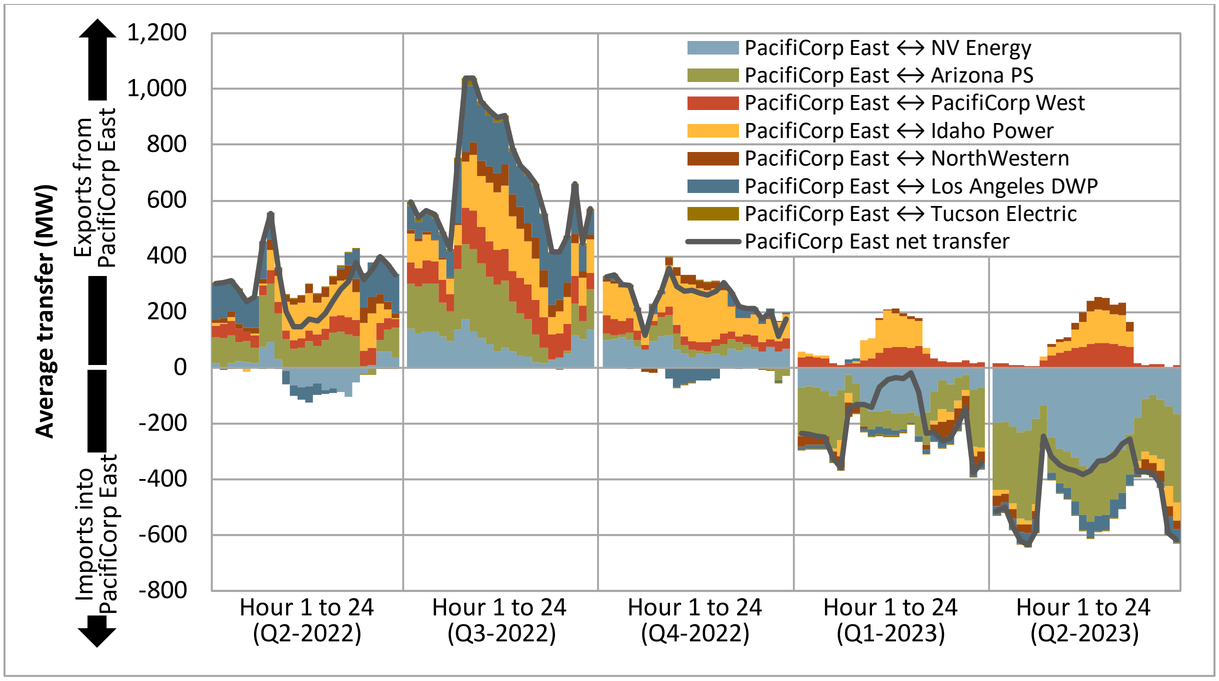
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q2 2023)

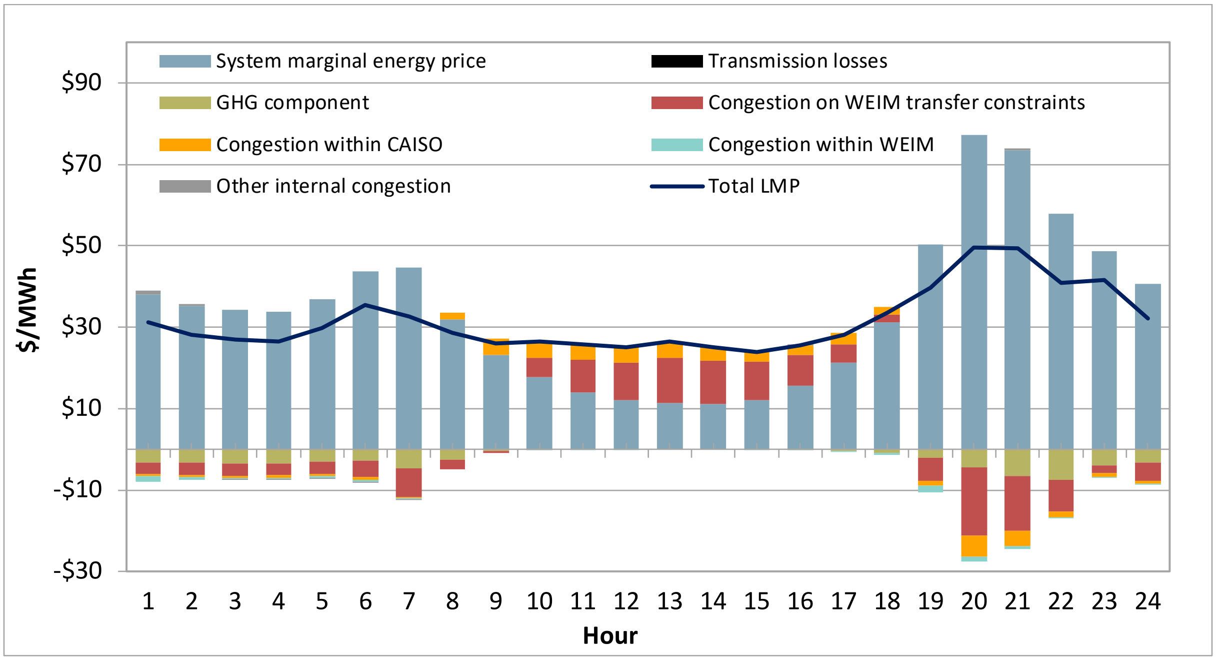


Appendix Figure A.52 Average hourly 5-minute market transfers

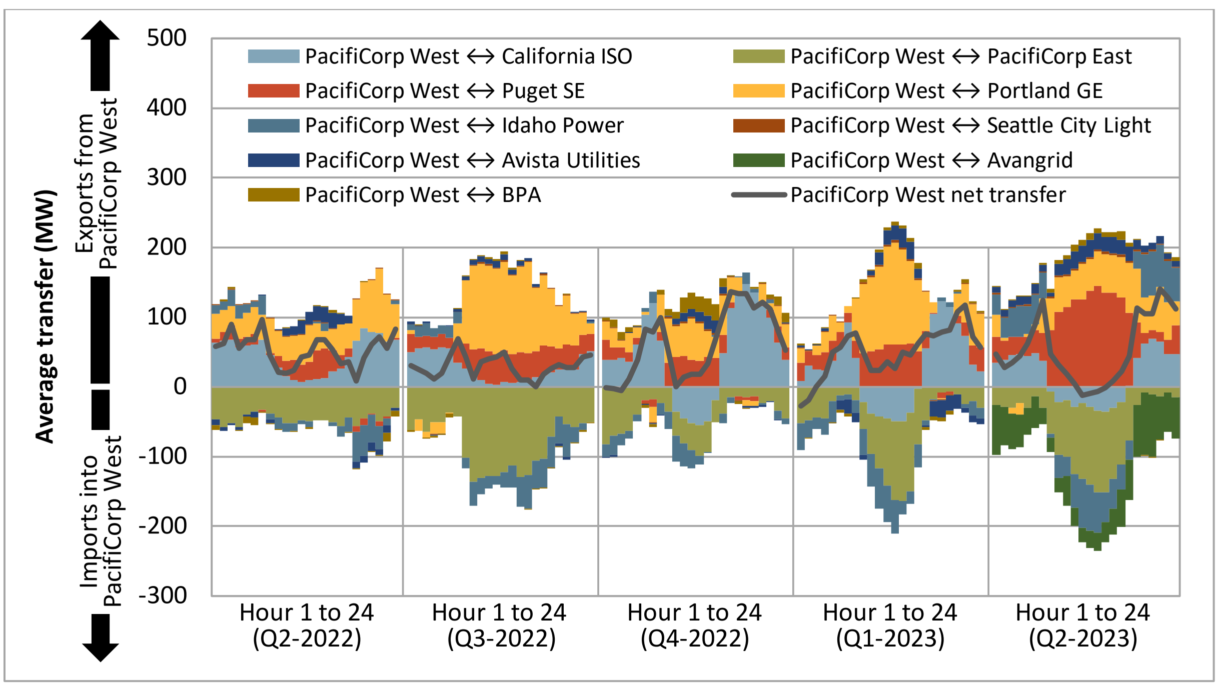


A.13 PacifiCorp West

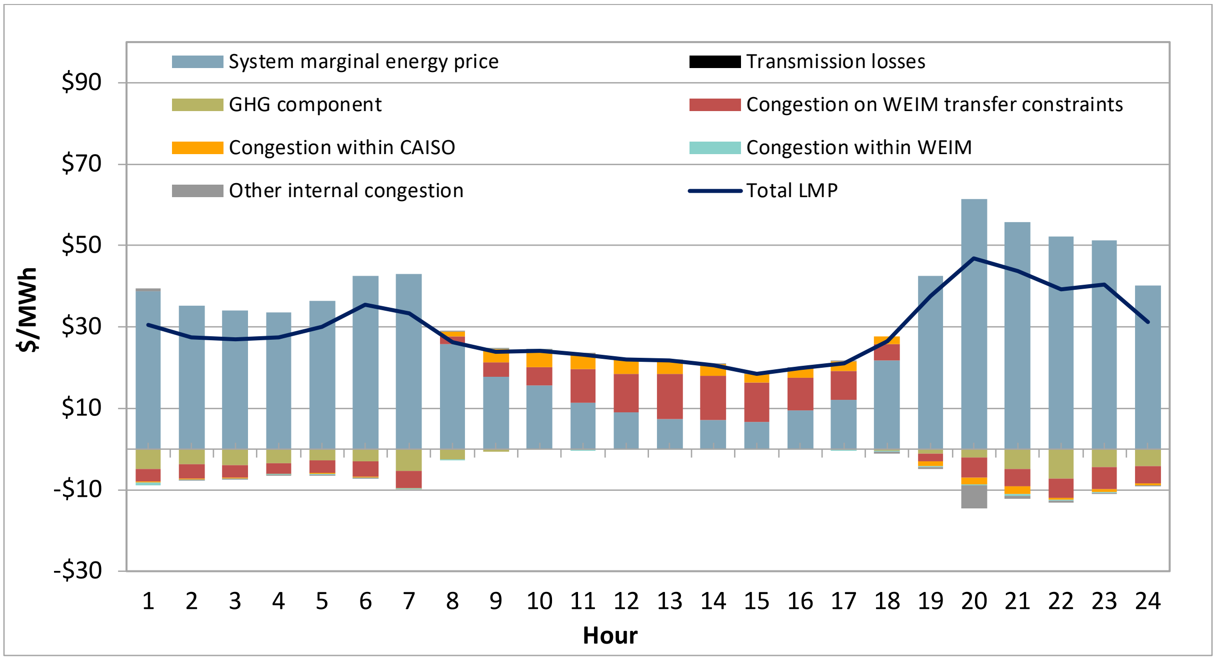
Appendix Figure A.53 Average hourly 15-minute price by component (Q2 2023)



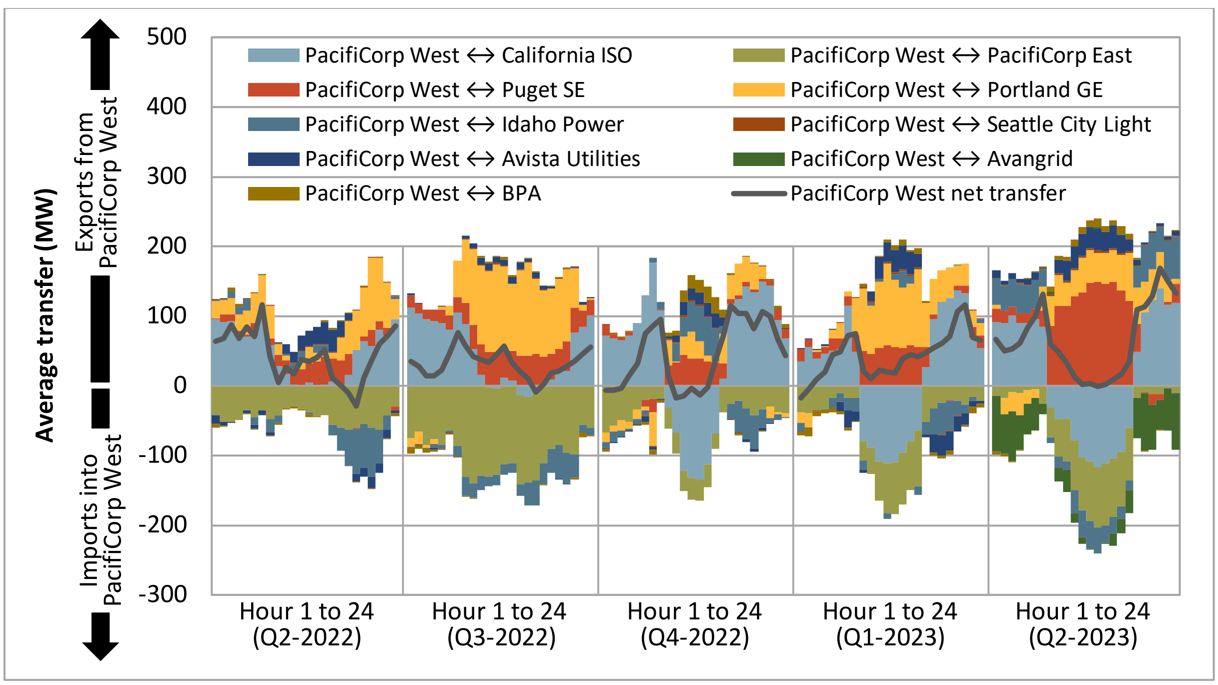
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q2 2023)

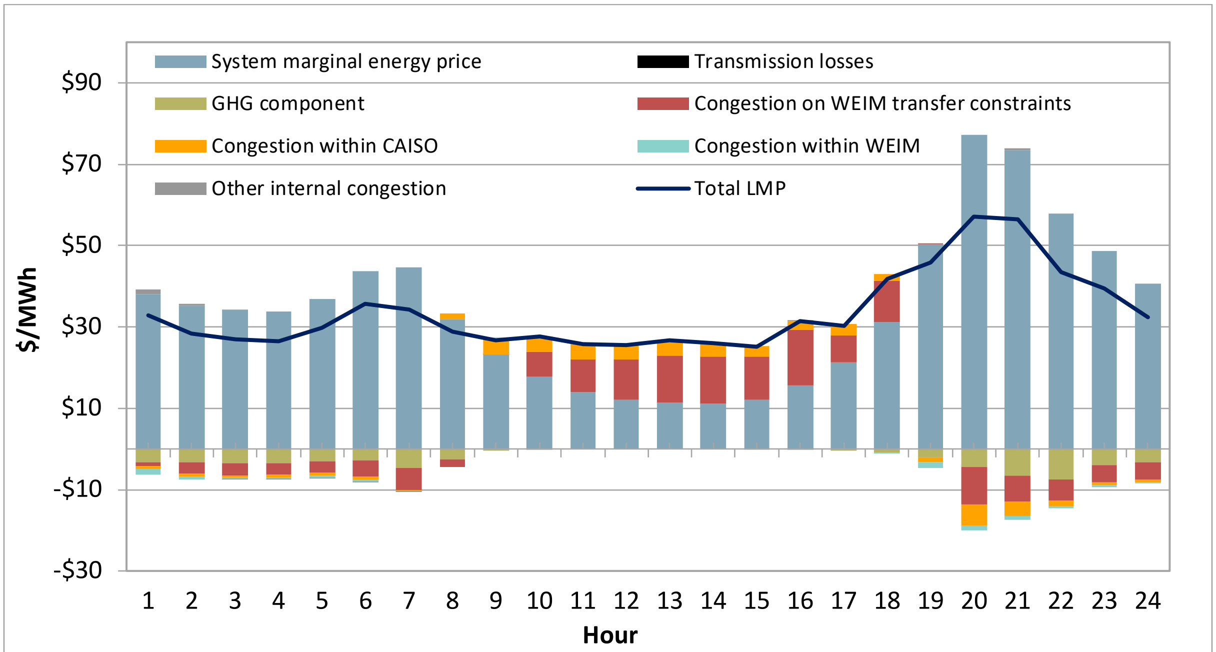


Appendix Figure A.56 Average hourly 5-minute market transfers

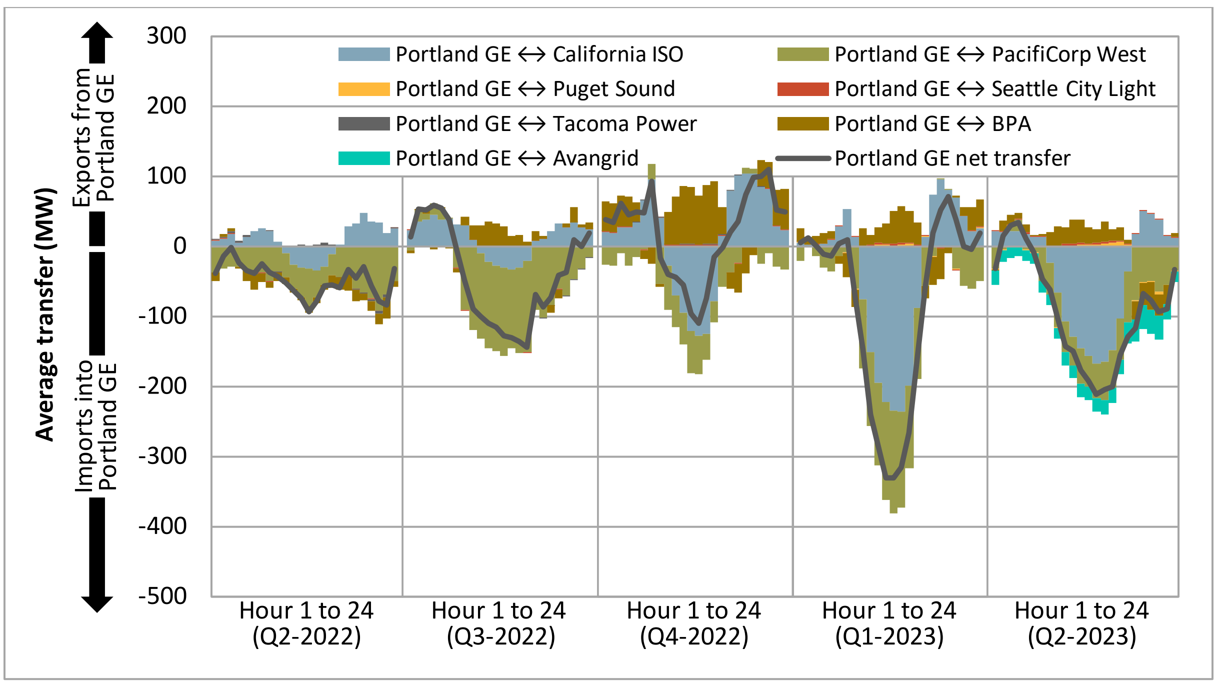


A.14 Portland General Electric

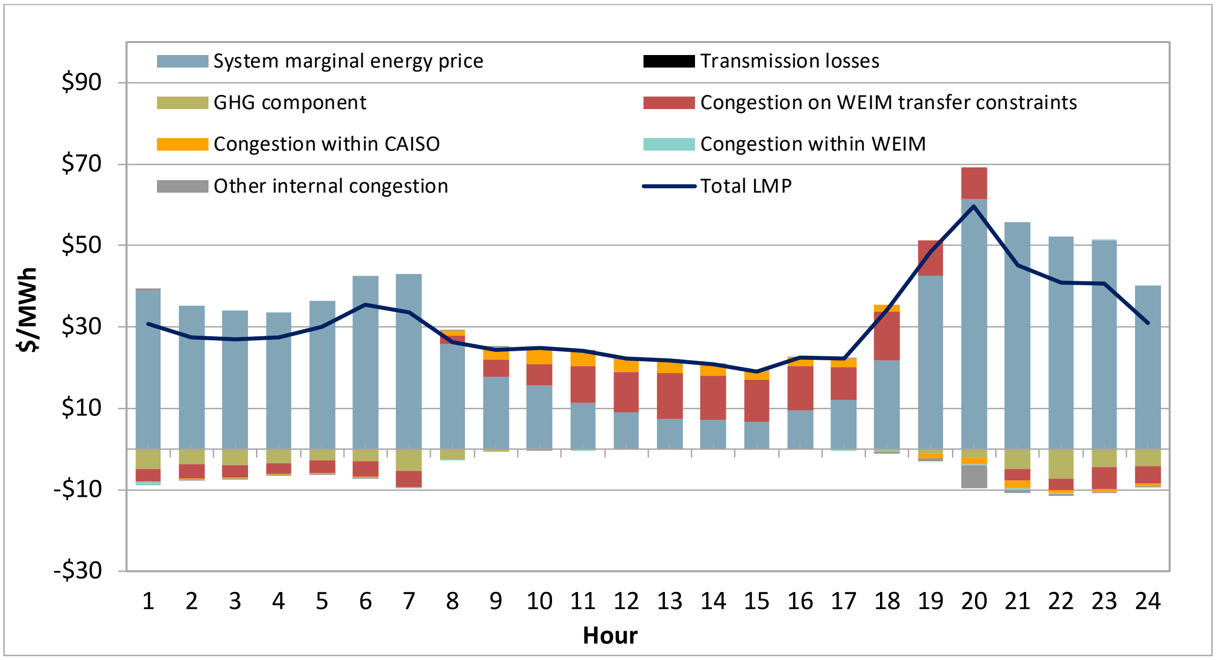
Appendix Figure A.57 Average hourly 15-minute price by component (Q2 2023)



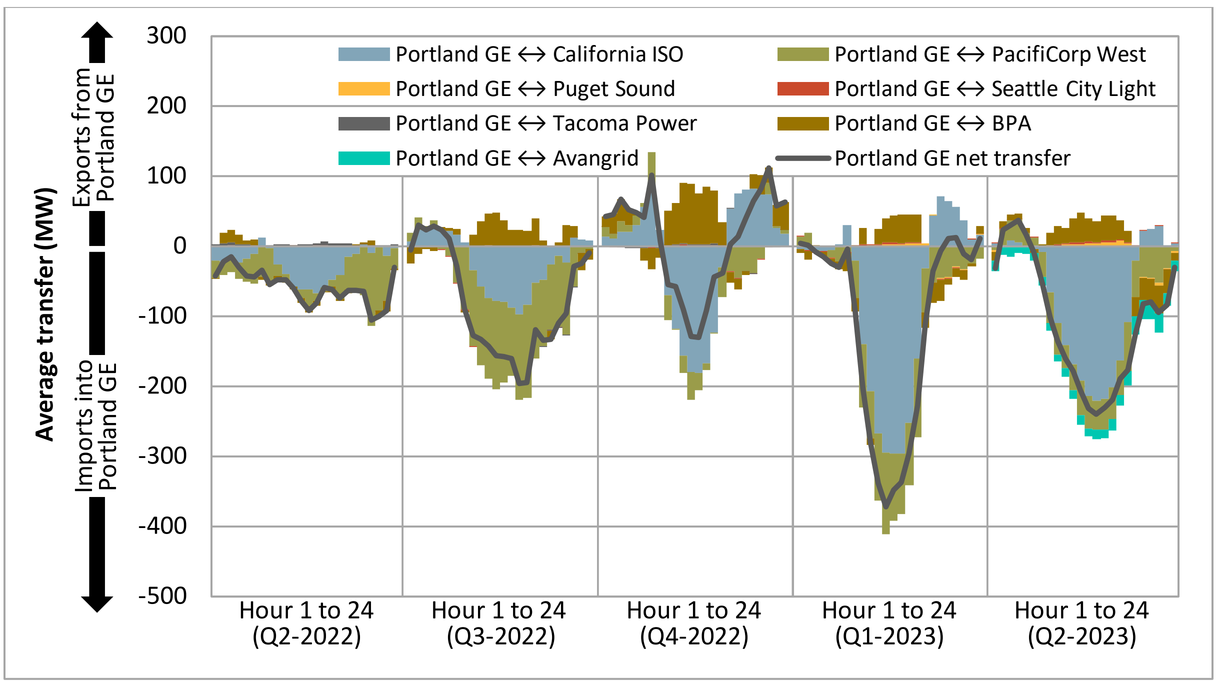
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q2 2023)

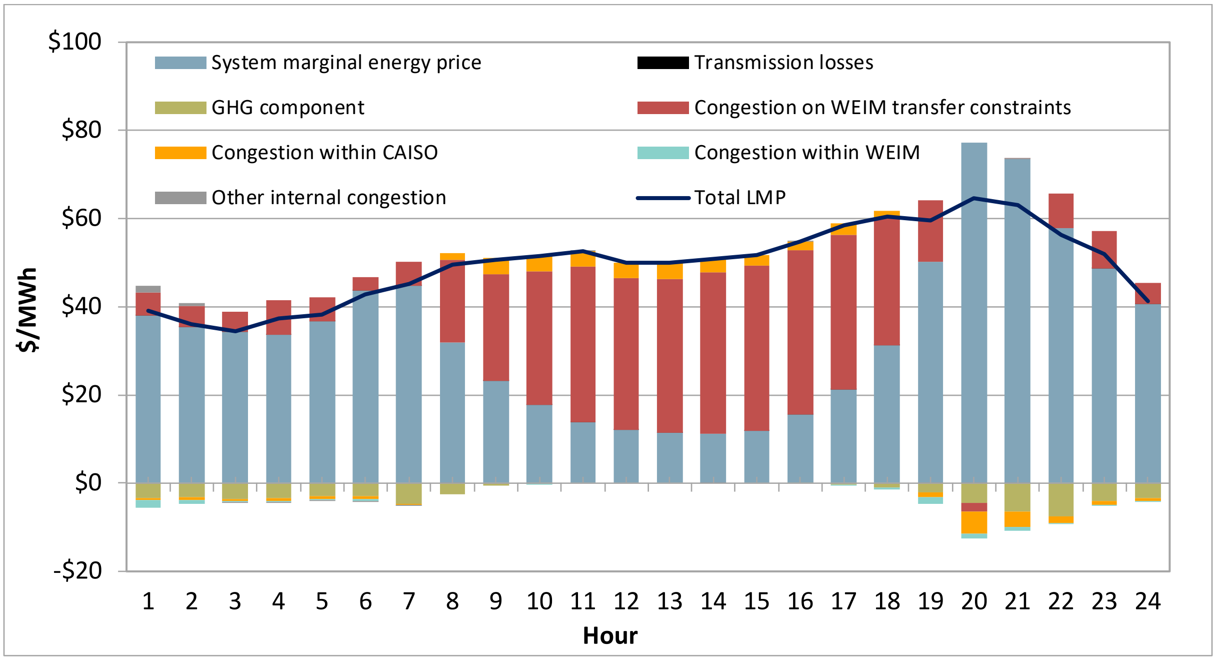


Appendix Figure A.60 Average hourly 5-minute market transfers

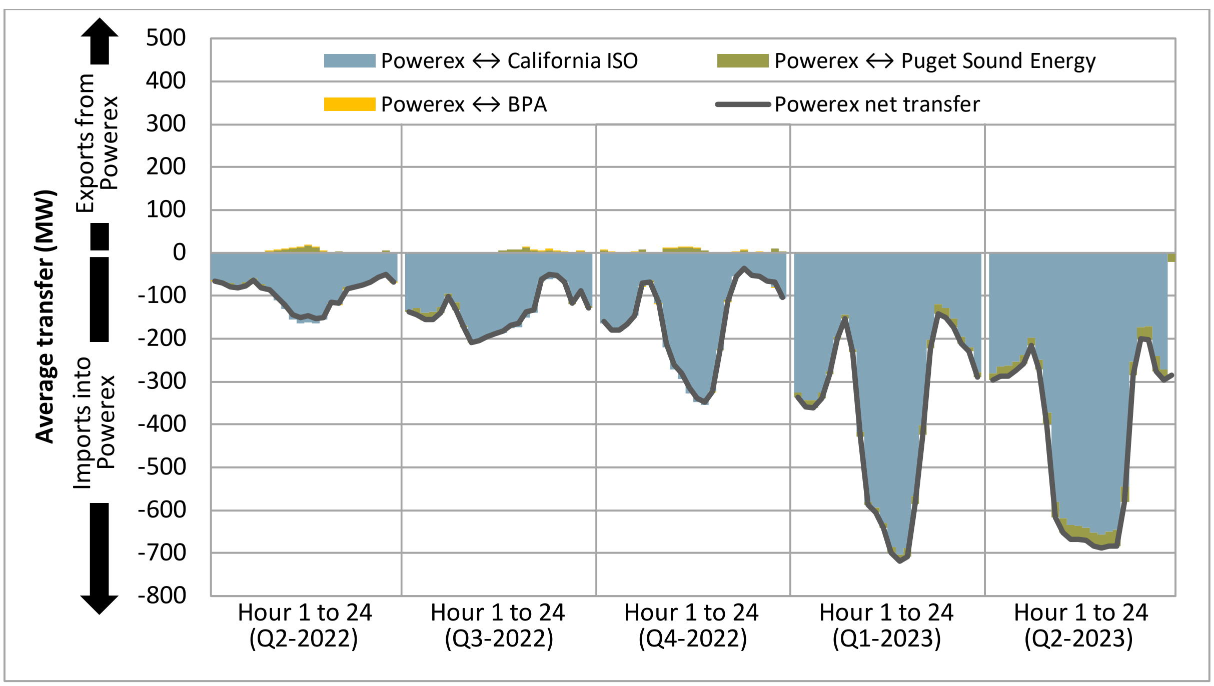


A.15 Powerex

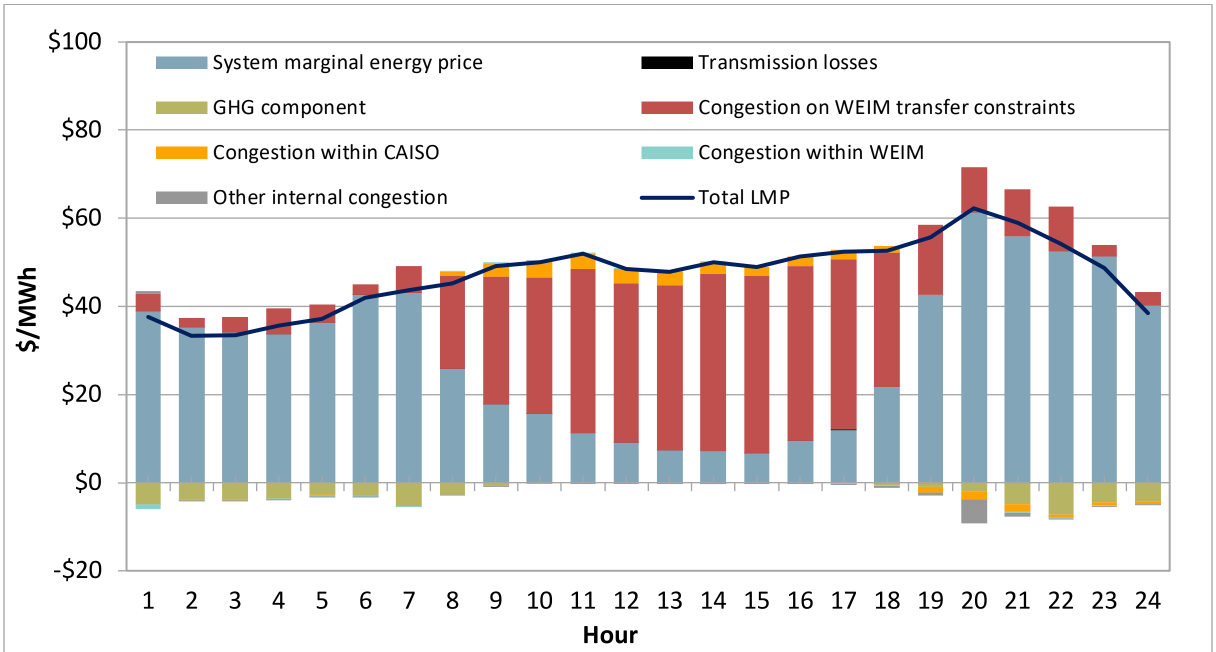
Appendix Figure A.61 Average hourly 15-minute price by component (Q2 2023)



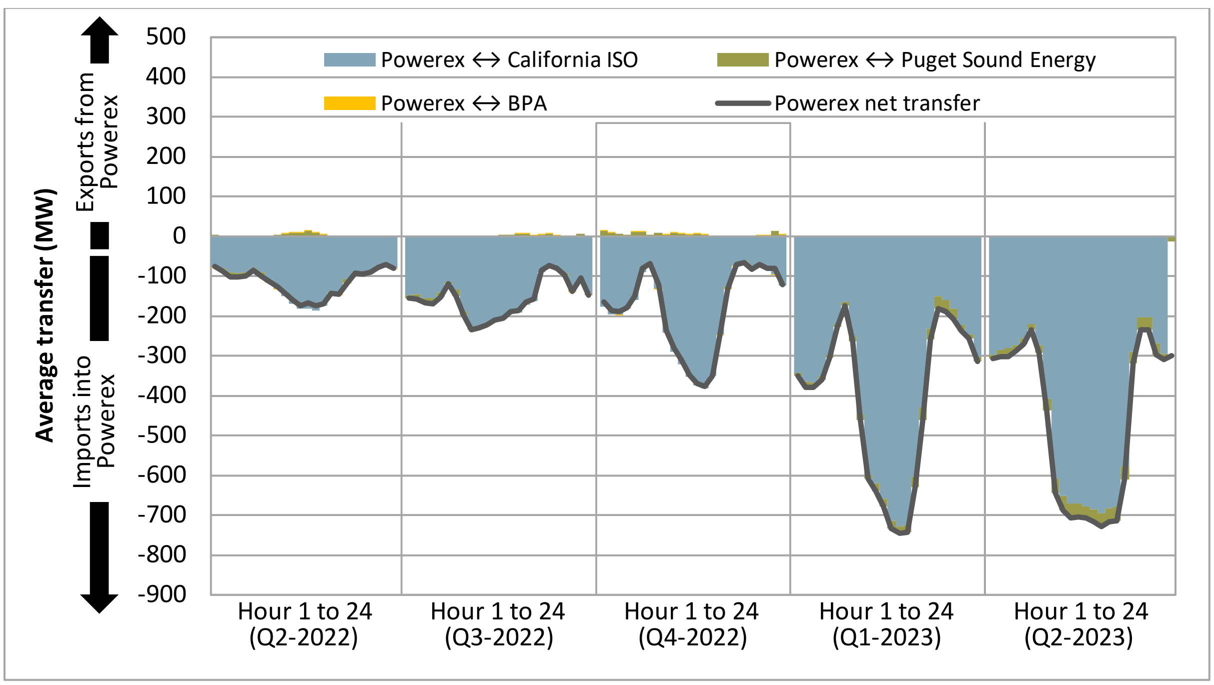
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q2 2023)

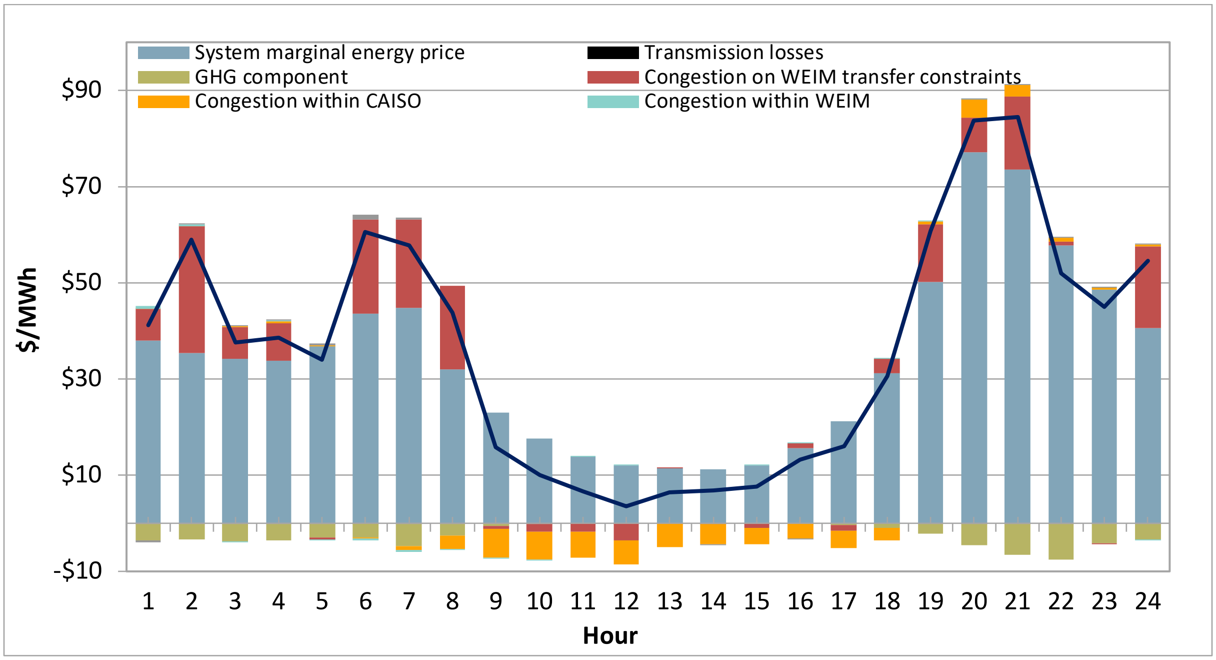


Appendix Figure A.64 Average hourly 5-minute market transfers

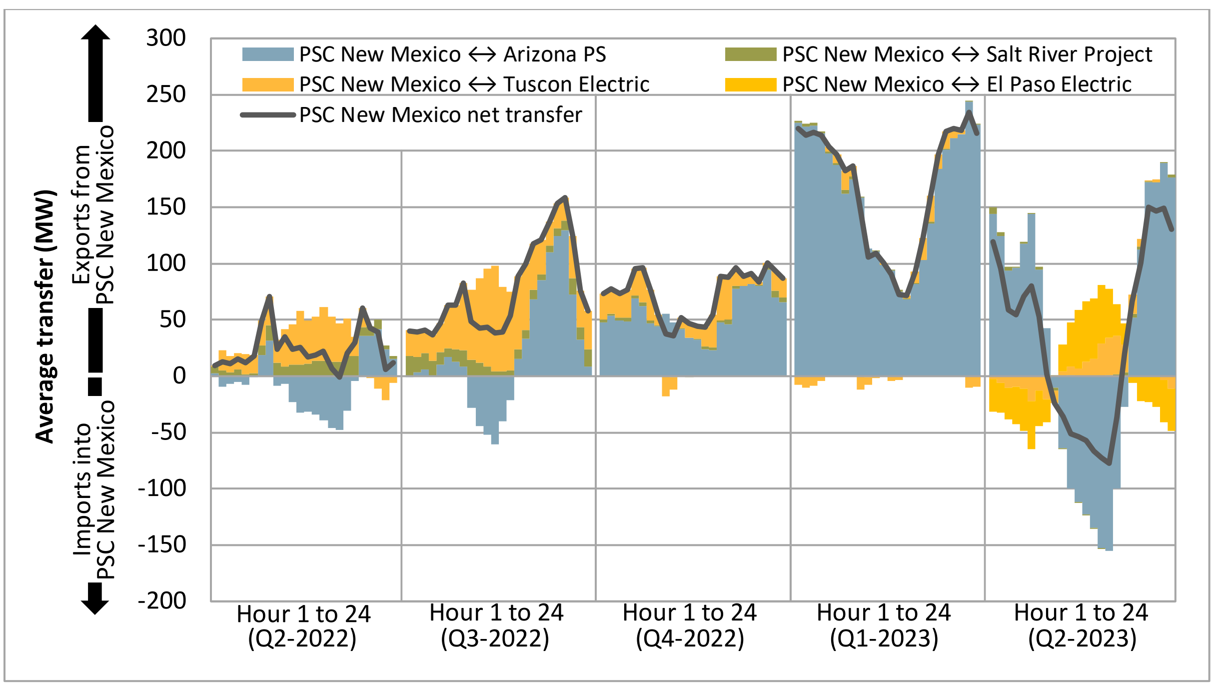


A.16 Public Service Company of New Mexico

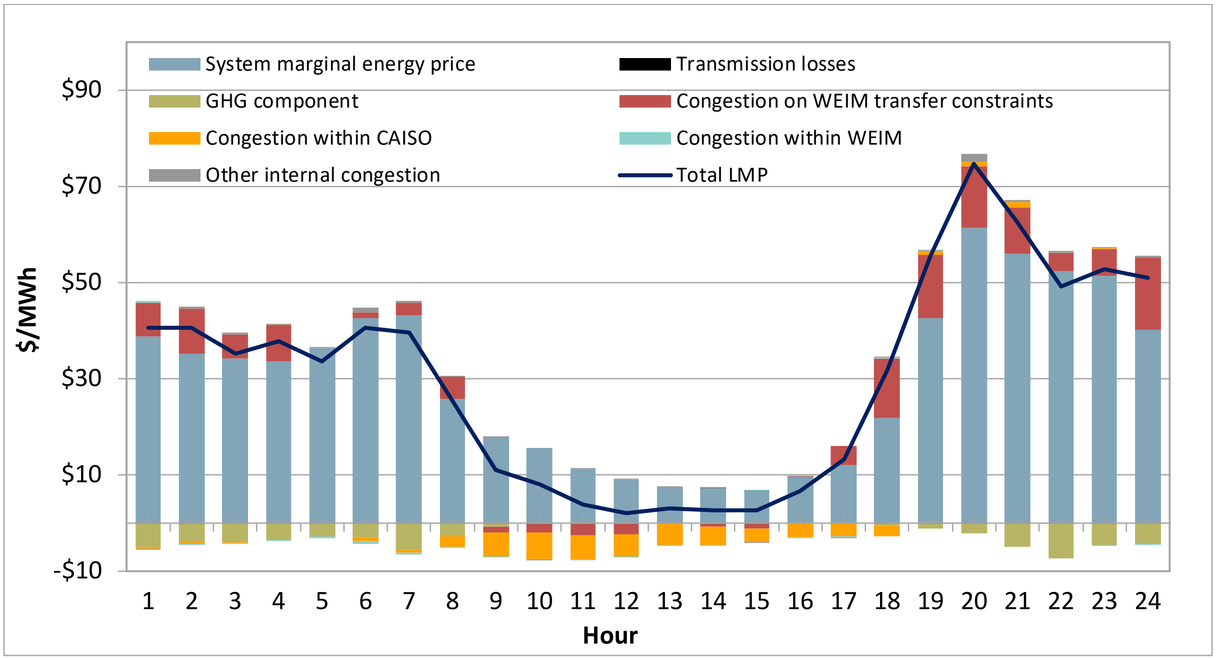
Appendix Figure A.65 Average hourly 15-minute price by component (Q2 2023)



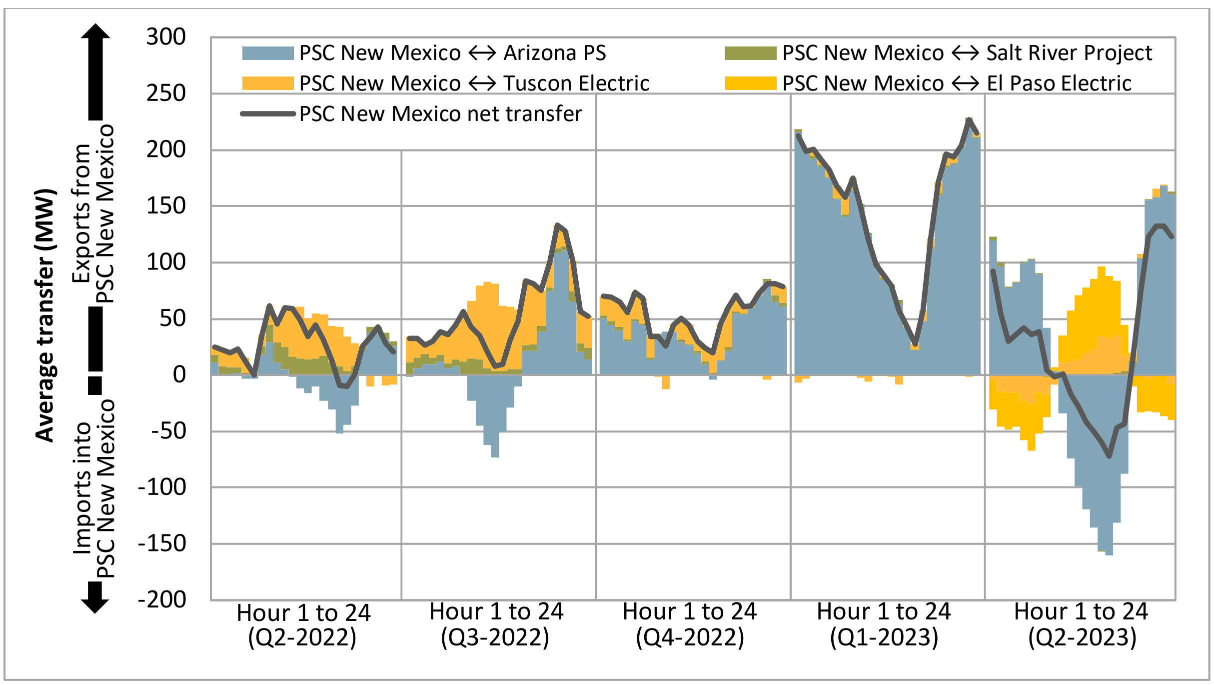
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q2 2023)

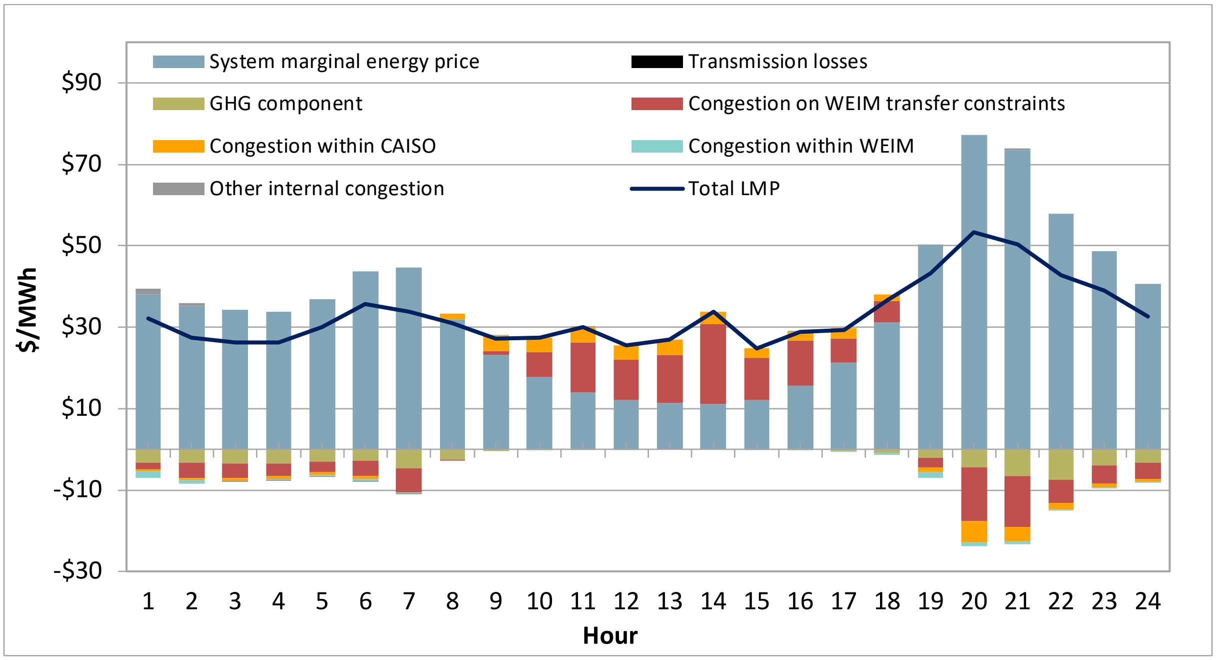


Appendix Figure A.68 Average hourly 5-minute market transfers

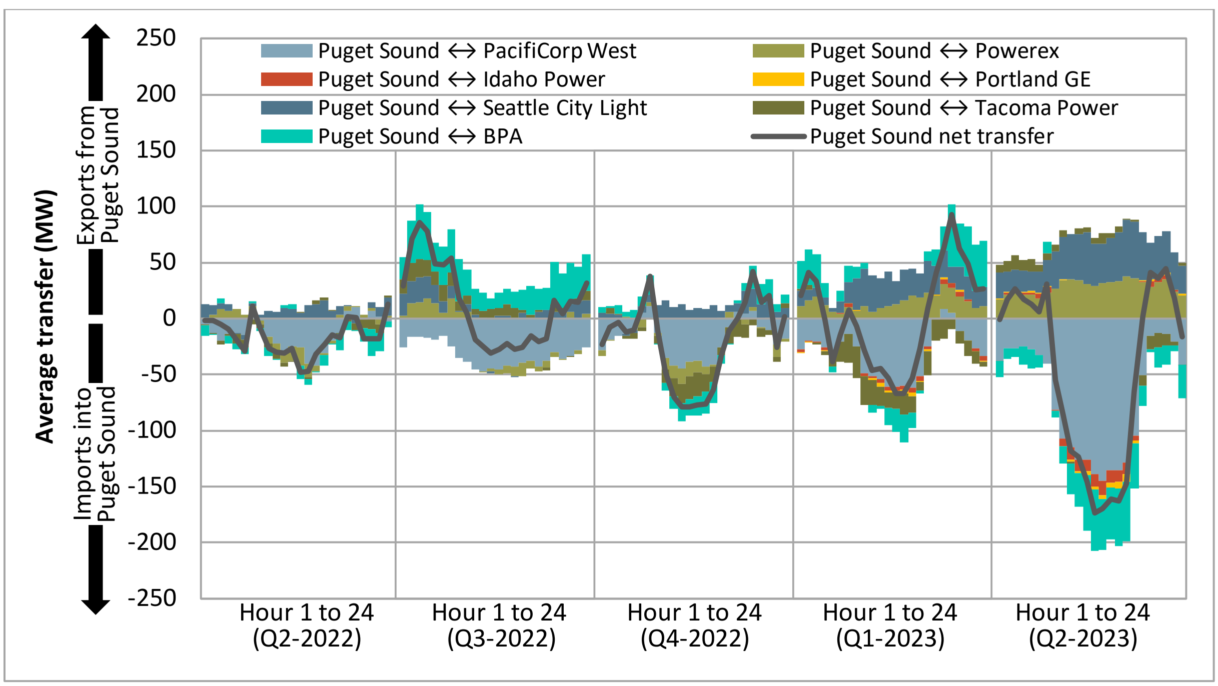


A.17 Puget Sound Energy

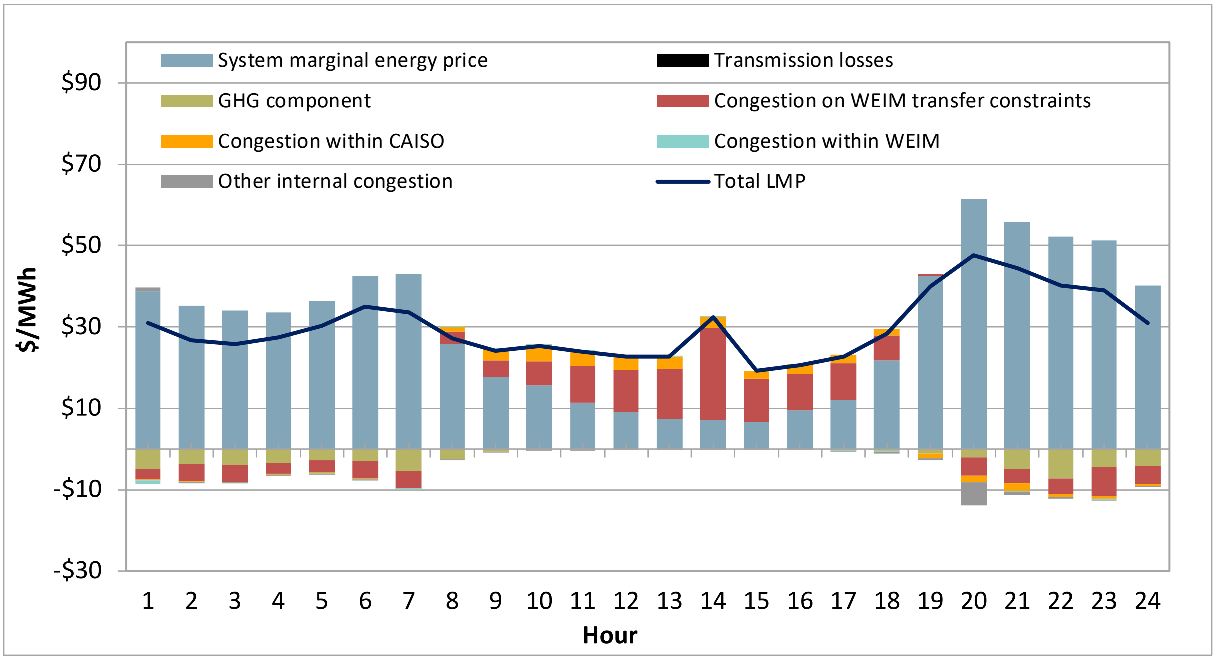
Appendix Figure A.69 Average hourly 15-minute price by component (Q2 2023)



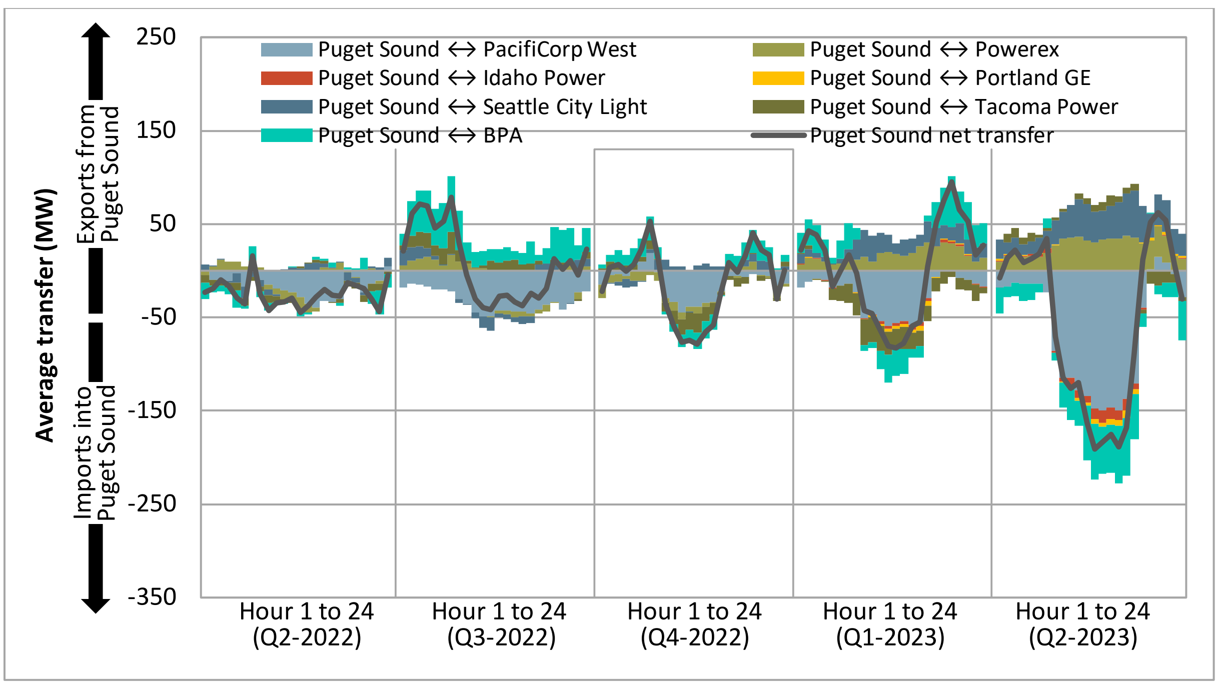
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q2 2023)

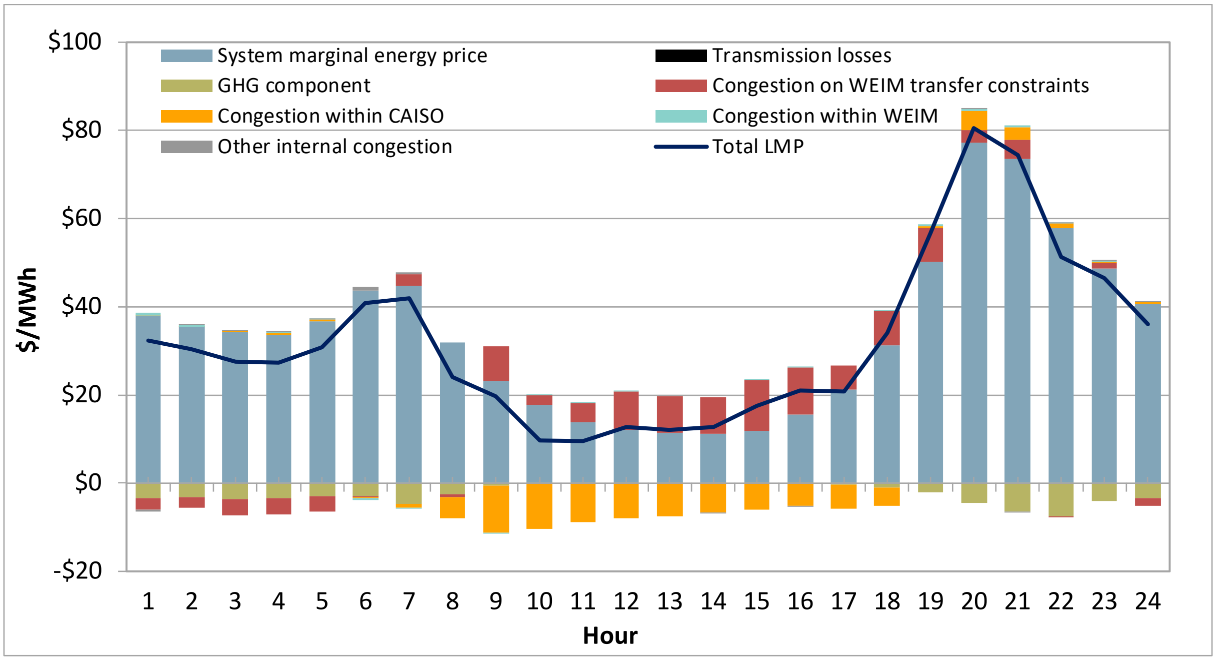


Appendix Figure A.72 Average hourly 5-minute market transfers

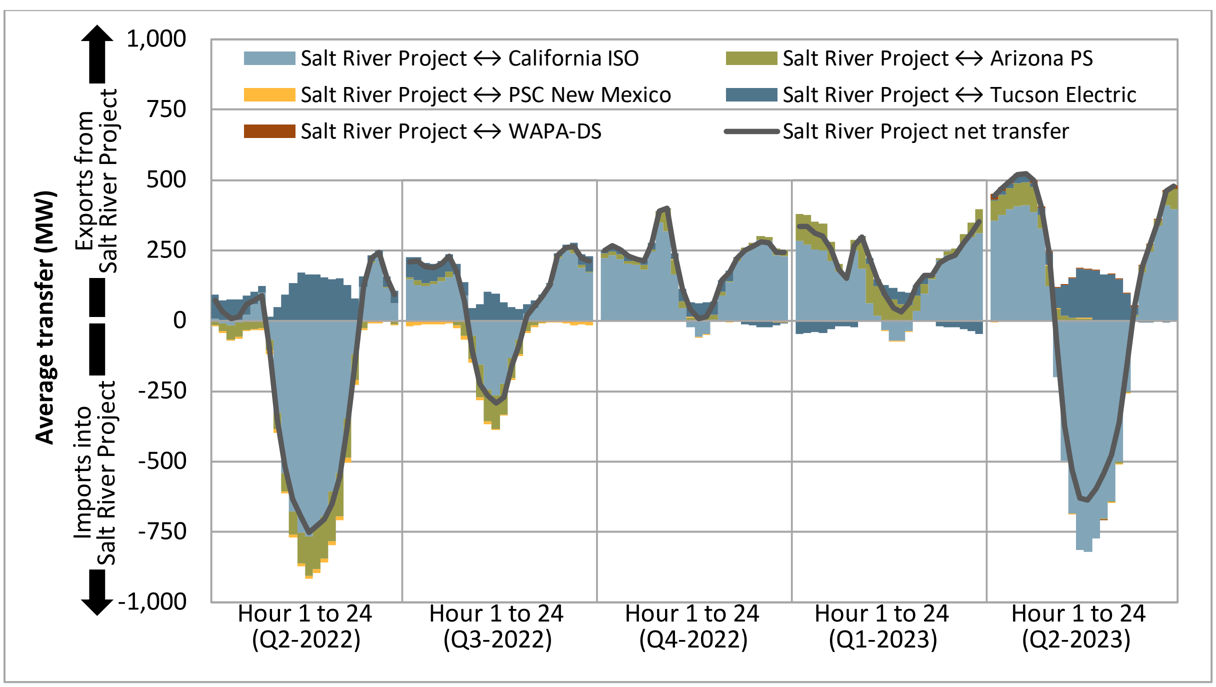


A.18 Salt River Project

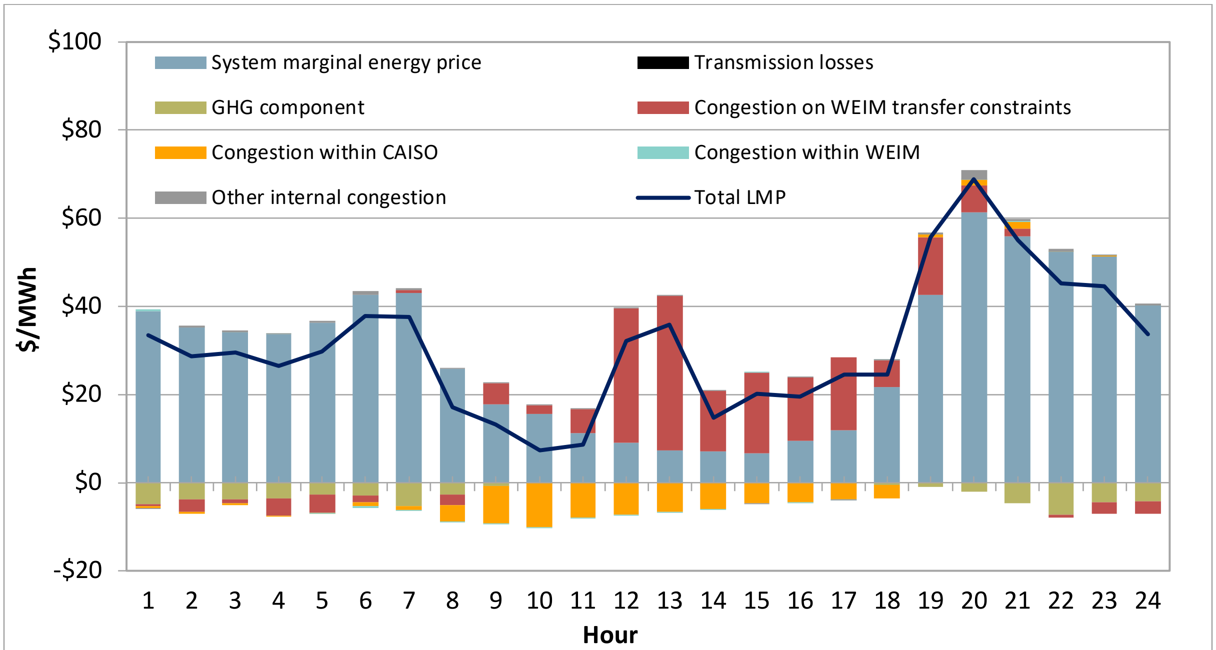
Appendix Figure A.73 Average hourly 15-minute price by component (Q2 2023)



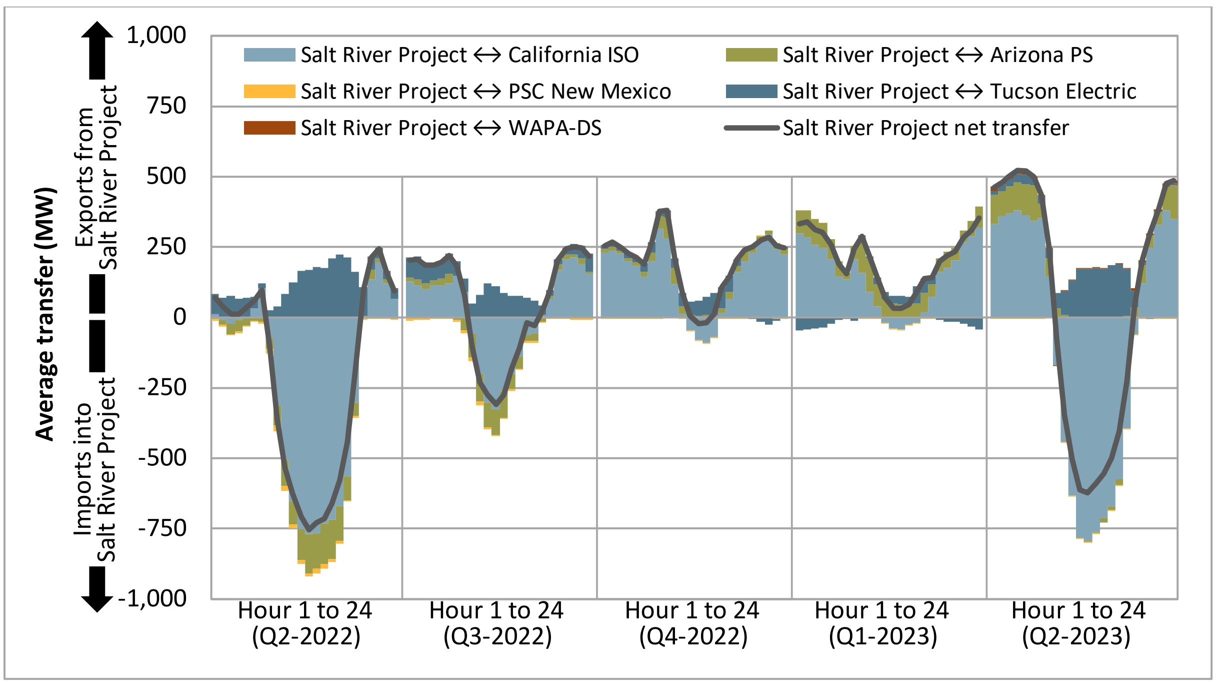
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q2 2023)

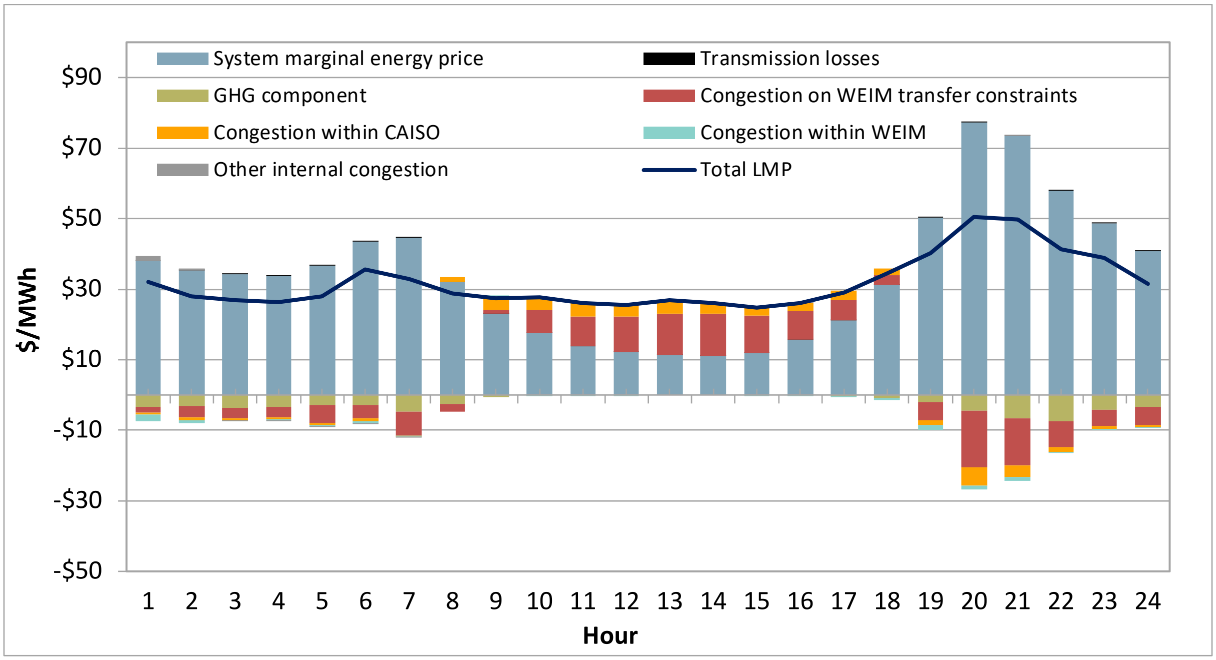


Appendix Figure A.76 Average hourly 5-minute market transfers

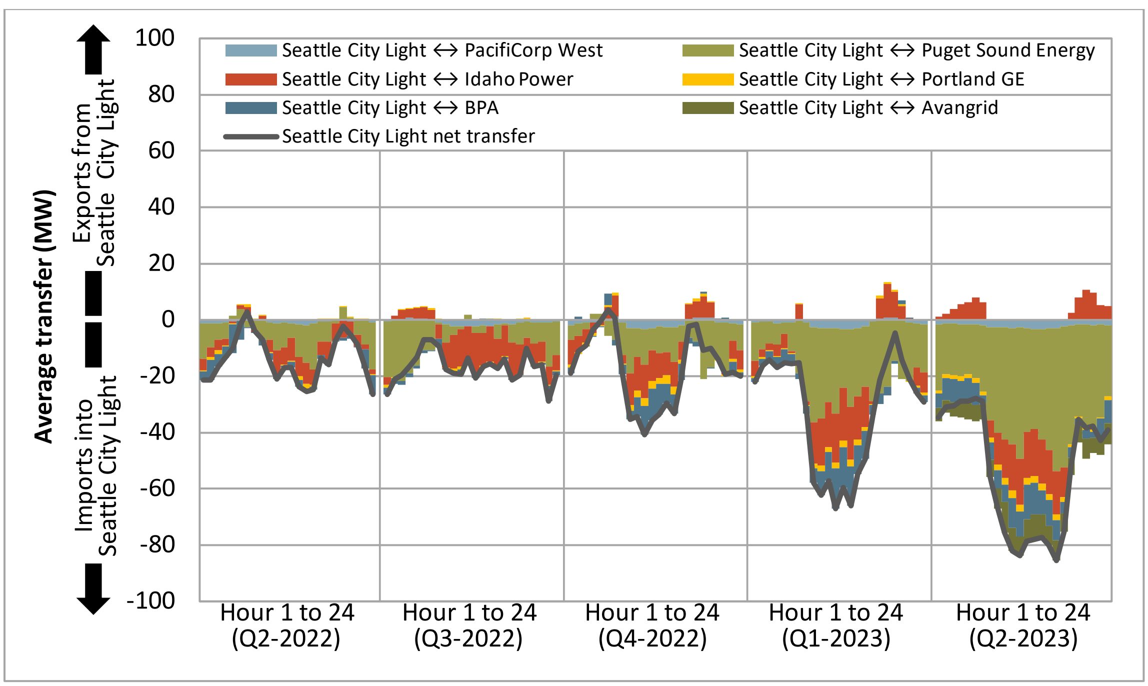


A.19 Seattle City Light

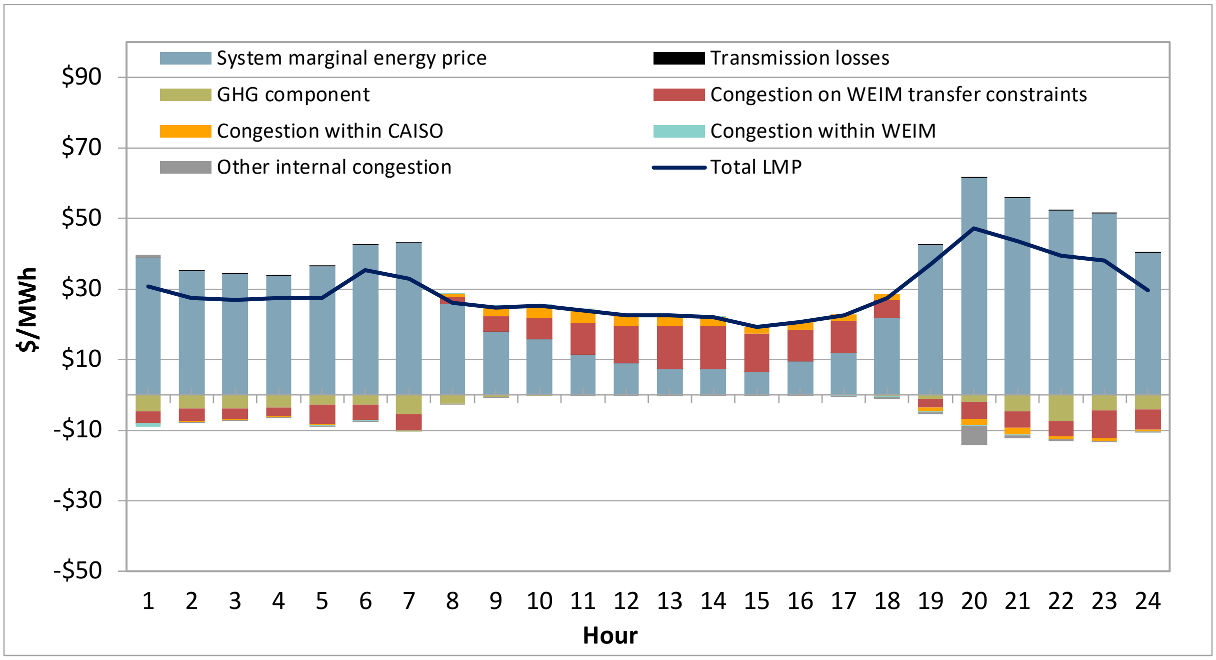
Appendix Figure A.77 Average hourly 15-minute price by component (Q2 2023)



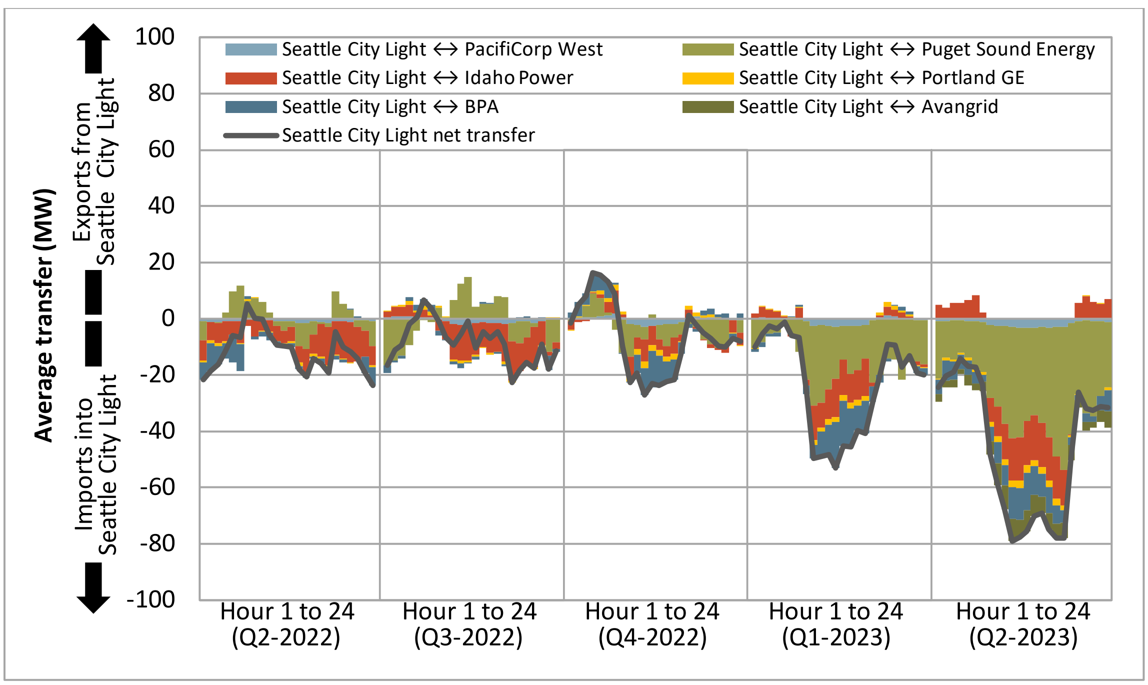
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q2 2023)

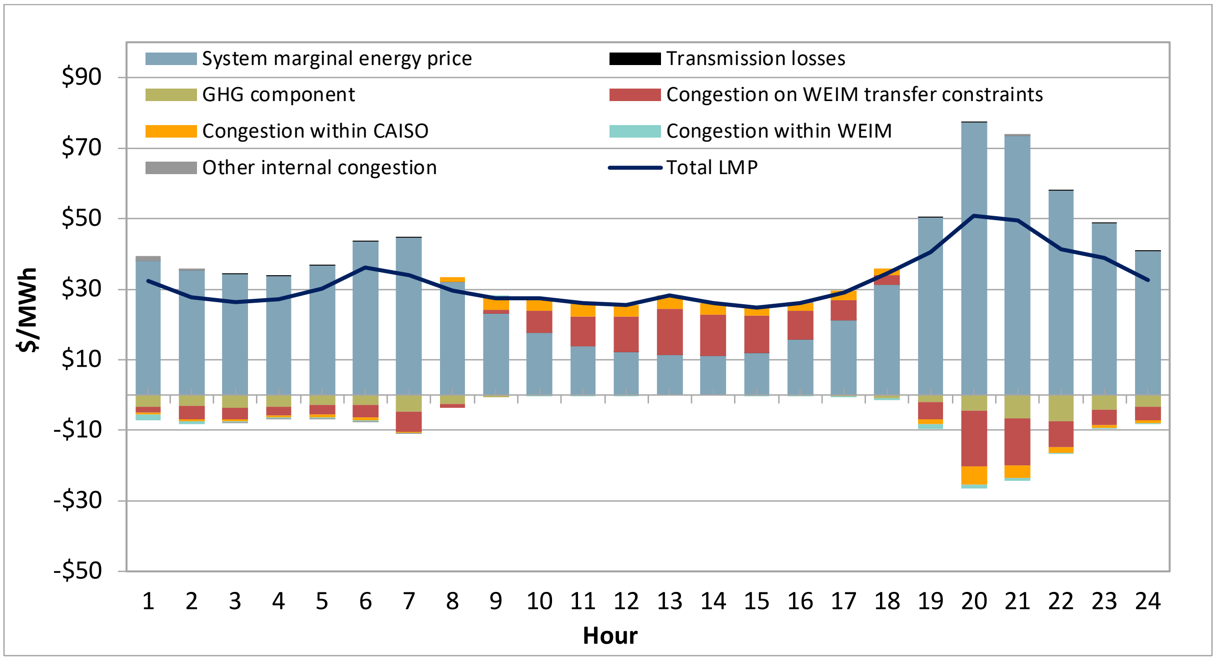


Appendix Figure A.80 Average hourly 5-minute market transfers

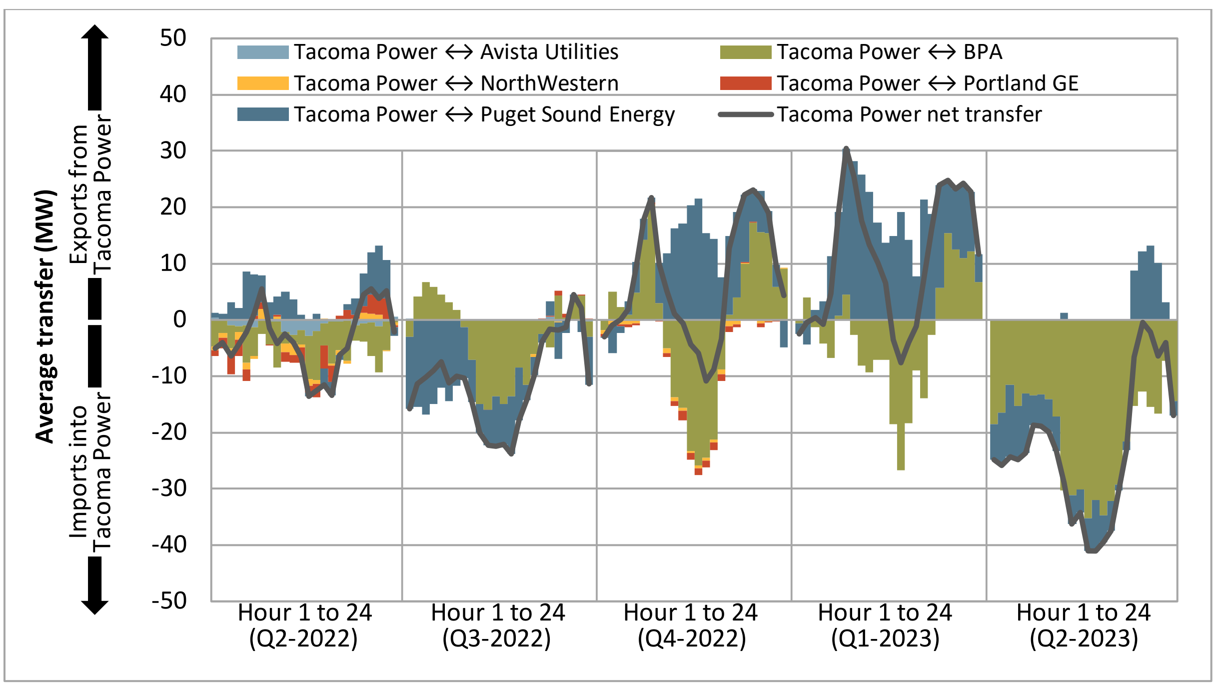


A.20 Tacoma Power

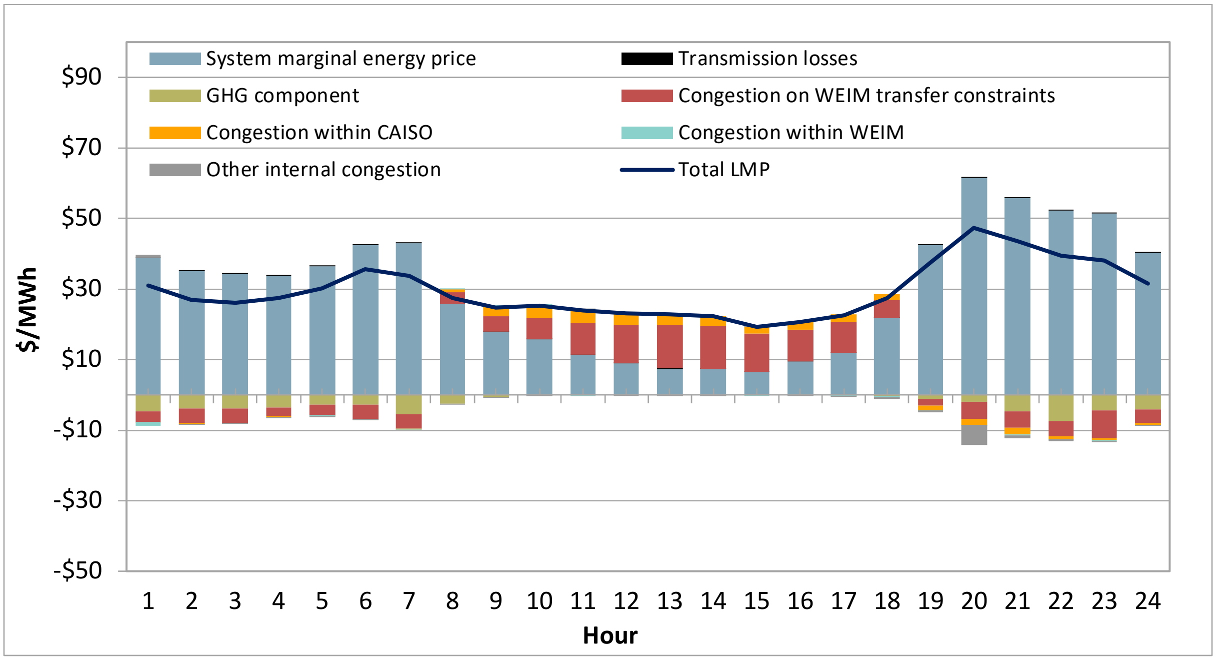
Appendix Figure A.81 Average hourly 15-minute price by component (Q2 2023)



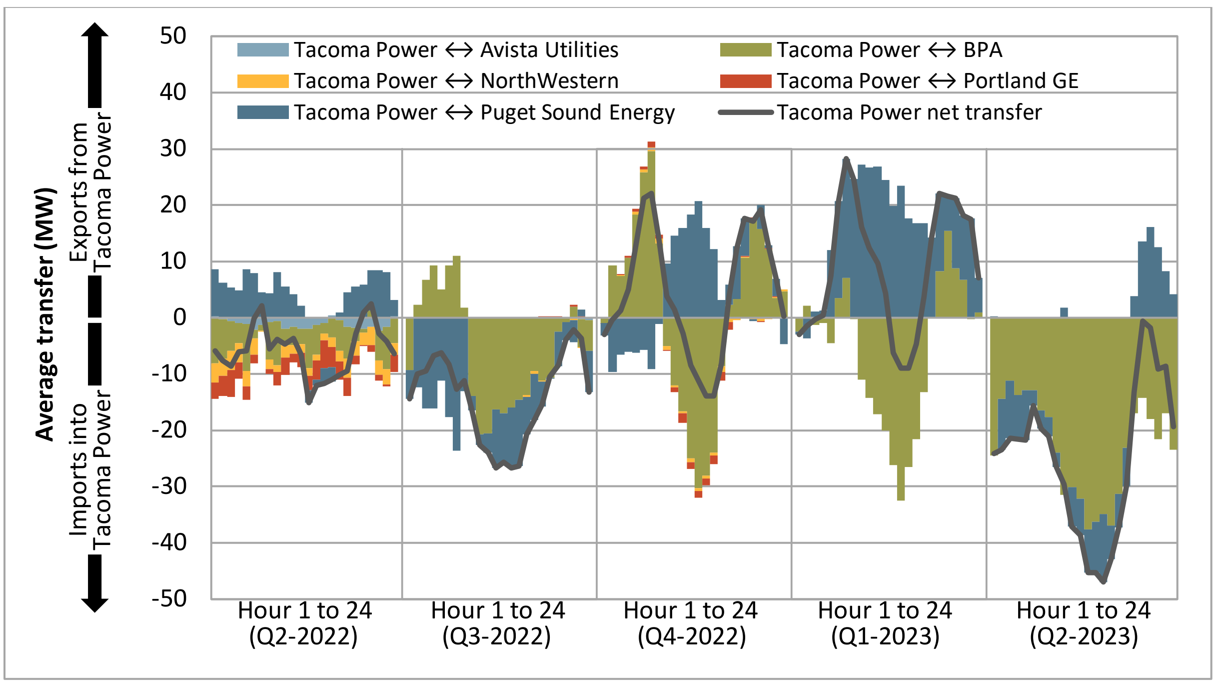
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q2 2023)

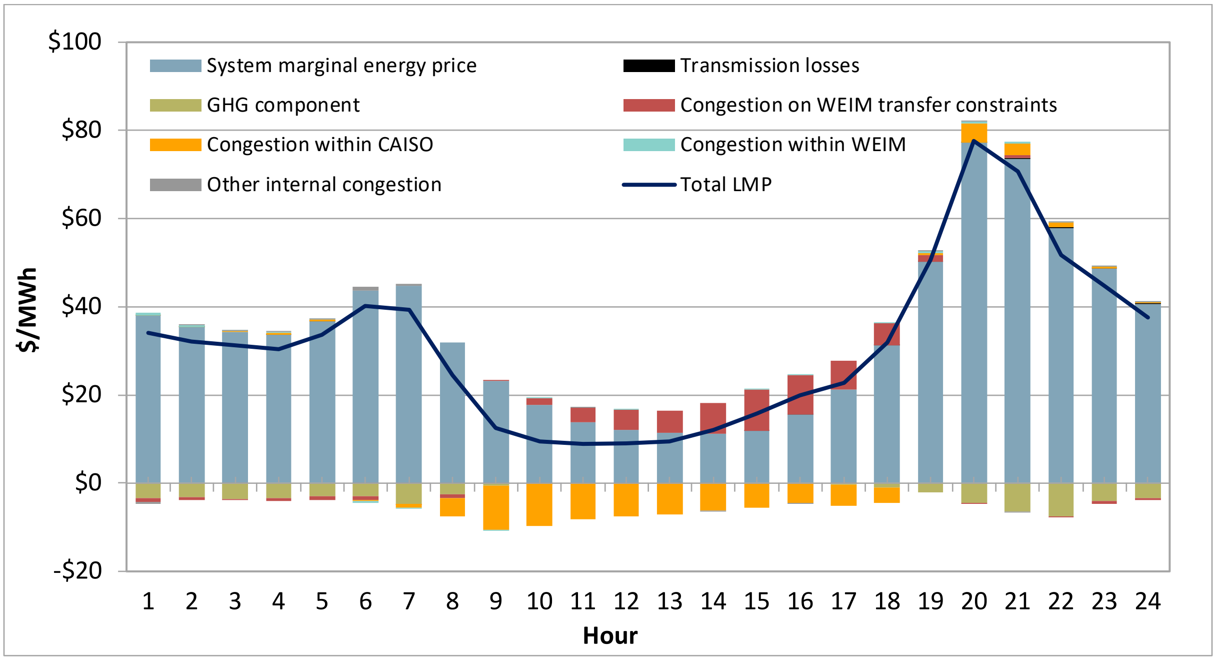


Appendix Figure A.84 Average hourly 5-minute market transfers

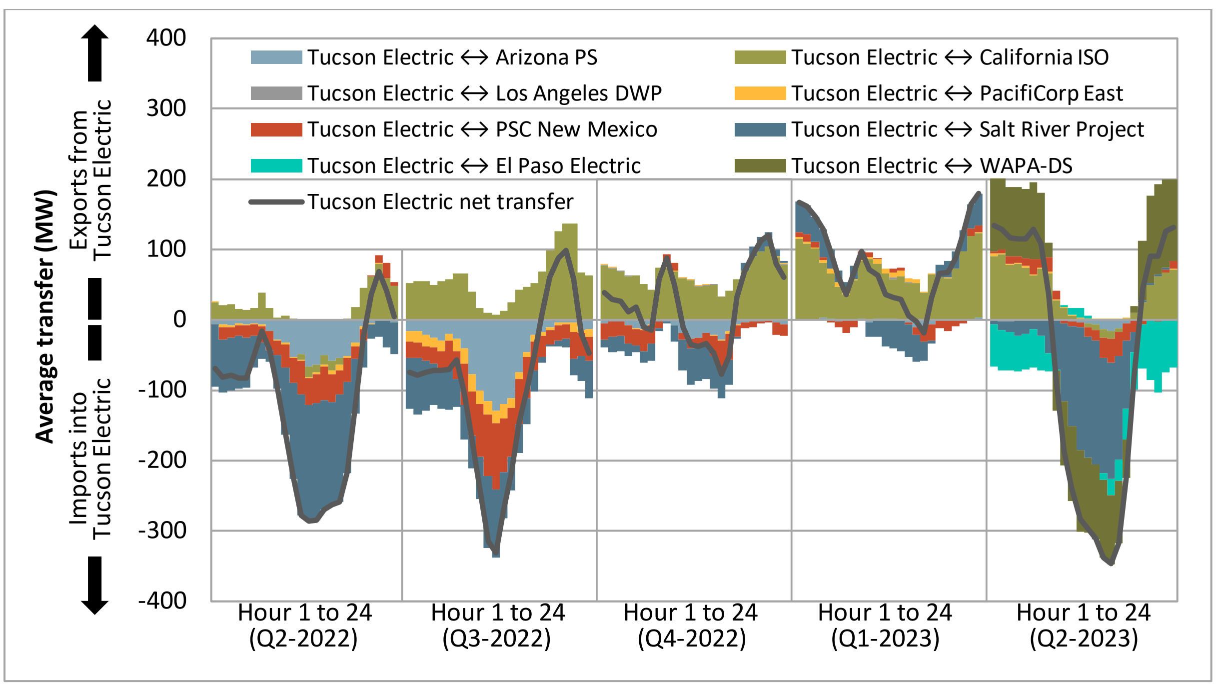


A.21 Tucson Electric Power

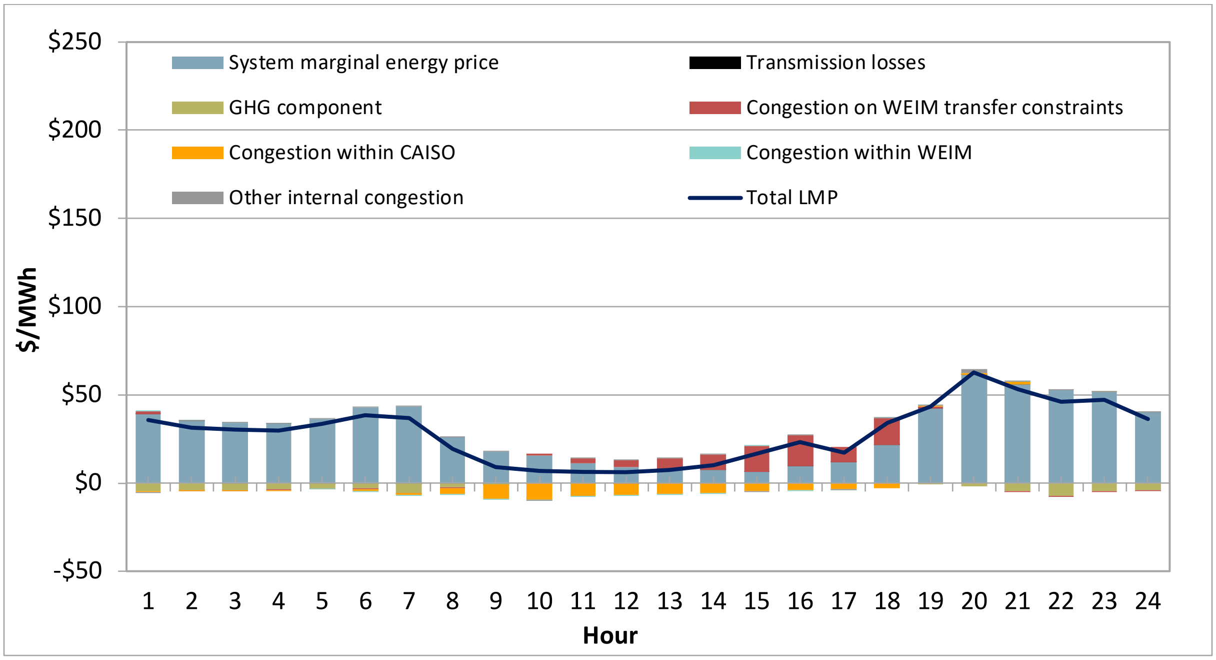
Appendix Figure A.85 Average hourly 15-minute price by component (Q2 2023)



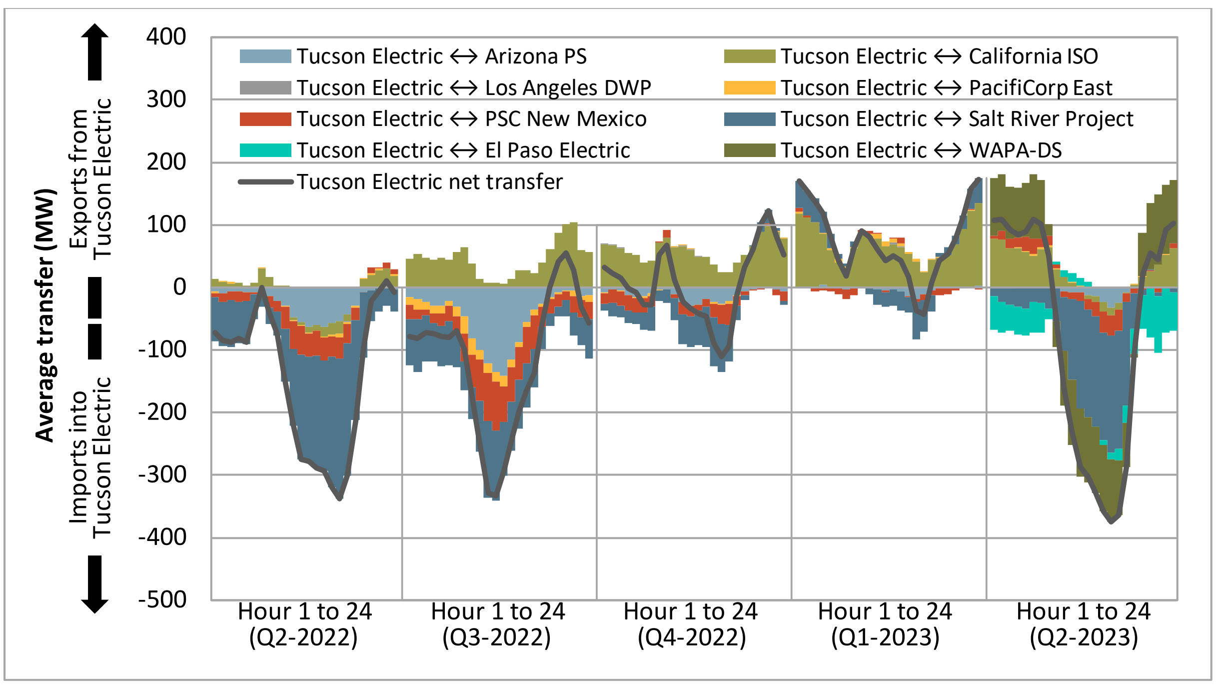
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q2 2023)

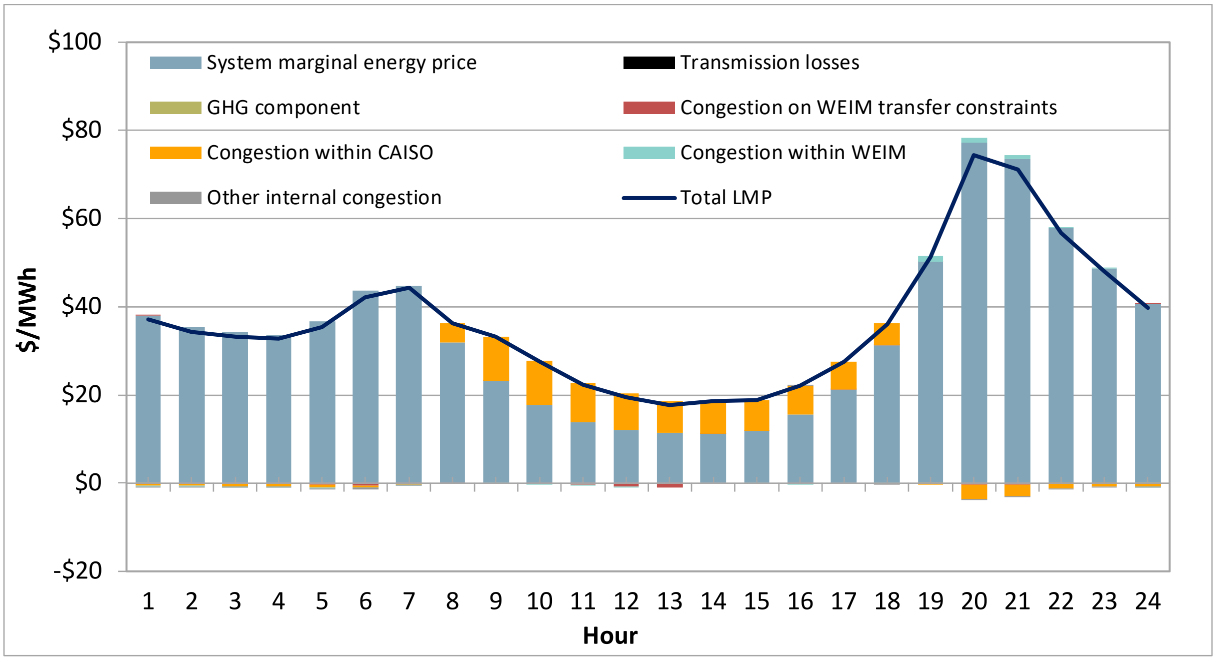


Appendix Figure A.88 Average hourly 5-minute market transfers

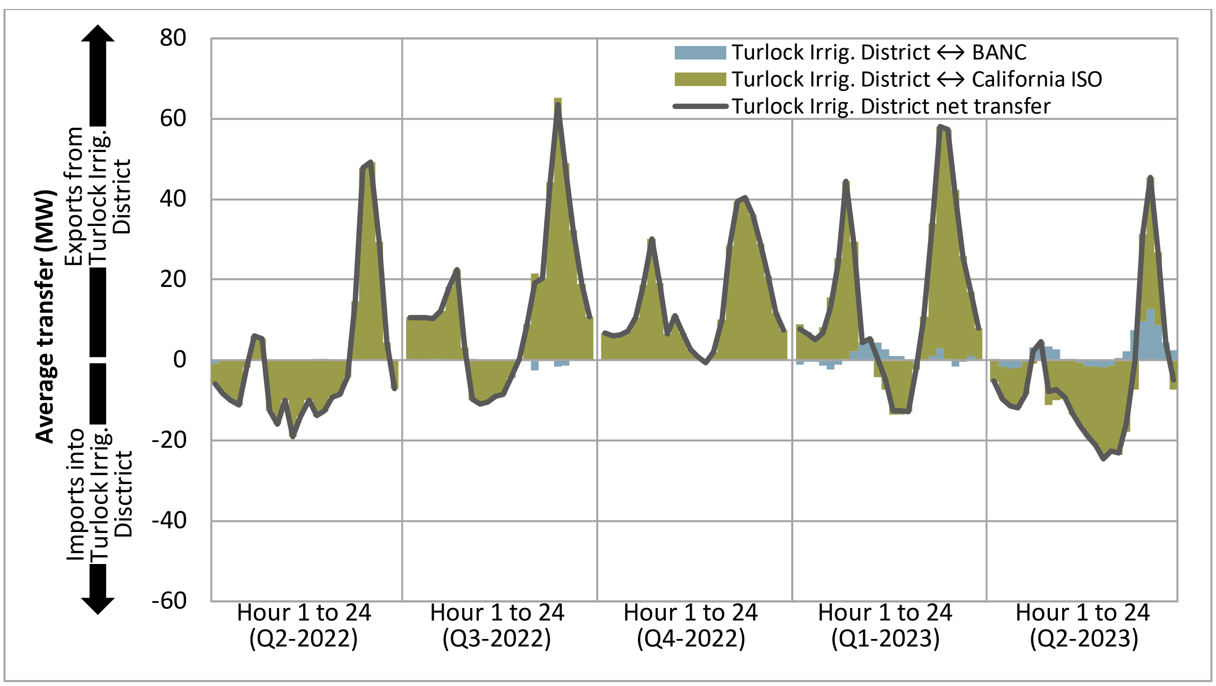


A.22 Turlock Irrigation District

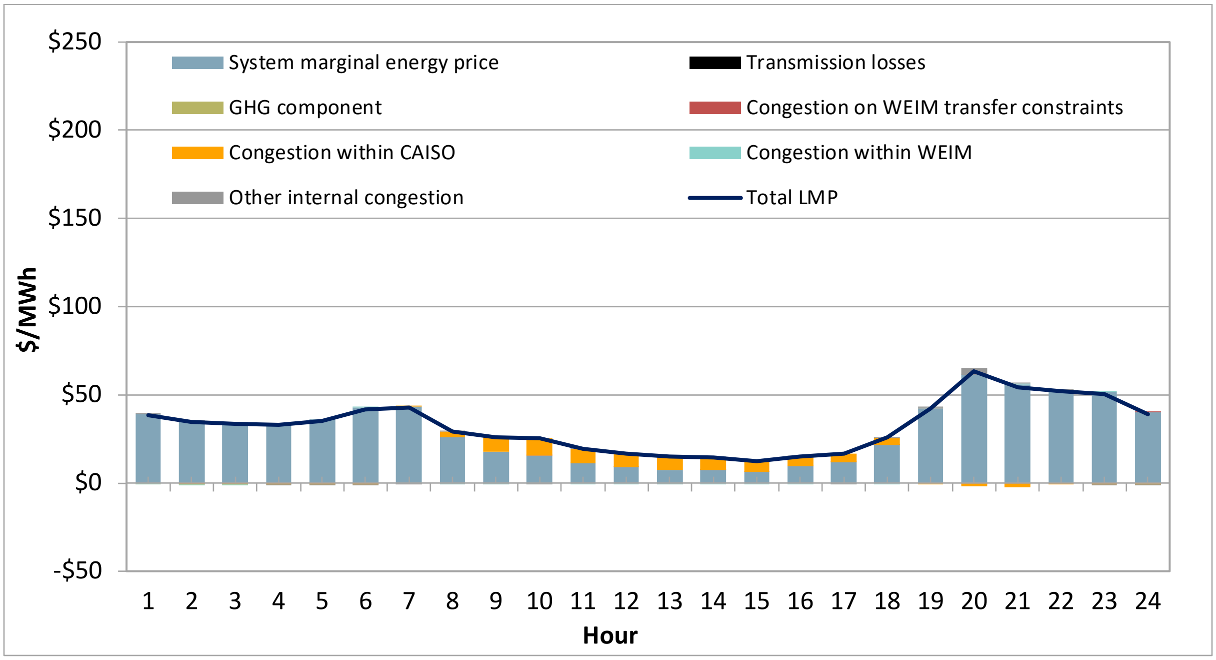
Appendix Figure A.89 Average hourly 15-minute price by component (Q2 2023)



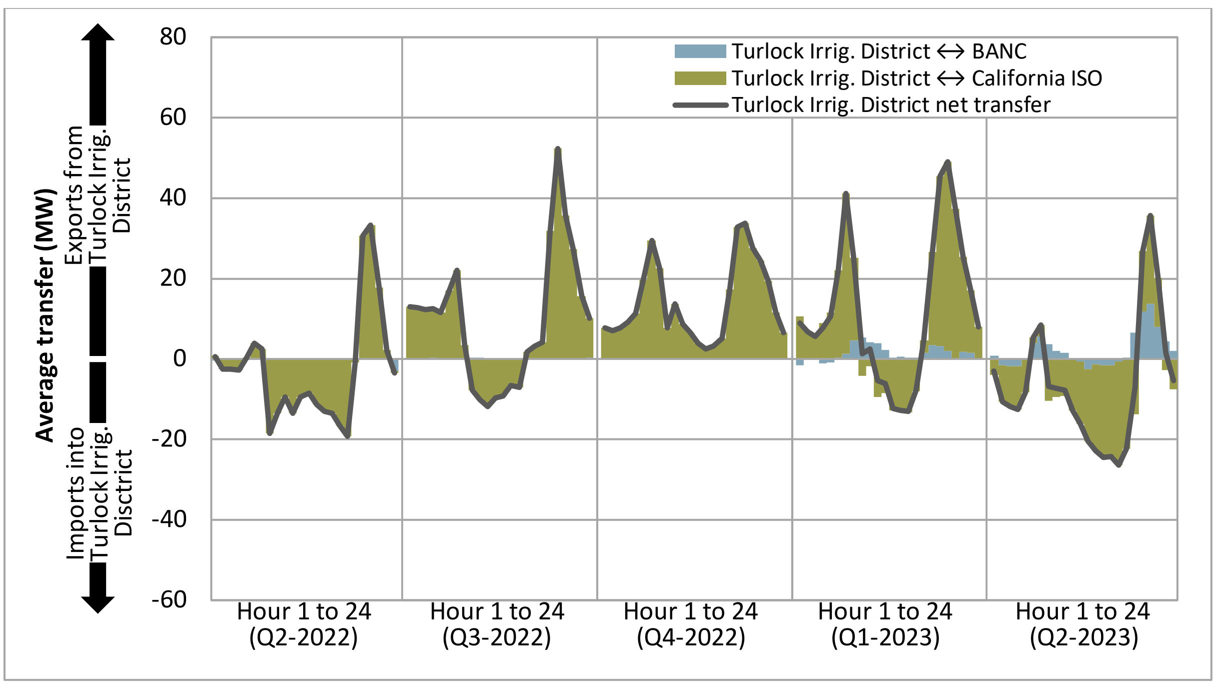
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q2 2023)

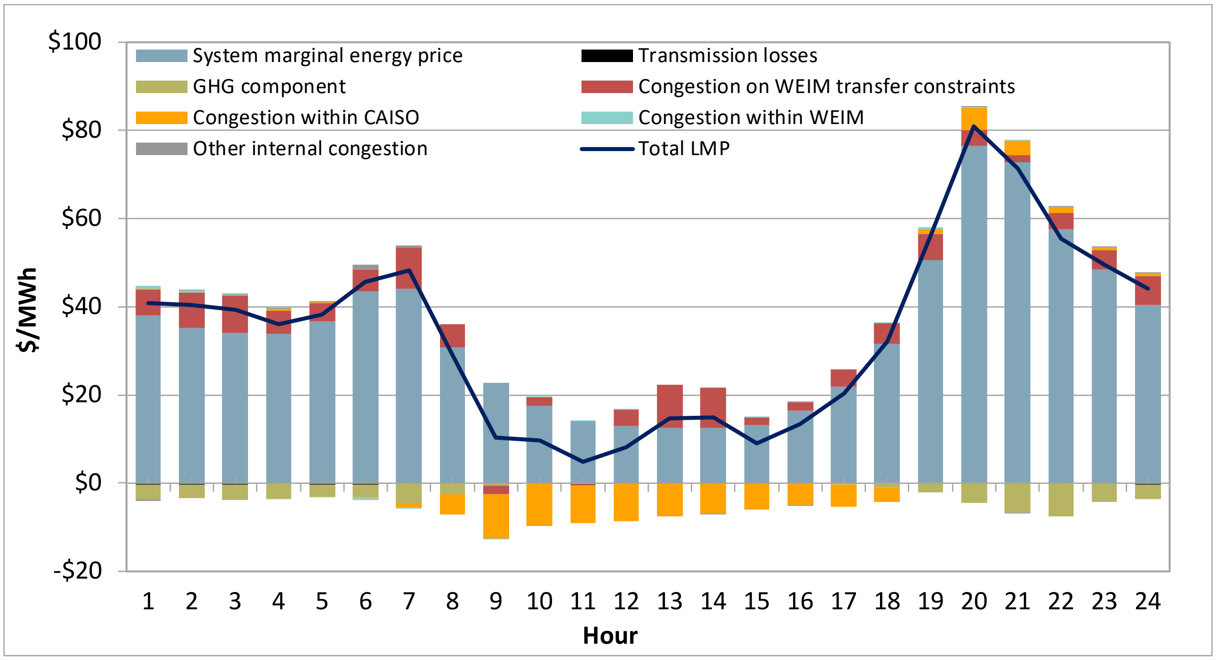


Appendix Figure A.92 Average hourly 5-minute market transfers



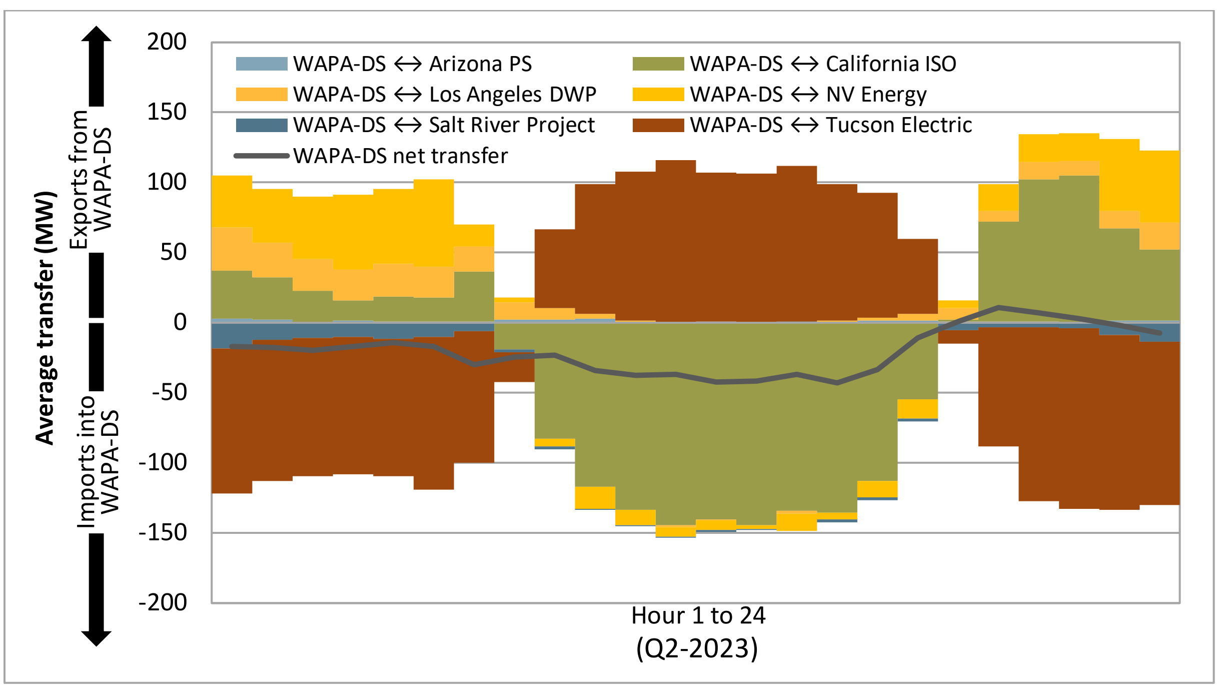
A.23 Western Area Power Administration Desert Southwest

Appendix Figure A.93 Average hourly 15-minute price by component (Q2 2023)



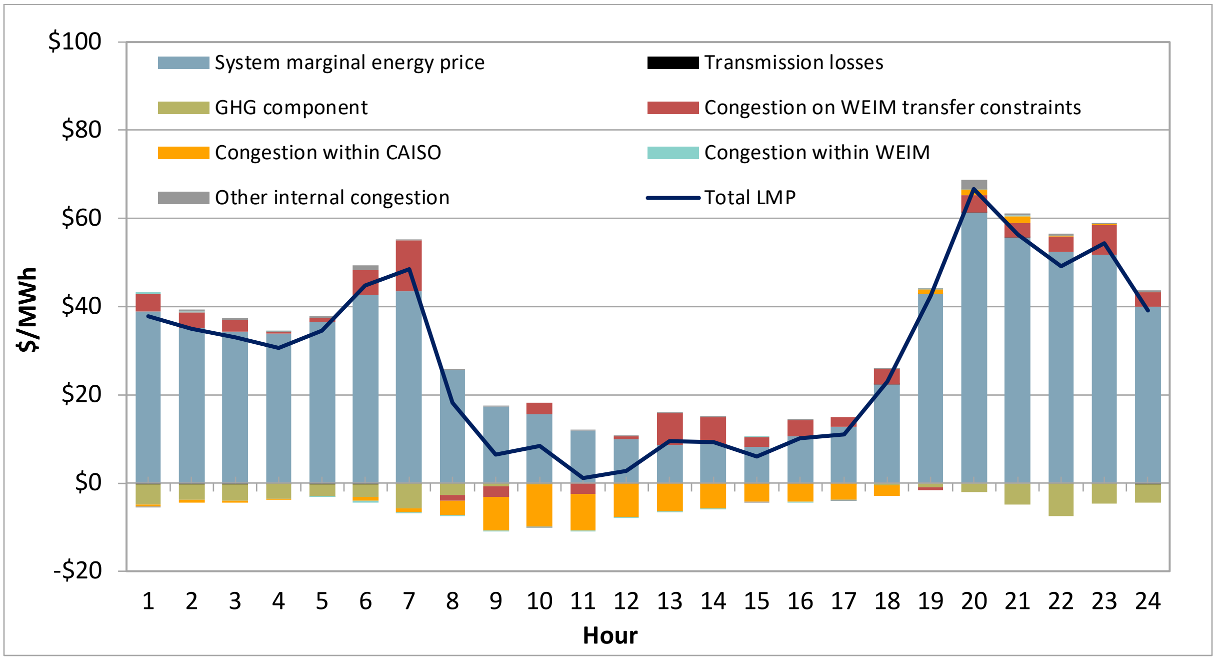
*Since joining the WEIM

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



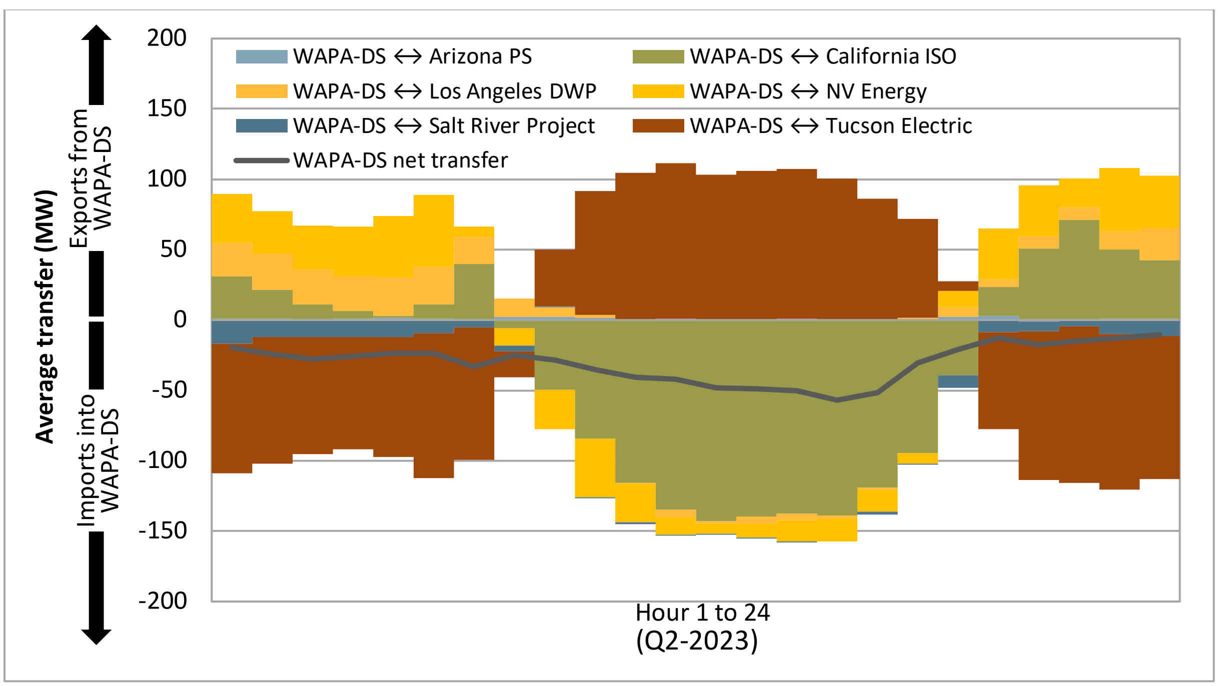
*Since joining the WEIM

Appendix Figure A.95 Average hourly 5-minute price by component (Q2 2023)



*Since joining the WEIM

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



*Since joining the WEIM