California Independent System Operator Corporation

California ISO

Q2 2018 Report on Market Issues and Performance

August 20, 2018

Department of Market Monitoring

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Executive summary

This report covers market performance during the second quarter of 2018 (April – June). Key highlights during this quarter include the following:

- Average energy prices decreased from the previous quarter, driven by lower gas prices and an increase in hydroelectric and renewable generation.
- During the second quarter of 2018, congestion revenue rights auction revenues were $18 million less than payments made to non-load-serving entities purchasing these financial products in the ISO's auction. This brings total losses to transmission ratepayers from congestion revenue rights sold in the ISO's auction to over $61 million during the first half of 2018.
- Operating reserve requirements increased significantly with the implementation of changes to meet NERC reliability standards (BAL-002-2) on January 1, 2018. These changes resulted in substantial increases in the requirements particularly during off-peak periods.
- The number of intervals with ancillary service scarcity pricing in the 15-minute market have increased significantly. In the first half of 2018, scarcity pricing was triggered in over 130 15-minute intervals, compared to 54 intervals during all of 2017 and 26 intervals in all of 2016.
- Despite significantly higher operating reserve requirements and more scarcities, total ancillary service costs in 2018 have not increased substantially. Costs for ancillary services totaled about $84 million between January and June, compared to about $77 million during the same period in 2017.
- Bid cost recovery payments totaled $21 million, $4 million less than Q1 2018 and $7 million less than Q2 last year.
- Measures adopted by the ISO in response to the Aliso Canyon issue included the addition of special gas constraints and real-time gas price scalars for the fuel component of default energy bids (25 percent) and commitment cost bids (75 percent). The ISO did not activate any of the special Aliso Canyon gas constraints or gas price scalars during the second quarter.
- DMM continues to recommend that rather than continuing use of special gas cost adders for units affected by the Aliso Canyon storage issues, the ISO develop the capability to update gas prices used in real-time market bid limits based on same-day gas market price information available each morning.[1] DMM believes that each use of the Aliso Canyon gas adders on default energy bids and commitment costs has highlighted problems associated with use of these adders. The first is the delay in activating and deactivating adders in response to actual same-day gas conditions. The second problem is the challenge of matching the real-time gas price resulting from using fixed adders to same-day gas price volatility.

[1] Further detail is available in DMM's comments on the ISO's recent tariff filing to extend Aliso provisions: http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

Other key highlights are summarized here and further detail is provided below.

- Idaho Power and Powerex became participants in the energy imbalance market on April 4. Prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex), have tended to be lower than those in the ISO and other energy imbalance market balancing areas because of more abundant supply and limited transfer capability out of the region. Prices for Idaho Power and PacifiCorp East often tracked close to ISO system prices, except during hours ending 19 through 22 when prices in these two areas were significantly lower.
- There was significant north-to-south congestion in the day-ahead market, similar to the previous quarter. Congestion was primarily a result of planned outages in Southern California. This congestion increased day-ahead prices in the San Diego Gas and Electric area by about $3.54/MWh and in the Southern California Electric area by about $0.81/MWh, and decreased prices in the Pacific Gas and Electric area by about $0.89/MWh.
- Outages in Southern California also caused congestion in the 15-minute market. Congestion increased prices in the San Diego Gas and Electric area by about $4.95/MWh and in the Southern California Edison area by about $1.32/MWh, and increased Pacific Gas and Electric area prices by about $0.88/MWh.
- Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity continued to decrease overall during the second quarter of 2018 to around $2.1 million, compared to around $2.2 million during the previous quarter and around $7.5 million during the second quarter of 2017.
- Convergence bidding was profitable overall during the second quarter, for the second consecutive quarter. Combined net revenues for virtual supply and demand increased to about $7.4 million after accounting for about $1.5 million of virtual bidding bid cost recovery charges.

1 Market performance

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

- Average prices decreased both from the previous quarter and from the second quarter of 2017. This was driven by a decrease in gas prices and an increase in hydroelectric and renewable generation.
- There was significant north-to-south congestion in the day-ahead market, similar to the previous quarter. Congestion was primarily a result of planned outages in Southern California. This congestion increased day-ahead prices in the San Diego Gas and Electric area by about $3.54/MWh and in the Southern California Electric area by about $0.81/MWh, and decreased prices in the Pacific Gas and Electric area by about $0.89/MWh.
- Outages in Southern California also caused congestion in the 15-minute market. Congestion increased prices in the San Diego Gas and Electric area by about $4.95/MWh and in the Southern California Edison area by about $1.32/MWh, and increased Pacific Gas and Electric area prices by about $0.88/MWh.
- The number of intervals with ancillary service scarcity pricing increased significantly in 2018 to over 130 valid scarcity intervals in the 15-minute market. In comparison, there were 54 instances during all of 2017 and 26 instances in all of 2016. Despite significantly higher operating reserve requirements and more scarcities, total ancillary service costs in the first and second quarter of 2018 were similar to the first half of 2017.
- During the second quarter of 2018, congestion revenue rights auction revenues were $18 million less than payments made to non-load-serving entities purchasing these rights. Losses in the first quarter represent $0.57 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders. Total transmission ratepayer losses from the congestion revenue rights auction since the market began in 2009 surpassed $790 million.
- Total bid cost recovery payments for the second quarter were about $21 million. This amount was about $4 million lower than payments in the previous quarter. Bid cost recovery payments for residual unit commitment almost doubled when compared to the prior quarter. This significant increase can be attributed to the increased residual unit commitment capacity procurement targets in June.
- Convergence bidding was profitable overall during the second quarter. For the second consecutive quarter virtual supply was profitable over the quarter. Combined net revenues for virtual supply and demand increased to about $7.4 million after accounting for about $1.5 million of virtual bidding bid cost recovery charges.

1.1 Energy market performance

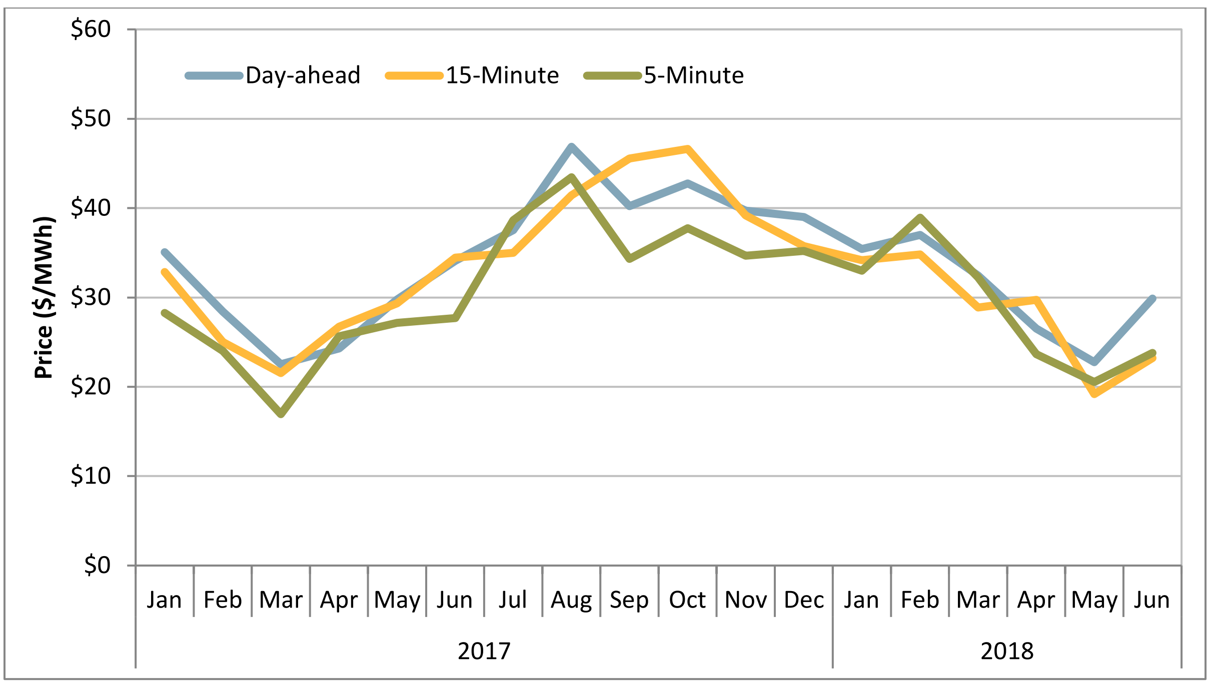
Average monthly energy market prices

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 1.1 shows average monthly system marginal energy prices during all hours. During the quarter, average prices decreased both from the previous quarter and from the second quarter of 2017. Factors contributing to these trends are discussed below.

- Average prices decreased compared to the same quarter in 2017. Average day-ahead prices decreased by about $3/MWh (10 percent), 15-minute by about $6/MWh (20 percent) and 5-minute market prices by about $4/MWh (16 percent).
- Average monthly day-ahead prices were higher than 15-minute market prices in April by about $3/MWh, but lower in May and June by about $4/MW and 7/MWh. Five-minute prices, on average, were less than day-ahead prices in all months.

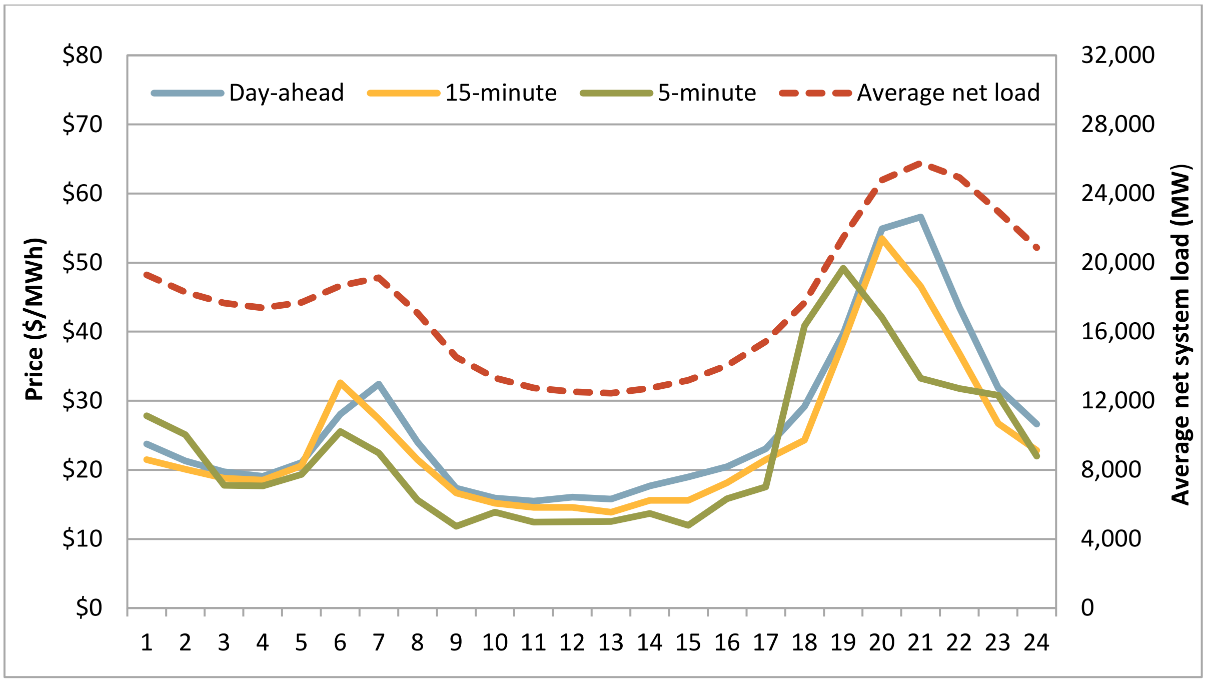
Figure 1.1 Average monthly prices (all hours) – system marginal energy price



Hourly average energy market prices

Figure 1.2 shows system marginal energy prices on an hourly basis in the second quarter compared to average hourly net load.[2] Hourly prices generally followed the net load pattern with the highest energy prices occurring during the morning and evening peak net load hours. In particular, day-ahead prices were highest during hours ending 20 and 21. Further, average prices in the day-ahead market were higher than 15-minute market prices in all hours except for hour ending 6. Prices in the middle of the day were lower on average than early morning and late evening hours.

Figure 1.2 Hourly system marginal energy prices



Factors contributing to energy market price trends

Monthly and hourly trends in wholesale electricity prices are largely driven by four things: load conditions, natural gas price trends, the availability of hydroelectric resources, and the production of renewable energy. Natural gas generators are frequently the marginal resource. Therefore, the cost of natural gas has a large impact on overall average wholesale prices. Annual snowpack and snowmelt largely determines the availability of hydroelectric resources, impacting seasonal trends in wholesale prices. The intermittent nature of wind and solar resources leads to a significant impact on hourly prices.

High levels of hydroelectric and renewable generation add lower cost supply, depressing monthly and hourly average wholesale electricity prices due to their relatively low cost. Conversely, low levels of hydroelectric and renewable generation raise costs as higher-cost natural gas generation is necessary to meet demand.

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2 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 1.3 shows natural gas prices at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate) as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. SoCal Citygate prices often impact overall system prices because 1) there are large numbers of natural gas resources in the south, and 2) there is often greater congestion in the south that creates load pockets. Figure 1.4 shows hourly average hydroelectric, wind, and solar generation by month in megawatts.

The following trends in prices and drivers of prices include:

- From February through May, monthly average prices in the day-ahead, 15-minute, and 5-minute markets decreased on average about 38 percent, 45 percent and 47 percent, respectively, as SoCal Citygate prices fell and as hydroelectric and renewable production increased.
- Between May and June, monthly average prices increased in the day-ahead, 15-minute, and 5-minute markets on average about 31 percent, 21 percent and 16 percent, respectively, correlating to an increase in gas prices at all three hubs by 8 percent on average. SoCal Citygate prices increased 12 percent.
- Solar generation doubled in the second quarter compared to the first quarter, corresponding to a decrease in mid-day (hours ending 9 to 16) hourly average prices by about 35 percent compared to the first quarter.
- Hourly average prices were lower at peak net load times of the day, average peak day-ahead market prices decreased about 6 percent while 15-minute and 5-minute market prices decreased about 15 percent. This is due, in part, to lower gas prices and greater hydro and renewable generation compared to the first quarter.
- Compared to the same quarter in 2017, there was less hydroelectric production due to reduced availability and snowfall. This was more than offset by an increase in solar and wind generation, though the lack of hydro likely impacted prices in hours when solar was not producing.

Figure 1.3 Monthly average natural gas prices

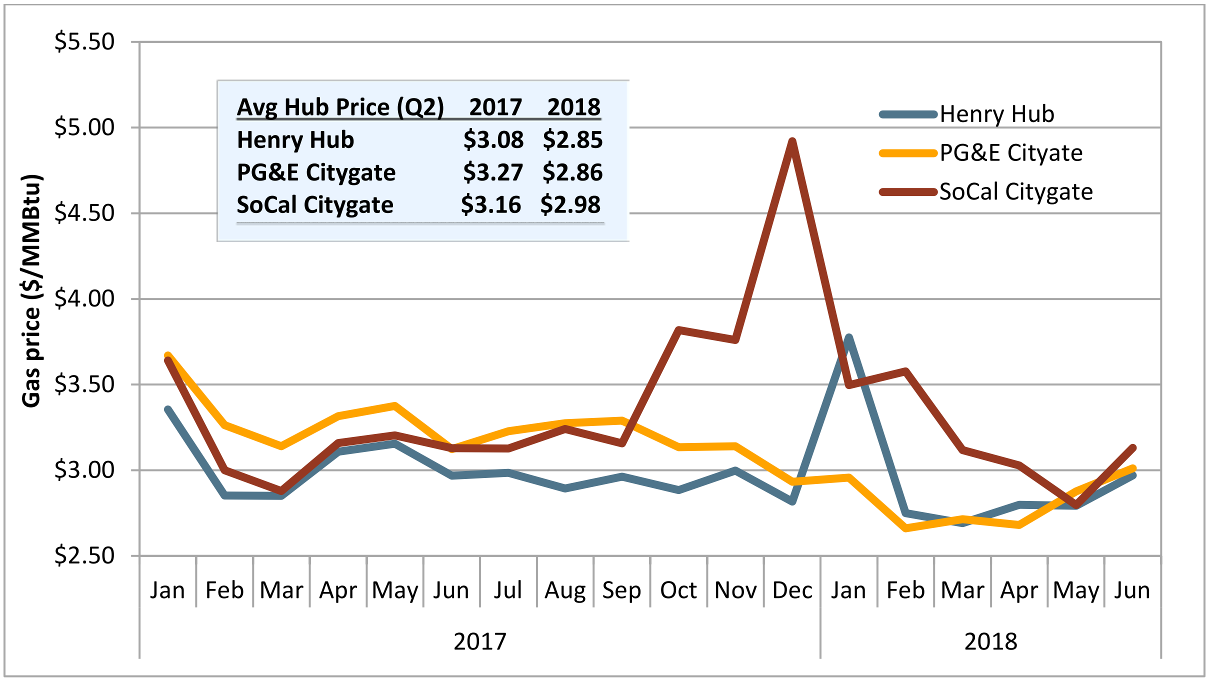
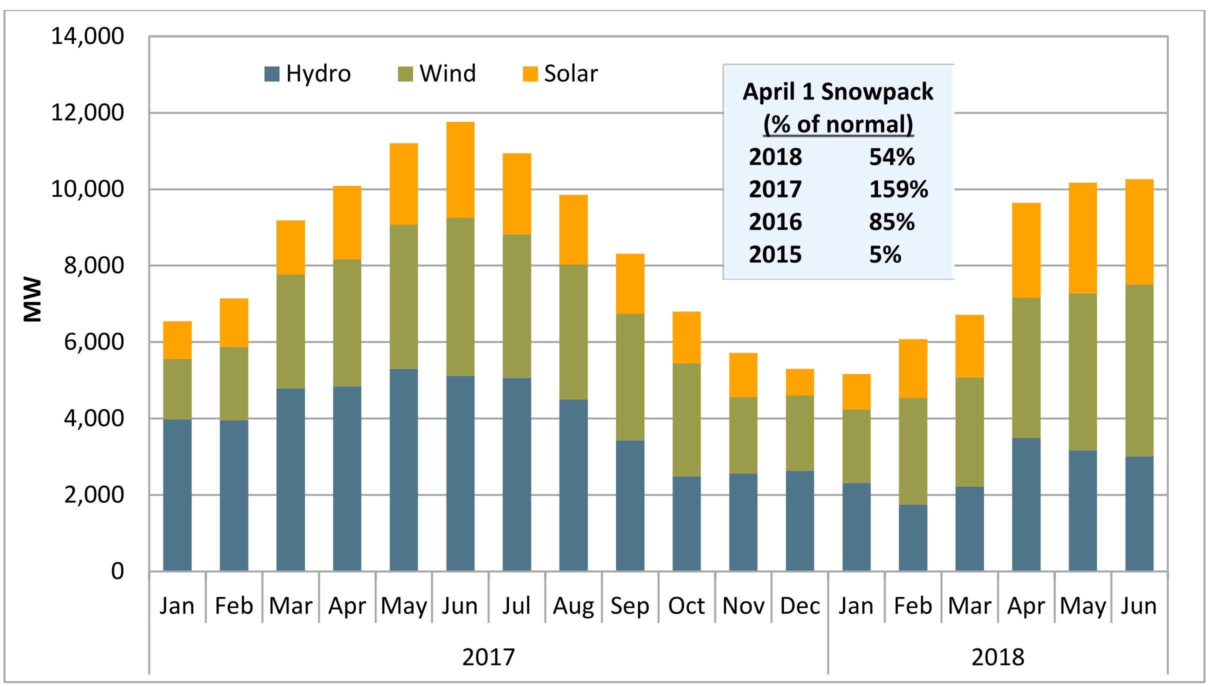


Figure 1.4 Average hourly hydroelectric, wind, and solar generation by month



1.2 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. The frequency of negative prices was significantly lower in the second quarter than in the second quarter of the previous year. In addition, with the exception of April, the frequency of high prices in the 15-minute and 5-minute markets was lower than in the second quarter of 2017.

During the quarter, most 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. 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 1.5, the frequency of high prices in the 15-minute market greater than $250/MWh remained around 0.4 percent of intervals, similar to the previous quarter. High prices during the second quarter of 2018 were most frequent in April, when prices above $250/MWh occurred during around 0.9 percent of 15-minute intervals.

Figure 1.6 shows the monthly frequency of under-supply infeasibilities in the 15-minute market. Under-supply infeasibilities in the 15-minute market occurred only in April during the quarter and were almost all resolved by the load bias limiter.

Figure 1.7 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 0.7 percent of intervals in the second quarter, down from around 1 percent of intervals in the previous quarter and 0.9 percent of intervals in the second quarter of 2017. Further, the frequency of more extreme 5-minute market prices larger than $750/MWh decreased throughout the quarter, down from about 0.7 percent in the first quarter to about 0.4 percent in the second quarter.

Figure 1.8 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. The conditions for the load bias limiter were met during more than half of the intervals when there were infeasibilities. Specifically, if the operator load adjustment exceeds the size of the power balance constraint infeasibility and is in the same direction, the size of the load adjustment is automatically reduced and the price is set by the last dispatched economic bid rather than the penalty parameter for the relaxation (for instance, the $1,000/MWh penalty price for shortages). However, during most of the under-supply infeasibilities in the second quarter when the limiter triggered, accessible economic bids near the bid cap of $1,000/MWh were dispatched such that the resulting price was near the penalty parameter.

Figure 1.5 Frequency of high 15-minute prices by month

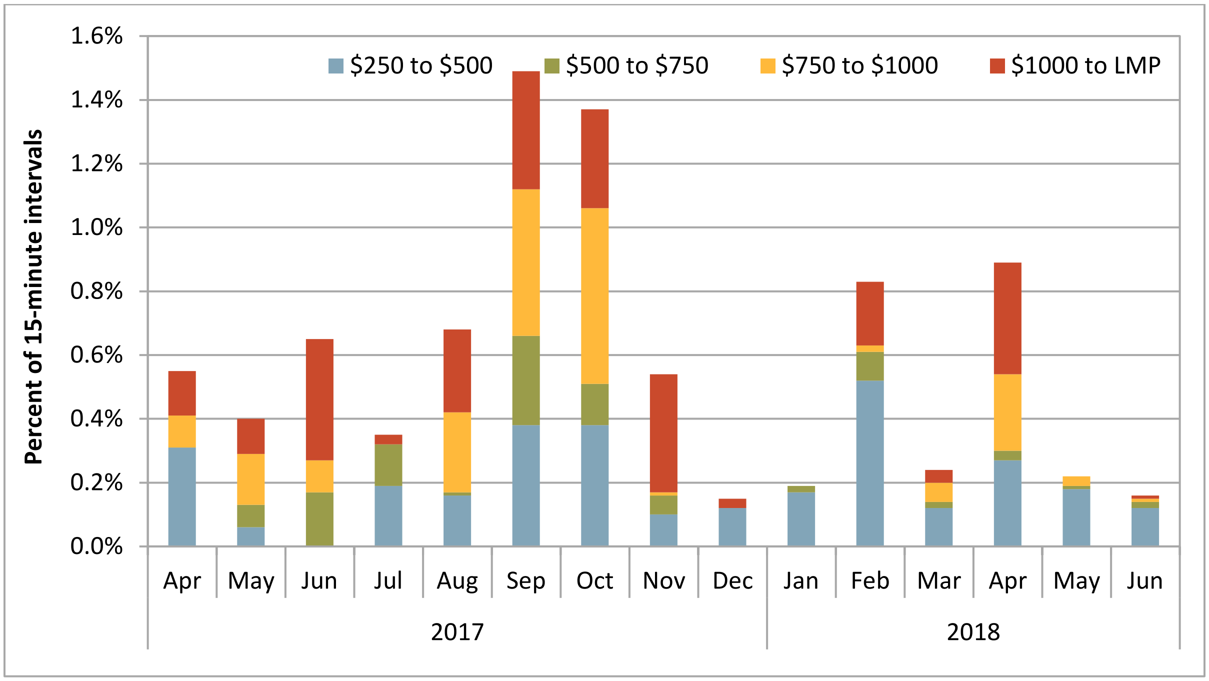


Figure 1.6 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

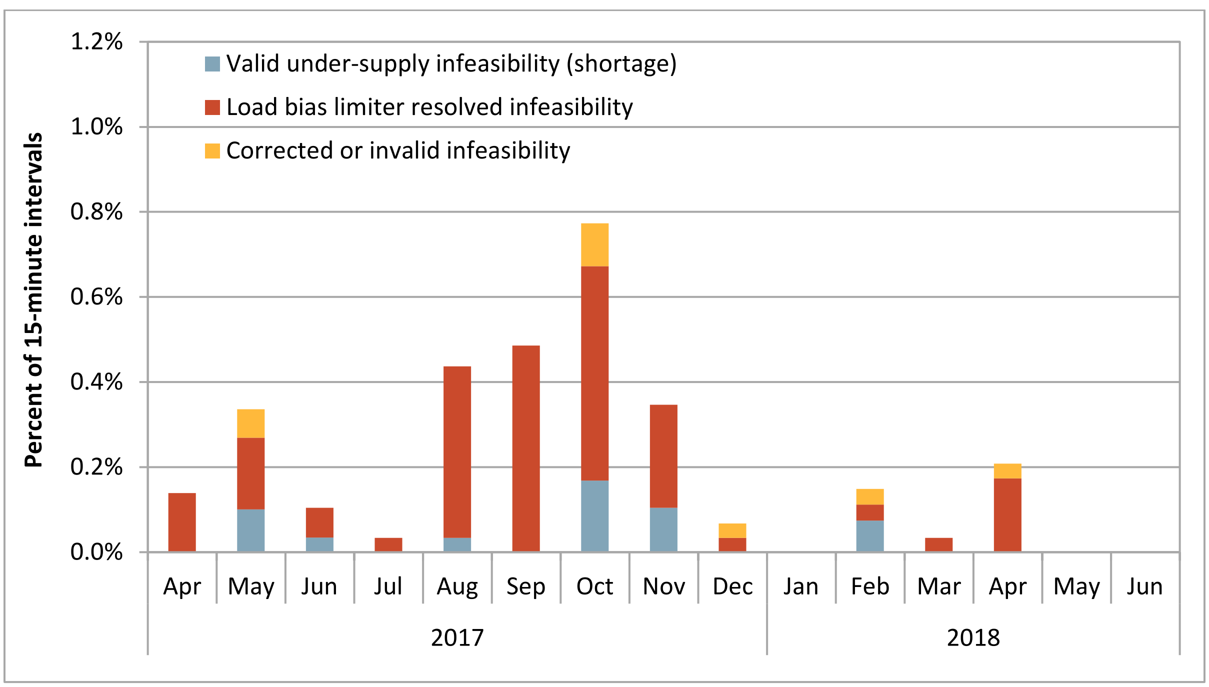


Figure 1.7 Frequency of high 5-minute prices by month

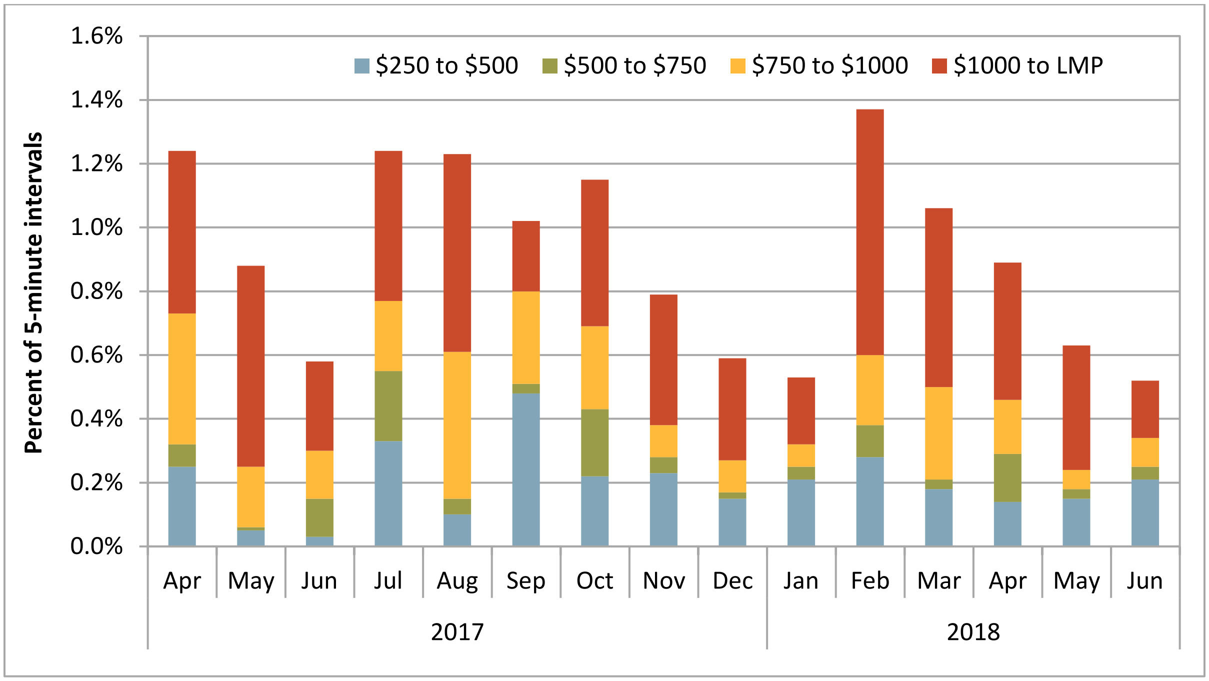
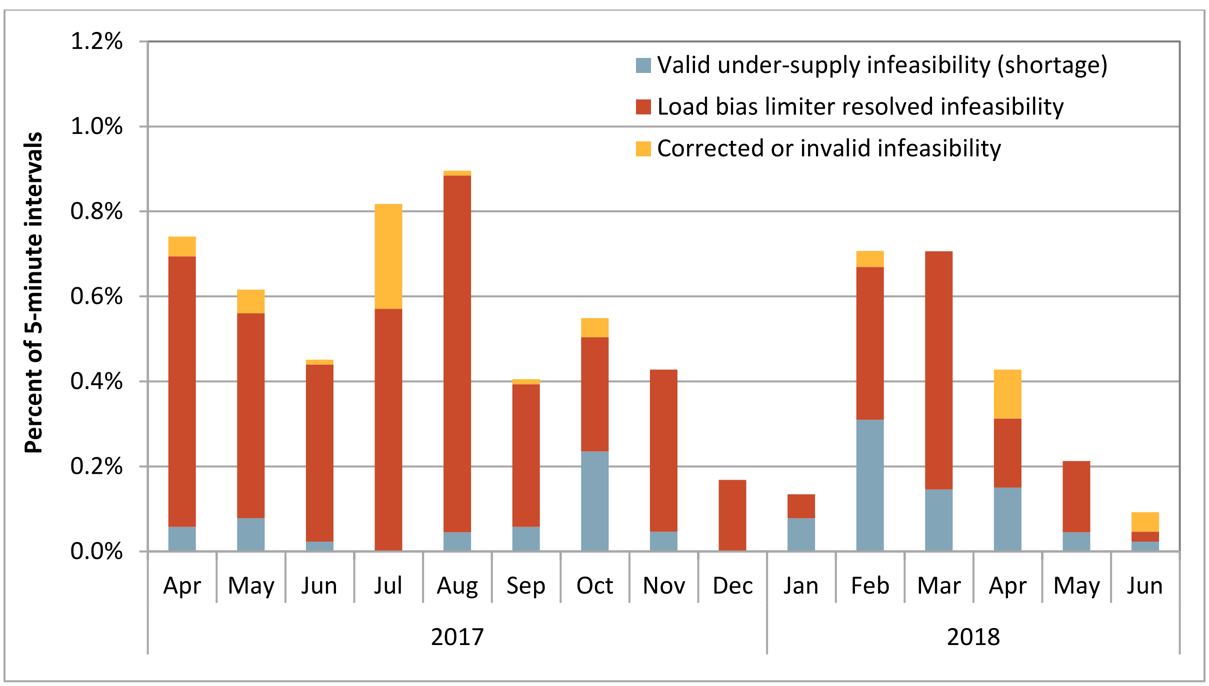


Figure 1.8 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



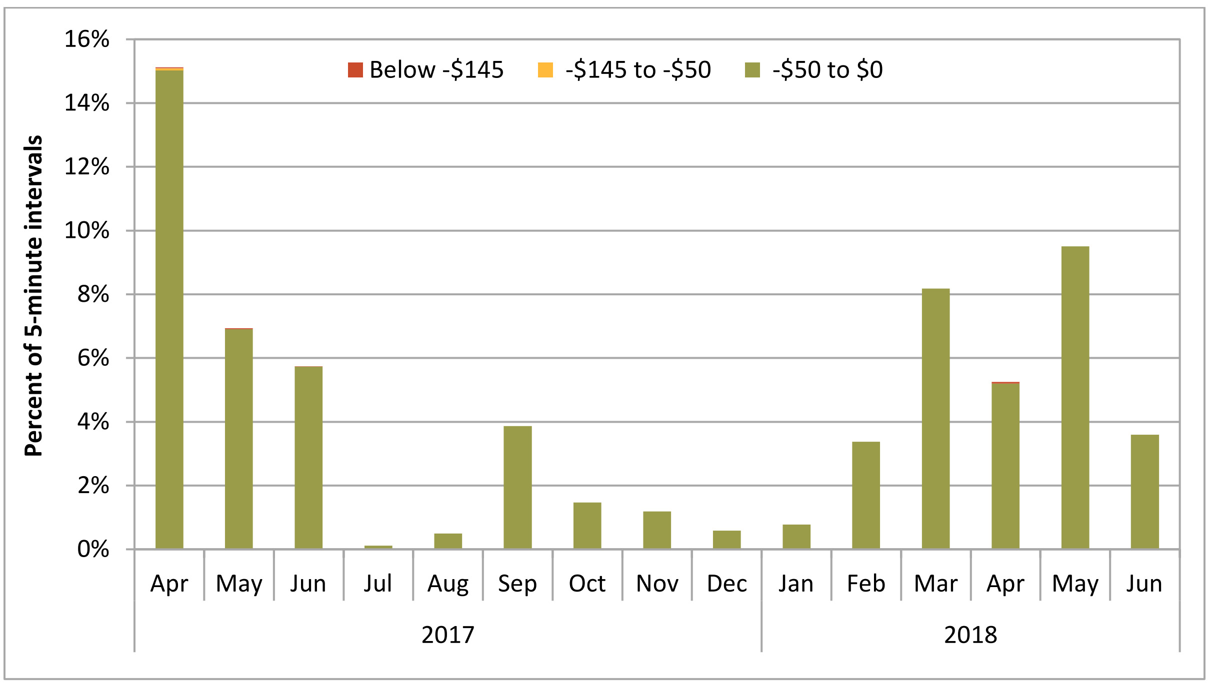
Negative prices

Figure 1.9 shows the frequency of negative prices in the 5-minute market by month.[3] The frequency of negative prices in the 15-minute and 5-minute markets increased during the second quarter relative to the previous three months. However, the frequency of negative prices was much lower than the second quarter of 2017.

Negative prices occurred during about 4 percent of intervals in the 15-minute market and around 6 percent of intervals in the 5-minute market during the second quarter of 2018. In comparison, negative prices occurred during about 7 percent and 9 percent of 15-minute and 5-minute intervals, respectively, during the second quarter of 2017.

Negative prices were most frequent between hours ending 8 and 17 when loads, net of wind and solar, were lowest. During these hours, negative prices occurred in over 10 percent of 5-minute intervals. The large majority of negative prices were between negative $50 and $0. However, there were four 5-minute intervals when prices were below negative $145 after relaxing the power balance constraint for over-supply conditions. In the 15-minute market, prices did not reach below negative $20/MWh for any of the load aggregation points in the ISO during the quarter.

Figure 1.9 Frequency of negative 5-minute prices by month



1.3 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

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

(Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)) 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.[4] 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*.[5]

Color shading has been added to congestion tables this quarter 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.

1.3.1 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.

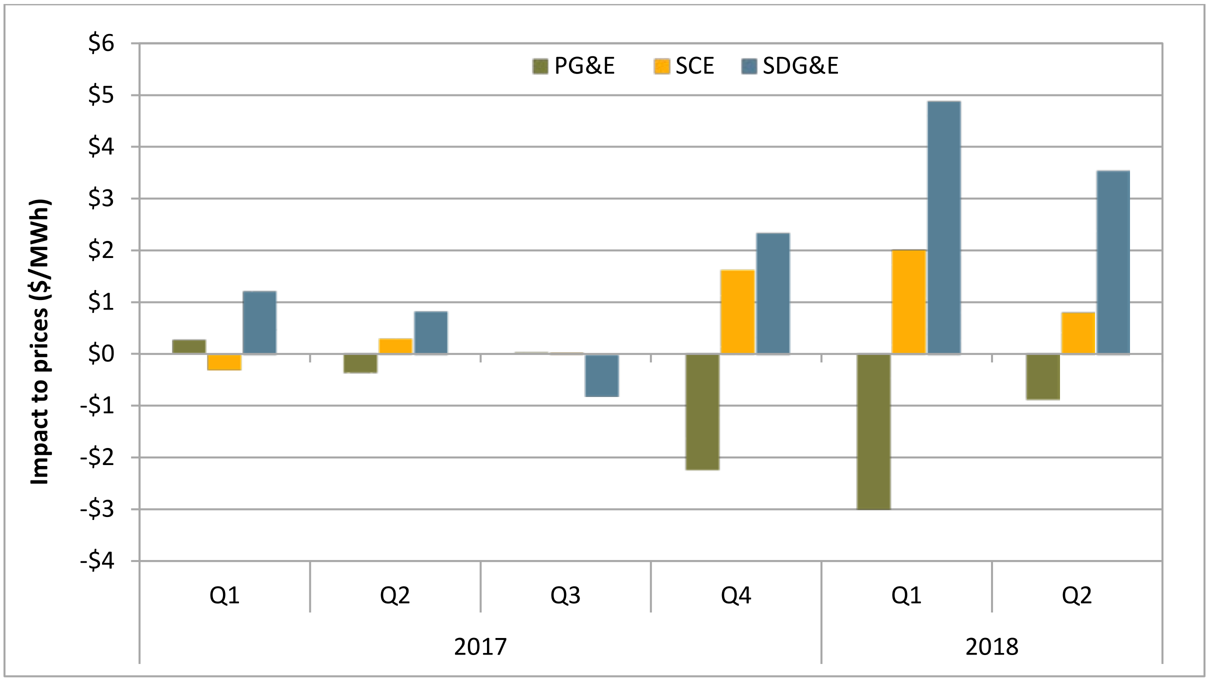
Impact of congestion to overall prices in each load area

Figure 1.10 shows the overall impact of congestion on day-ahead prices in each load area for each quarter in the last two years. Similar to the past two quarters, congestion increased prices in the SCE and SDG&E areas and decreased prices in the PG&E area. There was significantly more congestion in the second quarter compared to the second quarter of last year.

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

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

Figure 1.10 Impact of congestion on day-ahead prices



In the second quarter, SDG&E area prices were most impacted by congestion, increasing about $3.5/MWh (12 percent), compared to an increase of almost $5/MWh (12 percent) in the previous quarter. In the SCE area, prices increased almost $1/MWh (3 percent), which was a decrease in impact compared to the previous quarter. In the PG&E area, prices decreased by almost $1/MWh (3 percent). This impact was less than the impact on PG&E prices in the first quarter, when prices decreased $3/MWh due to congestion.

Table 1.1 breaks down the impact to prices in the second quarter by constraint.[6] The primary cause of overall price separation between the ISO areas was congestion due to the Doublet Tap-Friars 138 kV constraint (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1), which is located in the SDG&E area and contributed to roughly 40% of the price increase in that area. The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) had the next largest impact, also contributing to the increase in SDG&E prices. Finally, the Barre-Villa Park 230 kV line (24016_BARRE _230_24154_VILLA PK_230_BR_1 _1) had the greatest impact on price separation for SCE and PG&E, contributing to 40 percent and 35 percent of the separation, respectively. More information regarding individual constraints is discussed below.

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

Table 1.1 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	RM_TM12_NG	$0.08	0.30%	-$0.01	-0.03%	-$0.10	-0.34%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.04	0.17%	-$0.04	-0.14%	-$0.03	-0.11%
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.03	0.12%	-$0.03	-0.10%	-$0.03	-0.08%
	33020_MORAGA _115_30550_MORAGA _230_XF_3 _P	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
	33020_MORAGA _115_30550_MORAGA _230_XF_2 _P	$0.01	0.04%	$0.00	0.00%	$0.00	0.00%
	30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.31	-1.20%	$0.33	1.22%	$0.09	0.29%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	-$0.18	-0.70%	$0.16	0.59%	$0.01	0.03%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	-$0.14	-0.56%	$0.11	0.42%	$0.15	0.48%
	6410_CP5_NG	-$0.09	-0.33%	$0.07	0.27%	$0.07	0.23%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.05	-0.18%	$0.05	0.19%	$0.01	0.04%
	24091_MESA CAL_230_24126_RIOHONDO_230_BR_1 _1	-$0.03	-0.13%	$0.03	0.10%	$0.03	0.08%
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.04	-0.16%	$0.02	0.08%	$0.11	0.37%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.01	-0.04%	$0.01	0.05%	$0.02	0.07%
	25001_GOODRICH_230_24076_LAGUBELL_230_BR_1 _1	-$0.02	-0.06%	$0.01	0.02%	$0.01	0.03%
	24074_LA FRESA_230_24076_LAGUBELL_230_BR_1 _1	$0.00	-0.02%	$0.01	0.02%	$0.00	0.00%
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$1.52	5.02%
	7820_TL 230S_OVERLOAD_NG	-$0.06	-0.21%	$0.00	0.00%	$0.64	2.13%
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.15	-0.56%	$0.10	0.39%	$0.22	0.72%
	7820_TL23040_IV_SPS_NG	-$0.01	-0.04%	$0.00	0.00%	$0.15	0.48%
	OMS 5717006_50001_OOS_NG	-$0.01	-0.04%	$0.00	0.00%	$0.14	0.47%
	OMS 5649479 50002_OOS_TDM	$0.00	0.00%	$0.00	0.00%	$0.14	0.47%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.12	0.41%
	OMS 5730606 TL50003_NG	-$0.01	-0.03%	$0.00	0.00%	$0.08	0.27%
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.07	0.22%
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	$0.00	0.00%	$0.00	0.00%	$0.03	0.11%
	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.03	0.09%
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	$0.00	-0.01%	$0.00	0.00%	$0.02	0.06%
	OMS 5823292 MG_BK81_NG	$0.00	-0.01%	$0.00	0.00%	$0.01	0.05%
	22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.04%
Other		$0.01	0.05%	$0.01	0.04%	$0.07	0.22%
Total		**-$0.89**	**-3.45%**	**$0.81**	**3.01%**	**$3.54**	**11.73%**

Impact of congestion from individual constraints

Table 1.2 shows the impact of congestion from each constraint *only during congested intervals,* where the number of congested intervals is presented separately as frequency. The number of constraints binding frequently in the day-ahead market decreased compared to the previous quarter.[7] In the northern part of the state, the Round Mountain-Table Mountain nomogram (RM_TM12_NG) bound during about 7 percent of intervals, though had little impact on prices. It increased prices in the PG&E area by about $1/MWh and decreased prices in the SCE and SDG&E areas by about the same amount. The nomogram likely bound due to high north to south flows during this time of the year, and is enforced to protect for the loss of either Round Mountain-Table Mountain 500 kV #1 or Table Mountain 500 kV #2.

In the SCE area, the Eagle Rock-Gould 230 kV constraint (24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1) bound most frequently, in 15 percent of intervals. The constraint had a small impact on prices, increasing SCE and SDG&E area prices and decreasing PG&E area prices by about $1/MWh. Congestion on this line was due to a planned outage on the Eagle Rock-Mesa 220 kV line. As mentioned above, the Barre-Villa Park 230 kV constraint (24016_BARRE _230_24154_VILLA PK_230_BR_1 _1) had a greater impact on prices, increasing SCE and SDG&E area prices by $3/MWh and $1/MWh, respectively, and decreasing PG&E prices by about $3/MWh. Congestion on this constraint was partially due to a planned outage on the Mesa-Redondo 220 kV line.

In the SDG&E area, the Doublet Tap-Friars 138 kV constraint (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1) bound in about 23 percent of intervals and impacted SDG&E area prices by about $7/MWh. One reason for congestion on this constraint was a daily outage on the Penasquitos-Old Town 230 kV line. The Imperial Valley (7820_TL 230S_OVERLOAD_NG) and the East County-Miguel (7820_TL23040_IV_SPS_NG) nomograms also bound frequently during the quarter, in about 18 percent and 4 percent of intervals, respectively. Congestion from these constraints increased prices by about $7/MWh in the SDG&E area. These nomograms are enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV and East County-Miguel 500 kV lines, which were on outage for part of the second quarter.

Table 1.2 Impact of congestion on day-ahead prices during congested hours[8]

Constraint Location	Constraint	Frequency	Q2		
		Q2	PG&E	SCE	SDG&E
PG&E	RM_TM12_NG	7.2%	$1.16	-$1.36	-$1.44
SCE	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	15.6%	-$1.15	$1.08	$1.08
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.4%	-$3.28	$3.51	$1.37
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.5%	-$0.90	$0.75	$0.59
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	22.5%	$0.00	$0.00	$6.74
	7820_TL 230S_OVERLOAD_NG	17.7%	-$0.31	$0.00	$3.63
	7820_TL23040_IV_SPS_NG	4.3%	-$0.25	$0.00	$3.35

7 *Q4 2017 Report on Market Issues and Performance*, March 2018, pp. 18: http://www.caiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf

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

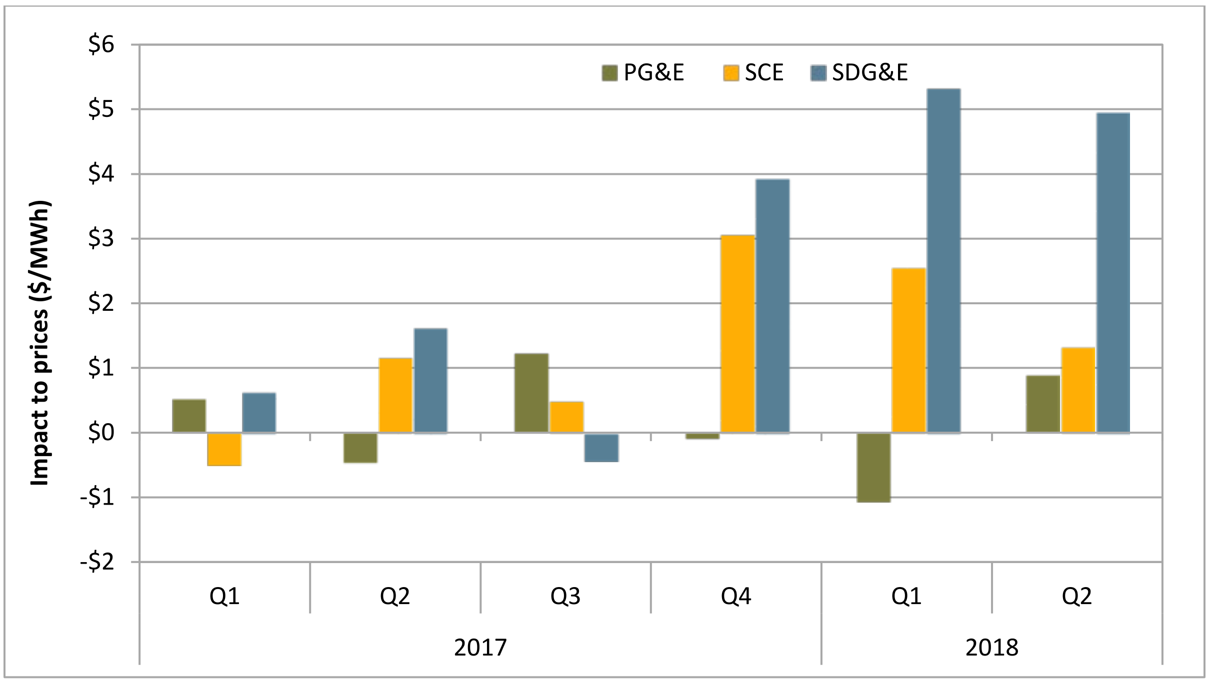
1.3.2 Congestion in the 15-minute market

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 1.11 shows the overall impact of congestion on fifteen-minute prices in each load area for each quarter in the last two years. Similar to the past two quarters and to the day-ahead market, congestion increased prices in the SCE and SDG&E areas. Congestion in the 15-minute market also increased prices in the PG&E area, a result that was different from day-ahead congestion impacts which decreased PG&E prices. The primary reason for this is that the fifteen-minute market includes the energy imbalance market. There was significantly more congestion in the second quarter of 2018 compared to the second quarter of last year.

Figure 1.11 Impact of congestion on 15-minute prices



Similar to the day-ahead market, SDG&E prices were most impacted by congestion in the fifteen-minute market, increasing $5/MWh (16 percent). The impact to prices was lower than last quarter though significantly higher than the impact of congestion in each quarter of 2017. In the PG&E area, prices increased almost $1/MWh (3 percent). In SCE, prices increased by $1.30/MWh (5 percent). In these areas, the impact to prices was also lower than in the previous quarter.

Table 1.3 breaks down the impact to prices in the second quarter by constraint.[9] The primary cause of overall price separation between the ISO areas in the fifteen-minute market was congestion due to the Doublet Tap-Friars 138 kV constraint (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1) and the

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

Round Mountain-Table Mountain nomogram (RM_TM12_NG). The Doublet Tap_Friars 138 kV constraint had the greatest impact to overall price separation in SDG&E, contributing to roughly 20 percent of the increase. The Round Mountain-Table Mountain nomogram (RM_TM12_NG) increased prices in all three areas, though had the greatest impact to prices in PG&E and SCE, contributing to 99 percent of the overall price increase in PG&E and 38 percent of the increase in SCE. More information regarding individual constraints is discussed below.

Table 1.3 Impact of congestion on overall 15-minute prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	RM_TM12_NG	$0.87	3.41%	$0.49	1.93%	$0.44	1.47%
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.22	0.86%	$0.20	0.77%	$0.18	0.60%
	RM_TM21_NG	$0.08	0.31%	$0.04	0.17%	$0.04	0.13%
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.03	0.10%	$0.01	0.05%	$0.01	0.04%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.02	0.08%	-$0.03	-0.13%	-$0.03	-0.11%
	30050_LOSBANOS_500_30056_GATES2 _500_BR_2 _1	$0.01	0.05%	-$0.02	-0.08%	-$0.02	-0.06%
SCE	6410_CP5_NG	-$0.15	-0.60%	$0.16	0.61%	$0.15	0.50%
	6410_CP6_NG	-$0.14	-0.55%	$0.14	0.56%	$0.14	0.45%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	-$0.06	-0.22%	$0.11	0.42%	$0.12	0.42%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	-0.01%	$0.08	0.33%	$0.04	0.12%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	-$0.02	-0.07%	$0.02	0.07%	$0.02	0.06%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.01	0.05%	$0.02	0.08%	$0.02	0.05%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.02	0.07%	$0.02	0.05%
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	$0.00	-0.02%	$0.01	0.02%	$0.02	0.07%
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.91	3.06%
	OMS 5820664 MG_BK80_NG	$0.00	0.00%	$0.00	0.00%	$0.66	2.22%
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.62	2.08%
	MIGUEL_BKs_MXFLW_NG	$0.00	0.00%	$0.00	0.00%	$0.35	1.16%
	OMS 5730606 TL50003_NG	$0.00	0.00%	$0.00	0.00%	$0.28	0.93%
	7820_TL23040_IV_SPS_NG	$0.00	0.00%	$0.00	0.00%	$0.26	0.88%
	7820_TL 230S_OVERLOAD_NG	$0.00	0.00%	$0.02	0.06%	$0.25	0.84%
	OMS 5717006_50001_OOS_NG	$0.00	0.00%	$0.00	0.02%	$0.21	0.72%
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.04	-0.14%	$0.07	0.29%	$0.17	0.56%
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	$0.00	0.00%	$0.00	0.00%	$0.16	0.53%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.10	0.32%
Other		$0.05	0.20%	-$0.02	-0.09%	-$0.14	-0.46%
Total		**$0.88**	**3.45%**	**$1.32**	**5.14%**	**$4.95**	**16.61%**

Impact of congestion from individual constraints

Table 1.4 shows the impact of congestion from each constraint *only during congested intervals,* where the congested intervals are presented as frequency. In the northern part of the state, the Round Mountain-Table Mountain nomogram (RM_TM12_NG) bound during about 8 percent of intervals. It increased prices in the PG&E area by about $11/MWh and increased prices in the SCE and SDG&E areas by about $6/MWh.

In the SCE area, the Path 26 Midway-Vincent (6410_CP5_NG) nomogram bound in 1.2 percent of intervals. The constraint increased SCE and SDG&E area prices by about $12/MWh and decreased PG&E

prices by about $13/MWh. Congestion on Path 26 was primarily a result of an outage on Midway-Whirlwind 500 kV line which returned to service in early May.

In the SDG&E area, similar to the day-ahead market, the Doublet Tap-Friars 138 kV (22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1) constraint bound most frequently, though in about 9 percent of intervals compared to 23 percent in the day-ahead market. During the intervals it bound, it increased SDG&E prices by about $10/MWh. Additionally, congestion from the nomogram OMS 5820664 MG_BK80_NG caused an increase of $109/MWh in the SDG&E area, though bound only in 0.6 percent of intervals. This nomogram was enforced to mitigate for a planned outage of the Miguel transformer.

Table 1.4 Impact of congestion on 15-minute prices in the ISO during congested intervals[10]

Constraint Location	Constraint	Frequency	Q2		
		Q2	PG&E	SCE	SDG&E
PG&E	RM_TM12_NG	7.9%	$11.03	$6.24	$5.53
	30055_GATES1 _500_30900_GATES _230_XF_11_S	3.2%	$6.89	$6.15	$5.62
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.6%	$3.56	-$6.11	-$5.81
	30050_LOSBANOS_500_30056_GATES2 _500_BR_2 _1	0.5%	$2.89	-$4.30	-$4.06
	RM_TM21_NG	0.4%	$19.46	$10.58	$9.51
SCE	6410_CP5_NG	1.2%	-$12.54	$12.78	$12.14
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	0.5%	-$11.01	$20.76	$24.08
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	0.4%	$3.46	$4.93	$4.16
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.3%	-$9.69	$26.16	$10.98
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	9.3%	$0.00	$0.00	$9.79
	7820_TL 230S_OVERLOAD_NG	1.7%	-$0.12	$0.95	$14.94
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	1.5%	$0.00	$0.00	$41.96
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	1.0%	-$3.58	$7.41	$16.60
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.9%	$0.00	$0.00	$10.42
	MIGUEL_BKs_MXFLW_NG	0.7%	$0.00	$0.00	$48.11
	OMS 5730606 TL50003_NG	0.7%	$0.00	$0.28	$38.82
	7820_TL23040_IV_SPS_NG	0.6%	$0.00	$0.00	$42.53
	OMS 5820664 MG_BK80_NG	0.6%	$0.00	$0.00	$108.89
	OMS 5717006_50001_OOS_NG	0.6%	$0.00	$1.86	$38.75

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

1.3.3 Congestion in the energy imbalance market

Impact of congestion from individual constraints

Table 1.4 shows the impact on prices of congestion from each constraint *only during congested intervals,* where the congested intervals are presented as frequency. Congestion on constraints within the ISO tends to decrease prices in the energy imbalance market, particularly in the north. For example, the Round Mountain-Table Mountain nomogram (RM_TM12_NG) bound in the northern part of California, decreasing prices in energy imbalance market areas north of the constraint by about $15/MWh on average. As shown above, this constraint increased prices in the ISO. One main driver of this is a large amount of low-cost hydroelectric resources in the north, which is unable to reach ISO areas when transmission limits bind. In the southern part of the state, constraints that are congested tend to have the greatest impact on prices in energy imbalance market areas east of the ISO.

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

Constraint Location	Constraint	Freq.	Q2							
			PACE	PACW	NEVP	PSEI	AZPS	PGE	PWRX	IPCO
PACE	WYOMING_EXPORT	4.4%	-$0.73	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	RM_TM12_NG	7.9%	-$6.32	-$16.38	$2.19	-$16.23	$4.25	-$16.51	-$16.11	-$11.90
	30055_GATES1 _500_30900_GATES _230_XF_11_S	3.2%	-$4.49	-$12.05	-$2.92	-$11.78	$3.70	-$12.01	-$11.73	-$9.31
	30523_CC SUB _230_30525_C.COSTA _230_BR_1 _1	2.5%	$0.00	-$2.98	$0.00	-$2.93	$0.00	-$2.92	-$2.91	-$2.85
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	0.6%	-$1.31	$4.63	-$3.28	$4.45	-$5.27	$4.62	$4.39	$1.51
	30050_LOSBANOS_500_30056_GATES2 _500_BR_2 _1	0.5%	$0.00	$2.94	-$2.37	$2.84	-$3.61	$2.92	$2.80	$1.52
	RM_TM21_NG	0.4%	-$10.13	-$25.76	$4.73	-$25.48	$7.48	-$25.95	-$26.47	-$19.81
SCE	6410_CP5_NG	1.2%	$2.82	-$9.04	$7.18	-$8.65	$10.97	-$8.98	-$8.55	-$3.80
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	0.5%	-$4.98	-$9.43	-$5.37	-$9.25	$5.41	-$9.42	-$9.21	-$7.64
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	0.4%	-$6.01	$1.61	-$11.76	$1.35	-$10.86	$1.58	$1.29	-$2.46
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.3%	-$10.75	-$7.11	-$13.02	-$7.95	-$14.27	-$7.11	-$7.95	-$9.02
SDG&E	7820_TL 230S_OVERLOAD_NG	1.7%	-$1.37	-$0.13	-$1.27	-$2.32	-$3.28	-$0.13	-$3.82	-$0.85
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	1.5%	-$5.46	$0.00	-$5.34	$0.00	-$13.74	$0.00	$0.00	$0.00
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	1.0%	-$3.82	-$3.63	-$4.43	-$3.64	-$3.21	-$3.63	-$3.45	-$3.53
	MIGUEL_BKs_MXFLW_NG	0.7%	-$4.13	$0.00	$0.00	$0.00	-$15.69	$0.00	$0.00	$0.00
	OMS 5730606 TL50003_NG	0.7%	-$3.55	$0.00	-$3.17	$0.00	-$8.16	$0.00	$0.00	-$2.64
	7820_TL23040_IV_SPS_NG	0.6%	-$2.88	$0.00	-$2.83	$0.00	-$7.27	$0.00	$0.00	-$2.28
	OMS 5820664 MG_BK80_NG	0.6%	-$13.40	$0.00	-$8.48	$0.00	-$34.32	$0.00	$0.00	$0.00
	OMS 5717006_50001_OOS_NG	0.6%	-$2.71	$0.00	-$2.62	$0.00	-$12.25	$0.00	$0.00	-$1.84

Congestion on energy imbalance market internal constraints

Table 1.6 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. Compared to the previous quarter, internal congestion in PacifiCorp East decreased to levels similar to the second quarter of 2017. Congestion in PacifiCorp East was primarily a result of a single constraint (WYOMING_EXPORT, also seen in the table above) binding during about 4 percent of intervals in both the 15-minute and 5-minute markets. In the NV Energy area, frequency of binding internal constraints increased compared to the previous quarters in both the 15-minute and 5-minute markets.

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

Persistent low congestion in some of the balancing authority areas may be a result of the following:

- Each energy imbalance market area may be incorporating some degree of congestion management in their process when making forward unit commitments and developing base schedules.
- Bids may be structured in such a way as to limit or prevent congestion within an energy imbalance market area.
- Within the PacifiCorp areas, physical limits on some local constraints, which are modeled in the full network model, may not be fully reflective of contractual limits that may be enforced through generating base schedules and the amount offered from some resources.

These reasons appear plausible because almost all of the generation within each energy imbalance market area is scheduled by a single entity.

Table 1.6 Percent of intervals with congestion on internal EIM constraints

	2014	2015	2016	2017				2018	
				Q1	Q2	Q3	Q4	Q1	Q2
15-minute market (FMM)									
PacifiCorp East	0.1%	0.9%	1.2%	16.1%	4.3%	5.1%	47.6%	14.9%	4.5%
PacifiCorp West	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
NV Energy		0.0%	0.1%	10.3%	1.8%	7.6%	5.8%	0.5%	0.9%
Puget Sound Energy				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Portland General Electric							0.0%	0.0%	0.0%
Powerex									0.0%
Idaho Power									0.0%
5-minute market (RTD)									
PacifiCorp East	0.0%	0.8%	1.2%	17.1%	3.3%	4.5%	46.1%	14.7%	3.9%
PacifiCorp West	0.1%	0.0%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
NV Energy		0.0%	0.1%	11.7%	1.6%	7.1%	5.6%	0.4%	0.9%
Puget Sound Energy				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Portland General Electric							0.0%	0.0%	0.0%
Powerex									0.0%
Idaho Power									0.0%

1.4 Ancillary services

1.4.1 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.

In the past, only four of these regions were typically utilized: expanded system (or expanded ISO), internal system, expanded South of Path 26, and internal South of Path 26. Since December 14, 2017, operators began setting expanded and internal North of Path 26 region minimum requirements to match the expanded and internal South of Path 26 region requirements. The new requirements were initially entered as a result of outages but were maintained to help with the distribution of ancillary service procurement across the ISO, particularly in preparation for the implementation of the NERC reliability standard, BAL-002-2.[12]

During the second quarter, operating reserves requirements in the day-ahead market have typically been set to 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.[13] Operating reserve requirements in real-time were calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast.

The Federal Energy Regulatory Commission approved a set of newly defined requirements in BAL-002-2, effective January 1, 2018, that required the ISO to reevaluate the most severe single contingency. This change resulted in a significant increase to the operating reserve requirements after January 1, 2018, to cover the potential sudden loss of scheduling on the Pacific DC Intertie.

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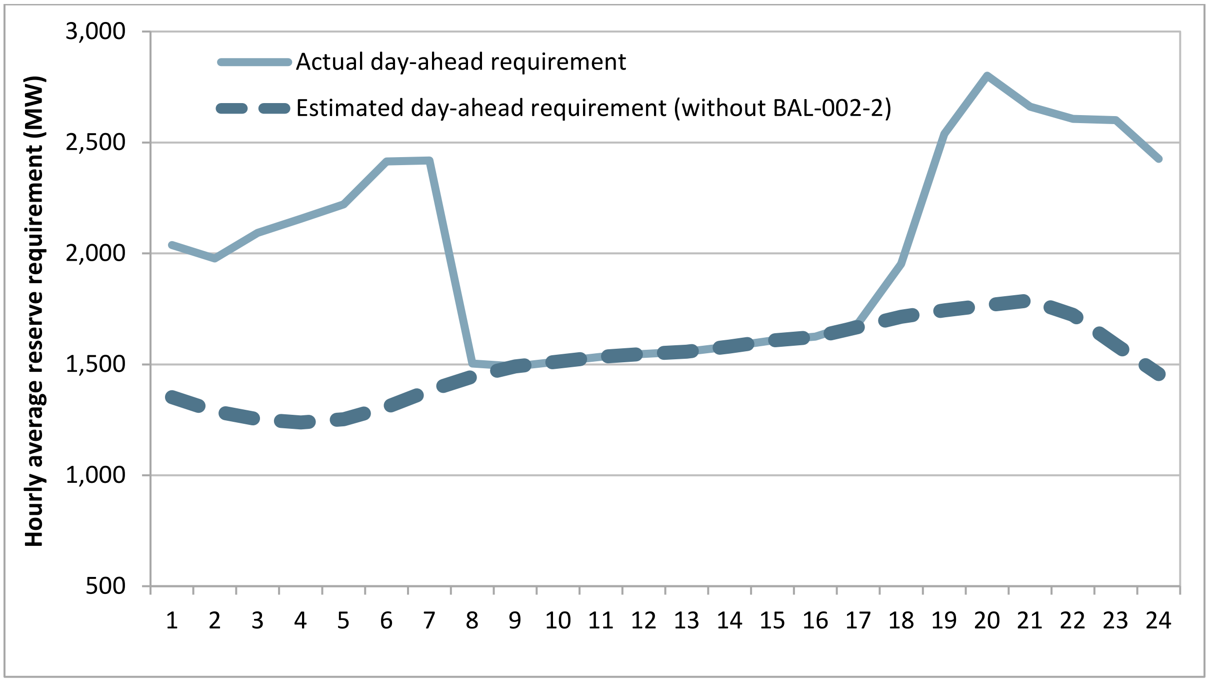
[12] Further information on BAL-002-2 and operating reserve requirement changes implemented by the ISO is available here: http://www.caiso.com/Documents/Presentation-BAL-002-2DisturbanceControlStandard-ContingencyReserveforRecoveryfromaBalancingContingencyEvent.pdf
or in the NERC BAL-002-2 reliability standard here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2.pdf.

[13] The ISO added functionality to explicitly pull solar forecasts when setting AS requirements in early May after the 15-percent threshold began binding in late April. The 15-percent is only of solar units with the potential for the inverter issue. The ISO indicated that the 25 percent solar criteria was reduced to 15 percent effective September 19, 2017 (http://www.caiso.com/Documents/Adjustment_TemporaryIncrease_DailyOperatingReservesProcurement.html)

Figure 1.12 shows actual hourly average operating reserve requirements during the second quarter as well as estimated hourly average operating reserve requirements had the changes associated with BAL-002-2 not been implemented.[14] During the second quarter, actual day-ahead operating reserve requirements were on average around 900 MW higher during morning hours ending 1 through 7 and evening hours ending 19 through 24.

Figure 1.12 Hourly average operating reserve requirement (April – June)



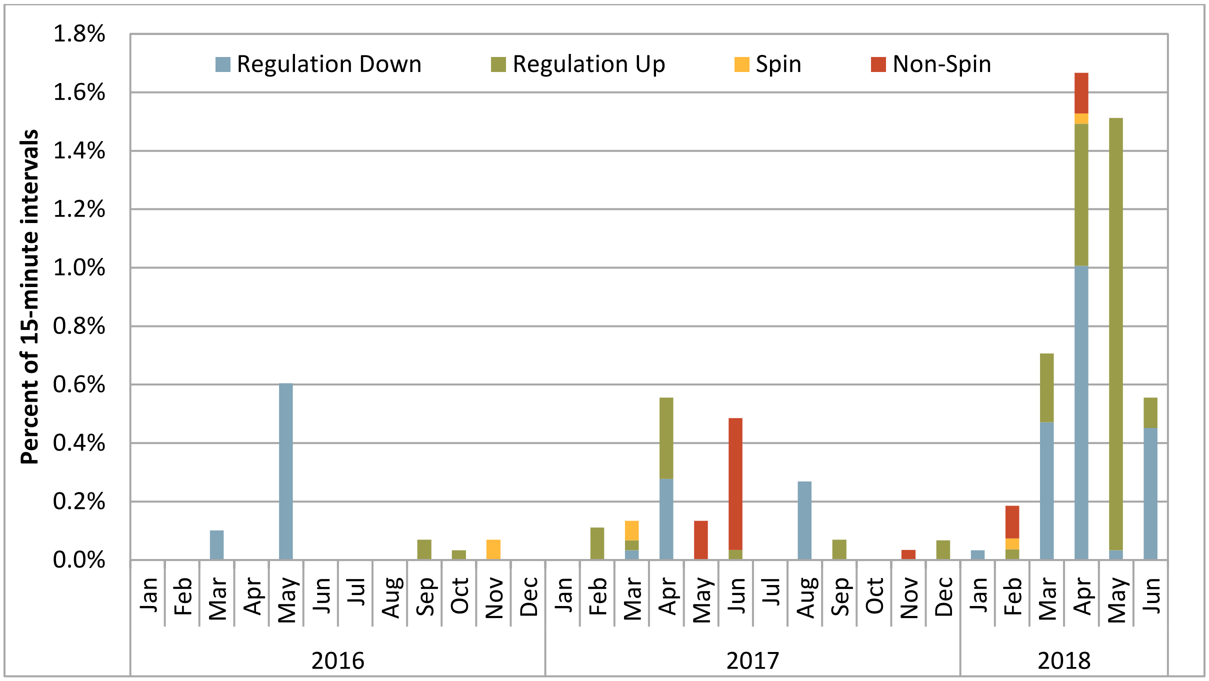
1.4.2 Ancillary service scarcity

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 1.13, the number of intervals with scarcity pricing increased significantly in 2018, particularly during April and May. During the first and second quarters of 2018, there were over 130 valid scarcity intervals in the 15-minute market. In comparison, there were 54 instances during all of 2017 and 26 instances in all of 2016. In the first half of 2018, around 51 percent of the scarcity intervals were for regulation up while 43 percent were for regulation down. By region, around 51 percent of scarcity events occurred in the expanded South of Path 26 region, 32 percent in the recently enforced expanded North of Path 26 region, and the remaining 17 percent in the expanded system region.

[14] Corresponding values for the real-time requirement are not included, but show a similar pattern.

Figure 1.13 Frequency of ancillary service scarcities (15-minute market)



The significant increase in scarcity events in real-time from the previous year is associated with both (1) modifications to the ancillary service requirements and (2) observed changes between available capacity between the day-ahead and 15-minute markets. First, higher operating reserve requirements and the enforcement of a North of Path 26 sub-regional requirement in 2018 put increased pressure on the supply stack to meet ancillary service needs. Next, decreases in available ancillary services in real-time from schedules in the day-ahead market prompted the majority of the scarcity events.

In particular, ancillary services scheduled in the day-ahead market can be capped in real-time at telemetry limits submitted by the plant. This can be a fraction of a megawatt that must then be replaced by other units to meet ancillary service requirements. However, it can often be economic to relax the requirement in this scenario at the scarcity price in lieu of committing a unit or moving a unit to a higher bid segment. This is because the majority of ancillary services are settled at the day-ahead market price with only incremental real-time awards settled at the 15-minute market price. For this reason, over 70 percent of the scarcities in 2018 were for less than 5 MW.

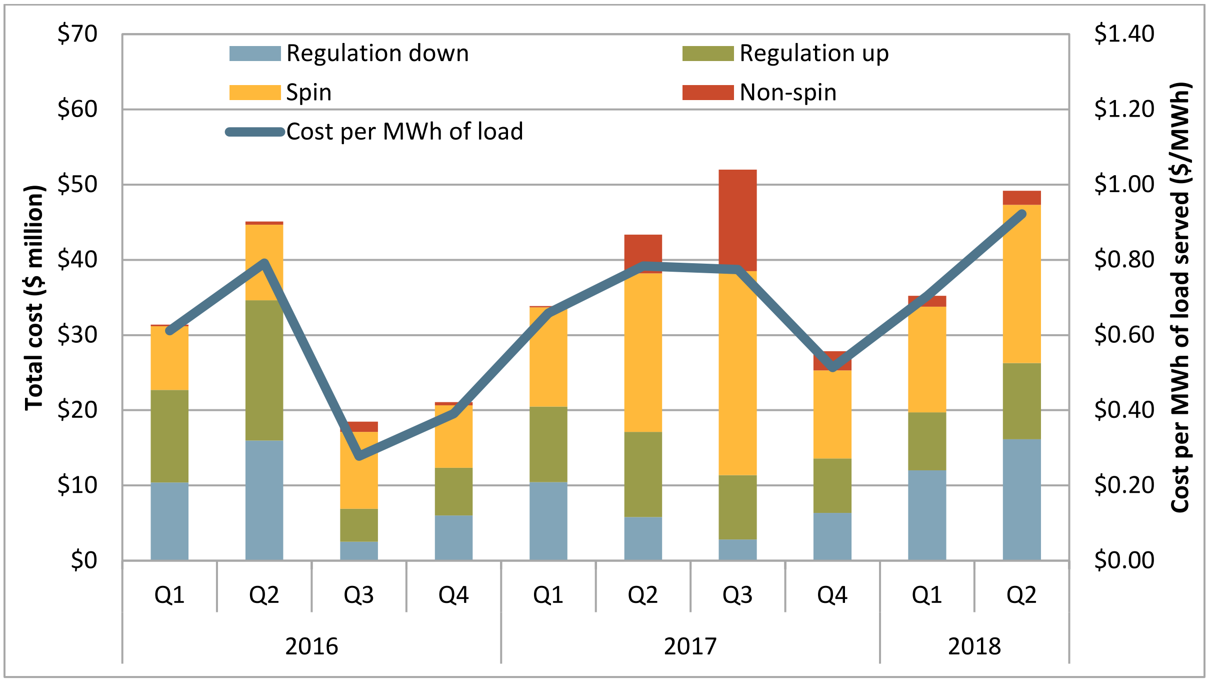
1.4.3 Ancillary service costs

Costs for ancillary services in the first half of 2018 were not significantly higher than costs in the first half of 2017. Costs for ancillary services totaled about $84 million between January and June, compared to about $77 million during the same period in 2017.[15]

15 Load-serving entities reduce their ancillary service requirements by self-providing ancillary service. The costs in this section do not account for the economic value of these quantities. By using their own resources to meet ancillary service requirements, load-serving entities are able to hedge against the risk of higher costs in the ISO market.

Figure 1.14 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. Despite significantly higher operating reserve requirements and more scarcities, total costs in the first and second quarter of 2018 were similar to the first half of 2017.

Figure 1.14 Ancillary service cost by product



First, the increases in operating reserve requirements associated with the BAL-002-2 reliability standard were mostly during off-peak periods when prices were lower which lessened the impact on overall costs. The exception was in hours ending 7, 19, 20 and 21 when increased requirements resulted in a sizeable increase in ancillary service costs in 2018 compared to the first half of 2017. However, this increase was offset by a decrease in costs during the middle of the day. In particular, day-ahead prices and operating reserve requirements in the second quarter of 2018 were lower in the middle of the day on average than in the second quarter of 2017.

Further, the ancillary service scarcities in the 15-minute market had a minimal impact on total costs because of the small volume of incremental real-time ancillary service awards during those intervals.

1.5 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.

Uncertainty calculation implementation issues

Flexible ramping product procurement and prices are determined through demand curves, expected to be calculated from historical net load forecast errors, or the *uncertainty* surrounding ramping needs. In February 2018, DMM identified specific errors in how the flexible ramping product was implemented related to the calculation of uncertainty.[16] In February 2018, the ISO corrected the net load error distributions so that uncertainty was based on an advisory and binding net load in the same time-interval. These distributions were used in the market to calculate the uncertainty requirements and demand curves beginning February 22, 2018.

Market outcomes for flexible ramping product

This section describes the amount of flexible ramping capacity that was procured in the second 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 1.15 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 second quarter, the system-level demand curves bound very infrequently in both directions, particularly in June. The system-level demand curves bound in less than 2 percent of 15-minute intervals during June for each direction. Positive system flexible ramping prices in the upward direction were most frequent in hours ending 6 and 10 and between hours ending 17 and 21. Positive flexible ramping prices in the downward direction were largely concentrated between hours ending 9 and 15. These hours coincide with higher demand for flexible ramping capacity. In the 5-minute market, system-level flexible ramping prices were positive during less than 0.2 percent of intervals in both the upward and downward direction.

[16] For more detailed information on the individual implementation issues and the impact of these errors, see DMM's special report: *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, April 18, 2018: http://www.caiso.com/Documents/FlexibleRampingProductUncertaintyCalculationImplementationIssues.pdf.

Figure 1.15 Monthly frequency of positive 15-minute market flexible ramping shadow price

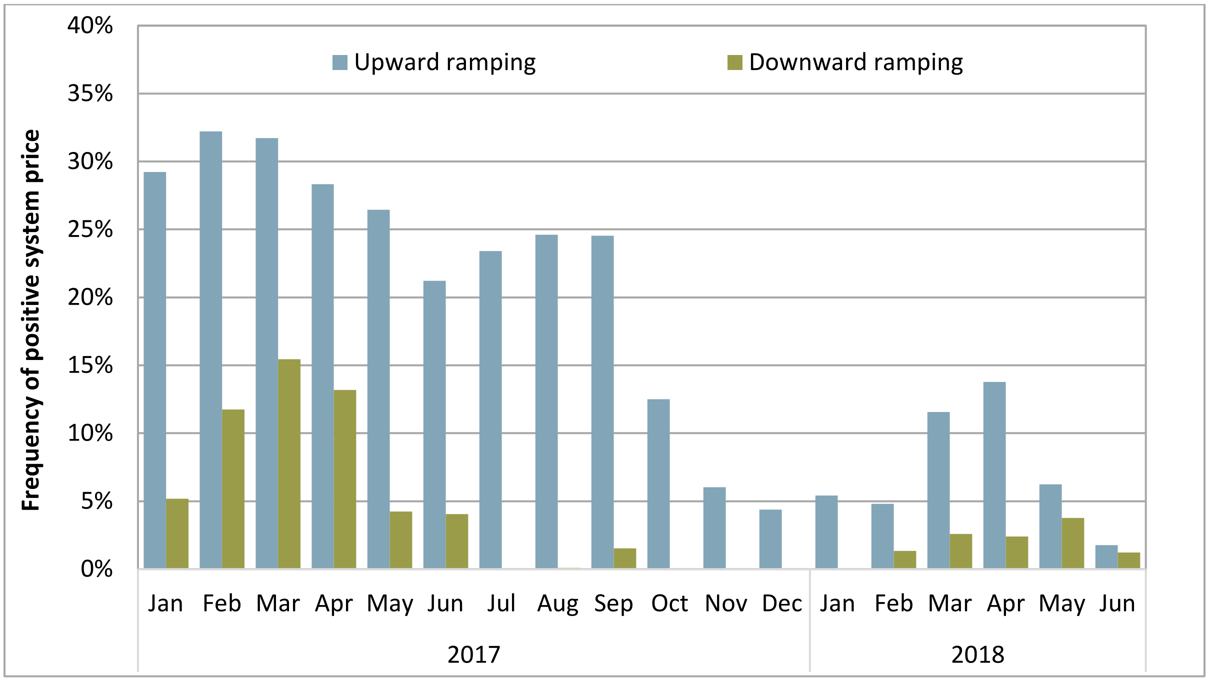
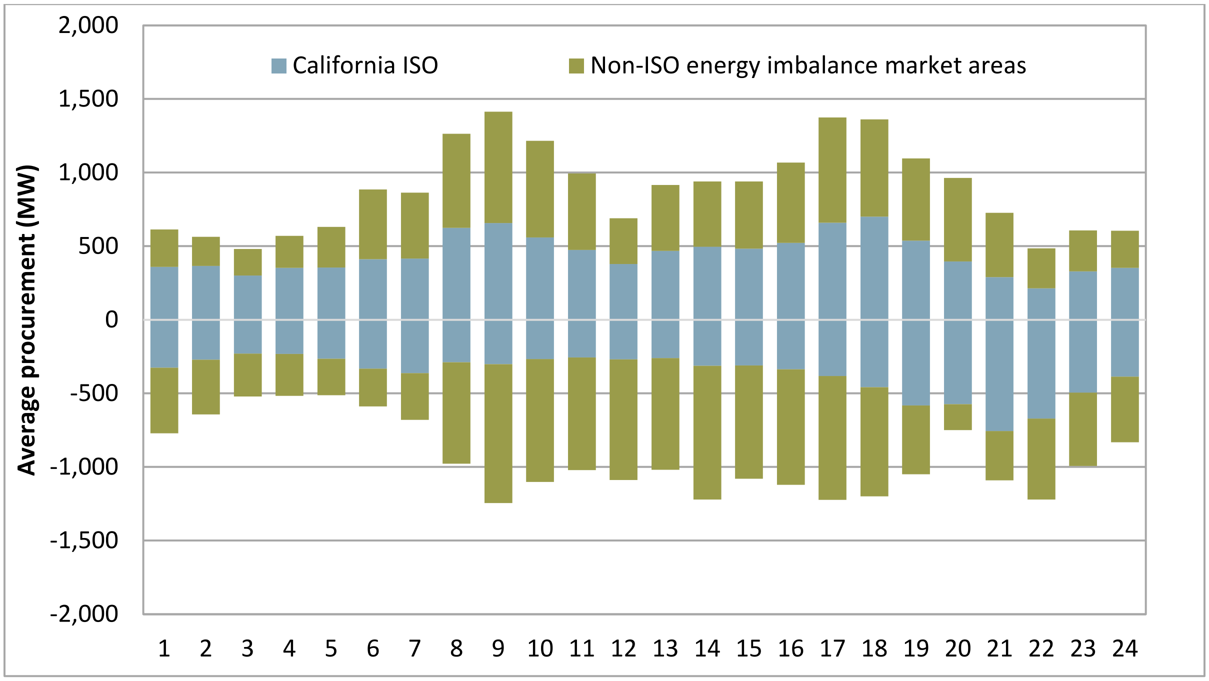


Figure 1.16 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the second quarter. This capacity may have been procured to satisfy system-level demand, area-specific demand, or both. The positive bars show procurement for upward flexible ramping capacity, 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 880 MW of upward capacity and 930 MW of downward capacity in the 15-minute market during the second quarter. Compared to the second quarter of 2017, this represents an increase in upward and downward capacity. The total hourly average quantity of flexible ramping capacity procured in the 5-minute market was about 200 MW in both the upward and downward directions.

Figure 1.16 Hourly average flexible ramping capacity procurement in 15-minute market (April – June)



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.[17]

Figure 1.17 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month.[18] 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 continued to decrease overall during the second quarter of 2018 to around $2.1 million, compared to around $2.2 million during the previous quarter and around $7.5 million during the second quarter of 2017. In particular, payments in June decreased to around $100,000. However, of

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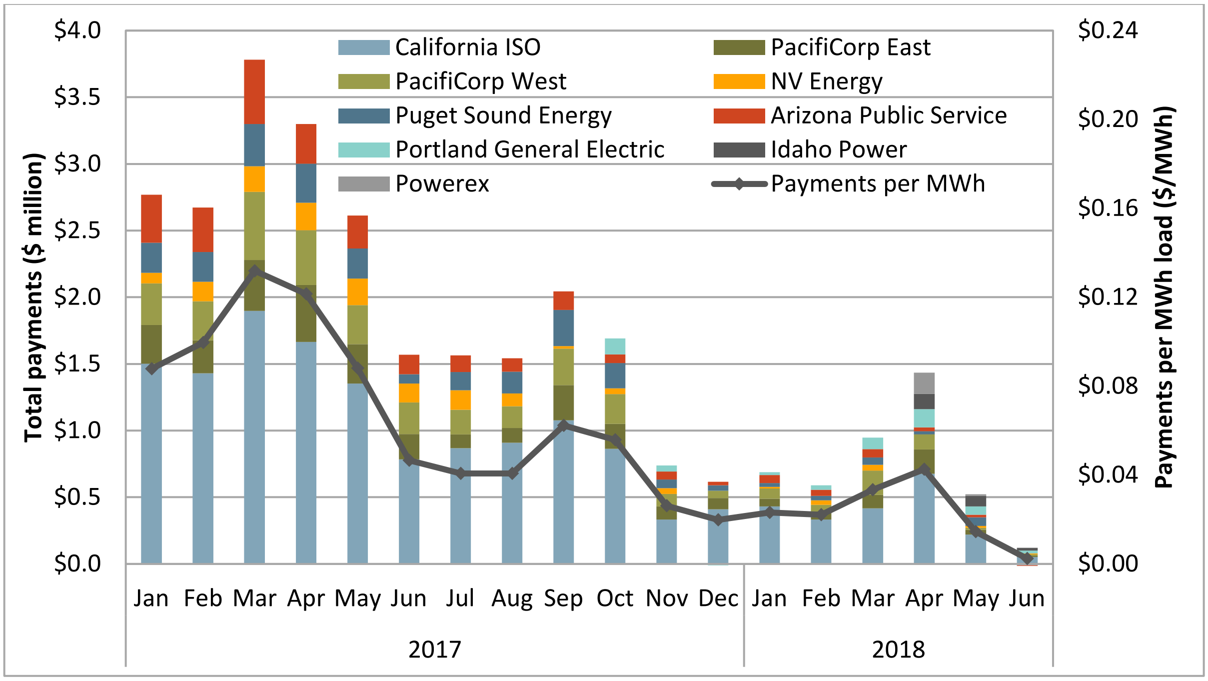
[17] More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

[18] Secondary costs, such as costs associated with impacts of flexible ramping procurement on energy costs, bid cost recovery payments or ancillary service payments are not included in these calculations. Assessment of these costs is complex and beyond the scope of this analysis.

note, power balance constraint relaxations in the 15-minute and 5-minute markets were very infrequent during June.

Figure 1.17 Monthly flexible ramping payments



1.6 Bid cost recovery

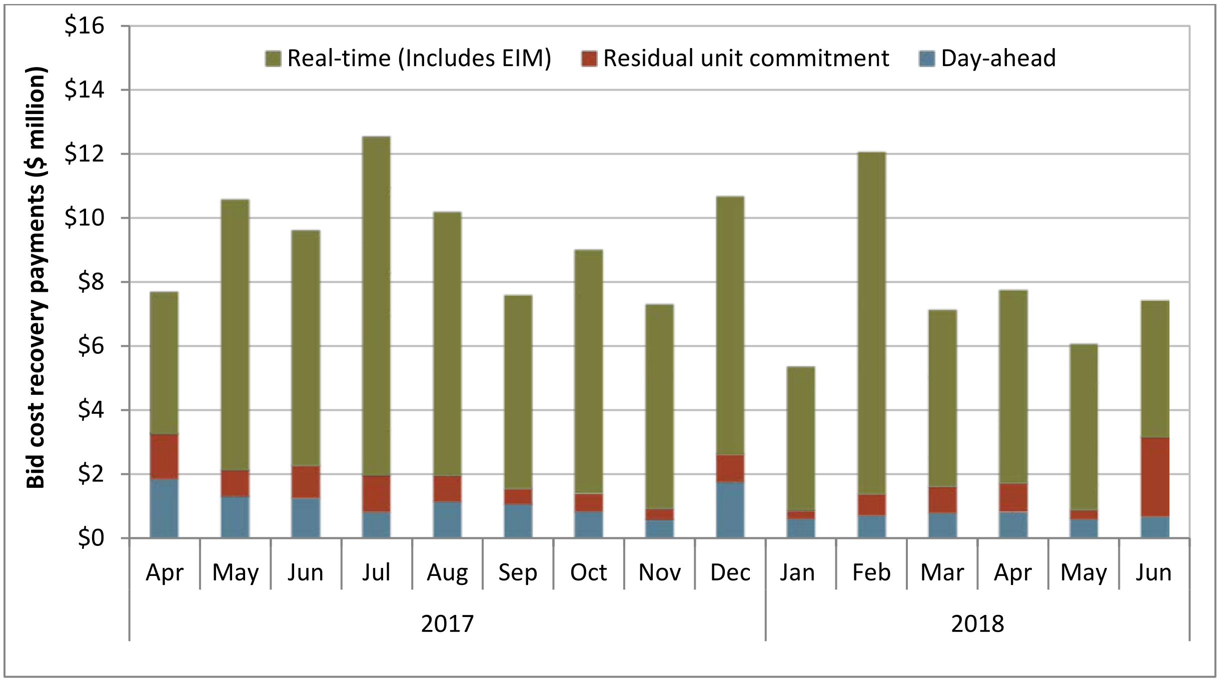
Estimated bid cost recovery payments for the second quarter of 2018 totaled about $21 million. This amount was lower than the total amount of bid cost recovery in the previous quarter and in the second quarter of 2017, which were about $25 million and $28 million, respectively.

Bid cost recovery attributed to the day-ahead market totaled about $2 million, which was about the same in the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $3.7 million, which almost doubled when compared to the prior quarter. In June, these payments were about $2.5 million. The significant increase in residual unit commitment bid cost recovery payments in June can be attributed to the increased residual unit commitment capacity procurement targets.[19]

Bid cost recovery attributed to the real-time market totaled about $15.5 million, or about $5 million lower than payments in the prior quarter and in the second quarter of 2017.

[19] Refer to Section 1.8 for more information on residual unit commitment sources.

Figure 1.18 Monthly bid cost recovery payments



1.7 Convergence bidding

Convergence bidding was profitable overall during the second quarter. For the second consecutive quarter, virtual supply was also profitable. Before accounting for bid cost recovery charges, virtual supply generated net revenues of about $9.9 million while virtual demand net revenues were a loss of about $1 million. Combined net revenues for virtual supply and demand were about $7.4 million after accounting for about $1.5 million of virtual bidding bid cost recovery charges.

1.7.1 Convergence bidding trends

Average hourly cleared volumes increased to about 3,000 MW from about 2,000 MW in the previous quarter. Average hourly virtual supply increased to about 1,700 MW compared to the previous quarter at about 1,200 MW. Virtual demand averaged around 1,300 MW during each hour of the quarter, higher than the previous quarter of about 840 MW. Also similar to the previous quarter, on average, about 38 percent of virtual supply and demand bids offered into the market cleared in the second quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 400 MW on average, which increased slightly from about 360 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply between hours ending 18 and 22. In the remaining 19 hours, net cleared virtual supply exceeded net cleared virtual demand. Net cleared virtual supply was highest during the most hours of the day except for hours ending 18 through 22. During these hours virtual demand cleared about 400 MW more than virtual supply, on average.

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 18 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 400 MW of virtual demand offset by 400 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 47 percent of all cleared virtual bids in the first quarter, up from about 40 percent in the previous quarter.

1.7.2 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 $8.9 million. Net revenues for virtual supply and demand fell to about $7.4 million after including about $1.5 million of virtual bidding bid cost recovery charges.[20]

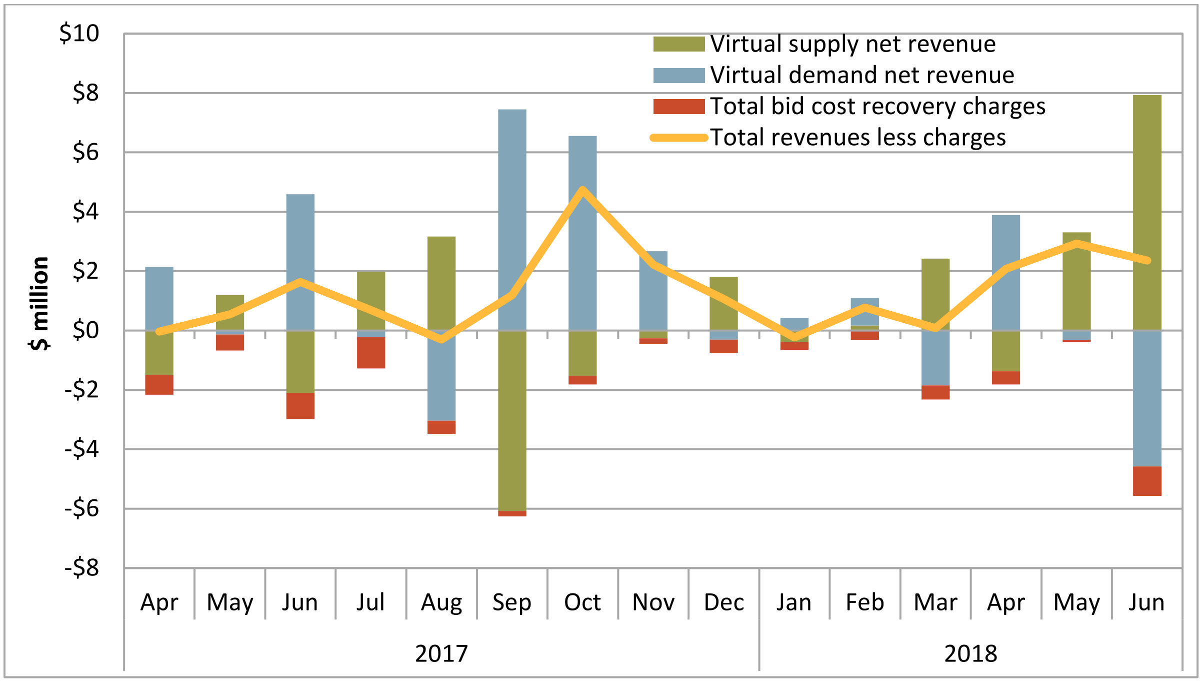
Figure 1.19 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

Before accounting for bid cost recovery charges:

- Total market revenues were positive during all three months in the quarter. Net revenues during the first quarter totaled about $8.2 million, compared to about $4.2 million during the same quarter in 2017, and about $1.2 million during the previous quarter.
- Virtual demand net revenues were positive in April and negative in May and June. In total, virtual demand generated negative net revenues of about $1 million for the quarter.
- Virtual supply net revenues were negative about $1.4 million in April but positive in May and June, $3.3 million and $7.9 million respectively. In total, virtual supply generated net revenues of about $9.9 million.

[20] 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.

Figure 1.19 Convergence bidding revenues and bid cost recovery charges



After accounting for bid cost recovery charges:

- Convergence bidders received about $7.4 million after subtracting bid cost recovery charges of about $1.5 million for the quarter.[21,22] Bid cost recovery charges were about $0.4 million in April, $0.06 in May and $1 million in June.

Net revenues and volumes by participant type

Table 1.7 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the second quarter.[23] Financial entities represented the largest segment of the virtual bidding market, accounting for about 56 percent of volume and a 72 percent of settlement revenue. Marketers represented about 39 percent of the trading volumes and about 26 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

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21 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.

22 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.

23 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.

revenue, at about 5 percent and 2 percent respectively. Similar to last quarter, load-serving entities accounted for around $0.2 million in net payments to the market.

Table 1.7 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	719	922	1,640	-$0.01	$6.15	$6.14
Marketer	542	598	1,140	-$1.17	$3.42	$2.25
Physical load	0	153	153	$0.00	-$0.17	-$0.17
Physical generation	7	0	7	-$0.02	$0.00	-$0.01
Total	**1,268**	**1,673**	**2,940**	**-$1.2**	**$9.4**	**$8.2**

1.8 Residual unit commitment adjustments

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase residual unit commitment requirements. Use of this tool increased significantly in June 2018.

As illustrated in Figure 1.20, residual unit commitment procurement appears to be driven in part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 30 percent lower in the second quarter of 2018 than in the second quarter of 2017.

The ISO in 2014 introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources.[24] This eligible intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.20.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor contributed towards decreased residual unit commitment in the second quarter of 2018. In addition, ISO operators were able to increase the amount of residual unit commitment requirements primarily due to weather change and fire danger concerns. This tool, noted as operator adjustments (red bar) in the figure, was used frequently in June averaging about 481 MW per hour.

Figure 1.21 illustrates the average hourly determinants of residual unit commitment procurement. Operator adjustments were concentrated in the peak load hours of the day, peaking in hours ending 10 through 22. While adjustments were low in the off-peak hours, net virtual supply and difference between forecasted load and cleared supply were the major drivers of residual unit commitment

[24] Specifically, the adjustment is only made for PIRP resources that have positive schedules in the day-ahead market. PIRP resources that are not scheduled in the day-ahead market are not adjusted at this time.

procurement in these periods. On average, day-ahead cleared capacity was greater than day-ahead load forecast during hours 10 through 18 in the second quarter. Intermittent resource adjustments were greatest during hours ending 8 through 19.

Figure 1.20 Determinants of residual unit commitment procurement

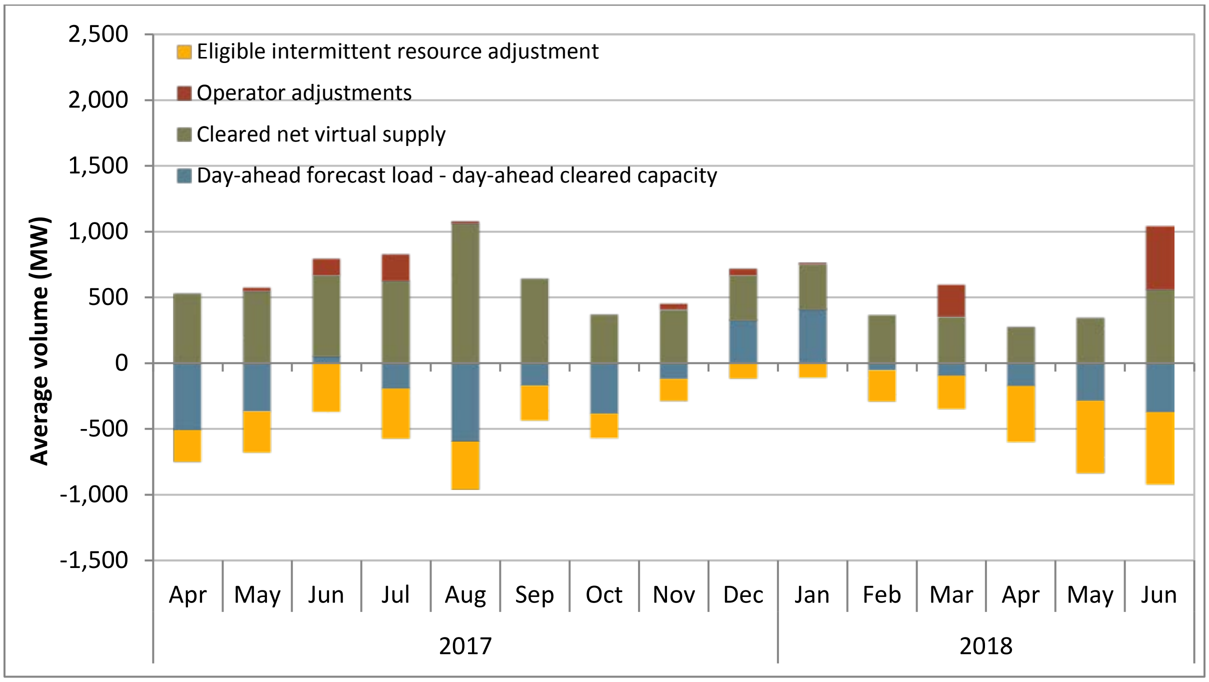
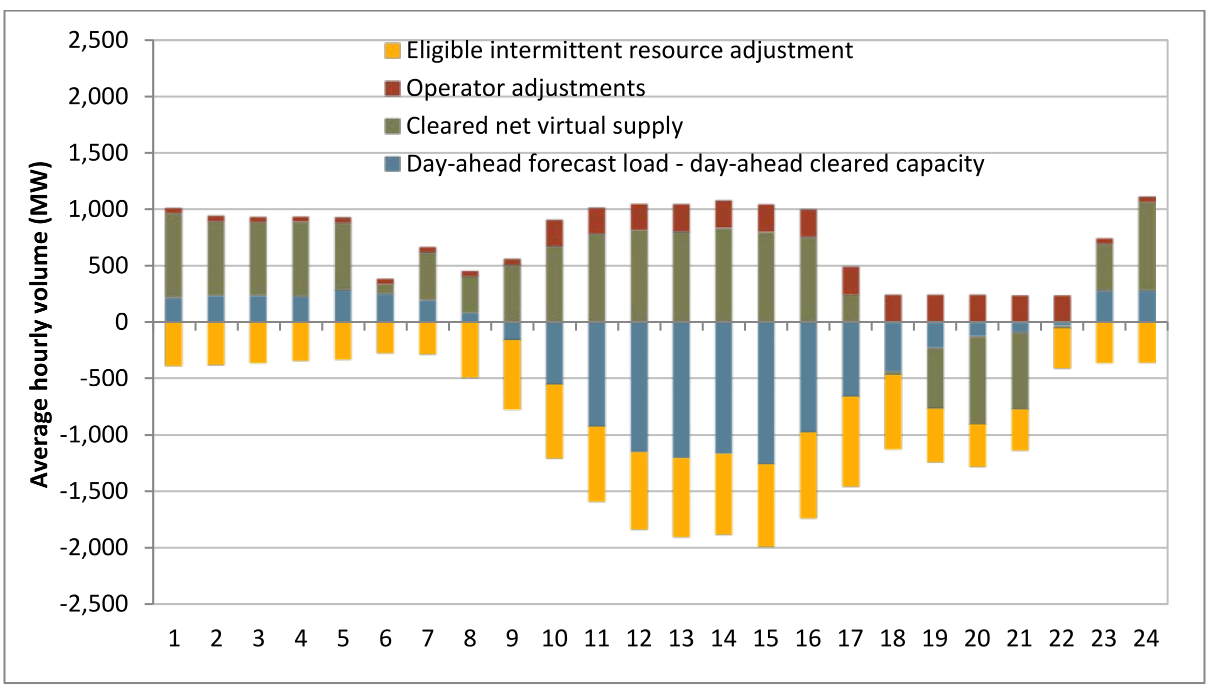


Figure 1.21 Average hourly determinants of residual unit commitment procurement (Apr - Jun)



1.9 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*. Recently, the ISO has begun using 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.[25] DMM will continue to use the terms load forecast adjustment and load bias limiter for consistency with prior reports.

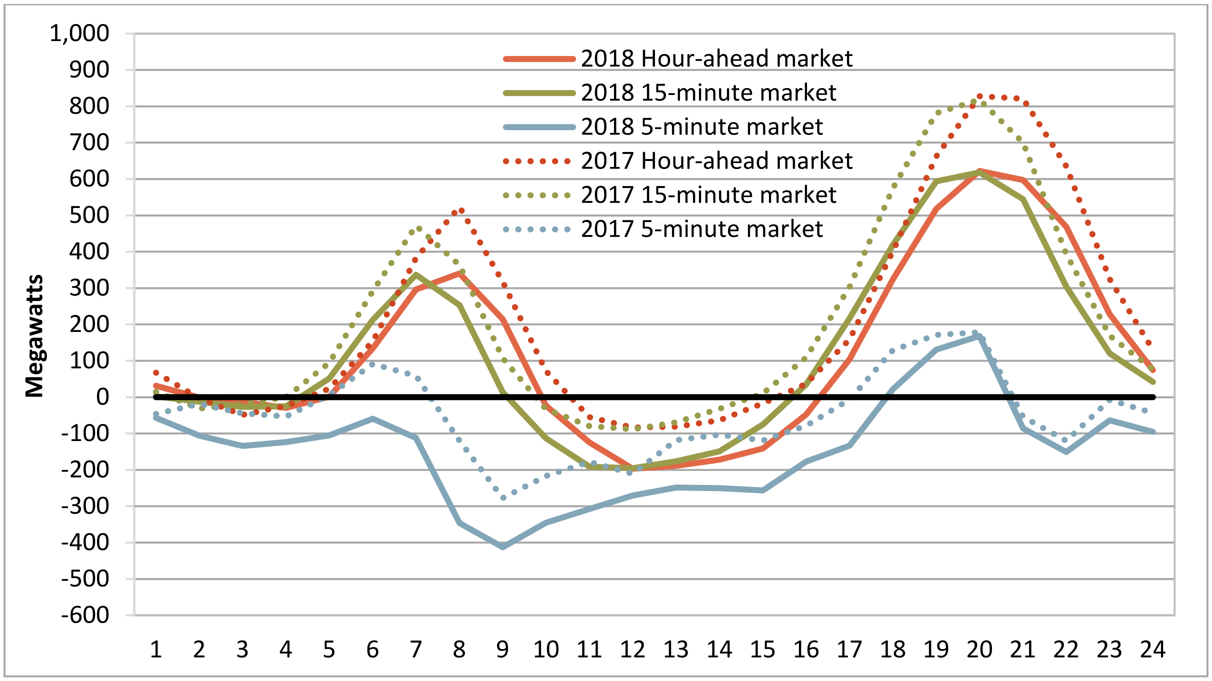
Frequency and size of load adjustments, generation/import prices and imports

The dramatic increase in load forecast adjustments experienced in the ISO's hour-ahead and 15-minute markets in 2017 appear to have slightly decreased in the second quarter of 2018 for the steep morning and evening net load ramp periods. The mid-day period experienced an increase in load forecast adjustments for these markets for the same time period. In general, the 5-minute market load forecast adjustments increased throughout the day when comparing the second quarter of 2018 with the same period in 2017. Figure 1.22 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for the second quarter in 2018 and 2017. The general shape and direction of load adjustments were similar for hour-ahead, 15-minute and 5-minute market adjustments.

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 2018 5-minute market adjustments differ dramatically from other markets for nearly all hours of the day. On average for the quarter there were only three hours where load forecast adjustments were positive in the 5-minute market, hour end 18, 19 and 20. In these hours the adjustment was on average about 400 MW positive compared to the hour-ahead and 15-minute markets adjustments. The largest negative deviations between the 5-minute and other markets were observed in hours ending 8, 9, 21, 22 when the hour-ahead adjustments exceeded the 5-minute adjustments by around 690 MW, 630 MW, 680 MW and 620 MW, respectively. Both positive and negative adjustments are often associated with over-forecasted load, changes in expected renewable generation as well as morning or evening net load ramp.

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

Figure 1.22 Average hourly load adjustment (Q2 2018 – Q2 2017)



1.10 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.

The owners of transmission, or entities paying for the cost of building and maintaining transmission, are entitled to congestion revenues associated with transmission capacity in the day-ahead market. 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).[26] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred.

Load-serving entities then pass that transmission access charge through to ratepayers in their customers' electricity bills. Therefore, these ratepayers are entitled to the revenues from this

[26] 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.

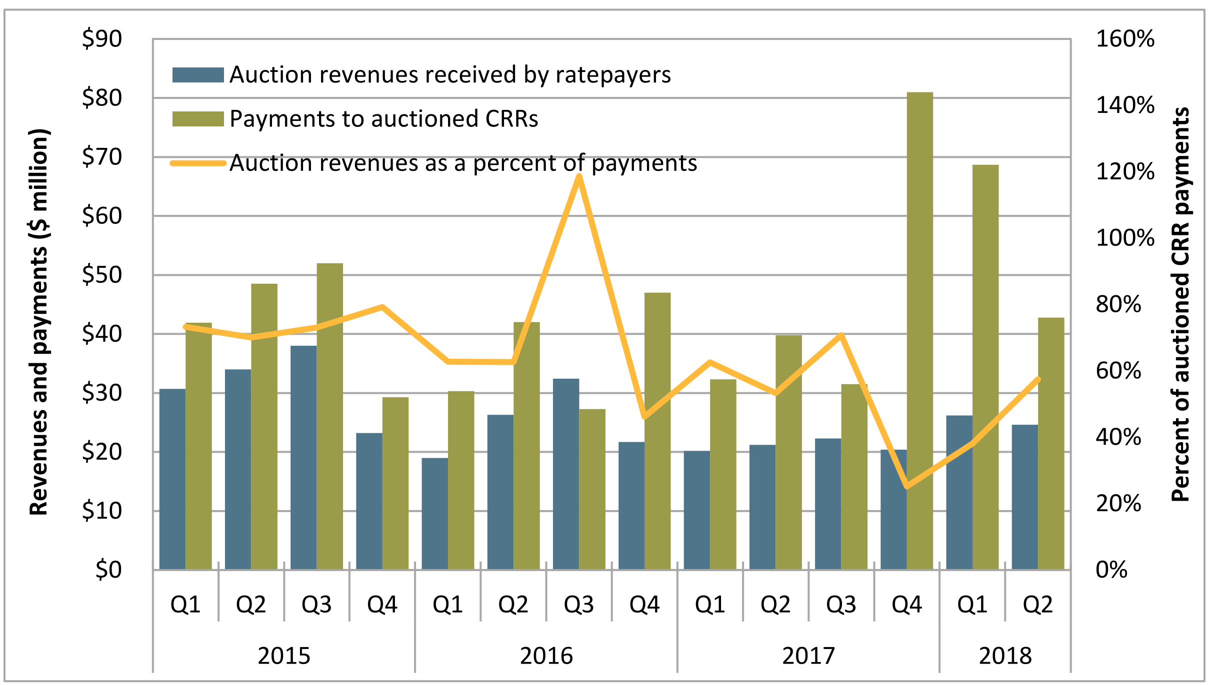
transmission. When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments represents a loss to ratepayers. The losses, therefore, cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights. As explained in DMM's 2016 annual report, DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction.[27]

Analysis of congestion revenue right auction returns

Ratepayers lost a total of $18 million during the second quarter of 2018 as payments to auctioned congestion revenue rights holders exceeded auction revenues by this amount. This brings total losses to transmission ratepayers from congestion revenue rights sold in the ISO's auction to over $61 million during the first half of 2018. Auction revenues were 57 percent of payments made to non-load-serving entities during the second quarter of 2018, slightly up from 53 percent during the same quarter in 2017.

Financial entities (which do not schedule or trade physical power or serve load) continued to have the highest profits between the entity types, at approximately $13 million. This was a decrease from $16 million profits during the second quarter of 2017. Profits by energy marketers totaled about $4 million, up from $1.6 million during the same quarter in 2017. Generators gained about $1.7 million compared to $1 million in the second quarter of 2017.

Figure 1.23 Auction revenues and payments to non-load-serving entities



[27] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

Congestion revenue rights auction modifications

DMM believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off these financial instruments on behalf of ratepayers after the congestion revenue right allocations.[28] DMM believes the current auction is unnecessary and could be eliminated.[29] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format should be changed to a *market* for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell congestion revenue rights.

On March 22, 2018, the Board of Governors approved policy changes that will reduce the number and pairs of nodes at which congestion revenue can be purchased in the auction (Track 1A). The changes also require transmission owners to submit planned outages prior to annual allocation and auction process. These tariff changes were approved by FERC on June 29, 2018. These changes are intended to be implemented in time for the 2019 annual allocation and auction processes.

A second set of changes (Track 1B) was approved by the Board of Governors on June 22, 2018.[30] This proposal would reduce the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.

In combination with the ISO's Track 1A changes, these additional changes will provide a measure of protection against the risks imposed on transmission ratepayers by the current auction design and will likely reduce the current level of ratepayer losses. DMM supported both initiatives as an incremental improvement, but continues to recommend that the auction process be replaced by a market for financial hedges based on clearing of bids from willing buyers and sellers.[31]

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28 DMM whitepaper on *Shortcomings in the congestion revenue right auction design*, November 28, 2016*:* http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf

29 DMM whitepaper on *Market alternatives to the congestion revenue rights auction*, November 27, 2017. http://www.caiso.com/Documents/Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

30 DMM presentation on *Potential Market Alternatives to the CRR Auction*, April 10, 2018: http://www.caiso.com/Documents/Presentation-RogerAvalosDMM-Apr102018.pdf

31 *DMM comments on congestion revenue rights auction efficiency track 1 B*, June 21, 2018: http://www.caiso.com/Documents/DecisiononCongestionRevenueRightsAuctionEfficiencyTrack1BProposal-DMMComments-Jun2018.pdf

2 Energy imbalance market

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

- Idaho Power and Powerex became participants in the energy imbalance market on April 4.
- Prices in the Idaho Power area tracked closely to prices in PacifiCorp East. Price separation between these areas and the ISO was most pronounced during peak load hours when high system prices caused transfers from these areas to reach export limits.
- Prices in the Northwest 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 the region.
- The frequency of congestion across the energy imbalance market decreased significantly during the second quarter, particularly from the areas in the Northwest toward the ISO. Congestion from PacifiCorp West, Portland General Electric, Puget Sound Energy and Powerex in the direction of the ISO occurred during around 35 percent of 15-minute intervals and 28 percent of 5-minute intervals. In comparison, congestion toward the ISO from these areas occurred in over 60 percent of 15-minute and 5-minute market intervals during the first quarter.

2.1 Energy imbalance market performance

Energy imbalance market prices

Figure 2.1 and Figure 2.2 show real-time prices for the energy imbalance market balancing areas. Several balancing areas were grouped together because of similar average hourly pricing. The figures also show prices for Southern California Edison for comparison with prices in the ISO. Average prices for NV Energy and Arizona Public Service tracked closely to system prices during most hours. Prices for PacifiCorp East and Idaho Power often tracked similarly to system prices on average, except during hours ending 19 through 22 when prices were significantly lower. This is primarily due to several days with high system prices when energy imbalance market transfers out of PacifiCorp East and Idaho Power reached their upper scheduling 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 in and out of this region. This resulted in local resources setting the price in a combined Northwest region during many intervals.

Figure 2.1 Hourly 15-minute market prices (April 4 – June 30)

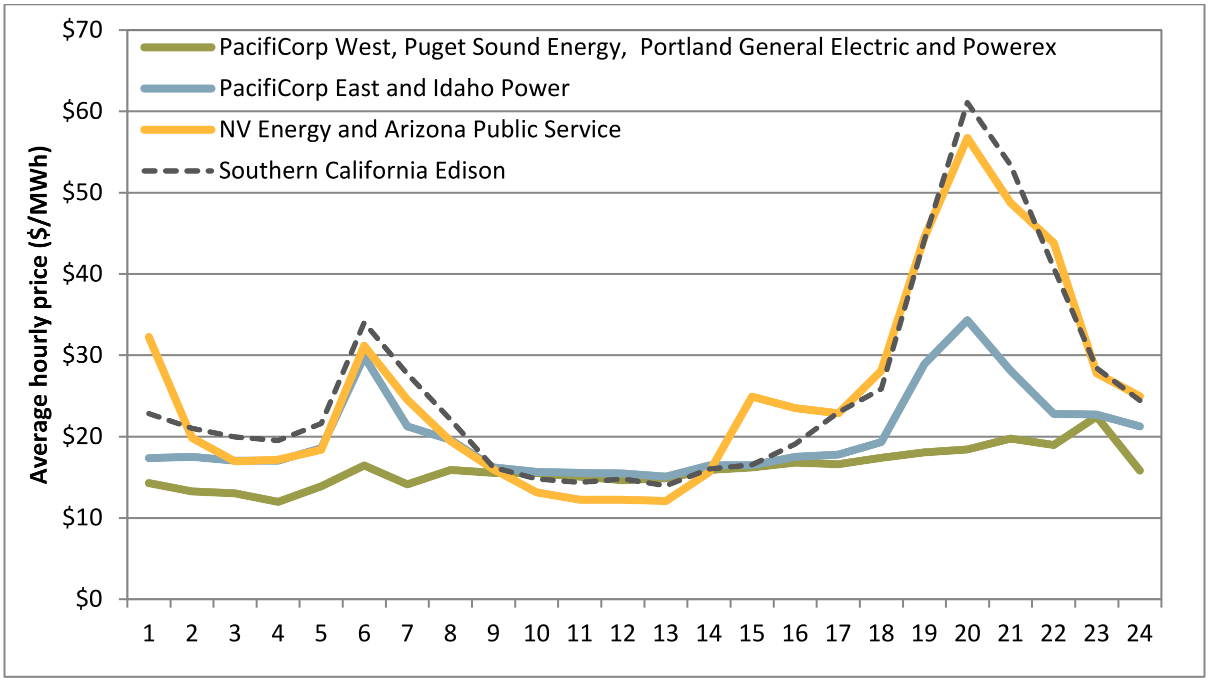
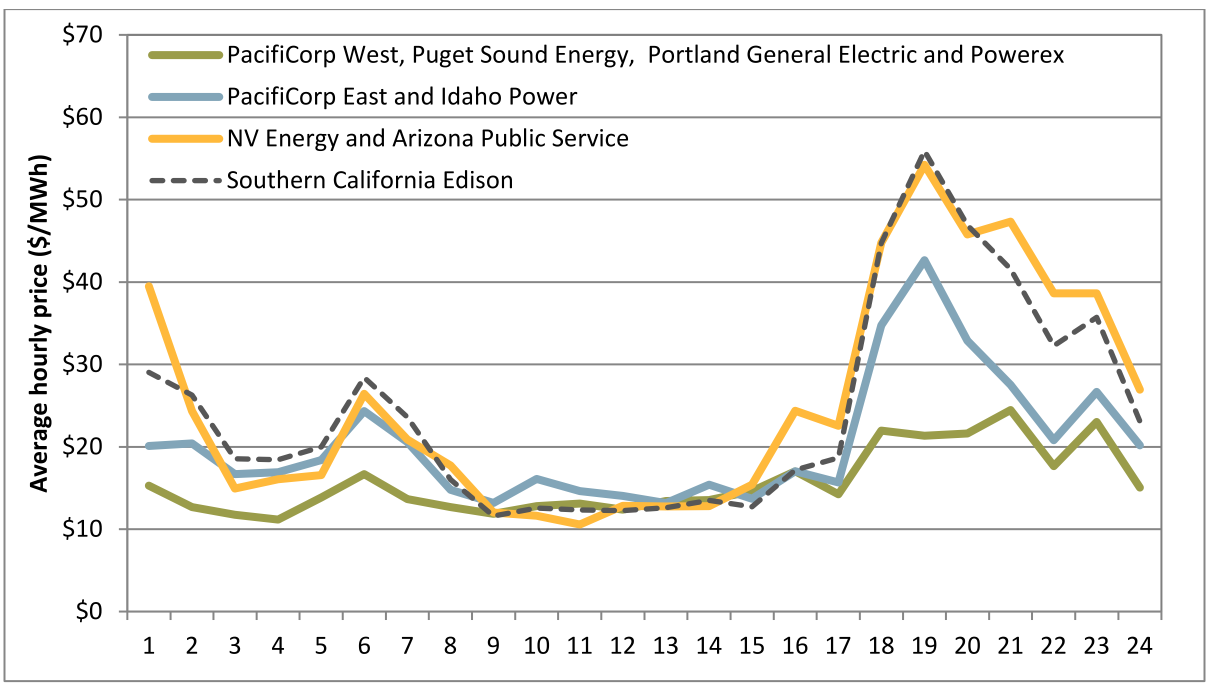


Figure 2.2 Hourly 5-minute market prices (April 4 – June 30)



2.2 Flexible ramping sufficiency test

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

When the energy imbalance market was initially implemented there was an upward ramping sufficiency test. In November 2016, the ISO implemented an additional downward ramping sufficiency test in the market with the introduction of the flexible ramping product, which replaced the flexible ramping constraint. If an area fails the upward sufficiency test, energy imbalance market imports cannot be increased.[32] Similarly, if an area fails the downward sufficiency test, exports cannot be increased. In addition to the sufficiency test, each area is also subject to a capacity test. If an area fails the capacity test, then the flexible ramping sufficiency test automatically fails as a result.[33]

Sufficiency test results

Limiting transfers can impact the frequency of power balance constraint relaxations and, thus, price separation across balancing areas. The majority of power balance constraint relaxations during the quarter, across all of the energy imbalance market balancing areas, occurred during hours when the area failed the flexible ramping sufficiency test. Constraining transfer capability may also 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.

Figure 2.3 and Figure 2.4 show the percent of hours in which an energy imbalance market area failed the sufficiency test in the upward and downward direction, respectively. During the second quarter, there was a slight increase in the frequency of upward and downward sufficiency test failures overall with the addition of Idaho Power and Powerex. In particular, Idaho Power failed the upward sufficiency test in around 5 percent of hours during the quarter.

32 *Business Practice Manual for the Energy Imbalance Market*, August 30, 2016, p. 45-52: https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V6_clean.docx.

33 *Business Practice Manual for the Energy Imbalance Market*, August 30, 2016, p. 45.

Figure 2.3 Frequency of upward failed sufficiency tests by month

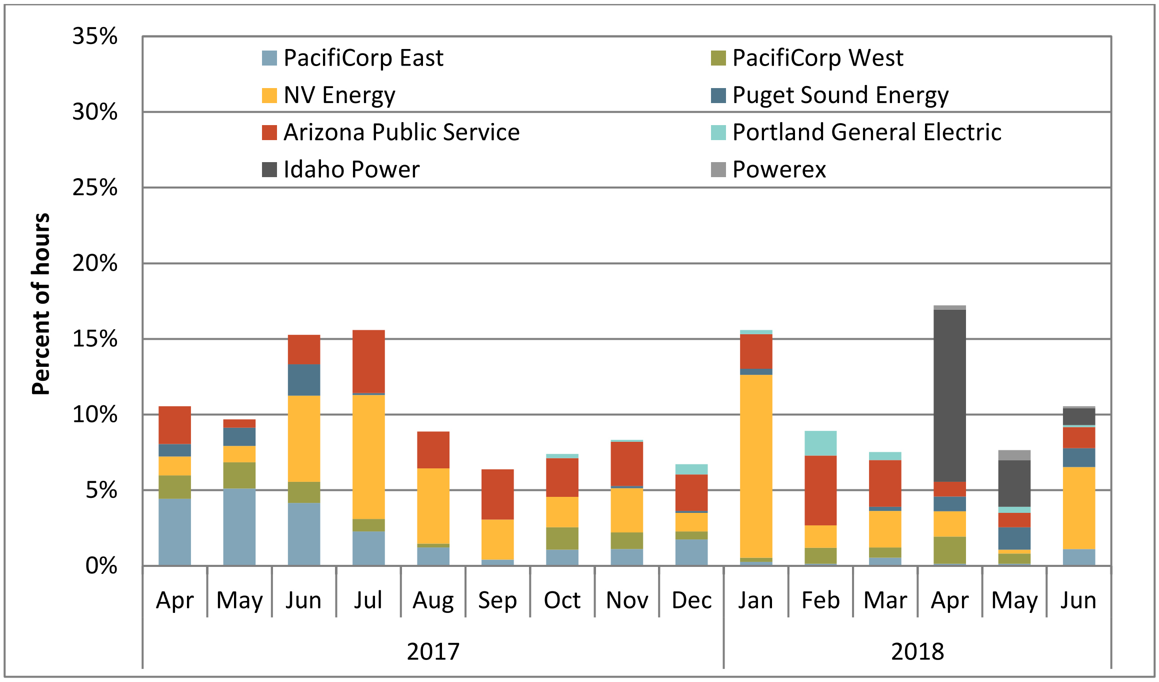
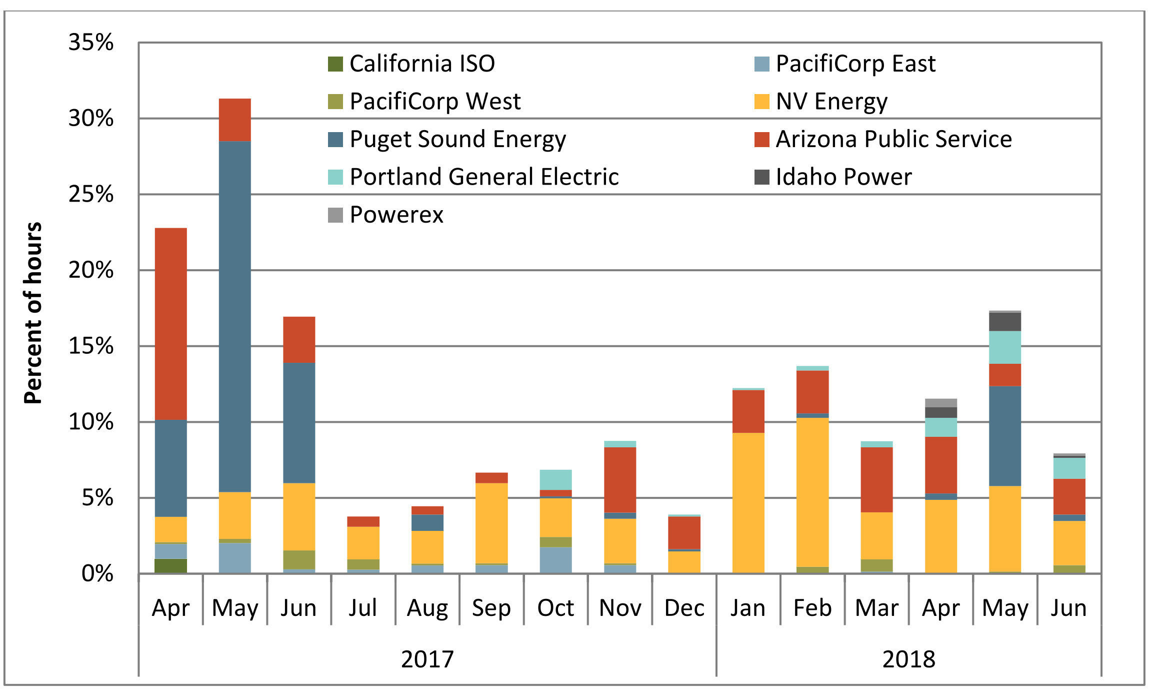


Figure 2.4 Frequency of downward failed sufficiency tests by month

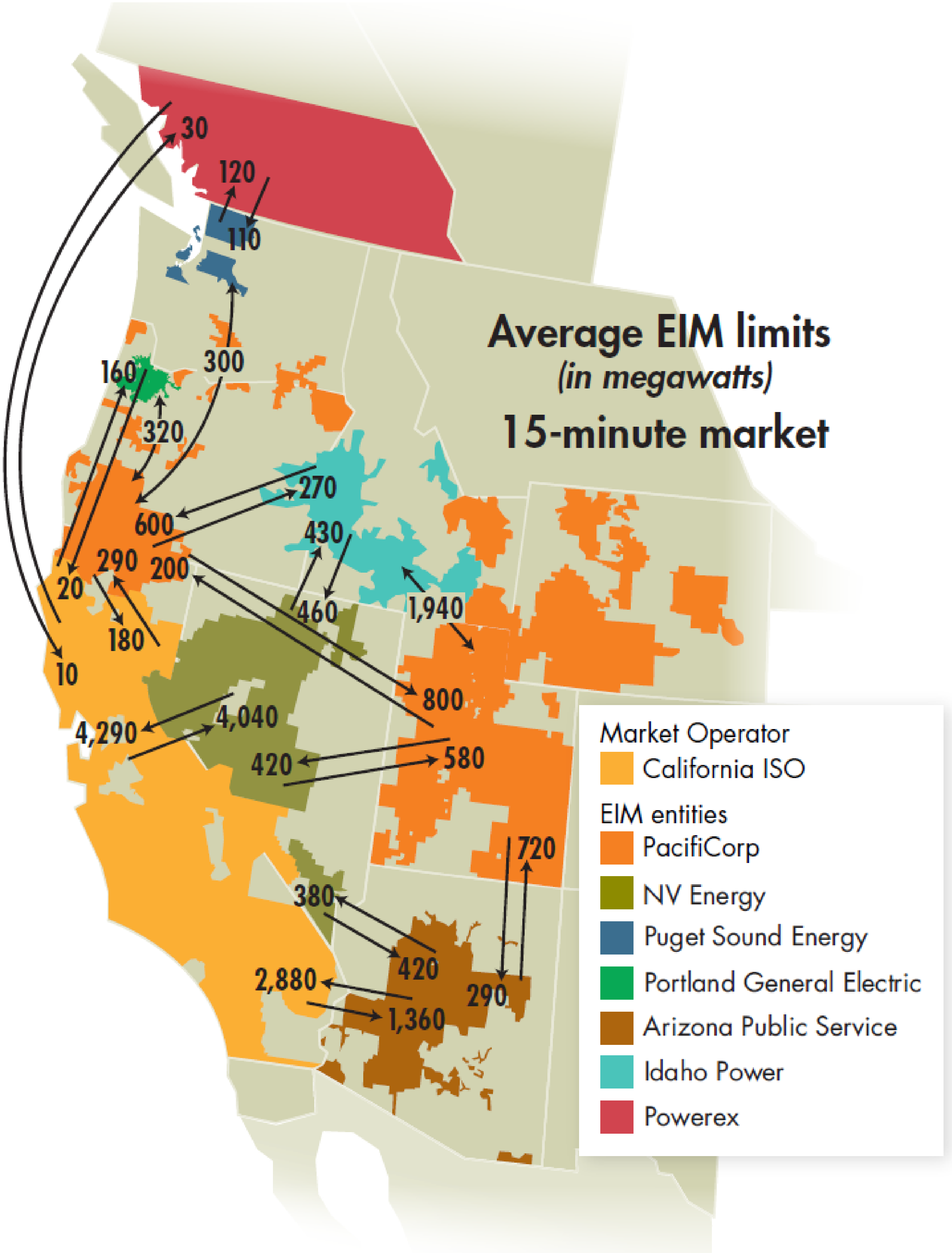


2.3 Energy imbalance market transfers

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. Initially, when PacifiCorp East and PacifiCorp West were the only energy imbalance market areas, there was little transfer capability between these areas and the ISO. Since then, the amount of transfer capability has increased significantly with the additions of NV Energy, Arizona Public Service, Puget Sound Energy and Portland General Electric. On April 4, 2018, Idaho Power and Powerex joined the energy imbalance market, expanding the transfer capability and benefits within the market.

Figure 2.5 shows average 15-minute market limits between each of the energy imbalance market areas between April 4 and June 30, 2018. 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 also large to an extent. 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, average 15-minute market limits from each of Portland General Electric and Powerex toward the ISO were less than 20 MW during the second quarter.

Figure 2.5 Average 15-minute market energy imbalance market limits (April 4 – June 30)



The frequency of congestion across the energy imbalance market decreased significantly during the second quarter, particularly from the areas in the Northwest toward the ISO. This was largely due to added west-to-east transfer capability both with the implementation of Idaho Power as well as new direct transfer capability from PacifiCorp West to PacifiCorp East. Previously, transfer capability between PacifiCorp West (and Northwest areas) and PacifiCorp East (and the rest of the system) was only one-directional, from East to West.

Table 2.1 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.[34]

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 from PacifiCorp West, Portland General Electric, Puget Sound Energy and Powerex in the direction of the ISO occurred during around 35 percent of 15-minute intervals and 28 percent of 5-minute intervals. This led to lower prices during the quarter in these areas relative to the rest of the energy imbalance market and the ISO. However, the Northwest region was much less frequently congested in comparison to the first quarter when congestion toward the ISO from these areas occurred in over 60 percent of 15-minute and 5-minute market intervals.

Table 2.1 also shows that congestion in either direction between NV Energy, Arizona Public Service, or the ISO area was infrequent during the quarter. There was also relatively little congestion in the PacifiCorp East and Idaho Power areas. In particular, the frequency of congestion in the 5-minute market from PacifiCorp East towards the ISO decreased from around 17 percent of intervals in the first quarter to around 4 percent of intervals in the second quarter.

Table 2.1 Frequency of congestion in the energy imbalance market (April 4 – June 30)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
NV Energy	2%	2%	2%	2%
Arizona Public Service	2%	4%	1%	5%
PacifiCorp East	8%	6%	4%	8%
Idaho Power	9%	8%	5%	10%
PacifiCorp West	32%	5%	27%	11%
Portland General Electric	34%	5%	29%	11%
Puget Sound Energy	34%	7%	29%	11%
Powerex	39%	28%	26%	22%

34 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.

Different areas in the energy imbalance market exhibited different hourly transfer patterns during the quarter. This pattern is driven by the resource mix and relative prices in these areas during these periods. For instance, Figure 2.6 shows average hourly imports (negative values) and exports (positive values) into and out of the ISO during the quarter in the 15-minute market.[35] The bars show the average hourly transfers with the connecting areas while the gold line shows the average hourly net transfer. Similar to previous quarters, the ISO was typically exporting during the middle of the day and mostly to NV Energy and Arizona Public Service where transfer capability is much more significant.

Figure 2.6 California ISO – average hourly 15-minute market transfer (April 4 – June 30)

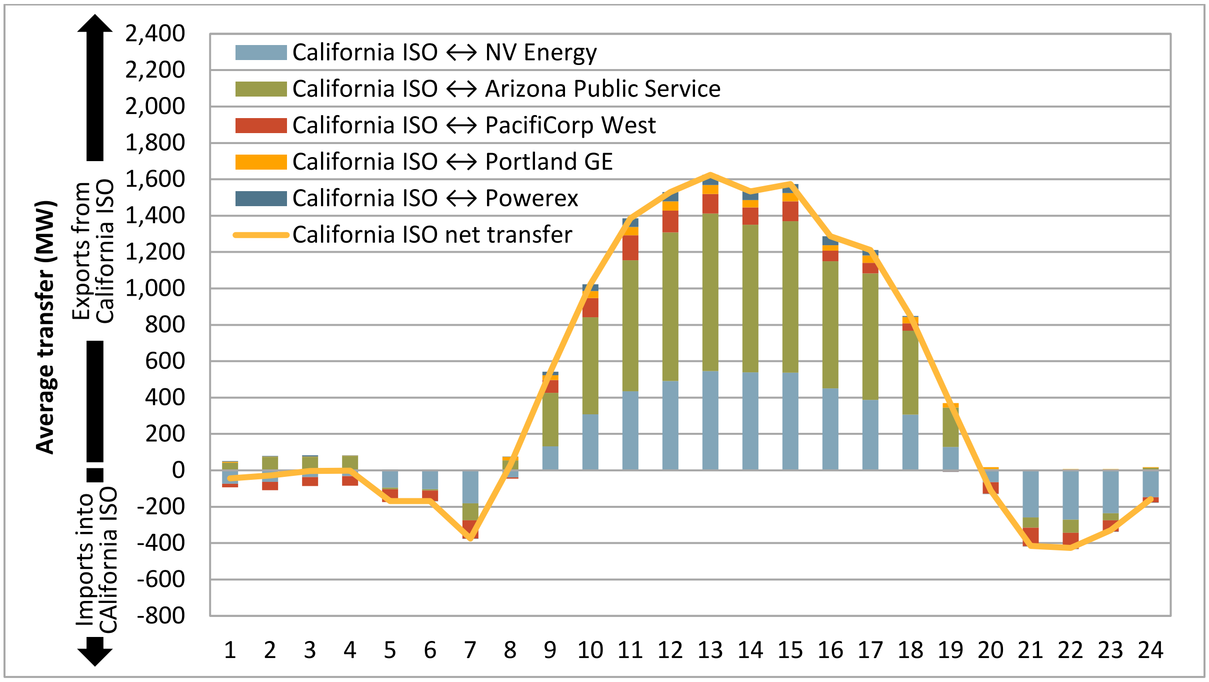


Figure 2.7 through Figure 2.11 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, and Powerex, net of all base schedules. As shown in Figure 2.7 and Figure 2.8, NV Energy and Arizona Public Service were net importers during midday hours (mostly from the ISO when solar generation was greatest), and net exporters during other hours of the day.

35 Transfer figures in this section show real-time energy market flows net of all base schedules in the 15-minute market. Transfer amounts in previous reports were in the 5-minute market.

Figure 2.7 NV Energy – average hourly 15-minute market transfer (April 4 – June 30)

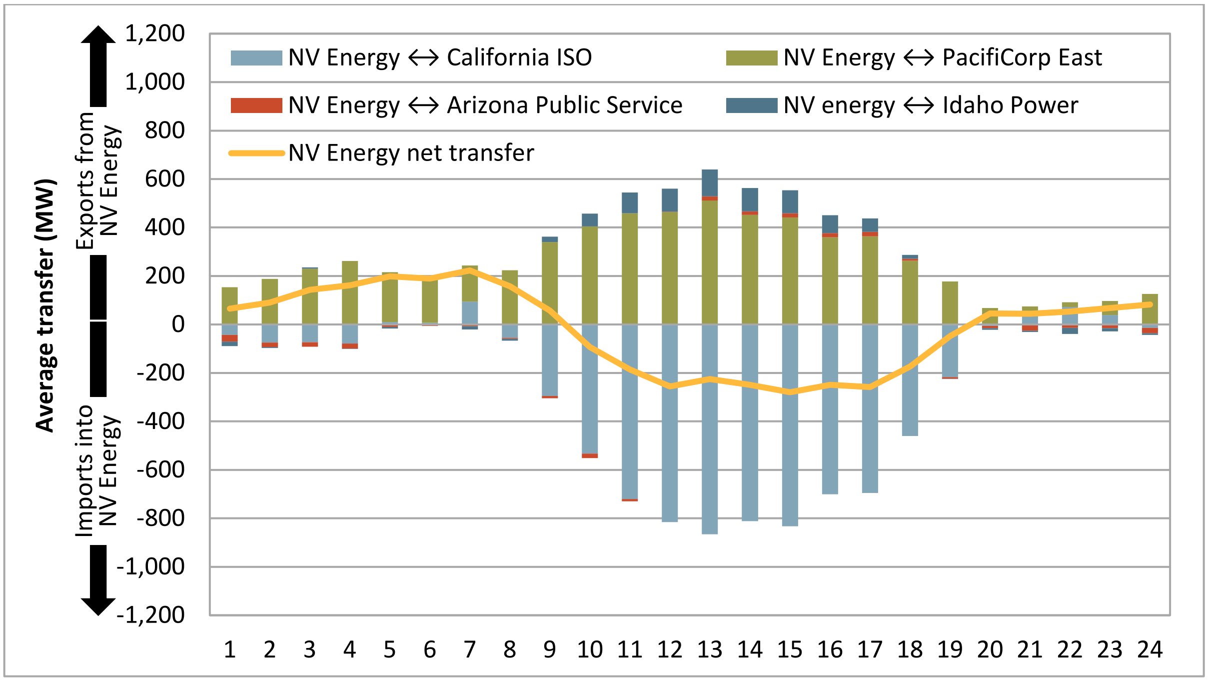
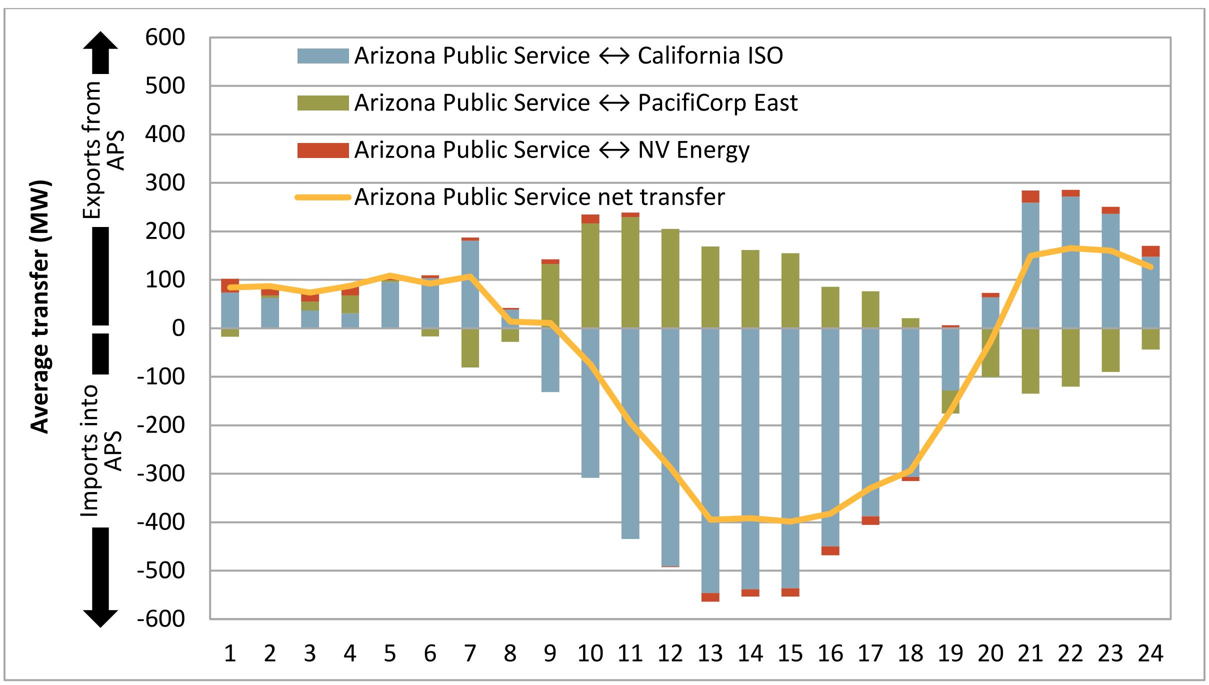
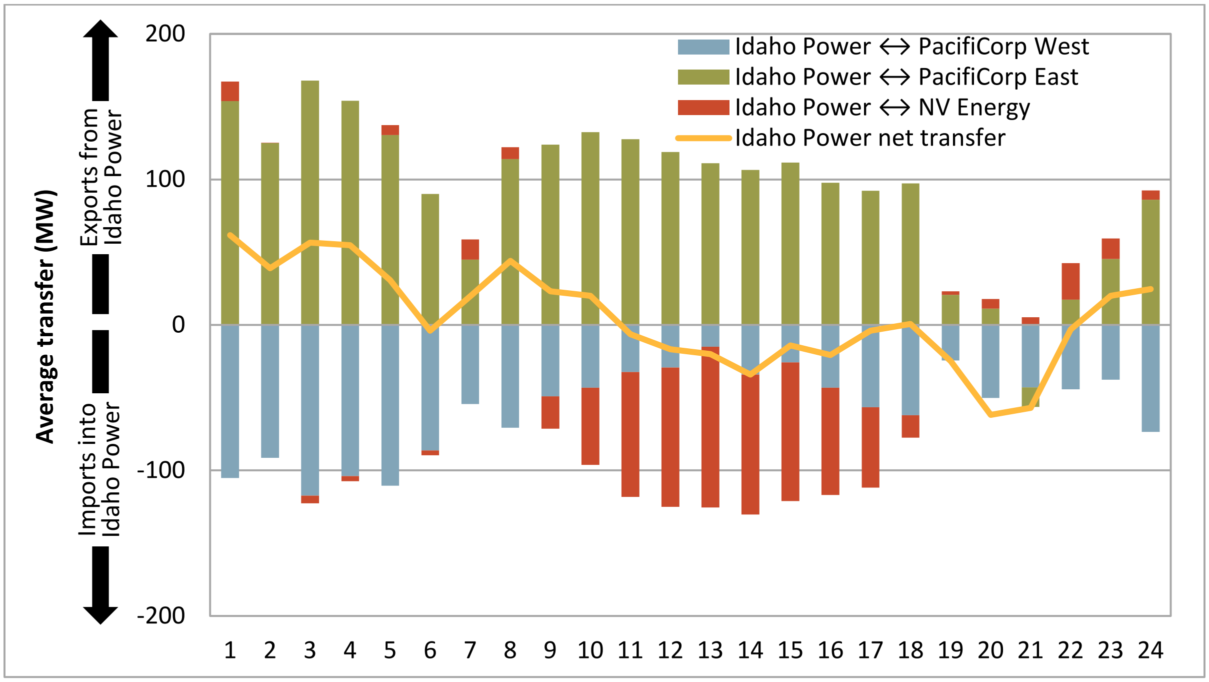


Figure 2.8 Arizona Public Service – average hourly 15-minute market transfer (April 4 – June 30)



Idaho Power added an average of around 3,000 MW of import and export transfer capability to the energy imbalance market during the second quarter. After netting base schedules, Idaho Power imported from PacifiCorp West and exported to PacifiCorp East on average during all hours as shown in Figure 2.9. During midday hours, Idaho Power imported from NV Energy on average.

Figure 2.9 Idaho Power – average hourly 15-minute market transfer (April 4 – June 30)



PacifiCorp West has transfer capacity between PacifiCorp East, Puget Sound Energy, the ISO, and Portland General Electric. Figure 2.10 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the second quarter. This figure shows that PacifiCorp West was a net importer during most hours. PacifiCorp West typically imported energy from the ISO during midday hours, when solar was greatest in the ISO, and exported energy to the ISO in the late evening and morning hours. PacifiCorp West exported over 700 MW to PacifiCorp East on average during the quarter, but net of all base schedules, imported around 75 MW on average.

Figure 2.11 shows average hourly 15-minute market imports and exports into and out of Powerex. The figure also includes average hourly transfer limits with the ISO and Puget Sound Energy. During the second quarter, import and export transmission capacity from Powerex to the ISO was limited to six megawatts or less in over 80 percent of 15-minute intervals. Within the remaining intervals, import limits from the ISO in the 15-minute market were more significant, though mostly concentrated during peak solar hours when system loads and prices were typically low. Powerex has explained that it has limited exports during many hours due to its concern that, if bid mitigation is in effect, exports may be scheduled from Powerex at mitigated prices less than its market bid price. Transfer limits between Powerex and the ISO were higher in both import and export directions in the 5-minute market. Powerex imported an hourly average of about 40 MW from the ISO in the 5-minute market, compared to about 17 MW in the 15-minute market.

Figure 2.10 PacifiCorp West – average hourly 15-minute market transfer (April 4 – June 30)

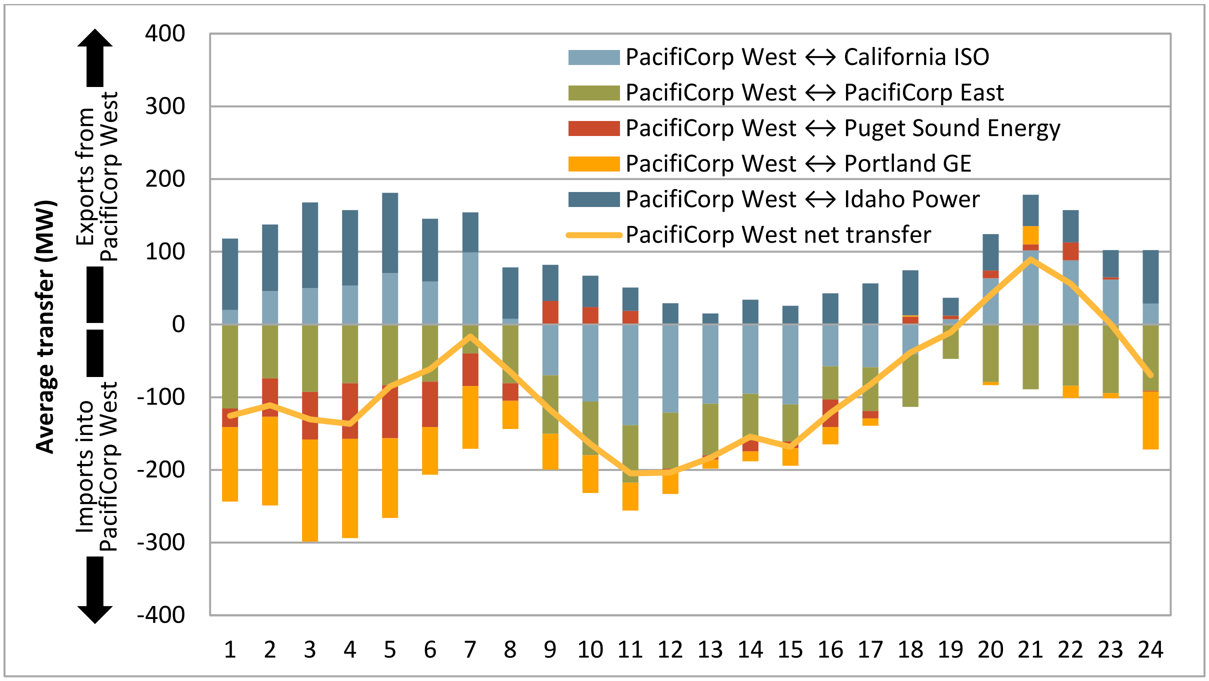
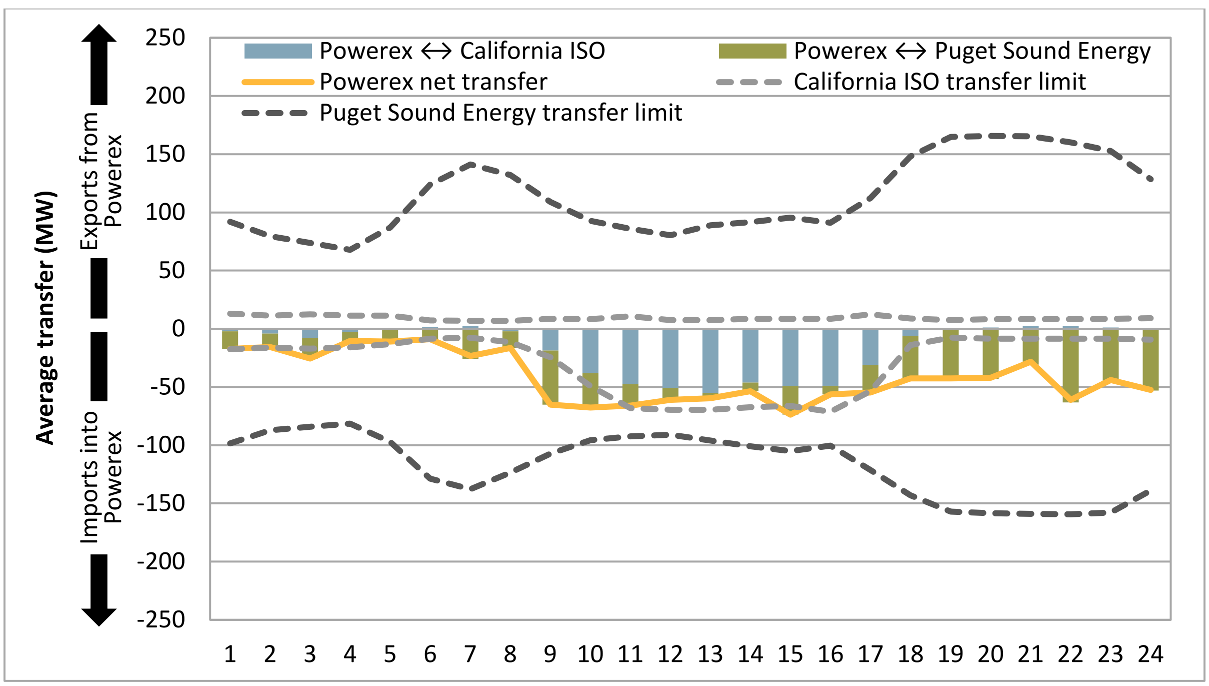


Figure 2.11 Powerex – average hourly 15-minute market transfer (April 4 – June 30)



2.4 Load adjustments

Table 2.2 summarizes the average frequency and size of positive and negative load forecast adjustments for the energy imbalance market areas during the second quarter for the 15-minute and 5-minute markets. The same data for the ISO is provided as a point of reference. Overall, load adjustments were typically positive in PacifiCorp East, Arizona Public Service, NV Energy and Portland General Electric, while load adjustments were frequently negative in Puget Sound Energy. Similar to the ISO, nearly all energy imbalance market entities had a much greater frequency of positive 5-minute market adjustments than 15-minute market adjustments during the second quarter. Also of note, Portland General Electric did not have any negative load adjustments in the 15-minute market for the entire quarter.

Table 2.2 also includes the average absolute positive and negative load adjustment as a percent of area load. Unlike the previous quarter, average load adjustments by Arizona Public Service, as a percent of total area load, were closer in magnitude compared to other areas. The change can be attributed to an increase in negative load adjustments which have typically followed the area's load curve with larger adjustments during the morning and evening peak load hours.

Table 2.2 Average frequency and size of load adjustments (April - June)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	36%	479	1.9%	17%	-336	1.5%	116
5-minute market	15%	249	1.0%	57%	-323	1.4%	-146
PacifiCorp East							
15-minute market	15%	84	1.6%	1%	-98	1.9%	12
5-minute market	65%	111	2.2%	8%	-90	1.9%	65
PacifiCorp West							
15-minute market	0%	55	2.3%	0%	-97	4.4%	0
5-minute market	17%	42	1.9%	14%	-41	2.0%	2
NV Energy							
15-minute market	16%	139	2.8%	1%	-88	1.7%	22
5-minute market	32%	101	2.1%	10%	-66	1.7%	26
Puget Sound Energy							
15-minute market	1%	59	2.4%	7%	-58	2.5%	-3
5-minute market	5%	57	2.2%	53%	-48	2.0%	-23
Arizona Public Service							
15-minute market	68%	104	3.0%	20%	-142	4.0%	42
5-minute market	66%	105	3.0%	20%	-142	4.0%	42
Portland General Electric							
15-minute market	3%	32	1.4%	0%	0	0.0%	1
5-minute market	24%	34	1.5%	3%	-41	1.8%	7

3 Special issues

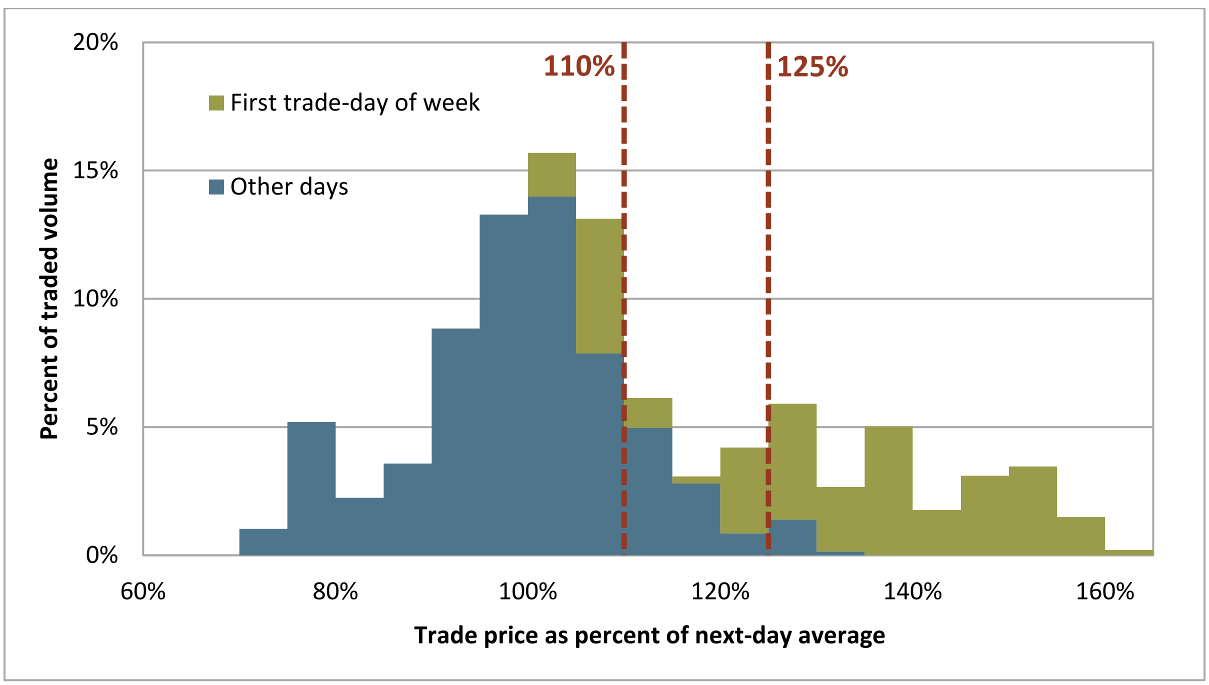
This section provides information about the following special issues:

3.1 Aliso Canyon gas-electric coordination

The ISO did not enforce gas burn constraints in either the day-ahead or real-time markets in the second quarter of 2018. Aliso gas price scalars were also not activated during the second quarter. Use of both nomograms and scalars in February of 2018 was associated with additional costs.[36]

Figure 3.1 shows Intercontinental Exchange (ICE) same-day natural gas trade prices for SoCal Citygate compared to the next-day average price from April through June 2018. About 13 percent of traded volume at SoCal Citygate exceeded the normal 10 percent adder and 24 percent of the traded volume exceeded the 25 percent adder. Figure 3.1 also shows that the most extreme same-day prices relative to next-day averages occurred on days that were the first trading day of the week, which was typically a Monday. These are shown as green bars on the chart.

Figure 3.1 Same-day trade prices compared to next-day index (April – June)



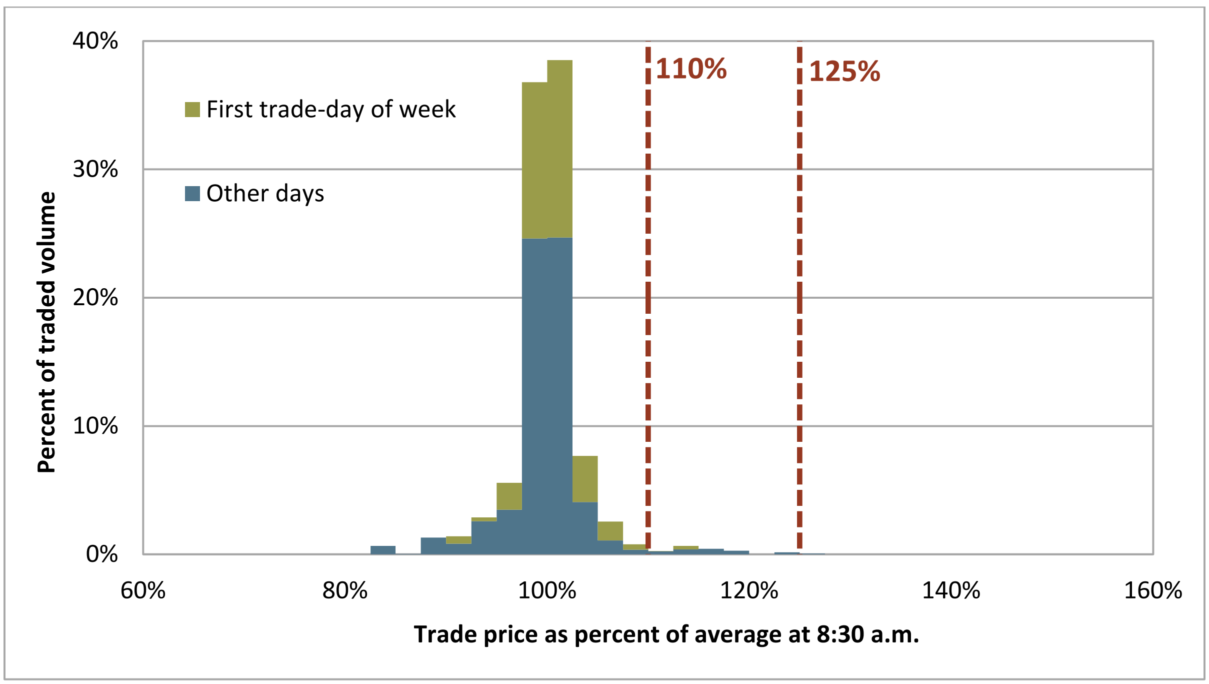
DMM is not supportive of a further extension of the gas cost scalars beyond the December 2018 date that was approved by FERC in 2017. Instead, DMM continues to recommend that the ISO develop the

[36] See 2018 First Quarter Report on Market Issues and Performance, July 10, 2018, Department of Market Monitoring, available here: http://www.caiso.com/Documents/2018_First_Quarter_Report_on_Market_Issues_and_Performance.pdf

ability to adjust gas prices used in the real-time market based on observed prices on ICE the morning of each operating day, rather than relying on much less effective and accurate tools such as the gas cost scalars. This approach would closely align the gas price used in the ISO's real-time market with the actual costs for gas purchased in the same-day gas market.[37,38]

Figure 3.2 compares the price of each same-day trade at SoCal Citygate to an updated volume-weighted average price of same-day trades reported on ICE before 8:30 am. For the second quarter of 2018, this figure shows that if the real-time gas prices were updated using an updated same-day price, then about 98 percent of the same-day trades would have been at or below the 10 percent adder at SoCal Citygate. About 2 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. Figure 3.2 also shows the same-day prices relative to updated same-day price for days that were the first trading day of the week, which was typically a Monday. These are shown by the green bars in the chart.

Figure 3.2 Same-day prices as a percent of updated same-day averages (April – June)



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[37] *FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 3 (ER17-2568),* Department of Market Monitoring, October 26,2017: http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

[38] *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

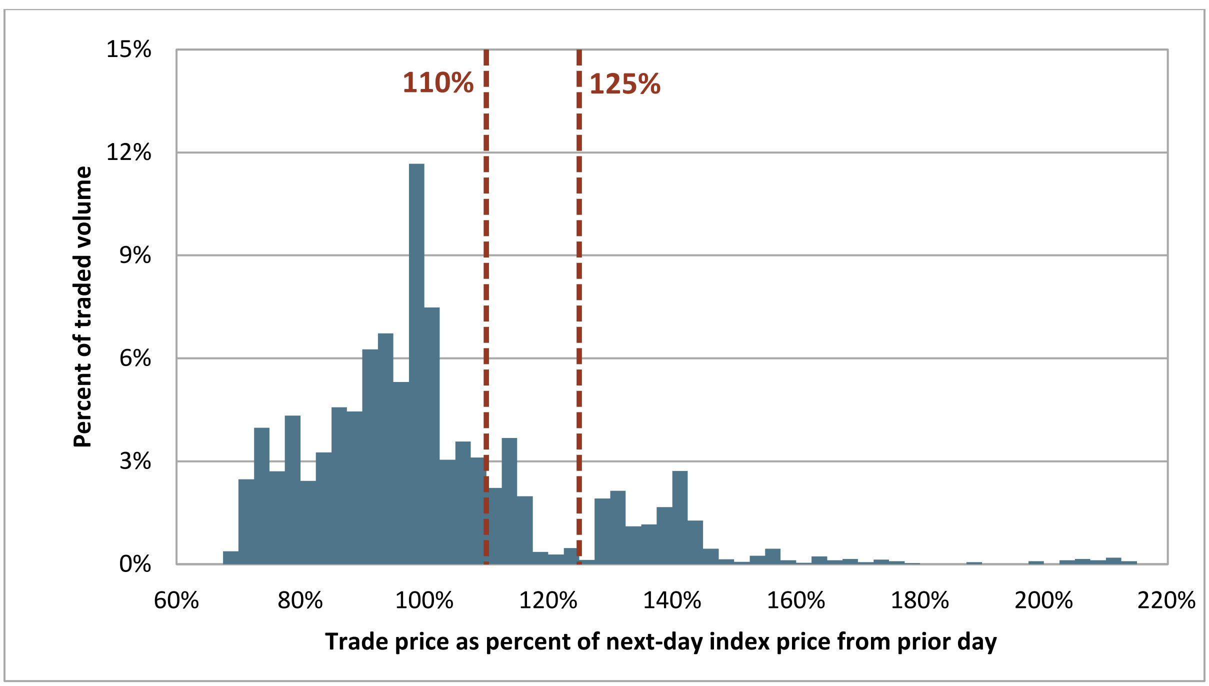
Updated natural gas prices for the day-ahead market

The November 28, 2017, FERC 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 for one additional year, through November 30, 2018. With this modification, the ISO is basing the updated gas price on next-day trades from the morning of the day-ahead market run instead of indices from the prior day.[39]

Figure 3.3 and Figure 3.4 illustrate the benefit of using the updated natural gas price index in the first quarter of 2018. Figure 3.3 shows next-day trade prices reported on ICE for the SoCal Citygate during the second 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 3.3, about 9 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids. About 15 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps.

Figure 3.4 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 3.4, about 2 percent of the traded volume exceeded the 10 percent adder included in default energy bids. None 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 3.3 Next-day trade prices compared to next-day index from prior day (April - June)



39 This market modification uses weighted average price of next-day trades at SoCalGas 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.

Figure 3.4 Next-day trade prices compared to updated next-day average price (April - June)