Q2 2022 Report on Market Issues and Performance

October 14, 2022

Prepared by: Department of Market Monitoring

California Independent System Operator

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Executive summary

This report covers market performance during the second quarter of 2022 (April - June).

Key highlights during this quarter include the following:

- **Market prices were significantly higher** than the same quarter of 2021 on average. Day-ahead prices in the California ISO rose about 72 percent. Increases were due to higher natural gas prices.
- **Gas prices increased by about $4/MMBtu** at Henry Hub, SoCal Citygate, PG&E Citygate, NW Sumas, and El Paso Permian hubs compared to the same quarter in 2021. This represents an increase of more than 100 percent in some natural gas prices, and resulted in 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**. Congestion in the day-ahead market decreased SCE and SDG&E area prices and increased prices in the PG&E area. Total day-ahead congestion rent rose to $269 million, a significant increase from $98 million in the same quarter of the previous year.
- **A 5-minute market only constraint 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 $131 million** in the second quarter, up from $45 million in the previous quarter. Real-time congestion imbalance offset costs were $77 million in June alone, the highest monthly congestion imbalance recorded since locational marginal pricing was introduced in 2009.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $70 million** during the first half of 2022 as payments to auctioned congestion revenue rights holders continued to exceed auction revenues. Second quarter losses at $57.6 million were higher than any other quarter since the California ISO instituted significant auction changes in 2019. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction.
- **Ancillary service payments totaled about $46 million**, an 18.5 percent increase from the second quarter of 2021. Average requirements were higher for operating reserves and regulation down.
- **Net profits paid to convergence bidders increased to about $41 million**, more than the annual total of $38 million in 2021. Overall, virtual supply bids were most profitable.
- **Flexible ramping product** system level prices were zero for over 99 percent of intervals in the 15-minute market and 99.9 percent of intervals in the 5-minute market for each of upward and downward flexible ramping capacity. Non-zero flexible ramping product prices occurred in areas where minimum area flexible ramping product constraints were binding.
- **Imbalance conformance adjustments** averaged 2,100 MW during the peak net load ramp hours in the California ISO. 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.

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

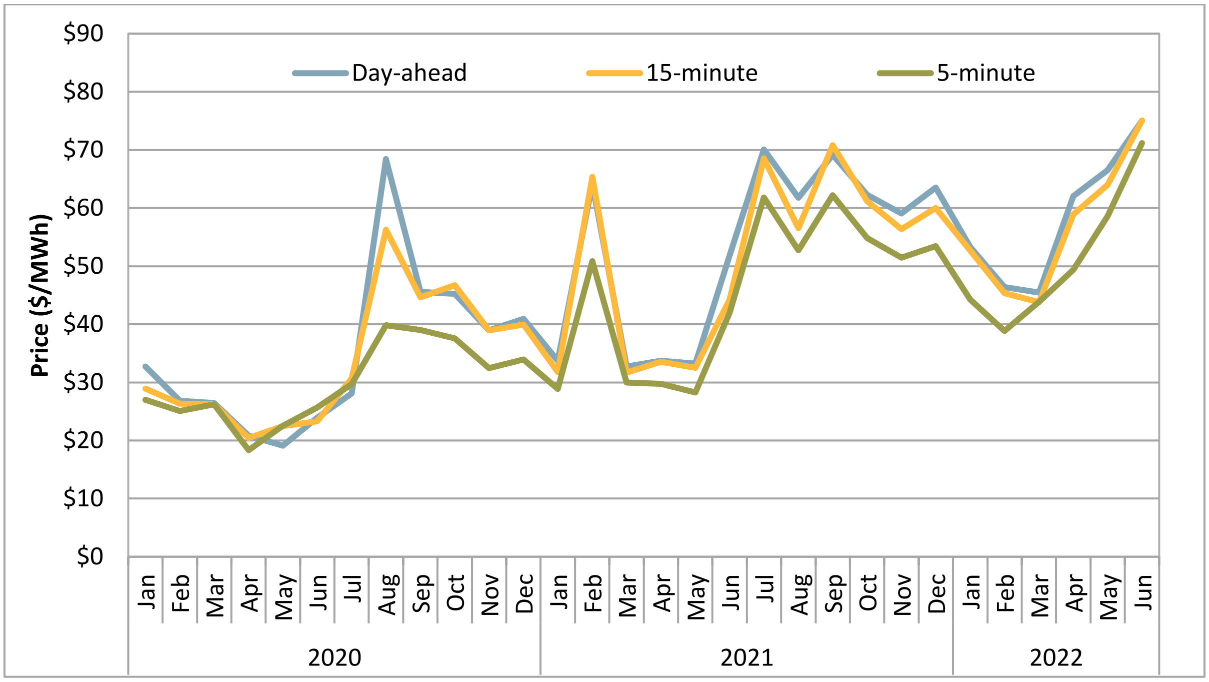
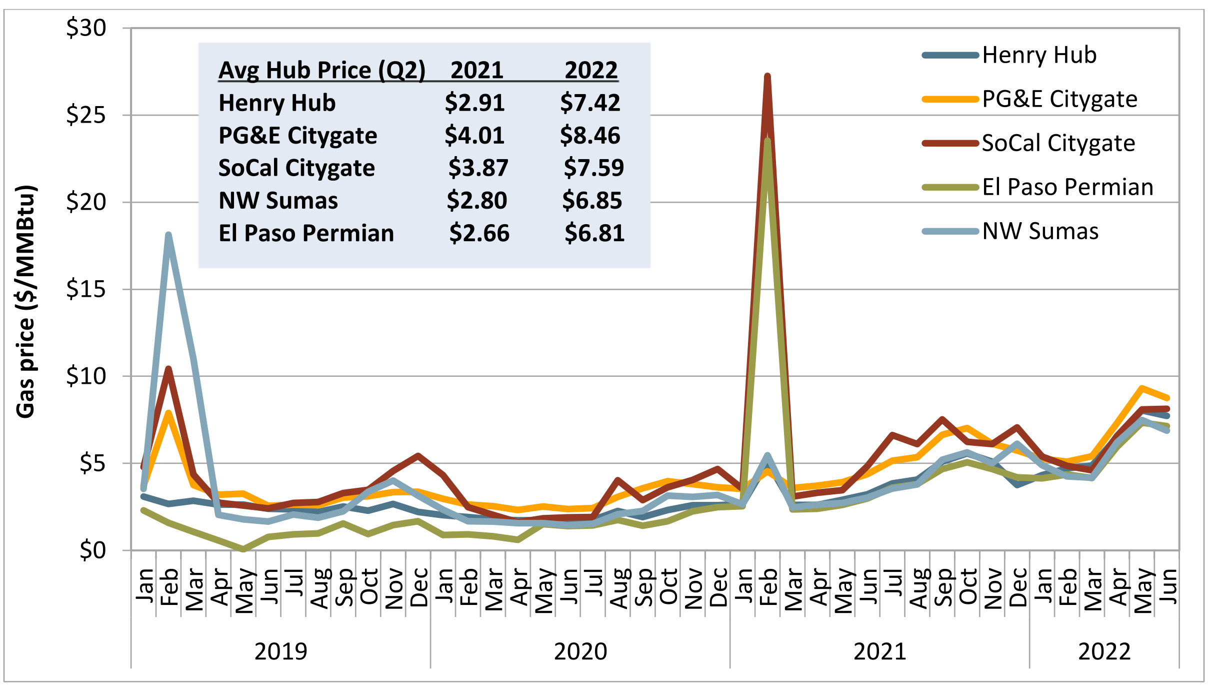


Figure E.2 Natural gas prices



Western Energy Imbalance Market

- **Natural gas prices rose across the WEIM**, resulting in higher energy prices in all balancing areas.
- **Bonneville Power Administration (BPA) and Tucson Electric Power (TEPC) joined** the Western Energy Imbalance Market in May, bringing the total number of participants up to 18.
- **Prices in California areas were about $25/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.
- **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 Energy, Avista Utilities, and Bonneville Power Administration.
- **Congestion from the Northwest decreased with the addition of transfer capacity.** Congestion from PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Powerex decreased an average of 27 percent in the 15-minute market, compared to the first quarter of 2022, due in part to the addition of Bonneville Power Administration, Avista Utilities, and Tacoma Power to the WEIM, which increased import and export transfer capacity in the region by 43 percent and 50 percent, respectively.
- **The California ISO was a net importer** during most hours except the middle of the day when low priced solar generation was typically exported to the rest of the system.
- **The CAISO implemented phase 1 of resource sufficiency evaluation enhancements** in June. Phase 1 included supply crediting enhancements.
- **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. DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable.
- **Appendix A includes hourly price and transfer figures for each WEIM area.** As highlighted in the appendix, the transmission loss component of the price in areas located in the Pacific Northwest was high over the quarter and increased during hours with high flows. Since joining the WEIM on May 3, 2022, Bonneville Power Administration has base scheduled the majority of its transfer capacity.

1 Market performance

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

- **Electricity prices were about 77 percent higher** than the same quarter of 2021 due to higher natural gas prices. Day-ahead prices averaged $68/MWh, 15-minute prices averaged $66/MWh, and 5-minute prices averaged $60/MWh.
- **Gas prices doubled at both SoCal Citygate and PG&E Citygate** compared to the same quarter in 2021. This resulted in higher system marginal energy prices across the California ISO footprint.
- **Renewable production increased** by 8 percent compared to the same quarter in 2021, due to an increase of wind, solar, and hydroelectric production.
- **Flexible ramping product system level prices** were zero for over 99 percent of intervals in the 15-minute market, and 99.9 percent of intervals in the 5-minute market for each of upward and downward flexible ramping capacity. Non-zero flexible ramping product prices occurred in areas where minimum area flexible ramping product constraints were binding.
- **Congestion increased in both the day-ahead and real-time markets**. Congestion in the day-ahead market decreased SCE and SDG&E area prices and increased prices in the PG&E area. Total day-ahead congestion rent rose to $269 million, a significant increase from $98 million in the same quarter of the previous year.
- **A 5-minute market only constraint 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 $131 million** in the second quarter, up from $45 million in the previous quarter. Real-time congestion imbalance offset costs were $77 million in June alone, the highest monthly congestion imbalance recorded since locational marginal pricing was introduced in 2009.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $70 million** during the first half of 2022, as payments to auctioned congestion revenue rights holders continued to exceed auction revenues. Second quarter losses at $57.6 million were higher than any other quarter since the California ISO instituted significant auction changes in 2019.
- **Imbalance conformance adjustments** averaged 600 MW during the morning load peak and just over 2,100 MW during the peak net load ramp hours, while maximum levels were about 2,000 MW and 2,700 MW, respectively, with a few outliers over 3,000 MW. 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 $46 million**, an 18.5 percent increase from the second quarter of 2021. Average requirements were higher for operating reserves and regulation down.
- **Net profits paid to convergence bidders increased to about $41 million**, more than the annual total of $38 million in 2021. Overall, virtual supply 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. During the second quarter of 2022, average gas prices at major trading hubs across the west were up by more than 50 percent compared to the previous quarter. When compared to the second quarter of 2021, prices at Henry Hub, PG&E Citygate, SoCal Citygate, El Paso Permian, and Northwest Sumas gas hubs rose by 155 percent, 111 percent, 96 percent, 156 percent, and 145 percent, respectively. Elevated gas prices at these hubs during most days of the quarter led to increased system marginal energy prices.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the West including PG&E Citygate, SoCal Citygate, Northwest Sumas, and El Paso Permian, as well as the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

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. Over the second quarter, prices at the SoCal Citygate gas hub averaged $7.59/MMBtu, up by 54 percent compared to the first quarter and up 96 percent compared to the second quarter of 2021. On November 4, 2021, the California Public Utilities Commission (CPUC) issued an order increasing the inventory limit for the Aliso Canyon Storage Field from 34 Bcf to 41.16 Bcf.[1] This is an interim solution for the winter season to maintain reliability in the SoCalGas territory because of ongoing pipeline constraints since mid-August 2021 on the El Paso system that restricted access to the Permian basin gas supply.

Consistent with the CPUC's ruling on April 29, 2019, SoCalGas Company made changes to its operational flow order (OFO) stages and associated non-compliance penalty structure.[2] The revisions from the CPUC's ruling expired on October 31, 2021. DMM submitted comments regarding a new CPUC ruling to revise the existing penalty structure.[3] On March 18, 2022, a proposed decision was issued to extend SoCalGas' 8-stage winter OFO penalty structure year-round and also make it applicable to the PG&E and

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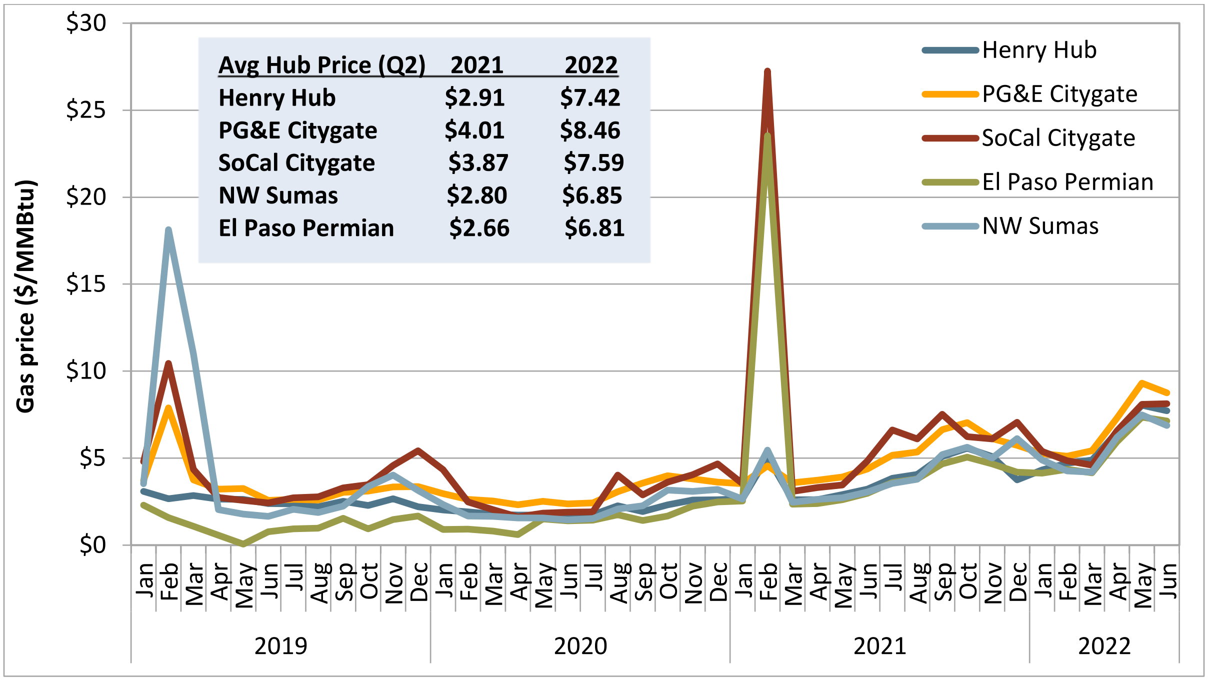
1 CPUC Docket No. I.17-02-002, *Decision Setting the Interim Range of Aliso Canyon Storage Capacity at Zero to 41.16 Bcf (D21-11-008)*, November 4, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

2 Proposed Decision for CPUC Docket No. A.14-12-017 and A.14-06-021, *Decision Granting In Part and Denying In Part for Modification Filed by Southern California Edison & Southern CA Generation Coalition of Commission Decisions D.15-06-004 and D.16-06-039 as Modified by D.16-12-016 Adoption in Part and Rejection in Part of the Settlement Agreement File by Settling Parties,* April 29, 2019, pp.31-32 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF

3 Department of Market Monitoring, *Response to Judge's Ruling Seeking Comments on Safe and Reliable Gas Systems for CPUC Docket No. R.20-01-007,* Aug 14, 2020: http://www.caiso.com/Documents/CPUC-ResponsetoJudgesRulingSeekingComments-SafeandReliableGasSystems-R20-01-007-Aug142020.pdf

SDG&E service territories.[4] In the first half of 2022, SoCalGas declared 14 low OFOs, primarily stage 1. This is in comparison to 42 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



1.1.2 Renewable generation

In the second quarter, the combined average monthly generation from renewable resources increased by about 890 MW (7.8 percent) compared to the same quarter of 2021.[5] Generation from hydroelectric, solar, and wind resources increased while geothermal and biogas-biomass generation decreased. 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 second quarter of 2022 increased by about 480 MW (29 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.[6]

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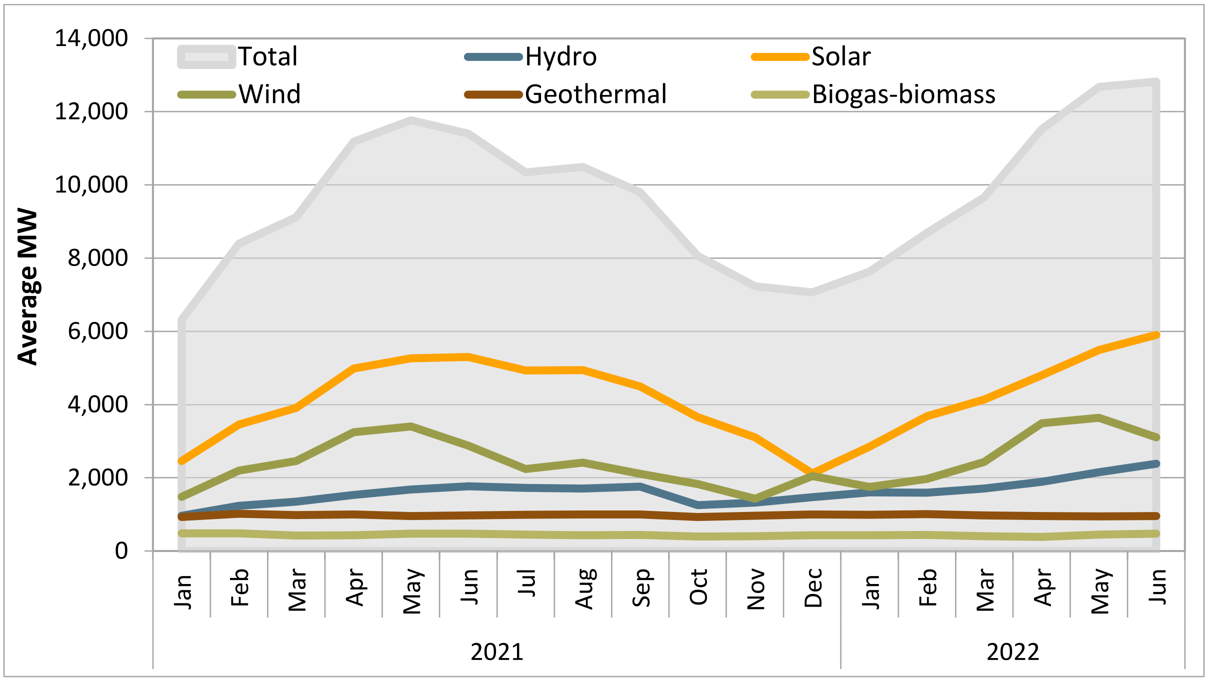
4 Proposed Decision for CPUC Docket No. R.20-01-007, *Decision Implementing Southern California Gas Company Rule 30 Operational Flow Order Winter Non-Compliance Penalty Structure Year-Round for Southern California Gas Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company,* March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

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

6 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/.

Figure 1.2 shows the average monthly renewable generation by fuel type.[7] Solar generation increased 210 MW (4.1 percent), while wind generation increased 240 MW (7.6 percent). Generation from geothermal and biogas-biomass resources decreased 22 and 23 MW (2.3 percent and 5.1 percent), respectively.

Figure 1.2 Average monthly renewable generation



1.1.3 Downward dispatch and curtailment of variable energy resources

Wind and solar downward dispatch and curtailments increased sharply in the second quarter, doubling in the California ISO and sextupling in the WEIM balancing areas, relative to the second quarter of 2021. The rise in downward dispatch in the California ISO and WEIM balancing areas was due to increased renewable generation and internal congestion.[8] 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

7 Hydroelectric generation greater than 30 MW is included.

8 See Section 1.1.2 for more information on renewable generation and Section 1.8.2 for more information on real-time internal congestion.

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.[9] 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; [10]
- **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;[11]
- **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 (97 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.

In the California ISO balancing area, economic downward dispatch peaked in April and totaled 1,272 GWh for the quarter. This is double the amount from the second quarter of 2021. Self-schedule curtailment totaled 9 GWh for the quarter, a 3 percent decrease relative to the second quarter of 2021.

Figure 1.4 shows the amount of downward dispatch of 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 spiked in June, jumping from 28 GWh in May to

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9 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. California ISO curtailment data will typically be lower than DMM's calculations.

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

11 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.

103 GWh in June. Much of the curtailment in the WEIM was due to the high levels of congestion in June from mitigating actions to address unscheduled flows.

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

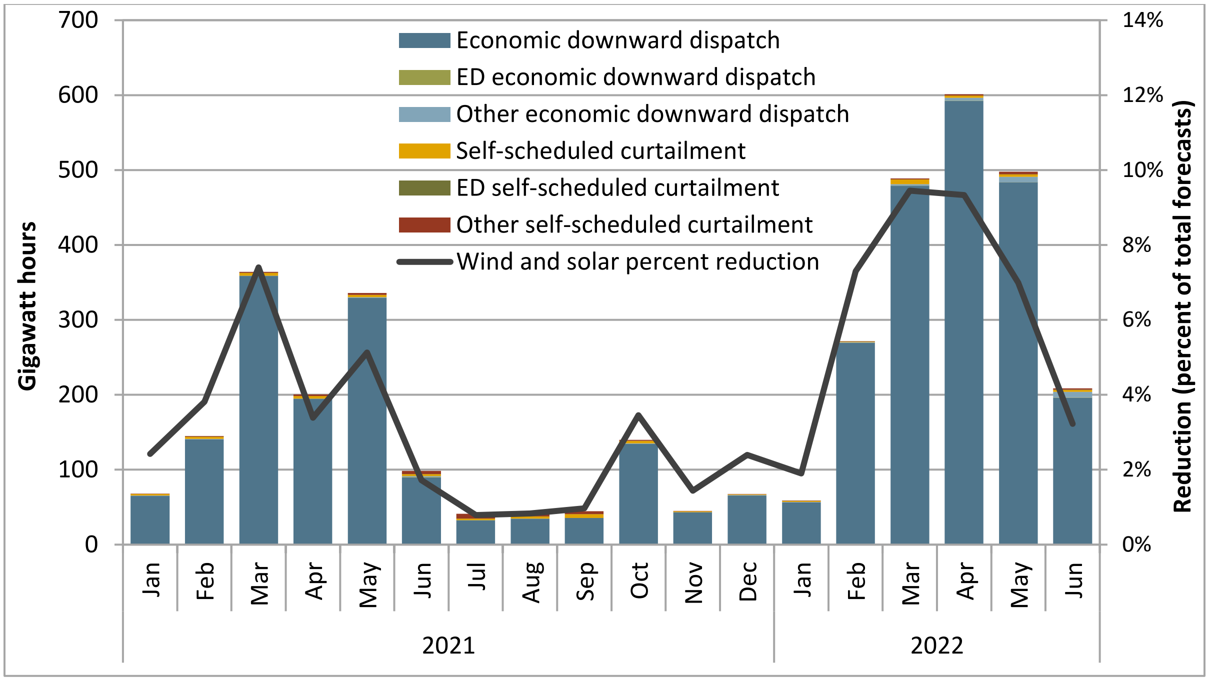
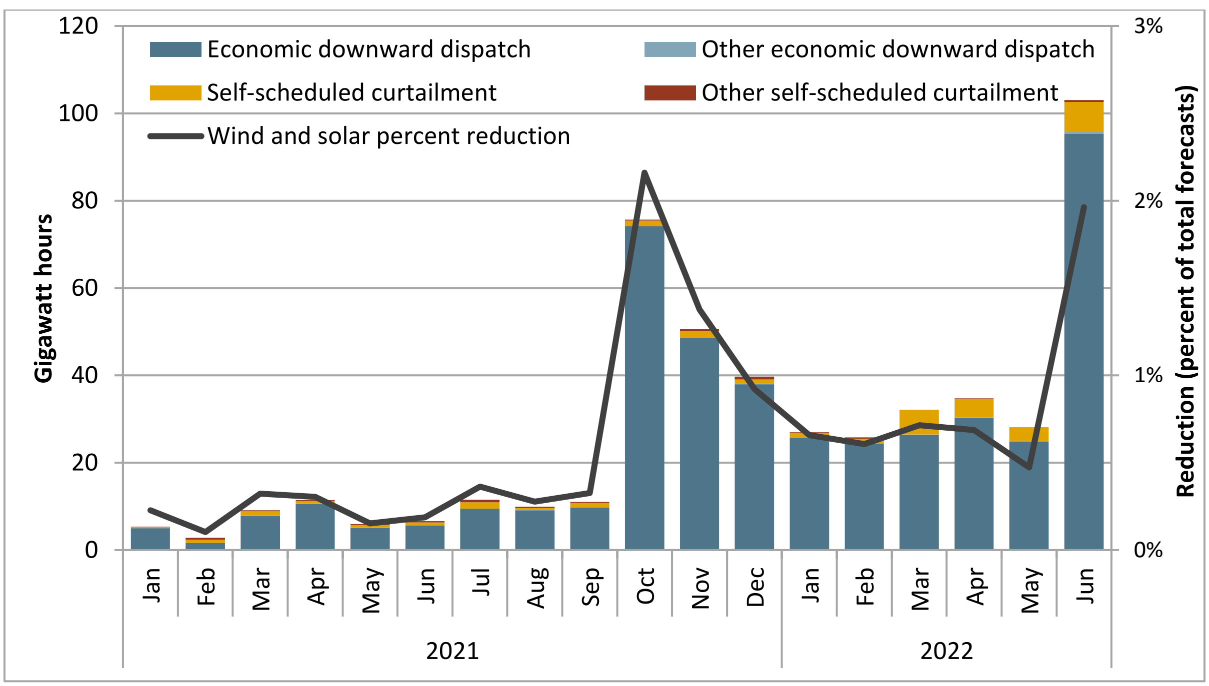


Figure 1.4 Reduction of wind and solar generation by month (WEIM)



1.1.4 Generation by fuel type

In the second quarter, natural gas generation decreased, while hydro, wind, and battery generation increased. Average hourly generation by natural gas resources fell by 14 percent compared to the same quarter of 2021. Hydroelectric and wind generation increased 28 percent and 7 percent, respectively. Average hourly generation by batteries more than doubled relative to the second quarter of 2021.

Figure 1.5 shows the average hourly generation by fuel type during the second quarter of 2022. Total hourly average generation peaked at about 29,450 MW during hour ending 19. Average hourly battery generation peaked at about 1,250 MW during hour ending 20, about three times more than the same time last year. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed to 37 percent of total generation during the peak net load hours of 17-21, up from 35 percent during the same time last year.

Figure 1.5 Average hourly generation by fuel type (Q2 2022)

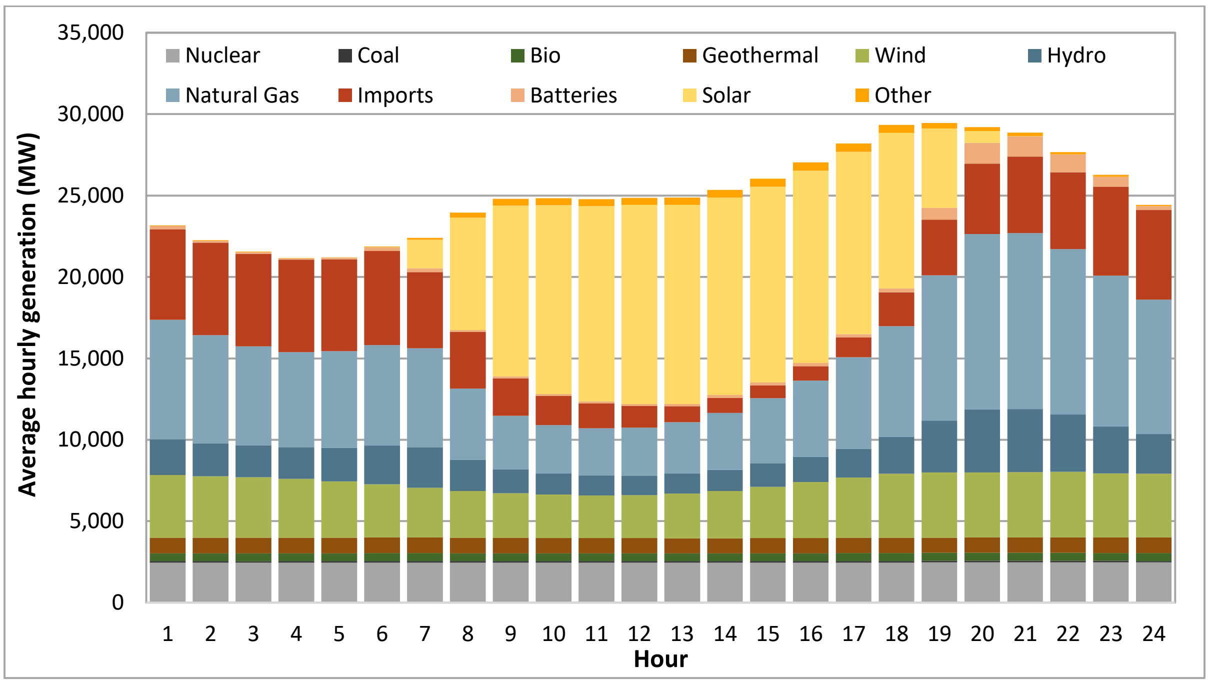


Figure 1.6 shows the change in hourly generation by fuel type between the second quarter of 2021 and the second quarter of 2022. In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

Overall, the net change shows that there was a decrease in average hourly generation in the middle of the day, accompanied by an increase in the evening and morning hours. During all hours of the day, natural gas and coal generation was lower than the second quarter of 2021. The reduction in natural gas generation was due in part to higher fuel costs and increased renewable generation.

Figure 1.6 Change in average hourly generation by fuel type (Q2 2021 to Q2 2022)

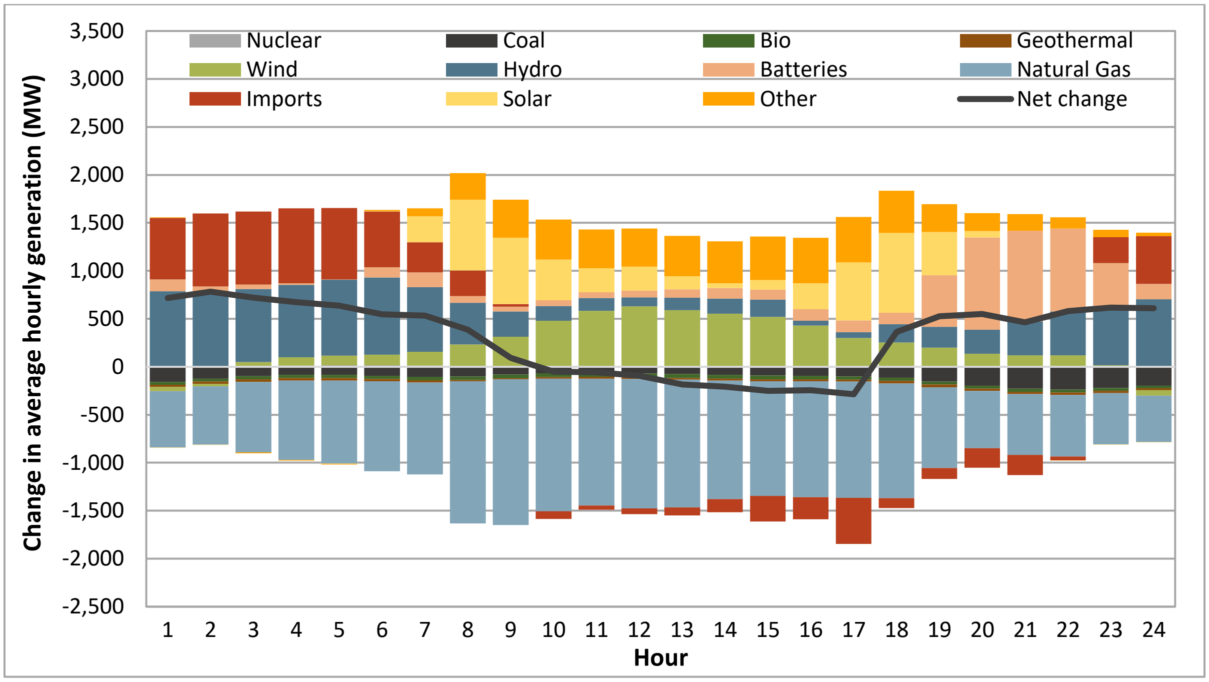
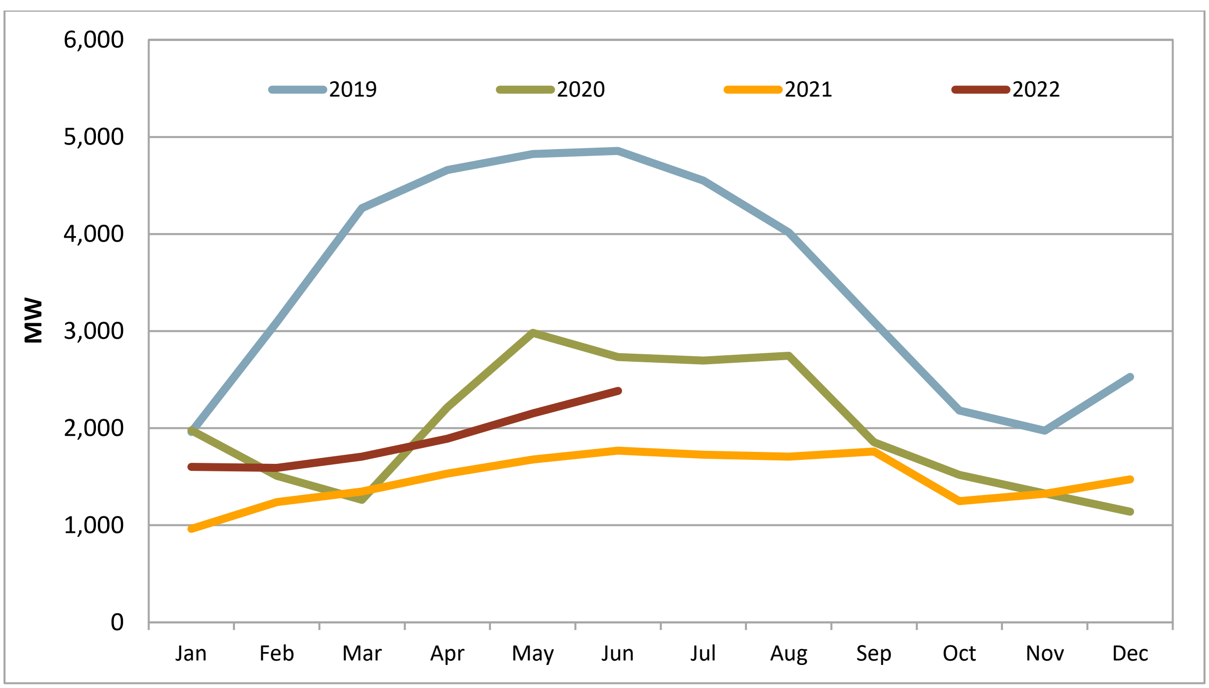


Figure 1.7 shows the monthly average hydroelectric generation from 2019 to 2022. Hydroelectric generation in the second quarter of 2022 was 28 percent higher than the same time last year.

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 15,150 MW, 6 percent higher than the second quarter of 2021. This increase was driven by forced outages, which increased 21 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 to be 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; 2022 follows this trend with planned maintenance outages decreasing over the second quarter as summer approaches.

During the second quarter of 2022, the average total generation on outage in the California ISO balancing area was 15,150 MW, almost 900 MW more than the second quarter of 2021, as shown in Figure 1.8.[12] There were 21 percent more forced outages and 15 percent fewer planned outages than the same quarter last year.

12 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

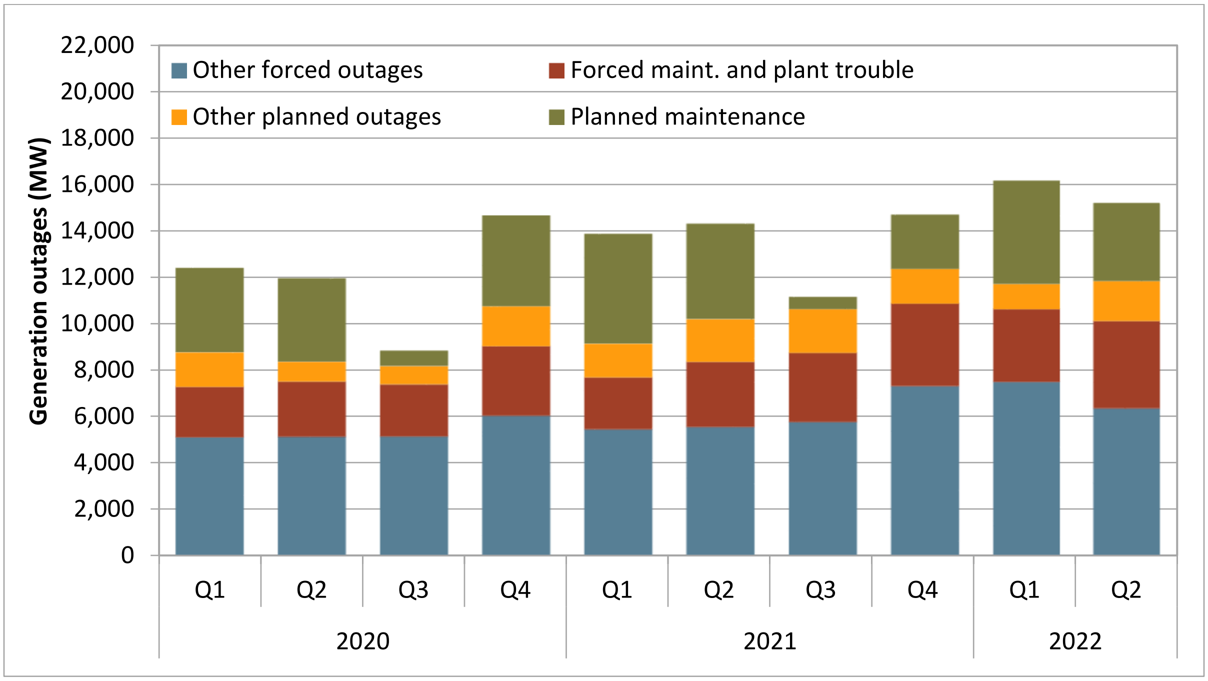
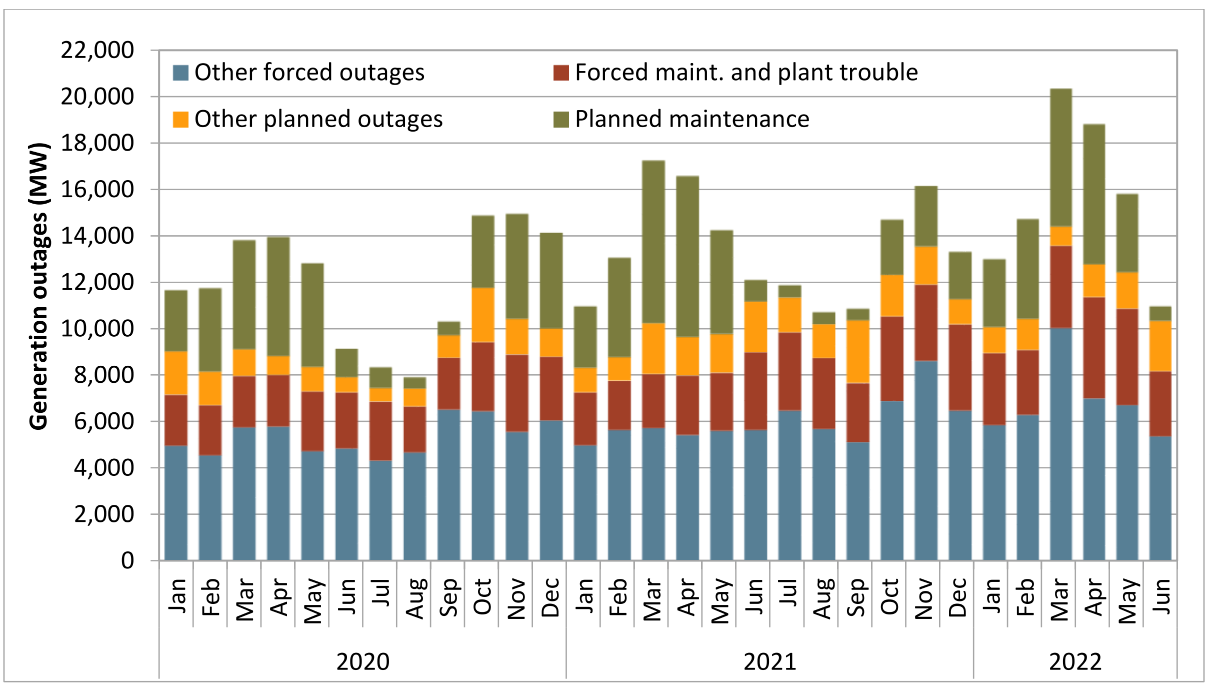


Figure 1.9 Monthly average of maximum daily generation outages by type – peak hours

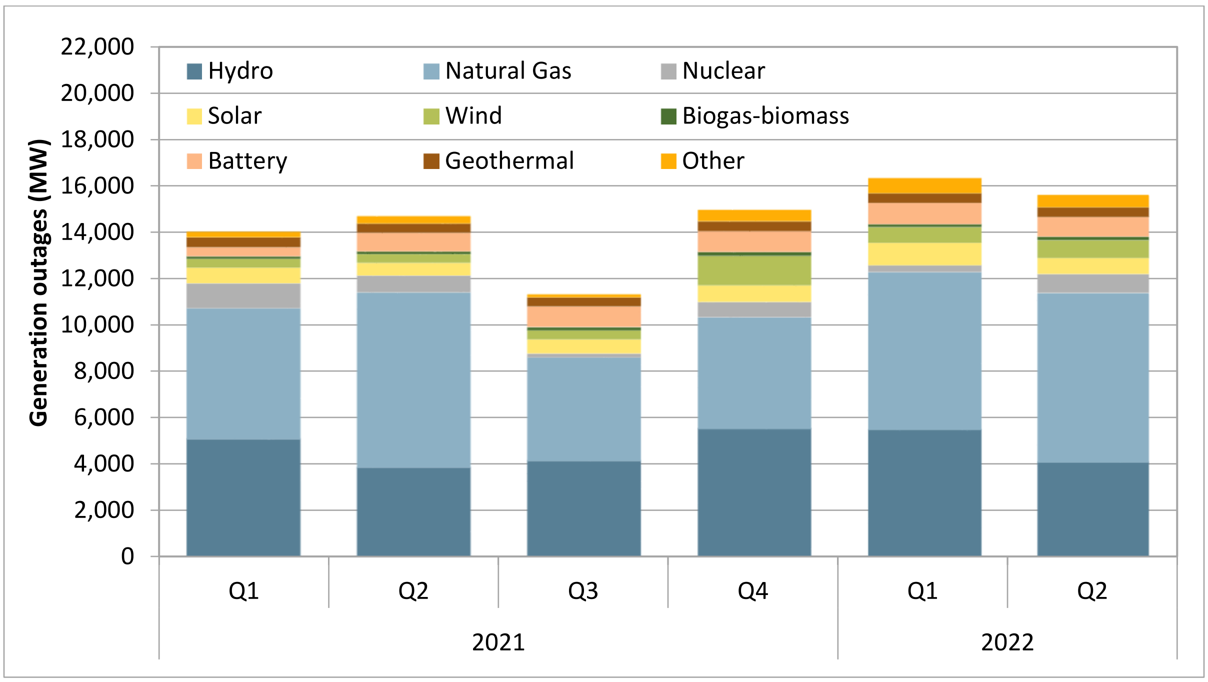


Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged 7,299 MW and 4,066 MW during the second quarter, respectively. These two fuel types accounted for a combined 73 percent of the generation on outage for the quarter. The amount of natural gas generation on outage decreased 3 percent relative to the second quarter of 2021 while hydroelectric generation on outage increased 6 percent.

Figure 1.10 shows the quarterly average of maximum daily generation outages by fuel type during peak hours.[13] All fuel types, with the exception of natural gas, saw higher average amounts of generation on outage compared to the second quarter of 2021. Wind generation outages doubled to 775 MW from 386 MW during the time last year.

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

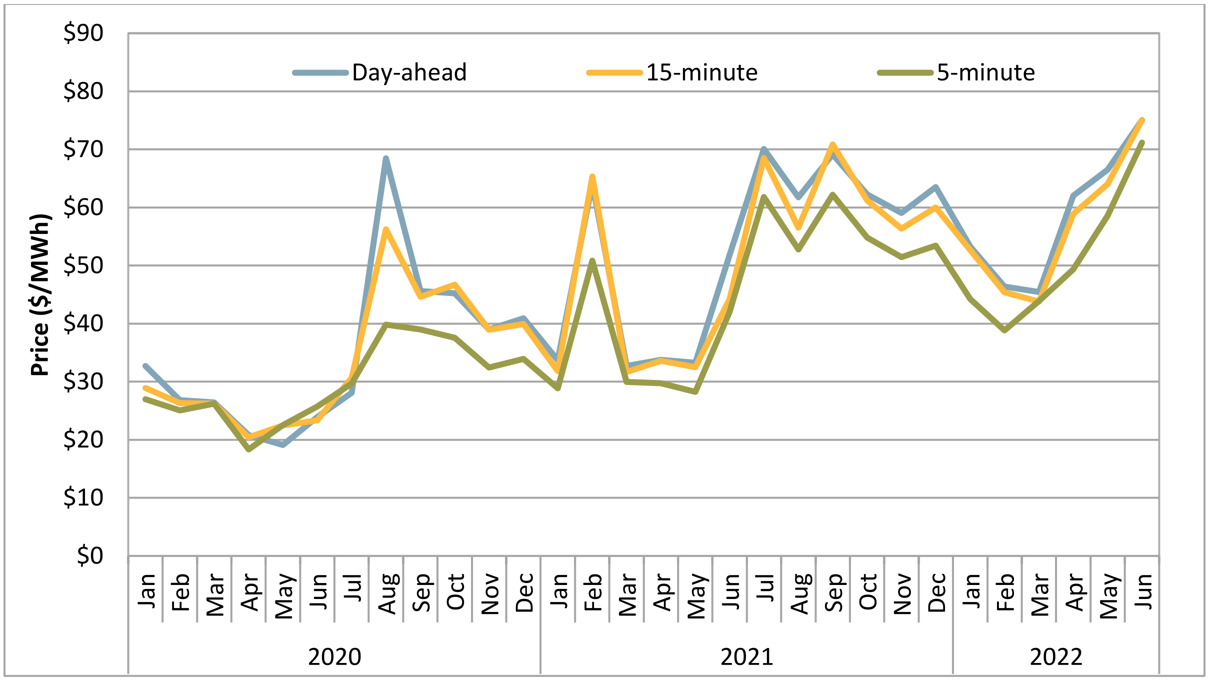
This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Prices in all three markets were about 77 percent higher this quarter compared to the second quarter last year.

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

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

Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2020 to June 2022.

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



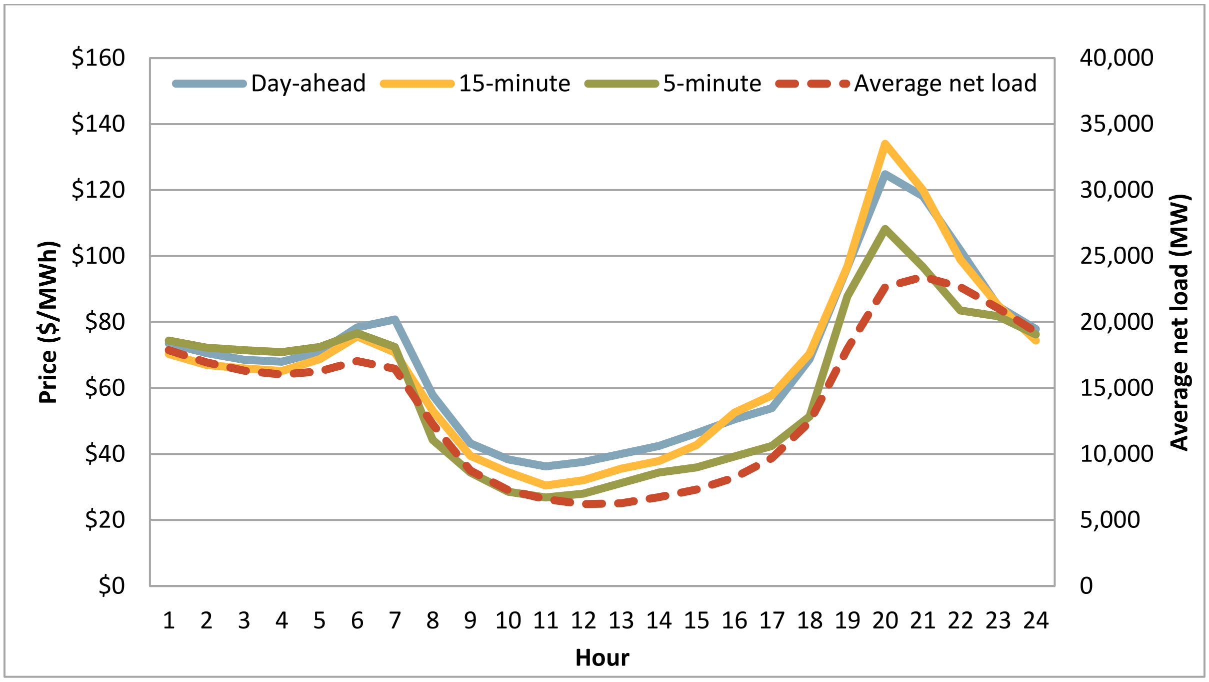
Day-ahead prices averaged $68/MWh, 15-minute prices averaged $66/MWh, and 5-minute prices averaged $60/MWh. Prices across all three markets were about 72-80 percent higher than the second quarter last year. All three prices in June 2022 recorded their highest price since January 2020. The day-ahead price for June 2022 reached $75/MWh, the 15-minute price reached $75/MWh, and the 5-minute price reached $71/MWh.

Figure 1.12 illustrates load-weighted average energy prices on an hourly basis for the quarter compared to average hourly net load.[14] 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 is still high but solar generation has substantially decreased. Overall, net load in the second quarter in 2022 was lower than the same quarter of the previous year in all hours of the day.

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

Figure 1.12 Hourly load-weighted average energy prices (April - June)



1.2.2 Bilateral price comparison

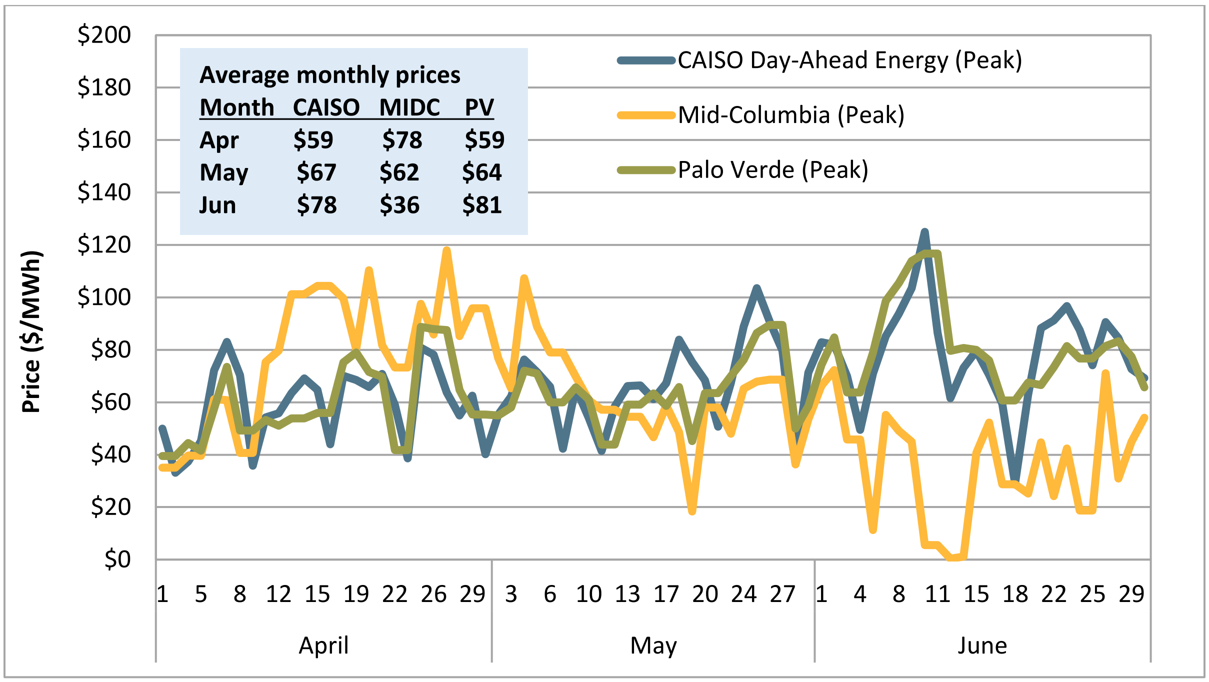
On average, day-ahead market prices were higher in the California ISO and Palo Verde hub than at the Mid-Columbia hub across peak hours in the second quarter. Regional differences in prices reflect transmission constraints as well as greenhouse gas compliance costs.

Figure 1.13 shows the California ISO's 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 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 that the California ISO and Palo Verde prices during peak hours followed closely and diverged significantly from Mid-Columbia bilateral hub prices during most days in the second quarter. Figure 1.14 uses the same data underlying Figure 1.13 but on an average monthly basis for 2021 and 2022. Prices in the California ISO balancing area are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points (DLAPs). As shown in this figure, average prices at these points and the Palo Verde hub are significantly higher than average bilateral prices at Mid-Columbia in June 2022.

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.[15] DMM estimates the refunds to be about $4 million out of $83 million in bilateral sales exceeding the WECC soft offer cap during August 2020.[16] FERC has yet to rule on some of the cost justification filings during August 2020 and begin issuing orders related to June 2021 filings.

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 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 $17/MWh and $13/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 $3/MWh and $7/MWh, respectively.

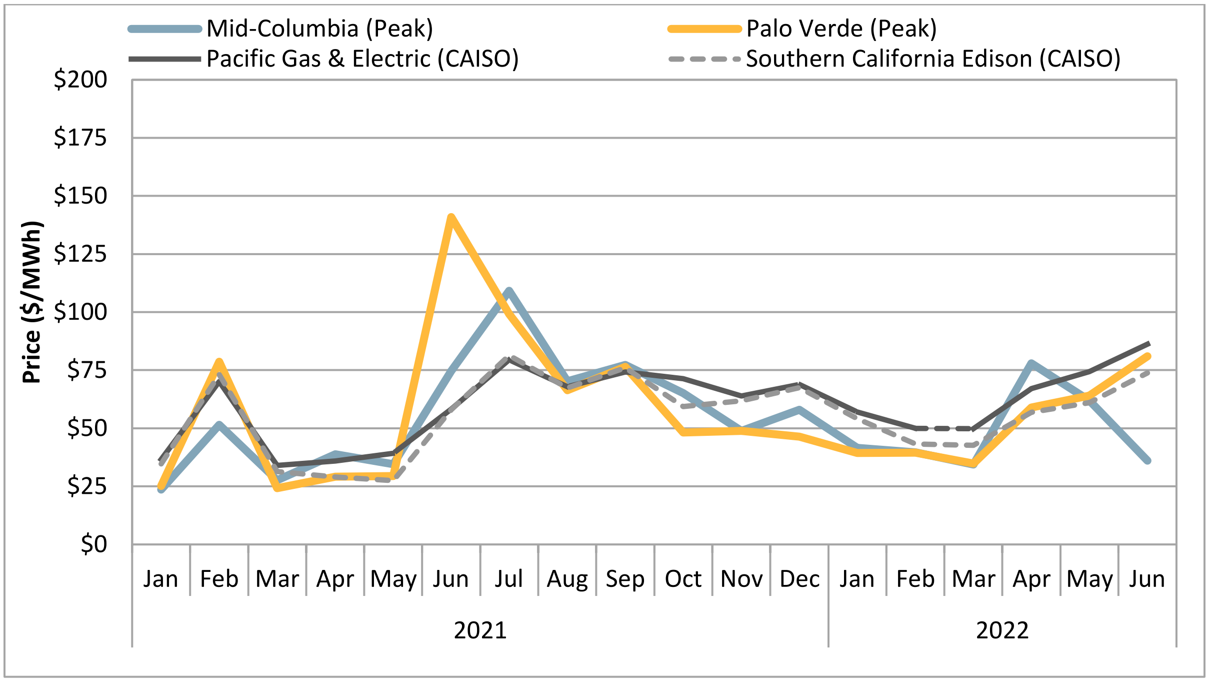
Figure 1.13 Day-ahead California ISO and bilateral market prices (Apr - Jun)



15 FERC issued orders on a number of sellers and directing them to refunds for sales during August 2020. Follow the order directing refunds regarding Mercuria Energy America, LLC under FERC Docket No. ER21-46: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220422-3059&optimized=false

16 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



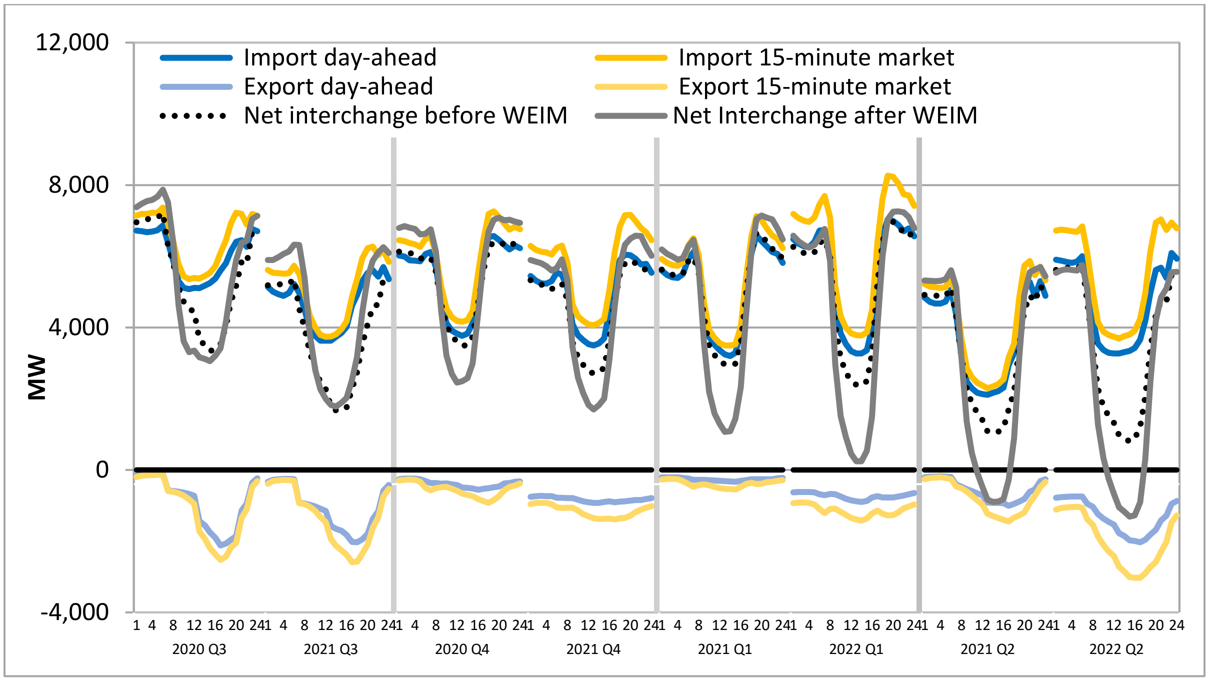
Imports and exports

Average imports and exports both 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 hour ending 23, from about 5,300 MW to 6,100 MW, compared to the same quarter of 2021. Peak 15-minute cleared imports (dark yellow line) also increased in all hours of the day, peaking at about 7,000 MW in hour ending 21, compared to about 5,900 MW in the same period last year. 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, peaking in hours ending 15 through 18 at about 2,000 MW and 3,000 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 including (solid grey line) and excluding WEIM transfers (dashed black line), about 100 MW and 200 MW on average by hour. During the solar ramp down period imports decreased both when including and excluding the WEIM, hourly average of 200 MW and 650 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 -1,300 MW in hour ending 15. The greatest import transfer into the California ISO area from the WEIM occurred in hour ending 7, at about 400 MW, compared to about 900 MW in hour ending 22 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 18, with hour ending 16 topping out at about 2,200 MW. This is an increase from the same quarter of the previous year with a maximum export in hour ending 16 at about 2,000 MW.

Figure 1.15 Average hourly net interchange by quarter



In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the CAISO markets at or below $0/MWh, at minimum in the availability assessment hours.[17] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices. An overall decline in volumes began in late 2020 and continued throughout 2021 as well as into the first half of 2022. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports.

Figure 1.16 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[18] 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.

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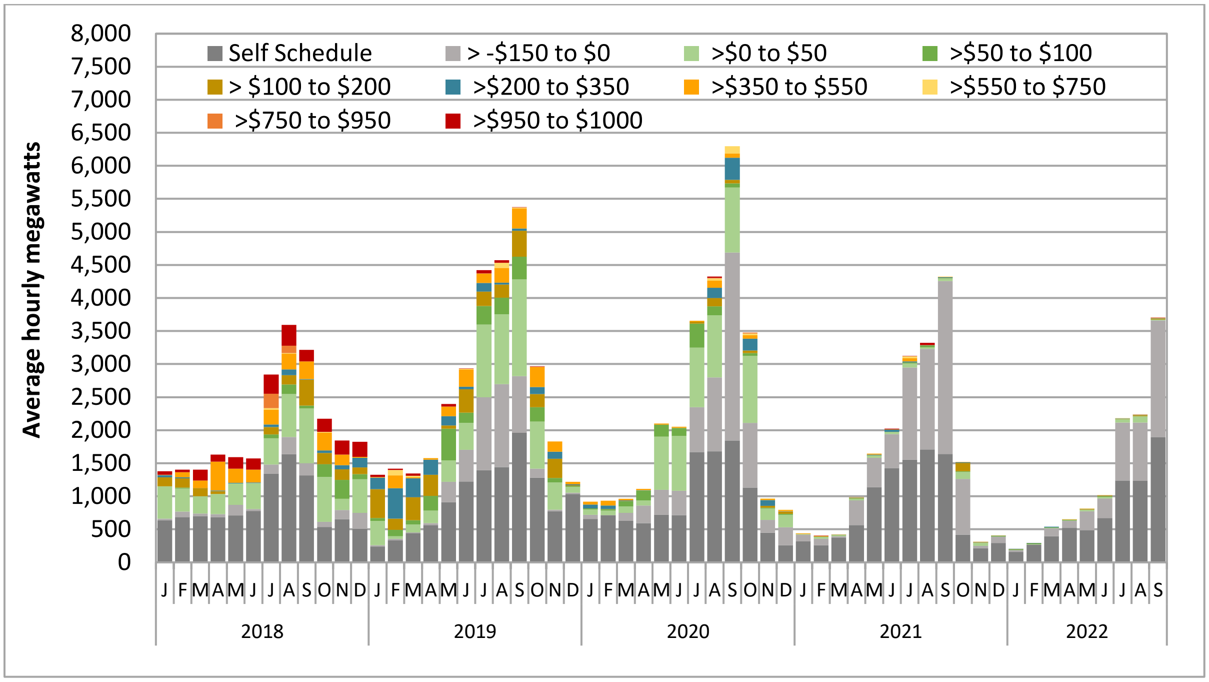
17 In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh or when the CAISO has accepted 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.

18 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

This quarter showed greater price variability in the 15-minute and 5-minute markets compared to last year's second quarter. Both markets showed a high frequency of prices between $250/MWh and $500/MWh. The day-ahead market exhibited relatively low price variability; the frequency of high prices fell to 0.05 percent from 0.31 percent in the second quarter of 2021

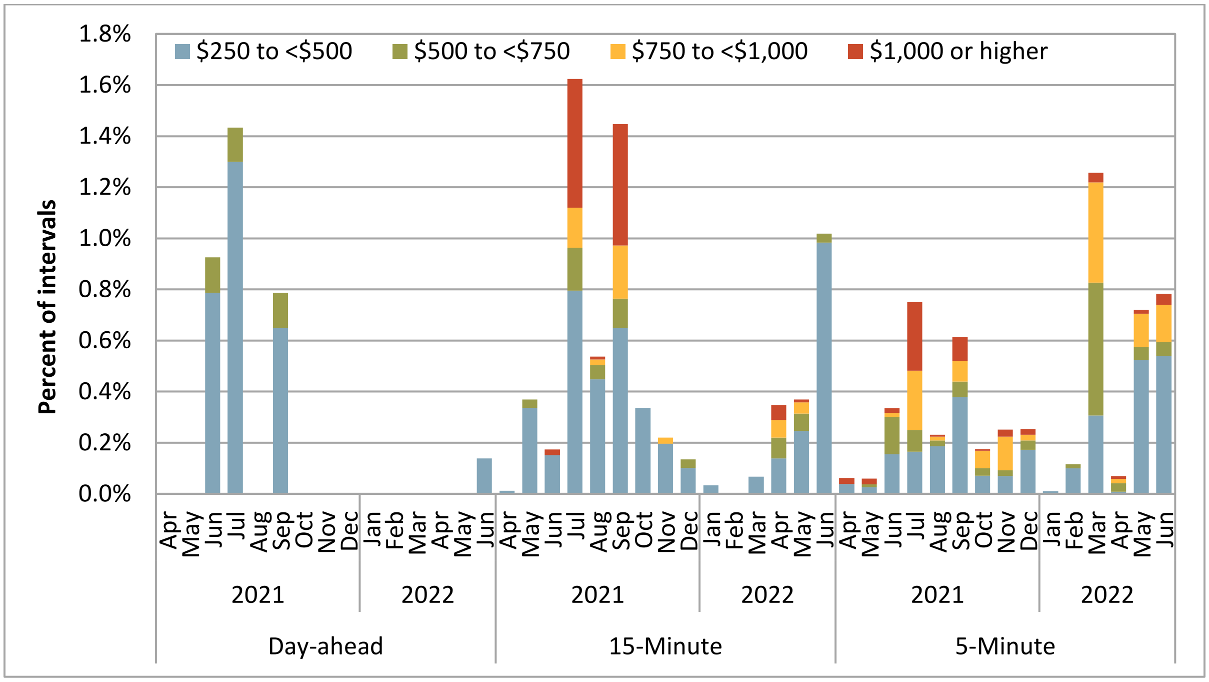
High prices

Figure 1.17 shows the monthly frequency of high prices across all three markets across the three largest load aggregation points (LAP) from April 2021 to June 2022. In the day-ahead market, the frequency of high prices over $250/MWh decreased in the second quarter this year compared to last year to an average of 0.05 percent of intervals.

The 15-minute market had a higher frequency of price spikes in this quarter. Prices above $250/MWh rose to about 0.58 percent from 0.18 percent in the second quarter of last year. About 80 percent of these high prices were between $250/MWh and $500/MWh, and about 20 percent were above $500/MWh. The frequency of high prices was highest in June 2022.

The 5-minute market also had more frequent price spikes this quarter. Prices above $250/MWh rose to 0.52 percent in the second quarter of 2022 from 0.15 percent in the same quarter last year. About 70 percent of these high prices ranged between $250/MWh and $500/MWh and about 30 percent of prices were above $500/MWh.

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



High prices can occur during intervals in which there is a power balance constraint relaxation. When the California ISO and the Western Energy Imbalance Market run out of ramping capability in the upward direction, prices can be set at the $1,000/MWh penalty parameter.[19] There were no under-supply infeasibilities in the second quarter.

The higher frequency of price spikes this quarter was due to higher fuel costs, increased congestion, and a higher frequency of high demand intervals. On the demand side, the California ISO area experienced above-average temperatures in May and June 2022. On the supply side, gas prices at key delivery points almost doubled in this quarter compared to the same quarter of 2021. For the 15-minute and 5-minute markets, the ISO area experienced a high frequency of transfer constraint congestion this quarter compared to the second quarter last year.

Negative prices

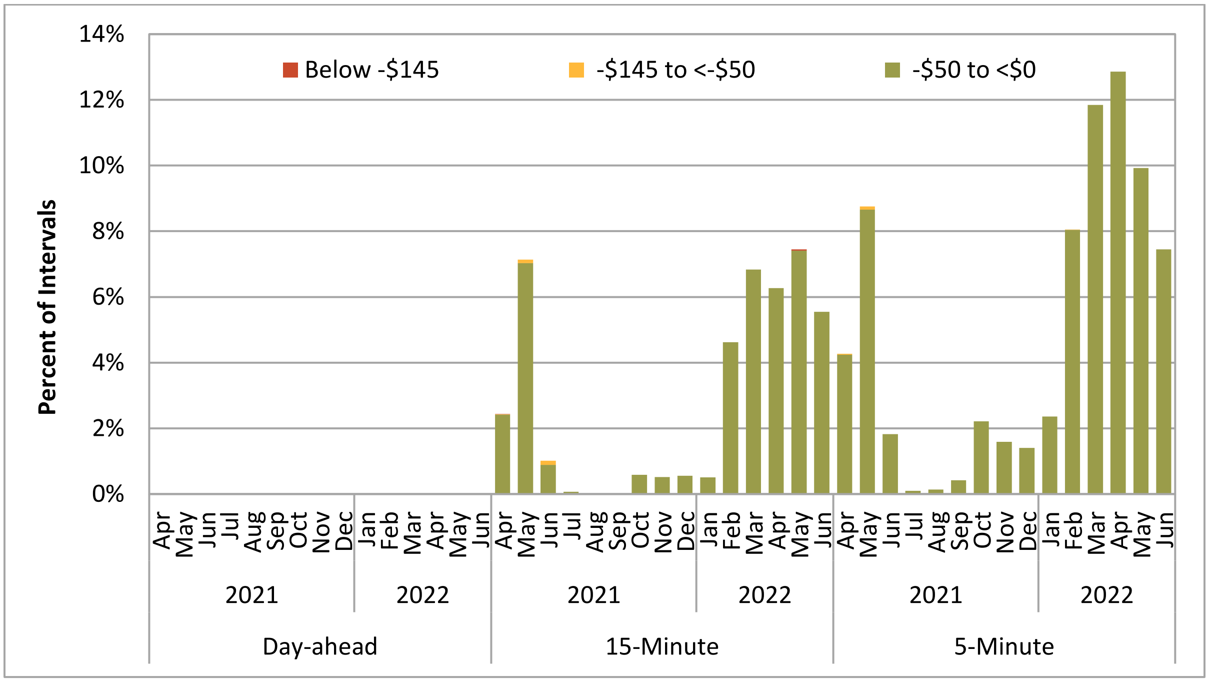
Figure 1.18 shows the frequency of market prices across all three markets in various low priced ranges from April 2021 to June 2022. Overall, negative prices were more frequent in the 15-minute and 5-minute markets, compared to the day-ahead market.

In the 15-minute and 5-minute markets, negative prices increased to about 8 percent this quarter compared to about 4 percent in the second quarter of last year. There were no negative prices in the day-ahead market, down from about 0.7 percent in the second quarter of last year.

[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

Negative prices tend to be the most common when renewable production is high but demand is low. These low-cost renewable resources often bid at or below zero. This quarter recorded a lower net load and higher renewable generation.[20] This increased chances of this low-cost generation being price-settling units, leading to higher frequency of negative prices in the real-time market.

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



1.4 Flexible ramping product

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

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

20 Section 1.1.2 shows that the lower cost renewable generation increased this quarter: hydroelectric and wind generation increased 23 percent and 8 percent, respectively. In addition, Figure 1.4 shows that wind and solar downward dispatch and curtailment increased in this quarter compared to the same quarter last year.

1.4.1 Flexible ramping product requirement

The end of the demand curve is implemented in the California ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This requirement for rampable capacity reflects the upper end of uncertainty that might materialize.[21] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

There are separate demand curves calculated for each WEIM area in addition to a system-level demand curve. The system uncertainty requirement for the entire footprint is always enforced in the market, while the uncertainty requirement for the individual balancing areas is reduced in every interval by their transfer capability.[22] Previously, if the transfer capability for each area was sufficient, then only the system-level uncertainty requirement was active.

The flexible ramping product refinements stakeholder initiative introduced a new minimum flexible ramping product requirement. Beginning in November 2020, if an individual balancing authority area requirement is greater than 60 percent of the system requirement, then a minimum procurement requirement will be enforced, equal to the balancing authority area's share of the diversity benefit.[23] The minimum requirement is intended to help mitigate some of the issues surrounding procurement of stranded flexible ramping product prior to the implementation of the nodal procurement, expected in fall 2022.

A minimum requirement helps procure flexible ramping capacity within areas that contribute to a large portion of system-wide uncertainty. This is typical only in the CAISO area, which had a minimum *upward* requirement enforced in around 90 percent of 15-minute market intervals during the quarter. The minimum *downward* requirement was enforced much less frequently for the California ISO area, in only 31 percent of 15-minute market intervals.

The minimum requirement was added to the 5-minute market on February 16, 2022. During the quarter, the 5-minute minimum requirement was enforced for the CAISO area during around 76 percent of intervals for each of upward and downward ramp.

1.4.2 Flexible ramping product prices

The flexible ramping product procurement and shadow prices are determined from demand curves. When the shadow price is $0/MWh, the maximum value of capacity on the demand curve is procured. This reflects that flexible ramping capacity is readily available relative to the need for it, such that there is no cost associated with the level of procurement.

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21 Based on a 95 percent confidence interval from historical data for the same hour. Weekdays use data from the last 40 weekdays; for weekends, the last 20 weekend days are used.

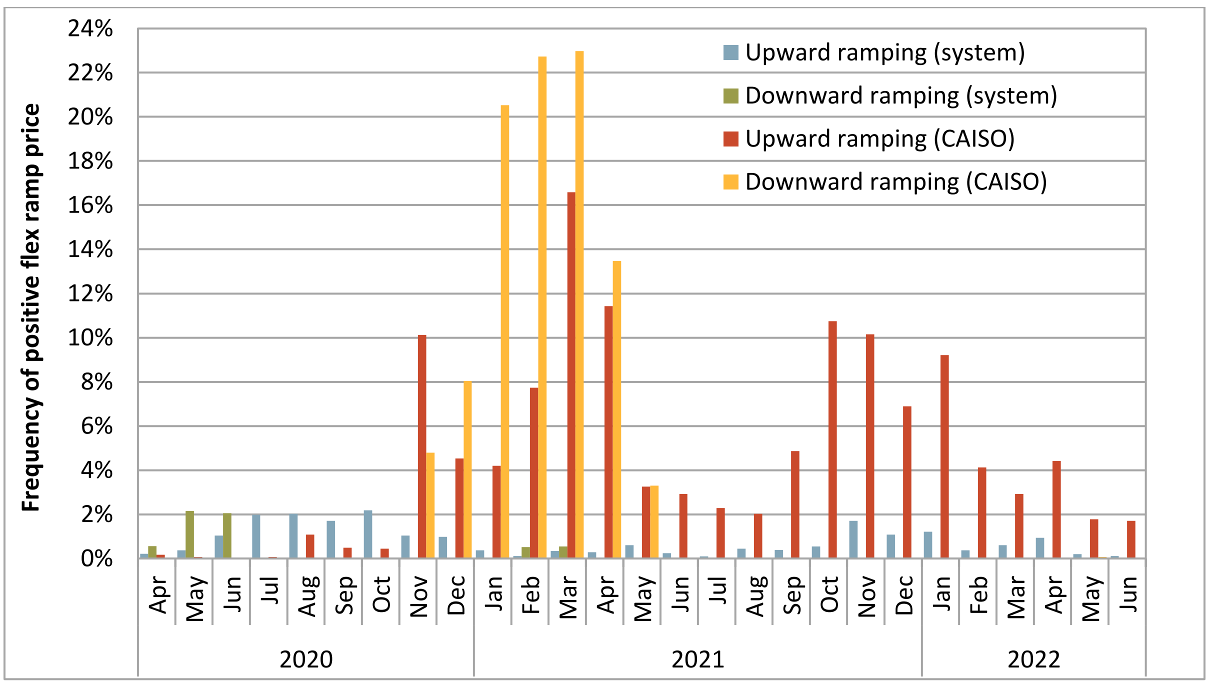
22 In each interval, the upward uncertainty requirement for each area is reduced by net import capability while the downward uncertainty requirement is reduced by net export capability. If the area fails the sufficiency test in the corresponding direction, the uncertainty requirement will not include this reduction.

23 For example, if a balancing authority area's upward requirement is 1,000 MW and it is greater than 60 percent of the system requirement, and the diversity benefit factor (ratio of the system requirement to the sum of all area requirements) is 25 percent, then the minimum requirement for this area would be 250 MW.
See California ISO, *Flexible Ramping Product Refinements Final Proposal*, August 31, 2020:
http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

Figure 1.19 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. The percent of intervals in which the CAISO demand curve bound at a positive shadow price is also shown. This is driven by the minimum requirement, which typically necessitates a portion of flexible ramping capacity to be procured within the CAISO area.

The frequency of positive shadow prices for the *system* continued to be low overall. During the quarter, the 15-minute market system-level demand curve bound in less than 1 percent of intervals for upward ramping and less than 0.1 percent of intervals for downward ramping. In the 5-minute market, the system-level demand curves for upward and downward ramping capacity were positive in less than 0.1 percent of intervals.

Figure 1.19 Monthly frequency of positive system or California ISO flexible ramping shadow price (15-minute market)



1.5 Convergence bidding

Convergence bidding is designed to align day-ahead and real-time prices by allowing financial arbitrage between the two markets. In this quarter, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014.

Overall, convergence bidding was profitable in the second quarter of 2022. Combined net revenue for virtual supply and demand was about $40.7 million, after including about $4.5 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about $9 million for the quarter, while virtual supply generated about $36.2 million, before accounting for bid cost recovery charges. The vast majority of profits continue to be received by financial entities and marketers, about 78 percent and 22 percent, respectively, with less than one percent going to physical load and generation.

1.5.1 Convergence bidding revenues

Participants engaged in convergence bidding in this quarter were overall profitable. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $45.3 million. Net revenues for virtual supply and demand fell to about $40.7 million after the inclusion of about $4.5 million of virtual bidding bid cost recovery charges,[24] primarily associated with virtual supply.

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

Before accounting for bid cost recovery charges:

- Total market revenues were positive during all months of the quarter. Net revenues during the quarter totaled about $45.3 million, compared to about $10.4 million during the same quarter from the previous year, and about $7.8 million during the previous quarter.
- Virtual demand net revenues were about -$0.7 million, $2.3 million, and $7.5 million for April, May, and June, respectively.
- Virtual supply net revenues were $8.7 million, $13 million, and $14.6 million for April, May, and June, respectively.

Convergence bidders received approximately $40.7 million after subtracting bid cost recovery charges of about $4.5 million for the quarter.[25,26] Bid cost recovery charges were about $1.2 million, $2.4 million, and $0.9 million for April, May, and June, respectively.

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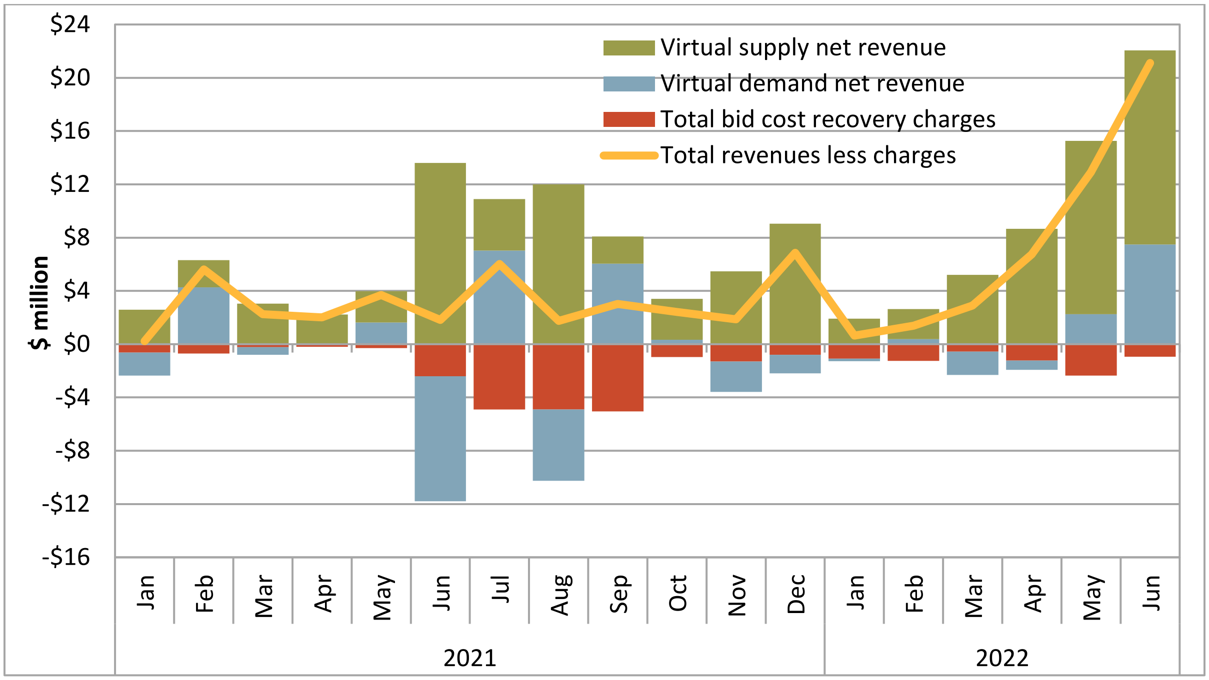
24 For more information on how bid cost recovery charges are allocated please refer to the *Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

25 Further detail on bid cost recovery and convergence bidding can be found in: Department of Market Monitoring, *Q1 2015 Report on Market Issues and Performance,* June 10, 2015, p. 25: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

26 Business Practice Manual configuration guide has been updated for CC 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation, to ensure that the residual unit commitment obligations do not receive excess residual unit commitment tier 1 charges or payments. For additional information on how this allocation may impact bid cost recovery, see: California ISO, *Business Practice Manual Change Management, CC 6806 Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation,* p. 3: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

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 net revenues,[27] in millions of dollars, among different groups of convergence bidding participants.[28]

Financial entities represented the largest segment of the virtual bidding market for the current quarter, with 75 percent of volume and 78 percent of the settlement revenue. Marketers continue to have about 23 percent of volume and 22 percent of settlement revenue while generation owners and load serving entities represent about two percent of volumes and less than one percent of settlement revenues.

Overall prices in the 15-minute market were consistently lower than day-ahead prices in the second quarter. This was a major contributing factor to the dramatic increase in revenue by financial entities to about $31.6 million from about $4.3 million from the previous quarter.

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

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

Table 1.1 Convergence bidding volumes and revenues by participant type – Q2

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	
2022 Q2								
Financial	1,653	2,150	3,803	$6.05	$28.83	-$3.26	$25.57	$31.62
Marketer	474	706	1,180	$2.95	$7.02	-$0.98	$6.04	$8.99
Physical load	0	43	43	$0.00	$0.25	-$0.21	$0.04	$0.04
Physical generation	15	18	32	$0.04	$0.13	-$0.07	$0.06	$0.10
Total	**2,142**	**2,916**	**5,058**	**$9.04**	**$36.23**	**-$4.53**	**$31.70**	**$40.74**

1.6 Residual unit commitment

On average, the total volume of capacity procured through the residual unit commitment process in the second quarter of 2022 was 13 percent lower 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 capacity was procured primarily 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 240 MW higher in the second quarter of 2022 than in the same quarter of 2021.

Residual unit commitment procurement can be increased by operator adjustments to the day-ahead load forecast. In this quarter, operators used this tool on 50 days to increase the residual unit commitment requirements by an average of about 303 MW per hour.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar in Figure 1.21) represents the difference in cleared supply (both physical and virtual) compared to the California ISO load forecast. On average, this factor contributed towards decreasing residual unit commitment requirements in the second quarter of 2022, averaging about -533 MW per hour.

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

Figure 1.21 Determinants of residual unit commitment procurement

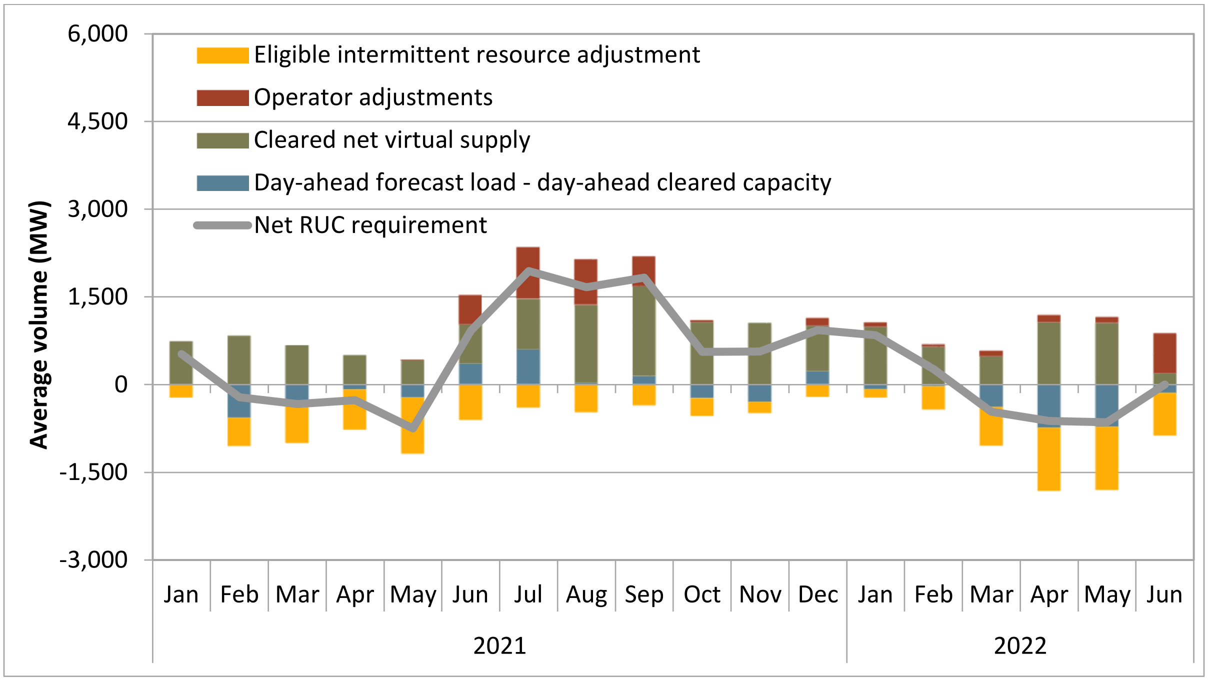
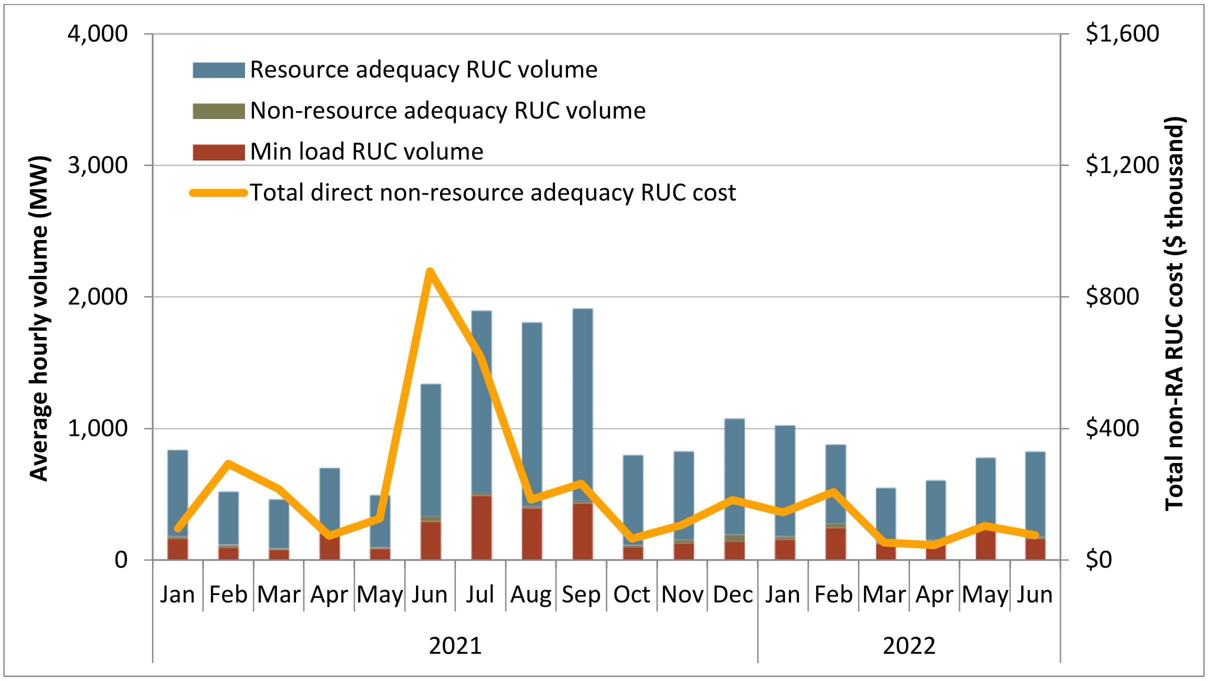


Figure 1.22 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement decreased to about 734 MW in the second quarter of 2022 from an average of 840 MW in the same quarter of 2021. Of the 734 MW capacity, the capacity committed to operate at minimum load averaged 178 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.[29] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.22. In the second quarter of 2022, these costs were about $0.2 million, about $0.8 million lower than the same quarter of 2021.

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

Figure 1.22 Residual unit commitment costs and volume



1.7 Ancillary services

Ancillary service payments this quarter totaled nearly $46 million, an 18.5 percent increase from the second quarter of 2021. Average requirements were higher for operating reserves and regulation down compared to the same quarter last year.

1.7.1 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.[30] 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.

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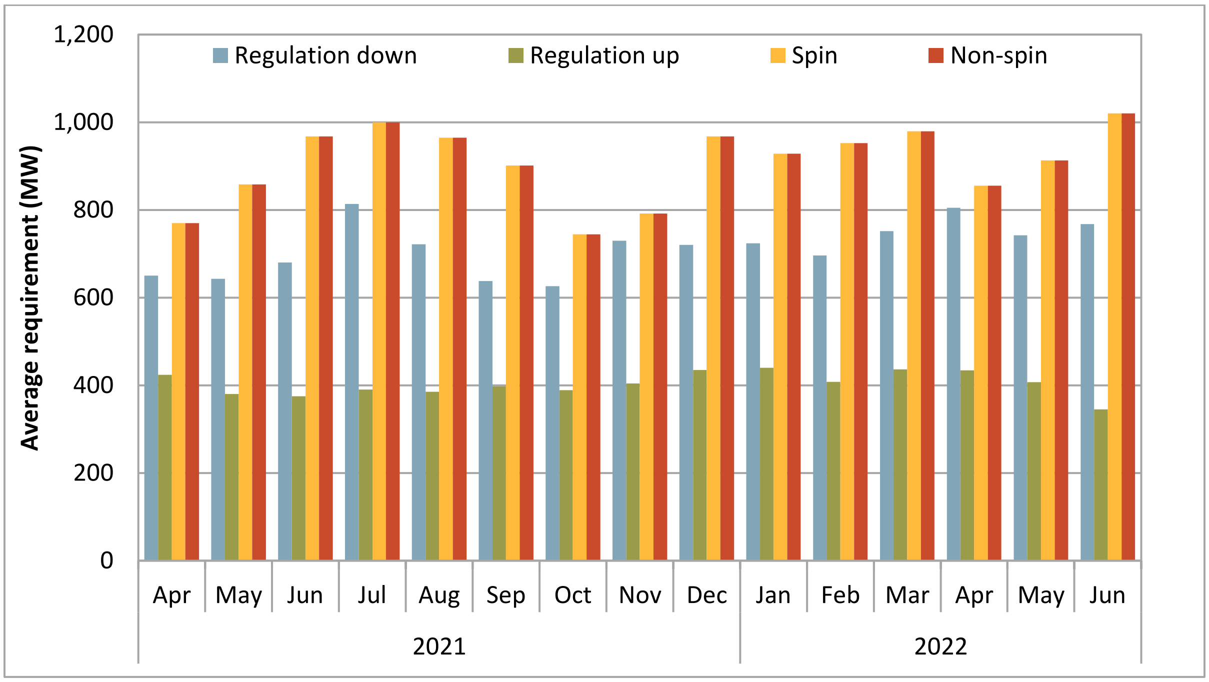
30 More information on ancillary services requirements and procurement for internal and expanded regions is available in Department of Market Monitoring, *2020 Annual Report on Market Issues & Performance*, August 2021, p. 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

Figure 1.23 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown, average requirements for operating reserves increased 7 percent this quarter compared to the second quarter of 2021. This increase is in part due to the increase in exports, since operating reserves are based on load forecast and generation. Average regulation up requirements were nearly the same as in the second quarter of 2021. However, average regulation down requirements increased by 17 percent in the same time frame, largely due to increased renewable penetration.

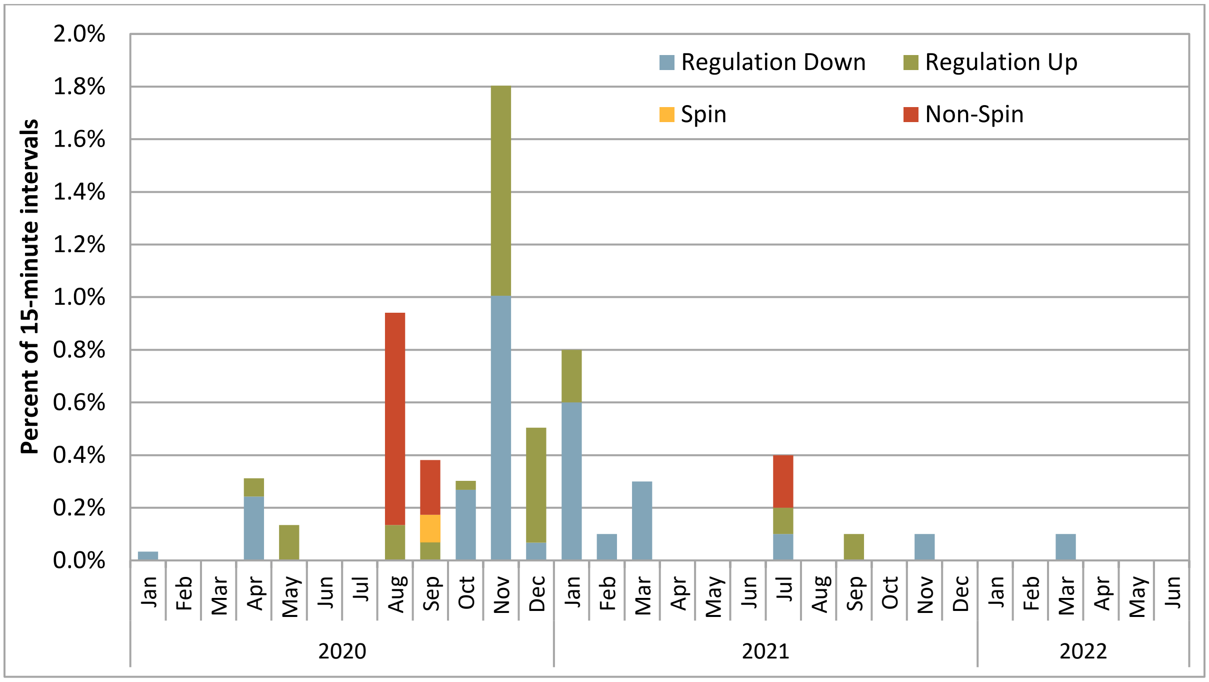
Figure 1.23 Average monthly day-ahead ancillary service requirements



1.7.2 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. Similarly to the second quarter of 2021, only one scarcity event occurred this quarter. As shown in Figure 1.24, the frequency of intervals with scarcity pricing have remained low in 2022.

Figure 1.24 Frequency of ancillary service scarcities (15-minute market)



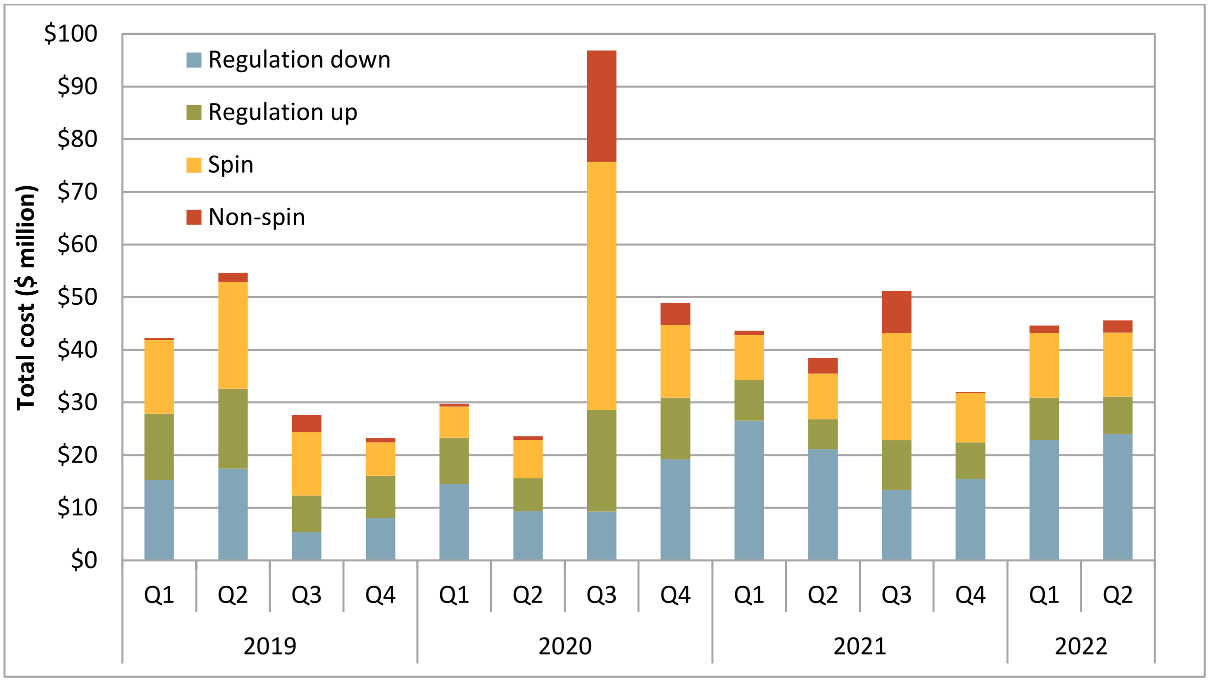
1.7.3 Ancillary service costs

Ancillary service payments reached nearly $46 million, around $1 million more than the previous quarter and $7 million more than the same quarter last year.

Figure 1.25 shows the total cost of procuring ancillary service products by quarter.[31] Spinning reserve procurement contributed the most to increased costs, with a $3.4 million increase, nearly 40 percent over what was paid in the second quarter of 2021. Over this same period, regulation down and regulation up payments increased by $2.9 million and $1.4 million respectively, whereas non-spinning reserve procurement decreased by around $600,000.

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

Figure 1.25 Ancillary service cost by product



1.8 Congestion

In the day-ahead market, congestion in the second quarter was more impactful than the same quarter last year, raising prices in PG&E and lowering prices in SCE and SDG&E areas. 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 California ISO balancing area (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric) as well as on the 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 California ISO system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes as well as for groups of nodes that represent different load aggregation points or local capacity areas.[32]

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

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.

1.8.1 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 second quarter of 2022, congestion rent and loss surplus was $269 million and $81 million, respectively. These respective amounts represent an increase of 174 percent and 83 percent relative to the same quarter of 2021.[33] Figure 1.26 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.[34]

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33 Due to the availability of data, comparative analysis in Figure 1.26 and the day-ahead congestion rent and loss surplus in the second quarter of 2022 are preliminary.

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

Figure 1.26 Day-ahead congestion rent and loss surplus by quarter (2021-2022)

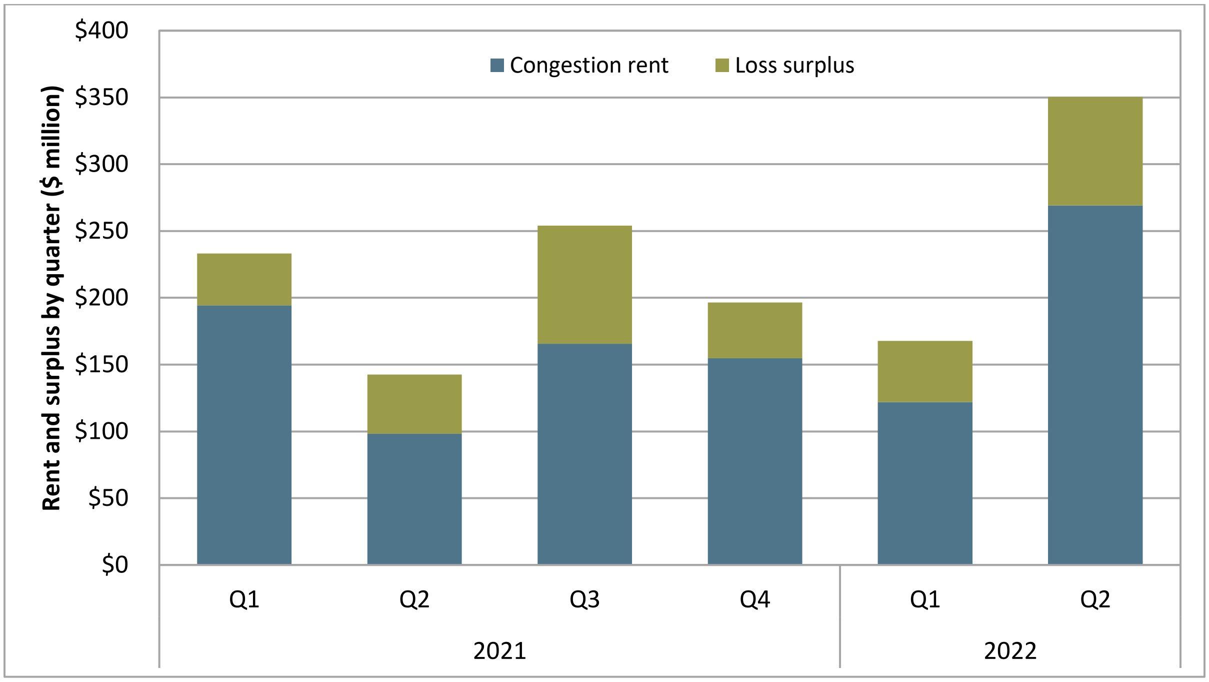


Figure 1.27 shows the overall impact of congestion on day-ahead prices in each load area in 2021 and 2022. Figure 1.28 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of congestion on price separation in the second quarter was greater than during any quarter last year. Day-ahead congestion during the quarter raised prices in PG&E 126 percent more than it did in the second quarter of 2021, while it lowered prices in SCE 57 percent more and in SDG&E 23 times more.
- Day-ahead congestion increased quarterly average prices in PG&E by $4.03/MWh (5.5 percent) while it decreased average prices in SCE and SDG&E by $2.17/MWh (3.4 percent) and $2.23/MWh (3.4 percent), respectively.
- The primary constraints impacting day-ahead market prices were the Los Banos-Quinto 230 kV line, Moss Landing-Las Aguilas 230 kV line, and the Tracy Pump-Tesla 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 1.27 Overall impact of congestion on price separation in the day-ahead market

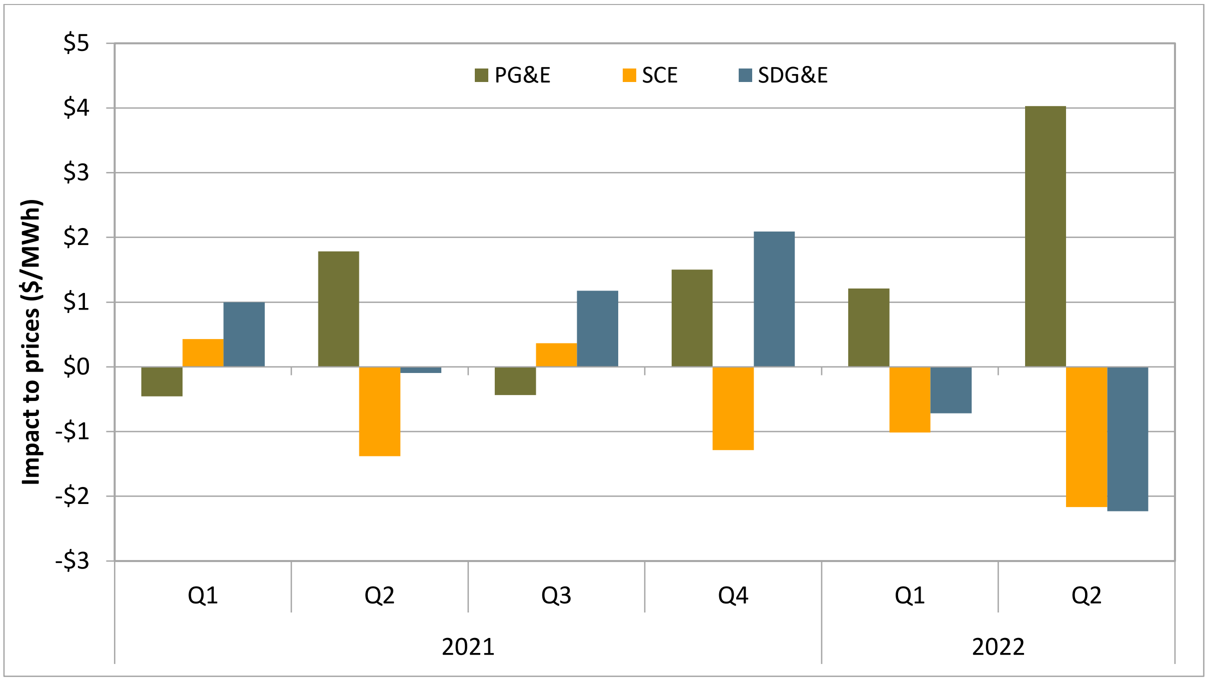
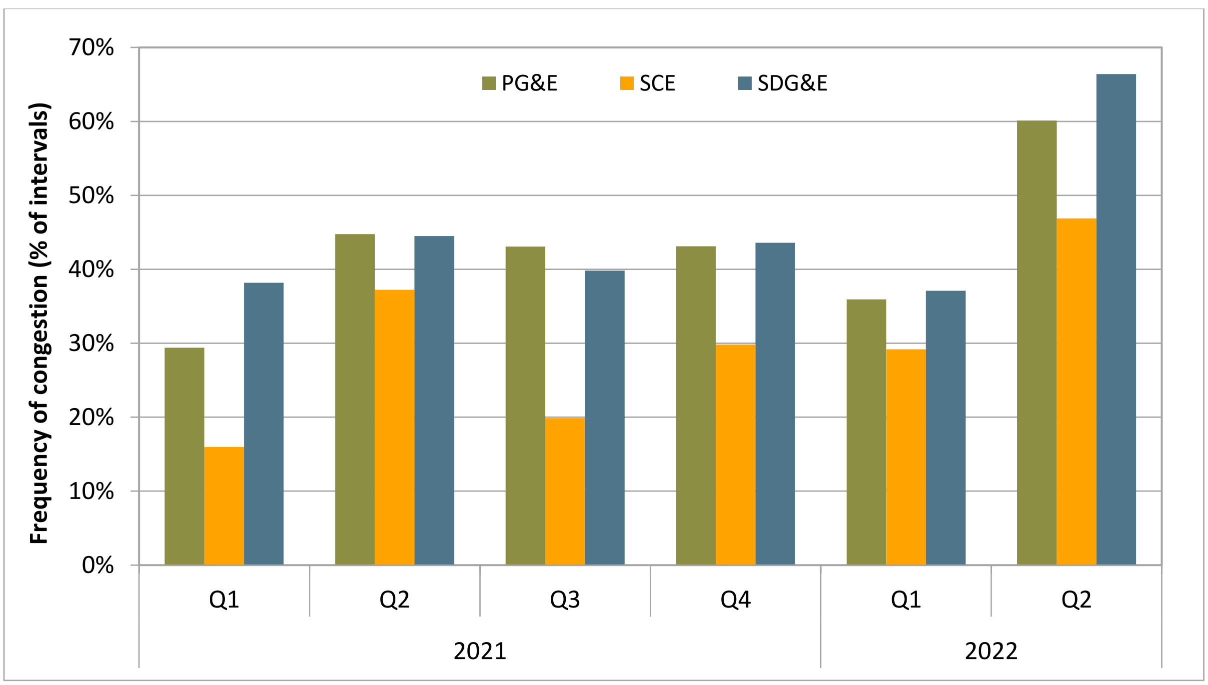


Figure 1.28 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation during the quarter by constraint.[35] 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 Los Banos-Quinto 230 kV line, Moss Landing-Las Aguilas 230 kV line, and the Tracy Pump-Tesla 230 kV line.

Los Banos-Quinto 230 kV line

The Los Banos-Quinto 230 kV line (30763_Q0577SS_230_30765_LOSBANOS_230_BR_1_1) had the greatest impact on day-ahead prices during the second quarter. The line was congested during 24 percent of hours. When binding, it decreased SCE and SDG&E prices by $4.51/MWh and $4.03/MWh, respectively, and increased PG&E prices by $5.74/MWh. For the quarter, congestion on the line decreased average SCE and SDG&E prices by $1.08/MWh (1.7 percent) and $0.96/MWh (1.5 percent), respectively, and increased average PG&E prices by $1.37/MWh (1.9 percent). This line was frequently binding due to the loss of the Tracy-Los Banos 500 kV line.

Moss Landing-Las Aguilas 230 kV line

The Moss Landing-Las Aguilas 230 kV line (30750_MOSSLD_230_30797_LASAGUIL_230_BR_1_1) bound in 25 percent of hours over the quarter. When binding, it increased prices in PG&E by $4.67/MWh and decreased prices in SCE and SDG&E by $4.47/MWh and $4.92/MWh, respectively. For the quarter, congestion on the line increased average PG&E prices by $1.19/MWh (1.6 percent) and decreased average SCE and SDG&E prices by $0.16/MWh (0.2 percent) and $0.12/MWh (0.2 percent), respectively. This line was mitigated for the loss of the Moss Landing-Los Banos 500 kV line.

Tracy Pump-Tesla 230 kV line

The Tracy Pump-Tesla 230 kV line (37585_TRCY PMP_230_30625_TESLA D _230_BR_1_1) bound in about 8 percent of hours. When binding, it increased PG&E prices by $5.68/MWh and decreased SCE and SDG&E prices by $4.45/MWh and $4.33/MWh, respectively. For the quarter, the nomogram increased average PG&E prices by about $0.42/MWh (0.6 percent), and decreased average SCE and SDG&E prices by $0.30/MWh (0.5 percent) and $0.33/MWh (0.5 percent), respectively. This line was impacted by maintenance on the Tesla-Tracy 230 kV line as well as mitigation for the contingency of the Malin 500 intertie.

[35] 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	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$1.37	1.88%	-$1.08	-1.69%	-$0.96	-1.49%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$1.19	1.64%	-$0.16	-0.24%	-$0.12	-0.19%
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.42	0.58%	-$0.30	-0.46%	-$0.33	-0.51%
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	$0.25	0.34%	-$0.18	-0.28%	-$0.18	-0.27%
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.20	0.28%	-$0.17	-0.27%	-$0.17	-0.26%
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.15	0.21%	-$0.12	-0.18%	-$0.12	-0.18%
	7440_MetcalfImport_Tes-Metcalf	$0.15	0.20%	-$0.12	-0.19%	-$0.12	-0.18%
	30733_VASONA _230_30735_METCALF _230_BR_1 _1	$0.14	0.20%	$0.00	0.00%	$0.00	0.00%
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.10	0.14%	$0.00	0.00%	$0.00	0.00%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	$0.10	0.13%	-$0.08	-0.13%	-$0.08	-0.12%
	30735_METCALF _230_30042_METCALF _500_XF_13	$0.09	0.12%	-$0.06	-0.10%	-$0.06	-0.09%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.08	0.11%	-$0.07	-0.11%	-$0.07	-0.10%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.03	0.04%	-$0.03	-0.04%	-$0.02	-0.04%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.03	0.04%	-$0.03	-0.04%	-$0.02	-0.04%
	RM_TM12_NG	$0.02	0.03%	$0.00	0.00%	-$0.02	-0.03%
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.01	0.02%	-$0.01	-0.02%	-$0.02	-0.03%
	30970_MIDWAY _230_30945_KERN PP _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
	24128_S.CLARA _230_24099_MOORPARK_230_BR_2 _1	-$0.01	-0.01%	$0.01	0.02%	-$0.01	-0.01%
	PACI_SN	-$0.01	-0.01%	$0.01	0.01%	$0.01	0.02%
	OMS_11396530_RED_BLUFF_XF	$0.00	0.00%	-$0.01	-0.02%	$0.00	0.00%
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.14	-0.19%	$0.16	0.25%	$0.03	0.04%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.05	-0.07%	$0.05	0.08%	$0.02	0.02%
	7520_Ventura_Voltage_NG	$0.00	0.00%	$0.02	0.02%	$0.00	0.00%
SDG&E	7820_TL 230S_OVERLOAD_NG	-$0.07	-0.09%	$0.00	0.00%	$0.74	1.14%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-$0.04	-0.06%	$0.00	0.00%	$0.28	0.44%
	OMS 11368744_50001_OOS_NG	-$0.02	-0.03%	$0.00	0.00%	$0.25	0.38%
	MIGUEL_BKs_MXFLW_NG	-$0.01	-0.02%	$0.00	0.00%	$0.21	0.32%
	OMS 11396189_50002_OOS_TDM	$0.00	0.00%	$0.00	0.00%	$0.17	0.26%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.11	0.16%
	OMS 11364971_50002_OOS_TDM	$0.00	0.00%	$0.00	0.00%	$0.09	0.14%
	OMS_11559168_TL23055_NG	$0.00	-0.01%	$0.00	0.00%	$0.05	0.08%
	7820_TL 230S_TL50001OUT_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.06%
	22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.04%
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.01%	$0.00	0.00%	$0.01	0.02%
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.05	-0.08%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$2.09	-3.23%
Other		$0.04	0.05%	$0.01	0.01%	$0.17	0.26%
Total		**$4.03**	**5.54%**	**-$2.17**	**-3.40%**	**-$2.23**	**-3.45%**

Table 1.3 Impact of congestion on day-ahead prices during congested hours[36]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30733_VASONA _230_30735_METCALF _230_BR_1 _1	0.5%	$26.13	$0.00	$0.00
	30735_METCALF _230_30042_METCALF _500_XF_12	1.4%	$10.62	-$8.18	-$8.15
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	2.5%	$9.92	-$10.70	-$10.72
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.9%	$9.51	-$8.22	-$7.56
	7440_MetcalfImport_Tes-Metcalf	2.0%	$7.32	-$6.15	-$5.89
	30735_METCALF _230_30042_METCALF _500_XF_13	1.4%	$6.13	-$4.31	-$4.30
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	23.9%	$5.74	-$4.51	-$4.03
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	7.6%	$5.68	-$4.45	-$4.33
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	25.5%	$4.67	-$4.47	-$4.92
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	2.4%	$3.99	-$3.39	-$3.15
	RM_TM12_NG	0.5%	$3.50	$0.00	-$3.76
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	1.0%	$3.17	-$2.74	-$2.52
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	1.3%	$2.32	-$1.87	-$1.71
	30055_GATES1 _500_30900_GATES _230_XF_12 _P	9.2%	$2.23	-$1.89	-$1.84
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	0.8%	$1.73	-$1.48	-$2.26
	30970_MIDWAY _230_30945_KERN PP _230_BR_1 _1	0.9%	$1.55	-$5.41	-$5.41
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	6.5%	$1.54	$0.00	$0.00
	24128_S.CLARA _230_24099_MOORPARK_230_BR_2 _1	0.4%	-$2.48	$3.25	-$2.48
	PACI_SN	0.3%	-$2.73	$2.09	$2.97
	OMS_11396530_RED_BLUFF_XF	1.9%	$0.00	-$0.70	$0.02
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	1.1%	-$4.21	$4.32	$3.80
	7520_Ventura_Voltage_NG	0.4%	$0.00	$4.20	$0.00
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	4.2%	-$3.27	$3.73	$2.48
SDG&E	MIGUEL_BKs_MXFLW_NG	0.8%	-$2.12	$0.00	$25.13
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	1.3%	-$3.29	$0.00	$22.09
	OMS_11559168_TL23055_NG	0.2%	-$1.63	$0.00	$21.76
	OMS 11396189_50002_OOS_TDM	0.9%	$0.00	$0.00	$19.37
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1	0.1%	$0.00	$0.00	$18.12
	OMS 11368744_50001_OOS_NG	1.6%	-$1.16	$0.00	$15.27
	OMS 11364971_50002_OOS_TDM	0.7%	$0.00	$0.00	$12.71
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.1%	-$6.69	$0.00	$10.80
	7820_TL 230S_OVERLOAD_NG	10.9%	-$0.61	$0.00	$6.75
	22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1	0.5%	$0.00	$0.00	$5.64
	7820_TL 230S_TL50001OUT_NG	0.7%	-$0.56	$0.00	$5.14
	7820_TL23040_IV_SPS_NG	0.3%	-$0.20	$0.00	$4.55
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	2.7%	$0.00	$0.00	$3.87
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	23.1%	$0.00	$0.00	-$9.06
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	0.5%	$0.00	$0.00	-$10.78

36 This table shows impacts on load aggregation point prices for constraints binding during more than 0.3 percent of the intervals during the quarter.

1.8.2 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 second quarter, a 5-minute market only constraint heavily impacted prices across the WEIM and led to notable differences between the markets.[37]

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

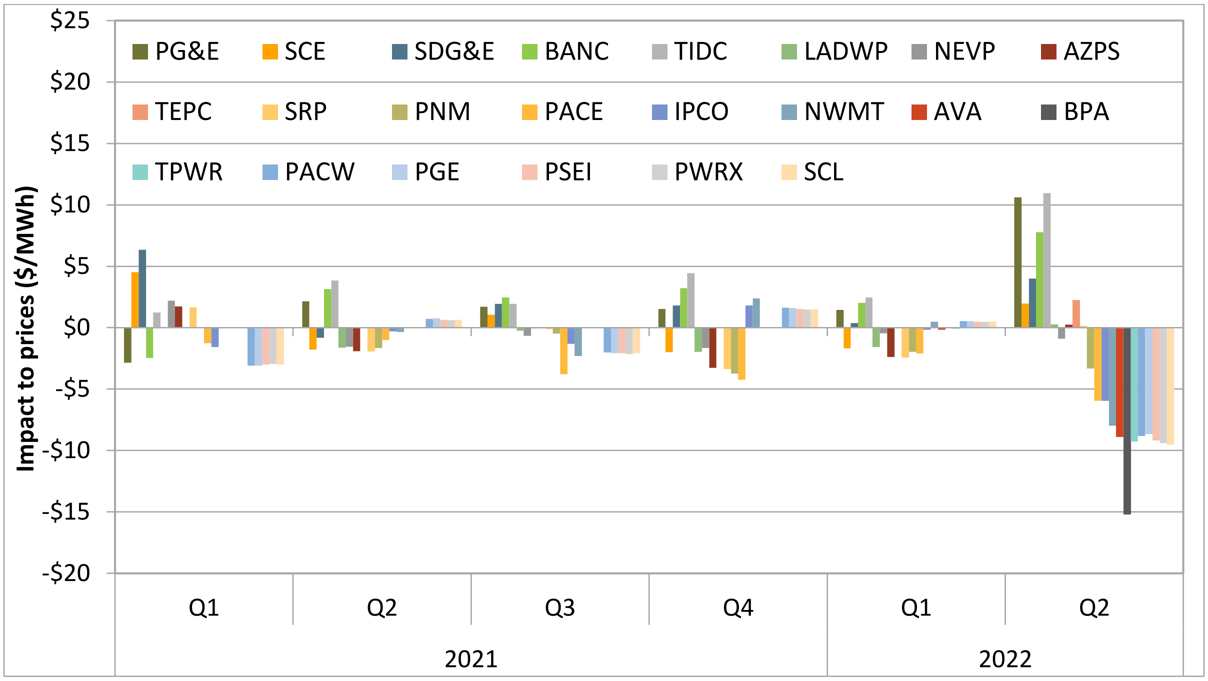
Figure 1.29 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2021 and 2022. Table 1.5 shows the frequency of this congestion. Highlights for this quarter include:

- 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 primary constraints creating price separation in the 15-minute market were a Malin-Round Mountain nomogram, the Los Banos-Quinto 230 kV line, and the Tracy Pump-Tesla 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.

37 This 5-minute only constraint, 6110_COI_N-S, will appear 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 1.29 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 second quarter, the constraints that had the greatest impact on price separation in the 15-minute market were a Malin-Round Mountain nomogram, the Los Banos-Quinto 230 kV line, and the Tracy Pump-Tesla 230 kV line.[38] These constraints were frequently mitigated due to high unscheduled flows, the loss of the Tesla-Los Banos 500 kV line, and for the contingency of the Malin 500, 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 power balance constraint (PBC) violations, which often have an impact on price separation. These topics are discussed in greater depth in Chapter 2.

[38] These constraints are shown as “ML_RM12_NS, 30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1” and “37585_TRCY PMP_230_30625_TESLA D _230_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		$0.08	$0.36				$0.00	$0.53	-$0.01	$0.51	-$2.53	-$0.69	-$0.33	-$0.16								
	Line_CC-GT_230KV								$0.03	$0.01	$0.01	$0.01											
	Line_FC-CH1_345KV			$0.01					$0.02		$0.01	-$0.07	-$0.02	-$0.01									
IPCO	T342.MPSN	$0.02	-$0.06	-$0.08	$0.06	$0.03	-$0.15	-$0.09	-$0.11	-$0.12	-$0.11	-$0.15	-$0.43	$0.50		$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.13	$0.14
	BLPR-HCPR1_A												$0.18	$0.47		-$0.20	-$0.18	-$0.19	-$0.17	-$0.12	-$0.18	-$0.19	-$0.19
	T341.MPSN	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	$0.02		$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEVP	BOR PS#1							$0.02							$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
PACE	BONANZA$_MONA_345						$0.01			-$0.01		-$0.02	$0.01	$0.01									
	WINDSTAR EXPORT TCOR												-$0.13										
	TOTAL_WYOMING_EXPORT												-$1.19										
PACW	INTRP				$0.00										-$0.20	-$0.26	$0.13	-$0.25	$0.10	$0.43	-$0.20	-$0.48	-$0.51
	WPTH75	$0.00			$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
PG&E	ML_RM12_NS	$4.29	$2.54	$2.31	$4.13	$4.07	$1.43	$1.02	$1.85	$1.71	$1.83	$1.23	-$2.04	-$3.92	-$4.74	-$5.36	-$5.55	-$5.54	-$5.52	-$5.63	-$5.53	-$5.49	-$5.53
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$3.02	$0.25	$0.21	-$3.52	-$2.56	$0.09	-$0.09	$0.09	$0.09	$0.10	$0.02	-$0.23	-$0.98	-$1.20	-$1.35	-$1.39	-$1.40	-$1.44	-$1.43	-$1.40	-$1.38	-$1.39
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$1.08	$0.71	$0.65	$0.70	$1.04	$0.42	$0.38	$0.50	$0.46	$0.49	$0.35	-$0.47	-$1.00	-$1.12	-$1.33	-$1.38	-$1.37	-$1.39	-$1.40	-$1.37	-$1.36	-$1.37
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.62	-$2.05	-$1.93	$2.69	$6.11	-$1.66	-$1.03	-$1.70	-$0.76	-$1.70	-$1.45	-$0.02	$0.56	$0.97	$1.28	$0.62	$1.36	$1.43	$1.41	$1.36	$1.34	$1.36
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.48	$0.32	$0.30	$0.34	$0.48	$0.19	$0.18	$0.23	$0.21	$0.23	$0.16	-$0.22	-$0.46	-$0.52	-$0.60	-$0.62	-$0.62	-$0.63	-$0.63	-$0.62	-$0.61	-$0.62
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.38	-$0.11	-$0.11		$0.16	-$0.10	-$0.08	-$0.10	-$0.10	-$0.10	-$0.09											
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.34	-$0.16	-$0.15	$0.12	$0.23	-$0.13	-$0.10	-$0.14	-$0.14	-$0.14	-$0.13		$0.00	$0.00	-$0.01	-$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01
	30970_MIDWAY _230_30945_KERN PP _230_BR_1 _1	$0.33																					
	6110_SOL10_NG	$0.26	$0.23	$0.21	$1.18	$0.32	$0.14	$0.08	$0.17	$0.16	$0.17	$0.11	-$0.15	-$0.32	-$0.39	-$0.44	-$0.55	-$0.56	-$0.46	-$0.61	-$0.55	-$0.52	-$0.55
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.20	$0.03	$0.03	$0.62	$0.19			$0.01	$0.00	$0.01			-$0.17	-$0.17	-$0.26	-$0.28	-$0.28	-$0.26	-$0.30	-$0.28	-$0.27	-$0.28
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.15	-$0.18	-$0.17	$0.14	$0.15	-$0.16	-$0.09	-$0.15	$0.00	-$0.15	-$0.13	-$0.02	$0.05	$0.08	$0.10	$0.00	$0.10	$0.11	$0.11	$0.10	$0.10	$0.10
	30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	$0.13			-$0.05											-$0.02	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05	-$0.04	-$0.05
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.13	-$0.23	-$0.11			-$0.03		-$0.01		-$0.01	$0.00											
	RM_TM21_NG	$0.10	$0.06	$0.06	$0.04	$0.06	$0.03	$0.02	$0.03	$0.02	$0.03	$0.02	-$0.03	-$0.06	-$0.09	-$0.10	-$0.06	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10
	7440_MetcalfImport_Tes-Metcalf	$0.08	-$0.05	-$0.04	$0.04	$0.05	-$0.04	-$0.03	-$0.04	-$0.04	-$0.04	-$0.03			$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
	30300_TABLMTN _230_30330_RIO OSO _230_BR_1 _1	$0.08			$0.12	$0.08								-$0.04	-$0.08	-$0.09	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10	-$0.09	-$0.09
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	$0.06																					
	30015_TABLE MT_500_30040_TESLA _500_BR_1 _3	$0.06	$0.05	$0.05	$0.03	$0.07	$0.03	$0.02	$0.04	$0.04	$0.04	$0.03	-$0.04	-$0.07	-$0.09	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10	-$0.10
	RM_TM12_NG	$0.05	$0.03	$0.03																			
	30114_DELEVAN _230_30450_CORTINA _230_BR_1 _1	$0.05														$0.00	$0.00	$0.00	-$0.04	-$0.02	$0.00	$0.00	$0.00
	30733_VASONA _230_30735_METCALF _230_BR_1 _1	$0.04																					
	XFMR1 500.TRY	$0.02	$0.02	$0.02	$0.02	$0.04	$0.01		$0.01	$0.01	$0.01		-$0.01	-$0.03	-$0.03	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	30735_METCALF _230_30042_METCALF _500_XF_13	$0.02	-$0.01	-$0.01			-$0.01	$0.00	-$0.01	$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
	37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1	$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
	SUMMIT_BG	$0.00			$0.12	$0.00		-$0.29					$0.01	$0.00									
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.02	$0.01	$0.01	-$0.02	-$0.02	$0.01	$0.01	$0.01	$0.03	$0.01	$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.03	-$0.01	-$0.02	-$0.02	-$0.01	-$0.01	-$0.01
	OMS_11396530_RED_BLUFF_XF	-$0.02	$0.00		-$0.02	-$0.02		$0.03	$0.00		$0.00	$0.00	$0.02										
	PACI_SN	-$0.16	-$0.10	-$0.10	-$0.15	-$0.16	-$0.08	-$0.05	-$0.08		-$0.08	-$0.06	$0.04	$0.10	$0.13	$0.15		$0.15	$0.15	$0.16	$0.15	$0.15	$0.15
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.24	$0.14	$0.14	-$0.22	-$0.23	$0.09	$0.10	$0.12	$0.17	$0.12	$0.10	$0.00	-$0.06	-$0.13	-$0.16	-$0.16	-$0.17	-$0.18	-$0.18	-$0.17	-$0.17	-$0.17
	30500_BELLOTA _230_30515_WARNERVL_230_BR_1 _1				$0.07	-$0.09																	
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1		$0.00		$0.01	$0.03																	
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1		-$0.09	-$0.08	$0.09	$0.12	$0.00		-$0.02	-$0.01	-$0.02	$0.00											
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1		$0.00	$0.00	$0.04	$0.00																	
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1							-$0.08															
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1							-$0.15															
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1							-$0.06															
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1							-$0.22															
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1							-$0.57															
	35120_NEWARK D_115_36851_NORTHERN_115_BR_1 _1					-$0.12																	
	7430_CP6_NG				$0.08																		
	SUMMIT-DRUM #1							$0.08															
	SUMMIT-DRUM #2				-$0.02			$0.12															
SCE	6410_CP1_NG	-$0.09	$0.07	$0.07	-$0.08	-$0.08	$0.06	$0.05	$0.06	$0.06	$0.06	$0.05		-$0.03	-$0.05	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06
	OMS 10666077_OP-6610	$0.01	$0.01	$0.00	$0.01	$0.01	-$0.02	-$0.01	-$0.01		-$0.01	-$0.01	-$0.01	-$0.01		$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6410_CP7_NG	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	-$0.01	-$0.01		-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.01		$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.21	$2.48	$0.00	$0.00	$0.00	-$0.15	-$0.48	-$0.26	-$0.52	-$0.40	-$0.16	-$0.03	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 11364971_50002_OOS_TDM			$0.61					-$0.12	-$0.06	-$0.05												
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.04	$0.30				-$0.02	-$0.09	-$0.08	-$0.09	-$0.07	-$0.02										
	OMS 11368744_50001_OOS_NG		$0.01	$0.17				-$0.01	-$0.03	-$0.02	-$0.03	-$0.02	-$0.01										
	7820_TL 230S_TL50001OUT_NG		$0.01	$0.12				-$0.01	-$0.03	-$0.03	-$0.03	-$0.02	-$0.01										
	OMS 11396189_50002_OOS_TDM			$0.05					-$0.01	$0.00	$0.00												
	22192_DOUBLTTP_138_22648_PENSQTOS_138_BR_1 _1			-$0.02					-$0.01		-$0.01	-$0.01											
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			-$1.58					-$0.48	-$0.08	-$0.52	-$0.19											
	Other	-$0.89	$0.20	$0.22	$1.18	$0.96	$0.16	$0.17	$0.18	$1.01	$0.16	$0.00	-$0.27	-$0.13	-$0.19	-$0.21	-$5.56	-$0.22	-$0.20	-$0.16	-$0.21	-$0.21	-$0.22
	Internal Total	**$10.62**	**$1.97**	**$3.99**	**$7.76**	**$10.94**	**$0.27**	**-$0.89**	**$0.25**	**$2.26**	**$0.14**	**-$3.34**	**-$5.95**	**-$5.96**	**-$7.99**	**-$8.91**	**-$15.21**	**-$9.27**	**-$8.81**	**-$8.66**	**-$9.19**	**-$9.39**	**-$9.51**
	Transfers				-$0.02	$0.40	$0.00	$0.75	$0.08	$1.86	$3.20	-$0.79	-$2.50	-$1.04	-$3.20	-$2.44	-$6.18	-$1.48	-$3.98	-$2.59	-$1.37	-$1.60	-$1.30
	Grand Total	**$10.62**	**$1.97**	**$3.99**	**$7.74**	**$11.34**	**$0.27**	**-$0.14**	**$0.33**	**$4.12**	**$3.34**	**-$4.13**	**-$8.45**	**-$7.00**	**-$11.19**	**-$11.35**	**-$21.39**	**-$10.75**	**-$12.79**	**-$11.25**	**-$10.56**	**-$10.99**	**-$10.81**

Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals [39]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	TEPC	SRP	PNM	PACE	IPCO	NWMT	AVA	BPA	TPWR	PACW	PGE	PSEI	PWRX	SCL
AZPS	Line_FC-CH2_345KV	4.6%		$6.94	$7.96				$27.79	$11.45	-$6.49	$10.89	-$54.66	-$14.95	-$7.99	-$8.40								
IPCO	BLPR-HCPR1_A	1.2%												$14.92	$39.09		-$16.79	-$14.86	-$15.42	-$14.50	-$17.60	-$15.28	-$15.45	-$15.51
	T342.MPSN	2.3%	$2.02	-$2.55	-$3.34	$2.52	$2.20	-$6.79	-$4.08	-$4.87	-$5.28	-$4.92	-$6.74	-$19.16	$21.91		$6.07	$6.36	$6.21	$6.23	$6.28	$6.17	$5.92	$6.18
PACE	WINDSTAR EXPORT TCOR	8.4%												-$1.57										
	TOTAL_WYOMING_EXPORT	30.0%												-$3.95										
PACW	INTRP	0.7%				$4.27										-$27.85	-$35.58	$17.81	-$34.46	$14.24	$60.27	-$27.17	-$67.14	-$70.72
PG&E	30735_METCALF _230_30042_METCALF _500_XF_12	0.5%	$72.00	-$22.90	-$22.83		$30.46	-$23.28	-$25.03	-$21.61	-$22.51	-$22.05	-$23.11											
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	8.3%	$36.38	$6.05	$5.22	-$42.47	-$30.87	$3.79	-$13.99	$3.16	$3.29	$3.54	$0.84	-$15.45	-$15.96	-$18.76	-$21.04	-$21.71	-$21.76	-$22.40	-$22.26	-$21.73	-$21.56	-$21.70
	30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	0.4%	$33.06			-$16.41											-$15.51	-$16.60	-$16.60	-$15.51	-$15.49	-$16.60	-$17.04	-$16.60
	ML_RM12_NS	13.8%	$31.10	$18.38	$16.70	$29.91	$29.51	$10.35	$7.35	$13.38	$12.39	$13.26	$8.89	-$14.78	-$28.37	-$34.31	-$38.81	-$40.21	-$40.12	-$40.01	-$40.78	-$40.09	-$39.76	-$40.05
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	3.9%	$27.45	$18.14	$16.52	$18.75	$27.71	$11.17	$10.17	$13.28	$12.41	$13.16	$9.24	-$12.68	-$26.74	-$29.80	-$35.55	-$36.78	-$36.71	-$37.15	-$37.39	-$36.69	-$36.46	-$36.66
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	2.1%	$22.91	$15.17	$14.24	$16.17	$23.00	$9.24	$8.83	$11.02	$10.17	$10.87	$7.55	-$10.57	-$21.90	-$25.13	-$28.65	-$29.70	-$29.59	-$30.02	-$30.13	-$29.58	-$29.32	-$29.56
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	2.4%	$22.76	$13.85	$12.75	$25.90	$23.17			$12.25	$0.79	$10.96			-$20.73	-$21.17	-$23.49	-$23.45	-$23.49	-$23.11	-$23.15	-$23.57	-$23.47	-$23.57
	7440_MetcalfImport_Tes-Metcalf	0.4%	$19.59	-$12.04	-$11.45	$10.13	$13.25	-$9.05	-$7.43	-$9.73	-$9.43	-$9.69	-$8.32			$2.63	$5.41	$5.89	$5.81	$6.14	$6.03	$5.80	$5.69	$5.80
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	1.0%	$16.18	-$19.33	-$18.22	$15.21	$15.93	-$16.77	-$9.96	-$16.14	$12.66	-$16.12	-$13.54	-$1.89	$5.32	$8.11	$10.00	-$13.02	$10.69	$11.26	$11.13	$10.68	$10.50	$10.65
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	0.4%	$15.89																					
	30300_TABLMTN _230_30330_RIO OSO _230_BR_1 _1	0.5%	$14.67			$23.60	$15.47								-$29.26	-$14.90	-$17.92	-$18.47	-$18.45	-$18.53	-$18.69	-$18.45	-$18.21	-$18.43
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	2.5%	$14.15	-$9.07	-$8.74			-$8.92		-$4.79		-$4.79	-$1.00											
	30114_DELEVAN _230_30450_CORTINA _230_BR_1 _1	0.4%	$13.20														-$37.66	-$39.37	-$37.66	-$13.09	-$13.97	-$37.66	-$37.66	-$37.66
	30015_TABLE MT_500_30040_TESLA _500_BR_1 _3	0.5%	$11.68	$11.34	$10.39	$6.77	$16.52	$7.75	$4.92	$9.12	$8.45	$9.02	$6.52	-$9.06	-$17.64	-$20.17	-$23.52	-$24.28	-$24.20	-$24.41	-$24.59	-$24.18	-$24.00	-$24.18
	30970_MIDWAY _230_30945_KERN PP _230_BR_1 _1	3.2%	$10.41																					
	30735_METCALF _230_30042_METCALF _500_XF_13	0.3%	$7.65	-$2.59	-$2.63			-$2.81	-$6.11	-$2.81	-$5.86	-$2.81	-$2.81	-$1.14	-$1.13	-$1.13	-$1.20		-$1.20	-$1.30	-$1.20	-$1.20	-$1.20	-$1.20
	6110_SOL10_NG	3.8%	$7.02	$6.14	$5.57	$31.55	$8.60	$3.64	$2.10	$4.46	$4.16	$4.42	$2.97	-$4.09	-$8.42	-$10.44	-$11.75	-$14.73	-$14.80	-$12.21	-$16.12	-$14.70	-$13.81	-$14.65
	30055_GATES1 _500_30900_GATES _230_XF_12_P	5.2%	$6.58	-$3.20	-$3.10	$2.64	$4.74	-$2.65	-$2.03	-$2.83	-$2.77	-$2.82	-$2.58		-$1.89	-$2.15	-$2.35	-$2.41	-$2.41	-$1.63	-$2.13	-$2.40	-$2.36	-$2.40
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	13.9%	$5.30	-$14.68	-$13.87	$19.32	$43.80	-$11.90	-$7.39	-$12.21	-$10.12	-$12.18	-$10.40	-$4.86	$5.83	$7.09	$9.17	$8.16	$9.77	$10.22	$10.14	$9.76	$9.62	$9.74
	SUMMIT_BG	3.9%	-$0.04			$5.39	-$0.07		-$7.58					$4.97	$0.57									
	OMS_11396530_RED_BLUFF_XF	2.0%	-$1.13	-$0.05		-$1.02	-$1.11		$1.38	$0.02		$0.00	$0.01	$1.14										
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	1.4%	-$1.30	$0.71	$0.69	-$1.27	-$1.29	$0.45	$0.70	$0.61	$3.85	$0.60	$0.57	-$0.03	-$0.48	-$0.81	-$0.96	-$3.64	-$1.02	-$1.08	-$1.06	-$1.02	-$1.00	-$1.02
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.4%	-$9.75	$5.81	$6.00	-$9.30	-$9.64	$3.93	$4.07	$4.85	$15.12	$4.82	$3.96	$0.03	-$2.58	-$5.42	-$6.67	-$14.83	-$7.11	-$7.40	-$7.33	-$7.11	-$7.00	-$7.09
	PACI_SN	0.9%	-$16.82	-$11.06	-$10.16	-$16.42	-$16.62	-$8.67	-$4.94	-$8.41		-$8.39	-$6.12	$4.69	$11.00	$13.72	$15.60		$16.24	$16.36	$16.58	$16.23	$16.07	$16.20
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	2.9%		-$2.96	-$2.80	$3.06	$4.23	-$1.80		-$2.00	-$1.72	-$2.03	-$1.23											
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1	0.4%							-$21.63															
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	1.4%							-$11.00															
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	1.5%							-$15.16															
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	3.0%							-$19.29															
	35120_NEWARK D_115_36851_NORTHERN_115_BR_1 _1	0.5%					-$23.83																	
	7430_CP6_NG	0.4%				$18.70																		
	SUMMIT-DRUM #2	0.6%				-$15.25			$20.39															
SCE	6410_CP1_NG	0.5%	-$17.11	$13.95	$14.12	-$16.16	-$16.82	$11.85	$8.99	$12.56	$12.03	$12.50	$10.34		-$5.57	-$9.10	-$11.26	-$11.99	-$11.91	-$12.29	-$12.27	-$11.88	-$11.72	-$11.87
	OMS 10666077_OP-6610	0.6%	$1.27	$1.02	$0.37	$1.18	$1.25	-$3.31	-$2.56	-$2.21		-$2.19	-$2.29	-$1.52	-$0.93		$0.40		$0.55	$0.71	$0.65	$0.55	$0.49	$0.55
	6410_CP7_NG	0.3%	$3.06	-$3.72	-$3.52	$2.90	$3.02	-$3.23	-$2.03	-$3.16		-$3.15	-$2.73	-$1.05	$0.71	$1.40	$1.91		$2.07	$2.19	$2.17	$2.07	$2.03	$2.07
SDG&E	OMS 11364971_50002_OOS_TDM	1.9%			$32.19					-$6.21	-$5.10	-$5.03												
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.9%		$4.12	$31.77				-$3.29	-$9.47	-$8.84	-$9.67	-$7.50	-$3.55										
	OMS 11368744_50001_OOS_NG	0.6%		$1.96	$31.02				-$1.27	-$4.55	-$4.18	-$4.58	-$3.57	-$1.36										
	7820_TL 230S_TL50001OUT_NG	0.5%		$2.53	$24.25				-$1.47	-$5.22	-$5.12	-$5.75	-$4.46	-$1.64										
	7820_TL 230S_OVERLOAD_NG	11.8%	$0.81	$1.77	$21.04	$0.64	$0.97	$3.58	-$1.32	-$4.17	-$4.97	-$4.53	-$3.50	-$1.41	-$1.01	-$3.85	$2.78	$3.01	$3.01	$3.12	$3.01	$3.01	$2.89	$3.01
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	12.2%			-$12.98					-$14.61	-$17.87	-$14.43	-$14.26											

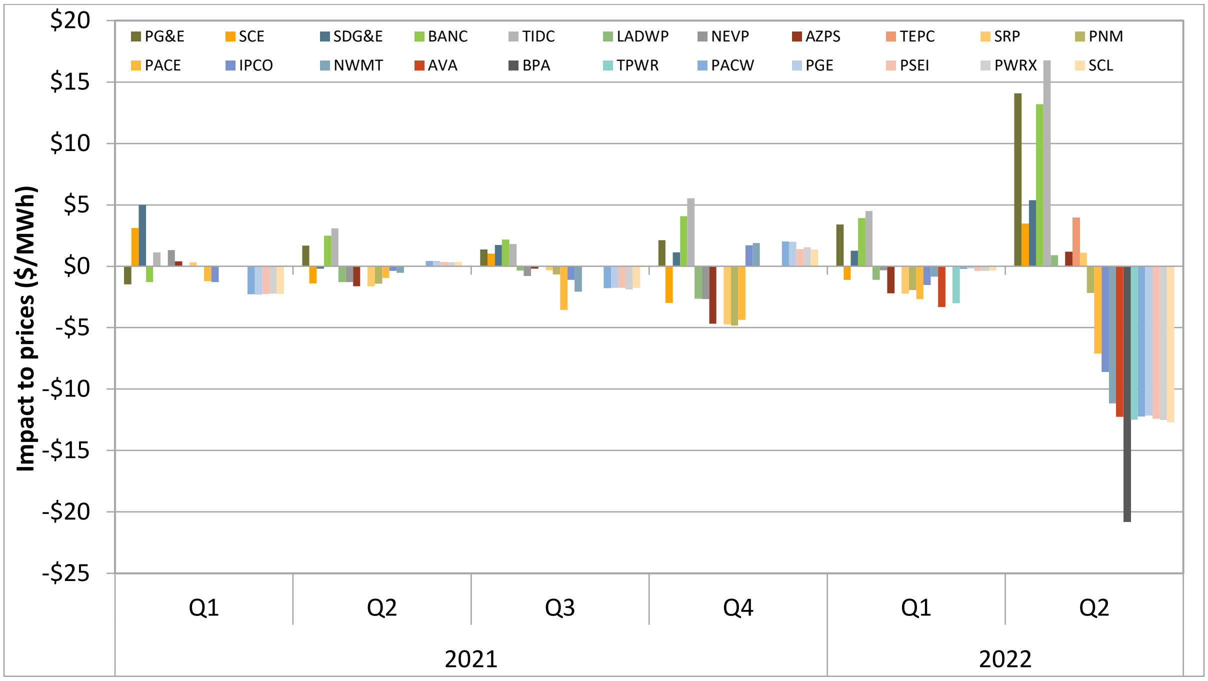
Impact of internal congestion to overall 5-minute prices in each load area

Figure 1.30 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.[37]
- Prices from 5-minute market congestion were significant, lowering average prices in BPA by $20.79/MWh over the quarter.

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

Figure 1.30 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 second quarter, a 5-minute market only constraint heavily impacted prices across the WEIM and led to notable differences between the markets. In the second quarter, the "other" category, which contains the 5-minute market only constraint, 6110_COI_N-S, had the greatest impact on 5-minute prices across the WEIM.

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.

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		$0.08	$0.27				$0.00	$0.41	-$0.01	$0.39	-$1.96	-$0.53	-$0.26	-$0.14								
	Line_CC-GT_230KV								$0.08	$0.03	$0.02	$0.03											
	Line_FC-CH1_345KV		$0.00	$0.01					$0.01		$0.01	-$0.06	-$0.02	-$0.01	$0.00								
IPCO	BLPR-HCPR1_A												$0.18	$0.47		-$0.20	-$0.18	-$0.18	-$0.17	-$0.11	-$0.18	-$0.18	-$0.18
	T342.MPSN	$0.01	-$0.05	-$0.07	$0.05	$0.03	-$0.13	-$0.08	-$0.10	-$0.10	-$0.10	-$0.13	-$0.38	$0.43		$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12
	T341.MPSN		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PACE	BONANZA$_MONA_345						$0.01			-$0.01		-$0.03	$0.01	$0.01									
	WINDSTAR EXPORT TCOR												-$0.14										
	TOTAL_WYOMING_EXPORT												-$1.02										
PACW	INTRP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								-$0.15	-$0.20	$0.10	-$0.19	$0.08	$0.33	-$0.16	-$0.38	-$0.40
	WPTH75	$0.01	$0.00		$0.02	$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.05	-$0.07	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
PG&E	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$1.53	$0.17	$0.15	-$1.87	-$1.36	$0.06	-$0.04	$0.08	$0.07	$0.08	$0.01	-$0.12	-$0.55	-$0.66	-$0.74	-$0.76	-$0.76	-$0.78	-$0.78	-$0.76	-$0.76	-$0.76
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$1.07	-$0.49	-$0.47	$0.35	$0.74	-$0.40	-$0.31	-$0.42	-$0.42	-$0.42	-$0.39		$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.00
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.84	-$2.72	-$2.57	$3.69	$8.55	-$2.18	-$1.39	-$2.27	-$1.31	-$2.26	-$1.94	-$0.03	$0.74	$1.25	$1.69	$1.06	$1.80	$1.88	$1.86	$1.80	$1.77	$1.79
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.38	$0.25	$0.23	$0.26	$0.38	$0.15	$0.14	$0.18	$0.17	$0.18	$0.13	-$0.16	-$0.34	-$0.39	-$0.47	-$0.48	-$0.48	-$0.49	-$0.49	-$0.48	-$0.48	-$0.48
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.28	$0.19	$0.17	$0.20	$0.28	$0.11	$0.11	$0.14	$0.13	$0.13	$0.09	-$0.13	-$0.27	-$0.31	-$0.35	-$0.36	-$0.36	-$0.37	-$0.37	-$0.36	-$0.36	-$0.36
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.25	-$0.30	-$0.28	$0.24	$0.25	-$0.26	-$0.15	-$0.25	$0.00	-$0.25	-$0.21	-$0.02	$0.08	$0.13	$0.16	$0.00	$0.17	$0.18	$0.17	$0.17	$0.16	$0.17
	6110_SOL10_NG	$0.22	$0.19	$0.18	$0.99	$0.27	$0.12	$0.07	$0.14	$0.13	$0.14	$0.10	-$0.12	-$0.26	-$0.32	-$0.36	-$0.45	-$0.45	-$0.38	-$0.48	-$0.45	-$0.43	-$0.45
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.15	-$0.04	-$0.04		$0.07	-$0.04	-$0.03	-$0.04	-$0.04	-$0.04	-$0.03											
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.09	-$0.18	-$0.09			-$0.02		-$0.01		-$0.01												
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.09	-$0.15	-$0.14	$0.09	$0.09	-$0.14	-$0.07	-$0.13	$0.02	-$0.13	-$0.11	-$0.02	$0.03	$0.04	$0.05	-$0.02	$0.06	$0.06	$0.06	$0.06	$0.05	$0.06
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.08			$0.30	$0.07								-$0.06	-$0.06	-$0.10	-$0.11	-$0.11	-$0.10	-$0.12	-$0.11	-$0.10	-$0.11
	RM_TM21_NG	$0.07	$0.04	$0.04	$0.01	$0.02	$0.01	$0.00	$0.01	$0.01	$0.01	$0.01	-$0.01	-$0.02	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	$0.07			-$0.03											-$0.01	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.02	-$0.03
	30735_METCALF _230_30042_METCALF _500_XF_13	$0.04	-$0.01	-$0.01			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7440_MetcalfImport_Tes-Metcalf	$0.04	-$0.02	-$0.02	$0.02	$0.03	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02			$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30114_DELEVAN _230_30450_CORTINA _230_BR_1 _1	$0.03																	-$0.03	-$0.01			
	30015_TABLE MT_500_30040_TESLA _500_BR_1 _3	$0.03	$0.03	$0.02	$0.02	$0.04	$0.02	$0.01	$0.02	$0.02	$0.02	$0.01	-$0.02	-$0.04	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	$0.01	-$0.03	-$0.02	$0.01	$0.01	-$0.02	-$0.01	-$0.02	$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.01	-$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30300_TABLMTN _230_30330_RIO OSO _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
	37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1	$0.00			$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$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	$0.00	$0.00	$0.00	$0.00
	SUMMIT-DRUM #2	$0.00			-$0.01			$0.10															
	OMS_11396530_RED_BLUFF_XF	-$0.02	$0.00		-$0.01	-$0.02	$0.00	$0.02	$0.00		$0.00	$0.00	$0.02										
	PACI_SN	-$0.18	-$0.12	-$0.11	-$0.17	-$0.17	-$0.09	-$0.05	-$0.09		-$0.09	-$0.06	$0.05	$0.12	$0.14	$0.16		$0.17	$0.17	$0.17	$0.17	$0.17	$0.17
	30500_BELLOTA _230_30515_WARNERVL_230_BR_1 _1				$0.05	-$0.06																	
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1		-$0.12	-$0.11	$0.13	$0.17	$0.00		-$0.02	$0.00	-$0.02	$0.00											
	30805_BORDEN _230_30810_GREGG _230_BR_2 _1		$0.00	$0.00	$0.04	$0.00																	
	32214_RIO OSO _115_32225_BRNSWKT1_115_BR_1 _1							-$0.03															
	32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1							-$0.06															
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1							-$0.18															
	32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1							-$0.46															
	35120_NEWARK D_115_36851_NORTHERN_115_BR_1 _1					-$0.11																	
	7430_CP6_NG				$0.04																		
	SUMMIT-DRUM #1							$0.06															
SCE	6410_CP1_NG	-$0.06	$0.05	$0.05	-$0.05	-$0.06	$0.04	$0.03	$0.04	$0.02	$0.04	$0.03	$0.00	-$0.01	-$0.03	-$0.04	-$0.02	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	OMS 10666077_OP-6610	$0.01	$0.01	$0.00	$0.01	$0.01	-$0.03	-$0.02	-$0.02		-$0.02	-$0.02	-$0.01	-$0.01		$0.00		$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	6410_CP7_NG	$0.01	-$0.02	-$0.02	$0.01	$0.01	-$0.02	-$0.01	-$0.02		-$0.02	-$0.01	$0.00	$0.00	$0.01	$0.01		$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.18	$2.15	$0.00	$0.00	$0.00	-$0.13	-$0.42	-$0.20	-$0.46	-$0.35	-$0.14	-$0.03	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 11364971_50002_OOS_TDM			$0.65					-$0.13	-$0.07	-$0.06												
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.04	$0.31				-$0.02	-$0.09	-$0.08	-$0.09	-$0.07	-$0.02										
	OMS 11368744_50001_OOS_NG		$0.02	$0.30				-$0.01	-$0.04	-$0.04	-$0.04	-$0.03	-$0.01										
	7820_TL 230S_TL50001OUT_NG		$0.02	$0.15				-$0.01	-$0.03	-$0.03	-$0.04	-$0.03	-$0.01										
	OMS 11396189_50002_OOS_TDM			$0.05					-$0.01	-$0.01	$0.00												
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			-$1.25					-$0.40	-$0.07	-$0.43	-$0.17											
	Other	$9.00	$6.45	$5.84	$8.83	$7.48	$3.75	$2.59	$4.62	$5.79	$4.60	$3.06	-$4.38	-$8.56	-$10.59	-$11.93	-$19.59	-$12.18	-$12.30	-$12.42	-$12.12	-$12.02	-$12.15
	Internal Total	**$14.09**	**$3.47**	**$5.39**	**$13.20**	**$16.76**	**$0.90**	**$0.01**	**$1.19**	**$3.96**	**$1.11**	**-$2.19**	**-$7.11**	**-$8.60**	**-$11.15**	**-$12.25**	**-$20.79**	**-$12.50**	**-$12.22**	**-$12.15**	**-$12.41**	**-$12.53**	**-$12.69**
	Transfers				$0.13	$0.45	$0.02	$1.15	$0.70	$2.38	$7.11	-$0.78	-$1.08	$1.65	$1.76	$1.89	-$1.35	$5.64	$0.93	$1.01	$0.00	$6.58	$5.51
	Grand Total	**$14.09**	**$3.47**	**$5.39**	**$13.33**	**$17.21**	**$0.92**	**$1.16**	**$1.89**	**$6.34**	**$8.22**	**-$2.97**	**-$8.19**	**-$6.95**	**-$9.39**	**-$10.36**	**-$22.14**	**-$6.86**	**-$11.29**	**-$11.14**	**-$12.41**	**-$5.95**	**-$7.18**

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. Price impacts between the 15-minute and 5-minute markets were very different during the second quarter. Transfer constraint congestion in the 15-minute market decreased prices in most areas, while the opposite occurred in the 5-minute market where it increased prices in most areas.

In the real-time market, the total impact of congestion on a specific WEIM area is equal to the sum of the price impact of flow-based constraints shown in Figure 1.29 and Table 1.4, and schedule-based constraints as 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 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 (Q2 2022)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	0%	-$0.02	0%	$0.13
L.A. Dept. of Water and Power	0%	$0.00	0%	$0.02
Turlock Irrigation District	1%	$0.40	1%	$0.45
Arizona Public Service	1%	$0.08	2%	$0.70
NV Energy	3%	$0.75	3%	$1.15
Public Service Company of NM	3%	-$0.79	3%	-$0.78
Tucson Electric Power*	9%	$1.86	10%	$2.38
PacifiCorp East	13%	-$2.50	10%	-$1.08
Salt River Project	11%	$3.20	12%	$7.11
Idaho Power	21%	-$1.04	19%	$1.65
Avista	28%	-$2.44	24%	$1.89
NorthWestern Energy	29%	-$3.20	24%	$1.76
PacifiCorp West	39%	-$3.98	32%	$0.93
Portland General Electric	40%	-$2.59	32%	$1.01
Puget Sound Energy	52%	-$1.37	52%	$5.90
Tacoma Power	52%	-$1.48	51%	$5.64
Seattle City Light	52%	-$1.30	52%	$5.51
Powerex	48%	-$1.60	68%	$6.58
Bonneville Power Admin.*	61%	-$6.18	55%	-$1.35

*Since joining the WEIM

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 1.31 and Figure 1.32 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 increase in the frequency and impact of transfer constraint congestion in the second quarter of 2022 compared to the same quarter in 2021. The average frequency of transfer constraint congestion in the Pacific Northwest reached 46 percent in the second quarter, up from 27 percent during the same time last year.[40]

[40] 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 in both quarters.

Figure 1.31 Transfer constraint congestion average impact on prices in the 15-minute market

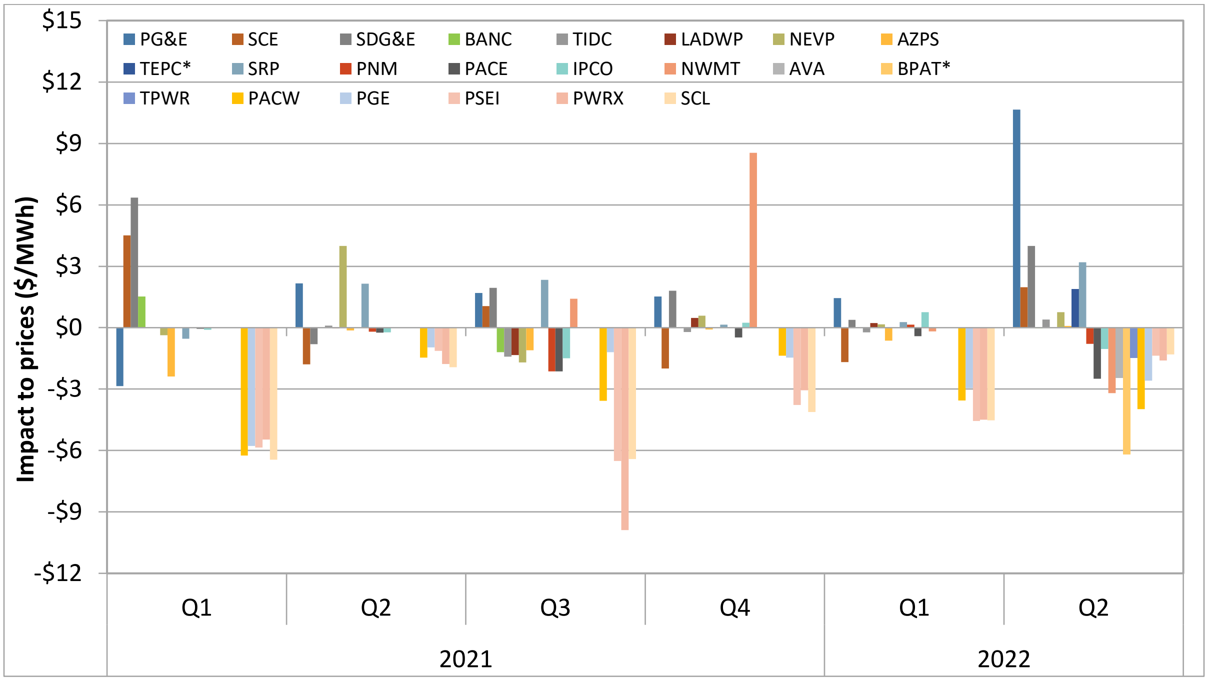
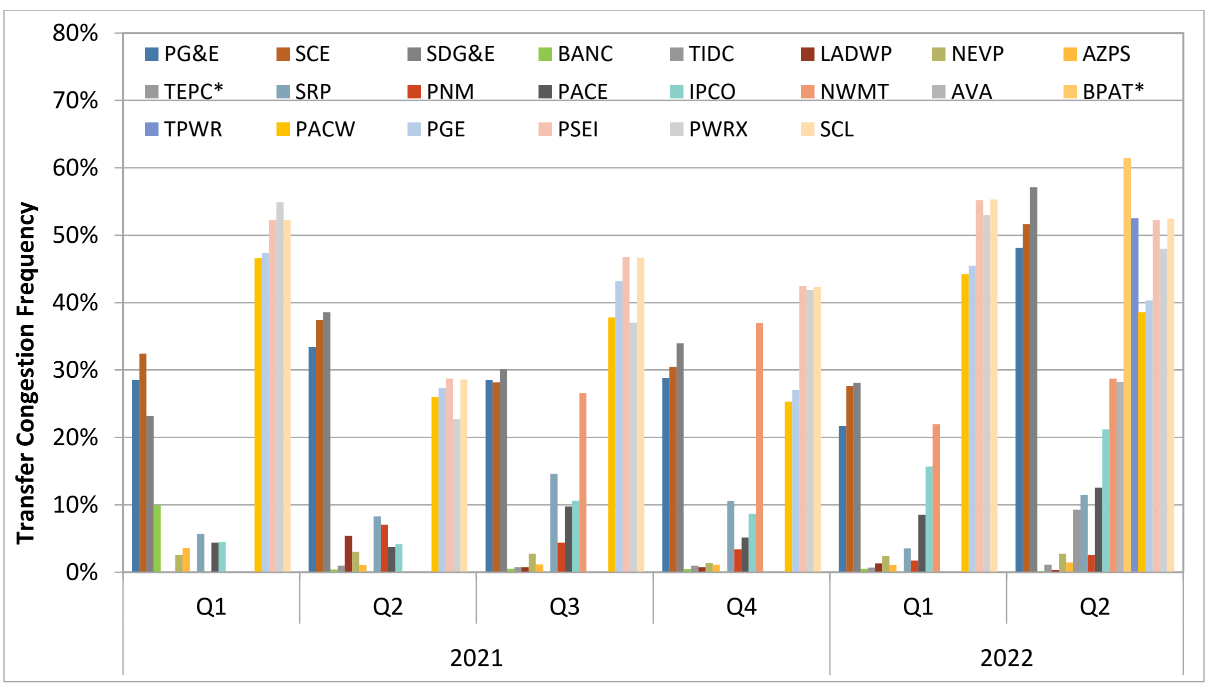


Figure 1.32 Transfer constraint congestion frequency in the 15-minute market



*Since joining the WEIM

1.8.3 Congestion on interties

In the second quarter of 2022, the frequency and import congestion rent on the Malin 500 and NOB increased significantly relative to same time last year. Figure 1.33 shows total import congestion charges in the day-ahead market for 2021 and 2022. Figure 1.34 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 California ISO side of the intertie and the lower price outside of the California ISO area. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside the California ISO area at points corresponding to these interties. The charts and table below highlight the following:

- Total import congestion charges for the second quarter of 2022 was over 4.5 times higher than the second quarter of 2021 at $71 million. The drivers of the increase between the quarters was from the Malin 500 and NOB.
- 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 the intertie was congested during 1 percent of intervals and accounted for $1.6 million in congestion charges.
- The frequency of congestion and magnitude of congestion charges is typically highest on the Malin 500, NOB, and Palo Verde interties, a trend that continued this quarter. Congestion on other interties continued to remain relatively low relative to these constraints.

Figure 1.33 Day-ahead import congestion charges on major interties

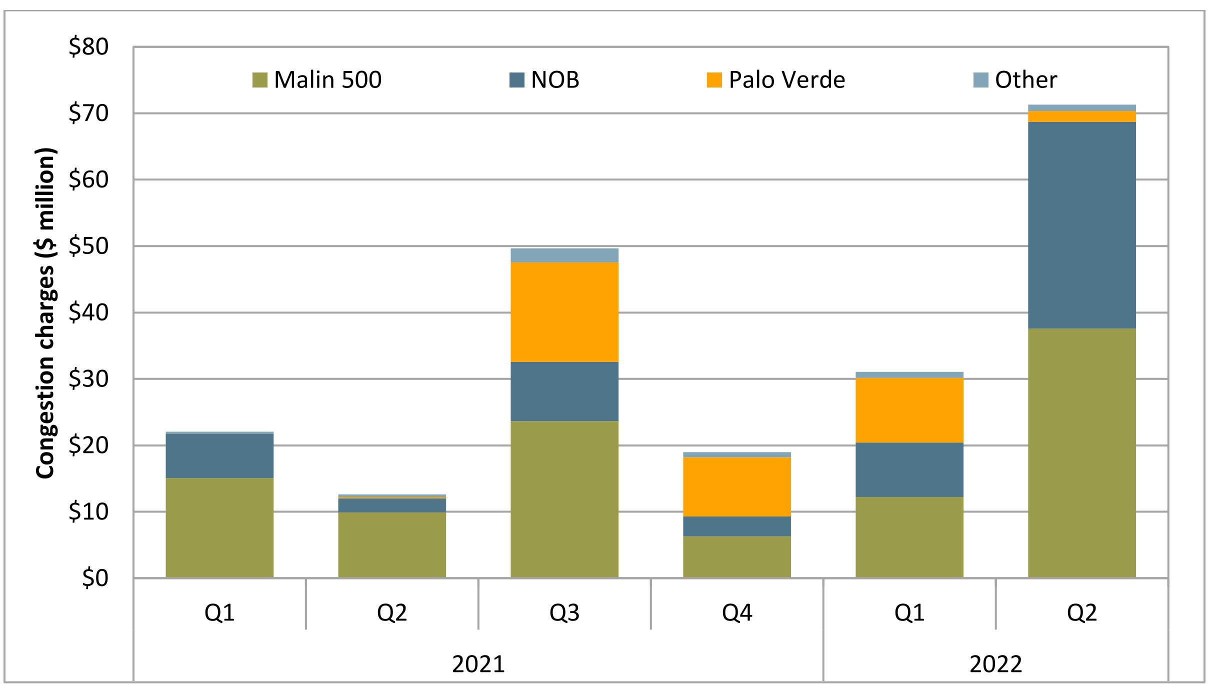


Figure 1.34 Frequency of import congestion on major interties in the day-ahead market

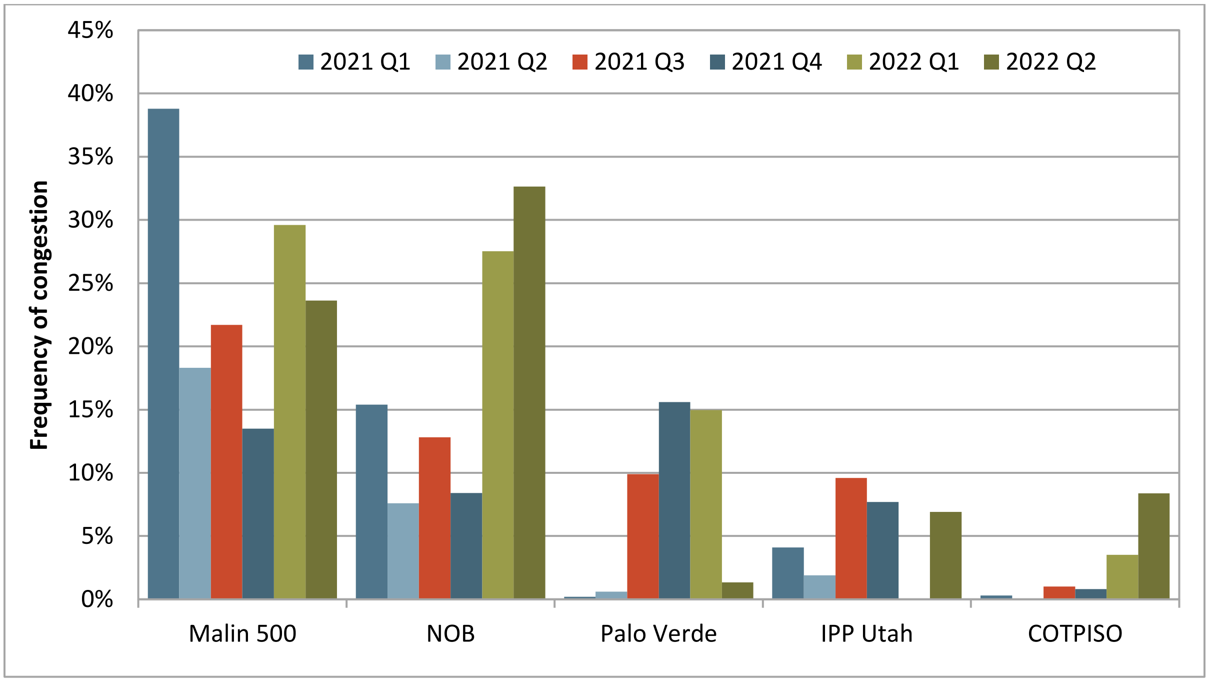


Table 1.8 Summary of import congestion in day-ahead market (2021-2022)

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

1.9 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 and then subtracting the auction price paid. While this represents a profit to entities purchasing rights in the auction, it also represents a loss to transmission ratepayers.

As shown in Figure 1.35, transmission ratepayers lost about $70 million during the first half of 2022 as payments to auctioned congestion revenue rights holders continued to exceed auction revenues. This figure also shows that second quarter losses at $57.6 million were higher than any other quarter since the California ISO instituted significant changes to the auction, starting in the 2019 settlement year.

Auction revenues were 43 percent of payments made to non-load-serving entities during the second quarter, down from 68 percent during the previous quarter.

Figure 1.35 Auction revenues and payments to non-load-serving entities

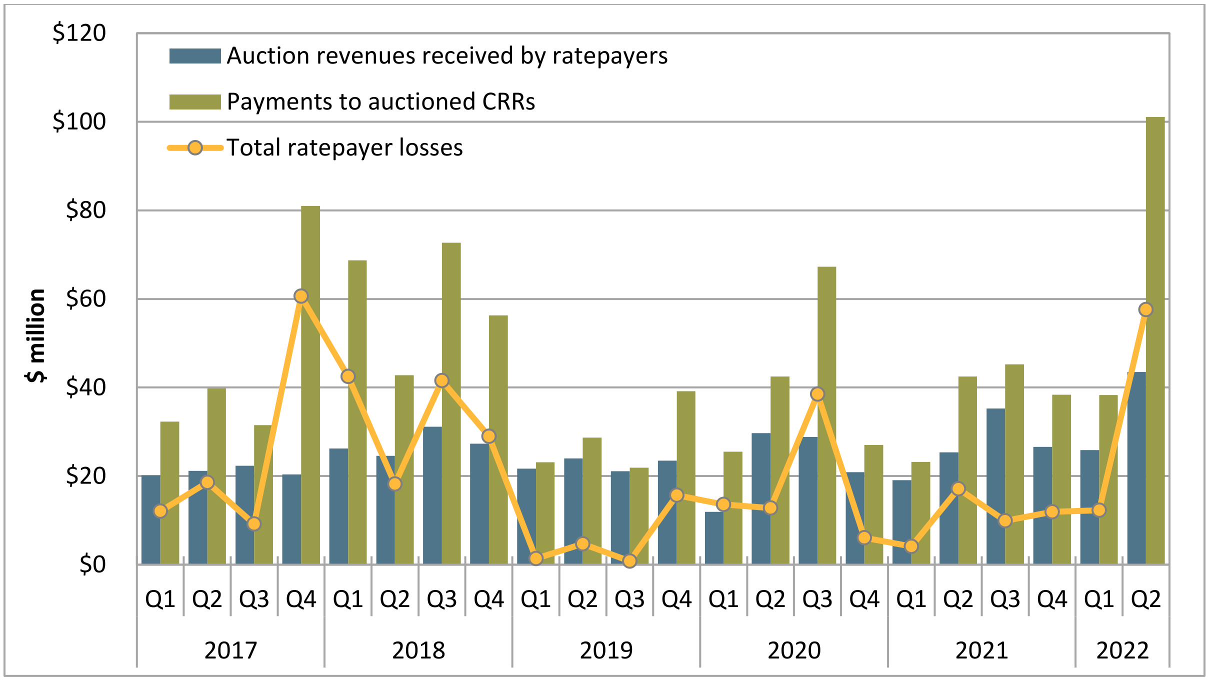


Figure 1.36 through Figure 1.38 compares the auction revenues paid for and payments received from congestion revenue rights traded in the auction by market participant type.[41] The difference between auction revenues and payments to congestion revenue rights is profit for the entities holding the auctioned rights. These profits are losses to ratepayers.

- Financial entities received net revenue of nearly $39 million in the first half of 2022, significantly up from $15 million during the first half of 2021. Total revenue deficit offsets were about $50 million.
- Marketers received net revenues of nearly $22 million from auctioned rights in 2022, up significantly from a total $3.4 million in the first half of 2021. Total revenue deficit offsets were nearly $20 million.
- Physical generation entities received about $8 million in net revenue from auctioned rights in 2022, which is four times higher when compared to the first half of 2021. Total revenue deficit offsets were about $1.2 million.

41 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. Balancing authority areas are participants that are balancing authority areas outside the California ISO area. Apart from financial entities, the groups classified as "other" is based on the primary function but could include instances where a particular entity performs a different function. For example, a generating entity that has load serving obligations may be classified as a generator and not a load serving entity.

The $58 million in second quarter 2022 auction losses was about 21 percent of day-ahead congestion rent. This is up from 10 percent from the previous quarter and 17 percent of rent in the second 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 $71 million in the first and second 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.

Figure 1.36 Auction revenues and payments (financial entities)

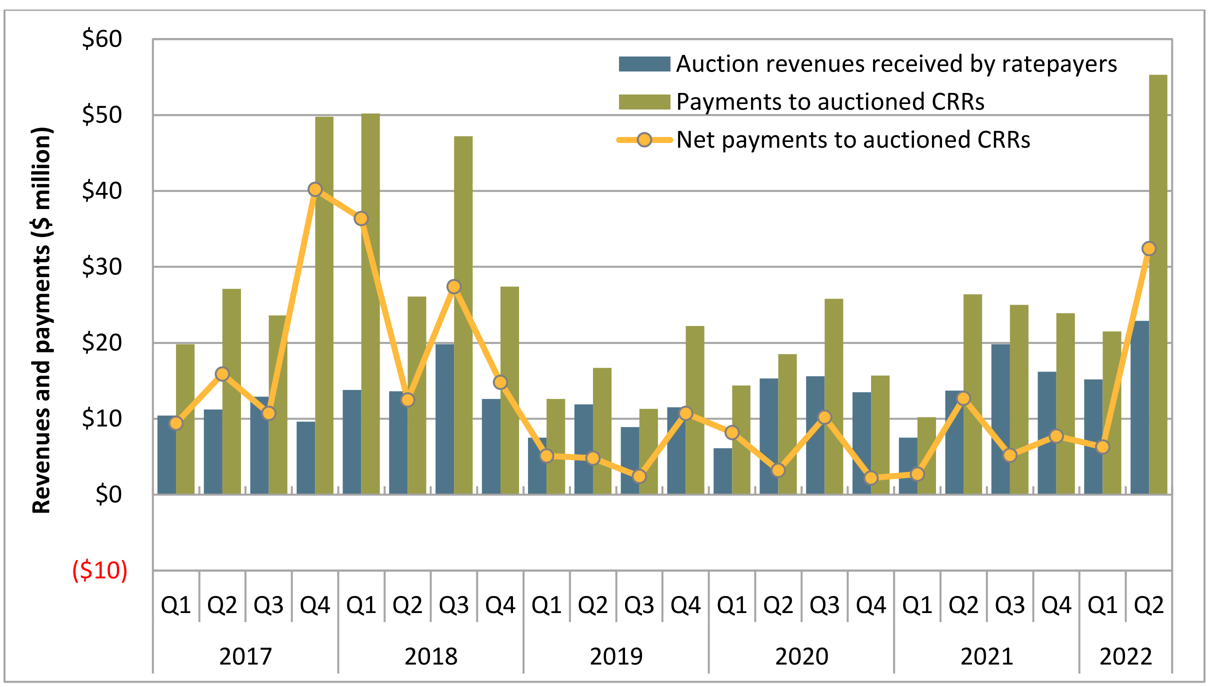


Figure 1.37 Auction revenues and payments (marketers)

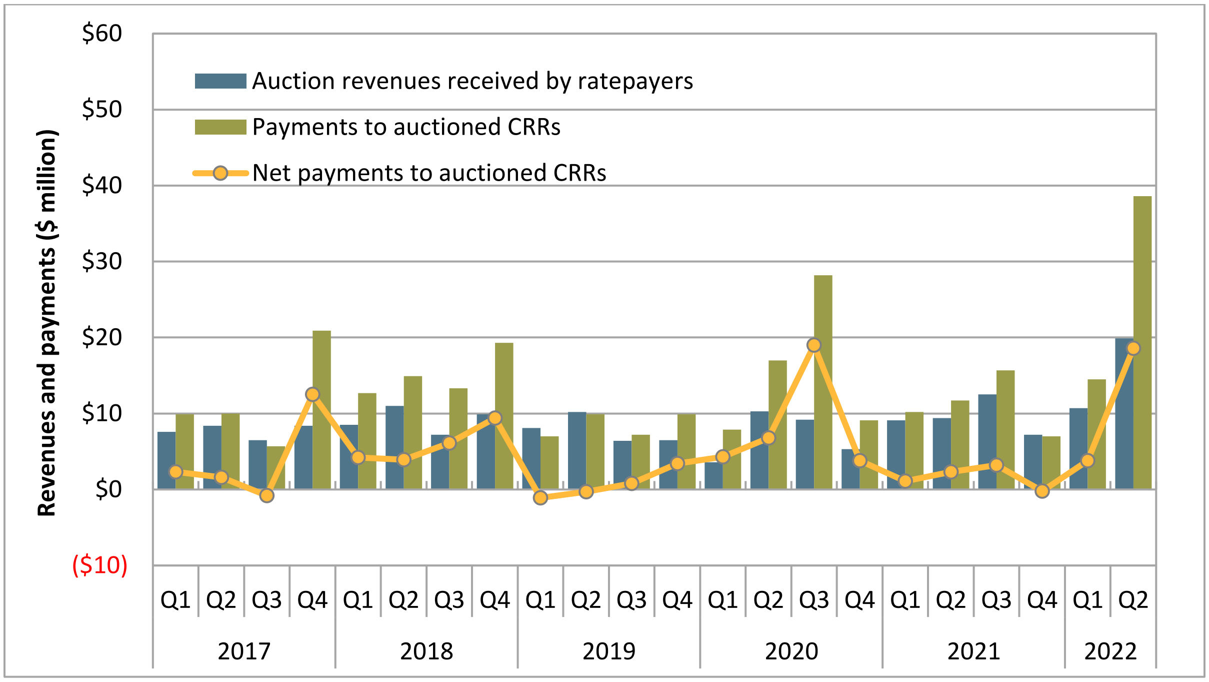
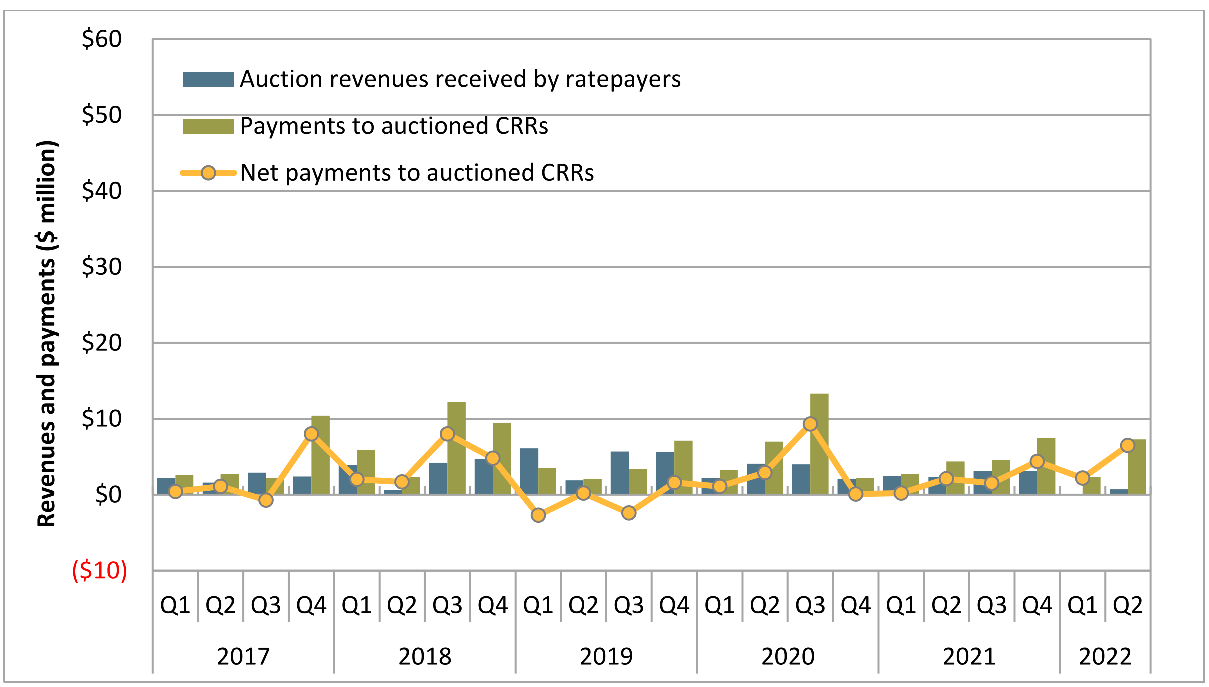


Figure 1.38 Auction revenues and payments (generators)



1.10 Real-time imbalance offset costs

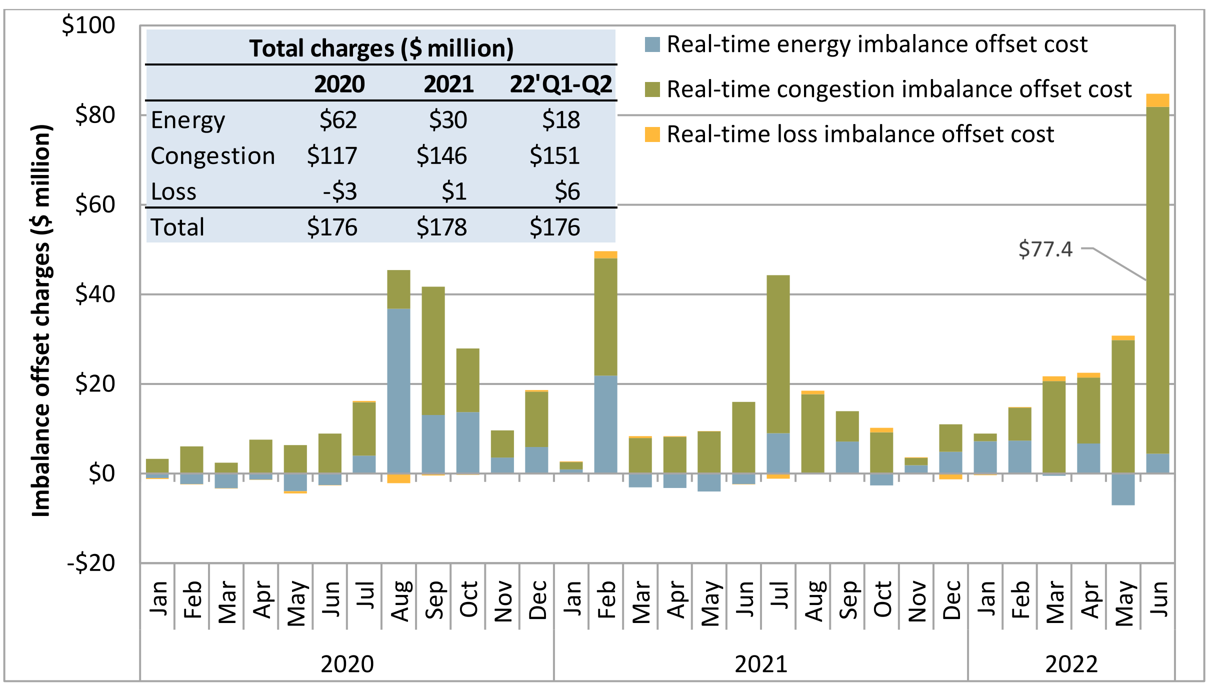
Real-time imbalance offset costs increased significantly to about $131 million in the second quarter, up from $45 million in the previous quarter. Real-time congestion imbalance offset costs were $77 million in June alone, the highest monthly congestion imbalance recorded since locational marginal pricing was introduced in 2009.

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

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

Figure 1.39 shows monthly imbalance charges. In June, real-time congestion imbalance charges reached $77 million.[42] For the quarter, real-time congestion imbalance charges were almost $122 million. Energy imbalance charges were $4 million while loss imbalance charges were $5 million.

Figure 1.39 Real-time imbalance offset costs



42 Settlement values are based on statements available at the time of drafting and may be updated in future reports.

Real-time congestion imbalance offset costs occur when the congestion payments the ISO pays out do not equal the congestion payments collected by the ISO, 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 ISO enough to cover the ISO's payments to the schedule that reduced flows—and the ISO congestion accounts would remain balanced.

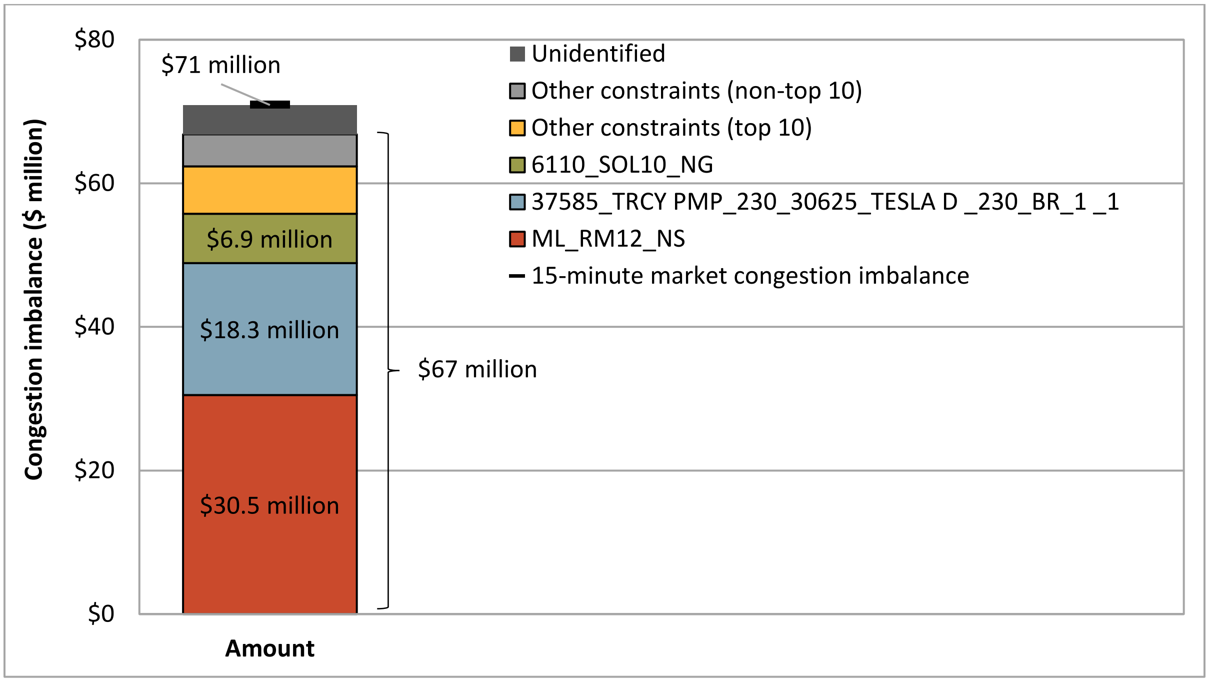
There are several reasons the congestion payments will not balance. One reason is that flows increase causing a constraint to bind, generating additional congestion rent. Another is that the real-time constraint limits are lower than the day-ahead market limits. With a lower limit, schedules may be forced to reduce flows over the binding constraint without a corresponding flow increase. The ISO will pay the flow reduction but cannot balance this payment with collections from a flow increase. To maintain revenue balance, the ISO 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.

Around $71 million of the total congestion offset costs in June were associated with *15-minute market* imbalances. Figure 1.40 shows the 15-minute market congestion offset costs split out by individual constraints.[43] The three largest constraints associated with real-time congestion offset costs during June are listed below. These three constraints accounted for about $56 million of the 15-minute market congestion imbalances, or around 79 percent.

1. **ML_RM12_NS ($30.5 million):** This constraint was one of the most frequently binding in the 15-minute market and was heavily impacted by unscheduled flows over Path 66 (COI) which were exacerbated by the loss of the Tesla-Tracy 500 kV line and Captain Jack CB 4977.
2. **37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1 ($18.3 million):** This line was impacted by maintenance on the Tesla-Tracy 230 kV line as well as mitigation for the contingency of the Malin 500 intertie.
3. **6110_SOL10_NG ($6.9 million):** Path 66 control point #10 is used to limit thermal loading on Round Mountain-Cottonwood 230 kV #3 line. This constraint is used to manage conditions similar to the 6110_COI_N-S constraint used only in the 5-minute market. As noted above, the 5-minute market only 6110_COI_N-S would generate additional congestion offset when binding.

43 Individual constraints were identified by replicating the nodal congestion component of the price (that was used in the RTCIO calculation) from individual constraints, shadow prices, and shift factors. In some cases, DMM could not replicate the marginal congestion component such that the entire congestion offset cost was instead flagged as unidentified.

Figure 1.40 15-minute market congestion imbalance by constraint

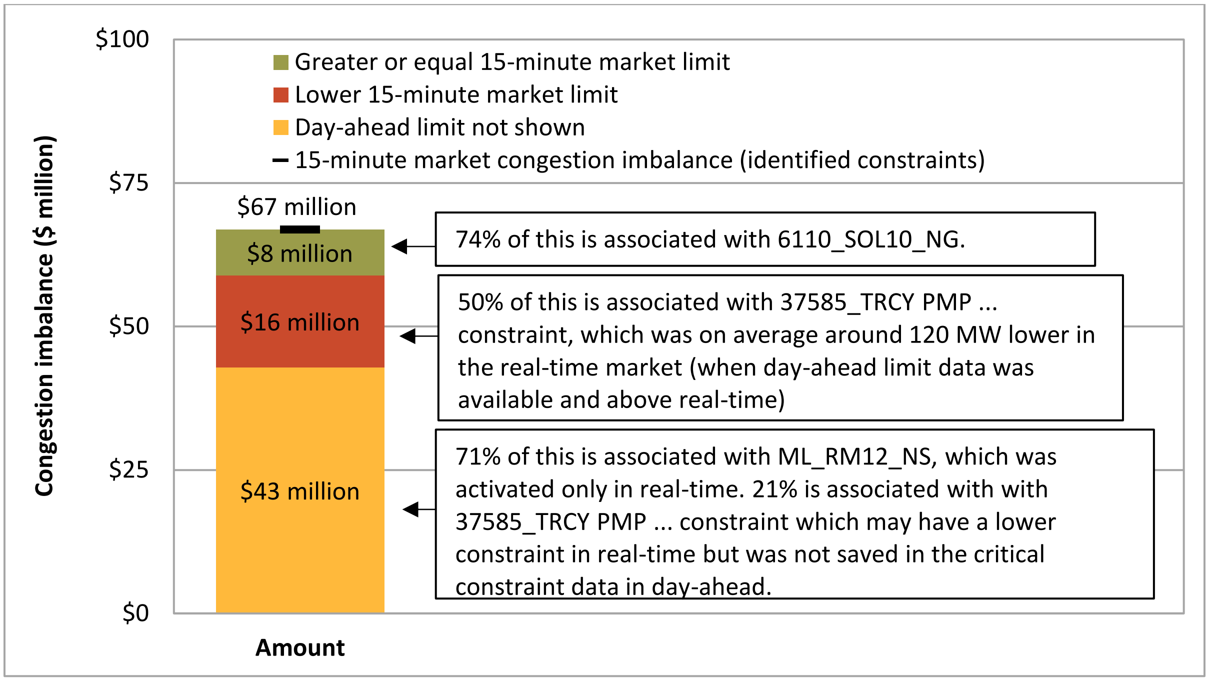


Much of the congestion imbalances observed in June occurred when the constraint limits in the 15-minute market were lower than the day-ahead limits, or with the activation of the ML_RM12_NS nomogram which was not enforced in the day-ahead market. Figure 1.41 summarizes the 15-minute congestion imbalance costs broken into three groups where the 15-minute market limit on the corresponding constraint was: (1) above the day-head limit; (2) below the day-ahead limit; or (3) there was no day-ahead limit available in the trade hour for comparison.

Around $16 million were associated with constraints in which the transmission limit was lower in the 15-minute market than in the day-ahead market. In particular, around half of this was associated with the binding 37585_TRCY PMP_230_30625_TESLA D_230_BR_1_1 constraint.

Around $43 million were associated with constraints in which the limits were not shown in the day-ahead data. This does not necessarily mean the constraint was not enforced in the day-ahead market. The constraint data may not have been saved in the critical constraint data as the constraint was not close enough to binding to be placed in the market run. However, around 71 percent of this was associated with the ML_RM12_NS nomogram, which was only activated in the real-time market.

Figure 1.41 15-minute market congestion imbalance by status, 15-minute market limit relative to day-ahead market limit



Last, Table 1.9 summarizes total 15-minute market congestion offset costs during June both individually for the top ten constraints (by imbalance) and grouped for all other constraints. The table highlights the percent of congestion imbalances which were associated with either a lower or higher limit in the 15-minute market relative to the day-ahead market. The table also shows the total intervals that each constraint was binding in the 15-minute market.[44] Outside the top three which were already discussed, the other constraints within the top ten were associated with around $6.6 million in congestion imbalances. Here, 57 percent of this deficit was associated with a lower 15-minute market limit and 25 percent had no day-ahead limit shown. Outside the top ten constraints (around $4.5 million), 80 percent was associated with a lower limit in the 15-minute market.

Table 1.9 15-minute market congestion imbalance by constraint

Constraint	Binding in 15-minute market (constraint/case intervals)	15-minute congestion imbalance ($ million)	Percent of congestion imbalance by 15-minute market limit relative to day-ahead		
			Lower FMM limit	Day-ahead limit not shown	Greater or equal FMM limit
ML_RM12_NS	1,209	$30.5	0%	100%	0%
37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	547	$18.3	43%	50%	7%
6110_SOL10_NG	328	$6.9	10%	4%	86%
31336_HPLND JT_60.0_31370_CLVRDLJT_60.0_BR_1 _1	889	$1.4	59%	7%	34%
30970_MIDWAY _230_30945_KERN PP _230_BR_1 _1	228	$1.3	61%	3%	36%
SUMMIT_BG	105	$0.9	0%	100%	0%
30055_GATES1 _500_30900_GATES _230_XF_12_P	324	$0.8	91%	9%	0%
30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	200	$0.8	100%	0%	0%
30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	92	$0.7	23%	51%	26%
32214_RIO OSO _115_30330_RIO OSO _230_XF_2A	172	$0.6	62%	38%	0%
Other identified constraints	8,496	$4.5	80%	27%	-7%
Totals		$67	24%	12%	64%

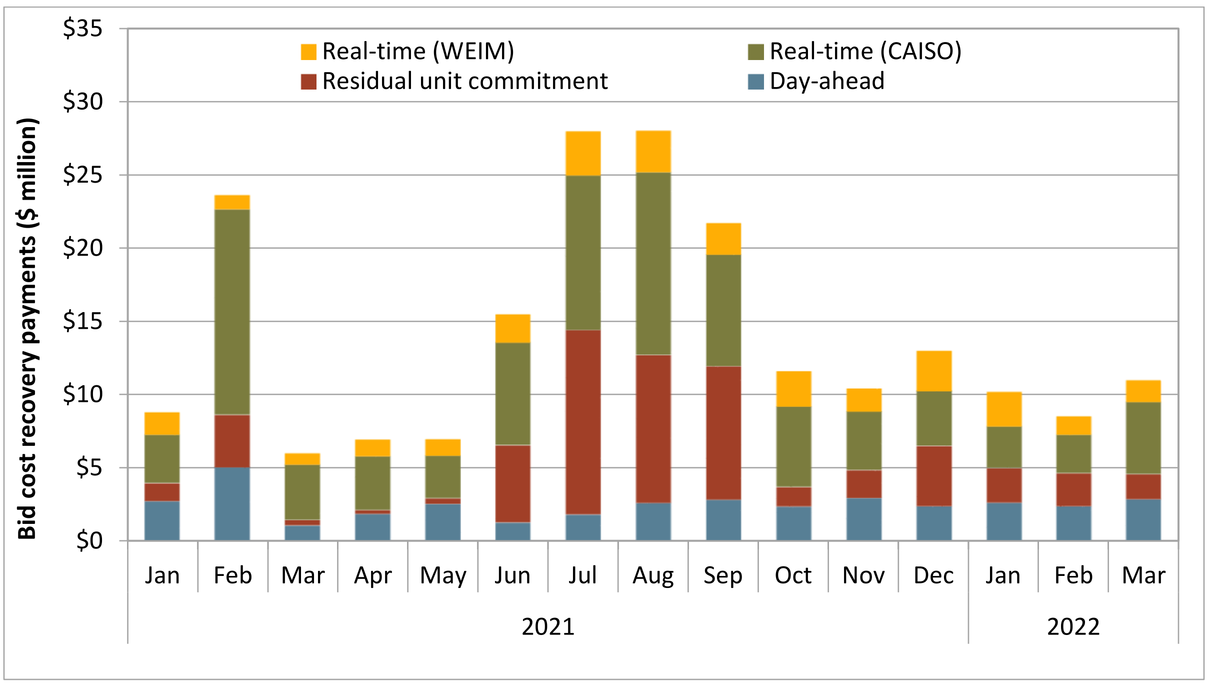
44 15-minute intervals are counted by unique constraint element *and* contingency. In some cases, the same constraint was binding for multiple contingencies in the same interval, which were counted separately.

1.11 Bid cost recovery

During the first quarter of 2022, estimated bid cost recovery payments for units in the California ISO and Western Energy Imbalance Market (WEIM) balancing areas totaled about $30 million. This was $5 million lower than total bid cost recovery in the previous quarter and about $8 million lower than the first quarter of 2021. Following settlement timeline changes effective January 1, 2021, bid cost recovery payments are reported with a lag of one quarter. More final settlement statements are issued at trade day plus 70 business days. Settlements can change between statements.[45]

Bid cost recovery attributed to the day-ahead market totaled about $8 million, which was $1 million lower than first quarter of 2021. Bid cost recovery payments for residual unit commitment during the quarter totaled about $6 million, $1 million higher than first quarter of 2021. Bid cost recovery attributed to the real-time market totaled about $16 million, or about $4 million lower than payments in the previous quarter, and $8 million lower than payments in the first quarter of 2021. Out of the $16 million in real-time payments, about $5 million was allocated to resources (non-California ISO) participating in the WEIM.

Figure 1.42 Monthly bid cost recovery payments



45 For further information on settlement timeline changes see: California ISO, *Market Settlements Timeline Transformation,* presented by Rashele Wiltzius, July 20, 2020: http://www.caiso.com/Documents/Presentation-MarketSettlementsTimelineTransformationTraining.pdf

1.12 Imbalance conformance

Operators in the California ISO and WEIM balancing areas can manually adjust the amount of imbalance conformance used in the market to balance supply and demand conditions to maintain system reliability. Imbalance conformance adjustments are used to account for potential modeling inconsistencies and inaccuracies.

Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the California ISO hour-ahead and 15-minute markets. This large increase continued in both the morning solar ramp up and the afternoon peak solar ramp down period. Average hourly imbalance conformance adjustments in these markets peaked in the morning at about 600 MW and at just over 2,100 MW in the afternoon, about a 350 MW and 950 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.

Figure 1.43 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.

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 1.44 shows the distribution of the 15-minute market into quartiles for the load adjustment profile for this quarter of 2022. This box and whiskers type of graph highlights the minimum, maximum, and the median, as well as the mean (line). The maximum load adjustments in the morning ramp were around 2,000 MW in hours ending 7 and 8, while the maximum evening ramp was about 2,700 MW in hours ending 19 through 21, with a few outliers over 3,000 MW.

Figure 1.43 Average hourly imbalance conformance adjustment (Q2 2021 – Q2 2022)

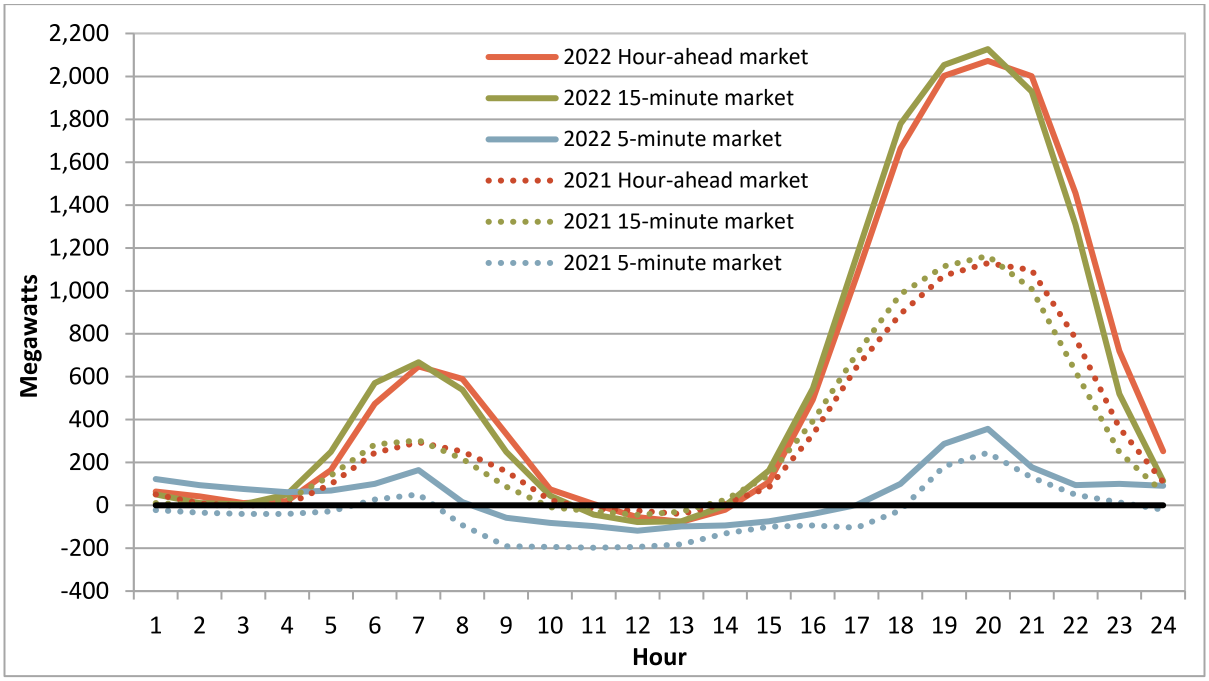
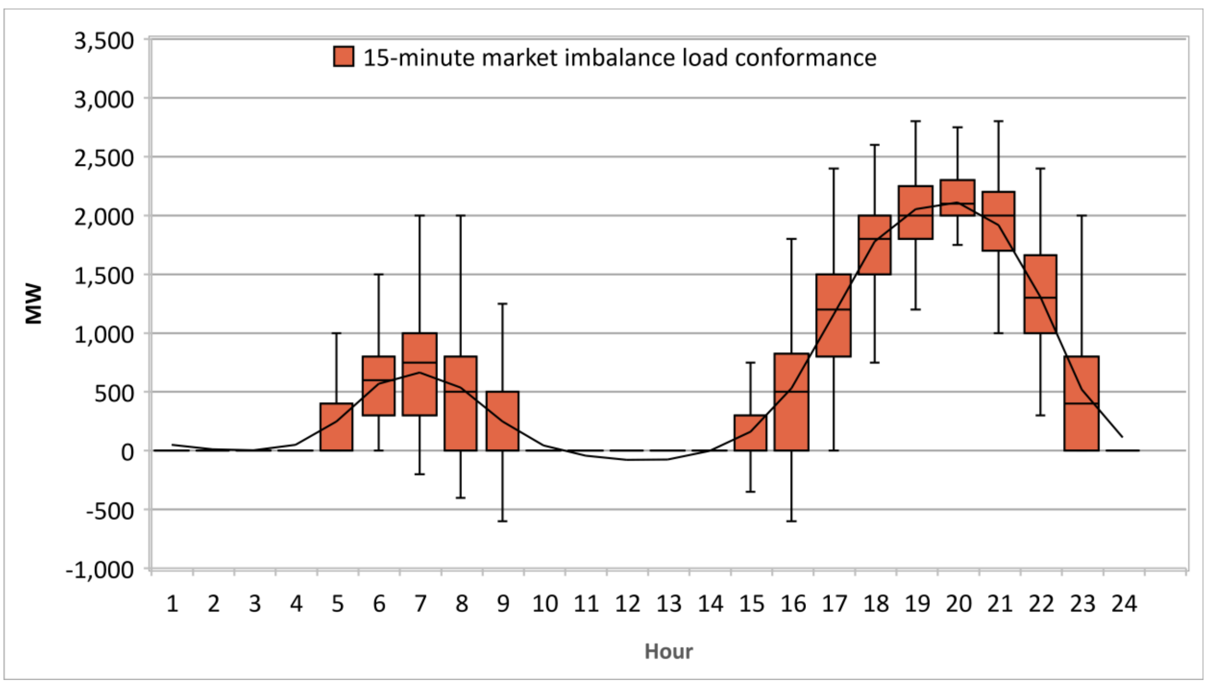


Figure 1.44 15-minute market hourly distribution of operator load adjustments (Q2 2022)



1.13 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

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

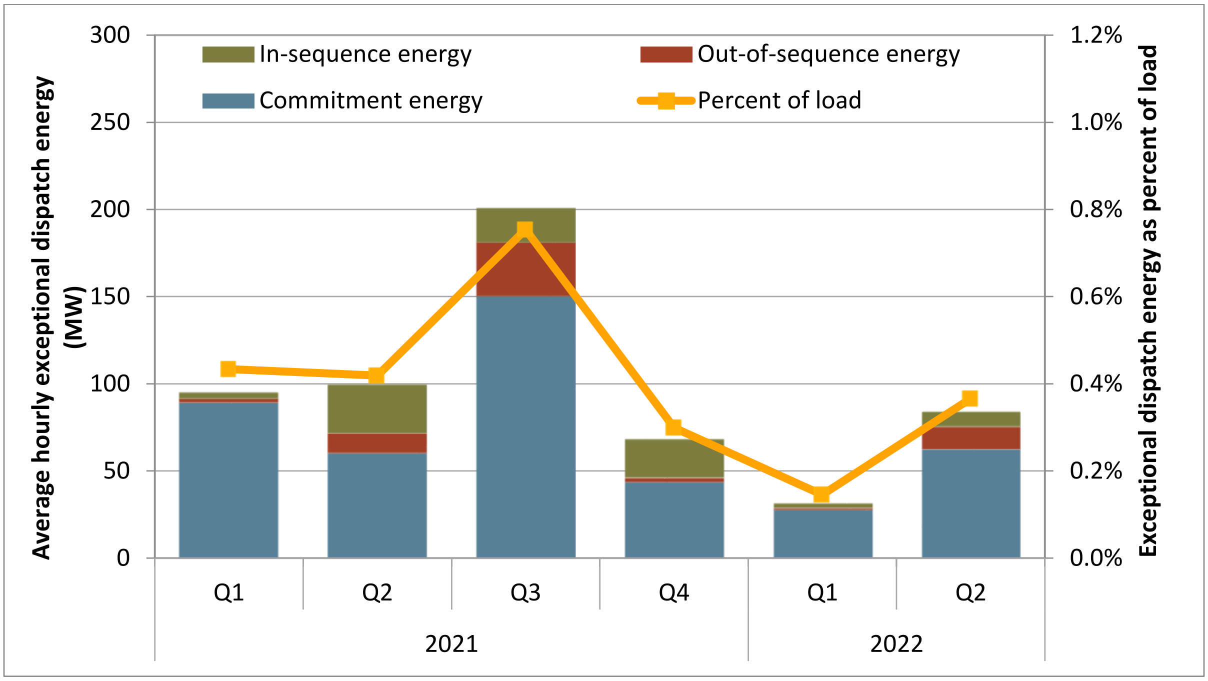
Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 1 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 84 MWh in the second quarter of 2022, which is down from 96 MWh in the same quarter in 2021.

As shown in Figure 1.45, exceptional dispatches for unit commitments accounted for about 74 percent of all exceptional dispatch energy in this quarter.[46] About 15 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 10 percent was from in-sequence energy.

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

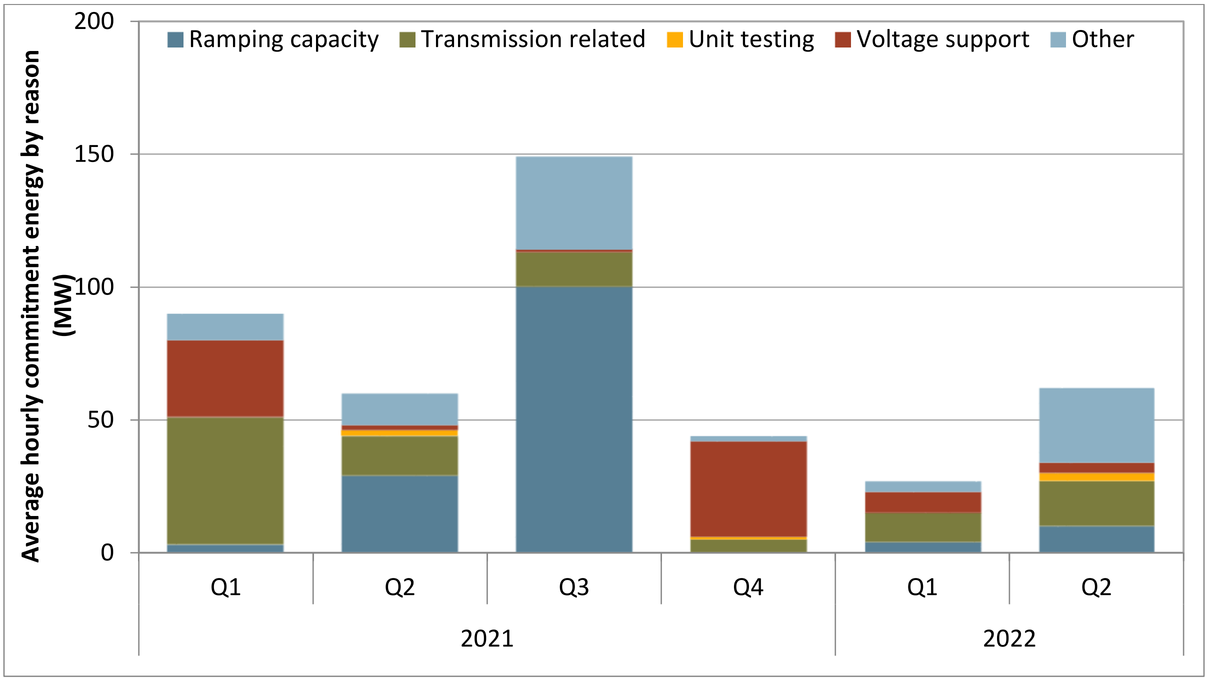
Figure 1.45 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

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.

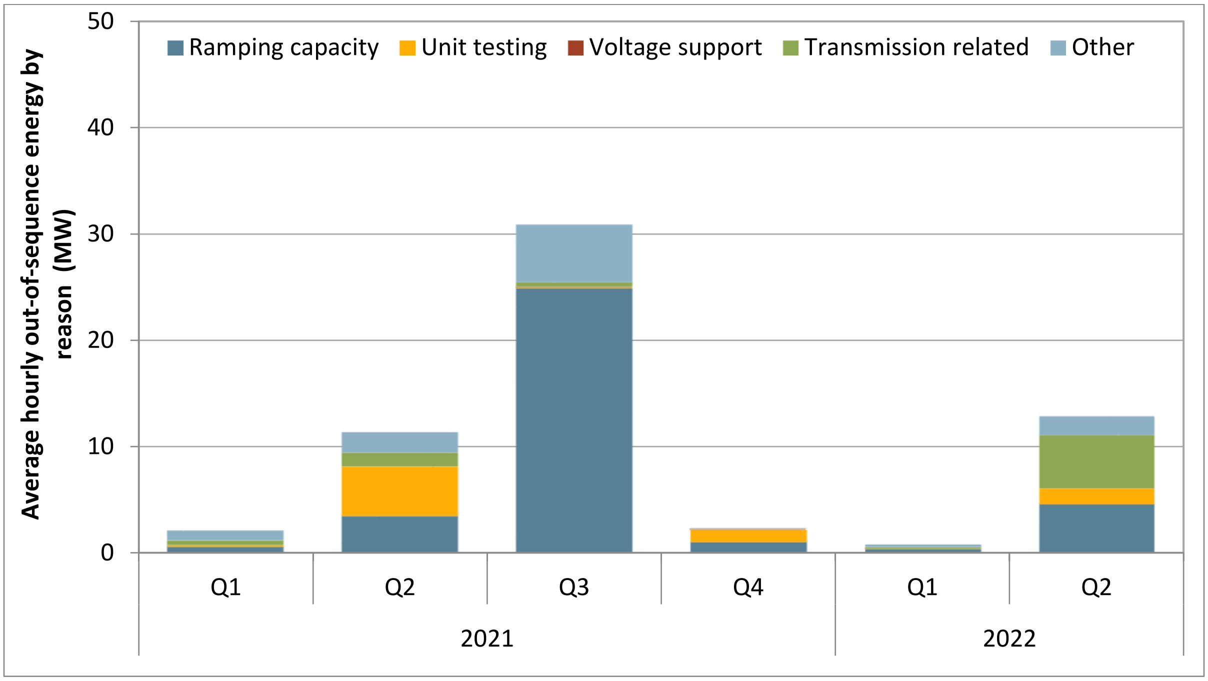
Figure 1.46 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

As shown in Figure 1.46, in the second quarter of 2022, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch increased by about 16 percent from the same quarter in 2021. The figure also shows about 15 percent of the total exceptional dispatch energy was out-of-sequence, meaning the bid price (or default energy bid if mitigated, or if the resource did not submit a bid) was greater than the locational market clearing price. Figure 1.47 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 second quarter of 2022 was “exceptional dispatches for transmission related needs,” closely followed by “ramping capacity.” Transmission related exceptional dispatches are commonly needed to overcome a transmission line outage. 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 1.47 Out-of-sequence exceptional dispatch energy by reason



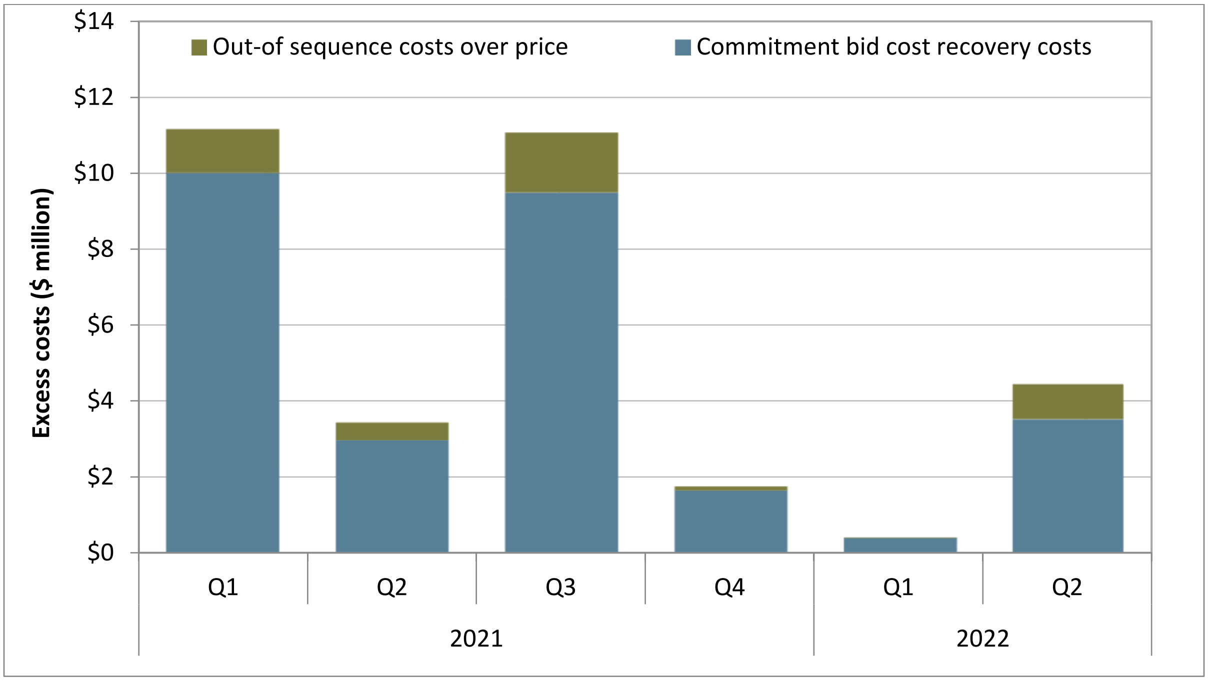
Exceptional dispatch costs

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 1.48 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 second quarter, out-of-sequence energy costs were $0.9 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $3.5 million.

Figure 1.48 Excess exceptional dispatch cost by type



2 Western Energy Imbalance Market

This section covers Western Energy Imbalance Market (WEIM) performance during the second quarter. Key observations and findings include:

- **Natural gas prices rose across the WEIM**, resulting in higher energy prices in all balancing areas.
- **Bonneville Power Administration (BPA) and Tucson Electric Power (TEPC) joined** the Western Energy Imbalance Market in May, bringing the total number of participants up to 18.
- **Prices in California areas were about $25/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.
- **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 Energy, Avista Utilities, and Bonneville Power Administration.
- **Congestion from the Northwest decreased with the addition of transfer capacity.** Congestion from PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Powerex decreased an average of 27 percent in the 15-minute market compared to the first quarter of 2022 due in part to the addition of Bonneville Power Administration, Avista Utilities, and Tacoma Power to the WEIM, which increased import and export transfer capacity in the region by 43 percent and 50 percent, respectively.
- **The California ISO was a net importer** during peak net load hours. During mid-day hours, the CAISO exported just under 1,800 MW on average out to neighboring areas including BANC, LADWP, Powerex, Arizona Public Service, NV Energy, and Salt River Project.
- **The CAISO implemented phase 1 of resource sufficiency evaluation enhancements** in June. Phase 1 included supply crediting enhancements.
- **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.
- **Appendix A includes hourly price and transfer figures for each WEIM area.** As highlighted in the appendix, the transmission loss component of the price in areas located in the Pacific Northwest was high over the quarter and increased during hours with high flows. Since joining the WEIM on May 3, 2022, Bonneville Power Administration has base scheduled the majority of its transfer capacity.

2.1 Western Energy Imbalance Market performance

New WEIM balancing authority areas

On May 3, 2022, Bonneville Power Administration (BPA) and Tucson Electric Power (TEPC) joined the Western Energy Imbalance Market, bringing the total number of participants up to 18. BPA and TEPC bring with them about 2,475 MW and 4,150 MW of participating capacity, respectively. BPA joined Avista Utilities and Tacoma Power as the new WEIM participants this year in the Pacific Northwest. Together, these three areas increased import and export transfer capacity in the region by 43 percent and 50 percent, respectively, which has reduced 15-minute market transfer congestion out of the region by 27 percent on average compared to the first quarter of 2022.[47]

Western Energy Imbalance Market prices

This section details the factors that generally influence changes in Western Energy Imbalance Market (WEIM) area prices and what causes price separation between participating areas. The WEIM benefits participating areas by committing lower-cost resources across all areas to balance fluctuations in supply and demand in the real-time energy market. Since dispatch decisions are determined across the whole WEIM footprint, prices within each balancing authority diverge from the system price when transfer constraints are binding, greenhouse gas compliance costs are enforced for imports into California, or 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 2020 through 2022. The combined average of WEIM prices outside of California was lower than California area prices by $25.32/MWh on average over the second quarter. Prices of WEIM entities within California were closer to those of Pacific Gas and Electric. The combined average prices of these areas, which include the Balancing Area of Northern California, Turlock Irrigation District, and Los Angeles Department of Water and Power, were $5.66/MWh lower than Pacific Gas and Electric prices.

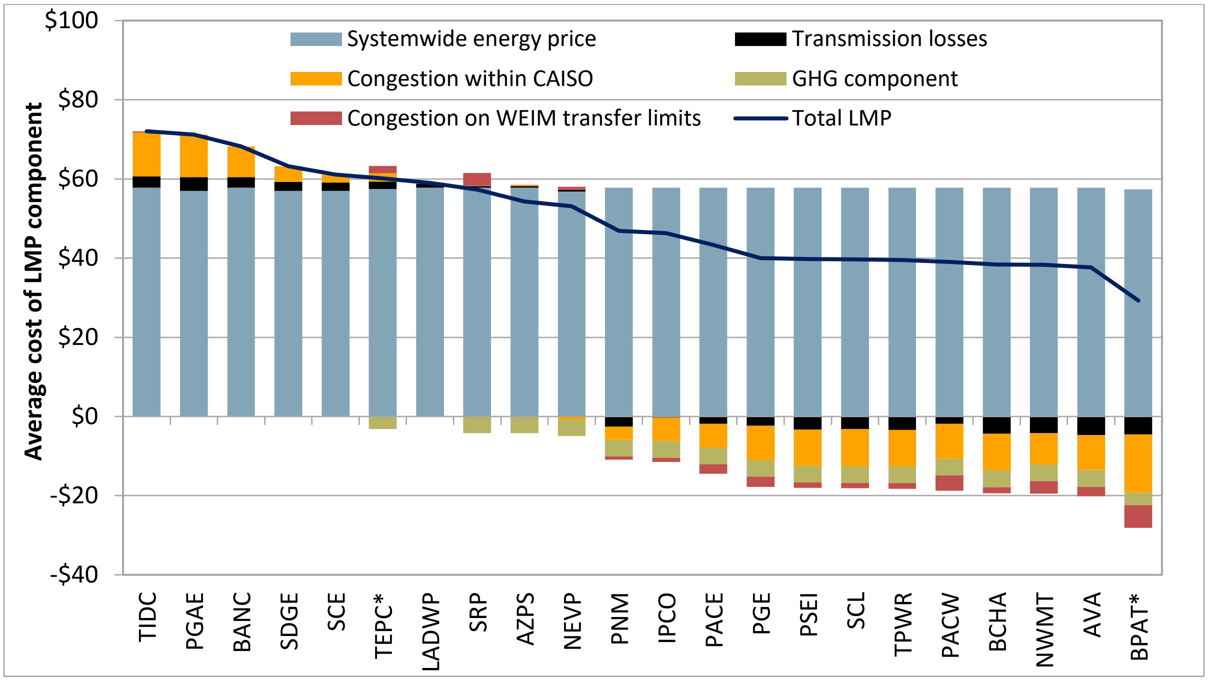
Price separation between balancing authorities occurs for several reasons. California area prices are typically higher than the rest of the WEIM due to greenhouse gas compliance cost for energy that is delivered to California. In addition, average prices in the Pacific Northwest are regularly lower than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

[47] See Section 2.2 for more details on transfer congestion in the WEIM.

Table 2.1 Monthly 15-minute market prices

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

Figure 2.1 Quarterly average 15-minute price by component (Q2 2022)



*Since joining the WEIM

Figure 2.1 depicts the average 15-minute price by component for each balancing authority area.[48] The system marginal energy price is the same for all entities in each hour.[49] The price difference between balancing authority areas is determined by area specific elements including transmission losses, greenhouse gas compliance costs, congestion, and power balance constraint (PBC) violations.

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

Table 2.2 and Table 2.3 show the variation in prices throughout the day in the second quarter of 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.

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

49 Except Bonneville Power Administration and Tucson Electric Power, as they joined part-way through the quarter. Therefore, their LMP components represent the average since they joined the WEIM.

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

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$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)	$74	$70	$69	$68	$72	$80	$74	$58	$46	$42	$37	$40	$45	$45	$51	$64	$68	$79	$99	$133	$127	$102	$88	$77
SCE (CAISO)	$67	$64	$63	$62	$66	$72	$68	$48	$32	$26	$24	$27	$28	$32	$36	$43	$49	$63	$94	$134	$116	$96	$83	$72
BANC	$71	$67	$66	$64	$68	$75	$72	$53	$48	$43	$39	$43	$46	$47	$49	$60	$65	$72	$93	$115	$108	$95	$84	$74
Turlock ID	$71	$67	$66	$64	$68	$75	$71	$54	$54	$50	$47	$50	$55	$56	$58	$71	$73	$75	$92	$126	$111	$95	$83	$73
LADWP	$63	$60	$59	$58	$61	$67	$64	$45	$32	$27	$24	$27	$29	$32	$36	$43	$48	$61	$89	$126	$109	$91	$78	$69
NV Energy	$55	$51	$51	$51	$54	$60	$51	$40	$32	$24	$25	$27	$29	$32	$41	$41	$42	$49	$84	$117	$91	$74	$72	$59
Arizona PS	$59	$58	$54	$54	$57	$62	$56	$37	$26	$20	$20	$24	$28	$30	$35	$40	$46	$58	$85	$118	$100	$82	$74	$63
Tucson Electric*	$60	$58	$56	$55	$57	$61	$52	$34	$27	$26	$30	$37	$44	$46	$52	$58	$62	$68	$88	$118	$109	$85	$75	$64
Salt River Project	$60	$55	$54	$53	$57	$62	$50	$35	$25	$24	$27	$31	$41	$39	$42	$48	$54	$69	$95	$117	$103	$83	$75	$62
PSC New Mexico	$48	$47	$46	$47	$48	$54	$49	$36	$23	$20	$17	$24	$24	$28	$33	$38	$43	$54	$76	$104	$83	$63	$55	$52
PacifiCorp East	$42	$39	$39	$39	$42	$48	$46	$36	$30	$29	$25	$28	$29	$30	$32	$36	$39	$46	$61	$75	$72	$59	$55	$47
Idaho Power	$39	$35	$36	$35	$40	$47	$49	$43	$41	$40	$37	$38	$38	$38	$39	$41	$45	$49	$59	$67	$68	$60	$56	$46
NorthWestern	$29	$27	$28	$27	$31	$37	$40	$41	$40	$36	$34	$36	$35	$36	$36	$36	$37	$42	$46	$47	$51	$46	$47	$36
Avista Utilities	$31	$27	$27	$27	$30	$35	$39	$38	$39	$37	$34	$36	$35	$35	$35	$37	$42	$42	$46	$40	$46	$44	$46	$35
BPA*	$25	$23	$18	$19	$16	$23	$22	$21	$22	$28	$31	$26	$32	$25	$24	$25	$30	$31	$33	$40	$44	$36	$40	$31
Tacoma Power	$36	$32	$30	$29	$30	$35	$35	$38	$40	$39	$39	$37	$40	$37	$36	$36	$39	$42	$48	$49	$51	$47	$49	$39
PacifiCorp West	$32	$29	$29	$28	$30	$36	$37	$39	$39	$39	$38	$37	$39	$37	$36	$36	$39	$44	$46	$47	$50	$45	$49	$37
Portland GE	$32	$28	$29	$28	$31	$36	$36	$40	$41	$41	$40	$38	$39	$38	$36	$36	$39	$47	$47	$50	$52	$52	$49	$37
Puget Sound Energy	$37	$31	$30	$29	$32	$36	$34	$37	$39	$38	$38	$37	$40	$37	$39	$36	$39	$42	$48	$50	$51	$47	$49	$39
Powerex	$38	$32	$31	$32	$34	$36	$36	$35	$38	$36	$35	$35	$35	$34	$37	$35	$39	$44	$45	$46	$47	$47	$45	$37
Seattle City Light	$36	$32	$30	$30	$32	$36	$36	$38	$40	$39	$38	$37	$38	$36	$36	$36	$39	$42	$48	$50	$51	$47	$50	$39

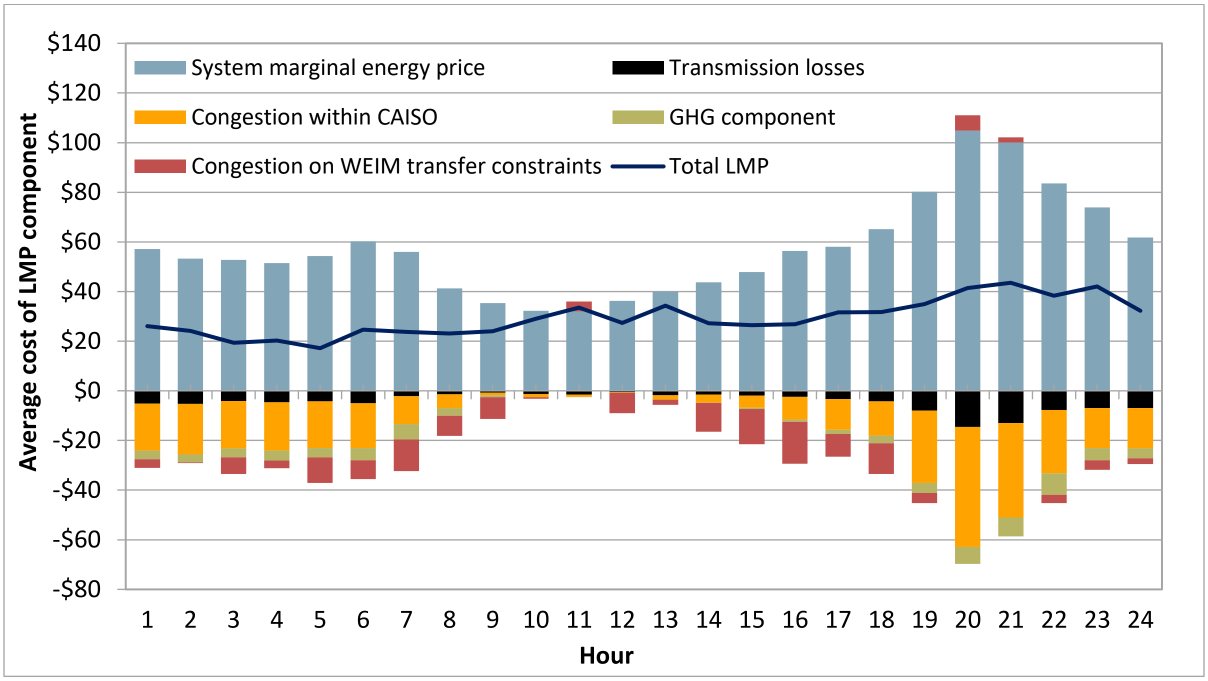
Table 2.3 Hourly 5-minute market prices (April-June)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$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)	$79	$75	$77	$74	$78	$83	$77	$50	$41	$36	$33	$35	$39	$41	$42	$50	$54	$60	$87	$111	$105	$87	$85	$80
SCE (CAISO)	$69	$67	$65	$65	$67	$71	$67	$39	$25	$20	$19	$21	$24	$26	$29	$33	$36	$47	$80	$101	$94	$81	$79	$72
BANC	$75	$73	$75	$71	$75	$80	$75	$49	$44	$39	$38	$43	$44	$45	$45	$51	$53	$56	$82	$97	$96	$83	$82	$78
Turlock ID	$77	$73	$75	$72	$76	$80	$75	$51	$51	$48	$47	$50	$55	$55	$54	$61	$60	$59	$83	$106	$98	$83	$82	$78
LADWP	$64	$61	$59	$58	$61	$64	$62	$36	$25	$20	$20	$22	$25	$28	$28	$32	$34	$44	$74	$93	$87	$75	$74	$67
NV Energy	$56	$53	$51	$53	$53	$57	$49	$35	$31	$18	$24	$23	$25	$32	$28	$37	$29	$37	$74	$91	$77	$64	$67	$57
Arizona PS	$59	$57	$55	$55	$57	$61	$54	$28	$19	$14	$18	$24	$26	$26	$28	$32	$36	$43	$74	$91	$84	$70	$75	$62
Tucson Electric*	$59	$59	$58	$57	$59	$62	$53	$27	$21	$21	$26	$33	$40	$42	$45	$52	$55	$58	$76	$103	$95	$73	$71	$62
Salt River Project	$62	$56	$55	$55	$57	$60	$49	$28	$19	$18	$23	$38	$46	$54	$48	$54	$46	$60	$92	$96	$88	$72	$72	$59
PSC New Mexico	$47	$47	$45	$47	$48	$52	$48	$27	$15	$15	$14	$19	$20	$23	$27	$30	$33	$42	$66	$80	$67	$53	$56	$51
PacifiCorp East	$40	$37	$35	$36	$39	$43	$41	$27	$24	$22	$21	$23	$26	$29	$26	$27	$27	$31	$49	$61	$53	$47	$50	$44
Idaho Power	$37	$33	$31	$32	$35	$39	$42	$35	$36	$36	$35	$34	$36	$36	$34	$33	$33	$35	$44	$51	$48	$47	$49	$42
NorthWestern	$26	$26	$23	$23	$27	$31	$35	$32	$41	$33	$32	$33	$34	$32	$30	$28	$27	$29	$32	$37	$35	$38	$40	$35
Avista Utilities	$27	$24	$21	$22	$24	$27	$32	$31	$35	$35	$33	$34	$34	$32	$30	$28	$29	$26	$30	$29	$30	$35	$38	$32
BPA*	$15	$13	$11	$10	$8	$15	$18	$12	$13	$21	$21	$22	$25	$24	$22	$18	$23	$17	$24	$26	$28	$29	$26	$19
Tacoma Power	$33	$28	$26	$25	$26	$31	$34	$34	$38	$37	$38	$34	$36	$34	$32	$31	$33	$35	$42	$43	$42	$40	$44	$38
PacifiCorp West	$29	$25	$22	$23	$25	$29	$30	$32	$35	$35	$36	$36	$40	$33	$30	$28	$29	$29	$31	$35	$34	$40	$41	$33
Portland GE	$27	$24	$22	$23	$24	$29	$30	$33	$36	$35	$37	$35	$37	$34	$31	$29	$28	$30	$33	$36	$38	$37	$41	$32
Puget Sound Energy	$32	$28	$26	$26	$26	$32	$34	$34	$37	$37	$37	$35	$36	$34	$36	$31	$33	$35	$43	$43	$41	$41	$46	$38
Powerex	$33	$30	$29	$29	$31	$33	$37	$34	$35	$32	$33	$33	$32	$32	$34	$33	$35	$38	$40	$43	$41	$42	$42	$35
Seattle City Light	$33	$28	$26	$26	$27	$32	$34	$35	$38	$37	$37	$34	$35	$33	$32	$31	$33	$35	$43	$43	$42	$40	$44	$35

*Since joining the WEIM

Similar to other areas located in the Pacific Northwest, Bonneville Power Administration (BPA) had a low average location marginal price (LMP) during the quarter, primarily due to congestion within CAISO.[50] Figure 2.2 breaks down BPA's average LMP by component throughout the day to exemplify the impact of congestion on prices in the region.[51]

Figure 2.2 Bonneville Power Administration average 15-minute price by component (May 3, 2022 – June 30, 2022)



2.2 Transfers, limits, and congestion

Transfers

One of the key benefits of the Western Energy Imbalance Market (WEIM) is the ability to transfer energy between 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.[52] WEIM transfers are constrained by *transfer limits* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 2.3 and Figure 2.4 highlight typical transfer patterns during two key periods that produce a high volume of transfers.[53] First, Figure 2.3 shows average dynamic 15-minute market exports out of each

50 See Section 1.8.2 for more information on price impacts to BPA and other WEIM entities from individual internal constraints.

51 See 2.4Appendix A for versions of this figure for each WEIM area in the 15-minute and 5-minute markets.

52 See 2.4Appendix A for figures on the average hourly transfers by quarter for each WEIM area.

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

area during mid-day hours during the quarter.[54] 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.

In particular, Figure 2.3 shows that the CAISO exported just under 1,800 MW, on average during these mid-day hours, out to neighboring areas including BANC, LADWP, Powerex, Arizona Public Service, NV Energy, and Salt River Project. These areas each remained a net importer on average, despite having some exports out to other connecting areas in the WEIM footprint. The mid-day typically contains the highest levels of exports out of the CAISO area because of significant solar production.

Figure 2.4 shows average dynamic transfers during peak load hours in the quarter. During these hours, imports into the CAISO are often highest. The figure shows an average of around 800 MW of exports out of LADWP, Turlock Irrigation District, PacifiCorp West, Portland General Electric, Arizona Public Service, NV Energy, Salt River Project, and Tucson Electric Power, going into the CAISO during these hours (CAISO import). PacifiCorp East was a significant exporter during these hours, with almost 500 MW on average out to neighboring areas.

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

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

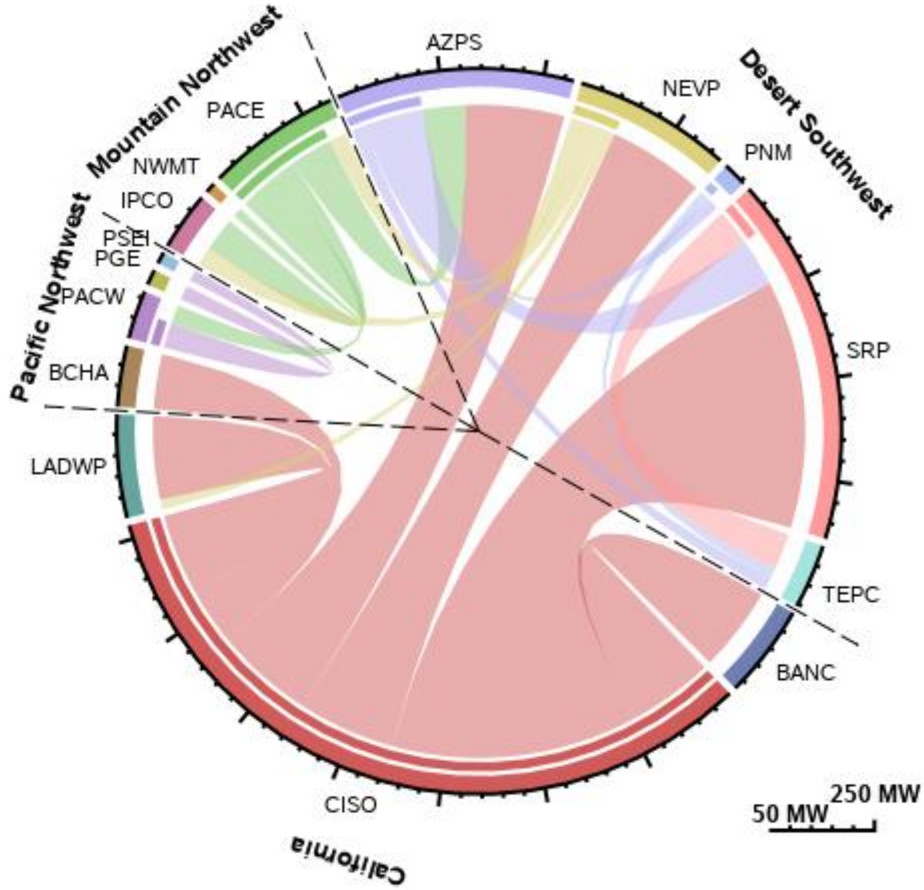
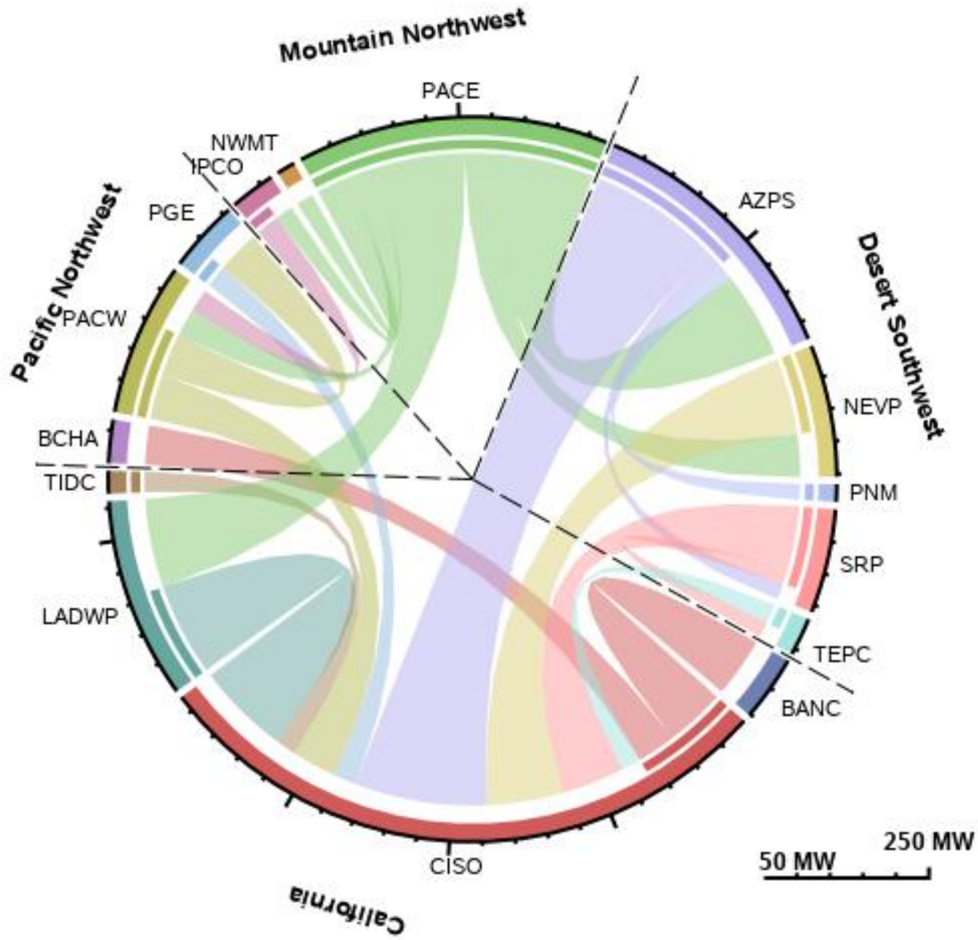


Figure 2.4 Average 15-minute market WEIM exports (peak load hours, April – June, 2022)



Transfer limits

WEIM transfers between areas are constrained by WEIM transfer limits. These 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 3,960 MW of exports and 4,390 MW of imports on average. This is low compared to the 30,120 MW of import and 33,180 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). This lack of transfer capability out of the Pacific Northwest creates large price separation between the WEIM entities located there and the rest of the WEIM.

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

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		3,270	1,260	4,830	3,490	1,230	110	1,550					0	20		10	50		300		16,120
BANC	3,370		510																		3,880
Turlock Irrig. District	1,260	780																			2,040
LADWP	8,560				1,640	220	230			290											10,940
NV Energy	4,080			1,040		310				630	350										6,410
Arizona Public Service	2,360			130	250		1,190	3,330	610	720											8,590
Tucson Electric*	510			110		1,710		1,800	160	250											4,540
Salt River Project	3,070					2,760	1,190		160												7,180
PSC New Mexico						530	210	190													930
PacifiCorp East				220	270	490	120				880	190				150					2,320
Idaho Power					190					1,500		200	300	0		270				30	2,490
NorthWestern Energy										150	190		360	10	10						720
Avista Utilities	0										310	320		10	10	60					710
BPA*	20										0	20	20		50	20	70	100	0	20	320
Tacoma Power												10	10	30			20	220			290
PacifiCorp West	110									0	150		50	10			300	100		10	730
Portland GE	120													50	20	350				10	550
Puget Sound Energy														120	240	150			50	350	910
Powerex	0													0				50			50
Seattle City Light											20			10		10	10	350			400
Total import limit	23,460	4,050	1,770	6,330	5,840	7,250	3,050	6,870	930	3,540	1,900	740	740	260	330	1,020	450	820	350	420	

*Since joining the WEIM

Congestion on transfer constraints

Congestion between a WEIM area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an area, the market software triggers local market power mitigation for resources in that area.[55] WEIM participants in the Pacific Northwest continued to be the most frequently congested region relative to the greater market footprint.[56]

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.[57] 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 1.8.2 of this report on congestion. Section 1.8.2 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.

During the second quarter, congestion out of PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Powerex decreased an average of 27 percent in the 15-minute market compared to the first quarter of 2022. This reduction in transfer congestion can be attributed, in part, to

55 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.

56 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.

57 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.

the addition of Bonneville Power Administration, Avista Utilities, and Tacoma Power to the WEIM, which increased import and export transfer capacity in the region by 43 percent and 50 percent, respectively.

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

Table 2.5 Frequency of congestion in the WEIM (April – June)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
L.A. Dept. of Water and Power	0%	0%	0%	0%
Turlock Irrigation District	0%	1%	0%	1%
Arizona Public Service	0%	1%	0%	1%
NV Energy	2%	1%	2%	1%
Public Service Company of NM	2%	1%	2%	1%
Tucson Electric Power*	2%	8%	1%	9%
PacifiCorp East	11%	1%	9%	2%
Salt River Project	3%	8%	3%	9%
Idaho Power	12%	9%	8%	12%
Avista	17%	11%	10%	14%
NorthWestern Energy	17%	11%	11%	14%
PacifiCorp West	24%	15%	14%	17%
Portland General Electric	24%	17%	14%	18%
Puget Sound Energy	27%	25%	18%	34%
Tacoma Power	27%	25%	18%	34%
Seattle City Light	27%	26%	18%	34%
Powerex	29%	19%	29%	40%
Bonneville Power Admin.*	38%	24%	28%	27%

*Since joining the WEIM

2.3 Resource sufficiency evaluation

As part of the Western Energy Imbalance Market (WEIM), 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.[58] Similarly, if an area fails either test in the downward direction, transfers out of that area cannot be increased.

Resource sufficiency evaluation enhancements phase 1

The CAISO implemented phase 1 of resource sufficiency evaluation enhancements on June 1, 2022. In particular, this included a number of changes regarding how supply is credited in the tests. Phase 1 included the following enhancements:

- **Consideration of offline resources in the capacity test.** The capacity test will now omit offline long-start capacity from the bid-range capacity test.[59] Short-start units which failed-to-start per the unit's telemetry will also be excluded.
- **Accounting for CAISO interchange awards that have not submitted Transmission Profile e-Tag.** CAISO hour-ahead import and export schedules which have not been tagged by 40 minutes prior to the test hour are expected to be removed from both the capacity and flexibility tests.
- **Adjustment to initial reference point used in the flexibility test.** The flexibility test requirement will now consider any power balance constraint shortage that is present in the interval immediately prior to the test hour.
- **Accounting for storage resource's state of charge in the resource sufficiency evaluation.** The capacity and flexibility test will now consider the state-of-charge from the market run immediately prior to the test hour.
- **Submission of load forecast adjustments to reflect non-participating demand response schedules.** Demand response programs, which cannot be accounted for otherwise in the real-time market, can be submitted as a load forecast adjustment to be accounted for in the resource sufficiency evaluation.
- **Suspension of uncertainty in the capacity test.** Intertie uncertainty was removed from the capacity test on June 1. Net load uncertainty was previously removed from the capacity test on February 15, 2022.
- **Exclusion of CAISO from allocation of funds associated with balancing test failure.** CAISO is now excluded from potential revenues from failures of the balancing test. CAISO is not subject to the balancing test as it does make supply available through the base scheduling process.

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[58] 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.

[59] Capacity for a unit that is offline in the last 15-minute interval prior to the test hour will only be considered for short-start units (start-up time plus minimum up time at or below 255 minutes).

Bid range capacity and flexible ramping sufficiency test results

Figure 2.5 and Figure 2.6 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.7 and Figure 2.8 provide the same information for the downward direction.[60] 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.[61] Intertie uncertainty was removed on June 1, 2022. Net load uncertainty is proposed to return to the capacity test in the summer of 2023.[62] 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 the fall of 2022. CAISO is also proposing to permanently remove intertie uncertainty from the capacity test.

In the second quarter of 2022:

- Bonneville Power Administration failed the upward flexibility test in 2 percent of intervals since joining the WEIM in May.
- Salt River Project failed the upward capacity test in 0.9 percent of intervals.
- NV Energy failed the downward flexibility test in over 2 percent of intervals and the upward flexibility test in around 0.7 percent of intervals.
- NorthWestern Energy, Public Service Company of New Mexico, and Puget Sound Energy each failed the downward flexibility test in around 0.9 percent of intervals.

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

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

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

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

	2021									2022					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona PS	—	0.3	—	0.2	0.3	0.2	—	0.3	0.0	—	—	0.0	0.0	—	—
Avista												—	0.0	—	0.2
BANC	—	—	—	0.2	—	0.0	—	—	—	—	—	—	—	—	—
BPA														—	0.1
California ISO	—	—	0.1	0.2	0.0	0.2	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	0.4	0.8	0.1	—	—	—	—	0.1	—	—	—	—
LADWP	—	—	0.1	—	—	—	0.3	0.2	0.1	—	—	—	—	—	—
NorthWestern			0.6	1.2	0.6	0.2	8.5	1.2	0.2	0.3	0.1	—	0.0	—	—
NV Energy	0.0	0.5	0.8	0.5	0.2	0.2	0.3	—	—	—	—	—	0.2	0.1	0.0
PacifiCorp East	—	—	0.3	0.3	0.1	0.2	0.1	—	—	—	—	—	—	—	—
PacifiCorp West	—	0.0	0.1	0.2	0.1	0.1	0.1	0.5	0.4	0.3	0.1	0.3	0.0	0.2	0.0
Portland GE	0.4	—	0.7	0.8	1.0	1.4	0.4	0.2	0.4	0.1	—	—	—	—	—
Powerex	—	—	0.0	0.0	—	0.1	0.5	0.2	0.2	0.2	—	—	0.1	—	—
PSC New Mexico	—	—	—	0.4	—	0.2	—	—	—	—	—	—	—	—	—
Puget Sound En	1.0	0.6	1.6	0.5	0.7	0.6	1.0	0.6	0.3	—	—	—	0.0	0.0	0.2
Salt River Proj.	0.1	0.1	0.7	3.0	2.6	2.0	0.1	0.7	—	—	—	0.2	1.5	1.0	0.2
Seattle City Light	—	—	—	—	0.0	0.5	0.1	—	0.1	—	—	0.1	—	—	—
Tacoma Power												—	0.6	0.1	0.0
Tucson Elec.														—	—
Turlock ID	—	0.0	—	—	1.1	0.8	1.5	—	—	—	—	—	—	—	0.1

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

	2021									2022					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona PS	—	0.6	—	0.0	—	0.2	—	0.3	0.0	0.0	0.2	0.1	—	—	—
Avista												—	0.2	0.5	1.0
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BPA														0.9	3.1
California ISO	—	—	0.0	0.3	0.1	0.4	—	0.1	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	—	—	—	—	0.0	—	0.2	—	—	—	—
LADWP	0.0	0.1	—	0.1	—	—	0.0	0.0	0.3	—	—	0.1	—	—	—
NorthWestern			1.3	3.6	0.7	1.6	8.3	0.5	0.5	—	0.1	0.1	0.3	—	0.1
NV Energy	0.4	0.7	0.9	0.4	0.5	0.1	0.3	0.0	0.0	0.0	0.7	0.4	1.0	0.8	0.2
PacifiCorp East	0.1	0.0	0.1	0.0	—	0.1	—	0.1	0.0	0.0	0.0	—	0.1	0.1	0.1
PacifiCorp West	0.1	0.0	—	0.0	0.1	—	—	0.6	0.2	0.0	0.0	0.1	0.2	0.1	0.0
Portland GE	0.2	0.2	0.3	0.5	0.2	—	0.0	—	0.2	0.3	0.0	—	—	—	0.0
Powerex	0.1	—	0.1	0.5	—	—	0.2	0.2	0.3	0.2	0.0	—	0.1	—	—
PSC New Mexico	0.4	0.0	0.1	0.5	—	0.1	—	0.1	—	—	—	0.1	0.0	0.1	—
Puget Sound En	—	0.1	0.1	0.0	0.0	—	—	0.1	—	—	—	0.0	0.1	—	0.1
Salt River Proj.	0.5	0.2	0.9	1.9	1.7	0.8	0.2	1.2	0.0	0.2	—	0.6	0.5	0.2	0.5
Seattle City Light	—	—	—	0.0	—	0.1	—	—	—	—	—	0.1	—	—	—
Tacoma Power												—	—	0.1	0.1
Tucson Elec.														0.1	—
Turlock ID	—	0.3	—	—	—	0.1	0.2	—	—	—	—	—	—	—	—

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

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

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

	2021									2022					
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Arizona PS	1.9	0.3	0.1	—	0.1	0.1	0.1	0.5	0.4	1.4	0.4	0.8	0.3	0.5	0.2
Avista												—	—	—	0.1
BANC	—	—	—	—	—	—	—	—	0.1	—	—	0.1	0.0	0.1	0.1
BPA														0.1	0.2
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	0.0	—	—	—	—	—	0.3	0.0	—	0.0	—	0.3	0.4	—
LADWP	—	—	0.1	—	—	—	0.1	—	—	0.1	—	—	—	—	—
NorthWestern			0.7	0.6	0.4	1.2	2.3	0.1	0.0	—	—	—	—	0.5	1.9
NV Energy	0.5	4.3	2.0	3.0	2.5	1.7	1.1	0.4	0.4	0.6	4.1	1.7	3.2	1.3	2.0
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	0.1	—	—	—	—	0.0	—	—	—	0.0	0.0	0.1	0.4
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0.2
Powerex	0.2	0.9	1.3	0.4	0.2	1.0	0.4	0.0	0.1	—	0.0	0.2	0.0	0.3	0.2
PSC New Mexico	1.4	—	0.0	—	—	0.1	0.4	0.7	0.1	0.3	0.0	1.2	0.3	1.8	0.7
Puget Sound En	—	—	—	—	—	—	—	0.0	—	—	—	—	—	0.2	2.3
Salt River Proj.	0.2	0.1	0.2	—	0.1	0.0	0.1	0.0	0.1	0.1	1.0	1.5	0.2	0.4	0.5
Seattle City Light	—	—	—	0.2	—	—	—	0.0	0.0	—	—	0.1	0.1	0.1	0.3
Tacoma Power												—	0.4	0.3	—
Tucson Elec.														—	—
Turlock ID	0.1	0.5	—	—	0.0	—	0.6	0.1	0.2	0.2	—	0.5	0.6	0.1	0.5

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 2.9 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.[63]

Figure 2.9 Imposed dynamic import limit following upward test failure (April – June 2022)

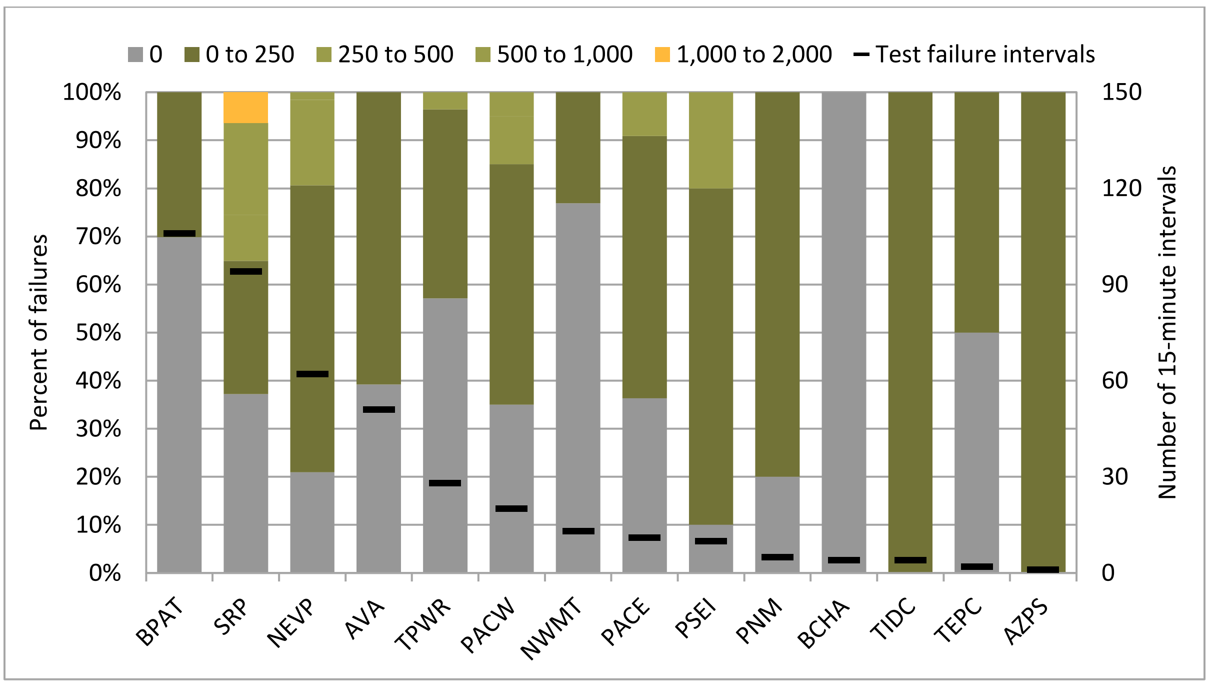

Figure 2.10 summarizes actual transfers optimized in the real-time market following an upward resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity test or a flexibility test failure, while the bars (left axis) show the net transfer quantity categorized by various levels. These figures summarize dynamic WEIM transfers only and therefore base transfers are again excluded.

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63 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.

As shown by Figure 2.10, balancing areas were commonly optimized as net exporters in 2021, despite failing the resource sufficiency evaluation for that interval. This result is in part driven from *uncertainty* that is included in both the capacity and the flexibility tests. During most of this period, the capacity test requirement included intertie uncertainty.[64] The flexibility test also includes net load uncertainty in the requirement. In some cases, the balancing area would fail the resource sufficiency evaluation in part because of the uncertainty component in either test, 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 2.10 Dynamic WEIM transfers during upward test failure (April – June 2022)

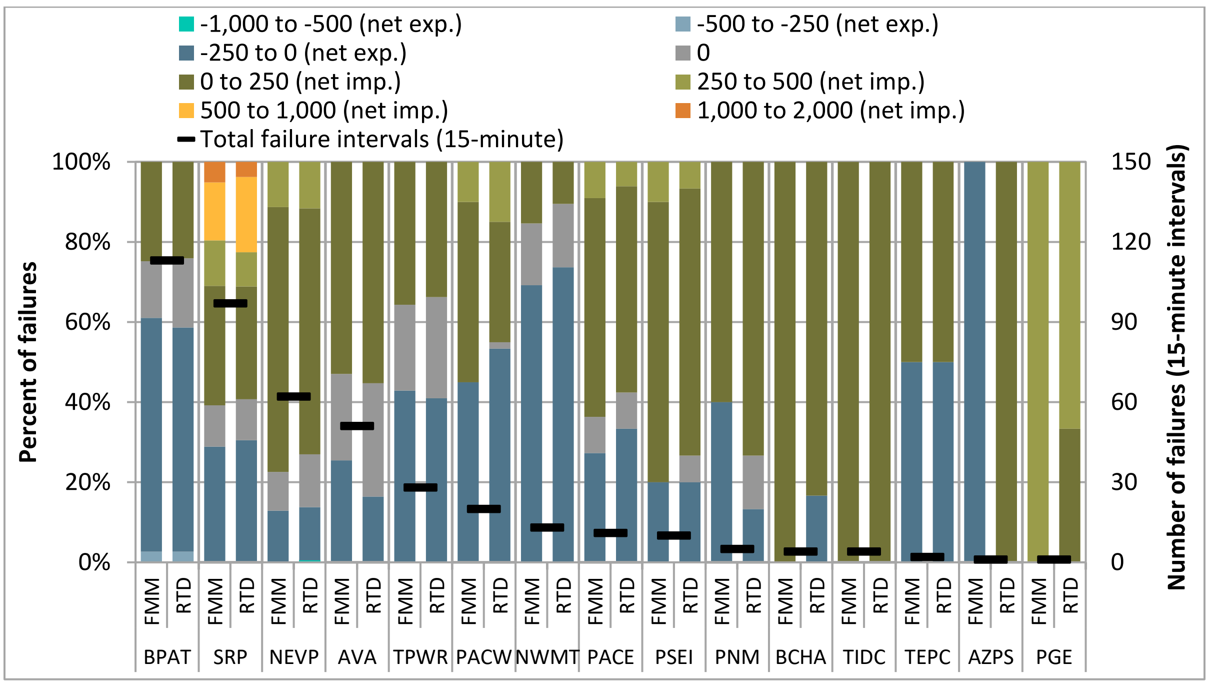
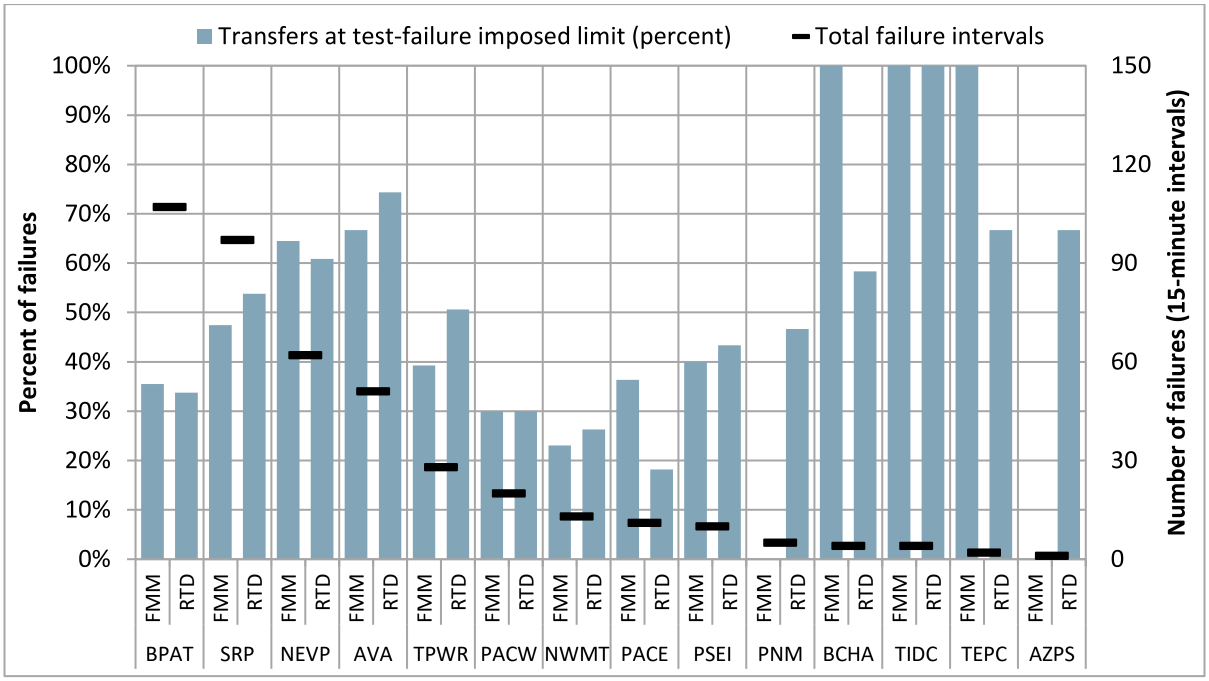


Figure 2.11 summarizes whether the import limit that was imposed after failing either test in the upward direction ultimately impacted market transfers. It shows the percent of failure intervals in which the resulting transfers are constrained to the limit imposed after failing the test. These results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

64 Intertie uncertainty was removed on June 1, 2022.

Figure 2.11 Percent of upward test failure intervals with market transfers at the imposed cap (April – June 2022)



Resource sufficiency evaluation monthly reports

As an outcome of the WEIM resource sufficiency evaluation stakeholder initiative, DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic.[65] 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.

2.4 Imbalance conformance in the Western Energy Imbalance Market

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. Since joining the WEIM, Bonneville Power Administration (BPA) has used either positive or negative imbalance conformance during nearly all intervals in both the 15-minute and 5-minute markets. Despite a high frequency of imbalance conformance in BPA, the percent of total load is 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.

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

Table 2.6 Average frequency and size of imbalance conformance (April – June)

Balancing area	Market	Positive imbalance conformance: Percent of intervals	Positive imbalance conformance: Average MW	Positive imbalance conformance: Percent of total load	Negative imbalance conformance: Percent of intervals	Negative imbalance conformance: Average MW	Negative imbalance conformance: Percent of total load	Average hourly adjustment MW
California ISO	FMM	47%	1264	5.0%	3.4%	-619	3.0%	580
	RTD	45%	271	1.1%	28%	-244	1.1%	52
BANC	FMM	0.0%	N/A	N/A	0.4%	-159	5.2%	-1
	RTD	0.4%	53	2.1%	1.0%	-112	3.8%	-1
LADWP	FMM	0.7%	56	2.3%	0.3%	-51	2.3%	0
	RTD	13%	48	1.9%	9.4%	-59	2.5%	1
Turlock Irrigation District	FMM	0.1%	7	1.9%	0.0%	-27	5.6%	0
	RTD	0.1%	8	2.1%	0.1%	-27	6.5%	0
NorthWestern Energy	FMM	30%	14	1.1%	1.9%	-13	1.1%	4
	RTD	42%	15	1.3%	4.7%	-24	2.0%	5
NV Energy	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	13%	132	2.6%	16%	-125	3.0%	-2
Arizona Public Service	FMM	0.0%	100	3.0%	0.3%	-50	1.5%	0
	RTD	34%	63	1.6%	29%	-58	1.7%	4
Salt River Project	FMM	0.7%	67	1.3%	0.0%	-50	1.7%	0
	RTD	7.0%	56	1.2%	1.1%	-71	1.9%	3
Idaho Power	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	18%	56	2.8%	8.2%	-52	2.8%	6
Public Service Co. of New Mexico	FMM	0.1%	131	10%	0.0%	N/A	N/A	0
	RTD	9.4%	101	7.0%	13%	-110	8.6%	-5
PacifiCorp East	FMM	0.1%	27	0.5%	0.1%	-113	2.2%	0
	RTD	17%	105	2.0%	43%	-129	2.5%	-38
PacifiCorp West	FMM	0.0%	N/A	N/A	0.2%	-59	3%	0
	RTD	6.2%	52	2.3%	38%	-61	2.8%	-20
Portland General Electric	FMM	0.0%	N/A	N/A	0.0%	N/A	N/A	0
	RTD	7.2%	27	1.2%	4.9%	-50	2.1%	-1
Seattle City Light	FMM	0.9%	22	2.2%	5.4%	-23	2.5%	-1
	RTD	6.6%	30	3.2%	61%	-23	2.3%	-12
Puget Sound Energy	FMM	1.8%	70	2.6%	2.0%	-45	1.8%	0
	RTD	4.3%	55	2.1%	32%	-38	1.5%	-10
Avista Utilities	FMM	1.9%	24	2.5%	2.7%	-26	2.5%	0
	RTD	8.5%	19	1.9%	15%	-19	1.8%	-1
Tacoma Power	FMM	0.0%	27	5.7%	0.3%	-12	3.5%	0
	RTD	5.9%	15	3.0%	11%	-13	2.9%	-1
Bonneville Power Administration*	FMM	81%	36	0.7%	16%	-21	0.4%	26
	RTD	82%	36	0.7%	17%	-23	0.5%	26
Tucson Electric Power*	FMM	0.8%	80	4.7%	0.0%	N/A	N/A	1
	RTD	16%	44	2.9%	23%	-52	3.3%	-5

*Since joining the WEIM

Appendix A Extended Western Energy Imbalance Market metrics

Sections A.1 to A.19 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:

- Bonneville Power Administration has base scheduled the majority of its transfer capacity since joining the WEIM on May 3, 2022. The transfer capacity that is dynamically scheduled switches from net export in the 15-minute market to net import in the 5-minute market.
- The transmission loss LMP in areas located in the Pacific Northwest was high over the quarter and increased during hours with high flows. This trend is not observed in balancing areas located elsewhere in the WEIM footprint.

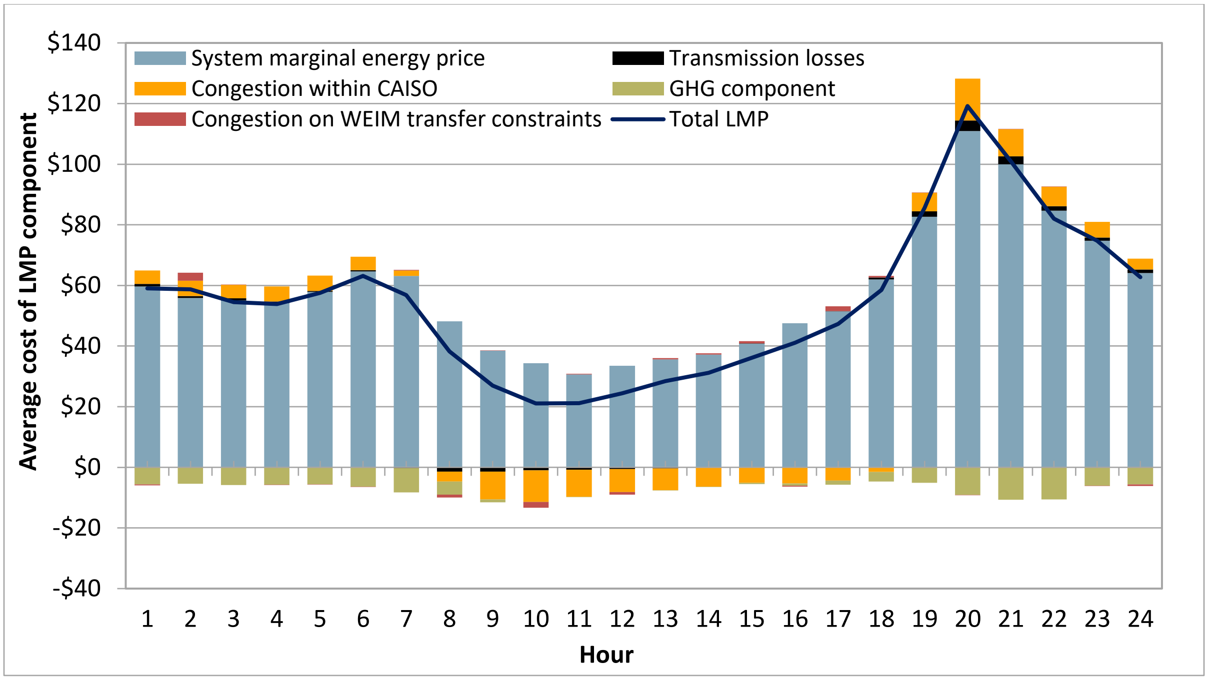
The hourly locational marginal price decomposition figures break down the price into five separate components. These components, listed below, can influence the prices in an area positively or negatively depending on the circumstances.

- **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 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 can contribute to higher prices for WEIM areas in California.

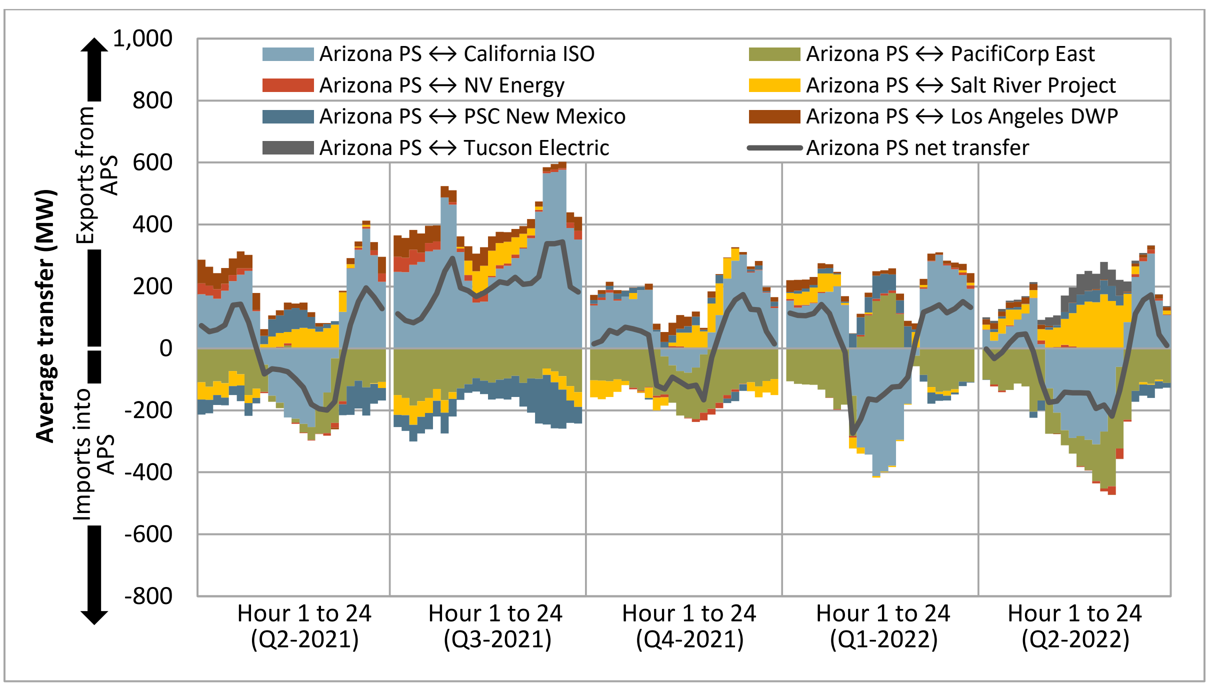
The transfer figures below show the hourly average imports and exports by WEIM area in the 15-minute and 5-minute markets by quarter. These figures only include dynamic transfer capacity that has been made available to the WEIM for optimization. Therefore, transfers that have been base scheduled will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

A.1 Arizona Public Service

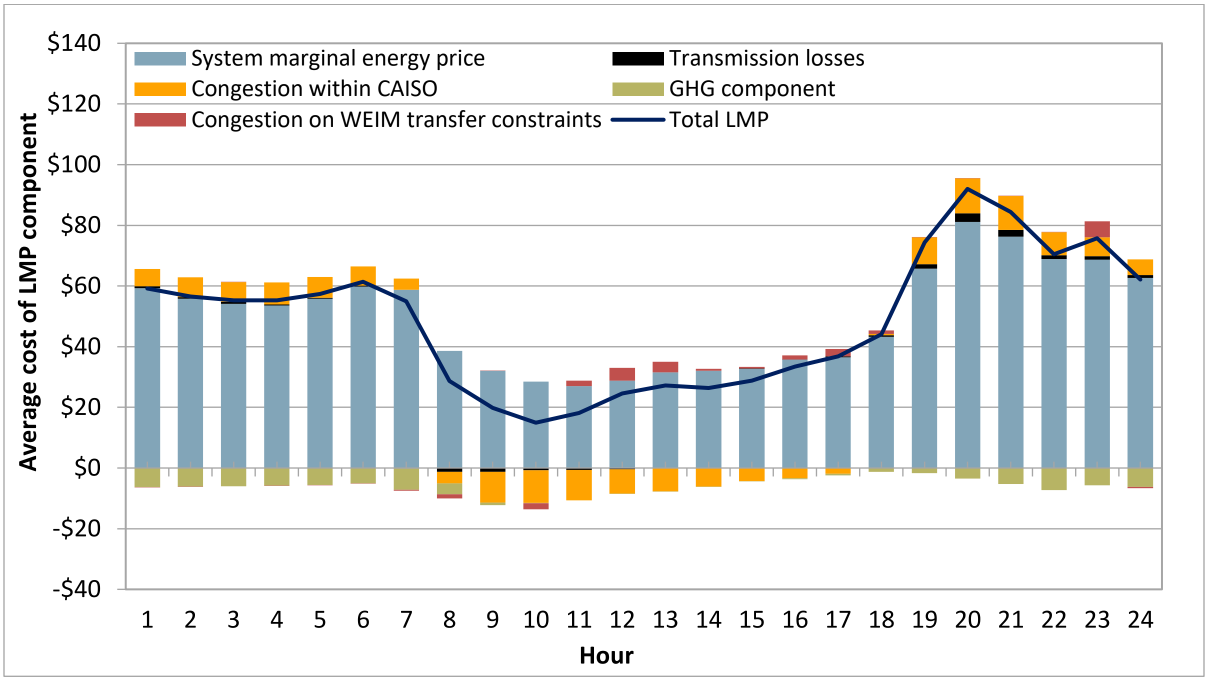
Appendix Figure A.1 Average hourly 15-minute price by component (Q2 2022)



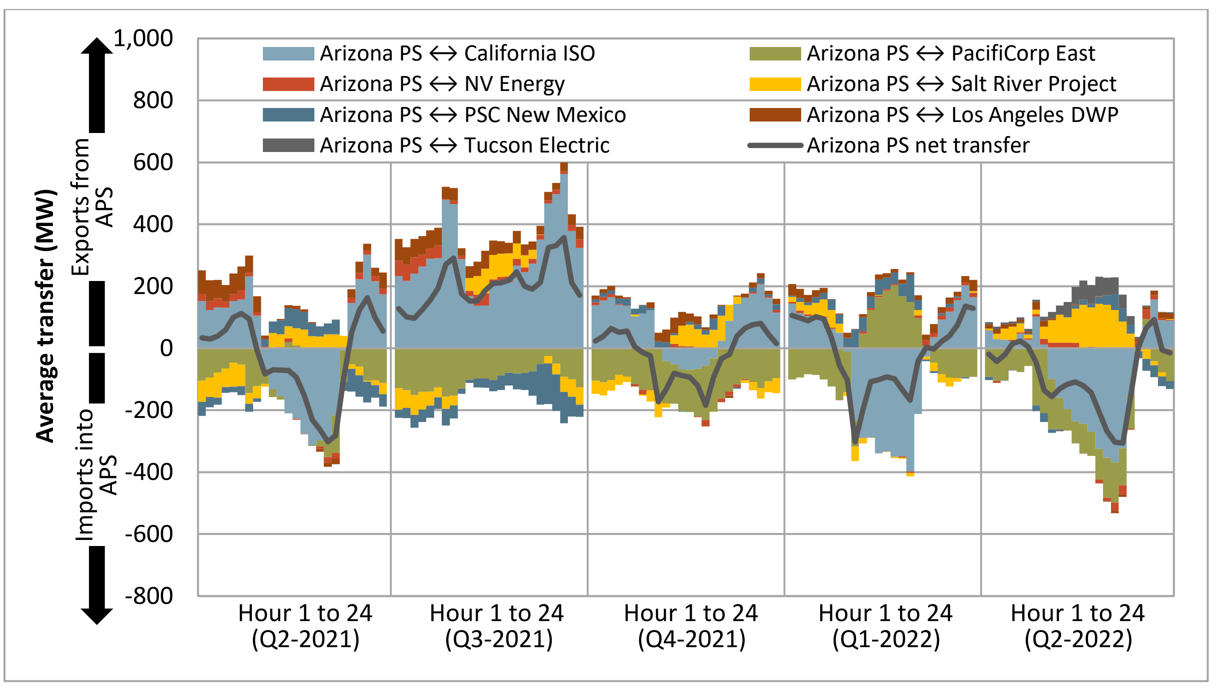
Appendix Figure A.2 Average hourly 15-minute market transfers



Appendix Figure A.3 Average hourly 5-minute price by component (Q2 2022)

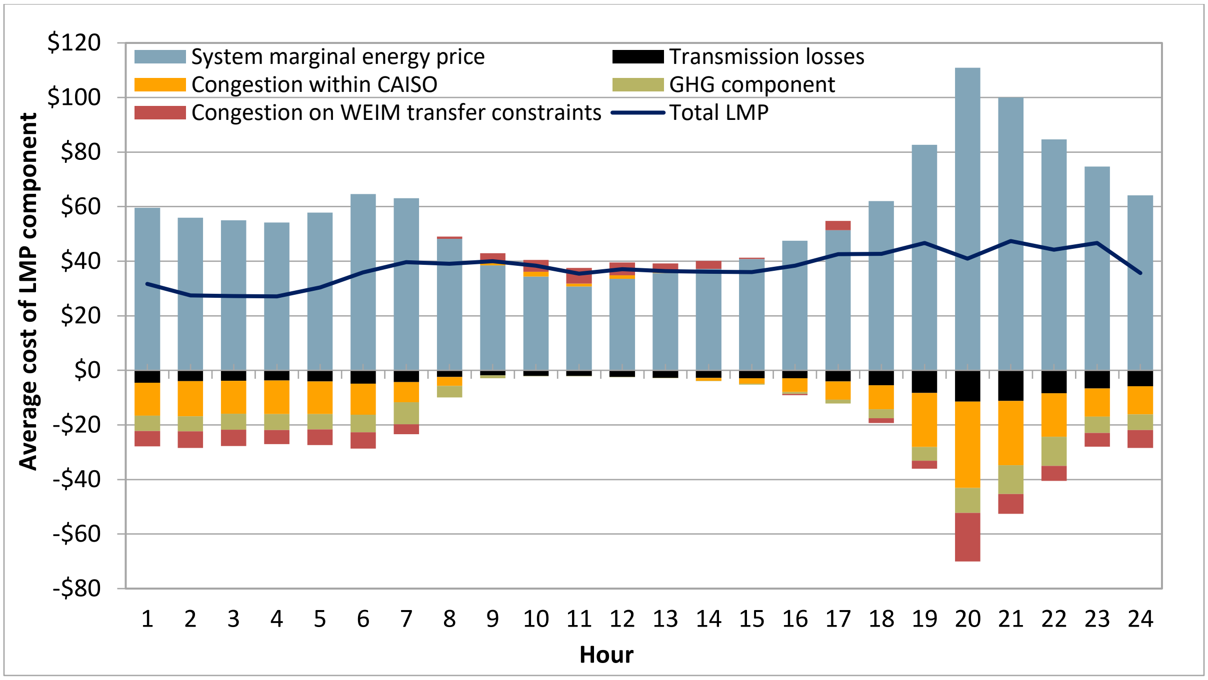


Appendix Figure A.4 Average hourly 5-minute market transfers

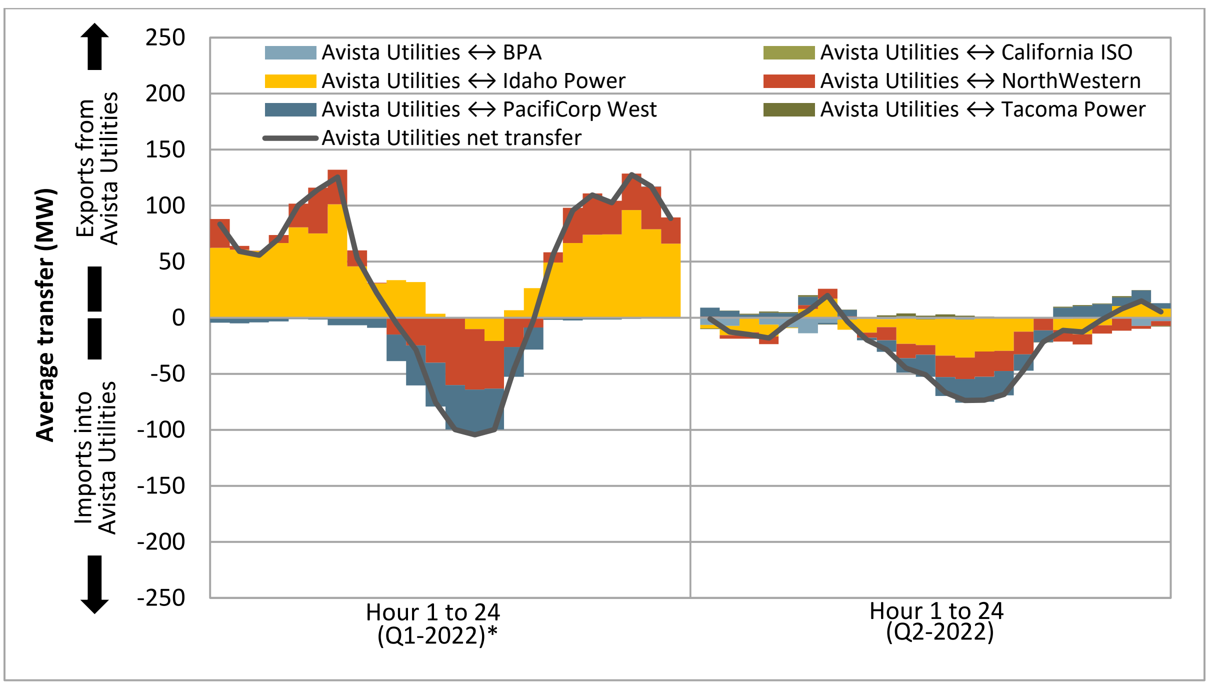


A.2 Avista Utilities

Appendix Figure A.5 Average hourly 15-minute price by component (Q2 2022)

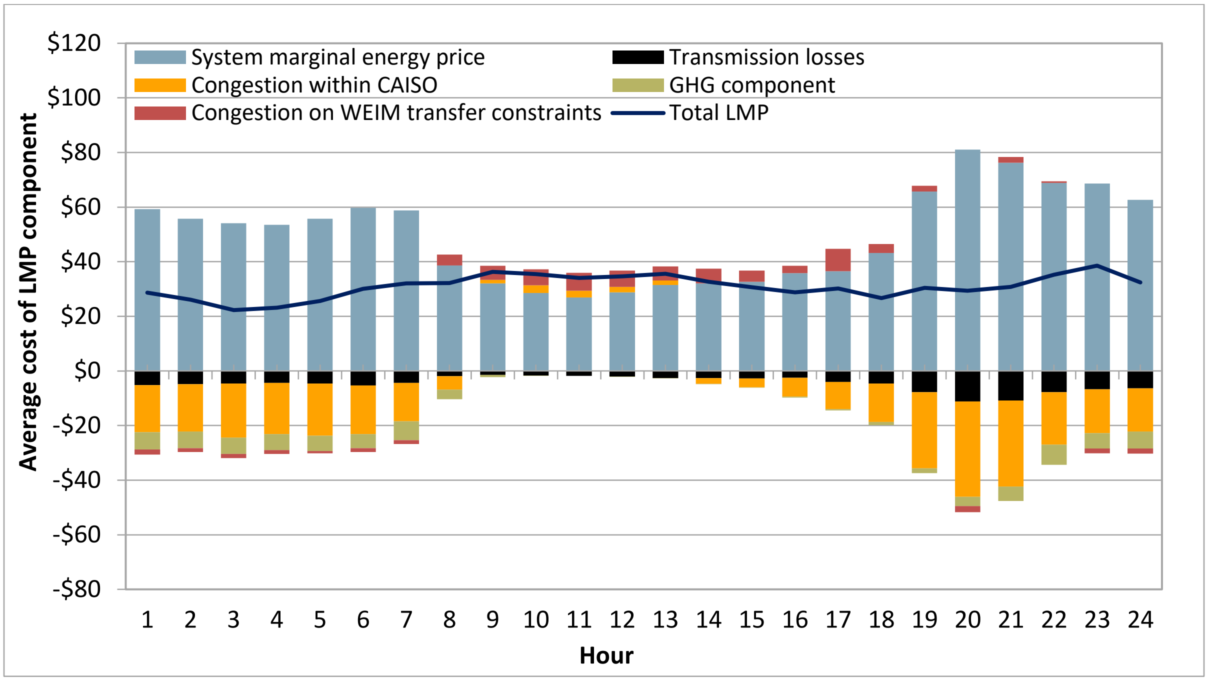


Appendix Figure A.6 Average hourly 15-minute market transfers

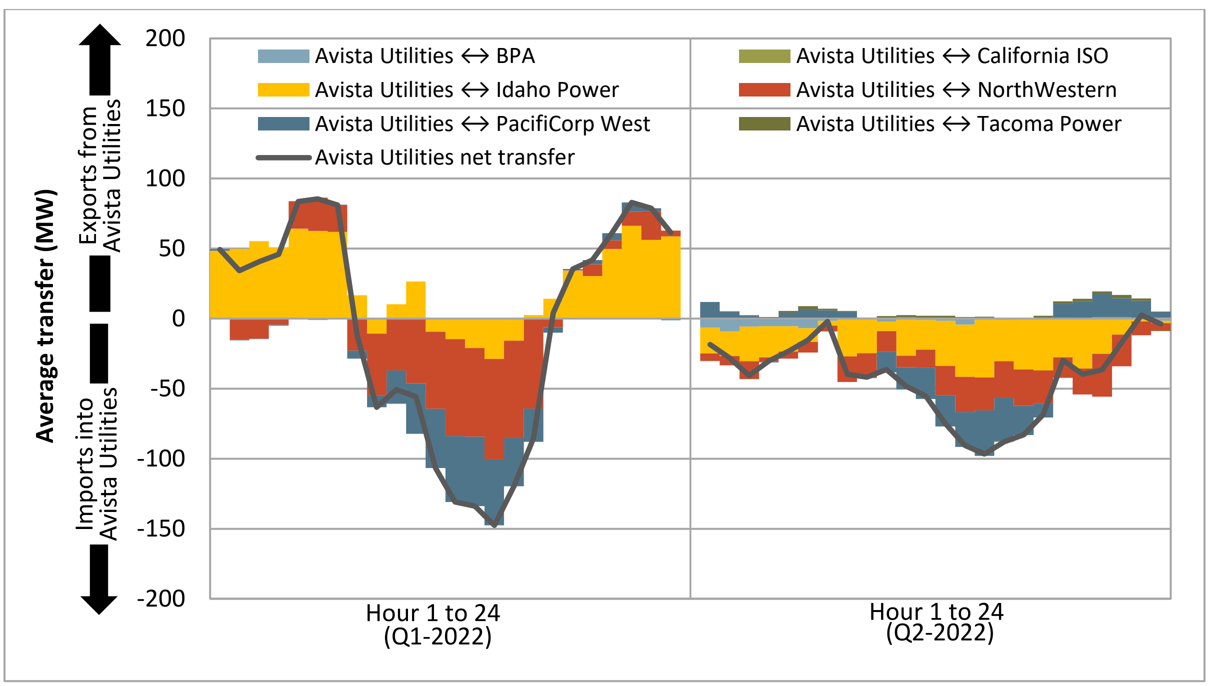


*Since joining the WEIM

Appendix Figure A.7 Average hourly 5-minute price by component (Q2 2022)



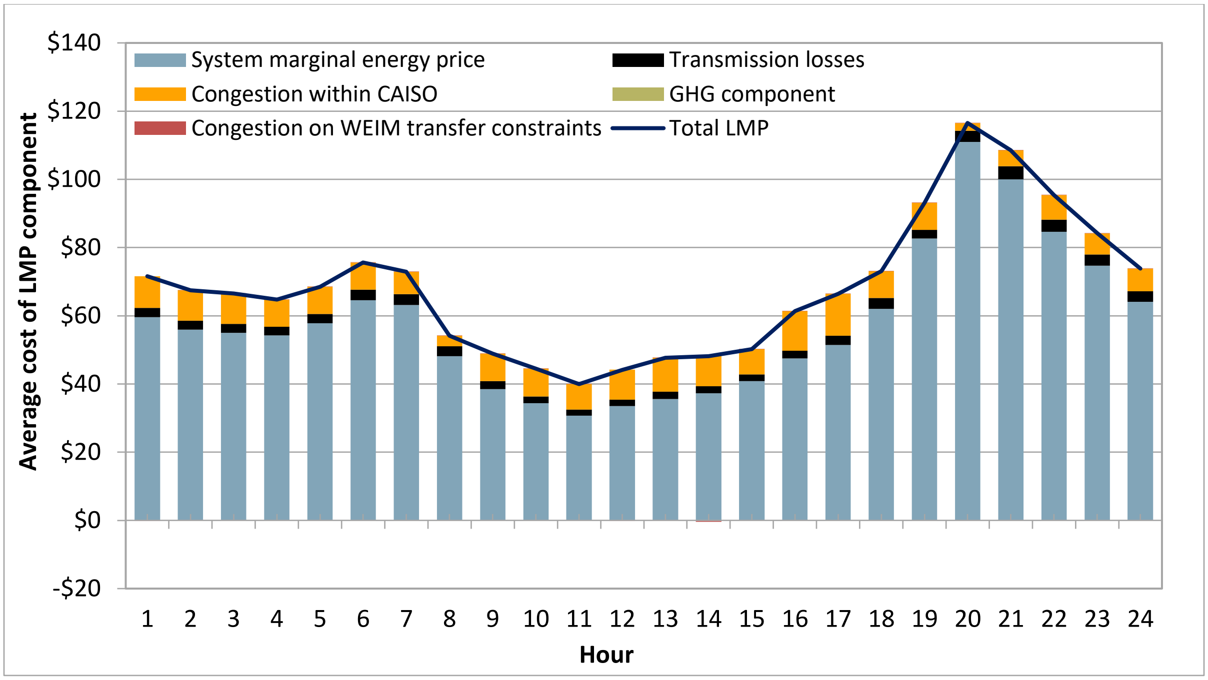
Appendix Figure A.8 Average hourly 5-minute market transfers



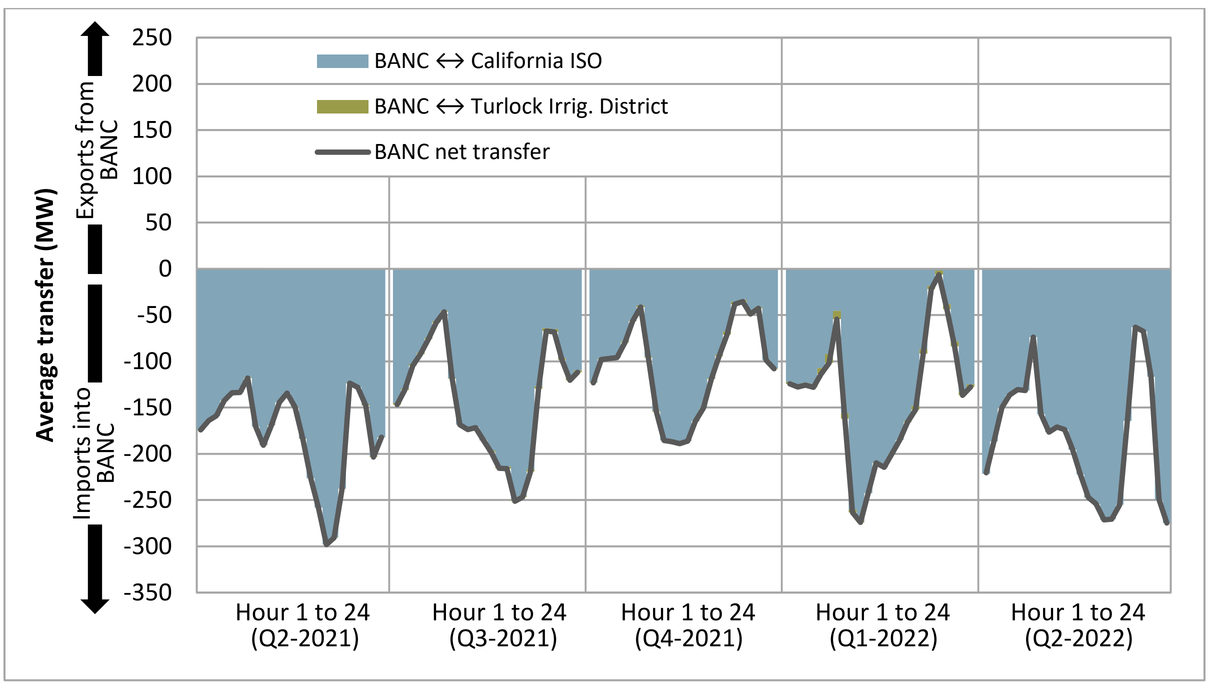
*Since joining the WEIM

A.3 Balancing Authority of Northern California

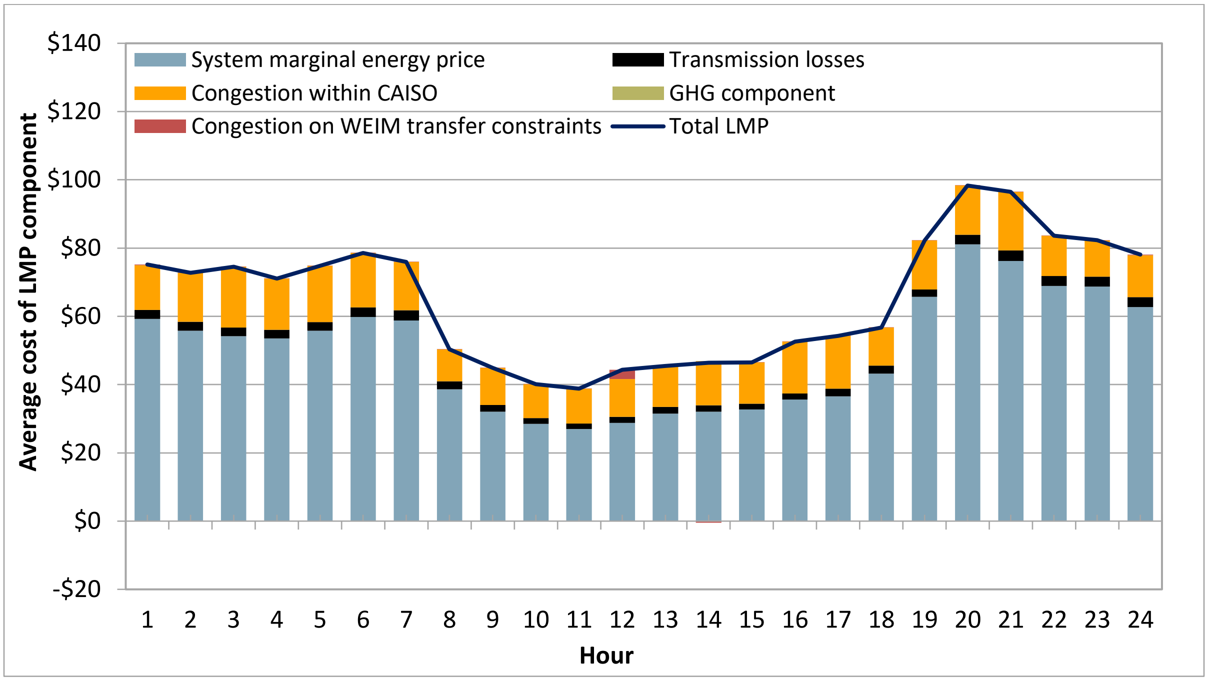
Appendix Figure A.9 Average hourly 15-minute price by component (Q2 2022)



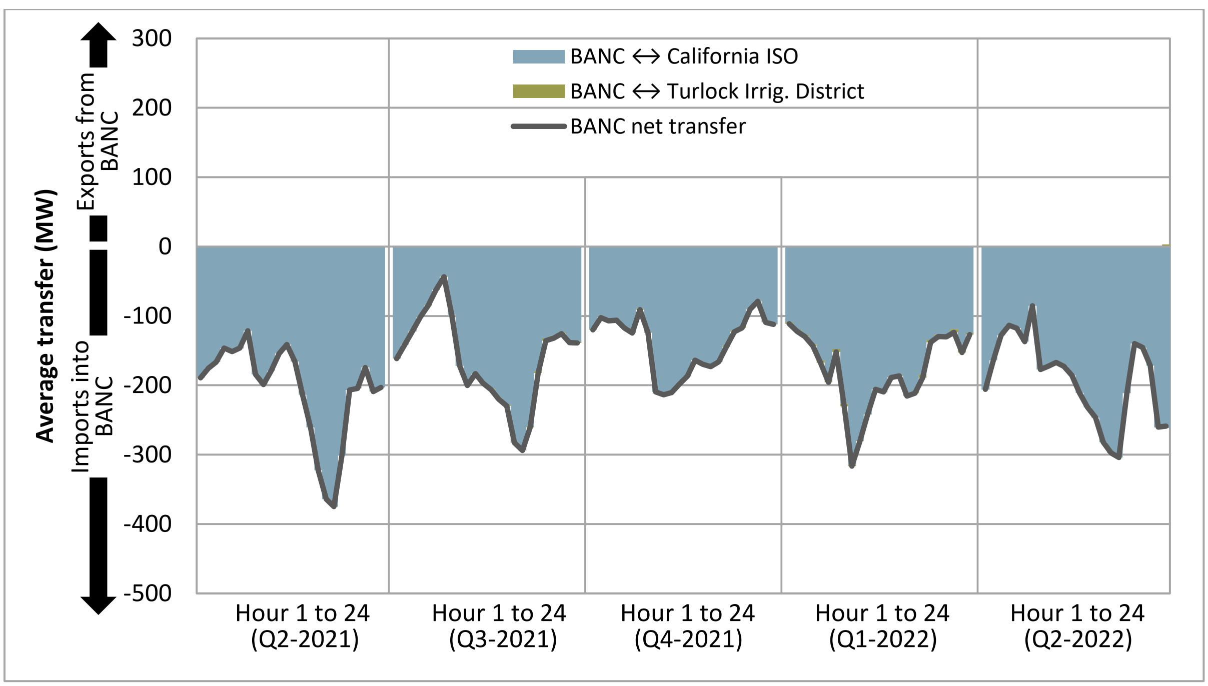
Appendix Figure A.10 Average hourly 15-minute market transfers



Appendix Figure A.11 Average hourly 5-minute price by component (Q2 2022)

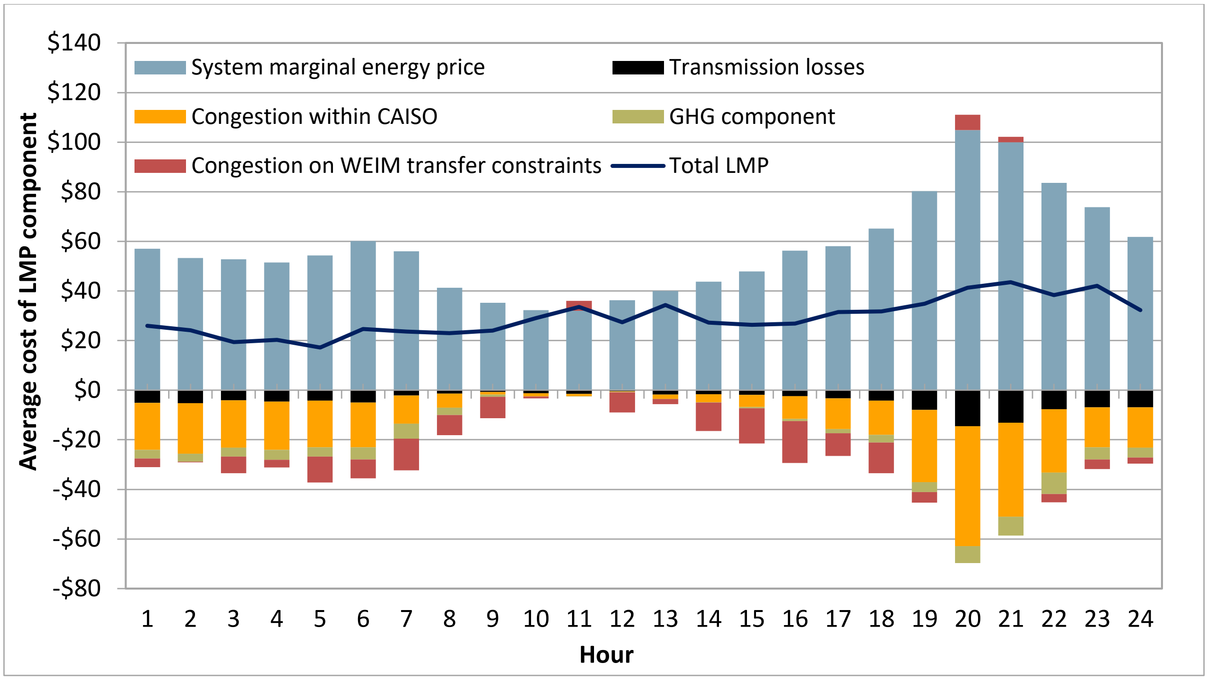


Appendix Figure A.12 Average hourly 5-minute market transfers

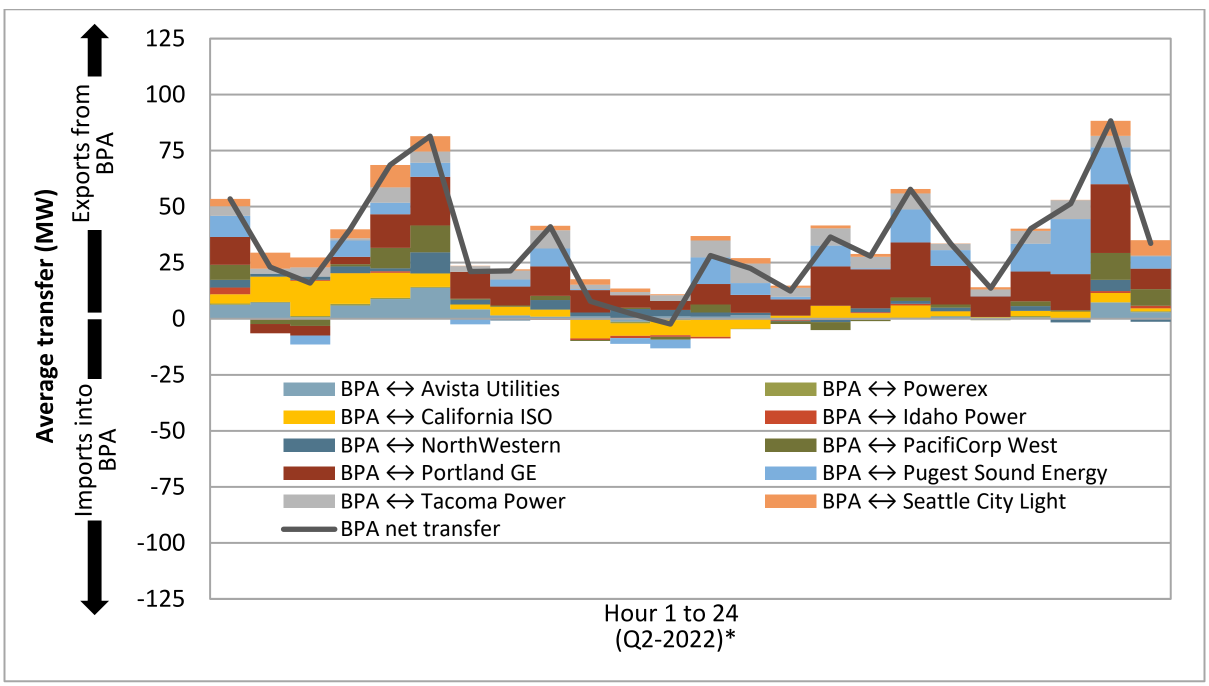


A.4 Bonneville Power Administration

Appendix Figure A.13 Average hourly 15-minute price by component (Q2 2022)

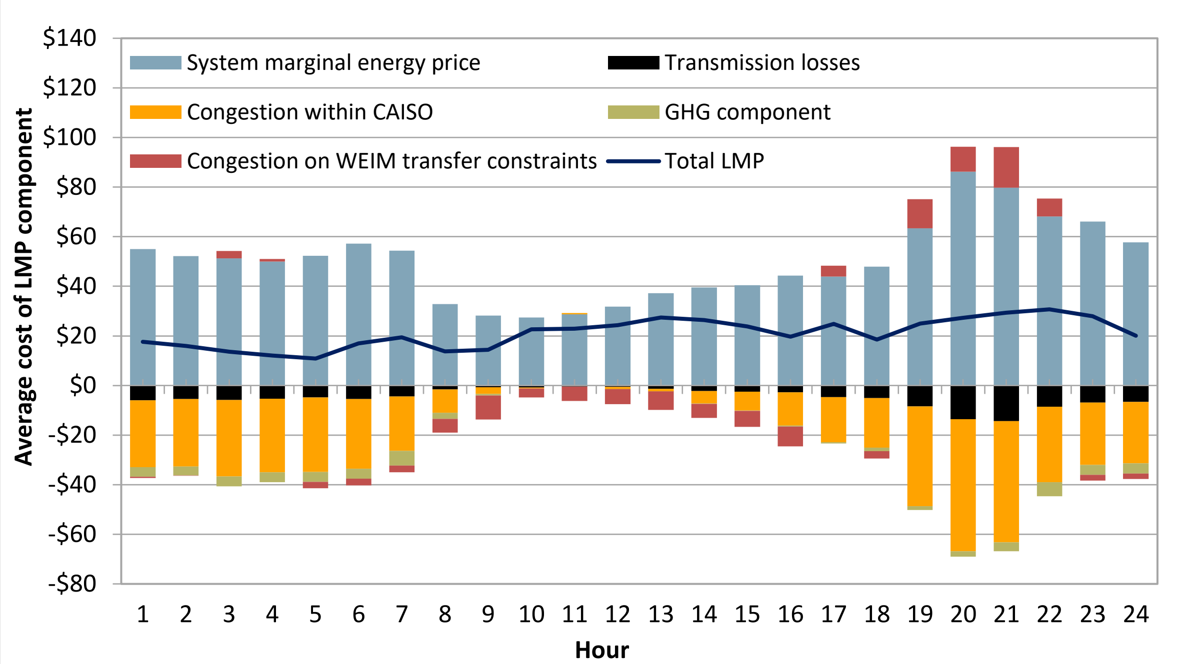


Appendix Figure A.14 Average hourly 15-minute market transfers

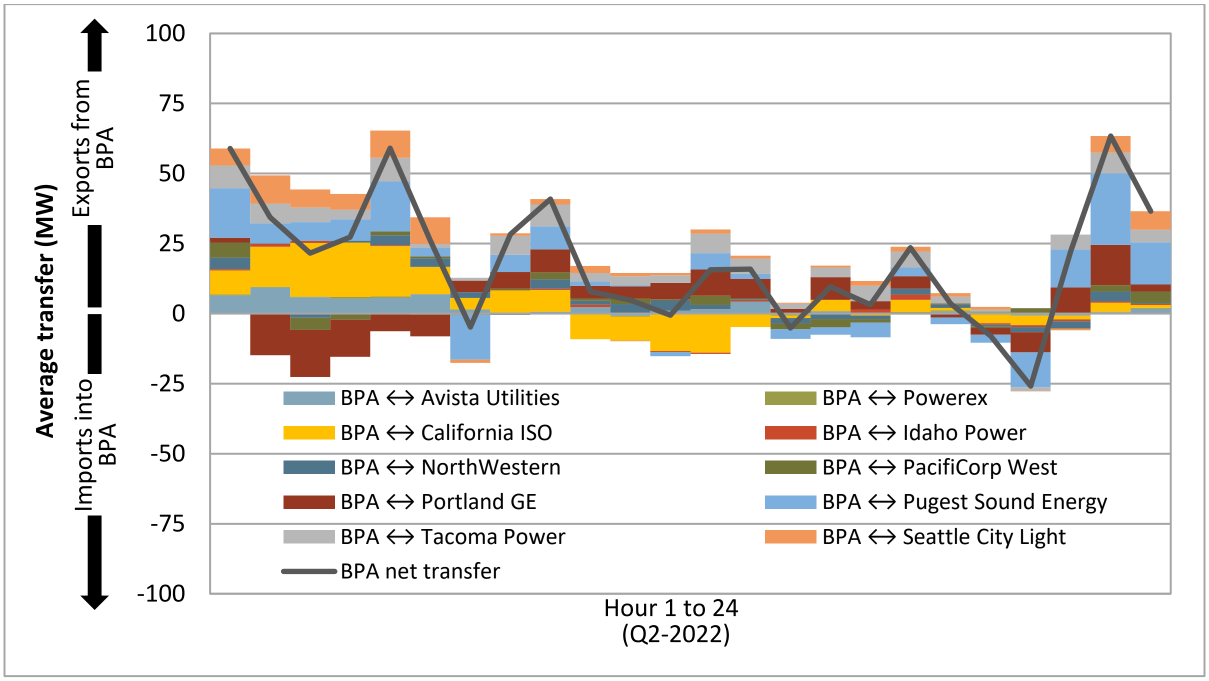


*Since joining the WEIM

Appendix Figure A.15 Average hourly 5-minute price by component (Q2 2022)



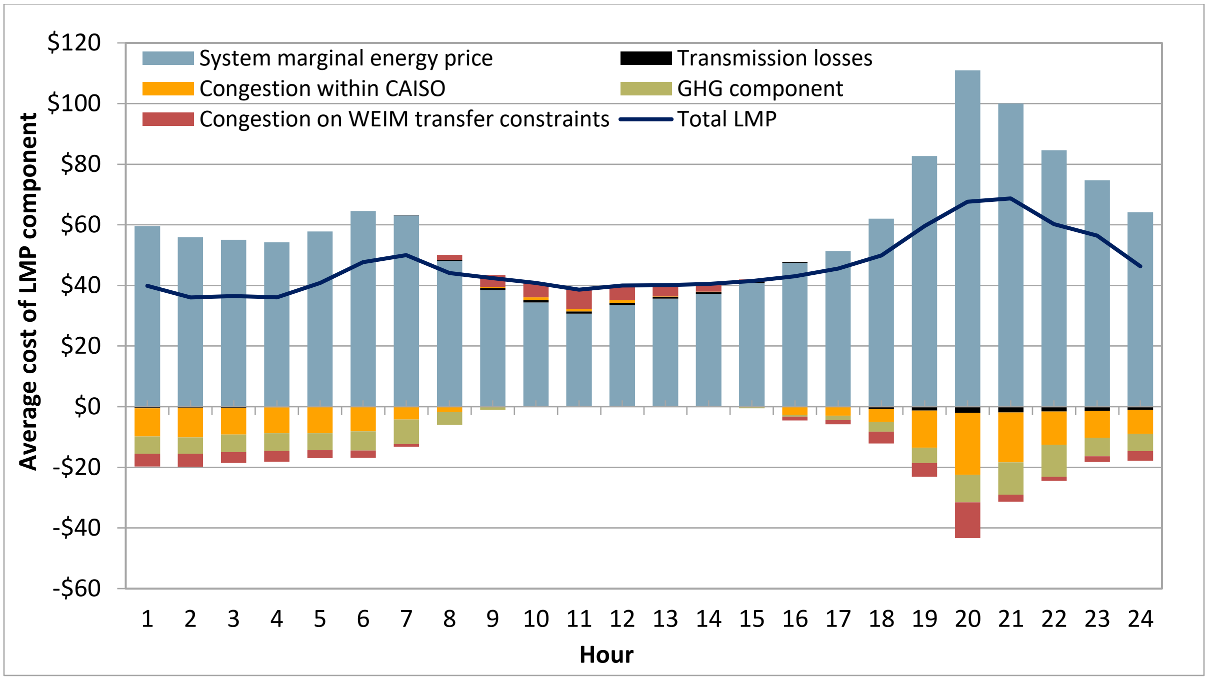
Appendix Figure A.16 Average hourly 5-minute market transfers



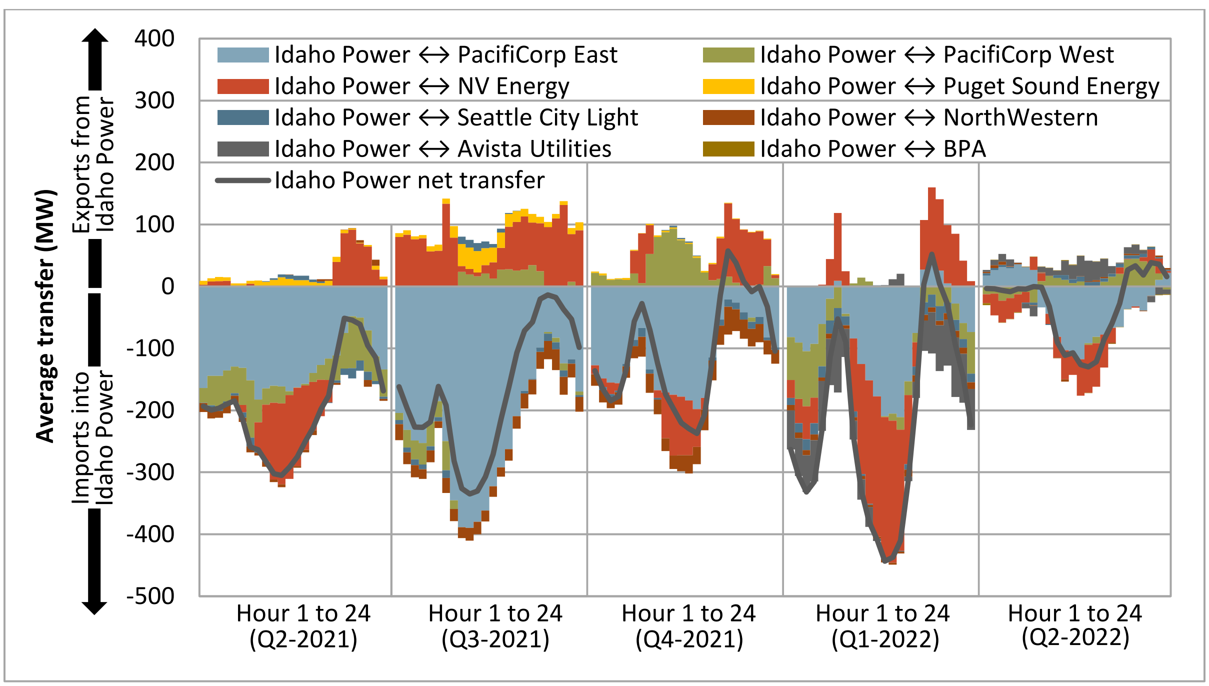
*Since joining the WEIM

A.5 Idaho Power

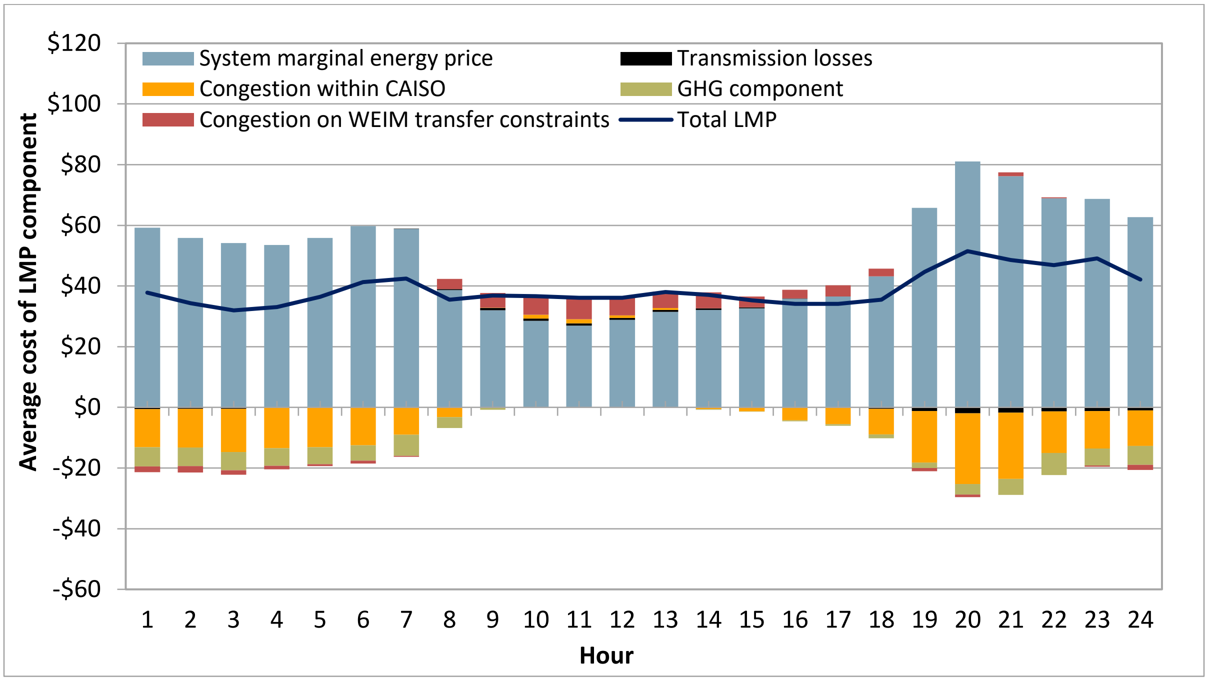
Appendix Figure A.17 Average hourly 15-minute price by component (Q2 2022)



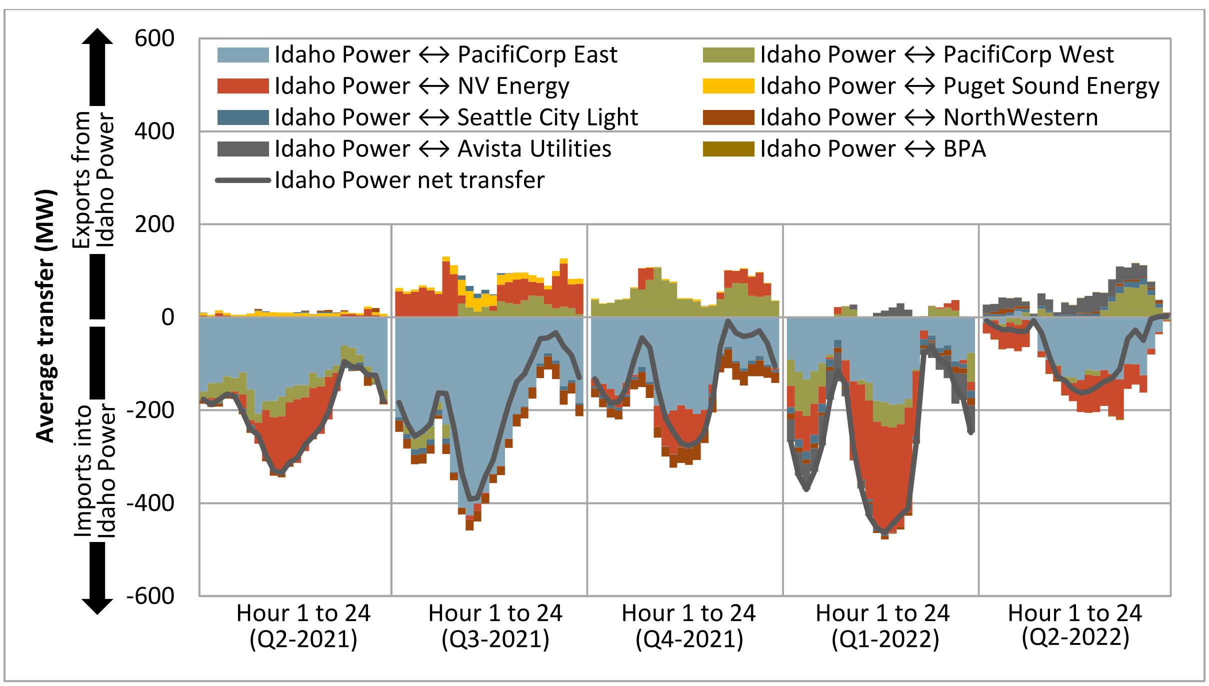
Appendix Figure A.18 Average hourly 15-minute market transfers



Appendix Figure A.19 Average hourly 5-minute price by component (Q2 2022)

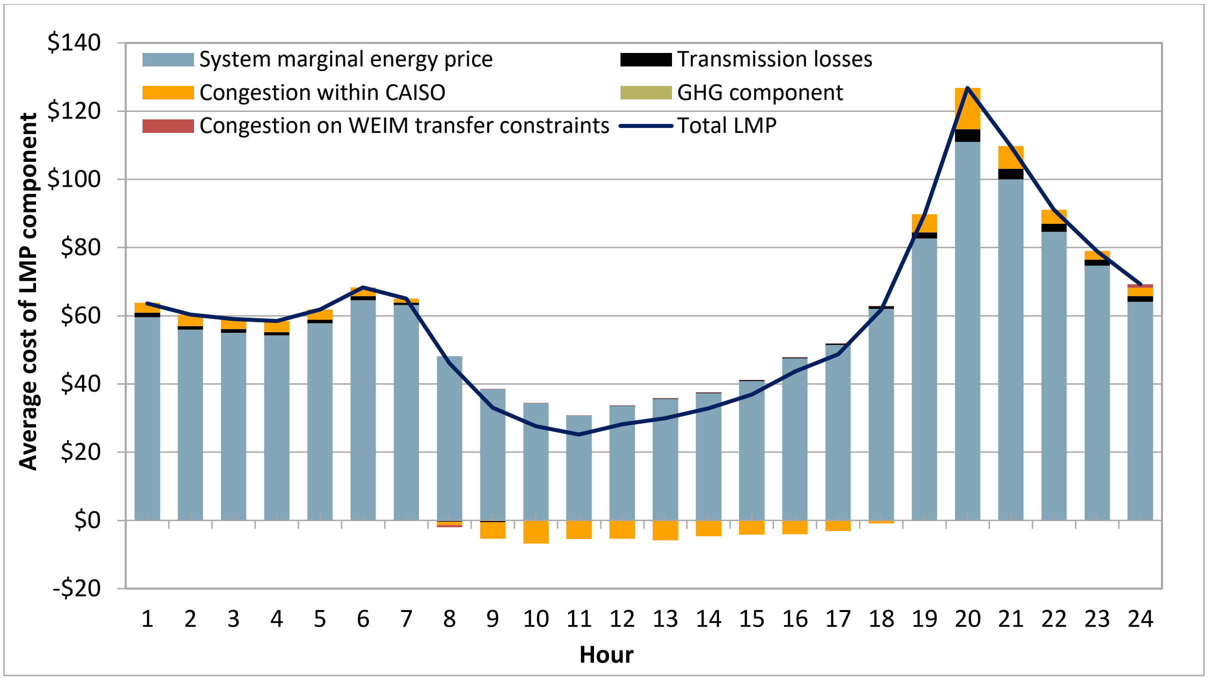


Appendix Figure A.20 Average hourly 5-minute market transfers

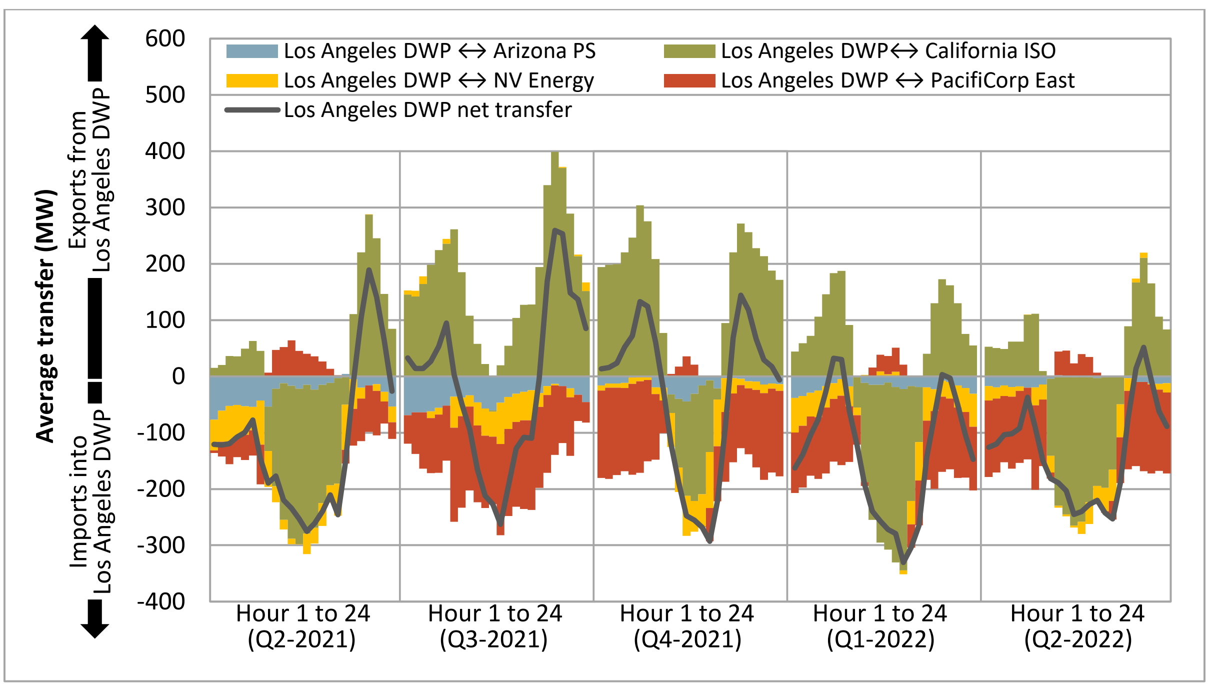


A.6 Los Angeles Department of Water and Power

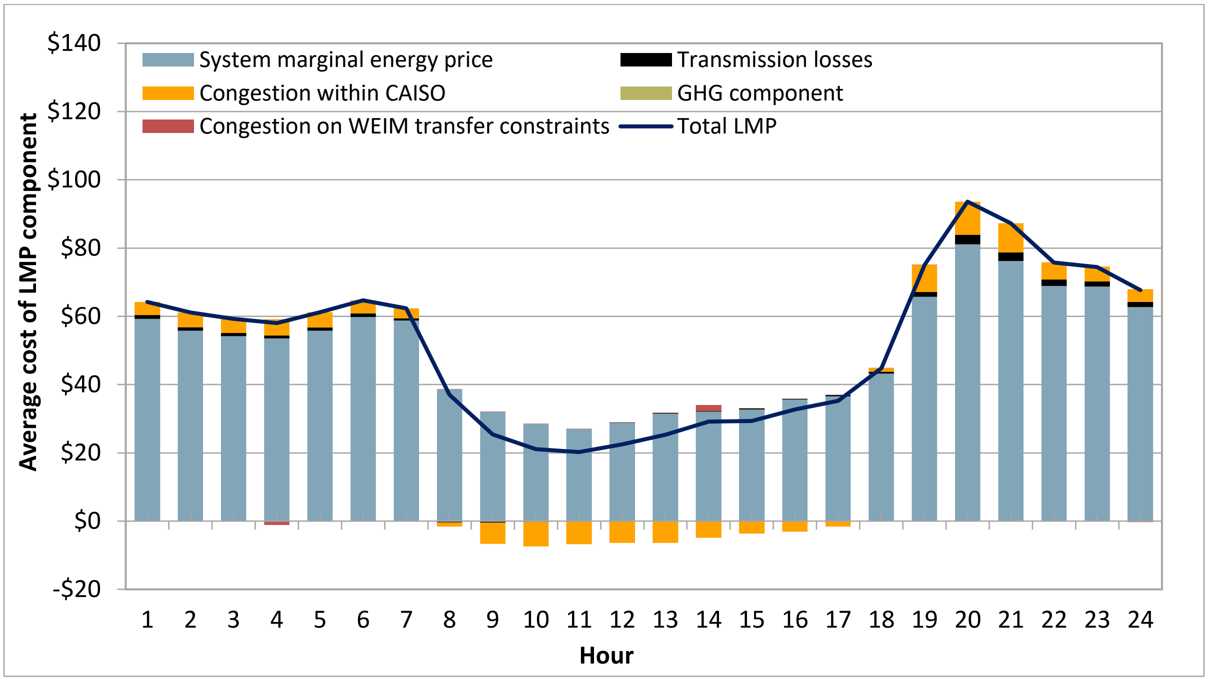
Appendix Figure A.21 Average hourly 15-minute price by component (Q2 2022)



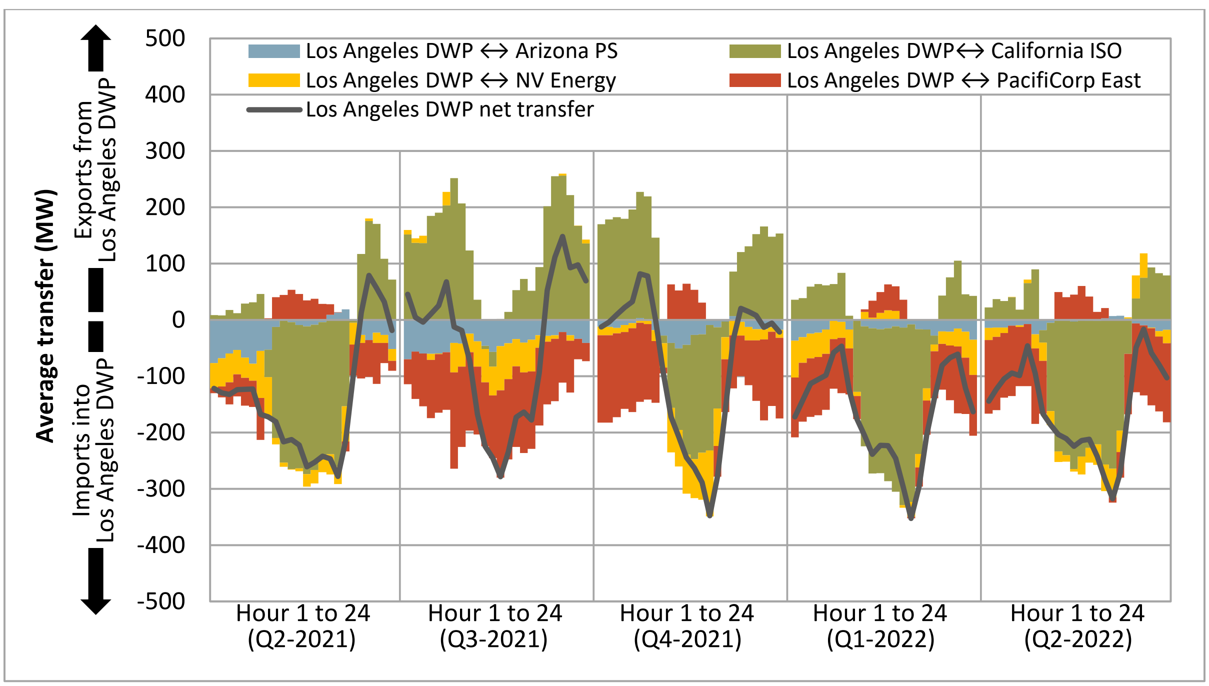
Appendix Figure A.22 Average hourly 15-minute market transfers



Appendix Figure A.23 Average hourly 5-minute price by component (Q2 2022)

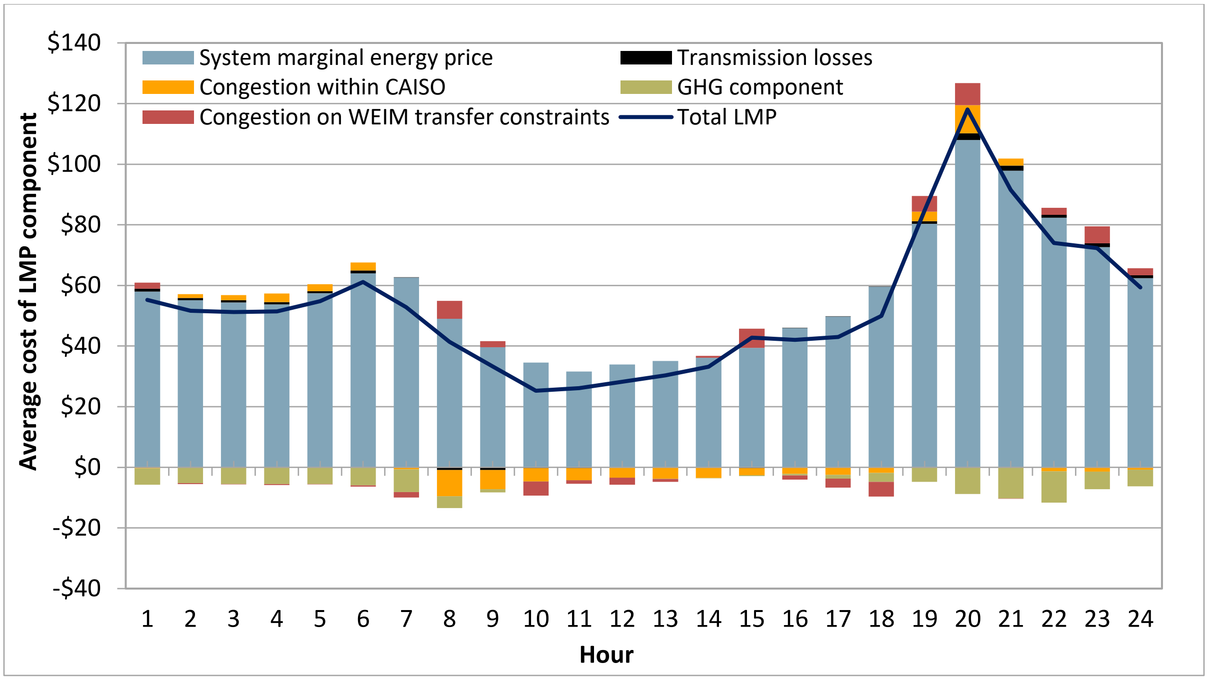


Appendix Figure A.24 Average hourly 5-minute market transfers

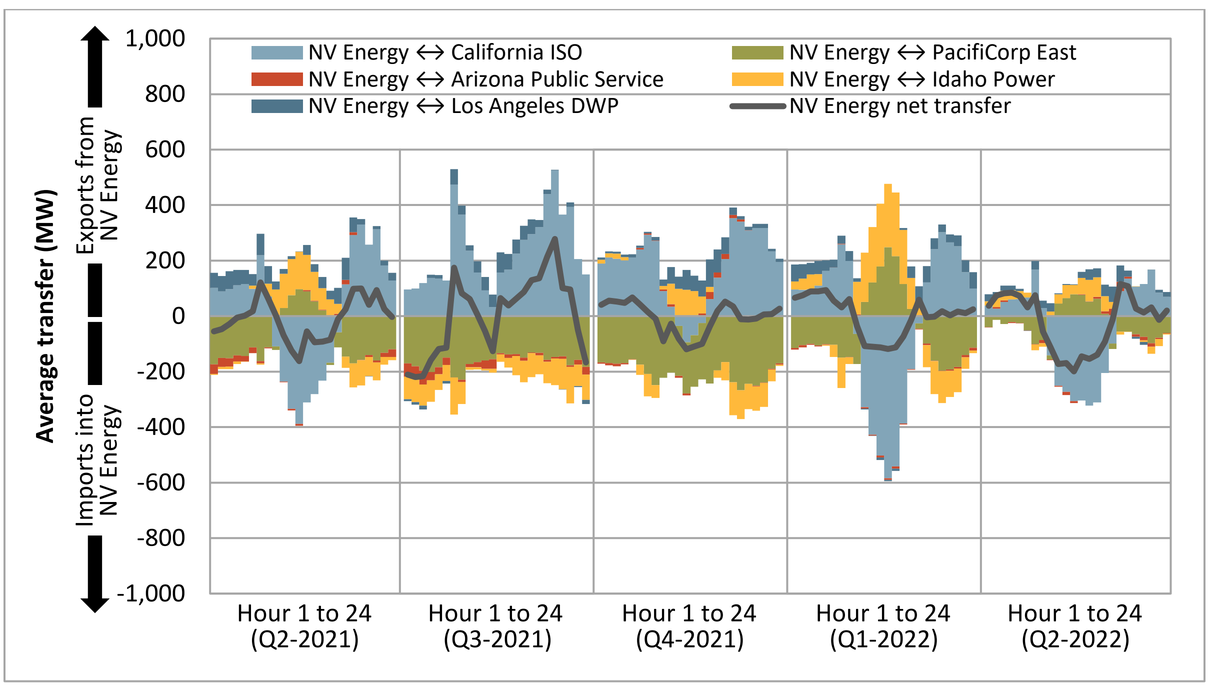


A.7 Nevada Energy

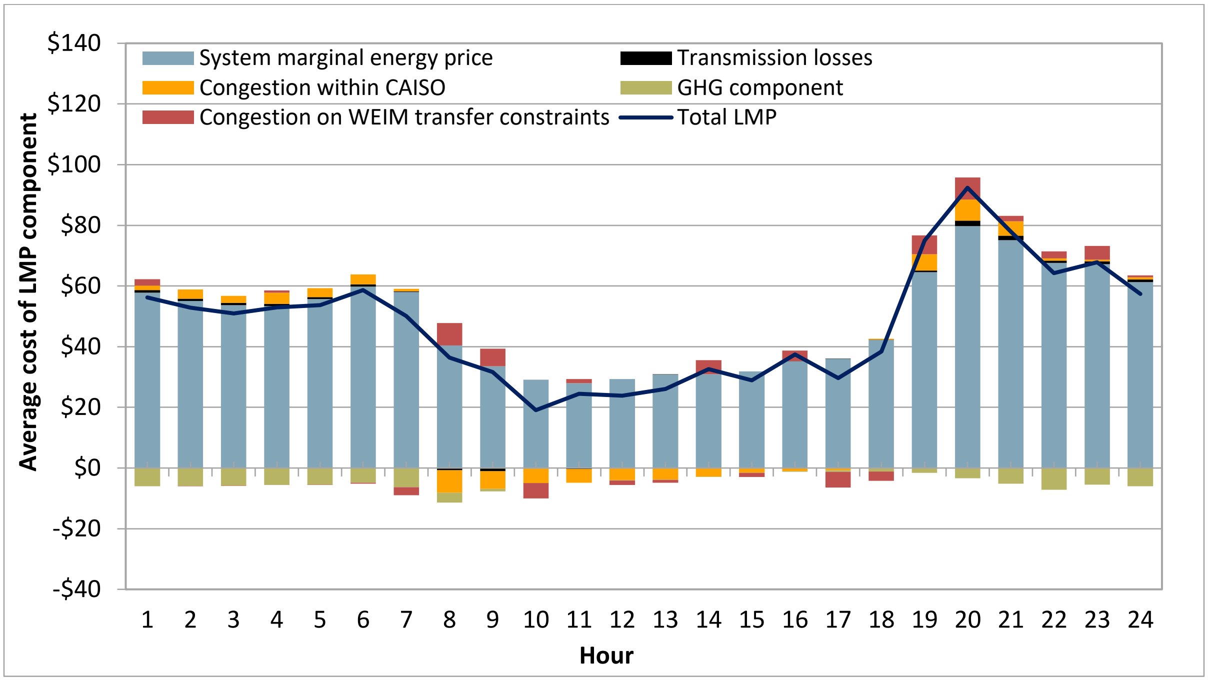
Appendix Figure A.25 Average hourly 15-minute price by component (Q2 2022)



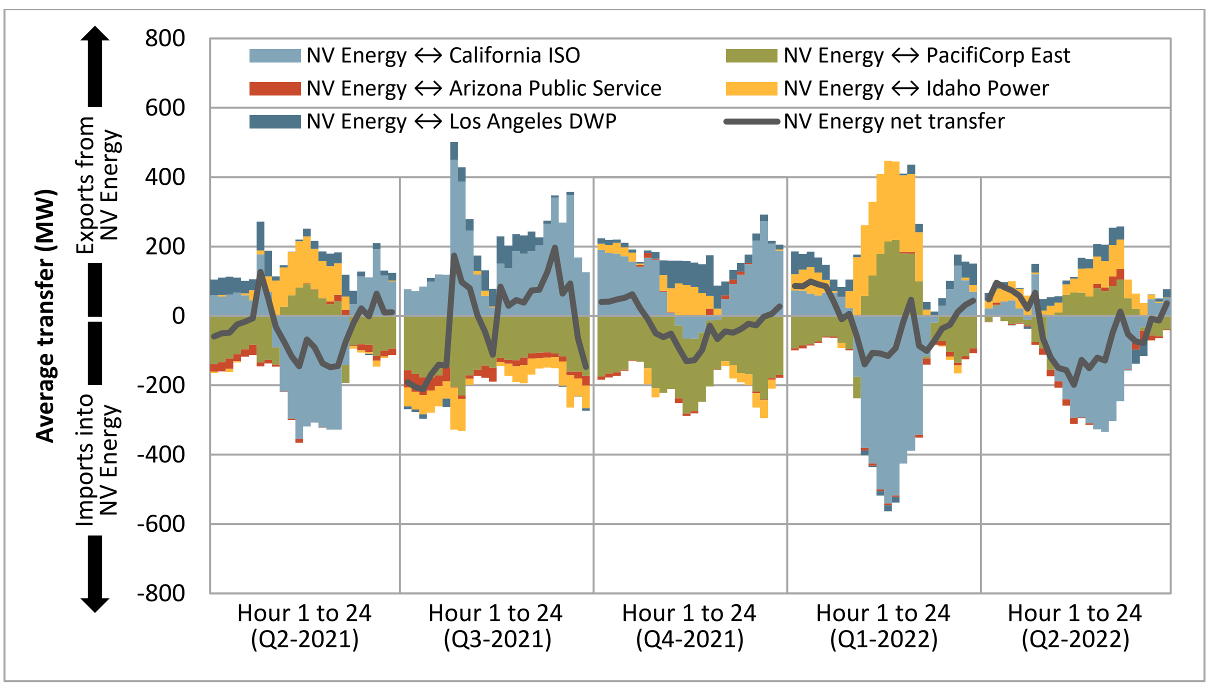
Appendix Figure A.26 Average hourly 15-minute market transfers



Appendix Figure A.27 Average hourly 5-minute price by component (Q2 2022)

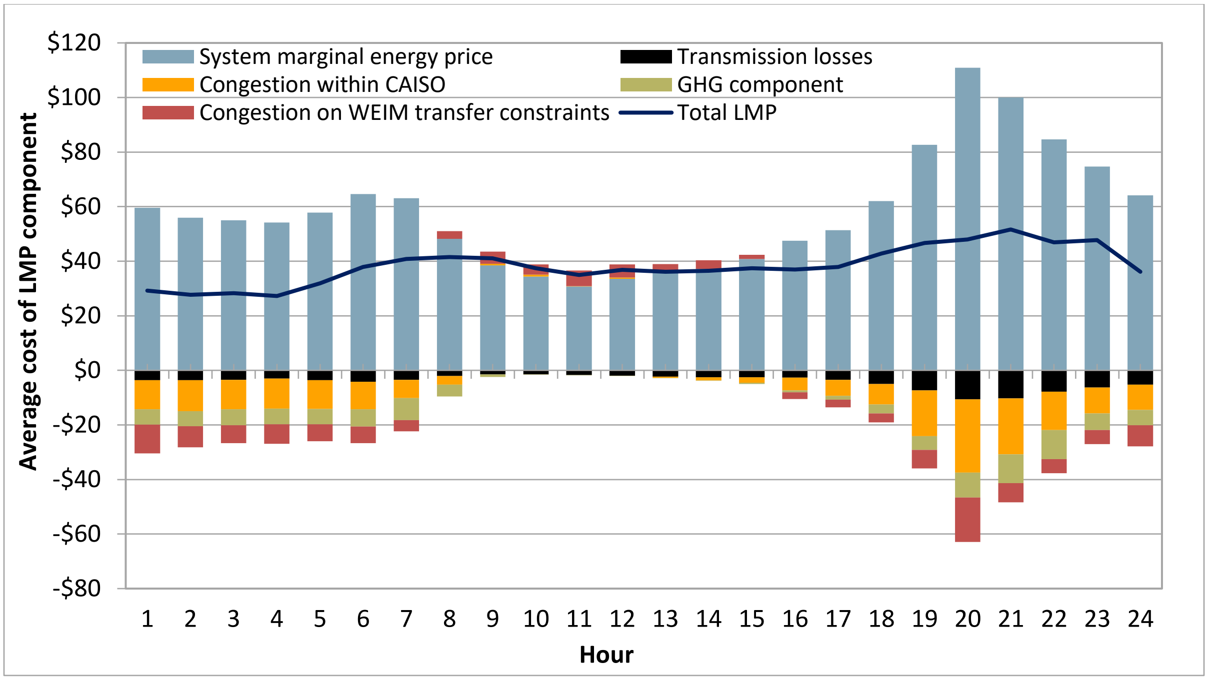


Appendix Figure A.28 Average hourly 5-minute market transfers

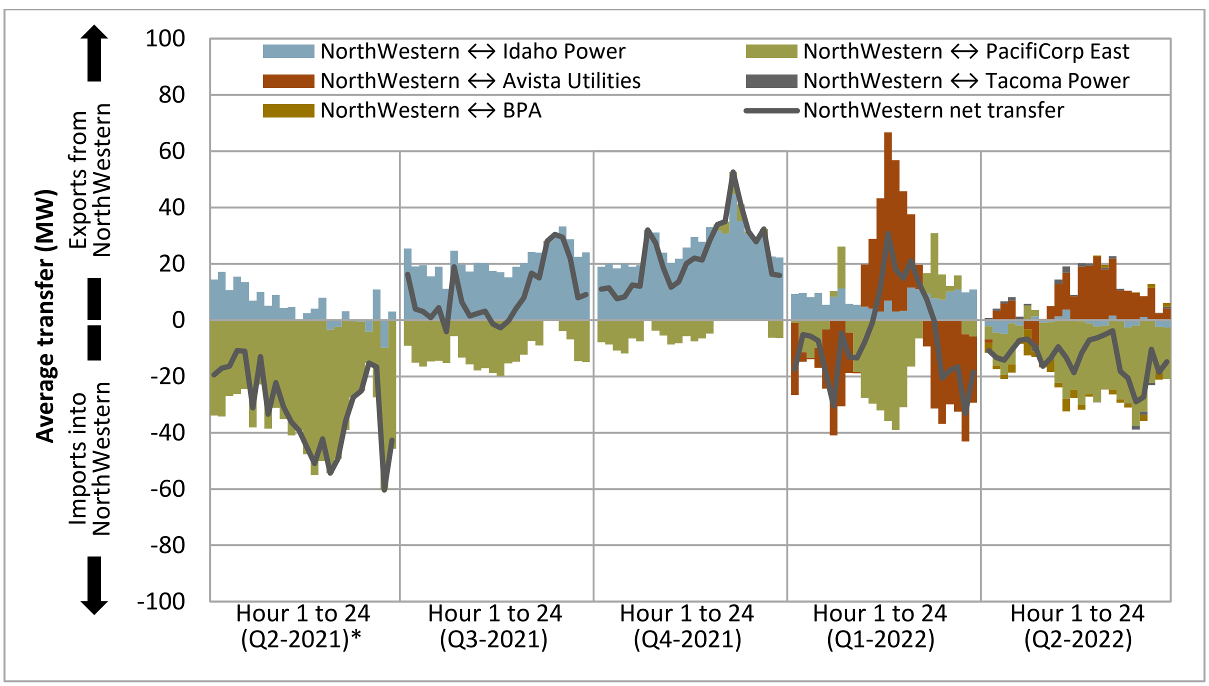


A.8 NorthWestern Energy

Appendix Figure A.29 Average hourly 15-minute price by component (Q2 2022)

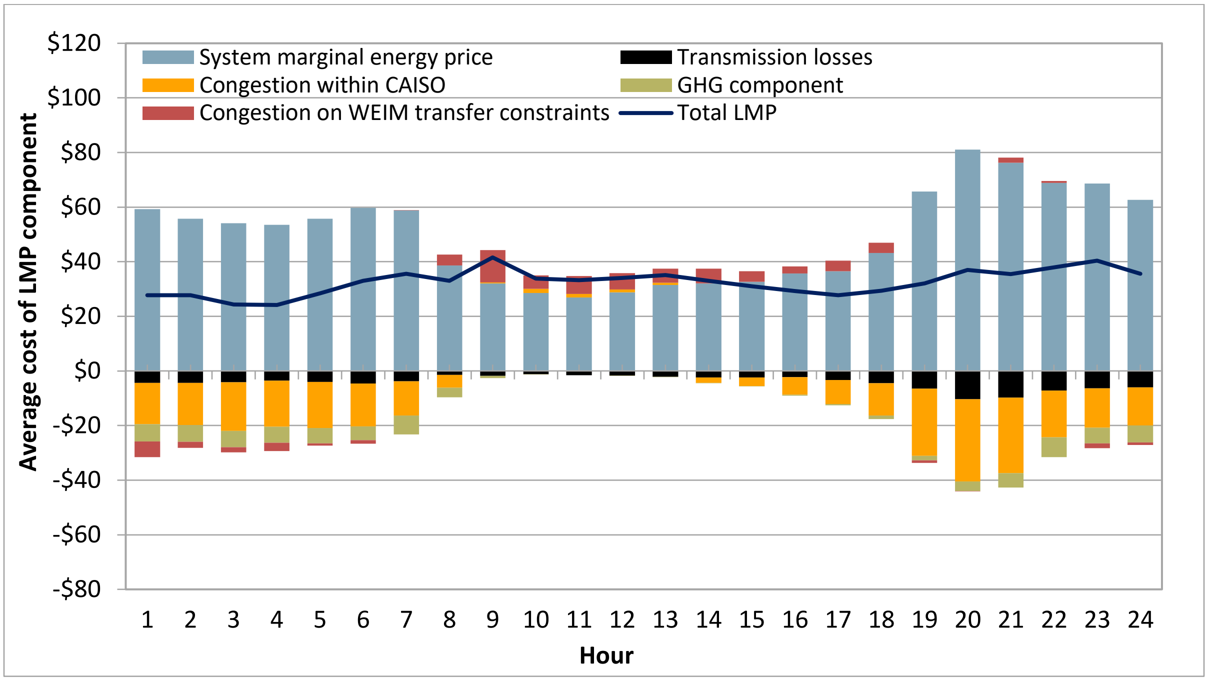


Appendix Figure A.30 Average hourly 15-minute market transfers

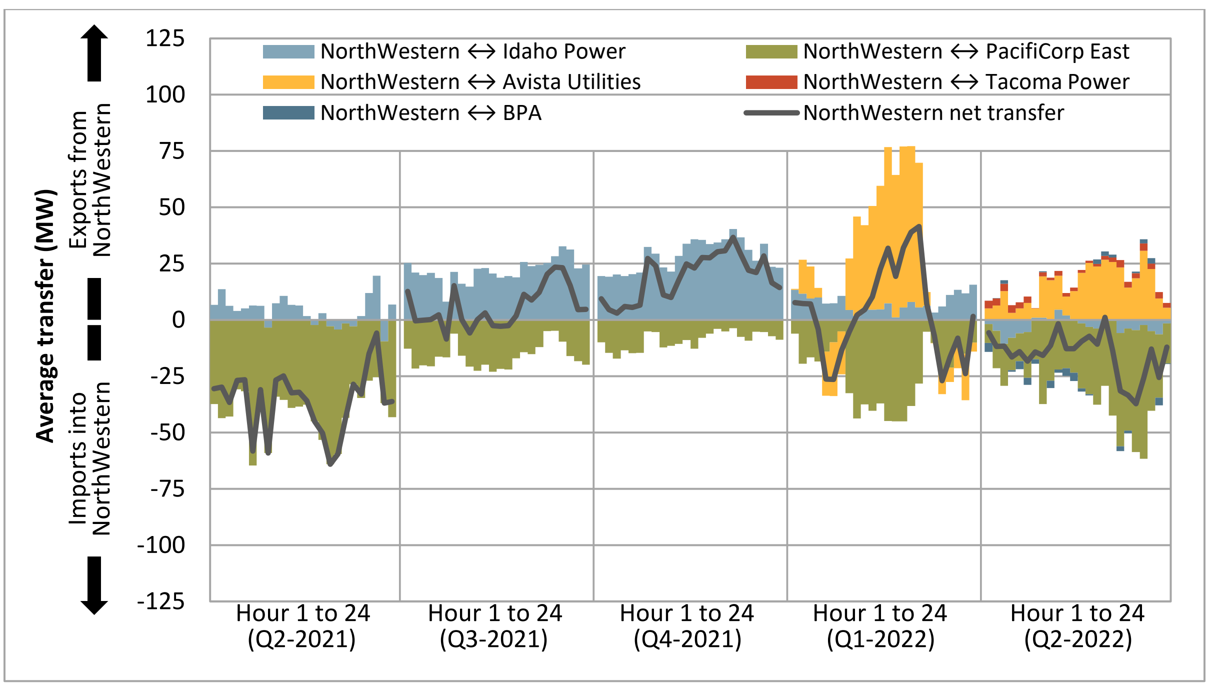


*Since joining the WEIM

Appendix Figure A.31 Average hourly 5-minute price by component (Q2 2022)



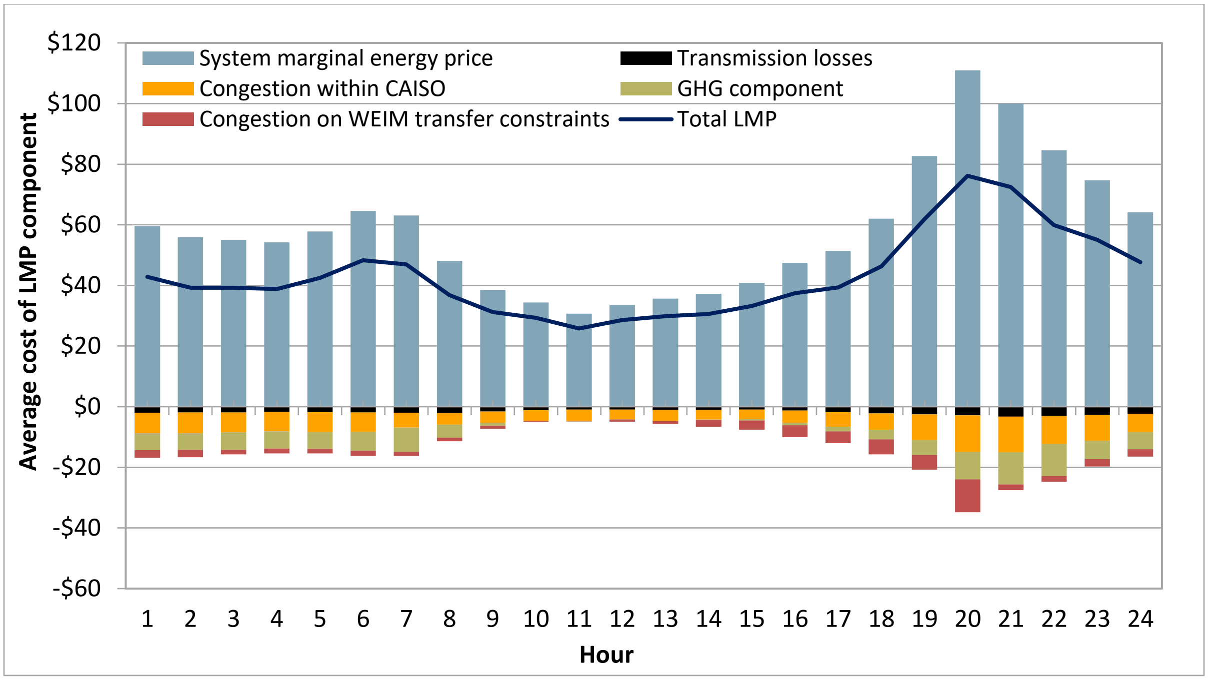
Appendix Figure A.32 Average hourly 5-minute market transfers



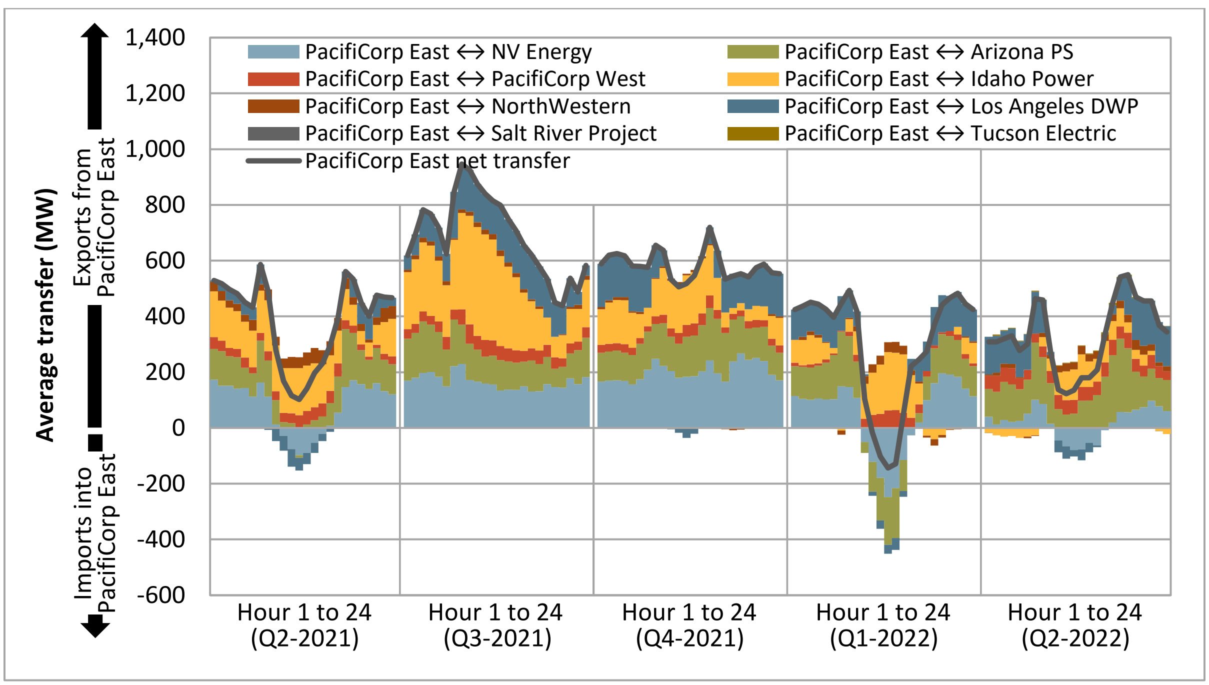
*Since joining the WEIM

A.9 PacifiCorp East

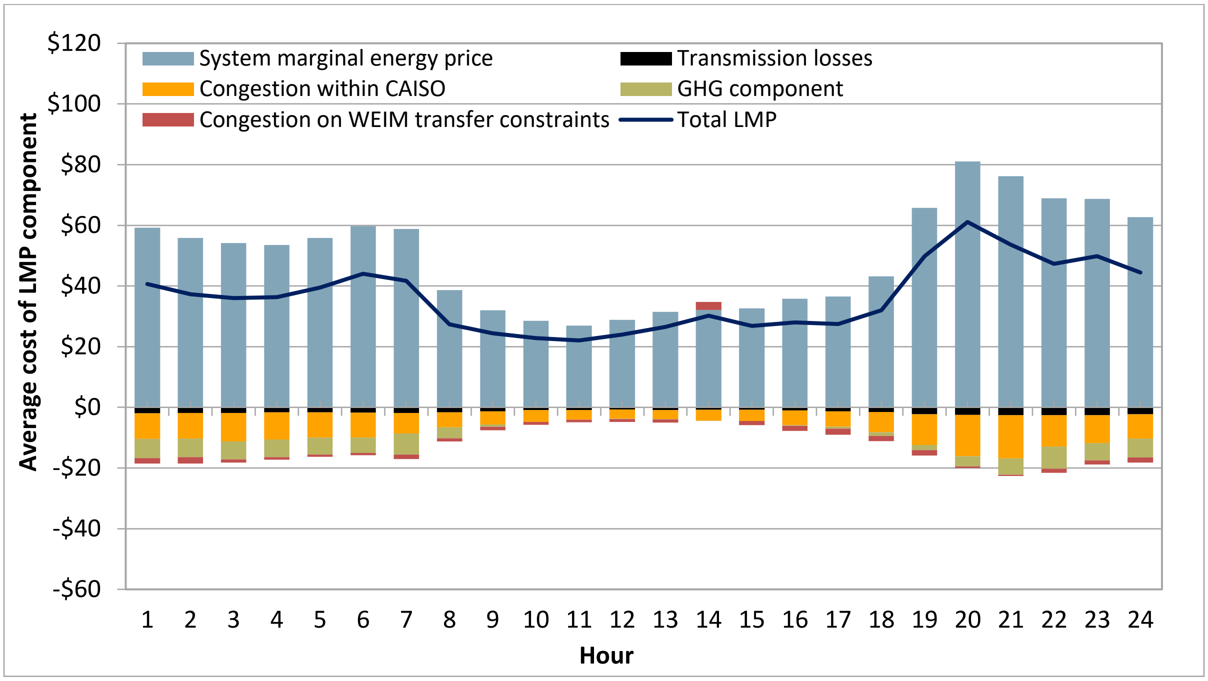
Appendix Figure A.33 Average hourly 15-minute price by component (Q2 2022)



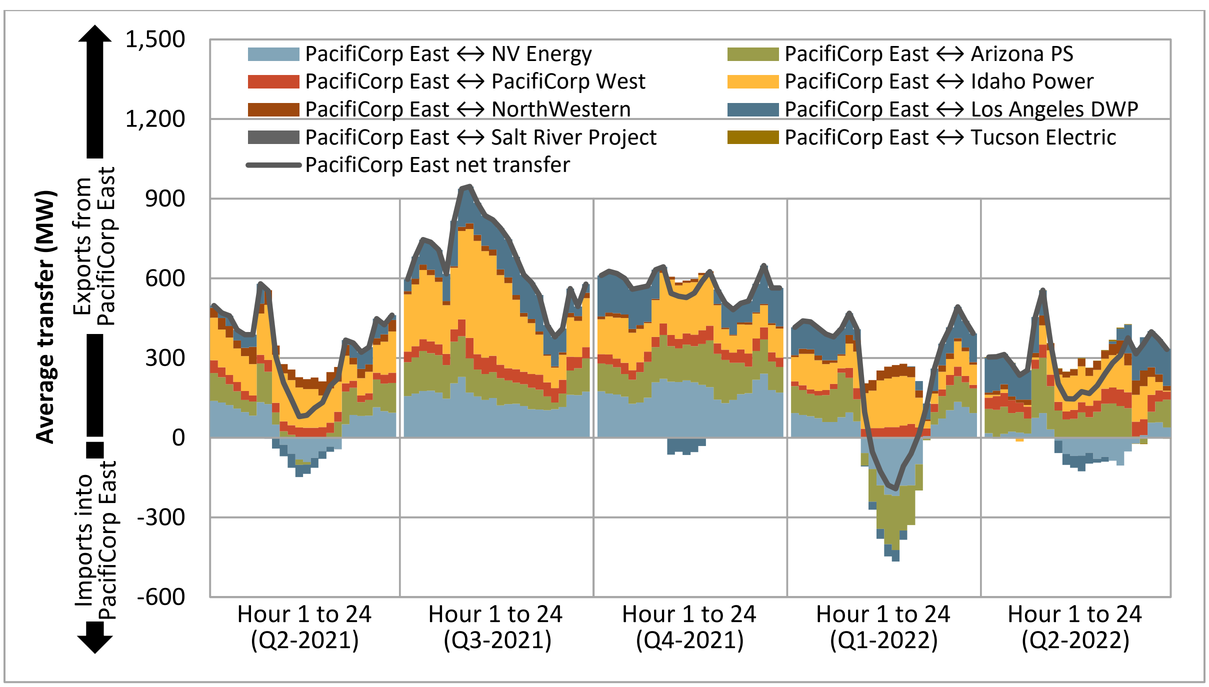
Appendix Figure A.34 Average hourly 15-minute market transfers



Appendix Figure A.35 Average hourly 5-minute price by component (Q2 2022)

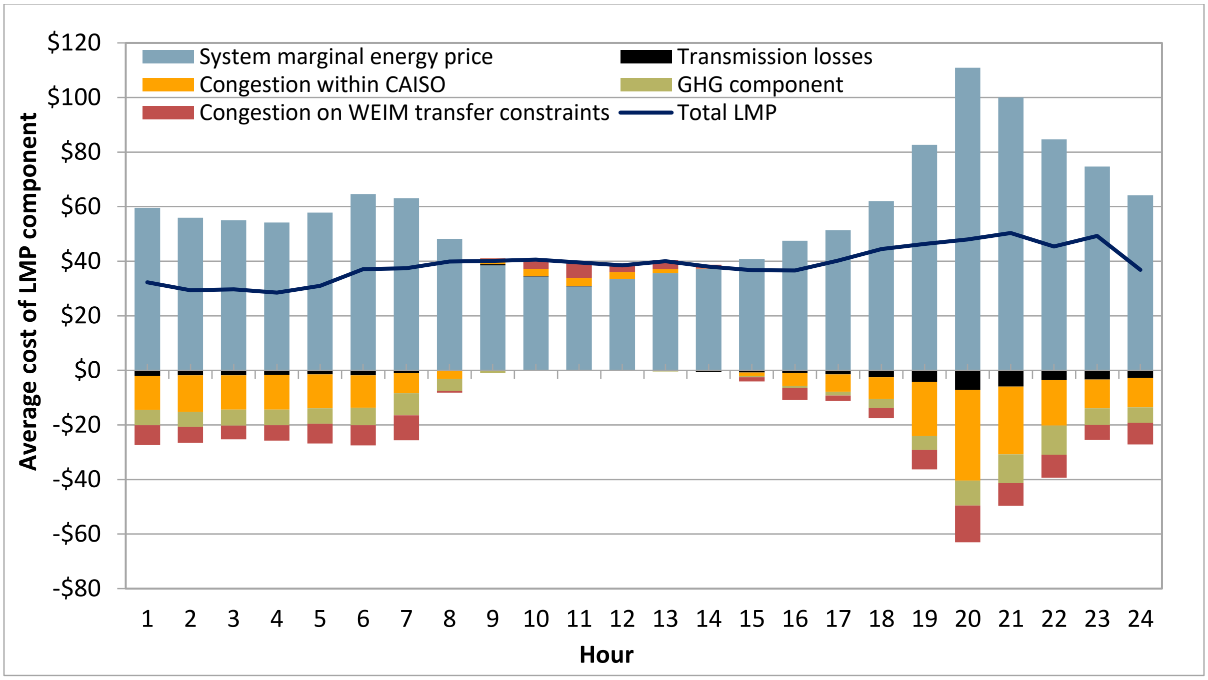


Appendix Figure A.36 Average hourly 5-minute market transfers

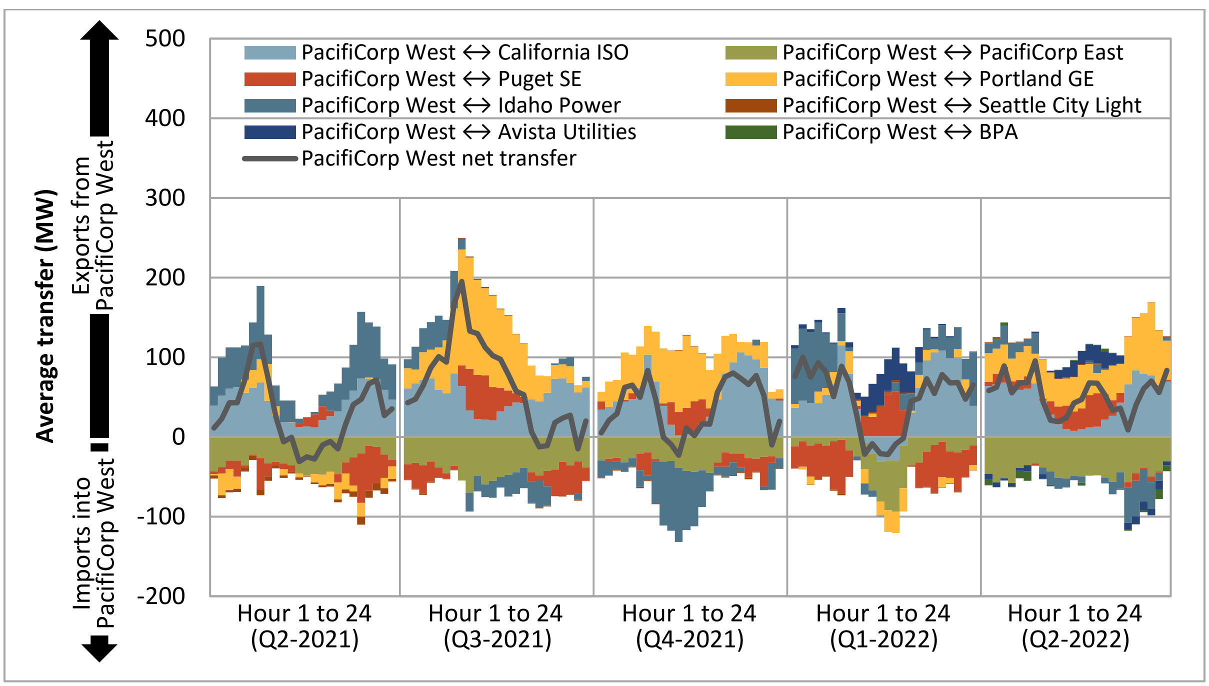


A.10 PacifiCorp West

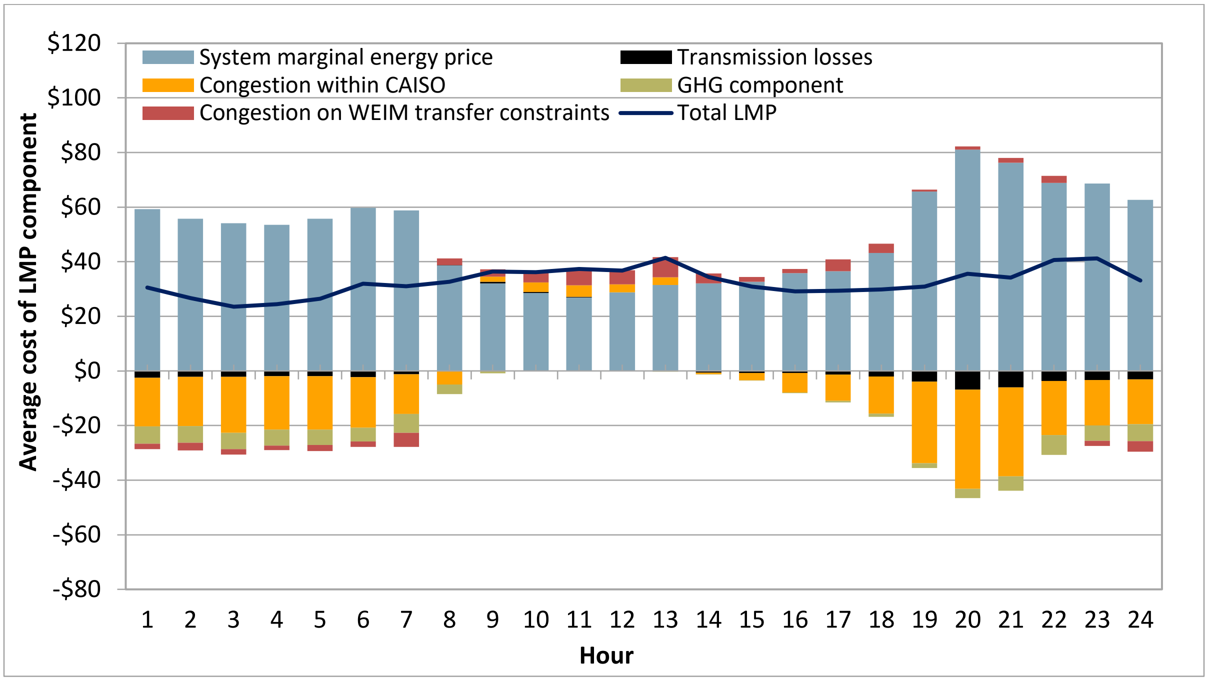
Appendix Figure A.37 Average hourly 15-minute price by component (Q2 2022)



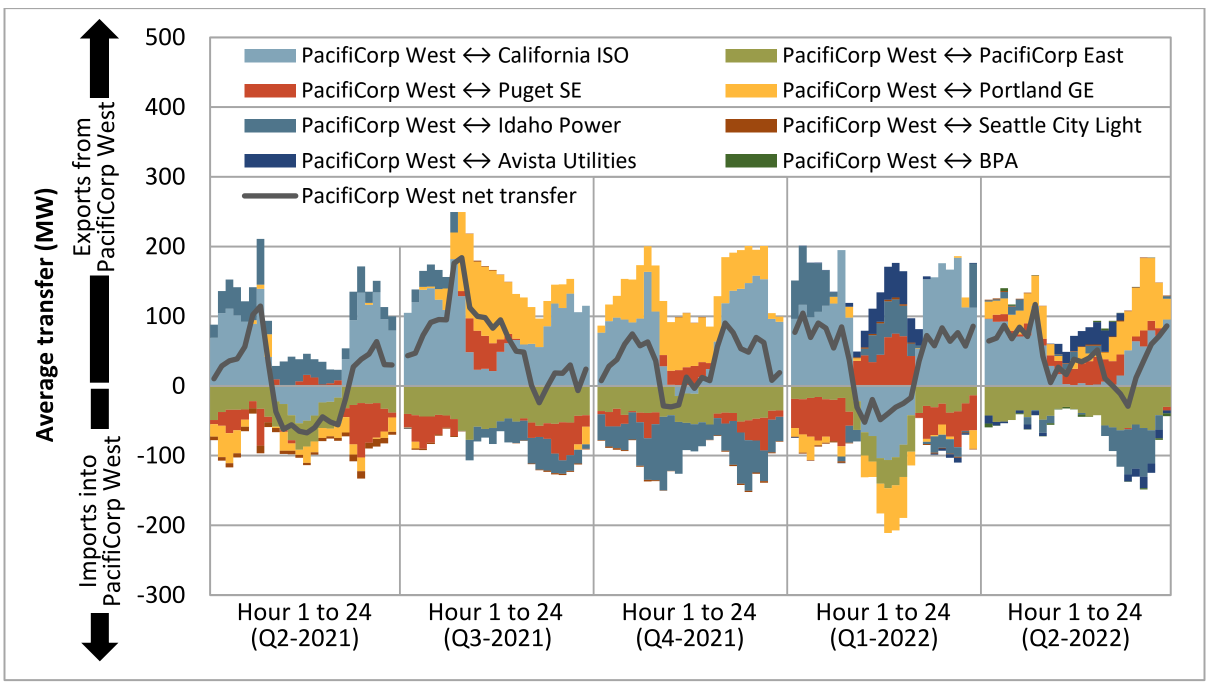
Appendix Figure A.38 Average hourly 15-minute market transfers



Appendix Figure A.39 Average hourly 5-minute price by component (Q2 2022)

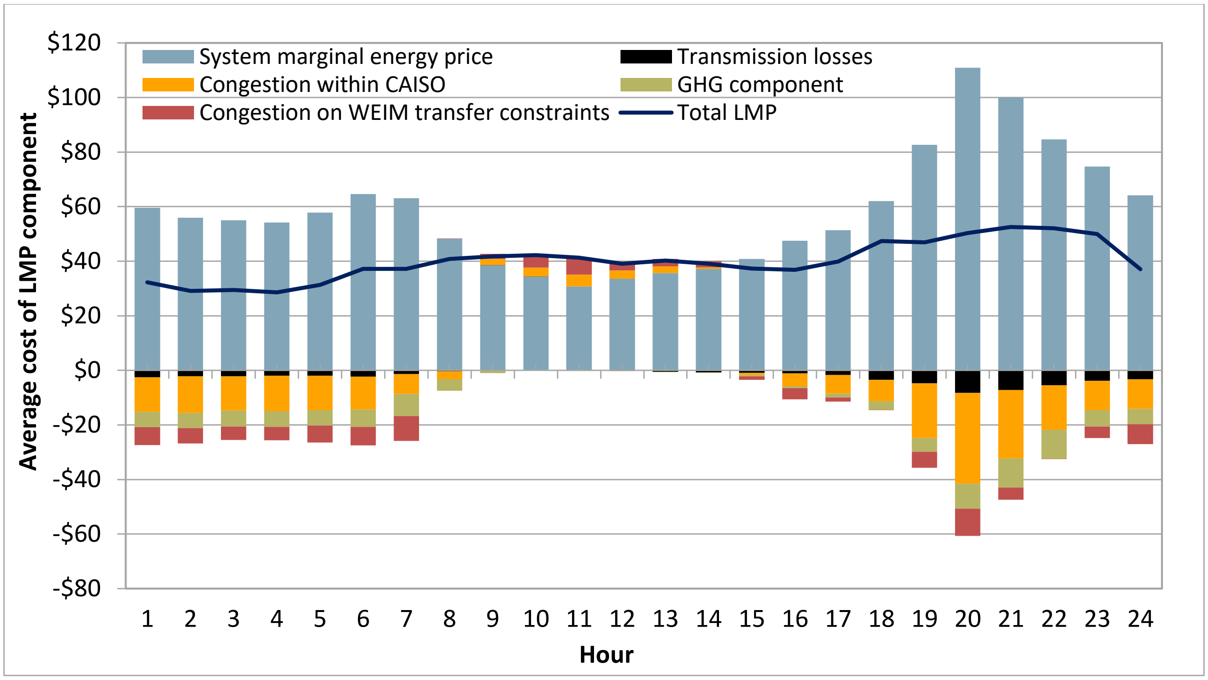


Appendix Figure A.40 Average hourly 5-minute market transfers

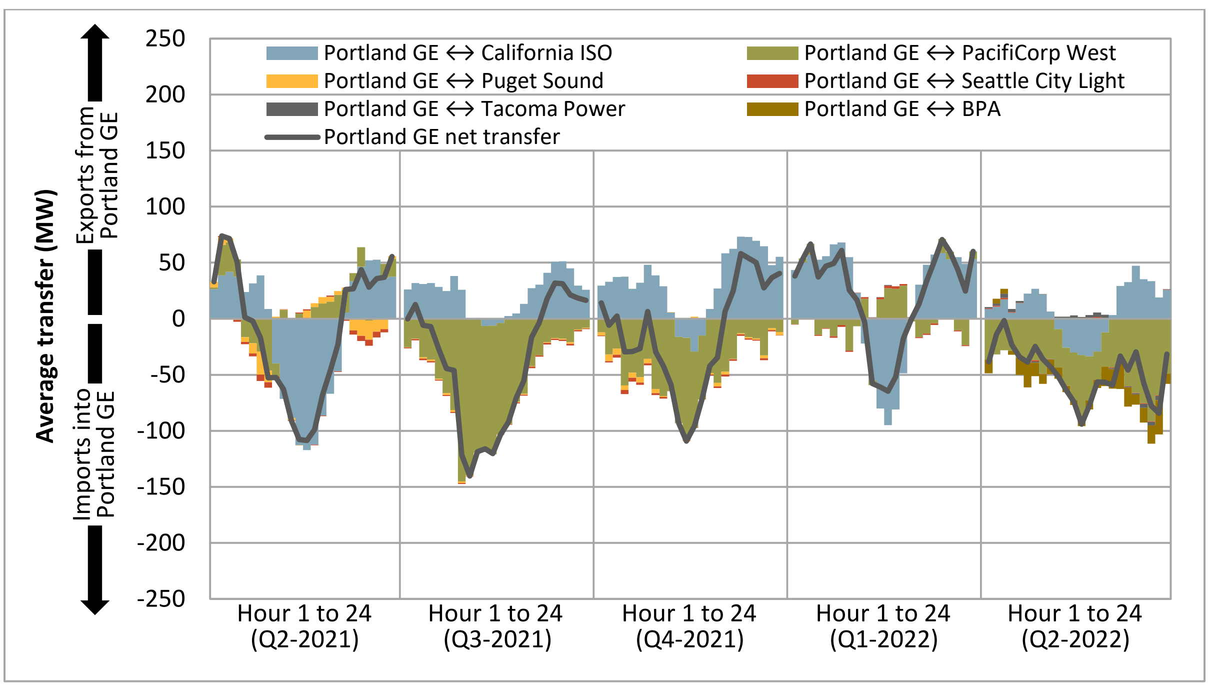


A.11 Portland General Electric

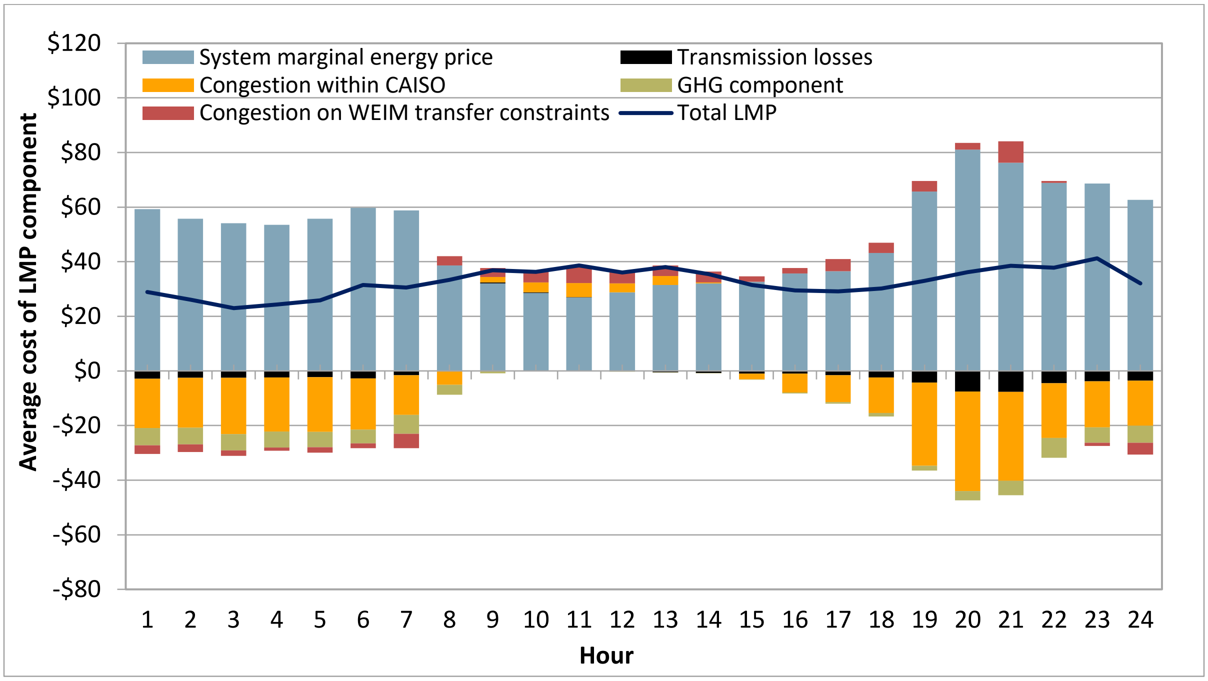
Appendix Figure A.41 Average hourly 15-minute price by component (Q2 2022)



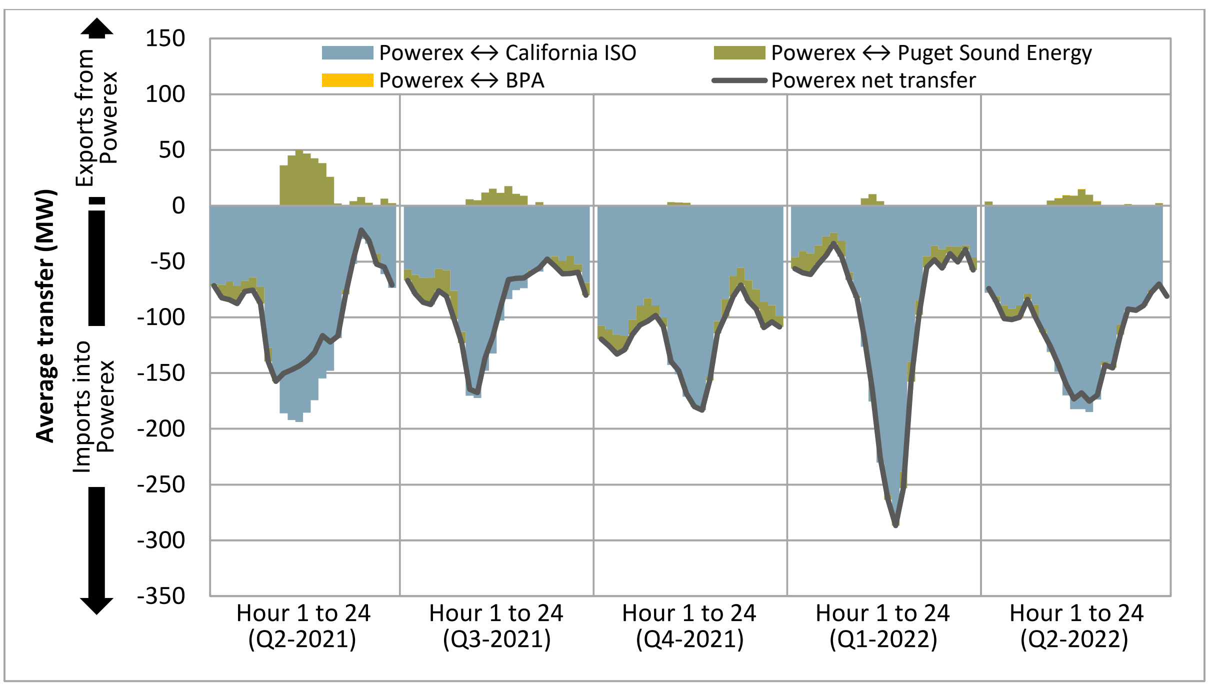
Appendix Figure A.42 Average hourly 15-minute market transfers



Appendix Figure A.43 Average hourly 5-minute price by component (Q2 2022)

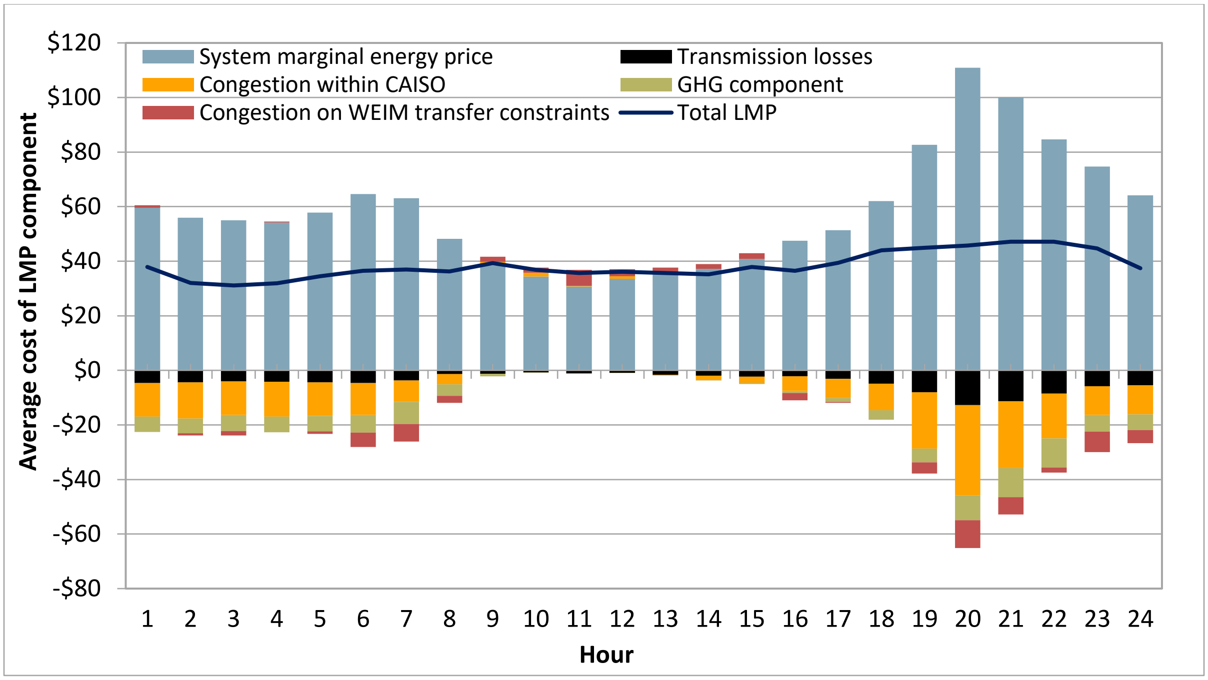


Appendix Figure A.44 Average hourly 5-minute market transfers

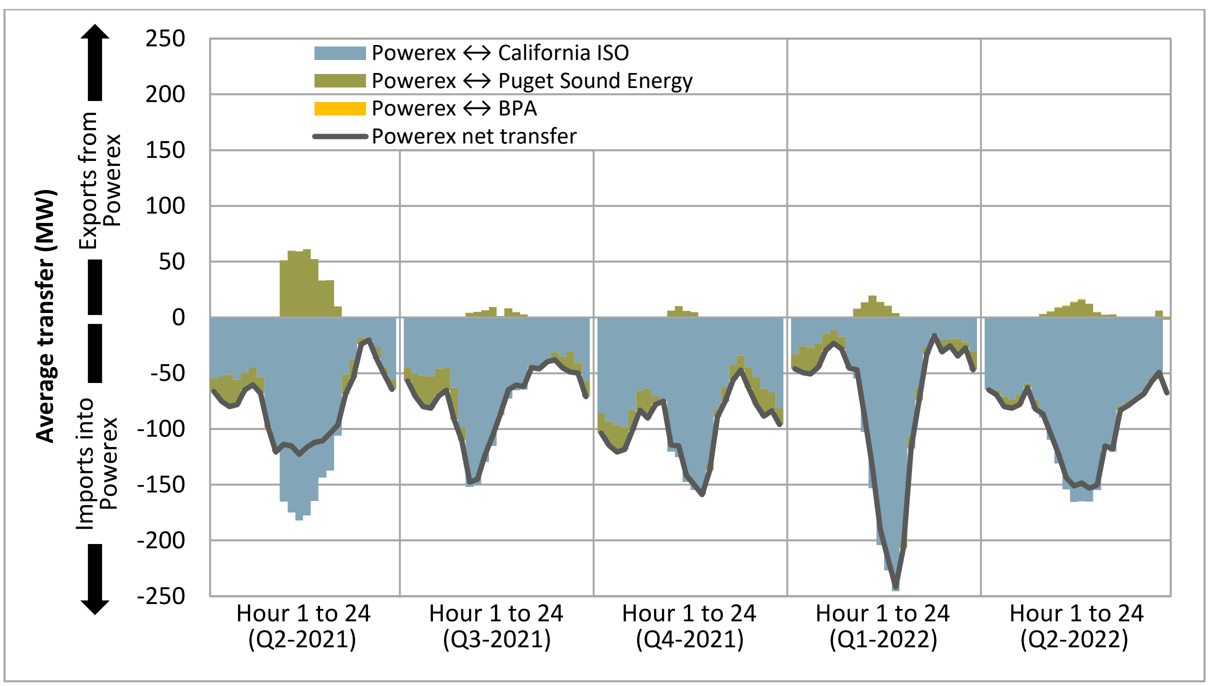


A.12 Powerex

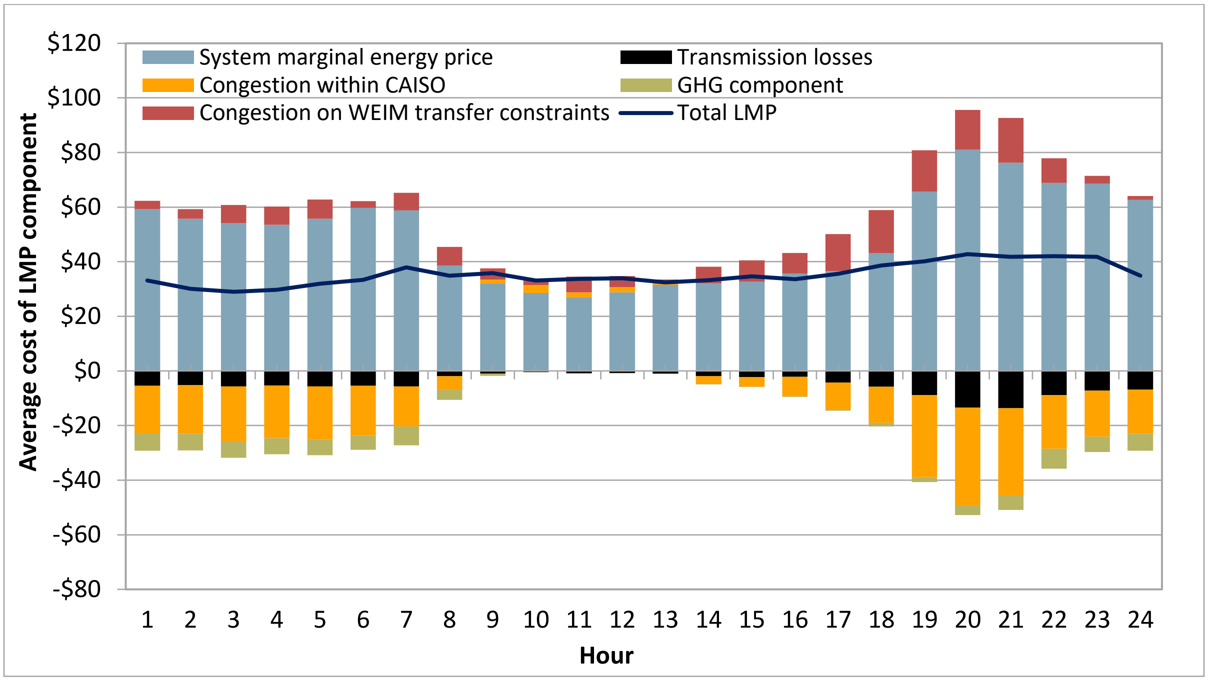
Appendix Figure A.45 Average hourly 15-minute price by component (Q2 2022)



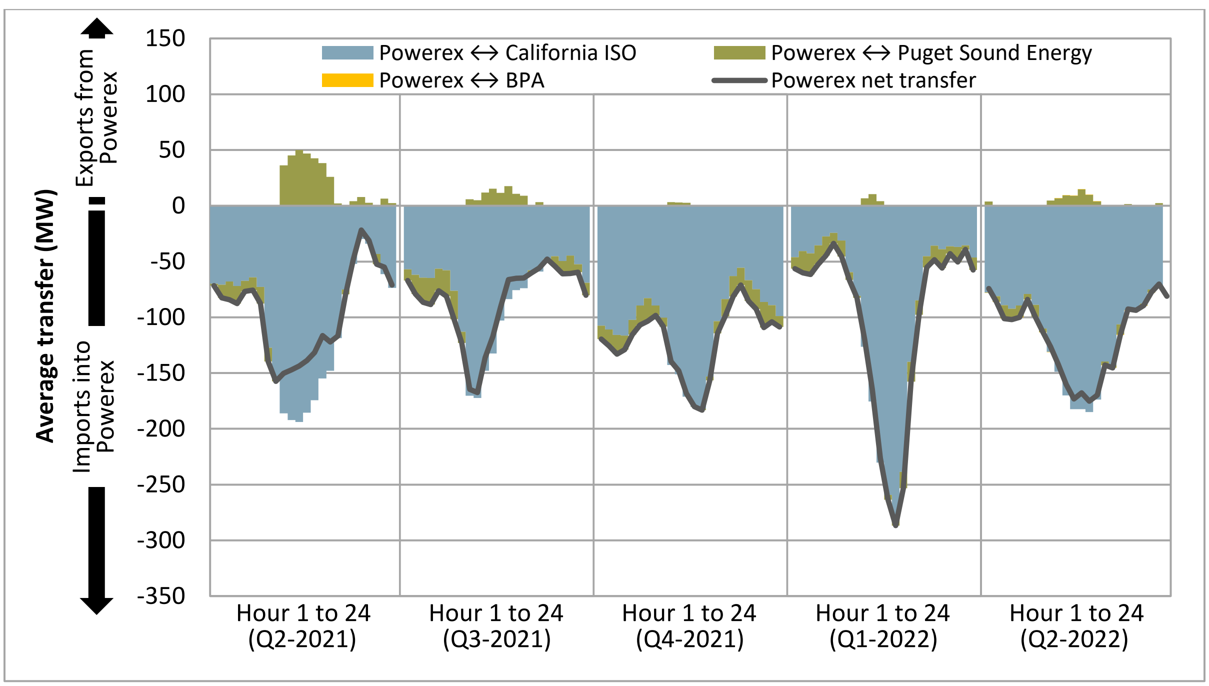
Appendix Figure A.46 Average hourly 15-minute market transfers



Appendix Figure A.47 Average hourly 5-minute price by component (Q2 2022)

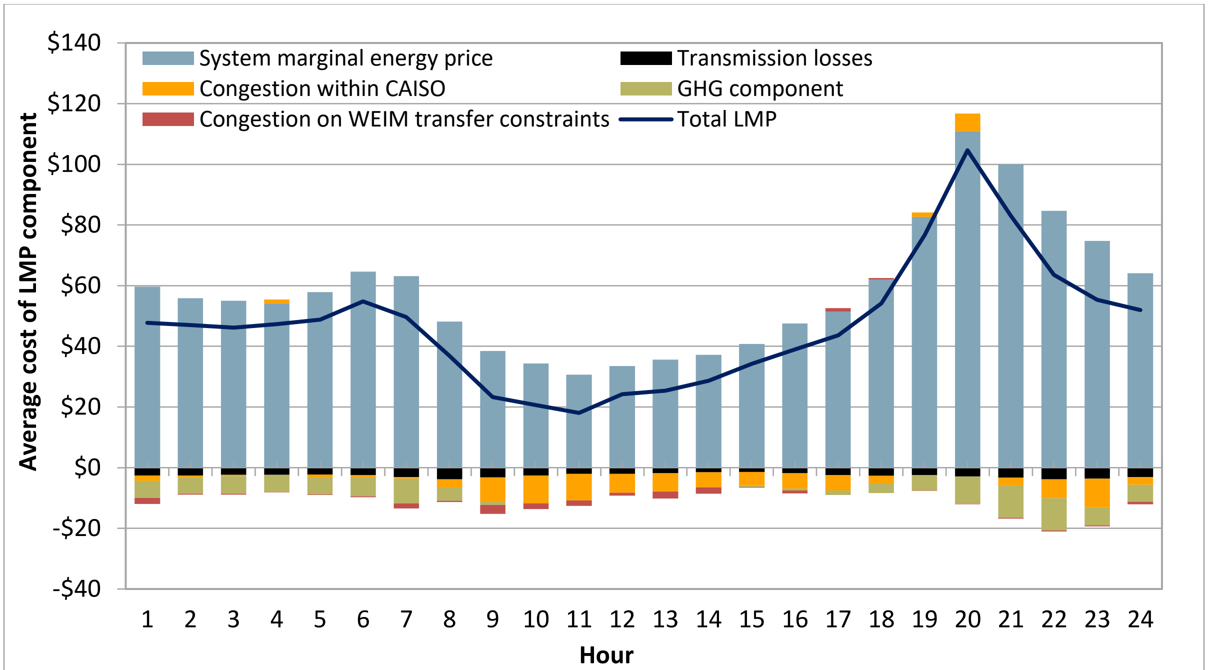


Appendix Figure A.48 Average hourly 5-minute market transfers

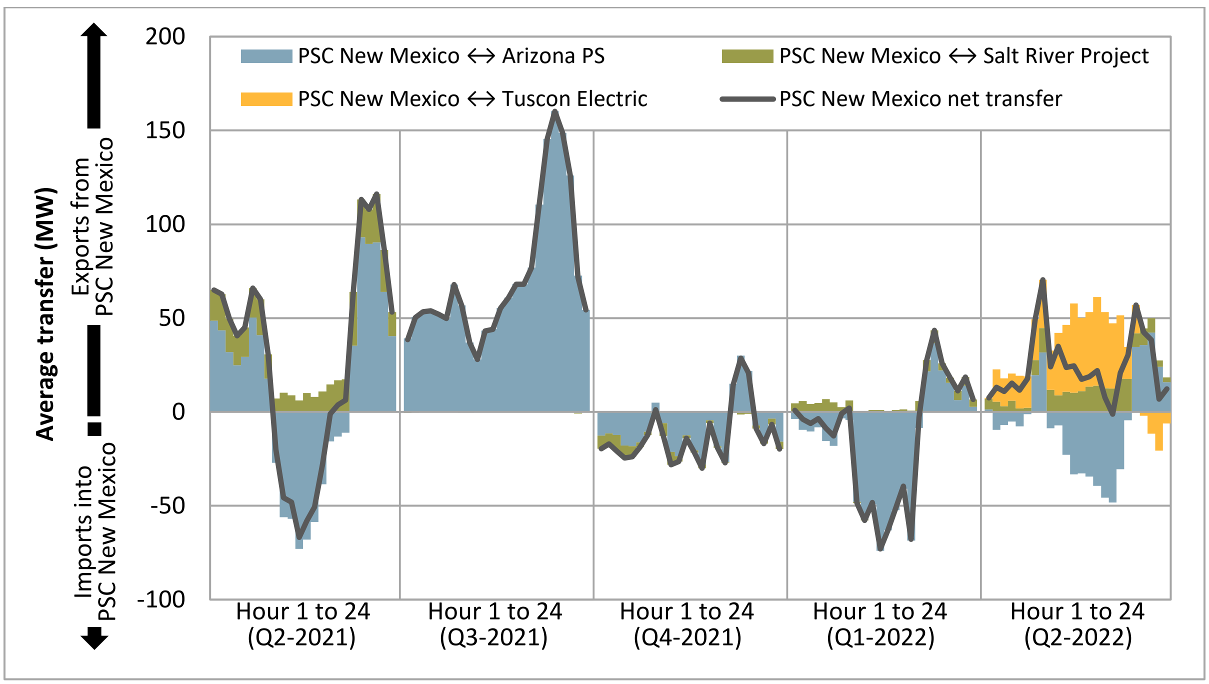


A.13 Public Service Company of New Mexico

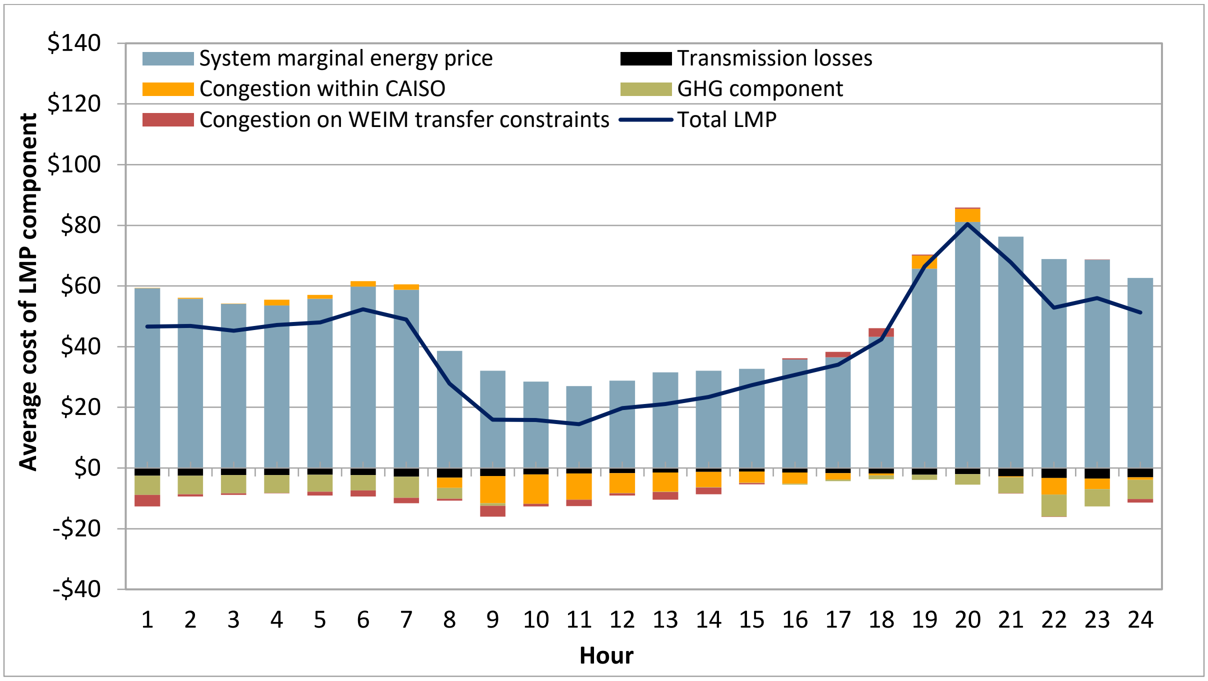
Appendix Figure A.49 Average hourly 15-minute price by component (Q2 2022)



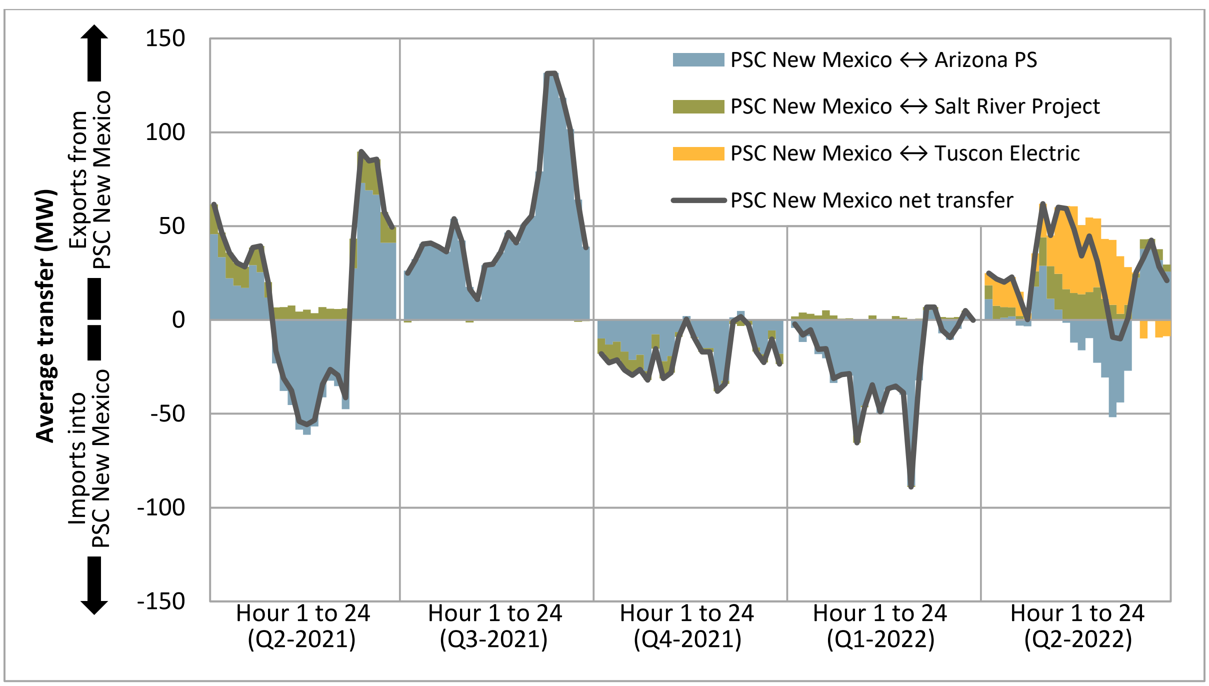
Appendix Figure A.50 Average hourly 15-minute market transfers



Appendix Figure A.51 Average hourly 5-minute price by component (Q2 2022)

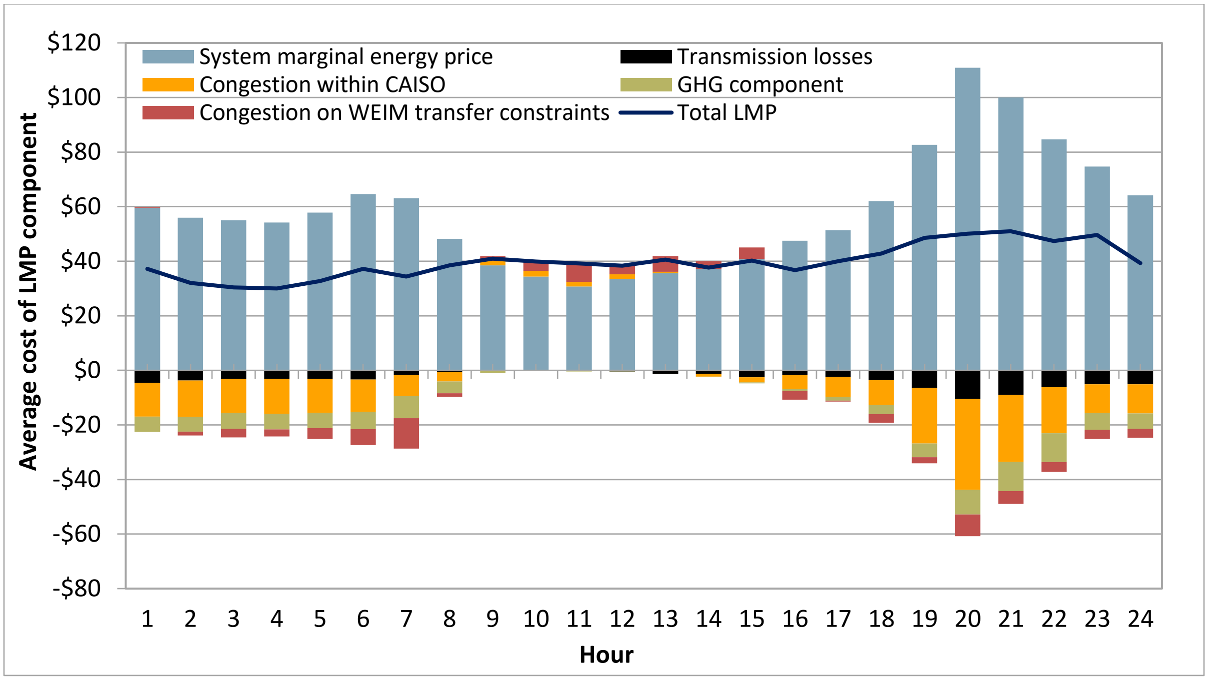


Appendix Figure A.52 Average hourly 5-minute market transfers

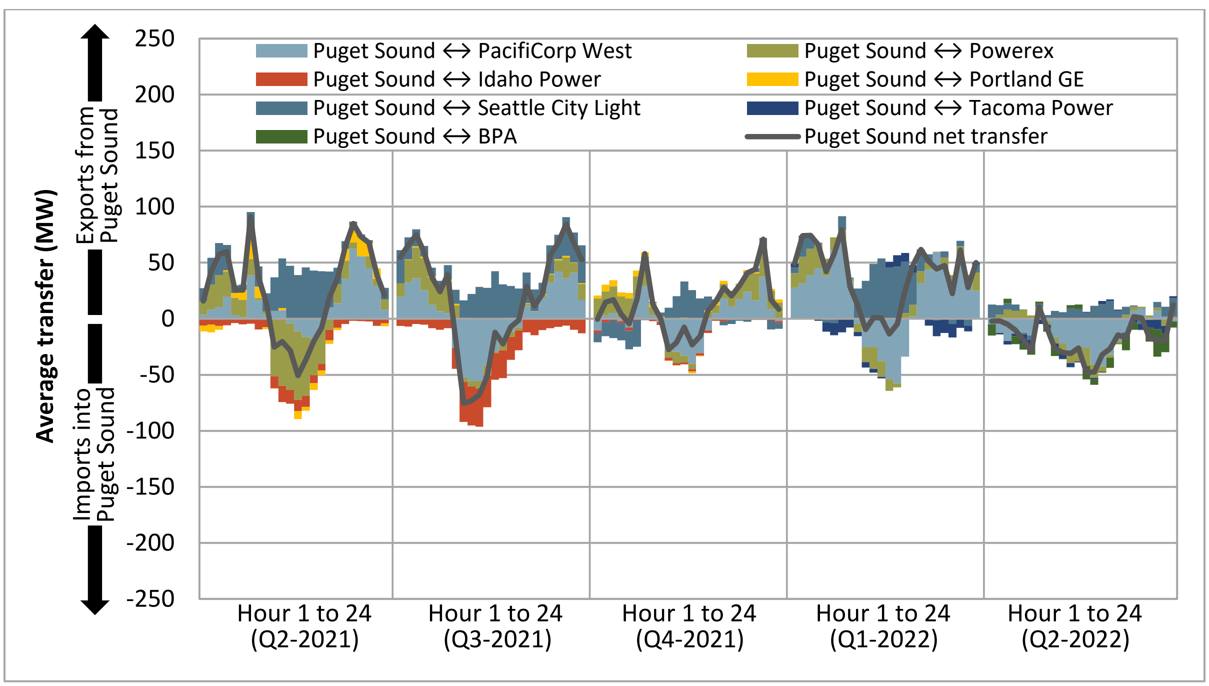


A.14 Puget Sound Energy

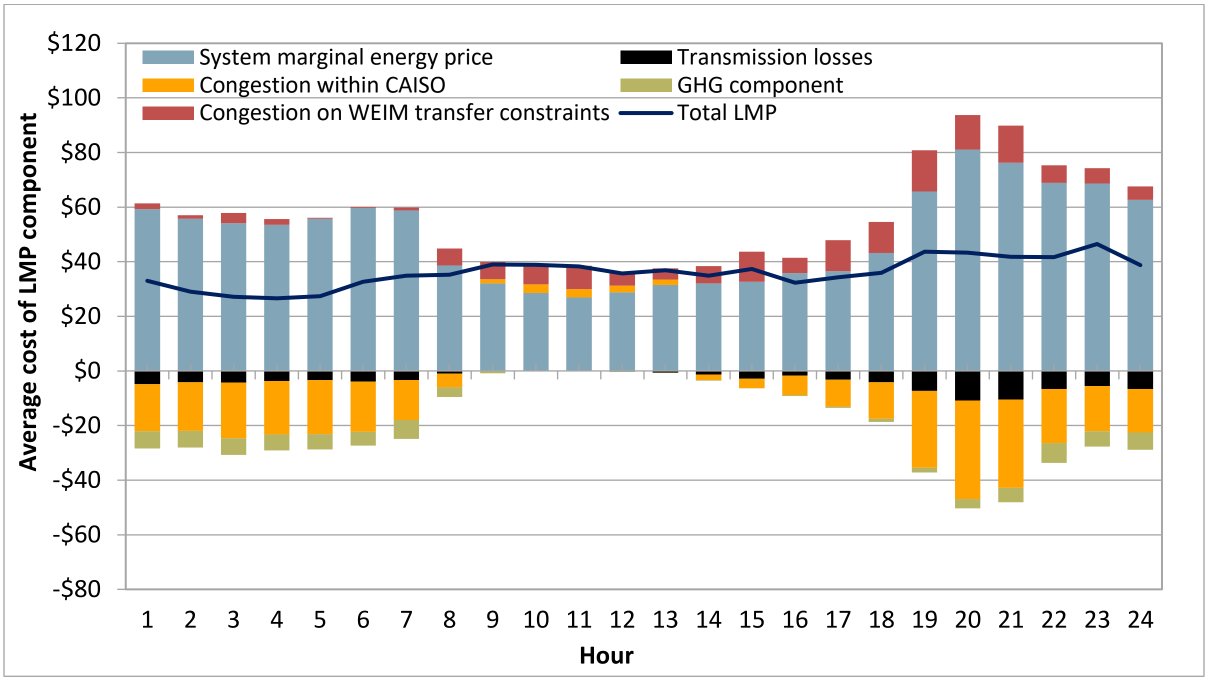
Appendix Figure A.53 Average hourly 15-minute price by component (Q2 2022)



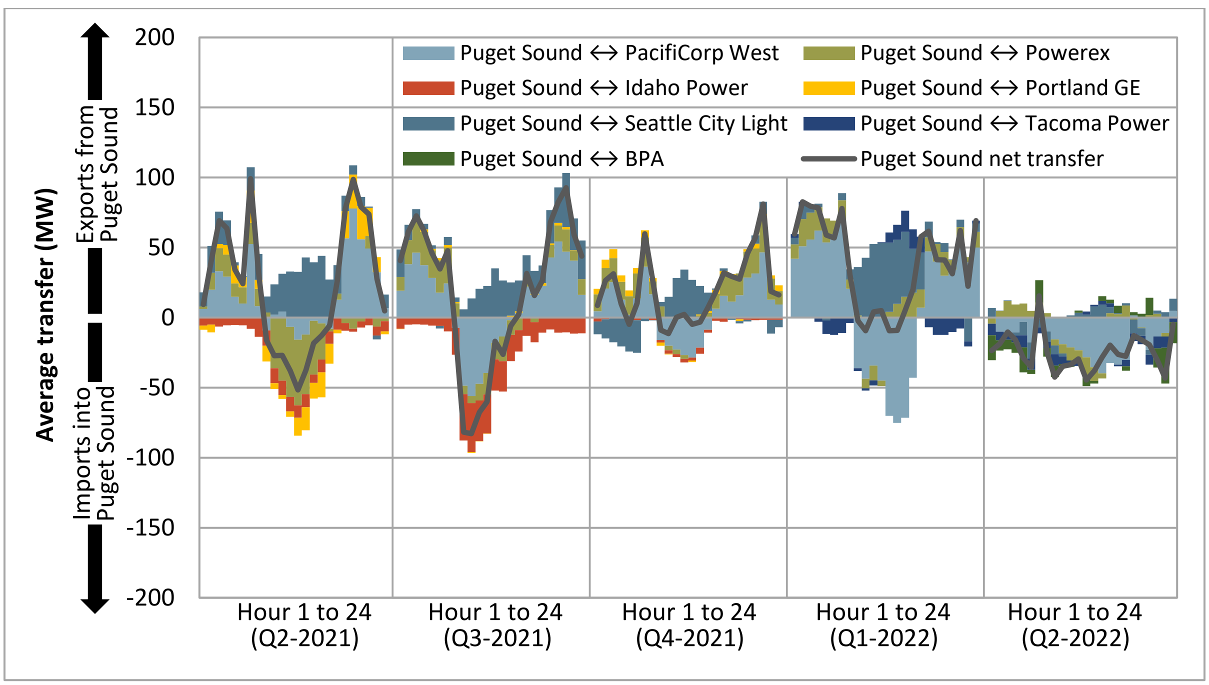
Appendix Figure A.54 Average hourly 15-minute market transfers



Appendix Figure A.55 Average hourly 5-minute price by component (Q2 2022)

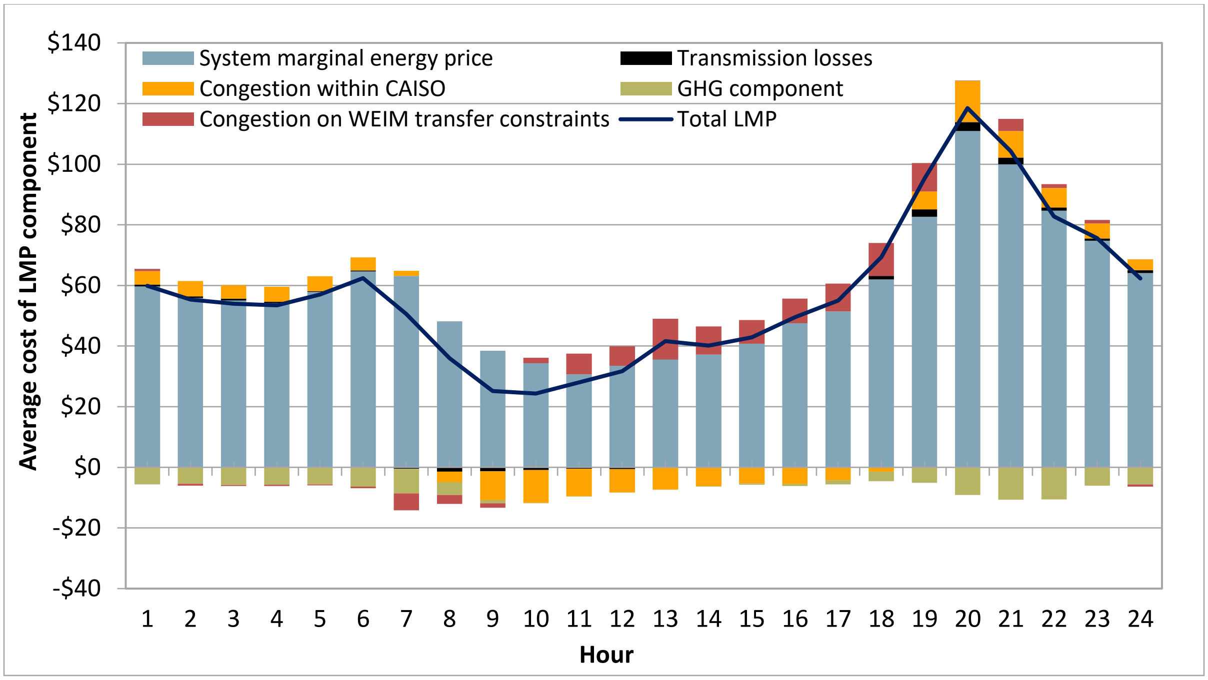


Appendix Figure A.56 Average hourly 5-minute market transfers

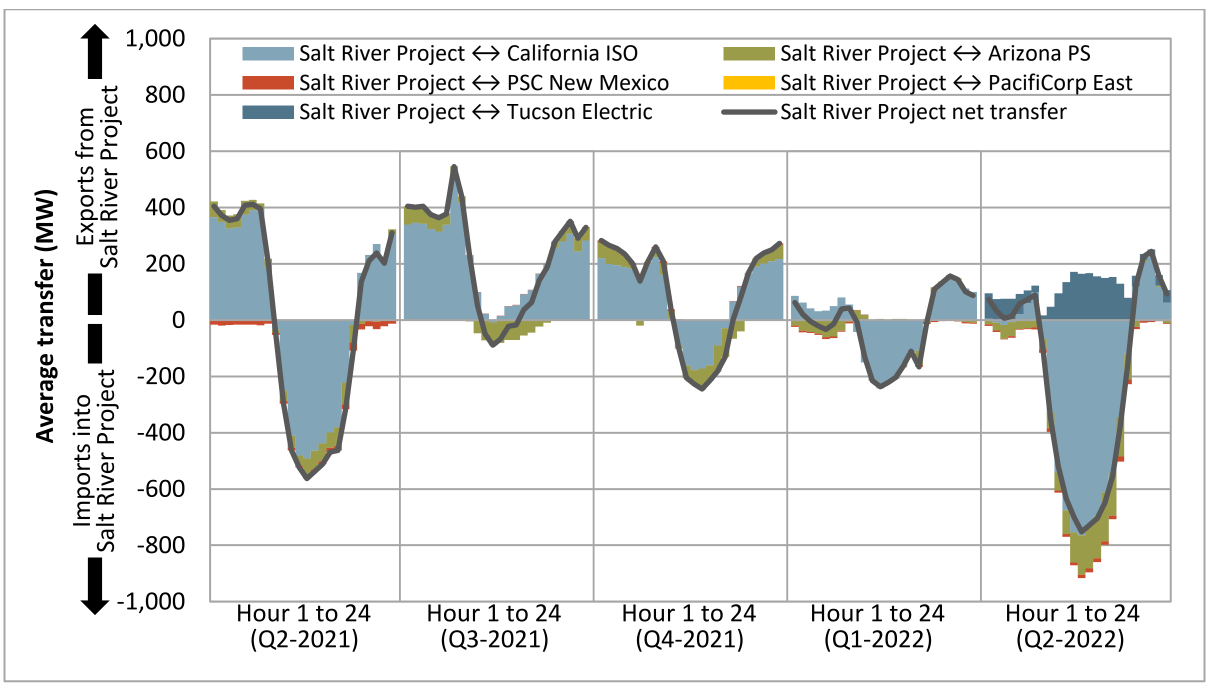


A.15 Salt River Project

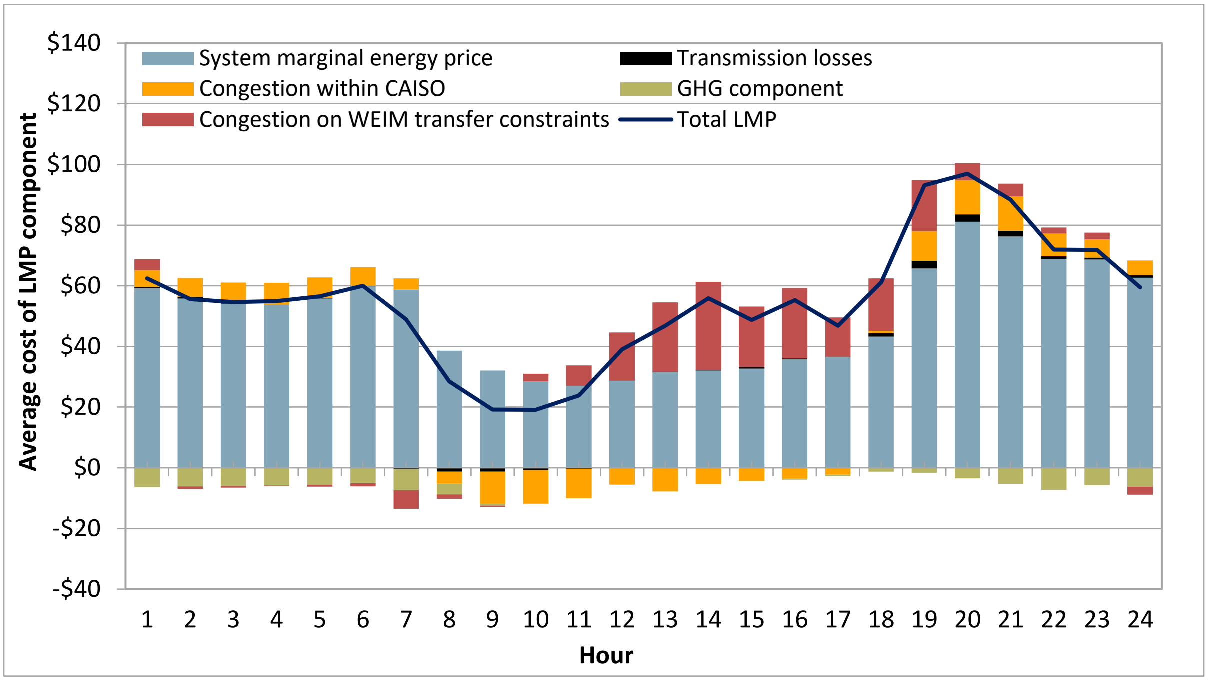
Appendix Figure A.57 Average hourly 15-minute price by component (Q2 2022)



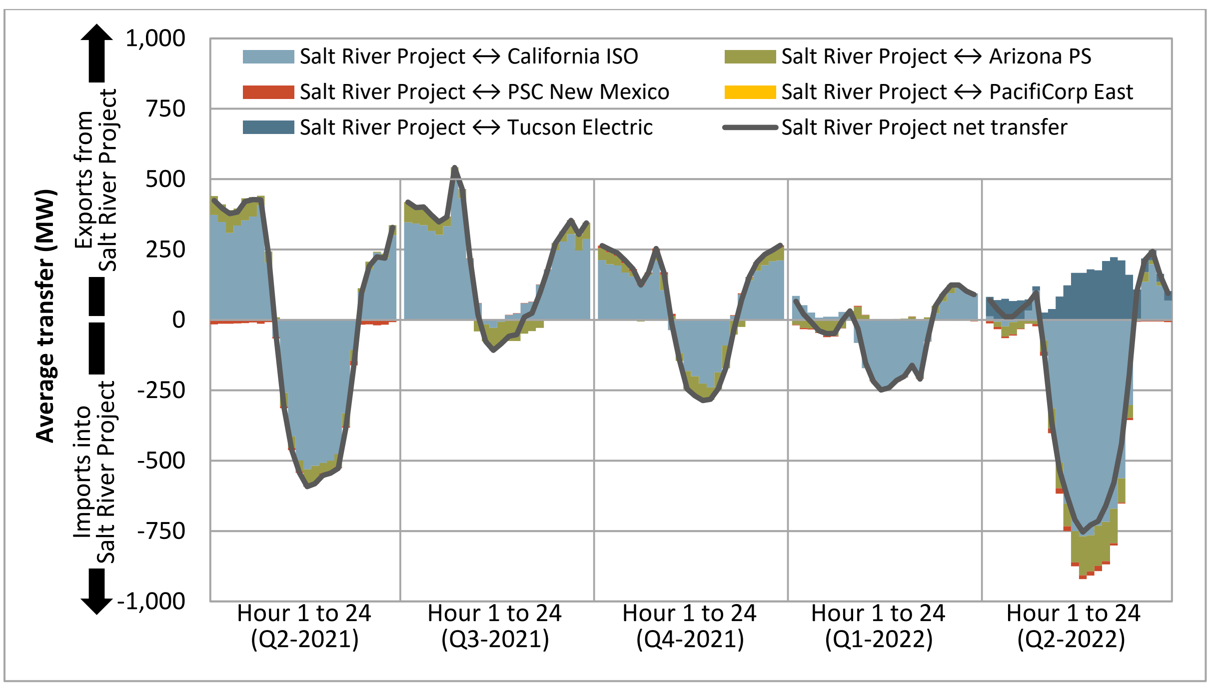
Appendix Figure A.58 Average hourly 15-minute market transfers



Appendix Figure A.59 Average hourly 5-minute price by component (Q2 2022)

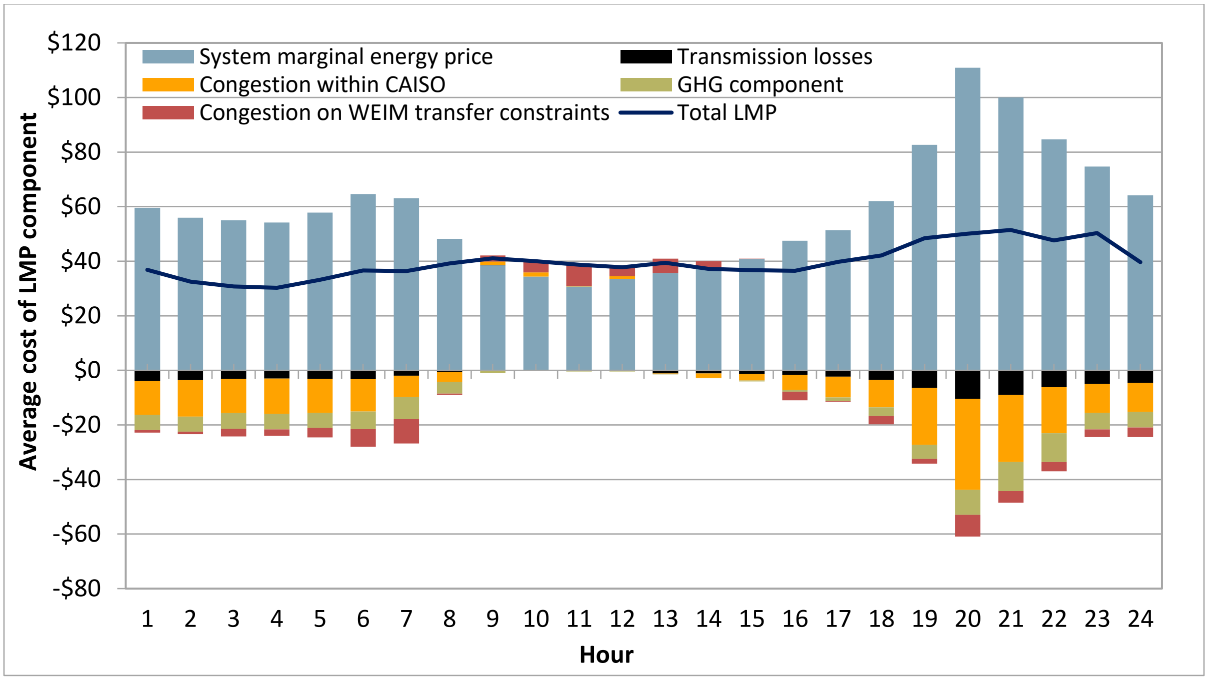


Appendix Figure A.60 Average hourly 5-minute market transfers

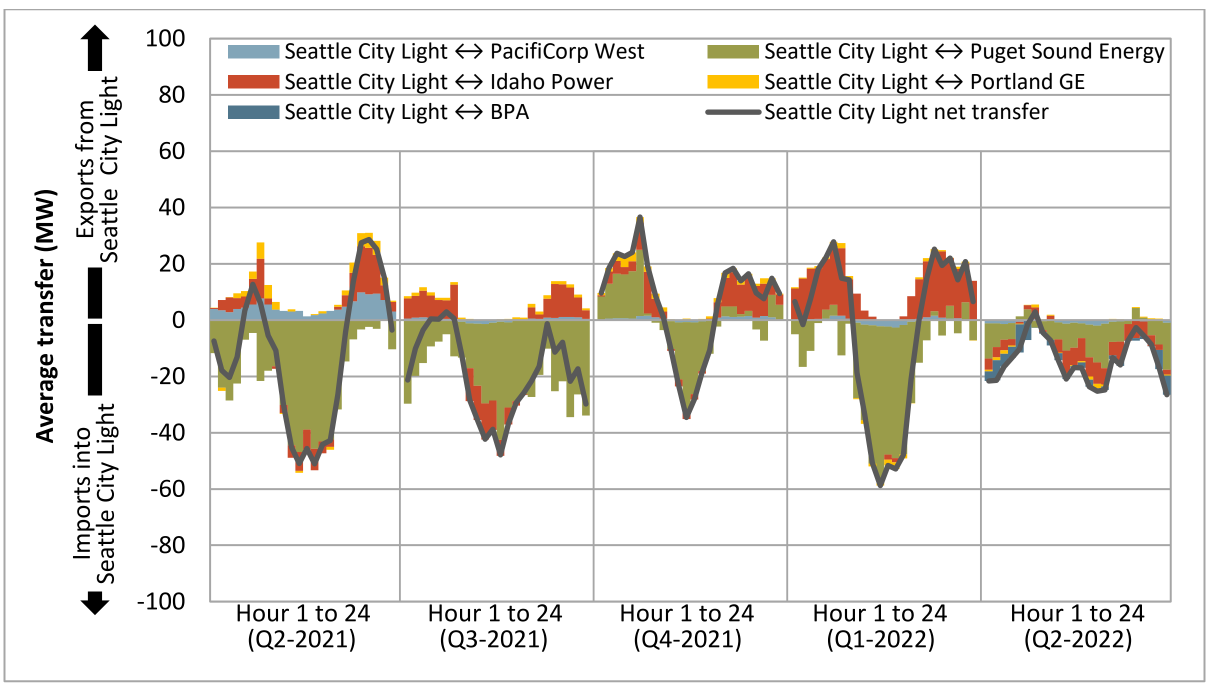


A.16 Seattle City Light

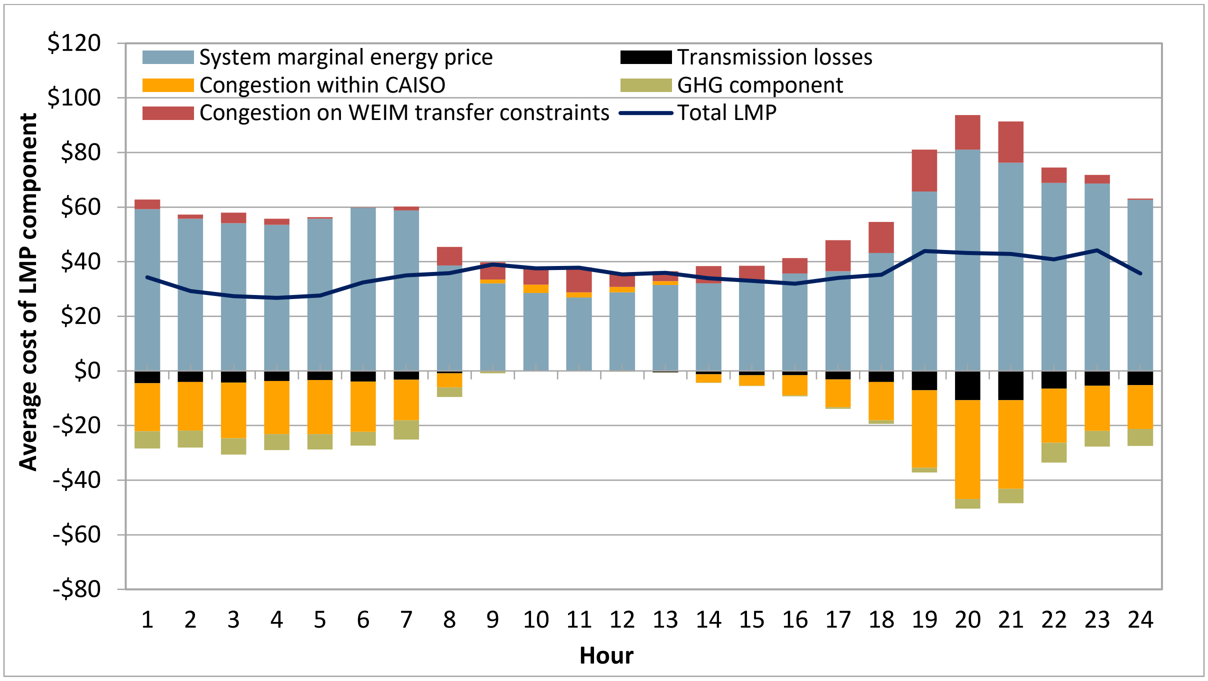
Appendix Figure A.61 Average hourly 15-minute price by component (Q2 2022)



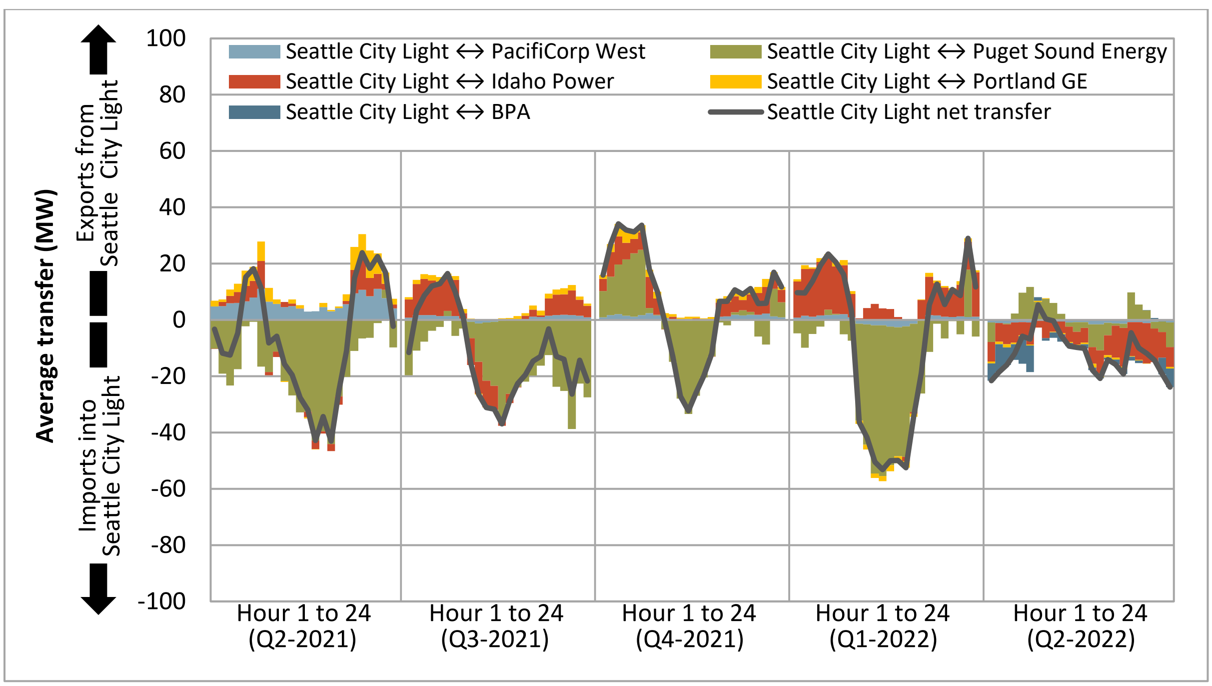
Appendix Figure A.62 Average hourly 15-minute market transfers



Appendix Figure A.63 Average hourly 5-minute price by component (Q2 2022)

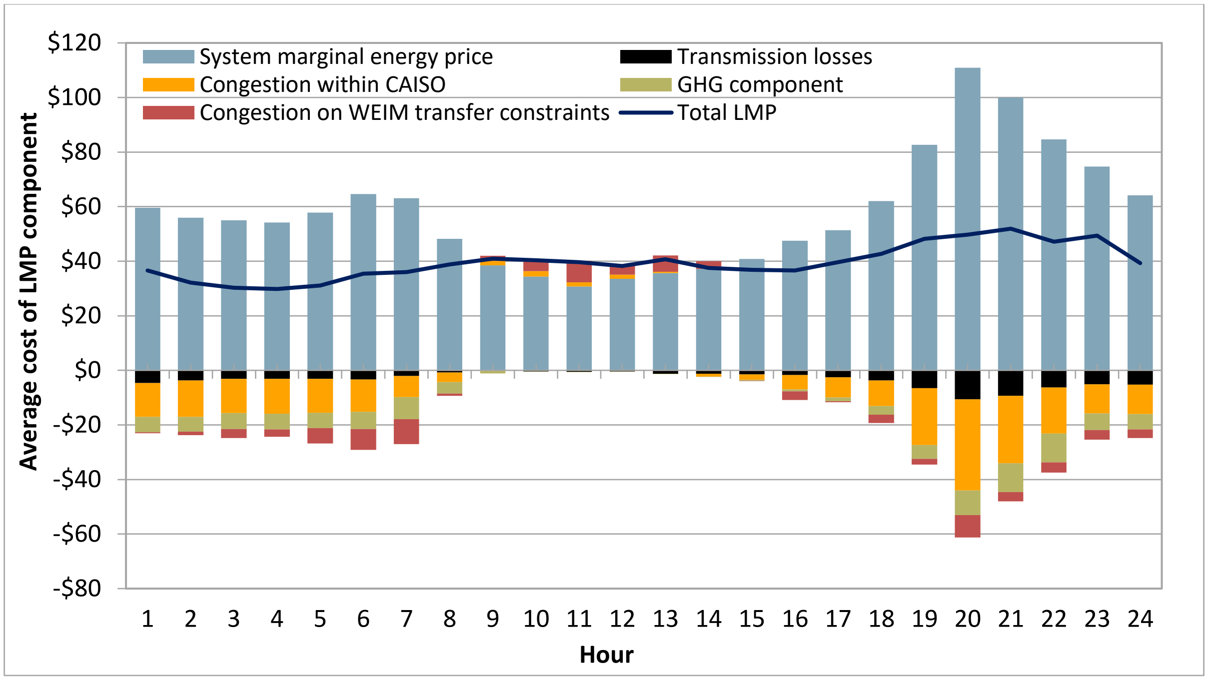


Appendix Figure A.64 Average hourly 5-minute market transfers

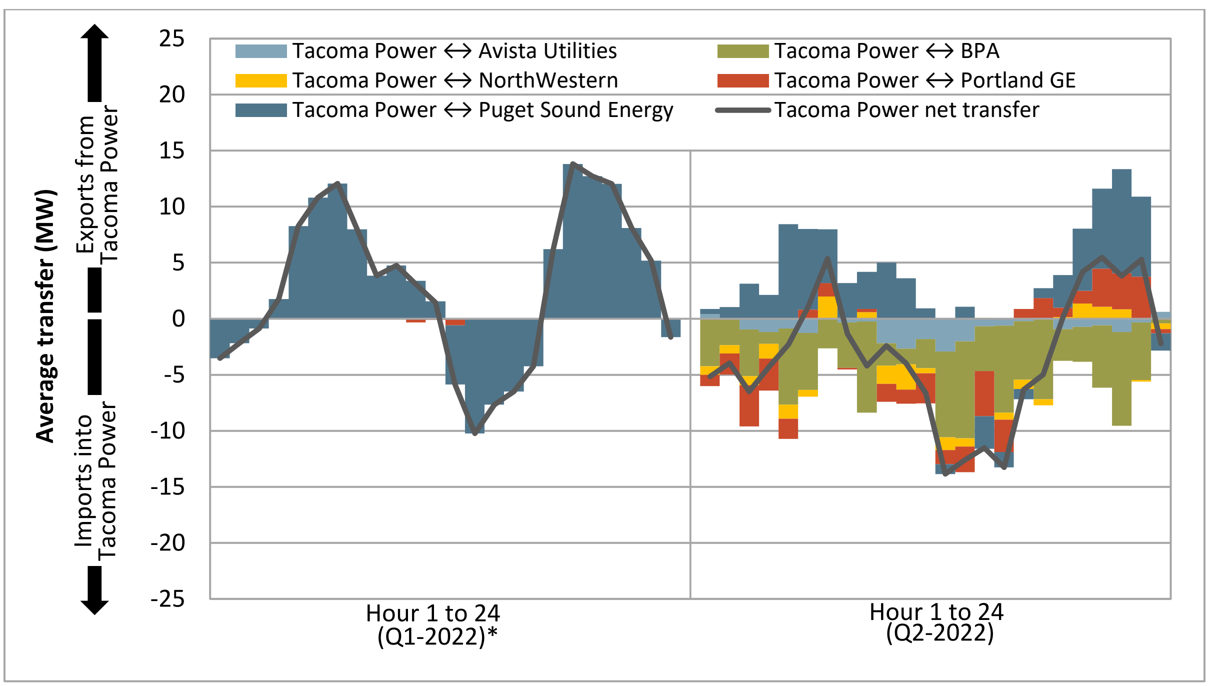


A.17 Tacoma Power

Appendix Figure A.65 Average hourly 15-minute price by component (Q2 2022)

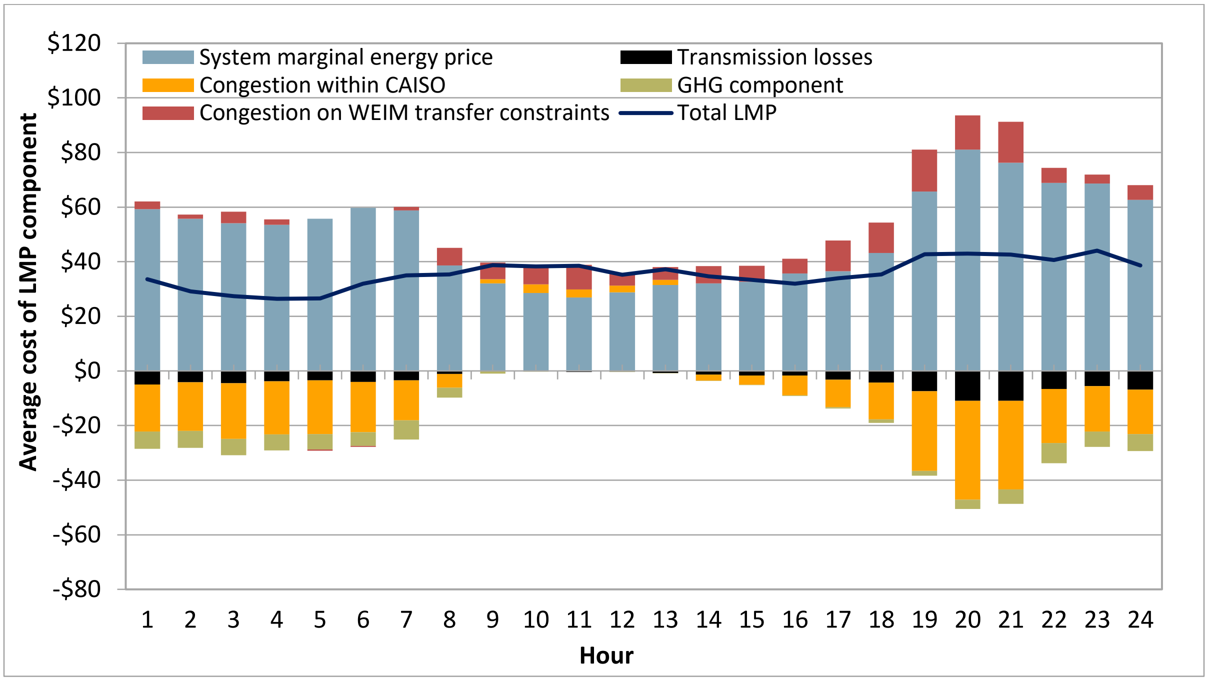


Appendix Figure A.66 Average hourly 15-minute market transfers

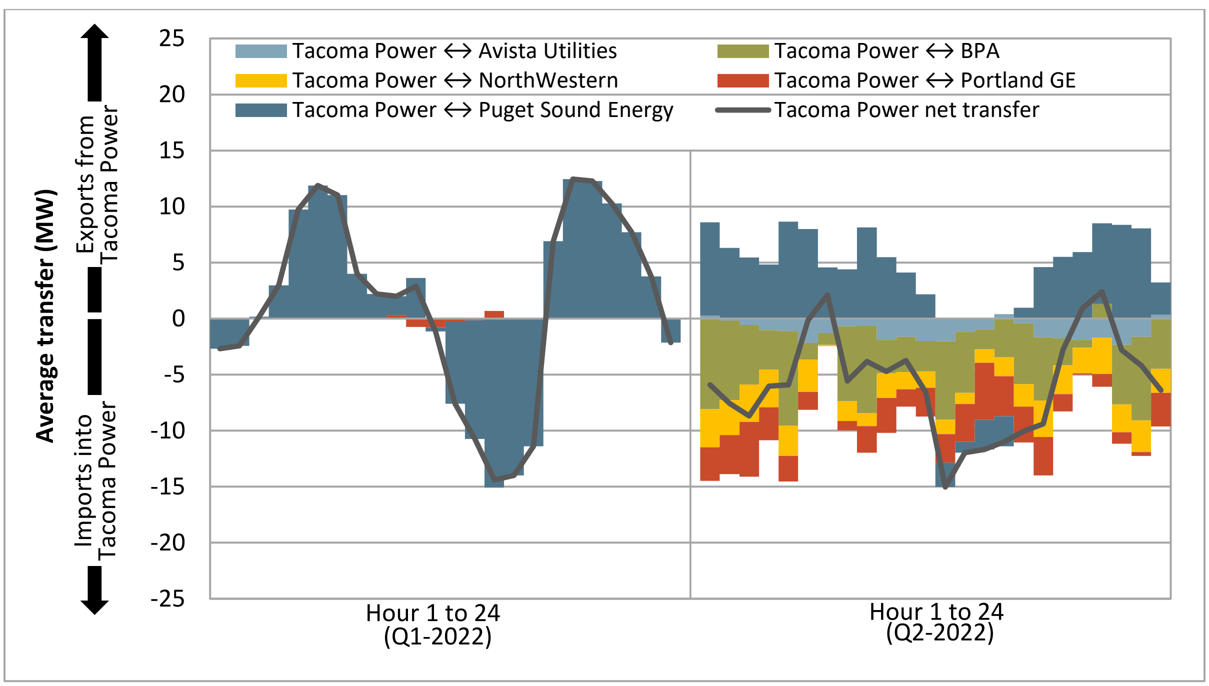


*Since joining the WEIM

Appendix Figure A.67 Average hourly 5-minute price by component (Q2 2022)



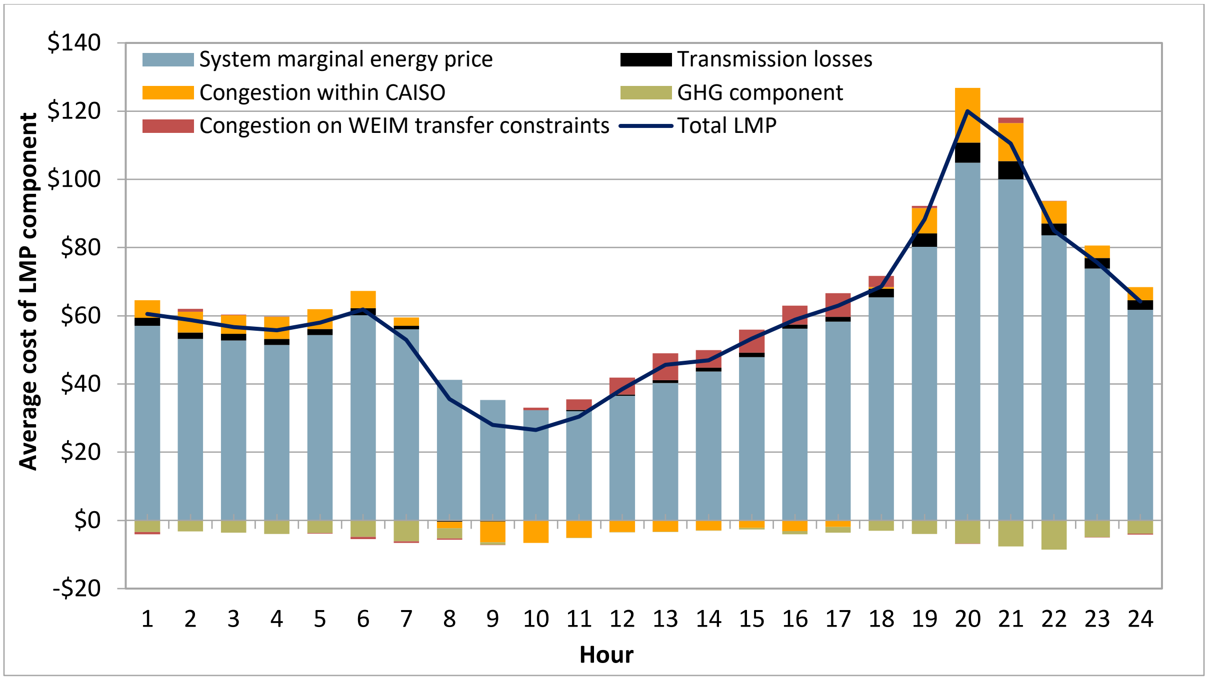
Appendix Figure A.68 Average hourly 5-minute market transfers



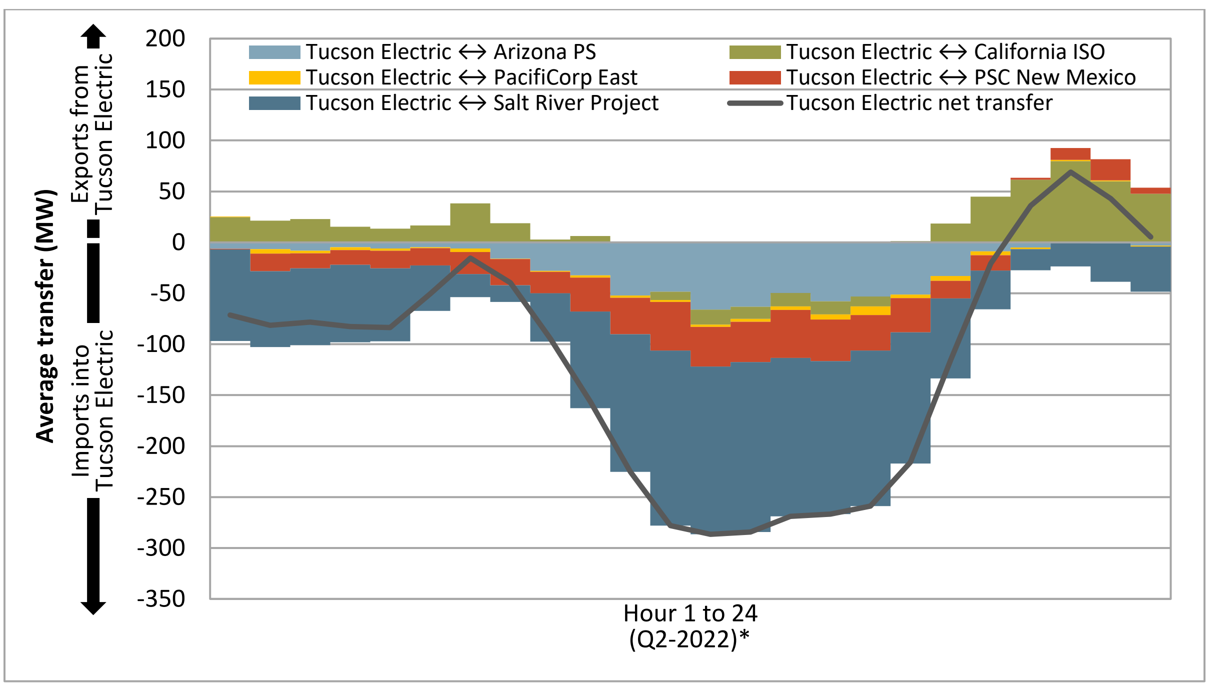
*Since joining the WEIM

A.18 Tucson Electric Power

Appendix Figure A.69 Average hourly 15-minute price by component (Q2 2022)

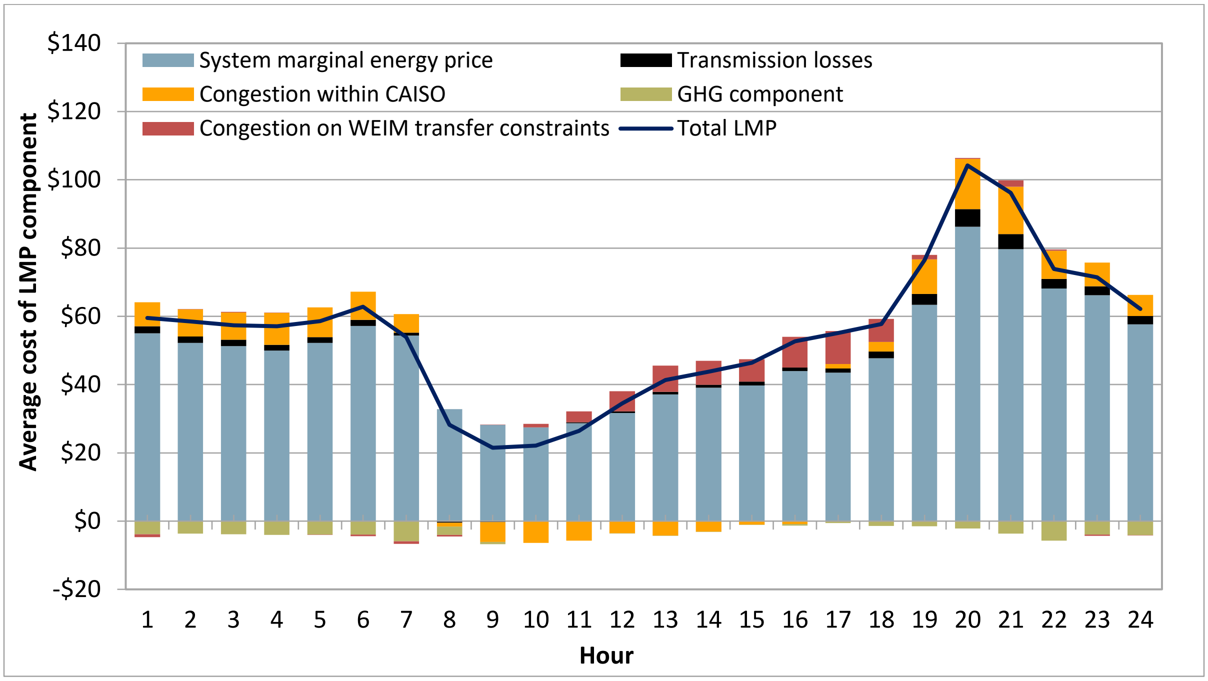


Appendix Figure A.70 Average hourly 15-minute market transfers

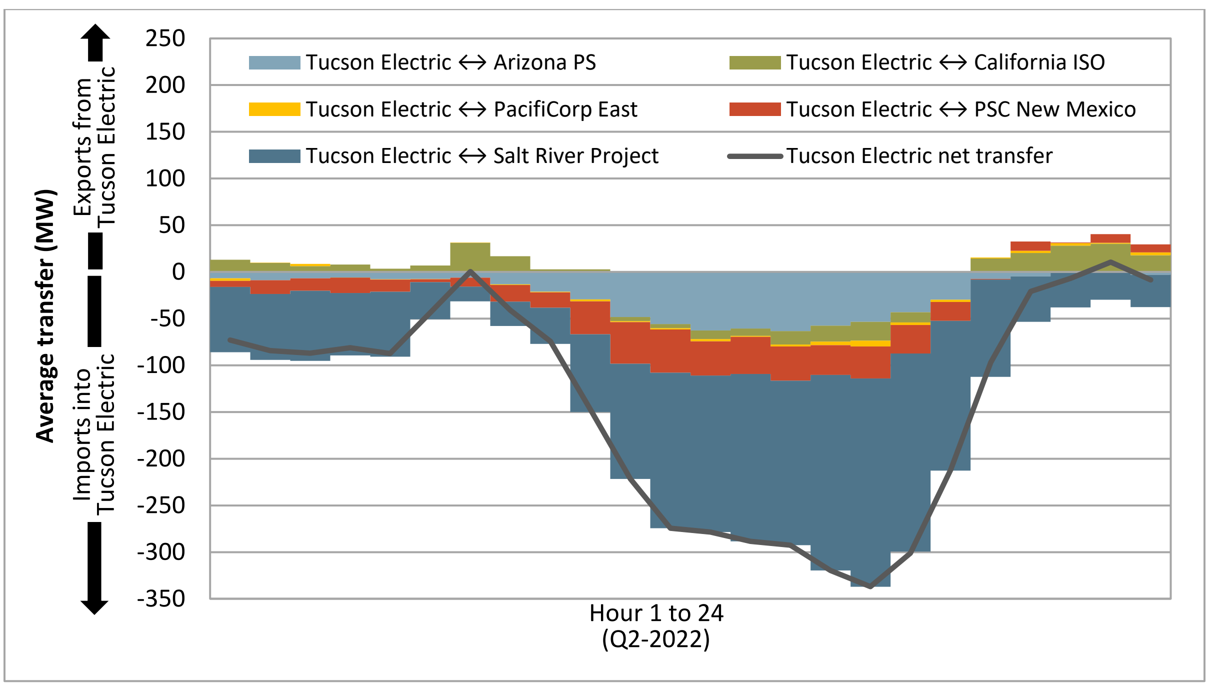


*Since joining the WEIM

Appendix Figure A.71 Average hourly 5-minute price by component (Q2 2022)



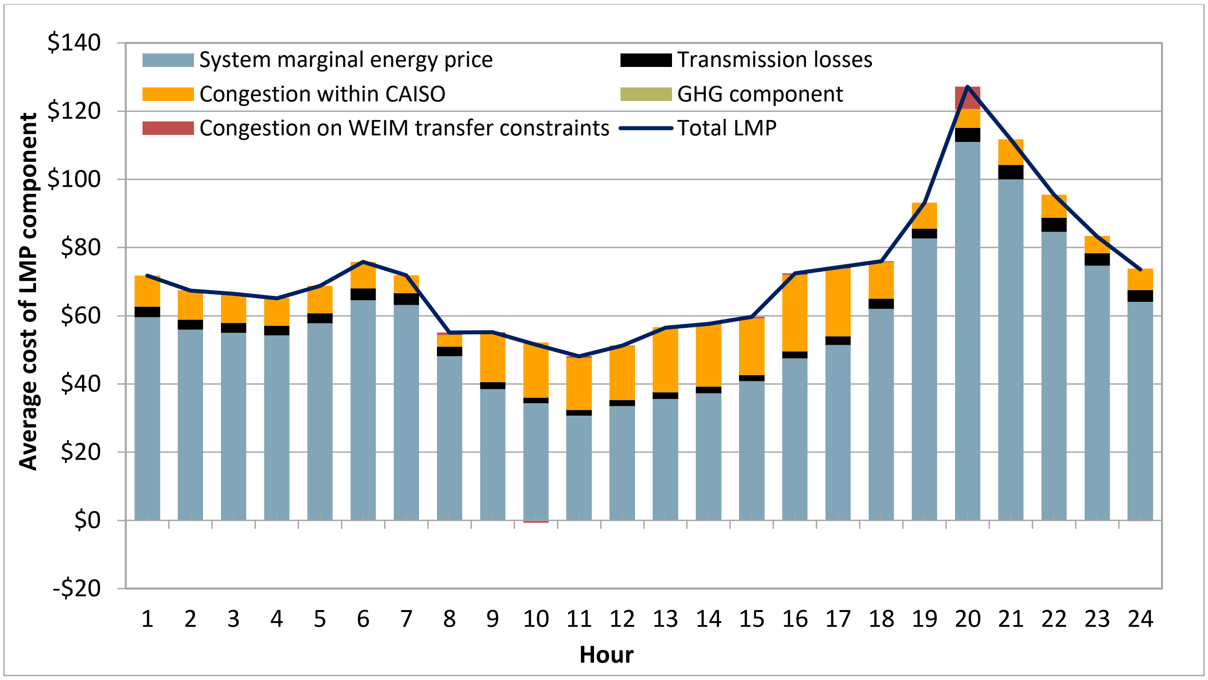
Appendix Figure A.72 Average hourly 5-minute market transfers



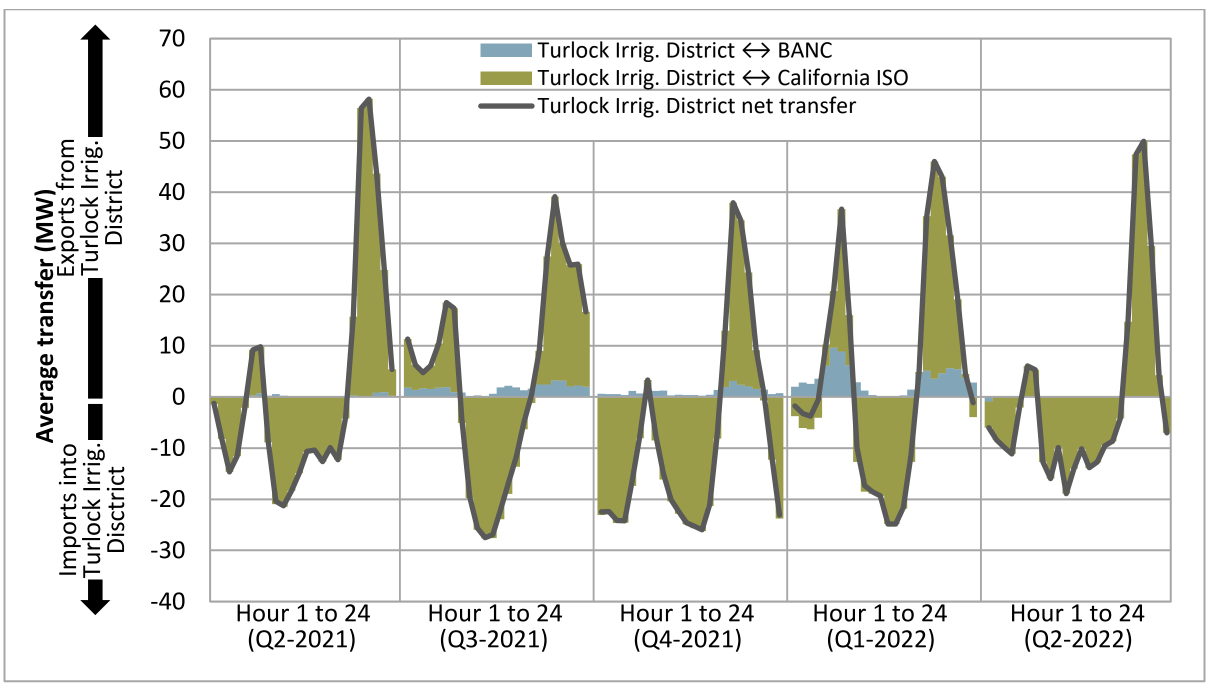
*Since joining the WEIM

A.19 Turlock Irrigation District

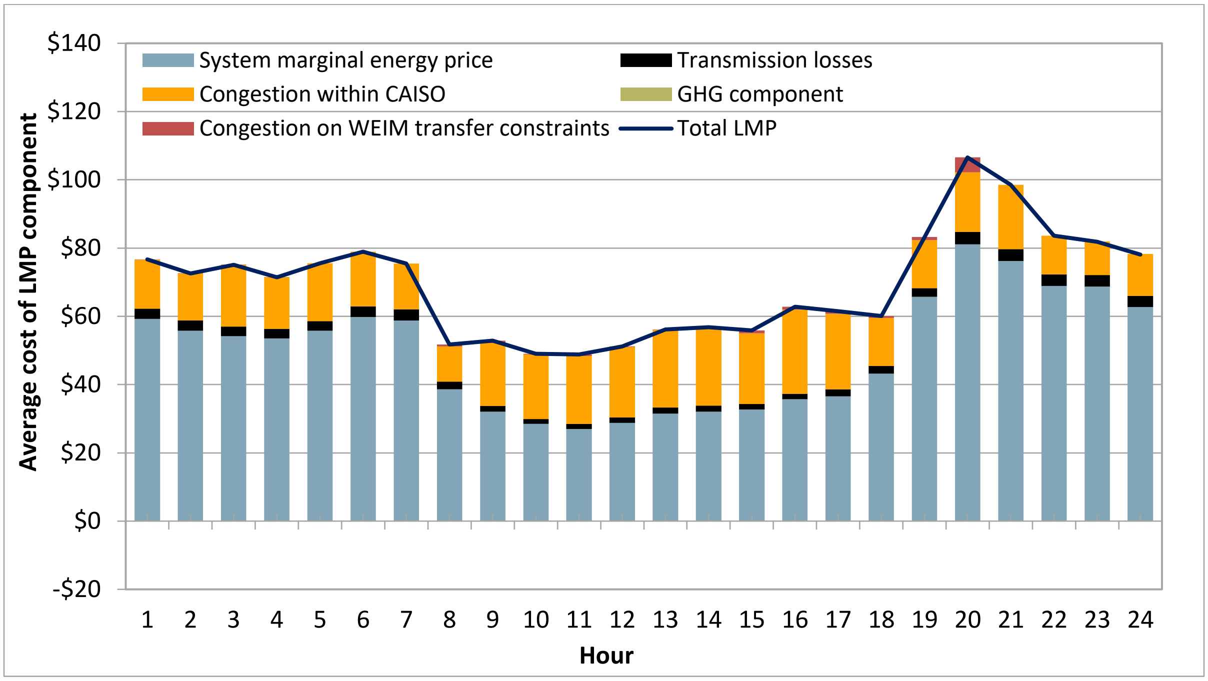
Appendix Figure A.73 Average hourly 15-minute price by component (Q2 2022)



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



Appendix Figure A.75 Average hourly 5-minute price by component (Q2 2022)



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