Q1 2022 Report on Market Issues and Performance

September 6, 2022

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California Independent System Operator

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Executive summary

This report covers market performance during the first quarter of 2022 (January - March).

Key highlights during this quarter include the following:

- **Market prices were higher** than the same quarter of 2021 on average. Day-ahead prices in the California ISO rose about 11 percent. Increases were due to higher natural gas prices.
- **Gas prices increased nationally and at SoCal Citygate and PG&E Citygate, excluding the extraordinarily high gas prices in February 2021.** This resulted in higher system marginal energy prices across the California ISO footprint and Western Energy Imbalance Market.
- **Renewable production increased** by 8.5 percent compared to the same quarter in 2021, due to an increase in solar and hydroelectric production.
- **Bilateral market prices in other balancing areas were often significantly lower than California ISO** market prices, due to both transmission constraints as well as greenhouse gas compliance costs.
- **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. The 15-minute market minimum area constraint was introduced in November 2020 and bound frequently for the California ISO but no other areas. The 5-minute minimum area constraint was introduced effective February 2022.
- **Congestion** in the day-ahead market was different from the same time last year, raising prices in PG&E and lowering prices in SCE and SDG&E areas. Total day-ahead congestion rent was $122 million, a decrease from $194 million in the same quarter of the previous year.
- **Imbalance conformance adjustments** averaged almost 1,400 MW during the morning load peak and almost 2,100 MW during the peak net load ramp hours, while maximum levels were 2,500 MW and 3,200 MW, respectively. 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 Average monthly system marginal energy prices (all hours)

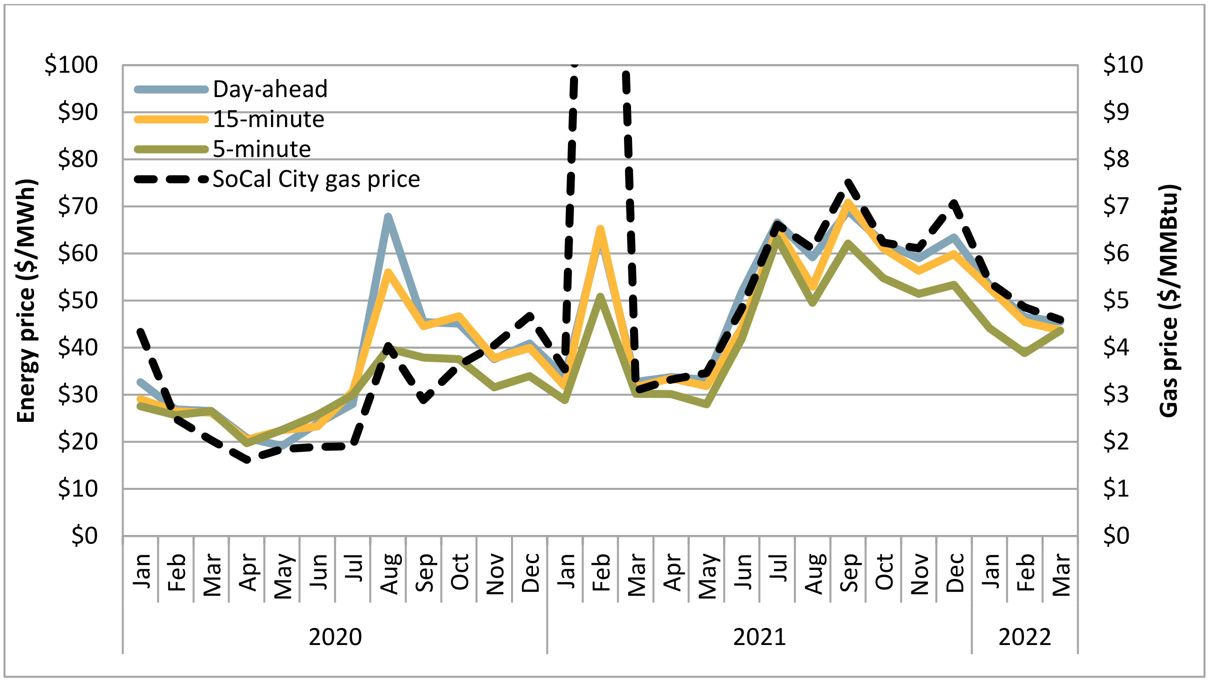
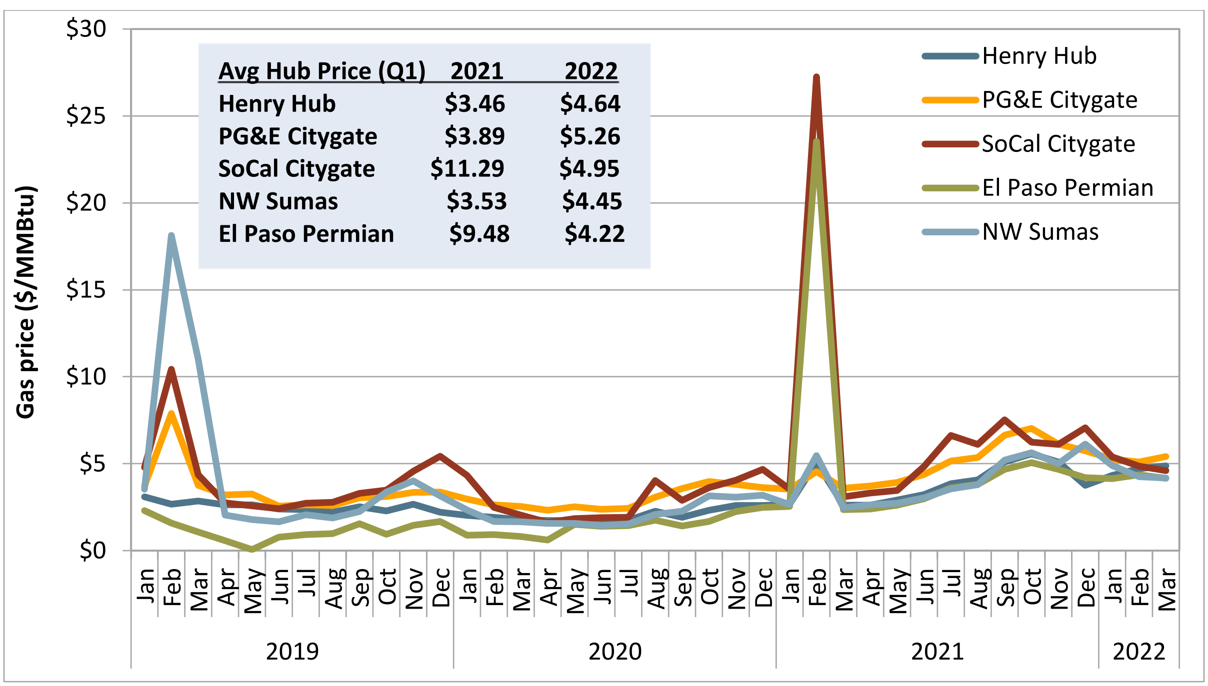


Figure E.2 Natural gas prices



Western Energy Imbalance Market

- **Natural gas prices rose in parts of the WEIM**, resulting in higher energy prices in some areas.
- **Prices in California areas were over $14/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. This region includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex.
- **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 exported just under 1,500 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.
- **Net load uncertainty was removed from the bid range capacity test** on February 15, 2022, while intertie uncertainty was removed on June 1, 2022. These adders are expected to be revisited as part of the next phase of the resource sufficiency evaluation enhancements stakeholder initiative.
- **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.

1 Market performance

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

- **Electricity prices were about 12 percent higher** than the same quarter of 2021 due to higher average natural gas prices. Day-ahead prices averaged $48/MWh, 15-minute prices averaged $47/MWh, and 5-minute prices averaged $42/MWh.
- **Gas prices increased nationally and at SoCal Citygate and PG&E Citygate, excluding the extraordinarily high gas prices in February 2021**. This resulted in higher system marginal energy prices across the California ISO footprint.
- **Renewable production increased** by 8.5 percent compared to the same quarter in 2021, due to an increase in solar and hydroelectric production. Wind and solar downward dispatch and curtailments increased by 42 percent in the California ISO balancing area, and quadrupled in the Western Energy Imbalance Market (WEIM).
- **Total generation on outage in the California ISO increased** 16 percent over the same quarter of 2021, driven by forced outages, primarily of natural gas resources.
- **Bilateral market prices in other balancing areas were often significantly lower than California ISO** market prices, due to both transmission constraints as well as greenhouse gas compliance costs. Average net imports increased, although net interchange decreased.
- **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. The 15-minute market minimum area constraint was introduced in November 2020 and bound frequently for the California ISO but no other areas. The 5-minute minimum area constraint was introduced effective February 2022.
- **Congestion** in the day-ahead market was different from the same time last year, raising prices in PG&E and lowering prices in SCE and SDG&E areas. Total day-ahead congestion rent was $122 million, a decrease from $194 million in the same quarter of the previous year.
- **Imbalance conformance adjustments** averaged 1,400 MW during the morning load peak and almost 2,100 MW during the peak net load ramp hours, while maximum levels were 2,500 MW and 3,200 MW, respectively. 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.

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 first quarter of 2022, average gas prices at the SoCal Citygate and El Paso Permian hubs declined significantly when compared to the same quarter of 2021. If we exclude the days with significant gas price volatility during mid-February 2021, then the average gas price at SoCal Citygate was higher during this quarter relative to the first quarter of 2021. For the same time period, prices at Henry Hub, PG&E Citygate, and Northwest Sumas gas hubs rose by 34 percent, 35 percent, and 26 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 first quarter, prices at the SoCal Citygate gas hub averaged $4.95/MMBtu compared to $11.29/MMBtu (down 56 percent) in the same 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] For the summer period, June 1 through September 30, SoCalGas temporarily reduced the number of non-compliance stages from 8 to 5. The non-compliance charge was reduced from $25/Dth and capped at $5/Dth for Stage 4 and Stage 5 flow orders.

For the winter period, October 1 through May 31, SoCalGas expanded the number of non-compliance stages from 5 to 8. The non-compliance charge for Stage 3 flow orders follows a tiered structure ranging from $5/Dth to $20/Dth; Stage 4 and Stage 5 were set at $25/Dth.

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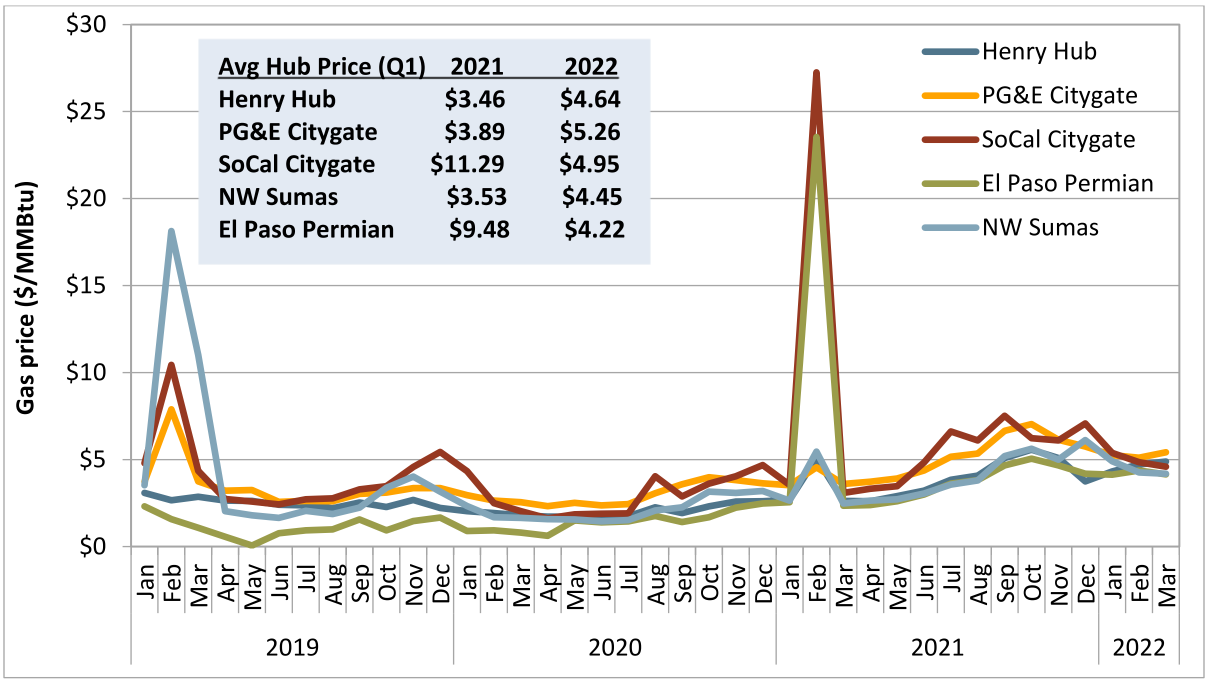
1 CPUC Docket No. I.17-02-002, *Decision Setting the Interim Range of Aliso Canyon Storage Capacity at Zero to 41.16 Bcf (D21-11-008)*, November 4, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

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, p.31-32 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF

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] Prior to a final decision being reached on this new ruling, the CPUC temporarily extended the 8-stage winter OFO structure for six months, commencing on November 1, 2021.[4] On March 18, 2022, a proposed decision was issued to extend SoCalGas' 8-stage winter OFO penalty structure year-round and make it applicable to the PG&E service territory.[5]

Figure 1.1 Monthly average natural gas prices



1.1.2 Renewable generation

In the first quarter, the combined average monthly generation from renewable resources increased by about 675 MW (8.5 percent) compared to the same quarter of 2021. Generation from hydroelectric, solar, and geothermal resources increased while biogas-biomass generation decreased, compared to the

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

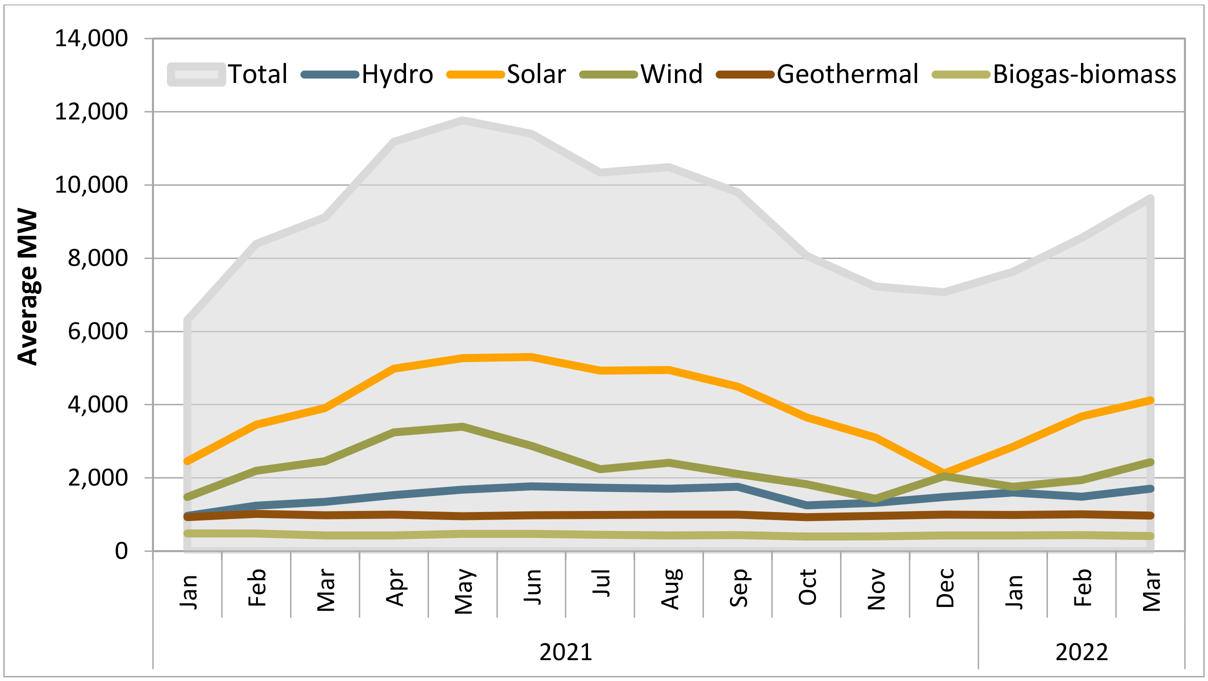
4 Proposed Decision for CPUC Docket No. R.20-01-007, *Decision Ordering Southern California Gas Company and San Diego Gas & Electric Company to Implement Rule 30 Operational Flow Order Non-Compliance Charge Structure for the Six Months Commencing November 1, 2021*, October 29, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M423/K447/423447100.PDF

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

first quarter of 2021.[6] The availability of variable energy resources contributes to price patterns, both seasonally and hourly, due to their low marginal cost relative to other resources.

Figure 1.2 shows the average monthly renewable generation by fuel type.[7] The largest increase in generation was from hydroelectric resources, which increased about 400 MW (35 percent) compared to the same quarter of 2021. Solar generation increased by 275 MW (8.5 percent), while wind generation was unchanged.

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 in the first quarter by 42 percent in the California ISO balancing area, and quadrupled in the Western Energy Imbalance Market (WEIM), relative to the first quarter of 2021. The sharp rise in downward dispatch in the WEIM was due to congestion on the Wyoming Export constraint, which heavily impacted resources in PacifiCorp East area. 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

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

7 Hydroelectric generation greater than 30 MW is included.

low-priced bids from these renewable resources. If the supply of bids to decrease energy is exhausted in the real-time market, the software will curtail self-scheduled generation, including wind and solar.

Figure 1.3 shows curtailment of wind and solar by month in the California ISO balancing area.[8] DMM developed curtailment categories based on: (1) whether the resource bid in economically or self-scheduled, (2) whether the resource received an out-of-market instruction, and (3) the relationship between the resource's bid and the resulting market price. The six categories are:

- **economic downward dispatch**, in which a resource is dispatched down and the market price falls within one dollar of or below a resource's economic bid, or the resource's upper limit is binding; [9]
- **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;[10]
- **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 (98 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 March and totaled 805 GWh for the quarter. This represents a 43 percent increase relative to the same quarter of 2021. Self-schedule curtailment totaled 8.5 GWh for the quarter, a 6 percent decrease relative to the first quarter of 2021.

Figure 1.4 shows the downward dispatch of WEIM wind and solar resources. 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. Downward dispatch in the WEIM was relatively stable over the quarter. Much of the curtailment in the WEIM was due to the high frequency of congestion on the Wyoming Export constraint, which led to resources in the PacifiCorp East area being heavily curtailed.[11] The increase in self-scheduled curtailment in March 2022 was due in part to lower load and high renewable generation.

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

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

10 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.

11 The Total_Wyoming_Export constraint was congested during 61.5 percent of intervals during the quarter as shown in Table 1.5. The overall effects of transfer congestion are discussed in detail in Section 1.8.3.

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

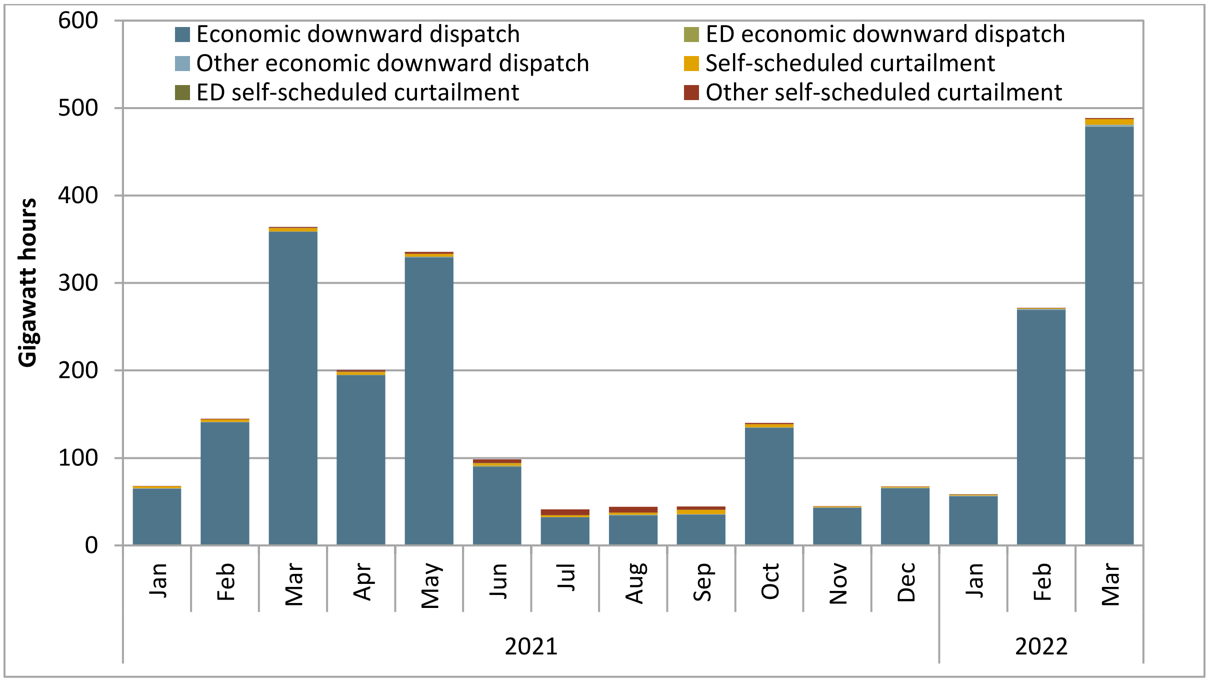
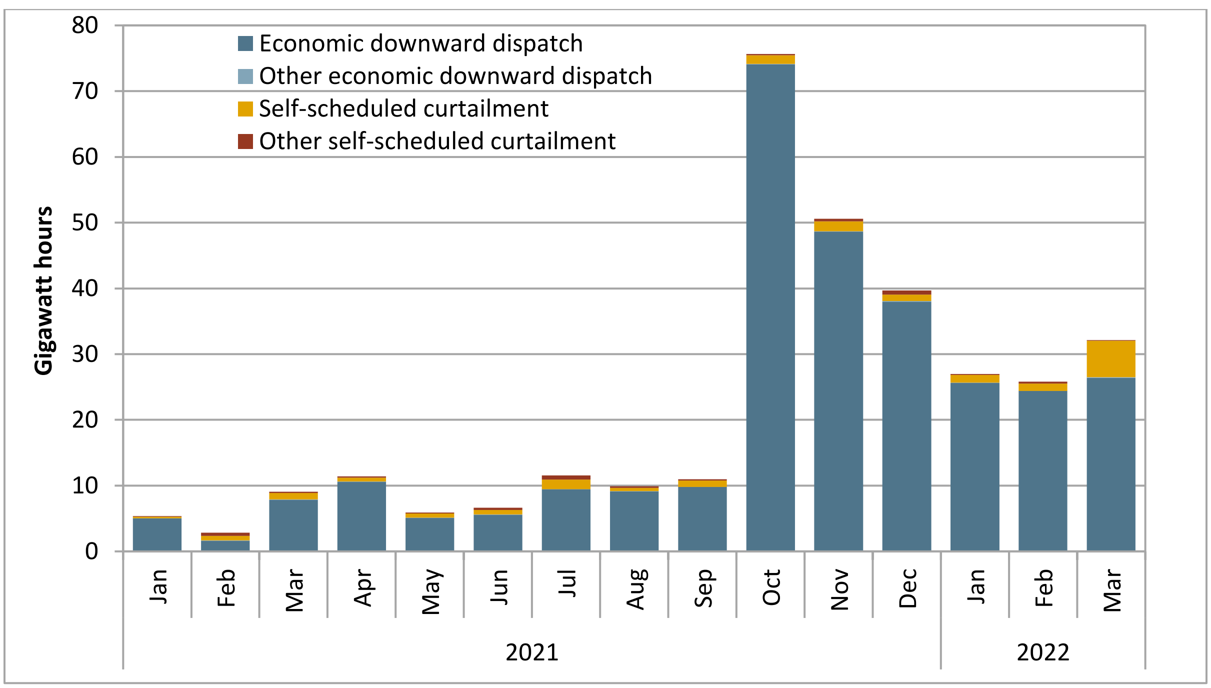


Figure 1.4 Reduction of wind and solar generation by month (WEIM)



1.1.4 Generation by fuel type

In the first quarter, natural gas generation decreased, while hydro and nuclear generation increased. Average hourly generation by natural gas resources fell by 15 percent compared to the same quarter of 2021, while hydroelectric and nuclear generation increased 35 percent and 38 percent, respectively.[12] Average hourly generation by batteries tripled relative to the first quarter of 2021.

Figure 1.5 shows the average hourly generation by fuel type during the first quarter of 2022. Total hourly average generation peaked at about 26,500 MW during hour ending 19. During this hour, battery generation was about 900 MW, about nine times more than the same time last year. Non-hydroelectric renewable generation, including geothermal, biogas-biomass, wind, and solar resources, contributed 19 percent of total generation during the peak net load hours of 17-21.

Figure 1.5 Average hourly generation by fuel type (Q1 2022)

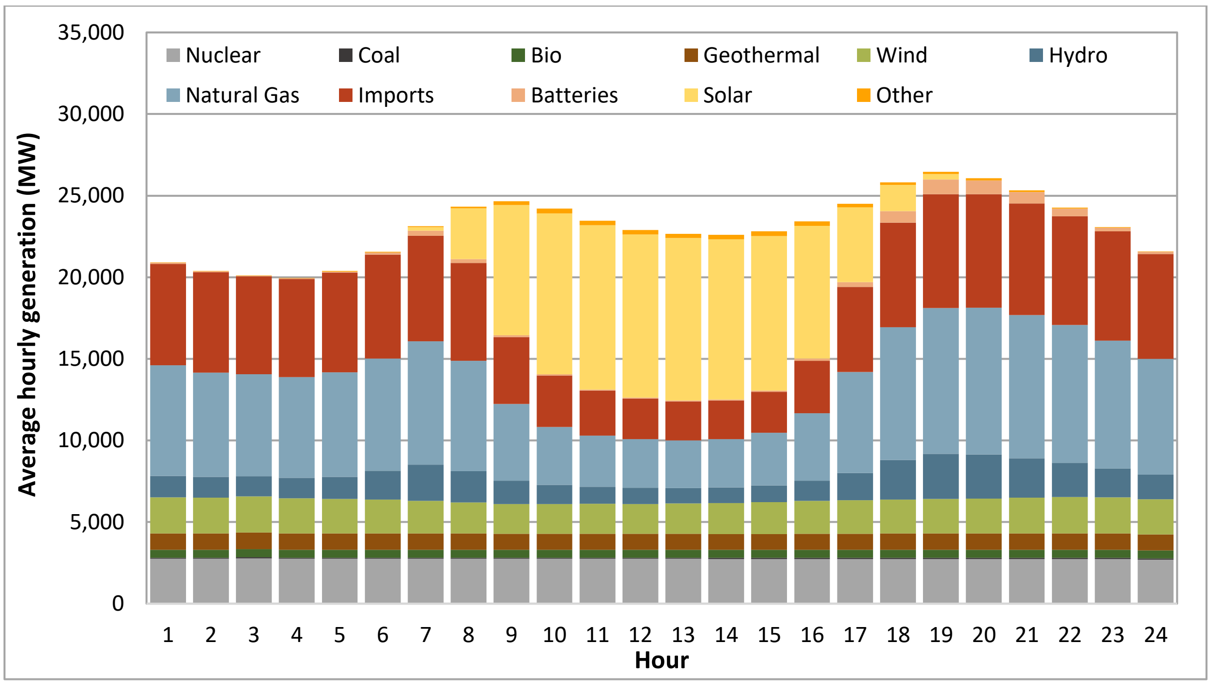


Figure 1.6 shows the change in hourly generation by fuel type between the first quarter of 2021 and the first quarter of 2022. In the chart, positive values represent increased generation relative to the same time last year and negative values represent a decrease in generation.

Overall, the net change shows that there was an increase in average hourly generation throughout the day. During all hours of the day, natural gas and coal generation was lower than the first quarter of 2021. The reduction in natural gas generation was due in part to higher fuel costs and increased nuclear generation.

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

Figure 1.6 Change in average hourly generation by fuel type (Q1 2021 to Q1 2022)

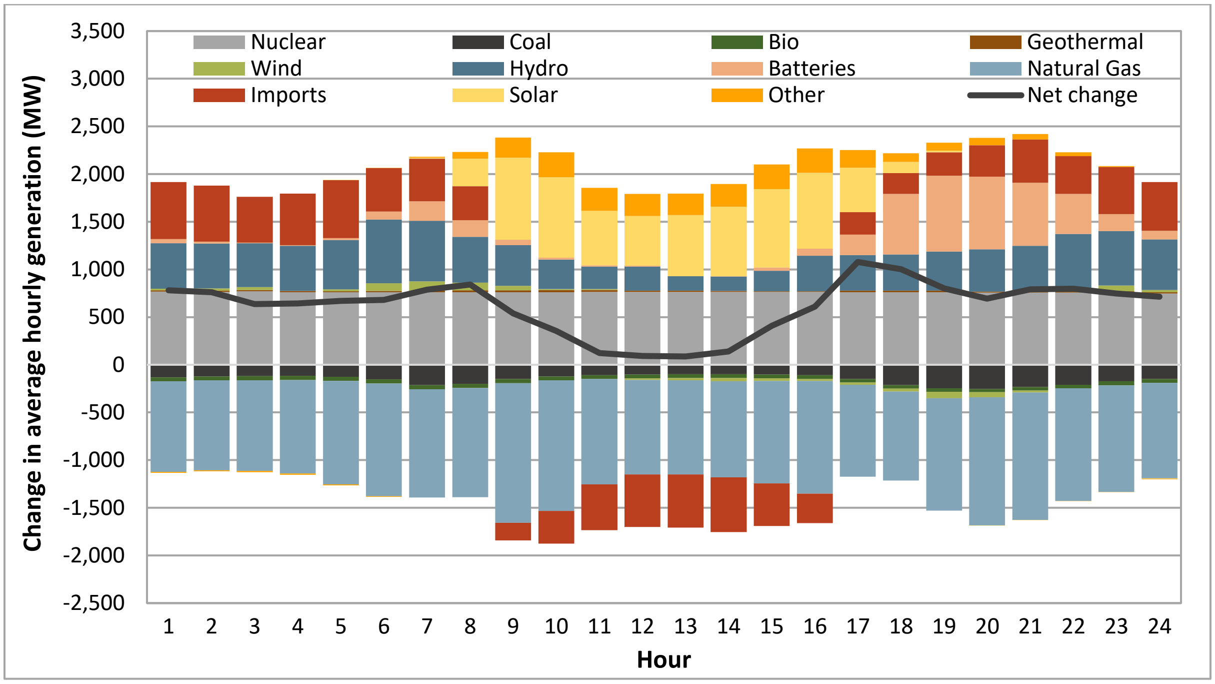
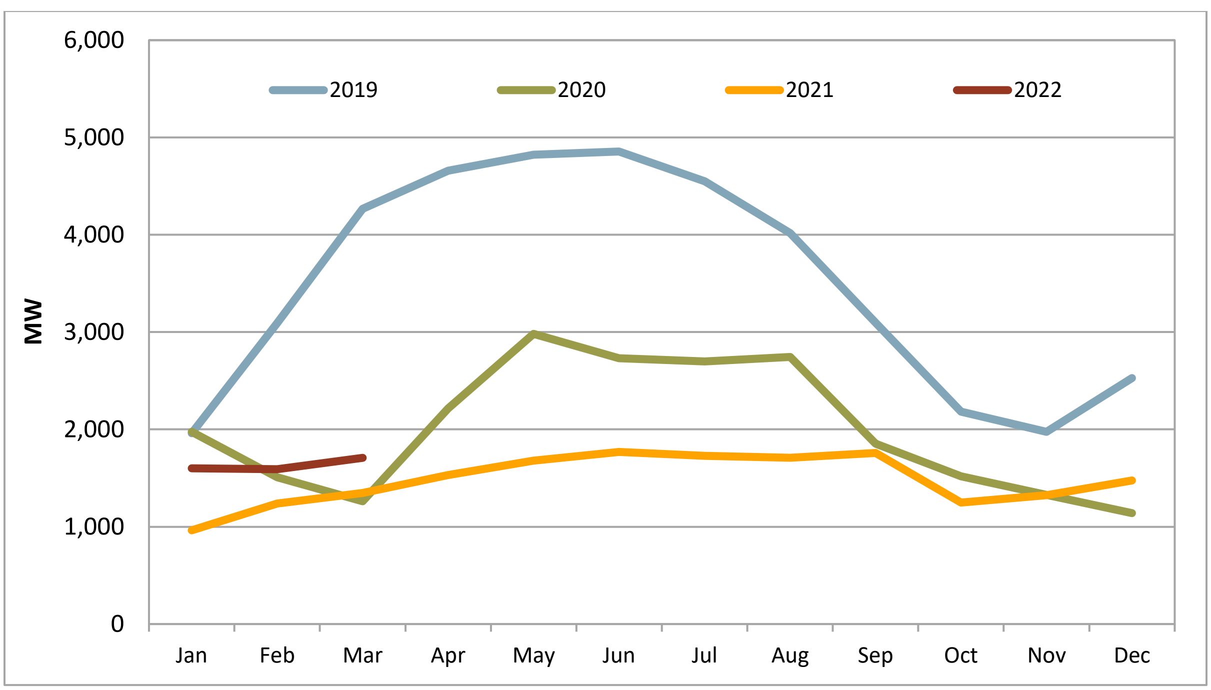


Figure 1.7 shows the monthly average hydroelectric generation from 2019 to 2022. Hydroelectric generation in second quarter was 38 percent higher than the same time last year. In March 2022, hydroelectric generation was higher than the same month in the previous two years.

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 16,150 MW, 16 percent higher than the first quarter of 2021. This increase was driven by forced outages, primarily of natural gas resources, which increased significantly relative to the same time last year. Total generation on outage was higher than the fourth quarter of 2021, an atypical trend that last occurred in 2017.

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 seven 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 for the same period. 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, March usually has a high number of outages. March 2022 follows this trend with increased planned outages relative to the months prior.

During the first quarter of 2022, the average total generation on outage in the California ISO balancing area was 16,150 MW, about 2,275 MW higher than the first quarter of 2021, as shown in Figure 1.8.[13] There were 38 percent more forced outages and 11 percent less planned outages than the same quarter last year. These forced generation outages were highest in March, when total generation on outage exceeded 20,000 MW. The majority of capacity on forced outage in March was natural gas fired.

[13] This is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the California ISO balancing area and do not include outages from the Western Energy Imbalance Market.

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

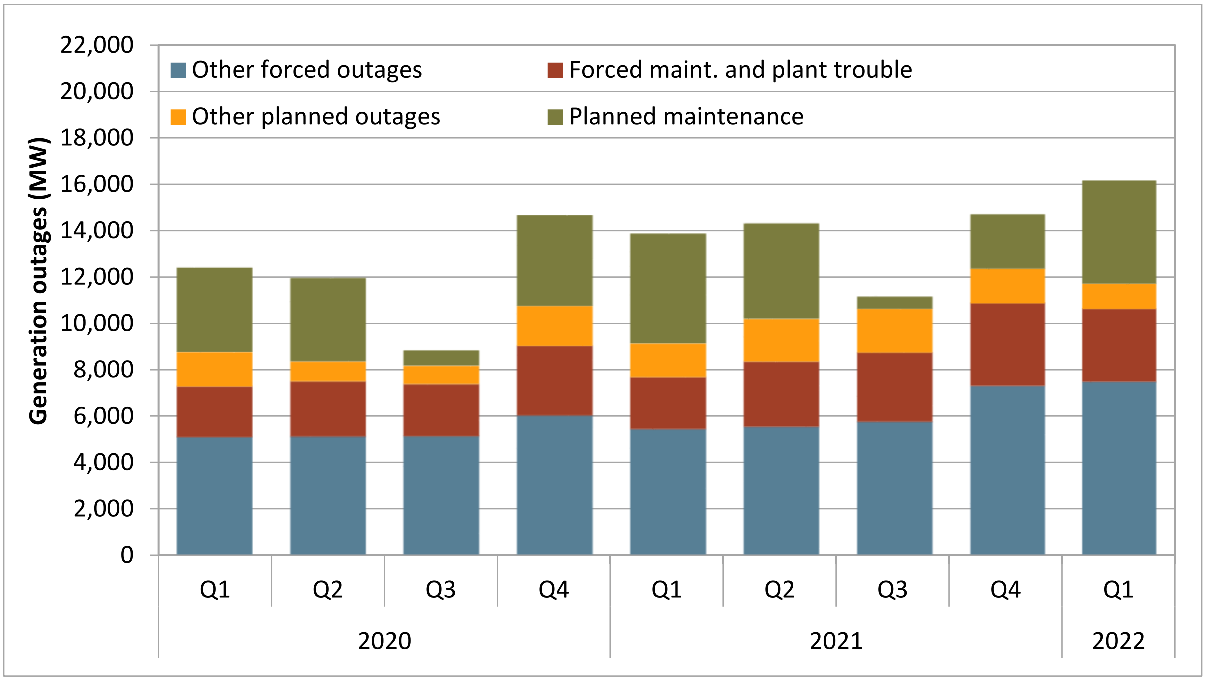
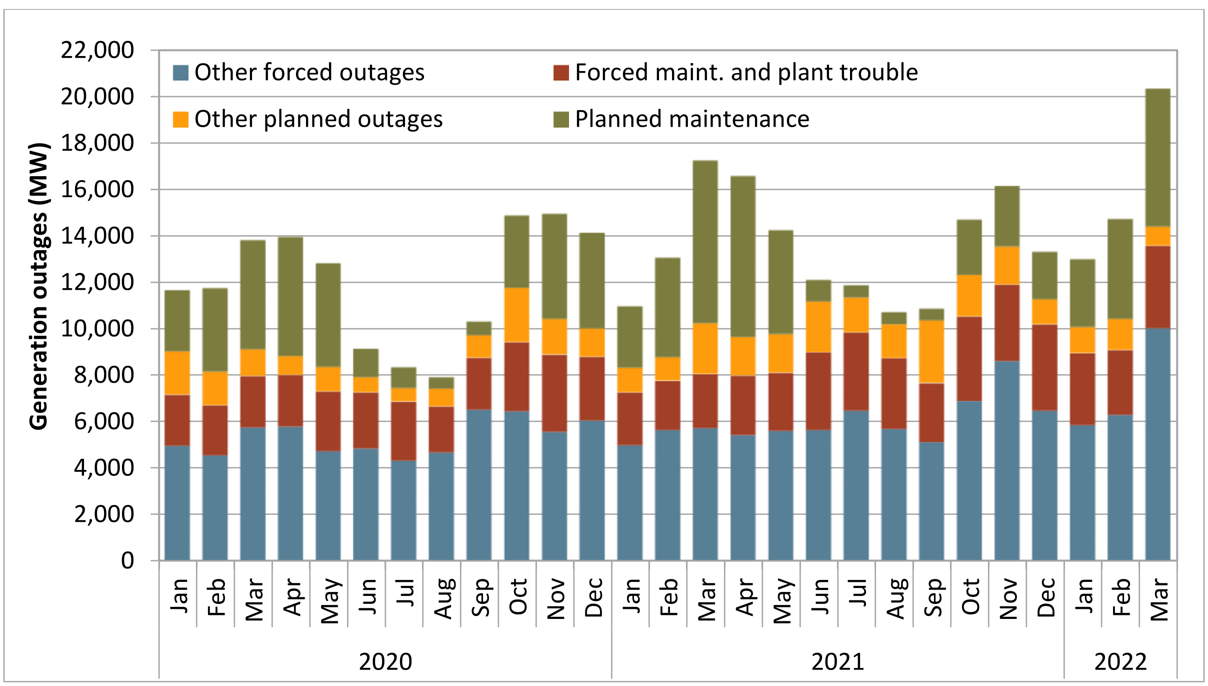


Figure 1.9 Monthly average of maximum daily generation outages by type – peak hours

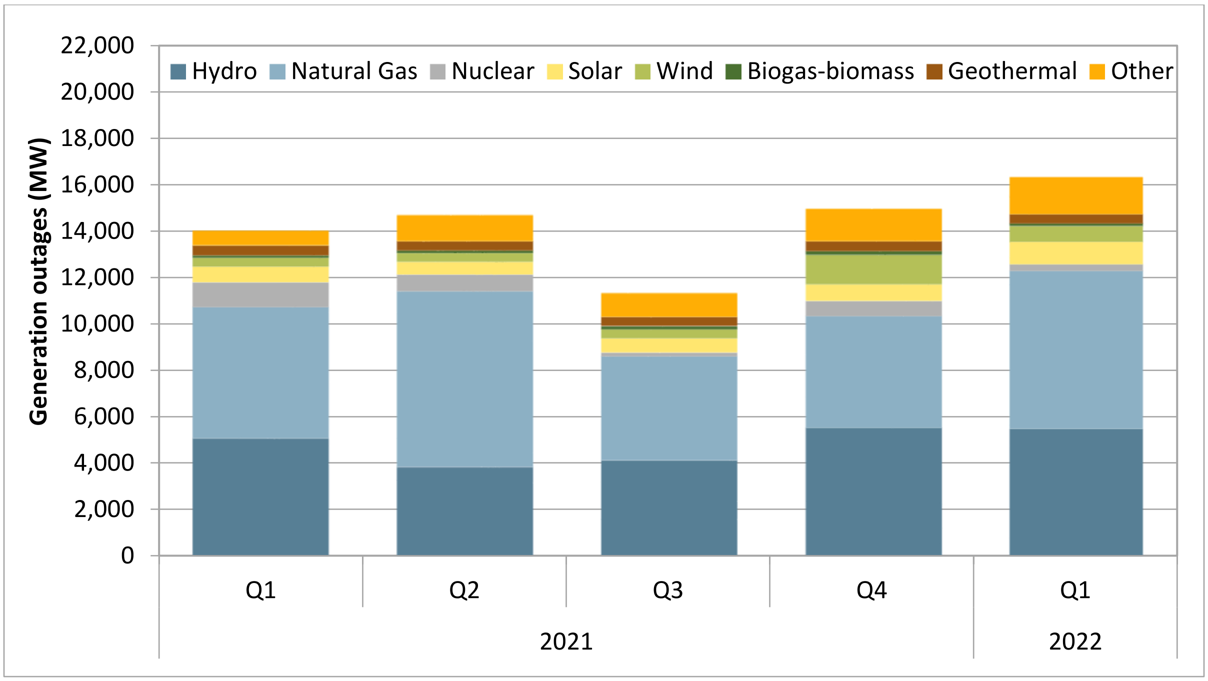


Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 6,775 MW and 5,475 MW during the first quarter, respectively. These two fuel types accounted for a combined 75 percent of the generation on outage for the quarter. The amount of natural gas generation on outage increased 20 percent relative to the first quarter of 2021.

Figure 1.10 shows the quarterly average of maximum daily generation outages by fuel type during peak hours. Nuclear generation returned to service from outages in early 2021, showing 73 percent less generation on outage compared to the same time last year. This was balanced out by higher wind and solar generation outages, which increased 71 percent and 43 percent, respectively.[14]

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

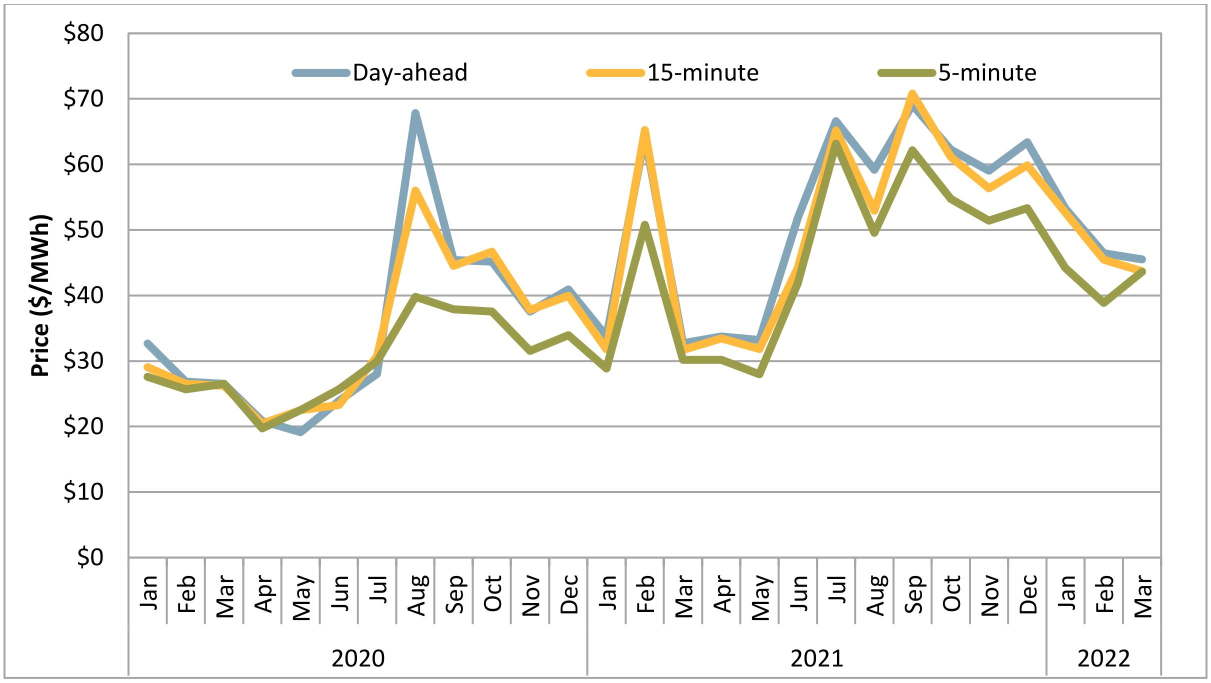
This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Prices in all three markets were about 12 percent higher this quarter compared to the first quarter last year.

Figure 1.11 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the

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

day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2020 to March 2022.

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



Day-ahead prices averaged $48/MWh, 15-minute prices averaged $47/MWh, and 5-minute prices averaged $42/MWh. Prices across all three markets were about 10-15 percent higher than the first quarter last year. While there was a spike in energy and gas prices in February 2021 due to winter extreme conditions in Texas and the Midwest, on average, both energy and gas prices were higher the first quarter this year compared to last.[15]

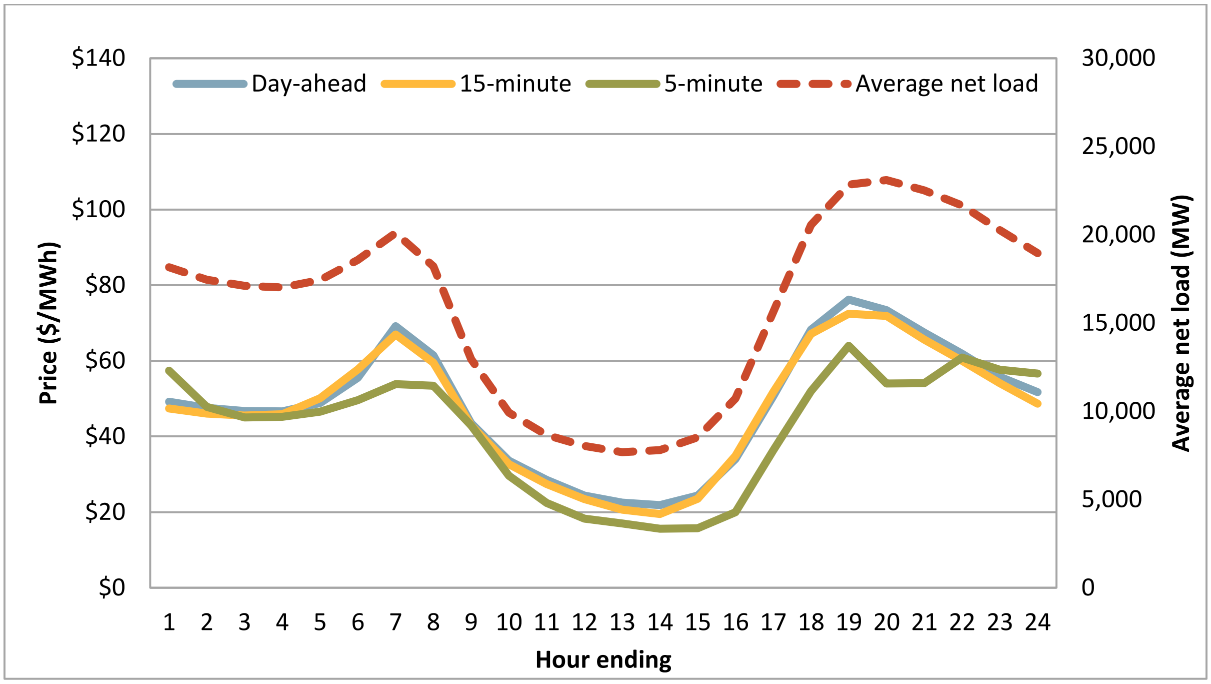
Figure 1.12 illustrates load-weighted average energy prices on an hourly basis for the quarter compared to average hourly net load.[16] Average hourly prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) and are measured by the left axis, while average hourly 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. Net load was lower across almost all hours of the day, particularly from 8:00 am to 3:00 pm when net load was about 10 percent lower. This was due to lower loads and increased wind and solar generation.

15 See Section 1.1.1 for additional details on natural gas prices.

16 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 (January - March)



1.2.2 Bilateral price comparison

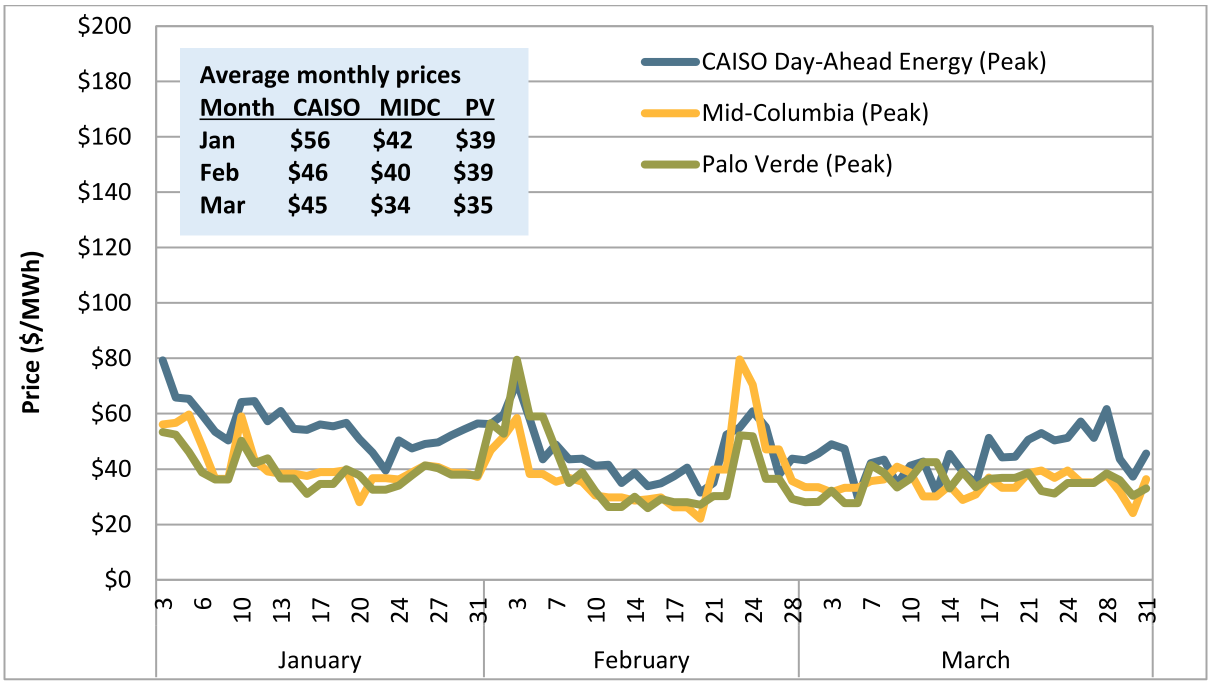
On average, day-ahead market prices were higher in the California ISO balancing area across peak hours in the first quarter than prices at the Mid-Columbia and Palo Verde electricity hubs. Regional differences in prices reflect transmission constraints as well as greenhouse gas compliance costs.

Figure 1.13 shows 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 prices during peak hours trended higher than bilateral hub prices across most days in the first 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 exceeded average bilateral prices at Mid-Columbia and Palo Verde hubs during this quarter.

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.[17] A motion is pending at FERC to raise the soft offer cap from $1,000/MWh to $2,000/MWh for spot sales in WECC's bilateral markets.[18]

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 $13/MWh and $11/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 $1/MWh.

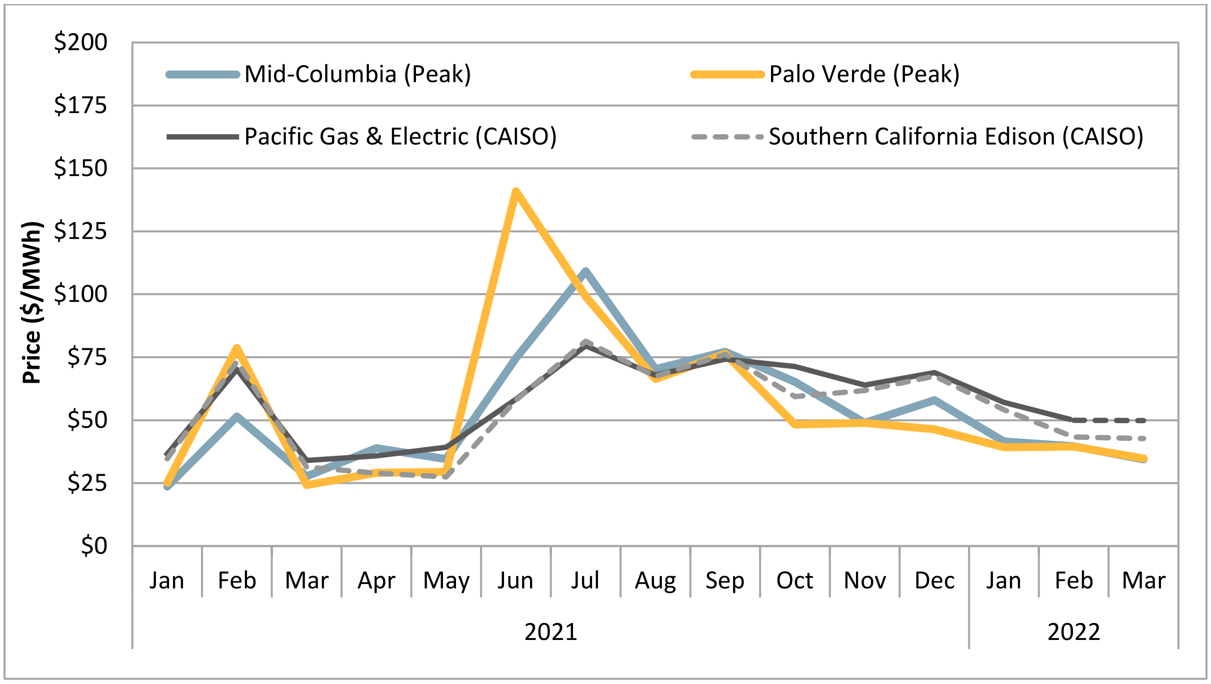
Figure 1.13 Day-ahead California ISO and bilateral market prices (Jan - Mar)



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

18 FERC Docket No. ER21-64*, Macquarie Energy, LLC submits Explanation for Bilateral Spot Sales in Western Electricity Coordinating Council:* eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. ER21-46, *Mercuria Energy America, LLC submits Tariff Filing per 35: Explanation for Bilateral Spot Sales in the West:* eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. EL10-56*, Macquarie Energy and Mercuria Energy filings, July 19, 2021:*
eLibrary | Docket Search Results (ferc.gov)

Figure 1.14 Monthly average day-ahead and bilateral market prices



Imports and exports

Unlike the previous quarter, average net imports increased compared to the same quarter in 2021, although net interchange decreased. As shown in Figure 1.15, peak imports in the day-ahead (dark blue line) increased in hour ending 19, from about 6,600 MW to 7,000 MW, compared to the same quarter of 2021. Peak 15-minute cleared imports (dark yellow line) also increased in the same hour compared to the same period last year, from about 7,100 MW to 8,300 MW. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased in both the day-ahead and 15-minute markets by 560 MW and 870 MW respectively, compared to the same quarter of 2021.

The average net interchange, excluding WEIM transfers (dashed black line), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental WEIM interchange, which reached a low point of about 240 MW in hour ending 14. The greatest import transfer into the California ISO balancing area from the WEIM occurred in hour ending 22, at about 580 MW, compared to about 820 MW in the same hour from the same quarter in the prior year. Export transfer from the California ISO area to the WEIM occurred between hour ending 8 to hour ending 18, with hour ending 13 topping out at about 2,100 MW. This is an increase from the same quarter of the previous year with a maximum export in hour ending 13 at about 1,900 MW.

Figure 1.15 Average hourly net interchange by quarter

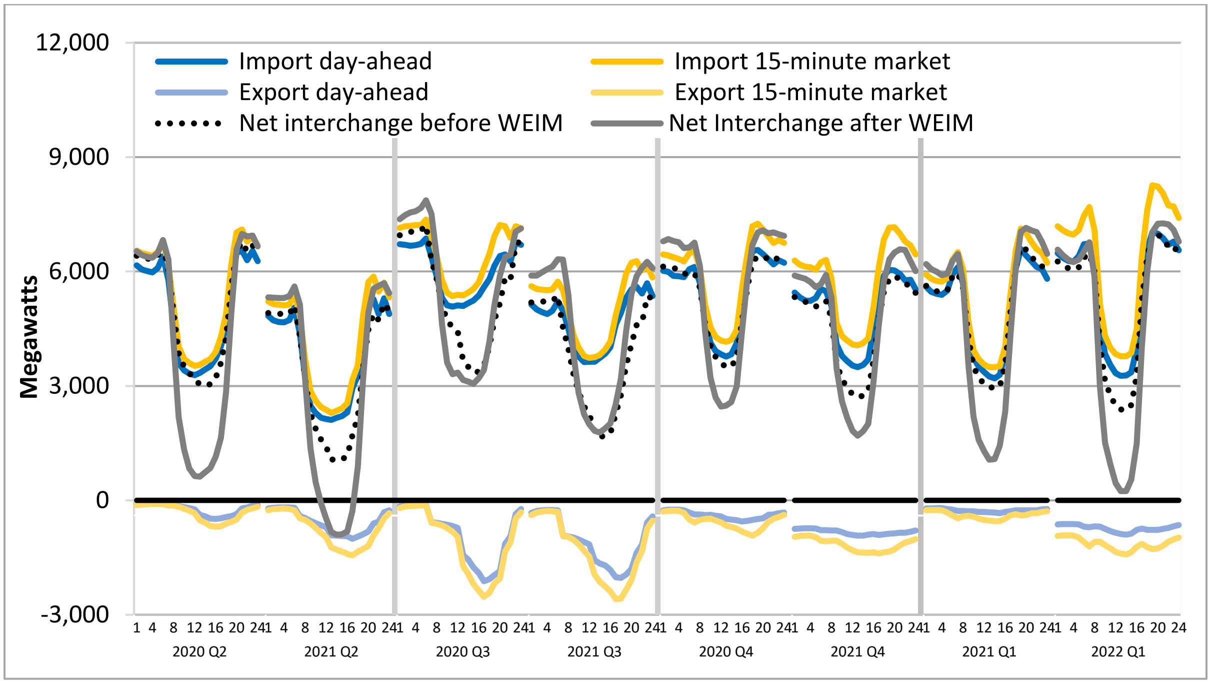
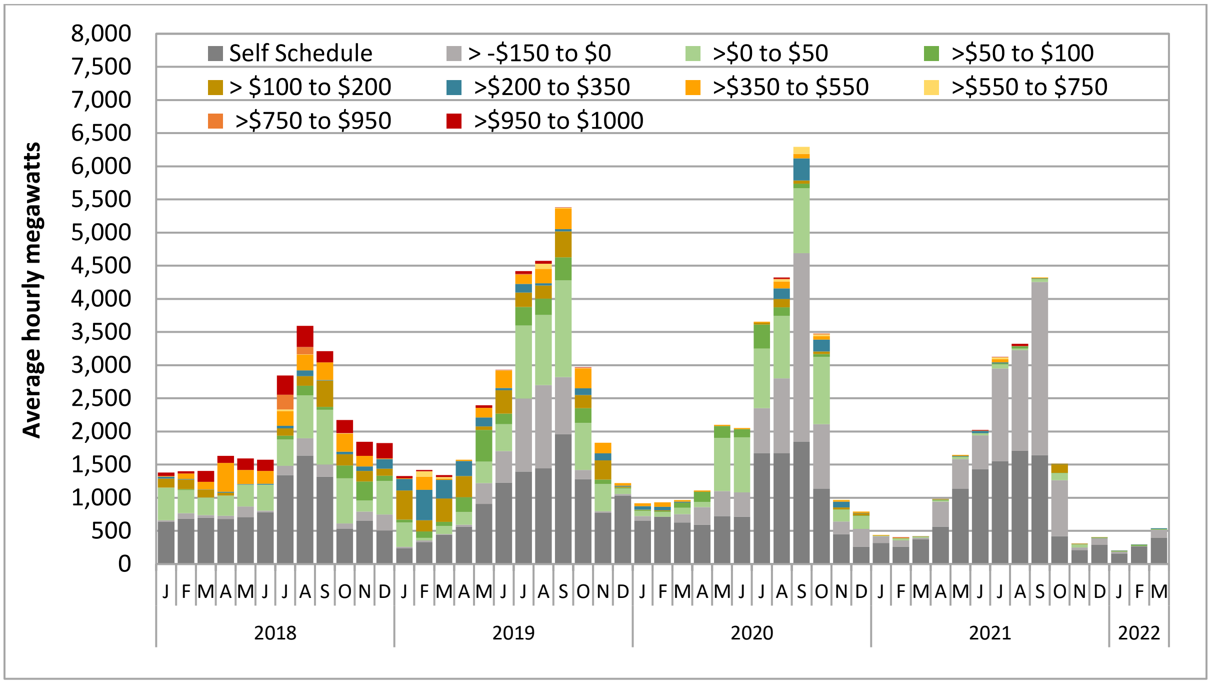


Figure 1.16 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[19] The grey bars reflect import capacity that was self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market.

19 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

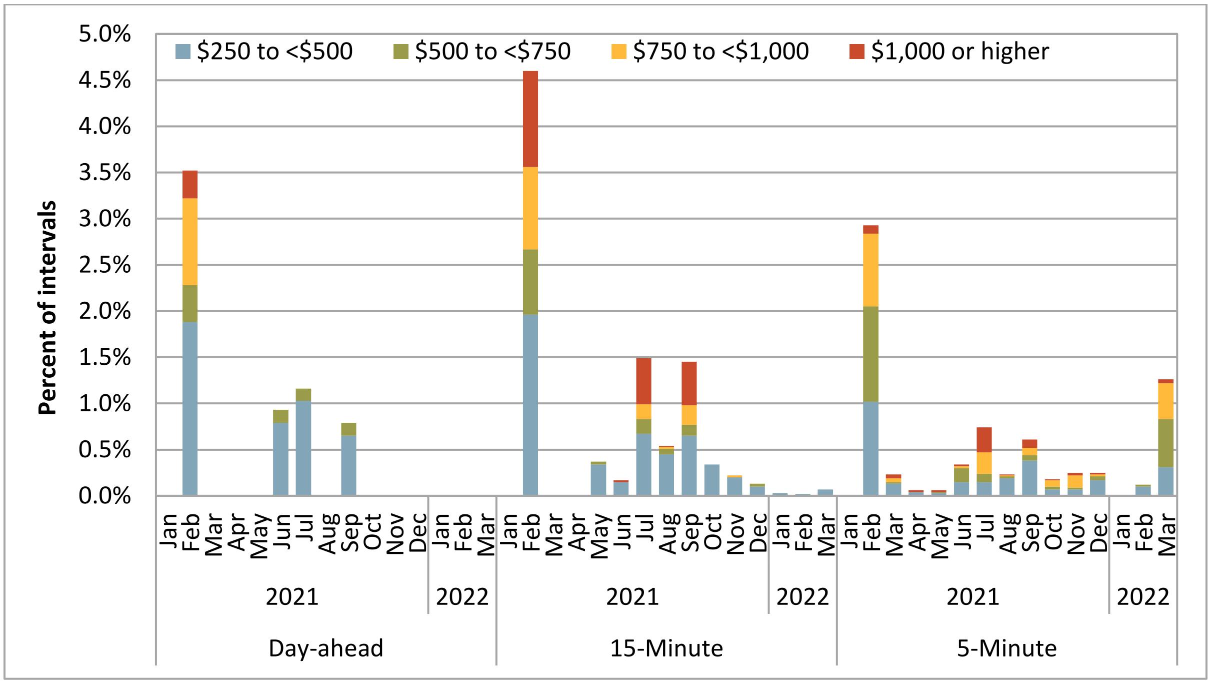
Under certain market conditions, prices can spike much higher or lower than the usual average prices. The frequency of high prices was lower this quarter compared to 2021, due to the spike in gas prices during the first quarter last year. The frequency of negative prices remained about the same, with a slight increase in negative prices in the 5-minute market.

High prices

Figure 1.17 shows the frequency of prices across all three markets in various high ranges from January 2021 to March 2022. The frequency of prices over $250/MWh decreased in the first quarter this year compared to last year, even though average prices were higher overall this quarter, partly because the spike in gas prices in February 2021 led to very high prices during a few days that month. Compared to last year, there was an increase in high price spikes in the 5-minute market in March, occurring in 1.3 percent of intervals, most of which occurred over two days.[20]

[20] California ISO, *Market Update Call Meeting Minutes,* March 24, 2022: http://www.caiso.com/Documents/MeetingMinutesMarketUpdateCallMar242022.pdf

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.[21] This quarter there were no under-supply infeasibilities in the 15-minute market although there were four in March in the 5-minute market.

Negative prices

Figure 1.18 shows the frequency of prices across all three markets in various low priced ranges from January 2021 to March 2022. Negative prices tend to be the most common in the spring months when renewable production is high but demand is relatively low due to moderate temperatures. The frequency of negative prices this quarter was similar to the first quarter last year, although the percent of intervals with negative prices in the 5-minute market increased from 6.6 to 7.4 percent. This higher frequency of negative prices is due in part to high renewable production.[22]

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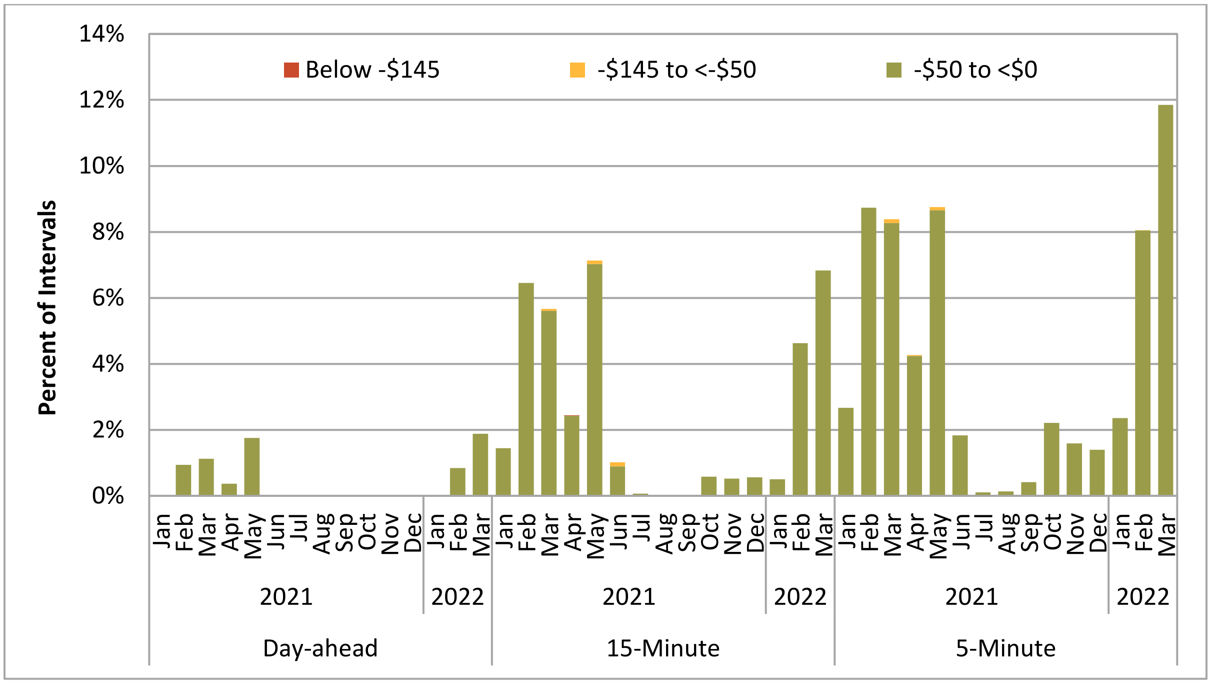
21 Prices may be set to a higher price under certain market conditions, see:
Department of Market Monitoring, *Q1 2021 Report on Market Issues and Performance,* June 9, 2021: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

22 Section 1.1.2 summarizes renewable generation this quarter.

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.

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.[23] 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 is reduced for the individual balancing areas in every interval by their transfer capability.[24] 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 will be enforced, equal to the balancing authority area's share of the diversity benefit.[25] The minimum requirement is intended to help mitigate some of the issues surrounding procurement of stranded flexible ramping product prior to the implementation of 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 89 percent of intervals and a minimum downward requirement enforced in around 73 percent of intervals during the quarter. For non-CAISO areas, notably PacifiCorp East had a minimum downward flexible requirement in around 6 percent of intervals during the quarter.

The minimum requirement was initially implemented in the 15-minute market only. DMM recommended that the minimum requirement also be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product until nodal procurement implementation.[26] The California ISO implemented the 5-minute market minimum requirement on February 16, 2022.

23 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.

24 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.

25 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

26 Procurement in the 5-minute market helps maintain available ramping capacity to manage uncertainty that may materialize between consecutive 5-minute market intervals. Without a minimum requirement in the 5-minute market, there can be cases where flexible ramping capacity, procured within the California ISO and settled in the 15-minute market, is released in the 5-minute market in favor of undeliverable flexible ramping capacity stranded behind the WEIM transfer constraints.

1.4.2 Flexible ramping product prices

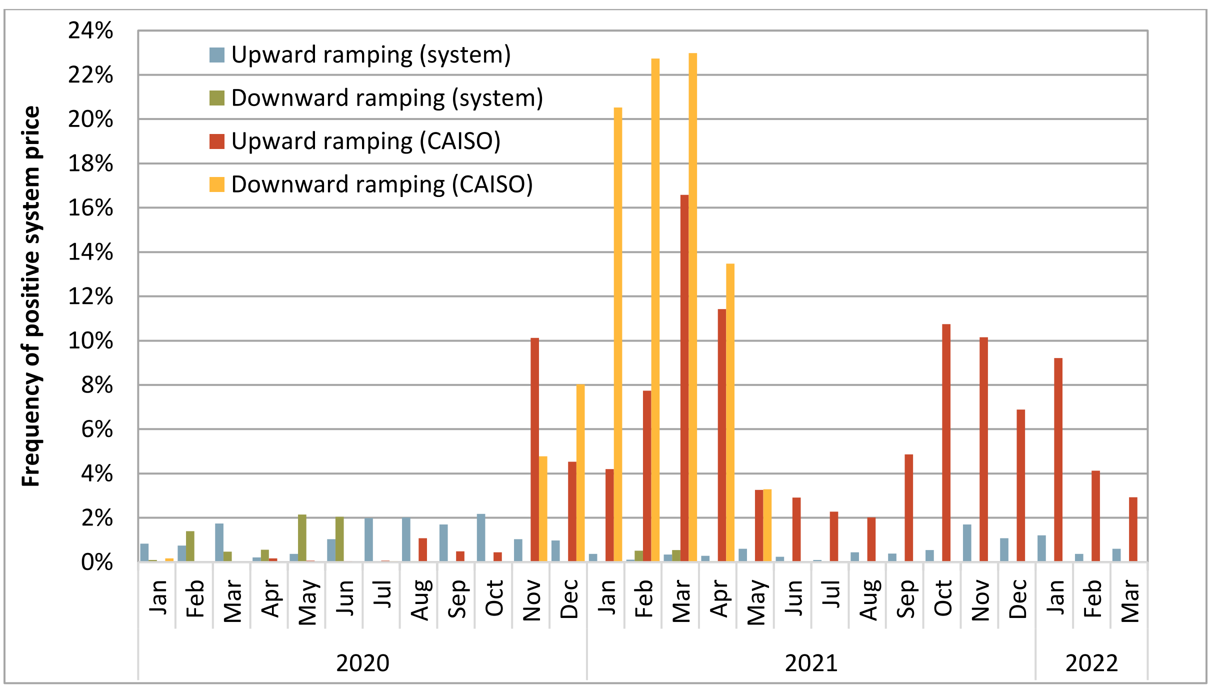
The flexible ramping product procurement and shadow prices are determined from demand curves. When the shadow price is \$0/MWh, the maximum value of capacity on the demand curve is procured. This reflects that flexible ramping capacity is readily available relative to the need for it, such that there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

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 never for downward ramping. In the 5-minute market, the system-level and California ISO-specific demand curves for upward and downward ramping capacity bound in less than 0.1 percent of intervals.

The following sections look at some of the reasons the system-level flexible ramping product prices have often been zero.

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



Stranded flexible ramping capacity

Flexible ramping capacity procured in the WEIM can be stranded behind transfer constraints. The system-level demand curve for the entire CAISO and WEIM footprint is always enforced in the market and can be met from ramping capacity in any area. In addition, there is a constraint that caps upward ramping procurement in each area by the sum of its local uncertainty requirement and net export capability.[27]

However, even with this constraint, there is the potential for stranded flexible ramping capacity. While this issue can occur in other areas, it is most prominent in the Northwest region, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex; this is because of limited transfer capability out of the Northwest region. For example, in cases when supply conditions are tight in the CAISO and surrounding system but export capability out of the Northwest region is zero, these areas may still have export capability to each other within the Northwest region. As a result, the export capability cap on upward flexible ramping capacity will often do little to prevent procurement that is stranded in this region. Further, when supply conditions are tight, it can often be most economic under the current structure to procure more flexible ramping capacity from the Northwest region than from the surrounding system as the opportunity cost of providing that ramping capacity in lieu of energy would then be lower in the Northwest.

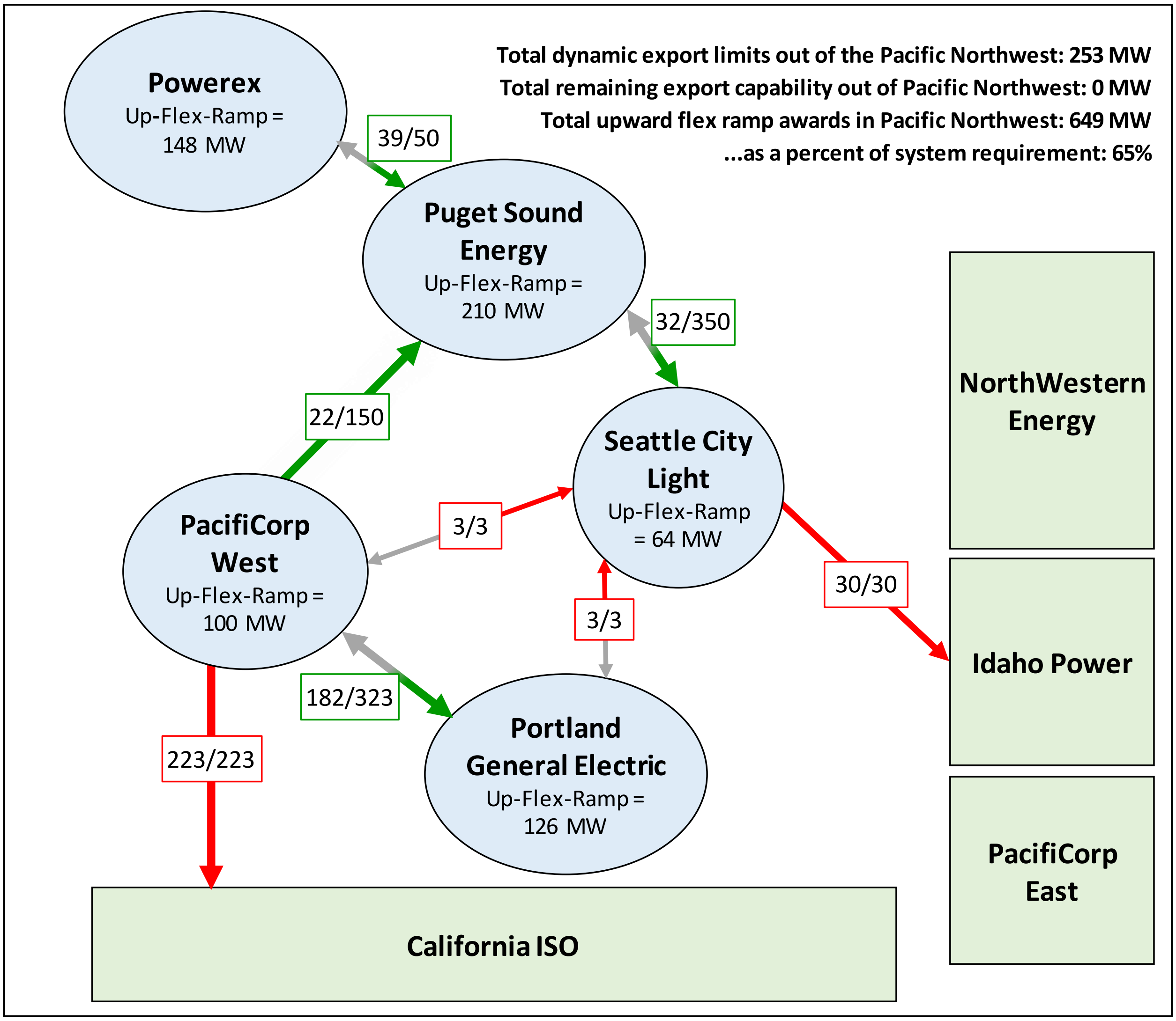
Figure 1.20 illustrates this interaction with an example interval from September 7, 2021. The figure shows dynamic (non-base) export limits and remaining export capability out of each area in the Northwest region. Transfers that were dedicated exclusively for base schedules (fixed bilateral transactions between WEIM entities) or had transmission limits set at zero were not able to support any upward flexible ramping capacity and were omitted from the figure. The red and green arrows show the direction of the transfer flows and whether they were fully constrained (red) or not (green).[28] In this interval, 649 MW of upward ramping capacity (or 65 percent of the system requirement) was awarded to resources in the Northwest region, but 0 MW of actual export capability out of the region was available. Here, export capability between areas within the Northwest region allowed for higher procurement of upward flexible ramping capacity than was actually accessible for the surrounding system.

Flexible ramping capacity awards to resources stranded behind transfer constraints (particularly in the Northwest) can contribute to lower deliverability of flexible capacity at the system level and suppress the true opportunity cost of providing such capacity instead of energy. This makes flexible ramping capacity appear more available and cheaper than it actually is.

27 Net export capability is the sum of export WEIM transfer limits in excess of the net WEIM transfer. Downward ramping capacity is instead capped by the sum of the area-specific downward uncertainty requirement and net import capability.

28 The gray arrows indicate that there is two-way transfer capability, but the flow is not going in that direction.

Figure 1.20 Example interval — Stranded upward ramping capacity in the Northwest (September 7, 2021)



Local relaxations effectively reduce system uncertainty requirements

There are separate local demand curves calculated for each WEIM area in addition to a system-level demand curve. Flexible ramping capacity procured in one balancing area can be used to meet local or system uncertainty needs (or both). The system uncertainty requirement for the entire footprint is always enforced in the market and a relaxation from this requirement will price flexible ramping capacity at the system level.

Each area also has a local uncertainty requirement that is reduced in every interval by their transfer capability. Previously, if the transfer capability for each area was sufficient, then only the system uncertainty requirement was active. However, with the implementation of the minimum requirement in 2020, areas that contribute to a significant portion of system uncertainty (typically only CAISO) will still have a nonzero local requirement even with sufficient transfer capability.

Any relaxation from a local requirement will meet the system-level requirement, reducing the footprint demand for flexibility across all areas, but only price flexible ramping capacity for that particular local area. System flexible ramping needs are typically smaller than the sum of the needs of individual areas because of reduced uncertainty across a larger footprint. As a result, a relaxation for a local requirement can disproportionately reduce the system requirement by an amount that exceeds the area's expected share of system uncertainty. This reduction in demand for system-level flexibility will therefore reduce the cost for providing that flexibility.

With the minimum requirement enhancement, a local flex ramp requirement is typically enforced for the CAISO area because of significant load and variable energy resources that contribute to a large share of system-wide uncertainty. This resolves some of the issues surrounding stranded flexible ramping capacity by ensuring that a nonzero quantity of flexible ramping capacity is procured within CAISO. However, when conditions across the system (including the CAISO) are tight, the market will often relax the minimum local requirement for the CAISO, reducing system flexibility needs, while pricing flexible ramping capacity in the CAISO area only. As upward flexibility in the CAISO becomes scarcer and more expensive, prices for system-level flexible ramping capacity typically remain low even though flexible ramping capacity external to CAISO may be physically able to meet CAISO flexibility needs.

As an example, Figure 1.21 shows how the 15-minute market system requirement for upward flexibility was met during the peak hours of July 9, 2021. On this day, system prices for flexible ramping capacity remained mostly at zero despite very tight system conditions and high energy prices. The bars show either flexible ramping capacity or local relaxation that effectively met the system requirement. The ramping capacity is then split out by whether it is to resources in the CAISO or another WEIM area (and whether that area is stranded behind the WEIM transfer constraints or not).

As discussed earlier, each area has a local uncertainty requirement. If the area passes the resource sufficiency evaluation, this local requirement is reduced by the area's transfer capability and capped from below by the minimum requirement (when active). The blue lines in the figure below show the minimum and effective requirement for the CAISO. The effective requirement reflects the final local requirement following any transfer capability reductions or enforcement of the minimum requirement. During the periods in the figure in which the effective requirement is higher than the minimum requirement, the CAISO failed the resource sufficiency evaluation such that there was no reduction to their local requirement because of any transfer capability. In these intervals, the full local uncertainty requirement was enforced.

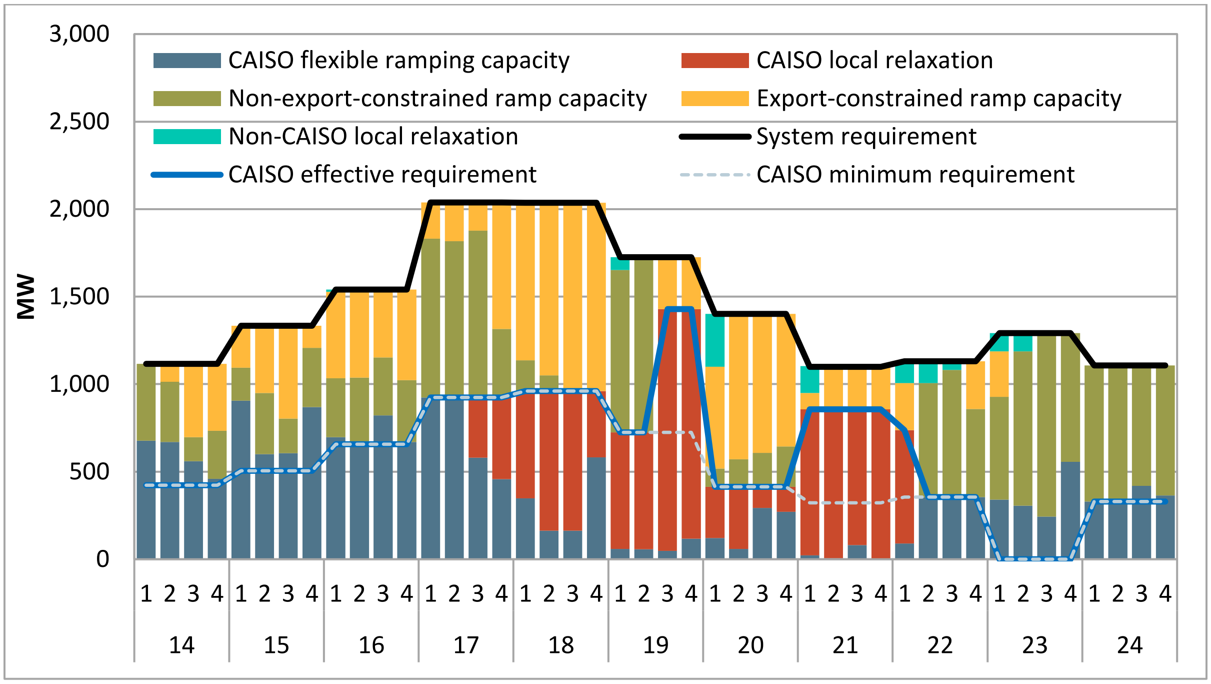
As shown in Figure 1.21, the system uncertainty requirement (black line) is met in every interval without any system relaxation such that the system-wide price for flexible ramping capacity was zero. Alternatively, relaxation of the CAISO local requirement (red bars) can meet a significant portion of the system requirement, which will price flexible ramping capacity in the CAISO, but not in the surrounding WEIM areas (even if these areas can provide flexibility). The yellow bars also highlight substantial flexible ramping capacity awards to resources within balancing areas that are export constrained relative to the greater WEIM system.

The California ISO is implementing nodal procurement for the flexible ramping product in the fall of 2022 as part of the flexible ramping product refinements stakeholder initiative.[29] This is expected to resolve both (1) stranded flexible ramping capacity and (2) the undesirable interplay between local and

[29] California ISO, *Flexible Ramping Product Refinements Final Proposal,* August 31, 2020. http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

system requirements. Locational procurement, accounting for transmission constraints, would result in deliverable reserves, which could significantly increase the efficiency of the CAISO market awards and dispatches. This change should also help to address the very low prices for flexible ramping capacity and instead allow this capacity to be priced based on the relative availability and actual tradeoff of providing that flexibility in lieu of energy.

Figure 1.21 System flexible ramping product requirement, procurement, and relaxation



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 first quarter of 2022. Combined net revenue for virtual supply and demand was about $4.9 million, after including about $3 million of virtual bidding bid cost recovery charges. Virtual demand generated negative revenues of about $1.6 million for the quarter, while virtual supply generated about $9.4 million, before accounting for bid cost recovery charges. The vast majority of profits continue to be received by financial entities and marketers, about 86 percent and 12 percent, respectively.

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 $7.8 million. Net revenues for virtual supply and demand fell to about $4.9 million after the inclusion of about $3 million of virtual bidding bid cost recovery charges,[30] primarily associated with virtual supply.

Figure 1.22 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 $7.8 million, compared to about $9.7 million during the same quarter from the previous year, and about $14.2 million during the previous quarter.
- Virtual demand net revenues were about -$0.2 million, $0.4 million, and -$1.7 million for January, February, and March, respectively.
- Virtual supply net revenues were $1.9 million, $2.3 million, and $5.2 million for January, February, and March, respectively.

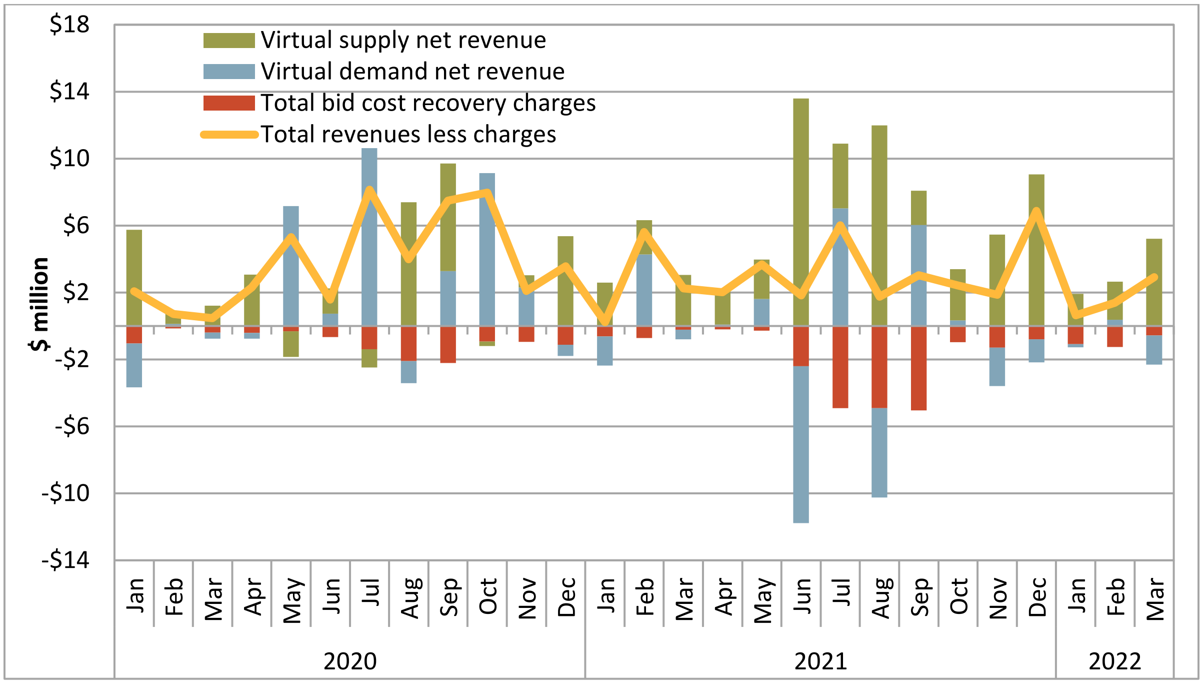
Convergence bidders received approximately $4.9 million after subtracting bid cost recovery charges of about $3 million for the quarter.[31,32] Bid cost recovery charges were about $1.1 million, $1.3 million, and $0.6 million for January, February, and March, respectively.

30 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, p. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

31 Further detail on bid cost recovery and convergence bidding can be found here, p.25: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

32 Business Practice Manual configuration guide has been updated for CC 6806, day-ahead residual unit commitment 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, refer to the configuration guide for CC 6806: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

Figure 1.22 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,[33] in millions of dollars, among different groups of convergence bidding participants.[34]

Financial entities represented the largest segment of the virtual bidding market for the current quarter, with 74 percent of volume and 86 percent of the settlement revenue. Marketers continue to have about 25 percent of volume and 12 percent of settlement revenue, while generation owners and load serving entities represent about one percent of both volumes and settlement revenue (negative).

33 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 here: http://www.caiso.com/market/Pages/Settlements/Default.aspx

34 DMM has defined financial entities as participants who do not own physical power and participate in the convergence bidding and congestion revenue rights markets only. 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 – Q1

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	
2021 Q1								
Financial	1,319	1,838	3,158	-$0.78	$7.29	-$2.19	$5.11	$4.32
Marketer	454	595	1,049	-$0.70	$1.91	-$0.61	$1.30	$0.60
Physical load	0	21	21	$0.00	$0.07	-$0.11	-$0.04	-$0.04
Physical generation	9	36	46	-$0.08	$0.12	-$0.07	$0.05	-$0.04
Total	**1,783**	**2,491**	**4,274**	**-$1.56**	**$9.39**	**-$2.98**	**$6.41**	**$4.85**

1.6 Residual unit commitment

On average, the total volume of capacity procured through the residual unit commitment process in the first quarter of 2022 was 35 percent higher than the same quarter of 2021. The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real-time. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load.

As illustrated in Figure 1.23, 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 40 MW lower in the first 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 30 days to increase the residual unit commitment requirements by an average of about 74 MW per hour.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar in Figure 1.23) represents the difference in cleared supply (both physical and virtual) compared to the California ISO's load forecast. On average, this factor contributed towards decreasing residual unit commitment requirements in the first quarter of 2022, averaging about -165 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 bars in Figure 1.23.

Figure 1.23 Determinants of residual unit commitment procurement

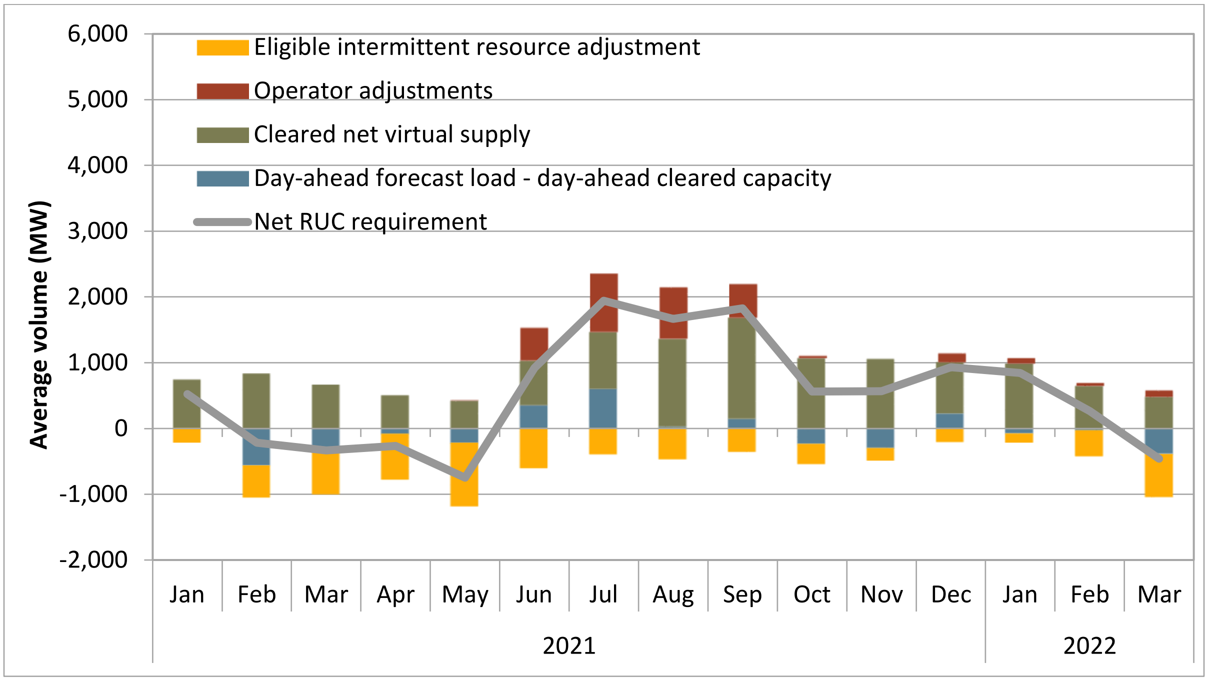


Figure 1.24 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to about 800 MW in the first quarter of 2022 from an average of 600 MW in the same quarter of 2021. Of the 800 MW capacity, the capacity committed to operate at minimum load averaged 175 MW.

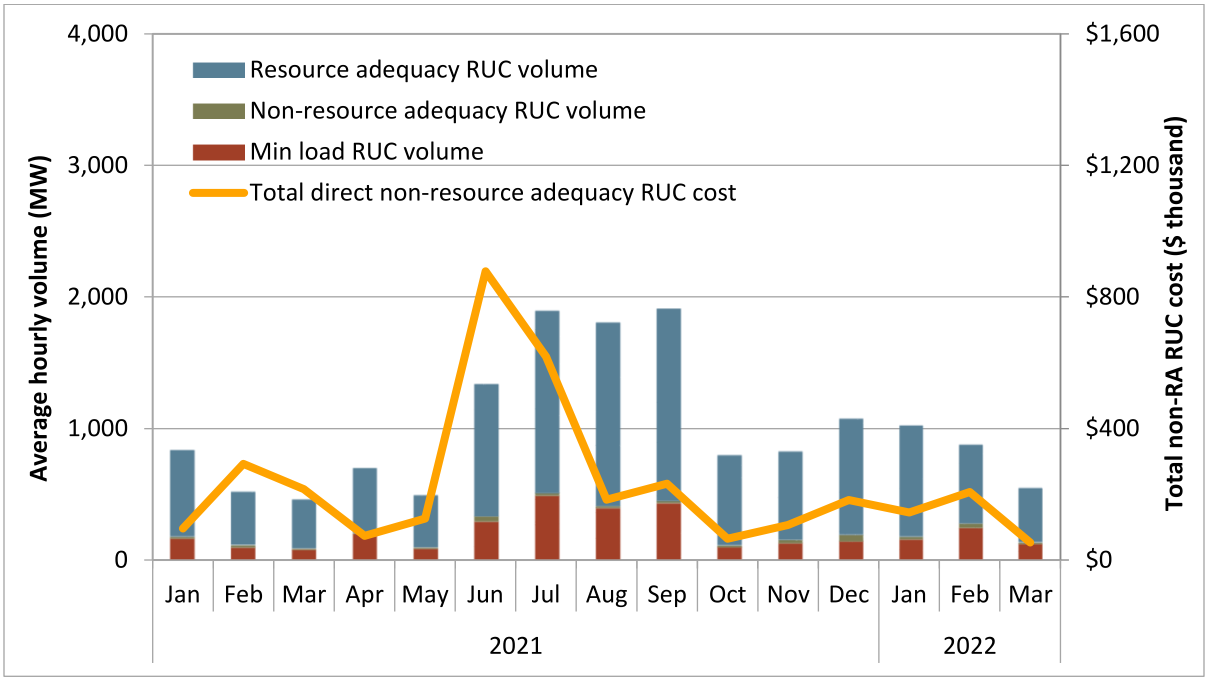
During the first quarter of 2022, the *residual unit commitment undersupply power balance constraint* was not infeasible in any hour. The market change that went in place on September 5, 2020, was designed to address the treatment of economic and self-scheduled exports that cleared the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment process is able to curtail certain exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds the California ISO's real-time load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[35]

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.[36] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.24. In the first quarter of 2022, these costs were about \$0.4 million, about \$0.2 million lower than 2021.

35 The California ISO provided details and examples of this change in the *Market Performance and Planning Forum* meeting on September 9, 2020: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum

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

Figure 1.24 Residual unit commitment costs and volume



1.7 Ancillary services

Ancillary service payments this quarter totaled $45 million, a 2 percent increase from the first quarter of 2021. Overall requirements were higher for operating reserves and regulation down compared to the same quarter last year.

1.7.1 Ancillary service requirements

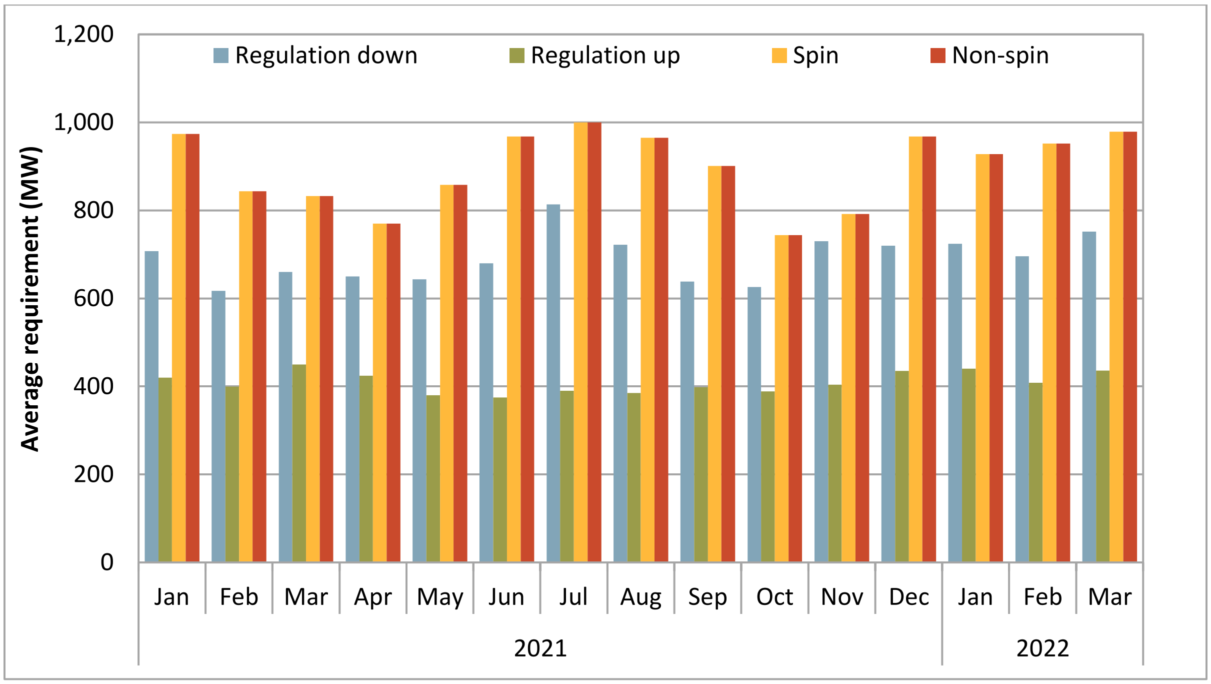
The California ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (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.[37] 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.

[37] 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*, p. 161: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

Figure 1.25 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown, average requirements for operating reserves increased 8 percent this quarter compared to the first quarter of 2021. This increase is in part due to the increase in exports, since operating reserves are based on load forecast and generation. Regulation down requirements increased 9 percent, due to increased renewable generation this quarter. Average regulation up requirements were about the same as the first quarter last year.

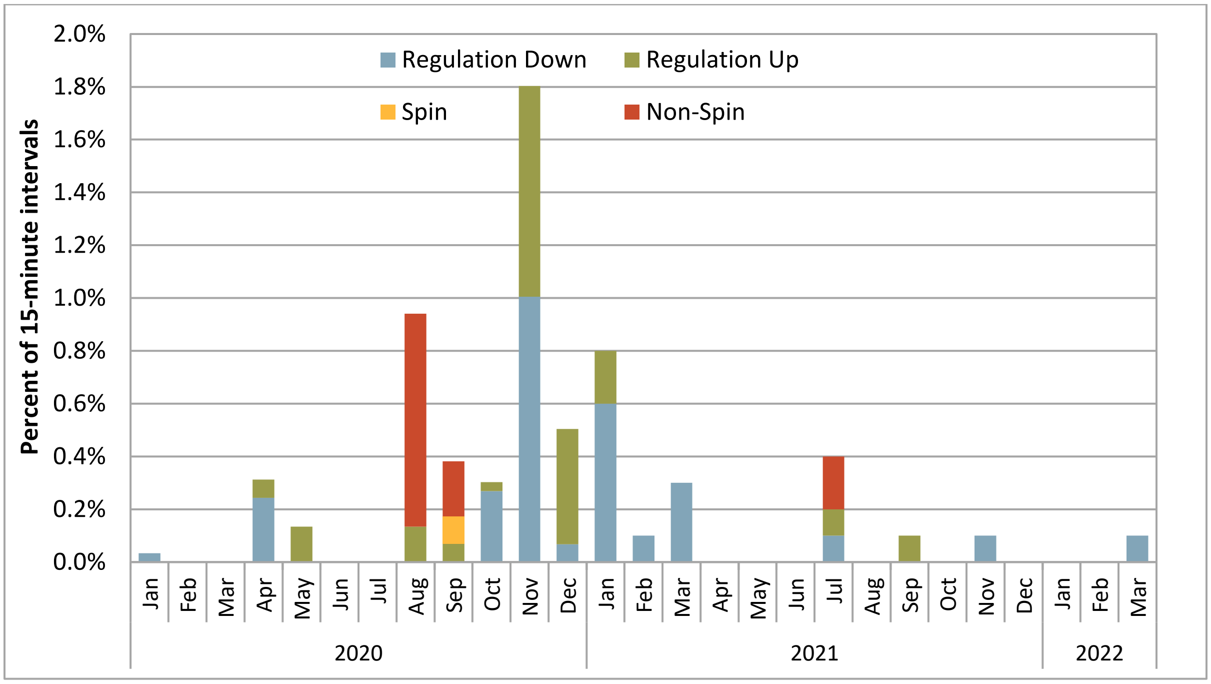
Figure 1.25 Average monthly day-ahead ancillary service requirements



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. As shown in Figure 1.26, the frequency of intervals with scarcity pricing decreased substantially from 0.40 percent of intervals in the first quarter last year to 0.03 percent this year.

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



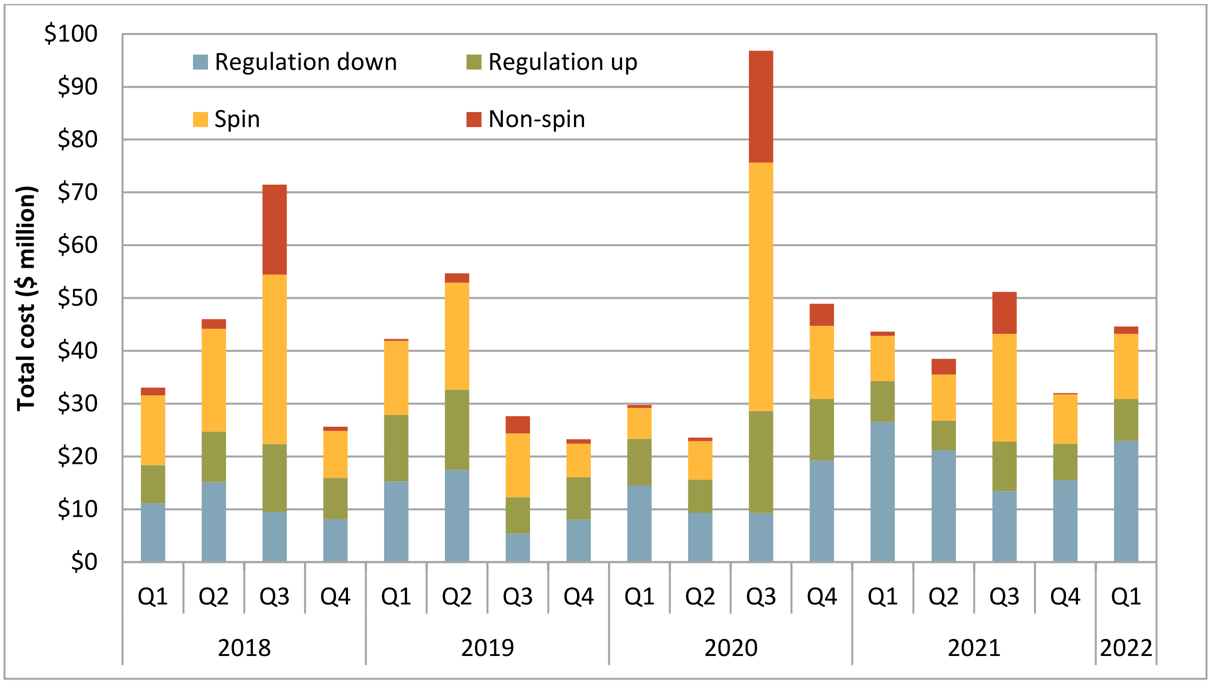
1.7.3 Ancillary service costs

Ancillary service payments increased this quarter to about $45 million, compared to $32 million in the previous quarter. Payments were similar to the first quarter of 2021 when ancillary service payments were almost $44 million.

Figure 1.27 shows the total cost of procuring ancillary service products by quarter.[38] The cost to procure operating reserves and regulation up increased by $4.6 million total, which was primarily driven by the large increase in the costs of procuring spinning reserves. On the other hand, the cost to procure regulation down decreased by about $3.7 million.

[38] 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 1.27 Ancillary service cost by product



1.8 Congestion

In the day-ahead market, congestion in the first quarter was different from the same time last year, raising prices in PG&E and lowering prices in the SCE and SDG&E areas. In the 15-minute market, the impact of internal congestion on prices generally raised prices in the Pacific Northwest and decreased prices in the East and Southwest.

The following sections provide an assessment of the frequency and impact of congestion on prices in the day-ahead and 15-minute markets. It assesses the impact of congestion on local areas in the California ISO balancing area (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric) as well as on 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.[39]

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

Color shading is used in the tables in this section 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 color of 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 first quarter of 2022, congestion rent and loss surplus was $122 million and $46 million, respectively. These respective amounts represent a 37 percent decrease and 17 percent increase relative to the same quarter of 2021.[40] Figure 1.28 shows the congestion rent and loss surplus by quarter for 2021 and 2022.

In the day-ahead market, hourly congestion rent collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day. The daily marginal loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[41]

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

41 For more information on marginal loss surplus allocation refer to the California ISO's business practice manual for settlements and billing, CG CC6947 IFM Marginal Losses Surplus Credit Allocation: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

Figure 1.28 Day-ahead congestion rent and loss surplus by quarter (2021-2022)

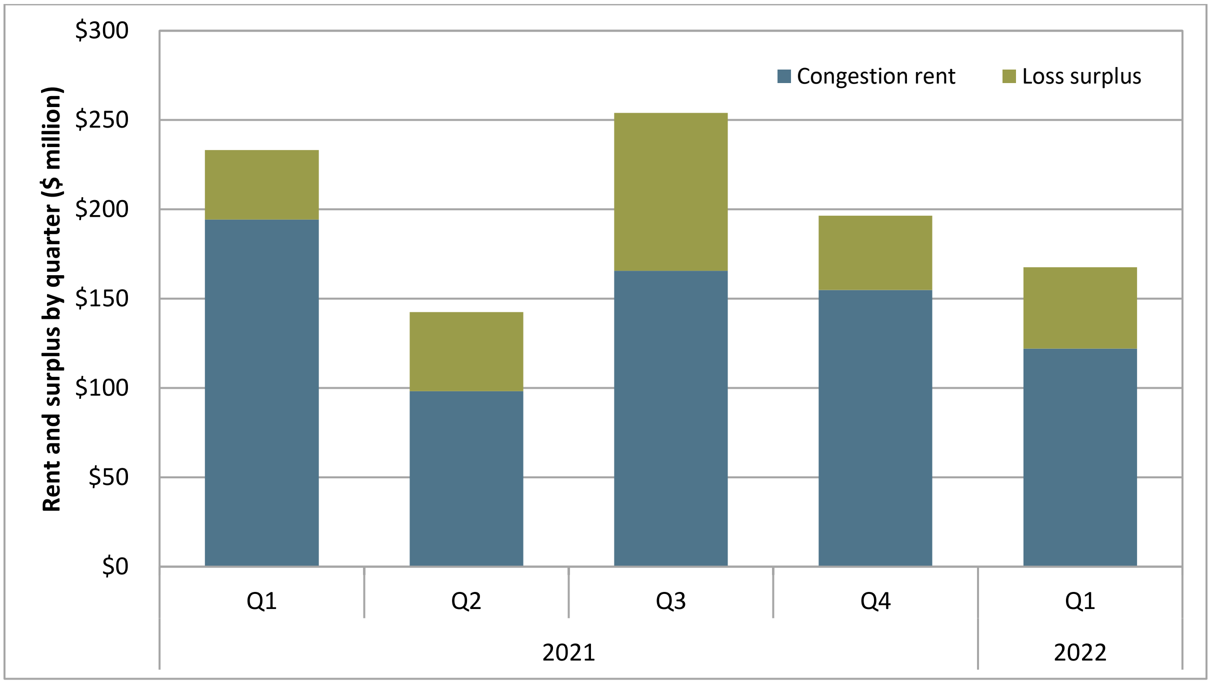


Figure 1.29 shows the overall impact of congestion on day-ahead prices in each load area in 2021 and 2022. Figure 1.30 shows the frequency of congestion. Highlights for this quarter include:

- The overall impact of congestion on price separation in the first quarter was very different from the same time last year. Day-ahead congestion raised prices in PG&E and lowered prices in the SCE and SDG&E areas, the opposite of what occurred in the first quarter of 2021. This south-to-north congestion is reflective of the lower load and higher renewable generation experienced during the quarter.
- Congestion increased quarterly average prices in PG&E by $1.21/MWh (2.4 percent) while it decreased prices in SCE and SDG&E by $1.01/MWh (2.2 percent) and $0.72/MWh (1.5 percent), respectively.
- The primary constraints impacting day-ahead market prices were the Panoche-Gates #2 230 kV line, the Doublet Tap-Friars 138 kV line, and the Suncrest bank 81 transformer outage nomogram.

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

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

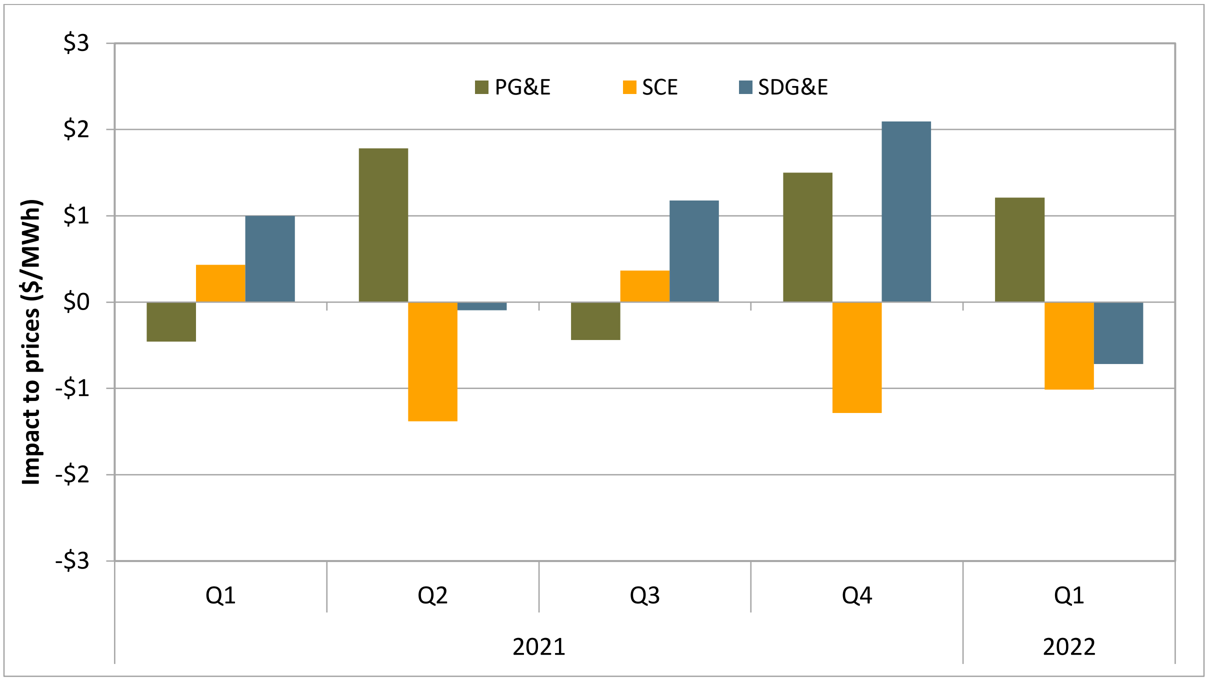
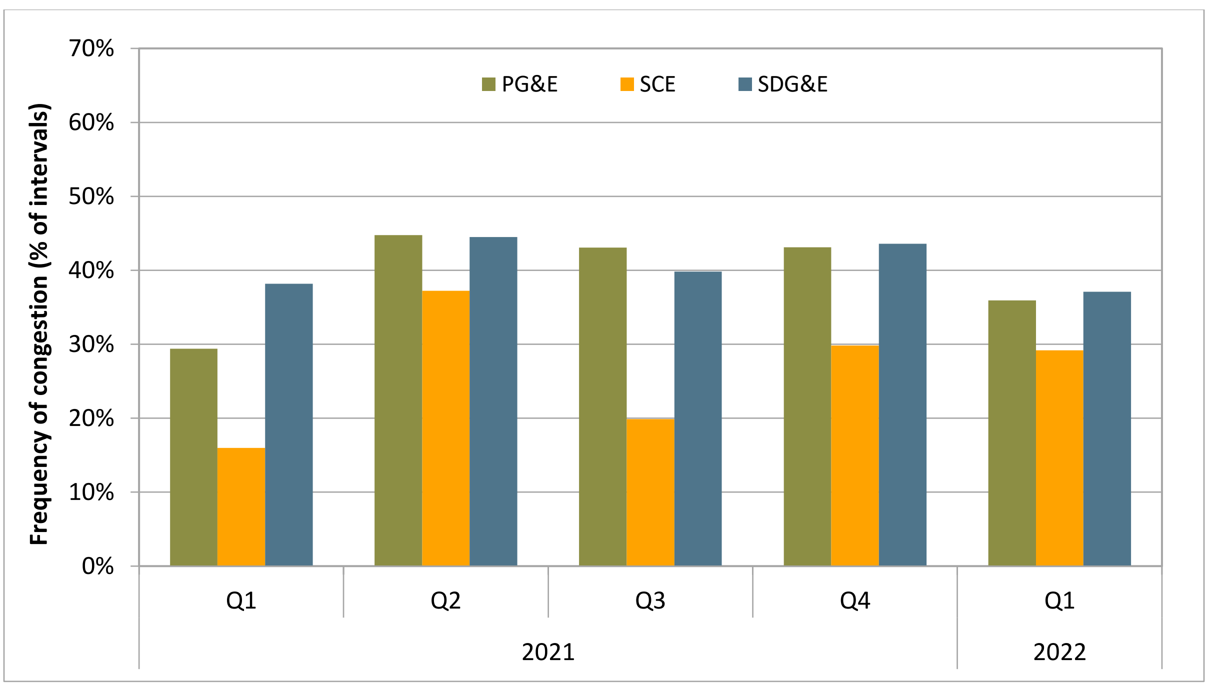


Figure 1.30 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the congestion impact on price separation during the quarter by constraint.[42] 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 price separation for the quarter were the Panoche-Gates #2 230 kV line, the Doublet Tap-Friars 138 kV line, and the Suncrest bank 81 transformer outage nomogram.

Panoche-Gates #2 230 kV line

The Panoche-Gates #2 230 kV line (30790_PANOCHE_230_30900_GATES_230_BR_2_1) had the greatest impact on day-ahead prices during the first quarter. The line was congested during 11 percent of hours. When congested, it decreased SCE and SDG&E prices by $5.15/MWh and $4.93/MWh, respectively, and increased PG&E prices by $6.44/MWh. For the quarter, congestion on the line decreased average SCE and SDG&E prices by $0.53/MWh (1.2 percent) and $0.43/MWh (0.9 percent), respectively, and increased average PG&E prices by $0.69/MWh (1.4 percent). This line was frequently mitigated due to the loss of the Gates-Los Banos 500 kV line.

Doublet Tap-Friars 138 kV line

The Doublet Tap-Friars 138 kV line (22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1) bound in 13 percent of hours over the quarter. When binding, it decreased prices in SDG&E by $6.11/MWh. For the quarter, congestion on the line decreased average SDG&E prices by $0.79/MWh (1.7 percent). This line was mitigated for the loss of the Sycamore-Penasquitos 230 kV line and Penasquitos-Old Town 230 kV line. Upgrade work on these lines is scheduled to be completed in June of 2022.

Suncrest bank 81 transformer outage nomogram

The Suncrest bank 81 transformer outage nomogram (OMS_11281965_SUNCREST BK81_NG) bound in about 4 percent of hours. When binding, it decreased PG&E prices by $0.68/MWh and increased SDG&E prices by $9.83/MWh. For the quarter, the nomogram decreased average PG&E prices by about $0.02/MWh (0.1 percent), and increased average SDG&E prices by $0.34/MWh (0.7 percent). This nomogram was used to mitigate for transformer work at the Suncrest substation.

42 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	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.69	1.36%	-$0.53	-1.15%	-$0.43	-0.91%
	7440_MetcalfImport_Mossld-Metclf	$0.14	0.28%	-$0.11	-0.24%	-$0.11	-0.23%
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	$0.14	0.27%	-$0.11	-0.25%	-$0.10	-0.22%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.12	0.24%	-$0.09	-0.20%	-$0.07	-0.14%
	7440_MetcalfImport_Tes-Metcalf	$0.05	0.09%	-$0.04	-0.08%	-$0.04	-0.07%
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	$0.04	0.08%	-$0.03	-0.07%	-$0.03	-0.06%
	OMS_11291263_Metcalf_Import_BG	$0.03	0.06%	-$0.02	-0.05%	-$0.02	-0.05%
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	$0.03	0.06%	-$0.02	-0.05%	-$0.02	-0.05%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.02	0.04%	-$0.02	-0.03%	-$0.01	-0.03%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
	ML_RM12_NS	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.02%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.01%	$0.00	0.00%
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _S	$0.01	0.01%	-$0.01	-0.01%	-$0.01	-0.01%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
	OMS_10860061_RED_BLUFF_XF	$0.00	0.01%	-$0.04	-0.09%	$0.01	0.01%
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.04	-0.07%	$0.04	0.08%	$0.01	0.01%
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	-$0.02	-0.05%	$0.03	0.06%	-$0.02	-0.05%
	6410_CP10_NG	$0.01	0.03%	-$0.01	-0.03%	-$0.01	-0.02%
SDG&E	OMS_11281965_SUNCREST BK81_NG	-$0.02	-0.05%	$0.00	0.00%	$0.34	0.72%
	7820_TL 230S_OVERLOAD_NG	-$0.02	-0.05%	$0.00	0.00%	$0.25	0.52%
	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1	-$0.03	-0.06%	$0.00	0.00%	$0.16	0.35%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-$0.01	-0.02%	$0.00	0.00%	$0.06	0.12%
	OMS 11136021_TL50003_NG	$0.00	-0.01%	$0.00	0.00%	$0.03	0.05%
	OMS_11282192_SUNCREST BK80_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.79	-1.68%
Other		$0.03	0.06%	$0.00	0.01%	$0.07	0.14%
Total		**$1.21**	**2.39%**	**-$1.01**	**-2.18%**	**-$0.72**	**-1.52%**

Table 1.3 Impact of congestion on day-ahead prices during congested hours[43]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	0.4%	$7.13	-$5.50	-$5.24
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	10.8%	$6.44	-$5.15	-$4.93
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	0.8%	$5.02	-$4.00	-$3.61
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.3%	$4.35	-$3.65	-$3.30
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.1%	$4.03	-$3.53	-$3.16
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	3.8%	$3.58	-$3.01	-$2.74
	7440_MetcalfImport_Tes-Metcalf	1.4%	$3.14	-$2.56	-$2.42
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.7%	$2.84	-$2.31	-$2.08
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	4.9%	$2.48	-$2.04	-$2.86
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	0.3%	$2.45	-$1.96	-$1.78
	ML_RM12_NS	0.5%	$2.26	-$1.43	-$2.27
	30055_GATES1 _500_30900_GATES _230_XF_12_P	0.5%	$2.13	-$1.77	-$1.67
	7440_MetcalfImport_Mossld-Metclf	8.2%	$1.72	-$1.35	-$1.33
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.3%	$1.57	-$1.27	-$1.14
	OMS_11291263_Metcalf_Import_BG	2.4%	$1.28	-$0.96	-$0.94
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	0.8%	$1.06	-$0.98	-$0.61
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _S	0.8%	$0.78	-$0.64	-$0.65
	OMS_10860061_RED_BLUFF_XF	13.5%	$0.45	-$0.33	$0.07
SCE	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	0.8%	-$2.98	$3.22	-$2.74
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.5%	-$2.35	$2.64	$1.09
	6410_CP10_NG	0.4%	$3.06	-$2.77	-$2.54
SDG&E	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1	0.8%	-$6.28	$0.00	$20.84
	OMS_11281965_SUNCREST BK81_NG	3.5%	-$0.68	$0.00	$9.83
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.9%	-$1.16	$0.00	$6.61
	OMS 11136021_TL50003_NG	0.4%	-$0.56	$0.00	$5.94
	MIGUEL_BKs_MXFLW_NG	0.3%	-$0.47	$0.00	$5.52
	OMS_11282192_SUNCREST BK80_NG	0.6%	-$0.28	$0.00	$3.73
	7820_TL 230S_OVERLOAD_NG	8.6%	-$0.28	$0.00	$2.88
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	1.0%	$0.00	$0.00	$1.99
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	0.6%	$0.00	$0.00	$1.51
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	13.0%	$0.00	$0.00	-$6.11

43 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.

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

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

- The net impact of internal flow-based constraint congestion generally raised prices in the Pacific Northwest and decreased prices in the East and Southwest. This is opposite the effects seen in the first quarter of 2021.
- The primary constraints creating price separation in the 15-minute market were Panoche-Gates #2 230 kV line, the Imperial Valley-El Centro 230 kV nomogram, and the Los Banos-Gates 500 kV line.

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

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

Impact of internal congestion from individual constraints

This section focuses on individual flow-based constraints. In the first quarter, the constraints that had the greatest impact on price separation in the 15-minute market were the Panoche-Gates #2 230 kV line, the Imperial Valley-El Centro 230 kV nomogram, and the Los Banos-Gates 500 kV line.[44] These constraints were frequently mitigated due to the loss of the Gates-Los Banos 500 kV line, the North Gila-Imperial Valley 500 kV line, and the Los Banos-Midway #2 500 kV line, 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 therefore excludes “other” in Table 1.4. The category labeled “other” 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.

Table 1.4 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	PWRX	SCL
AZPS	FC-CH2		$0.01	$0.01					$0.01	$0.01	-$0.05	-$0.01	-$0.01	-$0.01					
NWMT	RIMROCK_PAR											-$0.25		$0.47					
PACE	EAST_WYO_EXP											-$0.08							
	WINDSTAR EXPORT TCOR											-$0.12							
	TOTAL_WYOMING_EXPORT											-$1.29							
PG&E	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.54	-$1.08	-$1.02	$0.94	$1.16	-$0.88	-$0.16	-$0.90	-$0.90	-$0.70			$0.04	$0.44	$0.43	$0.41	$0.41	$0.41
	ML_RM12_NS	$0.21	$0.12	$0.11	$0.20	$0.21	$0.12	$0.04	$0.08	$0.08	$0.04	-$0.10	-$0.19	-$0.23	-$0.26	-$0.26	-$0.26	-$0.26	-$0.26
	7440_MetcalfImport_Tes-Metcalf	$0.14	-$0.12	-$0.12	$0.09	$0.12	-$0.11	-$0.07	-$0.11	-$0.11	-$0.09	$0.00			$0.04	$0.04	$0.03	$0.02	$0.03
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.12	-$0.26	-$0.24	$0.20	$0.20	-$0.22	-$0.13	-$0.21	-$0.21	-$0.18	$0.00	$0.08	$0.12	$0.16	$0.16	$0.16	$0.16	$0.16
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.10	-$0.15	-$0.14	$0.11	$0.13	-$0.11	-$0.07	-$0.12	-$0.12	-$0.10		$0.00	$0.05	$0.08	$0.08	$0.08	$0.08	$0.08
	7440_MetcalfImport_Mossld-Metclf	$0.07	-$0.03	-$0.03	$0.01	$0.03	-$0.03	-$0.02	-$0.03	-$0.03	-$0.03	-$0.02	-$0.01	-$0.01		$0.00	$0.00	$0.00	$0.00
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.06	$0.04	$0.03	$0.05	$0.07	$0.02	$0.02	$0.03	$0.03	$0.02	-$0.02	-$0.05	-$0.06	-$0.08	-$0.08	-$0.07	-$0.07	-$0.07
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.06	-$0.09	-$0.09	$0.07	$0.07	-$0.07	-$0.04	-$0.08	-$0.08	-$0.07	$0.00	$0.03	$0.04	$0.06	$0.06	$0.05	$0.05	$0.05
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	$0.04	-$0.09	-$0.09	$0.08	$0.07	-$0.09	-$0.05	-$0.08	-$0.08	-$0.06		$0.03	$0.05	$0.06	$0.06	$0.06	$0.06	$0.06
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.03	-$0.05	-$0.04	$0.03	$0.04	-$0.04	-$0.02	-$0.04	-$0.04	-$0.03	-$0.01	$0.01	$0.02	$0.03	$0.03	$0.03	$0.02	$0.03
	TMS_DLO_NG	$0.03	$0.01	$0.01	$0.04	$0.03	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	$0.02	-$0.04	-$0.03	$0.03	$0.03	-$0.03	-$0.02	-$0.03	-$0.03	-$0.03	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	$0.02	-$0.02	-$0.02	$0.01	$0.01	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01								
	30300_TABLMTN _230_30330_RIO OSO _230_BR_1 _1	$0.01			$0.02	$0.02							-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30042_METCALF _500_30045_MOSSLAND_500_BR_1 _1	$0.01	-$0.03	-$0.03	$0.02	$0.02	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02		$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.01	-$0.04	-$0.04	$0.05	$0.10	-$0.03	-$0.02	-$0.03	-$0.03	-$0.03		$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.01	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	OMS_11291263_Metcalf_Import_BG	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00							
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.01	-$0.04	-$0.04		$0.00	-$0.01		-$0.01	-$0.01	-$0.01								
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.00	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS_10860061_RED_BLUFF_XF	-$0.05	$0.00	$0.00	-$0.04	-$0.04	-$0.01	$0.06	$0.00	$0.00	$0.00	$0.06	$0.00						
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1		-$0.01	-$0.01	$0.02	$0.04	-$0.01		-$0.01	-$0.01	$0.00								
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1		-$0.04	-$0.04	$0.05	$0.11	-$0.01		-$0.03	-$0.03	$0.00								
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1							$0.42											
SCE	SYLMAR-AC_BG	$0.01	$0.02		$0.01	$0.01	-$0.07	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01			$0.01	$0.01	$0.00	$0.00	$0.00
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1		$0.01	-$0.01				-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00						
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 10666077_OP-6610	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	99002_MOE-ELD _500_24042_ELDORDO _500_BR_1 _2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	$0.00							
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00
	OP-6610_ELD-LUGO	$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
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.15	$1.70				-$0.13	-$0.36	-$0.39	-$0.31	-$0.13	-$0.04	$0.00					
	OMS_11281965_SUNCREST BK81_NG		$0.02	$0.74				-$0.02	-$0.25	-$0.26	-$0.20	-$0.03							
	OMS 11065185_50004_OOS_NG		$0.01	$0.15				-$0.01	-$0.05	-$0.06	-$0.02	-$0.01							
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.01	$0.11				-$0.01	-$0.04	-$0.04	-$0.03	-$0.01							
	OMS 11206402_50002_OOS_TDM			$0.10					-$0.03	-$0.02									
	OMS 11136021_TL50003_NG		$0.00	$0.03				$0.00	-$0.01	-$0.01	$0.00	$0.00							
	OMS_11282192_SUNCREST BK80_NG		$0.00	$0.03				$0.00	-$0.01	-$0.01	-$0.01	$0.00							
	MIGUEL_BKs_MXFLW_NG		$0.00	$0.01					$0.00	$0.00	$0.00								
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			-$0.72					$0.00	-$0.01									
	Other	$0.00	-$0.02	$0.01	-$0.01	$0.00	$0.06	-$0.13	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.00	-$0.01	$0.00	-$0.01	-$0.01	$0.01
	Internal Total	**$1.45**	**-$1.68**	**$0.38**	**$2.01**	**$2.45**	**-$1.58**	**-$0.45**	**-$2.39**	**-$2.43**	**-$1.97**	**-$2.09**	**-$0.16**	**$0.49**	**$0.53**	**$0.52**	**$0.48**	**$0.47**	**$0.50**
	Transfers				$0.00	-$0.22	$0.23	$0.17	-$0.63	$0.27	$0.14	-$0.41	$0.75	-$0.18	-$3.55	-$2.95	-$4.56	-$4.49	-$4.53
	Grand Total	**$1.45**	**-$1.68**	**$0.38**	**$2.01**	**$2.23**	**-$1.35**	**-$0.28**	**-$3.02**	**-$2.16**	**-$1.83**	**-$2.50**	**$0.59**	**$0.31**	**-$3.02**	**-$2.43**	**-$4.08**	**-$4.02**	**-$4.03**

44 These constraints are shown as 30790_PANOCHE_230_30900_GATES_230_BR_2_1, 7820_TL230S_OVERLOAD_NG, and 30050_LOSBANOS_500_30055_GATES1_500_BR_1_1 in the tables, respectively.

Table 1.5 Impact of internal congestion on 15-minute prices during congested intervals[45]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	PWRX	SCL
NWMT	RIMROCK_PAR	1.5%											-$16.61		$30.94					
PACE	WINDSTAR EXPORT TCOR	12.1%											-$1.03							
	EAST_WYO_EXP	7.6%											-$1.11							
	TOTAL_WYOMING_EXPORT	61.5%											-$2.10							
PG&E	ML_RM12_NS	1.0%	$20.85	$12.48	$11.12	$20.45	$20.69	$12.10	$4.04	$8.46	$8.35	$3.99	-$10.19	-$18.97	-$22.82	-$26.20	-$26.61	-$26.16	-$25.96	-$26.13
	7440_MetcalfImport_Tes-Metcalf	0.9%	$15.28	-$13.69	-$13.08	$9.71	$13.32	-$12.16	-$8.29	-$11.93	-$11.96	-$10.37	-$3.32			$4.09	$4.04	$3.83	$4.02	$3.93
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	0.5%	$12.51	$7.58	$6.81	$9.05	$12.86	$4.76	$2.95	$5.42	$5.44	$3.70	-$4.76	-$10.09	-$12.39	-$14.83	-$14.93	-$14.64	-$14.51	-$14.63
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	8.0%	$8.53	-$13.52	-$12.74	$11.83	$14.43	-$11.27	-$7.26	-$11.20	-$11.19	-$10.33			$6.17	$8.81	$8.80	$8.57	$8.43	$8.56
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	1.2%	$8.39	-$12.57	-$11.84	$11.33	$10.96	-$11.37	-$6.99	-$11.54	-$11.55	-$9.96		$2.16	$5.45	$8.11	$8.00	$7.73	$7.59	$7.72
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	1.8%	$6.67	-$14.56	-$13.66	$11.50	$11.32	-$12.31	-$7.23	-$11.97	-$12.01	-$9.93	-$0.51	$4.58	$6.94	$9.24	$9.17	$8.87	$8.74	$8.85
	7440_MetcalfImport_Mossld-Metclf	1.1%	$6.60	-$2.90	-$2.82	$1.59	$2.99	-$2.64	-$2.18	-$2.68	-$2.68	-$2.54	-$1.78	-$1.33	-$1.67		-$2.32	-$2.32	-$1.34	-$2.32
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.7%	$6.00	-$12.75	-$11.93	$10.30	$9.55	-$12.53	-$6.38	-$10.40	-$10.35	-$8.00		$4.68	$6.56	$8.56	$8.52	$8.26	$8.14	$8.24
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_1 _1	0.3%	$5.71	-$5.61	-$5.35	$3.14	$4.09	-$5.01	-$3.46	-$4.91	-$4.91	-$4.28								
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.5%	$5.45	-$8.94	-$8.34	$6.87	$7.08	-$7.09	-$4.44	-$7.35	-$7.32	-$6.26	-$1.03	$2.15	$3.69	$5.14	$5.10	$4.93	$4.85	$4.92
	30055_GATES1 _500_30057_DIABLO _500_BR_1 _1	0.5%	$4.98	-$8.13	-$7.67	$6.30	$6.50	-$6.34	-$3.99	-$6.77	-$6.73	-$5.81	-$0.58	$2.08	$3.51	$4.77	$4.73	$4.57	$4.50	$4.56
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	1.1%	$4.87	-$8.08	-$7.64	$6.35	$6.49	-$6.26	-$3.87	-$6.79	-$6.77	-$5.94	-$0.74	$2.25	$3.69	$4.90	$4.87	$4.71	$4.64	$4.70
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.6%	$3.55	-$2.60	-$2.48		$2.64	-$2.85		-$2.80	-$2.80	-$2.71								
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.8%	$1.53	-$4.93	-$4.65	$6.22	$13.39	-$4.00	-$2.27	-$4.06	-$4.06	-$3.44		$1.53	$2.25	$3.08	$3.05	$2.96	$2.91	$2.95
	OMS_10860061_RED_BLUFF_XF	9.9%	-$0.51	-$0.03	-$0.01	-$0.41	-$0.46	-$0.42	$0.61	$0.00	$0.01	$0.00	$0.63	$0.42						
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	0.3%		-$4.02	-$3.78	$7.57	$11.64	-$3.16		-$3.50	-$3.29	-$3.02								
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.5%		-$8.30	-$7.74	$9.97	$21.14	-$4.42		-$7.79	-$7.75	-$6.22								
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	2.3%							$17.80											
SCE	SYLMAR-AC_BG	0.4%	$2.97	$4.73		$2.63	$2.85	-$19.05	-$5.44	-$5.06	-$5.01	-$5.06	-$2.32			$1.43	$1.42	$1.30	$1.25	$1.30
	OMS 10666077_OP-6610	0.4%	$2.11	$2.58	$3.22	$1.82	$2.00	-$5.92	-$4.67	-$4.62	-$4.67	-$4.66	-$2.28	-$0.37		$0.71	$0.70	$0.64	$0.63	$0.63
SDG&E	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P																			
	OMS 11065185_50004_OOS_NG																			
	OMS_11281965_SUNCREST BK81_NG	0.3%		$1.32	$29.51				-$1.27	-$10.09	-$10.26	-$8.12	-$1.38							
	7820_TL 230S_OVERLOAD_NG	0.5%	$0.31	$1.28	$14.81				-$1.11	-$3.17	-$3.43	-$2.70	-$1.12	-$0.74	-$0.57					
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	2.5%			-$9.94					-$7.86	-$5.63									

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. The largest price impact over the quarter was in Puget Sound Energy, with an average decrease of about $4.56/MWh in the 15-minute market and $1.57/MWh in the 5-minute market.

In the 15-minute market, the total impact of congestion on a specific WEIM area is equal to the sum of the price impact of flow-based constraints shown in Figure 1.31 and Table 1.4, and schedule-based constraints as listed in Table 1.6. Transfer constraint congestion typically has the largest impact on prices; therefore, it is isolated here to better show its effects on WEIM load areas. Table 1.6 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter.

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

Table 1.6 Quarterly average price impact and congestion frequency on WEIM transfer constraints (Q1 2022)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	$0.00	0%	-$0.09
Turlock Irrigation District	1%	-$0.22	1%	-$0.17
Arizona Public Service	1%	-$0.63	1%	-$0.25
L.A. Dept. of Water and Power	1%	$0.23	1%	$0.13
Public Service Company of NM	2%	$0.14	1%	$0.66
NV Energy	2%	$0.17	2%	-$0.77
Salt River Project	4%	$0.27	3%	$1.09
PacifiCorp East	9%	-$0.41	5%	-$0.27
Idaho Power	16%	$0.75	12%	$1.37
NorthWestern Energy	22%	-$0.18	18%	$1.59
PacifiCorp West	44%	-$3.55	27%	-$1.15
Portland General Electric	45%	-$2.95	28%	-$1.27
Puget Sound Energy	55%	-$4.56	48%	-$1.57
Seattle City Light	55%	-$4.53	48%	-$1.44
Powerex	53%	-$4.49	67%	-$0.39

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 1.32 and Figure 1.33 show the average impact to prices and the frequency of congestion on transfer constraints in the 15-minute market by quarter for 2021 and 2022, respectively.

There was an overall decrease on the impact of average prices from transfer constraint congestion in the first quarter of 2022 compared to the same quarter in 2021. In contrast, there was an overall increase in the frequency of transfer constraint congestion relative to the same quarter of 2021. This is exemplified in Puget Sound Energy, which saw the impact of transfer constraint congestion decrease to -$4.56 from -$5.86 while the area's frequency of transfer constraint congestion increased to 55 percent from 52 percent a year ago.

Figure 1.32 Transfer constraint congestion average impact on prices in the 15-minute market

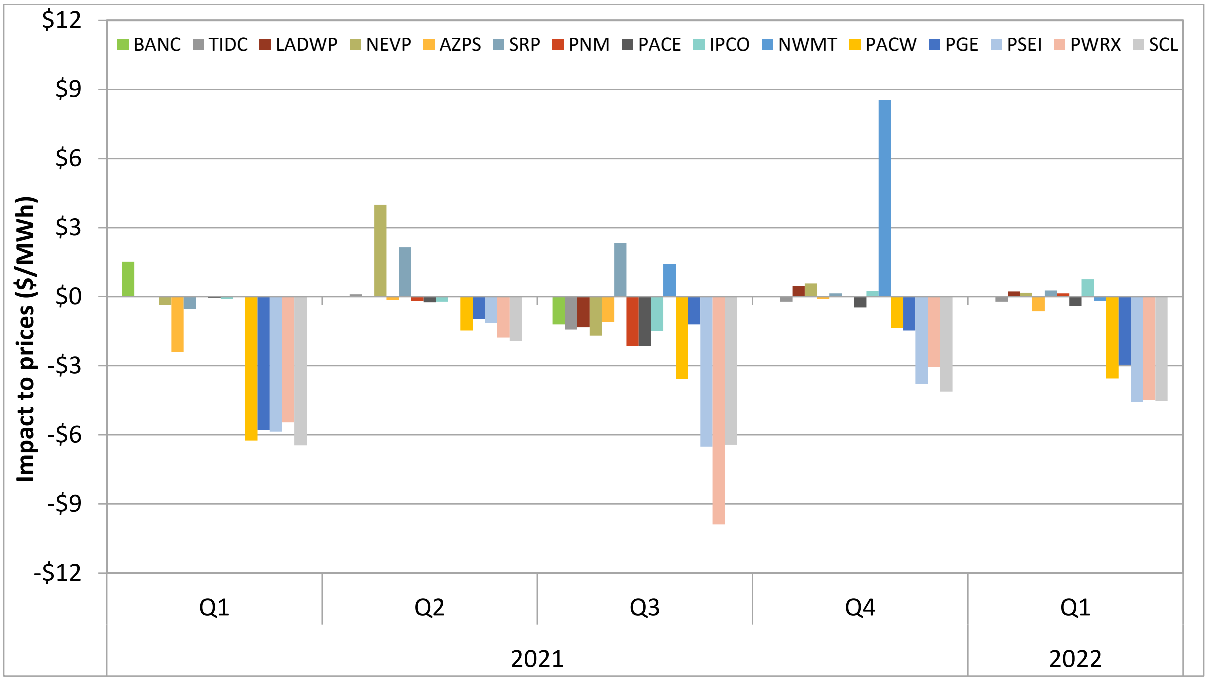
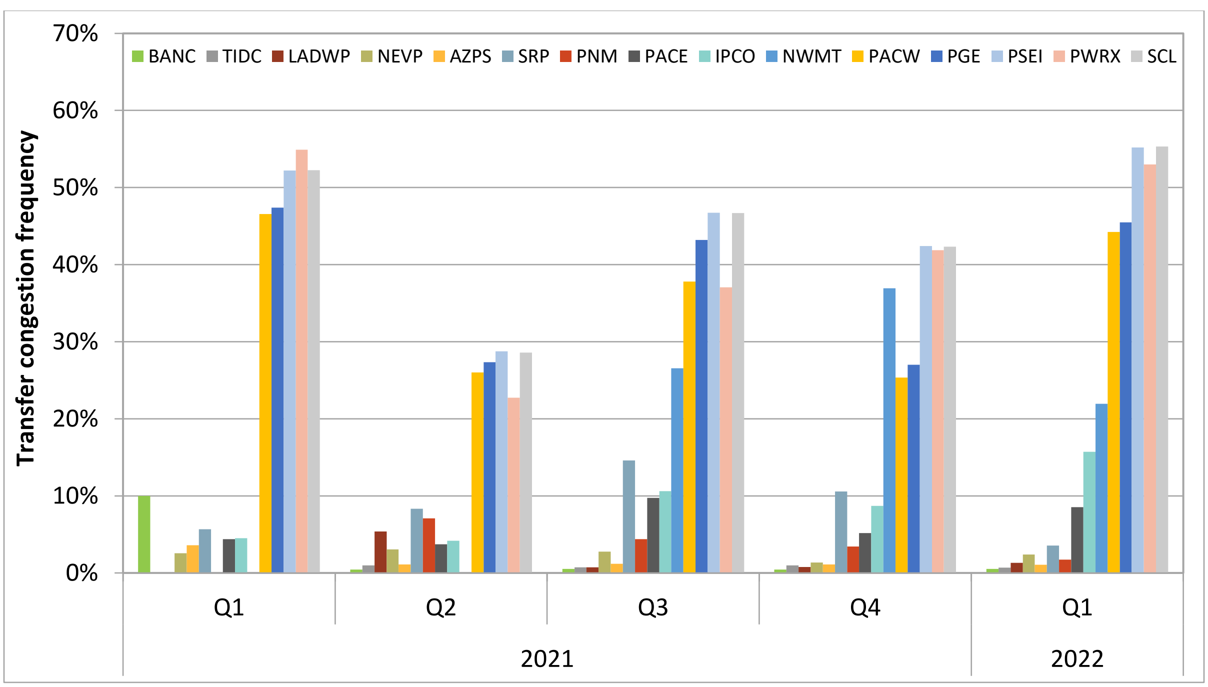


Figure 1.33 Transfer constraint congestion frequency in the 15-minute market



1.8.3 Congestion on interties

In the first quarter of 2022, congestion frequency and import congestion rent on Palo Verde remained notably high relative to the same quarter in 2021. Congestion on PACI/Malin 500 decreased while it increased over NOB relative to last year. Figure 1.34 shows total import congestion charges in the day-ahead market for 2021 and 2022. Figure 1.35 shows the frequency of congestion on five major interties. Table 1.7 provides a detailed summary of this data over a broader set of interties.

The total import congestion charges reported are the products of the shadow prices multiplied by the binding limits for the intertie constraints. For a supplier or load serving entity trying to import power over a congested intertie, assuming a radial line, the congestion price represents the difference between the higher price of the import on the 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 highlight the following:

- Total import congestion charges for the first quarter of 2022 were 41 percent higher than the first quarter of 2021 at $31 million. The primary change between the quarters was an increase in congestion rent from Palo Verde. Palo Verde accounted for 31 percent of the total import congestion charges for the quarter, compared to <1 percent in the same quarter last year.
- The frequency and impact of congestion on Palo Verde has remained elevated since the third quarter of 2021. Over the first quarter of 2022, the intertie was congested during 15 percent of intervals and accounted for $9.7 million in congestion charges.
- The frequency of congestion and magnitude of congestion charges is typically highest on the PACI/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 1.34 Day-ahead import congestion charges on major interties

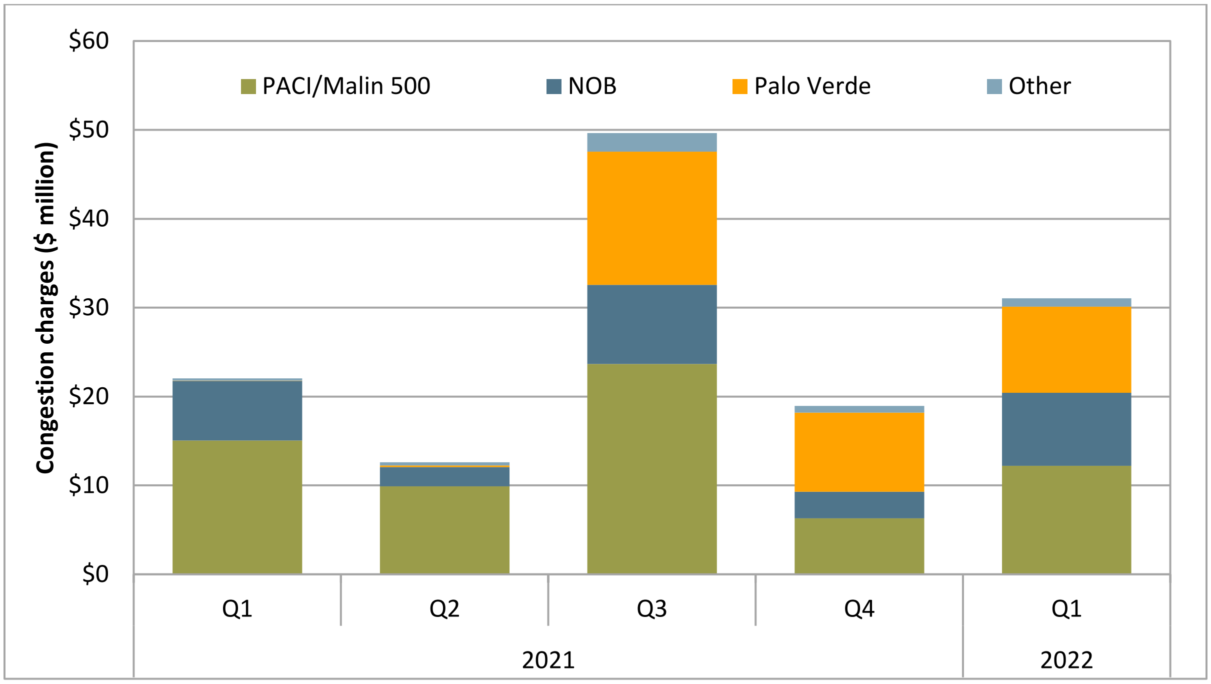


Figure 1.35 Frequency of import congestion on major interties in the day-ahead market

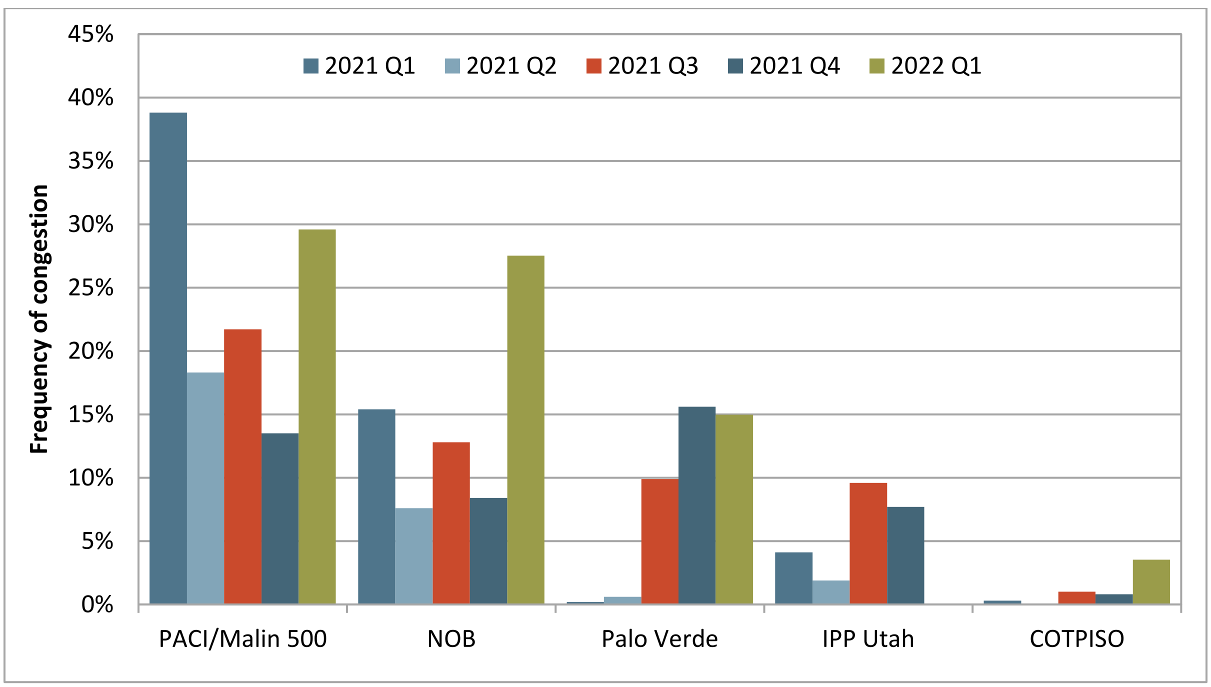


Table 1.7 Summary of import congestion in day-ahead market (2021-2022)

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

1.9 Bid cost recovery

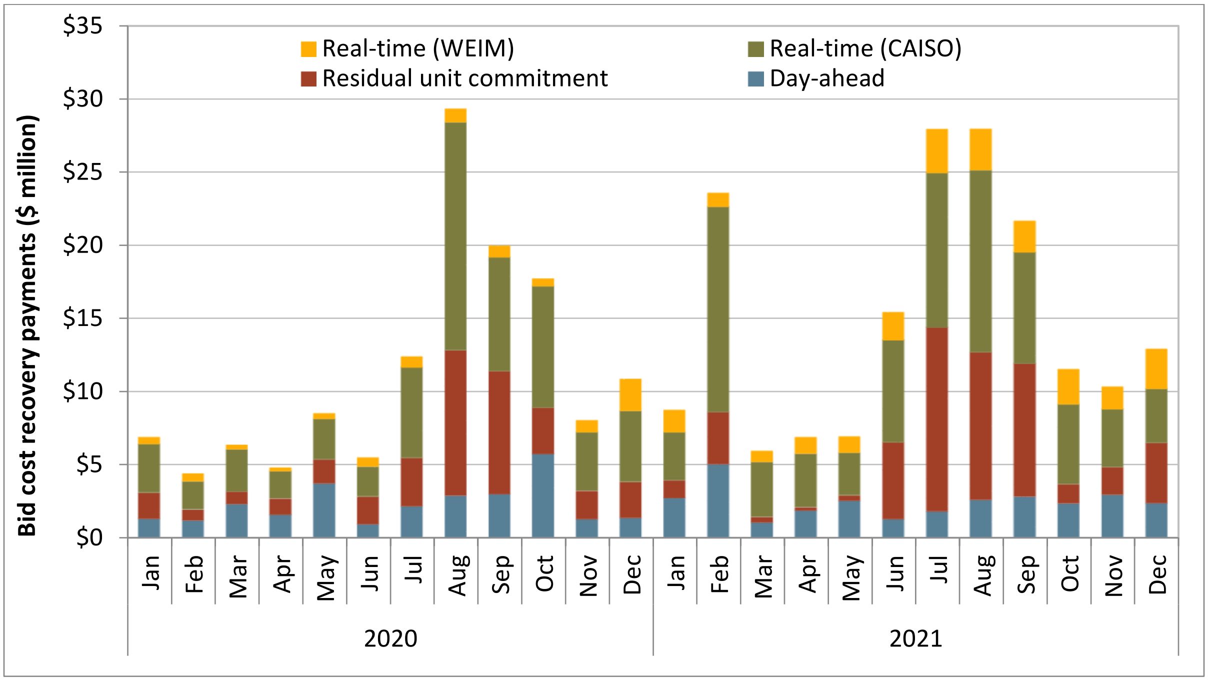
During the fourth quarter of 2021, estimated bid cost recovery payments for units in the California ISO and Western Energy Imbalance Market (WEIM) balancing areas totaled about $35 million. This was $43 million lower than total bid cost recovery in the previous quarter and about $2 million lower than the fourth quarter of 2020. 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 substantially between statements.[46]

Bid cost recovery attributed to the day-ahead market totaled about $8 million, which was similar to the fourth quarter of 2020. Bid cost recovery payments for residual unit commitment during the quarter totaled about $7 million, similar to the fourth quarter of 2020. Bid cost recovery attributed to the real-time market totaled about $20 million, or about $19 million lower than payments in the previous quarter, and $1 million lower than payments in the fourth quarter of 2020. Out of the $20 million in real-time payments, about $7 million was allocated to resources (non-California ISO) participating in the WEIM.

For 2021, bid cost recovery payments for units in the CAISO and WEIM balancing areas totaled around $158 million and $22 million, respectively, the highest total since 2011. The majority of these payments, about $164 million, were to gas resources followed by $7.2 million to hydro resources and about $4 million to battery energy storage resources.

[46] 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

Figure 1.36 Monthly bid cost recovery payments



1.10 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 continues 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 nearly 1,400 MW and at just about 2,100 MW in the afternoon, about a 900 MW and 1,000 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 1.37 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 1.38 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 median, as well as the mean (line). The maximum load adjustments in the morning ramp are around 2,500 MW in hour ending 8 while the maximum evening ramp is about 3,200 MW in hour ending 19.

Figure 1.37 Average hourly imbalance conformance adjustment (Q1 2021 – Q1 2022)

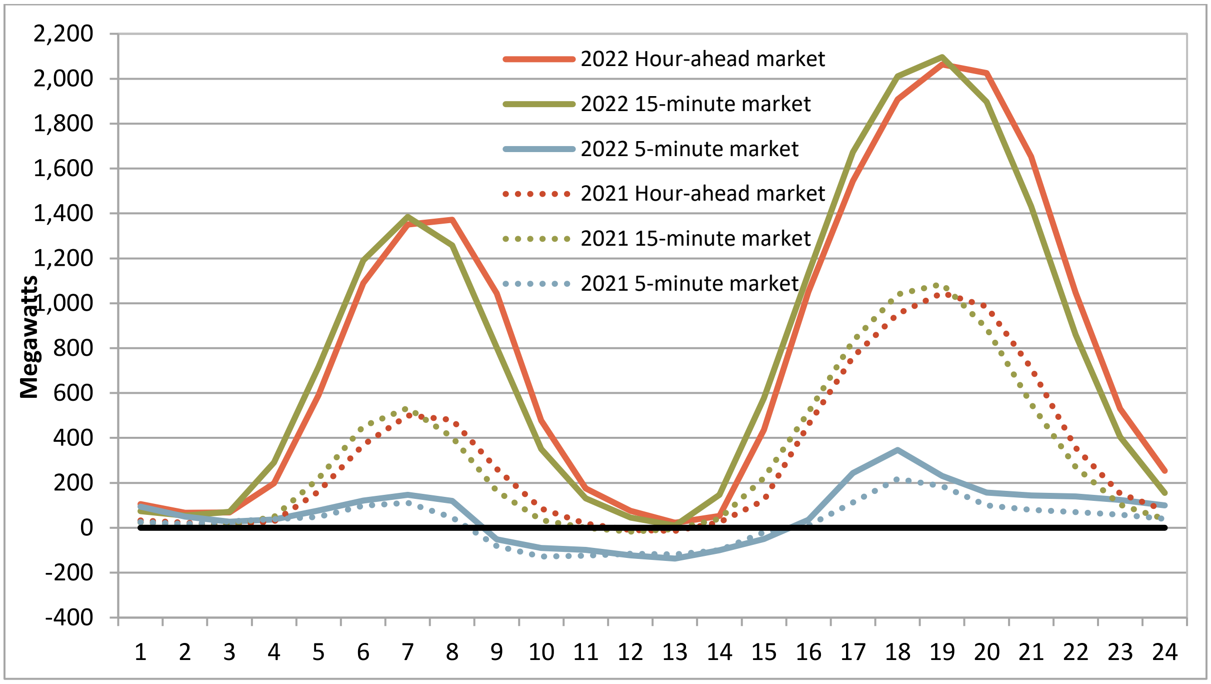
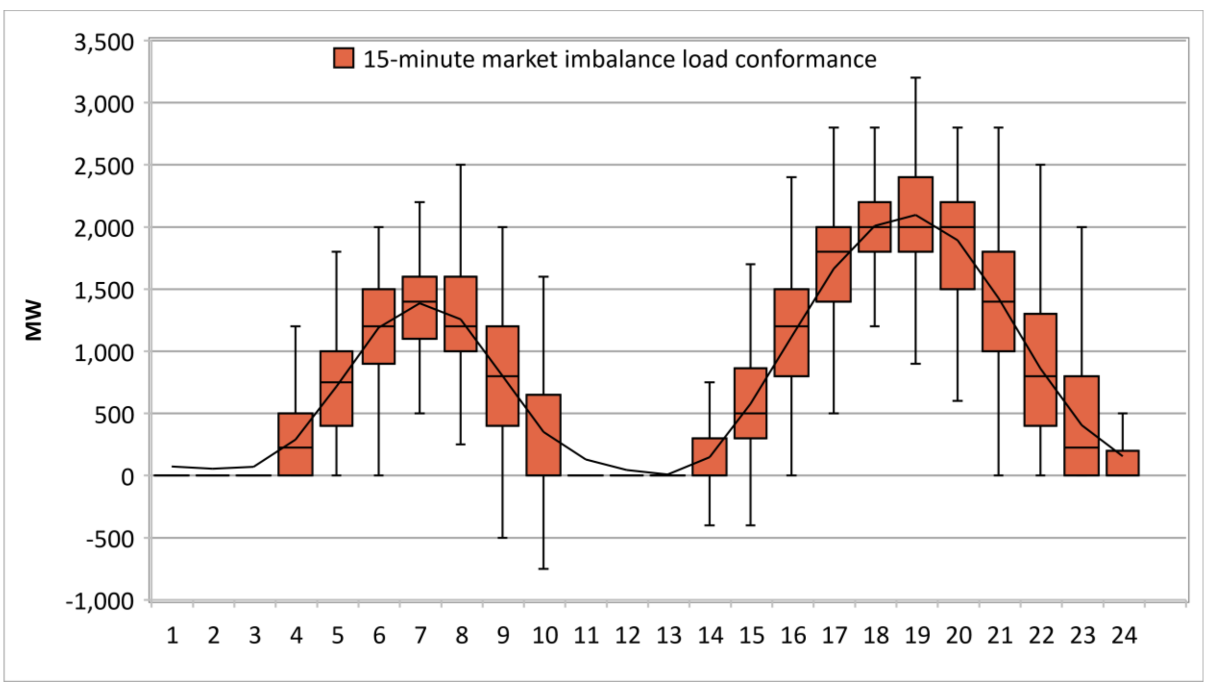


Figure 1.38 15-minute market hourly distribution of operator load adjustments (2022 Q1)



2 Western Energy Imbalance Market

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

- **Natural gas prices rose in parts of the WEIM**, resulting in higher energy prices in some areas.
- **Prices in California areas were about $14/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. This region includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex.
- **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 exported just under 1,500 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.
- **Net load uncertainty was removed from the bid range capacity test** on February 15, 2022, while intertie uncertainty was removed on June 1, 2022. These adders are expected to be revisited as part of the next phase of the resource sufficiency evaluation enhancements stakeholder initiative.
- **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.

2.1 Western Energy Imbalance Market performance

New WEIM balancing authority areas

On March 2, 2022, Avista Utilities and Tacoma Power joined the Western Energy Imbalance Market, bringing the total number of participants up to 16. Avista Utilities and Tacoma Power bring with them about 3,083 MW and 574 MW of participating capacity, respectively.

These areas were only a part of the WEIM for the final weeks of the first quarter; therefore, they are not included in this section’s analysis. The Department of Market Monitoring’s monthly WEIM transition reports will provide more information on these entities’ transition into the WEIM.

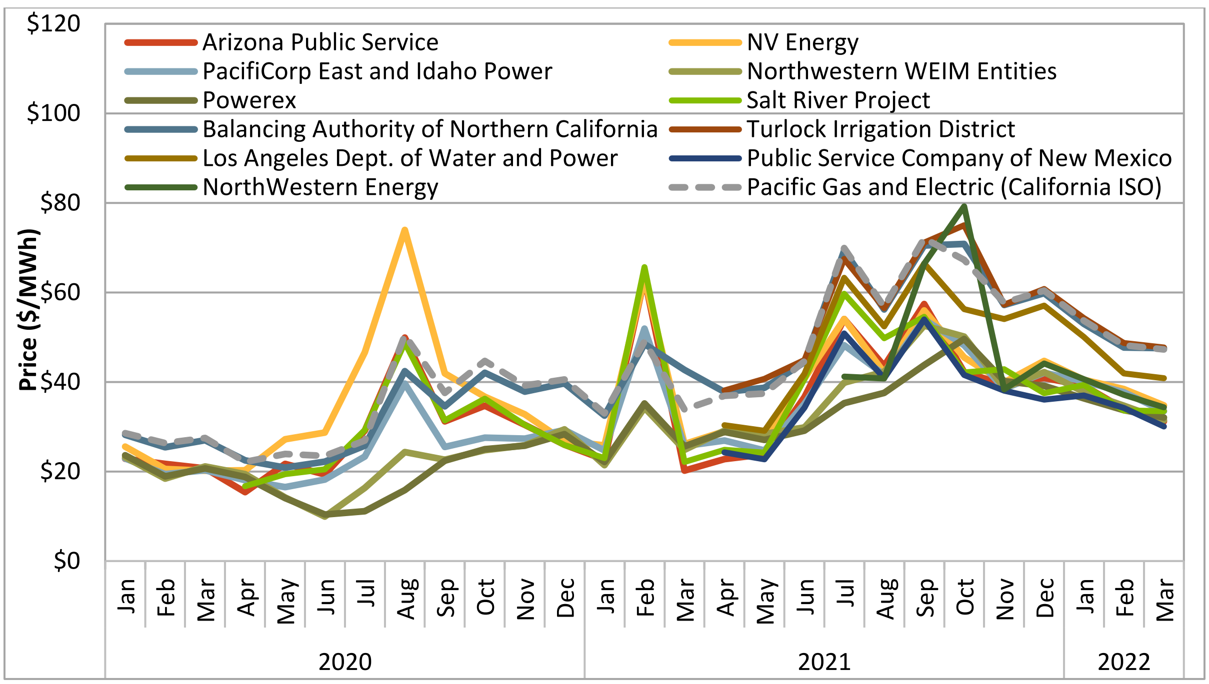
Western Energy Imbalance Market prices

This section details the factors that generally influence changes in 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.

Figure 2.1 shows average monthly prices for the 15-minute market by area for 2020 through 2022.[47] The combined average of WEIM prices outside of California was lower than California area prices by $14.08/MWh on average over the first 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 Balancing Authority of Northern California, Turlock Irrigation District, and Los Angeles Department of Water and Power, were $1.74/MWh lower than Pacific Gas and Electric prices.

Price separation between balancing authorities occurs for several reasons. California area prices tend to be 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.

Figure 2.1 Monthly 15-minute market prices



47 Northwestern WEIM Entities represents the average 15-minute price across PacifiCorp West, Puget Sound Energy, Portland General Electric, and Seattle City Light.

Figure 2.2 Quarterly average 15-minute price by component (Q1 2022)

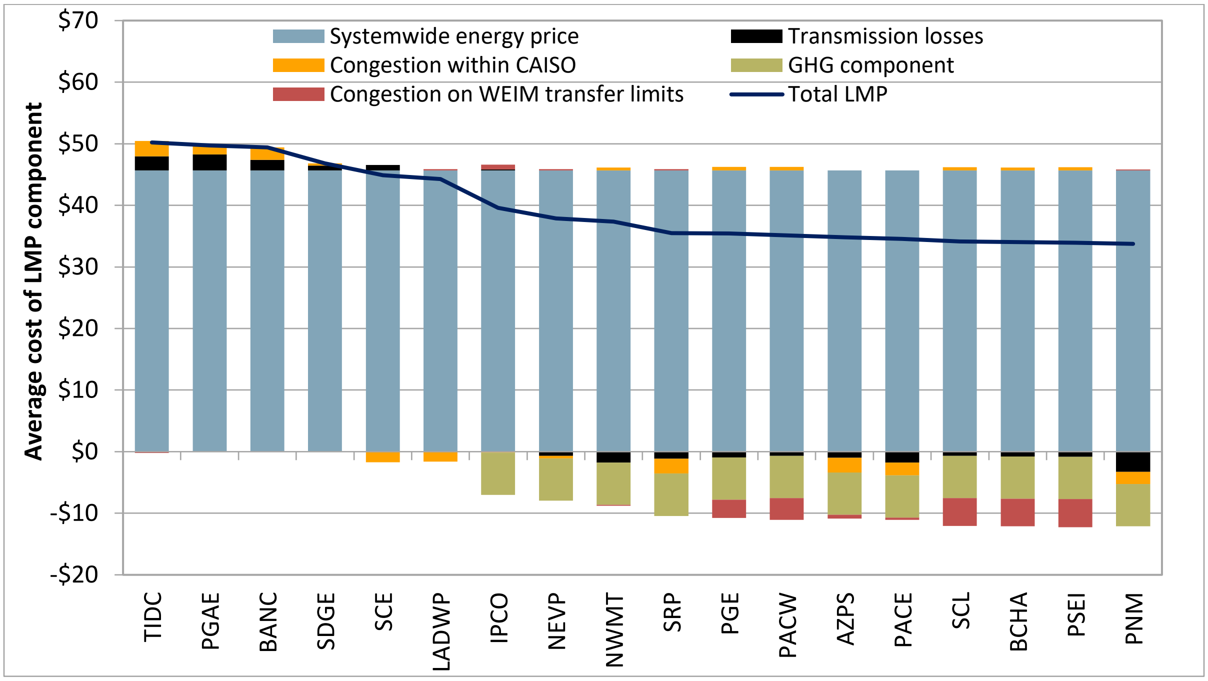


Figure 2.2 depicts the average 15-minute price by component for each balancing authority area.[48] The system marginal energy price is the same for all entities in each hour. The price difference between balancing authority areas is determined by area specific elements including transmission losses, 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 2.1 and Table 2.2 show the variation in prices throughout the day in the first 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.

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

Table 2.1 Hourly 15-minute market prices (January-March)

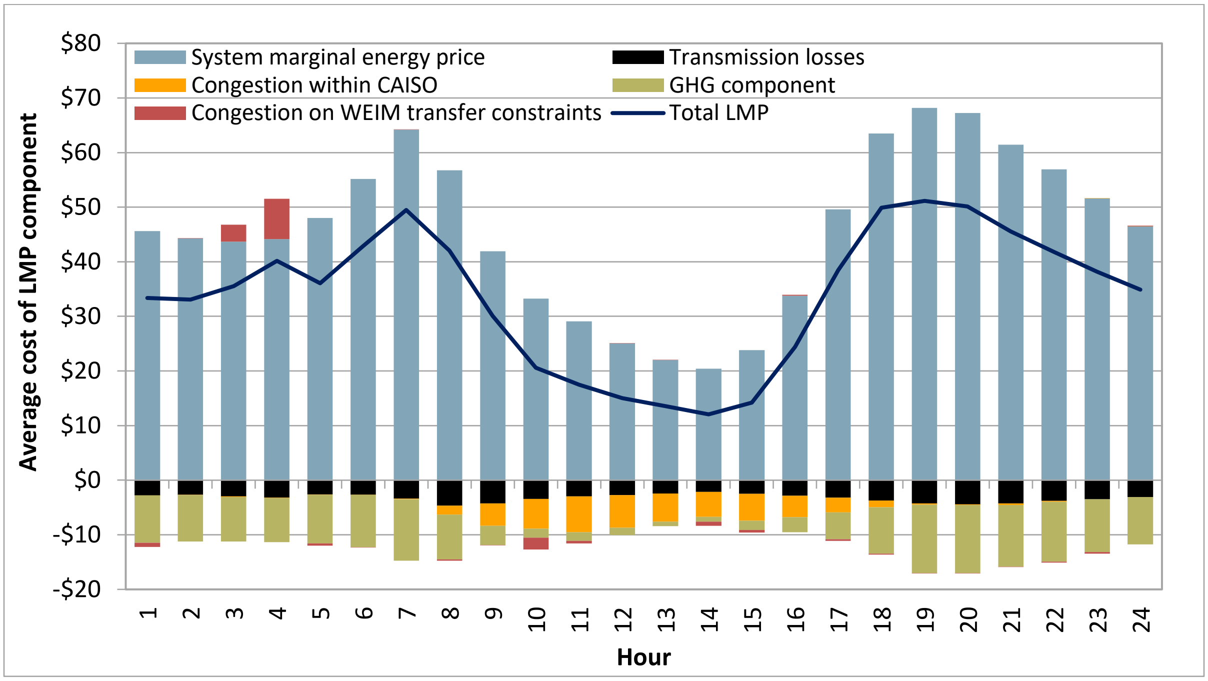
Hour ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$45	$44	$44	$44	$48	$55	$64	$57	$42	$33	$29	$25	$22	$20	$24	$33	$49	$63	$68	$68	$62	$57	$52	$46
PG&E (CAISO)	$48	$47	$46	$46	$51	$58	$68	$63	$48	$38	$34	$30	$26	$24	$28	$37	$53	$68	$74	$74	$67	$61	$55	$49
SCE (CAISO)	$47	$46	$45	$45	$50	$57	$66	$57	$39	$27	$21	$18	$16	$15	$19	$31	$49	$65	$71	$71	$64	$59	$53	$48
Arizona PS	$36	$34	$32	$34	$39	$45	$52	$46	$32	$25	$17	$14	$13	$10	$14	$21	$39	$51	$55	$54	$49	$45	$41	$37
BANC	$47	$46	$45	$46	$50	$57	$66	$61	$48	$40	$37	$33	$28	$26	$29	$38	$53	$66	$72	$72	$65	$60	$54	$49
Idaho Power	$36	$35	$37	$36	$38	$44	$53	$58	$40	$35	$32	$30	$27	$25	$26	$33	$45	$53	$52	$49	$47	$43	$40	$37
LADWP	$46	$44	$44	$44	$48	$56	$64	$55	$38	$28	$22	$19	$17	$16	$19	$29	$48	$63	$69	$76	$62	$57	$52	$47
NorthWestern	$36	$34	$32	$34	$36	$40	$47	$46	$40	$35	$33	$30	$28	$25	$25	$32	$42	$50	$49	$47	$43	$40	$37	$34
NV Energy	$37	$41	$40	$40	$40	$46	$54	$47	$48	$26	$22	$19	$18	$13	$12	$25	$40	$53	$62	$54	$49	$45	$43	$37
PacifiCorp East	$32	$31	$31	$32	$35	$41	$47	$43	$34	$32	$26	$23	$21	$19	$21	$28	$41	$48	$48	$46	$43	$40	$37	$33
PacifiCorp West	$33	$31	$31	$33	$34	$37	$41	$42	$38	$35	$35	$34	$27	$25	$26	$30	$37	$42	$44	$43	$40	$39	$37	$33
Portland GE	$36	$34	$31	$32	$33	$37	$40	$42	$39	$38	$35	$30	$27	$25	$25	$30	$38	$42	$43	$42	$40	$38	$38	$33
Powerex	$32	$32	$31	$32	$34	$36	$37	$35	$36	$33	$32	$30	$28	$27	$28	$31	$41	$39	$40	$39	$39	$37	$36	$33
PSC New Mexico	$33	$33	$35	$40	$36	$43	$49	$42	$30	$21	$18	$15	$14	$12	$14	$24	$38	$50	$51	$50	$46	$42	$38	$35
Puget Sound Energy	$31	$30	$30	$31	$32	$35	$36	$38	$37	$35	$33	$31	$28	$27	$27	$30	$35	$40	$41	$38	$39	$35	$38	$35
Salt River Project	$35	$34	$35	$34	$38	$45	$52	$46	$31	$28	$17	$14	$13	$11	$11	$20	$40	$50	$54	$57	$54	$49	$46	$37
Seattle City Light	$34	$32	$31	$31	$33	$35	$36	$39	$38	$35	$34	$31	$29	$28	$27	$30	$35	$40	$41	$39	$40	$35	$35	$32
Turlock ID	$48	$46	$46	$46	$50	$58	$67	$62	$49	$38	$38	$34	$29	$27	$31	$39	$54	$66	$73	$73	$66	$61	$56	$49

Table 2.2 Hourly 5-minute market prices (January-March)

Hour ending	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	$52	$45	$43	$43	$44	$47	$51	$47	$42	$30	$25	$20	$18	$17	$16	$19	$34	$48	$57	$49	$50	$53	$52	$51
PG&E (CAISO)	$59	$48	$46	$46	$48	$50	$55	$59	$50	$38	$32	$26	$23	$21	$20	$23	$38	$54	$67	$55	$55	$63	$59	$58
SCE (CAISO)	$56	$47	$45	$44	$46	$49	$53	$48	$38	$21	$14	$12	$12	$10	$11	$17	$34	$50	$61	$53	$53	$59	$56	$55
Arizona PS	$40	$33	$32	$34	$37	$42	$45	$41	$35	$19	$11	$10	$9	$6	$7	$10	$27	$43	$51	$43	$42	$53	$44	$42
BANC	$56	$46	$45	$46	$47	$49	$54	$58	$51	$41	$35	$29	$26	$23	$22	$24	$38	$52	$65	$54	$54	$62	$60	$58
Idaho Power	$39	$36	$37	$35	$37	$41	$44	$47	$31	$31	$29	$25	$24	$22	$19	$22	$34	$43	$44	$39	$39	$37	$37	$36
LADWP	$55	$47	$43	$43	$44	$45	$51	$47	$38	$22	$16	$13	$12	$11	$11	$16	$34	$49	$59	$55	$51	$55	$57	$54
NorthWestern	$37	$31	$32	$32	$34	$37	$41	$38	$32	$32	$32	$29	$25	$23	$19	$20	$32	$41	$44	$40	$36	$33	$36	$40
NV Energy	$41	$33	$35	$36	$38	$43	$46	$44	$40	$23	$18	$16	$14	$6	$5	$11	$30	$45	$57	$42	$42	$43	$43	$41
PacifiCorp East	$33	$31	$31	$31	$34	$38	$40	$35	$26	$27	$21	$18	$17	$15	$14	$17	$30	$39	$43	$37	$37	$36	$35	$34
PacifiCorp West	$33	$31	$31	$32	$33	$37	$40	$36	$31	$33	$31	$27	$24	$21	$18	$21	$30	$36	$37	$37	$37	$36	$38	$33
Portland GE	$32	$31	$31	$32	$33	$37	$45	$35	$30	$30	$29	$25	$23	$20	$18	$21	$30	$37	$36	$36	$37	$35	$36	$32
Powerex	$32	$31	$31	$31	$33	$34	$36	$35	$33	$31	$29	$28	$27	$26	$26	$28	$37	$36	$38	$37	$37	$36	$35	$33
PSC New Mexico	$38	$37	$35	$35	$35	$46	$42	$38	$31	$16	$12	$11	$9	$8	$9	$14	$27	$44	$47	$39	$39	$41	$41	$41
Puget Sound Energy	$31	$29	$30	$30	$32	$34	$34	$35	$33	$32	$31	$28	$26	$24	$23	$24	$30	$34	$36	$35	$35	$33	$37	$32
Salt River Project	$51	$34	$35	$34	$37	$41	$45	$41	$38	$21	$11	$9	$8	$6	$5	$11	$30	$43	$51	$48	$47	$47	$48	$41
Seattle City Light	$30	$30	$30	$30	$32	$34	$35	$35	$33	$32	$31	$27	$26	$25	$23	$24	$31	$35	$36	$35	$41	$34	$34	$32
Turlock ID	$57	$47	$45	$46	$47	$50	$54	$58	$51	$42	$37	$31	$28	$25	$23	$24	$38	$53	$66	$55	$55	$63	$59	$58

Public Service Company of New Mexico (PNM) had the lowest average prices in the WEIM during the quarter. This was due in part to the greenhouse gas component and congestion within CAISO.[49] Figure 2.3 breaks down PNM's average locational marginal price (LMP) by component throughout the day.

Figure 2.3 Public Service Company of New Mexico average 15-minute price by component (Q1 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. WEIM transfers are constrained by *transfer limits* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 2.4 and Figure 2.5 highlight typical transfer patterns during two key periods that produce a high volume of transfers.[50] First, Figure 2.4 shows average dynamic 15-minute market exports out of each area during mid-day hours during the quarter.[51] 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,

49 See Section 1.8.2 for more information on price impacts to PNM and other WEIM entities from individual constraints.

50 WEIM transfer paths less than 25 MW, on average, are excluded from the figures. In cases where total average area transfer capacity is less than 25 MW, the balancing area is excluded.

51 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.

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 2.4 shows that the CAISO exported just under 1,500 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 2.5 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 1,000 MW of exports out of LADWP, Turlock Irrigation District, PacifiCorp West, Portland General Electric, Arizona Public Service, NV Energy, and Salt River Project going into the CAISO during these hours (CAISO import). PacifiCorp East was also a significant exporter during these hours, with around 450 MW on average out to neighboring areas.

Figure 2.4 Average 15-minute market WEIM exports (mid-day hours, January – March, 2022)

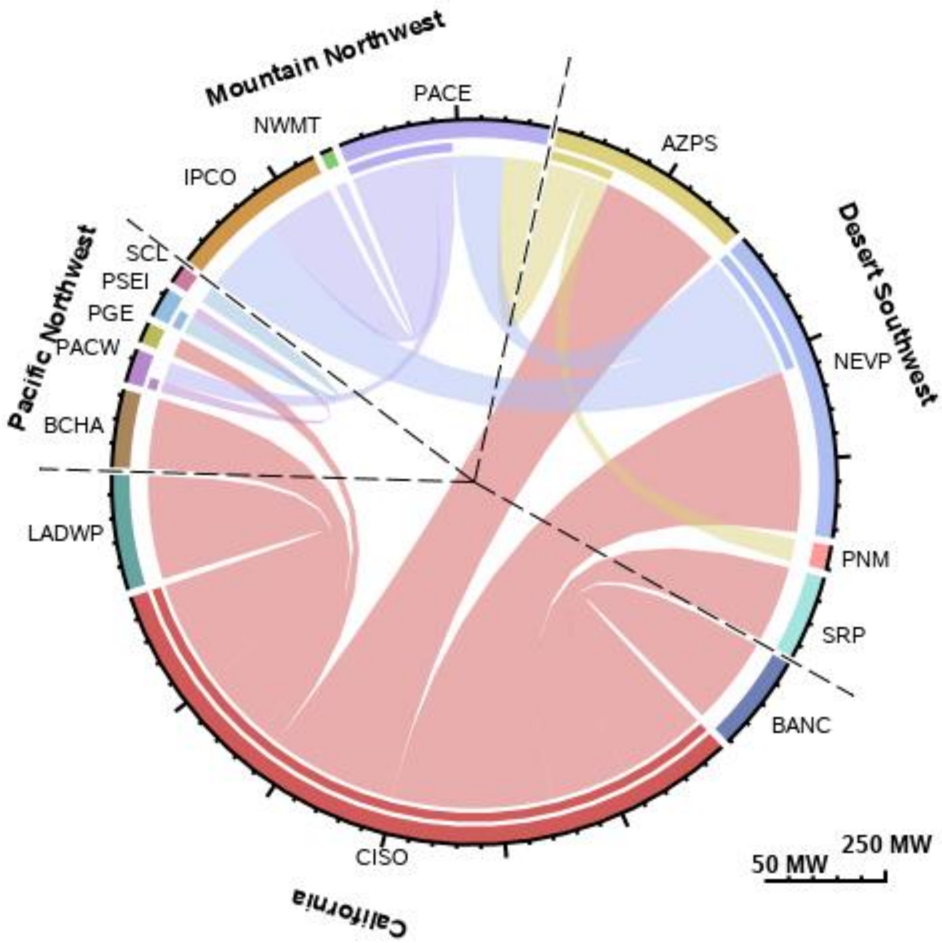
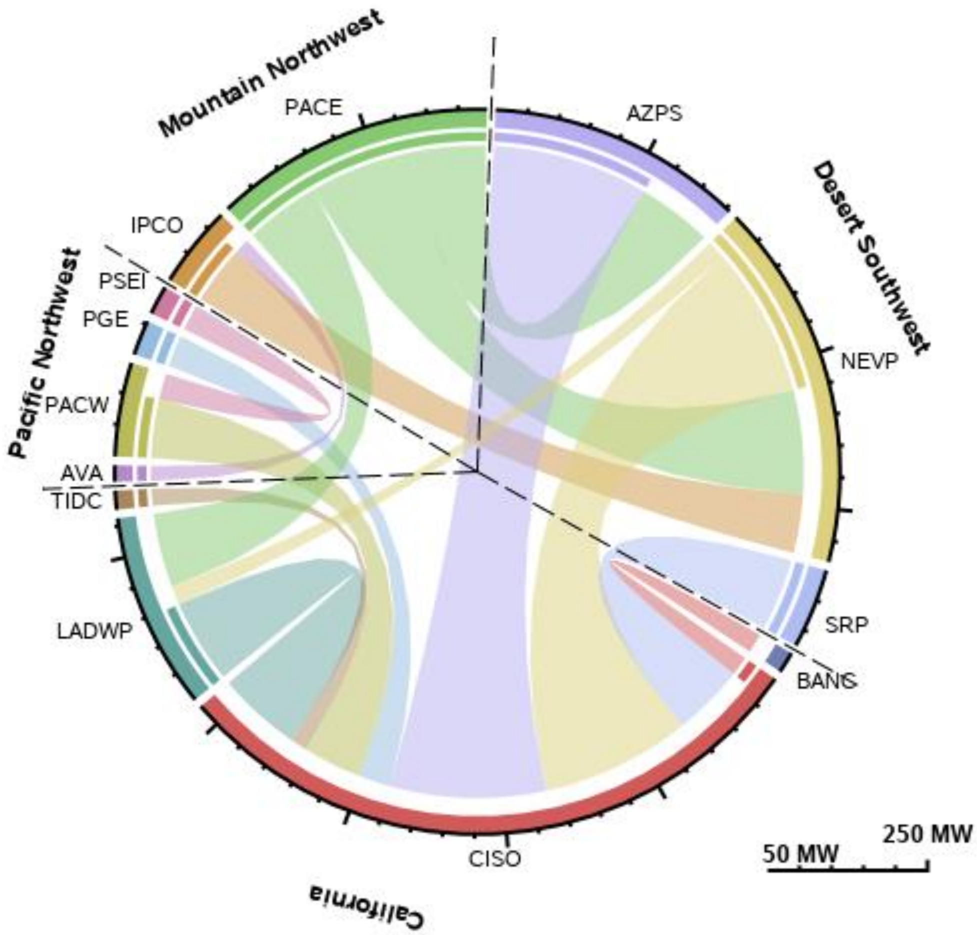


Figure 2.5 Average 15-minute market WEIM exports (peak load hours, January – March, 2022)



Transfer limits

WEIM transfers between areas are constrained by transfer limits. These largely reflect transmission and interchange rights made available to the market by participating entities. Table 2.3 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 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.

Import transfer capacity into CAISO from the Pacific Northwest (including PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Powerex) was around 210 MW on average, or roughly 1 percent of total import capability. Significant transfer capability between CAISO and the neighboring Southwest and WEIM areas within California allowed energy to flow between these areas with relatively little congestion.

Table 2.3 Average 15-minute market WEIM limits (January – March)

From Balancing Authority Area	To Balancing Authority Area: CAISO	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	SCL	PWRX	*Total export limit*
California ISO		3,780	900	4,130	3,650	1,560	2,050					70	60			260	16,460
BANC	3,650		550														4,200
Turlock Irrig. District	900	750															1,650
LADWP	8,430				1,660	390			100								10,580
NV Energy	3,930			950		330			780	430							6,420
Arizona Public Service	2,540			280	230		3,900	600	740								8,290
Salt River Project	3,180					3,190		50									6,420
PSC New Mexico						480	100										580
PacifiCorp East				210	450	440				550	220	150					2,020
Idaho Power					310				1,590		230	390			30		2,550
NorthWestern Energy									100	150							250
PacifiCorp West	100								0	110			320	160	10		700
Portland GE	110											350			10		470
Puget Sound Energy												150			350	50	550
Seattle City Light										30		10	10	350			400
Powerex	0													50			50
Total import limit	22,840	4,530	1,450	5,570	6,300	6,390	6,050	650	3,310	1,270	450	1,120	390	560	400	310	

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.[52] WEIM participants in the Pacific Northwest continued to be the most frequently congested relative to the greater market footprint.[53]

Table 2.4 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.[54] 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.

NorthWestern Energy experienced a high average frequency of congestion, while the highest frequency of congestion occurred in areas located in the Pacific Northwest. Exports were congested from this region during around 41 percent of 15-minute market intervals and 30 percent of 5-minute market intervals, on average, across these areas. Imports into the Pacific Northwest region were also frequently congested, typically during mid-day hours. PacifiCorp West, Portland General Electric, Seattle City Light, and Puget Sound Energy were congested with imports during roughly 10 percent of both 15-minute and

52 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.

53 These Pacific Northwest areas include Powerex, Puget Sound Energy, Seattle City Light, Portland General Electric, and PacifiCorp West.

54 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.

5-minute market intervals. Powerex was congested into the area during around 27 percent of 5-minute market intervals.

Congestion in either direction for other WEIM entities 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 2.4 Frequency of congestion in the WEIM (January – March)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
Turlock Irrigation District	0%	0%	0%	0%
Arizona Public Service	1%	0%	1%	0%
L.A. Dept. of Water and Power	1%	1%	1%	1%
Public Service Company of NM	1%	0%	1%	0%
NV Energy	2%	0%	1%	0%
Salt River Project	3%	0%	3%	1%
PacifiCorp East	6%	3%	3%	2%
Idaho Power	6%	10%	3%	9%
NorthWestern Energy	12%	10%	7%	11%
PacifiCorp West	37%	7%	21%	6%
Portland General Electric	37%	9%	22%	6%
Puget Sound Energy	44%	11%	33%	15%
Seattle City Light	44%	11%	33%	15%
Powerex	44%	9%	40%	27%

2.3 Resource sufficiency evaluation

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

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

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the upward direction, WEIM transfers into that area cannot be increased.[55] Similarly, if an area fails either test in the downward direction, transfers out of that area cannot be increased.

Bid range capacity and flexible ramping sufficiency test results

Figure 2.6 and Figure 2.7 show the percent of intervals in which each WEIM area failed the upward capacity and flexibility tests, while Figure 2.8 and Figure 2.9 provide the same information for the downward direction.[56] 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.[57] Intertie uncertainty was removed on June 1, 2022. Net load uncertainty is proposed to return to the capacity test in the summer of 2023.[58] 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. The California ISO is also proposing to permanently remove intertie uncertainty from the capacity test.

In the first quarter of 2022:

- NV Energy failed the upward flexibility test in 0.4 percent of intervals and the downward flexibility test in 2.1 percent of intervals.
- Salt River Project failed the upward flexibility test in 0.3 percent of intervals, the downward flexibility test in 0.9 percent of intervals, and the downward capacity test in 0.2 percent of intervals.
- Arizona Public Service failed the downward flexibility test in 0.9 percent of intervals.
- PacifiCorp West failed the upward capacity test in 0.2 percent of intervals.

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55 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.

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

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

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

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

	2021												2022		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona PS	0.2	0.4	—	—	0.3	—	0.2	0.3	0.2	—	0.3	0.0	—	—	0.0
Avista															—
BANC	—	—	0.1	—	—	—	0.2	—	0.0	—	—	—	—	—	—
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	—
NV Energy	—	0.3	—	0.0	0.5	0.8	0.5	0.2	0.2	0.3	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	0.3	0.3	0.1	0.2	0.1	—	—	—	—	—
PacifiCorp West	—	—	0.1	—	0.0	0.1	0.2	0.1	0.1	0.1	0.5	0.4	0.3	0.1	0.3
Portland GE	—	0.1	—	0.4	—	0.7	0.8	1.0	1.4	0.4	0.2	0.4	0.1	—	—
Powerex	0.1	0.0	—	—	—	0.0	0.0	—	0.1	0.5	0.2	0.2	0.2	—	—
PSC New Mexico				—	—	—	0.4	—	0.2	—	—	—	—	—	—
Puget Sound En	—	0.1	0.6	1.0	0.6	1.6	0.5	0.7	0.6	1.0	0.6	0.3	—	—	—
Salt River Proj.	—	8.0	—	0.1	0.1	0.7	3.0	2.6	2.0	0.1	0.7	—	—	—	0.2
Seattle City Light	—	—	—	—	—	—	—	0.0	0.5	0.1	—	0.1	—	—	0.1
Tacoma Power															—
Turlock ID			—	—	0.0	—	—	1.1	0.8	1.5	—	—	—	—	—

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

	2021												2022		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona PS	0.5	0.5	0.2	—	0.6	—	0.0	—	0.2	—	0.3	0.0	0.0	0.2	0.1
Avista															—
BANC	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	0.0	0.3	0.1	0.4	—	0.1	—	—	—	—
Idaho Power	—	0.1	—	—	—	—	—	—	—	—	—	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
NV Energy	0.1	0.5	0.4	0.4	0.7	0.9	0.4	0.5	0.1	0.3	0.0	0.0	0.0	0.7	0.4
PacifiCorp East	0.1	0.1	0.1	0.1	0.0	0.1	0.0	—	0.1	—	0.1	0.0	0.0	0.0	—
PacifiCorp West	0.0	0.2	0.1	0.1	0.0	—	0.0	0.1	—	—	0.6	0.2	0.0	0.0	0.1
Portland GE	0.3	0.6	0.1	0.2	0.2	0.3	0.5	0.2	—	0.0	—	0.2	0.3	0.0	—
Powerex	0.2	0.1	0.1	0.1	—	0.1	0.5	—	—	0.2	0.2	0.3	0.2	0.0	—
PSC New Mexico				0.4	0.0	0.1	0.5	—	0.1	—	0.1	—	—	—	0.1
Puget Sound En	—	—	—	—	0.1	0.1	0.0	0.0	—	—	0.1	—	—	—	0.0
Salt River Proj.	0.2	7.1	0.3	0.5	0.2	0.9	1.9	1.7	0.8	0.2	1.2	0.0	0.2	—	0.6
Seattle City Light	—	—	—	—	—	—	0.0	—	0.1	—	—	—	—	—	0.1
Tacoma Power															—
Turlock ID			—	—	0.3	—	—	—	0.1	0.2	—	—	—	—	—

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

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

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

	2021												2022		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Arizona PS	2.2	2.3	4.3	1.9	0.3	0.1	—	0.1	0.1	0.1	0.5	0.4	1.4	0.4	0.8
Avista															—
BANC	—	0.6	0.4	—	—	—	—	—	—	—	—	0.1	—	—	0.1
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	0.0	—	—	—	—	—	0.3	0.0	—	0.0	—
LADWP				—	—	0.1	—	—	—	0.1	—	—	0.1	—	—
NorthWestern						0.7	0.6	0.4	1.2	2.3	0.1	0.0	—	—	—
NV Energy	0.2	6.1	1.4	0.5	4.3	2.0	3.0	2.5	1.7	1.1	0.4	0.4	0.6	4.1	1.7
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	0.1	—	—	0.1	—	—	—	—	0.0	—	—	—	0.0
Portland GE	0.0	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.4	—	1.4	0.2	0.9	1.3	0.4	0.2	1.0	0.4	0.0	0.1	—	0.0	0.2
PSC New Mexico				1.4	—	0.0	—	—	0.1	0.4	0.7	0.1	0.3	0.0	1.2
Puget Sound En	—	—	—	—	—	—	—	—	—	—	0.0	—	—	—	—
Salt River Proj.	1.1	1.6	1.2	0.2	0.1	0.2	—	0.1	0.0	0.1	0.0	0.1	0.1	1.0	1.5
Seattle City Light	—	—	—	—	—	—	0.2	—	—	—	0.0	0.0	—	—	0.1
Tacoma Power															—
Turlock ID			0.4	0.1	0.5	—	—	0.0	—	0.6	0.1	0.2	0.2	—	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 2.10 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.[59]

Figure 2.10 Imposed dynamic import limit following upward test failure (January – March 2022)

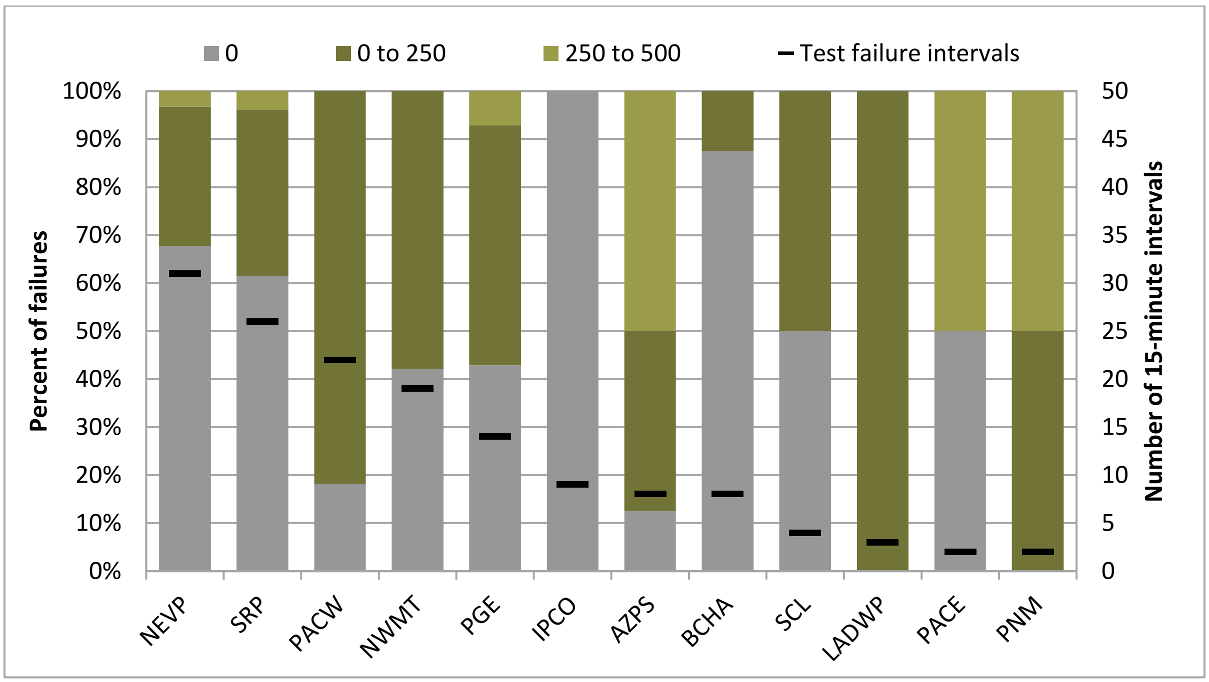


Figure 2.11 summarizes actual transfers optimized in the real-time market following an upward resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity test or a flexibility test failure, while the bars (left axis) show the net transfer quantity categorized by various levels. These figures summarize dynamic WEIM transfers only and therefore base transfers are again excluded.

59 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 2.11, 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 this period, the capacity test requirement included intertie uncertainty for all of the quarter and net load uncertainty for part of the quarter.[60] 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 2.11 Dynamic WEIM transfers during upward test failure (January – March 2022)

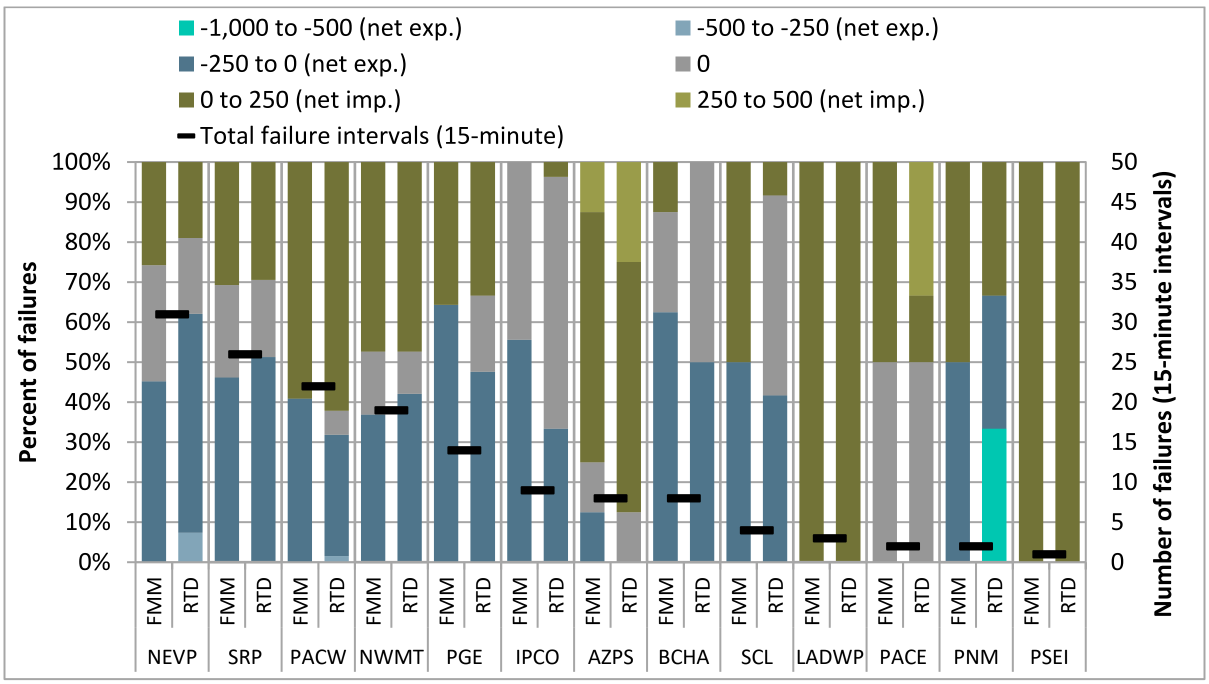
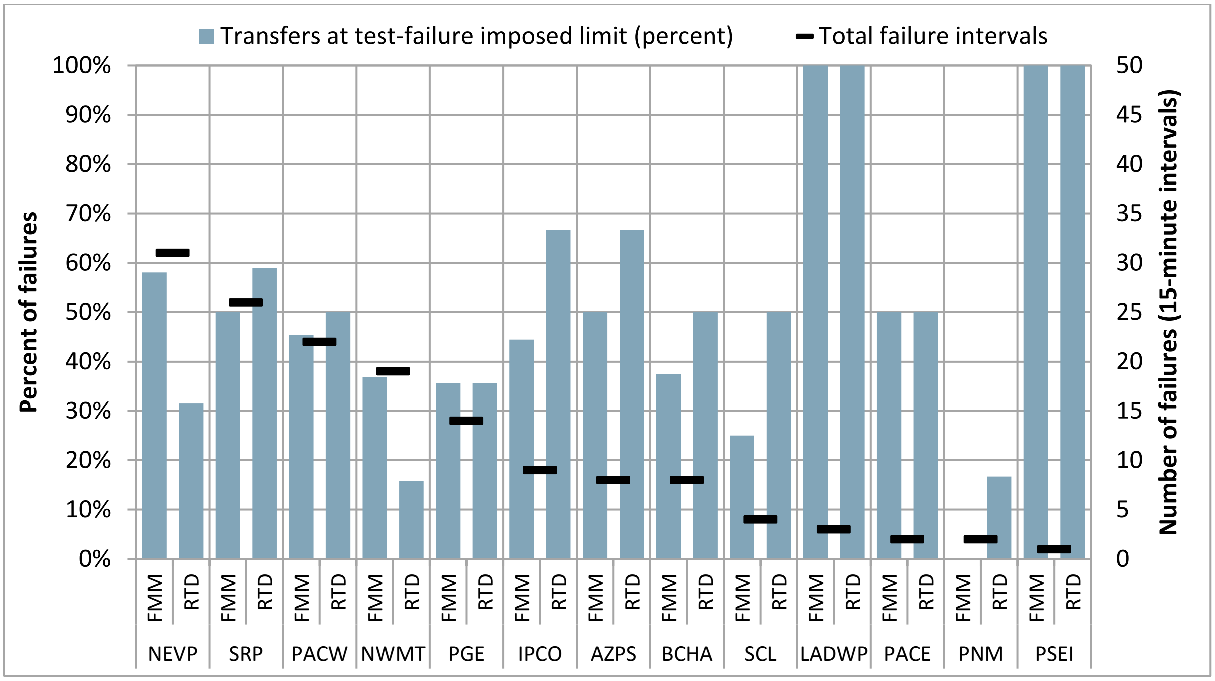


Figure 2.12 summarizes whether the import limit that was imposed after failing either test in the upward direction ultimately impacted market transfers. It shows the percent of failure intervals in which the resulting transfers were constrained to the limit imposed after failing the test. These results are shown separately for the 15-minute (FMM) and 5-minute (RTD) markets.

60 Net load uncertainty was removed on February 15, 2022.

Figure 2.12 Percent of upward test failure intervals with market transfers at the imposed cap (January – March 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.[61] 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 2.5 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the WEIM for the 15-minute and 5-minute markets during the quarter. The same data for the California ISO balancing area is provided as a point of reference. Portland General Electric saw a general decrease in the frequency and average megawatts of positive and negative imbalance conformance compared to the first quarter of 2021. Arizona Public Service had a significant decrease in the percent of intervals with negative imbalance conformance compared to the same time last year. Nearly all WEIM entities had a greater frequency of 5-minute market imbalance conformance than the 15-minute market during the quarter.

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

Table 2.5 Average frequency and size of imbalance conformance (January – March)

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	64%	1242	5.5%	2.0%	-451	2.4%	782
	RTD	45%	296	1.3%	27%	-263	1.3%	64
BANC	FMM	0.1%	34	2.0%	0.0%	-50	2.7%	0
	RTD	0.3%	48	2.9%	0.4%	-39	2.3%	0
LADWP	FMM	0.8%	55	2.3%	2.5%	-99	4.2%	-2
	RTD	11%	52	2.2%	13%	-60	2.5%	-2
Turlock Irrigation District	FMM	0.0%	16	5.4%	0.1%	-3	1.0%	0
	RTD	0.0%	15	5.0%	0.1%	-5	1.6%	0
NorthWestern Energy	FMM	32%	14	1.0%	3.1%	-53	3.9%	3
	RTD	50%	14	1.0%	5.8%	-54	4.0%	4
NV Energy	FMM	0.6%	120	3.4%	0.4%	-175	5.2%	0
	RTD	14%	97	2.6%	12%	-150	4.3%	-4
Arizona Public Service	FMM	1.1%	204	7.7%	0.8%	-151	5.4%	1
	RTD	40%	68	2.3%	29%	-64	2.5%	9
Salt River Project	FMM	0.1%	66	2.2%	0.0%	-80	2.8%	0
	RTD	4.3%	58	2.0%	0.8%	-59	2.0%	2
Idaho Power	FMM	0.1%	33	1.8%	0.0%	N/A	N/A	0
	RTD	19%	51	2.6%	5.0%	-52	2.8%	7
Public Service Co. of New Mexico	FMM	0.3%	61	4%	0.0%	N/A	N/A	0
	RTD	2.7%	95	6.4%	2.7%	-89	7.0%	0
PacifiCorp East	FMM	0.0%	N/A	N/A	0.0%	-400	6.9%	0
	RTD	15%	90	1.7%	40%	-114	2.1%	-32
PacifiCorp West	FMM	0.0%	N/A	N/A	0.1%	-310	11%	0
	RTD	3.6%	46	1.8%	35%	-61	2.4%	-20
Portland General Electric	FMM	0.0%	15	0.5%	1.0%	-11	0.4%	0
	RTD	7.5%	25	0.9%	0.8%	-44	1.6%	2
Seattle City Light	FMM	0.4%	16	1.1%	9.1%	-23	2.0%	-2
	RTD	2.3%	19	1.5%	68%	-22	1.9%	-15
Puget Sound Energy	FMM	0.3%	67	2.1%	8.7%	-52	1.6%	-4
	RTD	2.1%	63	1.9%	59%	-42	1.3%	-24