California ISO

California Independent System Operator Corporation

California ISO

Q1 2018 Report on Market Issues and Performance

July 10, 2018

Department of Market Monitoring

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Executive summary

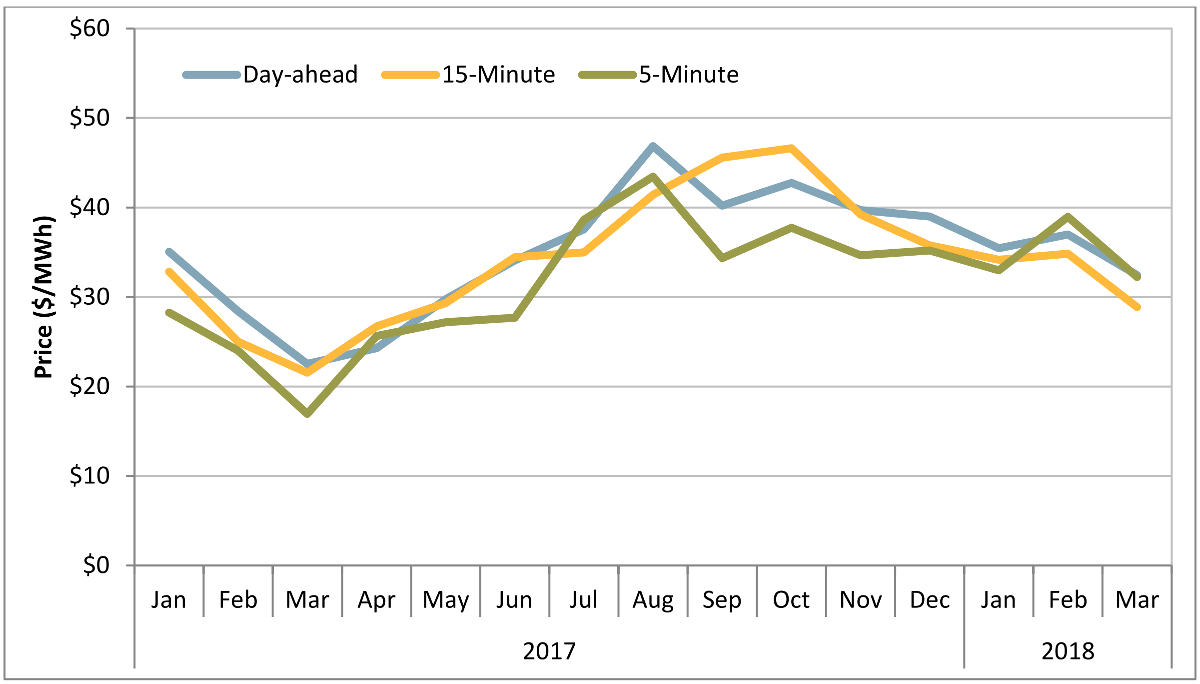
This report covers market performance during the first quarter of 2018 (January – March). Key highlights during this quarter include the following:

- Prices in the day-ahead market were systematically higher than prices in the 15-minute market for all months of the quarter. First quarter average day-ahead prices have been higher than fifteen minute prices in each year since 2015.
- Average day-ahead, 15-minute and 5-minute market prices were significantly higher in comparison to the same quarter in 2017, driven by higher gas costs and decreased hydroelectric production. Prices in the 15-minute market were about $6/MWh (over 20 percent) higher and 5-minute prices were about $12/MWh (50 percent) higher than in Q1 last year.
- During the first quarter of 2018, the frequency of negative prices was significantly lower than in the first quarter of 2017. In addition, the frequency of high prices in the 15-minute and 5-minute markets was higher than in the first quarter of 2017.
- Most high prices occurred as a result of unmitigated high bids in the market. In many of these instances, extremely high bids set the price after the load bias limiter was triggered when the power balance constraint was relaxed due to high load biasing by system operators. Without the load conformance limiter, power prices would have been slightly higher, equaling the power balance relaxation penalty.
- Bid cost recovery payments totaled $25 million, slightly less than the prior quarter. Real-time bid cost recovery costs in February totaled $11 million, the highest amount in any month since 2011.
- Limited gas supply to the SoCal Gas system during a period of high gas demand led to both high gas prices in the south as well as reinstatement of the Aliso gas cost scalars, which include a 175 percent scalar used in calculating commitment cost bid caps for resources on the SoCal Gas system. Both of these factors contributed to high real-time bid cost recovery in February.
- Aliso gas cost scalars were activated during two periods in the first quarter. In both periods, actual gas trades in the same day gas market were usually significantly lower than the prevailing prices for same-day gas trades. Activation of the scalars does not appear to significantly impact the merit order of commitment cost dispatch, but tends to increase bid cost recovery payments.
- The ISO enforced total gas burn constraints associated with Aliso canyon gas-electric coordination, in both the day-ahead and real-time markets. These constraints were binding in the real-time market during numerous intervals in peak hours on February 20 to 23. These gas constraints contributed to higher real-time imbalance energy offset costs, which totaled about $19 million during this four day period in February. In addition, use of the gas constraints may have contributed to the market impact of transmission constraints including congestion on the Serrano 500/230 kV constraint, binding for much of the quarter.
- During the first quarter of 2018, congestion revenue rights auction revenues were $43 million less than congestion payments made to non-load-serving entities purchasing these rights.

- On January 1, 2018, operating reserve requirements increased significantly with the implementation of a revision to NERC reliability standard, BAL-002-2. The revised standard required the ISO to reevaluate the most severe single contingency included in the requirement. 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. Requirements increased 50% or more in most hours, on average, across the quarter.

- In February 2018, DMM identified specific errors in how the flexible ramping product was implemented related to the calculation of uncertainty. This has resulted in under-procurement of upward flexible ramping capacity during some key net load ramping intervals.

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



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

- Prolonged outages in Southern California caused congestion and impacted prices in both day-ahead and real-time markets. Congestion in the day-ahead market increased Southern California Edison and San Diego Gas and Electric area prices by about $2/MWh and $5/MWh, respectively, and decreased Pacific Gas and Electric area prices by about $3/MWh. Congestion on the Serrano 500/230 kV constraint contributed to roughly 90 percent of the price differential between Northern and Southern California.

- In the 15-minute market, congestion increased Southern California Edison and San Diego Gas and Electric area prices by about $3/MWh and $5/MWh, respectively, and decreased Pacific Gas and Electric area prices by about $1/MWh. The greatest price impacts in the first quarter occurred due to outages that caused congestion on the Serrano 500/230 kV transformer.

- Prices in PacifiCorp East, NV Energy and Arizona Public Service were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation between these areas. This was most pronounced during peak load hours when high system prices caused transfers from PacifiCorp East to hit export limits. In other hours, one or more of these areas failed the sufficiency test which limited transfers and created price separation between the balancing areas.

- On December 14, 2017, operators began setting ancillary service requirements for both the internal and external North of Path 26 sub-regions. These requirements were set equal to the corresponding South of Path 26 sub-regions. Then on January 1, 2018, operating reserve requirements increased significantly with the implementation of the revised NERC reliability standard, BAL-002-2. Under the revised standard, the ISO considers the potential sudden loss of scheduling on the Pacific DC Intertie as one possible single largest contingency.

- 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. The implemented calculation systematically biased flexible ramping capacity procurement and prices in the direction opposite of the net load ramp (down when net load was ramping up and vice versa). In particular, this has resulted in under-procurement of upward flexible ramping capacity during some key net load ramping intervals.[1] The ISO corrected the net load error distributions so that the 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.

- Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity continued to decrease during the first quarter of 2018 to around $2 million, compared to around $3 million during the previous quarter and around $9 million during the first quarter of 2017.

- Convergence bidding was profitable overall during the first quarter. Virtual supply was profitable for the first time since the first quarter of 2017. Before accounting for bid cost recovery charges, virtual supply generated net revenues of about $2.2 million while virtual demand net revenues were a loss of about $0.5 million. Combined net revenues for virtual supply and demand fell to about $0.6 million after including about $1.1 million of virtual bidding bid cost recovery charges.

Special issues

The ISO activated gas burn constraints and the special Aliso Canyon gas price scalars on many days during the quarter. The measures adopted by the ISO in response to limited availability of Aliso Canyon gas storage and high gas utilization concerns expressed by the gas supplier included the addition of real-time gas price scalars for the fuel component of default energy bids (25 percent) and commitment cost bids (75 percent). Aliso gas price scalars were activated during two periods in the first quarter. In both periods, actual gas trades in the same day gas market were usually significantly lower than the prevailing

[1] See *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, Department of Market Monitoring, April 18, 2018: http://www.caiso.com/Documents/FlexibleRampingProductUncertaintyCalculationImplementationIssues.pdf.

prices for same-day gas trades. Activation of the scalars does not appear to significantly impact the merit order of commitment cost dispatch. DMM estimates that since the activation of the gas price scalars in July 2016, it has resulted in over $8 million in excess uplift payments to resources using the scalar. In the first quarter of 2018, approximately $1 million of these payments were accrued in February, most of it during cold weather days in Southern California. DMM has recommended that the ISO review this issue and reduce or eliminate the adders.

The ISO enforced total gas burn constraints on both the SoCal gas region, as well as subregions, in both the day-ahead and real-time markets. Binding enforcement of these constraints in the real-time market occurred for selected intervals in peak hours on four days over which the ISO accrued about $19 million in real-time imbalance energy offset costs. These days account for the great majority of such costs incurred during the first quarter. In addition, use of the gas constraints may have contributed to the market impact of transmission constraints including congestion on the Serrano 500/230 kV constraint, binding for much of the quarter.[2]

Key recommendations

Develop the capability to update gas prices in real-time rather than continuing use of gas cost adders. DMM believes that each use of the Aliso Canyon gas adders on default energy bids and commitment costs highlights the problems associated with use of these adders. The first problem 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. These events also highlight the need for the ISO to develop the capability to update gas prices used in the real-time market based on same-day gas market price information available each morning, as recommended by DMM.[3]

Reformulate the flexible ramping sufficiency test to reduce the punitive effect of a failure in one interval on sequential intervals. The use of net import capability and net export capability in the energy imbalance market flexible ramping sufficiency test, as a function of the sufficiency test result in the previous hour, can block balancing areas from the benefit of a lower uncertainty requirement. Failure of a test in one hourly interval can increase the likelihood of failure in the next interval. DMM recommends that the ISO reevaluate this interaction to create a sufficiency test that preserves the independence of consecutive hourly sufficiency test results.

[2] The ISO presented results showing a large increase in day-ahead congestion rent on both February 21 and 22, to a sum of over $25 million. Typical day-ahead rents during this period were less than $3 million per day. Market Performance and Planning Forum presentation, April 19 2018, slide 35. http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Apr192018.pdf

[3] 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

1 Market performance

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

- Average day-ahead, 15-minute and 5-minute market prices were significantly higher in comparison to the same quarter in 2017, driven by higher gas costs and decreased hydroelectric production. Prices in the 15-mintue market were about $6/MWh (over 20 percent) higher and 5-minute prices were about $12/MWh (50 percent) higher than in Q1 last year.
- The frequency of negative prices was significantly lower during the first quarter of 2018 than in the first quarter of 2017. Negative prices occurred during about 2 percent of intervals in the 15-minute market and around 4 percent of intervals in the 5-minute market during the first quarter of 2018. In comparison, negative prices occurred during about 10 percent and 13 percent of 15-minute and 5-minute intervals, respectively, during the first quarter of 2017.
- 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 $5/MWh and in the Southern California Electric area by about $3/MWh, and decreased prices in the Pacific Gas and Electric area by about $3/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 $5/MWh and in the Southern California Edison area by about $3/MWh, and decreased Pacific Gas and Electric area prices by about $1/MWh.
- During the first quarter of 2018, congestion revenue rights auction revenues were $43 million less than payments made to non-load-serving entities purchasing these rights. Losses in the first quarter represent $0.38 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders. Total ratepayer losses from the congestion revenue rights auction since the market began in 2009 surpassed $770 million.
- 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. The implemented calculation systematically biased flexible ramping capacity procurement and prices in the direction opposite of the net load ramp (down when net load is ramping up and vice versa). In particular, this has resulted in under-procurement of upward flexible ramping capacity during key net load ramping intervals.
- On December 14, 2017, operators began setting ancillary service requirements for both the internal and external North of Path 26 sub-regions. These requirements were set equal to the corresponding South of Path 26 sub-regions. Then on January 1, 2018, operating reserve requirements increased significantly with the implementation of the NERC reliability standard, BAL-002-2.
- Total bid cost recovery payments for the first quarter were about $25 million. This amount was slightly lower than payments in the previous quarter. A significant amount of the bid cost recovery payments was accrued in the real-time market during February when the SoCal Citygate natural gas trading hub prices were high.

- Convergence bidding was profitable overall during the first quarter with combined net revenues of about $0.6 million after accounting for bid cost recovery charges. Virtual supply was profitable for the first time since the first quarter of 2017.

1.1 Energy market performance

Energy market prices

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

Figure 1.1 shows average monthly system marginal energy prices during all hours. During the quarter average prices decreased slightly overall from the previous quarter, but were significantly higher compared to the same quarter in 2017.

- Average day-ahead, 15-minute were about $6/MWh (over 20 percent) higher and 5-minute market prices were almost $12/MWh (50 percent) higher in comparison to the same quarter in 2017. These price increases reflect decreased hydro-electric generation and higher natural gas prices relative to the same quarter in 2017.[4]
- Average day-ahead, 15-minute and 5-minute market prices increased slightly in February, in part due to increased gas prices and additional real-time bidding flexibility associated with Aliso Canyon gas-electric coordination, but otherwise decreased overall from the previous quarter.
- Average monthly day-ahead prices were higher than 15-minute market prices during all months of the quarter. Day-ahead prices averaged about $2/MWh above 15-minute market prices during the quarter. Five-minute prices exceeded both day-ahead and 15-minute prices, on average, in both February and March.

Figure 1.2 illustrates system marginal energy prices on an hourly basis in the first quarter compared to average hourly net load.[5] Prices in this figure generally follow the net load pattern with the highest energy prices during the morning and evening peak net load hours. In particular, prices were highest during hours ending 19 and 20. Figure 1.2 also shows that average prices in the day-ahead market were higher than 15-minute and 5-minute market prices between hours ending 10 and 16 when solar generation was greatest.

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[4] On average, natural gas prices at PG&E Citygate were 19 percent higher than the first quarter of 2017. SoCal Citygate prices were over 7 percent higher, on average. Metered generation from hydro-electric generation resources in the first quarter of 2017 was less than half that in 2017, primarily due a reduction in self-scheduled price taking bids from these resources.

[5] 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 1.1 Average monthly prices (all hours) – system marginal energy price

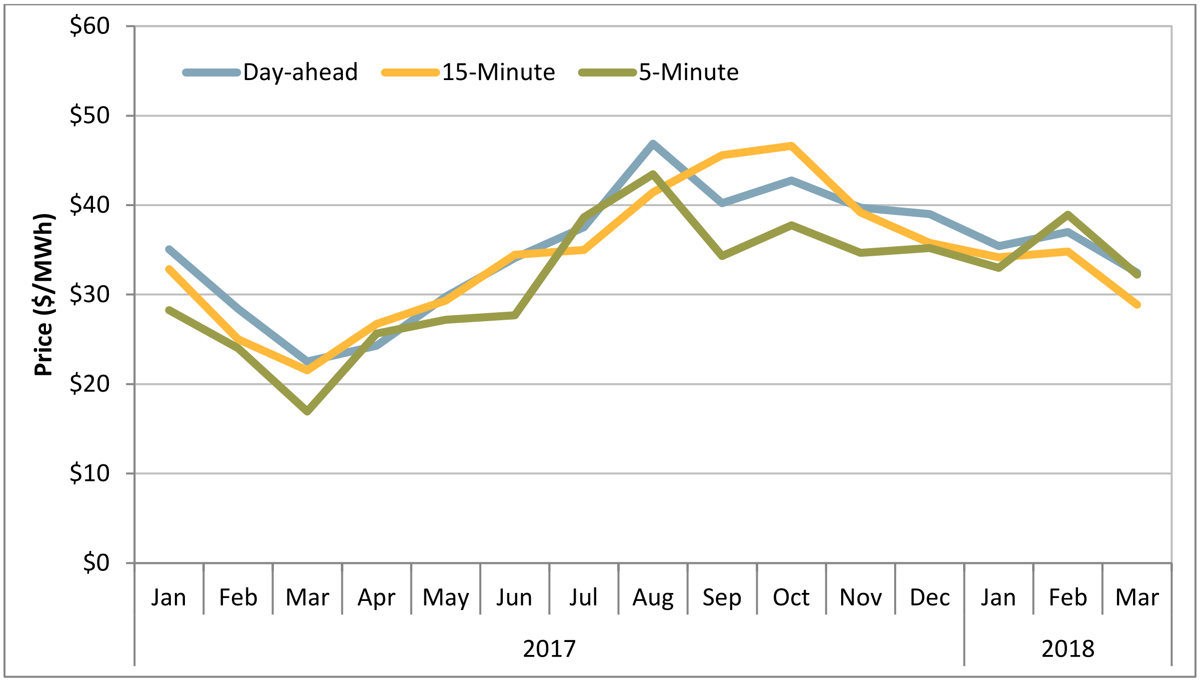
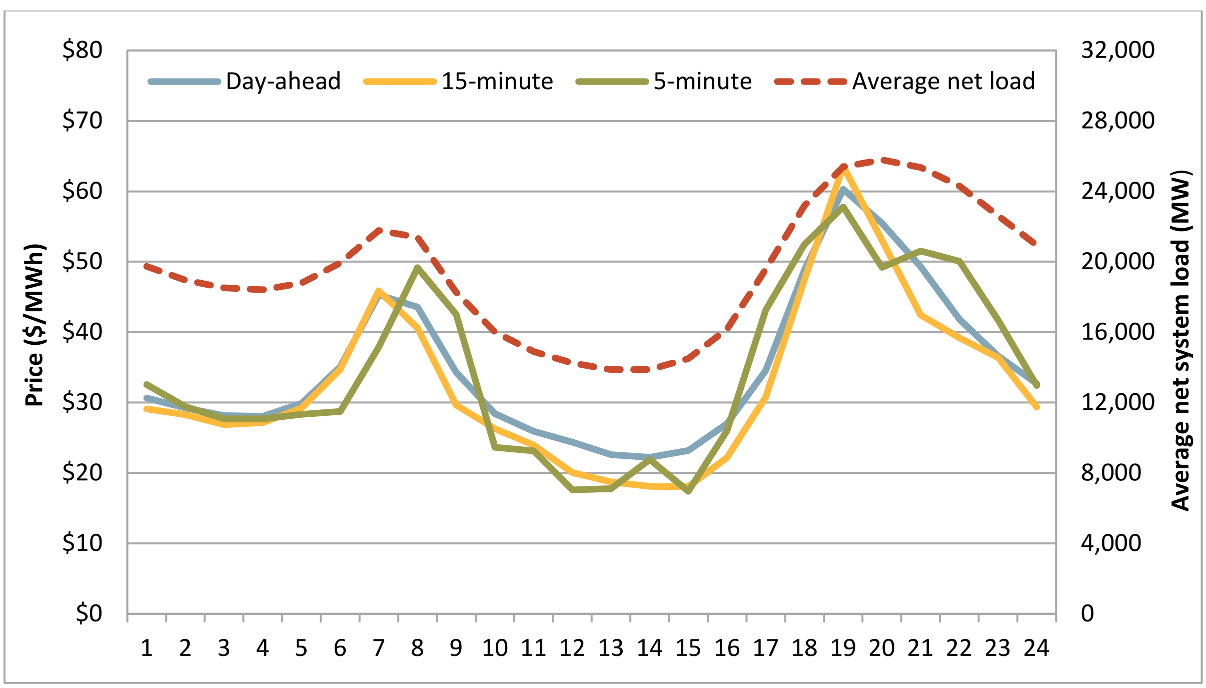


Figure 1.2 Hourly system marginal energy prices



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. During the first quarter of 2018, the frequency of negative prices was significantly lower than in the first quarter of 2017. In addition, the frequency of high prices in the 15-minute and 5-minute markets was higher than in the first quarter of 2017.

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

High prices

As shown in Figure 1.3, the frequency of high prices in the 15-minute market greater than $250/MWh decreased from around 0.7 percent of intervals in the previous quarter to 0.4 percent of intervals during the quarter. However, this was more frequent compared to the first quarter of 2017, when high 15-minute market prices occurred during less than 0.1 percent of intervals. High prices during the first quarter of 2018 were most frequent in February, when prices above $250/MWh occurred during around 0.8 percent of 15-minute intervals.

Figure 1.4 shows the monthly frequency of under-supply infeasibilities in the 15-minute market. In concurrence with the decreased frequency of larger 15-minute market price spikes, under-supply infeasibilities in the 15-minute market were less frequent in the first quarter.

Figure 1.5 shows the frequency of high prices in the 5-minute market. The frequency of price spikes greater than $250/MWh in the 5-minute market was about 1 percent of intervals in the first quarter, up from around 0.8 percent of intervals in the previous quarter and 0.6 percent of intervals in the first quarter of 2017. Further, the frequency of more extreme 5-minute market prices larger than $750/MWh increased slightly during the quarter, particularly during February and March when they occurred during around 0.9 percent of 5-minute intervals.

Figure 1.6 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. The conditions for the load bias limiter were met during most 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 many of the under-supply infeasibilities in the first 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 1.3 Frequency of high 15-minute prices by month

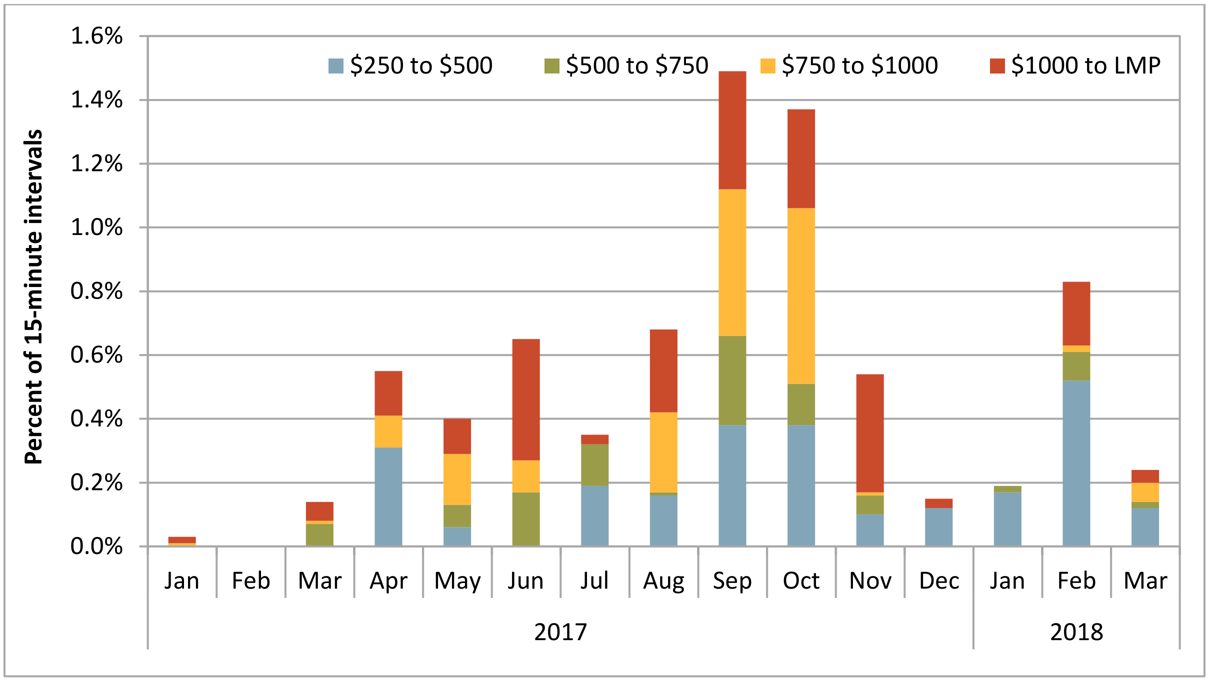


Figure 1.4 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

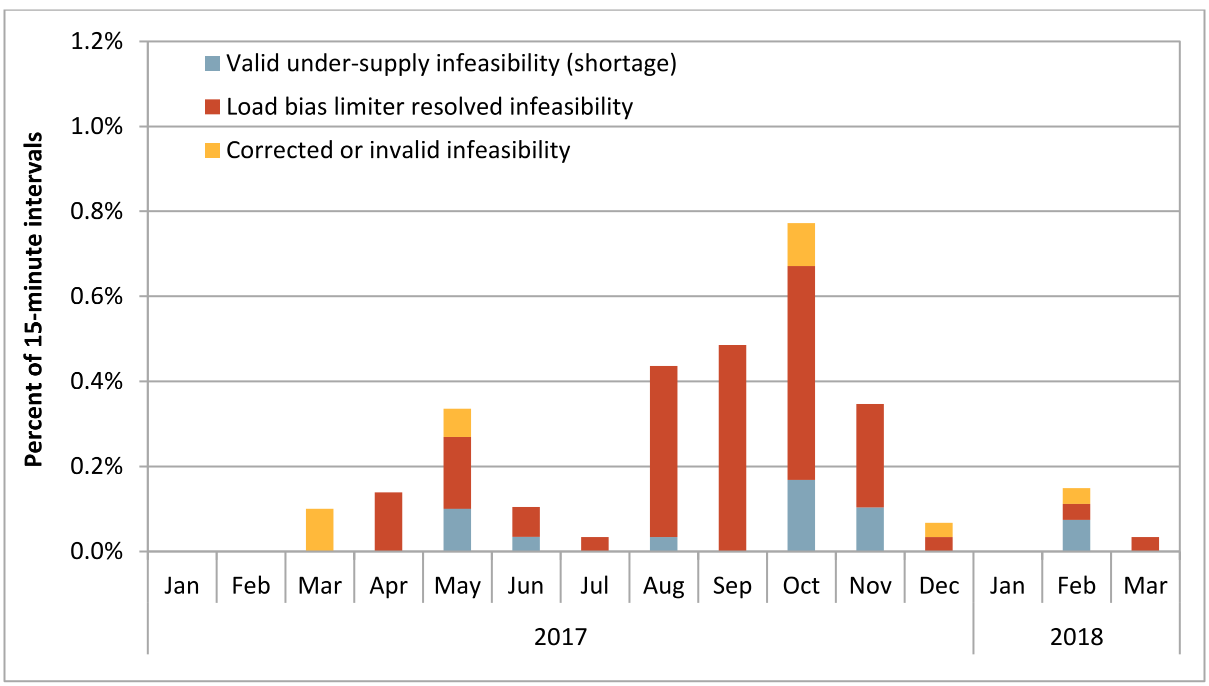


Figure 1.5 Frequency of high 5-minute prices by month

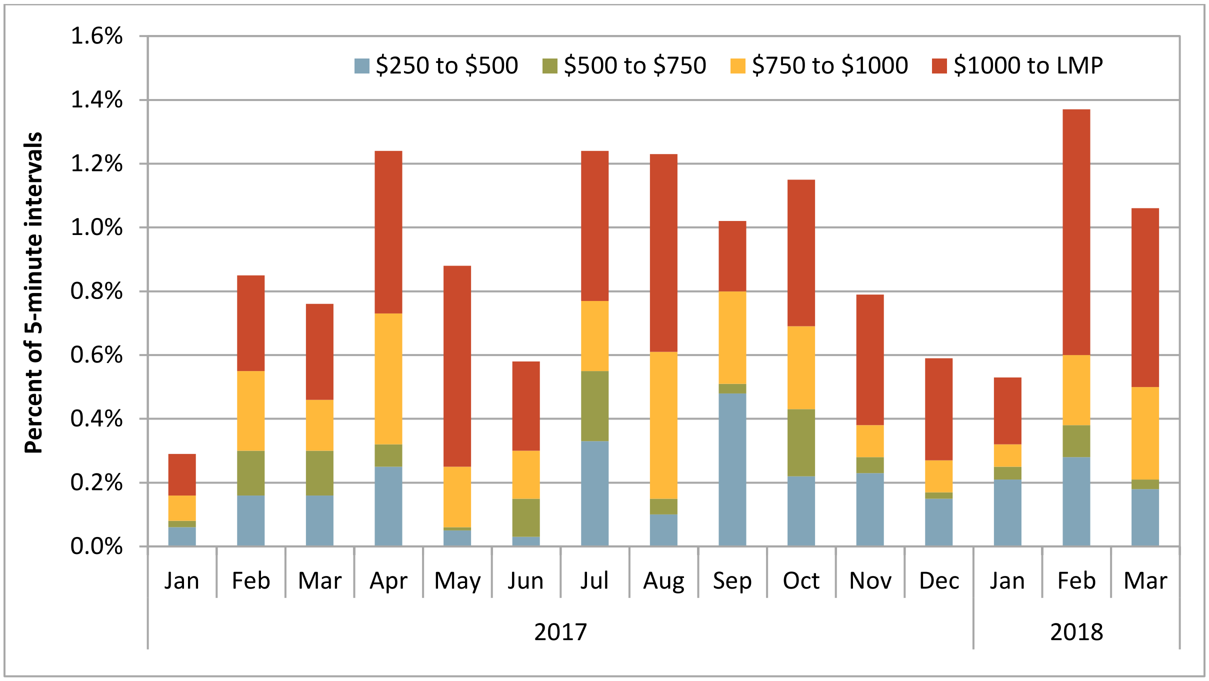
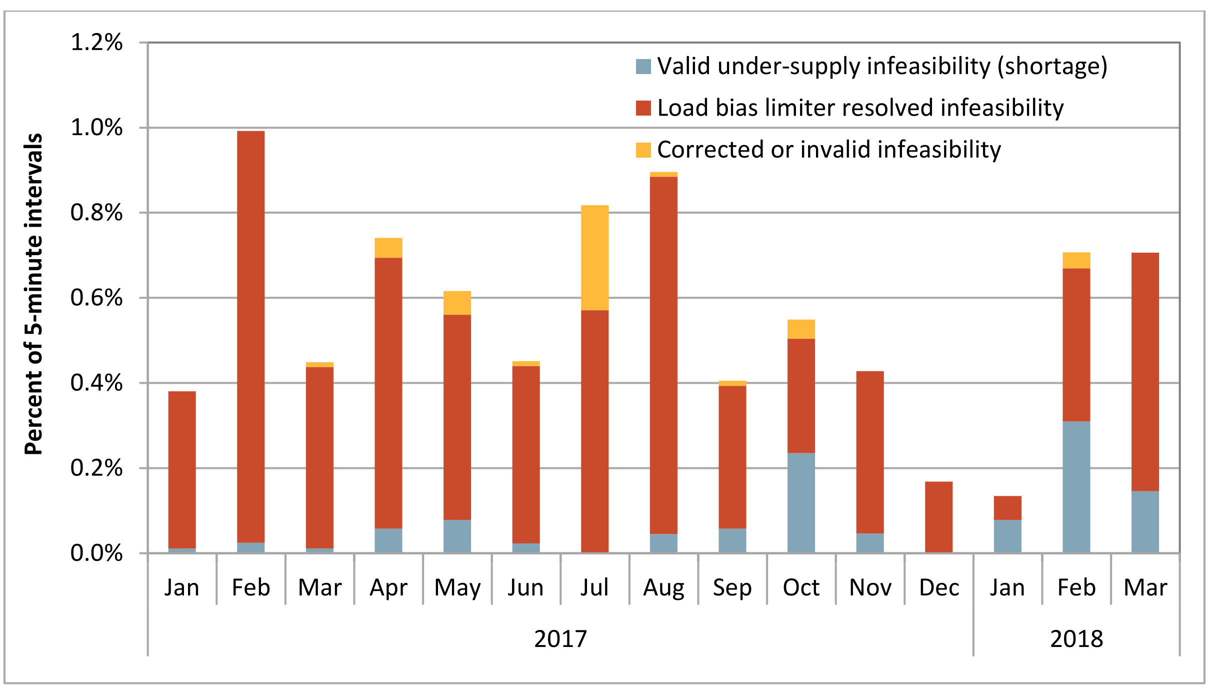


Figure 1.6 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



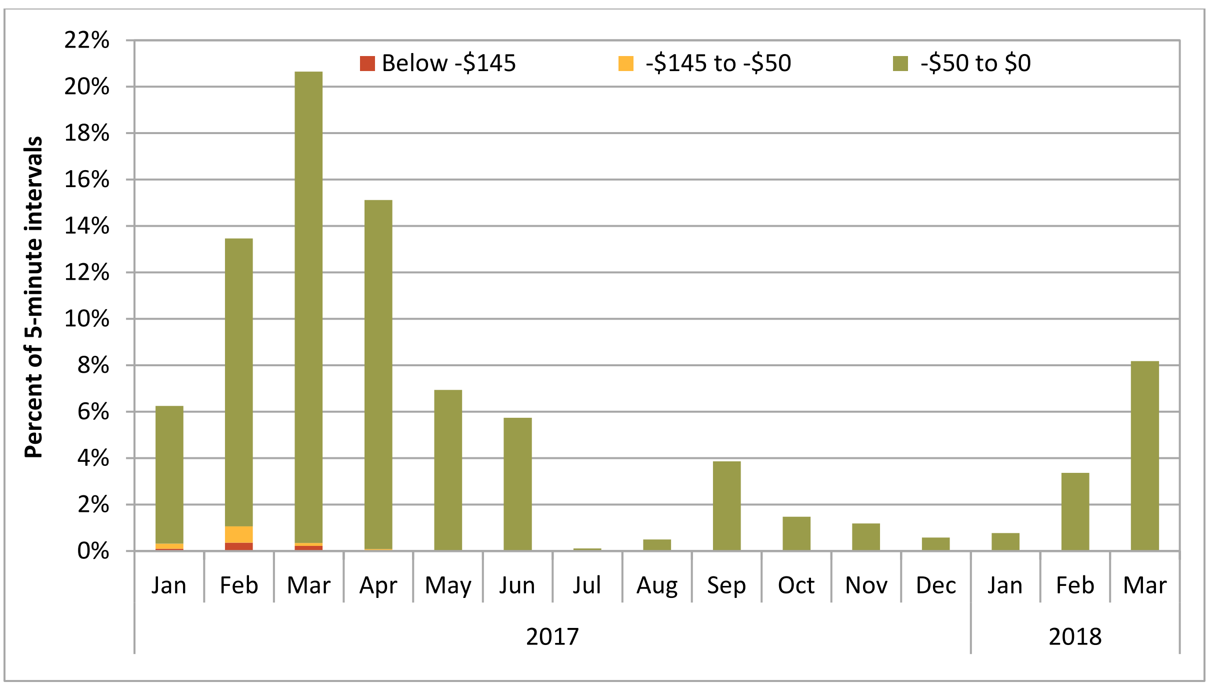
Negative prices

Figure 1.7 shows the frequency of negative prices in the 5-minute market by month.[6] Though the frequency of negative prices in the 15-minute and 5-minute markets increased during the first quarter relative to the previous three months, it remained much lower in comparison to the first quarter of 2017. One factor appears to be a reduction of self-scheduled generation from hydro resources in the market in the first quarter of 2018 compared to the same quarter of the previous year. A reduction in self-scheduled generation would result in increased bidding flexibility and reduce the likelihood of negative prices.

Negative prices occurred during about 2 percent of intervals in the 15-minute market and around 4 percent of intervals in the 5-minute market during the first quarter of 2018. In comparison, negative prices occurred during about 10 percent and 13 percent of 15-minute and 5-minute intervals, respectively, during the first quarter of 2017.

These were most frequent between hours ending 10 and 17 when loads, net of wind and solar, were lowest. However, prices did not reach below negative $45/MWh for any of the three load aggregation points during the quarter in either the 15-minute or 5-minute markets. Further there were no intervals when the power balance constraint was relaxed because of excess energy. In comparison, over-supply infeasibilities occurred during around 0.5 percent of intervals in the 5-minute market during the first quarter of 2017.

Figure 1.7 Frequency of negative 5-minute prices by month



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

1.3 Congestion

In the first quarter, prolonged outages in Southern California caused congestion and impacted prices in both day-ahead and real-time markets. Congestion in the day-ahead market increased Southern California Edison and San Diego Gas and Electric area prices by about $2/MWh and $5/MWh, respectively, and decreased Pacific Gas and Electric area prices by about $3/MWh. In the 15-minute market, congestion increased Southern California Edison and San Diego Gas and Electric area prices by about 3/MWh and $5/MWh, respectively, and decreased Pacific Gas and Electric area prices by about $1/MWh. The greatest price impacts in the first quarter occurred due to outages that caused congestion on the Serrano 500/230 kV transformer.

1.3.1 Congestion impacts of individual constraints

This section provides an assessment of the frequency and impact of congestion to prices in different areas of the ISO system. Price values presented in each table represent impacts to prices during the hours in which congestion occurred.[7]

Day-ahead congestion

In the first quarter of 2018, the overall frequency of congestion decreased in the day-ahead market compared to the previous quarter.[8] In the Pacific Gas and Electric area, there was relatively little congestion, impacting prices by about $5/MWh in less than 2 percent of intervals. In the Southern California Edison area, the Lugo-Victorville 500 kV constraint bound most frequently, during 7 percent of intervals, though had a small impact on prices. This constraint bound to mitigate for a potential loss of the Palo Verde-Colorado River 500 kV line. The Eagle Rock-Gould 230 kV constraint bound in 4 percent of intervals, impacted by a planned outage on the Lugo-Mira Loma 500 kV line. The Eagle Rock-Gould 230 kV constraint increased Southern California Edison area prices and decreased Pacific Gas and Electric area prices by about $2/MWh.

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

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

Table 1.1 Impact of congestion on day-ahead prices during congested hours[9]

Area	Constraint	Frequency	Q1		
		Q1	PG&E	SCE	SDG&E
PG&E	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	1.4%	$6.42	-$4.93	-$4.61
	30055_GATES1 _500_30900_GATES _230_XF_11_S	1.2%	-$1.03	$0.80	$0.69
SCE	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	7.0%	$0.30		-$0.34
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	4.3%	-$2.08	$1.98	
	24029_DELAMO _230_24021_CENTER S_230_BR_1 _1	2.8%	-$3.49	$3.26	$1.73
	24021_CENTER S_230_24091_MESA CAL_230_BR_1 _1	2.0%	-$2.20	$1.83	$2.13
	6410_CP10_NG	1.3%	$8.23	-$6.62	-$6.27
	25001_GOODRICH_230_24076_LAGUBELL_230_BR_1 _1	0.7%	-$1.79	$1.44	$1.56
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	40.7%	-$6.80	$4.47	$10.39
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	22.3%			-$0.80
	7820_TL 230S_OVERLOAD_NG	9.1%	-$0.33		$3.74
	OMS 4646120 ELD_MKP_SCIT_NG	2.8%	-$4.39	$3.41	$4.23
	22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_1 _1	2.2%			$3.50
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1	1.8%			$4.55
	OMS 4646112_OP-6610	1.3%			-$1.04
	IID-SCE_BG	0.8%			-$1.66
	7820_TL23040_IV_SPS_NG	0.7%	-$0.40		$4.60
	MIGUEL_BKs_MXFLW_NG	0.6%	-$0.71		$8.38
	22831_SYCAMORE_138_22120_CARLTNHS_138_BR_1 _1	0.6%			$2.01
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	0.5%			$2.70
	OMS 5092302 MG_BK81_NG	0.5%	-$0.47		$2.87
	22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1	0.4%			$5.25

In the San Diego Gas and Electric area, there were several outages which caused congestion on the transmission constraints. Congestion on the Serrano 500/230 kV transformer significantly impacted prices in the San Diego Gas and Electric area, which bound in more than 40 percent of the hours and increased prices by more than $10/MWh. This congestion was caused by a planned outage on a portion of the Serrano transformer bank, which was extended into April 2018.

The Doublet Tap-Friars 138 kV constraint, Imperial Valley nomogram, and the Southern California Import Transmission (SCIT) nomogram were the next most frequently binding constraints during the first quarter. Congestion from these constraints increased prices by about $7/MWh in the San Diego Gas and Electric area and $3/MWh in the Southern California Edison area, and decreased prices by about $4/MWh in Pacific Gas and Electric area. A major reason for congestion on the Doublet Tap-Friars 138 kV constraint was due to a daily outage on the Penasquitos-Old Town 230 kV line. The Imperial Valley nomogram was enforced to protect for the loss of the Imperial Valley-North Gila 500 kV line. The SCIT nomogram was binding for the loss of El Dorado-Moenkopi 500 kV line which returned to service mid-January 2018.

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

15-minute market congestion

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. Table 1.2 shows the frequency and magnitude of 15-minute market congestion for the quarter.

Similar to the day-ahead market, there was relatively small amounts of congestion in the Pacific Gas and Electric area, with congestion impacting prices in less than 2 percent of intervals. In the Southern California Edison area, the Center-Mesa 230 kV and Delamo-Center 230 kV constraints bound during 3 and 1.6 percent of intervals, respectively. When binding, they increased Southern California Edison and San Diego Gas and Electric area prices by about $29/MWh and $31/MWh, respectively, and decreased Pacific Gas and Electric area prices by $19/MWh.

In the San Diego Gas and Electric area, the Serrano 500/230 kV constraint bound most frequently, during about 13 percent of all intervals. When this constraint bound in the 15-minute market, it increased prices in the Southern California Edison and San Diego Gas and Electric areas there by about $10/MWh and $24/MWh respectively, and decreased prices in the Pacific Gas and Electric area by about $7/MWh. Similar to the day-ahead market, the Doublet Tap-Friars 138 kV, Imperial Valley nomogram, and Southern California Import Transmission (SCIT) nomogram frequently bound and caused prices to increase in the Southern California Edison and San Diego Gas and Electric areas.

Table 1.2 also shows that many of these same constraints impacted 15-minute energy imbalance market area prices when they bound. The frequency and impact of congestion in the 5-minute market was similar to that of the 15-minute market.

Table 1.2 Impact of congestion on 15-minute prices during congested intervals[10]

Area	Constraint	Frequency	Q1								
		Q1	PG&E	SCE	SDGE	PACE	PACW	NEVP	PSEI	AZPS	PGE
PG&E	30055_GATES1 _500_30900_GATES _230_XF_11_P	1.3%	$3.83	$1.18	$0.98	-$0.01	-$0.05	-$0.01	-$0.05	$0.01	-$0.05
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	1.1%	$11.21	-$13.85	-$13.01	$0.00	$0.12	-$0.07	$0.11	-$0.12	$0.11
	6310_CP6_NG	0.3%	$1.72	-$6.97	-$6.52	$0.00	$0.02	-$0.01	$0.02	-$0.02	$0.02
SCE	24021_CENTER S_230_24091_MESA CAL_230_BR_1 _1	3.3%	-$12.03	$16.82	$22.28	-$0.18	-$0.34	-$0.03	-$0.33	$0.00	-$0.34
	24029_DELAMO _230_24021_CENTER S_230_BR_1 _1	1.6%	-$7.36	$12.41	$8.56	-$0.08	-$0.11	-$0.07	-$0.10	-$0.02	-$0.10
	6410_CP10_NG	0.8%	$11.17	-$11.71	-$11.11	$0.00	$0.06	-$0.05	$0.06	-$0.07	$0.06
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	0.6%	-$10.45	$6.83	$5.23						
	OMS 5784730_OP-6610	0.4%	$5.31	$3.75	$0.33	-$0.03	$0.00	-$0.06	$0.00	-$0.06	$0.00
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	13.2%	-$6.58	$10.76	$24.57	-$0.86	-$0.86	-$0.95	-$0.86	-$0.69	-$0.86
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	4.9%	$0.00	$0.00	-$5.73						
	7820_TL 230S_OVERLOAD_NG	1.9%	$0.00	$0.65	$11.68	-$0.02	$0.00	-$0.02	$0.00	-$0.06	$0.00
	OMS 4646120 ELD_MKP_SCIT_NG	1.9%	-$4.74	$16.39	$18.14	-$0.19	-$0.11	-$0.08	-$0.11	-$0.43	-$0.11
	7820_TL23040_IV_SPS_NG	1.9%	$0.00	$0.00	$15.74	-$0.02	$0.00	-$0.02	$0.00	-$0.06	$0.00
	OMS 5092302 MG_BK81_NG	0.9%	$0.00	$0.00	$30.11	-$0.03	$0.00	-$0.03	$0.00	-$0.10	$0.00
	OMS 4646112_OP-6610	0.7%	$3.52	$3.33	$1.03	-$0.04	$0.00	-$0.08	$0.00	-$0.06	$0.00
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.5%	$0.00	$0.00	-$6.34						

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

1.3.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional prices in the day-ahead and 15-minute markets caused by congestion between different areas of the ISO system. The analysis provided in the previous section focused only on congested hours. This section is based on the average congestion component as a percent of the total price during all congested and non-congested intervals. This approach shows the impact of congestion when taking into account both the frequency congestion occurs and the magnitude of the impact.[11]

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.

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load area during the quarter by constraint.[12] Congestion increased prices in the Southern California Edison area by about $2/MWh (5 percent) and in San Diego Gas and Electric area by about $5/MWh (12 percent), and decreased prices in the Pacific Gas and Electric area by about $3/MWh (9 percent). As mentioned above, congestion on the Serrano 500/230 kV constraint contributed to roughly 90 percent of price differential between Northern and Southern California.

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

12 Details on constraints with shift factors less than 2 percent have been grouped in the ‘other’ category.

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint	PG&E		SCE		SDG&E	
	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$2.77	-8.59%	$1.82	4.97%	$4.23	10.60%
7820_TL 230S_OVERLOAD_NG	-$0.03	-0.09%			$0.34	0.85%
OMS 4646120 ELD_MKP_SCIT_NG	-$0.12	-0.38%	$0.10	0.26%	$0.12	0.30%
6410_CP10_NG	$0.11	0.33%	-$0.09	-0.24%	-$0.08	-0.20%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.09	0.29%	-$0.07	-0.19%	-$0.07	-0.17%
24029_DELAMO _230_24021_CENTER S_230_BR_1 _1	-$0.10	-0.30%	$0.09	0.25%	$0.04	0.09%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.18	-0.45%
24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	-$0.09	-0.28%	$0.09	0.23%		
24021_CENTER S_230_24091_MESA CAL_230_BR_1 _1	-$0.04	-0.14%	$0.04	0.10%	$0.04	0.11%
22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1					$0.10	0.24%
22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1					$0.08	0.20%
22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_1 _1					$0.08	0.20%
MIGUEL_BKs_MXFLW_NG	$0.00	-0.01%			$0.05	0.12%
7820_TL23040_IV_SPS_NG	$0.00	-0.01%			$0.03	0.08%
25001_GOODRICH_230_24076_LAGUBELL_230_BR_1 _1	-$0.01	-0.04%	$0.01	0.03%	$0.01	0.03%
30055_GATES1 _500_30900_GATES _230_XF_11_S	-$0.01	-0.04%	$0.01	0.03%	$0.01	0.02%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	0.00%			-$0.02	-0.06%
22740_SANYSDRO_69.0_22608_OTAY TP_69.0_BR_1 _1					$0.02	0.06%
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1					$0.02	0.05%
OMS_5554630_GATES_BNK_11	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.01%
OMS 5092302 MG_BK81_NG	$0.00	-0.01%			$0.01	0.03%
OMS 5736540 SUNCREST BK80_NG	$0.00	0.00%			$0.01	0.03%
OMS 4646112_OP-6610					-$0.01	-0.04%
22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1					$0.01	0.03%
6310_CP8_NG	$0.01	0.02%	$0.00	-0.01%	$0.00	-0.01%
IID-SCE_BG					-$0.01	-0.03%
6310_CP9_NG	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
22831_SYCAMORE_138_22120_CARLTNHS_138_BR_1 _1					$0.01	0.03%
6410_CP7_NG	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
Other	-$0.03	-0.09%	$0.03	0.08%	$0.06	0.15%
Total	**-$2.99**	**-9.29%**	**$2.00**	**5.46%**	**$4.88**	**12.23%**

15-minute price impacts

Table 1.4 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint.[13] Congestion during the first quarter increased Southern California Edison prices by $2.50/MWh (7 percent) and San Diego Gas and Electric area prices by more than $5/MWh (14 percent) while decreasing Pacific Gas and Electric area prices by about $1/MWh (3 percent). Congestion continued to increased prices in the Southern California areas in the first quarter compared to the previous quarter, following the trend of increased congestion impact from the third to fourth quarters of 2017. This was primarily caused by congestion on the Serrano 500/230 kV transformer constraint, Center-Mesa 230 kV line, and Southern California Import Transmission (SCIT) nomogram.

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

Table 1.4 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.87	-2.64%	$1.42	3.98%	$3.23	8.34%
24021_CENTER S_230_24091_MESA CAL_230_BR_1 _1	-$0.39	-1.20%	$0.55	1.55%	$0.73	1.88%
OMS 4646120 ELD_MKP_SCIT_NG	-$0.09	-0.28%	$0.32	0.89%	$0.35	0.90%
24029_DELAMO _230_24021_CENTER S_230_BR_1 _1	-$0.12	-0.35%	$0.20	0.55%	$0.12	0.32%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.12	0.37%	-$0.15	-0.42%	-$0.14	-0.36%
7820_TL23040_IV_SPS_NG					$0.29	0.76%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.28	-0.72%
OMS 5092302 MG_BK81_NG					$0.28	0.72%
6410_CP10_NG	$0.08	0.26%	-$0.09	-0.25%	-$0.08	-0.22%
7820_TL 230S_OVERLOAD_NG			$0.01	0.04%	$0.23	0.58%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.04	-0.12%	$0.10	0.27%	$0.07	0.19%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.04	-0.11%	$0.10	0.27%	$0.07	0.17%
37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.08	0.24%	-$0.04	-0.12%	-$0.04	-0.11%
37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1	$0.06	0.18%	-$0.03	-0.09%	-$0.03	-0.08%
22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80					$0.12	0.30%
OMS 5555651 CRY-MCC_6510_NG	-$0.01	-0.03%	$0.04	0.11%	$0.04	0.11%
OMS 5688351 TL23054_NG					$0.08	0.20%
OMS 5736536 SUNCREST BK80_NG					$0.07	0.19%
MIGUEL_BKs_MXFLW_NG					$0.07	0.19%
24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	$0.00	-0.01%	$0.04	0.11%	$0.03	0.08%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.04	0.12%	$0.02	0.04%	$0.01	0.03%
OMS 4646112_OP-6610	$0.03	0.08%	$0.02	0.07%	$0.01	0.02%
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	$0.02	0.06%	-$0.02	-0.05%	-$0.02	-0.05%
6310_CP6_NG	$0.01	0.02%	-$0.02	-0.07%	-$0.02	-0.06%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.05	0.13%
OMS 5687847_TL50003_NG			$0.00	0.00%	$0.04	0.09%
OMS 5784730_OP-6610	$0.02	0.06%	$0.02	0.04%	$0.00	0.00%
22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1					-$0.04	-0.09%
Other	$0.04	0.11%	$0.09	0.24%	$0.09	0.22%
Total	**-$1.06**	**-3.25%**	**$2.54**	**7.14%**	**$5.32**	**13.73%**

Internal congestion in the energy imbalance market

Table 1.5 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 first quarter of 2017. Congestion in PacifiCorp East was mainly a result of a single constraint binding during almost 15 percent of intervals in both the 15-minute and 5-minute markets. In the NV Energy area, frequency of binding internal constraints continued to decrease from the previous quarters in both the 15-minute and 5-minute markets.

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 1.5 Percent of intervals with congestion on internal EIM constraints

	2014	2015				2016				2017				2018
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
15-minute market (FMM)														
PacifiCorp East	0.1%	0.2%	0.2%	0.5%	2.6%	2.2%	0.2%	1.3%	14.9%	16.1%	4.3%	5.1%	47.6%	14.9%
PacifiCorp West	0.1%	0.0%	0.0%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%
NV Energy					0.0%	0.0%	0.1%	0.3%	3.2%	10.3%	1.8%	7.6%	5.8%	0.5%
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%
5-minute market (RTD)														
PacifiCorp East	0.0%	0.3%	0.2%	0.4%	2.3%	2.2%	0.2%	1.3%	15.2%	17.1%	3.3%	4.5%	46.1%	14.7%
PacifiCorp West	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%
NV Energy					0.0%	0.0%	0.2%	0.3%	3.2%	11.7%	1.6%	7.1%	5.6%	0.4%
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%

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.[14]

Operating reserves requirements in real-time have typically been set to the maximum of (1) the sum of 3 percent of the load forecast and 3 percent of generation and (2) the most severe single contingency.[15] Day-ahead operating reserve requirements have typically been set to the maximum of (1) about 6.3 percent of the load forecast and (2) the most severe single contingency.

With BAL-002-2, the Federal Energy Regulatory Commission approved new definitions 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. Figure 1.8 shows actual hourly average operating reserve requirements during the first quarter as well as *estimated* hourly average operating reserve requirements had the changes associated with BAL-002-2 not been implemented.[16] During the first quarter, actual day-ahead operating reserve requirements were on average around 600 MW to 1,100 MW higher during morning hours ending 1 through 8 and evening hours ending 17 through 24.

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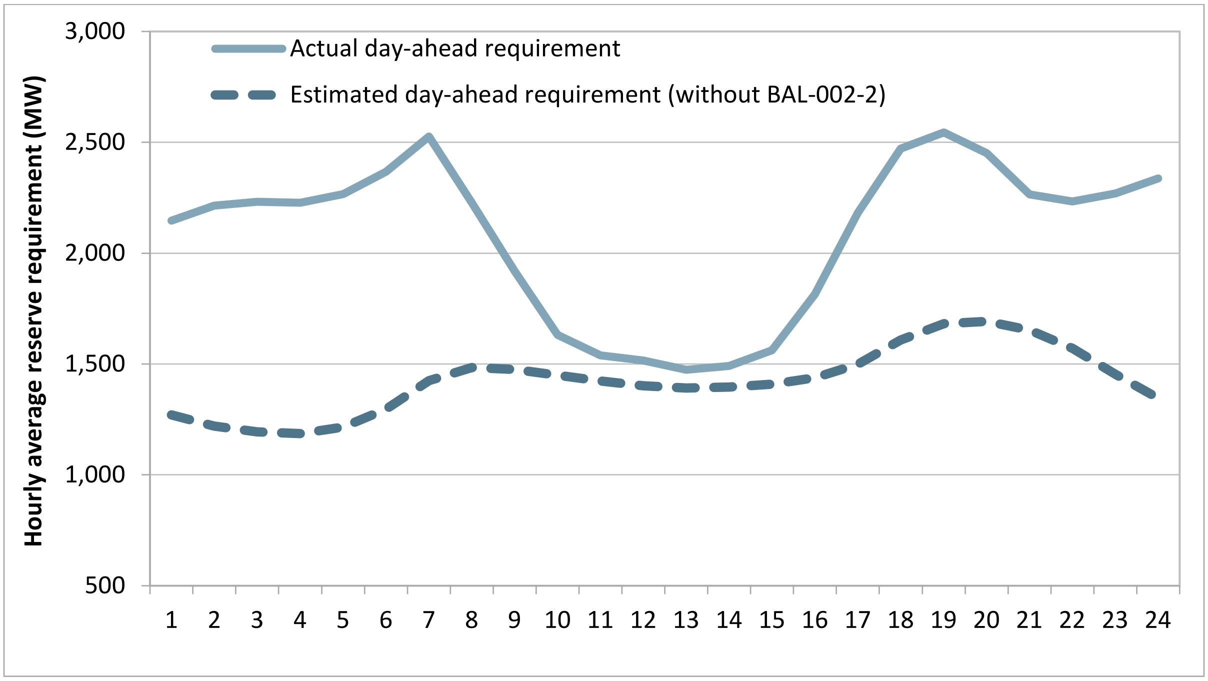
[14] Further information on BAL-002-2 and operating reserve requirement changes implemented by the ISO is available here: http://www.caiso.com/Documents/Presentation-BAL-002-2DisturbanceControlStandard-ContingencyReserveforRecoveryfromaBalancingContingencyEvent.pdf
or in the NERC BAL-002-2 reliability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

[15] Between June 14 and September 18, the ISO regularly increased the percent specified for the load forecast component of the calculation during midday hours to roughly meet 25 percent of solar production and mitigate a reliability risk related to potentially significant tripping of solar generation.

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

Figure 1.8 Hourly average operating reserve requirement (January – March)



1.5 Flexible ramping product

Background

The ISO implemented a new market feature in November 2016 for procuring real-time flexible ramping capacity known as *the flexible ramping product*. The product replaced the previous procurement mechanism called the *flexible ramping constraint*.

This new 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.

Further, 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.[17] The most significant of these errors is described below.

- The net load errors in the hourly historical distributions were intended to be calculated as the difference between (1) the binding net load forecast for the next interval and (2) the first advisory net load forecast for the same corresponding time interval from the prior market run.

- However, when the flexible ramping product was implemented, the net load error calculation was instead based on the difference between the binding and advisory interval in the same market run between two sequential time intervals, or the negative of the expected change in net load.

By calculating uncertainty in this manner (between sequential time intervals), the result systematically biased flexible ramping capacity procurement and prices in the direction opposite of the net load ramp (down when net load is ramping up and vice versa). Overall, this error had a significant impact on flexible ramping procurement and prices, though the direction and magnitude of the impact depends on the hour. In particular, this has resulted in under-procurement of upward flexible ramping capacity during key net load ramping intervals.

DMM recalculated the uncertainty requirements using the correct methodology and data. DMM believes that these corrected uncertainty requirements are highly consistent with what the uncertainty requirements would have been had the flexible ramping product been implemented as designed.

Figure 1.9 and Figure 1.10 show corrected average hourly uncertainty requirements for the 5-minute market and 15-minute market, respectively. The blue lines show the corrected upward and downward system-level uncertainty requirements between March and December 2017, pulled from recalculated hourly distributions of net load errors during 2017. For comparison, the green lines show average hourly uncertainty requirements used in the market by the ISO during the same period. The upward uncertainty requirements are depicted by the upper lines while the downward uncertainty requirements are depicted by the lower lines. The uncertainty requirements used in the market are capped at zero megawatts at one end and at the uncertainty thresholds at the other.[18]

During hours when the corrected uncertainty requirements were larger in magnitude than the implemented uncertainty requirements, flexible ramping capacity procurement was typically expected to be higher. As shown in Figure 1.9, upward uncertainty requirements in the 5-minute market were expected to be around 270 MW higher on average between hours ending 15 and 18, hours in which power balance shortages have occurred more often. Downward uncertainty requirements were expected to be larger by around 120 MW on average during morning hours ending 8 through 12 when solar generation is ramping up. In other hours, the incorrect uncertainty calculation resulted in higher

[17] 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.

[18] Uncertainty requirements are capped by uncertainty thresholds, designed to prevent extreme outlier or erroneous net load errors from impacting the uncertainty requirement and associated market outcomes. During 2017, these values were unchanged from values used since the implementation of the flexible ramping product and were binding more frequently than expected. The ISO updated the thresholds in April, 2018 and has submitted language for the BPM to evaluate the thresholds periodically.

than expected uncertainty requirements – which would tend to cause inefficiently higher ramping capacity procurement and prices.

As illustrated in Figure 1.10, the implementation issues had a similar impact on the uncertainty requirement in the 15-minute market. In particular, 15-minute market upward uncertainty requirements would have been around 460 MW higher on average between hours ending 15 and 19 had the flexible ramping product been implemented as designed.

Systematic under-procurement of flexible ramping capacity during key upward and downward net load ramping hours may have increased the frequency of power balance constraint violations. However it is not possible to determine whether any particular power balance violation would have been resolved had the flexible ramping product been implemented as designed.

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.

Figure 1.9 Average hourly 5-minute market system-level uncertainty requirements (March – December, 2017)

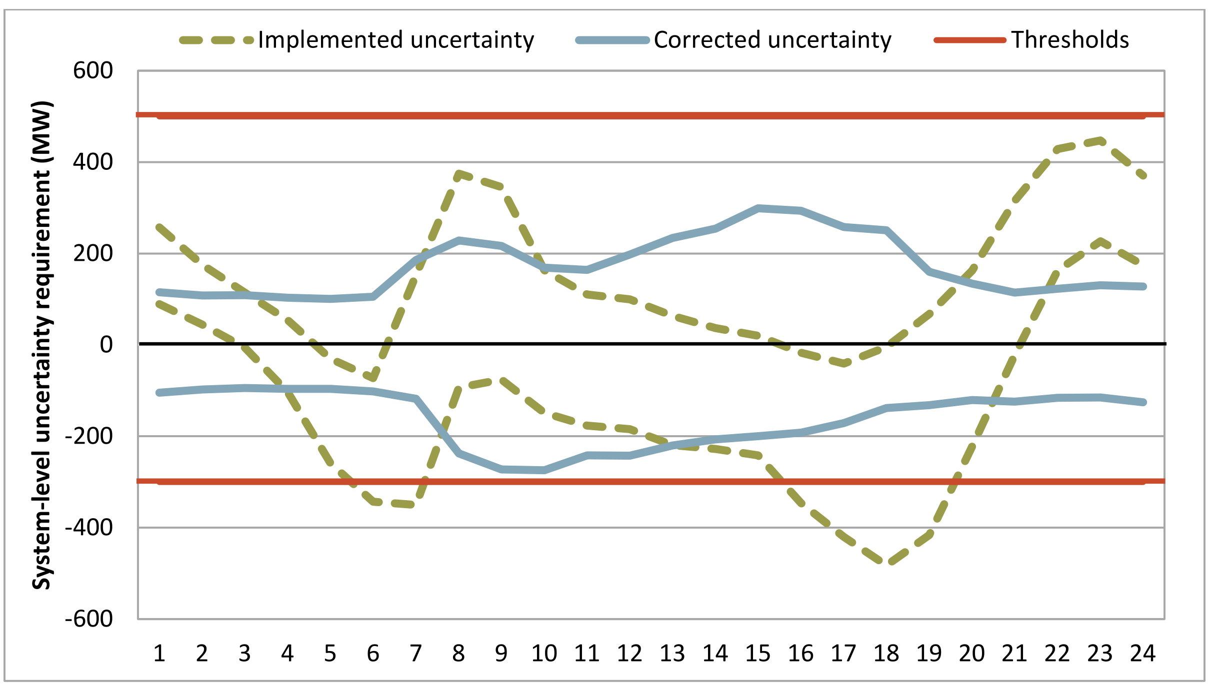
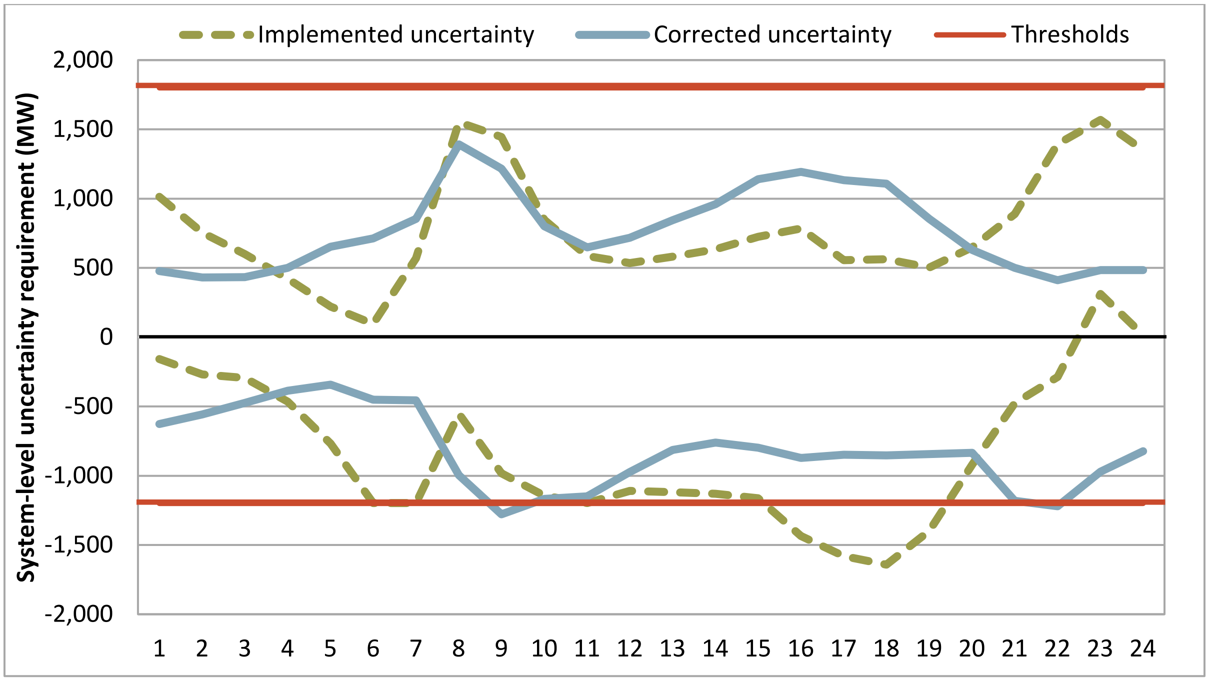


Figure 1.10 Average hourly 15-minute market system-level uncertainty requirements (March – December, 2017)



Other implementation issues

Since the implementation of the flexible ramping product, the demand curves for individual balancing areas are included in the constraint for system-level procurement. Initially, segments of relaxation capacity specific to the individual balancing area demand curves could be used to meet system-level uncertainty even when the uncertainty requirements for the individual balancing areas was reduced to zero. This approach resulted in system-level procurement of flexible ramping capacity and associated flexible ramping shadow prices that were lower than what would be consistent using the system-level demand curves alone.

On July 13, 2017, an adjustment was made to limit the use of flexible ramping product demand curves from individual balancing areas when sufficient transfer capability connected the area with system conditions. However, since this adjustment was made, resources providing flexible ramping capacity to meet system-level flexibility needs have often received lower payments based on the area-specific demand curve rather than the system-level demand curve though sufficient transfer capacity was present.[19] A fix for this issue went into production effective April 4, 2018. However, DMM continues to observe flexible ramping prices that appear disconnected from the demand curves. DMM recommends that the ISO investigate and resolve all issues that may result in inappropriate prices or procured quantities.

[19] For additional information on this pricing issue, see *DMM's Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 49-52: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

The ISO has also identified an issue related to the deliverability of flexible ramping product procurement. The concern being the potential for system-level flexible ramping capacity procurement external to the ISO to be stranded behind energy imbalance market transfer constraints when prices in the ISO and surrounding areas are extremely high and in need of flexible ramping capacity. The ISO discussed a proposed enhancement to resolve the issue at the Market Surveillance Committee meeting on February 2, 2018.[20]

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.[21]

Figure 1.11 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month and balancing area.[22] 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 during the first quarter of 2018 to around $2 million, compared to around $3 million during the previous quarter and around $9 million during the first quarter of 2017. Further, payments per megawatt-hour of load remained low during the quarter.[23] Average net payments per megawatt-hour of load during the first quarter were about $0.03/MWh, similar to the previous quarter.

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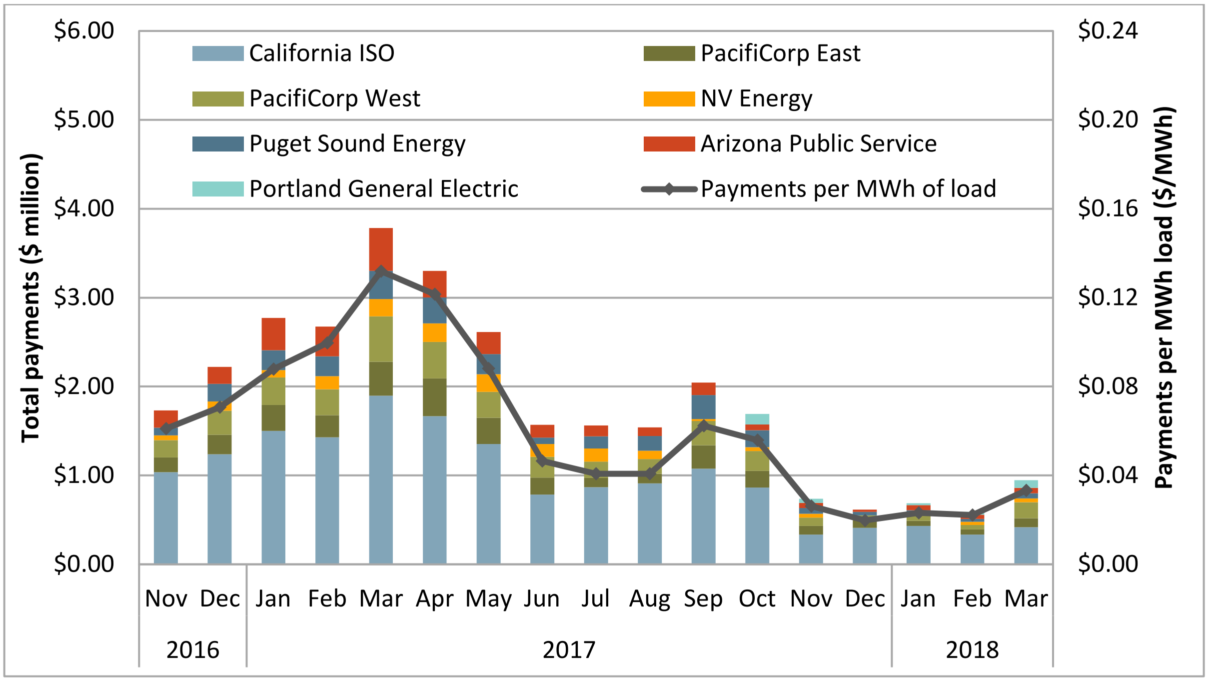
[20] Market Surveillance Committee Flexible Ramping Product Performance Discussion, February 2, 2018, slides 5-7: http://www.caiso.com/Documents/Presentation-FlexibleRampingProductPerformanceDiscussionFeb22018.pdf.

[21] 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.

[22] 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.

[23] Load is measured as the total load in the ISO and energy imbalance market areas.

Figure 1.11 Monthly flexible ramping payments by balancing area



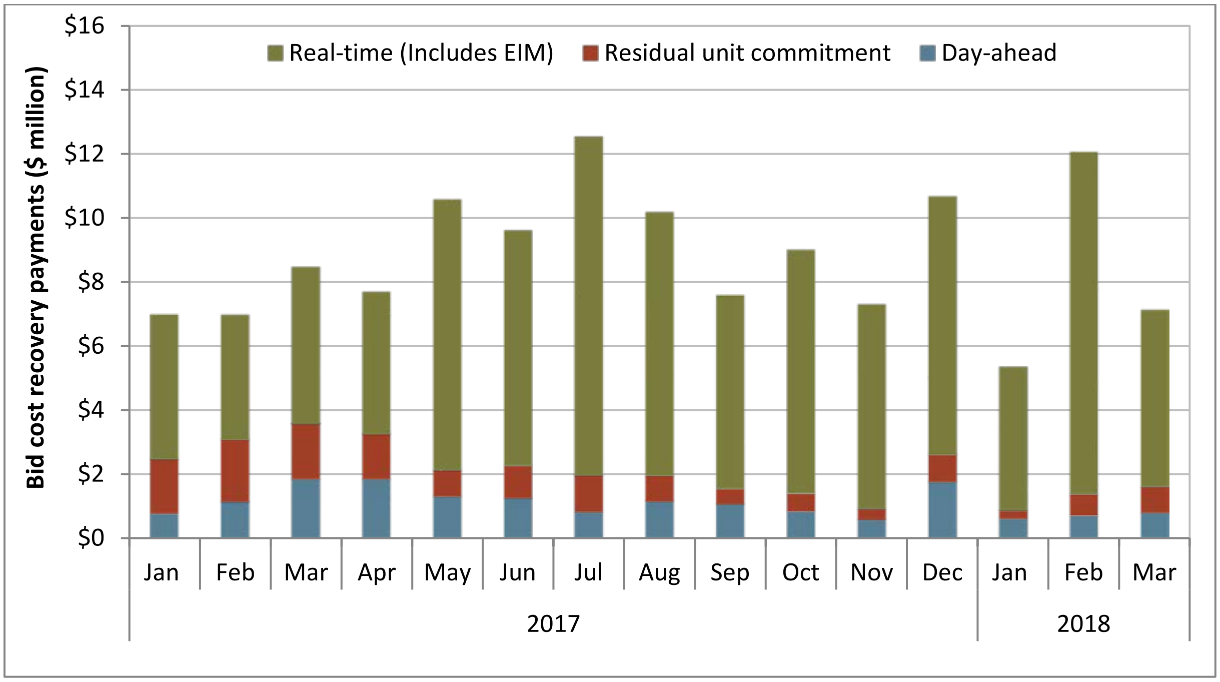
1.6 Bid cost recovery

Estimated bid cost recovery payments for the first quarter of 2018 totaled about $25 million. This amount was slightly lower than the total amount of bid cost recovery in the previous quarter and slightly higher than the first quarter of 2017, when it was about $23 million. Almost half of the bid cost recovery payments were accrued in the real-time market during February.

Bid cost recovery attributed to the day-ahead market totaled about $2 million, which was about a million lower than the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $1.8 million, similar to the prior quarter. Bid cost recovery attributed to the real-time market totaled about $21 million, or about $1 million lower than payments in the fourth quarter of 2017 and $8 million larger than payments in the first quarter of 2017.

In February, these real-time payments were about $11 million, the highest amount in any month since 2011. During February 20 – 23, when the natural gas prices were significantly high at SoCal Citygate, these payments totaled about $5 million.

Figure 1.12 Monthly bid cost recovery payments



1.7 Convergence bidding

Convergence bidding was profitable overall during the first quarter. Virtual supply was profitable for the first time since the first quarter of 2017. Before accounting for bid cost recovery charges, virtual supply generated net revenues of about $2.2 while demand net revenues were a loss of about $0.5 million. Combined net revenues for virtual supply and demand fell to about $0.6 million after including about $1.1 million of virtual bidding bid cost recovery charges.

1.7.1 Convergence bidding trends

Average hourly cleared volumes remained at about 2,000 MW, which is very similar to the previous quarter. Average hourly virtual supply remained similar to the previous quarter at about 1,200 MW compared. Virtual demand averaged around 840 MW during each hour of the quarter, higher than the previous quarter of about 800 MW. On average, about 38 percent of virtual supply and demand bids offered into the market cleared in the first quarter, which is up slightly from 35 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 360 MW on average, which decreased slightly from 370 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 7 and 8, as well as 18 and 20. In the remaining 19 hours, net cleared virtual supply exceeded net cleared virtual demand. Net cleared virtual supply was highest during the midday hours ending 11 through 16, as well as hour end 24. During these hours virtual supply cleared about 830 MW more than virtual demand, 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 20 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 355 MW of virtual demand offset by 355 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 40 percent of all cleared virtual bids in the first quarter, up from about 37 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 $1.7 million. Net revenues for virtual supply and demand fell to about $0.6 million after including about $1.1 million of virtual bidding bid cost recovery charges.[24]

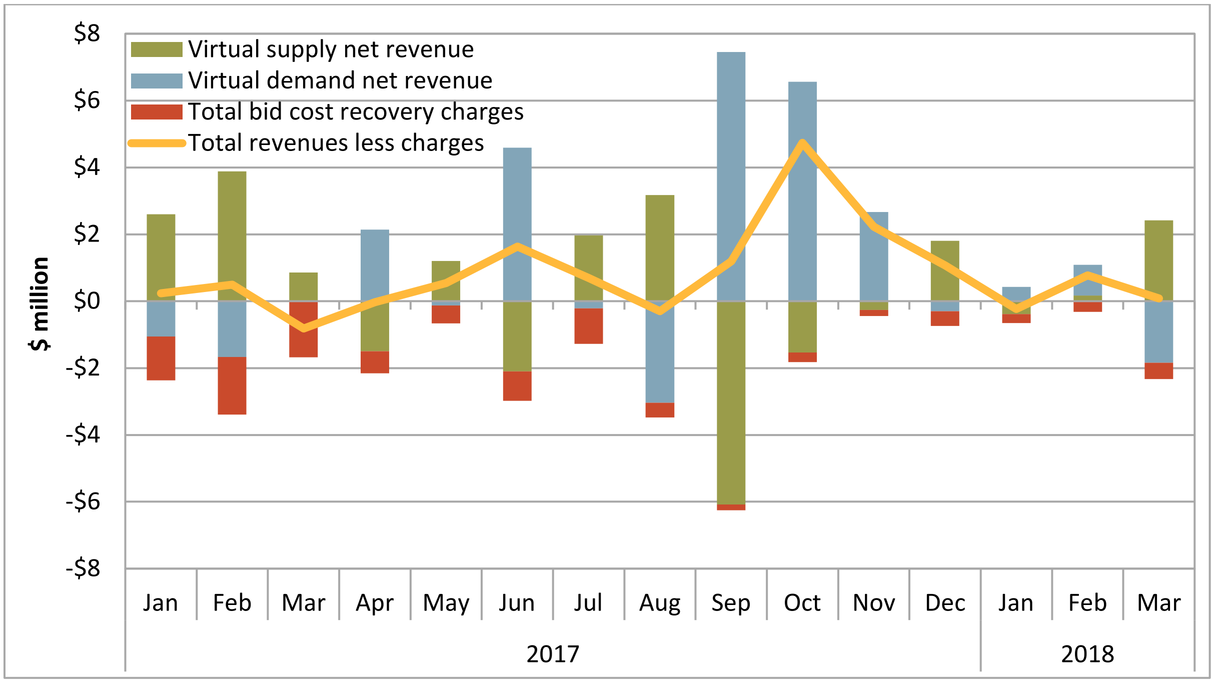
Figure 1.13 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

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 $1.7 million, compared to about $4.6 million during the same quarter in 2017, and about $8.9 million during the previous quarter.
- Virtual demand net revenues were positive in January and February but were negative in March. In total, virtual demand generated negative net revenues of about $0.5 million for the quarter.
- Virtual supply net revenues were nearly $0 in both January and February but were positive in March. In total, virtual supply generated net revenues of about $2.2 million. After accounting for bid cost recovery charges, virtual supply was profitable for the first time since the first quarter of 2017.

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

Figure 1.13 Convergence bidding revenues and bid cost recovery charges



After accounting for bid cost recovery charges:

- Convergence bidders received about $0.6 million after subtracting bid cost recovery charges of about $1.1 million for the quarter.[25,26] Bid cost recovery charges were about $0.3 million in January and February and $0.5 million in March.

Net revenues and volumes by participant type

Table 1.6 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the first quarter.[27] Financial entities represented the largest segment of the virtual bidding market, accounting for about 56 percent of volume and a 51 percent of settlement revenue. Marketers represented about 37 percent of the trading volumes and about 40 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

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

26 Business Practice Manual configuration guide has been updated for CC 6806, day-ahead residual unit commitment tier 1 allocation, to ensure that the residual unit commitment obligations do not receive excess residual unit commitment tier 1 charges or payments. For additional information on how this allocation may impact bid cost recovery, refer to page 3: BPM Change Management Proposed Revision Request.

27 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 7 percent and 9 percent respectively. In addition, load-serving entities accounted for around $0.2 million in net payments to the market.

Table 1.6 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	500	638	1,138	-$0.15	$1.21	$1.07
Marketer	326	419	745	-$0.22	$1.06	$0.84
Physical load	0	135	135	$0.00	-$0.07	-$0.07
Physical generation	10	0	11	-$0.13	$0.00	-$0.13
Total	**836**	**1,192**	**2,029**	**-$0.5**	**$2.2**	**$1.7**

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 March 2018.

As illustrated in Figure 1.14, residual unit commitment procurement appears to be driven in large 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 60 percent lower in the first quarter of 2018 than in the first 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.[28] 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 1.14.

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 increased residual unit commitment in January. In addition, ISO operators were able to increase the amount of residual unit commitment requirements primarily due to weather change and renewable variability concerns. This tool, noted as operator adjustments (red bar) in the figure, was used frequently in March averaging about 242 MW per hour.

Figure 1.15 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 8 through 20. 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

[28] 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 peak midday hours in the first quarter. Intermittent resource adjustments were greatest during hours ending 9 through 17.

Figure 1.14 Determinants of residual unit commitment procurement

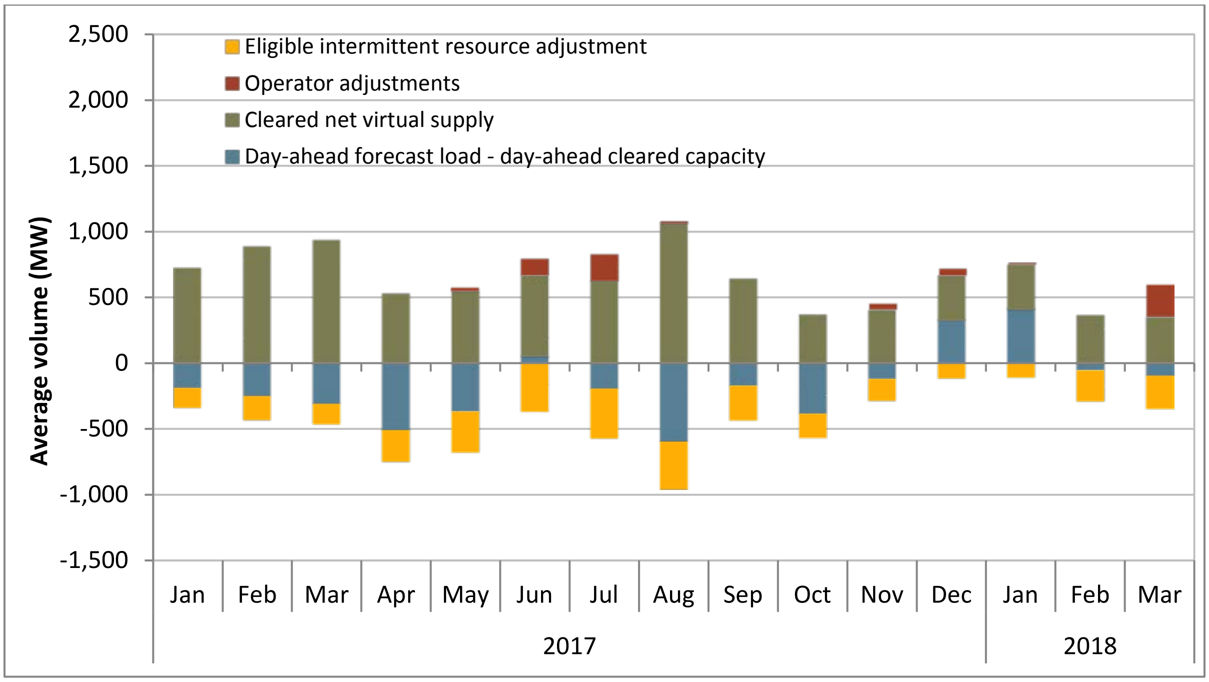
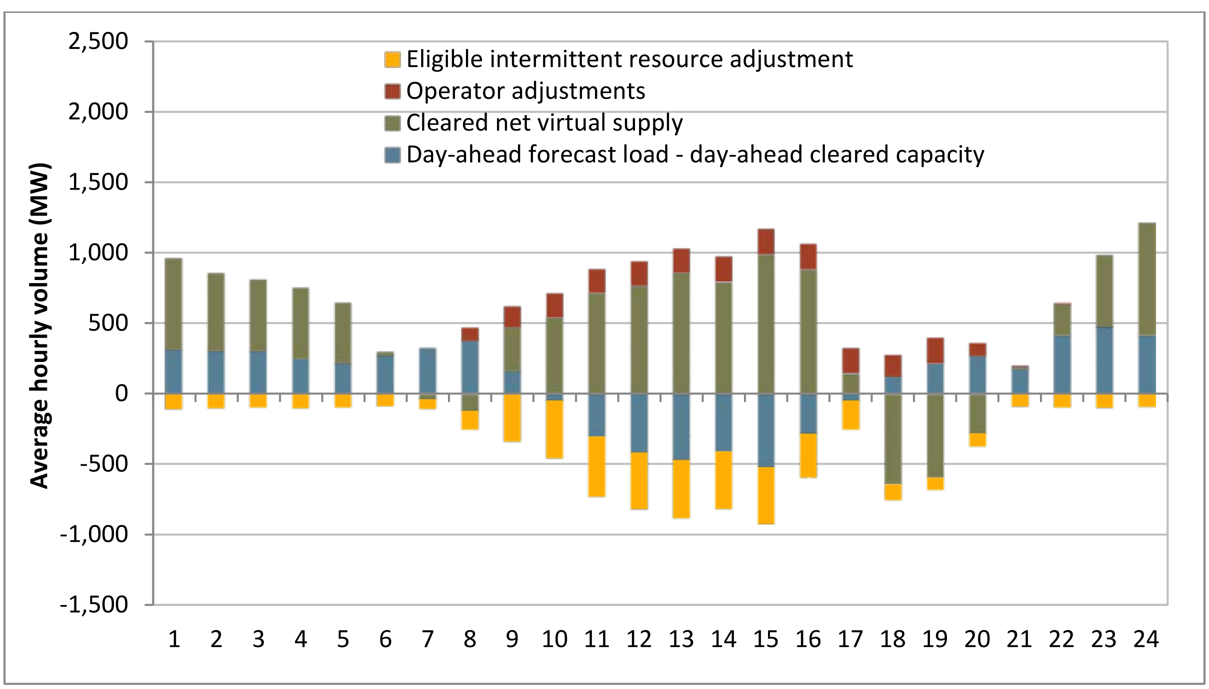


Figure 1.15 Average hourly determinants of residual unit commitment procurement (Jan - Mar)



1.9 Real-time imbalance offset costs

Total real-time imbalance offset costs increased by about 50 percent in 2017 (from $53 million in 2016 to $79 million for 2017). First quarter imbalance offset costs stayed high, totaling $21 million for the quarter.[29] All of the first quarter increases can be attributed to higher real-time energy imbalance costs totaling $24 million, about $19 million of which is attributable to four days (February 20 to 23) in which real-time gas burn constraints associated with Aliso Canyon gas-electric coordination were enforced and binding during peak hours in the real-time market. Real-time congestion imbalance offset and real-time imbalance offset costs fell during this time period.

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

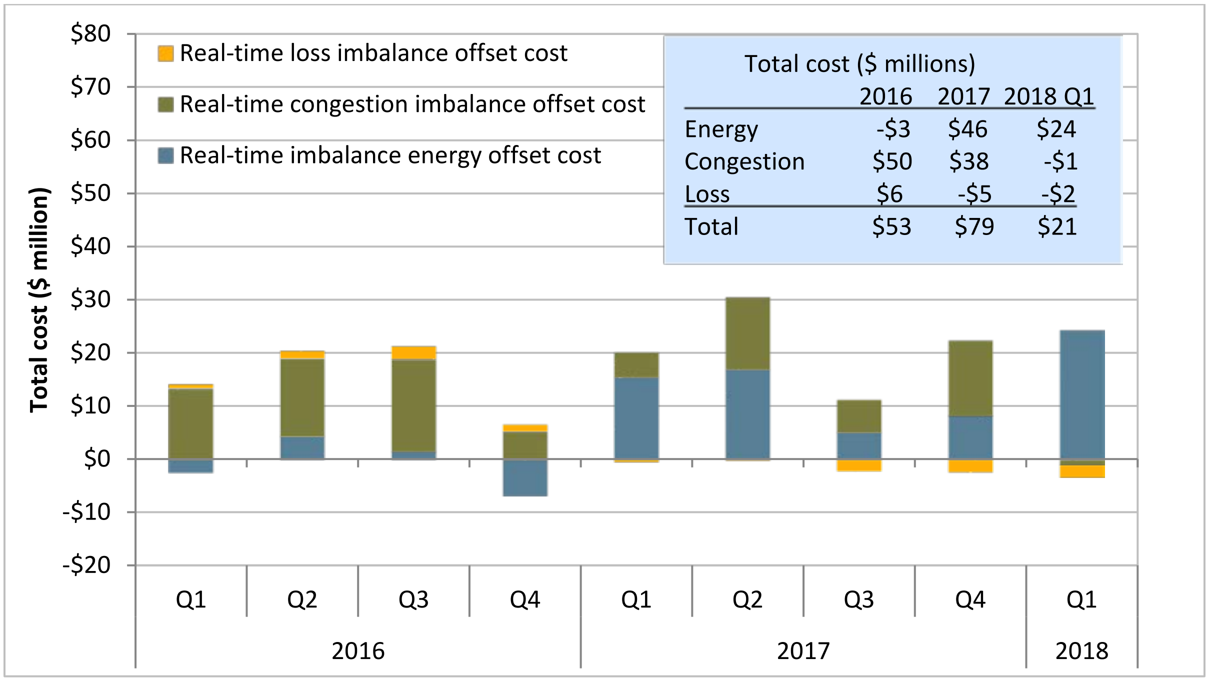
The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy components of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from the congestion component of these real-time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

A persistent premium of 15-minute prices over 5-minute prices, as occurred on average for 2017, can also contribute to real-time energy imbalance offset cost. This can occur because metered load imbalance is settled on a load-weighted average of 15-minute and 5-minute prices, but metered generation imbalance is settled only on the 5-minute price. Settlement of these intervals can result in real-time market revenues collected being less than revenues paid out, this may be one driver of the cost to measured demand in 2017. During the first quarter of 2018, 5-minute prices were higher, on average, than 15-minute prices in peak hours and on average in February and March, but not January.

As seen in Figure 1.16, the increase in total imbalance offset costs was attributable to an increase in imbalance costs for energy costs. Real-time congestion imbalance offset cost decreased to -$1 million in the first quarter from $24 million in the fourth quarter of 2017. Real-time loss imbalance offset and congestion imbalance offset costs remained about the same for the last two quarters at about -$1 million.

[29] Values reported here are the most current reported settlement imbalance charges, and are subject to change.

Figure 1.16 Real-time imbalance offset costs



1.10 Congestion revenue rights

Since 2009, electric ratepayers, who ultimately pay for the cost of transmission managed by the ISO, received an average of about $82 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments made to entities purchasing these rights. Total ratepayer losses since 2009 in the auction surpassed $770 million this quarter.

During the first quarter of 2018, congestion revenue rights auction revenues were $43 million less than congestion payments made to non-load-serving entities purchasing these rights. Losses in the first quarter represent $0.38 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders.

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).[30] 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 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.[31]

Analysis of congestion revenue right auction returns

As described above, the performance of the congestion revenue rights auction can be assessed by comparing the auction revenues ratepayers received to payments made by ratepayers to non-load-serving entities purchasing congestion revenue rights in the auction. Note that payments and charges to ratepayers are through load-serving entities. Figure 1.17 compares the following:

- auction revenues received by ratepayers from non-load-serving entities purchasing congestion revenue rights in the auction (blue bars on left axis);
- net payments from ratepayers to non-load-serving entities purchasing congestion revenue rights in the auction (green bars on left axis); and
- auction revenues received by ratepayers as a percentage of the net payments to non-load-serving entities purchasing congestion revenue rights in the auction (yellow line on right axis).

Ratepayers lost a total of $43 million during the first quarter of 2018 as payments to auctioned congestion revenue rights holders exceeded auction revenues by this amount, a significant increase from the $12 million loss in the same quarter of 2017. This represents the second highest amount of ratepayer losses in any quarter since 2015.

Auction revenues were 38 percent of payments made to non-load-serving entities during the first quarter of 2018, down from 63 percent during the same quarter in 2017.

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[30] 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.

[31] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

Figure 1.17 Auction revenues and payments to non-load-serving entities

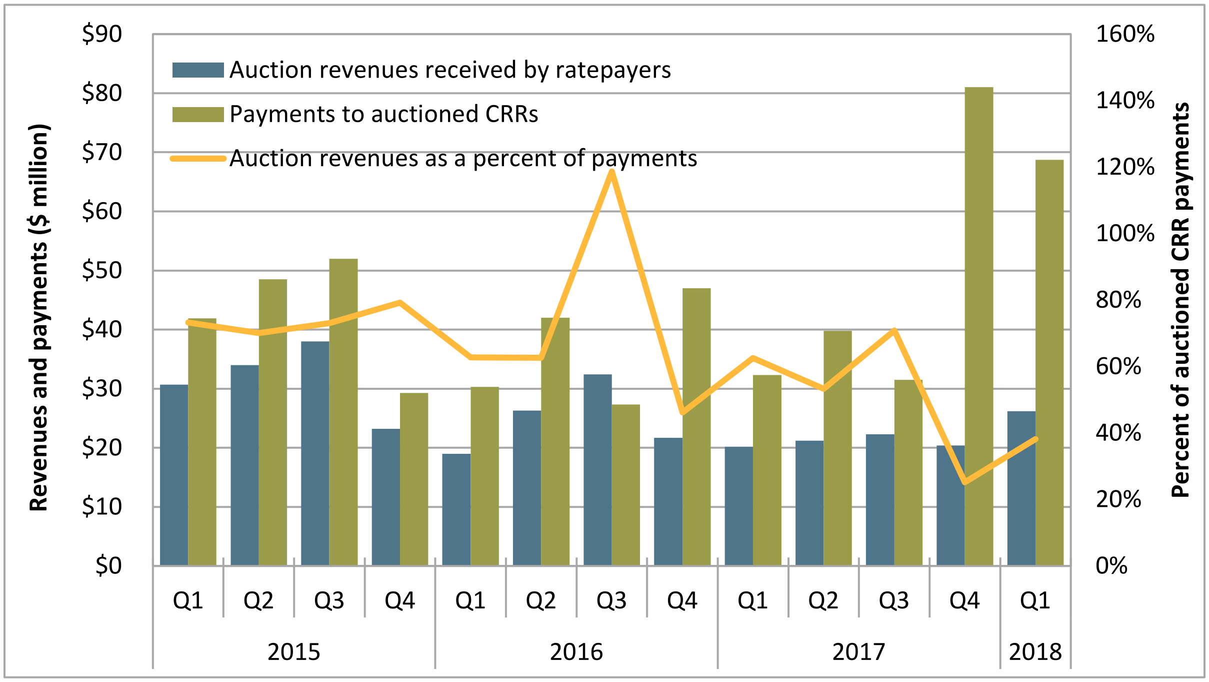


Figure 1.18 through Figure 1.21 show quarterly auction revenues paid to all entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- Financial entities participate in the ISO markets only through the convergence bidding and congestion revenue right products.
- Marketers participate in the ISO energy markets primarily through intertie transactions, rather than generators or loads internal to the ISO.
- Physical generation and load have generators and loads within the ISO footprint.

Similar to Figure 1.17, these charts show quarterly auction revenues and congestion revenue rights payments from 2015 through 2018. Highlights from these figures show the following for the first quarter of 2018.

- Financial entities continued to have the highest profits between the entity types, at approximately $36 million. This was a significant increase from $9 million profits during the first quarter of 2017. Marketer profits were approximately $4 million, up from $2 million during the same quarter in 2017. Generators gained about $2 million compared to $0.4 million in the first quarter of 2017.
- In the first quarter financial entities paid 27 cents in auction revenue per dollar received, compared to 53 cents paid in 2017 during the same quarter. Generators paid 66 cents per dollar received, compared to 85 cents on the dollar in the same quarter in 2017, and marketers paid 67 cents, down from 77 cents in the first quarter 2017.
- Load-serving entities were the only auction participant type that, on net, continued to sell rights into the auction from explicit bidding. Load-serving entities lost about $0.6 million from rights they

explicitly sold in the auction in the first quarter of 2018, this is an increase from a loss of about a $0.1 million in the same quarter of 2017.

Figure 1.18 Auction revenues and payments (financial entities)

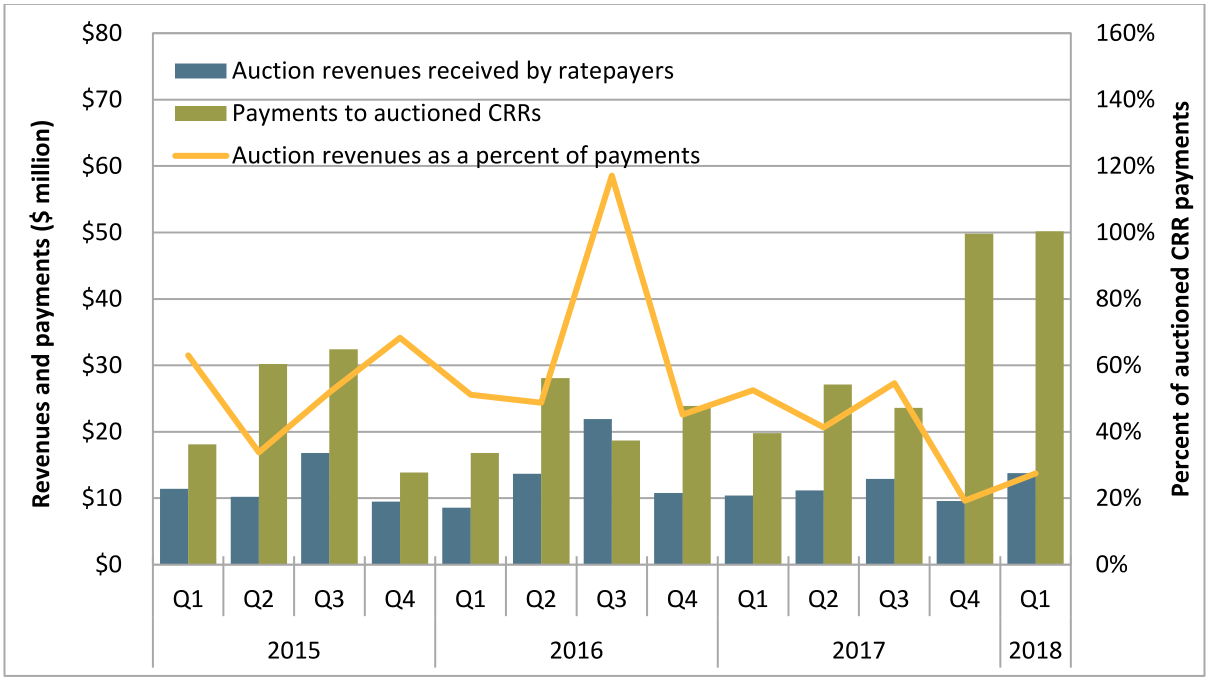


Figure 1.19 Auction revenues and payments (marketers)

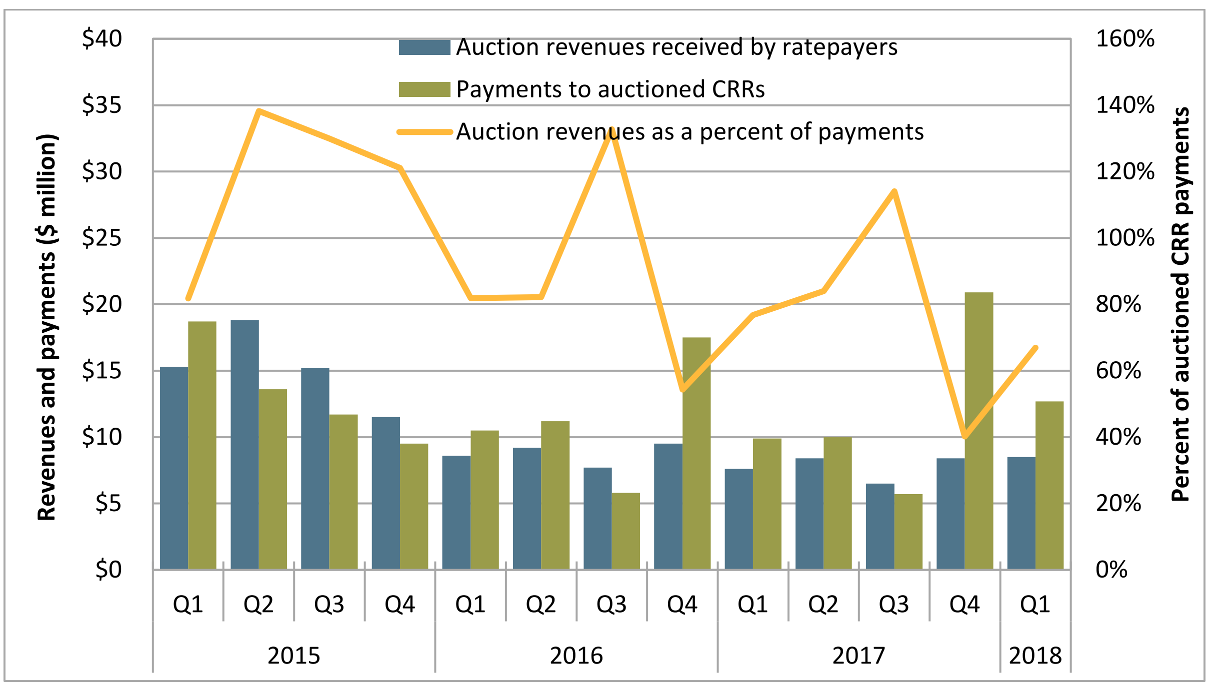


Figure 1.20 Auction revenues and payments (generators)

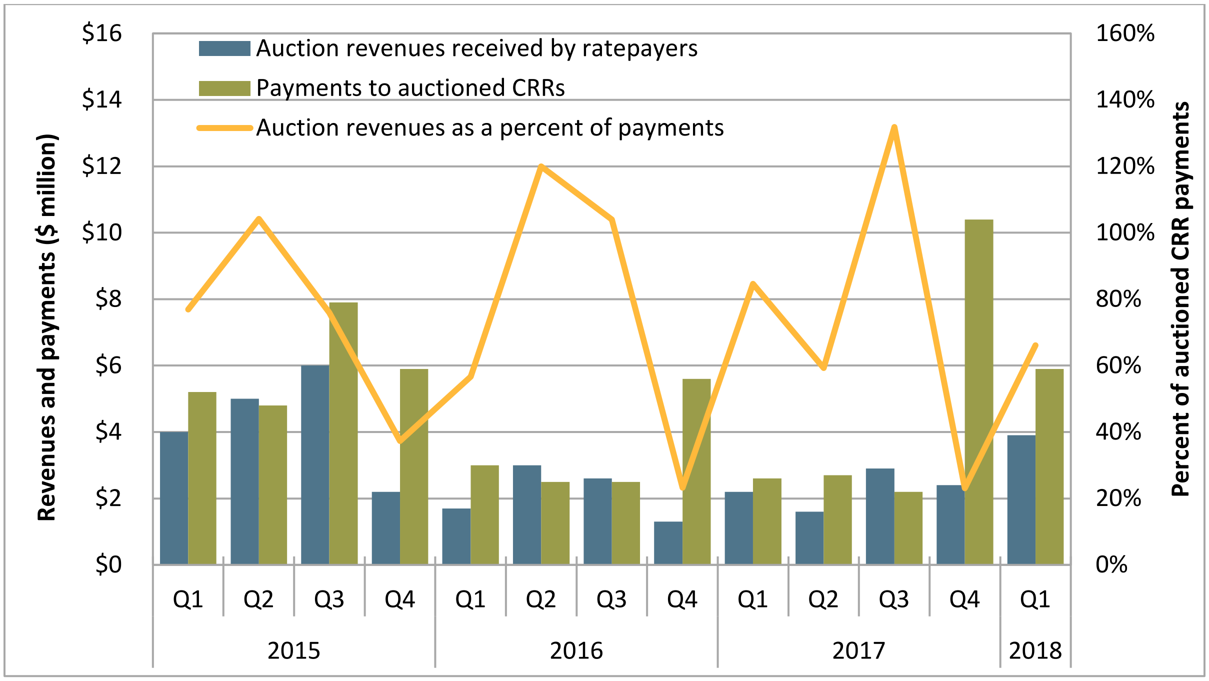
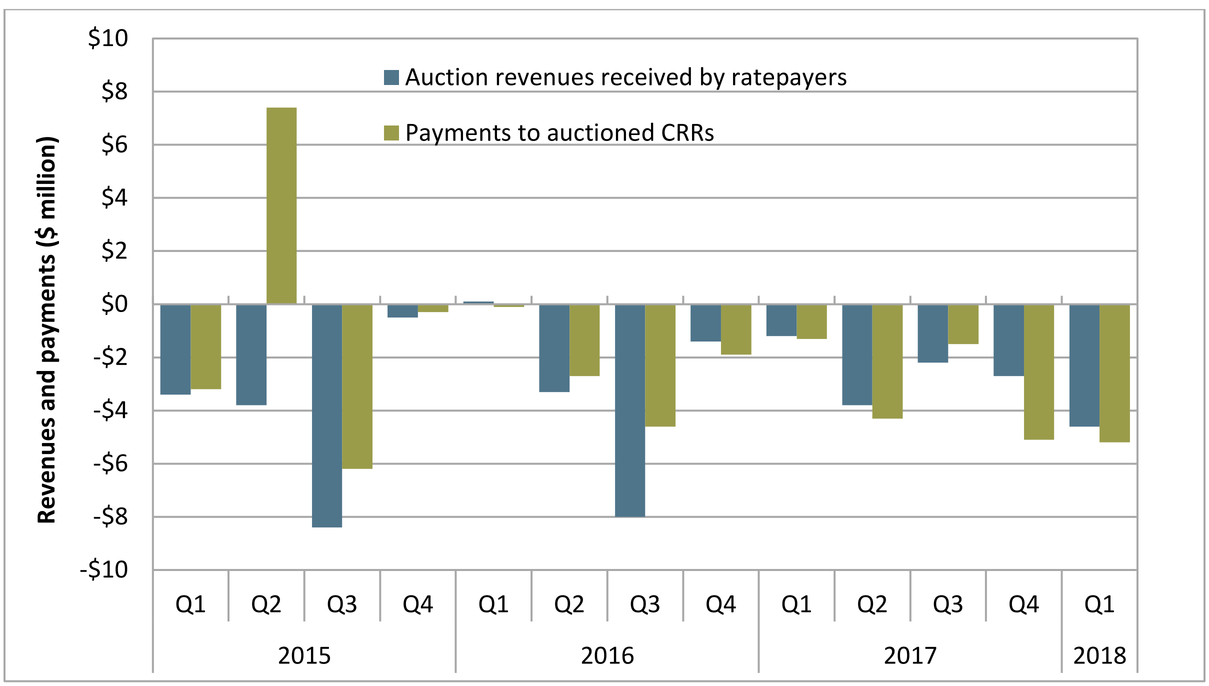


Figure 1.21 Auction revenues and payments (load-serving entities)



Potential improvements to the congestion revenue rights auction

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.[32] DMM believes the current auction is unnecessary and could be eliminated.[33] 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.

ISO management started the “Congestion revenue rights auction efficiency” initiative and adopted a two phase approach – an analysis phase and a policy development phase.[34] The ISO published analysis of the congestion revenue rights auction performance on November 21, 2017, and held a working group meeting on December 19, 2017.[35] On March 22, 2018, the Board of Governors approved Track 1A policy changes of this stakeholder initiative process. Tariff changes associated with Track 1A were approved by the Federal Energy Regulatory Commission on June 29, 2018. Track 1A policy includes limiting source and sink pairs to supply delivery and require transmission owners to submit planned outages prior to annual allocation and auction process. These changes are intended to be implemented in time for the 2019 annual allocation and auction processes.

Track 1B of this initiative was approved by the Board of Governors on June 22, 2018.[36] The 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.[37]

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

33 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

34 ISO stakeholder processes – Congestion revenue rights auction efficiency: http://www.caiso.com/informed/Pages/StakeholderProcesses/CongestionRevenueRightsAuctionEfficiency.aspx

35 *Congestion Revenue Rights Auction Efficiency Analysis*, November 21, 2017: http://www.caiso.com/Documents/CRRAuctionAnalysisReport.pdf

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

37 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 first quarter. Key observations and findings include the following.

- Prices in PacifiCorp East, NV Energy, and Arizona Public Service were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation between these areas. This was most pronounced during peak load hours when high system prices caused transfers from PacifiCorp East to hit export limits.
- There were a significant number of congested intervals (around 62 percent) from PacifiCorp West, Portland General Electric and Puget Sound Energy in the direction of the ISO. This congestion led to lower prices during the quarter in the region including PacifiCorp West, Portland General Electric and Puget Sound Energy relative to the rest of the energy imbalance market and the ISO.
- During the first quarter, there was a slight uptick in the frequency of upward and downward sufficiency test failures overall. In particular, NV Energy failed the sufficiency test more frequently in both directions, during around 5 percent of hours in the upward direction and 7 percent of hours in the downward direction.

2.1 Energy imbalance market performance

Energy imbalance market prices

Prices in PacifiCorp East, NV Energy and Arizona Public Service were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation between these areas. This was most pronounced during peak load hours when high system prices caused transfers from PacifiCorp East to hit export limits. In other hours one or more of these areas failed the sufficiency test which limited transfers and created price separation between the balancing areas.

Prices in the region including PacifiCorp West, Puget Sound Energy and Portland General Electric 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 PacifiCorp West, Puget Sound Energy and Portland General Electric region during many intervals.

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 PacifiCorp East, NV Energy, and Arizona Public Service tracked closely to system prices during most hours; however, hourly average prices in PacifiCorp East were significantly lower than hourly average prices in NV Energy, Arizona Public Service and the ISO during hours ending 17 through 20. This is primarily due to several days when energy imbalance market transfers out of PacifiCorp East reached their upper scheduling limits during these hours.

PacifiCorp West, Puget Sound Energy, and Portland General Electric prices were often lower than those in the ISO during the morning and evening peak net load periods because of inexpensive generation in these areas and relatively little transfer capability toward the ISO.

When the power balance constraint is relaxed because of insufficient upward ramping capacity (shortage or under-supply), prices could be set using the $1,000/MWh penalty price. Power balance constraint relaxation due to insufficient downward ramping capacity (surplus or over-supply) can set prices at -$155/MWh. When the load bias limiter is triggered, the infeasibility is resolved and prices are instead set by the last dispatched bid rather than the penalty parameters for under-supply and over-supply.

During the first quarter, under-supply and over-supply infeasibilities were infrequent. Under-supply infeasibilities occurred during less than 0.2 percent of intervals in the 15-minute and 5-minute markets in each of the energy imbalance market balancing areas. Over-supply infeasibilities occurred during around 0.9 percent of real-time intervals in Arizona Public Service and in less than 0.3 percent of intervals in each of the other balancing areas.

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

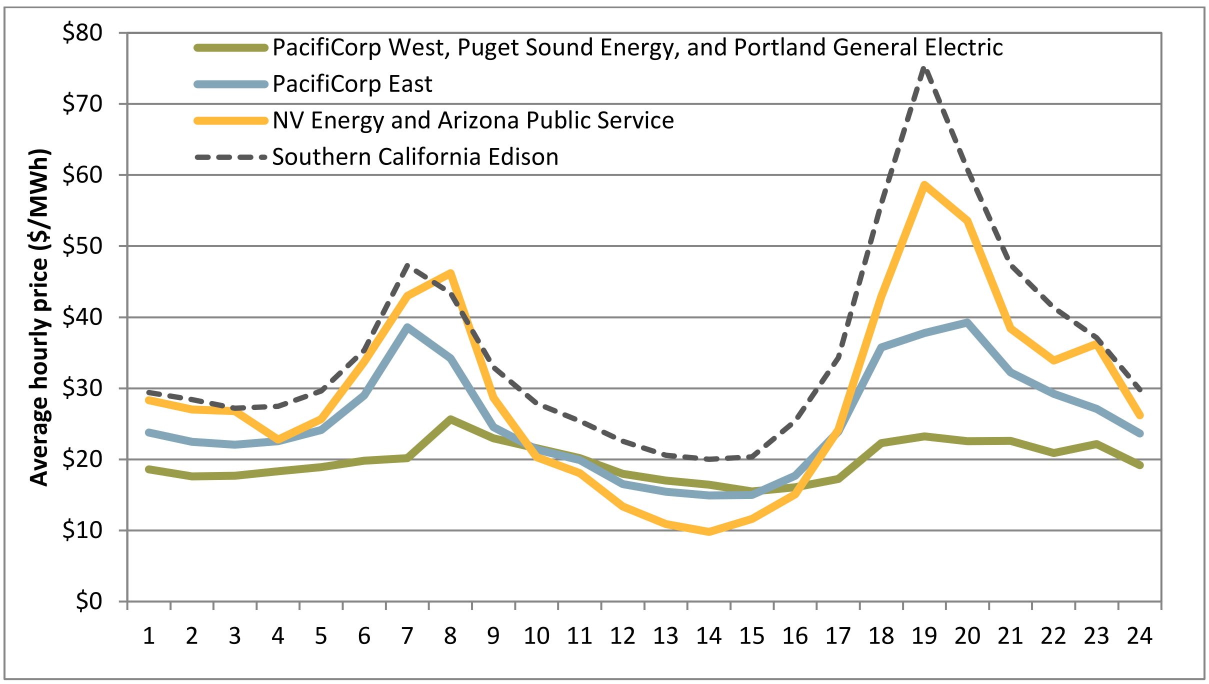
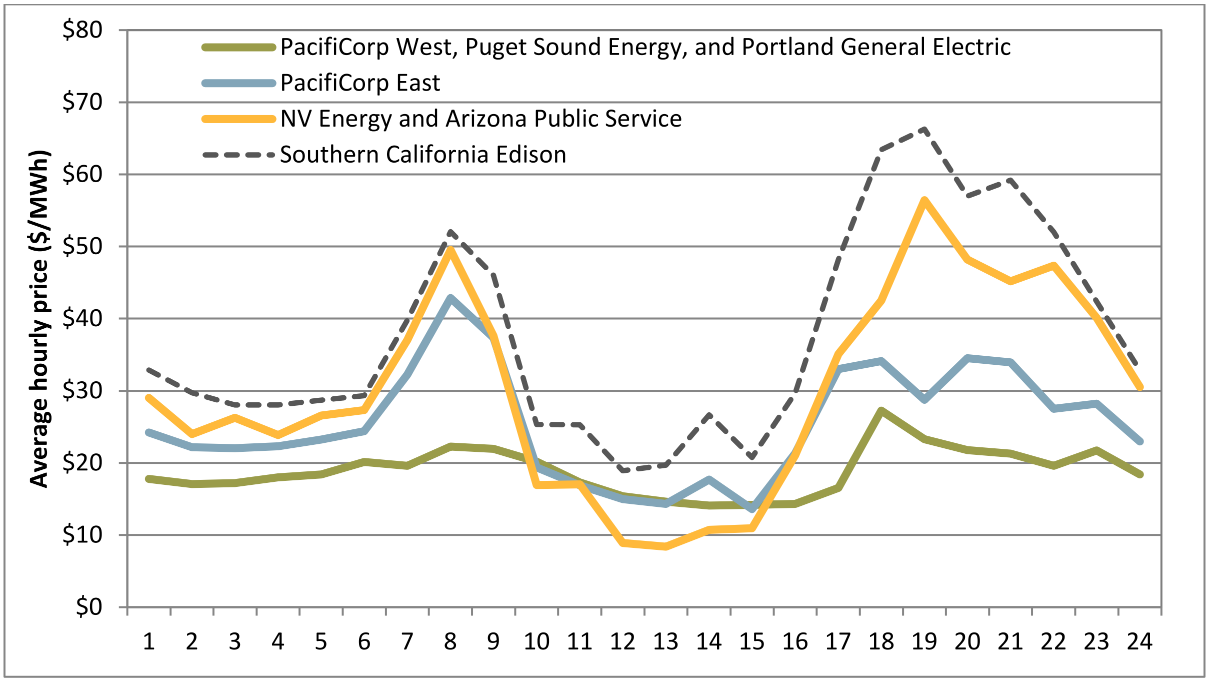


Figure 2.2 Hourly 5-minute market prices (January – March)



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.[38] 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.[39]

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

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38 *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.

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

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 Frequency of upward failed sufficiency tests by month

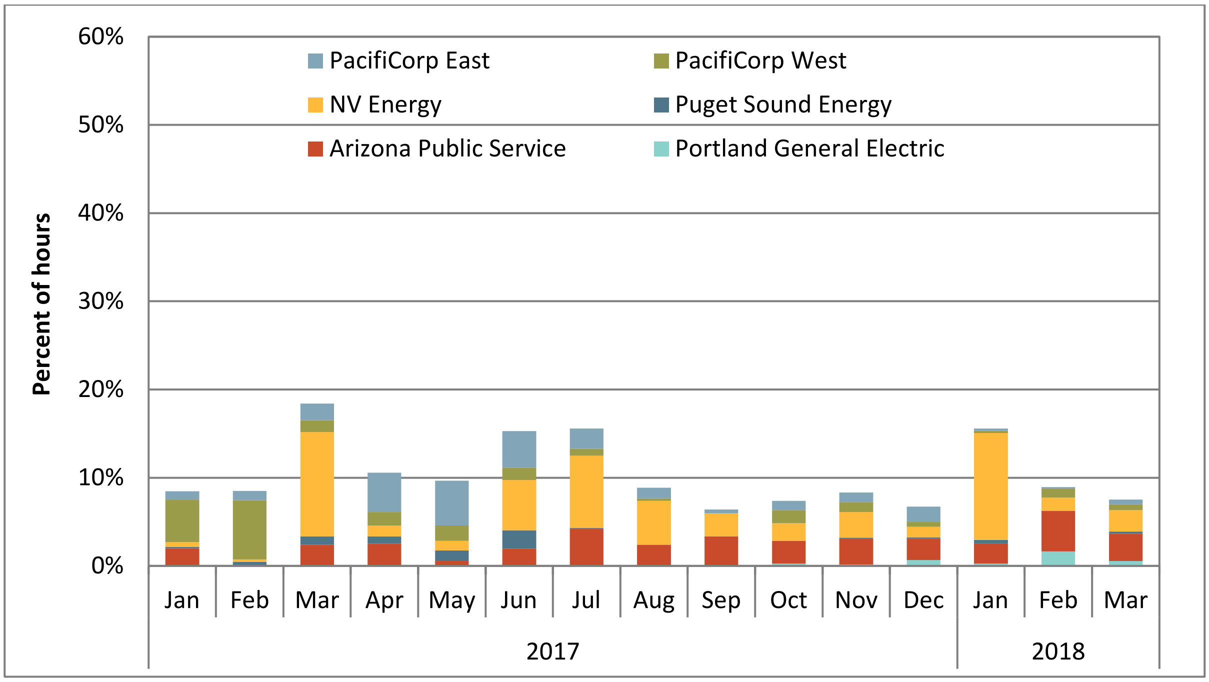


Figure 2.4 Frequency of downward failed sufficiency tests by month

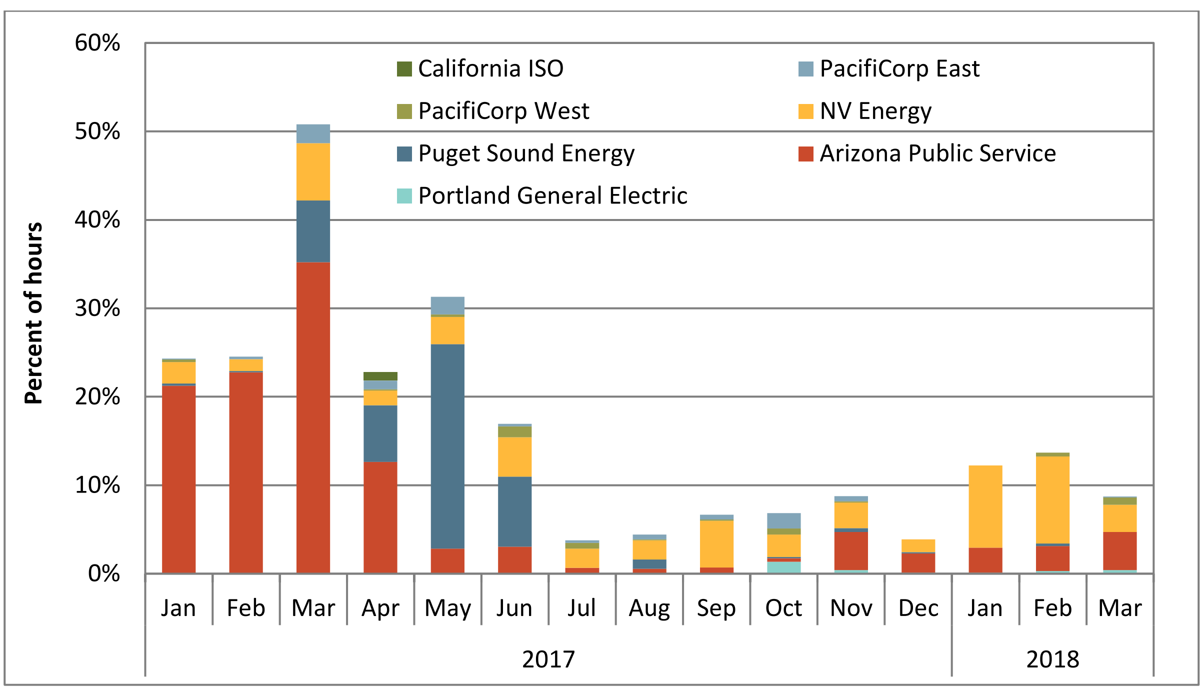


Figure 2.3 and Figure 2.4 show the average percent of hours in which an energy imbalance market area failed the sufficiency test in the upward and downward direction, respectively. During the first quarter, there was a slight uptick in the frequency of upward and downward sufficiency test failures overall. In particular, NV Energy failed the sufficiency test more frequently in both directions, during around 5 percent of hours in the upward direction and 7 percent of hours in the downward direction.

2.3 Energy imbalance market transfers

The real-time market software solves a large cost minimization problem for dispatch instructions to generation considering all of the resources available to the market, including those in the energy imbalance market areas. This software also considers a number of constraints including transmission availability between balancing areas within the energy imbalance market. Because of real-time differences in system conditions, real-time schedules for generation are frequently different than day-ahead schedules for resources in the ISO and base schedules for resources in the energy imbalance market. When aggregated, these differences can cause large changes in scheduled flows between balancing areas in the real-time market, or *energy transfers*. These transfers may represent the market software electing to use lower cost generation in one area in lieu of higher cost generation in another area, thus reducing the overall cost to meet load in the energy imbalance market. This section includes results for energy transfers between areas, which is one of the key sources of value that the energy imbalance market provides.

Table 2.1 shows the percent of 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.[40] The table shows that congestion in the 5-minute market generally occurred in the direction of the ISO, particularly from the areas in the northwest.

Table 2.1 shows that congestion in either direction between NV Energy, Arizona Public Service, or the ISO area was infrequent during the quarter in the 5-minute market. There was also very little congestion in the direction of the ISO toward PacifiCorp East. Congestion from PacifiCorp East in the direction of the ISO was more frequent, during about 17 percent of intervals. This primarily occurred when less expensive generation in PacifiCorp East was constrained going into NV Energy and Arizona Public Service.

Finally, Table 2.1 also shows that there were a significant number of congested intervals (around 62 percent) from PacifiCorp West, Portland General Electric and Puget Sound Energy in the direction of the ISO. Limited transfer capability, particularly from PacifiCorp West and Portland General Electric to the ISO, resulted in a high frequency of congested intervals. This congestion led to lower prices during the quarter in the region including PacifiCorp West, Portland General Electric and Puget Sound Energy relative to the rest of the energy imbalance market and the ISO.

[40] Greenhouse gas prices can contribute to lower energy imbalance market prices relative to those inside the ISO. The previous methodology for congestion toward the ISO accounted for price separation as a result of greenhouse gas prices by removing instances of congestion toward the ISO of smaller magnitude than -$6/MWh. The new methodology uses prevailing greenhouse gas prices in each interval to account for price separation that is the result of greenhouse gas prices only.

Table 2.1 Estimated congestion status and flows in EIM (January – March)

	Congested toward ISO	Congested from ISO
Arizona Public Service	2%	1%
NV Energy	5%	2%
PacifiCorp East	17%	2%
PacifiCorp West	62%	10%
Portland General Electric	62%	11%
Puget Sound Energy	63%	11%

Different areas in the energy imbalance market exhibited different hourly transfer patterns during the quarter. For example, NV Energy imported, on average, from the ISO during the middle of the day, when solar generation was greatest, and exported to the ISO during the morning and late evening hours. NV Energy primarily exported energy to PacifiCorp East during midday hours. This pattern is driven by the resource mix and relative prices in these areas during these periods. Figure 2.5 through Figure 2.8 show average hourly imports (negative values) and exports (positive values) into and out of NV Energy, Arizona Public Service, PacifiCorp West, and Portland General Electric during the quarter in the 5-minute market.[41]

Figure 2.5 shows average for NV Energy during the quarter in the 5-minute market.[42] Transfers between NV Energy and the ISO are shown by the blue bars, transfers with PacifiCorp East are shown by the green bars, and net transfers are shown by the gold line. As seen in the chart, NV Energy was a net importer during the midday hours, and a net exporter during other hours of the day.

Figure 2.6 highlights transfer information in the Arizona Public Service area during first quarter in the 5-minute market. Transfers between Arizona Public Service and the ISO are shown by the blue bars, transfers with PacifiCorp East are shown by the green bars. The average hourly net transfer is shown by the gold line. Arizona Public Service was generally a net importer of energy during midday hours and a net exporter during the early morning and late evening hours. On average, Arizona Public service received imports from the ISO during the midday hours, when solar generation was greatest, and exported to the ISO during other hours of the day. Arizona Public Service also imported energy from PacifiCorp East during the morning and evening and exported energy to PacifiCorp East during midday hours, on average.

41 These figures show real-time energy market flows net of all base schedules.

42 Average hourly transfers between NV Energy and Arizona Public Service were near zero MW during all hours and are therefore not depicted in Figure 2.5 and Figure 2.6.

Figure 2.5 NV Energy – average hourly 5-minute market transfer (January - March)

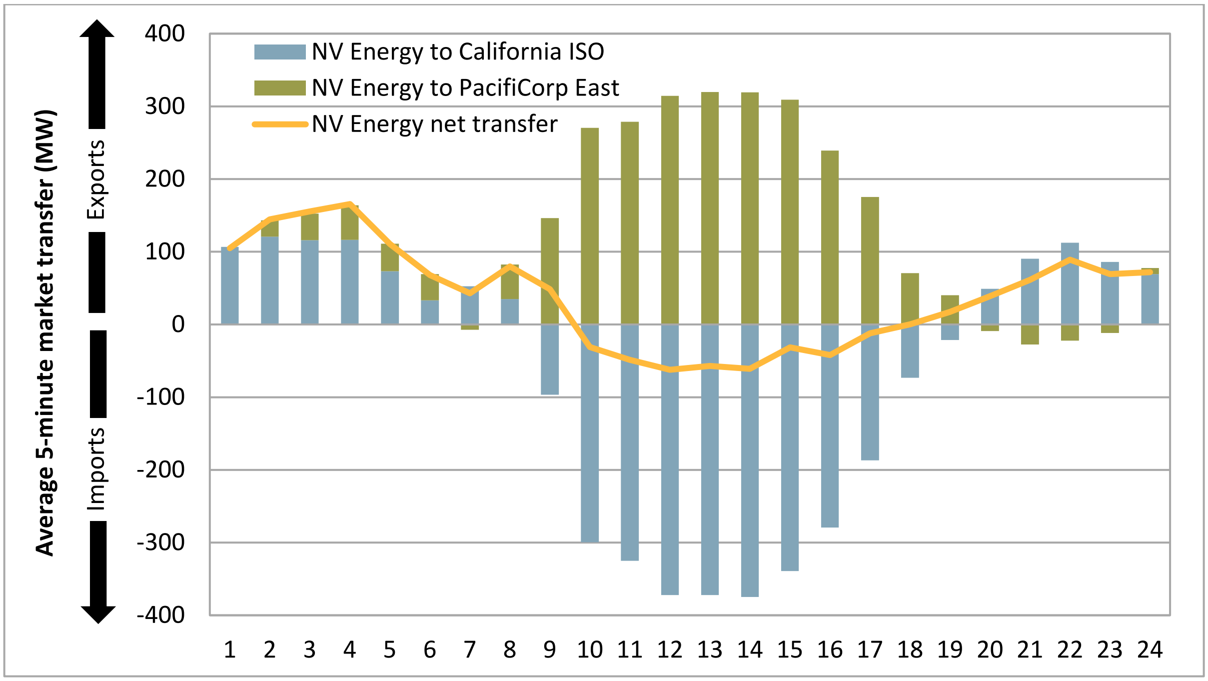
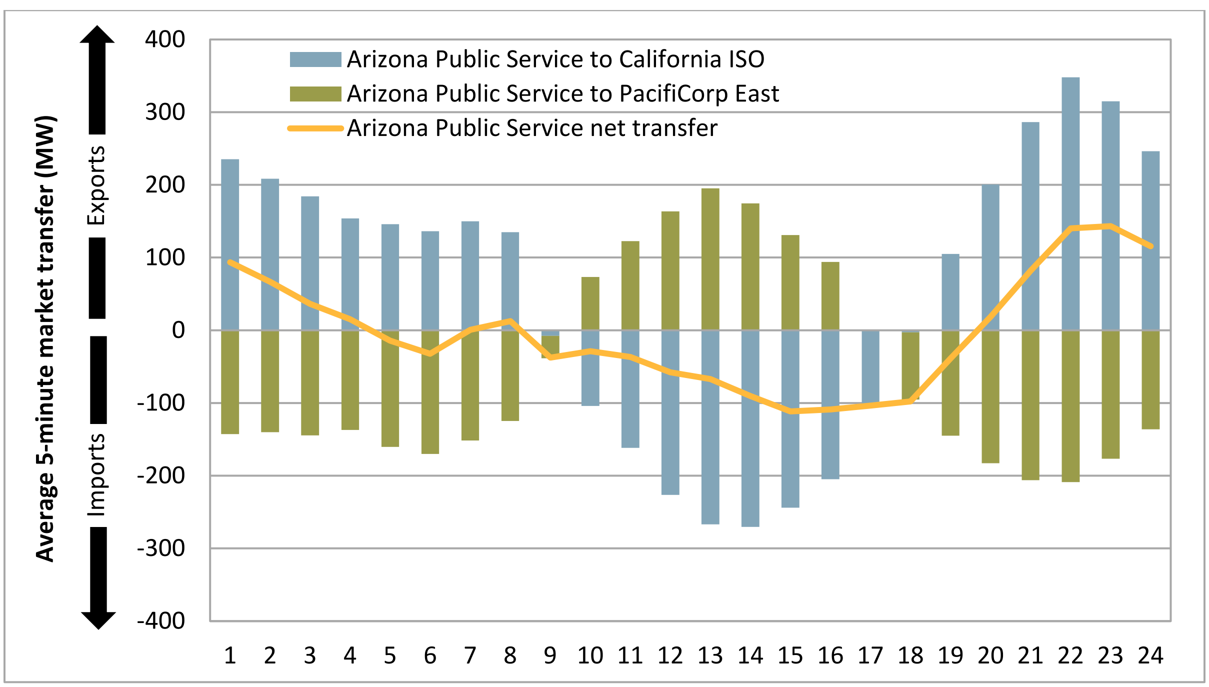


Figure 2.6 Arizona Public Service – average hourly 5-minute market transfer (January - March)



PacifiCorp West has transfer capacity between PacifiCorp East, Puget Sound Energy, the ISO, and – beginning October 1, 2017 – Portland General Electric. Figure 2.7 shows the hourly 5-minute market transfer pattern between PacifiCorp West and neighboring areas averaged during the first quarter. This figure shows that PacifiCorp West was a net importer during most hours. Specifically, this is mostly from PacifiCorp East, Puget Sound Energy and Portland General Electric.

For most hours of the day, including the early evening through morning, PacifiCorp West typically exported energy to the ISO except for the midday hours, when solar was greatest in the ISO, when they imported slightly form the ISO. Figure 2.7 shows that PacifiCorp West always received imports from PacifiCorp East on average. This is a byproduct of the transfer limits imposed between the two areas, which require that transfers only occur in the east-to-west direction between these two areas.

Figure 2.8 shows average hourly 5-minute market imports and exports into and out of Portland General Electric between January and March. As shown in the figure, Portland General Electric on average imported from the ISO during midday hours and exported to PacifiCorp East during early morning and afternoon periods.

Figure 2.7 PacifiCorp West – average hourly 5-minute market transfer (January - March)

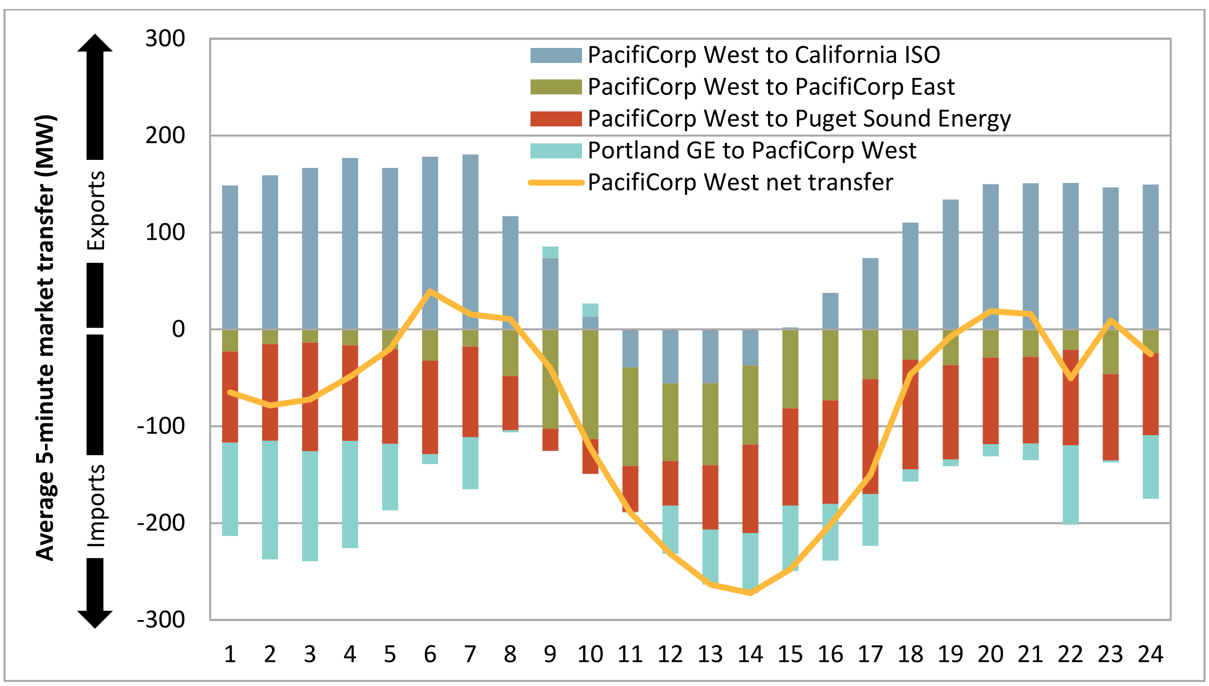
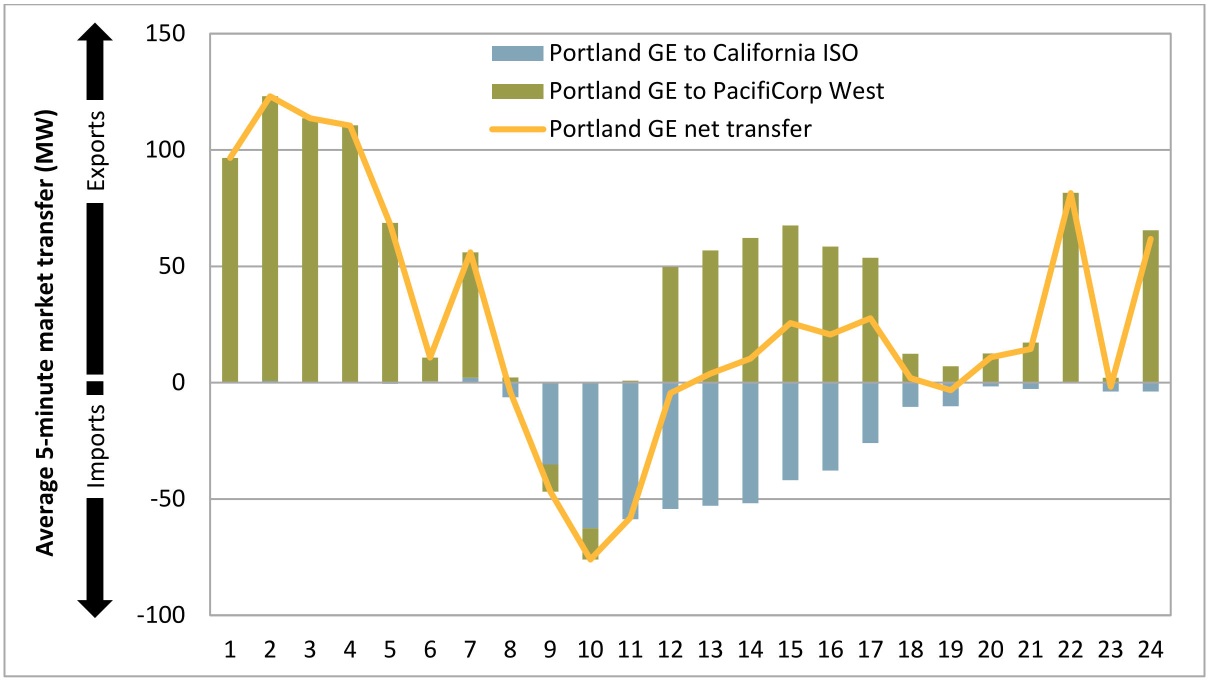


Figure 2.8 Portland General Electric – average hourly 5-minute market transfer (January - March)



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 first 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. In contrast 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 first quarter. Also of note, NV Energy 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. As with the previous quarter, average load adjustments by Arizona Public Service, as a percent of total area load, were larger in magnitude compared to other areas. The majority of these adjustments were positive and 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 (January - March)

	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	38%	439	1.8%	13%	-367	1.7%	120
5-minute market	22%	268	1.1%	45%	-340	1.5%	-95
PacifiCorp East							
15-minute market	46%	84	1.7%	1%	-86	1.7%	38
5-minute market	74%	106	2.1%	7%	-81	1.7%	73
PacifiCorp West							
15-minute market	1%	99	4.0%	1%	-40	1.6%	1
5-minute market	23%	43	1.8%	21%	-39	1.6%	2
NV Energy							
15-minute market	15%	70	2.0%	0%	N/A	N/A	11
5-minute market	35%	53	1.5%	18%	-54	1.6%	9
Puget Sound Energy							
15-minute market	1%	44	1.4%	17%	-44	1.5%	-7
5-minute market	2%	48	1.5%	65%	-46	1.5%	-29
Arizona Public Service							
15-minute market	90%	125	4.5%	3%	-58	2.4%	111
5-minute market	89%	125	4.5%	3%	-59	2.4%	109
Portland General Electric							
15-minute market	31%	31	1.3%	0%	-45	1.9%	10
5-minute market	52%	35	1.4%	7%	-40	1.6%	16

3 Special issues

This section provides information about the following special issues:

- The ISO enforced total gas burn constraints on both the SoCal gas region, as well as subregions, in both the day-ahead and real-time markets. Binding enforcement of these constraints in the real-time market occurred for selected intervals in peak hours on four days over which the ISO accrued about $19 million in real-time imbalance energy offset costs.
- Aliso gas price scalars were activated during two periods in the first quarter. In both periods, actual gas trades in the same day gas market were usually significantly lower than the prevailing prices for same-day gas trades. Activation of the scalars does not appear to significantly impact the merit order of commitment cost dispatch.
- DMM estimates that since the activation of the gas price scalars in July 2016, it has resulted in over $8 million in excess uplift payments to resources using the scalar. In the first quarter of 2018, approximately $1 million of these payments were accrued in February, most of it during cold weather days in Southern California.

3.1 Aliso Canyon gas-electric coordination

Following a significant natural gas leak in late 2015, the injection and withdrawal capabilities of the Aliso Canyon natural gas storage facility in Southern California were severely restricted. These restrictions impact the ability of pipeline operators to manage real-time natural gas supply and demand deviations, which in turn could have impacts on the real-time flexibility of natural gas-fired electric generators in Southern California. This primarily impacts resources operated in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E) service areas, collectively referred to as the SoCalGas system.

Operational tools and corresponding mitigation measures

The ISO developed a set of operational tools to manage potential gas system limitations that allow operators to restrict the gas burn of ISO natural gas-fired generating units in the SoCalGas system areas. The tools, which were implemented as a set of nomogram constraints, can be used to limit either the total gas burn or deviations in gas burn compared to day-ahead schedules for particular subregions within the ISO. These tools were available to operators beginning June 2, 2016.[43] The November 28, 2017, FERC Order rejected permanent tariff provisions granting the ISO authority to implement and enforce, throughout the ISO and energy imbalance market balancing areas, maximum gas burn constraints limiting the dispatch of gas-fired generators.[44] However, the December 15, 2017, FERC

[43] Refer to *Operating Procedure 4120C – SoCalGas service area limitations or outages:* http://www.caiso.com/Documents/4120C.pdf.

[44] *FERC Order on Tariff Revisions - Aliso Canyon Gas-Electric Coordination Enhancements Phase 3,* November 28, 2017: http://www.caiso.com/Documents/Nov28_2017_Order_TariffRevisions-AlisoCanyonGas-ElectricCoordinationEnhancementsPhase3_ER17-2568.pdf

Order extended the ISO's previously held authority to utilize the gas constraints for one additional year.[45]

In the first quarter of 2018, the ISO enforced these constraints in both day-ahead and real-time markets in selected subregions. In the day-ahead market, these nomograms were enforced on all the days from February 21 through March 5 except February 23. In the real-time market, they were enforced during some hours from February 20 through March 5 except February 24 – 25.

In 2017, the ISO enforced these constraints on three occasions: January 23- January 26, some hours on August 3, and a few intervals on August 4. On most occasions, these constraints do not appear to have been sufficient, on their own, to limit gas burn from participating gas resources. In each case, measured gas burn was far in excess of the limit for the day due to the units used to define the nomogram limit and the effectiveness with which each gas resource could resolve the constraint. This issue was resolved in February 2018.

Constraints enforced in the first quarter of 2018 were sufficient, on their own, to limit gas burn in some intervals. The ISO enforced four constraints on total gas burn during this period. The first, limiting gas burn from all gas resources on the SoCalGas system, was in place from February 28 through March 5 in the day-ahead market and for selected intervals in the real-time market on these days as well as February 23 and February 27. This constraint was binding in 11 percent of intervals in the real-time market and for 19 percent of intervals in the day-ahead market during this period.

The ISO also enforced three sub-regional constraints on total gas burn, one on resources in the San Diego Gas and Electric area, one on resources in the Los Angeles Basin and one on resources in the Inland area.

- The San Diego constraint was in place in the day-ahead market from February 25 through March 5 and in the real-time market from February 26 through March 5. When enforced, this constraint was binding in 4 percent of intervals in the day-ahead market and 3 percent of intervals in the real-time market.
- The Los Angeles Basin and Inland constraints were enforced during all hours in the day-ahead market and for selected intervals, typically in peak hours, from February 21 to February 22 and on February 26. On February 20, these constraints were enforced for selected intervals in the real-time market only. Both constraints were enforced in the day-ahead market only on February 25 and February 27. When enforced, the Los Angeles Basin constraint was binding in 23 percent of intervals in the day-ahead market and 70 percent of intervals in the five minute real-time market.
- The Inland constraint was binding or scheduled at the limit in 11 percent of intervals in the day-ahead market and 80 percent of intervals in the five minute real-time market, when enforced.

Enforcement of gas burn nomograms in peak hours in the real-time market from February 20 to 23 is concurrent with very high levels of real-time energy offset, totaling about $19 million and accounting for most of the $21 million total offset cost for the quarter. Real-time constraints were not enforced or not binding in most intervals when enforced on other days during the quarter. Energy offset costs are

[45] *Order accepting tariff amendment to re-implement expired provisions - Aliso Canyon Gas-Electric Coordination Enhancements,* December 15, 2017: http://www.caiso.com/Documents/Dec15_2017_OrderAccepting_Re-ImplementExpiredProvisions_AlisoCanyonGas-ElectricCoordination_ER18-375.pdf

allocated as an uplift to measured demand (i.e., physical load plus exports). If additional offset costs are caused by real-time gas burn constraint enforcement, DMM recommends that the additional cost, and allocation of that cost, be considered before placing real-time gas burn constraints in the market. In addition, use of the gas constraints may have contributed to the market impact of transmission constraints including congestion on the Serrano 500/230 kV constraint, binding for much of the quarter.[46]

DMM's review of the ISO's limited experience with maximum gas usage constraints suggests that while such constraints may be a useful tool in the future, additional refinement of the software and operational processes through which the constraints are implemented is necessary before expanding usage of the constraint to other parts of the ISO or EIM.

For example, while gas usage constraints are modeled as 15-minute constraints in the ISO's real-time market, these gas constraints are actually applicable only over a much longer multi-hour time period. Although operators are able to adjust constraints in real-time in response to changing conditions, the ISO does not adjust these constraints in real time based on actual gas usage in prior hours. Therefore, when these gas constraints bind in the ISO's real-time market during the peak ramping hours, there appears to be surplus gas from hours prior in the day when actual usage was well below the constraint as modeled by the ISO. This represents a significant design flaw that remains in the gas nomograms. Thus, DMM continues to recommend that the ISO improve how gas usage constraint limits are set and adjusted in real-time based on actual gas usage in prior hours.[47]

Additional bidding flexibility for SoCalGas resources

On July 6, 2016, the ISO implemented a mechanism to adjust the gas price indices used to calculate commitment cost caps and default energy bids in the real-time market for natural gas-fired generators on the SoCalGas system. This mechanism was implemented to allow these resources to reflect higher same-day natural gas prices and to avoid dispatch of these resources for system needs, instead of local needs, during potential constrained gas conditions in Southern California.

These changes included a 75 percent adder (or 175 percent scalar) on the fuel cost component used for calculating proxy commitment costs, and a 25 percent adder (or 125 percent scalar) on the fuel cost component of default energy bids in the real-time market.[48] The November 28, 2017, FERC Order extended the ISO's authority to use these adders for an additional year, through November 30, 2018. The 75 percent and 25 percent adders implemented by the ISO were based on analysis presented by DMM in comments on the final Aliso Canyon gas-electric coordination proposal in early 2016.[49]

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46 The ISO presented results showing a large increase in day-ahead congestion rent on both February 21 and 22, to a sum of over $25 million. Typical day-ahead rents during this period were less than $3 million per day. Market Performance and Planning Forum presentation, April 19 2018, slide 35. http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Apr192018.pdf

47 See example and discussion in Comments of the Department of Market Monitoring of the California Independent System Operator, ER17-2568, October 26, 2017, pp 14-17. http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

48 These gas price adders are in addition to the 10 percent adder that is included in cost-based default energy bids, and the 25 percent adder that is included in the calculation for commitment cost caps.

49 *Comments on Final Aliso Canyon Gas-Electric Coordination Proposal*, Department of Market Monitoring, May 6, 2016: http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationRevisedDraftFinalProposal.pdf.

In the first quarter of 2018, these adders were available in the real-time market for an entire month of January and during the last week of February through the end of first week of March. The ISO, Los Angeles Department of Water and Power, California Energy Commission and California Public Utilities Commission published a supplemental risk assessment and technical report on November 28, 2017, and stated that colder temperatures during winter months could lead to limitations for gas generators.[50] These concerns, in addition to the Southern California wildfires, caused the ISO to reinstate the gas adders on December 7, 2017. The adders remained in place until January 31, 2018.[51,52]

Due to the cold weather leading to high gas usage and potential gas curtailments in Southern California, the ISO re-instated the gas price scalars on February 20 and lasted until March 7, 2018.[53,54]

Figure 3.1 shows Intercontinental Exchange (ICE) same-day natural gas trade prices for SoCal Citygate compared to the next-day average price from January through March 2018. In Southern California, lower temperatures led to increased demand for natural gas and caused high next-day prices as well as significant same-day price volatility from February 20 – 22.

About 24 percent of traded volume at SoCal Citygate exceeded the normal 10 percent adder and 10 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.

50 *Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement,* November 28, 2017: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221863_20171128T103411_Aliso_Canyon_Winter_Risk_Assesment_Technical_Report_201718_Supp.pdf

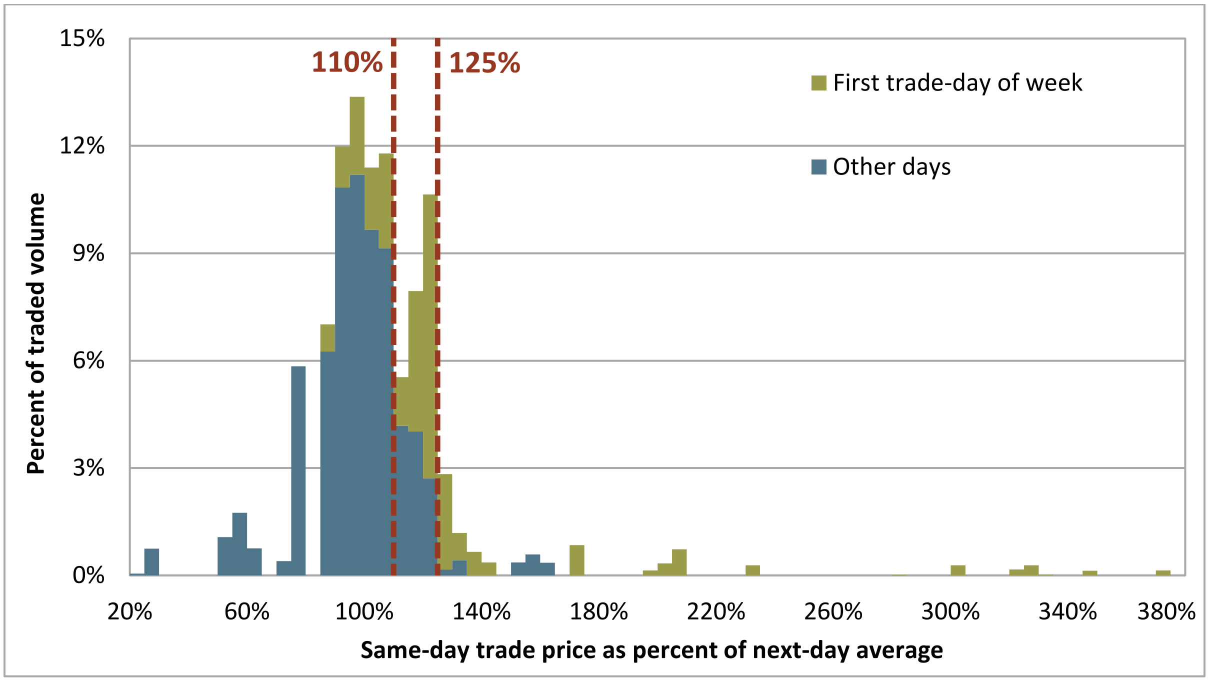
51 Market Notices - Adjustment of Gas Price Index Scaling Factors, December 6, 2017: http://www.caiso.com/Documents/Adjustment-GasPriceIndexScalingFactorsEffective120717.html

52 Market Notices - Adjustment of Gas Price Index Scaling Factors, January 31, 2018: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactorsEffective02012018.html

53 Market Notices - Adjustment of Gas Price Index Scaling Factors, February 19, 2018: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactorsEffective022018.html

54 Market Notices - Adjustment of Gas Price Index Scaling Factors, March 7, 2018: http://www.caiso.com/Documents/Adjustment-GasPriceIndexScalingFactorsEffective030818.html

Figure 3.1 Same-day trade prices compared to next-day index (January – March)



Evaluating the effectiveness of the gas price scalars

The ISO's proposal to use gas price scalars was intended to allow natural gas generators in the SoCalGas system reflect higher same-day gas prices as well as to change the merit order of commitment cost bids so that the ISO market dispatches these resources only for local reliability needs and not for system needs. This section provides supporting analysis to show why the use of gas price scalars is a crude tool to reflect the volatility in same-day gas prices and to manage potential reliability issues associated with gas limitations in the real-time market.

Figure 3.2 and Figure 3.3 show a comparison between SoCal Citygate next-day index and same-day price distribution when the scalars were active during the two occasions mentioned earlier. The solid red line represents the next-day index without any scalar and the dashed red lines represent 125 percent and 175 percent of the next-day index used in the default energy bids and commitment cost caps, respectively. Same-day prices from ICE are represented as a green box and whisker plot for each day when there were same-day trades.

As shown in Figure 3.2, gas price scalars were set at 175 percent and 125 percent for the entire month of January 2018, which were originally put in place on December 7, 2017 owing to concerns of cold weather leading to high gas usage in Southern California. In this case, on each of the days the scalars were active in January, the gas price used in the real-time commitment costs was much higher than the observed same-day gas prices on that day.

On February 20, the gas price scalars were activated for the second time in the first quarter of 2018. As shown in Figure 3.3, same-day gas prices rose sharply on February 20, 2018, averaging about 250 percent of the next-day gas price index of $4. Thus, the 175 percent and 125 percent scalars resulted in gas costs that were well below prevailing gas prices in the same-day market. On the remaining days the scalars were active, the resulting gas prices used in the real-time market were significantly higher than actual gas prices in the same-day market.

Figure 3.3 also shows that even if the scalars are activated in time to reflect the same-day price volatility, having a fixed 125 percent and 175 percent scalar on the next-day price would not have been sufficient. For example, on February 20, the scalars were put in place to reflect the high same-day prices. But the resulting gas price was still lower than the prevailing same-day prices.

Figure 3.2 SoCal Citygate next-day index versus ICE same-day price distribution (January 1 – 31)

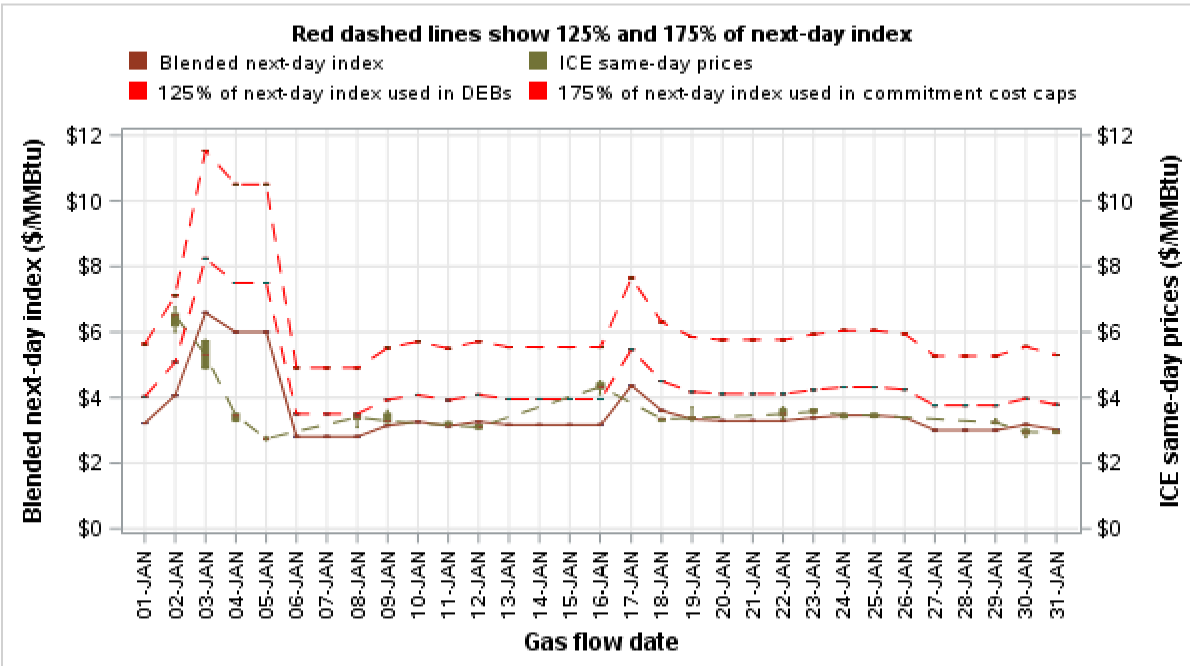
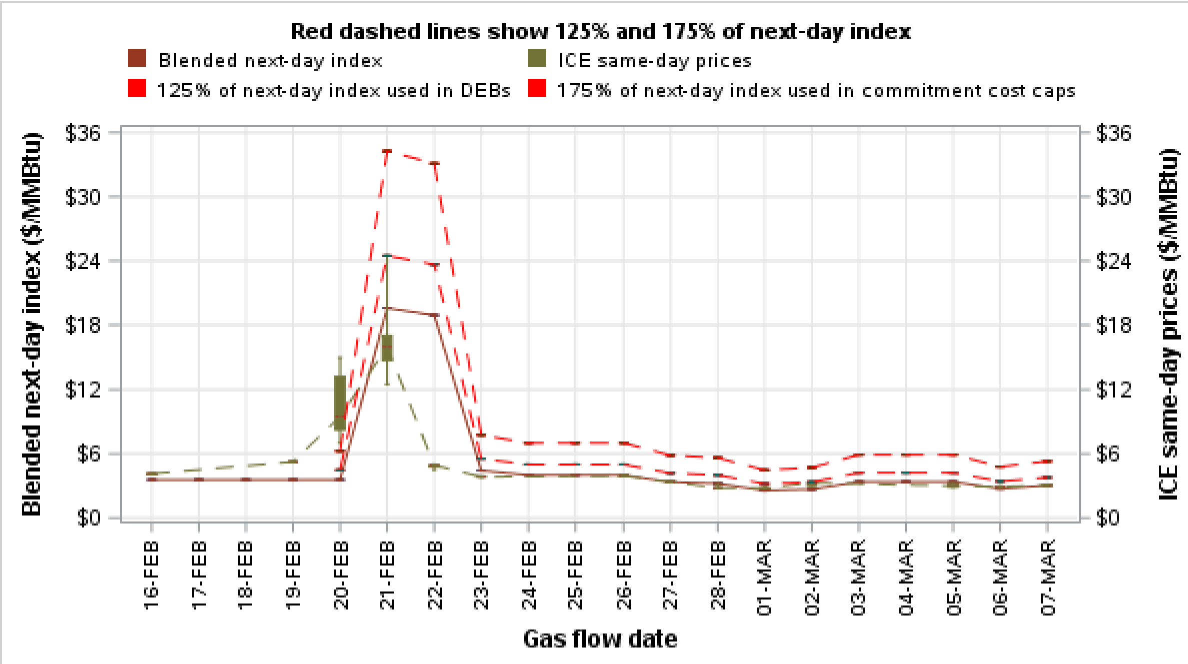


Figure 3.3 SoCal Citygate next-day index versus ICE same-day price distribution (Feb 16 – Mar 7)



As mentioned earlier, the gas price scalars were also implemented to change the merit order of gas resources on SoCalGas system. This is achieved by using a 175 percent scalar in the gas price used in calculating the commitment cost caps for these resources. The resulting commitment costs are intended to be high enough to allow Southern California resources to be committed for local reliability needs but not for system needs. However, on the days with low temperatures in Southern California, the differential between the next-day gas price indices at SoCal Citygate and PG&E Citygate was sufficiently high to push SoCalGas system resources to the high end of the merit order without the need for an additional scalar.

Access to additional real-time bidding flexibility does not appear to have had a significant impact on the merit order of commitment dispatch. Figure 3.4 shows the percent of SoCalGas resources minimum load capacity that constitutes the high end of economic merit order when using various minimum load cost scenarios.[55] As shown in Figure 3.4 , the dotted yellow line tracks the blue line on most of the days which means that the activation of scalars did not have a significant impact on the merit order of commitment (from minimum load perspective).[56]

The red and green lines in Figure 3.4 show the percent of SoCalGas minimum load capacity at high end of merit order calculated using proxy minimum load cost cap with and without scalar, respectively. The blue line shows the percentage calculated using actual minimum load bids on those days. The dotted yellow line shows the percentage using actual minimum load bids but capped at their proxy cost cap

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55 DMM's analysis focuses on minimum load rather than start or transition costs due to the difficulty of comparing start up and transition cost bids from resources with different start-up and cycle times. The methodology used to calculate the high end of merit order is described in Section 2 of DMM comments on the Aliso gas-electric coordination initiative: http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationRevisedDraftFinalProposal.pdf

56 Example for a specific day is discussed in Market Performance and Planning Form, February 20 2018, pp. 82 -84: http://www.caiso.com/Documents/AgendaandPresentation-MarketPerfomanceandPlanningForum-Feb202018.pdf

which does not include any scalar. The transparent lines show the trend before and after the Aliso gas price scalars were active during February and March.

Figure 3.4 Percent of SoCalGas resources minimum load capacity at high end of merit order

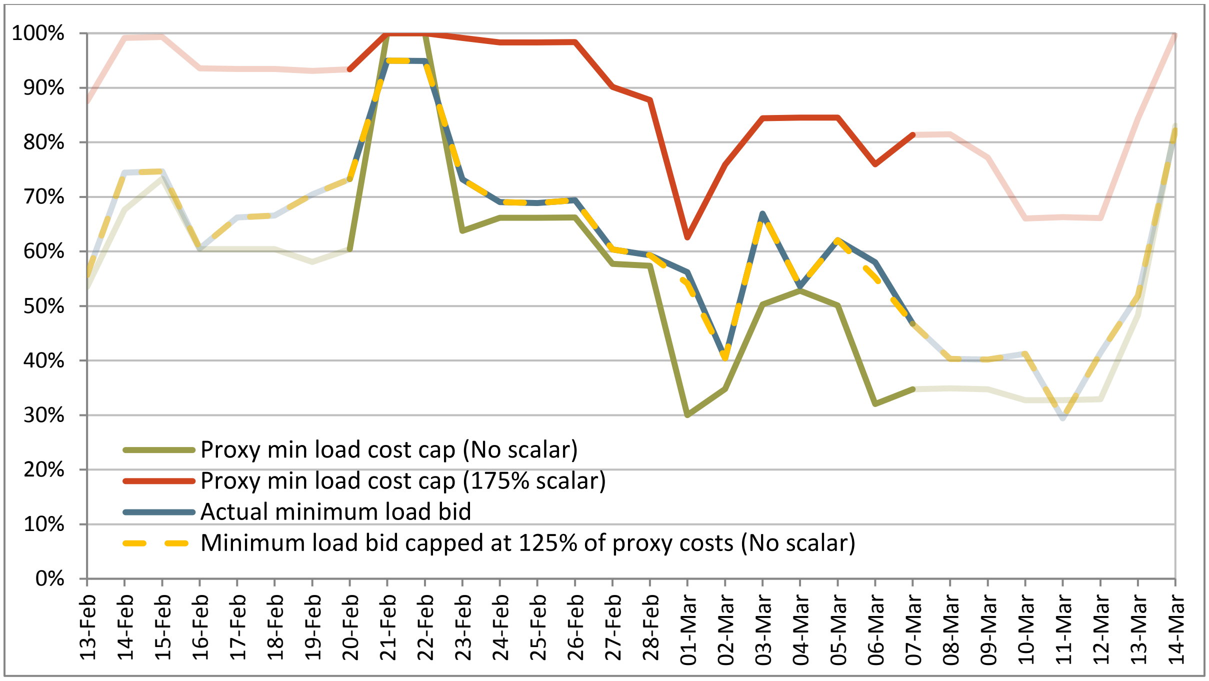
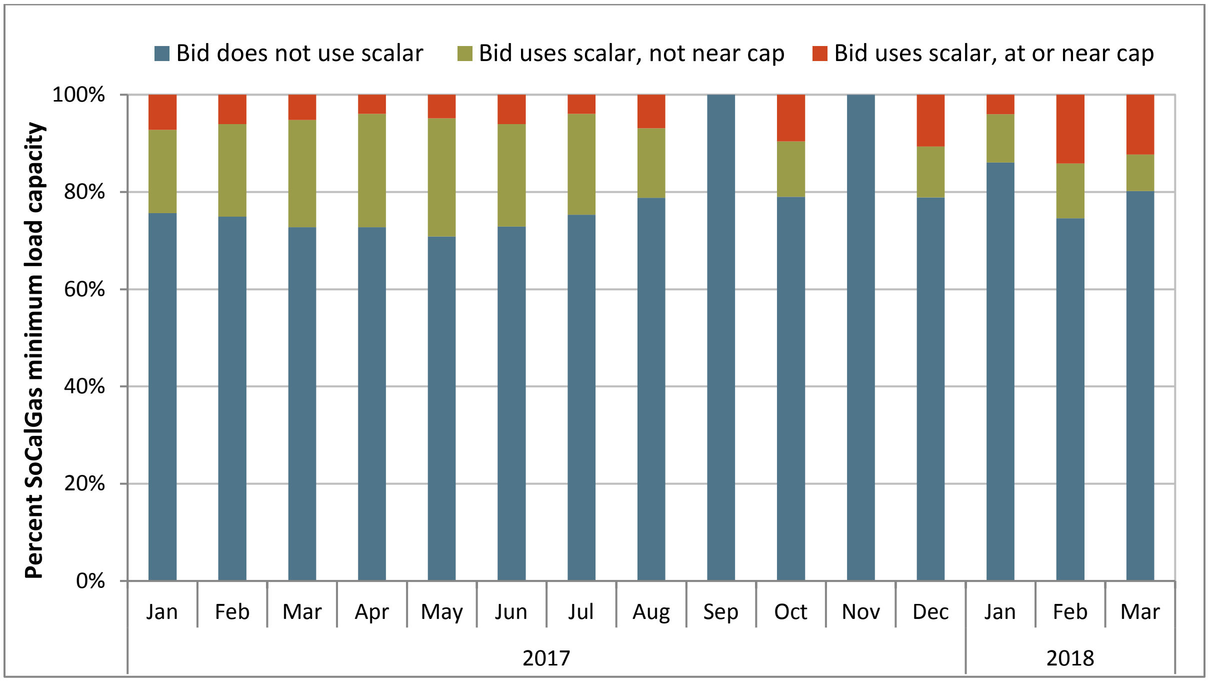


Figure 3.5 shows the bidding pattern of minimum load bids for all gas capacity on the SoCalGas system when the gas price scalars were active during the first quarter of 2018.[57] Figure 3.5 breaks down the minimum load bids from these gas resources into three sub-categories. Bids which did not incorporate any scalar are shown by blue bars. Bids which utilized a portion of the scalar and bid up to 119 percent of proxy minimum load costs are shown in green. And finally, minimum load bids that utilized the scalar and bid at or near the 125 percent of proxy minimum load cost cap are shown in red.

On average, about 83 percent of capacity on the SoCalGas system did not use the additional headroom provided by the scalar for minimum load costs in the first quarter. About 10 percent of the minimum load capacity bid their minimum load costs at or near the bid cap. The remaining 10 percent of the capacity submitted bids that took advantage of the additional flexibility but did not do so near the cap.

[57] For multi-stage generating resources, the PMin of each individual configuration is taken into account while calculating minimum load capacity for each bid level.

Figure 3.5 SoCalGas system resources minimum load capacity bid level

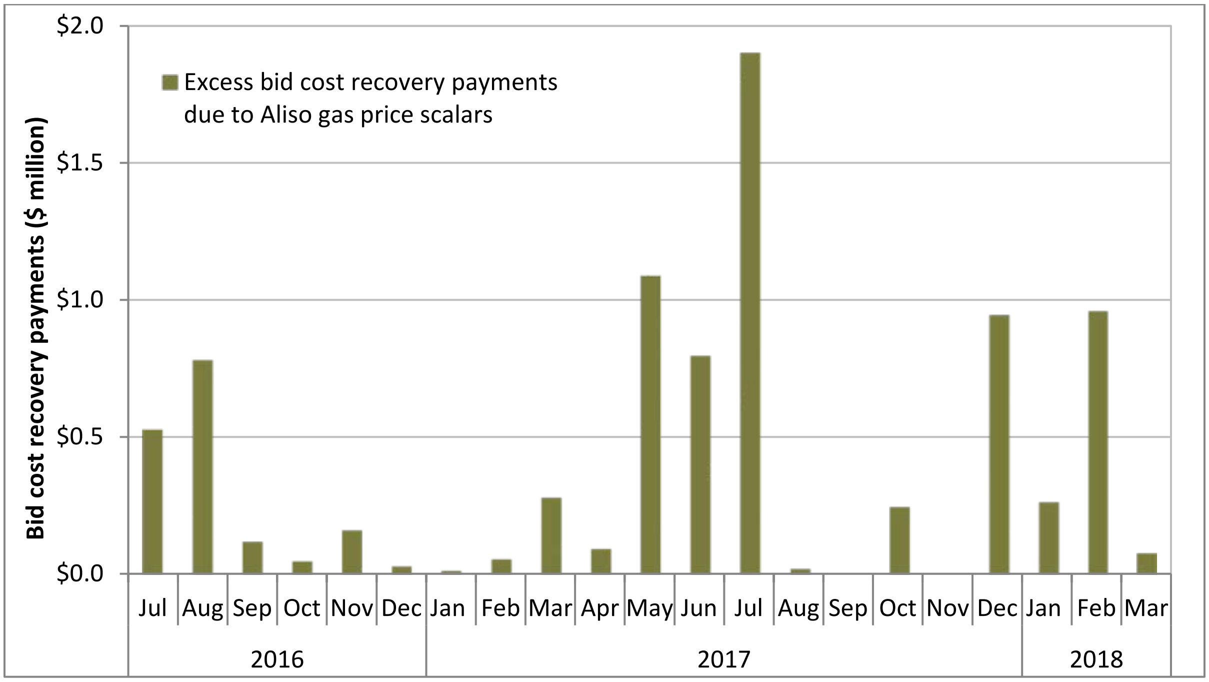


DMM estimates that since the activation of the gas price scalars in July 2016, it has resulted in over $8 million in excess uplift payments to resources using the scalar. Figure 3.6 shows an estimate of monthly excess bid cost recovery payments made in the real-time market since 2016 due to the use of these scalars.[58] In the first quarter of 2018, approximately $1 million of these payments were accrued in February, most of it during cold weather days in Southern California.

This analysis shows that having a fixed 175 percent gas price scalar in place during these days not only inflated the commitment costs that were bid into the market, without a significant impact on merit order of commitment, but also resulted in extra bid cost recovery payments to the resources utilizing the scalar.

58 The gas price scalars were not active in September and November. DMM calculates excess bid cost recovery payments by recalculating bid cost recovery payments using commitment costs capped at a value excluding scalars.

Figure 3.6 Monthly excess bid cost recovery payments due to gas price scalars



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 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.[59,60]

Figure 3.7 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 first 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 3.7 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.

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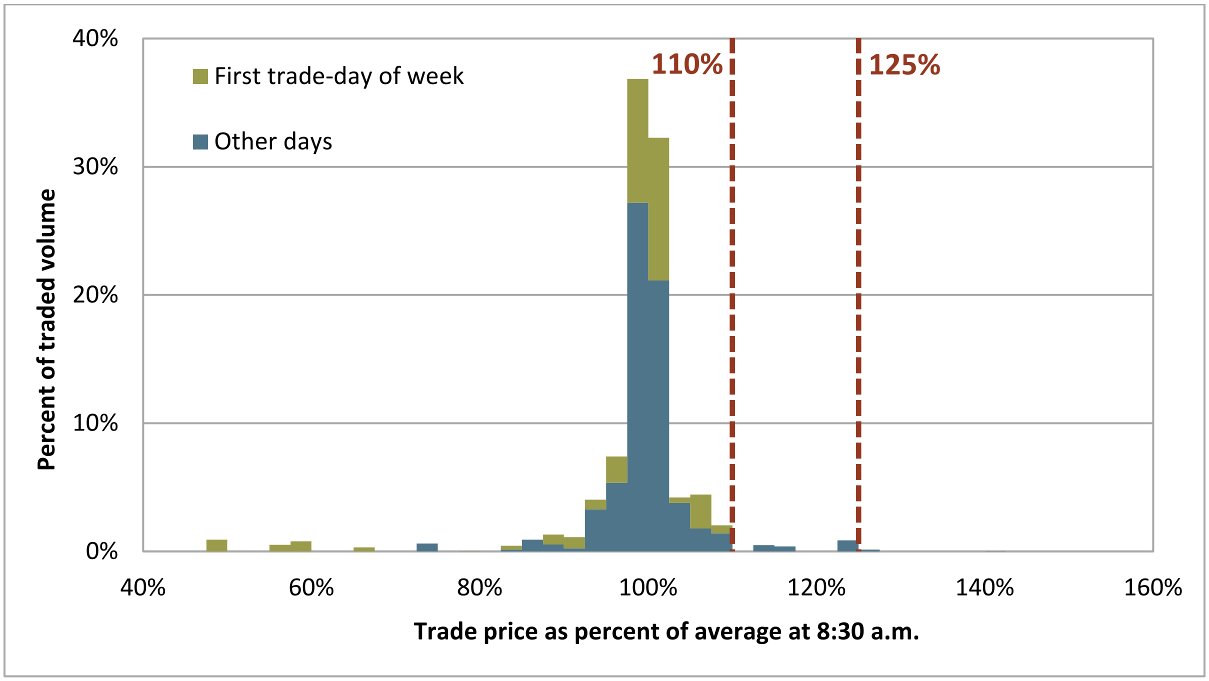
[59] *FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 3 (ER17-2568), Department of Market Monitoring,* October 26,2017: http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

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

Figure 3.7 Same-day prices as a percent of updated same-day averages (January – March)



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.[61]

Figure 3.8 and Figure 3.9 illustrate the benefit of using the updated natural gas price index in the first quarter of 2018. Figure 3.8 shows next-day trade prices reported on ICE for the SoCal Citygate during the first quarter, compared to the next-day price index previously used in the day-ahead market which was lagged by one trade day. As shown in Figure 3.8, about 11 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids. About 17 percent of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps.

Figure 3.9 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 3.9, about 2 percent of the traded volume exceeded the 10 percent adder included in default energy bids. Less than 1 percent of the volume exceeded the 25 percent adder included in the commitment cost caps. This

[61] 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.

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

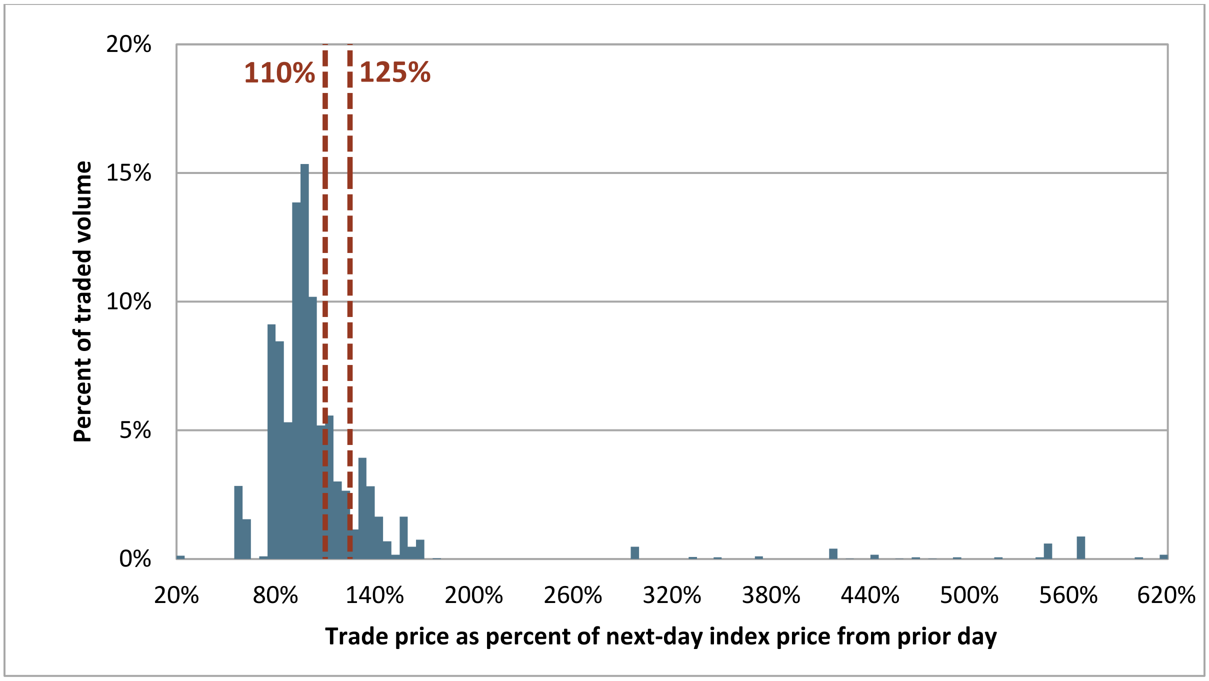


Figure 3.9 Next-day trade prices compared to updated next-day average price (Jan - Mar)