Q3 2021 Report on Market Issues and Performance

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California Independent System Operator

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Executive summary

This report covers market performance during the third quarter of 2021 (July - September).

Key highlights during this quarter include the following:

- **Market prices were significantly higher** than the same quarter of 2020 on average. Day-ahead prices in the ISO rose more than 35 percent. Increases were due to higher natural gas prices and ongoing drought conditions causing low hydroelectric production.
- **Performance of the day-ahead and real-time markets remained highly competitive**, despite several periods of extremely high region-wide loads and prices. Load peaked at about 43,947 MW on September 8, well below any peak load reported in the last decade.
- **Gas prices more than doubled** at SoCal Citygate and almost doubled at PG&E Citygate compared to the same quarter in 2020. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint during the third quarter.
- **Renewable production decreased** by 1 percent compared to the same quarter in 2020, due to a decrease of 29 percent for hydroelectric production, which offset increasing non-hydro renewables.
- **Generation outages increased** by 20 percent over Q3 2020 and were higher than any third quarter in the previous five years. Together, increased outages taken by gas, hydroelectric, and storage account for almost all of the increase.
- **Bilateral market prices in other balancing areas were often significantly higher than ISO** market prices, reflecting extremely tight supply conditions in these other regions, during high load periods.
- **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.
- **The day-ahead market was structurally uncompetitive** in fewer hours than the third quarter of 2020, but more than any other year in the previous five years.
- **Congestion** in the day-ahead market decreased PG&E prices while it increased SDG&E and SCE area prices. Total day-ahead congestion rent was $166 million, a decrease from $220 million in the same quarter of the previous year.
- **Congestion revenue rights** auction revenues are estimated to be $10 million less than payments made to non-load-serving entities during the third quarter representing about 6 percent of day-ahead congestion rent.
- **Real-time offset costs totaled** $72 million in the third quarter for a total of $156 million for the first three quarters of 2021. Offset costs this quarter were about 40 percent higher than ancillary services costs, which summed to about $51 million, and were more than double total ISO bid cost recovery costs for the quarter, estimated to be $26 million.
- **Imbalance conformance adjustments** reached almost 1,400 MW during peak net load ramp hours, on average, continuing the increase in operator use of imbalance conformance that began in 2017.

Figure E.1 Average monthly system marginal energy prices (all hours)

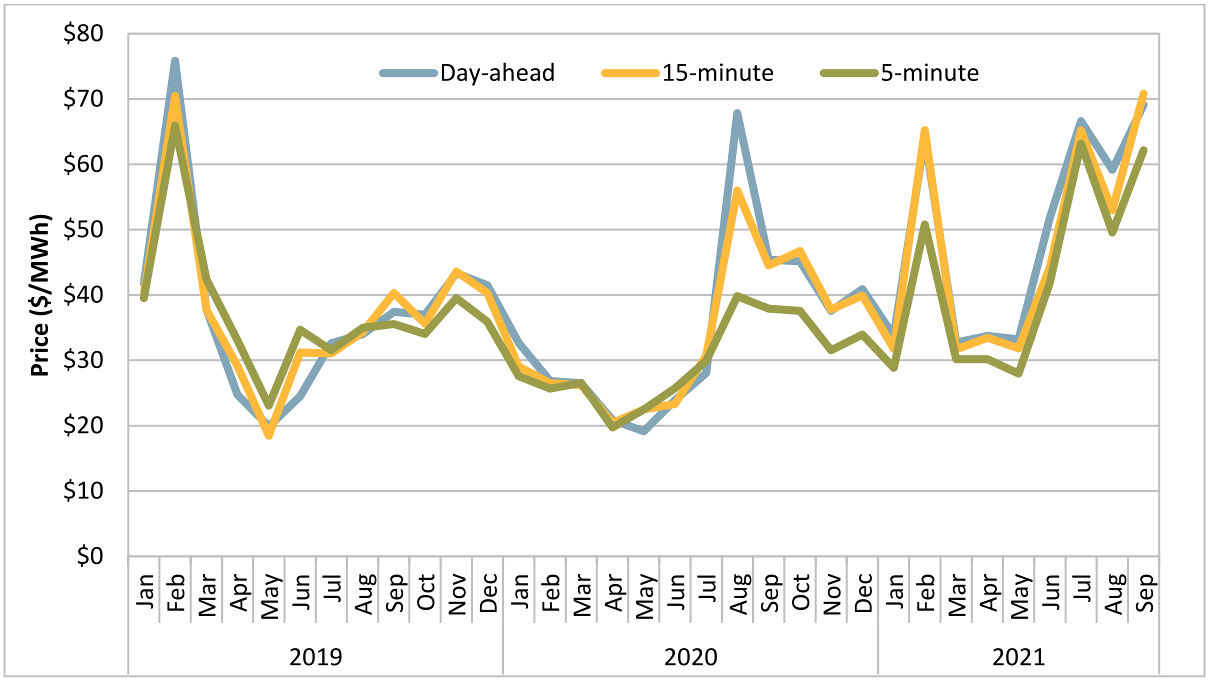
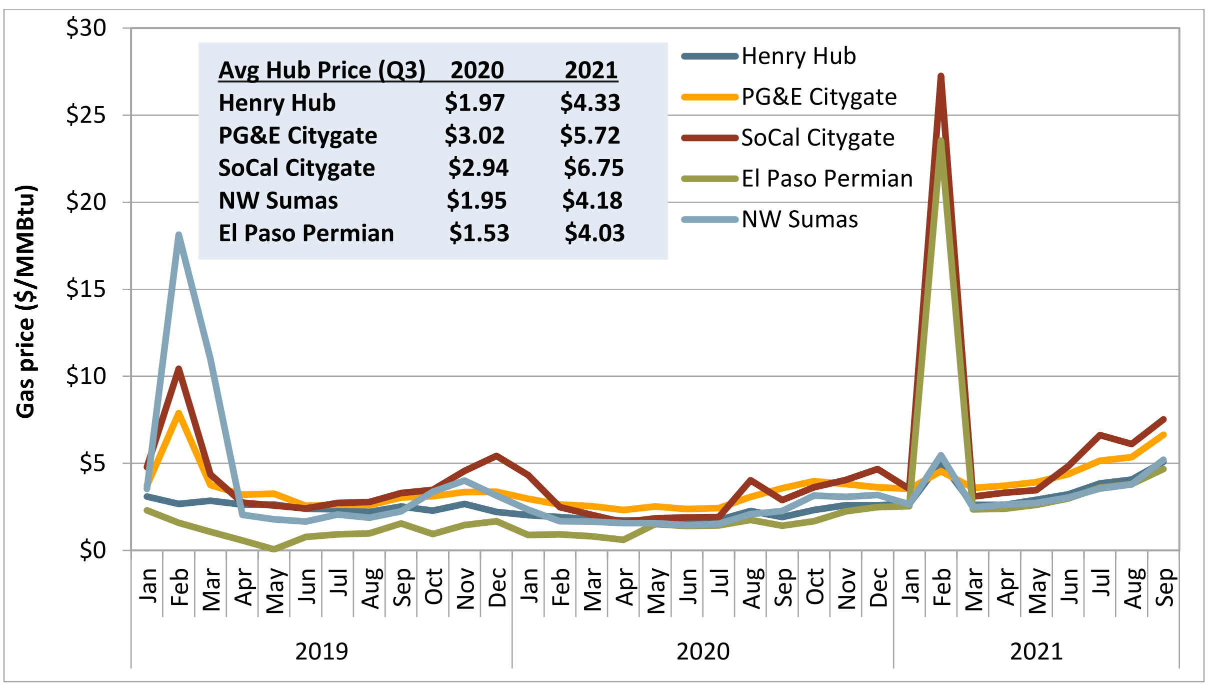


Figure E.2 Natural gas prices



Western Energy Imbalance Market

- **Prices in Salt River Project were over $100/MWh on average in the hours between 6 and 8 pm** in both the 15-minute and 5-minute markets, driven by high penalty prices associated with undersupply infeasibilities when the area was separated from the rest of the system. Penalty prices were raised from $1,000/MWh to $2,000/MWh in March. As in previous quarters, undersupply infeasibilities often occurred following the failure of a resource sufficiency test which can limit imports into a failing area. In June, the ISO implemented Phase 2 of FERC Order 831, limiting conditions in which the $2,000/MWh penalty price would apply.
- **Natural gas prices across the EIM more than doubled**. This increase in natural gas prices resulted in higher energy prices.
- **Prices in California areas were almost $18/MWh higher than other regions,** on average. Prices tend to be higher in California than the rest of the system due to both transfer constraint congestion and greenhouse gas compliance costs for energy that is delivered to California.
- **The California ISO was a net importer**, on average, in all but one hour of the quarter, even during the peak mid-day solar generation hours when, in earlier quarters, lower priced solar generation was typically exported to the rest of the system. Net imports decreased in several areas in the southwest (both APS and SRP) and in both PacifiCorp East and PacifiCorp West.
- **On June 16, 2021, the ISO added net load uncertainty to the requirement of the bid range capacity test** as part of a package of market enhancements for summer 2021 readiness. During the quarter, 60 percent of upward test failures would have passed without the additional uncertainty component.
- **NorthWestern Energy, Salt River Project, and NV Energy had the most resource sufficiency test failures.** NorthWestern Energy failed the upward sufficiency test in around 2 percent of intervals. Salt River Project failed the upward sufficiency and capacity tests in around 1.5 and 2.5 percent of intervals, respectively. NV Energy failed the downward sufficiency test in around 2.4 percent of intervals.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in monthly reports** as part of the EIM resource sufficiency evaluation stakeholder initiative. DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable.

Special issues

- **The ISO implemented several market enhancements** designed to address concerns raised following the load curtailment event of August 2020.
- **As a result of changes made last year to the ISO's process for setting export scheduling priorities, significant volumes of exports clearing the day-ahead market were curtailed through the residual unit commitment process on the highest load days**. On these days, some exports rebid into the real-time market cleared, ultimately meeting high demand in other regions.
- **Under August 4 tariff changes, exports clearing both the day-ahead market and residual unit commitment process can be curtailed before internal load in the real-time market**. Exports are

now required to demonstrate support from non-resource adequacy capacity to have equal priority with native load if curtailment is necessary. Thus far, no curtailment has been necessary.

- **Under August 4 tariff changes, wheeling transactions** are required to register 45 days in advance of the month and must demonstrate both a firm power supply contract to serve the load of an external load serving entity and monthly firm transmission to the CAISO border to qualify for prioritization equal to or above native load. Thus far, no curtailment has been necessary.
- **High priority wheels were not scheduled in the market on most days**, although over 1,000 MW of high priority wheels registered in August and over 680 MW registered in September. The maximum scheduled on any day in the quarter was less than 350 MW.
- **The volume of wheeled energy increased significantly,** compared to the summer of 2020. The highest volumes were observed in June and were mostly north-to-south source-to-sink combinations, representing power from balancing areas in the Northwest being wheeled through the ISO to balancing areas in the Southwest.
- **In the real-time market, less than 90 percent of system resource adequacy capacity was bid or self-scheduled during high load hours**. During the top 200 load hours of the year, 90 percent of system resource adequacy capacity was offered in the day-ahead market and 88 percent was offered in the real-time market.
- **Non-resource-specific imports** accounted for about 3,500 MW of resource adequacy capacity during peak hours of 2021, down from over 4,500 MW in 2020.
- **Over half of resource adequacy capacity was classified as use-limited** during peak load hours. Although 87 percent of this capacity was bid into the real-time market on high load days, performance of some use-limited fuel types was lower: storage (86%), solar (71%), wind (77%), non-utility demand response (42%), and hydroelectric (83%). In most cases, performance rose to above 100% for these groups once accounting for non-resource adequacy capacity from these resource types: storage (111%), solar (147%), wind (140%), and hydroelectric (88%).
- **Intra-monthly capacity procurement mechanism (CPM) designations cost about $9.7 million, up from $2.1 million in 2020**. Intra-monthly significant event designations were issued in July, August, and September to ensure reliability following extreme heat events in the early part of the summer.

1 Market performance

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

- **Market prices were significantly higher** than the same quarter of 2020 on average; day-ahead prices in the ISO rose more than 35 percent. Increases were due to higher natural gas prices and ongoing drought conditions causing low hydroelectric production. Day-ahead prices averaged $65/MWh, 15-minute prices averaged $63/MWh, and 5-minute prices averaged $58/MWh.
- **Gas prices more than doubled** at SoCal Citygate and almost doubled at PG&E Citygate compared to the same quarter in 2020. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint during the third quarter.
- **Load peaked at about 43,947 MW** on September 8, well below any peak load reported in the last decade, despite several high temperature high demand periods during the quarter.
- **Renewable production decreased** by 1 percent compared to the same quarter in 2020, due to a decrease of 29 percent for hydroelectric production offset by increasing non-hydro renewables.
- **Generation outages increased** by 20 percent over Q3 2020 and were higher than any third quarter in the previous five years. Together, increased outages taken by gas, hydroelectric, and storage account for almost all of the increase.
- **Bilateral market prices in other balancing areas were often significantly higher than ISO** market prices, reflecting extremely tight supply conditions in these other regions, during high load periods.
- **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. The ISO introduced a minimum area flexible ramping product procurement requirement in November 2020, which bound frequently for the ISO but no other areas, and is applied in the 15-minute market but not the 5-minute market.
- **The day-ahead market was structurally uncompetitive** in fewer hours than the third quarter of 2020, but more than any other year in the previous five years.
- **Congestion** in the day-ahead market decreased PG&E prices while it increased SDG&E and SCE area prices. Total day-ahead congestion rent was $166 million, a decrease from $220 million in the same quarter of the previous year.
- **Congestion revenue rights** auction revenues are estimated to be $10 million less than payments made to non-load-serving entities during the third quarter representing about 6 percent of day-ahead congestion rent. Losses as a percent of day-ahead congestion rent were well below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 to 2018).
- **Real-time offset costs totaled** $72 million in the third quarter for a total of $156 million for the first three quarters of 2021. Offset costs this quarter were about 40 percent higher than ancillary services costs, which summed to about $51 million, and were more than double total ISO bid cost recovery costs for the quarter, estimated to be $26 million.
- **Imbalance conformance adjustments** reached almost 1,400 MW during the peak net load ramp hours, on average, continuing 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 contributes 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 natural gas units are often the marginal source of generation in the ISO and other regional markets. During the third quarter of 2021, gas prices at major trading hubs across the west trended significantly higher when compared to the same quarter of 2020. This increase in natural gas prices resulted in higher system marginal energy prices across the ISO footprint in this quarter.

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 third quarter, prices at the SoCal Citygate gas hub averaged $6.75/MMBtu compared to $2.94/MMBtu (up 129 percent) in the third quarter of 2020. In September, SoCal Citygate experienced elevated price levels reaching a high of $20/MMBtu for the September 9 gas day. This was because of high gas demand during this period combined with pipeline constraints on the El Paso system, which restricted access to the Permian basin gas supply.[1]

Consistent with the California Public Utilities Commission's ruling on April 29, 2019, SoCalGas Company made changes to its operational flow orders (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 and for Stage 4 and Stage 5 was set at $25/Dth. During the third quarter, SoCalGas Company declared low OFOs on only four gas days, primarily Stage 1.

The revisions from the CPUC's ruling expired on October 31, 2021. DMM submitted comments to a new CPUC ruling to revise the existing penalty structure.[3] Until a final decision on this new ruling is reached,

1 Curtailment Watch Update for SoCalGas and SDG&E Southern System, September 2, 2021: SoCalGas Envoy critical notices for Sep 2, 2021

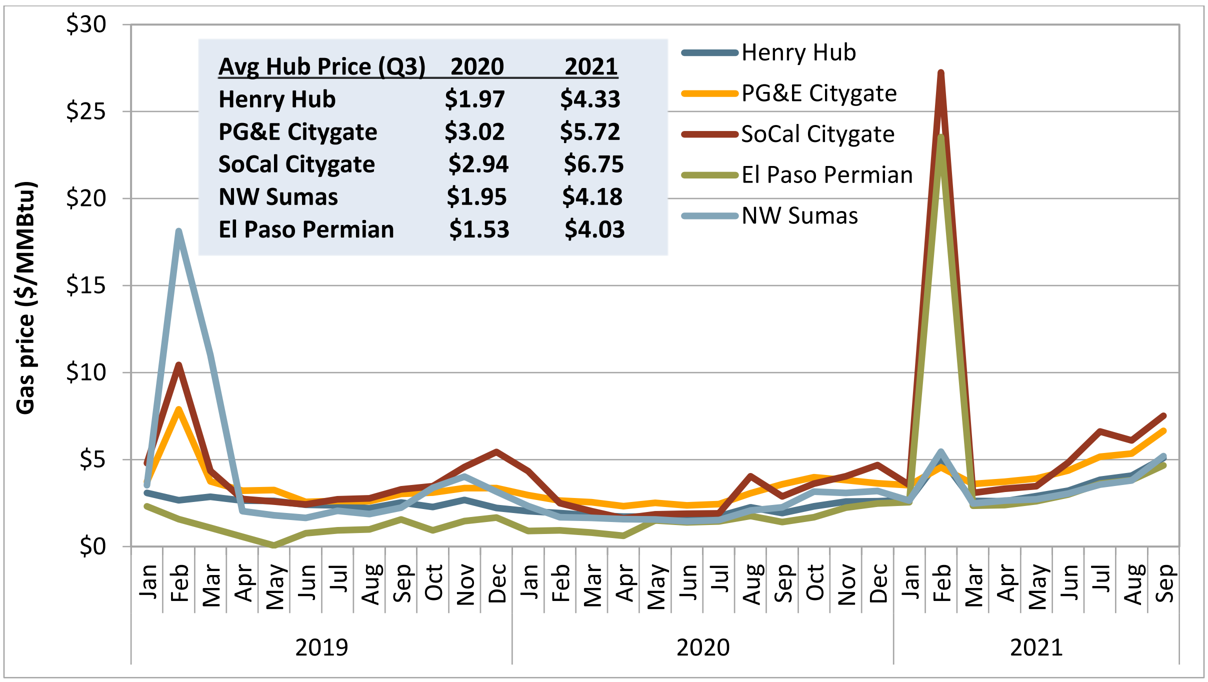
2 *CPUC's Proposed Decision Granting In Part and Denying In Part for Modification Filed by Southern California Edison & Southern CA Generation Coalition of Commission*, pp 31-32, April 29,2019: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF

3 *DMM Response to Judge's Ruling Seeking Comments - Safe and Reliable Gas Systems - R20-01-007,* Aug 14, 2020: http://www.caiso.com/Documents/CPUC-ResponsetoJudgesRulingSeekingComments-SafeandReliableGasSystems-R20-01-007-Aug142020.pdf

CPUC has temporarily extended the 8-stage winter OFO structure for six months commencing on November 1, 2021.[4]

As mentioned earlier, gas prices at other major gas trading hubs in this quarter were also significantly higher than prices during the third quarter of 2020. At Henry Hub, PG&E Citygate, El Paso Permian, and Northwest Sumas gas hubs, the prices rose by 119 percent, 89 percent, 163 percent, and 114 percent, respectively.

Figure 1.1 Monthly average natural gas prices



1.1.2 Renewable generation

In the third quarter, the combined average hourly generation from renewable resources decreased by about 100 MW (1 percent) compared to the same quarter of 2020. Generation from non-hydro renewable resources increased 7 percent while hydroelectric generation decreased 29 percent, compared to the third quarter of 2020.[5] The availability of variable energy resources contributes to price patterns both seasonally and hourly due to their low marginal cost relative to other resources.

Figure 1.2 shows the average hourly renewable generation by month and fuel type.[6] Non-hydroelectric renewable generation, which includes wind, solar, geothermal, and biogas-biomass resources, increased by a total of 147 MW (7 percent) compared to the same quarter in 2020, primarily from higher solar and

4 Proposed 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: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M423/K447/423447100.PDF

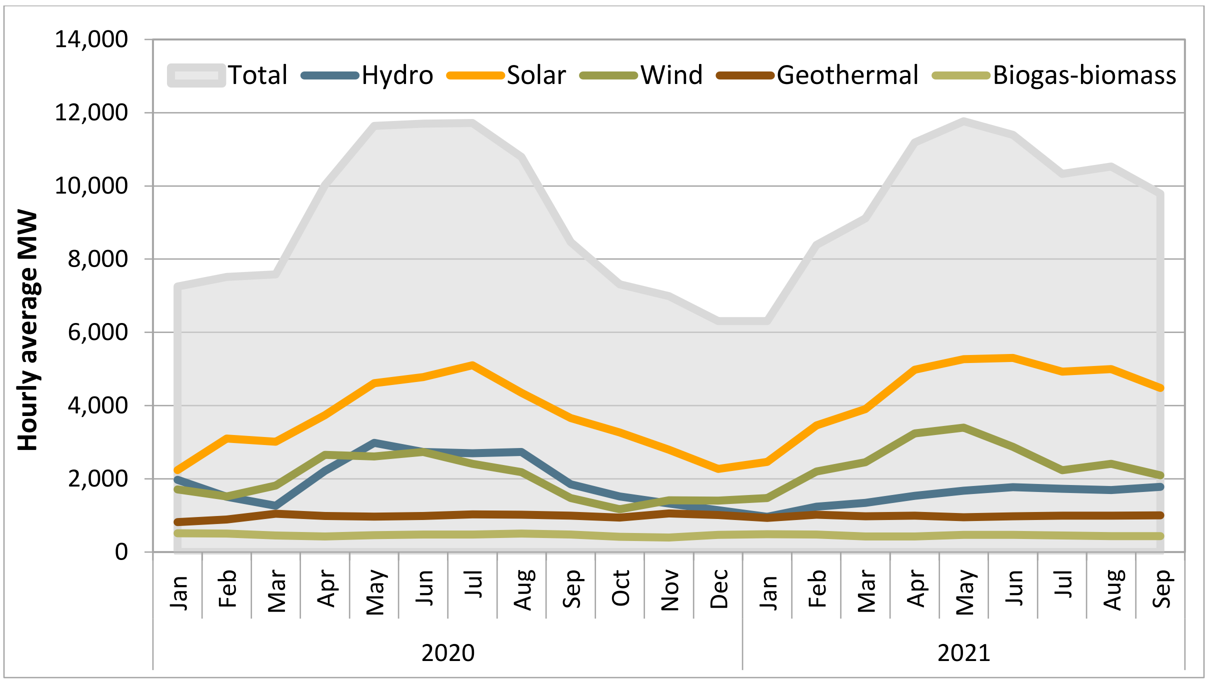
5 Figures and data provided in this section for Q3 2021 are preliminary and may be subject to change.

6 Hydroelectric generation greater than 30 MW is included.

wind generation. Hourly average wind and solar production increased by about 11 percent and 10 percent, respectively, compared to the third quarter of 2020. Geothermal and biogas-biomass generation decreased over the quarter, by 2 percent and 10 percent, respectively, compared to the third quarter of 2020.

Hourly average hydroelectric production in the third quarter decreased by about 700 MW (29 percent), compared to the same period in 2020.[5] As of April 1, 2021, the statewide weighted average snowpack in California was 62 percent of normal compared to 50 percent of normal on April 1, 2020.[7] In California, statewide reservoir storage is down to 60 percent of average because the water year 2021 (October 2020 – September 2021) was the driest year in California since 1924.[8]

Figure 1.2 Average hourly renewable generation by month



1.1.3 Downward dispatch and curtailment of variable energy resources

Wind and solar downward dispatch and curtailments increased in the third quarter of 2021, relative to last year, by 9 percent in the ISO balancing area and 120 percent in the energy imbalance market. 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. However, the overall increase in the ISO was driven by increased curtailments of self-scheduled solar resources over the quarter.

When the amount of supply on-line exceeds demand, the real-time market dispatches generators down. Generally, generators are dispatched down in merit order from the highest bid to lowest. As with typical

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

8 California Department of Water Resources – Water Year 2021 Brochure: https://water.ca.gov/-/media/DWR-Website/Web-Pages/Water-Basics/Drought/Files/Publications-And-Reports/091521-Water-Year-2021-broch_v2.pdf

incremental dispatch, the last unit dispatched sets the system price and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, even wind and solar resources are dispatched down economically, implying that the nodal price is even lower than the typically low priced bids from wind and solar resources. If the supply of bids to decrease energy is completely exhausted in the real-time market, the software may curtail self-scheduled generation, including self-scheduled wind and solar generation.

Figure 1.3 shows the curtailment of wind and solar resources by month in the ISO. DMM has developed the following six categories for curtailment based on whether the resource bid in economically or self-scheduled, whether the resource received an exceptional dispatch/out of market instruction to decrease supply, and the relationship between the resource's bid price and the resulting market price:

- **economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls within one dollar of or below a resource's bid or the resource's upper limit is binding;[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 greater 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 during the third quarter of 2021 (79 percent) was a result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation dispatched down in the ISO were solar resources (93 percent) rather than wind (7 percent).

In the ISO, economic downward dispatch was steady during the third quarter of 2021, totaling just over 102 GWh. This represents a 9 percent decrease relative to the same quarter of 2020. Self-schedule curtailment totaled 10 GWh for the quarter, a 132 percent increase relative to the third quarter of 2020.

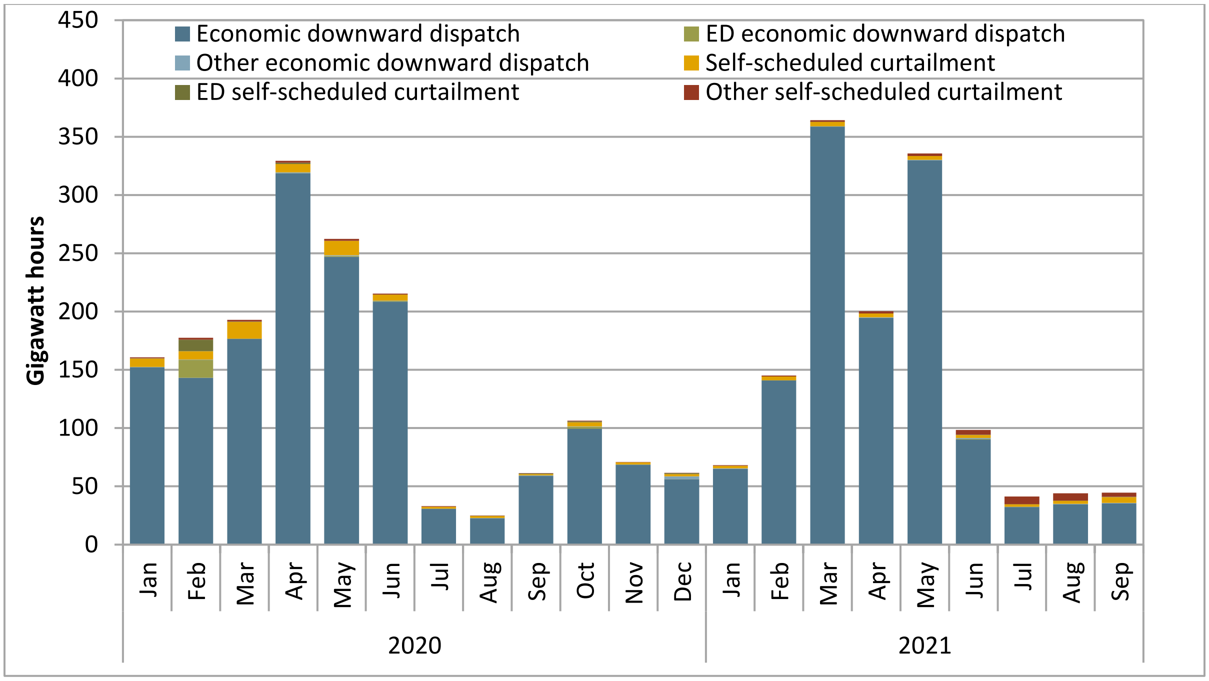
Figure 1.4 shows the amount of downward dispatch of non-ISO wind and solar resources. Curtailments in the EIM fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment, each defined above. Downward dispatch was higher in the energy imbalance market areas outside of the ISO compared to the same quarter of

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.

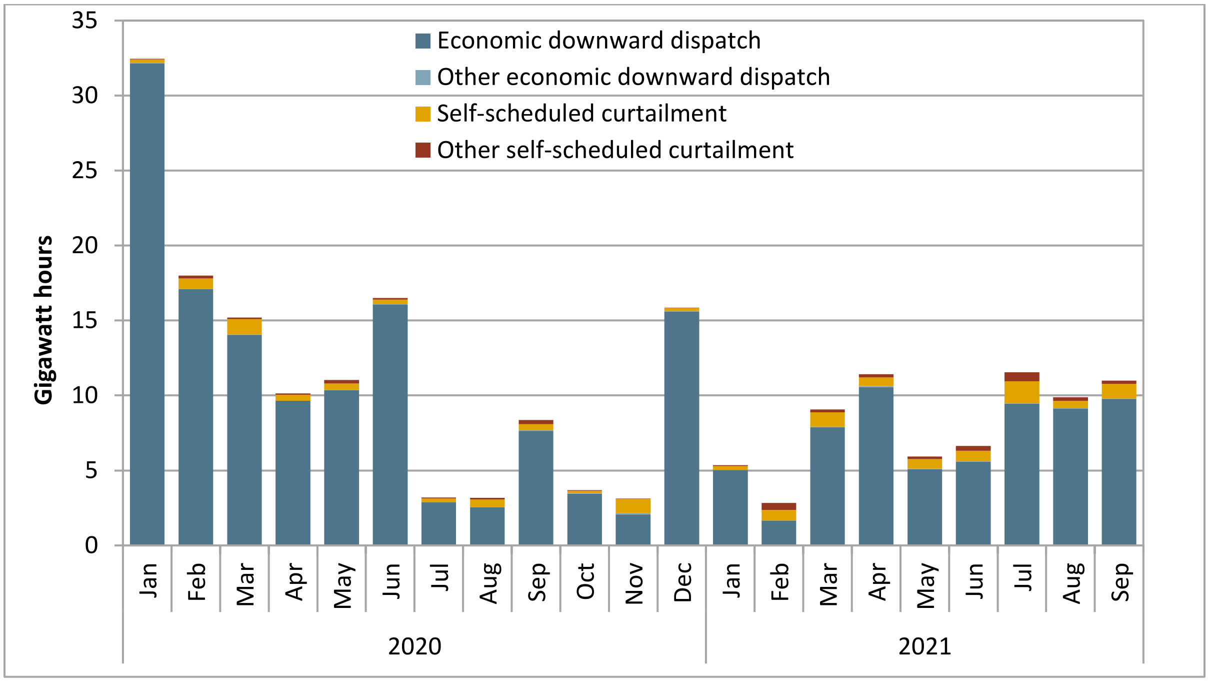
2020. Much of the curtailment in the EIM is due to the high frequency of congestion on the Wyoming Export constraint, which leads to one resource being heavily curtailed.[11]

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



[11] The Total_Wyoming_Export constraint was congested during 52.1 percent of intervals during the quarter as shown in Table 1.4. The overall effects of transfer congestion are discussed in detail in Section 1.9.2.

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



1.1.4 Generation by fuel type

In the third quarter, generation increased on average for some fuel types, while decreasing significantly for others. Average hourly generation by both wind and solar resources increased by 11 percent and 10 percent, respectively, while average hourly generation by imports and hydroelectric resources fell by 31 percent and 29 percent, respectively, compared to the same quarter of 2020.[12]

Figure 1.5 shows the average hourly generation by fuel type during the third quarter of 2021. As shown in the figure, average nuclear, geothermal, and bio-based resources comprised about 4,400 MW of inflexible base generating capacity, about 200 MW more than the same quarter of 2020. Hourly average natural gas generation peaked at about 17,100 MW, during hour ending 20. Natural gas generation accounted for about 45 percent of total average hourly generation during the net peak load of hours ending 17 through 21. Compared to the third quarter of 2020, total average hourly natural gas generation increased 8 percent, driven by a decrease in hydroelectric generation and imports.

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

Figure 1.5 Average hourly generation by fuel type (Q3 2021)

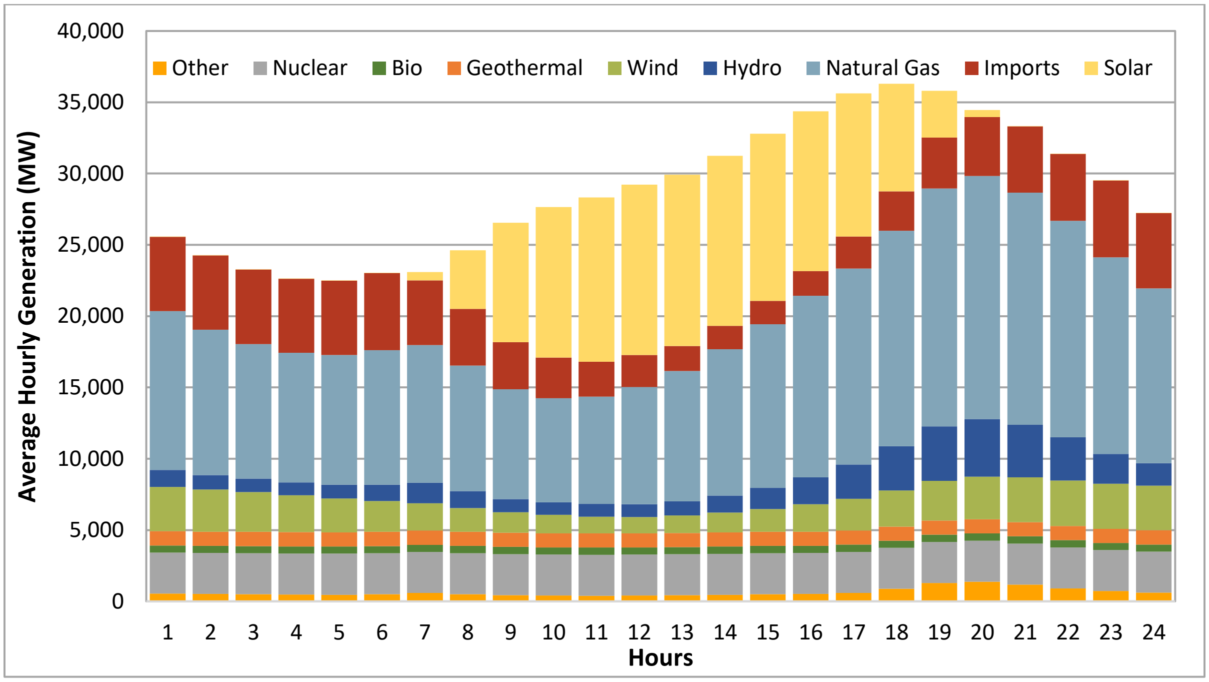


Figure 1.6 shows hourly variation of generation by fuel group, driven primarily by the hourly variation of solar production. Compared to the third quarter of 2020, solar generation variability increased 10 percent, while natural gas generation variability decreased 10 percent. Average hourly imports trended similarly to natural gas generation over the quarter, with most imports occurring during non-peak hours. Average hourly generation from resources in the "other" category showed increased variability throughout the day, increasing 158 percent compared to the same quarter of 2020, due in large part to an increase in battery storage resources.[13]

[13] In this figure, the "other" category contains nuclear, geothermal, bio-based resources, coal, battery storage, demand response, and additional resources of unique technologies.

Figure 1.6 Hourly variation in generation by fuel type (Q3 2021)

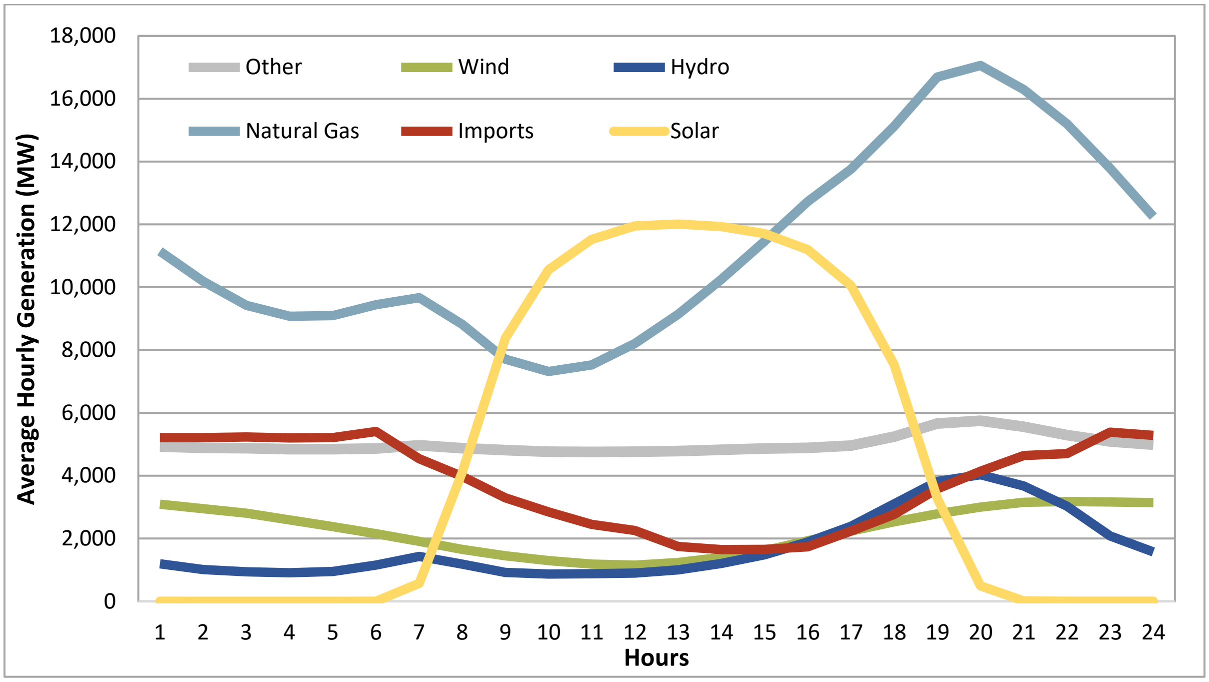
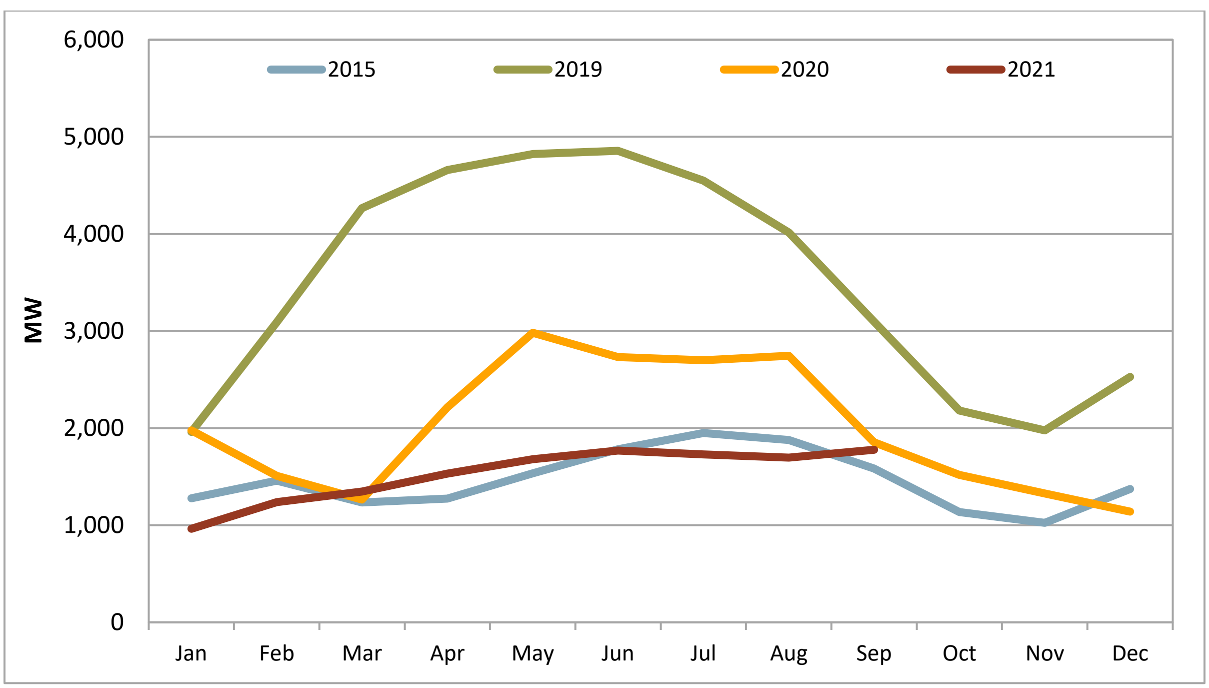


Figure 1.7 shows the monthly average hydroelectric generation for 2015, 2019, 2020, and 2021. Hydroelectric generation in 2021 is well below 2019 and 2020, while trending similarly to 2015. Conditions are similar to those of 2015 as both years saw April 1 snowpack percentages that were below normal, with 62 percent of normal in 2021 and 5 percent in 2015. The decline in hydroelectric generation has been made up for, in part, by increased wind and solar generation.

Figure 1.7 Monthly average hydroelectric generation by year



1.1.5 Generation outages

The average total generation on outage for the quarter was about 11,300 MW, a 20 percent increase relative to the third quarter of 2020 and higher than the same quarter of the last five years. Forced and planned outages increased 18 percent and 67 percent, respectively, relative to the same time last year.[14]

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

Figure 1.8 shows the quarterly averages of maximum daily outages during peak hours by type from 2019 to 2021. Figure 1.9 shows the monthly averages of maximum daily outages during peak hours broken out by type for 2020 and 2021. The typical seasonal outage pattern is primarily driven by planned outages for maintenance, which are generally performed outside of the high summer load period.

During the third quarter of 2021, the average total generation on outage in the ISO surpassed the same period in 2020 by about 2,300 MW, as shown in Figure 1.8.[15] Planned maintenance outages averaged 521 MW, while other types of planned outages averaged 1,884 MW, which represent a 21 percent decrease and a 142 percent increase, respectively, compared to the third quarter of 2020. Some common types of outages that fall into the other planned outages category include ambient outages (both due to temperature and not due to temperature) and transmission outages. These planned outage categories combined for the quarter was about 67 percent higher than the third quarter of 2020.

Total forced outages averaged 8,750 MW during peak hours in the third quarter of 2021, about 18 percent higher than the same time last year. Forced outages for either plant maintenance or plant trouble averaged 3,000 MW, while all other types of forced outages averaged 5,800 MW during the quarter. These other types of forced outages include categories ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations.

On a monthly basis, total outages remained steady during the quarter. The key difference from the third quarter of 2020 is that planned outages increased over the quarter, which countered the decrease in forced outages. Based on the historical seasonal trend and the high levels of generation on outage during 2021 thus far, the fourth quarter will likely experience the most generation outages to date.

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[14] Includes 'Other forced outages' and 'Other planned outages'.

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

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

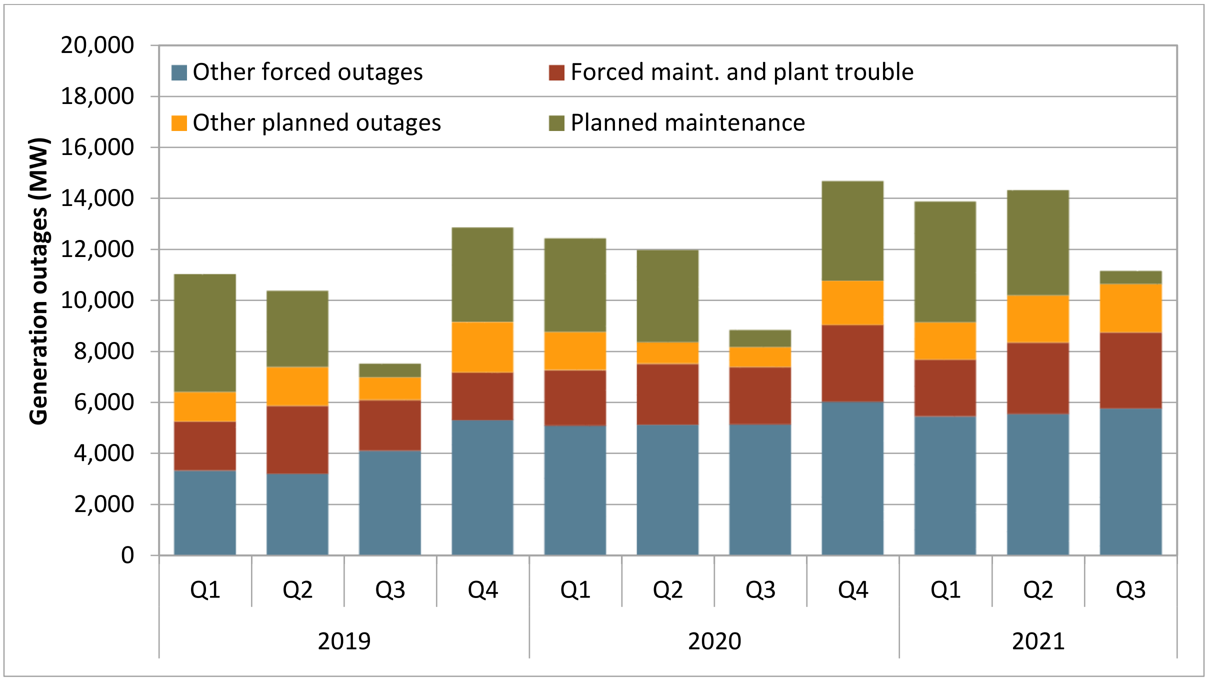
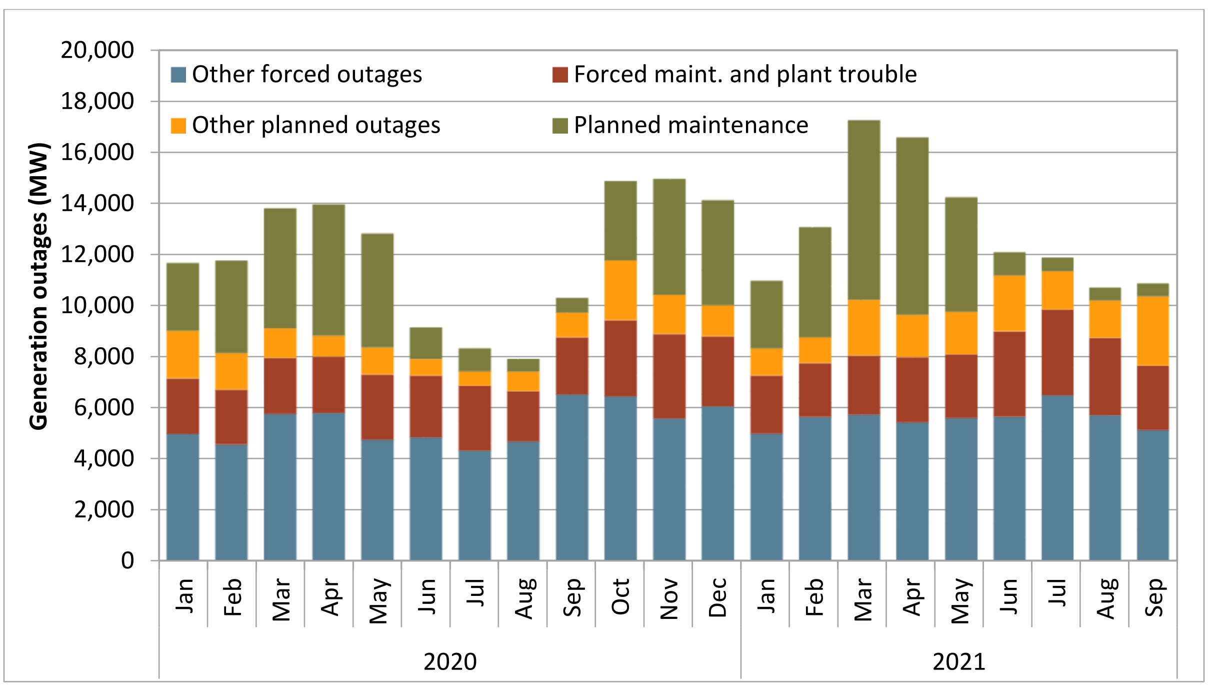


Figure 1.9 Monthly average of maximum daily generation outages by type – peak hours

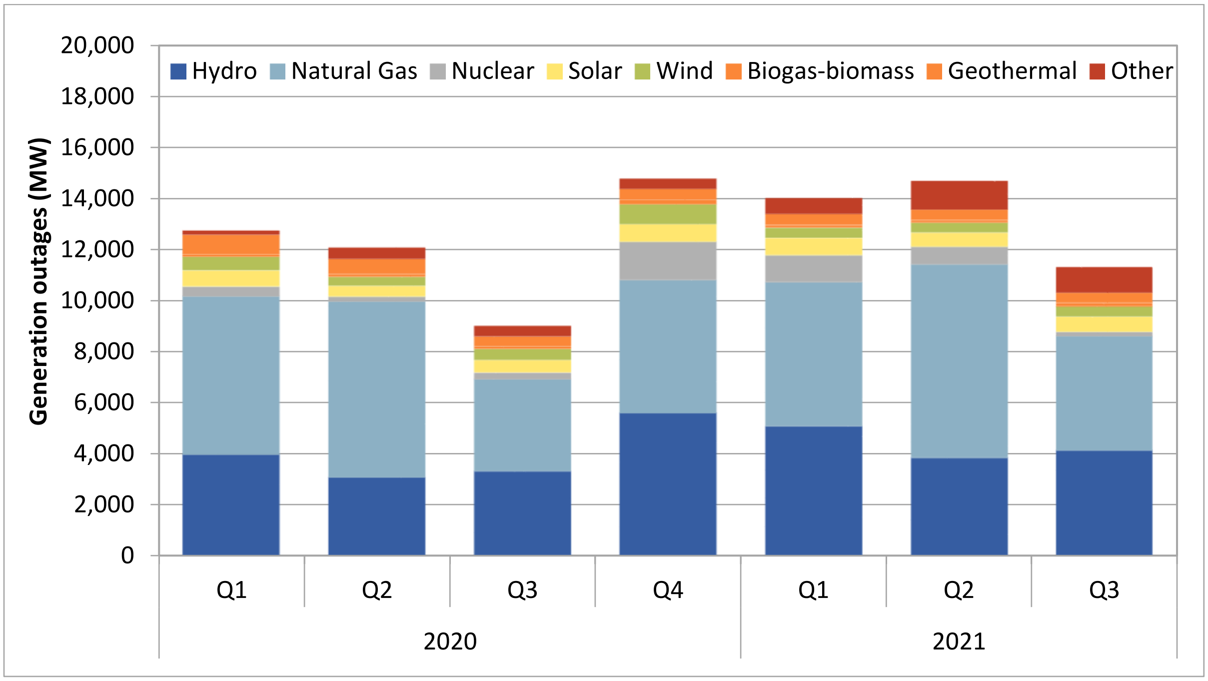


Generation outages by fuel type

Natural gas and hydroelectric generation on outage averaged about 4,500 MW and 4,100 MW during the third quarter. These two fuel types accounted for 40 percent and 36 percent of the generation on outage for the quarter, respectively.

Figure 1.10 shows the quarterly average of maximum daily generation outages by fuel type during peak hours. The overall increase in generation outages in the third quarter was primarily due to an increase in natural gas, hydroelectric, and "Other" generation outages, which increased by 24 percent (863 MW), 25 percent (819 MW) and 245 percent (598 MW), respectively. Nuclear generation returned to service from outages earlier in the year, showing 76 percent less generation on outage compared to Q2 2021. Wind and geothermal generation experienced less generation on outage compared to the third quarter of 2020, decreasing by 9 percent and 1 percent, respectively.

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



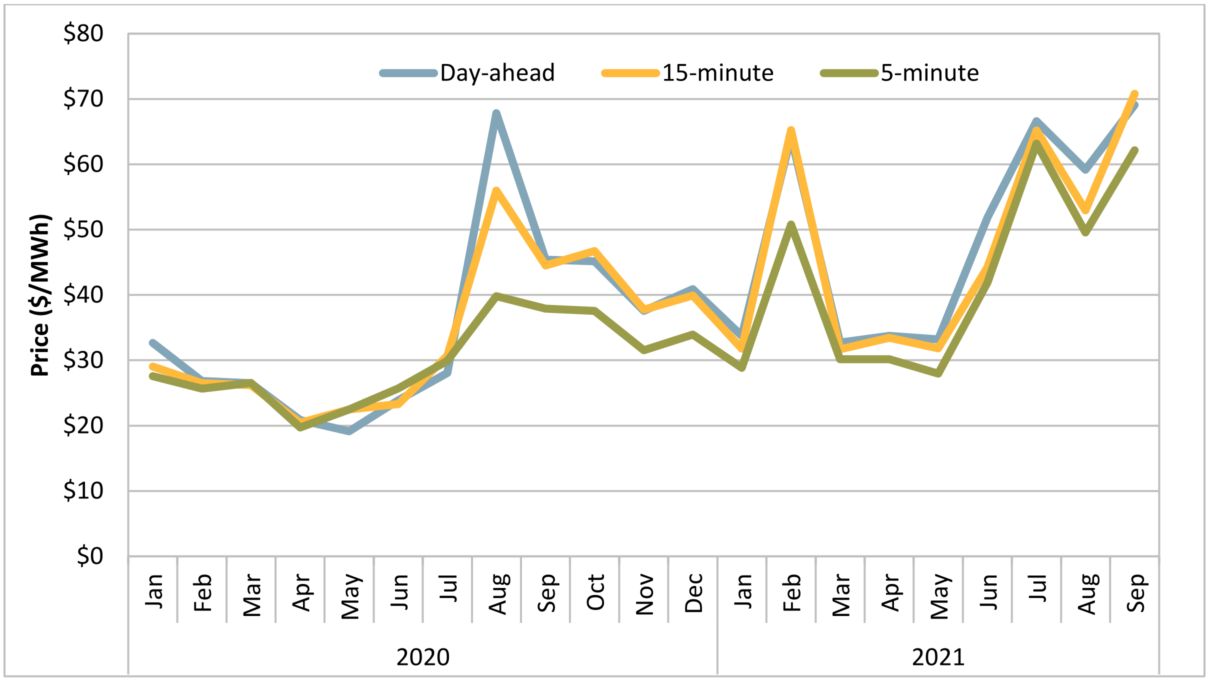
1.2 Energy market performance

1.2.1 Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources. Compared to the third quarter of 2020, prices across all three markets were generally higher in July and September, but lower in August.

Figure 1.11 shows load-weighted average monthly energy prices during all hours across the four largest aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Valley Electric Association). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2020 to September 2021.

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

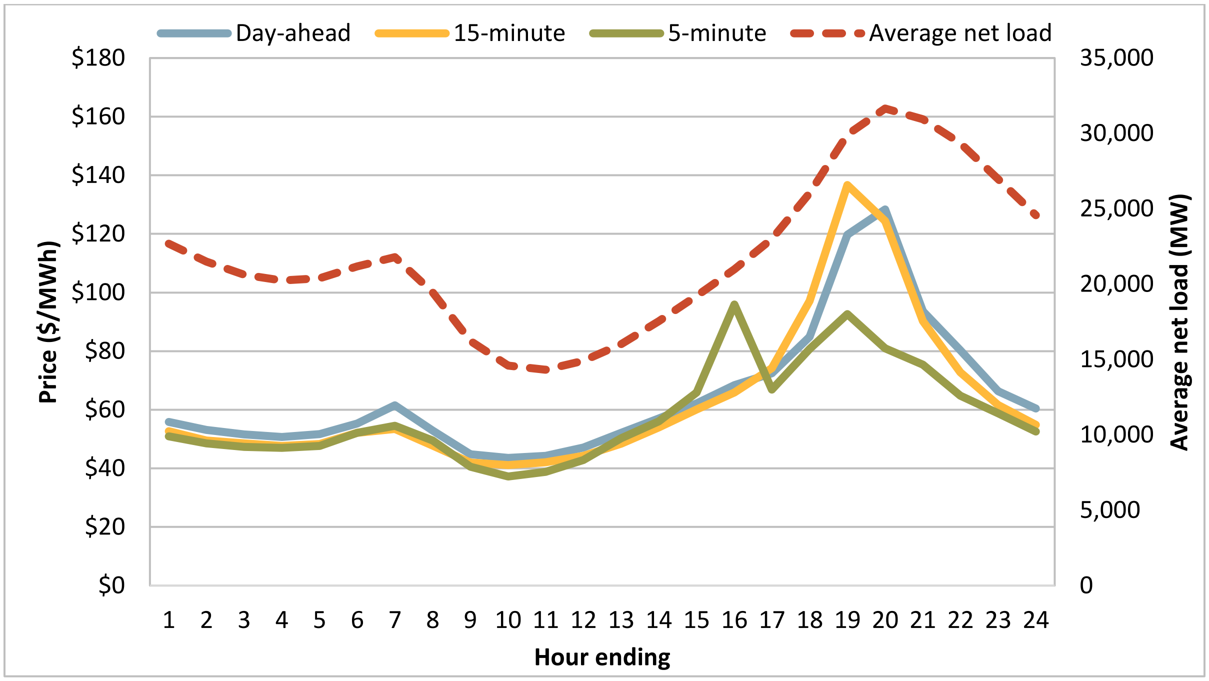


Market prices were significantly higher than the same quarter of 2020 on average. Higher prices are likely due to the ongoing drought conditions causing low hydroelectric production along with higher natural gas prices, which were roughly twice as high this quarter compared to the third quarter last year. Day-ahead prices averaged $65/MWh, 15-minute prices averaged $63/MWh, and 5-minute prices averaged $58/MWh.

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.

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

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



1.2.2 Bilateral price comparison

On average, day-ahead market prices in the ISO across peak hours in the third quarter were lower 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 the 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 ISO market. Average prices in the ISO and bilateral trading hubs were calculated during peak hours (hours ending 7 through 22) for all days, excluding Sundays and holidays. The figure shows significant price divergence between the ISO and these bilateral hubs during the high demand period during mid and late July across the western US.

Figure 1.14 uses the same data underlying Figure 1.13 but on an average monthly basis for 2020 and 2021. Prices in the ISO are represented at the Southern California Edison and Pacific Gas and Electric default load aggregation points. As shown in this figure, average bilateral prices at Mid-Columbia and Palo Verde hubs exceeded ISO prices during the high demand period in July 2021.

Figure 1.13 Day-ahead ISO and bilateral market prices (Jul - Sep)

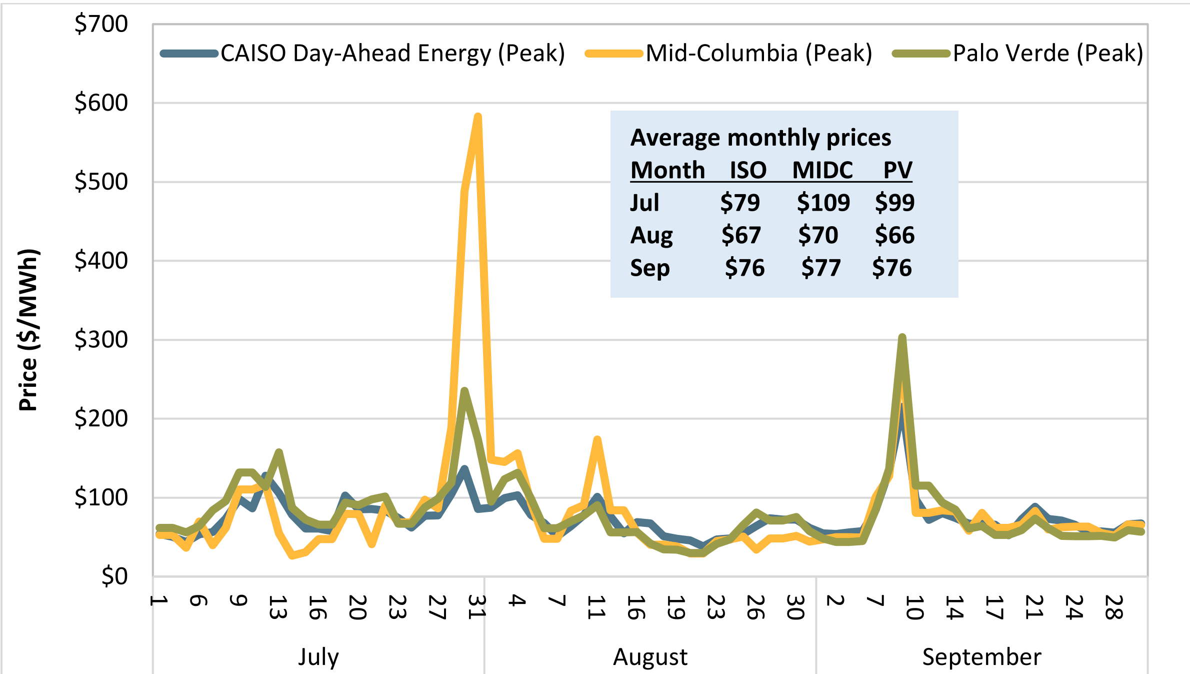
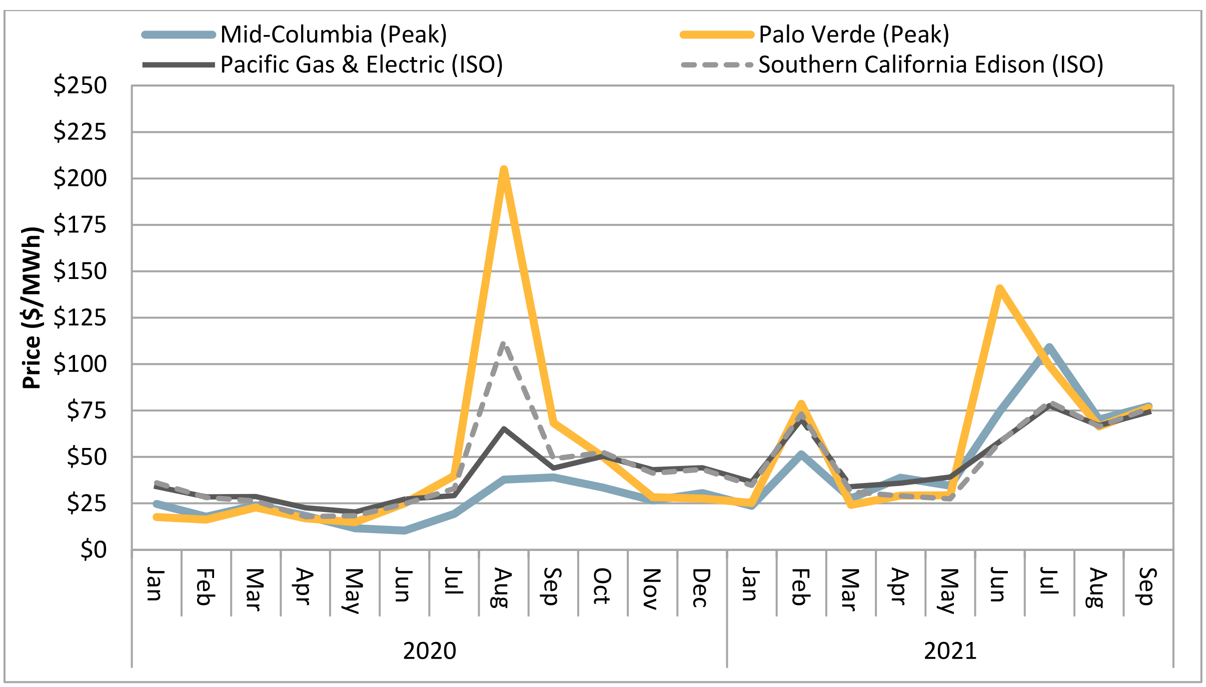


Figure 1.14 Monthly average day-ahead and bilateral market prices



Average day-ahead prices in the ISO 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 ISO were greater than average real-time prices at Mid-Columbia and Palo Verde by $15/MWh and $4/MWh, respectively. Average day-ahead prices at Mid-Columbia and Palo Verde (from ICE) were greater than the average real-time prices at Mid-Columbia and Palo Verde (from Powerdex) by $21/MWh and $7/MWh, respectively.

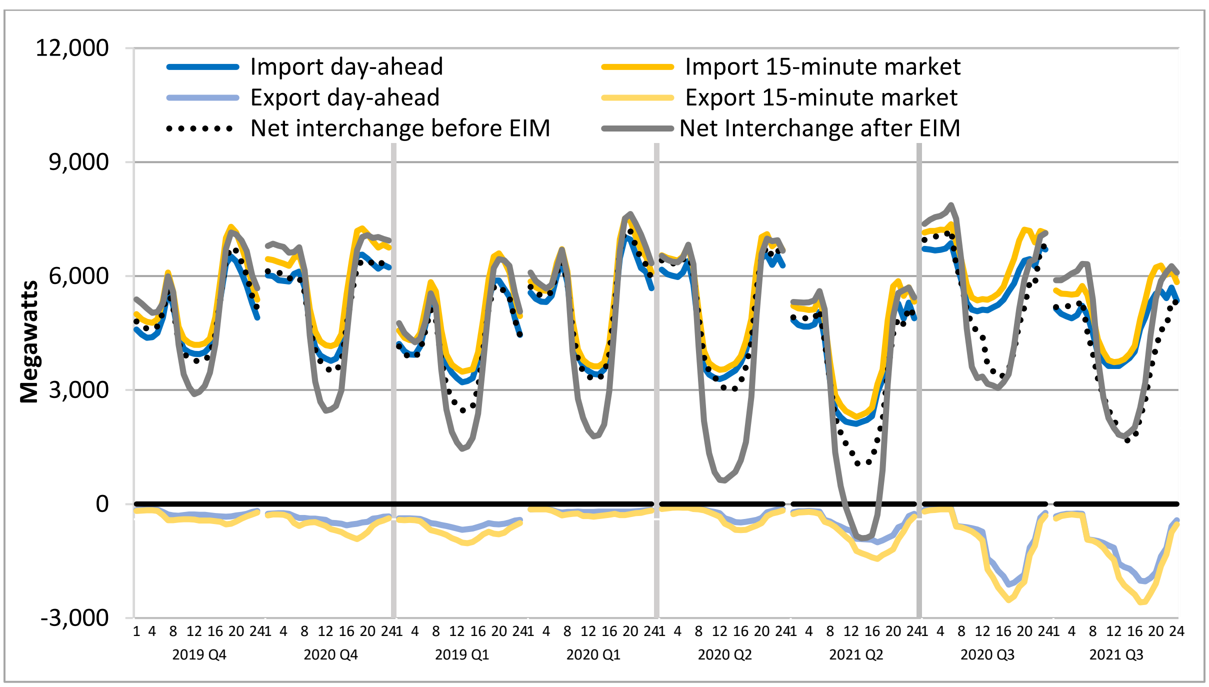
Imports and exports

As with the previous quarter, average net imports decreased compared to the same quarter in 2020. This may be due to low hydroelectric production caused by ongoing drought conditions in the west.[17]

As shown in Figure 1.15, peak imports in the day-ahead (dark blue line) decreased in hour ending 21, from about 6,900 MW to 5,700 MW, compared to the same quarter of 2020. Peak 15-minute cleared imports (dark yellow line) also decreased, from about 7,400 MW to 6,300 MW, compared to last year. Peak exports (shown as negative numbers below the horizontal axis in pale blue and yellow), were very similar compared to the same quarter of 2020.

The average net interchange, excluding EIM transfers (dashed grey line), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental EIM interchange, which reached a low point of about 1,800 MW in hour ending 14. The greatest import transfer into the ISO from the EIM occurred in hour ending 7, at about 1,800 MW, compared to about 1,200 MW in hour ending 12 from the same quarter in the prior year. Export transfer from the ISO to the EIM was minimal and only occurred between hour-ending 10 to hour-ending 12, with hour-ending 12 topping out at about 250 MW. This is a decrease from the same quarter of the previous year with a maximum export in hour-ending 12 at about 1,200 MW.

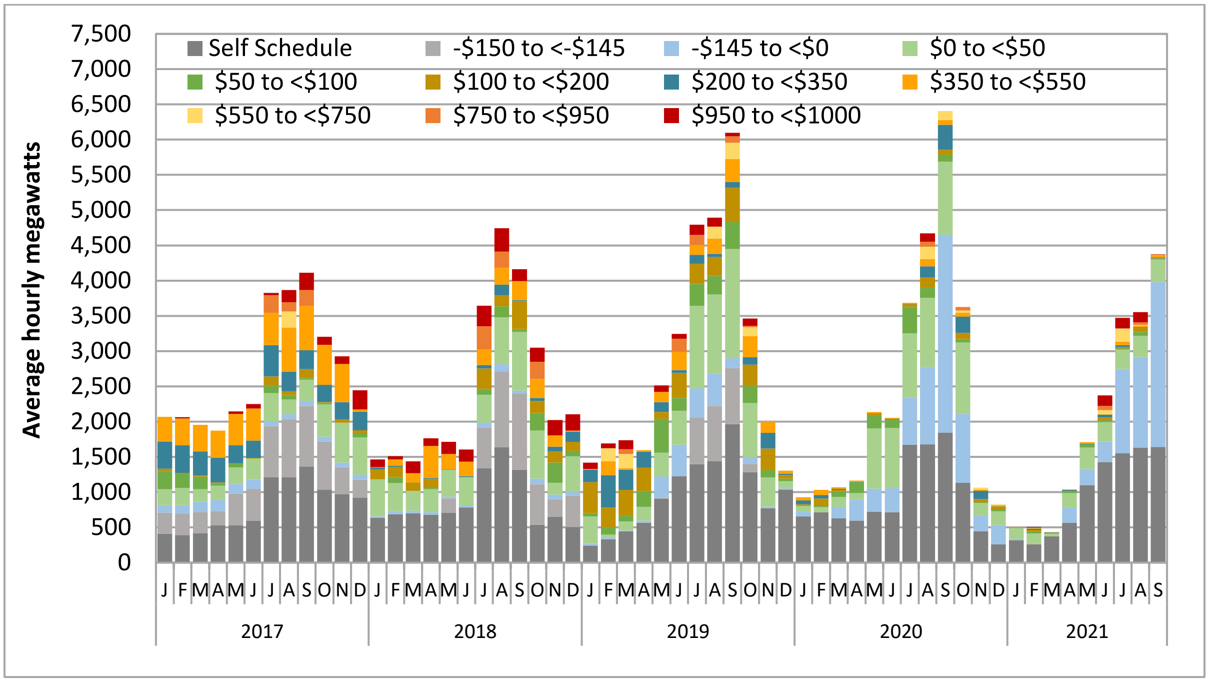
Figure 1.15 Average hourly net interchange by quarter



17 U.S. Drought Monitor Conditions for California: https://www.drought.gov/states/california

Figure 1.16 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours.[18] The grey bars reflect import capacity that was self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market.

Figure 1.16 Average hourly resource adequacy imports by price bin



1.3 Structural measures of competitiveness

Market structure refers to the ownership of available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the *pivotal supplier test* and the *residual supply index*. Both of these measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test.** If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal; this is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[19] A residual supply index less than 1.0 indicates an uncompetitive level of supply.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. The potential for such behavior is high in the

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

19 For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120 – 30)/100.

electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

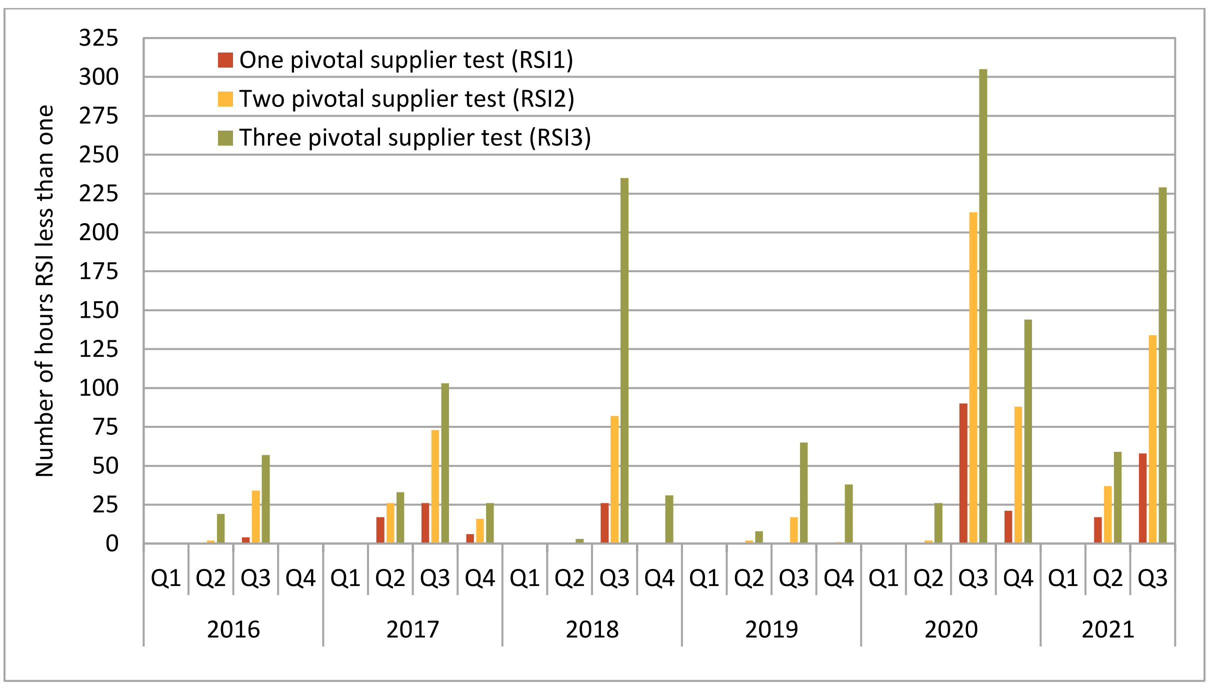
In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI_1. With the two or three largest suppliers excluded, we refer to these results as RSI_2 and RSI_3, respectively.[20]

Figure 1.17 shows the quarterly number of hours with a residual supply index less than one since 2016. During the third quarter, the number of hours with an RSI less than one was lower relative to the same quarter of the previous year. The residual supply index with the three largest suppliers removed (RSI_3) was less than one during 229 hours. These primarily occurred during peak net load hours, between hour-ending 17 and 22.

With the largest two suppliers removed (RSI_2), the residual supply index for the third quarter was less than one in 134 hours. With the largest supplier removed (RSI_1), it was less than one in 58 hours.

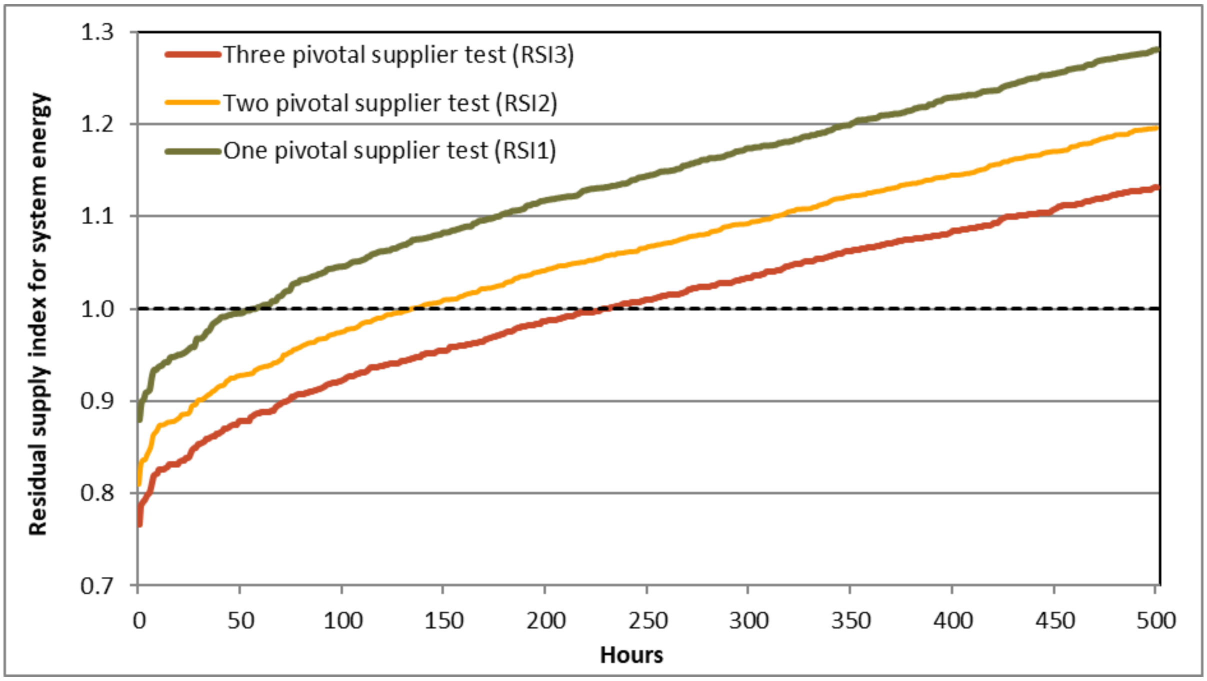
Figure 1.18 illustrates the level of the residual supply index measurements by showing the lowest 500 RSI values during the quarter. With the three largest suppliers removed, the RSI_3 was less than 0.9 in 73 hours, and less than 0.8 in 5 hours.

Figure 1.17 Hours with residual supply index less than one



[20] For more information on the supply and demand elements used to calculate the residual supply index, see the *Q4 2020 Report on Market Issues and Performance,* April 2021, pp. 111: http://www.caiso.com/Documents/2020-Fourth-Quarter-Report-on-Market-Issues-and-Performance-April-28-2021.pdf

Figure 1.18 Lowest 500 residual supply index with largest one, two, or three suppliers excluded (July – September)



1.4 Price variability

Day-ahead market prices range greatly over the course of a year, with periods of high and low prices. These variations tend to follow seasonal patterns, primarily due to the availability of variable energy resources such as wind and solar. Real-time market prices can be volatile with periods of extreme positive or negative prices; even a short period of extremely high or low prices can significantly impact average prices. Compared to the third quarter last year there were fewer intervals with substantially high energy prices while intervals with negative prices remained infrequent.

1.4.1 Day-ahead price variability

In the third quarter of 2021 the frequency of high day-ahead prices decreased while negative day-ahead prices remained the same compared to the same quarter in 2020.

High prices

Figure 1.19 shows the frequency of day-ahead market prices in various high priced ranges from July 2020 to September 2021. The frequency of prices over $250/MWh increased in July but decreased substantially in August and slightly in September. In this quarter, roughly 1 percent of hours in July and September had prices over $250, but there were very few hours with prices over $500/MWh and none over $750/MWh.

Negative prices

Figure 1.20 shows the frequency of day-ahead market prices in various low priced ranges from July 2020 to September 2021. There were no hours in this quarter where prices in the day-ahead market were below $1/MWh, same as the third quarter of 2020.

Figure 1.19 Frequency of high day-ahead prices ($/MWh) by month

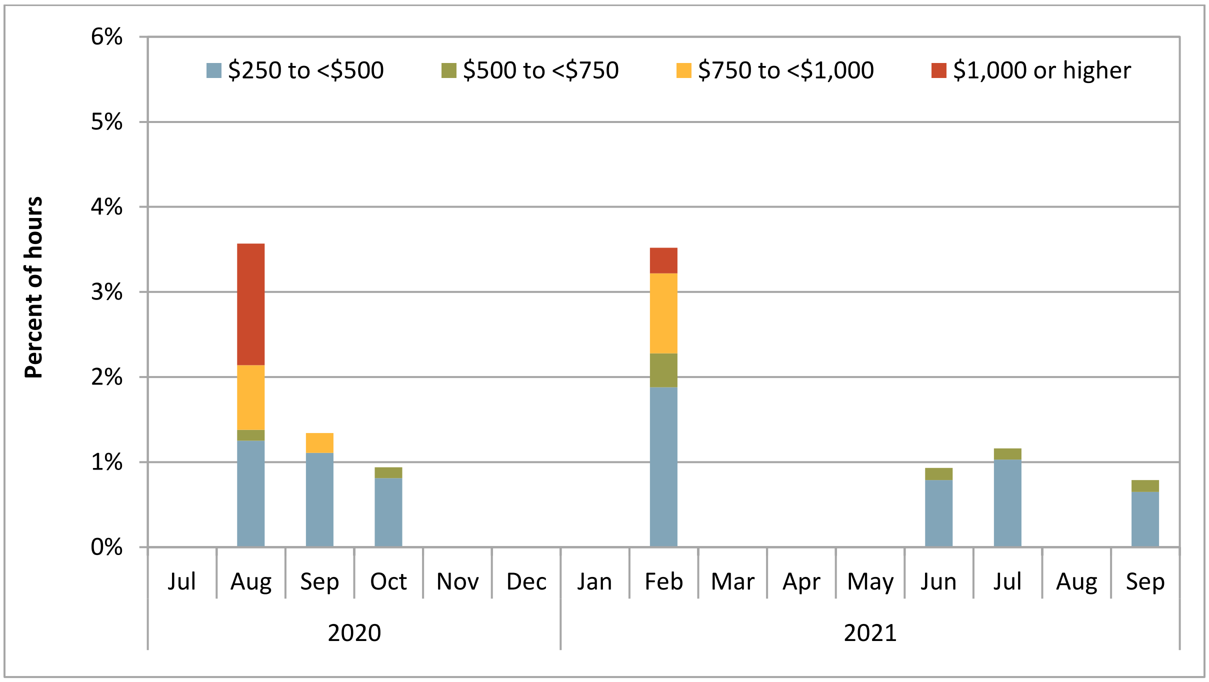
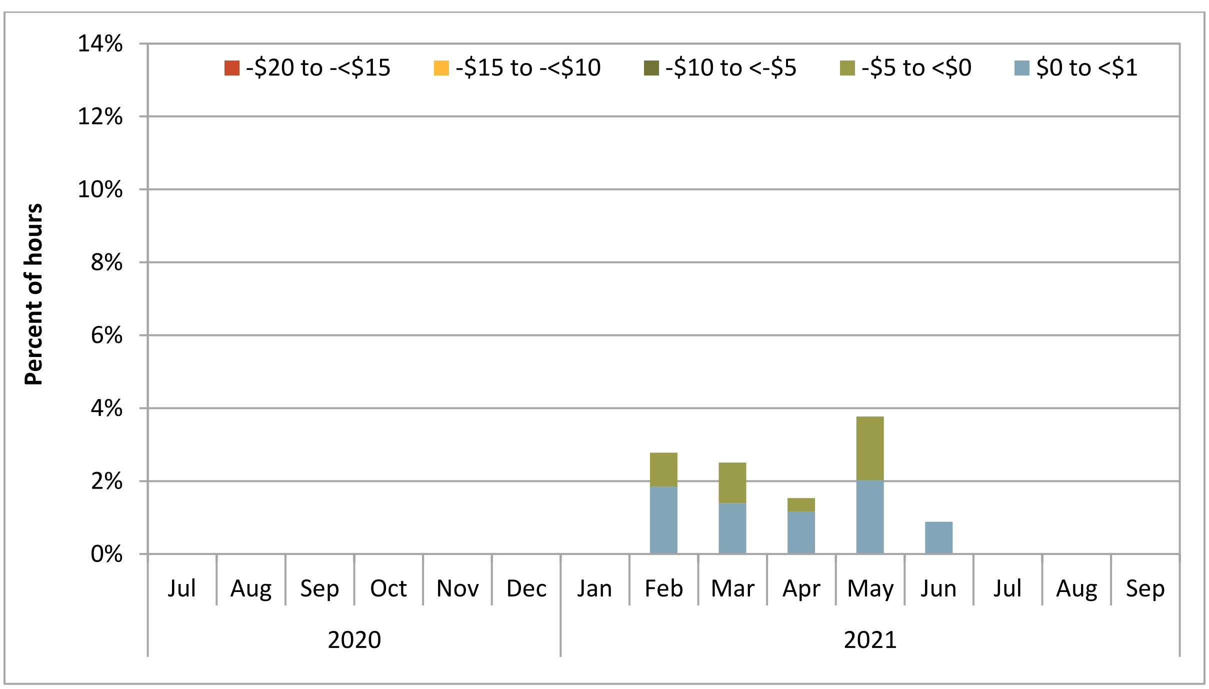


Figure 1.20 Frequency of negative day-ahead prices ($/MWh) by month



1.4.2 Real-time price variability

During the third quarter of 2021, variability in the real-time market was similar to the third quarter last year. This year there were more instances of high prices in July, compared to last year when high prices were more prevalent in August. This difference is driven by the weather patterns in the third quarter this year compared to last year. There were very few instances of negative prices this quarter, similar to the third quarter of 2020.

High prices

Figure 1.21 and Figure 1.22 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.21, the frequency of prices over $250/MWh in the 15-minute market was higher in July, substantially lower in August, and about the same in September compared to the third quarter of 2020. In the 5-minute market the frequency of prices over $250/MWh decreased across each month of the quarter, particularly in August, as seen in Figure 1.22.Figure 1.23 and Figure 1.24 show the frequency of undersupply infeasibilities and whether they were resolved by the load conformance limiter. Infeasibilities resolved by the load conformance limiter continued to be infrequent and had an insignificant impact on prices in the ISO because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap, such that the resulting price is often very similar with or without the limiter.

Figure 1.21 Frequency of high 15-minute prices by month (ISO LAP areas)

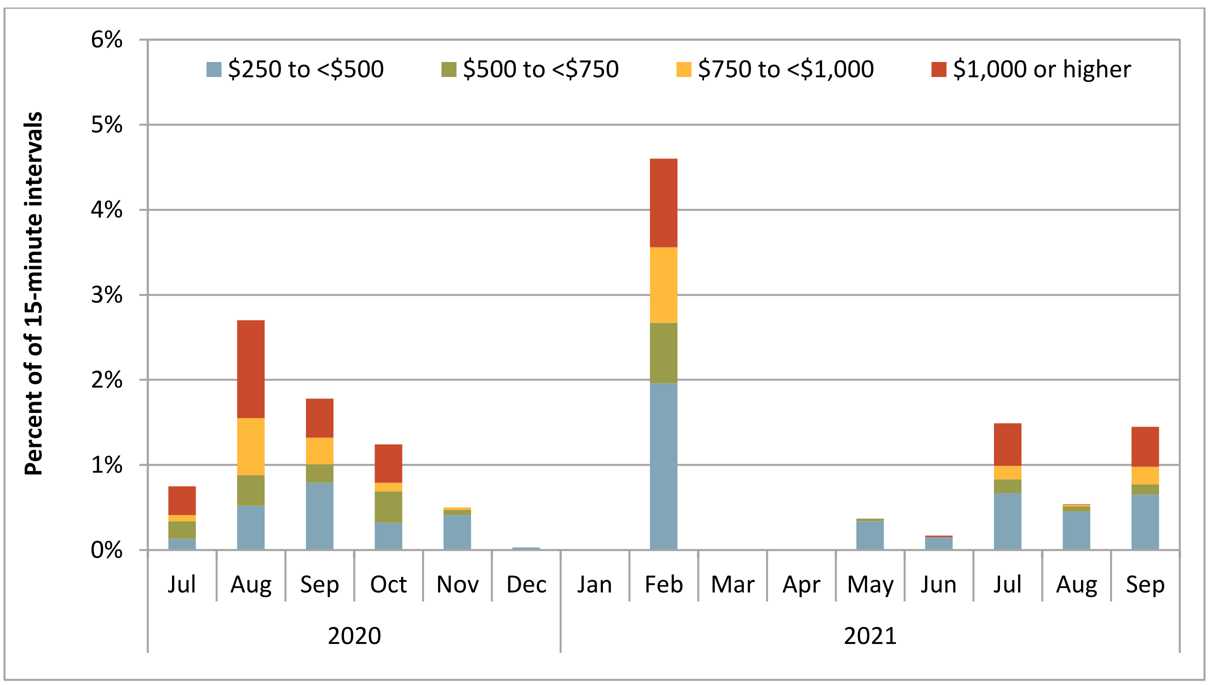


Figure 1.22 Frequency of high 5-minute prices by month (ISO LAP areas)

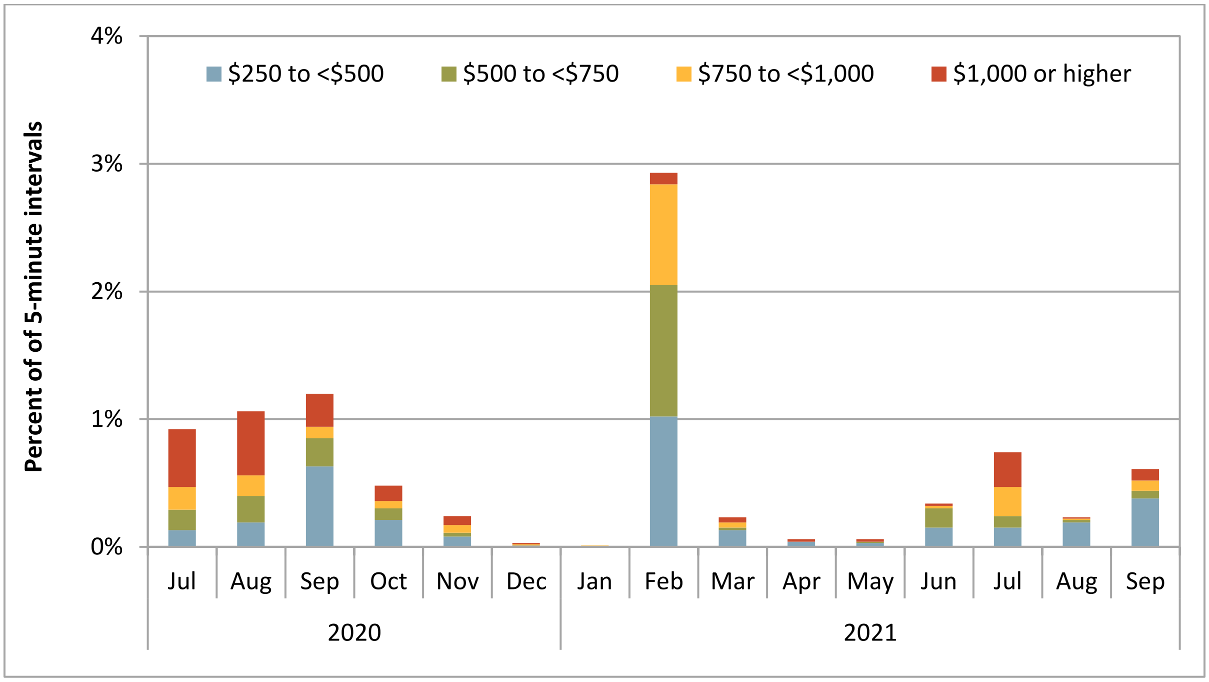


Figure 1.23 Frequency of undersupply power balance constraint infeasibilities (15-minute market)

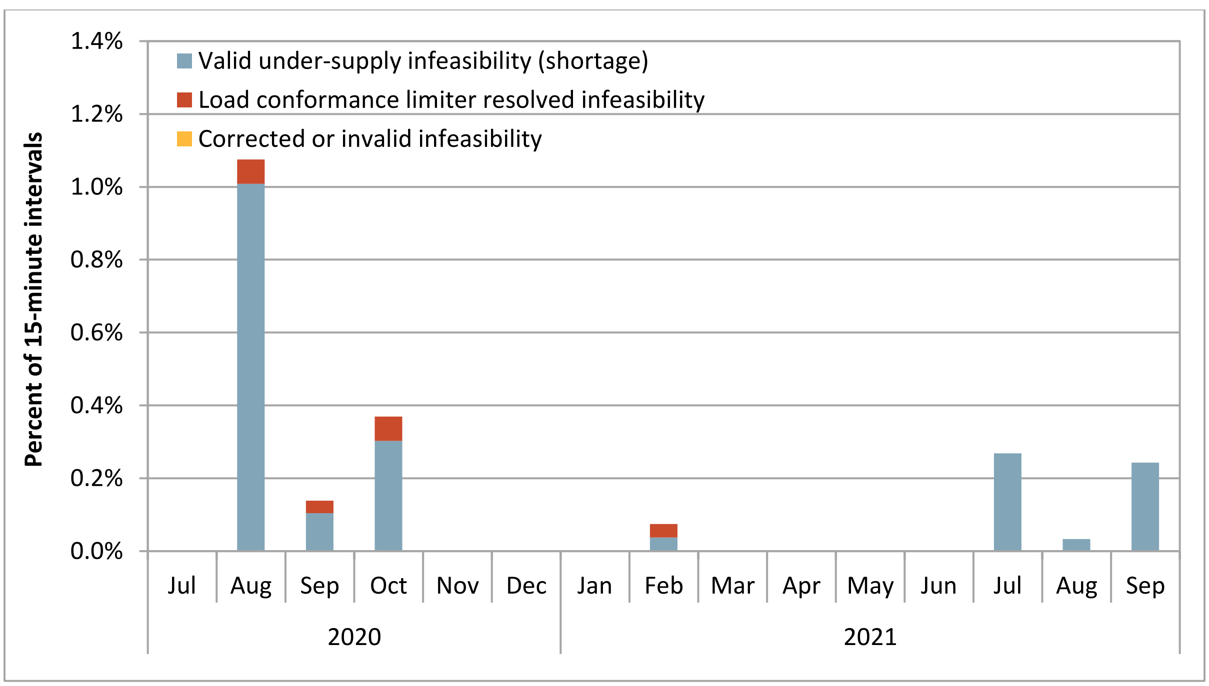
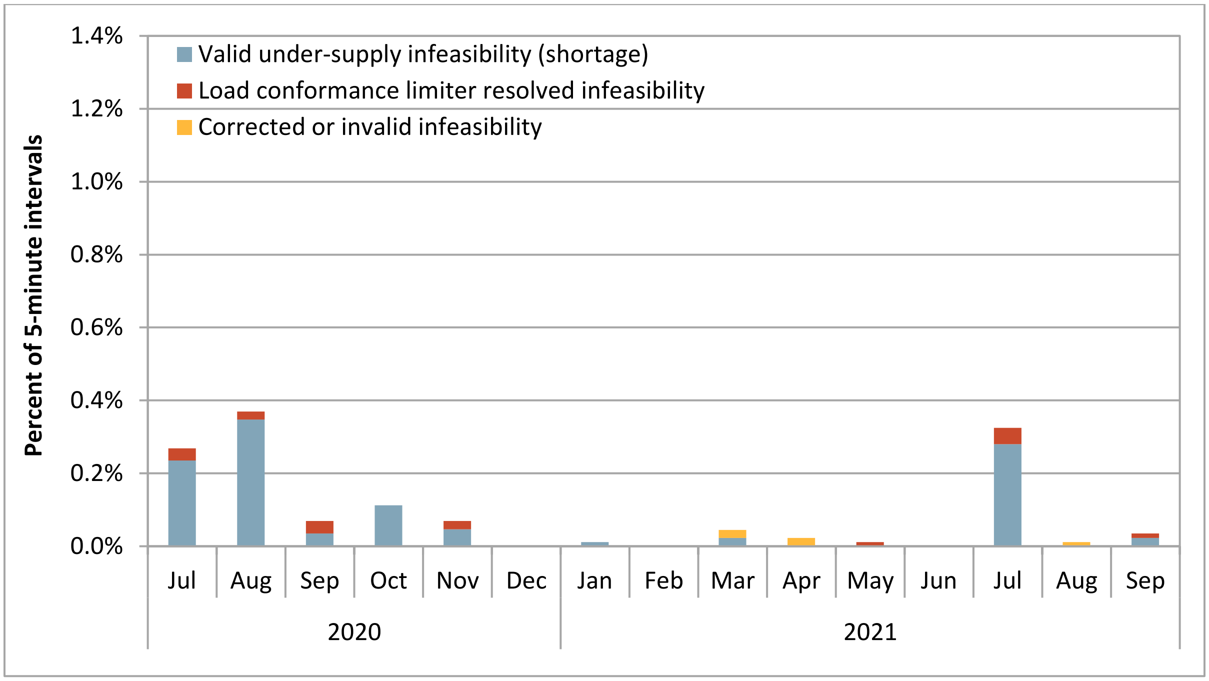


Figure 1.24 Frequency of undersupply power balance constraint infeasibilities (5-minute market)

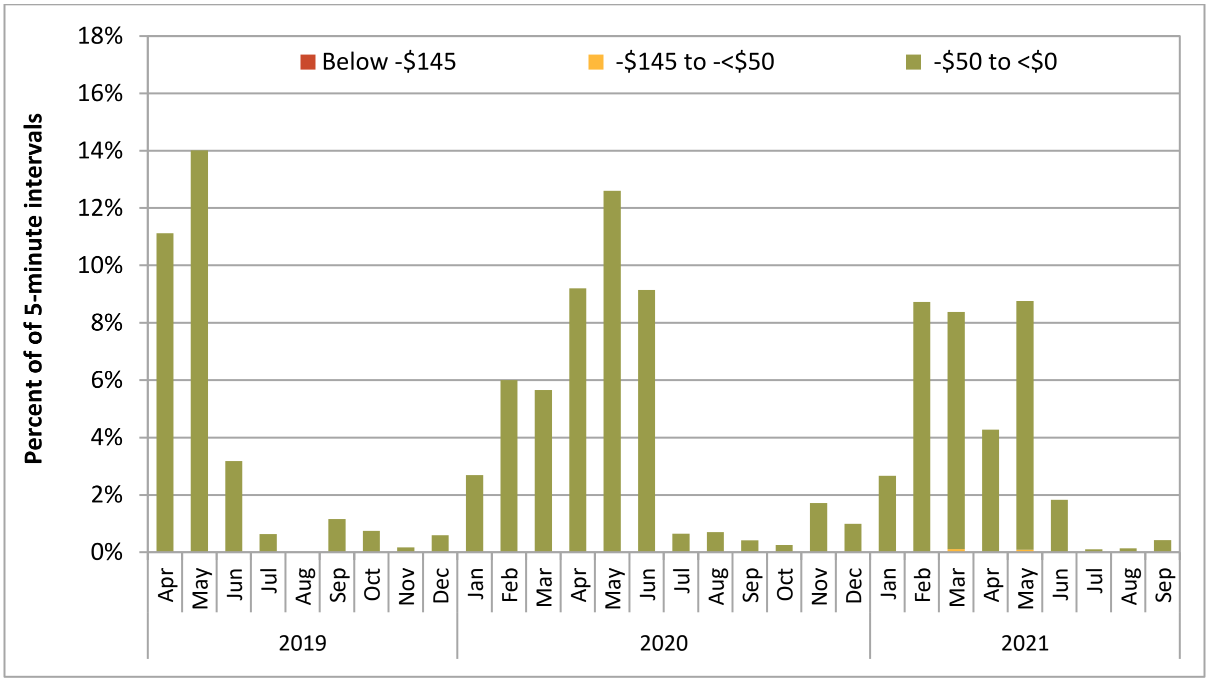


Negative prices

Figure 1.25 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[21] There were very few instances of negative prices in the 5-minute market in this quarter.

[21] Corresponding values for the 15-minute market show a similar pattern but at a lower frequency.

Figure 1.25 Frequency of negative 5-minute prices by month (ISO LAP areas)



1.5 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 5-minute market runs within that 15-minute interval. Procurement in the 5-minute market is designed to ensure enough ramping capacity is available to manage differences between the consecutive 5-minute market intervals.

1.5.1 Minimum flexible ramping product requirement

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

The flexible ramping product refinements stakeholder initiative introduced a new minimum flexible ramping product requirement. Beginning in November 2020, if an individual balancing authority area requirement is greater than 60 percent of the system requirement, then a minimum will be enforced, equal to the balancing authority area's share of the diversity benefit.[23] The minimum requirement is intended to help mitigate some of the issues surrounding procurement of stranded flexible ramping product prior to the implementation of 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. Figure 1.26 shows the frequency in which a minimum requirement was active for the ISO in the 15-minute market since the implementation of the minimum requirement in early November 2020. During the third quarter of 2021, the ISO had a minimum upward requirement enforced in around 84 percent of intervals, and a minimum downward requirement enforced in around 60 percent of intervals. These are both down from the previous quarter.

The minimum requirement was only implemented in the 15-minute market, not in the 5-minute market. Procurement in the 5-minute market ensures that enough ramping capacity is available 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 ISO and settled in the 15-minute market, is released in the 5-minute market in favor of undeliverable flexible ramping capacity stranded behind energy imbalance market transfer constraints.

While the minimum requirement was intended as a temporary measure prior to implementation of nodal procurement, DMM believes the minimum requirement should be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product.

Non-ISO areas that exceed the 60 percent threshold in any interval can similarly have a minimum requirement applied that will procure and price flexible ramping capacity in that area. In particular, PacifiCorp East had a minimum downward flexible ramping requirement in approximately 23 percent of intervals during the third quarter, most frequently in morning hours. During some cases in hour-ending 7, the downward system requirement was so low such that most areas met the threshold and had a minimum requirement enforced.

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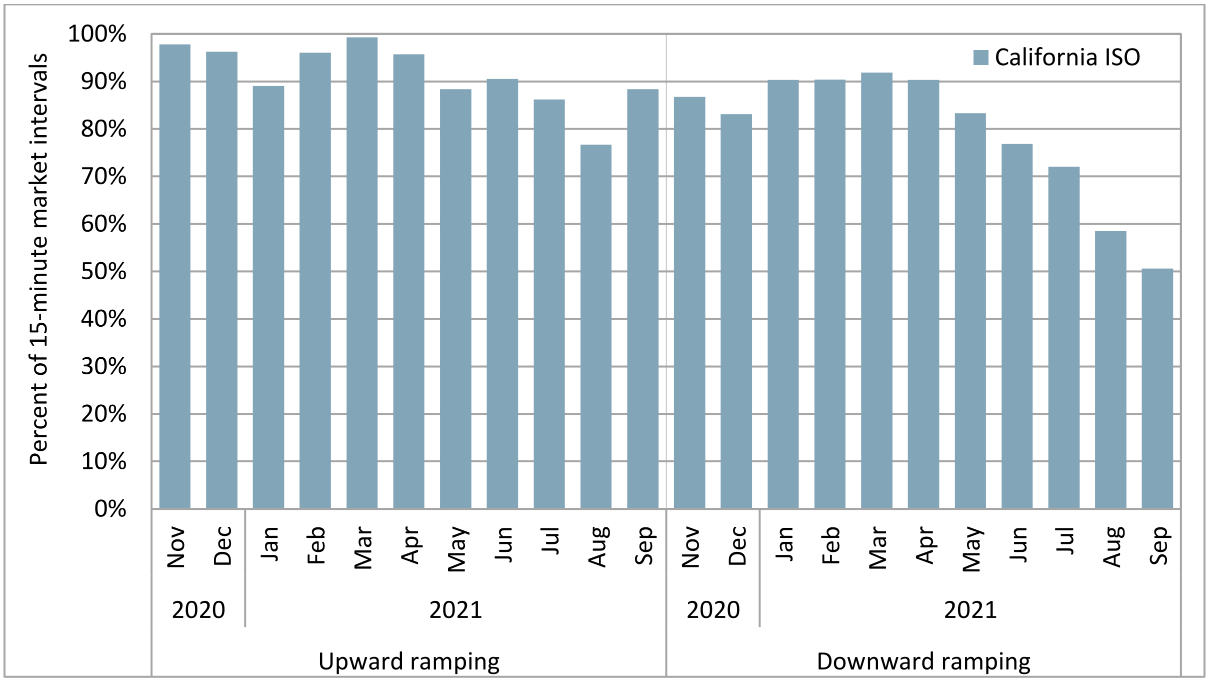
22 In each interval, the upward uncertainty requirement for each area is reduced by net import capability while the downward uncertainty requirement is reduced by net export capability. If the area fails the sufficiency test in the corresponding direction, the uncertainty requirement will not include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

23 For example, if a balancing authority area's upward requirement is greater than 60 percent of the system requirement at 1,000 MW 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 *Flexible Ramping Product Refinements Final Proposal*, August 31, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

Figure 1.26 California ISO frequency of enforced minimum requirement (15-minute market)



1.5.2 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 full value of capacity on the demand curve is procured. This reflects that flexible ramping capacity was readily available relative to the need for it, such that there is no cost associated with the level of procurement.

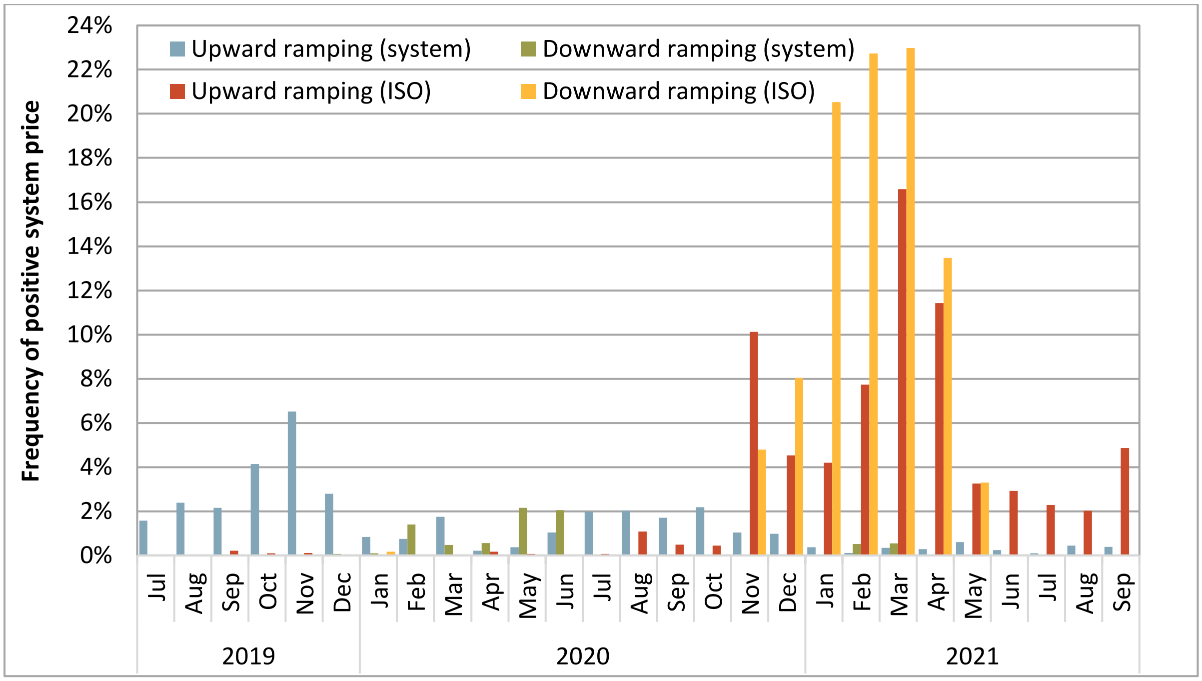
Figure 1.27 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. The percent of intervals in which the ISO-specific demand curve bound at a positive shadow price is also shown.

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 downward ramping.

Following a review by the ISO on intermittent resources and flexible ramping product eligibility, the ISO implemented a change effective May 9 to set all five-minute dispatchable resources with economic bids eligible to receive flexible ramping product awards. In particular, additional flexible ramping capacity from wind and solar resources (which were previously ineligible to receive these awards) contributed to the decreased frequency of positive prices. Since the change, the shadow price for downward flexible ramping capacity has been zero in all intervals.

In the 5-minute market, the system-level and ISO-specific demand curves for upward and downward ramping capacity bound in less than 0.1 percent of intervals.

Figure 1.27 Monthly frequency of positive system or ISO flexible ramping shadow price (15-minute market)



1.6 Convergence bidding

Convergence bidding was profitable overall for entities placing convergence bids in the third quarter of 2021. Combined net revenue for virtual supply and demand was about $12.7 million, after including about $15.5 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about $10.2 million for the quarter, while virtual supply generated about $18 million, before accounting for bid cost recovery charges.

1.6.1 Convergence bidding trends

Average hourly cleared volumes were about 4,300 MW, an increase of about 800 MW from the same quarter of 2020. Average hourly cleared virtual supply increased about 300 MW to about 2,800 MW, from about 2,500 MW in the previous quarter. Cleared virtual demand averaged about 1,500 MW during each hour of the quarter, about the same for the quarter of the previous year which was also about 500 MW less than the previous quarter. On average, about 30 percent of virtual supply and demand bids offered into the market cleared in the quarter, down from 36 percent from the same quarter of the previous year.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 1,250 MW on average, an increase from 550 MW of net virtual supply in the same quarter of the previous year. On average, in all hours except hours ending 17 and 18, net cleared virtual supply exceeded net cleared virtual demand - even in hour-ending 19. Cleared virtual supply exceeded virtual demand by more than 1,000 MW in all hours except the afternoon and peak evening hours of 15-21.

Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. For the quarter, convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 22 of 24 hours.

Offsetting virtual supply and demand bids

Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual supply and demand bids at different locations during the same hour. These virtual supply and demand bids offset each other in terms of system energy, and are not exposed to bid cost recovery settlement charges. When virtual supply and demand bids are paired this way, one of these bids may be unprofitable independently but the combined bids may break even or be profitable because of congestion differences between the day-ahead and real-time markets.

Offsetting virtual positions accounted for an average of 1,100 MW of virtual demand, offset by 1,100 MW of virtual supply, in each hour of the quarter. This represented an increase of about 300 MW over the same quarter from the previous year. These offsetting bids represented about 53 percent of all cleared virtual bids in this quarter, an increase of about 3 percent from the same quarter of the previous year.

1.6.2 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 $28.2 million. Net revenues for virtual supply and demand fell to about $12.7 million after the inclusion of about $15.5 million of virtual bidding bid cost recovery charges,[24] primarily associated with virtual supply.

Figure 1.28 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:

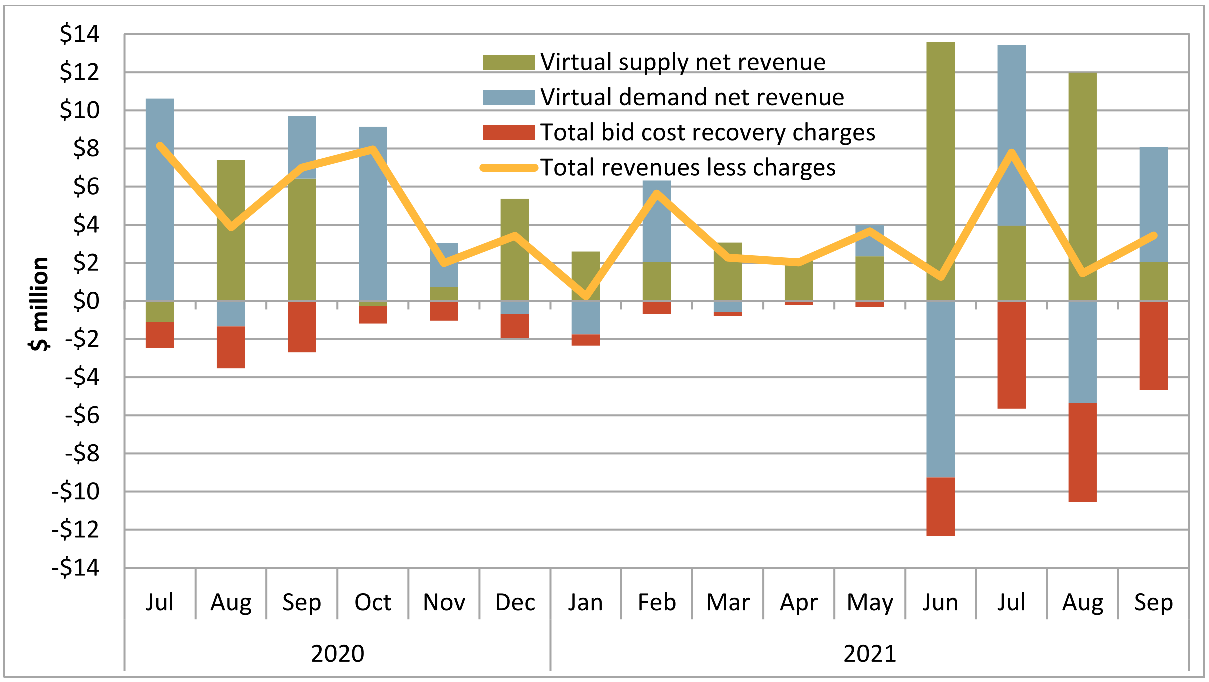
- Total market revenues were positive during all months of the quarter. Net revenues during the quarter totaled about $28.2 million, compared to about $25.3 million during the same quarter from the previous year, and about $10.5 million during the previous quarter.
- Virtual demand net revenues were about $9.5 million, negative $5.3 million, and $6 million for July, August, and September, respectively.
- Virtual supply net revenues were $4 million, $12 million, and $2 million for July, August, and September, respectively.

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

Convergence bidders received approximately $12.7 million after subtracting bid cost recovery charges of about $15.5 million for the quarter.[25,26] Bid cost recovery charges were about $5.7 million, $5.2 million, and $4.7 million for July, August, and September, respectively.

August, similar to June, is a month of note in this quarter since day-ahead prices were consistently higher than 15-minute prices. This resulted in high positive virtual supply revenues and inversely low negative virtual demand revenues.

Figure 1.28 Convergence bidding revenues and bid cost recovery charges



1.7 Residual unit commitment

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 1.29, residual unit commitment capacity is 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 700 MW higher in the third quarter of 2021 than in the same quarter of 2020.

25 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.

26 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 page 3: BPM Change Management Proposed Revision Request.

Residual unit commitment procurement can be increased by operator adjustments to the day-ahead load forecast. These manual adjustments decreased by 40 percent in the third quarter relative to the same quarter in 2020. Figure 1.30 shows the hourly distribution of these operator adjustments during the third quarter of 2021. The black line shows the average adjustment quantity in each hour and the red markers highlight outliers in each hour. In this quarter, operators used this tool on 82 days to increase the residual unit commitment requirements by an average of about 720 MW per hour.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar in Figure 1.29) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor contributed towards increasing residual unit commitment requirements in the third quarter of 2021, averaging about 260 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; it is represented by the yellow bar in Figure 1.29.

Figure 1.29 Determinants of residual unit commitment procurement

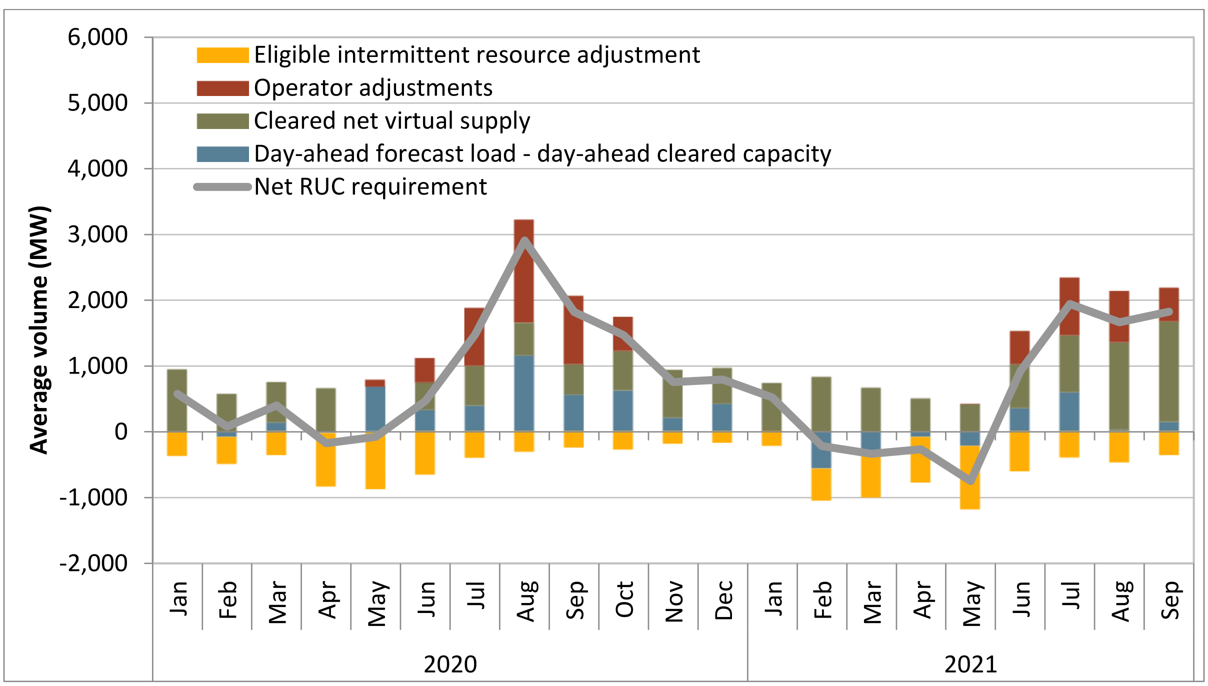


Figure 1.30 Hourly distribution of residual unit commitment operator adjustments (Jul – Sep)

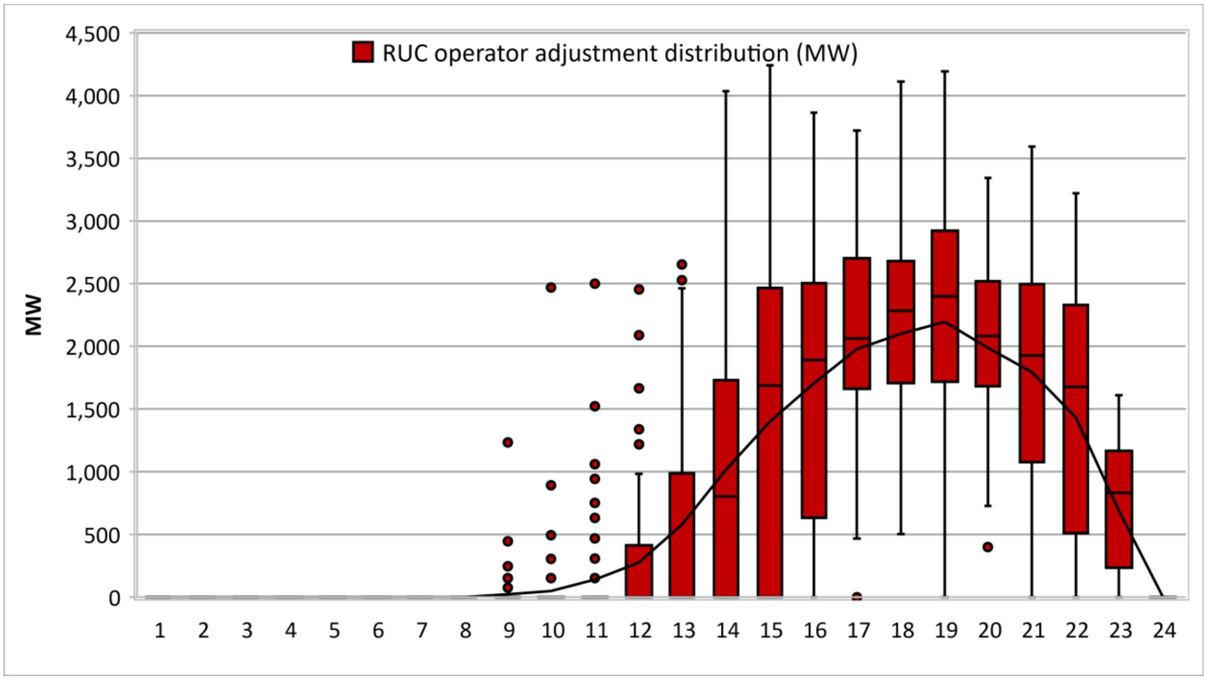


Figure 1.31 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement decreased to about 1,869 MWh in the third quarter of 2021 from an average of 2,060 MWh in the same quarter of 2020. Of the 1,869 MWh capacity, the capacity committed to operate at minimum load averaged 436 MWh, similar to the third quarter of 2020.

During the third quarter of 2021, the residual unit commitment undersupply power balance constraint was infeasible on three days, July 9 (hour ending 20) and July 28-29 (hours ending 19-21). These infeasibilities resulted in prices being set around $250/MWh during those hours. 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 real-time ISO load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[27]

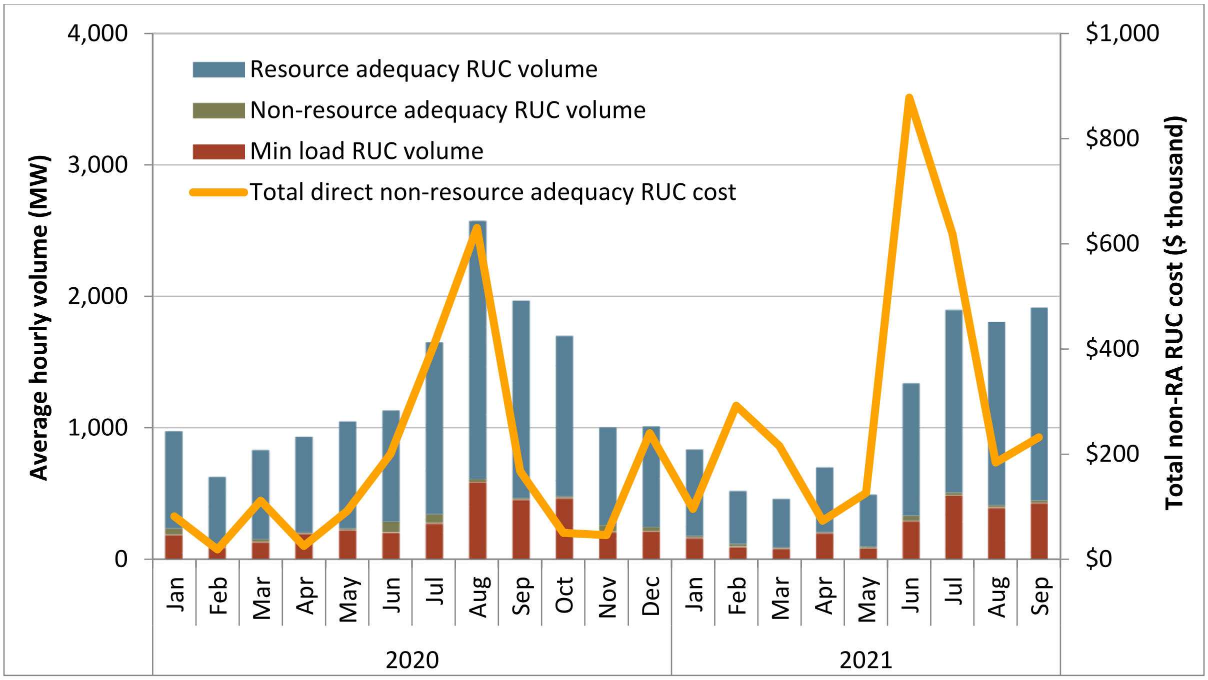
Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in this process receive capacity payments.[28] The total direct cost of non-resource adequacy residual unit

[27] The 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

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

commitment is represented by the gold line in Figure 1.31. In the third quarter of 2021, these costs were about $1 million, down by $0.2 million when compared to the same quarter of 2020.

Figure 1.31 Residual unit commitment costs and volume



1.8 Ancillary services

Ancillary service payments increased this quarter to about $51 million, compared to about $38 million in the previous quarter. Payments were substantially lower than the same quarter of 2020 when ancillary service payments were almost $100 million, in part due to the extreme conditions experienced in third quarter last year.

1.8.1 Ancillary service requirements

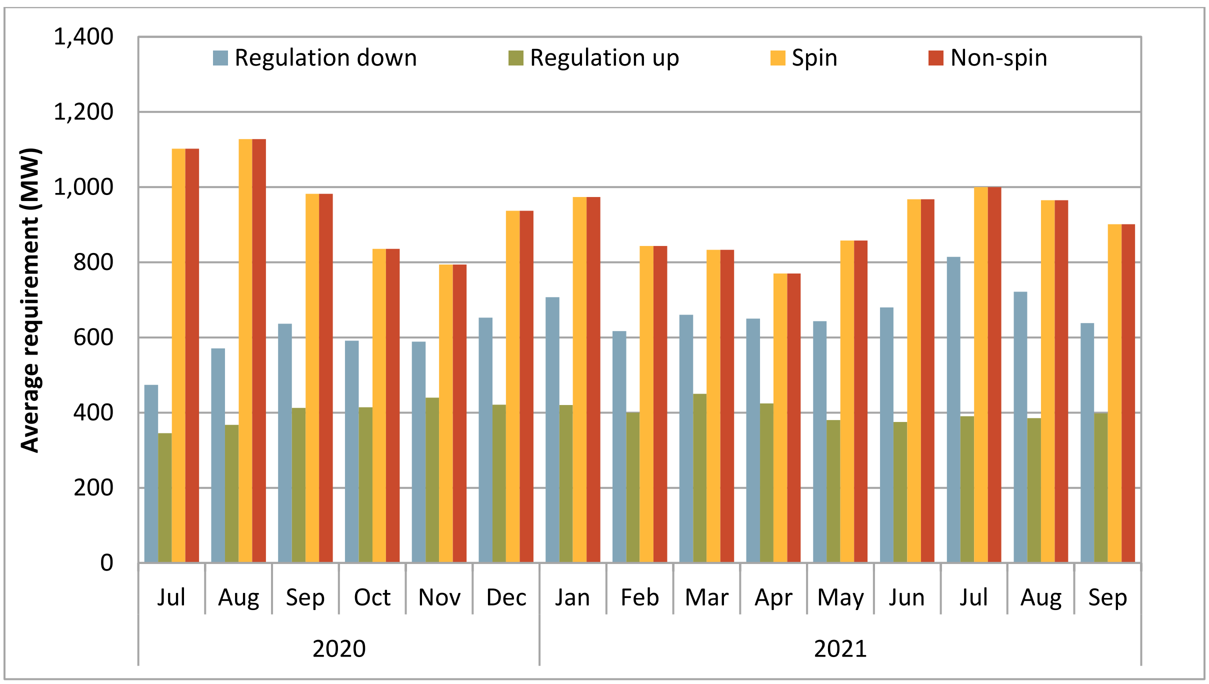
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC)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

The 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. The expanded regions are identical to the corresponding internal regions, but also include interties. Each of these regions can have minimum requirements set for procurement of ancillary services where the internal sub-regions are nested within the system and corresponding expanded regions. Therefore, ancillary services procured in an inward region also count toward meeting the minimum requirement of the outer region. Then, both internal resources and imports meet ancillary service requirements, where imports are indirectly limited by the minimum requirements from the internal regions.

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

Figure 1.32 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown, average requirements for spinning and non-spinning reserves decreased this quarter compared to the same quarter last year. Average regulation down requirements, on the other hand, increased about 30 percent this quarter compared to the third quarter last year.

Figure 1.32 Average monthly day-ahead ancillary service requirements

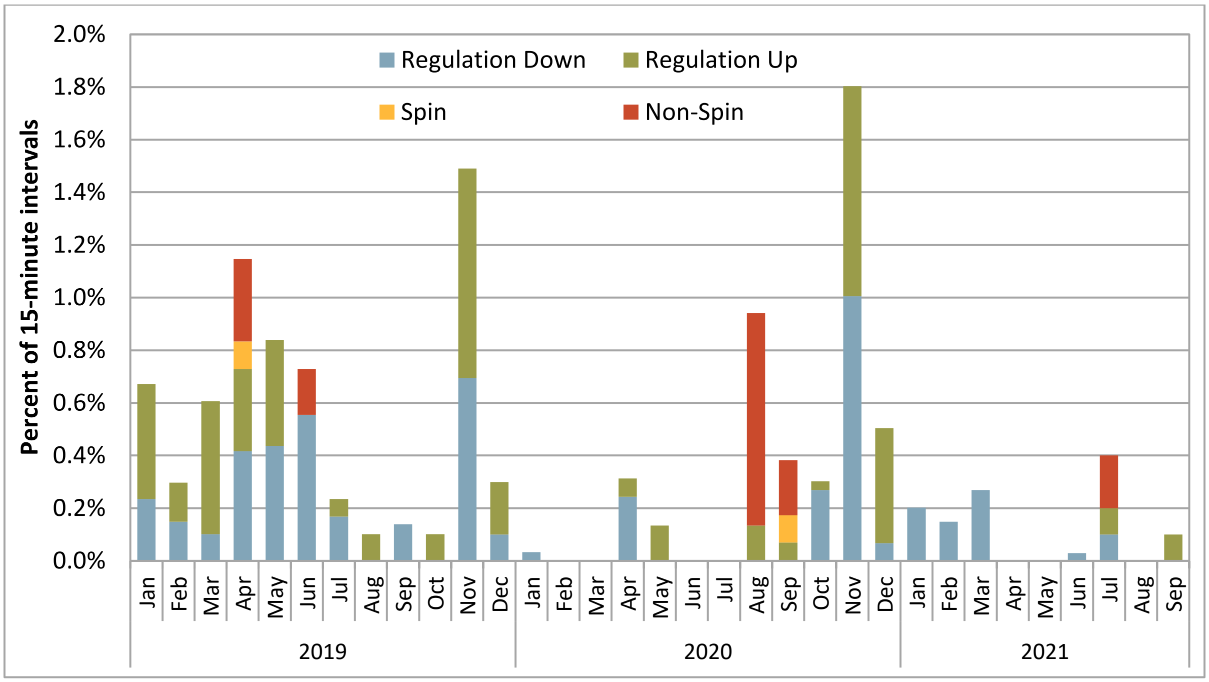


1.8.2 Ancillary service scarcity

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

As shown in Figure 1.33, the frequency of intervals with scarcity pricing decreased this quarter from 0.44 percent of intervals last year to 0.17 percent this year. Most scarcity events occurred in July when the California ISO experienced high temperatures that led to stressed grid conditions.[29]

Figure 1.33 Frequency of ancillary service scarcities (15-minute market)



1.8.3 Ancillary service costs

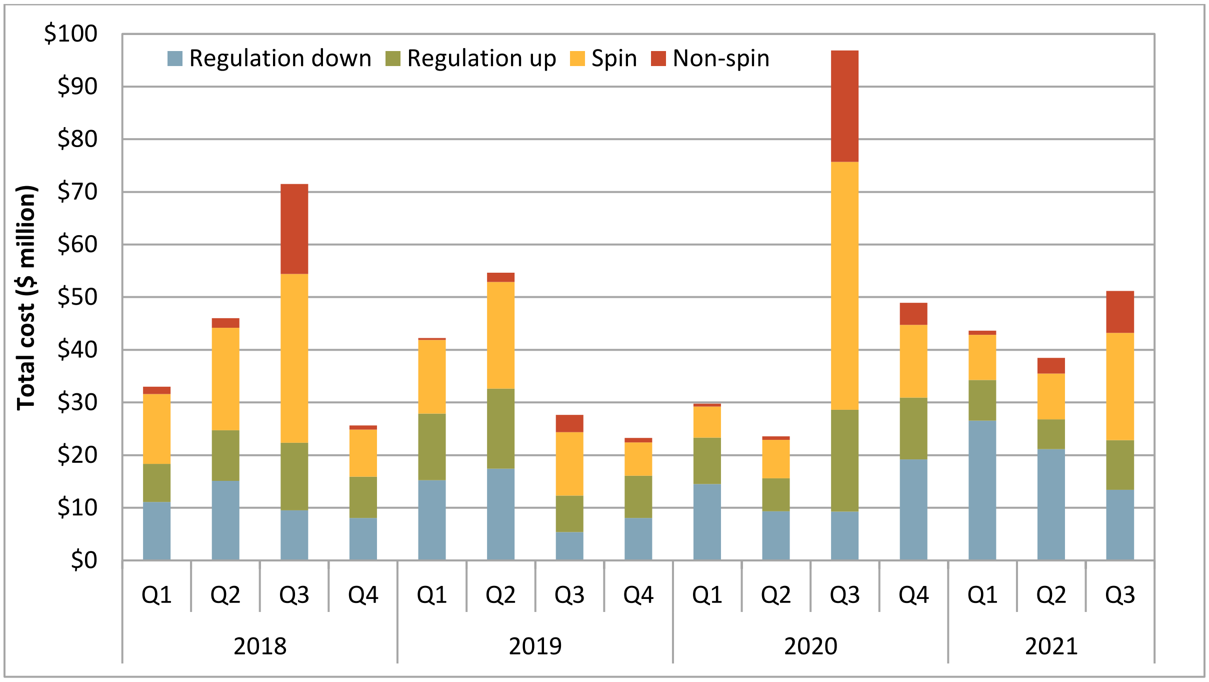
Ancillary service payments decreased this quarter compared to the third quarter last year, primarily due to less extreme heat this year compared to the third quarter of 2020. Third quarter costs totaled about $51 million, down from $97 million in the same quarter of 2020, but an increase from $38 million in the previous quarter.

Figure 1.34 shows the total cost of procuring ancillary service products by quarter.[30] The cost to procure spinning and non-spinning reserves decreased about 60 percent this quarter compared to the third quarter last year. The cost to procure regulation up decreased about 51 percent while the cost to procure regulation down increased 45 percent. This is consistent with the increase in regulation down requirements.

[29] Summer Market Performance Report, July 2021: http://www.caiso.com/Documents/SummerMarketPerformanceReportforJuly2021.pdf

[30] 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 1.34 Ancillary service cost by product



1.9 Congestion

In the day-ahead market, congestion in the third quarter increased prices in the Southern California Edison and San Diego Gas & Electric areas and decreased prices in the Pacific Gas and Electric area. In the 15-minute market, the impact of internal congestion on prices decreased in most areas relative to the same quarter of 2020.

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

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

The impact of congestion on each pricing node in the ISO system is calculated as the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes as well as for groups of nodes that represent different load aggregation points or local capacity areas.[31]

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

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

1.9.1 Congestion in the day-ahead market

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

Congestion rent and loss surplus

In the third quarter of 2021, congestion rent and loss surplus was $166 million and $88 million, respectively. These respective amounts represent a 25 percent decrease and a 40 percent increase relative to the same quarter of 2020.[32] Figure 1.35 shows the congestion rent and loss surplus by quarter for 2020 and 2021.

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.[33]

32 Due to the availability of data, Figure 1.35 and the comparative analysis of day-ahead congestion rent and loss surplus in the third quarter of 2021 are preliminary.

33 For more information on marginal loss surplus allocation refer to 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 1.35 Day-ahead congestion rent and loss surplus by quarter (2020-2021)

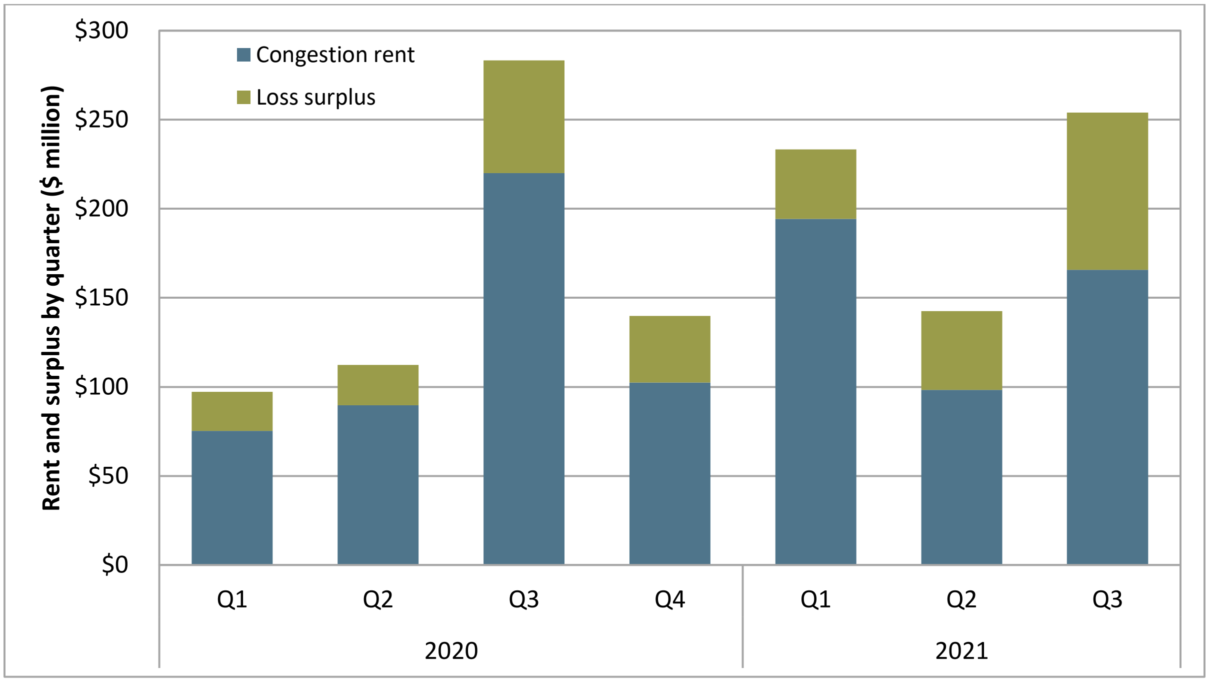


Figure 1.36 shows the overall impact of congestion on day-ahead prices in each load area in 2020 and 2021. Figure 1.37 shows the frequency of congestion. Highlights for this quarter include:

- In the third quarter of 2021, the overall net impact of congestion on price separation decreased significantly in PG&E, SCE, and SDG&E relative to the same quarter of 2020. The frequency of congestion increased in PG&E and SDG&E while it decreased in SCE compared to the same quarter in 2020.
- Congestion increased quarterly average prices in SCE and SDG&E by $0.37/MWh (0.6 percent) and $1.18/MWh (1.7 percent), respectively, while it decreased prices in PG&E by $0.44/MWh (0.7 percent).
- The congestion impact was more frequently offsetting in SCE and SDG&E compared to the same quarter of 2020. For the quarter, PG&E and SDG&E experienced positive congestion more frequently, while SCE experienced negative congestion more frequently.
- The primary constraints impacting day-ahead market prices were the Midway-Vincent #2 500 kV line, the Otay Mesa-Tijuana nomogram, and the Mustang-Gates #1 230 kV line.

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

Figure 1.36 Overall impact of congestion on price separation in the day-ahead market

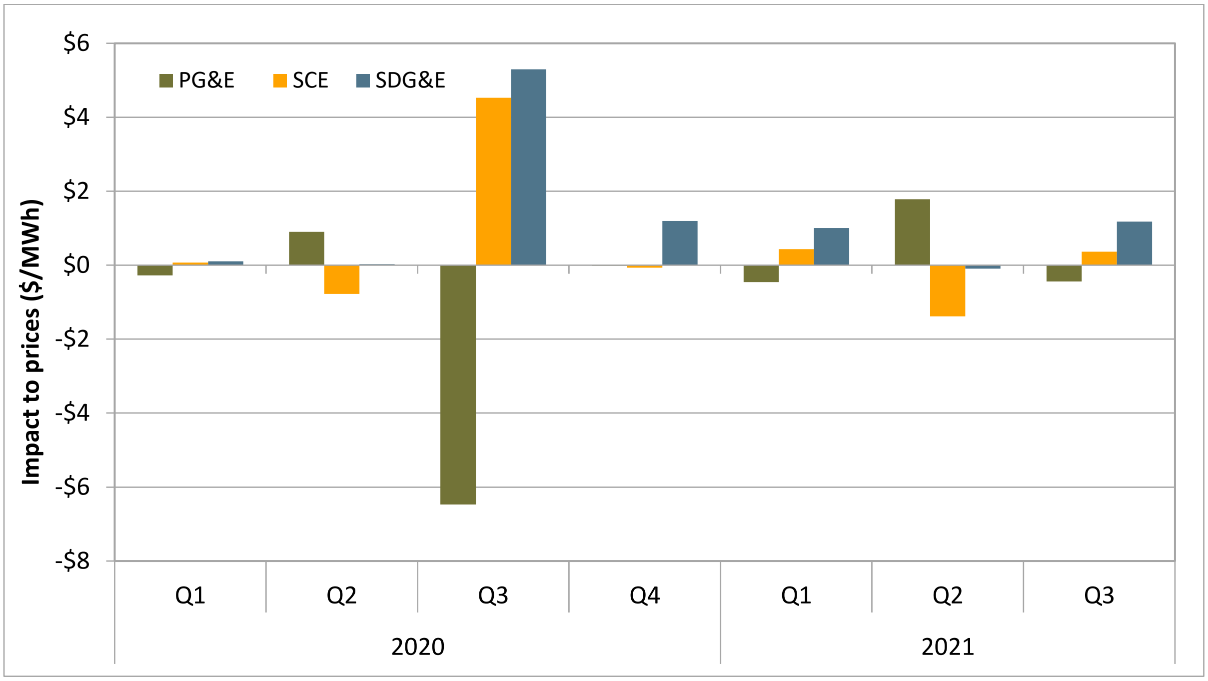


Figure 1.37 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

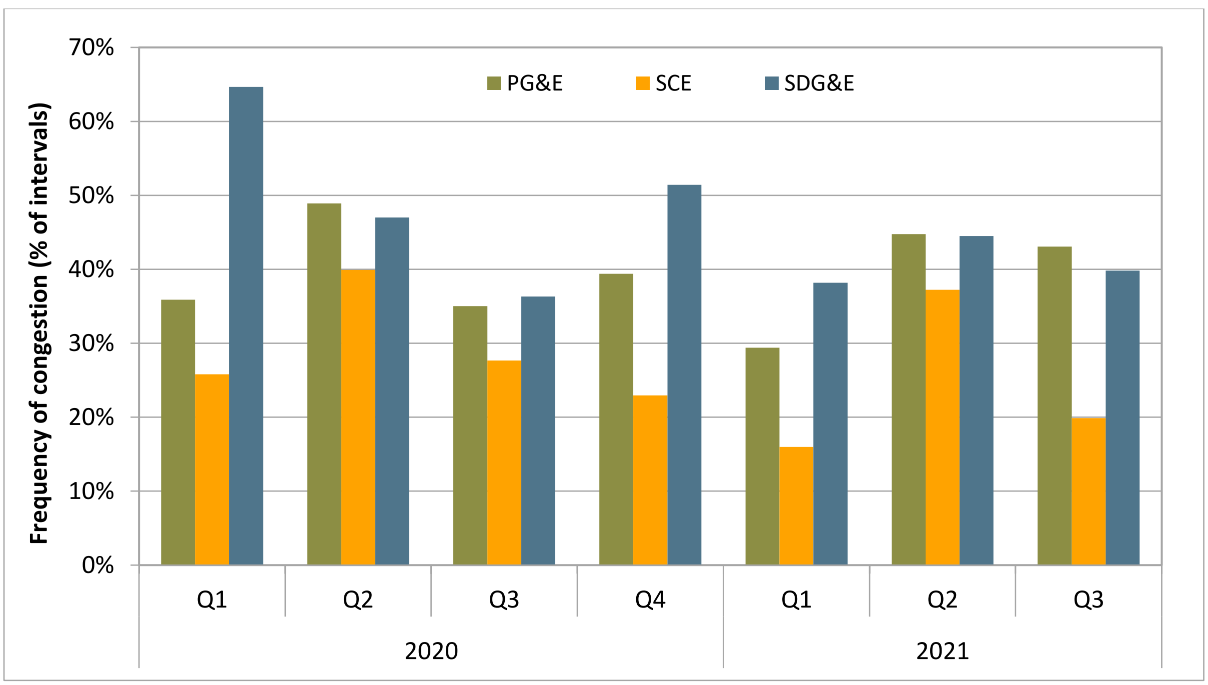
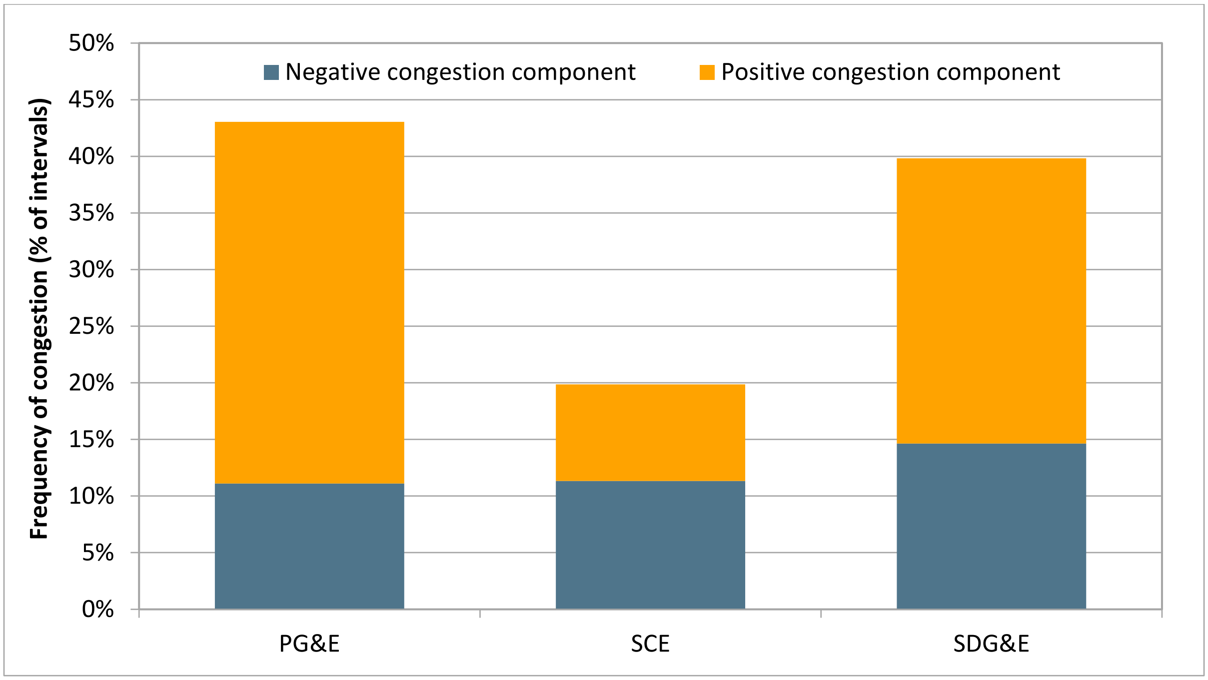


Figure 1.38 Percent of hours with congestion increasing versus decreasing day-ahead prices in the third quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.1 breaks down the congestion impact on price separation in the third quarter by constraint.[34] Table 1.2 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 Midway-Vincent #2 500 kV line, the Otay Mesa-Tijuana nomogram, and the Mustang-Gates #1 230 kV line.

Midway-Vincent #2 500 kV

The Midway-Vincent #2 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) had the greatest impact on day-ahead prices during the third quarter. It was one of the most frequently binding constraints of the quarter, binding in 5.4 percent of hours. When binding, it increased SCE and SDG&E prices by about $9.45/MWh and $9.01/MWh, respectively, while it decreased PG&E prices by $13.91/MWh. On average for the quarter, it increased average SCE and SDG&E prices by about $0.51/MWh (0.8 percent) and $0.49/MWh (0.7 percent), respectively, while it decreased average PG&E prices by $0.76/MWh (1.1 percent). This line was impacted by fires and system-wide high load conditions.

Otay Mesa-Tijuana nomogram

The Otay Mesa-Tijuana nomogram (7820_TL23040_IV_SPS_NG) frequently bound over the quarter, during 5 percent of hours. When binding, it raised prices in SDG&E by $9.45/MWh and lowered prices in

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

PG&E by $0.42/MWh. Overall for the quarter, congestion on the nomogram increased average SDG&E prices by $0.47/MWh (0.7 percent) and decreased average PG&E prices by $0.02/MWh (<0.1 percent).

Mustang-Gates #1 230 kV line

The Mustang-Gates 230 kV line (30885_MUSTANGS_230_30900_GATES _230_BR_1 _1) was one of the most frequently binding constraints of the quarter, binding in 5.4 percent of hours. When binding, it increased PG&E prices by about $2.30/MWh, while it decreased prices in SCE and SDG&E by about $1.70/MWh and $1.64/MWh, respectively. Overall for the quarter, it increased average PG&E prices by about $0.13/MWh (0.2 percent) and decreased average prices in both SCE and SDG&E by $0.09/MWh (0.2 percent). This line was congested due to mitigation for the contingency of the Mustang-Gates #2 230 kV line during the quarter.

Table 1.1 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	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	$0.13	0.19%	-$0.09	-0.14%	-$0.09	-0.13%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.10	0.15%	-$0.02	-0.04%	-$0.02	-0.03%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.06	0.09%	-$0.04	-0.07%	-$0.04	-0.06%
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.02	0.03%	-$0.02	-0.03%	-$0.02	-0.03%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.02	0.03%	-$0.02	-0.02%	-$0.01	-0.02%
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	$0.02	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	RM_TM21_NG	$0.02	0.03%	$0.00	0.00%	-$0.02	-0.03%
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-$0.07	-0.10%	$0.05	0.07%	$0.05	0.07%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.76	-1.13%	$0.51	0.77%	$0.49	0.72%
SCE	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1	$0.00	-0.01%	$0.01	0.01%	$0.00	-0.01%
SDG&E	7820_TL23040_IV_SPS_NG	-$0.02	-0.03%	$0.00	0.00%	$0.47	0.69%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.26	0.38%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.04	0.05%
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.02	-0.02%	$0.01	0.01%	$0.03	0.04%
	7820_TL 230S_OVERLOAD_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.02%
	22372_KEARNY _69.0_22140_CLARMTTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	OMS 10184664_50004_OOS_NG	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.03	-0.04%
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.06	-0.08%
Other		$0.05	0.08%	$0.01	0.01%	$0.09	0.14%
Total		**-$0.44**	**-0.65%**	**$0.37**	**0.55%**	**$1.18**	**1.73%**

Table 1.2 Impact of congestion on day-ahead prices during congested hours[35]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.3%	$6.31	-$4.90	-$4.57
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	1.9%	$3.10	-$2.28	-$2.07
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	5.4%	$2.30	-$1.70	-$1.64
	RM_TM21_NG	1.0%	$1.94	-$0.99	-$2.07
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	5.3%	$1.88	-$1.92	-$1.83
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	0.3%	$1.75	-$1.31	-$1.22
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.3%	$1.75	-$1.31	-$1.22
	30055_GATES1 _500_30900_GATES _230_XF_12 _P	2.0%	$1.06	-$0.85	-$0.83
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	2.6%	$0.70	-$0.51	-$0.49
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	1.0%	-$6.36	$4.62	$4.46
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	5.4%	-$13.91	$9.45	$9.01
SCE	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1	1.0%	-$0.59	$0.55	-$0.59
SDG&E	22372_KEARNY _69.0_22140_CLARMTTP_69.0_BR_1 _1	0.1%	$0.00	$0.00	$9.83
	7820_TL23040_IV_SPS_NG	5.0%	-$0.42	$0.00	$9.45
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	0.2%	$0.00	$0.00	$7.31
	OMS 10184664_50004_OOS_NG	0.2%	-$0.45	$0.00	$7.24
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	0.5%	-$2.98	$1.56	$5.76
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	5.4%	$0.00	$0.00	$4.72
	7820_TL 230S_OVERLOAD_NG	0.7%	-$0.32	$0.00	$3.36
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	2.2%	$0.00	$0.00	$1.60
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.6%	$0.00	$0.00	-$4.42
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	0.4%	$0.00	$0.00	-$15.57

1.9.2 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 1.39 shows the overall impact of internal flow-based constraint congestion on 15-minute prices in each load area for 2020 and 2021. Figure 1.40 shows the frequency of this congestion. Highlights for this quarter include:

- The overall net impact of internal flow-based constraint congestion on price separation in the third quarter of 2021 decreased in most areas compared to the same quarter of 2020. Congestion resulted in a net increase to prices in the PG&E, SCE, SDG&E, BANC, and TIDC areas, while it resulted in a net decrease to prices in all other EIM areas.
- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, which worked to offset some of the impact of congestion over the quarter. The

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

overall frequency of congestion was highest in PACE, where congestion predominantly decreased prices.

- The primary constraints impacting price separation in the 15-minute market were the Malin-Round Mountain constraint, a Malin area transformer constraint, and the Midpoint 345/230 kV transformer.

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

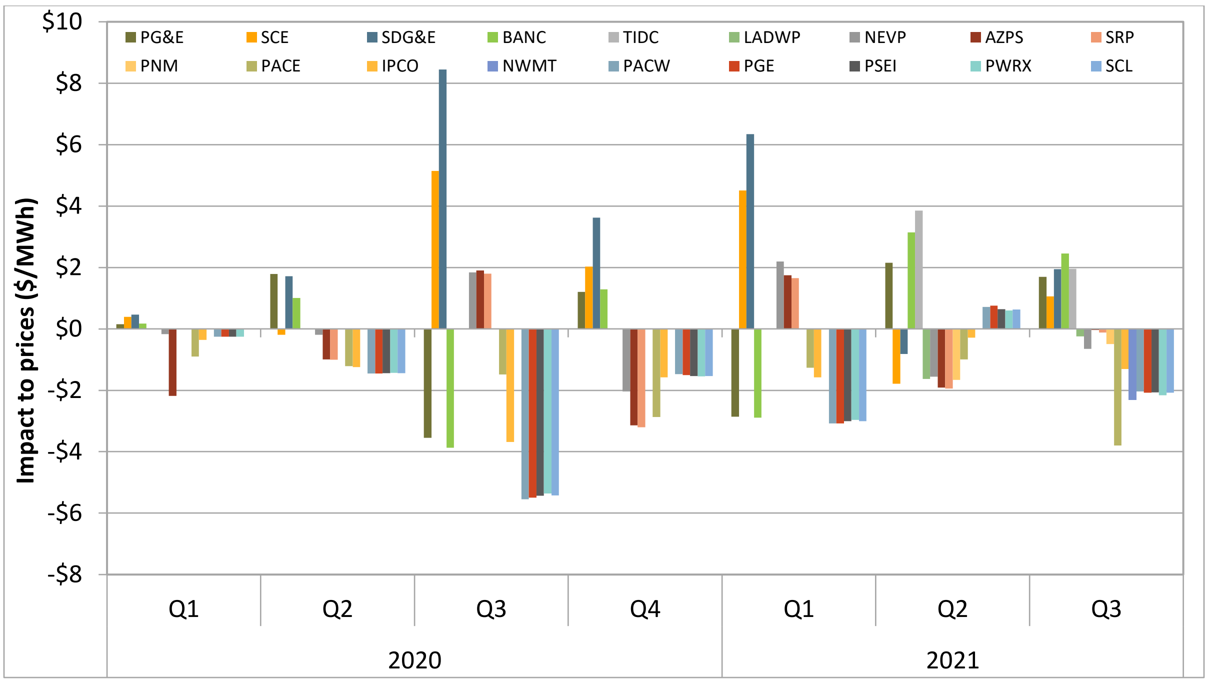
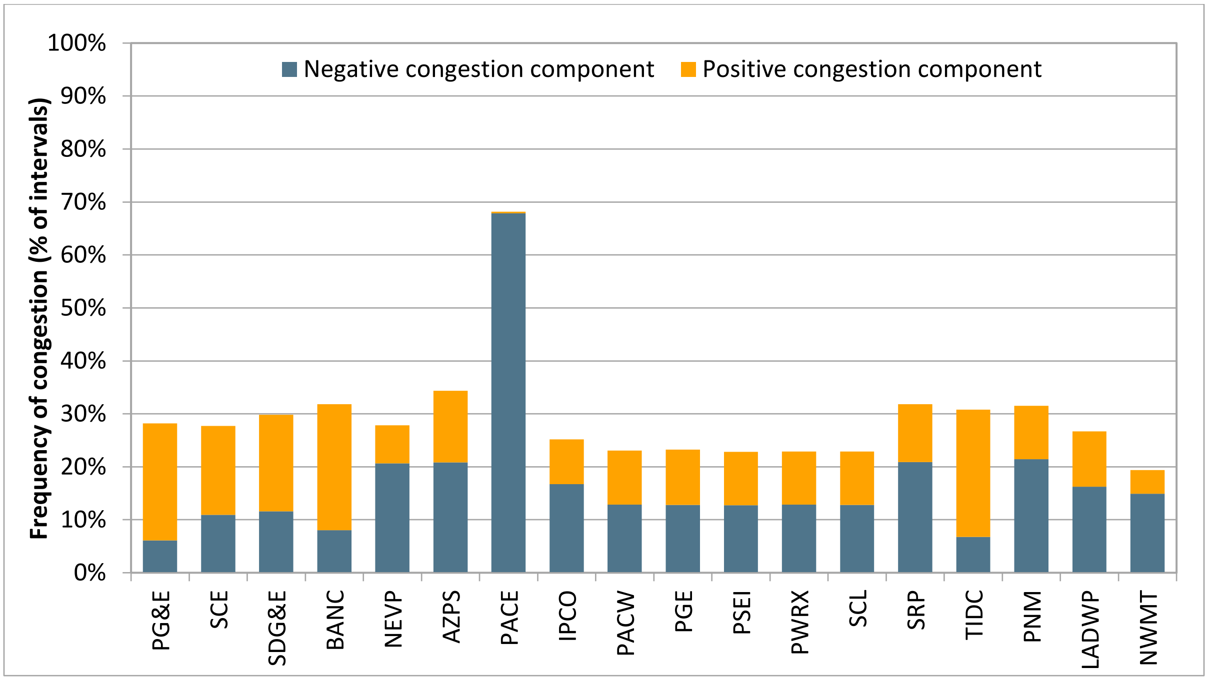


Figure 1.40 Percent of intervals with internal congestion increasing versus decreasing 15-minute prices in the third quarter (>$0.05/MWh)



Impact of internal congestion from individual constraints

This section focuses on individual flow-based constraints. In the third quarter, the constraints that had the greatest impact on price separation in the 15-minute market were the Malin-Round Mountain constraint, a Malin area transformer constraint, and the Midpoint 345/230 kV transformer.

Table 1.3 shows the overall impact (during all intervals) of internal congestion on average 15-minute prices in each load area. Table 1.4 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 1.3. 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.

Malin-Round Mountain constraint

The Malin-Round Mountain constraint (ML_RM12) was used to limit flows over the Malin-Round Mountain 500 kV lines during the Bootleg fire in July. This constraint bound during about 4 percent of intervals during the quarter. When binding, it affected prices across the EIM, increasing prices in areas south of Path 66 (COI) by about $10.14/MWh on average, and decreasing north of Path 66 (COI) by $27.40/MWh on average. Overall for the quarter, the constraint increased prices in the former areas by about $0.40/MWh and decreased prices in the latter areas by $1.10/MWh.

Malin area transformer constraint

A constraint for a transformer in the Malin area (T501_xA) bound during about 4 percent of intervals over the quarter. When binding, it affected prices across most of the EIM, increasing prices in PG&E,

BANC, TIDC, PACW, PGE, PSEI, PWRX, and SCL by $8.40/MWh on average, and decreasing prices elsewhere in the ISO and EIM, with the exception of SCE and NWMT which were unaffected, by $8.36/MWh on average. Overall for the quarter, the constraint increased the former areas' prices by $0.29/MWh on average and decreased prices in the latter areas by $0.27/MWh on average.

Midpoint 345/230 kV transformer

The Midpoint 345/230 kV transformer (T342.MPSN) bound during about 5 percent of intervals over the quarter. When binding, it affected prices across the EIM, increasing prices in PG&E, BANC, TIDC, IPCO, NWMT, PACW, PGE, PSEI, PWRX, and SCL by about $4.80/MWh on average, and decreasing prices elsewhere in the ISO and EIM, by $3.87/MWh on average. Over the entire quarter, it increased the former areas' prices by about $0.25/MWh on average, and decreased the latter areas' prices by about $0.20/MWh on average. This constraint was congested due to potential loss of the Hemmingway-Midpoint 500 kV line.

Table 1.3 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	LN-LL								$0.04										
IPCO	T342.MPSN	$0.09	-$0.04	-$0.10	$0.13	$0.11	-$0.19	-$0.26	-$0.15	-$0.15	-$0.20	-$0.53	$0.84	$0.05	$0.26	$0.26	$0.26	$0.25	$0.26
	IMNH-LOLO1_A							$0.00				$0.02	$0.04	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	T501_xA	$0.24		$0.00	$0.28	$0.26	-$0.19	-$0.24	-$0.14	-$0.14	-$0.24	-$0.77	-$0.44		$0.34	$0.34	$0.30	$0.28	$0.30
PACE	AMASA_DIFFICUL_230										$0.00	$0.00	$0.04	-$0.04					
	WINDSTAR EXPORT TCOR											-$0.07							
	TOTAL_WYOMING_EXPORT											-$1.41			$0.00				
PACW	ALVEY$_DIXONVIL_500	$0.02	$0.01	$0.01	$0.02	$0.02	$0.01	$0.01	$0.01	$0.01	$0.00	-$0.02	-$0.03	-$0.04	-$0.02	-$0.05	-$0.05	-$0.05	-$0.05
	DIXONVIL_MERIDIAN_500	$0.11	$0.07	$0.06	$0.12	$0.12	$0.03	$0.03	$0.04	$0.04	$0.02	-$0.08	-$0.16	-$0.21	-$0.16	-$0.26	-$0.25	-$0.24	-$0.24
PG&E	ML_RM12	$0.79	$0.43	$0.38	$0.74	$0.76	$0.20	$0.02	$0.28	$0.28	$0.15	-$0.48	-$0.86	-$1.07	-$1.36	-$1.30	-$1.26	-$1.24	-$1.25
	30885_MUSTANGS_230_30900_GATES _230_BR_1_1	$0.55	-$0.31	-$0.30	$0.31	$0.32	-$0.27	-$0.23	-$0.28	-$0.28	-$0.25								
	30879_HENTAP1_230_30885_MUSTANGS_230_BR_1_1	$0.23	-$0.08	-$0.05	$0.16	$0.15	-$0.02		-$0.04	-$0.04									
	40687_MALIN _500_30005_ROUND MT_500_BR_1_3	$0.12	$0.06	$0.05	$0.11	$0.12	$0.03	$0.00	$0.04	$0.04	$0.01	-$0.09	-$0.15	-$0.18	-$0.20	-$0.20	-$0.20	-$0.20	-$0.20
	RM_TM12_NG	$0.10	$0.06	$0.05	$0.06	$0.10	$0.03	$0.01	$0.04	$0.04	$0.01	-$0.07	-$0.13	-$0.17	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19
	ROUND_MOUNTAIN	$0.07	$0.04	$0.04	$0.07	$0.07	$0.02		$0.03	$0.03		-$0.05	-$0.09	-$0.12	-$0.14	-$0.14	-$0.13	-$0.13	-$0.13
	MIDWAY-KERNPP_230_BR_3_1	$0.05																	
	30900_GATES _230_30970_MIDWAY _230_BR_1_1	$0.05	-$0.04	-$0.04	$0.06	$0.06	-$0.03	-$0.02	-$0.04	-$0.04	-$0.03		$0.02	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1_1	$0.03	-$0.05	-$0.05	$0.09	$0.14	-$0.04	-$0.03	-$0.04	-$0.04	-$0.04		$0.03	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05
	30055_GATES1 _500_30900_GATES _230_XF_12_P	$0.03	-$0.01	-$0.01	$0.01	$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00							
	30790_PANOCHE _230_30900_GATES _230_BR_1_1	$0.02	-$0.02	-$0.02	$0.03	$0.04	-$0.01		-$0.02	-$0.02	-$0.02				$0.02	$0.02	$0.02	$0.02	$0.02
	30790_PANOCHE _230_30900_GATES _230_BR_2_1	$0.02	-$0.02	-$0.02	$0.02	$0.03	-$0.01	-$0.01	-$0.02	-$0.02	-$0.01			$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30055_GATES1 _500_30060_MIDWAY _500_BR_1_1	$0.01	-$0.01	-$0.01	$0.02	$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1_2	$0.01	$0.00	$0.00	$0.01	$0.01	$0.00		$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3_1	$0.00			$0.01	$0.00							-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1_1	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00				$0.00	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1_2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1_2	-$0.08	$0.07	$0.06	-$0.07	-$0.07	$0.05	$0.04	$0.05	$0.05	$0.05	$0.00	-$0.03	-$0.04	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1_1	-$0.08	$0.07	$0.06	-$0.08	-$0.08	$0.05	$0.04	$0.05	$0.05	$0.05		-$0.03	-$0.04	-$0.06	-$0.05	-$0.05	-$0.05	-$0.05
	30060_MIDWAY _500_24156_VINCENT _500_BR_1_3	-$0.10	$0.08	$0.07	-$0.09	-$0.10	$0.06	$0.04	$0.06	$0.06	$0.05	$0.00	-$0.04	-$0.05	-$0.07	-$0.07	-$0.07	-$0.06	-$0.07
	30060_MIDWAY _500_24156_VINCENT _500_BR_2_3	-$0.18	$0.14	$0.14	-$0.17	-$0.17	$0.11	$0.09	$0.12	$0.12	$0.10	$0.00	-$0.07	-$0.09	-$0.12	-$0.12	-$0.12	-$0.12	-$0.12
	30515_WARNERVL_230_30800_WILSON _230_BR_1_1				-$0.07	-$0.09													
	7430_CP6_NG				$1.10	$0.50													
	7430_MEL_WIL_NG				-$0.10														
	30330_RIO OSO _230_30348_BRIGHTON_230_BR_1_1				$0.04														
SCE	OMS_10629362_LUGO-RVISTA	-$0.05	$0.19	$0.19	-$0.05	-$0.05	-$0.11	-$0.13	-$0.04	-$0.02	-$0.06	-$0.08	-$0.07	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06	-$0.06
	6410_CP1_NG	-$0.19	$0.14	$0.14	-$0.18	-$0.18	$0.11	$0.09	$0.13	$0.12	$0.11	$0.00	-$0.08	-$0.10	-$0.14	-$0.14	-$0.13	-$0.13	-$0.13
	24385_WEST TS _500_24384_EAST TS _500_BR_1_1	-$0.13	$0.11	$0.15	-$0.12	-$0.13		$0.05	$0.08	$0.08	$0.06		-$0.06	-$0.07	-$0.09	-$0.09	-$0.09	-$0.09	-$0.09
	6410_CP6_NG	-$0.03	$0.02	$0.02	-$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
	24086_LUGO _500_26105_VICTORVL_500_BR_1_1	$0.01	$0.02	$0.02	$0.01	$0.01	-$0.05	-$0.02	-$0.03	-$0.03	-$0.02	-$0.01		$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	24016_BARRE _230_24154_VILLA PK_230_BR_1_1		$0.01	$0.01				$0.00	$0.00	$0.00	$0.00	$0.00							
	SYLMAR-AC_BG	$0.00	$0.00		$0.00	$0.00	-$0.02	$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	$0.06	$0.76		$0.00		-$0.06	-$0.16	-$0.17	-$0.13	-$0.06	-$0.01	$0.00					
	24138_SERRANO _500_24137_SERRANO _230_XF_1_P	-$0.01	$0.03	$0.09	-$0.01	-$0.01		-$0.02				-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2_P		$0.01	$0.08				-$0.01	-$0.02	-$0.02	-$0.02	$0.00							
	OMS 10214484 ML_BK80_NG		$0.00	$0.07					-$0.02	-$0.02	-$0.02								
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1_1			$0.04															
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3_1	$0.00	$0.00	-$0.03	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00				$0.00	$0.00	$0.00		$0.00
	Other	-$0.06	$0.05	$0.10	$0.01	-$0.01	$0.01	-$0.04	$0.00	-$0.04	-$0.05	-$0.07	-$0.01	-$0.06	-$0.04	-$0.03	-$0.05	-$0.14	-$0.07
	Internal Total	**$1.70**	**$1.06**	**$1.94**	**$2.46**	**$1.95**	**-$0.24**	**-$0.65**	**-$0.04**	**-$0.12**	**-$0.50**	**-$3.80**	**-$1.31**	**-$2.30**	**-$2.03**	**-$2.08**	**-$2.07**	**-$2.16**	**-$2.08**
	Transfers				-$1.20	-$1.42	-$1.33	-$1.69	-$1.10	$2.33	-$2.14	-$2.13	-$1.49	$1.41	-$3.57	-$1.20	-$6.51	-$9.89	-$6.42
	Grand Total	**$1.70**	**$1.06**	**$1.94**	**$1.26**	**$0.53**	**-$1.57**	**-$2.34**	**-$1.14**	**$2.21**	**-$2.64**	**-$5.93**	**-$2.80**	**-$0.89**	**-$5.60**	**-$3.28**	**-$8.58**	**-$12.05**	**-$8.50**

Table 1.4 Impact of internal congestion on 15-minute prices during congested intervals[36]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDG&E	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	PWRX	SCL
AZPS	LN-LL	4.2%								$0.90										
IPCO	T342.MPSN	5.3%	$1.82	-$1.20	-$1.88	$2.38	$2.00	-$3.58	-$4.86	-$2.79	-$2.82	-$3.82	-$10.02	$15.89	$1.33	$4.94	$5.01	$4.93	$4.75	$4.94
	T501_xA	3.5%	$7.02		-$4.60	$8.11	$7.37	-$5.63	-$6.85	-$3.97	-$4.07	-$6.81	-$22.22	-$12.73		$9.72	$9.82	$8.60	$8.01	$8.52
PACE	AMASA_DIFFICUL_230	2.2%										-$0.32	$0.41	$1.86	-$1.98					
	WINDSTAR EXPORT TCOR	11.3%											-$0.64							
	TOTAL_WYOMING_EXPORT	52.1%											-$2.70			-$1.38				
PACW	PATH_19_BRIDGER_WEST	0.3%										-$1.19	-$2.03	$2.68	-$1.52					
PG&E	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	0.8%	$27.66	-$17.29	-$24.12	$19.05	$18.20	-$21.77		-$30.57	-$31.44									
	ML_RM12	4.0%	$19.69	$10.67	$9.42	$18.40	$18.98	$4.99	$1.50	$7.01	$6.92	$3.81	-$11.84	-$21.37	-$26.73	-$33.78	-$32.24	-$31.22	-$30.87	-$31.15
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.4%	$13.44	-$12.39	-$11.65	$16.31	$17.15	-$9.50	-$6.92	-$10.34	-$10.32	-$8.62		$5.65	$8.37	$11.16	$10.91	$10.50	$10.30	$10.46
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	0.9%	$12.44	$6.89	$5.89	$11.72	$12.40	$2.91	$0.67	$4.05	$3.97	$1.51	-$9.32	-$16.25	-$18.94	-$21.47	-$21.62	-$21.27	-$21.12	-$21.25
	RM_TM12_NG	1.0%	$9.74	$5.74	$5.00	$6.03	$10.03	$2.90	$1.68	$3.63	$3.58	$1.61	-$7.03	-$12.98	-$16.30	-$18.98	-$19.00	-$18.62	-$18.45	-$18.59
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	7.3%	$7.48	-$4.29	-$4.13	$4.29	$4.42	-$3.62	-$3.25	-$3.83	-$3.81	-$3.45								
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.4%	$4.37	-$4.40	-$4.20	$5.55	$7.86	-$3.36	-$3.43	-$3.80	-$3.80	-$3.25			$1.46	$3.43	$3.40	$3.31	$3.24	$3.28
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.4%	$3.94	-$4.10	-$3.88	$4.47	$4.64	-$3.11	-$2.48	-$3.50	-$3.49	-$3.07	-$0.79	$1.26	$2.38	$3.34	$3.29	$3.16	$3.10	$3.15
	30055_GATES1 _500_30900_GATES _230_XF_12_P	0.7%	$3.83	-$1.90	-$1.83	$1.59	$2.22	-$1.61	-$1.42	-$1.69	-$1.69	-$1.54	-$3.56							
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	0.9%	$3.49	-$5.74	-$5.39	$9.19	$15.35	-$4.30	-$3.08	-$4.72	-$4.71	-$3.89		$3.21	$4.44	$5.75	$5.68	$5.49	$5.42	$5.48
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	0.3%	$2.03	-$3.88	-$2.60	$2.38	$4.78	-$1.91		-$2.06	-$2.06	-$1.17				$1.91	$1.88	$1.80	$1.47	$1.65
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.8%	-$9.83	$7.94	$7.58	-$9.36	-$9.68	$6.10	$4.90	$6.67	$6.64	$5.54	-$0.21	-$3.86	-$5.30	-$6.96	-$6.86	-$6.67	-$6.58	-$6.66
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.9%	-$11.31	$8.73	$8.36	-$10.78	-$11.10	$6.66	$5.20	$7.36	$7.34	$6.19	-$0.14	-$4.20	-$5.97	-$7.92	-$7.82	-$7.59	-$7.48	-$7.57
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.6%	-$14.14	$11.37	$10.43	-$13.50	-$13.91	$8.95	$6.70	$9.24	$9.20	$7.69		-$4.78	-$6.70	-$9.38	-$9.15	-$8.86	-$8.74	-$8.84
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	0.8%				-$8.76	-$12.11													
	7430_CP6_NG	3.7%				$29.90	$13.70													
	7430_MEL_WIL_NG	1.1%				-$9.54														
SCE	OMS_10629362_LUGO-RVISTA	0.5%	-$10.35	$39.73	$39.38	-$10.64	-$10.41	-$22.20	-$26.25	-$12.49	-$11.25	-$13.23	-$16.52	-$14.27	-$13.11	-$12.20	-$12.23	-$12.38	-$12.44	-$12.38
	24385_WEST TS _500_24384_EAST TS _500_BR_1 _1	0.8%	-$14.89	$13.47	$17.58	-$14.23	-$14.73		$5.62	$9.60	$9.46	$7.44		-$6.62	-$8.81	-$11.00	-$10.90	-$10.62	-$10.51	-$10.57
	6410_CP1_NG	1.9%	-$9.80	$7.50	$7.48	-$9.32	-$9.56	$5.94	$4.56	$6.63	$6.61	$5.65	-$1.83	-$4.22	-$5.53	-$7.22	-$7.16	-$6.96	-$6.85	-$6.95
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	0.6%	$2.48	$2.62	$3.63	$2.26	$2.42	-$7.86	-$3.86	-$4.33	-$4.46	-$4.08	-$1.65		$0.63	$1.29	$1.25	$1.17	$1.10	$1.16
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	0.3%	-$4.14	$8.92	$26.31	-$4.12	-$4.12		-$4.83				-$4.00	-$4.11	-$4.05	-$4.09	-$4.09	-$4.09	-$4.09	-$4.09
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.5%		$1.98	$15.96				-$1.48	-$4.57	-$4.54	-$3.48	-$1.42							
	7820_TL 230S_OVERLOAD_NG	5.1%	$0.31	$1.20	$14.97		$0.18		-$1.09	-$3.05	-$3.31	-$2.64	-$1.09	-$1.06	-$0.04					
	OMS 10214484 ML_BK80_NG	0.6%		$0.53	$11.71					-$3.30	-$3.27	-$2.53								

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 EIM 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 the Powerex area, with an average decrease of about $9.89/MWh in the 15-minute market and $6.05/MWh in the 5-minute market.

In the 15-minute market, the total impact of congestion on a specific energy imbalance market (EIM) area is equal to the sum of the price impact of flow-based constraints as shown in Figure 1.39 and Table 1.3, and schedule-based constraints as listed in Table 1.5. Transfer constraint congestion typically has the largest impact on prices; therefore, it is isolated here to better show its effects on EIM load areas. Table 1.5 shows the congestion frequency and average price impact from transfer constraint congestion in the 15-minute and 5-minute markets during the quarter.

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

Table 1.5 Quarterly average price impact and congestion frequency on EIM transfer constraints (Q3 2021)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$1.20	0%	$0.19
L.A. Dept. of Water and Power	1%	-$1.33	0%	-$0.05
Turlock Irrigation District	1%	-$1.42	1%	-$0.52
Arizona Public Service	1%	-$1.10	2%	$1.57
NV Energy	3%	-$1.69	3%	-$0.49
Public Service Company of NM	4%	-$2.14	5%	-$0.62
PacifiCorp East	10%	-$2.13	10%	-$0.47
Idaho Power	11%	-$1.49	10%	-$0.11
Salt River Project	15%	$2.33	14%	$5.35
NorthWestern Energy	27%	$1.41	22%	-$1.79
PacifiCorp West	38%	-$3.57	28%	-$1.50
Portland General Electric	43%	-$1.20	32%	$0.82
Seattle City Light	47%	-$6.42	47%	-$4.57
Powerex	37%	-$9.89	57%	-$6.05
Puget Sound Energy	47%	-$6.51	48%	-$4.14

Transfer constraint congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market may occur with vastly different frequencies and average price impacts across the EIM. Figure 1.41 shows the average impact to prices in the 15-minute market by quarter for 2020 and 2021. Figure 1.42 shows the frequency of congestion on transfer constraints by quarter for 2020 and 2021.

There was an overall decrease in the impact on average prices from transfer constraint congestion in the third quarter of 2021 compared to the same quarter in 2020. The price impacts were greatest for Powerex, where transfer constraint congestion decreased prices in the area by $9.89/MWh in the 15-minute market on average for the quarter.

The frequency of transfer constraint congestion in the third quarter of 2021 was lower than that of the same quarter of 2020. Frequencies averaged less than 50 percent across the EIM during the quarter, a reduction compared to the same quarter of 2020 where Powerex experienced transfer congestion during 61 percent of intervals. Puget Sound Energy and Seattle City Light had the highest average frequency of transfer congestion overall for the quarter, occurring during about 47 percent of 15-minute market intervals.

Figure 1.41 Transfer constraint congestion average impact on prices in the 15-minute market

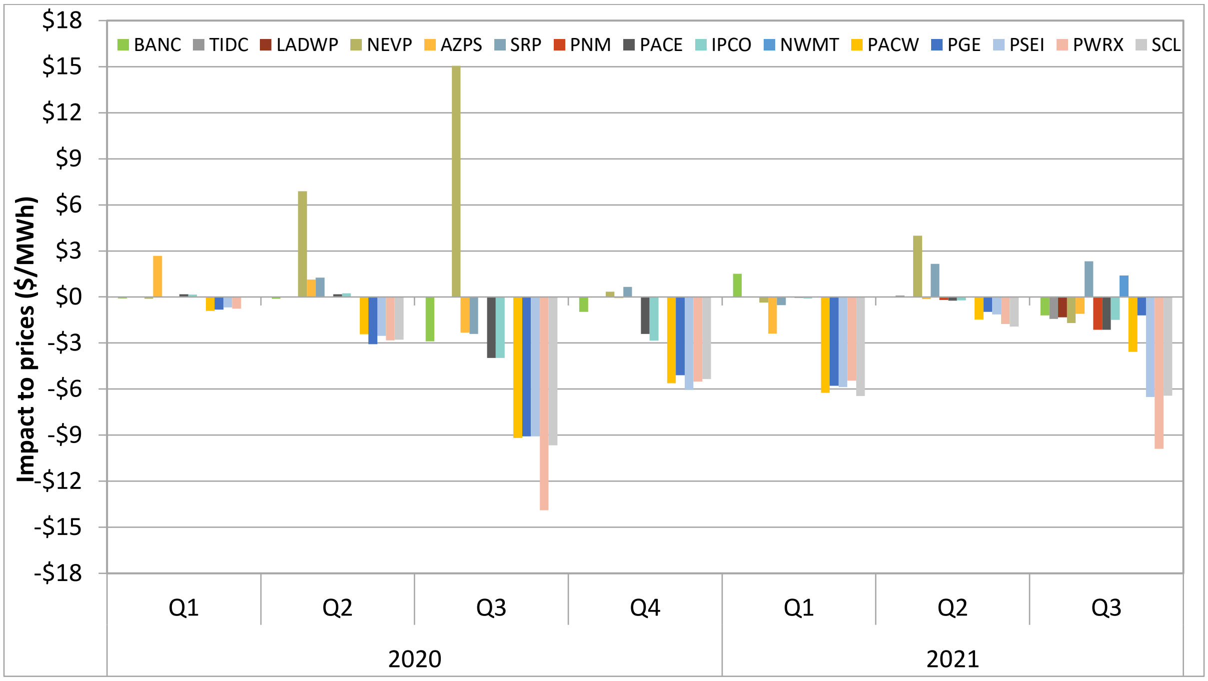
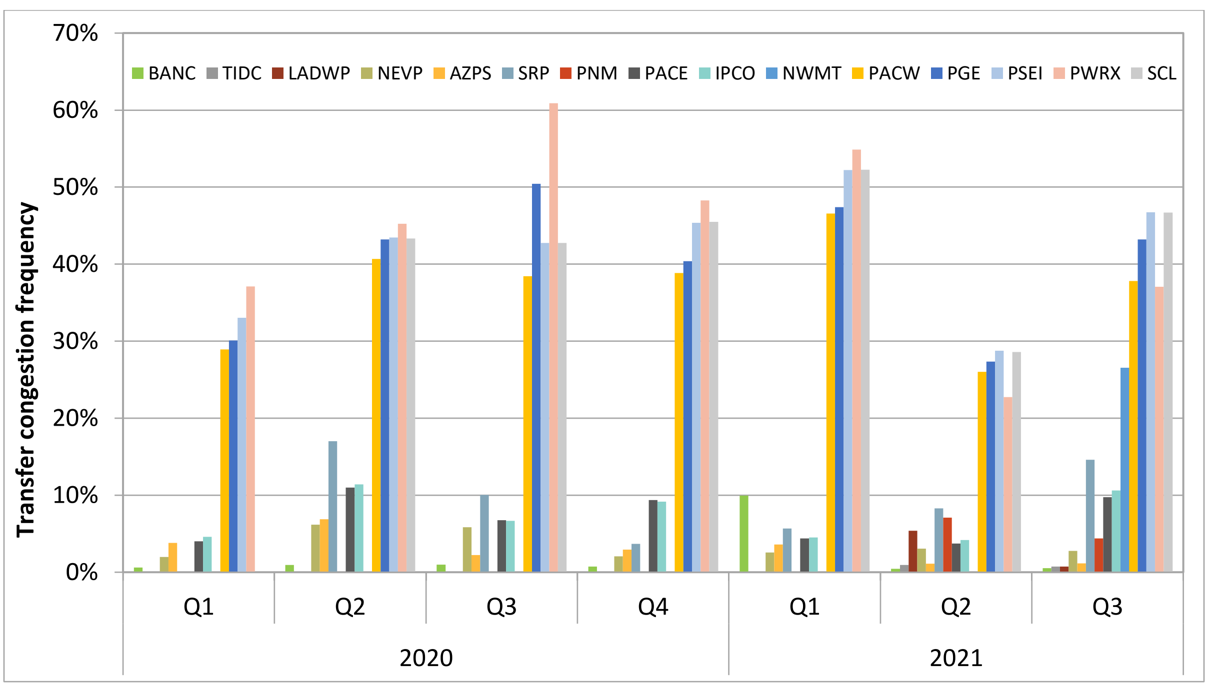


Figure 1.42 Transfer constraint congestion frequency in the 15-minute market



1.9.3 Congestion on interties

In the third quarter of 2021, both frequency and import congestion rent decreased on PACI/Malin 500 and NOB relative to the same quarter in 2020. Figure 1.43 shows total import congestion charges in the day-ahead market for 2020 and 2021. Figure 1.44 shows the frequency of congestion on five major interties. Table 1.6 provides a detailed summary of this data over a broader set of interties.

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

The charts and table highlight the following:

- Total import congestion charges for the third quarter of 2021 decreased to about $50 million compared to about $115 million in the same quarter of 2020. This decrease was driven by a reduction in congestion on the PACI/Malin 500 and NOB interties, which together account for 66 percent of the total import congestion charges for the quarter.
- The frequency of congestion in the third quarter increased significantly on Palo Verde, rising to 10 percent of hours in the third quarter of 2021 compared to 1 percent during the same quarter of 2020.
- 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 in the third quarter of 2021. Congestion on other interties continued to remain relatively low relative to these constraints.

Figure 1.43 Day-ahead import congestion charges on major interties

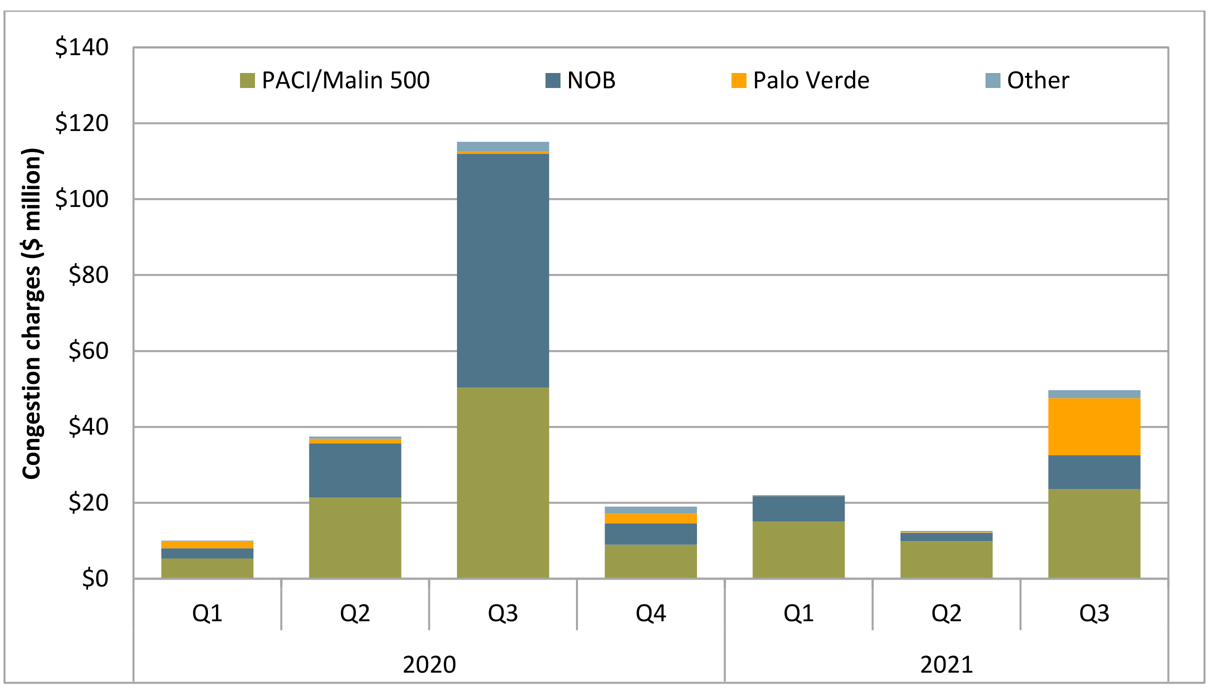


Figure 1.44 Frequency of import congestion on major interties in the day-ahead market

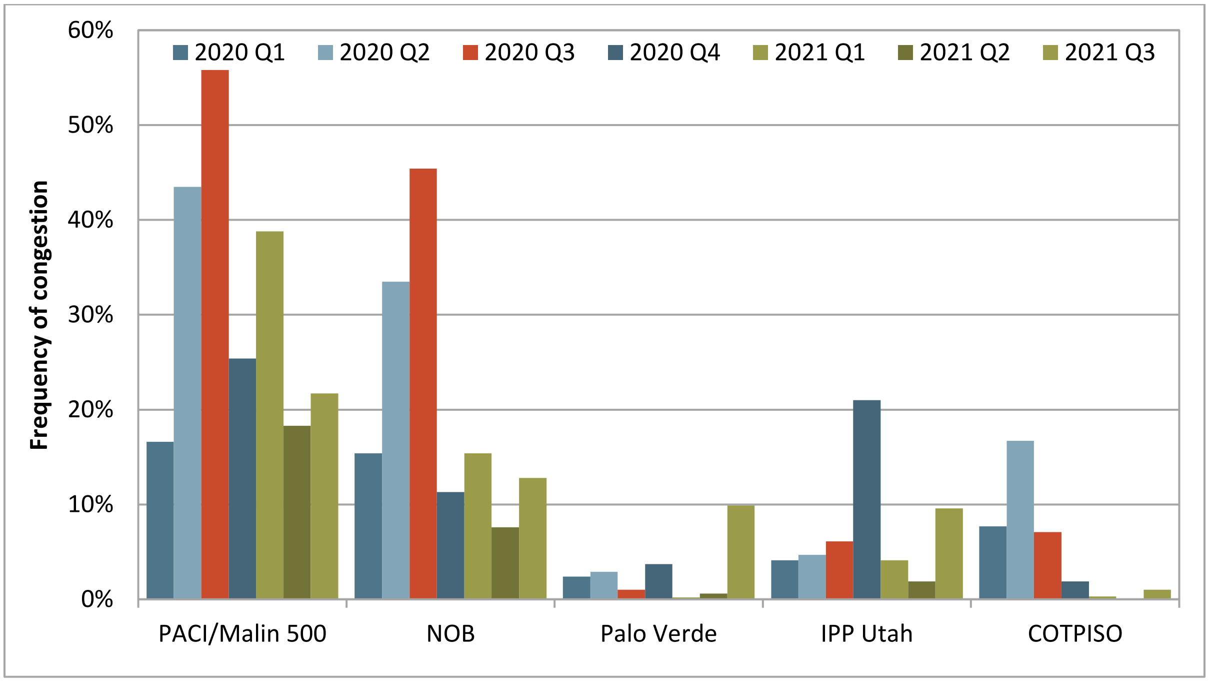


Table 1.6 Summary of import congestion in day-ahead market (2020-2021)

Area	Intertie	Frequency of import congestion							Import congestion charges ($ thousand)						
		2020				2021			2020				2021		
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Northwest	PACI/Malin 500	17%	44%	56%	25%	39%	18%	22%	5,318	21,358	50,334	8,919	15,055	9,920	23,650
	NOB	15%	34%	45%	11%	15%	8%	13%	2,715	14,317	61,672	5,670	6,689	2,132	8,899
	COTPISO	8%	17%	7%	2%	0%		1%	85	258	66	14	3	0	17
Southwest	Palo Verde	2%	3%	1%	4%	0%	1%	10%	1,827	1,174	576	2,516	35	178	15,005
	IPP Utah	4%	5%	6%	21%	4%	2%	10%	136	136	528	1,459	65	16	1,278
	Mead		1%	1%	2%	0%		0%		133	856	357	10		665
	Westwing Mead				0%			1%				19			142
	IPP Adelanto		0%	0%		1%		0%		96	12		38		2
	Gonder IPP Utah						2%							339	
	IID-SDGE													5	
	Merchant					1%							150		

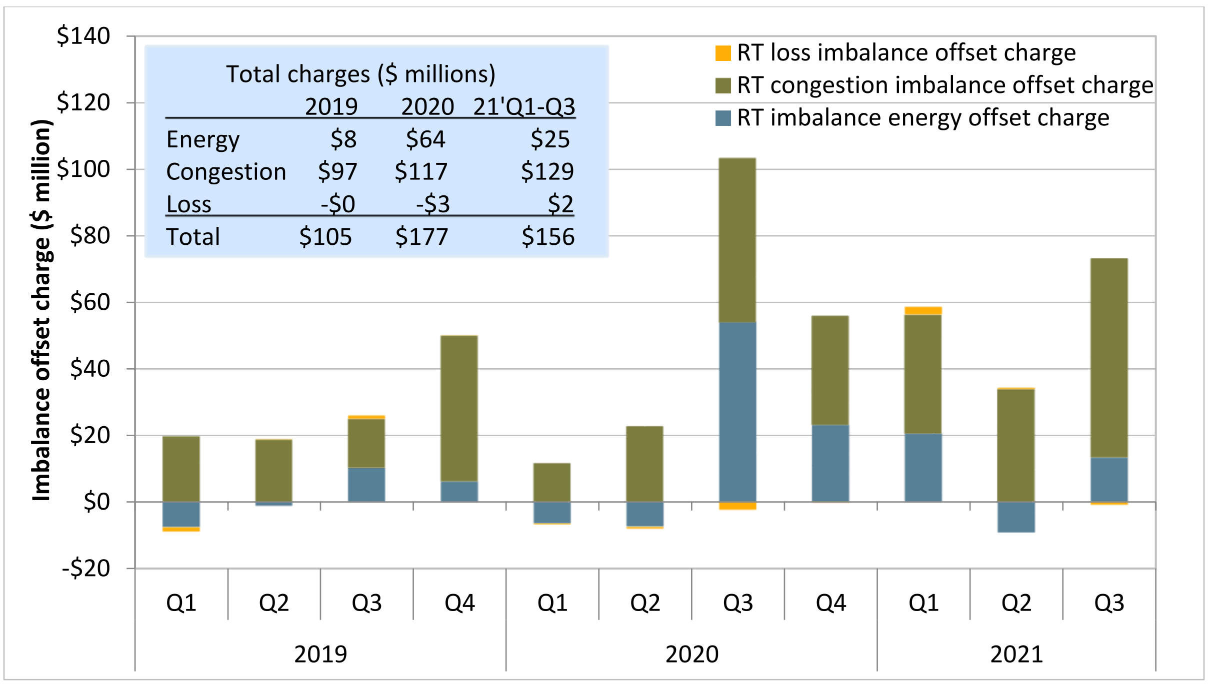
1.10 Real-time imbalance offset costs

Third quarter real-time imbalance offset costs were about $72 million, up from about $25 million in the second quarter of 2021. Real-time imbalance offset costs were comprised of about $60 million in congestion deficits, about $13 million in energy imbalance deficits, and about $1 million in loss surpluses.[37]

The real-time imbalance offset charge consists of three components corresponding to the main components of real-time settlement prices: energy, congestion, and loss.[38] Any revenue imbalance from the energy components of real-time settlement prices is collected through the real-time imbalance energy offset charge (RTIEO). Revenue imbalance from the congestion component is recovered through the real-time congestion imbalance offset charge (RTCIO), and revenue imbalance from the loss component is collected through the real-time loss imbalance offset charge.

The real-time imbalance offset cost is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled in the real-time energy markets—the 15-minute market and the 5-minute market. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

Figure 1.45 Real-time imbalance offset costs



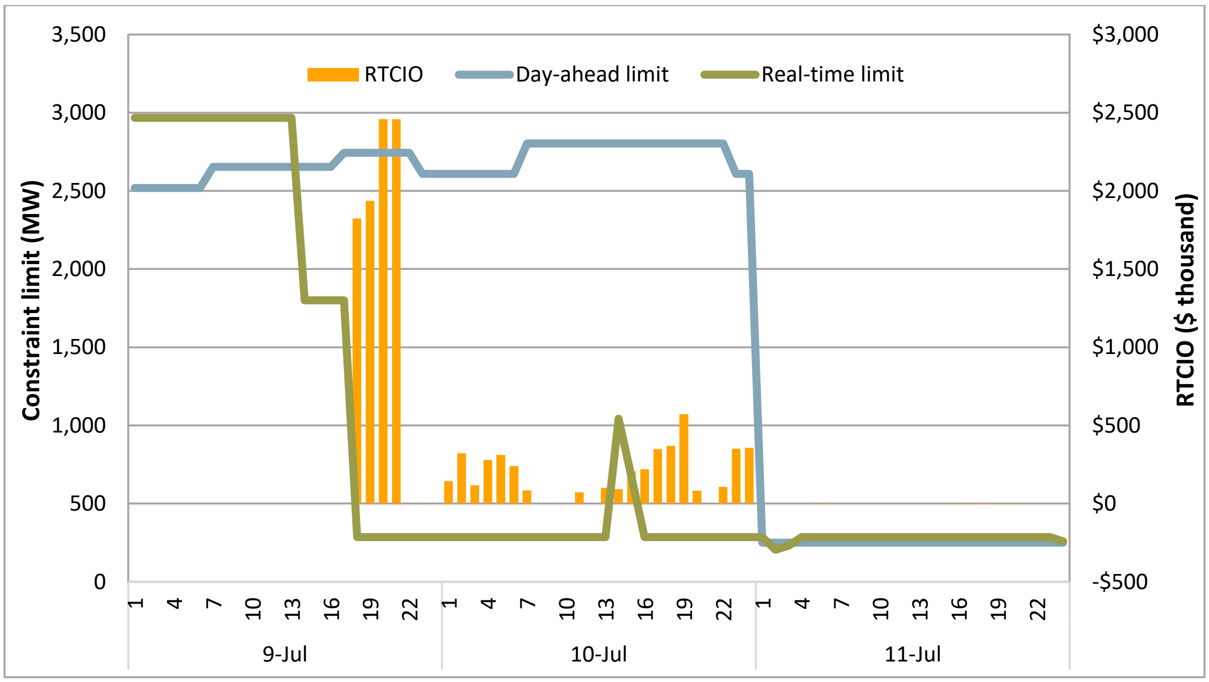
37 Values reported here are based on available settlement data at the time of drafting (September 23, 2021) and thus include both preliminary and post-meter data submission settlements. Following settlement timeline changes effective January 1, 2021, only preliminary data is available until meter data is received and more final settlement statements are issued at trade day plus 70 business days. Settlements can change substantially between statements. For example, estimates of Q2 offset costs rose from $12 million, based on data available July 27 2021, to $25 million about 8 weeks later. For further information on settlement timeline changes see: http://www.caiso.com/Documents/Presentation-MarketSettlementsTimelineTransformationTraining.pdf

38 The greenhouse gas (GHG) price component rent is not settled through the real-time offset accounts but is used to pay schedules backing Western EIM transfers for taking on greenhouse gas compliance obligations.

On July 9, 2021, the Bootleg fire threatened transmission and led to reduced transmission capacity over a number of lines.[39] Included in these de-rates were the Malin 500 and NOB interties, where the sudden change in the transmission capacity created large amounts real-time congestion imbalance offset charges (RTCIO).

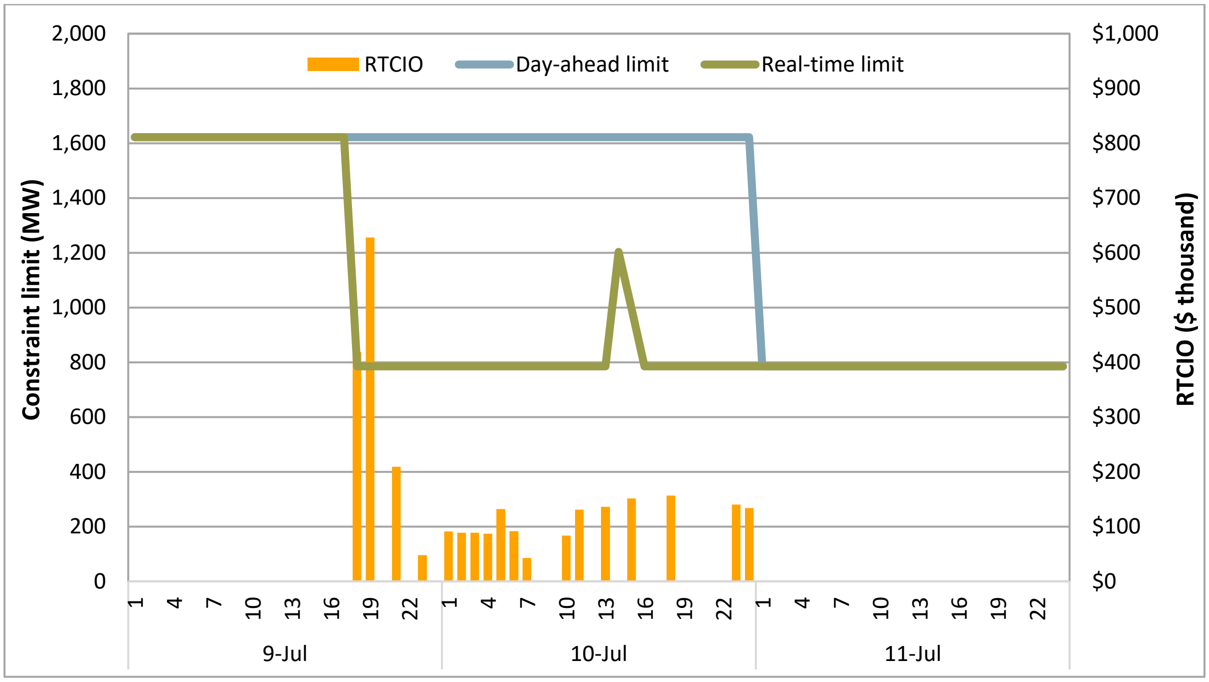
Figure 1.46 and Figure 1.47 show the day-ahead and real-time transmission limits as well as the estimated RTCIO between July 9 and July 11 on the Malin 500 and NOB interties, respectively. On July 9, the limit on the Malin 500 fell from around 2,700 MW in the day-ahead to 285 MW in the real-time. This change created an estimated $8.7 million in RTCIO on July 9th alone, and just over $13 million in total between July 9 and July 11. Similarly, the limit on NOB fell from around 1,625 MW in the day-ahead to 785 MW in the real-time on July 9, and created an estimated $2.9 million in RTCIO between July 9 and July 11.

Figure 1.46 Estimated real-time imbalance offset costs and transmission limits – Malin 500



39 CAISO Summer Market Performance Report for July 2021, Section 15: http://www.caiso.com/Documents/SummerMarketPerformanceReportforJuly2021.pdf

Figure 1.47 Estimated real-time imbalance offset costs and transmission limits – NOB



1.11 Congestion revenue rights

Congestion revenue right auction returns

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

As shown in Figure 1.48, transmission ratepayers lost about $10 million during the third quarter of 2021 as payments to auctioned congestion revenue rights holders continued to exceed auction revenues. This is lower than the $17 million loss in the second quarter of 2021. Auction revenues were 78 percent of payments made to non-load-serving entities during the third quarter, up from 60 percent during the second quarter.

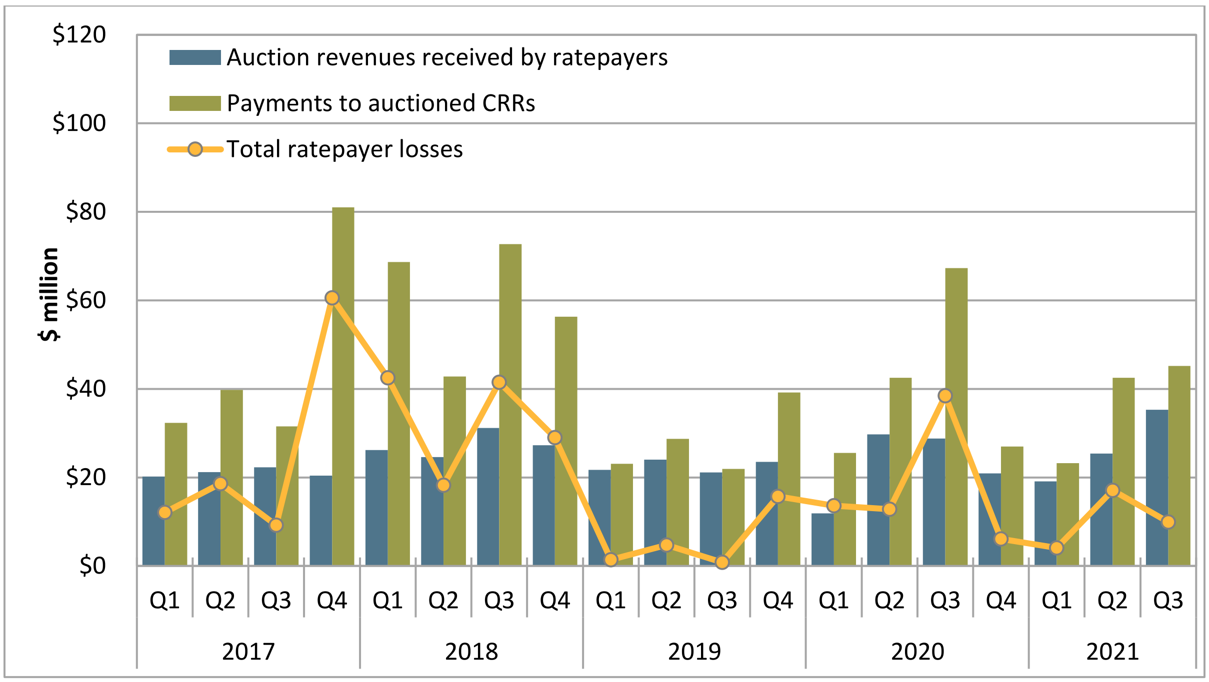
In the third quarter of 2020, a majority of transmission ratepayer losses were from congestion revenue right sales made by load serving entities. This was the first time this has happened. In the fourth quarter, ratepayer losses returned to the normal pattern of being primarily from sales of congestion revenue rights by the ISO. This pattern has continued so far through 2021 with load serving entities on net making money on their congestion revenue right trades.

In the third quarter, financial entities (which do not schedule or trade physical power or serve load) had profits of about $5 million, down from nearly $13 million in profits during the second quarter of 2021. Marketers' profits were a little over $3 million, up from just over $2 million in the second quarter. Generators had profits of about $1.5 million in the third quarter down from about $2 million in the second quarter.

The $10 million in third quarter 2021 auction losses was about 6 percent of day-ahead congestion rent. This is down from 17 percent of rent in the second quarter of 2021 and down from 17 percent for the third quarter of 2020. The losses as a percent of day-ahead congestion rent were below the average of 28 percent during the three years before the Track 1A and 1B changes (2016 through 2018).

The impact of Track 1A changes which limit the types of congestion revenue rights that can be sold in the auction cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under Track 1B reduced payments to non-load-serving entities by about $45 million in the second quarter. The Track 1B effects on auction bidding behavior and reduced auction revenues are not known.

Figure 1.48 Auction revenues and payments to non-load-serving entities



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

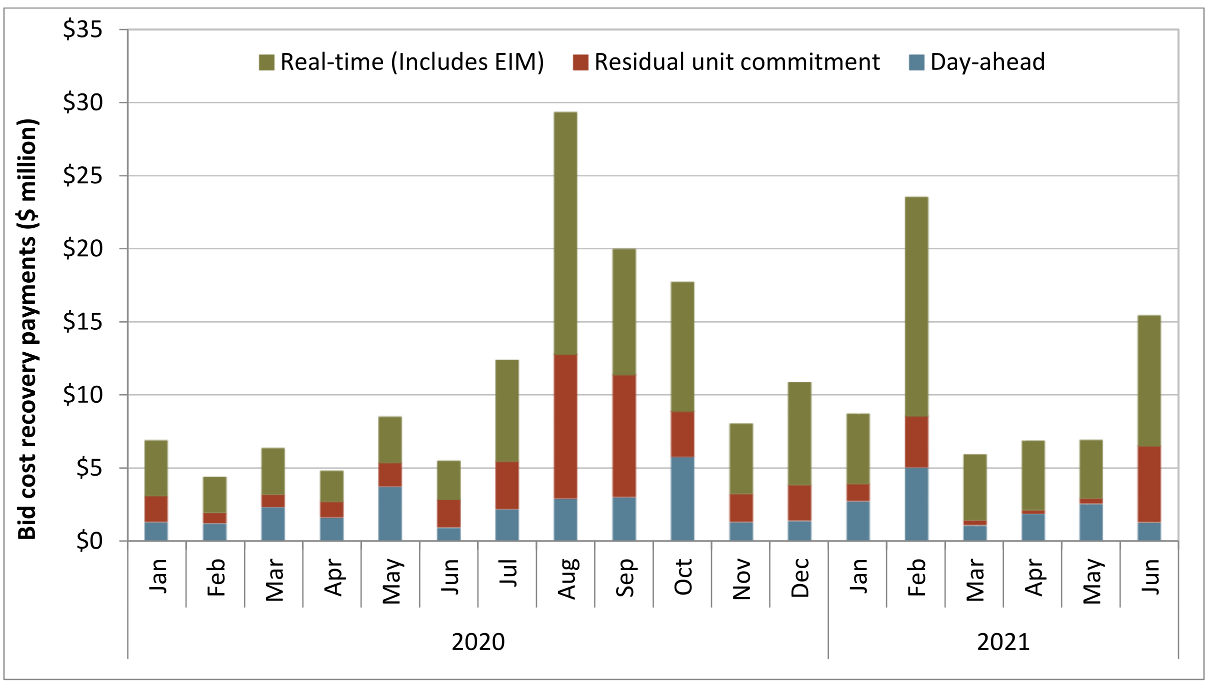
1.12 Bid cost recovery

During the second quarter of 2021, estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled about $30 million.[40] This was $8 million lower than total bid cost recovery in the previous quarter and about $11 million higher than in the second quarter of 2020.

Bid cost recovery attributed to the day-ahead market totaled about $6 million, which is similar to the second quarter of 2020. Bid cost recovery payments for residual unit commitment during the quarter totaled about $6 million, compared to $5 million in the second quarter of 2020. Bid cost recovery attributed to the real-time market totaled about $18 million, or about $6 million lower than payments in the previous quarter and $10 million higher than payments in the second quarter of 2020. Out of the $18 million in real-time payments, about $4 million is allocated to resources (non-ISO) participating in the energy imbalance market.

During the first half of 2021, total bid cost recovery payments totaled $68 million. The majority of these payments, about $61 million, were to gas resources followed by $2.7 million to hydro resources and about $1.2 million to battery energy storage resources.

Figure 1.49 Monthly bid cost recovery payments



1.13 Local market power mitigation

The ISO's automated local market power mitigation (LMPM) procedures are triggered when congestion occurs on a constraint that is determined to be uncompetitive. When this occurs, bids are mitigated to

40 Due to changes in the availability of settlement data, bid cost recovery payments will be reported with a lag of one quarter.

the higher of the system market energy price or a default energy bid designed to reflect a unit's marginal energy cost.

The impact on market prices of bids that were mitigated can only be assessed precisely by re-running the market software without bid mitigation. Currently, DMM does not have the ability to re-run the day-ahead or real-time market software under this scenario. Instead, DMM has developed a variety of metrics to estimate the frequency with which mitigation is triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and also estimate the additional energy dispatched from these price changes.[41]

The following sections provide analysis on the frequency and impact of bid mitigation in the day-ahead and real-time markets for the ISO balancing authority area.

Mitigation in the ISO balancing area

In the day-ahead and real-time markets, mitigation rates during the third quarter of 2021 declined significantly when compared to the same quarter of 2020.

As shown in Figure 1.50, in the day-ahead market, an hourly average of about 923 MW was subject to mitigation but corresponding bids were not lowered, compared to 1,747 MW in the third quarter of 2020. About 248 MW of incremental energy bids were lowered due to mitigation compared to 490 MW in 2020. As a result, there was an average 20 MW increase in dispatch, down from 71 MW in 2020.

Figure 1.51 and Figure 1.52 show the same metrics but for the ISO's 15-minute and 5-minute markets on a monthly level instead. As shown in the figures, the frequency of mitigation in both 15-minute and 5-minute markets declined significantly in August and September relative to the same months in 2020.

[41] The methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. Prior to the LMPM enhancements in November 2019, this metric also captured carry over mitigation (balance of hour mitigation) in 15-minute and 5-minute markets by comparing the market participant submitted bid at the top of each hour (in the 15-minute market) to the bid used in each interval of 15-minute and 5-minute market runs.

Figure 1.50 Average incremental energy mitigated in day-ahead market

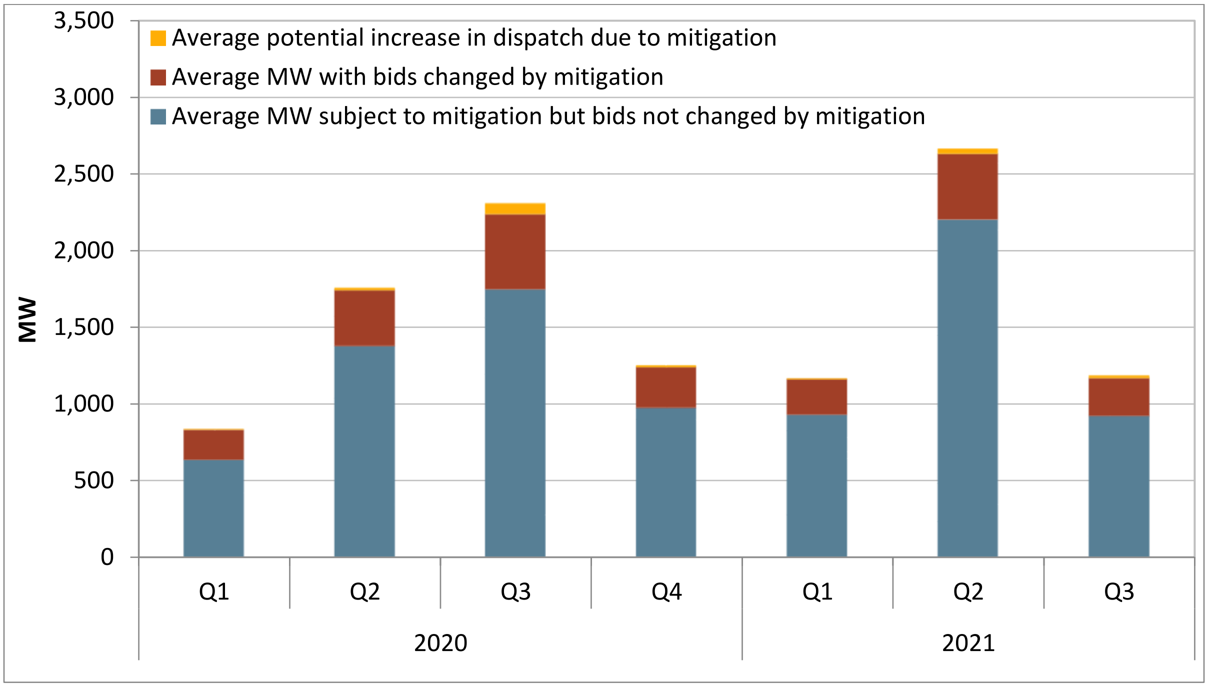


Figure 1.51 Average incremental energy mitigated in 15-minute real-time market (ISO)

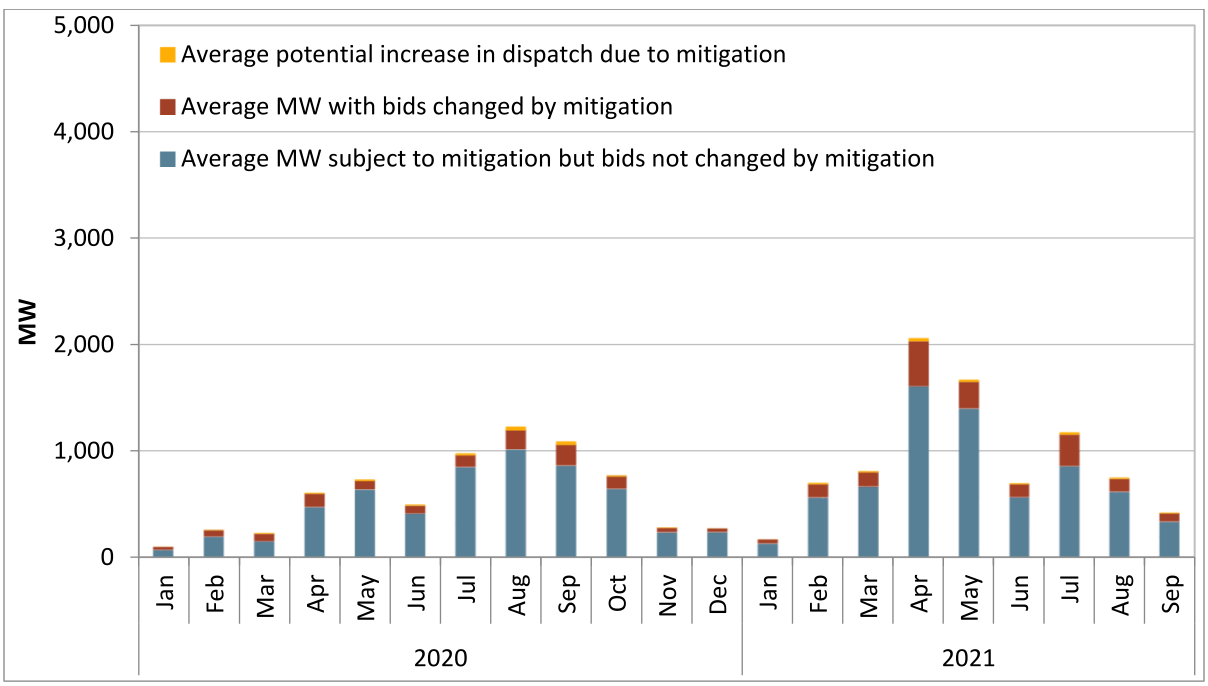
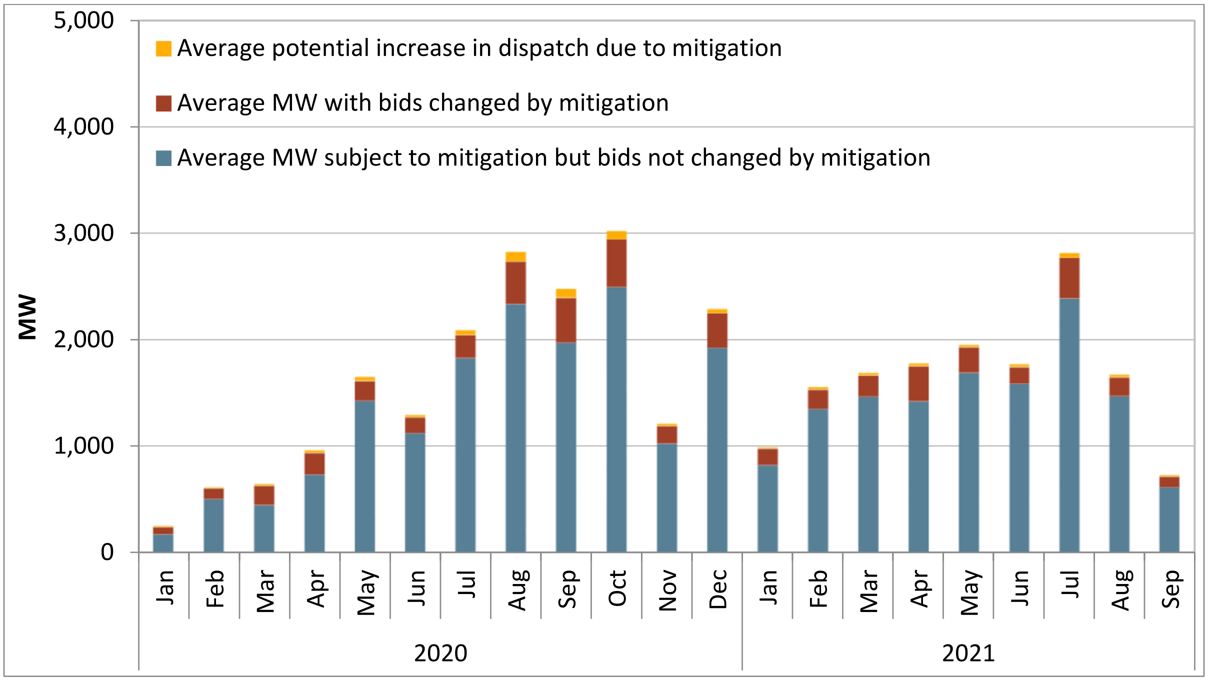


Figure 1.52 Average incremental energy mitigated in 5-minute real-time market (ISO)



1.14 Imbalance conformance

Operators in the California ISO and EIM 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.

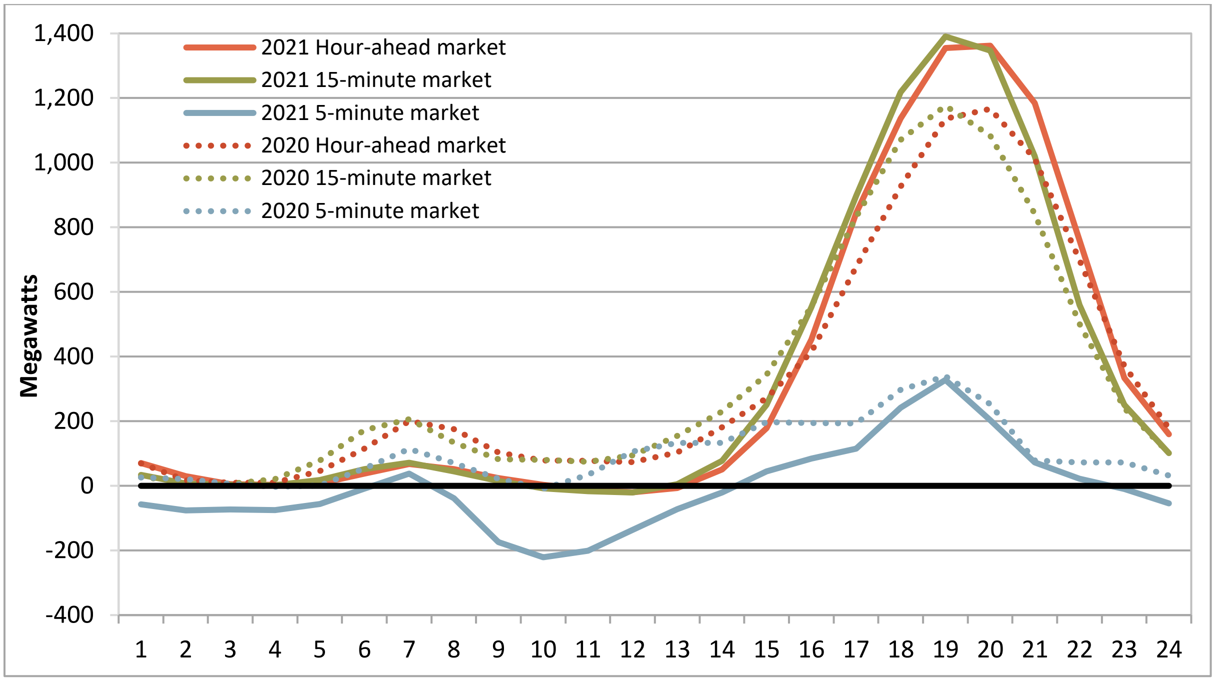
Frequency and size of imbalance conformance adjustments

Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the ISO hour-ahead and 15-minute markets. This large increase continues in the afternoon peak solar ramp down period, with average hourly imbalance conformance adjustments in these markets peaking at just about 1,400 MW, which is about 200 MW greater than the similar peak in the same quarter of the previous year. Imbalance conformance in the morning ramp up period decreased this quarter compared to the prior year, averaging around 50 MW in hour ending 7.

Figure 1.53 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 1.53 Average hourly imbalance conformance adjustment (Q3 2020 – Q3 2021)



1.15 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

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

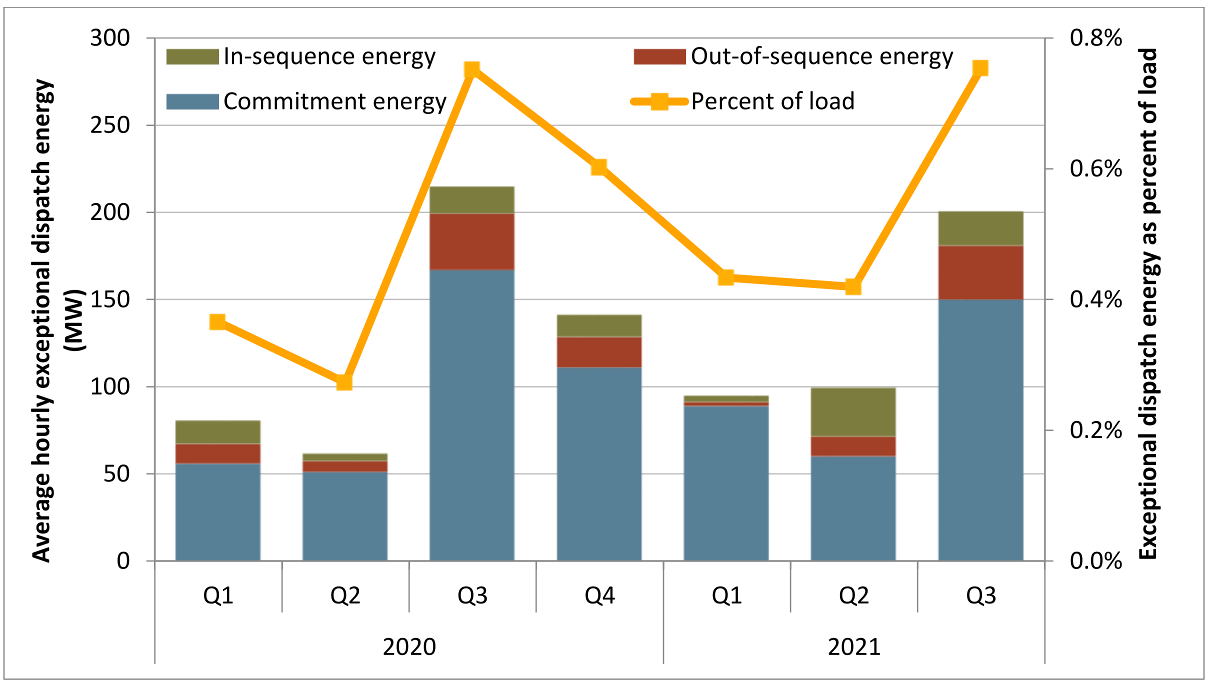
to the local market power mitigation provisions in the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Energy from exceptional dispatch

Energy from exceptional dispatch accounted for under 0.75 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 200 MWh in the third quarter of 2021, slightly down from 214 MWh in the same quarter in 2020.

As shown in Figure 1.54, exceptional dispatches for unit commitments accounted for about 75 percent of all exceptional dispatch energy in this quarter.[42] About 15 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 10 percent was from in-sequence energy.

Figure 1.54 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

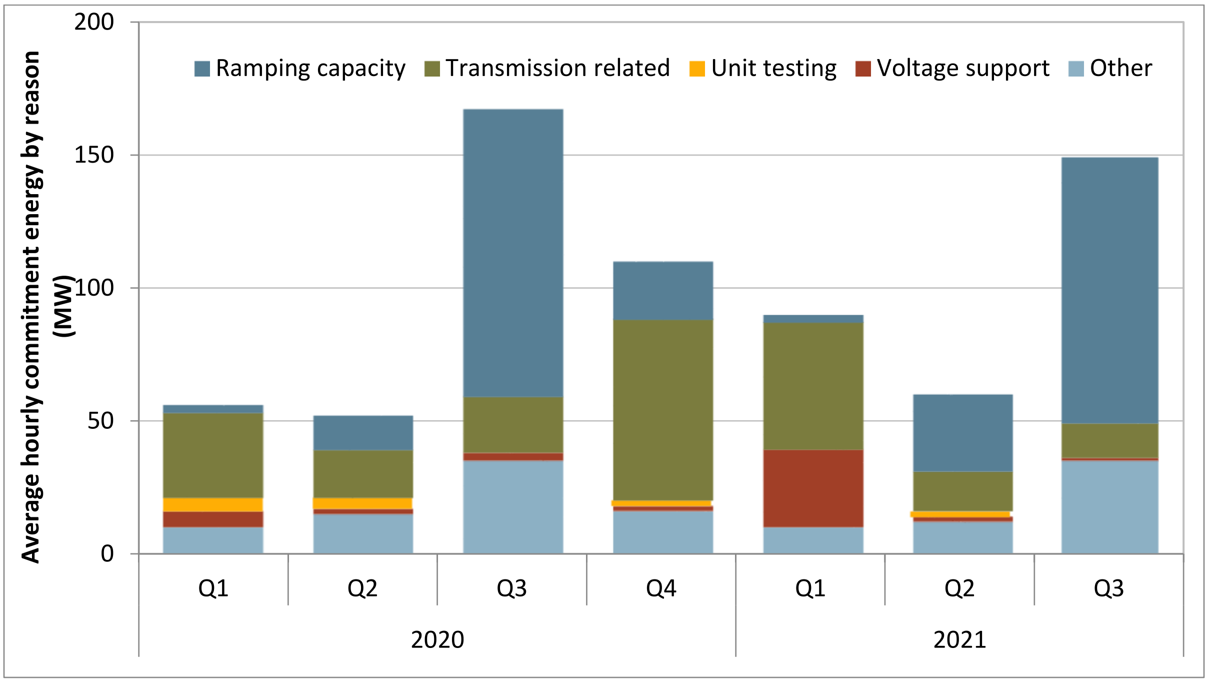
ISO operators sometimes find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements indirectly incorporated in the day-ahead market model. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load. Multi-stage generating units may be

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

committed to operate at the minimum output of a specific multi-stage generator configuration, e.g., one by one or duct firing.

As shown in Figure 1.55, minimum load energy from exceptional dispatch unit commitments in the third quarter decreased slightly on average by about 11 percent relative to the same quarter of the prior year. The most frequent reason given for exceptional dispatch unit commitments was for ramping capacity. Exceptional dispatch unit commitments for ramping capacity may be issued to address load forecast uncertainty or to commit a unit to its minimum dispatchable level.

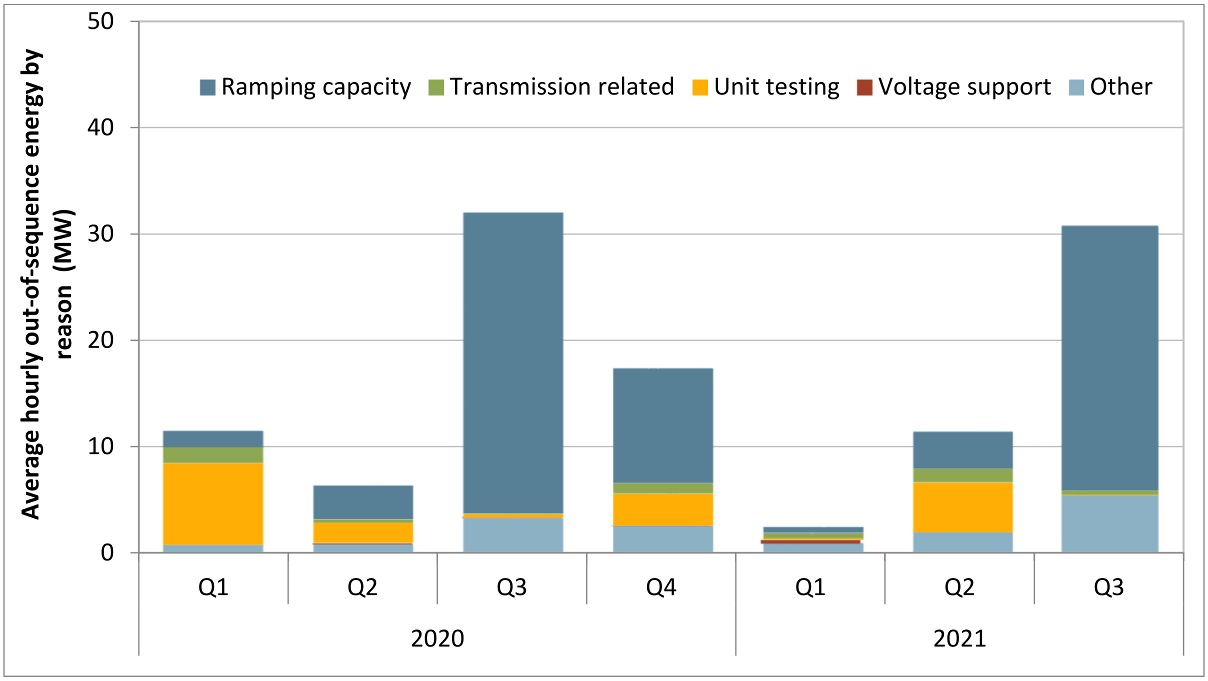
Figure 1.55 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

As shown in Figure 1.54, in the third quarter of 2021, energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch increased very slightly from the same quarter in 2020. Figure 1.54 also shows that about 15 percent of the total exceptional dispatch energy was out-of-sequence, meaning the bid price (or default energy bid if mitigated or if the resource did not submit a bid) was greater than the locational market clearing price. Figure 1.56 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2020 and 2021. In the third quarter, the primary reason logged for out-of-sequence energy was for ramping capacity.

Figure 1.56 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

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

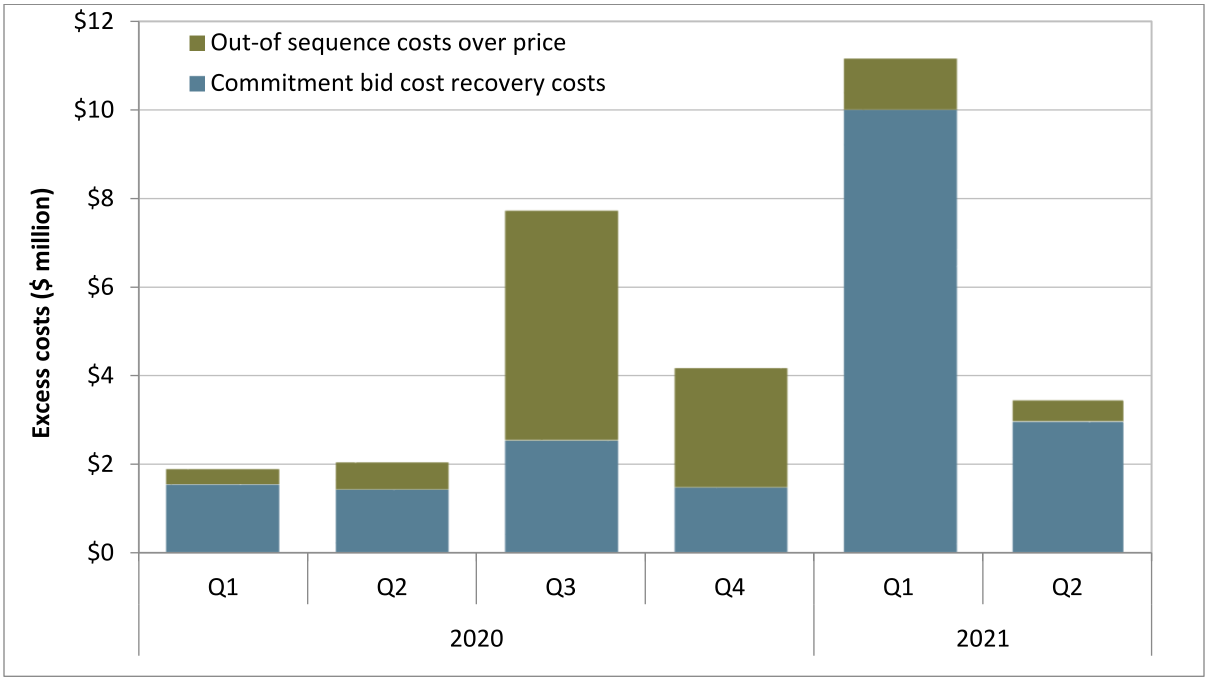
- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.
- Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover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

Figure 1.57 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market clearing price for this energy.[43] In the first half of 2021, commitment costs for exceptional dispatch paid through bid cost recovery increased significantly to about $13 million, compared to the first half of 2020. This increase can be attributed to significantly high gas prices during February 13 through 17 when these payments totaled $8.7 million. The figure also shows that out-of-sequence energy costs totaled $1.6 million in 2021 compared to $0.9 million in the first half of 2020.[44]

43 Due to changes in the availability of cost data, exceptional dispatch costs will be reported with a lag of one quarter.

44 The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated or the resource had not submitted a bid) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

Figure 1.57 Excess exceptional dispatch cost by type



2 Western Energy Imbalance Market

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

- **Natural gas prices across the EIM more than doubled**, resulting in higher energy prices in all areas.
- **Prices in Salt River Project were over $100/MWh on average in the hours between 6 and 8 pm** in both the 15-minute and 5-minute markets, driven by high penalty prices associated with undersupply infeasibilities when the area was separated from the rest of the system. Penalty prices were raised from $1,000/MWh to $2,000/MWh in March. As in previous quarters, undersupply infeasibilities often occurred following the failure of a resource sufficiency test which can limit imports into a failing area. In June, the ISO implemented Phase 2 of FERC Order 831, limiting conditions in which the $2,000/MWh penalty price would apply.
- **Prices in California areas were almost $18/MWh higher than other regions,** on average. 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**, which include PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex, were regularly lower than prices in other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **The California ISO was a net importer**, on average, in all but one hour of the quarter, even during the peak mid-day solar generation hours when, in earlier quarters, lower priced solar generation was typically exported to the rest of the system. Net imports decreased in several areas in the southwest (both APS and SRP) and in both PacifiCorp East and PacifiCorp West.
- **On June 16, 2021, the ISO added net load uncertainty to the requirement of the bid range capacity test** as part of a package of market enhancements for summer 2021 readiness.
- **NorthWestern Energy, Salt River Project, and NV Energy had the most test failures.** NorthWestern Energy failed the upward sufficiency test in around 2 percent of intervals. Salt River Project failed the upward sufficiency and capacity tests in around 1.5 and 2.5 percent of intervals, respectively. NV Energy failed the downward sufficiency test in around 2.4 percent of intervals.
- **In the California ISO**, significantly more 15-minute market transfers were affected by test failures than 5-minute market transfers. This may be due in part to differences in imbalance conformance.
- **DMM is providing additional metrics, data, and analysis on the resource sufficiency tests in monthly reports** as part of the EIM resource sufficiency evaluation stakeholder initiative. DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable.

2.1 Western EIM performance

Western EIM prices

This section details the factors that generally influence changes in Western EIM balancing authority prices and what causes price separation between participating areas. The Western EIM benefits participating balancing authorities 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 Western EIM system, 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 Monthly 15-minute market prices

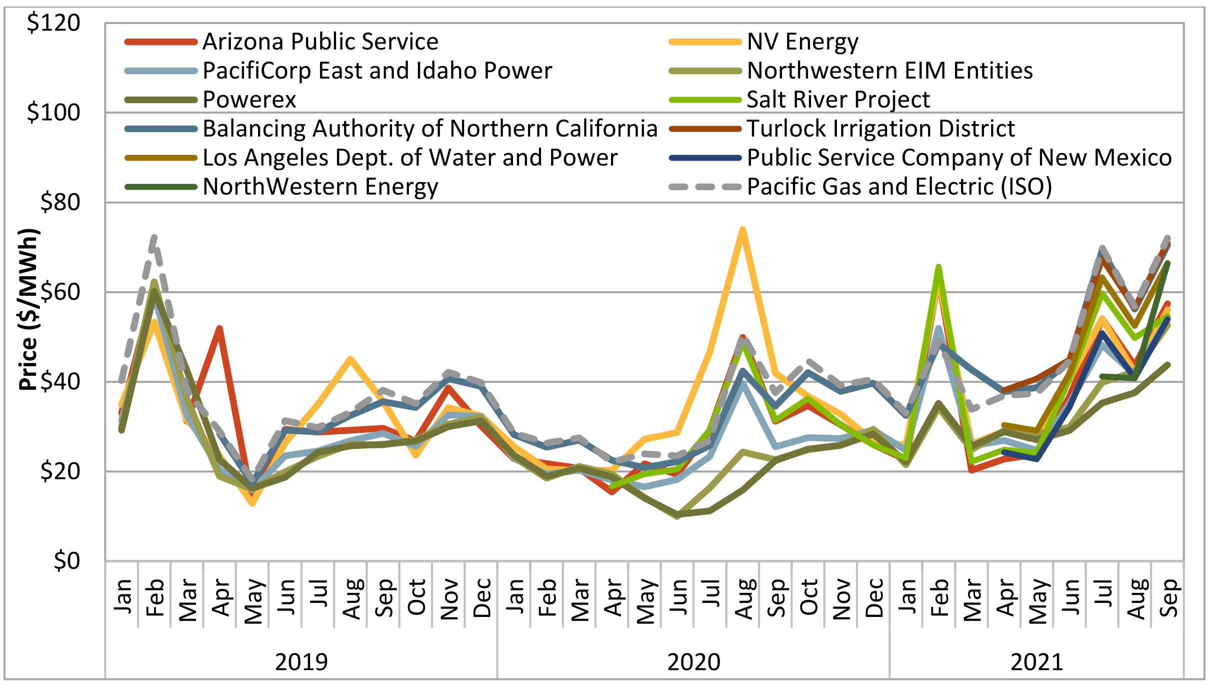


Figure 2.1 shows average monthly prices for the 15-minute market by balancing authority area for 2019 through 2021.[45]

The combined average of Western EIM prices outside of California were below California area prices by $17.91/MWh on average for the quarter. Prices of EIM entities within California were closer to those of Pacific Gas and Electric. The combined average prices of these California EIM areas, which include

45 The 'Northwestern EIM Entities' line consists of PacifiCorp West, Puget Sound Energy, Portland General Electric, and Seattle City Light, which have been grouped together due to their similar average monthly prices. Prices for the Balancing Authority of Northern California (blue line) begin in April of 2019 when the Sacramento Municipal Utility District joined the market, while the rest of BANC joined in March 2021. Prices for Seattle City Light (included in medium green line) and Salt River Project (bright green line) begin in April 2020 when they joined the Western EIM. Prices for Turlock Irrigation District (dark red line), Los Angeles Department of Water and Power (brown line), and Public Service Company of New Mexico (dark blue line) begin in April 2021. Turlock Irrigation District was a part of the EIM for one week of March 2021; therefore, data for the TID area in March 2021 are not included in this section's analysis.

Balancing Area of Northern California, Turlock Irrigation District, and Los Angeles Department of Water and Power, was $2.57/MWh lower than Pacific Gas and Electric prices.

Price separation between Western EIM balancing authorities occurs for several reasons. California area prices tend to be higher than the rest of the Western EIM due to greenhouse gas compliance cost for energy that is delivered to California. In addition, average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex) are regularly lower than other balancing areas because of limited transfer capability out of the region.

Figure 2.2 Quarterly average 15-minute price by component (Q3 2021)

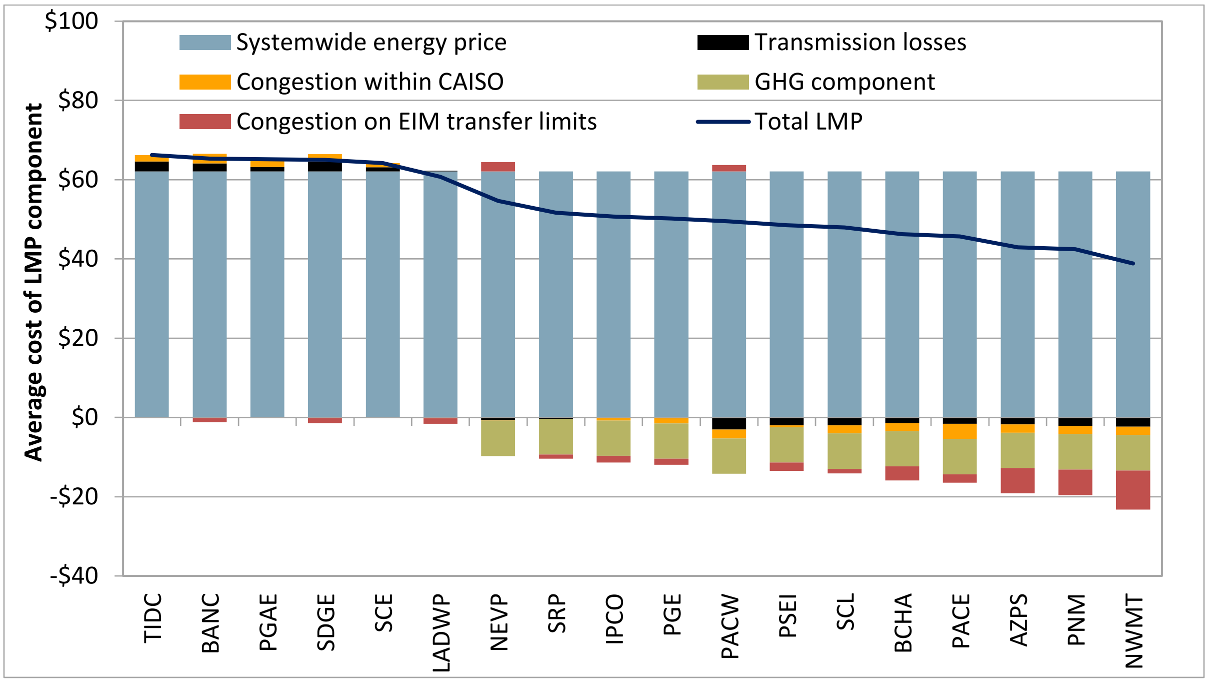
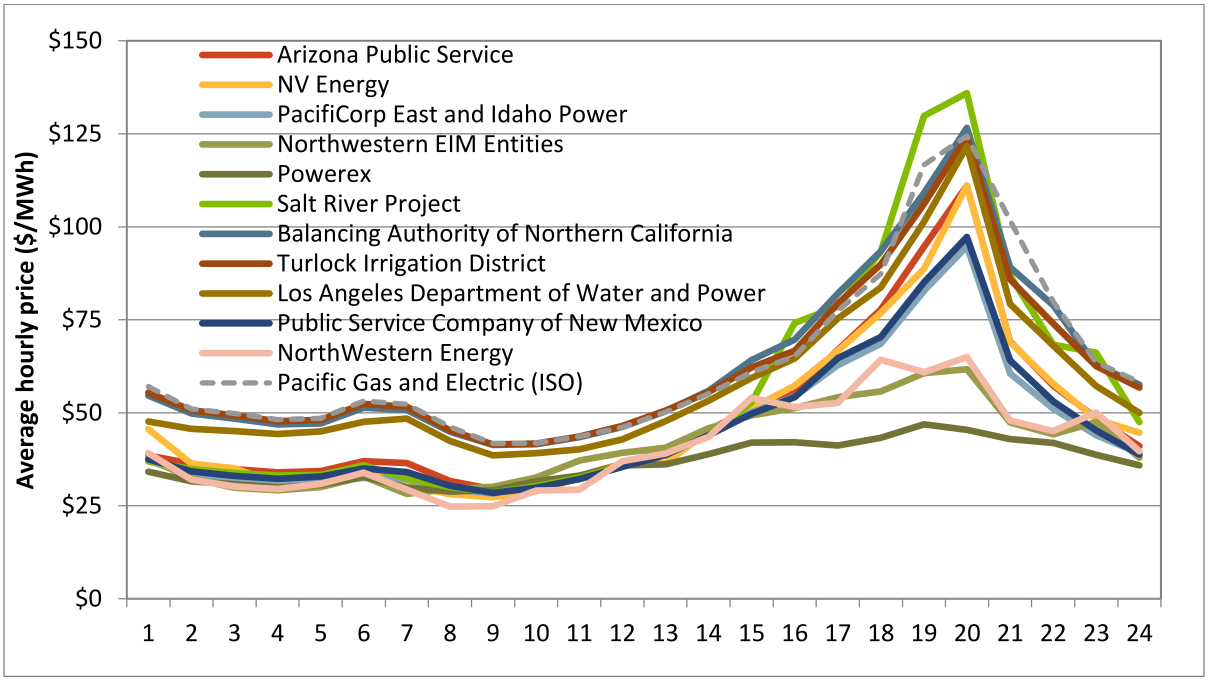


Figure 2.2 depicts the average 15-minute price by component for each balancing authority area.[46] The system marginal energy price is the same for all entities in each hour. The price difference between EIM balancing authority areas is determined by area specific elements including transmission losses, greenhouse gas compliance costs, congestion, and power balance constraint (PBC) violations. Congestion on EIM 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 EIM transfer constraints, including any PBC relaxations that increase the price in a single area. Transfer congestion can also result in lower prices in an area, when a lower priced region is separated from the system by congestion on a transfer constraint.

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

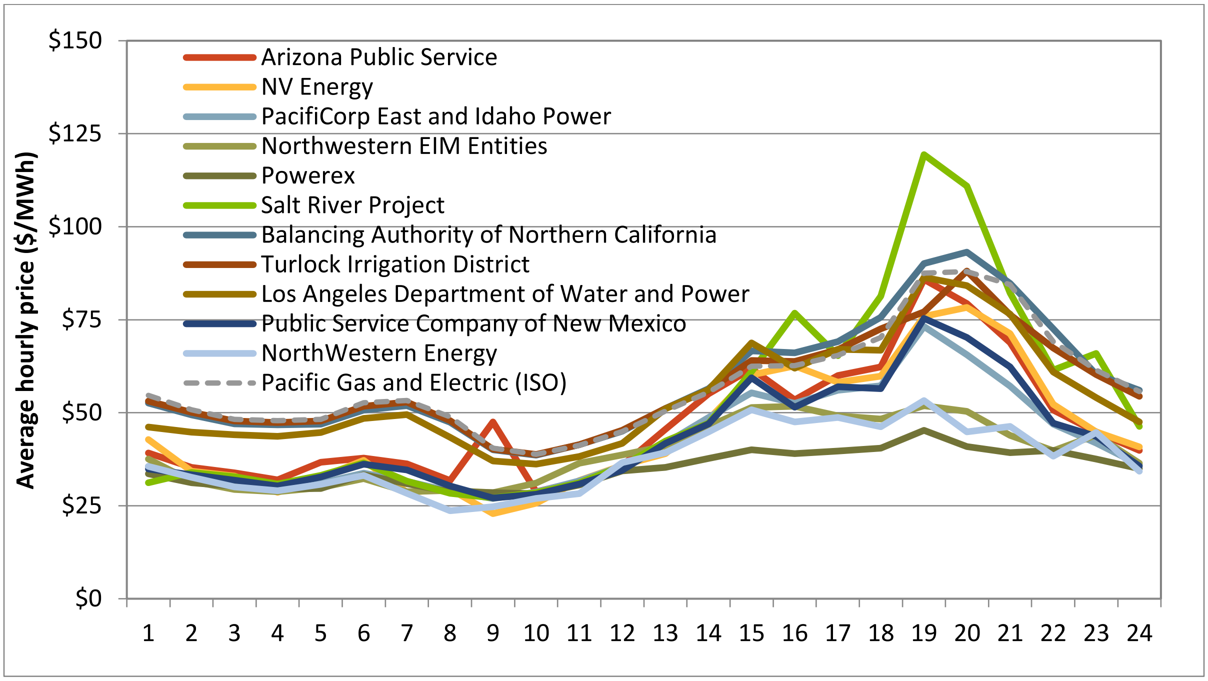
Figure 2.3 and Figure 2.4 show the variation in Western EIM prices throughout the day in the third quarter of 2021.[47] Prices in balancing areas outside of California tend to be lower than California prices in most hours, particularly during the evening ramping hours, when California areas are typically importing energy subject to greenhouse gas compliance costs. Other differences in prices reflect transfer limitations between the different areas.

Figure 2.3 Hourly 15-minute market prices (July-September)



47 The 'Northwestern EIM Entities' line consists of PacifiCorp West, Puget Sound Energy, Portland General Electric, and Seattle City Light.

Figure 2.4 Hourly 5-minute market prices (July-September)



As seen in Figure 2.3 and Figure 2.4, Salt River Project had the highest average prices during the evening peak hours. This is due in part to an increase in congestion on EIM transfer constraints and internal CAISO constraints during these hours. Figure 2.5 breaks down Salt River Project's average locational marginal price (LMP) by component for every hour of the day.

Figure 2.5 Salt River Project average 15-minute price by component (Q3 2021)

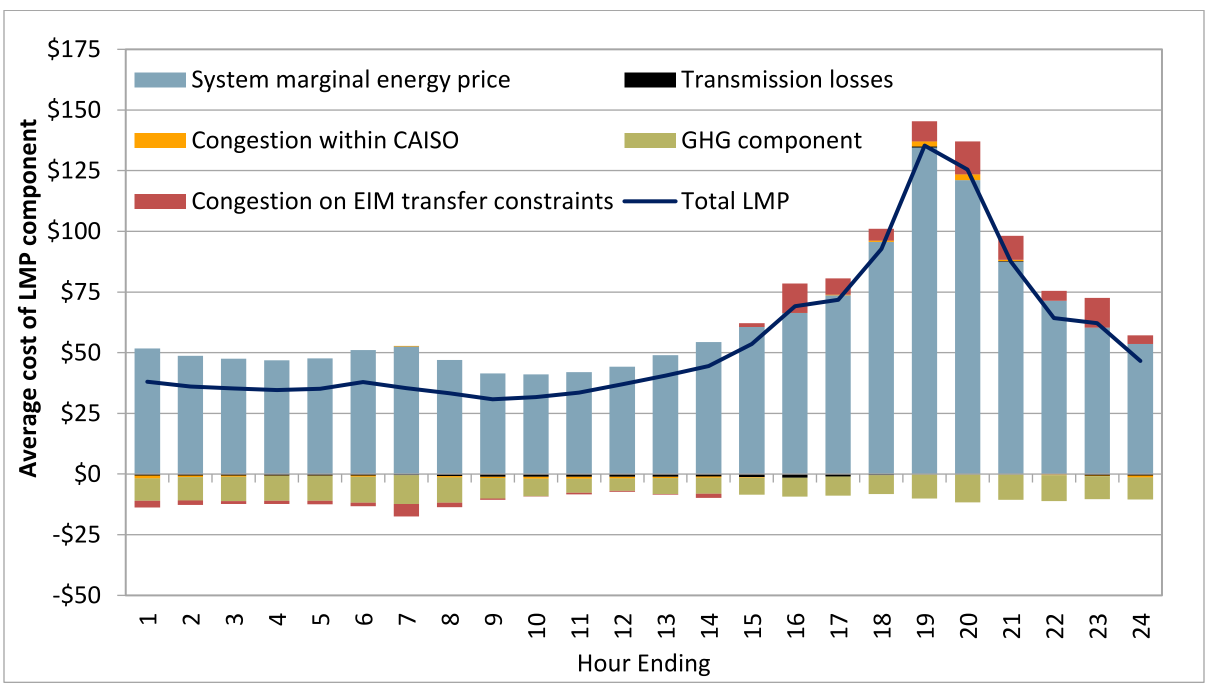


Figure 2.6 Turlock Irrigation District average 15-minute price by component (Q3 2021)

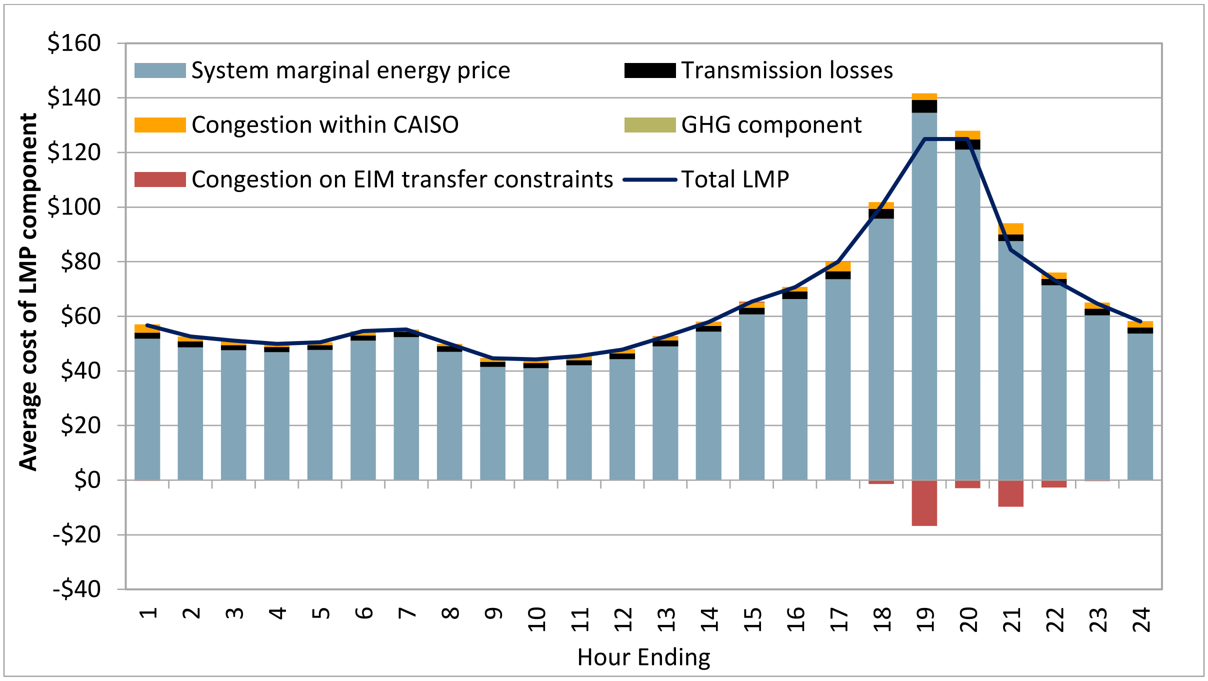


Figure 2.7 Portland General Electric average 15-minute price by component (Q3 2021)

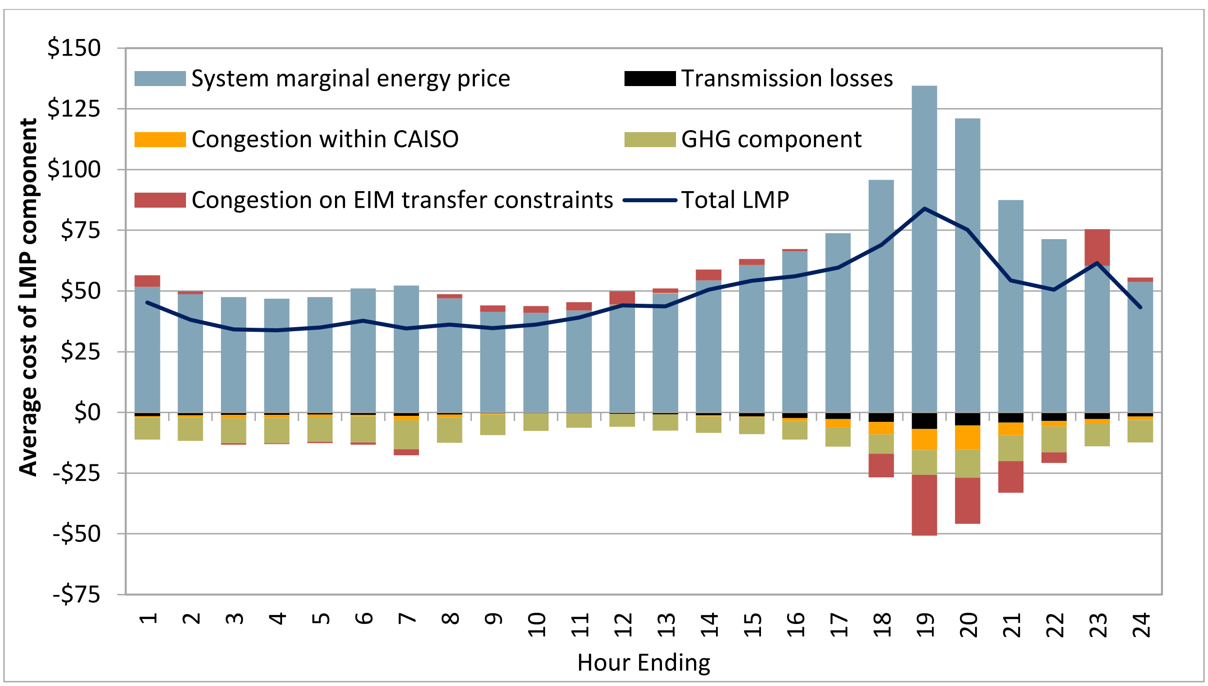
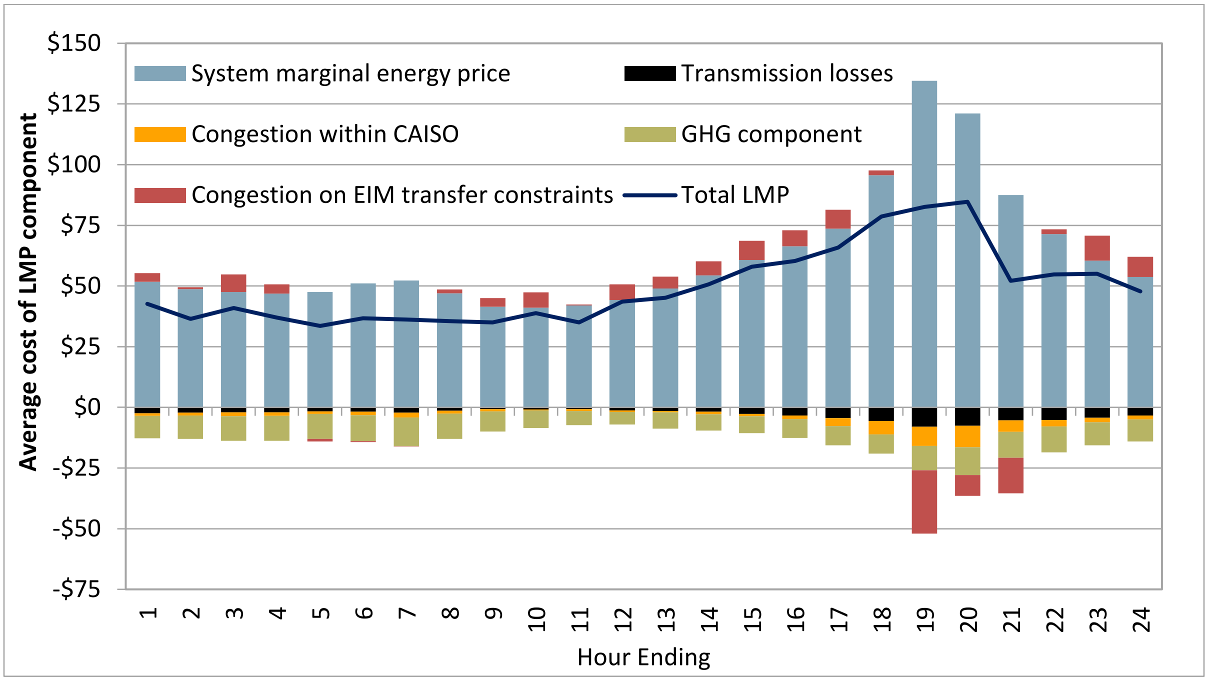


Figure 2.8 NorthWestern Energy average 15-minute price by component (Q3 2021)



2.2 EIM resource sufficiency evaluation

As part of the energy imbalance market, each area including the California ISO is subject to a resource sufficiency evaluation. 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 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 (sufficiency test)** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the upward direction, energy imbalance market transfers into that area cannot be increased.[48] 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 2.9 and Figure 2.10 show the percent of intervals in which each EIM area failed the upward capacity and sufficiency tests, while Figure 2.11 and Figure 2.12 provide the same information for the

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

downward direction.[49] The dash indicates the area did not fail the test during the month. The flexible ramping sufficiency test and bid range capacity test failures reported below reflect results independent of the other test. In the third quarter of 2021:

- NorthWestern Energy failed the upward sufficiency test in around 2 percent of intervals.
- Salt River Project failed the upward sufficiency test in around 1.5 percent of intervals and the upward capacity test in around 2.5 percent of intervals.
- NV Energy failed the downward sufficiency test in around 2.4 percent of intervals.

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

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

	2020						2021								
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona PS	—	—	—	—	—	0.3	0.2	0.4	—	—	0.3	—	0.2	0.3	0.2
BANC	0.0	0.0	—	0.1	0.0	—	—	—	0.1	—	—	—	0.2	—	0.0
California ISO	—	—	—	—	—	—	—	—	—	—	—	0.1	0.2	0.0	0.2
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	0.4	0.8	0.1
LADWP										—	—	0.1	—	—	—
NorthWestern												0.6	1.2	0.6	0.2
NV Energy	—	—	—	0.1	0.2	—	—	0.3	—	0.0	0.5	0.8	0.5	0.2	0.2
PacifiCorp East	—	—	—	—	0.1	—	—	—	—	—	—	0.3	0.3	0.1	0.2
PacifiCorp West	—	—	—	—	0.1	—	—	—	0.1	—	0.0	0.1	0.2	0.1	0.1
Portland GE	—	—	—	—	—	—	—	0.1	—	0.4	—	0.7	0.8	1.0	1.4
Powerex	—	—	0.1	0.1	0.1	—	0.1	0.0	—	—	—	0.0	0.0	—	0.1
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
Salt River Proj.	—	—	—	0.1	0.1	—	—	8.0	—	0.1	0.1	0.7	3.0	2.6	2.0
Seattle City Light	0.2	0.1	—	—	—	—	—	—	—	—	—	—	—	0.0	0.5
Turlock ID									—	—	0.0	—	—	1.1	0.8

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

	2020						2021								
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona PS	—	—	0.3	0.8	0.7	0.6	0.5	0.5	0.2	—	0.6	—	0.0	—	0.2
BANC	—	0.2	0.0	0.1	—	0.1	—	—	—	—	—	—	—	—	—
California ISO	0.1	1.1	0.5	0.4	0.5	—	—	—	—	—	—	0.0	0.3	0.1	0.4
Idaho Power	0.1	0.2	—	—	—	—	—	0.1	—	—	—	—	—	—	—
LADWP										0.0	0.1	—	0.1	—	—
NorthWestern												1.3	3.6	0.7	1.6
NV Energy	4.5	7.1	2.6	1.4	0.8	—	0.1	0.5	0.4	0.4	0.7	0.9	0.4	0.5	0.1
PacifiCorp East	0.2	0.2	0.1	0.5	0.0	—	0.1	0.1	0.1	0.1	0.0	0.1	0.0	—	0.1
PacifiCorp West	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.2	0.1	0.1	0.0	—	0.0	0.1	—
Portland GE	0.2	0.2	0.6	0.1	0.1	0.2	0.3	0.6	0.1	0.2	0.2	0.3	0.5	0.2	—
Powerex	0.2	0.1	0.3	0.1	0.6	0.2	0.2	0.1	0.1	0.1	—	0.1	0.5	—	—
PSC New Mexico										0.4	0.0	0.1	0.5	—	0.1
Puget Sound En	0.6	0.4	—	0.2	—	—	—	—	—	—	0.1	0.1	0.0	0.0	—
Salt River Proj.	0.7	1.8	1.1	1.7	0.9	0.3	0.2	7.1	0.3	0.5	0.2	0.9	1.9	1.7	0.8
Seattle City Light	0.1	—	0.1	0.2	0.2	0.1	—	—	—	—	—	—	0.0	—	0.1
Turlock ID									—	—	0.3	—	—	—	0.1

Figure 2.11 Frequency of downward capacity test failures by month and area (percent of intervals)

	2020						2021								
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona PS	—	—	—	—	—	—	—	—	—	—	0.0	—	—	—	—
BANC	—	—	—	0.1	0.1	—	—	0.0	0.1	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
LADWP										—	—	0.1	—	—	—
NorthWestern												—	—	—	—
NV Energy	—	—	—	—	—	—	—	—	—	—	—	0.0	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	0.0	0.0	—	0.0	—	—	—	—	—	0.0	—	0.3	0.1	—	0.8
PSC New Mexico										—	—	—	—	—	—
Puget Sound En	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	—	—	—	—	—	—	—	—	—	0.0	—	0.0	—	—	—
Seattle City Light	—	—	—	—	—	—	—	—	—	—	—	—	0.0	0.0	0.0
Turlock ID									—	—	0.3	0.2	0.0	0.2	0.2

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

	2020						2021								
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona PS	0.1	—	0.1	1.9	0.9	2.5	2.2	2.3	4.3	1.9	0.3	0.1	—	0.1	0.1
BANC	—	—	—	0.1	0.3	—	—	0.6	0.4	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	0.0	—	—	0.0	0.0	—	—	—	—	—	0.0	—	—	—	—
LADWP										—	—	0.1	—	—	—
NorthWestern												0.7	0.6	0.4	1.2
NV Energy	0.7	0.8	2.2	0.5	1.4	1.1	0.2	6.1	1.4	0.5	4.3	2.0	3.0	2.5	1.7
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	0.1	—	—	0.1	—	—	—
Portland GE	—	—	—	—	—	—	0.0	—	—	—	—	—	—	—	—
Powerex	0.0	0.1	0.1	0.1	—	—	0.4	—	1.4	0.2	0.9	1.3	0.4	0.2	1.0
PSC New Mexico										1.4	—	0.0	—	—	0.1
Puget Sound En	0.1	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Salt River Proj.	—	0.0	0.1	0.1	0.2	0.8	1.1	1.6	1.2	0.2	0.1	0.2	—	0.1	0.0
Seattle City Light	0.1	0.2	0.2	0.1	0.1	0.1	—	—	—	—	—	—	0.2	—	—
Turlock ID									0.4	0.1	0.5	—	—	0.0	—

Impact of adding uncertainty to the bid range capacity test

On June 16, the ISO added net load uncertainty to the requirement of the bid range capacity test as part of a package of market enhancements for summer 2021 readiness. The uncertainty component is net of the diversity benefit, similar to that already in effect for the flexible ramping sufficiency test.[50]

Figure 2.13 shows the impact of this change by showing actual capacity test failure intervals that would have passed the test without the additional uncertainty component. During the quarter, 60 percent of upward test failures would have passed without the additional uncertainty component. Figure 2.14 shows the same information, except without intervals in which the sufficiency test also failed in that interval. Since the outcome of failing either the capacity or the sufficiency test is the same, this figure therefore summarizes additional intervals in which energy imbalance market transfers were capped.

Figure 2.13 Additional capacity test failures with implemented uncertainty (15-minute market)

	Upward capacity test				Downward capacity test			
	Jun*	Jul	Aug	Sep	Jun*	Jul	Aug	Sep
Arizona PS	—	3	7	2	—	—	—	—
BANC	—	3	—	1	—	—	—	—
California ISO	3	2	1	5	—	—	—	—
Idaho Power	—	13	21	3	—	—	—	—
LADWP	—	—	—	—	—	—	—	—
NorthWestern	4	30	12	6	—	—	—	—
NV Energy	3	9	6	5	—	—	—	—
PacifiCorp East	7	9	4	4	—	—	—	—
PacifiCorp West	4	7	2	2	—	—	—	—
Portland GE	17	20	25	34	—	—	—	—
Powerex	1	1	—	2	4	3	—	4
PSC New Mexico	—	3	—	2	—	—	—	—
Puget Sound En	7	8	10	8	—	—	—	—
Salt River Proj.	8	49	19	32	—	—	—	—
Seattle City Light	—	—	1	6	—	—	—	1
Turlock ID	—	—	9	10	4	—	1	2

*June 16-30, 2021 (implementation of uncertainty in the capacity test)

50 The diversity benefit reflects that system-level flexible ramping needs are typically smaller than the sum of the individual balancing area flexible ramping needs because of reduced uncertainty across a larger footprint. The diversity benefit is a prorated discount based on this proportion.

Figure 2.14 Additional capacity test failures with implemented uncertainty excluding sufficiency test failures (15-minute intervals)

	Upward capacity test				Downward capacity test			
	Jun*	Jul	Aug	Sep	Jun*	Jul	Aug	Sep
Arizona PS	—	3	7	2	—	—	—	—
BANC	—	3	—	1	—	—	—	—
California ISO	3	2	—	2	—	—	—	—
Idaho Power	—	13	21	3	—	—	—	—
LADWP	—	—	—	—	—	—	—	—
NorthWestern	2	9	9	—	—	—	—	—
NV Energy	2	9	6	5	—	—	—	—
PacifiCorp East	7	8	4	4	—	—	—	—
PacifiCorp West	4	6	2	2	—	—	—	—
Portland GE	17	19	25	34	—	—	—	—
Powerex	1	1	—	2	3	1	—	2
PSC New Mexico	—	1	—	2	—	—	—	—
Puget Sound En	7	8	10	8	—	—	—	—
Salt River Proj.	5	34	15	27	—	—	—	—
Seattle City Light	—	—	1	3	—	—	—	1
Turlock ID	—	—	9	10	4	—	1	2

*June 16-30, 2021 (implementation of uncertainty in the capacity test)

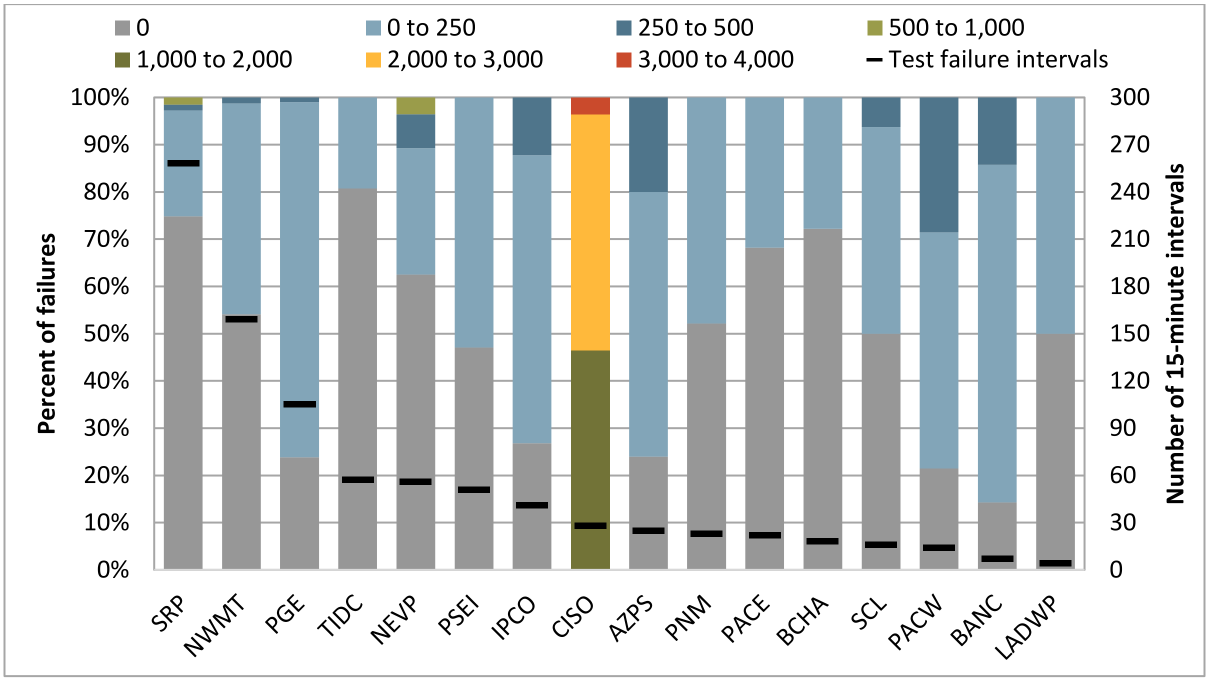
Transfer consequences for failing the bid range capacity or flexible ramping sufficiency tests

This section summarizes current consequences of failing the bid range capacity or flexible ramping sufficiency tests in terms of the import limit that is imposed when a balancing area fails either of these tests in the upward direction. When either test fails in the upward direction, imports will be capped at the greater of the base transfer or the optimal transfer from the last 15-minute market interval.

As a change from the previous report, Figure 2.15 summarizes *incremental* EIM import limits above base transfers (fixed bilateral transactions between EIM entities) after failing either test during the quarter. From this perspective, the incremental EIM import limit after a test failure is set by the greater of (1) zero or (2) the transfer from the last 15-minute market interval minus the current base transfer. The incremental EIM import limit therefore shows the incremental flexibility that is available through the energy imbalance market 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 quantity ranges.[51]

[51] 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.

Figure 2.15 Upward capacity/sufficiency test failure intervals by *incremental* import limit amount (July – September 2021)

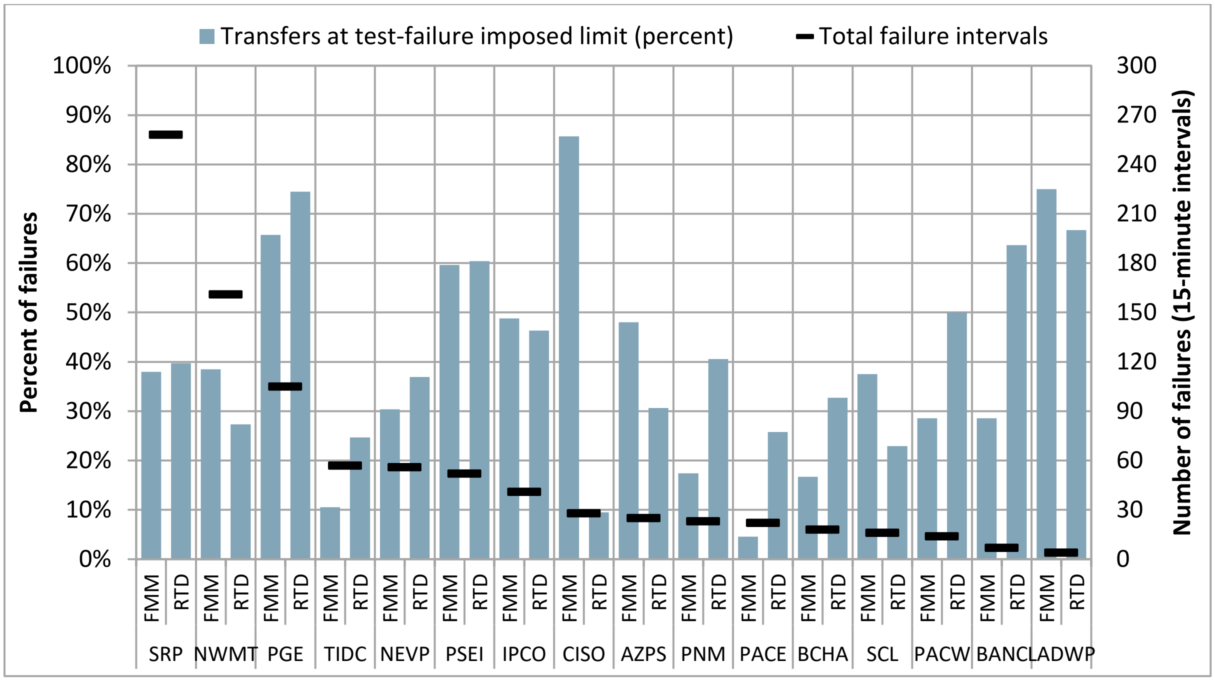


*Since joining the energy imbalance market in the spring of 2021

Figure 2.16 summarizes whether the import limit that was imposed after failing either test in the upward direction ultimately impacted market transfers. It shows the percent of failure intervals in which the resulting transfers are constrained to the limit imposed after failing the test during the quarter. These results are separated between energy imbalance market transfers in the 15-minute and 5-minute markets.

In the California ISO balancing area, 86 percent of 15-minute market transfers during failure intervals were affected by the test failure but only 10 percent of 5-minute market transfers. This is in part because of systematically higher imbalance conformance adjustments entered by ISO operators in the 15-minute market relative to the 5-minute market. Here, the optimal transfer in the last 15-minute interval prior to the test increases as the optimization solves for load plus imbalance conformance, potentially setting a higher import limit than would exist absent imbalance conformance. The limit enforced in both the 15-minute and 5-minute markets is set by the last optimal 15-minute transfer prior to the failed test.

Figure 2.16 Percent of upward test failure intervals with market transfers at the imposed cap (July – September 2021)



The ISO and stakeholders should reassess the need for applying the balancing test to any EIM balancing area

DMM recommends that the ISO and stakeholders reassess whether or not the balancing test and over- and under-scheduling penalties are appropriate elements of the resource sufficiency test framework. Based on policy developed in the EIM Foundation stakeholder initiative, the purpose of the resource sufficiency tests appears to be to serve two purposes: (1) to prevent one EIM balancing area from leaning on others for capacity, and (2) to notify EIM entities if base schedules are overloading flow-based constraints.[52]

Well-designed flexible ramping sufficiency tests and bid range capacity tests may be sufficient for identifying if one area is leaning on other areas for capacity. It is not clear to DMM that there is additional value added in assessing whether or not an EIM area's base generation schedule is close to its load forecast.

Furthermore, over- and under-scheduling penalties may be more appropriate additional consequences of failing the flexible ramping sufficiency or bid range capacity tests, rather than a consequence of base schedules not being close to load forecasts.

Therefore, DMM recommends that the ISO and stakeholders clarify what the intended purpose of the balancing test is and consider eliminating this test for all EIM areas before designing other potential changes to the balancing test.

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[52] See Section 3.3.6 of *Energy Imbalance Market Draft Final Proposal*, California ISO, September 23, 2013, pp. 37-39: http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf

Special monthly reports

As part of the EIM resource sufficiency evaluation stakeholder initiative, DMM is providing additional transparency surrounding test accuracy and performance in regular reports specific to this topic. DMM will provide ongoing reporting and data on the EIM tests before and after changes adopted through this stakeholder process. DMM has developed numerous metrics and has also begun to develop additional metrics and analysis to assess the potential impact and implications of the changes being proposed.

Both the latest reports and data underlying most metrics are available on DMM's website.[53] DMM is seeking feedback from stakeholders on existing or additional metrics and analysis that would be most valuable. Please communicate any suggestions either through comments in the ISO's EIM resource sufficiency evaluation stakeholder initiative or directly to DMM.[54]

2.3 Western EIM transfers

Western EIM transfer limits

One of the key benefits of the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Table 2.1 shows average 15-minute market limits between each of the areas between July 1 and September 30.[55] 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.

Table 2.1 Average 15-minute market energy imbalance market limits (July 1 – September 30)

	To Balancing Authority Area																*Total*
From Balancing Authority Area	CISO	BANC	TIDC	LADWP	NEVP	AZPS	SRP	PNM	PACE	IPCO	NWMT	PACW	PGE	PSEI	SCL	PWRX	*export limit*
California ISO		3,360	1,190	5,790	3,480	1,180	1,340					0	20	0		250	16,610
BANC	3,370		650														4,020
Turlock Irrig. District	1,200	780															1,980
LADWP	8,240				1,780	360			210								10,590
NV Energy	3,960			1,280		240			940	530							6,950
Arizona Public Service	2,700			510	310		7,160	1,090	820								12,590
Salt River Project	2,570					5,010		10	0								7,590
PSC New Mexico						960	0										960
PacifiCorp East				240	660	610	0			1,110	410	260					3,290
Idaho Power					630				1,970		210	300		80	30		3,220
NorthWestern Energy									320	150		0	0	0			470
PacifiCorp West	120								590	350	60		330	150	0		1,600
Portland GE	90										60	330		0	0		480
Puget Sound Energy	0									0	20	100	0		370	60	550
Seattle City Light										30		0	0	350			380
Powerex	0													220			220
Total import limit	22,250	4,140	1,840	7,820	6,860	8,360	8,500	1,100	4,850	2,170	760	990	350	800	400	310	

53 Department of Market Monitoring website: http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx

54 Please submit comments within the stakeholder process when the opportunity is available here: https://stakeholdercenter.caiso.com/StakeholderInitiatives/EIM-resource-sufficiency-evaluation-enhancements. If unable to do so, please submit comments to DMM directly via email to dmm@caiso.com.

55 The blank cells indicate that the pair of areas have no energy transfer system resource (ETSR) defined between them. A cell with zero MW indicates that there is an ETSR defined between the pair of areas, but the limit was zero on average during the quarter.

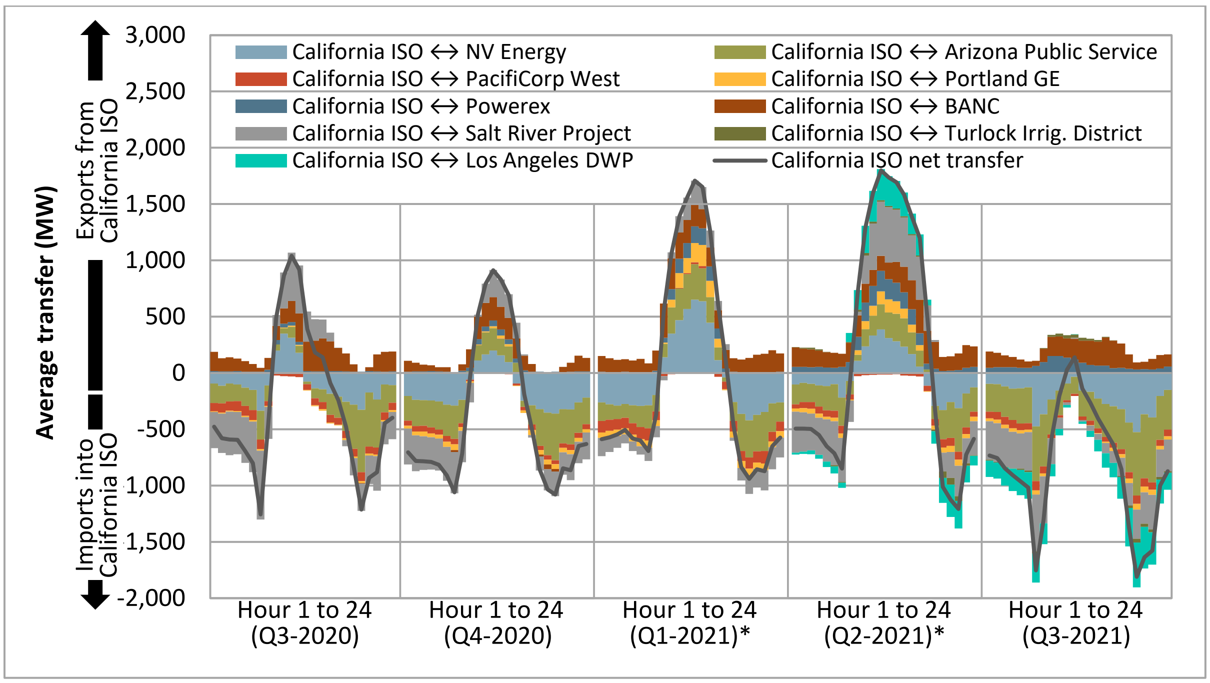
Hourly energy imbalance market transfers

As highlighted in this section, transfers in the EIM are marked by distinct daily and seasonable patterns, which reflect differences in regional supply conditions and transfer limitations.

Figure 2.17 compares average hourly imports (negative values) and exports (positive values) between the ISO and other EIM areas during the last five quarters in the 15-minute market.[56] The bars show the average hourly transfers with the connecting areas. The grey line shows the average hourly net transfer.

The California ISO was a net importer, on average, in all but one hour of the quarter, even during the peak mid-day solar generation hours when, in earlier quarters, lower priced solar generation was typically exported to the rest of the system. Net imports decreased in several areas in the southwest (both APS and SRP) and in both PacifiCorp East and West.

Figure 2.17 California ISO - average hourly 15-minute market transfer



*See footnote 56

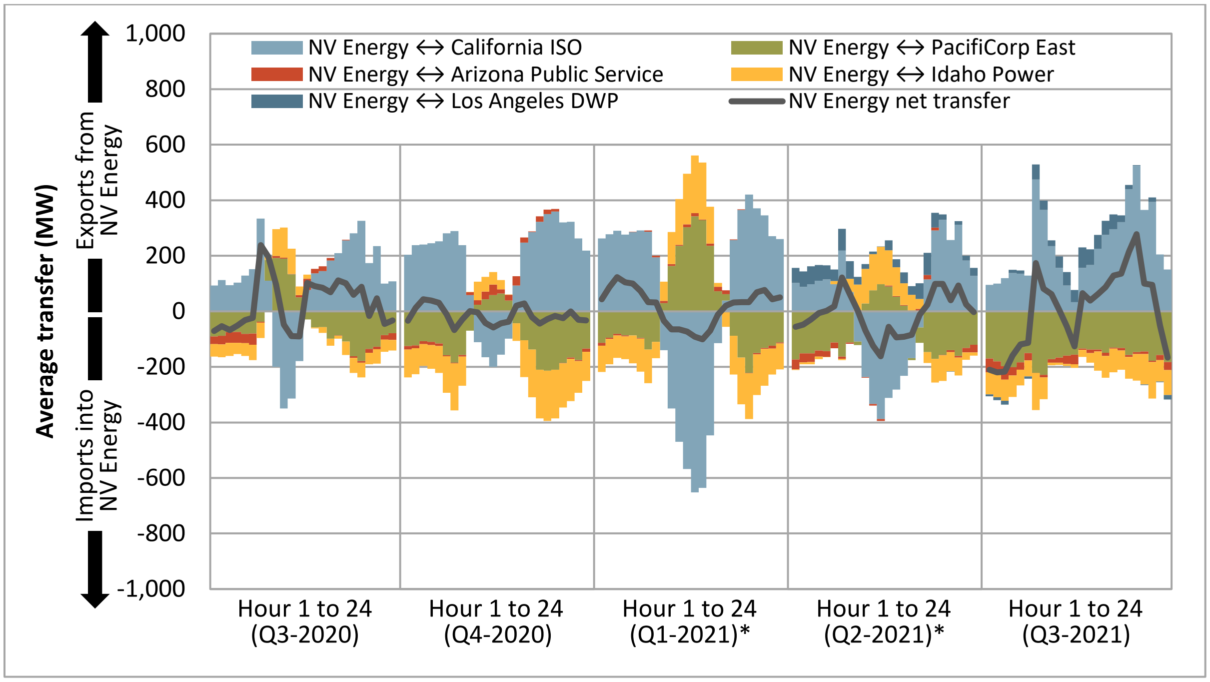
Figure 2.18 through Figure 2.28 show the same quarterly information on imports and exports for the other energy imbalance market areas in the 15-minute market.[57] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[58]

56 Average transfers for the first quarter of 2021 include only January 1 to March 24, and therefore do not include transfers following the addition of the Balancing Area of Northern California (phase 2) and Turlock Irrigation District on March 25. Transfers from March 25 to March 31 are included in the second quarter average.

57 Figures showing transfer information from the perspective of Los Angeles Department of Water and Power, Turlock Irrigation District, Public Service Company of New Mexico, and NorthWestern Energy are not explicitly included, but are depicted in the other figures.

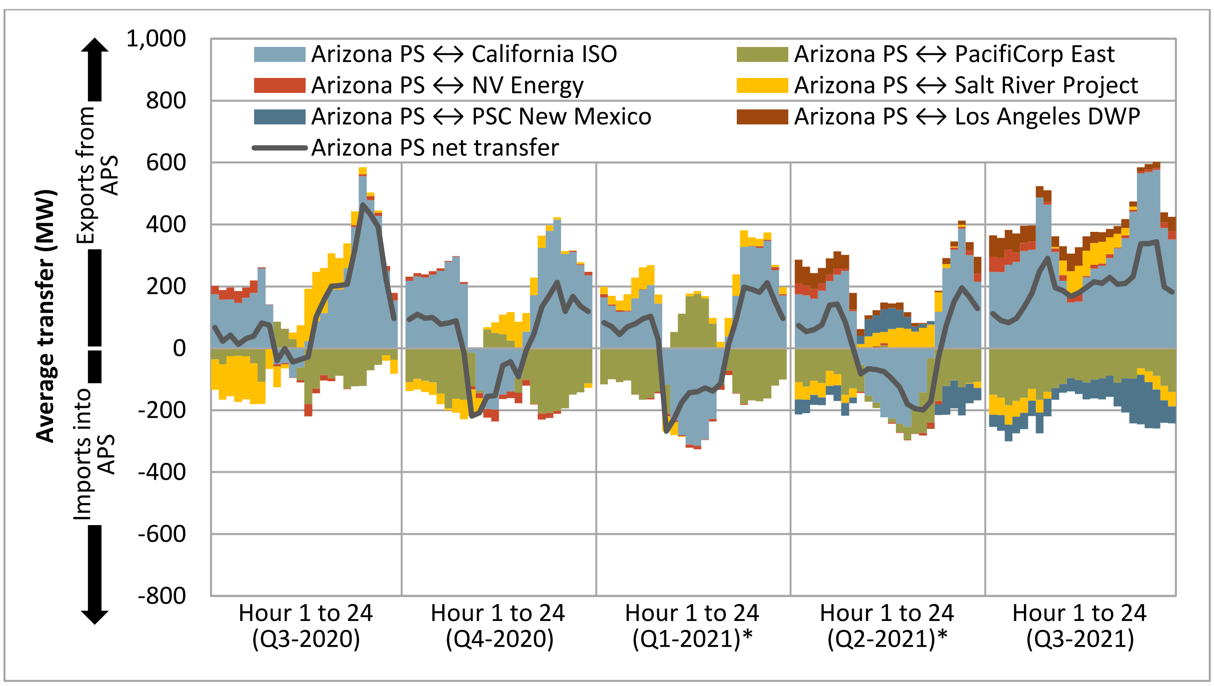
58 Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

Figure 2.18 NV Energy – average hourly 15-minute market transfer



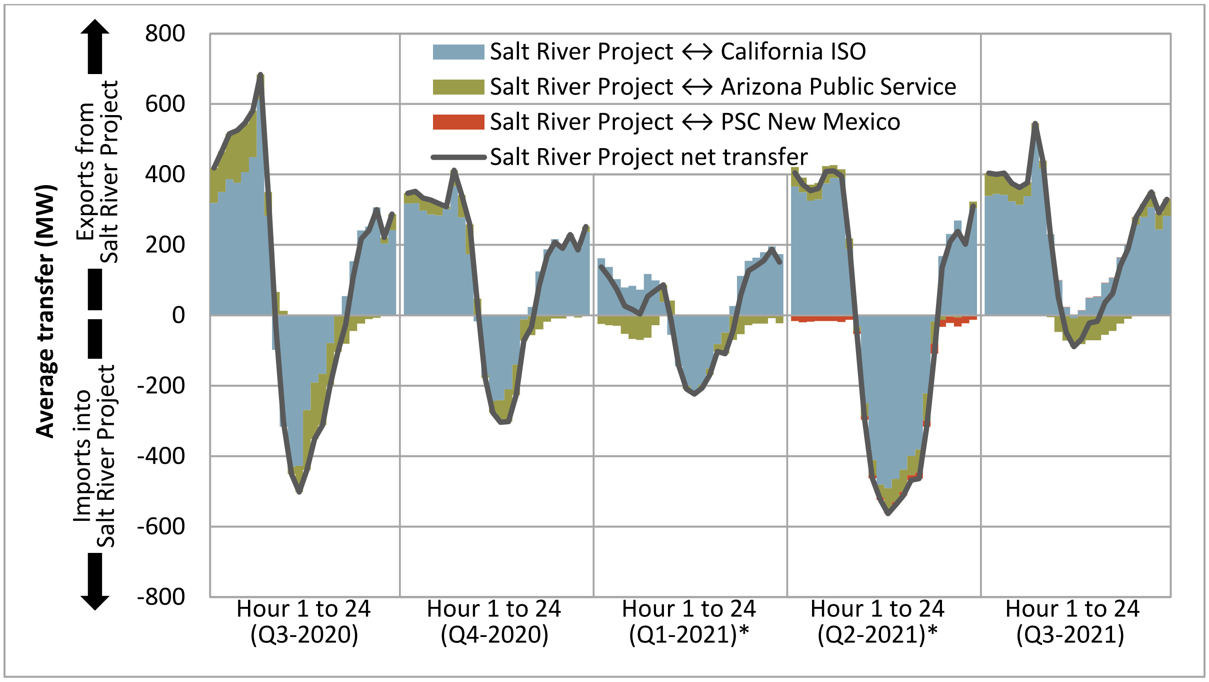
*See footnote 56

Figure 2.19 Arizona Public Service – average hourly 15-minute market transfer



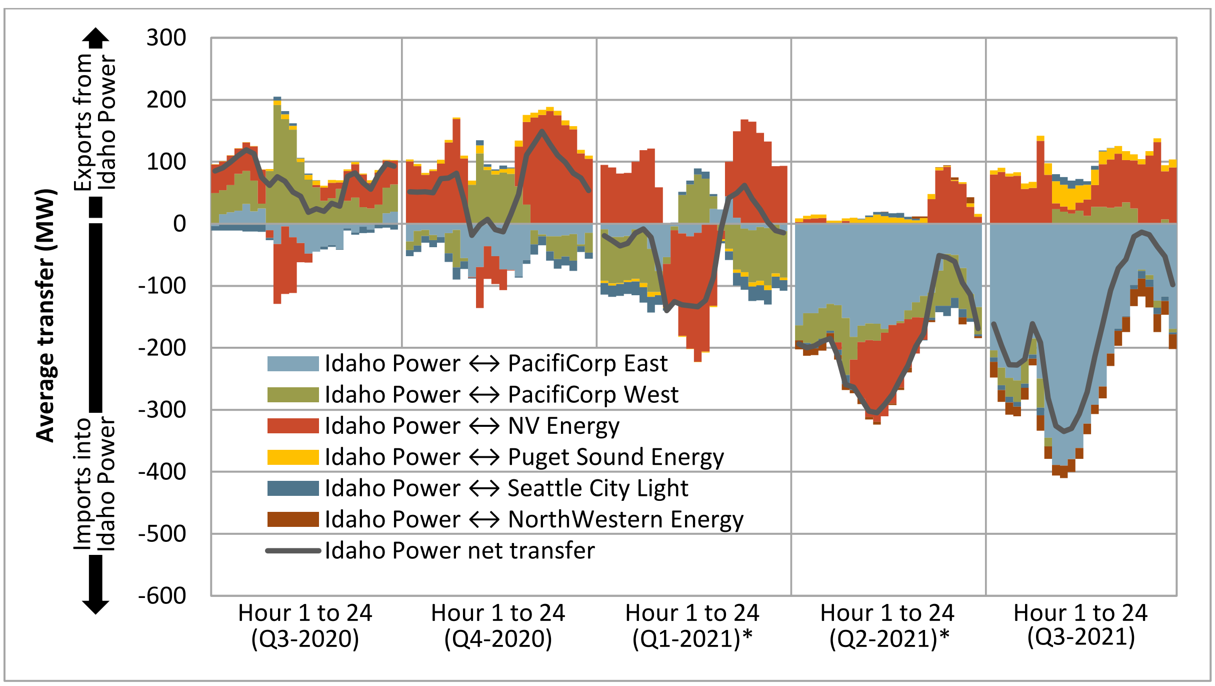
*See footnote 56

Figure 2.20 Salt River Project – average hourly 15-minute market transfer



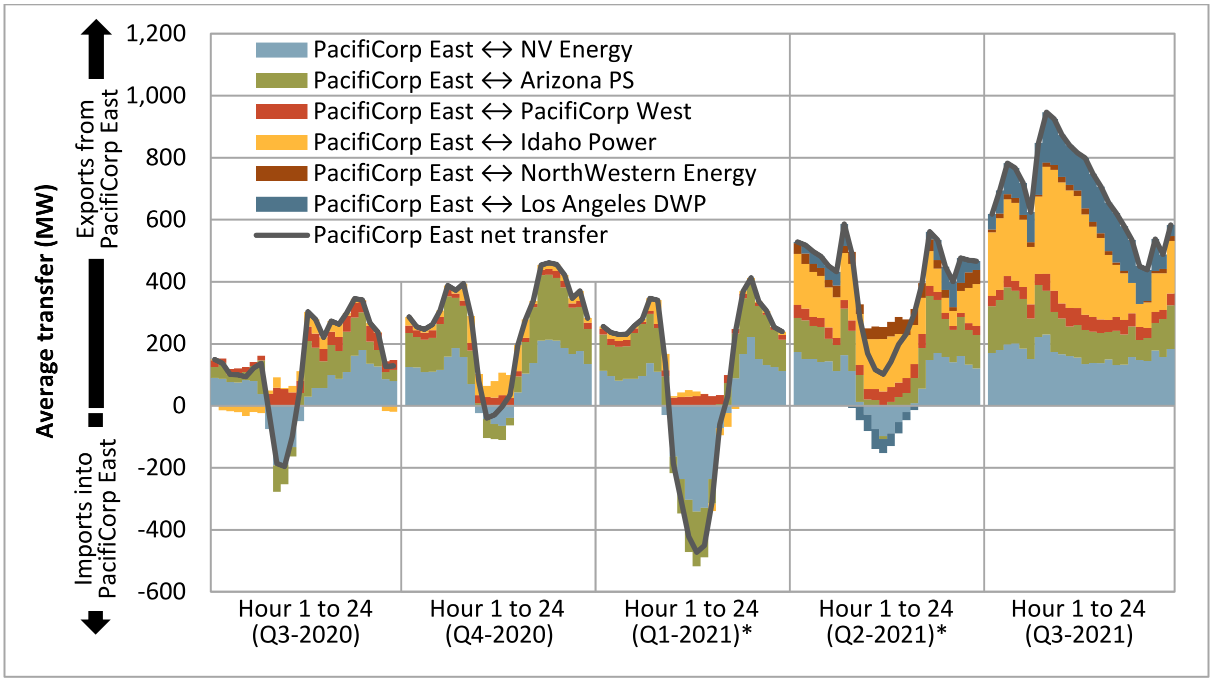
*See footnote 56

Figure 2.21 Idaho Power – average hourly 15-minute market transfer



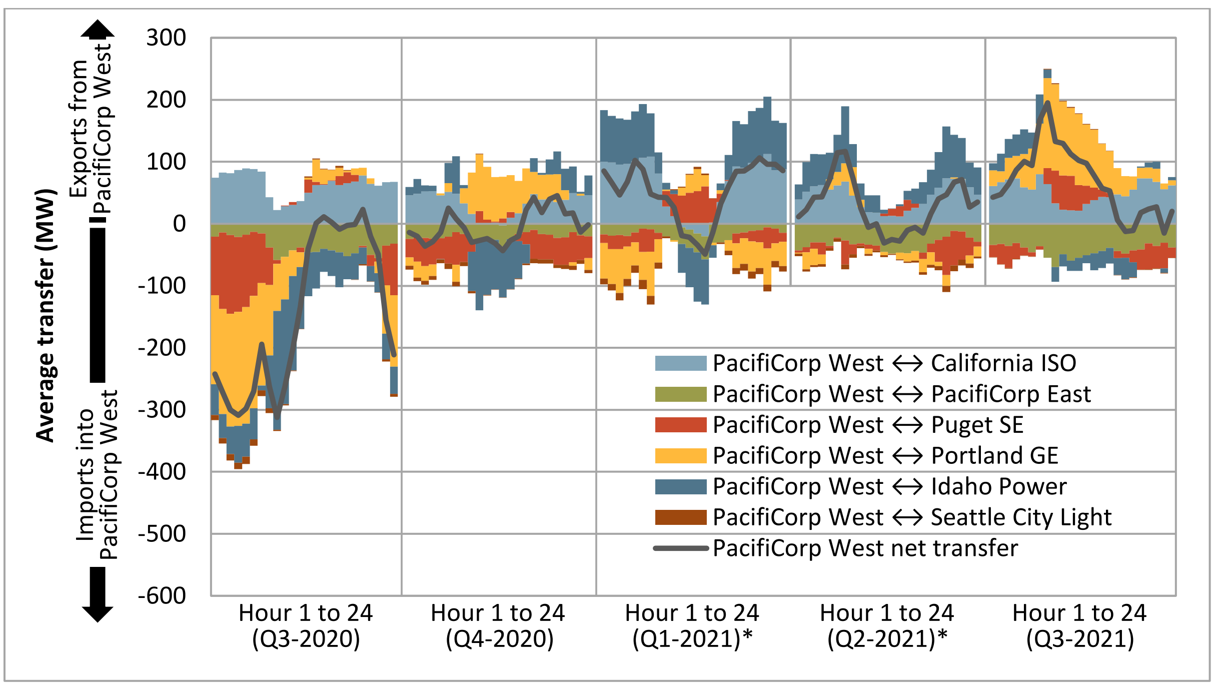
*See footnote 56

Figure 2.22 PacifiCorp East – average hourly 15-minute market transfer



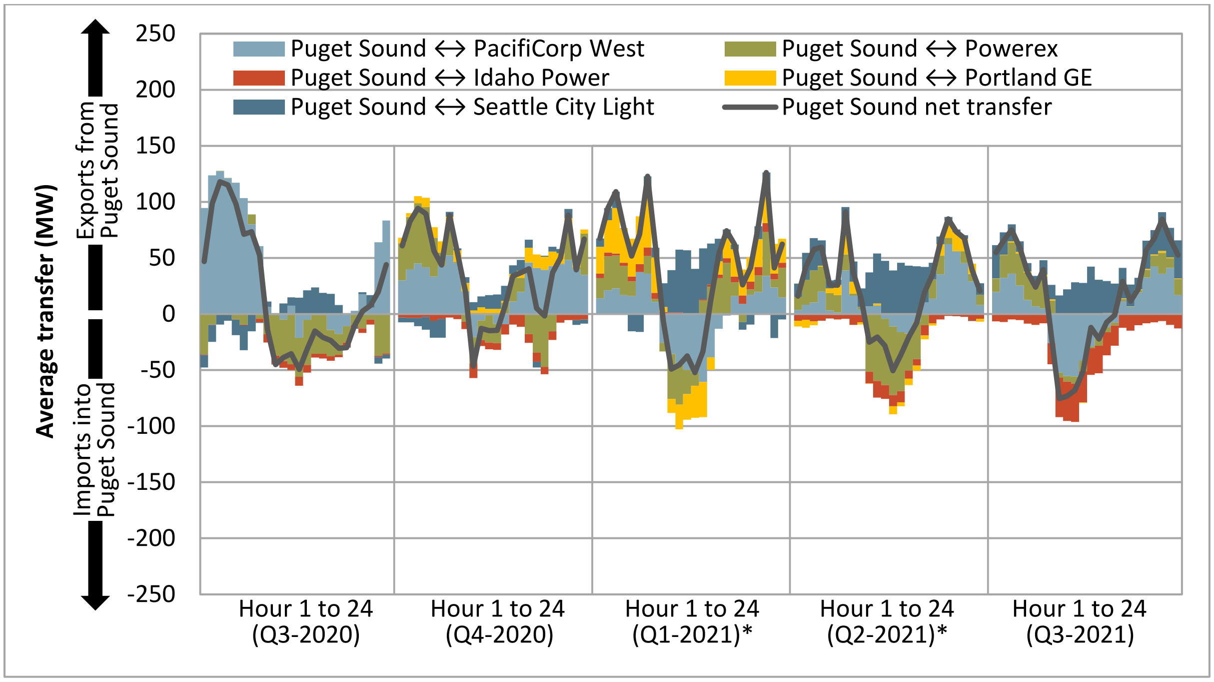
*See footnote 56

Figure 2.23 PacifiCorp West – average hourly 15-minute market transfer



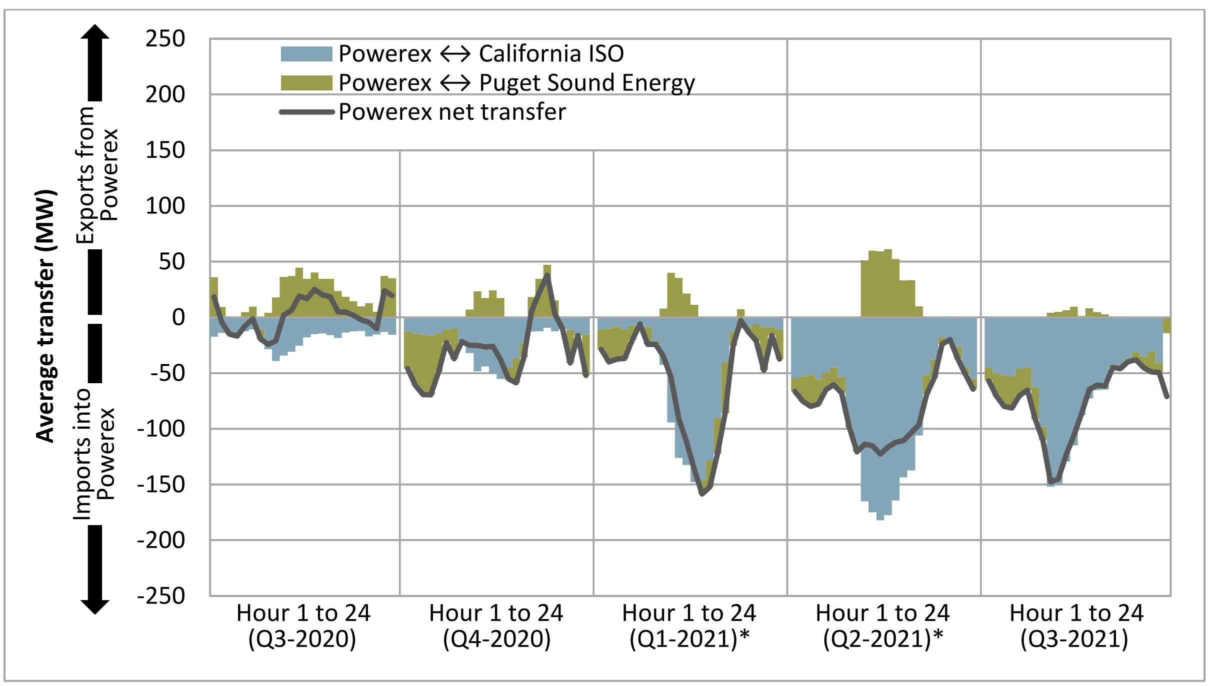
*See footnote 56

Figure 2.24 Puget Sound Energy – average hourly 15-minute market transfer



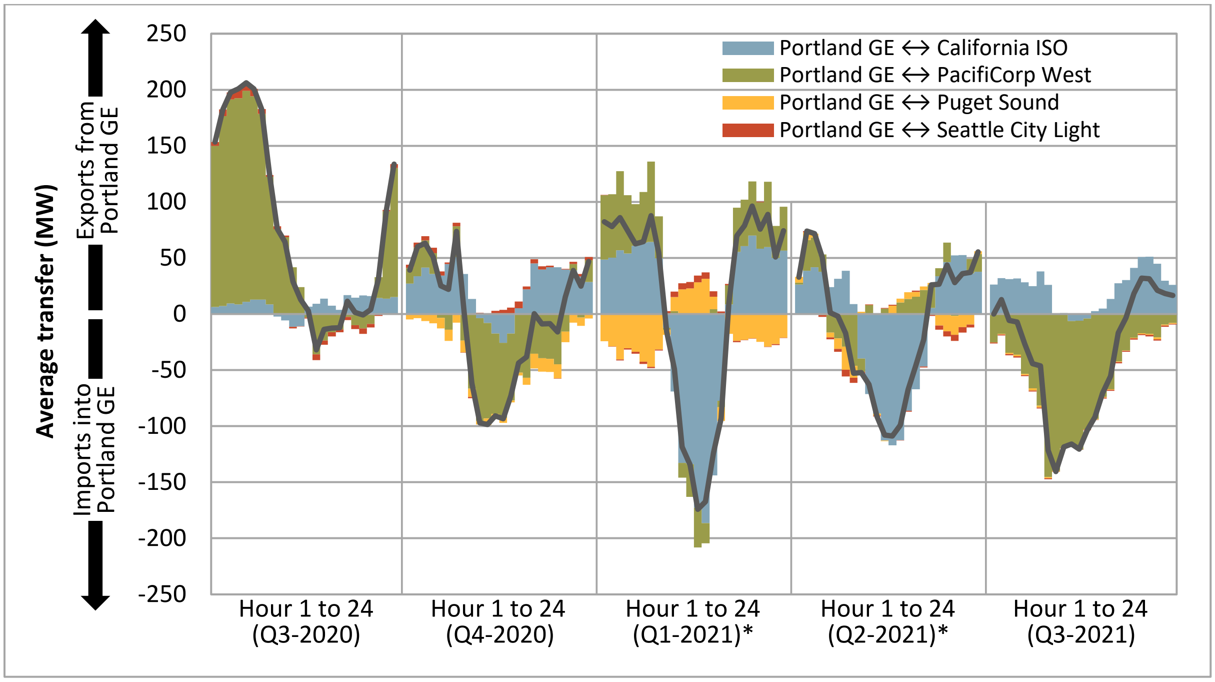
*See footnote 56

Figure 2.25 Powerex – average hourly 15-minute market transfer



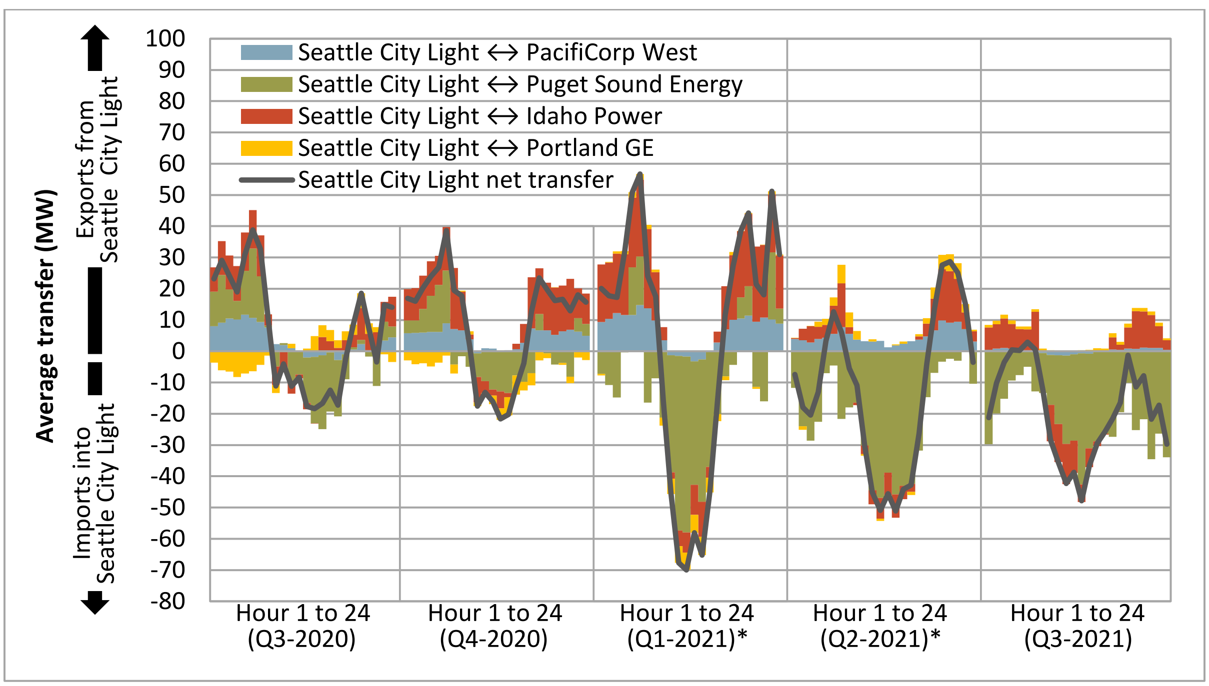
*See footnote 56

Figure 2.26 Portland General Electric – average hourly 15-minute market transfer



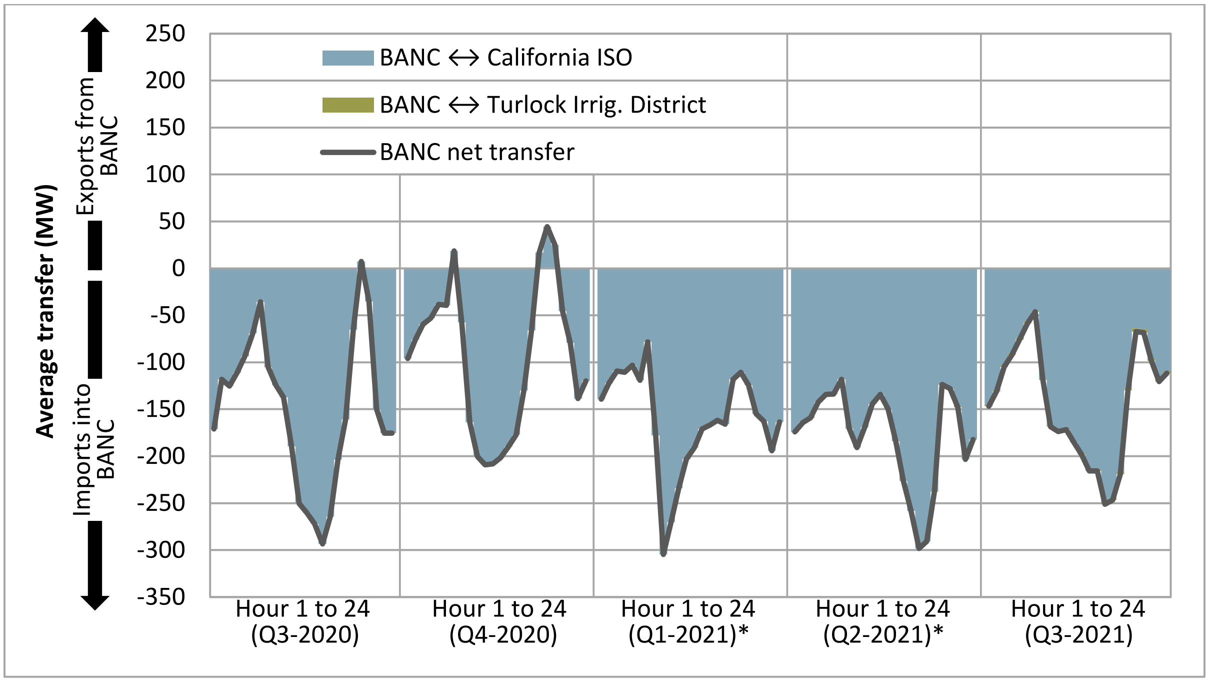
*See footnote 56

Figure 2.27 Seattle City Light – average hourly 15-minute market transfer



*See footnote 56

Figure 2.28 Balancing Authority of Northern California - average hourly 15-minute market transfer



*See footnote 56

Inter-balancing area congestion

Congestion between an energy imbalance market 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 energy imbalance market area, the market software triggers local market power mitigation for resources in that area.[59]

Table 2.2 shows the percent of 15-minute and 5-minute market intervals with congestion on transfer constraints into or out of an energy imbalance market 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.[60] When prices are lower relative to the system, this indicates congestion out of an area and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for energy outside of an area to serve that area's load. Chapter 1 focused on the impact of congestion to EIM prices, whereas this section describes the same information in terms of the impact to import or export capability and the potential for market power mitigation.

59 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 ISO or other competitive markets. The ISO area is not subject to market power mitigation under these conditions.

60 Greenhouse gas prices can contribute to lower energy imbalance market prices relative to those inside the ISO. The current methodology uses the energy imbalance market greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only.

Table 2.2 Frequency of congestion in the energy imbalance market (July – September)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
L.A. Dept. of Water and Power	0%	0%	0%	0%
Turlock Irrigation District	1%	0%	0%	0%
Arizona Public Service	1%	0%	1%	1%
NV Energy	2%	1%	2%	1%
Public Service Company of NM	4%	0%	4%	1%
PacifiCorp East	10%	0%	9%	1%
Idaho Power	7%	3%	6%	4%
Salt River Project	11%	3%	11%	4%
NorthWestern Energy	16%	11%	15%	7%
PacifiCorp West	23%	14%	17%	11%
Portland General Electric	23%	20%	17%	14%
Seattle City Light	36%	11%	37%	11%
Powerex	32%	6%	41%	16%
Puget Sound Energy	36%	11%	37%	11%

The highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas toward the larger energy imbalance market system. This congestion in the 15-minute market from PacifiCorp West, Portland General Electric, Seattle City Light, Powerex, and Puget Sound Energy occurred during 30 percent of intervals on average during the quarter. This is lower than the same quarter of 2020 when congestion from these areas occurred during an average of 41 percent of intervals.

The highest frequency of net import congestion (such that the ISO market software triggers local market power mitigation in that area) occurred in the Portland General Electric area, during 20 percent of 15-minute market intervals and 14 percent of 5-minute market intervals during the third quarter.

Congestion in either direction for BANC, Los Angeles Department of Water and Power, Turlock Irrigation District, Arizona Public Service, and NV Energy was relatively infrequent during the quarter. Congestion that did occur for these areas was often the result of a failed upward or downward sufficiency test, which limited transfer capability.

2.4 Imbalance conformance in the Western EIM

Frequency and size of imbalance conformance

NorthWestern Energy had the highest frequency of positive imbalance conformance during the third quarter. While Public Service of New Mexico infrequently used positive or negative imbalance conformance, its average megawatt biased was the highest average percent of its total load.

Table 2.3 Average frequency and size of imbalance conformance (July – September)

	Positive imbalance conformance			Negative imbalance conformance			Average hourly adjustment MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	36%	925	2.8%	1.8%	-304	1.1%	329
5-minute market	33%	248	0.8%	38%	-227	0.8%	-5
BANC							
15-minute market	1.0%	43	1.6%	0.4%	-41	2.0%	0
5-minute market	2.4%	42	1.5%	0.6%	-43	2.2%	1
Los Angeles Dept. of Water and Power							
15-minute market	8.0%	68	2.0%	0.6%	-62	1.9%	5
5-minute market	34%	60	1.9%	4.4%	-54	1.7%	18
Turlock Irrigation District							
15-minute market	0.0%	21	4.7%	0.0%	N/A	N/A	0
5-minute market	0.1%	17	3.6%	0.0%	-25	7.3%	0
Northwestern Energy							
15-minute market	61%	14	1.1%	2.4%	-16	1.3%	8
5-minute market	65%	16	1.3%	2.4%	-25	2.0%	10
NV Energy							
15-minute market	1.5%	78	1.3%	0.1%	-80	1.0%	1
5-minute market	8.4%	93	1.3%	8.3%	-98	1.9%	0
Arizona Public Service							
15-minute market	2.2%	81	1.5%	7.6%	-71	1.6%	-4
5-minute market	15%	83	1.6%	55%	-76	1.8%	-29
Salt River Project							
15-minute market	0.0%	40	0.7%	0.3%	-85	2.1%	0
5-minute market	4.6%	62	1.2%	8.0%	-67	1.6%	-3
Idaho Power							
15-minute market	7.1%	50	1.9%	1.2%	-46	1.9%	3
5-minute market	17%	49	1.9%	4.8%	-51	2.0%	6
Public Service Company of New Mexico							
15-minute market	0.0%	75	3.6%	0.5%	-94	6.1%	0
5-minute market	1.2%	88	4.7%	1.6%	-122	7.8%	-1
PacifiCorp East							
15-minute market	0.2%	67	1.1%	0.1%	-374	6.6%	0
5-minute market	20%	119	1.9%	23%	-120	2.0%	-4
PacifiCorp West							
15-minute market	0.0%	N/A	N/A	0.0%	N/A	N/A	0
5-minute market	2.8%	57	2.5%	19%	-53	2.1%	-9
Portland General Electric							
15-minute market	0.0%	N/A	N/A	0.0%	N/A	N/A	0
5-minute market	14%	25	1.0%	1.6%	-34	1.4%	3
Seattle City Light							
15-minute market	0.2%	31	3.1%	10%	-20	2.3%	-2
5-minute market	1.7%	26	2.8%	66%	-23	2.5%	-15
Puget Sound Energy							
15-minute market	0.3%	26	0.7%	19%	-40	1.7%	-8
5-minute market	1.9%	29	0.9%	47%	-37	1.5%	-17

Table 2.3 summarizes the average frequency and size of positive and negative imbalance conformance entered by operators in the EIM for the 15-minute and 5-minute markets during the quarter.[61,62] The same data for the ISO balancing area is provided as a point of reference. In particular, NorthWestern Energy entered positive imbalance conformance in around 61 and 65 percent of 15-minute and 5-minute intervals, respectively, at an average of 15 MW. Seattle City Light entered negative imbalance conformance in around 10 and 66 percent of 15-minute and 5-minute intervals, respectively, at an average of 22 MW. Nearly all EIM entities had a greater frequency of 5-minute market imbalance conformance than 15-minute market during the quarter.

2.5 Mitigation in the EIM

In the third quarter of 2021, average incremental energy that was subject to mitigation increased significantly in the 15-minute and 5-minute markets, compared to the same quarter in 2020. Figure 2.29 and Figure 2.30 highlight the volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the EIM outside the ISO:

- Blue bars in Figure 2.29 and Figure 2.30 show average incremental energy subject to mitigation but whose bids were not lowered in the 15-minute and 5-minute markets, respectively. In the third quarter of 2021, on average, this portion increased by about 700 MW when compared to the same quarter in 2020.
- Volume of bids that were lowered as a result of mitigation (shown by red bars) more than doubled in the Western EIM when compared to the same quarter in 2020.

61 Imbalance conformance is sometimes referred to as *load bias* or *load adjustments*. The ISO uses the term *imbalance conformance* to describe this process.

62 Through recent revisions, load bias has been removed from the total load used in the calculation of the percentage of total load. The effect of this update is minimal, but means that the percentage of total load increased for positive imbalance conformance figures and decreased for negative imbalance conformance figures.

Figure 2.29 Average incremental energy mitigated in 15-minute real-time market (EIM)

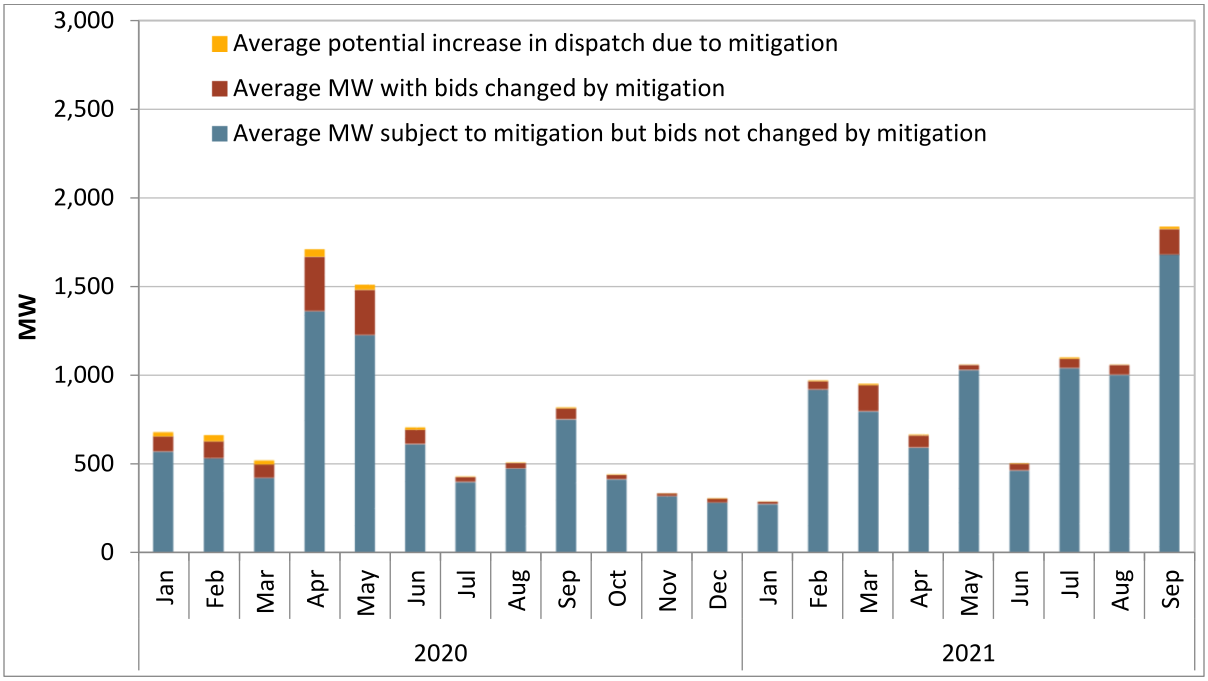
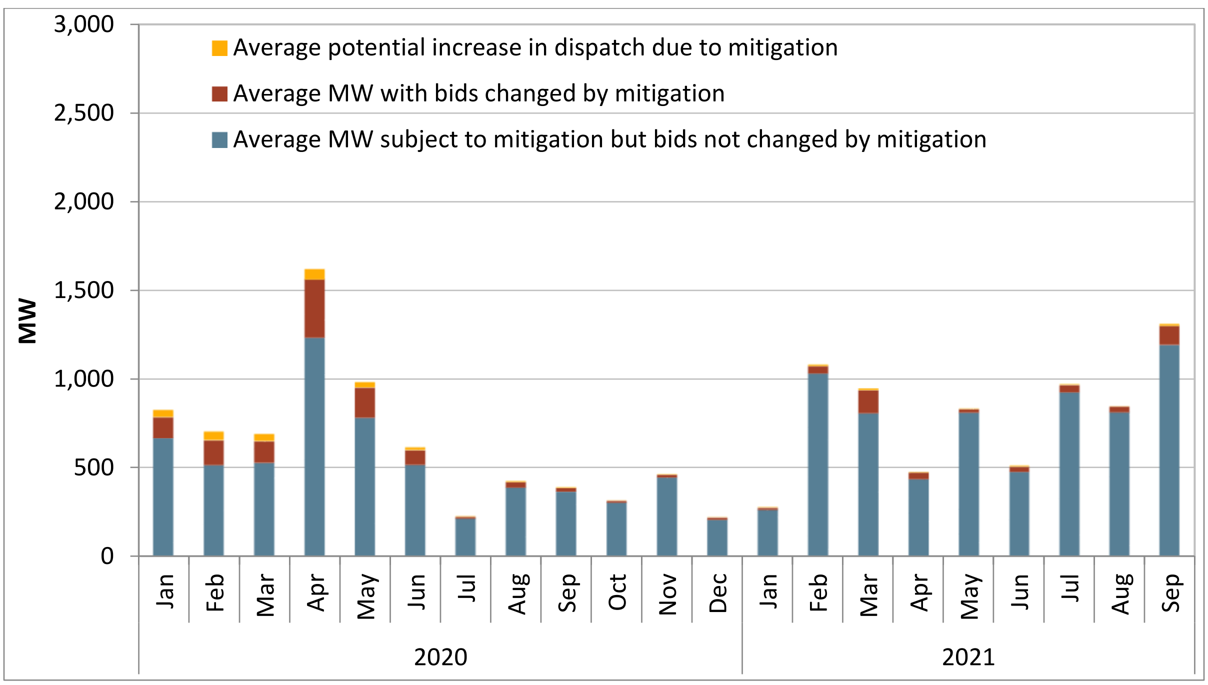


Figure 2.30 Average incremental energy mitigated in 5-minute real-time market (EIM)



3 Special issues

This section provides information about the following special issues:

- **The ISO implemented several market enhancements** designed to address concerns raised following the load curtailment event of August 2020.
- **As a result of changes made last year to the ISO's process for setting export scheduling priorities, significant volumes of exports clearing the day-ahead market were curtailed through the residual unit commitment process on the highest load days**. On these days, some exports rebid into the real-time market cleared, ultimately meeting high demand in other regions.
- **Under August 4 tariff changes, exports clearing both the day-ahead market and residual unit commitment process can be curtailed before internal load in the real-time market**. Exports are now required to demonstrate support from non-resource adequacy capacity to have equal priority with native load if curtailment is necessary. Thus far, no curtailment has been necessary.
- **Under August 4 tariff changes, wheeling transactions** are required to register 45 days in advance of the month and must demonstrate both a firm power supply contract to serve the load of an external load serving entity and monthly firm transmission to the CAISO border to qualify for prioritization equal to or above native load. Thus far, no curtailment has been necessary.
- **High priority wheels were not scheduled in the market on most days**, although over 1,000 MW of high priority wheels registered in August and over 680 MW registered in September. The maximum scheduled on any day in the quarter was less than 350 MW.
- **The volume of wheeled energy increased significantly,** compared to the summer of 2020. The highest volumes were observed in June and were mostly north-to-south source-to-sink combinations, representing power from balancing areas in the Northwest being wheeled through the ISO to balancing areas in the Southwest.
- **In the real-time market, less than 90 percent of system resource adequacy capacity was bid or self-scheduled during high load hours**. During the top 200 load hours of the year, 90 percent of system resource adequacy capacity was offered in the day-ahead market and 88 percent was offered in the real-time market.
- **Non-resource-specific imports** accounted for about 3,500 MW of resource adequacy capacity during peak hours of 2021, down from over 4,500 MW in 2020.
- **Over half of resource adequacy capacity was classified as use-limited** during peak load hours. Although 87 percent of this capacity was bid into the real-time market on high load days, performance of some use-limited fuel types was lower: storage (86%), solar (71%), wind (77%), non-utility demand response (42%), and hydroelectric (83%). In most cases, performance rose to above 100% for these groups once accounting for non-resource adequacy capacity from these resource types: storage (111%), solar (147%), wind (140%), and hydroelectric (88%).
- **Intra-monthly capacity procurement mechanism (CPM) designations cost about $9.7 million, up from $2.1 million in 2020**. Intra-monthly significant event designations were issued in July, August, and September to ensure reliability following extreme heat events in the early part of the summer.

3.1 Market changes implemented in Q3

The California ISO implemented several market enhancements in response to analysis of market performance during the heat wave of summer 2020 which included two load curtailment events on August 14 and August 15, 2020. These changes address concerns raised in the joint agency final root cause analysis report[63] and in a DMM report on system and market conditions.[64]

The ISO initiated stakeholder processes at the end of 2020 to identify market enhancements which address these inefficient market operations and ensure grid reliability for summer 2021. These enhancements were developed under the Market Enhancements for Summer Readiness and Resource Adequacy Enhancements stakeholder processes and were implemented before or during the summer of 2021. The enhancements are listed below along with the associated tariff amendment where applicable:[65]

- Enhance interconnection process (tariff ER21-1536);
- Improve import market incentives during tight system conditions (tariff ER21-1536);
- Enhance real-time scarcity pricing (tariff ER21-1536);
- Add uncertainty to EIM resource capacity test (tariff ER21-1536);
- Improve management of storage resources during tight system conditions (tariff ER21-1551);
- Require substitution for resource adequacy capacity on planned outage (tariff ER21-1551);
- Publish intertie schedules on OASIS;
- Change priorities of load, export, and wheel through transactions (tariff ER21-1790);
- Enhance reliability demand response dispatch (tariff ER21-1536); and
- Add displays in Today's Outlook for projected conditions.

Table 3.1 includes a list and timeline of the enhancements along with a brief summary and whether the feature is triggered under special circumstances or is a standing feature of market operation. As seen in Table 3.1, many of these enhancements are triggered during tight system conditions or system

63 *Final Root Cause Analysis of Mid-August 2020 Extreme Heat Wave*, January 13, 2021: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

64 *DMM Report on System and Market Conditions, August and September 2020*, November 24, 2020: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

65 *Tariff Amendment to Implement Summer 2021 Market Enhancements*, ER21-1536, March 26, 2021: http://www.caiso.com/Documents/Mar26-2021-Tariff-Amendment-2021SummerReadiness-ER21-1536.pdf

Tariff Amendment to Implement the Resource Adequacy Enhancements Phase 1 Initiative – Summer 2021 Provisions, ER21-1551, March 29, 2021: http://www.caiso.com/Documents/Mar29-2021-Tariff-Amendment-ResourceAdequacyRAEnhancements-ER21-1551.pdf

Tariff Amendment to Implement Market Enhancements for Summer 2021 – Load, Export, and Wheeling Priorities, ER21-1790, April 28, 2021: http://www.caiso.com/Documents/Apr28-2021-Tariff-Amendment-Load-Exports-and-Wheeling-Tariff-Amendment-ER21-1790.pdf emergencies. lists the days in the third quarter where some of these enhancements were triggered and describes the outcome in the market.

Table 3.1 Summary of summer 2021 market enhancements

Enhancement	Implementation date	Summary	Standing or triggered feature
Interconnection process enhancements	May 25, 2021	Remove cap on behind-the-meter expansions and award interim deliverability on temporary basis	Standing feature
Import market incentives during tight system conditions	June 15, 2021	Provide make-whole payments for hourly intertie block schedules issued through HASP[66]	Triggered during tight system conditions[67]
Real-time scarcity pricing enhancements	June 15, 2021	Price all operating reserves at energy bid cap when dispatched to provide energy in a system emergency[68]	Triggered during stage 2 emergencies
Add uncertainty to EIM resource capacity test	June 15, 2021	Add uncertainty requirement to EIM resource sufficiency evaluation	Standing feature
Management of storage resources during tight system conditions	June 30, 2021	Minimum state of charge (MSOC) requirement[69]	Triggered when RUC identifies shortfalls
Substitution for capacity on planned outage	June 30, 2021	Requires scheduling coordinators for all resource adequacy resource to provide substitute capacity to be approved for planned outages	Standing feature
Publication of intertie schedules information on OASIS	July 26, 2021	Provide additional information on OASIS	Standing feature
Load, export, and wheeling priorities	August 4, 2021	Defines high-priority and low-priority self-schedule wheels and establishes new priority ranking for load, exports, and wheels	Standing feature (but sunsets after May 31, 2022)
Reliability demand response dispatch and real-time price impacts	August 4, 2021	Expands functionality to dispatch RDRR resources in FMM, adds expected RDRR load drop back into real-time load forecasts	Triggered by activation of RDRR
New displays in Today's outlook for projected conditions	August 17, 2021	Daily resource adequacy capacity trends for current day and upcoming 7 days	Standing feature

66 Imports that are scheduled in the hour-ahead scheduling process but settled at 15-minute prices will be provided make-whole payments during tight conditions if the 15-minute price is lower than the hour-ahead price.

67 Summer Readiness Training Part 2, Slide 9: http://www.caiso.com/InitiativeDocuments/Presentation-Summer-2021-Readiness-Training-Part-2-Apr-29-2021.pdf

68 Previously in a system emergency, contingency-only reserves were released at bid cap but non-contingency-only reserves were released at the resource's bid which could be lower than the current market price.

Table 3.2 Outcome of market enhancements during Q3[70]

Market enhancement	Days triggered	Outcome
Enhanced real-time pricing signals	July 9	Reserves were released at bid cap ($1,000/MWh)[71]
Import market incentives	July 9, 10	Moderate payments were made to a handful of resources using the settlement charge code associated with these uplift payments
Minimum state of charge requirements	July 9, 28, 29	Impact on dispatches was small since most resources were at or above their MSOC

3.2 Exports and wheels

As noted in DMM's report on the August 2020 load curtailment event, a contributing factor was the large volume of exports clearing the day-ahead market.[72] Those exports were passed into the real-time market with a higher scheduling priority than internal load, and were therefore not curtailed during the hours when the ISO curtailed internal load. The ISO implemented changes to export priorities on an expedited basis in early September 2020, and implemented additional changes on August 4, 2021, to address some of the concerns raised following the load curtailment events of August 2020.

September 2020 changes

As a result of changes made in September 2020 to the ISO's process for setting export scheduling priorities, significant volumes of exports clearing the day ahead market in 2021 were curtailed through the residual unit commitment process on most of the highest load days of June and July. As shown in Figure 3.1, on some high load days more than 2.5 GW of exports cleared in the day-ahead market were cut in the residual unit commitment process.

69 This may require resources to be forced to charge in order to meet their minimum state of charge. If storage resources are required to charge at a price higher than their bid price they will qualify for bid cost recovery payments.

70 Section 2.2 includes a discussion of the results of adding uncertainty to the EIM resource sufficiency test. Section 3.2 reviews the results of implementing the load, export, and wheeling priorities tariff amendment.

71 In this hour the energy bid cap was set at the soft bid cap of $1,000/MWh.

72 *DMM Report on System and Market Conditions, August and September 2020*, November 24, 2020: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Figure 3.1 Cleared day-ahead exports in peak hours on high load days

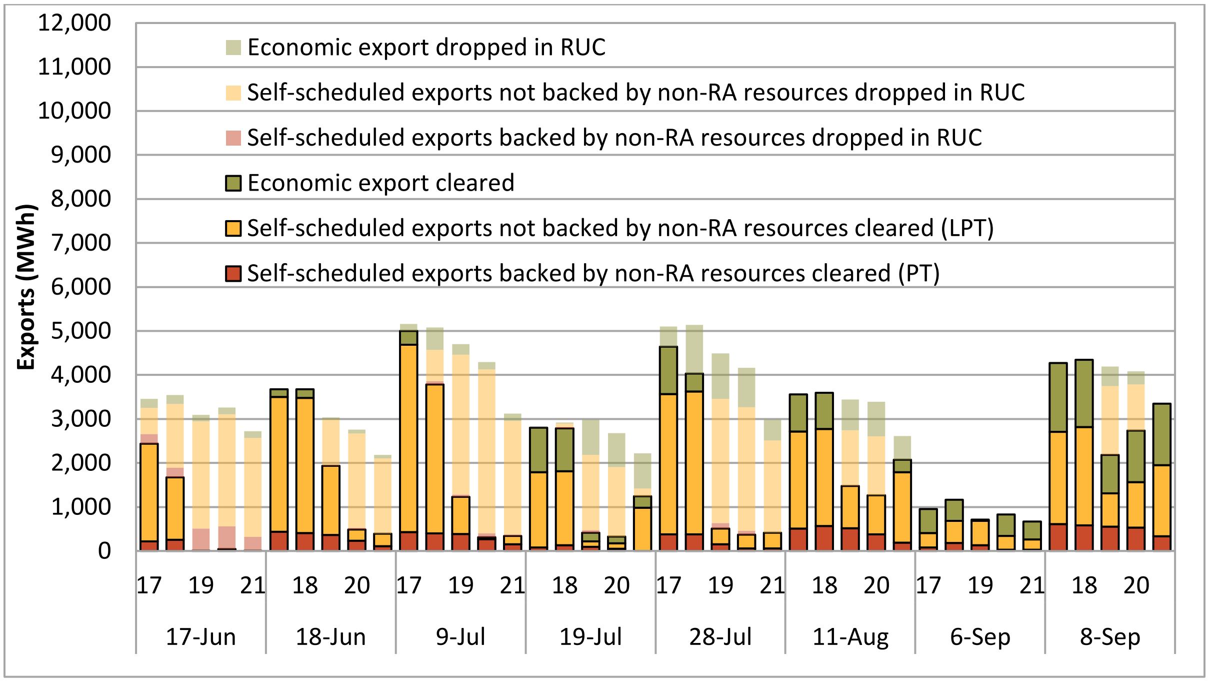
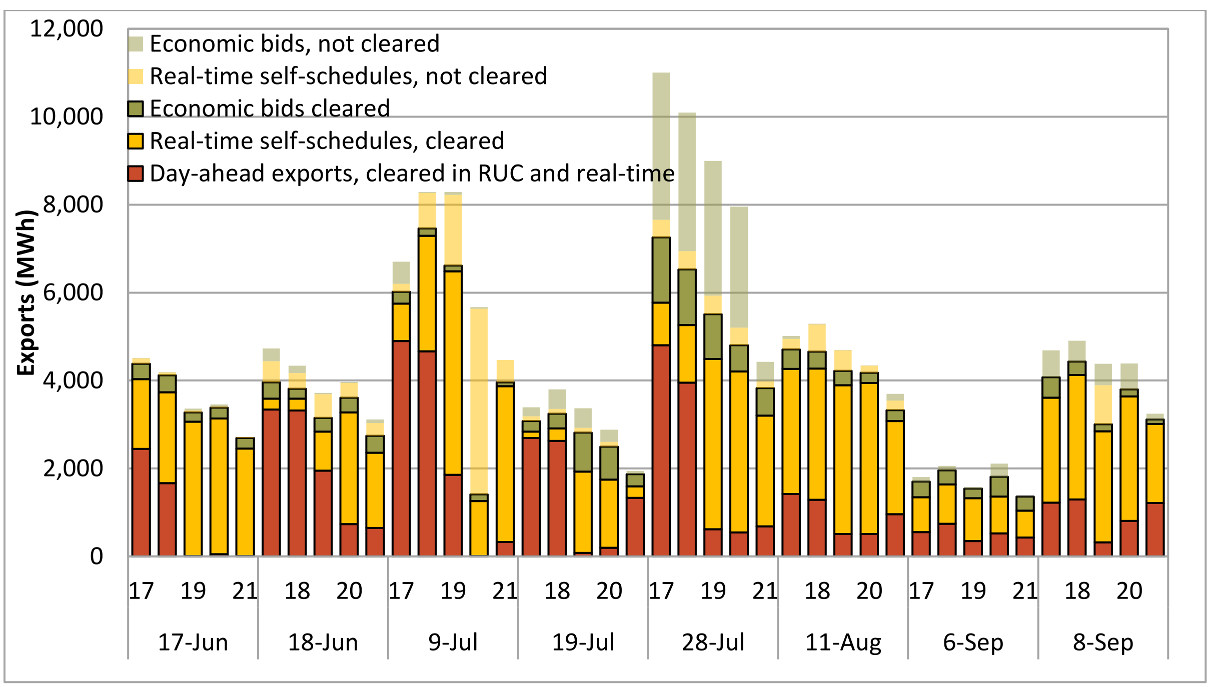


Figure 3.2 Real-time export bids in peak hours on high load days



Exports that clear the day-ahead process are automatically scheduled in the real-time market with a relatively high scheduling priority, while exports that do not clear the residual unit commitment process are not. Some day-ahead market exports that did not clear the residual unit commitment process were rebid into the real-time market and cleared, ultimately meeting high demand in other regions.

As shown in Figure 3.2, real-time exports on these days included exports with day-ahead priority, as well as lower priority self-schedules and economic bids entered in the real-time market.

By limiting the quantity of exports entering the real-time market with a scheduling priority above native load to the quantity feasible in the residual unit commitment process, market rule changes implemented in September 2020 more effectively positioned the ISO's market to reliably meet both native load and day-ahead high priority export demand in the real-time market in the summer of 2021.

August 2021 changes

To further address this issue, the ISO implemented tariff changes in August 2021 clarifying scheduling priorities of ISO load, self-scheduled exports, and self-scheduled wheel-through transactions. Under the load, export, and wheeling priorities tariff amendment, a scheduling coordinator self-scheduling an export into the ISO market shall designate it as either a low- or high-priority export.[73] High-priority price taking (PT) exports are those supported by non-resource adequacy capacity, while low-priority price taking (LPT) exports are not.[74]

Under the August 2021 tariff changes, all low-priority exports that clear the residual unit commitment process will be prioritized below internal load.[75] In addition, the ISO will now prioritize exports that bid into the day-ahead market and clear the residual unit commitment process over new exports that self-schedule into the real-time market. The goal of this is to incentivize bidders to procure resources in the day-ahead timeframe to allow the market to set more reliable schedules. Several new measures were also implemented to better ensure high-priority exports are supported by non-resource-adequacy capacity.[76]

The tariff changes also established two categories of self-scheduled wheel-through transactions. The ISO now designates high-priority (PT) and low-priority (LPT) self-scheduled wheels. High-priority wheels are required to register with the ISO ahead of time and must be supported by a firm power supply contract to serve the load of an external load serving entity, as well as monthly firm transmission to the California ISO balancing area border. High-priority wheels will have priority equal to or above ISO native load[77] while low-priority wheels will have priority below native load.

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73 Tariff amendment: http://www.caiso.com/Documents/Apr28-2021-Tariff-Amendment-Load-Exports-and-Wheeling-Tariff-Amendment-ER21-1790.pdf

74 http://www.caiso.com/Documents/Section34-Real-TimeMarket-asof-Aug4-2021.pdf, page 25.

75 Previously all exports that cleared the residual unit commitment process would be self-scheduled into the real-time with a priority above load.

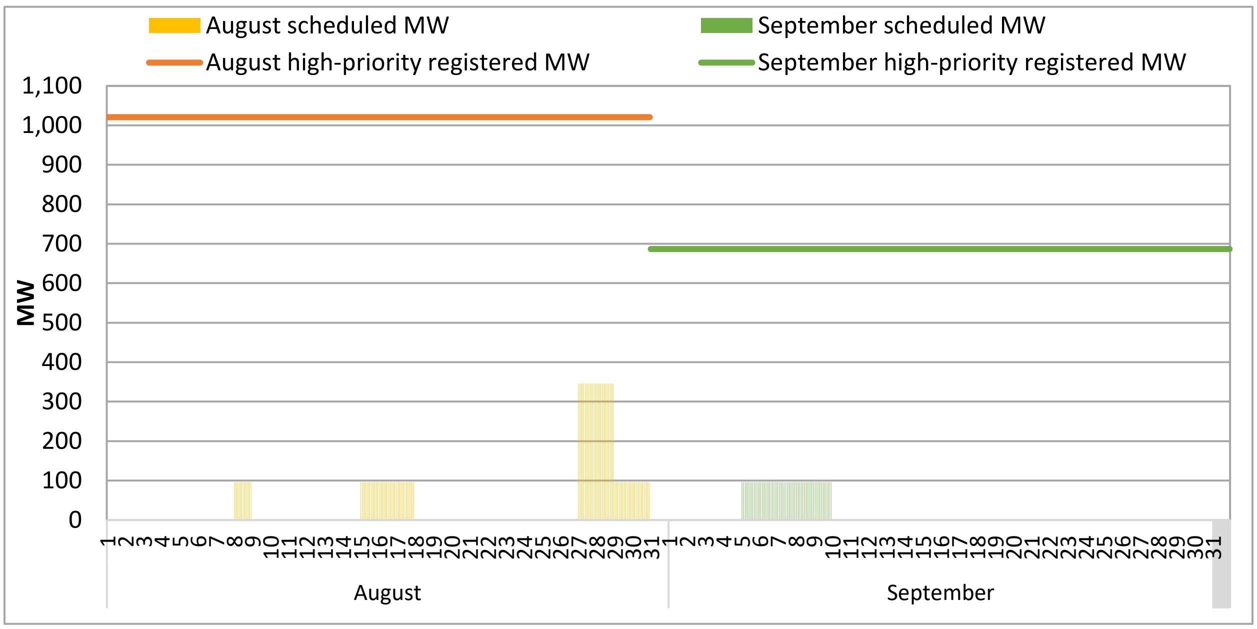
76 Tariff Amendment: http://www.caiso.com/Documents/Apr28-2021-Tariff-Amendment-Load-Exports-and-Wheeling-Tariff-Amendment-ER21-1790.pdf, page 5. DMM noted several instances in which high-priority exports were not supported by non-resource adequacy capacity. The ISO has resolved some of these issues with market software fixes. Other refinements necessary to ensure that the non-resource adequacy capacity supporting a high-priority export is available in real-time may be addressed in the ISO's External Load Forward Scheduling Rights initiative.

77 Due to the additive nature of penalty prices, the combined penalty price for the import and export wheel of a high-priority wheel exceeds that of California ISO balancing area native load; however, the combined penalty price of self-scheduled imports and ISO native load is equal to that of a high-priority wheel. This implies that ISO load served by self-scheduled imports has equal priority to a high-priority wheel, but ISO load served by other types of supply will have priority below a high-priority wheel.

The load, export, and wheeling priorities revisions were implemented on August 4, 2021.[78] High-priority wheels are required to register monthly and 45 days before each month except for August, the first applicable month, when they were able to register until June 29. Figure 3.3 shows the total amount of high priority wheeling capacity registered in August and September, along with the portion of this capacity that was actually scheduled in the day-ahead market during the next peak hours of each day (7 to 22).

- In August, a total of 1,021 MW was registered as high-priority wheel-through transactions. However, this capacity was scheduled in the day-ahead market on only seven days. A total of 346 MW was scheduled on August 28 and 29, with about 96 MW per hour scheduled on five other days.
- In September, 687 MW of high-priority wheels were registered.[79,80] Only 96 MW of this capacity was scheduled in the net peak hours of the month.

Figure 3.3 High-priority wheels (HE07-HE22 between August 1 and September 31)



While these enhancements are an important incremental improvement, they represent an interim step. Additional refinements are needed for high-priority export rules, and a more robust, long-term process

78 http://www.caiso.com/Documents/Aug11-2021-InformationalFiling-EffectiveDate-Load-Export-Wheeling-ER21-1790.pdf

79 http://www.caiso.com/Documents/SummerMarketPerformanceReportforAug2021.pdf
http://www.caiso.com/Documents/SummerMarketPerformanceReport-Sep2021.pdf

80 The ISO has identified issues with the process of priority for registered wheels, http://www.caiso.com/Documents/Presentation-SummerMarketPerformanceReport-Aug2021-Oct6-2021.pdf, Slide 14
http://www.caiso.com/Documents/Presentation-Sep2021SummerMarketPerformanceReport-Nov3-2021.pdf, Slide 15

for transmission procurement by high-priority wheel-through transactions.[81] These efforts are currently underway in the ISO's External Load Forward Scheduling Rights stakeholder initiative.[82]

3.2.1 Wheel transactions

The volume of energy wheeled through the ISO balancing area increased considerably in the summer of 2021 compared to 2020. In 2020, a maximum of about 150 MW of wheeling transactions were scheduled in August and September, mainly importing on the Sylmar intertie and exporting on the PVWest intertie (which is a south-to-south combination). In 2021, maximum wheeling volumes totaled 1,200 MW in June followed by about 700 MW in August and September. Most of these schedules involved power from the northwest wheeling to balancing areas in the southwest.

Table 3.3 summarizes maximum hourly wheels cleared between June and September in the day-ahead market by source-to-sink combination.[83] The table also categorizes the source and sink wheeling paths as being in the north or south of the ISO system.[84] The highest maximum import volume over the entire period was the Nevada-Oregon Border (NOB) scheduling. The highest export volume scheduling point was at PVWest.

81 DMM comments on scheduling priorities enhancement: http://www.caiso.com/Documents/DMM-Comments-on-Summer-2021-Readiness-Final-Proposal-Apr-2-2021.pdf

82 Stakeholder initiative documents: https://stakeholdercenter.caiso.com/StakeholderInitiatives/External-load-forward-scheduling-rights-process

83 Wheeling transactions are defined by the terms described in Section 3.4.1 of the Market Instruments business practice manual. This definition is important as resource naming conventions for wheels containing '-W-' or '_WHL_' are not the sole determining factors for recognizing wheeling resource pairs in the Scheduling Infrastructure Business Rules (SIBR) application. In short, a wheel transaction must provide a counter resource that aligns the import and export in order for SIBR to recognize the transaction as a wheel, both in the day-ahead and real-time markets. This excludes transmission ownership rights (TOR) and existing transmission contract rights (ETC), as described in the Modeling - Scheduling ETC and TOR Rights operating procedure: https://www.caiso.com/Documents/3630.pdf.

84 Nevada-Oregon Border (NOB) is highlighted as it is the scheduling interface for the Pacific DC Intertie. This tie brings energy from the Pacific Northwest into California but is modelled as a southern scheduling point.

Table 3.3 Maximum hourly volume (MW) of wheels by path in June – September

Import			Export										
			South									North	*Total import*
			PVWest	McCullough500	Mead230	MDWP	ElDorado230	MIR2	Mead2MSCHD	Westwing500	NOB	Malin500	
Jun	North	Crag	79										**79**
		Malin500	167	133	10								**310**
		NOB	238	142	150	125							**655**
	South	Sylmar	122	122									**244**
		Mead230						89					**89**
		Total Export	***606***	***397***	***160***	***125***		***89***					***1,377***
Jul	North	Malin500	186		10		96			15			**307**
		Crag	79	79									**158**
		TrcyCOTP	117	8									**125**
		NOB	321	75	50	25				15			**486**
	South	PVWest									288	288	**576**
		Sylmar	38	122									**160**
		Total Export	***741***	***284***	***60***	***25***	***96***			***30***	***288***	***288***	***1,812***
Aug	North	Malin500	150	100			96						**346**
		NOB	100	75									**175**
	South	Sylmar		252	104								**356**
		MDWP	21										**21**
		Total Export	***271***	***427***	***104***		***96***						***898***
Sep	North	Malin500					96						**96**
	South	Sylmar	52										**52**
		Total Export	***52***				***96***						***148***

Figure 3.4 shows the directional flow of day-ahead wheels into and out of the ISO system. NP26 refers to Northern California or the region north of Path 26. Likewise, SP26 refers to Southern California for the region south of Path 26. Most wheels are imported into SP26 (which includes imports on NOB/Sylmar), with some imports coming into NP26. Almost all wheels are exported from SP26. Wheels were exported from NP26 on only one day during this time period.

Figure 3.5 provides a closer look at the individual intertie scheduling points in HE17-HE21 between June 1, 2021 and 31, 2021. In the early part of the summer imports were sourced primarily at Malin, NOB, and Sylmar and export sinks were primarily at PVWest and McCullough 500. A shift occurred in the latter part of summer to Malin and Sylmar for import scheduling points and McCullough 500 as the primary export scheduling point.

Figure 3.4 Regional source and sink of day-ahead wheels excluding TORs and ETCs (HE17-HE21 between June 1 and September 31)

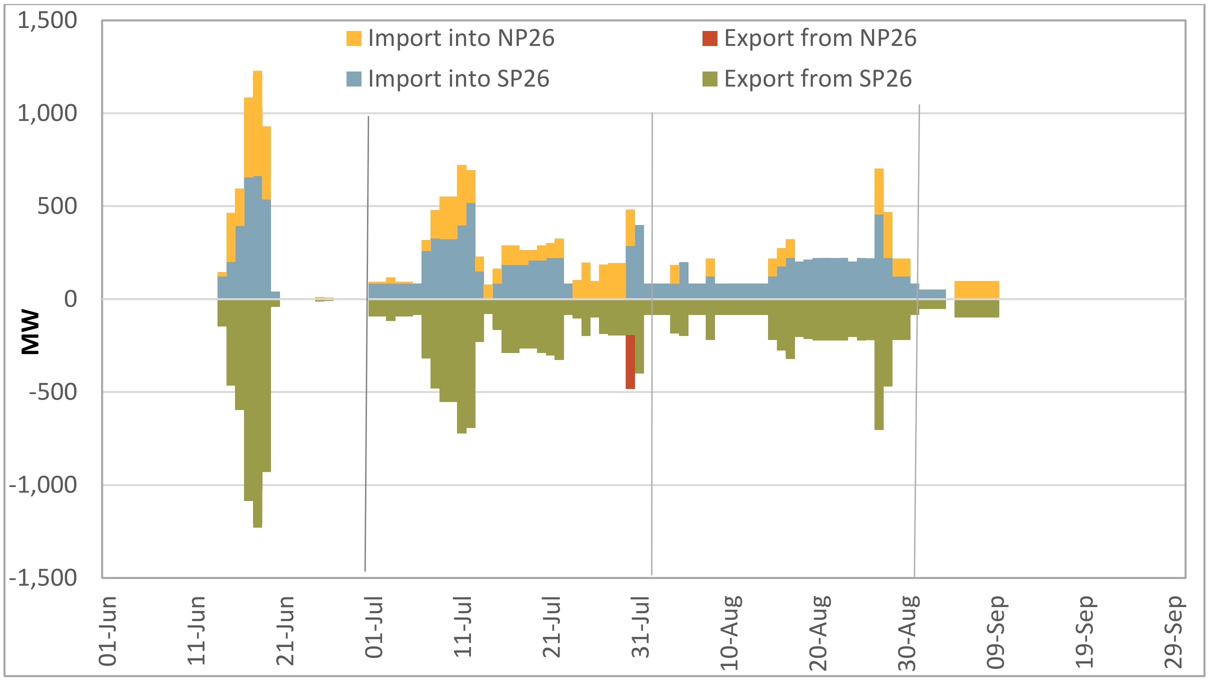
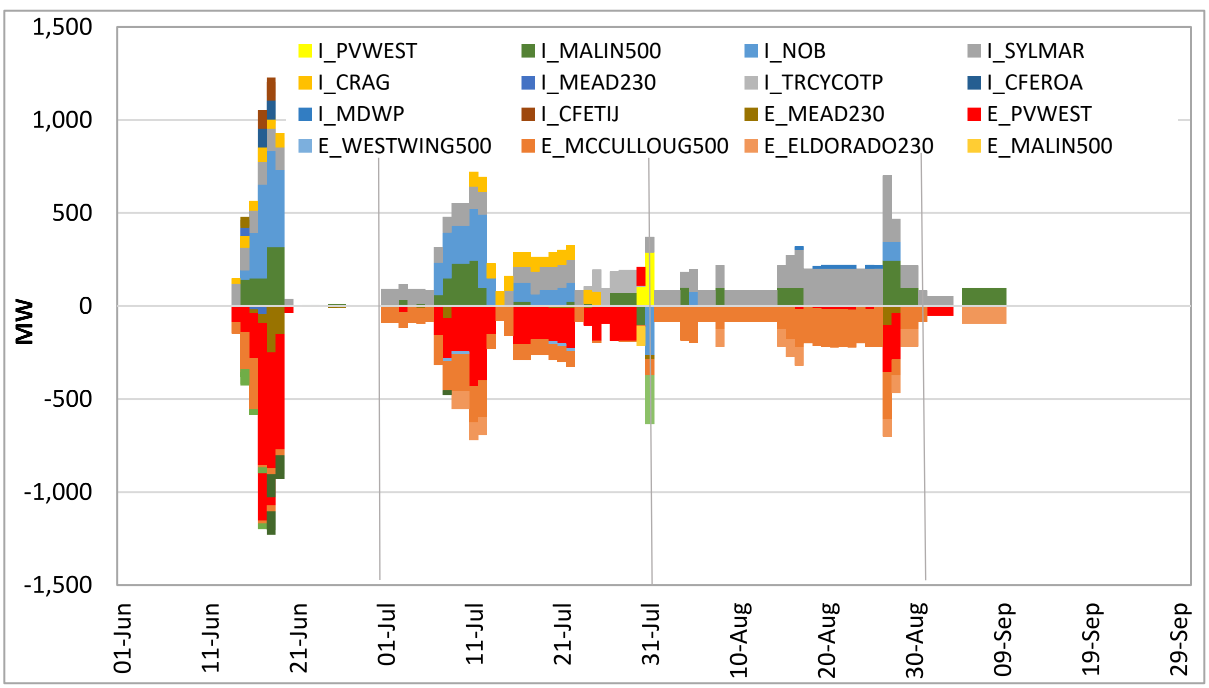


Figure 3.5 Source and sink of day-ahead wheels excluding TORs and ETCs (HE17-HE21 between June 1 and September 31)



3.3 Resource adequacy availability

System resource adequacy requirements are set based on system-level peak demand. The yearly peak demand in the ISO system typically occurs in the third quarter summer months.[85]

Table 3.4 lists the average hourly availability of resource adequacy capacity in the day-ahead and real-time markets during the top 200 load hours of the third quarter in 2021.[86] This table shows resource adequacy capacity bids compared to the amount of capacity that was shown towards their obligations, by resource type. Bids and self-schedule megawatt totals for the day-ahead and real-time markets are derived by adjusting the bids and self-schedules of individual resources for outages and de-rates, and aggregating by fuel type.[87]

The availability of resource adequacy units (in terms of bids submitted) remained relatively high and approximately equal to results for all resource types in 2020.[88] Results for 2020 are provided in Table 9.1 of DMM's 2020 annual report. In recent years, it has become equally – or more – important to assess resource adequacy availability during net peak load hours. In future reports, DMM will include analysis of resource adequacy availability during net peak load hours.

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85 The CPUC sets rules to ensure that use-limited resources are not overly relied upon. For instance, there is a cap on the maximum percentage of a portfolio that can come from resources with the most restricted availability – those that can be offered for a minimum of 200 hours from May until September each year. This requirement is based off of the Maximum Cumulative Capacity categories for non-demand response resources. The cumulative total of 200 hours is comprised of minimum monthly availability requirements of at least 40 hours per month, May through September, respectively. For more information, refer to the *2021 Filing guide for system, local, and flexible resource adequacy (RA) compliance filings*, CPUC, April 23, 2021: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442462872https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/final-2021-ra-guide_20210423.pdf

86 This analysis does not include capacity credited against resource adequacy obligations such as utility demand response capacity and reliability must-run capacity under legacy contracts.

87 Day-ahead market bids include energy bids and non-overlapping ancillary service bids; real-time market bids include energy bids only. To calculate hourly real-time bid amounts, bids from variable energy resources were averaged over the hour. Bids from non-variable energy resources reflect the maximum hourly bid in the hour-ahead, 15-minute, and 5-minute markets adjusted for de-rates, due to data issues. Bids are capped at the resource adequacy capacity values shown for individual resources to measure the availability of capacity that was secured in the planning timeframe. Bids are also capped according to individual resource outages and de-rates. While the analysis below includes available resource adequacy bids at the system level, congestion and operating constraints may prevent the market from actually utilizing all of the bid capacity in this analysis.

88 2020 annual report on market issues and performance: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf, pp, 246-249.

Table 3.4 Average system resource adequacy capacity and availability by fuel type (200 highest load hours)

Resource type	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
Must-Offer:									
Gas-fired generators	19,388	17,751	92%	17,750	92%	17,417	90%	17,386	90%
Other generators	1,415	1,324	94%	1,324	94%	1,312	93%	1,311	93%
Subtotal	**20,803**	**19,075**	**92%**	**19,074**	**92%**	**18,729**	**90%**	**18,697**	**90%**
Other:									
Imports	3,185	3,091	97%	3,041	95%	3,159	99%	2,886	91%
Imports - MSS	293	293	100%	236	81%	293	100%	240	82%
Use-limited gas units	8,581	8,264	96%	8,212	96%	8,249	96%	8,189	95%
Hydro generators	5,889	5,244	89%	4,901	83%	5,201	88%	4,870	83%
Nuclear generators	2,893	2,887	100%	2,868	99%	2,874	99%	2,856	99%
Solar generators	3,786	3,767	99%	2,702	71%	3,724	98%	2,697	71%
Wind generators	1,310	1,306	100%	964	74%	1,304	100%	1,013	77%
Qualifying facilities	881	859	98%	822	93%	846	96%	804	91%
Demand response	261	261	100%	188	72%	259	99%	109	42%
Storage	1,166	1,071	92%	1,048	90%	1,057	91%	998	86%
Other non-dispatchable	362	344	95%	330	91%	333	92%	331	91%
Subtotal	**28,607**	**27,387**	**96%**	**25,312**	**88%**	**27,299**	**95%**	**24,993**	**87%**
Total	**49,410**	**46,462**	**94%**	**44,386**	**90%**	**46,028**	**93%**	**43,690**	**88%**

- **Gas-fired units subject to must-offer requirements** accounted for about 19,400 MW (or about 40 percent) of units used to meet resource adequacy requirements. In the highest 200 load hours of this quarter, about 92 percent of capacity was self-scheduled or bid in the day-ahead markets. The rest of this capacity was unavailable due to outages or de-rates.

- **Use-limited gas-fired units** accounted for about 8,600 MW of capacity used to meet resource adequacy requirements in the quarter. These are mainly combustion turbines classified as use-limited due to environmental and other limitations. This resource adequacy capacity is not required to offer capacity during specific hours, but about 96 percent was offered in the day-ahead and real-time markets.

- **Hydro generators** accounted for about 5,900 MW of capacity used to meet resource adequacy requirements in the quarter. During the highest 200 load hours of the third quarter, about 83 percent of this capacity was scheduled or offered into the day-ahead and real-time markets. However, since additional capacity was available from some of these resources (beyond the level used to meet resource adequacy requirements), total hydro capacity scheduled or offered in the real-time market equaled about 88 percent of resource adequacy capacity met by hydro.

- **Non-resource-specific imports** accounted for about 3,500 MW of resource adequacy requirements during these hours, down from over 4,500 MW in the peak hours of 2020. This includes about 300 MW of non-resource-specific imports shown by load-following metered sub-system entities. These resources bid or self-scheduled 90 and 94 percent of procured capacity into the day-ahead and real-time markets, respectively.

- **Solar resources** were used to meet about 3,800 MW of resource adequacy requirements in the quarter. During the highest 200 load hours, these resources bid or self-scheduled 70 percent of this capacity into the day-ahead and real-time markets. However, since additional capacity was available from some of these resources beyond the level used to meet resource adequacy requirements, total solar capacity scheduled or offered in the real-time market equaled about 147 percent of resource adequacy capacity in the day-ahead and real-time markets.
- **Wind resources** were used to meet about 1,300 MW of resource adequacy requirements in the quarter. During the highest 200 load hours, these resources bid or self-scheduled about 74 to 77 percent of this capacity into the day-ahead and real-time markets. After including additional capacity that was available from some of these resources beyond the level used to meet resource adequacy requirements, total wind capacity scheduled or offered in the day-ahead and real-time markets equaled at least 140 percent of resource adequacy capacity from these units during these hours.
- **Non-utility operated demand response resources** were used to meet about 260 MW of resource adequacy requirements in the quarter. During the highest 200 load hours, these resources bid or self-scheduled about 72 percent of this capacity into the day-ahead market and 42 percent into the real-time markets. Some demand response providers saw a large proportion of capacity dispatched on high load days this summer. However, other providers' capacity was rarely dispatched and was largely unavailable in real-time if not cleared in the day-ahead market. Limited availability of demand response capacity in real-time can primarily be attributed to demand response programs with start-up times of 5 hours or greater which qualify these resources as long-start. Many of these resources are uneconomic in the day-ahead market and, if not scheduled in the day-ahead market, are not available in residual unit commitment or in real-time.
- **Storage resources** were used to meet about 1,200 MW of resource adequacy requirements in the quarter. These resources bid or self-scheduled 85 to 90 percent of this capacity into the day-ahead and real-time markets. After including additional capacity that was available from some of these resources beyond the level used to meet resource adequacy requirements, resources in this category bid or self-scheduled 101 and 111 percent of this level of resource adequacy capacity in the day-ahead and real-time market.

3.4 Capacity procurement mechanism

The capacity procurement mechanism (CPM) provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism facilitates pay-as-bid competitive solicitations for backstop capacity and also establishes a price cap at which the ISO can procure backstop capacity to meet resource adequacy requirements that are not met through resource adequacy showings by load serving entities.

The ISO uses the competitive solicitation process to procure backstop capacity in three different processes:

- First, if insufficient cumulative system, local, or flexible capacity is shown in annual resource adequacy plans, the ISO may procure backstop capacity through a year-ahead competitive solicitation process using annual bids. The year-ahead process may also be used to procure backstop capacity to resolve a collective deficiency in any local area.

- Second, the ISO may procure backstop capacity through a monthly competitive solicitation process in the event of insufficient cumulative capacity in monthly plans for local, system, or flexible resource adequacy. The monthly process may also be used to procure backstop capacity in the event that cumulative system capacity is insufficient due to planned outages.
- Third, the intra-monthly competitive solicitation process can be triggered by exceptional dispatch or other significant events.

Annual designations

There were no annual capacity procurement designations for 2021. Since the implementation of the current capacity procurement mechanism framework in 2016, the only annual designations were made in 2018.

Monthly designations

There were no monthly capacity procurement mechanism designations made for 2021, and there have not been any since the program was implemented in 2016.

Intra-monthly designations

In response to climate change and extreme heat events in the early part of the summer, CPUC President Marybel Batjer, CEC Chair David Hochschild, and ISO CEO Elliot Mainzer issued a joint statement on July 1, 2021, to secure additional energy resources and ensure electricity reliability during the summer.[89] The ISO used its authority to issue a CPM Significant Event to procure additional capacity starting on July 9. The original designation was for 30 days. The ISO offered 60-day extensions at the time, but no resources accepted. The ISO procured about 1,700 MW of capacity at a total cost of about $8.3 million to address the significant event.

In addition to the capacity procured for the significant event, the ISO also issued Exceptional Dispatch CPM designations to address a capacity deficiency that risked it not being able to meet load and reserve obligations. The ISO procured about 230 MW of capacity at a total coast of about $1.3 million to address the exceptional dispatch system reliability need.

Table 3.5 shows the intra-monthly capacity procurement mechanism designations that occurred in the third quarter. The table shows which resources were designated, amount of megawatts procured, the date range of the designation, the price, estimated cost of the procurement, the area that had insufficient capacity, and the event that triggered the designation.

89 The joint statement and the letter from the CPUC and CEC to the ISO can be found here: https://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-JointStatementandLetter.pdf.

Table 3.5 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM Start Date	CPM End Date	CPM Type	Price ($/kW-mon)	Estimated cost ($ mil)	Estimated cost Q3 ($mil)	Local capacity area	CPM designation trigger
ARCOGN_2_UNITS	17	7/22/21	7/31/21	SIGEVT	$6.31	$0.03	$0.03	SYS	Significant Event CPM Designation
BARRE_6_PEAKER	44	7/12/21	7/31/21	SIGEVT	$6.31	$0.19	$0.19	SYS	Significant Event CPM Designation
BLKCRK_2_GMCBT1	133	7/9/21	7/31/21	SIGEVT	$6.31	$0.64	$0.64	SYS	Significant Event CPM Designation
BUCKBL_2_PL1X3	51	7/9/21	7/31/21	SIGEVT	$6.31	$0.25	$0.25	SYS	Significant Event CPM Designation
CALFTN_2_CFSBT1	60	9/1/21	9/30/21	SIGEVT	$6.31	$0.38	$0.38	SYS	Significant Event CPM Designation
DRACKR_2_DSUBT1	63	9/1/21	9/30/21	SIGEVT	$6.31	$0.40	$0.40	SYS	Significant Event CPM Designation
DRACKR_2_DSUBT3	81	8/2/21	8/31/21	SIGEVT	$6.31	$0.51	$0.51	SYS	Significant Event CPM Designation
ELKHIL_2_PL1X3	30	8/1/21	8/31/21	SIGEVT	$6.30	$0.20	$0.20	SYS	Significant Event CPM Designation
GARLND_2_GARBT1	45	9/1/21	9/30/21	SIGEVT	$6.31	$0.28	$0.28	SYS	Significant Event CPM Designation
HINSON_6_LBECH1	5	7/9/21	7/31/21	SIGEVT	$6.31	$0.02	$0.02	SYS	Significant Event CPM Designation
HINSON_6_LBECH2	7	7/9/21	7/31/21	SIGEVT	$6.31	$0.03	$0.03	SYS	Significant Event CPM Designation
HINSON_6_LBECH3	7	7/9/21	7/31/21	SIGEVT	$6.31	$0.03	$0.03	SYS	Significant Event CPM Designation
HINSON_6_LBECH4	4	7/9/21	7/31/21	SIGEVT	$6.31	$0.02	$0.02	SYS	Significant Event CPM Designation
INTKEP_2_UNITS	121	7/9/21	7/31/21	ED	$6.31	$0.59	$0.59	SYS	Exceptional Dispatch CPM Capacity Need
JOANEC_2_STABT1	20	7/12/21	7/31/21	SIGEVT	$6.31	$0.08	$0.08	SYS	Significant Event CPM Designation
KRNCNY_6_UNIT	5	7/9/21	7/31/21	SIGEVT	$6.31	$0.02	$0.02	SYS	Significant Event CPM Designation
KRNCNY_6_UNIT	3	8/1/21	8/8/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
MNDALY_6_MCGRTH	43	7/9/21	8/8/21	ED	$6.31	$0.28	$0.28	SYS	Exceptional Dispatch CPM Capacity Need
OMAR_2_UNIT 1	1	8/2/21	8/31/21	SIGEVT	$6.31	$0.00	$0.00	SYS	Significant Event CPM Designation
OMAR_2_UNIT 1	1	9/1/21	9/30/21	SIGEVT	$6.31	$0.00	$0.00	SYS	Significant Event CPM Designation
OMAR_2_UNIT 2	2	8/2/21	8/31/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 2	2	9/1/21	9/30/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 3	2	8/2/21	8/31/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 3	2	9/1/21	9/30/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 4	2	8/2/21	8/31/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 4	2	9/1/21	9/30/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
RUSCTY_2_UNITS	350	8/11/21	8/31/21	SIGEVT	$6.31	$1.55	$1.55	SYS	Significant Event CPM Designation
RUSCTY_2_UNITS	251	9/1/21	9/10/21	SIGEVT	$6.31	$0.53	$0.53	SYS	Significant Event CPM Designation
SBERDO_2_PSP3	15	7/9/21	7/31/21	SIGEVT	$6.31	$0.07	$0.07	SYS	Significant Event CPM Designation
SBERDO_2_PSP4	45	7/9/21	7/31/21	SIGEVT	$6.31	$0.22	$0.22	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_262626	42	9/1/21	9/30/21	SIGEVT	$6.31	$0.27	$0.27	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_272727	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	$0.16	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_282828	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	$0.16	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_292929	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	$0.16	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_303030	50	9/1/21	9/30/21	SIGEVT	$6.31	$0.32	$0.32	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_313131	50	9/1/21	9/30/21	SIGEVT	$6.31	$0.32	$0.32	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_414141	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	$0.16	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	8/2/21	8/31/21	SIGEVT	$6.31	$0.02	$0.02	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	9/1/21	9/30/21	SIGEVT	$6.31	$0.02	$0.02	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 2	5	8/2/21	8/31/21	SIGEVT	$6.31	$0.03	$0.03	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 2	3	9/1/21	9/30/21	SIGEVT	$6.31	$0.02	$0.02	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	70	7/10/21	8/9/21	ED	$6.31	$0.46	$0.46	SYS	Exceptional Dispatch CPM Capacity Need
SYCAMR_2_UNIT 3	73	8/10/21	8/31/21	SIGEVT	$6.31	$0.34	$0.34	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	4	9/1/21	9/9/21	SIGEVT	$6.31	$0.01	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	3	9/10/21	10/10/21	SIGEVT	$6.31	$0.02	$0.01	SYS	Significant Event CPM Designation
VESTAL_2_WELLHD	38	7/9/21	7/31/21	SIGEVT	$6.31	$0.18	$0.18	SYS	Significant Event CPM Designation
VISTRA_5_DALBT4	100	8/2/21	8/31/21	SIGEVT	$6.31	$0.63	$0.63	SYS	Significant Event CPM Designation
Total	1,956					$9.66	$9.65		