Q1 Report on Market Issues and Performance

September 11, 2020

Prepared by: Department of Market Monitoring

California Independent System Operator

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Executive Summary

This report covers market performance during the first quarter of 2020 (January - March). Key highlights during this quarter include the following:

- **Market prices** remained highly competitive in the first quarter due to a combination of favorable market and system conditions. Electricity prices decreased from the previous quarter to the first quarter of 2020, with average day-ahead prices ($29/MWh) greater than both 15-minute ($27/MWh) and 5-minute prices ($26/MWh) (Figure E.1).
- **The total estimated wholesale cost of serving load** in the first quarter of 2020 was about $1.5 billion ($31/MWh), a decrease from $2.7 billion ($54/MWh) in the same quarter of 2019. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 10 percent to $34/MWh from $38/MWh.
- **The overall net impact and frequency of internal congestion** on load was low in both the day-ahead and real-time markets. The frequency of congestion increased in SDG&E, while it decreased in PG&E and SCE.
- **Real-time offset costs** decreased substantially in the first quarter to $5 million from $50 million in the fourth quarter of 2019. Real-time offset costs were driven by congestion with a deficit of about $12 million and energy with a surplus of about $6 million.
- **Congestion revenue rights** auction revenues were $13.6 million less than payments made to non-load-serving entities during the first quarter of 2020. Auction revenues were 46 percent of payments made to non-load-serving entities during the first quarter of 2020, a significant decrease from 94 percent during the same quarter in 2019. The first quarter auction losses were about 18 percent of day-ahead congestion rent, an increase from 2 percent of rent in the first quarter of 2019, 6 percent for all of 2019, and 15 percent in the fourth quarter of 2019.
- **Ancillary services** costs increased during the first quarter to about $30 million, compared to about $23 million in the previous quarter, driven by an increase in regulation down payments.
- **Flexible ramping product** system level prices were zero for around 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. Some resources supplying flexible ramping capacity continue to not be able to resolve system level uncertainty because of congestion, reducing the efficacy with which the product can manage net load volatility or prevent power balance violations.
- **Bid cost recovery payments** for the first quarter of 2020 totaled about $18 million, or about $9 million less than the previous quarter and $11.5 million lower than the first quarter of 2019.

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

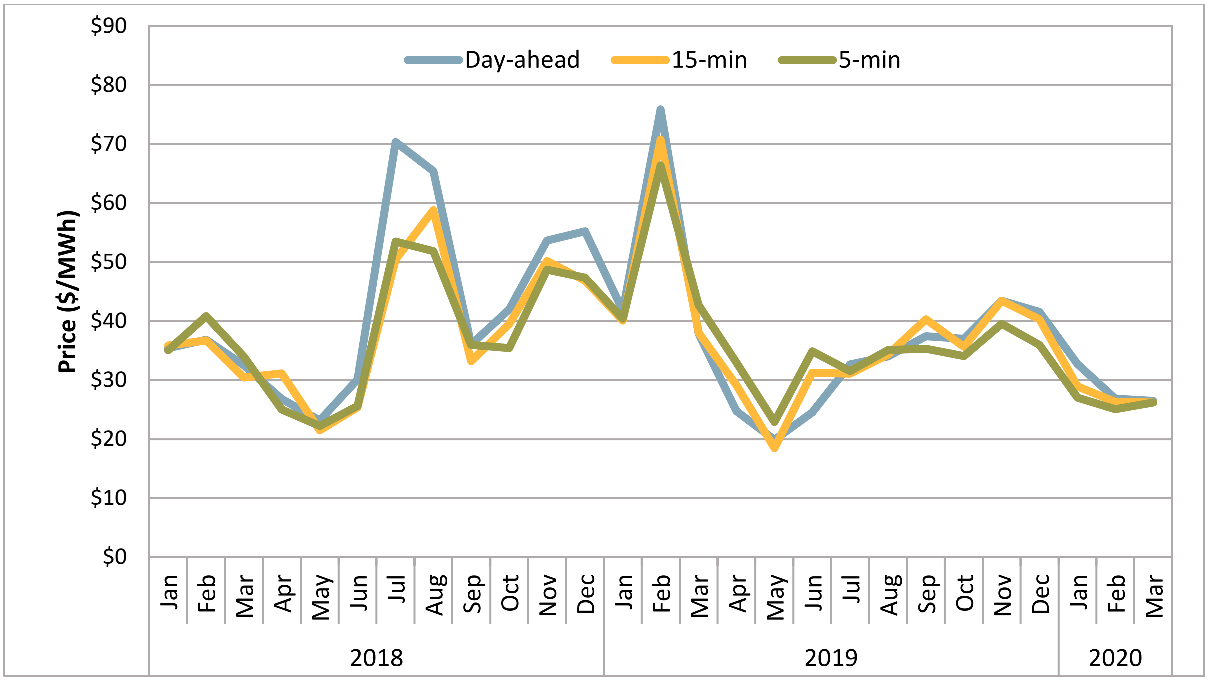
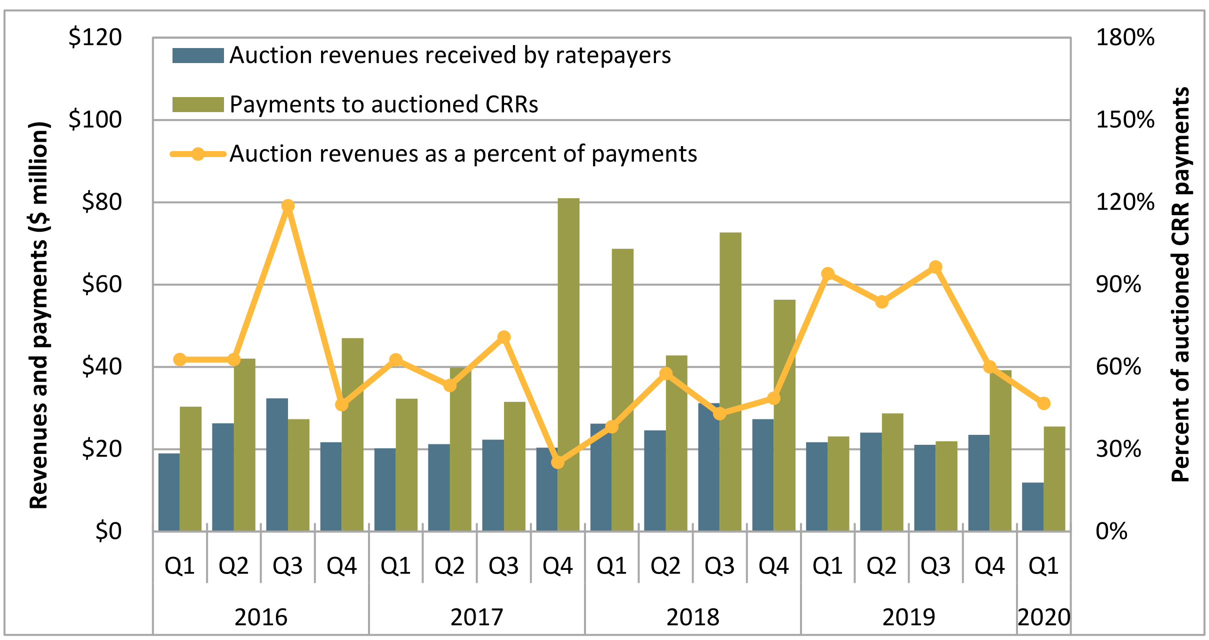


Figure E.2 Auction revenues and payments to non-load-serving entities



Western energy imbalance market

- **Prices in the Northwest region**, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex, were regularly lower than prices in the ISO and other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **Prices in the ISO and the BANC** exceeded the rest of the system in each month, on average, due to binding transfer constraints and greenhouse gas compliance costs enforced for imports into California.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices for Arizona Public Service higher than the rest of the system in some hours. Almost all intervals with power balance relaxations were priced at the penalty parameter of $1,000/MWh.
- **Congestion imbalance deficits related to base schedules** remained low in the first quarter, totaling about $0.7 million in PacifiCorp East. Balancing areas may allocate these imbalances to third party customers and others. PacifiCorp East is the only area to have significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018.
- **Western EIM greenhouse gas** prices increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions, relative to before the policy change in 2018. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. In some intervals in the first quarter, all eligible supply was imported, limiting energy imbalance market imports into California.
- **Rates of mitigation** fell in the Western EIM, following the elimination of carryover mitigation in November of 2019.

Special issues

Stay-at-home orders to control COVID-19

- **Stay-at-home orders to control COVID-19 reduced load** by over 5 percent on weekdays following a California state-wide public health order to preserve public health effective March 19. DMM plans to publish an analysis of the impact of COVID-19 on ISO market prices in the second quarterly report of 2020. Reductions in natural gas prices, associated with reduced demand, and lower electricity load have both contributed to lower ISO market prices.

Downward dispatch of renewable resources

- **Downward dispatch of renewable resources was considerably higher** in every month of the first quarter compared to the same quarter of 2019 in both the ISO and energy imbalance market. This downward dispatch, often called curtailment, was most often the result of economic downward dispatch rather than self-schedule curtailment.

System market power

- **Market results were competitive in the first quarter**. DMM estimates that the impact of gas resources bidding above reference levels, a conservative measure of the average price-cost markup, was about $0.38/MWh or just over 1 percent for the default energy bid scenario.
- **DMM introduced several new competiveness scenarios**. These include a scenario that replaces bid in demand with actual load and removes virtual bids, a scenario that caps gas commitment costs at 110% of estimated reference levels, and a scenario that caps import bids at a conservative measure of opportunity cost based on the recently introduced hydro default energy bid. DMM also runs combinations of scenarios.
- **The price-cost markup** for the gas default energy bid scenario averaged $0.38/MWh or 1.28 percent for the first quarter. The markup for that scenario combined with capping of import bids and commitment costs was $0.68/MWh or 2.16 percent. When this scenario is combined with the physical scenario including both actual load and removal of virtual bids, the markup fell to $0.16 or 0.54%. This slight positive markup indicates that overall prices have been very competitive for the year.
- **Market power** has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.

DMM continues to recommend several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM also continues to recommend that the ISO's plan for implementing FERC Order 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of Order 831.

1 Market Performance

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

- **Market prices** were highly competitive in the first quarter due to a combination of favorable market and system conditions as both lower load and lower gas prices led to a decrease in wholesale electric costs compared to the previous quarter.
- **The total estimated wholesale cost of serving load** in the first quarter of 2020 was about $1.5 billion ($31/MWh), a decrease from $2.7 billion ($54/MWh) in the same quarter of 2019. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 10 percent to $34/MWh from $38/MWh.
- **Gas prices** were lower in the first quarter compared to Q1 2019 at both SoCal and PG&E Citygates, following the return to service of gas pipeline capacity that had been out of service since 2017, as well as other changes to Operational Flow Order and Aliso Canyon Storage withdrawal protocols.
- **Renewable production** fell by 15 percent contributing to higher wholesale energy costs relative to the first quarter of 2019 as hydro-electric production fell by about 49 percent.
- **Electricity prices** decreased from the previous quarter to the first quarter of 2020, with average day-ahead prices ($29/MWh) greater than both 15-minute ($27/MWh) and 5-minute prices ($26/MWh).
- **Flexible ramping product** system level prices were zero for around 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. Some resources supplying flexible ramping capacity continue to not be able to resolve system level uncertainty because of congestion, reducing the efficacy with which the product can manage net load volatility or prevent power balance violations.
- **Bid cost recovery payments** for the first quarter of 2020 totaled about $18 million, or about $9 million less than the previous quarter and $11.5 million lower than the first quarter of 2019.
- **Congestion.** The overall net impact and frequency of internal congestion on load was low in both the day-ahead and real-time markets. The frequency of congestion increased in SDG&E, while it decreased in PG&E and SCE.
- **Real-time offset costs** decreased substantially in the first quarter to $5 million from $50 million in the fourth quarter of 2019. Real-time offset costs were driven by congestion with a deficit of about $12 million and energy with a surplus of about $6 million.
- **Congestion revenue rights** auction revenues were $13.6 million less than payments made to non-load-serving entities during the first quarter of 2020. Auction revenues were 46 percent of payments made to non-load-serving entities during the first quarter of 2020, a significant decrease from 94 percent during the same quarter in 2019. The first quarter auction losses were about 18 percent of day-ahead congestion rent, an increase from 2 percent of rent in the first quarter of 2019, 6 percent for all of 2019, and 15 percent in the fourth quarter of 2019.
- **Ancillary services** costs increased during the first quarter to about $30 million, compared to about $23 million in the previous quarter, driven by an increase in regulation down payments.

1.1 Supply conditions

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 first quarter of 2020, natural gas prices declined significantly across major gas trading hubs in the west, when compared to the same quarter in 2019. This decrease in natural gas prices led to lower system marginal energy prices across the ISO footprint during the first 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, El Paso Permian and for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. As shown in the figure, natural gas prices at SoCal Citygate, PG&E Citygate and Northwest Sumas declined sharply in the first quarter when compared to the same quarter in 2019.

Prices at the SoCal Citygate gas hub averaged $2.95/MMBtu compared to $6.53/MMBtu in the first quarter of 2019. SoCal Citygate prices fell sharply beginning April 2019. Key factors contributing to lower winter prices in 2019-2020 include:

- On September 17, the California Public Utilities Commission (CPUC) urged Southern California Gas Company (SoCalGas) to increase injections of natural gas at its underground storage fields to prepare for winter.[1]
- On October 14, SoCalGas announced the completion of the Line 235-2 maintenance and its return to service at reduced pressure. This line had been out of service since October 2, 2017, causing significant supply constraints, which increased SoCal Citygate gas prices during the outage.
- Gas pipeline capacity of 270 million cubic feet per day at Topock and Needles returned to service. These lines support access to lower cost natural gas supplies in the San Juan and Permian Basins.
- The CPUC granted SoCalGas more flexibility this winter to withdraw from the Aliso Canyon natural gas storage facility. During the past few winters, Aliso Canyon was only available for withdrawals as a last resort.[2]

According to SoCalGas Company's annual report, there were 67 low operational flow order (OFO) events called from April 1, 2019, through March 31, 2020. This represents a 52 percent decrease in comparison to the 139 low OFOs called during the previous report period. It also mentions that the new Aliso Canyon Withdrawal Protocol probably helped SoCalGas and SDG&E customers avoid low OFOs on 44 out

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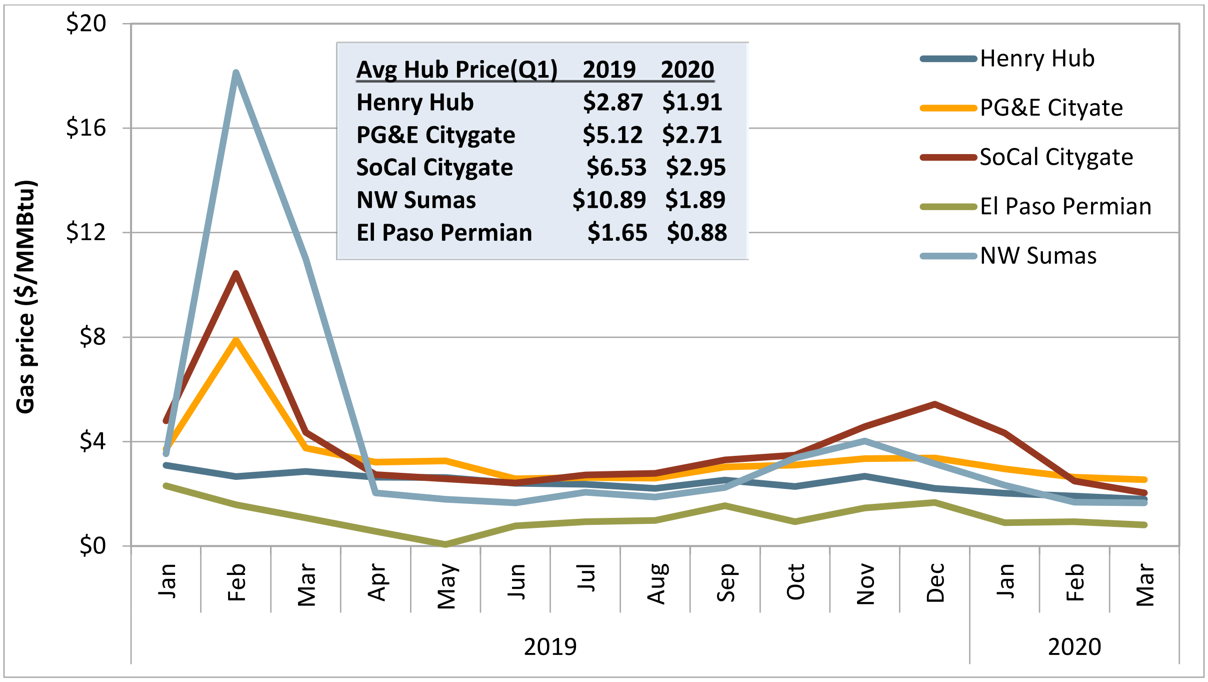
1 Southern California Daily Energy Report: https://www.eia.gov/special/disruptions/socal/summer/#commentary

2 Aliso Canyon Withdrawal Protocol, July 23, 2019: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

of the 57 gas days it was implemented.[3] SoCal Citygate prices often impact overall electric system prices because 1) there are large numbers of natural gas resources in the south, and 2) these resources can set system prices in the absence of congestion.

Figure 1.1 Monthly average natural gas prices



Northwest Sumas prices have also declined compared to the first quarter of 2019. On November 28, 2019, the Canada Energy Regulator approved the Enbridge Westcoast line to return to full operating pressure, following an October 2018 explosion.

Permian prices continued to be low, sometimes negative, in the first quarter of 2020. Limited takeaway capacity out of Permian basin due to maintenance activities has led to continued downward pressure on prices.

Monthly variation in hydroelectric, wind, and solar

In the first quarter, total generation from hydroelectric, solar, and wind resources increased by about 2 percent compared to the previous quarter. Generation from these resources tends to peak in the second quarter. Total generation from these resources decreased by 15 percent compared to the same quarter in 2019, primarily due to the decrease in availability of hydroelectric in February and March.

Compared to the same period in 2019, hydroelectric production in the first quarter decreased by roughly 49 percent. As of April 1, the statewide weighted average snowpack in California was 50 percent

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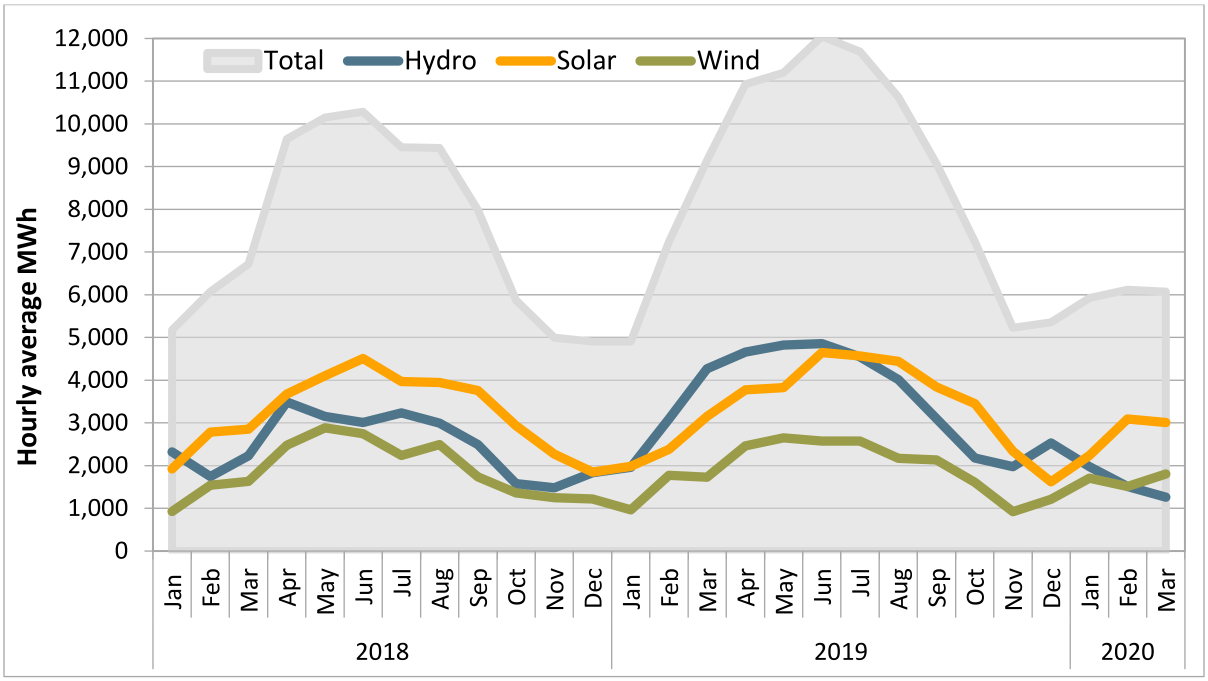
3 SoCalGas's Eleventh Annual Report of System Reliability Issues, April 29, 2020: https://scgenvoy.sempra.com/ebb/attachments/1588197649834_Eleventh_Annual_Report_of_System_Reliability_Issues_04-29-2020.pdf

of normal compared to 175 percent of normal on April 1, 2019.[4] Compared to the previous quarter, hydroelectric generation decreased about 29 percent.

Compared to the first quarter of 2019, solar production increased by about 11 percent while wind production increased by about 12 percent. Compared to the fourth quarter of 2019, solar and wind production increased by about 13 percent and 34 percent, respectively.

The availability of variable resources contributes to patterns in prices both seasonally and hourly due to their low marginal cost relative to other resources. Although hydroelectric generation declined in all hours of the day compared to the same time last year, increased solar and wind generation coupled with lower gas prices contributed to lower wholesale electric prices in the first quarter.

Figure 1.2 Average hourly hydroelectric, wind, and solar generation by month



Generation by fuel type

Figure 1.3 shows average hourly generation for the quarter by fuel type. In the first quarter, slightly higher loads and much lower hydroelectric generation coupled with an increase in solar generation in the middle of the day has resulted in a mid-day decrease in imports but an increase in both natural gas generation and imports during ramping periods. Generally bio-based resources remained static and generation from nuclear and geothermal resources increased compared to the previous quarter. Combined these types of resources comprised about 4,300 MW of inflexible base generating capacity, an increase of over 1,000 MW primarily from nuclear generation. Generation from "other" resources, including coal, battery storage, demand response, and additional non-gas technologies, decreased in

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

this quarter, but continues to be a small share of overall generating capacity (about 250 MW on average).

Figure 1.3 Average hourly generation by fuel type (Q1 2020)

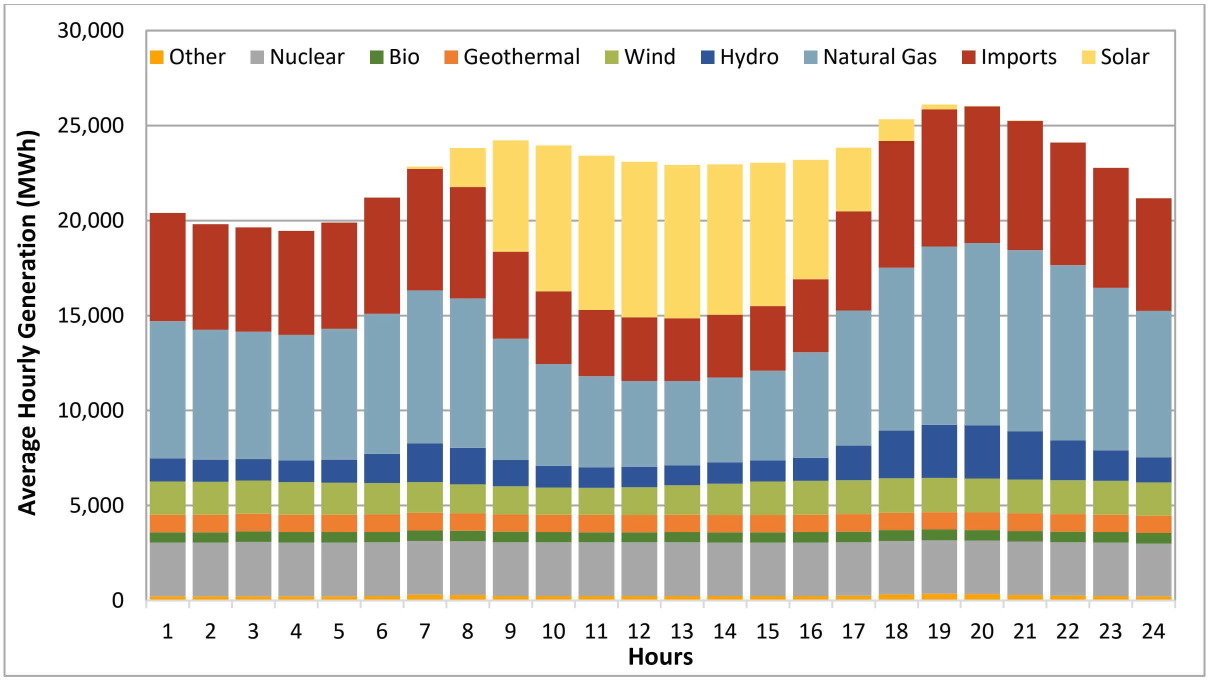
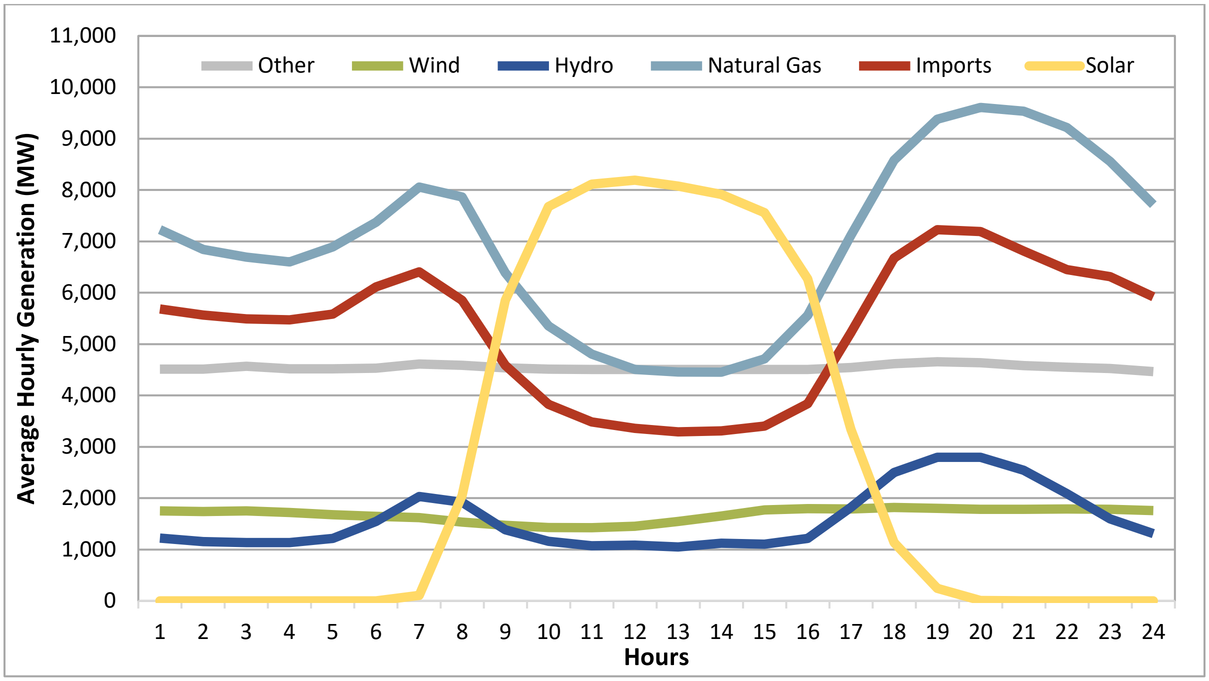


Figure 1.4 shows hourly variation of generation by fuel group, driven by hourly variation of solar production. In the first quarter, natural gas varied most over the day and produced significantly more than any resource during the peak net load hours, similar to previous quarters. Compared to the previous quarter, net imports varied more significantly over the day, generally increasing for the morning and evening net load peaks; however, unlike the previous quarter imports remained at a higher level in non-solar generating hours.

Similar to the previous quarter, imports consistently produced more than hydroelectric resources throughout the day. On a daily basis, wind generation typically complements solar production by generating more in the early morning and late evening, and less in the middle of the day. However, similar to the previous quarter, on average for this quarter there was little variation in wind generation over the day. Average hourly generation from the "other" category was elevated compared to the previous quarter due to increases in nuclear generation output; however, there continued to be little variability from the resources in this category on an hourly basis.[5]

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

Figure 1.4 Hourly variation in generation by fuel type (Q1 2020)



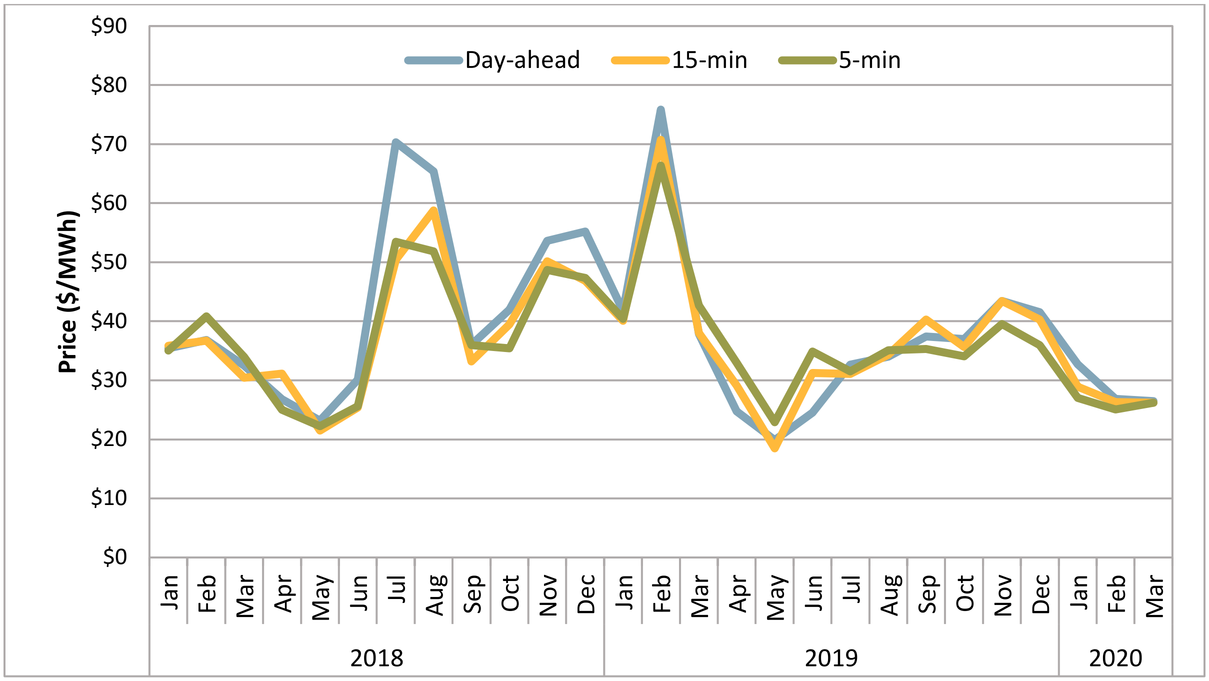
1.2 Energy market performance

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.

Figure 1.5 shows load-weighted average monthly energy prices during all hours across the three largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric). Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2018 to March 2020.

Figure 1.5 Monthly load-weighted average energy prices (all hours)



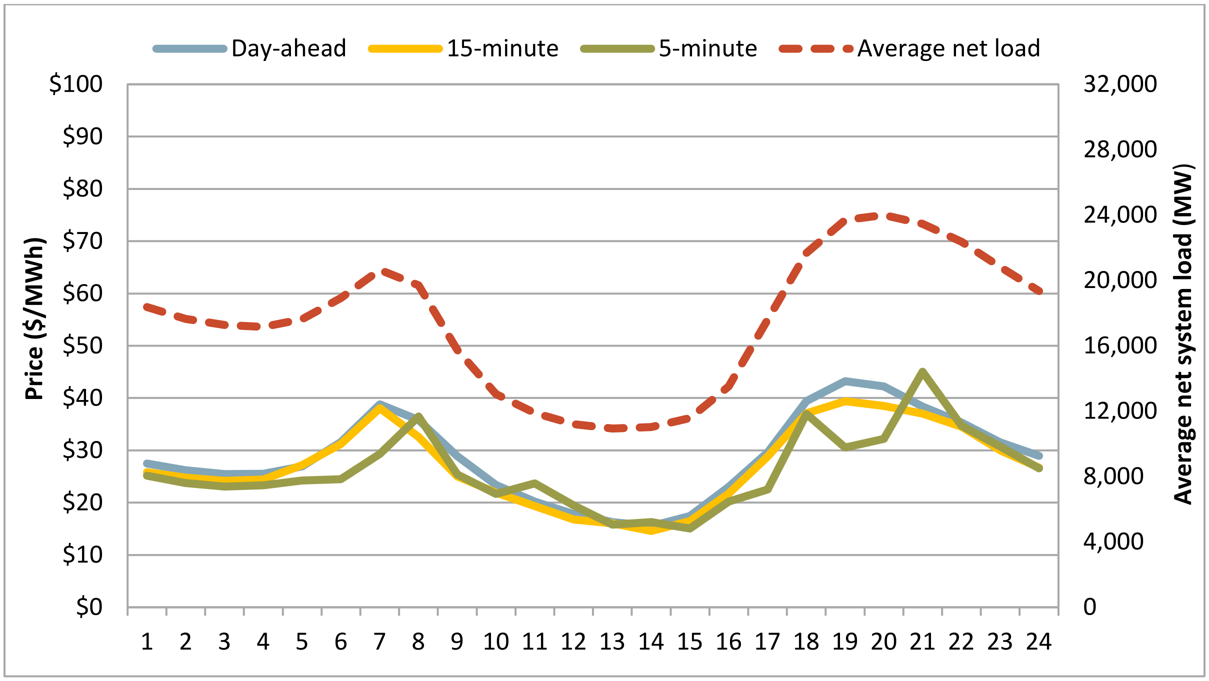
Prices decreased from the fourth quarter of 2019 to the first quarter of 2020. Average day-ahead prices decreased by 29 percent, 15-minute prices decreased by 32 percent, and 5-minute prices decreased by 29 percent. This marks a reversal from the general trend of rising average prices since the second quarter of 2019. Market prices decreased by nearly 50 percent compared to the first quarter in 2019 when natural gas prices spiked in multiple trading hubs across the West.

Average day-ahead prices were greater than the 15-minute and 5-minute market prices during the first quarter. Day-ahead prices averaged about $29/MWh, 15-minute prices averaged $27/MWh, and 5-minute prices averaged $26/MWh over the quarter. This relationship between market prices where day-ahead prices exceed 15-minute and 5-minute prices has been the general trend since 2014.

Figure 1.6 illustrates load-weighted average energy prices on an hourly basis in the first quarter compared to average hourly net load.[6] 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.

[6] 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 1.6 Hourly load-weighted average energy prices



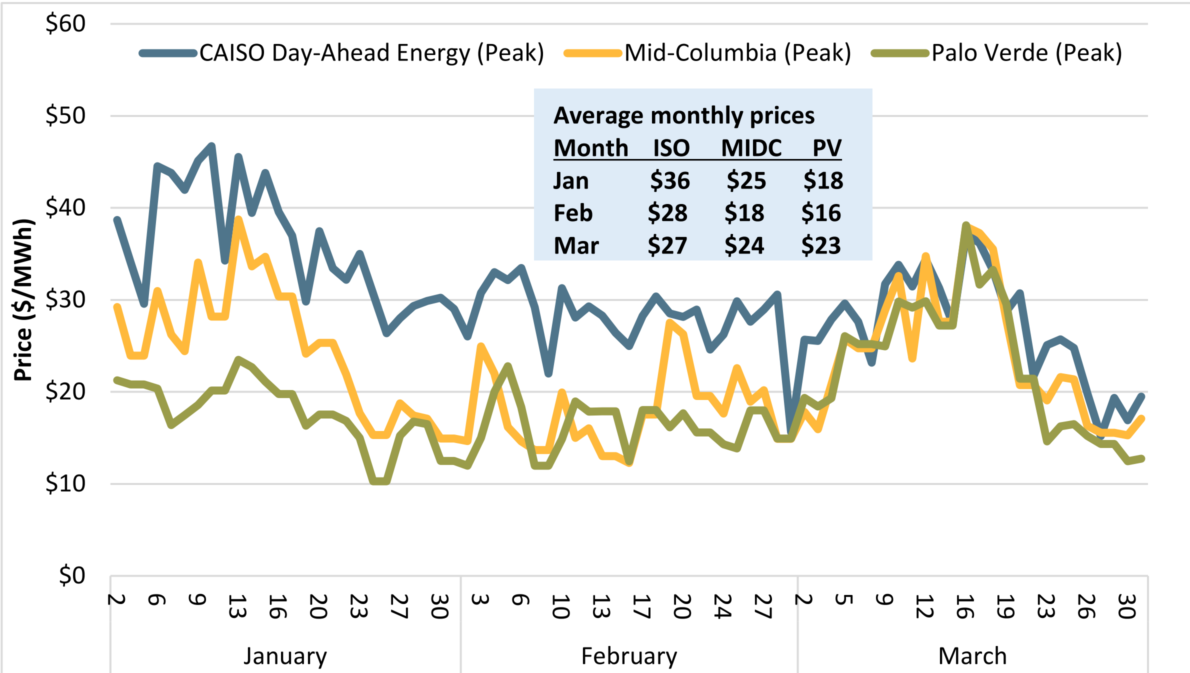
Average hourly prices in the first quarter continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours, particularly between hours ending 18 and 21. The greatest price divergence between the markets coincided with the evening peak during hours ending 19 and 20 when day-ahead prices exceeded 5-minute prices by over $10/MWh. Prices in the 5-minute market were typically lower than the other markets during the evening peak by at least $6/MWh. The pattern reversed in hour-ending 21, however, when 5-minute prices exceeded day-ahead and 15-minute prices by about $7/MWh. This is when most of the power balance constraint violations occurred over the quarter.[7]

1.2.2 Bilateral price comparison

Average prices in the ISO, across all hours in the first quarter, were greater on average than prices at Mid-Columbia and Palo Verde, reflecting transmission constraints as well as greenhouse gas compliance costs. Figure 1.7 shows day-ahead weighted average prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) in the ISO, as well as average peak energy prices at the Palo Verde and Mid-Columbia hubs outside of the ISO market.

[7] For more information about power balance constraint violations during the quarter, see Section 1.6.

Figure 1.7 Daily system and bilateral market prices (Jan – Mar)



Average prices in the ISO and trade hubs were calculated during peak hours (hours ending 7 through 22) for all days excluding Sundays and holidays. Daily ISO system prices were generally higher than both bilateral hub prices during the first two months of the first quarter. Daily energy prices converged in March which resulted in bilateral prices exceeding ISO prices for seven days (9 percent of total) at Mid-Columbia and for four days (5 percent of total) at Palo Verde.

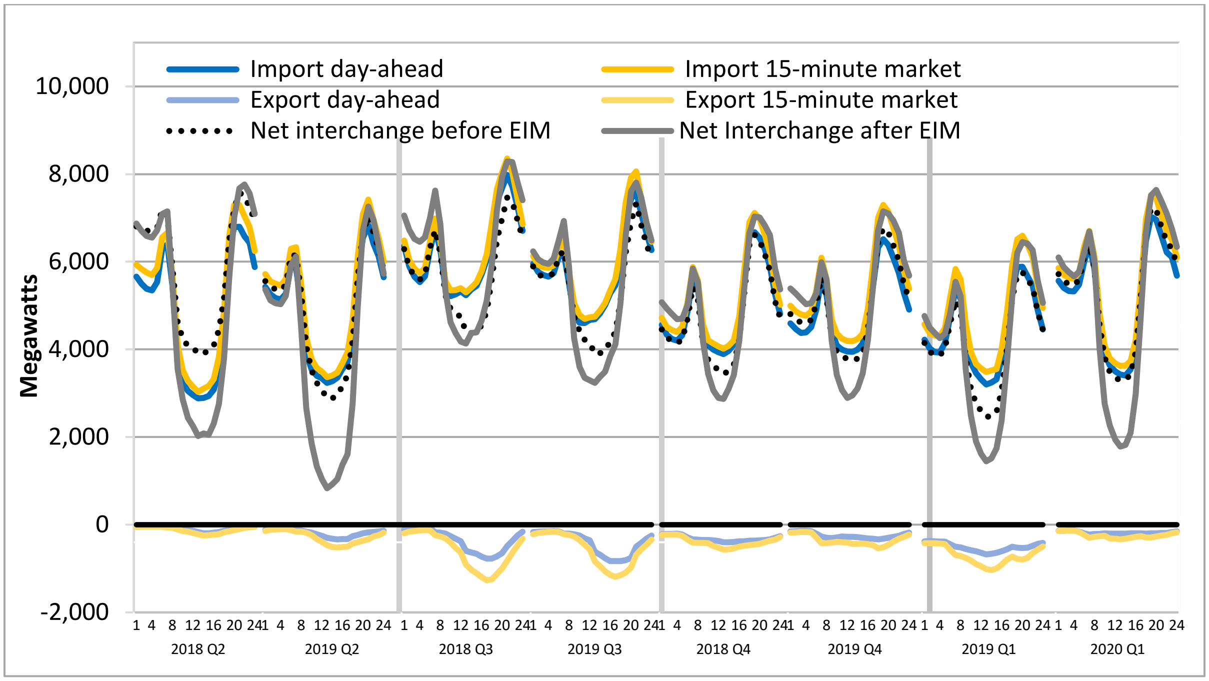
Average day-ahead prices in the ISO were also compared to hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average hourly prices in the ISO were greater than prices in Mid-Columbia and Palo Verde by $8.41/MWh and $6.98/MWh, respectively.

Imports and exports

As shown in Figure 1.8, average hourly cleared imports (shown in dark blue and dark yellow) peaked at the same time and approximately the same volumes as the same quarter from the previous year. First quarter peak imports in the day-ahead (dark blue line) increased slightly from about 5,900 MW to 7,000 MW compared to the same period the previous year. For the same comparable period the peak 15-minute (dark yellow line) cleared imports also slightly increased from about 6,600 MW to 7,500 MW.

The greatest import transfer into the ISO from the EIM occurred in hour ending 22 at about 650 MW and the greatest export transfer from the ISO to the EIM occurred in hour ending 13 at about 1,500 MW. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), decreased from the same quarter in 2019, peaking at about 330 MW in hour ending 13 and 14. The average net interchange, excluding EIM transfers (shown in dashes), 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 13.

Figure 1.8 Average hourly net interchange by quarter



1.3 Load conditions

ISO load decreased in the first quarter of 2020. Figure 1.9 shows average hourly load by month from 2018 to 2020. Average load decreased between 2 and 5 percent compared to the same months in the previous two years. Lower loads are due, in part, to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, and relatively warmer statewide temperatures, particularly in February. Lower loads in March were partially due to the public health order that directed Californians to stay at home except for essential needs or to work at essential jobs in response to COVID-19.[8]

8 For more information on how the stay-at-home orders in response to COVID-19 affected the ISO, please refer to Section 3.1.

Figure 1.9 Average hourly load by first quarter month (2018-2020)

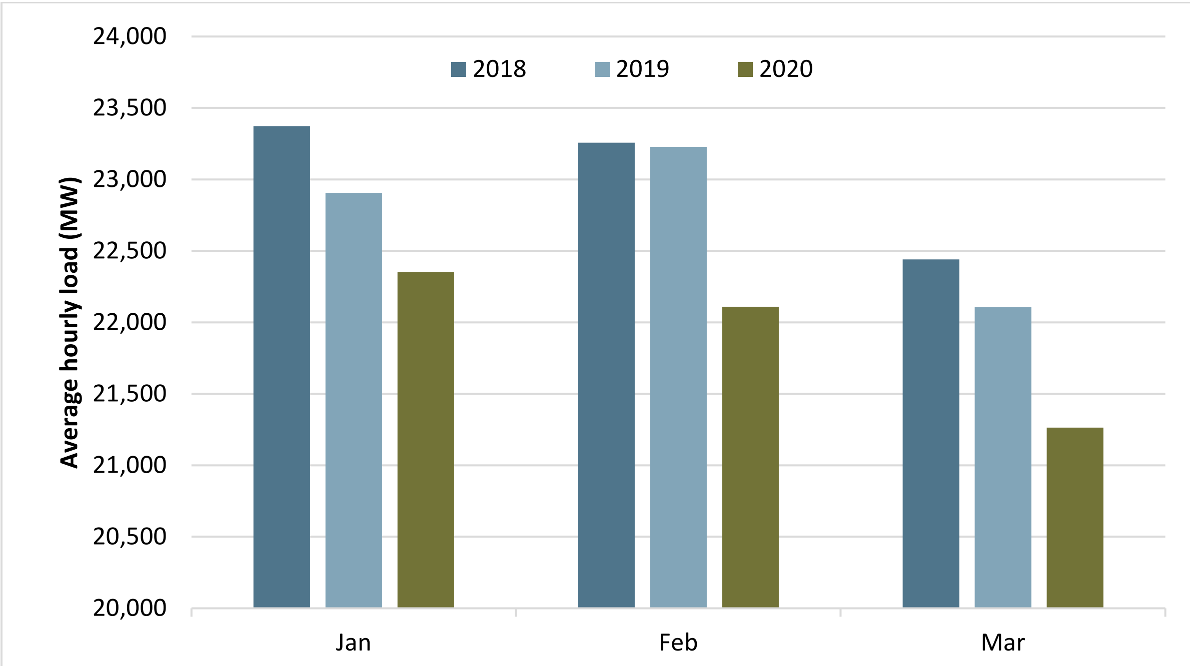


Figure 1.10 shows how the variability of the net load curve has changed over time. It shows the average hourly net load as well as the minimum and maximum hourly average net load from January 2018 to March 2020. Average net load tends to follow seasonal patterns in California by increasing during warmer months and decreasing during cooler months. Apart from this general pattern, average net loads have decreased by almost nine percent since the first quarter of 2018.

The figure also shows that the maximum and minimum hourly average net load per month difference has increased over time. Net load is a measure of load minus generation from wind and solar resources. Therefore, the monthly maximum net load is influenced by the high net loads in the evenings when the combination of wind and solar resource production is low. The minimum monthly net load is influenced by the low net loads during the middle of the day when the combination of solar and wind production is at its highest. An increase in this difference over time is indicative of increased penetration of solar and wind resources in the ISO market. The net load minimum has decreased over time, and notably reached as low as 5,000 MW multiple times since the second quarter of 2019.

Figure 1.10 Average hourly net load by month (2018-2020)

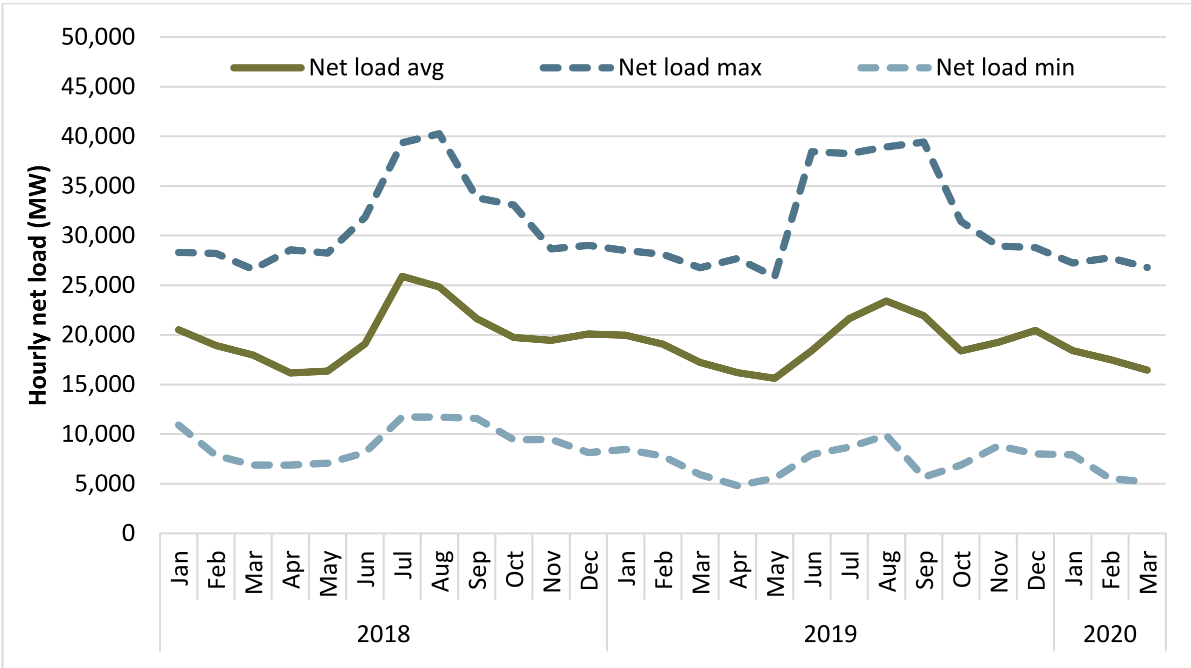
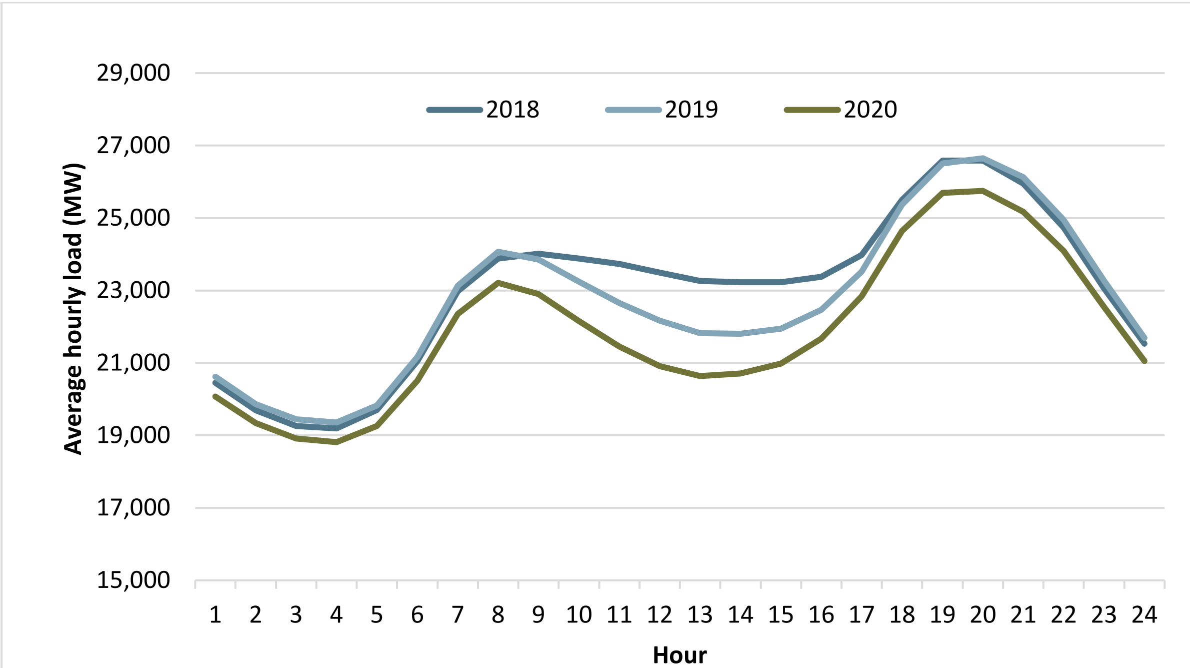


Figure 1.11 offers insight into how behind-the-meter solar resources affect ISO load. Generation from utility scale wind and solar resources indirectly affects load by influencing how other generation sources must meet demand after wind and solar have been factored out, i.e., the net load. Conversely, generation from behind-the-meter solar resources directly reduces the amount of load that must be met by generation from the ISO market, regardless of source.

The figure shows average load by hour in the first quarter of 2018 to 2020. Average hourly load during the morning and evening peaks tracked closely together in the first quarter of 2018 and 2019. Loads in the first quarter of 2020 decreased, as previously shown. This is true for all hours on average. The divergence in load across years through the middle of the day, when solar production is high, shows the effect of increased behind-the-meter solar generation on load in California.

Figure 1.11 Average load by first quarter hour (2018-2020)



1.4 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the first quarter of 2020 was about $1.5 billion, down from about $2.7 billion in the same quarter of 2019. The average cost per megawatt-hour of load decreased 42 percent to about $31/MWh for the first quarter from $54/MWh in the same quarter of 2019 (nominal costs shown in blue bars in Figure 1.12).

The decrease in average wholesale electric prices is primarily from a 44 percent decrease in natural gas prices compared to the same quarter in 2019. Load-weighted gas prices decreased to about $3.81/MMBtu, a 44 percent decrease from about $6.81/MMBtu in the same quarter of 2019. When normalizing for changes in natural gas and greenhouse gas costs using the 2010 gas price as a reference year, the gold bar in Figure 1.12 shows the wholesale energy costs to serve load decreased by 10 percent to about $34/MWh from about $38/MWh in the same quarter of 2019. In addition to lower natural gas costs, increased production from solar resources contributed to lower wholesale energy costs this quarter.

Figure 1.12 Total quarterly wholesale costs per MWh of load

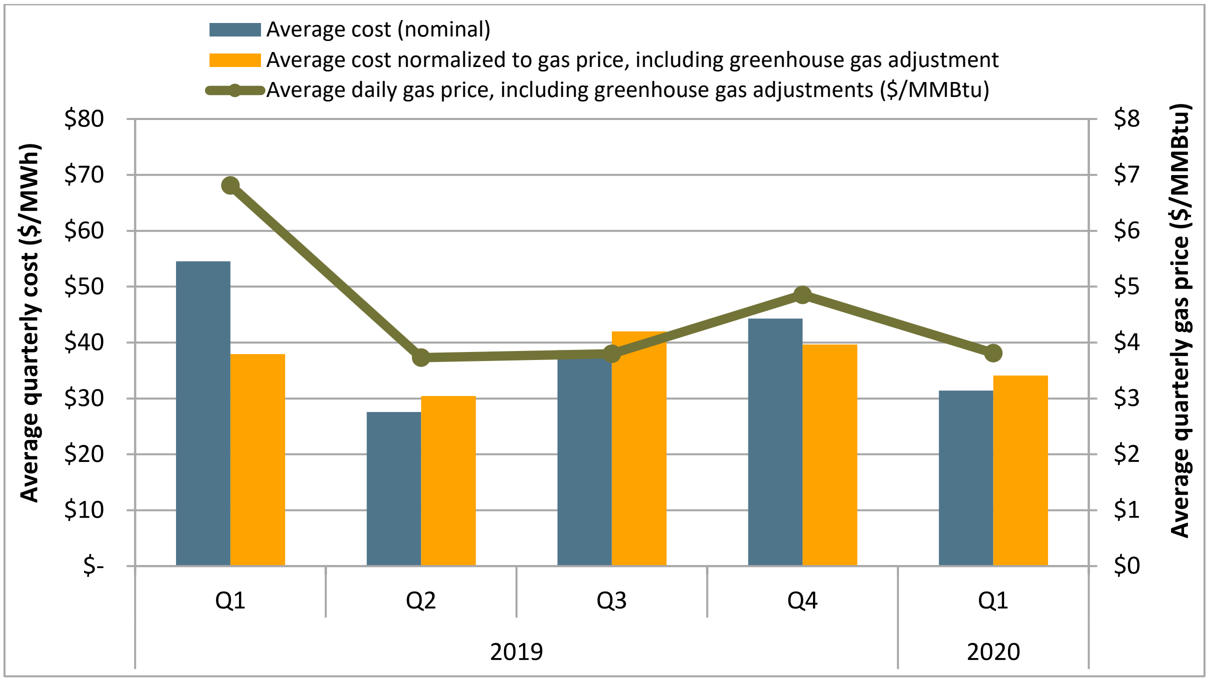


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (94 percent) of the total cost to deliver energy to the market, similar to the previous quarter and the first quarter of 2019. Real-time market costs decreased to about 1.5 percent of the total cost from about 3.3 percent in the previous quarter. Bid cost recovery costs were about 1 percent of total cost, similar to the previous quarter and the first quarter of 2019. Costs for reliability remained low at just below 0.1 percent, and reserve costs increased slightly to about 2 percent of total costs.

Table 1.1 Estimated average wholesale energy costs per MWh

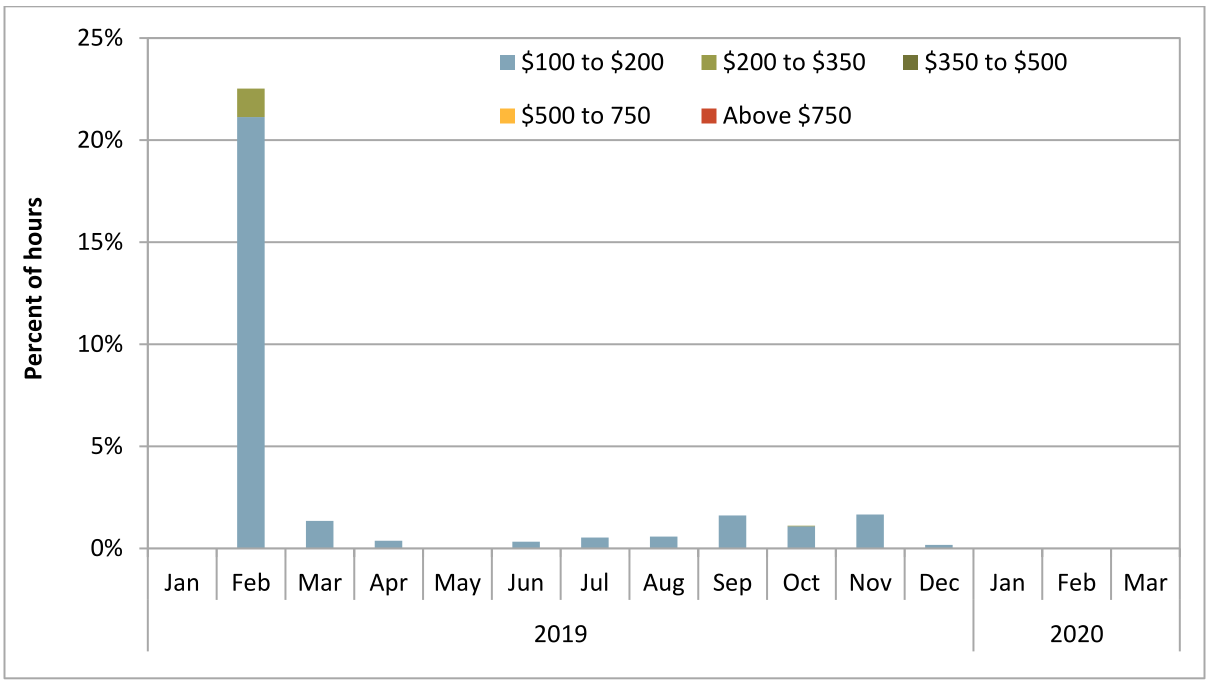
	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Change Q1 2019-Q1 2020
Day-ahead energy costs	$ 52.23	$ 24.08	$ 35.94	$ 41.36	$ 29.45	$ (22.78)
Real-time energy costs (incl. flex ramp)	$ 0.30	$ 1.30	$ 0.97	$ 1.45	$ 0.49	$ 0.19
Grid management charge	$ 0.46	$ 0.47	$ 0.45	$ 0.46	$ 0.45	$ (0.00)
Bid cost recovery costs	$ 0.56	$ 0.50	$ 0.72	$ 0.47	$ 0.34	$ (0.21)
Reliability costs (RMR and CPM)	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.03	$ (0.03)
Average total energy costs	**$ 53.60**	**$ 26.41**	**$ 38.14**	**$ 43.80**	**$ 30.76**	**$ (22.84)**
Reserve costs (AS and RUC)	$ 0.94	$ 1.15	$ 0.46	$ 0.49	$ 0.65	$ (0.29)
Average total costs of energy and reserve	**$ 54.54**	**$ 27.56**	**$ 38.60**	**$ 44.29**	**$ 31.41**	**$ (23.13)**

1.5 Day-ahead price variability

High prices

Figure 1.13 shows the frequency of day-ahead market prices in various high priced ranges from January 2019 to March 2020. There were no high prices over $100/MWh in the day-ahead market during the first quarter of 2020. High prices have been relatively infrequent in the day-ahead market since the first quarter of 2019 when high natural gas prices caused prices in February to surpass $100/MWh over 20 percent of hours.

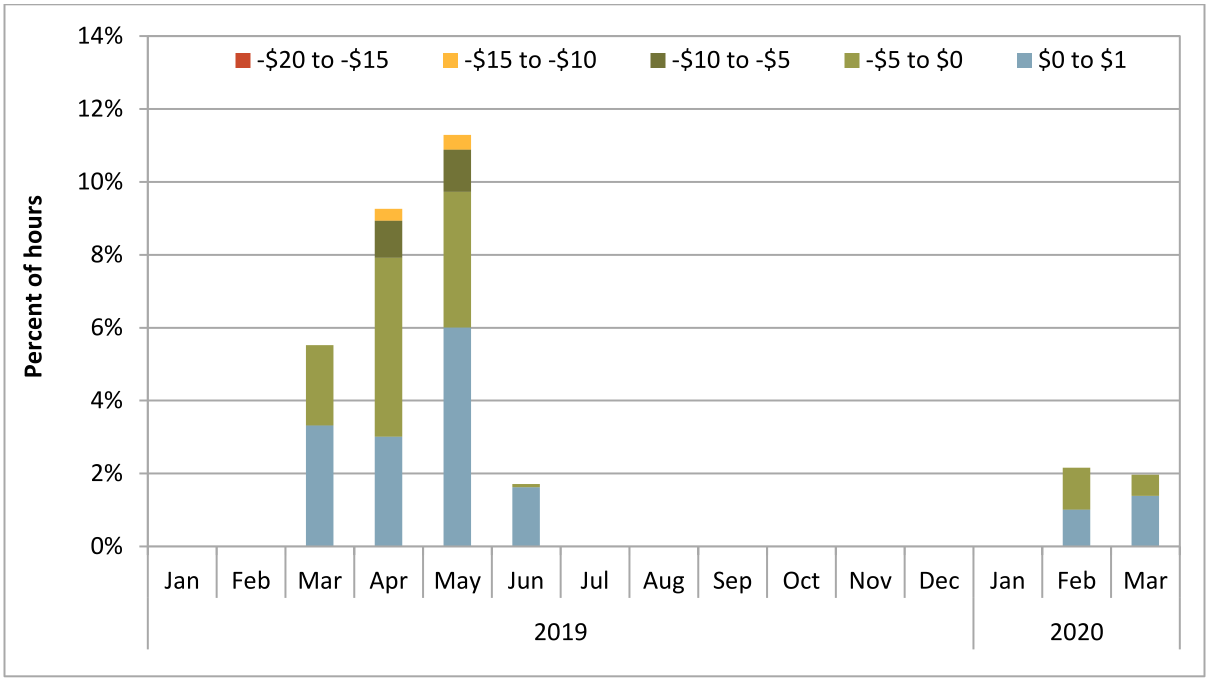
Figure 1.13 Frequency of high day-ahead prices (MWh) by month



Negative prices

Figure 1.14 shows the frequency of day-ahead market prices in various low priced ranges from January 2019 to March 2020. After two consecutive quarters of no negative prices, day-ahead prices dipped below $0/MWh during about 1 percent of hours or less in February and March. Negative day-ahead prices typically occur during the middle of the day when production from generators with low marginal costs, like solar resources, are at their highest.

Figure 1.14 Frequency of negative day-ahead prices ($/MWh) by month



1.6 Real-time price variability

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. During the first quarter of 2020, the frequency of high real-time prices was very low. The frequency of negative prices in the real-time markets increased from the previous quarter, but remained low relative to the first quarter of 2019.

High prices

Figure 1.15 and Figure 1.16 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.15, the occurrence of high prices in the 15-minute market greater than $250/MWh was extremely infrequent during the first quarter. There were no system under-supply infeasibilities for the quarter in the 15-minute market.

Figure 1.16 shows the frequency of high prices in the 5-minute market. During the first quarter, the frequency of price spikes greater than $250/MWh in the 5-minute market occurred during less than 0.5 percent of intervals, similar to the previous quarter.

Figure 1.17 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. Valid under-supply infeasibilities were very infrequent in the first quarter, occurring during less than 0.1 percent of 5-minute market intervals.

Infeasibilities resolved by the load conformance limiter continued to be infrequent. However, the load conformance limiter did not have a significant impact on prices in the ISO. This is 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 1.15 Frequency of high 15-minute prices by month (ISO LAP areas)

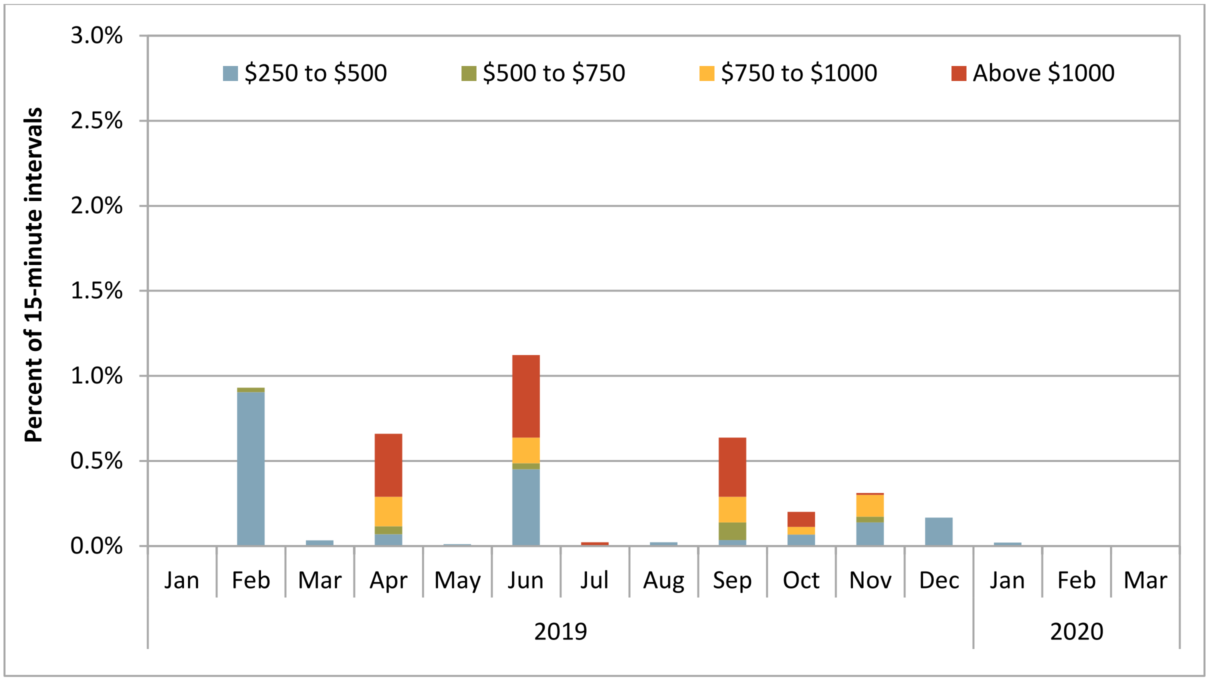


Figure 1.16 Frequency of high 5-minute prices by month (ISO LAP areas)

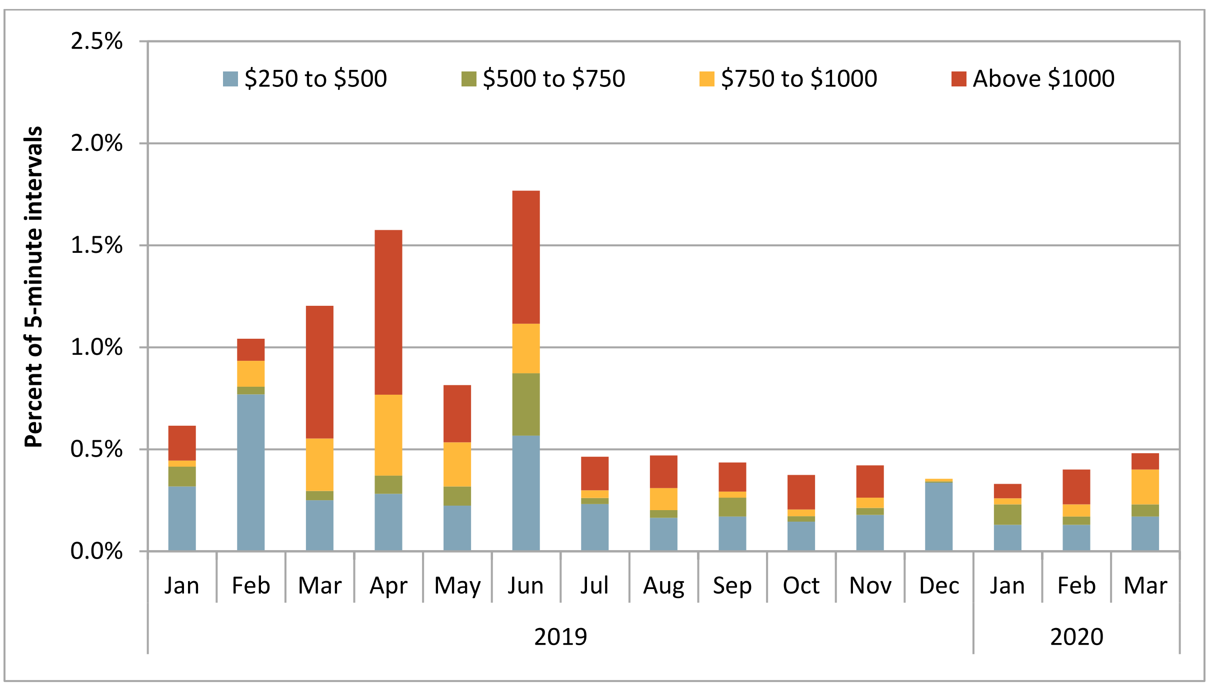
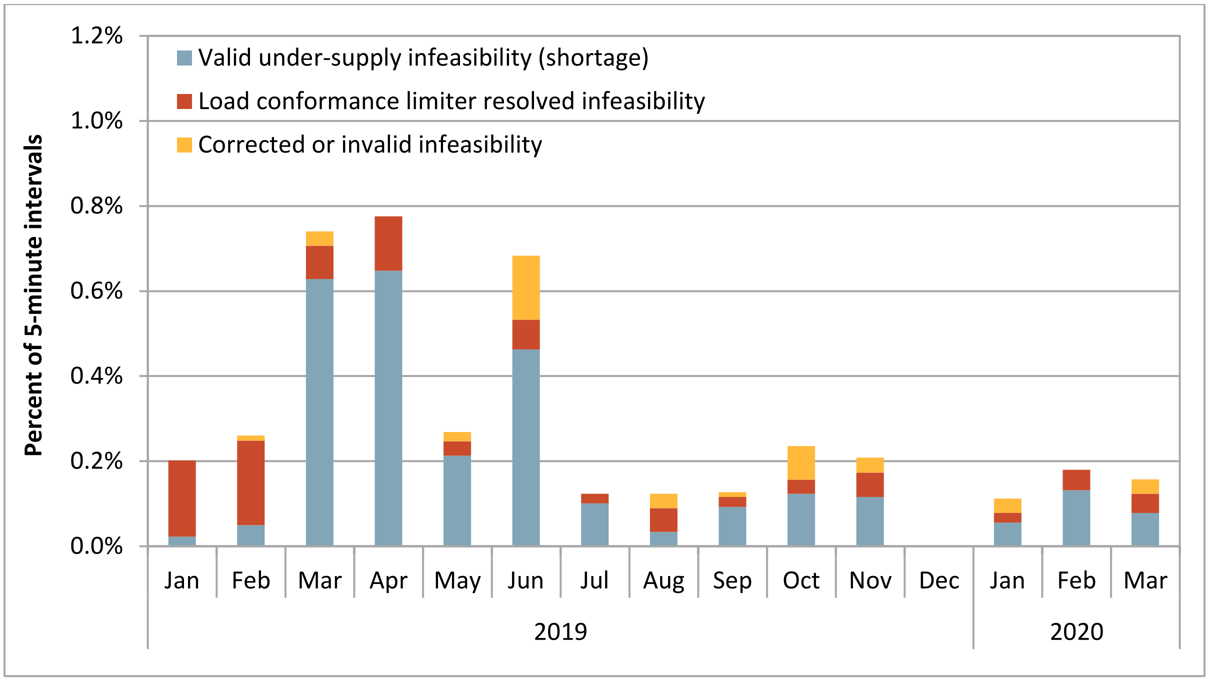


Figure 1.17 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



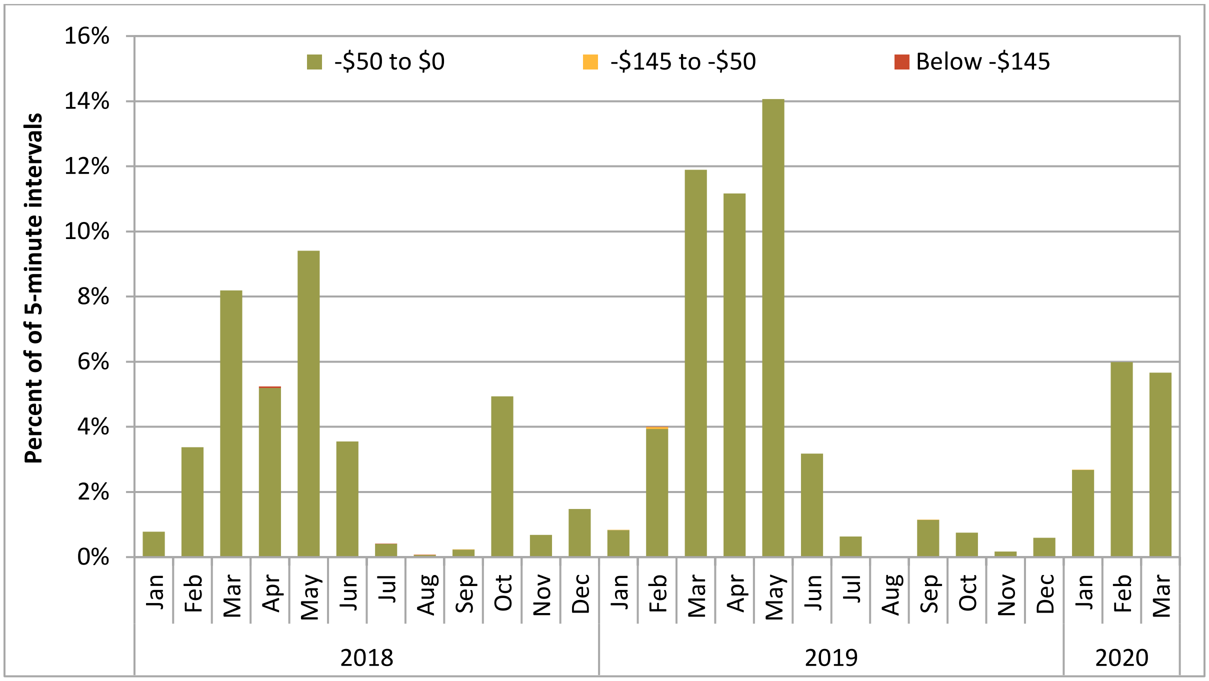
Negative prices

Figure 1.18 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[9] The frequency of negative prices in the 15-minute and 5-minute markets increased from the previous quarter, but remained low relative to the first quarter of 2019. Negative prices during the first quarter of 2020 occurred during around 3 percent of 15-minute intervals and 5 percent of 5-minute intervals.

There were no intervals when the power balance constraint was relaxed because of excess energy during the quarter. Instead, negative prices were typically set by economic bids from wind and solar resources reflecting their relatively low marginal costs. During the first quarter, this was most frequent between hours ending 10 and 17 when loads, net of wind and solar, were lowest.

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

Figure 1.18 Frequency of negative 5-minute prices by month (ISO LAP areas)



1.7 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.

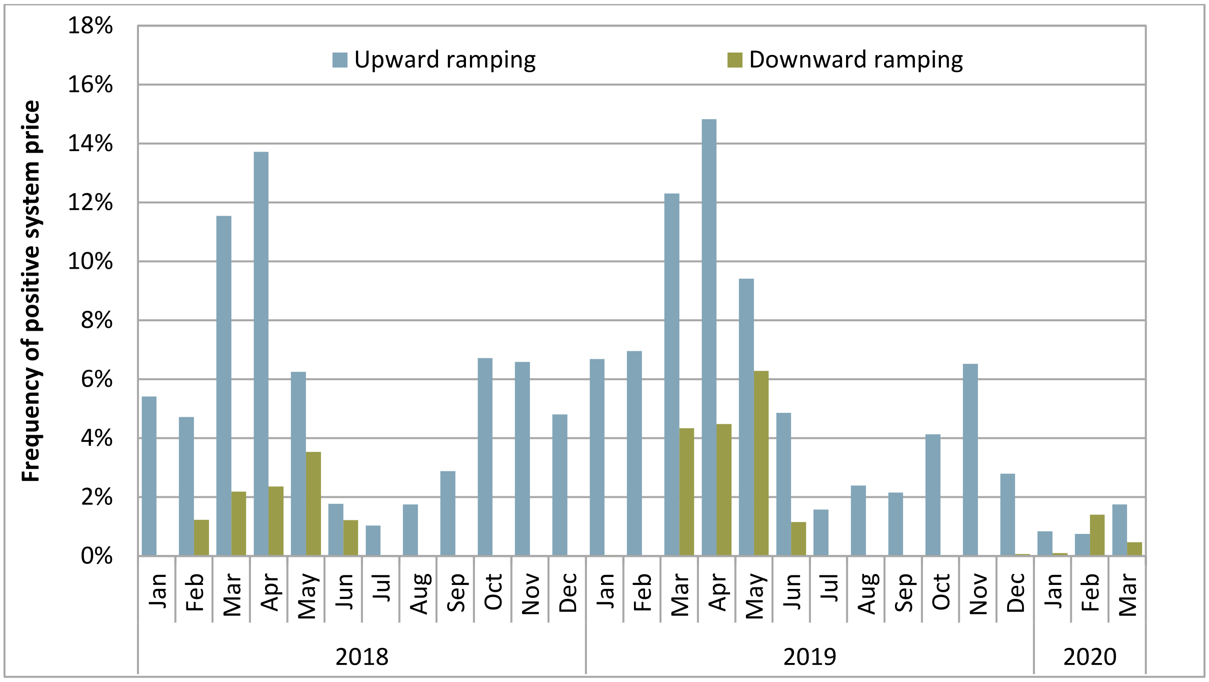
The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the three 5-minute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

1.7.1 Flexible ramping product prices

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

Figure 1.19 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. In the first quarter, the frequency of positive shadow prices was very low. The 15-minute market system-level demand curves for both upward ramping and downward ramping bound in around 1 percent of intervals during the quarter. In the 5-minute market, the system-level demand curves bound in less than 0.1 percent of intervals.

Figure 1.19 Monthly frequency of positive 15-minute market flexible ramping shadow price



1.7.2 Flexible ramping product costs

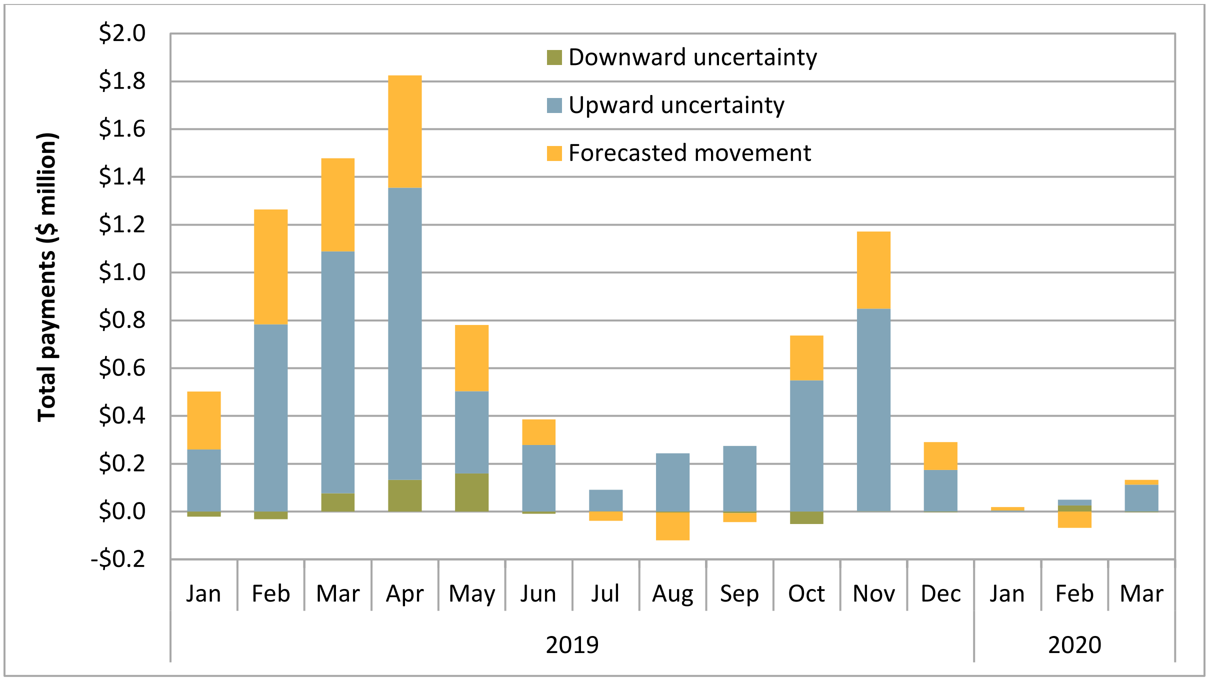
Flexible ramping capacity that satisfy the demand for upward and downward uncertainty receive payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price is used to pay or charge for forecasted ramping movements. This means a generator that was given an advisory dispatch by the market to increase output was paid the upward flexible ramping price and charged the downward flexible ramping price. Similarly, a generator that was forecast to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[10]

Figure 1.20 shows the total monthly net payments to resources from the flexible ramping product, including both payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. Payments for flexible ramping capacity were down significantly from the previous quarter, consistent with a lower frequency of nonzero prices for flexible ramping capacity. Total uncertainty payments to generators in the ISO and the EIM for providing flexible

[10] More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

ramping capacity during the first quarter were around \$0.2 million, compared to around \$1.5 million in the previous quarter.

Figure 1.20 Monthly flexible ramping product payments by type



1.7.3 Flexible ramping product procurement

One of the key objectives of the flexible ramping product is to address the challenges of maintaining power balance in real-time between supply and demand. The flexible ramping product allows the market to account and procure for uncertainty surrounding a forecasted value that could otherwise result in an infeasibility. However, procurement of flexible ramping capacity from resources that are not able to meet system uncertainty — either because of resource characteristics or congestion — can reduce the effectiveness of the flexible ramping product to both manage net load volatility and prevent power balance violations.

The ISO's September 2019 report highlighted the issue of procuring flexible ramping capacity from proxy demand response units that were not able to respond to isolated 5-minute dispatches.[11] As part of the energy storage and distributed energy resources phase 3a initiative, effective November 13, 2019, additional bidding options were made available to proxy demand response units including 60-minute and 15-minute dispatchability. A fix was implemented at the start of April 2020 to ensure that proxy demand response resources flagged as 60-minute or 15-minute dispatchable do not receive flexible ramping product uncertainty awards. As of June 2020, only about 5 percent of proxy demand response resources are still on the 5-minute dispatch option.

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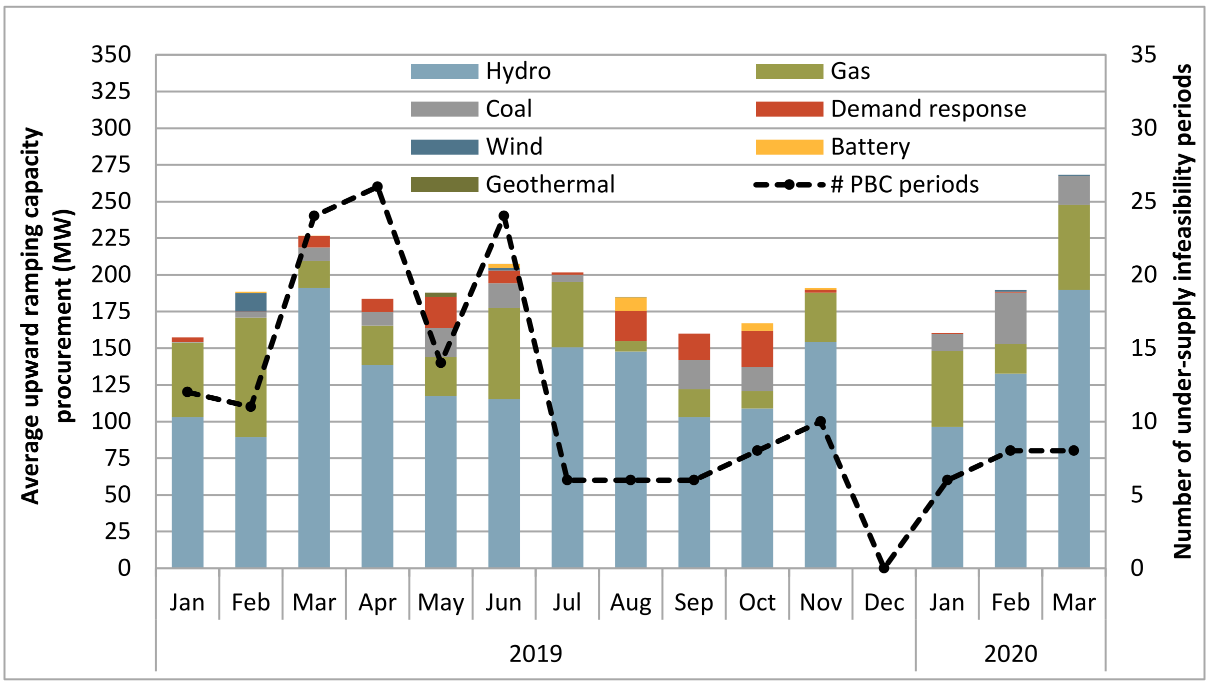
[11] CAISO Energy Markets Price Performance Report, California ISO, September 23, 2019: http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

Figure 1.21 shows the average upward ramping capacity procured in the 5-minute market by fuel type in the interval prior to any system under-supply infeasibility (or period of consecutive infeasibilities).[12] The dotted line shows the underlying number of under-supply infeasibility periods in each month. The bars show the average procurement of upward ramping capacity by fuel type in the interval prior to these periods. During the first quarter, flexible ramping capacity awards in the interval prior to under-supply infeasibility periods were largely to hydro resources (67 percent) and gas resources (20 percent).

Figure 1.22 shows the same procurement information as Figure 1.21, except by area instead of fuel type. DMM has previously highlighted how resources stranded behind transfer constraints (particularly in the Northwest) can contribute to lower deliverability of flexible ramping capacity at the system level and suppress the true opportunity cost of providing such capacity instead of energy.[13] During the first quarter, flexible ramping capacity awards to resources in the Northwest region made up 43 percent of procurement in the interval prior to under-supply infeasibility periods.

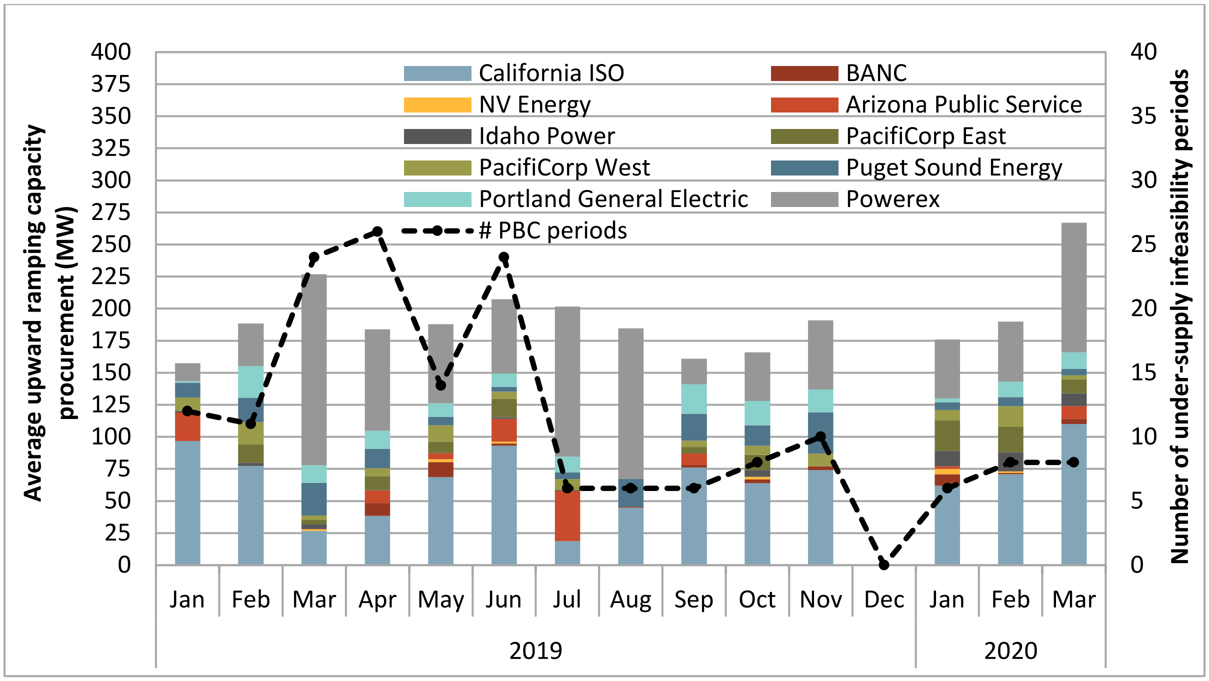
Figure 1.21 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by fuel type



[12] For under-supply infeasibility periods lasting longer in duration than one 5-minute interval, only procurement in the interval prior to these periods is summarized in these figures.

[13] For more detailed information on this issue, see Section 3.1.3 in DMM's *Q3 2019 Report on Market Issues and Performance*, December 5, 2019: http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf.

Figure 1.22 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by area



1.8 Convergence bidding

Convergence bidding was profitable overall for the first quarter of 2020. Virtual supply has been consistently profitable beginning in the first quarter of 2017, with the exception of the second quarter of 2019. Combined net revenue for virtual supply and demand was about $3.2 million after including about $1.6 million of virtual bidding bid cost recovery charges. Virtual demand generated revenues of about -$2.6 million. Before accounting for bid cost recovery charges, virtual supply generated positive net revenues of $7.5 million.

1.8.1 Convergence bidding trends

Average hourly cleared volumes were about 3,100 MW, a decrease of about 100 MW from the previous quarter. Average hourly virtual supply remained similar to the previous quarter at about 1,900 MW. Virtual demand averaged around 1,200 MW during each hour of the quarter, a 100 MW decrease from the previous quarter. On average, about 24 percent of virtual supply and demand bids offered into the market cleared in the quarter, down slightly from 25 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 720 MW on average, an increase from 560 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand only exceeded net cleared virtual supply in hour ending 6. In the remaining 23 hours, net cleared virtual supply exceeded net cleared virtual demand. Similar to the previous quarter, cleared virtual supply exceeded virtual demand by 1,000 MW during hours ending 21 through 24. Additionally, virtual supply exceeded virtual demand between 750 MW and 1,000 MW between hours ending 9 and 16.

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, net convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 22 of 24 hours. The two inconsistent volumes occurred in hours ending 6 and 13.

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 demand and supply bids at different locations during the same hour. These virtual demand and supply 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 in 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 about 760 MW of virtual demand offset by 760 MW of virtual supply in each hour of the quarter, a slight decrease of 20 MW from the previous quarter. These offsetting bids represented about 48 percent of all cleared virtual bids in the first quarter, a decrease of about 1 percent from the previous quarter.

1.8.2 Convergence bidding revenues

Participants engaged in convergence bidding in the first quarter were profitable overall. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $4.8 million. Net revenues for virtual supply and demand fell to about $3.2 million after the inclusion of about $1.6 million of virtual bidding bid cost recovery charges.[14] This decline is due primarily to bid cost recovery charges associated with virtual supply.

Figure 1.23 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).

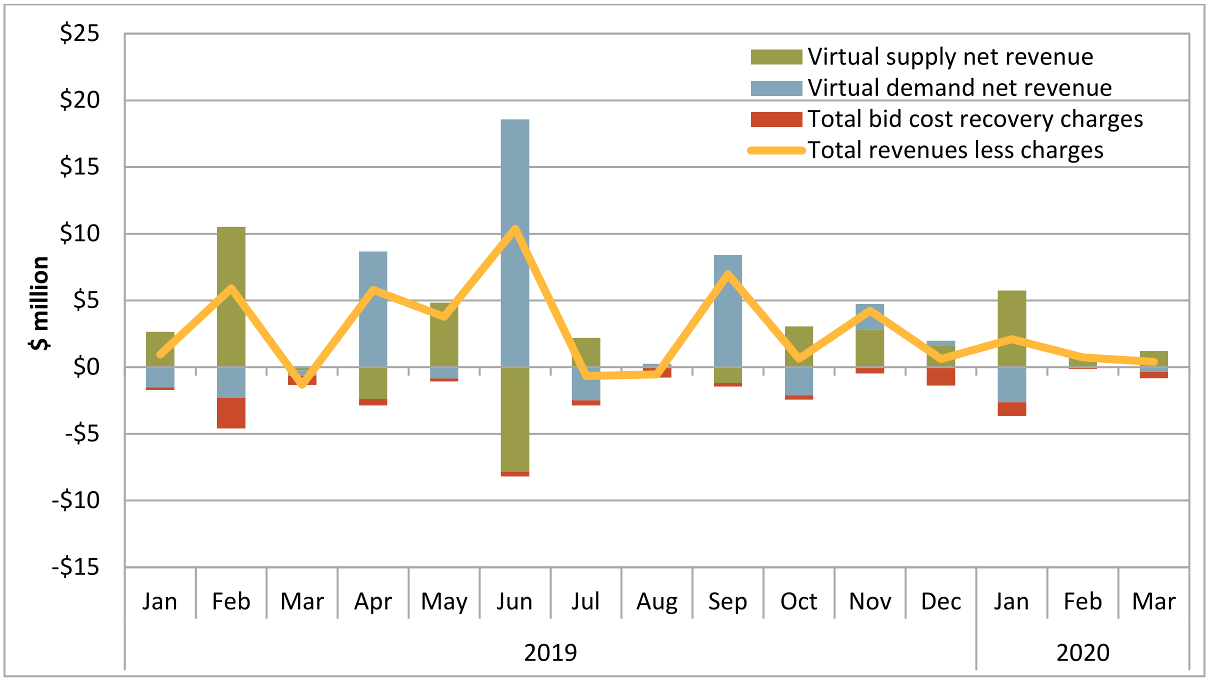
Before accounting for bid cost recovery charges:

- Total market revenues were positive during all months of the quarter. Net revenues during the first quarter totaled about $4.8 million, compared to about $8.7 million during the same quarter in 2019, and about $7.62 million during the previous quarter.
- Virtual demand net revenues were negative or close to zero in all months of the quarter with January the most negative at about $2.6 million.

[14] 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.

- Virtual supply net revenues were positive in all months of the quarter with $5.8 million, $0.7 million and $1.2 million for January, February, and March, respectively.

Figure 1.23 Convergence bidding revenues and bid cost recovery charges



Convergence bidders received about $4.8 million before subtracting bid cost recovery charges of about $1.6 million for the quarter.[15,16] Bid cost recovery charges were about $1 million in January, $0.15 million in February and $0.5 million in March.

Net revenues and volumes by participant type

Table 1.2 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the quarter.[17] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market,

15 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.

16 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.

17 DMM has defined financial entities as participants who own no physical power and participate in the convergence bidding and congestion revenue rights markets only. Physical generation and load are represented by participants that primarily participate in the ISO markets as physical generators and load serving entities, respectively. Marketers include participants on the interties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

accounting for about 73 percent of volume and 69 percent of settlement revenue. Marketers represented about 25 percent of the trading volumes and about 28 percent of settlement revenue. Generation owners and load serving entities represented a smaller segment of the virtual market in terms of both volumes and settlement revenue, at about 2 percent and 3 percent respectively. Generation owners and load serving entities accounted for around $0.14 million of net revenues in the market.

Table 1.2 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	845	1,268	2,113	-$1.89	$5.28	$3.39
Marketer	254	483	737	-$0.69	$2.06	$1.37
Physical load	6	32	38	-$0.05	$0.10	$0.05
Physical generation	0	22	22	$0.00	$0.09	$0.09
Total	**1,105**	**1,804**	**2,909**	**-$2.6**	**$7.5**	**$4.9**

1.9 Ancillary services

1.9.1 Ancillary service requirements

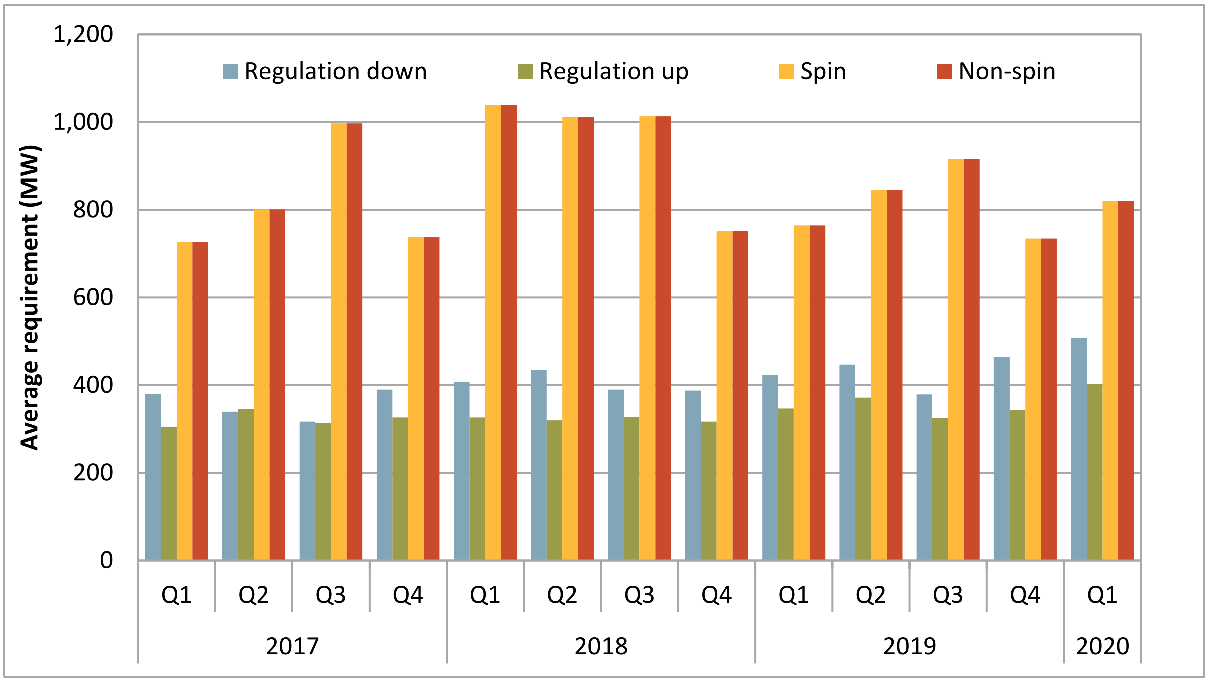
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) 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 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. Both internal resources and imports then 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. Projected schedules on the Pacific DC intertie that sink in the ISO balancing area (which can include a higher volume than the share that sinks directly in the ISO) often serve as the most severe single contingency.

Figure 1.24 shows quarterly average ancillary service requirements for the expanded system region in the day-ahead market. As shown in the figure, average requirements for all ancillary service types increased from the previous quarter.

Figure 1.24 Average quarterly day-ahead ancillary service requirements

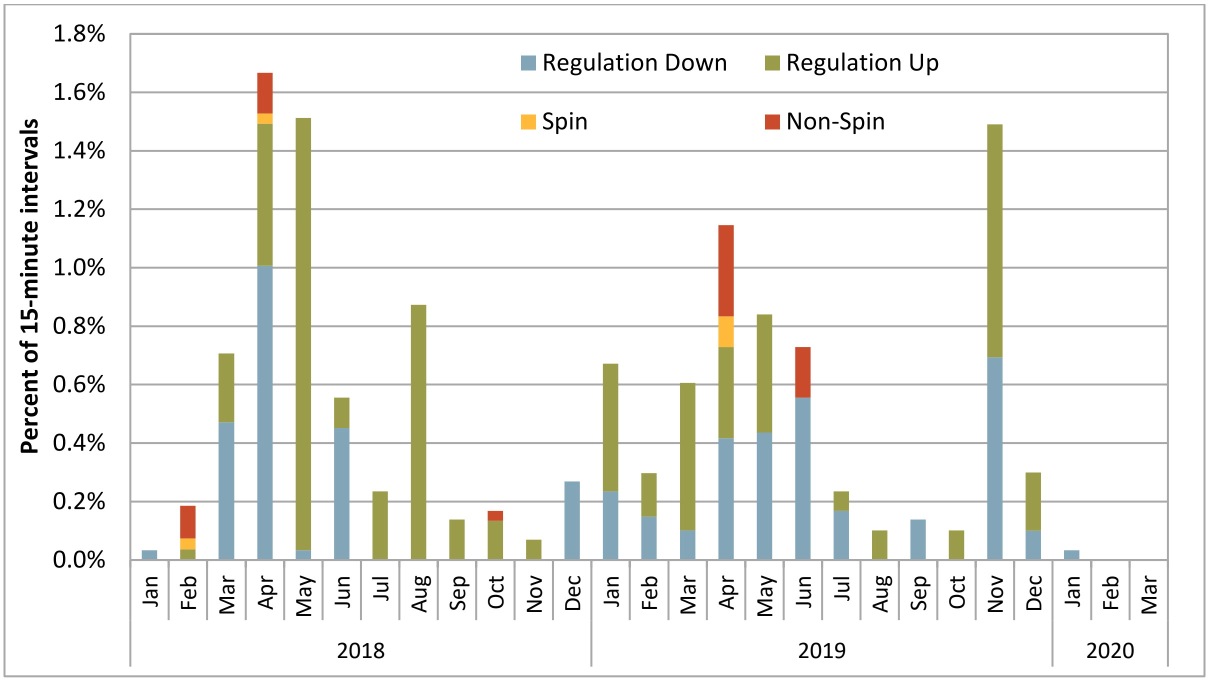


1.9.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, implemented in December 2010, 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 1.25, the frequency of intervals with scarcity pricing was very low during the first quarter. There was only one interval in January with a scarcity of regulation down in the expanded South of Path 26 sub-region.

Figure 1.25 Frequency of ancillary service scarcities (15-minute market)

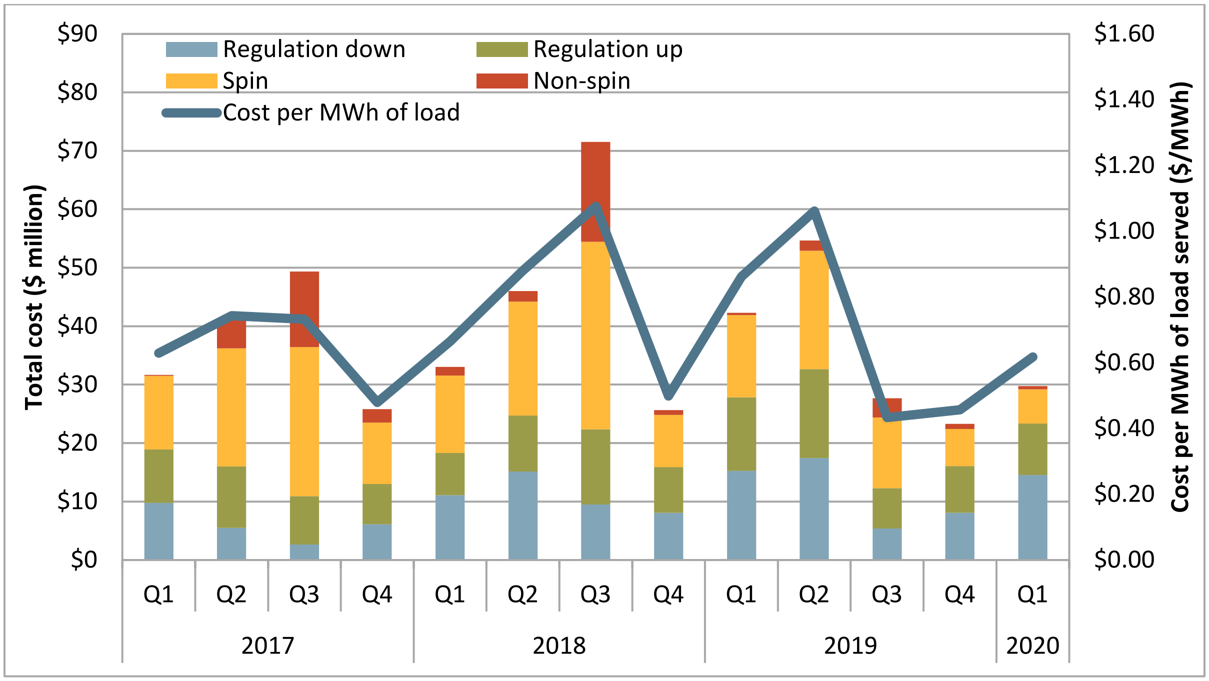


1.9.3 Ancillary service costs

Ancillary service payments increased during the first quarter to about $30 million, compared to about $23 million in the previous quarter and $42 million during the same quarter in 2019. Total payments were higher relative to the previous quarter despite much fewer ancillary service scarcities. In particular, total payments associated with regulation down increased by around $6 million from the previous quarter.

Figure 1.26 shows the total cost of procuring ancillary service products by quarter as well as the total ancillary service cost for each megawatt-hour of load served. 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.

Figure 1.26 Ancillary service cost by product



1.10 Congestion

This section provides an assessment of the frequency and impact of congestion on prices in the day-ahead, 15-minute, and 5-minute markets. It assesses the impact of congestion on local areas in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and 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.[18]

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.

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

1.10.1 Congestion in the day-ahead market

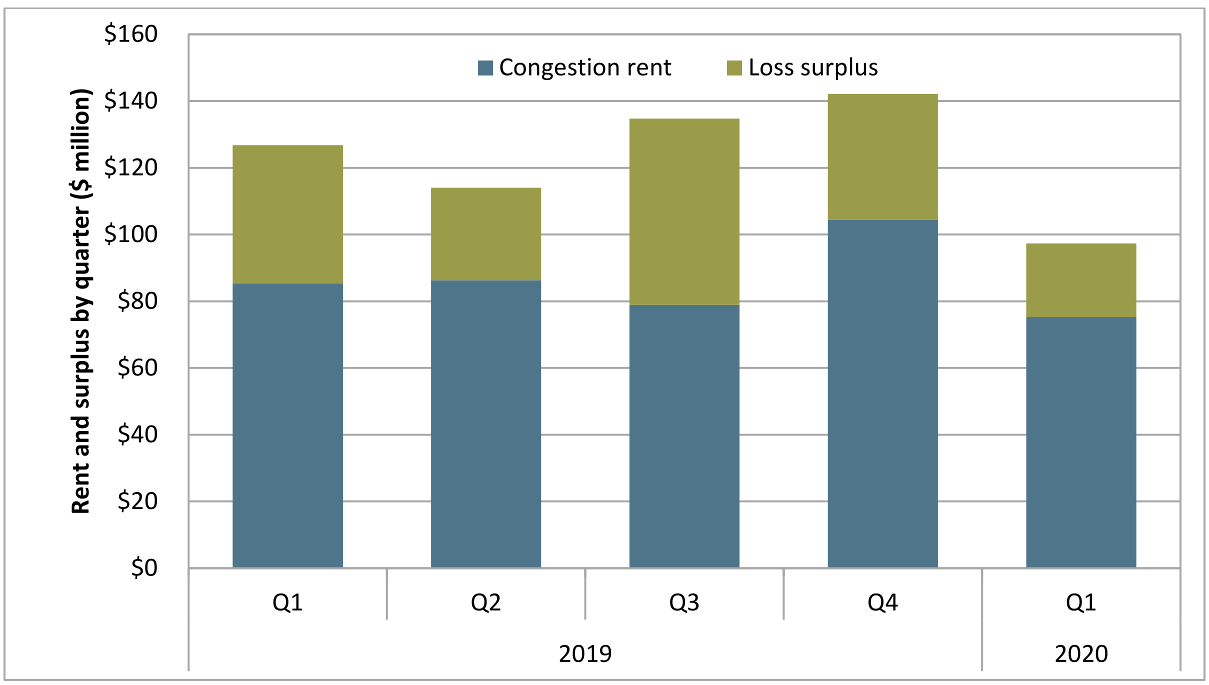
Day-ahead market congestion frequency tends to be higher than in the 15-minute market, but price impacts to load tend to be lower. The congestion pattern in this quarter reflects this overall trend.

Congestion rent and loss surplus

In the 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.[19]

Figure 1.27 shows the congestion and loss rent by quarter for 2019 and 2020. Both congestion rents and loss surplus were lower in the first quarter of 2020 compared to any quarter of 2019, with totals only reaching about $75 million and $22 million, respectively. Comparing the first quarter of 2020 to the first quarter of 2019 shows that congestion rent decreased by 12 percent while the loss surplus decreased by 47 percent.

Figure 1.27 Day-ahead congestion rent and loss surplus by quarter (2019-2020)



[19] 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

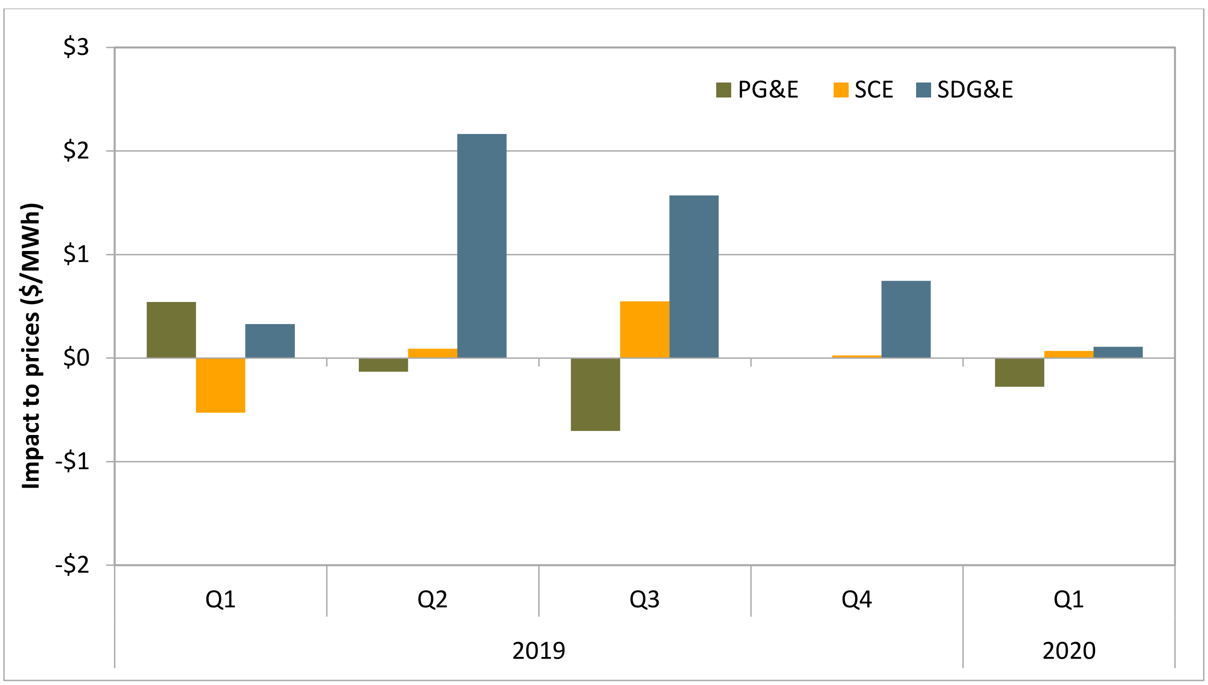
Impact of congestion to overall prices in each load area

Figure 1.28 shows the overall impact of congestion on day-ahead prices in each load area for each quarter in 2019 and 2020.[20] Figure 1.29 shows the frequency of congestion. Highlights for this quarter include:

- The overall net impact to price separation was low relative to most quarters in 2019. Although the frequency of congestion decreased in PG&E and SCE compared with the last quarter of 2019, it increased significantly in SDG&E in the first quarter.
- Congestion decreased PG&E prices by \$0.28/MWh (-1.0 percent) but had little net impact on SDG&E and SCE (less than \$0.11/MWh increase).
- On an average quarterly basis, congestion impact was frequently offsetting, as shown in Figure 1.30. In the first quarter, the number of intervals when congestion increased versus decreased prices was relatively close in each of the load areas.
- The primary constraints impacting price separation in the day-ahead market were the Doublet Tap-Friars 138 kV line, the Serrano transformer 500/230 kV, and the Imperial Valley nomogram.

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

Figure 1.28 Overall impact of congestion on price separation in the day-ahead market



[20] The values in the figure represent the net impact of constraints on prices. Congestion sometimes increased and sometimes decreased values in each of the areas.

Figure 1.29 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

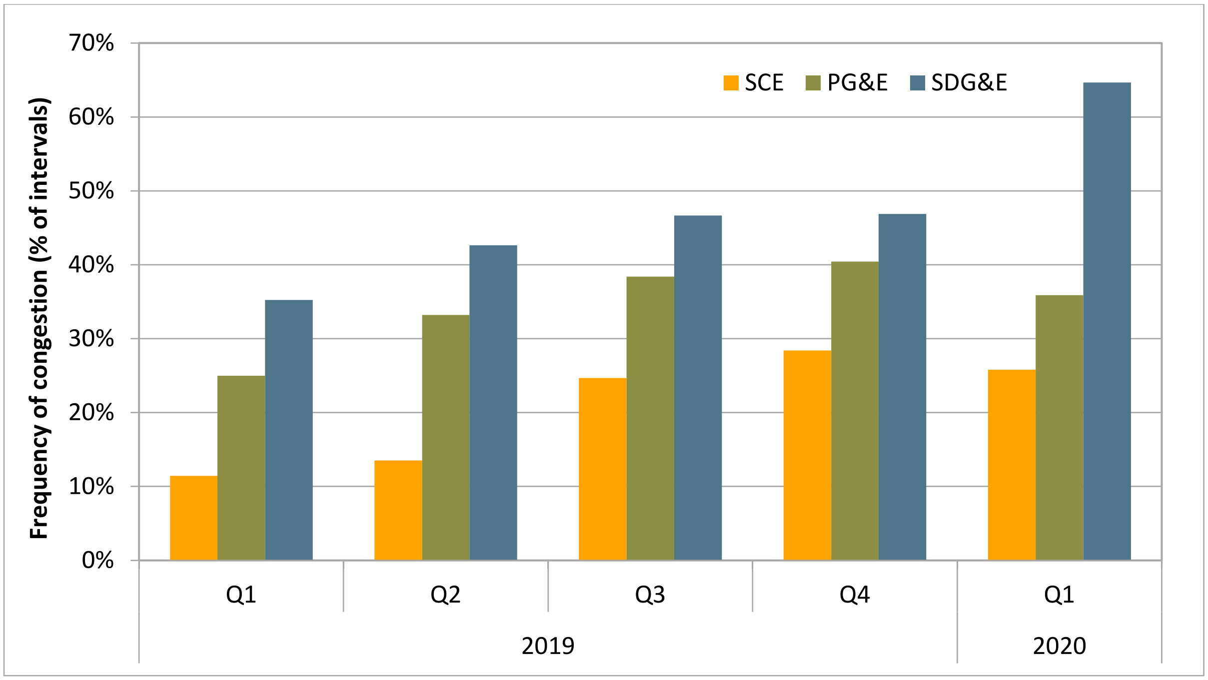
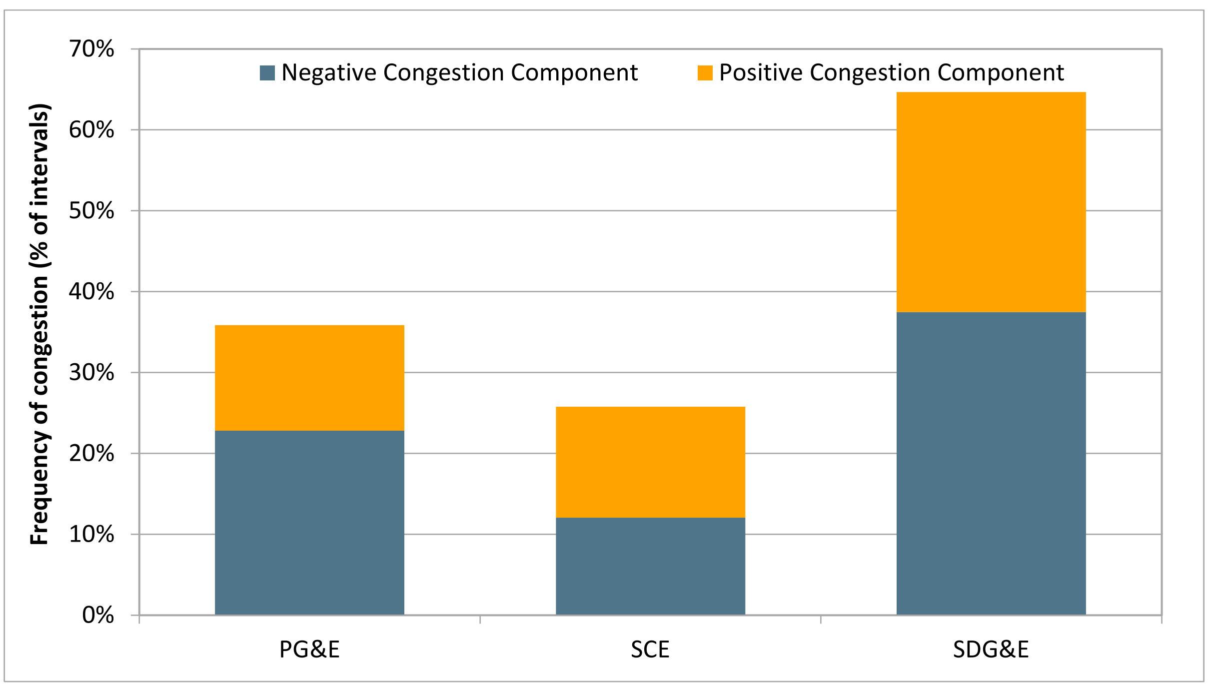


Figure 1.30 Percent of hours with congestion increasing versus decreasing day-ahead prices in the first quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.3 breaks down the impact to price separation in the quarter by constraint.[21] Table 1.4 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 Doublet Tap-Friars 138 kV line, the Serrano transformer 500/230 kV, and the Imperial Valley nomogram.

Doublet Tap-Friars 138 kV line

The Doublet Tap-Friars 138 kV line (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1) bound frequently in about 37 percent of hours. When binding, it decreased prices in SDG&E by about $3.07/MWh. Overall for the quarter, the constraint decreased prices in SDG&E by about $1.13/MWh (4 percent). This constraint primarily bound due to normal flow conditions and was not a result of outages.

Serrano transformer 500/230 kV

Congestion on the Serrano 500/230 kV transformer (24138_SERRANO _500_24137_SERRANO _230_XF_3) significantly impacted price separation in the quarter, binding in roughly 9 percent of intervals. When binding, the constraint increased SCE and SDG&E prices by about $2.29/MWh and $6.95/MWh, respectively, and decreased prices for PG&E by about $3.93/MWh. Overall for the quarter, the constraint had the most impact on SDG&E, where it increased prices by an average of $0.59/MWh (2 percent).

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the quarter, during 11 percent of hours. When binding, it increased SDG&E prices by about $3.29/MWh and decreased PG&E prices slightly by about $0.31/MWh. Over the entire quarter, it increased SDG&E prices by about $0.37/MWh (1.27 percent) and decreased PG&E prices $0.03/MWh (0.12 percent). In the 2017-2018 transmission planning cycle, an upgrade to the Imperial Valley-El Centro 230 kV S-Line was approved. The project, which is planned to be complete in 2021, will help to alleviate congestion in this area.

21 Details on constraints with shift factors less than 2 percent have been grouped in the “other” category.

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.11	0.39%	-$0.10	-0.34%	-$0.09	-0.31%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.04	0.14%	-$0.04	-0.13%	-$0.03	-0.12%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.04	0.14%	-$0.03	-0.11%	-$0.03	-0.11%
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.02	0.08%	-$0.02	-0.07%	-$0.02	-0.07%
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.01	0.03%	-$0.01	0.00%	-$0.01	0.00%
SCE	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	-$0.08	-0.28%	$0.07	0.25%	$0.08	0.26%
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	-$0.03	-0.11%	$0.03	0.10%	$0.00	0.01%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.03%	$0.01	0.03%	$0.00	0.00%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.01	-0.02%	$0.00	0.01%	$0.04	0.13%
	24114_PARDEE _230_24147_SYLMAR S_230_BR_1 _1	$0.00	0.01%	$0.00	0.00%	-$0.02	0.00%
	6410_CP10_NG	$0.01	0.04%	-$0.01	-0.04%	-$0.01	-0.04%
	OMS 8095129_D-SBLR_OOS_N1SV500	$0.01	0.00%	-$0.01	0.00%	$0.00	-0.01%
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.33	-1.15%	$0.19	0.00%	$0.59	2.03%
	7820_TL 230S_OVERLOAD_NG	-$0.03	-0.12%	$0.00	0.00%	$0.37	1.27%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-$0.01	-0.03%	$0.00	0.00%	$0.06	0.22%
	OMS 8092833 MG-BK81_NG	-$0.01	-0.03%	$0.00	0.00%	$0.06	0.22%
	OMS 8098960_TL50003_NG	-$0.01	0.00%	$0.00	0.00%	$0.06	0.21%
	OMS 8286163_50001_OOS_NG	$0.00	-0.01%	$0.00	0.00%	$0.06	0.20%
	OMS 8286167_50001_OOS_NG	$0.00	0.00%	$0.00	0.00%	$0.06	0.20%
	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.05	0.17%
	OMS 8286176_50001_OOS_NG	$0.00	-0.01%	$0.00	0.00%	$0.05	0.16%
	OMS 8247851_50001_OOS_NG	$0.00	0.00%	$0.00	0.00%	$0.05	0.16%
	OMS 8098953_TL50003_NG	$0.00	0.00%	$0.00	0.00%	$0.04	0.14%
	OMS 8092823 MG-BK81_NG	-$0.01	0.00%	$0.00	0.00%	$0.04	0.12%
	OMS 8286076_50001_OOS_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.11%
	OMS 8286183_50001_OOS_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.10%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.07%
	7820_TL 230S_TL50001OUT_NG	$0.00	0.00%	$0.00	0.00%	$0.02	0.06%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.05%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	8282545_D-VISTA1_2_OOS_CP6_NG	$0.01	0.00%	-$0.01	0.00%	$0.00	-0.01%
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.31	-1.07%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$1.13	-3.92%
Other		$0.00	0.01%	$0.00	0.00%	$0.06	0.20%
Total		**-$0.28**	**-0.96%**	**$0.07**	**0.24%**	**$0.11**	**0.37%**

Table 1.4 Impact of congestion on day-ahead prices during congested hours[22]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	4.9%	$2.33	-$2.00	-$1.82
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	4.7%	$0.86	-$0.68	-$0.66
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.2%	$1.82	-$1.59	-$1.49
	30735_METCALF _230_30042_METCALF _500_XF_12	1.2%	$1.96	-$1.60	-$1.59
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	0.6%	$1.70	-$1.43	-$1.43
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.6%	$1.44	-$1.17	-$1.09
SCE	OMS 8095129_D-SBLR_OOS_N1SV500	4.0%	$0.29	-$0.31	-$0.16
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	3.1%	-$2.56	$2.24	$2.43
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.0%	-$0.73	$0.72	$1.22
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	2.3%	-$1.39	$1.19	$0.70
	24114_PARDEE _230_24147_SYLMAR S_230_BR_1 _1	1.2%	$0.45	$0.00	-$1.73
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.6%	-$1.28	$1.59	$0.55
	6410_CP10_NG	0.6%	$2.27	-$1.99	-$1.87
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	36.9%	$0.00	$0.00	-$3.07
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	34.5%	$0.00	$0.00	-$0.90
	7820_TL 230S_OVERLOAD_NG	11.2%	-$0.31	$0.00	$3.29
	24138_SERRANO _500_24137_SERRANO _230_XF_3	8.5%	-$3.93	$2.29	$6.95
	8282545_D-VISTA1_2_OOS_CP6_NG	1.5%	$0.63	-$0.74	-$0.72
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	1.4%	-$0.66	$0.00	$4.59
	7820_TL 230S_TL50001OUT_NG	0.8%	-$0.21	$0.00	$2.13
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	0.6%	$0.00	$0.00	$2.23
	OMS 8286167_50001_OOS_NG	0.6%	-$0.65	$0.00	$9.48
	OMS 8092833 MG-BK81_NG	0.6%	-$1.50	$0.00	$11.42
	OMS 8286163_50001_OOS_NG	0.5%	-$0.80	$0.00	$11.25
	OMS 8247851_50001_OOS_NG	0.5%	-$0.68	$0.00	$10.15
	OMS 8286076_50001_OOS_NG	0.5%	-$0.46	$0.00	$6.73
	OMS 8098960_TL50003_NG	0.5%	-$1.38	$0.00	$13.37
	OMS 8286183_50001_OOS_NG	0.5%	-$0.42	$0.00	$6.51
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	0.4%	-$0.28	$0.00	$2.06
	MIGUEL_BKs_MXFLW_NG	0.4%	-$0.99	$0.00	$11.92
	OMS 8286176_50001_OOS_NG	0.4%	-$0.75	$0.00	$11.48
	OMS 8098953_TL50003_NG	0.4%	-$1.04	$0.00	$9.66
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.3%	$0.00	$0.00	$7.56
	OMS 8092823 MG-BK81_NG	0.2%	-$2.41	$0.00	$15.43

1.10.2 Congestion in the real-time market

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

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

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

Figure 1.31 shows the overall impact of congestion on 15-minute prices in each load area for each quarter of 2019 and 2020. Figure 1.32 shows the frequency of congestion. Highlights for this quarter include:

- The overall net impact to price separation of congestion was lower in the first quarter of 2020 compared to the same quarter of 2019. Congestion resulted in a net increase to PG&E, SCE, SDG&E, and BANC prices and a net decrease to prices in NEVP, AZPS, PACE, IPCO, PACW, PGE, PSEI, and PWRX.
- Congestion continued to impact prices in both the positive and negative direction over the quarter in each load area, often offsetting the impact of congestion over the quarter. The frequency of congestion was highest in PacifiCorp East (63 percent of total intervals), where congestion predominantly decreased prices (62 percent of total intervals).
- The primary constraints impacting price separation in the 15-minute market were the Los Banos-Quinto 230 kV line, the Imperial Valley nomogram, and the Doublet Tap-Friars 138 kV line.

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

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

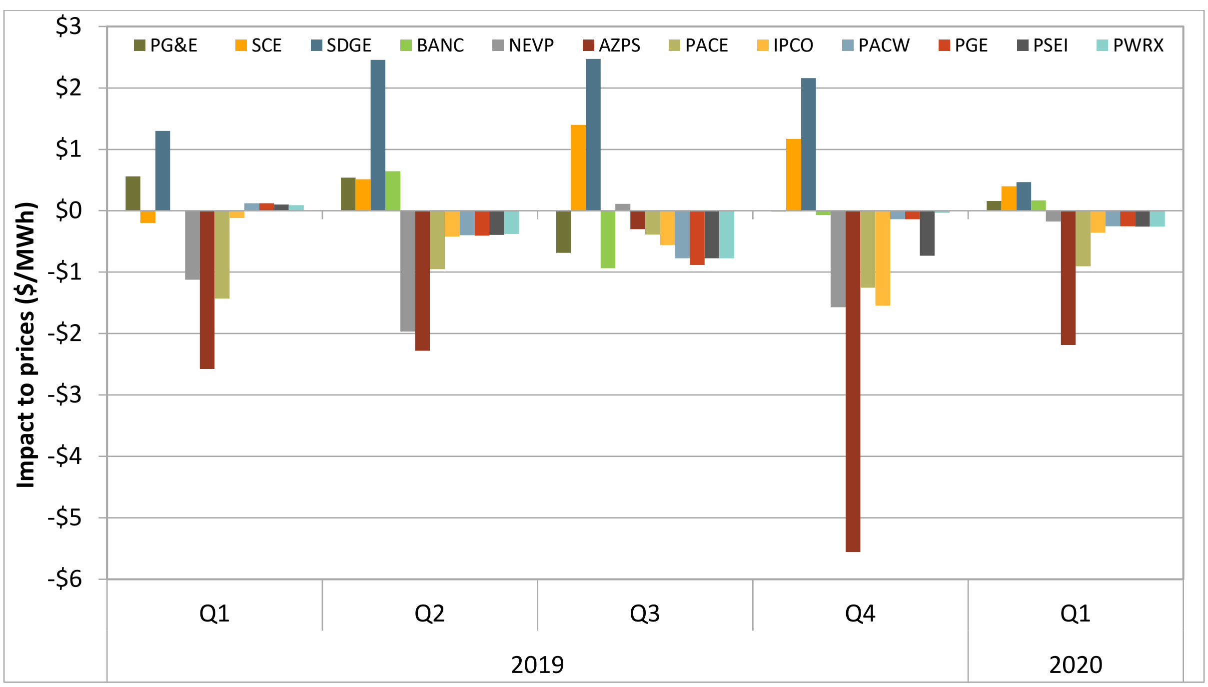


Figure 1.32 Percent of intervals with internal congestion increasing versus decreasing 15-minute prices in the first quarter (>$0.05/MWh)

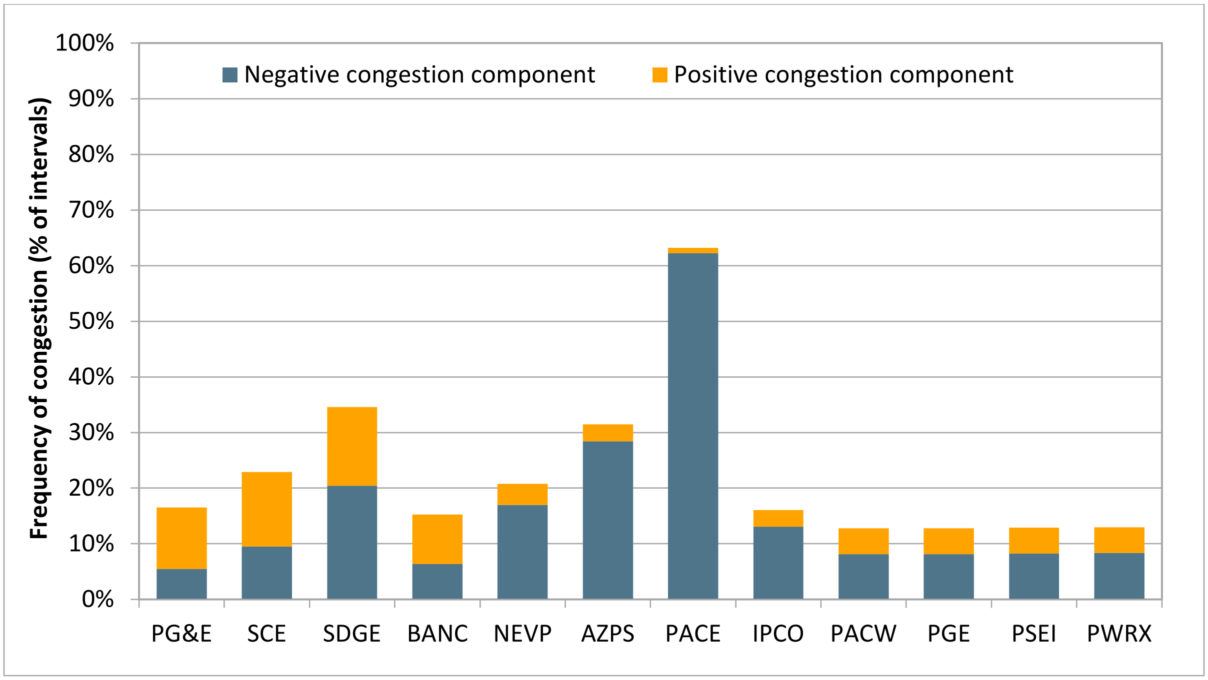
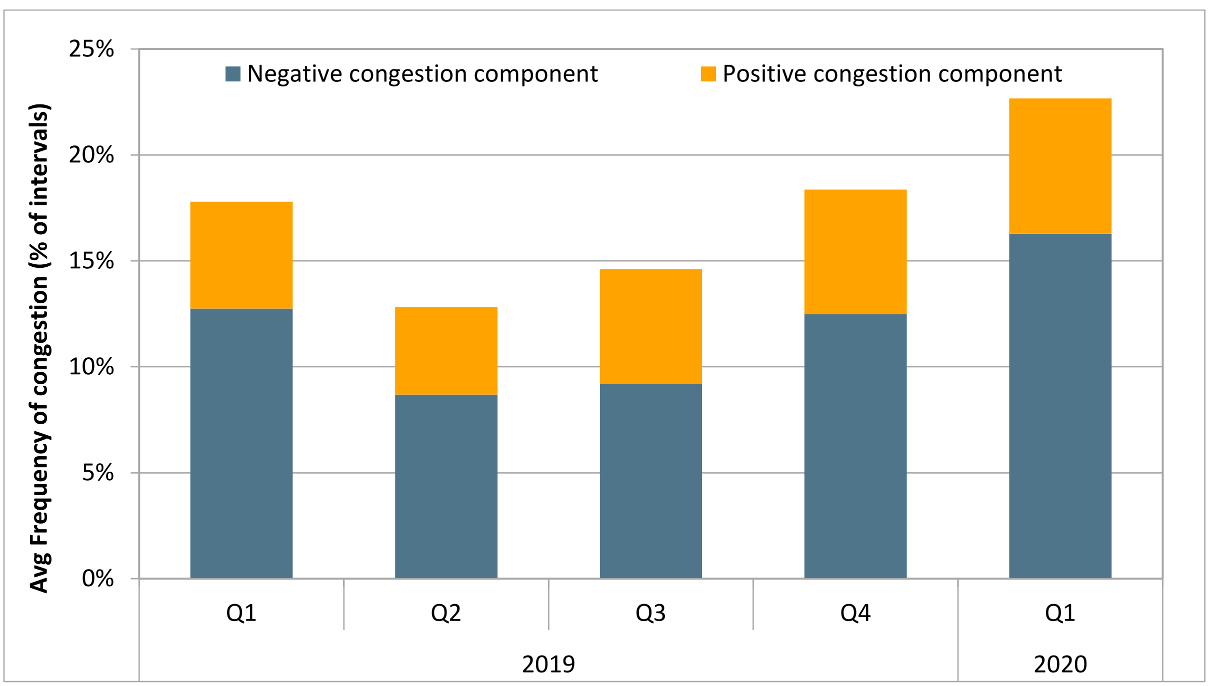


Figure 1.33 Percent of intervals with internal congestion impacting 15-minute prices (quarterly average of load areas)



Impact of internal congestion from individual constraints

Table 1.5 shows the overall impact (during all intervals) of internal congestion on average 15-minute prices in each load area. Table 1.6 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 (excludes "other" in Table 1.5). 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. This section will focus on individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the Los Banos-Quinto 230 kV line, the Imperial Valley nomogram, and the Doublet Tap-Friars 138 kV line.

Los Banos-Quinto 230 kV line

The Los Banos-Quinto 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) bound infrequently in the quarter during about 4 percent of intervals. When binding, it affected prices across the EIM, during which it increased prices in PG&E, BANC, IPCO, PACW, PGE, PSEI, and PWRX by $4.68/MWh on average and decreased prices in SCE, SDG&E, NEVP, AZPS, and PACE by $6.43/MWh on average. Overall for the quarter, the constraint increased the former areas' prices by about $0.17/MWh on average and decreased the latter areas' prices by $0.21/MWh on average. This constraint is impacted by an outage on the Los Banos-Tesla 500 kV line.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the quarter, during 7 percent of intervals. When binding, it increased prices in SDG&E and SCE by about $14.08/MWh and $0.94/MWh, respectively, and decreased prices in all EIM areas by about $1/MWh on average. Over the entire quarter, it increased SDG&E and SCE prices by about $0.96/MWh and $0.06/MWh, respectively, and decreased EIM area prices by about $0.04/MWh on average. The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. In the 2017-2018 transmission planning cycle, an upgrade to the Imperial Valley-El Centro 230 kV S-Line was approved. The project, which is planned to be complete in 2021, will help to alleviate congestion in this area.

Doublet Tap-Friars 138 kV line

The Doublet Tap-Friars 138 kV line (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1) bound frequently in the quarter, during 17 percent of intervals. When binding, it decreased prices in SDG&E, AZPS, and PACE by about $6/MWh on average. Congestion on this line did not impact prices in other EIM areas. Overall for the quarter, the constraint decreased prices in SDG&E, AZPS, and PACE by about $0.47/MWh on average.

Table 1.5 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
IPCO	ANTELOPI_GOSHENI_161		-$0.01	-$0.01		-$0.01	-$0.01	-$0.02	$0.19				
PACE	90TH.SO_106THSO_138	-$0.01	$0.00		-$0.01	-$0.01		$0.07	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	WYOMING_EXPORT							-$0.43					
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.11	-$0.31	-$0.30	$0.32	-$0.16	-$0.27	-$0.01	$0.05	$0.18	$0.18	$0.17	$0.17
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.08	$0.05	$0.04	$0.08	$0.02	$0.03	-$0.03	-$0.06	-$0.09	-$0.09	-$0.09	-$0.09
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.05	-$0.06	-$0.05			-$0.02						
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.05	$0.00	$0.00	-$0.02		$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	RM_TM21_NG	$0.05	$0.03	$0.03	$0.03	$0.01	$0.02	-$0.02	-$0.04	-$0.05	-$0.05	-$0.05	-$0.05
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.02	-$0.03	-$0.03	$0.02	$0.00	-$0.03	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.01	-$0.01	-$0.01	$0.00	$0.00	-$0.01	$0.00					
	30630_NEWARK _230_30635_NWK DIST_230_BR_1 _1	$0.01			$0.00					$0.00	$0.00	$0.00	$0.00
	30640_TESLA C _230_30040_TESLA _500_XF_6	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.00	$0.00	-$0.01		$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.08	$0.10	$0.10	-$0.08	$0.06	$0.09	$0.01	-$0.02	-$0.06	-$0.06	-$0.05	-$0.05
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				-$0.05	$0.46							
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1		-$0.01	-$0.01	$0.00								
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.03	$0.10	$0.07	-$0.03	$0.00	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1		$0.04			-$0.02	-$0.02	-$0.01	-$0.01				
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.04	$0.03	$0.13	-$0.04	-$0.03	-$0.01	-$0.02	-$0.03	-$0.04	-$0.04	-$0.03	-$0.03
	99010_VELAS-LB_230_24076_LAGUBELL_230_BR_1 _1		$0.02	$0.01		-$0.02	-$0.01	-$0.01					
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	$0.00	$0.00	$0.01	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6410_CP10_NG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8095129_D-SBLR_OOS_N1SV500	$0.01	-$0.01	$0.00	$0.01	-$0.01	-$0.03	-$0.01		$0.00	$0.00		
	24804_DEVERS _230_25666_EL CASCO_230_BR_1 _2		-$0.02				-$0.01						
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1			-$0.07									
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.06	$0.96	$0.00	-$0.07	-$0.22	-$0.09	-$0.03	$0.00	$0.00	$0.00	$0.00
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.08	$0.19	$0.42	-$0.08	-$0.02	-$0.07	-$0.09	-$0.09	-$0.08	-$0.08	-$0.08	-$0.08
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.00	$0.20		-$0.02	-$0.07	-$0.03	-$0.01				
	OMS 8092823 MG-BK81_NG			$0.17		-$0.02	-$0.06						
	OMS 8286176_50001_OOS_NG		$0.00	$0.14		-$0.01	-$0.04	-$0.01	$0.00				
	24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.03	$0.06	$0.14	-$0.03	-$0.01	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	OMS 8286163_50001_OOS_NG		$0.00	$0.12		-$0.01	-$0.03	-$0.01	$0.00				
	OMS 8247851_50001_OOS_NG		$0.00	$0.10		-$0.01	-$0.03	-$0.01	$0.00				
	OMS 8092838 MG-BK81_NG			$0.09		-$0.01	-$0.03	-$0.01					
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	-$0.04	$0.12	$0.07	-$0.04	-$0.06	-$0.05	-$0.05	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	OMS 8092833 MG-BK81_NG			$0.06		-$0.01	-$0.02	-$0.01					
	OMS 8304550_50001_OOS_NG		$0.00	$0.03		$0.00	-$0.01	$0.00	$0.00				
	OMS 8286076_50001_OOS_NG		$0.00	$0.02		$0.00	-$0.01	$0.00	$0.00				
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1			$0.01			$0.00						
	OMS 8286102_50001_OOS_NG			$0.01		$0.00	$0.00	$0.00	$0.00				
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1			-$0.03			-$1.09						
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	$0.00	$0.00	-$0.03	$0.00		-$0.01						
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1			-$0.56									
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			-$1.32			-$0.08	$0.00					
	24804_DEVERS _230_24901_VSTA _230_BR_2 _2						-$0.02						
	8282545_D-VISTA1_2_OOS_CP6_NG	$0.02	-$0.02		$0.01	-$0.02	-$0.06	-$0.02					
	Other	$0.04	$0.05	-$0.03	$0.06	-$0.22	$0.05	-$0.04	-$0.17	$0.03	$0.03	$0.02	$0.02
	Total	**$0.16**	**$0.40**	**$0.47**	**$0.17**	**-$0.17**	**-$2.18**	**-$0.90**	**-$0.36**	**-$0.25**	**-$0.26**	**-$0.26**	**-$0.26**
	Transfers	$0.00	$0.00	$0.00	-$0.09	-$0.12	$2.67	$0.17	$0.16	-$0.90	-$0.83	-$0.68	-$0.76
	Grand Total	**$0.16**	**$0.40**	**$0.47**	**$0.08**	**-$0.29**	**$0.49**	**-$0.73**	**-$0.20**	**-$1.15**	**-$1.09**	**-$0.94**	**-$1.02**

Table 1.6 Impact of internal congestion on 15-minute prices in the ISO during congested intervals[23]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
PACE	WYOMING_EXPORT	55.8%							-$0.77					
PG&E	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	1.0%	$8.40	$4.98	$4.44	$8.19	$1.95	$3.57	-$3.14	-$6.57	-$9.75	-$9.82	-$9.61	-$9.51
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	0.8%	$6.78	-$2.56	-$2.28	-$2.91		-$1.65	-$1.86	-$2.18	-$2.56	-$2.56	-$2.53	-$2.52
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.3%	$5.35	-$9.78	-$9.30	$6.79	-$0.46	-$8.41	-$1.26	$2.72	$4.92	$4.82	$4.82	$4.82
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.8%	$3.78	-$3.11	-$3.10			-$3.02						
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	3.7%	$3.04	-$8.48	-$8.03	$8.62	-$4.24	-$7.25	-$4.16	$2.14	$4.87	$4.84	$4.67	$4.58
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.2%	-$3.95	$4.77	$4.49	-$3.73	$2.64	$4.02	$0.59	-$1.13	-$2.60	-$2.59	-$2.47	-$2.42
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.6%		-$2.27	-$2.29	$2.21								
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	2.6%				-$8.32	$17.39							
	RM_TM21_NG	0.4%												
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.7%	-$5.03	$15.46	$11.18	-$5.03	$0.00	-$5.03	-$5.03	-$5.03	-$5.03	-$5.03	-$5.03	-$5.03
	OMS 8095129_D-SBLR_OOS_N1SV500	1.4%	$0.54	-$0.78	-$0.05	$0.50	-$0.48	-$2.03	-$0.48		$0.38	$0.34		
	24804_DEVERS _230_25666_EL CASCO_230_BR_1 _2	1.1%		-$1.50				-$7.56						
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.6%			-$11.14									
SDG&E	OMS 8092823 MG-BK81_NG	0.5%			$31.55		-$3.34	-$11.17						
	OMS 8247851_50001_OOS_NG	0.4%		$1.01	$25.56		-$1.33	-$8.77	-$1.59	-$1.20				
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	1.7%	-$5.04	$11.21	$24.19	-$5.04	-$1.00	-$4.57	-$4.94	-$4.92	-$5.04	-$5.04	-$5.04	-$5.04
	OMS 8092838 MG-BK81_NG	0.4%			$20.19		-$2.40	-$6.42	-$2.40					
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.7%	-$3.79	$8.68	$18.71	-$3.80	-$1.22	-$3.94	-$3.91	-$3.85	-$3.84	-$3.84	-$3.84	-$3.84
	7820_TL 230S_OVERLOAD_NG	6.8%	-$0.33	$0.94	$14.08	-$0.33	-$1.04	-$3.24	-$1.28	-$0.60	-$0.37	-$0.82	-$0.47	-$0.58
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	1.5%		$0.86	$13.03		-$1.50	-$4.25	-$1.62	-$1.54				
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	1.0%	-$4.23	$11.84	$7.59	-$4.26	-$5.80	-$5.06	-$5.23	-$4.85	-$4.54	-$4.55	-$4.56	-$4.59
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	16.8%			-$7.84			-$6.11	-$3.79					
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	0.3%	$0.56	$1.40	-$10.01	$0.59		-$2.13						
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	4.2%			-$13.42									
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	11.2%			-$27.85			-$9.70						
	24804_DEVERS _230_24901_VSTA _230_BR_2 _2	0.4%						-$3.82						
	8282545_D-VISTA1_2_OOS_CP6_NG	1.7%		-$1.12		$0.91	-$1.02	-$3.63	-$0.94					
	OMS 8286163_50001_OOS_NG	0.4%												
	OMS 8286176_50001_OOS_NG	0.5%												

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

Figure 1.34 shows the overall impact of internal congestion on 5-minute prices in each load area for each quarter of 2019 and 2020. Figure 1.35 shows the frequency of intervals with internal congestion increasing versus decreasing prices. Figure 1.36 shows the percent of intervals with congestion impacting 5-minute prices as a quarterly average of load areas. Highlights for this quarter include:

- The overall net impact to price separation of congestion was marginally lower in the first quarter of 2020 compared to the same quarter of 2019. Congestion resulted in a net increase to SCE, SDG&E, and AZPS 5-minute prices and a net decrease to 5-minute prices in PG&E, BANC, PACE, IPCO, PACW, PGE, PSEI, and PWRX.
- Congestion continued to impact prices in both the positive and negative direction in each load area, often offsetting the impact of congestion over the quarter. The frequency of congestion was highest in PacifiCorp East (57 percent of total intervals), where congestion predominantly decreased prices (56 percent of total intervals).

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

Figure 1.34 Overall impact of internal congestion on price separation in the 5-minute market

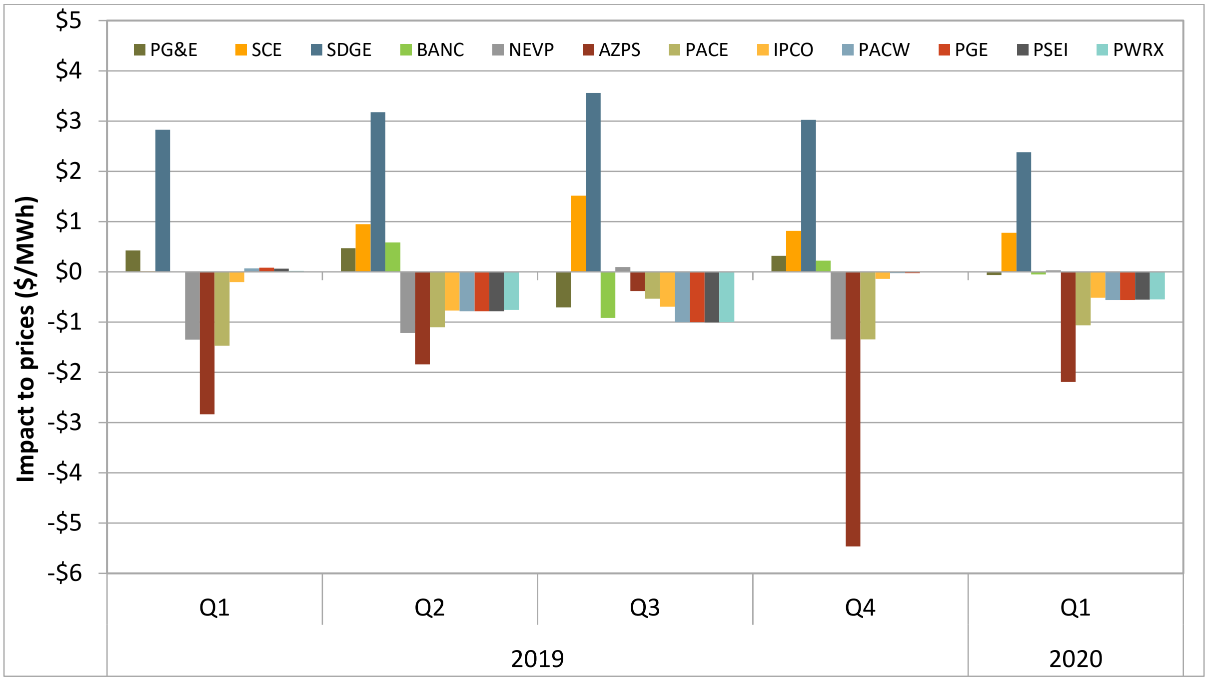


Figure 1.35 Percent of intervals with internal congestion increasing versus decreasing 5-minute prices in the first quarter (>$0.05/MWh)

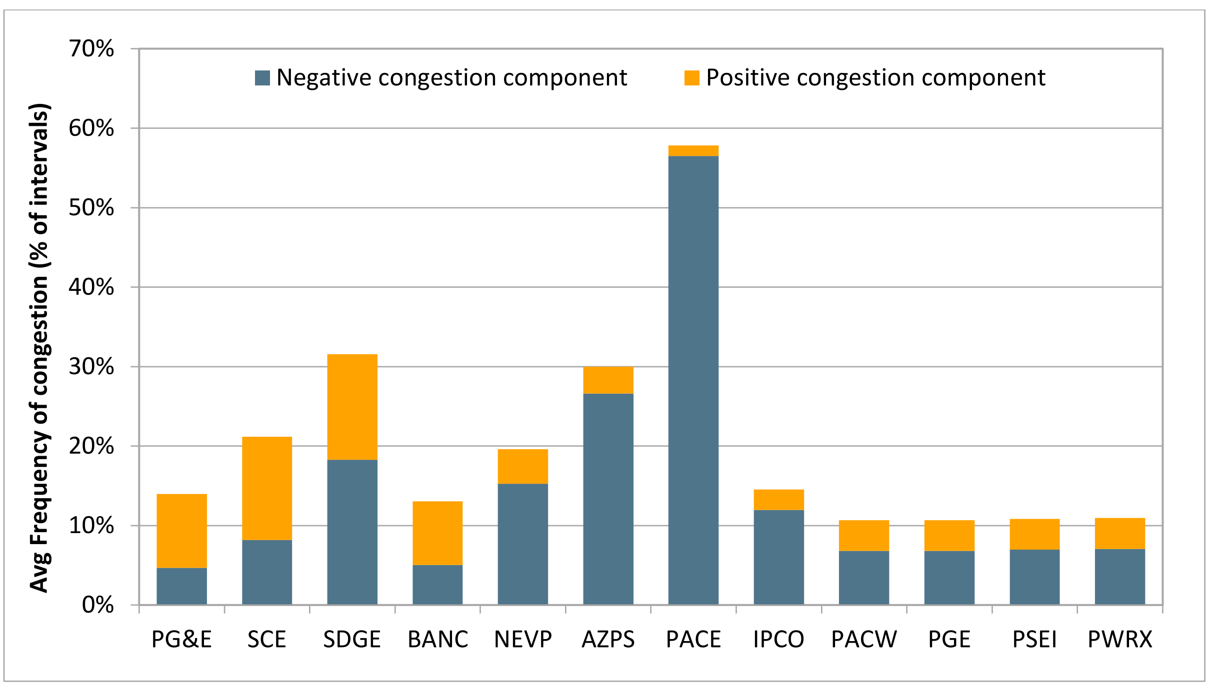
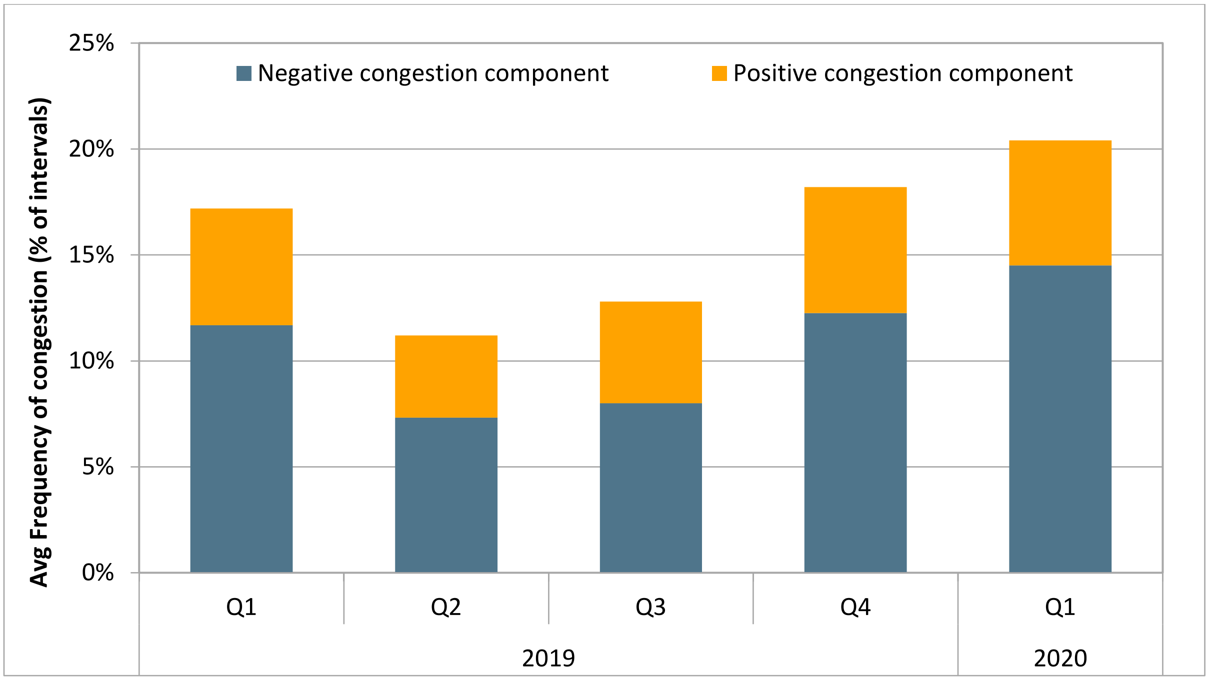


Figure 1.36 Percent of intervals with internal congestion impacting 5-minute prices (quarterly average of load areas)



Impact of congestion from transfer constraints

The impact of transfer constraint congestion was formerly included in the “other” category of constraint congestion in Table 1.5.This has been corrected and isolated to better show the effects of transfer constraints on EIM entities as they play a significant role in causing price separation between areas.

Table 1.7 Congestion Frequency and Average Price Impact from Transfer Constraint Congestion

Constraint Location	Constraint	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
IPCO	ANTELOPI_GOSHENI_161		-$0.01	-$0.01		-$0.01	-$0.01	-$0.02	$0.19				
PACE	90TH.SO_106THSO_138	-$0.01	$0.00		-$0.01	-$0.01		$0.07	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	WYOMING_EXPORT							-$0.43					
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.11	-$0.31	-$0.30	$0.32	-$0.16	-$0.27	-$0.01	$0.05	$0.18	$0.18	$0.17	$0.17
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.08	$0.05	$0.04	$0.08	$0.02	$0.03	-$0.03	-$0.06	-$0.09	-$0.09	-$0.09	-$0.09
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.05	-$0.06	-$0.05			-$0.02						
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.05	$0.00	$0.00	-$0.02		$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	RM_TM21_NG	$0.05	$0.03	$0.03	$0.03	$0.01	$0.02	-$0.02	-$0.04	-$0.05	-$0.05	-$0.05	-$0.05
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.02	-$0.03	-$0.03	$0.02	$0.00	-$0.03	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.01	-$0.01	-$0.01	$0.00	$0.00	-$0.01	$0.00					
	30630_NEWARK _230_30635_NWK DIST_230_BR_1 _1	$0.01			$0.00					$0.00	$0.00	$0.00	$0.00
	30640_TESLA C _230_30040_TESLA _500_XF_6	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.00	$0.00	-$0.01		$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.08	$0.10	$0.10	-$0.08	$0.06	$0.09	$0.01	-$0.02	-$0.06	-$0.06	-$0.05	-$0.05
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				-$0.05	$0.46							
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1		-$0.01	-$0.01	$0.00								
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.03	$0.10	$0.07	-$0.03	$0.00	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1		$0.04			-$0.02	-$0.02	-$0.01	-$0.01				
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.04	$0.03	$0.13	-$0.04	-$0.03	-$0.01	-$0.02	-$0.03	-$0.04	-$0.04	-$0.03	-$0.03
	99010_VELAS-LB_230_24076_LAGUBELL_230_BR_1 _1		$0.02	$0.01		-$0.02	-$0.01	-$0.01					
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	$0.00	$0.00	$0.01	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6410_CP10_NG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8095129_D-SBLR_OOS_N1SV500	$0.01	-$0.01	$0.00	$0.01	-$0.01	-$0.03	-$0.01		$0.00	$0.00		
	24804_DEVERS _230_25666_EL CASCO_230_BR_1 _2		-$0.02				-$0.01						
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1			-$0.07									
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.06	$0.96	$0.00	-$0.07	-$0.22	-$0.09	-$0.03	$0.00	$0.00	$0.00	$0.00
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.08	$0.19	$0.42	-$0.08	-$0.02	-$0.07	-$0.09	-$0.09	-$0.08	-$0.08	-$0.08	-$0.08
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P		$0.00	$0.20		-$0.02	-$0.07	-$0.03	-$0.01				
	OMS 8092823 MG-BK81_NG			$0.17		-$0.02	-$0.06						
	OMS 8286176_50001_OOS_NG		$0.00	$0.14		-$0.01	-$0.04	-$0.01	$0.00				
	24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.03	$0.06	$0.14	-$0.03	-$0.01	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	OMS 8286163_50001_OOS_NG		$0.00	$0.12		-$0.01	-$0.03	-$0.01	$0.00				
	OMS 8247851_50001_OOS_NG		$0.00	$0.10		-$0.01	-$0.03	-$0.01	$0.00				
	OMS 8092838 MG-BK81_NG			$0.09		-$0.01	-$0.03	-$0.01					
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	-$0.04	$0.12	$0.07	-$0.04	-$0.06	-$0.05	-$0.05	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	OMS 8092833 MG-BK81_NG			$0.06		-$0.01	-$0.02	-$0.01					
	OMS 8304550_50001_OOS_NG		$0.00	$0.03		$0.00	-$0.01	$0.00	$0.00				
	OMS 8286076_50001_OOS_NG		$0.00	$0.02		$0.00	-$0.01	$0.00	$0.00				
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1			$0.01			$0.00						
	OMS 8286102_50001_OOS_NG			$0.01		$0.00	$0.00	$0.00	$0.00				
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1			-$0.03			-$1.09						
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	$0.00	$0.00	-$0.03	$0.00		-$0.01						
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1			-$0.56									
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			-$1.32			-$0.08	$0.00					
	24804_DEVERS _230_24901_VSTA _230_BR_2 _2						-$0.02						
	8282545_D-VISTA1_2_OOS_CP6_NG	$0.02	-$0.02		$0.01	-$0.02	-$0.06	-$0.02					
	Other	$0.04	$0.05	-$0.03	$0.06	-$0.22	$0.05	-$0.04	-$0.17	$0.03	$0.03	$0.02	$0.02
	Total	**$0.16**	**$0.40**	**$0.47**	**$0.17**	**-$0.17**	**-$2.18**	**-$0.90**	**-$0.36**	**-$0.25**	**-$0.26**	**-$0.26**	**-$0.26**
	Transfers	$0.00	$0.00	$0.00	-$0.09	-$0.12	$2.67	$0.17	$0.16	-$0.90	-$0.83	-$0.68	-$0.76
	Grand Total	**$0.16**	**$0.40**	**$0.47**	**$0.08**	**-$0.29**	**$0.49**	**-$0.73**	**-$0.20**	**-$1.15**	**-$1.09**	**-$0.94**	**-$1.02**

Table 1.8 shows the congestion frequency and average price impact from transfer constraint congestion over the course of the first quarter of 2020 in the 15-minute and 5-minute markets. The highest frequency is in Powerex, where 37 percent and 45 percent of intervals in the 15-minute market and 5-minute market, respectively, were congested. The largest price impact was experienced by Arizona Public Service, with an average increase of about $2.67/MWh in the 15-minute market and $2.41/MWh

in the 5-minute market. PacifiCorp East and Idaho Power are different in this table as they each experienced an average decrease in prices in the 15-minute market but increase in the 5-minute market. The reverse of this was true for BANC, as it had an average decrease in prices in the 15-minute market but an increase in the 5-minute market.

Table 1.8 Quarterly average price impact and congestion frequency on EIM transfer constraints (Q1 2020)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$0.09	1%	$0.05
Arizona Public Service	4%	$2.67	3%	$2.41
NV Energy	2%	-$0.12	2%	-$0.49
PacifiCorp East	4%	$0.17	4%	-$0.55
Idaho Power	5%	$0.16	5%	-$0.74
PacifiCorp West	29%	-$0.90	19%	-$1.18
Portland General Electric	30%	-$0.83	20%	-$1.44
Puget Sound Energy	33%	-$0.68	28%	-$0.50
Powerex	37%	-$0.76	45%	-$0.94

Transfer congestion in the 15-minute market

Transfer constraint congestion in the 15-minute market occurred with vastly different frequencies and average price impacts across the EIM. Figure 1.37 shows the average impact to prices in the 15-minute market by quarter for 2019 and 2020. Figure 1.38 shows the frequency of congestion on transfer constraints by quarter for 2019 and 2020.

There was an overall decline in the impact on average prices from transfer constraint congestion in the first quarter of 2020, compared to the same quarter in 2019. AZPS is the outlier in this observation, as the impact to its prices remained relatively the same compared to the same quarter in 2019. Furthermore, AZPS had the highest average price impact, where transfer constraint congestion increased prices by $2.67/MWh on average.

Transfer constraint congestion frequency in the first quarter of 2020 was similar to that of the same quarter of 2019, although there are two notable exceptions. First, Powerex transfer constraints were congested in 37 percent of intervals, a significant reduction from the 63 percent in the first quarter of 2019. Secondly, PacifiCorp West had a dramatic increase in congestion, increasing from 6 percent in the first quarter of 2019 to 29 percent in the first quarter of 2020.

Figure 1.37 Transfer constraint congestion average impact on prices in the 15-minute market

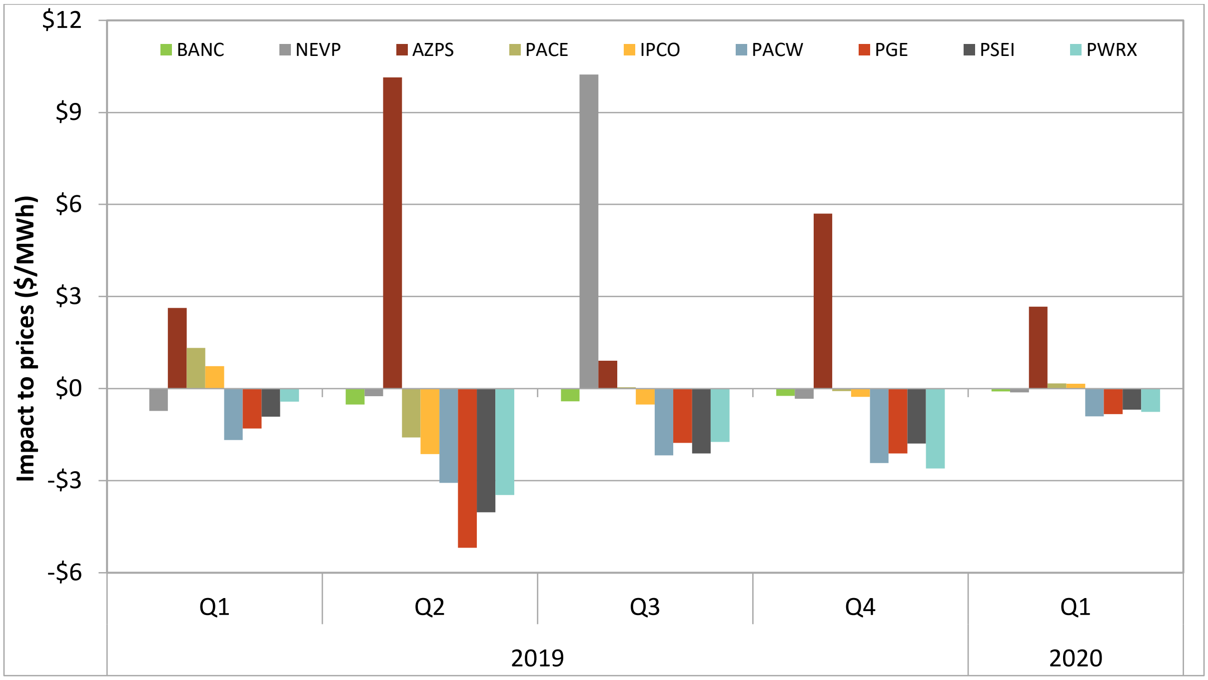
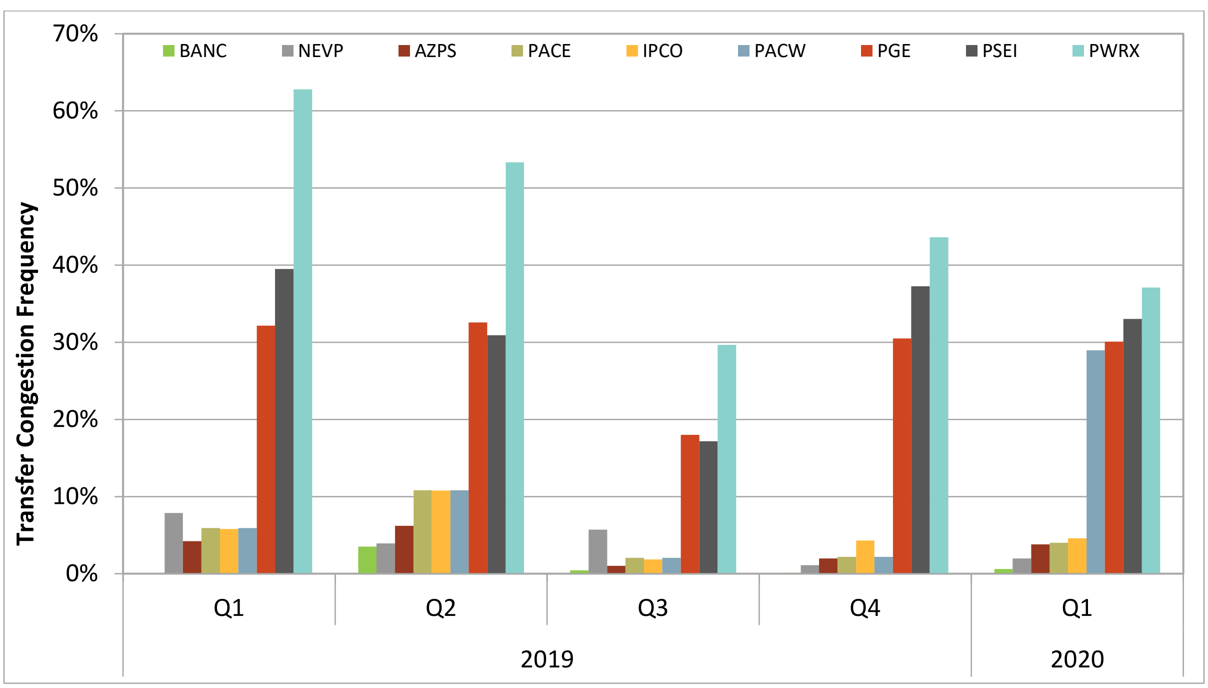


Figure 1.38 Transfer constraint congestion frequency in the 15-minute market



Transfer congestion in the 5-minute market

Similar to the 15-minute market, transfer constraint congestion in the 5-minute market occurred with vastly different frequencies and average price impacts across the EIM. Figure 1.39 shows the average impact on price in the 5-minute market by quarter for 2019 and 2020. Figure 1.40 shows the frequency of congestion on transfer constraints in the 5-minute market by quarter for 2019 and 2020.

Overall, the frequency of transfer constraint congestion was lower in the first quarter of 2020 compared to the same quarter in 2019. Despite a higher than average frequency of transfer constraint congestion, Powerex typically experiences a relatively low impact to prices. AZPS experienced the largest impact on prices in the 5-minute market for the first quarter of 2020, which increased average prices by $2.41/MWh.

There were four areas that had high frequencies of transfer constraint congestion in the first quarter of 2020. Those areas include PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex. In each of these areas, the quarterly congestion frequency was above 19 percent. Other than these four areas, the frequency of congestion was relatively low.

Figure 1.39 Transfer constraint congestion average impact on prices in the 5-minute market

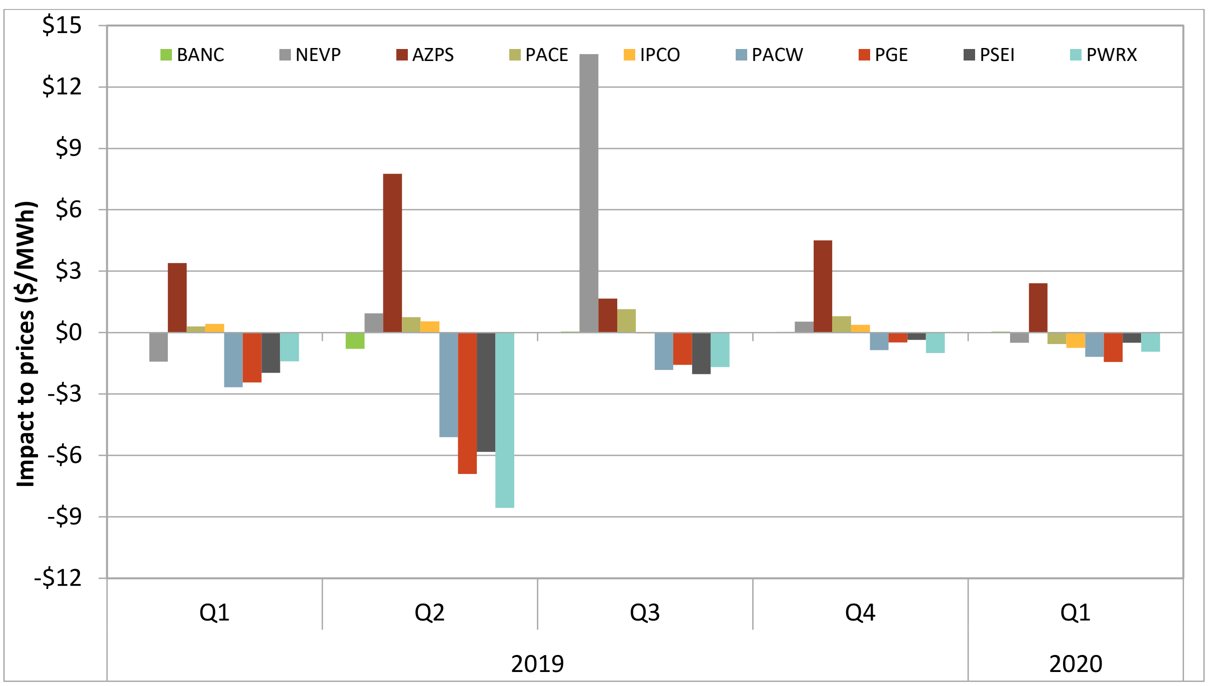
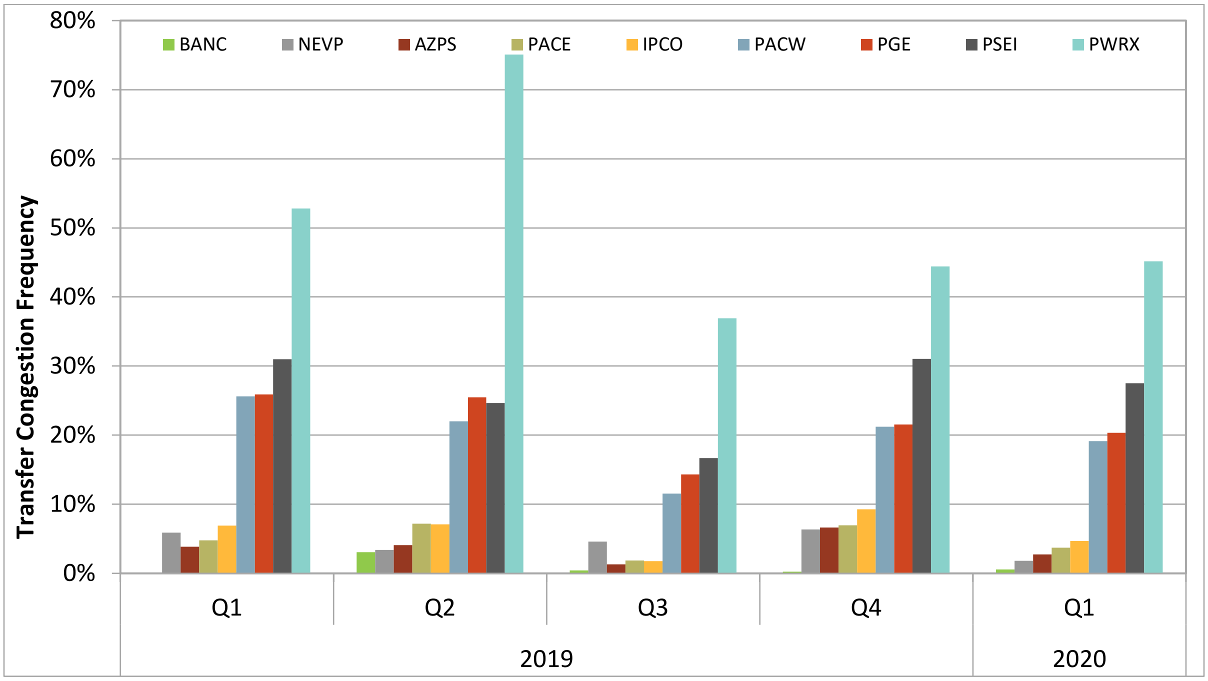


Figure 1.40 Transfer constraint congestion frequency in the 5-minute market



1.10.3 Congestion on interties

Figure 1.41 shows total import congestion charges in the day-ahead market for 2019 and 2020. Figure 1.42 shows the frequency of congestion on five major interties for the first quarter of 2020. Table 1.9 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 times the binding limits for the intertie constraints. For a supplier or load serving entity trying to import power over a congested intertie, the congestion price represents a decrease in the price for imports into 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 first quarter of 2020 decreased significantly to about $10 million compared to $34 million in the same quarter of 2019.
- The frequency of congestion in the first quarter increased on NOB and COTPISO, while decreasing significantly elsewhere.
- The frequency of congestion and magnitude of congestion charges is typically highest on PACI/Malin 500, NOB, Palo Verde, and the IPP Utah interties. The first quarter followed this trend. Congestion on other interties continues to remain relatively low relative to these top constraints.

Figure 1.41 Summary of import congestion in day-ahead market

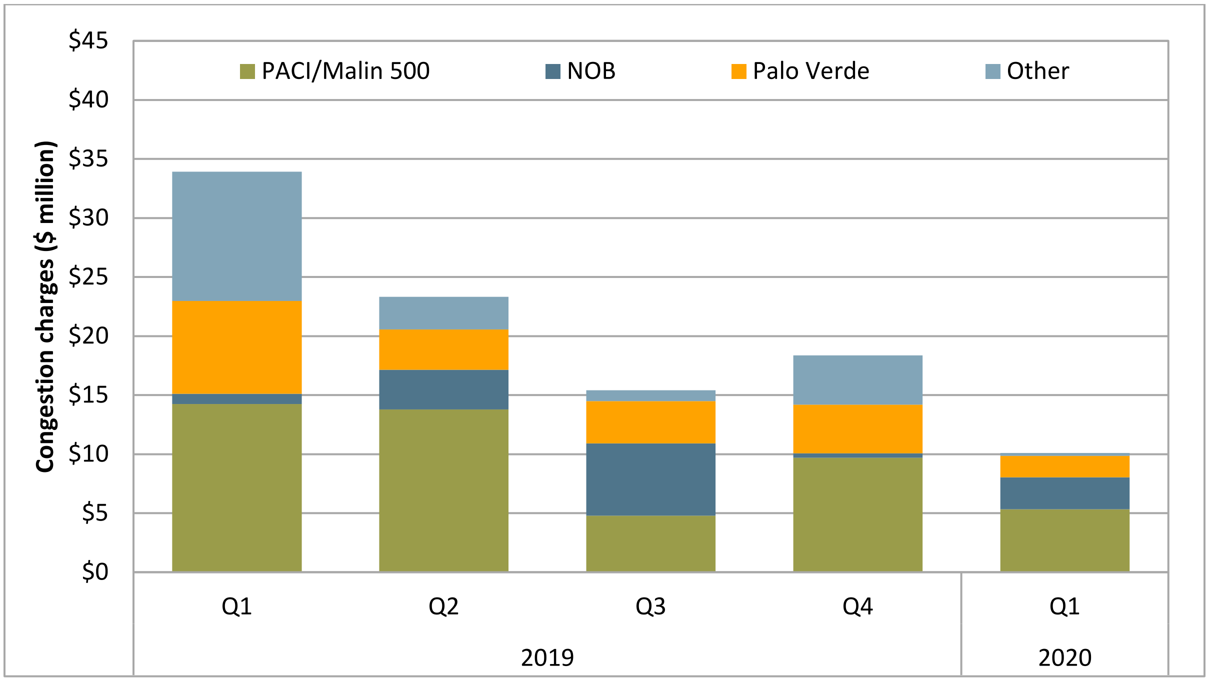


Figure 1.42 Frequency of import congestion on major interties in the day-ahead market (2020)

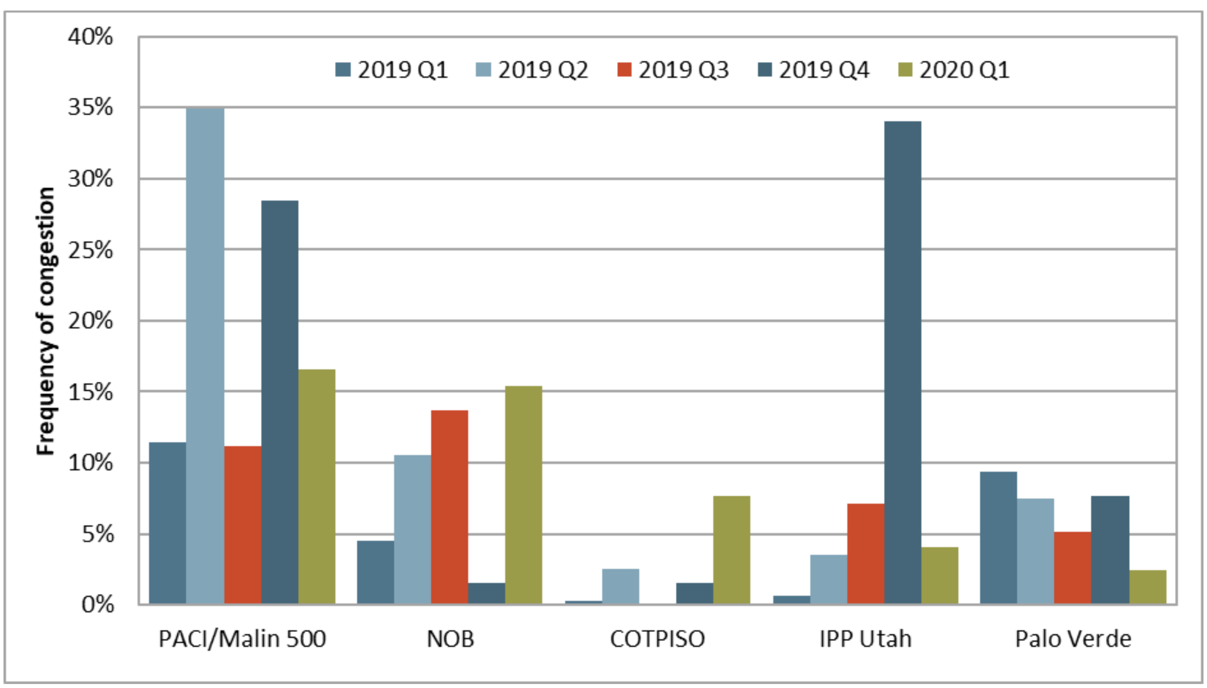


Table 1.9 Summary of import congestion in day-ahead market (2019-2020)

Area	Intertie	Frequency of import congestion					Import congestion charges ($ thousand)				
		2019				2020	2019				2020
		Q1	Q2	Q3	Q4	Q1	Q1	Q2	Q3	Q4	Q1
Northwest	PACI/Malin 500	11%	35%	11%	29%	17%	14,246	13,773	4,787	9,681	5,318
	NOB	5%	11%	14%	2%	15%	858	3,380	6,128	382	2,715
	COTPISO	0%	3%		2%	8%	4	20		21	85
	Cascade		1%	2%	0%	0%		30	162	1	2
	Summit			1%		1%			26		6
Southwest	Palo Verde	9%	8%	5%	8%	2%	7,864	3,409	3,579	4,128	1,827
	IPP Utah	1%	4%	7%	34%	4%	13	99	186	2,528	136

1.11 Real-time imbalance offset costs

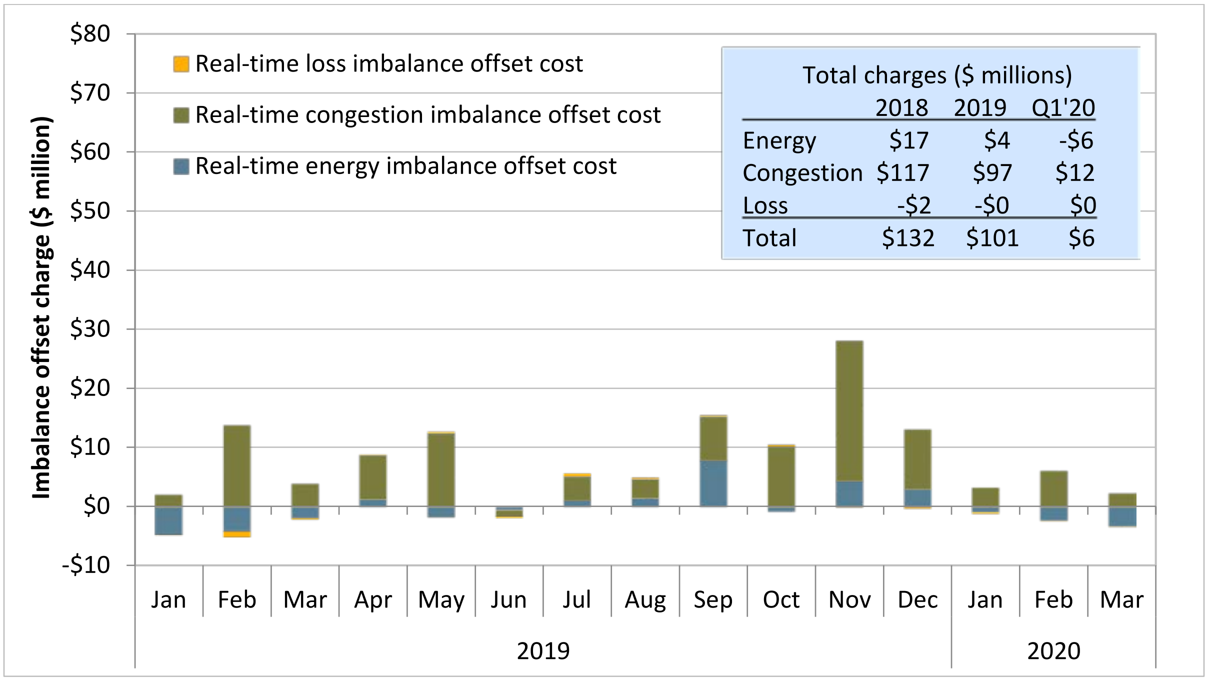
First quarter real-time offset costs were about $5 million, down significantly from $50 million in the fourth quarter of 2019. Real-time imbalance offset costs were comprised of about $12 million in congestion deficits, about $6 million in energy surpluses, and negligible loss offsets.

The real-time imbalance offset charge consists of three components corresponding to the main components of real-time settlement prices: energy, congestion and loss.[24] 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 and 5-minute markets. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

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

Figure 1.43 Real-time imbalance offset costs



1.12 Congestion revenue rights

Background

Congestion revenue rights are paid (or charged), for each megawatt held, based on the congestion between the sink and source nodes defining the right. These rights can have monthly or seasonal (quarterly) terms, and can include on-peak or off-peak hourly prices. Congestion revenue rights are allocated to entities serving load, and can also be procured in monthly and seasonal auctions.

In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities, and other load serving entities, through the transmission access charge (TAC).[25] The ISO charges utility distribution companies the transmission access charge to reimburse the entity that builds each transmission line for the costs incurred. As the owners of transmission or the entities paying for the cost of building and maintaining transmission, the ratepayers of utility distribution companies should collect the congestion revenues associated with transmission capacity in the day-ahead market.

When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments represents a loss to

[25] Some ISO transmission is built or owned by other entities such as merchant transmission operators. The revenues from transmission not owned or paid for by load serving entities gets paid directly to the owners through transmission ownership rights or existing transmission contracts. The analysis in this section is not applicable to this transmission. Instead, this analysis focuses on transmission that is owned or paid for by load serving entities only.

ratepayers. The losses cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

In the eleven years since the start of the congestion revenue rights auction, revenues from rights sold in the auction have consistently been well below the congestion revenues paid to entities purchasing these rights. Through 2019, transmission ratepayers have lost about $890 million in congestion revenues paid in excess of revenues received from the auction. This represents about 51 cents in auction revenues for every dollar paid to congestion revenue rights holders. Most of these profits to entities purchasing congestion rights in the auction are received by financial entities that do not sell power or serve load in the ISO.[26]

Congestion revenue rights auction modifications

In 2016, DMM recommended the ISO modify or eliminate the congestion revenue rights auction to reduce the losses to transmission ratepayers from rights sold in the auction. Starting in the 2019 auctions, the ISO implemented several significant changes to the auction design to reduce the systematic losses from rights sold in the auction.

- **Track 1A.** The first major change significantly reduces the number and pairs of nodes at which congestion revenue rights are purchased in the auction.[27] This change was designed to limit rights sold in the auction to pairs of nodes consistent with those that might be used as hedge for actual sales and trading of energy.
- **Track 1B.** The second major change limits the net payments to congestion revenue right holders if payments exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.[28]

Congestion revenue right auction returns

Non-load serving entity congestion revenue right auction profits are calculated by summing revenue paid out to these 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.

Transmission ratepayers lost about $13.6 million during the first quarter of 2020 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This is above the $1.4 million loss in the first quarter of 2019, but below average losses of $22 million in the first quarters of the three years before the Track 1A and 1B changes (2016 through 2018). As shown in Figure 1.44, auction revenues were 47 percent of payments made to non-load serving entities during the first quarter of 2020, down from 94 percent during the same quarter in 2019.

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26 A more detailed discussion of congestion revenue rights is provided in DMM's *2018 Annual Report on Market Issues and Performance* (pp.197-205). http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

27 See *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1A,* April 11, 2018*:* http://www.caiso.com/Documents/Apr11_2018_TariffAmendment-CRRAuctionEfficiencyTrack1A_ER18-1344.pdf

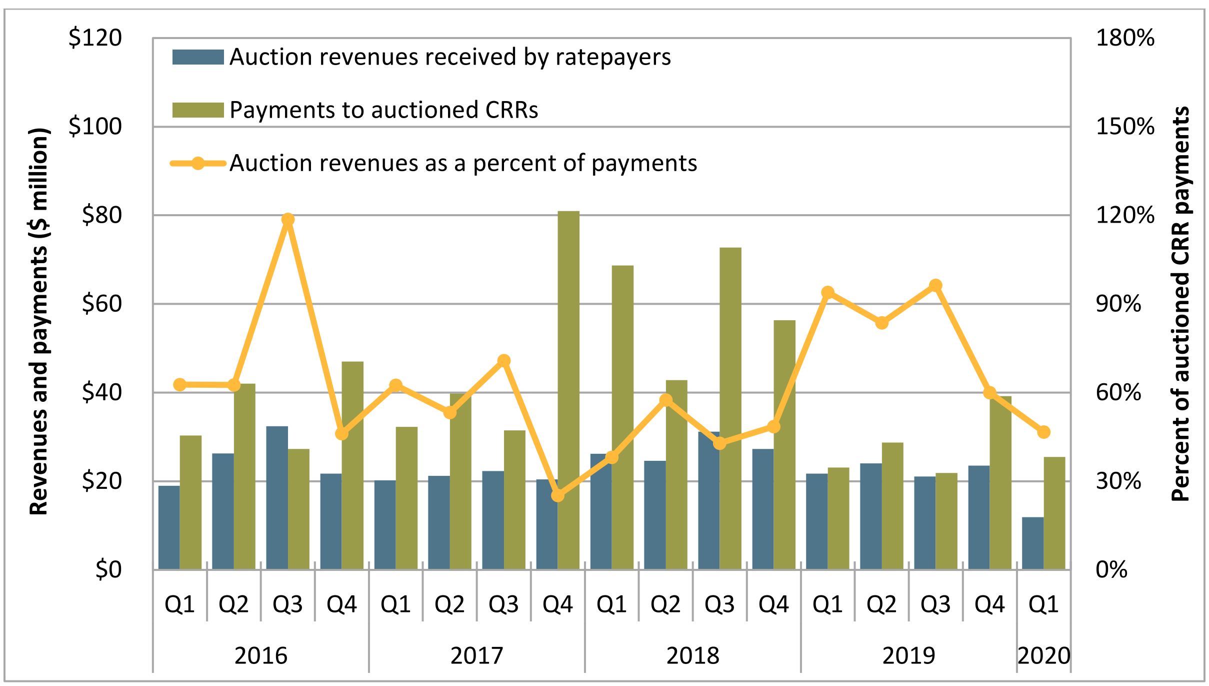
28 See *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B,* November 9, 2018*:* http://www.caiso.com/Documents/Nov9-2018-OrderAcceptingTariffRevisions-CRRTrack1BModification-ER19-26.pdf

In the first quarter, financial entities (which do not schedule or trade physical power or serve load) continued to have the highest profits among the entity types, at approximately $8.2 million. This was an increase from $5.1 million profits during the first quarter of 2019. Marketers' profits were about $4.3 million, up from a $1.1 million loss during the first quarter of 2019. Generators profited about $1.1 million compared to a $2.7 million loss in the first quarter of 2019.

The $13.6 million in first quarter auction losses was about 18 percent of day-ahead congestion rent. This is up from 2 percent of rent in the first quarter of 2019, 6 percent for all of 2019, and 15 percent in the fourth quarter of 2019. However, the losses as a percent of day-ahead congestion rent are below the average of 26 percent in the first quarters of the three years before the Track 1A and 1B changes (2016 through 2018) and below the 28 percent for all quarters from 2009 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 $22 million in the first quarter. The Track 1B effects on auction bidding behavior and reduced auction revenues is not known.

Figure 1.44 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. 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.

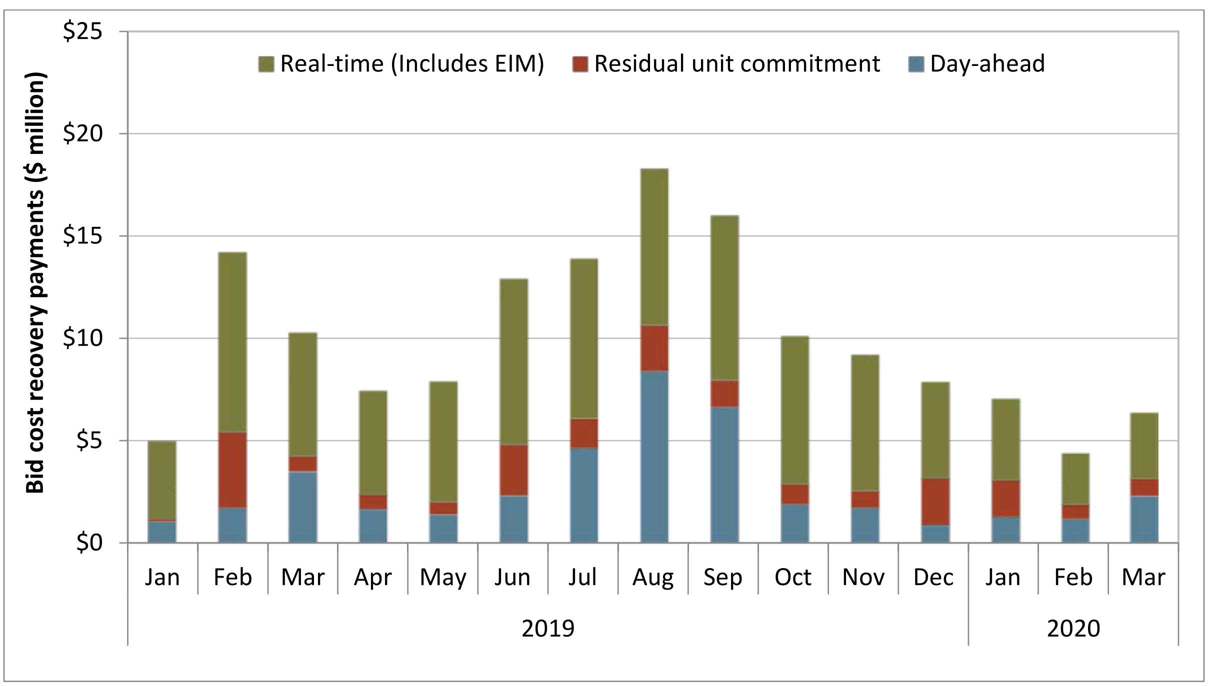
1.13 Bid cost recovery

Estimated bid cost recovery payments for the first quarter of 2020 totaled about $18 million. This was $9 million lower than the total bid cost recovery in the previous quarter and about $11.5 million lower than in the first quarter of 2019. Part of this decline can be attributed to lower gas prices at major trading hubs across the west.

Bid cost recovery attributed to the day-ahead market totaled about $4.8 million, similar to the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $3.4 million, compared to $4 million in the prior quarter. Bid cost recovery attributed to the real-time market totaled about $9.7 million, or about $9 million lower than payments in the first and fourth quarters of 2019.

Total bid cost recovery payments in the ISO were $0.34/MWh of load (1.1 percent), compared to $0.56/MWh of load (1.04 percent) in the first quarter of 2019 when both fuel costs and wholesale energy costs were higher. First quarter bid cost recovery payments also decreased relative to fourth quarter of 2019 ($0.47/MWh of load or 1.06 percent) as system load requirements and natural gas prices decreased.

Figure 1.45 Monthly bid cost recovery payments



1.14 Imbalance conformance

Operators in the 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. Previously imbalance conformance was sometimes referred to as load adjustment, load bias or load conformance; however, these terms did not accurately encapsulate the reasons and actions taken by the operators. Imbalance conformance adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of imbalance conformance adjustments including managing load and generation deviations, automatic time error corrections, scheduled interchange variations, reliability events, and software issues.[29] Going forward the term "imbalance conformance" will be used to describe manual adjustments to the imbalance conformance account.

Frequency and size of imbalance conformance adjustments, generation/import prices and imports

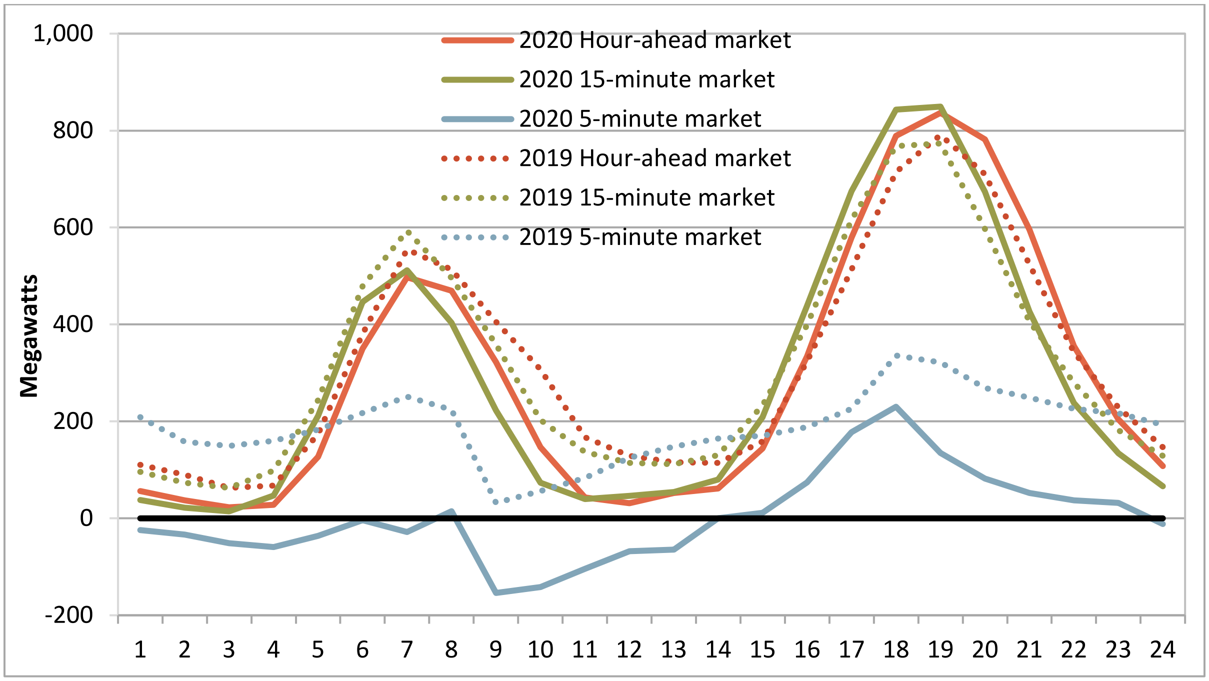
Beginning in 2017, there was a large increase in imbalance conformance adjustments during the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets. This large increase continues into the current quarter, with average hourly imbalance conformance adjustments in these markets peaking at about 850 MW, slightly above the 800 MW peak in the same quarter of the previous year. Figure 1.46 shows imbalance conformance adjustments for these markets tends to follow a similar shape, with large increases during the morning and evening net load ramp periods and the lowest adjustments during the early morning, late evening, and mid-day hours. In the first quarter, mid-day adjustments were about 50 MW in the hour-ahead and the 15-minute market while the 5-minute market adjustments were negative. The 2020 first quarter adjustments in the 5-minute market were consistently lower than the same quarter from the previous year.

The 5-minute market adjustments tend to follow a much less exaggerated shape throughout the day, and are often well below the hour-ahead and 15-minute adjustments during the steep net load ramp periods. The 5-minute adjustment in hour ending 18 was about 230 MW, much lower than the nearly 850 MW adjustment in the hour-ahead and 15-minute markets. In the first quarter of 2020, the average hourly adjustment in the 5-minute market was nearly zero compared with an hourly average of about 190 MW in the same quarter in the previous year. This average was low due to over 50 percent of hours in the first quarter of 2020 with a negative hourly average adjustment, often occurring during the mid-day and low load periods.

Imbalance conformance adjustments are often associated with over/under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods.

[29] Additional detail can be found in Section 9, Market Adjustments, in the *2016 Annual Report on Market Issues and Performance*, which is available on the ISO website at: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

Figure 1.46 Average hourly imbalance conformance adjustment (Q1 2019 – Q1 2020)



1.15 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.

- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would 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.

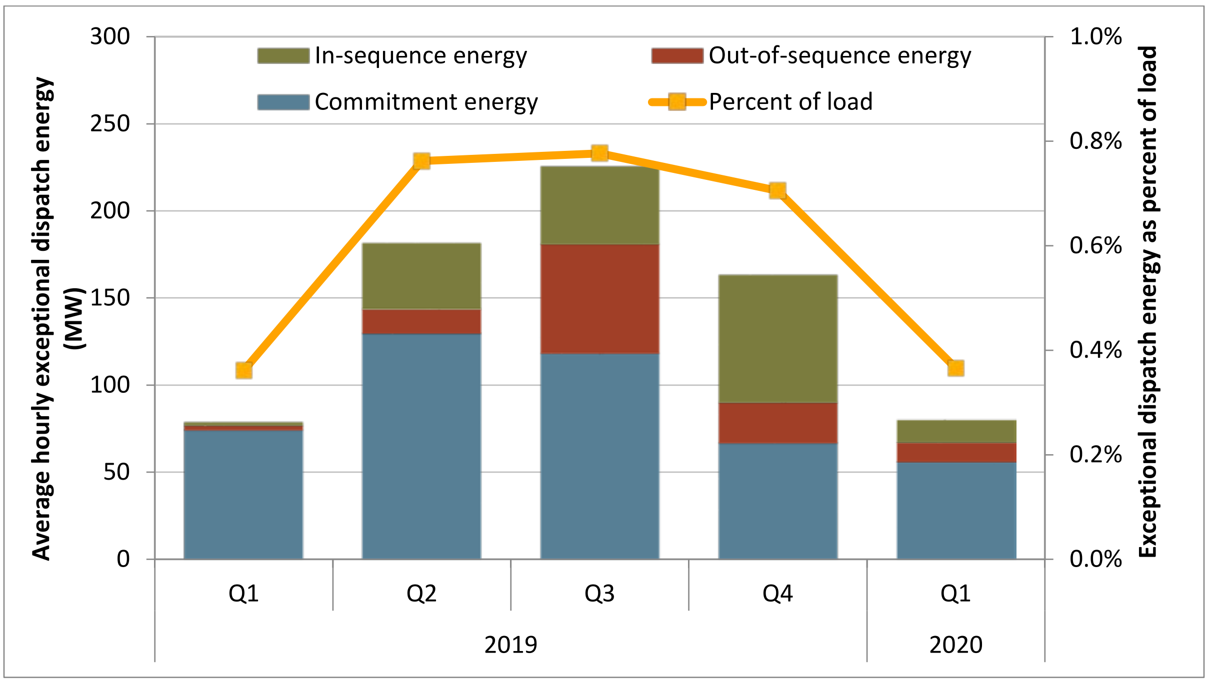
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to 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 1 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 80 MWh in the first quarter of 2020 which is about the same as the first quarter in 2019.

As shown in Figure 1.47, exceptional dispatches for unit commitments accounted for about 70 percent of all exceptional dispatch energy in this quarter.[30] About 16 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 14 percent was from in-sequence energy.

Figure 1.47 Average hourly energy from exceptional dispatch



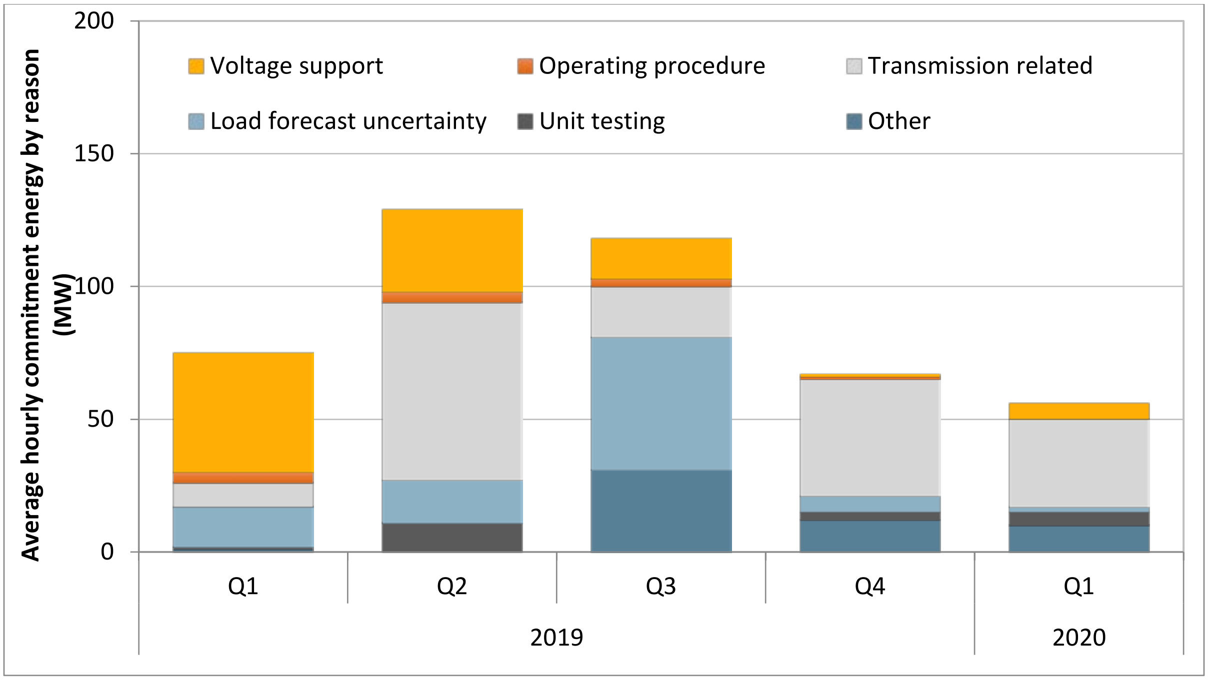
Exceptional dispatches for unit commitment

Minimum load energy from exceptional dispatch unit commitments in the first quarter decreased on average by about 25 percent relative to the first quarter of the prior year. Lower levels of exceptional dispatch unit commitment were offset by an increase in exceptional dispatch energy above minimum

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

load. The most frequent reason given for exceptional dispatch unit commitments was for transmission related exceptional dispatches.

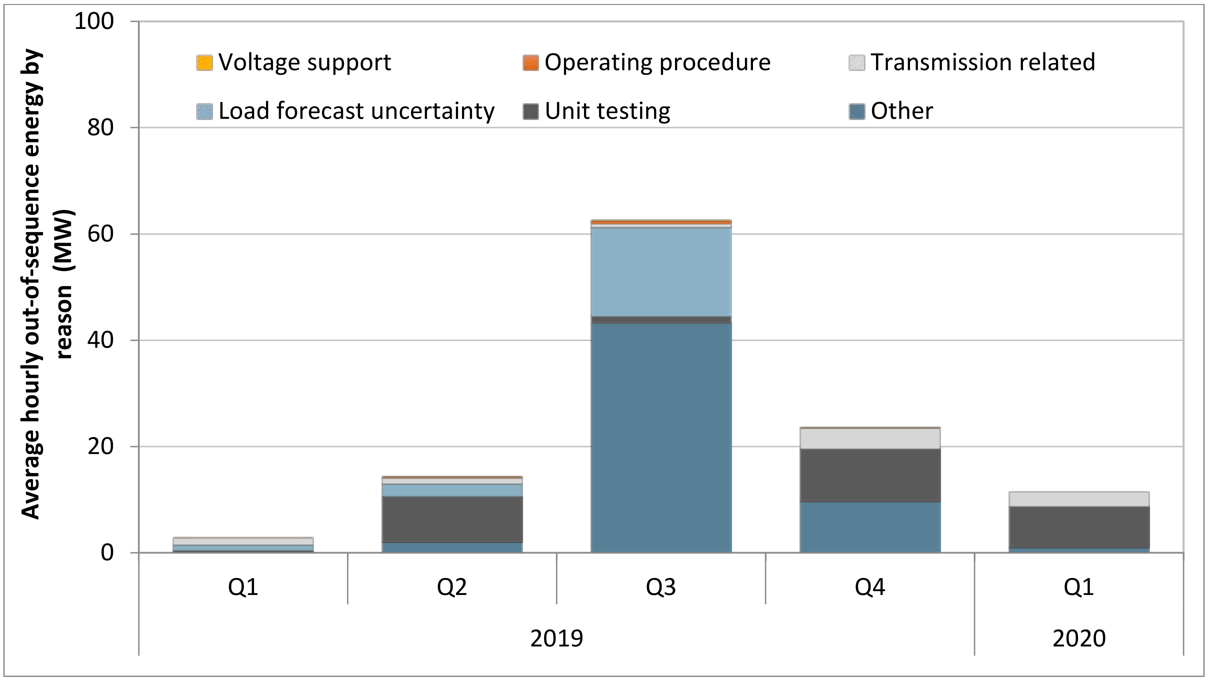
Figure 1.48 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch more than tripled relative to the same quarter in 2019 but was substantially lower than the previous quarter. As previously illustrated in Figure 1.47, about 16 percent of this 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 1.49 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2019 and 2020. Most of the out-of-sequence energy in the first quarter of 2020 was exceptionally dispatched for unit testing and transmission outages.

Figure 1.49 Out-of-sequence exceptional dispatch energy by reason



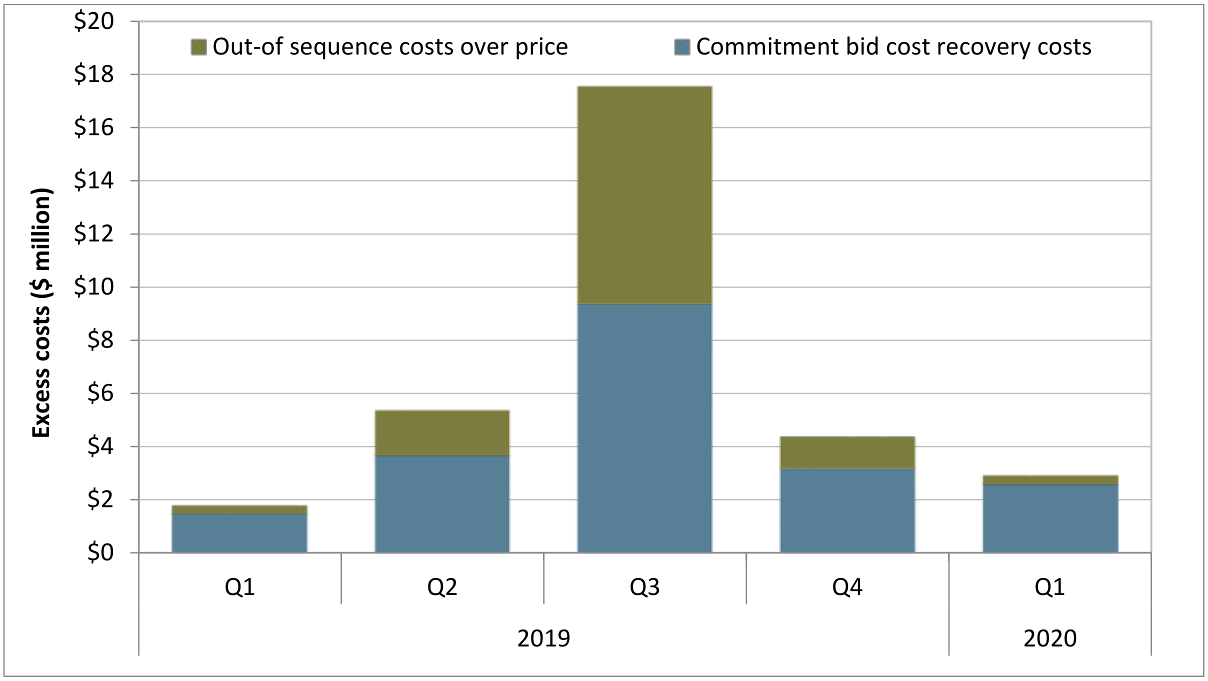
Exceptional dispatch costs

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 1.50 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. In the first quarter, out-of-sequence energy costs were $0.3 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $2.6 million.

Figure 1.50 Excess exceptional dispatch cost by type



1.16 Local market power mitigation enhancements

The ISO's automated local market power mitigation (LMPM) procedures were enhanced in numerous ways since 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and real-time markets. The ISO proposed the following enhancements to the local market power mitigation process for implementation in November 2019:[31]

1. Eliminate carryover mitigation by not mitigating a resource in subsequent market intervals only because the resource was mitigated in a prior interval of the same hour.
2. Allow an EIM entity balancing authority area in the real-time market to limit dispatch of incremental net exports when mitigation is triggered due to import congestion.
3. Introduce a new hydro default energy bid (hydro DEB) option that would apply to all hydroelectric resources with storage capability that participate in the ISO or the EIM.

On September 30, 2019, FERC rejected the proposal to limit net exports by an EIM balancing authority area.[32] Subsequently, the ISO filed on October 30, 2019, a request for rehearing at FERC regarding the

[31] Draft final proposal, *Local market power mitigation enhancements*, January 31, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

[32] FERC order on LMPM enhancements tariff revisions, September 30, 2019: http://www.caiso.com/Documents/Sep30-2019-Order-TariffRevisions-Accepting-Part-Rejecting-Part-LMPME-ER19-2347.pdf

net export limit proposal.[33] The rest of the enhancements were implemented on November 13, 2019. On June 18, 2020, FERC denied the request for rehearing but granted the motion for clarification.[34]

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 and 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 estimate the additional energy dispatched from these price changes.[35]

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

Mitigation in the ISO

In the day-ahead market, rates of mitigation increased significantly relative to the first quarter of 2019. In the real-time market, the rates of mitigation in the first quarter also increased compared to the same quarter in 2019. Incremental energy subject to mitigation has increased relative to prior years due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

As shown in Figure 1.51, in the day-ahead market, an hourly average of about 1,228 MW was subject to mitigation but corresponding bids were not lowered compared to 76 MW in the same quarter of 2019. About 198 MW of incremental energy had bids lowered due to mitigation compared to 22 MW in 2019. As a result, there was on average about 5 MW increase in dispatch, compared to 1 MW in 2019.

Figure 1.52 and Figure 1.53 show the same metrics but for the ISO's 15-minute and 5-minute markets on a monthly level. As shown in the figures, the average incremental energy that is subject to mitigation and either had bids lowered or not due to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market. The frequency of mitigation in both 15-minute and 5-minute markets increased in the first quarter relative to the same quarter in 2019.

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33 ISO's request for rehearing and alternative motion for clarification, October 30, 2019: http://www.caiso.com/Documents/Oct302019_RequestforRehearingorClarification-LocalMarketPowerMitigationER19-2347.pdf

34 FERC order denying rehearing and granting clarification, ER19-2347-001, June 18, 2020: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14869989

35 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 captures 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 1.51 Average incremental energy mitigated in day-ahead market

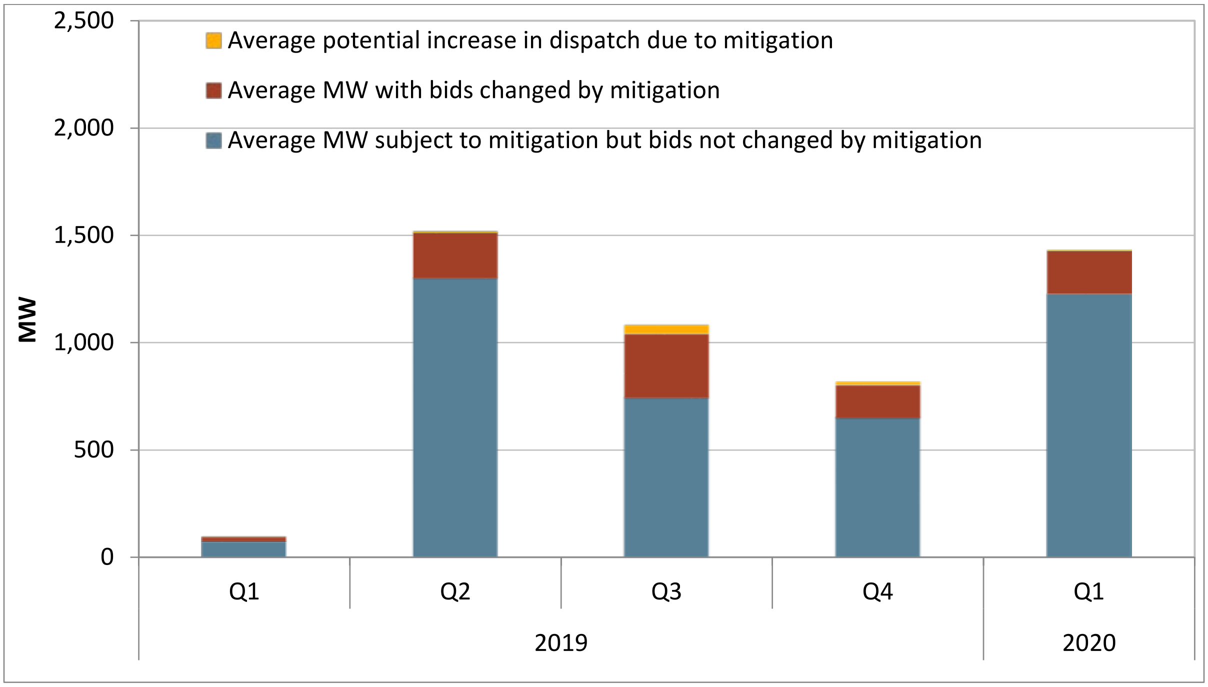


Figure 1.52 Average incremental energy mitigated in 15-minute real-time market (ISO)

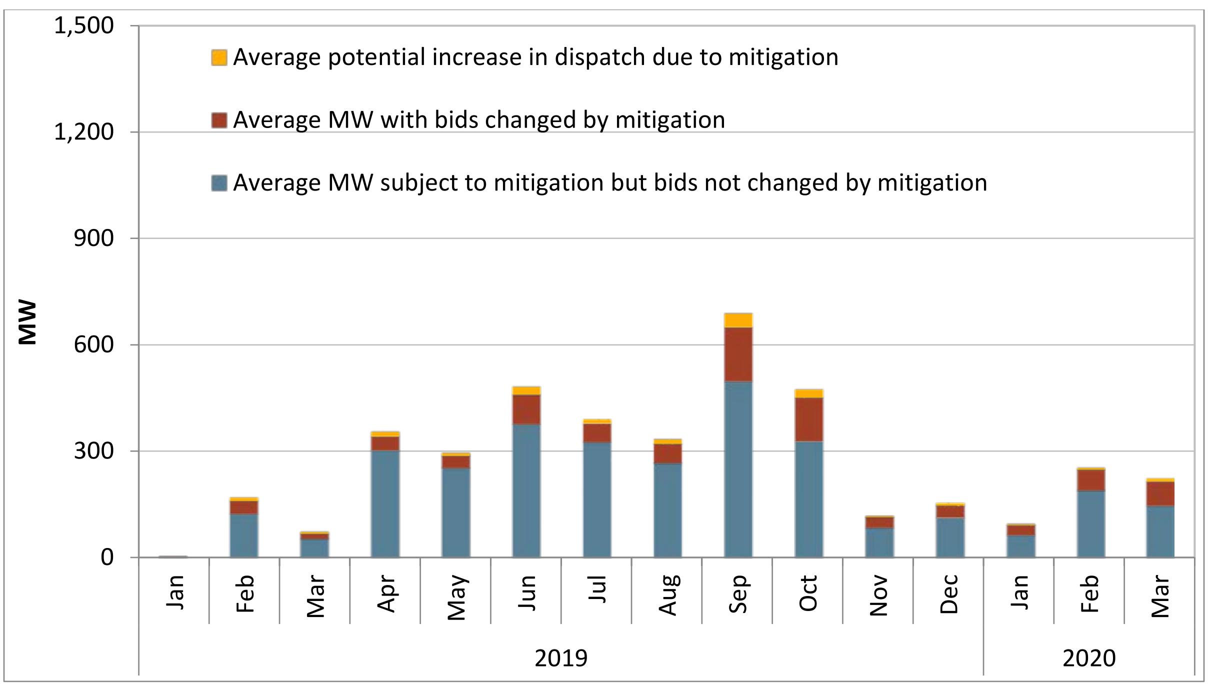
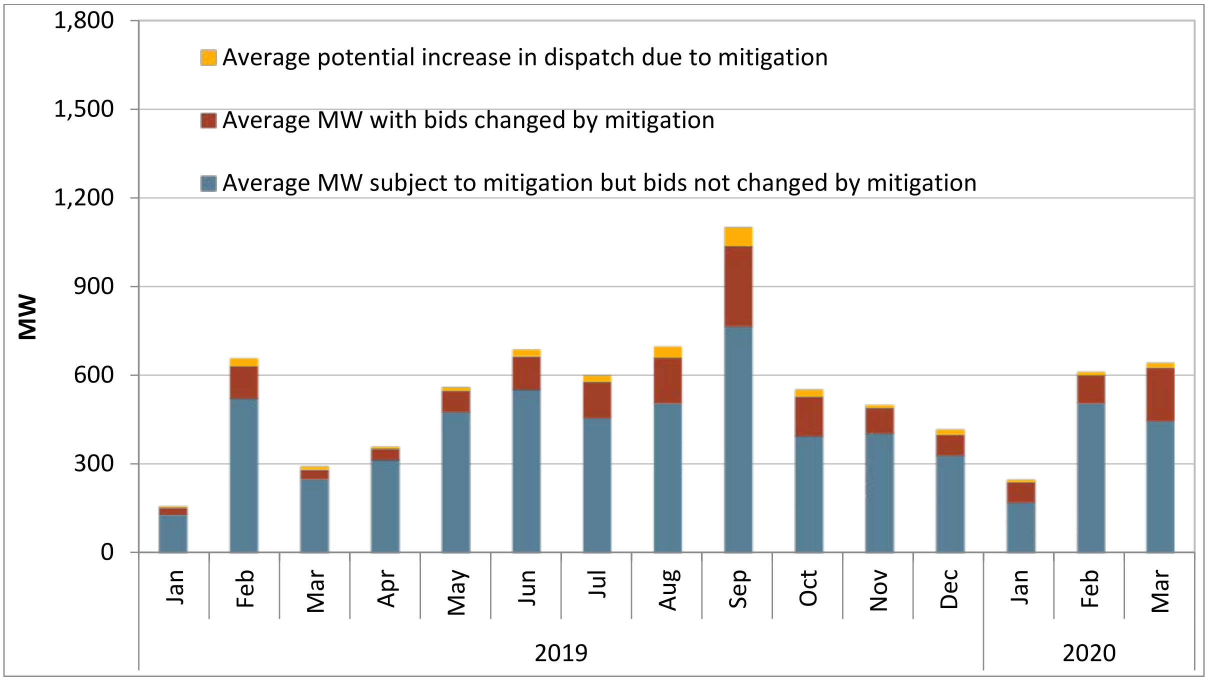


Figure 1.53 Average incremental energy mitigated in 5-minute real-time market (ISO)



2 Western energy imbalance market

This section covers Western EIM performance during the first quarter. Key observations and findings include:

- **Prices in the Northwest region**, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex, were regularly lower than prices in the ISO and other balancing areas due to limited transfer capability out of this region during peak system load hours.
- **Prices in the ISO and BANC** exceeded the rest of the system in each month, on average, due to binding transfer constraints and greenhouse gas compliance costs enforced for imports into California.
- **Sufficiency test failures and subsequent under-supply power balance constraint relaxations** drove average real-time prices for Arizona Public Service higher than the rest of the system in some hours. Almost all intervals with power balance relaxations were priced at the penalty parameter of $1,000/MWh.
- **Congestion imbalance deficits related to base schedules** remained low in the first quarter, totaling about $0.7 million in PacifiCorp East. Balancing areas may allocate these imbalances to third party customers and others. PacifiCorp East is the only area to have significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018.
- **Western EIM greenhouse gas** prices increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions, relative to before the policy change in 2018. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity. In some intervals in the first quarter, all eligible supply was imported, limiting energy imbalance market imports into California.
- **Rates of mitigation** fell in the Western EIM, following the elimination of carryover mitigation in November of 2019.

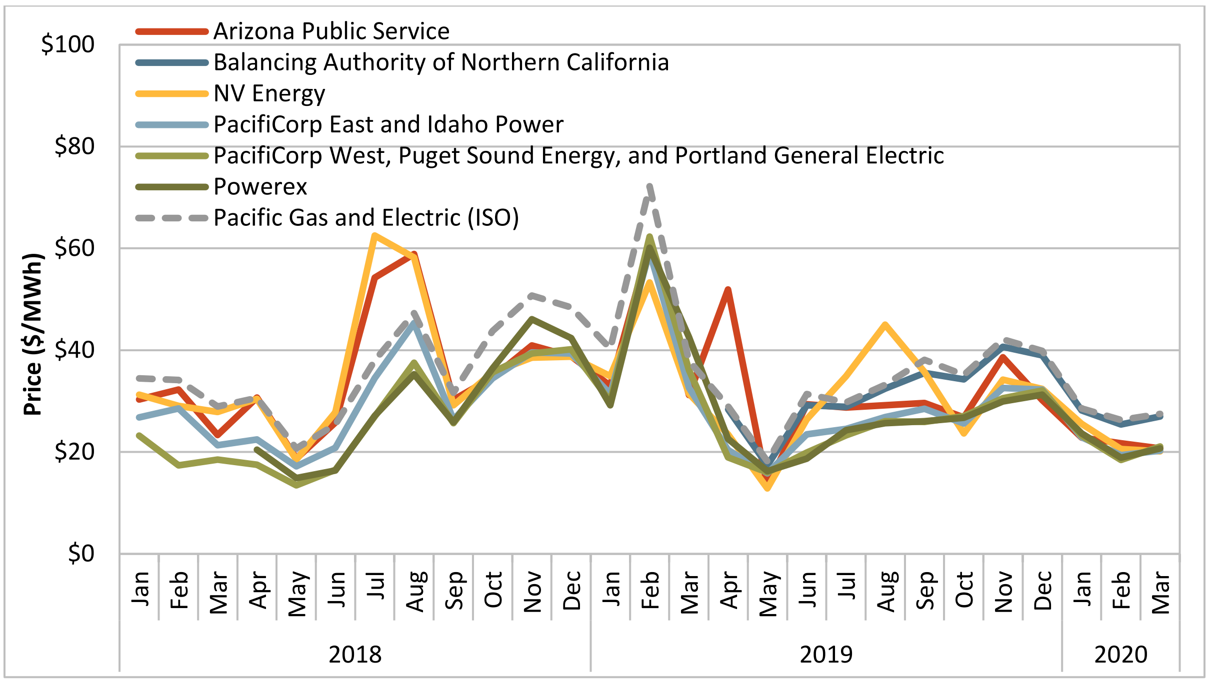
2.1 Western EIM performance

Western EIM prices

This section details the factors that influence changes in Western EIM balancing authority prices in general and what causes price separation between entities. 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 capability constraints are binding, greenhouse gas compliance costs are enforced for imports into California, or power balance constraint violations within a single area are assigned penalty prices.

Figure 2.1 shows average monthly prices from the 15-minute market by balancing authority from January 2018 to March 2020. Several balancing areas are grouped together due to similar average monthly prices. Prices for Powerex (dark green line) and Idaho Power (included in light blue line) begin in April of 2018 while prices for the Balancing Authority of Northern California (dark blue line) begin in April of 2019 when they joined the Western EIM.[36] Prices for Pacific Gas and Electric (grey dashed line) are included in the figure as a point of comparison for this analysis.

Figure 2.1 Monthly 15-minute market prices



The variability of Western EIM system prices over time is largely explained by natural gas prices. Natural gas price spikes at the SoCal Citygate, PG&E Citygate, and NW Sumas hubs, as shown in Figure 1.1 from the previous chapter, drove the sharp increases in Western EIM system prices between July 2018 and February 2019. In the first quarter of 2020, Western EIM prices outside of California were about $21/MWh and about $6/MWh below the Balancing Authority of Northern California and Pacific Gas and Electric.

Price separation between Western EIM balancing authorities occurs for several reasons. ISO and BANC 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.[37] In addition to this, average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex) are regularly lower than the ISO and other balancing areas because of limited transfer capability out of this region. Though not as common in the first quarter of 2020, Figure 2.1 also highlights high price spikes in NV

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36 Prices for Idaho Power are not included in average prices for the PacifiCorp East and Idaho Power grouping from January to March of 2018.

37 See Section 2.5 for more information about California's greenhouse gas compliance cost and its impact on the ISO and EIM.

Energy and Arizona Public Service in the months when a relatively high number of power balance constraint violations occurred. In many cases, these occurred in intervals in which Western EIM imports into these areas were frozen due to failed resource sufficiency tests.

Figure 2.2 Hourly 15-minute market prices (January – March)

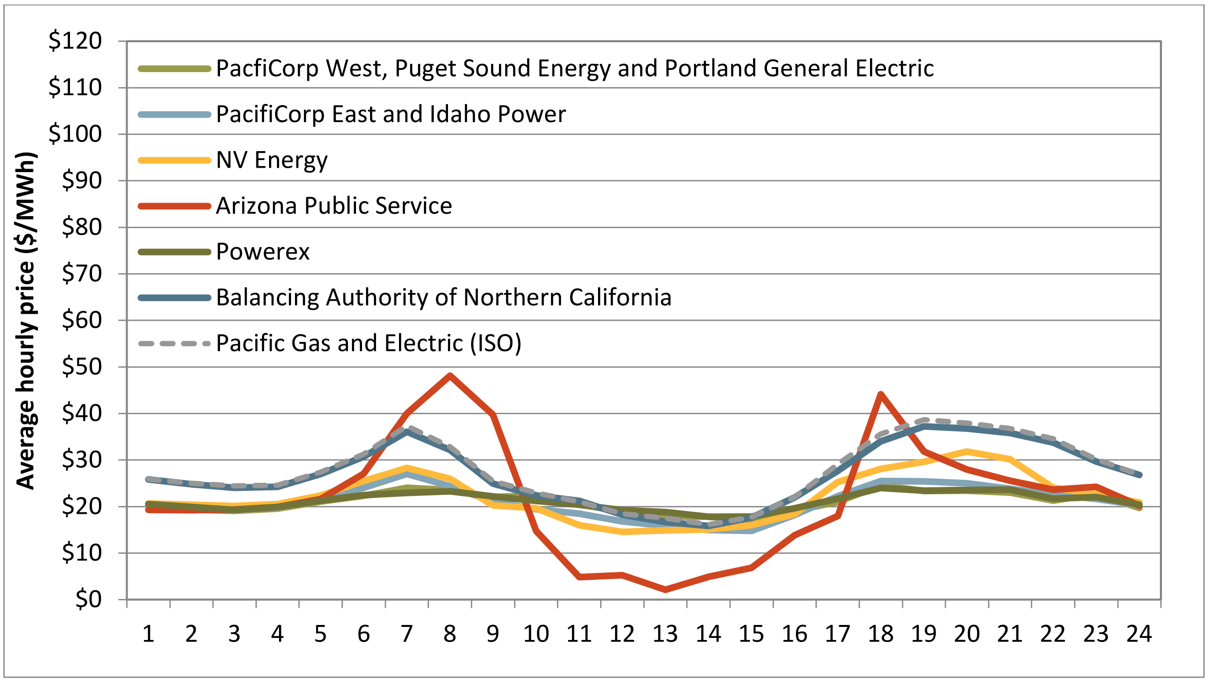


Figure 2.3 Hourly 5-minute market prices (January – March)

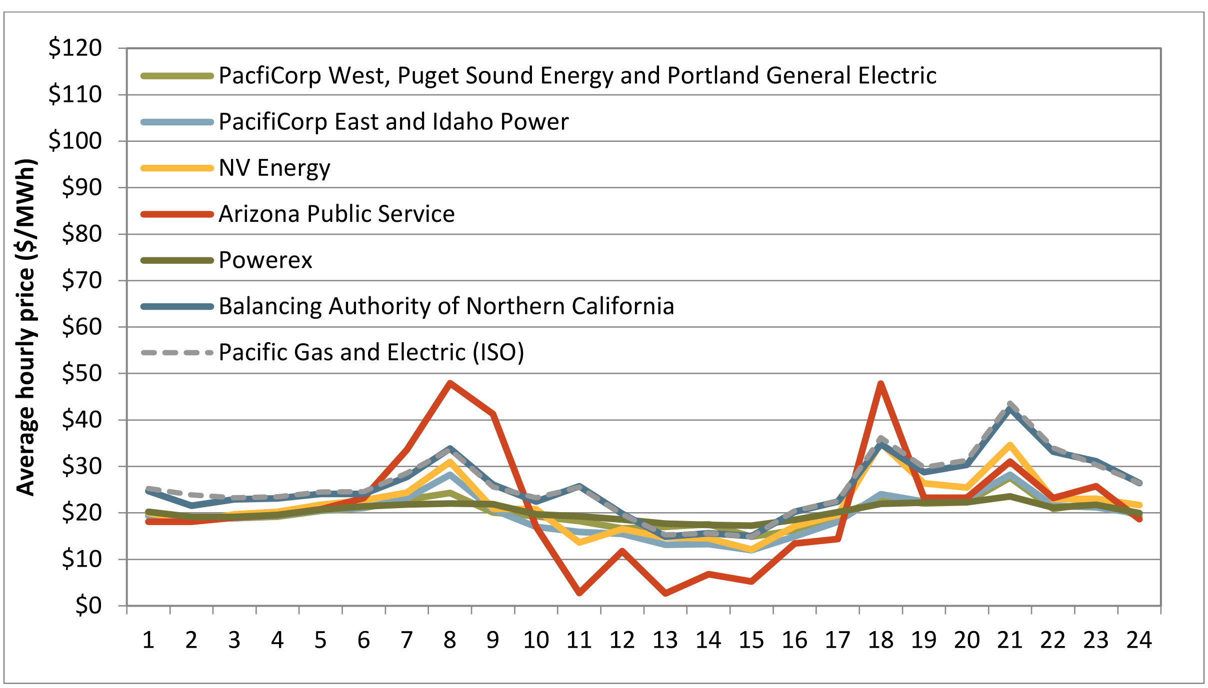


Figure 2.2 and Figure 2.3 continue this analysis by showing how Western EIM prices vary throughout the day in the first quarter of 2020. Average hourly prices are shown for participating balancing authorities between January 1 and March 31, 2020. Prices continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours in some Western EIM balancing areas just as in the ISO. As in the previous analysis, several balancing areas are grouped together because of similar average hourly pricing, and prices at the Pacific Gas and Electric default load aggregation point are shown as a point of comparison.

These figures also show that the relative price differences between Western EIM entities vary throughout the day. Prices in entities outside of California tend to be lower than ISO prices throughout all hours. This price divergence is more pronounced during the morning and evening ramping periods when the ISO is typically importing energy that is subject to greenhouse gas compliance costs. Western EIM entity prices converge with the ISO prices in the middle of the day when the ISO tends to export energy. The Balancing Authority of Northern California (BANC) is the exception to this rule due to their location in California. Prices in the BANC tracked very closely to prices in the ISO in the first quarter because of significant transfer capability and little congestion between the areas.

These figures show that average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex) remain very flat throughout the day and do not increase much during ramping hours. This reflects the limited transmission that is available in the Western EIM to support transfers from the Northwest to California and other balancing authorities in the Southwest.

Prices in Arizona Public Service area diverged from the rest of the Western EIM during the morning and afternoon peak load hours as well as throughout the middle of the day. This area experienced a number of flexible ramping sufficiency test failures in the upward direction between hours ending 7 to 9 and 18. This resulted in under-supply power balance constraint relaxations in the market software. The majority of these infeasibilities were not resolved by the enhanced load conformance limiter and were therefore priced at the penalty parameter of $1,000/MWh.[38] Arizona Public Service also experienced relatively lower prices in the middle of the day when its own solar generation peaks due to ISO and Western EIM internal congestion.[39]

Prices in PacifiCorp East and Idaho Power were often similar to each other and lower than prices in the ISO and the BANC. As shown in Figure 2.2 and Figure 2.3, price separation between these areas and the ISO and the BANC was most pronounced during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO met export limits.

Average real-time prices for NV Energy were similar to PacifiCorp East and Idaho Power, but diverged when the area experienced failed flexible ramping sufficiency tests and power balance constraint relaxations.

Western EIM wholesale energy cost

In the energy imbalance market, total estimated wholesale cost to serve load, excluding the ISO, was about -$250,000 or near $0/MWh of total load in the first quarter of 2020, similar to the same quarter

[38] See Section 2.4 for further details on the load conformance limiter enhancement and its impact.

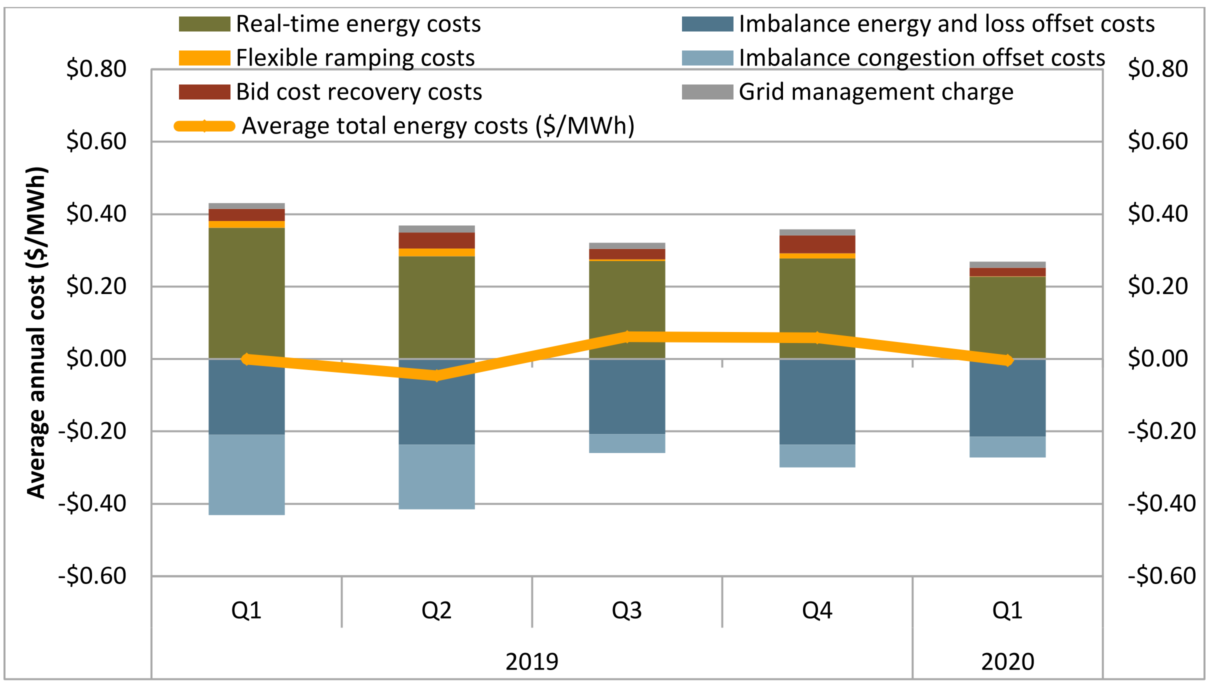
[39] See Section 1.10 for further details on the effect congestion had on ISO and EIM prices.

of 2019.[40] Wholesale costs estimated here are costs associated with serving imbalance load in the Western EIM measured per megawatt-hour of total load.

As shown in Figure 2.4 and Table 2.1, real-time energy costs contributed the largest portion of the costs. Imbalance offset costs typically reduced costs to serve load in the energy imbalance market, such that for the first quarter of 2020 the overall costs were slightly negative, similar to the same quarter in 2019.

Real-time energy costs and real-time congestion imbalance offset costs decreased by about 37 percent and 74 percent, respectively, from the same quarter in the previous year. The flexible ramping product and bid cost recovery costs also decreased modestly from the same period in the prior year, while other costs remained similar to previous quarters. In the EIM, offset costs paid to non-California balancing areas include payments to offset greenhouse gas cap-and-trade obligations incurred due to market dispatch.

Figure 2.4 Total EIM quarterly wholesale costs per MWh of load



40 Total wholesale costs for both ISO and EIM areas are calculated from settlements data. Because settlements data may be updated multiple times during a calendar year according to the settlements timeline, the values reported here may be different than previously reported.

Table 2.1 Estimated average EIM wholesale energy costs per MWh

	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Change Q1 2019-Q1 2020
Real-time energy costs	$0.36	$0.28	$0.27	$0.28	$0.23	($0.14)
Imbalance congestion offset costs	($0.22)	($0.18)	($0.05)	($0.06)	($0.06)	$0.17
Imbalance energy and loss offset costs	($0.21)	($0.24)	($0.21)	($0.24)	($0.21)	($0.01)
Flexible ramping costs	$0.02	$0.02	$0.00	$0.01	$0.00	($0.02)
Grid management charge	$0.02	$0.02	$0.02	$0.02	$0.02	$0.00
Bid cost recovery costs	$0.03	$0.04	$0.03	$0.05	$0.02	($0.01)
Average total energy costs ($/MWh)	**($0.00)**	**($0.05)**	**$0.06**	**$0.06**	**($0.00)**	**($0.00)**

Fifteen-minute market congestion imbalances from EIM internal transmission constraints

Real-time congestion imbalances occur when payments made to schedules reducing flows on binding transmission constraints differ from payments collected from schedules increasing flows on constraints. A deficit is created when payments to flow reductions exceed collections from flow increases. When collections exceed payments there is a congestion surplus.

The ISO allocates real-time congestion imbalance deficits and surpluses to the balancing authority area in which the constraints are located. The balancing authority areas then allocate these imbalances based on their tariffs, which can include allocations to third party customers.

EIM base schedules can create flows above limits on constraints internal to a balancing authority area. If base schedule flows exceed internal constraint limits the 15-minute market must adjust schedules to reduce flows. The reduced flows would be paid without corresponding flow increases to collect payments from, causing a congestion imbalance deficit. This leads to concerns that third party customers, who are not responsible for submitting base schedules or transmission limits to the ISO, will have to pay to offset deficits caused by base schedule flows that exceed internal constraint limits.

Table 2.2 shows estimated real-time congestion imbalance charges from internal transmission constraints in the 15-minute market. These estimates do not include congestion imbalances from the real-time dispatch or inter-balancing authority area transfer constraints. With the exception of the California ISO, which settles deviations from day-ahead market schedules, these data estimate the extent to which congestion imbalance deficits are the result of base schedule flows exceeding 15-minute market transmission limits. Negative values indicate a congestion imbalance deficit and positive values a surplus. Please note that these estimates are calculated from non-settlement quality data.

PacifiCorp East is the only area to have significant base schedule related congestion imbalance deficits which occurred primarily in late 2017 and early 2018. These deficits were in part allocated to third party customers within PacifiCorp East. In 2018 the ISO conducted extensive outreach with EIM balancing authority areas and streamlined processes to reduce and prevent base scheduling that creates flows exceeding internal transmission limits. In 2019 PacifiCorp East had a small 15-minute market congestion surplus from internal constraints. In the first quarter, base schedule offsets in this area were about $0.7 million.

There have not been significant congestion imbalance deficits caused by base schedules exceeding transmission limits in other balancing authority areas. The lack of congestion imbalances from internal constraints in many EIM areas results in part from a lack of binding internal constraints.

Table 2.2 Estimated 15-minute market EIM internal constraint congestion imbalances ($ million)

	Annual				2019				2020
Balancing Authority Area	**2016**	**2017**	**2018**	**2019**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**
Arizona Public Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
BANC				$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Powerex	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
California ISO	-$51.1	-$26.2	-$70.4	-$92.3	-$17.9	-$18.4	-$14.0	-$42.0	-$12.7
Idaho Power Company			$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NV Energy	-$0.3	-$0.8	-$0.3	-$0.4	-$0.3	-$0.1	$0.0	$0.0	$0.0
PacifiCorp - East	-$4.0	-$18.1	-$2.0	$0.7	$0.8	$0.0	$0.1	-$0.3	-$0.7
PacifiCorp - West	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Portland General Electric		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Puget Sound Energy	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

2.2 Flexible ramping sufficiency test

The flexible ramping sufficiency test is performed every hour and ensures each balancing area has enough ramping resources to meet expected upward and downward ramping needs in the real-time market without relying on transfers from other balancing areas. The test requires balancing areas to show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals within the hour.

If an area fails the upward sufficiency test, EIM transfers into that area cannot be increased.[41] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased. An area will also fail the flexible ramping sufficiency test when the capacity test fails for the specific direction. The capacity test ensures that there are sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.[42]

Figure 2.5 and Figure 2.6 show the percent of *intervals* in which an EIM area failed the sufficiency test in the upward or downward direction.[43] During the first quarter of 2020, EIM areas failed the upward sufficiency test very infrequently. Arizona Public Service failed the upward sufficiency test most frequently in the energy imbalance market, during around 1 percent of intervals during the quarter. The frequency of downward sufficiency test failures increased from the previous quarter, but remained infrequent overall. Arizona Public Service and NV Energy each failed the downward sufficiency test during roughly 2 percent of intervals during the quarter.

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41 If an area fails the upward sufficiency test, net EIM imports (negative) cannot exceed the lower of either the base transfer or optimal transfer from the last 15-minute interval. Similarly, if an area fails the downward sufficiency test, net EIM exports are capped at the higher of either the base transfer or optimal transfer from the last 15-minute interval.

42 *Business Practice Manual for the Energy Imbalance Market*, February 28, 2019, p. 50.

43 Intervals in which an energy imbalance market entity is entirely disconnected from the market (market interruption) are removed.

Failures of the sufficiency test are important because these outcomes limit transfer capability. Constraining transfer capability may affect the efficiency of the EIM by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas. Reduced transfer capability also affects the ability for an area to balance load, as there is less availability to import from or export to neighboring areas. This can result in local prices being set at power balance constraint penalty parameters.

Figure 2.5 Frequency of upward failed sufficiency tests by month

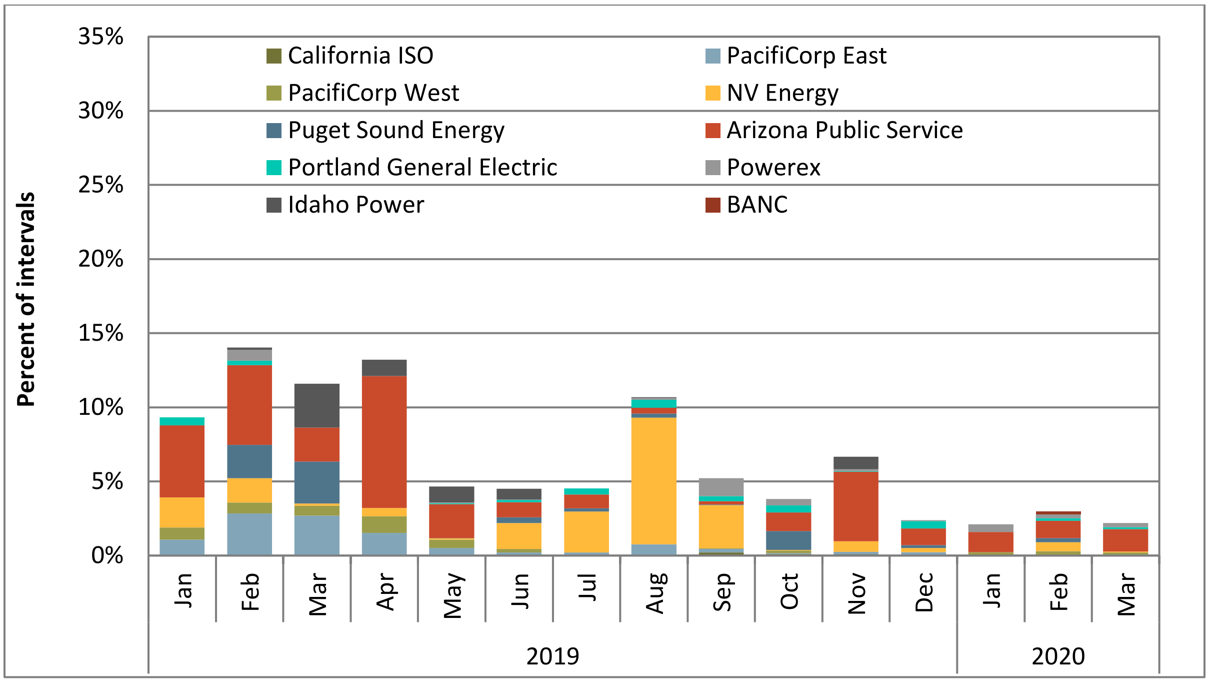
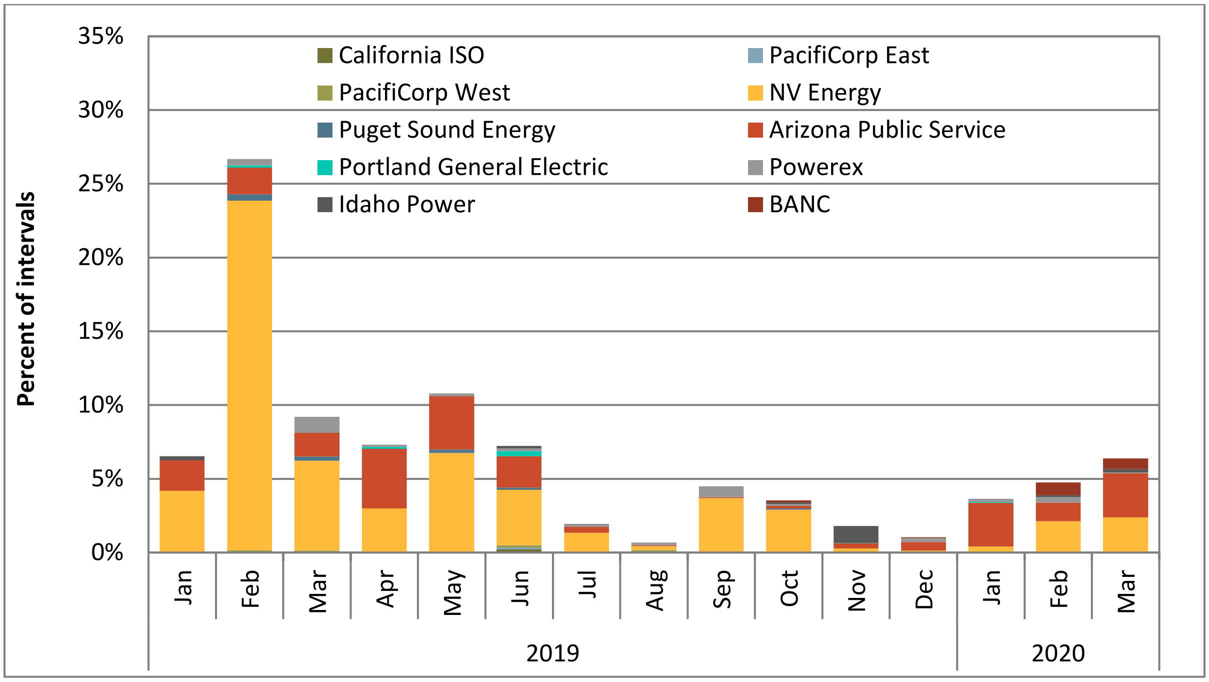


Figure 2.6 Frequency of downward failed sufficiency tests by month

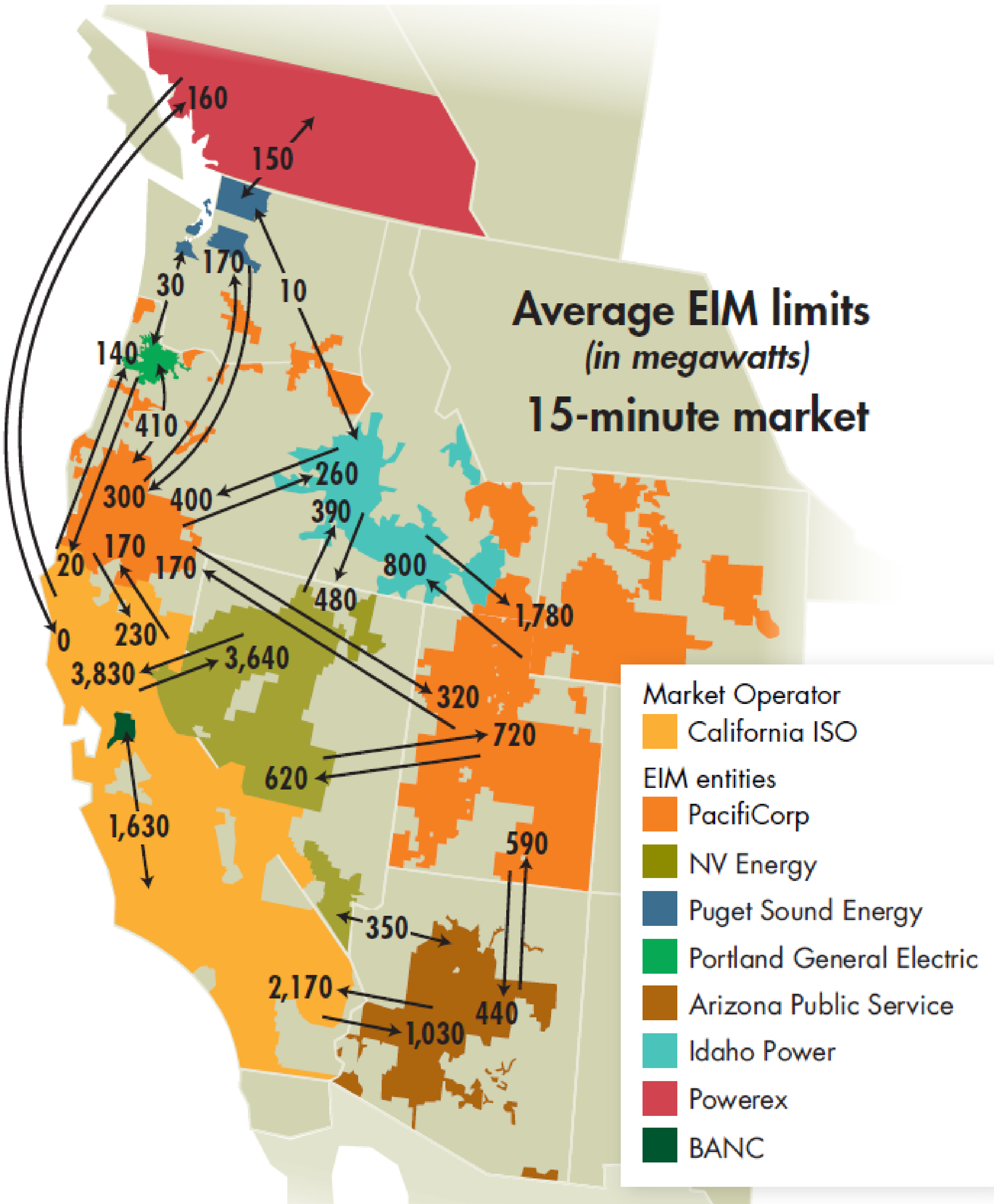


2.3 Western EIM transfers

Western EIM transfer limits

One of the key benefits of the EIM is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Figure 2.7 shows average 15-minute market limits between each of the areas during the first quarter. The map shows that there was significant transfer capability between the ISO, NV Energy, Arizona Public Service, and the BANC. Transfer capability between these areas, PacifiCorp East, and Idaho Power was lower but still significant. These limits allowed energy to flow between these areas with relatively little congestion. Transfer capability was more limited between the ISO and the Northwest areas which include PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. In particular, export limits from Powerex toward the ISO were limited to zero in all intervals in both the 15-minute and 5-minute markets.

Figure 2.7 Average 15-minute market energy imbalance market limits (January – March)



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 2.8 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.[44] The bars show the average hourly transfers with the connecting areas. The gray line shows the average hourly net transfer.

In the first quarter of 2020, average exports from the ISO during the middle of the day increased compared to both the previous quarter and the first quarter of 2019. Exports from the ISO during the first quarter of 2020 averaged just under 1,200 MW between hours ending 11 and 15.

Figure 2.8 California ISO - average hourly 15-minute market transfer

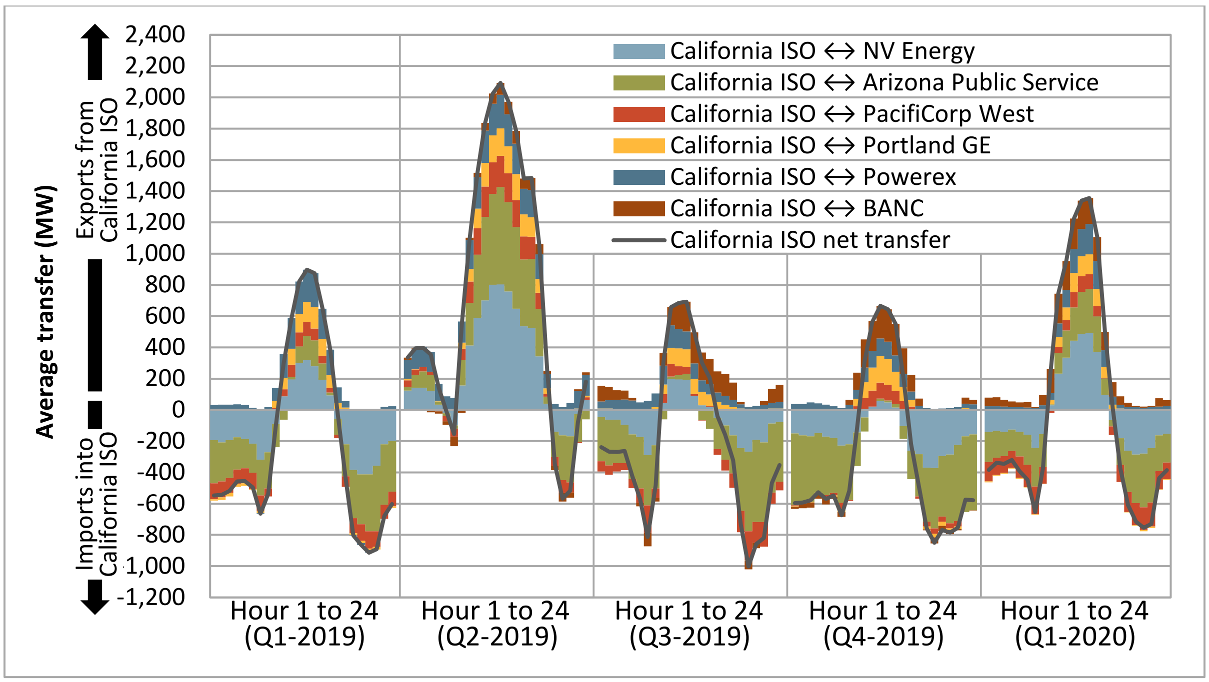


Figure 2.9 through Figure 2.17 show the same information on imports and exports for all energy imbalance market areas in the 15-minute market. The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[45]

Figure 2.9 and Figure 2.10 show average hourly transfers for NV Energy and Arizona Public Service. During the quarter, these areas typically imported from the ISO during midday hours and exported out to the eastward areas including PacifiCorp East and Idaho Power. During off-solar hours, these areas were generally net exporters with most transfers out to the ISO.

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44 Average transfers for the second quarter of 2019 include April 3 to June 30 only, and therefore reflect transfers after the Balancing Authority of Northern California joined the energy imbalance market.

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

Figure 2.11 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas, net of all base schedules. Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, NV Energy, and — to a limited extent — Puget Sound Energy. During the first, third, and fourth quarters of 2019, Idaho Power typically imported from PacifiCorp East.

Figure 2.12 through Figure 2.14 show average hourly 15-minute market imports and exports out of PacifiCorp East, PacifiCorp West, and Puget Sound Energy. PacifiCorp East has transfer capacity between PacifiCorp West, NV Energy, Arizona Public Service, and Idaho Power. PacifiCorp West has transfer capacity between the ISO, PacifiCorp East, Puget Sound Energy, Portland General Electric, and Idaho Power. The majority of Puget Sound Energy's transfer capacity is with PacifiCorp West and Powerex.

Figure 2.15 and Figure 2.16 show the average hourly 15-minute market transfer patterns for Powerex, Portland General Electric, and their neighboring areas. Export transmission capacity from Powerex toward the ISO was limited to zero megawatts during all intervals in the first quarter of 2020 in both the 15-minute and 5-minute markets. Similarly, export limits from Portland General Electric toward the ISO were set to zero during 72 percent of 15-minute intervals and 87 percent of 5-minute intervals during the quarter.

Figure 2.17 shows average hourly transfers between the Balancing Authority of Northern California and the ISO since joining the energy imbalance market on April 3, 2019. The BANC area imported from the ISO during all hours on average during the first quarter of 2020.

Figure 2.9 NV Energy – average hourly 15-minute market transfer

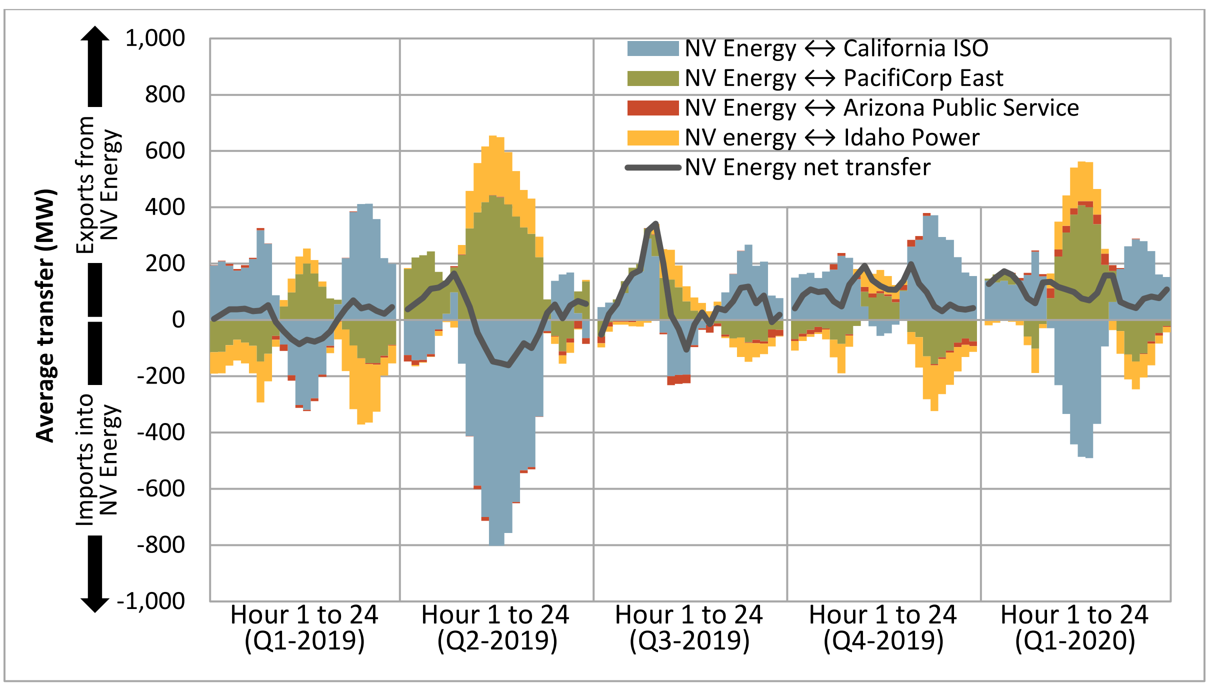


Figure 2.10 Arizona Public Service – average hourly 15-minute market transfer

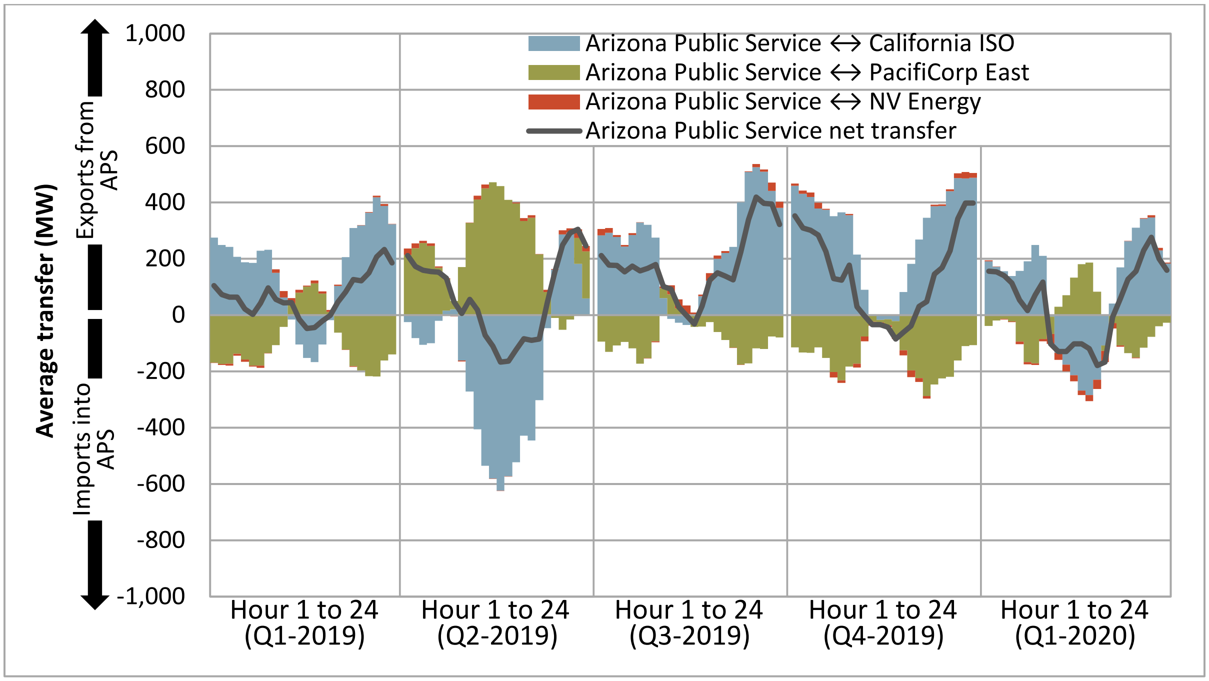


Figure 2.11 Idaho Power – average hourly 15-minute market transfer

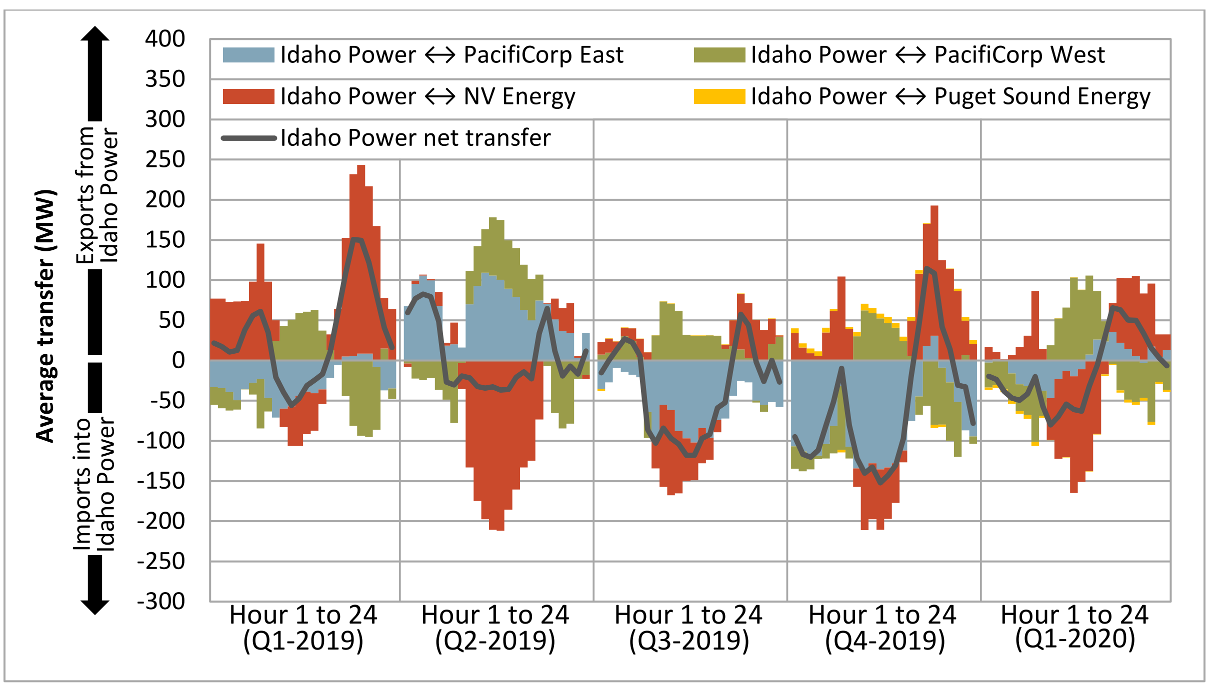


Figure 2.12 PacifiCorp East – average hourly 15-minute market transfer

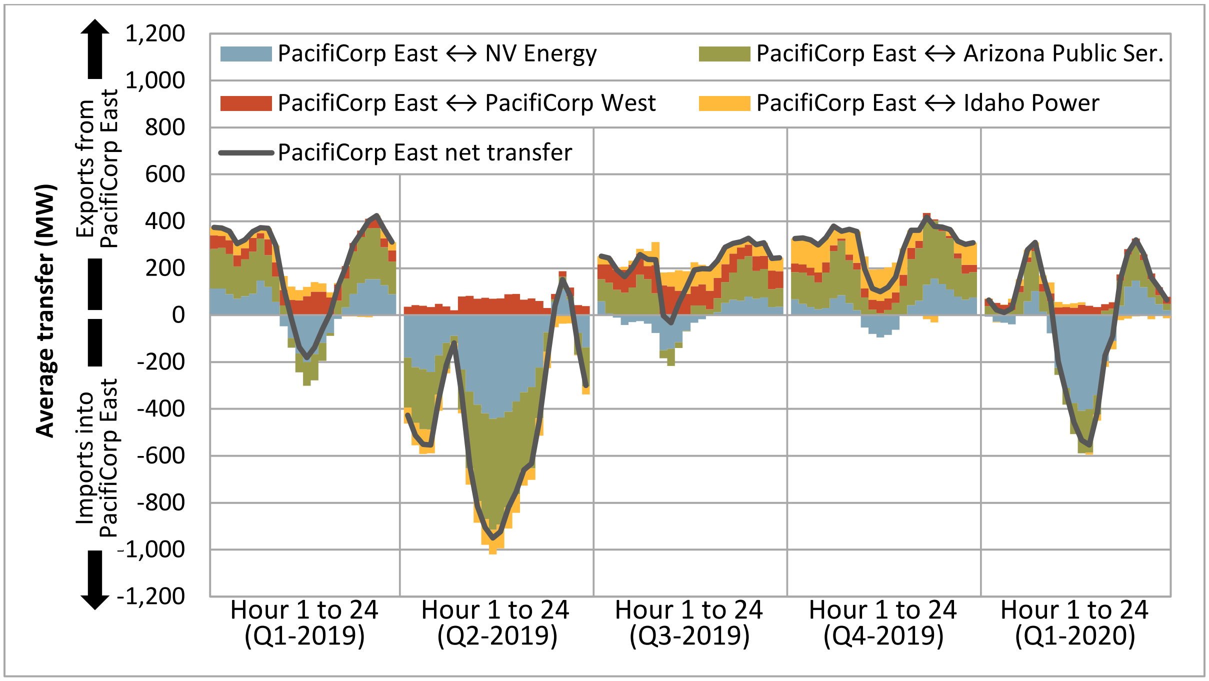


Figure 2.13 PacifiCorp West – average hourly 15-minute market transfer

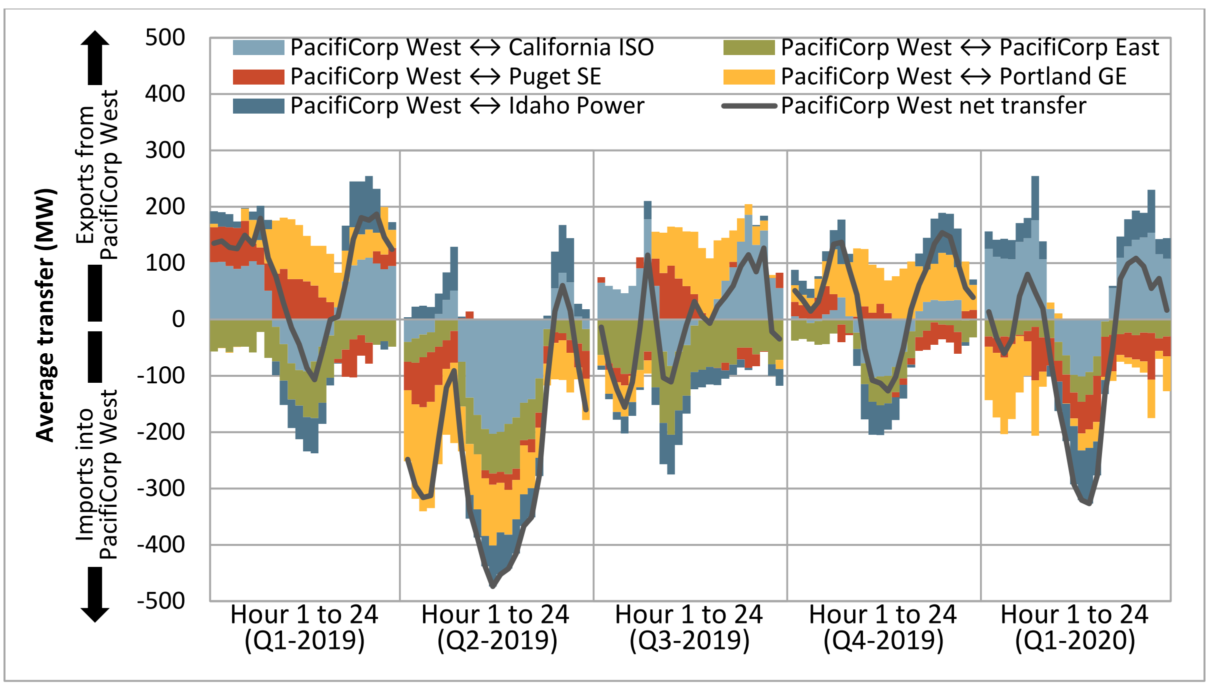


Figure 2.14 Puget Sound Energy – average hourly 15-minute market transfer

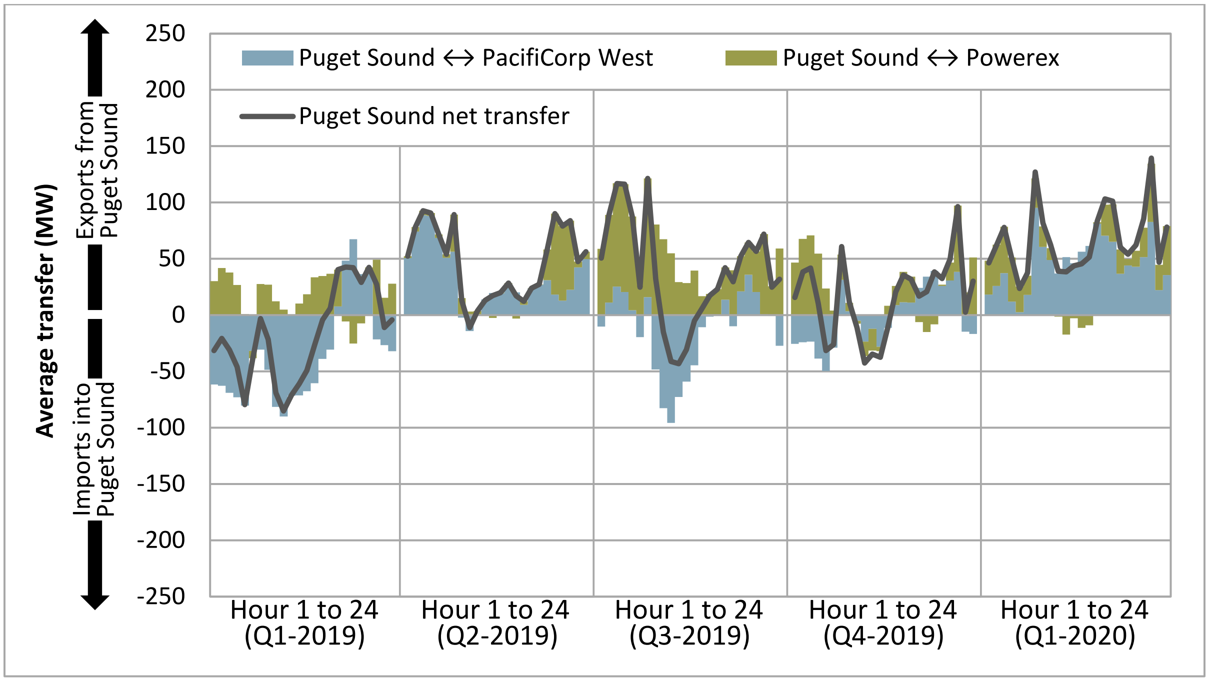


Figure 2.15 Powerex – average hourly 15-minute market transfer

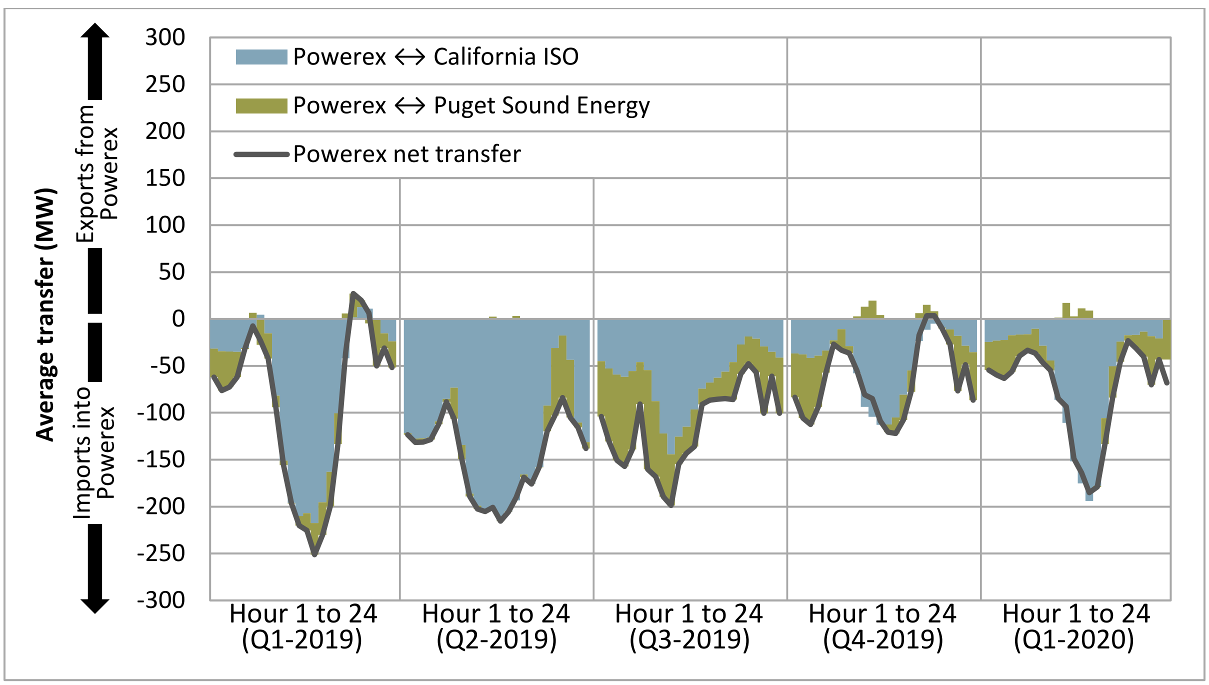


Figure 2.16 Portland General Electric – average hourly 15-minute market transfer

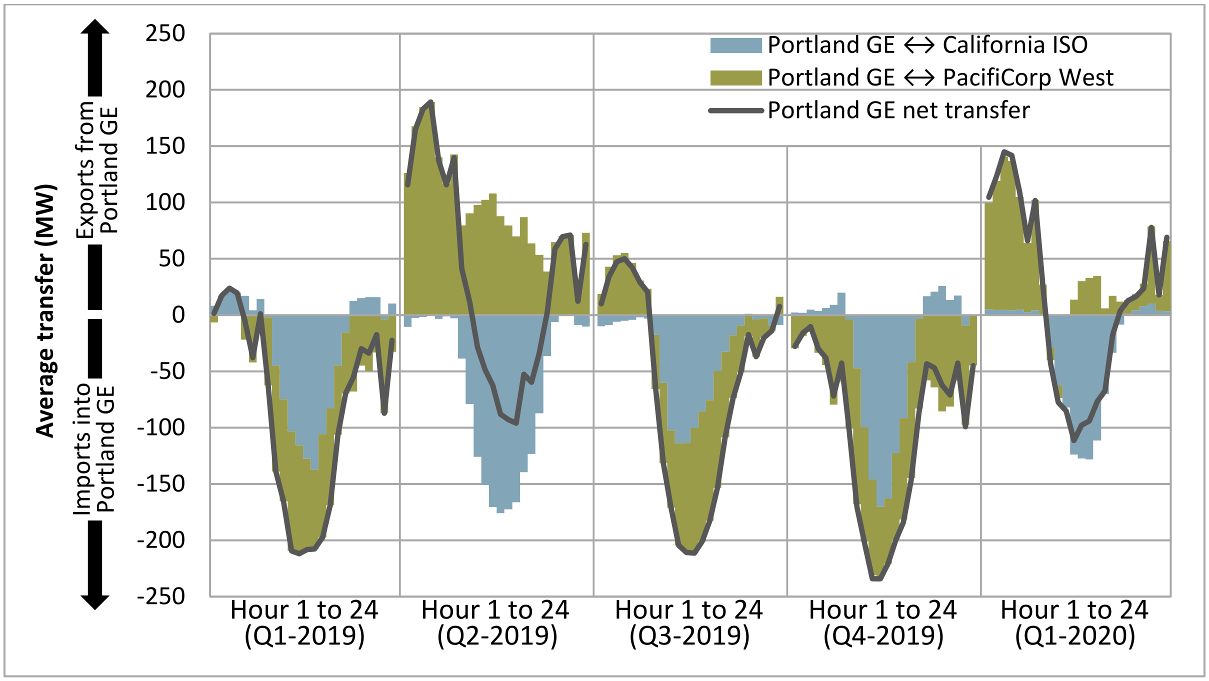
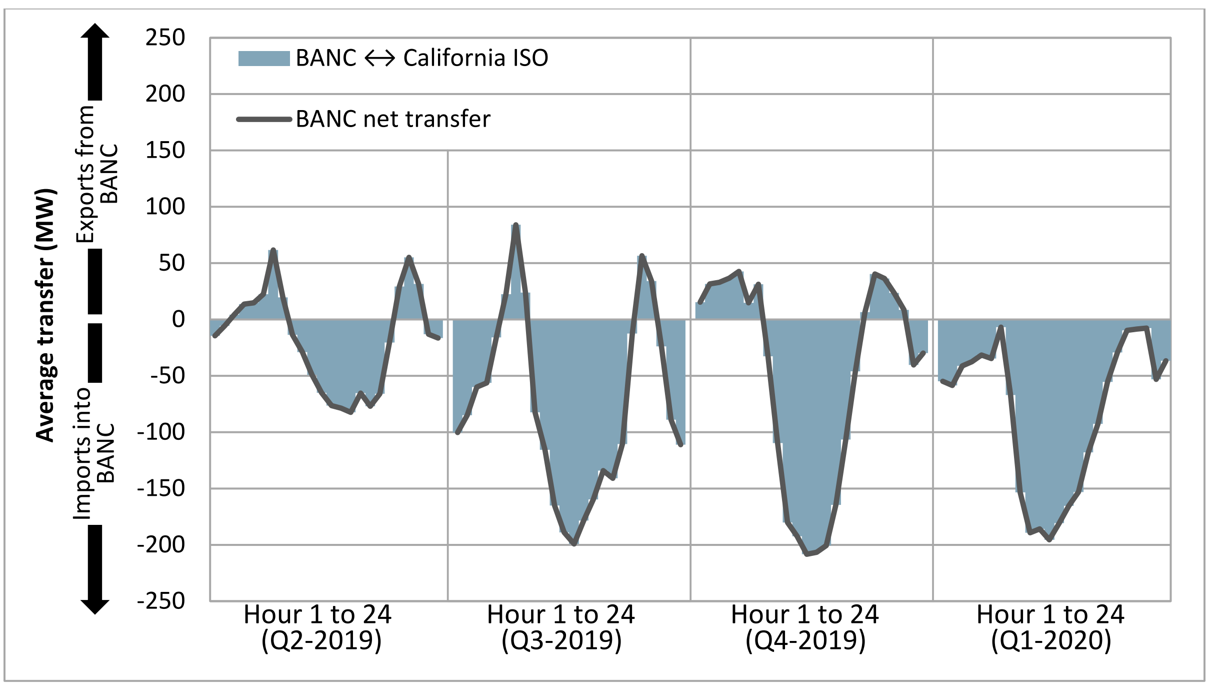


Figure 2.17 Balancing Authority of Northern California - average hourly 15-minute market transfer



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.[46]

Table 2.3 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of an energy imbalance market area. This is calculated as the frequency of intervals when 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.[47] 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. The results of this section are the same as those found in section 1.10.2 of this report on EIM transfers. Chapter 1 focuses 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.

Table 2.3 Frequency of congestion in the energy imbalance market (January – March)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
NV Energy	2%	0%	2%	0%
Arizona Public Service	2%	2%	2%	1%
PacifiCorp East	1%	3%	1%	2%
Idaho Power	1%	3%	1%	3%
PacifiCorp West	24%	5%	13%	6%
Portland General Electric	25%	5%	14%	6%
Puget Sound Energy	25%	8%	16%	12%
Powerex	26%	11%	19%	26%

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, Puget Sound Energy, and Powerex occurred

46 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.

47 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.

during roughly 25 percent of intervals during the quarter. This is slightly lower than the previous quarter when this occurred during 27 percent of intervals from these areas.

The highest frequency of net import congestion (such that the ISO market software triggers local market power mitigation in that area) occurred in the Powerex area, during 11 percent of 15-minute market intervals and 26 percent of 5-minute market intervals during the first quarter.

Table 2.3 also shows that congestion in either direction between the BANC, NV Energy, Arizona Public Service, PacifiCorp East, Idaho Power, or the ISO area was infrequent during the first quarter. Congestion that did occur between 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

Table 2.4 summarizes the average frequency and size of positive and negative imbalance conformance (load adjustments) entered by operators in the EIM for the 15-minute and 5-minute markets during the first quarter.[48] The same data for the ISO is provided as a point of reference. Arizona Public Service entered load adjustments in around 36 percent of intervals in the upward direction and 42 percent of intervals in the downward direction. Puget Sound Energy entered negative load adjustments in around 25 percent of 15-minute intervals and 55 percent of 5-minute intervals.

48 Load adjustments are sometimes referred to as *load bias* or *load conformance*. The ISO uses the term *imbalance conformance* to describe this process.

Table 2.4 Average frequency and size of imbalance conformance (January – March)

	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	52%	563	2.4%	4%	-260	1.3%	282
5-minute market	36%	262	1.2%	37%	-247	1.2%	3
PacifiCorp East							
15-minute market	0%	N/A	N/A	2%	-57	1.0%	-1
5-minute market	10%	67	1.3%	30%	-84	1.6%	-19
PacifiCorp West							
15-minute market	0%	N/A	N/A	3%	-54	2.2%	-1
5-minute market	2%	44	1.7%	31%	-52	2.2%	-16
NV Energy							
15-minute market	2%	78	2.1%	0.1%	-100	2.8%	2
5-minute market	20%	61	1.7%	6%	-118	3.5%	5
Puget Sound Energy							
15-minute market	0.3%	38	1.3%	25%	-34	1.1%	-8
5-minute market	0.9%	48	1.4%	55%	-36	1.2%	-20
Arizona Public Service							
15-minute market	36%	54	1.9%	42%	-53	2.2%	-3
5-minute market	36%	54	1.9%	42%	-54	2.2%	-3
Portland General Electric							
15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
5-minute market	31%	24	1.0%	0.3%	-99	4.1%	7
Idaho Power							
15-minute market	0%	N/A	N/A	0.3%	-50	3.3%	0
5-minute market	0.7%	46	2.4%	26%	-52	3.1%	-13
BANC							
15-minute market	0.4%	22	2.2%	0.1%	-40	4.1%	0
5-minute market	4%	21	1.9%	3%	-26	2.5%	0

2.5 Greenhouse gas in the Western EIM

Under the current design, all energy serving California ISO or BANC load through a non-California EIM transfer is subject to California's cap-and-trade regulation.[49] A participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving the ISO load. The EIM optimization minimizes costs of serving load in both the ISO and EIM taking into account greenhouse gas compliance cost for all energy deemed delivered to the ISO. The EIM greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt attributed as serving the ISO load. This information serves as the basis for greenhouse gas compliance obligations under California's cap-and-trade program.

This greenhouse gas revenue is returned to participating resource scheduling coordinators with energy that is deemed delivered as compensation for compliance obligations. The revenue is equal to the cleared 15-minute market quantity priced at the 15-minute price plus the incremental greenhouse gas dispatch in the 5-minute market valued at the 5-minute market price. Incremental dispatch in the 5-minute market may be either positive or negative.

As of November 2018, the ISO implemented a policy change to address the concerns that the market design was not capturing the full greenhouse gas effect of energy imbalance market imports into California to serve the ISO load for compliance with California's cap-and-trade regulation.[50] The amount of capacity that can be deemed delivered to California is now limited to the upper economic bid limit of a resource minus the resource's base schedule.

Greenhouse gas prices

Figure 2.18 shows monthly average cleared EIM greenhouse gas prices and hourly average quantities for transfers serving the ISO load settled in the EIM. Weighted average prices are calculated using 15-minute deemed delivered megawatts to weight 15-minute prices and the absolute value of incremental 5-minute greenhouse gas dispatch to weight 5-minute prices. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

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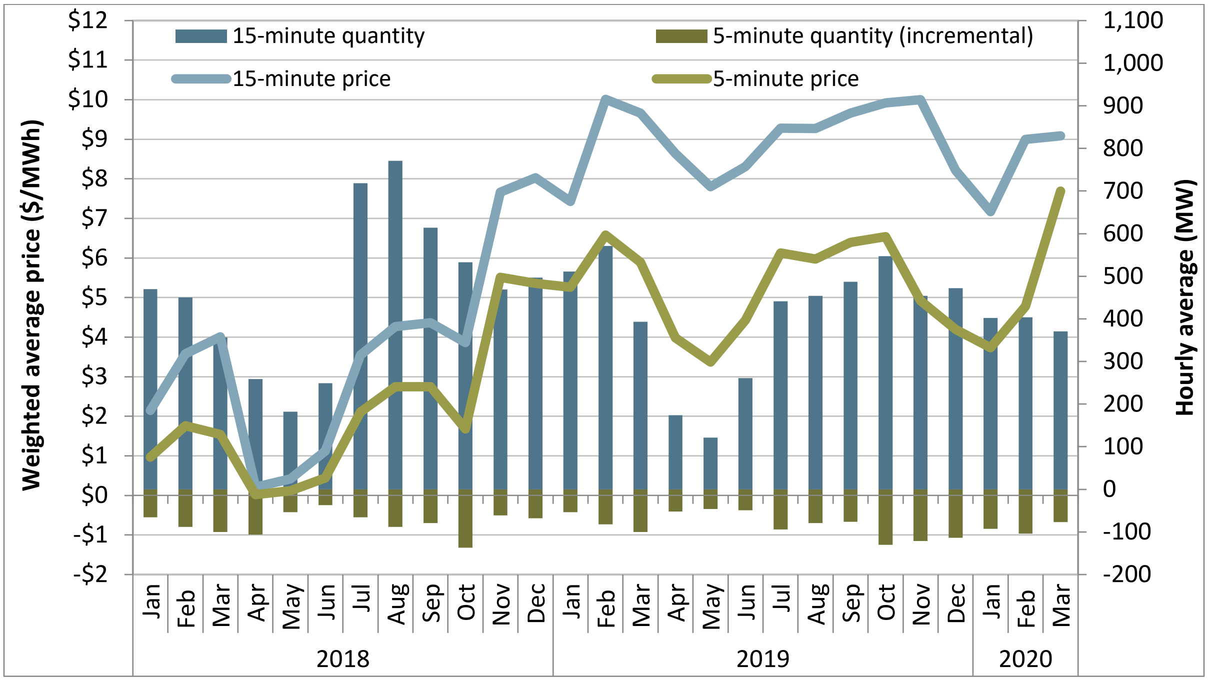
49 Further information on energy imbalance market entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on ARB's website here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/eim-faqs.pdf.

50 Further information on the energy imbalance market greenhouse gas enhancements proposal can be found here: http://www.caiso.com/Documents/ThirdRevisedDraftFinalProposal-EnergyImbalanceMarketGreenhouseGasEnhancements.pdf

Figure 2.18 Energy imbalance market greenhouse gas price and cleared quantity



Weighted 15-minute greenhouse gas prices averaged around $8/MWh for the first quarter while 5-minute prices averaged about $5/MWh. Greenhouse gas prices continue to remain higher relative to before the policy change in 2018 when monthly greenhouse gas prices averaged around $3/MWh in the 15-minute market and $2/MWh in the 5-minute market. The increase in greenhouse gas prices relative to before 2019 appears to be a result of the policy change, which limits the EIM capacity that can be deemed delivered to California and results in higher emitting resources setting the price.

Price differences between markets can occur if high emitting resources are procured in the 15-minute market and subsequently decrementally dispatched in the 5-minute market. Separation between 15-minute prices and 5-minute prices has also increased since the policy change in 2018. In the first quarter, the price difference between the 15-minute and 5-minute markets is about $3/MWh, about the same as the first quarter of the previous year. This price separation is often correlated with operator load adjustments (described in section 1.14), which are consistently higher in the 15-minute market than the 5-minute market. Operator load adjustments have been used for a number of years, but more recently contribute to accentuated differences in greenhouse gas prices due to the compressed bid stack.

Historically, EIM greenhouse gas prices have not exceeded $7/MWh in either the 15-minute or 5-minute market. After November 2018, prices around $7/MWh occur frequently and some prices are set higher than the highest cleared bid. Figure 2.19 and Figure 2.20 show the frequency of high prices and maximum price by quarter for each market for the last two years. In the first quarter, nearly 40 intervals in the 15-minute market and 132 intervals in the 5-minute market were greater than $18/MWh. In the first quarter, the highest 15-minute price was $18.97/MWh and the highest 5-minute price was $970.96/MWh which is significantly higher than the highest bid-in offer.

Figure 2.19 High 15-minute EIM greenhouse gas prices

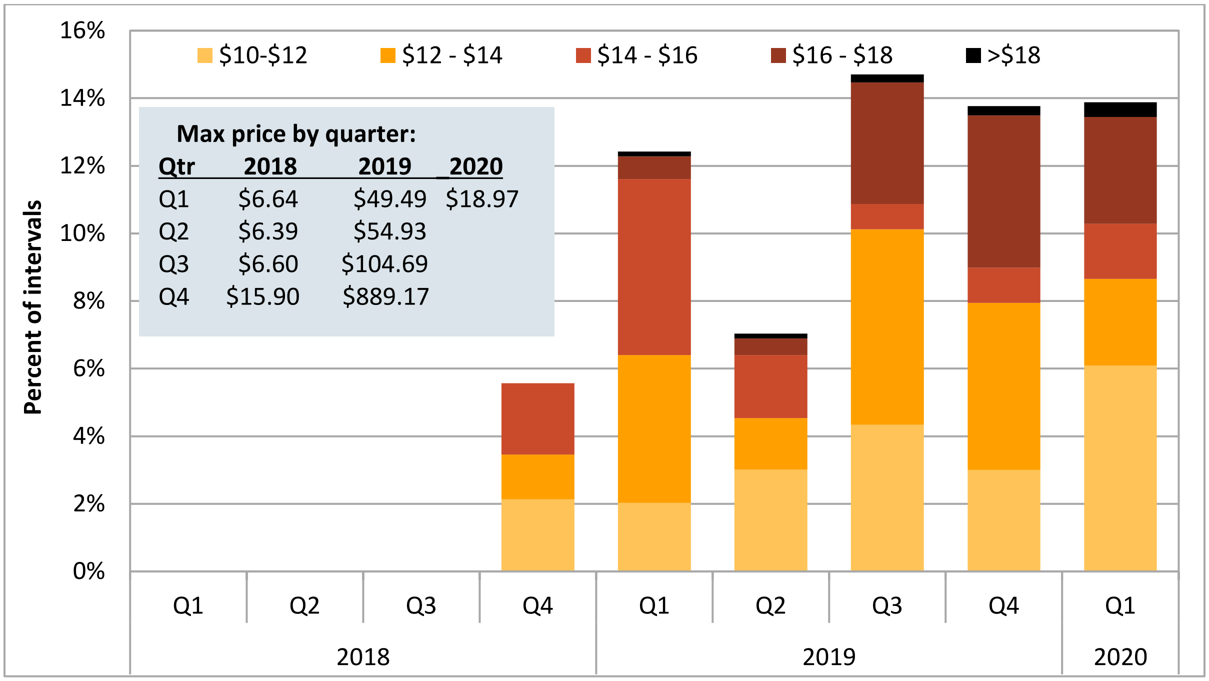
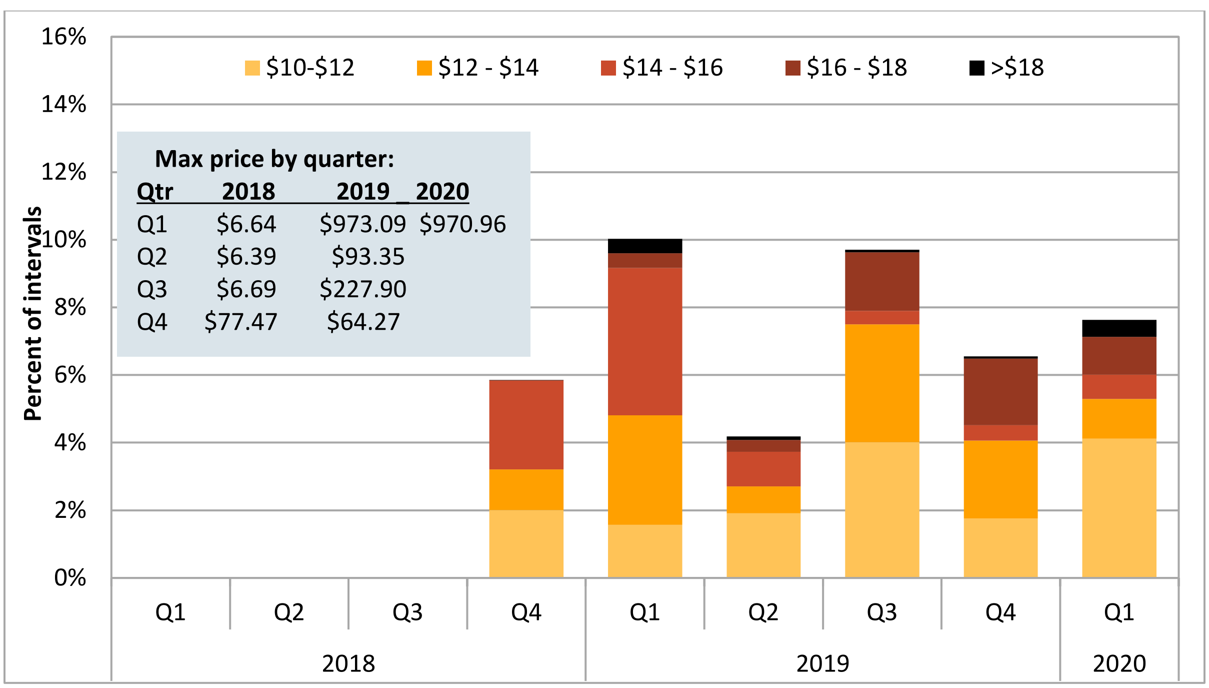


Figure 2.20 High 5-minute EIM greenhouse gas prices

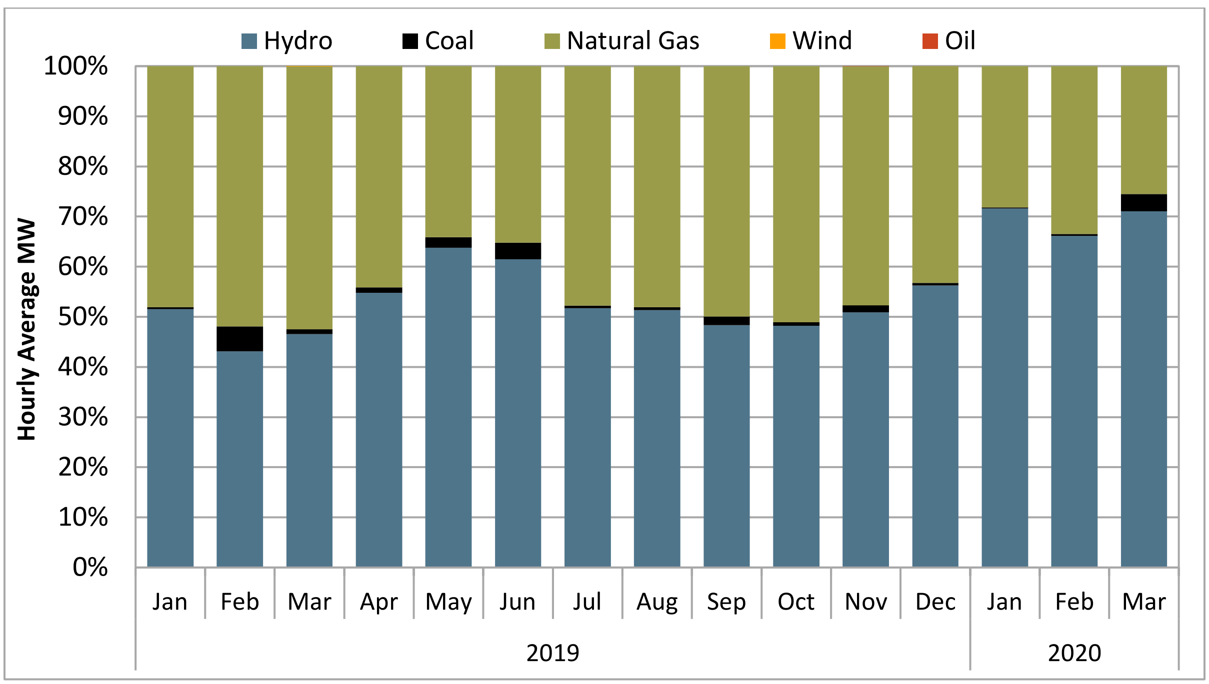


DMM estimates the total revenue accruing for greenhouse gas bids attributed to EIM participating resources serving the ISO load before subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $7.4 million in the first quarter, compared to roughly $9.6 million in the same quarter of the previous year.

Energy delivered to California by fuel type

Figure 2.21 shows the hourly average energy deemed delivered to California by fuel type and by month. In the first quarter, about 29 percent of EIM greenhouse gas compliance obligations were awarded to gas resources, a decrease from 51 percent in the first quarter of the previous year. Hydro-electric resources accounted for about 70 percent of total energy delivered to California which increased from around 47 percent in the same quarter of 2019. Additionally, energy originating from coal resources has increased since the policy change, but only accounted for about 1 percent of energy delivered in the first quarter, a slight decrease compared to the first quarter of 2019.

Figure 2.21 Hourly average EIM greenhouse gas generation by fuel type



2.6 Mitigation in the EIM

The elimination of carryover mitigation appears to have reduced mitigation rates in the Western EIM. Figure 2.22 and Figure 2.23 highlight the low frequency and volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the EIM:

- Average incremental energy subject to mitigation in the EIM in February and March 2020 in the 15-minute and 5-minute markets decreased when compared to the same quarter in 2019.

- An insignificant volume of bids was lowered as a result of mitigation in the Western EIM.

Figure 2.22 Average incremental energy mitigated in 15-minute real-time market (EIM)

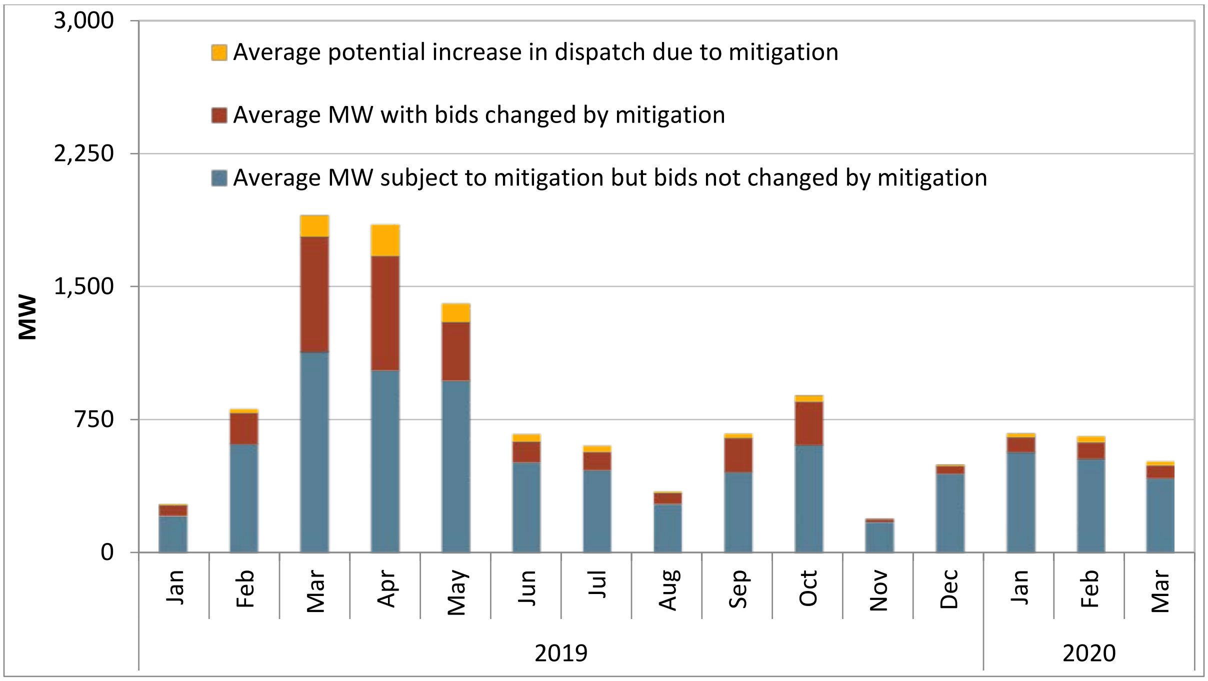
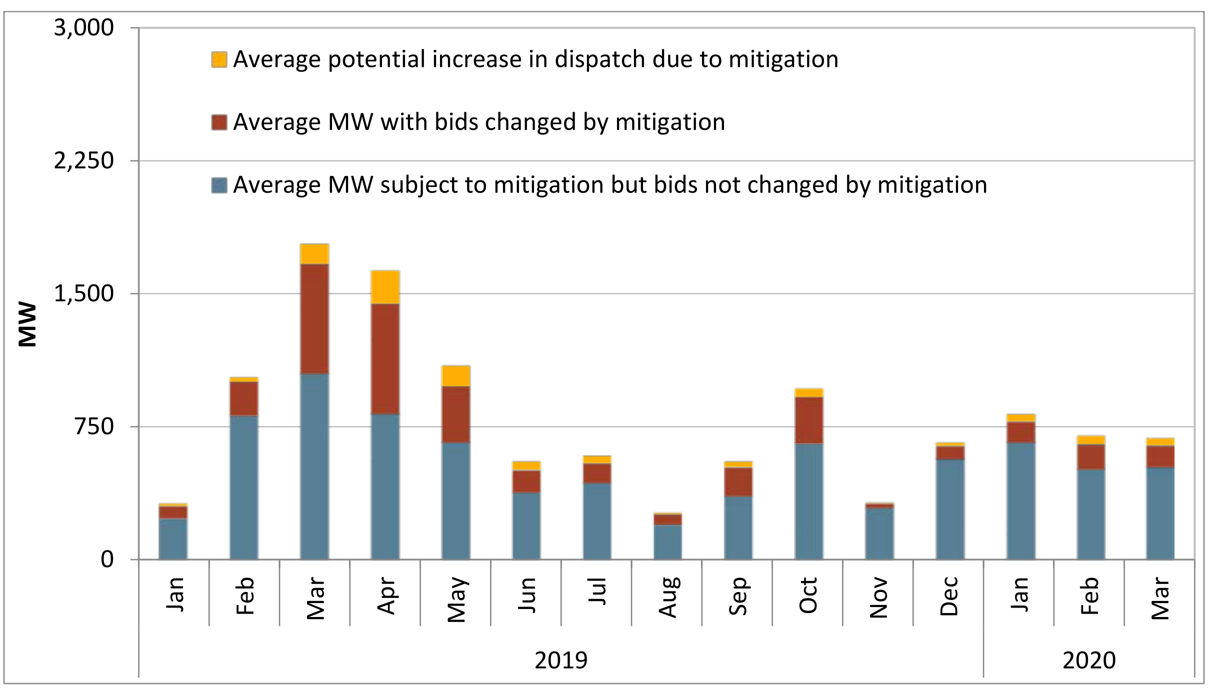


Figure 2.23 Average incremental energy mitigated in 5-minute real-time market (EIM)



3 Special issues

This section provides information about the following special issues:

- **Stay-at-home orders to control COVID-19 reduced load** by over 5 percent on weekdays following a California state-wide public health order to preserve public health effective March 19.
- **Downward dispatch of renewable resources was considerably higher** in every month of the first quarter compared to the same quarter of 2019 in both the ISO and energy imbalance market. This downward dispatch, often called curtailment, was most often the result of economic downward dispatch rather than self-schedule curtailment.
- **Market results were competitive in the first quarter**. DMM estimates that the impact of gas resources bidding above reference levels, a conservative measure of the average price-cost markup, was about $0.38/MWh or just over 1 percent for the default energy bid scenario.
- **DMM introduced several new competiveness scenarios**. These include a scenario that replaces bid-in demand with actual load and removes virtual bids, a scenario that caps gas commitment costs at 110 percent of estimated reference levels, and a scenario that caps import bids at a conservative measure of opportunity cost based on the recently introduced hydro default energy bid. DMM also runs combinations of scenarios.
- **The price-cost markup** for the gas default energy bid scenario averaged $0.38/MWh or 1.28 percent for the first quarter. The markup for that scenario combined with capping of import bids and commitment costs was $0.68/MWh or 2.16 percent. When this scenario is combined with the physical scenario including both actual load and removal of virtual bids, the markup fell to $0.16/MWh or 0.54 percent. This slight positive markup indicates that overall prices have been very competitive for the year.
- **Market power has had a very limited effect on system market prices** even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.

3.1 COVID-19

In response to the spread of the novel coronavirus causing COVID-19, local governments in California started to declare local health emergencies beginning in February 2020. On March 4, 2020, the governor of California proclaimed a state of emergency to formalize actions needed to prepare the state for the spread of the novel coronavirus. Seven counties around the San Francisco bay area began shelter-in-place orders for residents to not leave their homes except for essential needs. A statewide executive order and a public health order took effect on March 19, 2020, to preserve public health and safety by disrupting the spread of the virus. Californians were directed to stay at their place of residence except to go to an essential job in a critical infrastructure sector or to shop for essential needs.

The economic impacts of the spread of the virus and resulting shelter-in-place orders are numerous and widespread, and therefore difficult to quantify. The same can be said about impacts to the ISO market; however, careful analysis can isolate partial impacts in specific situations.

Shelter-in-place orders have lowered load and altered the shape of load. The ISO's Market Analysis and Forecasting team conducted an analysis to calculate how the stay-at-home orders caused a change in the typical load pattern.[51] Initial results from the first full week of the statewide stay-at-home order show that loads decreased from their typical levels by 4.9 to 7.5 percent on weekdays and 1.1 to 3.1 percent on weekends.

DMM plans to publish an analysis of the impact of COVID-19 on ISO market prices in the second quarterly report of 2020. Reductions in natural gas prices, associated with reduced demand, and lower electricity load have both contributed to lower ISO market prices.

3.2 Downward dispatch and curtailment of variable energy resources

When the amount of supply on-line exceeds demand, the real-time market dispatches generation down. Generally, generators are dispatched down in merit order from highest bid to lowest. As with typical 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, wind and solar resources, which generally have very low or negative bids, are dispatched down economically.

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 3.1 shows the curtailment of wind and solar resources by month in the ISO. Curtailments fall into six categories:

- **economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls within one dollar of a resource bid, below a resource bid, or the resource's upper limit is binding[52];
- **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;
- **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

[51] *COVID-19 impacts to California ISO Load & Markets: March 17 – April 26, 2020*: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf. This document has since been updated to include more dates since the original publication.

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

- **other self-schedule curtailment**, in which a self-scheduled resource receives an instruction to reduce output and the market price is above the bid floor.

The majority of the reduction in wind and solar output during 2019 and the first quarter of 2020 was the result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation dispatched down in the ISO was solar resources, rather than wind, because solar resources bid more economic downward capacity.

In the ISO, economic downward dispatch was considerably higher in every month of the first quarter compared to the same quarter of 2019. Economic downward dispatch accounted for 152,115 MWh of curtailment in January 2020, compared to 13,413 MWh during the same time in 2019. The relatively high level of economic downward dispatch over the quarter was due to both higher renewable production and lower load. Compared to the first quarter of 2019, solar production increased by about 11 percent while wind production increased by about 12 percent. The largest exceptional dispatch curtailments of both self-scheduled and economic bid resources occurred during February, totaling 25,289 MWh.

Downward dispatch also increased in the energy imbalance market outside of the ISO Figure 3.2 shows the amount of economic downward dispatch of non ISO wind and solar resources. Curtailments fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment each defined above. Economic downward dispatch in the EIM during January 2020 reached 32,153 MWh, which is higher than any month of 2019. This large one month increase was related to the high frequency of congestion on the Wyoming_Export constraint, which led to one resource being heavily curtailed.[53]

[53] The Wyoming_Export constraint was congested during 55.8% of intervals as shown in Table 1.6. The overall effects of transfer congestion is discussed in detail in Section 1.10.2.

Figure 3.1 Reduction of wind and solar generation by month (ISO)

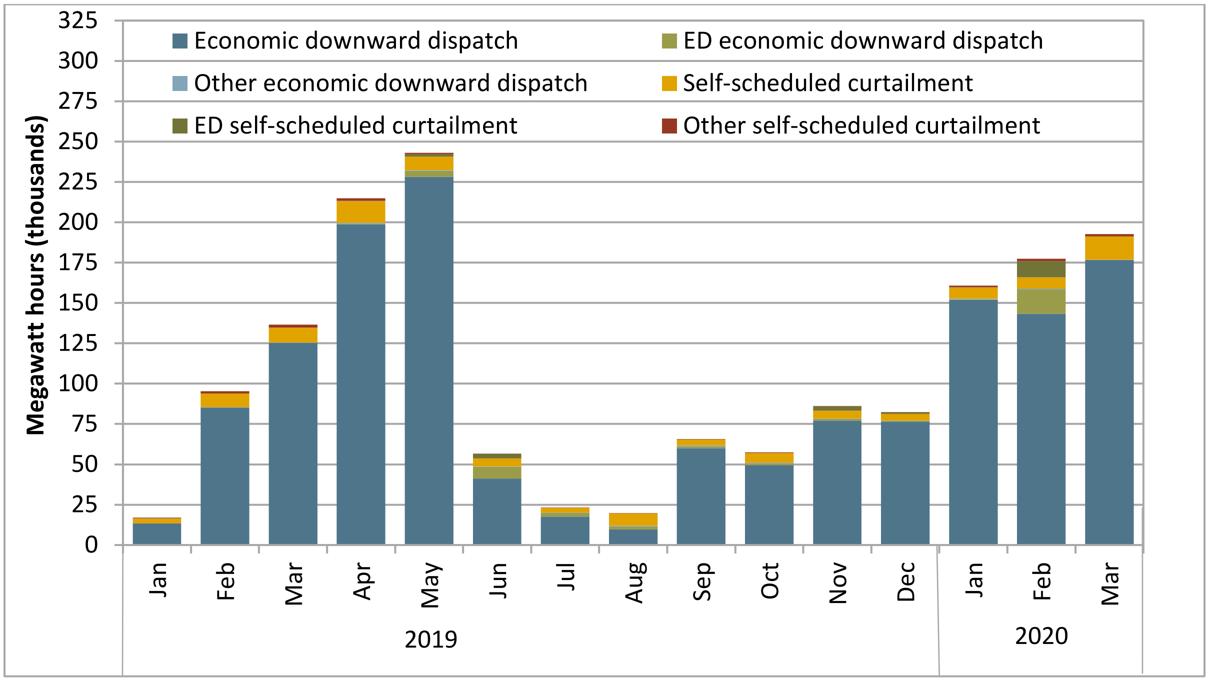
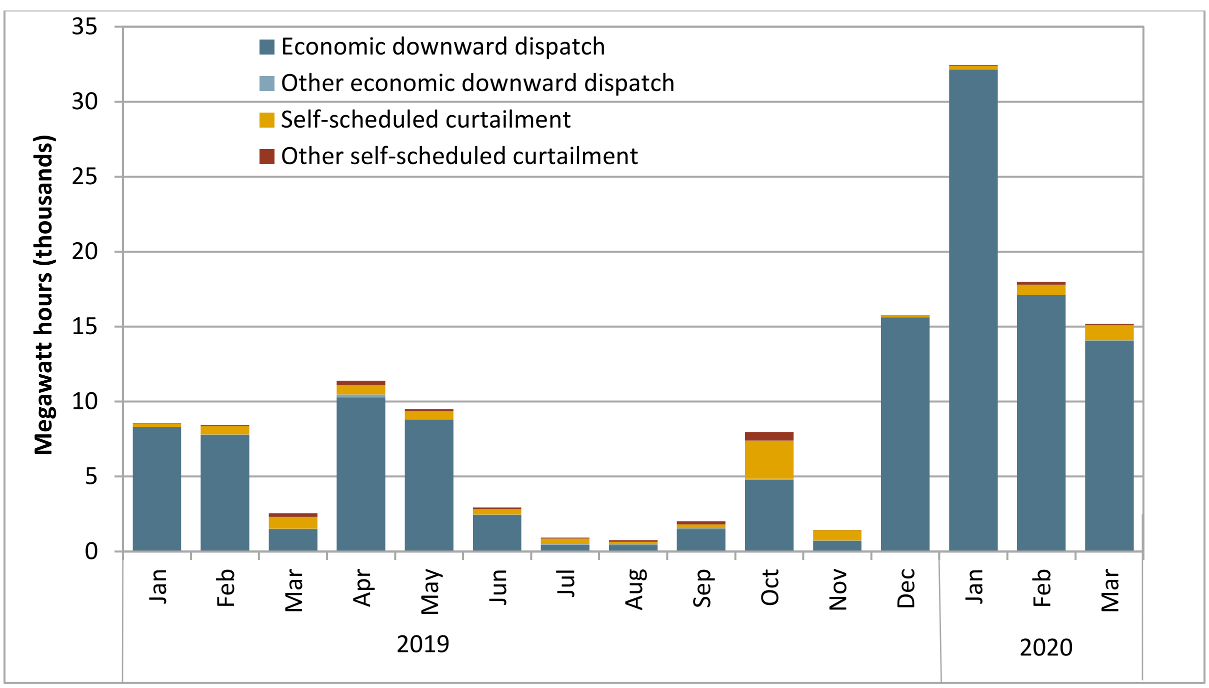


Figure 3.2 Reduction of wind and solar generation by month (EIM)



3.3 Measuring ISO market competitiveness: day-ahead market software simulation

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive benchmark prices by re-simulating the market after replacing bids or other market inputs using DMM's version of the actual market software.

In previous reports, the competitive baseline price was calculated by re-running the day-ahead market after replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids (DEB).[54] This methodology assumes competitive bidding of price-setting resources. Beginning in January 2020, the functionality of DMM's version of the actual market software was expanded to allow additional day-ahead market simulations to further analyze competitiveness under different scenarios. This section includes preliminary results from the following scenarios:

1. Replace market bids of gas-fired units with the lower of their submitted bids or their default energy bids (DEBs), to capture the effect of competitive bidding of energy by gas resources;
2. Replace bid-in commitment costs (start-up, transition and minimum load) of gas-fired units with the lower of their submitted bids or 110 percent of their proxy cost, to capture the effect of competitive bidding of commitment costs by gas resources;
3. Replace bids for import resources with the lower of their submitted bids or an estimated default energy bid based on a generous opportunity cost default energy bid option offered by the ISO (the hydro DEB), to capture the effect of competitive bidding of imports; and
4. Replace day-ahead bid-in load with actual 5-minute real-time market requirement and remove convergence bids as a proxy for actual system conditions.

In addition, simulations with various combinations of the above scenarios were completed to evaluate market competitiveness under different conditions:

5. (1) Default energy bids, (2) commitment costs, and (3) import bids;
6. (1) Default energy bids, and (4) insert 5-minute real-time market requirement and remove convergence bids; and
7. (1) Default energy bids, (2) commitment costs, (3) import bids, and (4) insert 5-minute real-time market requirement and remove convergence bids.

Each market simulation run is preceded by a base case rerun with all of the same inputs as the original market run before completing the benchmark simulation, to screen for accuracy. For 2020, the base

54 Historically, the competitive baseline was a scenario where bids for gas-fired generation were set to their default energy bids, convergence bids were removed, and system demand was set to actual system load. In recent years DMM moved away from this scenario as it tended to overestimate the competitive baseline price, because a significant amount of gas-fired supply is bid at prices lower than their default energy bids (which include a 10 percent adder), and actual system load tended to be greater than day-ahead bid-in load.

case reruns have replicated original prices with a greater frequency than recent years, allowing a higher percentage of days to be included in this analysis.[55]

As shown in Figure 3.3, average hourly prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices when comparing with the scenario that replaces submitted bids with default energy bids. Prices are shown separately for each default load aggregation point in the ISO balancing area. Figure 3.4 shows the hourly price-cost markup, calculated as the difference between the default energy bid scenario and base case prices, averaged by hour and load area. In the first quarter of 2020, prices remained very competitive, with average hourly prices in the competitive baseline scenario very close to actual market results.

55 In 2017 and 2018, DMM was unable to include multiple days in the analysis because of issues replicating original prices in the base case rerun. For 2019 and 2020, the ISO was able to resolve these issues such that a greater percentage of dates was able to be included.

Figure 3.3 Default energy bid scenario price results (Jan-Mar)

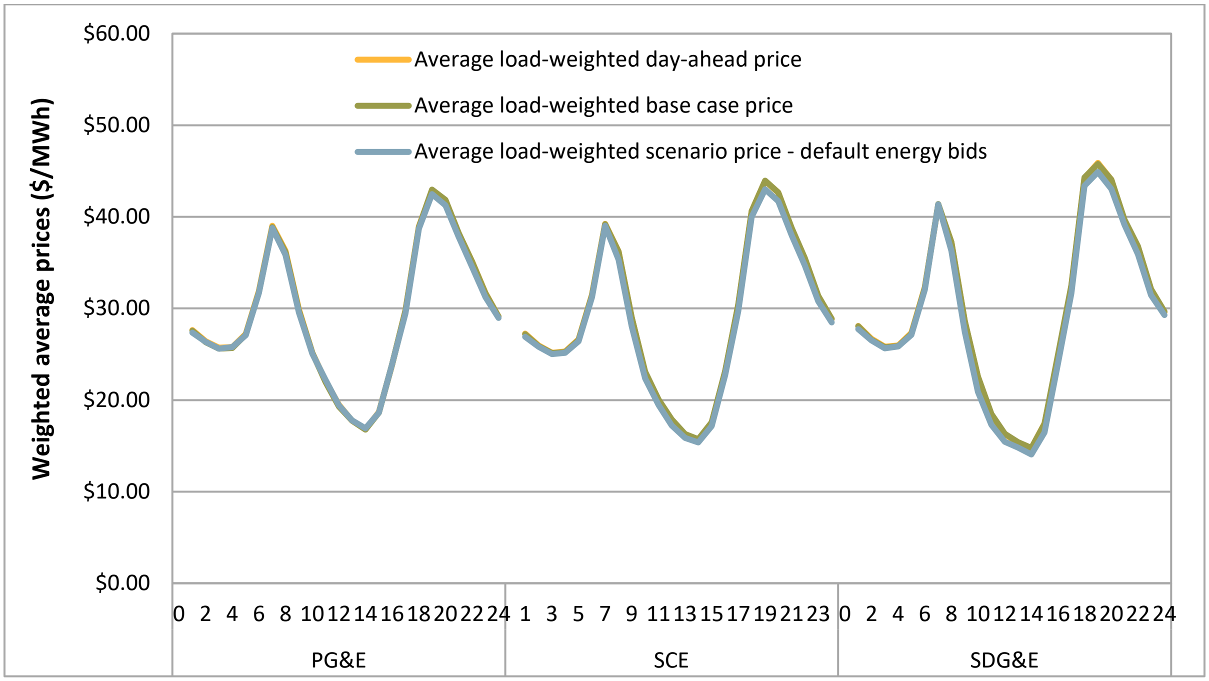
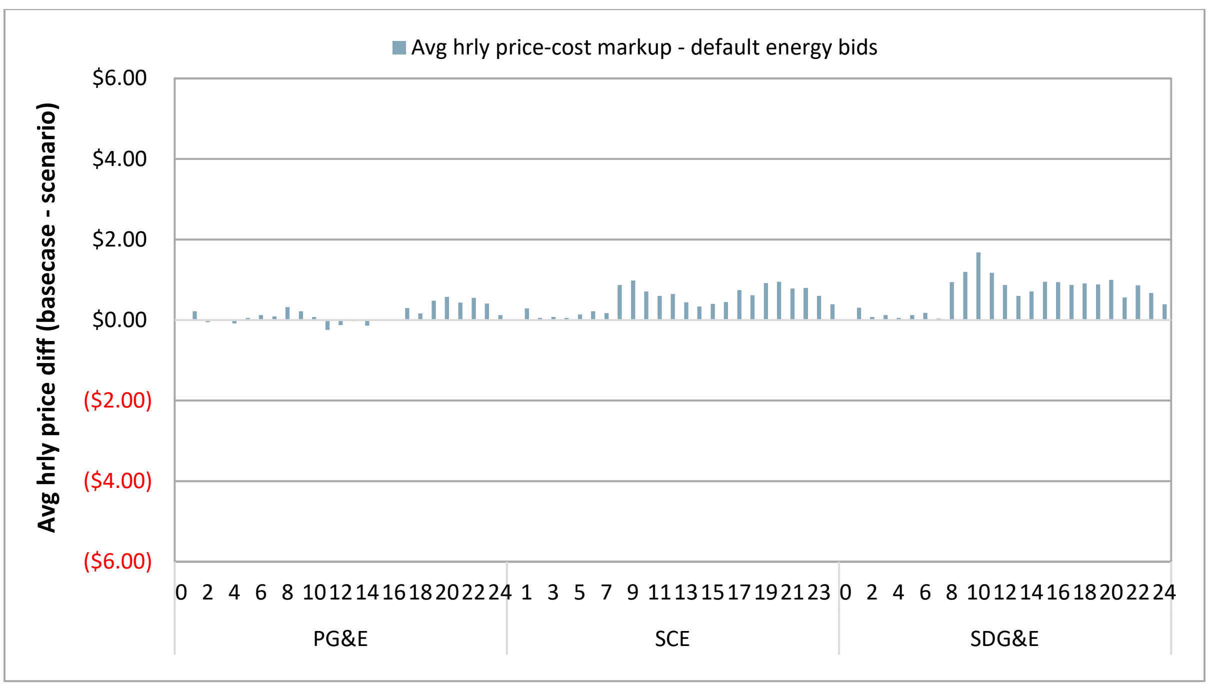


Figure 3.4 Hourly price-cost markup – default energy bid scenario (Jan-Mar)



Subsequent charts show these same values for additional scenarios. As expected, the scenarios with the largest hourly differences when compared with the base case reruns are those where system demand is set to the 5-minute market requirement and convergence bids are removed. The real-time market requirement can be higher or lower than the day-ahead demand, and corresponding price differences follow the same pattern. Even with these hourly price differences, however, prices for these scenarios are still very close to actual market results when averaged over the quarter.

Figure 3.5 Commitment cost scenario price results (Jan-Mar)

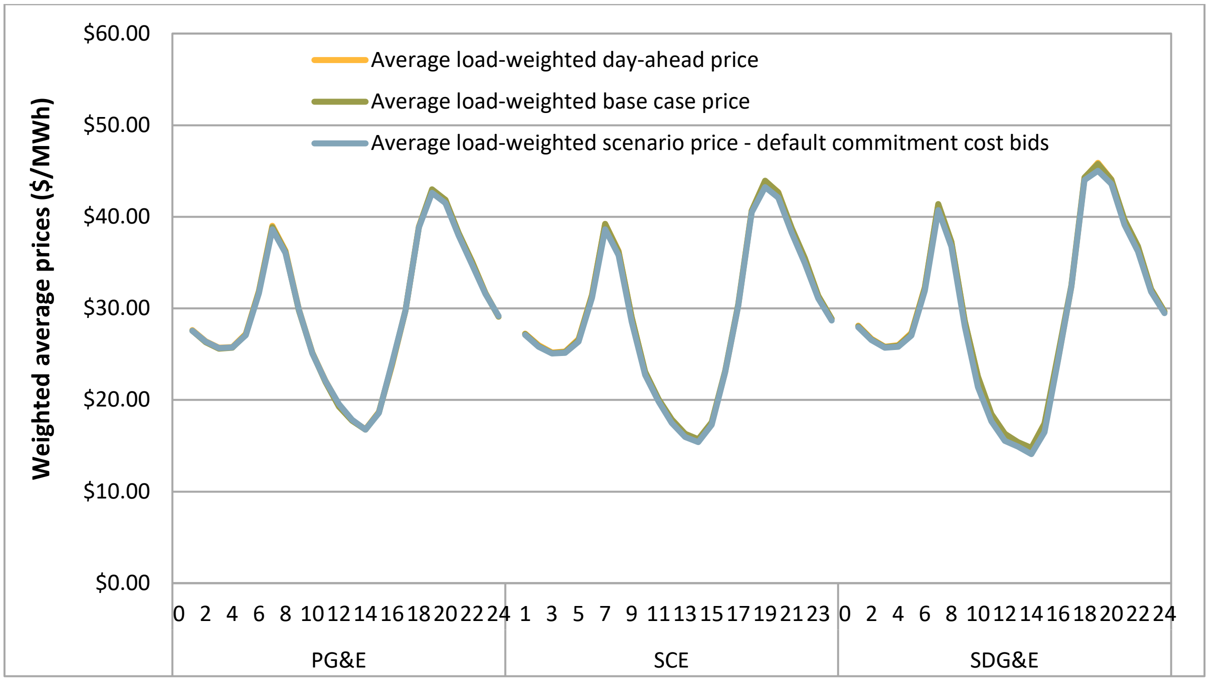


Figure 3.6 Hourly price-cost markup – commitment cost scenario (Jan-Mar)

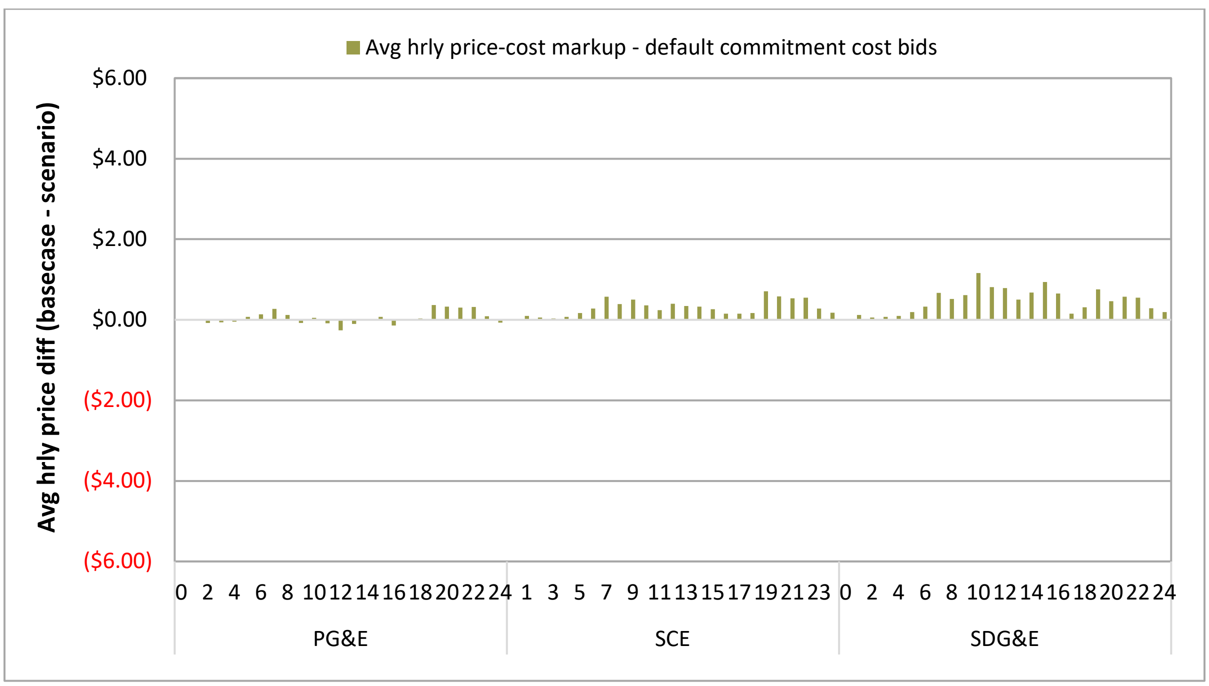


Figure 3.7 Import bid scenario price results (Jan-Mar)

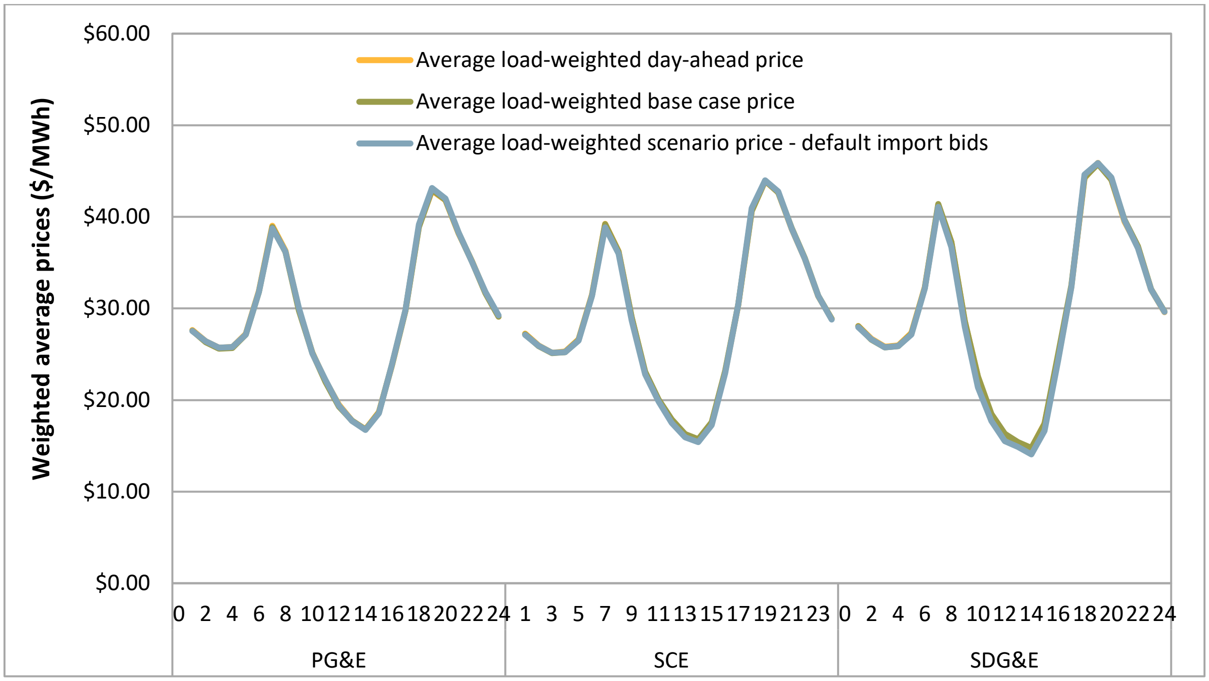


Figure 3.8 Hourly price-cost markup – import bid scenario (Jan-Mar)

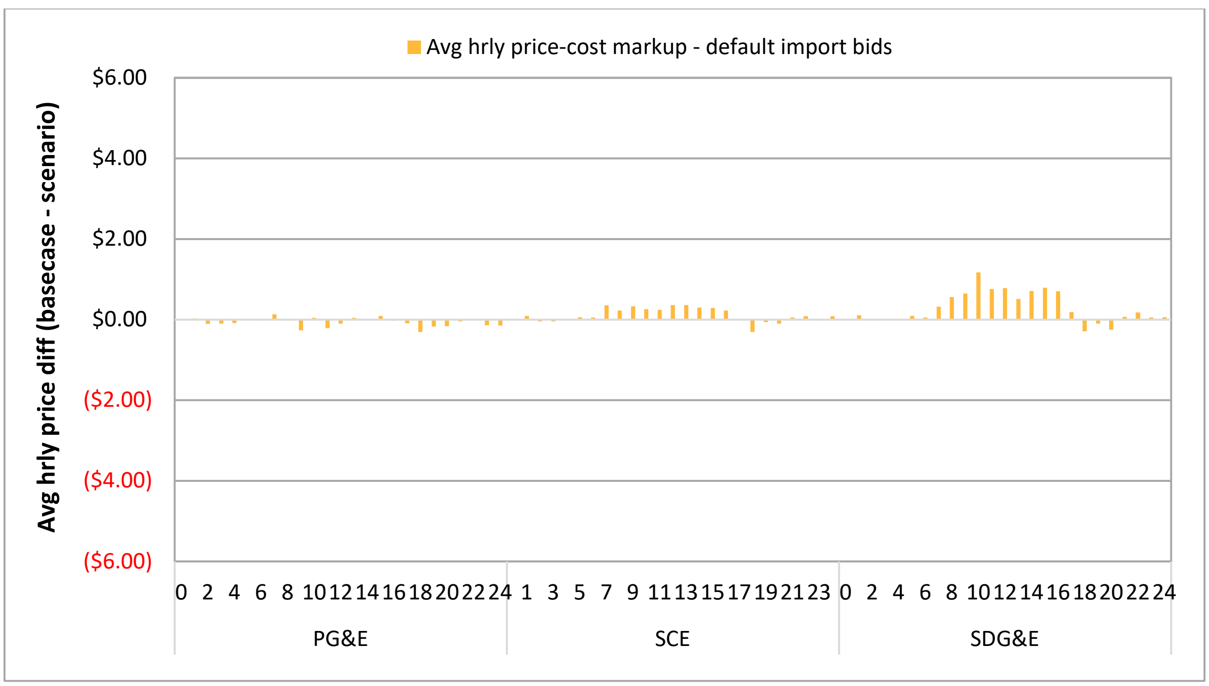


Figure 3.9 Default energy, commitment cost, and import bids scenario price results (Jan-Mar)

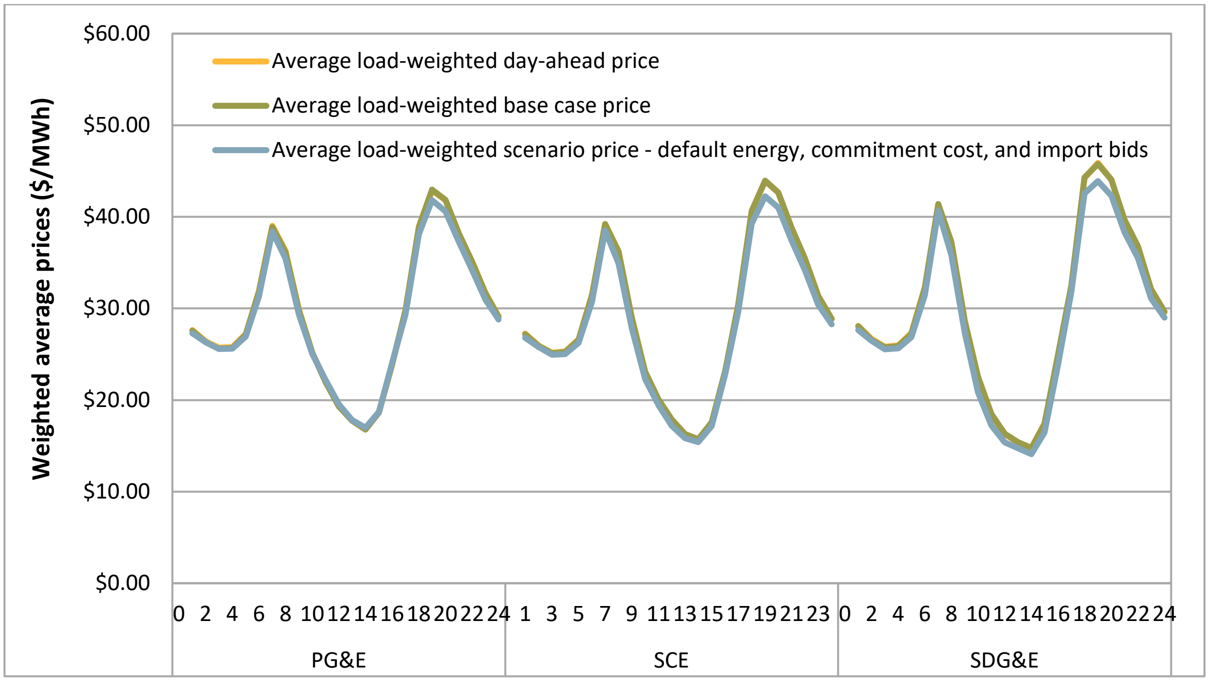


Figure 3.10 Hourly price-cost markup – default energy, commitment cost, and import bids scenario (Jan-Mar)

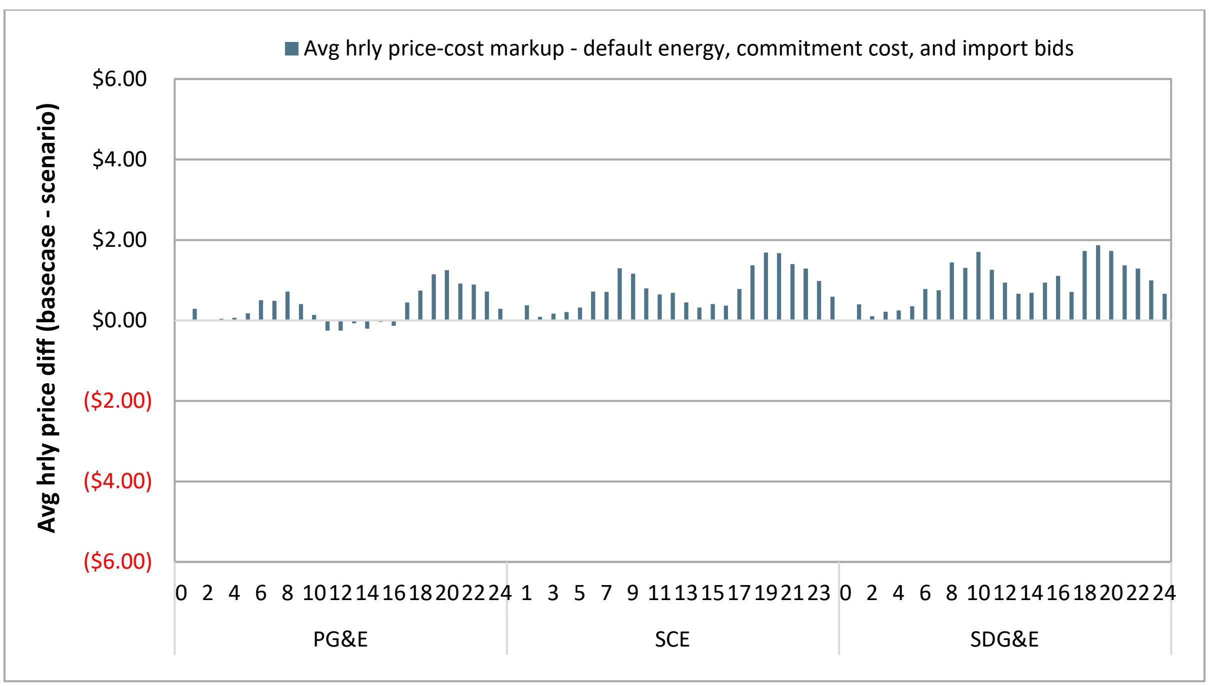


Figure 3.11 Actual load scenario price results (Jan-Mar)

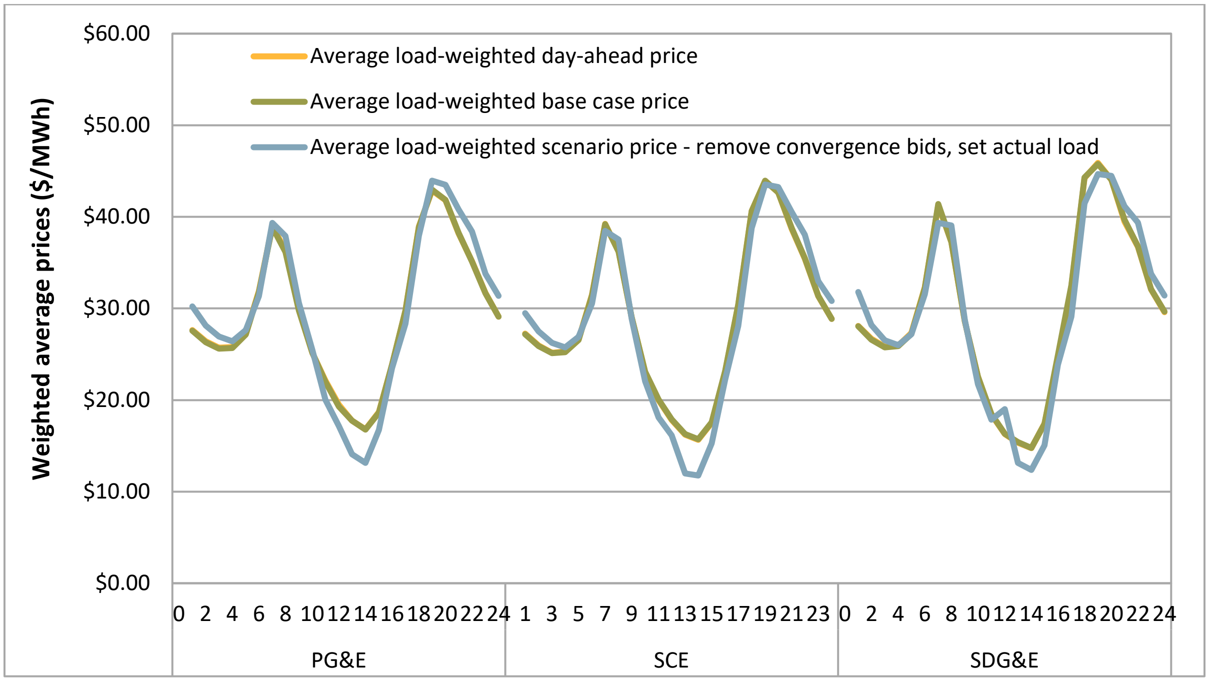


Figure 3.12 Hourly price-cost markup – actual load scenario (Jan-Mar)

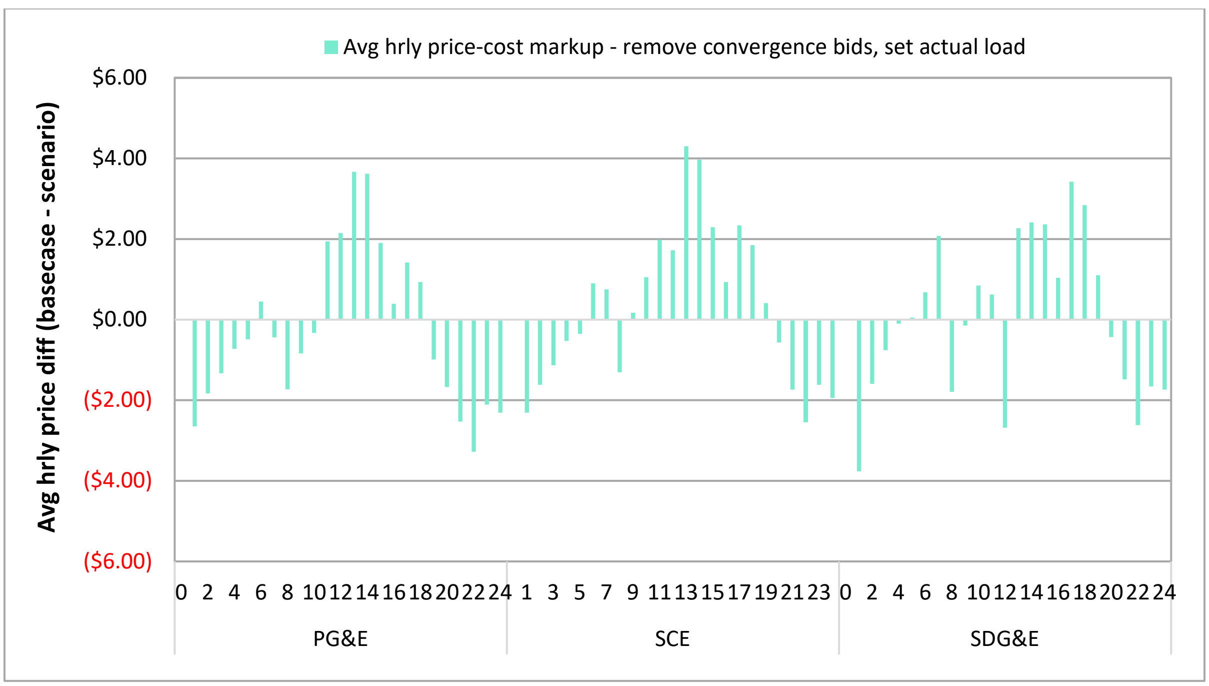


Figure 3.13 Actual load and default energy bids scenario price results (Jan-Mar)

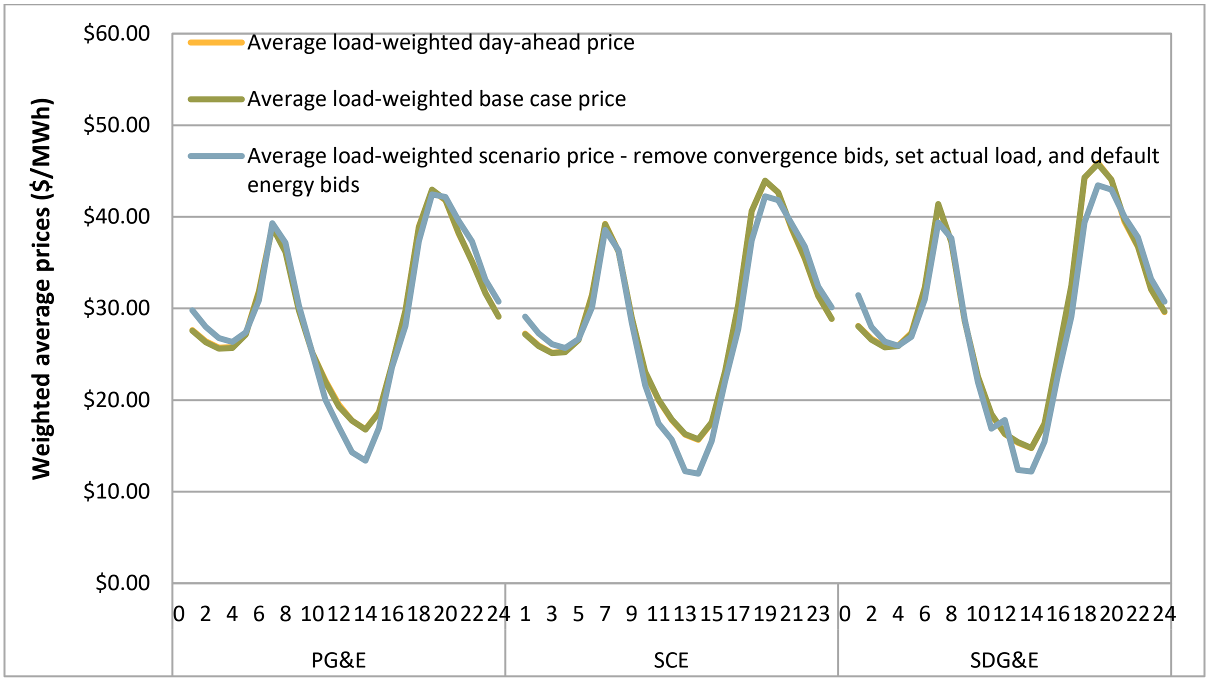


Figure 3.14 Hourly price-cost markup – actual load and default energy bids (Jan-Mar)

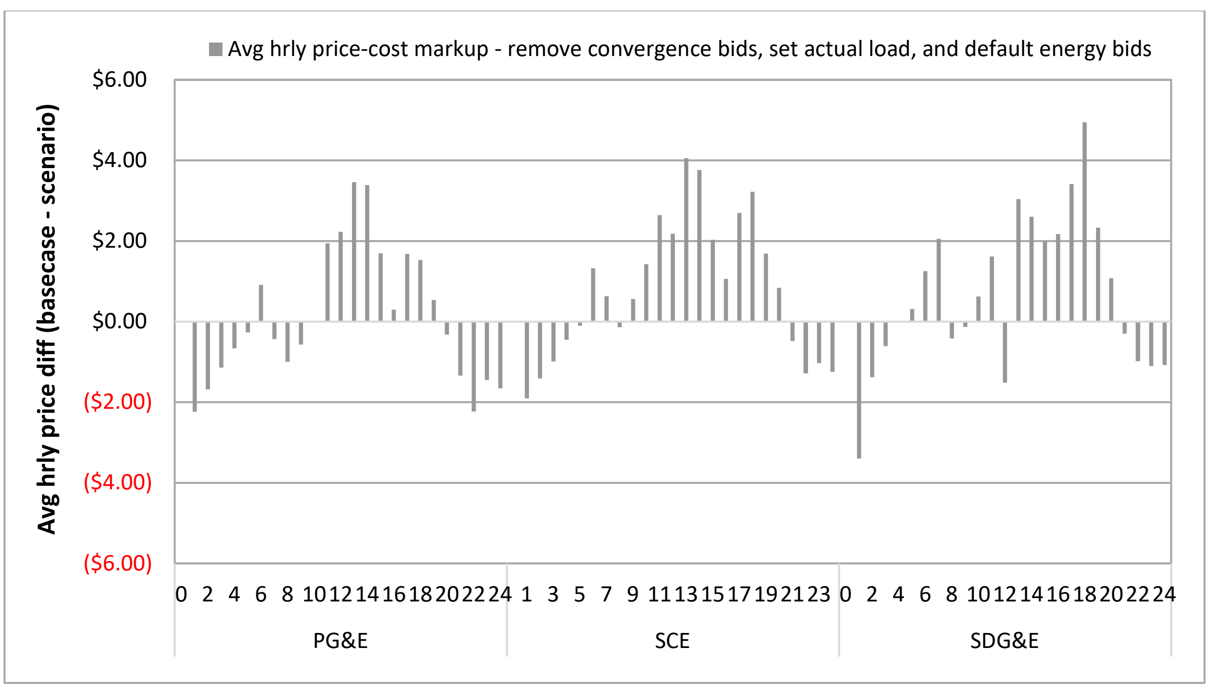


Figure 3.15 Actual load and default energy, commitment cost, and import bids scenario price results (Jan-Mar)

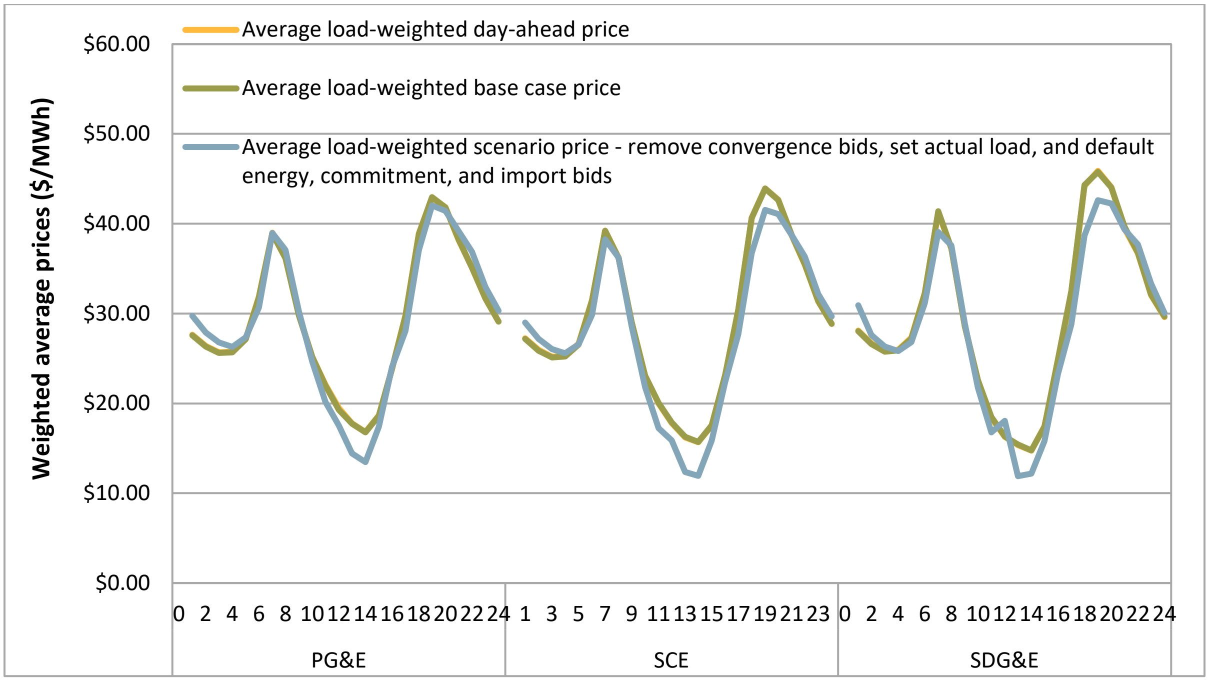
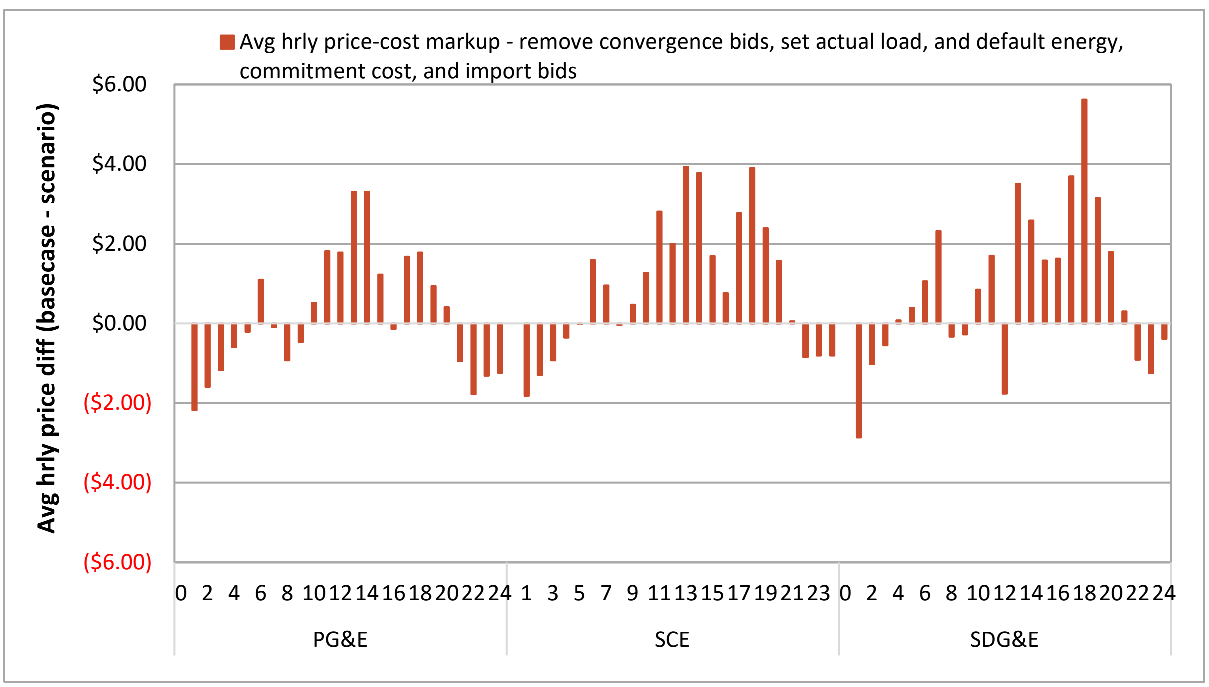


Figure 3.16 Hourly price-cost markup – actual load and default energy, commitment cost, and import bids scenario (Jan-Mar)



DMM calculates the day-ahead price-cost markup by comparing the load-weighted average competitive benchmark prices to the base case load-weighted average price for all energy transactions in the day-ahead market. As shown in Figure 3.17, in the first quarter of 2020 the average price-cost markup was about $0.38/MWh or just over 1 percent for the default energy bid scenario.

This slight positive markup indicates that prices have been very competitive, overall, for the first quarter.[56] However, this price-cost metric may be a low-end measure of system market power for several reasons. The only change in market inputs made in this scenario is that energy bids of gas-fired resources are capped by each resource's default energy bid – which includes a 10 percent adder above estimated marginal costs. All other bids are assumed to be competitive, including those of non-resource specific imports. Also, this analysis does not change commitment cost bids for gas-fired resources which are capped at 125 percent of each resource's estimated start-up and minimum load costs. When calculating the price-cost markup for a scenario where bids for gas-fired resources are set to the minimum of the submitted bid or the default energy bid, bids for gas-fired resources' commitment costs are set to the minimum of the bid or 110 percent of proxy cost, and import bids are set to the minimum of the bid or an estimated hydro default energy bid, the price-cost markup is $0.64/MWh or just over 2 percent.

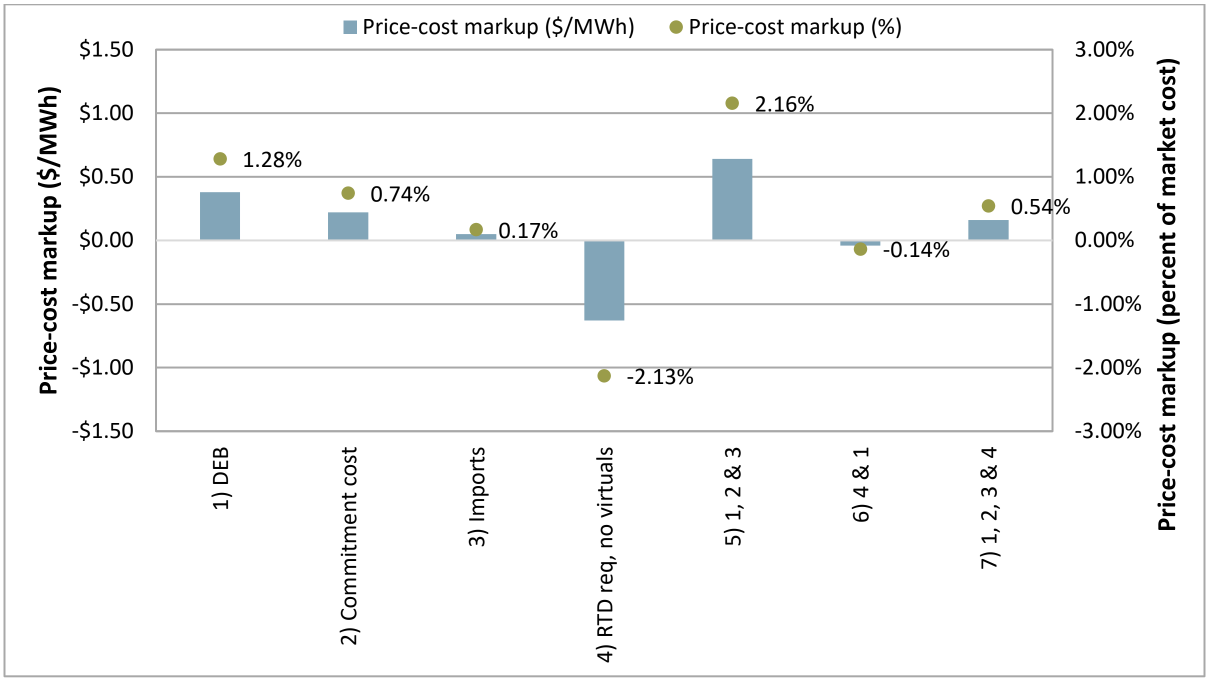
Another way to look at price-cost markup is to re-run the market simulation with these same input adjustments, and also set day-ahead load equal to the 5-minute real-time market requirement and remove convergence bids. This assumes competitive bidding of price-setting resources, perfect load forecast, and physical generation only. When comparing these results against the base case load-weighted average price, the average markup for the first quarter is only $0.16/MWh or less than 1 percent. The results for this and the remaining scenarios indicate that prices remain very competitive, overall, for the quarter.

As measured by the price-cost markup, market power has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.

DMM continues to recommend several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM also continues to recommend that the ISO's plan for implementing FERC Order 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of Order 831.

[56] DMM calculates the price-cost markup index as the percentage difference between base case market prices and prices resulting under this competitive baseline scenario. For example, if base case prices averaged $55/MWh and the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent.

Figure 3.17 Quarterly price-cost markup by scenario (Jan-Mar)[57]



[57] The scenarios included on this chart are as follows: 1) Insert lower of bid or default energy bid for gas-fired resources; 2) insert lower of bid or 110 percent of proxy cost for gas-fired resources' commitment costs; 3) insert lower of bid or estimated hydro DEB for imports; 4) insert 5-minute real-time market requirement and remove convergence bids; 5) default energy, commitment cost, and import bids; 6) default energy bids, insert real-time market requirement, and remove convergence bids; and 7) default energy, commitment cost, and import bids; insert real-time market requirement; and remove convergence bids.