California ISO

Q1 Report on Market Issues and Performance

June 28, 2019

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California Independent System Operator

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Executive summary

This report covers market performance during the first quarter of 2019 (January – March). Key highlights during this quarter include the following:

- The total estimated wholesale cost of serving load in the first quarter of 2019 was about $2.7 billion or about $55/MWh. This represents a 42 percent increase relative to the first quarter of 2018, which was driven primarily by a 73 percent increase in natural gas price compared to Q1 2018. After adjusting for higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 7 percent to $38/MWh from $41/MWh.

- Despite increased renewable and hydroelectric production, higher gas costs drove average energy prices in the ISO's day-ahead, 15-minute and 5-minute markets significantly higher in comparison to the same quarter in 2018, (see Figure E.1). Average day-ahead prices were higher by around $17/MWh (50 percent), 15-minute by about $15/MWh (45 percent) and 5-minute market prices by $13/MWh (35 percent) than the first quarter of 2018.

- Total generation from hydroelectric, solar, and wind resources increased compared to the previous quarter and compared to the first quarter of 2018. Hydroelectric production in the first quarter increased by roughly 47 percent. As of April 1, the average snowpack in California was 175 percent of normal compared to 58 percent of normal on April 1, 2018.

- The ISO became a net exporter on average during peak solar hours (12 to 15) over the entire quarter, as imports fell and exports increased in these hours relative to prior quarters.

- During the first quarter of 2019, congestion revenue rights auction revenues were $1.5 million less than payments made to non-load-serving entities purchasing these rights, compared to a difference of $43 million in the first quarter of 2018. Payments to financial entities purchasing congestion revenue rights exceeded auction revenues by about $6 million. However, generation owners and energy marketers paid over $4 million more in auction revenues than the revenues they received from these congestion revenue rights.

- The decrease in losses to transmission ratepayers from sales of congestion revenue rights is due in part to changes to the auction implemented by the ISO in 2019 which limit the source and sink of congestion revenue rights that can be purchased in the auction (Track 1A).[1] In addition, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under Track 1B reduced losses to transmission ratepayers from sales of congestion revenue rights by about $8.8 million.

- The decrease in losses to transmission ratepayers from sales of congestion revenue rights was also driven in part by a very significant drop in the impact and direction of congestion on day-ahead prices compared to the same quarter in 2018, as shown in Figure E.2.

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1 An explanation of these changes is available in Section 1.13 or in DMM's 2018 Annual Report on Market Issues & Performance, Section 8.4, available here: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

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

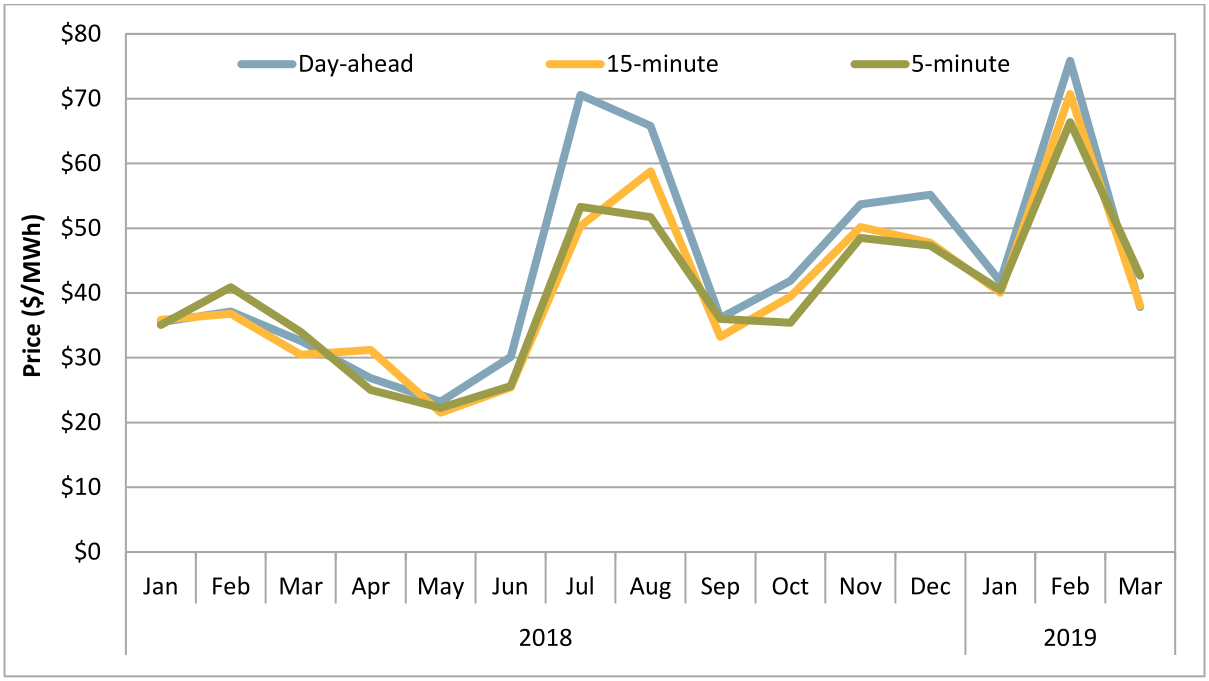
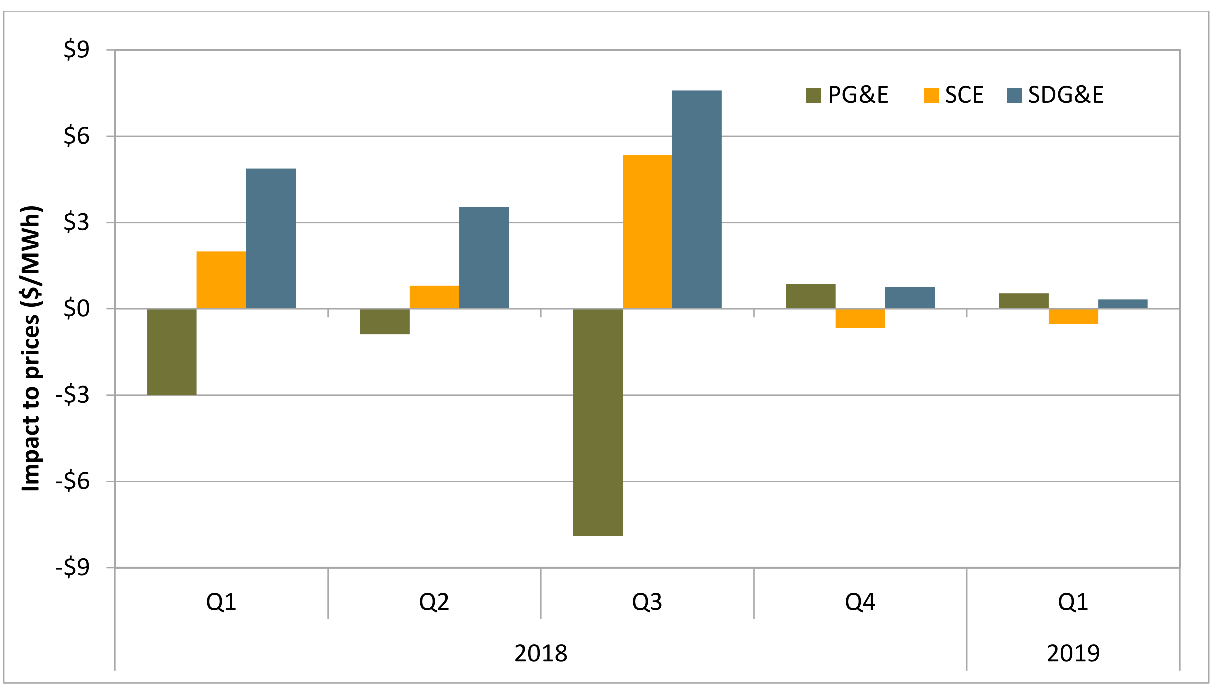


Figure E.2 Impact of congestion on day-ahead market prices by load area



1 Market performance

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

- The total estimated wholesale cost of serving load in the first quarter of 2019 was about $2.7 billion or about $55/MWh. This represents a 42 percent increase compared to the first quarter of 2018, which was driven primarily by a 73 percent increase in natural gas prices from Q1 2018. After adjusting for higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 7 percent to $38/MWh from $41/MWh.

- Despite increased renewable and hydroelectric production, higher gas costs drove average day-ahead, 15-minute and 5-minute market prices significantly higher in comparison to the same quarter in 2018. Average day-ahead prices were higher by around $17/MWh (50 percent), 15-minute by about $15/MWh (45 percent) and 5-minute market prices by $13/MWh (35 percent) than the first quarter of 2018.

- The ISO became a net exporter on average during peak solar hours (12 to 15) over the entire quarter, as imports fell and exports increased in these hours relative to prior quarters.

- The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. The enhancement significantly reduced the frequency with which the limiter triggered for under-supply conditions, particularly for Arizona Public Service during March. However, the load conformance limiter (and the changes implemented in Q1 2019) continue to have a very limited effect on overall prices in the ISO's real-time market.

- During the first quarter of 2019, congestion revenue rights auction revenues were $1.5 million less than payments made to non-load-serving entities purchasing these rights. Payments to financial entities purchasing congestion revenue rights exceeded auction revenues by about $6 million. However, generation owners and energy marketers paid over $4 million more in auction revenues than the revenues they received from these congestion revenue rights.

- The decrease in losses from sales of congestion revenue rights was driven by auction and settlement changes taking effect 2019, as well as drop in the impact and direction of day-ahead congestion.

- Costs for ancillary services increased during the first quarter. Costs for ancillary services totaled about $45 million during the first quarter, compared to about $27 million in the previous quarter and $35 million during the same quarter in 2018.

- Total bid cost recovery payments for the first quarter were about $30 million. This amount was slightly lower than payments in the previous quarter and about $5 million higher than the first quarter of 2018.

- Convergence bidding was profitable overall during the first quarter with combined net revenues of $5.5 million after accounting for bid cost recovery charges. Virtual supply was profitable for the fifth consecutive quarter.

1.1 Supply conditions

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. In the first quarter of 2019, natural gas prices increased significantly across major gas trading hubs in the west, compared to the same quarter in 2018. High natural gas prices in February 2019, at both SoCal and PG&E Citygate, were the main driver of high system marginal energy prices across the ISO footprint.

Figure 1.1 shows monthly average natural gas prices at key delivery points across the west - PG&E Citygate, SoCal Citygate, Northwest Sumas, El Paso Permian as well as 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, prices increase sharply in the first quarter of 2019 for all the hubs except El Paso Permian gas hub. Prices at SoCal Citygate gas hub averaged $10.44/MMBtu in February 2019, compared to $4.80/MMBtu in January and $8.15/MMBtu in December 2018.

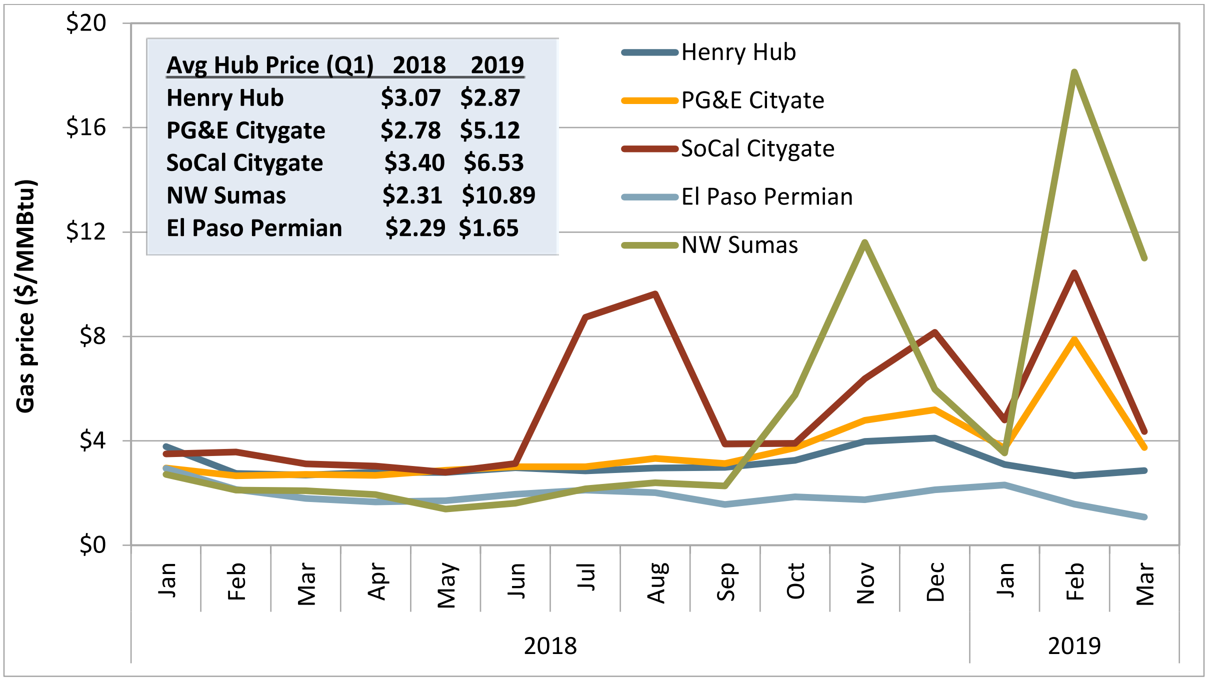
High heating demand and limited availability of gas due to supply constraints led to high prices at SoCal Citygate during February 2019. These factors also led to SoCalGas issuing electric power generation curtailment orders and withdrawing gas from the Aliso Canyon storage facility throughout February. On most days in February, a low operational flow order was in effect, which might also have had an impact on the prices. SoCal Citygate prices often impact overall 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.

PG&E Citygate gas prices also increased in February 2019. This was primarily due to increased regional demand reflecting colder weather and regional supply limitations. PG&E also issued high stage low operational flow orders on some days in February which may have contributed to high Citygate spot prices.

Northwest Sumas gas hub in the Pacific Northwest saw record high gas prices during the winter of 2019. The price spike comes amid limited supply deliverability and unseasonably cold temperatures, which drove up demand in the Northwest. Prices at the Sumas gas hub have been volatile since the October 9, 2018, Canadian gas pipeline explosion reducing imports into hubs in the Northwest.

In contrast to the other gas hubs across the west, prices at Permian basin declined sharply during the first quarter of 2019. This price drop is related to a force majeure on El Paso Natural Gas's pipeline because of a potential leak. This outage led to a constraint on takeaway capacity out of the Permian basin thus putting downward pressure on gas prices.

Figure 1.1 Monthly average natural gas prices



Variable renewable generation

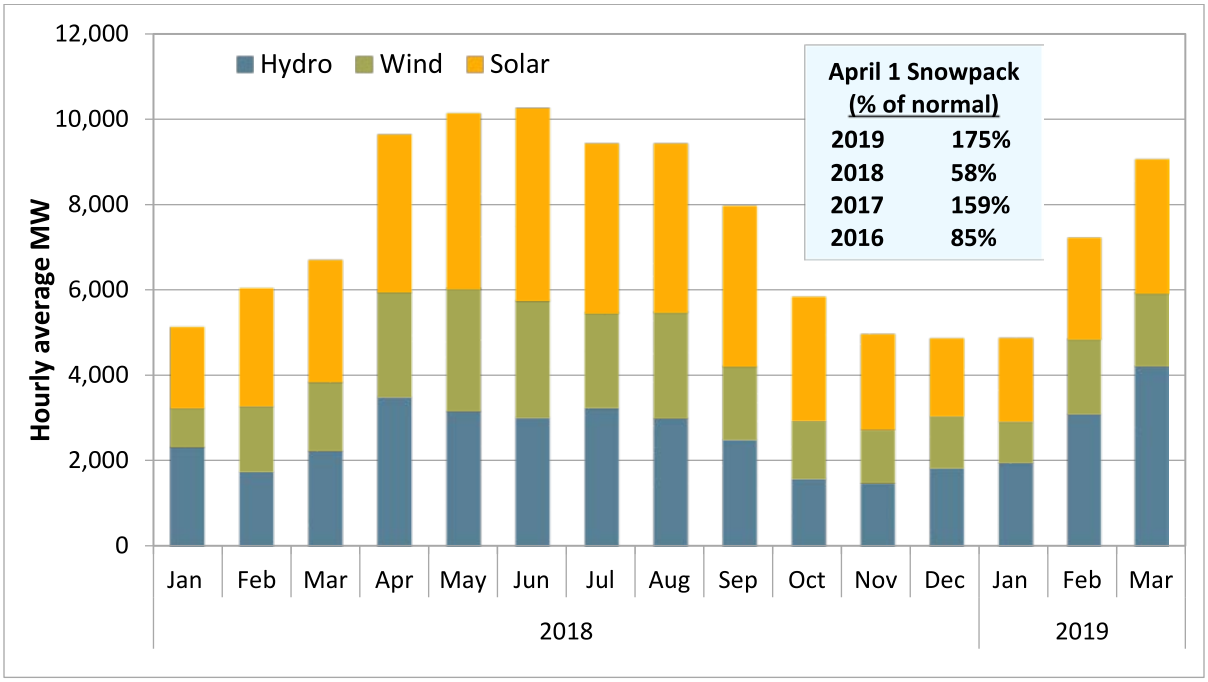
Overall, total generation from hydroelectric, solar, and wind resources increased compared to the previous quarter and compared to the first quarter of 2018. This was primarily due to increased snow melt and therefore a greater availability of hydroelectric production. Compared to 2018, hydroelectric production in the first quarter increased by roughly 47 percent. As of April 1, the statewide weighted average snowpack in California was 175 percent of normal compared to 58 percent of normal on April 1, 2018.[2]

Wind and solar production increased compared to the fourth quarter of 2018. Compared to the first quarter of 2018, wind production increased while solar production decreased slightly, despite increases in installed solar capacity from the previous year. This was likely due to greater curtailments resulting from high hydro and wind production. In March 2019, renewable curtailment reached record levels, roughly 125,000 MWh.

The availability of renewable resources contributes to patterns in prices both seasonally and hourly. Many factors influenced the increase in monthly prices relative to the first quarter of 2018 seen in Section 1.2. The increase in renewable production compared to the same quarter last year contributed to lower prices due to the low marginal cost of renewables relative to other resources. The 48 percent increase in hydroelectric output is one contributing factor to this trend.

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

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



1.2 Energy market performance

Energy market prices

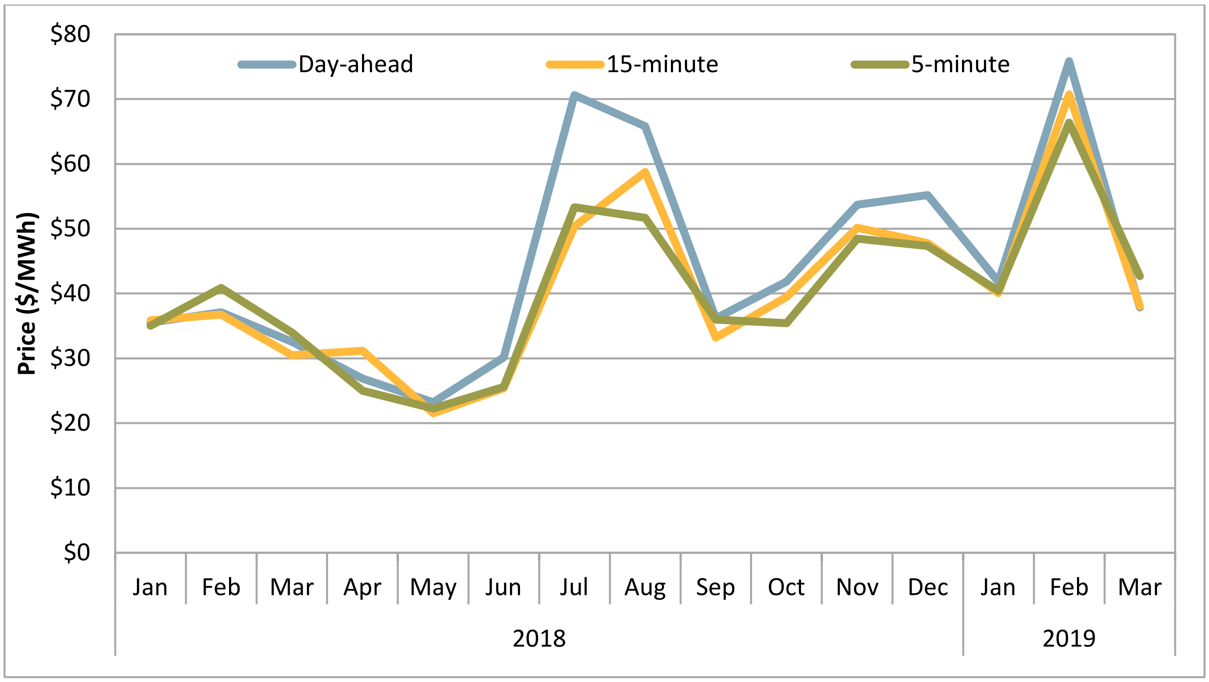
This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources.

Figure 1.3 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). During the quarter average prices increased slightly overall from the previous quarter, but were significantly higher compared to the same quarter in 2018. The increase in average monthly energy prices was largely driven by high average prices in the month of February.

- Average day-ahead prices increased by around $17/MWh (almost 50 percent), 15-minute by about $15/MWh (45 percent) and 5-minute market prices by $13/MWh (35 percent) in comparison to the same quarter in 2018. High natural gas prices in February 2019, at both SoCal and PG&E Citygate, were the main driver of the increase in quarterly average energy prices in the ISO.
- Average monthly day-ahead prices were higher than 15-minute prices in January and February and slightly lower in March. Day-ahead prices averaged about $2/MWh above 15-minute and 5-minute prices during the quarter.

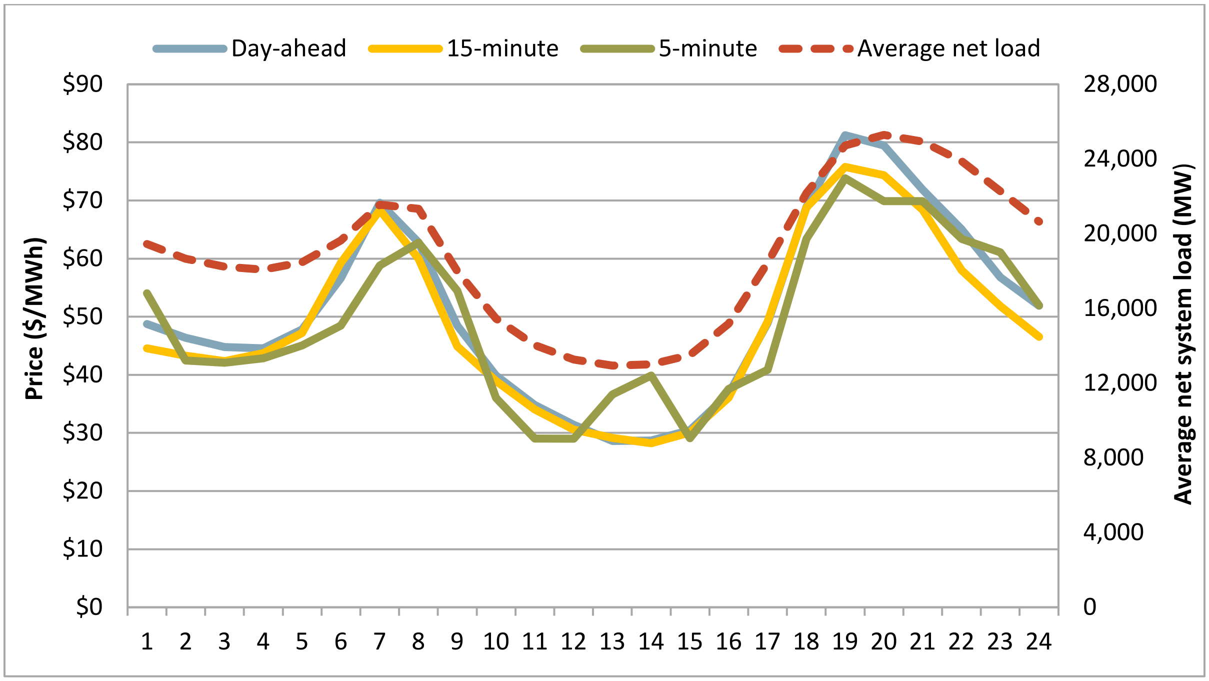
Figure 1.4 illustrates load-weighted average energy prices on an hourly basis in the first quarter compared to average hourly net load.[3] Prices in this figure generally follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. In particular, prices were highest during hours ending 19 and 20. Figure 1.4 also shows that average prices in the 5-minute market were consistently higher than day-ahead and 15-minute market prices between hours ending 13 and 14.

Figure 1.3 Load-weighted average monthly energy prices (all hours)



[3] 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 1.4 Hourly load-weighted average marginal energy prices



1.3 Comparison to bilateral market prices

Figure 1.4 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 California ISO market in the first quarter. 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 energy prices at the Mid-Columbia and Palo Verde trading hubs were lower than prices in the ISO, during about 60 percent and 97 percent of the days in the quarter, respectively.

Average day-ahead prices in the ISO were also compared to hourly energy prices traded at Mid-Columbia and Palo Verde hubs published by Powerdex. Average prices in the ISO across all hours in the first quarter were greater on average than prices in Mid-Columbia and Palo Verde hubs by $2.75/MWh and $11.15/MWh, respectively.

Prices in California tend to be higher relative to bilateral prices at trading hubs elsewhere in the west, reflecting the greenhouse gas compliance cost associated with delivering energy into the state and the cost of congestion associated with limited transfer capacity with other balancing authority areas. One exception to this trend occurred on March 4 when prices in the Mid-Columbia hub peaked and exceeded ISO prices. The price spike in the Mid-Columbia hub was primarily driven by extreme natural gas prices in the Pacific Northwest region and limited transfer capacity to the area.

Figure 1.5 Daily system and bilateral market prices (Jan-Mar)

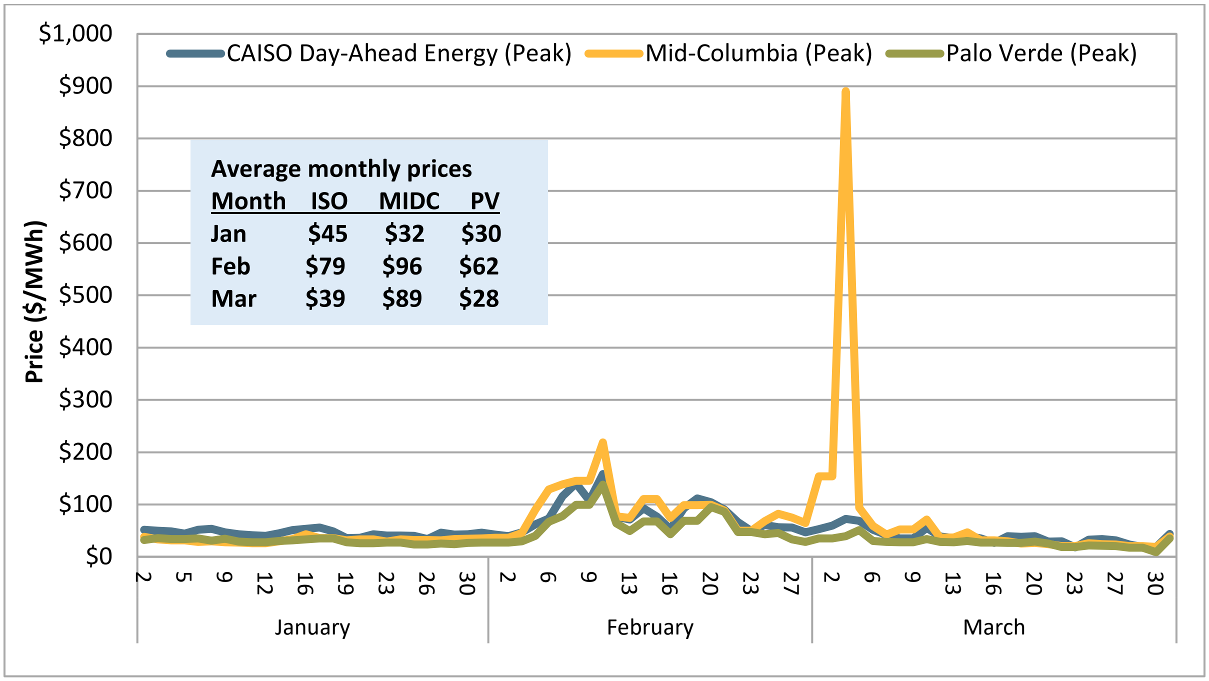
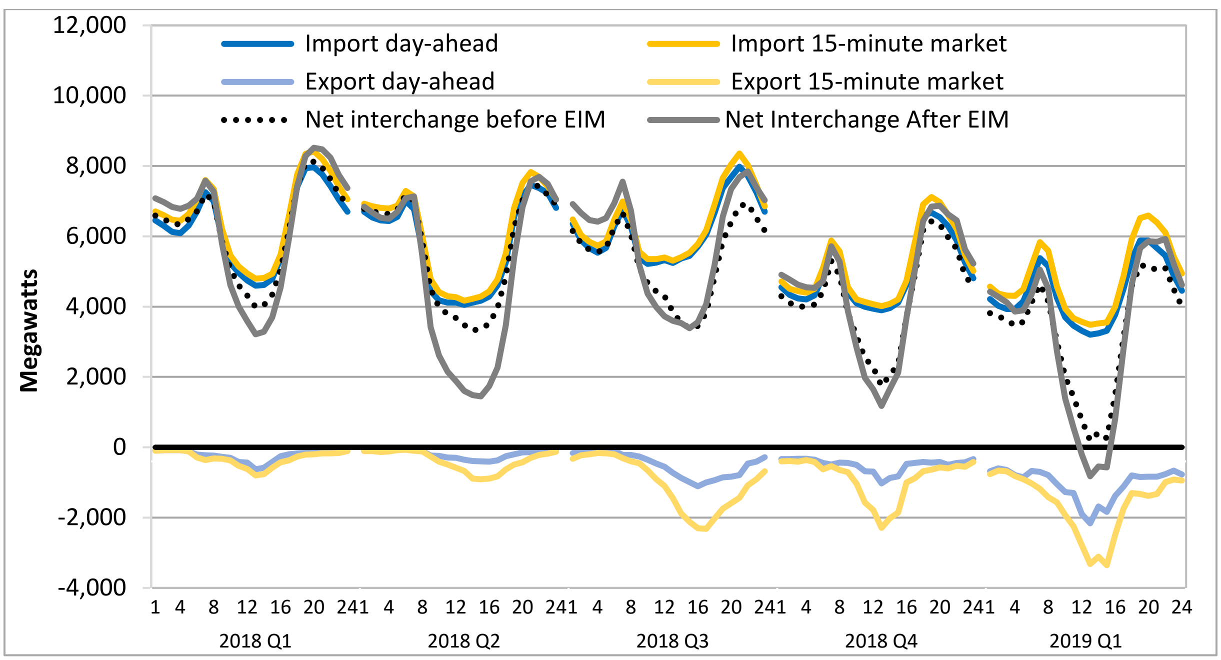


Figure 1.6 Average hourly net interchange by quarter



The ISO became a net exporter between hours ending 12 and 15, including energy imbalance market transfers. As shown in Figure 1.6, average hourly cleared imports (shown in dark blue and dark yellow), peaked at almost 6,600 MW in hour ending 20, compared to an average over 8,400 in the same quarter of 2018. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), also increased, peaking at over 3,300 MW in hour ending 15. The average net interchange excluding energy imbalance market transfers (shown in dashes), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental energy imbalance market interchange.

Average exports in hour ending 20, when imports peaked, increased to over 1,300 MW, resulting in net average imports of about 5,000 MW in the day-ahead market and about 5,200 MW in the 15-minute market. The addition of almost 690 MW of average energy imbalance market transfer into the ISO brought average net interchange up to over 5,800 MW.

1.4 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the first quarter of 2019 was about $2.7 billion, compared to about $1.9 billion in the first quarter of 2018. The average cost per megawatt-hour of load increased 42 percent to about $55/MWh for this quarter from $39/MWh in the first quarter of 2018 (nominal costs shown in blue bars in Figure 1.7).

Higher gas prices continue to explain most of the differences in costs, particularly in the south, with volume-weighted average gas prices increasing to about $6.81/MMBtu in the first quarter of 2019 from about $3.93/MMBtu in the same quarter in 2018. When normalizing for changes in natural gas and greenhouse gas costs, the gold bar in Figure 1.7 shows that wholesale energy costs to serve load actually decreased by about 7 percent to about $38/MWh from just under $41/MWh in the same quarter in 2018.

Figure 1.7 Total quarterly wholesale costs per MWh of load

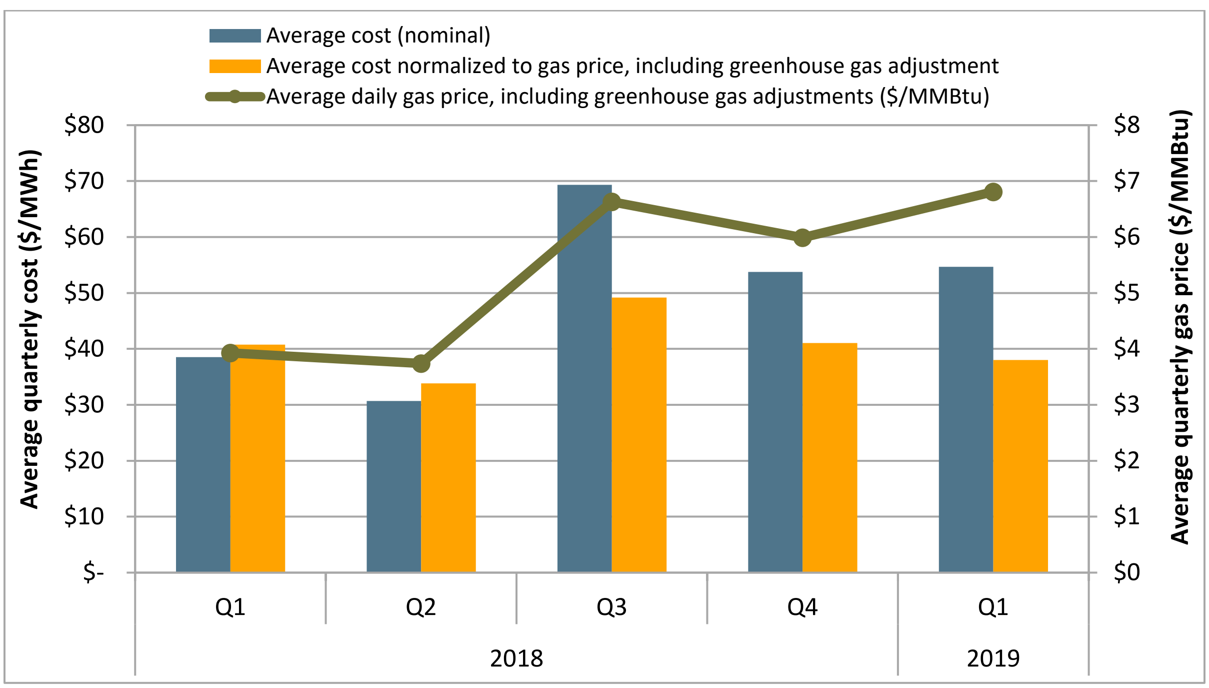


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (95 percent) of the total cost to deliver energy to the market, while costs for the real-time market dropped to less than 1 percent. Costs for reliability decreased to almost zero in the first quarter of 2019 from about 2 percent of total costs in the same quarter in 2018.

Table 1.1 Estimated average wholesale energy costs per MWh

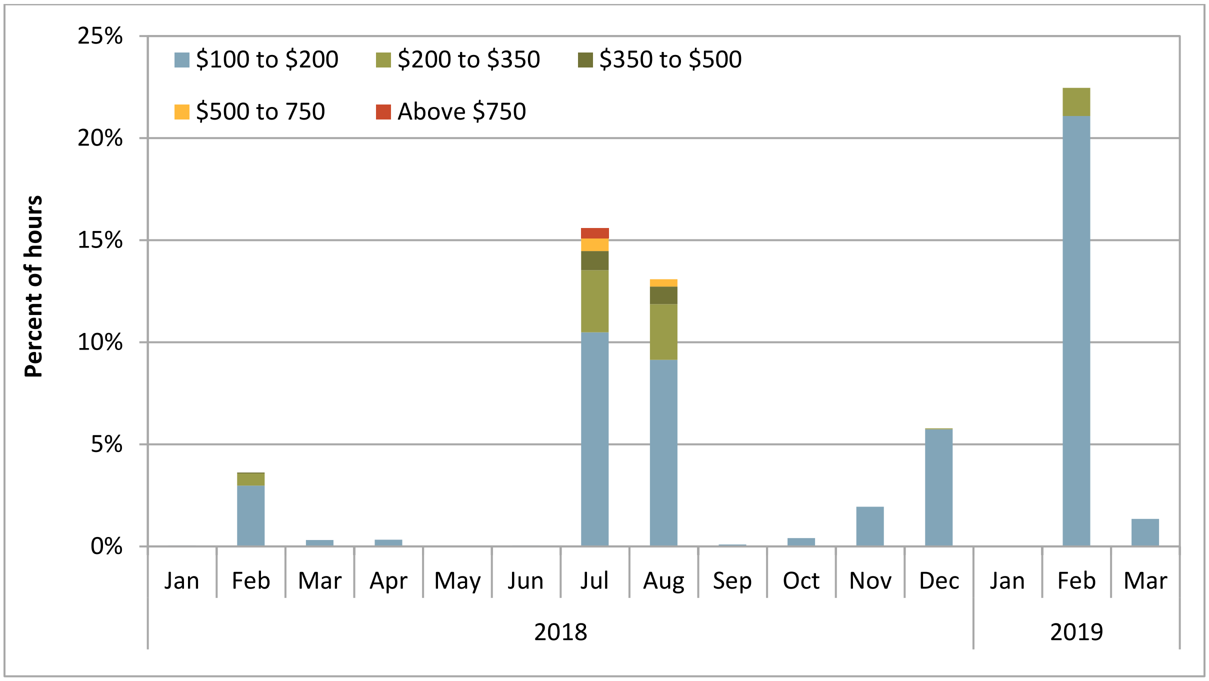
	Q1 2018	Q2 2018	Q3 2018	Q4 2018	Q1 2019	Change Q1 2018-Q1 2019
Day-ahead energy costs	$ 35.05	$ 27.66	$ 64.52	$ 51.47	$ 52.18	$ 17.13
Real-time energy costs (incl. flex ramp)	$ 1.14	$ 0.61	$ 1.33	$ (0.14)	$ 0.54	$ (0.60)
Grid management charge	$ 0.43	$ 0.43	$ 0.43	$ 0.43	$ 0.42	$ (0.01)
Bid cost recovery costs	$ 0.41	$ 0.34	$ 1.27	$ 0.57	$ 0.57	$ 0.15
Reliability costs (RMR and CPM)	$ 0.76	$ 0.68	$ 0.63	$ 0.90	$ 0.06	$ (0.70)
Average total energy costs	**$ 37.79**	**$ 29.72**	**$ 68.18**	**$ 53.22**	**$ 53.76**	**$ 15.97**
Reserve costs (AS and RUC)	$ 0.71	$ 0.95	$ 1.19	$ 0.53	$ 0.94	$ 0.23
Average total costs of energy and reserve	**$ 38.51**	**$ 30.67**	**$ 69.36**	**$ 53.76**	**$ 54.70**	**$ 16.19**

1.5 Day-ahead price variability

High prices

Figure 1.8 shows the frequency of high prices in the day-ahead market. High average day-ahead prices were frequent in the first quarter with prices greater than $100/MWh occurring around 8 percent of intervals compared with around 1.3 percent in the same quarter of 2018. Average day-ahead prices greater than $100/MWh in just the month of February occurred in around 22.5 percent of intervals, largely driven by high natural gas prices at trade hubs located within the ISO area.

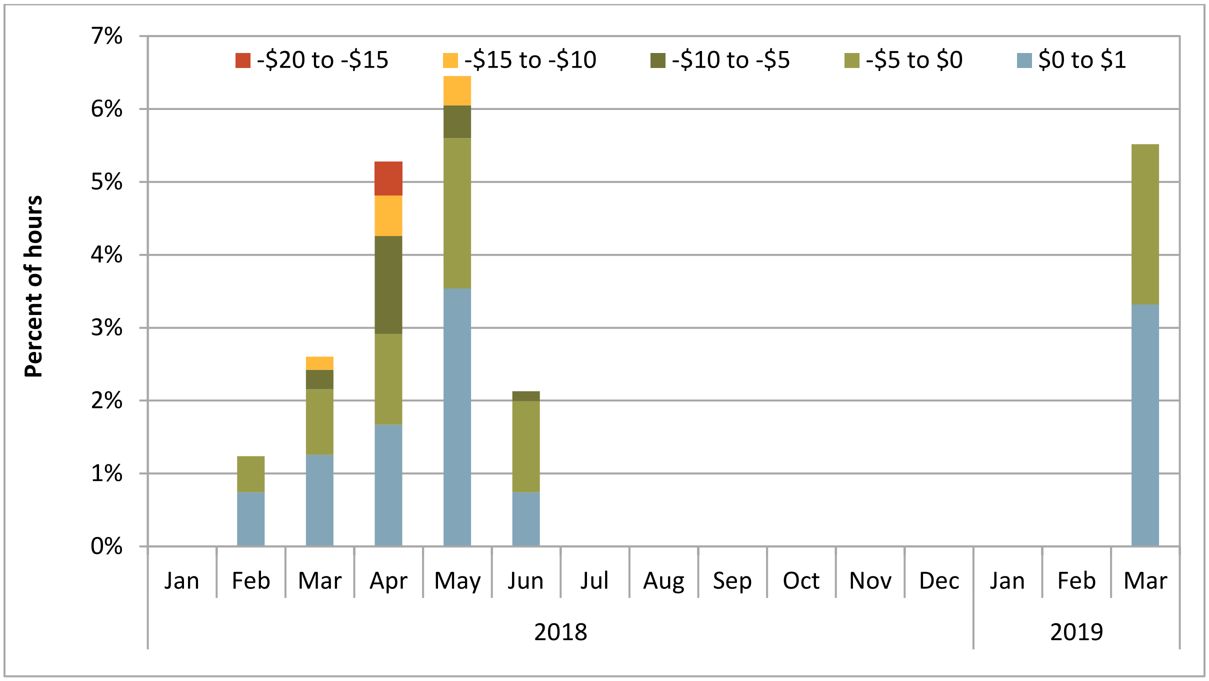
Figure 1.8 Frequency of high day-ahead prices (MWh) by month



Negative prices

Figure 1.9 shows the frequency of negative prices in the day-ahead market for the first quarter. During January and February, there were no occurrences of negative prices in the day-ahead market. In March, negative prices occurred in around 5.5 percent of intervals primarily during mid-day hours when generation from solar was at its peak in conjunction with relatively low load conditions.

Figure 1.9 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 and negative prices. Even a short period of extremely high or low prices can significantly impact average prices. During the first quarter of 2019, the frequency of negative prices was slightly higher than in the first quarter of 2018. In addition, the frequency of high prices in the 15-minute and 5-minute markets was slightly lower than in the first quarter of 2018.

During the quarter, most of the high prices occurred as a result of high bids in the market. In many of these instances, extremely high bids set the price after the load bias limiter was triggered when the power balance constraint was relaxed due to high load biasing by system operators. In other instances, prices were set by the $1,000/MWh penalty parameter for a power balance constraint relaxation.

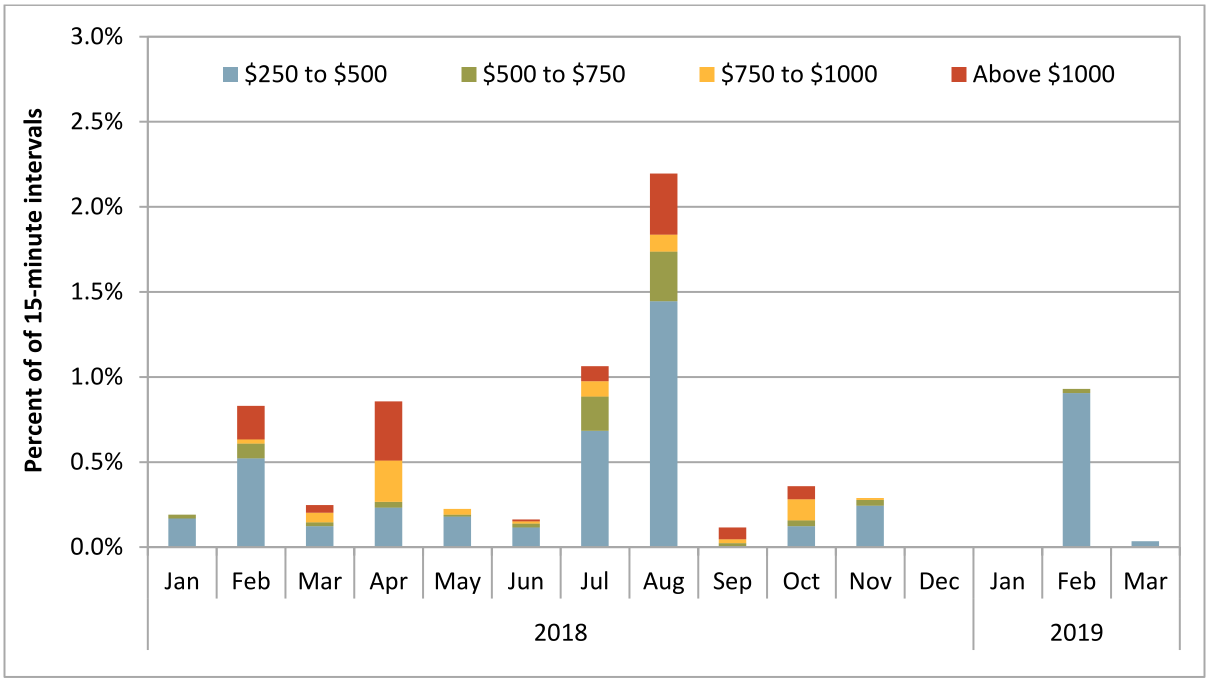
High prices

As shown in Figure 1.10, the frequency of high prices in the 15-minute market greater than $250/MWh increased from around 0.2 percent of intervals in the previous quarter to 0.3 percent of intervals during the quarter. This was less frequent compared to the first quarter of 2018, when high 15-minute market prices occurred during around 0.4 percent of intervals. High prices during the first quarter of 2019 were most frequent in February, when prices above $250/MWh occurred during around 0.9 percent of 15-minute intervals. There were no under-supply infeasibilities in the 15-minute market during the quarter.

Figure 1.11 shows the frequency of high prices in the 5-minute market. The frequency of price spikes greater than $250/MWh in the 5-minute market was about 1 percent of intervals in the first quarter, around the same as the first quarter of 2018. Further, the frequency of more extreme 5-minute market prices larger than $750/MWh increased slightly during the end of the quarter, particularly during March when they occurred during around 0.9 percent of 5-minute intervals.

Figure 1.12 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. The number of infeasibilities resolved by the imbalance conformance limiter decreased significantly during March as a result of changes to the limiter implemented at the end of February.[4] However, this 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 bid cap such that the resulting price is often very similar with or without the limiter.

Figure 1.10 Frequency of high 15-minute prices by month



4 With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than the total level of load adjustment. For more information on the load conformance limiter enhancement, see Section 2.4.

Figure 1.11 Frequency of high 5-minute prices by month

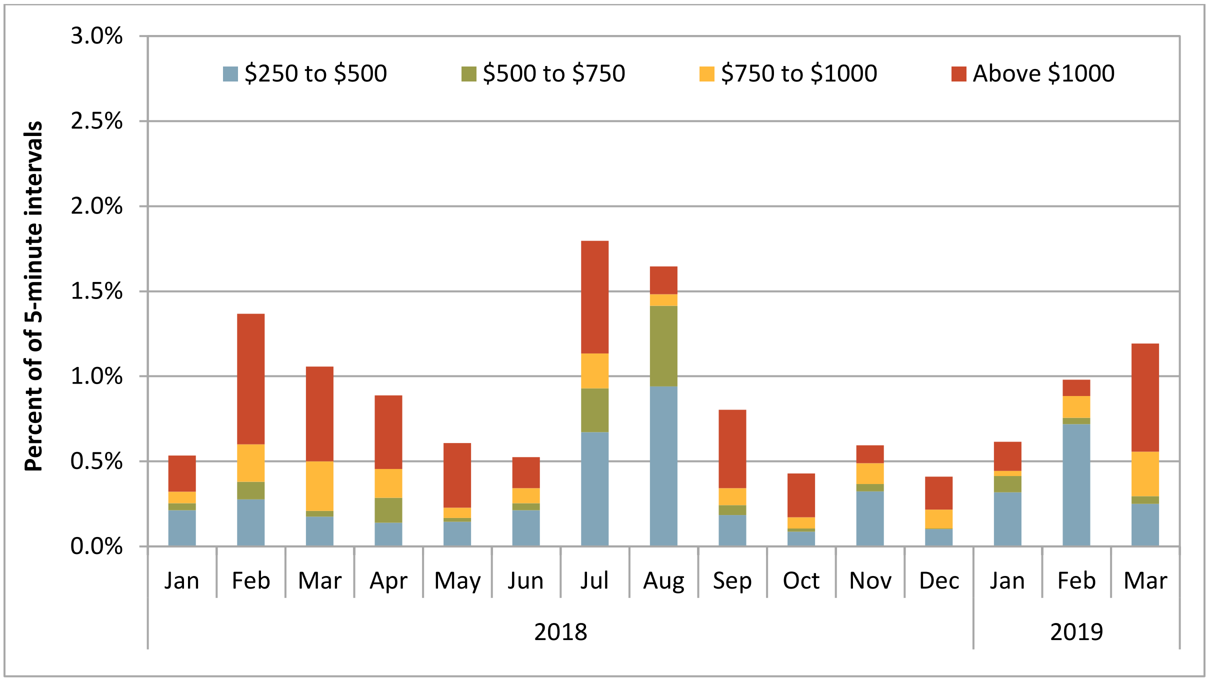
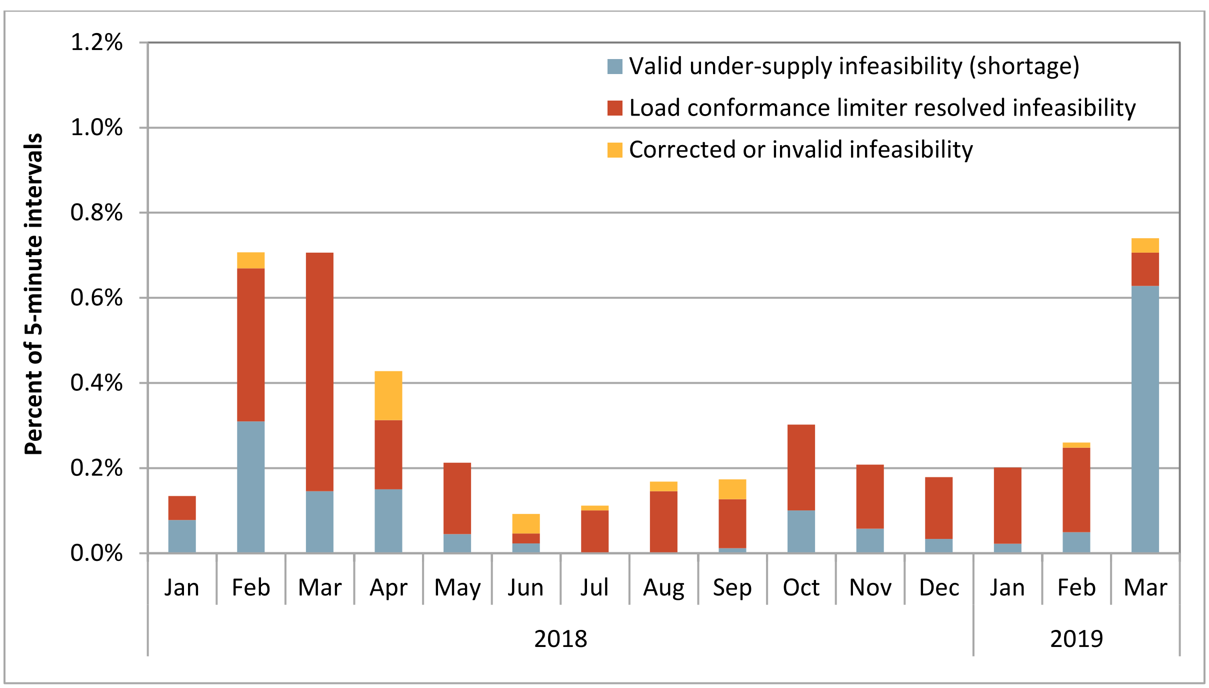


Figure 1.12 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



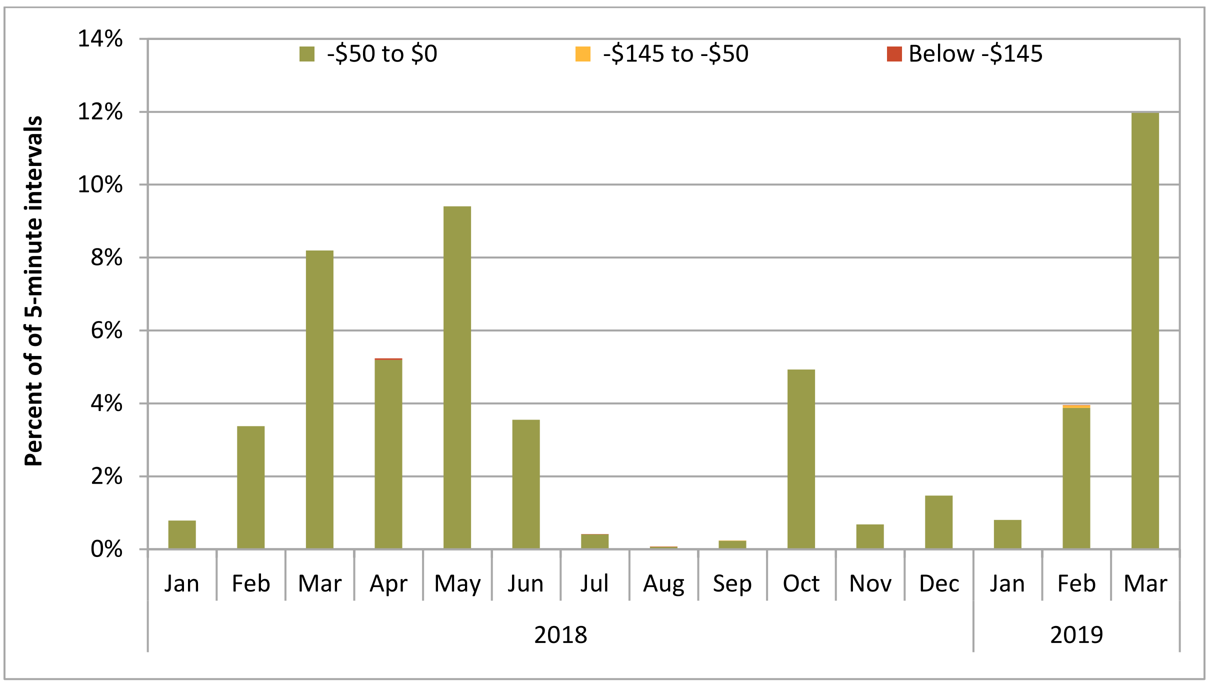
Negative prices

Figure 1.13 shows the frequency of negative prices in the 5-minute market by month.[5] The frequency of negative prices in the 15-minute and 5-minute markets increased during the first quarter relative to the previous three months and increased compared to the first quarter of 2018. This was likely due to a near 50 percent increase in hydroelectric production compared to the first quarter of the previous year.

Negative prices occurred during about 3 percent of intervals in the 15-minute market and around 6 percent of intervals in the 5-minute market during the first quarter of 2019. In comparison, negative prices occurred during about 2 percent and 4 percent of 15-minute and 5-minute intervals, respectively, during the first quarter of 2018.

These were most frequent between hours ending 10 and 17 when loads, net of wind and solar, were lowest. However, prices very rarely reached below negative $45/MWh for any of the three load aggregation points during the quarter in either the 15-minute or 5-minute markets. Further, there were no intervals when the power balance constraint was relaxed because of excess energy, a similar result to the first quarter of 2018.

Figure 1.13 Frequency of negative 5-minute prices by month



1.7 Congestion

This section provides an assessment of the frequency and impact of congestion on prices in the day-ahead and 15-minute markets. It assesses both the impact of congestion to local areas in the ISO (Pacific

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

Gas and Electric, Southern California Edison, and San Diego Gas and Electric) as well as to energy imbalance market 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 can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.

Two metrics of congestion impact are presented in each section of this chapter. First, the *overall impact* to average regional prices is presented, which shows the impact of congestion accounting for both the frequency and magnitude of impact. These values are calculated by taking the average congestion component as a percent of the total price during all congested and non-congested intervals.[6] Second, each section provides a more detailed assessment of the impact of congestion from individual constraints that are broken out to separately show the frequency and magnitude of impact *only during the congested intervals*.[7]

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

1.7.1 Congestion in the day-ahead market

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

Impact of congestion to overall prices in each load area

Figure 1.14 shows the overall impact of congestion on day-ahead prices in each load area for each quarter in 2018 and 2019.[8] Figure 1.15 shows the frequency of congestion. Highlights for the first quarter include:

- The overall net impact to price separation as well as the frequency of congestion was lower in the first quarter of 2019 than in all quarters of 2018. The frequency of congestion was highest in SDG&E, where some constraints increased prices while others decreased prices.

6 This approach identifies price differences caused by congestion and does not include price differences that result from transmission losses at different locations.

7 This approach does not include price differences that result from transmission losses.

8 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.

- Congestion resulted in a net increase to PG&E and SDG&E prices by $0.54/MWh (1 percent) and $0.33/MWh (0.6 percent), respectively, and a net decrease to prices in SCE by $0.53/MWh (1 percent). This impact was similar to the fourth quarter of 2018.
- The primary constraints impacting price separation in the day-ahead market were the Imperial Valley nomogram, the Gates-Midway 500 kV lines, the Midway-Vincent 500 kV line, and the Devers-El Casco nomograms.

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

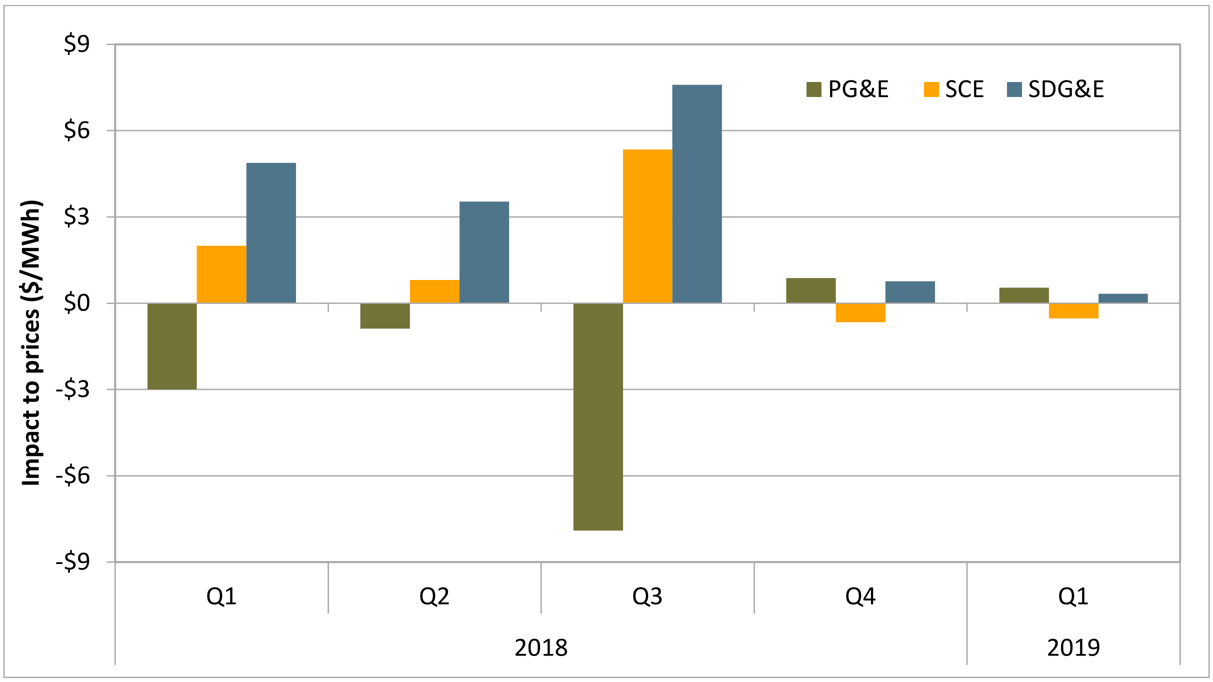
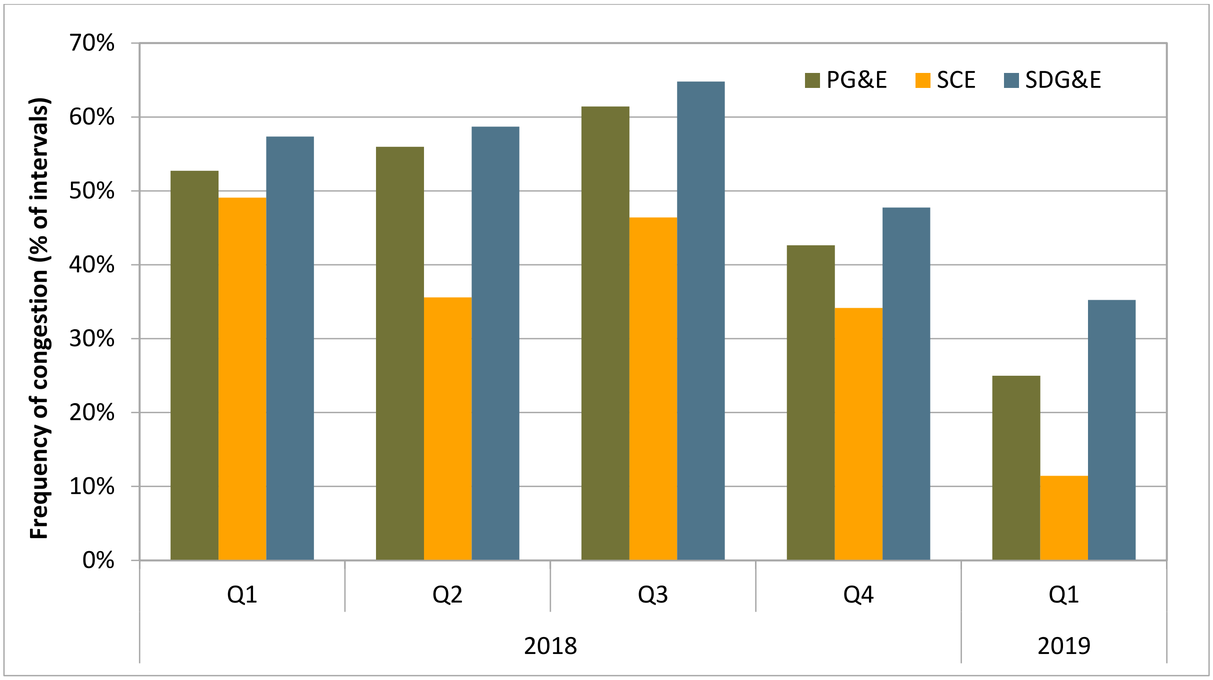


Figure 1.15 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the impact to price separation in the first quarter by constraint.[9] Table 1.3 shows the impact of congestion from each constraint *only during congested intervals,* where the number of congested intervals is presented separately as frequency.

The constraints that had the greatest impact on price separation for the quarter were the Imperial Valley nomogram, the Gates-Midway 500 kV lines, the Midway-Vincent 500 kV line, and the Devers-El Casco nomograms. These constraints are discussed below.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the first quarter, during nearly 17 percent of hours. When binding, it increased SDG&E prices by about $4/MWh. Over the entire quarter, it increased SDG&E prices by about $0.70/MWh (1.3 percent), which was the greatest impact on price separation of any individual constraint. 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.

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

Gates-Midway 500 kV lines

The two Gates-Midway 500 kV lines (30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3 and 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3) impacted prices across all three areas, increasing PG&E prices by about $0.25/MWh (0.5 percent) and decreasing SCE and SDG&E prices by about $0.20/MWh (about 40 percent). The Gates-Midway #1 500 kV line bound in about 4 percent of intervals, while the Gates-Midway #2 500 kV line bound during about 1.4 percent of intervals. These constraints were congested due to system conditions, and were not significantly impacted by any direct outages throughout the quarter. The primary cause of this congestion was likely heavier south-to-north flows due to very high gas prices in the Pacific Northwest.

Midway-Vincent 500 kV line

Congestion on the Midway-Vincent 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) had a similar impact on price separation as the Gates-Midway lines, increasing prices in PG&E by about $0.13/MWh (0.26 percent) and decreasing prices in SCE and SDG&E by about $0.11/MWh (22 percent). This constraint, similar to the Gates-Midway lines, is a main point of connection between the northern and southern parts of the state and likely bound due to heavier south-to-north flows related to high gas prices in the Pacific Northwest.

Devers-El Casco nomograms

The Devers-El Casco nomograms (7750_D-ECASCO_OOS_CP6_NG and 7750_D-ECASCO_OOS_N1SV500_NG) bound frequently throughout the quarter, during about 13 percent and 4 percent of intervals. Together, the constraints had the greatest impact on SDG&E, decreasing prices by about $0.15/MWh. The constraints had a smaller impact on the other areas, increasing PG&E prices and decreasing SCE prices by about $0.02/MWh (0.05 percent). This congestion was in part related to an outage on the El Casco-San Bernardino 230 kV line which returned to service in May.

Table 1.2 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.25	0.47%	-$0.21	-0.41%	-$0.19	-0.37%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.13	0.26%	-$0.12	-0.23%	-$0.11	-0.21%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.12	0.23%	-$0.10	-0.20%	-$0.10	-0.18%
	OMS_5413443_LOSBNS_MDWY2	$0.02	0.04%	-$0.02	-0.04%	-$0.02	-0.03%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.02	0.04%	-$0.02	-0.04%	-$0.02	-0.03%
	30050_LOSBANOS_500_30056_GATES2 _500_BR_2 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.01%
	22372_KEARNY _69.0_22496_MISSION _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.05%
SCE	24092_MIRALOMA_500_24093_MIRALOM _230_XF_2 _P	$0.00	-0.01%	$0.00	0.00%	$0.01	0.01%
	OMS 6895938 BARRE-ELLIS_NG	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.05%
	7750_D-ECASCO_OOS_N1SV500_NG	$0.00	0.00%	$0.00	0.00%	-$0.05	-0.09%
	7750_D-ECASCO_OOS_CP6_NG	$0.02	0.04%	-$0.02	-0.05%	-$0.10	-0.19%
	6410_CP7_NG	$0.04	0.08%	-$0.04	-0.07%	-$0.03	-0.07%
SDG&E	7820_TL 230S_OVERLOAD_NG	-$0.06	-0.12%	$0.00	0.00%	$0.69	1.33%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.11	0.20%
	OMS 6791208_TL23054_55_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.07%
	OMS_6773765_TL23054_NG	$0.00	-0.01%	$0.00	0.00%	$0.04	0.07%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.04	0.07%
	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.06%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.08	-0.16%
Other		$0.01	0.02%	$0.00	-0.01%	$0.03	0.05%
Total		**$0.54**	**1.05%**	**-$0.53**	**-1.06%**	**$0.33**	**0.64%**

Table 1.3 Impact of congestion on day-ahead prices during congested hours[10]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	3.7%	$6.61	-$5.57	-$5.20
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.8%	$6.51	-$5.59	-$5.27
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	1.4%	$9.34	-$8.14	-$7.61
	OMS_5413443_LOSBNS_MDWY2	0.7%	$2.98	-$2.35	-$2.17
	22372_KEARNY _69.0_22496_MISSION _69.0_BR_1 _1	0.5%	$0.00	$0.00	$5.57
SCE	7750_D-ECASCO_OOS_CP6_NG	13.3%	$0.91	-$0.93	-$0.72
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	6.6%	-$0.66	$0.00	$0.42
	7750_D-ECASCO_OOS_N1SV500_NG	3.8%	$0.00	$0.00	-$1.23
	6410_CP7_NG	0.4%	$10.01	-$8.57	-$8.11
SDG&E	7820_TL 230S_OVERLOAD_NG	16.9%	-$0.35	$0.00	$4.07
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	1.3%	$0.00	$0.00	-$6.70
	7820_TL23040_IV_SPS_NG	0.9%	-$0.23	$0.00	$3.78
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.6%	$0.00	$0.00	$18.82
	OMS 6791208_TL23054_55_NG	0.4%	-$0.90	$0.00	$9.34
	OMS_6773765_TL23054_NG	0.3%	-$0.73	$0.00	$10.79

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

1.7.2 Congestion in the 15-minute market

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

Impact of congestion to overall prices in each load area

Figure 1.16 shows the overall impact of congestion on 15-minute prices in each load area for each quarter of 2018 and 2019. Figure 1.17 shows the frequency of congestion. Highlights for the first quarter include:

- The overall net impact to price separation as well as the frequency of congestion was lower in the first quarter of 2019 than in all quarters of 2018. The frequency of congestion was highest in Powerex, where some constraints increased prices while others decreased prices.
- Congestion resulted in a net increase to PG&E, SDG&E, AZPS, PACE, and IPCO prices by about $0.70/MWh on average, and a net decrease to prices in SCE, NEVP, PACW, PGE, PSEI, and PWRX by about $1/MWh on average. This impact was similar to the fourth quarter of 2018.
- The primary constraints impacting price separation in the 15-minute market were the Imperial Valley nomogram, the Gates-Midway 500 kV lines, the Devers-El Casco nomograms, and the San Luis Rey-San Onofre 230 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 1.16 Overall impact of congestion on price separation in the 15-minute market

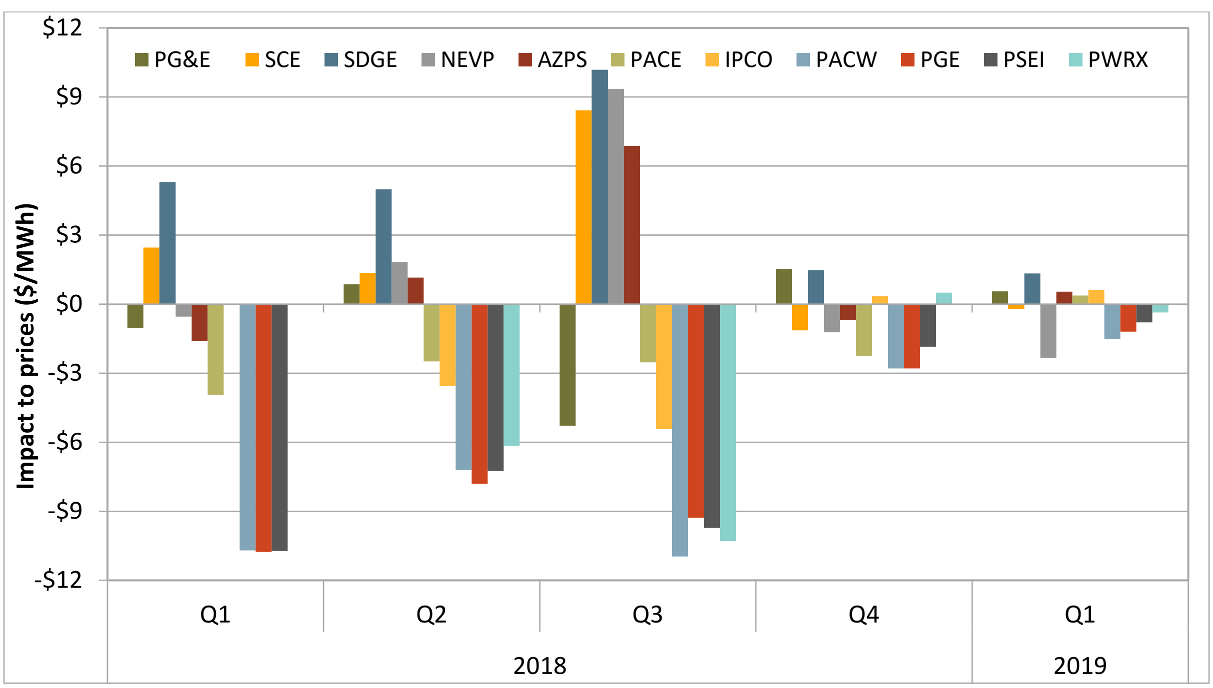
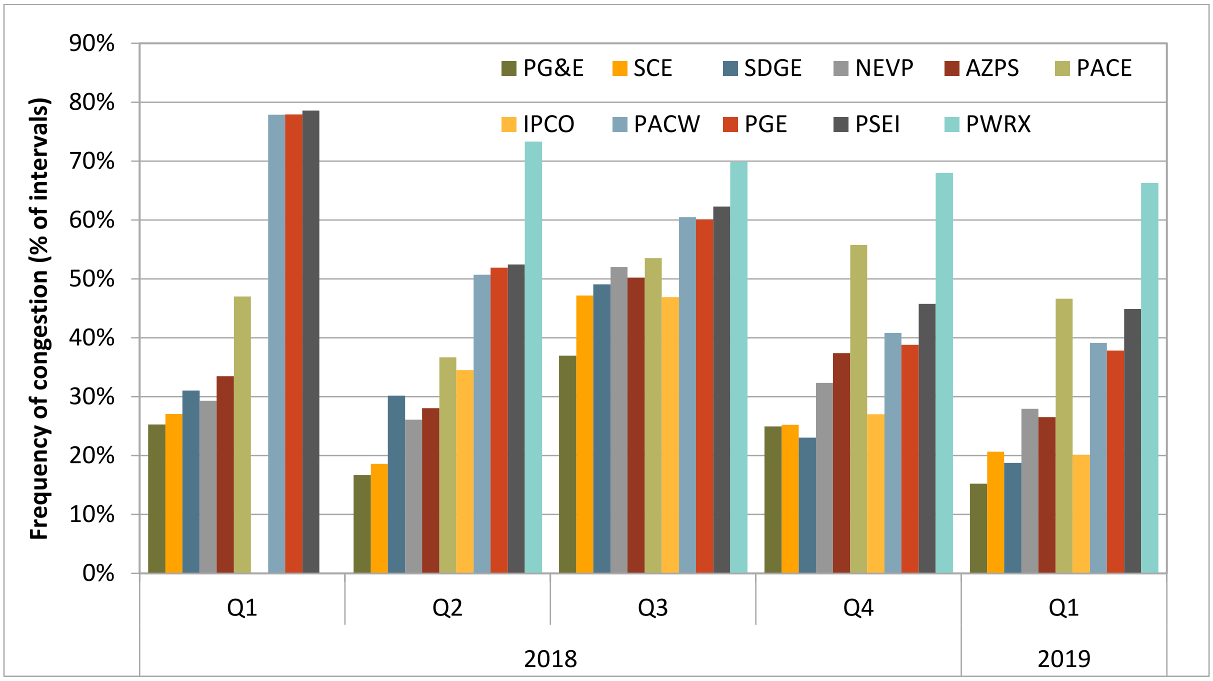


Figure 1.17 Percent of hours with congestion impacting 15-minute prices by load area



Impact of congestion from individual constraints

Table 1.4 shows the overall impact (during all hours) of congestion on average 15-minute prices in each load area. Table 1.5 shows the impact of 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 1.4). The category labeled "other" includes the impact of EIM transfer constraints, which have the greatest impact on price separation for EIM areas. These transfer constraints are discussed in greater depth in Chapter 2. This section will focus on the individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the Imperial Valley nomogram, the Gates-Midway 500 kV lines, the Devers-El Casco nomograms, and the San Luis Rey-San Onofre 230 kV line.

Imperial Valley nomogram

Similar to the day-ahead market, the Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the 15-minute market and had the greatest net impact to price separation for the quarter. Congestion on the constraint increased prices in SDG&E and SCE by nearly $2/MWh and $0.13/MWh, respectively, and decreased prices throughout the rest of the west. Located in Southern California, the constraint had the greatest impact on the Arizona Public Service area in the energy imbalance market, decreasing prices by about $0.43/MWh. 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.

Gates-Midway 500 kV lines

The two Gates-Midway 500 kV lines (30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3 and 30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3), which are located between the northern and southern parts of California, had an impact on all areas across the west, increasing prices north of the constraint and decreasing prices south of the constraint. The constraints bound in few intervals, but had a significant impact on prices when binding. On average, they decreased overall quarterly prices in the south (SCE, SDG&E, NEVP, and AZPS) by about $0.23/MWh and increased prices in all other areas by about $0.14/MWh. These constraints were congested due to system conditions, and were not significantly impacted by any direct outages throughout the quarter. The primary cause of this congestion was likely heavier south-to-north flows due to high gas prices in the Pacific Northwest.

Devers-El Casco nomograms

The Devers-El Casco nomograms (7750_D-ECASCO_OOS_CP6_NG and 7750_D-ECASCO_OOS_N1SV500_NG) had a similar impact on prices to the Gates-Midway constraints, decreasing prices south and east of the constraints (SCE, SDG&E, AZPS, NEVP, and PACE), and increasing prices in some areas north of the constraints (PG&E, IPCO, PACW, PGE). On average, the nomograms decreased southern area prices by about $0.18/MWh, and had little impact on northern areas with the exception of PG&E, where prices increased about $0.20/MWh due to the congestion. This congestion was in part related to an outage on the El Casco-San Bernardino 230 kV line which returned to service in May.

San Luis Rey-San Onofre 230 kV line

The San Luis Rey-San Onofre 230 kV line (22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1) in southern California bound in few intervals (about 1 percent), though had a large impact on prices when binding that contributed to a meaningful overall impact on price separation for the quarter. The constraint decreased prices in SDG&E and AZPS by $0.62/MWh and $0.11/MWh, respectively, and increased prices in the rest of the west by about $0.01/MWh on average. This constraint bound fewer than 5 days and was related to a planned outage on one of the three lines connecting the San Luis Rey and San Onofre substations.

Table 1.4 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E	SCE	SDGE	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
IPCO	BORAH_POPULUS_345_2	$0.00	$0.00	$0.00		-$0.01	-$0.03	$0.02	$0.01	$0.01	$0.01	$0.01
NEVP	CRY PS-5				$0.04	-$0.02						
	GON-IPP 230				$0.02		-$0.03					
	HBT-COY_3423		-$0.02	-$0.02	-$0.11	-$0.03	$0.02	$0.07	$0.02	$0.03	$0.03	$0.03
	RBS-HA_525KV		$0.01	$0.01		$0.01	-$0.01	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01
	GON 345TXF#3						-$0.06					
	GON 230TXF#3						-$0.13					
	GON 345TXF#4						-$0.19					
	GON 230TXF#4						-$0.24					
PACE	WYOMING_EXPORT						-$0.26					
PG&E	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.12	-$0.18	-$0.17	-$0.09	-$0.16	-$0.03	$0.04	$0.10	$0.10	$0.10	$0.09
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.06	-$0.10	-$0.09	-$0.05	-$0.08	-$0.01	$0.02	$0.05	$0.05	$0.05	$0.05
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.03	-$0.06	-$0.06	-$0.03	-$0.05		$0.02	$0.04	$0.04	$0.03	$0.03
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	$0.03	-$0.01	-$0.01	-$0.01	-$0.01						
	COI_600 N-S	$0.02	$0.01	$0.01	$0.00	$0.01	-$0.01	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03
	OMS_5413443_LOSBNS_MDWY2	$0.02	-$0.03	-$0.03	-$0.01	-$0.02	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	$0.01	-$0.02	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30056_GATES2 _500_BR_2 _1	$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01
	6310_MWN_NRAS	$0.00	-$0.01	-$0.01	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1		-$0.07	-$0.04								
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1				-$0.06							
SCE	24092_MIRALOMA_500_24093_MIRALOM _230_XF_2 _P	-$0.07	$0.14	$0.23	-$0.05		-$0.02	-$0.05	-$0.06	-$0.06	-$0.06	-$0.06
	24042_ELDORDO _500_24086_LUGO _500_BR_1 _3	$0.02	$0.04	$0.00	-$0.07	-$0.07	-$0.04	-$0.02				
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1		$0.03	$0.03	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	-$0.01	$0.02	$0.03	-$0.01	$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	OMS 6747250 LUGO-MOH	$0.01	$0.01	$0.00	-$0.03	-$0.03	-$0.02	-$0.01				
	OMS 6764682 LUGO-MOH	$0.01	$0.01	$0.00	-$0.03	-$0.02	-$0.01	$0.00				
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.01	$0.01	$0.00	-$0.02	-$0.02	-$0.01	$0.00				
	OP-6610_ELD-LUGO	$0.01	$0.01	$0.00	-$0.03	-$0.02	-$0.01	$0.00				
	OMS 6417757 LUGO-MOH	$0.01	$0.01	$0.00	-$0.02	-$0.01	-$0.01	$0.00				
	24016_BARRE _230_25201_LEWIS _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
	7750_D-ECASCO_OOS_CP5_NG		$0.00			-$0.03						
	7750_D-ECASCO_OOS_N1SV500_NG	$0.04	-$0.01	$0.00	-$0.04	-$0.32	-$0.04					
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1		-$0.03									
	7750_D-ECASCO_OOS_CP6_NG	$0.16	-$0.17	-$0.01	-$0.10	-$0.60	-$0.13	$0.00	$0.00	$0.00		
SDG&E	7820_TL 230S_OVERLOAD_NG		$0.13	$1.96	-$0.16	-$0.43	-$0.18	-$0.11	-$0.02	-$0.02	-$0.03	-$0.03
	7820_TL23040_IV_SPS_NG		$0.00	$0.13	-$0.01	-$0.01	-$0.01	$0.00				
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80			$0.06	$0.00	-$0.02	-$0.01					
	OMS_6742815_TL23054_NG		$0.00	$0.04	$0.00	-$0.02	$0.00					
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1			$0.03								
	OMS 5601922_DV_RDBLF1	$0.01	$0.02	$0.01	-$0.05	-$0.05	-$0.02	-$0.01				
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1					-$0.04						
	OMS 6484294_7750_D-SBLR_NG	$0.02	-$0.02		$0.00	-$0.11			$0.01	$0.01	$0.00	$0.00
	OMS 7024011 DV_VST2					-$0.07						
	22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1		$0.00	-$0.03		-$0.01						
	22716_SANLUSRY_230_22232_ENCINA _230_BR_1 _1	$0.00	$0.01	-$0.05		-$0.01	$0.00					
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			-$0.17		-$0.06						
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.04	$0.09	-$0.62	$0.00	-$0.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other		$0.01	-$0.01	$0.12	-$1.39	$2.97	$1.89	$0.73	-$1.64	-$1.32	-$0.90	-$0.46
Total		**$0.56**	**-$0.21**	**$1.34**	**-$2.33**	**$0.54**	**$0.37**	**$0.62**	**-$1.51**	**-$1.19**	**-$0.80**	**-$0.37**

Table 1.5 Impact of congestion on 15-minute prices in the ISO during congested intervals[11]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
NEVP	GON 230TXF#4	1.8%	$0.00	$0.00	$0.00	$0.00	$0.00	-$13.40	$0.00	$0.00	$0.00	$0.00	$0.00
	GON 345TXF#4	1.4%	$0.00	$0.00	$0.00	$0.00	$0.00	-$14.27	$0.00	$0.00	$0.00	$0.00	$0.00
	GON 230TXF#3	0.9%	$0.00	$0.00	$0.00	$0.00	$0.00	-$13.85	$0.00	$0.00	$0.00	$0.00	$0.00
	HBT-COY_3423	0.5%	$0.00	-$4.58	-$4.83	-$20.67	-$5.13	$5.50	$13.88	$4.67	$5.01	$5.35	$5.46
	GON 345TXF#3	0.4%	$0.00	$0.00	$0.00	$0.00	$0.00	-$14.93	$0.00	$0.00	$0.00	$0.00	$0.00
PACE	WYOMING_EXPORT	26.5%	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.97	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.2%	$0.67	-$2.02	-$1.90	-$0.63	-$1.74	-$1.35	-$1.44	-$0.03	-$0.02	-$0.05	-$0.04
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	1.0%	$11.87	-$18.43	-$17.31	-$9.00	-$15.57	-$2.85	$3.55	$10.01	$9.94	$9.56	$9.39
	OMS_5413443_LOSBNS_MDWY2	0.8%	$2.21	-$3.48	-$3.33	-$1.77	-$2.93	-$0.24	$1.02	$1.98	$1.97	$1.89	$1.86
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	0.8%	$0.00	-$8.70	-$10.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	0.4%	$0.00	$0.00	$0.00	-$15.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.4%	$7.36	-$15.57	-$14.68	-$7.62	-$13.15	$0.00	$4.86	$9.54	$9.47	$9.13	$8.97
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	0.3%	$16.76	-$28.14	-$26.58	-$15.25	-$23.96	-$4.06	$6.41	$15.81	$15.73	$15.06	$14.78
SCE	7750_D-ECASCO_OOS_CP6_NG	6.6%	$2.37	-$3.10	-$0.77	-$2.03	-$9.07	-$2.16	-$1.06	$2.04	$1.76	$0.00	$0.00
	7750_D-ECASCO_OOS_N1SV500_NG	1.7%	$2.48	-$4.33	-$1.40	-$2.67	-$18.64	-$2.75	$0.00	$0.00	$0.00	$0.00	$0.00
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1	0.7%	$0.00	-$3.97	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_2 _P	0.7%	-$10.45	$21.20	$35.49	-$6.96	$0.00	-$5.16	-$7.68	-$9.06	-$9.03	-$8.87	-$8.83
SDG&E	7820_TL 230S_OVERLOAD_NG	8.7%	$0.00	$1.46	$22.61	-$1.83	-$4.93	-$2.07	-$1.33	-$1.26	-$1.19	-$1.13	-$1.14
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	1.1%	$3.31	$7.56	-$54.82	-$0.31	-$9.63	-$0.32	-$0.36	-$0.39	-$0.39	-$0.39	-$0.39
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	1.1%	$0.00	$0.00	-$15.08	$0.00	-$14.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_TL23040_IV_SPS_NG	0.7%	$0.00	$1.08	$17.54	-$0.82	-$2.09	-$0.89	-$0.42	$0.00	$0.00	$0.00	$0.00
	22716_SANLUSRY_230_22232_ENCINA _230_BR_1 _1	0.5%	$0.40	$2.08	-$11.20	$0.00	-$3.03	-$0.53	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 7024011 DV_VST2	0.4%	$0.00	$0.00	$0.00	$0.00	-$16.43	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

1.8 Ancillary services

1.8.1 Ancillary service requirements

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

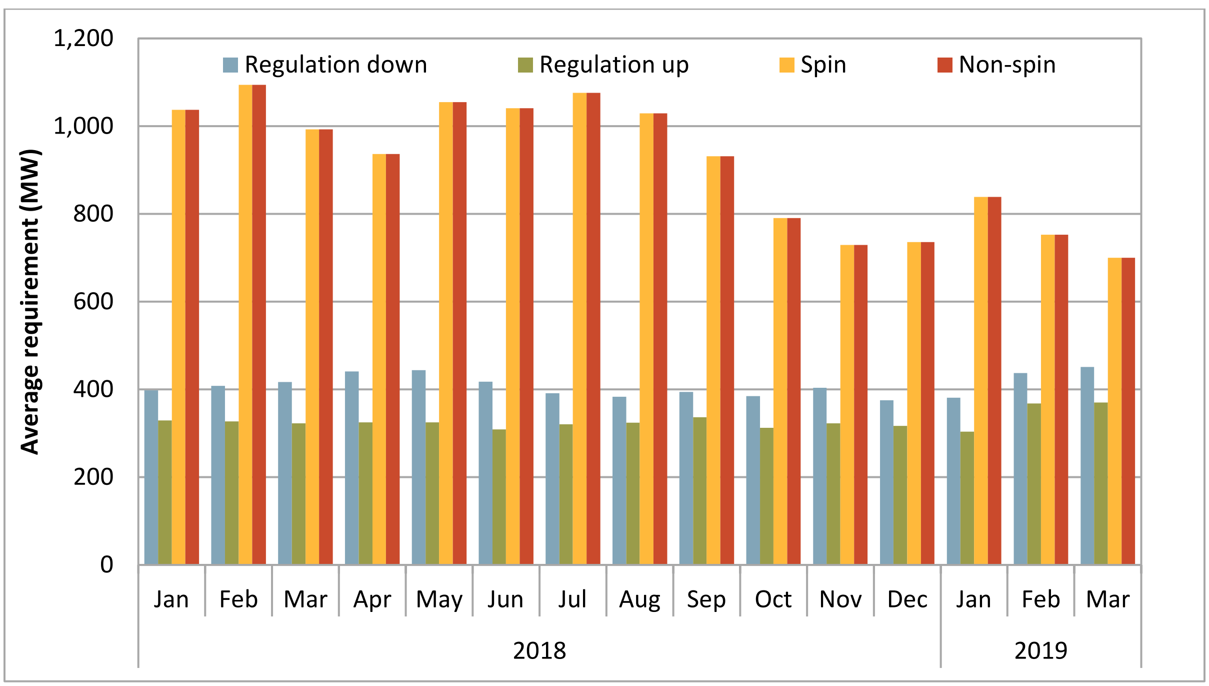
The ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions. The expanded regions are identical to the corresponding internal regions but include interties. Each of these regions can have minimum requirements set for procurement of ancillary services where the internal sub-regions are all nested within the system and corresponding expanded regions. Therefore, ancillary services procured in a more inward region also count toward meeting the minimum requirement of the outer region. Ancillary service requirements are then met by both internal resources and imports where imports are indirectly limited by the minimum requirements from the internal regions.

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

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 serves as the most severe single contingency.

Figure 1.18 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown in the figure, average spinning and non-spinning operating reserve requirements increased in January and decreased thereafter in February and March. Operating reserve requirements during the quarter were highest during the morning and evening load ramping hours. In particular, Pacific DC intertie schedules frequently set the operating reserve requirement during these hours as the most severe single contingency.

Figure 1.18 Average monthly day-ahead ancillary service requirements



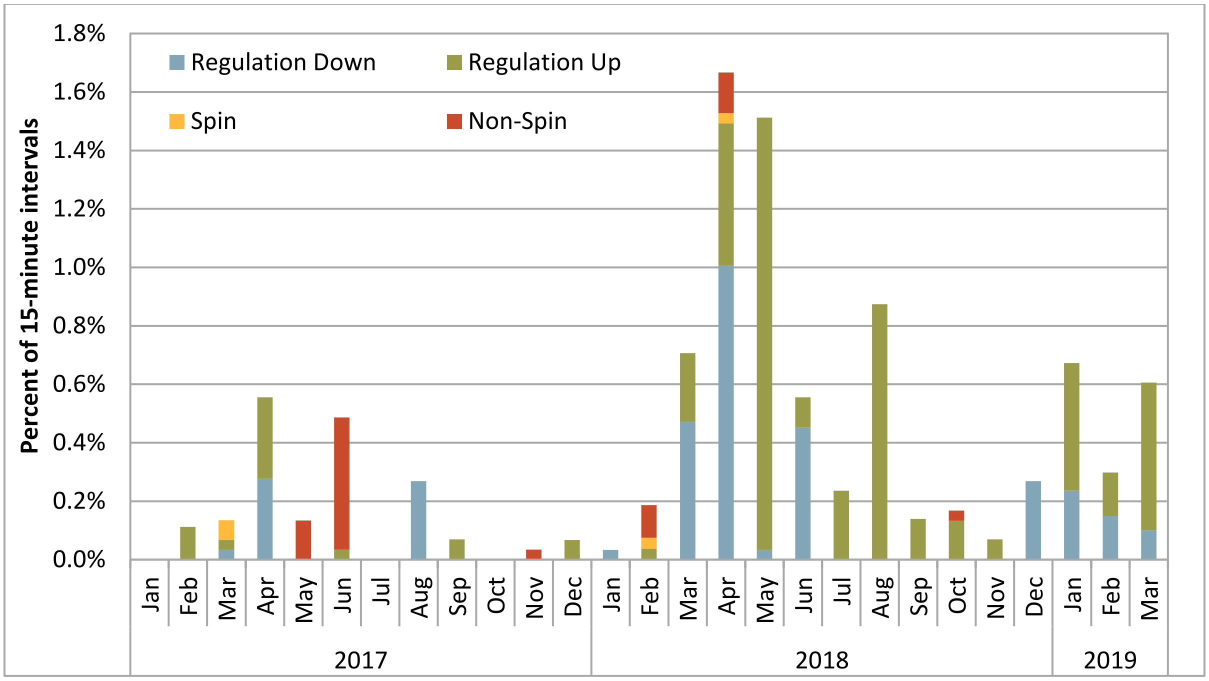
1.8.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, 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 1.19 the number of intervals with scarcity pricing increased during the first quarter of 2019, particularly from the shortage of regulation down and regulation up. During the quarter, around

57 percent of the scarcity intervals occurred in the expanded South of Path 26 region; the remaining 43 percent occurred in the expanded system region.

Figure 1.19 Frequency of ancillary service scarcities (15-minute market)

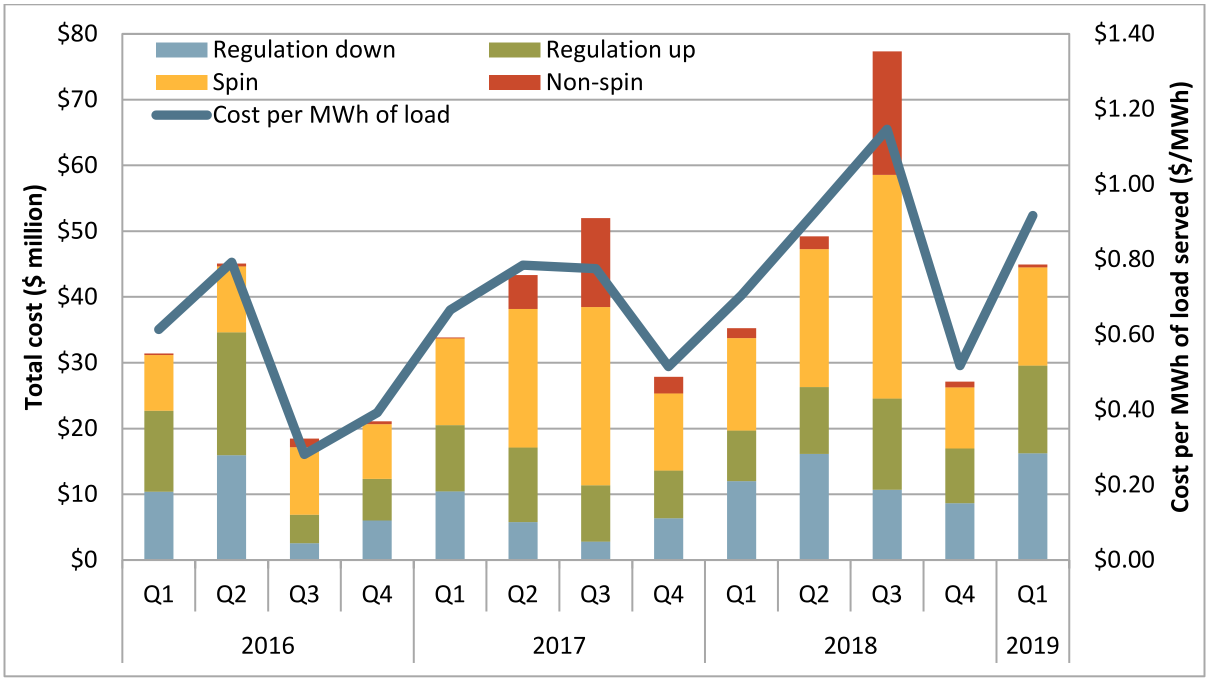


1.8.3 Ancillary service costs

Costs for ancillary services increased during the first quarter to about $45 million, compared to about $27 million in the previous quarter and $35 million during the same quarter in 2018.

Figure 1.20 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. In particular, total payments associated with regulation down, regulation up, and spinning reserve each increased by $5 to $8 million from the previous quarter. Payments associated with non-spinning reserves were less than $0.5 million during the first quarter.

Figure 1.20 Ancillary service cost by product



1.9 Flexible ramping product

Background

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 runs and the three 5-minute market runs with that 15-minute interval. Procurement in the 5-minute market is aimed at ensuring that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

Market outcomes for flexible ramping product

This section describes the amount of flexible ramping capacity that was procured in the first quarter, and the 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 1.21 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, there was an increase in binding shadow prices, but these remained infrequent overall in both directions. The 15-minute market system-level demand curves bound in around 9 percent of intervals in the upward direction and 1.5 percent of intervals in the downward direction during the quarter.

Figure 1.21 Monthly frequency of positive 15-minute market flexible ramping shadow price

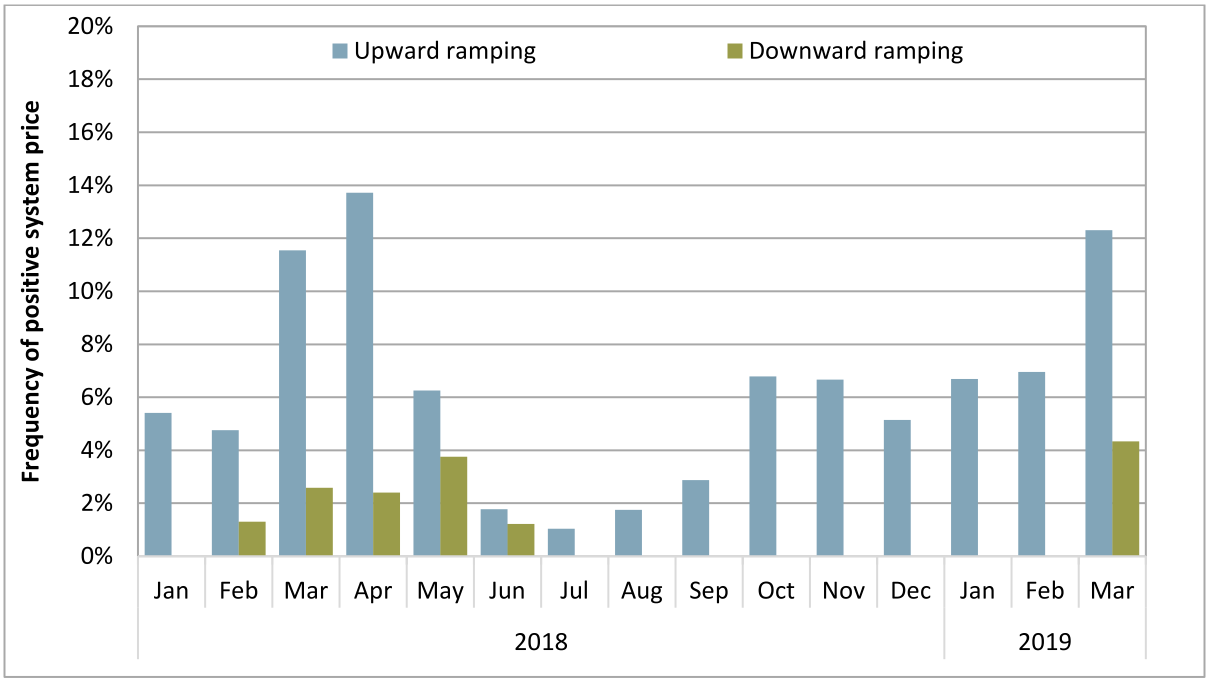


Figure 1.22 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the first quarter. This capacity may have been procured to satisfy system-level demand, area-specific demand, or both. The positive bars show procurement for upward flexible ramping capacity, and the negative bars show procurement for downward flexible ramping capacity. The hourly procurement profile is very similar to the profile of the system-level demand curves, and reflects that most of the flexible ramping capacity was procured to meet system-level uncertainty needs. Overall, the market procured an hourly average of about 980 MW of upward capacity and 1,110 MW of downward capacity in the 15-minute market during the first quarter.

Figure 1.23 shows the same information for flexible ramping capacity procured in the 5-minute market. During the first quarter, system uncertainty requirements (and many of the BAA-specific uncertainty requirements) were very high for hour-ending one in the 5-minute market. This is the result of a data issue which impacted particular net load error observations used in the uncertainty calculation. The issue also impacted the 15-minute market uncertainty calculation, though only in the upward direction, and to a lesser extent. However, the percent of intervals that the flexible ramping demand curves bound and had a positive shadow price was very infrequent in hour-ending one as significant flexible ramping capacity was typically available during this hour.

Figure 1.22 Hourly average flexible ramping capacity procurement in 15-minute market (January – March)

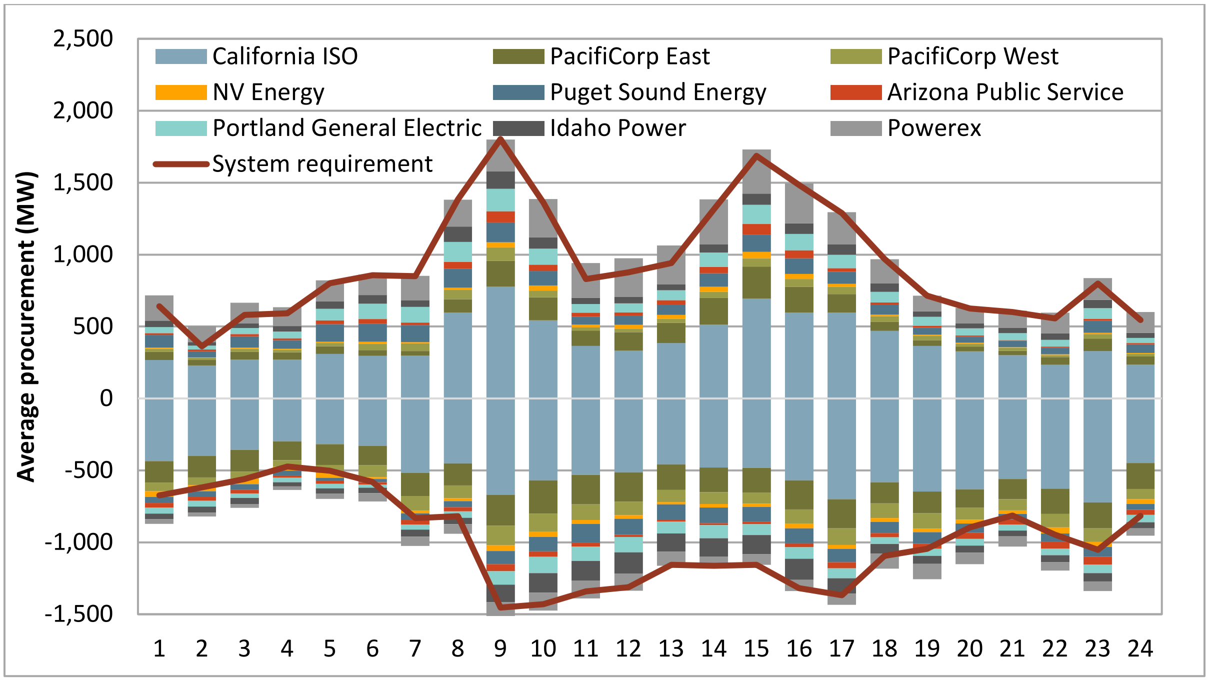
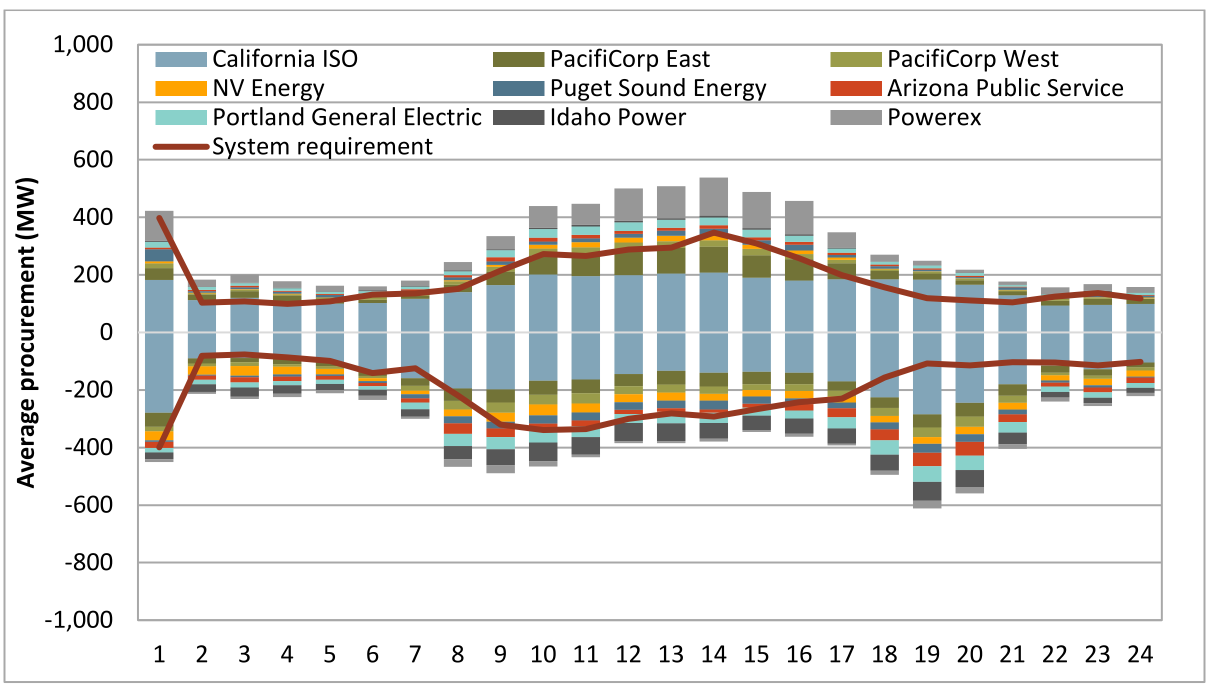


Figure 1.23 Hourly average flexible ramping capacity procurement in 5-minute market (January – March)



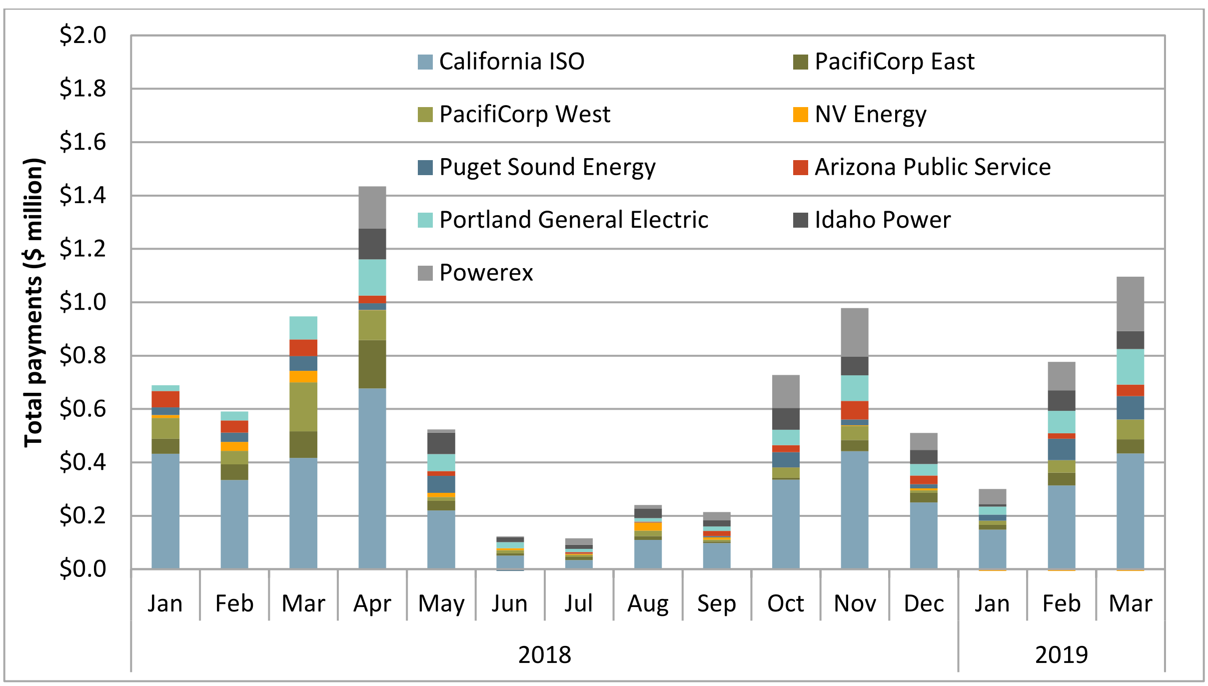
Flexible ramping procurement costs

Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price was also used to pay or charge for forecasted ramping movements. This means that 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.[12]

Figure 1.24 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month. This includes the total net amount paid for upward and downward flexible ramping capacity in both the 15-minute and 5-minute markets. Payments for forecast movements are not included.

Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity decreased slightly during the first quarter of 2019 to around $2.1 million, compared to $2.2 million during the previous quarter. Of note, net payments to NV Energy for flexible ramping capacity were negative during all three months of the first quarter.[13]

Figure 1.24 Monthly flexible ramping payments by balancing area



12 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.

13 Flexible ramping capacity is settled as the sum of: (1) the 15-minute market uncertainty award times the combined system and area-specific 15-minute market shadow price, and (2) the *incremental* 5-minute market uncertainty award times the combined system and area-specific 5-minute market shadow price. A negative incremental award from the 15-minute market to the 5-minute market can contribute to negative net payments.

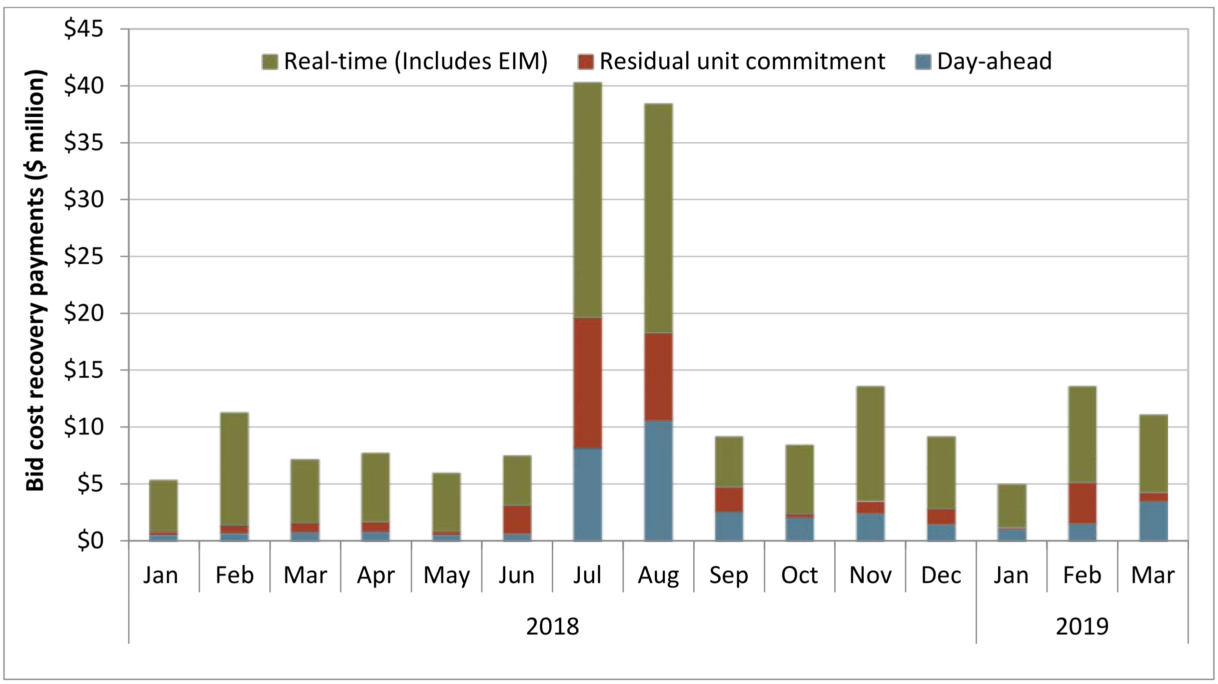
1.10 Bid cost recovery

Estimated bid cost recovery payments for the first quarter of 2019 totaled about $30 million. This amount was slightly lower than the total amount of bid cost recovery in the previous quarter and about $5 million higher than the first quarter of 2018.

Bid cost recovery attributed to the day-ahead market totaled about $6 million, which was about the same as the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $4.5 million, compared to $3 million in the prior quarter. Bid cost recovery attributed to the real-time market totaled about $19 million, or about $1 million lower than payments in the first quarter of 2018 and $3 million lower than payments in the last quarter of 2018.

In February, these real-time payments were about $8.5 million. High bid cost recovery payments in February can be attributed to high natural gas prices at both SoCal Citygate and PG&E Citygate gas hubs.

Figure 1.25 Monthly bid cost recovery payments



1.11 Convergence bidding

Convergence bidding was profitable overall during the first quarter. Additionally, virtual supply was profitable for the fifth consecutive quarter. Before accounting for bid cost recovery charges, virtual supply generated net revenues of about $13 million while demand net revenues were a loss of about $4.2 million. Combined net revenues for virtual supply and demand fell to about $5.5 million after including about $3.1 million of virtual bidding bid cost recovery charges.

1.11.1 Convergence bidding trends

Average hourly cleared volumes remained at about 3,100 MW, which is very similar to the previous quarter. Average hourly virtual supply remained similar to the previous quarter at about 2,000 MW.

Additionally, virtual demand averaged around 1,100 MW during each hour of the quarter, similar to the previous quarter. On average, about 30 percent of virtual supply and demand bids offered into the market cleared in the first quarter, which is about the same as in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 940 MW on average, which decreased slightly from 990 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand only exceeded net cleared virtual supply during hour ending 19. In the remaining 23 hours, net cleared virtual supply exceeded net cleared virtual demand. Cleared virtual supply exceeded virtual demand by 1,000 MW during all hours except morning hours ending 5 through 8, and peak hours ending 17 through 21.

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

Offsetting virtual supply and demand bids

Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual 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 695 MW of virtual demand offset by 695 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 44 percent of all cleared virtual bids in the first quarter, down from about 52 percent in the previous quarter.

1.11.2 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 $8.7 million. Net revenues for virtual supply and demand fell to about $5.5 million after including about $3.1 million of virtual bidding bid cost recovery charges.[14]

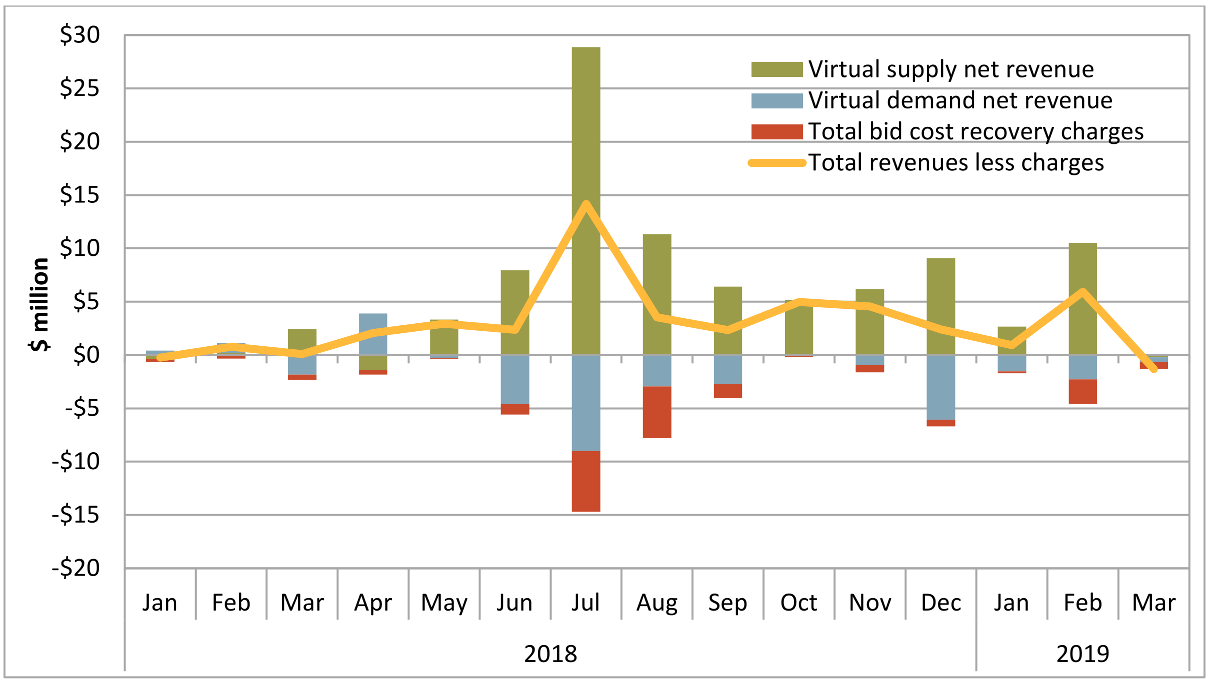
Figure 1.26 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

[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.

Before accounting for bid cost recovery charges:

- Total market revenues were positive during January and February and negative in March. Net revenues during the first quarter totaled about $8.7 million, compared to about $1.7 million during the same quarter in 2018, and about $13.4 million during the previous quarter.
- Virtual demand net revenues were negative for all months in the first quarter. In total, virtual demand generated negative net revenues of about $4.2 million for the quarter.
- Virtual supply net revenues were positive in January and February and negative in March. In total, virtual supply generated net revenues of nearly $13 million. After accounting for bid cost recovery charges, virtual supply was profitable for the fifth consecutive quarter.

Figure 1.26 Convergence bidding revenues and bid cost recovery charges



After accounting for bid cost recovery charges:

- Convergence bidders received about $5.5 million after subtracting bid cost recovery charges of about $3.1 million for the quarter.[15,16] Bid cost recovery charges were about $0.2 million in January, $2.3 million in February and $0.7 million in March.

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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.

Net revenues and volumes by participant type

Table 1.6 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the first quarter.[17] Financial entities represented the largest segment of the virtual bidding market, accounting for about 70 percent of volume and 72 percent of settlement revenue. Marketers represented about 29 percent of the trading volumes and about 25 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. In addition, generation owners and load-serving entities accounted for around $0.3 million of net revenues in the market.

Table 1.6 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	764	1,421	2,185	-$2.28	$8.48	$6.21
Marketer	329	573	902	-$2.05	$4.22	$2.17
Physical load	9	21	30	$0.05	$0.11	$0.16
Physical generation	0	22	22	$0.00	$0.14	$0.14
Total	**1,102**	**2,037**	**3,139**	**-$4.3**	**$13.0**	**$8.7**

1.12 Real-time imbalance offset costs

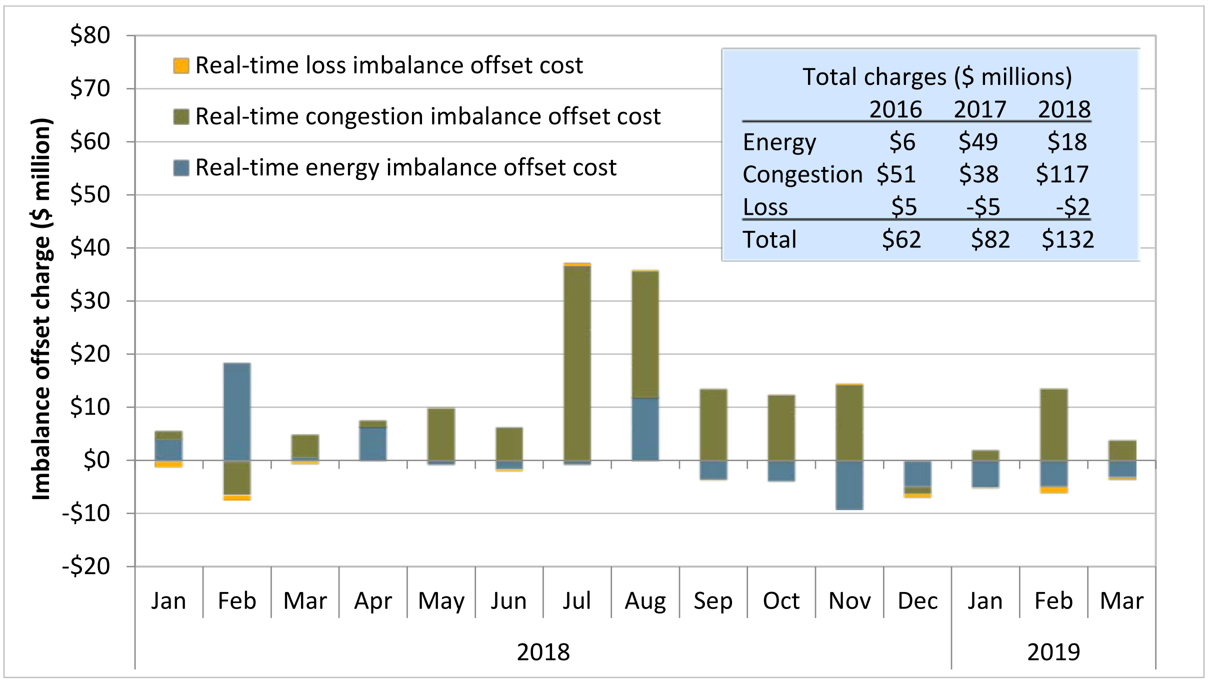
Total real-time imbalance offset costs increased by 61 percent from $82 to $132 million between 2017 and 2018. Much of this increase appears to have been caused by persistent and significant reductions in constraint limits made by grid operators in the 15-minute market relative to higher limits used in the day-ahead market. First quarter imbalance offset costs totaled $6 million, the sum of $20 million congestion offset costs less $13 million energy offset and $1 million loss offset. High real-time congestion imbalance offset costs were again associated with significant reductions in constraint limits in the 15-minute market relative to higher limits in the day-ahead market.

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy components of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from the congestion component of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO). Until October 2014, the ISO aggregated real-time loss imbalance offset costs with real-time energy imbalance costs. This was changed so that any revenue imbalance from the loss component of real-time energy settlement prices is now collected through the *real-time loss imbalance offset charge*.

[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.

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. Historically, this included energy settled at hour-ahead and 5-minute prices. The ISO implemented market changes related to FERC Order No. 764 in May 2014, which included a financially binding 15-minute market. Following this change, real-time imbalance offsets include energy settled at 15-minute and 5-minute prices. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

Figure 1.27 Real-time imbalance offset costs



1.13 Congestion revenue rights

Background

Congestion revenue rights are paid (or charged), for each megawatt held, the difference between the hourly day-ahead congestion prices at the sink and source node 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. Congestion revenue rights 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).[18] The ISO charges utility distribution companies the transmission access charge in order to reimburse the entity that builds each transmission

[18] 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.

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 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 ten years since the start of the congestion revenue rights auction in 2009, revenue from congestion revenues rights sold in the auction have consistently been well below the congestion revenues paid out to entities purchasing these congestion revenue rights. Through 2018, transmission ratepayers have lost about $860 million in congestion revenues paid out in excess of revenues received from the auction. This represents only about 50 cents in auction revenues for every dollar paid to congestion revenue rights holders. Most of these profits have been received by financial entities that do not sell power or serve load in the ISO.[19]

Congestion revenue rights auction modifications

In 2016, DMM began recommending the ISO modify or eliminate the congestion revenue rights auction to reduce the losses to transmission ratepayers from congestion revenue rights sold in the auction. In 2018, the ISO proposed several changes to the congestion revenue rights auction design in order to reduce the systematic losses which have occurred from congestion revenue rights sold in the auction.

- **Track 1A.** The first major change significantly reduces the number and pairs of nodes at which congestion revenue rights can be purchased in the auction.[20] These changes were designed to limit rights sold in the auction to pairs of nodes at which physical generation and load is located, which in some cases may be purchased 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 to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.[21]

These tariff changes were implemented by the ISO beginning with the annual and monthly auctions for 2019.

Congestion revenue right auction returns

Auctioned congestion revenue rights profitability or ratepayer losses are calculated as payments received by buyers of auctioned rights less the auction price and estimated offsets charged to auctioned congestion revenue rights. Based on this framework, ratepayers lost about $1.5 million during the first quarter of 2019 as payments to auctioned congestion revenue rights holders exceeded auction

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[19] A more detailed discussion of congestion revenue rights is provided in DMM's *2018 Annual Report* (pp.197-205). http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

[20] 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

[21] 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

revenues. This compares to average losses of $24 million in the first quarter of the prior three years. As shown in Figure 1.28, auction revenues were 92 percent of payments made to non-load-serving entities during the first quarter of 2019, up significantly from 38 percent during the same quarter in 2018.

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 $6 million. This was a substantial decrease from $36 million profits during the first quarter of 2018. Energy marketers lost about $1 million, down from over $4 million profit during the same quarter in 2018. Generators lost over $3 million compared to $2 million profit in the first quarter of 2018.

The reduction in losses from the congestion revenue rights in the auction in the first quarter was due to a combination of at least three factors:

- Changes implemented by the ISO in 2019 which limit the source and sink of congestion revenue rights that can be purchased in the auction (Track 1A).[22]
- Changes in the settlement of congestion revenue rights implemented in 2019 (Track 1B).
- A significant drop in the impact and direction of congestion on day-ahead prices compared to Q1 in prior years.

The impact of Track 1A changes limiting the types of congestion revenue rights 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 losses to transmission ratepayers from sales of congestion revenue rights by about $8.8 million. A more detailed description of these Track 1B changes and how the impact of these changes is estimated is provided in a later section of this report.

The impact of the drop in congestion and change in congestion patterns in 2019 on transmission ratepayer losses from congestion revenue rights in Q1 cannot be directly quantified. However, as shown by Figure 1.14 and Figure 1.15 in the section of this report on congestion, there was a very significant drop in the impact and direction of congestion on day-ahead prices compared to the same quarter in 2018.[23]

As shown in Figure 1.14, day-ahead congestion drove average prices in the PG&E area down by about $3/MWh in the first quarter of 2018, but increased average prices by about $0.50/MWh in the first quarter of this year. In the SCE area, congestion drove average day-ahead prices up by about $2/MWh in the first quarter of 2018, but drove average prices down by about $0.50 in the first quarter of this year.

The significant drop in congestion during the first quarter of 2019 compared to prior years is also reflected in Figure 1.28 and Figure 1.29. Congestion revenues paid out to auctioned congestion revenue rights, prior to offset adjustments, totaled about $28.4 million in Q1 2019, compared to an average of $43.8 million over the prior four years (2015-2018), or about 35 percent lower.

22 An explanation of these changes is available in Section 1.13 or in DMM's 2018 Annual Report on Market Issues & Performance, Section 8.4, available here: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

23 See Figure 1.14 and Figure 1.15 on page 20 of this report. Figure 1.14 is also provided as Figure E.2 in Executive Summary.

Figure 1.28 Auction revenues and payments to non-load-serving entities

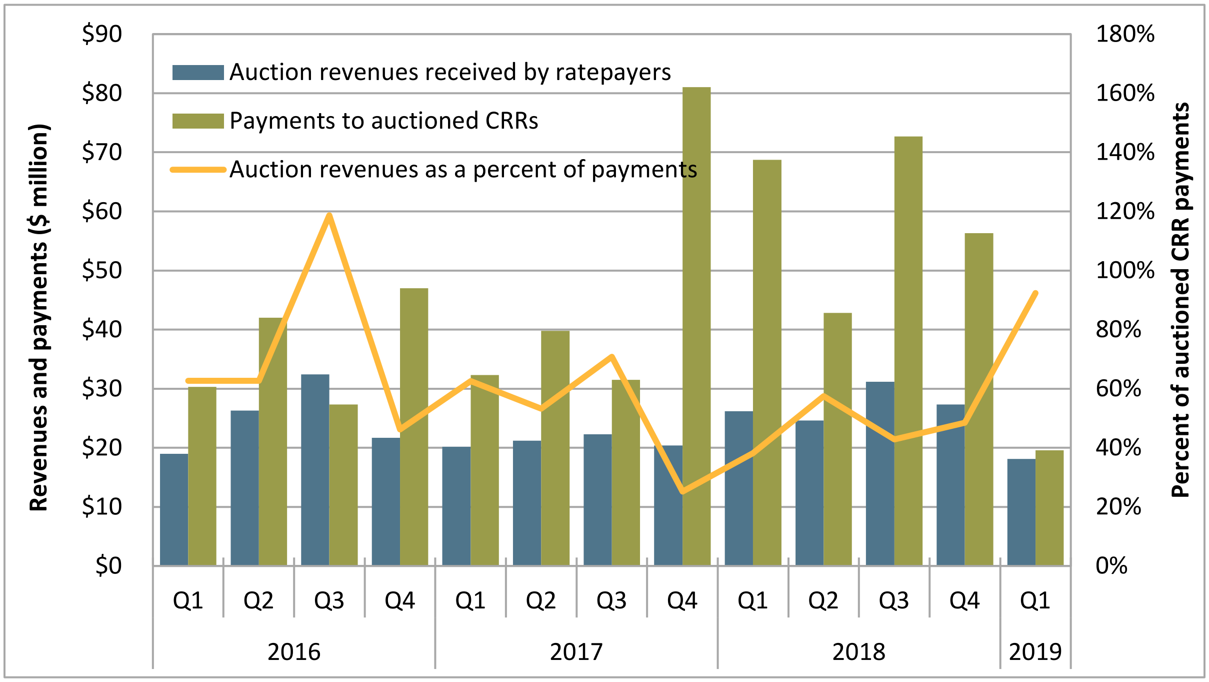
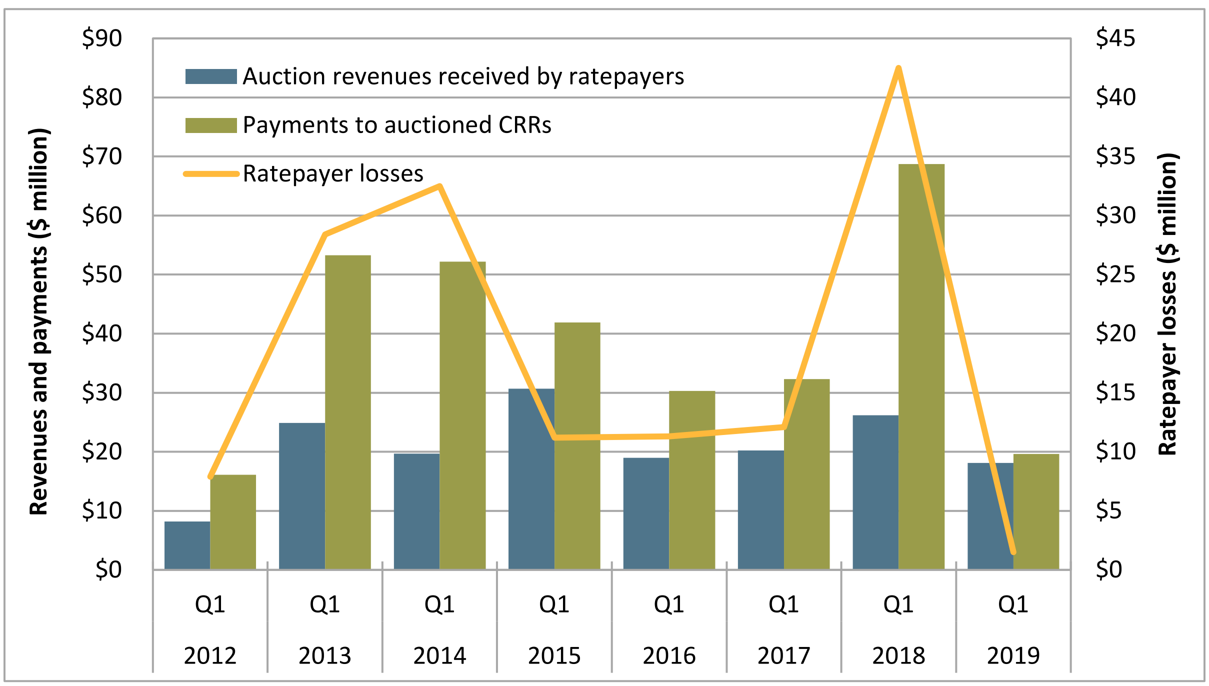


Figure 1.29 Q1 auction revenues and payments to non-load-serving entities (2012-2019)



Impact of Track 1B changes

Under changes made under the ISO's Track 1B filing, starting on January 1, 2019, congestion revenue rights are paid only up to the amount of congestion rent actually collected on the constraints underlying the congestion revenue right source and sink marginal congestion components (MCC). The total congestion revenue rights payments, netted by scheduling coordinator from each constraint, are calculated over the month. The total congestion rent is calculated by constraint and compared to the total congestion revenue rights payments across all scheduling coordinators from the constraint. If the congestion revenue rights payments are greater than the congestion rent collected for a constraint, the difference is charged as an offset to the scheduling coordinators with net positive flows on the constraint.

Based on current settlement records, DMM estimates that the changes made under Track 1B described above reduced losses to transmission ratepayers from sales of congestion revenue rights by about $8.8 million. This estimate is based on data which DMM understands could be subject to significant changes as part of the settlement process due to implementation issues with the Track 1B rule changes.

1.14 Load forecast adjustments

Load forecast adjustments

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. The ISO uses the term *imbalance conformance* to describe these adjustments. Load forecast adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error corrections, scheduled interchange variations, reliability events, and software issues.[24] DMM will continue to use the terms load forecast adjustment and load bias limiter for consistency with prior reports.

Frequency and size of load adjustments, generation/import prices and imports

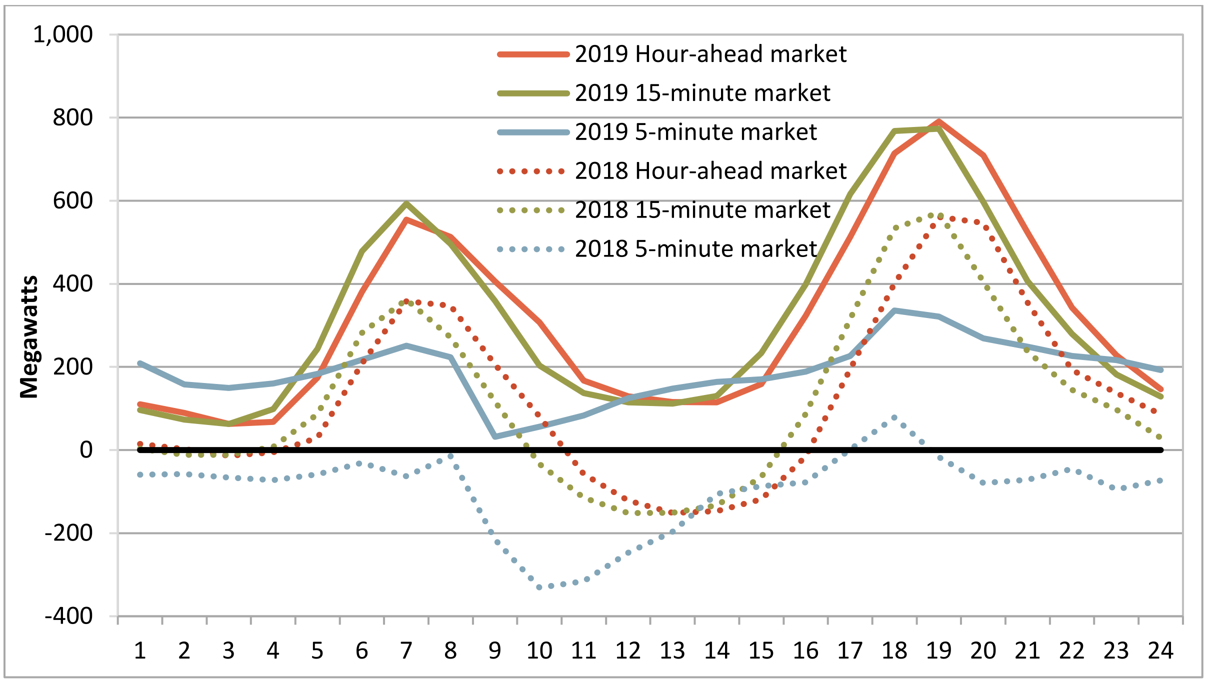
The dramatic increase in load forecast adjustments during the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets in 2017 appears to have continued throughout 2018 and into the second quarter of 2019. Adjustments during the mid-day period also increased for these markets for the same time period but, on average by hour, changed from a negative adjustment to positive. In general, load forecast adjustments for the 5-minute market increased throughout the day and remained positive when comparing the first quarter of 2019 with the same period in 2018. Figure 1.30 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for the first quarter in 2019 and 2018.

Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. But, like the previous year, the 2019 5-minute market adjustments differ dramatically from other markets for nearly all hours of the day. Unlike the same quarter in 2018 where the daily average

[24] 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

hourly adjustment was about 100 MW in the negative direction, the average hourly adjustment for the first quarter of 2019 was nearly 200 MW in the positive direction – no negative conformance on average. In all markets the lowest adjustment periods were typically early morning/late evening as well as mid-day. The shape of the adjustments for the 5-minute market were generally flat during the day, around 200 MW, while the hour-ahead and 15-minute market adjustments changed sharply surrounding the morning and evening ramp periods, up to 800 MW in hour-end 19. Adjustments are often associated with over/under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods.

Figure 1.30 Average hourly load adjustment (Q1 2018 – Q1 2019)



2 Energy imbalance market

This section covers the energy imbalance market performance during the first quarter. Key observations and findings include the following.

- Real-time energy costs per megawatt-hour of total load decreased by about 14 percent from the same quarter in 2018.
- During midday hours, NV Energy and Arizona Public Service had an increased frequency of surplus power balance constraint relaxations after failing the flexible ramping sufficiency test, which resulted in price separation between these areas and the ISO.
- NV Energy failed the downward sufficiency test frequently in February, during almost 24 percent of hours during the quarter.
- Congestion in the 15-minute market in the direction toward the ISO occurred during 31 percent of intervals from Powerex and around 24 percent of intervals from PacifiCorp West, Portland General Electric and Puget Sound Energy. However, the Northwest region was less frequently congested in comparison to the first quarter of the previous year when congestion toward the ISO from areas in this region occurred in around 62 percent of intervals.
- The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. The enhancement significantly reduced the frequency with which the limiter triggered for under-supply conditions for Arizona Public Service during March.
- In November, the ISO implemented a revised energy imbalance market greenhouse gas bid design, addressing concerns that the previous design did not capture the full impact of energy imbalance market imports into California on global greenhouse gas emissions for compliance with California's cap-and-trade regulation. Following implementation of these changes, which limited greenhouse gas bid capacity to the differences between base schedule and energy dispatch, the weighted average greenhouse gas cost increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions.

2.1 Energy imbalance market performance

Energy imbalance market prices

Prices in PacifiCorp East and Idaho Power were often similar to each other and slightly lower than prices in the ISO. As shown in Figure 2.1 and Figure 2.2, price separation between these areas and the ISO was most pronounced during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO hit export limits.

Prices in the region including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex were regularly different than those in the ISO and other energy imbalance market balancing areas because of limited transfer capability into and out of this region. This resulted in local resources setting the price in a combined PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex region during many intervals.

Average prices for NV Energy and Arizona Public Service tracked relatively closely to system prices during most hours except during mid-day hours and evening peak load hours. During hours ending 11 through 16 NV Energy and Arizona Public Service had a number of surplus power balance constraint relaxations after flexible ramping sufficiency test failures leading to price separation between these areas and the ISO. Price separation in the evening peak load hours was largely due to binding export constraints from these areas to the ISO.

Figure 2.1 Hourly 15-minute market prices (January – March)

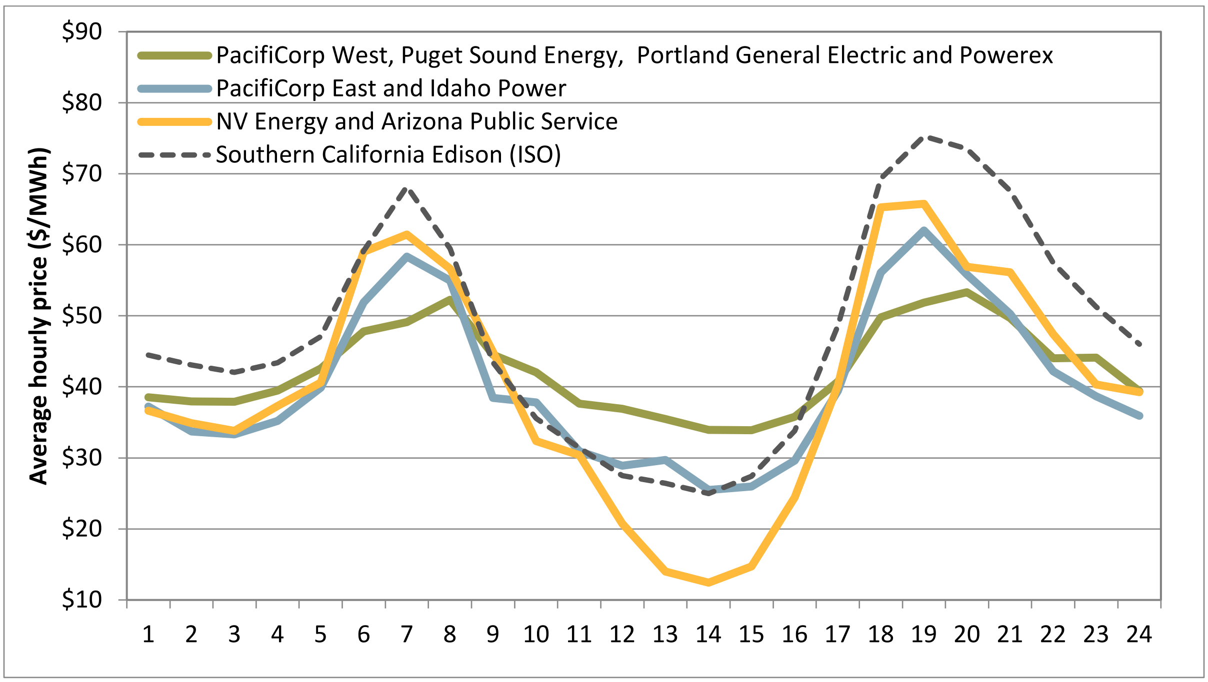
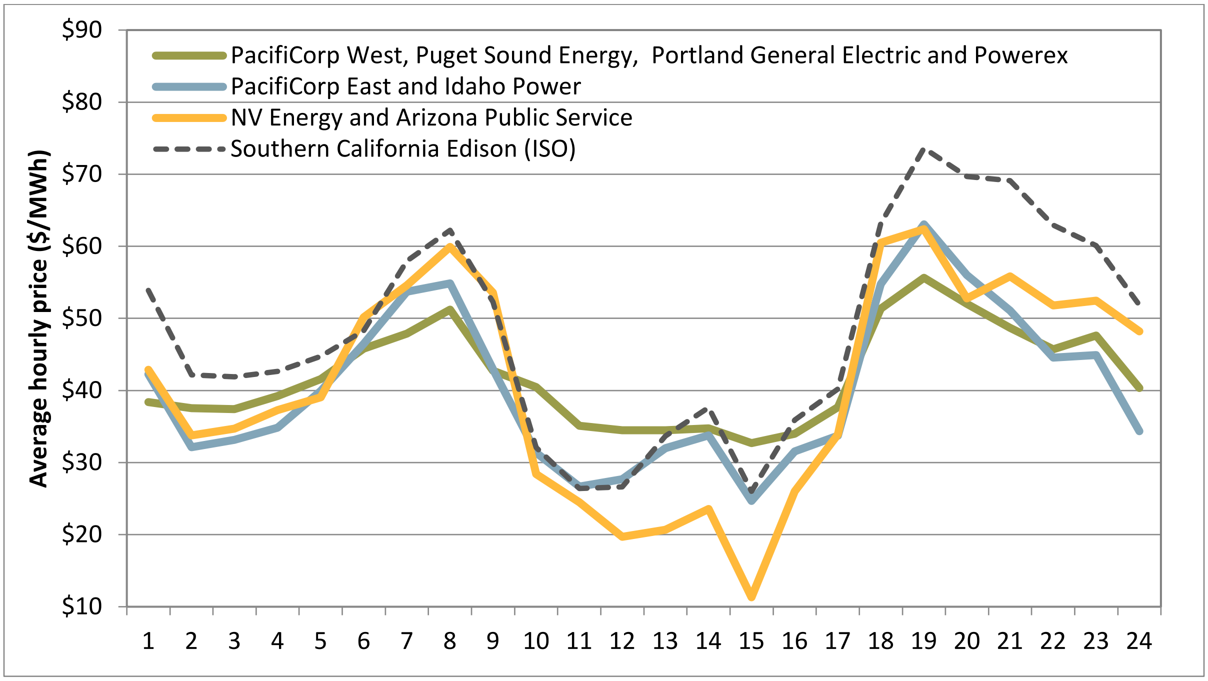


Figure 2.2 Hourly 5-minute market prices (January – March)



Energy imbalance market wholesale energy cost

In the energy imbalance market, total estimated wholesale cost to serve load, excluding the ISO, was about $6 million or $0.10/MWh in the first quarter of 2019, down almost 75 percent from about $16 million or $0.38/MWh in the same quarter in 2018. As shown in Figure 2.3 and Table 2.1, real-time energy costs contributed the largest portion of the costs, while imbalance offset costs typically reduced costs overall. Real-time energy costs per megawatt-hour of total load decreased by about 14 percent from the same quarter in 2018, while imbalance offset costs increased over 90 percent from the same quarter in the previous year. In the energy imbalance market, offset costs paid to non-California balancing areas include payments to offset greenhouse gas cap-and-trade obligations incurred due to market dispatch. Other costs typically make up a small portion of the total, and decreased by about 40 percent from the same quarter in 2018.

Figure 2.3 Total EIM quarterly wholesale costs per MWh of load

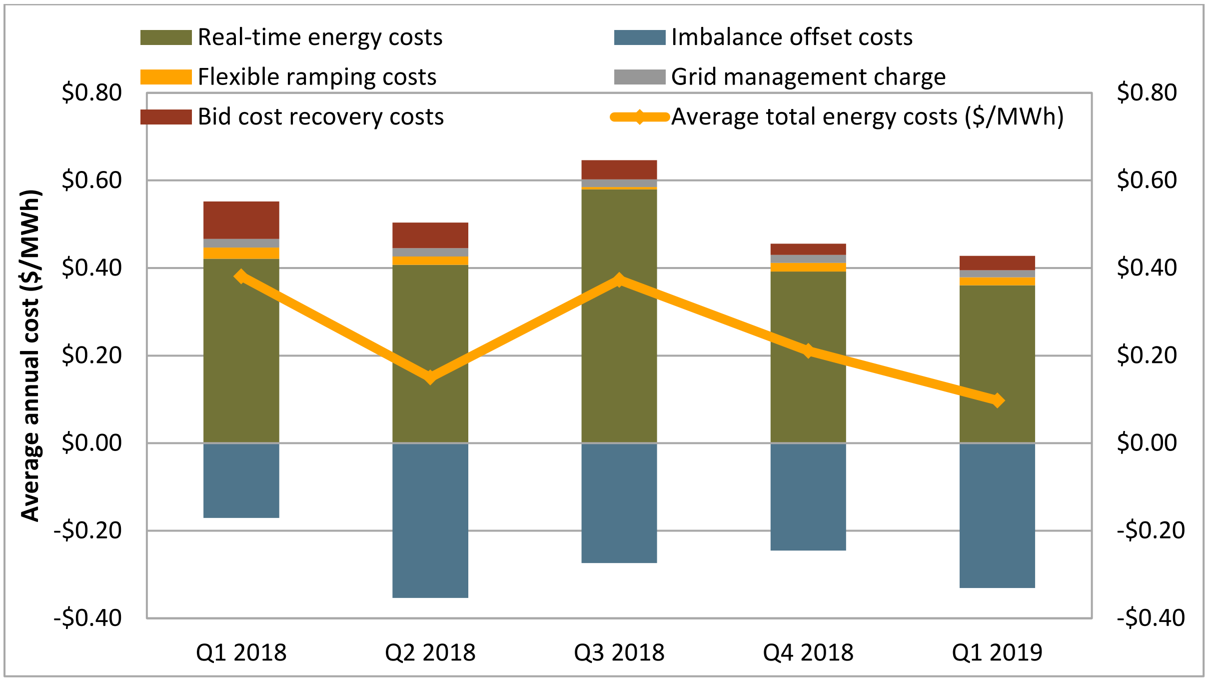


Table 2.1 Estimated average EIM wholesale energy costs per MWh

	Q1 2018	Q2 2018	Q3 2018	Q4 2018	Q1 2019	Change Q1 2018- Q1 2019
Real-time energy costs	$ 0.42	$ 0.41	$ 0.58	$ 0.39	$ 0.36	$ (0.06)
Imbalance offset costs	$ (0.17)	$ (0.35)	$ (0.27)	$ (0.25)	$ (0.33)	$ (0.16)
Flexible ramping costs	$ 0.03	$ 0.02	$ 0.00	$ 0.02	$ 0.02	$ (0.01)
Grid management charge	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ (0.00)
Bid cost recovery costs	$ 0.09	$ 0.06	$ 0.04	$ 0.03	$ 0.03	$ (0.05)
Average total energy costs ($/MWh)	**$ 0.38**	**$ 0.15**	**$ 0.37**	**$ 0.21**	**$ 0.10**	**$ (0.28)**

2.2 Flexible ramping sufficiency test

The flexible ramping sufficiency test ensures that each balancing area has enough ramping resources over an hour to meet expected upward and downward ramping needs. The test is designed to ensure that each energy imbalance market area, including the ISO area, has sufficient ramping capacity to meet real-time market requirements without relying on transfers from other balancing areas. This test is performed prior to each operating hour.

If an area fails the upward sufficiency test, energy imbalance market transfers into that area cannot be increased.[25] 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 for any hour when the capacity test fails for the specific direction. The capacity test is a test designed to ensure that there are sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.[26]

Figure 2.4 shows the monthly frequency with which an energy imbalance market area failed the sufficiency test in the upward direction. Most notably, Arizona Public Service failed the upward sufficiency test during around 4 percent of hours in the first quarter.

Figure 2.5 provides the same information on failed sufficiency tests for the downward direction. In particular, NV Energy failed the downward sufficiency test frequently in February, during almost 24 percent of hours during the quarter.

Failures of the sufficiency test are important because these outcomes limit transfer capability. Constraining transfer capability may impact the efficiency of the energy imbalance market by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas. Reduced transfer capability also impacts 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.

The ISO implemented multiple enhancements to the flexible ramping sufficiency test during 2019. First, a tolerance threshold was implemented effective February 15, 2019, that allows an energy imbalance market entity to pass the test if the insufficiency is less than either of 1 MW or 1 percent of the requirement.[27] A second enhancement, implemented on May 6, 2019, evaluates sufficiency test results and limits transfers on a 15-minute interval basis rather than for the entire hour.

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

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

27 Market Notice - EIM Resource Sufficiency Enhancements 1% Threshold Implementation, February 8, 2019: http://www.caiso.com/Documents/EIMResourceSufficiencyEnhancements-1-ThresholdImplementation-021519-Active-MAPStage.html

Figure 2.4 Frequency of upward failed sufficiency tests by month

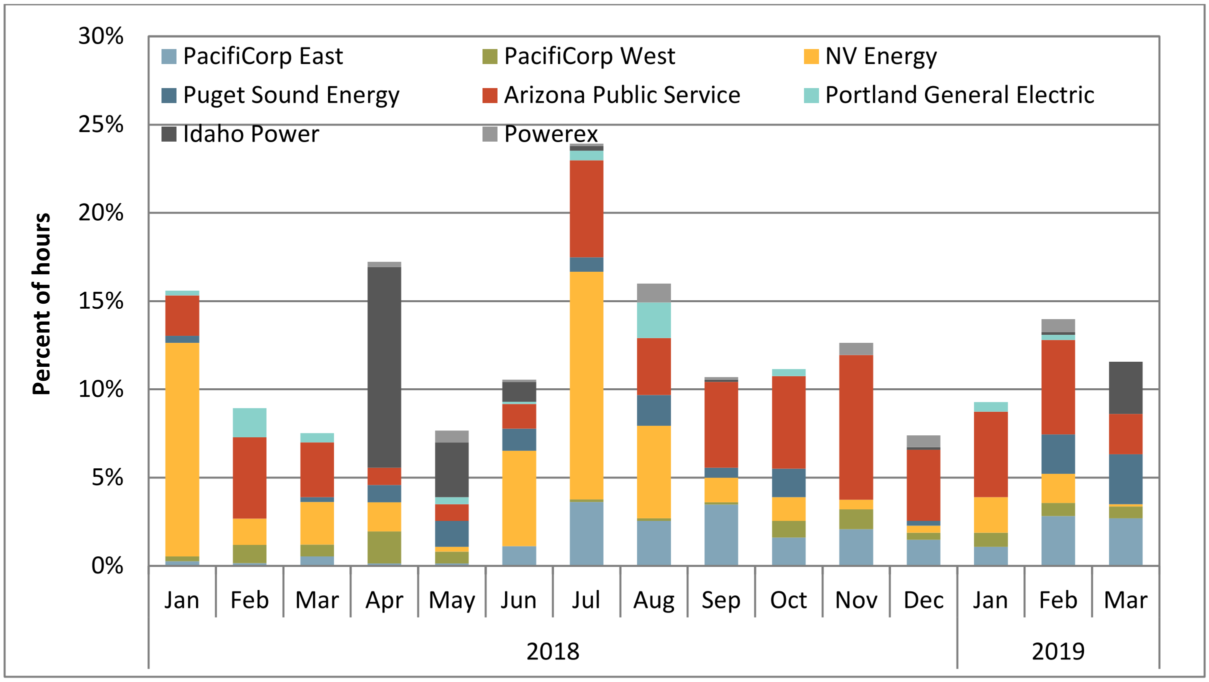
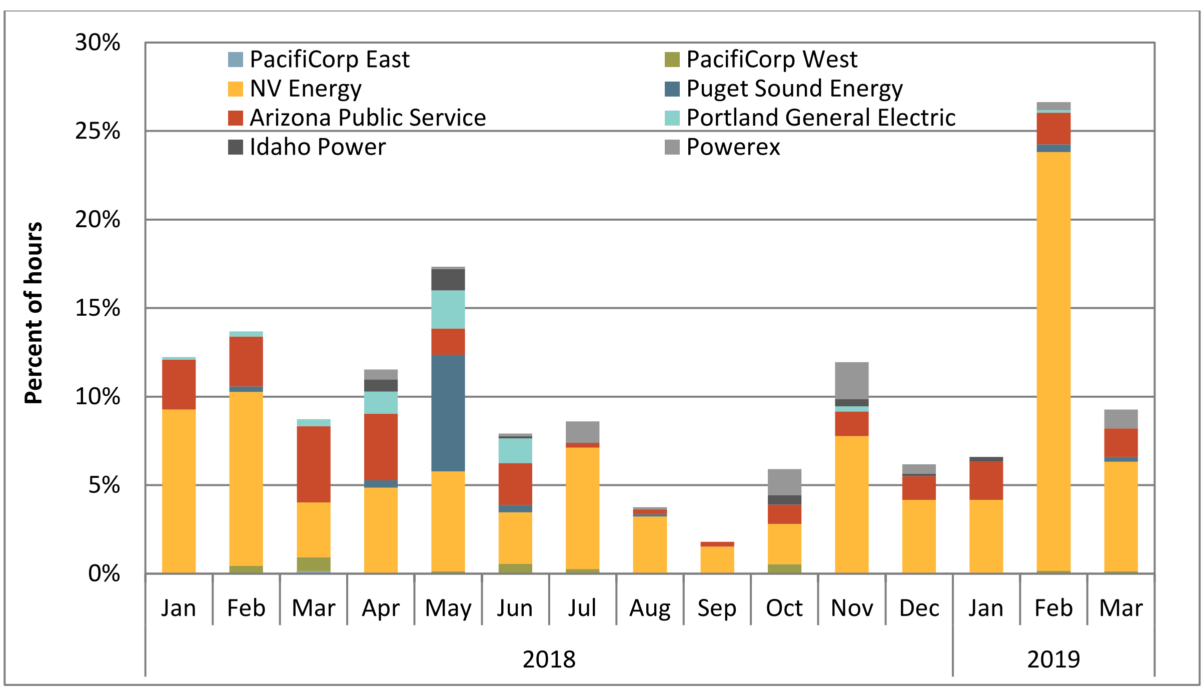


Figure 2.5 Frequency of downward failed sufficiency tests by month

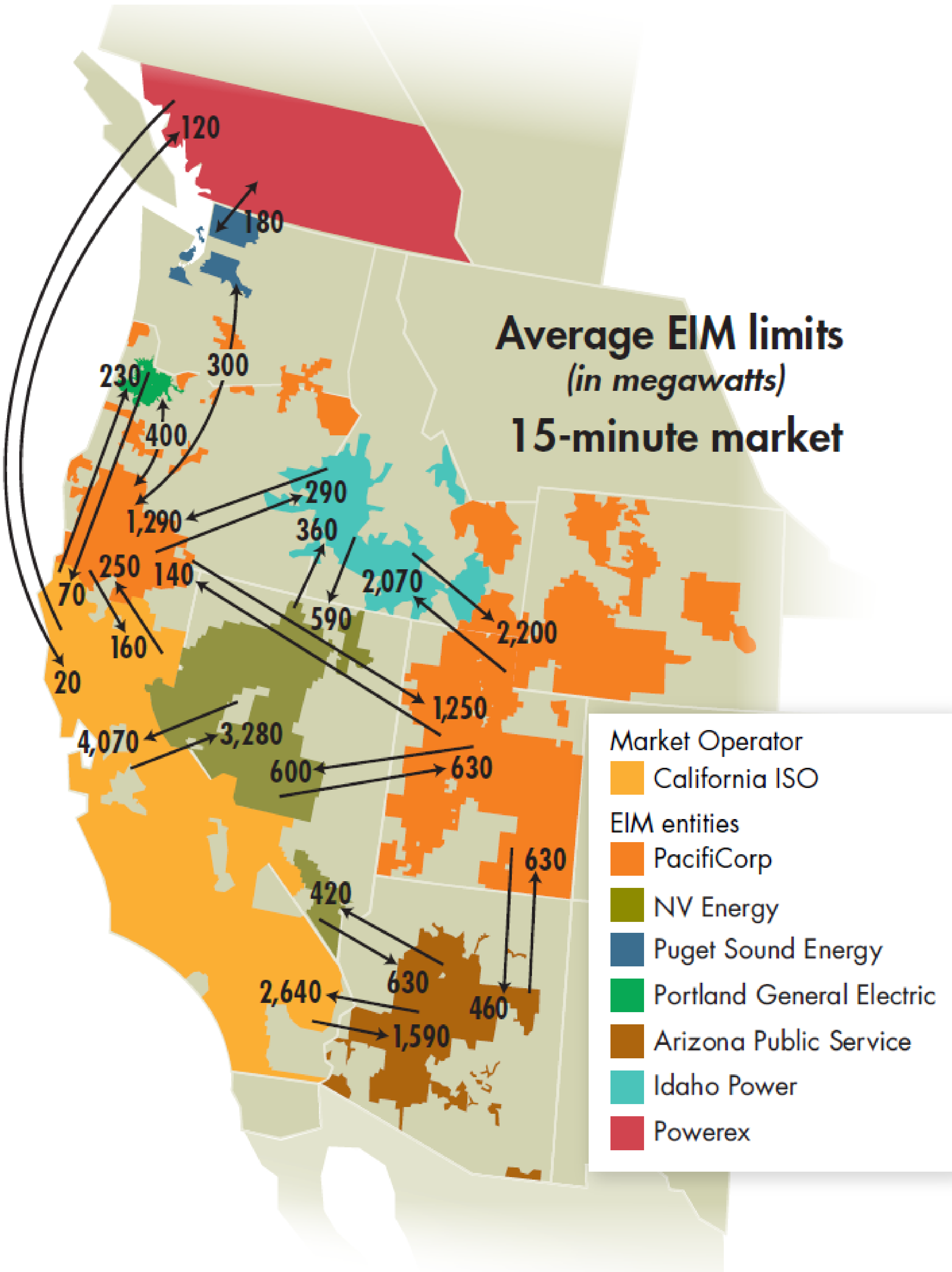


2.3 Energy imbalance market transfers

Energy imbalance market transfer limits

One of the key benefits of the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Figure 2.6 shows average 15-minute market limits between each of the energy imbalance market areas during the first quarter. The map shows that there was significant transfer capability between the ISO, NV Energy, and Arizona Public Service. 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 includes PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex. In particular, the average 15-minute market limit from Powerex toward the ISO was around 20 MW during the first quarter.

Figure 2.6 Average 15-minute market energy imbalance market limits (January – March)



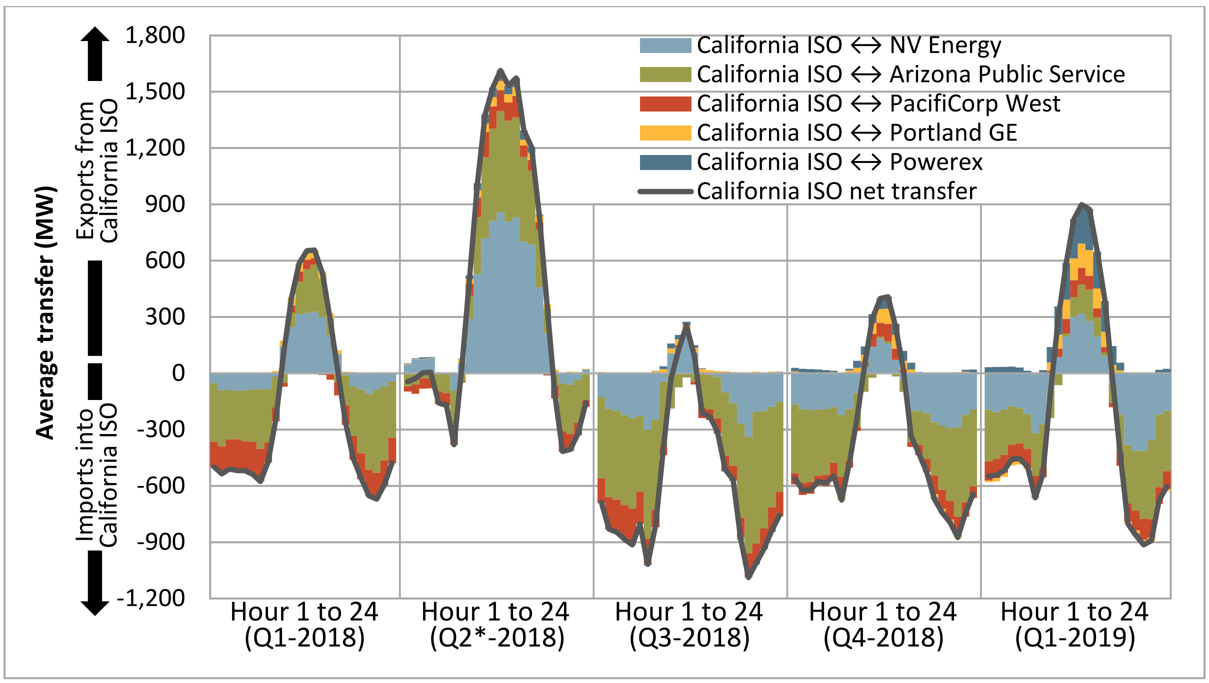
Hourly energy imbalance market transfers

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

Figure 2.7 compares average hourly imports (negative values) and exports (positive values) between the ISO and other energy imbalance market areas during the last five quarters in the 15-minute market. 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 2019, average exports during the middle of the day from the ISO were higher overall compared to both the previous quarter and the first quarter of the previous year. In particular, exports from the ISO towards energy imbalance areas in the Northwest increased from the previous year.

Figure 2.7 California ISO - average hourly 15-minute market transfer



*April 4 to June 30, 2018

Figure 2.8 through Figure 2.12 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, and Powerex in the 15-minute market.[28] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[29]

As shown in Figure 2.7, a large portion of the ISO's transfer capability in the energy imbalance market is with NV Energy and Arizona Public Service. Per Figure 2.8 and Figure 2.9, NV Energy and Arizona Public

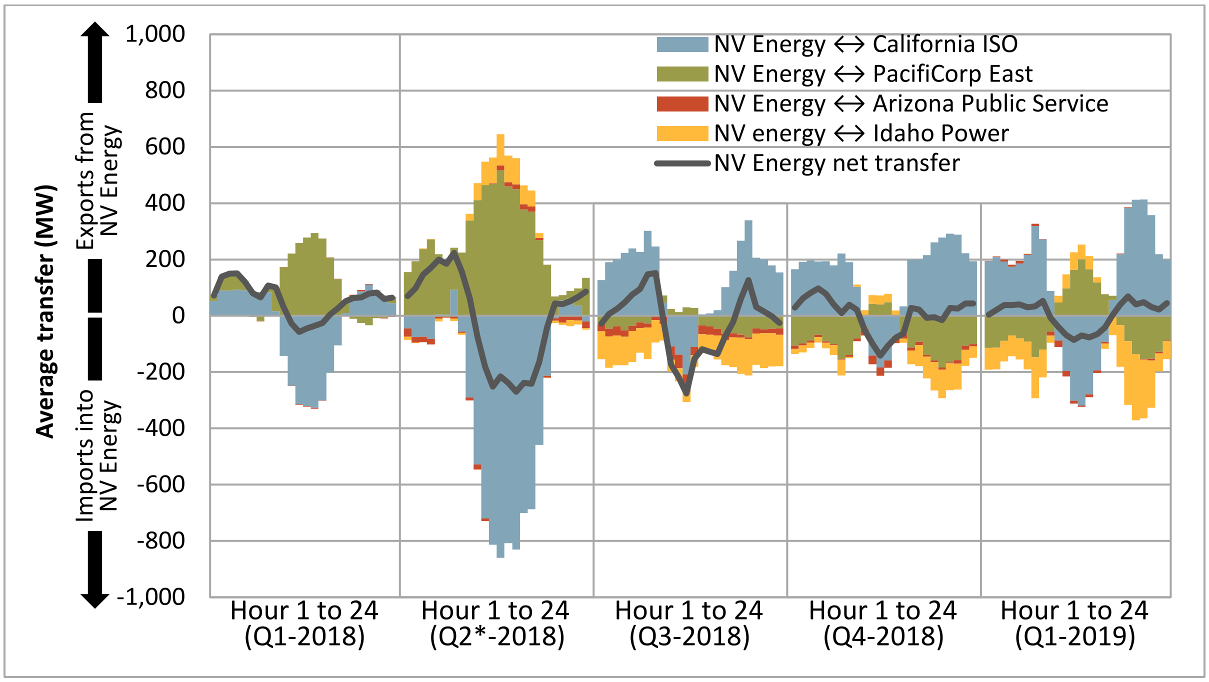
28 Figures showing transfer information from the perspective of PacifiCorp East, Puget Sound Energy and Portland General Electric are not explicitly included, but are represented in Figure 2.7 through Figure 2.12.

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

Service were generally net importers during periods when ISO load net of solar generation was lowest and net exporters during other periods.

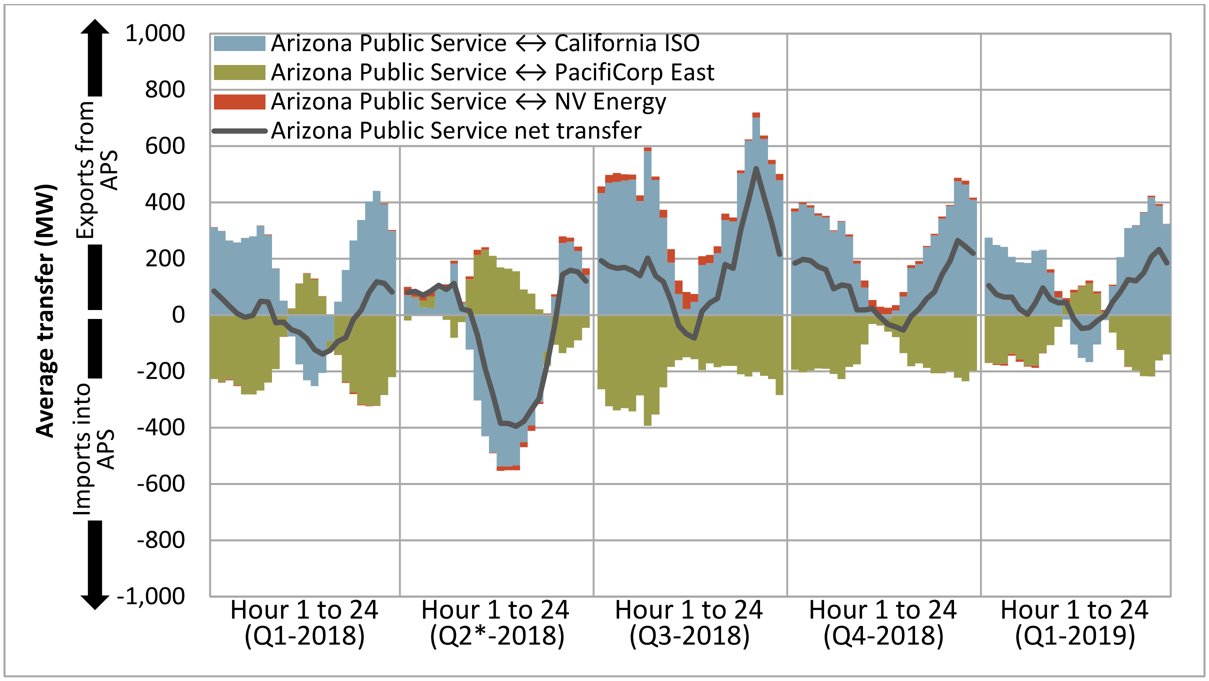
Figure 2.10 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas, net of all base schedules. Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, and NV Energy. On average during the first quarter, Idaho Power base scheduled around 1,200 MW in imports from PacifiCorp East and 900 MW in exports to PacifiCorp West. However, as shown in Figure 2.10, dynamic transfers were significantly lower in all hours during the quarter.

Figure 2.8 NV Energy – average hourly 15-minute market transfer



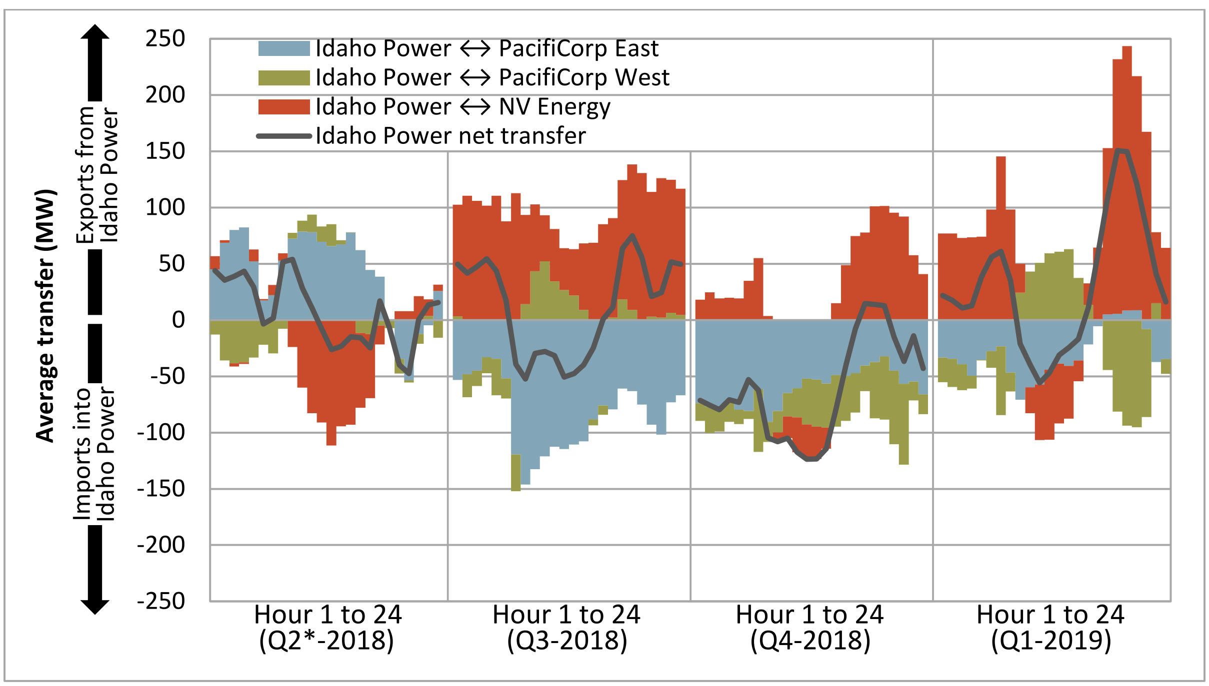
*April 4 to June 30, 2018

Figure 2.9 Arizona Public Service – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Figure 2.10 Idaho Power – average hourly 15-minute market transfer

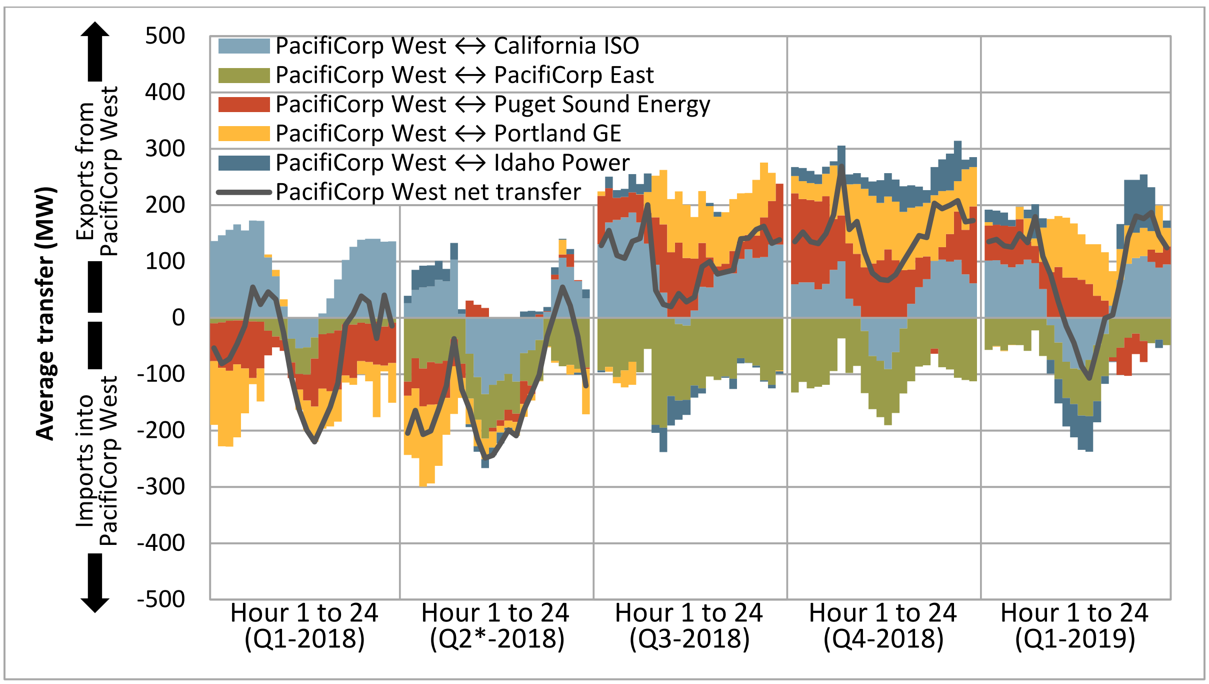


*April 4 to June 30, 2018

Figure 2.11 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the last five quarters. PacifiCorp West has transfer capacity between the ISO, PacifiCorp East, Puget Sound Energy, Portland General Electric, and Idaho Power. Similar to previous quarters, most of the transfers with Idaho Power and PacifiCorp East were base scheduled in the market, so therefore fixed. PacifiCorp West base scheduled roughly 1,260 MW in exports to PacifiCorp East on average during the first quarter. However, net of all base schedules, PacifiCorp West imported around 60 MW on average from PacifiCorp East.

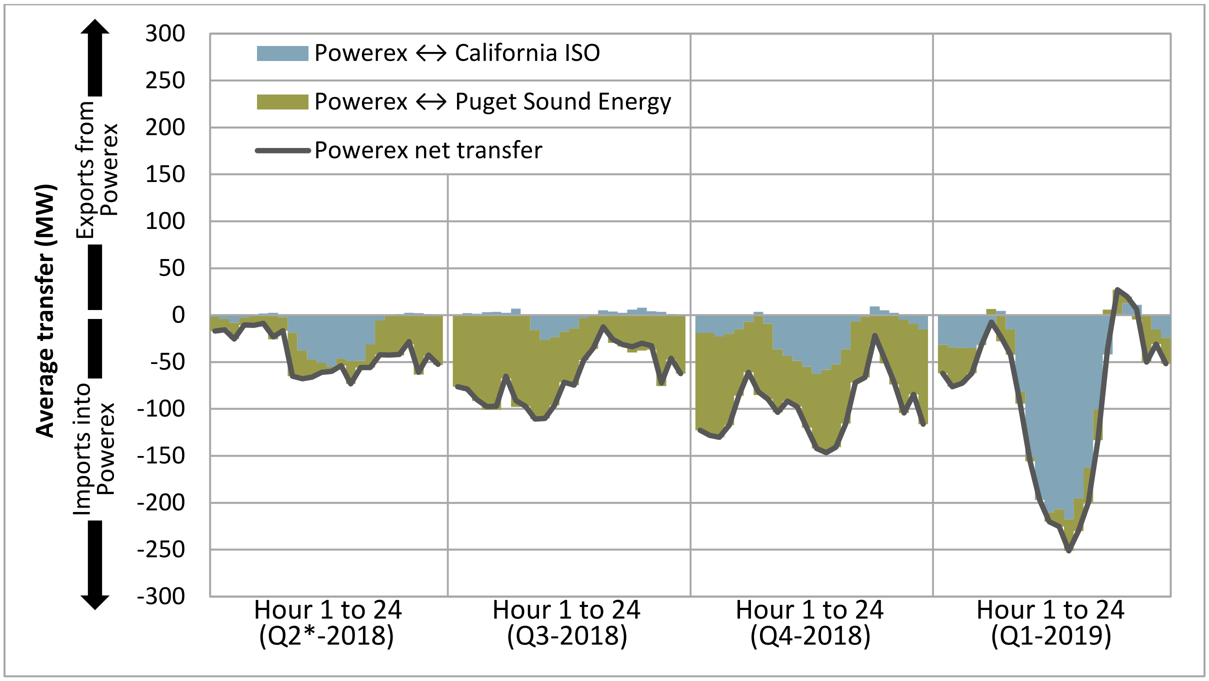
Figure 2.12 shows average hourly 15-minute market imports and exports into and out of Powerex. During the first quarter of 2019, export transmission capacity from Powerex toward the ISO continued to be limited in the 15-minute market, at an average of around 20 MW. However, average import limits into the Powerex area from the ISO increased significantly during the quarter, particularly during the middle of the day. During March, average 15-minute market import limits into Powerex from the ISO were roughly 400 MW in midday hours.

Figure 2.11 PacifiCorp West – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Figure 2.12 Powerex – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Inter-balancing area congestion

Congestion between an energy imbalance market area and the ISO causes price separation.

Table 2.2 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, relative to prevailing system prices in the ISO.[30]

During intervals when there is net import congestion into an energy imbalance market area, the ISO market software triggers local market power mitigation in that area.[31] Table 2.2 includes the frequency in which transfer limits bound from the ISO into the other balancing areas. For example, the highest frequency of such congestion was from the ISO into the Powerex area, during 32 percent of 15-minute market intervals during the first quarter.

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

[31] 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.

Table 2.2 Frequency of congestion in the energy imbalance market (January – March)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
NV Energy	8%	1%	6%	1%
Arizona Public Service	2%	3%	2%	2%
PacifiCorp East	4%	3%	3%	2%
Idaho Power	2%	4%	1%	6%
PacifiCorp West	23%	8%	14%	11%
Portland General Electric	24%	8%	14%	11%
Puget Sound Energy	25%	14%	16%	16%
Powerex	31%	32%	17%	36%

As shown in the table, the highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas in the direction toward the ISO. Congestion in the 15-minute market in the direction toward the ISO occurred during 31 percent of intervals from Powerex and around 24 percent of intervals from PacifiCorp West, Portland General Electric and Puget Sound Energy. This primarily occurred during peak load hours and led to lower prices in these areas relative to the rest of the energy imbalance market and the ISO.

However, the Northwest region was less frequently congested in comparison to the first quarter of the previous year when congestion toward the ISO from areas in this region occurred in around 62 percent of intervals. The difference was mostly due to added transfer capability in the second quarter of 2018 both with the joining of Idaho Power and Powerex as well as the addition of new direct transfer capability from PacifiCorp West to PacifiCorp East.

Table 2.2 also shows that congestion in either direction between 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 Load adjustments in the energy imbalance market

Frequency and size of load adjustments

Table 2.3 summarizes the average frequency and size of positive and negative load adjustments entered by operators in the energy imbalance market for the 15-minute and 5-minute markets during the first quarter.[32] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive load adjustments in around 91 percent of 15-minute and 5-minute intervals, at an average of around 120 MW (or around 4 percent of the area's load). Also, nearly all energy imbalance

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

market entities had a greater frequency of positive 5-minute market load adjustments than 15-minute market load adjustments during the first quarter.

Table 2.3 Average frequency and size of load adjustments (January - March)

	Positive load adjustments			Negative load adjustments			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	58%	551	2.3%	1%	-298	1.4%	316
5-minute market	69%	304	1.3%	8%	-239	1.1%	190
PacifiCorp East							
15-minute market	0.2%	172	2.9%	3%	-61	1.2%	-2
5-minute market	7%	66	1.2%	22%	-81	1.6%	-14
PacifiCorp West							
15-minute market	0.3%	50	1.9%	0.3%	-53	2.0%	0
5-minute market	2%	59	2.3%	7%	-46	1.8%	-2
NV Energy							
15-minute market	0.4%	96	2.4%	0.2%	-100	2.9%	0
5-minute market	5%	68	1.7%	15%	-93	2.7%	-11
Puget Sound Energy							
15-minute market	0.2%	38	1.0%	9%	-47	1.6%	-4
5-minute market	1%	34	1.0%	57%	-46	1.5%	-26
Arizona Public Service							
15-minute market	91%	122	4.2%	3%	-85	3.4%	109
5-minute market	91%	122	4.2%	3%	-84	3.5%	108
Portland General Electric							
15-minute market	0.4%	45	1.5%	0%	N/A	N/A	0
5-minute market	22%	27	1.1%	3%	-38	1.4%	5
Idaho Power							
15-minute market	0.2%	56	2.8%	0.1%	-83	4.7%	0
5-minute market	7%	49	2.8%	10%	-57	3.3%	-2

Load conformance limiter enhancement

The load conformance limiter works the same way in the energy imbalance market as it does in the ISO. It reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. Previously, if the operator load adjustment exceeded the size of a power balance constraint and in the same direction, the size of the adjustment was automatically reduced and the price was set by the last economic signal rather than the penalty parameter for the relaxation, for instance the $1,000/MWh price for a shortage. However, there have been instances in which the application of this logic did not appear to reflect actual conditions such as periods when a persistent load conformance across multiple intervals would resolve smaller infeasibilities that did not appear to be caused by the level of load adjustment.

The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than the total level of load adjustment. DMM's monitoring and review of real-time market performance suggests that the enhanced logic for the load conformance limiter is likely to better capture the cause-and-effect relationship between an excessive operator adjustment and an infeasibility. Previous analysis by DMM showed that this change is expected to significantly reduce the frequency in which the limiter triggers.[33]

Figure 2.13 shows the frequency of infeasibilities in the 5-minute market during March in which the current (enhanced) conformance limiter triggered and/or the previous limiter would have triggered.[34] The green bars represent intervals when the current limiter did not trigger, but would have under the previous approach. For intervals with ramping shortages in this category, the current approach increases prices relative to the previous method since prices would have been set by an economic bid under the previous approach, but were instead set by the $1,000/MWh penalty parameter. There were no intervals during March when the current limiter triggered, but would not have under the previous approach (red bars).

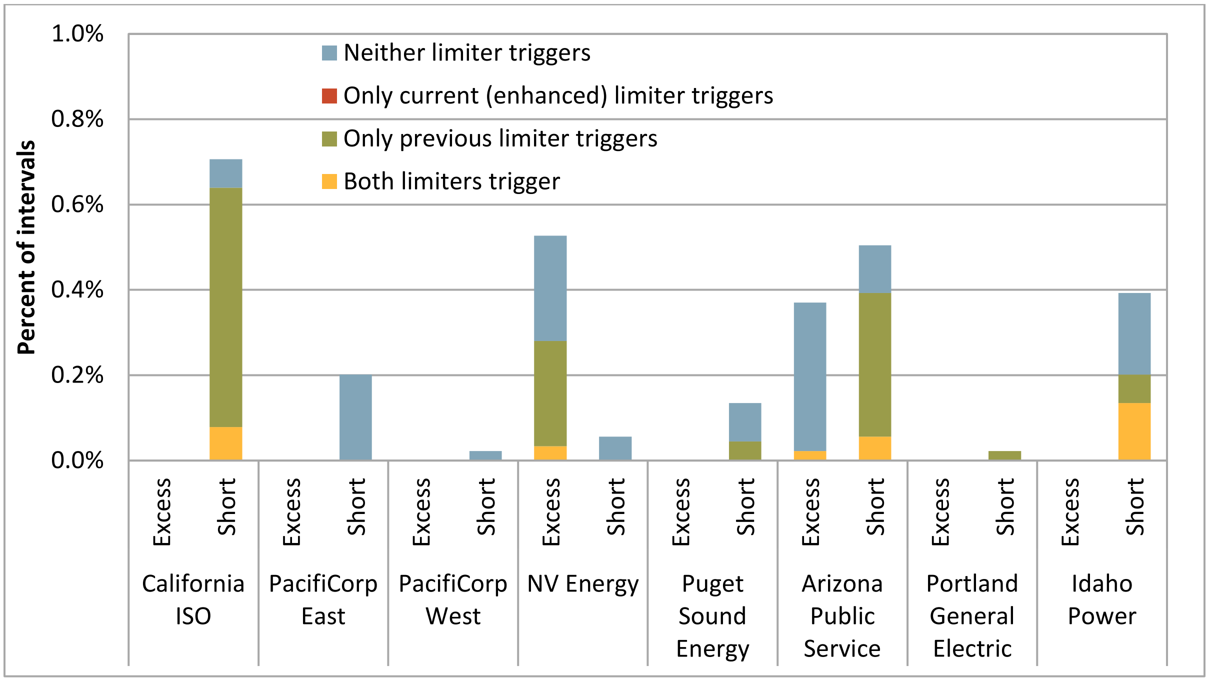
Under current market conditions, the enhancement to the conformance limiter is not expected to have a significant impact on average prices in the ISO. This is because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often very similar with or without the limiter.

However, the changes to the conformance limiter can have a significant impact on prices for some of the energy imbalance market areas. As shown in Figure 2.13, the enhancement significantly reduced the frequency in which the conformance limiter triggered for under-supply conditions for Arizona Public Service during March. Analysis by DMM for 2018 showed that if the enhanced limiter had been in effect for all of 2018, average prices in the Arizona Public Service area would have been higher by roughly $4/MWh (10 percent) in the 15-minute market and $5/MWh (13 percent) in the 5-minute market. A reduction in the frequency of prices set under the conformance limiter increases the frequency of prices set at the higher penalty price.

33 *EIM power balance constraint relaxation and imbalance conformance limiter*, Department of Market Monitoring, January 18, 2019. http://www.caiso.com/Documents/EIMpowerbalanceconstraintrelaxationandimbalanceconformancelimiter.pdf

34 In the figure, intervals when the power balance constraint needed to be relaxed due to excess supply are labeled *Excess*. Intervals when the power balance constraint needed to be relaxed due to a shortage of upward ramping capability are labeled *Short*.

Figure 2.13 Frequency of load conformance limiter in the 5-minute market (March 2019)



2.5 Greenhouse gas in the energy imbalance market

Background

Under the current energy imbalance market design, all energy transferred into the ISO to serve ISO load through an energy imbalance market transfer is subject to California's cap-and-trade regulation.[35] Under the energy imbalance market design, a participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving ISO load. The energy imbalance market optimization minimizes costs of serving load in both the ISO and energy imbalance market taking into account greenhouse gas compliance cost for all energy deemed delivered to California. The energy imbalance market 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 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.

35 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.

As of November 2018, the ISO implemented a new 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 ISO load for compliance with California's cap-and-trade regulation.[36] The amount of capacity that can be deemed delivered to California will now be limited to the upper economic bid limit of a resource minus the resource's base schedule. Since the policy change in November, there have been notable changes in the greenhouse gas price in the energy imbalance market discussed below.

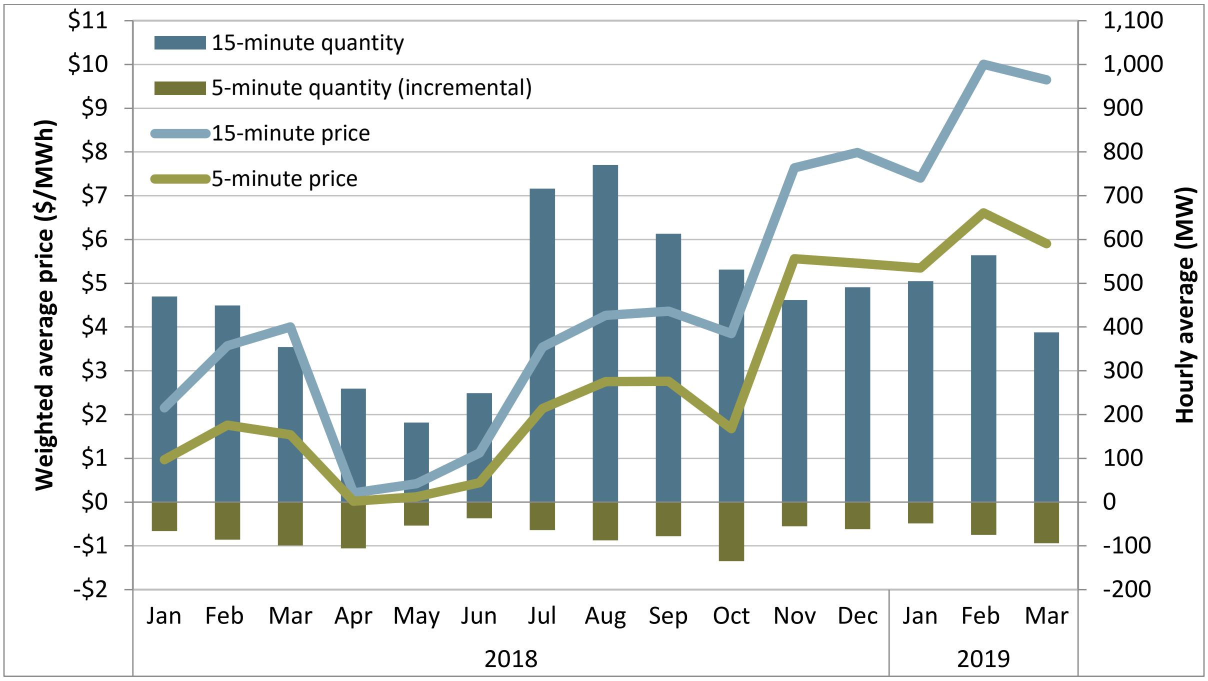
Greenhouse gas prices

Figure 2.14 shows monthly average cleared energy imbalance market greenhouse gas prices and hourly average quantities for transfers serving ISO load settled in the energy imbalance market in the first quarter of 2019. Weighted average prices are calculated using 15-minute deemed delivered megawatts as weights in the 15-minute market and the absolute value of incremental 5-minute greenhouse gas dispatch in the 5-minute market. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

Weighted 15-minute greenhouse gas prices averaged around $9/MWh for each month of the first quarter while 5-minute prices averaged around $6/MWh. Prior to the policy change in November 2018, monthly greenhouse gas prices from January to October averaged around $2.75/MWh in the 15-minute market and $1.40/MWh in the 5-minute market. The increase in greenhouse gas prices was due in part to higher emitting resources setting the price which was, in turn, likely the result of policy changes limiting the energy imbalance market capacity that can be deemed delivered to California as the upper economic bid limit of a resource minus their base schedule. Additionally, there was a notable increase in the market clearing price of the California Air Resources Board quarterly auction for emission allowances that may also have contributed to the increase in the energy imbalance market greenhouse gas price.

[36] Further information on the Energy Imbalance Market Greenhouse Gas Enhancements proposal can be found here: http://www.caiso.com/Documents/ThirdRevisedDraftFinalProposal-EnergyImbalanceMarketGreenhouseGasEnhancements.pdf

Figure 2.14 Energy imbalance market greenhouse gas price and cleared quantity

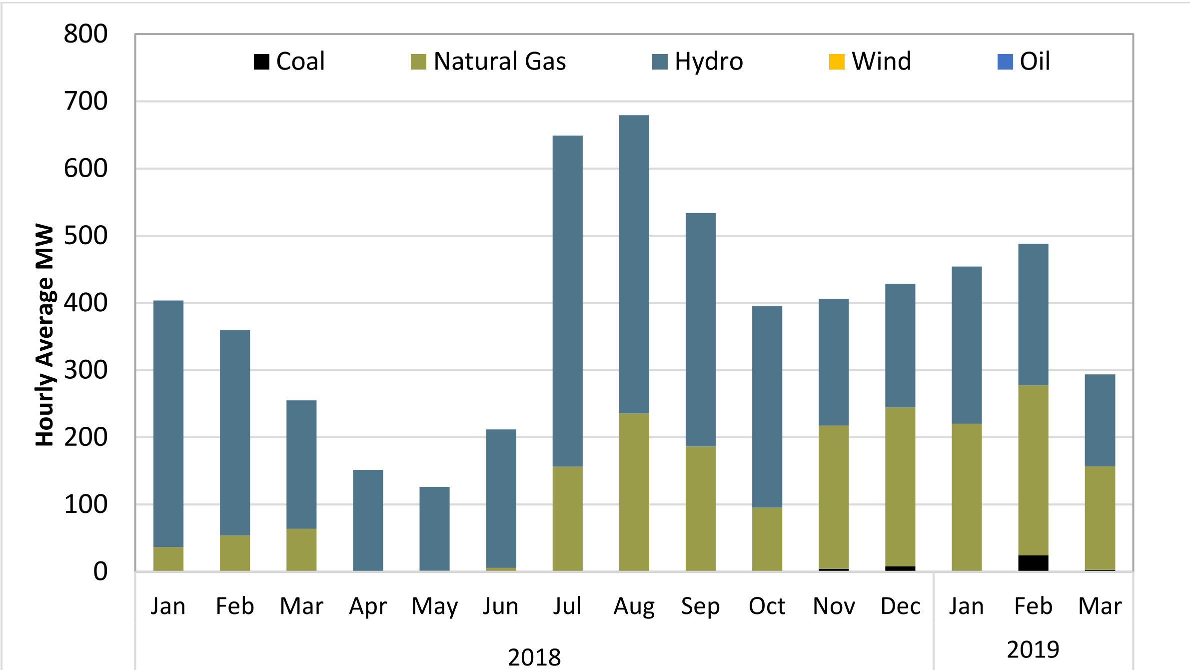


DMM estimates the total profit accruing for greenhouse gas bids attributed to energy imbalance market participating resources serving ISO load by subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $5.3 million in the first quarter, compared to roughly $2.1 million in the first quarter of the previous year.

Energy transfers to California by fuel type and balancing area

Figure 2.15 shows the hourly average energy deemed delivered to California by fuel type in the first quarter. About 51 percent of energy imbalance market greenhouse gas compliance obligations were assigned to gas resources, a sharp increase from 15 percent in the first quarter of the previous year. Hydroelectric resources accounted for about 47 percent of total energy deliveries to California which decreased from around 85 percent in the first quarter of 2018. Additionally, energy deliveries originating from coal resources have increased since the policy change, but only accounted for around 2 percent of energy imbalance greenhouse gas compliance obligations in the first quarter.

Figure 2.15 Hourly average EIM greenhouse gas megawatts by fuel type



3 Special issues

This section provides information about the following special issues:

- The ISO enforced total gas burn constraints on the SoCalGas region in both the day-ahead and real-time markets. The nomograms bound infrequently in the day-ahead market and were not binding in the real-time market when enforced. However, based on the shape of these gas burn constraints over different hours of the day when these constraints were enforced in Q1, it does not appear that enhancements have been implemented that address DMM's key recommendations about how to set and adjust the gas constraints.
- If real-time gas prices had been updated to same-day prices, more than 95 percent of the same-day trades at SoCal and PG&E Citygate would have been at or below the 10 percent adder included in default energy bids used in mitigation.
- Without real-time gas price updating, about 87 percent of traded volume was at or below the normal 25 percent adder and 77 percent was at or below the 10 percent adder at SoCal Citygate. Similarly, at PG&E Citygate, about 91 percent was at or below the 25 percent adder and 78 percent of the traded volume was at or below the 10 percent adder.

3.1 Gas burn constraints

On September 28, 2018, the ISO filed tariff amendments to extend Aliso Canyon provisions until December 31, 2019.[37] One of these measures was to have the authority to enforce gas burn constraints (or nomograms) in the ISO energy markets to directly limit gas usage by groups of power plants in the SoCalGas system.

DMM supported temporary extension of the ISO's ability to enforce a maximum gas constraint for groups of units in the SoCalGas system, but continues to recommend that the ISO refine how it utilizes the maximum gas constraint and improve how gas usage constraint limits are set and adjusted in real-time.[38]

In the first quarter of 2019, the ISO enforced gas burn constraints in either the day-ahead or real-time markets on two occasions: February 6 – 8 and February 20. In the day-ahead market, these constraints were binding in about 10 percent of hours during which they were enforced and were not binding when enforced in the real-time market.

Based on the shape of these gas burn constraints over different hours of the day when these constraints were enforced in Q1, it does not appear that enhancements have been implemented that address DMM's key recommendations about how to set and adjust the gas constraints. Specifically, it appears

37 Tariff Amendment - Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), September 28, 2018: http://www.caiso.com/Documents/Sep28-2018-TariffAmendment-AlisoCanyonGas-ElectricCoordination-Phase4-ER18-2520.pdf

38 FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), Department of Market Monitoring, October 19,2018: http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

daily gas use limits still appear to be implemented as constraints on each interval of the ISO markets, with gas use limits for each interval being set by allocating daily use limits based on the shape of total system loads over the day. DMM has recommended setting gas use limits for individual intervals based more on the shape of net loads or actual gas usage over the course of the day. This modification could allow the gas limits to be highest during the ramping hours when gas units are needed most to meet ramping needs.[39]

3.2 Updating natural gas prices in the real-time market

DMM continues to recommend that the ISO develop the ability to adjust gas prices used in the real-time market based on observed prices on ICE the morning of each operating day. This approach would closely align the gas price used in the real-time market with the actual costs for gas purchased in the same-day gas market.[40]

Figure 3.1 and Figure 3.2 show Intercontinental Exchange (ICE) same-day natural gas trade prices at SoCal Citygate and PG&E Citygate compared to the next-day average price in the first quarter of 2019, respectively. At SoCal Citygate, about 13 percent of traded volume exceeded the normal 25 percent adder and an additional 10 percent of the traded volume exceeded the 10 percent adder. Similarly, at PG&E Citygate, about 9 percent exceeded the 25 percent adder and an additional 13 percent of the traded volume exceeded the 10 percent adder. Prices during February 2019 were extremely volatile at both PG&E and SoCal Citygate gas hubs. Main drivers include higher heating demand due to colder-than-normal temperatures, supply constraints and low operational flow order penalties. Refer to Section 1.1 for more detailed information on natural gas prices.

These figures further show that a significant portion of same-day traded volume that was more than 10 percent higher than the next-day average occurred on the first trade day of the week. These trades are represented by the green bars. Same-day trades for the first trade day of the week (which is typically a Monday, unless the Monday is a holiday) are more likely to exceed the next-day average because, in the next-day market, the first day of the week is traded as a package together with the weekend. The next-day prices for these weekend packages are typically somewhat lower than for weekdays.

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39 DMM's 2018 Annual Report on Market Issues & Performance, Section 11.4, available here: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

40 *Decision on Commitment costs and default energy bids enhancements proposal,* Department of Market Monitoring board memo, March 2018: http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

Figure 3.1 SoCal Citygate same-day trade prices compared to next-day index (January – March)

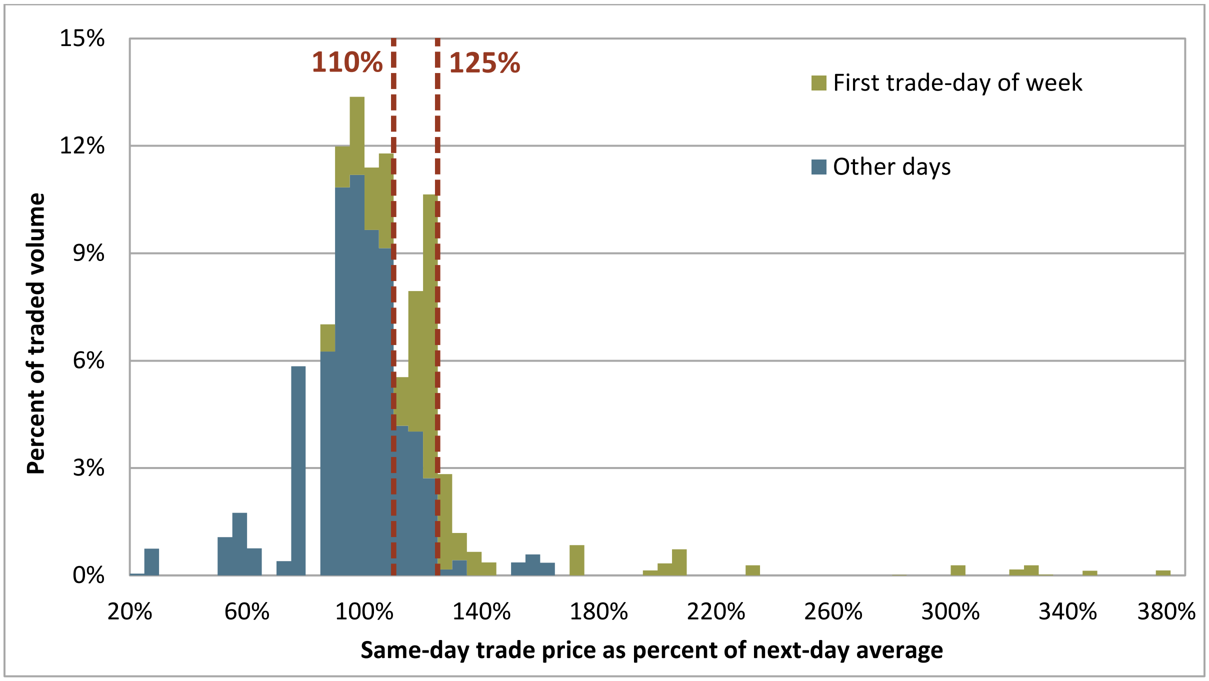


Figure 3.2 PG&E Citygate same-day trade prices compared to next-day index (January – March)

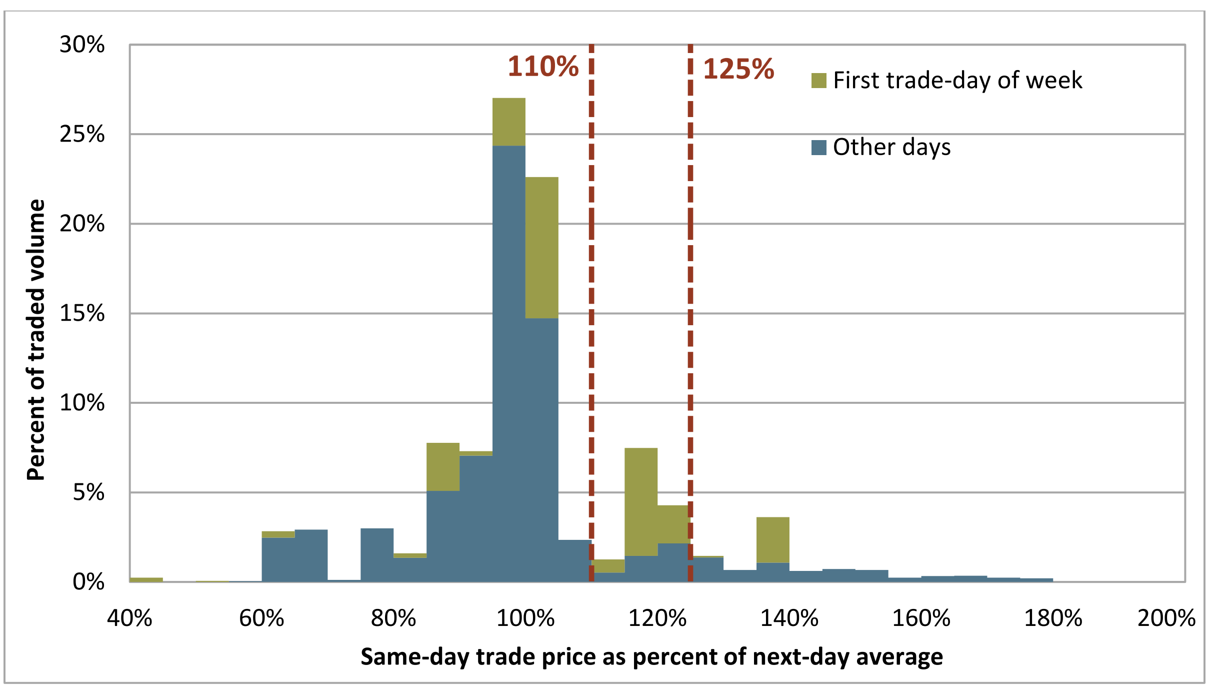


Figure 3.3 and Figure 3.4 compare the price of each same-day trade at SoCal Citygate and PG&E Citygate, respectively, to an updated volume-weighted average price of same-day trades reported on ICE before 8:30 am. This reflects gas prices that would be used for the real-time market under DMM's recommendation.

For the first quarter of 2019, these figures show that if the real-time gas prices were updated using an updated same-day price, more than 95 percent of the same-day trades at SoCal and PG&E Citygate would have been at or below the 10 percent adder included in default energy bids used in mitigation. About 4 percent of the traded volume would have exceeded the 10 percent adder, but still would have been less than the 25 percent adder normally included in commitment cost caps. An insignificant amount of the same-day traded volume would have exceeded the 25 percent adder.

Figure 3.3 SoCal Citygate same-day prices as a percent of updated same-day averages (Jan - Mar)

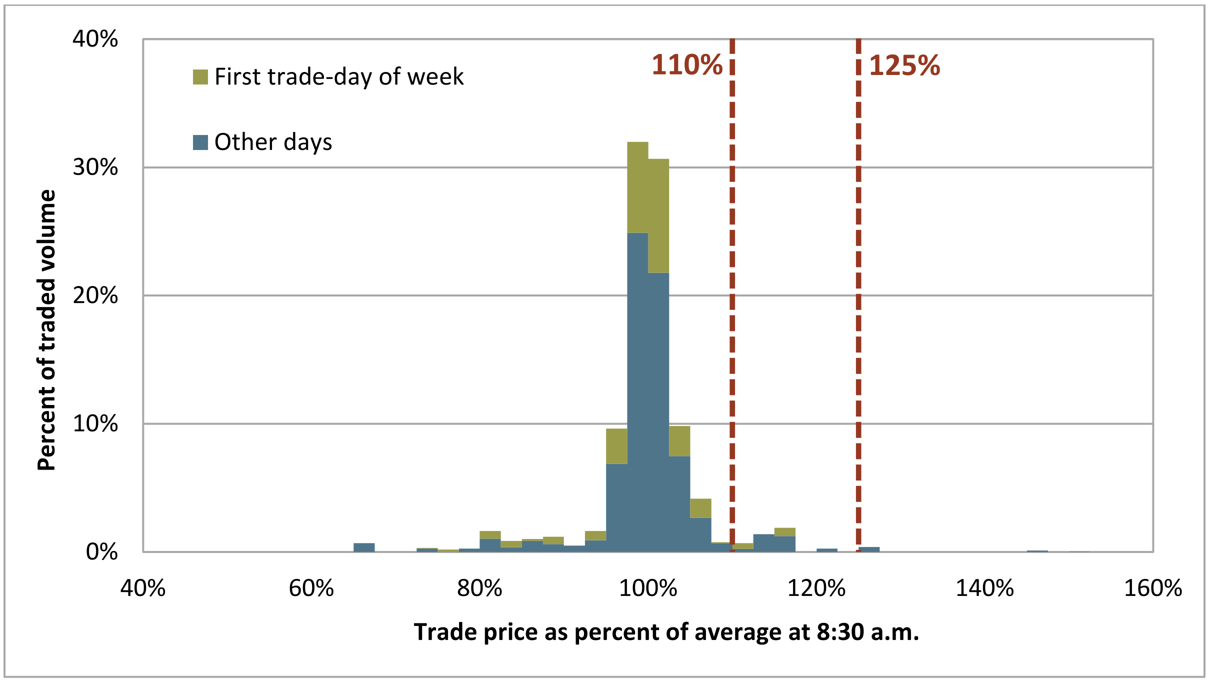
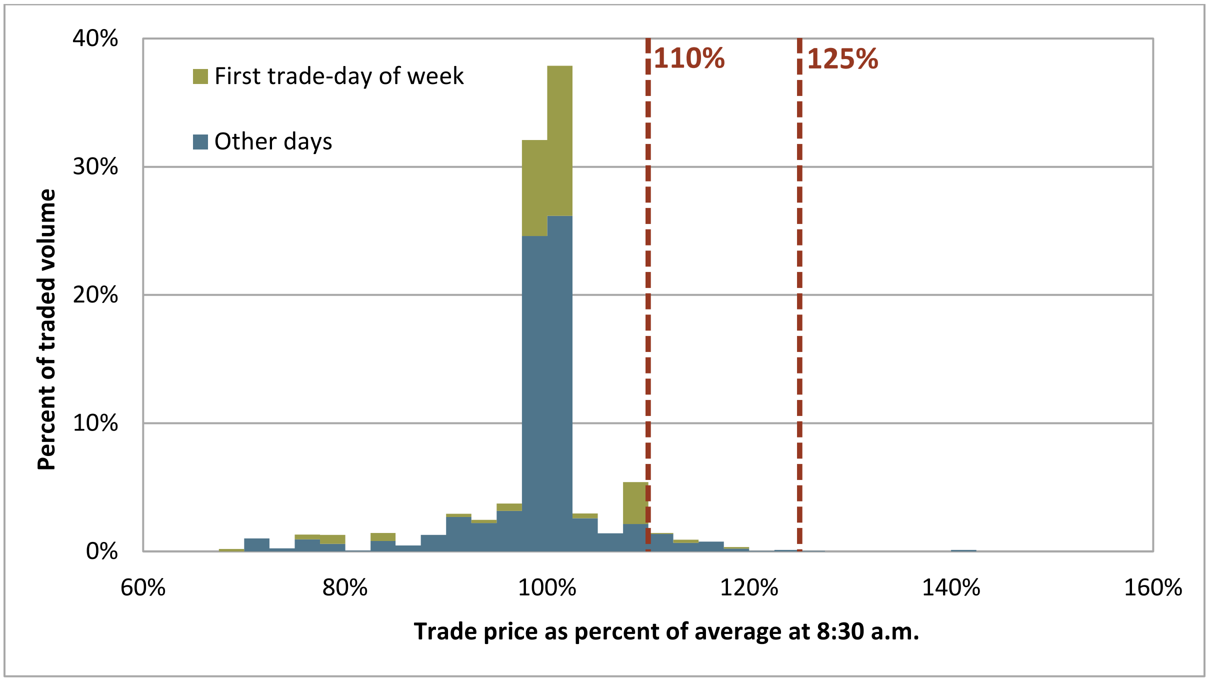


Figure 3.4 PG&E Citygate same-day prices as a percent of updated same-day averages (Jan - Mar)



The ISO did not include DMM's recommendation to update gas prices used in calculating bid caps for the real-time market in the proposed commitment cost and default energy bid enhancement (CCDEBE) that was approved by the ISO Board in May 2018. However, in 2019, the ISO subsequently included provisions to update bid caps using same-day gas prices as part of the local market power mitigation enhancements initiative. Under this revised proposal*, reasonableness thresholds* used to automatically approve generators' requests to increase bid caps will be updated if the same-day gas price for a fuel region exceeds 10 percent of the next-day index for the same gas flow day.[41]

Updated natural gas prices for the day-ahead market

FERC's November 26, 2018, order extended the ISO's authority to use more timely natural gas prices for calculating default energy bids and proxy commitment costs in the day-ahead market through December 31, 2019. Under this extension, the ISO updates the gas price on next-day trades from the morning of the day-ahead market run instead of using indices from the prior day.[42] DMM is very supportive of this change and recommends that this be permanently extended. As part of the

41 Draft final proposal, Local Market Power Mitigation Enhancements, February 1, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

42 This market modification uses weighted average price of next-day trades at SoCal Citygate before 8:30 am from Intercontinental Exchange (ICE). These are next-day trades that occur prior to the ISO beginning the day-ahead market run.

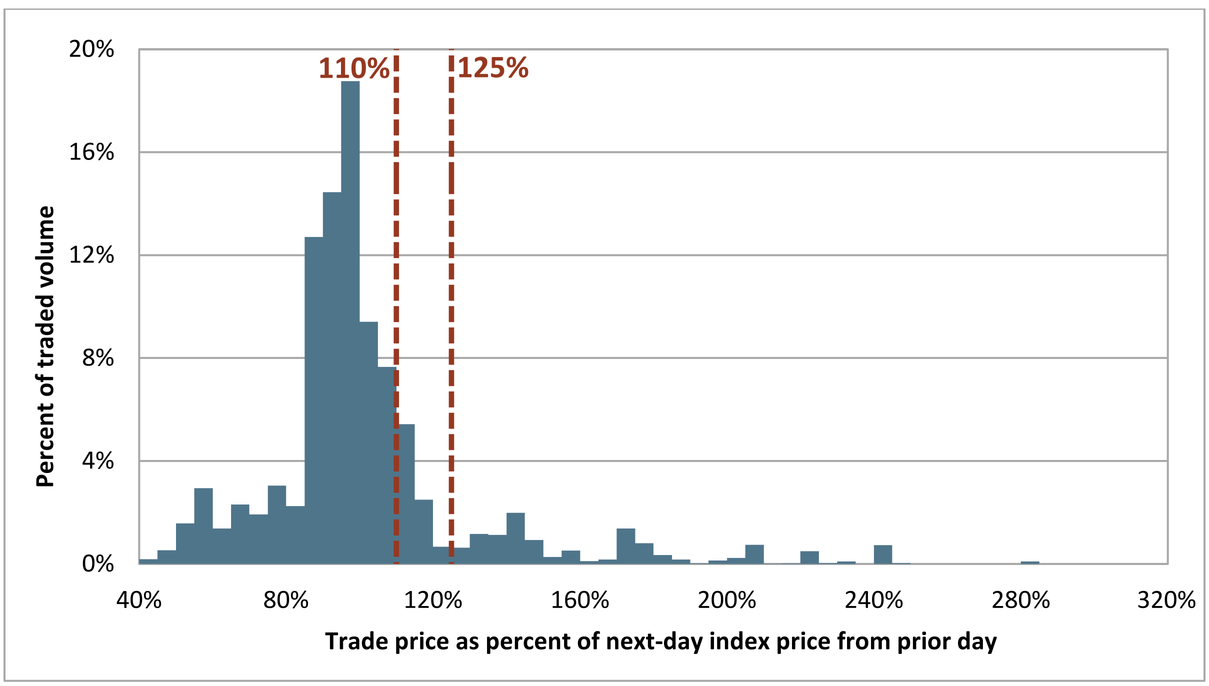
commitment cost and default energy bid enhancements initiative, the ISO has proposed to make this a permanent measure.[43]

As part of the local market power mitigation enhancements initiative, the ISO plans to use updated Monday-only gas price index in the day-ahead market for Mondays only and when available.[44]

Figure 3.5 and Figure 3.6 illustrate the benefit of using the updated natural gas price index in the first quarter of 2019. Figure 3.5 shows next-day trade prices reported on ICE for SoCal Citygate during the first quarter, compared to the next-day price index previously used in the day-ahead market which was lagged by one trade day. As shown in Figure 3.5, about 12 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps. An additional 9 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids.

Figure 3.6 shows the same data but compares the price of each next-day trade to a weighted average price of next-day trades reported on ICE before 8:30 am, just before the ISO runs the day-ahead market. This represents the updated method that the ISO is currently using. As shown in Figure 3.6, about 4 percent of the traded volume exceeded the 10 percent adder included in default energy bids. Only 2 percent of the volume exceeded the 25 percent adder included in the commitment cost caps. This shows that the methodology currently in place is significantly more reflective of next-day trading prices than the methodology that was in place prior to the Aliso measure.

Figure 3.5 Next-day trade prices compared to next-day index from prior day (Jan - Mar)



[43] Second Revised Draft Final Proposal - Commitment Costs and Default Energy Bid Enhancements, March 2018: http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-CommitmentCosts-DefaultEnergyBidEnhancements.pdf

[44] *White paper – Temporary use of gas price index for day-ahead market*, January 11, 2019: http://www.caiso.com/Documents/WhitePaper-TemporaryUse-GasPriceIndex-Day-AheadMarket.pdf

Figure 3.6 Next-day trade prices compared to updated next-day average price (Jan - Mar)