# Q3 2022 Report on Market Issues and Performance

December 14, 2022

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California Independent System Operator

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# Executive Summary

This report covers market performance during the third quarter of 2022 (July - September).

Key highlights during this quarter include the following:

- **Between August 31 and September 9, the combined CAISO and WEIM system experienced a prolonged heat event**, resulting in demand for electricity well in excess of current resource planning targets over an extended period. Although several areas called the highest level of emergency alert, no area curtailed load to maintain reliability.
- **Market prices were significantly higher** than the same quarter of 2021 on average (Figure E.1). Day-ahead prices increased more than 50 percent due to both higher load and higher natural gas prices. Gas prices increased by more than 50 percent at Henry Hub, PG&E Citygate, NW Sumas, and El Paso Permian hubs and by more than 30 percent at SoCal Citygate, compared to the same quarter in 2021 (Figure E.2). This contributed to higher marginal energy prices across the Western Energy Imbalance Market, including the California ISO.
- **Congestion increased in both the day-ahead and real-time markets**. Day-ahead congestion increased SCE and SDG&E area prices and decreased prices in the PG&E area. Total day-ahead congestion rent rose to $238 million, up from $166 million in the same quarter of the previous year. A constraint that is enforced only in the 5-minute market drove 5-minute prices down significantly in WEIM areas north of the CAISO and drive prices down in the CAISO and WEIM areas in the southwest.
- **Real-time imbalance offset costs increased significantly to about $206 million in the third quarter,** up from $131 million in the second quarter and $45 million in the first quarter. Real-time imbalance energy costs were $89 million in September alone; the highest monthly energy offset costs since locational marginal pricing was introduced in 2009. Congestion offsets remained high.
- **Estimated bid cost recovery payments increased** for units in the California ISO and WEIM balancing areas, totaling about $167 million and $27 million, respectively, during the first three quarters of 2022. These payments already exceeded the total bid cost recovery payments in 2021, which were about $158 million in the CAISO and $22 million in the WEIM.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues received for these rights by $20 million.** These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. DMM continues to recommend further changes to eliminate or at least reduce these losses.
- **Flexible ramping product system level prices** were zero for over 99 percent of intervals in the 15-minute market and in the 5-minute market. Implementation of nodal pricing for the product has been delayed until February of 2023.
- **Imbalance conformance adjustments** averaged about 2,200 MW in the peak net load ramp hours in the California ISO. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributed to the price difference between these markets.

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

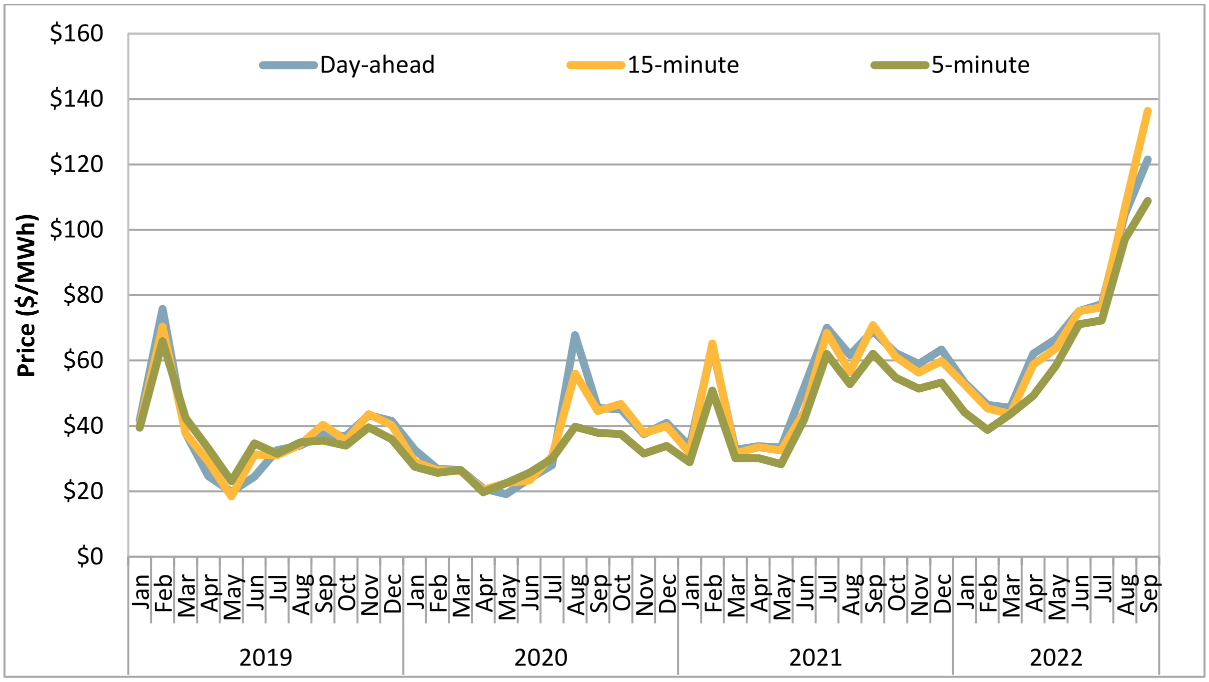
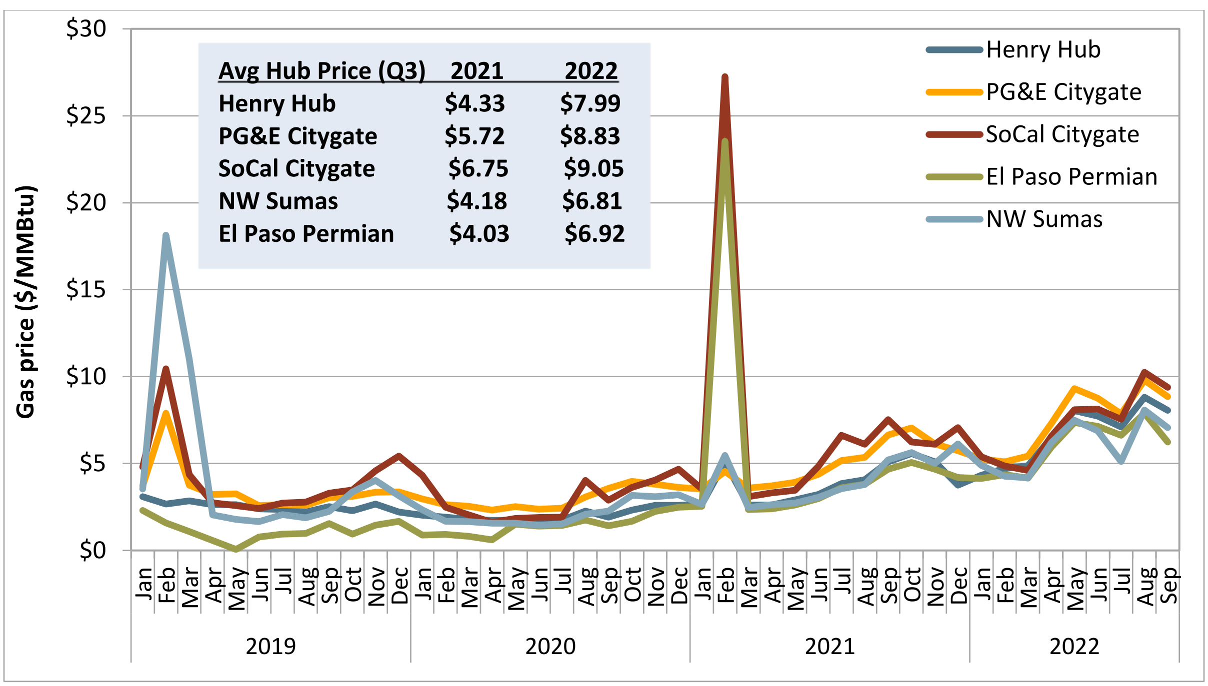



**Figure E.2 Average monthly natural gas prices by hub**



## Western Energy Imbalance Market

- **Natural gas prices rose across the WEIM**, resulting in higher energy prices in all balancing areas.
- **Prices in the Northwest region** were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours and congestion internal to the California ISO. This region includes, Portland General Electric, Puget Sound Energy, Seattle City Light, Tacoma Power, PacifiCorp West, Powerex, NorthWestern, Avista Utilities, and Bonneville Power Administration.
- **Prices in WEIM balancing areas within California were about $29/MWh higher than other regions**. Prices tend to be higher in California than the rest of the system due to both transfer constraint congestion and greenhouse gas compliance costs for energy that is delivered to California.
- **The California ISO was a major net importer** during peak net load hours. During these hours, the CAISO imported an average of around 1,600 MW from neighboring areas including LADWP, Turlock Irrigation District, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, and Tucson Electric Power.
- **The California ISO revised the loss sensitivity factor calculation** in August, reducing the impact on prices in WEIM areas that base scheduled the majority of their transfer capacity, especially those located in the Pacific Northwest.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in monthly reports** as part of the *WEIM resource sufficiency evaluation* stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.
- **Appendix A includes hourly price and transfer figures for each WEIM area**.

## Western heatwave

Between August 31 through September 9, the combined CAISO and WEIM system experienced a prolonged heat event. This period was marked by record setting, extremely high temperature weather conditions across most of the western United States. The CAISO published a comprehensive review of market results during the heat wave.[1] DMM concurs with many of the key findings and recommendations in the CAISO report. This quarterly report includes additional analysis based on DMM's independent review.

Key findings in this report are consistent with findings in the CAISO's report:

- **Extreme temperatures and energy demand** across the entire western region resulted in demand for electricity well in excess of current resource planning targets over an extended period.
- **High bilateral market price indices** reflected regional market conditions. Traded volumes were relatively low over the Labor Day holiday weekend.
- **The maximum import bid cap allowed imports to bid up to the hard bid cap ($2,000/MWh)** in some hours when bilateral market price indices were high. Hours with the $2,000/MWh bid cap closely matched hours when the CAISO declared EEA2 and EEA3 alerts. The $2,000 bid cap attracted a limited quantity of additional imports into CAISO market.
- **Penalty prices were raised up to $2,000/MWh** on days with high bilateral market prices. During the heatwave, 15-minute and 5-minute prices in the CAISO rose above $1,000/MWh, exceeding

[1] California ISO, *Summer Market Performance Report - Sept 2022,* November 2, 2022: http://www.caiso.com/Documents/Sept2022_summer_readiness_reportFinal.pdf#search=summer

day-ahead prices in many intervals. Real-time prices were often set by penalty prices in these intervals.

- **Balancing areas declaring emergencies were able to import supplemental energy**, both through emergency assistance from other balancing areas and WEIM imports. Most WEIM areas were net exporters in net peak hours during the heatwave, with the CAISO accounting for most imports.
- **CAISO supply was additionally supplemented** by out of market imports, non-market capacity procured through California's strategic reserve and through voluntary demand reduction.
- **Congestion limited imports from the Northwest into California** in the real-time market but otherwise had little impact on market outcomes.
- **CAISO operators raised real-time imbalance conformance and operator the load forecast used** in the day-ahead market's residual unit commitment process to extraordinarily high levels. Doing so helped to ensure that lower priority exports not be supported by physical supply did not clear in the market.
- **Some low priority exports cleared the real-time market inappropriately due to an issue with how penalty prices were set.** This required the CAISO operators to take manual action and increased CAISO demand in the real-time market. The market optimization appropriately prioritized load over lower priority exports in the day-ahead market residual unit commitment process. The CAISO implemented a market enhancement on October 13 to resolve the market issue in the real-time market.

# 1 Market performance

This section highlights key indicators of market performance in the third quarter:

- **Electricity prices were about 50 percent higher** than the same quarter of 2021 due to higher natural gas prices and higher load. Day-ahead prices averaged $101/MWh, 15-minute prices averaged $106/MWh, and 5-minute prices averaged $92/MWh.
- **Gas prices rose across the market footprint as the Henry Hub price, the national index, rose by 84 percent with increased demand for exports.** This resulted in higher system marginal energy prices across the California ISO footprint.
- **Average CAISO generation increased over 1,000 MW in each hour over the same quarter in 2021.** Most of the increase was from solar, storage, and hydro-electric generation. Capacity on outage decreased by 6 percent compared to the same quarter, despite higher temperatures.
- **Flexible ramping product system level prices** were zero for over 99 percent of intervals in the 15-minute market and in the 5-minute market. Implementation of nodal pricing for the product has been delayed until February 2023.
- **Congestion increased in both the day-ahead and real-time markets**. Congestion in the day-ahead market increased SCE and SDG&E area prices and decreased prices in the PG&E area. Total day-ahead congestion rent and loss surplus were $238 million and $133 million, respectively.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $20 million, down from $70 million** during the first half of 2022 as payments to auctioned congestion revenue rights holders continued to exceed auction revenues.
- **A 5-minute market only constraint continued to heavily impacted 5-minute prices** across the WEIM and led to notable differences between the markets. The constraint, (6110_COI_N-S), was created and implemented in September 2021 to manage unscheduled flow.
- **Real-time imbalance offset costs increased significantly to about $206 million in the third quarter,** up from $131 million in the second quarter, and $45 million in the first quarter. Real-time imbalance energy costs were $89 million in September alone; the highest monthly energy offset costs since locational marginal pricing was introduced in 2009.
- **Imbalance conformance adjustments** averaged 2,200 MW during the net load peak in the 15-minute market, about 1,000 MW over the average for the same time last year. This continued the increase in operator use of imbalance conformance that began in 2017. The widening gap between high conformance in the 15-minute market and lower conformance in the 5-minute market contributed to the price difference between these markets.
- **Ancillary service payments totaled about $112 million**, more than double the third quarter of 2021. Average requirements were higher for both operating reserves and regulation.
- **Estimated bid cost recovery payments increased** for units in the California ISO and Western Energy Imbalance Market balancing areas, totaling about $167 million and $27 million, respectively during the first three quarters of 2022, exceeding the total for 2021.
- **Net profits paid to convergence bidders fell to about $36 million from about $41 million in the second quarter**, together more than the annual total of $38 million in 2021. Overall, virtual demand bids were most profitable.

## 1.1 Supply conditions

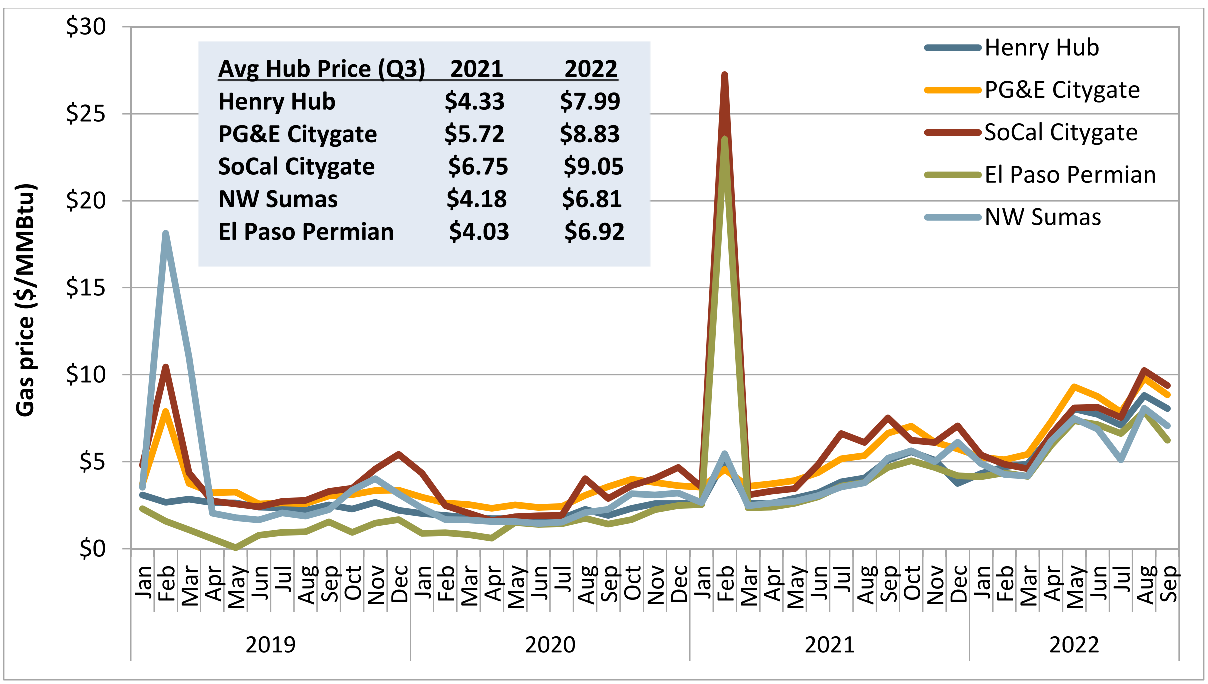
### 1.1.1 Natural gas prices

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. SoCal Citygate prices often affect overall electric system prices because there are large numbers of natural gas resources in the south, and these resources can set system prices in the absence of congestion.

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. Prices the two main delivery points in California (PG&E Citygate and SoCal Citygate) rose by 54 percent and 34 percent, respectively, compared to the third quarter of 2021. Prices for El Paso Permian and Northwest Sumas gas hubs were up 72 percent and 61 percent, respectively, compared to last year. Prices at Henry hub were up 84 percent compared to the third quarter of 2021.

On March 18, 2022, the CPUC issued a proposed decision to extend SoCalGas' 8-stage winter OFO penalty structure year-round and made it applicable to the PG&E and SDG&E service territories.[2] Until the third quarter of 2022, SoCalGas declared 14 low OFOs, primarily stage 1. This is in comparison to 46 low OFOs in 2021, which were also primarily stage 1 or 2 with some stage 4 declared during the volatile gas price event in mid-February 2021.

**Figure 1.1 Monthly average natural gas prices**




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

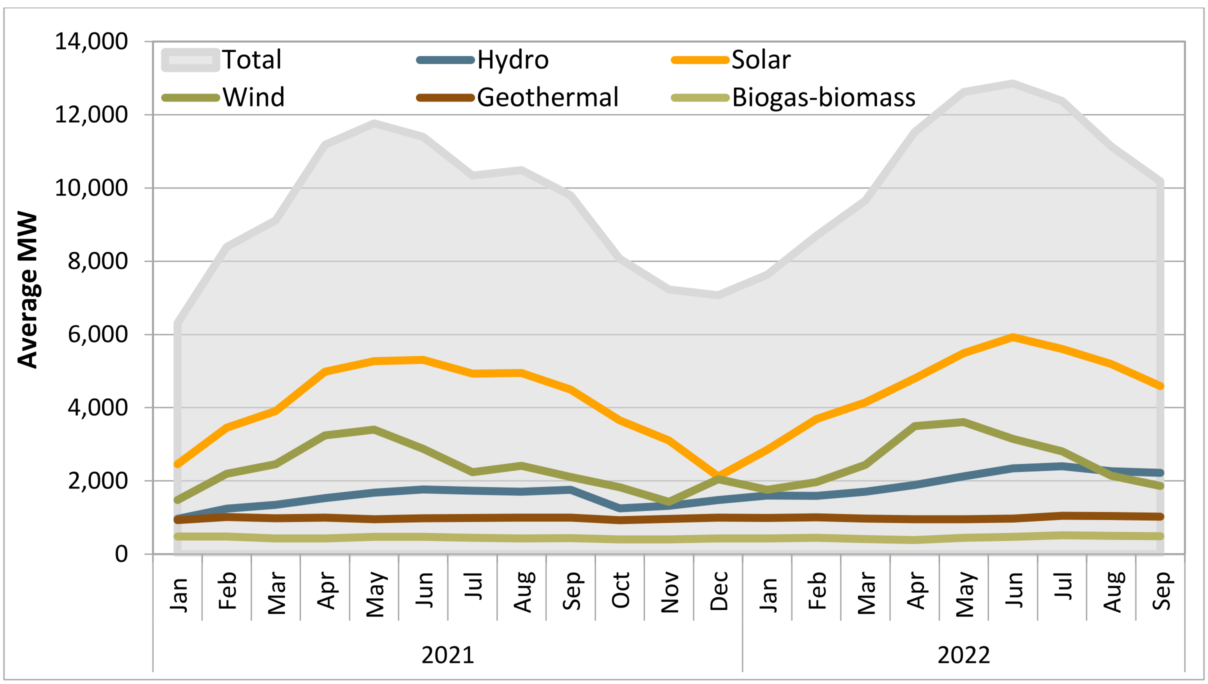
### 1.1.2 Renewable generation

In the third quarter, the combined average monthly generation from renewable resources increased by about 1,000 MW (10 percent) compared to the same quarter of 2021.[3] Hydroelectric generation increased 31 percent, while generation from solar, wind, geothermal, and biogas-biomass resources increased 5 percent. The availability of variable energy resources contributes to price patterns, both seasonally and hourly, due to their low marginal cost relative to other resources.

Hourly average hydroelectric production in the third quarter of 2022 increased by about 550 MW (31 percent), compared to the same quarter in 2021. As of April 1, 2022, the statewide weighted average snowpack in California was 35 percent of normal compared to 62 percent of normal on April 1, 2021.[4]

Figure 1.2 shows the average monthly renewable generation by fuel type.[5] Solar generation increased 335 MW (7 percent), while wind generation remained the same. Generation from geothermal and biogas-biomass resources increased 43 MW and 61 MW (4 percent and 14 percent), respectively.

**Figure 1.2 Average monthly renewable generation**




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

4 For snowpack information, please see California Cooperative Snow Survey's Snow Course Measurements on the California Department of Water Resources website: https://cdec.water.ca.gov/snow/current/snow/.

5 Hydroelectric generation greater than 30 MW is included.

### 1.1.3 Downward dispatch and curtailment of variable energy resources

Wind and solar downward dispatch and curtailments were higher in the third quarter relative to the same time last year, increasing 62 percent in the California ISO and 186 percent in the WEIM balancing areas. The majority of the reduction in wind and solar output continued to be the result of economic downward dispatch, meaning the wind/solar bid price was above (or close to) the resulting market price.

When scheduled supply exceeds demand, the real-time market dispatches generators down in merit order from the highest bid to lowest, with the last unit dispatched setting the system price. Dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, wind and solar resources may be dispatched down when the nodal price drops below low-priced bids from these renewable resources. If the supply of bids to decrease energy is exhausted in the real-time market, the software will curtail self-scheduled generation, including wind and solar generation.

Figure 1.3 shows the curtailment of wind and solar resources by month in the California ISO balancing area.[6] The figure also includes the total reduction of wind and solar as a percent of total 5-minute market wind and solar forecasts. DMM developed six categories for curtailment based on: (1) whether the resource self-scheduled or bid in economically, (2) whether the resource received an exceptional dispatch or out-of-market instruction, and (3) the relationship between the resource's bid price and the resulting market price. The six categories are:

- **economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls within one dollar of or below a resource's bid, or the resource's upper limit is binding; [7]
- **exceptional economic downward dispatch**, in which a resource receives an exceptional dispatch or out-of-market instruction to decrease dispatch;
- **other economic downward dispatch**, in which the market price is more than one dollar above a resource bid and that resource is dispatched down;[8]
- **self-schedule curtailment**, in which a price-taking self-scheduled resource receives an instruction to reduce output while the market price is below a resource bid or the resource's upper limit is binding;
- **exceptional self-schedule curtailment**, in which a self-scheduled resource receives an exceptional dispatch or out-of-market instruction to reduce output; and
- **other self-schedule curtailment**, in which a self-scheduled resource receives an instruction to reduce output and the market price is above the -$150/MWh bid floor.

The majority of the reduction in wind and solar output (87 percent) during the quarter was a result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation resources dispatched down in the California ISO area were solar rather than wind.

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6 The levels of downward dispatch and curtailment presented here may differ from curtailment data published by the California ISO. This is due to varied methodologies. The California ISO curtailment data will typically be lower than DMM's calculations.

7 A resource's upper limit is determined by a variety of factors and can vary throughout the day.

8 The one-dollar threshold is included in the categorization of downward dispatch and curtailment types to mitigate small price discrepancies between bids and market prices.

In the California ISO balancing area, economic downward dispatch totaled 195 GWh for the quarter. This is almost double the amount from the third quarter of 2021. Self-schedule curtailment totaled 15 GWh for the quarter, a 43 percent decrease relative to the third quarter of 2021.

Figure 1.4 shows the amount of downward dispatch of participating WEIM wind and solar resources. The figure also includes the total reduction of wind and solar as a percent of total 5-minute market wind and solar forecasts. Curtailments in the WEIM fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment, as defined above. Total downward dispatch in the WEIM during the third quarter was nearly three times higher than during the third quarter of 2021.

**Figure 1.3 Reduction of wind and solar generation by month (California ISO)**

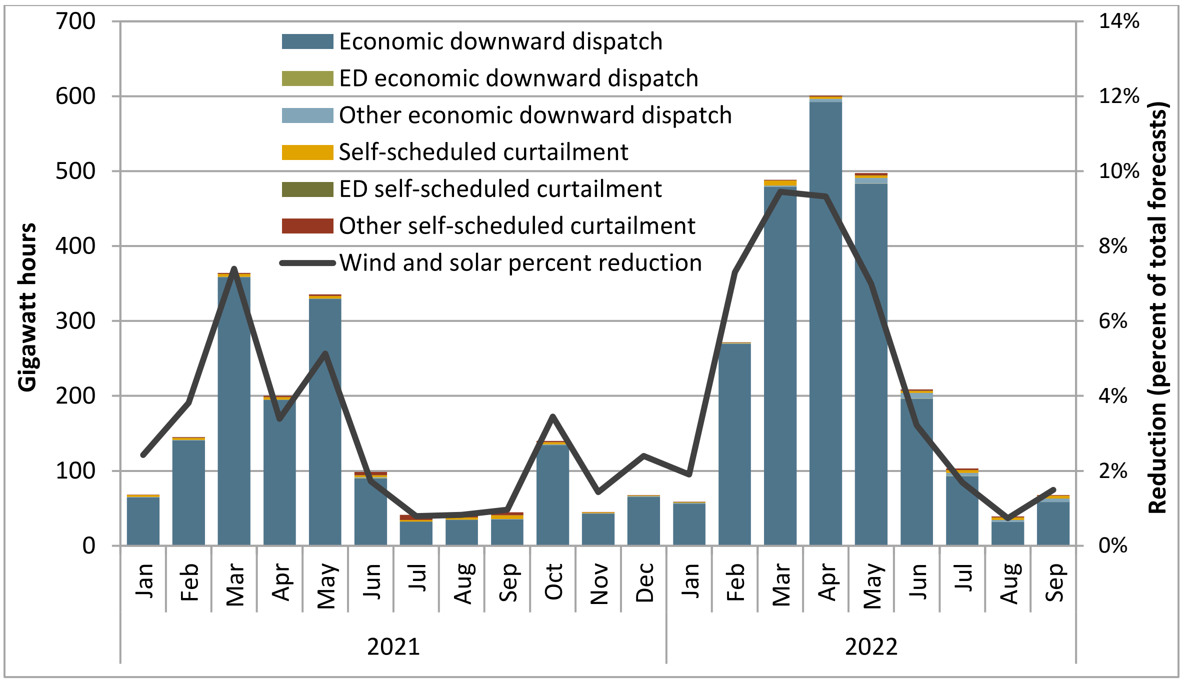
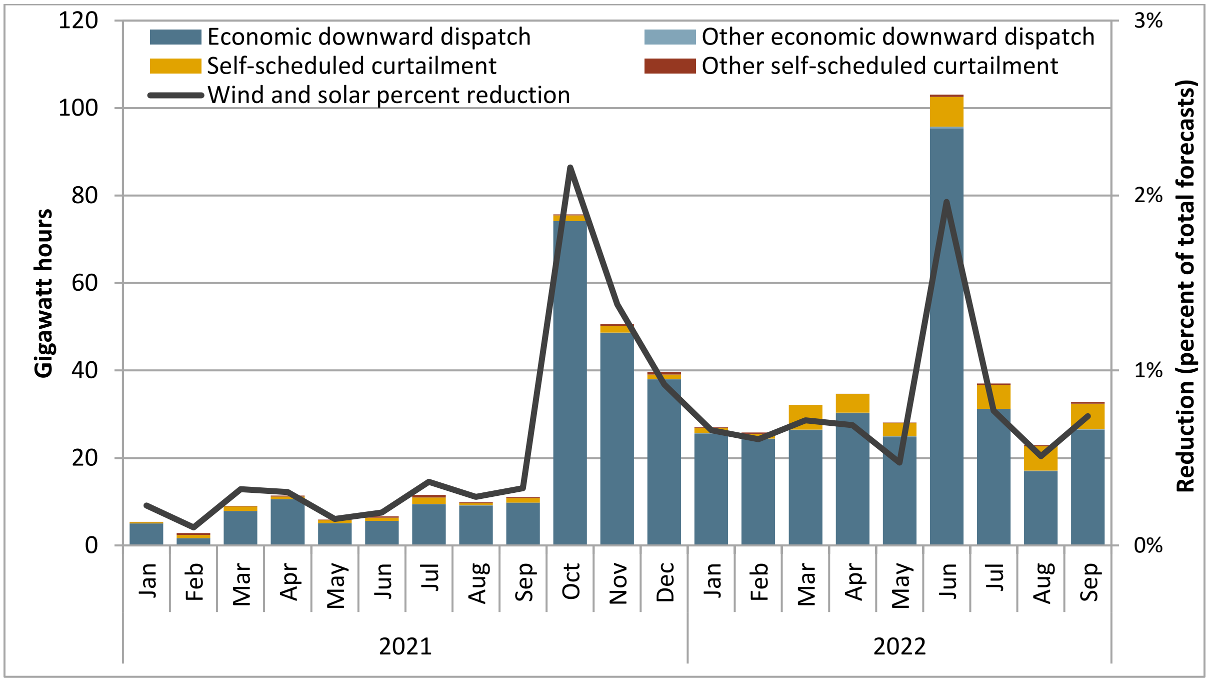


**Figure 1.4 Reduction of wind and solar generation by month (WEIM)**




## 1.1.4 Generation by fuel type

In the third quarter, renewable generation increased while generation from imports decreased. Average hourly generation by natural gas resources remained the same compared to the third quarter of 2021. Hydroelectric and biogas-biomass generation increased 31 percent and 12 percent, respectively. Average hourly generation by batteries more than doubled relative to the third quarter of 2021.[9]

Figure 1.5 shows the average hourly generation by fuel type during the third quarter of 2022. Total hourly average generation peaked at about 37,375 MW during hour ending 18. Average hourly battery generation peaked at about 1,625 MW during hour ending 20, about double the same time last year. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed to 25 percent of total generation during the peak net load hours of 17-21, up less than 1 percent during the same time last year.

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

**Figure 1.5 Average hourly generation by fuel type (Q3 2022)**

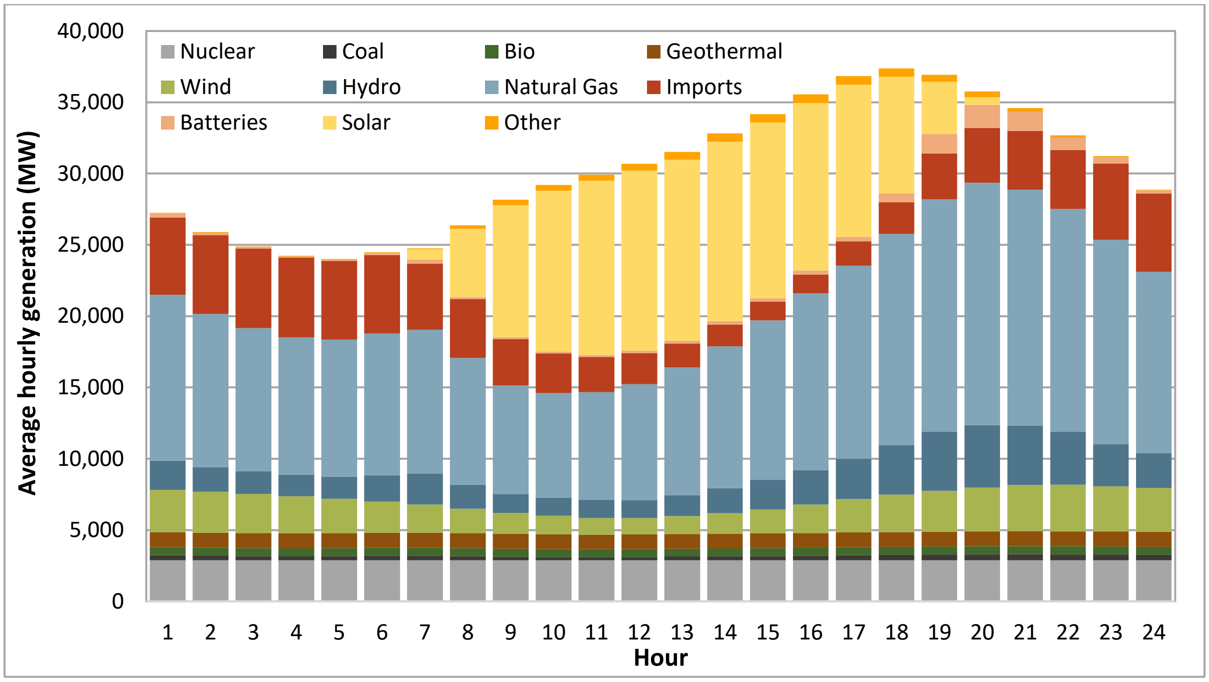



Figure 1.6 shows the change in hourly generation by fuel type between the third quarter of 2021 and the third quarter of 2022. In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

Overall, the net change shows that there was an increase in average hourly generation throughout the day. During middle of the day, natural gas generation was replaced by increased solar and battery generation. The category of generation labeled as "other" was higher during the middle of the day as well, likely due to an increase in hybrid resources.

Figure 1.7 shows the monthly average hydroelectric generation from 2019 to 2022. Hydroelectric generation in the third quarter of 2022 was 31 percent higher than the same time last year.

**Figure 1.6 Change in average hourly generation by fuel type (Q3 2021 to Q3 2022)**

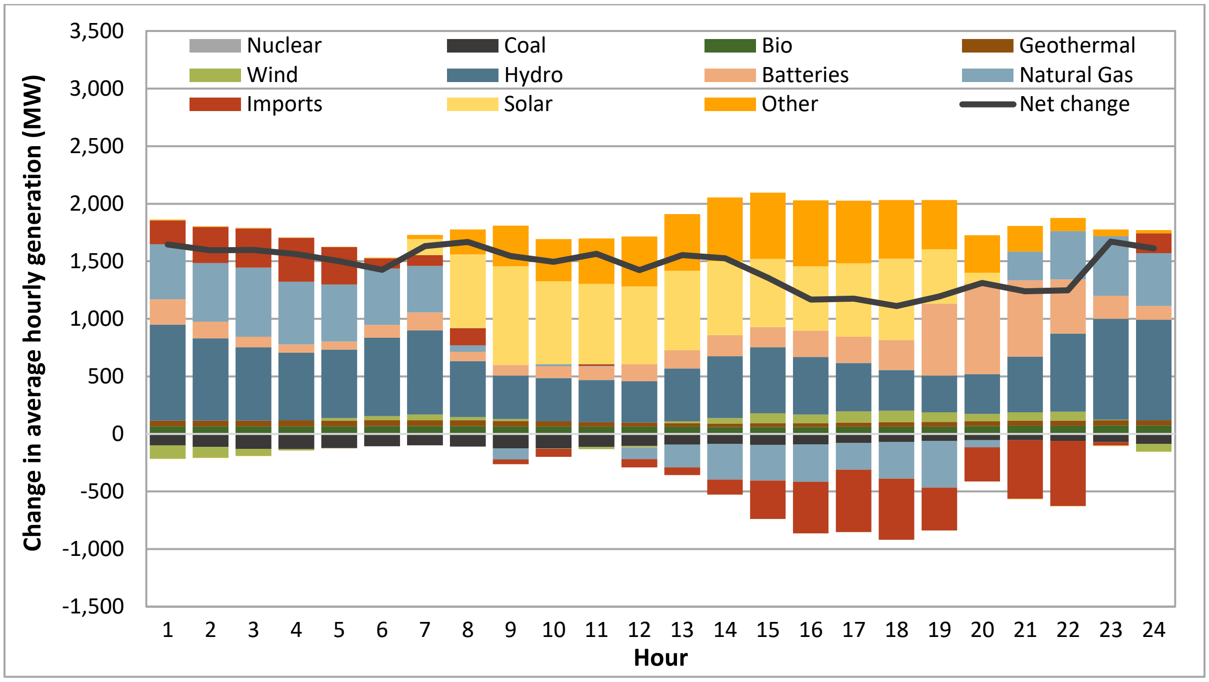
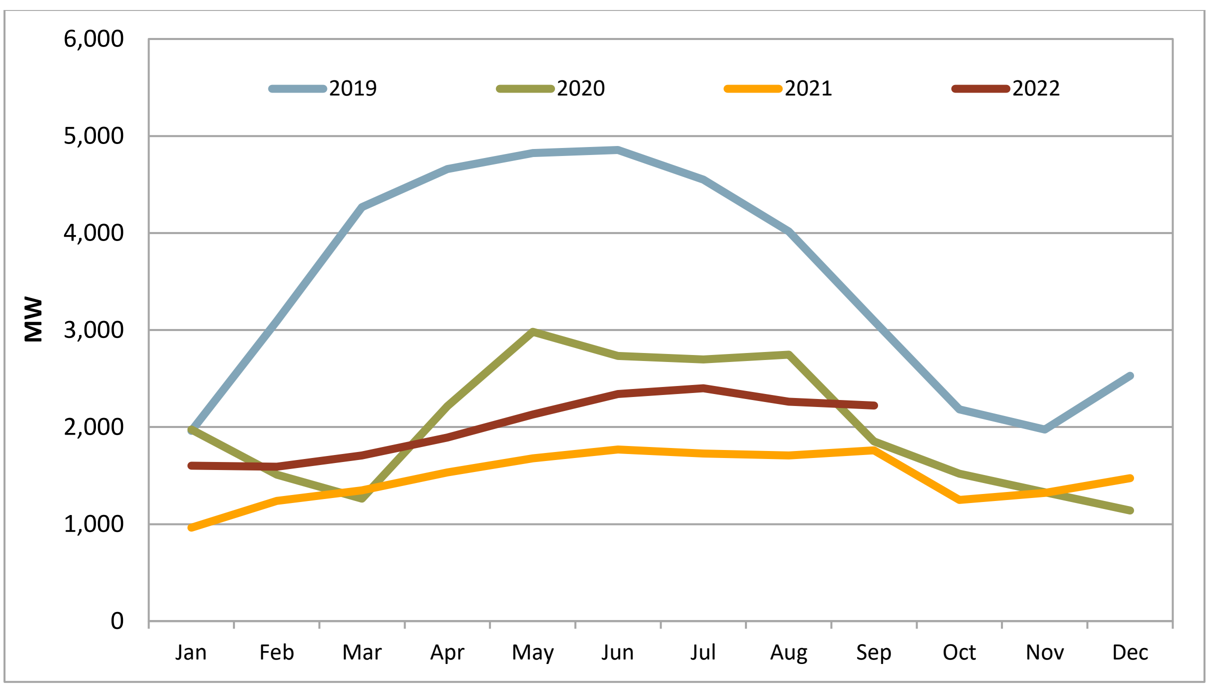



**Figure 1.7 Monthly average hydroelectric generation by year**



### 1.1.5 Generation outages

Total generation on outage in the California ISO balancing area averaged about 10,475 MW, 6 percent lower than the third quarter of 2021. This increase was driven by planned outages, which decreased 11 percent relative to the same time last year.

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

Figure 1.8 shows the quarterly averages of maximum daily outages during peak hours by type from 2020 to 2022. Figure 1.9 shows the monthly averages of maximum daily outages during peak hours broken out by type from 2020 to 2022. The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period. Looking at the monthly outages, there is usually a high number of outages in the spring months. So far, this year followed this trend with planned maintenance outages decreasing over the second quarter and remaining low during the summer months.

During the third quarter of 2022, the average total generation on outage in the California ISO balancing area was 10,475 MW, about 675 MW less than the third quarter of 2021, as shown in Figure 1.8.[10] There were 5 percent less forced outages and 11 percent fewer planned outages than the same quarter last year.

10 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 from the Western Energy Imbalance Market.

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

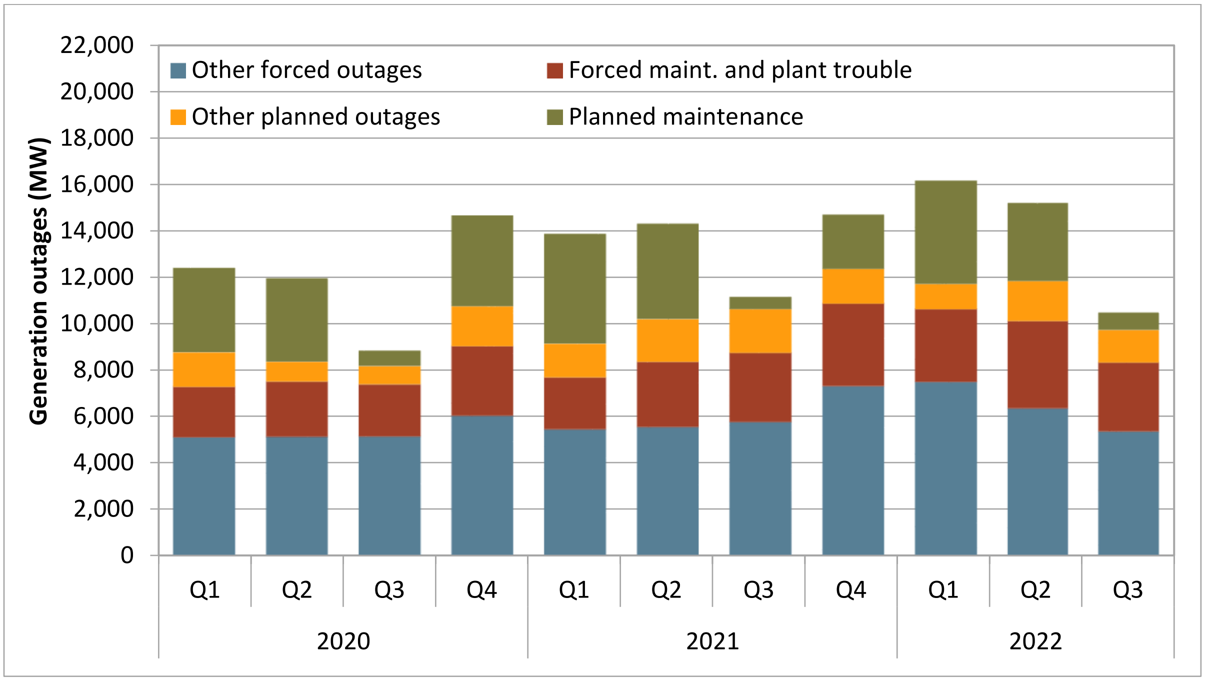
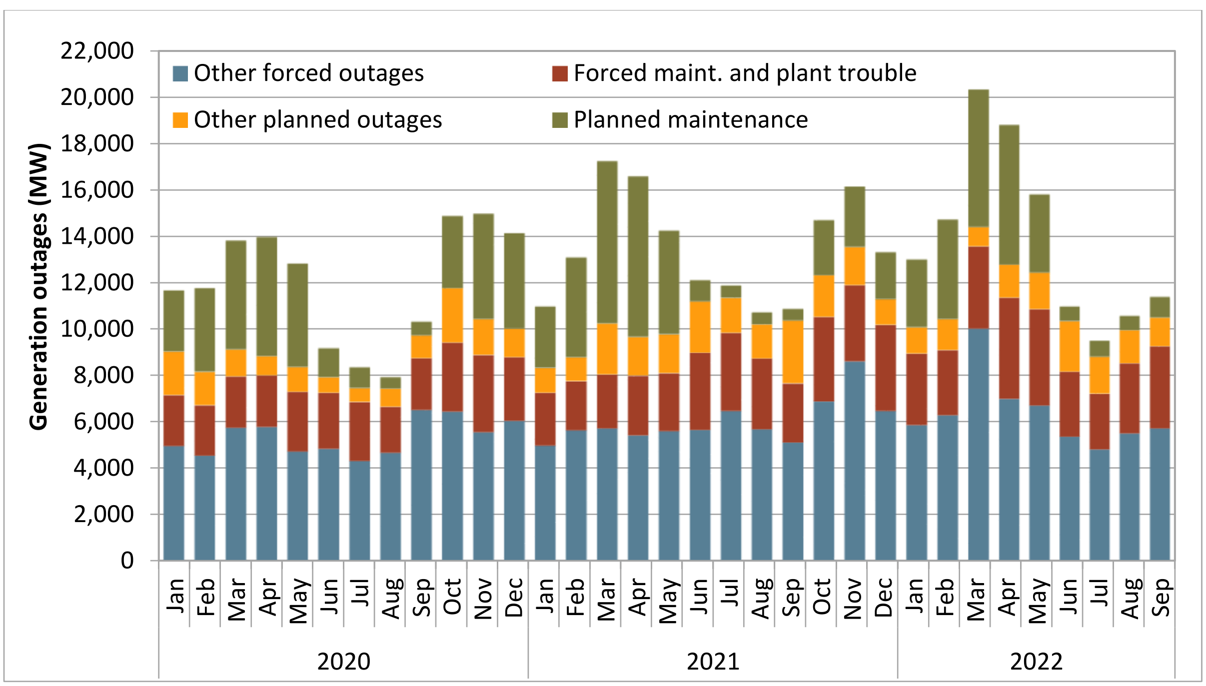



**Figure 1.9 Monthly average of maximum daily generation outages by type – peak hours**

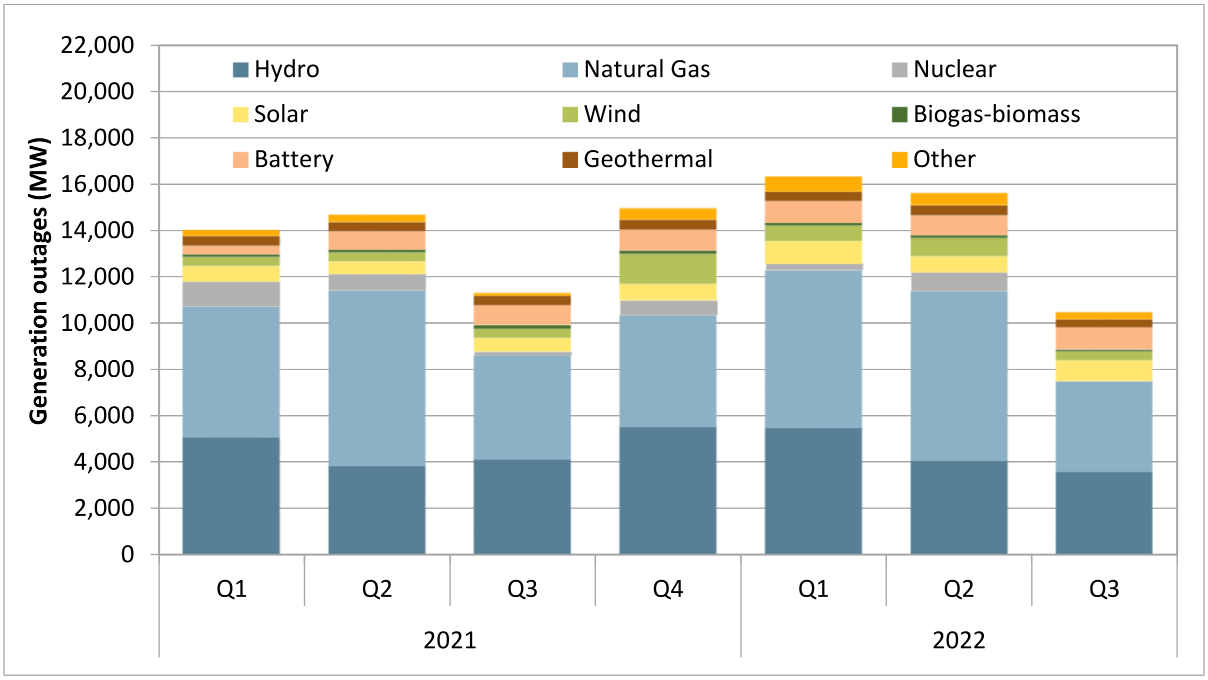



## Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 3,900 MW and 3,575 MW during the third quarter, respectively. These two fuel types accounted for a combined 71 percent of the generation on outage for the quarter. The amount of both natural gas and hydroelectric generation on outage decreased 13 percent relative to the third quarter of 2021.

Figure 1.10 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[11] Most fuel types saw lower average amounts of generation on outage compared to the third quarter of 2021.

**Figure 1.10 Quarterly average of maximum daily generation outages by fuel type – peak hours**




## 1.2 Energy market performance

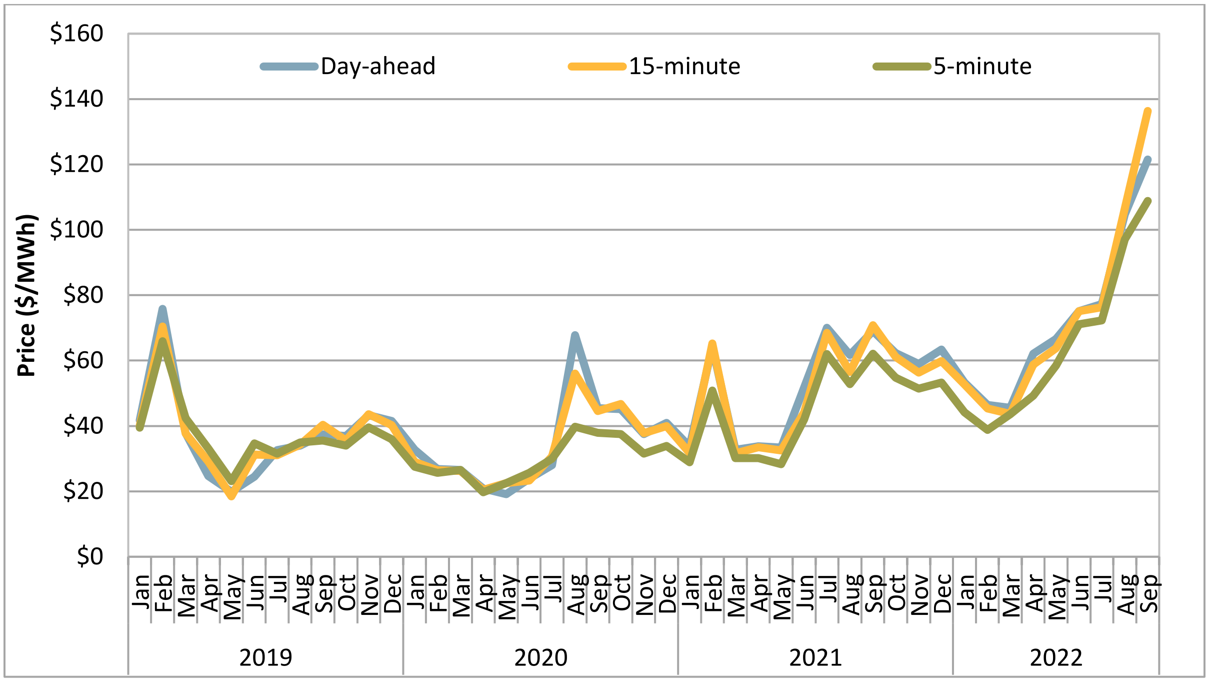
### 1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Prices in all three markets were about 51 percent higher this quarter compared to the third quarter last year.

Figure 1.11 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 2019 to September 2022.

11 In this figure, the “other” category contains demand response, coal, and additional resources of unique technologies.

**Figure 1.11 Monthly load-weighted average energy prices for California ISO (all hours)**




Day-ahead prices averaged $101/MWh, 15-minute prices averaged $106/MWh, and 5-minute prices averaged $92/MWh. Prices across all three markets were about 51 percent higher than the third quarter last year. All three prices in September 2022 recorded their highest price since January 2019. The California ISO balancing areas experienced an extraordinary heat wave between August 31, 2022 and September 9, 2022. The heat wave increased the net load, and, the CAISO raised bid caps and penalty prices. As a result, the average day-ahead price for September 2022 reached $121/MWh, the 15-minute price reached about $136/MWh, and the 5-minute price reached about $108/MWh.

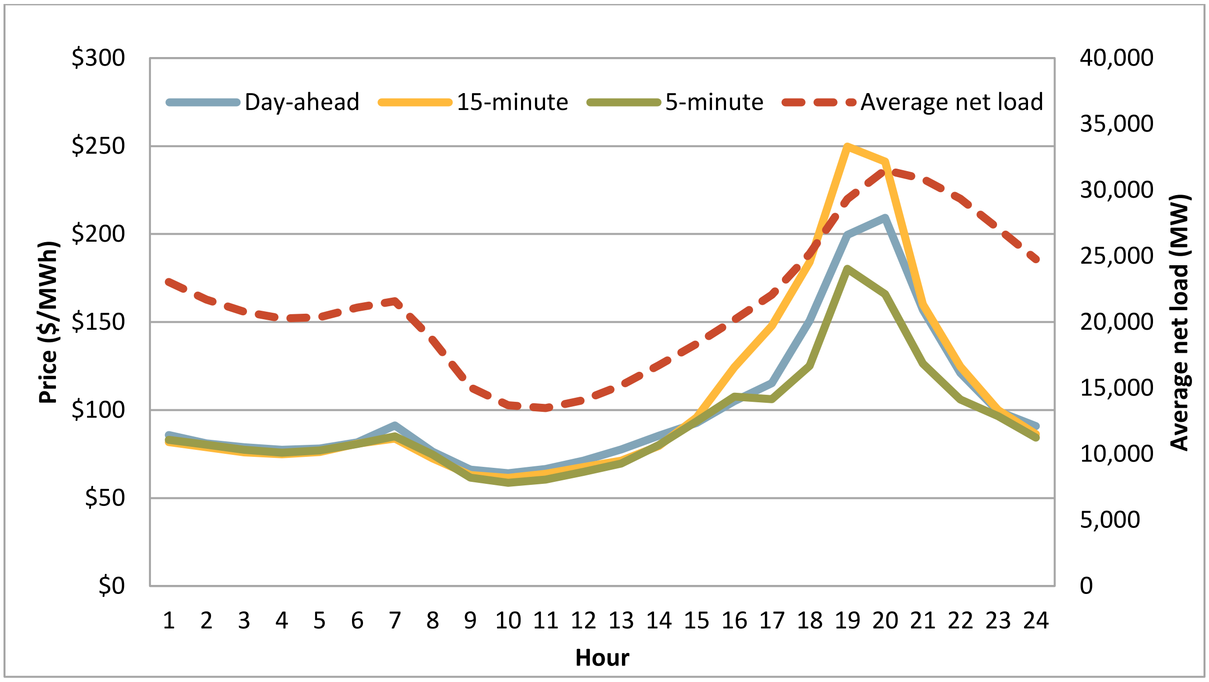
Figure 1.12 illustrates load-weighted average energy prices on an hourly basis for the quarter compared to average hourly net load.[12] Average hourly prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) and are measured by the left axis, while average hourly net load (red dashed line) is measured by the right axis.

Average hourly prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. Energy prices and net load both increased sharply during the early evening, and peaked at 8:00 p.m. when demand was still high but solar generation substantially decreased. The average net load in this quarter reached 31,517 MW at 8:00 p.m. On September 6, 2022, the peak of the heat wave period, the net load reached 41,496 MW at 8:00 p.m. At this hour, the day-ahead load-weighted average energy price was $1,126/MWh, the 15-minute price was $1,984/MWh, and the 5-minute price was $1,897/MWh.[13]

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

[13] In chapter 3, Figure 3.3 shows the load-weighted average energy price and hourly net load chart during the heat wave period, from August 31, 2022 to September 9, 2022.

**Figure 1.12 Hourly load-weighted average energy prices (July - September)**




## 1.2.2 Bilateral price comparison

During the heat wave conditions that existed across the west from September 1 through September 10, bilateral index prices at Mid-Columbia exceeded the $1,000/MWh WECC soft offer cap while index prices at Palo Verde were at or below the cap on some days. Consequently, the California ISO raised its energy bid cap and penalty prices to $2,000/MWh during this period. On average, day-ahead market prices in July and August were higher in the CAISO and the Palo Verde hub than at the Mid-Columbia hub across peak hours. In September, average bilateral prices across peak hours exceeded CAISO prices. Regional differences in prices reflect transmission constraints as well as greenhouse gas compliance costs.

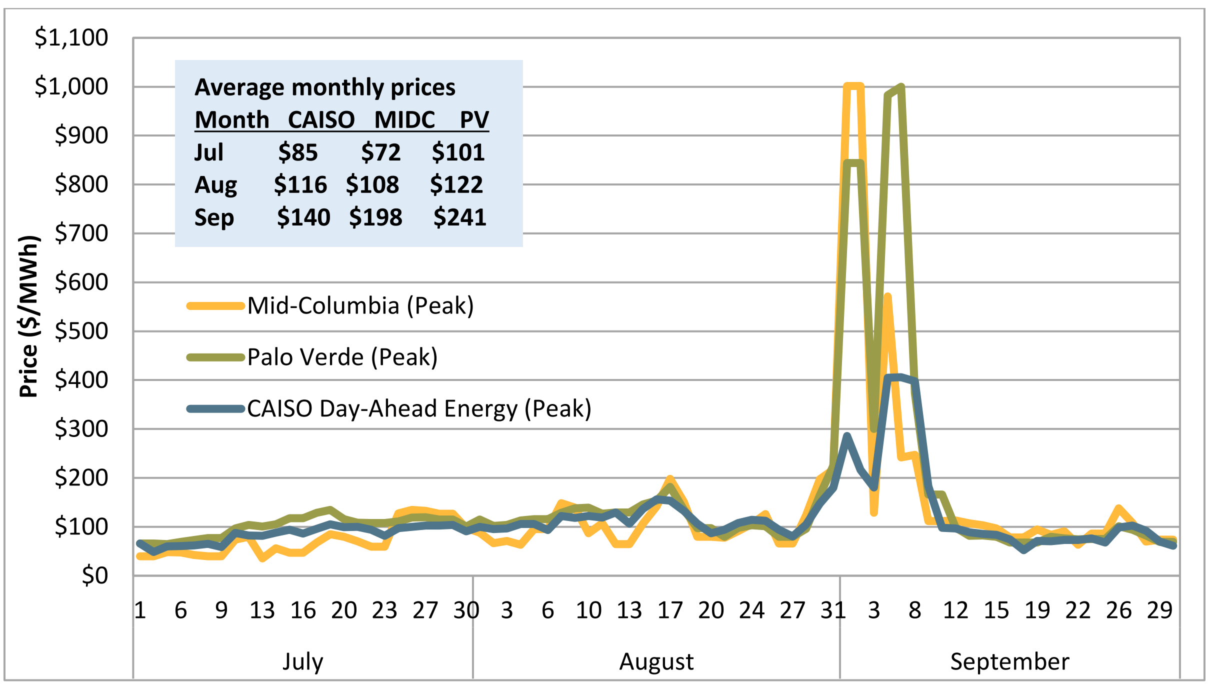
Figure 1.13 shows the CAISO day-ahead weighted average peak prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the average day-ahead peak energy prices from the Intercontinental Exchange (ICE) at the Mid-Columbia and Palo Verde hubs outside of the California ISO market. These prices were calculated during peak hours (hours ending 7 through 22) for all days, excluding Sundays and holidays. The figure shows significant price divergence between the CAISO and bilateral hubs during the heat wave conditions that existed in early September. Trade prices at the Mid-Columbia, Palo Verde, and other locations exceeded the $1,000/MWh WECC soft offer cap, requiring sellers to submit cost justification for sales made above this cap to FERC.

Beginning 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, for sellers whose sales were above the prevailing index price, FERC has ordered them to refund the premium they charged above the index price.[14] 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.[15] FERC has yet to rule on some of the cost justification filings for June 2021, and has not begun to issue orders related to the August and September 2022 filings.

Figure 1.14 uses the same data underlying Figure 1.13 but on an average monthly basis for 2021 and 2022. Prices in the CAISO balancing area are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). As shown in this figure, average prices in September at the Palo Verde and Mid-Columbia hubs are significantly higher than prices at the California ISO DLAPs.

Average day-ahead prices in the California ISO balancing area and bilateral hubs (from ICE) were also compared to real-time hourly energy prices traded at the Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average day-ahead hourly prices in the California ISO balancing area were greater than average real-time prices at Mid-Columbia and Palo Verde by $29/MWh and $17/MWh, respectively. Average day-ahead prices at Mid-Columbia and Palo Verde (from ICE) were greater than average real-time prices at these hubs (from Powerdex) by $27/MWh and $45/MWh, respectively.

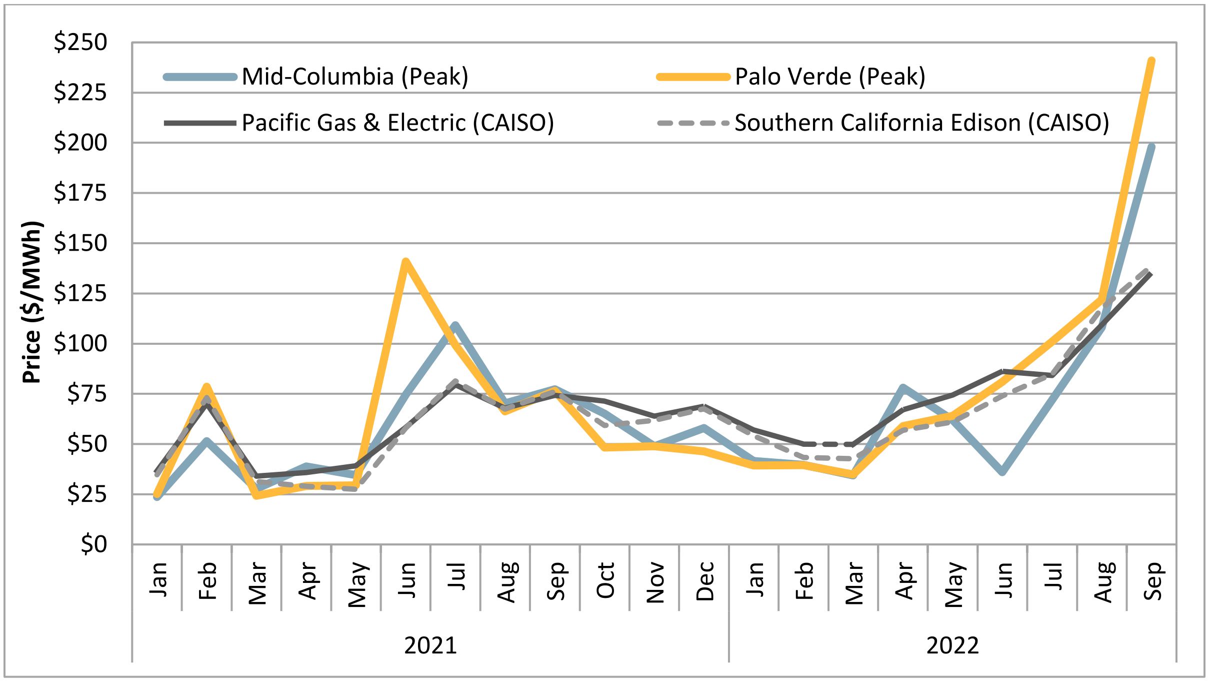
**Figure 1.13 Day-ahead California ISO and bilateral market prices (July - September)**




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

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

**Figure 1.14 Monthly average day-ahead and bilateral market prices**



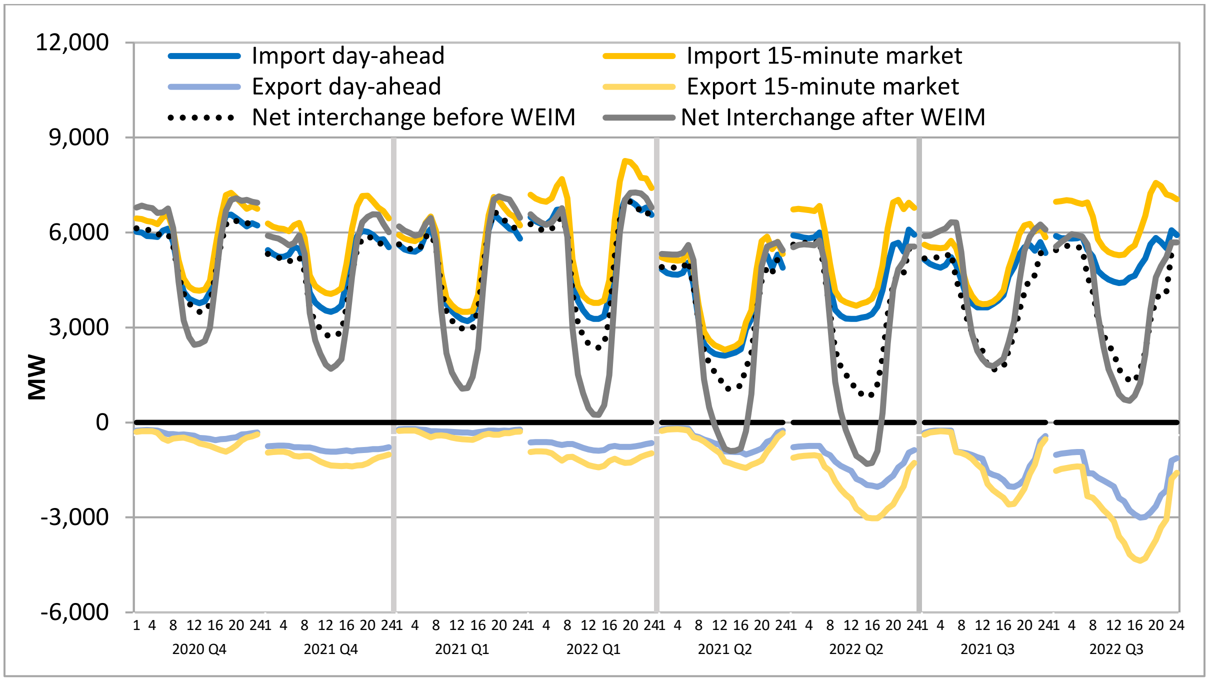

### Imports and exports

Average imports and exports increased compared to the same quarter in 2021. As shown in Figure 1.15, peak imports in the day-ahead (dark blue line) increased in all hours than compared to the same quarter of 2021, peaking at about 6,100 MW in hour-ending 23. Peak 15-minute cleared imports (dark yellow line) also increased in all hours of the day, about 1,200 MW over the peak hours of 17 to 21. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased in both the day-ahead and 15-minute markets compared to the same quarter of 2021, the increases over the peak hours of 17 to 21 were about 900 MW and 1,600 MW, respectively.

Compared to the same quarter in the previous year, the average net interchange when exporting increased in the middle of the day, both excluding (dashed black line) and including (solid grey line) WEIM transfers, about 100 MW and 700 MW on average by hour. During the solar ramp down period imports decreased both when excluding and including the WEIM, hourly average of 400 MW and 1,000 MW, respectively. These values are based on meter data and averaged by hour and quarter.

The solid grey line, which adds incremental WEIM interchange, reached a low point of about 700 MW in hour ending 15. The greatest import transfer into the California ISO area from the WEIM occurred in hour ending 22, at about 1,000 MW, compared to about 1,800 MW in hour ending 7 from the same quarter in the prior year. Export transfer from the California ISO to the WEIM primarily occurred between hour ending 9 to hour ending 17, with hour ending 12 topping out at about 900 MW. This is an increase from the same quarter of the previous year with a maximum export in hour ending 12 at about 250 MW.

**Figure 1.15 Average hourly net interchange by quarter**



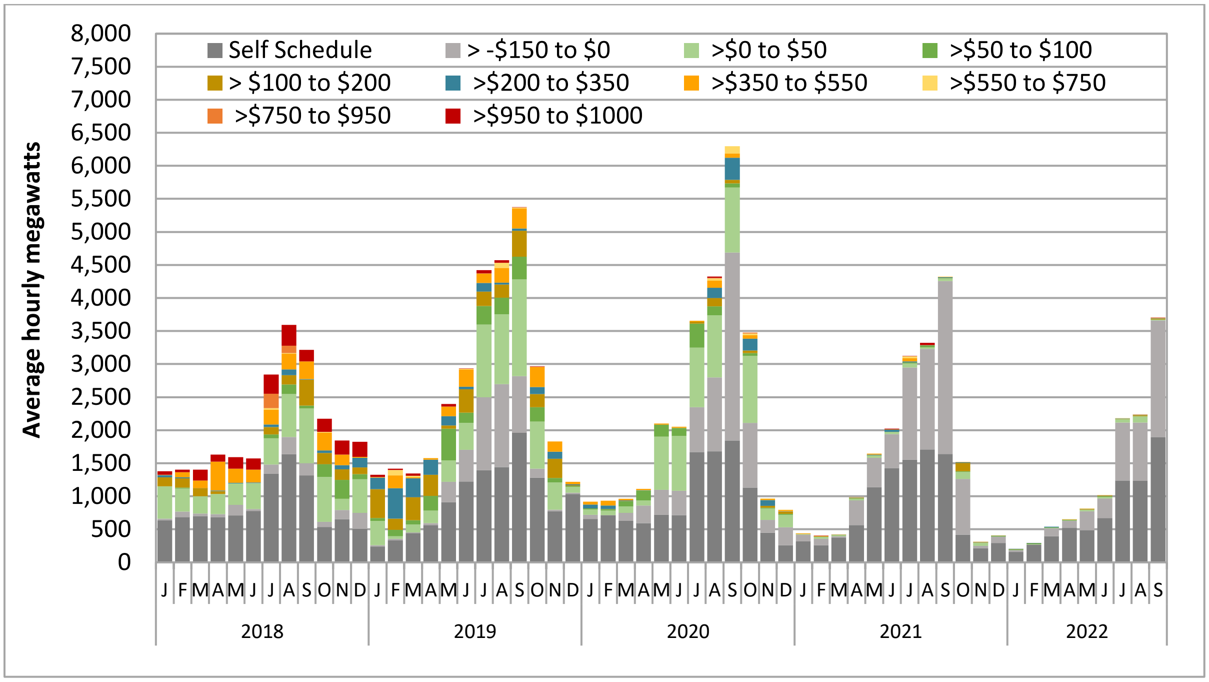

In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the CAISO markets at or below $0/MWh, at minimum in the availability assessment hours.[16] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices. An overall decline in volumes began in late 2020 and continued throughout 2021 as well as into the first half of 2022. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 1.16**Error! Not a valid bookmark self-reference.** 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 grey bars reflect import capacity that was self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market.

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

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

**Figure 1.16 Average hourly resource adequacy imports by price bin**




## 1.3 Price variability

Price variability this quarter was greater in the day-ahead, the 15-minute, and 5-minute markets compared to the same quarter last year. All three markets experienced a high frequency of prices between $250/MWh and $500/MWh. No negative prices occurred in the day-ahead market and only few in the real-time markets.

### High prices

Figure 1.17 shows the frequency of high prices across all three markets for the three largest load aggregation points (LAP) by month between April 2021 and September 2022. In the day-ahead market, the frequency of high prices over $250/MWh significantly increased in the third quarter compared to the previous year. In 2021, 0.7 percent of intervals had prices above $250/MWh between July and September. However, in 2022, 1.9 percent of intervals had prices above $250/MWh during the period. The majority of the high prices occurred during the heat wave period.

The 15-minute market had a higher frequency of price spikes in this quarter compared to previous periods. Prices above $250/MWh rose to 1.4 percent from 0.7 percent in the third quarter compared to the same period last year. About 41 percent of these high prices were $1,000/MWh or higher.

The 5-minute market also had more frequent price spikes this quarter. Prices above $250/MWh rose to 1.1 percent in the second quarter of 2022 from 0.3 percent in the same quarter last year. About 30 percent of these high prices were $1,000/MWh or higher.

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

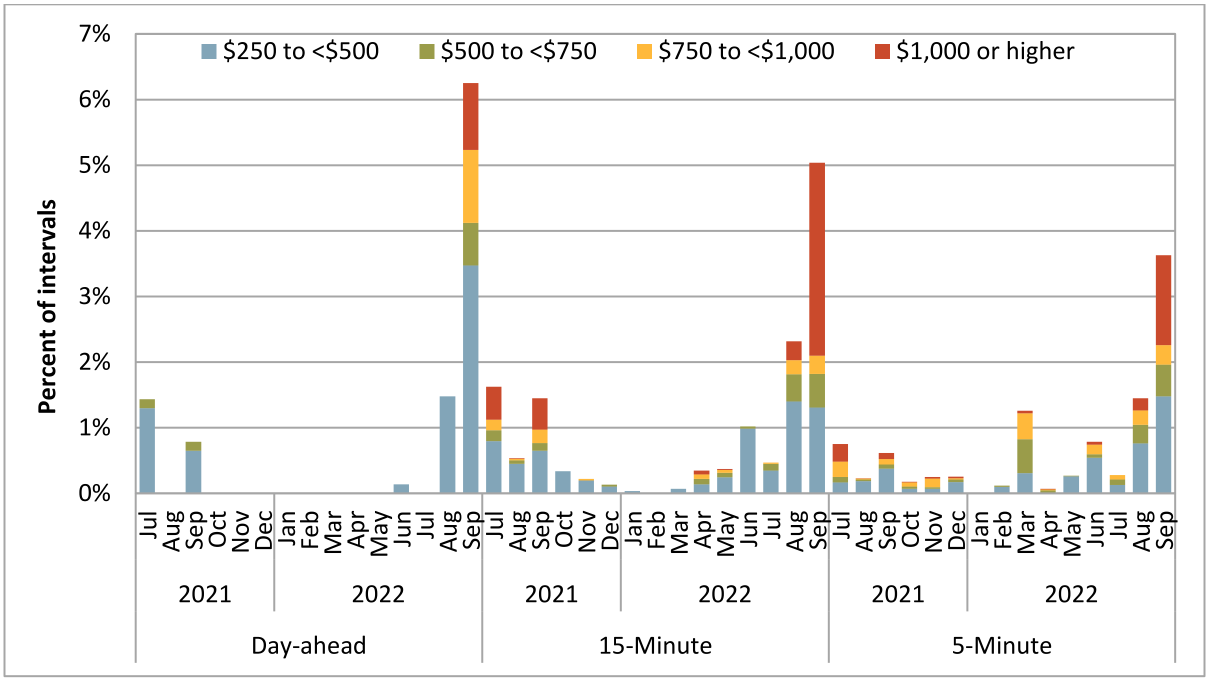


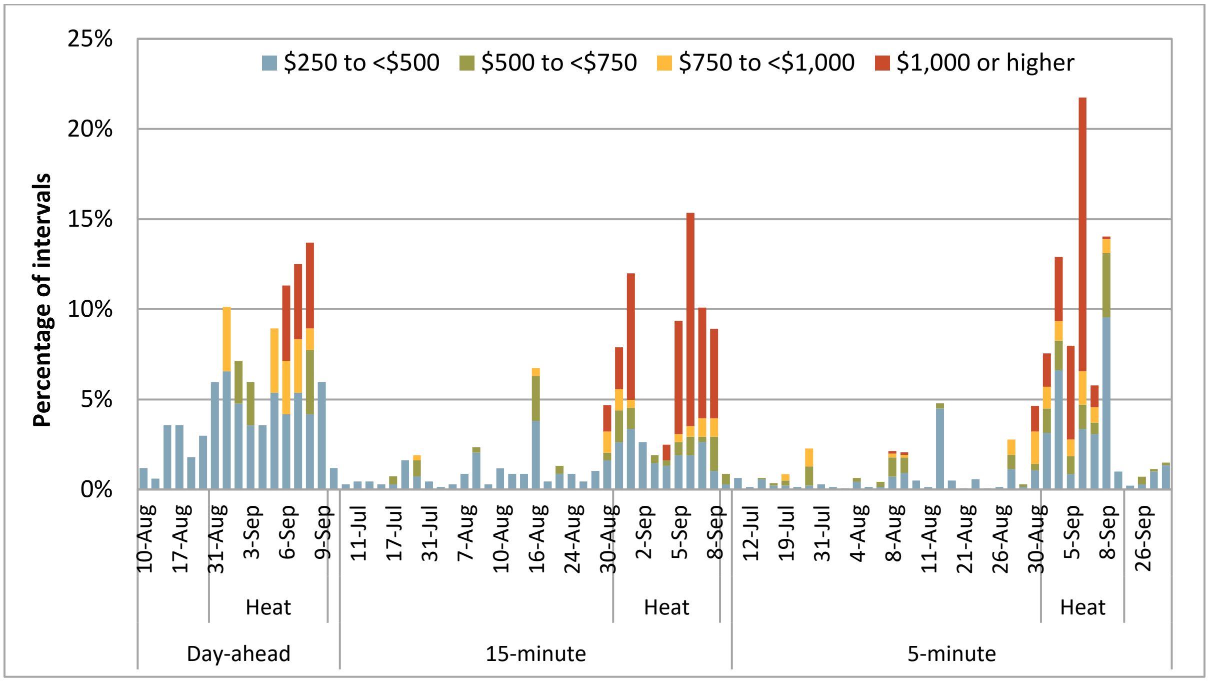

Figure 1.18 focuses on the distribution of days with prices equal to or higher than $250/MWh for each market for this quarter. The horizontal axis represents only days when these prices occurred in each market, a vertical line and the word 'Heat' was added to denote the heat wave period. The vertical axis identifies the distribution of high prices.[18]

A significant increase in high price frequency occurred this quarter in the heat wave period with about 95 percent of extremely high price ($1,000/MWh or higher) in this period. This occurred when the California ISO balancing authority experienced a record high load and a shortage of energy and ramping capacity and at times removed the $1,000/MWh pricing cap and increased the penalty price in order to procure more energy.[19] High natural gas prices also contributed to the greater frequency of high prices this quarter as illustrated in Figure 1.1. Natural gas-fired units are often the marginal energy source of generation in the CAISO balancing area, as well as other regional markets, and often results in higher system marginal energy prices across the CAISO footprint.

18 Prices equal to or above $250/MWh are categorized into four groups (see the legend in Figure 1.18). The distribution first counts the number of trade intervals when the high price occurred for each day during the quarter. Each category is summed by day and market, and divided by the total number of intervals of all high prices for each market in the quarter.

19 Prices may be set to a higher price under certain market conditions, see: Department of Market Monitoring, *Q1 2021 Report on Market Issues and Performance,* June 9, 2021: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

**Figure 1.18 Distribution of high price interval in the third quarter 2022**

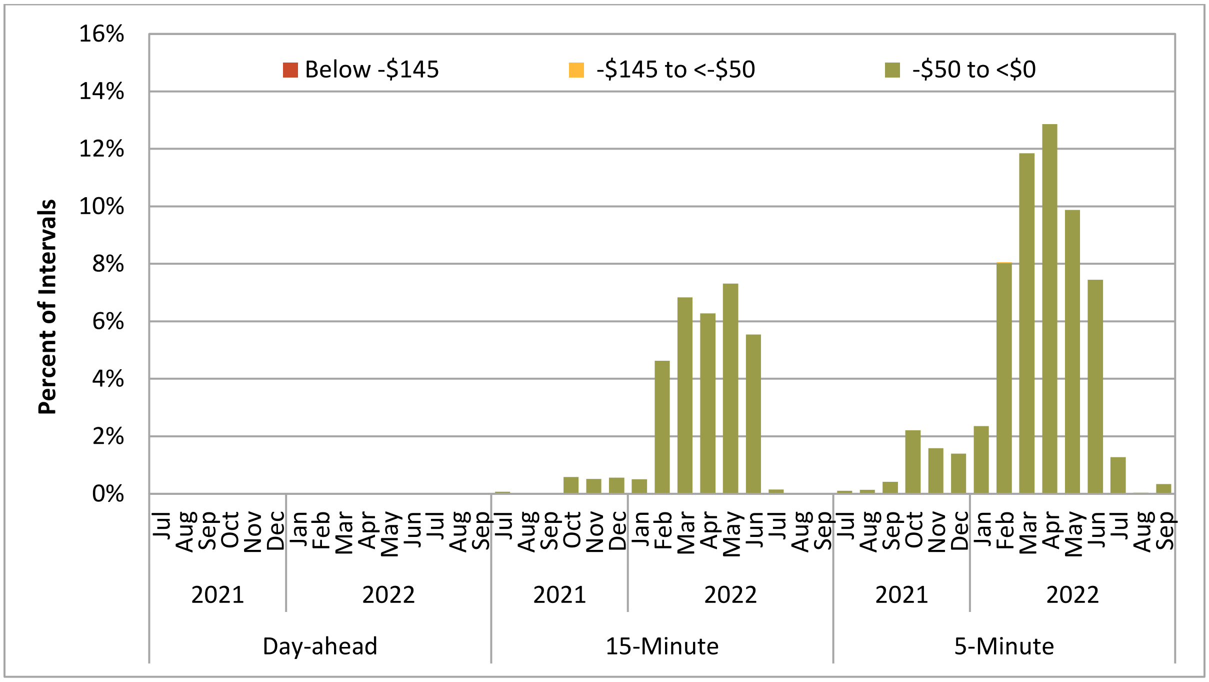



## Negative prices

Figure 1.19 shows the frequency of negative prices across all three markets for the three largest load aggregation points (LAP) by month between April 2021 and September 2022. The frequency of negative price intervals increased compared to the third quarter in 2021, even taking into account the heat wave period. Negative prices tend to be the most common when renewable production is high but demand is low. Low-cost renewable resources often bid at or below zero, increasing the potential of becoming the marginal energy source for that period. This leads to a higher frequency of negative prices in the real-time markets, which experience more negative prices than the day-ahead market.

In the 15-minute market, negative prices increased to 0.05 percent this quarter compared to 0.03 percent in the third quarter of last year. In the 5-minute markets, negative prices increased to 0.55 percent this quarter compared to 0.22 percent in the second quarter of last year. There were no negative prices in the day-ahead market the third quarter of either 2021 or 2022.

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




## 1.4 Convergence bidding

Convergence bidding is designed to align day-ahead and real-time prices by allowing financial arbitrage between the two markets. During most hours, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014. Convergence bidding continued to be profitable overall for most entities engaged in virtual bidding in the third quarter of 2022. The majority of profits continue to be received by financial entities (81 percent and marketers (11 percent), with about 8 percent going to entities with physical load and generation.

### 1.4.1 Convergence bidding revenues

Revenues for convergence bidders, before accounting for bid cost recovery charges, were about $47.2 million. Net revenues for virtual supply and demand fell to about $36.5 million after the inclusion of about $10.7 million of virtual bidding bid cost recovery charges, primarily associated with virtual supply.

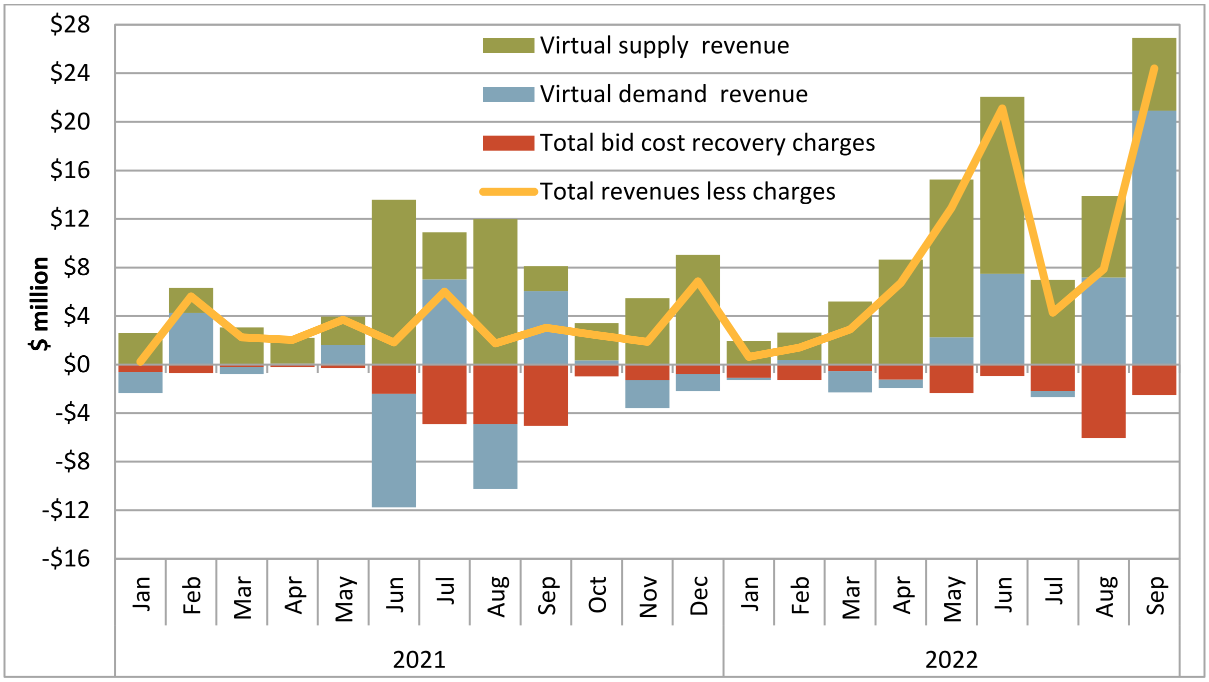
Figure 1.20 shows total monthly revenues for virtual supply (green bars), total revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). Before accounting for bid cost recovery charges:

- Total market revenues were positive during all months of the quarter. Revenues during the quarter, before taking into account bid cost recover charges, totaled about $47.2 million, compared to about $25.4 million during the same quarter from the previous year, and about $45.3 million during the previous quarter.
- Virtual demand revenues were about -$0.5 million, $7.2 million, and $20.9 million for July, August, and September, respectively.

- Virtual supply revenues were $7 million, $6.7 million, and $6 million for July, August, and September, respectively.

Convergence bidders received approximately $36.5 million after subtracting bid cost recovery charges of about $10.7 million for the quarter. Bid cost recovery charges were about $2.2 million, $6 million, and $20.9 million July, August, and September, respectively.

**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,[20] in millions of dollars, among different groups of convergence bidding participants.[21]

Financial entities represented the largest segment of the virtual bidding market for the current quarter, with 72 percent of volume and 81 percent of the settlement revenue. Marketers continue to have about 27 percent of volume and 11 percent of settlement revenue while generation owners and load serving entities represent about one percent of volumes and around eight percent of settlement revenues.

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

[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.

Outside of the heat wave period, overall prices in the 15-minute market were consistently lower than day-ahead prices in the third quarter. Higher fifteen-minute prices compared to the day-ahead market during the heatwave were a major factor that contributed to the large virtual demand revenues. This resulted in virtual demand revenues of $27.5 million from $9 million the previous quarter and $7.4 million from the same quarter of the previous year.

**Table 1.1 Convergence bidding volumes and revenues by participant type – Q3**

| Trading entities | Average hourly megawatts | | | Revenues\Losses ($ million) | | | | Total Revenue after BCR |
|---|---|---|---|---|---|---|---|---|
| | Virtual demand | Virtual supply | Total | Virtual demand | Virtual supply before BCR | Virtual Bid Cost Recovery | Virtual Supply after BCR | |
| Financial | 1,640 | 1,913 | 3,553 | $20.28 | $17.73 | -$5.79 | $11.93 | $32.22 |
| Marketer | 578 | 772 | 1,350 | $5.56 | $2.31 | -$3.45 | -$1.14 | $4.42 |
| Physical load | 1 | 26 | 28 | $0.09 | -$0.33 | -$1.46 | -$1.79 | -$1.70 |
| Physical generation | 11 | 0 | 11 | $1.60 | $0.00 | $0.00 | $0.00 | $1.60 |
| **Total** | **2,230** | **2,712** | **4,942** | **$27.54** | **$19.70** | **-$10.70** | **$9.00** | **$36.54** |

## 1.5 Residual unit commitment

On average, the total volume of capacity procured through the residual unit commitment process in the second quarter of 2022 was 3 percent higher than the same quarter of 2021. The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real-time. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load.

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 by 92 percent in the third quarter, relative to the same quarter in 2021. Figure 1.22 shows the hourly distribution of these operator adjustments during the third quarter of 2022. The black line shows the average adjustment quantity in each hour and the red markers highlight outliers in each hour. In this quarter, operators used this tool on 90 days to increase the residual unit commitment requirements by an average of about 1,387 MW per hour.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar in Figure 1.21) represent the difference in cleared supply (both physical and virtual) compared to the CAISO load forecast. On average, this factor contributed towards increasing residual unit commitment requirements in the third quarter of 2022, averaging 668 MW per hour.

Figure 1.21 also shows that residual unit commitment capacity is procured in part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 61 percent lower in the third quarter of 2022 than in the same quarter of 2021.

Lastly, residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid-in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market, illustrated by the yellow bar in Figure 1.21.

**Figure 1.21 Determinants of residual unit commitment procurement**

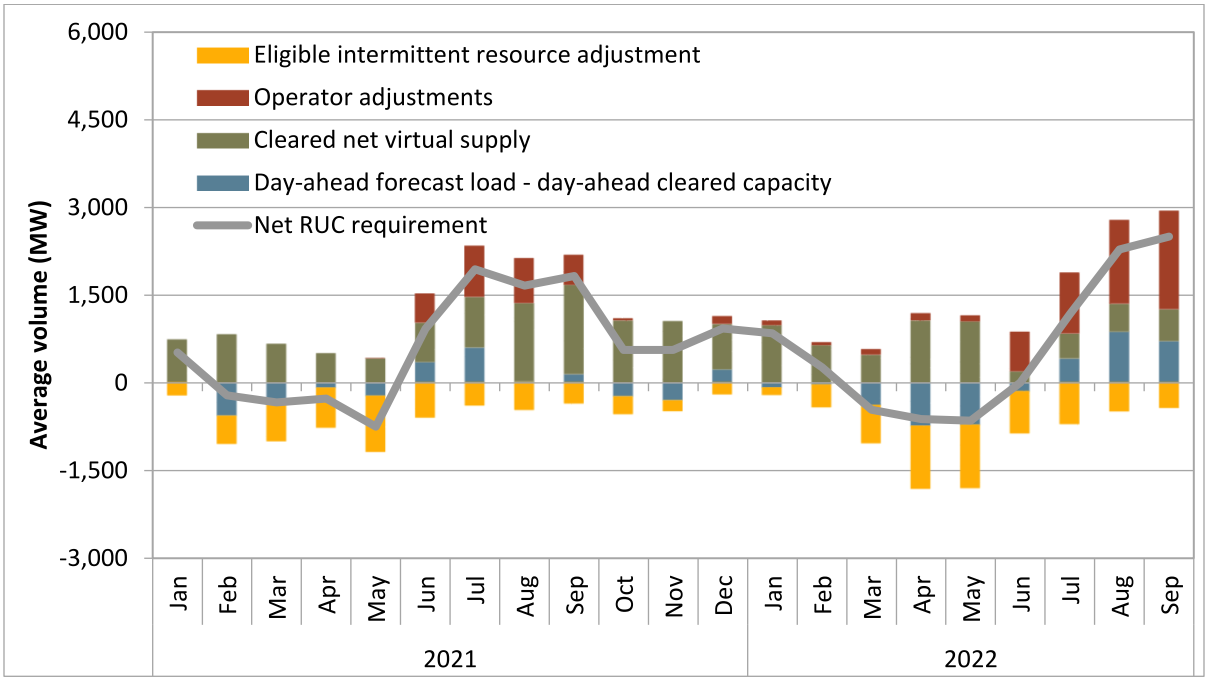



**Figure 1.22 Hourly distribution of residual unit commitment operator adjustments (July – September)**

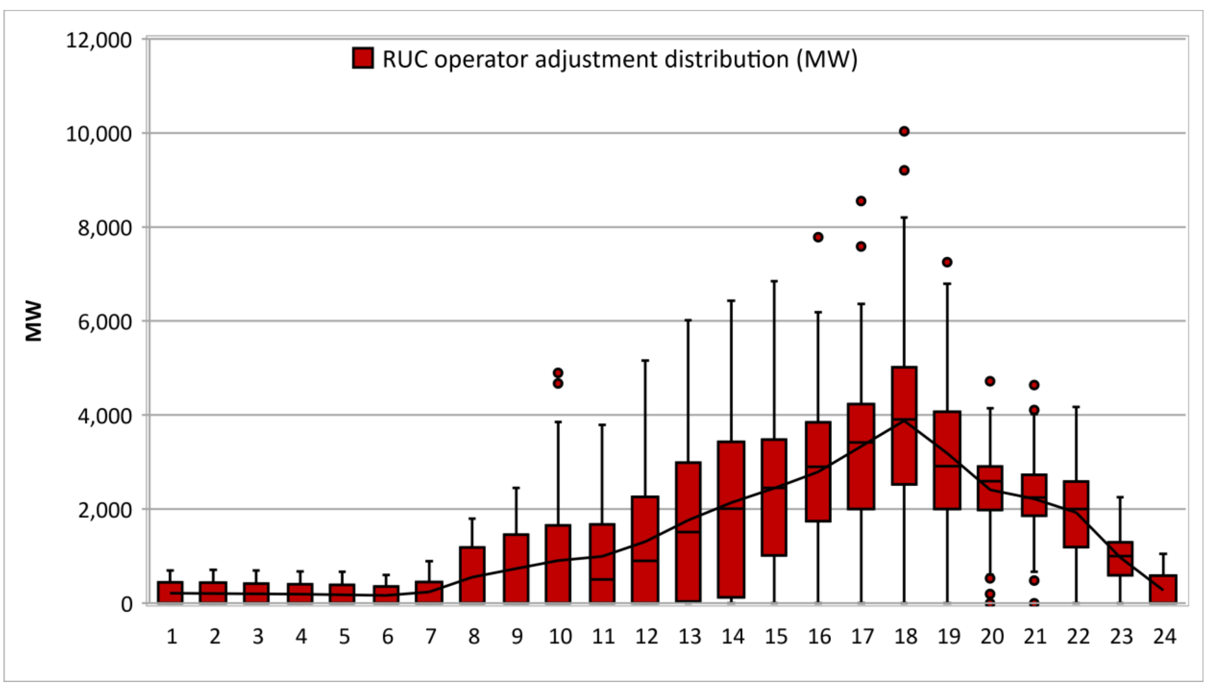


Figure 1.23 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased slightly to about 1,923 MW in the third quarter of 2022 from an average of 1,869 MW in the same quarter of 2021. Of the 1,923 MW capacity, the capacity committed to operate at minimum load averaged 349 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 2022, these costs were about $0.2 million, about $0.9 million lower than the same quarter of 2021.

**Figure 1.23 Residual unit commitment costs and volume**

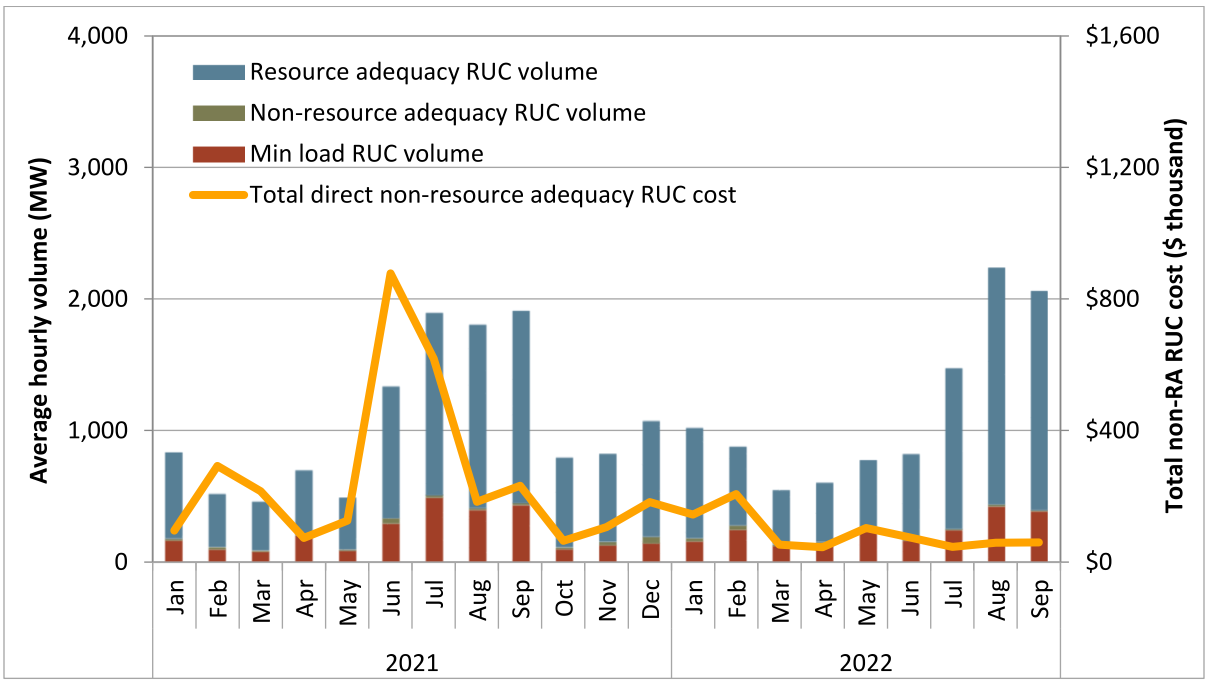



Figure 1.24 shows the residual unit commitment power balance constraint hourly under-supply infeasibility quantities that resulted during the heat wave conditions from September 1 through 9. These infeasibilities resulted in prices being set around $250/MWh during those hours. In addition, significant volumes of economic exports and low-priority self-schedule exports were cut in the residual unit commitment process prior to relaxing the power balance constraint.[23]

The market change that went in place 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 process is able to curtail economic and lower priority self-scheduled exports before relaxing the power balance constraint. These reduced exports no longer

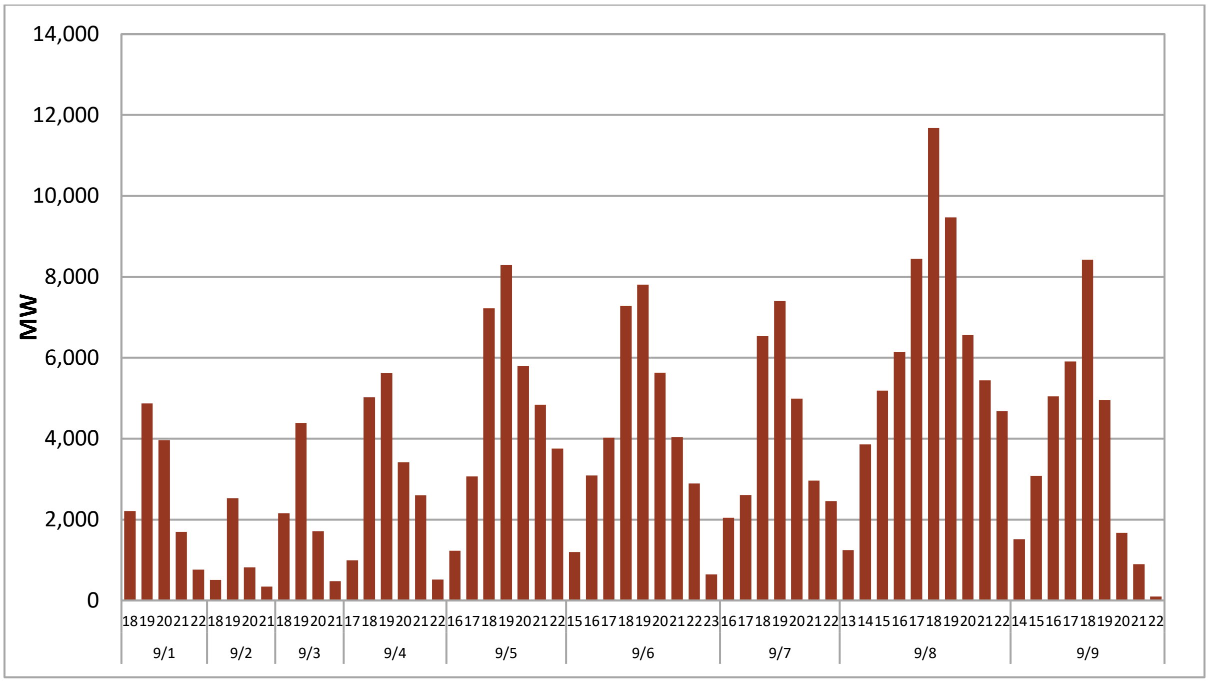
22 If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

23 More information on residual unit commitment export schedule cuts can be found in: California ISO, *Summer Market Performance Report Sept 2022,* November 2, 2022, Section 5.1: http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

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 addition, the California ISO will prioritize exports that bid into the day-ahead market and clear the residual unit commitment process over new exports that self-schedule into the real-time market.

**Figure 1.24 Residual unit commitment under-supply infeasibilities (Sep 1 – 9, 2022)**




## 1.6 Ancillary services

Ancillary service payments this quarter totaled nearly $112 million, a 118 percent increase from the third quarter of 2021. This is the highest year-over-year increase in quarterly payments since the third quarter of 2020. Average requirements were higher for operating reserves, regulation up, and regulation down compared to the same quarter last year.

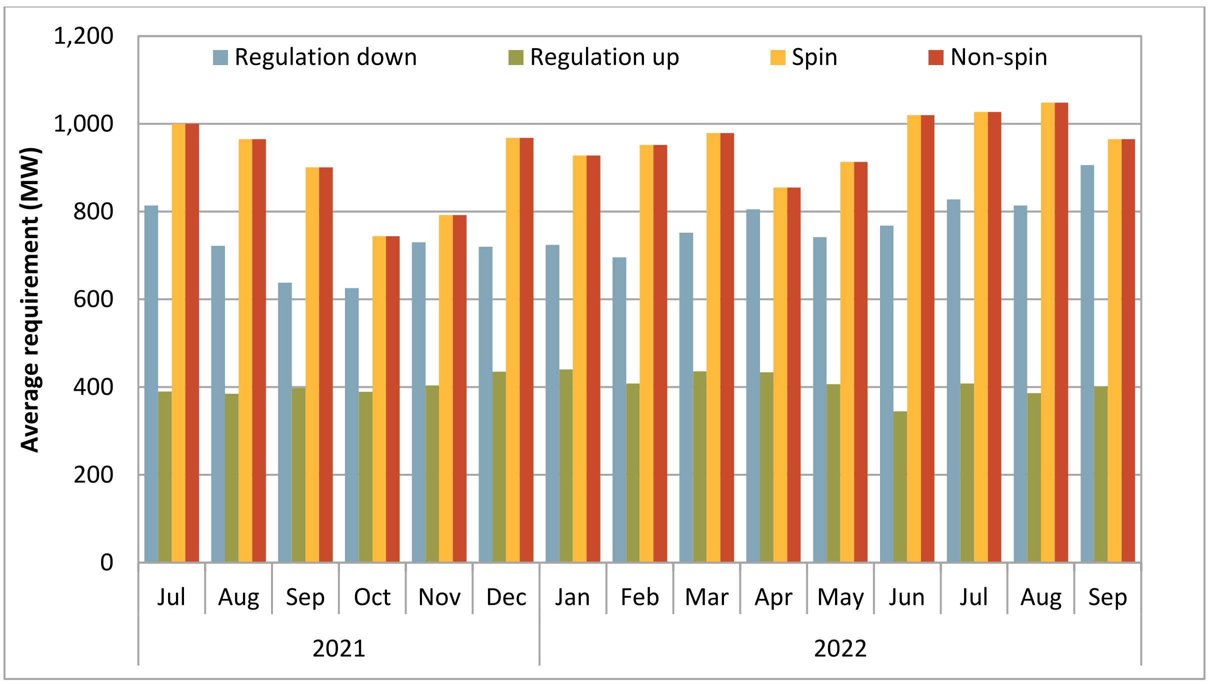
### 1.6.1 Ancillary service requirements

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

The California ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions.[24] Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency, and (3) 15 percent of forecasted solar production. Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

Figure 1.25 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. Average requirements for operating reserves increased 6 percent this quarter compared to the third quarter of 2021. This increase is in part due to the continued increase in exports, since operating reserves are based on load forecast and generation. Average regulation up requirements increased slightly from the third quarter of 2021—around 1.9 percent. However, average regulation down requirements increased by 17 percent in the same period, largely due to increased renewable penetration.

**Figure 1.25 Average monthly day-ahead ancillary service requirements**

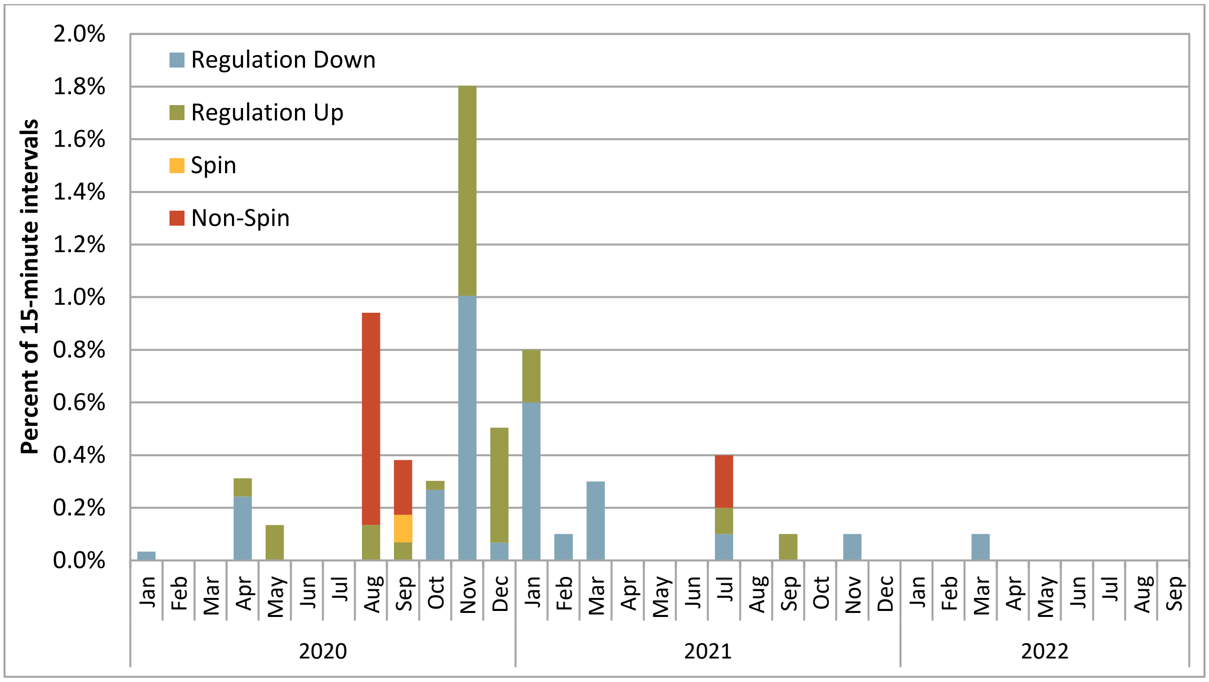



## 1.6.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California ISO pays a pre-determined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger. No scarcity events occurred in the third quarter of 2022. As shown in Figure 1.26, the frequency of intervals with scarcity pricing has decreased in recent years.

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

**Figure 1.26 Frequency of ancillary service scarcities (15-minute market)**

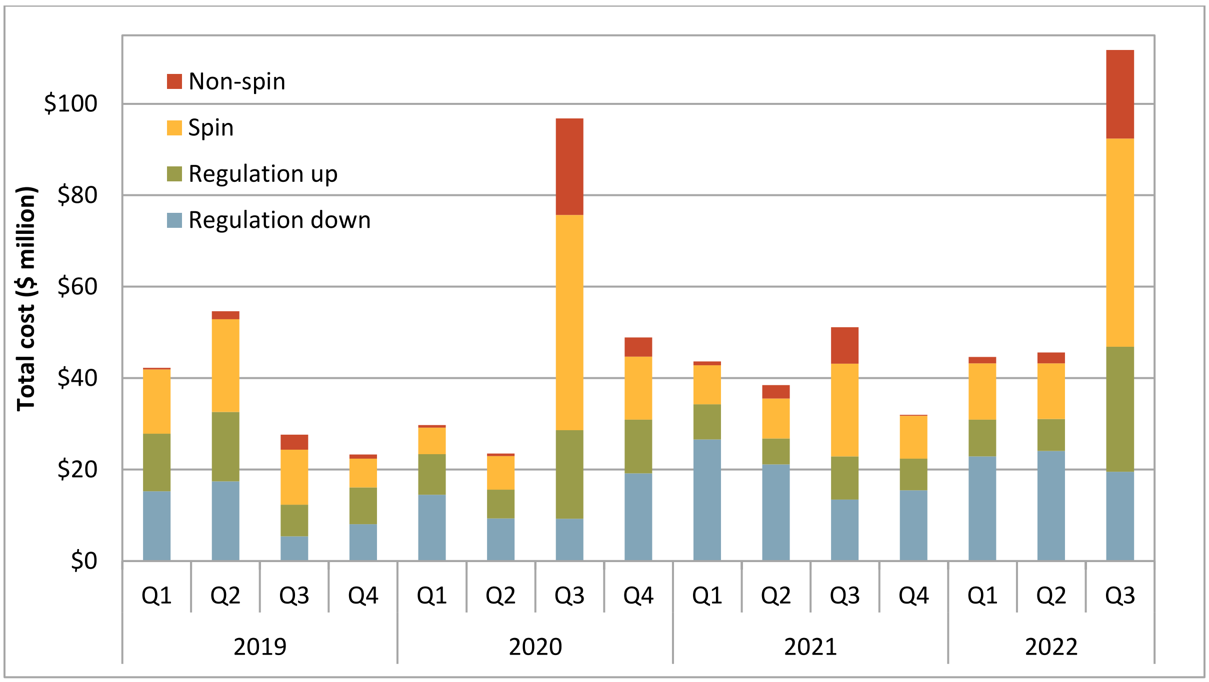


### 1.6.3 Ancillary service costs

Ancillary service payments reached nearly $112 million, around $66 million more than the previous quarter and $61 million more than the same quarter last year.

Figure 1.27 shows the total cost of procuring ancillary service products by quarter.[25] Spinning reserve procurement contributed the most to increased costs, with a $25.2 million increase, nearly 124 percent over what was paid in the second quarter of 2021. Over this same period, non-spinning reserve, regulation down, and regulation up payments increased by $11.4 million, $6.1 million, and $19.9 million respectively. Regulation down payments increased the least out of all ancillary service products despite its requirements increasing the most in the same timeframe. This is likely caused in part by the increased participation of battery resources in providing regulation down.

**Figure 1.27 Ancillary service cost by product**




## 1.7 Congestion

In the day-ahead market, congestion in the third quarter was more impactful than the same quarter last year, raising prices in SCE and SDG&E, while lowering prices in PG&E. In the 15-minute market, the impact of internal congestion on prices generally decreased prices in the Pacific Northwest and the East and raised prices in the Southwest. In the 5-minute market, a 5-minute market only constraint heavily impacted prices across the WEIM.

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

25 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.

California ISO balancing area (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric) as well as on WEIM entities.

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

The impact of congestion on each pricing node in the CAISO system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes as well as for groups of nodes that represent different load aggregation points or local capacity areas.[26]

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

## 1.7.1 Congestion in the day-ahead market

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

### Congestion rent and loss surplus

In the third quarter of 2022, congestion rent and loss surplus was $238 million and $133 million, respectively. These respective amounts represent an increase of 43 percent and 51 percent relative to the same quarter of 2021.[27] Figure 1.28 shows the congestion rent and loss surplus by quarter for 2021 and 2022.

In the day-ahead market, hourly congestion rent collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day. The daily marginal loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[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 1.28 and the day-ahead congestion rent and loss surplus in the third quarter of 2022 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 1.28 Day-ahead congestion rent and loss surplus by quarter (2021-2022)**

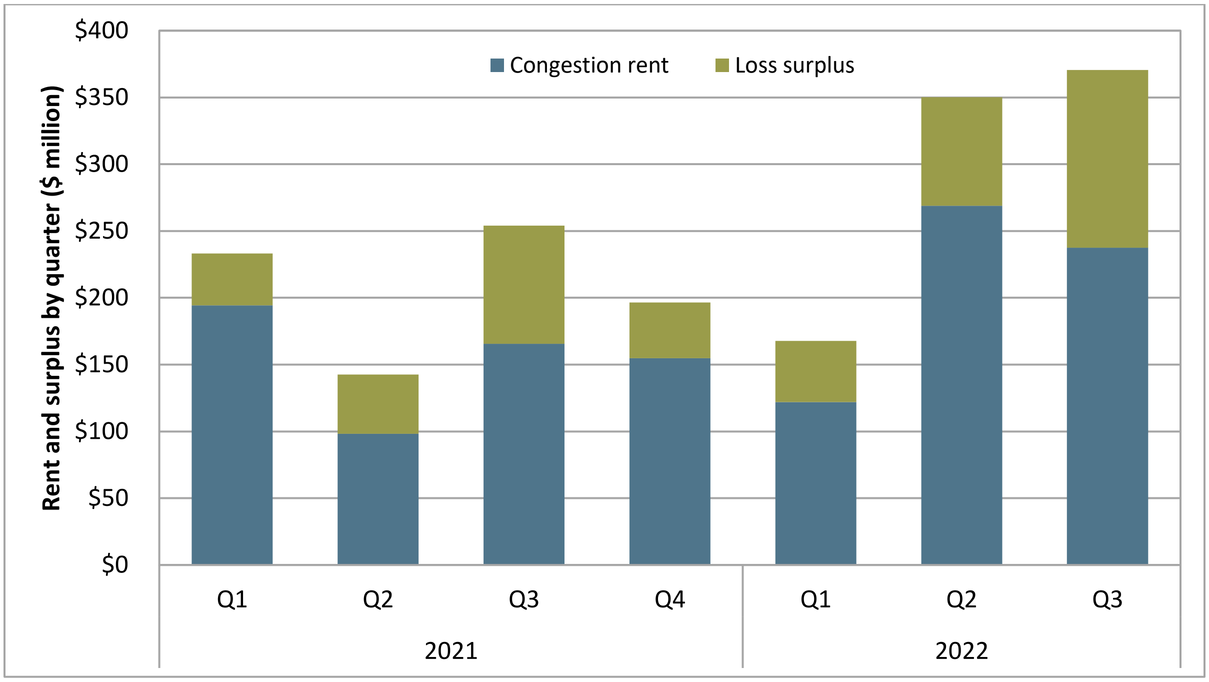



Figure 1.29 shows the overall impact of congestion on day-ahead prices in each load area in 2021 and 2022. Figure 1.30 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of day-ahead congestion on price separation in the third quarter was greater than during same quarter last year. Day-ahead congestion during the quarter raised prices 50 percent more in PG&E and SDG&E than it did in the third quarter of 2021.
- Day-ahead congestion increased quarterly average prices in SCE and SDG&E by $0.43/MWh (0.4 percent) and $1.77/MWh (1.7 percent), respectively, while it decreased average PG&E prices by $0.65/MWh (0.7 percent).
- The primary constraints impacting day-ahead market prices were the Midway-Vincent #2 500 kV line, Gates bank 12 500/230 kV transformer, and the Moss Landing-Las Aguilas 230 kV line.

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

**Figure 1.29 Overall impact of congestion on price separation in the day-ahead market**

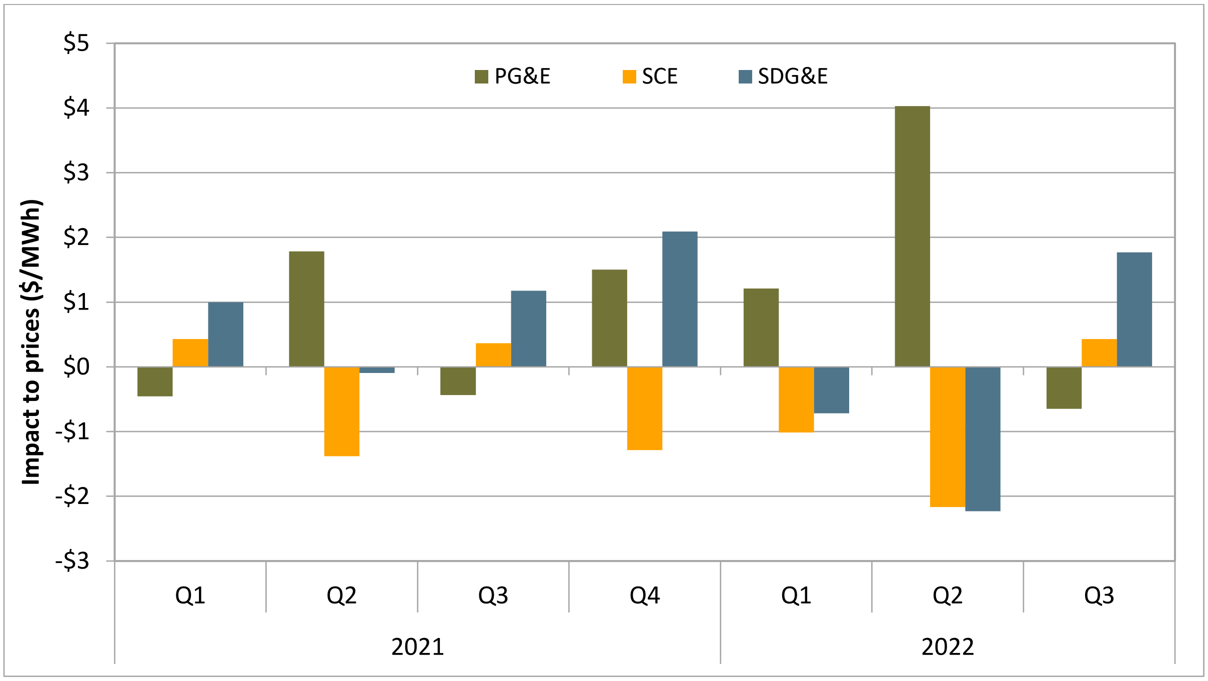
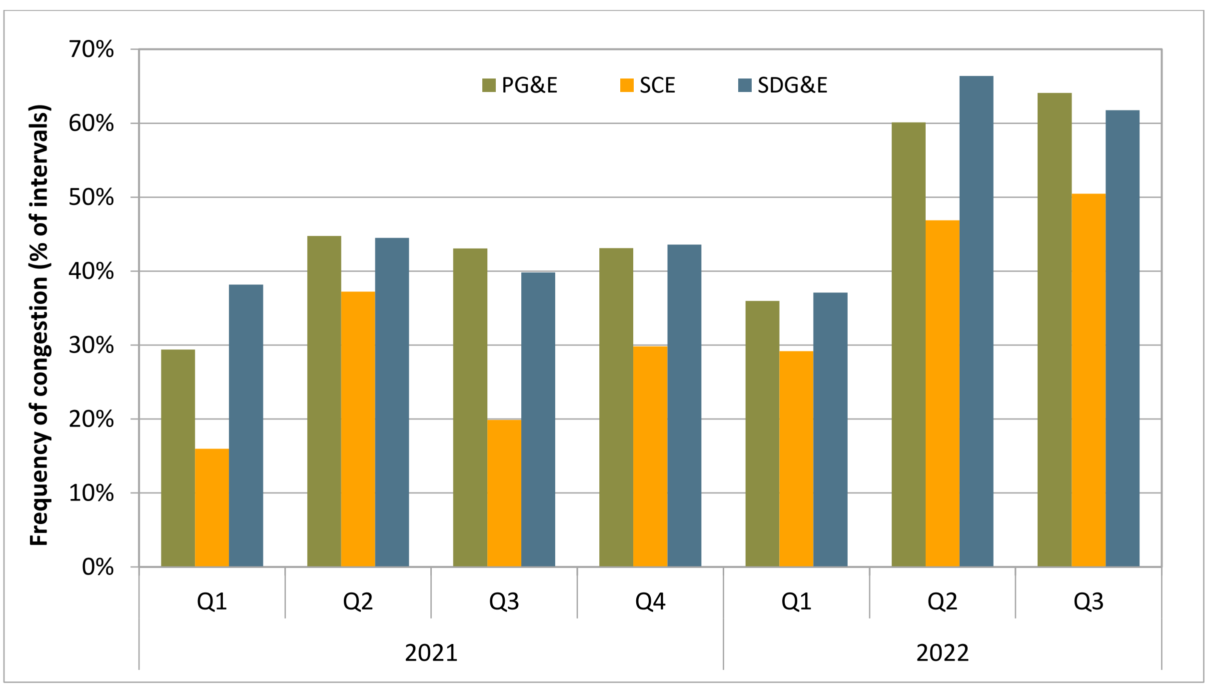



**Figure 1.30 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)**



### Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation during the quarter by constraint.[29] Table 1.3 shows the impact of congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The constraints with the greatest impact on day-ahead price separation for the quarter were the Midway-Vincent #2 500 kV line, Gates bank 12 500/230 kV transformer, and the Moss Landing-Las Aguilas 230 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 13 percent of hours. When binding, it increased SCE and SDG&E prices by $10.25/MWh and $9.69/MWh, respectively, and decreased PG&E prices by $15.43/MWh. For the quarter, congestion on the line increased average SCE and SDG&E prices by $1.34/MWh (1.3 percent) and $1.27/MWh (1.2 percent), respectively, and decreased average PG&E prices by $2.02/MWh (2.0 percent). This line was frequently binding due to the loss of the parallel 500 kV line.

**Gates bank 12 500/230 kV transformer**

The Gates #12 500/230 kV transformer (30055_GATES1_500_30900_GATES_230_XF_12_P) bound in 18 percent of hours over the quarter. When binding, it increased prices in PG&E by $3.25/MWh and decreased prices in SCE and SDG&E by $4.21/MWh and $4.69/MWh, respectively. For the quarter, congestion on the constraint increased average PG&E prices by $0.60/MWh (0.6 percent) and decreased average SCE and SDG&E prices by $0.48/MWh (0.5 percent) and $0.47/MWh (0.5 percent), respectively. This transformer constraint was binding due to maintenance at the substation. This work is expected to be completed in the spring of 2023.

**Moss Landing-Las Aguilas 230 kV line**

The Moss Landing-Las Aguilas 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in about 16 percent of hours. When binding, it increased PG&E prices by $2.93/MWh and decreased SCE and SDG&E prices by $2.19/MWh and $2.18/MWh, respectively. For the quarter, the nomogram increased average PG&E prices by about $0.46/MWh (0.5 percent), and decreased average SCE and SDG&E prices by $0.28/MWh (0.3 percent) and $0.26/MWh (0-.3 percent), respectively. This line was impacted by maintenance on the Tesla-Los Banos 500 kV line.

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

### Table 1.2 Impact of congestion on overall day-ahead prices

| Constraint Location | Constraint | PG&E | | SCE | | SDG&E | |
|---|---|---|---|---|---|---|---|
| | | $ per MWh | Percent | $ per MWh | Percent | $ per MWh | Percent |
| PG&E | 30055_GATES1 _500_30900_GATES _230_XF_12_P | $0.60 | 0.60% | -$0.48 | -0.47% | -$0.47 | -0.45% |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | $0.46 | 0.46% | -$0.28 | -0.28% | -$0.26 | -0.25% |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | $0.14 | 0.14% | -$0.11 | -0.11% | -$0.10 | -0.09% |
| | 7440_MetcalfImport_Tes-Metcalf | $0.10 | 0.10% | -$0.08 | -0.07% | -$0.07 | -0.07% |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | $0.05 | 0.05% | -$0.03 | -0.03% | -$0.02 | -0.02% |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | -$0.05 | -0.05% | $0.03 | 0.03% | $0.03 | 0.03% |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | -$2.02 | -2.03% | $1.34 | 1.33% | $1.27 | 1.22% |
| SCE | 24091_MESA CAL_230_24076_LAGUBELL_230_BR_2_1 | -$0.05 | -0.05% | $0.03 | 0.03% | $0.00 | 0.00% |
| SDG&E | 22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.81 | 0.78% |
| | 22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.33 | 0.32% |
| | 22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.13 | 0.12% |
| | 22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_2 | $0.00 | 0.00% | $0.00 | 0.00% | $0.13 | 0.12% |
| | 22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.09 | 0.08% |
| | 22556_NAVSTMTR_69.0_22824_SWTWTRTP_69.0_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.04 | 0.04% |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | $0.03 | 0.03% |
| | OMS_11878904_13810A_NG | $0.00 | 0.00% | $0.00 | 0.00% | -$0.02 | -0.02% |
| | OMS_11878920_13810A_NG | $0.00 | 0.00% | $0.00 | 0.00% | -$0.02 | -0.02% |
| | 22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1 | $0.00 | 0.00% | $0.00 | 0.00% | -$0.19 | -0.19% |
| Other | | $0.13 | 0.13% | $0.00 | 0.00% | $0.08 | 0.07% |
| **Total** | | **-$0.65** | **-0.65%** | **$0.43** | **0.42%** | **$1.77** | **1.70%** |

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

| Constraint Location | Constraint | Frequency | PG&E | SCE | SDG&E |
|---|---|---|---|---|---|
| PG&E | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | 0.8% | $5.47 | -$4.21 | -$4.69 |
| | 30055_GATES1 _500_30900_GATES _230_XF_12_P | 18.3% | $3.25 | -$2.60 | -$2.54 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | 4.5% | $3.10 | -$2.39 | -$2.15 |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | 15.6% | $2.93 | -$2.19 | -$2.18 |
| | 7440_MetcalfImport_Tes-Metcalf | 3.5% | $2.77 | -$2.11 | -$2.01 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | 13.1% | -$15.43 | $10.25 | $9.69 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | 0.2% | -$21.34 | $13.13 | $12.38 |
| SCE | 24091_MESA CAL_230_24076_LAGUBELL_230_BR_2_1 | 0.2% | -$22.52 | $12.45 | $0.00 |
| SDG&E | 22556_NAVSTMTR_69.0_22824_SWTWTRTP_69.0_BR_1 _1 | 0.1% | $0.00 | $0.00 | $45.11 |
| | 22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1 | 0.4% | $0.00 | $0.00 | $31.40 |
| | 22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_2 | 0.4% | $0.00 | $0.00 | $31.40 |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | 0.3% | $0.00 | $0.00 | $10.54 |
| | 22331_MIRASNTO_69.0_22644_PENSQTOS_69.0_BR_1 _1 | 1.0% | $0.00 | $0.00 | $8.94 |
| | 22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1 | 12.6% | $0.00 | $0.00 | $6.38 |
| | 22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1 | 6.6% | $0.00 | $0.00 | $5.02 |
| | OMS_11878904_13810A_NG | 0.4% | $0.00 | $0.00 | -$5.91 |
| | OMS_11878920_13810A_NG | 0.4% | $0.00 | $0.00 | -$6.45 |
| | 22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1 | 1.3% | $0.00 | $0.00 | -$15.15 |

### 1.7.2 Congestion in the real-time market

Congestion frequency in the real-time market is typically lower than in the day-ahead market, but has higher price impacts on load area prices. The congestion pattern in this quarter reflects this overall trend. Congestion patterns in the 15-minute and 5-minute markets are typically very similar. However, during the third quarter, a constraint that is only enforced in the 5-minute market (6110_COI_N-S) continued to drive 5-minute prices down significantly in WEIM areas north of the CAISO and drive prices up in the CAISO and WEIM areas in the southwest.[30]

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

Figure 1.31 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2021 and 2022. Table 1.5 shows the frequency of this congestion. Highlights for this quarter include:

- The net impact of internal flow-based constraint congestion has significant impacts across the WEIM. Congestion generally lowered prices in the Pacific Northwest and raised prices in California and the Southwest.
- The impact of internal congestion positively and negatively has increased significantly compared to the third quarter of last year.
- The primary constraints creating price separation in the 15-minute market were a Malin-Round Mountain nomogram, the Midway-Vincent #2 500 kV line, and the Midway-Whirlwind 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.

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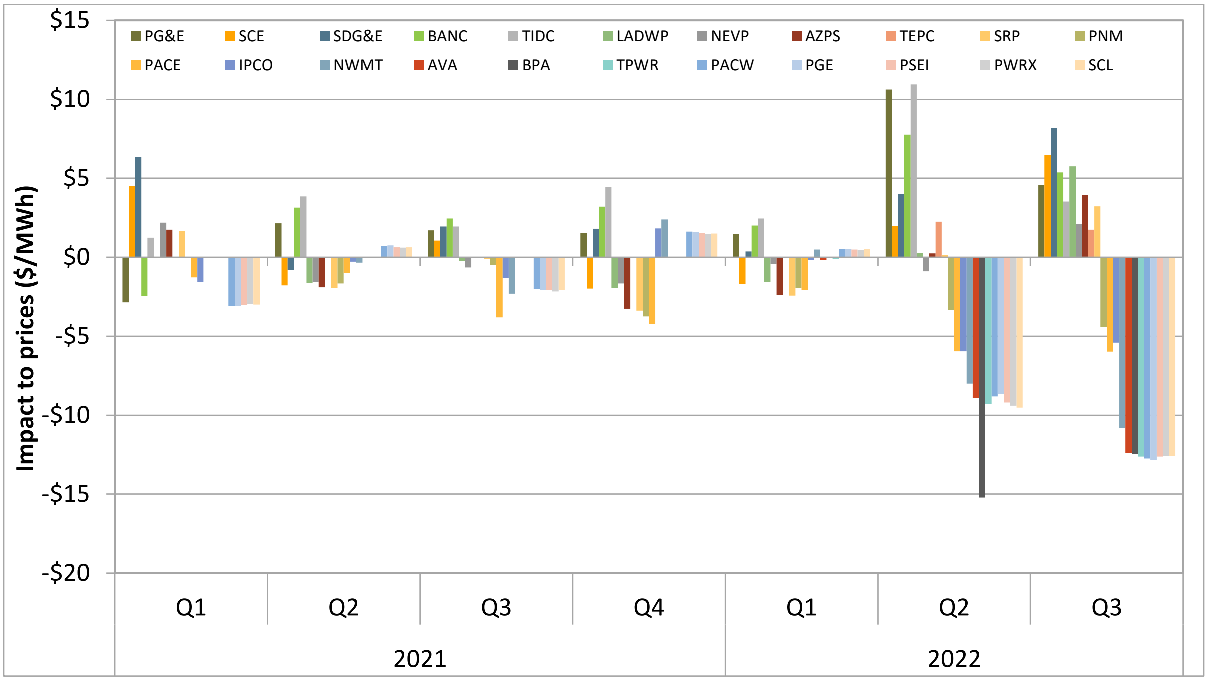
[30] This 5-minute only constraint (6110_COI_N-S) appears in the "other" category in this analysis due to a lack of shift factor data. This constraint was created and implemented in September 2021. Documentation of this constraint is limited but can be found on *California ISO Operating Procedures Index List:* http://www.caiso.com/documents/operatingprocedureindex.pdf
It was also mentioned in California ISO, *Market Update Call Meeting Minutes,* March 24, 2022: http://www.caiso.com/Documents/MeetingMinutesMarketUpdateCallMar242022.pdf

**Figure 1.31 Overall impact of internal congestion on price separation in the 15-minute market**




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

This section focuses on individual flow-based constraints. In the third quarter, the constraints that had the greatest impact on price separation in the 15-minute market were a Malin-Round Mountain nomogram, the Midway-Vincent #2 500 kV line, and the Midway-Whirlwind 500 kV line.[31] These constraints were frequently used to mitigate unscheduled high flows, the loss of the Midway-Vincent #1 500 kV line, and high flows on high load days, respectively.

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

[31] These constraints are shown as ML_RM12_NS, 30060_MIDWAY_500_24156_VINCENT_500_BR_2_3, and 30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_1 in the tables, respectively.

## Table 1.4 Impact of congestion on overall 15-minute prices

| Constraint Location | Constraint | PG&E | SCE | SDG&E | BANC | TIDC | LADWP | NEVP | AZPS | TEPC | SRP | PNM | PACE | IPCO | NWMT | AVA | BPA | TPWR | PACW | PGE | PSEI | PWRX | SCL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AZPS | Line_FC-CH2_345KV | | $0.20 | $0.28 | | | $0.18 | $0.00 | $0.53 | | $0.47 | -$2.49 | -$0.68 | -$0.36 | -$0.23 | | | | | | | | |
| | CC XFMR8 A 69KV | | | | | | | | $0.46 | | | | | | | | | | | | | | |
| | Line_FC-CH1_345KV | | $0.01 | $0.01 | | | $0.01 | | $0.02 | | $0.02 | -$0.09 | -$0.02 | -$0.01 | -$0.01 | | | | | | | | |
| | Line_FC-MK_500KV | $0.00 | $0.46 | $0.33 | | | $0.50 | $0.53 | | -$0.93 | | -$3.85 | -$0.88 | -$0.40 | -$0.34 | | | | | | | | |
| IPCO | IMNH-OBPR1_B | | | | | | | | | | | | $0.56 | $1.61 | -$0.64 | -$1.13 | -$0.55 | -$0.65 | -$0.41 | -$0.50 | -$0.65 | -$0.70 | -$0.66 |
| | HEMWY | -$0.35 | | | -$0.40 | -$0.37 | $0.19 | $0.22 | $0.13 | $0.15 | $0.13 | $0.25 | $0.92 | $1.41 | | -$0.26 | -$0.40 | -$0.40 | -$0.47 | -$0.47 | -$0.39 | -$0.37 | -$0.39 |
| | PATH_14 | -$0.05 | | $0.01 | -$0.06 | -$0.05 | | $0.05 | $0.03 | $0.04 | $0.03 | $0.05 | $0.18 | $0.33 | -$0.02 | -$0.09 | -$0.09 | -$0.09 | -$0.10 | -$0.10 | -$0.09 | -$0.09 | -$0.09 |
| | WECC_PATH_14 | -$0.02 | | $0.01 | -$0.02 | -$0.02 | | $0.02 | $0.01 | $0.01 | $0.01 | $0.02 | $0.06 | $0.11 | -$0.01 | -$0.03 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.03 | -$0.04 |
| | T341.MPSN | | | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.02 | $0.03 | | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 |
| | T342.MPSN | | | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.02 | $0.03 | | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 |
| NEVP | HA-RE_345KV | | $0.00 | $0.00 | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | | -$0.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| PACE | WINDSTAR EXPORT TCOR | | | | | | | | | | | | -$0.68 | | | | | | | | | | |
| | TOTAL_WYOMING_EXPORT | | | | | | | | | | | | -$1.87 | | | | | | | | | | |
| PACW | WPTH75 | $0.08 | | | $0.09 | $0.09 | -$0.04 | -$0.04 | -$0.02 | -$0.03 | -$0.02 | -$0.05 | -$0.22 | -$0.34 | | $0.05 | $0.09 | $0.09 | $0.10 | $0.10 | $0.09 | $0.08 | $0.08 |
| PG&E | ML_RM12_NS | $4.53 | $2.57 | $2.28 | $4.47 | $4.41 | $2.25 | $0.68 | $1.69 | $1.55 | $1.67 | $0.97 | -$2.59 | -$4.84 | -$5.73 | -$6.47 | -$6.69 | -$6.68 | -$6.77 | -$6.79 | -$6.68 | -$6.62 | -$6.67 |
| | 30055_GATES1 _500_30900_GATES _230_XF_12_P | $1.21 | -$0.33 | -$0.32 | $0.26 | $0.61 | -$0.32 | -$0.30 | -$0.31 | -$0.31 | -$0.31 | -$0.30 | $0.00 | -$0.18 | -$0.25 | -$0.28 | -$0.29 | -$0.29 | -$0.30 | -$0.30 | -$0.29 | -$0.29 | -$0.29 |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | $0.54 | -$0.04 | $0.00 | $0.02 | $0.03 | -$0.02 | | $0.00 | $0.00 | $0.00 | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1 | $0.51 | $0.07 | $0.06 | $1.10 | $0.47 | $0.07 | | $0.04 | $0.03 | $0.04 | $0.01 | -$0.03 | -$0.42 | -$0.59 | -$0.82 | -$0.89 | -$0.88 | -$0.89 | -$0.90 | -$0.88 | -$0.86 | -$0.88 |
| | RM_TM12_NG | $0.47 | $0.27 | $0.24 | $0.33 | $0.47 | $0.26 | $0.00 | $0.17 | $0.15 | $0.17 | $0.01 | -$0.32 | -$0.57 | -$0.68 | -$0.77 | -$0.79 | -$0.79 | -$0.80 | -$0.80 | -$0.79 | -$0.78 | -$0.79 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | $0.30 | -$0.49 | -$0.46 | $1.00 | $1.96 | -$0.46 | -$0.26 | -$0.38 | -$0.37 | -$0.38 | -$0.32 | | $0.12 | $0.28 | $0.35 | $0.37 | $0.37 | $0.39 | $0.39 | $0.37 | $0.37 | $0.37 |
| | TMS_DLO_NG | $0.20 | $0.04 | $0.04 | $0.30 | $0.21 | $0.04 | $0.01 | $0.03 | $0.03 | $0.03 | $0.02 | -$0.03 | -$0.09 | -$0.21 | -$0.23 | -$0.23 | -$0.23 | -$0.24 | -$0.24 | -$0.23 | -$0.23 | -$0.23 |
| | 30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1 | $0.17 | -$0.04 | -$0.04 | $0.11 | $0.05 | -$0.04 | $0.00 | -$0.03 | -$0.03 | -$0.03 | $0.00 | | | | | | | | | | | |
| | 30640_TESLA C _230_30040_TESLA _500_XF_6H | $0.14 | | | $0.09 | $0.14 | | | | | | | -$0.03 | -$0.05 | -$0.05 | -$0.05 | -$0.05 | -$0.05 | -$0.05 | -$0.05 | -$0.05 | -$0.05 | -$0.05 |
| | 30733_VASONA _230_30735_METCALF _230_BR_1 _1 | $0.14 | | | | | | | | | | | | | | | | | | | | | |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_1 _1 | $0.13 | -$0.06 | -$0.06 | $0.02 | $0.06 | -$0.06 | -$0.02 | -$0.05 | -$0.05 | -$0.05 | -$0.04 | | | | | | | | | | | |
| | 30624_TESLA E _230_30670_WSTLYSMD_230_BR_1 _1 | $0.13 | -$0.06 | -$0.06 | $0.08 | -$0.31 | -$0.04 | -$0.03 | -$0.04 | -$0.04 | -$0.04 | -$0.03 | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 |
| | 30005_ROUND MT_500_30245_ROUND MT_230_XF_1 _P | $0.11 | $0.07 | $0.06 | $0.13 | $0.11 | $0.07 | $0.03 | $0.05 | $0.05 | $0.05 | $0.03 | -$0.05 | -$0.11 | -$0.13 | -$0.15 | -$0.15 | -$0.15 | -$0.16 | -$0.16 | -$0.15 | -$0.15 | -$0.15 |
| | 30300_TABLMTN _230_30330_RIO OSO _230_BR_1 _1 | $0.09 | | | $0.19 | $0.10 | | | | | | | | $0.00 | -$0.10 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1 | $0.08 | $0.01 | $0.01 | $0.28 | $0.02 | $0.01 | | $0.01 | $0.00 | $0.01 | $0.00 | -$0.01 | -$0.13 | -$0.17 | -$0.19 | -$0.20 | -$0.20 | -$0.19 | -$0.20 | -$0.20 | -$0.19 | -$0.20 |
| | 30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1 | $0.07 | | | | | | | | | | | | | | | | | | | | | |
| | 7440_MetcalfImport_Tes-Metcalf | $0.06 | -$0.04 | -$0.04 | $0.03 | $0.04 | -$0.03 | -$0.02 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | | | $0.00 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 |
| | 30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1 | $0.06 | | | -$0.02 | | | | | | | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 6110_SOL10_NG | $0.04 | $0.04 | $0.04 | $0.21 | $0.05 | $0.04 | $0.01 | $0.03 | $0.03 | $0.03 | $0.02 | -$0.02 | -$0.05 | -$0.06 | -$0.07 | -$0.07 | -$0.07 | -$0.07 | -$0.09 | -$0.07 | -$0.07 | -$0.07 |
| | 30655_ADCC _230_30630_NEWARK _230_BR_2 _1 | $0.03 | | | | $0.03 | | | | | | | | | | | | | | | | | |
| | 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1 | $0.03 | -$0.04 | -$0.04 | $0.04 | $0.04 | -$0.04 | -$0.02 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | | $0.01 | $0.02 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_2 _1 | $0.03 | -$0.05 | -$0.05 | $0.06 | $0.08 | -$0.05 | | -$0.03 | -$0.03 | -$0.03 | $0.00 | | | | $0.01 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 |
| | 30300_TABLMTN _230_30325_PALERMO _230_BR_1 _1 | $0.02 | | | $0.03 | $0.02 | | | | | | | | -$0.01 | -$0.01 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | $0.02 | -$0.02 | -$0.02 | $0.02 | $0.03 | -$0.02 | | -$0.02 | -$0.02 | -$0.02 | $0.00 | | | | $0.00 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 |
| | 30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2 | $0.01 | $0.00 | $0.00 | $0.00 | $0.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 |
| | XFMR1 500.TRY | $0.01 | | | $0.02 | $0.02 | | | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1 | $0.00 | $0.00 | $0.00 | -$0.01 | -$0.01 | | | | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 30015_TABLE MT_500_30040_TESLA _500_BR_1 _3 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.01 | -$0.01 | $0.00 | $0.00 | $0.00 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | -$0.04 | $0.03 | $0.03 | -$0.04 | -$0.04 | $0.03 | $0.02 | $0.03 | $0.02 | $0.03 | $0.02 | | -$0.01 | -$0.02 | -$0.02 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 |
| | 30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1 | -$1.23 | $1.09 | $1.01 | -$1.16 | -$1.21 | $1.05 | $0.60 | $0.88 | $0.85 | $0.88 | $0.74 | $0.00 | -$0.44 | -$0.66 | -$0.80 | -$0.78 | -$0.85 | -$0.89 | -$0.88 | -$0.85 | -$0.84 | -$0.85 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | -$2.10 | $1.80 | $1.73 | -$1.99 | -$2.07 | $1.75 | $1.00 | $1.50 | $1.45 | $1.50 | $1.25 | -$0.01 | -$0.84 | -$1.13 | -$1.36 | -$1.44 | -$1.43 | -$1.49 | -$1.47 | -$1.43 | -$1.41 | -$1.43 |
| | 30515_WARNERVL_230_30800_WILSON _230_BR_1 _1 | | | | -$0.09 | -$0.06 | | | | | | | | | | | | | | | | | |
| | 30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1 | | | | -$0.05 | $0.05 | | | | | | | | | | | | | | | | | |
| | 32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1 | | | | | | | -$0.05 | | | | | | | | | | | | | | | |
| | 32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1 | | | | | | | -$0.17 | | | | | | | | | | | | | | | |
| | 32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1 | | | | | | | -$0.05 | | | | | | | | | | | | | | | |
| | 7430_CP6_NG | | | | $1.20 | $0.02 | | | | | | | | | | | | | | | | | |
| | XFMR2 230.ROSEMR | | | | $0.12 | -$0.03 | | | | | | | | | | | | | | | | | |
| SCE | 6410_CP1_NG | -$0.65 | $0.54 | $0.54 | -$0.61 | -$0.64 | $0.54 | $0.32 | $0.47 | $0.45 | $0.47 | $0.39 | | -$0.24 | -$0.34 | -$0.41 | -$0.43 | -$0.43 | -$0.45 | -$0.45 | -$0.43 | -$0.42 | -$0.43 |
| | OP-6610_ELD-LUGO | $0.10 | $0.11 | $0.04 | $0.09 | $0.09 | -$0.25 | -$0.19 | -$0.16 | -$0.16 | -$0.16 | -$0.16 | -$0.08 | -$0.01 | $0.01 | $0.03 | $0.04 | $0.04 | $0.04 | $0.04 | $0.04 | $0.04 | $0.04 |
| | 24086_LUGO _500_24238_RANCHVST_500_BR_1 _1 | $0.00 | $0.01 | $0.01 | $0.00 | $0.00 | -$0.01 | -$0.01 | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 24091_MESA CAL_230_24076_LAGUBELL_230_BR_1 _1 | $0.00 | $0.01 | $0.01 | $0.00 | $0.00 | $0.00 | | | | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 24042_ELDORDO _500_24086_LUGO _500_BR_1 _4 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | $0.00 | $0.00 | | | | | | | | | |
| SDG&E | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P | | $0.17 | $1.57 | | | | -$0.19 | -$0.49 | -$0.48 | -$0.51 | -$0.40 | -$0.17 | | | | | | | | | | |
| | 7820_TL 230S_OVERLOAD_NG | $0.00 | $0.04 | $0.41 | | $0.00 | $0.00 | -$0.03 | -$0.08 | -$0.09 | -$0.09 | -$0.07 | -$0.03 | $0.00 | | | | | | | | | |
| | 7820_TL 230S_TL50001OUT_NG | | $0.02 | $0.25 | | | | -$0.02 | -$0.06 | -$0.06 | -$0.07 | -$0.05 | -$0.02 | | | | | | | | | | |
| | 92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1 | | | $0.20 | | | | | -$0.06 | -$0.06 | -$0.06 | -$0.05 | | | | | | | | | | | |
| | 92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1 | | | $0.17 | | | | | -$0.05 | -$0.05 | -$0.05 | -$0.04 | | | | | | | | | | | |
| | 22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1 | | | $0.14 | | | | | -$0.04 | -$0.04 | -$0.05 | -$0.04 | | | | | | | | | | | |
| | 22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1 | | | $0.14 | | | | | -$0.04 | -$0.04 | -$0.05 | -$0.04 | | | | | | | | | | | |
| | OMS TL50001_OOS_NG | | $0.00 | $0.08 | | | | -$0.01 | -$0.01 | -$0.01 | -$0.02 | -$0.01 | $0.00 | | | | | | | | | | |
| | OMS_12251471_TL23055_NG | | $0.00 | $0.07 | | | | $0.00 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | $0.00 | | | | | | | | | | |
| | 92861_SUNC TP2_230_92321_SYCA TP2_230_BR_2 _1 | | | $0.06 | | | | | | | | | | | | | | | | | | | |
| | OMS_11878920_13810A_NG | | | -$0.03 | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | | | | | | | | | | | |
| | 7820_CP6_OMS_12226638_MS-SA | | | -$0.03 | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | | | | | | | | | | | |
| | OMS_12137628_13810A_NG | | | -$0.03 | | | | | -$0.02 | -$0.02 | -$0.02 | -$0.02 | | | | | | | | | | | |
| | OMS_11878904_13810A_NG | | | -$0.04 | | | | | -$0.02 | -$0.02 | -$0.03 | -$0.01 | | | | | | | | | | | |
| | 22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1 | $0.02 | $0.04 | -$0.27 | $0.02 | $0.02 | $0.02 | | -$0.04 | -$0.04 | -$0.04 | -$0.03 | | | | | | | $0.00 | | | | |
| | 24801_DEVERS _500_24804_DEVERS _230_XF_1 _P | | | | | | | | -$0.05 | -$0.05 | -$0.06 | $0.00 | | | | | | | | | | | |
| | Other | -$0.34 | $0.00 | -$0.20 | -$0.51 | -$0.89 | $0.11 | $0.05 | $0.02 | -$0.03 | -$0.09 | $0.00 | $0.11 | $0.07 | $0.29 | $0.37 | $0.27 | $0.21 | $0.13 | $0.17 | $0.21 | $0.16 | $0.21 |
| | **Internal Total** | **$4.59** | **$6.47** | **$8.16** | **$5.38** | **$3.53** | **$5.75** | **$2.09** | **$3.94** | **$1.75** | **$3.23** | **-$4.42** | **-$5.98** | **-$5.41** | **-$10.82** | **-$12.40** | **-$12.45** | **-$12.63** | **-$12.74** | **-$12.83** | **-$12.62** | **-$12.58** | **-$12.61** |
| | **Transfers** | | | | -$1.87 | -$0.49 | -$0.41 | -$0.52 | -$0.50 | -$1.62 | -$12.20 | -$0.77 | -$1.09 | -$2.74 | -$11.14 | -$11.22 | $1.90 | -$5.81 | -$3.40 | -$1.33 | -$4.93 | -$13.28 | -$5.61 |
| | **Grand Total** | **$4.59** | **$6.47** | **$8.16** | **$3.51** | **$3.04** | **$5.34** | **$1.57** | **$3.44** | **$0.13** | **-$8.97** | **-$5.19** | **-$7.07** | **-$8.15** | **-$21.96** | **-$23.62** | **-$10.55** | **-$18.44** | **-$16.14** | **-$14.16** | **-$17.55** | **-$25.86** | **-$18.22** |

## Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals [32]

| Constraint Location | Constraint | Freq. | PG&E | SCE | SDG&E | BANC | TIDC | LADWP | NEVP | AZPS | TEPC | SRP | PNM | PACE | IPCO | NWMT | AVA | BPA | TPWR | PACW | PGE | PSEI | PWRX | SCL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AZPS | CC XFMR8 A 69KV | 1.6% | | | | | | | | $28.26 | | | | | | | | | | | | | | |
| | Line_FC-CH2_345KV | 2.9% | | $11.55 | $11.25 | | | $10.47 | $1.84 | $17.97 | | $16.00 | -$84.43 | -$23.09 | -$12.22 | -$12.39 | | | | | | | | |
| | Line_FC-MK_500KV | 4.6% | $3.03 | $9.90 | $7.17 | | | $10.73 | $11.45 | | -$20.01 | | -$83.02 | -$18.96 | -$8.68 | -$7.27 | | | | | | | | |
| IPCO | IMNH-OBPR1_B | 2.2% | | | | | | | | | | | | $25.73 | $74.30 | -$29.67 | -$52.26 | -$25.65 | -$29.91 | -$21.43 | -$22.98 | -$30.08 | -$32.35 | -$30.49 |
| | HEMWY | 2.5% | -$13.82 | | | -$16.01 | -$14.82 | $8.47 | $8.96 | $5.13 | $6.12 | $5.20 | $10.11 | $36.96 | $56.32 | | -$10.36 | -$16.13 | -$15.86 | -$18.73 | -$18.66 | -$15.76 | -$14.59 | -$15.57 |
| PACE | WINDSTAR EXPORT TCOR | 37.1% | | | | | | | | | | | | -$1.83 | | | | | | | | | | |
| | TOTAL_WYOMING_EXPORT | 37.4% | | | | | | | | | | | | -$5.00 | | | | | | | | | | |
| PACW | WPTH75 | 0.7% | $11.56 | | | $13.29 | $12.36 | -$5.62 | -$6.13 | -$6.28 | -$4.27 | -$5.96 | -$7.68 | -$31.45 | -$48.53 | | $7.81 | $12.55 | $12.33 | $14.62 | $14.66 | $12.25 | $11.31 | $12.11 |
| PG&E | RM_TM12_NG | 0.4% | $115.99 | $66.54 | $57.94 | $79.98 | $115.44 | $63.20 | $1.31 | $41.37 | $37.73 | $40.78 | $2.71 | -$77.94 | -$140.11 | -$167.75 | -$188.84 | -$193.53 | -$193.65 | -$196.45 | -$196.05 | -$193.57 | -$192.36 | -$193.49 |
| | ML_RM12_NS | 11.4% | $39.70 | $22.53 | $19.93 | $39.21 | $38.63 | $19.75 | $6.26 | $14.79 | $13.56 | $14.63 | $8.53 | -$22.66 | -$42.41 | -$50.23 | -$56.71 | -$58.63 | -$58.54 | -$59.35 | -$59.53 | -$58.49 | -$58.03 | -$58.44 |
| | TMS_DLO_NG | 0.6% | $31.59 | $6.88 | $6.21 | $47.02 | $33.64 | $6.61 | $2.38 | $4.89 | $4.54 | $4.83 | $3.12 | -$4.57 | -$13.52 | -$32.42 | -$35.49 | -$36.70 | -$36.54 | -$37.17 | -$37.13 | -$36.50 | -$36.30 | -$36.46 |
| | 30733_VASONA _230_30735_METCALF _230_BR_1 _1 | 0.5% | $25.55 | | | | | | | | | | | | | | | | | | | | | |
| | 30300_TABLMTN _230_30330_RIO OSO _230_BR_1 _1 | 0.4% | $24.61 | | | $48.19 | $25.43 | | | | | | | | -$14.26 | -$25.19 | -$27.57 | -$28.68 | -$28.68 | -$29.13 | -$29.52 | -$28.68 | -$28.67 | -$28.68 |
| | 30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1 | 0.8% | $21.58 | -$12.68 | -$12.53 | $16.35 | $11.20 | -$12.94 | -$0.08 | -$11.82 | -$11.60 | -$11.82 | -$2.69 | | | | | | | | | | | |
| | 30624_TESLA E _230_30670_WSTLYSMD_230_BR_1 _1 | 0.8% | $16.15 | -$7.49 | -$7.23 | $11.36 | -$39.52 | -$5.20 | -$13.20 | -$5.29 | -$5.66 | -$5.25 | -$7.14 | | -$5.55 | -$6.96 | -$6.46 | -$6.74 | -$6.67 | -$6.94 | -$6.87 | -$6.67 | -$6.67 | -$6.67 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1 | 5.0% | $13.54 | $9.03 | $8.17 | $21.70 | $13.45 | $8.78 | | $6.66 | $7.30 | $6.69 | $16.04 | -$11.51 | -$12.48 | -$15.25 | -$18.34 | -$18.89 | -$18.83 | -$18.81 | -$19.15 | -$18.81 | -$18.70 | -$18.80 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1 | 1.1% | $12.44 | $14.36 | $12.81 | $25.65 | $20.92 | $14.01 | | $12.62 | $21.67 | $12.62 | $14.86 | -$11.08 | -$15.00 | -$15.46 | -$17.15 | -$17.74 | -$17.74 | -$17.20 | -$17.89 | -$17.70 | -$17.54 | -$17.70 |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_1 _1 | 1.2% | $10.98 | -$5.20 | -$5.00 | $7.29 | $5.16 | -$5.12 | -$11.85 | -$4.59 | -$4.47 | -$4.57 | -$5.08 | | | | | | | | | | | |
| | 7440_MetcalfImport_Tes-Metcalf | 0.6% | $9.89 | -$6.24 | -$5.93 | $5.06 | $7.11 | -$4.96 | -$3.93 | -$5.26 | -$5.11 | -$5.23 | -$4.52 | | | $1.53 | $2.54 | $2.77 | $2.73 | $2.89 | $2.89 | $2.72 | $2.68 | $2.71 |
| | 30055_GATES1 _500_30900_GATES _230_XF_12_P | 15.1% | $8.00 | -$2.37 | -$2.34 | $1.89 | $4.39 | -$2.29 | -$2.32 | -$2.25 | -$2.24 | -$2.25 | -$2.20 | -$3.32 | -$3.47 | -$4.27 | -$4.76 | -$4.96 | -$4.93 | -$5.06 | -$5.03 | -$4.93 | -$4.88 | -$4.92 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | 3.9% | $7.67 | -$12.58 | -$11.81 | $25.56 | $50.12 | -$11.70 | -$6.68 | -$9.81 | -$9.50 | -$9.79 | -$8.17 | | $4.21 | $7.12 | $9.02 | $9.55 | $9.53 | $9.89 | $9.83 | $9.52 | $9.42 | $9.52 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_2 _1 | 1.0% | $7.27 | -$5.41 | -$5.44 | $6.57 | $8.46 | -$5.43 | | -$7.80 | -$7.52 | -$7.77 | -$5.89 | | | | $5.99 | $7.01 | $7.01 | $7.23 | $7.14 | $7.01 | $7.43 | $7.26 |
| | 30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1 | 0.9% | $6.67 | | | -$4.52 | | | | | | | | | | | -$1.16 | -$1.12 | -$1.12 | -$1.19 | -$0.97 | -$1.12 | -$1.11 | -$1.12 |
| | 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1 | 0.5% | $6.52 | -$8.41 | -$7.95 | $7.97 | $8.21 | -$8.21 | -$4.68 | -$7.04 | -$6.81 | -$7.00 | -$5.92 | | $3.06 | $4.49 | $5.51 | $5.87 | $5.84 | $6.11 | $6.04 | $5.84 | $5.75 | $5.83 |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | 8.5% | $6.37 | -$3.07 | $0.00 | $8.59 | $95.76 | -$1.67 | | $2.02 | $1.95 | $2.01 | | | | | -$2.03 | -$2.17 | -$2.15 | -$2.22 | -$2.21 | -$2.13 | -$2.12 | -$2.13 |
| | 6110_SOL10_NG | 0.8% | $5.09 | $4.64 | $4.20 | $24.74 | $5.97 | $4.42 | $1.61 | $3.29 | $3.04 | $3.25 | $2.02 | -$2.82 | -$5.79 | -$7.01 | -$7.83 | -$8.15 | -$8.11 | -$8.25 | -$10.24 | -$8.11 | -$8.04 | -$8.10 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | 0.3% | $5.03 | -$5.75 | -$5.42 | $6.96 | $8.79 | -$5.58 | | -$4.78 | -$4.64 | -$4.74 | -$3.82 | | | | $3.52 | $4.38 | $4.36 | $4.41 | $4.58 | $4.35 | $4.25 | $4.32 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | 0.4% | -$9.96 | $8.86 | $8.77 | -$9.45 | -$9.74 | $8.03 | $4.93 | $6.83 | $6.61 | $6.77 | $5.70 | | -$3.95 | -$5.46 | -$6.66 | -$6.86 | -$7.02 | -$7.26 | -$7.20 | -$7.01 | -$6.93 | -$7.00 |
| | 30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1 | 5.2% | -$23.96 | $21.22 | $19.51 | -$22.59 | -$23.51 | $20.41 | $11.66 | $17.13 | $16.56 | $17.06 | $14.31 | $0.68 | -$8.59 | -$12.83 | -$15.53 | -$15.16 | -$16.52 | -$17.27 | -$17.18 | -$16.50 | -$16.28 | -$16.47 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | 5.7% | -$36.50 | $31.38 | $30.06 | -$34.58 | -$36.05 | $30.50 | $17.47 | $26.15 | $25.31 | $26.07 | $21.72 | -$2.72 | -$14.59 | -$19.73 | -$23.62 | -$25.12 | -$24.96 | -$26.02 | -$25.61 | -$24.93 | -$24.59 | -$24.88 |
| | 32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1 | 1.2% | | | | | | | -$14.37 | | | | | | | | | | | | | | | |
| | 7430_CP6_NG | 4.2% | | | | $28.70 | $12.29 | | | | | | | | | | | | | | | | | |
| SCE | OP-6610_ELD-LUGO | 0.6% | $17.64 | $19.30 | $7.29 | $16.03 | $16.03 | -$43.43 | -$33.19 | -$28.05 | -$28.11 | -$27.51 | -$28.13 | -$13.71 | -$1.84 | $2.81 | $5.96 | $6.66 | $6.66 | $7.17 | $7.04 | $6.65 | $6.49 | $6.65 |
| | 6410_CP1_NG | 4.8% | -$13.66 | $11.36 | $11.37 | -$12.74 | -$13.32 | $11.28 | $6.63 | $9.85 | $9.52 | $9.82 | $8.15 | | -$5.08 | -$7.11 | -$8.54 | -$9.09 | -$9.03 | -$9.43 | -$9.35 | -$9.02 | -$8.89 | -$9.00 |
| SDG&E | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P | 0.7% | | $24.52 | $220.44 | | | | -$27.21 | -$69.26 | -$67.33 | -$71.20 | -$55.81 | -$23.77 | | | | | | | | | | |
| | 7820_TL 230S_OVERLOAD_NG | 3.5% | $0.62 | $1.05 | $11.68 | | $0.66 | $0.85 | -$0.91 | -$2.43 | -$2.47 | -$2.67 | -$2.06 | -$0.83 | -$0.51 | | | | | | | | | |
| | 7820_CP6_OMS_12226638_MS-SA | 0.4% | | | -$7.98 | | | | | -$3.36 | -$1.93 | -$3.83 | -$1.46 | | | | | | | | | | | |
| | OMS_12137628_13810A_NG | 0.4% | | | -$8.30 | | | | | -$6.00 | -$5.90 | -$6.32 | -$4.83 | | | | | | | | | | | |
| | OMS_11878904_13810A_NG | 0.3% | | | -$12.35 | | | | | -$7.91 | -$7.72 | -$8.36 | -$3.70 | | | | | | | | | | | |
| | 24801_DEVERS _500_24804_DEVERS _230_XF_1 _P | 0.8% | | | | | | | | -$6.05 | -$5.82 | -$6.85 | -$4.00 | | | | | | | | | | | |

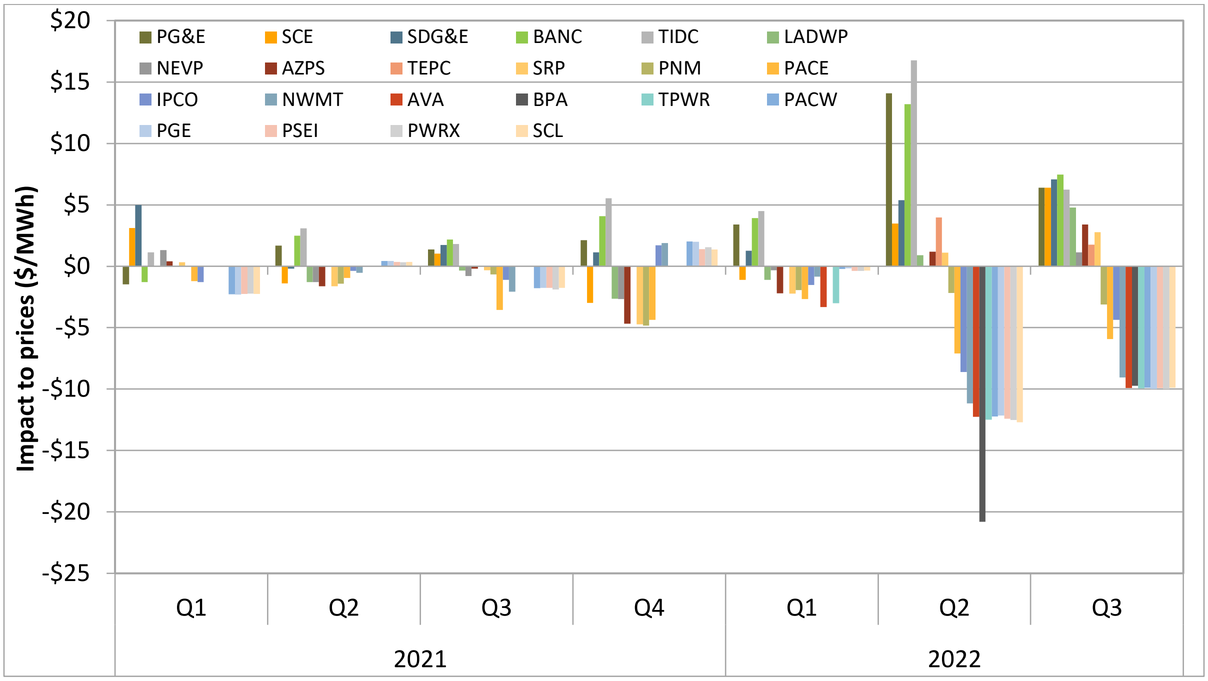
### Impact of internal congestion to overall 5-minute prices in each load area

Figure 1.32 shows the overall impact of internal flow-based constraint congestion on 5-minute prices in each load area for 2021 and 2022. Highlights for this quarter include:

- Congestion from a 5-minute market only constraint heavily impacted prices across the WEIM and lead to notable differences between the 15-minute and 5-minute markets.[30]
- Price impacts from 5-minute market congestion continued to be significant, lowering average prices across the Pacific Northwest by over $10/MWh over the quarter.

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

**Figure 1.32 Overall impact of internal congestion on price separation in the 5-minute market**




### Impact of internal congestion from individual constraints in the 5-minute market

Congestion patterns in the 15-minute and 5-minute markets are typically very similar. However, during the third quarter, a constraint that is only enforced in the 5-minute market (6110_COI_N-S) continued to heavily impact prices across the WEIM and led to notable differences between the markets. During the quarter, the "other" category, which contains this 5-minute market constraint, had the greatest impact on 5-minute prices across the WEIM.[33]

Table 1.6 shows the overall impact (during all intervals) of internal congestion on average 5-minute prices in each load area. The color scales in the table below apply only to the individual constraints and the "other" category. In addition to the 5-minute market only constraint, the "other" category includes the impact of power balance constraint (PBC) violations, which often have an impact on price separation.

33 Future enhancements to this metric aim to isolate and quantify the impact of the 6110_COI_N-S constraint directly.

### Table 1.6 Impact of congestion on overall 5-minute prices

| Constraint Location | Constraint | PG&E | SCE | SDG&E | BANC | TIDC | LADWP | NEVP | AZPS | TEPC | SRP | PNM | PACE | IPCO | NWMT | AVA | BPA | TPWR | PACW | PGE | PSEI | PWRX | SCL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AZPS | Line_FC-CH2_345KV | | $0.16 | $0.23 | | | $0.14 | | $0.42 | | $0.37 | -$1.97 | -$0.54 | -$0.28 | -$0.17 | | | | | | | | |
| | CC XFMR8 A 69KV | | | | | | | | $0.29 | | | | | | | | | | | | | | |
| | Line_FC-CH1_345KV | | $0.00 | $0.00 | | | $0.00 | | $0.01 | | $0.01 | -$0.03 | -$0.01 | $0.00 | $0.00 | | | | | | | | |
| | Line_FC-MK_500KV | $0.00 | $0.32 | $0.23 | | | $0.35 | $0.37 | | -$0.65 | | -$2.71 | -$0.62 | -$0.28 | -$0.24 | | | | | | | | |
| IPCO | IMNH-OBPR1_B | | | | | | | | | | | | $0.45 | $1.31 | -$0.52 | -$0.91 | -$0.45 | -$0.53 | -$0.32 | -$0.40 | -$0.53 | -$0.57 | -$0.54 |
| | HEMWY | -$0.31 | | | -$0.36 | -$0.33 | $0.17 | $0.19 | $0.11 | $0.13 | $0.11 | $0.22 | $0.81 | $1.24 | | -$0.23 | -$0.36 | -$0.36 | -$0.42 | -$0.42 | -$0.35 | -$0.33 | -$0.35 |
| | PATH_14 | -$0.12 | | $0.03 | -$0.13 | -$0.12 | | $0.11 | $0.07 | $0.08 | $0.08 | $0.12 | $0.42 | $0.77 | -$0.04 | -$0.20 | -$0.22 | -$0.22 | -$0.22 | -$0.22 | -$0.22 | -$0.21 | -$0.22 |
| | WECC_PATH_14 | -$0.01 | | $0.00 | -$0.01 | -$0.01 | | $0.01 | $0.00 | $0.00 | $0.00 | $0.01 | $0.02 | $0.04 | $0.00 | -$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 | -$0.02 | $0.03 | | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 |
| | T342.MPSN | | | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.02 | $0.03 | | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 |
| | T231.BOMT | | | | | | | | | | | | -$0.01 | -$0.03 | | | | | | | | | |
| | T232.BOMT | | | | | | | | | | | | -$0.01 | -$0.03 | | | | | | | | | |
| PACE | WINDSTAR EXPORT TCOR | | | | | | | | | | | | -$0.72 | | | | | | | | | | |
| | TOTAL_WYOMING_EXPORT | | | | | | | | | | | | -$1.43 | | | | | | | | | | |
| PACW | WPTH75 | $0.07 | | | $0.08 | $0.07 | -$0.03 | -$0.03 | -$0.01 | -$0.02 | -$0.01 | -$0.04 | -$0.18 | -$0.28 | | $0.05 | $0.07 | $0.07 | $0.08 | $0.09 | $0.07 | $0.07 | $0.07 |
| PG&E | 30055_GATES1 _500_30900_GATES _230_XF_12_P | $1.78 | -$0.68 | -$0.66 | $0.58 | $1.14 | -$0.64 | -$0.52 | -$0.61 | -$0.60 | -$0.61 | -$0.56 | $0.00 | -$0.12 | -$0.16 | -$0.18 | -$0.18 | -$0.18 | -$0.19 | -$0.19 | -$0.18 | -$0.18 | -$0.18 |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | $0.43 | -$0.02 | $0.00 | $0.00 | $0.00 | -$0.01 | | $0.00 | $0.00 | $0.00 | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | $0.32 | -$0.51 | -$0.48 | $1.01 | $2.03 | -$0.50 | -$0.29 | -$0.42 | -$0.41 | -$0.42 | -$0.35 | | $0.16 | $0.31 | $0.37 | $0.40 | $0.39 | $0.41 | $0.41 | $0.39 | $0.39 | $0.39 |
| | RM_TM12_NG | $0.21 | $0.12 | $0.11 | $0.14 | $0.20 | $0.11 | $0.00 | $0.07 | $0.07 | $0.07 | $0.00 | -$0.14 | -$0.25 | -$0.30 | -$0.34 | -$0.34 | -$0.34 | -$0.35 | -$0.36 | -$0.34 | -$0.34 | -$0.34 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1 | $0.17 | $0.02 | $0.02 | $0.48 | $0.17 | $0.02 | | $0.01 | $0.01 | $0.01 | $0.01 | -$0.01 | -$0.15 | -$0.21 | -$0.31 | -$0.33 | -$0.33 | -$0.33 | -$0.34 | -$0.33 | -$0.33 | -$0.33 |
| | 30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1 | $0.13 | -$0.03 | -$0.03 | $0.08 | $0.04 | -$0.03 | | -$0.02 | -$0.02 | -$0.02 | $0.00 | | | | | | | | | | | |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_1 _1 | $0.12 | -$0.05 | -$0.05 | $0.02 | $0.05 | -$0.05 | -$0.01 | -$0.04 | -$0.04 | -$0.04 | -$0.03 | | | | | | | | | | | |
| | 30640_TESLA C _230_30040_TESLA _500_XF_6H | $0.11 | $0.00 | $0.00 | $0.07 | $0.11 | $0.00 | | $0.00 | $0.00 | $0.00 | $0.00 | -$0.01 | -$0.02 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.03 |
| | 7440_MetcalfImport_Tes-Metcalf | $0.11 | -$0.07 | -$0.07 | $0.06 | $0.08 | -$0.06 | -$0.04 | -$0.06 | -$0.06 | -$0.06 | -$0.05 | | | $0.01 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 |
| | TMS_DLO_NG | $0.10 | $0.02 | $0.02 | $0.15 | $0.10 | $0.02 | $0.01 | $0.02 | $0.01 | $0.02 | $0.01 | -$0.01 | -$0.04 | -$0.10 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 | -$0.11 |
| | 30624_TESLA E _230_30670_WSTLYSMD_230_BR_1 _1 | $0.09 | -$0.04 | -$0.04 | $0.09 | -$0.34 | -$0.04 | -$0.03 | -$0.04 | -$0.04 | -$0.04 | -$0.03 | | $0.00 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 |
| | 30733_VASONA _230_30735_METCALF _230_BR_1 _1 | $0.08 | | | | | | | | | | | | | | | | | | | | | |
| | 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1 | $0.06 | -$0.07 | -$0.07 | $0.07 | $0.07 | -$0.07 | -$0.04 | -$0.06 | -$0.06 | -$0.06 | -$0.05 | $0.00 | $0.03 | $0.04 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 |
| | 6110_SOL10_NG | $0.05 | $0.05 | $0.04 | $0.25 | $0.06 | $0.04 | $0.02 | $0.03 | $0.03 | $0.03 | $0.02 | -$0.03 | -$0.06 | -$0.07 | -$0.08 | -$0.08 | -$0.08 | -$0.08 | -$0.11 | -$0.08 | -$0.08 | -$0.08 |
| | 30300_TABLMTN _230_30330_RIO OSO _230_BR_1 _1 | $0.05 | $0.00 | $0.00 | $0.09 | $0.05 | $0.00 | | $0.00 | | | | $0.00 | $0.00 | -$0.05 | -$0.05 | -$0.06 | -$0.06 | -$0.06 | -$0.06 | -$0.06 | -$0.06 | -$0.06 |
| | 30735_METCALF _230_30731_LS ESTRS_230_BR_1 _1 | $0.03 | | | $0.02 | $0.05 | | | | | | | | | | | | | | | | | |
| | 30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1 | $0.03 | | | -$0.01 | | | | | | | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 30005_ROUND MT_500_30245_ROUND MT_230_XF_1 _P | $0.03 | $0.02 | $0.02 | $0.04 | $0.03 | $0.02 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | -$0.02 | -$0.03 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.04 | -$0.04 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_2 _1 | $0.03 | -$0.06 | -$0.05 | $0.07 | $0.09 | -$0.05 | | -$0.03 | -$0.03 | -$0.03 | $0.00 | | | | $0.01 | $0.02 | $0.02 | $0.03 | $0.03 | $0.02 | $0.02 | $0.02 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_2 _1 | $0.03 | $0.00 | $0.00 | $0.14 | $0.01 | $0.00 | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.06 | -$0.08 | -$0.09 | -$0.09 | -$0.09 | -$0.09 | -$0.09 | -$0.09 | -$0.09 | -$0.09 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | $0.02 | -$0.02 | -$0.02 | $0.03 | $0.04 | -$0.02 | | -$0.02 | -$0.02 | -$0.02 | $0.00 | | | | $0.01 | $0.01 | $0.01 | $0.02 | $0.02 | $0.01 | $0.01 | $0.01 |
| | XFMR1 500.TRY | $0.01 | | | $0.04 | $0.05 | | | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 30625_TESLA D _230_30040_TESLA _500_XF_4H | $0.01 | $0.00 | $0.00 | $0.02 | $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 | $0.00 | $0.00 |
| | XFMR2 500.TRY | $0.01 | | | $0.03 | $0.04 | | | | | | | | | | | | | | | | | |
| | XFMR1 500.OLN | $0.00 | $0.00 | $0.00 | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 |
| | 30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | -$0.03 | $0.03 | $0.03 | -$0.03 | -$0.03 | $0.03 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | | -$0.01 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 |
| | 30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1 | -$1.03 | $0.90 | $0.83 | -$0.98 | -$1.01 | $0.88 | $0.50 | $0.73 | $0.70 | $0.73 | $0.61 | $0.00 | -$0.36 | -$0.56 | -$0.68 | -$0.67 | -$0.72 | -$0.75 | -$0.75 | -$0.72 | -$0.71 | -$0.72 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | -$1.35 | $1.19 | $1.14 | -$1.28 | -$1.34 | $1.16 | $0.67 | $0.99 | $0.96 | $0.99 | $0.82 | $0.00 | -$0.52 | -$0.73 | -$0.87 | -$0.93 | -$0.92 | -$0.96 | -$0.95 | -$0.92 | -$0.91 | -$0.92 |
| | 30515_WARNERVL_230_30800_WILSON _230_BR_1 _1 | | | | -$0.03 | -$0.02 | | | | | | | | | | | | | | | | | |
| | 30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1 | | | | -$0.04 | $0.04 | | | | | | | | | | | | | | | | | |
| | 32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1 | | | | | | | -$0.05 | | | | | | | | | | | | | | | |
| | 32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1 | | | | | | | -$0.12 | | | | | | | | | | | | | | | |
| | 32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1 | | | | | | | -$0.06 | | | | | | | | | | | | | | | |
| | 7430_CP6_NG | | | | $1.44 | $0.01 | | | | | | | | | | | | | | | | | |
| | XFMR2 230.ROSEMR | | | | $0.08 | -$0.02 | | | | | | | | | | | | | | | | | |
| | 30505_WEBER _230_30624_TESLA E _230_BR_1 _1 | | | | $0.05 | -$0.01 | | | | | | | | | | | | | | | | | |
| SCE | 6410_CP1_NG | -$0.41 | $0.34 | $0.34 | -$0.39 | -$0.40 | $0.34 | $0.20 | $0.30 | $0.29 | $0.30 | $0.25 | | -$0.15 | -$0.22 | -$0.26 | -$0.28 | -$0.27 | -$0.29 | -$0.28 | -$0.27 | -$0.27 | -$0.27 |
| | OP-6610_ELD-LUGO | $0.24 | $0.26 | $0.10 | $0.22 | $0.24 | -$0.65 | -$0.48 | -$0.40 | -$0.40 | -$0.39 | -$0.40 | -$0.19 | -$0.02 | $0.02 | $0.08 | $0.09 | $0.09 | $0.10 | $0.10 | $0.09 | $0.09 | $0.09 |
| | 24086_LUGO _500_24238_RANCHVST_500_BR_1 _1 | -$0.01 | $0.03 | $0.03 | -$0.01 | -$0.01 | -$0.02 | -$0.02 | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 |
| | 24086_LUGO _500_26105_VICTORVL_500_BR_1 _1 | $0.01 | $0.01 | $0.00 | $0.01 | $0.01 | -$0.03 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.01 | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.01 | $0.00 | $0.00 | $0.00 |
| | 24091_MESA CAL_230_24076_LAGUBELL_230_BR_1 _1 | $0.00 | $0.01 | $0.00 | $0.00 | $0.00 | $0.00 | | | | | | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| SDG&E | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P | | $0.12 | $1.09 | | | | -$0.13 | -$0.34 | -$0.33 | -$0.35 | -$0.27 | -$0.12 | | | | | | | | | | |
| | 7820_TL 230S_OVERLOAD_NG | $0.00 | $0.03 | $0.35 | | $0.00 | $0.00 | -$0.03 | -$0.07 | -$0.08 | -$0.08 | -$0.06 | -$0.03 | $0.00 | | | | | | | | | |
| | 7820_TL 230S_TL50001OUT_NG | | $0.01 | $0.13 | | | | -$0.01 | -$0.03 | -$0.03 | -$0.03 | -$0.03 | -$0.01 | | | | | | | | | | |
| | OMS_12251471_TL23055_NG | | $0.00 | $0.09 | | | | -$0.01 | -$0.03 | -$0.03 | -$0.03 | -$0.02 | $0.00 | | | | | | | | | | |
| | 92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1 | | | $0.04 | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | | | | | | | | | | | |
| | 7820_13810A_OVERLOAD_NG | | $0.00 | -$0.01 | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | | | | | | | | | | | |
| | OMS_12137628_13810A_NG | | | -$0.03 | | | | | -$0.02 | -$0.02 | -$0.02 | -$0.02 | | | | | | | | | | | |
| | OMS_11878920_13810A_NG | | | -$0.03 | | | | | -$0.01 | -$0.01 | -$0.02 | -$0.01 | | | | | | | | | | | |
| | 7820_CP6_OMS_12226638_MS-SA | | | -$0.03 | | | | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | | | | | | | | | | | |
| | OMS_11878904_13810A_NG | | | -$0.04 | | | | | -$0.03 | -$0.03 | -$0.03 | -$0.01 | | | | | | | | | | | |
| | 22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1 | $0.01 | $0.02 | -$0.13 | $0.01 | $0.01 | $0.01 | | -$0.02 | -$0.02 | -$0.02 | -$0.01 | | | | | | | $0.00 | | | | |
| | 24801_DEVERS _500_24804_DEVERS _230_XF_1 _P | | | | | | | | -$0.06 | -$0.06 | -$0.07 | $0.00 | | | | | | | | | | | |
| | Other | $5.29 | $4.27 | $3.94 | $5.36 | $5.06 | $3.70 | $0.95 | $2.70 | $2.45 | $2.44 | $1.55 | -$3.48 | -$5.24 | -$5.88 | -$6.10 | -$6.18 | -$6.27 | -$6.31 | -$6.30 | -$6.26 | -$6.35 | -$6.24 |
| | **Internal Total** | **$6.38** | **$6.38** | **$7.08** | **$7.45** | **$6.23** | **$4.78** | **$1.13** | **$3.40** | **$1.76** | **$2.76** | **-$3.10** | **-$5.93** | **-$4.36** | **-$9.05** | **-$9.92** | **-$9.72** | **-$9.93** | **-$9.89** | **-$10.00** | **-$9.92** | **-$9.99** | **-$9.89** |
| | **Transfers** | | | | -$1.34 | $0.03 | $0.17 | $2.84 | $2.01 | $1.00 | -$5.70 | $0.75 | $0.14 | -$0.10 | -$3.72 | -$3.55 | $1.19 | -$1.15 | -$1.51 | -$0.38 | -$0.48 | -$4.12 | -$1.35 |
| | **Grand Total** | **$6.38** | **$6.38** | **$7.08** | **$6.11** | **$6.26** | **$4.95** | **$3.97** | **$5.41** | **$2.76** | **-$2.94** | **-$2.35** | **-$5.79** | **-$4.46** | **-$12.77** | **-$13.47** | **-$8.53** | **-$11.08** | **-$11.40** | **-$10.38** | **-$10.40** | **-$14.11** | **-$11.24** |

## Impact of congestion from transfer constraints

This section focuses on price impacts from congestion on schedule-based transfer constraints. The highest frequency occurred either into or away from the WEIM load areas located in the Pacific Northwest, where the transfer congestion reduced prices in those areas. Transfer constraint congestion in the 15-minute market decreased prices in most areas, while generally it raised 5-minute market prices in the South and lowered prices in North and East.

In the real-time market, the total impact of congestion on a specific WEIM area is equal to the sum of the price impact of flow-based constraints shown in Figure 1.31 and Table 1.4, and schedule-based constraints listed in Table 1.7. Transfer constraint congestion typically has the largest impact on prices; therefore, it is isolated here to better show its effects on the WEIM load areas. Table 1.7 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter.

**Table 1.7 Quarterly average price impact and congestion frequency on WEIM transfer constraints (Q3 2022)**

| | 15-minute market | | 5-minute market | |
|---|---|---|---|---|
| | Congestion Frequency | Price Impact ($/MWh) | Congestion Frequency | Price Impact ($/MWh) |
| Turlock Irrigation District | 0% | -$0.49 | 0% | $0.03 |
| BANC | 0% | -$1.87 | 0% | -$1.34 |
| L.A. Dept. of Water and Power | 0% | -$0.41 | 0% | $0.17 |
| Arizona Public Service | 0% | -$0.50 | 1% | $2.01 |
| NV Energy | 1% | -$0.52 | 2% | $2.84 |
| Public Service Company of NM | 1% | -$0.77 | 1% | $0.75 |
| PacifiCorp East | 6% | -$1.09 | 5% | $0.14 |
| Idaho Power | 7% | -$2.74 | 5% | -$0.10 |
| Tucson Electric Power | 7% | -$1.62 | 9% | $1.00 |
| PacifiCorp West | 22% | -$3.40 | 10% | -$1.51 |
| NorthWestern Energy | 19% | -$11.14 | 13% | -$3.72 |
| Avista | 21% | -$11.22 | 14% | -$3.55 |
| Salt River Project | 23% | -$12.20 | 22% | -$5.70 |
| Portland General Electric | 32% | -$1.33 | 16% | -$0.38 |
| Bonneville Power Admin. | 47% | $1.90 | 40% | $1.19 |
| Tacoma Power | 47% | -$5.81 | 42% | -$1.15 |
| Puget Sound Energy | 47% | -$4.93 | 42% | -$0.48 |
| Seattle City Light | 47% | -$5.61 | 42% | -$1.35 |
| Powerex | 49% | -$13.28 | 67% | -$4.12 |

### Transfer constraint congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market occurs with vastly different frequencies and price impacts across the WEIM. Figure 1.33 and Figure 1.34 shows the average impact to prices and the frequency of congestion on transfer constraints in the 15-minute market by quarter for 2021 and 2022, respectively.

There was an overall decrease in the frequency and an increase in impact of transfer constraint congestion in the third quarter of 2022 compared to the same quarter in 2021. The average frequency of transfer constraint congestion in the Pacific Northwest was 40 percent in the third quarter, down from 42 percent during the same time last year.[34]

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

**Figure 1.33 Transfer constraint congestion average impact on prices in the 15-minute market**

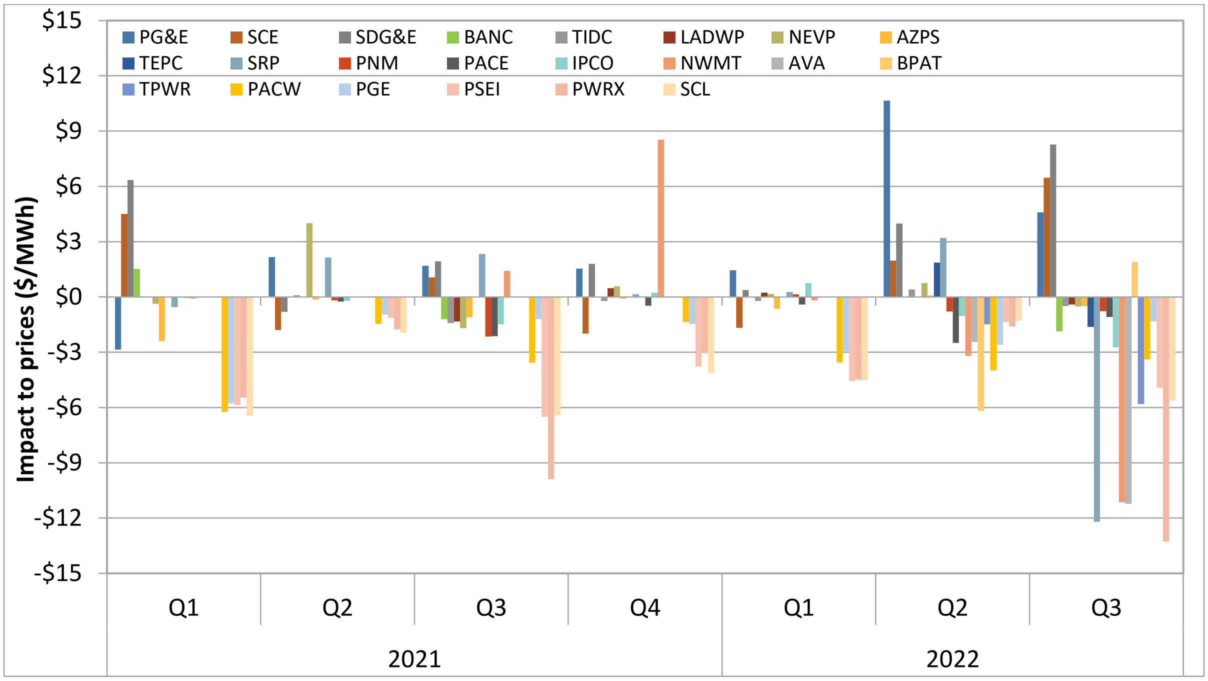
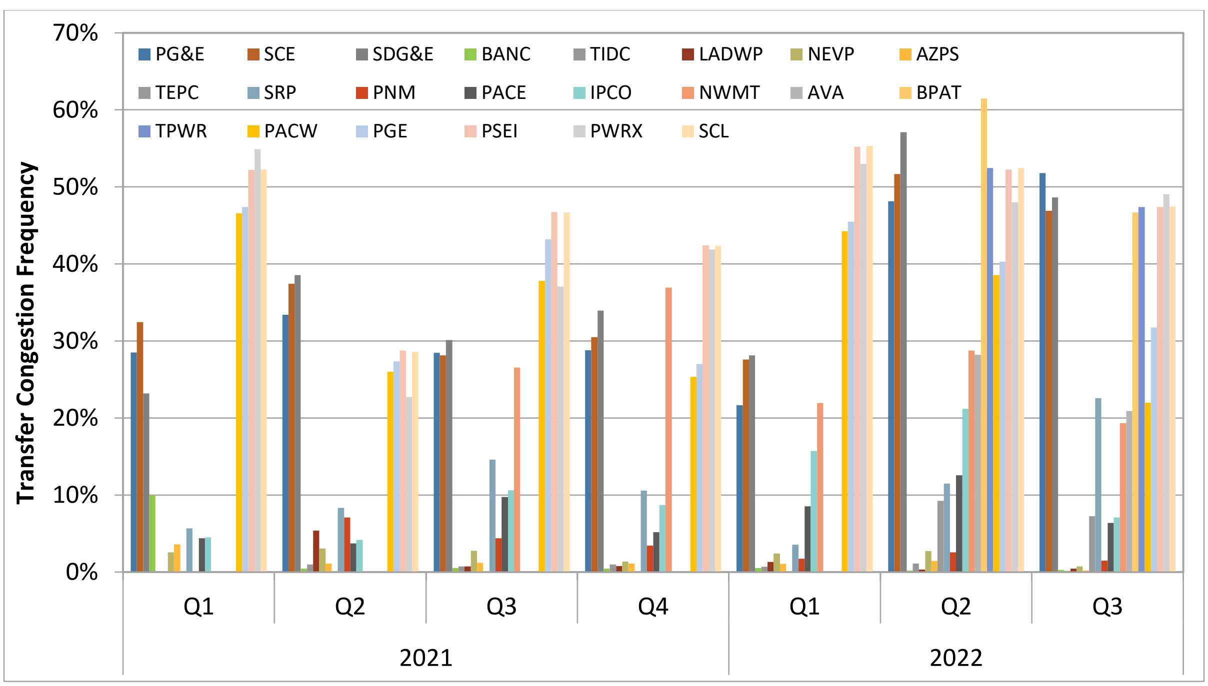



**Figure 1.34 Transfer constraint congestion frequency in the 15-minute market**



### 1.7.3 Congestion on interties

In the third quarter of 2022, the frequency and import congestion rent on the Malin 500 and NOB increased significantly relative to same time last year. Figure 1.35 shows total import congestion charges in the day-ahead market for 2021 and 2022. Figure 1.36 shows the frequency of congestion on five major interties. Table 1.8 provides a detailed summary of this data over a broader set of interties.

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

- Total import congestion charges for the third quarter of 2022 was 32 percent higher than the third quarter of 2021 at $66 million. The Malin 500 and NOB interties remain the primary drivers of congestion charges in the day-ahead market.
- Congestion charges on the Malin 500 and NOB were heavily influenced by the high load periods in July and September.
- The frequency and impact of congestion on Palo Verde was elevated from the third quarter of 2021 to the first quarter of 2022. This changed in the second quarter of 2022 where it decreased significantly. The intertie decreased further in the third quarter as it generated no congestion charges during the quarter.
- The frequency of congestion and magnitude of congestion charges was highest on the Malin 500, NOB, which accounted for 93 percent of the total congestion charges for the quarter. Congestion on other interties continued to remain relatively low relative to these constraints, with the exception of IPP Utah, which generated $4 million in congestion charges.

**Figure 1.35 Day-ahead import congestion charges on major interties**

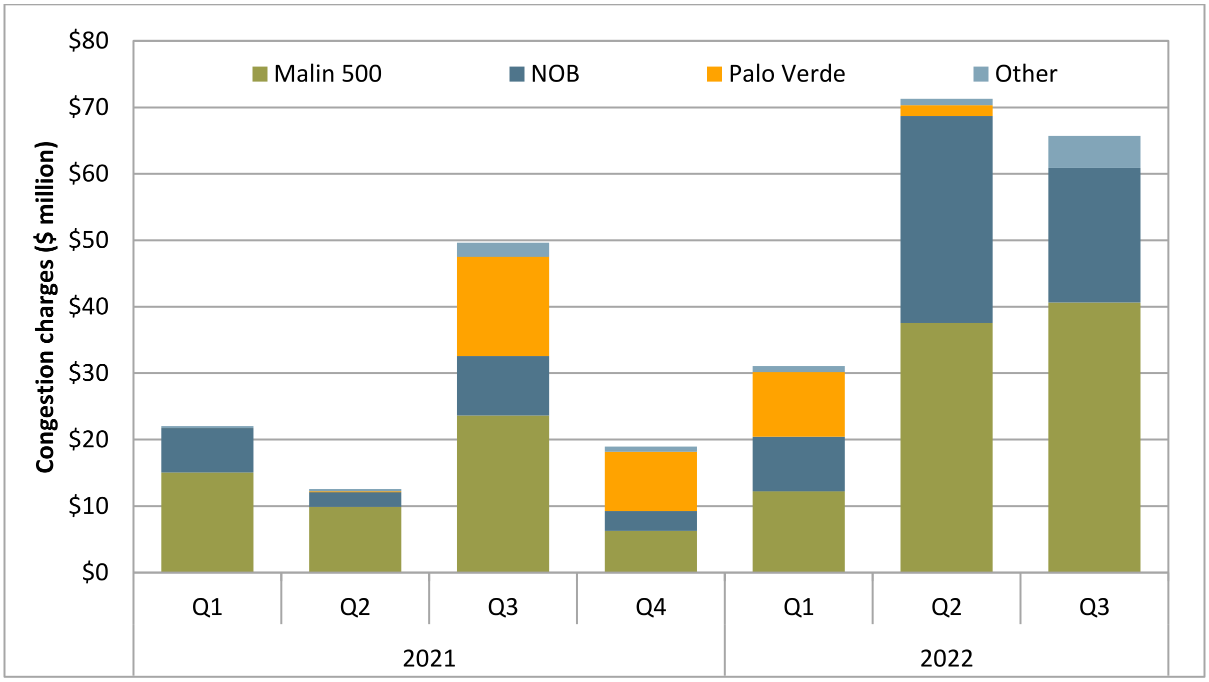



**Figure 1.36 Frequency of import congestion on major interties in the day-ahead market**

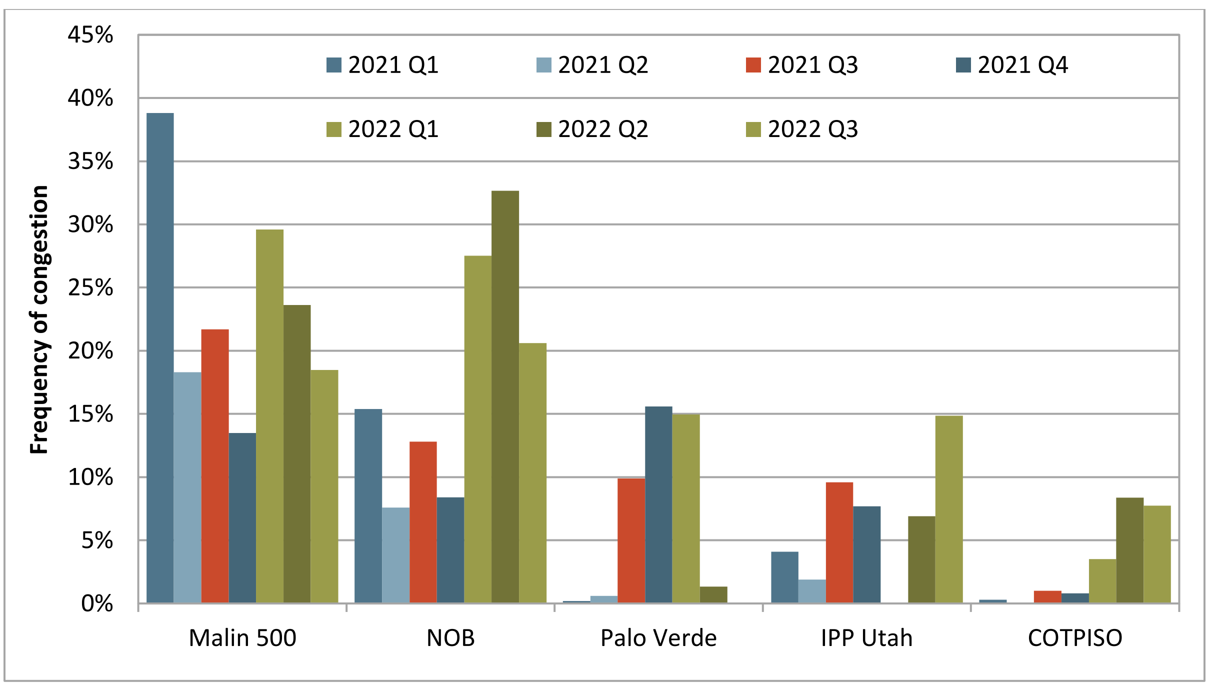


**Table 1.8 Summary of import congestion in day-ahead market (2021-2022)**

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

## 1.8 Congestion revenue rights

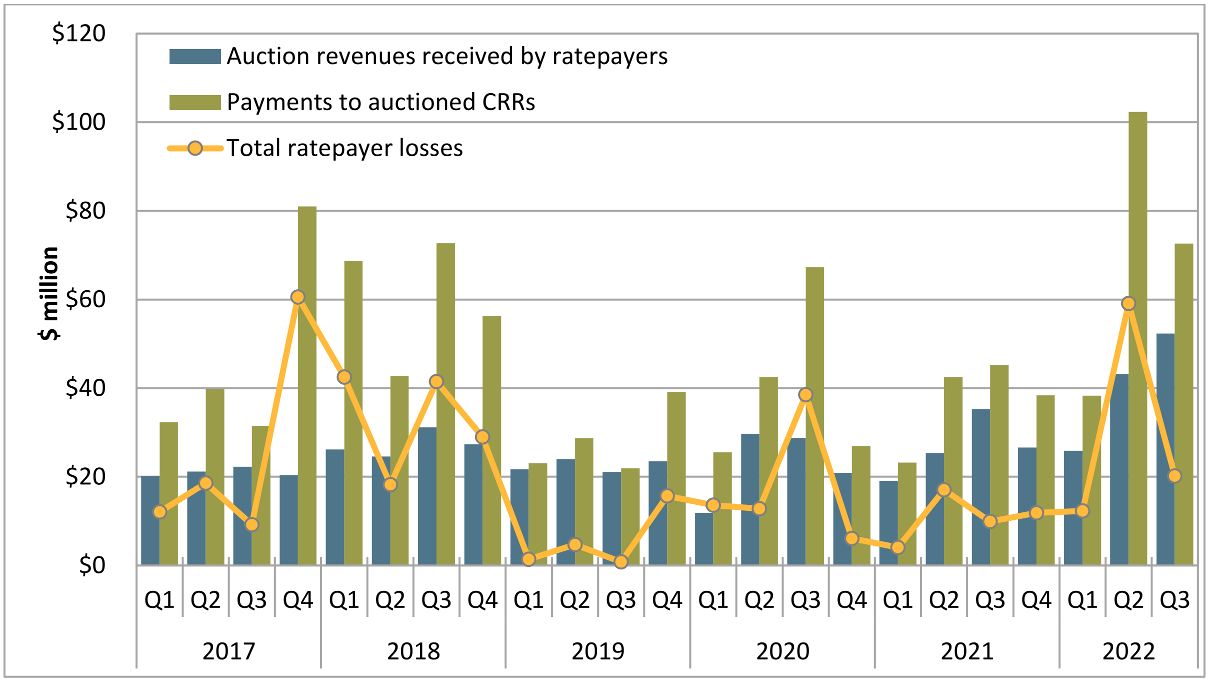
### Congestion revenue right auction returns

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

As shown in Figure 1.37, transmission ratepayers lost about $20 million during the third quarter of 2022 as payments to auctioned congestion revenue rights holders continued to exceed auction revenues.[35] This brings total losses to transmission ratepayers to about $82 million during the first three quarters of 2022.

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

**Figure 1.37 Auction revenues and payments to non-load-serving entities**




During the third quarter of 2022:

- Financial entities received profits of nearly $12.7 million in the third quarter of 2022, up from $5.2 million during the same quarter of 2021. Total revenue deficit offsets were about $42 million.
- Marketers received profits of nearly $5 million from auctioned rights in the third quarter of 2022, up from $3.2 million in 2021. Total revenue deficit offsets were nearly $10 million.
- Physical generation entities received about $2 million in profits from auctioned rights in the third quarter of 2022, up by $0.7 million in 2021. Total revenue deficit offsets were about $0.6 million.

The $20 million in third quarter 2022 auction losses was about 8 percent of day-ahead congestion rent. This is down from 21 percent from the previous quarter and slightly up from 6 percent of rent in the third quarter of 2021. The losses as a percent of day-ahead congestion rent were below the average of 28 percent during the three years before the track 1A and 1B changes (2016 through 2018).

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 $52 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 California ISO reduced losses from sales of congestion revenue rights significantly in 2019, particularly in the first three quarters following their implementation. However, DMM continues to recommend that the California ISO take steps to discontinue auctioning congestion revenue rights on behalf of ratepayers. The auction consistently continues to cause millions of dollars of losses to transmission ratepayers each year, while exposing transmission ratepayers to risk of significantly higher losses in the event of unexpected increases in congestion or modeling errors. If the California ISO believes it is highly beneficial to actively facilitate hedging of congestion costs by suppliers, DMM recommends the California ISO modify the congestion revenue rights auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

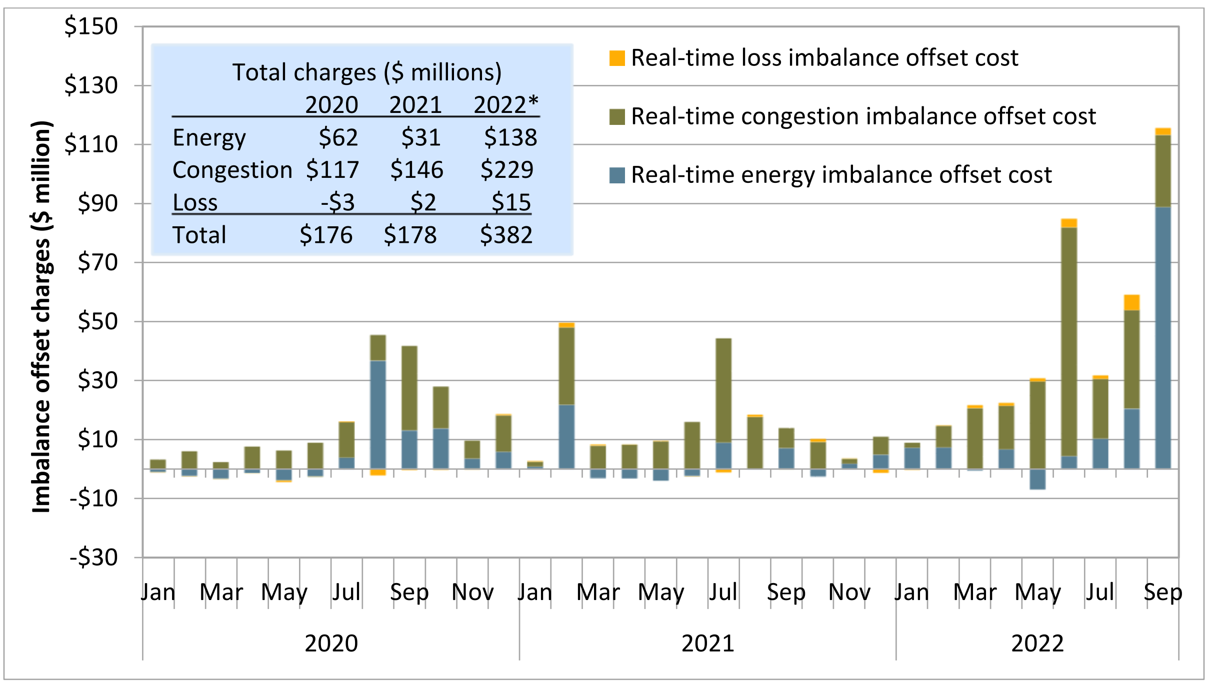
## 1.9 Real-time imbalance offset costs

Real-time imbalance offset costs increased significantly to about $206 million in the third quarter, up from $131 million in the second quarter and $45 million in the first quarter. Real-time imbalance energy costs were $89 million in September alone; the highest monthly energy offset costs since locational marginal pricing was introduced in 2009. Congestion imbalance offset costs were $77 million in June alone; the highest monthly congestion imbalance recorded.

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

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the congestion components of real-time energy settlement prices is *collected* through the *real-time congestion imbalance offset charge* (RTCIO). Similarly, any revenue imbalance from the *loss* component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge,* while any remaining revenue imbalance is *recovered* through the *real-time imbalance energy offset charge* (RTIEO).

**Figure 1.38 Real-time imbalance offset costs**




Real-time congestion imbalance offset costs occur when the congestion payments the CAISO pays out does not equal the congestion payments collected by the CAISO, i.e. the payments and collections do not balance. This can occur because of either a change from the day-ahead market to the 15-minute market (*15-minute imbalance*), or a change from the 15-minute market to the 5-minute market (*5-minute imbalance*). When a change to a real-time energy schedule reduces flows on a constraint, that schedule is paid the real-time constraint congestion price for making space available on the constraint.

Generally, if the constraint is still binding with a non-zero price, another schedule has increased flows on the constraint. The schedule that increased flows would then pay the CAISO enough to cover the CAISO payments to the schedule that reduced flows—and the CAISO congestion accounts would remain balanced.

There are several reasons the congestion payments will not balance. One reason is that flows increase causing a constraint to bind, generating additional congestion rent. Another is that the real-time constraint limits are lower than the day-ahead market limits. With a lower limit, schedules may be forced to reduce flows over the binding constraint without a corresponding flow increase. The CAISO will pay the flow reduction but cannot balance this payment with collections from a flow increase. To maintain revenue balance, the CAISO charges an uplift to measured demand to offset the imbalance. Congestion imbalances can also occur from differences in transmission modeling and the modeling of non-settled flows.

## 1.10 Bid cost recovery

During the three quarters of 2022, estimated bid cost recovery payments for units in the California ISO and Western Energy Imbalance Market (WEIM) balancing areas totaled about $167 million and $27 million, respectively.[36] These payments already exceeded the total bid cost recovery payments in 2021, which were about $158 million in the CAISO and $22 million in the WEIM.

In the third quarter of 2022, the California ISO and WEIM payments totaled $110 million, which are significantly higher than previous quarter ($55 million) and the same quarter of 2021 ($78 million). As shown in Figure 1.39, bid cost recovery payments were the highest during August and September. These significantly high payments can be attributed to record high loads in August and September, in addition to relatively higher gas prices.

The figure also shows that in the third quarter of 2022, bid cost recovery attributed to the day-ahead market totaled about $6.4 million, which was $0.7 million lower than third quarter of 2021. Bid cost recovery payments for residual unit commitment during the quarter totaled about $36 million, or about $4 million higher than the third quarter of 2021. Bid cost recovery attributed to the real-time market totaled about $67 million, or about $28 million higher than payments in the previous quarter, and in the third quarter of 2021. Out of the $67 million in real-time payments, about $15 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 83 percent of these payments, or about $91 million, were made to gas resources, followed by about $11.5 million to battery energy storage resources.

On November 18, 2022, FERC issued an order to prevent battery energy storage resources from receiving real-time market bid cost recovery payments for market intervals in which the *Ancillary Service*

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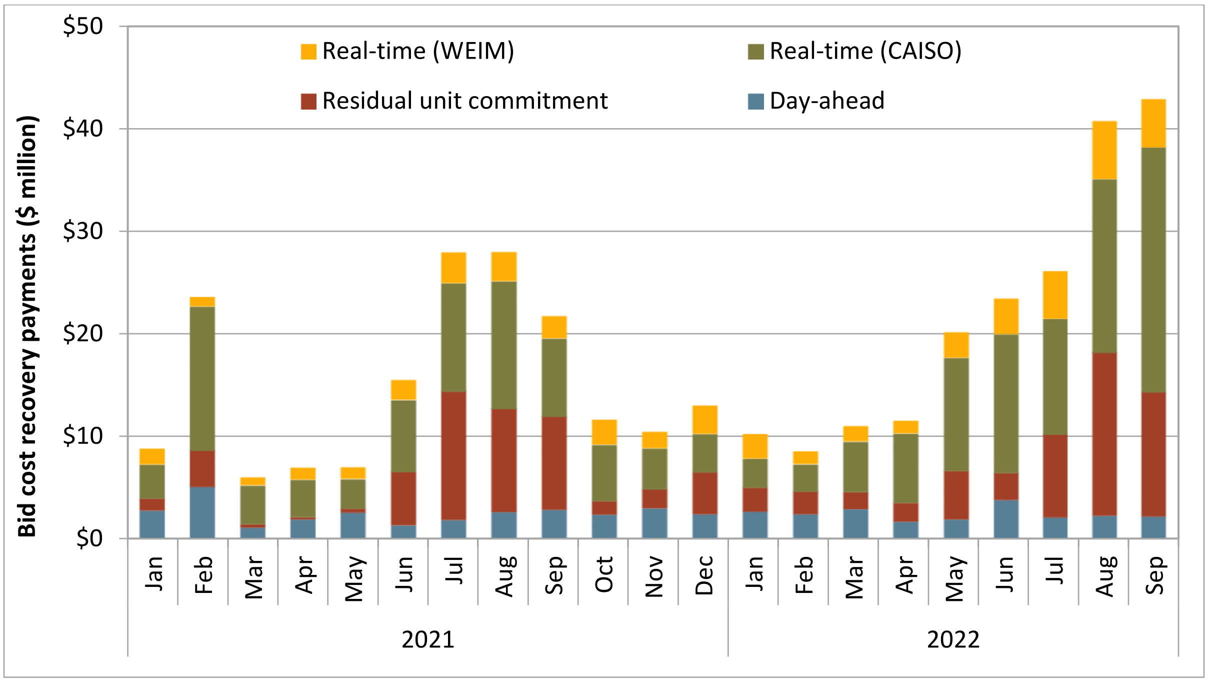
[36] Settlement data for the third quarter of 2022 is preliminary. More final settlement statements are issued at trade day plus 70 business days. Settlements can change substantially between statements. For further information on settlement timeline changes see: California ISO, *Market Settlements Timeline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

*State of Charge* constraint requires such a resource to charge or discharge.[37] This is in response to DMM's observations in 2022; where under certain circumstances, battery storage resources with ancillary service awards and high energy bids receive significant real-time bid cost recovery payments.

**Figure 1.39 Monthly bid cost recovery payments**




## 1.11 Imbalance conformance

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

### Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO hour-ahead and 15-minute markets. This large increase continued in both the morning solar ramp up and the afternoon peak solar ramp down period. Average hourly imbalance conformance adjustments in these markets peaked in the morning at about 450 MW, and at just over 2,200 MW in the afternoon, about a 400 MW and 775 MW increase, respectively, over the same quarter peak periods of the previous year. Solar weather forecast ramping uncertainty contributed to the morning increase in imbalance conformance levels compared to previous quarters of the year.

37 California ISO, *Order Accepting Tariff Revisions (on energy storage bid cost recovery changes), FERC Docket No. ER22-2881,* November 18, 2022: https://www.caiso.com/Documents/Nov18-2022-OrderAccepting-EnergyStorageBidCostRecovery-ER22-2881.pdf

Figure 1.40 shows imbalance conformance adjustments in real-time markets tend to follow a similar shape, with increases during the morning and evening net load ramp periods, and the lowest adjustments during the early morning pre-ramp, mid-day, and post-evening ramp periods.

Outside of the heat wave period, the 5-minute market adjustments in this quarter were consistently lower than 15-minute market imbalance conformance. The wider gap between the 15-minute and 5-minute imbalance conformance contributed to the greater deviation between 15-minute and 5-minute prices this quarter.

**Figure 1.40 Average hourly imbalance conformance adjustment (Q3 2021 – Q3 2022)**

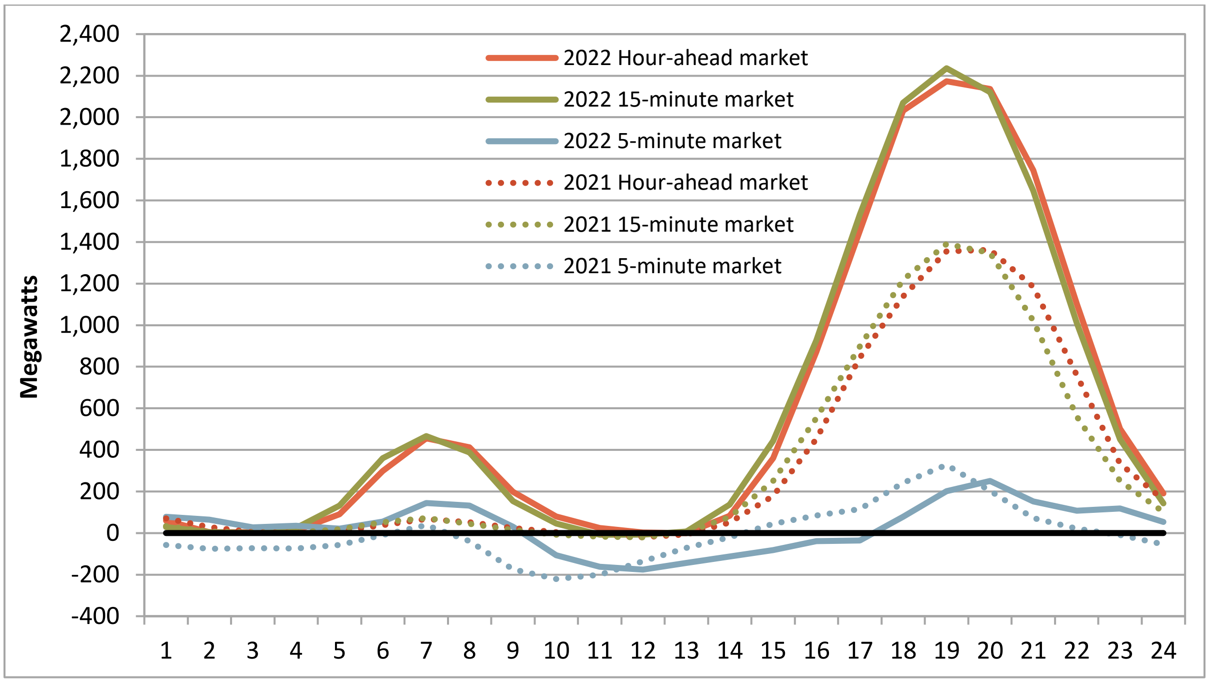


**Figure 1.41 15-minute market hourly distribution of operator load adjustments (Q3 2022)**

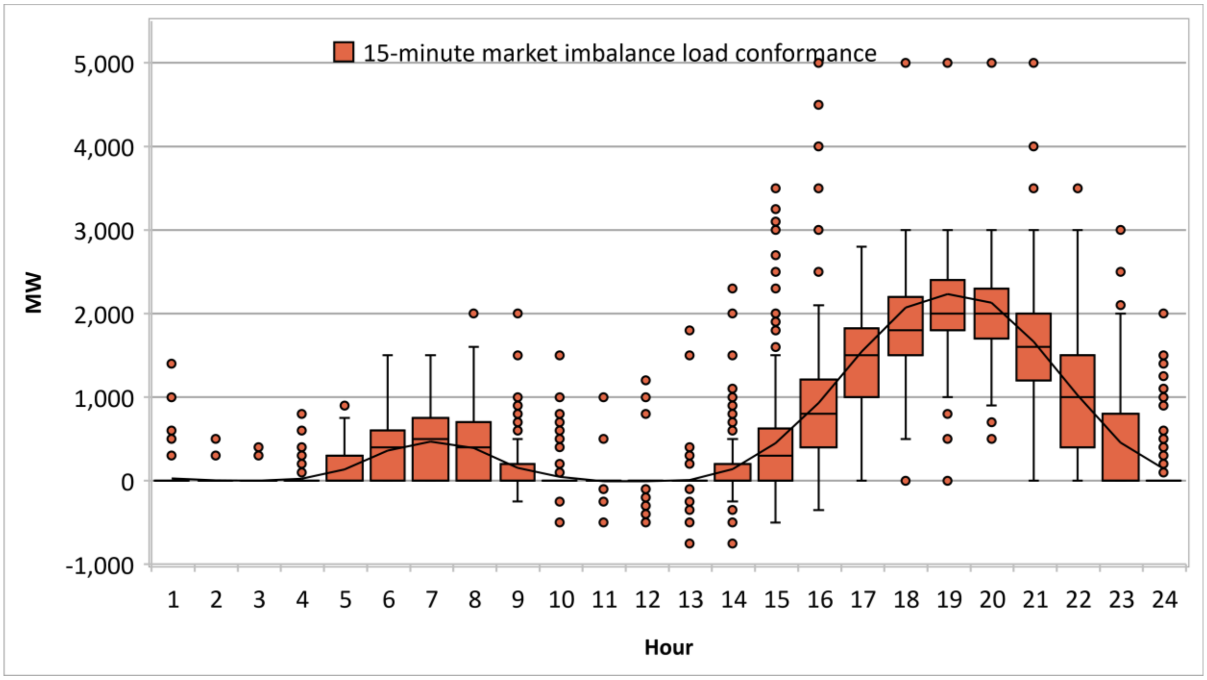



Figure 1.41 shows the distribution of the 15-minute market into quartiles for the load adjustment profile for the third quarter of 2022. This box and whisker graph highlights extreme outliers (positive and negative), minimum, lower quartile, median, upper quartile, and maximum, as well as the mean (line). The extreme outliers are represented by the filled 'dots and the outside whiskers do not include these outliers. For the quarter there were outliers of 5,000 MWs in hours-ending 16 to 21, these occurred entirely during the heat wave period. This is discussed further in the heat wave period in section 3.3. The maximum load adjustments, excluding identification of outliers, in the morning ramp were around 1,500 MW in hours ending 6 through 8, while the maximum evening ramp was about 3,000 MW in hours ending 18 through 22.

## 1.12 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches 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.

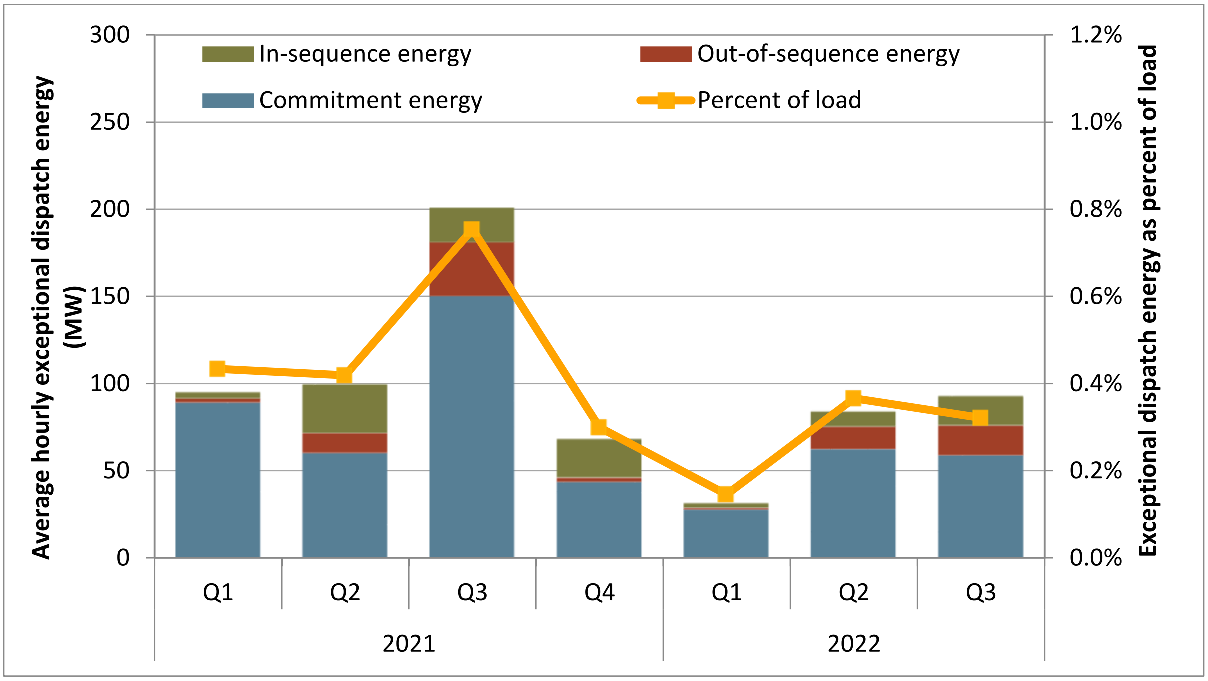
### Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 1 percent of total load in the CAISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 93 MWh in the third quarter of 2022, which is down from 200 MWh in the same quarter of 2021.

As shown in Figure 1.42, exceptional dispatches for unit commitments accounted for about 64 percent of all exceptional dispatch energy in this quarter,[38] about 18 percent was from out-of-sequence energy, and the remaining 18 percent was from in-sequence energy.

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

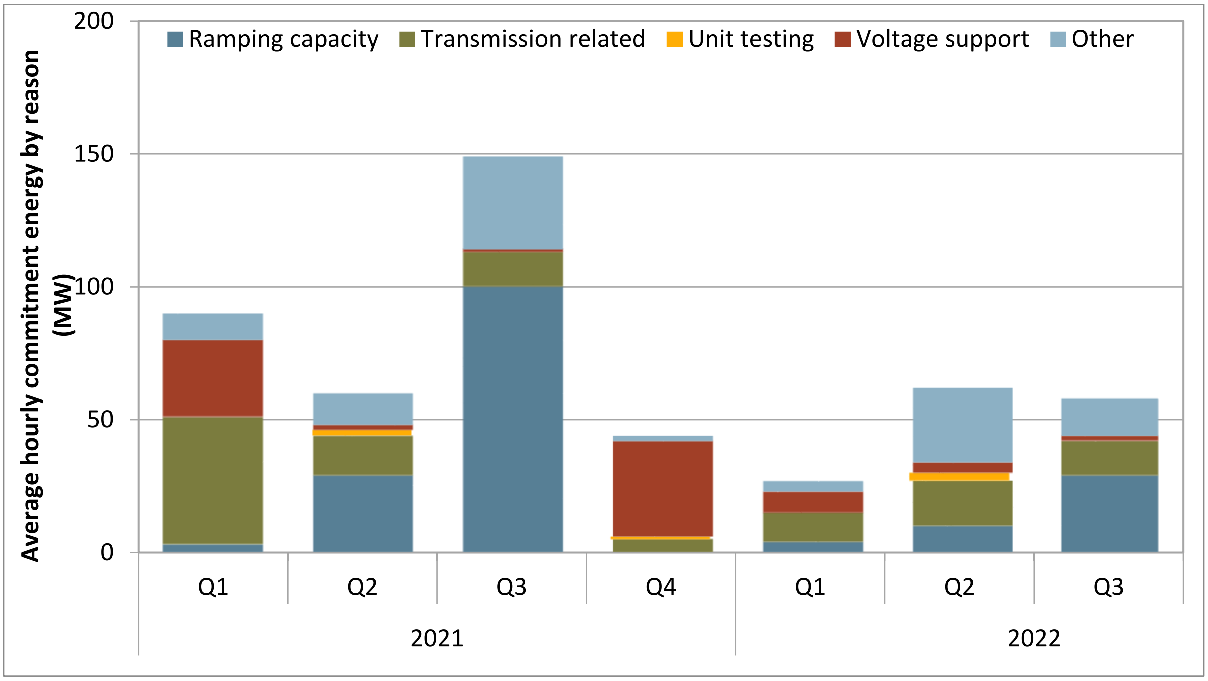
**Figure 1.42 Average hourly energy from exceptional dispatch**




### Exceptional dispatches for unit commitment

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

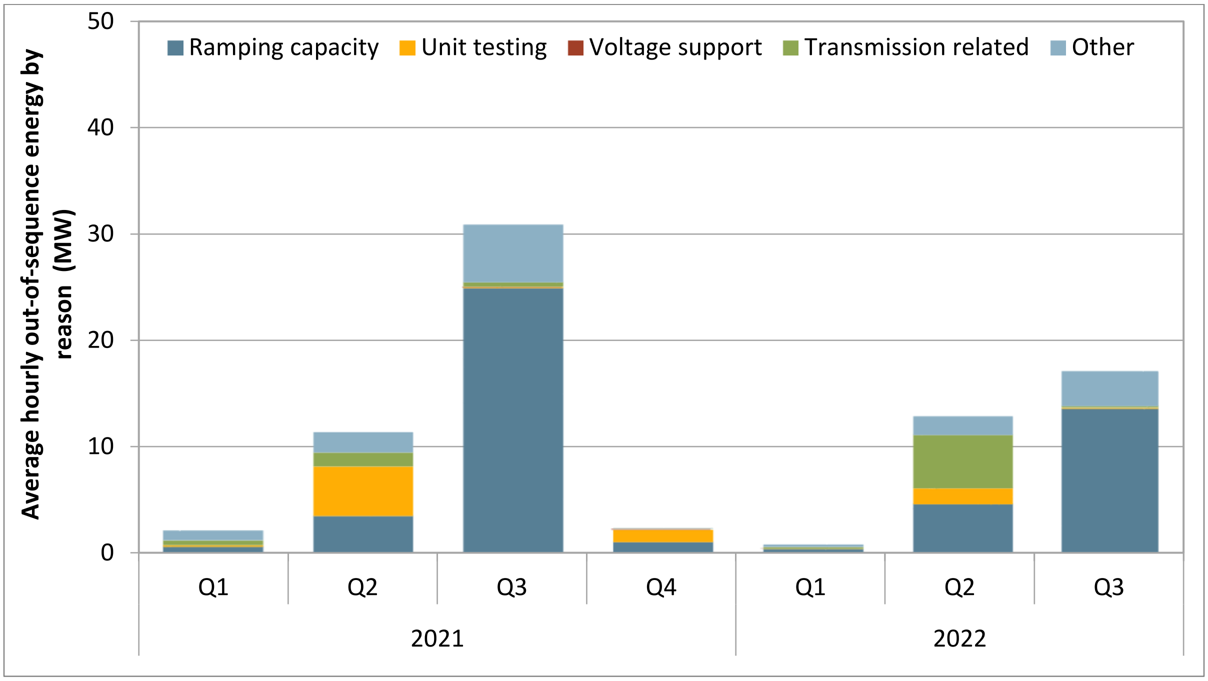
**Figure 1.43 Average minimum load energy from exceptional dispatch unit commitments**




### Exceptional dispatches for energy

As shown in Figure 1.43, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch in the second quarter of 2022 decreased by about 71 percent from the same quarter in 2021. Figure 1.44 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2021 and 2022. The primary reason logged for out-of-sequence energy in the third quarter of 2022 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**



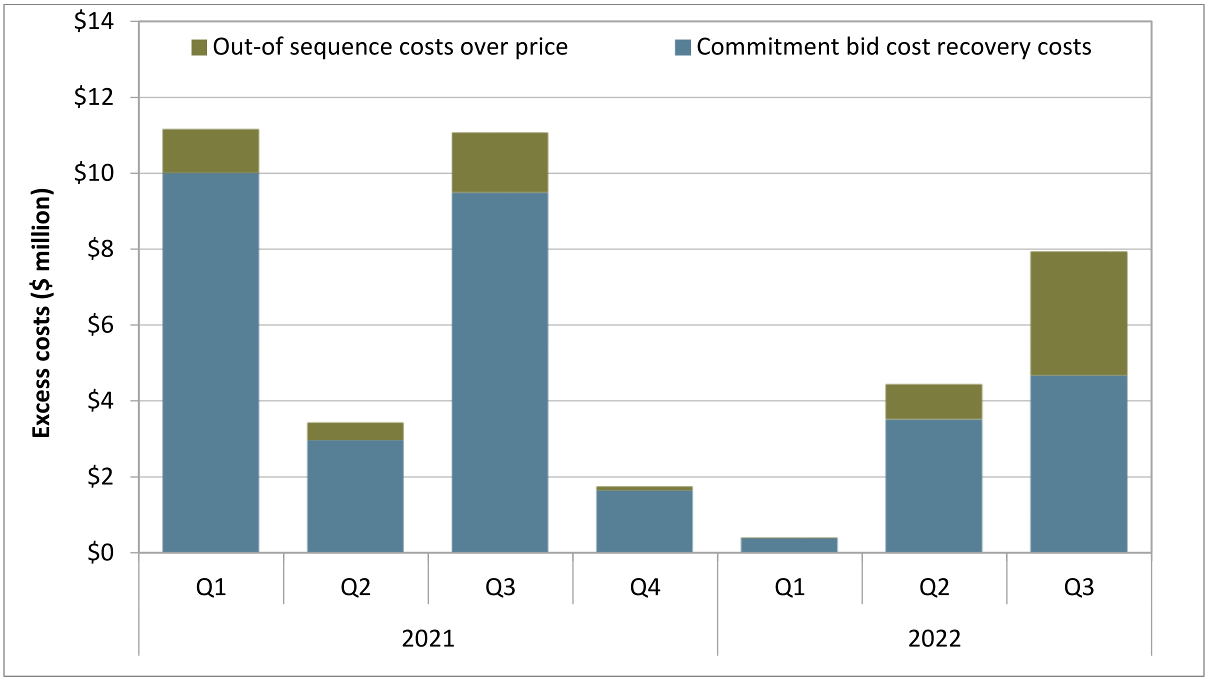

## Exceptional dispatch costs

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 additional energy resulting from exceptional dispatches in excess of the market price for this energy. In the third quarter, out-of-sequence energy costs were $3.25 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $4.7 million.

**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. Key observations and findings include:

- **Prices rose across the WEIM**, driven in large part by significant higher natural gas prices.
- **Prices in the Northwest region** were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours and congestion internal to the California ISO. This region includes, Portland General Electric, Puget Sound Energy, Seattle City Light, Tacoma Power, PacifiCorp West, Powerex, NorthWestern, Avista Utilities, and Bonneville Power Administration.
- **Prices in California areas were about $29/MWh higher than other regions**. Prices tend to be higher in California than the rest of the system due to both transfer constraint congestion and greenhouse gas compliance costs for energy that is delivered to California.
- **The California ISO was a major net importer** during peak net load hours. During these hours, the CAISO imported an average of around 1,600 MW from neighboring areas including LADWP, Turlock Irrigation District, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, and Tucson Electric Power.
- **The California ISO revised the loss sensitivity factor calculation** in August, reducing the impact on prices in the WEIM areas that base scheduled the majority of their transfer capacity, especially those located in the Pacific Northwest.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in monthly reports** as part of the WEIM resource sufficiency evaluation stakeholder initiative. These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process, as well as a detailed look at the net load uncertainty adders used in the tests.[39]
- **Appendix A includes hourly price and transfer figures for each WEIM area.**

## 2.1 Performance

### Prices

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

Table 2.1 shows average monthly prices for the 15-minute market by area for 2021 through 2022. The combined average of WEIM prices outside of California was lower than California area prices by $29.46/MWh on average over the third quarter. The combined average prices of these areas, which include the Balancing Area of Northern California, Turlock Irrigation District, and Los Angeles

[39] See Department of Market Monitoring, *Western Energy Imbalance Market resource sufficiency evaluation reports:* http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

Department of Water and Power, were $0.28MWh lower than Pacific Gas and Electric's average price of $104.36/MWh.

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

**Table 2.1 Monthly 15-minute market prices**

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

**Figure 2.1 Quarterly average 15-minute price by component (Q3 2022)**

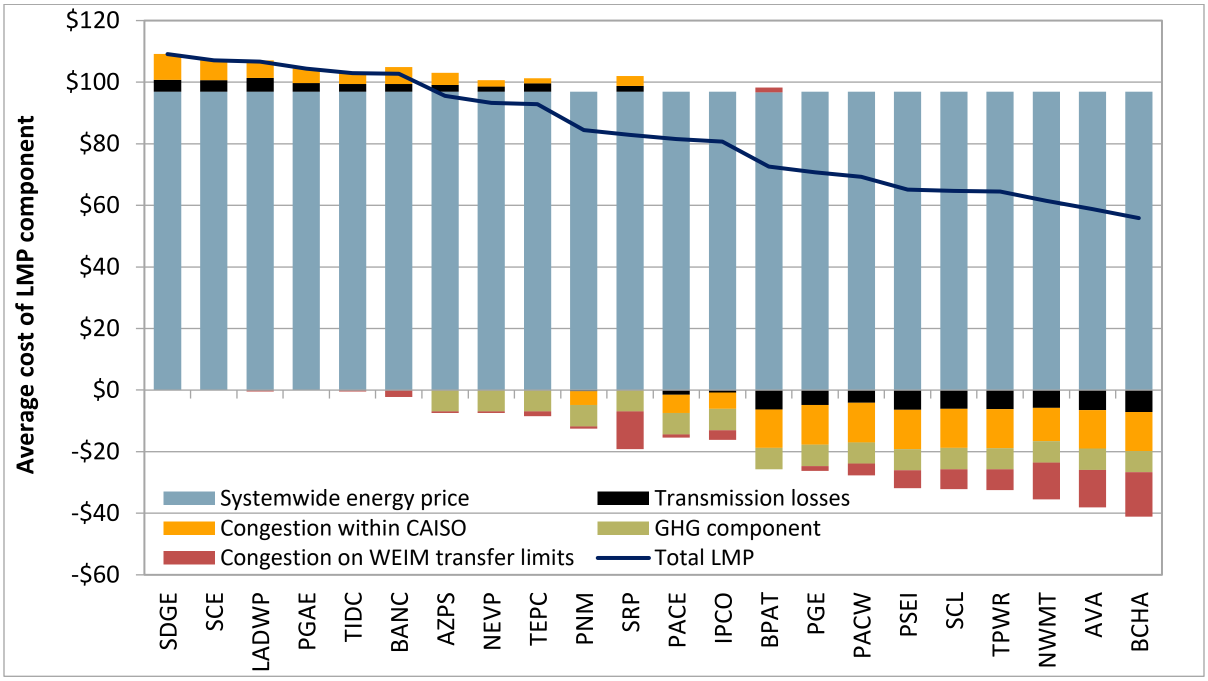



**Figure 2.2 Quarterly average 5-minute price by component (Q3 2022)**

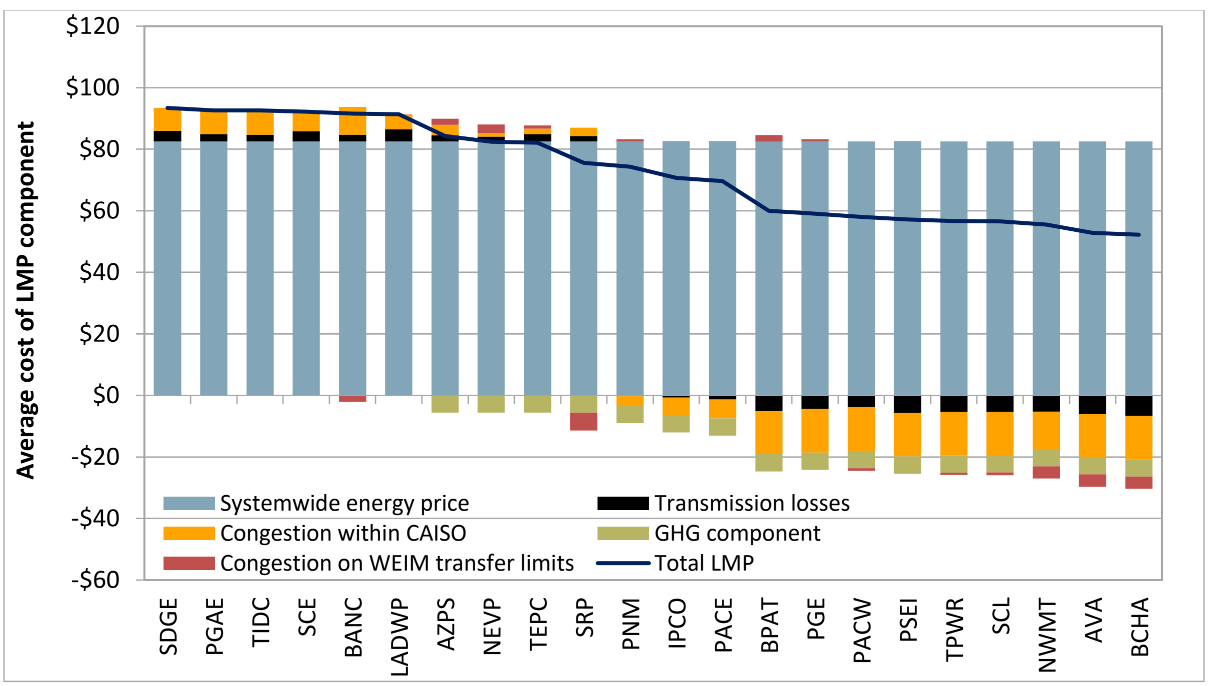


Figure 2.1 depicts the average 15-minute price by component for each balancing authority area.[40] The system marginal energy price is the same for all entities in each hour.[41] The price difference between balancing authority areas is determined by area specific elements including transmission losses, greenhouse gas compliance costs, congestion, and power balance constraint (PBC) violations.

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

Table 2.2 and Table 2.3 show the variation in prices throughout the day in the third quarter of 2022. In these tables, the colors change based on the deviation from the average system marginal energy price (SMEC). Therefore, blue represents prices below that hour's average system price and orange indicates prices above. Prices in balancing areas outside of California tend to be lower than prices in California for most hours, particularly during hours when California areas are typically importing energy subject to greenhouse gas compliance costs. Other differences in prices reflect transfer limitations between the different areas and congestion within BAAs.

The WEIM areas that base scheduled the majority of their transfer capacity, especially those that are located in the Pacific Northwest, saw high loss price components during hours with high volumes of transfers over the summer. This issue is exemplified in Figure 2.5, which breaks down BPA's average hourly locational marginal price by component during July.[42] The California ISO made changes to the loss sensitivity factor calculation to address this issue on August 22, 2022.[43] Figure 2.6 breaks down BPA's average hourly price by component in September, and shows the dramatic reduction in the loss LMP component during all hours.

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

41 With the exception of Bonneville Power Administration and Tucson Electric Power, as they joined partway through the quarter; therefore, their LMP components represent the average since joining the WEIM.

42 See Appendix A for quarterly versions of this figure for each WEIM area in the 15-minute and 5-minute markets.

43 California ISO, *Market Performance and Planning Forum*, presented on September 29, 2022, slide 58: http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Sep29-2022.pdf

## Table 2.2 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 | $59 | $56 | $55 | $54 | $57 | $64 | $62 | $48 | $38 | $34 | $31 | $34 | $36 | $38 | $41 | $48 | $52 | $62 | $82 | $110 | $100 | $84 | $74 | $64 |
| PG&E (CAISO) | $82 | $80 | $77 | $76 | $77 | $81 | $84 | $74 | $65 | $62 | $63 | $67 | $70 | $79 | $96 | $121 | $144 | $176 | $233 | $229 | $154 | $125 | $97 | $84 |
| SCE (CAISO) | $81 | $78 | $75 | $74 | $75 | $81 | $83 | $71 | $61 | $60 | $64 | $68 | $71 | $79 | $94 | $124 | $148 | $188 | $260 | $250 | $164 | $125 | $102 | $88 |
| BANC | $78 | $77 | $74 | $73 | $74 | $78 | $82 | $73 | $64 | $62 | $63 | $67 | $72 | $80 | $104 | $129 | $151 | $179 | $223 | $219 | $140 | $118 | $96 | $81 |
| Turlock ID | $80 | $79 | $76 | $75 | $76 | $79 | $83 | $72 | $64 | $62 | $63 | $67 | $71 | $80 | $99 | $128 | $141 | $167 | $224 | $228 | $151 | $118 | $95 | $83 |
| LADWP | $81 | $78 | $75 | $74 | $75 | $81 | $83 | $71 | $61 | $61 | $64 | $67 | $71 | $80 | $95 | $122 | $147 | $187 | $255 | $251 | $164 | $121 | $102 | $87 |
| NV Energy | $73 | $69 | $65 | $64 | $66 | $71 | $66 | $58 | $53 | $54 | $57 | $62 | $65 | $72 | $82 | $105 | $129 | $164 | $224 | $222 | $142 | $100 | $89 | $78 |
| Arizona PS | $75 | $71 | $67 | $66 | $68 | $72 | $70 | $60 | $52 | $54 | $58 | $61 | $64 | $73 | $86 | $109 | $132 | $166 | $234 | $229 | $145 | $104 | $93 | $79 |
| Tucson Electric | $72 | $69 | $66 | $65 | $67 | $72 | $69 | $59 | $53 | $56 | $61 | $65 | $67 | $75 | $82 | $108 | $129 | $164 | $233 | $213 | $130 | $90 | $85 | $75 |
| Salt River Project | $69 | $64 | $60 | $62 | $63 | $65 | $63 | $56 | $50 | $56 | $59 | $62 | $65 | $71 | $78 | $92 | $100 | $139 | $210 | $153 | $112 | $83 | $82 | $71 |
| PSC New Mexico | $56 | $58 | $56 | $55 | $58 | $66 | $62 | $56 | $51 | $53 | $57 | $61 | $63 | $71 | $81 | $104 | $124 | $154 | $216 | $206 | $122 | $78 | $57 | $58 |
| PacifiCorp East | $62 | $60 | $56 | $55 | $56 | $62 | $61 | $53 | $50 | $51 | $54 | $58 | $61 | $69 | $76 | $97 | $115 | $139 | $191 | $195 | $114 | $80 | $71 | $65 |
| Idaho Power | $65 | $62 | $58 | $57 | $58 | $65 | $62 | $55 | $51 | $53 | $57 | $60 | $64 | $72 | $78 | $97 | $113 | $119 | $160 | $192 | $109 | $82 | $75 | $68 |
| NorthWestern | $54 | $51 | $49 | $47 | $47 | $53 | $52 | $47 | $47 | $49 | $51 | $55 | $56 | $62 | $65 | $82 | $74 | $80 | $94 | $97 | $78 | $61 | $65 | $56 |
| Avista Utilities | $55 | $50 | $48 | $46 | $46 | $51 | $51 | $44 | $45 | $48 | $50 | $53 | $54 | $59 | $61 | $78 | $70 | $72 | $85 | $89 | $72 | $59 | $63 | $56 |
| BPA | $61 | $54 | $50 | $49 | $49 | $56 | $61 | $62 | $55 | $55 | $58 | $62 | $62 | $74 | $78 | $79 | $89 | $104 | $113 | $126 | $104 | $100 | $77 | $61 |
| Tacoma Power | $56 | $53 | $49 | $46 | $48 | $52 | $51 | $53 | $53 | $54 | $57 | $61 | $62 | $66 | $71 | $72 | $74 | $84 | $100 | $105 | $82 | $66 | $69 | $59 |
| PacifiCorp West | $62 | $54 | $50 | $50 | $50 | $56 | $52 | $49 | $48 | $50 | $52 | $56 | $57 | $61 | $66 | $79 | $88 | $103 | $142 | $152 | $85 | $64 | $69 | $60 |
| Portland GE | $58 | $53 | $50 | $49 | $50 | $55 | $53 | $53 | $51 | $54 | $55 | $59 | $60 | $65 | $71 | $84 | $93 | $104 | $144 | $149 | $85 | $66 | $69 | $60 |
| Puget Sound Energy | $56 | $51 | $48 | $47 | $48 | $53 | $52 | $53 | $53 | $54 | $57 | $61 | $61 | $66 | $71 | $75 | $74 | $85 | $107 | $109 | $81 | $66 | $68 | $61 |
| Powerex | $55 | $51 | $50 | $48 | $49 | $51 | $51 | $50 | $49 | $50 | $51 | $54 | $53 | $58 | $57 | $57 | $60 | $66 | $68 | $66 | $65 | $62 | $61 | $56 |
| Seattle City Light | $63 | $49 | $47 | $47 | $48 | $52 | $52 | $54 | $53 | $55 | $57 | $61 | $61 | $66 | $72 | $73 | $72 | $84 | $101 | $105 | $83 | $67 | $69 | $60 |

Hour

## Table 2.3 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 | $59 | $55 | $54 | $53 | $55 | $59 | $58 | $38 | $32 | $28 | $27 | $29 | $32 | $33 | $33 | $36 | $37 | $43 | $66 | $81 | $76 | $69 | $68 | $62 |
| PG&E (CAISO) | $85 | $84 | $81 | $78 | $79 | $82 | $88 | $80 | $64 | $60 | $60 | $65 | $69 | $78 | $94 | $105 | $104 | $117 | $172 | $158 | $126 | $107 | $97 | $85 |
| SCE (CAISO) | $81 | $77 | $74 | $74 | $75 | $79 | $82 | $70 | $59 | $57 | $60 | $65 | $69 | $80 | $93 | $108 | $106 | $129 | $189 | $172 | $127 | $105 | $96 | $83 |
| BANC | $83 | $80 | $78 | $76 | $77 | $80 | $84 | $75 | $63 | $60 | $61 | $65 | $72 | $82 | $103 | $111 | $116 | $119 | $167 | $144 | $114 | $108 | $95 | $82 |
| Turlock ID | $84 | $83 | $80 | $77 | $78 | $81 | $86 | $77 | $63 | $61 | $62 | $66 | $73 | $83 | $97 | $108 | $104 | $114 | $172 | $158 | $124 | $106 | $95 | $84 |
| LADWP | $81 | $77 | $74 | $74 | $75 | $78 | $81 | $71 | $59 | $57 | $60 | $63 | $69 | $80 | $90 | $103 | $103 | $129 | $189 | $174 | $125 | $104 | $93 | $84 |
| NV Energy | $79 | $75 | $69 | $65 | $66 | $69 | $70 | $58 | $53 | $50 | $56 | $58 | $64 | $75 | $80 | $93 | $92 | $112 | $167 | $158 | $109 | $85 | $89 | $81 |
| Arizona PS | $76 | $70 | $66 | $66 | $72 | $71 | $69 | $59 | $50 | $50 | $54 | $58 | $63 | $77 | $87 | $96 | $95 | $127 | $175 | $161 | $110 | $89 | $93 | $87 |
| Tucson Electric | $71 | $69 | $66 | $65 | $66 | $71 | $69 | $58 | $51 | $54 | $60 | $65 | $68 | $76 | $81 | $96 | $93 | $116 | $174 | $155 | $106 | $86 | $80 | $72 |
| Salt River Project | $65 | $62 | $59 | $61 | $61 | $58 | $56 | $51 | $45 | $67 | $63 | $61 | $69 | $80 | $81 | $96 | $86 | $105 | $155 | $119 | $91 | $79 | $78 | $67 |
| PSC New Mexico | $60 | $60 | $57 | $57 | $59 | $64 | $63 | $55 | $53 | $56 | $53 | $57 | $62 | $71 | $80 | $100 | $87 | $106 | $165 | $139 | $90 | $69 | $60 | $57 |
| PacifiCorp East | $59 | $57 | $54 | $53 | $54 | $59 | $59 | $53 | $47 | $48 | $52 | $55 | $61 | $69 | $74 | $86 | $80 | $95 | $141 | $127 | $79 | $67 | $74 | $65 |
| Idaho Power | $60 | $59 | $55 | $54 | $56 | $61 | $61 | $55 | $50 | $50 | $54 | $58 | $64 | $72 | $75 | $87 | $91 | $93 | $132 | $132 | $73 | $68 | $71 | $64 |
| NorthWestern | $52 | $49 | $45 | $45 | $46 | $50 | $51 | $48 | $46 | $47 | $49 | $52 | $56 | $61 | $60 | $77 | $64 | $67 | $73 | $70 | $59 | $51 | $59 | $53 |
| Avista Utilities | $50 | $47 | $44 | $43 | $44 | $49 | $48 | $47 | $45 | $46 | $47 | $51 | $54 | $58 | $57 | $67 | $59 | $62 | $71 | $62 | $55 | $48 | $59 | $52 |
| BPA | $52 | $50 | $46 | $46 | $47 | $52 | $55 | $53 | $48 | $50 | $54 | $57 | $59 | $64 | $66 | $72 | $71 | $72 | $78 | $80 | $74 | $71 | $64 | $53 |
| Tacoma Power | $51 | $49 | $45 | $43 | $45 | $50 | $49 | $49 | $48 | $50 | $53 | $56 | $59 | $62 | $62 | $66 | $67 | $68 | $75 | $72 | $63 | $59 | $61 | $54 |
| PacifiCorp West | $54 | $50 | $46 | $47 | $48 | $53 | $51 | $49 | $46 | $47 | $50 | $53 | $57 | $60 | $60 | $70 | $64 | $69 | $96 | $87 | $61 | $52 | $63 | $55 |
| Portland GE | $53 | $50 | $46 | $46 | $48 | $53 | $51 | $50 | $47 | $48 | $50 | $54 | $58 | $60 | $61 | $72 | $66 | $73 | $101 | $89 | $63 | $58 | $63 | $54 |
| Puget Sound Energy | $51 | $48 | $45 | $44 | $45 | $50 | $50 | $49 | $47 | $50 | $53 | $56 | $59 | $62 | $62 | $66 | $67 | $73 | $83 | $76 | $63 | $59 | $60 | $54 |
| Powerex | $50 | $48 | $47 | $46 | $47 | $49 | $52 | $49 | $47 | $47 | $49 | $50 | $51 | $54 | $53 | $55 | $57 | $60 | $60 | $60 | $60 | $54 | $54 | $53 |
| Seattle City Light | $51 | $45 | $43 | $44 | $45 | $49 | $50 | $48 | $48 | $51 | $53 | $56 | $59 | $62 | $62 | $66 | $65 | $68 | $75 | $73 | $64 | $60 | $61 | $56 |

Hour

**Figure 2.3 Bonneville Power Administration average 5-minute price by component (July 2022)**

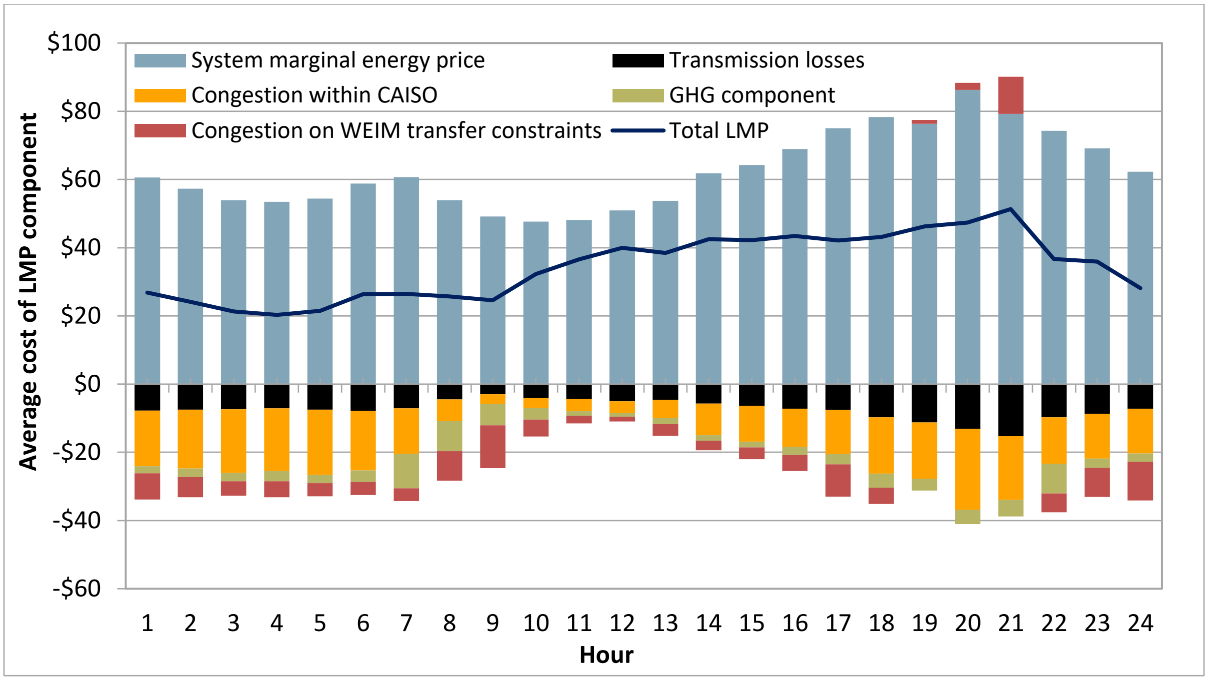
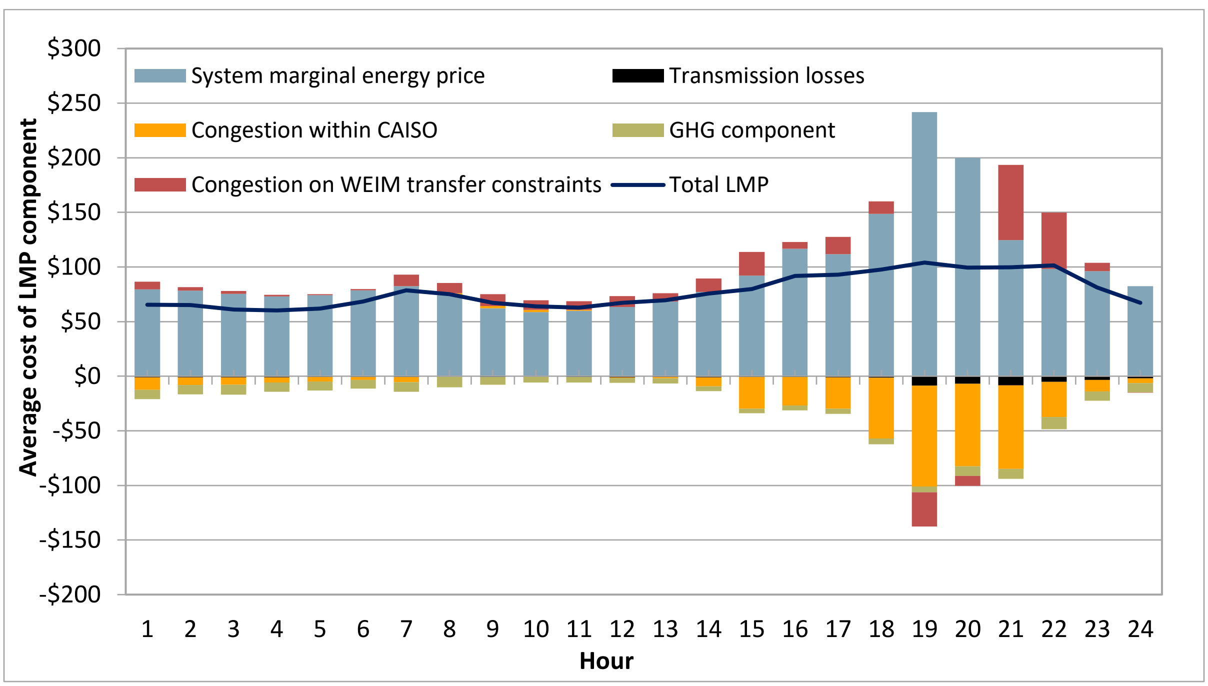



**Figure 2.4 Bonneville Power Administration average 5-minute price by component (September 2022)**



## 2.2 Transfers, limits, and congestion

### Energy transfers

One of the key benefits of the WEIM is the ability to transfer energy between balancing areas in the 15-minute and 5-minute markets. These transfers are the result of regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint.[44] WEIM transfers are constrained by *transfer limits* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 2.5 and Figure 2.6 highlight typical transfer patterns during two key periods that produce a high volume of transfers.[45] Figure 2.5 shows average dynamic 15-minute market exports out of each area during mid-day hours (between hours 10 and 17) during the quarter.[46] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area. Each small tick is 50 MW and each large tick is 250 MW.
Figure 2.5 shows that the CAISO exported just over 600 MW, on average during these mid-day hours, out to neighboring areas including BANC, Powerex, and Salt River Project. The mid-day typically contains the highest levels of exports out of the CAISO area because of significant solar production.

Figure 2.6 shows average dynamic transfers during peak net load hours (between hours 19 and 22) in the quarter. During these hours, imports into the CAISO are often highest. The figure shows an average of just under 1,600 MW of exports out of LADWP, Turlock Irrigation District, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, and Tucson Electric Power, going into the CAISO during these hours (CAISO import). PacifiCorp East was also significant exporter during these hours, with over 550 MW on average out to neighboring areas.

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

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

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

**Figure 2.5 Average 15-minute market WEIM exports (mid-day hours, July – September, 2022)**

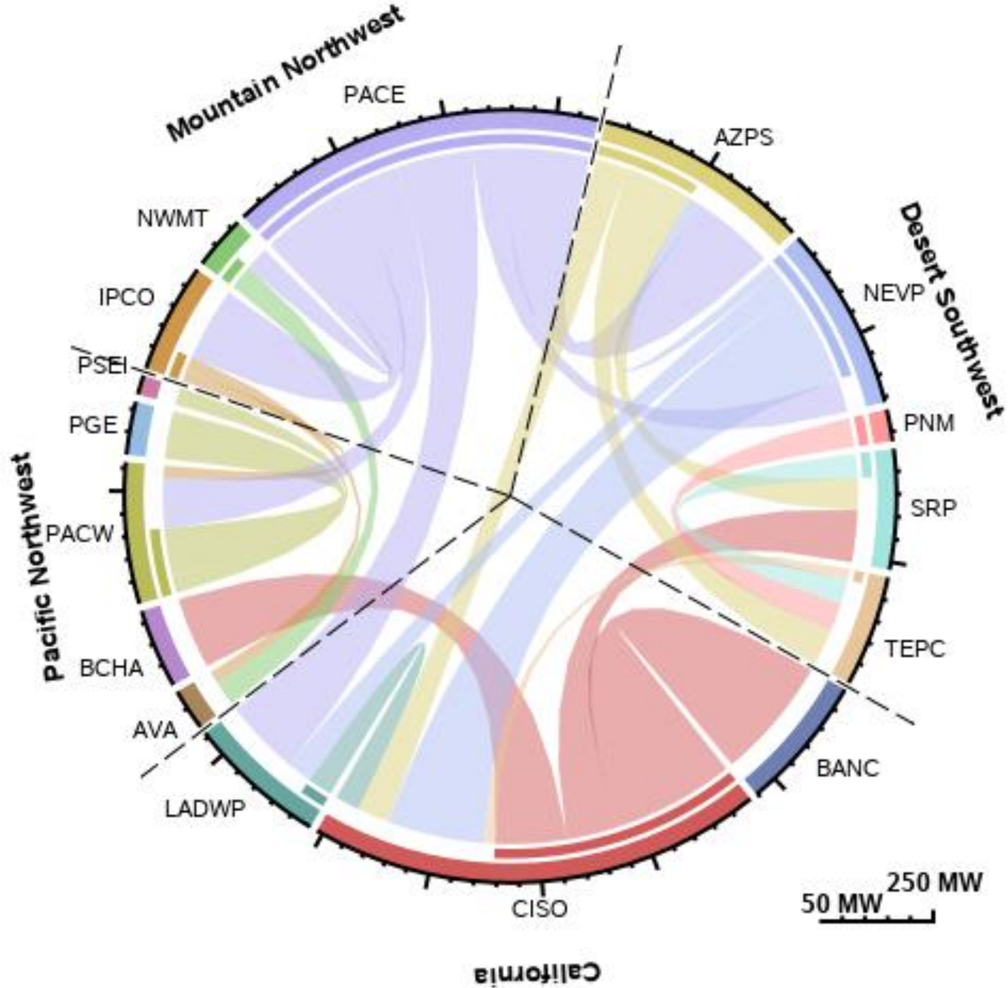
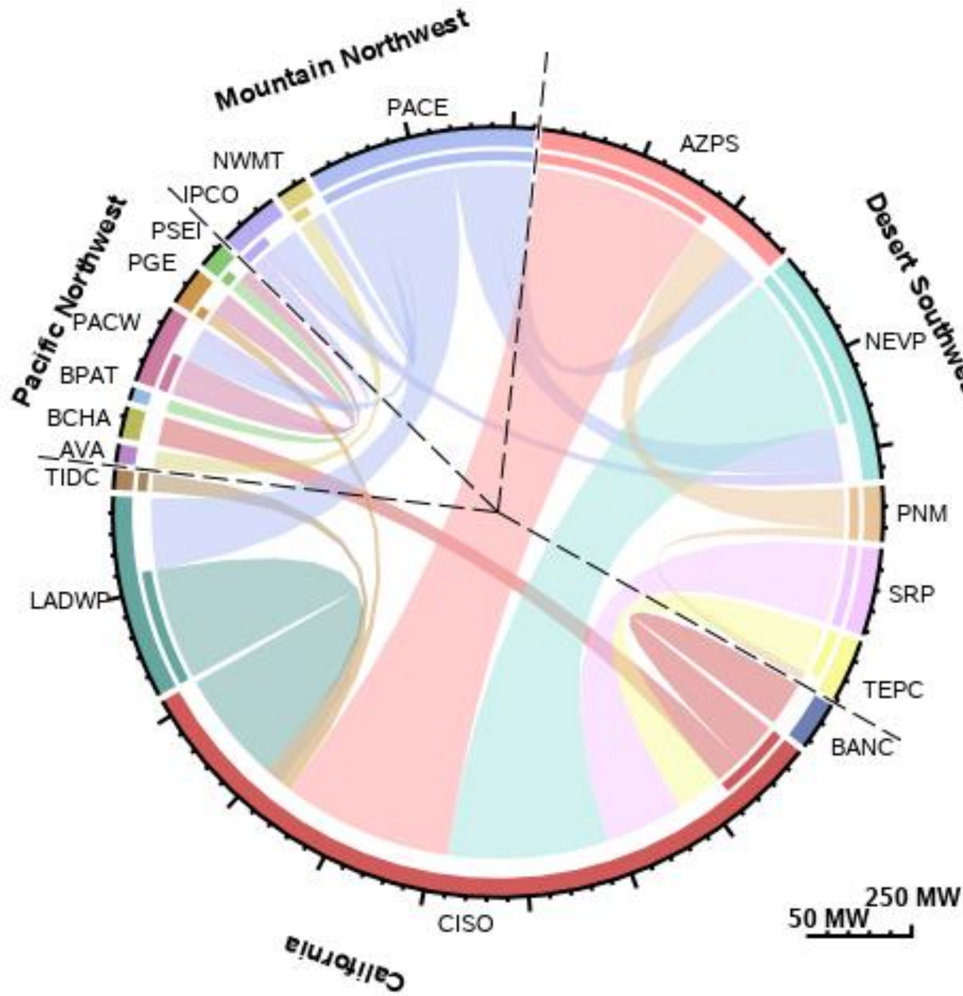


**Figure 2.6 Average 15-minute market WEIM exports (peak load hours, July – September, 2022)**




### Transfer limits

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

Transfer capacity into or out of the Pacific Northwest (including PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, Powerex, Avista Utilities, Tacoma Power, and Bonneville Power Administration) was around 3,710 MW of exports and 4,600 MW of imports on average during the quarter. There was an average of 30,050 MW of import and 33,900 MW of export transfer capacity in the east WEIM (including NV Energy, Arizona Public Service, Tucson Electric, Salt River Project, Public Service Company of New Mexico, PacifiCorp East, Idaho Power, and NorthWestern Energy). The lack of transfer capability out of the Pacific Northwest created large price separation between the WEIM entities located within the Pacific Northwest and the rest of the WEIM.

**Table 2.4 Average 15-minute market WEIM limits (July-September)**

| From Balancing Authority Area | CAISO | BANC | TIDC | LADWP | NEVP | AZPS | TEPC | SRP | PNM | PACE | IPCO | NWMT | AVA | BPA | TPWR | PACW | PGE | PSEI | PWRX | SCL | *Total export limit* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | To Balancing Authority Area | | | | | | | | | | | | | | | | | | | | |
| California ISO | | 3,300 | 1,270 | 5,030 | 3,590 | 1,300 | 190 | 1,190 | | | | | 0 | 20 | | 20 | 60 | | 300 | | 16,270 |
| BANC | 3,410 | | 490 | | | | | | | | | | | | | | | | | | 3,900 |
| Turlock Irrig. District | 1,250 | 790 | | | | | | | | | | | | | | | | | | | 2,040 |
| LADWP | 6,870 | | | | 1,750 | 330 | 310 | | | 160 | | | | | | | | | | | 9,420 |
| NV Energy | 4,020 | | | 1,080 | | 330 | | | | 940 | 500 | | | | | | | | | | 6,870 |
| Arizona Public Service | 2,660 | | | 180 | 240 | | 1,450 | 3,150 | 600 | 570 | | | | | | | | | | | 8,850 |
| Tucson Electric | 510 | | | 160 | | 1,810 | | 1,560 | 210 | 260 | | | | | | | | | | | 4,510 |
| Salt River Project | 3,090 | | | | | 2,610 | 910 | | 20 | | | | | | | | | | | | 6,630 |
| PSC New Mexico | | | | | | 440 | 290 | 160 | | | | | | | | | | | | | 890 |
| PacifiCorp East | | | | 290 | 270 | 430 | 170 | | | | 1,060 | 270 | | | | 250 | | | | | 2,740 |
| Idaho Power | | | | | 350 | | | | | 1,580 | | 270 | 350 | 0 | | 310 | | | | 30 | 2,890 |
| NorthWestern Energy | | | | | | | | | | 60 | 90 | | 350 | 20 | 0 | | | | | | 520 |
| Avista Utilities | 0 | | | | | | | | | | 200 | 280 | | 30 | 0 | 10 | | | | | 520 |
| BPA | 30 | | | | | | | | | | 0 | 20 | 40 | | 120 | 20 | 170 | 80 | 0 | 30 | 510 |
| Tacoma Power | | | | | | | | | | | | 0 | 0 | 60 | | | 0 | 220 | | | 280 |
| PacifiCorp West | 60 | | | | | | | | | 0 | 110 | | 30 | 10 | | | 290 | 80 | | 10 | 590 |
| Portland GE | 100 | | | | | | | | | | | | | 150 | 0 | 330 | | | | 10 | 590 |
| Puget Sound Energy | | | | | | | | | | | | | | 130 | 240 | 0 | | | 50 | 350 | 770 |
| Powerex | 0 | | | | | | | | | | | | | 0 | | | | 40 | | | 40 |
| Seattle City Light | | | | | | | | | | | 20 | | | 20 | | 10 | 10 | 350 | | | 410 |
| *Total import limit* | 22,000 | 4,090 | 1,760 | 6,740 | 6,200 | 7,250 | 3,320 | 6,060 | 830 | 3,570 | 1,980 | 840 | 770 | 440 | 360 | 950 | 530 | 770 | 350 | 430 | |

## Congestion on transfer constraints

Congestion between a WEIM area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an area, the market software triggers local market power mitigation for resources in that area.[47] WEIM participants in the Pacific Northwest continued to be the most frequently congested region relative to the greater market footprint.[48]

Table 2.6 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of a WEIM area. This is calculated as the frequency of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices.[49] When prices are lower relative to the system, this indicates congestion out of an area (or region) and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for outside energy to serve that area's load. The results of this section are the same as those found in Section 1.7.2 of this report on congestion. Section 1.7.2 focuses on the impact of congestion on prices, whereas this section describes the same information in terms of the impact to WEIM import or export capability.

Congestion in either direction for Los Angeles Department of Water and Power, Arizona Public Service, and NV Energy was relatively infrequent during the year. Congestion that did occur between these areas and the larger WEIM was often the result of a failed upward or downward resource sufficiency evaluation, which limited transfer capability.

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

48 These Pacific Northwest areas include Powerex, Puget Sound Energy, Seattle City Light, Portland General Electric, PacifiCorp West, Tacoma Power, Avista Utilities, and Bonneville Power Administration.

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

**Table 2.5 Frequency of congestion in the WEIM (July-September)**

| | 15-minute market | | 5-minute market | |
|---|---|---|---|---|
| | Congested from area | Congested into area | Congested from area | Congested into area |
| L.A. Dept. of Water and Power | 0% | 0% | 0% | 0% |
| Arizona Public Service | 0% | 0% | 0% | 1% |
| NV Energy | 1% | 1% | 1% | 1% |
| Tucson Electric Power | 2% | 0% | 1% | 8% |
| Idaho Power | 7% | 0% | 4% | 1% |
| PacifiCorp East | 6% | 3% | 5% | 1% |
| BANC | 0% | 17% | 0% | 0% |
| Turlock Irrigation District | 0% | 22% | 0% | 0% |
| Public Service Company of NM | 1% | 22% | 1% | 1% |
| NorthWestern Energy | 19% | 0% | 12% | 1% |
| Portland General Electric | 19% | 0% | 10% | 6% |
| Avista | 20% | 1% | 13% | 1% |
| PacifiCorp West | 19% | 13% | 9% | 1% |
| Salt River Project | 19% | 5% | 17% | 4% |
| Bonneville Power Admin. | 22% | 1% | 17% | 22% |
| Tacoma Power | 26% | 0% | 21% | 21% |
| Seattle City Light | 26% | 4% | 21% | 21% |
| Puget Sound Energy | 26% | 22% | 21% | 21% |
| Powerex | 32% | 24% | 36% | 31% |

## 2.3 Resource sufficiency evaluation

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

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

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the *upward* direction, WEIM transfers *into* that area cannot be increased.[50] Similarly, if an area fails either test in the *downward* direction, transfers *out of* that area cannot be increased.

50 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.

### Bid range capacity and flexible ramping sufficiency test results

Figure 2.7 and Figure 2.8 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.9 and Figure 2.10 provide the same information for the downward direction.[51] The dash indicates the area did not fail the test during the month.

Net load uncertainty was removed from the bid-range capacity test on February 15, 2022.[52] Intertie uncertainty was removed on June 1, 2022. Net load uncertainty is proposed to return to the capacity test in the summer of 2023.[53] This is following the introduction of the new quantile regression methodology for calculating uncertainty that will be deployed as part of the *flexible ramping product enhancements* expected in February 2023.[54] The CAISO is also proposing to permanently remove intertie uncertainty from the capacity test.

In the third quarter of 2022:

- Bonneville Power Administration failed the upward flexibility test in just under 2 percent of intervals.
- Salt River Project failed the upward flexibility test in around 0.8 percent of intervals.

The California ISO failed the capacity test in three intervals during the third quarter. Accuracy issues identified in the capacity test resulted in fewer CAISO capacity test failures than expected. In particular, between August 30 and September 9, the CAISO would have failed the capacity test in 14 additional intervals after adjusting for implementation errors associated with over-counting battery capacity.[55] As part of phase 2 of *resource sufficiency evaluation enhancements*, the CAISO proposes to exclude lower priority exports from the capacity test requirement.[56] All of the additional intervals that would have failed after accounting for incorrect battery capacity would have instead passed after also removing lower priority exports under the proposal.

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

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

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

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

55 For further information on the accuracy issues in the capacity test, see DMM's report, *Western Energy Imbalance Market Resource Sufficiency Evaluation Report covering October 2022,* November 30, 2022: http://www.caiso.com/Documents/2022-10-Metrics-Report-on-Resource-Sufficiency-Evaluation-in-WEIM-2022-11-30.pdf

56 California ISO, *WEIM Resource Sufficiency Evaluation Enhancements Phase 2 Revised Final Proposal,* November 7, 2022: http://www.caiso.com/InitiativeDocuments/RevisedFinalProposal-WEIMResourceSufficiencyEvaluationEnhancementsPhase2.pdf

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

| | 2021 | | | | | | 2022 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
| Arizona PS | 0.2 | 0.3 | 0.2 | — | 0.3 | 0.0 | — | — | 0.0 | 0.0 | — | — | — | — | — |
| Avista | | | | | | | | | — | 0.0 | — | 0.2 | 0.2 | 0.0 | — |
| BANC | 0.2 | — | 0.0 | — | — | — | — | — | — | — | — | — | — | 0.0 | 0.3 |
| BPA | | | | | | | | | | | — | 0.1 | — | 0.0 | 0.5 |
| California ISO | 0.2 | 0.0 | 0.2 | — | — | — | — | — | — | — | — | — | — | — | 0.1 |
| Idaho Power | 0.4 | 0.8 | 0.1 | — | — | — | — | 0.1 | — | — | — | — | — | 0.2 | 0.2 |
| LADWP | — | — | — | 0.3 | 0.2 | 0.1 | — | — | — | — | — | — | 0.0 | — | — |
| NorthWestern | 1.2 | 0.6 | 0.2 | 8.5 | 1.2 | 0.2 | 0.3 | 0.1 | — | 0.0 | — | — | — | 0.1 | 0.1 |
| NV Energy | 0.5 | 0.2 | 0.2 | 0.3 | — | — | — | — | — | 0.2 | 0.1 | 0.0 | 0.1 | — | — |
| PacifiCorp East | 0.3 | 0.1 | 0.2 | 0.1 | — | — | — | — | — | — | — | — | — | — | 0.1 |
| PacifiCorp West | 0.2 | 0.1 | 0.1 | 0.1 | 0.5 | 0.4 | 0.3 | 0.1 | 0.3 | 0.0 | 0.2 | 0.0 | 1.0 | 0.2 | 0.0 |
| Portland GE | 0.8 | 1.0 | 1.4 | 0.4 | 0.2 | 0.4 | 0.1 | — | — | — | — | — | — | 0.1 | — |
| Powerex | 0.0 | — | 0.1 | 0.5 | 0.2 | 0.2 | 0.2 | — | — | 0.1 | — | — | — | 0.2 | — |
| PSC New Mexico | 0.4 | — | 0.2 | — | — | — | — | — | — | — | — | — | — | — | — |
| Puget Sound En | 0.5 | 0.7 | 0.6 | 1.0 | 0.6 | 0.3 | — | — | — | 0.0 | 0.0 | 0.2 | — | — | 0.2 |
| Salt River Proj. | 3.0 | 2.6 | 2.0 | 0.1 | 0.7 | — | — | — | 0.2 | 1.5 | 1.0 | 0.2 | 0.2 | 0.4 | 0.4 |
| Seattle City Light | — | 0.0 | 0.5 | 0.1 | — | 0.1 | — | — | 0.1 | — | — | — | 0.2 | 0.1 | 0.2 |
| Tacoma Power | | | | | | | | | — | 0.6 | 0.1 | 0.0 | 0.0 | 0.2 | 0.0 |
| Tucson Elec. | | | | | | | | | | | — | — | — | 0.1 | — |
| Turlock ID | — | 1.1 | 0.8 | 1.5 | — | — | — | — | — | — | — | 0.1 | — | — | — |

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

| | 2021 | | | | | | 2022 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
| Arizona PS | 0.0 | — | 0.2 | — | 0.3 | 0.0 | 0.0 | 0.2 | 0.1 | — | — | — | 0.0 | 0.1 | — |
| Avista | | | | | | | | | — | 0.2 | 0.5 | 1.0 | 0.5 | 0.1 | — |
| BANC | — | — | — | — | — | — | — | — | — | — | — | — | — | — | 0.3 |
| BPA | | | | | | | | | | | 0.9 | 3.1 | 3.3 | 1.0 | 1.1 |
| California ISO | 0.3 | 0.1 | 0.4 | — | 0.1 | — | — | — | — | — | — | — | — | 0.1 | 0.5 |
| Idaho Power | — | — | — | — | — | 0.0 | — | 0.2 | — | — | — | — | 0.2 | 0.2 | 0.5 |
| LADWP | 0.1 | — | — | 0.0 | 0.0 | 0.3 | — | — | 0.1 | — | — | — | — | — | 0.1 |
| NorthWestern | 3.6 | 0.7 | 1.6 | 8.3 | 0.5 | 0.5 | — | 0.1 | 0.1 | 0.3 | — | 0.1 | 0.3 | 1.0 | 0.2 |
| NV Energy | 0.4 | 0.5 | 0.1 | 0.3 | 0.0 | 0.0 | 0.0 | 0.7 | 0.4 | 1.0 | 0.8 | 0.2 | — | 0.1 | 0.1 |
| PacifiCorp East | 0.0 | — | 0.1 | — | 0.1 | 0.0 | 0.0 | 0.0 | — | 0.1 | 0.1 | 0.1 | 0.2 | 0.1 | — |
| PacifiCorp West | 0.0 | 0.1 | — | — | 0.6 | 0.2 | 0.0 | 0.0 | 0.1 | 0.2 | 0.1 | 0.0 | — | 0.1 | 0.1 |
| Portland GE | 0.5 | 0.2 | — | 0.0 | — | 0.2 | 0.3 | 0.0 | — | — | — | 0.0 | 0.4 | 0.1 | 0.1 |
| Powerex | 0.5 | — | — | 0.2 | 0.2 | 0.3 | 0.2 | 0.0 | — | 0.1 | — | — | — | 0.3 | 0.1 |
| PSC New Mexico | 0.5 | — | 0.1 | — | 0.1 | — | — | — | 0.1 | 0.0 | 0.1 | — | 0.4 | — | 0.0 |
| Puget Sound En | 0.0 | 0.0 | — | — | 0.1 | — | — | — | 0.0 | 0.1 | — | 0.1 | 0.4 | 0.2 | 0.3 |
| Salt River Proj. | 1.9 | 1.7 | 0.8 | 0.2 | 1.2 | 0.0 | 0.2 | — | 0.6 | 0.5 | 0.2 | 0.5 | 0.6 | 1.1 | 0.6 |
| Seattle City Light | 0.0 | — | 0.1 | — | — | — | — | — | 0.1 | — | — | — | 0.2 | 0.0 | 0.2 |
| Tacoma Power | | | | | | | | | — | — | 0.1 | 0.1 | 0.0 | 0.1 | 0.1 |
| Tucson Elec. | | | | | | | | | | | 0.1 | — | — | — | 0.4 |
| Turlock ID | — | — | 0.1 | 0.2 | — | — | — | — | — | — | — | — | — | — | 0.1 |

**Figure 2.9 Frequency of downward capacity test failures by month and area (percent of intervals)**

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

**Figure 2.10 Frequency of downward flexibility test failures by month and area (percent of intervals)**

| | 2021 | | | | | | 2022 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
| Arizona PS | — | 0.1 | 0.1 | 0.1 | 0.5 | 0.4 | 1.4 | 0.4 | 0.8 | 0.3 | 0.5 | 0.2 | — | — | 0.1 |
| Avista | | | | | | | | | — | — | — | 0.1 | — | — | 0.1 |
| BANC | — | — | — | — | — | 0.1 | — | — | 0.1 | 0.0 | 0.1 | 0.1 | — | — | — |
| BPA | | | | | | | | | | | 0.1 | 0.2 | — | 0.0 | 0.3 |
| California ISO | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| Idaho Power | — | — | — | — | 0.3 | 0.0 | — | 0.0 | — | 0.3 | 0.4 | — | — | 0.0 | — |
| LADWP | — | — | — | 0.1 | — | — | 0.1 | — | — | — | — | — | — | — | — |
| NorthWestern | 0.6 | 0.4 | 1.2 | 2.3 | 0.1 | 0.0 | — | — | — | — | 0.5 | 1.9 | 0.2 | — | — |
| NV Energy | 3.0 | 2.5 | 1.7 | 1.1 | 0.4 | 0.4 | 0.6 | 4.1 | 1.7 | 3.2 | 1.3 | 2.0 | 0.6 | 0.2 | 0.5 |
| PacifiCorp East | — | — | — | — | — | — | — | — | — | — | — | — | — | — | — |
| PacifiCorp West | — | — | — | — | 0.0 | — | — | — | 0.0 | 0.0 | 0.1 | 0.4 | 0.5 | — | — |
| Portland GE | — | — | — | — | — | — | — | — | — | — | — | 0.2 | — | — | — |
| Powerex | 0.4 | 0.2 | 1.0 | 0.4 | 0.0 | 0.1 | — | 0.0 | 0.2 | 0.0 | 0.3 | 0.2 | — | 0.1 | 0.1 |
| PSC New Mexico | — | — | 0.1 | 0.4 | 0.7 | 0.1 | 0.3 | 0.0 | 1.2 | 0.3 | 1.8 | 0.7 | 0.0 | 0.0 | 0.2 |
| Puget Sound En | — | — | — | — | 0.0 | — | — | — | — | — | 0.2 | 2.3 | 0.1 | — | — |
| Salt River Proj. | — | 0.1 | 0.0 | 0.1 | 0.0 | 0.1 | 0.1 | 1.0 | 1.5 | 0.2 | 0.4 | 0.5 | 0.2 | 0.2 | 1.0 |
| Seattle City Light | 0.2 | — | — | — | 0.0 | 0.0 | — | — | 0.1 | 0.1 | 0.1 | 0.3 | 0.1 | 0.8 | 0.3 |
| Tacoma Power | | | | | | | | | — | 0.4 | 0.3 | — | 0.5 | 0.2 | — |
| Tucson Elec. | | | | | | | | | | | — | — | — | — | — |
| Turlock ID | — | 0.0 | — | 0.6 | 0.1 | 0.2 | 0.2 | — | 0.5 | 0.6 | 0.1 | 0.5 | 0.1 | 0.1 | — |

### Import limits and transfers following a test failure

This section summarizes the import limits that are imposed when a WEIM entity fails either the bid-range capacity test or flexible ramping sufficiency test in the upward direction. When either test fails, imports will be capped at the greater of the base transfer or the optimal transfer from the last 15-minute market interval. These limits are also compared against actual WEIM transfers during these insufficiency periods in this section.

Figure 2.11 summarizes dynamic import limits excluding base transfers (fixed bilateral transactions between entities) imposed after failing either upward test during the quarter. The dynamic import limit shows the incremental flexibility above base schedules that is available through the WEIM after a resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with an import limit imposed after a test failure, while the bars (left axis) show the frequency of various ranges.[57]

**Figure 2.11 Imposed dynamic import limit following upward test failure (July – September 2022)**

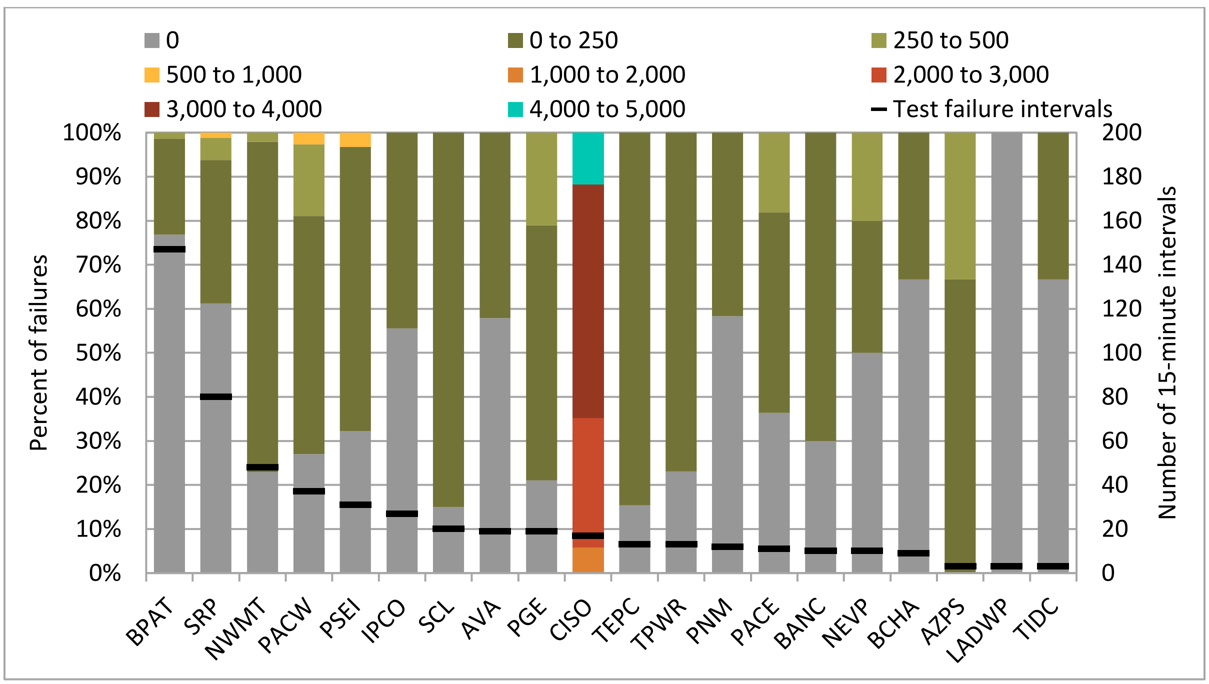



Figure 2.12 summarizes actual transfers optimized in the real-time market following an upward resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity test or a flexibility test failure, while the bars (left axis) show the net transfer quantity categorized by various levels. These figures summarize dynamic WEIM transfers only and therefore base transfers are again excluded.

As shown by Figure 2.12, balancing areas were commonly optimized as net exporters during the quarter, despite failing the resource sufficiency evaluation for that interval. This result is in part driven from

[57] Test failure intervals in which an import limit was not imposed because it was at or above the unconstrained total import capacity were excluded from this summary.

uncertainty that is included in the flexibility tests.[58] In some cases, the balancing area would fail the resource sufficiency evaluation in part because of the uncertainty component, but then in the real-time market it could then be economically optimal to export if that uncertainty does not materialize.

Other factors can also contribute to this outcome as a net exporter. A decrease in the load forecast (or an increase in wind or solar forecasts) from the resource sufficiency evaluation to the real-time market can lead to greater resource sufficiency and WEIM exports. A negative imbalance conformance adjustment entered by the WEIM operators can also be included in the market run to effectively lower load, but will not be included in the resource sufficiency evaluation.

**Figure 2.12 Dynamic WEIM transfers during upward test failure (July – September 2022)**

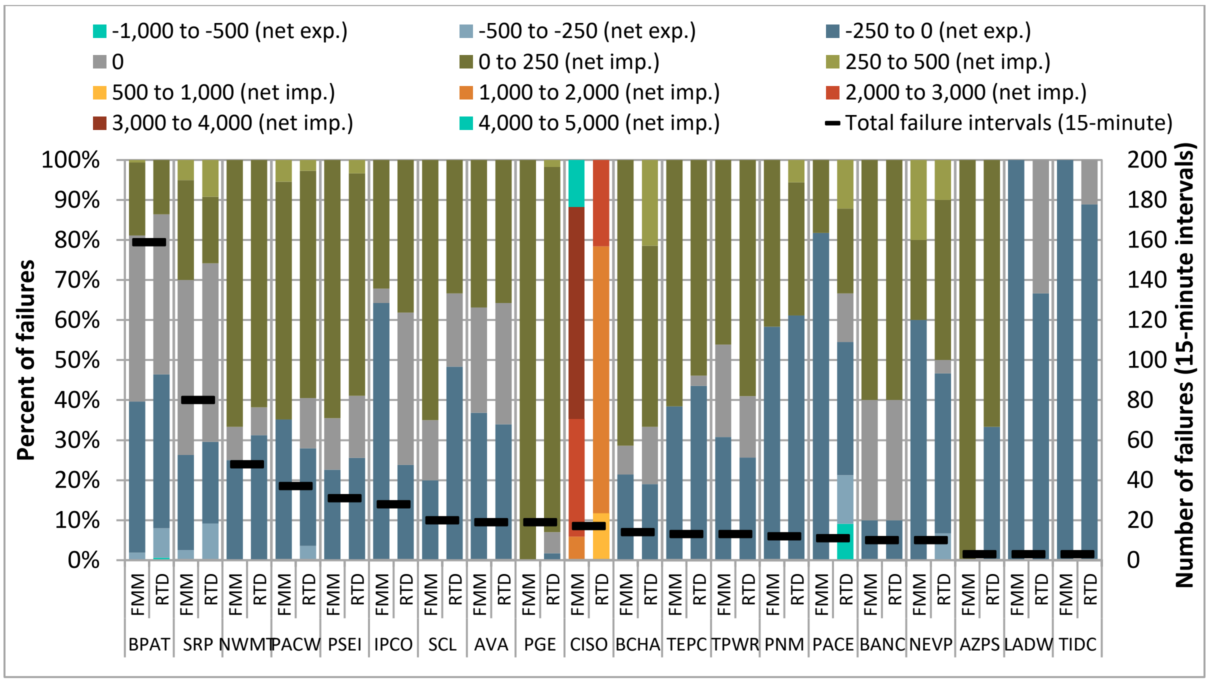
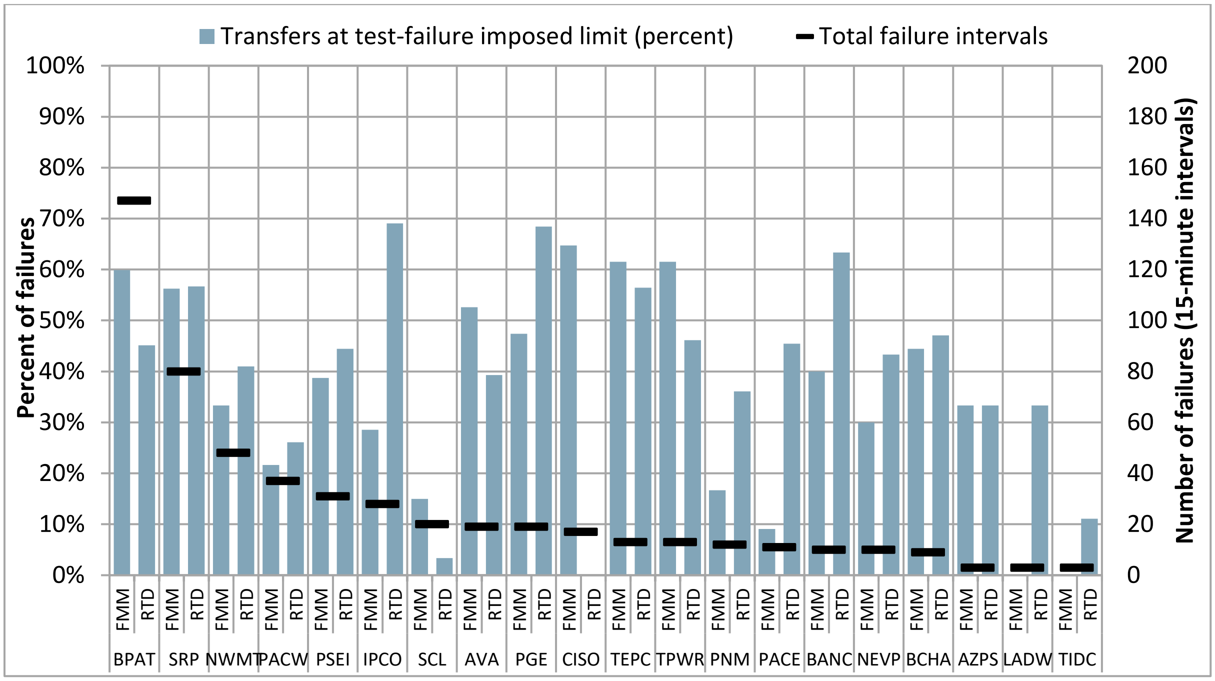



Figure 2.11 summarizes whether the import limit that was imposed after failing either test in the upward direction ultimately impacted market transfers. It shows the percent of failure intervals in which the resulting transfers are constrained to the limit imposed after failing the test. These results are shown separately for the 15-minute (FMM) and 5-minute (RTD) markets.

58 Net load uncertainty was removed from the capacity test on February 15, 2022. Intertie uncertainty was removed from the capacity test on June 1, 2022.

**Figure 2.13 Percent of upward test failure intervals with market transfers at the imposed cap (July – September 2022)**




### Resource sufficiency evaluation monthly reports

DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic.[59] These reports include many metrics and analyses not included in this report, such as the impact of several changes proposed or adopted through the stakeholder process.

## 2.4 Imbalance conformance

### Frequency and size of imbalance conformance

Table 2.6 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM and CAISO for the 15-minute and 5-minute markets during the quarter. Bonneville Power Administration (BPA) used either positive or negative imbalance conformance during nearly all intervals in both the 15-minute and 5-minute markets. Despite this high frequency of imbalance conformance in BPA, the percent of total load remained small, averaging less than 1 percent. Similar to previous quarters, nearly all WEIM entities had a greater frequency of imbalance conformance in the 5-minute market than in the 15-minute market.

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

**Table 2.6 Average frequency and size of imbalance conformance (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 | 45% | 1344 | 4.1% | 1.6% | -340 | 1.2% | 596 |
| | RTD | 40% | 275 | 0.9% | 27% | -310 | 1.1% | 29 |
| *BANC* | FMM | 0.1% | 43 | 1.5% | 0.7% | -99 | 3.1% | -1 |
| | RTD | 0.6% | 41 | 1.7% | 1.2% | -81 | 2.8% | -1 |
| *Turlock Irrigation District* | FMM | 0.9% | 12 | 3.1% | 0.1% | -25 | 6.6% | 0 |
| | RTD | 1.4% | 12 | 3.1% | 0.2% | -23 | 5.7% | 0 |
| *LADWP* | FMM | 1.6% | 51 | 1.5% | 0.3% | -79 | 2.9% | 1 |
| | RTD | 18% | 55 | 1.6% | 9.0% | -54 | 1.9% | 5 |
| *NV Energy* | FMM | 1.9% | 198 | 2.9% | 0.0% | N/A | N/A | 4 |
| | RTD | 43% | 128 | 2.1% | 2.5% | -110 | 2.0% | 53 |
| *Arizona Public Service* | FMM | 0.0% | N/A | N/A | 0.0% | N/A | N/A | 0 |
| | RTD | 40% | 64 | 1.3% | 21% | -58 | 1.2% | 13 |
| *Tucson Electric Power* | FMM | 1.2% | 49 | 2.5% | 0.5% | -43 | 2.7% | 0 |
| | RTD | 21% | 53 | 2.9% | 11% | -61 | 3.7% | 4 |
| *Salt River Project* | FMM | 3.4% | 57 | 1.0% | 0.8% | -115 | 2.4% | 1 |
| | RTD | 14% | 58 | 1.0% | 2.6% | -90 | 2.2% | 6 |
| *Public Service Co. of New Mexico* | FMM | 0.0% | 90 | 4.4% | 0.0% | N/A | N/A | 0 |
| | RTD | 21% | 56 | 3.4% | 2.7% | -76 | 4.8% | 10 |
| *PacifiCorp East* | FMM | 0.0% | N/A | N/A | 0.0% | -420 | 6.6% | 0 |
| | RTD | 20% | 108 | 1.6% | 27% | -121 | 1.9% | -11 |
| *Idaho Power* | FMM | 0.0% | N/A | N/A | 0.0% | N/A | N/A | 0 |
| | RTD | 30% | 54 | 2.1% | 5.3% | -47 | 2.0% | 14 |
| *NorthWestern Energy* | FMM | 11% | 12 | 0.9% | 1.5% | -15 | 1.1% | 1 |
| | RTD | 22% | 15 | 1.1% | 4.5% | -18 | 1.4% | 2 |
| *Avista Utilities* | FMM | 0.4% | 24 | 1.8% | 3.5% | -26 | 2.3% | -1 |
| | RTD | 4.7% | 19 | 1.4% | 35% | -21 | 1.8% | -7 |
| *Bonneville Power Administration* | FMM | 76% | 47 | 0.8% | 22% | -24 | 0.5% | 31 |
| | RTD | 77% | 47 | 0.8% | 22% | -24 | 0.5% | 31 |
| *Tacoma Power* | FMM | 0.0% | N/A | N/A | 0.0% | N/A | N/A | 0 |
| | RTD | 5.2% | 14 | 2.9% | 7.1% | -14 | 3.5% | 0 |
| *PacifiCorp West* | FMM | 0.0% | N/A | N/A | 0.0% | N/A | N/A | 0 |
| | RTD | 2.3% | 51 | 2.0% | 27% | -53 | 2.3% | -13 |
| *Portland General Electric* | FMM | 0.0% | N/A | N/A | 0.3% | -31 | 0.8% | 0 |
| | RTD | 11% | 33 | 1.2% | 1.7% | -39 | 1.5% | 3 |
| *Puget Sound Energy* | FMM | 0.3% | 81 | 3.1% | 1.3% | -47 | 1.8% | 0 |
| | RTD | 5.4% | 56 | 2.3% | 39% | -37 | 1.5% | -12 |
| *Seattle City Light* | FMM | 0.7% | 16 | 1.6% | 15% | -20 | 2.2% | -3 |
| | RTD | 2.3% | 18 | 1.8% | 77% | -24 | 2.5% | -18 |

# 3 Western region heat wave

Between August 31 and September 9, the combined CAISO and WEIM system experienced a prolonged heat event. This period was marked by record setting extremely high temperature weather conditions across most of the Western United States. This section describes market performance during this critical period. The California ISO has published a comprehensive review of market results during the heat wave.[60] DMM concurs with many of the key findings and recommendations in the CAISO report; this report provides additional analysis based on DMM's independent review.

## 3.1 Key findings

Key findings in this report are consistent with findings in the CAISO's report:

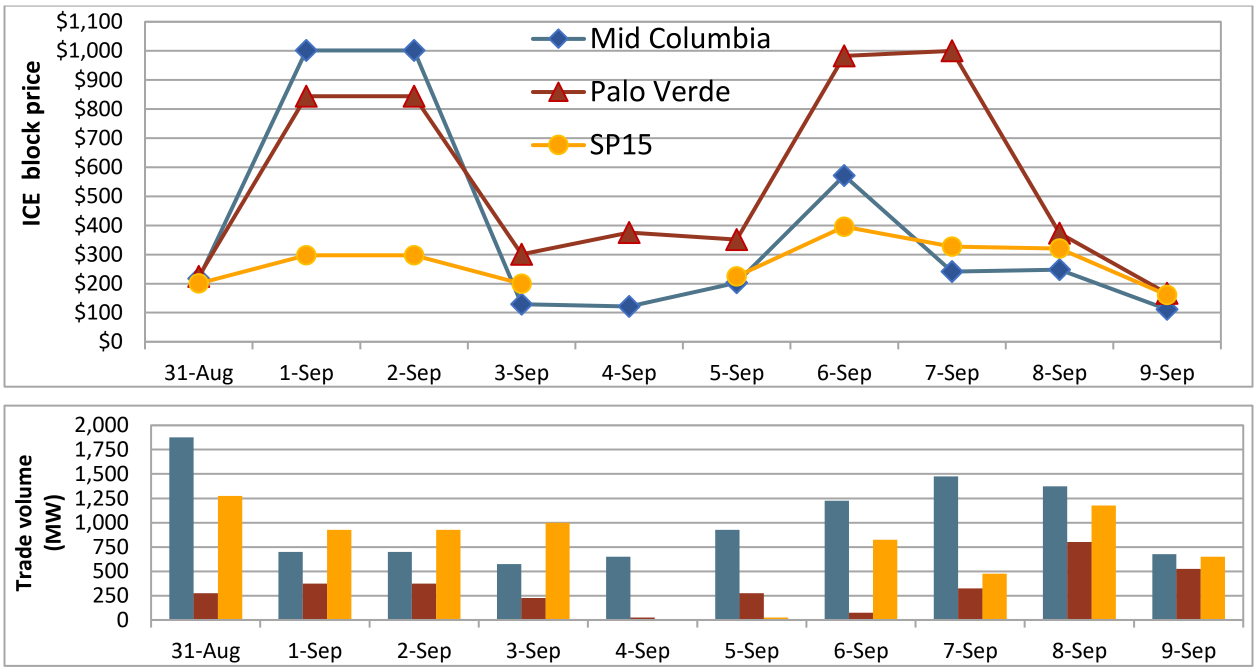
- **Extreme temperatures and energy demand** across the entire western region resulted in demand for electricity well in excess of current resource planning targets over an extended period.
- **High bilateral market price indices** reflected regional market conditions. Traded volumes were high at the main northwest trading hub (Mid-C), but were relatively low at the southwest trading hub (Palo Verde) throughout the heat wave.
- **The maximum import bid cap allowed imports to bid up to the hard bid cap ($2,000/MWh)** in some hours when bilateral market price indices were high. Hours with the $2,000/MWh bid cap closely matched hours when the CAISO declared EEA2 and EEA3 alerts. The $2,000 bid cap attracted a limited quantity of additional imports into CAISO market.
- **Penalty prices were scaled up to $2,000/MWh** on days with high bilateral market prices. During the heatwave, both the 15-minute and 5-minute prices in the CAISO rose above $1,000/MWh, exceeding day-ahead prices in many intervals. Real-time prices were often set by penalty prices in these intervals.
- **Balancing areas declaring emergencies were able to import supplemental energy**, both through emergency assistance from other balancing areas and from WEIM imports. Most WEIM areas were net exporters in net peak hours during the heatwave, with the CAISO accounting for most imports.
- **CAISO supply was additionally supplemented** by out of market imports, non-market capacity procured through California's strategic reserve, and through voluntary demand reduction.
- **Congestion limited imports from the Northwest into California** in the real-time market but otherwise had little impact on market outcomes.
- **CAISO operators raised both real-time imbalance conformance and operator adjustments** in the day-ahead market's residual unit commitment process to extraordinarily high levels. Doing so helped to ensure that the market would not clear lower priority exports that would not be supported by dispatched physical capacity.
- **Low priority exports cleared the real-time market inappropriately**, requiring the CAISO operators to take manual action and increasing CAISO demand in the real-time. The market optimization appropriately prioritized load over lower priority exports in the day-ahead market residual unit commitment process. The CAISO implemented a market enhancement on October 13 to resolve the market issue in the real-time market.

60 California ISO, *Summer market performance report Sept 2022,* November 2, 2022: http://www.caiso.com/Documents/Sept2022_summer_readiness_reportFinal.pdf#search=summer

## 3.2 Energy market prices during the heat wave

High bilateral market price indices reflected regional market conditions. The top panel of Figure 3.1 shows the index prices for power traded on the InterContinental Exchange (ICE) at Mid-Columbia, Palo Verde and SP15 hubs. Mid-Columbia prices slightly exceeded $1,000/MWh on September 1 and 2 and Palo Verde prices were close to $1,000/MWh on September 6 and 7. Because the heatwave occurred over the Labor Day weekend, the volume traded was for 16, 24, or 32 hours, depending on the day.[61] The bottom panel shows the hourly volume traded at each location. Volumes were extremely low over the Labor Day holiday weekend at the Palo Verde trading hub.

**Figure 3.1 Bilateral prices and trade volume (August 31, 2022 – September 9, 2022)**




Market changes implemented in March 2021 to comply with FERC Order 831, introduced two sets of market parameter changes triggered by high bilateral index prices. The first raises bid caps for imports to a maximum import bid cap.[62] The second scales penalty prices to $2,000/MWh from $1,000/MWh.

Bilateral market prices are converted to hourly maximum import bid prices based on the historical shape of day-ahead market system marginal energy price (SMEC).[63] As shown in Figure 3.2, bid caps (red dashed line) rose to $2,000/MWh in most intervals when the CAISO was in EEA2 or EEA3 alerts (yellow and red shaded areas). The bid cap was also raised on days without EEA2 or EEA3 alerts.

61 September 1 and 2, traded as a two-day package as did September 9 and 10. The off-peak hours of September 3 traded with the full day of September 4. September 5 (Labor Day) traded as a package with the off-peak hours of September 6.

62 Non-resource-specific non-RA imports, non-participating load, demand, export, and virtual bids can be submitted up to $2,000/MWh. Non-resource-specific RA imports can bid to the maximum of the highest cost-verified bid or the Max Import Bid Price

63 Details on Max Import Bid Price calculation can be found in: California ISO, *FERC Order No. 831 – Import Bidding and Market Parameters, Final Proposal,* August 24, 2020, p. 25: http://www.caiso.com/InitiativeDocuments/FinalProposal-FERCOrder831-ImportBidding-MarketParameters.pdf

Penalty prices were scaled up to $2,000/MWh in all hours on days with a maximum import bid price over $1,000/MWh which can occur with high bilateral market prices. During the heatwave, both 15-minute and 5-minute prices in the CAISO rose above $1,000/MWh, exceeding day-ahead prices in many intervals. Load-weighted 15-minute CAISO prices are shown as a blue line in Figure 3.2. Real-time prices were often set by penalty prices in these intervals.

**Figure 3.2 CAISO bid cap, alert status and 15-minute prices (August 31 – September 9, 2022)**

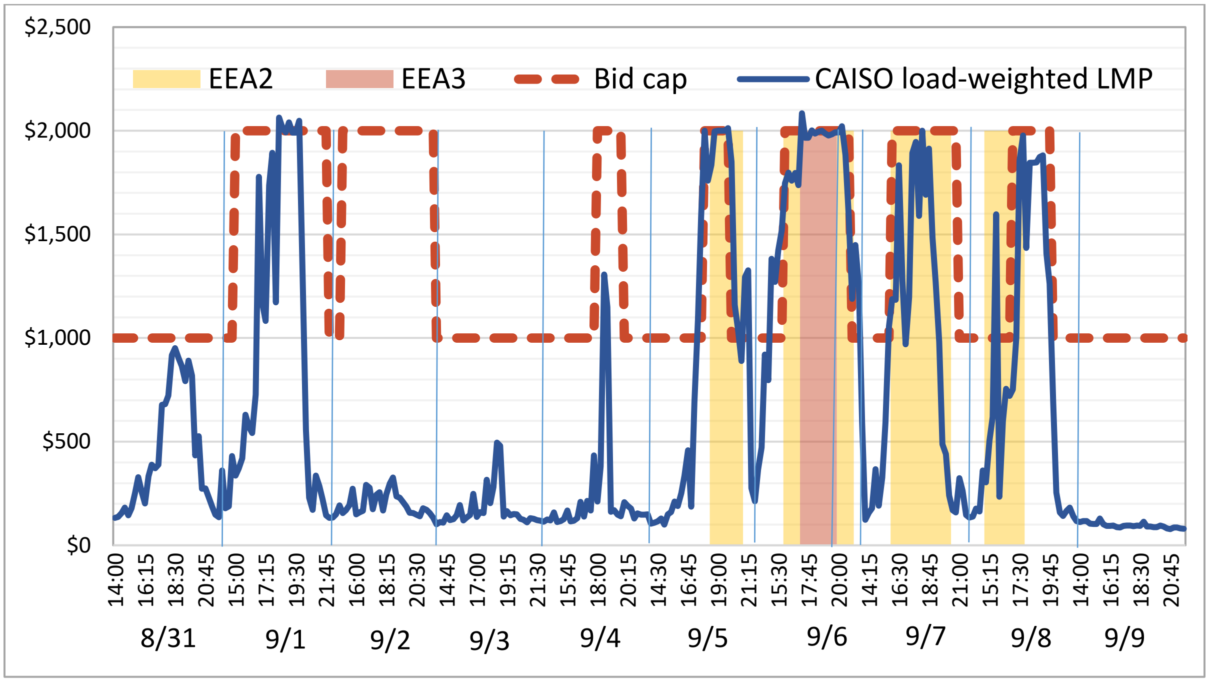


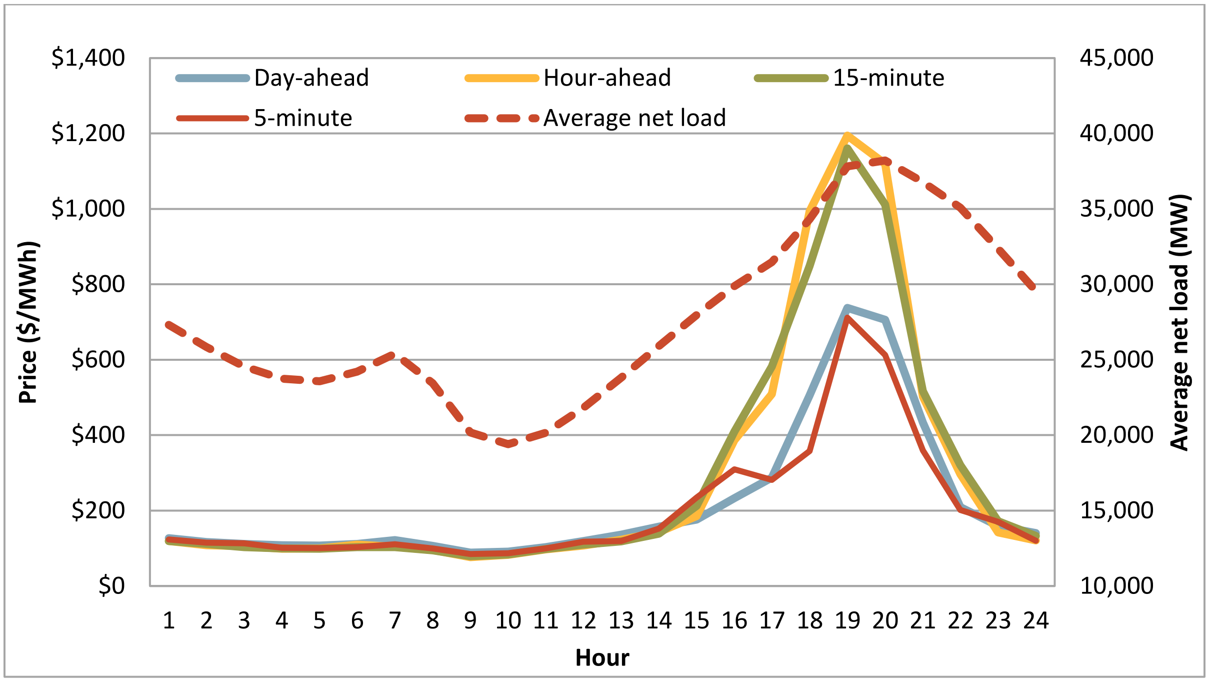

Figure 3.3 shows load-weighted average energy prices and net load on an hourly basis for the heat wave period, from August 31, 2022 to September 9, 2022.[64] Average hourly CAISO prices are shown for the day-ahead (blue line), hour-ahead (gold line), 15-minute (green line), and 5-minute (red line) and are shown on the left axis, while average hourly net load (red dashed line) is shown on the right axis.

As shown in Figure 3.3, average hourly load-weighted CAISO prices exceeded the $1,000/MWh soft offer cap in both the 15-minute and hour-ahead markets over the heatwave period. Average hour-ahead and 15-minute market prices peaked in the same hours when bid caps were raised (hours ending 18, 19, and 20). Day-ahead and 5-minute prices were lower, with averages peaking just over $700/MWh.

The load-weighted average energy prices in the hour-ahead market peaked at $1,194/MWh in hour 19, and in the 15-minute market, the price peaked at $1,161/MWh in the same hour. Average day-ahead prices peaked at $704/MWh and 5-minute price at $712/MWh in hour 19, far higher than the average hourly price of this quarter in these hours. The heat wave average net load peaked at hour 20, reaching 38,818 MW, which was about 700 MW higher than the average net load in this hour in this quarter.

64 Net load is calculated by subtracting wind and solar generation that is directly connected to the CAISO grid from actual load.

**Figure 3.3 Hourly load-weighted average energy prices (August 31, 2022 – September 9, 2022)**




Although system marginal energy prices were high across the WEIM during the heatwave, congestion separated areas in the Pacific Northwest and East, lowering prices in those regions. Figure 3.4 and Figure 3.5 show the 15-minute and 5-minute price by component for each WEIM area between August 31 and September 9, respectively. In the 15-minute market, most price separation was due to congestion on WEIM transfer constraints. In the 5-minute market, most congestion was due to congestion on constraints internal to the CAISO. The individual constraints that created much of the internal congestion were a Malin-Round Mountain nomogram in the 15-minute and a nomogram used to mitigate unscheduled flow over Path 66 in the 5-minute market.[65]

65 The price impacts from these constraints by area are shown in Table 3.1 and Table 3.2.

**Figure 3.4 Average 15-minute price by component (August 31-September 9, 2022)**

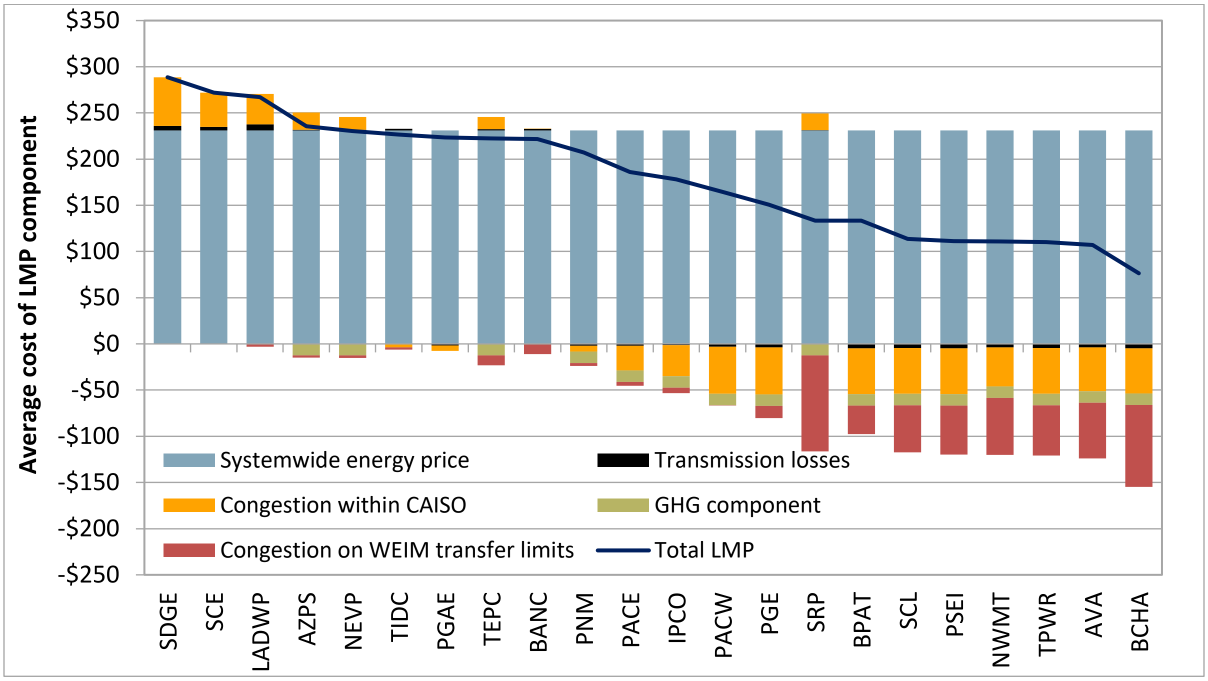
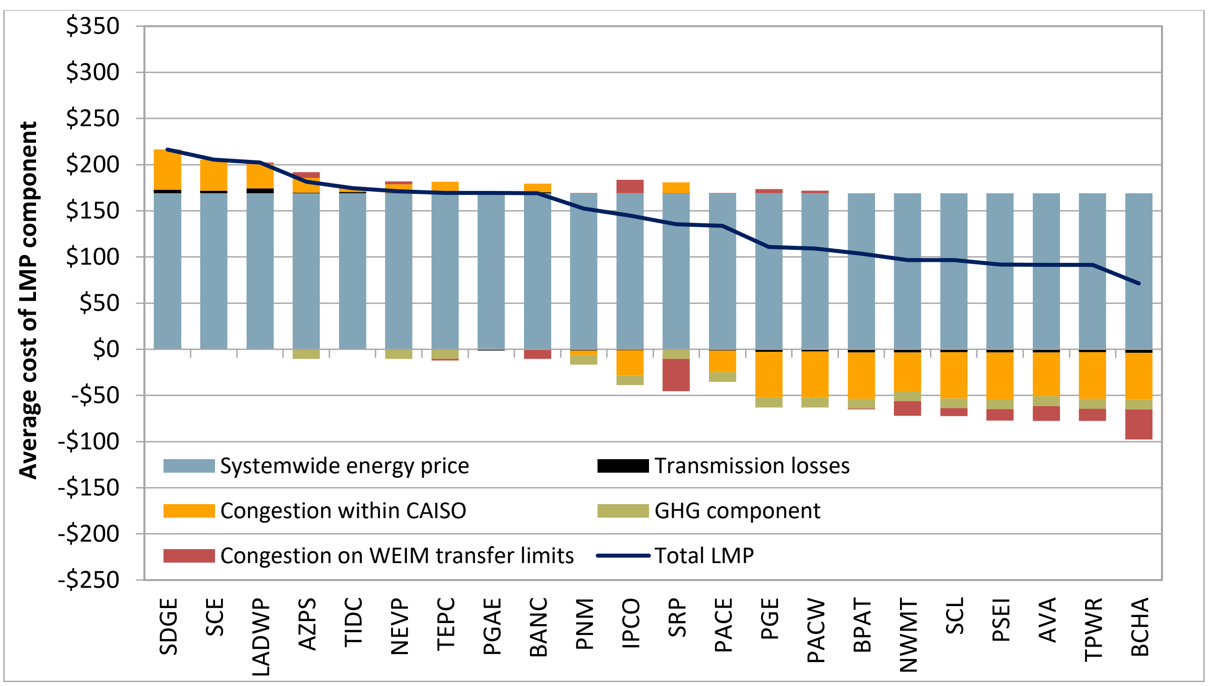



**Figure 3.5 Average 5-minute price by component (August 31-September 9, 2022)**



## 3.3 Load adjustments

During the heat wave, the CAISO operators raised the load forecast used in the day-ahead market's residual unit commitment process to extraordinarily high levels. In the hour-ahead and 15-minute market, the operators also used the real-time imbalance conformance to raise the load forecast used in these markets to extraordinary levels. Both these manual adjustments helped ensure that the day-ahead and real-time markets would not clear lower priority exports that would not be supported by available physical capacity.

### Frequency and size of load adjustments

Figure 3.6 and Figure 3.7 shows the extraordinarily high distribution of the load adjustments during the heat wave for the residual unit commitment (RUC) process and in the 15-minute market.[66] Hour-ahead adjustments were similar to the 15-minute market.

Upward load adjustments hit historical high levels in the residual unit commitment process with a maximum of 10,000 MWs on September 9 in hour-ending 18. September 2020 market changes to the residual unit commitment process allow exports to be curtailed when procurement of physical energy and capacity in the residual unit commitment fails to bridge the gap between physical supply cleared in the day-ahead and the day-ahead forecasted load plus conformance.[67]

Because of these changes, significant volumes of exports clearing the day-ahead market were identified as unsupportable through the residual unit commitment process during the heat wave. Unsupported exports do not receive a residual unit commitment schedule but are financially binding in the day-ahead IFM market and can rebid into the real-time market.

Figure 3.7 shows the 15-minute market imbalance conformance. Imbalance conformance was set at 5,000 MW in hours 18 and 19 throughout the heatwave and reached 5,000 MW in hours 16, 17, 20 and 21 on some days. High levels of imbalance conformance add demand at a higher priority than economic demand, including exports, and lower priority self-schedules. In cases when demand exceeds supply, imbalance conformance may displace this lower priority demand, which would then be curtailed.

[66] Hour-ahead adjustments were similar to the 15-minute market. 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). Extreme outliers are represented by the filled 'dots and the outside whiskers do not include these outliers.

[67] Figure 1.24 shows the residual unit commitment power balance constraint hourly under-supply infeasibility quantities that resulted during the heat wave conditions from September 1 through 9. These infeasibilities resulted in prices being set around $250/MWh during those hours. In addition, significant volumes of economic exports and low-priority self-schedule exports were cut in the residual unit commitment process prior to relaxing the power balance constraint.

**Figure 3.6 Residual unit commitment (RUC) hourly distribution of operator load adjustments (August 31, 2022 – September 09, 2022)**

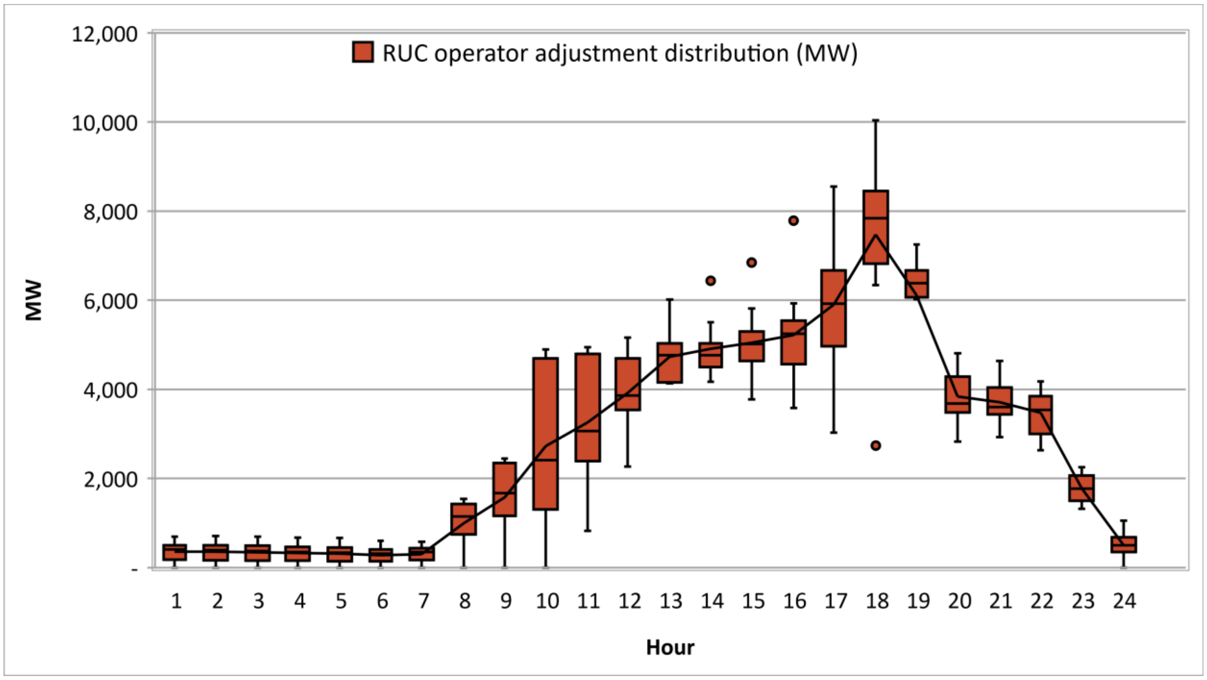
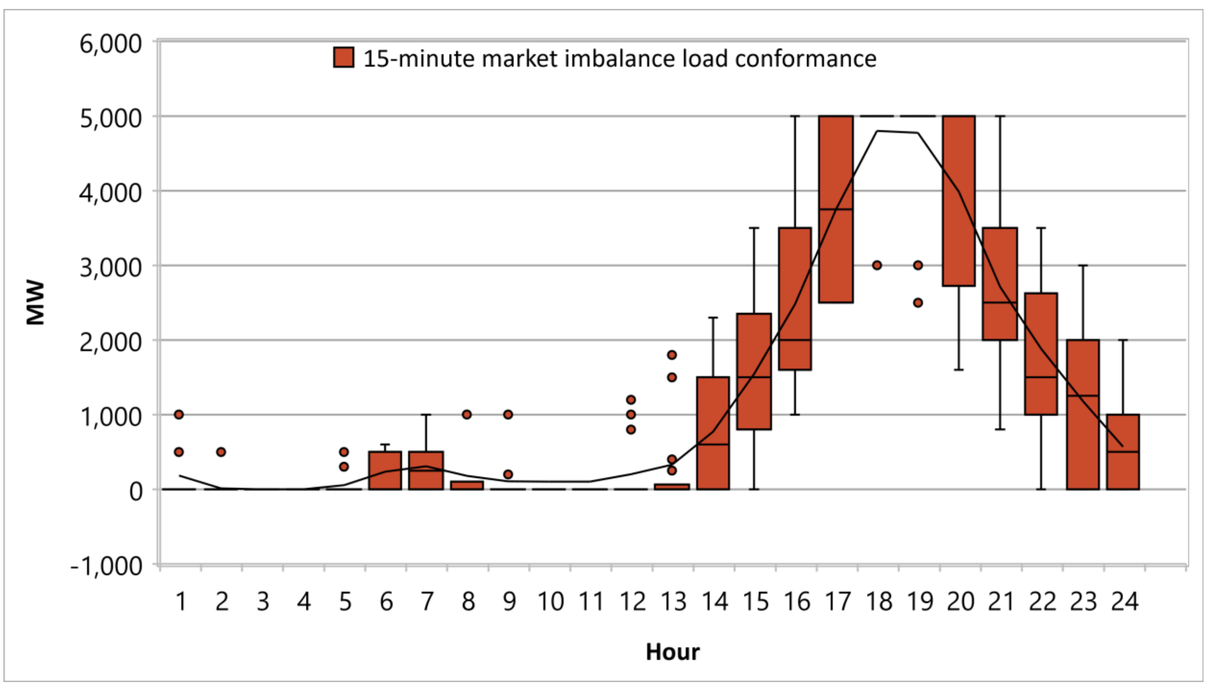



**Figure 3.7 15-minute market hourly distribution of operator load adjustments (August 31, 2022 – September 09, 2022)**



## 3.4 Imports and exports

The interchange between the CAISO and other balancing authorities, as well as the WEIM, was vital to maintaining reliability during the heat wave. Balancing areas declaring emergencies were able to import supplemental energy, both through emergency assistance from other balancing areas and WEIM imports. Most WEIM areas were net exporters in net peak hours during the heatwave, with the CAISO accounting for most imports.

As shown in Figure 3.8, average CAISO imports in the day-ahead (dark blue line) and 15-minute imports (dark yellow line) generally increased, while the average exports in the day-ahead (light blue line) and 15-minute exports (light yellow line) decreased. This resulting in an increase positive net interchange before (dashed black line) and after (solid grey line) taking into account the WEIM.

Over the most critical peak hours of 17 to 21, real-time imports consistently exceeded day-ahead imports. The average peak hour increase between markets was about 2,200 MW.

Following the first three days of the heatwave, there was an abrupt reduction in day-ahead export volume, from more than 6,000 MW to less than 3,000 MW. In addition to changes in demand and supply across the WECC, curtailment of export schedules in the day-ahead residual unit commitment process and real-time markets, may have discouraged bids from some scheduling coordinators.

As identified in the CAISO's *Summer Market Performance Report for September 2022*, high load conformance resulted in fewer non-wheel exports clearing the residual unit commitment (RUC) process than the IFM process, often resulting in reductions ranging between 1,000 MW and 2,000 MWs during peak hours.[68] The 5,000 MW of peak hour load conformance in the hour-ahead and 15-minute markets appears to have had a similar impact on new or re-bid low-price taker export MWs.

Additionally, the California ISO communicated a courtesy reminder to market participants during the heat wave to check the residual unit commitment schedules via the *Day-Ahead Residual Commitment Capacity* report in the *Customer Market Results Interface* (CMRI) and not to rely on the IFM energy schedules in the *Day-Ahead Import-Export Schedules* report in CMRI. The message also referred to the priority rules per Tariff Section 34.12.1.

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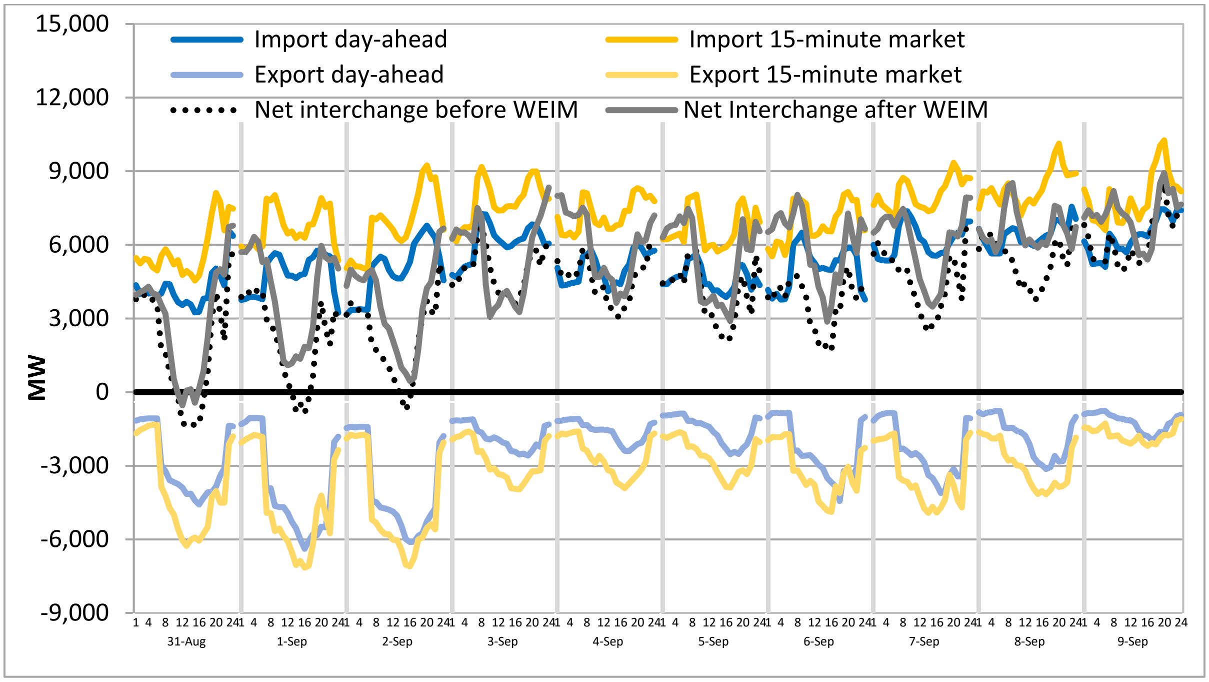
68 California ISO, *Summer Market Performance Report Sept 2022,* November 2, 2022, Figure 113, *Day-ahead non-wheel bid in capacity:* http://www.caiso.com/Documents/Sept2022_summer_readiness_reportFinal.pdf#search=summer

**Figure 3.8 Average hourly net interchange (August 31, 2022 – September 09, 2022)**




The solid grey line, which adds incremental WEIM interchange, reached a high point of the heat wave at about 8,900 MW in hour ending 20 on September 9, 2022. The greatest import transfer into the CAISO area from the WEIM occurred in hour ending 21 on September 1, 2022.

Most WEIM areas were net exporters during net peak hours during the heatwave, with CAISO accounting for most imports. Further coverage of WEIM market performance is available in DMM's *Western Energy Imbalance Market (WEIM) Resource Sufficiency Evaluation Report for October 2022*, which includes extended coverage of the heat wave.[69]

The $2,000/MWh bid cap attracted a limited quantity of additional imports into CAISO market. Bids above $1,000/MWh totaled less than 225 MW in any hour in the day-ahead market and less than 175 MW in the real-time market. Bids above $1,000/MWh are shown in the red columns in Figure 3.9 in the day-ahead market and in Figure 3.10 in the real-time market. Import bids under $1,000/MWh, shown in blue, exceeded bids over $1,000/MWh in most peak hours during this period.

69 Department of Market Monitoring, *Western Energy Imbalance Market (WEIM) Resource Sufficiency Evaluation Report covering October 2022*, November 30, 2022. http://www.caiso.com/Documents/2022-10-Metrics-Report-on-Resource-Sufficiency-Evaluation-in-WEIM-2022-11-30.pdf

**Figure 3.9 Day-ahead import bids**

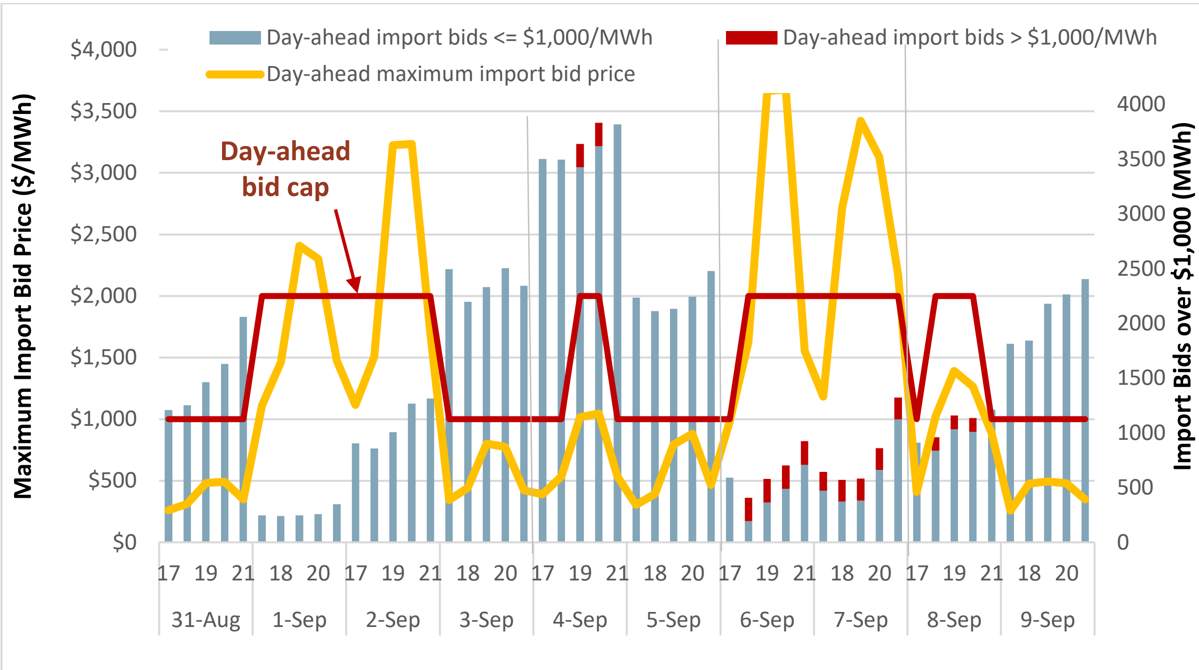
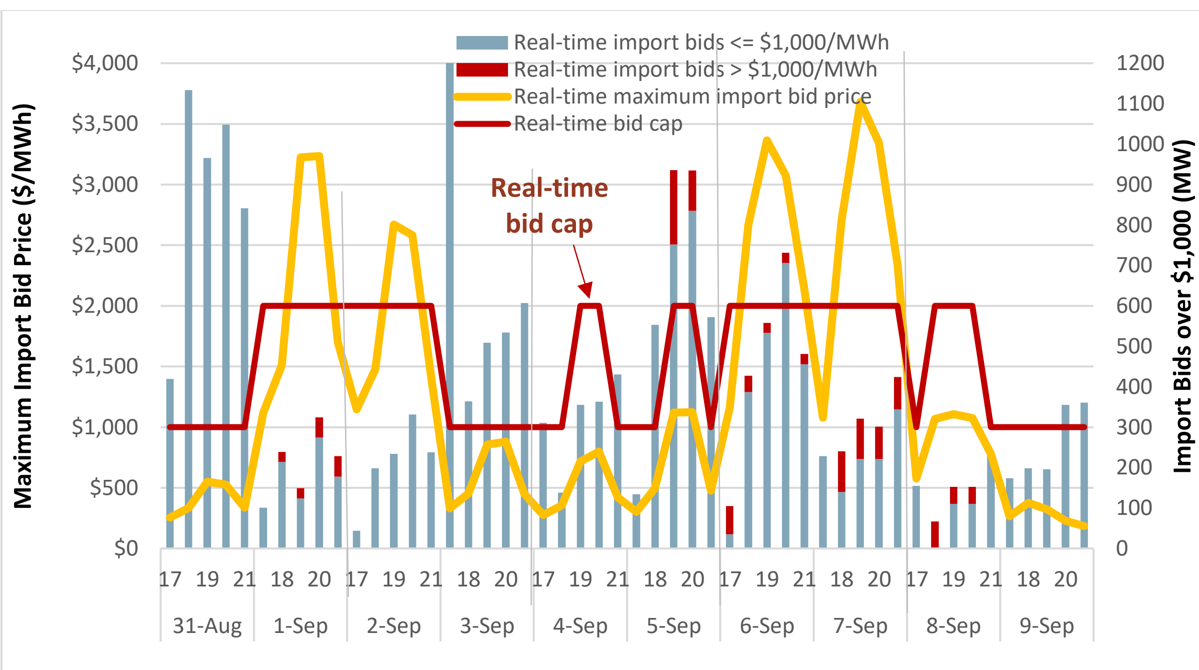
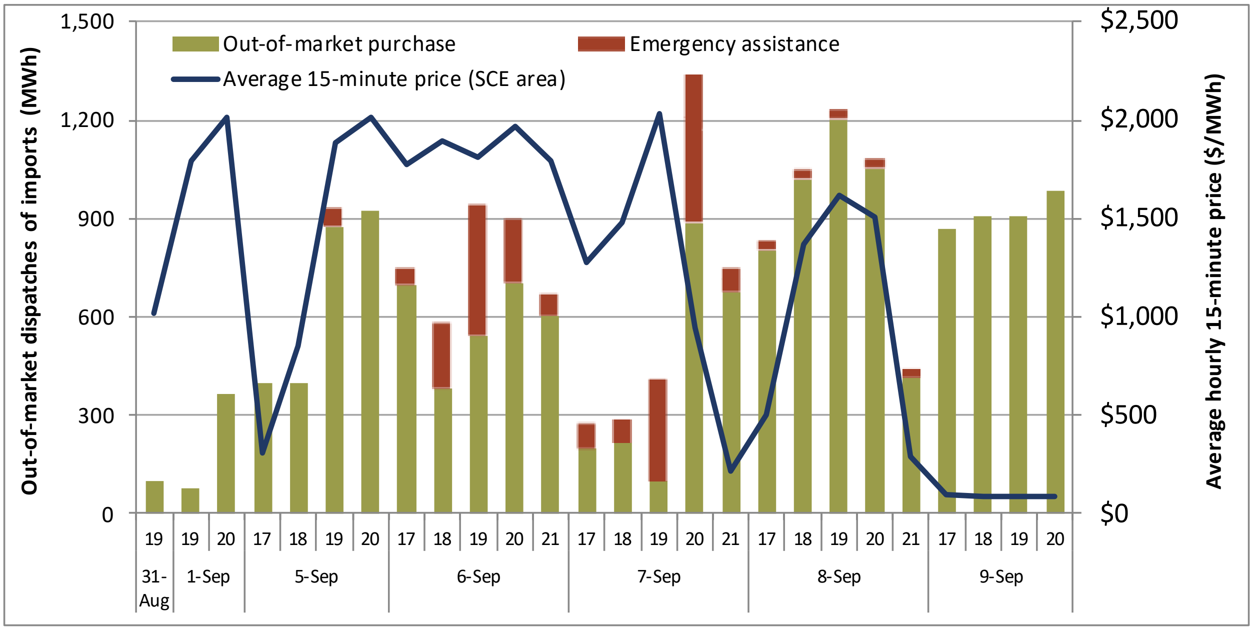



**Figure 3.10 Real-time import bids**



Balancing areas declaring emergencies were able to import supplemental energy, both through emergency assistance from other balancing areas and WEIM imports. The CAISO supply was additionally supplemented by out of market imports, non-market capacity procured through California's strategic reserve, and through voluntary demand reduction.[70]

**Figure 3.11 Real-time import bids**




### Wheel through schedules

Up to 55 percent of the 861 MW of price-taking wheeling through schedules pre-registered at the CAISO were utilized during the heat wave.[71,72] There were periods of congestion on individual interties where an import leg of a wheel cleared the real-time markets. Constraints that typically separate Northern and Southern CA were not binding, so wheels did not appear to be contributing to significant congestion within the CAISO.

Wheels were typically imported over the Malin 500 and the Nevada/Oregon Border (NOB) interties. These two import points accounted for 70 to 100 percent of wheeled energy in peak hours during the heatwave. Wheels were primarily exported on two interties in the south, PV West (19 percent) and Mead 230 (32 percent), and over the TRCYTEA intertie in Northern California (38 percent).

70 California ISO, *California Summer Market Performance Report Sept 2022*, November 2, 2022, p. 38, Section 2.5, *Demand response and non-market resources*: http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

71 Ibid. p. 80, Section 5.3, *Wheel-through transactions* http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

72 High-priority wheels are established by notifying the California ISO 45 days prior to the month of the MW quantity of the wheel and attesting that they have secured firm transmission to the CAISO border for the entire month. California ISO, *Informational Filing of Effective Date of Load, Exports, and Wheeling Tariff Amendment - FERC Docket No. ER21-1790*, August 11, 2021: http://www.caiso.com/Documents/Aug11-2021-InformationalFiling-EffectiveDate-Load-Export-Wheeling-ER21-1790.pdf

## 3.5 Congestion

Congestion on both internal and transfer constraints created significant price separation across the WEIM footprint during the heat wave period of August 31 – September 9, 2022, with lower prices in the Pacific Northwest. North-to-South congestion on a Malin-Round Mountain nomogram and an RTD-only nomogram contributed significantly to this price separation. The WEIM areas located in the Pacific Northwest were impacted by congestion in the export direction on transfer constraints for more than half the time during the heat wave.

Table 3.1 and Table 3.2 show the average impact of congestion in 15-minute and 5-minute markets during the heat wave period. In the 15-minute market, a Malin-Round Mountain nomogram (ML_RM12_NS) created large price separation across the WEIM footprint. In the 5-minute market, a constraint within the "other" category (6110_COI_N-S) led to significant price separation as well. This constraint is found in the 5-minute market only. These constraints are used to manage flows between Northern California and Oregon.

### Table 3.1 Impact of congestion on overall 15-minute prices (August 31– September 09, 2022)

| Constraint Location | Constraint | PG&E | SCE | SDG&E | BANC | TIDC | LADWP | NEVP | AZPS | TEPC | SRP | PNM | PACE | IPCO | NWMT | AVA | BPA | TPWR | PACW | PGE | PSEI | PWRX | SCL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AZPS | Line_FC-CH2_345KV | | | $0.10 | | | | | $1.21 | | $0.97 | -$6.00 | -$1.66 | -$0.88 | -$0.17 | | | | | | | | |
| | Line_FC-MK_500KV | | $3.05 | $2.17 | | | $3.31 | $3.58 | | -$6.29 | | -$26.34 | -$6.01 | -$2.76 | -$2.30 | | | | | | | | |
| IPCO | PATH_14 | -$0.46 | | $0.12 | -$0.52 | -$0.49 | | $0.46 | $0.29 | $0.33 | $0.30 | $0.49 | $1.65 | $3.03 | -$0.16 | -$0.80 | -$0.86 | -$0.85 | -$0.88 | -$0.88 | -$0.85 | -$0.83 | -$0.85 |
| PACE | WINDSTAR EXPORT TCOR | | | | | | | | | | | | -$1.11 | | | | | | | | | | |
| | TOTAL_WYOMING_EXPORT | | | | | | | | | | | | -$4.83 | | | | | | | | | | |
| PG&E | ML_RM12_NS | $27.41 | $15.39 | $13.51 | $26.37 | $26.67 | $14.55 | $3.37 | $9.76 | $8.93 | $9.65 | $5.35 | -$17.21 | -$31.67 | -$37.16 | -$42.14 | -$43.49 | -$43.45 | -$44.19 | -$44.16 | -$43.42 | -$43.09 | -$43.38 |
| | RM_TM12_NG | $4.31 | $2.47 | $2.15 | $2.97 | $4.29 | $2.35 | | $1.54 | $1.40 | $1.52 | $0.05 | -$2.90 | -$5.22 | -$6.25 | -$7.03 | -$7.21 | -$7.21 | -$7.32 | -$7.30 | -$7.21 | -$7.17 | -$7.21 |
| | 30055_GATES1 _500_30900_GATES _230_XF_12_P | $3.21 | -$1.37 | -$1.32 | $1.52 | $2.02 | -$1.35 | -$0.97 | -$1.22 | -$1.21 | -$1.21 | -$1.11 | | -$0.11 | -$0.20 | -$0.21 | -$0.22 | -$0.22 | -$0.22 | -$0.22 | -$0.22 | -$0.22 | -$0.22 |
| | 30640_TESLA C _230_30040_TESLA _500_XF_6H | $1.31 | | | $0.81 | $1.30 | | | | | | | -$0.27 | -$0.42 | -$0.43 | -$0.46 | -$0.46 | -$0.46 | -$0.46 | -$0.46 | -$0.46 | -$0.46 | -$0.46 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | $1.24 | -$2.00 | -$1.87 | $4.84 | $9.29 | -$1.83 | -$0.99 | -$1.52 | -$1.47 | -$1.52 | -$1.27 | | $0.32 | $1.19 | $1.58 | $1.66 | $1.66 | $1.71 | $1.70 | $1.66 | $1.65 | $1.66 |
| | 30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1 | $1.19 | -$0.37 | -$0.35 | $0.83 | $0.34 | -$0.36 | | -$0.29 | -$0.29 | -$0.29 | -$0.01 | | | | | | | | | | | |
| | 30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1 | $0.34 | | | | | | | | | | | | | | | | | | | | | |
| | 30655_ADCC _230_30630_NEWARK _230_BR_2 _1 | $0.31 | | | | $0.24 | | | | | | | | | | | | | | | | | |
| | 30733_VASONA _230_30735_METCALF _230_BR_1 _1 | $0.29 | | | | | | | | | | | | | | | | | | | | | |
| | 30735_METCALF _230_30731_LS ESTRS_230_BR_1 _1 | $0.12 | | | $0.11 | $0.20 | | | | | | | | | | | | | | | | | |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_1 _1 | $0.12 | -$0.06 | -$0.06 | $0.08 | $0.06 | -$0.06 | -$0.02 | -$0.06 | -$0.05 | -$0.05 | -$0.05 | | | | | | | | | | | |
| | XFMR1 500.TRY | $0.04 | | | $0.13 | $0.17 | | | | | | | | | | | | | | | | | |
| | XFMR2 500.TRY | $0.04 | | | $0.13 | $0.17 | | | | | | | | | | | | | | | | | |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | -$0.26 | $0.23 | $0.23 | -$0.25 | -$0.25 | $0.22 | $0.13 | $0.17 | $0.17 | $0.17 | $0.14 | | -$0.10 | -$0.14 | -$0.17 | -$0.18 | -$0.18 | -$0.19 | -$0.19 | -$0.18 | -$0.18 | -$0.18 |
| | 30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1 | -$2.64 | $2.25 | $2.06 | -$2.45 | -$2.53 | $2.16 | $1.13 | $1.75 | $1.69 | $1.74 | $1.44 | -$0.03 | -$1.06 | -$1.45 | -$1.71 | -$1.82 | -$1.81 | -$1.88 | -$1.91 | -$1.81 | -$1.78 | -$1.80 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | -$10.22 | $8.65 | $8.30 | -$9.73 | -$10.09 | $8.40 | $4.78 | $7.21 | $6.97 | $7.18 | $5.98 | -$0.08 | -$4.23 | -$5.64 | -$6.77 | -$7.18 | -$7.14 | -$7.43 | -$7.29 | -$7.13 | -$7.04 | -$7.12 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1 | | | | $2.15 | | | | | | | | | | -$0.35 | -$1.60 | -$1.71 | -$1.71 | -$1.73 | -$1.75 | -$1.71 | -$1.71 | -$1.71 |
| | 30515_WARNERVL_230_30800_WILSON _230_BR_1 _1 | | | | -$0.79 | -$0.52 | | | | | | | | | | | | | | | | | |
| | 30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1 | | -$0.22 | | $0.22 | $0.30 | -$0.07 | | | | | | | | | | | | | | | | |
| | 7430_CP6_NG | | | | $5.73 | | | | | | | | | | | | | | | | | | |
| | SUMMIT-DRUM #2 | | | | -$0.05 | | | $0.09 | | | | | | | | | | | | | | | |
| SCE | 6410_CP1_NG | -$1.78 | $1.44 | $1.43 | -$1.70 | -$1.76 | $1.49 | $0.79 | $1.24 | $1.20 | $1.24 | $1.03 | | -$0.72 | -$1.00 | -$1.19 | -$1.26 | -$1.25 | -$1.30 | -$1.29 | -$1.25 | -$1.23 | -$1.25 |
| | OP-6610_ELD-LUGO | $0.94 | $1.03 | $0.39 | $0.85 | $0.85 | -$2.31 | -$1.76 | -$1.49 | -$1.49 | -$1.46 | -$1.49 | -$0.73 | -$0.06 | $0.10 | $0.32 | $0.35 | $0.35 | $0.38 | $0.37 | $0.35 | $0.34 | $0.35 |
| | 24042_ELDORDO _500_24086_LUGO _500_BR_1 _4 | $0.02 | $0.03 | $0.03 | $0.02 | $0.02 | $0.02 | -$0.06 | -$0.06 | -$0.06 | -$0.06 | -$0.06 | -$0.03 | -$0.01 | | | | | | | | | |
| | 24114_PARDEE _230_24217_WARNETAP_230_BR_1 _1 | | | | | | $0.25 | | | | | | | | | | | | | | | | |
| | 99254_J.HINDS2_230_24806_MIRAGE _230_BR_1 _1 | | | | | | | | -$0.06 | -$0.06 | -$0.06 | | | | | | | | | | | | |
| SDG&E | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P | | $1.61 | $14.47 | | | | -$1.79 | -$4.54 | -$4.42 | -$4.67 | -$3.66 | -$1.56 | | | | | | | | | | |
| | 7820_TL 230S_TL50001OUT_NG | | $0.21 | $2.29 | | | | -$0.21 | -$0.54 | -$0.55 | -$0.60 | -$0.47 | -$0.19 | | | | | | | | | | |
| | 92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1 | | | $1.80 | | | | | -$0.57 | -$0.56 | -$0.59 | -$0.46 | | | | | | | | | | | |
| | 92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1 | | | $1.52 | | | | | -$0.48 | -$0.47 | -$0.50 | -$0.39 | | | | | | | | | | | |
| | 22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1 | | | $1.28 | | | | | -$0.40 | -$0.40 | -$0.42 | -$0.33 | | | | | | | | | | | |
| | 22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1 | | | $1.28 | | | | | -$0.40 | -$0.40 | -$0.42 | -$0.33 | | | | | | | | | | | |
| | OMS TL50001_OOS_NG | | $0.04 | $0.71 | | | | -$0.05 | -$0.13 | -$0.12 | -$0.22 | -$0.10 | -$0.04 | | | | | | | | | | |
| | 92861_SUNC TP2_230_92321_SYCA TP2_230_BR_2 _1 | | | $0.58 | | | | | | | | | | | | | | | | | | | |
| | 7820_TL 230S_OVERLOAD_NG | | $0.05 | $0.57 | | | $0.00 | -$0.05 | -$0.13 | -$0.13 | -$0.14 | -$0.11 | -$0.05 | -$0.02 | | | | | | | | | |
| | 22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1 | | | $0.37 | | | | | | | | | | | | | | | | | | | |
| | 22420_SILVERGT_69.0_22430_SILVERGT_230_XF_2 | | | $0.16 | | | | | | | | | | | | | | | | | | | |
| | 7820_13810A_OVERLOAD_NG | | | -$0.02 | | | | | -$0.03 | -$0.03 | -$0.03 | -$0.02 | | | | | | | | | | | |
| | 22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1 | $0.18 | $0.32 | -$2.47 | $0.17 | $0.18 | $0.20 | | -$0.39 | -$0.37 | -$0.40 | -$0.29 | | | | | | | $0.04 | | | | |
| | Other | -$1.25 | $0.65 | -$1.86 | -$2.63 | -$5.11 | $0.70 | $0.45 | $1.05 | $0.78 | $0.73 | $0.50 | -$0.30 | -$0.54 | -$0.61 | -$0.07 | $0.13 | $0.12 | -$0.06 | $0.05 | $0.12 | $0.10 | $0.12 |
| | **Internal Total** | **$24.49** | **$33.39** | **$47.56** | **$28.82** | **$25.34** | **$27.66** | **$8.88** | **$11.90** | **$3.10** | **$10.84** | **-$27.50** | **-$35.34** | **-$44.44** | **-$54.58** | **-$60.29** | **-$62.26** | **-$62.17** | **-$63.55** | **-$63.34** | **-$62.12** | **-$61.61** | **-$62.06** |
| | **Transfers** | | | | -$16.93 | -$4.20 | -$3.80 | -$4.88 | -$4.17 | -$19.49 | -$85.84 | -$5.79 | -$7.08 | -$21.30 | -$65.83 | -$60.96 | -$17.29 | -$45.48 | -$9.73 | -$6.47 | -$43.07 | -$80.62 | -$43.71 |
| | **Grand Total** | **$24.49** | **$33.39** | **$47.56** | **$11.89** | **$21.14** | **$23.86** | **$4.00** | **$7.73** | **-$16.39** | **-$75.00** | **-$33.29** | **-$42.42** | **-$65.74** | **-$120.41** | **-$121.25** | **-$79.55** | **-$107.65** | **-$73.28** | **-$69.81** | **-$105.19** | **-$142.23** | **-$105.77** |

### Table 3.2 Impact of congestion on overall 5-minute prices (August 31– September 09, 2022)

| Constraint Location | Constraint | PG&E | SCE | SDG&E | BANC | TIDC | LADWP | NEVP | AZPS | TEPC | SRP | PNM | PACE | IPCO | NWMT | AVA | BPA | TPWR | PACW | PGE | PSEI | PWRX | SCL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AZPS | Line_FC-CH2_345KV | | | $0.07 | | | | | $0.79 | | $0.62 | -$3.95 | -$1.09 | -$0.58 | | | | | | | | | |
| | Line_FC-MK_500KV | | $2.30 | $1.64 | | | $2.48 | $2.69 | | -$4.70 | | -$19.73 | -$4.50 | -$2.07 | -$1.72 | | | | | | | | |
| IPCO | PATH_14 | -$1.07 | | $0.27 | -$1.23 | -$1.14 | | $1.05 | $0.68 | $0.76 | $0.69 | $1.14 | $3.87 | $7.08 | -$0.37 | -$1.86 | -$2.03 | -$2.00 | -$2.06 | -$2.05 | -$1.99 | -$1.94 | -$1.99 |
| NEVP | HA-RE_345KV | | $0.00 | $0.00 | | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | | -$0.02 | -$0.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| PACE | WINDSTAR EXPORT TCOR | | | | | | | | | | | | -$0.99 | | | | | | | | | | |
| | TOTAL_WYOMING_EXPORT | | | | | | | | | | | | -$2.70 | | | | | | | | | | |
| PACW | WPTH71 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | | | -$0.01 | -$0.01 | -$0.01 | -$0.03 | $0.00 | $0.02 | -$0.03 | -$0.02 | -$0.03 |
| PG&E | 30055_GATES1 _500_30900_GATES _230_XF_12_P | $3.06 | -$1.29 | -$1.25 | $1.43 | $2.03 | -$1.27 | -$0.93 | -$1.16 | -$1.14 | -$1.16 | -$1.06 | | -$0.10 | -$0.14 | -$0.15 | -$0.16 | -$0.15 | -$0.16 | -$0.16 | -$0.15 | -$0.15 | -$0.15 |
| | RM_TM12_NG | $1.93 | $1.11 | $0.96 | $1.30 | $1.87 | $1.02 | | $0.67 | $0.61 | $0.66 | | -$1.27 | -$2.27 | -$2.74 | -$3.08 | -$3.15 | -$3.15 | -$3.20 | -$3.28 | -$3.15 | -$3.13 | -$3.15 |
| | 30640_TESLA C _230_30040_TESLA _500_XF_6H | $1.03 | -$0.02 | -$0.02 | $0.62 | $1.05 | -$0.02 | | -$0.01 | -$0.01 | -$0.01 | -$0.01 | -$0.13 | -$0.18 | -$0.25 | -$0.31 | -$0.31 | -$0.31 | -$0.31 | -$0.31 | -$0.31 | -$0.31 | -$0.31 |
| | 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1 | $0.86 | -$1.35 | -$1.26 | $3.15 | $6.36 | -$1.32 | -$0.70 | -$1.10 | -$1.06 | -$1.10 | -$0.91 | | $0.44 | $0.87 | $1.08 | $1.14 | $1.13 | $1.18 | $1.16 | $1.13 | $1.13 | $1.13 |
| | 30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1 | $0.71 | -$0.21 | -$0.20 | $0.50 | $0.21 | -$0.21 | | -$0.17 | -$0.15 | -$0.17 | -$0.01 | | | | | | | | | | | |
| | 30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1 | $0.33 | | | | | | | | | | | | | | | | | | | | | |
| | 30735_METCALF _230_30731_LS ESTRS_230_BR_1 _1 | $0.32 | | | $0.22 | $0.51 | | | | | | | | | | | | | | | | | |
| | 30885_MUSTANGS_230_30900_GATES _230_BR_1 _1 | $0.28 | -$0.11 | -$0.11 | $0.15 | $0.11 | -$0.11 | | -$0.10 | -$0.10 | -$0.10 | -$0.09 | | | | | | | | | | | |
| | 30733_VASONA _230_30735_METCALF _230_BR_1 _1 | $0.23 | | | | | | | | | | | | | | | | | | | | | |
| | 30435_LAKEVILE_230_30440_TULUCAY _230_BR_1 _1 | $0.15 | | | | | | | | | | | | | | | | | | | | | |
| | XFMR1 500.TRY | $0.11 | | | $0.32 | $0.41 | | | | | | | | | | | | | | | | | |
| | 30625_TESLA D _230_30040_TESLA _500_XF_4H | $0.11 | -$0.04 | -$0.02 | $0.20 | $0.27 | -$0.04 | | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 | -$0.02 |
| | XFMR2 500.TRY | $0.10 | | | $0.29 | $0.38 | | | | | | | | | | | | | | | | | |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3 | -$0.22 | $0.19 | $0.19 | -$0.21 | -$0.22 | $0.18 | $0.11 | $0.14 | $0.14 | $0.14 | $0.12 | | -$0.09 | -$0.12 | -$0.15 | -$0.16 | -$0.16 | -$0.16 | -$0.16 | -$0.16 | -$0.15 | -$0.16 |
| | 30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1 | -$2.53 | $2.21 | $2.03 | -$2.38 | -$2.45 | $2.14 | $1.15 | $1.74 | $1.68 | $1.73 | $1.44 | -$0.02 | -$1.04 | -$1.40 | -$1.66 | -$1.77 | -$1.75 | -$1.83 | -$1.82 | -$1.75 | -$1.73 | -$1.75 |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 | -$4.72 | $3.98 | $3.83 | -$4.49 | -$4.67 | $3.86 | $2.18 | $3.32 | $3.21 | $3.30 | $2.75 | -$0.04 | -$1.96 | -$2.62 | -$3.11 | -$3.31 | -$3.28 | -$3.42 | -$3.38 | -$3.28 | -$3.24 | -$3.27 |
| | 30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1 | | | | $0.99 | | | | | | | | | | -$0.15 | -$0.77 | -$0.80 | -$0.80 | -$0.80 | -$0.80 | -$0.80 | -$0.79 | -$0.80 |
| | 30515_WARNERVL_230_30800_WILSON _230_BR_1 _1 | | | | -$0.26 | -$0.17 | | | | | | | | | | | | | | | | | |
| | 30805_BORDEN _230_30810_GREGG _230_BR_2 _1 | | | | $0.13 | | | | | | | | | | | | | | | | | | |
| | 7430_CP6_NG | | | | $8.27 | | | | | | | | | | | | | | | | | | |
| SCE | OP-6610_ELD-LUGO | $2.24 | $2.42 | $0.95 | $2.05 | $2.16 | -$5.95 | -$4.45 | -$3.67 | -$3.66 | -$3.59 | -$3.71 | -$1.79 | -$0.14 | $0.22 | $0.78 | $0.87 | $0.86 | $0.93 | $0.91 | $0.86 | $0.84 | $0.86 |
| | 6410_CP1_NG | -$1.23 | $0.99 | $0.99 | -$1.17 | -$1.21 | $1.03 | $0.55 | $0.86 | $0.83 | $0.85 | $0.71 | | -$0.50 | -$0.68 | -$0.82 | -$0.87 | -$0.86 | -$0.90 | -$0.89 | -$0.86 | -$0.85 | -$0.86 |
| | 24086_LUGO _500_26105_VICTORVL_500_BR_1 _1 | $0.07 | $0.08 | $0.04 | $0.06 | $0.06 | -$0.22 | -$0.11 | -$0.10 | -$0.10 | -$0.10 | -$0.10 | -$0.04 | | | $0.03 | $0.03 | $0.03 | $0.03 | $0.04 | $0.03 | $0.03 | $0.03 |
| | 24114_PARDEE _230_24217_WARNETAP_230_BR_1 _1 | | | | | | $0.22 | | | | | | | | | | | | | | | | |
| SDG&E | 22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P | | $1.12 | $10.02 | | | | -$1.23 | -$3.14 | -$3.05 | -$3.22 | -$2.53 | -$1.07 | | | | | | | | | | |
| | 7820_TL 230S_TL50001OUT_NG | | $0.11 | $1.22 | | | | -$0.11 | -$0.28 | -$0.29 | -$0.32 | -$0.25 | -$0.10 | | | | | | | | | | |
| | 7820_TL 230S_OVERLOAD_NG | | $0.06 | $0.67 | | | $0.00 | -$0.06 | -$0.15 | -$0.16 | -$0.17 | -$0.13 | -$0.06 | -$0.01 | | | | | | | | | |
| | 92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1 | | | $0.41 | | | | | -$0.13 | -$0.12 | -$0.13 | -$0.10 | | | | | | | | | | | |
| | 22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1 | | | $0.28 | | | | | | | | | | | | | | | | | | | |
| | 92861_SUNC TP2_230_92321_SYCA TP2_230_BR_2 _1 | | | $0.17 | | | | | | | | | | | | | | | | | | | |
| | OMS TL50001_OOS_NG | | $0.01 | $0.17 | | | | -$0.01 | -$0.03 | -$0.03 | -$0.05 | -$0.02 | -$0.01 | | | | | | | | | | |
| | 92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1 | | | $0.12 | | | | | -$0.04 | -$0.04 | -$0.04 | -$0.03 | | | | | | | | | | | |
| | 22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1 | | | $0.08 | | | | | -$0.02 | -$0.02 | -$0.02 | -$0.02 | | | | | | | | | | | |
| | 22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1 | | | $0.08 | | | | | -$0.02 | -$0.02 | -$0.02 | -$0.02 | | | | | | | | | | | |
| | 22771_BAY BLVD_230_22430_SILVERGT_230_BR_1 _1 | | | $0.06 | | | | | -$0.03 | -$0.03 | -$0.03 | | | | | | | | | | | | |
| | 7820_13810A_OVERLOAD_NG | | | -$0.03 | | | | | -$0.04 | -$0.04 | -$0.04 | -$0.03 | | | | | | | | | | | |
| | 22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1 | $0.09 | $0.15 | -$1.17 | $0.08 | $0.09 | $0.09 | | -$0.18 | -$0.18 | -$0.19 | -$0.14 | | | | | | | $0.00 | | | | |
| | Other | $18.34 | $19.89 | $17.80 | $18.02 | $16.71 | $18.59 | $2.50 | $11.61 | $10.53 | $10.59 | $5.99 | -$19.65 | -$24.08 | -$18.41 | -$15.93 | -$15.73 | -$16.29 | -$15.89 | -$15.85 | -$16.28 | -$16.75 | -$16.09 |
| | **Internal Total** | **$20.19** | **$31.60** | **$37.97** | **$28.03** | **$22.36** | **$20.49** | **$2.64** | **$9.41** | **$2.83** | **$8.09** | **-$20.69** | **-$29.62** | **-$25.50** | **-$27.54** | **-$25.99** | **-$26.26** | **-$26.78** | **-$26.60** | **-$26.60** | **-$26.76** | **-$27.10** | **-$26.56** |
| | **Transfers** | | | | **-$1.34** | **$0.03** | **$0.17** | **$2.84** | **$2.01** | **$1.00** | **-$5.70** | **$0.75** | **$0.14** | **-$0.10** | **-$3.72** | **-$3.55** | **$1.19** | **-$1.15** | **-$1.51** | **-$0.38** | **-$0.48** | **-$4.12** | **-$1.35** |
| | **Grand Total** | **$20.19** | **$31.60** | **$37.97** | **$26.69** | **$22.39** | **$20.66** | **$5.48** | **$11.42** | **$3.83** | **$2.39** | **-$19.94** | **-$29.48** | **-$25.60** | **-$31.26** | **-$29.54** | **-$25.07** | **-$27.93** | **-$28.11** | **-$26.98** | **-$27.24** | **-$31.22** | **-$27.91** |

Transfer constraint congestion in the export direction during the heat wave period created significant price separation between WEIM areas located in the Pacific Northwest and rest of the WEIM system. Table 3.3 shows the average congestion price impact and frequency on WEIM transfer constraints by area during the heat wave. Transfer constraint congestion decreased average prices in the Salt River Project area by $85.84/MWh in the 15-minute market and $47.27/MWh in the 5-minute market. Bonneville Power Administration, Puget Sound Energy, Seattle City Light, Tacoma Power, and Powerex were impacted by transfer constraint congestion during more than half of all intervals in both markets between August 31 and September 9.

**Table 3.3 Average congestion price impact and frequency on WEIM transfer constraints (August 31– September 09, 2022)**

| | 15-minute market | | 5-minute market | |
|---|---|---|---|---|
| | Congestion Frequency | Price Impact ($/MWh) | Congestion Frequency | Price Impact ($/MWh) |
| Turlock Irrigation District | 1% | -$4.20 | 0% | $0.26 |
| NV Energy | 1% | -$4.88 | 2% | $0.56 |
| Arizona Public Service | 1% | -$4.17 | 2% | $11.39 |
| BANC | 2% | -$16.93 | 2% | -$12.31 |
| L.A. Dept. of Water and Power | 3% | -$3.80 | 3% | $0.72 |
| Public Service Company of NM | 7% | -$5.79 | 3% | -$0.11 |
| Tucson Electric Power | 13% | -$19.49 | 7% | -$3.03 |
| PacifiCorp East | 16% | -$7.08 | 8% | -$0.07 |
| Idaho Power | 18% | -$21.30 | 9% | $0.64 |
| PacifiCorp West | 21% | -$9.73 | 9% | -$0.52 |
| Avista | 25% | -$60.96 | 14% | -$8.70 |
| NorthWestern Energy | 26% | -$65.83 | 15% | -$10.66 |
| Portland General Electric | 40% | -$6.47 | 15% | $1.46 |
| Salt River Project | 40% | -$85.84 | 35% | -$47.27 |
| Bonneville Power Admin. | 61% | -$17.29 | 55% | $12.71 |
| Puget Sound Energy | 64% | -$43.07 | 55% | -$1.39 |
| Seattle City Light | 63% | -$43.71 | 55% | -$2.10 |
| Tacoma Power | 64% | -$45.48 | 55% | -$1.67 |
| Powerex | 65% | -$80.62 | 78% | -$16.37 |

## 3.6 Resource adequacy performance

This section shows the availability of resource adequacy (RA) units during the Energy Emergency Alert (EEA) events. System RA requirements are set based on forecast system-level peak demand. During the heat wave, CAISO's peak demand reached 52,061 MW, an all-time high, well above the month ahead forecast of 44,758 MW.[73] The availability of RA units plays a critical role in meeting energy demand and maintaining the reliability of the grid.

The California ISO declared Energy Emergency Alerts (EEA) to keep the public and market participants informed about the shortage. The alert system has multiple stages.[74] The CAISO can declare EEA 2 when all resources are in use and emergency load management programs are needed. The highest alert level, EEA 3, can be declared when the CAISO cannot meet expected energy and minimum contingency reserve requirement, and has asked utilities to prepare for potential electricity interruptions through

[73] California ISO, *California Summer Market Performance Report Sept 2022*, November 2, 2022, p. 49, Section 3.2, *Peak loads:* http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

[74] The California ISO determines when and where energy conservation will be needed and what levels of Energy Emergency Alert (EEA) system to be classified. This series of notifications matches the North America Electric Reliability Corporation's (NERC) Energy Emergency Alert (EEA) system. To learn more about EEAs, go to: http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx

firm load shedding. In this quarter, the CAISO declared EEA 2 and EEA 3 in hours between 5:00 p.m. and 9:00 p.m. on September 5, 6, 7, and 8. The duration of the EEA events totaled 747 minutes for EEA 2 and 163 minutes for EEA 3.

**Figure 3.12 Average system RA capacity and availability in the day-ahead market by fuel type during EEA 2 and EEA 3 hours**

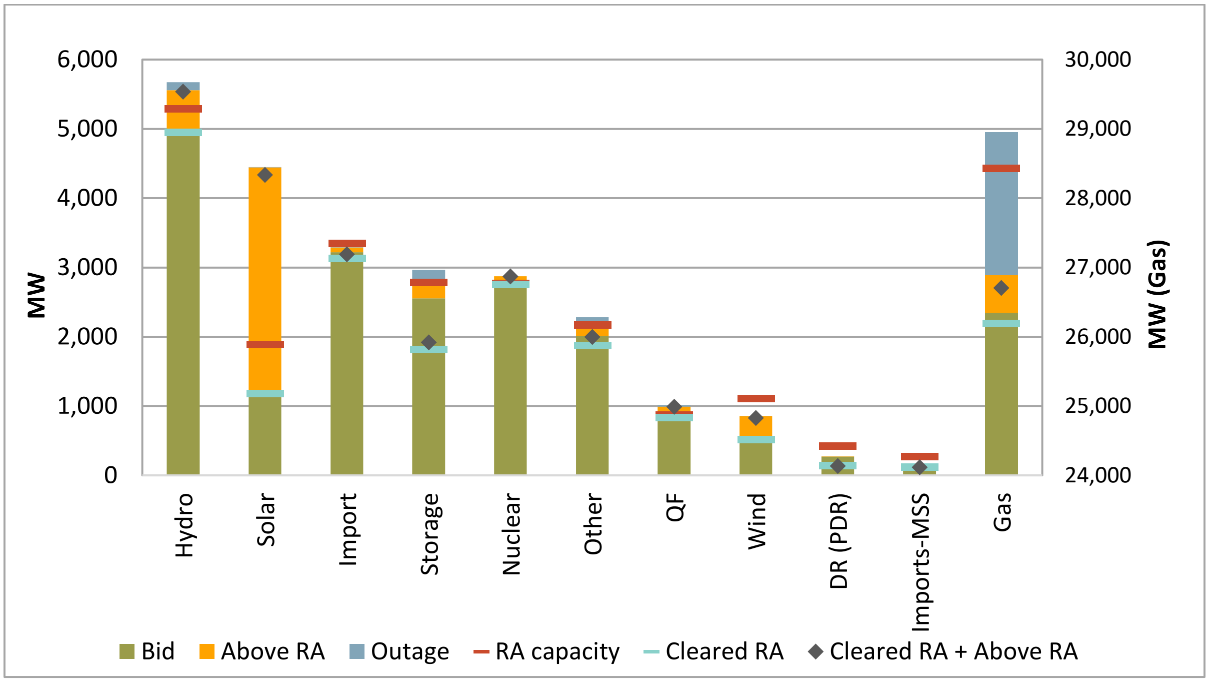



**Figure 3.13 Average system RA capacity and availability in the real-time market by fuel type during EEA 2 and EEA 3 hours**

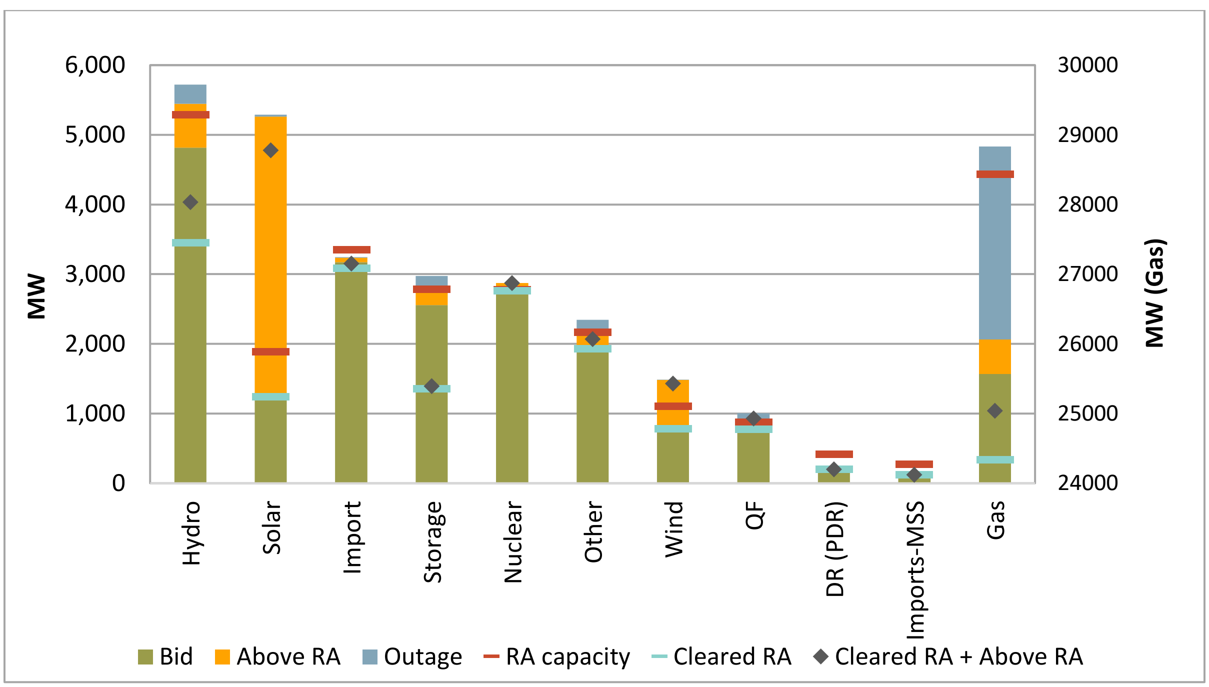


Figure 3.12 and Figure 3.13 show the average hourly availability of RA capacity in the day-ahead market and the real-time market, respectively, during the EEA 2 and EEA 3 events. These charts show RA capacity bids compared to the amount of capacity that was shown towards their monthly obligations by resource type. The chart also shows the scheduled MW of these units, the amount on outage, and above RA bids and schedules. The left vertical axis shows the availability of resources except gas-fired units, and the right vertical axis shows that of gas-fired units.

- **Gas-fired units** accounted for about 28,400 MW (58 percent) of capacity used to meet RA requirements. During the EEA events, about 93 percent of capacity was bid into the day-ahead market and 90 percent into the real-time market. Of these bids, 99 percent were scheduled in the day-ahead market and 95 percent were scheduled in the real-time market. The rest of this capacity was unavailable due to outages or de-rates.
- **Hydroelectric** generators accounted for about 5,300 MW of capacity used to meet RA requirements during the EEA event. About 93 percent of this capacity was bid into the day-ahead market and 91 percent into the real-time market. Of these bids, about 99 percent was scheduled in the day-ahead market, but only 71 percent was scheduled in the real-time market. Outages or de-rates accounted for about 2 percent of hydroelectric RA capacity in the day-ahead market and about 5 percent in the real-time market.
- **Solar** resources were used to meet about 1,880 MW of RA requirements during the EEA hours. These resources bid or self-scheduled 63 percent of this capacity into the day-ahead and about 68 percent into the real-time markets. However, since additional capacity was available from some of these resources beyond the level used to meet RA requirements, total solar capacity scheduled in the real-time market was about 230 percent of solar RA capacity in the day-ahead and 250 percent in the real-time markets.
- **Non-resource-specific imports** accounted for about 3,300 MW of RA requirements during the EEA hours. About 96 percent of this capacity was bid into the day-ahead market and about 95 percent into the real-time market. Of these bids, about 97 percent were scheduled in the day-ahead market and 97 percent in the real-time market. Outages or de-rates accounted for about 1.6 percent of import RA capacity in the day-ahead market and about 2 percent in the real-time market.
- **Storage** resources were used to meet about 2,800 MW of RA requirements in the quarter. These resources bid or self-scheduled 92 percent of this capacity into the day-ahead and real-time markets. After including additional capacity, that was available from some of these resources beyond the level used to meet RA requirements, total storage resources scheduled or offered in the day-ahead market equaled about 69 percent of storage RA capacity and about 50 percent in the real-time market.
- **Wind** resources were used to meet about 1,100 MW of RA requirements during the EEA hours. These resources bid or self-scheduled about 47 percent of their RA capacity into the day-ahead market and about 72 percent into the real-time markets. After including additional capacity that was available from some of these resources beyond the level used to meet RA requirements, total wind capacity scheduled or offered in the market equaled about 75 percent of wind RA capacity in the day-ahead market and about 140 percent in the real-time market.
- **Proxy demand response (PDR)** resources were used to meet about 410 MW of RA requirements during the EEA hours. These resources bid or self-scheduled about 65 percent of their capacity into the day-ahead market and 53 percent into the real-time markets. About 51 percent of day-ahead bids were scheduled and about 88 percent of PDR real-time bids were scheduled. There were no outages or de-rates observed in the day-ahead market. About 2 percent of PDR RA capacity was de-rated or on outage in the real-time market.

- **Imports from Metered Subsystem (MSS)** resources accounted for about 270 MW of RA requirements during the EEA hours. These resources were shown by load-following metered sub-system entities. The import-MSS resources bid into the day-ahead market 44 percent of their RA capacity and 47 percent of their RA capacity in the real-time market. Their entire day-ahead bid was scheduled in the day-ahead market and about 95 percent was scheduled in the real-time market. These resources showed no outage or de-rate during the EEA hours. Unlike non-resource-specific import resources, import-MSS does not have must-offer obligation since they are not within the CPUC jurisdiction.

### Import resource adequacy schedules

This section analyzes the performance of non-resource specific import RA during the heat wave period. Import RA resources are the fourth largest RA source in the California ISO balancing authority area. Their performance played a critical role in meeting high load during the heat wave. Import RA resources under CPUC jurisdiction must self-schedule or bid into the CAISO day-ahead and real-time markets between -$150/MWh and $0/MWh during the availability assessment hours, and the energy must be delivered to load serving entities.[75] Non-CPUC jurisdictional RA imports and load-following subsystem import RA resources can bid above $0/MWh.

During the heat wave period, some import RA resources were not scheduled in the market. Figure 3.14 provides an overview of RA import schedules in day-ahead and real-time markets during the availability assessment hours from 5:00 p.m. to 9:00 p.m. Real-time import RA schedules were consistently lower than de-rate adjusted RA capacity, day-ahead schedules, and residual unit commitment (RUC) schedules.[76] One of the largest gaps between RA and real-time market schedules occurred on September 7, 2022. On average, the hour-ahead schedule were 640 MW less than RUC schedule between 6:00 p.m. and 8 p.m., and 5-minute schedule were 330 MW less than RUC in these hours.

Figure 3.15 suggests that most of the under-scheduling occurred at the NOB intertie, which was heavily congested during the heatwave. The figure shows the non-scheduled MW of import RA resources in hour-ahead, 15-minute, and 5-minute market for each intertie. Non-scheduled MWs is the portion of bid-in MW that did not clear the market. The figure shows the aggregated MW in the three real-time markets. On September 7, 2022, 2,100 MW of import RA resources were not scheduled in the real-time markets. The NOB intertie was import constrained between 4:40 p.m. and 7:45 p.m. on that day. This congestion possibly impacted the scheduling of import RA resources.

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75 The availability assessment hours refer to the hours of greatest need of energy and an incentive structure. RA resources are rewarded for availability during these hours. The California ISO determines the assessment hours annually. In the 2022 summer season, the hours were between 17 and 21. For a more information, see section 40.9 of the California ISO tariff: http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-asof-Aug15-2022.pdf

76 The de-rated adjusted RA capacity indicates the remaining RA capacity after subtracting outage or de-rated MW from the original RA capacity.

**Figure 3.14 Hourly average of resource adequacy imports scheduled by market**

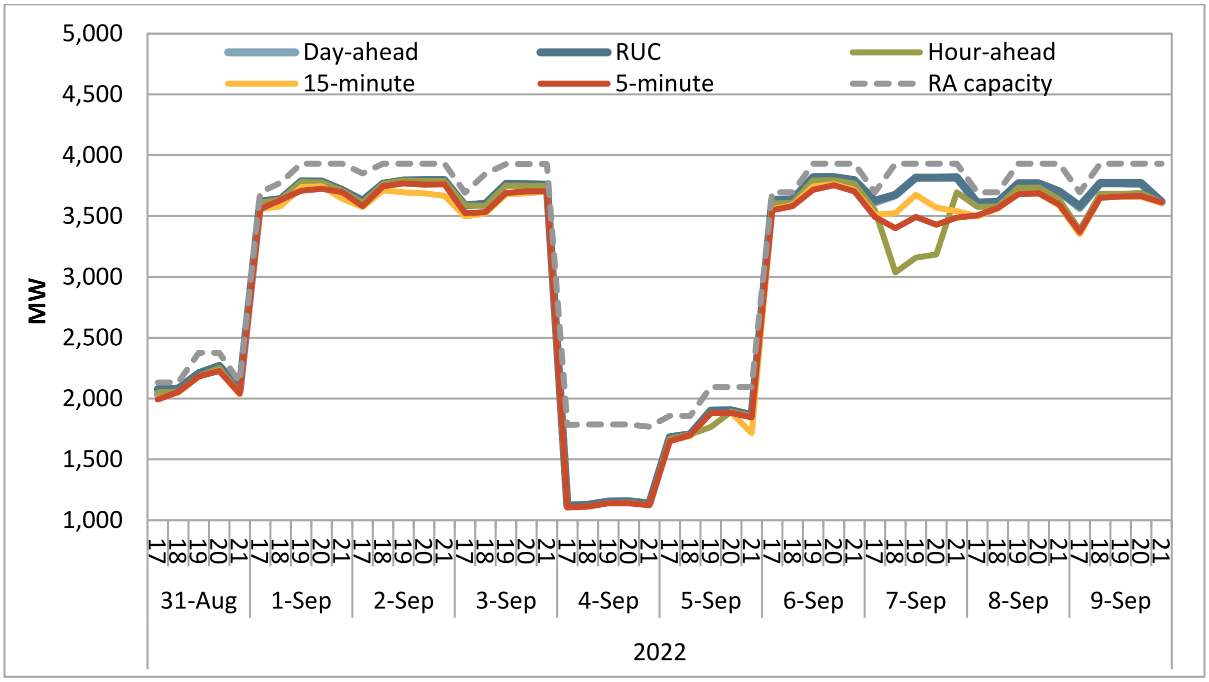
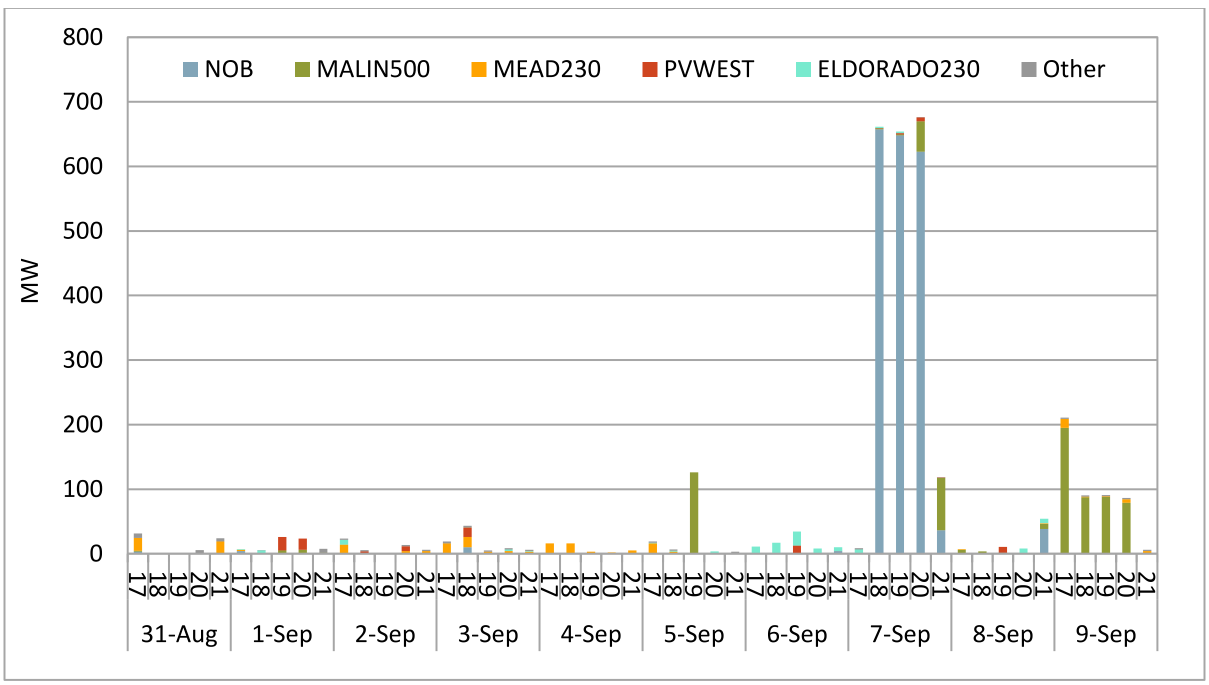



**Figure 3.15 Total resource adequacy imports not scheduled in real-time market by intertie**



# Appendix A | Extended Western Energy Imbalance Market metrics

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

- The system marginal energy price (SMEC) was the largest contributor to the overall LMP in each area. Congestion within the CAISO was the largest source of price separation over the quarter.
- Average quarterly transfers in the 15-minute and 5-minute markets have remained relatively consistent over recent quarters.

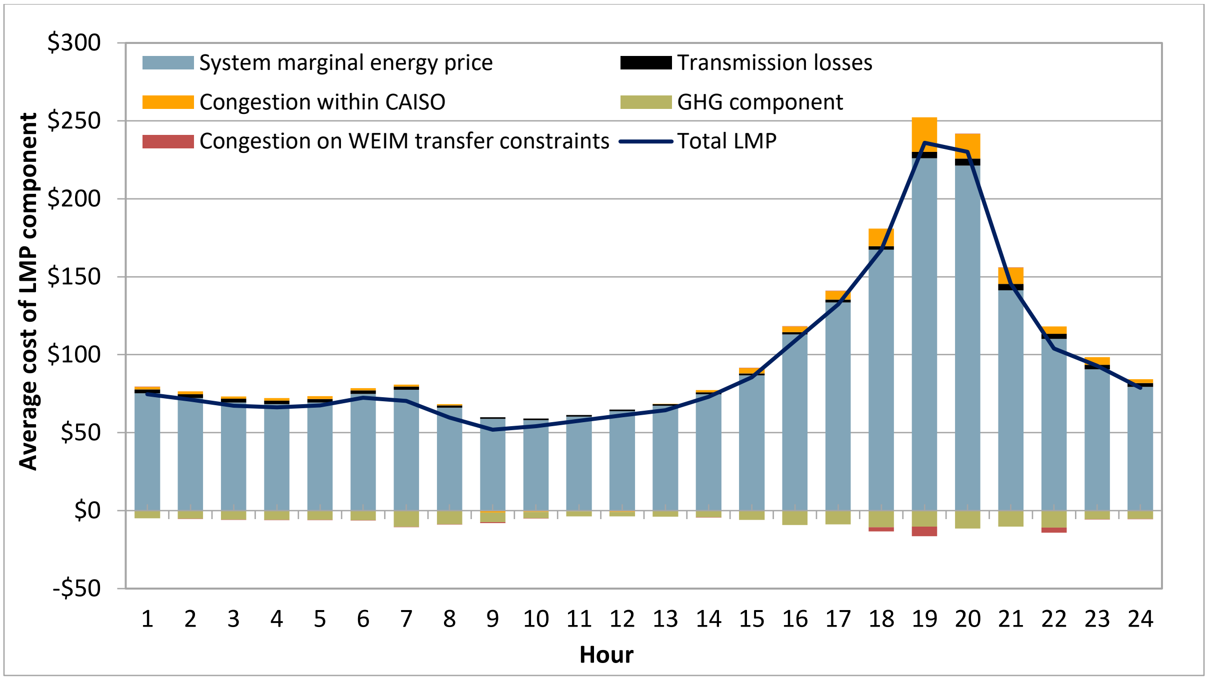
The hourly locational marginal price decomposition figures break down the price into five separate components. These components, listed below, can influence the prices in an area positively or negatively depending on the circumstances.

- **System marginal energy price**, often referred to as SMEC, is the marginal clearing price for electricity in the WEIM footprint. Therefore, the SMEC is the same for all WEIM areas.
- **Transmission losses** are the price impact of energy lost on the path from source to sink.
- **Congestion within the CAISO** is the price impact from internal transmission constraints that are restricting the flow of energy within an area. While these constraints are located within a single balancing area, they can create price impacts across the WEIM. This LMP component is labeled 'within CAISO' as it is primarily transmission constraints within the CAISO area that are affecting prices. However, price impacts from internal constraints within other WEIM balancing areas are included in the category as well.
- **Congestion on WEIM transfer constraints** is the price impact from intertie transmission constraints that link two balancing areas together. Price impacts from failed resource sufficiency evaluation (RSE) tests are included in this category as failed tests limit transfer capabilities.
- **Greenhouse gas price** is the price in each 15-minute or 5-minute interval set at the greenhouse gas bid of the marginal megawatt deemed to serve California load. This price, determined within the optimization, is also included in the price difference between serving both California and non-California WEIM load, which contributes to higher prices for WEIM areas in California.

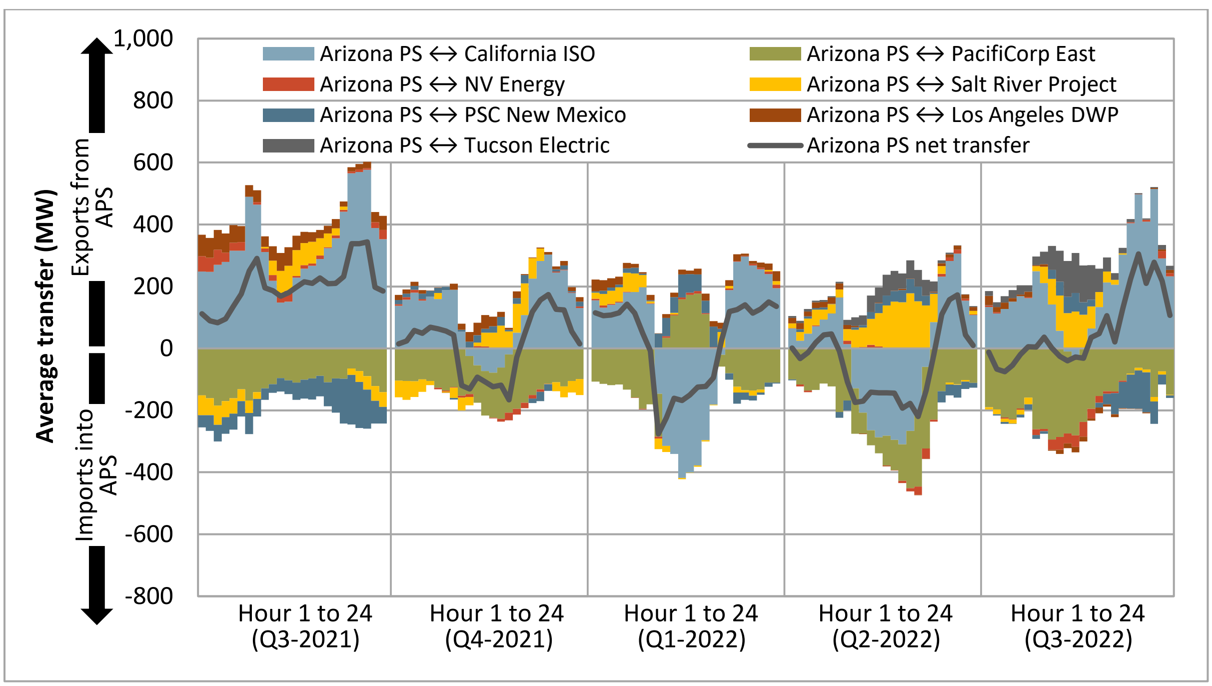
The transfer figures below show the hourly average imports and exports by WEIM area in the 15-minute and 5-minute markets by quarter. These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will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

## A.1 Arizona Public Service

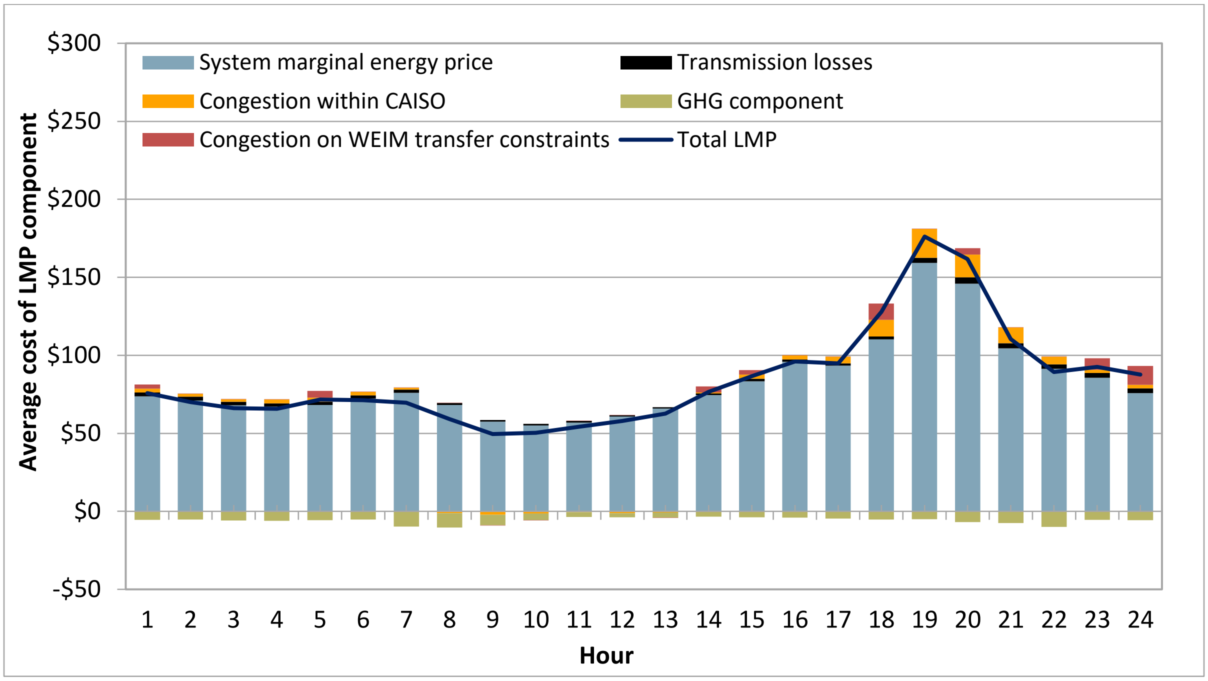
**Appendix Figure A.1 Average hourly 15-minute price by component (Q3 2022)**



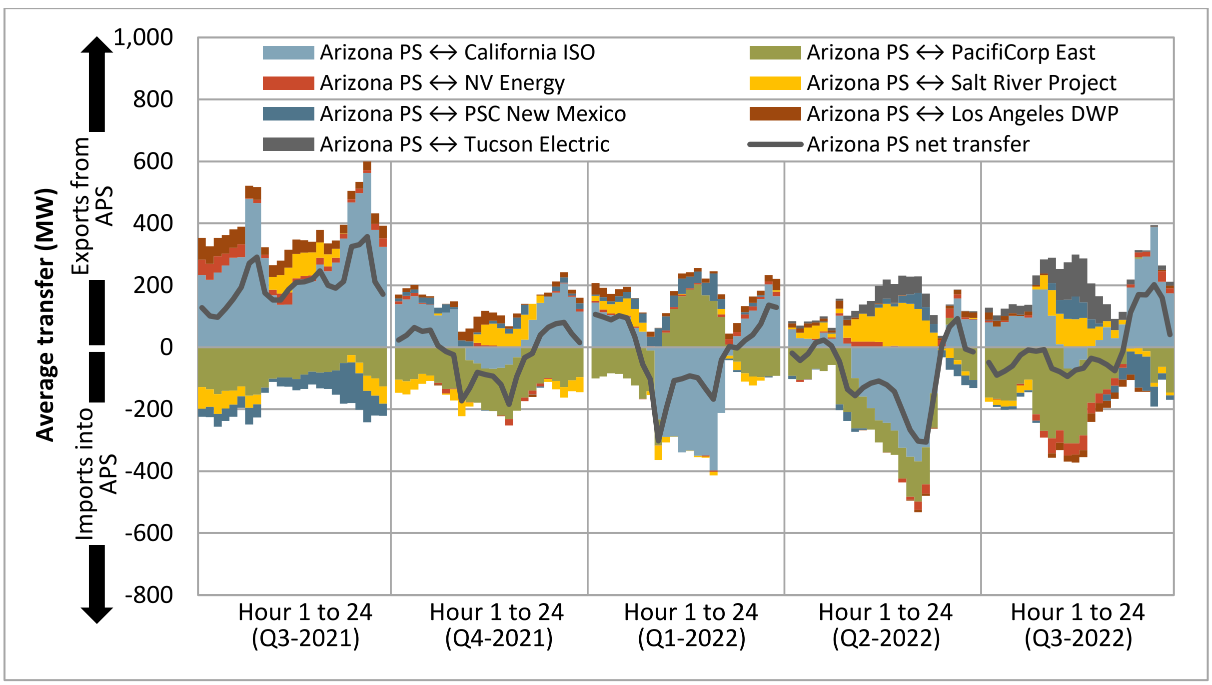

**Appendix Figure A.2 Average hourly 15-minute market transfers**



**Appendix Figure A.3 Average hourly 5-minute price by component (Q3 2022)**

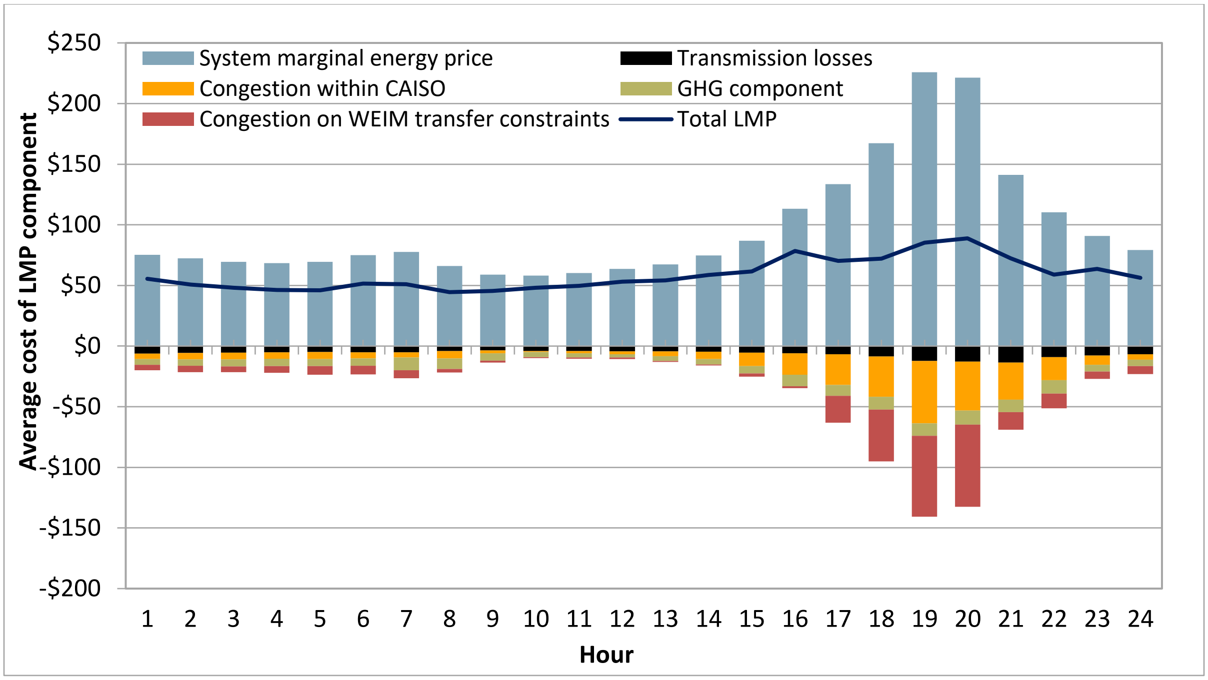



**Appendix Figure A.4 Average hourly 5-minute market transfers**

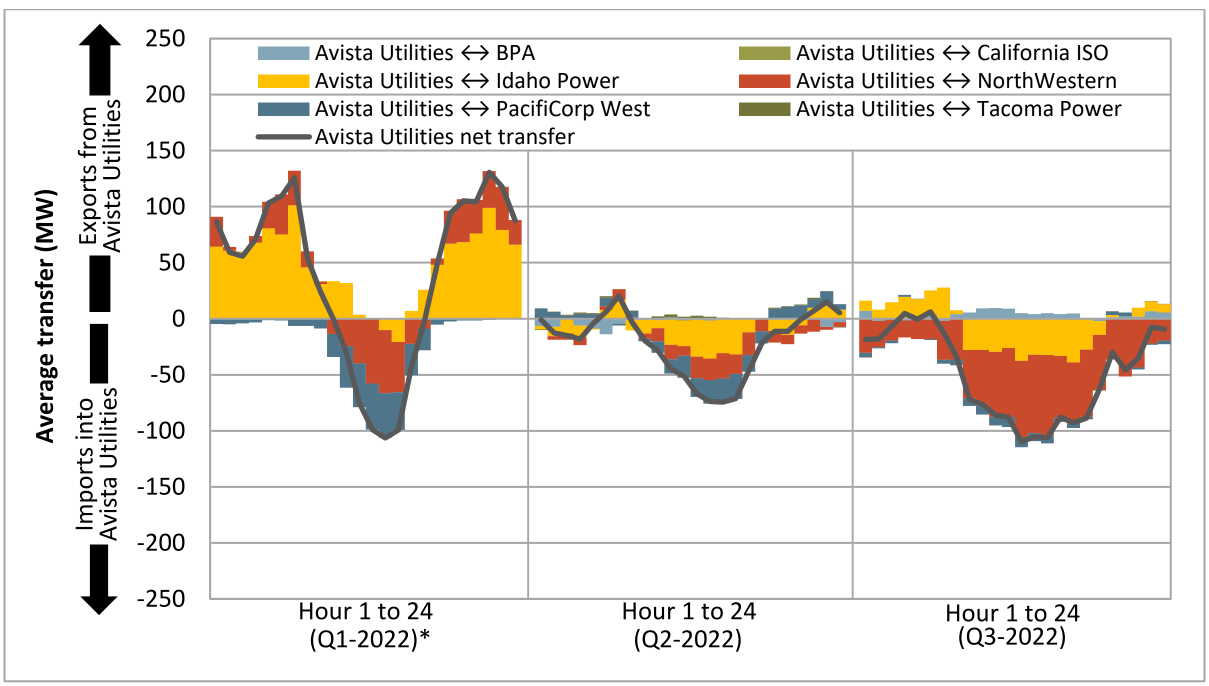


## A.2 Avista Utilities

**Appendix Figure A.5 Average hourly 15-minute price by component (Q3 2022)**

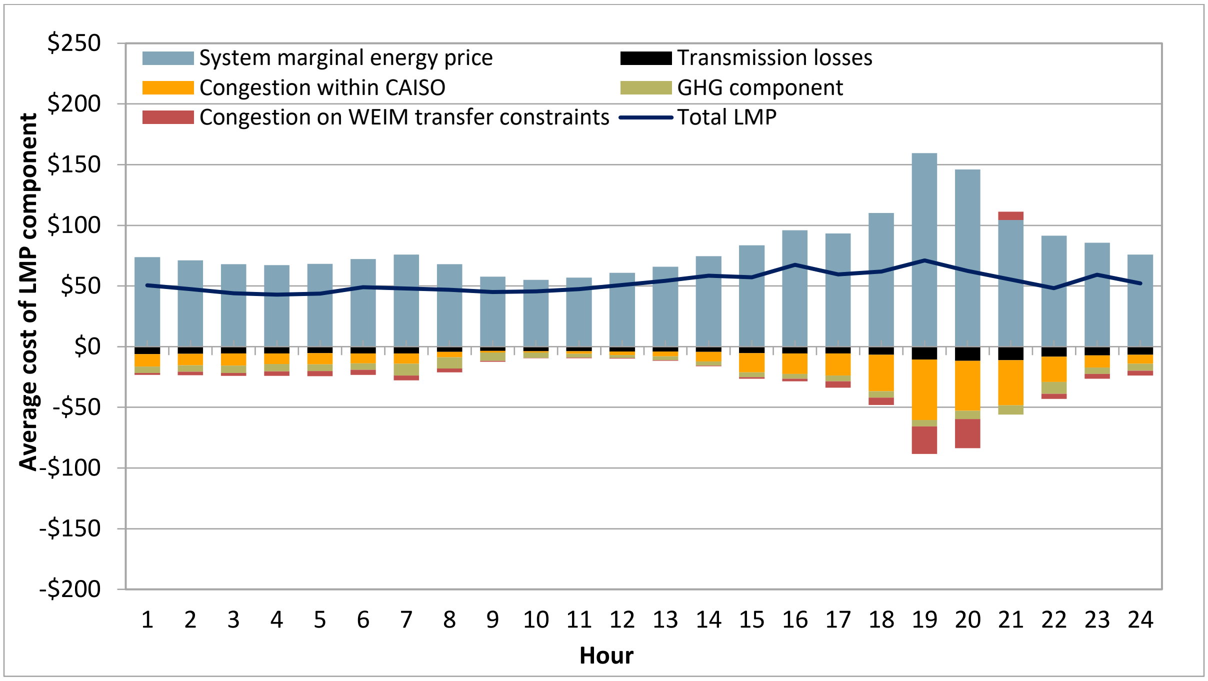



**Appendix Figure A.6 Average hourly 15-minute market transfers**

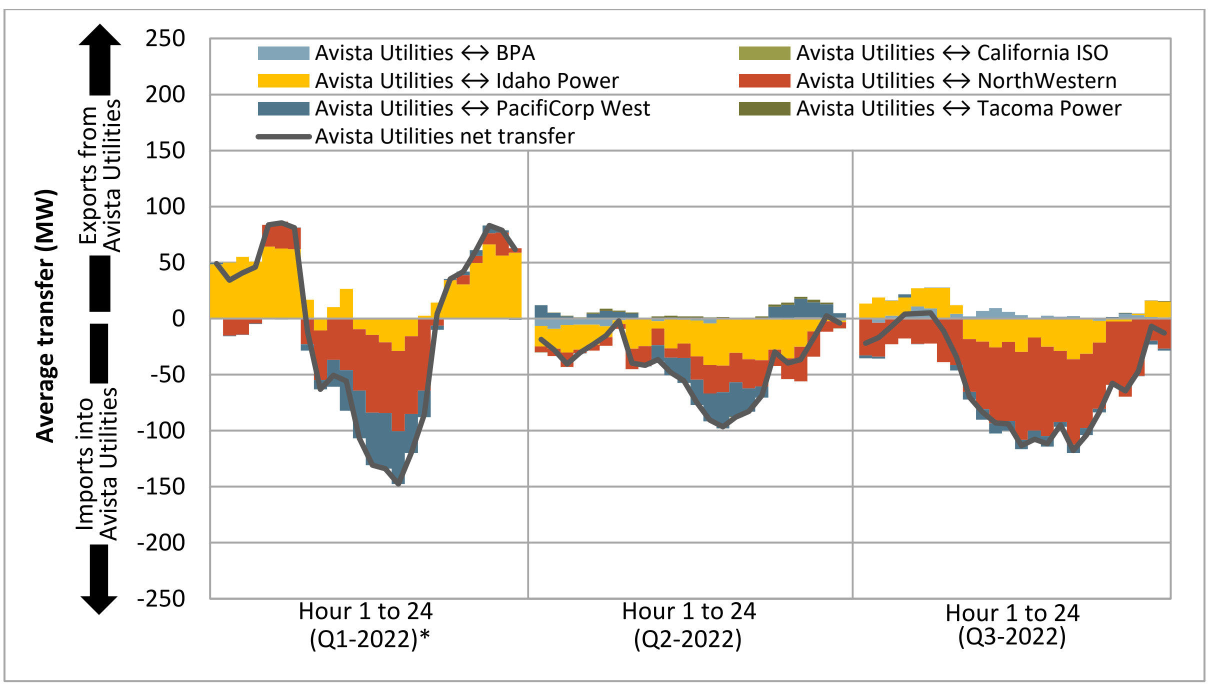



*Since joining the WEIM

**Appendix Figure A.7 Average hourly 5-minute price by component (Q3 2022)**



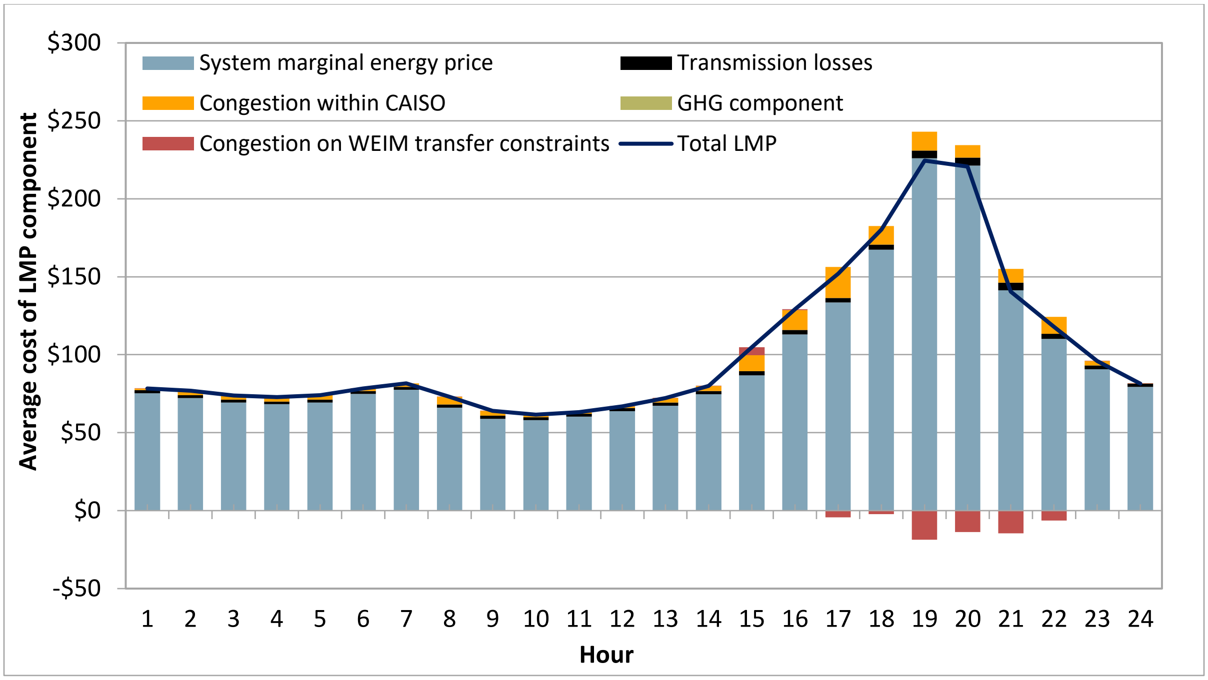

**Appendix Figure A.8 Average hourly 5-minute market transfers**



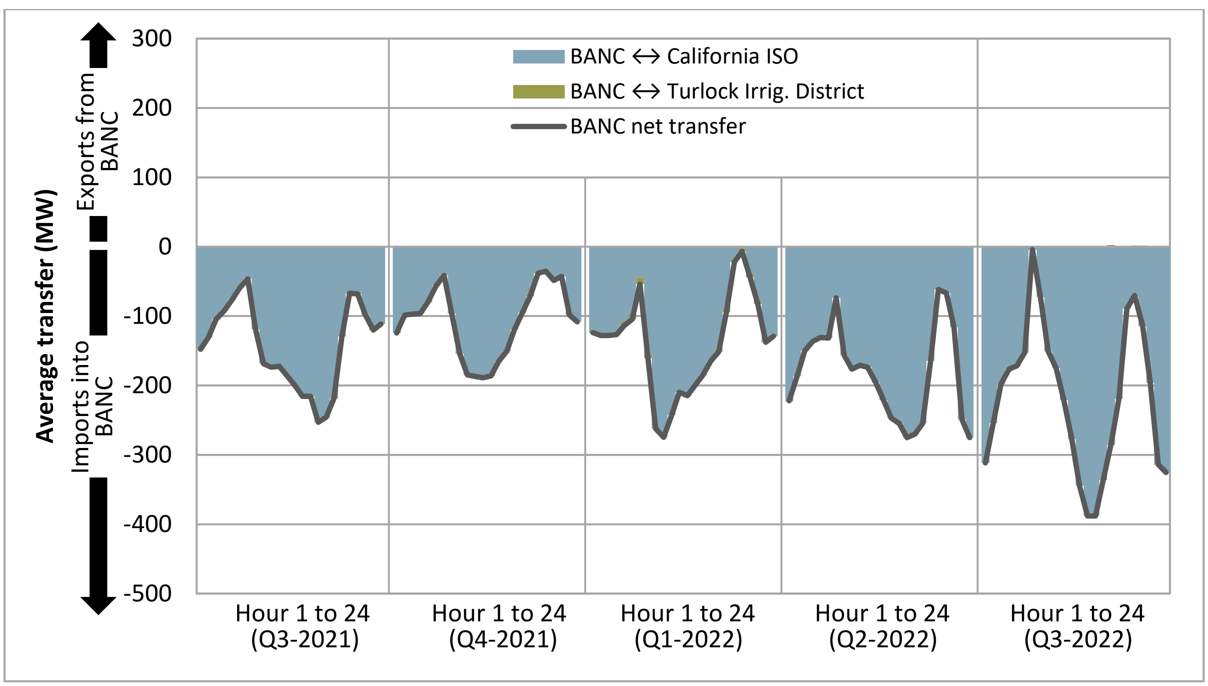

*Since joining the WEIM

## A.3 Balancing Authority of Northern California

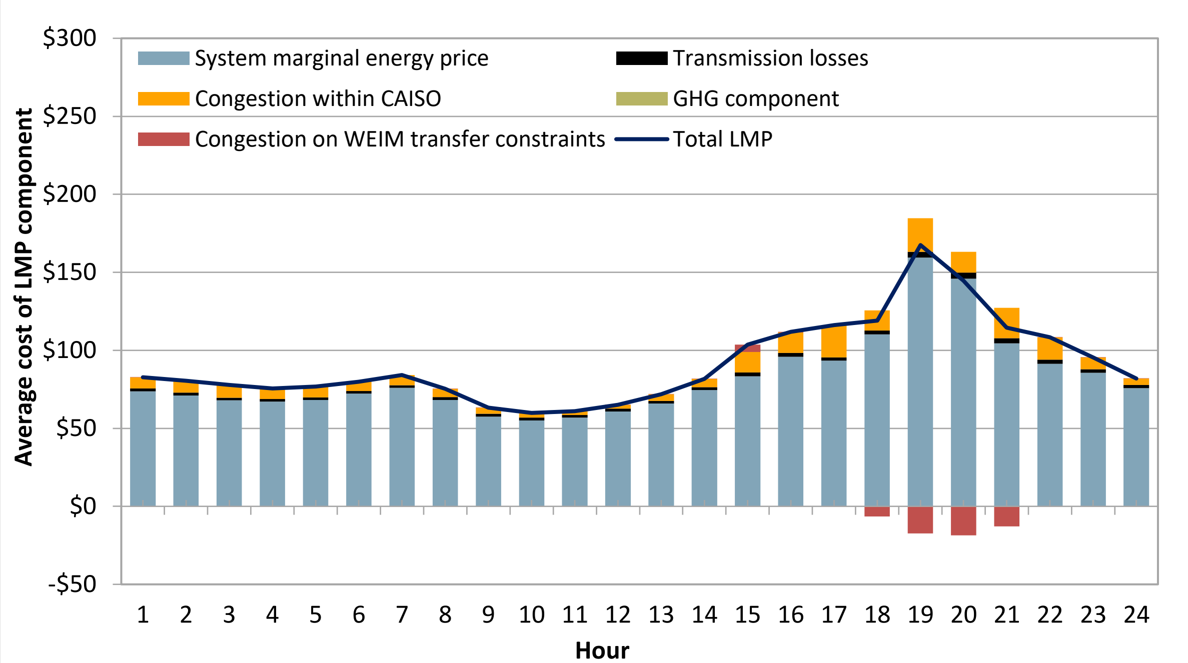
**Appendix Figure A.9 Average hourly 15-minute price by component (Q3 2022)**



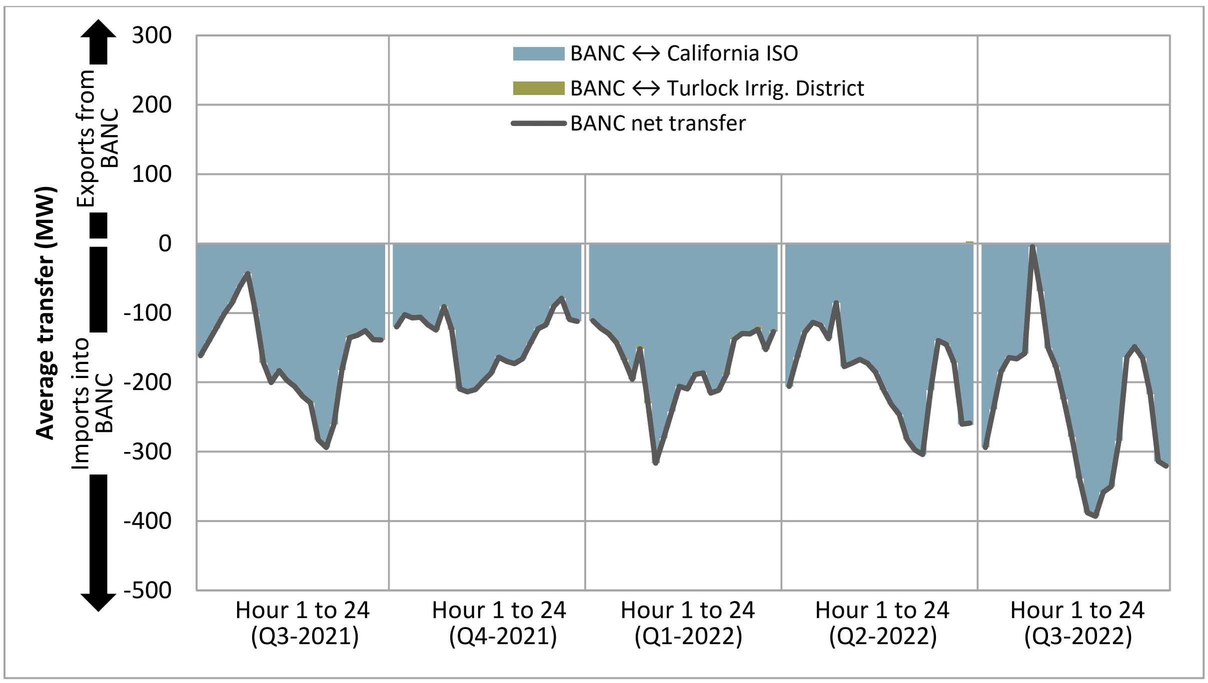

**Appendix Figure A.10 Average hourly 15-minute market transfers**



**Appendix Figure A.11 Average hourly 5-minute price by component (Q3 2022)**

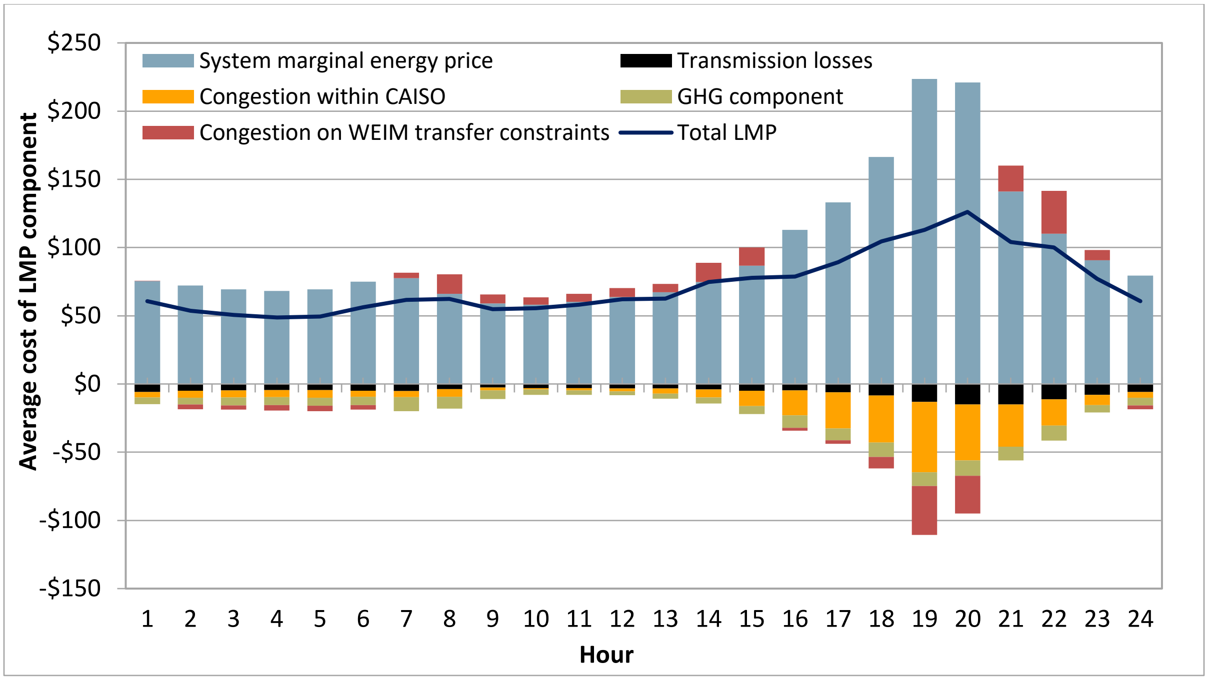



**Appendix Figure A.12 Average hourly 5-minute market transfers**

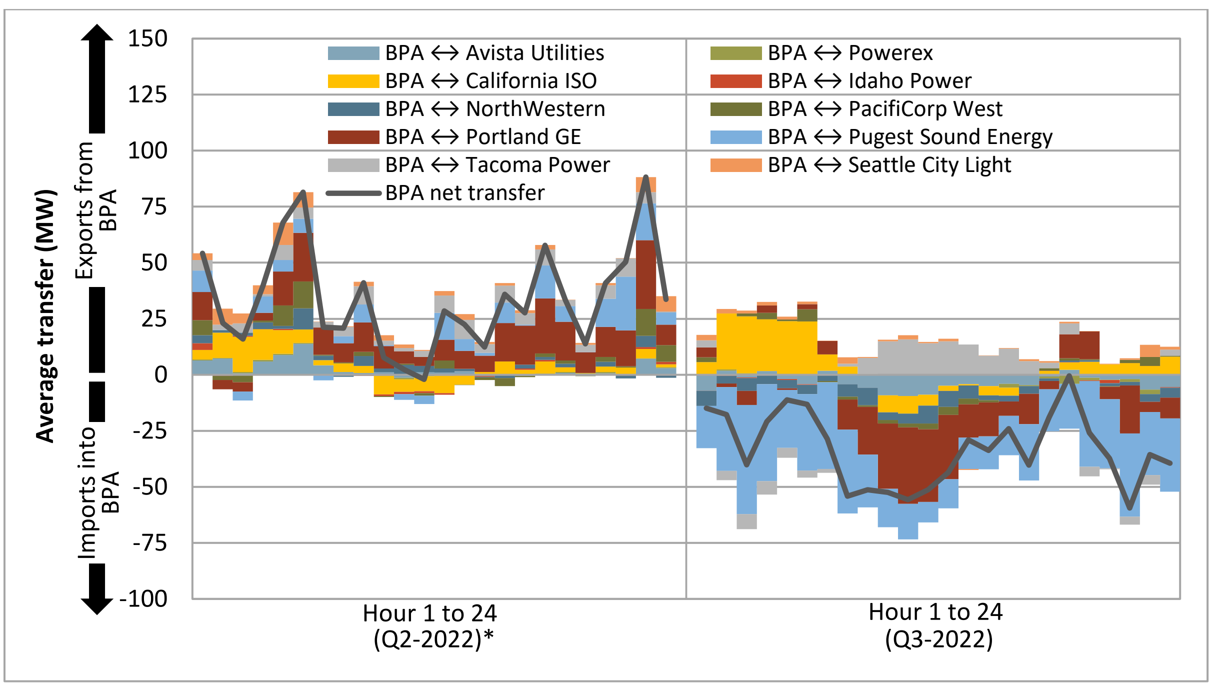


## A.4 Bonneville Power Administration

**Appendix Figure A.13 Average hourly 15-minute price by component (Q3 2022)**

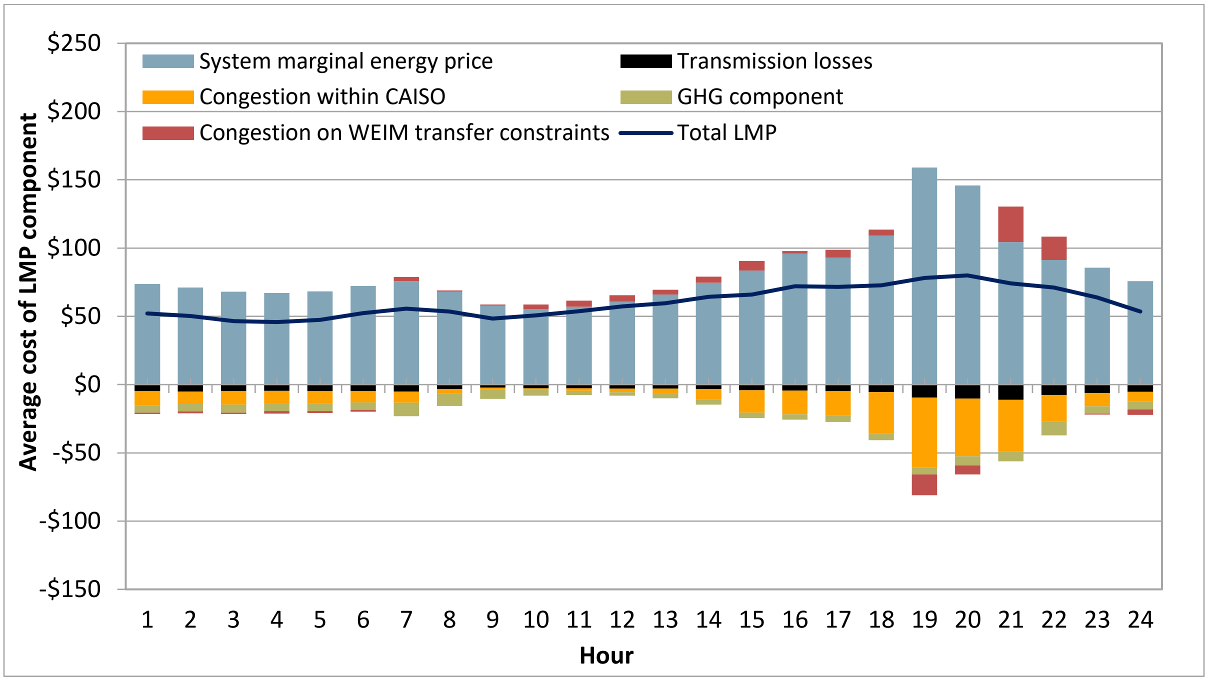



**Appendix Figure A.14 Average hourly 15-minute market transfers**

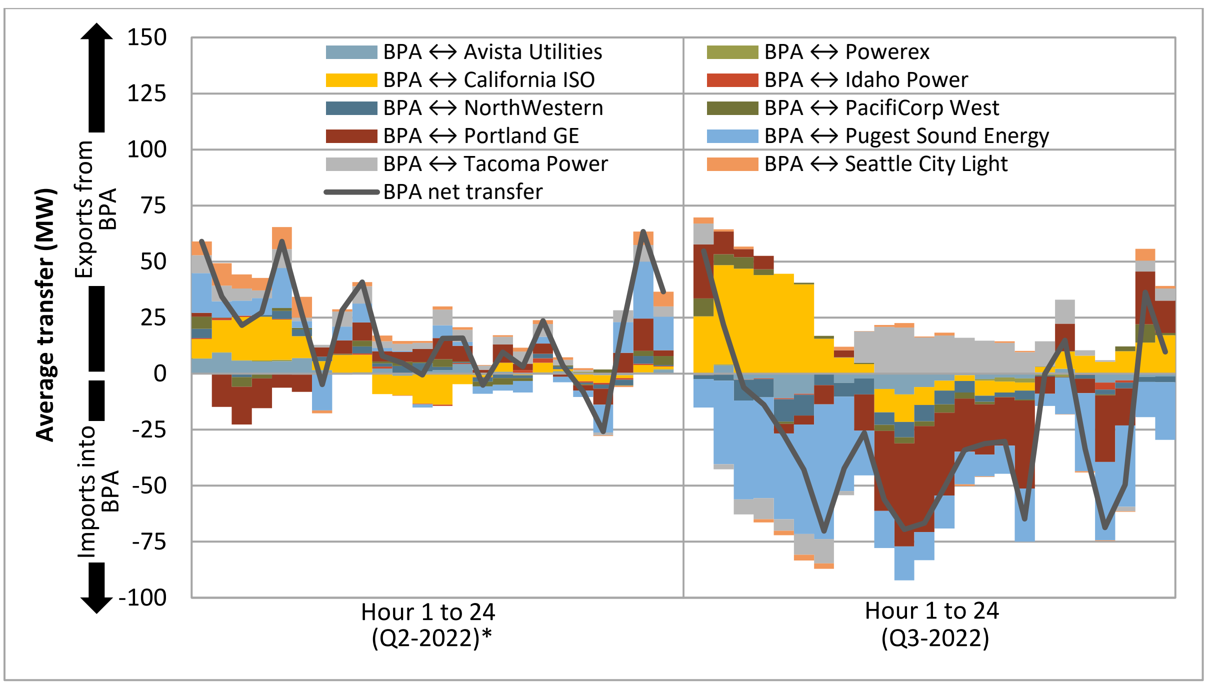



*Since joining the WEIM

**Appendix Figure A.15 Average hourly 5-minute price by component (Q3 2022)**



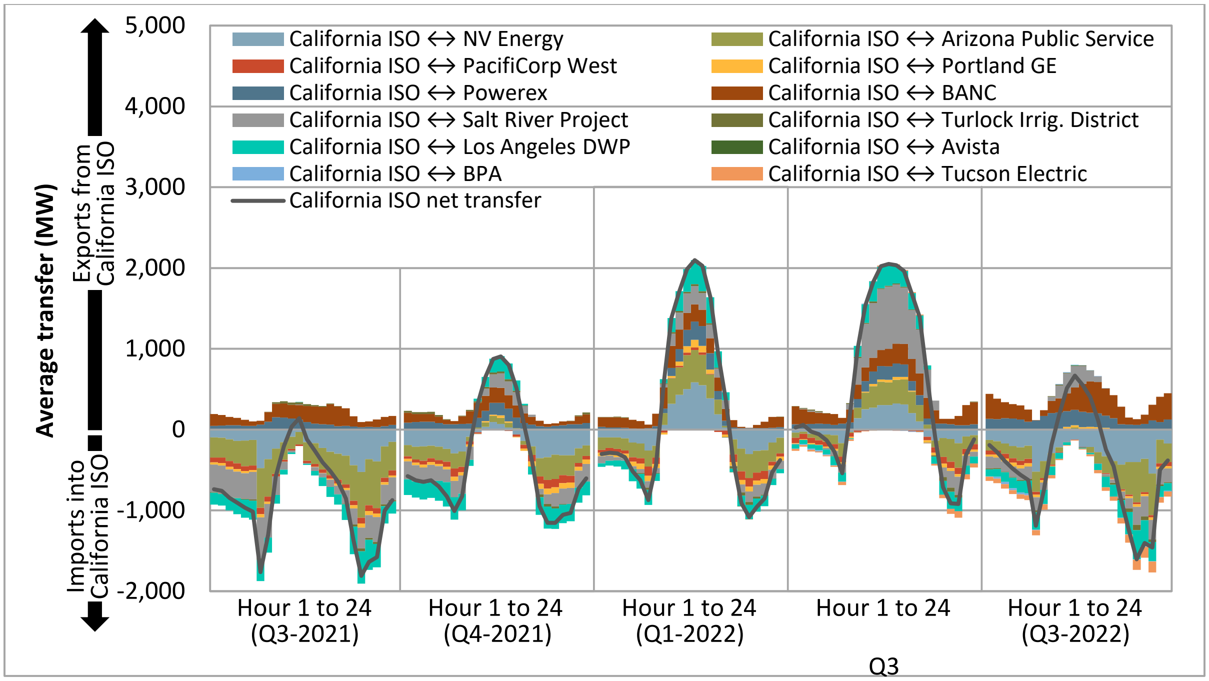

**Appendix Figure A.16 Average hourly 5-minute market transfers**



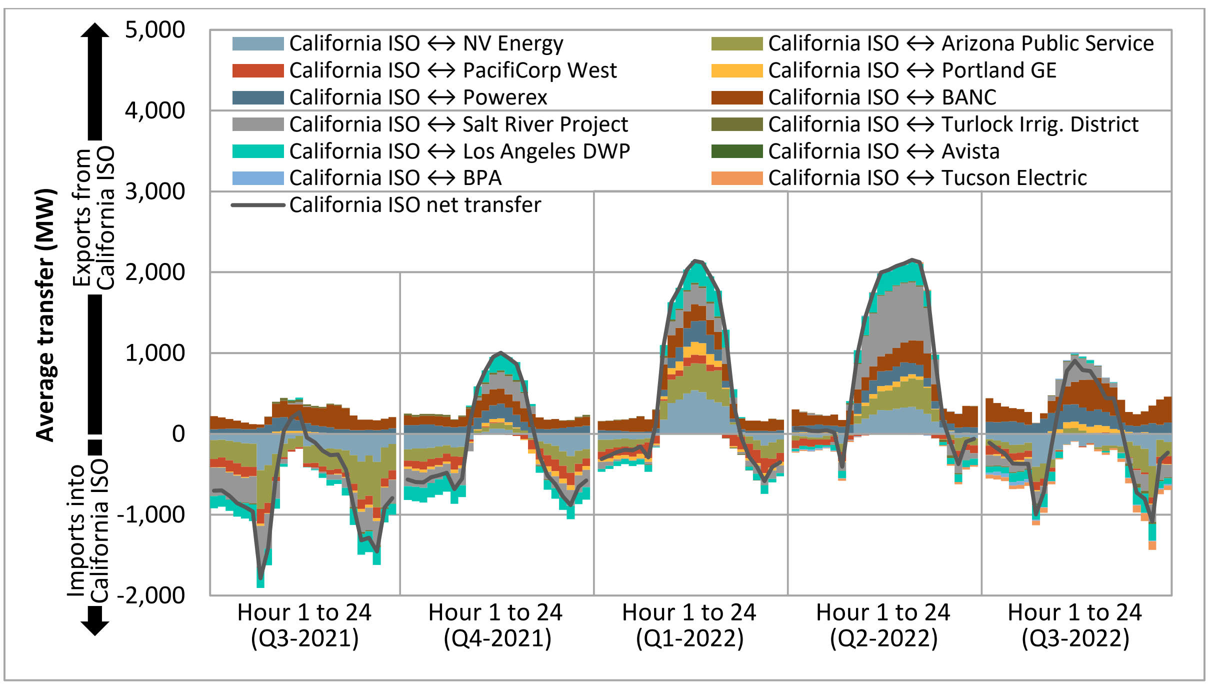

*Since joining the WEIM

## A.5 California ISO

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

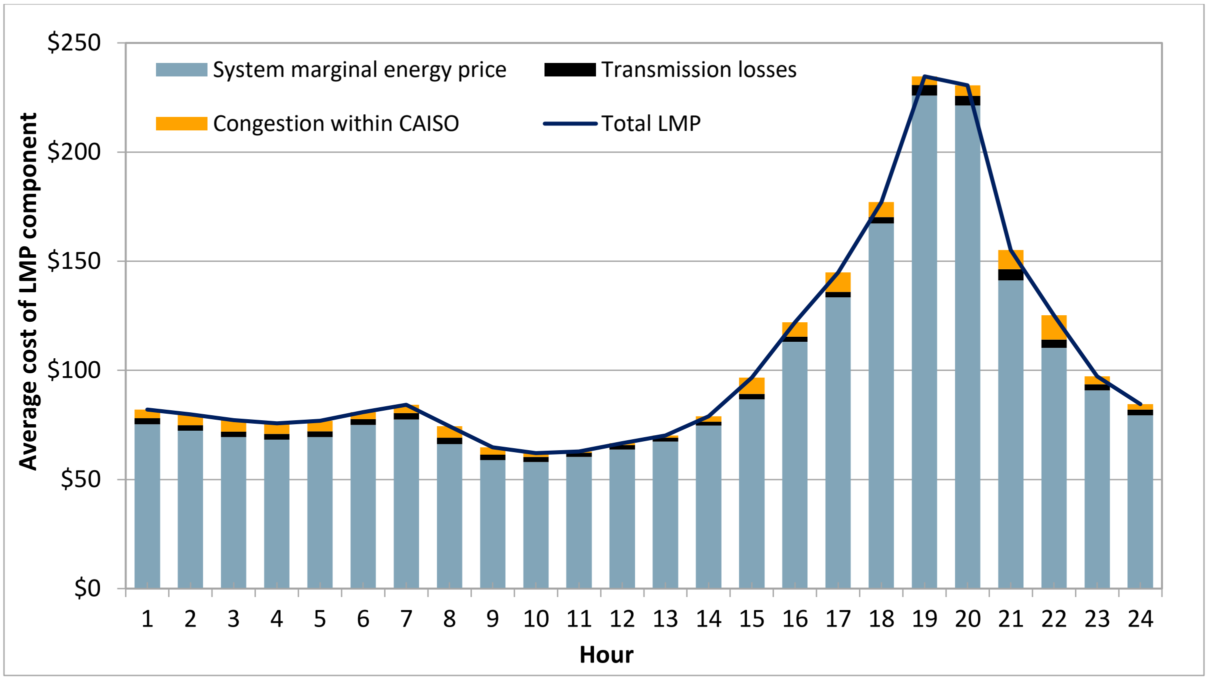



**Appendix Figure A.18 Average hourly 5-minute market transfers**

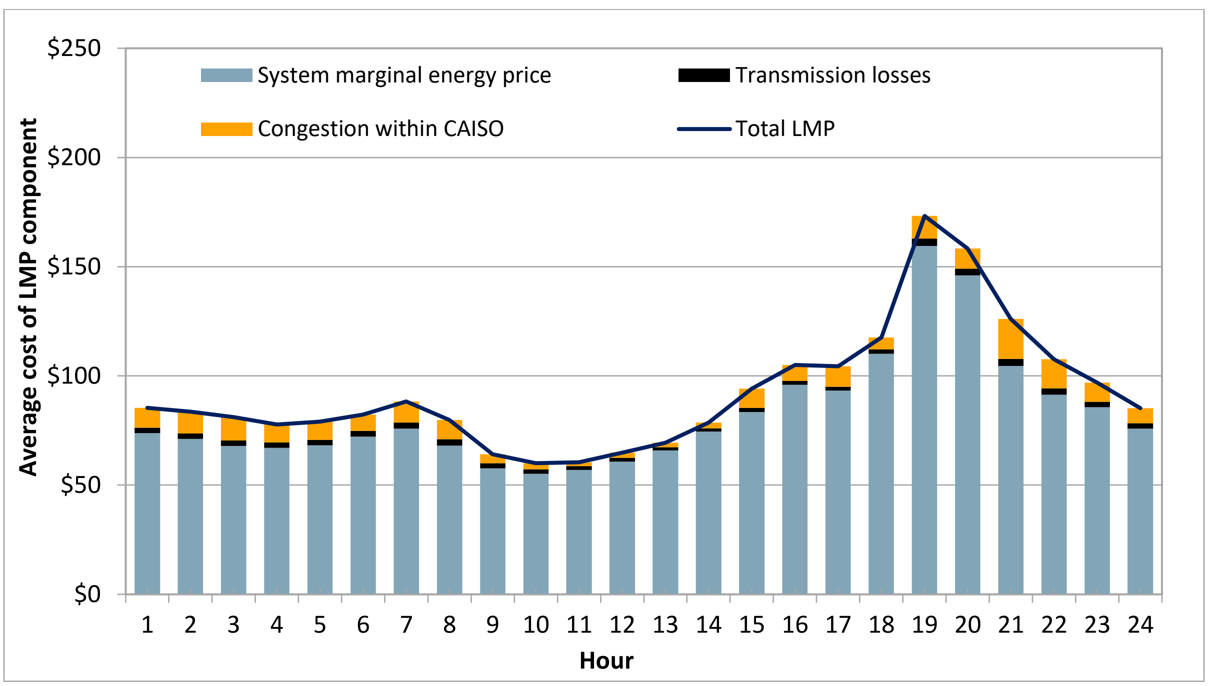


### A.5.1 Pacific Gas and Electric

**Appendix Figure A.19 Average hourly 15-minute price by component (Q3 2022)**

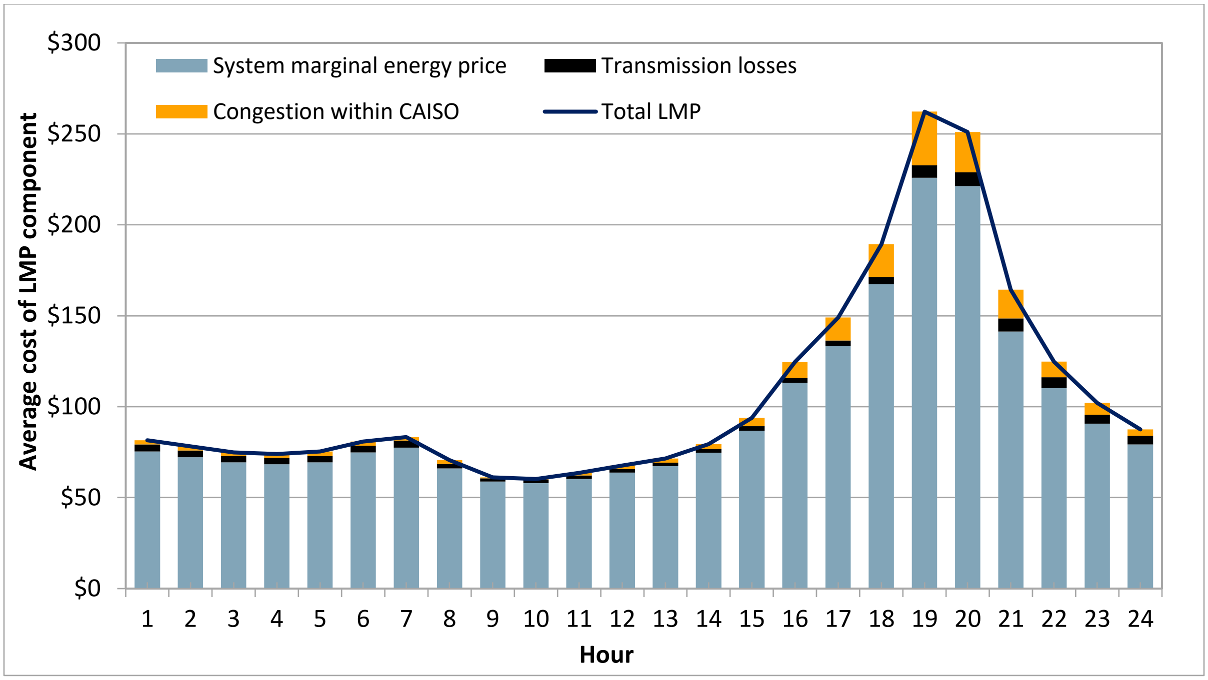



**Appendix Figure A.20 Average hourly 5-minute price by component (Q3 2022)**

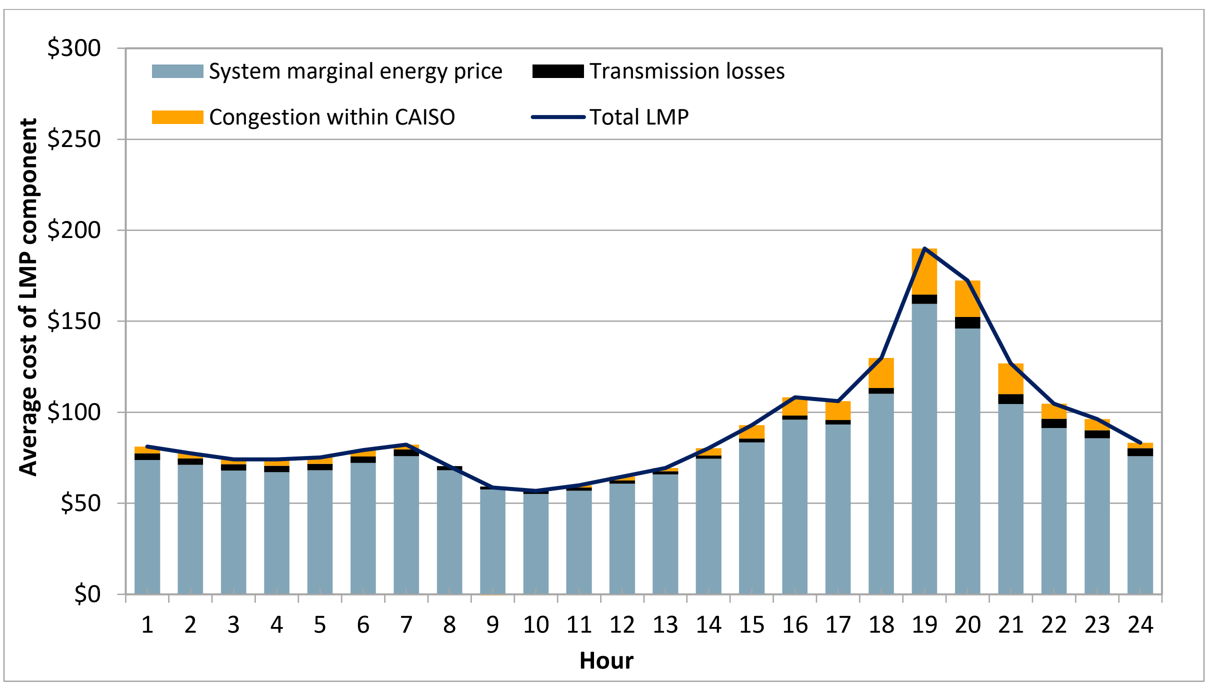


## A.5.2 Southern California Edison

**Appendix Figure A.21 Average hourly 15-minute price by component (Q3 2022)**

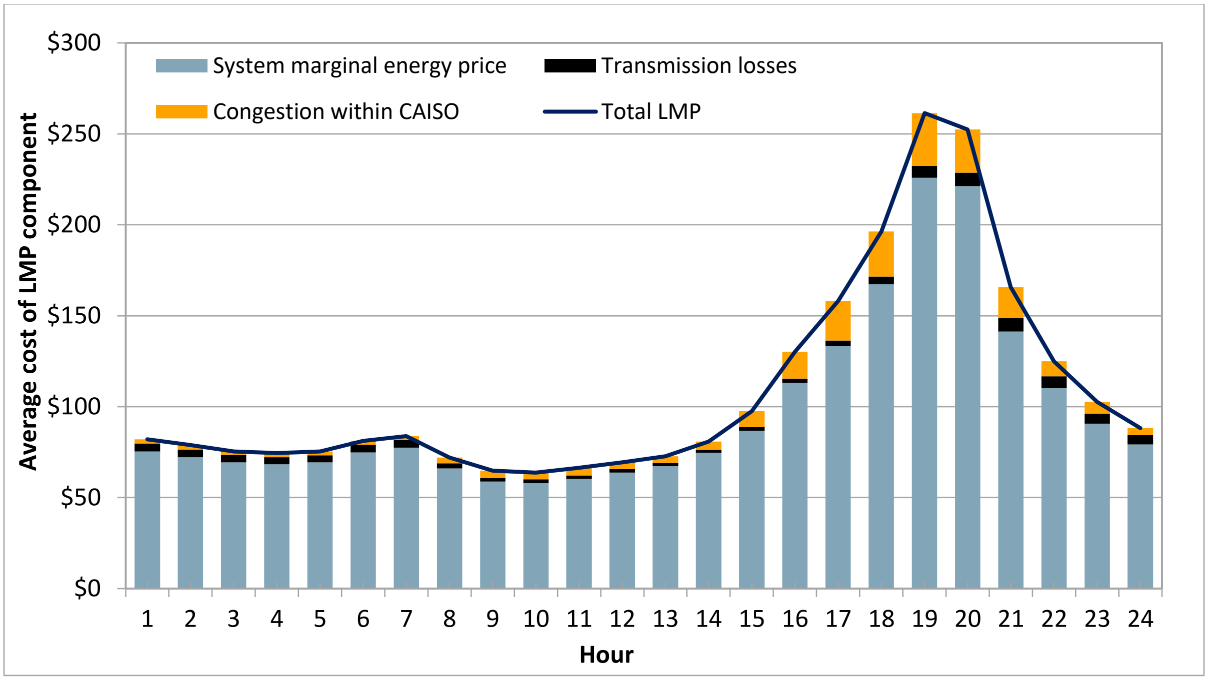



**Appendix Figure A.22 Average hourly 5-minute price by component (Q3 2022)**

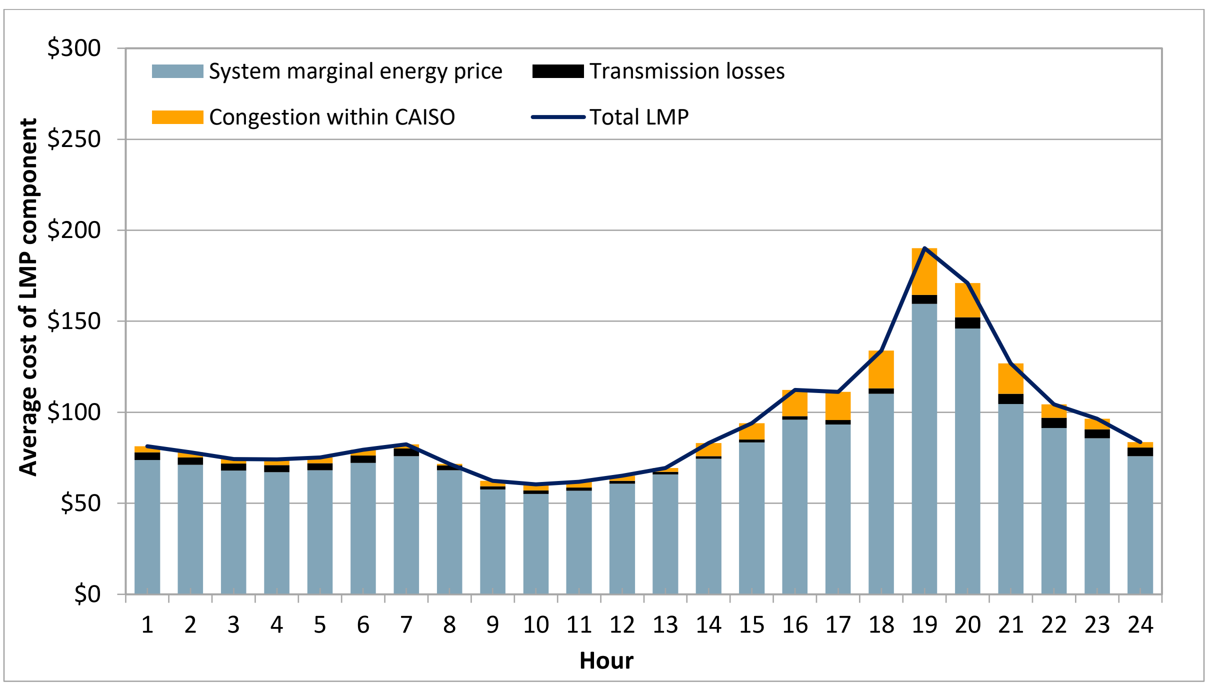


## A.5.3 San Diego Gas & Electric

**Appendix Figure A.23 Average hourly 15-minute price by component (Q3 2022)**

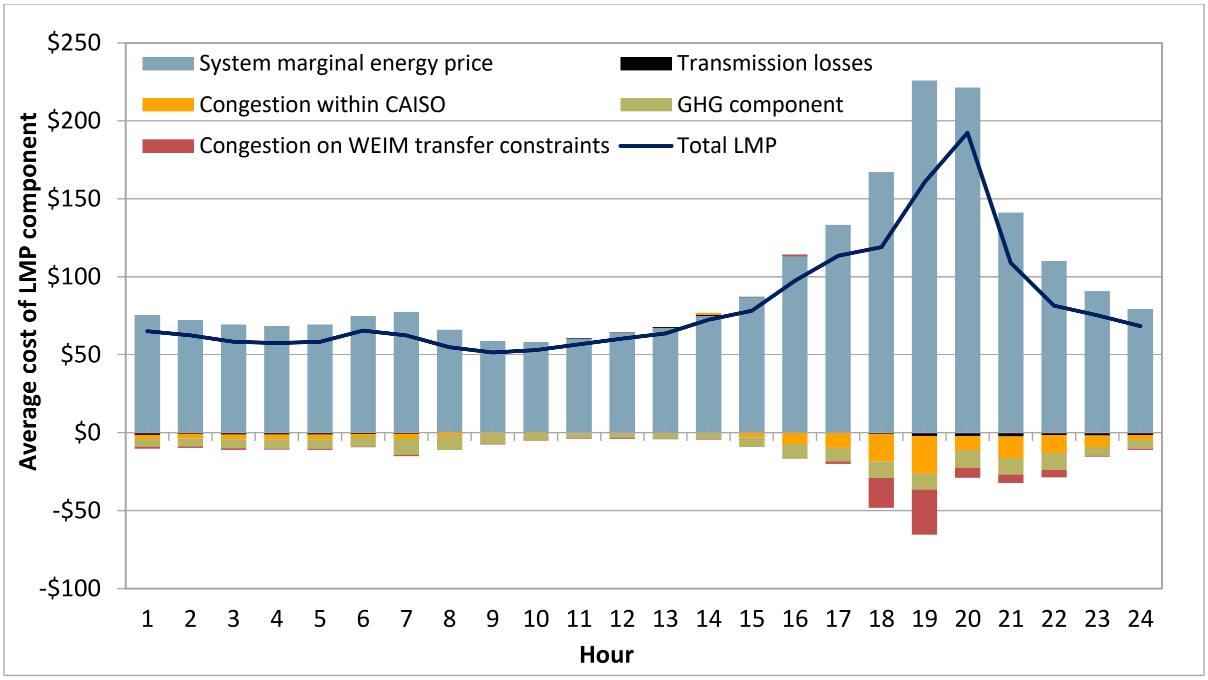



**Appendix Figure A.24 Average hourly 5-minute price by component (Q3 2022)**

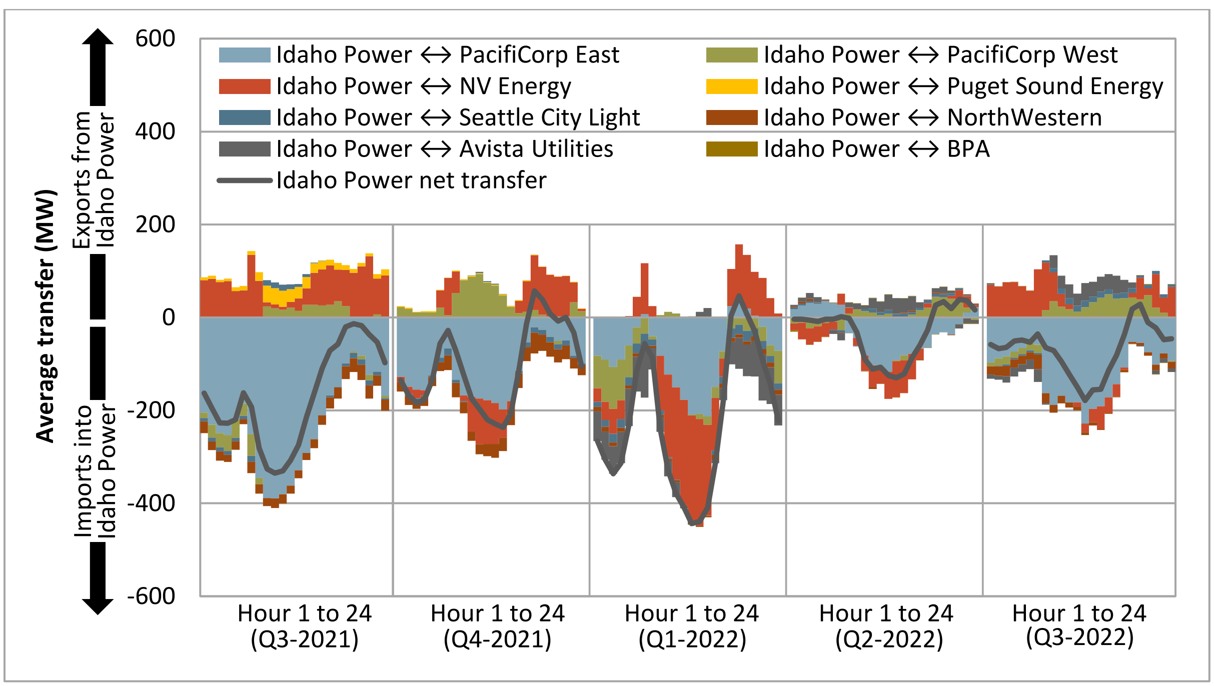


## A.6 Idaho Power

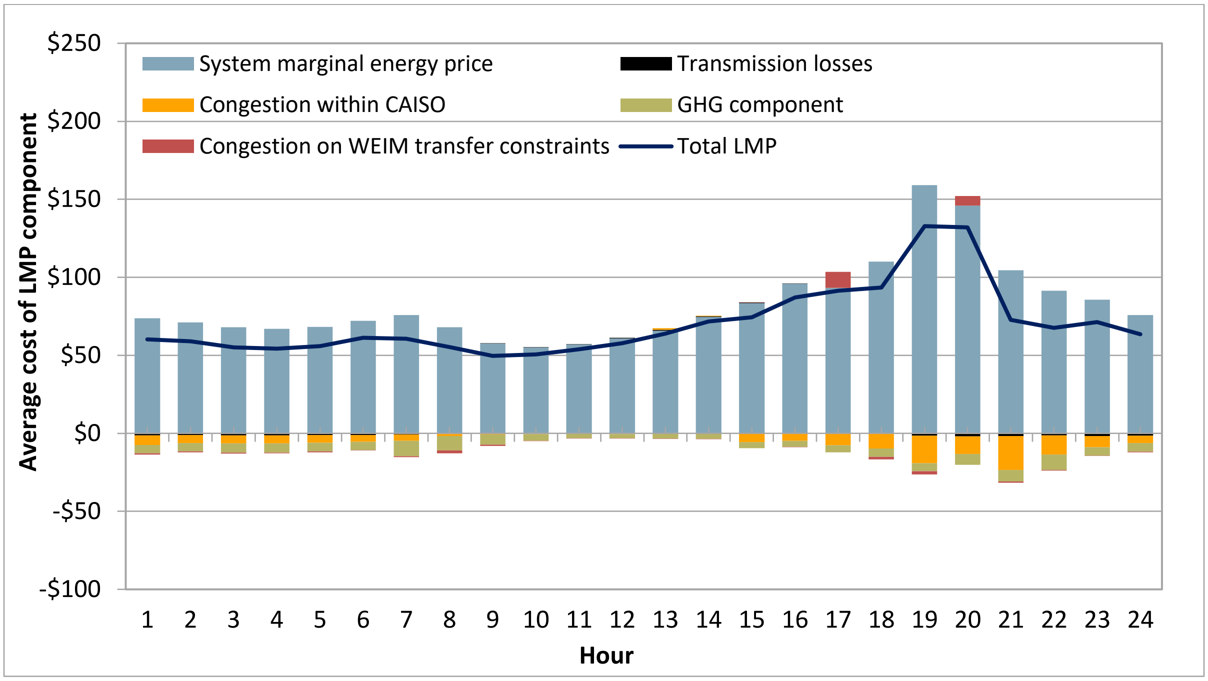
**Appendix Figure A.25 Average hourly 15-minute price by component (Q3 2022)**



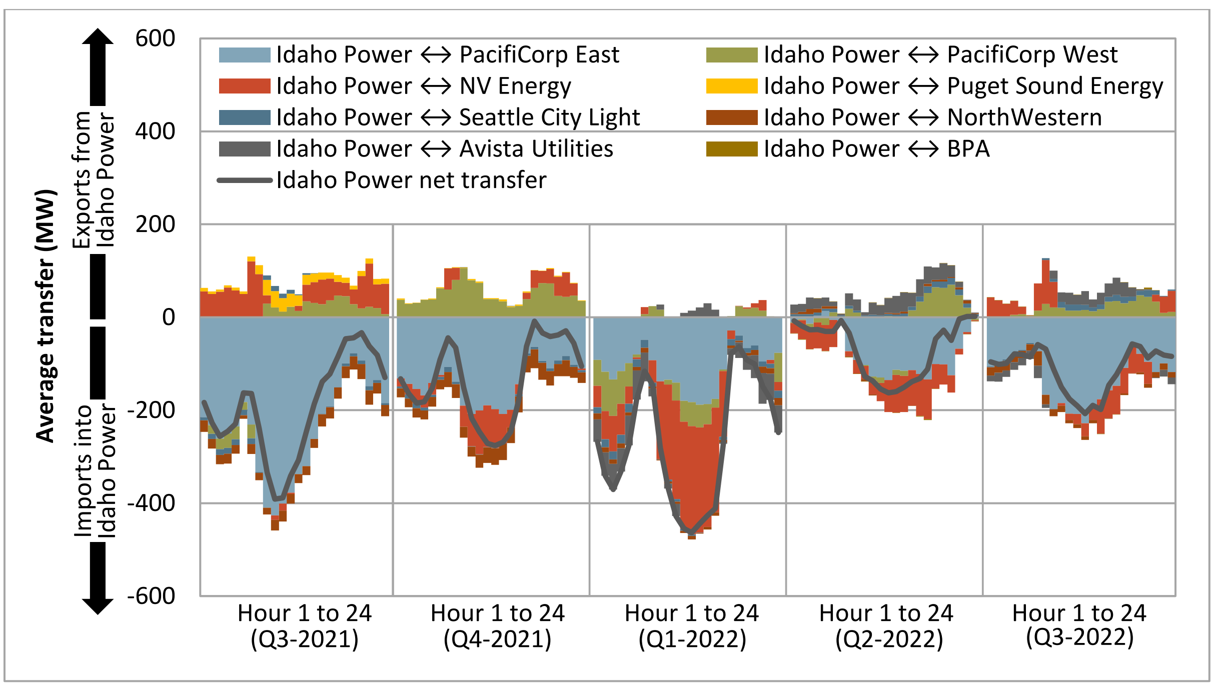

**Appendix Figure A.26 Average hourly 15-minute market transfers**



**Appendix Figure A.27 Average hourly 5-minute price by component (Q3 2022)**

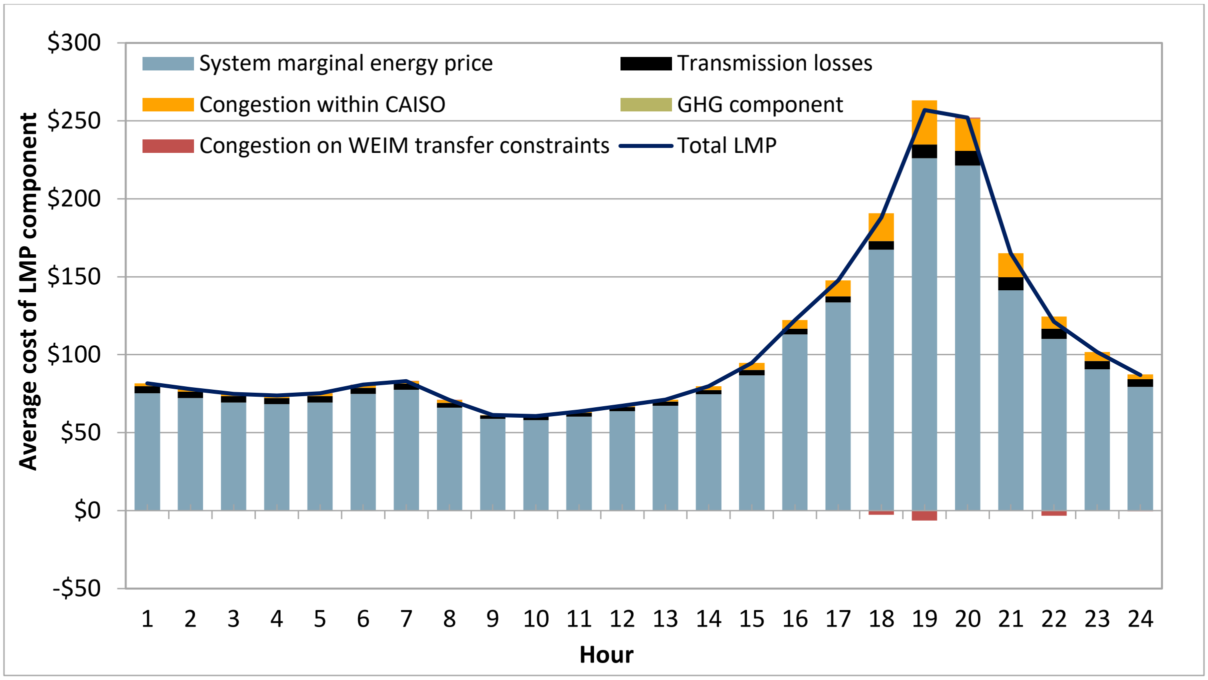



**Appendix Figure A.28 Average hourly 5-minute market transfers**

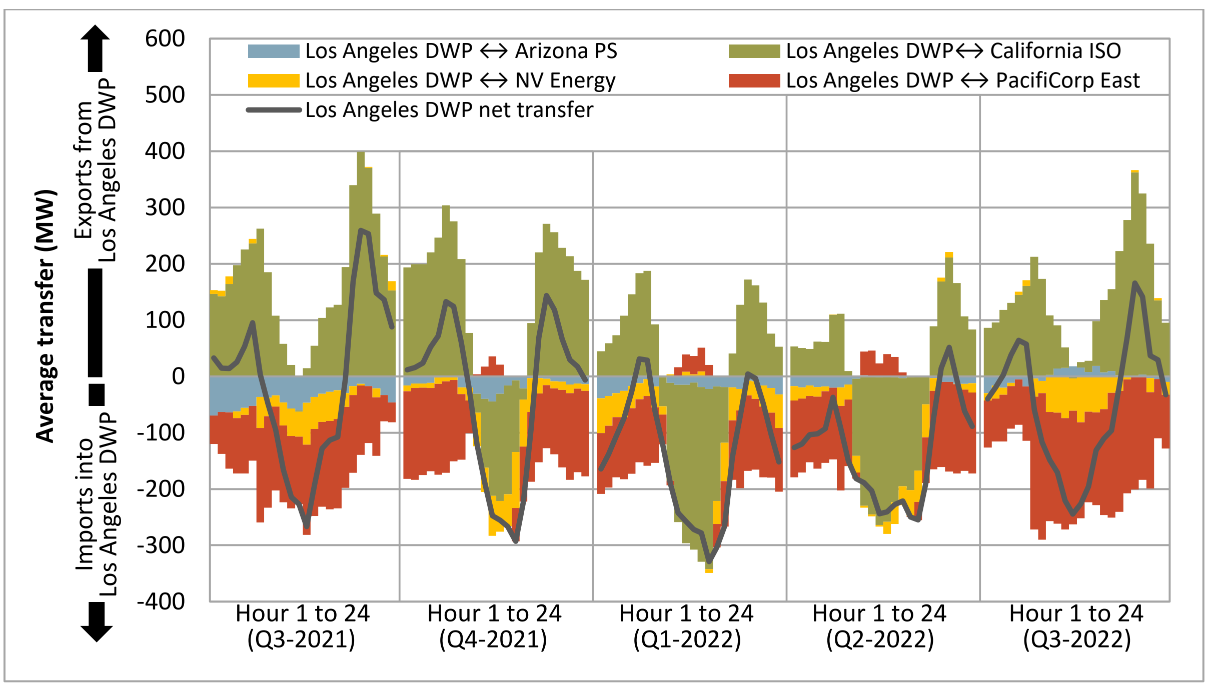


## A.7 Los Angeles Department of Water and Power

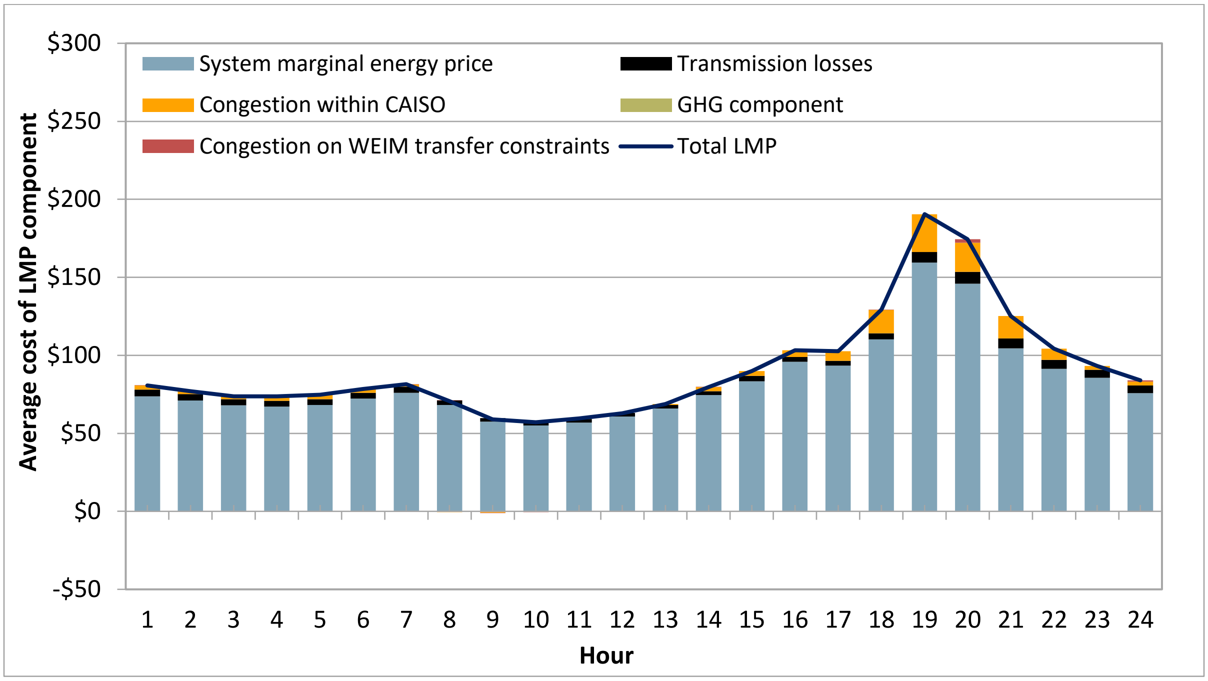
**Appendix Figure A.29 Average hourly 15-minute price by component (Q3 2022)**



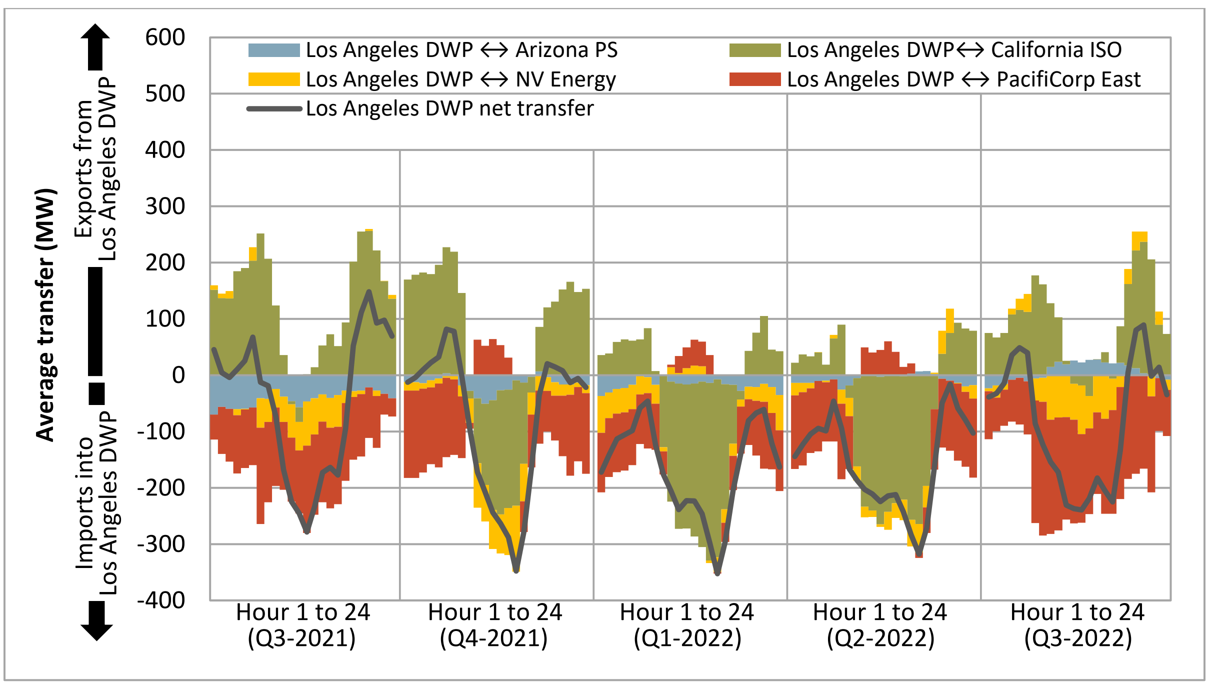

**Appendix Figure A.30 Average hourly 15-minute market transfers**



**Appendix Figure A.31 Average hourly 5-minute price by component (Q3 2022)**

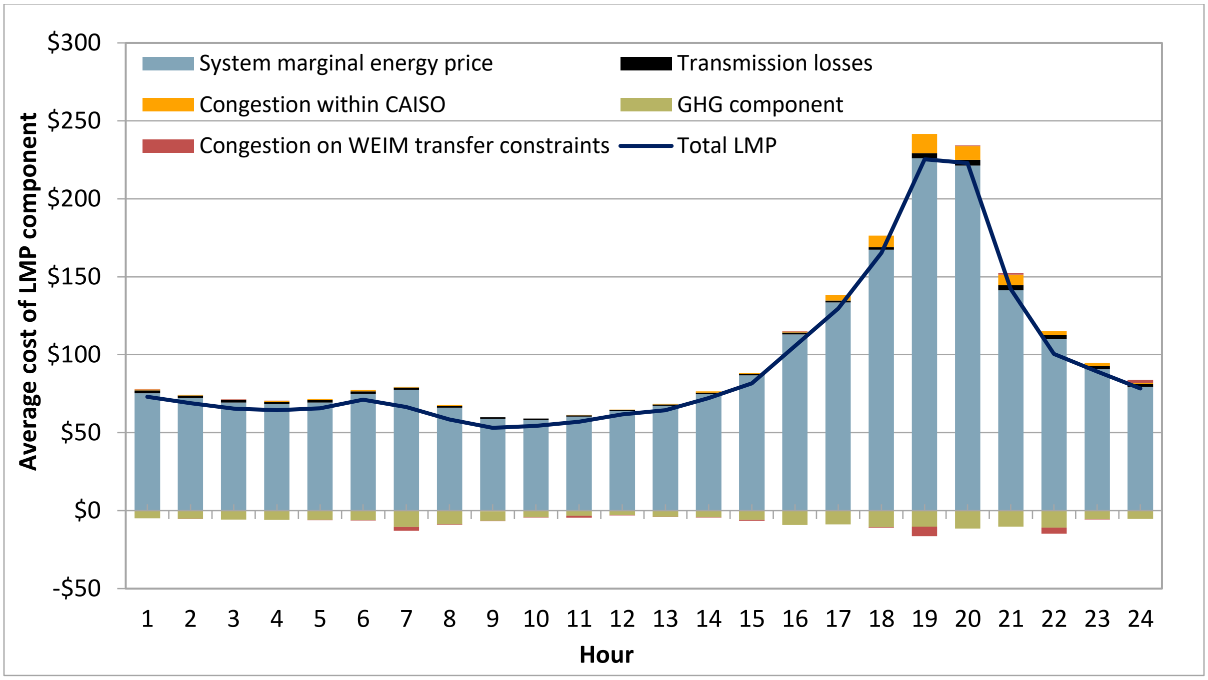



**Appendix Figure A.32 Average hourly 5-minute market transfers**

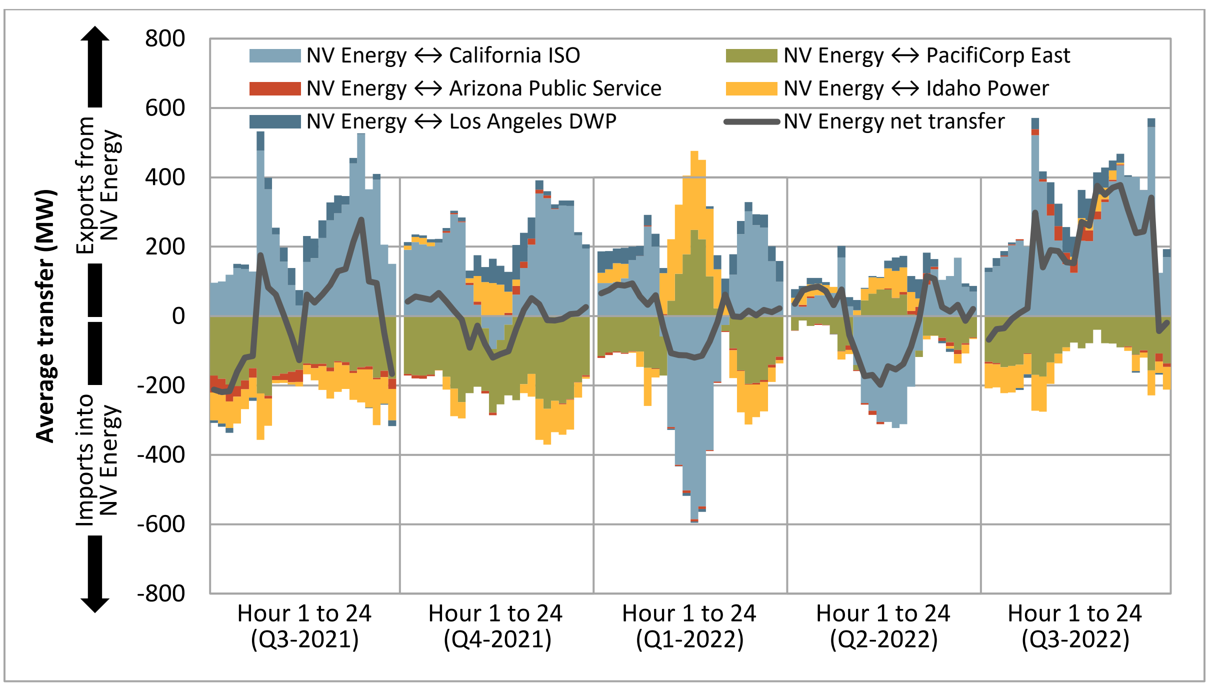


## A.8 Nevada Energy

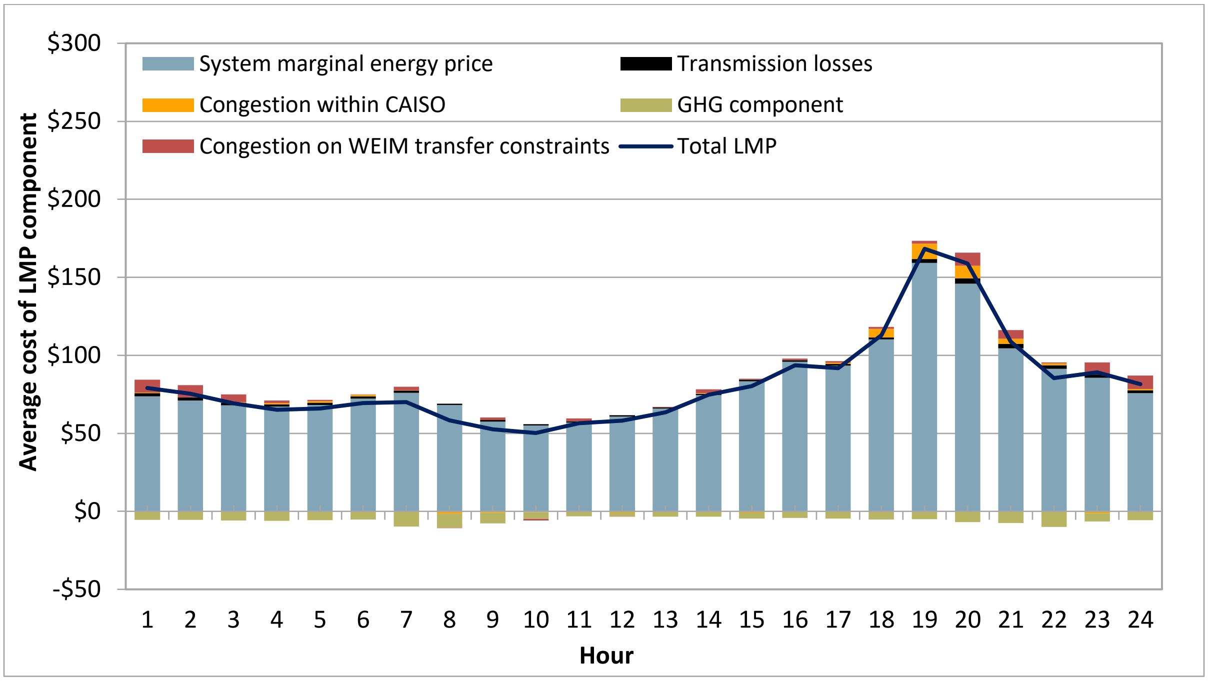
**Appendix Figure A.33 Average hourly 15-minute price by component (Q3 2022)**



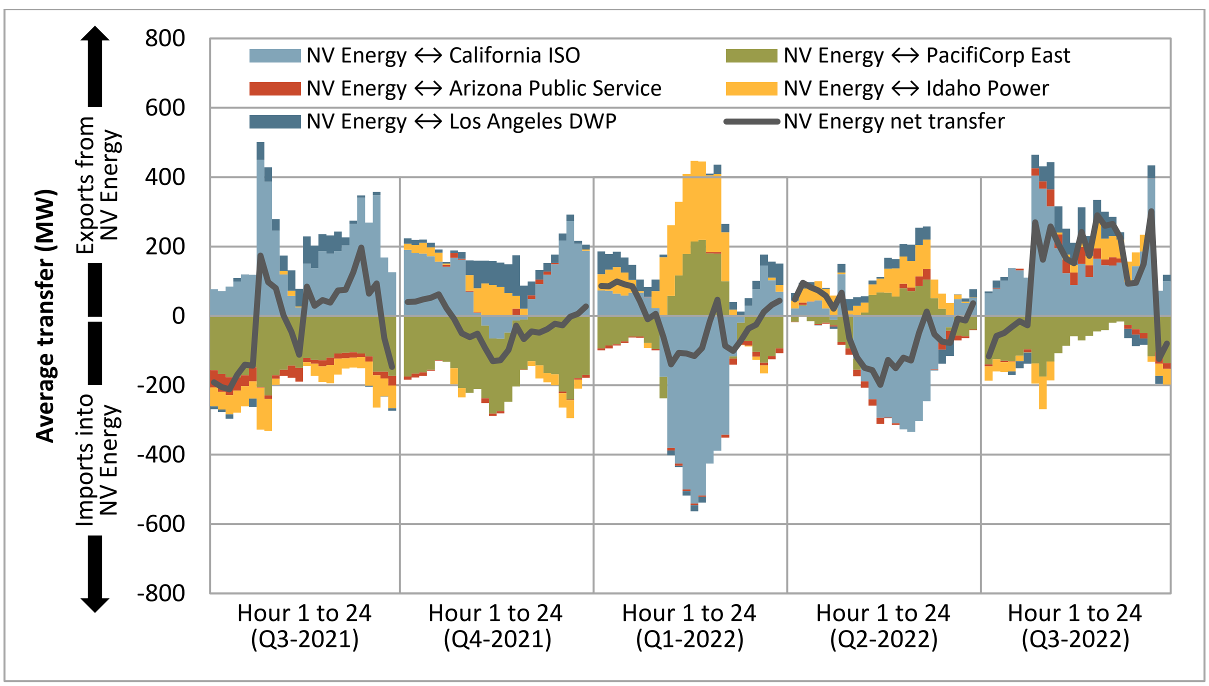

**Appendix Figure A.34 Average hourly 15-minute market transfers**



**Appendix Figure A.35 Average hourly 5-minute price by component (Q3 2022)**

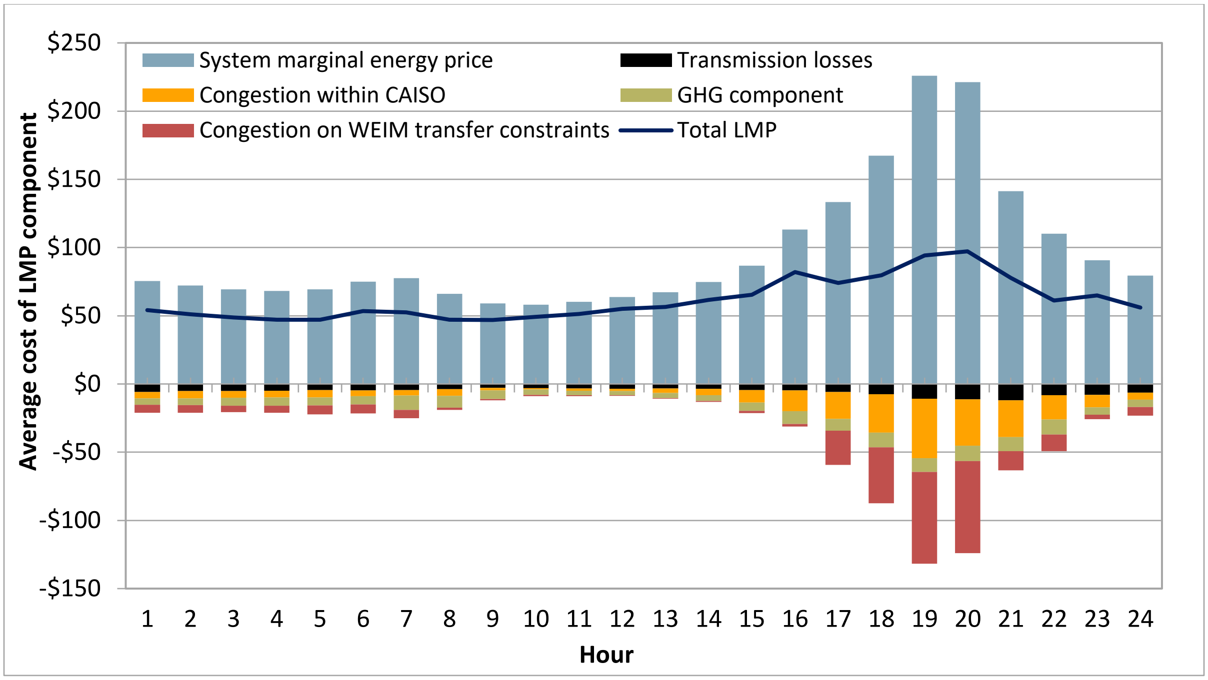



**Appendix Figure A.36 Average hourly 5-minute market transfers**

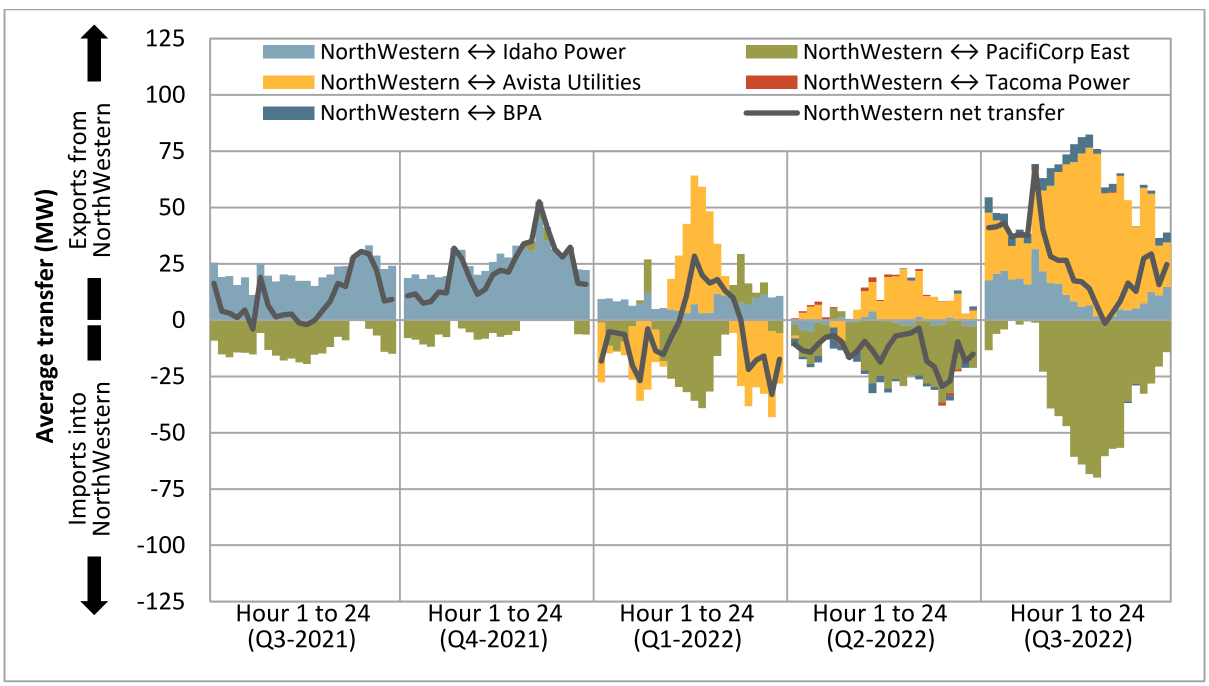


## A.9 NorthWestern Energy

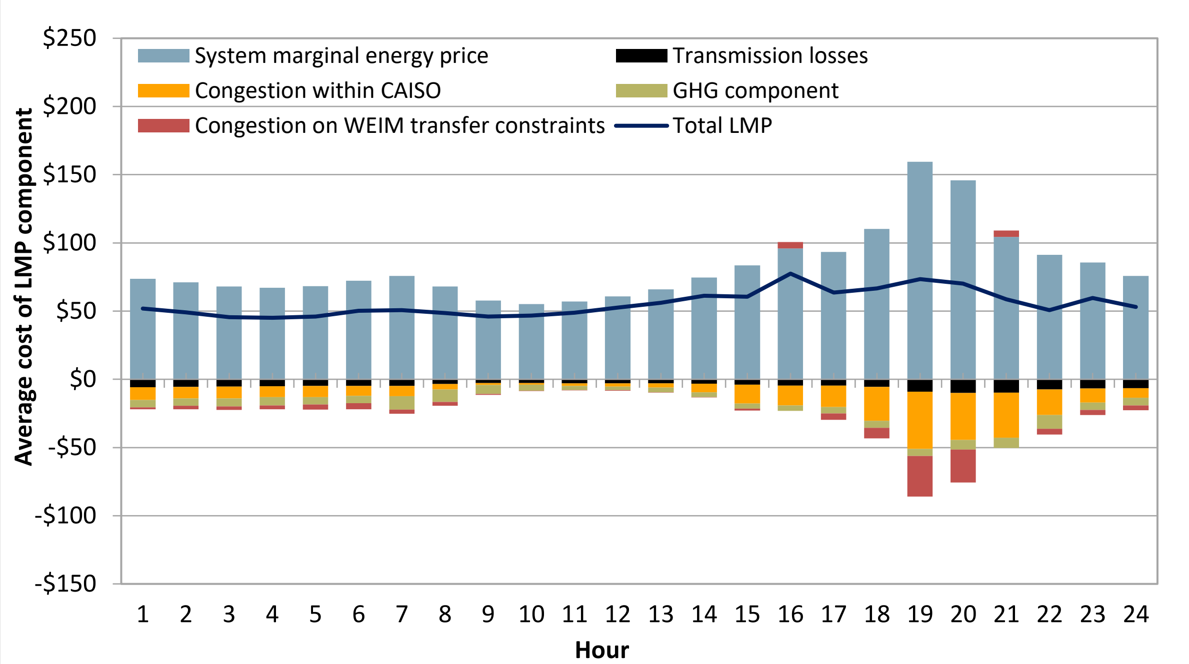
**Appendix Figure A.37 Average hourly 15-minute price by component (Q3 2022)**



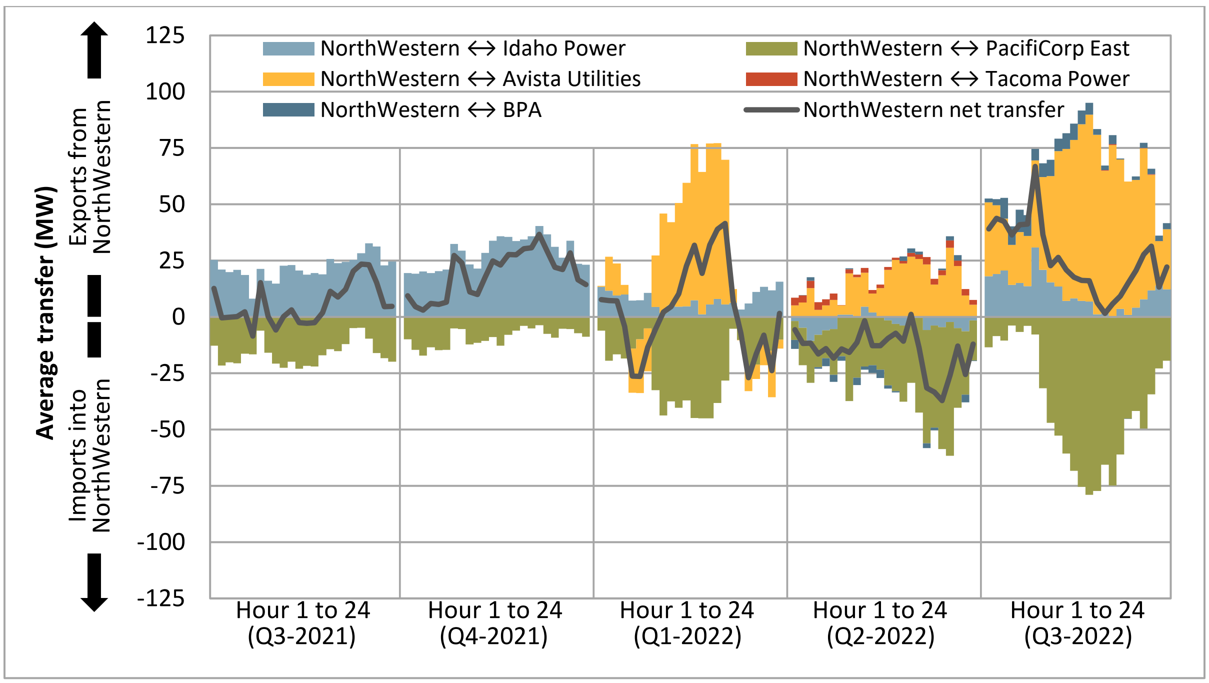

**Appendix Figure A.38 Average hourly 15-minute market transfers**



**Appendix Figure A.39 Average hourly 5-minute price by component (Q3 2022)**

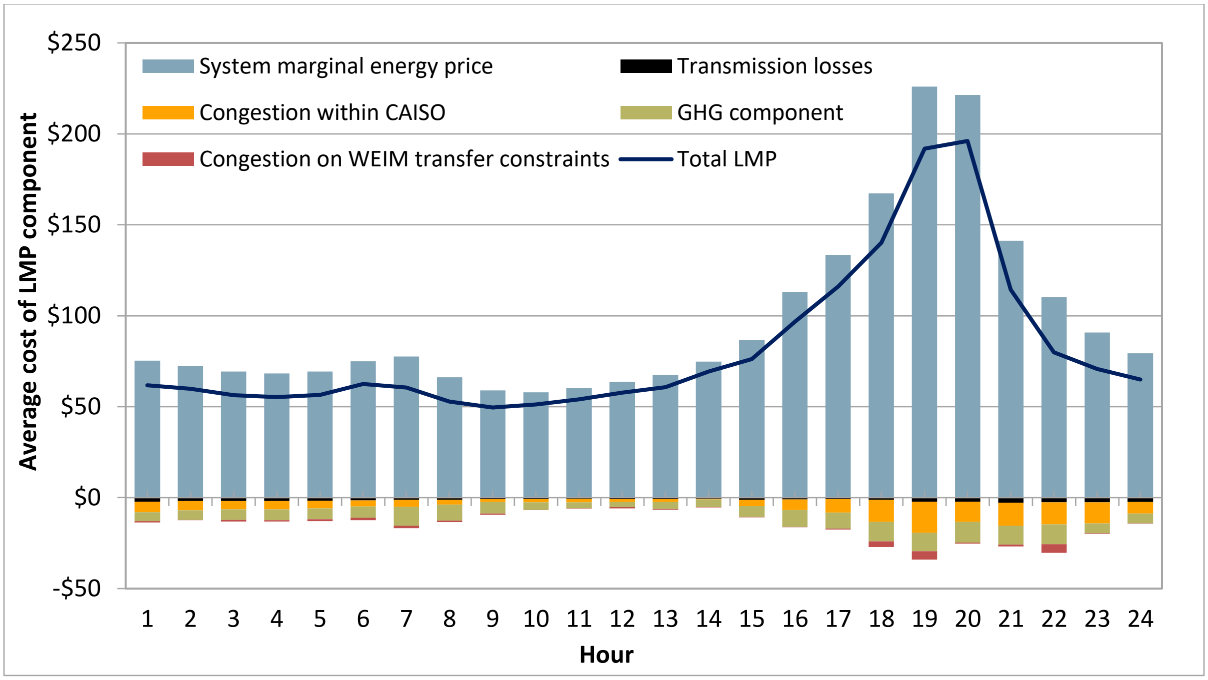



**Appendix Figure A.40 Average hourly 5-minute market transfers**

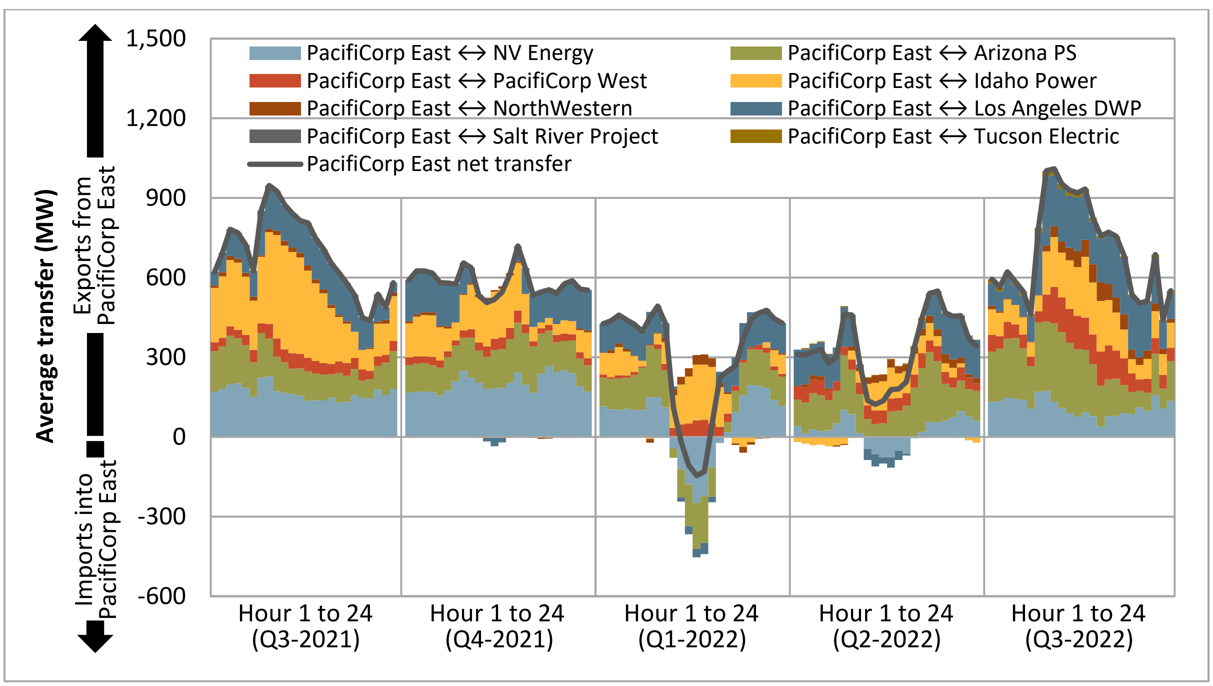


## A.10 PacifiCorp East

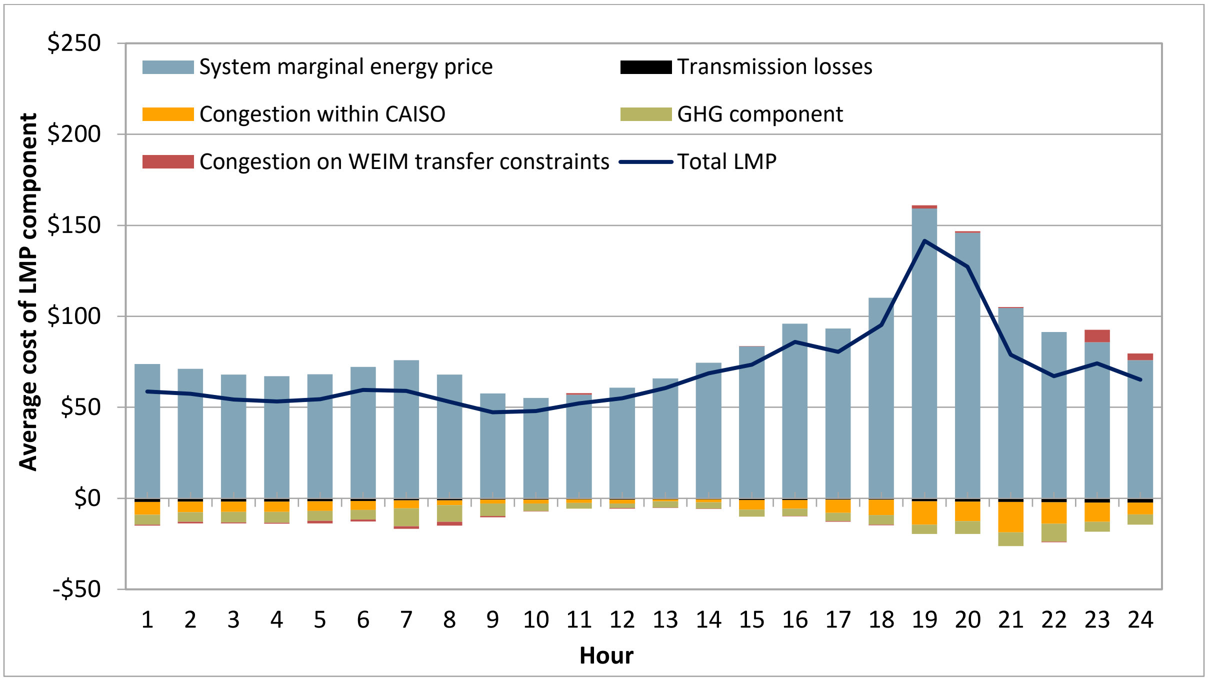
**Appendix Figure A.41 Average hourly 15-minute price by component (Q3 2022)**



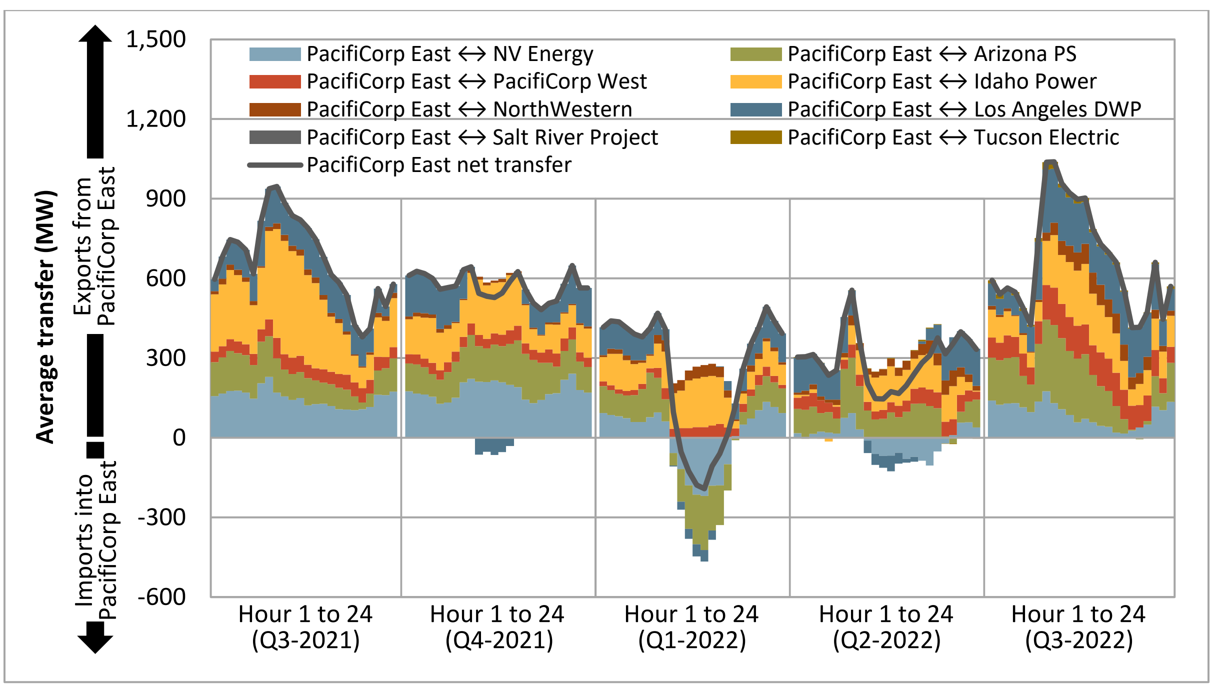

**Appendix Figure A.42 Average hourly 15-minute market transfers**



**Appendix Figure A.43 Average hourly 5-minute price by component (Q3 2022)**

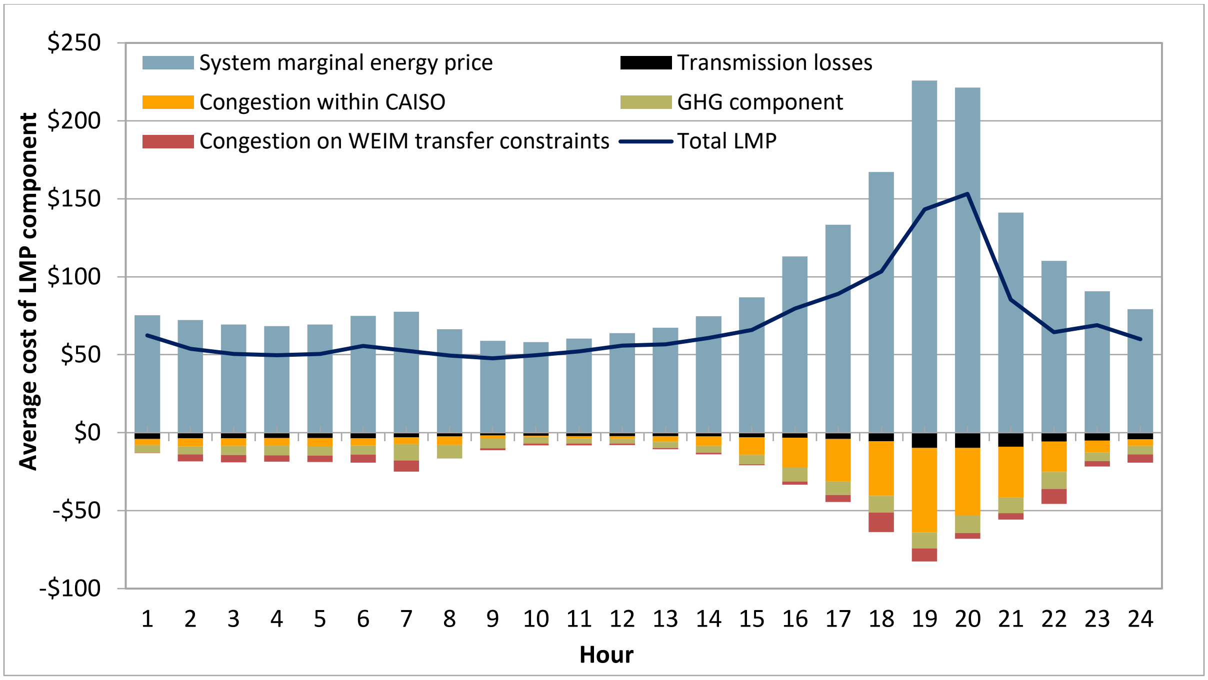



**Appendix Figure A.44 Average hourly 5-minute market transfers**

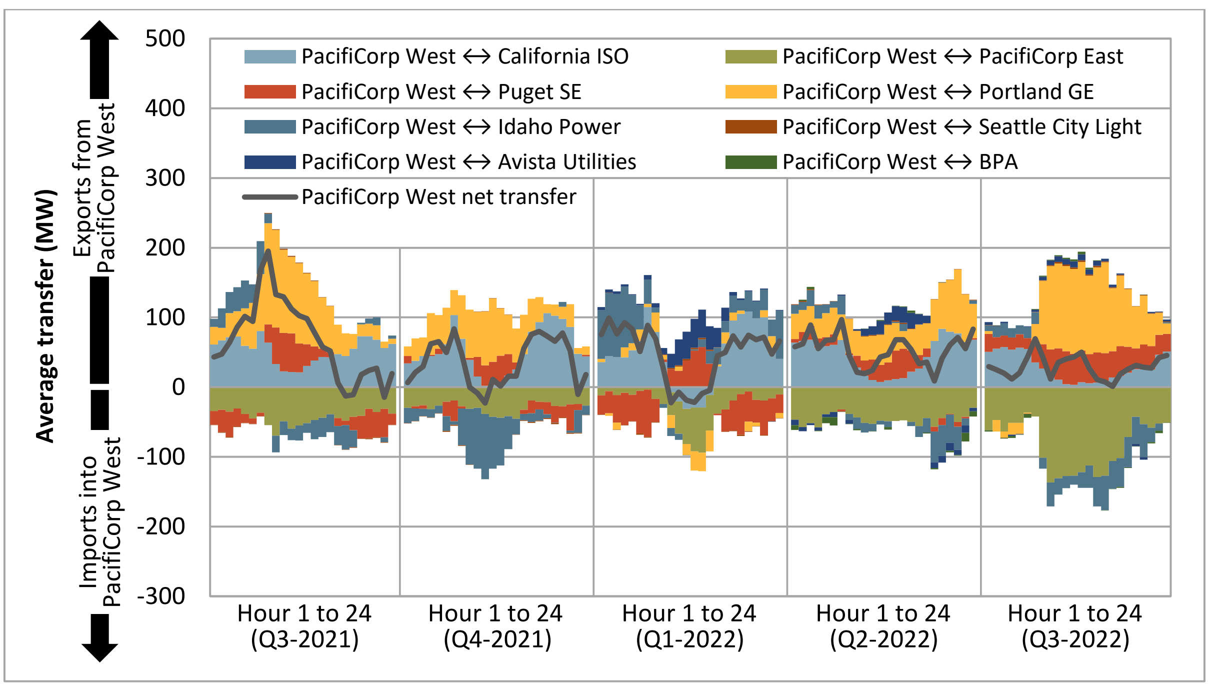


## A.11 PacifiCorp West

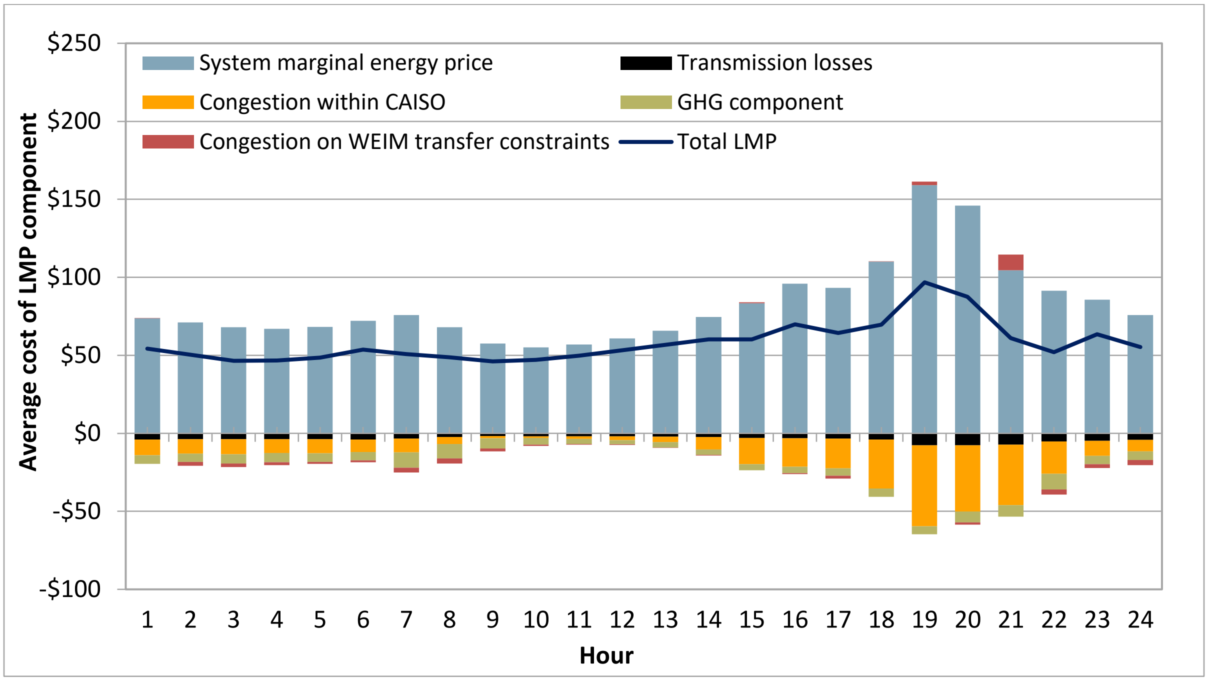
**Appendix Figure A.45 Average hourly 15-minute price by component (Q3 2022)**



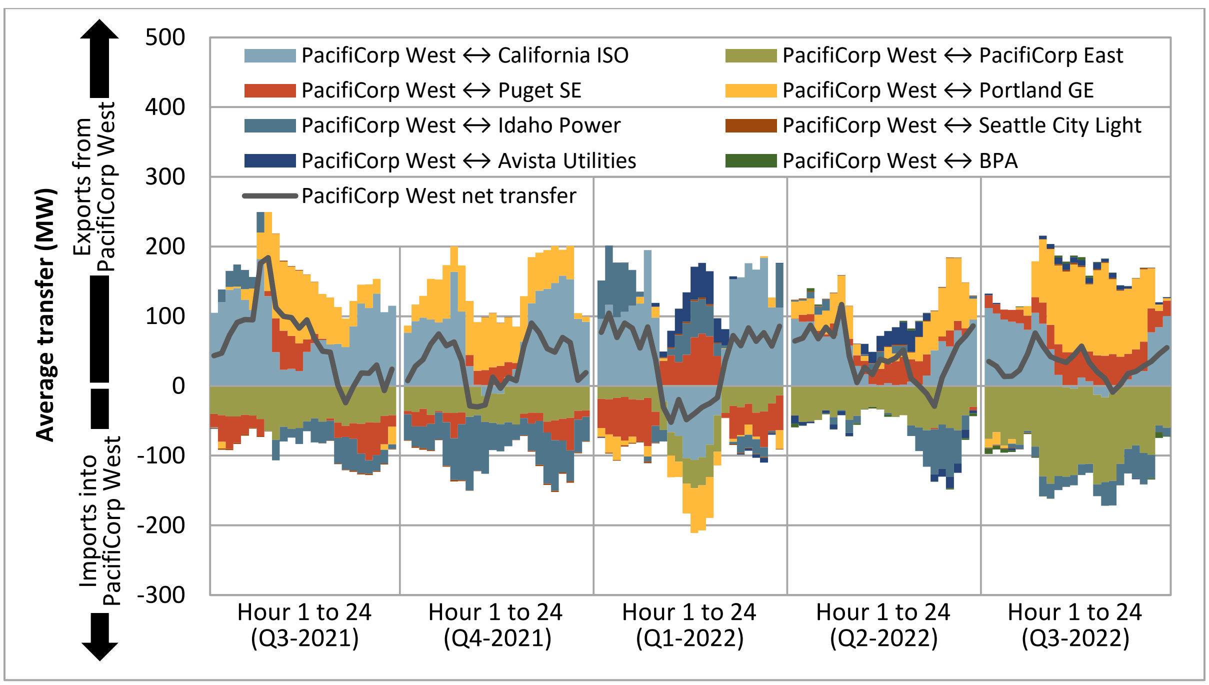

**Appendix Figure A.46 Average hourly 15-minute market transfers**



**Appendix Figure A.47 Average hourly 5-minute price by component (Q3 2022)**

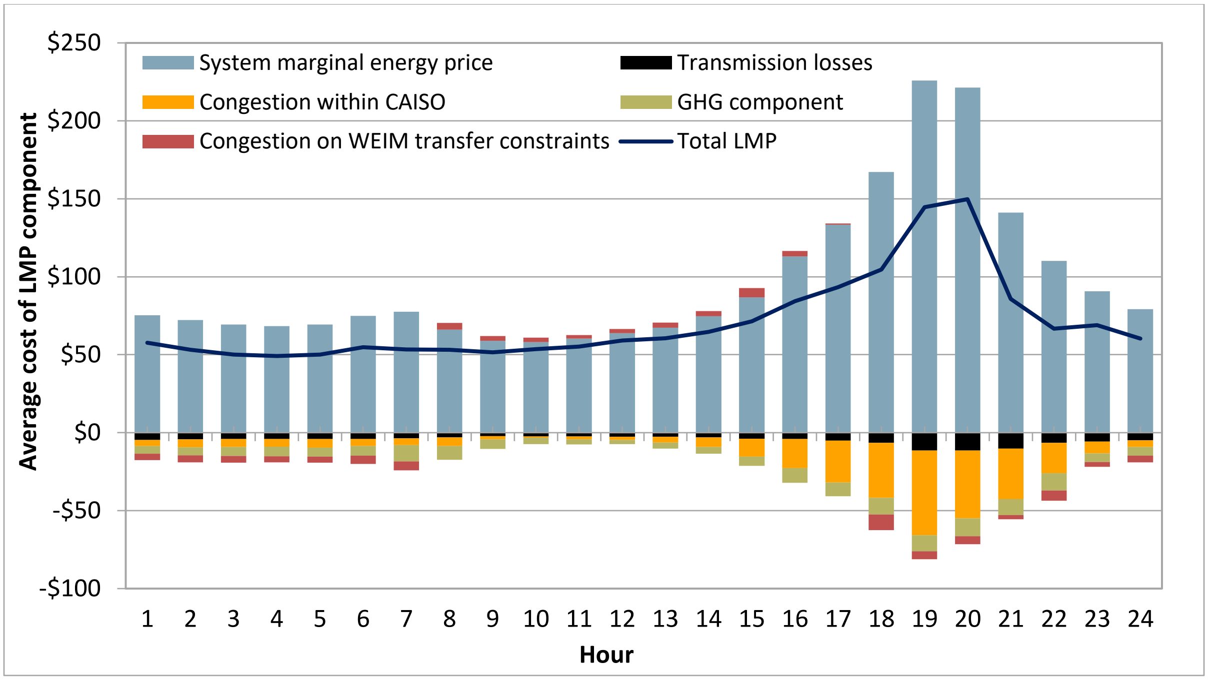



**Appendix Figure A.48 Average hourly 5-minute market transfers**

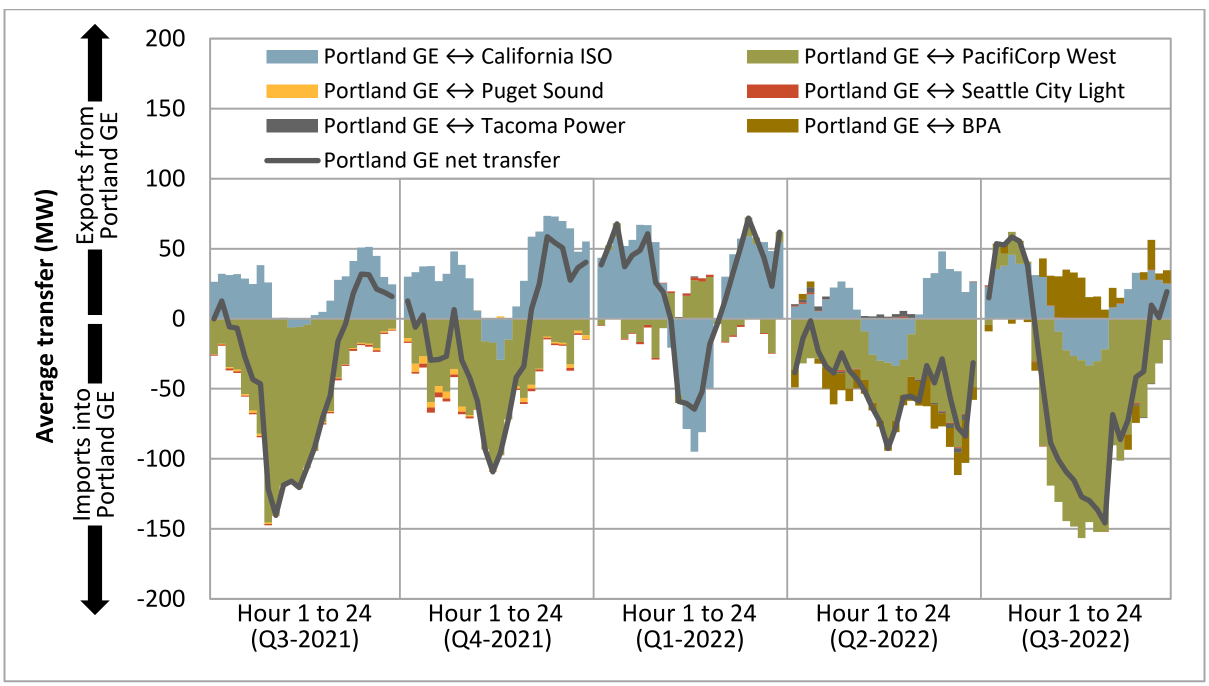


## A.12 Portland General Electric

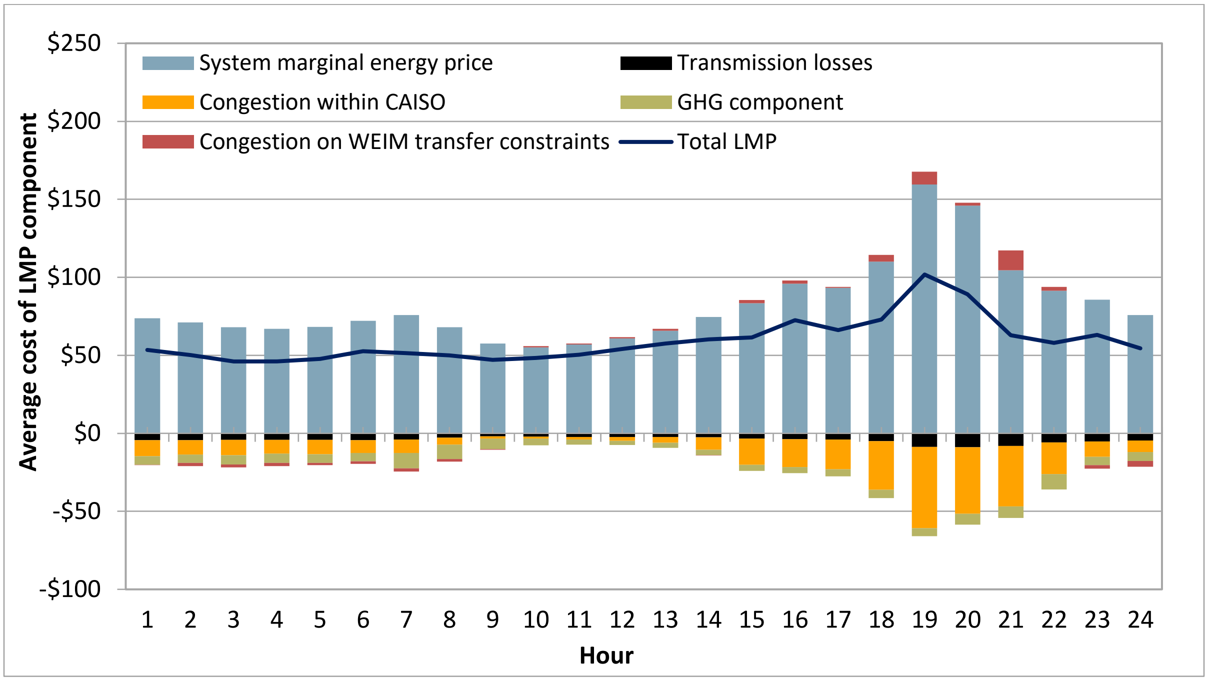
**Appendix Figure A.49 Average hourly 15-minute price by component (Q3 2022)**



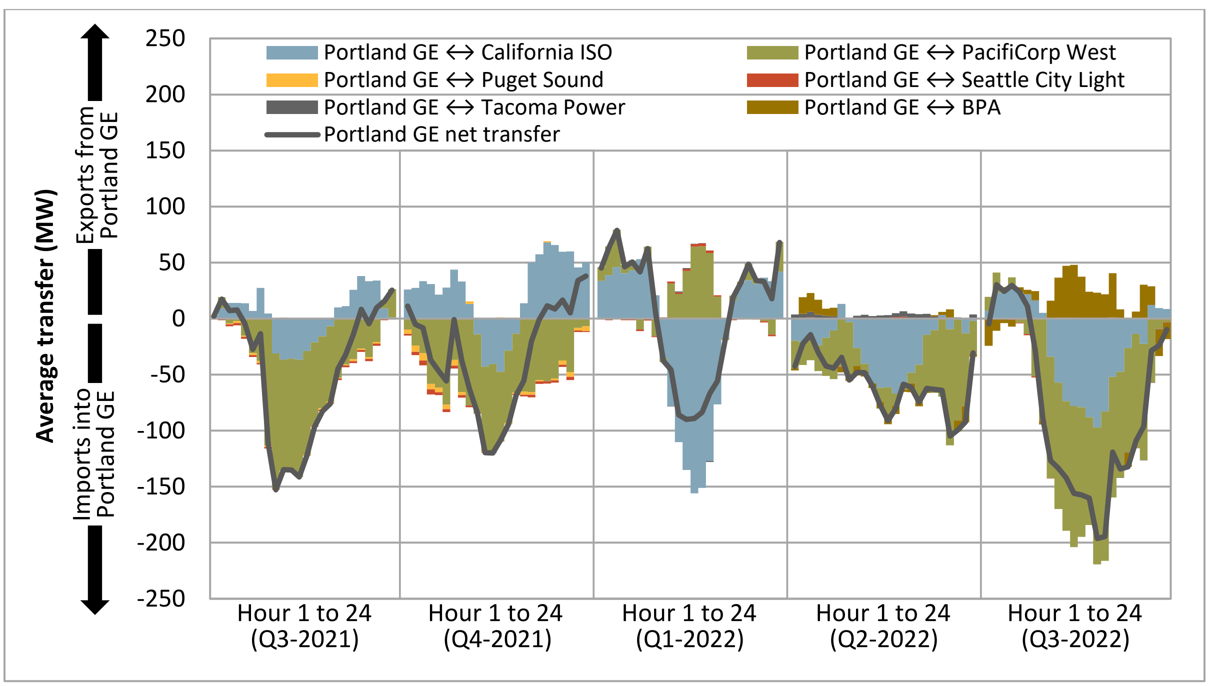

**Appendix Figure A.50 Average hourly 15-minute market transfers**



**Appendix Figure A.51 Average hourly 5-minute price by component (Q3 2022)**

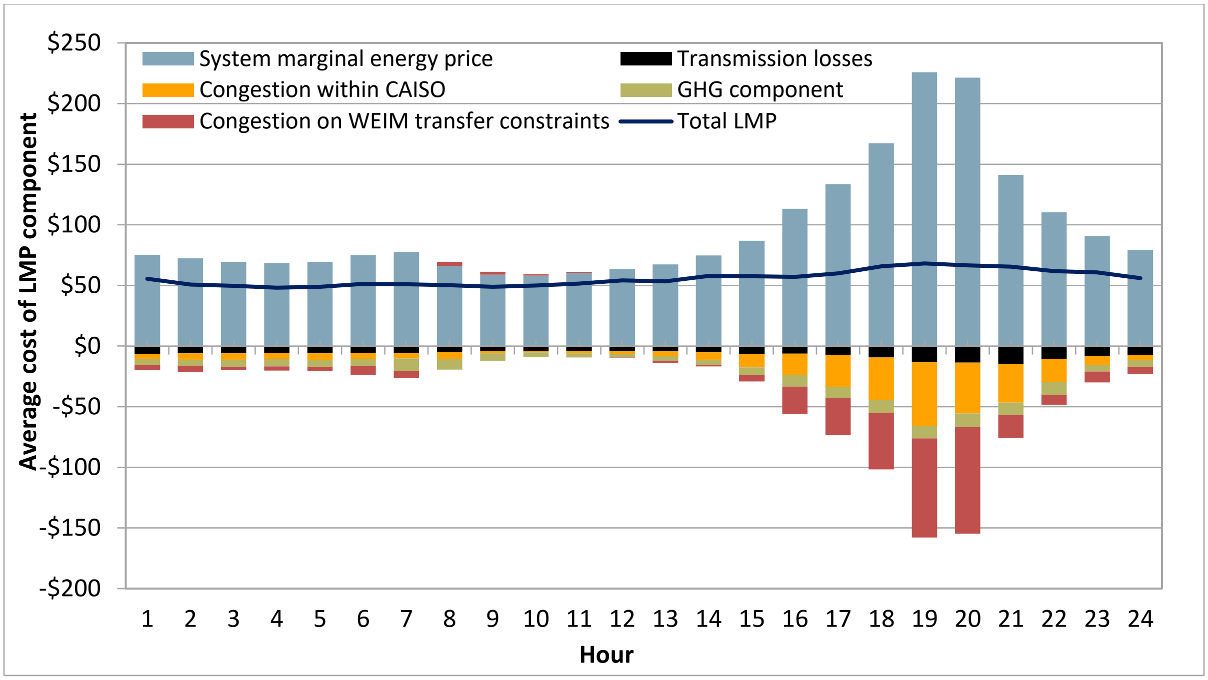



**Appendix Figure A.52 Average hourly 5-minute market transfers**

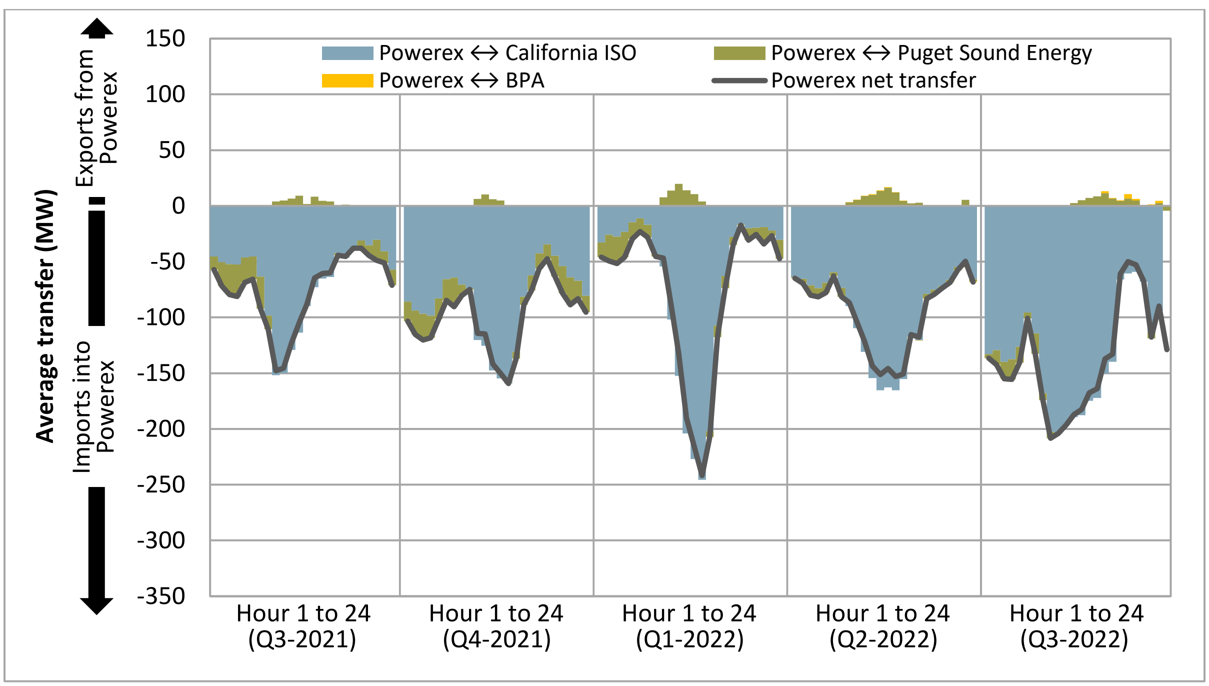


## A.13 Powerex

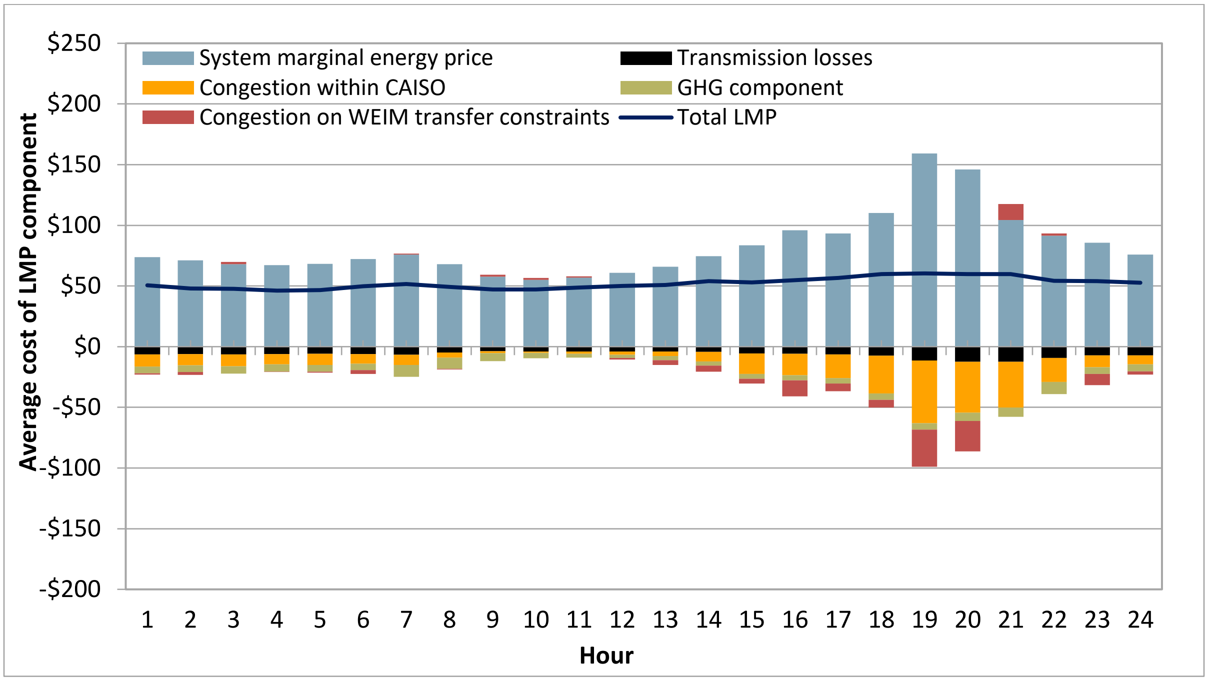
**Appendix Figure A.53 Average hourly 15-minute price by component (Q3 2022)**



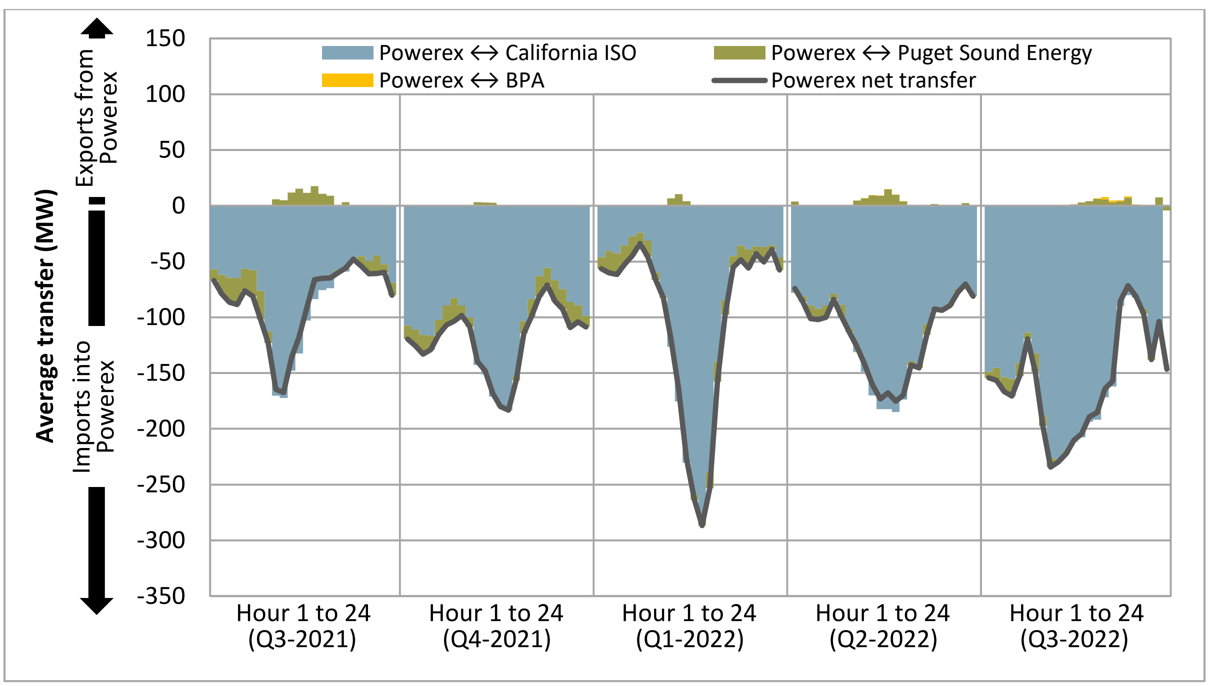

**Appendix Figure A.54 Average hourly 15-minute market transfers**



**Appendix Figure A.55 Average hourly 5-minute price by component (Q3 2022)**

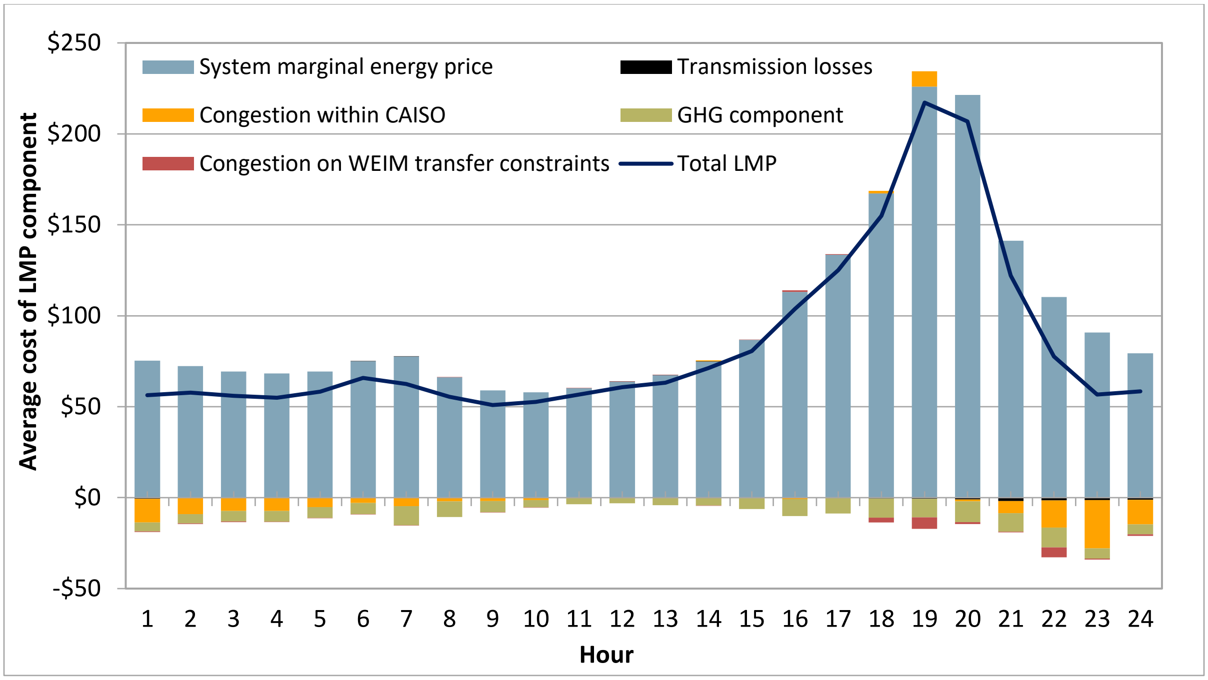



**Appendix Figure A.56 Average hourly 5-minute market transfers**

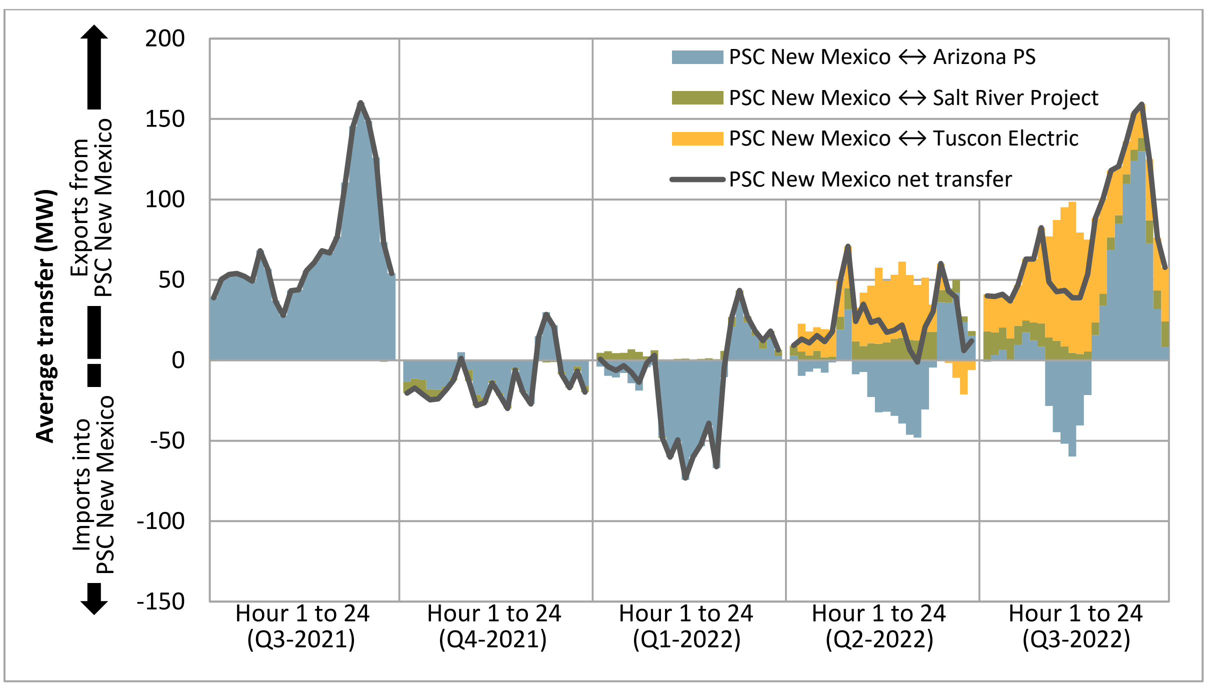


## A.14 Public Service Company of New Mexico

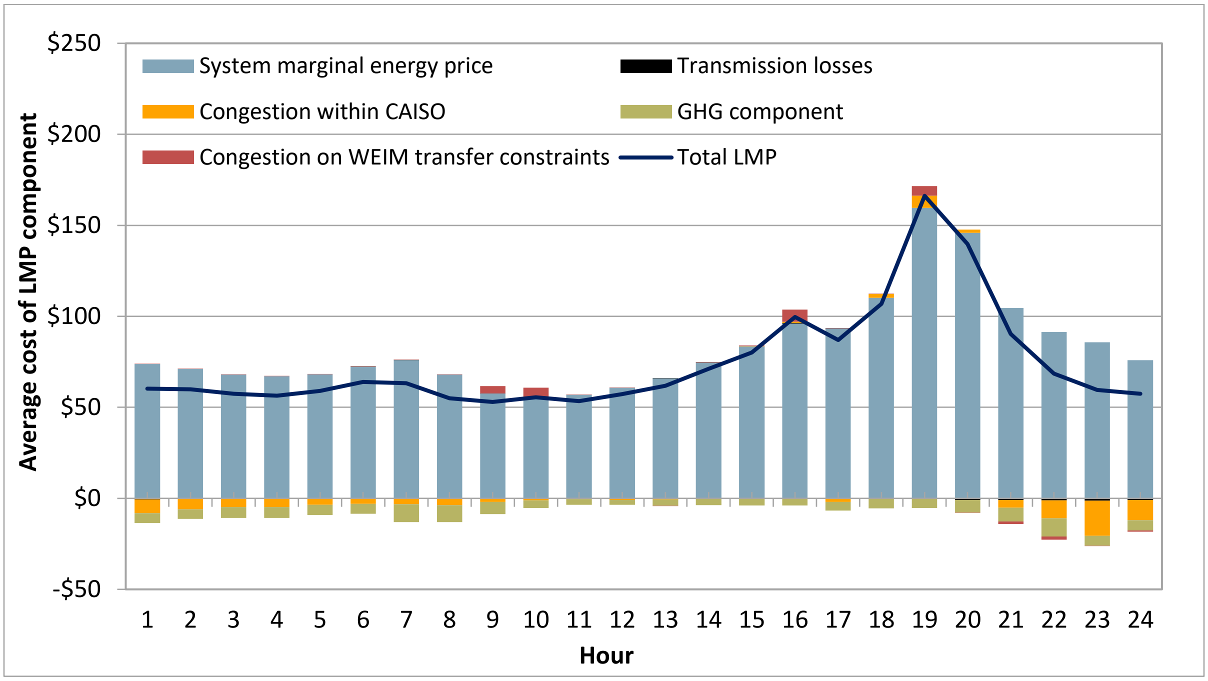
**Appendix Figure A.57 Average hourly 15-minute price by component (Q3 2022)**



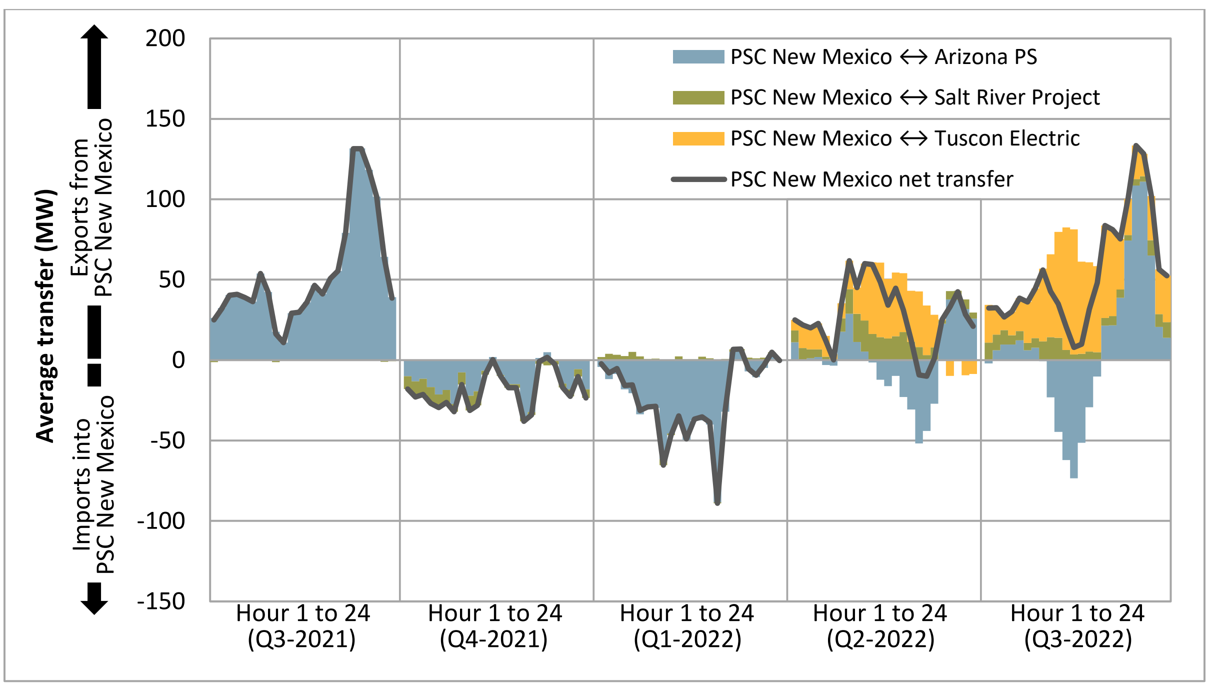

**Appendix Figure A.58 Average hourly 15-minute market transfers**



**Appendix Figure A.59 Average hourly 5-minute price by component (Q3 2022)**

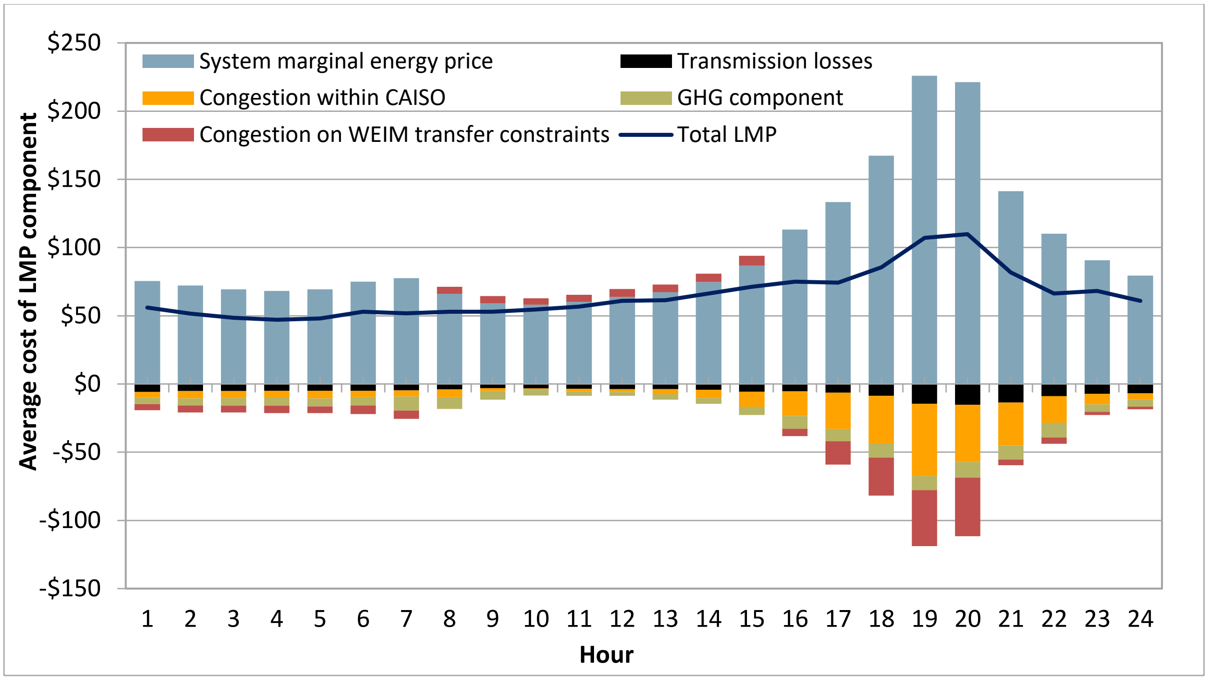



**Appendix Figure A.60 Average hourly 5-minute market transfers**

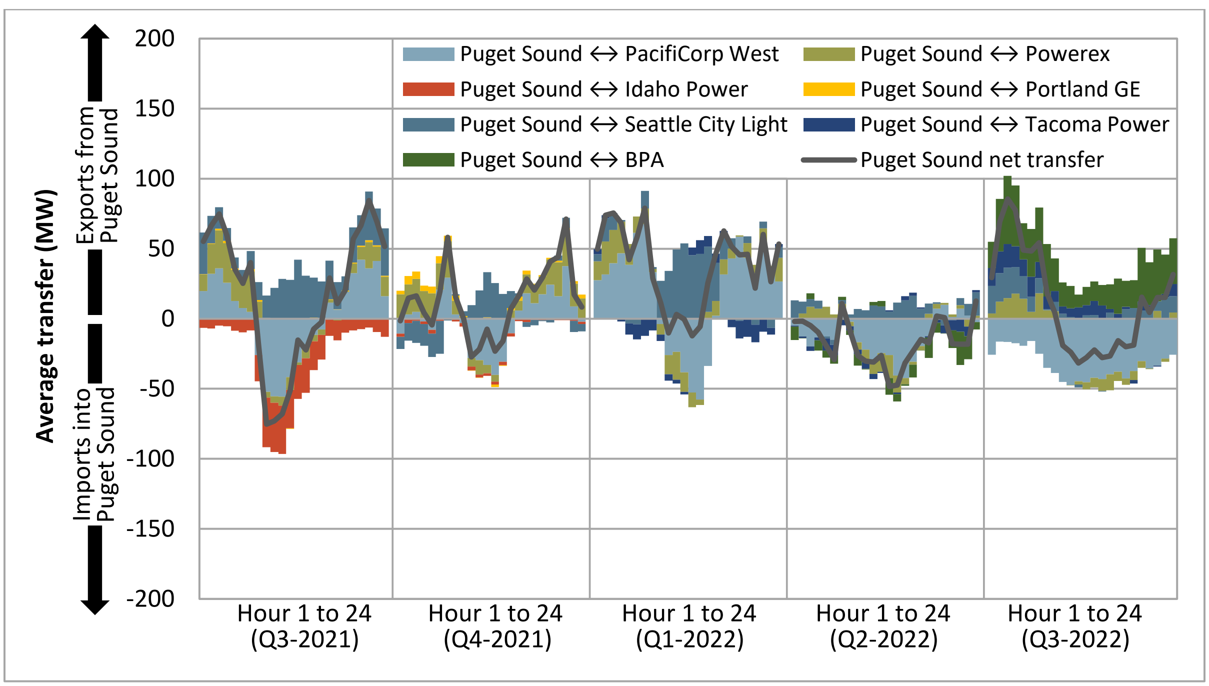


## A.15 Puget Sound Energy

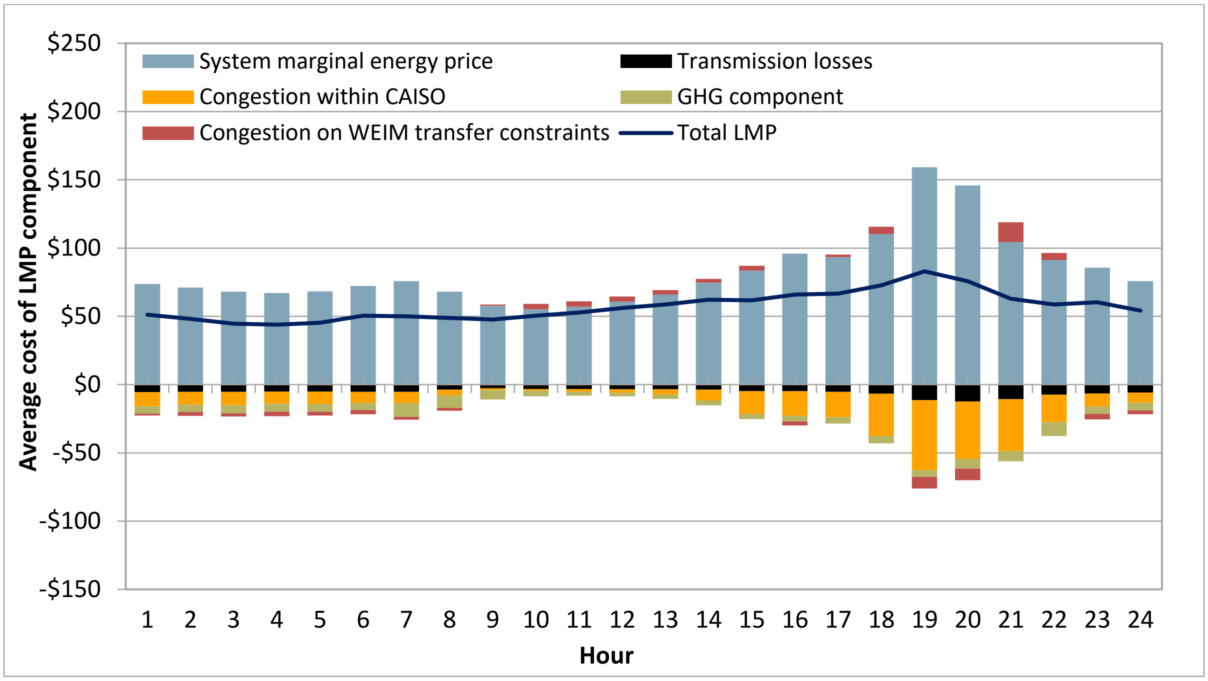
**Appendix Figure A.61 Average hourly 15-minute price by component (Q3 2022)**



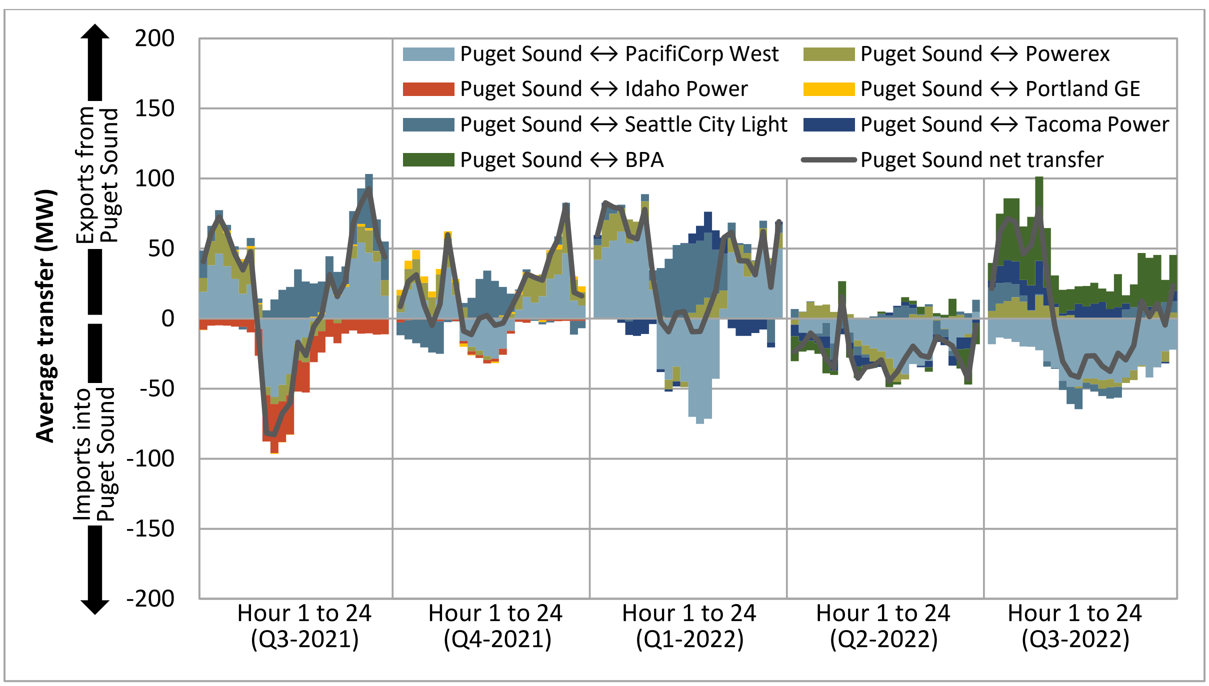

**Appendix Figure A.62 Average hourly 15-minute market transfers**



**Appendix Figure A.63 Average hourly 5-minute price by component (Q3 2022)**

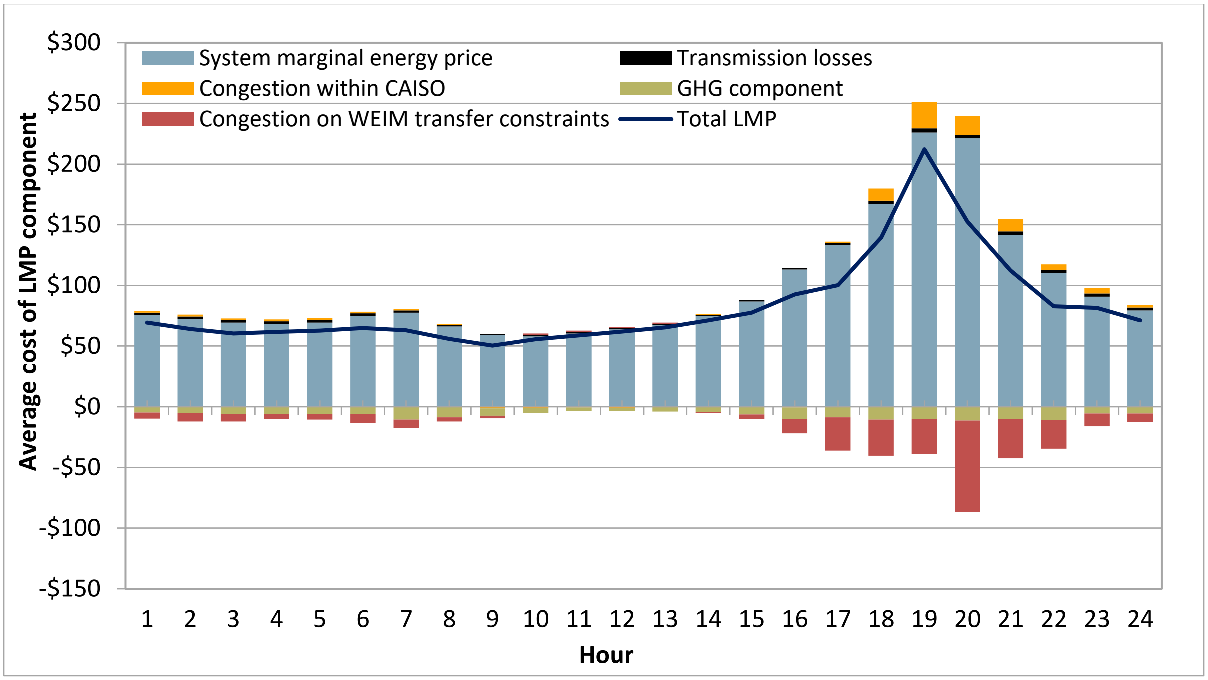



**Appendix Figure A.64 Average hourly 5-minute market transfers**

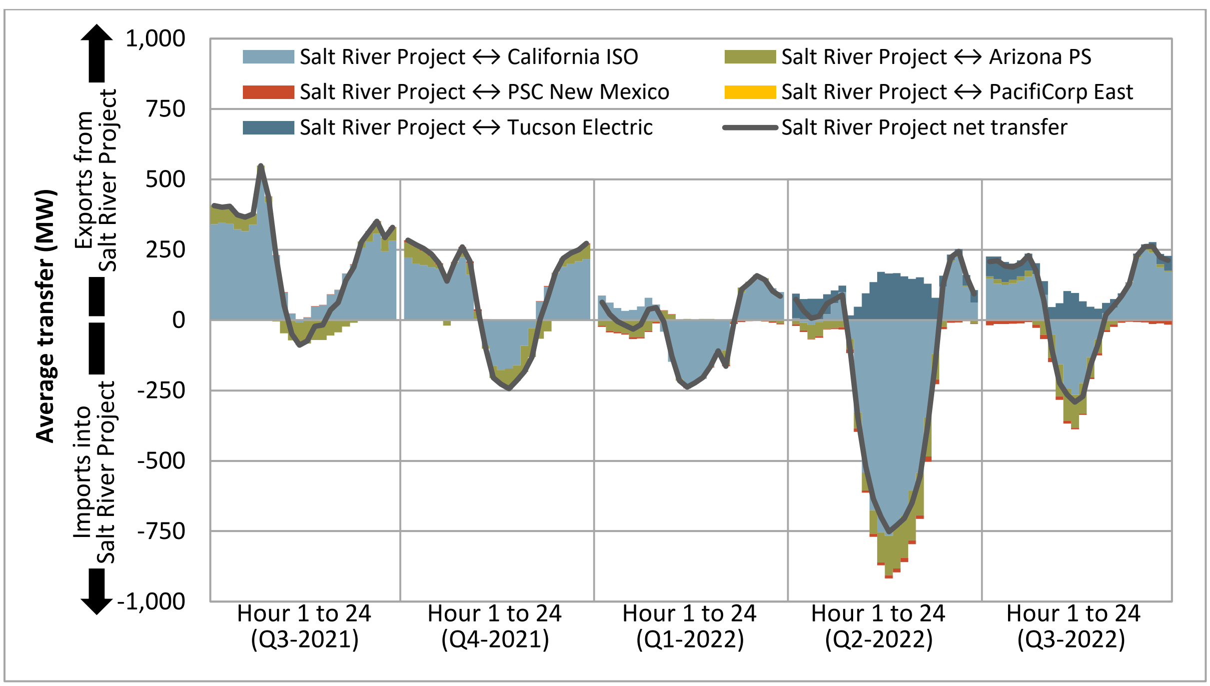


## A.16 Salt River Project

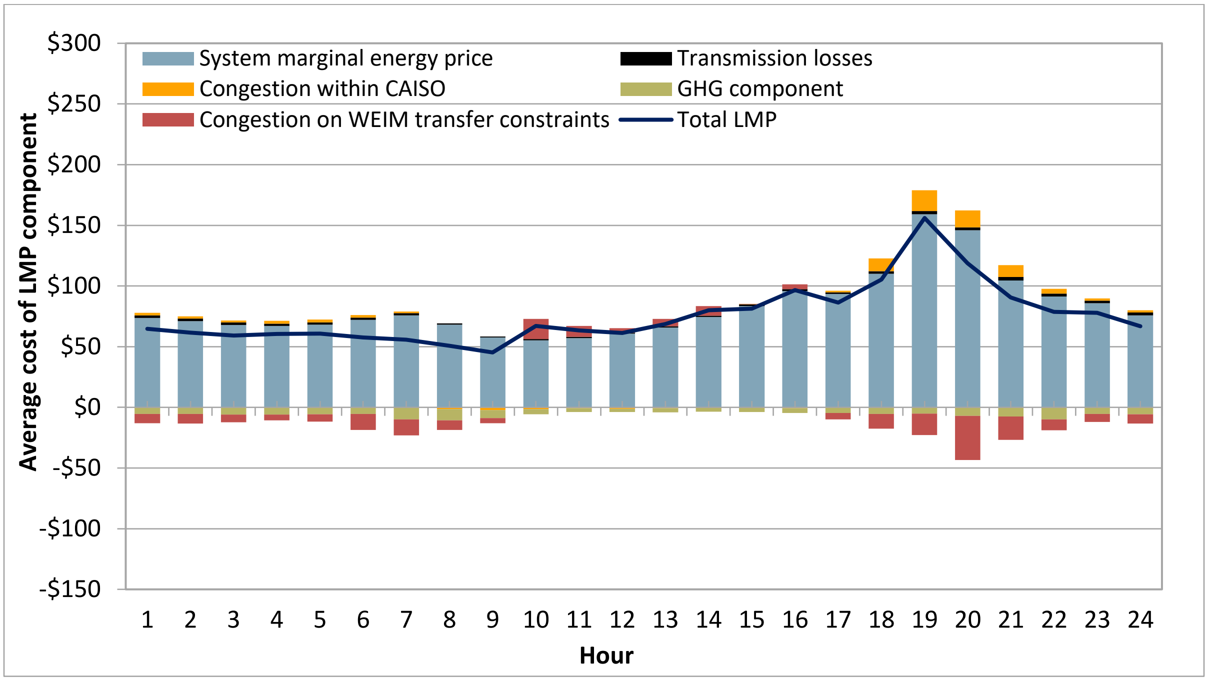
**Appendix Figure A.65 Average hourly 15-minute price by component (Q3 2022)**



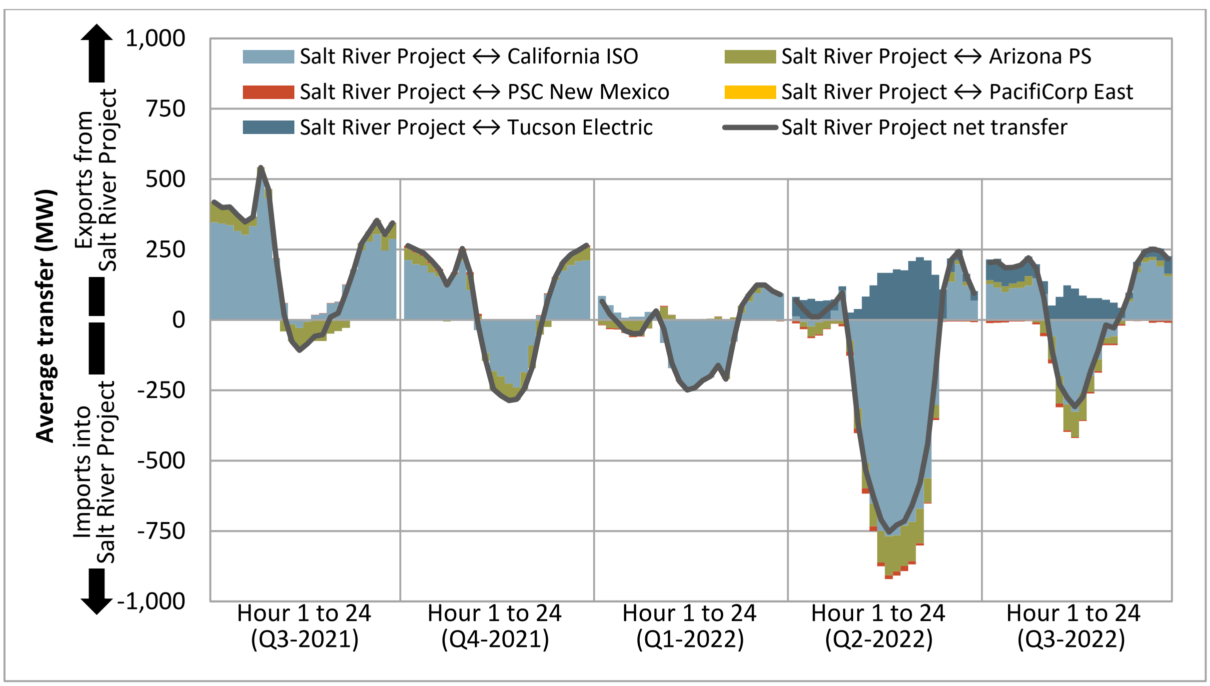

**Appendix Figure A.66 Average hourly 15-minute market transfers**



**Appendix Figure A.67 Average hourly 5-minute price by component (Q3 2022)**

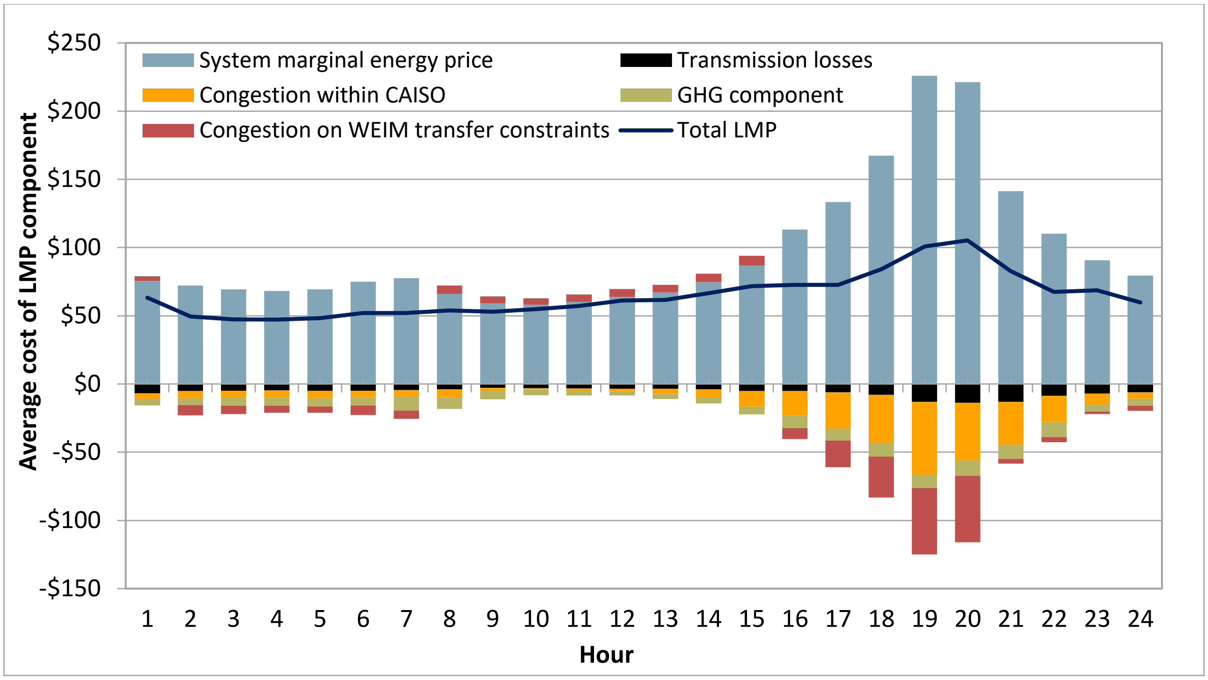



**Appendix Figure A.68 Average hourly 5-minute market transfers**

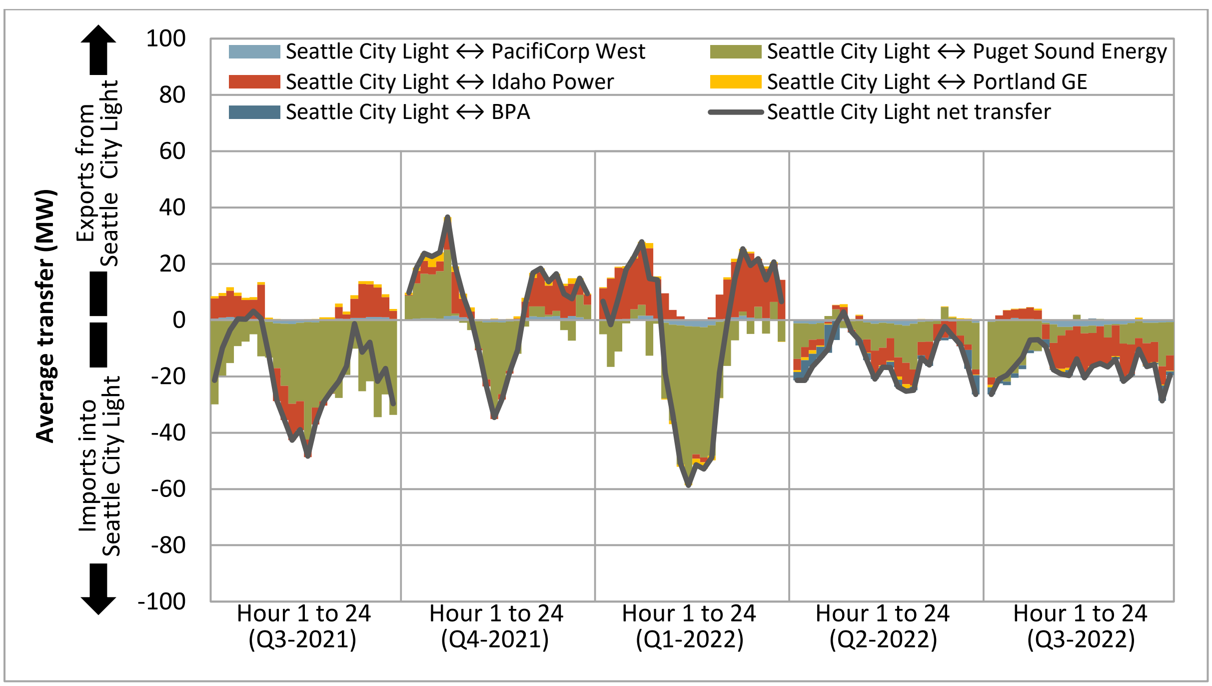


## A.17 Seattle City Light

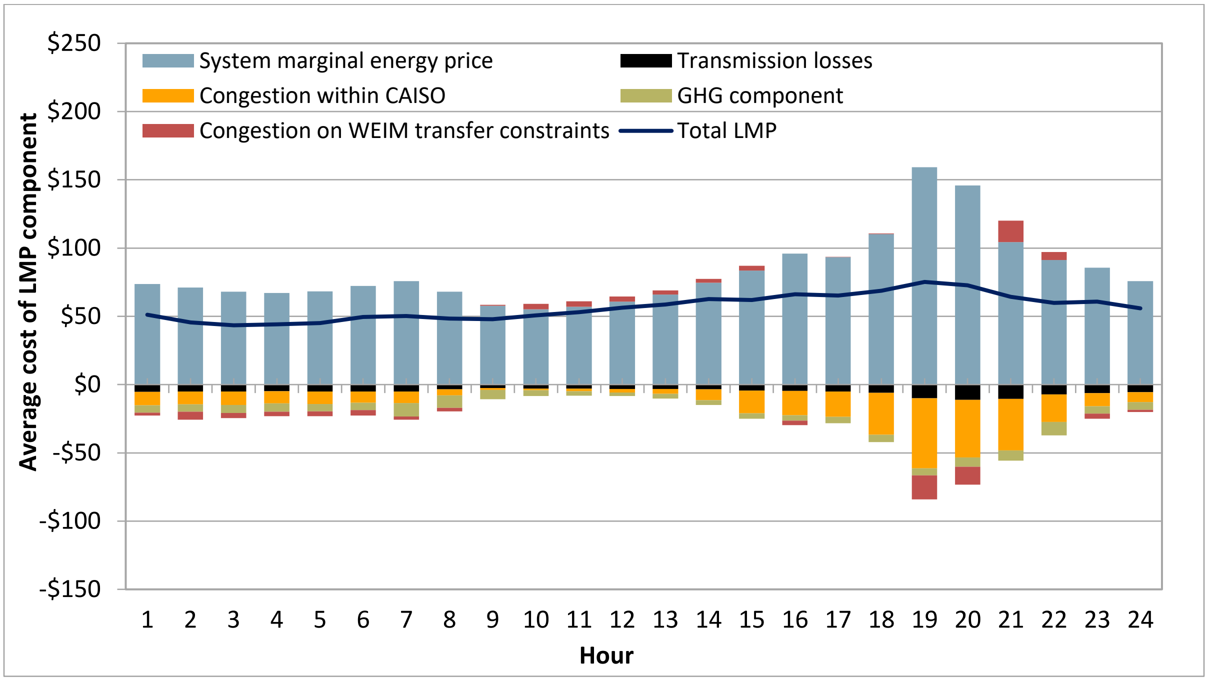
**Appendix Figure A.69 Average hourly 15-minute price by component (Q3 2022)**



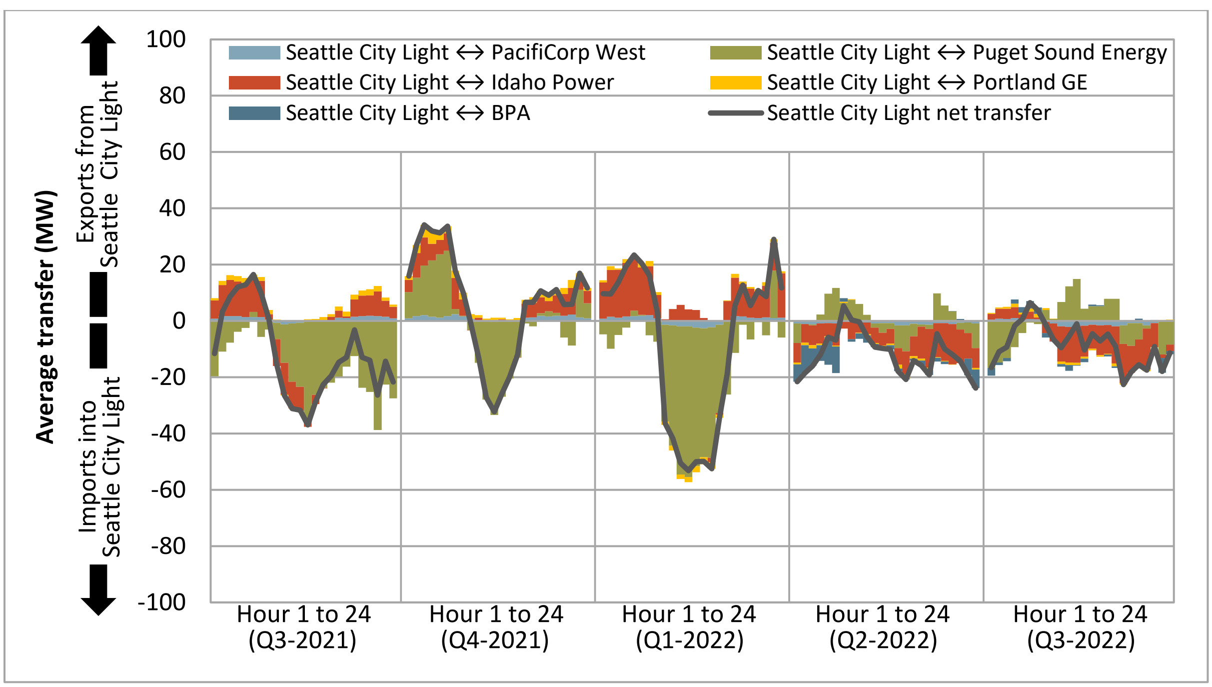

**Appendix Figure A.70 Average hourly 15-minute market transfers**



**Appendix Figure A.71 Average hourly 5-minute price by component (Q3 2022)**

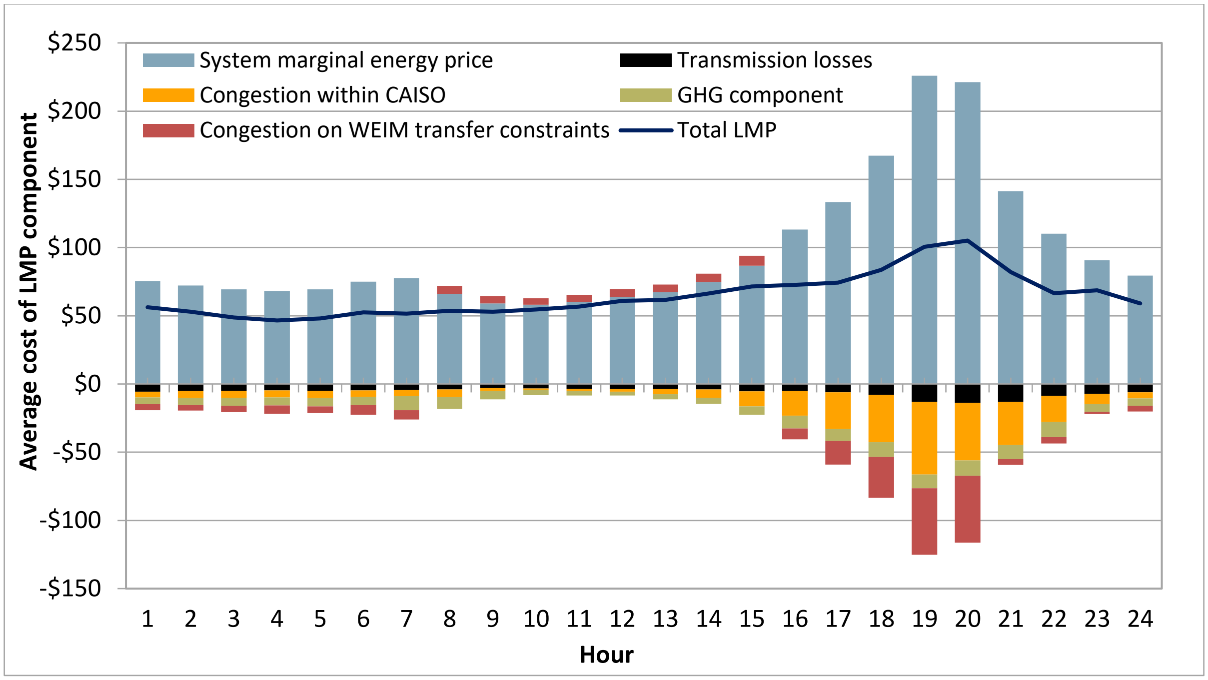



**Appendix Figure A.72 Average hourly 5-minute market transfers**

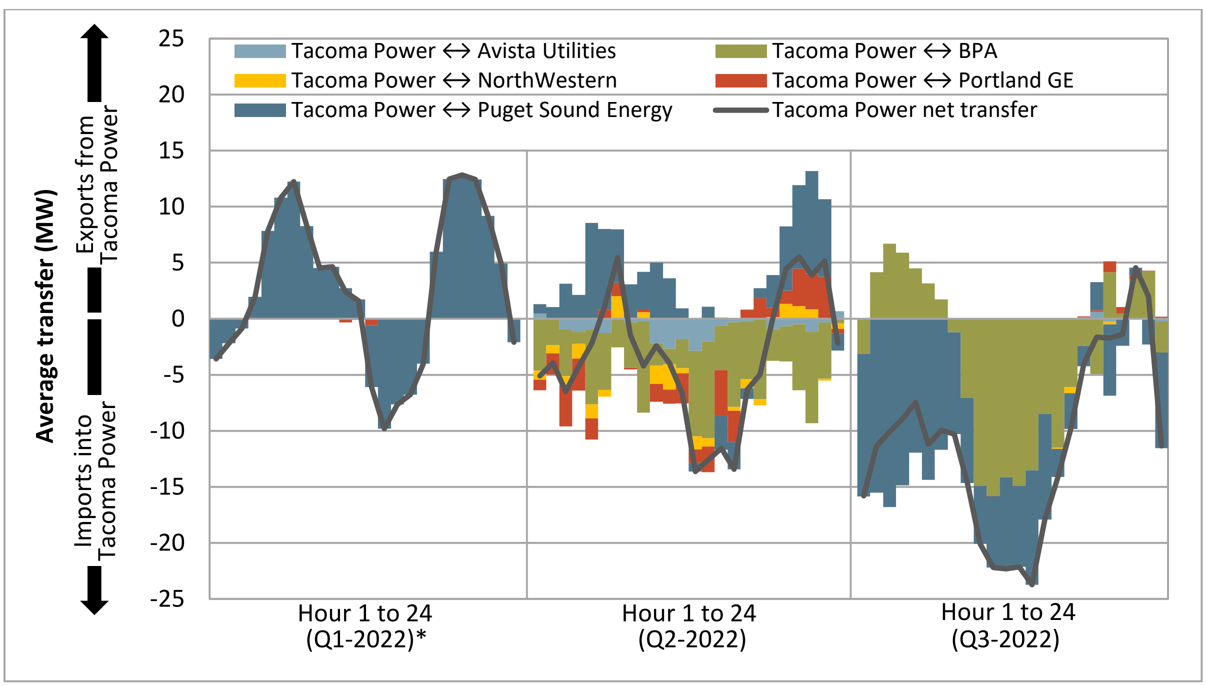


## A.18 Tacoma Power

**Appendix Figure A.73 Average hourly 15-minute price by component (Q3 2022)**

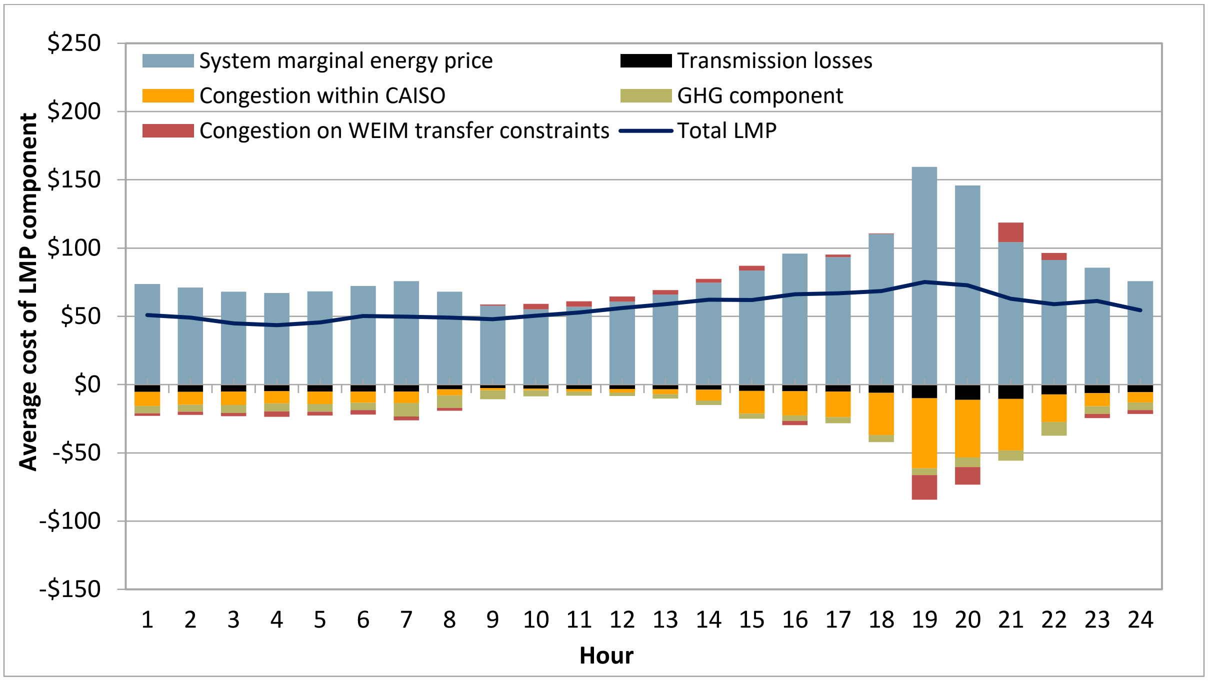



**Appendix Figure A.74 Average hourly 15-minute market transfers**

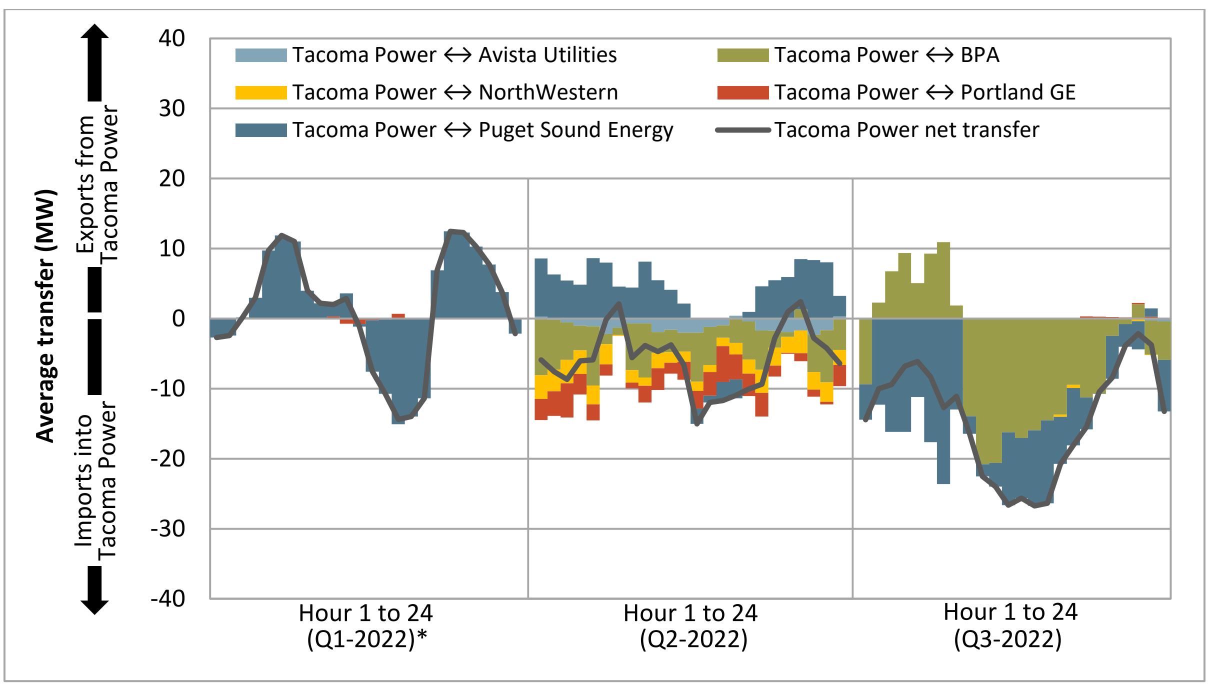



*Since joining the WEIM

**Appendix Figure A.75 Average hourly 5-minute price by component (Q3 2022)**



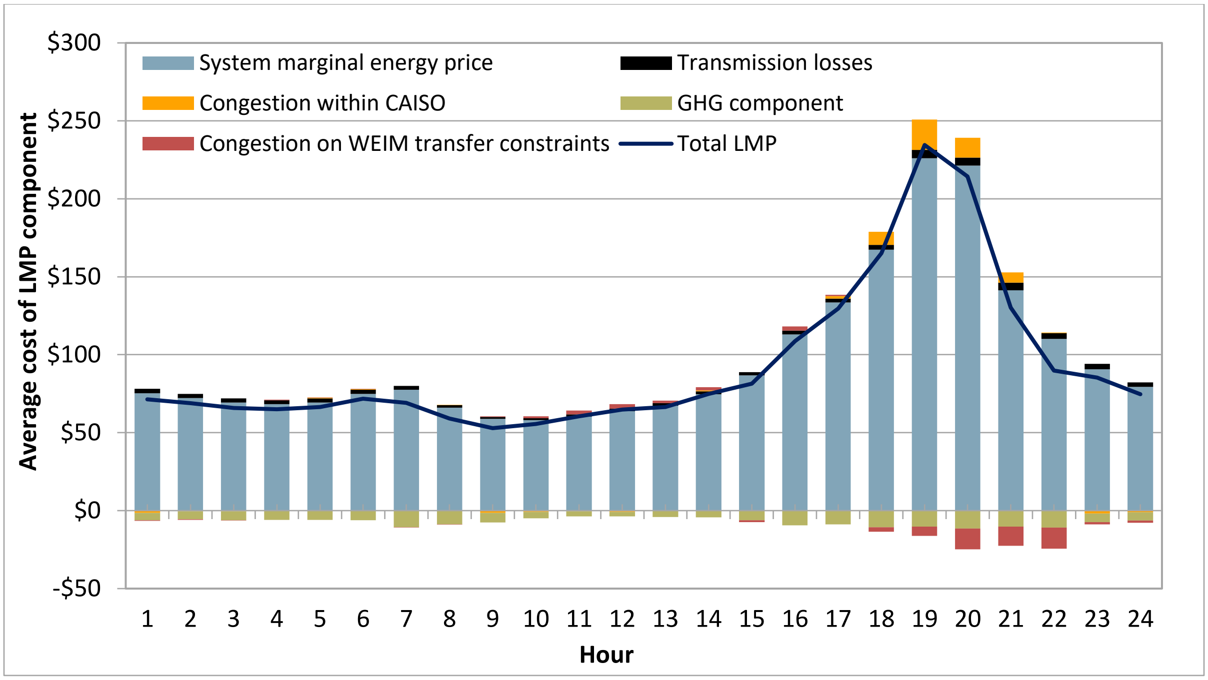

**Appendix Figure A.76 Average hourly 5-minute market transfers**



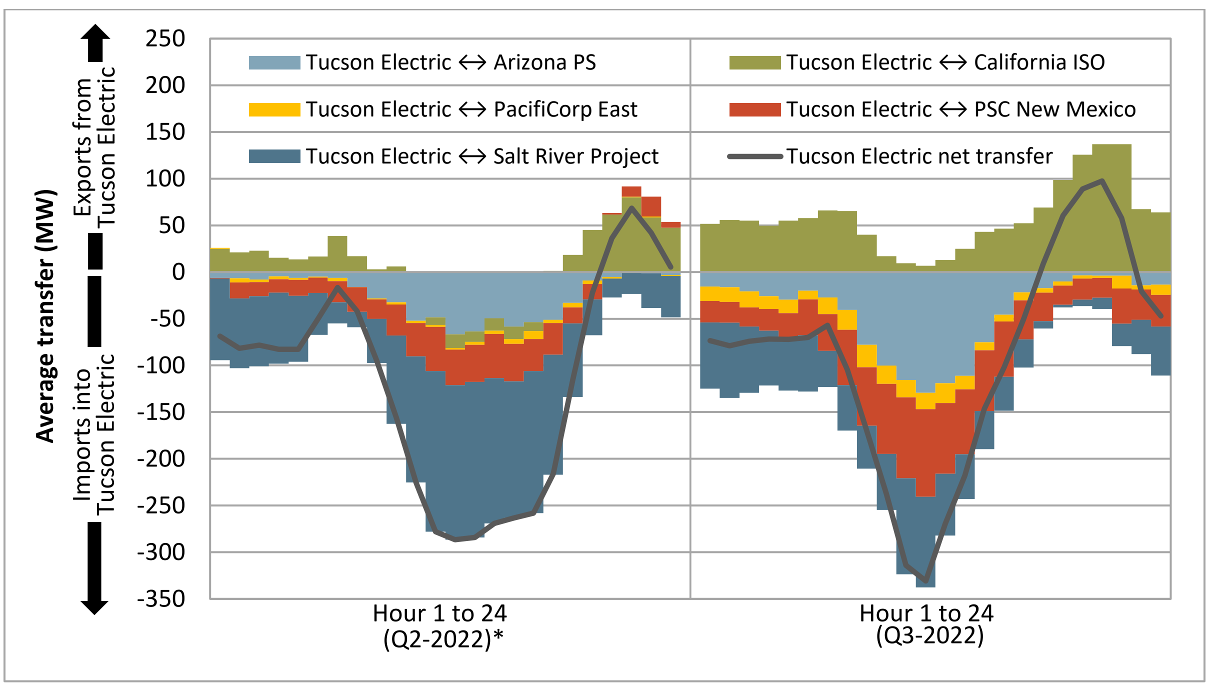

*Since joining the WEIM

## A.19 Tucson Electric Power

**Appendix Figure A.77 Average hourly 15-minute price by component (Q3 2022)**

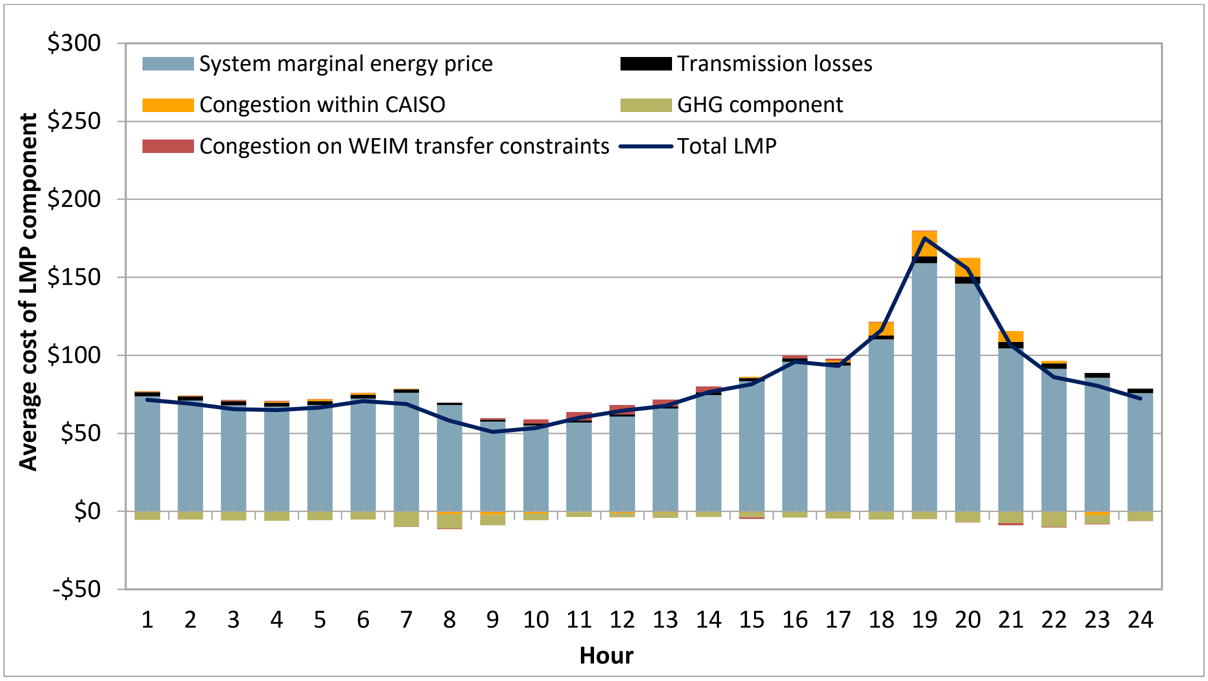



**Appendix Figure A.78 Average hourly 15-minute market transfers**

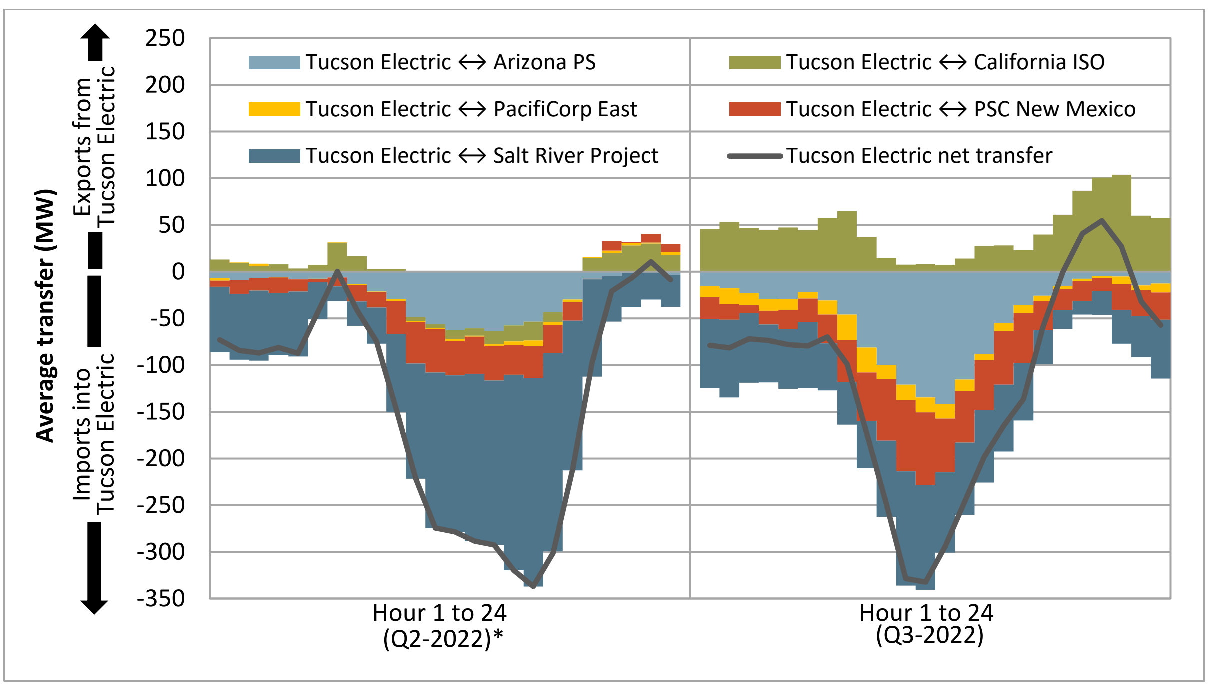



*Since joining the WEIM

**Appendix Figure A.79 Average hourly 5-minute price by component (Q3 2022)**



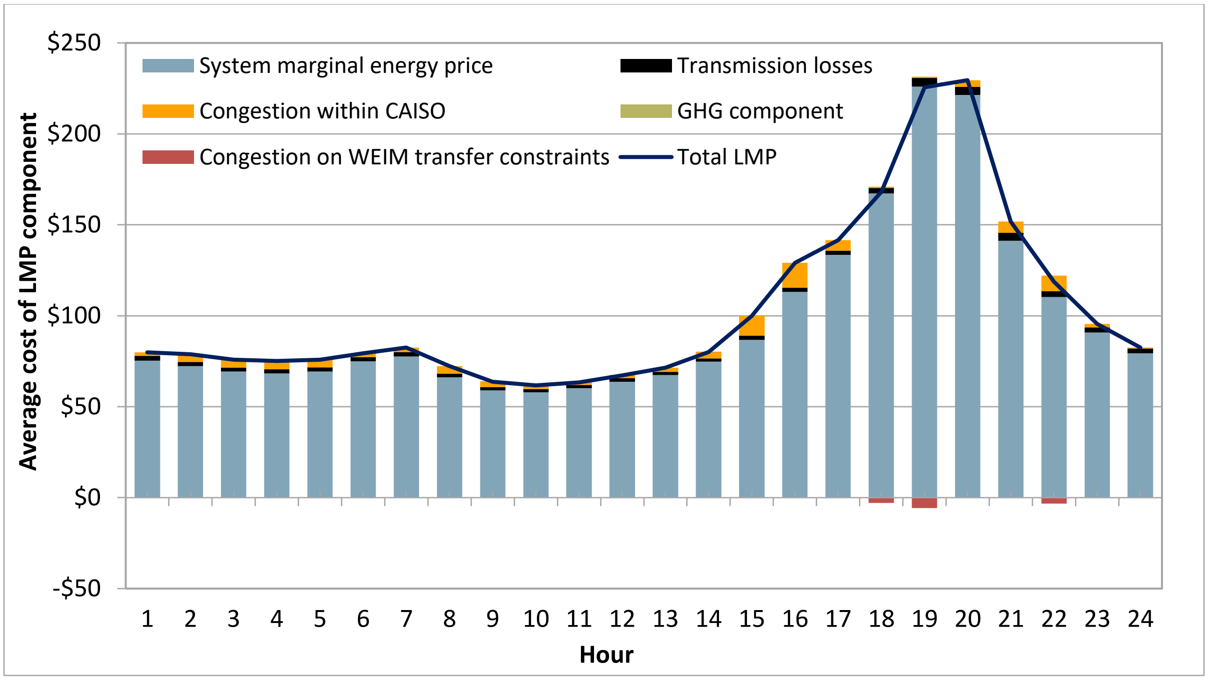

**Appendix Figure A.80 Average hourly 5-minute market transfers**



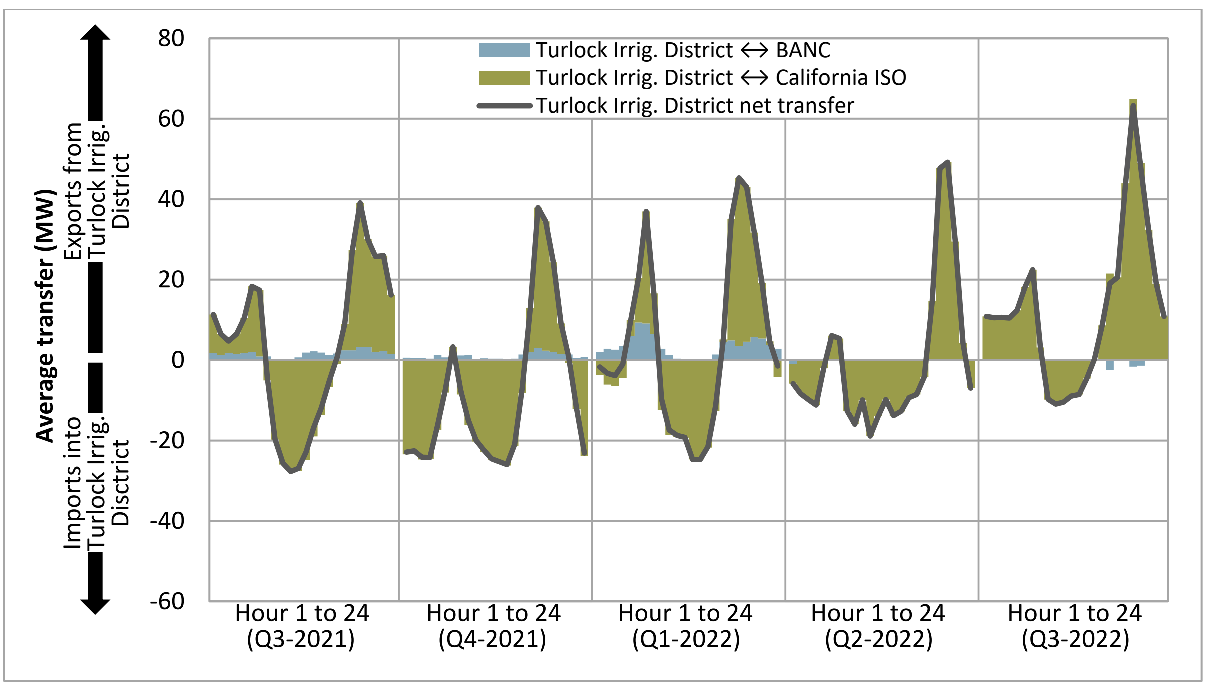

*Since joining the WEIM

## A.20 Turlock Irrigation District

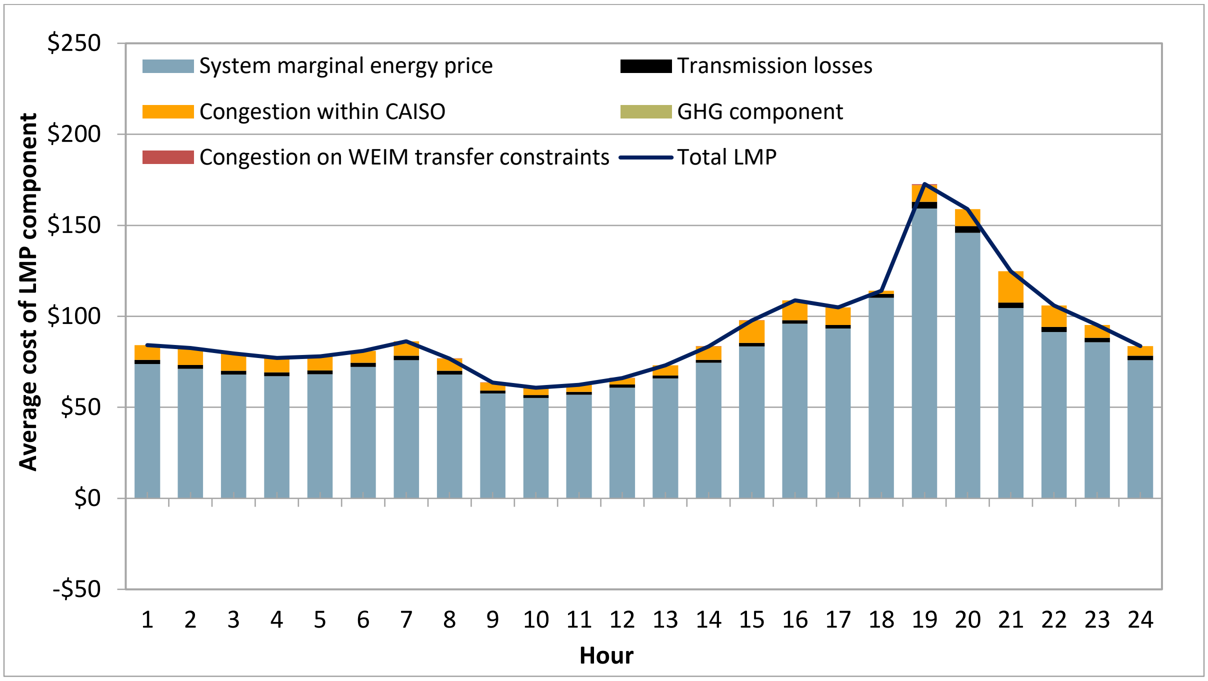
**Appendix Figure A.81 Average hourly 15-minute price by component (Q3 2022)**




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



**Appendix Figure A.83 Average hourly 5-minute price by component (Q3 2022)**




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