Q3 2023 Report on Market Issues and Performance

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California Independent System Operator

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Executive summary

This report covers market performance during the third quarter of 2023 (July-September). Key highlights during this quarter include the following:

- **Prices decreased substantially compared to the same quarter of 2022** (Figure E.1). Day-ahead and real-time market prices decreased by more than 40 percent and 45 percent, respectively, due to lower natural gas prices and higher renewable generation.
- **Natural gas prices were significantly lower than in the third quarter of 2022.** Average gas prices at Henry Hub, the national index, decreased over 65 percent from the same quarter of 2022, while prices at both California hubs decreased more than 40 percent (Figure E.2). This was the major driver of lower system marginal energy prices across the market.
- **Hydroelectric generation in the California ISO area increased 60 percent compared to Q3 2022.** This increase in hydro power lowered reliance on net imports and gas-fired generation, which dropped 24 percent and 7 percent, respectively.
- **Net imports – including net Western energy imbalance market (WEIM) transfers into the California ISO balancing area – decreased substantially across all hours.** Average net interchange for each hour of the day decreased by more than 2,000 MW compared to the third quarter of 2022. Average net interchange was in the export direction in hours-ending 10 through 18. The CAISO balancing area has typically been a net importer of power during the third quarter's hot summer months.
- **Congestion on internal constraints increased, but congestion on intertie constraints decreased compared to the third quarter of 2022.** North to south congestion on constraints within the CAISO balancing area contributed to greater price separation between the major PG&E load area in the north and the major SCE and SDG&E load areas in the south. However, total day-ahead congestion rent decreased to $198 million, down from $238 million in the same quarter of the previous year. This was mainly due to congestion rent decreasing by almost $50 million on the Malin and NOB intertie constraints at the northern CAISO balancing area border.
- **Adjustments to residual unit commitment requirements to account for net load uncertainty increased significantly** due to a change in the methodology used to determine these adjustments. With this new approach, these adjustments are set using the mosaic quantile regression based on the 97.5th percentile of net load error between day-ahead and real-time. This led to a significant increase in residual unit commitment requirements and bid cost recovery payments resulting from units committed in the residual unit commitment process.
- **Real-time imbalance offset costs remained high,** but decreased to about $86 million in the third quarter of 2023, down from $207 million in the third quarter of 2022. Real-time imbalance energy offset costs made up more than half of these offset costs. Much of the energy portion of these costs is caused by load settling on an average real-time price that can differ significantly from the real-time market prices that generating resources are settled on.
- **Bid cost recovery payments decreased** for units in the California ISO and WEIM balancing areas compared to Q3 2022. In the California ISO, estimated Q3 payments totaled about $84 million compared to $93 million in Q3 of the prior year. However, estimated bid cost recovery payments driven by the residual unit commitment market increased by $10 million. In the WEIM balancing areas, estimated Q3 payments totaled about $8 million compared to $14 million in Q3 2022.

- **Ancillary service costs totaled $62 million – or $50 million less than Q3 2022.** Costs fell due to replacement of spinning reserves with lower cost non-spinning reserves, less stressed conditions, and increased participation of battery storage resources, which provide a substantial portion of CAISO area ancillary services.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by $23 million in the third quarter,** up slightly from the $20 million losses in 2022. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. The Department of Market Monitoring (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 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 in the 15-minute market decreased slightly compared to Q3 2022.** During the peak adjustment hour, hour-ending 19, the average adjustment fell to 2,000 MW from about 2,200 MW in 2022. The combination of high load adjustments up in the 15-minute market and much lower adjustments in the 5-minute market contributed to the lower average prices in the latter market.

Figure E.1 Monthly load-weighted average energy prices California ISO (all hours)

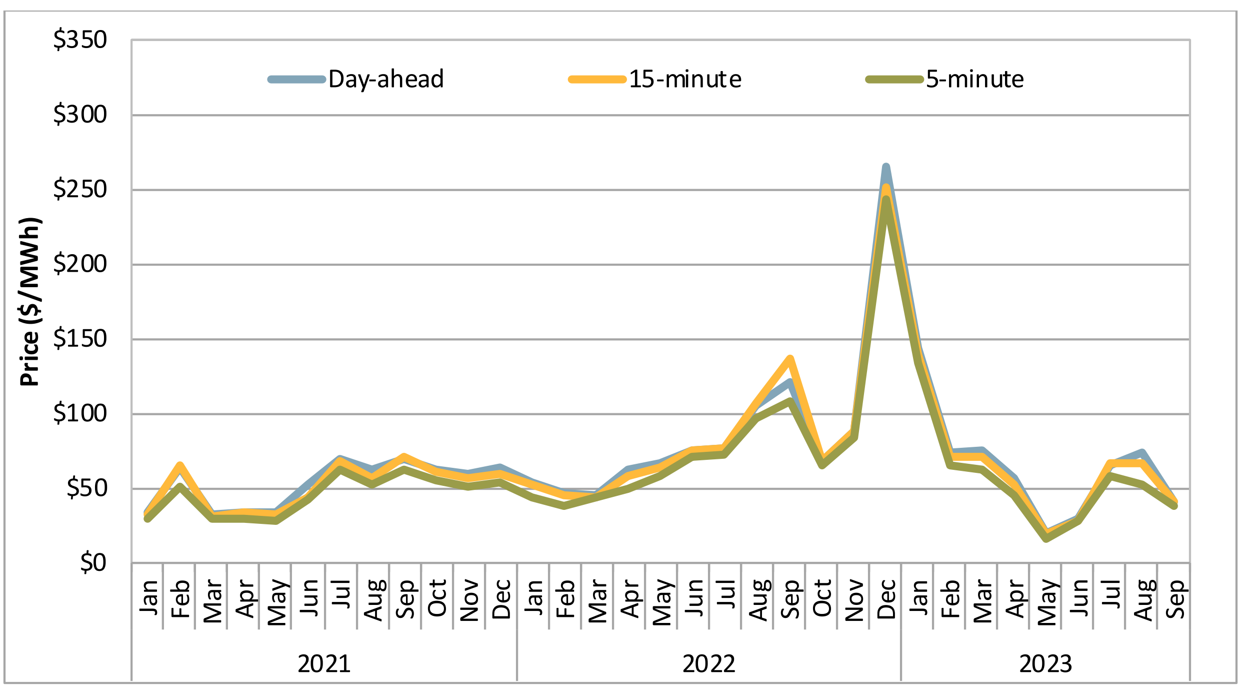
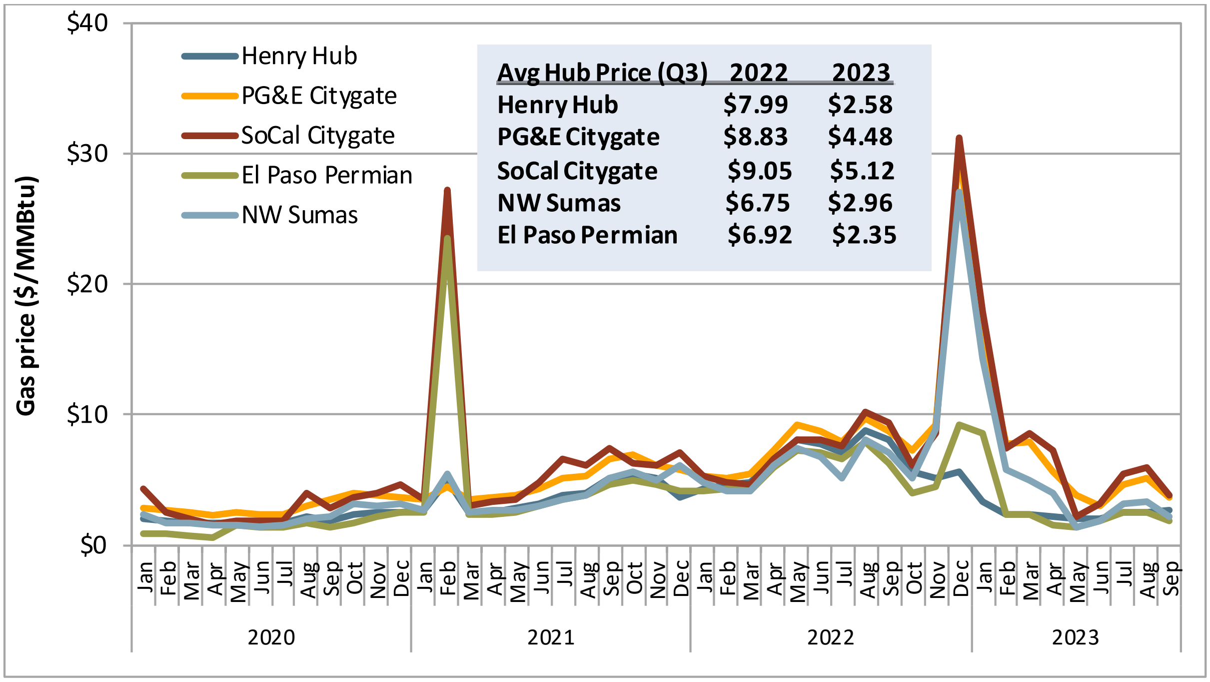


Figure E.2 Average monthly natural gas prices by hub



Western energy imbalance market

- **California ISO balancing area operators restricted most Western energy imbalance market (WEIM) transfers into the CAISO area in the hour-ahead and 15-minute markets during peak net load hours from July 26 through November 16.** CAISO area operators did not limit transfers in the 5-minute market. This created a significant, systematic modeling difference between the 15-minute and 5-minute markets. This modeling difference contributed to greater congestion between CAISO and other WEIM areas in the 15-minute market than in the 5-minute market. This difference in congestion was a major cause of lower prices in the 15-minute market than in the 5-minute market during peak hours in desert southwest WEIM areas. Transfer capacity out of the desert southwest region was dramatically reduced in the 15-minute market due to these CAISO balancing area operator actions.
- **The transfer limitations had the intended effect of increasing hourly block imports into the CAISO area and decreasing hourly block exports out of the CAISO area** to protect reliability during peak net load hours in late July and August. It is not clear why the CAISO area continued these transfer limitations after the mid-August heatwave and through November 16. DMM recommends that CAISO work with stakeholders to consider other methods of achieving the intended reliability outcomes without creating the large and systematic modeling differences between the 15-minute and 5-minute markets.
- **Natural gas prices fell across the WEIM** compared to the third quarter of 2022, resulting in lower energy prices in almost all balancing areas.
- **Prices in WEIM balancing areas within California were about $3/MWh higher than other WEIM regions**. Prices tend to be higher in California than the rest of the system on average due to

greenhouse gas compliance costs for energy that is delivered to California and transmission congestion into California balancing areas during hours of low solar production.

- **Prices in the Northwest region** were frequently higher than system prices due to congestion on WEIM transfer constraints into the Northwest.[1] This congestion typically increased prices in mid-day hours, preventing these areas from importing lower marginal cost system power.
- **Powerex continued to have significantly higher prices than other WEIM areas**. This was due to transfer congestion into the area during most intervals.
- **Powerex and the California ISO were major net importers of WEIM transfers.** Powerex imported over 1,000 MW per hour from hour-ending 9 through 14 and averaged over 800 MW across all hours. The California ISO was a significant net importer in the morning and evening hours, importing over 1,000 MW during hour-ending 7.
- **The major net exporters of WEIM transfers shifted significantly** between the mid-day period, when solar generation is typically at its highest, and the non-mid-day hours.
- **During the peak solar mid-day hours, the California ISO was the major net exporter of WEIM transfers**, exporting an average of over 2,200 MW to areas in the Northwest, California, and Southwest.
- **During non-mid-day hours, major exporters were Salt River Project, Arizona Public Service, and Tucson Electric Power.**
- **PacifiCorp East was a significant net exporter throughout the day.**
- **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.[2]
- **Appendix A includes hourly price and transfer figures for each WEIM area**.

[1] 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.

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

1 Market Performance

This section covers performance of the California ISO wholesale energy markets and resource adequacy program during the third quarter.

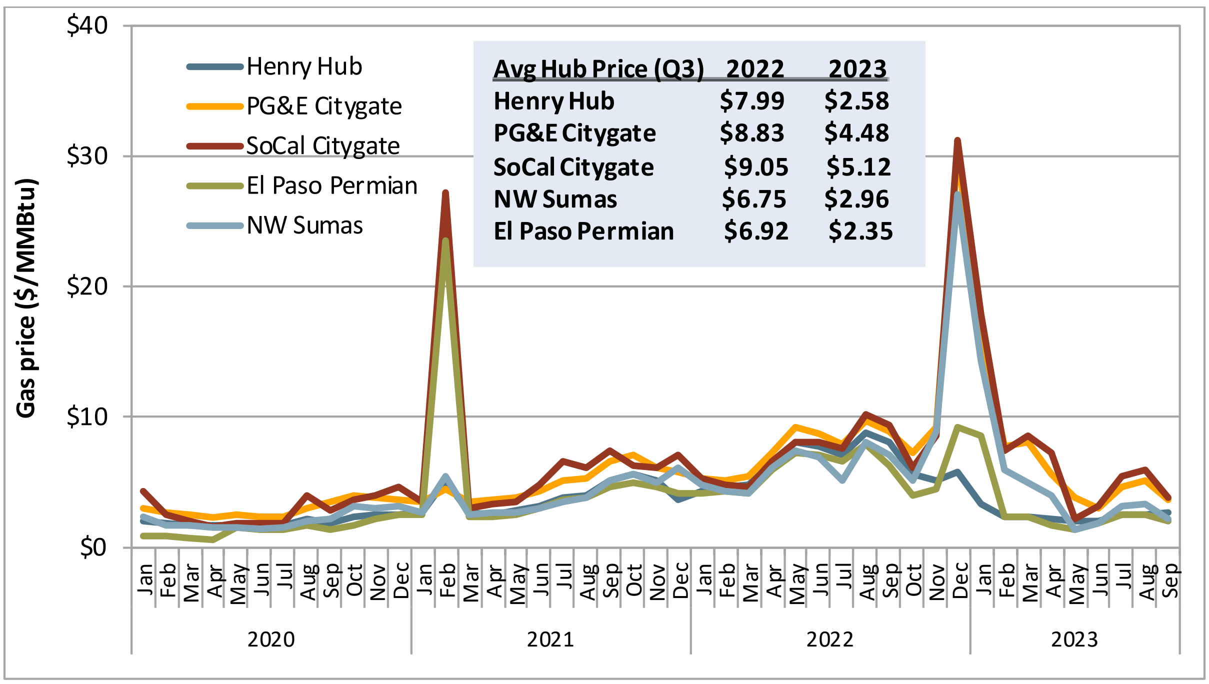
1.1 Supply conditions

1.1.1 Natural gas prices

Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in the California ISO (CAISO) balancing area and other regional markets. During the third quarter of 2023, average gas prices at major Western U.S. gas trading hubs trended higher than the previous quarter but significantly down when compared to the same quarter of 2022.

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 third quarter prices at the two main delivery points in California (PG&E Citygate and SoCal Citygate) increased by 8 percent and 21 percent, respectively, compared to the previous quarter. The Northwest Sumas gas hub price increased by 21 percent during the same time period. Prices at Henry Hub and Permian basin also increased by 23 percent and 44 percent, respectively. When compared to the same quarter of 2022, prices at PG&E Citygate, SoCal Citygate, and Northwest Sumas decreased by 49 percent, 43 percent, and 56 percent, respectively. Prices at Henry Hub and Permian also declined by more than 65 percent during the same time period.

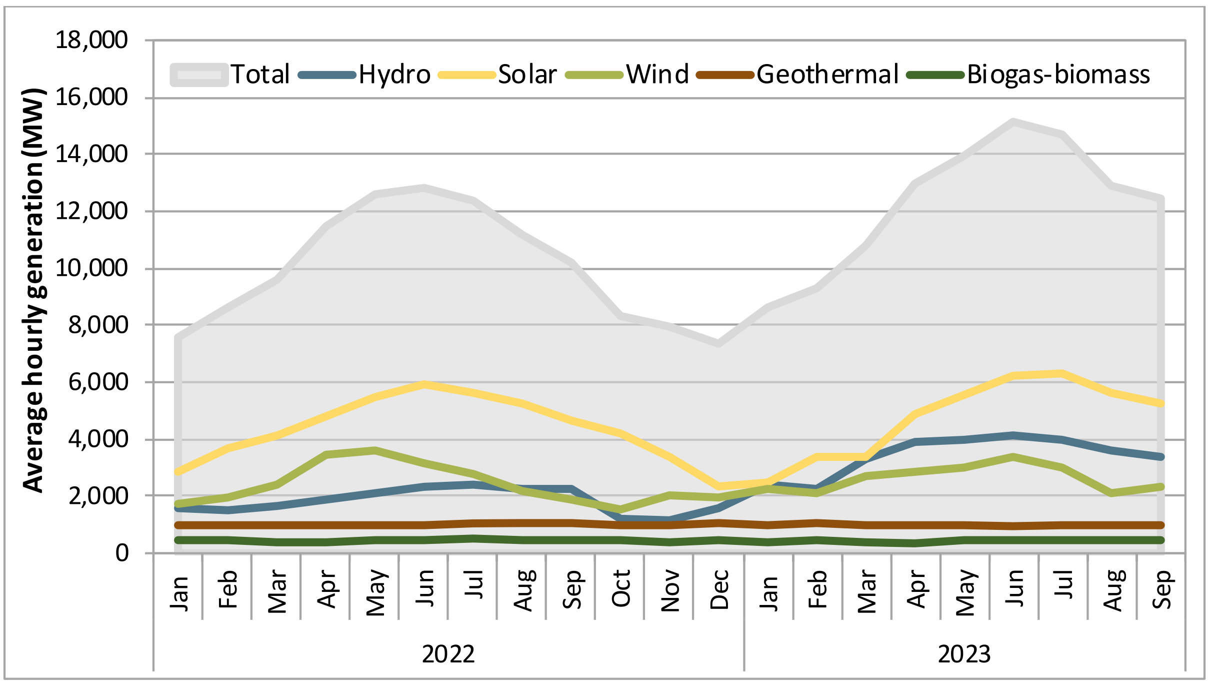
On August 31, 2023, the CPUC issued an order increasing the inventory limit for the Aliso Canyon storage facility from 41.16 Bcf to 68.6 Bcf, which builds on the storage level set in 2021 of about 34 Bcf.[3] This action contributed to increasing SoCal Gas total authorized storage inventory capacity to 119.5 Bcf.[4]

1.1.2 Renewable generation

In the third quarter, the average hourly generation from renewable resources increased by about 2,000 MW (18 percent) compared to the same quarter of 2022.[5] 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.[6] Compared to the third quarter of 2022, generation from hydroelectric, wind, and solar resources increased 60 percent, 8 percent, and 11 percent, respectively. Generation from geothermal generation and biogas-biomass resources decreased 3 percent and 7 percent, respectively.

Figure 1.2 Average monthly renewable generation



3 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

4 SoCalGas owns and operates four underground storage facilities: Aliso, Honor Rancho, La Goleta, and Playa Del Rey.: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M328/K289/328289863.PDF

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

6 Hydroelectric generation greater than 30 MW is included.

1.1.3 Generation by fuel type

Hydroelectric and battery generation increased relative to the third quarter of 2022 by 60 percent and 34 percent, respectively. Average hourly generation by natural gas resources decreased by 7 percent overall. Net imports into the ISO balancing area decreased by 24 percent overall from the third quarter of 2022.[7]

Figure 1.3 shows the average hourly generation by fuel type during the third quarter of 2023 as measured by preliminary meter data. Total hourly average generation from California ISO resources peaked at about 35,500 MW during hour-ending 19. Battery generation peaked during hour-ending 20 at about 2,800 MW. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed to 28 percent of total generation during the peak net load hours, up from 23 percent during the same time last year.

Figure 1.3 Average hourly generation by fuel type (Q3 2023)

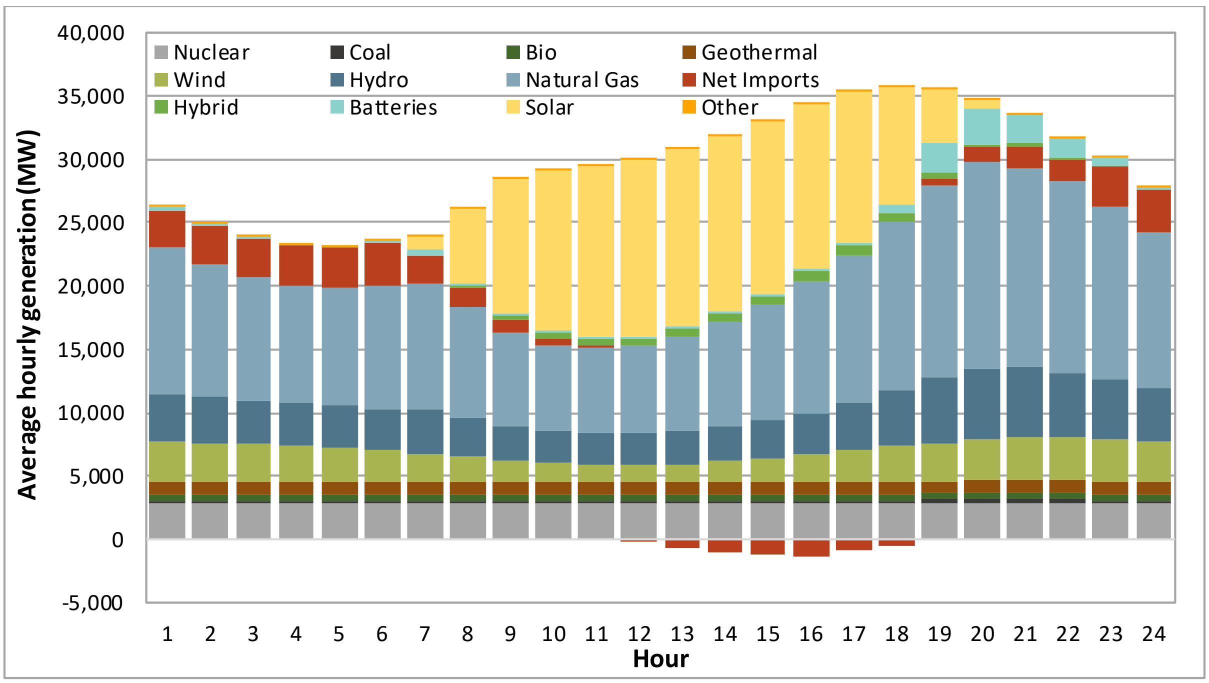


Figure 1.4 shows the change in hourly generation by fuel type between the third quarter of 2022 and the third quarter of 2023.[8] In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

The net change shows that there was a decrease in average hourly generation in nearly every hour compared to last year. Loads in the California ISO were much lower compared to the third quarter of 2022, largely due to the prolonged heat wave throughout California and much of the Western United States in August and September of 2022.

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

8 Hybrid generation was included in the "Other" category in Q3 2022 but is identified as "Hybrid" in Q3 2023. Therefore, reductions in "Other" generation are offset by the additional "Hybrid" generation.

Figure 1.5 shows the monthly average hydroelectric generation from 2019 to 2023. Hydroelectric generation in the third 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 (Q3 2022 to Q3 2023)

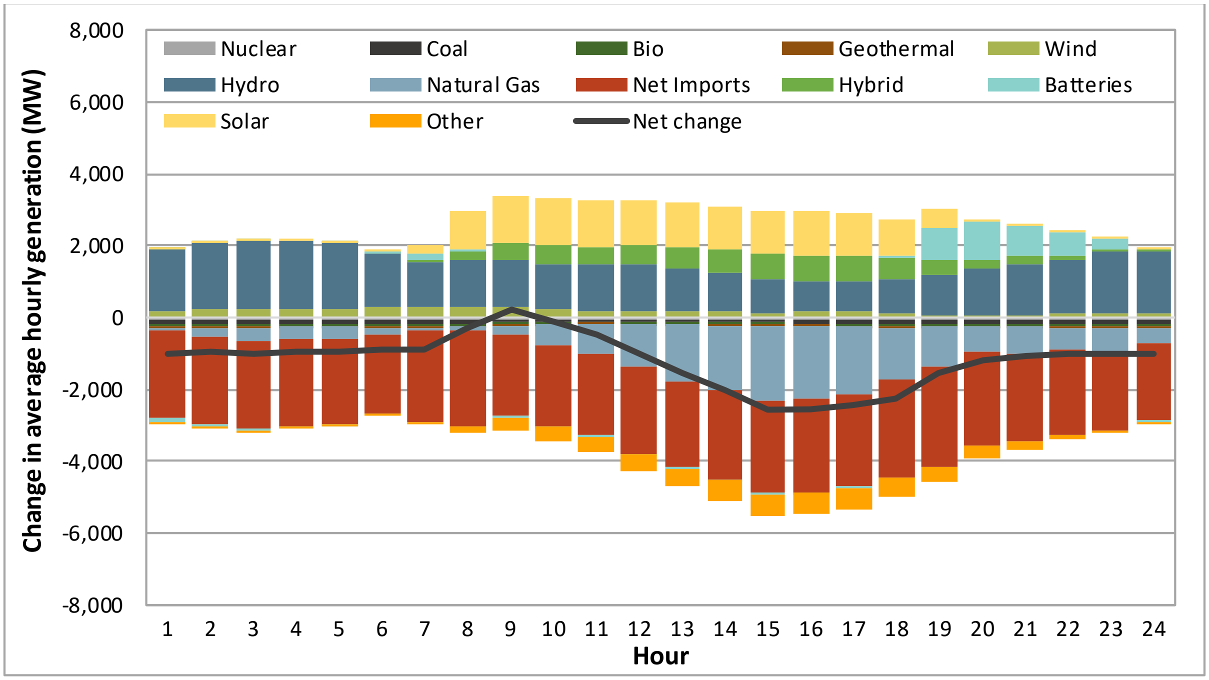
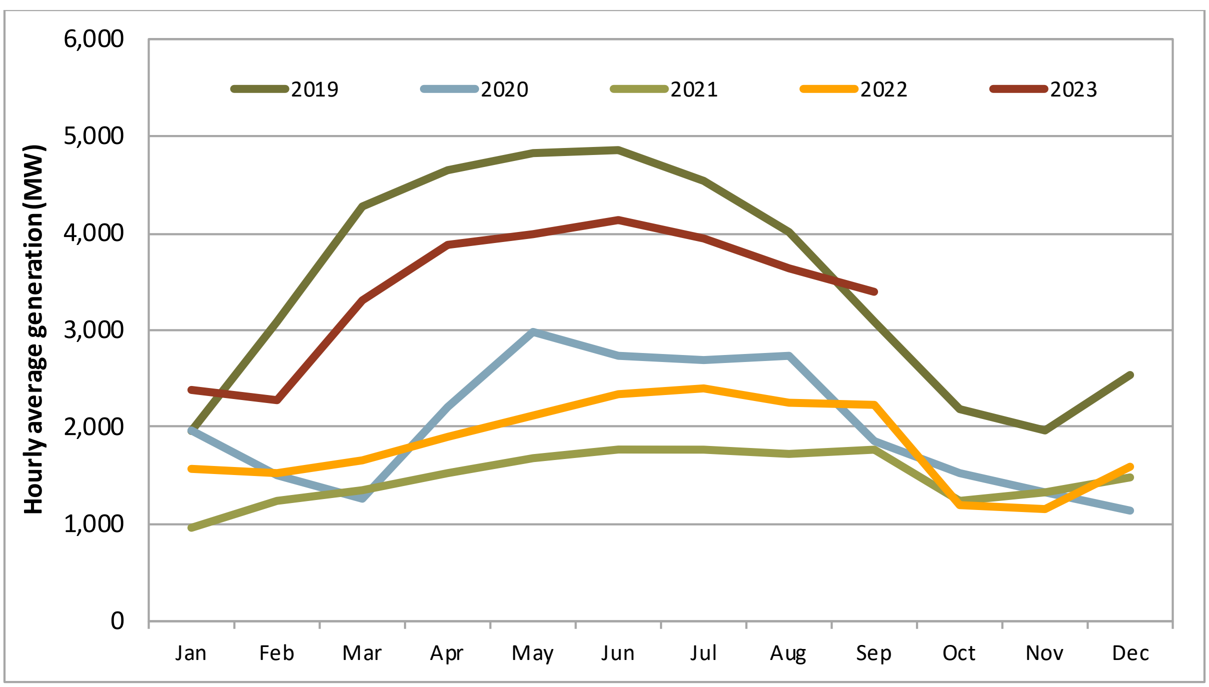


Figure 1.5 Monthly average hydroelectric generation by year



1.1.4 Generation outages

Total generation on outage in the California ISO balancing area averaged about 11,438 MW, or 9 percent above the third quarter of 2022. This increase was driven by forced outages, which increased 20 percent relative to the same time last year.

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

Figure 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.[9] The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period. Looking at the monthly outages, there are usually a low number of outages in the summer and fall months. This trend continued in 2023 with planned maintenance outages decreasing over the third quarter from the second quarter by 69 percent.

During the third quarter of 2023, the average total generation on outage in the California ISO balancing area was 11,438 MW, about 961 MW greater than the third quarter of 2022, as shown in Figure 1.6. Forced outages increased by 20 percent compared to the same quarter last year, while planned outages decreased by 33 percent.

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

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

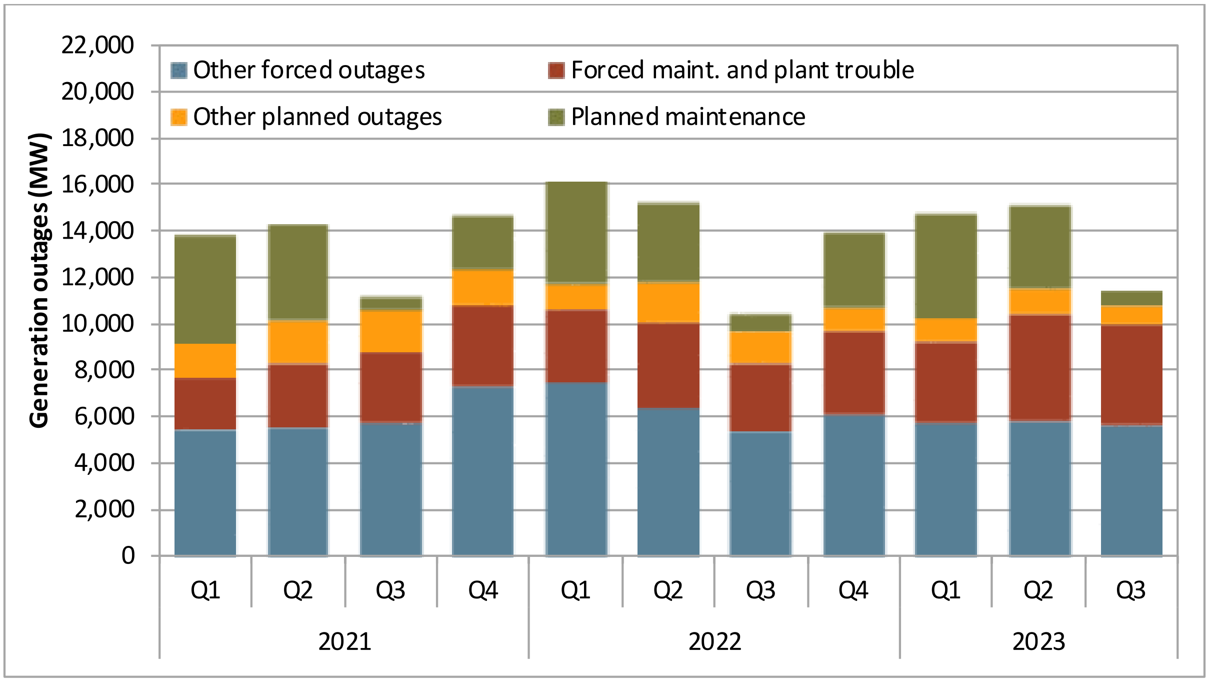
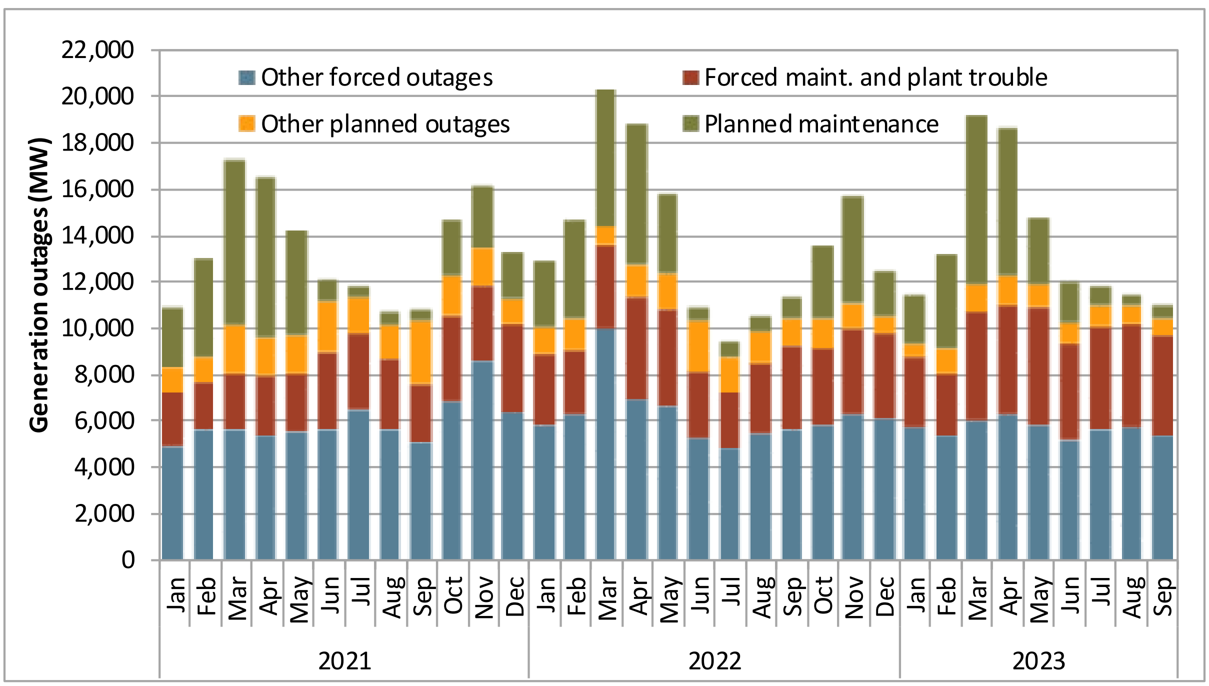


Figure 1.7 Monthly average of maximum daily generation outages by type – peak hours

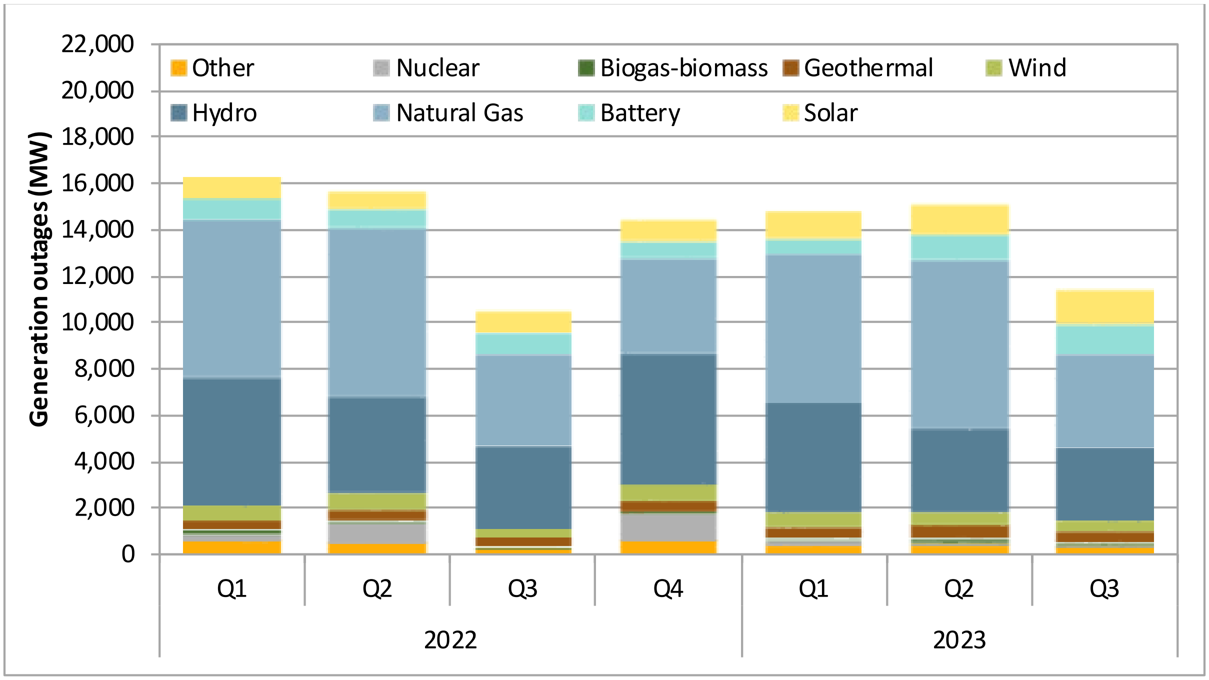


Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 4,075 MW and 3,050 MW during the third quarter, respectively. These two fuel types accounted for a combined 62 percent of the generation on outage for the quarter. The amount of hydroelectric generation on outage decreased 14 percent relative to the same time last year.

Figure 1.8 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[10] Only hydroelectric and nuclear outages decreased compared to the third quarter of 2022, while outages for all other resource types increased.

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



1.2 Energy market performance

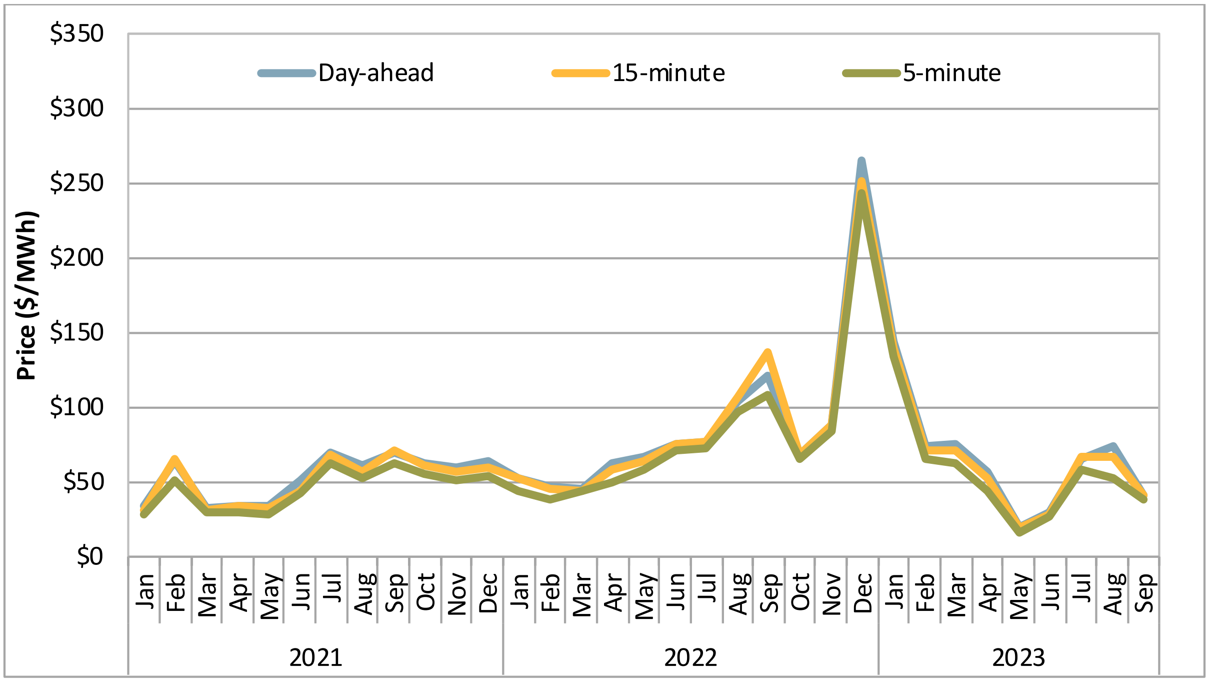
1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. In 2023, the third quarter prices in the day-ahead, 15-minute, and 5-minute markets dropped by about half compared to the third quarter of the previous year. The average price of the three markets this quarter decreased to $56/MWh from $100/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 California ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2021 to September 2023.

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

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



Over the quarter, day-ahead prices averaged $60/MWh, 15-minute prices averaged $58/MWh, and 5-minute prices averaged $50/MWh. Prices across all three markets were almost half of those in the third quarter of the prior year. September had the lowest prices, with an average over the three markets of about $40/MWh.

Low gas prices contributed to the low prices observed this quarter. Figure 1.10 shows monthly average gas prices at SoCal Citygate and load-weighted energy prices from April 2022 to September 2023. The chart shows that the monthly variation of the energy prices is highly correlated with gas prices. The black dashed line shows the monthly average gas price at SoCal Citygate. The colored lines illustrate energy prices. Over the past 18 months, both gas and energy prices exhibited similar fluctuations. After reaching its peak in December 2022, the SoCal City gas price has declined, averaging about $5/MMBtu this quarter.

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

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

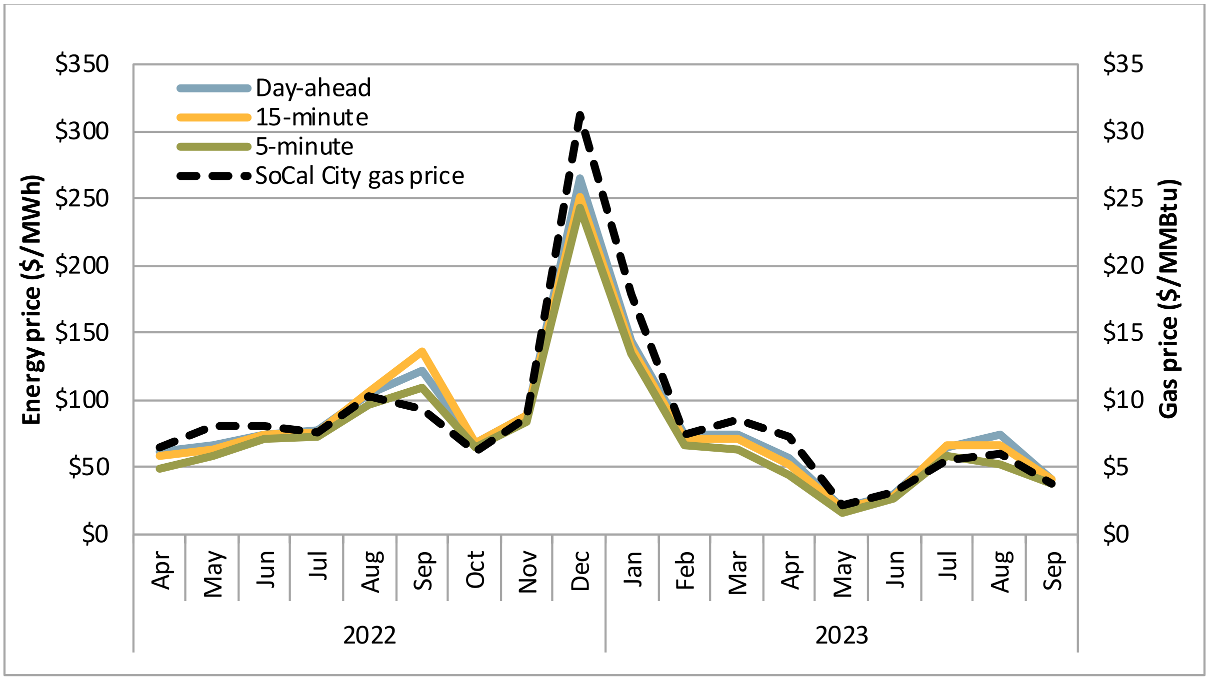


Figure 1.11 illustrates the hourly load-weighted average energy prices for the third quarter compared to the average hourly net load.[11] Average hourly prices shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) are measured by the left axis, while the average hourly net load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening, and peaked at hour-ending 20, when demand was still high but solar generation was substantially below its peak. The average net load in this quarter reached 30,169 MW at 8:00 p.m.

At this hour, the day-ahead load-weighted average energy price was $144/MWh, the 15-minute price was $157/MWh, and the 5-minute price was $88/MWh. The 5-minute price consistently fell below the day-ahead and 15-minute market prices between hours-ending 18 and 21. This price gap was significant, with the average 5-minute price being $45/MWh lower than those of the other two markets. Day-ahead and 15-minute market prices typically tend to converge on average due to convergence (virtual) bidding. One major cause of the observed price separation between the 15-minute and 5-minute markets this quarter was load conformance. California ISO operators typically adjust the load forecast up significantly more in the 15-minute market than in the 5-minute market over the peak net load hours.[12] Another significant cause of the price separation this quarter was CAISO area operators limiting WEIM transfers into the CAISO area in the 15-minute market but not in the 5-minute market during peak net load hours starting on July 26. This is described in detail in Section 2 of this report.

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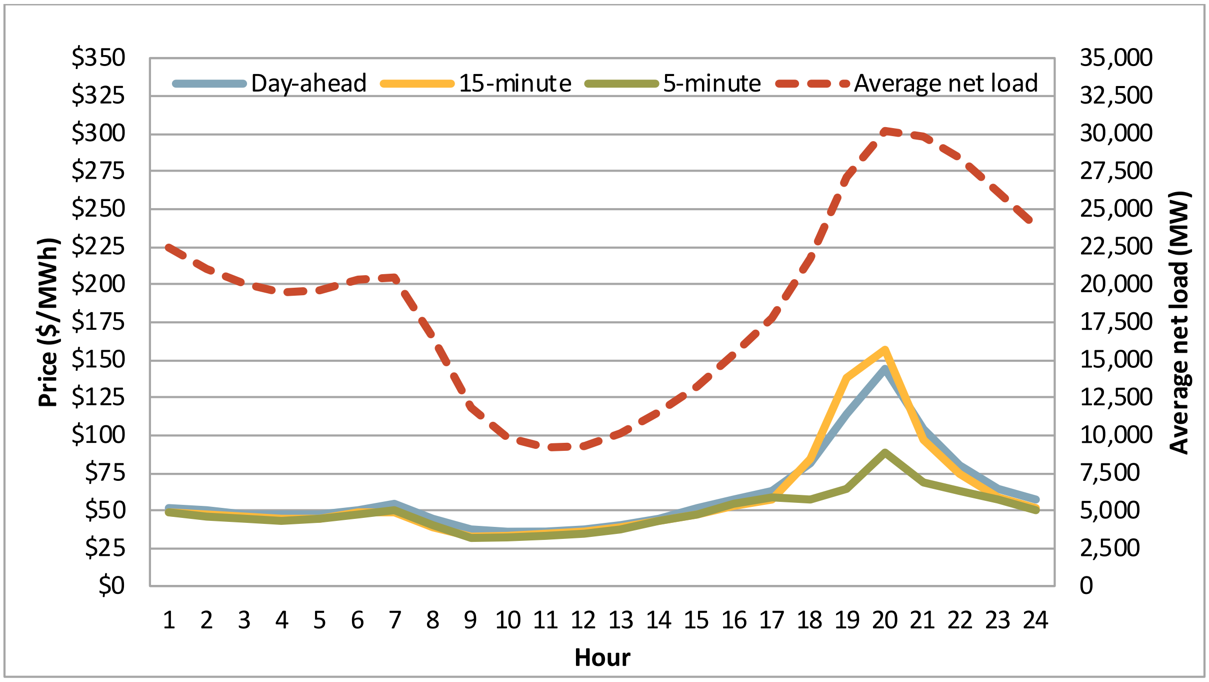
11 Net load is calculated by subtracting the generation produced by wind and solar that is directly connected to the California ISO grid from actual load.

12 Please see Section 1.11 for a detailed discussion on load conformance.

Figure 1.11 Hourly load-weighted average energy prices (July-September)

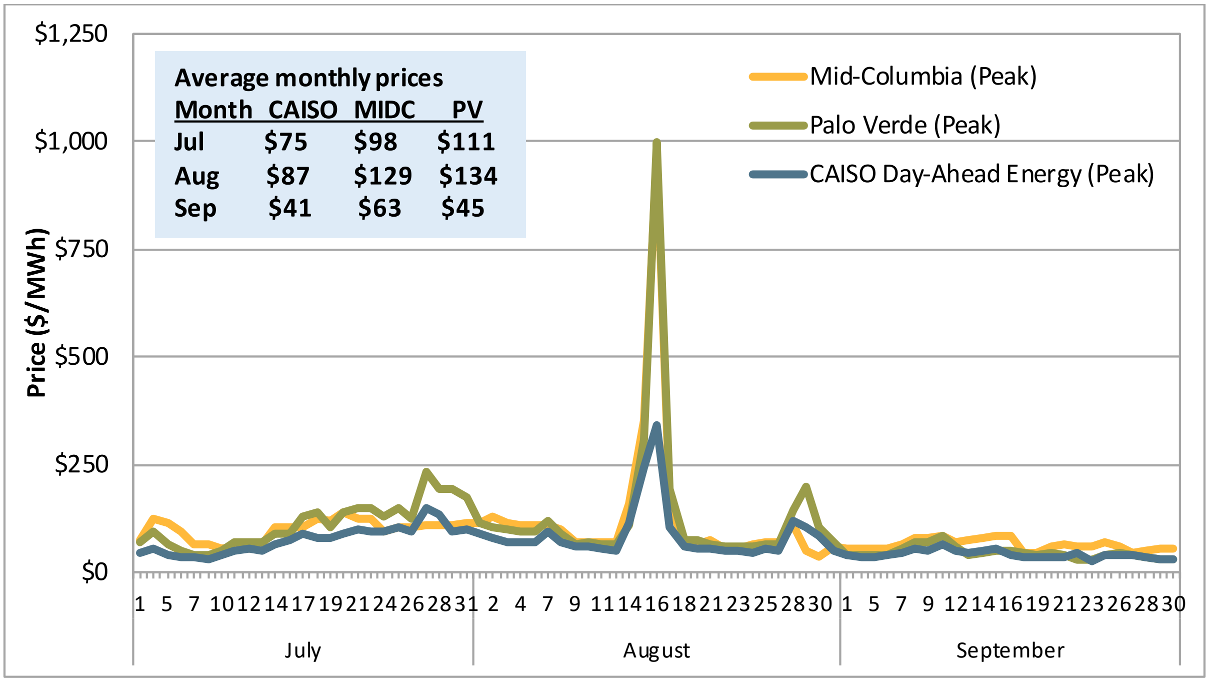


1.2.2 Bilateral price comparison

Figure 1.12 shows the California 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 California ISO market. These prices were calculated during peak hours (hours-ending 7 through 22) for all days, excluding Sundays and holidays. The figure shows prices at Mid-Columbia and Palo Verde hubs spiked significantly on August 16 but were slightly below the $1,000/MWh Western Electricity Coordinating Council (WECC) soft offer cap.

The California ISO FERC Order 831 policy will increase the California ISO energy bid cap to $2,000/MWh if a 16-hour block peak bilateral price, scaled and shaped into hourly prices according to the shape of California ISO hourly prices, exceeds $1,000/MWh. With the 16-hour block bilateral prices reaching almost $1,000/MWh, the scaled bilateral prices over the peak net load hours significantly exceeded $1,000/MWh. Therefore, the California ISO raised its energy bid cap and penalty prices to $2,000/MWh during this period. Regional differences in prices reflect transmission constraints and greenhouse gas compliance costs.

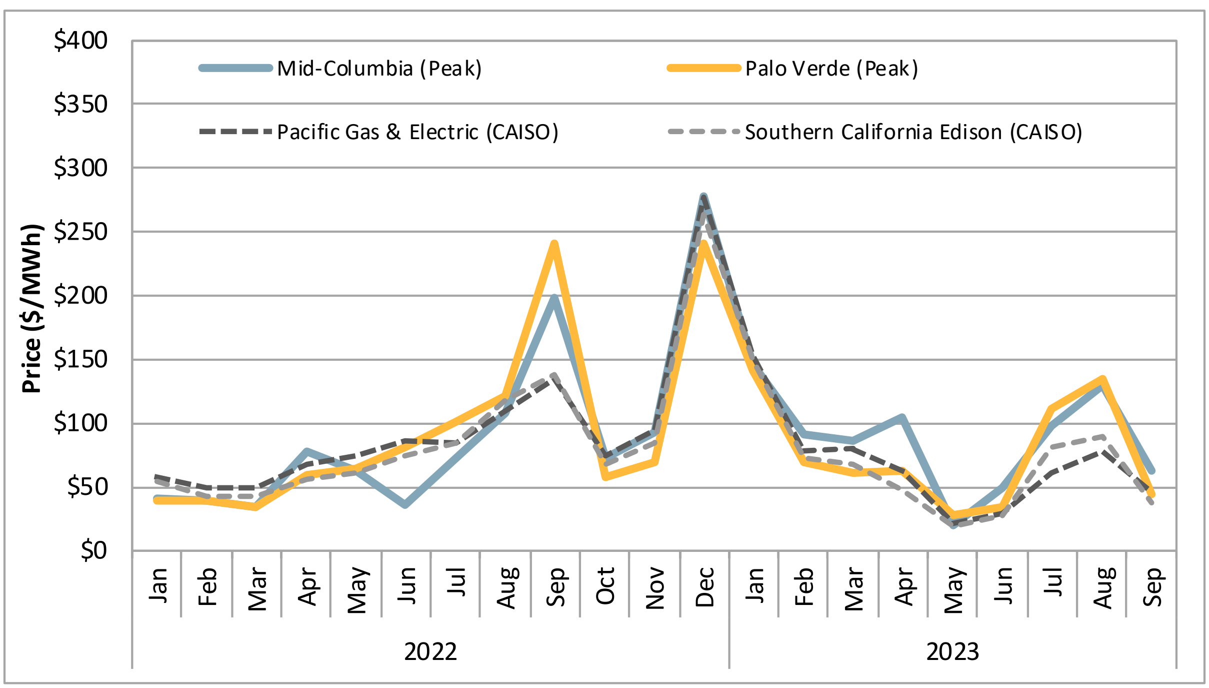
Figure 1.12 Day-ahead California ISO and bilateral market prices (July-September)



DLAPs.

Figure 1.13 compares monthly average bilateral and California ISO day-ahead market prices for 2022 and 2023. Prices in the California 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 bilateral prices in July and August significantly exceeded prices at the California ISO DLAPs.

Figure 1.13 Monthly average day-ahead and bilateral market prices



Average day-ahead prices in the California ISO balancing area and bilateral hubs (from ICE) were also compared to real-time hourly energy prices traded at the Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average day-ahead hourly prices in the California ISO balancing area were lower than the average real-time prices at Mid-Columbia and Palo Verde by $2/MWh and $3/MWh, respectively. Average day-ahead prices at Mid-Columbia and Palo Verde were greater than the average real-time prices (from Powerdex) by about $18/MWh.

Beginning on April 8, 2022, FERC started issuing orders in response to cost justification filings from sellers who made sales above the WECC soft offer cap during the August 2020 heat wave event. In particular, FERC has ordered some sellers to refund the premium they charged above the index price, for sellers whose sales were above the prevailing index price.[13] DMM estimates the refunds to be about $5.1 million out of $90 million in bilateral sales exceeding the WECC soft offer cap during August 2020.[14] 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.[15]

1.2.3 Imports and exports

During the third quarter, average imports decreased while exports increased compared to the same quarter in 2022. As shown in Figure 1.14, imports in the day-ahead market (dark blue line) decreased in all hours when compared to the same quarter of 2022, peaking at about 5,500 MW in hour-ending 20. 15-minute cleared imports (dark yellow line) also decreased in all hours of the day compared to the third quarter of 2022, peaking in hour-ending 20 at around 6,100 MW. Exports over the peak hours of 17-21 (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 exports increased between 1,000 MW and 2,000 MW.

Figure 1.14 shows power flowing into the CAISO balancing area as positive and power flowing out of the CAISO area as negative. The dashed black line shows net imports into the CAISO area before including WEIM transfers into or out of the CAISO area. Average net interchange for each hour of the day

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

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

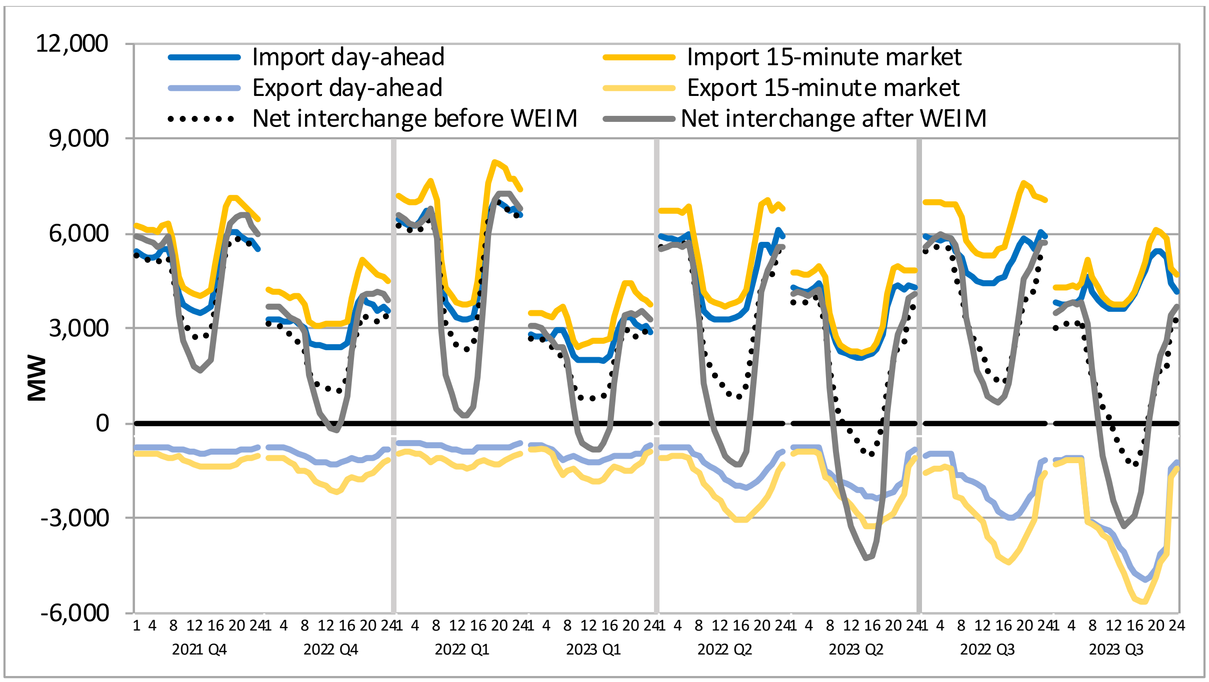
15 FERC Docket No. ER21-64, *Macquarie Energy, LLC submits Explanation for Bilateral Spot Sales in Western Electricity Coordinating Council*: https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=er21-64&sub_docket=000&dt_from=1960-01-01&dt_to=2022-06-20&chklegadata=false&pagenm=dsearch&date_range=custom&search_type=docket&date_type=filed_date&sub_docket_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

decreased by more than 2,000 MW compared to the third quarter of 2022. CAISO was a net exporter on average during hours-ending 12-18, with a maximum average net export of 1,360 MW during hour-ending 16. The CAISO balancing area has typically been a net importer of power during the third quarter's hot summer months. Therefore, net exporting large amounts of power to the rest of the west during the mid-day solar hours on average from July to September represents a significant change from CAISO historical interchange patterns.

The solid grey line includes WEIM transfers in the net interchange calculation. The maximum average net interchange out of the CAISO area including WEIM transfers was over 3,200 MW in hour-ending 14. The grey line above the dashed black line indicates WEIM transfers into the CAISO balancing area during the hour. Average WEIM transfers into the CAISO area peaked at about 1,050 MW during hour-ending 7.

The grey line below the dashed black line indicates WEIM transfers out of the CAISO balancing area. WEIM transfers were in the export direction on average between hours-ending 9 and 19. Average WEIM transfers out of the CAISO area peaked at about 2,300 MW during hour-ending 14, almost 1,400 MW more than the largest average WEIM transfer out of CAISO in Q3 2022.

Figure 1.14 Average hourly net interchange by quarter



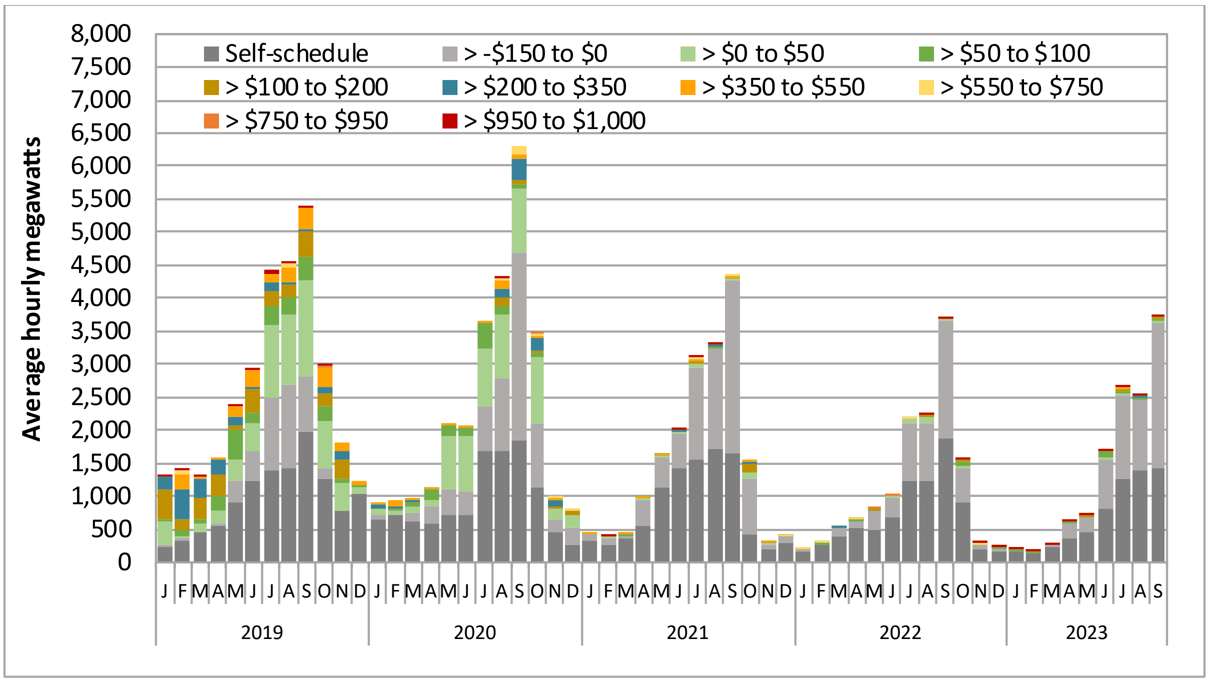
In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the California ISO markets at or below $0/MWh, at minimum in the availability assessment hours.[16] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices of imports. An overall decline in

[16] In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh or when the California ISO has accepted a cost-verified bid over $1,000/MWh. Phase 2 imposed bidding rules capping resource adequacy import bids over $1,000/MWh at the greater of MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

volumes began in late 2020 and continued throughout 2021, as well as into the first half of 2022. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 1.15 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[17] The dark grey bars reflect import capacity that was self-scheduled. The light grey bars show imports bid at or below $0/MWh. The remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market bid above $0/MWh. Levels of resource adequacy imports appear to be reaching a new level of consistency after an initial decline following the June 2020 CPUC decision.

Figure 1.15 Average hourly resource adequacy imports by price bin



Uncleared exports

Following the August 2020 heat wave event, the market change implemented on September 5, 2020 was designed to address the treatment of economic and self-scheduled exports that cleared the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment (RUC) process is able to not give RUC awards to IFM economic and lower priority self-scheduled exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds the California ISO real-time load, and can choose to re-bid in real-time or resubmit as self-schedules in real-time.

Effective August 4, 2021, further changes were implemented to designate self-schedule exports as either a low- or high-priority export. High-priority price taking (PT) exports are those supported by non-resource adequacy capacity, while low-priority price taking (LPT) exports are not. All low-priority exports that clear the residual unit commitment process will be prioritized below internal load in the real-time markets. In addition, the California ISO will prioritize exports that bid into the day-ahead market and

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

clear the residual unit commitment process (DA-LPT) over new exports that self-schedule into the real-time market (RT-LPT). The highest priority is given to Existing Transmission Contract (ETC) and Transmission Ownership Right (TOR) export schedules.

Figure 1.16 shows the distribution of non-wheel exports that cleared in the integrated forward market (IFM) but did not receive awards in the residual unit commitment (RUC) process in the two highest load periods in the third quarter of 2023. Significant volumes – up to 5.8 GW – of low-priority (LPT) exports (gold bars) that had received IFM awards subsequently did not receive awards in the RUC process in peak net load hours of 17 through 22 during the August 14-16 heat wave days. These days also had some high-priority (PT) exports (red bars) not receiving awards during hours with a power balance infeasibility in the RUC process. On days when the California ISO balancing authority area issued Energy Emergency Alerts (EEA1 or EEA Watch) on July 20, July 25, and July 26, much lower quantities of low-priority exports did not receive RUC awards. All high-priority exports that cleared the day-ahead IFM process received RUC awards on these July Energy Emergency Alert days.[18]

Figure 1.16 Reductions in day-ahead market energy schedules made in residual unit commitment process (high load days in July and August)

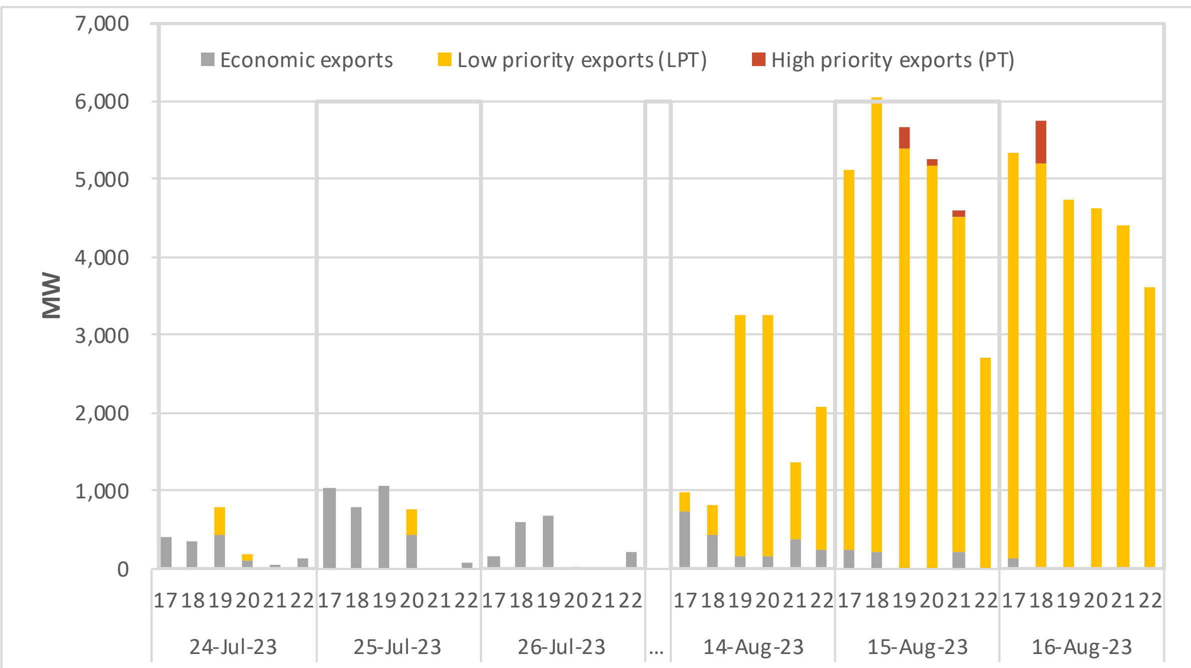


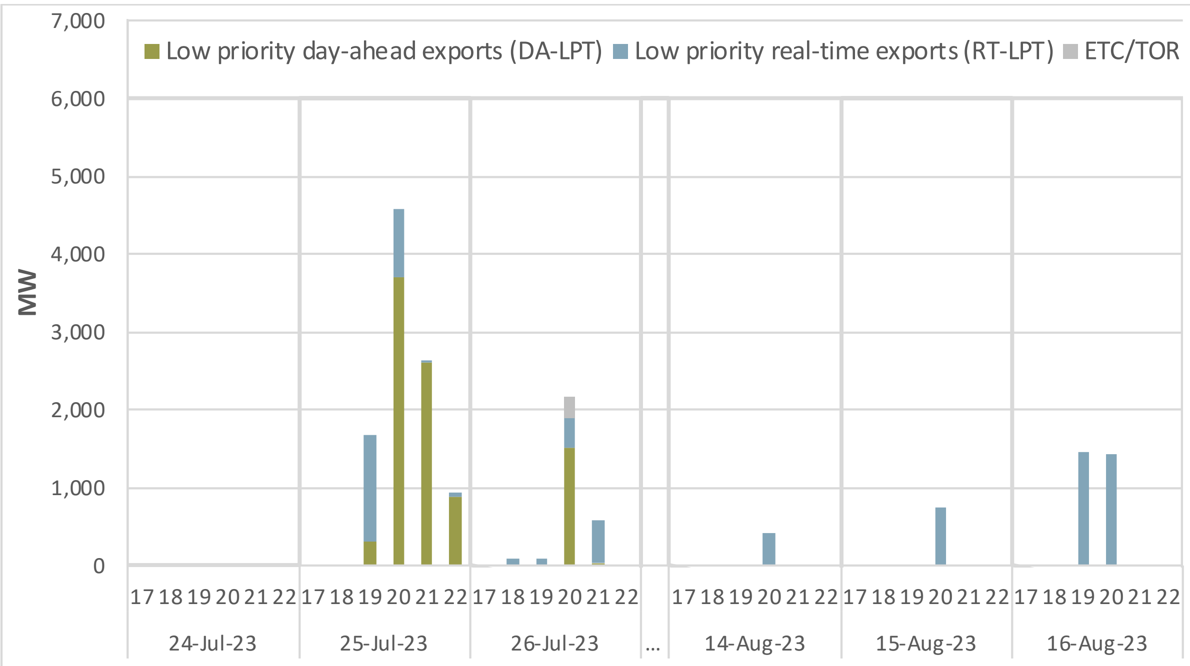
Figure 1.17 shows the uncleared non-wheel self-schedule exports in the hour-ahead market (HASP) over the two highest load periods in the third quarter of 2023. As shown in the figure, low-priority day-ahead exports (green bars) and low-priority real-time exports (blue bars) had uncleared MW as high as 3,700

[18] More information on intertie transactions can be found in California ISO's Summer Market Performance Report for July and August 2023:
https://www.caiso.com/Documents/Summer-Market-Performance-Report-for-July-2023.pdf
https://www.caiso.com/Documents/SummerMarketPerformanceReportforAugust2023.pdf

MW and 1,380 MW, respectively, in hour-ending 20 and hour-ending 19, on July 25 when the California ISO declared an EEA Watch.

On July 26 in hour-ending 20, ETC/TOR export schedules of about 260 MW did not receive hour-ahead market awards, in addition to low-priority day-ahead and real-time exports. During the August 15-16 high load days, only low-priority real-time exports in the range of 730 MW-1,460 MW did not receive hour-ahead market awards.

Figure 1.17 Self-schedule exports not clearing in hour-ahead scheduling process (high load days in July and August)



1.3 Price variability

In this quarter, instances of prices exceeding $250/MWh decreased to 0.9 percent from 2.3 percent when compared to the same quarter of the previous year. Meanwhile, the proportion of intervals with zero or negative prices increased to 0.5 percent from 0.2 percent.

High prices

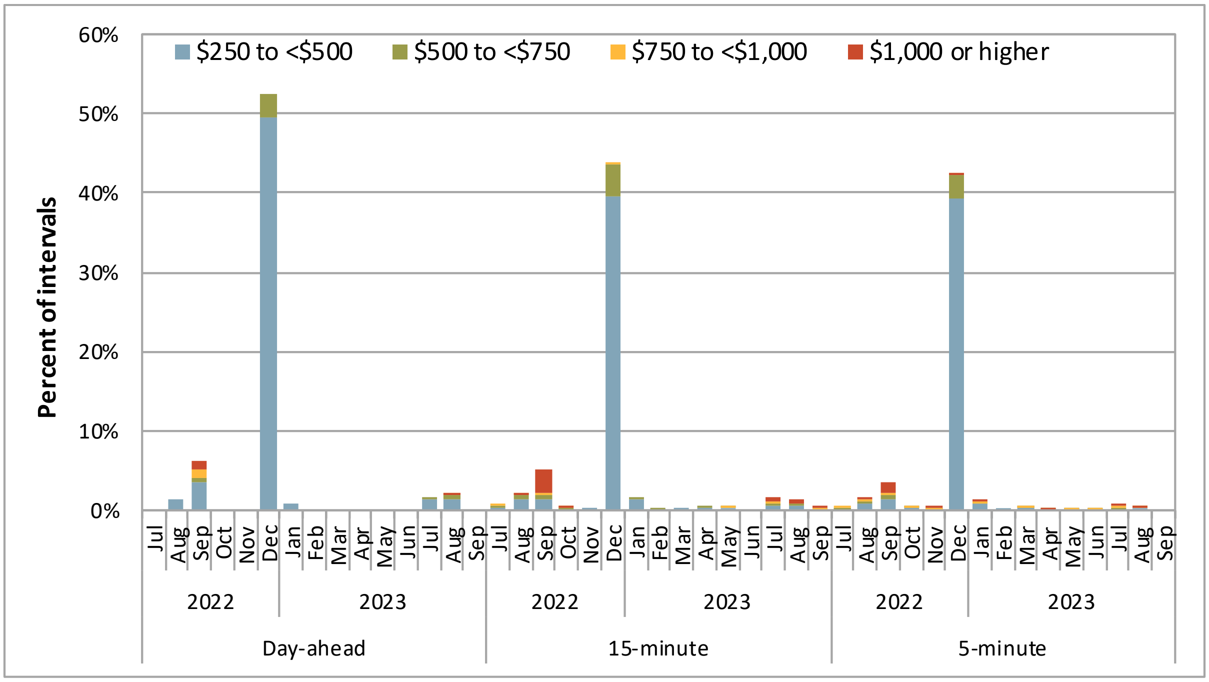
Figure 1.18 shows the frequency of high prices across all three markets for the three largest California ISO balancing area load aggregation points (LAP) by month between July 2022 and September 2023.

In the day-ahead market, the frequency of high prices over $250/MWh decreased in this third quarter compared to the previous year. In this quarter, the day-ahead market recorded 1.2 percent of intervals with an average price exceeding $250/MWh. In the same quarter of the previous year, 2.6 percent of intervals had prices above $250/MWh.

The 15-minute market had a lower frequency of price spikes in this quarter compared to previous periods. The percentage of intervals with prices above $250/MWh was 1.1 percent, a decrease from 2.6 percent in the same quarter of 2022.

The 5-minute market also had a reduced frequency of high prices this quarter. The percentage of intervals with prices above $250/MWh decreased to 0.3 percent in the third quarter of 2023 from 1.8 percent in the same quarter last year.

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



The notable reduction in the percentage of intervals with high prices this quarter can be attributed to less severe load conditions, when compared to the same quarter in 2022. In the third quarter in 2022, not only were extreme load conditions more frequent, but the peak load levels were also higher.[19]

Negative prices

Figure 1.19 shows the frequency of negative prices across all three markets for the three largest load aggregation points (LAP) by month between July 2022 and September 2023. The frequency of negative price intervals increased compared to the third quarter of 2022.

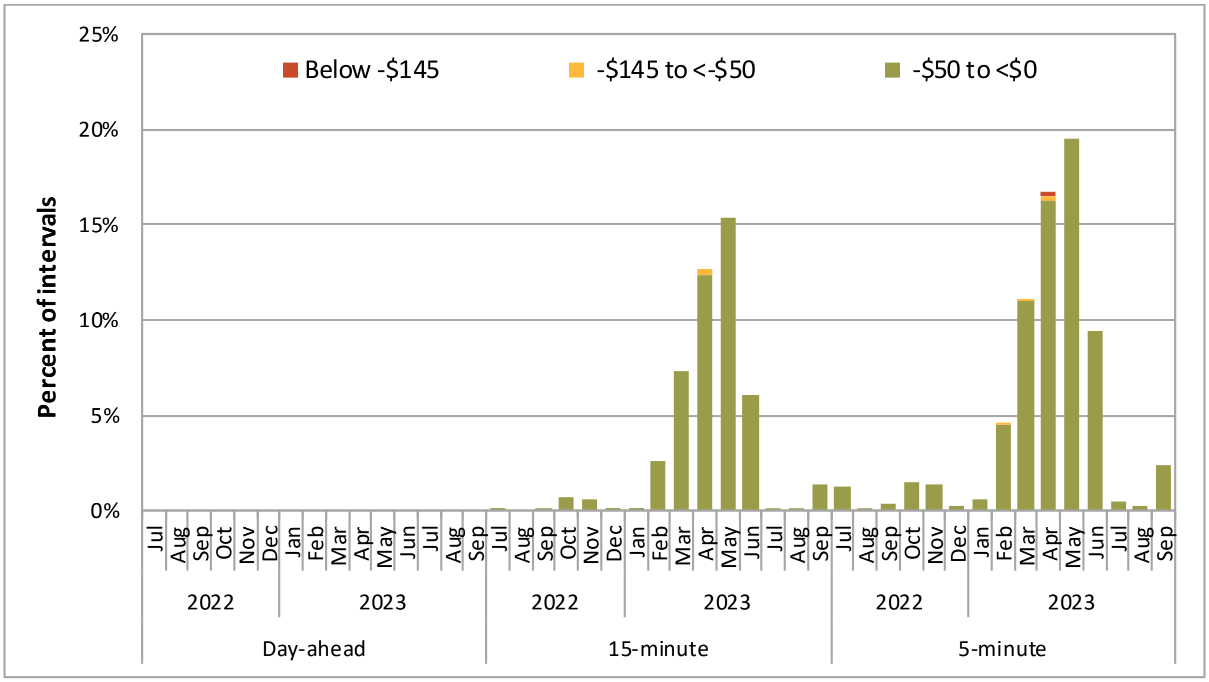
Negative prices tend to be most common when renewable production is high and demand is low. Low-cost renewable resources often bid at or below zero dollars, increasing the potential of becoming the

[19] In early September 2022, the California ISO balancing area experienced an extreme heat wave. The average hourly load-weighted price in the 15-minute market exceeded $1,000/MWh, and day-ahead and 5-minute market prices were over $700/MWh. The average hourly load peaked at 38,818 MW during hour-ending 20. For more details on the 2022 heat wave, please see the following link: https://www.caiso.com/Documents/2022-Third-Quarter-Report-Market-Issues-Performance-2022-12-14.pdf

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 0.48 percent this quarter compared to 0.05 percent in the third quarter of 2022. In the 5-minute market, negative prices increased to 1 percent this quarter compared to 0.6 percent in the third quarter of 2022. There were no negative prices in the day-ahead market during the third quarters of 2022 or 2023.

Figure 1.19 Frequency of negative prices ($/MWh) by month



1.4 Convergence bidding

Convergence bidding is designed to align day-ahead and 15-minute market prices by allowing financial arbitrage between the two markets. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. In the third quarter of 2023, financial entities were the only convergence bidding participants who profited overall.

1.4.1 Convergence bidding revenues

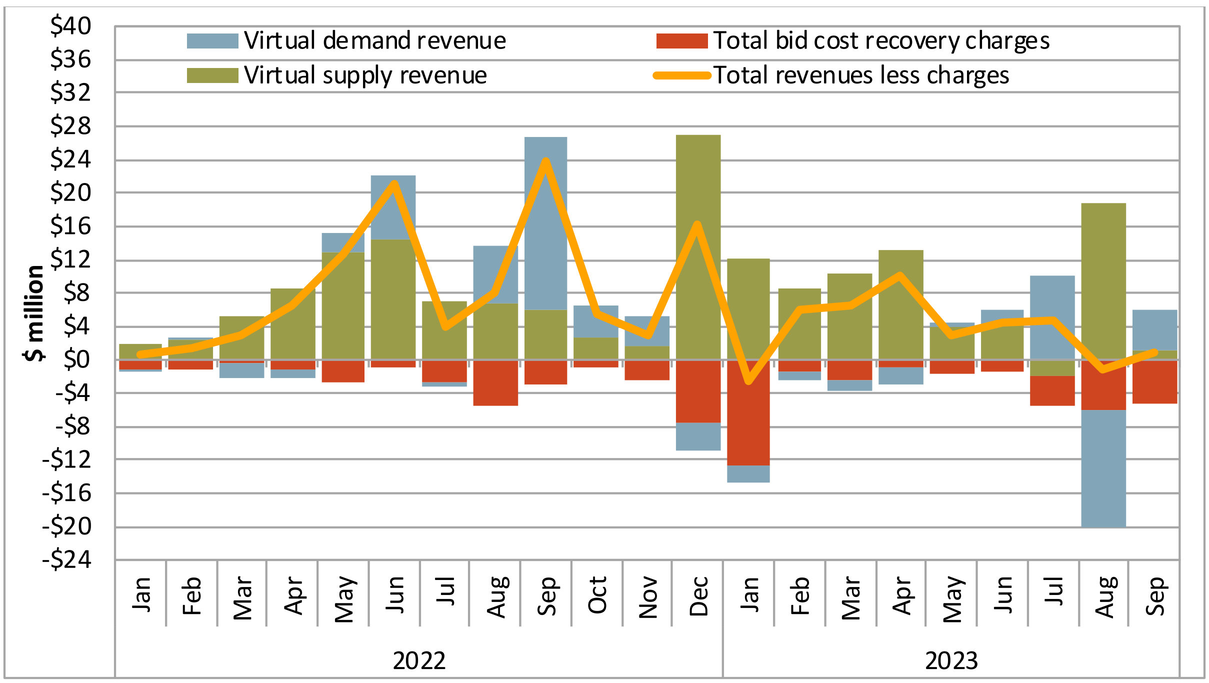
Net revenues for convergence bidders were about $4.2 million for the third quarter, after inclusion of about $15.1 million of virtual bidding bid cost recovery charges, which are primarily associated with virtual supply. Figure 1.20 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

- Total market revenues were negative for August and positive for July and September. Bid cost recovery charges – especially those associated with sharing costs from RUC procurement – contributed to low market revenues in August and September.

- Virtual demand revenues were about $10.2 million, -$14.1 million, and $4.9 million for July, August, and September, respectively.
- Virtual supply revenues were about -$1.8 million, $18.9 million, and $1.2 million for July, August, and September, respectively.

Convergence bidders received approximately $4.2 million after subtracting bid cost recovery charges during the third quarter. Bid cost recovery charges were about $3.8 million, $6.1 million, and $5.3 million for July, August, and September, respectively. The majority of bid cost recovery in this quarter was charged to the residual unit commitment (RUC) tier 1 allocation, which helps offset costs related to periods with net virtual supply. Virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in RUC, which may not be economic.

Figure 1.20 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.[20,21]

After accounting for bid cost recovery, financial entities were the only participants who profited from convergence bidding overall. Before accounting for bid cost recovery, nearly all virtual bidding revenue was split between financial entities and marketers, at around 93 percent and 7 percent, respectively. Financial entities and marketers accounted for around 82 percent and 16 percent, respectively, of the volume of virtual trades in the third 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 Q3								
Financial	2,251	2,815	5,066	$2.25	$16.35	-$11.13	$5.22	$7.47
Marketer	412	557	970	-$0.76	$2.14	-$2.90	-$0.76	-$1.52
Physical load	0	23	23	$0.00	$0.09	-$0.36	-$0.27	-$0.27
Physical generation	33	106	139	-$0.46	-$0.31	-$0.74	-$1.04	-$1.50
Total	**2,696**	**3,501**	**6,198**	**$1.03**	**$18.27**	**-$15.13**	**$3.15**	**$4.18**

1.5 Residual unit commitment

The average total volume of capacity procured through the residual unit commitment (RUC) process in the third quarter of 2023 was 74 percent higher than the same quarter of 2022. The majority of this increase can be attributed to manual operator adjustments, which increased by 70 percent compared to the third quarter of 2022. Throughout the third quarter, the ISO began making these adjustments using the mosaic quantile regression based on the 97.5th percentile of net load error between day-ahead and real-time.

20 This table summarizes data from the California 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 California ISO settlements page: http://www.caiso.com/market/Pages/Settlements/Default.aspx

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

The 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 physical supply cleared in the day-ahead market and the amount of physical supply that may be needed to meet actual real-time demand.

Operators will often manually increase the residual unit commitment market's target load requirement to a value above the day-ahead market load forecast. This allows the residual unit commitment market to procure extra capacity to account for uncertainty that may materialize in the load forecast and scheduled physical supply.

As illustrated in Figure 1.21, residual unit commitment procurement was primarily driven by operator adjustments to residual unit commitment requirements. These manual adjustments increased significantly to about 2,360 MW per hour in the third quarter, compared to 1,387 MW per hour in the same quarter of 2022.

Figure 1.22 shows the hourly distribution of these operator adjustments during the third quarter of 2023. The black line shows the average adjustment quantity in each hour and the red markers highlight outliers in each hour.

Figure 1.21 shows that residual unit commitment procurement was also 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 up by 67 percent when compared to the same quarter of 2022.

The blue bar in Figure 1.21 depicts the day-ahead forecasted load versus cleared day-ahead capacity, which includes both physical supply and net virtual supply. This represents the difference between the CAISO day-ahead load forecast and the physical load that cleared the IFM. On average, this factor contributed towards increasing residual unit commitment requirements by 842 MW per hour in the third quarter of 2023, up from 668 MW in 2022.

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 bars in Figure 1.21.

Figure 1.21 Determinants of residual unit commitment procurement

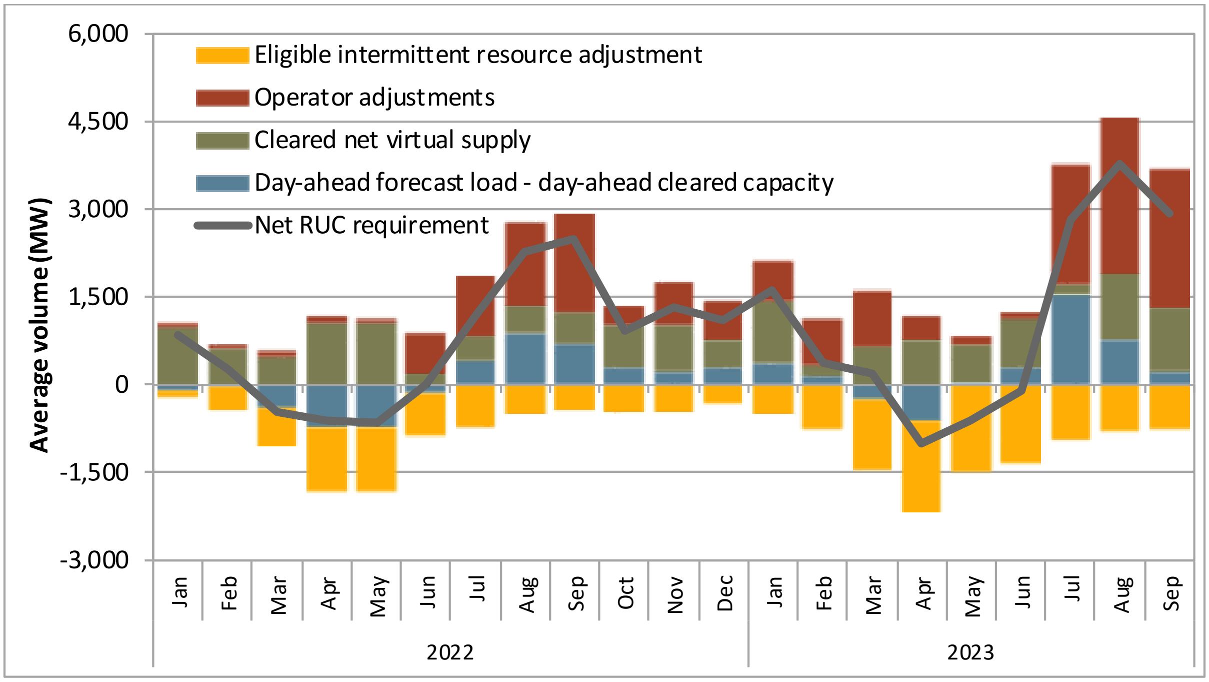


Figure 1.22 Hourly distribution of residual unit commitment operator adjustments (July-September 2023)

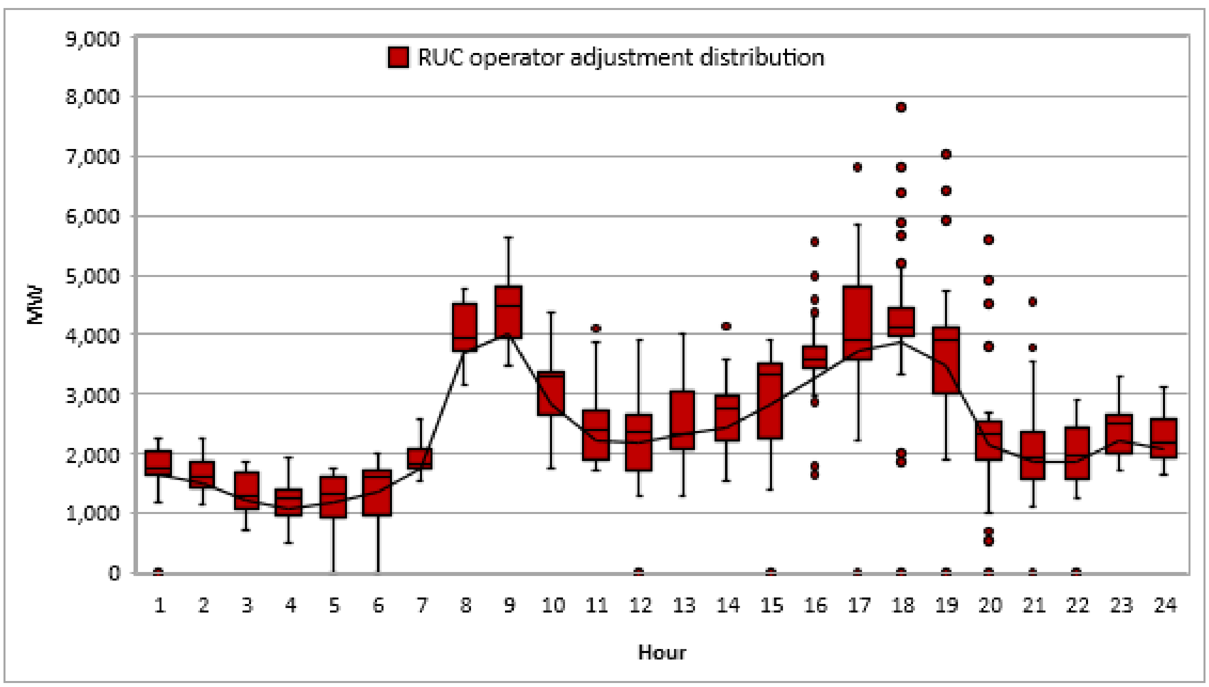
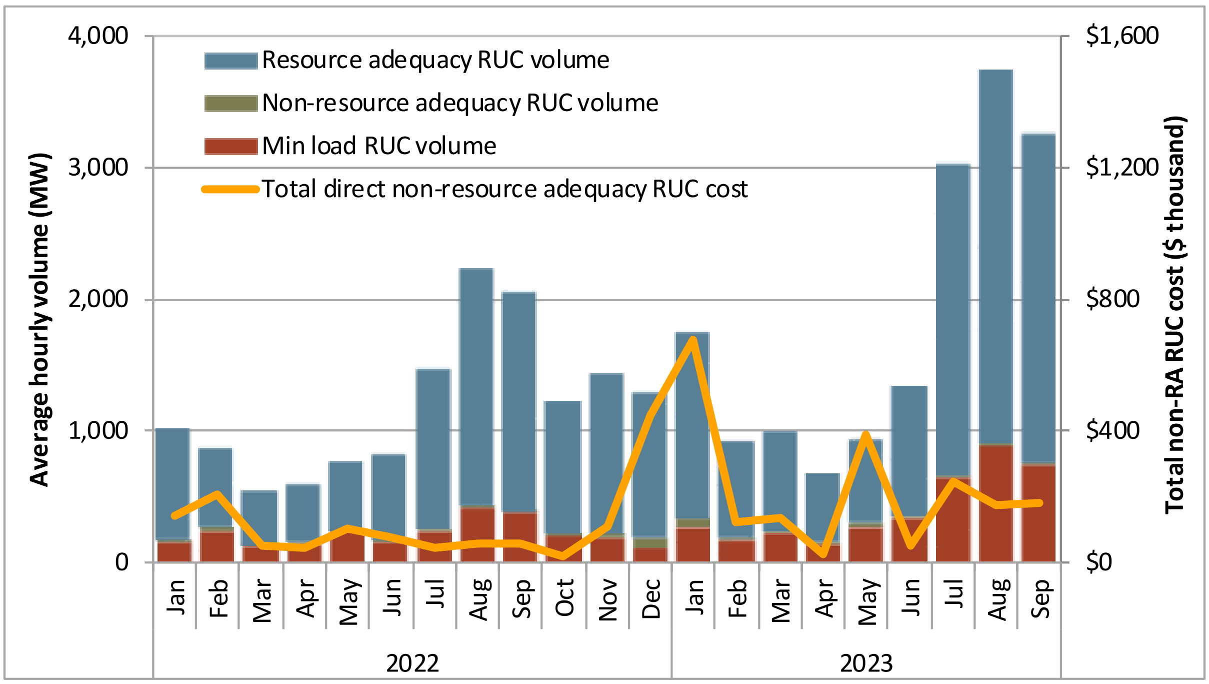


Figure 1.23 shows the monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased by 74 percent to about 3,342 MW in the third quarter of 2023 from an average of about 1,923 MW in the same quarter of 2022. Of the 3,342 MW capacity, the capacity committed to operate at minimum load averaged 760 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.[22] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.23. In the third quarter of 2023, these costs were about $0.6 million, more than three times the costs in the same quarter of 2022.

Figure 1.23 Residual unit commitment costs and volume



1.6 Ancillary services

Ancillary service payments totaled $62.2 million, a 44 percent decrease from the same quarter last year. Average requirements were higher for regulation down and non-spinning reserves, while average requirements for regulation up and spinning reserves were lower compared to the third quarter of 2022.

1.6.1 Ancillary service requirements

The California ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum

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

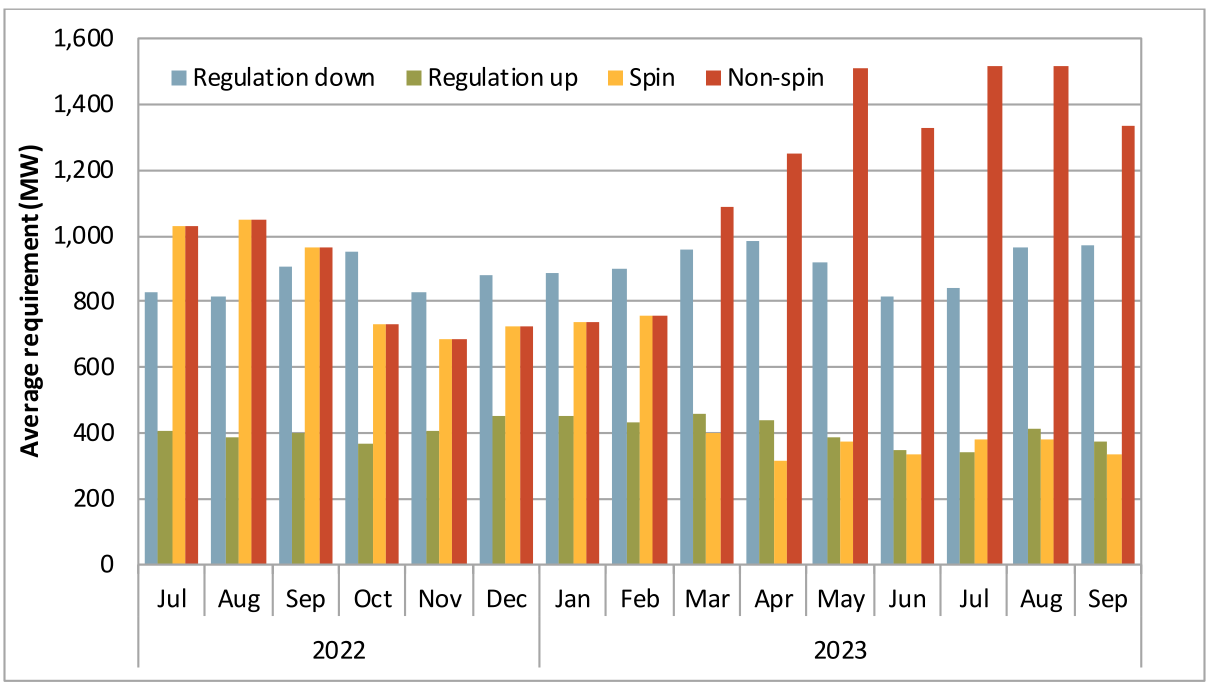
operating reliability criteria, and North American Electric Reliability Corporation's (NERC) control performance standards.

The California ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions.[23] 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.

Starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. In the third quarter of 2023, CAISO operators procured 25 percent of operating reserves as spinning reserves and the rest as non-spinning reserves.

Figure 1.24 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Regulation down requirements increased 28 percent and regulation up decreased by 5 percent compared to the third quarter of 2022. Average requirements for spinning and non-spinning reserves changed drastically due to CAISO operators' new procurement targets. Average total operating reserve requirements declined by about 200 MW, or 10 percent, compared to the third quarter of 2022.

Figure 1.24 Average monthly day-ahead ancillary service requirements



23 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

1.6.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California ISO balancing area pays a predetermined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

There was one scarcity event in the third quarter of 2023, which occurred on July 25, 2023, due to a shortage of 5 percent of the non-spinning reserve requirement. This was one of three days in 2023 where the California ISO issued an Energy Emergency Alert (EEA) to warn about potential supply shortages. This event follows four consecutive quarters 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 the California ISO balancing area's ancillary services.

1.6.3 Ancillary service costs

Ancillary service payments totaled $62.2 million in the third quarter of 2023, around $31.6 million more than the previous quarter and $49.8 million less than the same quarter of the previous year.

Figure 1.25 shows the total cost of procuring ancillary service products by quarter.[24] Similar to the first two quarters of 2023, payments for spinning reserve had the largest year-over-year decrease as a result of lower requirements relative to total operating reserve requirements. The remaining operating reserve requirements were fulfilled by non-spinning reserves, which are cheaper to procure. Spinning reserve payments decreased $28.2 million, or 62 percent, compared to the third quarter of 2022. Payments for regulation up, regulation down, and non-spinning reserve decreased by 40 percent, 30 percent, and 24 percent, respectively, compared to the third quarter of 2022.

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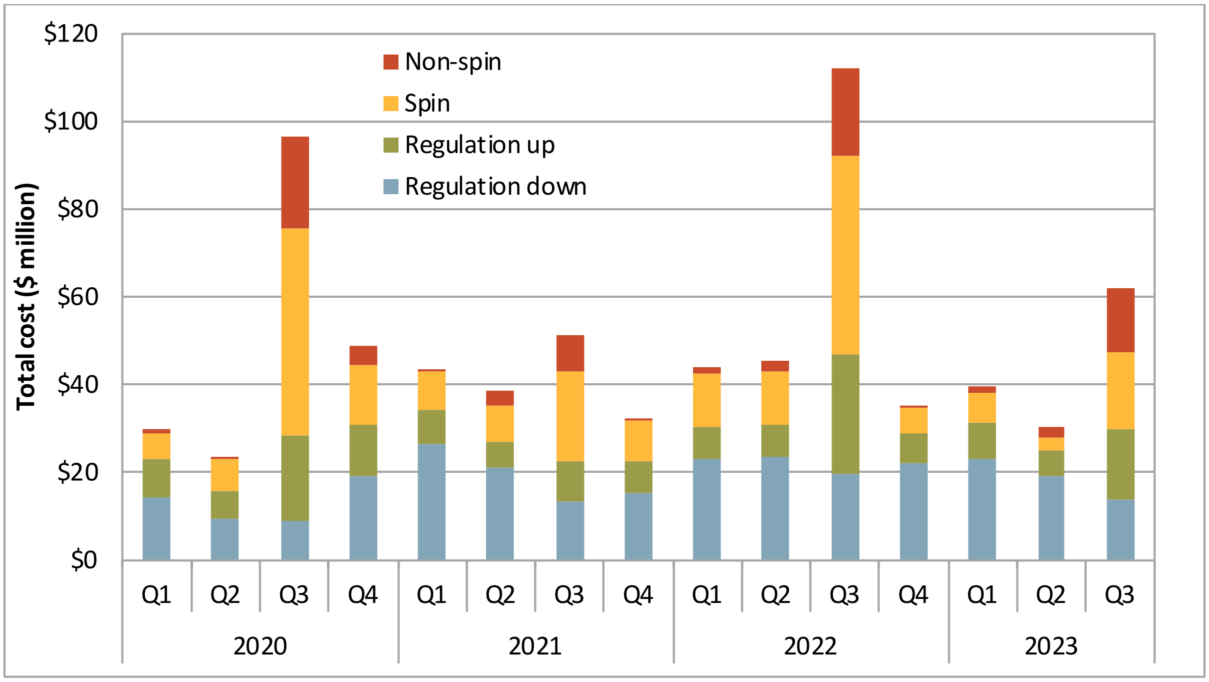
[24] The costs reported in this figure account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability requirements associated with the awards. As noted elsewhere in the report, settlements values are based on statements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

Figure 1.25 Ancillary service cost by product



1.7 Congestion

This section presents analysis of the effect of internal congestion on both day-ahead and real-time markets within the California ISO balancing area.[25] Additionally, it examines the impact of day-ahead congestion on interties. Detailed analysis of WEIM transfer congestion impact is addressed in Section 2.1.5. For metrics on WEIM internal congestion, refer to 2.4Appendix B.

In the third quarter of 2023, congestion on internal constraints had a greater impact on load area price separation than in the same quarter of 2022. Internal congestion was on average in the north to south direction, decreasing prices in the PG&E load area relative to the SCE and SDG&E load areas in the south. Despite this increased congestion on internal constraints, total day-ahead congestion rent decreased to $198 million, down from $238 million in the same quarter of the previous year. This was mainly due to congestion rent decreasing by almost $50 million on the Malin and NOB intertie constraints at the northern CAISO balancing area border.

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

The following sections provide an assessment of the frequency and impact of congestion on prices in the day-ahead, 15-minute, and 5-minute markets. It assesses the impact of congestion on local areas in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric).

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 California 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.[26]

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. However, in this quarter, the price impacts of congestion are slightly higher in the day-ahead market.

Congestion rent and loss surplus

In the third quarter of 2023, congestion rent and loss surplus was $198 million and $63 million, respectively. These respective amounts represent a decrease of 17 percent and 52 percent relative to the same quarter of 2022.[27] The decrease in congestion rent was primarily due to a decrease in congestion rent of about $50 million on the northern interties of Malin 500 and NOB. Figure 1.26 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 surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[28]

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

27 Due to the availability of data, comparative analysis in Figure 1.27 and the day-ahead congestion rent and loss surplus in the third quarter of 2023 are preliminary.

28 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 1.26 Day-ahead congestion rent and loss surplus by quarter (2022-2023)

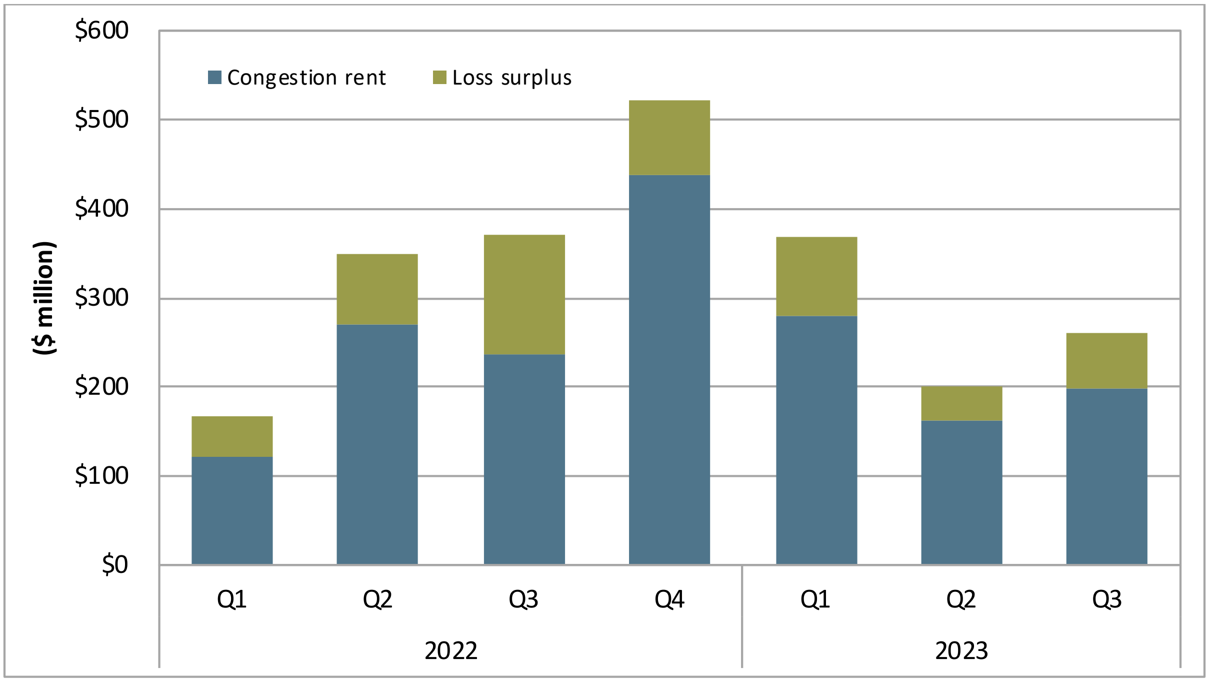


Figure 1.27 shows the overall impact of congestion on day-ahead prices in each load area in 2022 and 2023. Figure 1.28 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in the third quarter was higher than during the same quarter of 2022. The impact during the third quarter of 2023 was also higher than during the second quarter of 2023.
- Day-ahead congestion decreased quarterly average prices in PG&E by $2.86/MWh (5 percent), while it increased average SCE and SDG&E prices by $2.24/MWh (3.6 percent) and $2.74/MWh (4.3 percent), respectively.[29]
- The primary constraints affecting day-ahead market prices were the Midway-Vincent #2 500 kV line, Path 26 Control Point 1 nomogram, and Midway-Whirlwind #1 500 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.

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

Figure 1.27 Overall impact of congestion on price separation in the day-ahead market

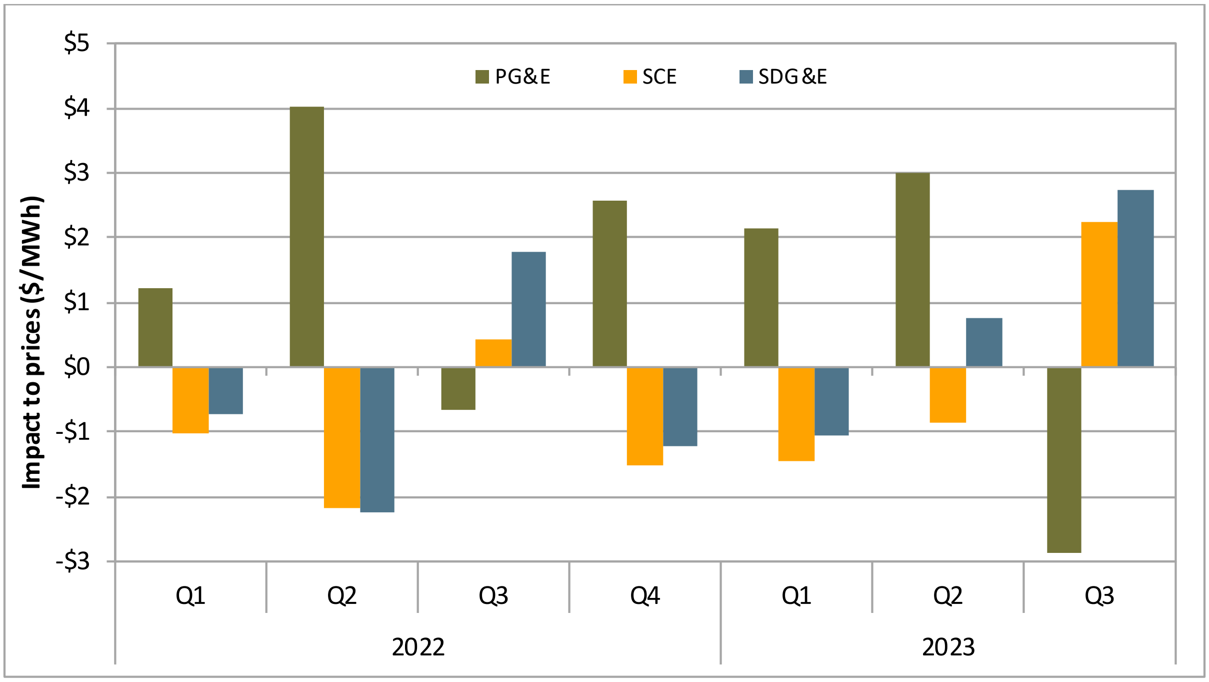
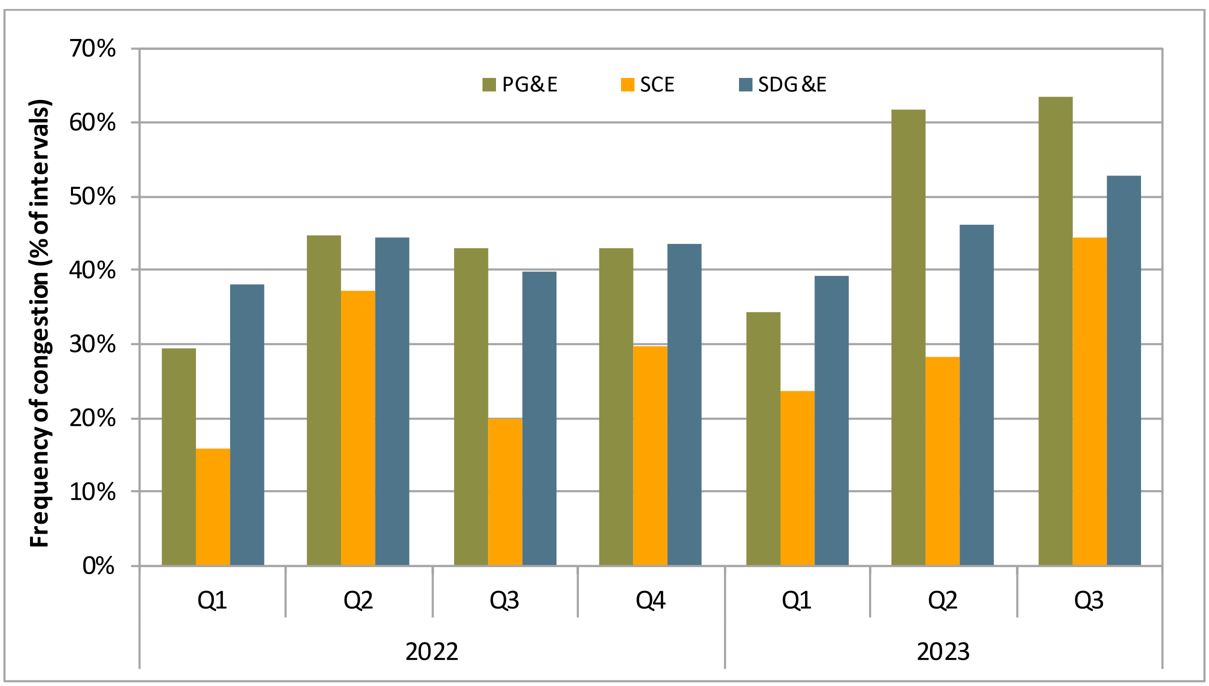


Figure 1.28 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion effect on price separation during the quarter by constraint.[30] Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact – the stronger the shading, the greater the impact in either the positive or the negative direction.

The constraints with the greatest impact on day-ahead price separation for the quarter were the Midway-Vincent #2 500 kV line, Path 26 Control Point 1 nomogram, and Midway-Whirlwind #1 500 kV line.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) had the greatest impact on day-ahead prices during the third quarter. The line was congested during 12 percent of hours. For the quarter, congestion on the line decreased average PG&E prices by $2.43/MWh, and increased average SCE and SDG&E prices by $1.79/MWh and $1.71/MWh. This line was frequently binding due to a loss of the parallel 500 kV line.

Path 26 Control Point 1 nomogram

Path 26 Control Point 1 nomogram (6410_CP1_NG) bound in 9.6 percent of hours over the quarter. For the quarter, congestion on the constraint decreased average PG&E prices by $1.22/MWh and increased average SCE and SDG&E prices by $0.88/MWh and $0.91/MWh, respectively. This nomogram is used to limit flows on the Midway-Whirlwind line for the contingency of the Midway-Vincent #1 and #2 lines.

Midway-Whirlwind #1 500 kV line

The Midway-Whirlwind #1 500 kV line (30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1) bound in about 2 percent of hours. For the quarter, the constraint decreased average PG&E prices by about $0.69/MWh, and increased average SCE and SDG&E prices by $0.52/MWh and $0.48/MWh, respectively. This line was frequently binding due to a loss of the Midway-Vincent #1 and #2 500 kV lines.

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

Table 1.2 Impact of congestion on overall day-ahead prices

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	12.4%	-2.43	1.79	1.71
6410_CP1_NG	9.6%	-1.22	0.88	0.91
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	2.1%	-0.69	0.52	0.48
30790_PANOCHE _230_30900_GATES _230_BR_2 _1	9.4%	0.41	-0.32	-0.29
30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	19.3%	0.42	-0.17	-0.16
30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	4.4%	0.26	-0.20	-0.18
35621_IBM-HR J_115_35642_METCALF _115_BR_1 _1	7.5%	0.16	-0.13	-0.12
30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	2.5%	0.07	-0.06	-0.06
22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	5.4%	0.00	0.00	0.18
32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	7.0%	-0.03	0.03	0.04
22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.9%	-0.01	0.00	0.08
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	0.3%	0.00	0.00	-0.09
30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.5%	0.03	-0.02	-0.02
33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	2.8%	0.02	-0.02	-0.02
22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1	2.9%	0.00	0.00	0.06
22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	2.4%	0.00	0.00	0.04
30580_ALTM MDW_230_30625_TESLA D _230_BR_1 _1	1.6%	0.01	-0.02	-0.02
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.3%	0.00	0.00	0.04
30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	1.2%	0.02	-0.01	-0.01
30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	2.9%	0.01	-0.01	-0.01
22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	2.4%	0.00	0.00	0.03
OMS 50004 IV-ML OUTAGE_NG	0.2%	0.00	0.00	0.02
7820_TL23040_IV_SPS_NG	0.4%	0.00	0.00	0.02
22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	0.1%	0.00	0.00	0.02
22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	0.4%	0.00	0.00	0.01
32214_RIO OSO _115_30330_RIO OSO _230_XF_1	3.5%	0.01	0.00	0.00
Other	—	0.11	-0.03	0.08
Total		-2.86	2.24	2.74

1.7.2 Congestion in the real-time market

This section outlines the effects of internal congestion on both the 15-minute and 5-minute markets within the California ISO balancing area.[31]

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.

[31] The metrics for WEIM internal congestion can be found in Appendix B.

In the third quarter, the constraints that had the greatest impact on price separation in the 15-minute and 5-minute markets were the Path 26 Control Point 1 nomogram, Los Banos-Gates #1 500 kV line, and Midway-Vincent #2 500 kV line.[32] These constraints were impacted by maintenance in their respective areas.

Table 1.3 shows the average effect of internal congestion on 15-minute market prices in the California ISO balancing area. The color scales in the table below apply only to the individual constraints and the "Other" category in Table 1.3.

In the 5-minute market, Table 1.4 shows that the constraints affecting prices were similar to those in the 15-minute market. However, each individual constraint has a slightly lesser price impact, and there are more constraints with price impact exceeding $0.01/MWh.

Overall, in both the 15-minute and 5-minute markets, internal congestion generally led to lower prices in the PG&E area but higher prices in the SCE and SDG&E areas, suggesting a north-to-south congestion pattern. The extent of this price impact was more pronounced in the 15-minute market.

32 These constraints are shown as 6410_CP1_NG, 30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2, and 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 in the tables, respectively.

Table 1.3 Impact of internal transmission constraint congestion on 15-minute market prices

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
6410_CP1_NG	11.9%	-2.07	1.67	1.68
30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	9.3%	0.57	-0.82	-0.78
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	3.1%	-0.80	0.66	0.63
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	1.9%	-0.51	0.46	0.42
ML_RM12_NS	0.5%	0.30	0.17	0.15
30790_PANOCHE _230_30900_GATES _230_BR_2 _1	3.6%	0.17	-0.20	-0.19
22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	1.4%	0.00	0.03	0.36
30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	4.2%	0.09	-0.12	-0.10
7820_TL 230S_OVERLOAD_NG	3.0%	0.00	0.02	0.27
30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.8%	0.05	-0.09	-0.08
OMS_14013927_TL23055_NG	0.3%	0.00	0.01	0.20
35621_IBM-HR J_115_35642_METCALF _115_BR_1 _1	1.6%	0.10	-0.04	-0.04
32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	1.7%	-0.15	-0.03	0.00
29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	0.4%	-0.06	0.05	0.05
OMS 13938629_CP1_NG	0.2%	-0.07	0.05	0.05
INTNEL	0.8%	-0.06	-0.05	-0.05
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.1%	-0.06	0.05	0.04
22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	0.3%	0.00	0.00	0.12
30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	4.2%	-0.06	0.02	0.01
35620_EL PATIO_115_35621_IBM-HR J_115_BR_1 _1	0.5%	0.03	-0.01	-0.01
22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	0.2%	0.01	0.01	0.02
24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	0.1%	0.01	0.03	0.00
22464_MIGUEL _230_22468_MIGUEL _500_XF_81	0.4%	0.00	0.00	0.04
OMS_14040245_Miguel_BK81	0.3%	0.00	0.00	0.03
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.3%	0.00	0.00	0.03
22380_KETTNER _69.0_22024_B _69.0_BR_1 _1	0.1%	0.00	0.00	0.03
22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.2%	0.00	0.00	0.02
34116_LE GRAND_115_34115_ADRA TAP_115_BR_1 _1	6.8%	-0.03	0.00	0.00
7430_CP6_NG	1.0%	0.01	-0.01	-0.01
30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.6%	0.00	-0.01	-0.01
22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	0.1%	0.00	0.00	0.02
22357_IV PFC1 _230_22358_IV PFC _230_PS_1	0.1%	0.00	0.00	0.02
30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	0.6%	-0.01	-0.01	0.00
OMS_13825582_TL23055_NG	0.03%	0.00	0.00	0.01
Other	—	0.04	0.00	0.03
Total		-2.49	1.86	2.97

Table 1.4 Impact of internal transmission constraint congestion on 5-minute market prices

Constraint	Frequency	Average quarter impact ($/MWh)		
		PG&E	SCE	SDG&E
6410_CP1_NG	10.6%	-1.55	1.25	1.26
30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	10.0%	0.74	-1.05	-0.99
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.6%	-0.39	0.32	0.31
30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	5.0%	0.23	-0.28	-0.27
30790_PANOCHE _230_30900_GATES _230_BR_2 _1	3.9%	0.20	-0.24	-0.22
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	1.7%	-0.23	0.20	0.19
7820_TL 230S_OVERLOAD_NG	2.9%	0.00	0.02	0.30
22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	1.4%	0.00	0.02	0.30
30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	3.7%	0.07	-0.11	-0.09
30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.8%	0.06	-0.11	-0.10
35621_IBM-HR J_115_35642_METCALF _115_BR_1 _1	1.6%	0.10	-0.04	-0.04
32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	1.9%	-0.14	-0.03	0.00
29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	0.4%	-0.06	0.05	0.05
INTNEL	0.7%	-0.06	-0.05	-0.05
OMS_14013927_TL23055_NG	0.3%	0.00	0.01	0.15
22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	0.4%	0.00	0.00	0.15
OMS 13938629_CP1_NG	0.2%	-0.04	0.03	0.03
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.1%	-0.04	0.03	0.03
22380_KETTNER _69.0_22024_B _69.0_BR_1 _1	0.3%	0.00	0.00	0.05
22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	0.1%	0.00	0.00	0.05
24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	0.1%	0.01	0.03	0.00
22464_MIGUEL _230_22468_MIGUEL _500_XF_81	0.4%	0.00	0.00	0.04
35620_EL PATIO_115_35621_IBM-HR J_115_BR_1 _1	0.5%	0.02	-0.01	-0.01
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.3%	0.00	0.00	0.04
22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	0.1%	0.01	0.01	0.02
22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	0.1%	0.00	0.00	-0.03
OMS_14040245_Miguel_BK81	0.3%	0.00	0.00	0.03
WINDSTAR EXPORT TCOR	8.9%	0.01	0.01	0.01
22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.2%	0.00	0.00	0.03
30015_TABLE MT_500_30030_VACA-DIX_500_BR_1 _3	0.2%	0.01	0.01	0.01
6110_COI_N-S	0.3%	0.01	0.01	0.01
ML_RM12_SN	0.1%	-0.01	-0.01	-0.01
34116_LE GRAND_115_34115_ADRA TAP_115_BR_1 _1	6.8%	-0.03	0.00	0.00
30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	1.0%	-0.01	-0.02	0.00
30735_METCALF _230_30042_METCALF _500_XF_13	0.2%	0.02	0.00	0.00
30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.5%	0.00	-0.01	-0.01
OMS_13824882_TL23054 NG	0.1%	0.00	0.00	0.02
OMS_13982569_13810A_NG	0.1%	0.00	0.00	0.02
33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	0.3%	0.01	0.00	0.00
Other	—	0.02	-0.01	0.03
Total		-1.01	0.06	1.27

1.7.3 Congestion on interties

In the third quarter of 2023, the import congestion rent and frequency of import congestion on the Malin 500 and NOB interties decreased significantly relative to the same quarter of 2022. The NOB intertie generated 60 percent of the total import congestion charges for the quarter. 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 1.5 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 an intertie congested in the import direction, assuming a radial line, the congestion price represents the difference between the higher price of generation on the California ISO side of the intertie and the lower price of import bids outside of the California ISO area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO area at points corresponding to these interties. The charts and table below highlight the following:

- Total import congestion charges for the third quarter of 2023 were $15 million, which is 77 percent lower than the $65 million recorded in the third quarter of 2022. The NOB intertie was the primary driver of congestion charges in the day-ahead market for Q3 2023, after congestion rent on the Malin 500 intertie decreased from $40 million in Q3 2022 down to only $3 million this quarter.
- The frequency of congestion on interties continued to decrease from the second quarter of 2023 to the third quarter of 2023, where on average, the frequency dropped to 2 percent from 4 percent. However, the total congestion charges increased from $9.5 million to $15 million.
- The frequency of congestion and magnitude of congestion charges were highest on NOB, Malin 500, and Mead interties, which accounted for 99 percent of the total congestion charges for the quarter. Congestion on other interties was relatively low in comparison to these constraints, accounting for 1 percent of the total congestion charges.

Figure 1.29 Day-ahead import congestion charges on major interties

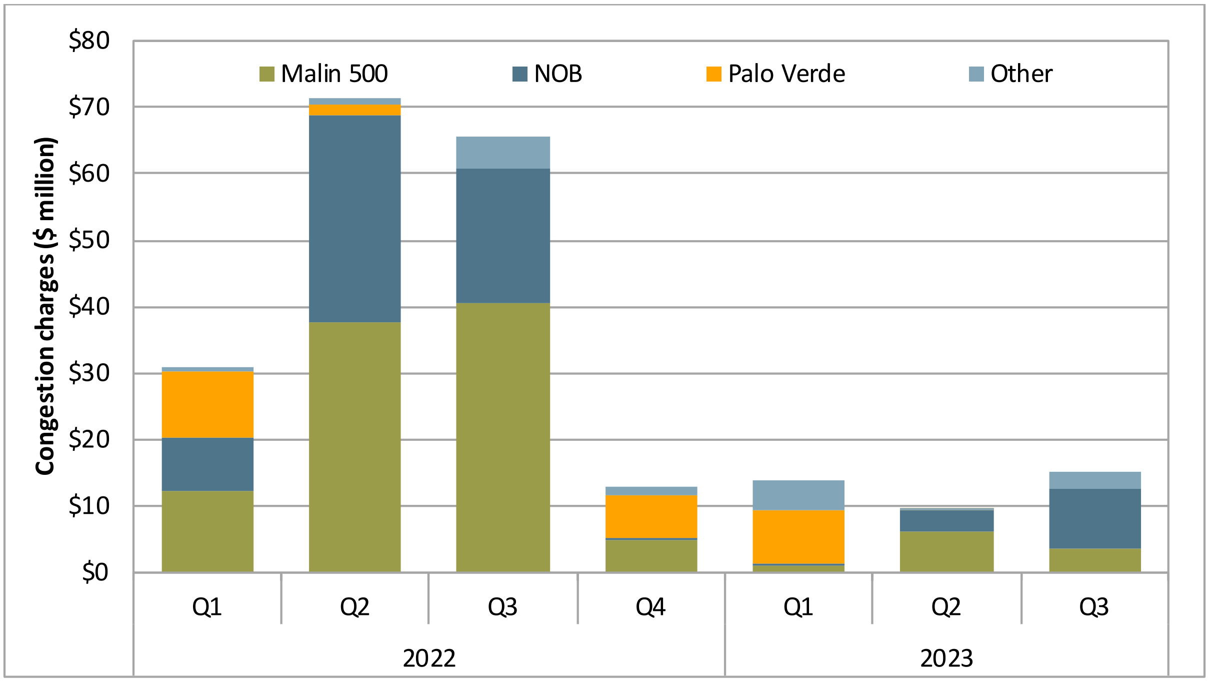


Figure 1.30 Frequency of import congestion on major interties in the day-ahead market

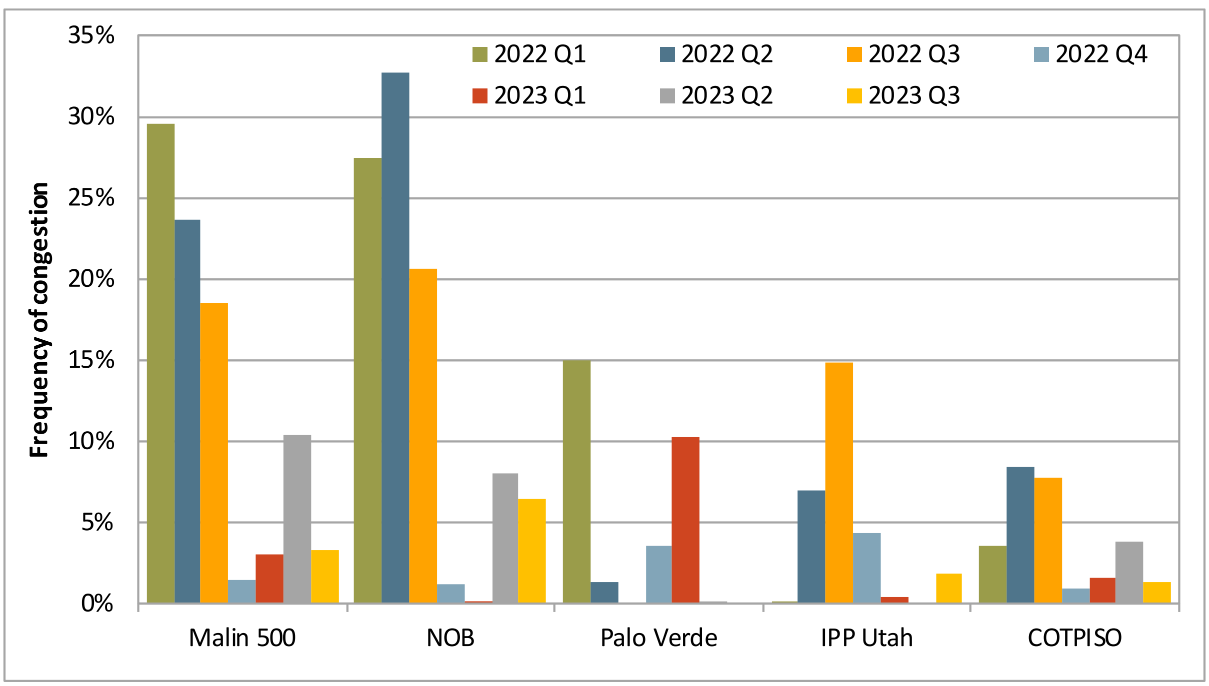


Table 1.5 Summary of import congestion in day-ahead market (2022-2023)

Area	Intertie	Frequency of import congestion							Import congestion charges ($ thousand)						
		2022				2023			2022				2023		
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Northwest	Malin 500	30%	24%	18%	1%	3%	10%	3%	12,221	37,557	40,646	4,786	1,183	6,266	3,467
	NOB	28%	33%	21%	1%	0%	8%	6%	8,216	31,130	20,229	333	68	3,075	9,007
	COTPISO	4%	8%	8%	1%	2%	4%	1%	53	435	310	15	39	77	46
	Summit		0%	0%	1%	0%		1%		1	14	4	10		42
Southwest	IID-SCE					1%	1%						150	91	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%		2%	182		308		75		2,370
	IPP Utah	0%	7%	15%	4%	0%		2%	0	480	4,092	1,084	18		59

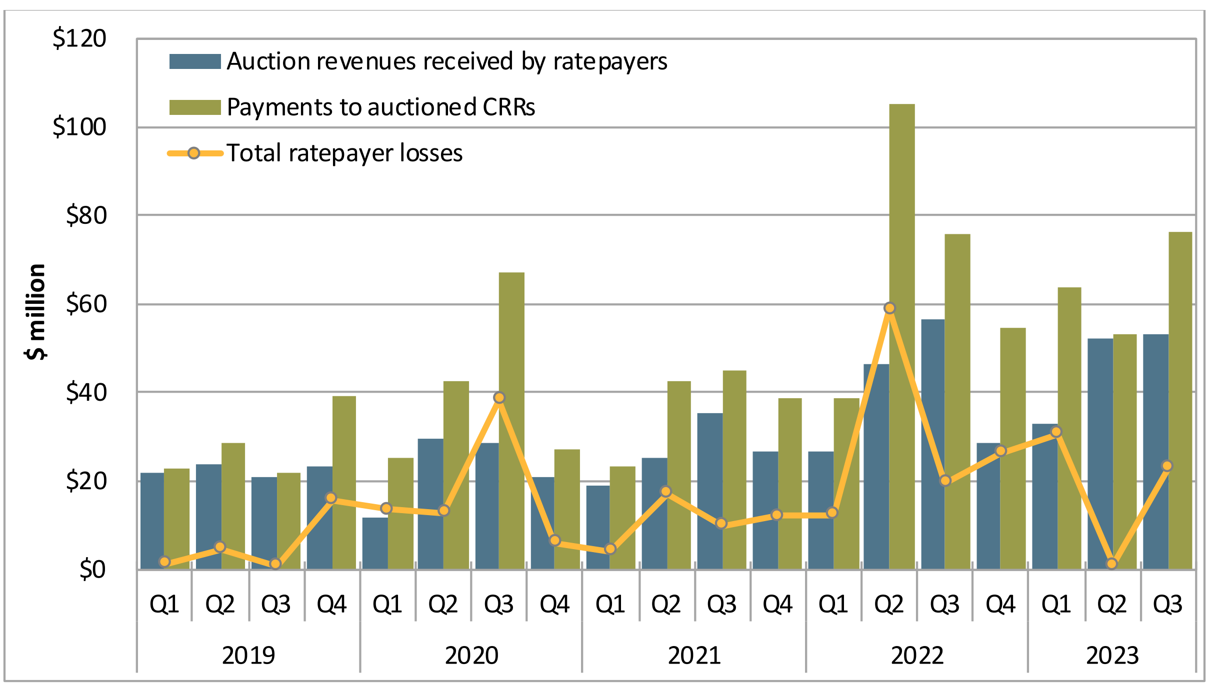
1.8 Congestion revenue rights

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 $23 million during the third quarter of 2023 as payments to auctioned congestion revenue rights holders were higher than auction revenues. In the same quarter of 2022, ratepayers lost about $20 million.

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



During the third quarter of 2023:

- Financial entities received profits of nearly $15 million, up from $12 million during the same quarter of 2022. Total revenue deficit offsets were about $26 million.[33]
- Marketers profited about $7.5 million from auctioned rights, up from $5.3 million in 2022. Total revenue deficit offsets were nearly $8 million.
- Physical generation entities gained about $0.3 million from auctioned rights, down from $2.2 million in 2022. Total revenue deficit offsets were about $3 million.

The $23 million in third quarter 2023 auction losses was about 12 percent of day-ahead congestion rent. This is significantly up from 1 percent from the previous quarter and up from 8 percent in the third quarter of 2022. 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).[34,35]

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 $37 million in the third quarter. The track 1B effects on auction bidding behavior and reduced auction revenues are not known.

Rule changes made by the ISO reduced losses from sales of congestion revenue rights significantly in 2019, 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 in losses to transmission ratepayers each year, while exposing transmission ratepayers to a risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends the ISO convert the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

1.9 Real-time imbalance offset costs

Real-time imbalance offset costs were $86 million in the third quarter of 2023, down significantly from $207 million in the third quarter of 2022. As shown in Figure 1.32, during the third quarter of 2023, real-time *energy* imbalance offset costs made up $48 million of these costs while real-time *congestion* imbalance offset costs made up $39 million.

33 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.

34 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

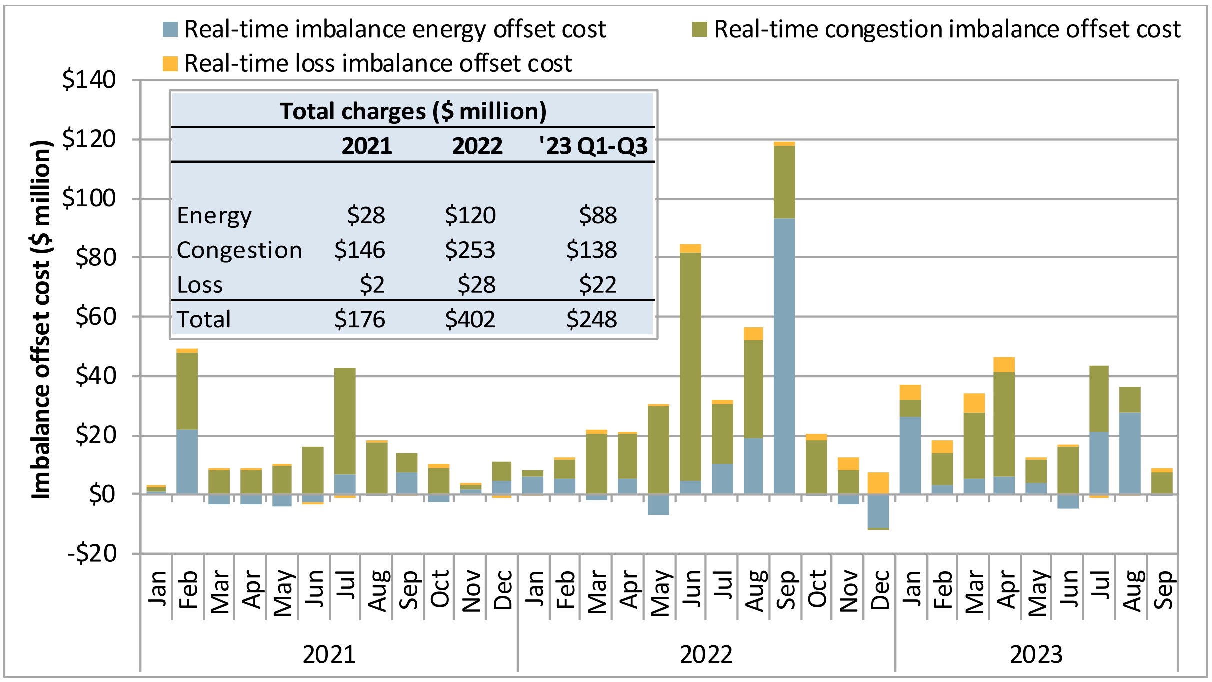
35 California ISO, Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

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

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.[36] 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



1.10 Bid cost recovery

During the third quarter of 2023, estimated bid cost recovery payments for units in the California ISO and Western energy imbalance market (WEIM) balancing areas totaled about $84 million and $8 million,

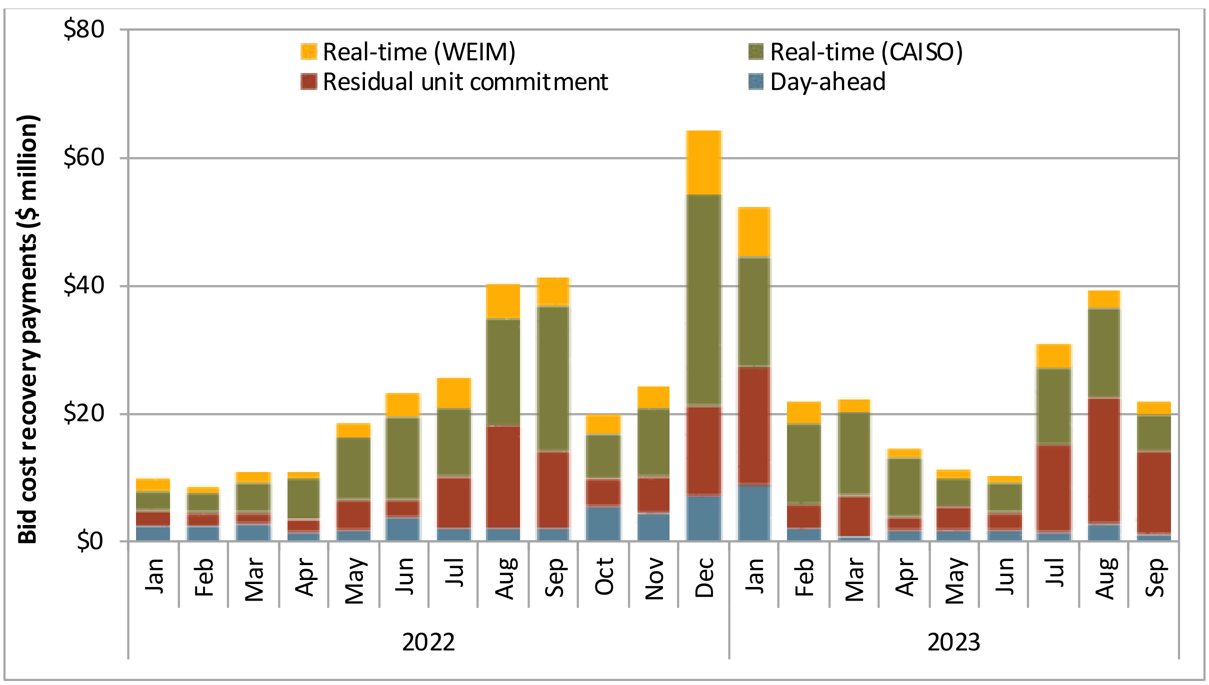
[36] For more information, see DMM's special report: Department of Market Monitoring, *Real-time load settlement price calculation causing revenue imbalances*, August 30, 2023: http://www.caiso.com/Documents/Real-Time-Load-Settlements-and-Revenue-Imbalances-Aug-30-2023.pdf

respectively. These payments were lower than the same quarter of 2022 when payments totaled $93 million in the California ISO and $14 million in the WEIM areas.

Figure 1.33 shows that in the third quarter of 2023, bid cost recovery attributed to the day-ahead integrated forward market totaled about $6 million, which was similar to the third quarter of 2022. Bid cost recovery payments for residual unit commitment during the quarter totaled about $46 million, or about $10 million higher than the third quarter of 2022. Bid cost recovery attributed to the real-time market totaled about $40 million, $18 million higher than the payments in the previous quarter, and about $24 million lower than the same quarter of 2022. Out of the $40 million in real-time payments, about $8 million was allocated to non-California ISO resources participating in the WEIM.

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. In the third quarter, about 84 percent of these payments, or about $77 million, were made to gas resources, followed by about $9 million to battery energy storage resources.

Figure 1.33 Monthly bid cost recovery payments



1.11 Imbalance conformance

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

Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO balancing area hour-ahead and 15-minute markets. Figure 1.34 shows imbalance conformance adjustments in real-time markets for the third quarter of 2022 and 2023. Average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets decreased in the third quarter of 2023 relative to the same quarter of 2022, over both the morning and evening ramp periods. Over the morning ramp, the highest average hourly adjustments were less than 50 MW. This was a decrease of about 400 MW compared to the third quarter of 2022.

This resulted in a notable change to the historical shape of the average hourly conformance adjustments in the hour-ahead and 15-minute markets, with a peak adjustment during the morning load ramp hours becoming barely perceptible.

The 5-minute market adjustments, on the other hand, maintained their typical shape with net adjustments peaking over both the morning and evening load ramps during the third quarter of 2023. However, outside of the evening peak net load period, the average hourly 5-minute market adjustments decreased compared to the same quarter of 2022, and were negative adjustments to the load forecast during most of these hours.

Figure 1.34 Average hourly imbalance conformance adjustment (Q3 2022 and Q3 2023)

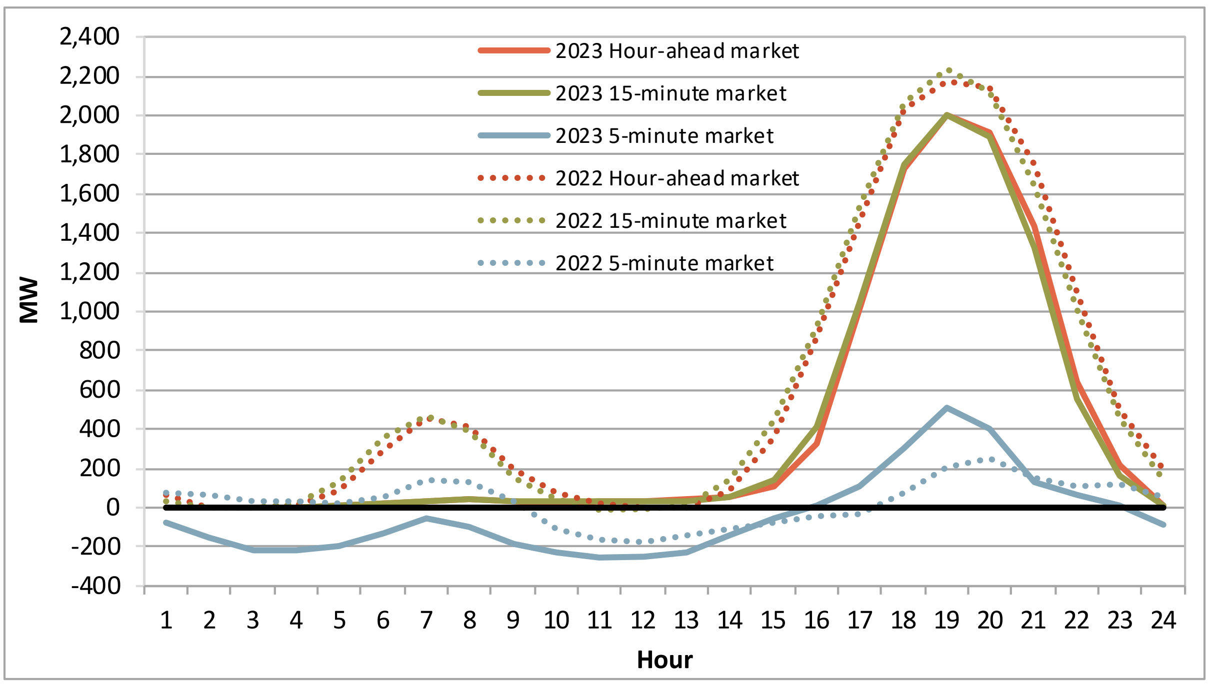
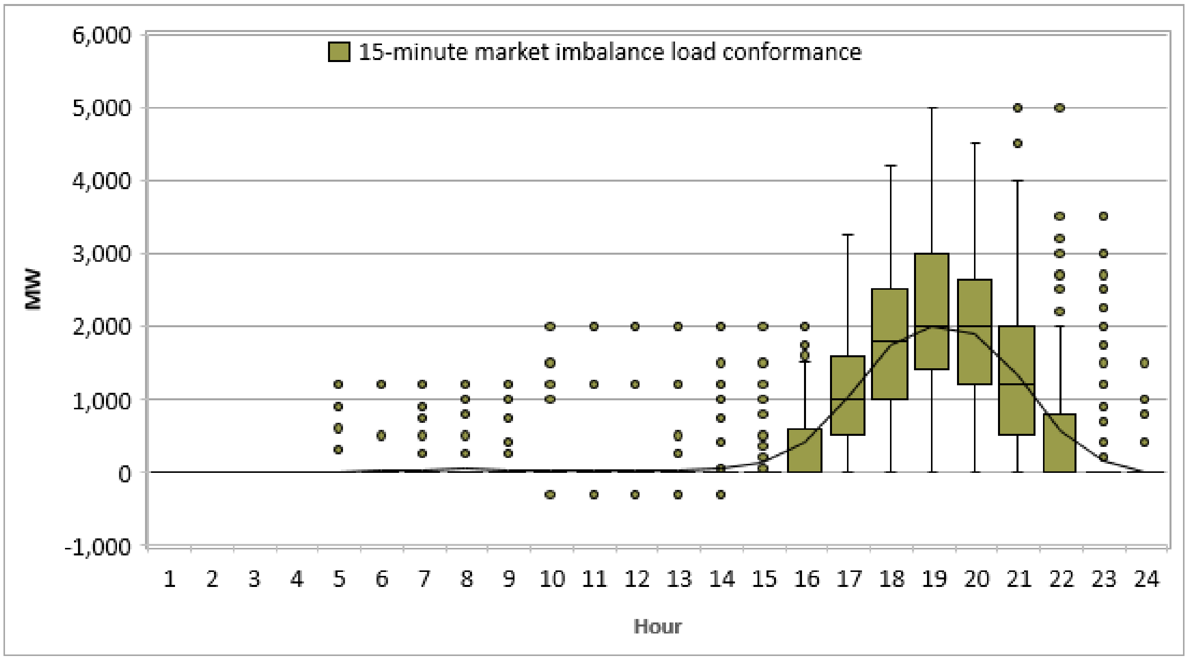


Figure 1.35 shows the distribution of the 15-minute market into quartiles for the load adjustment profile for the third quarter of 2023. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the filled “dots”. The outside whiskers do not include these outliers. For the quarter, the maximums and major outliers, e.g. 5,000 MW, occurred during the July heat wave period. These high load adjustments occurred after the CAISO balancing area declared an EEA 1 on July 20. CAISO area operators had typically entered relatively low hour-ahead and 15-minute

market peak net load adjustments during the summer of 2023 prior to July 20. These low load adjustments were not sufficient to set up the CAISO system to address the load and supply uncertainty that materialized quickly during the evening net load ramp hours on July 20. The CAISO balancing area responded by increasing the load adjustments and by limiting WEIM transfers into its area over the evening peak net load hours in the hour-ahead and 15-minute markets.[37]

Figure 1.35 15-minute market hourly distribution of operator load adjustments (Q3 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.[38] 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.

37 See the California ISO Summer Market Performance Report for July 2023: https://www.caiso.com/Documents/Summer-MarketPerformance-Report-for-July-2023.pdf

38 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.

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.

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.[39] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

The real-time market enforces an area-specific uncertainty requirement for balancing areas that fail the resource sufficiency evaluation. This requirement can only be met by flexible capacity within that area. Flexible capacity for the group of balancing areas that 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 marginal 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 marginal 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 for this issue, effective August 8, 2023.[40] For more

39 Based on a 95 percent confidence interval.

40 A subsequent issue with this implementation caused the price for each segment beyond the first to be incorrectly shifted by one segment. This was corrected on October 4, 2023.

information on the implementation error, including the cause of the issue and its impact, see DMM's special report on the topic.[41]

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 implementation of the enhancements on February 1, 2023, only base-case flow-based transmission constraints were modeled in the deployment scenarios. Nomogram constraints were later enforced for flexible ramping product procurement on September 13, 2023. Contingency flowgate constraints are being assessed for potential implementation in the future.

Flexible ramping product prices for the group of balancing areas that pass the resource sufficiency evaluation continue to be frequently 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.*[42] 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 higher during the quarter compared to the same quarter of the previous year (prior to the enhancements), but remained low overall. For the quarter, 15-minute market prices for upward flexible capacity within the pass-group were non-zero in around 1.4 percent of intervals. The frequency of non-zero prices in the 5-minute market were more infrequent, in less than 0.1 percent of intervals.

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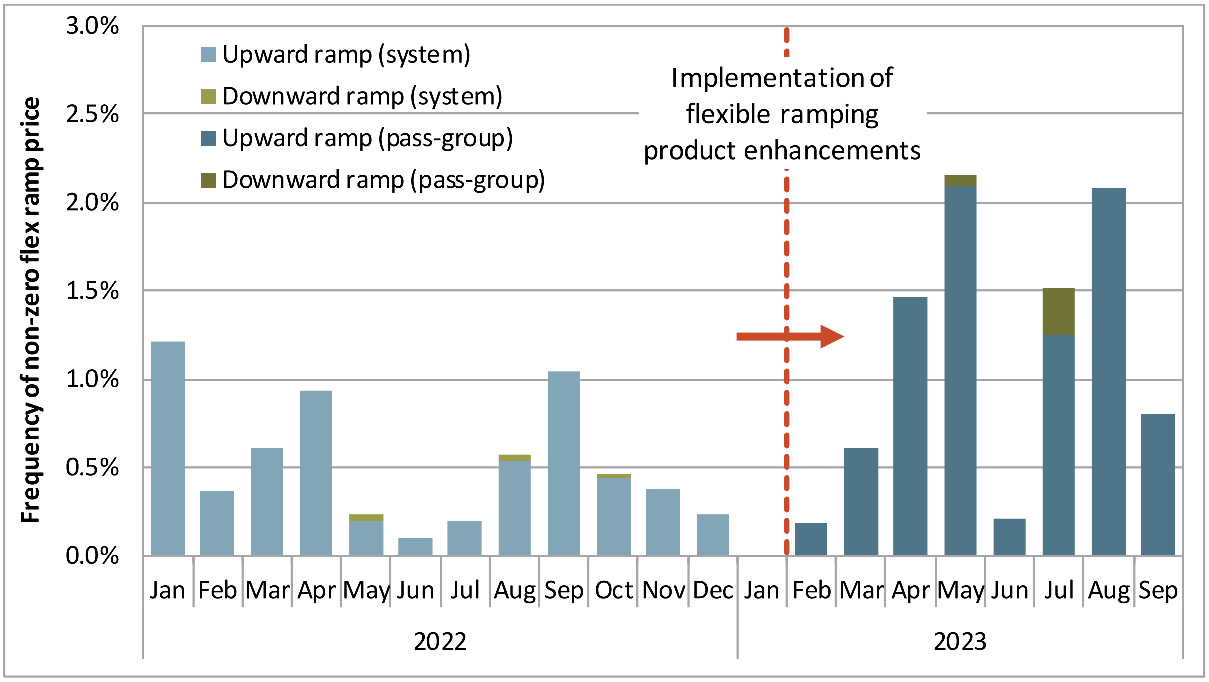
[41] Department of Market Monitoring, Flexible ramping product enhancements demand curve implementation error, July 20, 2023: https://www.caiso.com/Documents/Flexible-Ramping-Product-Enhancements-Demand-Curve-Implementation-Error-Jul-20-2023.pdf

[42] 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 area (or by LAP in the case of California 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 at a cost less than the value of the final segment of the demand curve. This figure will only capture shadow prices for the greater pass-group region and will not include prices associated with local "insufficiency".

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



Flexible ramping product procurement and impact of the enhancements

This section summarizes flexible capacity procured to meet the uncertainty needs of the greater WEIM system and the impact from flexible ramping product enhancements. Figure 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, 2023. 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 quarter, most upward flexible capacity continued to come from hydro resources (68 percent). Battery resources made up almost 20 percent of upward flexible capacity while gas resources were only 9 percent. For the downward direction, wind and solar resources made up much of the flexible capacity at around 39 percent while gas made up around 38 percent of downward flexible capacity.

Figure 1.38 shows the percent of upward or downward flexible capacity that was procured in various regions.[43] 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 third quarter (59 percent).

43 For a list of the balancing areas in each region, see Appendix B.

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

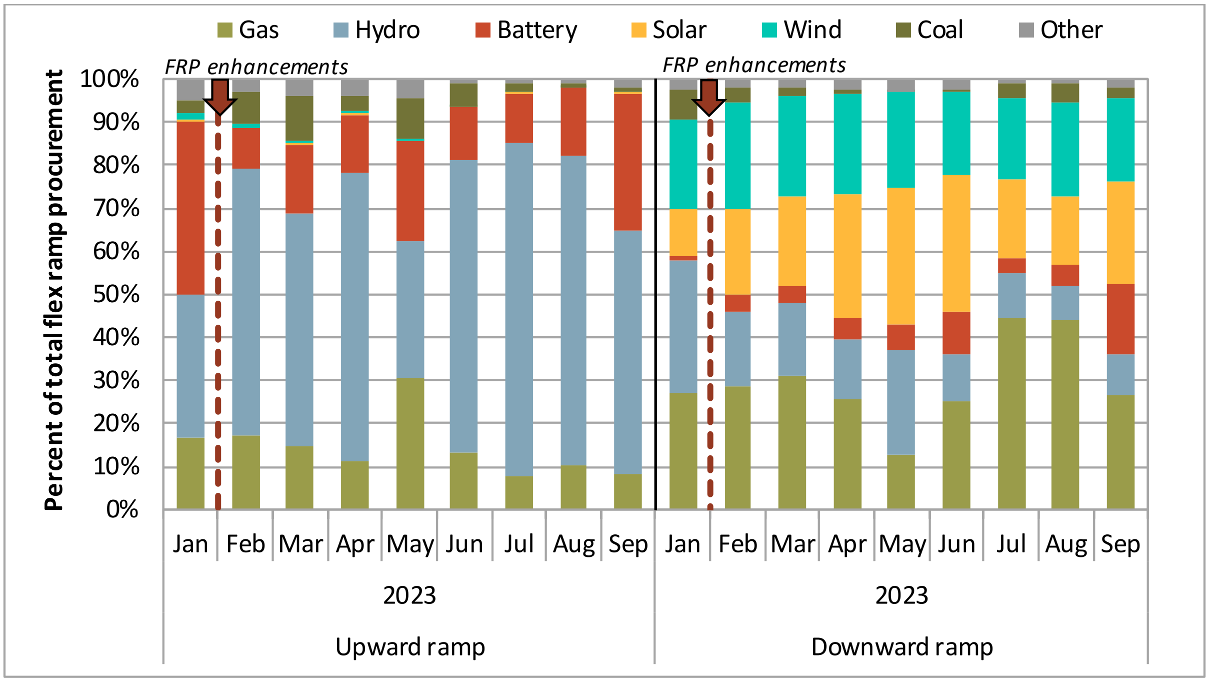
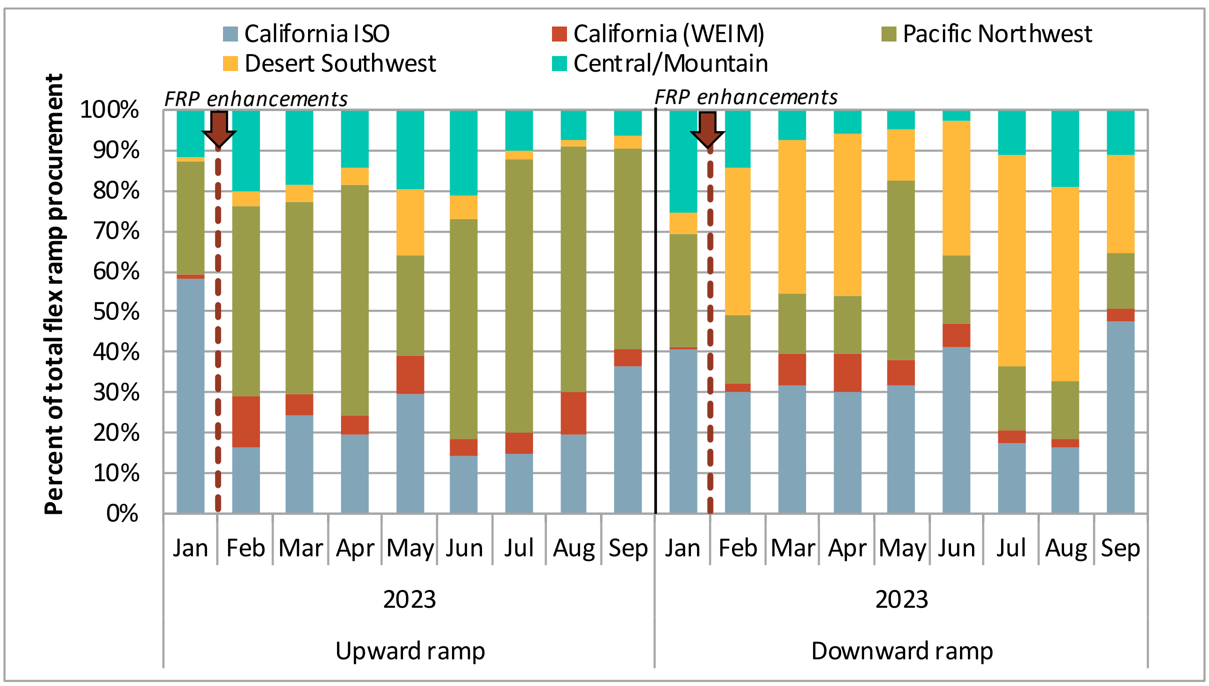


Figure 1.38 Percent of system or pass-group flexible ramp procurement by region



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).[44]

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

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

However, the current weather information that is ultimately combined with the regression results to calculate uncertainty are instead consistent with the group of balancing areas in the pass-group for flexible ramping capacity procurement. This is based on the second run of the resource sufficiency evaluation (T-55) for interval 1 and the final resource sufficiency evaluation (T-40) for intervals 2 through 4. Table 1.6 summarizes this inconsistency by showing which resource sufficiency evaluation run is used for each interval and process.

44 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

Table 1.6 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)

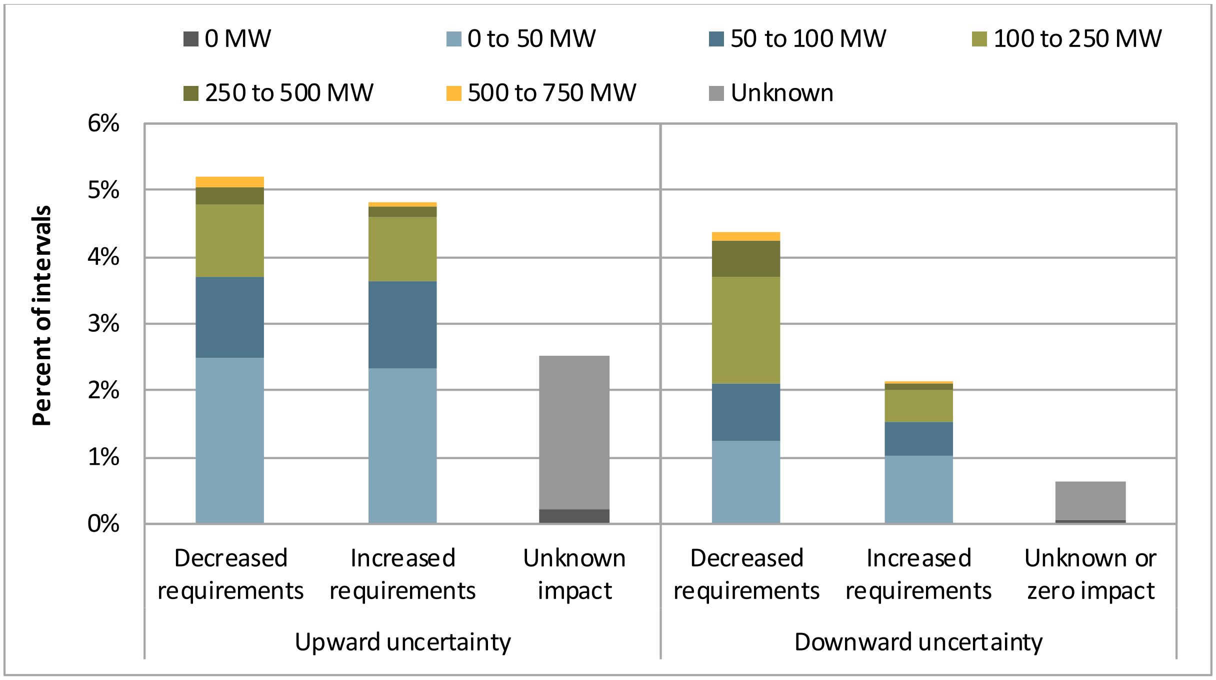
Using an inconsistent composition of balancing areas in the pass-group between the forecast and regression information can create significant swings in the calculated uncertainty for this group. For example, if you have a model to predict uncertainty based on forecast information of all but one balancing 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 18 percent of intervals for the third quarter of 2023, 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.[45] These results are shown separately for the following categories to highlight the impact of this inconsistency on uncertainty requirements.

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

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

Figure 1.39 Impact of pass-group inconsistency on uncertainty requirements (July-September 2023)



Threshold for capping uncertainty

Uncertainty calculated from the quantile regressions is capped by the lesser of two thresholds. The thresholds are designed to help prevent extreme outlier results from impacting the final uncertainty. The *histogram* threshold is pulled for each hour from the 1st and 99th percentile of net load error observations from the previous 180 days.[46] The seasonal threshold is updated each quarter and is calculated based on the 1st and 99th percentile using the quantile regression method and observations over the previous 90 days. Here, each hour is calculated separately and the greatest upward and downward uncertainty across all hours sets the mosaic threshold for each hour of the same direction.

During the quarter, the thresholds capped upward and downward uncertainty for the group of balancing areas that passed the resource sufficiency evaluation in around 10 percent of intervals in the 15-minute market and 11 percent of intervals in the 5-minute market. The histogram threshold capped calculated uncertainty much more frequently compared to the mosaic threshold — during nearly all cases in which pass-group uncertainty was capped by one of the two thresholds.

A threshold is also in place that sets the floor for uncertainty at 0.1 MW in both directions. The upward and downward uncertainty is therefore set near zero when the uncertainty calculated from the quantile regression would be negative. During the quarter, the 15-minute market uncertainty calculated for the group of balancing areas that passed the resource sufficiency evaluation was set near zero by this threshold in around 1.3 percent of intervals for upward uncertainty and 0.9 percent of intervals for downward uncertainty.

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

Results of quantile regression uncertainty calculation

Figure 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. The dashed red and yellow lines show the average histogram and mosaic thresholds, respectively, during the period.

Figure 1.41 shows 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.

On average, pass-group uncertainty calculated from the quantile regression approach was often lower or comparable to uncertainty calculated with the histogram approach. However, results of the regression-based approach vary more widely, including periods with much lower uncertainty.

Figure 1.40 15-minute market pass-group uncertainty requirements (weekdays, July-September 2023)

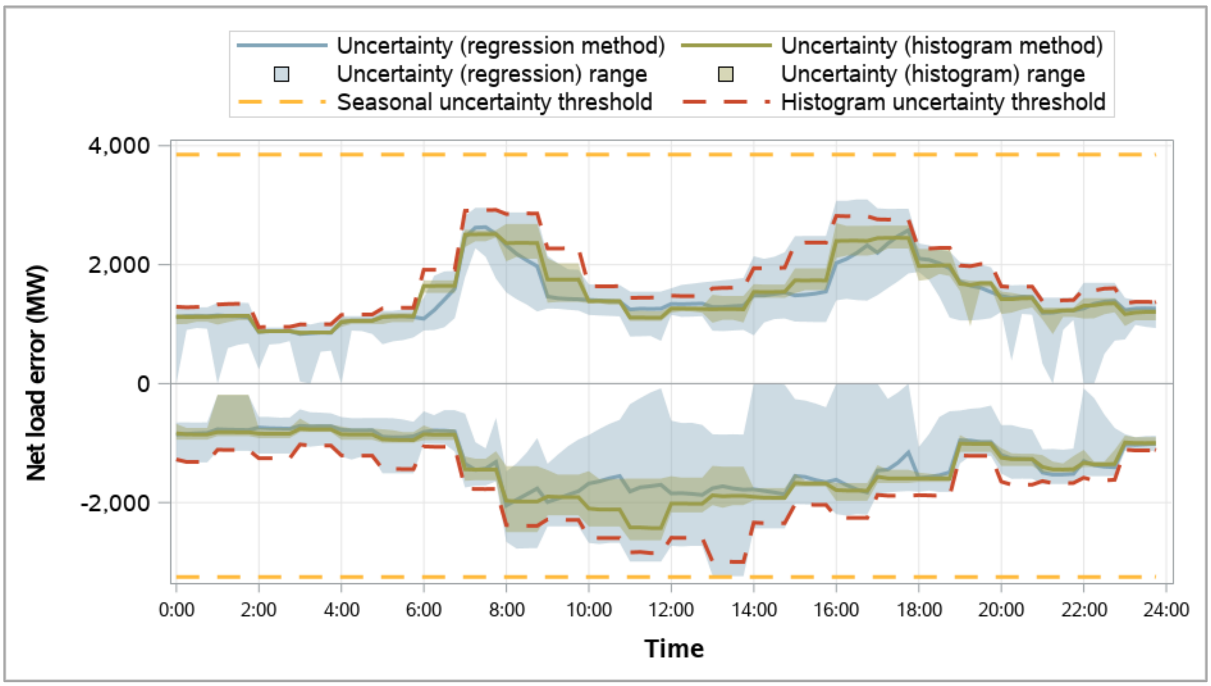


Figure 1.41 5-minute market pass-group uncertainty requirements (weekdays, July-September 2023)

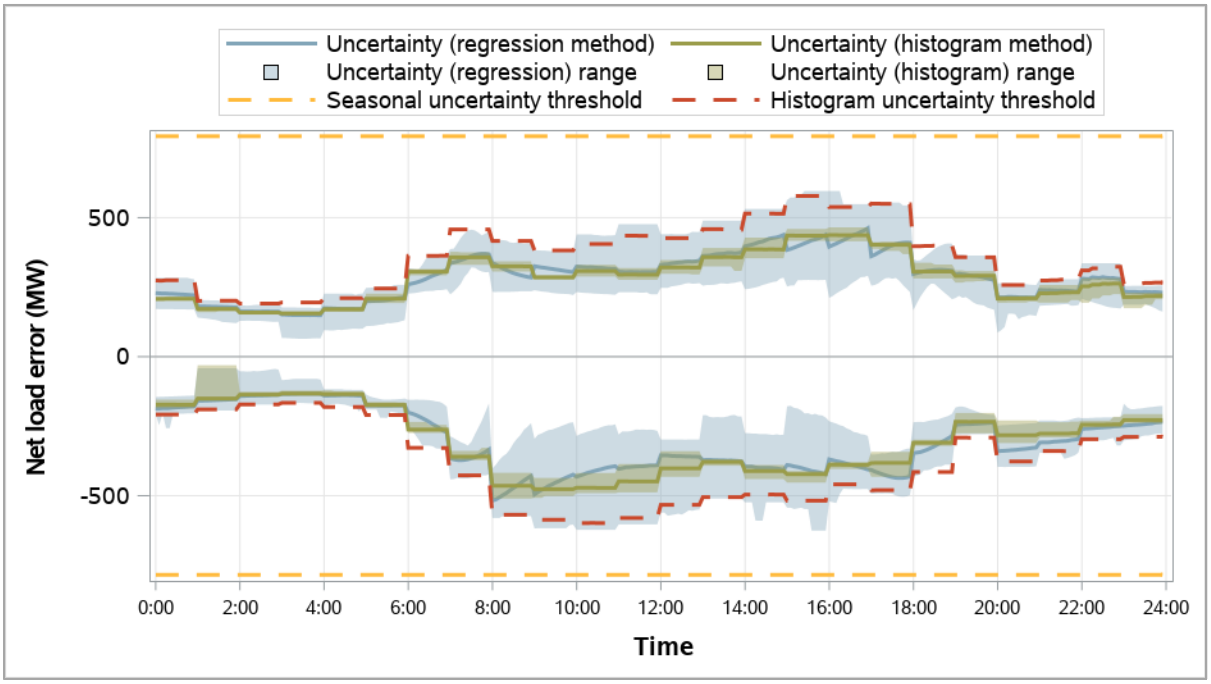


Table 1.7 summarizes the average uncertainty requirement for the group of balancing areas that passed the resource sufficiency evaluation, using both the histogram and mosaic quantile regression methods. On average across all hours, the 15-minute uncertainty calculated from the regression method was less than the histogram method for both directions.

Table 1.8 summarizes the actual net load error for the pass-group and how that compares to the mosaic regression uncertainty requirements for the same interval.[47] 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 96 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 1.9 shows the same information except with requirements calculated from the histogram method. Coverage from the histogram method was more than the mosaic regression method, but by around 1 percent or less across both directions and markets.

For more information on the calculated uncertainty used in the resource sufficiency evaluation for each balancing area since February, see DMM's monthly WEIM resource sufficiency evaluation reports.[48]

47 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.

48 https://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

Table 1.7 Average pass-group uncertainty requirements (July-September 2023)

Market	Uncertainty type	Pass-group uncertainty Histogram	Mosaic	*Difference*
15-minute market	Upward	1,529	1,450	-78
	Downward	1,416	1,309	-107
5-minute market	Upward	280	279	0
	Downward	302	299	-3

Table 1.8 Actual net load error compared to mosaic regression pass-group uncertainty requirements (July-September 2023)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*		*Actual net load error exceeds requirement*	
		Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	96%	1,331	4%	375
	Downward	97%	1,543	3%	285
5-minute market	Upward	97%	297	3%	77
	Downward	97%	304	3%	89

Table 1.9 Actual net load error compared to histogram regression pass-group uncertainty requirements (July-September 2023)

Market	Uncertainty type	*Actual net load error falls within calculated uncertainty requirements*		*Actual net load error exceeds requirement*	
		Percent of intervals	Average distance to requirement (MW)	Percent of intervals	Average amount (MW)
15-minute market	Upward	97%	1,391	3%	338
	Downward	98%	1,635	2%	244
5-minute market	Upward	97%	297	3%	84
	Downward	97%	307	3%	86

DMM has published a more detailed review of the mosaic quantile regression approach.[49] DMM finds that the regression model has limited predictive capability for forecasting net load uncertainty. The coefficients estimated with the quantile regression method (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 in more than 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. DMM continues to recommend that the ISO and stakeholders consider developing much

[49] Department of Market Monitoring, Review of mosaic quantile regression for estimating net load uncertainty, November 20, 2023: http://www.caiso.com/Documents/Review-of-the-Mosaic-Quantile-Regression-Nov-20-2023.pdf

simpler and more transparent uncertainty adders. Using a forecasting technique that is more extensively studied and used in other applications could also increase transparency for market participants.

1.13 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

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

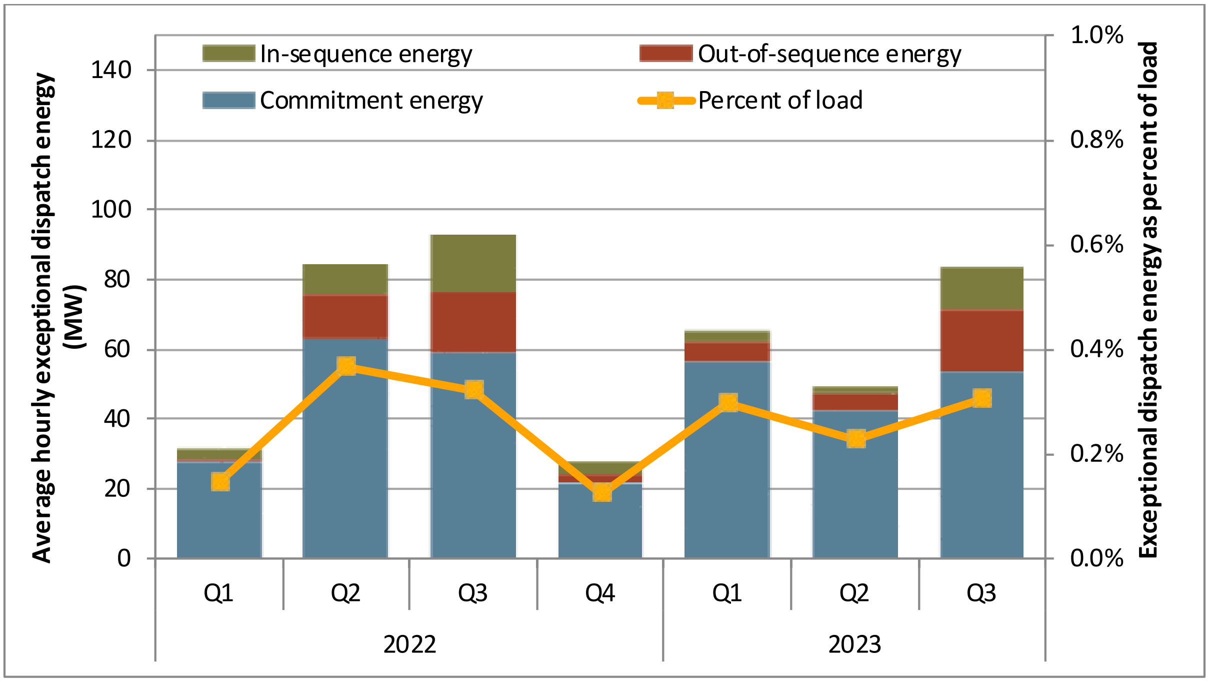
Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 1 percent of total load in the California ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 84 MWh in the third quarter of 2023, which is down from 93 MWh in the same quarter of 2022.

As shown in Figure 1.42, exceptional dispatches for unit commitments accounted for about 64 percent of all exceptional dispatch energy in this quarter,[50] about 22 percent was from out-of-sequence energy, and the remaining 14 percent was from in-sequence energy.

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

Figure 1.42 Average hourly energy from exceptional dispatch

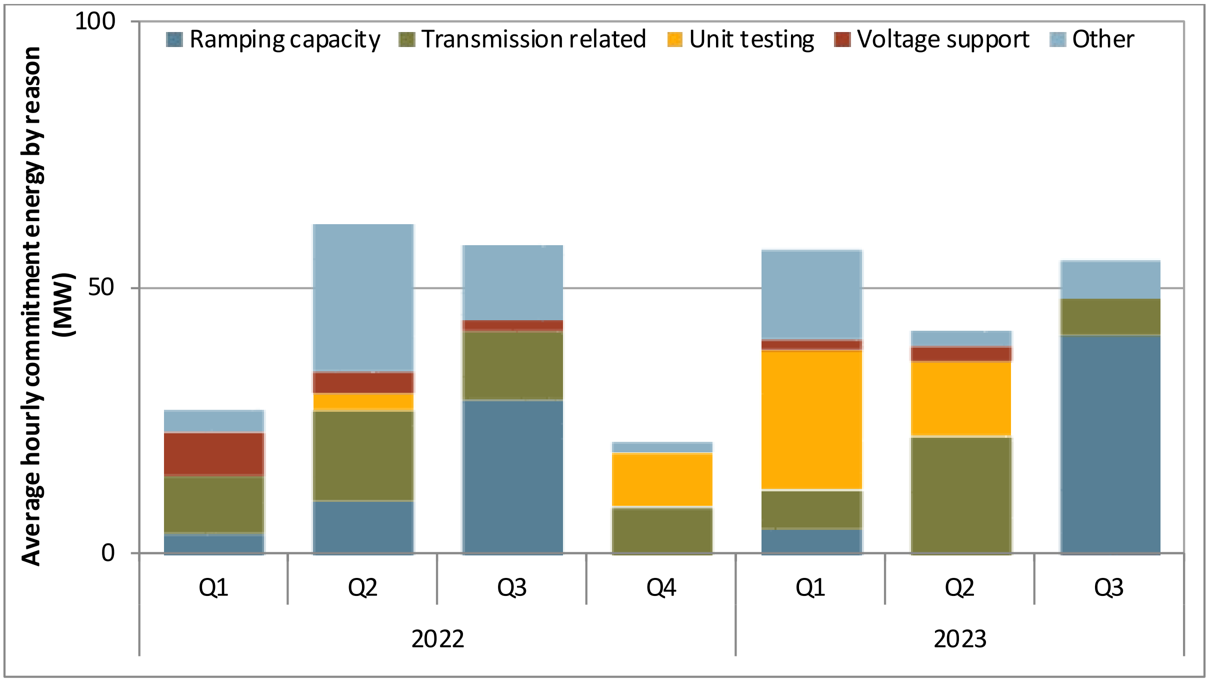


Exceptional dispatches for unit commitment

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

As shown in Figure 1.43, minimum load energy from unit commitment exceptional dispatches to provide ramping capacity in the third quarter of 2023 increased by about 41 percent from the same quarter in 2022.

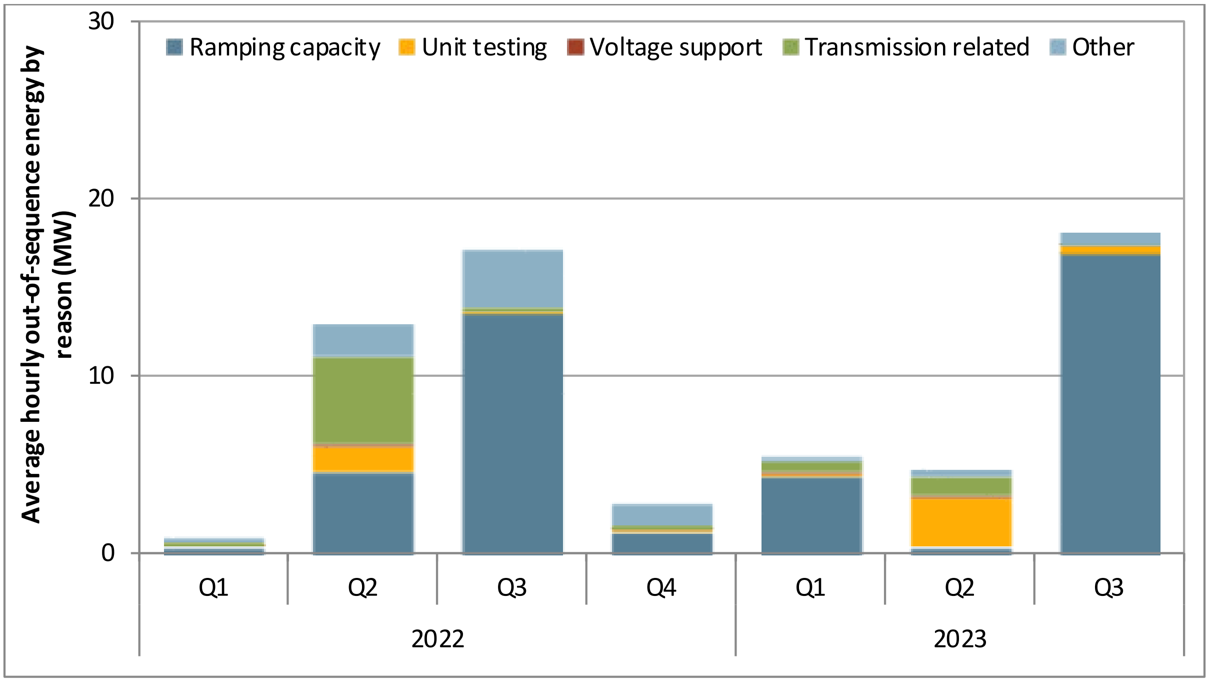
Figure 1.43 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Figure 1.44 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2022 and 2023. The primary reason logged for out-of-sequence energy in the third quarter of 2023 was "exceptional dispatches for ramping capacity". Ramping capacity exceptional dispatches are predominately used to ramp thermal resources to their minimum dispatchable level, which is a higher operating level, with a faster ramp rate, that allows these units to be more available to meet reliability requirements.

Figure 1.44 Out-of-sequence exceptional dispatch energy by reason



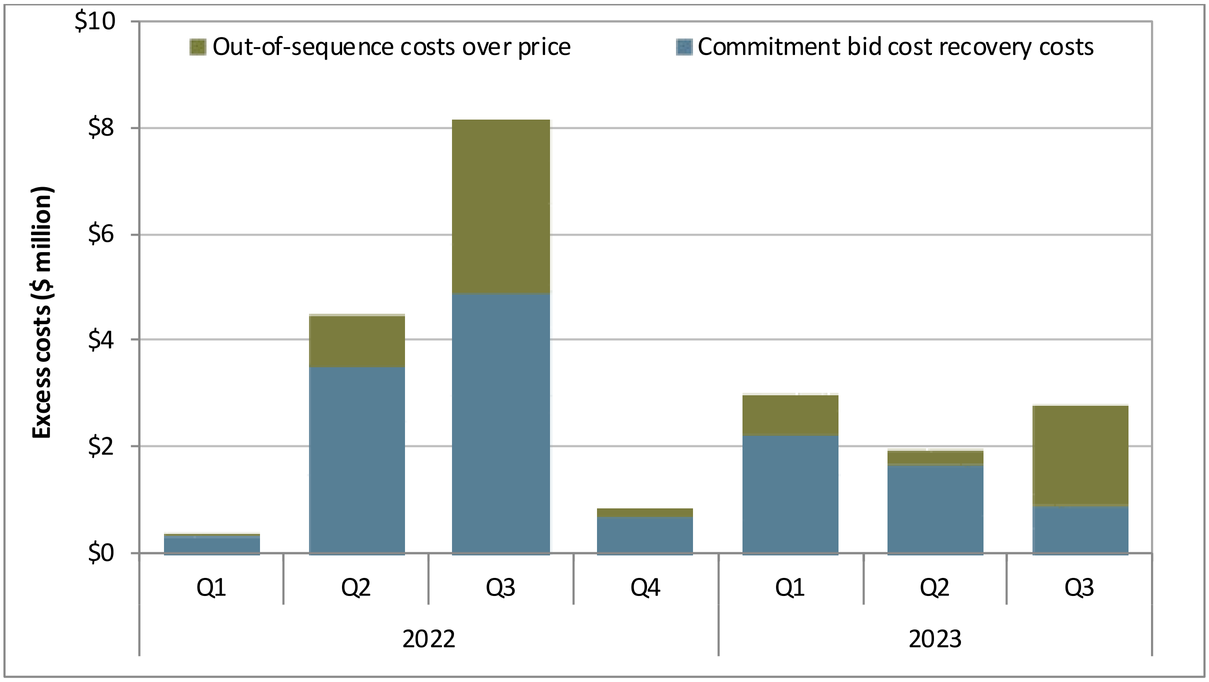
Exceptional dispatch costs

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

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

Figure 1.45 shows the estimated costs for unit commitment and exceptional dispatch for energy above minimum load whose bid price exceeded the resource's locational marginal price. In the third quarter of 2023, out-of-sequence energy costs were $1.9 million, a 42% decrease from the third quarter of 2022. Commitment costs for exceptional dispatch paid through bid cost recovery were $0.93 million, an 81% decrease from the third quarter of 2022.

Figure 1.45 Excess exceptional dispatch cost by type



2 Western energy imbalance market

This section covers Western energy imbalance market (WEIM) performance during the third quarter.

2.1 Limitation of WEIM transfers to the ISO

On July 26, CAISO balancing area operators began limiting WEIM import transfers into the CAISO balancing area each day during the net peak hours. This limitation was put in place for the hour-ahead and 15-minute markets to mitigate the risk during the critical hours that internal generation and hourly-block intertie schedules might be displaced by WEIM imports that may not materialize in real-time. This limitation typically lasted five hours each day and concluded on November 16, 2023. Additional details on this action as well as its impact on the market are described in this section.

2.1.1 WEIM 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.[51] WEIM transfers are constrained by *transfer limits* that are made available by the WEIM entities to optimally transfer energy between areas.

WEIM transfers are defined as either *base*, *dynamic, or static*. Base WEIM transfers are fixed bilateral transactions between WEIM entities and are not optimized in the market. Dynamic WEIM transfers are optimized in all markets. Static WEIM transfers are a smaller subset of transfers (primarily between the Pacific Northwest areas and the CAISO area) that are only optimized in the hour-ahead and 15-minute markets.

The hour-ahead scheduling process (HASP) produces an optimized solution for four 15-minute intervals in the upcoming hour. It is included as part of a special run of the real-time unit commitment process that starts approximately 71.5 minutes prior to the hour. The majority of CAISO balancing area intertie schedules must be scheduled in hourly blocks and HASP is the final opportunity for these to be optimized in the market. These schedules are optimized against forecasted load, advisory generation dispatches, *and advisory WEIM transfers* across the footprint.

Operators can modify the load forecast used in the market through *load conformance* adjustments. In the CAISO balancing area, these adjustments are routinely used in the hour-ahead and 15-minute scheduling process to increase capacity to address uncertainty that can materialize around net load ramping periods. Load conformance in the 5-minute market is then typically much lower.

Figure 2.1 shows ISO load conformance adjustments between July 24 and July 27. When operators increase the load conformance in HASP, this can be met by a combination of factors including increased commitment or dispatch of internal resources, increased hourly imports, decreased hourly exports, and changes to advisory WEIM transfers. To the extent that the increased load conformance is met by

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

advisory WEIM imports, these transfers may not materialize in the 5-minute market due to either lower levels of load conformance or changes to projected supply conditions in the surrounding WEIM system.

Starting on July 26, during peak hours each day, CAISO balancing area operators limited dynamic WEIM import transfers into the CAISO balancing area in the hour-ahead and 15-minute markets to zero.[52] The intent of this action was to limit advisory WEIM imports that might offset a significant portion of the demand forecast or load conformance. This would instead allow increased load conformance to be served by internal generation and intertie schedules. As a result, the CAISO balancing area would have a reduced reliance on imports from the WEIM to meet internal demand, and its system would be better positioned to address uncertainty that may materialize. In the 5-minute market, the limit on WEIM transfers was lifted, allowing transfers to freely and optimally flow between the CAISO balancing area and neighboring balancing areas.[53]

Figure 2.2 shows dynamic WEIM imports into the CAISO balancing area in the evening hours between July 24 and July 27. The blue bars show advisory WEIM imports in the hour-ahead market. The red bars show WEIM imports in the 5-minute market. The green line shows the transfer lock periods in which imports were limited to zero in the hour-ahead market. Outside the lock periods, WEIM transfers into the CAISO balancing area in the hour-ahead market significantly exceeded what was realized in the 5-minute market in most intervals. During the lock periods, hour-ahead (and 15-minute market) transfers into the CAISO balancing area were limited to zero, but substantial 5-minute market imports were still able to flow in those peak evening hours.

Figure 2.3 shows the same information, except with both WEIM imports into the CAISO balancing area (positive) and WEIM exports out of the CAISO balancing area (negative) shown. The dotted red and blue lines show the *net* WEIM transfers. The limit put in place in the hour-ahead and 15-minute markets did not impact WEIM transfers out of the CAISO balancing area, only WEIM transfers into the CAISO balancing area.

52 Static WEIM transfers were not impacted by the limit put in place in the peak hours starting July 26. Dynamic export transfers were also not impacted.

53 Subject to normal WEIM transmission limitations.

Figure 2.1 ISO area load conformance adjustments (July 24-27)

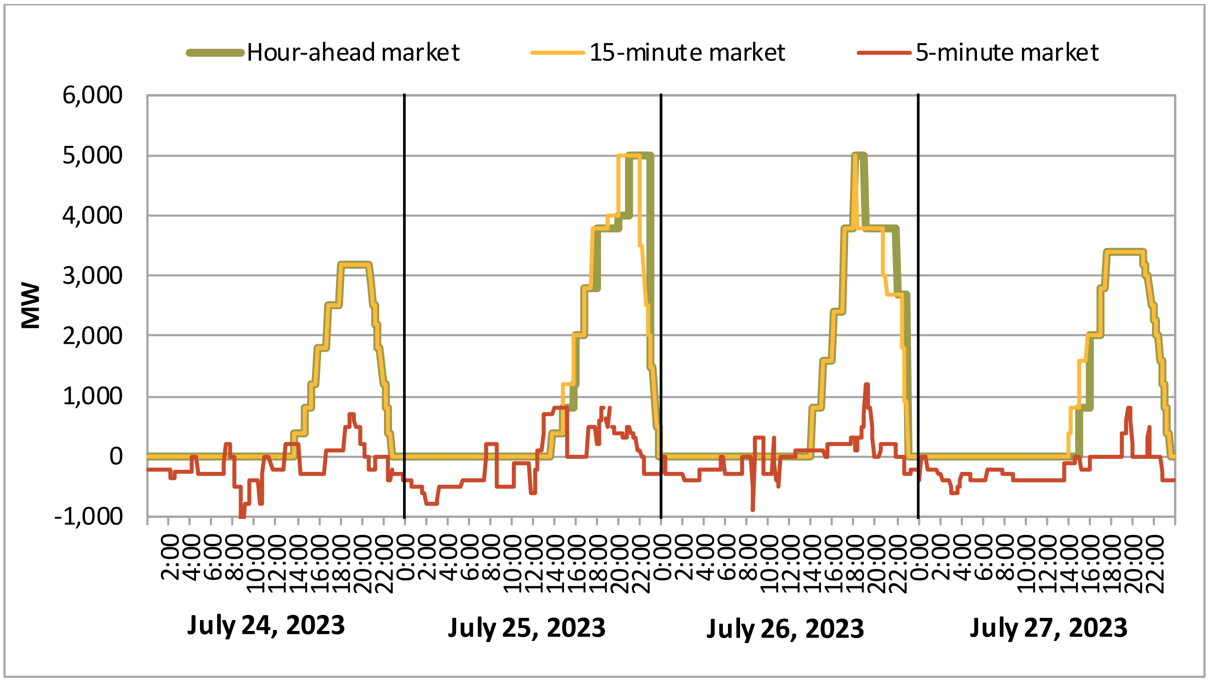


Figure 2.2 Dynamic WEIM imports into ISO area (evening hours, July 24-July 27)

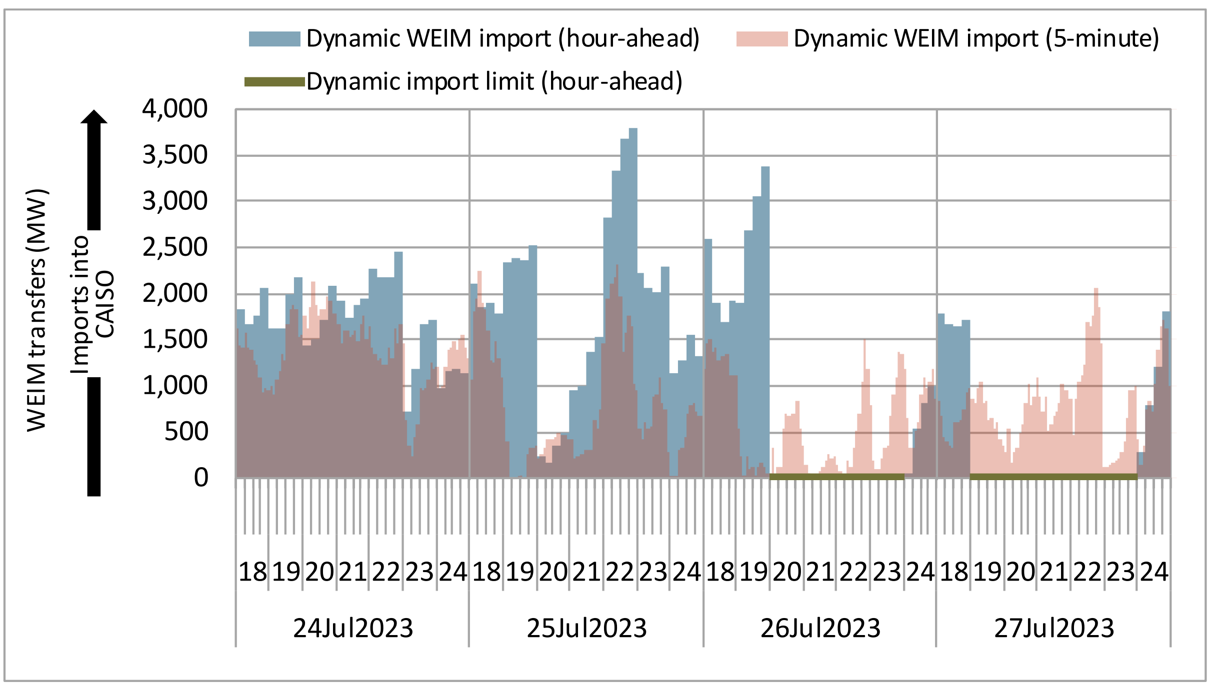
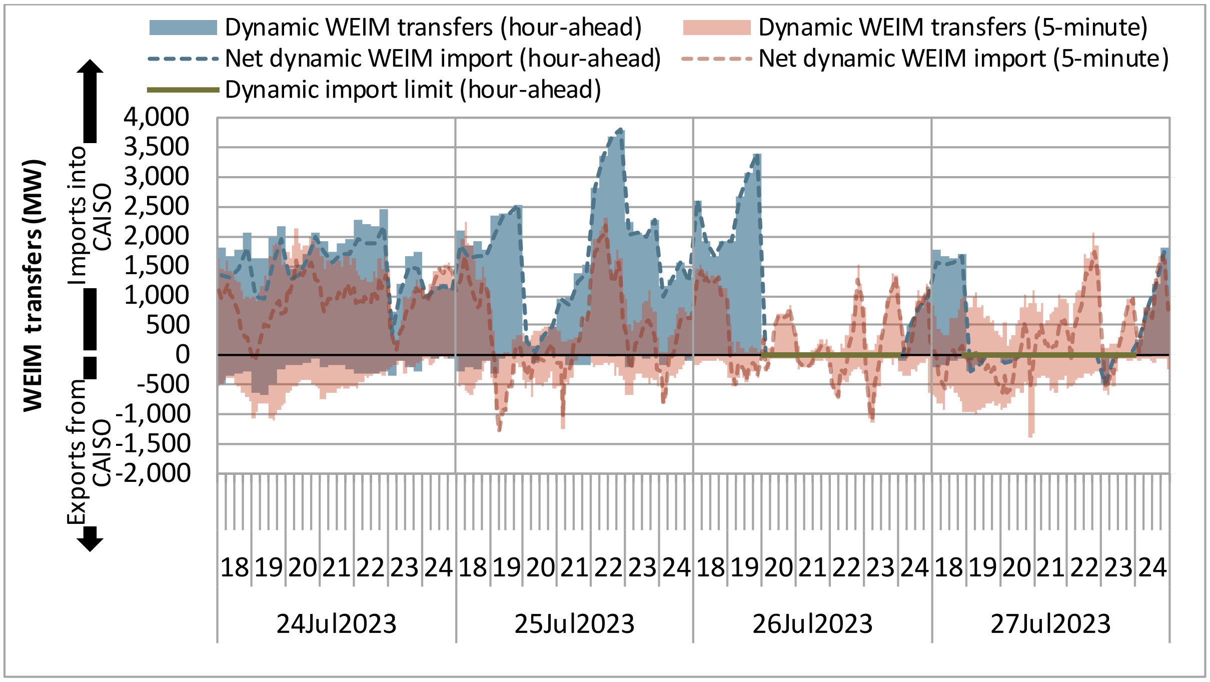


Figure 2.3 Dynamic WEIM transfers into and out of ISO area (evening hours, July 24-July 27)



2.1.2 Impact on California ISO balancing area supply and demand

When the WEIM imports into the California ISO balancing area are limited to zero in the hour-ahead market, the optimization instead balances the total load (including any load conformance) mostly from a combination of (1) increased internal generation, (2) increased hourly-block imports, (3) decreased hourly-block exports, and (4) decreased WEIM exports. This section summarizes supply and demand differences before and after the limitation on WEIM imports into the CAISO balancing area.

Figure 2.4 shows hour-ahead supply (S) and demand (D) during the peak hours of July 26. On this day, WEIM imports (dashed gray bars) decreased by over 3,000 MW following the WEIM import lock.[54] This was mostly answered with a reduction of around 2,900 MW from hourly block exports (blue bars).

Figure 2.5 summarizes supply and demand components during the highest load days in the interval immediately before and after the WEIM transfer lock.[55] On average over these peak summer days, WEIM imports decreased by over 1,600 MW in the interval immediately following the WEIM transfer limitation. This loss was absorbed in the market through changes to other components. Hourly-block exports decreased by over 1,100 MW. Hourly-block imports increased by around 420 MW.

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54 WEIM transfers in Figure 2.4 and Figure 2.5 include both dynamic and static WEIM transfers. Static WEIM transfers were not impacted by the limit put in place in the peak hours starting July 26. WEIM imports are therefore shown above zero following the transfer lock in these figures.

55 This figure is an average over the nine days during the summer of 2023 in which the ISO load forecast reached 40,000 MW or more and the dynamic WEIM imports were limited: July 26, July 27, August 14, August 15, August 16, August 17, August 28, August 29, and August 30.

Figure 2.4 CAISO area hour-ahead supply and demand (net peak hours, July 26, 2023)

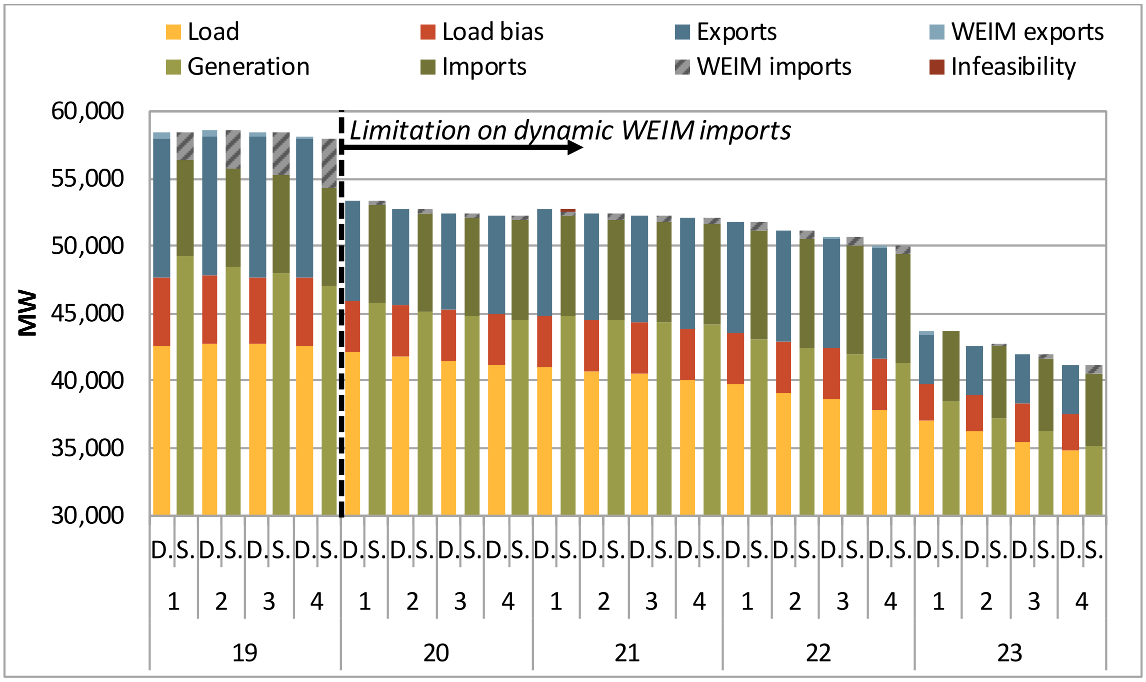
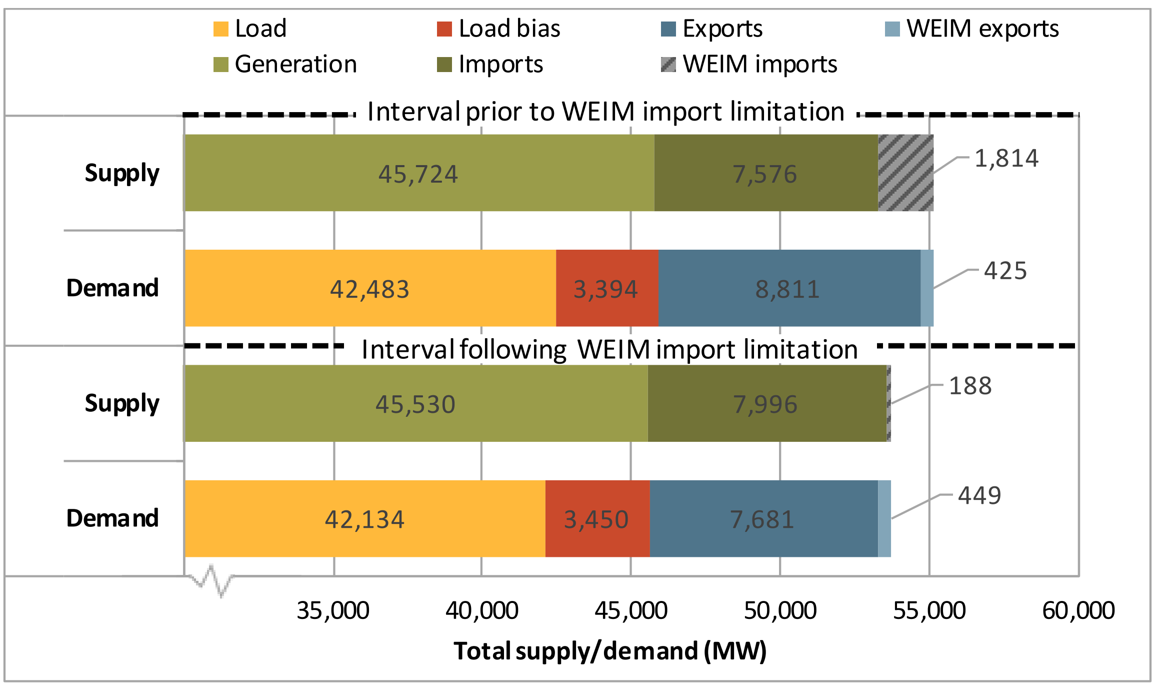


Figure 2.5 Average hour-ahead CAISO balancing area supply and demand in interval before and after WEIM import limitation (summer 2023 peak days)



2.1.3 Impact on WEIM transfer flows

The limitation on WEIM imports into the CAISO balancing area impacted transfer patterns throughout the WEIM footprint. Figure 2.6 shows average hour-ahead WEIM exports out of each area in the interval immediately prior to the WEIM import lock during the same highest summer load days.[56] Figure 2.7 instead shows average exports in the interval immediately following the WEIM import lock.[57] 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 100 MW and each large tick is 500 MW.

As shown in these figures:

- **The amount of exports from the Desert Southwest region decreased, while transfers in the Intermountain West region increased significantly.** With the CAISO balancing area no longer able to import cheaper excess energy from the Desert Southwest region, excess energy from these balancing areas instead generally flowed north to PacifiCorp East and Idaho Power. Some of this energy was moved onward to balancing areas in the PacifiCorp Northwest region.
- **As expected, CAISO balancing area imports through the WEIM decreased significantly, by over 1,600 MW on average.** The CAISO balancing area continued to transfer out around 400 MW on average to Powerex and BANC on these peak days.

[56] These figures exclude the fixed bilateral transfers between WEIM entities (base WEIM transfer schedules) and therefore reflect optimized flows in the market. Optimized dynamic and static WEIM transfers are both included.

[57] Static WEIM imports into the ISO area (mostly from Portland General Electric and PacifiCorp West) were not impacted.

Figure 2.6 Average hour-ahead WEIM exports in interval prior to WEIM import limitation (summer 2023 peak days)

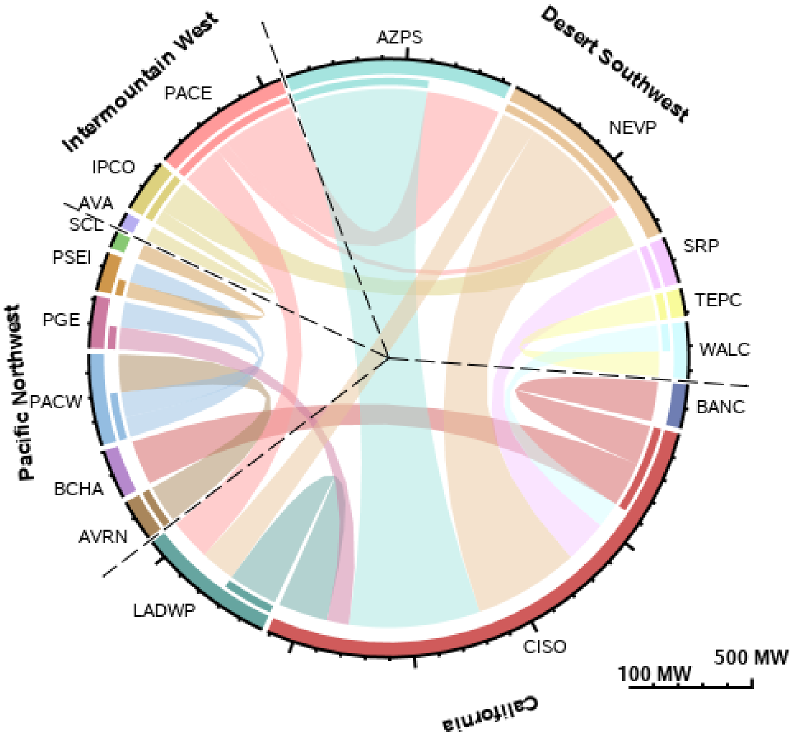
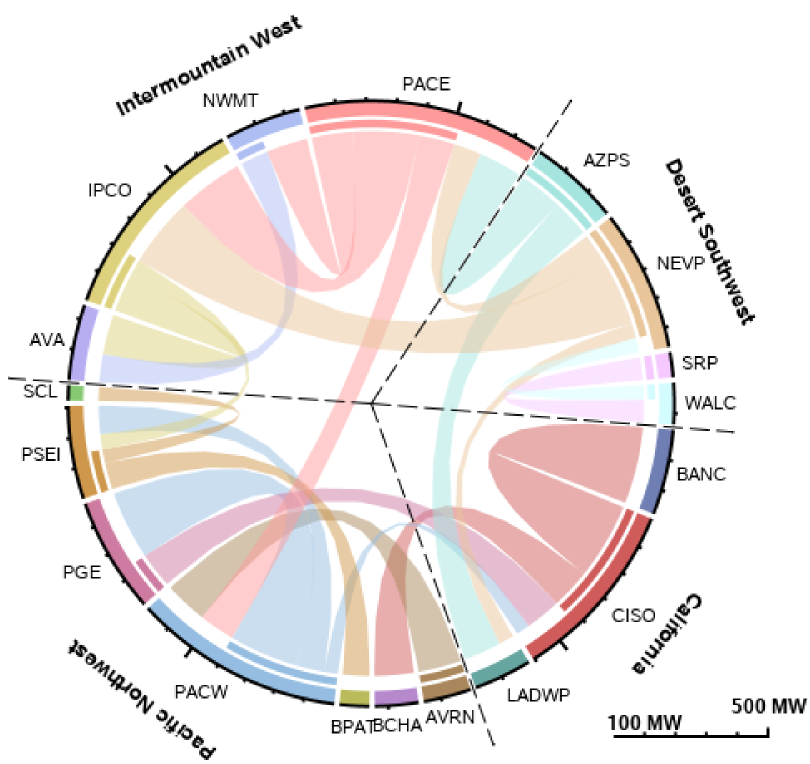


Figure 2.7 Average hour-ahead WEIM exports in interval following WEIM import limitation (summer 2023 peak days)



2.1.4 WEIM 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 2.1 shows average 15-minute market import and export limits for each balancing area outside of the transfer lock periods during the third quarter.
- Table 2.2 shows average 15-minute market import and export limits during the peak-hour transfer lock periods. During these periods, the limit on *dynamic* WEIM imports into the CAISO balancing area are zero such that the positive CAISO area *total import limit* (around 200 MW) reflects only limits on *static* WEIM imports.
- Table 2.3 shows average 5-minute market import and export limits across all intervals during the third quarter.

The volumes shown in these tables exclude base WEIM transfer schedules and therefore reflect transfer capability that is made available by WEIM entities to optimally transfer energy between areas.

The balancing areas in these tables are grouped in one of four regions: California, Desert Southwest, Intermountain West, 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 these tables shows WEIM transfer limits between these regions (out-of-region import and export limits).

The limitation on WEIM imports into the CAISO balancing area in the 15-minute market was not present in the 5-minute market. Import and export transfer capacity into or out of the Desert Southwest region was around 31,760 MW and 33,970 MW, respectively, in the 5-minute market. For the Pacific Northwest region, there was an average of around 2,010 MW of import and 640 MW of export transfer capacity into or out of the region. The lack of transfer capability out of the Pacific Northwest continued to contribute to price separation between the region and the rest of the WEIM.

Table 2.1 Average 15-minute market WEIM limits — excluding transfer lock periods (July-September, 2023)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**32,283**	**31,450**
California ISO	42,168	36,577	29,062	27,207
BANC	3,979	3,726	0	0
LADWP	8,110	12,906	3,221	4,243
Turlock Irrig. District	1,802	2,018	0	0
Desert Southwest			**31,743**	**33,803**
Arizona Public Service	33,815	32,202	24,195	24,675
El Paso Electric	436	472	0	0
NV Energy	4,136	3,683	3,567	3,260
PSC New Mexico	928	1,181	0	0
Salt River Project	7,600	9,840	1,624	3,060
Tucson Electric	4,042	5,223	620	808
WAPA - Desert SW	5,121	5,538	1,738	2,001
Intermountain West			**2,610**	**2,639**
Avista Utilities	786	863	111	77
Idaho Power	2,026	2,975	635	829
NorthWestern Energy	798	732	39	33
PacifiCorp East	3,594	2,662	1,824	1,701
Pacific Northwest			**1,963**	**707**
Avangrid	671	659	0	13
Powerex	886	50	838	0
BPA	608	818	151	159
PacifiCorp West	1,510	1,381	545	333
Portland General Electric	624	635	120	110
Puget Sound Energy	1,292	904	280	61
Seattle City Light	434	437	30	31
Tacoma Power	360	246	0	0

Table 2.2 Average 15-minute market WEIM limits — during transfer lock periods (July-September, 2023)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**3,716**	**30,421**
California ISO	204	36,486	204	26,391
BANC	4,059	505	0	0
LADWP	9,081	4,030	3,512	4,030
Turlock Irrig. District	1,767	795	0	0
Desert Southwest			**30,996**	**5,403**
Arizona Public Service	33,470	7,948	24,533	1,276
El Paso Electric	362	477	0	0
NV Energy	3,985	2,828	3,444	2,591
PSC New Mexico	908	1,159	0	0
Salt River Project	6,018	6,126	943	0
Tucson Electric	3,705	4,392	540	329
WAPA - Desert SW	4,634	4,559	1,537	1,207
Intermountain West			**2,529**	**2,480**
Avista Utilities	748	823	48	108
Idaho Power	1,999	2,917	622	742
NorthWestern Energy	798	629	10	16
PacifiCorp East	3,577	2,703	1,849	1,616
Pacific Northwest			**1,521**	**459**
Avangrid	616	582	0	14
Powerex	601	50	553	0
BPA	444	451	74	61
PacifiCorp West	1,549	1,219	586	207
Portland General Electric	581	606	83	136
Puget Sound Energy	1,059	975	195	11
Seattle City Light	414	420	30	30
Tacoma Power	324	225	0	0

Table 2.3 Average 5-minute market WEIM limits (July-September, 2023)

Region/ balancing area	Total import limit	Total export limit	Out-of-region import limit	Out-of-region export limit
California			**32,402**	**31,536**
California ISO	42,364	36,773	29,142	27,324
BANC	3,988	3,754	0	0
LADWP	8,226	12,955	3,260	4,212
Turlock Irrig. District	1,796	2,025	0	0
Desert Southwest			**31,761**	**33,972**
Arizona Public Service	33,906	32,279	24,360	24,851
El Paso Electric	426	472	0	0
NV Energy	4,105	3,665	3,536	3,265
PSC New Mexico	926	1,178	0	0
Salt River Project	7,412	9,720	1,543	3,013
Tucson Electric	4,001	5,180	609	809
WAPA - Desert SW	5,062	5,555	1,713	2,034
Intermountain West			**2,595**	**2,621**
Avista Utilities	780	857	103	81
Idaho Power	2,025	2,969	632	818
NorthWestern Energy	798	717	35	31
PacifiCorp East	3,589	2,673	1,825	1,691
Pacific Northwest			**2,013**	**643**
Avangrid	665	649	0	13
Powerex	841	50	792	0
BPA	600	775	153	148
PacifiCorp West	1,671	1,453	706	410
Portland General Electric	673	546	169	29
Puget Sound Energy	1,155	872	163	13
Seattle City Light	431	435	30	30
Tacoma Power	356	243	0	0

2.1.5 Congestion on WEIM transfer constraints

When limits on transfer constraints between WEIM areas are reached, this can create congestion — resulting in higher or lower prices in the area relative to prevailing system prices. Table 2.4 shows the percent of intervals and price impact of 15-minute and 5-minute market transfer constraint congestion in each WEIM area over the quarter. When prices are lower relative to the system, this indicates congestion out of the area (or region) and limited export capability. When prices are higher within an area, this indicates that congestion is limiting the ability for outside energy to serve that area's load (limited import capability).

The congestion on the WEIM transfer constraints are measured relative to the CAISO balancing area. Therefore, when the CAISO balancing area limited WEIM transfer imports to zero in the hour-ahead and 15-minute markets, most of the WEIM footprint was collectively export constrained at a lower price based on regional supply conditions outside of the CAISO area. As shown in Table 2.4, most WEIM balancing areas were consequently congested toward the CAISO area (congested from area) in at least 10 percent of intervals in the 15-minute market — resulting in a price impact of roughly -$10/MWh over the quarter. In the 5-minute market, WEIM imports into the CAISO balancing area were not limited and the congestion frequency and price impact were both much smaller.

Powerex was instead frequently WEIM transfer import constrained (congested into area) during around 80 percent of intervals in the 15-minute and 5-minute market. When a balancing area has net WEIM transfer import congestion into an area, the market software triggers local market power mitigation for resources in that area.[58]

Table 2.4 Frequency and impact of transfer congestion in the WEIM (July-September)

	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	4%	-$5.73	0.0%	$0.00	0.0%	$0.00	0.1%	$0.10
Turlock Irrigation District	4%	-$5.73	0.0%	$0.02	0.0%	$0.00	0.0%	$0.00
Arizona Public Service	11%	-$9.91	0.0%	$0.00	0.1%	-$0.01	0.1%	$0.61
NV Energy	11%	-$9.90	0.0%	$0.00	0.1%	-$0.06	0.0%	$0.33
L.A. Dept. of Water and Power	12%	-$10.26	0.4%	$0.21	0.3%	-$0.14	0.6%	$0.80
WAPA – Desert Southwest	11%	-$10.04	1%	$0.90	0.3%	-$0.25	1%	$1.43
Public Service Company of NM	13%	-$10.61	0.2%	$0.40	1%	-$0.37	0.2%	$0.75
PacifiCorp East	12%	-$9.96	0.9%	$0.06	0.6%	-$0.16	0.8%	$0.71
Idaho Power	12%	-$9.90	4%	$0.42	0.7%	-$0.24	3%	$0.35
Avista Utilities	12%	-$9.94	4%	$0.45	0.9%	-$0.34	3%	$0.61
NorthWestern Energy	12%	-$9.97	5%	$1.44	1%	-$0.41	3%	$1.96
Avangrid Renewables	15%	-$10.13	10%	$1.11	5%	-$1.48	5%	$0.63
PacifiCorp West	15%	-$10.49	10%	$1.09	5%	-$1.55	5%	$0.82
Portland General Electric	14%	-$8.50	12%	$1.56	5%	-$1.35	6%	$1.22
Tacoma Power	14%	-$8.71	11%	$1.73	8%	-$1.86	8%	$1.67
Seattle City Light	14%	-$9.04	12%	$2.55	8%	-$2.36	8%	$2.36
Puget Sound Energy	14%	-$8.58	12%	$5.20	8%	-$1.82	8%	$6.01
Salt River Project	28%	-$14.56	3%	$6.38	17%	-$5.14	2%	$6.55
Tucson Electric Power	30%	-$12.60	3%	$1.00	16%	-$1.86	4%	$1.96
Bonneville Power Admin.	14%	-$7.95	17%	$4.93	6%	-$1.50	13%	$3.75
El Paso Electric Company	34%	-$15.67	3%	$0.63	22%	-$5.58	4%	$0.70
Powerex	2%	-$5.31	79%	$46.38	5%	-$2.55	80%	$44.04

2.2 Prices in the WEIM

The Western energy imbalance market benefits participating areas by committing lower-cost resources across all areas to balance fluctuations in the supply and demand in the real-time energy market. Since dispatch decisions are determined across the whole WEIM footprint, prices within each balancing area diverge from the system price when transfer constraints are binding, when greenhouse gas compliance

58 Structural market power may exist if the demand for imbalance energy within a balancing area exceeds the transfer capacity into that balancing area from competitive surrounding areas. The California ISO balancing area is not subject to market power mitigation when WEIM transfer limits into the CAISO area are constrained.

costs are enforced for imports into California, or if power balance constraint violations within a single area are assigned penalty prices.

Table 2.5 shows average monthly prices for the 15-minute market by area for 2022 through 2023. 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 costs for energy that is delivered to California. In addition, average prices in the Pacific Northwest are typically lower than other balancing areas because of limited transfer capability out of the region.

Table 2.5 Monthly 15-minute market prices

	2022												2023								
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
SMEC	$51	$44	$42	$59	$59	$55	$69	$97	$125	$69	$90	$246	$140	$73	$73	$55	$19	$28	$66	$67	$42
PG&E (CAISO)	$54	$48	$47	$63	$68	$82	$74	$103	$136	$73	$95	$257	$140	$75	$76	$57	$18	$29	$58	$65	$44
SCE (CAISO)	$52	$43	$40	$55	$60	$69	$78	$108	$135	$64	$83	$246	$140	$68	$65	$48	$20	$27	$73	$68	$39
BANC	$53	$48	$48	$65	$69	$68	$72	$106	$131	$75	$95	$252	$142	$75	$76	$58	$19	$30	$56	$54	$42
Turlock ID	$54	$49	$48	$69	$76	$68	$72	$100	$136	$76	$95	$266	$142	$76	$77	$61	$19	$30	$56	$54	$43
LADWP	$50	$42	$41	$55	$57	$63	$77	$108	$135	$67	$87	$256	$142	$73	$68	$49	$20	$27	$67	$50	$36
NV Energy	$40	$38	$35	$49	$53	$55	$69	$93	$117	$58	$79	$243	$131	$66	$66	$50	$17	$23	$59	$40	$33
Arizona PS	$39	$34	$31	$45	$52	$64	$72	$97	$118	$56	$80	$251	$130	$66	$64	$50	$17	$24	$63	$41	$30
Tucson Electric					$54	$64	$72	$96	$111	$57	$76	$222	$129	$63	$60	$47	$21	$26	$58	$38	$30
Salt River Project	$39	$34	$33	$47	$56	$67	$67	$88	$93	$56	$76	$157	$119	$52	$60	$50	$22	$24	$62	$46	$28
PSC New Mexico	$37	$34	$30	$43	$47	$49	$67	$84	$102	$58	$64	$114	$127	$64	$64	$67	$17	$24	$59	$40	$30
WAPA - Desert SW																$57	$20	$24	$62	$41	$30
El Paso Electric																$33	$18	$23	$48	$37	$29
PacifiCorp East	$37	$35	$32	$45	$43	$40	$65	$81	$99	$59	$72	$193	$120	$63	$67	$52	$18	$26	$53	$38	$31
Idaho Power	$43	$41	$35	$57	$47	$32	$69	$82	$92	$63	$84	$237	$132	$71	$73	$59	$16	$27	$52	$39	$33
NorthWestern	$41	$37	$34	$57	$41	$15	$42	$69	$73	$64	$87	$243	$133	$72	$75	$62	$13	$27	$53	$39	$34
Avista Utilities			$35	$57	$41	$12	$36	$68	$72	$65	$86	$246	$133	$72	$74	$64	$12	$27	$49	$39	$34
Avangrid																$61	$7	$28	$49	$40	$38
BPA					$46	$10	$46	$80	$91	$65	$86	$251	$133	$73	$73	$62	$5	$29	$55	$49	$38
Tacoma Power			$30	$59	$44	$13	$39	$74	$80	$64	$85	$248	$134	$72	$73	$62	$6	$29	$50	$43	$37
PacifiCorp West	$39	$35	$32	$59	$42	$13	$42	$76	$89	$64	$85	$244	$132	$71	$72	$61	$6	$28	$48	$39	$35
Portland GE	$38	$35	$33	$59	$43	$16	$43	$77	$92	$65	$87	$244	$133	$71	$72	$62	$9	$29	$50	$43	$37
Puget Sound Energy	$37	$34	$31	$60	$44	$13	$41	$74	$81	$64	$85	$249	$133	$73	$74	$62	$8	$29	$59	$44	$37
Seattle City Light	$37	$34	$31	$60	$45	$12	$40	$74	$80	$64	$85	$249	$133	$75	$72	$61	$6	$28	$50	$45	$37
Powerex	$36	$34	$32	$52	$46	$15	$37	$61	$69	$67	$82	$212	$129	$79	$84	$79	$14	$55	$94	$99	$83

Figure 2.8 and Figure 2.9 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. When transfer capacity limits the amount of energy that can flow from areas with lower cost supply to areas with higher cost supply, prices will be higher on the side of the constraint with higher cost supply. 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 power balance constraints relaxations that increase the price in a single area.

Figure 2.8 Quarterly average 15-minute price by component (Q3 2023)

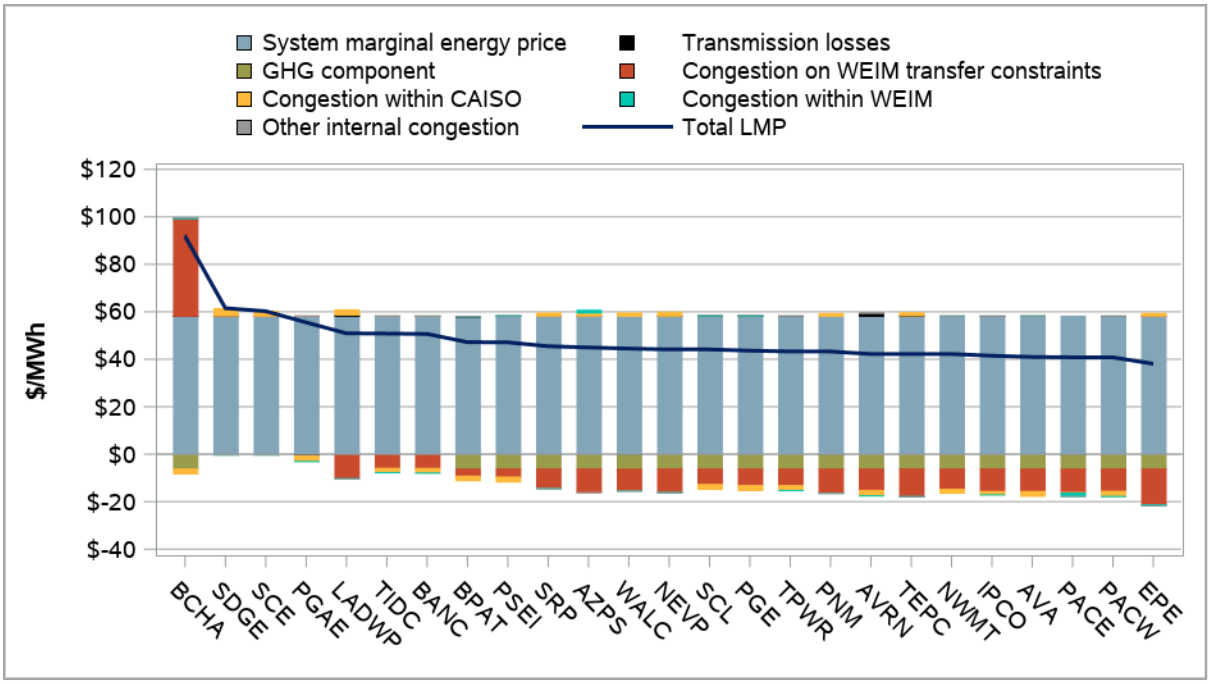


Figure 2.9 Quarterly average 5-minute price by component (Q3 2023)

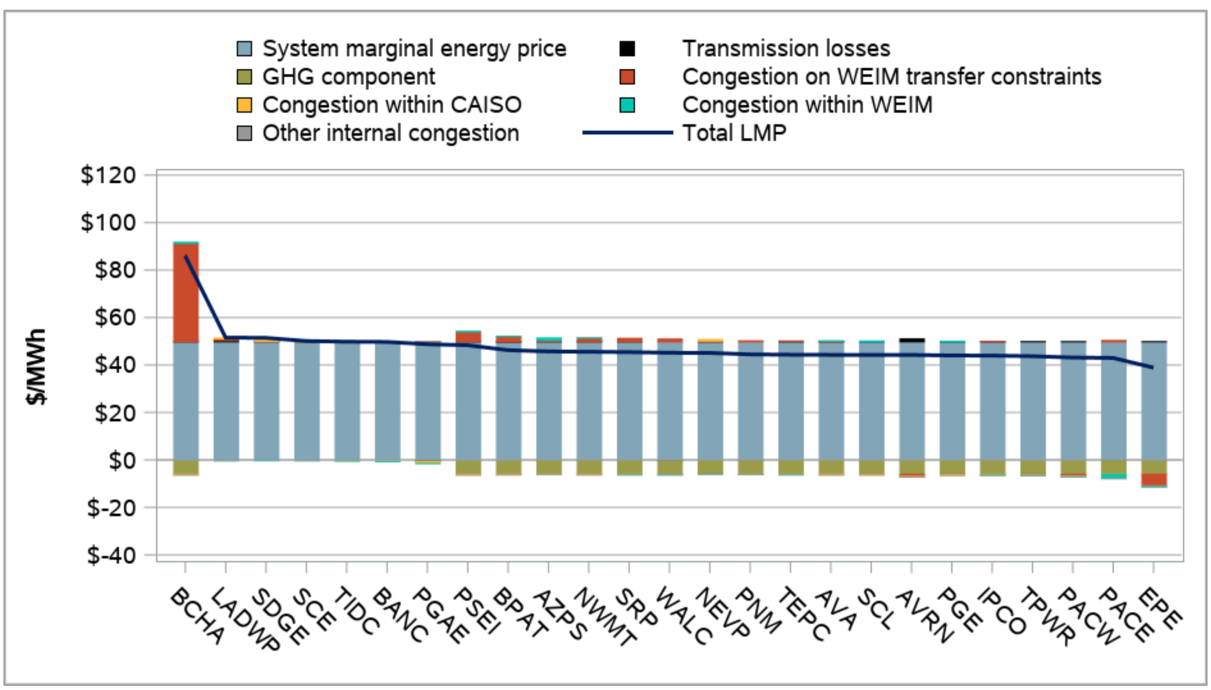


Table 2.6 and Table 2.7 show the variation in prices throughout the day in the third quarter of 2023. In these tables, the colors change based on the deviation from the average system marginal energy price (SMEC). Therefore, blue represents prices below that hour's average system price and orange indicates prices above.

In the 15-minute market, prices in most balancing areas were typically lower than those in the CAISO balancing area during the peak hours. This was largely because of the limitation on WEIM imports into the CAISO area which created congestion between these two regions. Other differences are because of greenhouse gas compliance costs for balancing areas outside of California, transfer limitations between areas, or from internal transmission constraint congestion within balancing areas.

Table 2.6 Hourly 15-minute market prices (July-September)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$49	$47	$46	$45	$45	$48	$49	$39	$34	$34	$35	$37	$40	$44	$47	$52	$57	$82	$136	$153	$94	$74	$59	$51
PG&E (CAISO)	$48	$45	$44	$44	$44	$47	$48	$40	$38	$38	$38	$40	$42	$46	$47	$50	$55	$77	$122	$132	$81	$63	$54	$49
SCE (CAISO)	$51	$48	$47	$46	$46	$49	$49	$37	$29	$29	$31	$32	$35	$41	$46	$53	$58	$88	$149	$176	$108	$84	$63	$53
BANC	$48	$46	$44	$44	$44	$47	$48	$40	$39	$39	$39	$42	$44	$47	$49	$52	$56	$64	$68	$82	$70	$62	$55	$50
Turlock ID	$48	$46	$44	$44	$44	$47	$48	$40	$39	$39	$40	$42	$45	$48	$49	$52	$56	$64	$66	$82	$71	$62	$55	$49
LADWP	$51	$49	$47	$46	$47	$50	$50	$40	$31	$30	$32	$34	$37	$42	$47	$54	$58	$61	$71	$95	$66	$68	$63	$54
NV Energy	$41	$38	$35	$34	$35	$39	$38	$30	$27	$30	$32	$34	$38	$42	$46	$52	$53	$54	$64	$82	$63	$57	$52	$43
Arizona PS	$42	$38	$36	$35	$35	$40	$37	$30	$25	$27	$29	$32	$36	$44	$51	$57	$56	$57	$65	$86	$65	$58	$54	$45
Tucson Electric	$37	$33	$32	$30	$31	$32	$31	$26	$24	$27	$31	$33	$38	$43	$46	$52	$54	$54	$64	$82	$64	$56	$53	$41
Salt River Project	$45	$39	$37	$32	$31	$35	$29	$25	$23	$26	$28	$36	$46	$50	$55	$54	$53	$53	$77	$78	$59	$54	$75	$51
PSC New Mexico	$41	$38	$35	$34	$35	$39	$36	$33	$22	$26	$30	$32	$35	$40	$42	$51	$49	$58	$65	$84	$63	$59	$52	$43
WAPA - Desert SW	$51	$39	$37	$35	$35	$39	$37	$30	$25	$25	$29	$32	$35	$40	$44	$50	$52	$54	$66	$86	$67	$58	$55	$46
El Paso Electric	$34	$30	$29	$28	$29	$33	$29	$26	$24	$26	$29	$31	$34	$39	$40	$46	$49	$51	$61	$71	$56	$41	$45	$35
PacifiCorp East	$39	$36	$34	$33	$34	$37	$35	$30	$28	$30	$33	$35	$37	$41	$44	$48	$49	$48	$53	$65	$52	$49	$49	$41
Idaho Power	$40	$37	$35	$34	$35	$38	$36	$32	$32	$34	$36	$38	$41	$45	$46	$49	$51	$47	$48	$56	$48	$46	$49	$42
NorthWestern	$39	$37	$35	$33	$34	$38	$36	$33	$33	$35	$37	$40	$42	$46	$47	$58	$64	$48	$48	$51	$45	$44	$49	$42
Avista Utilities	$40	$37	$35	$33	$34	$38	$36	$32	$34	$36	$38	$40	$43	$46	$47	$49	$51	$46	$45	$48	$44	$43	$49	$42
Avangrid	$41	$39	$36	$35	$36	$40	$37	$34	$36	$37	$39	$42	$44	$47	$48	$49	$49	$48	$45	$50	$46	$44	$50	$43
BPA	$43	$38	$35	$34	$35	$40	$39	$36	$40	$38	$39	$44	$48	$49	$50	$59	$58	$58	$64	$71	$62	$54	$61	$42
Tacoma Power	$41	$38	$35	$34	$35	$39	$36	$33	$35	$36	$38	$41	$44	$47	$47	$49	$48	$49	$62	$64	$51	$46	$49	$42
PacifiCorp West	$39	$36	$33	$32	$34	$39	$36	$33	$34	$36	$39	$41	$44	$47	$47	$48	$48	$46	$44	$47	$44	$42	$49	$42
Portland GE	$41	$38	$35	$34	$35	$39	$37	$35	$36	$37	$39	$42	$46	$47	$50	$53	$50	$51	$61	$60	$50	$44	$49	$42
Puget Sound Energy	$43	$38	$35	$34	$35	$39	$37	$34	$36	$37	$39	$42	$44	$47	$47	$53	$61	$72	$77	$81	$55	$50	$53	$44
Seattle City Light	$45	$40	$35	$34	$35	$39	$36	$34	$36	$38	$37	$42	$44	$47	$47	$50	$49	$50	$60	$65	$55	$51	$49	$43
Powerex	$75	$66	$65	$61	$64	$73	$91	$101	$104	$98	$99	$98	$101	$100	$103	$105	$108	$107	$105	$108	$100	$97	$95	$82

Hour

Table 2.7 Hourly 5-minute market prices (July-September)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$49	$46	$44	$44	$44	$48	$51	$41	$34	$34	$34	$36	$39	$44	$48	$55	$58	$56	$64	$86	$67	$62	$57	$49
PG&E (CAISO)	$48	$45	$43	$43	$44	$47	$50	$43	$39	$38	$38	$40	$43	$47	$49	$56	$59	$52	$56	$73	$57	$56	$55	$49
SCE (CAISO)	$50	$47	$45	$44	$45	$49	$51	$38	$27	$27	$29	$30	$34	$40	$46	$54	$59	$61	$72	$100	$76	$68	$60	$52
BANC	$48	$45	$43	$43	$44	$47	$50	$43	$40	$40	$39	$42	$46	$50	$51	$58	$60	$53	$56	$76	$58	$57	$56	$49
Turlock ID	$48	$45	$43	$43	$44	$47	$50	$43	$40	$40	$40	$43	$46	$50	$51	$58	$60	$53	$57	$75	$58	$57	$55	$49
LADWP	$51	$48	$45	$45	$45	$49	$52	$40	$31	$28	$29	$30	$35	$41	$46	$57	$62	$62	$74	$100	$77	$68	$66	$58
NV Energy	$42	$38	$35	$34	$36	$41	$40	$31	$27	$29	$31	$33	$37	$42	$46	$55	$58	$56	$69	$89	$65	$54	$54	$45
Arizona PS	$42	$38	$35	$34	$35	$41	$39	$34	$25	$26	$28	$30	$35	$43	$51	$63	$61	$59	$67	$93	$66	$57	$52	$43
Tucson Electric	$39	$35	$32	$32	$32	$36	$33	$27	$24	$26	$29	$32	$38	$46	$53	$56	$60	$57	$66	$89	$72	$56	$55	$41
Salt River Project	$42	$38	$31	$29	$31	$36	$26	$24	$23	$25	$31	$37	$45	$43	$49	$66	$53	$59	$80	$88	$65	$48	$76	$48
PSC New Mexico	$42	$37	$35	$34	$35	$40	$38	$35	$22	$26	$28	$30	$35	$41	$49	$53	$56	$62	$69	$90	$65	$55	$51	$42
WAPA - Desert SW	$52	$39	$37	$36	$37	$41	$40	$31	$24	$25	$28	$30	$34	$41	$45	$52	$56	$59	$67	$90	$68	$55	$54	$47
El Paso Electric	$33	$30	$29	$29	$30	$35	$31	$27	$25	$26	$29	$30	$34	$38	$42	$49	$48	$55	$63	$71	$60	$42	$46	$34
PacifiCorp East	$40	$36	$33	$32	$34	$43	$42	$31	$28	$30	$32	$34	$37	$42	$45	$51	$54	$52	$58	$80	$57	$49	$49	$45
Idaho Power	$41	$37	$34	$34	$35	$40	$39	$33	$32	$34	$36	$38	$42	$47	$49	$54	$57	$51	$56	$74	$55	$48	$50	$42
NorthWestern	$41	$37	$34	$33	$35	$40	$39	$34	$33	$35	$37	$39	$43	$48	$53	$67	$63	$53	$59	$71	$53	$47	$53	$49
Avista Utilities	$41	$37	$34	$33	$35	$40	$38	$34	$34	$36	$38	$40	$44	$48	$50	$57	$58	$50	$54	$70	$54	$46	$49	$44
Avangrid	$41	$38	$35	$34	$35	$41	$39	$34	$35	$37	$39	$41	$45	$50	$51	$53	$54	$50	$54	$65	$51	$47	$51	$43
BPA	$42	$37	$34	$33	$35	$40	$40	$36	$36	$37	$38	$43	$47	$51	$54	$65	$57	$54	$63	$72	$58	$47	$51	$41
Tacoma Power	$41	$37	$34	$33	$34	$40	$38	$34	$34	$36	$38	$40	$44	$48	$48	$51	$53	$50	$62	$67	$50	$46	$49	$42
PacifiCorp West	$41	$37	$34	$33	$35	$40	$38	$34	$34	$36	$38	$41	$44	$48	$49	$51	$52	$47	$51	$66	$50	$45	$49	$42
Portland GE	$41	$37	$34	$33	$34	$40	$38	$34	$34	$36	$39	$42	$46	$49	$52	$54	$53	$50	$60	$64	$50	$45	$49	$42
Puget Sound Energy	$41	$37	$34	$33	$34	$40	$39	$34	$35	$37	$38	$41	$44	$48	$49	$54	$62	$77	$82	$89	$63	$47	$56	$47
Seattle City Light	$45	$39	$34	$33	$34	$40	$37	$34	$36	$37	$37	$41	$45	$49	$49	$53	$53	$50	$61	$68	$52	$50	$48	$41
Powerex	$72	$62	$62	$60	$62	$68	$87	$83	$91	$92	$92	$92	$97	$96	$95	$95	$96	$97	$99	$104	$98	$94	$90	$79

Hour

2.3 Resource sufficiency evaluation

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

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

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

If an area that has not opted into Assistance Energy Transfers fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[59] See below for an explanation of the Assistance Energy Transfer feature, implemented July 1, 2023. Similarly, if an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

Figure 2.10 and Figure 2.11 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.12 and Figure 2.13 provide the same information for the downward direction.[60] The dash indicates the area did not fail the test during the month.

In the third quarter of 2023:

- Salt River Project failed the upward flexibility test in 1.7 percent of intervals and the upward capacity test in 1.3 percent of intervals.
- Puget Sound Energy failed the upward flexibility test in 1.4 percent of intervals.
- El Paso Electric failed the upward flexibility test in around 1.1 percent of intervals.
- All other balancing areas failed in less than 1 percent of intervals for each test type and direction.

Phase 2 (track 1) of resource sufficiency evaluation enhancements was implemented on July 1, 2023. This included the following enhancements:

- **Adjustment for real-time low-priority and economic exports in the California ISO balancing area's resource sufficiency evaluation.** These exports are no longer strictly counted as part of the California ISO balancing area's demand obligation.
- **Implementation of Assistance Energy Transfers (AET).** This new option gives balancing areas access to excess WEIM supply that may not have been available otherwise following a resource sufficiency evaluation failure. Balancing areas can opt into AET to prevent their WEIM transfers from being limited during a test failure but will be subject to an ex-post surcharge.

More detailed information on each of these enhancements is available in DMM's resource sufficiency evaluation report for July 2023.[61]

59 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.

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

61 Western Energy Imbalance Market Resource Sufficiency Evaluation Report covering July 2023 from the Department of Market Monitoring, August 31, 2023: https://www.caiso.com/Documents/Jul-2023-Metrics-Report-on-Resource-Sufficiency-Evaluation-in-WEIM-Aug-31-2023.pdf

Figure 2.10 Frequency of upward capacity test failures by month and area (percent of intervals)

	2022						2023								
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona Publ. Serv.	—	—	—	—	—	0.1	0.4	0.5	0.7	0.2	0.0	0.1	—	—	—
Avangrid										0.0	—	—	—	—	0.8
Avista	0.2	0.0	—	—	—	0.1	—	—	—	0.1	0.0	—	—	—	—
BANC	—	0.0	0.3	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	0.0	0.5	—	—	0.4	—	—	—	0.2	—	0.3	0.4	—	0.1
California ISO	—	—	0.1	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric										0.0	0.1	0.3	0.8	0.0	0.1
Idaho Power	—	0.2	0.2	—	—	—	—	—	—	0.0	0.1	—	—	—	—
LADWP	0.0	—	—	—	—	—	0.1	—	—	—	—	—	0.1	0.0	—
NorthWestern En.	—	0.1	0.1	—	0.2	0.1	0.3	0.1	—	—	—	—	0.3	—	—
NV Energy	0.1	—	—	—	—	—	—	—	—	—	0.0	—	0.0	0.0	—
PacifiCorp East	—	—	0.1	—	—	0.3	—	—	—	—	—	—	0.0	—	—
PacifiCorp West	1.0	0.2	0.0	—	0.0	0.0	0.1	0.1	—	—	—	—	—	0.1	—
Portland Gen. Elec.	—	0.1	—	—	0.3	—	—	0.0	0.0	0.1	0.4	0.1	0.0	—	0.0
Powerex	—	0.2	—	—	0.0	—	—	—	—	—	0.1	—	—	—	0.1
PSC of New Mexico	—	—	—	—	—	—	—	—	0.7	0.3	0.2	0.0	—	0.0	0.1
Puget Sound En.	—	—	0.2	0.1	0.0	—	—	0.0	0.2	—	0.1	0.5	1.5	0.5	0.2
Salt River Proj.	0.2	0.4	0.4	0.2	0.0	0.0	1.0	0.4	1.1	0.9	0.2	0.0	2.8	1.2	0.0
Seattle City Light	0.2	0.1	0.2	0.0	0.0	0.2	0.0	0.1	—	—	—	—	0.1	0.9	—
Tacoma Power	0.0	0.2	0.0	—	—	—	0.0	0.1	0.1	—	0.1	—	—	0.1	—
Tucson Elec. Pow.	—	0.1	—	—	—	—	0.1	0.0	—	—	—	—	0.3	—	—
Turlock Irrig. Dist.	—	—	—	—	—	0.2	—	—	—	0.0	—	—	0.1	—	—
WAPA DSW										2.3	0.8	0.7	1.1	0.6	0.1

Figure 2.11 Frequency of upward flexibility test failures by month and area (percent of intervals)

	2022						2023								
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona Publ. Serv.	0.0	0.1	—	—	0.1	0.4	0.9	1.8	2.5	1.1	0.2	0.1	—	0.0	—
Avangrid										1.0	0.7	0.1	0.2	0.0	0.9
Avista	0.5	0.1	—	0.1	—	0.1	—	0.0	0.0	0.2	0.2	0.0	—	—	—
BANC	—	—	0.3	—	—	—	—	—	—	—	0.1	—	—	—	—
BPA	3.3	1.0	1.1	0.2	0.1	0.4	—	0.1	0.6	0.2	1.2	0.3	1.3	0.2	0.2
California ISO	—	0.1	0.5	0.0	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric										0.8	0.7	0.3	2.1	0.5	0.6
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	0.0	0.2	0.0
NorthWestern En.	0.3	1.0	0.2	—	0.5	0.8	0.3	0.1	0.2	0.8	0.3	0.2	1.0	0.4	0.2
NV Energy	—	0.1	0.1	0.1	0.2	0.0	0.1	0.3	0.0	0.1	0.1	0.0	0.1	0.2	0.1
PacifiCorp East	0.2	0.1	—	0.1	—	0.0	0.1	—	0.0	0.1	—	0.0	0.2	—	—
PacifiCorp West	—	0.1	0.1	—	0.1	—	0.1	0.1	—	0.1	0.6	0.0	0.2	—	—
Portland Gen. Elec.	0.4	0.1	0.1	0.2	1.0	0.1	0.0	0.1	0.0	0.1	1.5	0.7	0.1	—	—
Powerex	—	0.3	0.1	—	—	—	—	0.2	—	—	—	—	—	—	—
PSC of New Mexico	0.4	—	0.0	0.2	0.1	0.8	0.2	—	1.2	5.1	0.9	0.6	0.7	0.5	0.3
Puget Sound En.	0.4	0.2	0.3	—	0.0	—	—	0.1	0.8	0.2	1.0	0.6	2.6	1.3	0.2
Salt River Proj.	0.6	1.1	0.6	0.6	0.5	0.8	3.5	1.2	1.7	2.0	0.6	0.2	3.7	1.1	0.3
Seattle City Light	0.2	0.0	0.2	—	0.1	0.0	—	0.1	—	—	—	—	—	0.5	0.0
Tacoma Power	0.0	0.1	0.1	—	0.2	—	0.2	0.1	0.2	—	0.1	—	—	—	—
Tucson Elec. Pow.	—	—	0.4	0.0	—	0.2	0.3	0.3	0.3	0.1	0.1	—	0.2	0.3	—
Turlock Irrig. Dist.	—	—	0.1	—	—	1.2	—	—	—	0.0	—	—	0.1	—	—
WAPA DSW										2.7	0.7	0.8	0.3	0.6	0.2

Figure 2.12 Frequency of downward capacity test failures by month and area (percent of intervals)

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

Figure 2.13 Frequency of downward flexibility test failures by month and area (percent of intervals)

	2022						2023								
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona Publ. Serv.	—	—	0.1	0.2	0.2	0.1	0.9	0.5	2.1	0.7	1.2	0.1	—	—	—
Avangrid										0.1	—	—	—	—	0.1
Avista	—	—	0.1	0.2	—	0.0	—	—	0.1	0.1	0.1	—	—	—	—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA	—	0.0	0.3	—	0.2	0.2	—	0.0	0.1	0.6	5.5	0.0	0.4	—	0.0
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
El Paso Electric										0.2	0.9	1.9	0.5	—	0.3
Idaho Power	—	0.0	—	—	—	—	—	—	0.9	0.2	—	—	—	—	0.0
LADWP	—	—	—	—	—	—	0.1	—	—	—	—	—	—	—	—
NorthWestern En.	0.2	—	—	—	0.0	0.1	—	0.0	—	—	0.2	0.2	—	0.1	0.0
NV Energy	0.6	0.2	0.5	0.5	0.6	0.1	0.1	0.1	0.1	0.0	0.1	0.4	0.1	0.1	0.0
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.0
PacifiCorp West	0.5	—	—	0.1	—	0.0	—	—	—	0.0	0.2	0.0	—	—	1.1
Portland Gen. Elec.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	0.1	0.1	0.1	—	—	0.1	0.1	—	0.2	—	—	0.0	—	0.2
PSC of New Mexico	0.0	0.0	0.2	0.2	0.1	—	0.0	—	0.4	1.6	2.1	—	0.1	0.4	1.1
Puget Sound En.	0.1	—	—	0.1	—	—	—	—	—	—	0.8	—	—	—	—
Salt River Proj.	0.2	0.2	1.0	0.2	0.9	0.3	1.4	3.3	1.0	0.3	0.1	0.1	0.1	—	—
Seattle City Light	0.1	0.8	0.3	—	0.2	0.6	0.1	0.2	0.0	0.3	0.0	0.3	0.4	1.1	0.2
Tacoma Power	0.5	0.2	—	—	—	0.1	—	0.2	0.1	—	—	—	0.0	—	0.1
Tucson Elec. Pow.	—	—	—	—	0.0	—	—	—	—	—	—	—	—	—	—
Turlock Irrig. Dist.	0.1	0.1	—	—	0.1	—	0.1	0.1	0.1	0.1	0.4	—	—	—	—
WAPA DSW										2.7	0.5	0.7	0.1	0.2	0.6

Resource sufficiency evaluation monthly reports

DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic.[62] 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 WEIM imbalance conformance

Frequency and size of imbalance conformance

Table 2.8 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM and California ISO for the 15-minute and 5-minute markets during the quarter.

The El Paso Electric, Bonneville Power Administration, and Seattle City Light areas used negative imbalance conformance in the 15-minute market most frequently. Other areas had little to no negative conformance in the 15-minute market. Negative imbalance conformance in the 5-minute market was much more frequent by nearly all areas.

The Bonneville Power Administration, El Paso Electric, Salt River Project, and NorthWestern Energy areas had the greatest percent of positive imbalance conformance in the 15-minute market. Other areas had very little or no positive conformance in the 15-minute market. Nearly all areas used positive imbalance conformance in the 5-minute market, however BANC, Turlock Irrigation District, Avista Utilities, Tacoma Power, and Seattle City Light used positive imbalance in three percent or less intervals.

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

Table 2.8 Average frequency and size of imbalance conformance (July-September)

Balancing area	Market	Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
		Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO	FMM	24.8%	1,613	4.8%	0.2%	-300	1.2%	401
	RTD	32.6%	359	1.2%	48.4%	-331	1.3%	-43
Avangrid Renewables*	FMM	0.0%	100	N/A	0.1%	-122	N/A	0
	RTD	48.9%	62	N/A	11.2%	-98	N/A	19
BANC	FMM	0.4%	69	2.4%	0.7%	-51	3.0%	0
	RTD	1.2%	63	2.2%	1.3%	-48	2.8%	0
Turlock Irrigation District	FMM	0.0%	25	7.5%	0.0%	N/A	N/A	0
	RTD	0.1%	27	6.6%	0.1%	-20	3.9%	0
LADWP	FMM	2.6%	51	1.4%	0.4%	-85	2.5%	1
	RTD	23.3%	48	1.5%	13.7%	-45	1.7%	5
NV Energy	FMM	0.1%	200	3.9%	0.0%	N/A	N/A	0
	RTD	33.9%	114	1.9%	5.6%	-114	2.2%	32
Arizona Public Service	FMM	0.3%	68	1.5%	0.0%	N/A	N/A	0
	RTD	45.6%	62	1.2%	20.8%	-56	1.1%	17
Tucson Electric Power	FMM	0.0%	N/A	N/A	0.0%	-50	N/A	0
	RTD	8.5%	47	2.5%	17.6%	-56	3.3%	-6
WAPA - Desert Southwest	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	47.1%	25	2.5%	6.2%	-17	2.0%	11
El Paso Electric	FMM	22.2%	18	1.3%	21.0%	-14	1.0%	1
	RTD	25.8%	19	1.4%	22.2%	-15	1.0%	2
Salt River Project	FMM	12.6%	136	2.3%	1.0%	-101	2.2%	16
	RTD	34.9%	120	2.1%	4.3%	-76	1.7%	39
Public Service Co. of New Mexico	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	40.6%	63	3.6%	11.6%	-69	4.1%	18
PacifiCorp East	FMM	0.0%	N/A	N/A	0.0%	-460	N/A	0
	RTD	9.9%	89	1.3%	27.9%	-89	1.5%	-16
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	19.5%	65	2.5%	19.0%	-65	2.7%	0
NorthWestern Energy	FMM	15.2%	19	1.4%	0.3%	-13	1.1%	3
	RTD	37.1%	18	1.3%	4.3%	-25	2.0%	6
Avista Utilities	FMM	0.3%	68	6.4%	3.3%	-33	3.0%	-1
	RTD	1.4%	31	2.4%	49.9%	-24	2.0%	-12
Bonneville Power Administration	FMM	36.9%	26	0.4%	62.1%	-36	0.7%	-13
	RTD	37.3%	27	0.4%	61.6%	-36	0.7%	-12
Tacoma Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	2.6%	12	2.5%	5.7%	-12	3.0%	0
PacifiCorp West	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	4.2%	186	9.2%	20.6%	-50	2.1%	-3
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	11.2%	48	1.8%	1.2%	-45	1.7%	5
Puget Sound Energy	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	4.9%	30	1.3%	29.2%	-33	1.3%	-8
Seattle City Light	FMM	0.2%	13	1.2%	9.5%	-21	2.2%	-2
	RTD	3.1%	19	1.9%	76.5%	-25	2.6%	-18

*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.[63] 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 third 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.
- Average dynamic WEIM transfers into the ISO area decreased in the 15-minute market during the evening hours. This reduction is due to a manual action by the ISO to limit dynamic WEIM imports to zero during the peak hours for the hour-ahead and 15-minute markets starting on July 26, 2023. For more information, see Section 2.

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.

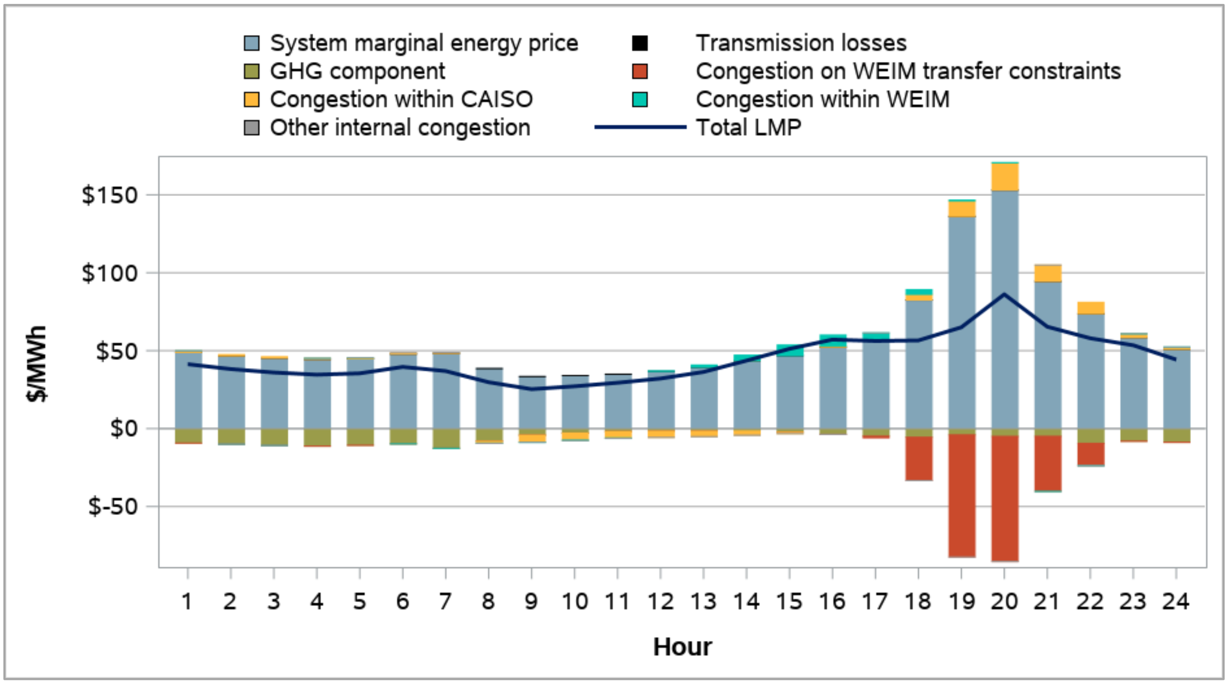
- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for electricity in the WEIM footprint. Therefore, the SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **GHG component** is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

[63] 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.

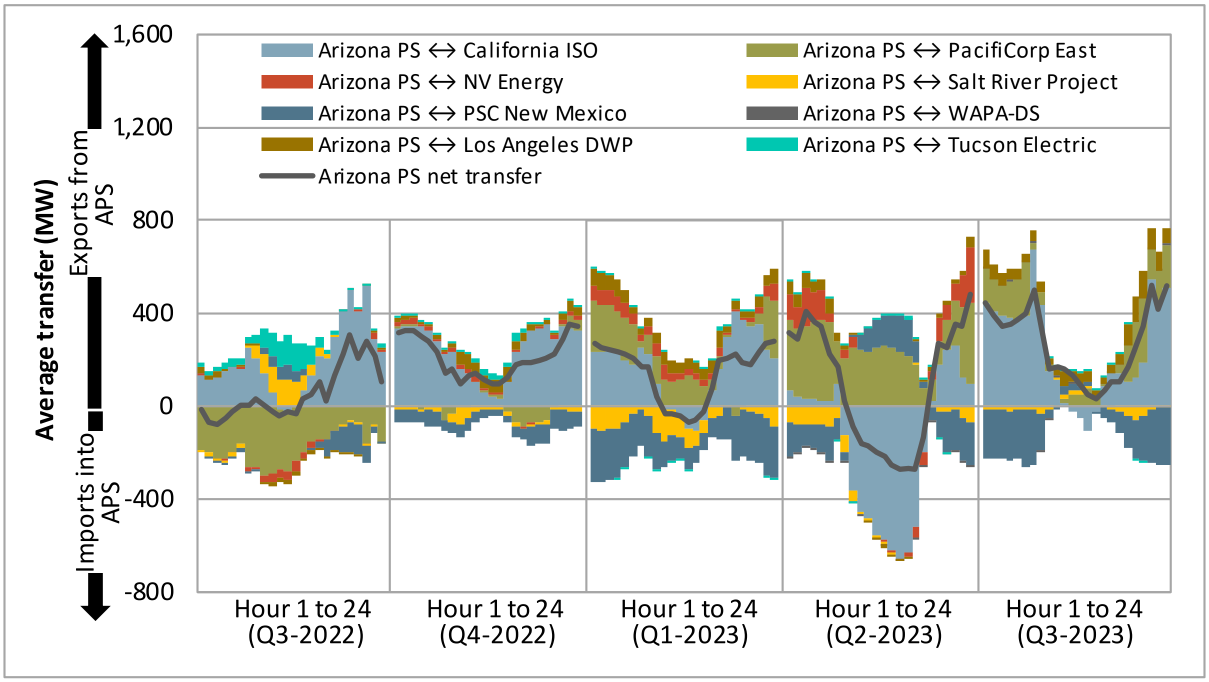
sufficiency evaluation (RSE) tests can have on a balancing area after limiting its total WEIM transfer capability.

A.1 Arizona Public Service

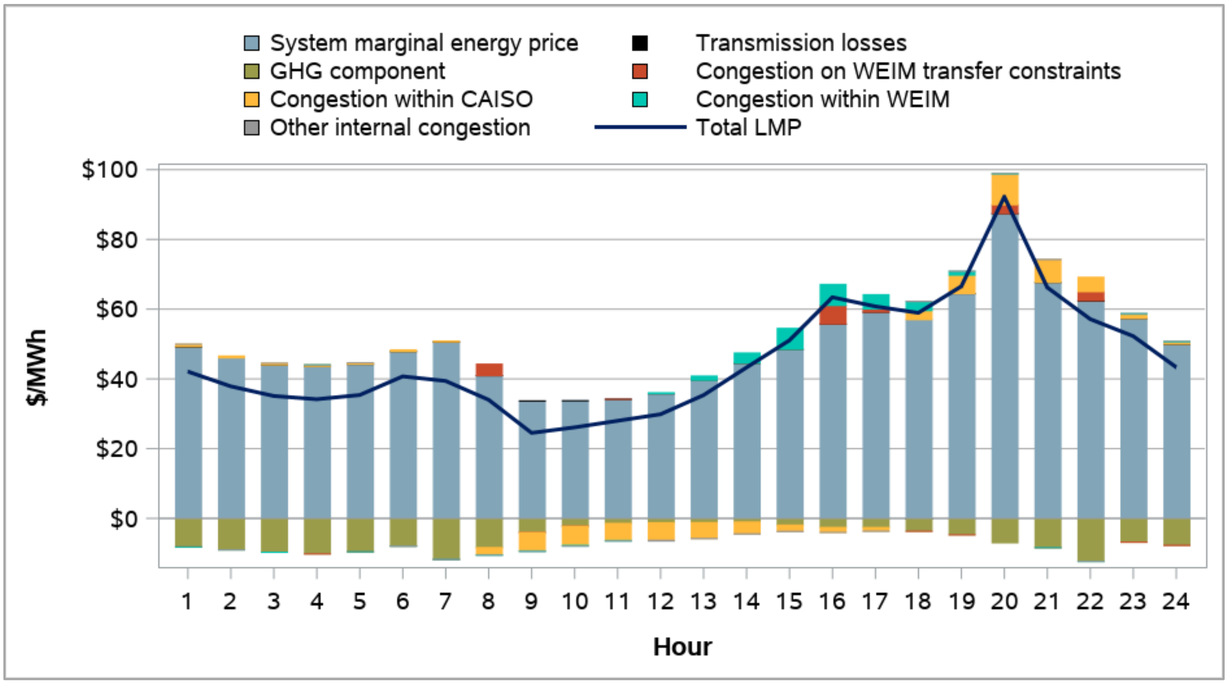
Appendix Figure A.1 Average hourly 15-minute price by component (Q3 2023)



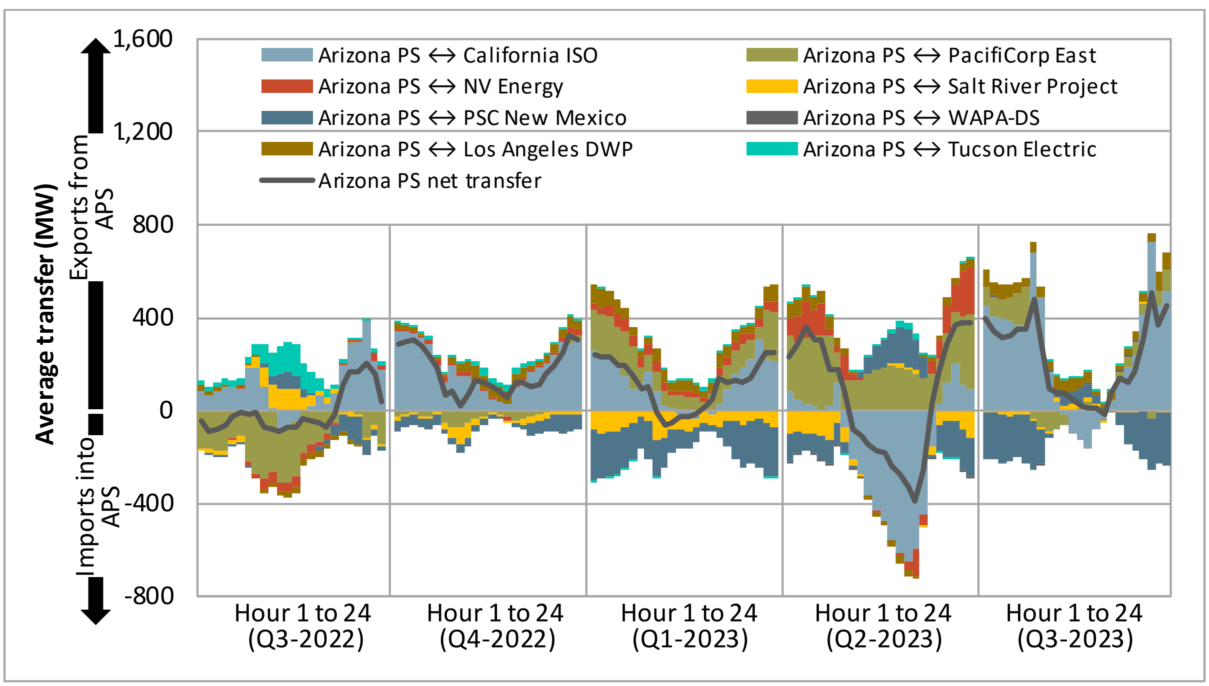
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q3 2023)

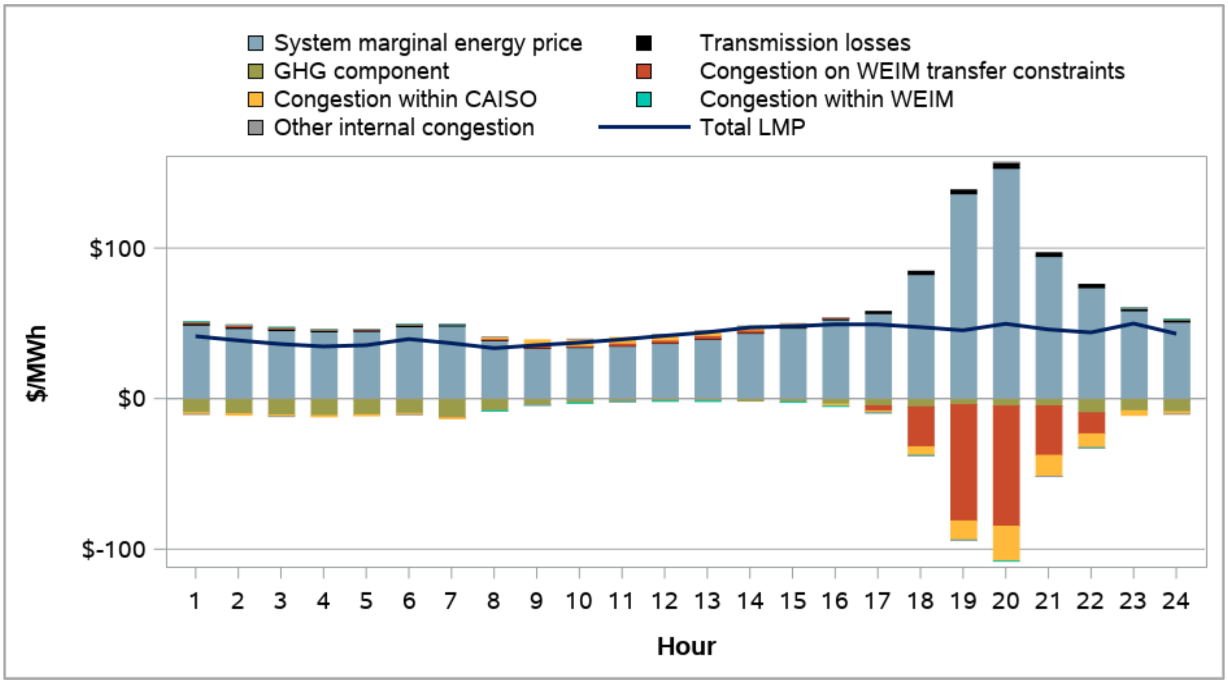


Appendix Figure A.4 Average hourly 5-minute market transfers

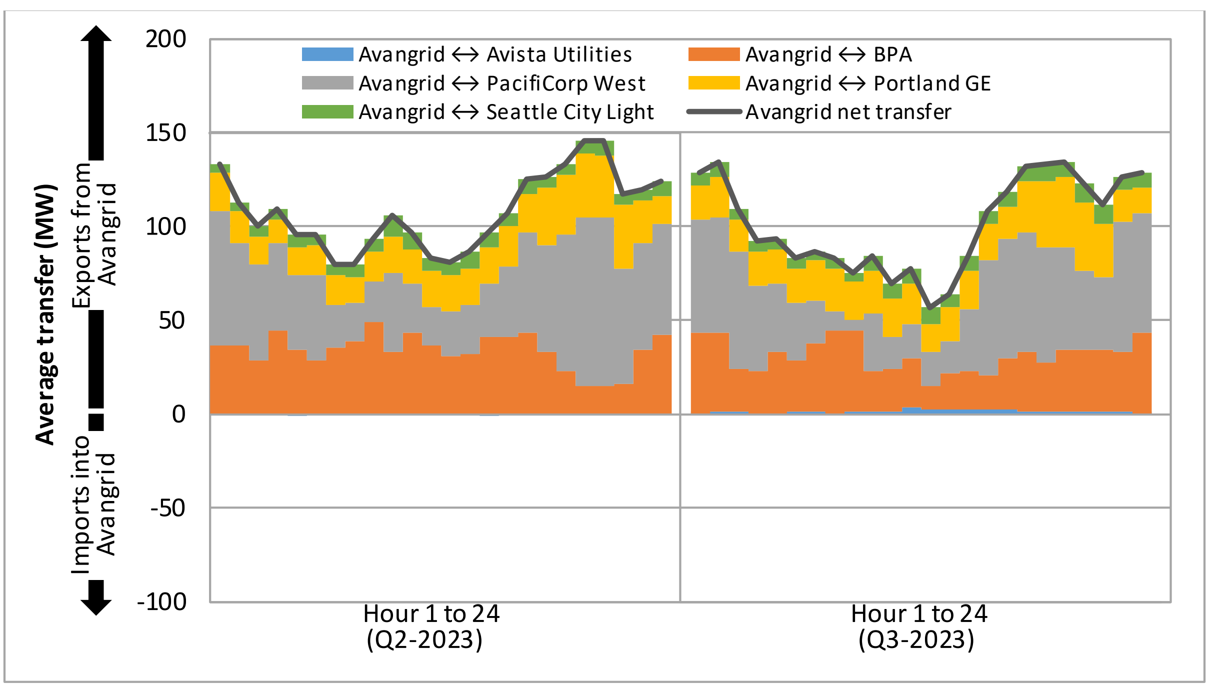


A.2 Avangrid

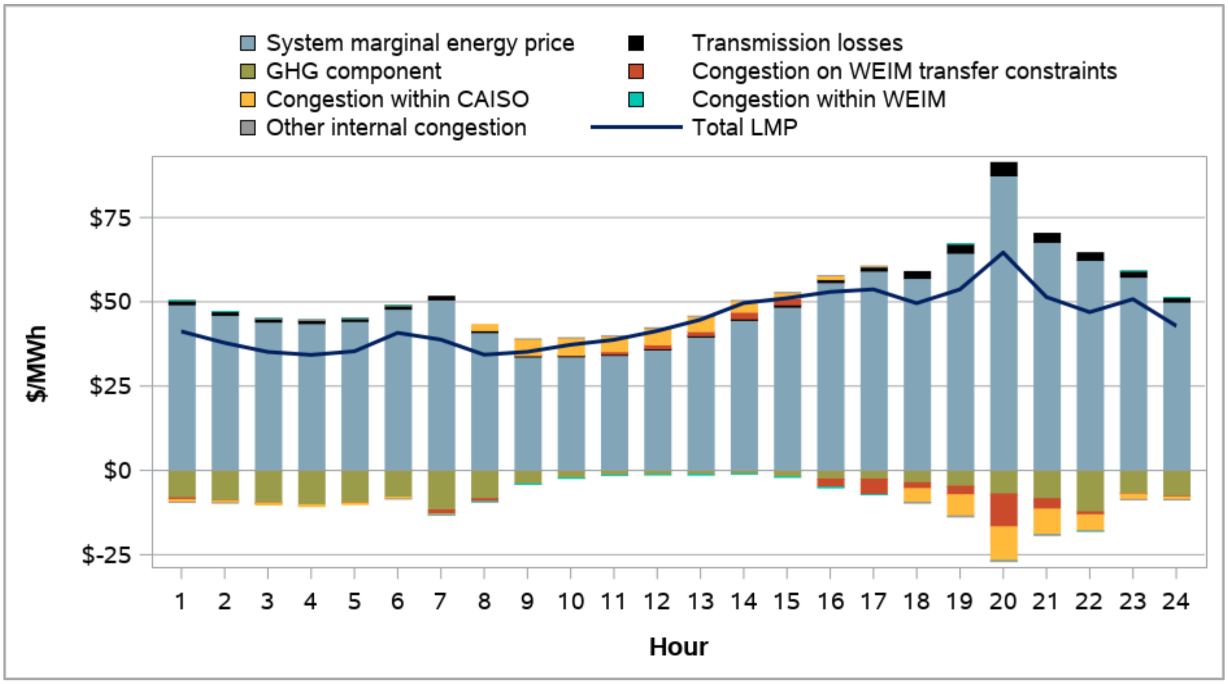
Appendix Figure A.5 Average hourly 15-minute price by component (Q3 2023)



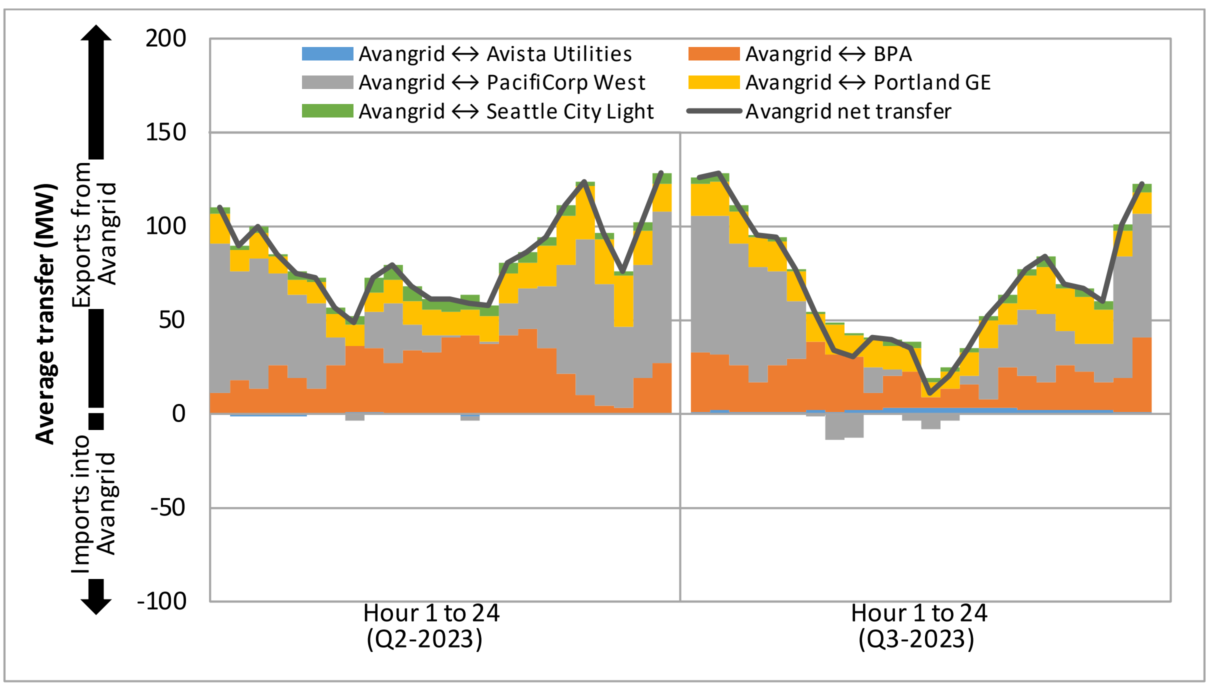
Appendix Figure A.6 Average hourly 15-minute market transfers



Appendix Figure A.7 Average hourly 5-minute price by component (Q3 2023)

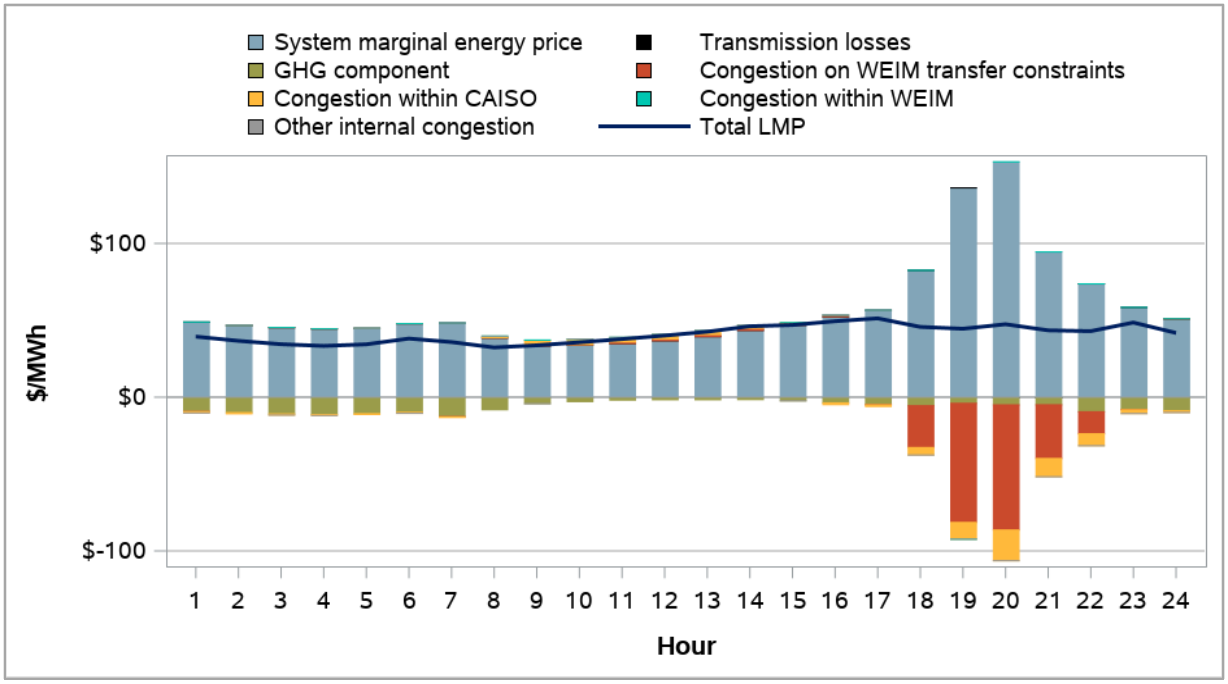


Appendix Figure A.8 Average hourly 5-minute market transfers

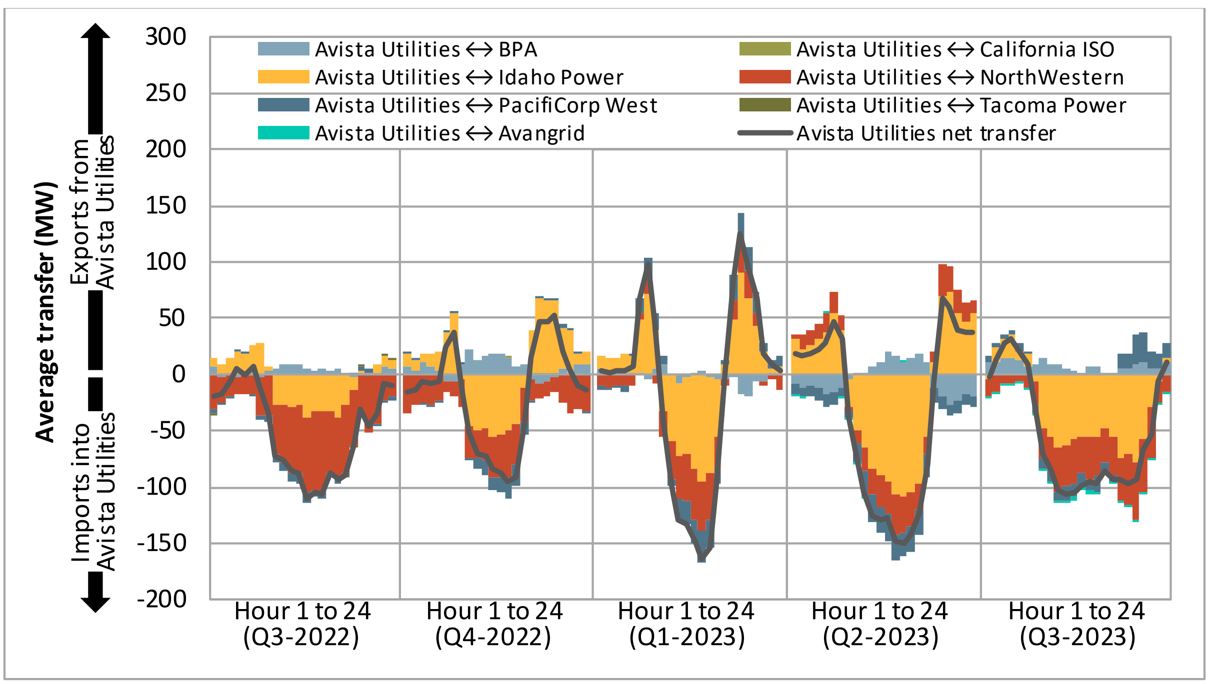


A.3 Avista Utilities

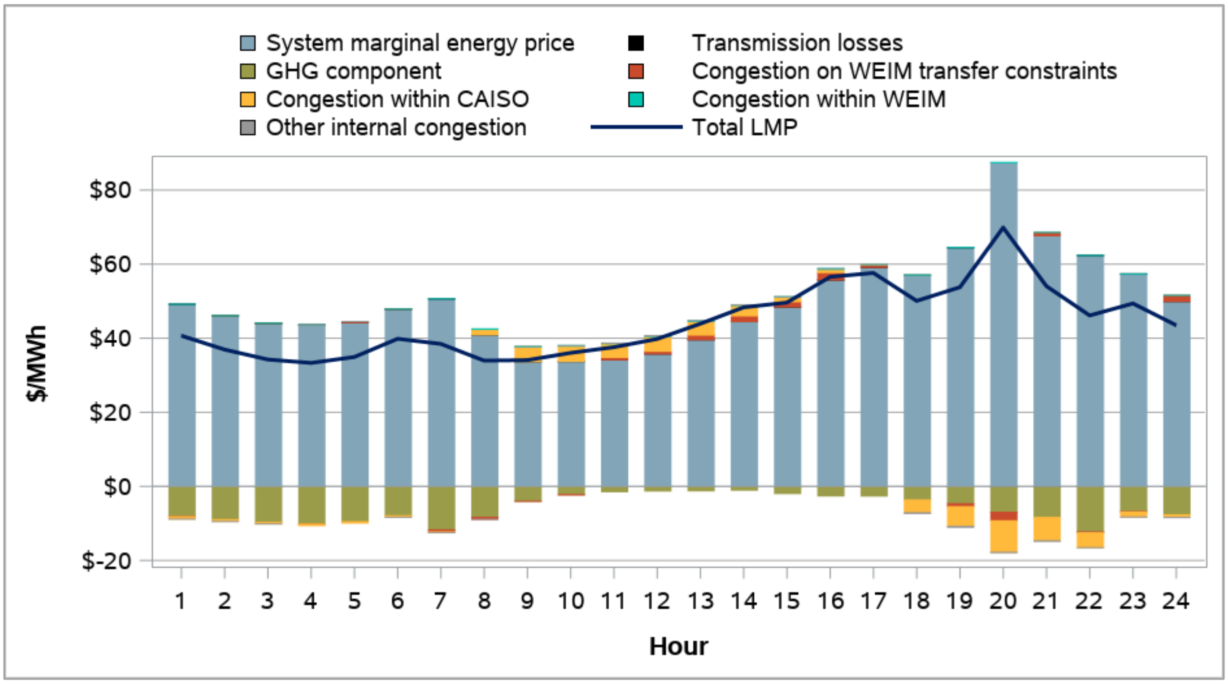
Appendix Figure A.9 Average hourly 15-minute price by component (Q3 2023)



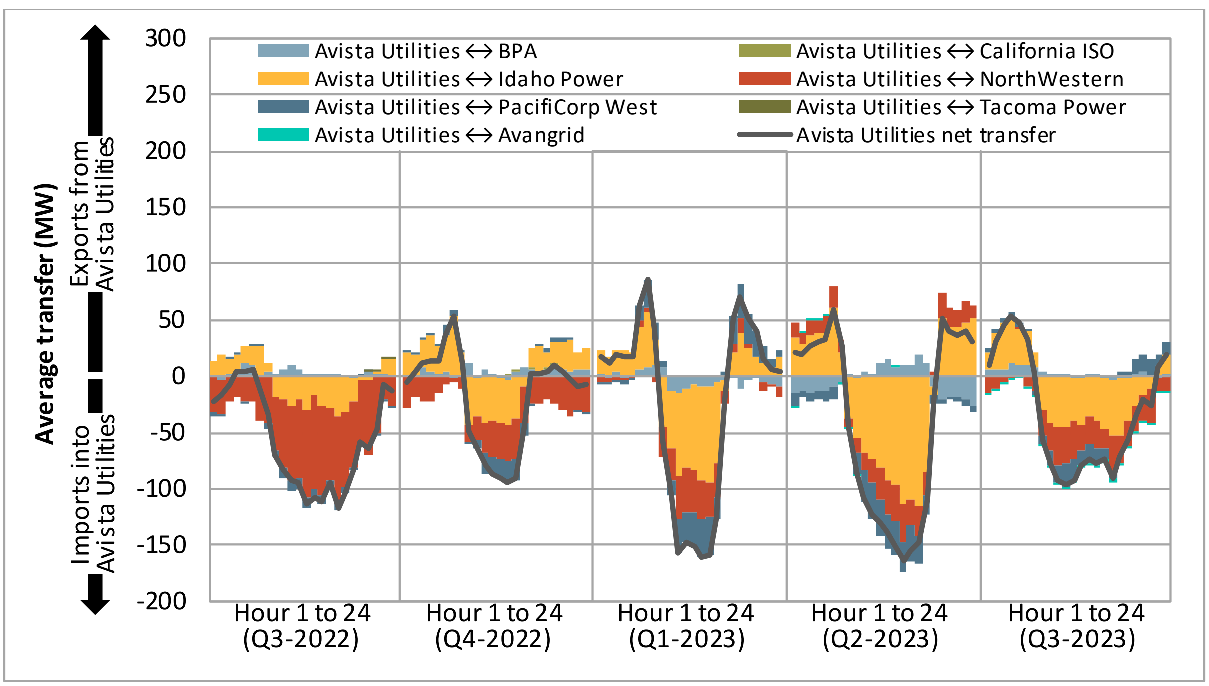
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q3 2023)

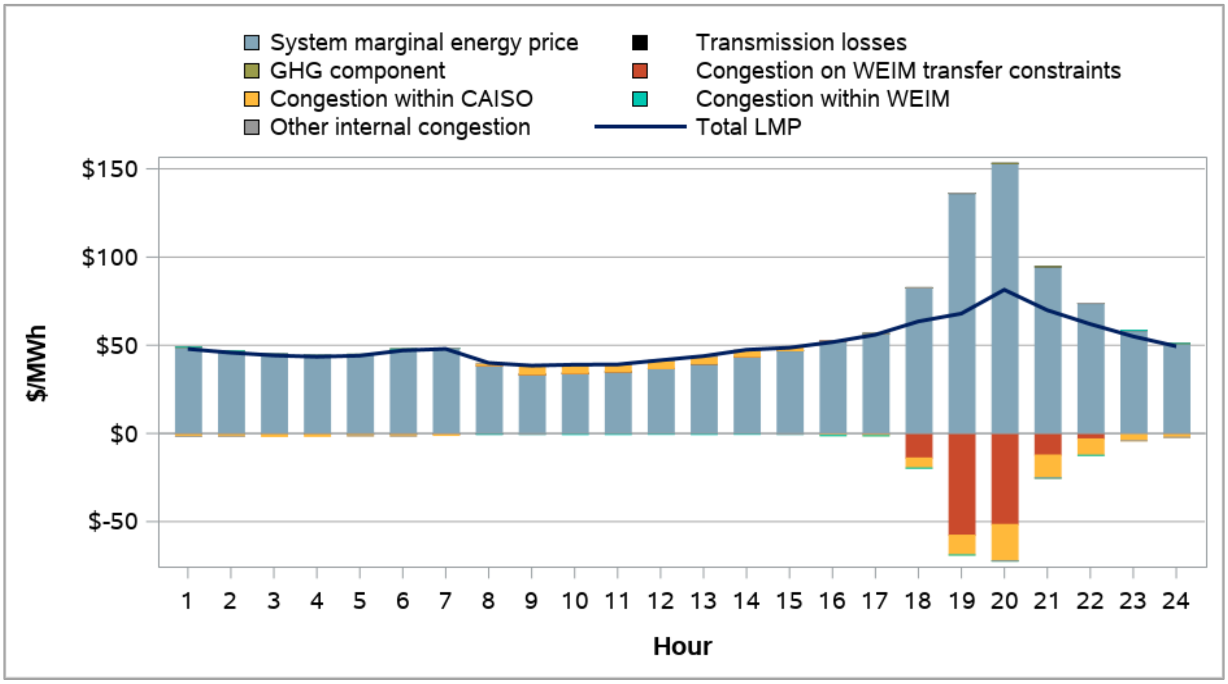


Appendix Figure A.12 Average hourly 5-minute market transfers

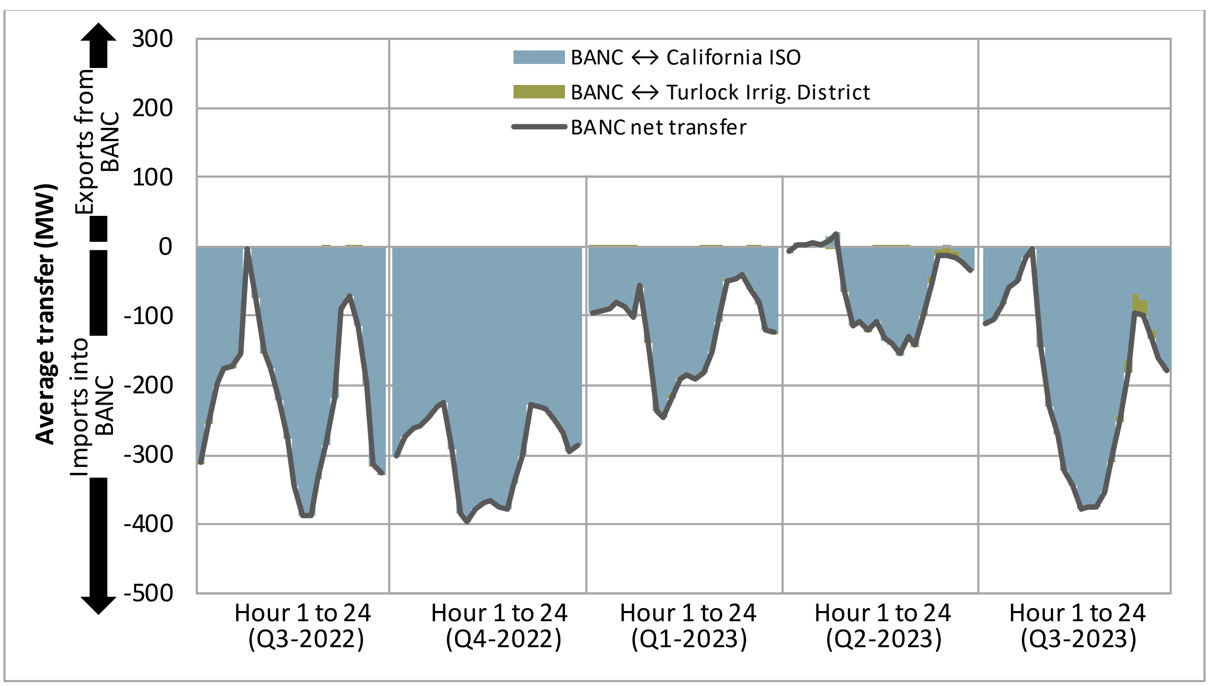


A.4 Balancing Authority of Northern California

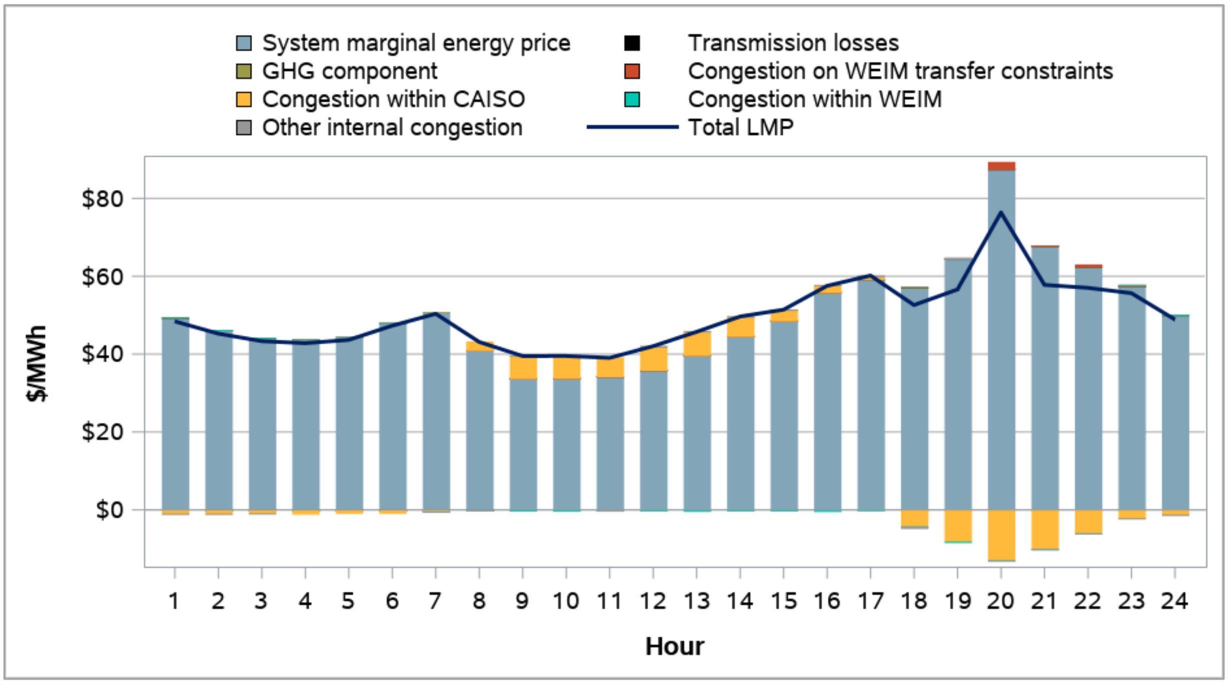
Appendix Figure A.13 Average hourly 15-minute price by component (Q3 2023)



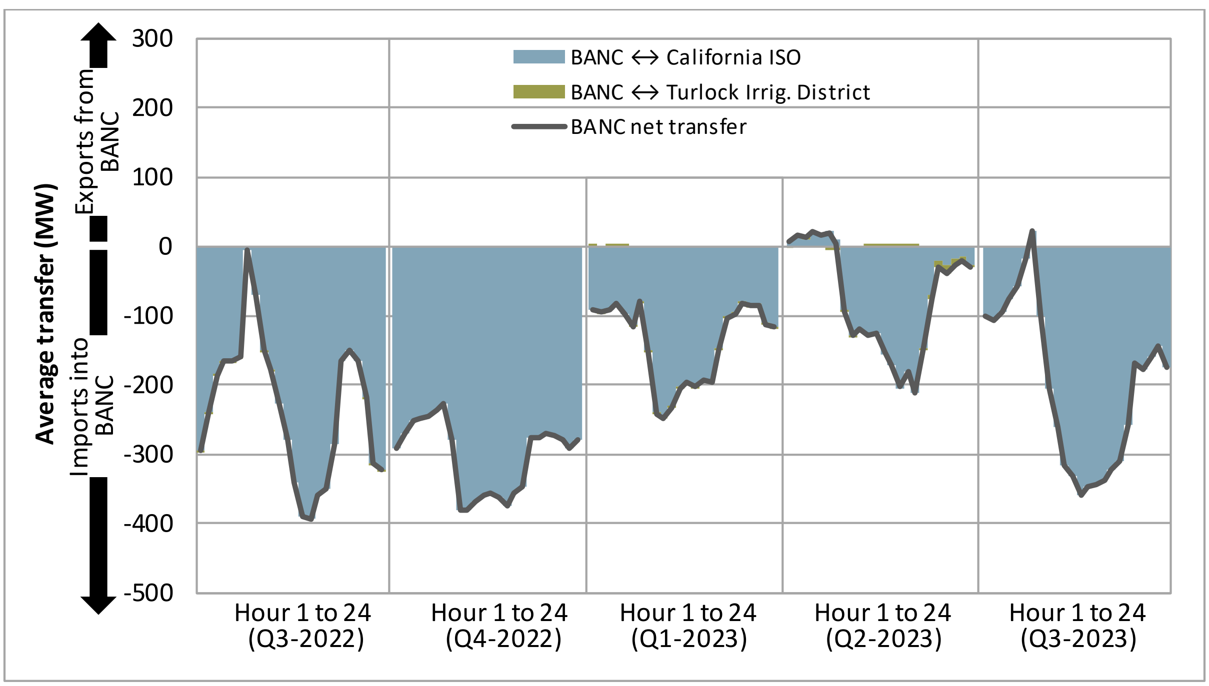
Appendix Figure A.14 Average hourly 15-minute market transfers



Appendix Figure A.15 Average hourly 5-minute price by component (Q3 2023)

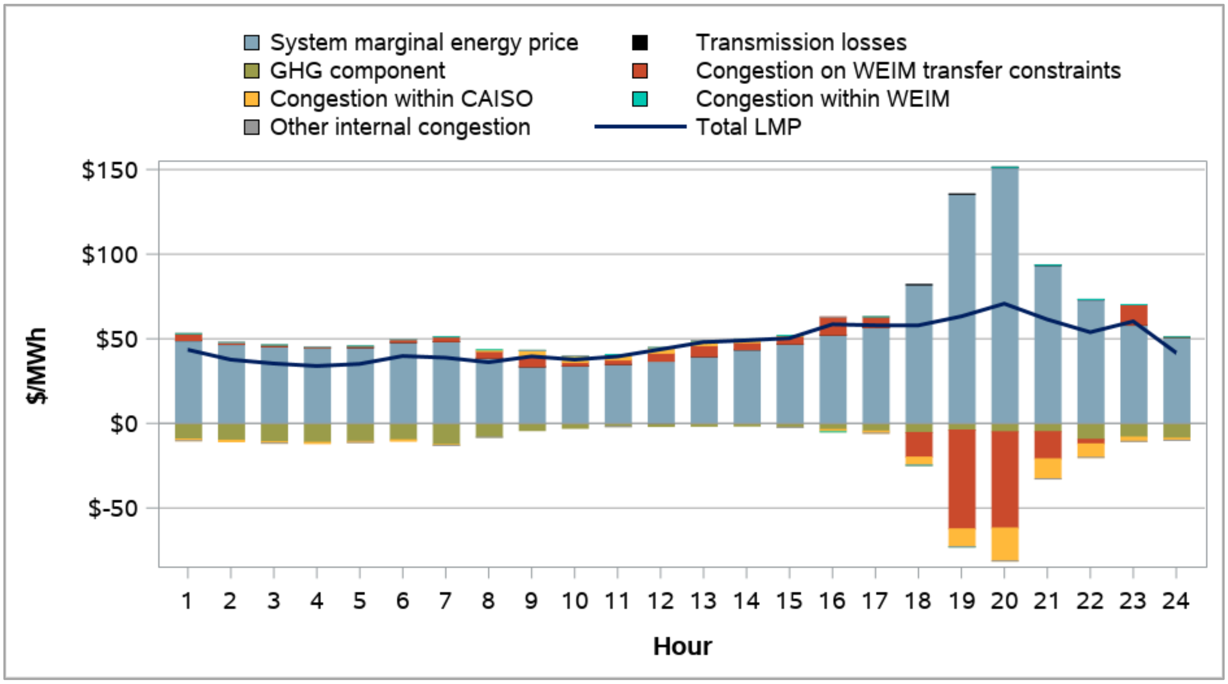


Appendix Figure A.16 Average hourly 5-minute market transfers

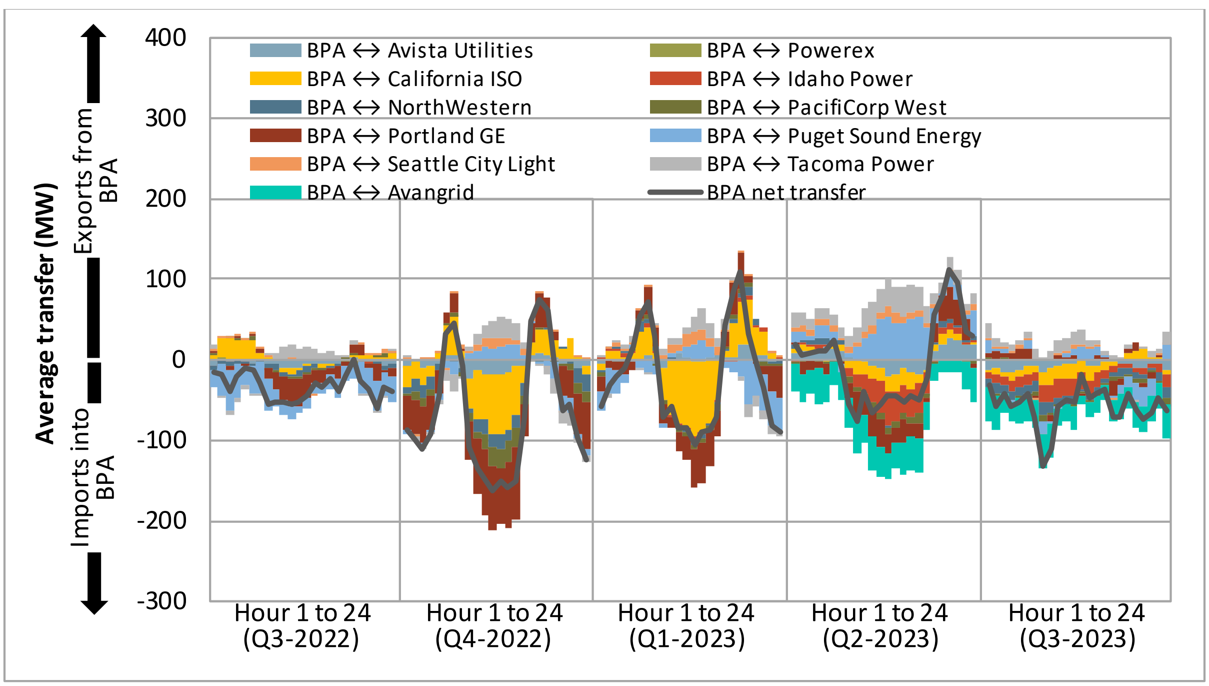


A.5 Bonneville Power Administration

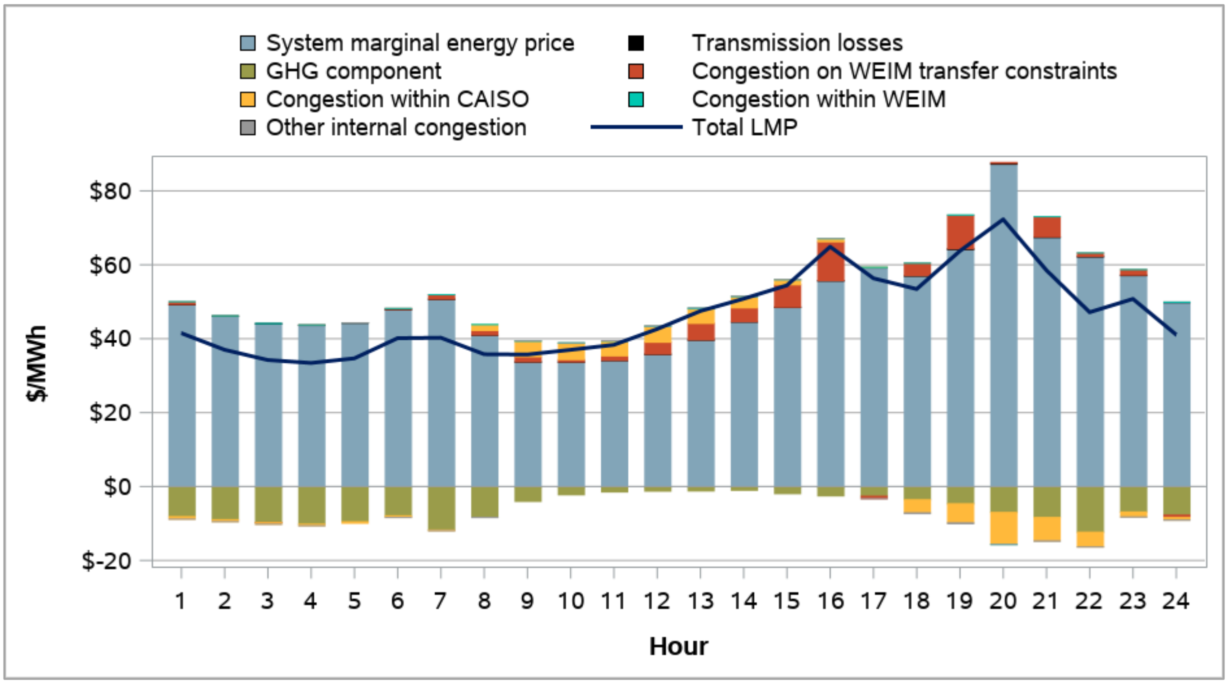
Appendix Figure A.17 Average hourly 15-minute price by component (Q3 2023)



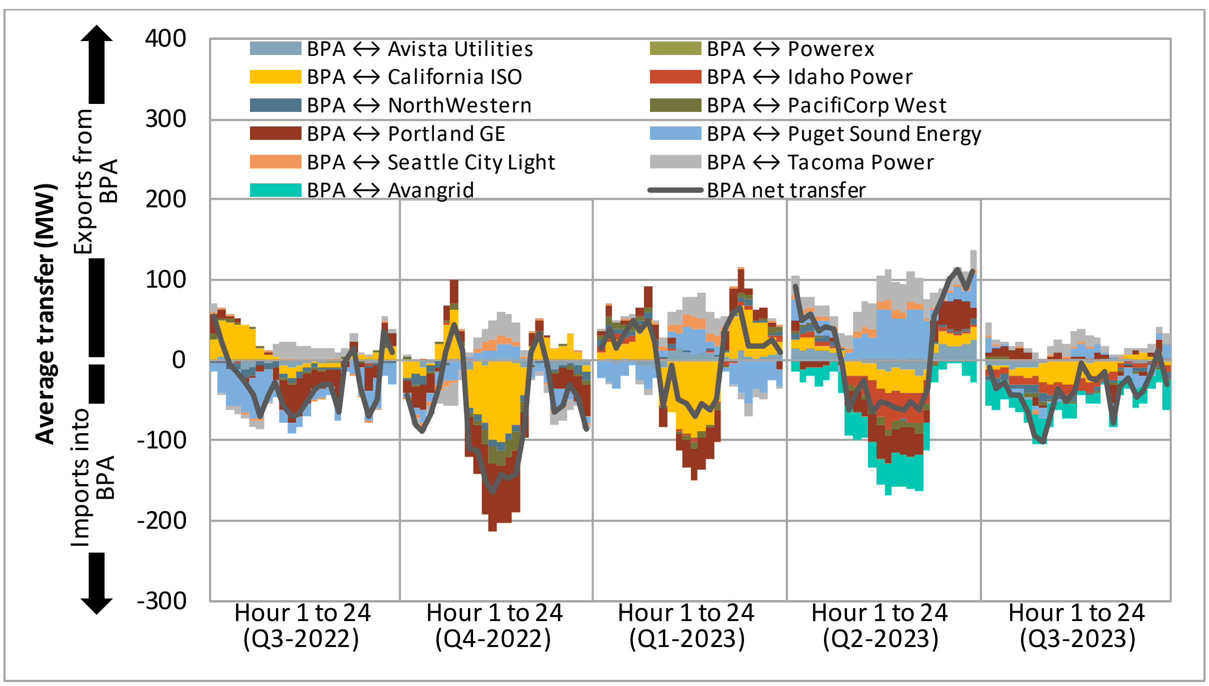
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q3 2023)

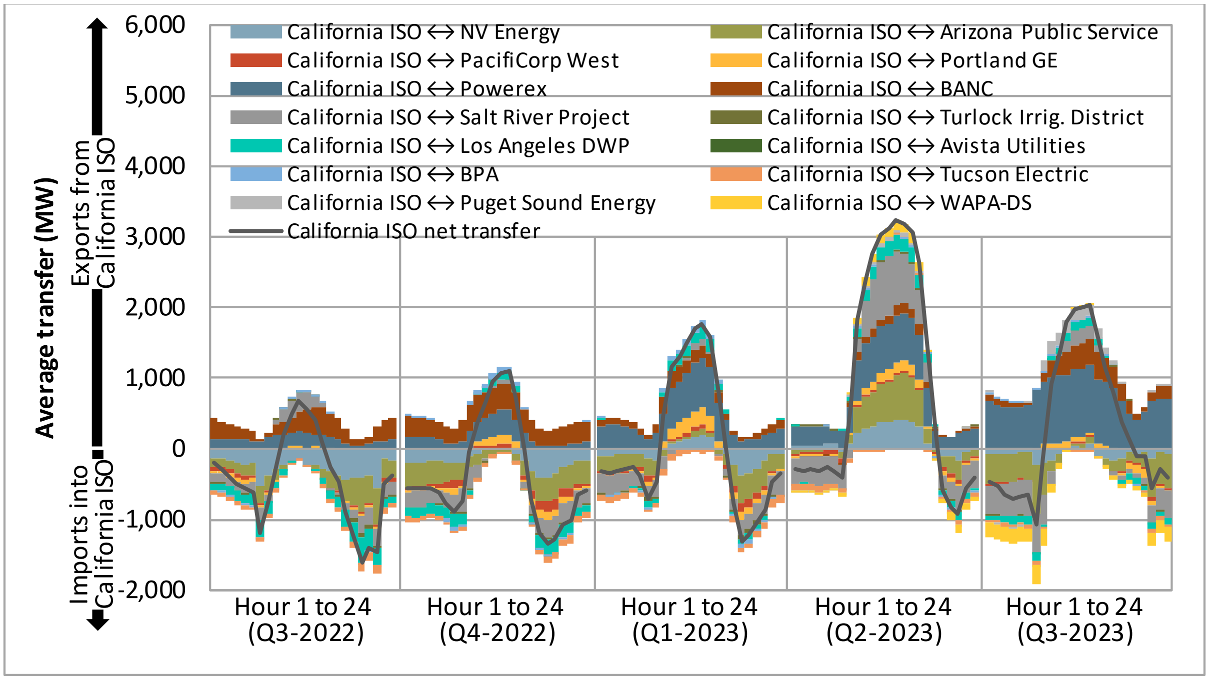


Appendix Figure A.20 Average hourly 5-minute market transfers

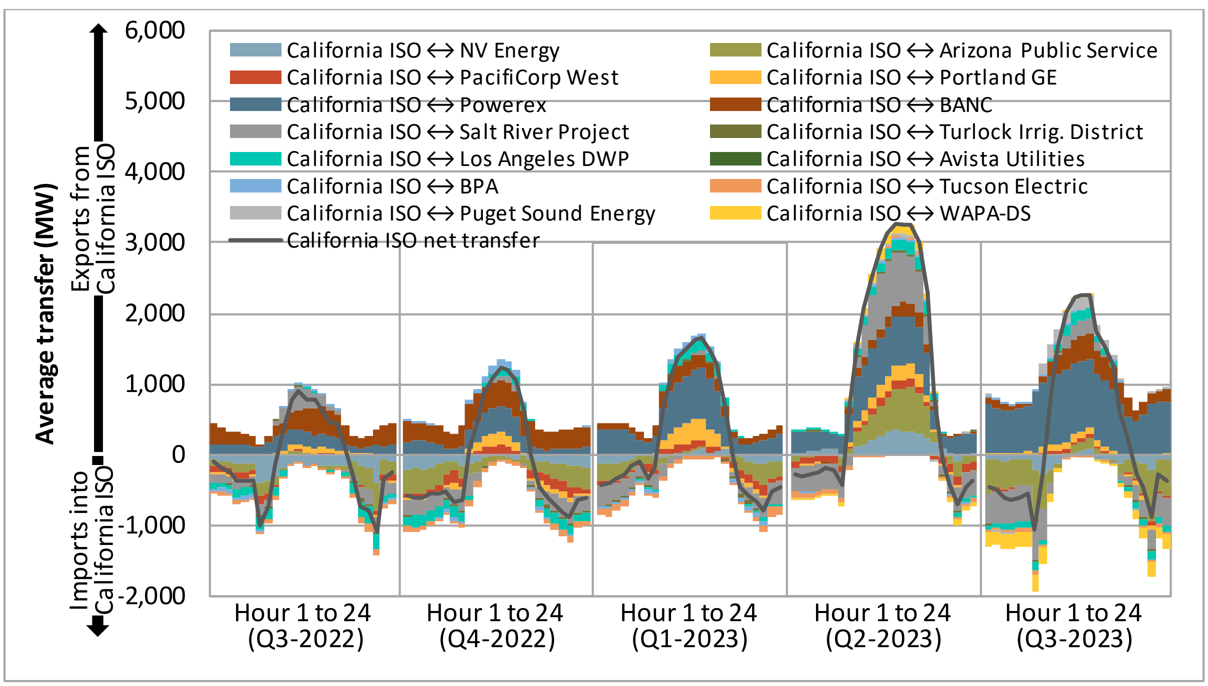


A.6 California ISO

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

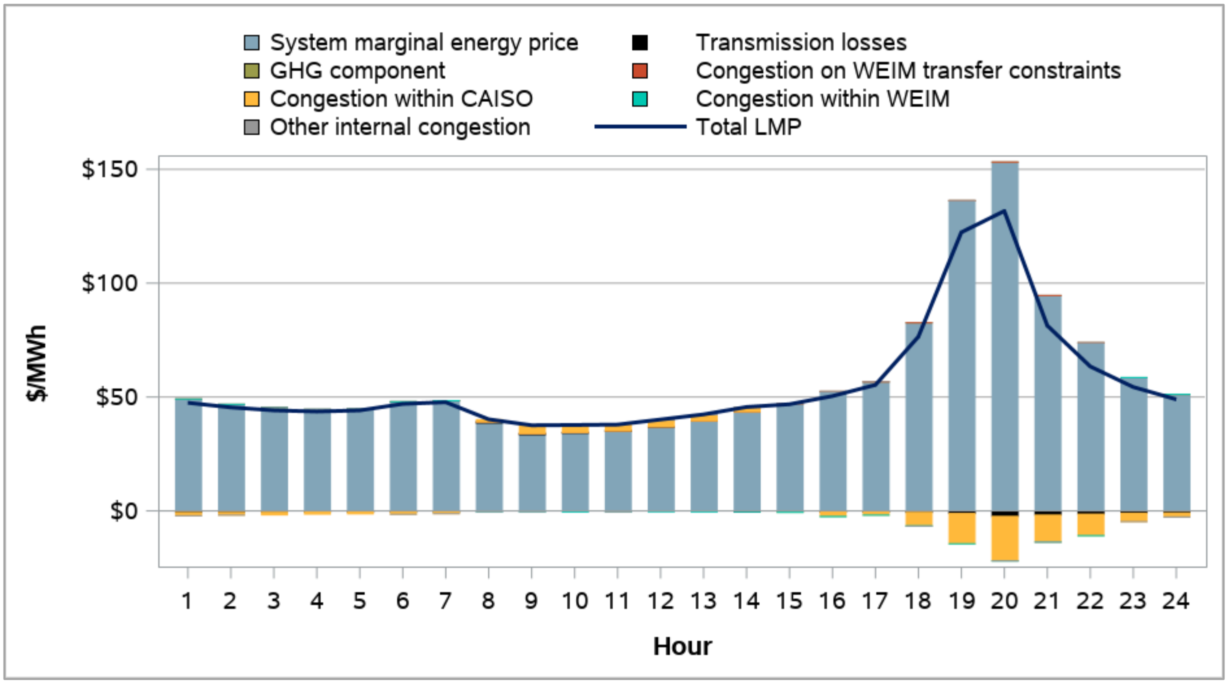


Appendix Figure A.22 Average hourly 5-minute market transfers

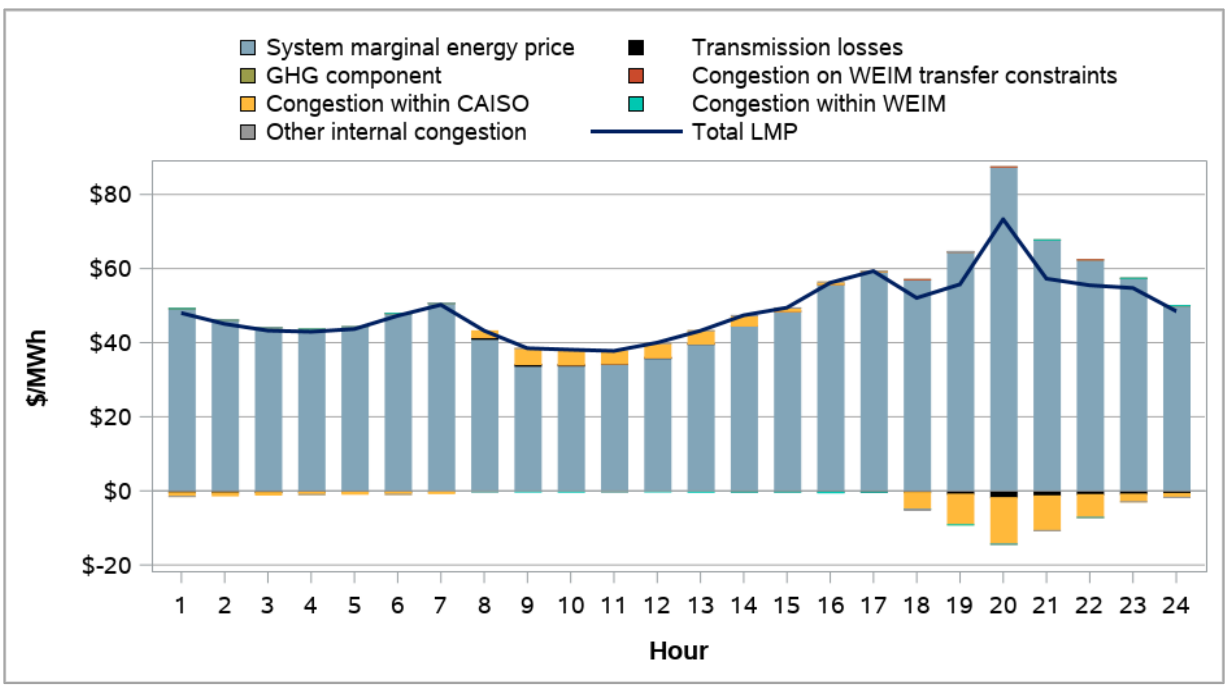


A.6.1 Pacific Gas and Electric

Appendix Figure A.23 Average hourly 15-minute price by component (Q3 2023)

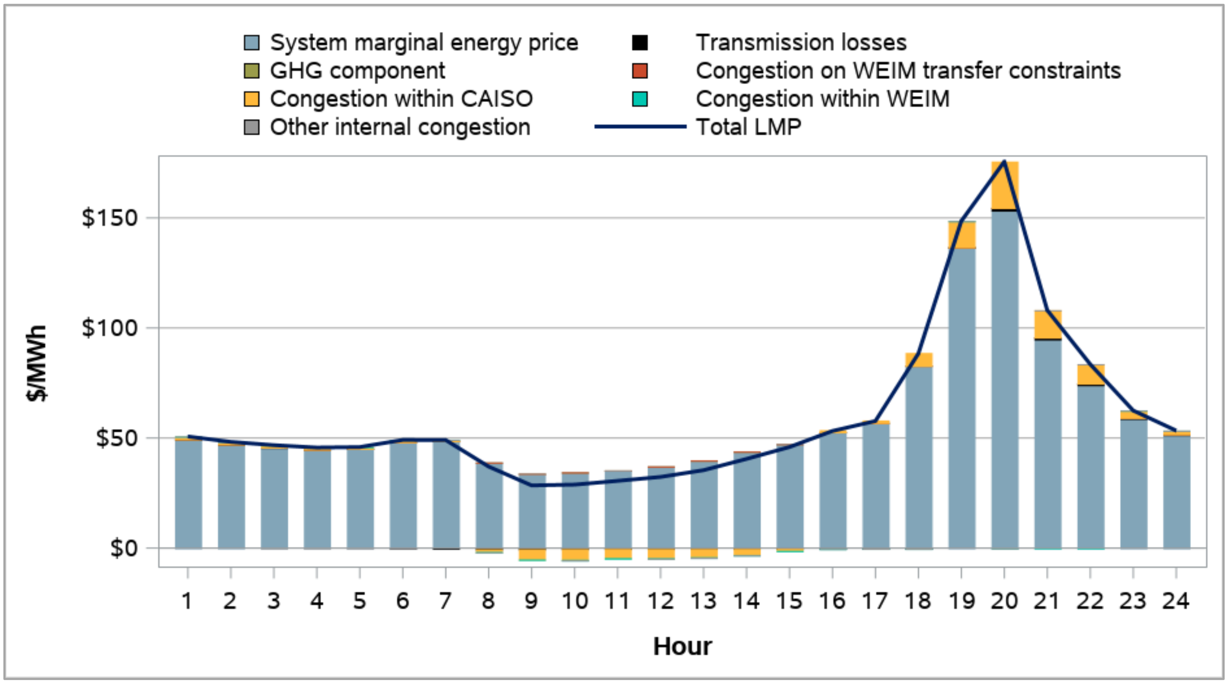


Appendix Figure A.24 Average hourly 5-minute price by component (Q3 2023)

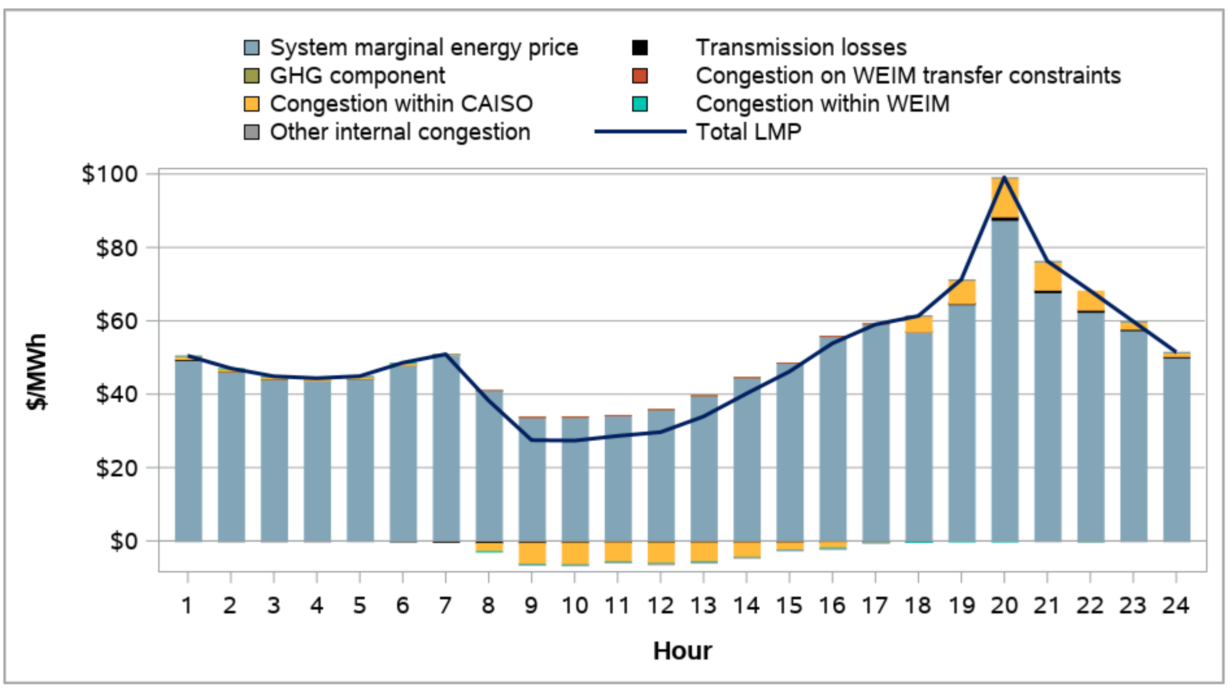


A.6.2 Southern California Edison

Appendix Figure A.25 Average hourly 15-minute price by component (Q3 2023)

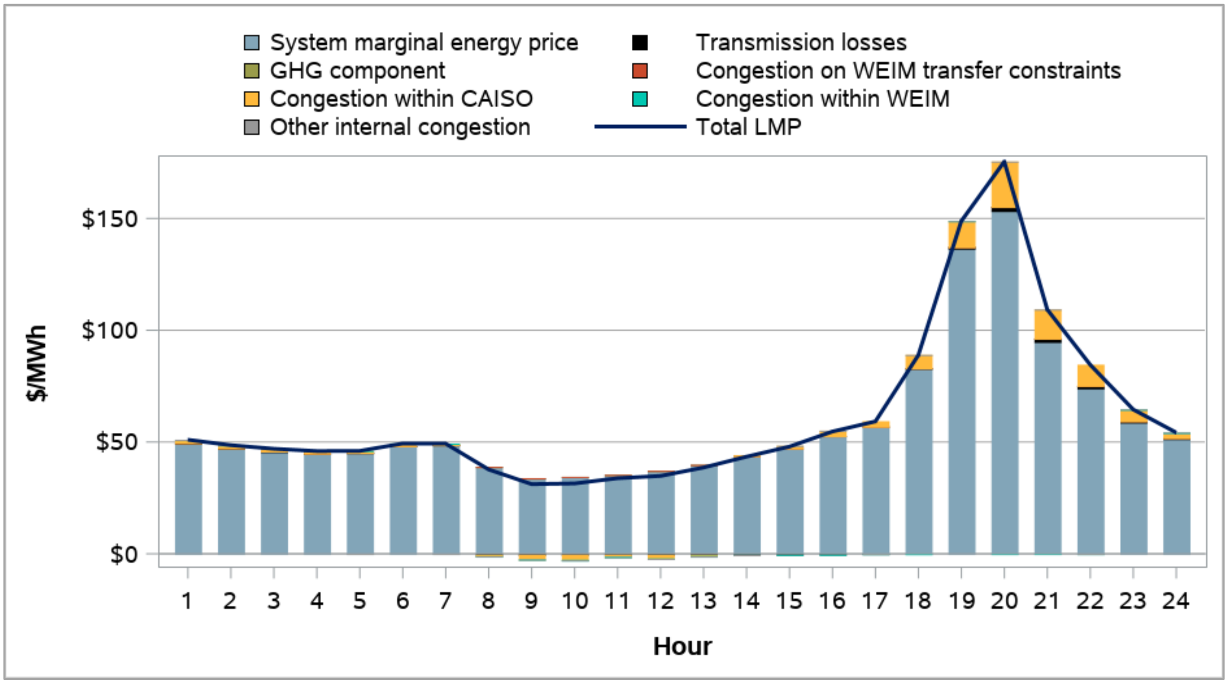


Appendix Figure A.26 Average hourly 5-minute price by component (Q3 2023)

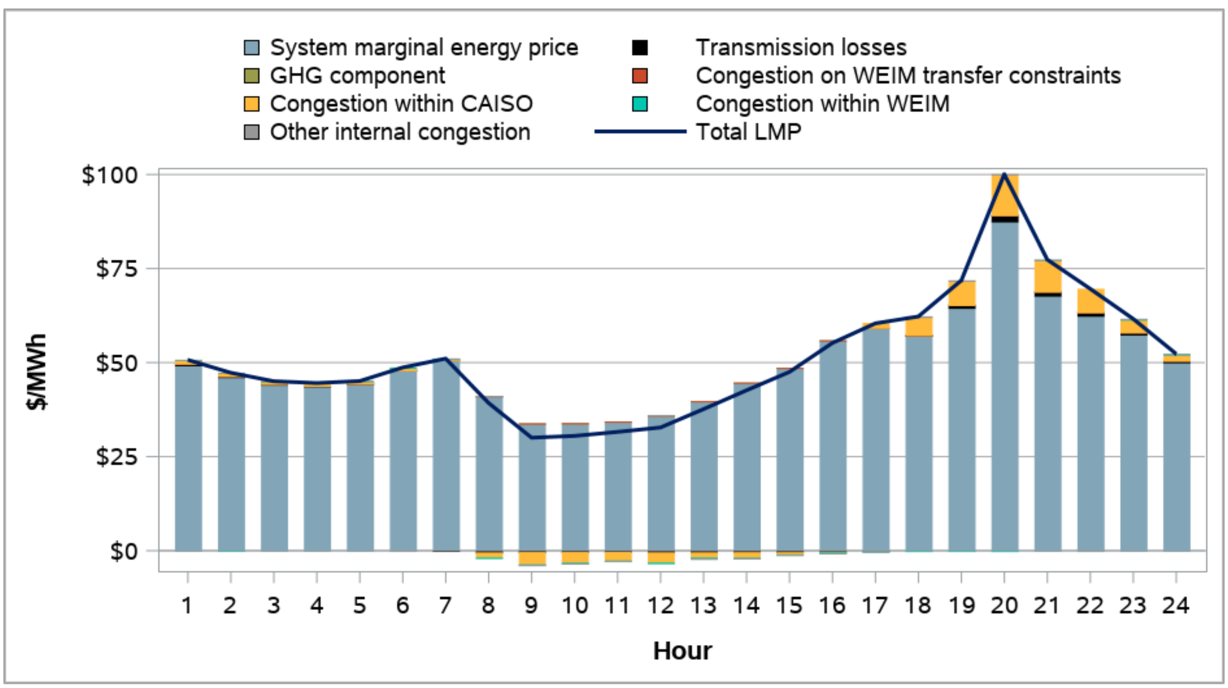


A.6.3 San Diego Gas & Electric

Appendix Figure A.27 Average hourly 15-minute price by component (Q3 2023)

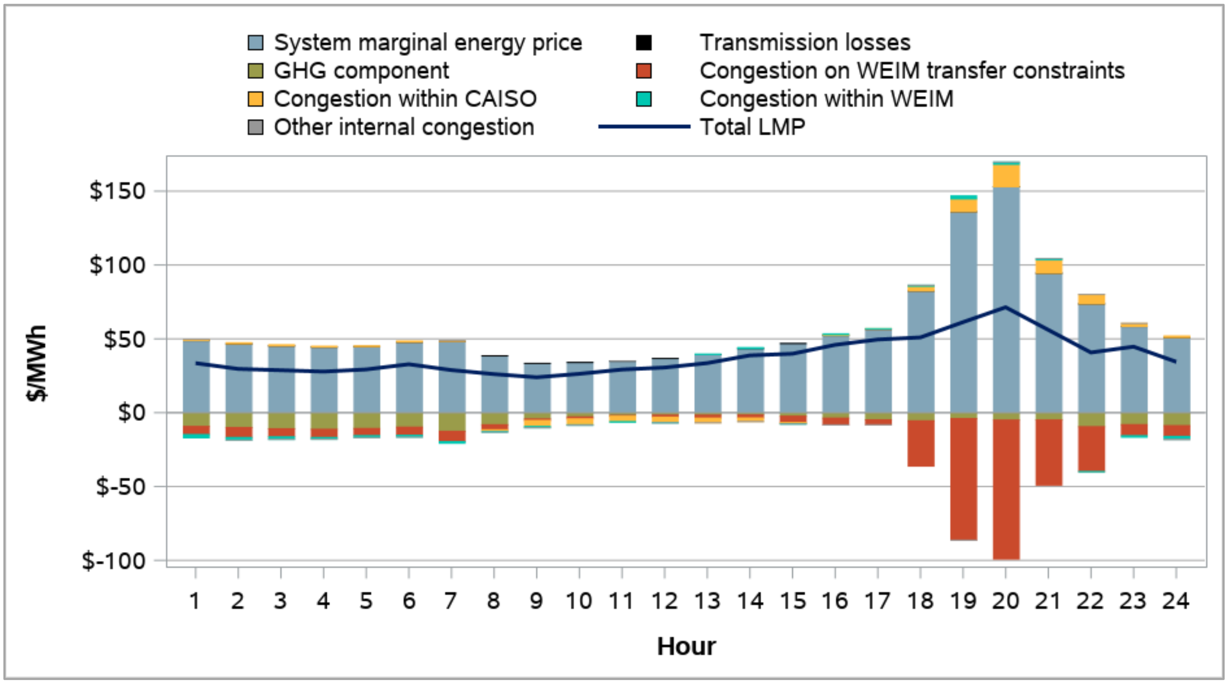


Appendix Figure A.28 Average hourly 5-minute price by component (Q3 2023)

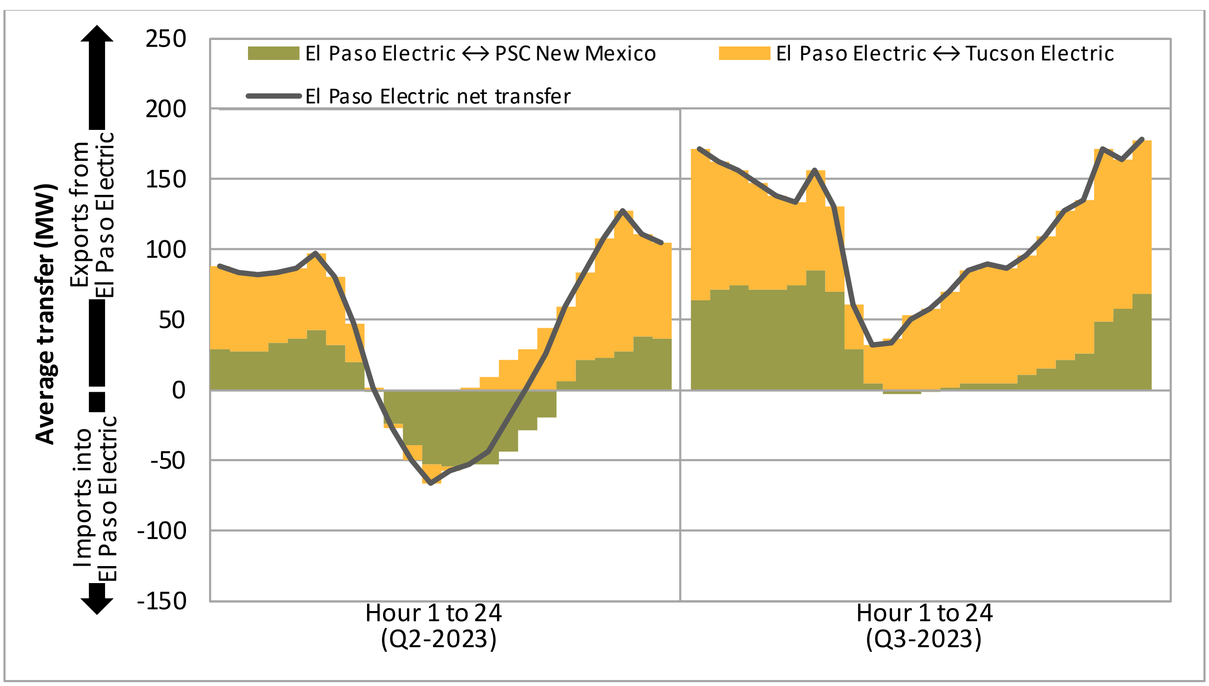


A.7 El Paso Electric

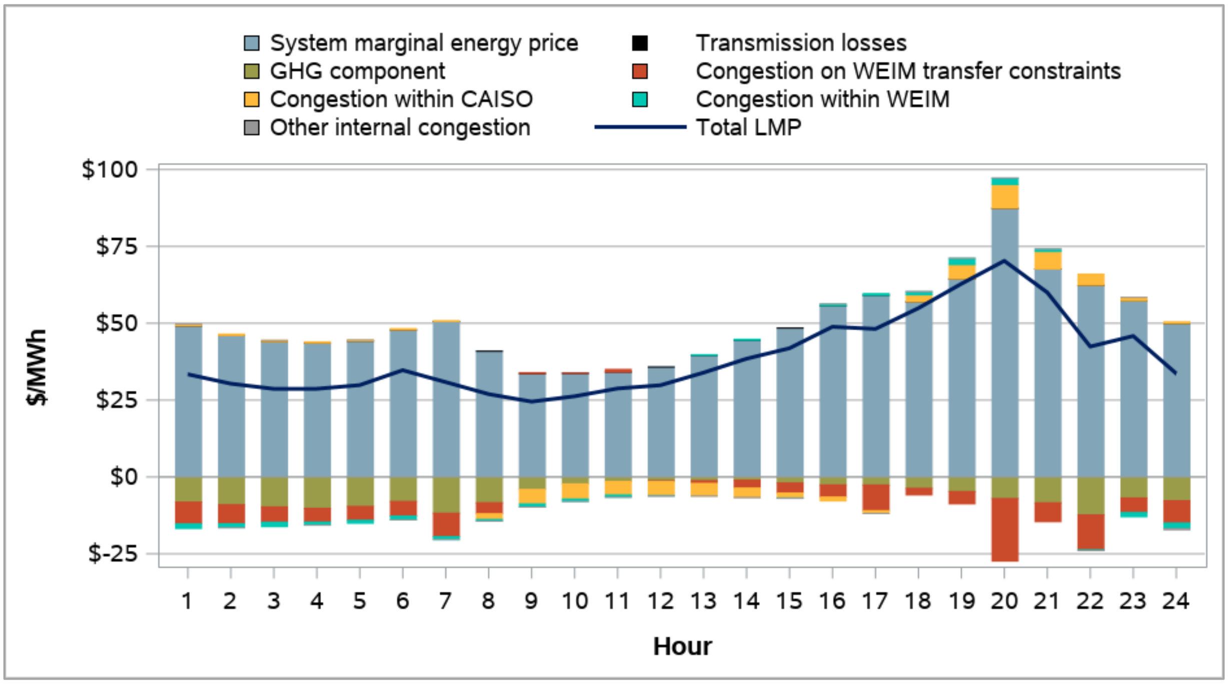
Appendix Figure A.29 Average hourly 15-minute price by component (Q3 2023)



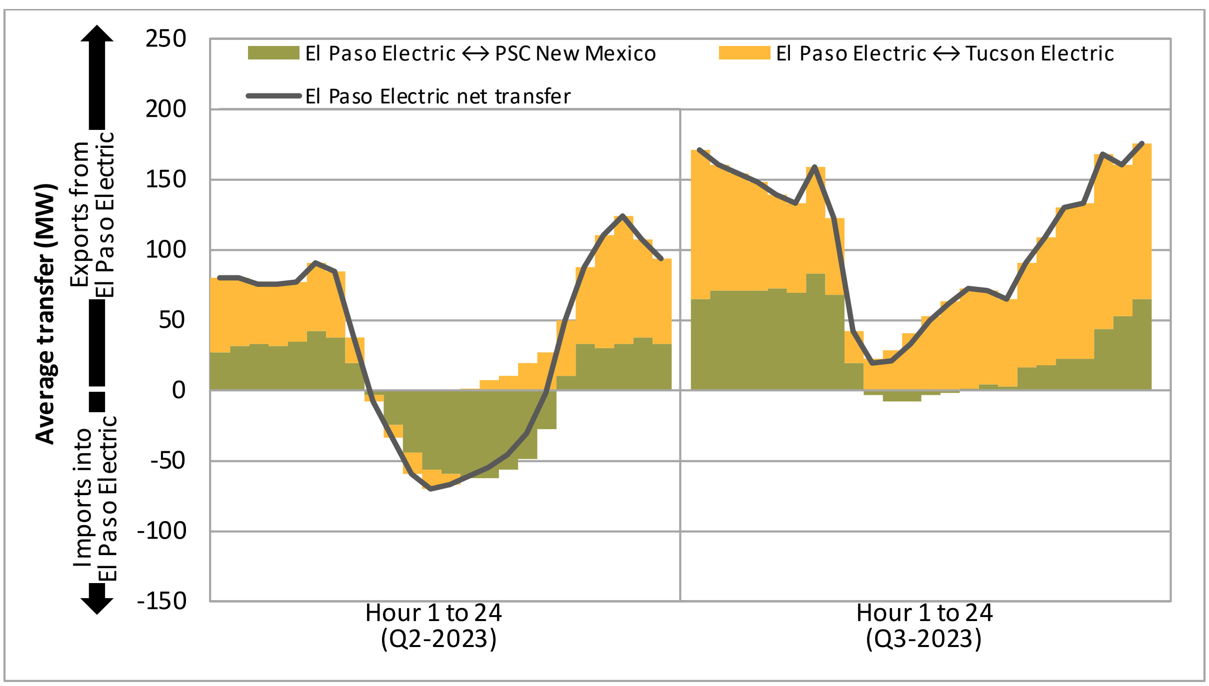
Appendix Figure A.30 Average hourly 15-minute market transfers



Appendix Figure A.31 Average hourly 5-minute price by component (Q3 2023)

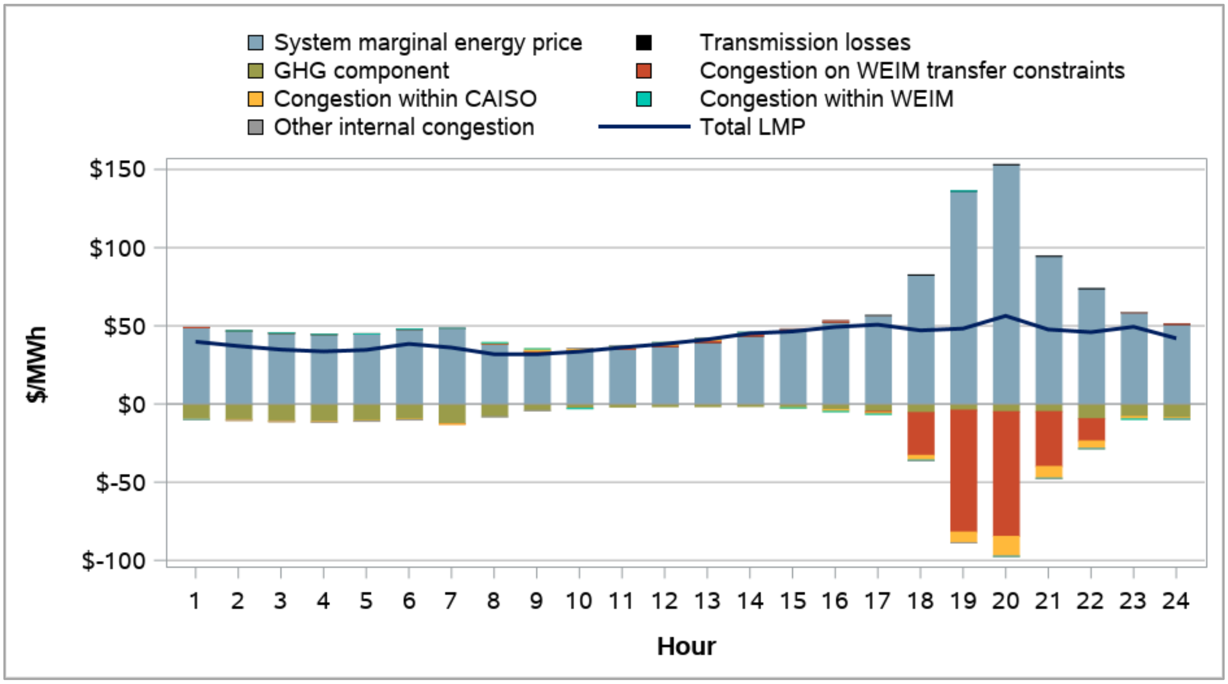


Appendix Figure A.32 Average hourly 5-minute market transfers

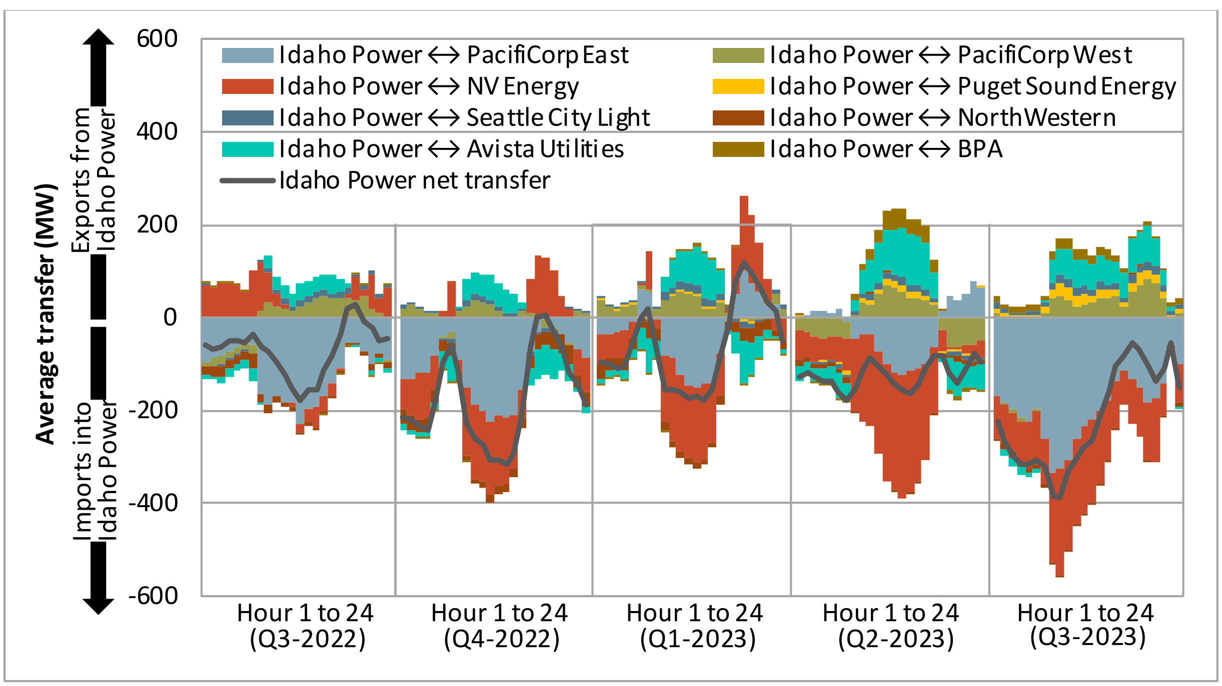


A.8 Idaho Power

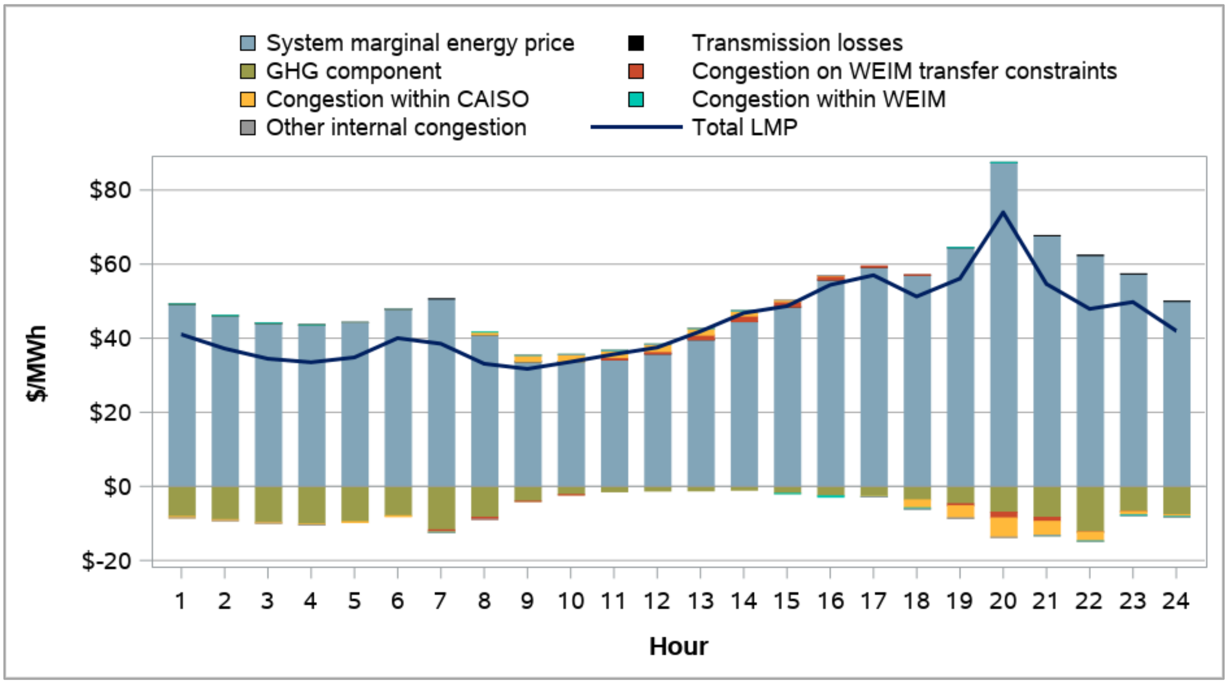
Appendix Figure A.33 Average hourly 15-minute price by component (Q3 2023)



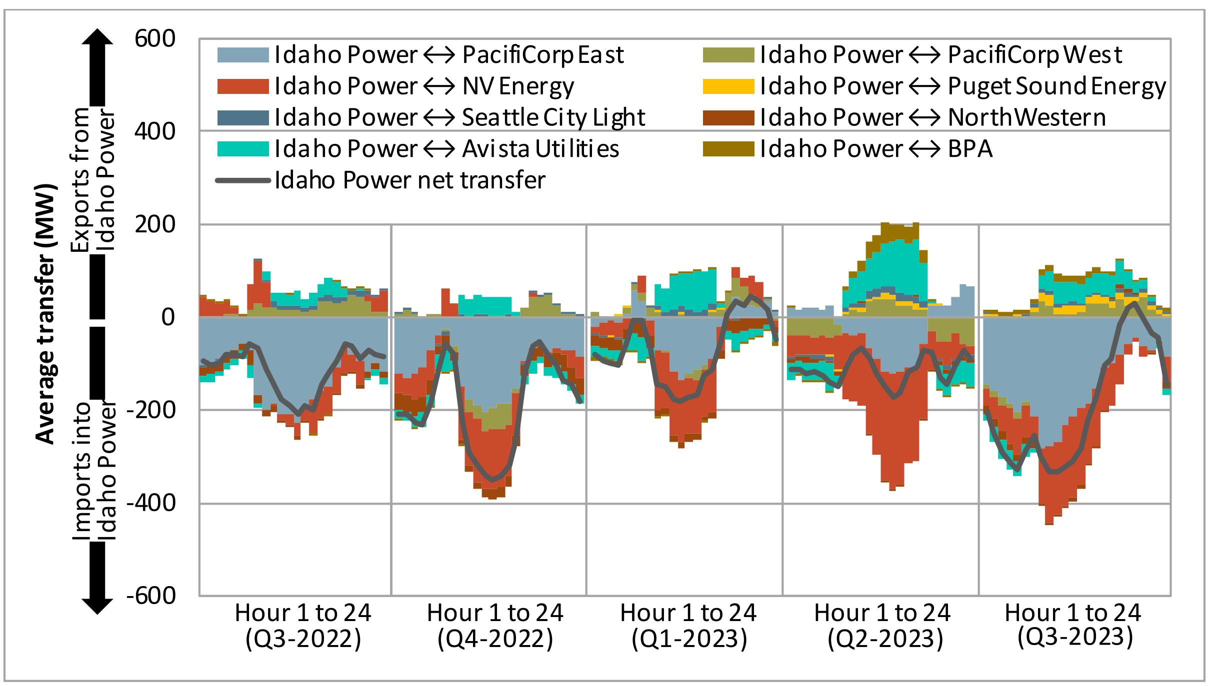
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q3 2023)

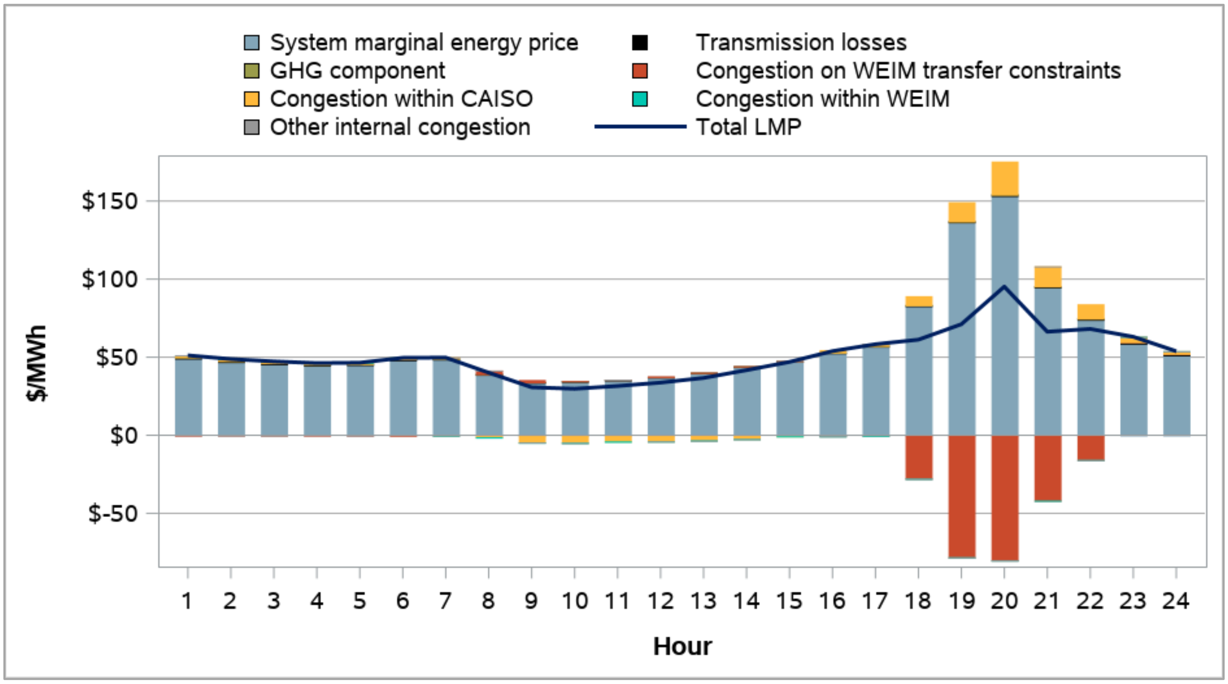


Appendix Figure A.36 Average hourly 5-minute market transfers

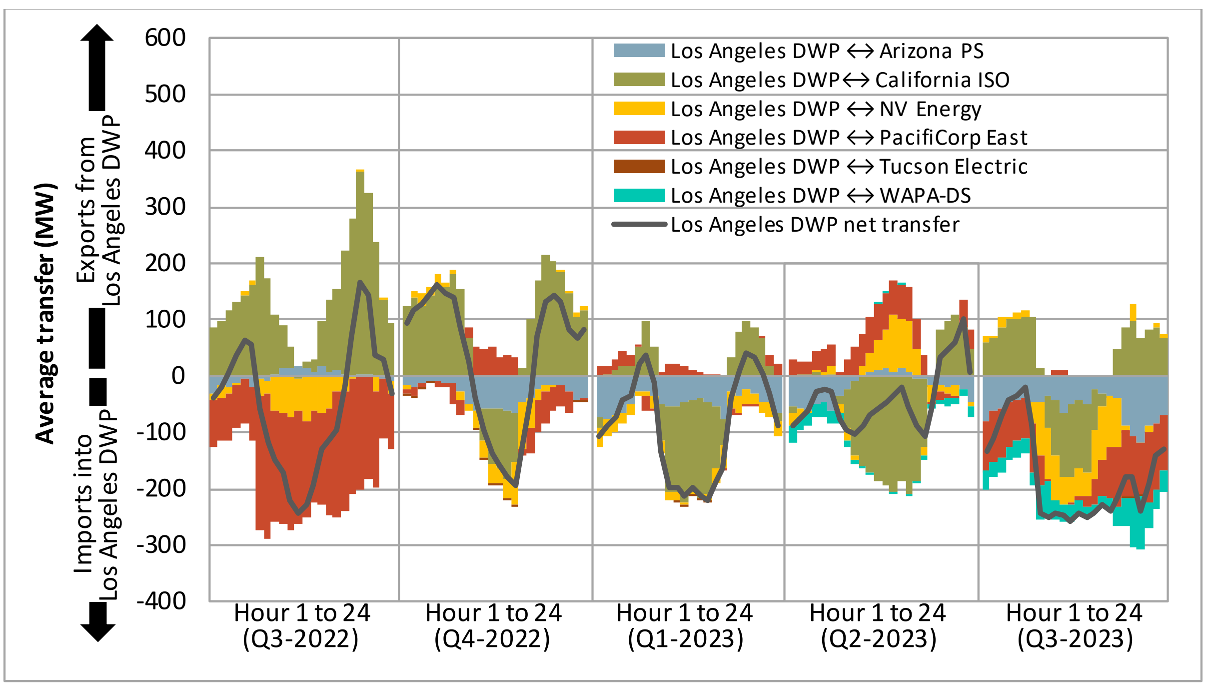


A.9 Los Angeles Department of Water and Power

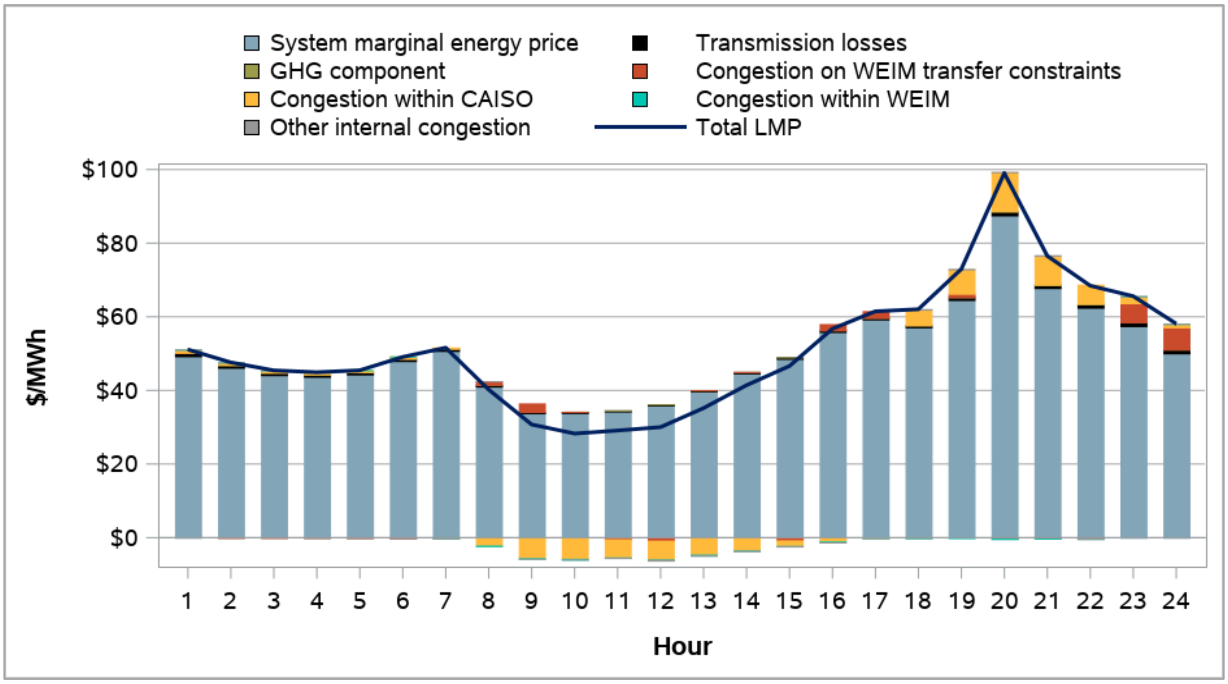
Appendix Figure A.37 Average hourly 15-minute price by component (Q3 2023)



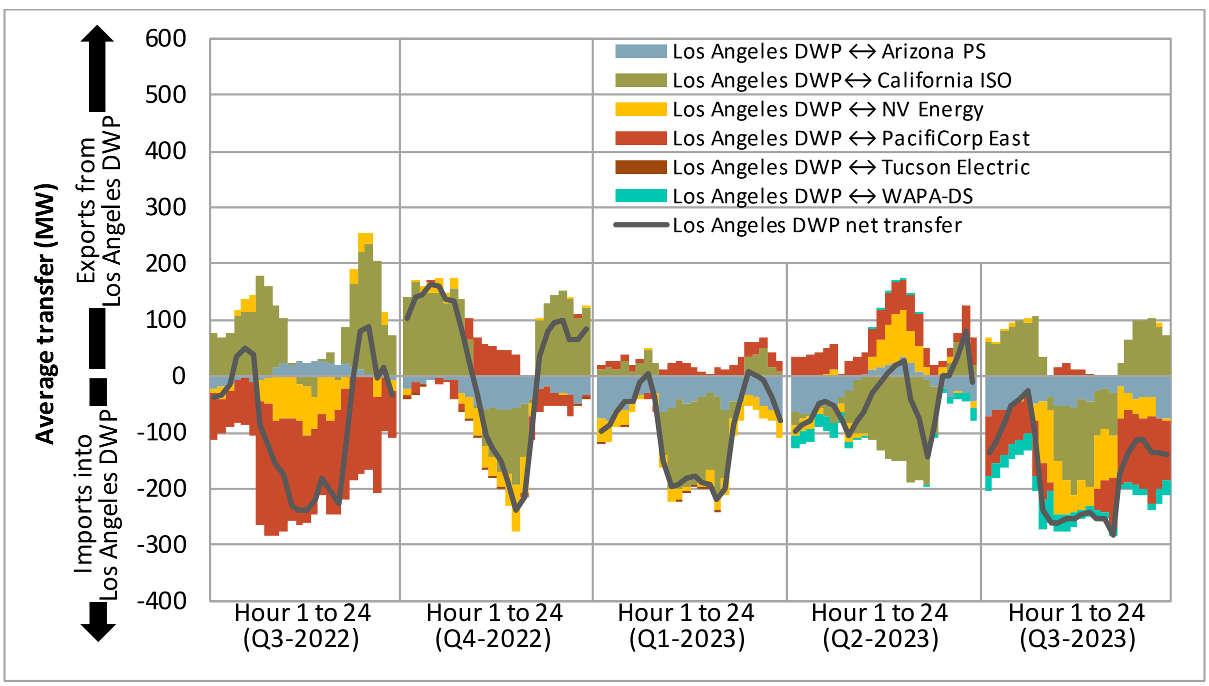
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q3 2023)

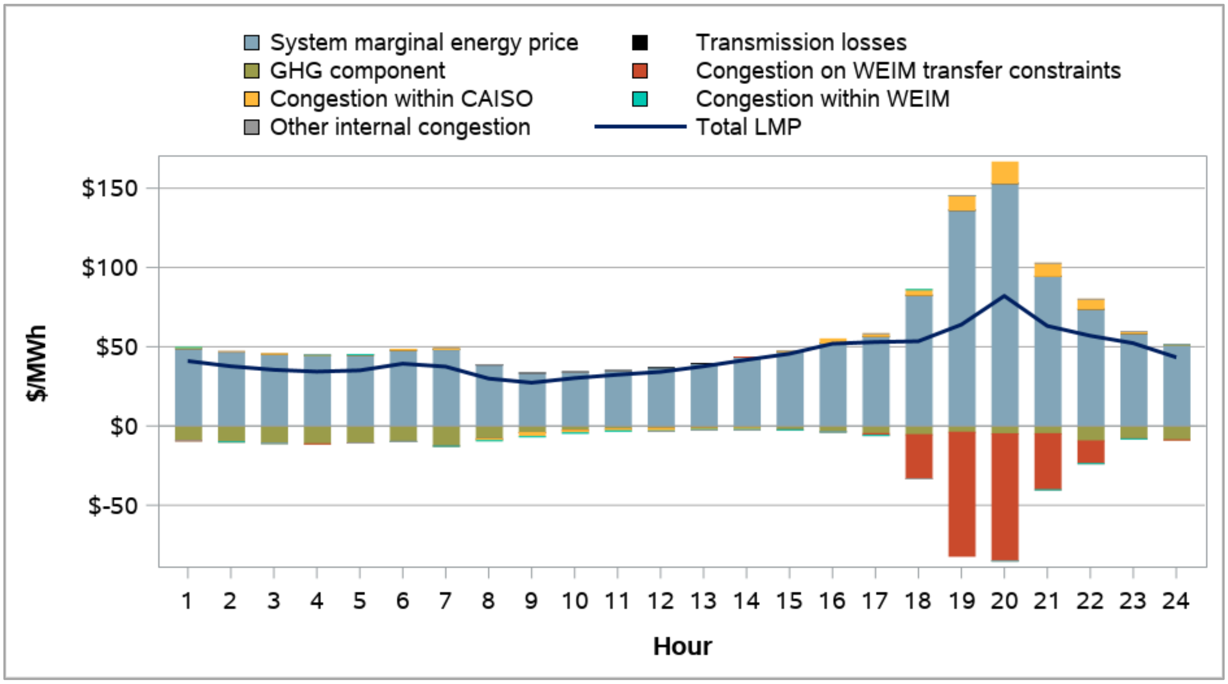


Appendix Figure A.40 Average hourly 5-minute market transfers

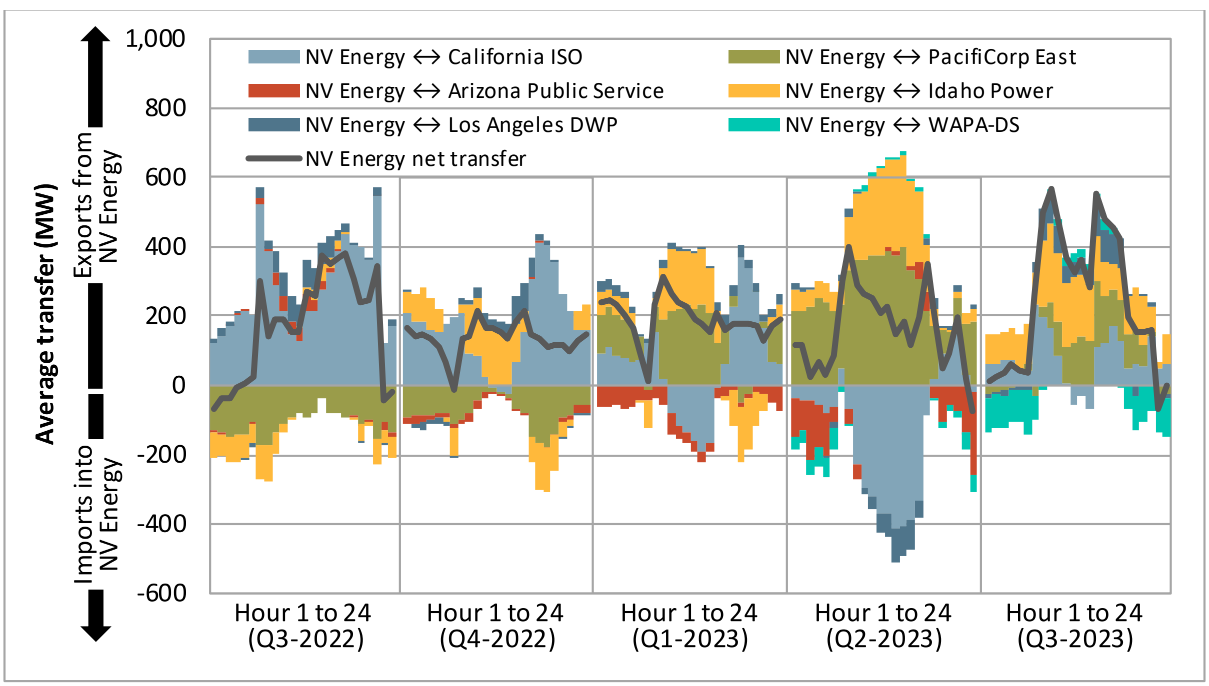


A.10 NV Energy

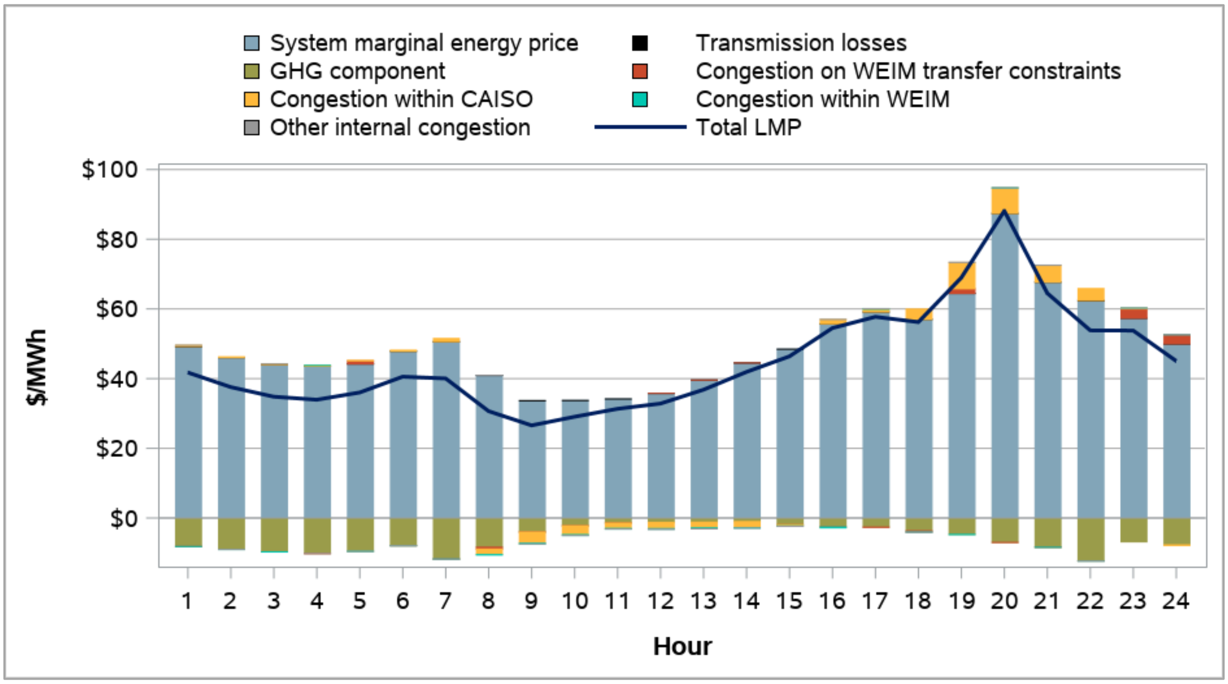
Appendix Figure A.41 Average hourly 15-minute price by component (Q3 2023)



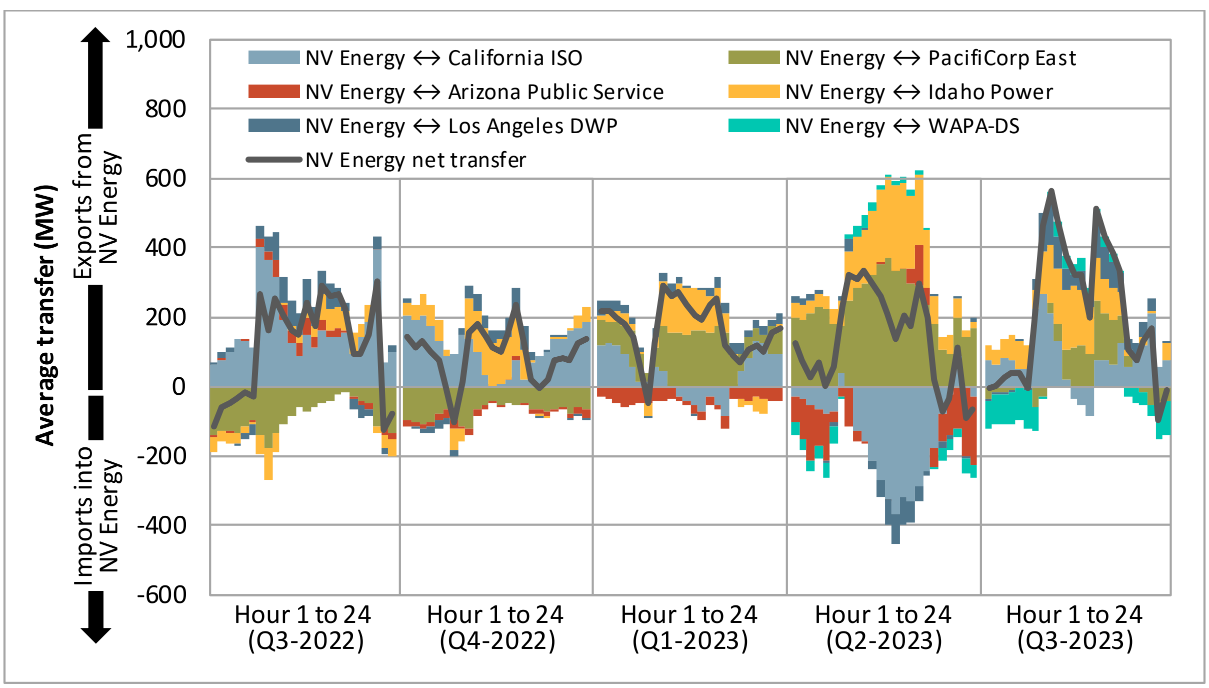
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q3 2023)

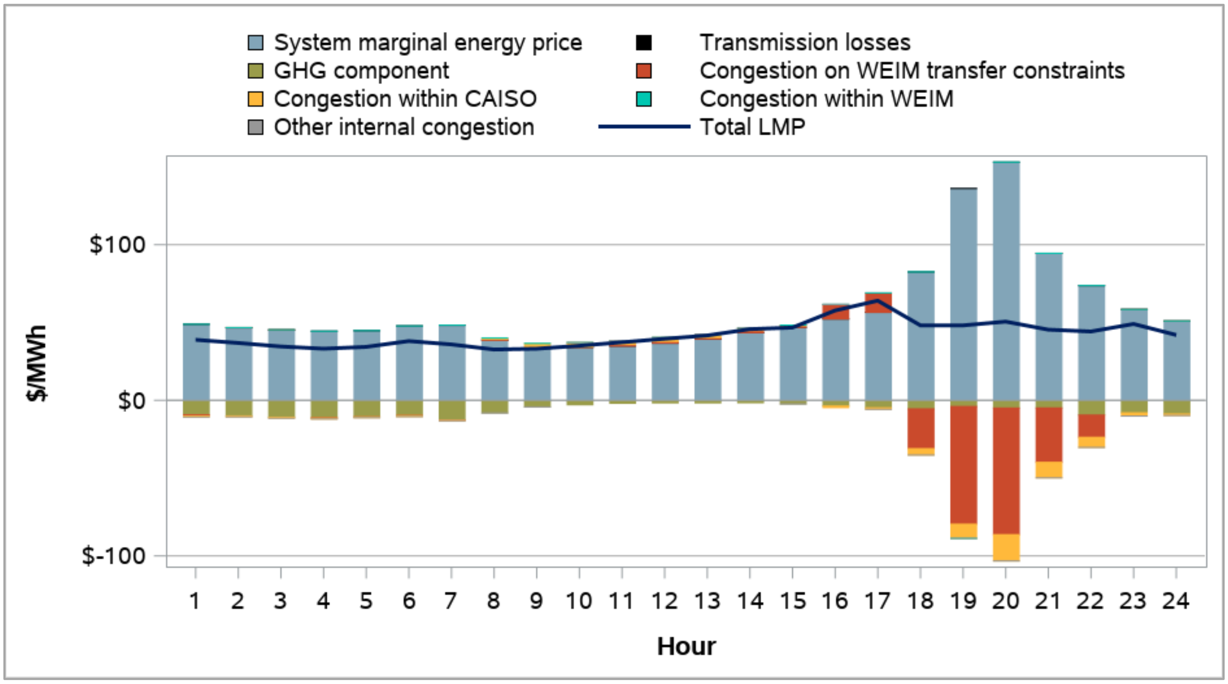


Appendix Figure A.44 Average hourly 5-minute market transfers

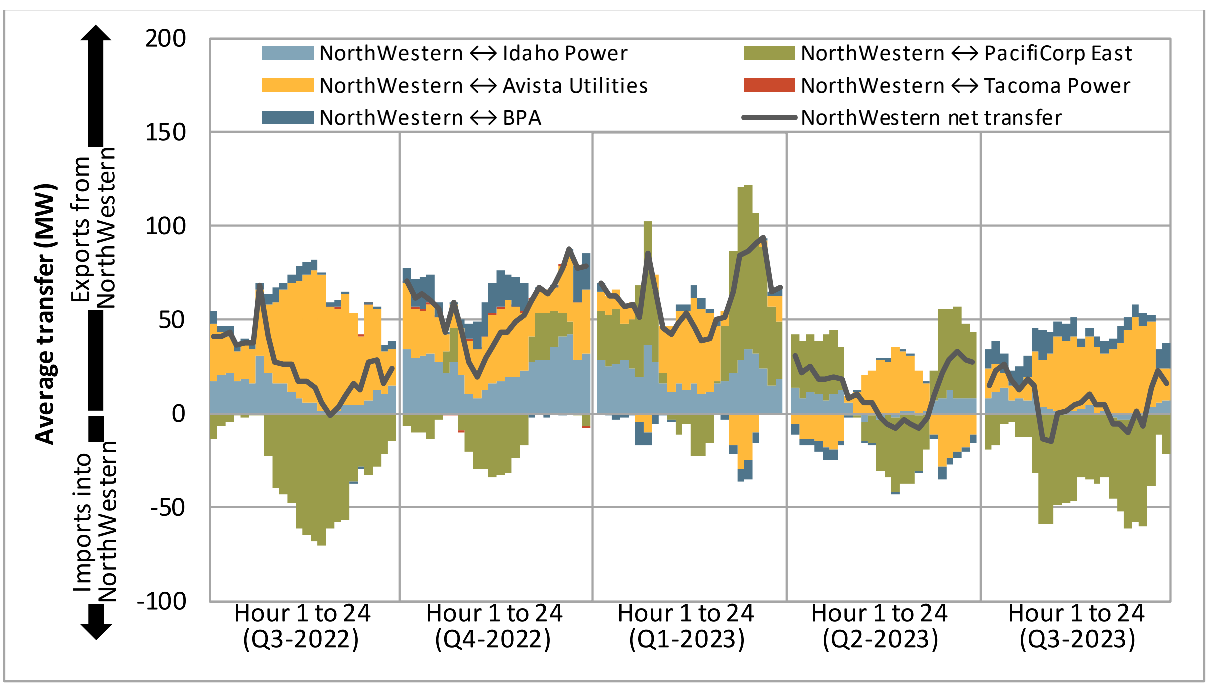


A.11 NorthWestern Energy

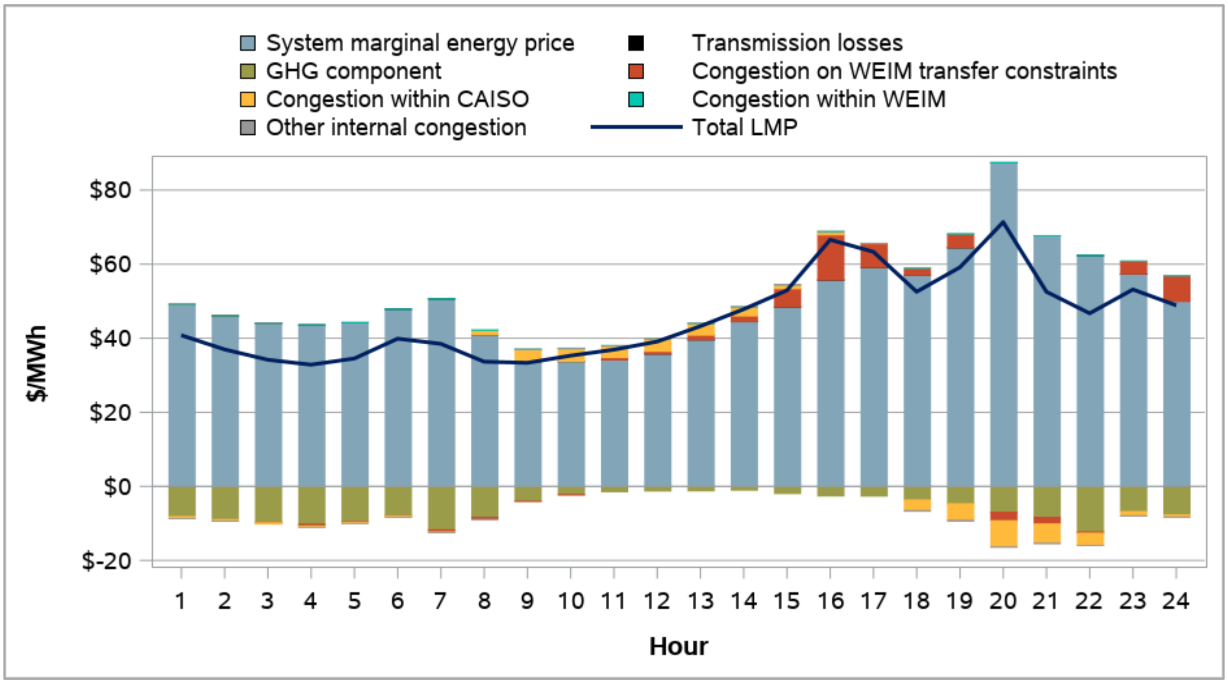
Appendix Figure A.45 Average hourly 15-minute price by component (Q3 2023)



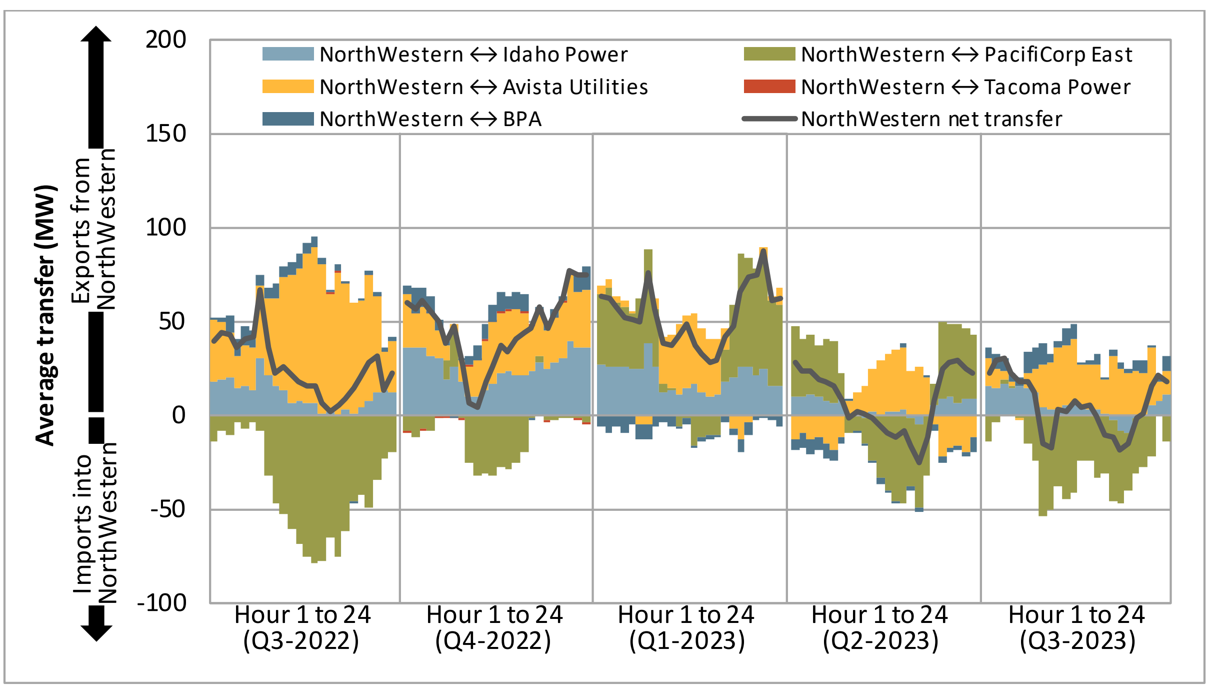
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q3 2023)

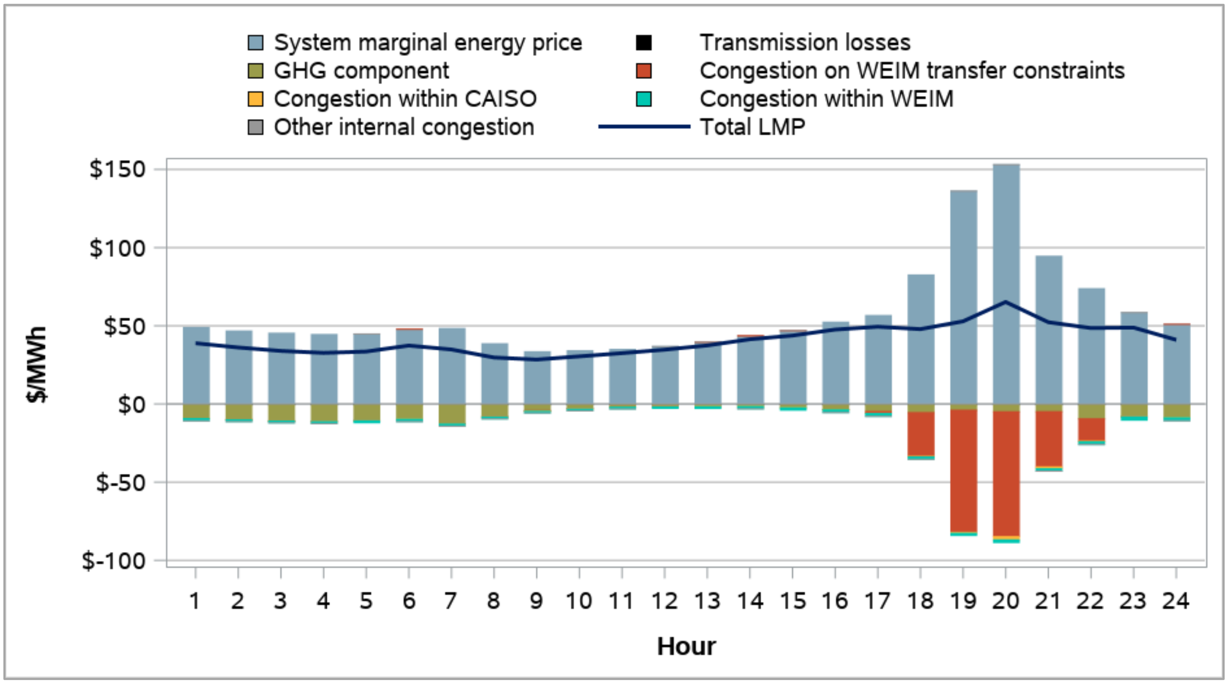


Appendix Figure A.48 Average hourly 5-minute market transfers

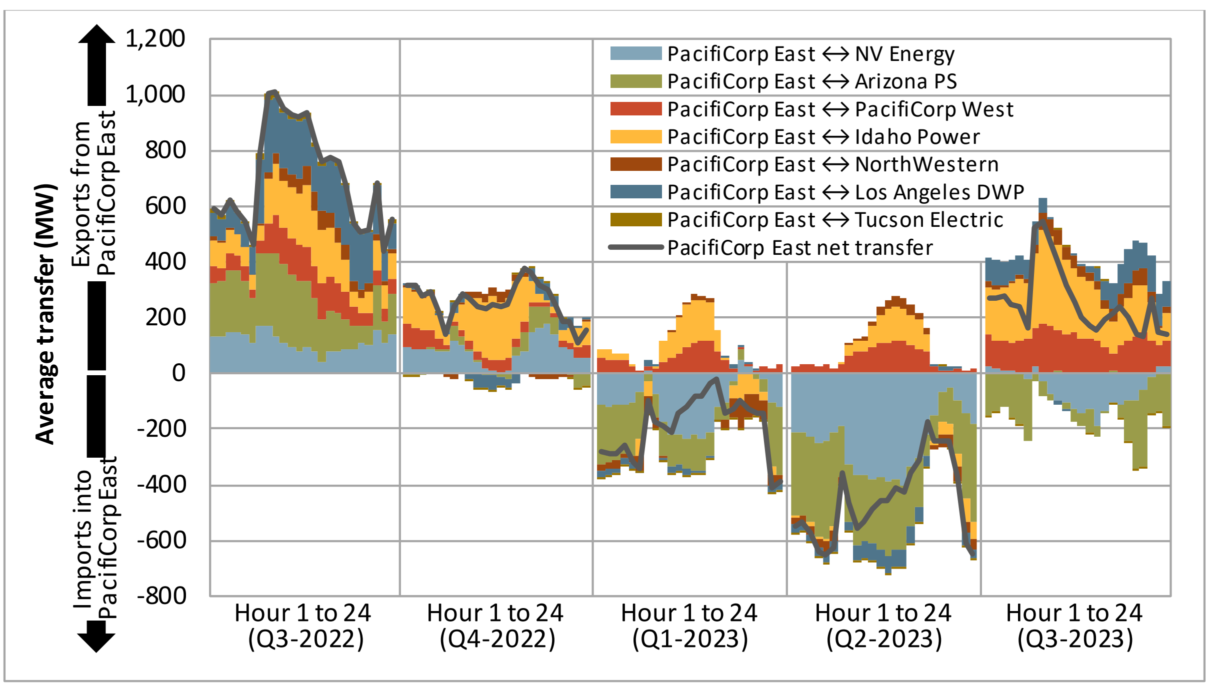


A.12 PacifiCorp East

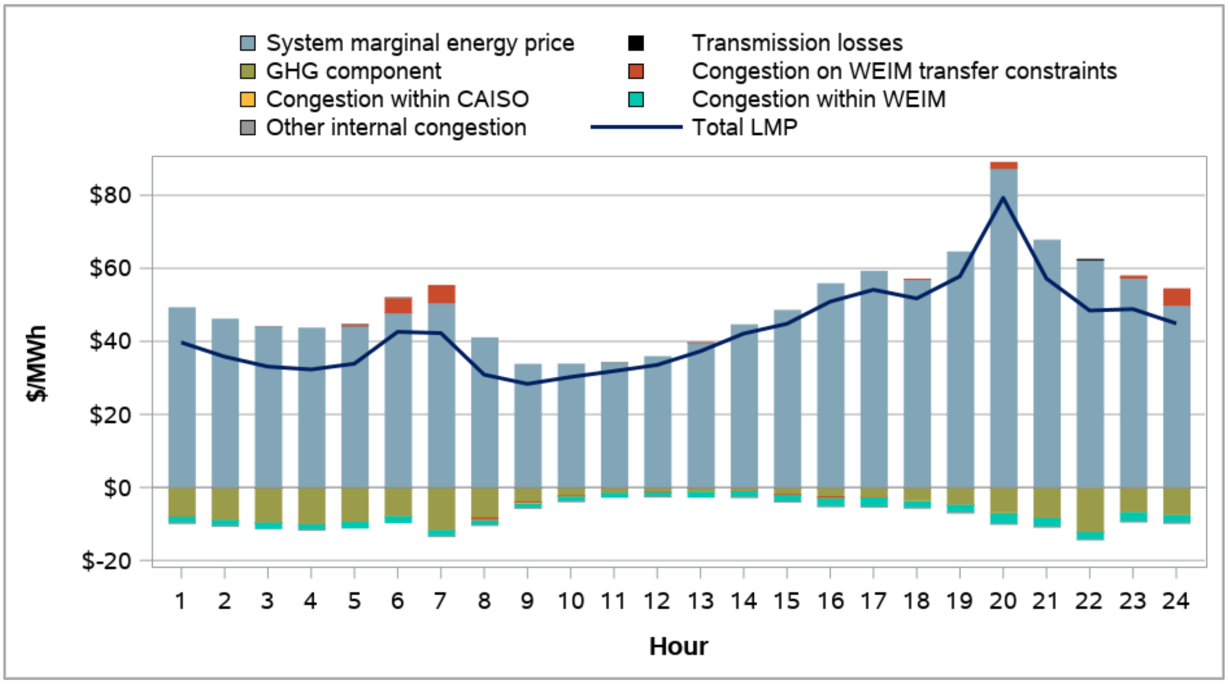
Appendix Figure A.49 Average hourly 15-minute price by component (Q3 2023)



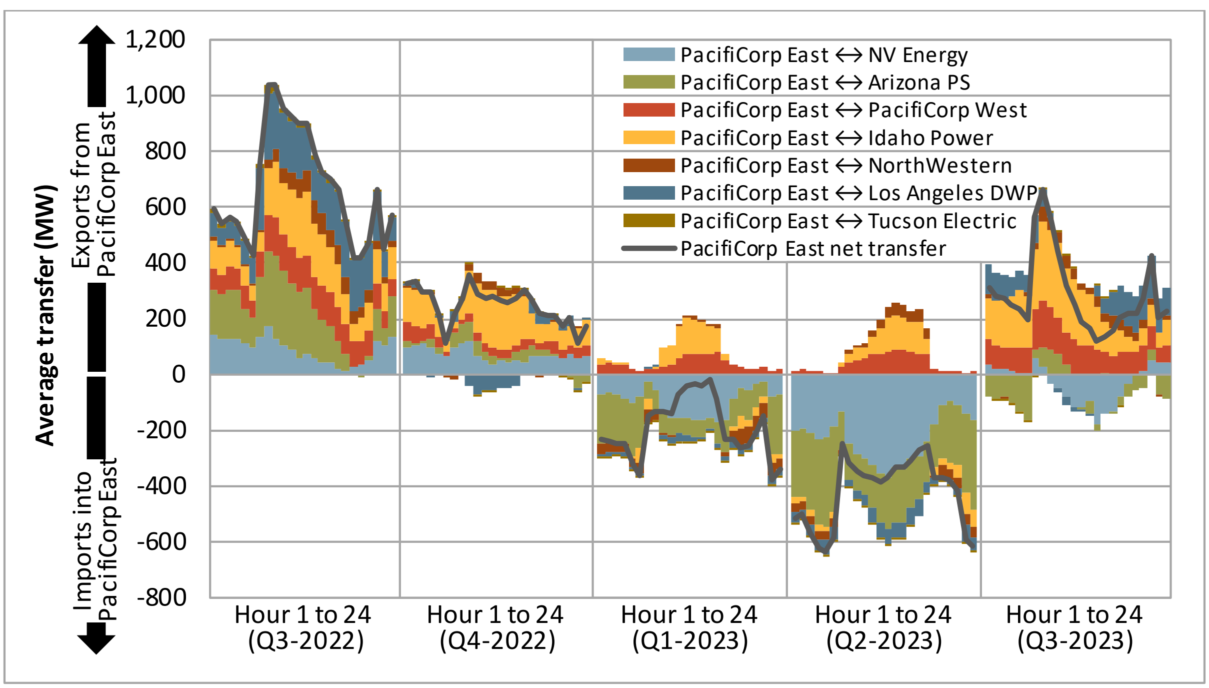
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q3 2023)

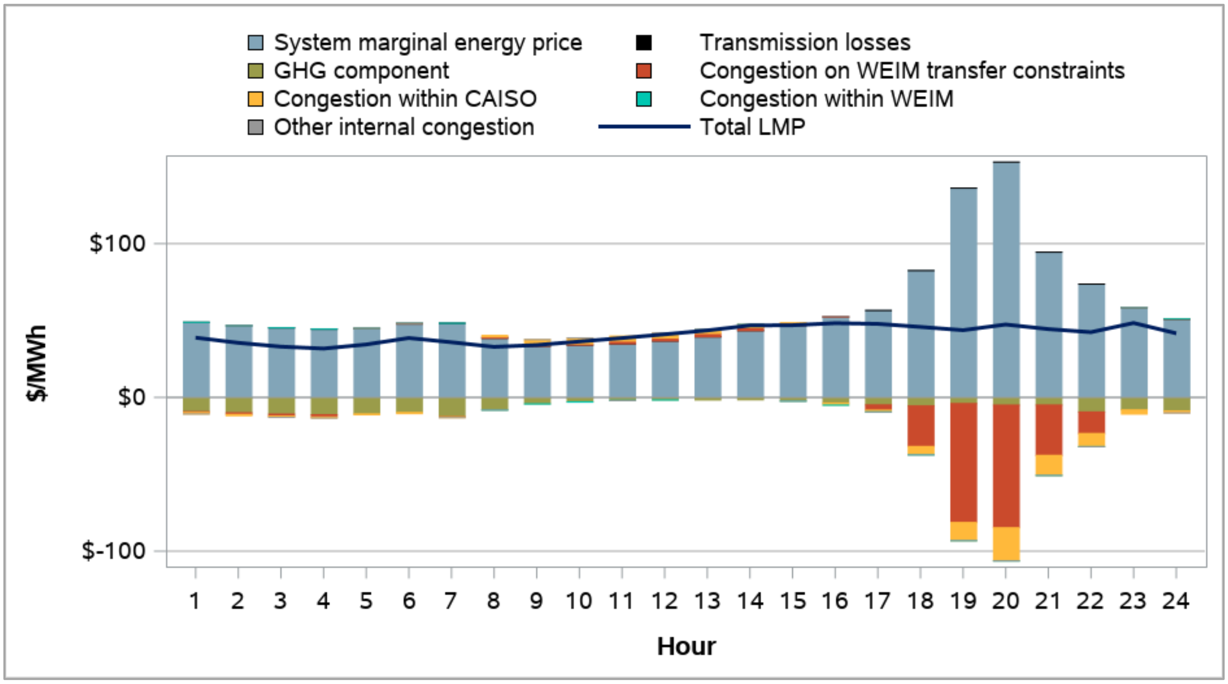


Appendix Figure A.52 Average hourly 5-minute market transfers

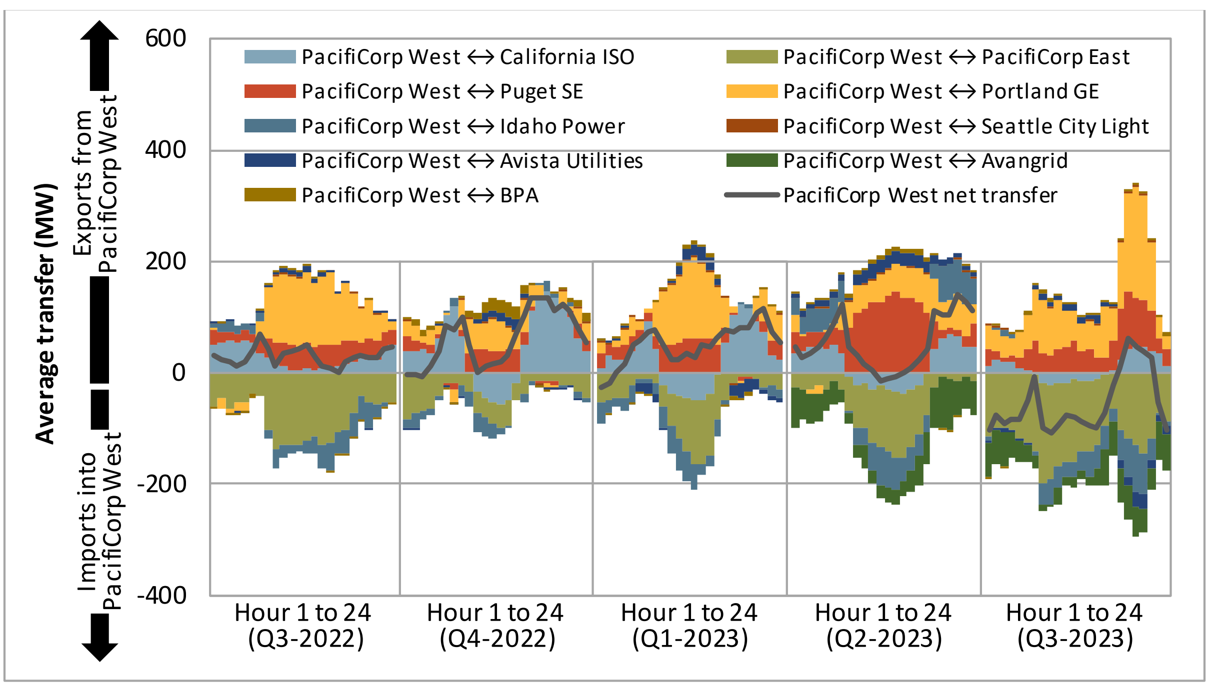


A.13 PacifiCorp West

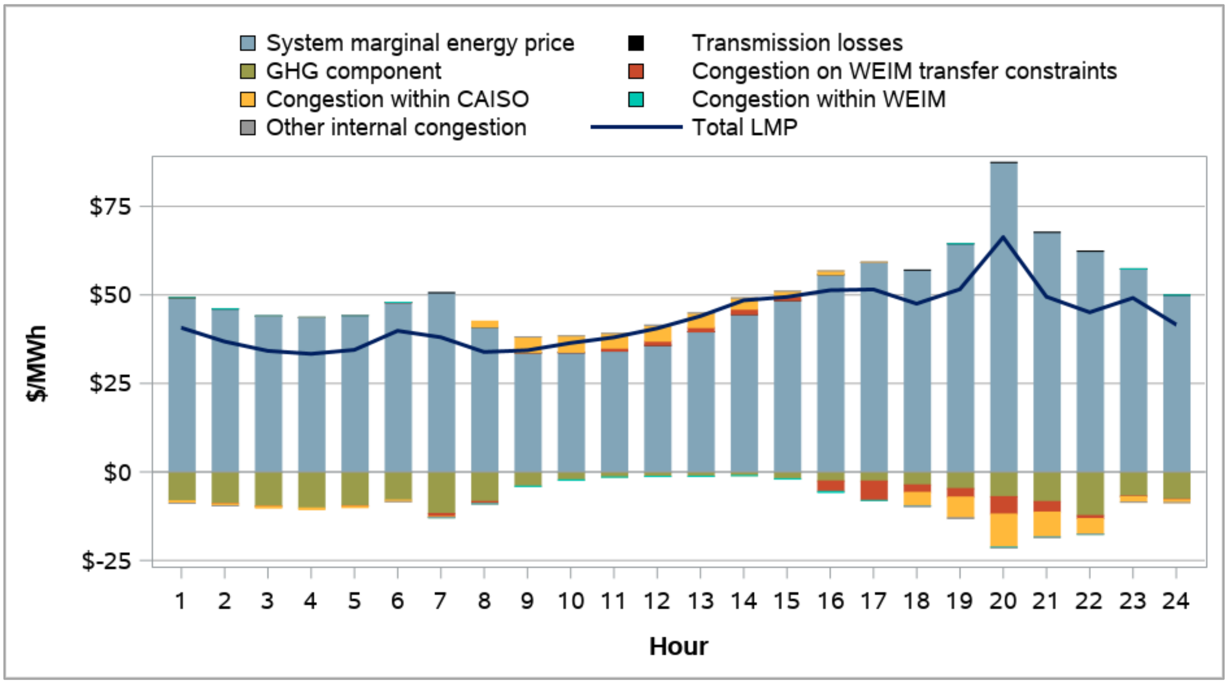
Appendix Figure A.53 Average hourly 15-minute price by component (Q3 2023)



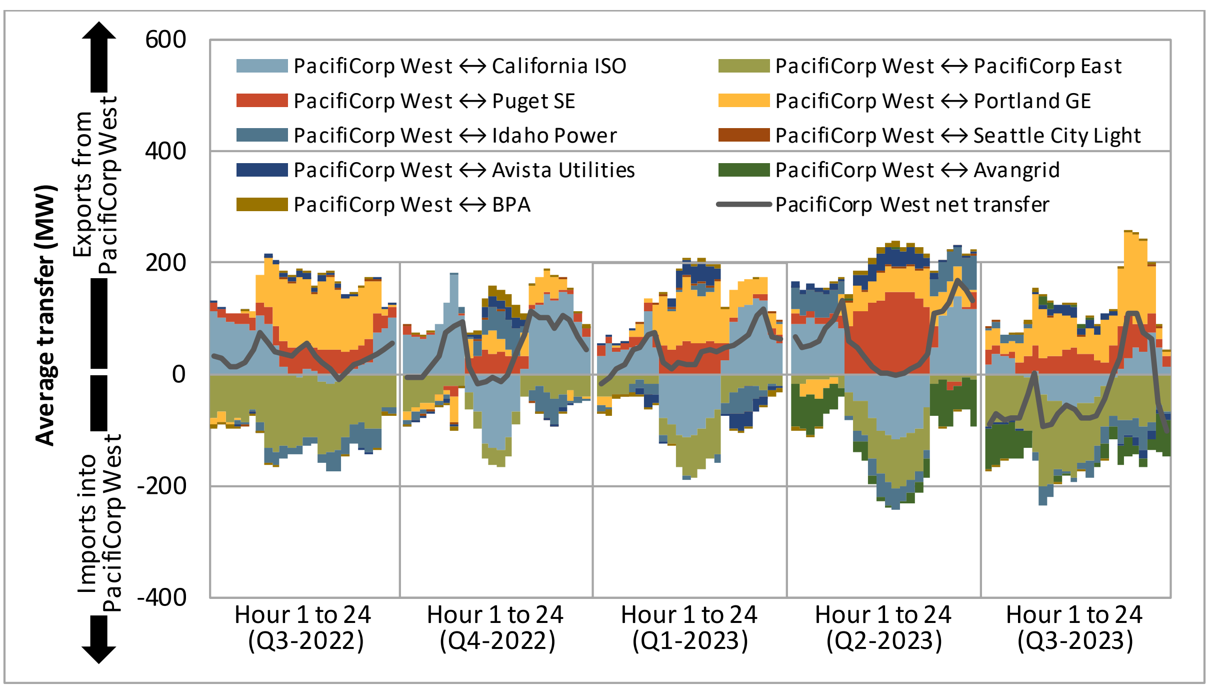
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q3 2023)

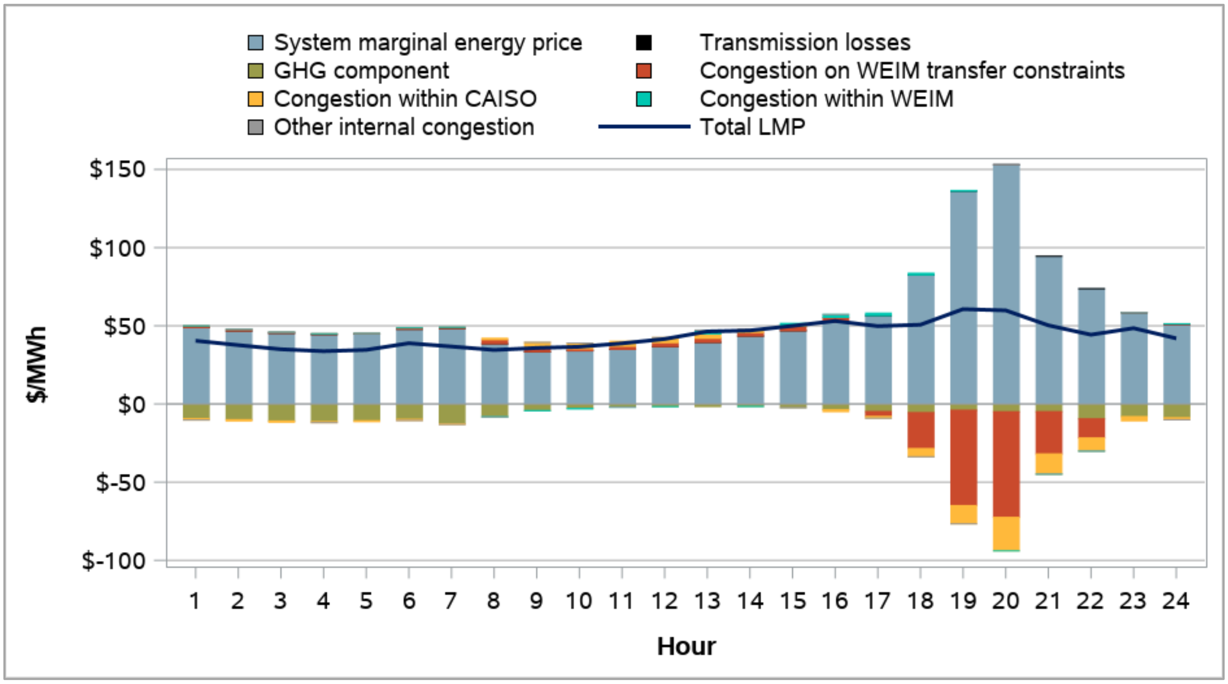


Appendix Figure A.56 Average hourly 5-minute market transfers

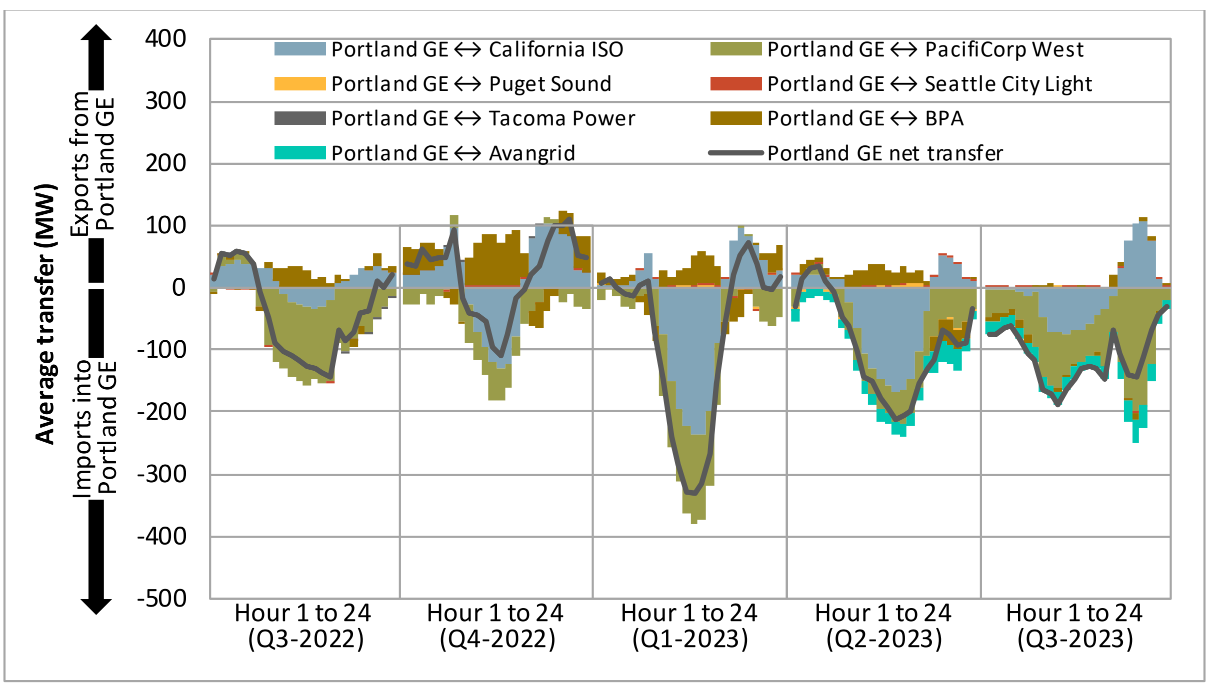


A.14 Portland General Electric

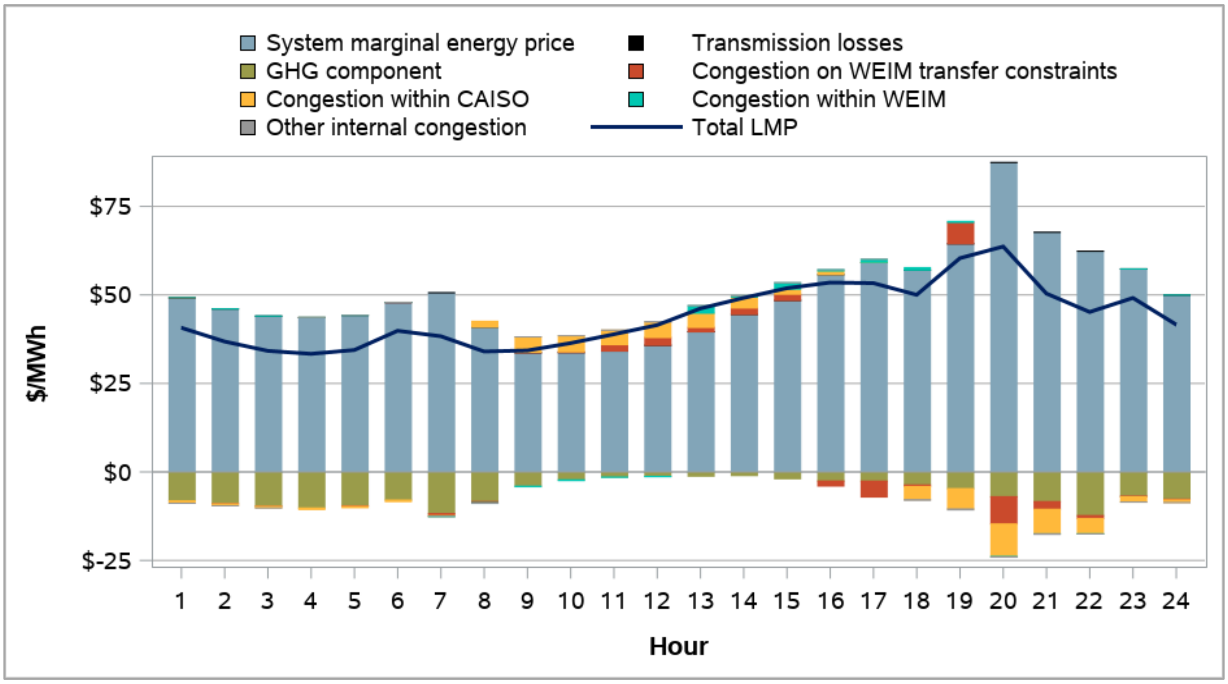
Appendix Figure A.57 Average hourly 15-minute price by component (Q3 2023)



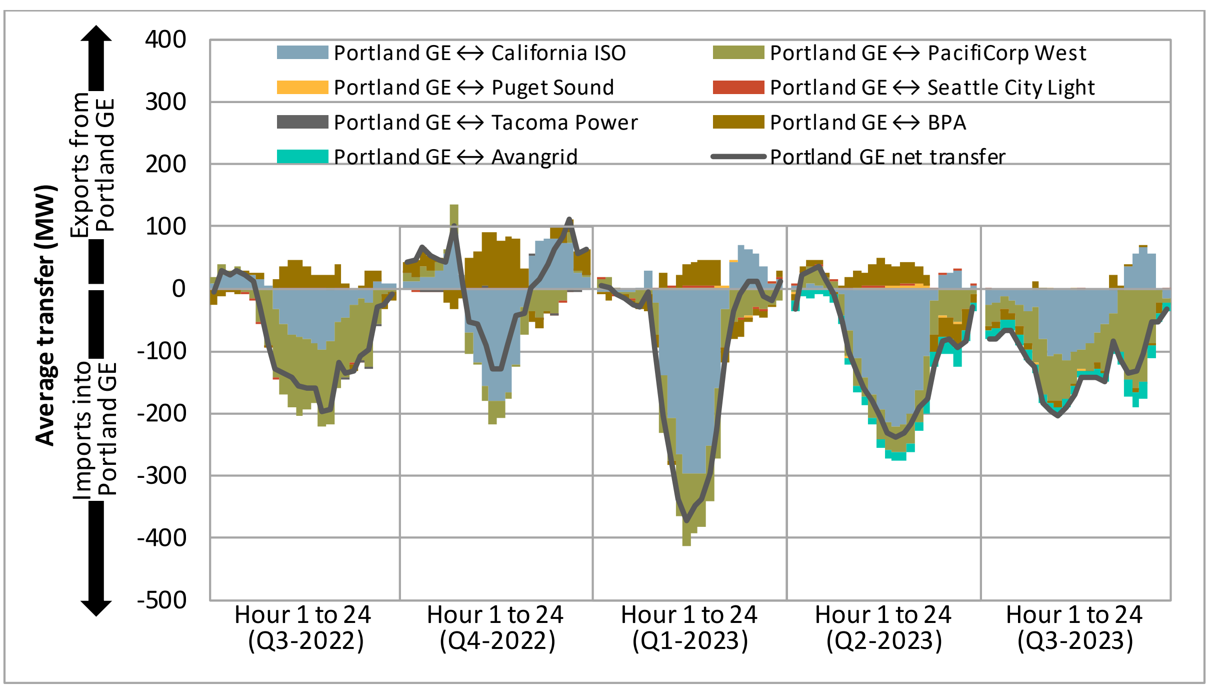
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q3 2023)

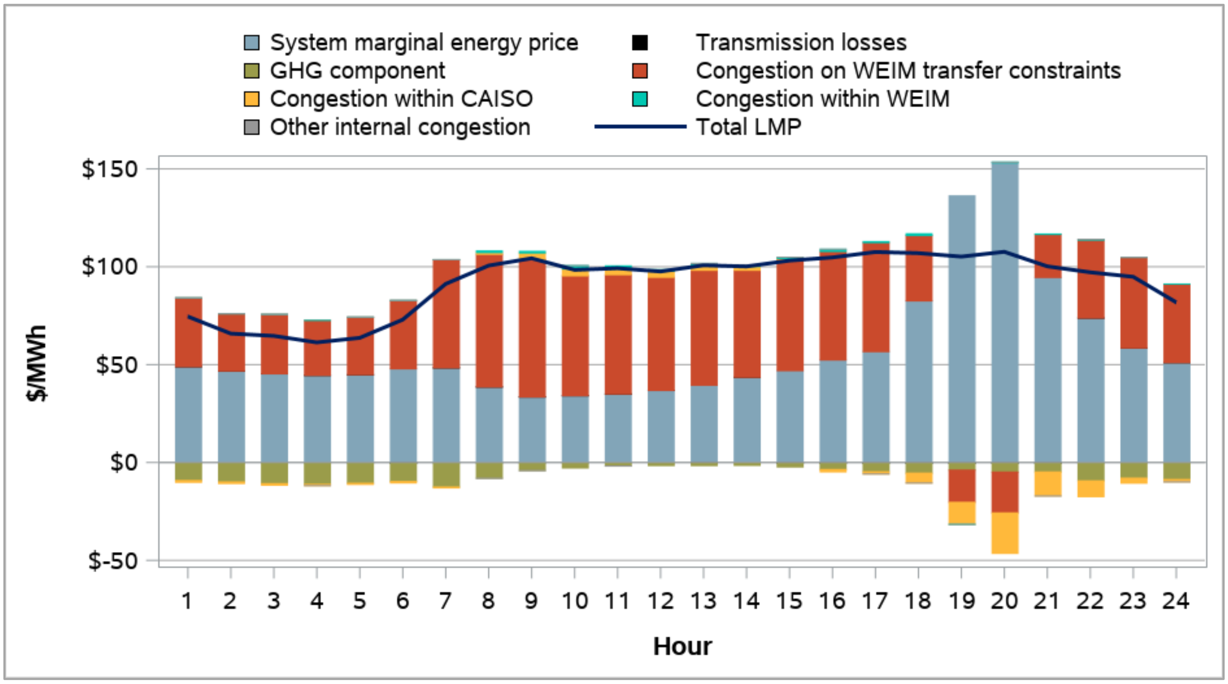


Appendix Figure A.60 Average hourly 5-minute market transfers

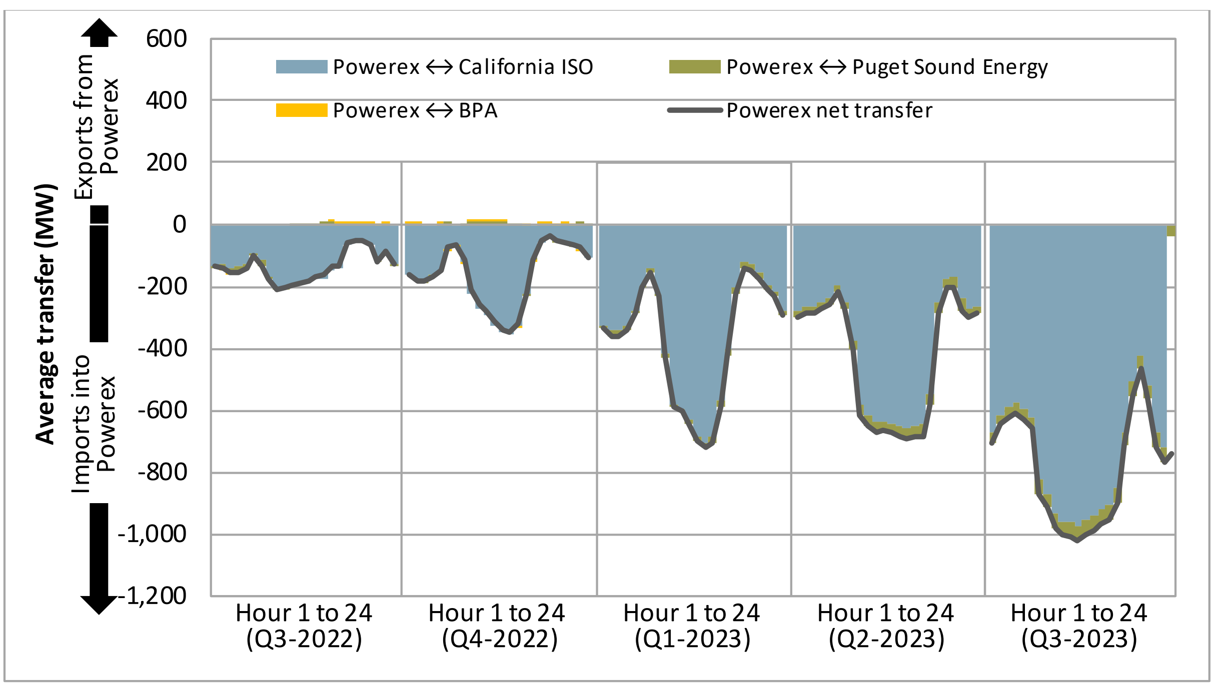


A.15 Powerex

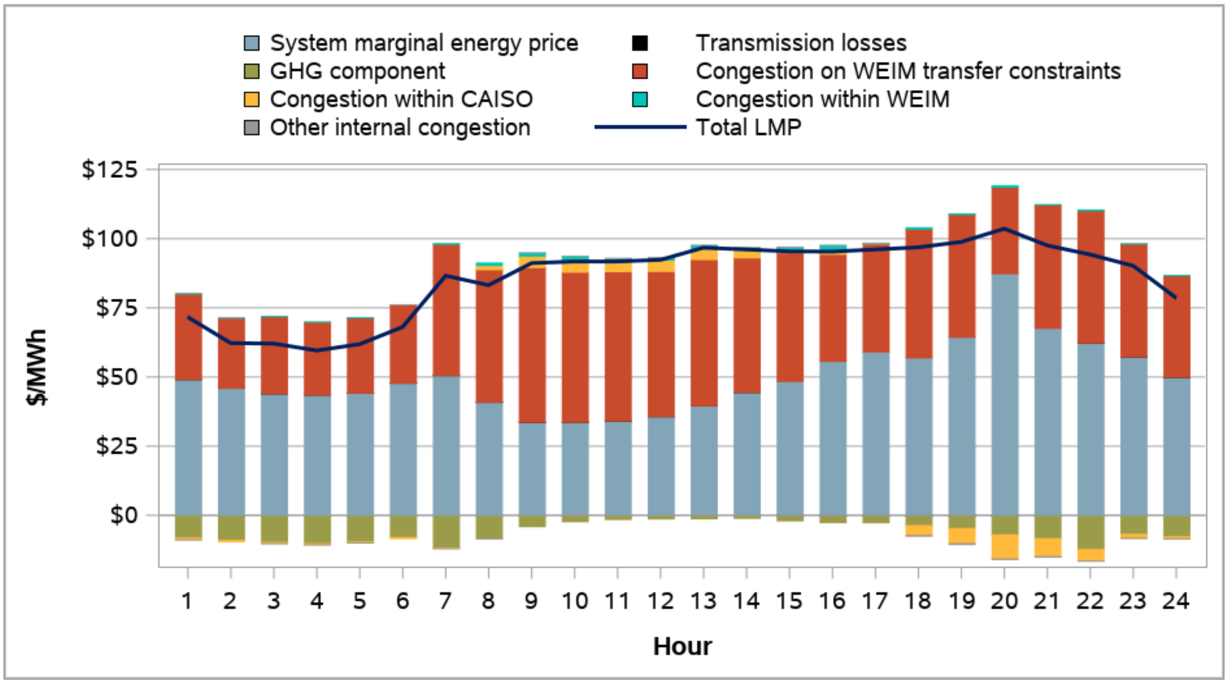
Appendix Figure A.61 Average hourly 15-minute price by component (Q3 2023)



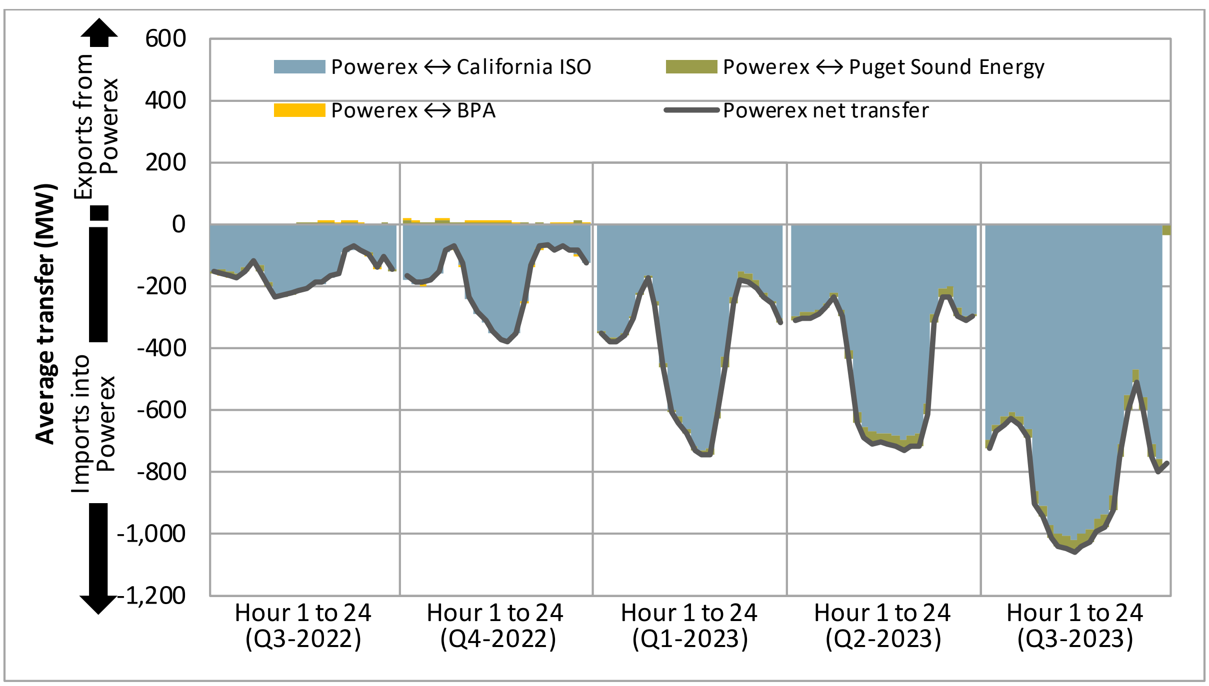
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q3 2023)

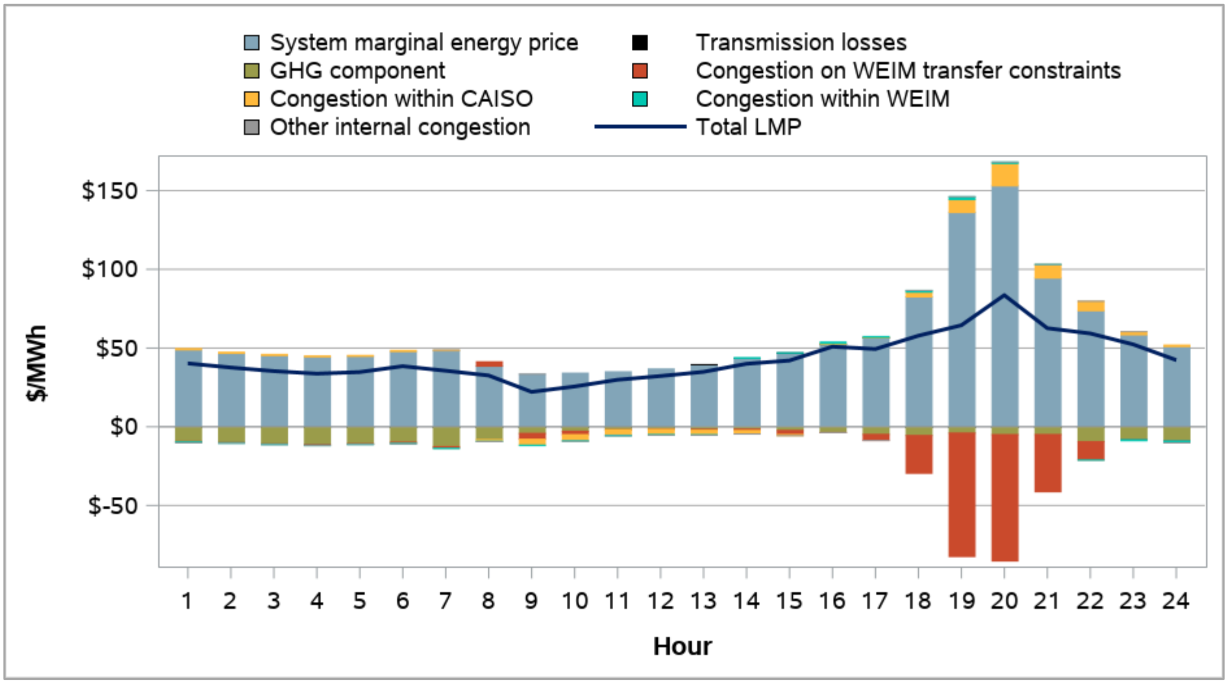


Appendix Figure A.64 Average hourly 5-minute market transfers

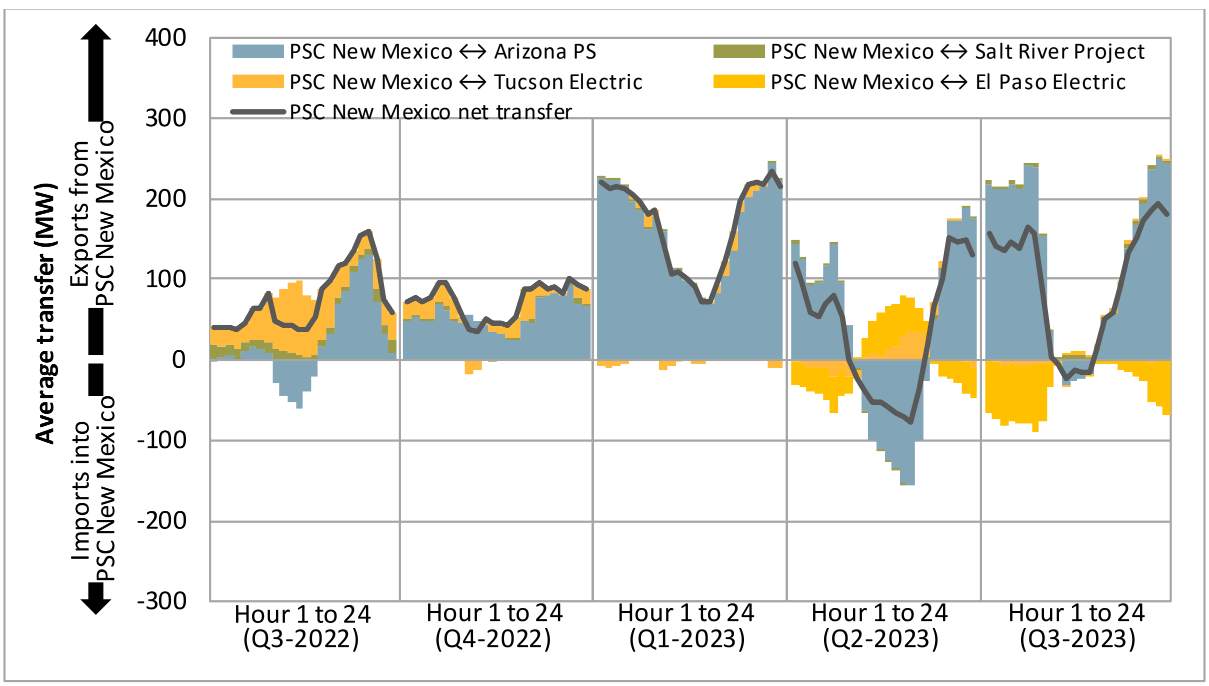


A.16 Public Service Company of New Mexico

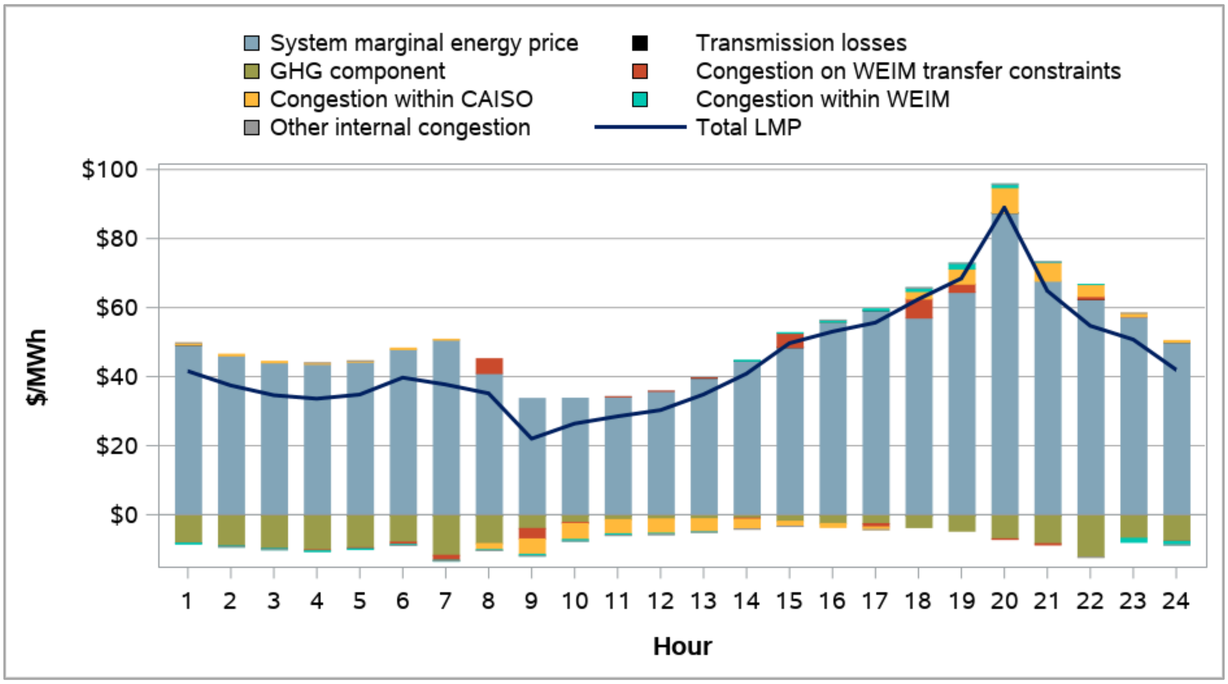
Appendix Figure A.65 Average hourly 15-minute price by component (Q3 2023)



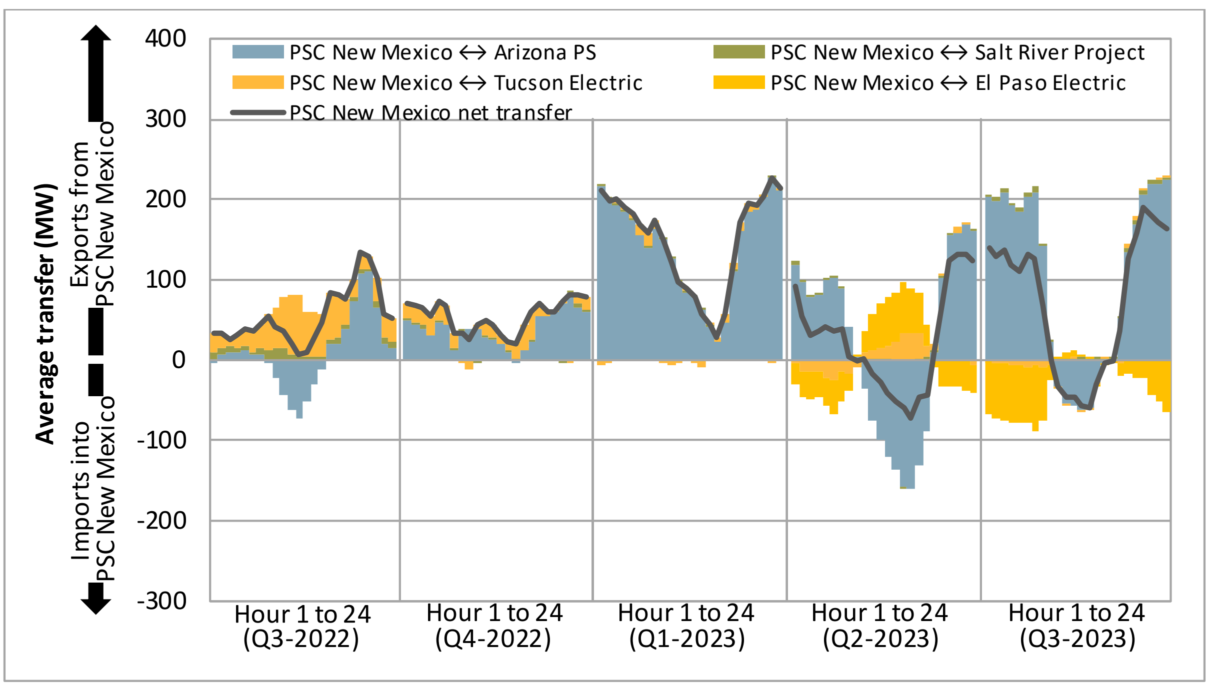
Appendix Figure A.66 Average hourly 15-minute market transfers



Appendix Figure A.67 Average hourly 5-minute price by component (Q3 2023)

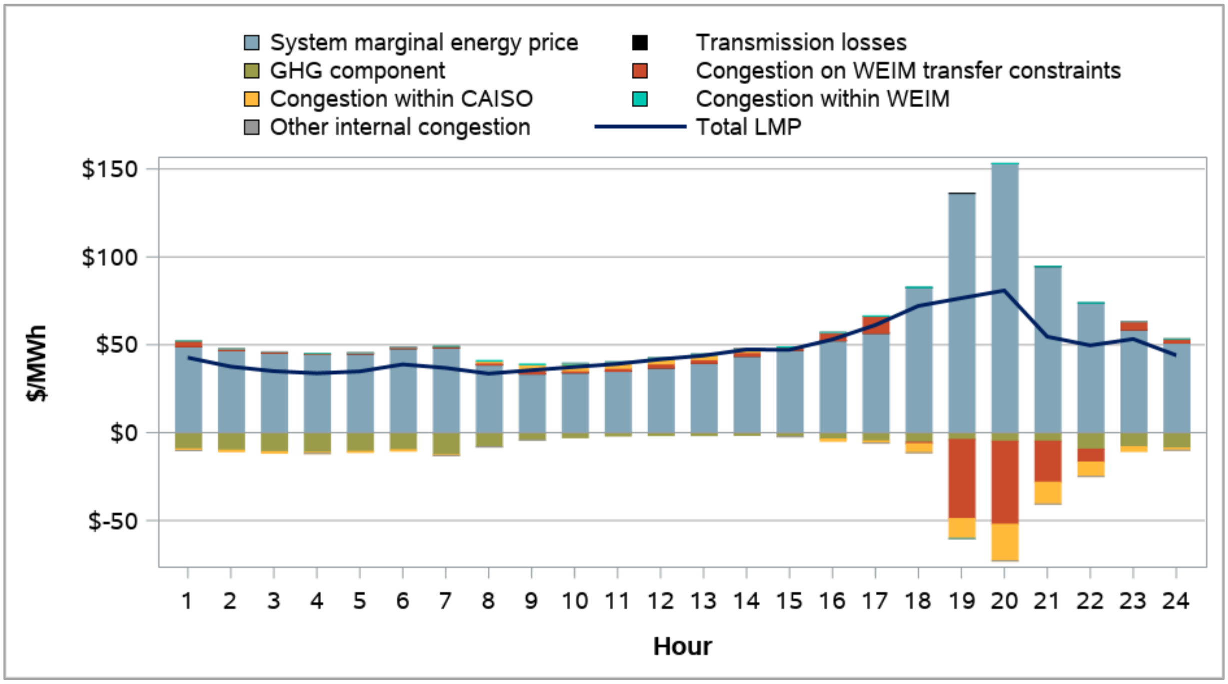


Appendix Figure A.68 Average hourly 5-minute market transfers

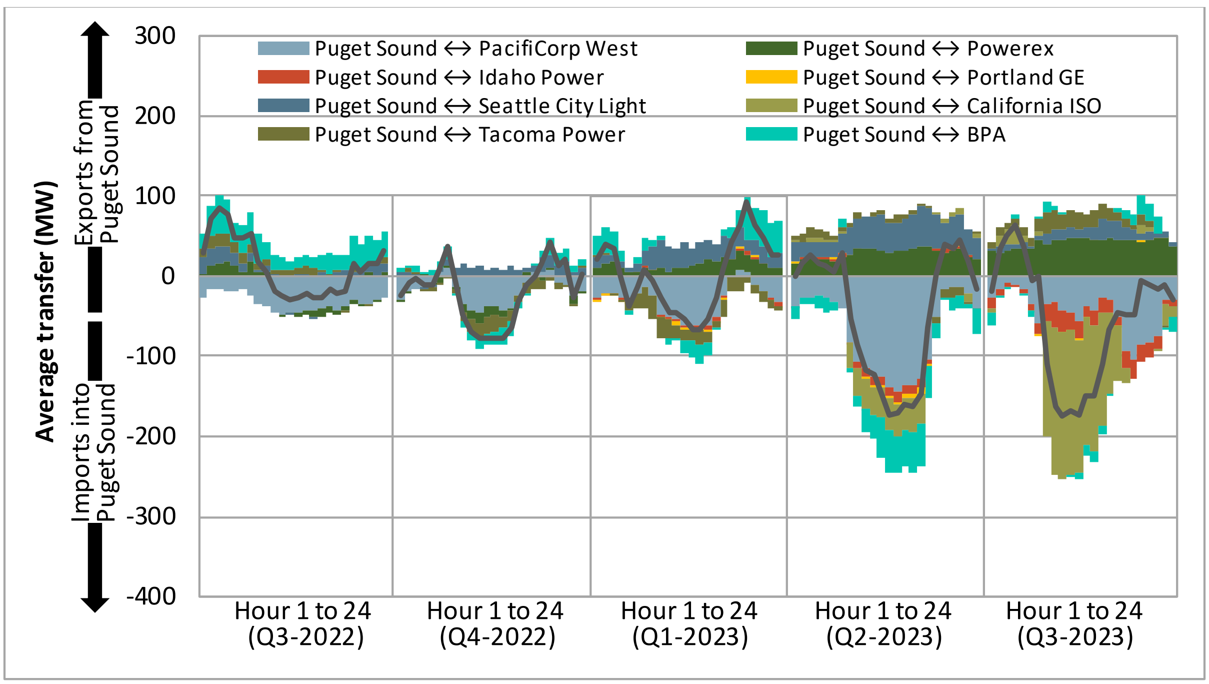


A.17 Puget Sound Energy

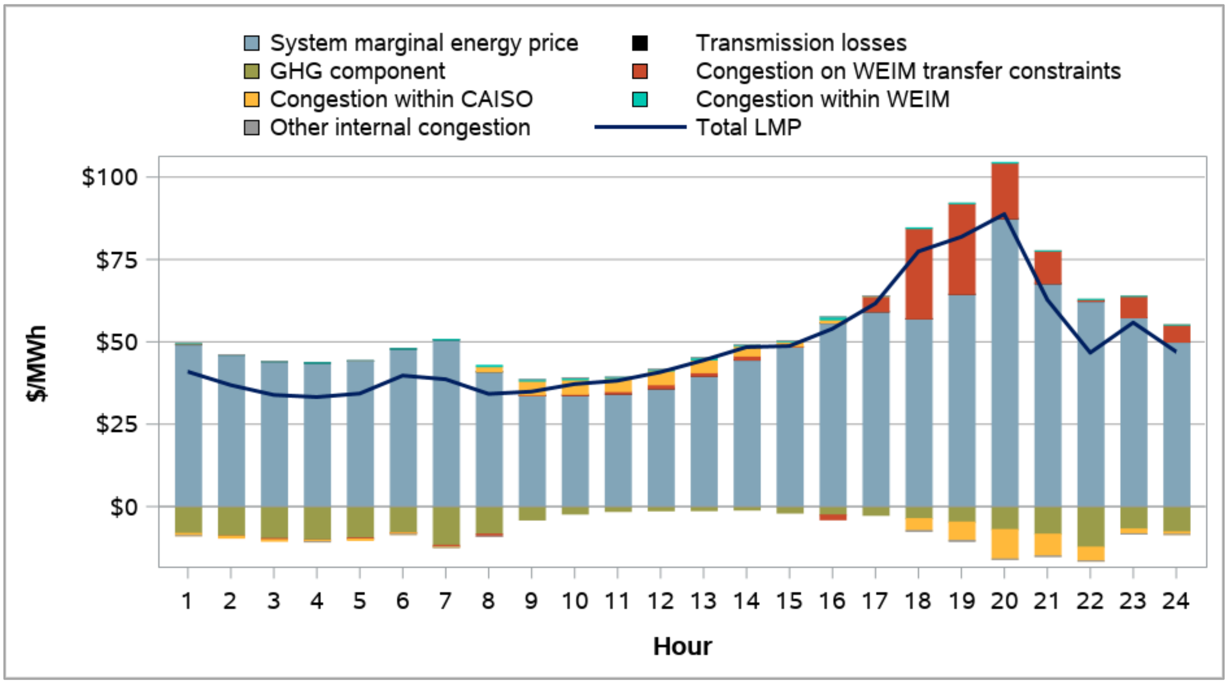
Appendix Figure A.69 Average hourly 15-minute price by component (Q3 2023)



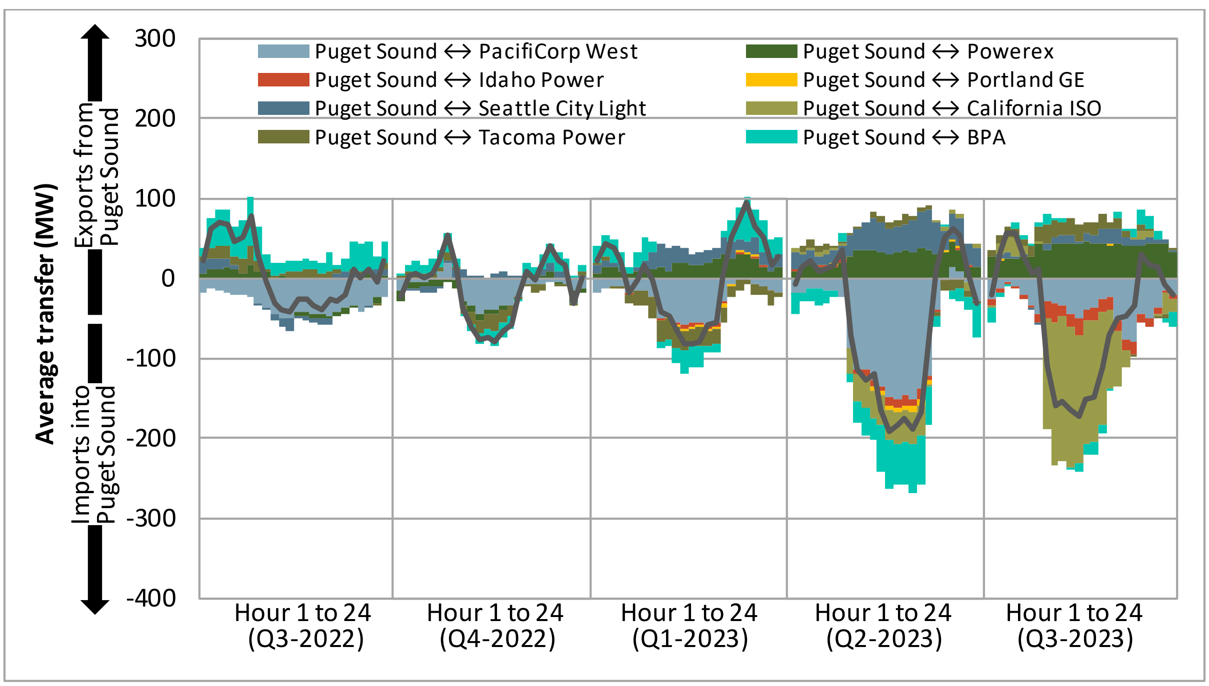
Appendix Figure A.70 Average hourly 15-minute market transfers



Appendix Figure A.71 Average hourly 5-minute price by component (Q3 2023)

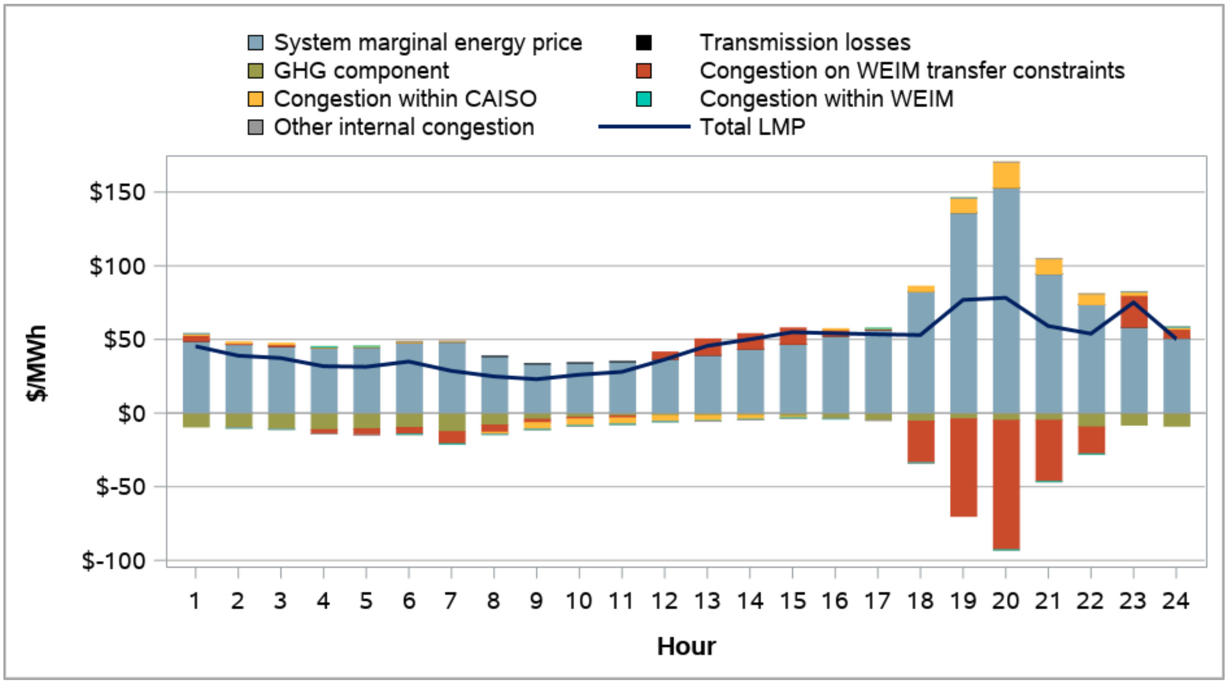


Appendix Figure A.72 Average hourly 5-minute market transfers

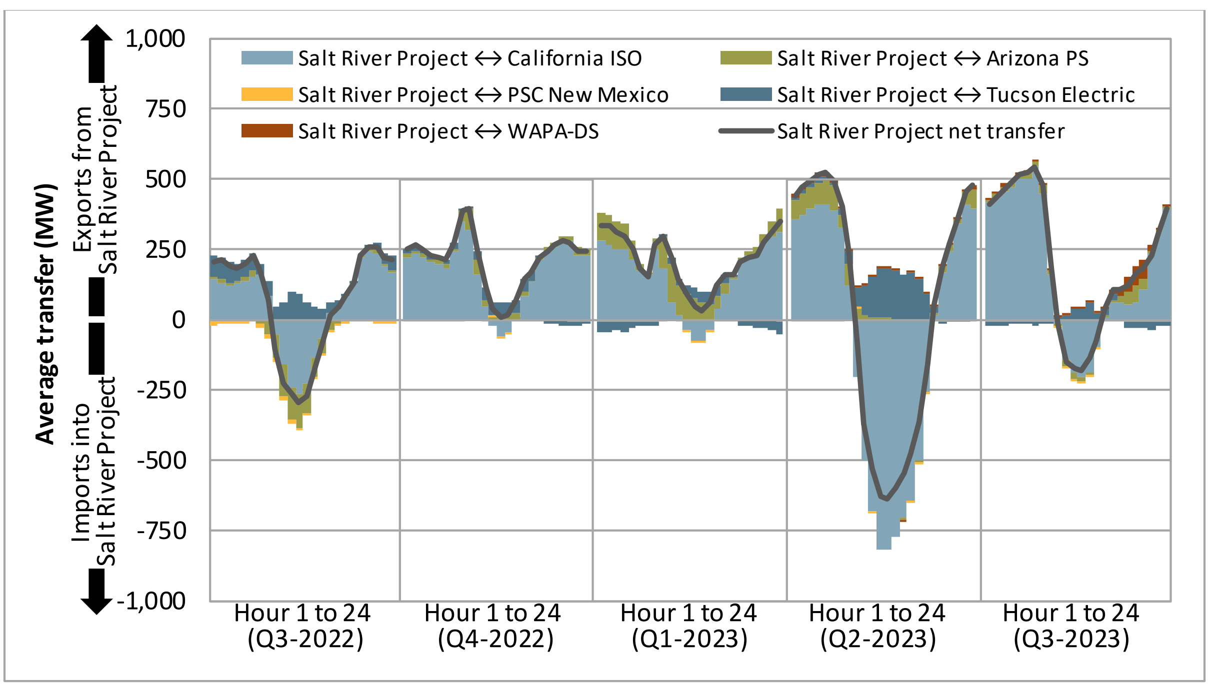


A.18 Salt River Project

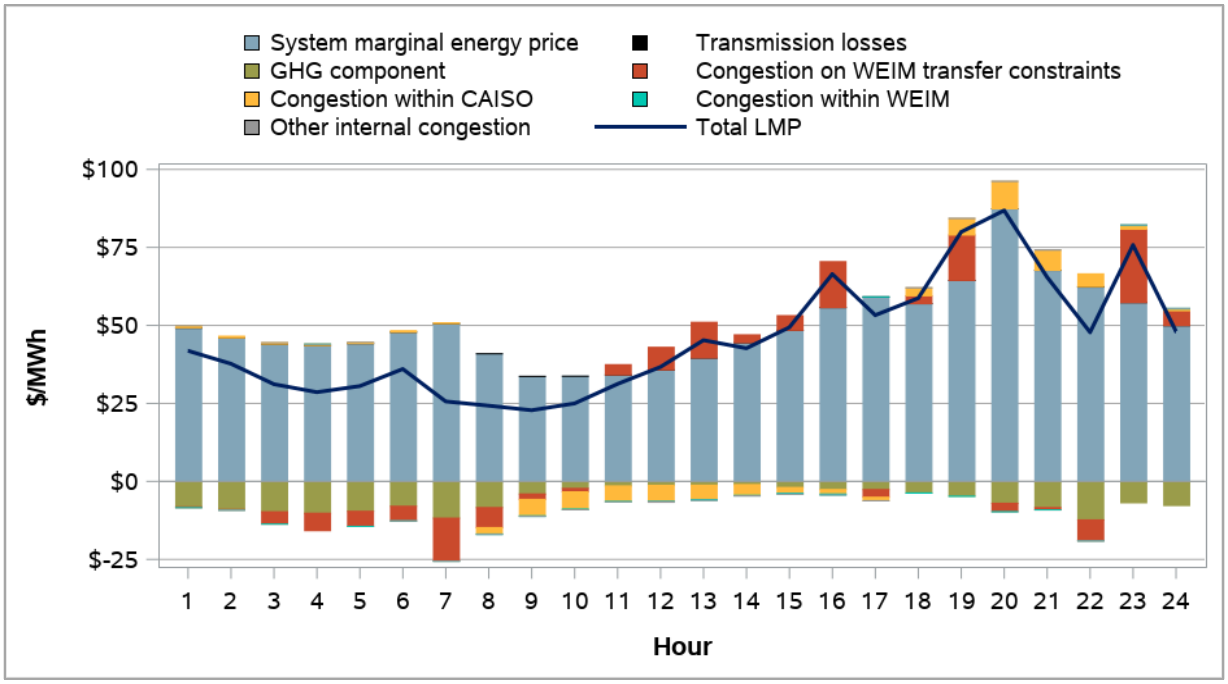
Appendix Figure A.73 Average hourly 15-minute price by component (Q3 2023)



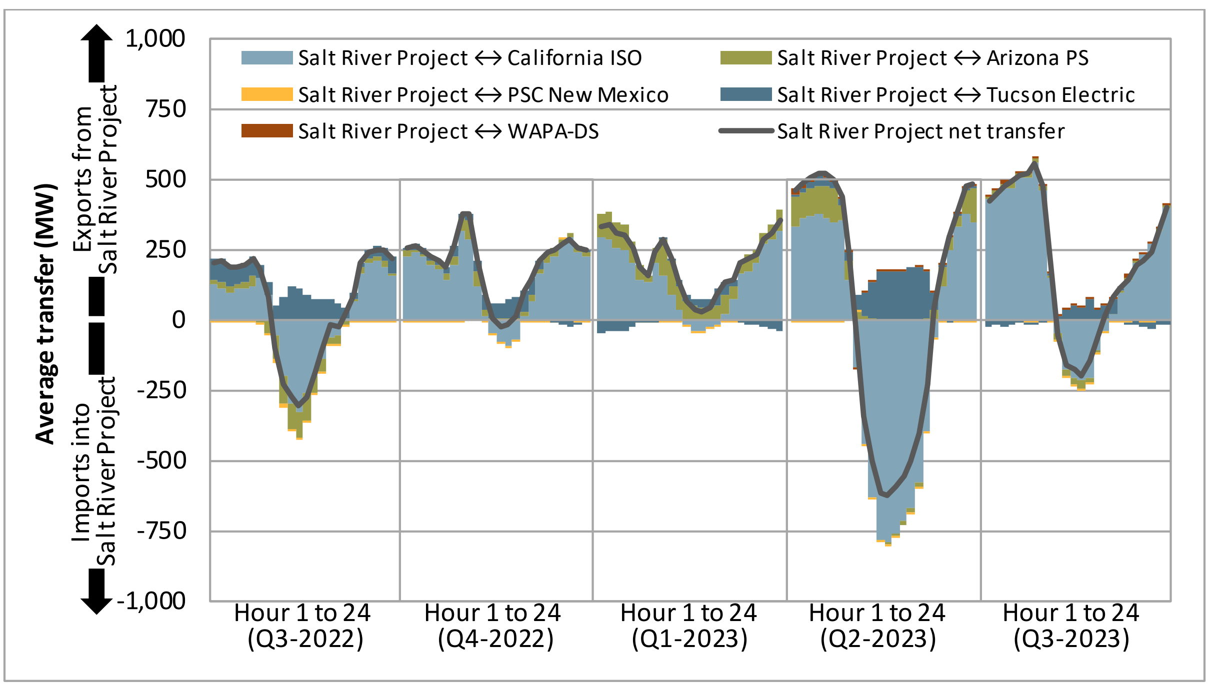
Appendix Figure A.74 Average hourly 15-minute market transfers



Appendix Figure A.75 Average hourly 5-minute price by component (Q3 2023)

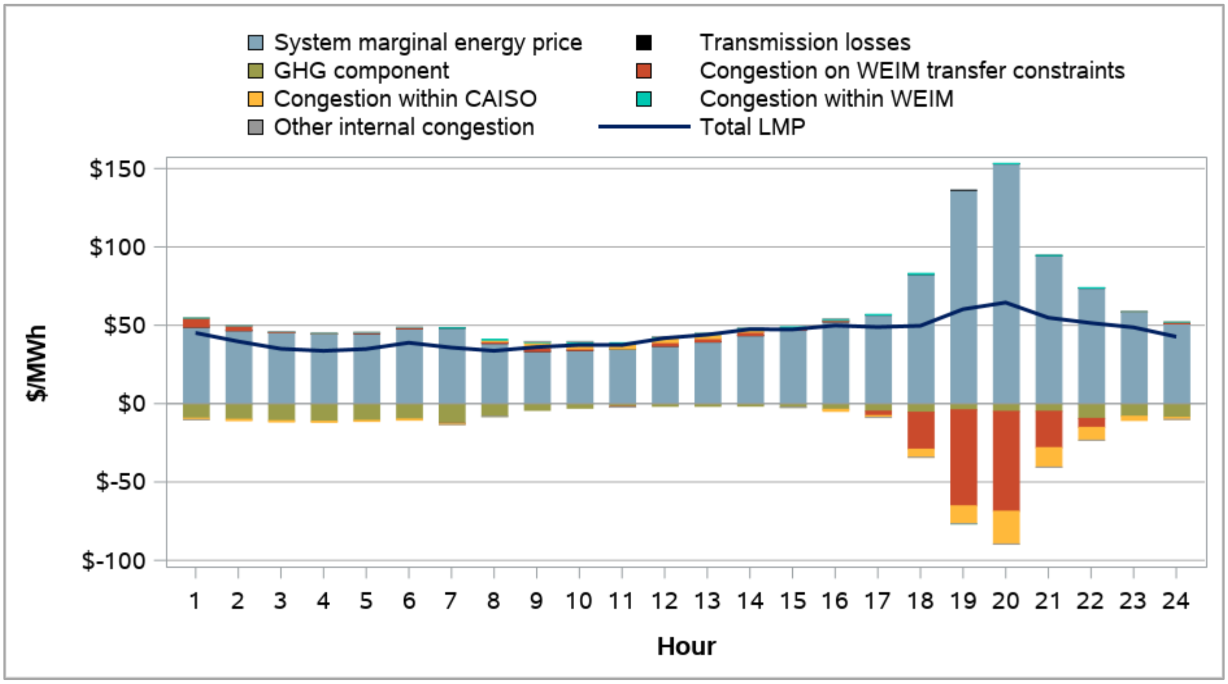


Appendix Figure A.76 Average hourly 5-minute market transfers

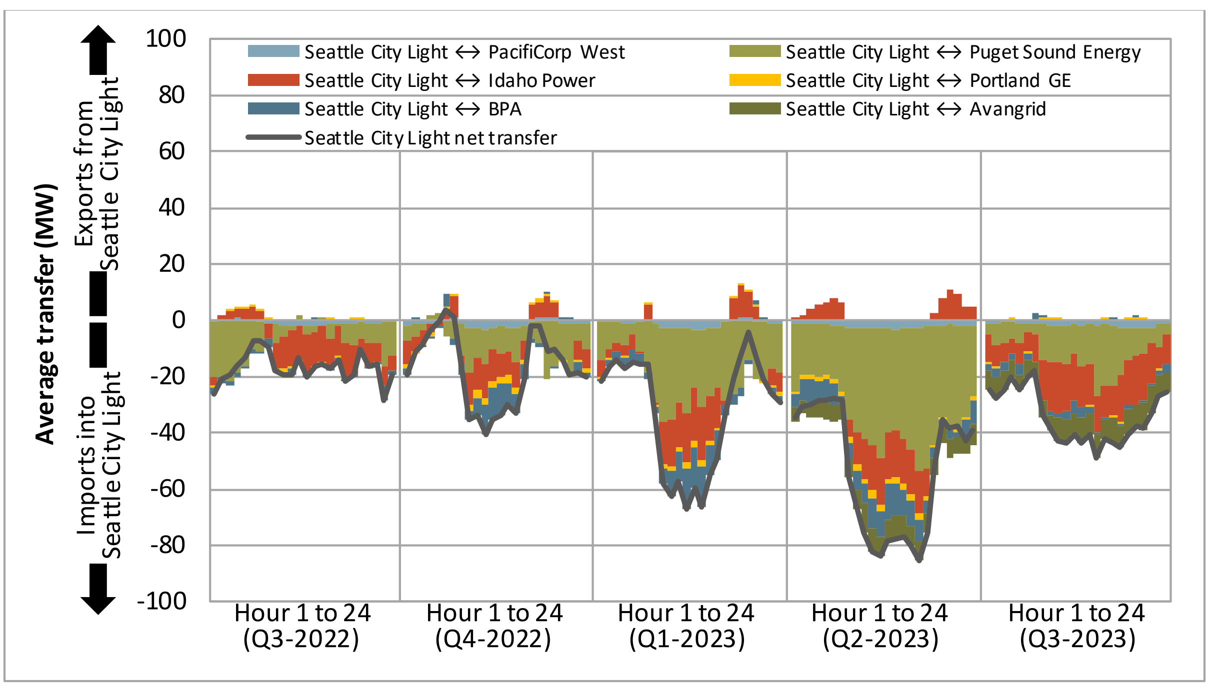


A.19 Seattle City Light

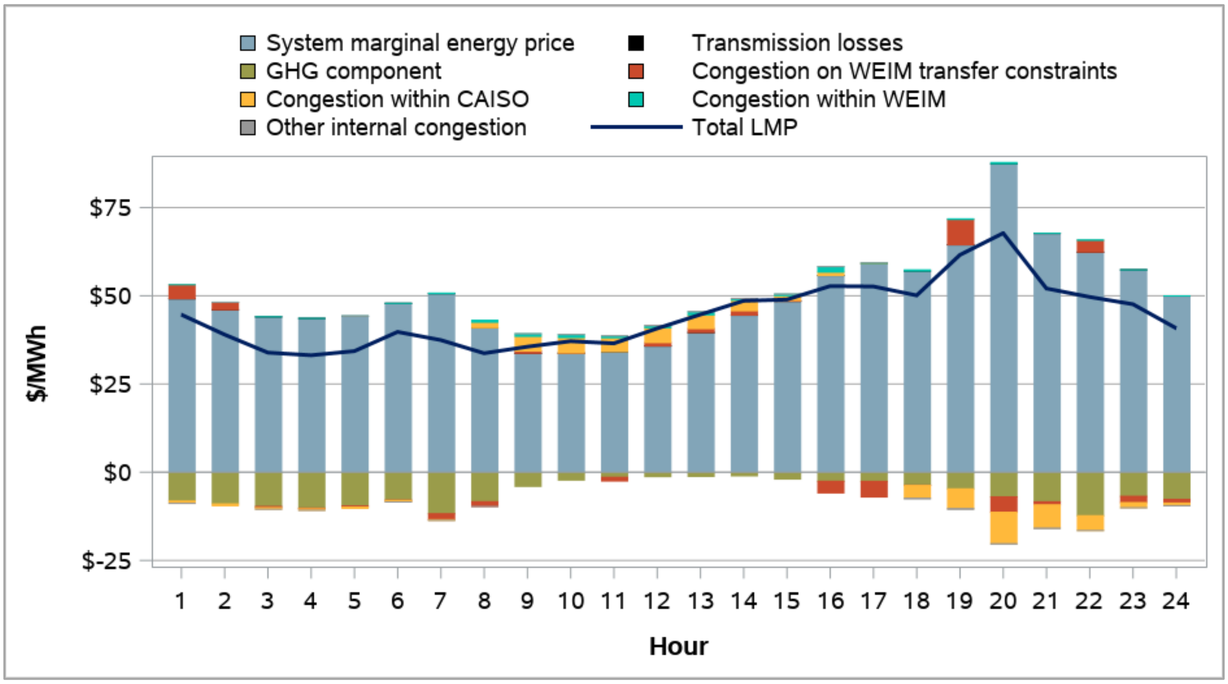
Appendix Figure A.77 Average hourly 15-minute price by component (Q3 2023)



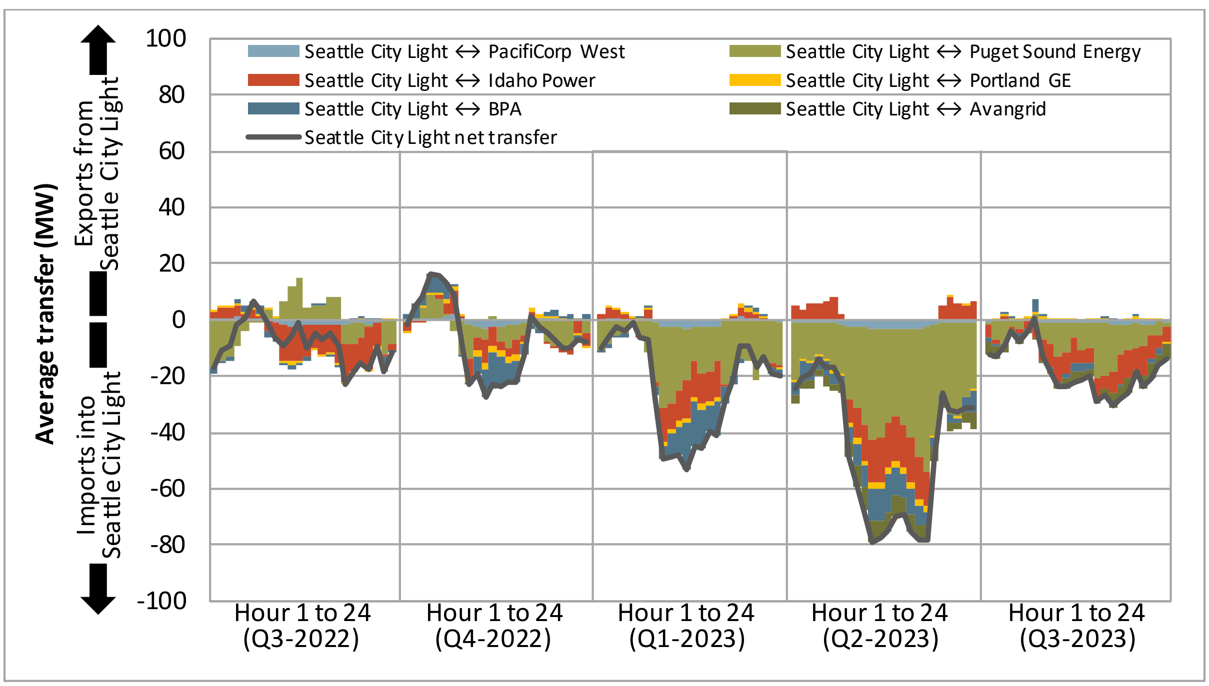
Appendix Figure A.78 Average hourly 15-minute market transfers



Appendix Figure A.79 Average hourly 5-minute price by component (Q3 2023)

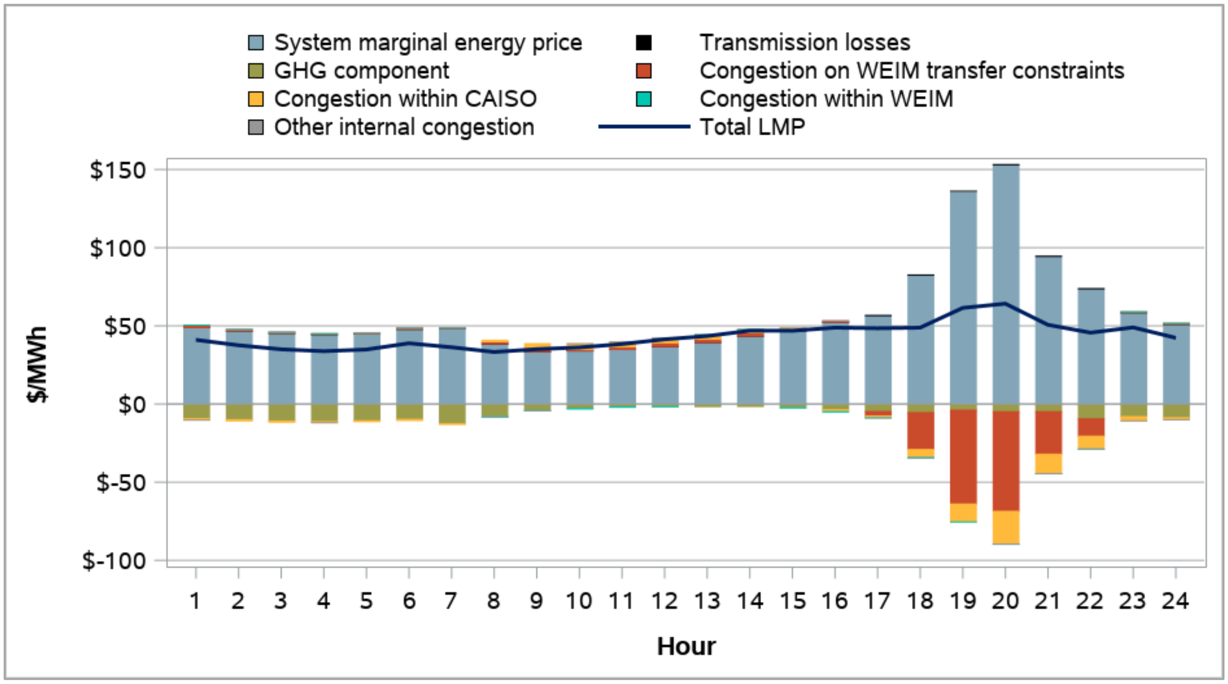


Appendix Figure A.80 Average hourly 5-minute market transfers

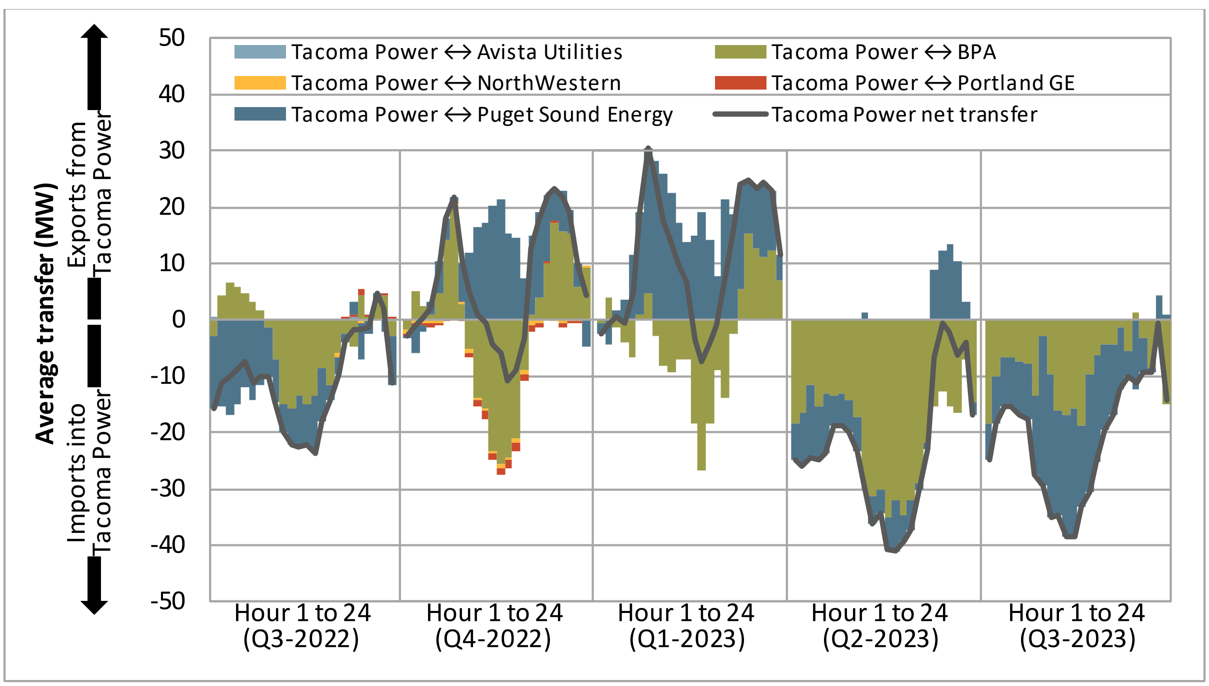


A.20 Tacoma Power

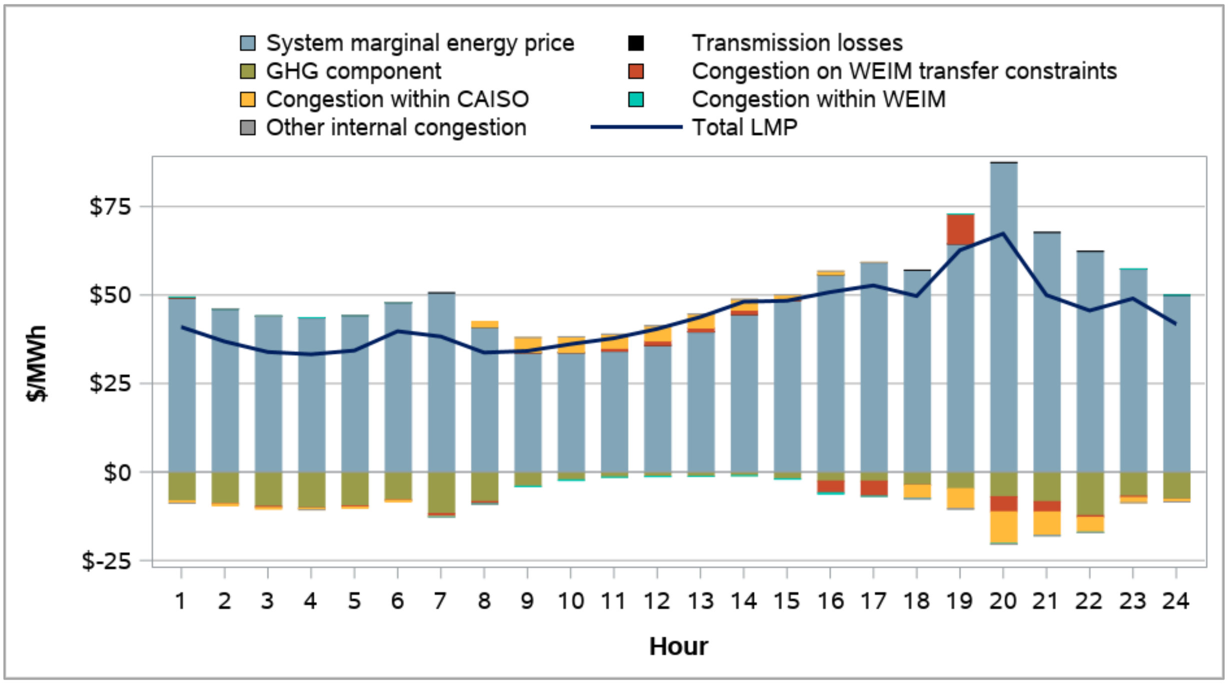
Appendix Figure A.81 Average hourly 15-minute price by component (Q3 2023)



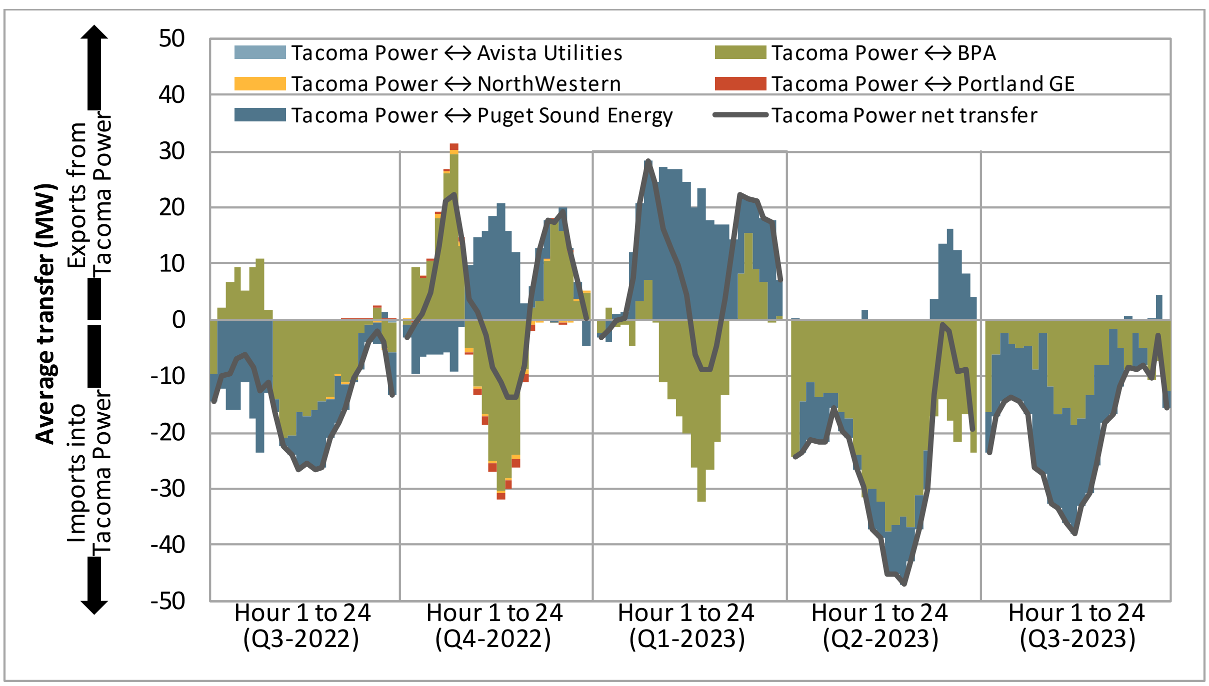
Appendix Figure A.82 Average hourly 15-minute market transfers



Appendix Figure A.83 Average hourly 5-minute price by component (Q3 2023)

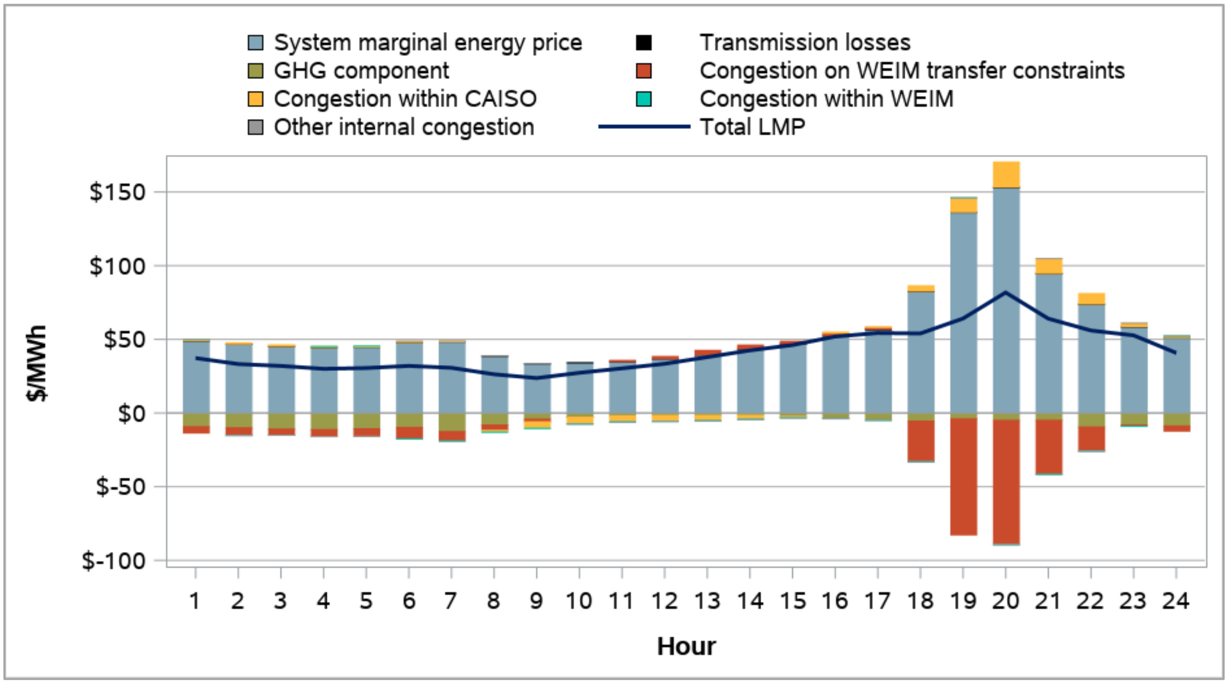


Appendix Figure A.84 Average hourly 5-minute market transfers

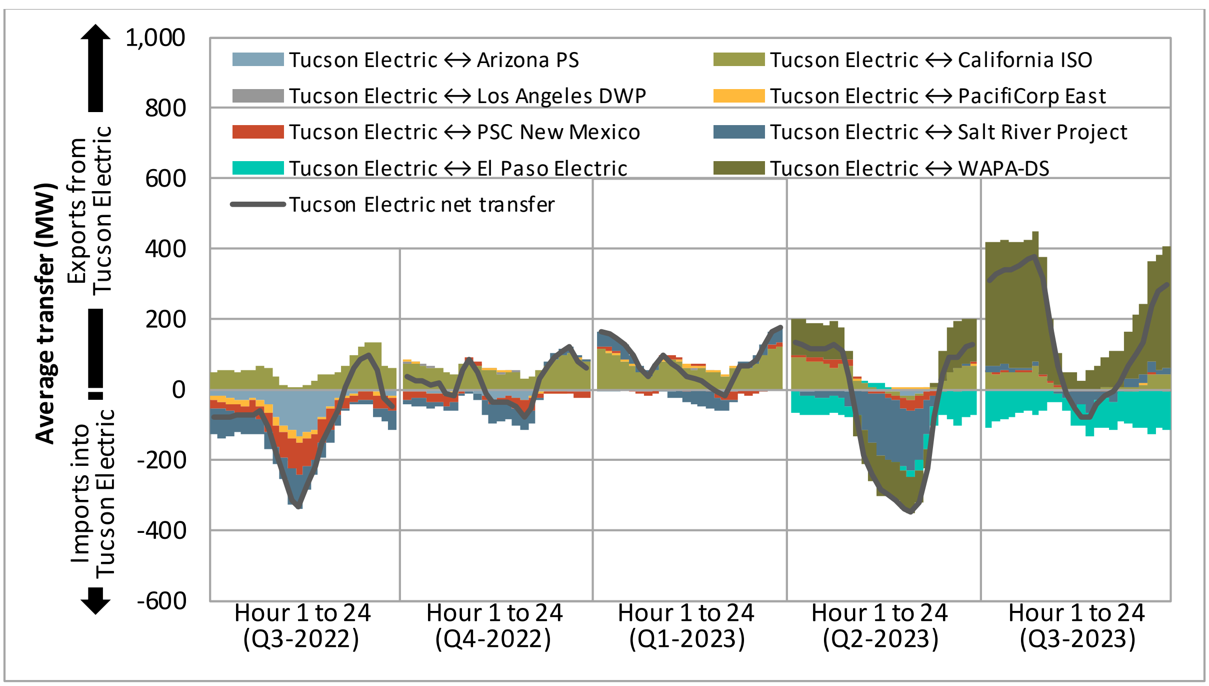


A.21 Tucson Electric Power

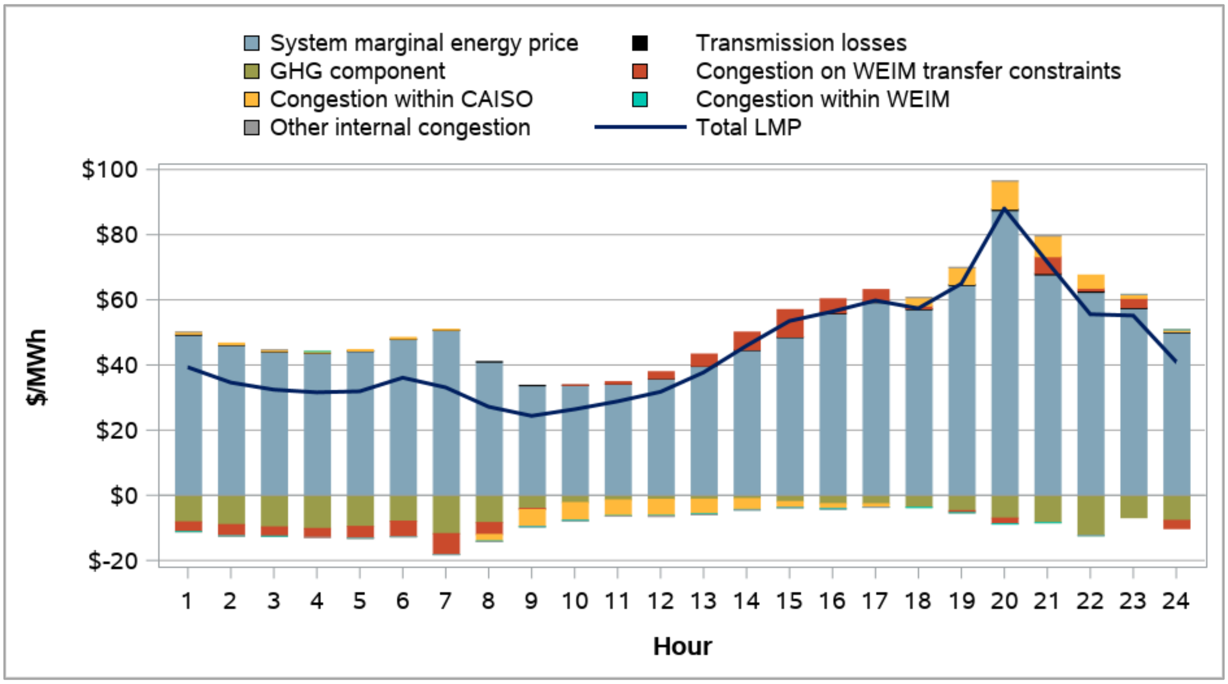
Appendix Figure A.85 Average hourly 15-minute price by component (Q3 2023)



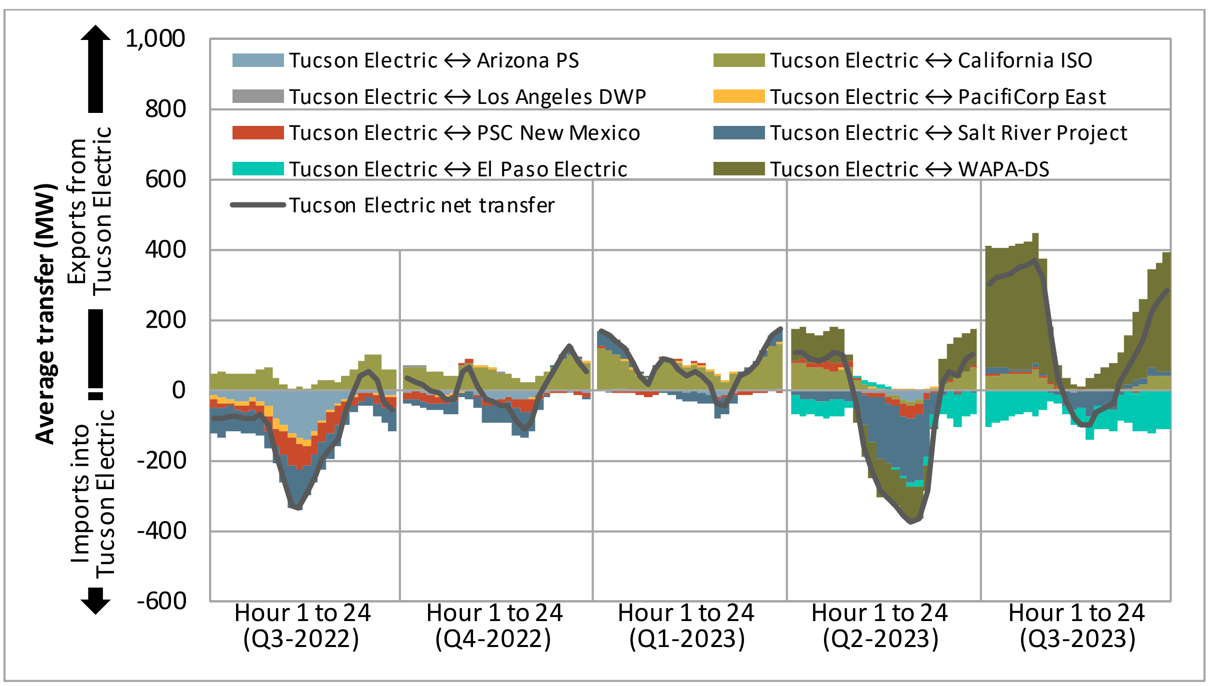
Appendix Figure A.86 Average hourly 15-minute market transfers



Appendix Figure A.87 Average hourly 5-minute price by component (Q3 2023)

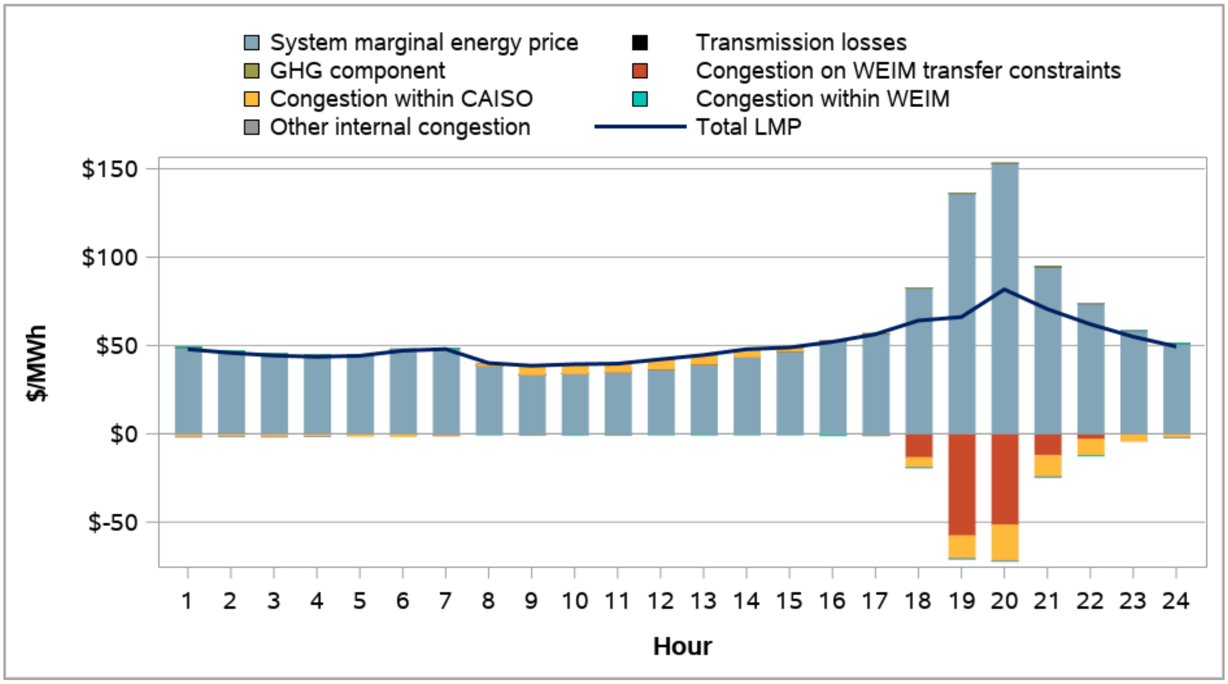


Appendix Figure A.88 Average hourly 5-minute market transfers

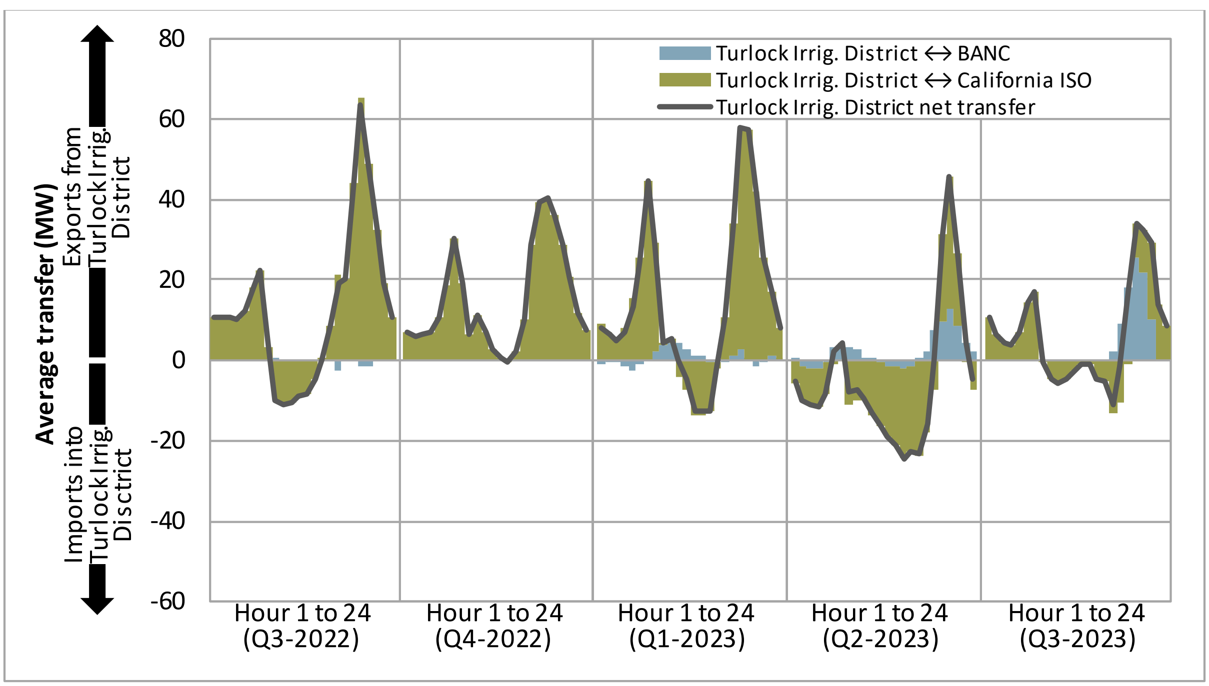


A.22 Turlock Irrigation District

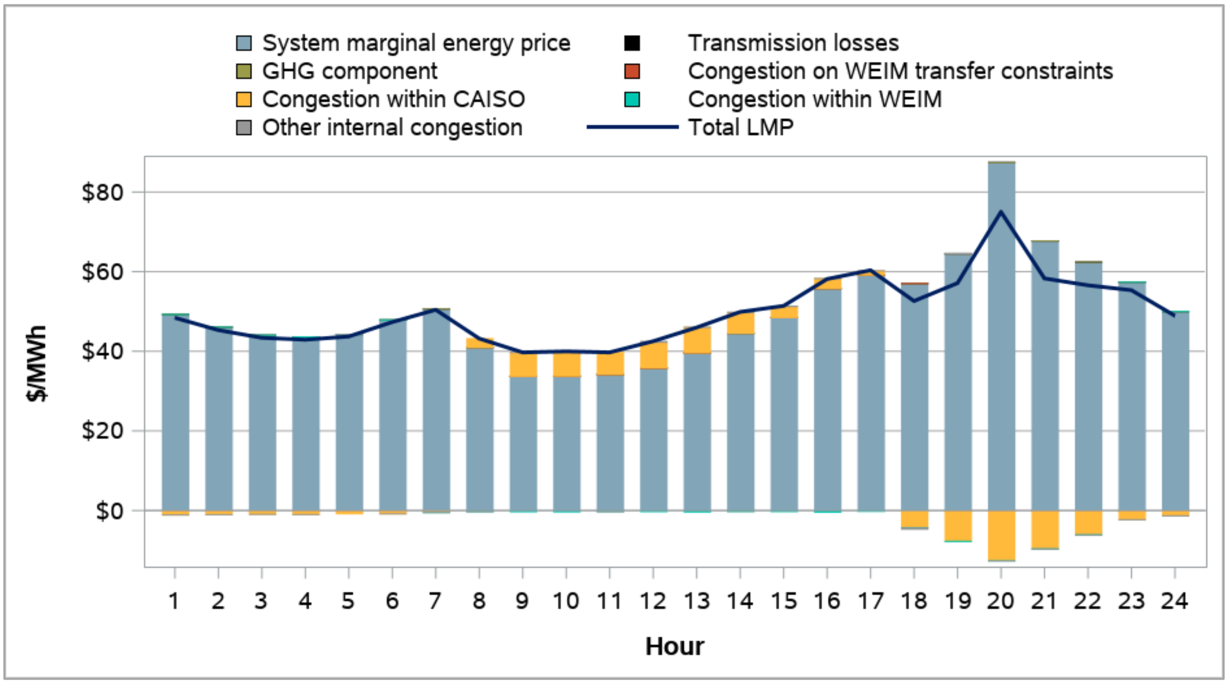
Appendix Figure A.89 Average hourly 15-minute price by component (Q3 2023)



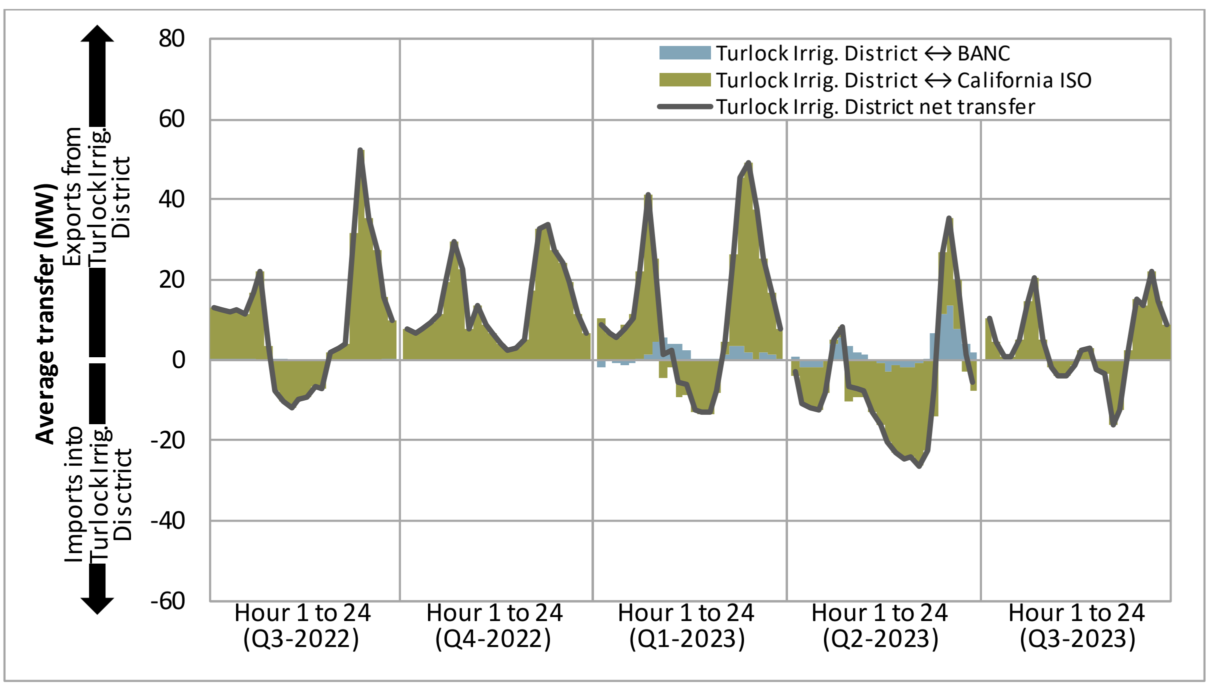
Appendix Figure A.90 Average hourly 15-minute market transfers



Appendix Figure A.91 Average hourly 5-minute price by component (Q3 2023)

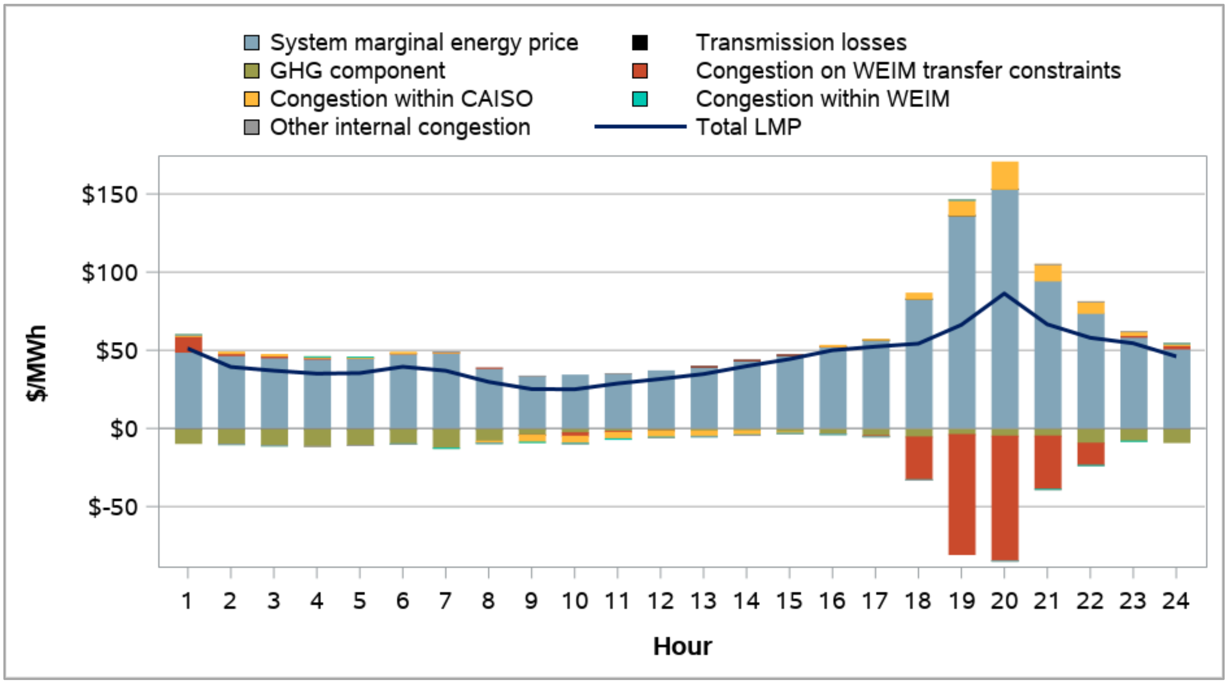


Appendix Figure A.92 Average hourly 5-minute market transfers

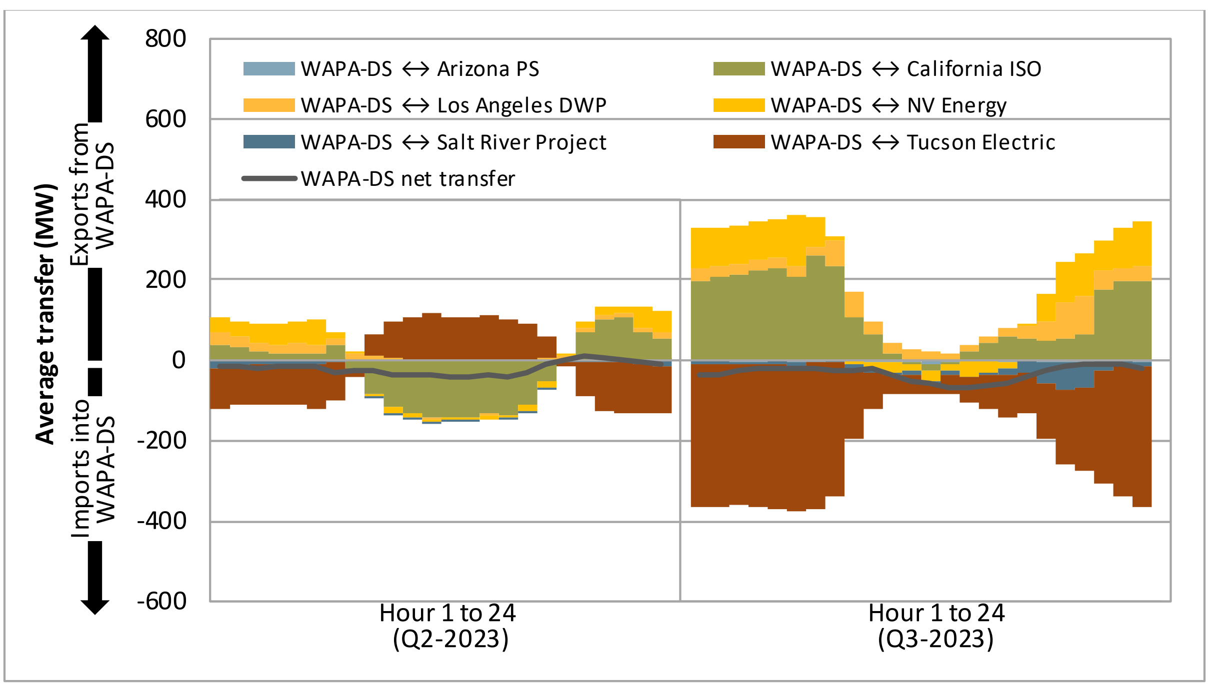


A.23 Western Area Power Administration Desert Southwest

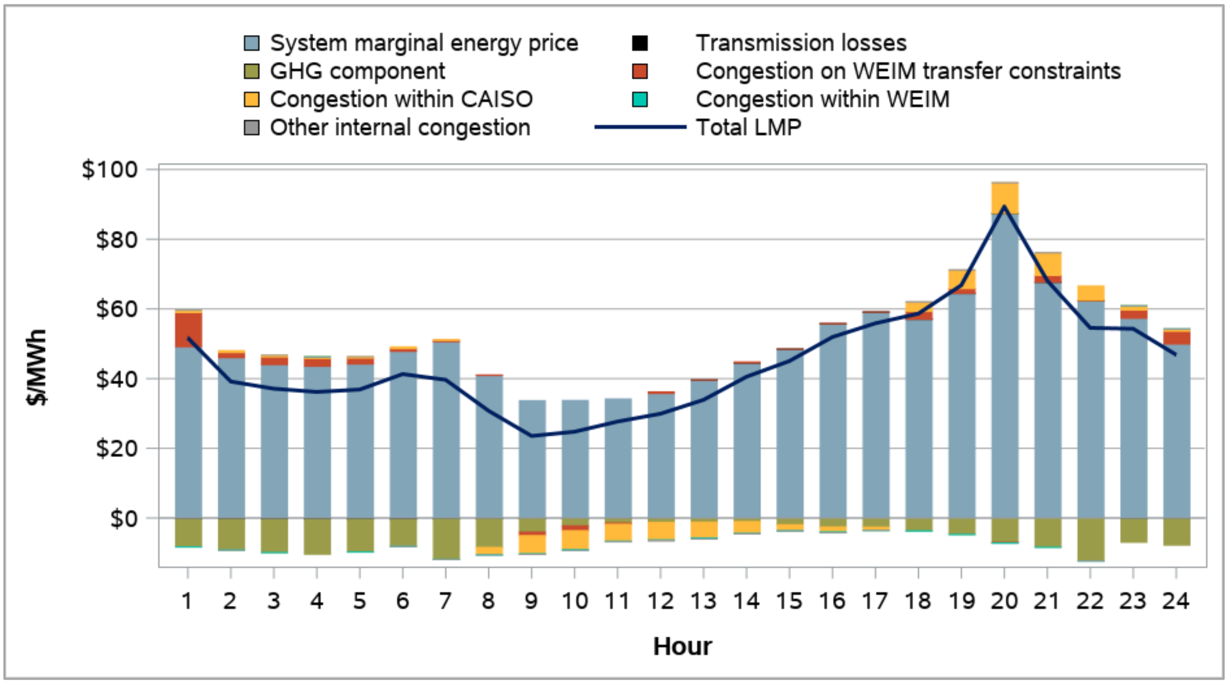
Appendix Figure A.93 Average hourly 15-minute price by component (Q3 2023)



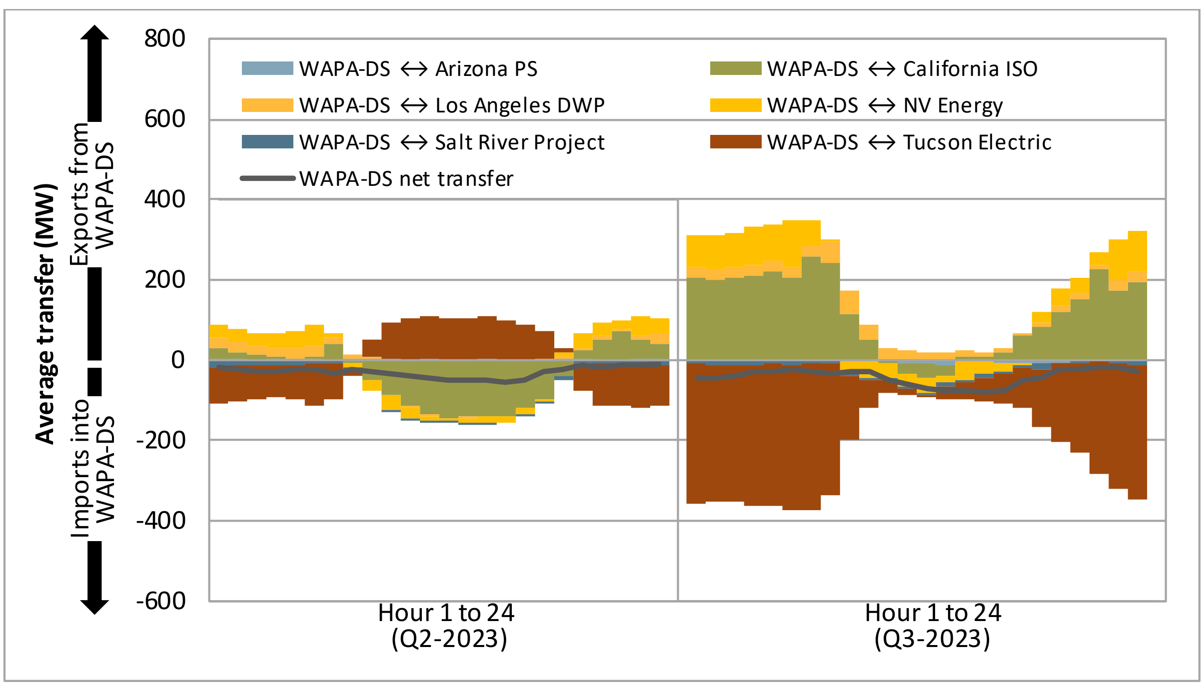
Appendix Figure A.94 Average hourly 15-minute market transfers



Appendix Figure A.95 Average hourly 5-minute price by component (Q3 2023)



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



Appendix B | Internal constraint congestion impact on WEIM

This section summarizes the price impact of internal congestion from individual constraints for each WEIM Load Aggregation Point (LAP). Table B.9 through Table B.12 show the overall impact of internal constraint congestion in the 15-minute market.[64] The WEIM entities are grouped into one of the four tables based on region: California, Desert Southwest, Intermountain West, and Pacific Northwest.[65] Table B.13 provides a consolidated view encompassing all groups. The constraints are sorted based on the location of the constraint and descending impact across LAPs in the region.

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.

Highlights for this quarter include:

- The net impact of internal constraint congestion had varied impacts across the WEIM. Similar to the third quarter of 2022, congestion lowered prices in the Pacific Northwest and raised prices in the Southwest.
- Internal congestion was most impactful in the AZPS and LADWP where it increased prices in by $2.52/MWh and $2.04/MWh, as well as in AVRN, PACW, and TPWR where it decreased prices by an average of $2.2/MWh.
- The primary constraints creating price separation in the 15-minute market were the Path 26 Control Point 1 nomogram, Los Banos-Gates #1 500 kV line and Midway-Vincent #2 500 kV line.

64 Constraints with price impact of less than $0.01/MWh for all LAPs in the region are grouped in 'Other.'

65 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.

Table B.9 California — Impact of internal constraint congestion on 15-minute market prices (July-September, 2023)

Constraint Location	Constraint	Average quarter impact ($/MWh)		
		BANC	TIDC	LADWP
BPAT	INTNEL	-0.06	-0.06	-0.05
CISO	6410_CP1_NG	-1.97	-2.04	1.76
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.85	0.87	-0.80
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-0.76	-0.79	0.65
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-0.49	-0.51	0.45
	ML_RM12_NS	0.29	0.29	0.16
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.23	0.31	-0.19
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.08	0.06	-0.08
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	-0.12	-0.08	—
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	-0.06	-0.06	0.06
	OMS 13938629_CP1_NG	-0.06	-0.06	0.05
	7430_MEL_COT_NG	0.17	—	—
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	0.04	0.12	0.00
	7430_CP6_NG	0.16	—	—
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-0.06	-0.06	0.04
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	-0.07	-0.07	0.02
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	-0.14	—	—
	30765_LOSBANOS_230_38625_SN LS PP_230_BR_1 _1	0.03	0.06	—
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1	—	0.09	—
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.02	0.05	0.00
	37563_MELONES _230_30800_WILSON _230_BR_1 _1	-0.06	—	—
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	0.01	0.01	0.01
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	0.00	—	-0.03
	64228_SUMMIT 1_115_32218_DRUM _115_BR_1 _1	-0.02	—	—
	30765_LOSBANOS_230_38625_SN LS PP_230_BR_2 _1	0.01	0.01	—
	38206_COTTLE A_230_37563_MELONES _230_BR_1 _1	0.01	—	—
[redacted]	Other	0.00	0.01	0.01
Total	Total	-1.98	-1.84	2.04

Table B.10 Desert Southwest — Impact of internal constraint congestion on 15-minute market prices (July-September, 2023)

Constraint Location	Constraint	Average quarter impact ($/MWh)						
		AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC
AZPS	CC XFMR8 A 69KV	0.93	—	—	—	—	—	—
	Line_CC-ME_230KV	0.11	—	—	0.05	-0.02	—	—
	Line_FC-CH2_345KV	0.01	-0.03	—	-0.07	0.01	—	0.00
	OC XFMR1 A 69KV	0.07	—	—	—	—	—	—
	LSS XFMR10 A 230KV	0.05	—	—	—	—	—	—
BPAT	INTNEL	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05
CISO	6410_CP1_NG	1.48	1.31	1.03	1.23	1.48	1.44	1.47
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	-0.68	-0.61	-0.44	-0.57	-0.68	-0.67	-0.68
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.56	0.49	0.39	0.46	0.55	0.54	0.55
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.37	0.33	0.26	0.31	0.37	0.36	0.37
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	-0.16	-0.15	-0.08	-0.14	-0.16	-0.16	-0.16
	ML_RM12_NS	0.11	0.08	0.06	0.07	0.11	0.11	0.11
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	-0.09	-0.08	—	-0.07	-0.10	-0.09	-0.09
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	—	—	0.48	—	—	—	—
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	-0.07	-0.06	-0.05	-0.06	-0.07	-0.07	-0.07
	7820_TL 230S_OVERLOAD_NG	-0.05	-0.05	-0.02	-0.04	-0.06	-0.05	-0.05
	OMS_14013927_TL23055_NG	-0.05	-0.04	—	-0.04	-0.05	-0.05	-0.05
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	0.04	0.04	0.03	0.04	0.04	0.04	0.04
	OMS 13938629_CP1_NG	0.04	0.04	0.03	0.03	0.04	0.04	0.04
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	-0.04	-0.04	-0.01	-0.04	-0.05	-0.04	-0.04
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.04	0.03	0.03	0.03	0.04	0.04	0.04
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	-0.04	-0.03	—	-0.03	-0.04	-0.04	-0.04
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	—	—	-0.20	—	—	—	—
	64228_SUMMIT 1_115_32218_DRUM _115_BR_1 _1	—	—	0.20	—	—	—	—
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	-0.03	-0.02	—	-0.02	-0.03	-0.03	-0.03
	64229_SUMMIT 2_115_32218_DRUM _115_BR_1 _1	—	—	0.09	—	—	—	—
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	—	—	-0.08	—	—	—	—
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.01	0.00	0.01	0.00	0.01	0.01	0.01
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	—	—	-0.02	—	—	—	—
IPCO	T342.MPSN	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	T341.MPSN	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
PACE	BONANZA$_MONA_345	—	-0.03	—	-0.04	—	—	—
PNM	115kv LK	—	-0.73	—	-0.16	—	—	—
	115kv ML	—	0.21	—	0.17	—	—	—
	115kv DL_Mi_Wm	—	0.12	—	—	—	—	—
	ABO S_COMP_WESP1	—	0.06	—	0.03	—	—	—
	LunaPNM345_115X	—	—	—	0.06	—	—	—
	PAJA_ABO S_COMP	—	0.04	—	0.00	—	—	—
	115kv EB Fron	—	0.03	—	—	—	—	—
	Other	-0.02	-0.04	0.01	-0.02	-0.03	-0.03	-0.04
Total	Total	2.52	0.78	1.66	1.12	1.30	1.28	1.33

Table B.11 Intermountain West — Impact of internal constraint congestion on 15-minute market prices (July-September, 2023)

Constraint Location	Constraint	Average quarter impact ($/MWh)			
		AVA	IPCO	NWMT	PACE
AZPS	Line_FC-CH2_345KV	—	-0.01	—	-0.02
BPAT	INTNEL	0.03	-0.04	0.03	-0.04
CISO	6410_CP1_NG	-1.36	-0.81	-1.13	0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.65	0.36	0.55	-0.01
	ML_RM12_NS	-0.44	-0.33	-0.39	-0.17
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-0.53	-0.32	-0.44	—
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-0.34	-0.20	-0.28	—
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.15	—	0.12	—
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	-0.05	-0.05	-0.05	-0.02
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.07	0.04	0.06	0.00
	OMS 13938629_CP1_NG	-0.04	-0.03	-0.04	—
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	-0.04	-0.03	-0.04	—
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-0.04	-0.03	-0.03	—
	6110_COI_N-S	-0.01	-0.01	-0.01	0.00
	ML_RM12_SN	0.01	0.01	0.01	0.00
	7820_TL 230S_OVERLOAD_NG	—	0.00	—	-0.02
IPCO	T342.MPSN	0.01	0.04	0.00	-0.03
	T341.MPSN	0.01	0.04	0.00	-0.03
	T232.BOMT	—	-0.02	—	-0.01
	T231.BOMT	—	-0.02	—	-0.01
PACE	TOTAL_WYOMING_EXPORT	—	—	—	-0.71
	WINDSTAR EXPORT TCOR	—	—	—	-0.56
	BONANZA$_MONA_345	—	—	—	0.03
	EAST_WYO_EXP	—	—	—	-0.02
[redacted]	Other	-0.01	0.00	-0.01	0.00
Total	Total	-1.94	-1.42	-1.64	-1.63

Table B.12 Pacific Northwest — Impact of internal constraint congestion on 15-minute market prices (July-September, 2023)

Constraint Location	Constraint	Average quarter impact ($/MWh)							
		AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
BPAT	INTNEL	-0.06	0.45	—	-0.06	-0.09	0.17	0.29	-0.08
CISO	6410_CP1_NG	-1.61	-1.41	-1.39	-1.49	-1.47	-1.43	-1.43	-1.43
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.76	0.68	0.69	0.71	0.71	0.69	0.68	0.69
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-0.62	-0.55	-0.51	-0.58	-0.57	-0.55	-0.55	-0.55
	ML_RM12_NS	-0.47	-0.45	-0.46	-0.46	-0.46	-0.45	-0.45	-0.45
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-0.40	-0.35	-0.34	-0.37	-0.37	-0.36	-0.35	-0.36
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.17	0.15	0.15	0.16	0.16	0.15	0.15	0.15
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	-0.06	-0.05	0.01	-0.05	-0.05	-0.05	-0.05	-0.05
	OMS 13938629_CP1_NG	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	-0.05	-0.04	-0.05	-0.05	-0.05	-0.04	-0.04	-0.04
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-0.05	-0.04	-0.03	-0.04	-0.04	-0.04	-0.04	-0.04
	6110_COI_N-S	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	ML_RM12_SN	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	-0.01	—	0.00	-0.01	-0.01	0.00	0.00	0.00
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	0.03	0.00	0.00	0.01	0.00	0.00	0.00	0.00
IPCO	T342.MPSN	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	T341.MPSN	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
PGE	MCL_PE_SHW_V682	0.00	0.00	0.01	—	0.40	0.01	0.00	0.01
[redacted]	Other	-0.02	-0.01	-0.01	-0.02	-0.01	-0.01	-0.01	-0.01
Total	Total	-2.33	-1.58	-1.88	-2.20	-1.81	-1.88	-1.76	-2.14

Table B.13 WEIM — Impact of internal constraint congestion on 15-minute market prices (July-September, 2023)

Constraint Location	Constraint	Average quarter impact ($/MWh)																					
		Califonia			Desert Southwest							Intermountain West				Pacific Northwest							
		BANC	TIDC	LADWP	AZPS	EPE	NEVP	PNM	SRP	TEPC	WALC	AVA	IPCO	NWMT	PACE	AVRN	BCHA	BPAT	PACW	PGE	PSEI	SCL	TPWR
AZPS	CC XFMR8 A 69KV	—	—	—	0.93	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	Line_CC-ME_230KV	—	—	—	0.11	—	—	0.05	-0.02	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	Line_FC-CH2_345KV	—	—	—	0.01	-0.03	—	-0.07	0.01	—	0.00	—	-0.01	—	-0.02	—	—	—	—	—	—	—	—
	OC XFMR1 A 69KV	—	—	—	0.07	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	LSS XFMR10 A 230KV	—	—	—	0.05	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPAT	INTNEL	-0.06	-0.06	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	0.03	-0.04	0.03	-0.04	-0.06	0.45	—	-0.06	-0.09	0.17	0.29	-0.08
CISO	6410_CP1_NG	-1.97	-2.04	1.76	1.48	1.31	1.03	1.23	1.48	1.44	1.47	-1.36	-0.81	-1.13	0.00	-1.61	-1.41	-1.39	-1.49	-1.47	-1.43	-1.43	-1.43
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.85	0.87	-0.80	-0.68	-0.61	-0.44	-0.57	-0.68	-0.67	-0.68	0.65	0.36	0.55	-0.01	0.76	0.68	0.69	0.71	0.71	0.69	0.68	0.69
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-0.76	-0.79	0.65	0.56	0.49	0.39	0.46	0.55	0.54	0.55	-0.53	-0.32	-0.44	—	-0.62	-0.55	-0.51	-0.58	-0.57	-0.55	-0.55	-0.55
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-0.49	-0.51	0.45	0.37	0.33	0.26	0.31	0.37	0.36	0.37	-0.34	-0.20	-0.28	—	-0.40	-0.35	-0.34	-0.37	-0.37	-0.36	-0.35	-0.36
	ML_RM12_NS	0.29	0.29	0.16	0.11	0.08	0.06	0.07	0.11	0.11	0.11	-0.44	-0.33	-0.39	-0.17	-0.47	-0.45	-0.46	-0.46	-0.46	-0.45	-0.45	-0.45
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.23	0.31	-0.19	-0.16	-0.15	-0.08	-0.14	-0.16	-0.16	-0.16	0.15	—	0.12	—	0.17	0.15	0.15	0.16	0.16	0.15	0.15	0.15
	30040_TESLA _500_30050_LOSBANOS_500_BR_1 _1	0.08	0.06	-0.08	-0.07	-0.06	-0.05	-0.06	-0.07	-0.07	-0.07	0.07	0.04	0.06	0.00	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	-0.06	-0.06	0.06	0.04	0.04	0.03	0.04	0.04	0.04	0.04	-0.04	-0.03	-0.04	—	-0.05	-0.04	-0.05	-0.05	-0.05	-0.04	-0.04	-0.04
	OMS 13938629_CP1_NG	-0.06	-0.06	0.05	0.04	0.04	0.03	0.03	0.04	0.04	0.04	-0.04	-0.03	-0.04	—	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-0.06	-0.06	0.04	0.04	0.03	0.03	0.03	0.04	0.04	0.04	-0.04	-0.03	-0.03	—	-0.05	-0.04	-0.03	-0.04	-0.04	-0.04	-0.04	-0.04
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	-0.07	-0.07	0.02	0.01	0.00	0.01	0.00	0.01	0.01	0.01	-0.05	-0.05	-0.05	-0.02	-0.06	-0.05	0.01	-0.05	-0.05	-0.05	-0.05	-0.05
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	-0.14	—	—	—	—	0.48	—	—	—	—	—	0.00	—	0.00	—	—	—	—	—	—	—	—
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	—	—	—	-0.09	-0.08	—	-0.07	-0.10	-0.09	-0.09	—	—	—	—	—	—	—	—	—	—	—	—
	7820_TL 230S_OVERLOAD_NG	0.00	0.00	0.01	-0.05	-0.05	-0.02	-0.04	-0.06	-0.05	-0.05	—	0.00	—	-0.02	0.00	—	—	—	—	—	—	—
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	0.01	0.01	0.01	-0.04	-0.04	-0.01	-0.04	-0.05	-0.04	-0.04	—	—	—	-0.01	—	—	—	—	—	—	—	—
	OMS_14013927_TL23055_NG	—	—	—	-0.05	-0.04	—	-0.04	-0.05	-0.05	-0.05	—	—	—	—	—	—	—	—	—	—	—	—
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	-0.12	-0.08	—	—	—	—	—	—	—	—	—	—	—	—	-0.01	—	0.00	-0.01	-0.01	0.00	0.00	0.00
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1A _1	0.04	0.12	0.00	—	—	—	—	—	—	—	—	—	—	—	0.03	0.00	0.00	0.01	0.00	0.00	0.00	0.00
	64228_SUMMIT 1_115_32218_DRUM _115_BR_1 _1	-0.02	—	—	—	—	0.20	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	—	—	—	-0.04	-0.03	—	-0.03	-0.04	-0.04	-0.04	—	—	—	—	—	—	—	—	—	—	—	—
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	—	—	—	—	—	-0.20	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	6110_COI_N-S	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	0.00	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	ML_RM12_SN	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	7430_MEL_COT_NG	0.17	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	7430_CP6_NG	0.16	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	—	—	—	-0.03	-0.02	—	-0.02	-0.03	-0.03	-0.03	—	—	—	—	—	—	—	—	—	—	—	—
	64229_SUMMIT 2_115_32218_DRUM _115_BR_1 _1	—	—	—	—	—	0.09	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	30765_LOSBANOS_230_38625_SN LS PP_230_BR_1 _1	0.03	0.06	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	30765_LOSBANOS_230_30766_PADR FLT_230_BR_1 _1	—	0.09	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.02	0.05	0.00	—	—	—	—	—	—	—	—	—	—	—	0.00	—	—	—	—	—	—	—
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	—	—	—	—	—	-0.08	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	37563_MELONES _230_30800_WILSON _230_BR_1 _1	-0.06	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	0.00	—	-0.03	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
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	—	—	—	—	—	-0.02	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	30765_LOSBANOS_230_38625_SN LS PP_230_BR_2 _1	0.01	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	38206_COTTLE A_230_37563_MELONES _230_BR_1 _1	0.01	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
IPCO	T342.MPSN	—	—	0.00	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	0.04	0.00	-0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	T341.MPSN	—	—	0.00	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.01	0.04	0.00	-0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	T232.BOMT	0.00	—	—	—	—	—	—	—	—	—	—	-0.02	—	-0.01	0.01	—	—	—	—	—	—	—
	T231.BOMT	0.00	—	—	—	—	—	—	—	—	—	—	-0.02	—	-0.01	0.01	—	—	—	—	—	—	—
PACE	TOTAL_WYOMING_EXPORT	—	—	—	—	—	—	—	—	—	—	—	—	—	-0.71	—	—	—	—	—	—	—	—
	WINDSTAR EXPORT TCOR	—	—	—	—	—	—	—	—	—	—	—	—	—	-0.56	—	—	—	—	—	—	—	—
	BONANZA$_MONA_345	—	—	—	—	-0.03	—	-0.04	—	—	—	—	—	—	0.03	—	—	—	—	—	—	—	—
	EAST_WYO_EXP	—	—	—	—	—	—	—	—	—	—	—	—	—	-0.02	—	—	—	—	—	—	—	—
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	0.01	—	0.40	0.01	0.00	0.01
PNM	115kv LK	—	—	—	—	-0.73	—	-0.16	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	115kv ML	—	—	—	—	0.21	—	0.17	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	115kv DL_Mi_Wm	—	—	—	—	0.12	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	ABO S_COMP_WESP1	—	—	—	—	0.06	—	0.03	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	LunaPNM345_115X	—	—	—	—	—	—	0.06	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	PAJA_ABO S_COMP	—	—	—	—	0.04	—	0.00	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	115kv EB Fron	—	—	—	—	0.03	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
[redacted]	Other	0.00	0.01	0.01	-0.02	-0.04	0.01	-0.02	-0.03	-0.03	-0.04	-0.01	0.00	-0.01	0.00	-0.02	-0.01	-0.01	-0.02	-0.01	-0.01	-0.01	-0.01
Total	Total	-1.98	-1.84	2.05	2.51	0.78	1.66	1.11	1.30	1.27	1.33	-1.94	-1.42	-1.64	-1.63	-2.32	-1.58	-1.88	-2.20	-1.81	-1.88	-1.76	-2.14