California ISO

California Independent System Operator Corporation

California ISO

Q4 2017 Report on Market Issues and Performance

February 14, 2018

Department of Market Monitoring

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Executive summary

This report covers market performance during the fourth quarter of 2017 (October – December). Key highlights during this quarter include the following:

- Average 15-minute system market prices continued to increase in October to almost $47/MWh, but then decreased in November and December. In October, average 15-minute market prices were higher than day-ahead and 5-minute market prices by about $4/MWh and $9/MWh, respectively. Prices in the 15-minute market were above $750/MWh during almost 1 percent of intervals in October.

- High 15-minute prices during October were concentrated between hours ending 18 and 20, when net load was highest. Many of these high prices occurred in intervals when the supply of ramping capability bid into the market was fully utilized and the power balance constraint was relaxed. Even when the load bias limiter was triggered, prices were often set by bids greater than $900/MWh.

- During the fourth quarter of 2017, auction revenues for congestion revenue rights were $61 million less than congestion payments made to non-load-serving entities purchasing these rights. This increased the total 2017 ratepayer losses in the congestion revenue rights auction to about $101 million. Losses in the fourth quarter represent $0.25 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders.

- In the fourth quarter, gas price adders used in calculating bid caps for units in the areas affected by Aliso Canyon gas storage limitations were active in the market for a few days in October and almost the entire month of December. DMM estimates that activation of the gas price adders in 2017 resulted in over $5 million in additional uplift payments to resources using these adders. Approximately $1 million of these payments was accrued in December during Southern California wildfires.

- On December 14, 2017, operators began setting ancillary service requirements for both the internal and external North of Path 26 sub-regions, sub-regions that had never had positive requirements previously. These requirements were set equal to the corresponding South of Path 26 regions.

- Portland General Electric became a participant in the energy imbalance market on October 1. Prices in Portland General Electric were often lower than prices in the ISO because of limited transmission from PacifiCorp West and Portland General Electric to the ISO.

- The ISO made annual capacity procurement designations for 2018 in response to sub-area deficiencies in the resource adequacy showings of load-serving entities. Designations were made for three resources for more than 500 MW of capacity in the San Diego Gas and Electric area and more than 500 MW of capacity in the Pacific Gas and Electric area. Estimated costs for these designations are about $80 million. The ISO also procured the Metcalf resource (593 MW) through a reliability must-run procurement for 2018. This resource has a fixed revenue requirement of about $72 million.

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

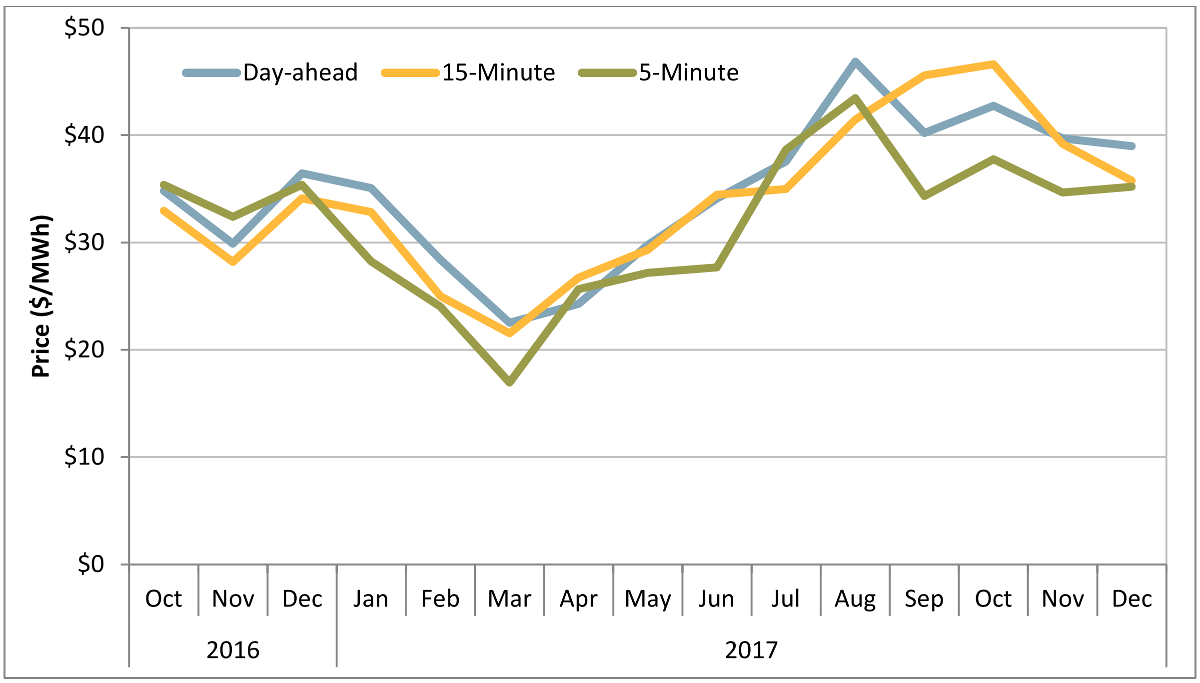
- There was significant north-to-south congestion in the day-ahead market during the quarter, primarily the result of planned outages in Southern California. This congestion increased day-ahead prices in Southern California by about $2/MWh and decreased prices in Northern California by about the same amount.
- Outages in Southern California also caused congestion in the 15-minute market. Congestion increased prices in the San Diego Gas and Electric area by about $4/MWh and in the Southern California Edison area by about $3/MWh, but had little impact on Pacific Gas and Electric area prices.
- Total bid cost recovery payments for the fourth quarter were about $27 million. This amount was slightly lower than payments in the previous quarter and significantly higher than payments in the fourth quarter of 2016. A significant amount of the bid cost recovery payments was accrued in the real-time market during the months of October and December.
- Convergence bidding was profitable overall during the fourth quarter with combined net revenues of about $8 million after accounting for bid cost recovery charges. However, virtual supply continued to be unprofitable for the third consecutive quarter after accounting for bid cost recovery charges.
- Total payments to generators for flexible ramping capacity decreased during the fourth quarter to about $3 million, compared to about $5 million during the previous quarter. This is the lowest amount of quarterly payment since the flexible ramping product was implemented in 2016. This was in part driven by adequate system availability in most intervals resulting in $0/MWh 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, particularly during hours ending 17 through 21. This was often the result when one or more of these areas failed their flexible ramping sufficiency test or an area's export limits bound when prices in the surrounding balancing areas were high.
- Balancing areas failed the flexible ramping sufficiency test relatively infrequently during the fourth quarter, during less than 3 percent of hours, for each area and direction. NV Energy failed the upward sufficiency test less frequently during only about 2 percent of hours during the quarter, compared to about 5 percent of hours in the previous quarter.

Energy market performance

This section provides a more detailed summary of energy market performance in the fourth quarter.

Average 15-minute energy prices continued to be higher than day-ahead prices in October. In October, average 15-minute prices reached about $47/MWh, after increasing since the spring. This was the second consecutive month that average 15-minute prices were higher than day-ahead prices. The higher average 15-minute prices were driven by more frequent shortages of ramping capacity in the 15-minute market, many of which triggered the load bias limiter but still resulted in prices higher than $900/MWh. These high prices occurred primarily during the peak load hours, on a small number of days in October, and tended to be the same hours that operators in the ISO were entering positive load adjustments.

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



Outage related congestion impacted prices across the footprint. In the day-ahead market, there was significant north-to-south congestion which increased prices in the Pacific Gas and Electric area by about $2/MWh and decreased prices in Southern California Edison and San Diego Gas and Electric by about the same amount. In the 15-minute market, congestion increased Southern California Edison area prices by about $3/MWh and increased San Diego Gas and Electric area prices by about $4/MWh. This congestion had little impact on the Pacific Gas and Electric area.

Bid cost recovery continued to be primarily from the real-time market. Overall bid cost recovery payments were $27 million during the quarter, higher than the $19 million cost during the same quarter of 2016. Real-time bid cost recovery totaled about $22 million in the fourth quarter, a significant increase from $11 million during the same quarter from last year. Bid cost recovery attributed to the day-ahead market totaled about $3 million while payments for residual unit commitment totaled about $1.8 million.

Virtual supply tended to be slightly unprofitable. Convergence bidding was profitable overall during the fourth quarter. However, virtual supply continued to be unprofitable for the third consecutive quarter after accounting for bid cost recovery charges. Before accounting for bid cost recovery charges, virtual demand generated net revenues of about $8.9 million while virtual supply net revenues were negligible. Combined net revenues for virtual supply and demand fell to about $8 million after including about $0.9 million of virtual bidding bid cost recovery charges.

Losses to ratepayers from the congestion revenue rights auction were the highest in three years. In the fourth quarter of 2017, congestion revenue rights auction revenues were $61 million less than congestion payments made to non-load-serving entities purchasing these rights. This represents only $0.25 in auction revenues received by transmission ratepayers for every dollar paid out to auctioned rights holders. Financial participants continued to receive the highest profits, netting about $40 million (paying 19 cents in the auction per dollar of congestion revenue rights revenue). Generators gained about $8 million (paying 23 cents per dollar of revenue), while marketers gained $13 million (paying 40 cents per dollar of revenue). Load-serving entities lost about $2 million from rights they explicitly sold in the auction in the fourth quarter of 2017, down from about $0.5 million in the same quarter of 2016.

Total ratepayer losses for the year from the congestion revenue rights auction were about $101 million, and totaled about $730 million since the market began in 2009.

Special issues

The ISO activated the special Aliso Canyon gas price scalars on many days during the quarter. The measures adopted by the ISO in response to the Aliso Canyon issue 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). Since these scalars were implemented in July 2016, same-day natural gas prices in Southern California resulted in gas prices, with these adders, exceeding prices of all but a very small portion of natural gas transactions. DMM has recommended that the ISO review this issue and reduce or eliminate the adders. Adders were used on three days during October, and nearly the entire month of December. DMM estimates that excess bid cost recovery costs due to the activation of these adders were about $5.5 million in 2017.

Key recommendations

DMM continues to recommend that the ISO modify the congestion revenue rights auction to eliminate losses to transmission ratepayers. Losses to ratepayers from the congestion revenue rights auction during Q4 totaled $61 million – the highest quarterly loss in three years**.** Total ratepayer losses from the congestion revenue rights auction were about $101 million in 2017, and now total about $730 million since the market began in 2009. These results highlight the need to modify the congestion revenue rights auction to protect transmission ratepayers. DMM supports continuing the congestion revenue rights allocation process for load-serving entities, and supports options under which the ISO could continue to run a market for additional congestion revenue rights based on bids from willing buyers and sellers.

DMM opposes the proposal for the risk of retirement capacity procurement mechanism. On February 2, 2018, DMM protested the ISO's filing for changes to the risk of retirement capacity procurement mechanism, citing that changes in payments would be unjust and unreasonable.[1] The proposed payments for the risk of retirement capacity procurement mechanism would allow for resources to recover all sunk fixed costs (including a 12.5 percent return on investment) and also retain all revenues earned while operating in the ISO or bilateral markets. This level of compensation would create market inefficiencies, and undermine the resource adequacy mechanism program and capacity procurement mechanism competitive solicitation process.

Develop enhancement to avoid lowering system-level flexible ramping product prices and procured quantities when inappropriate. In the initial implementation of the flexible ramping product, demand curves for individual balancing areas were included in the constraint for system-level procurement. DMM believes that this implementation approach leads to system-level procurement of flexible ramping capacity, and associated flexible ramping shadow prices, that are lower than what would be consistent with the system-level flexible ramping demand curves. The ISO implemented a software change in July 2017 to limit the use of demand curves from individual balancing areas to zero when sufficient transfer capability connected the area with system conditions. However, the implementation of this enhancement resulted in market outcomes where resources providing flexible ramping capacity received lower payments based on the balancing area specific demand curve rather than the system-level demand curve.

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 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.[2]

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.

[1] Motion to intervene and protest of the Department of Market Monitoring of the California Independent System Operator Corporation, February 2, 2018: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14814722.

[2] 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 fourth quarter.

- Average 15-minute market prices continued to increase in October to almost $47/MWh, then decreased in November and December. In October, average 15-minute market prices were higher than day-ahead and 5-minute market prices by about $4/MWh and $9/MWh, respectively, and were above $750/MWh during almost 0.9 percent of intervals. High prices were concentrated between hours ending 18 and 20, when net load and ramping needs were the highest.
- There was significant north-to-south congestion in the day-ahead market during the quarter. Congestion was primarily a result of planned outages in Southern California. This congestion increased day-ahead prices in Southern California by about $2/MWh, and decreased prices in Northern California by about the same amount.
- Outages in Southern California also caused congestion in the 15-minute market. Congestion increased prices in the San Diego Gas and Electric area by about $4/MWh and in the Southern California Edison area by about $3/MWh, but had little impact on Pacific Gas and Electric area prices.
- During the fourth quarter of 2017, congestion revenue rights auction revenues were $61 million less than payments made to non-load-serving entities purchasing these rights. This increased the total 2017 ratepayer losses in the congestion revenue rights auction to about $101 million. Losses in the fourth quarter represent $0.25 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 were $730 million.
- In July, an adjustment was made to limit the use of flexible ramping product demand curves from individual balancing areas to zero when sufficient transfer capability connected the area to the rest of the system. However, resources providing flexible ramping capacity continued to receive lower payments based on prices set by area-specific demand curves, rather than the system-level demand curves, during many intervals when sufficient transfer capacity was available.
- Total payments to generators for flexible ramping capacity decreased during the fourth quarter to about $3 million, compared to about $5 million during the previous quarter. This is the lowest amount of quarterly payment since the flexible ramping product was implemented in 2016. This was in part driven by adequate system availability in most intervals resulting in $0/MWh prices.
- 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 regions.
- Total bid cost recovery payments for the fourth quarter were about $27 million. This amount was slightly lower than payments in the previous quarter and significantly higher than payments in the fourth quarter of 2016. A significant amount of the bid cost recovery payments was accrued in the real-time market during the months of October and December.

- Convergence bidding was profitable overall during the fourth quarter with combined net revenues of about $8 million after accounting for bid cost recovery charges. However, virtual supply continued to be unprofitable, for the third consecutive quarter, after accounting for bid cost recovery charges.

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.

- Average 15-minute market prices continued to increase in October to almost $47/MWh. This was the highest average monthly 15-minute market price since 2014. Average 15-minute market prices in October were higher than day-ahead and 5-minute market prices by about $4/MWh and $9/MWh respectively. However, average 15-minute market prices decreased in November and December and were below day-ahead market prices in these months.
- Monthly average day-ahead and 5-minute market prices were relatively stable at about $40/MWh and $36/MWh, respectively. Average 5-minute market prices were lower than day-ahead and 15-minute market prices during every month of the quarter, consistent with historical trends.

Figure 1.2 illustrates system marginal energy prices on an hourly basis in the fourth quarter compared to average hourly net load.[3] Prices in this figure generally follow the net load pattern with the highest energy prices during the evening peak net load hours. In particular, prices were highest during hours ending 18 through 20. Average 15-minute market prices were significantly higher than average day-ahead and 5-minute market prices in hours ending 18 and 19. Under-supply infeasibilities largely contributed to the high average 15-minute market prices in these hours.

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

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

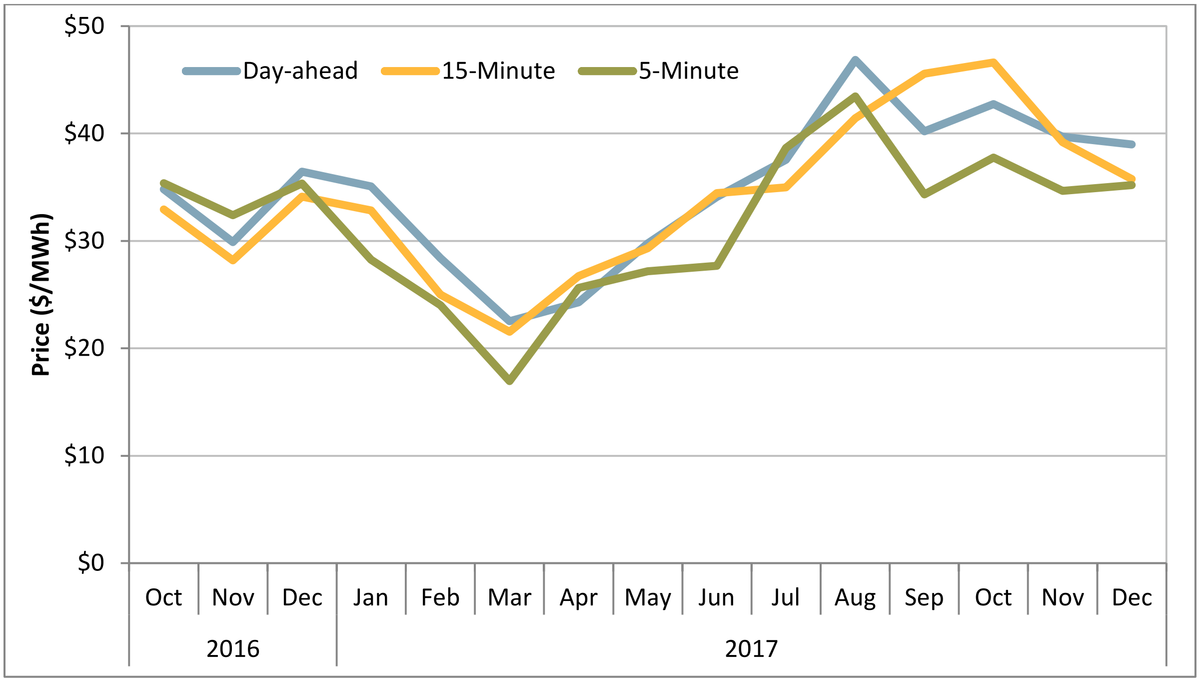
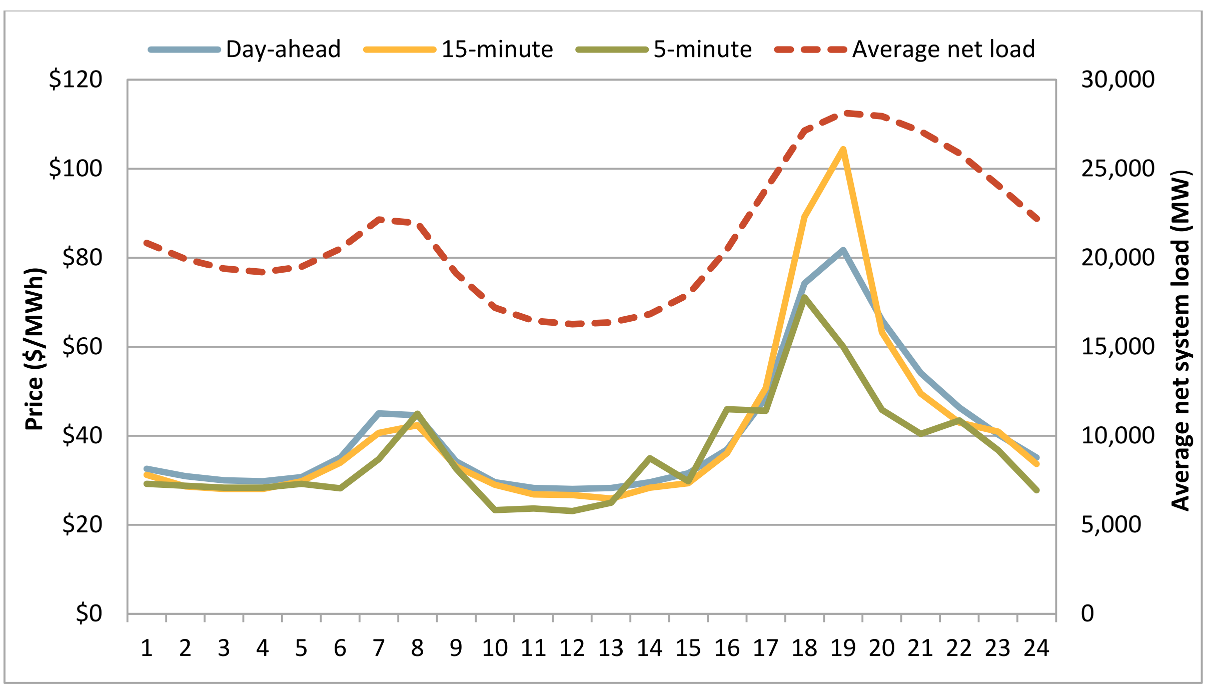


Figure 1.2 Hourly system marginal energy prices



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 fourth quarter, the frequency of high prices increased in both the 15-minute and 5-minute markets, while the frequency of negative prices decreased slightly.

During the quarter, most of the high prices occurred as a result of high bids in the market. In many instances, extremely high bids cleared the market and when the load bias limiter resolved infeasibilities, these were the prices that were used to set prices. In other instances, high prices were the result of congestion in the system, particularly in the Southern California areas.

High prices

As shown in Figure 1.3, the frequency of high prices in the 15-minute market remained high during October and decreased in November and December. During October, prices above $250/MWh occurred during more than 1 percent of 15-minute intervals. In addition, the frequency of larger price spikes in the 15-minute market greater than $750/MWh increased in October from the previous month to just under 1 percent of intervals. High prices in the 15-minute market were concentrated between hours ending 18 and 20 when load net of wind and solar was highest. During many of these intervals, the power balance constraint was relaxed in the 15-minute market due to insufficient incremental energy (shortages).

Figure 1.4 shows the monthly frequency of under-supply infeasibilities in the 15-minute market. In concurrence with the increased frequency of larger 15-minute market price spikes, under-supply infeasibilities in the 15-minute market were relatively high in the third quarter and continued in October. In comparison, valid under-supply infeasibilities in the 15-minute market did not occur during 2016 in this 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 fourth quarter when the limiter triggered, accessible economic bids near the bid cap of $1,000/MWh were dispatched such that the resulting price was near the penalty parameter.

Figure 1.5 shows the frequency of high prices in the 5-minute market. The frequency of price spikes greater than $250/MWh in the 5-minute market was about 0.8 percent of intervals in the fourth quarter, down from around 1.2 percent of intervals in the previous quarter and 1 percent of intervals in the fourth quarter of 2016. Similarly, the frequency of more extreme 5-minute market prices larger than $750/MWh decreased slightly during the quarter.

Figure 1.6 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. On average for the year, the frequency of under-supply infeasibilities in the 5-minute market was about the same from the previous year. During September and October, under-supply infeasibilities were slightly more frequent in the 15-minute market than in the 5-minute market. However, overall, the frequency of under-supply infeasibilities in the 15-minute market was more consistent with the frequency in the 5-minute market during the fourth quarter, particularly in comparison to quarterly frequencies in 2016.

Figure 1.3 Frequency of high 15-minute prices by month

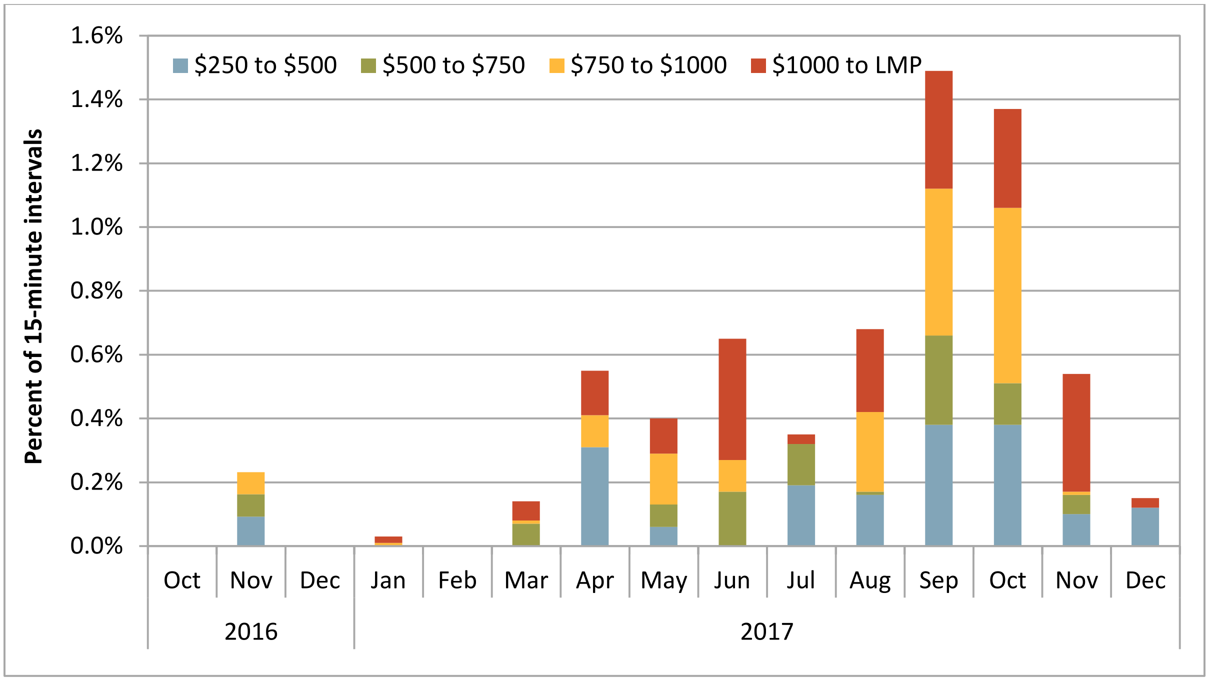


Figure 1.4 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

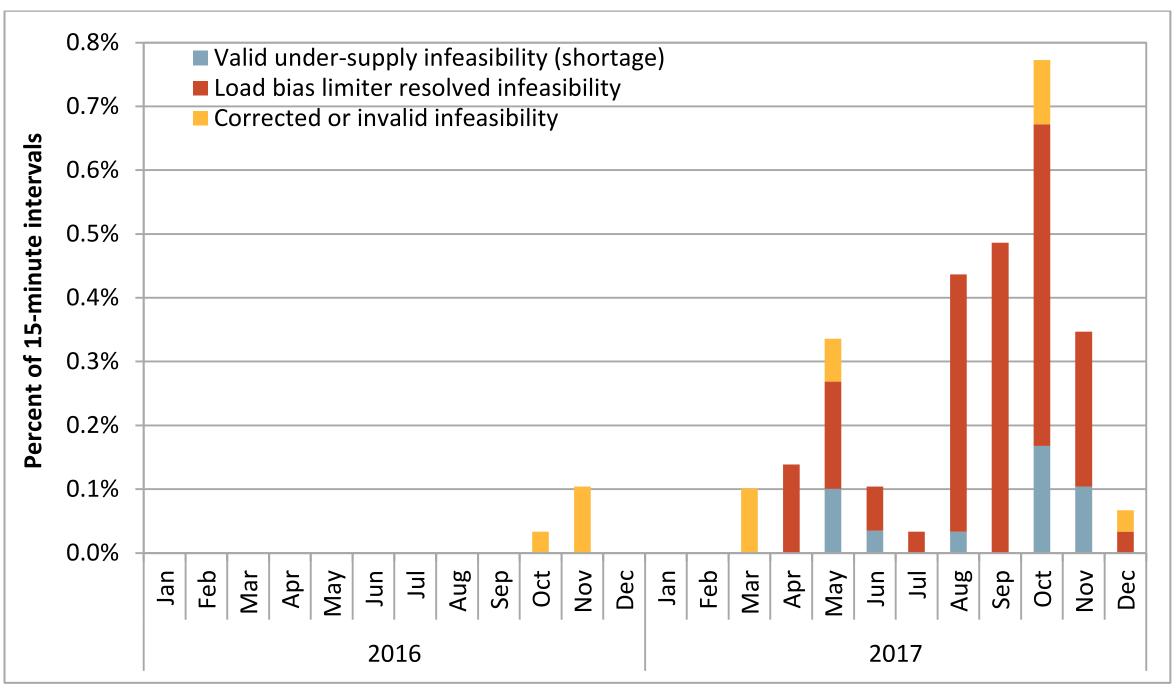


Figure 1.5 Frequency of high 5-minute prices by month

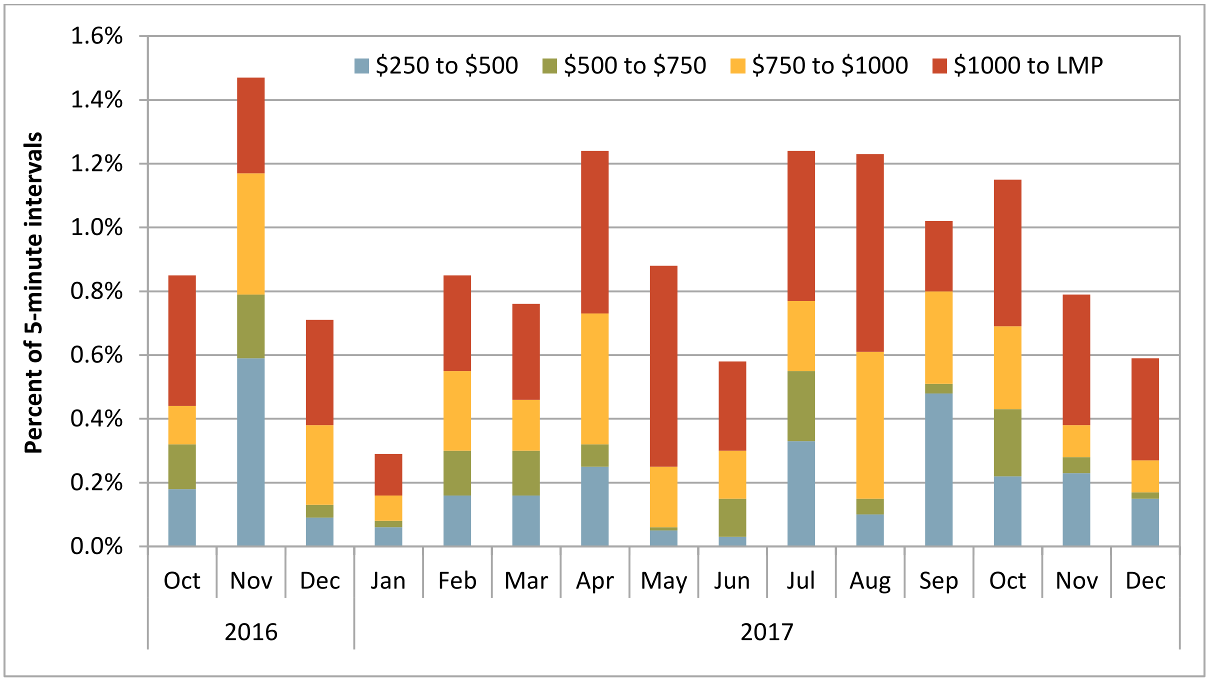
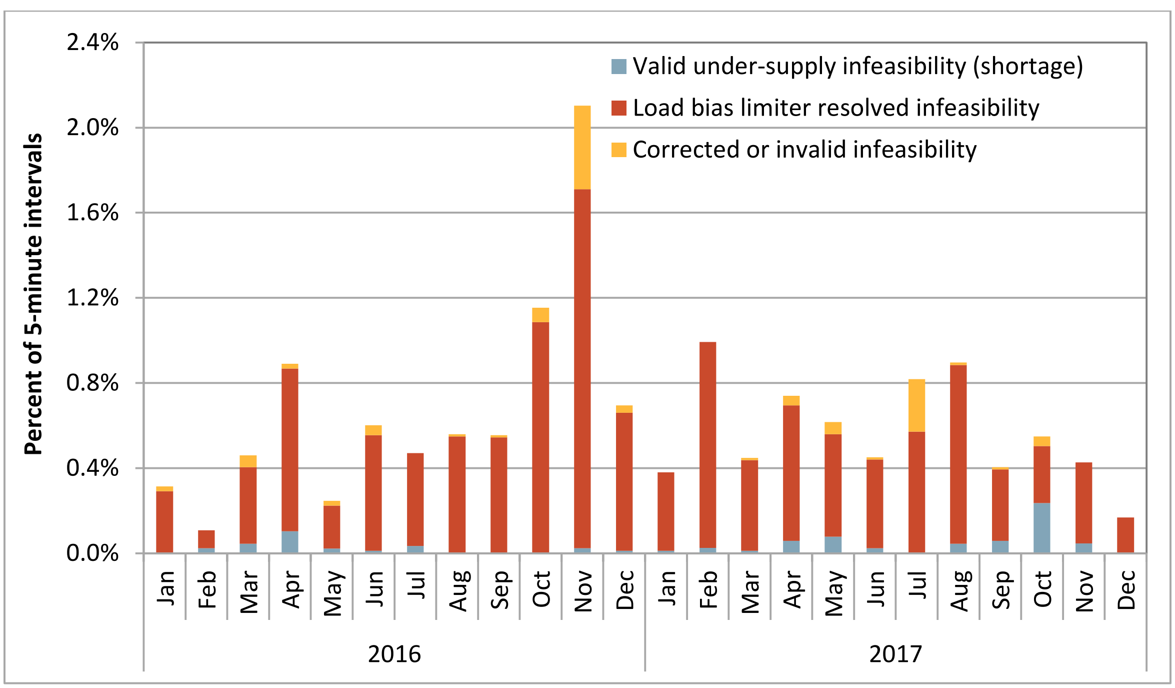


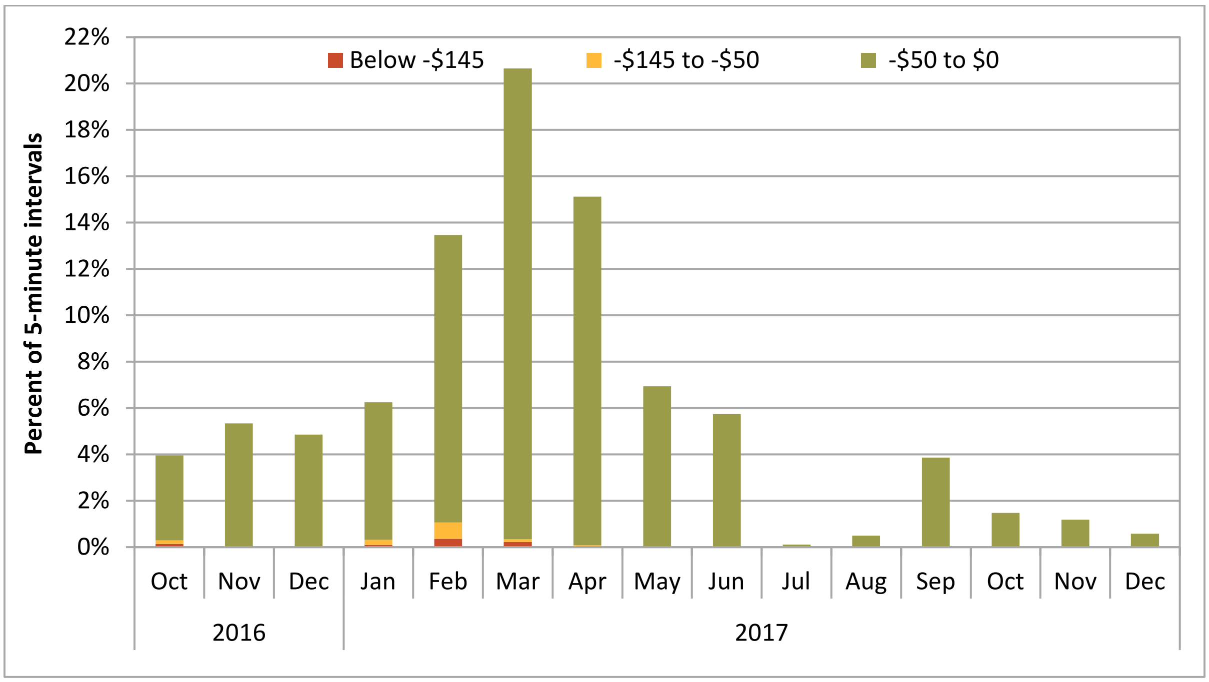
Figure 1.6 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



Negative prices

The frequency of negative prices in the 15-minute and 5-minute markets remained low during the fourth quarter. Figure 1.7 shows the frequency of negative prices in the 5-minute market by month.[4] Negative prices occurred during about 0.3 percent of intervals in the 15-minute market and around 1.1 percent of intervals in the 5-minute market. These were most frequent between hours ending 9 and 15 when loads, net of wind and solar, were lowest. However, prices did not reach below -$45/MWh for any of the three load aggregation points during the quarter, and there were no intervals when the power balance constraint bound because of excess energy.

Figure 1.7 Frequency of negative 5-minute prices by month



1.3 Congestion

In the fourth 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 decreased Pacific Gas and Electric area prices by about the same amount. In the 15-minute market, congestion increased Southern California Edison and San Diego Gas and Electric area prices by about 3/MWh and $4/MWh, respectively, and had little impact on Pacific Gas and Electric area prices. Outages in Southern California areas caused congestion at the Serrano 500/230 kV transformer and on the Southern California Import Transmission (SCIT) nomogram.

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

1.3.1 Congestion impacts of individual constraints

Day-ahead congestion

In the fourth quarter of 2017, the overall frequency of congestion increased in the day-ahead market compared to the previous quarter.[5] The constraints that bound most frequently in the Pacific Gas and Electric area were the Metcalf transformer and Path 15 (6310_CP6_NG), at approximately 2 percent of all hours. When these constraints bound, the combined impact increased Pacific Gas and Electric area prices by about $3/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by approximately $2/MWh. The congestion on Metcalf constraint was primarily the result of an outage on the Metcalf #13 500/230 kV transformer bank. Path 15 nomogram was enforced to mitigate for the loss of the Los Banos North double line outage.

Table 1.1 Impact of congestion on day-ahead prices during congested hours[6]

		Frequency	Q4		
Area	Constraint	Q4	PG&E	SCE	SDG&E
PG&E	30735_METCALF _230_30042_METCALF _500_XF_13	2.3%	$1.00	-$0.70	-$0.70
	6310_CP6_NG	2.3%	$1.52	-$1.06	-$0.90
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.8%	-$3.04	$2.34	$2.20
	30735_METCALF _230_30042_METCALF _500_XF_12	0.5%	$1.64	-$1.12	-$1.11
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	0.4%	-$3.30	$2.09	$1.93
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	5.4%	-$2.43	$1.72	$4.80
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	2.8%	-$1.30	$1.18	
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.9%		$0.68	-$1.12
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	24.1%			-$3.29
	OMS 4646112_OP-6610	19.0%	$0.46		-$1.53
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	18.8%	-$3.76	$2.35	$6.18
	OMS 4646120 ELD_MKP_SCIT_NG	15.8%	-$8.23	$6.33	$7.77
	7820_TL 230S_OVERLOAD_NG	12.8%	-$0.48		$5.39
	IID-SCE_BG	0.9%			-$4.73
	22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1	0.9%		$0.93	-$6.10
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1	0.7%			$2.01
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	0.5%		$0.89	-$5.78
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	0.5%			$10.07
	OMS_5349592_SCIT	0.4%	-$5.15	$3.59	$4.30
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	0.4%			-$2.66
	OMS 5459385 VIC-RNL_SCIT	0.4%	-$9.27	$7.34	$8.38
	22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1	0.3%			$2.82

In the Southern California Edison area, Barre-Villa Park 230 kV constraint bound most frequently. This constraint bound because an operating procedure was in effect to mitigate for the loss of the Barre-Lewis 230 kV line. This constraint bound during 6 percent of intervals and increased Southern California

[5] *Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 29: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf

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

Edison and San Diego Gas and Electric area prices by $2/MWh and $5/MWh, respectively, and decreased Pacific Gas and Electric area prices by about $2/MWh.

In the San Diego Gas and Electric area, there were several outages which caused congestion on the transmission constraints. Doublet Tap-Friars 138 kV constraint bound most frequently in about 24 percent of hours with a negative price impact of $3.3/MWh. A major reason for congestion on this constraint is the loss of Penasquitos-Old Town 230 kV line. The second most binding constraint is the nomogram (OMS 4646112_OP-6610) that was modelled to mitigate for the loss of El Dorado-Mohave 500 kV line which was congested in approximately 19 percent of the hours.

Congestion on the Serrano 500/230 kV transformer, Southern California Import Transmission (SCIT) nomogram, and the Imperial Valley nomogram significantly impacted prices in the San Diego Gas and Electric area. These constraints all bound between 10 and 20 percent of the hours. This congestion increased prices by about $19/MWh in the San Diego Gas and Electric area and $9/MWh in the Southern California Edison area, and decreased prices by about $12/MWh in Pacific Gas and Electric area.

An outage on a portion of the Serrano transformer bank caused congestion on the modeled constraint. This outage returns to service at the end of March 2018. The SCIT nomogram was binding for the loss of El Dorado-Moenkopi 500 kV line which returned to service mid-January 2018. Imperial Valley nomogram was enforced to protect for the loss of the Imperial Valley-North Gila 500 kV line.

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.

In the Pacific Gas and Electric area, the Path 15 constraint bound most frequently during the fourth quarter during about 2 percent of intervals. When binding, it increased Pacific Gas and Electric area prices by $4/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by about $6/MWh. Path 15 bound because of an outage on the Los Banos North double line.

In the Southern California Edison area, the Barre-Villa Park 230 kV constraint bound frequently, during 3 percent of intervals. When binding, it increased Southern California Edison and San Diego Gas and Electric area prices by about $7/MWh and $20/MWh, respectively, and decreased Pacific Gas and Electric area prices by $5/MWh.

In the San Diego Gas and Electric area, the Doublet Tap-Friars 138 kV constraint bound most frequently, during about 9 percent of all intervals. This constraint bound because of an overload in the real-time contingency analysis (RTCA) run for the loss of Penasquitos-Old Town 230 kV line. When this constraint bound it created a generation pocket in the San Diego Gas and Electric area and decreased prices there by about $11/MWh. Similar to the day-ahead market, the Southern California Import Transmission (SCIT) nomogram, Serrano 500/230 kV constraint, OMS 4646112_OP-6610 nomogram and Imperial Valley 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 significantly 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[7]

		Frequency	Q4								
Area	Constraint	Q4	PG&E	SCE	SDG&E	PACE	PACW	NEVP	PSEI	AZPS	PGE
PG&E	6310_CP6_NG	1.7%	$4.10	-$6.38	-$5.88	$1.16	$7.02	-$1.64	$6.92	-$5.14	$7.05
	30735_METCALF _230_30042_METCALF _500_XF_12	0.6%	$12.13	-$4.91	-$4.89	-$4.46	-$4.24	-$4.50	-$4.27	-$4.82	-$4.24
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	2.9%	-$5.08	$7.32	$19.76	-$5.73	-$5.44	-$6.68	-$5.44	-$5.11	-$5.44
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	8.7%			-$11.10					-$7.93	
	OMS 4646120 ELD_MKP_SCIT_NG	8.0%	-$4.31	$14.28	$15.78	-$8.96	-$5.41	-$4.13	-$5.42	-$20.36	-$5.41
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	7.5%	-$6.52	$11.13	$23.58	-$6.62	-$6.58	-$7.54	-$6.58	-$5.53	-$6.58
	OMS 4646112_OP-6610	5.9%	$10.22	$9.23	$1.62	-$14.83	$1.01	-$33.65	$0.89	-$24.85	$1.05
	7820_TL 230S_OVERLOAD_NG	2.3%	-$0.28	$0.42	$9.60	-$0.93	-$0.48	-$0.78	-$0.49	-$2.04	-$0.48
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	2.2%	$6.83	$6.85	$10.50	-$10.63	$2.09	-$20.50	$2.16	-$20.68	$2.09
	7820_TL23040_IV_SPS_NG	1.4%			$40.28	-$2.97		-$2.72		-$6.99	
	22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1	0.8%		$6.91	-$36.63					-$8.89	
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1	0.6%			$34.40	-$6.19		-$5.19		-$13.37	
	OMS 5364247 MIGUEL	0.4%			$28.23	-$3.69		-$2.19		-$7.48	
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1	0.4%			$23.22						
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	0.3%			$59.80					-$20.37	

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.[8]

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.[9] Congestion significantly increased prices in the Southern California Edison and San Diego Gas and Electric areas by about $2/MWh (5 percent), and decreased prices in the Pacific Gas and Electric area by about $2/MWh (6 percent). As mentioned earlier, congestion on Southern California Import Transmission (SCIT) nomogram, Serrano 500/230 kV constraint and Imperial Valley nomogram increased prices in Southern California.

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

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

[9] 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

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
OMS 4646120 ELD_MKP_SCIT_NG	-$1.30	-3.39%	$1.00	2.39%	$1.23	2.85%
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.71	-1.84%	$0.44	1.05%	$1.16	2.70%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.80	-1.84%
7820_TL 230S_OVERLOAD_NG	-$0.06	-0.16%			$0.69	1.60%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.13	-0.34%	$0.09	0.22%	$0.25	0.57%
OMS 4646112_OP-6610	$0.02	0.06%			-$0.29	-0.68%
OMS 5459385 VIC-RNL_SCIT	-$0.03	-0.09%	$0.03	0.06%	$0.03	0.07%
6310_CP6_NG	$0.03	0.09%	-$0.02	-0.06%	-$0.02	-0.05%
22500_MISSION _138_22496_MISSION _69.0_XF_1					$0.07	0.15%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.03	-0.07%	$0.02	0.05%	$0.02	0.04%
22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1			$0.01	0.02%	-$0.05	-0.12%
24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	-$0.03	-0.07%	$0.03	0.08%		
30735_METCALF _230_30042_METCALF _500_XF_13	$0.02	0.06%	-$0.02	-0.04%	-$0.02	-0.04%
OMS_5349592_SCIT	-$0.02	-0.06%	$0.02	0.04%	$0.02	0.04%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.05	0.11%
IID-SCE_BG					-$0.04	-0.10%
22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1			$0.00	0.01%	-$0.03	-0.06%
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.01	-0.04%	$0.01	0.02%	$0.01	0.02%
24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.01	-0.02%	$0.00	0.01%	$0.01	0.03%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1			$0.00	0.00%	-$0.02	-0.05%
30735_METCALF _230_30042_METCALF _500_XF_12	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	$0.00	-0.01%	$0.00	0.01%	$0.01	0.02%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1	$0.00	-0.01%			$0.01	0.03%
22773_BAY BLVD_69.0_22352_IMPRLBCH_69.0_BR_1 _1					$0.01	0.03%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.01	0.03%
OMS 5305814 50002_OOS_TDM					$0.01	0.03%
6310_CP8_NG	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
24801_DEVERS _500_24804_DEVERS _230_XF_1 _P					-$0.01	-0.02%
22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1					$0.01	0.02%
Other	$0.00	0.01%	$0.01	0.03%	$0.03	0.07%
Total	**-$2.24**	**-5.82%**	**$1.62**	**3.86%**	**$2.34**	**5.43%**

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.[10] Congestion during the fourth quarter increased Southern California Edison and San Diego Gas and Electric area prices by more than $3/MWh (8 percent). Congestion increased prices in the Southern California areas more in the fourth quarter than in the third. This was caused by congestion on the Serrano 500/230 kV transformer constraint and Southern California Import Transmission (SCIT) nomogram.

[10] 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

Constraint	PG&E $/MWh	PG&E Percent	SCE $/MWh	SCE Percent	SDG&E $/MWh	SDG&E Percent
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.49	-1.18%	$0.84	1.90%	$1.77	3.91%
OMS 4646120 ELD_MKP_SCIT_NG	-$0.35	-0.83%	$1.15	2.60%	$1.27	2.80%
OMS 4646112_OP-6610	$0.60	1.44%	$0.54	1.23%	$0.04	0.09%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.96	-2.13%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.14	-0.35%	$0.21	0.48%	$0.57	1.25%
7820_TL23040_IV_SPS_NG					$0.58	1.28%
22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1			$0.06	0.13%	-$0.30	-0.66%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.15	0.36%	$0.15	0.34%	$0.05	0.12%
6310_CP6_NG	$0.07	0.17%	-$0.11	-0.25%	-$0.10	-0.23%
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.10	-0.25%	$0.08	0.18%	$0.08	0.17%
7820_TL 230S_OVERLOAD_NG	$0.00	0.00%	$0.01	0.02%	$0.22	0.48%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1					$0.22	0.48%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.18	0.40%
22716_SANLUSRY_230_22232_ENCINA _230_BR_1 _1	$0.01	0.02%	$0.03	0.06%	-$0.11	-0.24%
30735_METCALF _230_30042_METCALF _500_XF_12	$0.07	0.18%	-$0.03	-0.07%	-$0.03	-0.07%
30015_TABLE MT_500_30040_TESLA _500_BR_1 _3	$0.05	0.12%	$0.04	0.10%	$0.04	0.08%
OMS 5364247 MIGUEL					$0.11	0.23%
OMS 5489791 TL23055_NG					$0.10	0.23%
RBS-HA_525KV			-$0.04	-0.09%	-$0.04	-0.10%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.08	0.19%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.01	-0.02%	$0.02	0.04%	$0.02	0.05%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.02%	$0.01	0.03%	$0.03	0.06%
OMS 4859482 MIDWAY_VINCENT_1	-$0.01	-0.03%	$0.01	0.03%	$0.01	0.03%
IID-SCE_BG					-$0.04	-0.08%
22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1					$0.03	0.07%
Other	$0.06	0.15%	$0.09	0.20%	$0.12	0.26%
Total	**-$0.09**	**-0.23%**	**$3.05**	**6.91%**	**$3.93**	**8.68%**

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 increased significantly in the fourth quarter of 2017. Congestion in PacifiCorp East was mainly a result of a single constraint binding during more than 45 percent of intervals in both the 15-minute and 5-minute markets. Congestion frequency was specifically higher in October because the limits on the constraint were almost reduced by 50 percent on some days. In the NV Energy area, frequency of binding internal constraints decreased slightly from the previous quarter 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			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
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%
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%
NV Energy					0.0%	0.0%	0.1%	0.3%	3.2%	10.3%	1.8%	7.6%	5.8%
Puget Sound Energy									0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	0.0%	0.0%	0.0%
Portland General Electric													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%
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%
NV Energy					0.0%	0.0%	0.2%	0.3%	3.2%	11.7%	1.6%	7.1%	5.6%
Puget Sound Energy									0.0%	0.0%	0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	0.0%	0.0%	0.0%
Portland General Electric													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. In particular, the spinning and non-spinning operating reserve requirements for the expanded and internal South of Path 26 regions have been historically set at 35 percent and 17.5 percent of the expanded system requirement, respectively. In other words, at least 35 percent of the operating reserve requirement was met from resources south of Path 26 where at least half was required from internal generation.

On October 10, 2016, the ISO began using a new method for determining regulation procurement requirements.[11] Since the implementation of the new methodology, regulation requirements for the expanded and internal South of Path 26 regions have typically been set at around 105 MW and 10 MW, respectively, rather than as a percent of the expanded system requirement.

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 maintained to help with the distribution of ancillary service procurement across the ISO, particularly in preparation for the implementation of the NERC reliability standard, BAL-002-2.[12]

Since October 2014, procurement requirements in real-time for operating reserves 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. 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 the Pacific DC Intertie. DMM will continue to monitor the impact of this adjustment in future reports.

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[11] The new method was implemented in response to growing needs for regulation to balance variable renewable generation. With the new method, each hour is calculated independently, based on observed regulation needs during the same month in the previous year. Further, the ISO can adjust requirements manually for periods when conditions indicate higher net load variability. The new methodology was initially implemented only in the day-ahead market because of software limitations. The ISO began using the new methodology in real-time in January 2017.

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

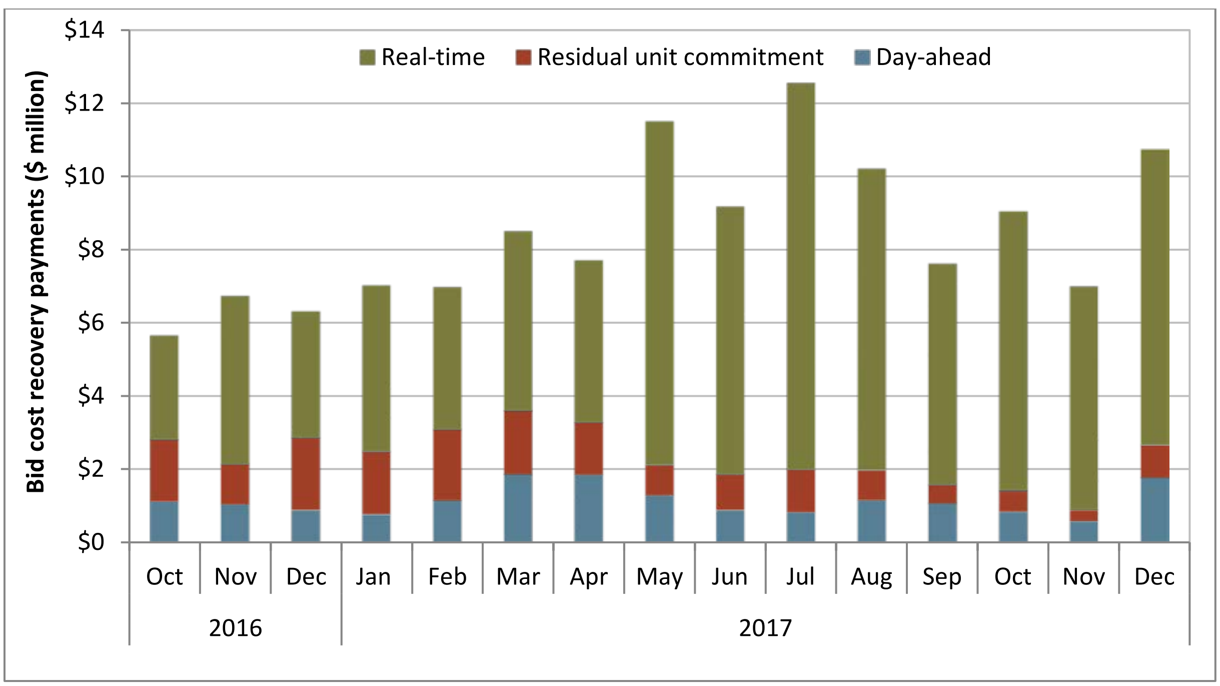
1.5 Bid cost recovery

Estimated bid cost recovery payments for the fourth quarter totaled about $27 million. This amount was slightly lower than the total amount of bid cost recovery in the previous quarter and significantly higher than the fourth quarter of 2016, when it was about $19 million. A significant amount of the bid cost recovery payments was accrued in the real-time market during the months of October and December.

Bid cost recovery attributed to the day-ahead market totaled about $3 million, which was about the same as the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $1.8 million, down from $2.5 million during the prior quarter. After netting against real-time revenues in the fourth quarter of 2017, short-start and long-start resources received about $0.8 million and $1 million, respectively, for these payments.[13]

Bid cost recovery attributed to the real-time market totaled about $22 million, or about $3 million lower than payments in the third quarter of 2017, and $11 million larger than payments in the fourth quarter of 2016. More than $3 million of these fourth quarter payments were awarded to a single resource that routinely had schedules in the day-ahead market, but could not be started in the real-time market, when prices were high, because of daily start limitations. More than $2 million of real-time payments accrued in December because of exceptional dispatches from conditions created by the wildfires in Southern California.

Figure 1.8 Monthly bid cost recovery payments



13 Residual unit commitment bid cost recovery charges are calculated by netting residual unit commitment shortfalls with real-time surpluses in revenue. The same methodology is used in calculating virtual bidding bid cost recovery charges.

1.6 Convergence bidding

Convergence bidding was profitable overall during the fourth quarter. However, virtual supply continued to be unprofitable for the third consecutive quarter after accounting for bid cost recovery charges. Before accounting for bid cost recovery charges, virtual demand generated net revenues of about $8.9 while virtual supply net revenues were negligible. Combined net revenues for virtual supply and demand fell to about $8 million after including about $0.9 million of virtual bidding bid cost recovery charges.

1.6.1 Convergence bidding trends

Average hourly cleared volumes decreased in the fourth quarter to about 2,000 MW from about 2,400 MW during the previous quarter. Average hourly virtual supply decreased during the quarter to about 1,200 MW compared to around 1,600 MW in the previous quarter. Virtual demand averaged around 800 MW during each hour of the quarter, similar to the previous quarter. On average, about 35 percent of virtual supply and demand bids offered into the market cleared in the fourth quarter, which is down slightly from 36 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 370 MW on average, which decreased significantly from 780 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 17 and 20. In the remaining 20 hours, net cleared virtual supply exceeded net cleared virtual demand. Net cleared virtual supply was highest during the midday hours ending 11 through 15. During these hours virtual supply cleared about 800 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 22 of 24 hours.

Offsetting virtual supply and demand bids

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

Offsetting virtual positions accounted for an average of about 370 MW of virtual demand offset by 370 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 37 percent of all cleared virtual bids in the fourth quarter, down from about 40 percent in the previous quarter.

1.6.2 Convergence bidding revenues

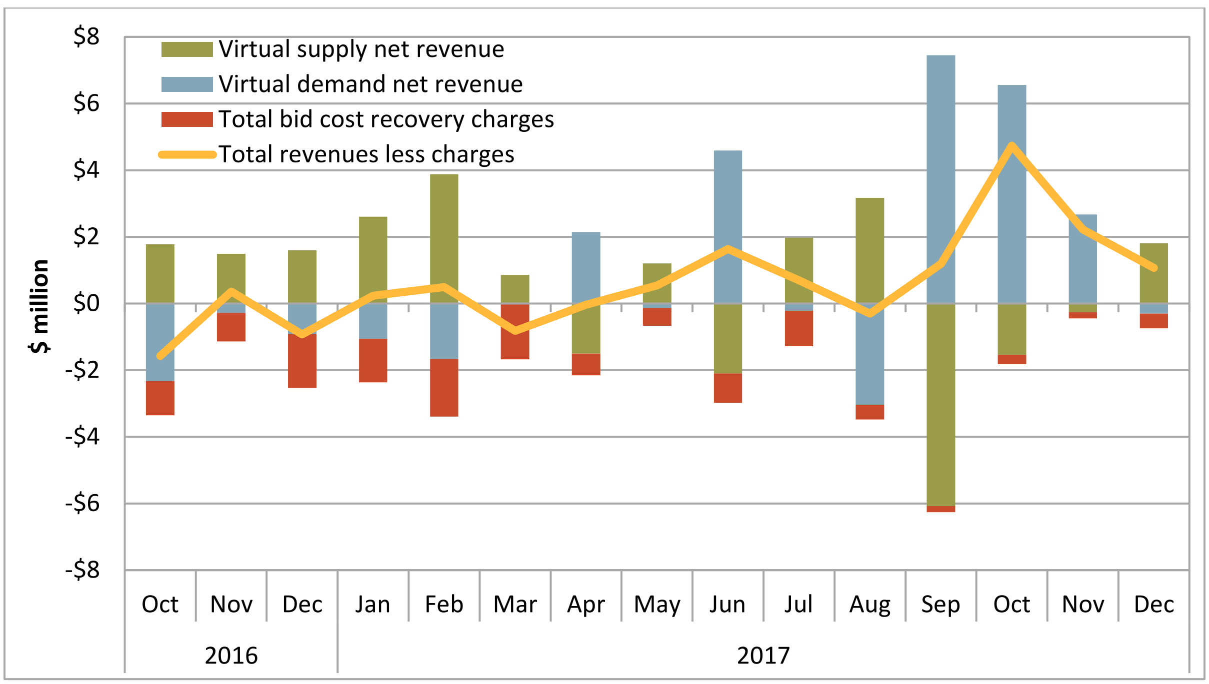
Participants engaged in convergence bidding in the fourth quarter were profitable overall. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $8.9 million. Net revenues for virtual supply and demand fell to about $8 million after including about $0.9 million of virtual bidding bid cost recovery charges.[14]

Figure 1.9 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 fourth quarter totaled about $8.9 million, compared to about $1.3 million during the same quarter in 2016, and about $3.3 million during the previous quarter.
- Virtual demand net revenues were positive in October and November but were negative in December. In total, virtual demand generated net revenues of about $8.9 million during the quarter.
- Virtual supply net revenues were negative in October and November but were positive in December. In total, virtual supply generated net revenues of about $0. After accounting for bid cost recovery charges, virtual supply was not profitable for the third consecutive quarter.

Figure 1.9 Convergence bidding revenues and bid cost recovery charges



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

After accounting for bid cost recovery charges:

- Convergence bidders received about $8 million after subtracting bid cost recovery charges of about $0.9 million for the quarter.[15,16] Bid cost recovery charges were about $0.3 million in October, $0.2 million in November, and $0.4 million in December.

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 fourth quarter.[17] Financial entities represented the largest segment of the virtual bidding market, accounting for about 60 percent of volume and a similar proportion of settlement revenue. Marketers represented about 31 percent of the trading volumes and a similar proportion of settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of both volumes and settlement revenue, at about 9 percent. In addition, load-serving entities accounted for around $0.3 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	512	685	1,197	$4.85	$0.77	$5.62
Marketer	275	336	611	$3.47	-$0.43	$3.04
Physical load	0	157	157	$0.00	-$0.33	-$0.33
Physical generation	16	1	17	$0.61	$0.00	$0.61
Total	**803**	**1,179**	**1,983**	**$8.9**	**$0.0**	**$8.9**

1.7 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 $730 million this quarter.

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

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

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

During the fourth quarter of 2017, congestion revenue rights auction revenues were $61 million less than congestion payments made to non-load-serving entities purchasing these rights, and total losses to ratepayers in 2017 were approximately $101 million. Losses in the fourth quarter represent $0.25 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, which is significantly lower than the rate during the last three years.

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).[18] 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.[19]

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 1.10 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);

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

[19] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

- 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 $61 million during the fourth quarter of 2017 as payments to auctioned congestion revenue rights holders exceeded auction revenues by this amount, a significant increase from the $25 million loss in the fourth quarter of 2016. This represents the highest amount of ratepayer losses in any quarter since 2015.

Auction revenues were 25 percent of payments made to non-load-serving entities during the fourth quarter of 2017, down from 46 percent during the same quarter in 2016.

Figure 1.10 Auction revenues and payments to non-load-serving entities

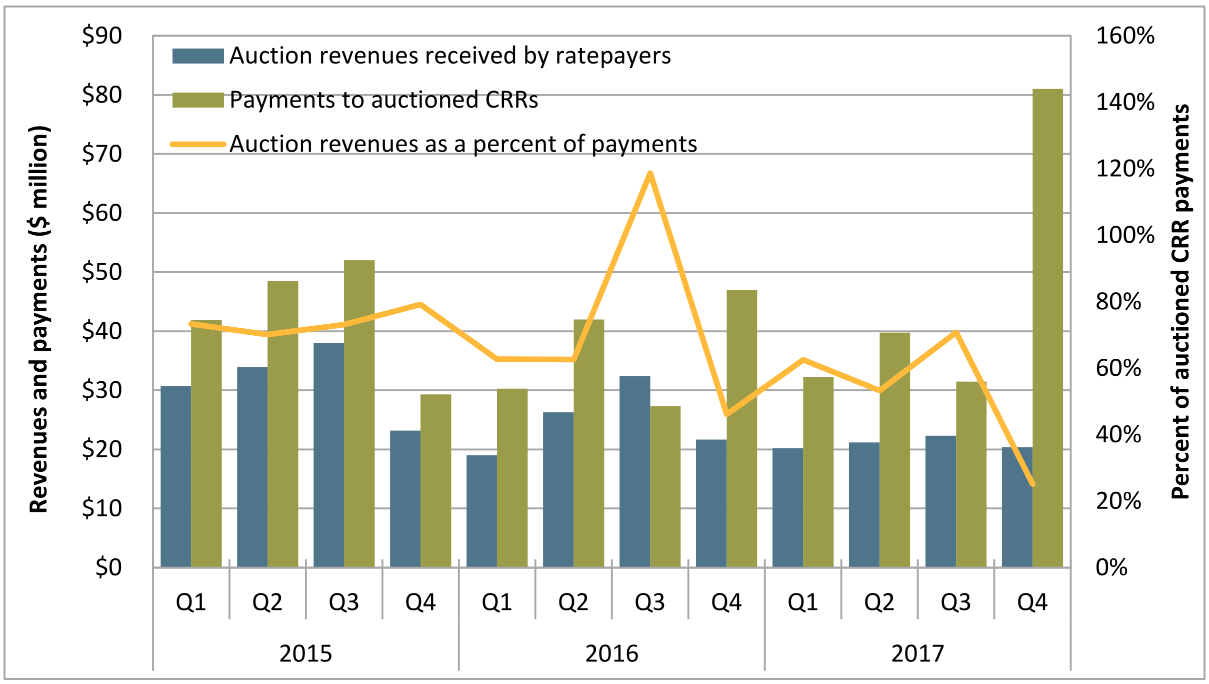


Figure 1.11 through Figure 1.14 show quarterly auction revenues paid to all entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- 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 1.10, these charts show quarterly auction revenues and congestion revenue rights payments from 2015 through 2017. Highlights from these figures show the following for the fourth quarter of 2017.

- Financial entities continued to have the highest profits between the entity types, at approximately $40 million. This was a significant increase from $13 million profits during the fourth quarter of 2016. Marketer profits were approximately $13 million, up from $8 million during the same quarter in 2016. Generators gained about $8 million compared to $4 million in the fourth quarter of 2016.
- In the fourth quarter financial entities paid 19 cents in auction revenue per dollar received, compared to 45 cents paid in 2016 during the same quarter. Generators paid 23 cents per dollar received, which was about the same as the same quarter in 2016, and marketers paid 40 cents, down from 54 cents in the fourth quarter 2016.
- 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 $2 million from rights they explicitly sold in the auction in the fourth quarter of 2017, down from about a $0.5 million loss in the same quarter of 2016.

Figure 1.11 Auction revenues and payments (financial entities)

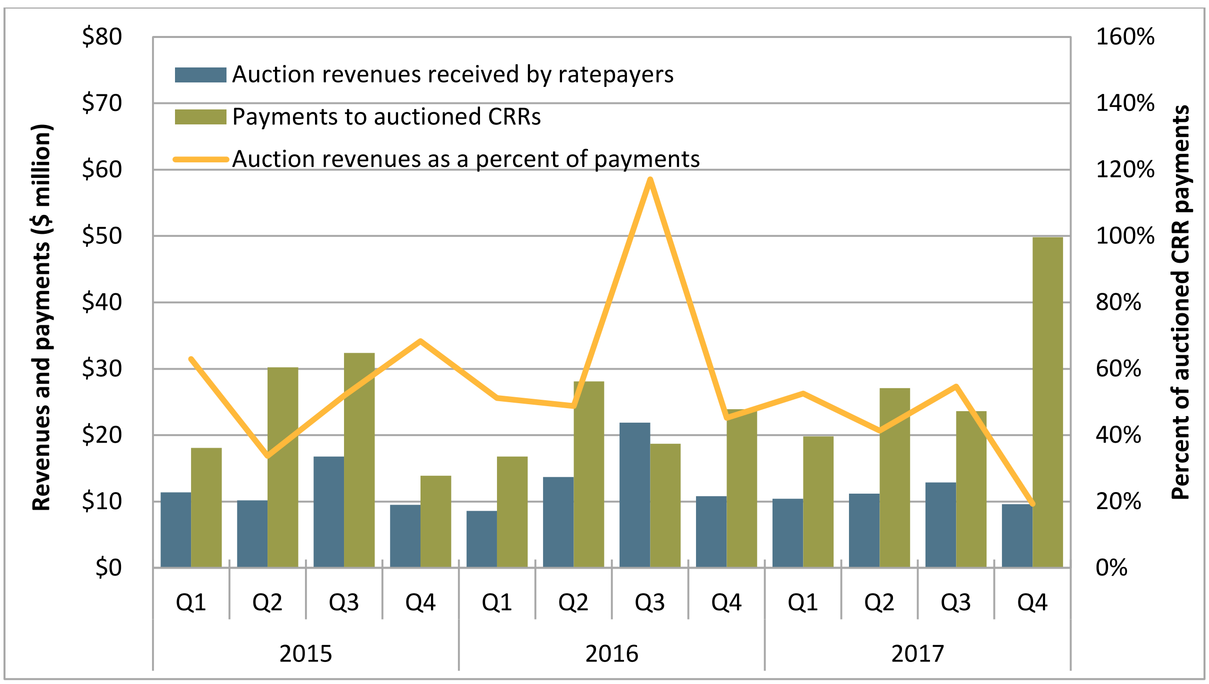


Figure 1.12 Auction revenues and payments (marketers)

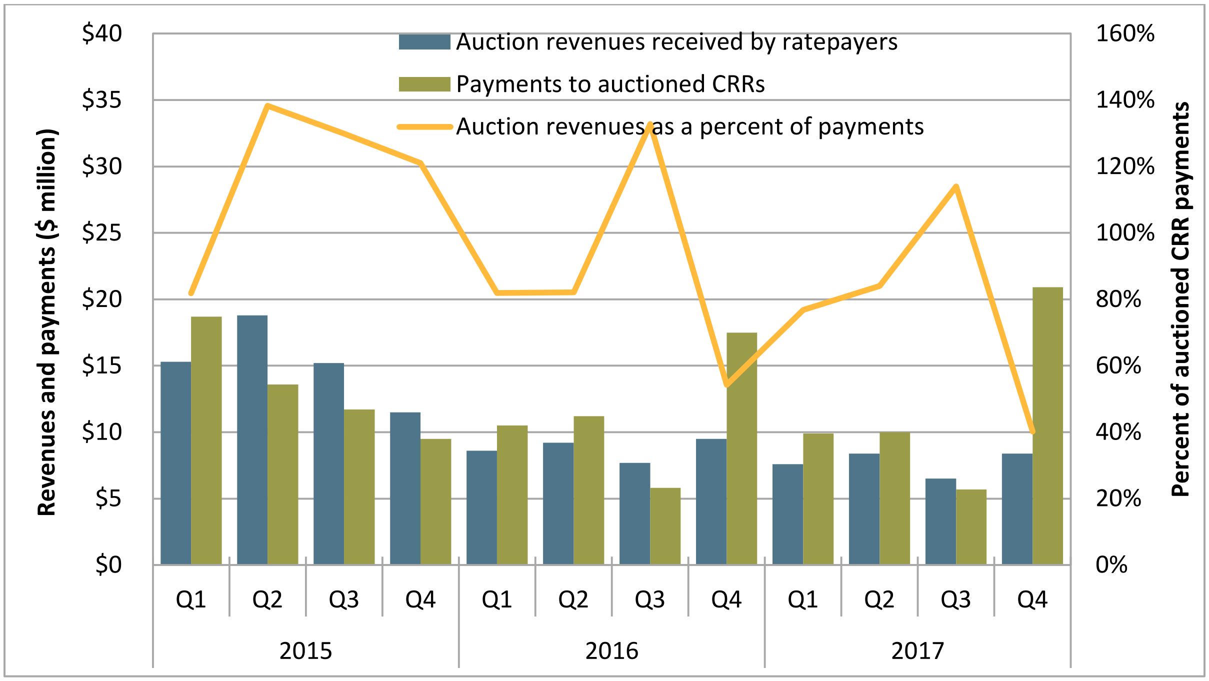


Figure 1.13 Auction revenues and payments (generators)

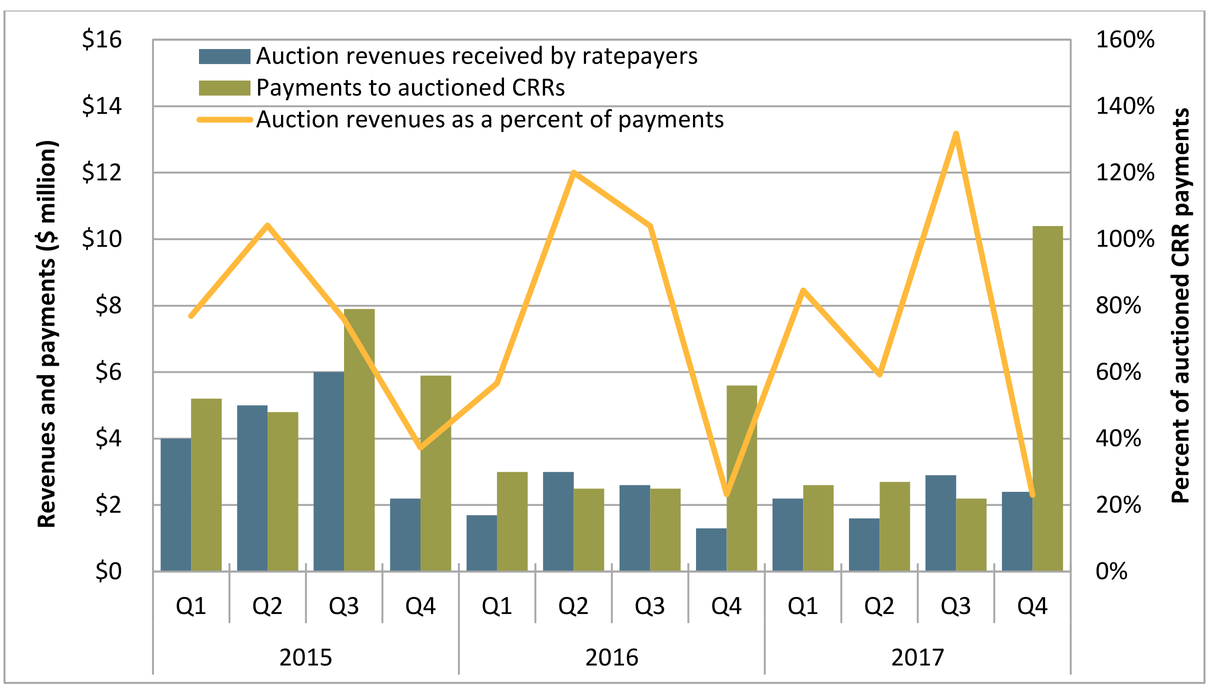
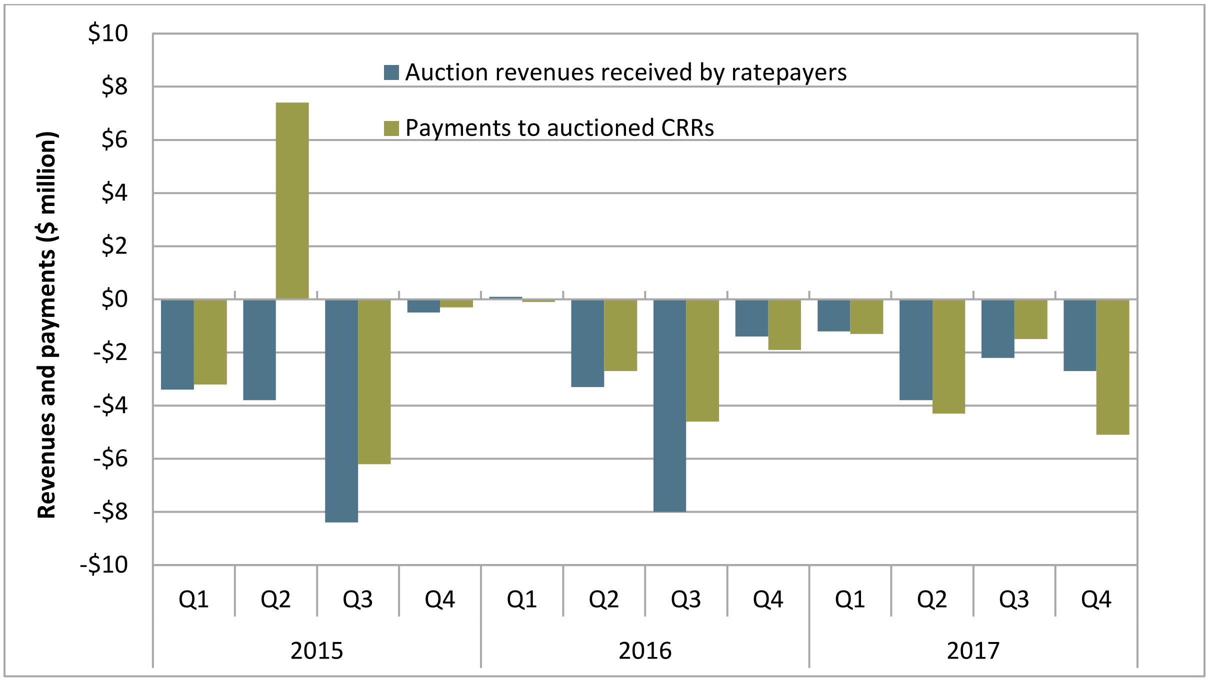


Figure 1.14 Auction revenues and payments (load-serving entities)



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.[20] DMM believes the current auction is unnecessary and could be eliminated.[21] 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.

In response to DMM's recommendation at the June 2016 Board of Governors meeting, ISO management started the "Congestion revenue rights auction efficiency" initiative and adopted a two phase approach.[22] The first phase will be for analysis, in which the ISO will assess the differences between auction prices and payouts in the congestion revenue rights market. The second phase will be policy development, in which the ISO will consider potential policy changes. The ISO published analysis of the congestion revenue rights auction performance on November 21, 2017, and held a working group

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

21 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

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

meeting on December 19, 2017.[23] Congestion revenue rights working group reviewed the results and discussed issues which subsequently will lead to an issue paper in February 2018.

1.8 Flexible ramping product

This section provides information about market outcomes for the flexible ramping product during the fourth quarter.

Background

The ISO implemented a new market feature on November 1, 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. The flexible ramping product differs from the flexible ramping constraint in several important ways.

First, while the constraint procured only upward flexible capacity in the 15-minute market, the product procures both upward and downward flexible capacity in both the 15-minute and the 5-minute markets. As with the constraint, procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the corresponding 5-minute market runs for the same time period. Procurement in the 5-minute market aims to ensure that enough ramping capacity is available to handle differences between consecutive 5-minute market intervals.

Second, the amount of flexible capacity that the product procures is determined from a demand curve instead of from a fixed requirement. This means that the amount of flexible capacity procured in a given market interval will depend on the willingness-to-pay for procuring flexible capacity in that interval derived from the demand curve.

Third, the shadow prices for the flexible ramping product are used not only for compensating resources that are counted towards meeting the flexible ramping capacity demand, but also to pay or charge resources for their forecasted ramping movement.

Flexible ramping product demand curves

The ISO procures flexible ramping capacity using demand curves that represent the ISO's willingness-to-pay for flexible ramping 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 constraint violation costs with the additional ramping capacity.

The demand curves are calculated independently for each hour of the day, and differ by market (15-minute and 5-minute) and direction (upward ramping and downward ramping).[24] Further, there are

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

[24] The demand curves are calculated from historical net load forecast error data. Weekdays use data for the same hour from the last 40 weekdays. For weekends, the last 20 weekend days are used. Additional information about the construction of the demand curves was provided by the ISO at the December 7, 2016, Market Performance and Planning Forum (pp. 24-50): http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Dec7_2016.pdf.

separate demand curves calculated for each energy imbalance market area in addition to a system-level demand curve.

The flexible ramping product is incorporated into the ISO's market optimization as a constraint. In this approach, the demand curves are first entered into the market software as segments of *relaxation capacity* that reflect the expected cost of a power balance constraint violation for the level of foregone capacity procurement. The maximum amount of capacity on the demand curve (or uncertainty) is then treated as a requirement and is met in every interval through a combination of flexible ramping capacity procurement or relaxation capacity.[25]

The system-level demand curve is always enforced in the market. However, the uncertainty requirement for the individual balancing areas is reduced in every interval by their transfer capability.[26] The demand curves for the individual areas are therefore binding when insufficient transfer capability is present, which indicates that the area is unable to benefit from the flexible capacity from other areas. When the uncertainty requirement for all of the individual areas is zero, then only the system-level uncertainty requirement is active. During the fourth quarter, the area-specific upward and downward uncertainty requirement was reduced to zero for each area in the majority of 15-minute and 5-minute intervals such that only the system-level uncertainty requirement was active.

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 from the individual balancing area demand curves could be used to meet system-level uncertainty even when the uncertainty requirements for the individual balancing areas were reduced to zero. DMM believes that this implementation 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.

However, an adjustment was made on July 13 to limit the use of demand curves from individual balancing areas in meeting system-level uncertainty when sufficient transfer capability connected the area with system conditions. This enhancement was expected to avoid lowering system-level flexible ramping product prices and procured quantities in intervals when market conditions indicate that there was no need to procure any area-specific flexible ramping capacity. However, since this change was implemented, there are many intervals when resources providing ramping capacity received payments based on the first segment of their area-specific demand curve rather than the shadow price associated with the system demand curve.

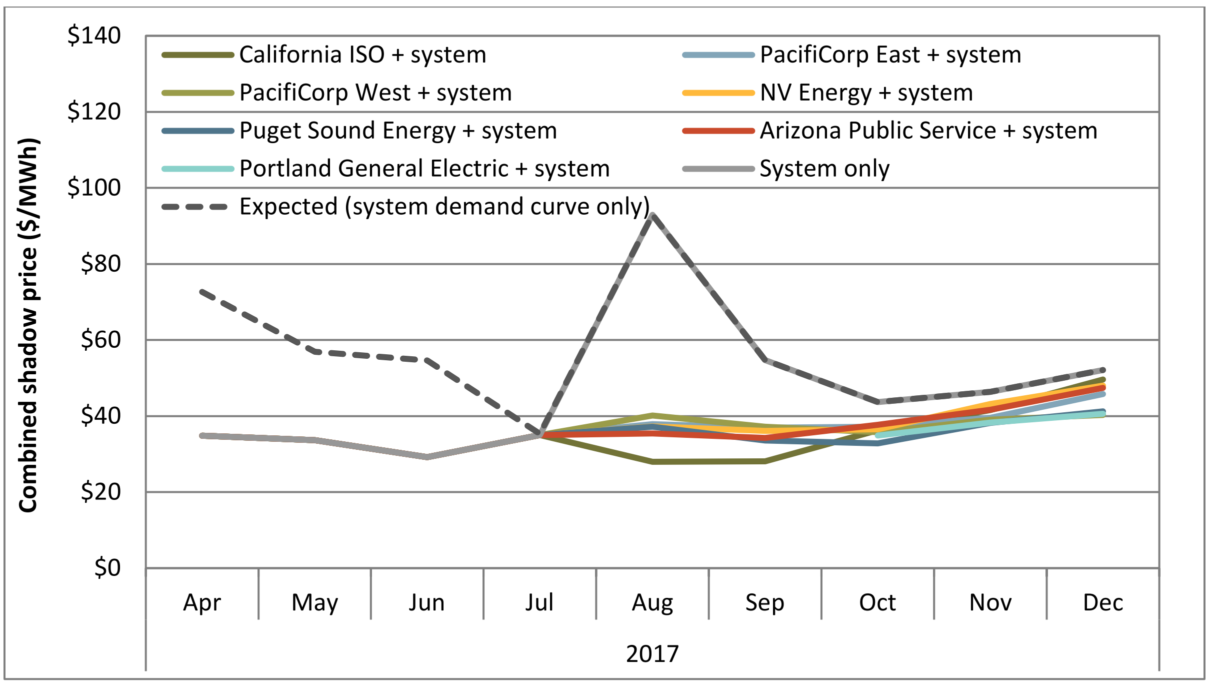
When system-level capacity procurement is foregone through relaxation capacity, the system-level demand curve will be binding with a positive shadow price. Further, an area-specific demand curve may also be binding, creating a separate price for resources in that area. Resources providing flexible ramping capacity receive payments based on the combined shadow price, the sum of the system and area-specific shadow price.

25 While the uncertainty requirement is commonly referred to as a requirement, DMM notes that this value reflects the end point of the demand curve, or the maximum amount of flexible capacity the market is willing to pay for, rather than a hard requirement.

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

Figure 1.15 shows the average combined system and area-specific shadow price when system-level flexible ramping capacity is foregone (relaxation) for the upward direction in the 15-minute market.[27] For simplicity, intervals in which one or more areas failed the flexible ramping sufficiency test or did not have sufficient transfer capability are excluded. The solid gray line shows the average system shadow price on its own. The dotted gray line shows the expected average shadow price for the level of flexible ramping capacity procured if only the system demand curve was used.[28] As shown in the figure, before July 13, all resources providing ramping capacity when only the system demand curve was binding were paid uniformly based on the system shadow price alone, though at levels below what would be expected (as discussed above).

Figure 1.15 Average combined shadow price with foregone system-level flexible ramping capacity



Since August, DMM has observed intervals when the system demand curves are binding where the area specific demand curves are also binding at a negative shadow price such that the net of the system shadow price and the area-specific shadow price is equal to the price associated with relaxing the first segment of the area's demand curve. In most of these intervals, sufficient transfer capability between all of the energy imbalance market areas was available such that only the system demand curve was expected to be binding. In these instances, resources that provided ramping capacity received payments based on the first segment of the area-specific demand curve rather than the shadow price associated with the system demand curve. DMM continues to recommend that the ISO work with DMM

[27] Corresponding values for the 5-minute market or downward direction are omitted because of less frequent occurrence of foregone flexible ramping capacity but show a similar pattern.

[28] This reflects the shadow price indicated by the demand curve with the actual amount of flexible ramping capacity procured. However, had the demand curves for the individual balancing areas not been included in the constraint for system-level procurement, the optimization would have likely procured more flexible ramping capacity at a therefore lower shadow price.

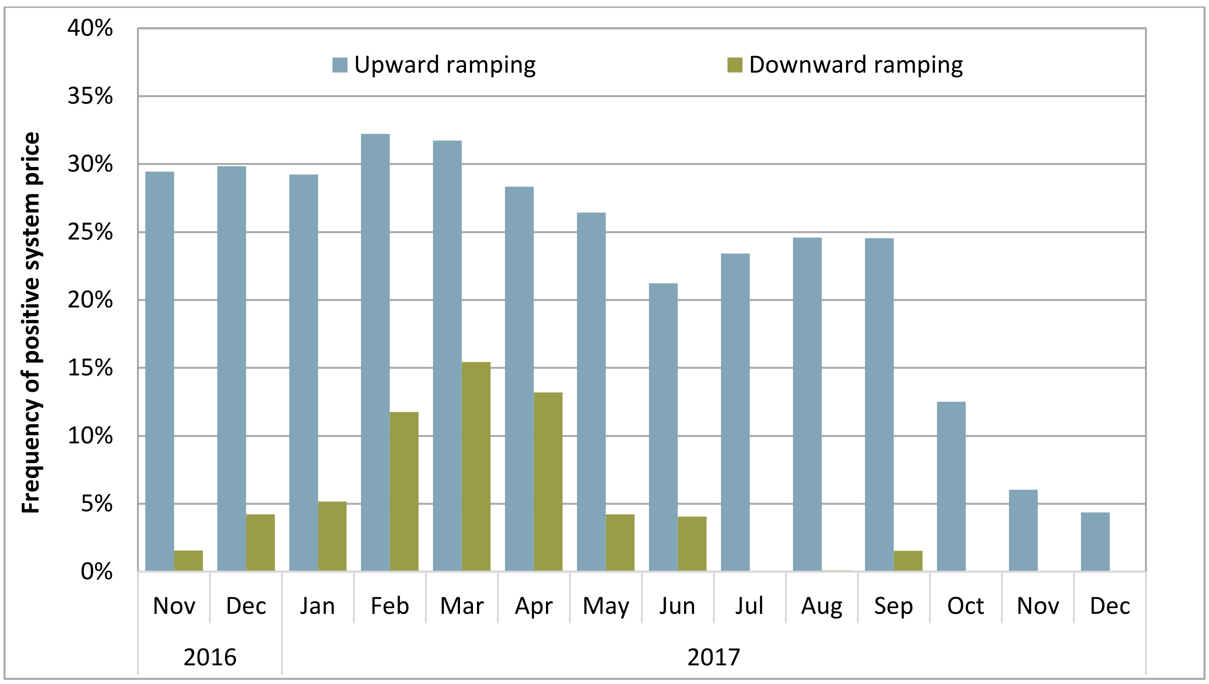
and stakeholders to determine an appropriate enhancement that could avoid lowering system-level flexible ramping product prices and procured quantities.

Market outcomes for flexible ramping product

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

Figure 1.16 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. In the fourth quarter, the system-level demand curves bound much less frequently in the upward direction than in previous quarters. The system-level upward demand curves bound in about 8 percent of 15-minute intervals during the fourth quarter, compared to about 24 percent during the third quarter. Positive prices in the upward direction were most frequent in hours ending 8 and 9 and between hours ending 18 and 24. These hours coincide with higher demand for upward flexible ramping capacity.

Figure 1.16 Monthly frequency of positive 15-minute market flexible ramping shadow price



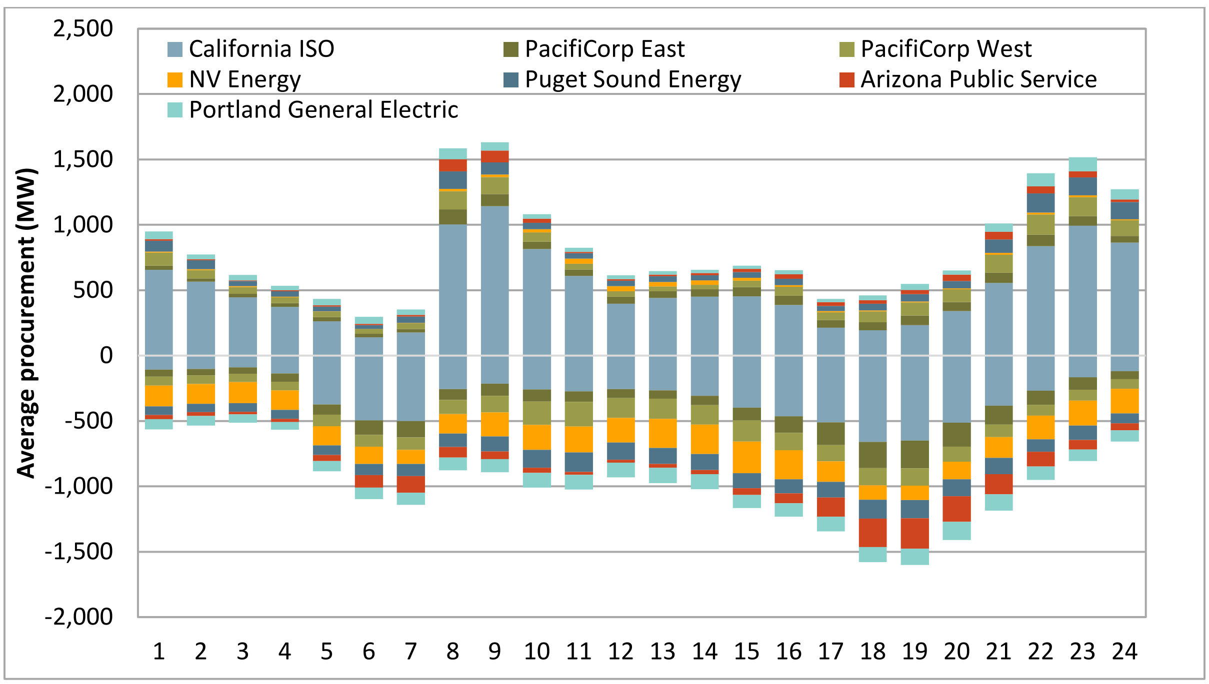
In the downward direction, positive system-level flexible ramping prices were observed very infrequently in the 15-minute market, during less than 0.1 percent of intervals.

In the 5-minute market, system-level flexible ramping prices were positive during less than 0.3 percent of intervals in both the upward and downward direction. This is because the quantity of flexible ramping capacity demanded in the 5-minute market was significantly lower than in the 15-minute market.

Figure 1.17 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the fourth quarter. This capacity may have been procured to satisfy system-level demand, area-specific demand, or both. The different colors indicate the area capacity was procured from. The positive bars show procurement for upward flexible ramping capacity, and the negative bars show procurement for downward flexible ramping capacity. The hourly procurement profile is similar to the profile of the system-level demand curves, and reflects that most of the flexible ramping capacity was procured to meet system-level uncertainty needs.

Overall, the market procured an hourly average of about 820 MW of upward capacity and 1,000 MW of downward capacity in the 15-minute market during the fourth quarter. Compared to the third quarter, this represents an increase in downward capacity and about the same amount in upward capacity. The total hourly average quantity of flexible ramping capacity procured in the 5-minute market was about 230 MW in the upward direction and 240 MW in the downward direction.

Figure 1.17 Hourly average flexible ramping capacity procurement in 15-minute market (October – December)

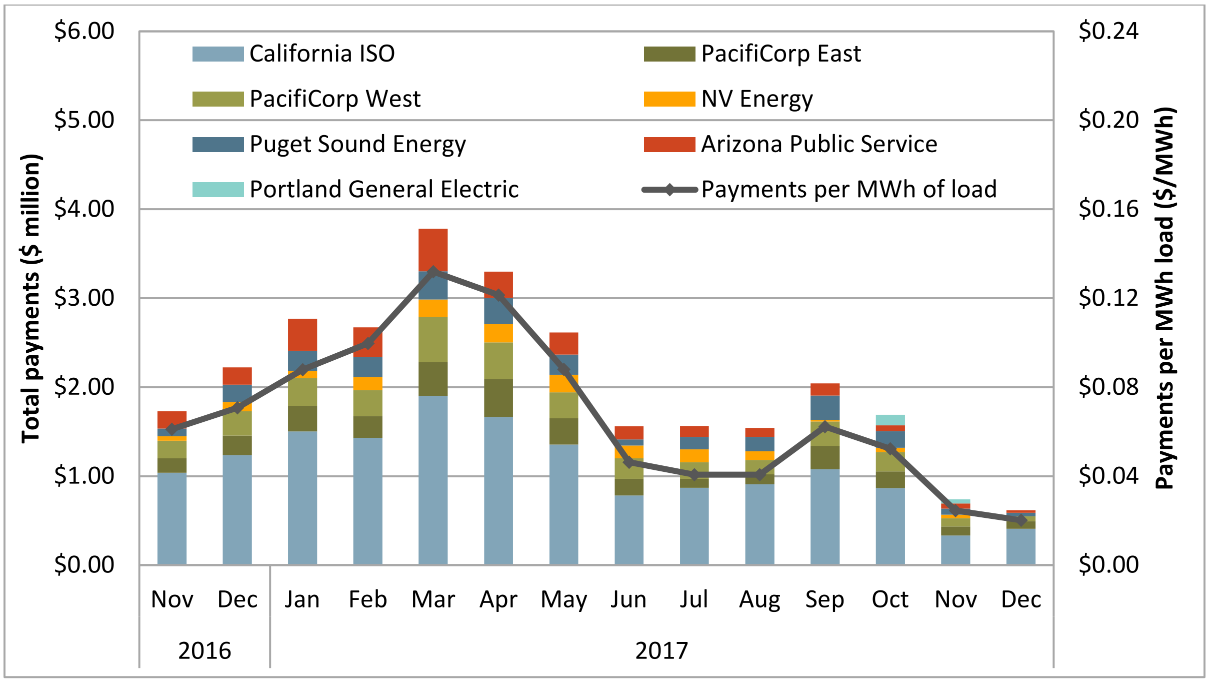


Flexible ramping procurement costs

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.[29]

Figure 1.18 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month and balancing area.[30] 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.

Figure 1.18 Monthly flexible ramping payments by balancing area



As shown in Figure 1.18, total payments to generators for flexible ramping capacity decreased during the fourth quarter to about $3 million, compared to about $5 million during the previous quarter. This was in part driven by the lower frequency of non-zero system flexible ramping shadow prices.

Total payments to NV Energy and Portland General Electric for flexible ramping capacity during December were slightly negative, which was the first time any balancing area received negative payments. Flexible ramping capacity is settled as the sum of: (1) the 15-minute market uncertainty award times the combined system and area-specific 15-minute market shadow price, and (2) the *incremental* 5-minute market uncertainty award times the combined system and area-specific 5-minute market shadow price. A negative incremental award from the 15-minute market to the 5-minute

[29] 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.

[30] 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.

market with a high 5-minute market flexible ramping shadow price contributed to the negative net payments for the month.

During the fourth quarter, payments per megawatt-hour of load remained low.[31] Average net payments per megawatt-hour of load during the fourth quarter were about $0.03/MWh, a decrease from about $0.08/MWh during the third quarter.

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

2 Energy imbalance market

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

- Portland General Electric became a participant in the energy imbalance market on October 1. Prices in Portland General Electric were often lower than prices in the ISO because of limited transmission from PacifiCorp West and Portland General Electric to the ISO.
- 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, particularly during hours ending 17 through 21. This was often the result when one or more of these areas failed the flexible ramping sufficiency test or an area's export limits bound when prices in the surrounding balancing areas were high.
- Valid under-supply and over-supply infeasibilities were infrequent in the energy imbalance market. Valid under-supply infeasibilities occurred during less than 0.3 percent of intervals in the 15-minute and 5-minute markets in each of the energy imbalance market balancing areas. Valid over-supply infeasibilities occurred during around 0.9 percent of real-time intervals in Arizona Public Service and in less than 0.1 percent of intervals in each of the other energy imbalance market balancing areas.
- Balancing areas failed the flexible ramping sufficiency test relatively infrequently during the fourth quarter, during less than 3 percent of hours, for each area and direction. NV Energy failed the upward sufficiency test less frequently during only about 2 percent of hours during the quarter, compared to about 5 percent of hours in the previous quarter.
- The ISO, Puget Sound Energy, Arizona Public Service, and Portland General Electric were net importers during the quarter. The PacifiCorp areas and NV Energy tended to export energy during the quarter.
- Load adjustments were typically positive in PacifiCorp East, Portland General Electric and Arizona Public Service, and negative in Puget Sound Energy. PacifiCorp East, PacifiCorp West, NV Energy and Puget Sound Energy entered load adjustments significantly more frequently in the 5-minute market than in the 15-minute market during the fourth quarter.

2.1 Energy imbalance market performance

Energy imbalance market prices

Portland General Electric became a participant in the energy imbalance market on October 1. Prices in Portland General Electric were often lower than prices in the ISO because of limited transmission from PacifiCorp West and Portland General Electric to the ISO. This resulted in local resources setting the price in a combined PacifiCorp West, Puget Sound Energy and Portland General Electric region during many intervals.

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, particularly during hours ending 17 through 21. When there was price separation, it was often when one or more of these areas failed the flexible ramping sufficiency test or an area's export limits bound during periods when prices in the surrounding balancing areas were high.

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 was the result of several days when energy imbalance market transfers out of PacifiCorp East reached upper limits during these hours. PacifiCorp West, Puget Sound Energy, and Portland General Electric prices were often lower than those in the ISO because of inexpensive generation in these areas and relatively little transfer capability into 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 fourth quarter, valid under-supply and over-supply infeasibilities were infrequent. Valid under-supply infeasibilities occurred during less than 0.3 percent of intervals in the 15-minute and 5-minute markets in each of the energy imbalance market balancing areas. Valid over-supply infeasibilities occurred during around 0.9 percent of real-time intervals in Arizona Public Service and in less than 0.1 percent of intervals in each of the other balancing areas.

Figure 2.1 Hourly 15-minute market prices (October – December)

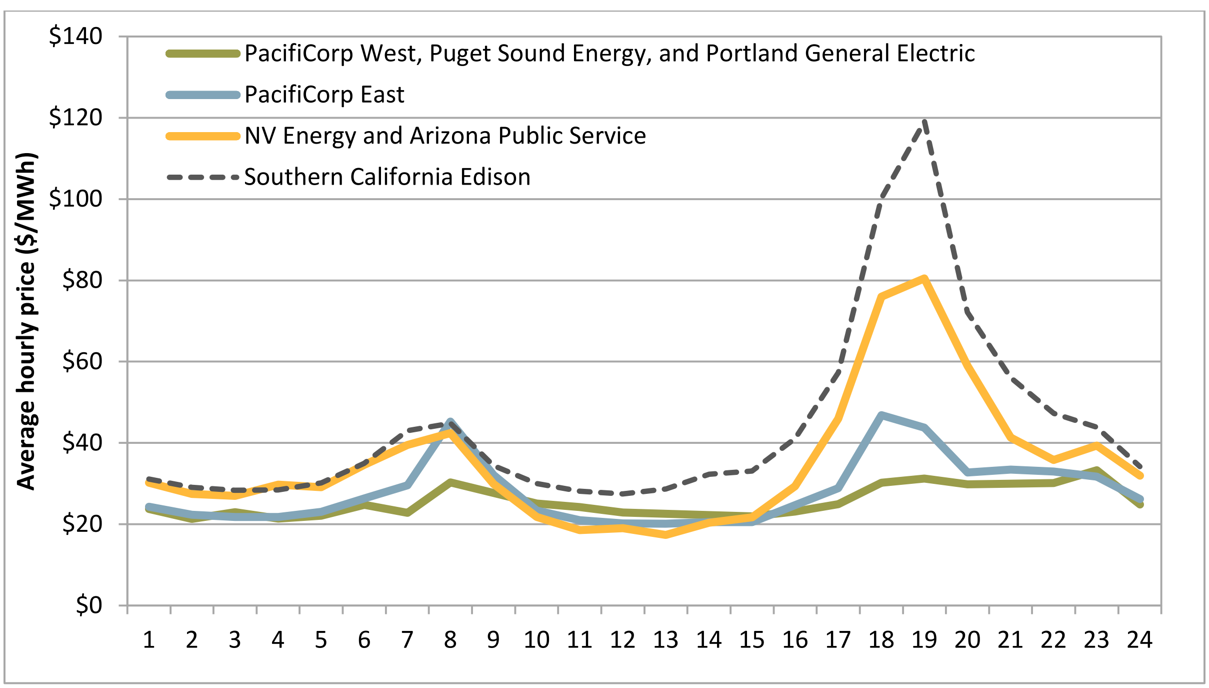
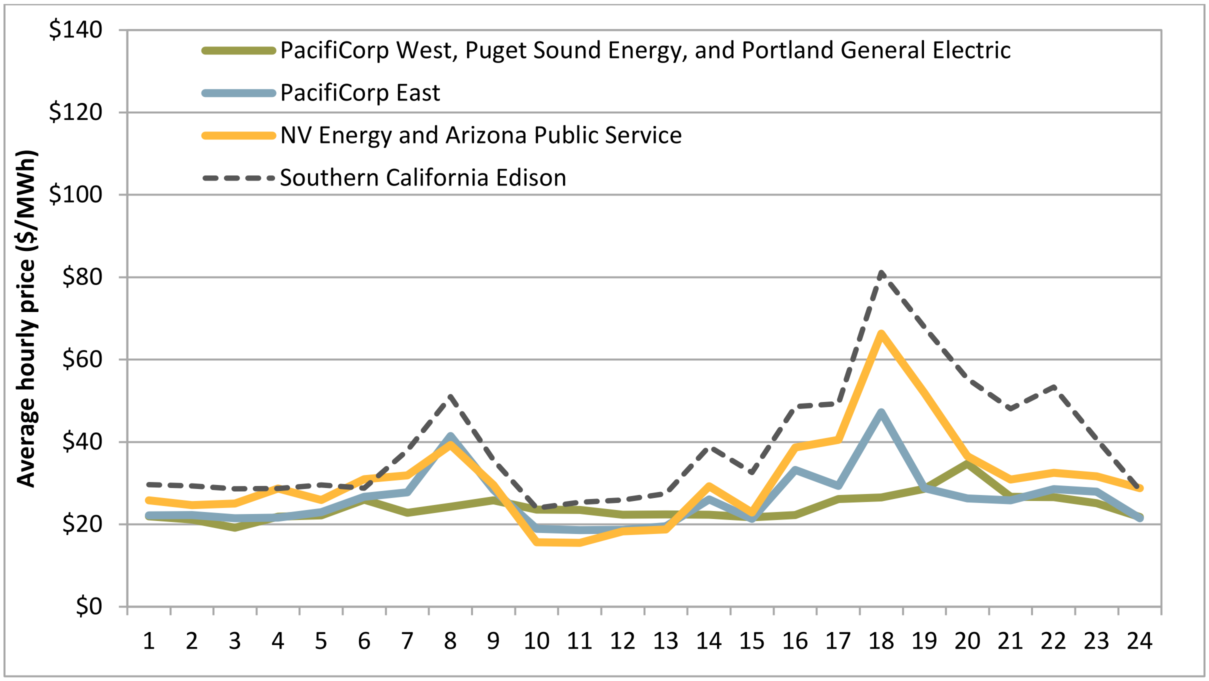


Figure 2.2 Hourly 5-minute market prices (October – December)



2.2 Flexible ramping sufficiency test

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

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

Sufficiency test results

Limiting transfers can impact the frequency of power balance constraint relaxations and, thus, price separation across balancing areas. The majority of power balance constraint relaxations during the quarter, across all of the energy imbalance market balancing areas, occurred during hours when the

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

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

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

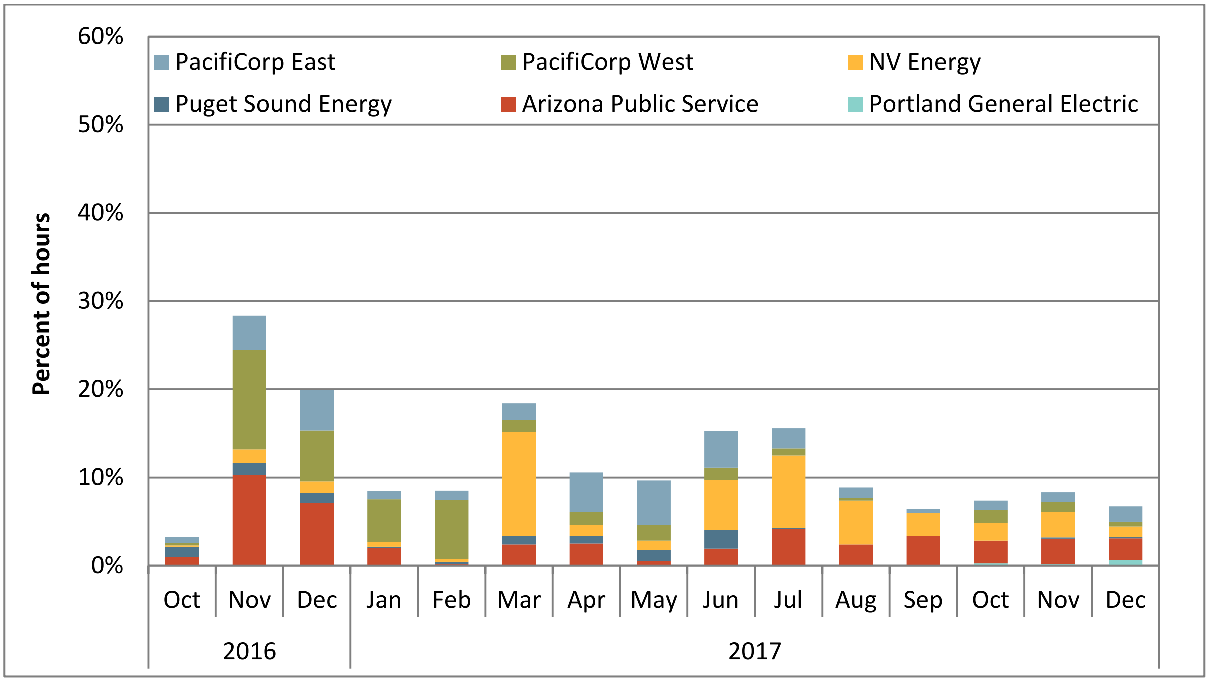


Figure 2.4 Frequency of downward failed sufficiency tests by month

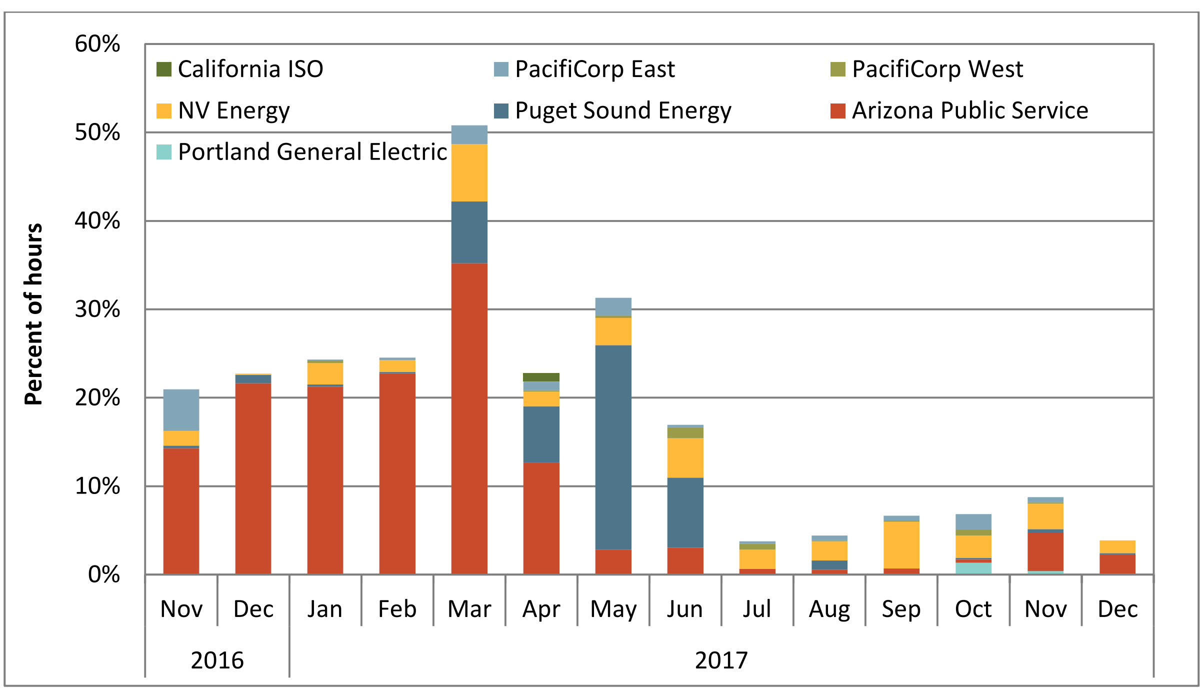


Figure 2.3 and Figure 2.4 show the average percent of hours in which an energy imbalance market area failed the sufficiency test in the upward and downward direction, respectively. Overall, all areas continued to fail the test relatively infrequently during the fourth quarter, during less than 3 percent of hours for each area and direction. NV Energy failed the upward sufficiency test most frequently during the quarter, during about 2 percent of hours, compared to about 5 percent of hours in the previous quarter.

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.[34]

Table 2.1 shows the percentage of intervals that each energy imbalance market area and the ISO either exported or imported energy on net and the associated average quantity of imports and exports in the 5-minute market. Table 2.2 shows estimates for how frequently congestion occurred between any energy imbalance area and the ISO.[35] These tables show that scheduled transfers typically flowed into the ISO and Portland General Electric and energy typically flowed out of the PacifiCorp areas and NV Energy.

Table 2.1 shows that the ISO, Puget Sound Energy, Arizona Public Service and Portland General Electric were net importers during the quarter, and that the ISO and Portland General Electric imported more frequently than they exported and tended to transfer significantly greater quantities of energy while importing than while exporting. The PacifiCorp areas and NV Energy tended to export energy during the quarter. High loads and less expensive generation available outside of the ISO during the quarter made it economic for the ISO to import more energy from the energy imbalance market areas.

Table 2.2 shows estimates for congestion. 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. Historically, there has been frequent congestion from the PacifiCorp West and Puget Sound Energy areas in the direction of the ISO. The frequency observed this quarter is consistent with these values.

Congestion for exports from PacifiCorp West to the ISO caused 5-minute prices in PacifiCorp West, Puget Sound Energy, and Portland General Electric to differ frequently from system prices and prices in the other energy imbalance market areas. When system prices were high, constraints out of PacifiCorp

[34] In prior quarterly reports, DMM has shown real-time energy flows within the energy imbalance market. These figures show real-time energy market flows net of all base schedules.

[35] This table removes all intervals when congestion could be caused by greenhouse gas compliance costs, which are usually about $6/MWh.

West into the ISO and PacifiCorp East bound frequently and caused price separation between the PacifiCorp West, Puget Sound Energy, and Portland General Electric areas and prices in the other energy imbalance market areas.

Estimates for congestion from the other energy imbalance areas, including PacifiCorp East, NV Energy and Arizona Public Service, toward the ISO was comparable to prior quarters. Table 2.2 also shows that there continued to be little congestion from the ISO to other areas in the energy imbalance market. In fact, there continues to be almost no congestion from the ISO to PacifiCorp East, NV Energy, or Arizona Public Service.

Table 2.1 Average net energy imbalance market transfer (October – December)

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	68%	-286	32%	165
PacifiCorp East	39%	-89	61%	129
PacifiCorp West	31%	-43	69%	121
NV Energy	33%	-43	66%	122
Puget Sound Energy	53%	-62	46%	48
Arizona Public Service	49%	-121	50%	101
Portland General	62%	-79	38%	37

Table 2.2 Estimated congestion status and flows in EIM (October – December)[36]

	Congested toward ISO	Congested from ISO
PacifiCorp East	16%	1%
PacifiCorp West	37%	14%
NV Energy	7%	1%
Puget Sound Energy	37%	15%
Arizona Public Service	8%	2%
Portland General Electric	37%	14%

Different areas in the energy imbalance market exhibited different hourly transfer patterns. Generally, the ISO exported energy, or imported less energy, during the peak solar hours of the day and imported during other hours. Energy transfers in each area were driven by the system resource mix and relative prices during these times of the day.

Figure 2.5 through Figure 2.7 show details about how energy transfers moved between NV Energy, Arizona Public Service, and PacifiCorp West, respectively, and neighboring areas on an hourly basis

[36] Table 2.2 shows 5-minute market congestion between PacifiCorp West and the ISO inclusive of the transfer constraint and the constraint governing flows into the ISO on the Malin 500 kV constraint. These 5-minute constraints account for the dynamic limits imposed on transfers between the ISO and PacifiCorp West.

during the quarter. Figure 2.5 shows that NV Energy typically was an exporter during almost all hours of the day. During the midday peak solar hours NV Energy received imports from the ISO, and exported to the ISO during almost all other hours of the day. NV Energy also exported energy to PacifiCorp East during almost all hours of the day.

Figure 2.6 shows similar information for Arizona Public Service. This chart shows that Arizona Public Service was a net importer during the middle of the day, and a net exporter during early morning and late evening hours of the day. In the middle of the day, Arizona Public Service imported from both the ISO and PacifiCorp East, and during the rest of the day exported energy to the ISO and imported energy from PacifiCorp East, on average.

Figure 2.7 shows average transfers between PacifiCorp West and the neighboring areas: Portland General Electric, Puget Sound Energy, PacifiCorp East, and the ISO. This figure shows that PacifiCorp West was generally a net exporter during almost all hours of the day. On average during all hours of the day, PacifiCorp West tended to export energy to the ISO and import from PacifiCorp East. Transfers from PacifiCorp East are a byproduct of the transfer limits imposed between the two areas, which specify that transfers only occur in the east-to-west direction between these two areas. This figure also shows that PacifiCorp West had a mix of imports and exports from Puget Sound Energy and Portland General Electric during the day.

Figure 2.5 Average hourly imports into NV Energy (October – December)

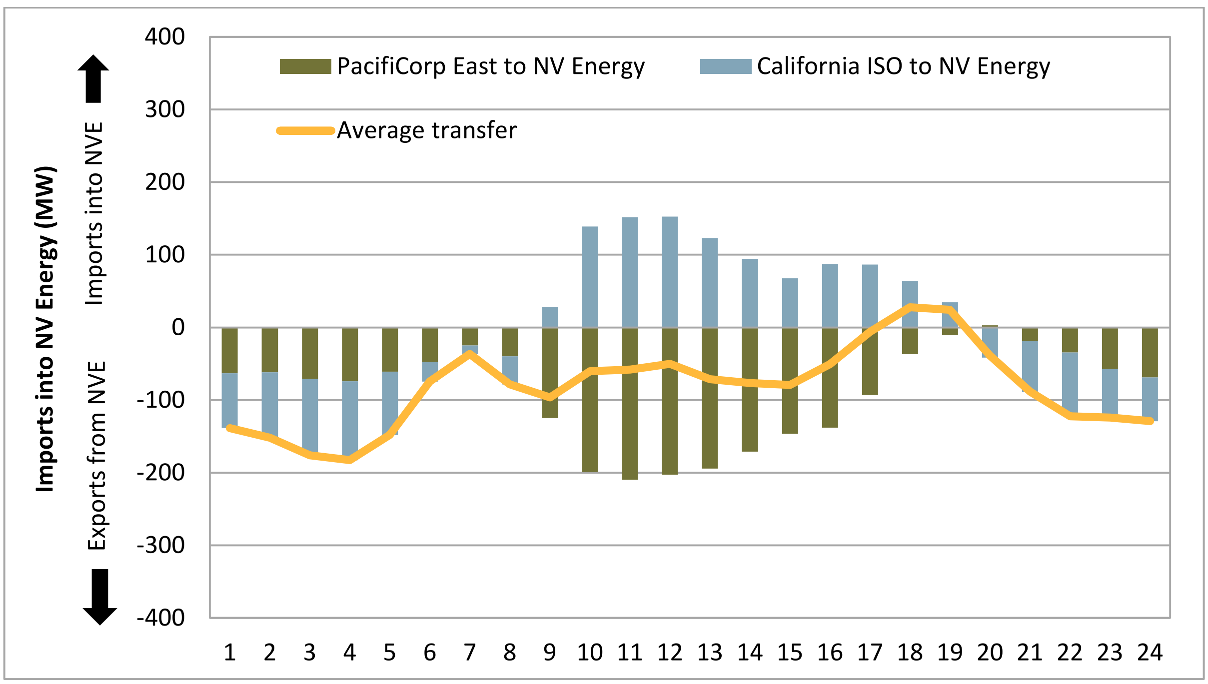


Figure 2.6 Average hourly imports into Arizona Public Service (October – December)

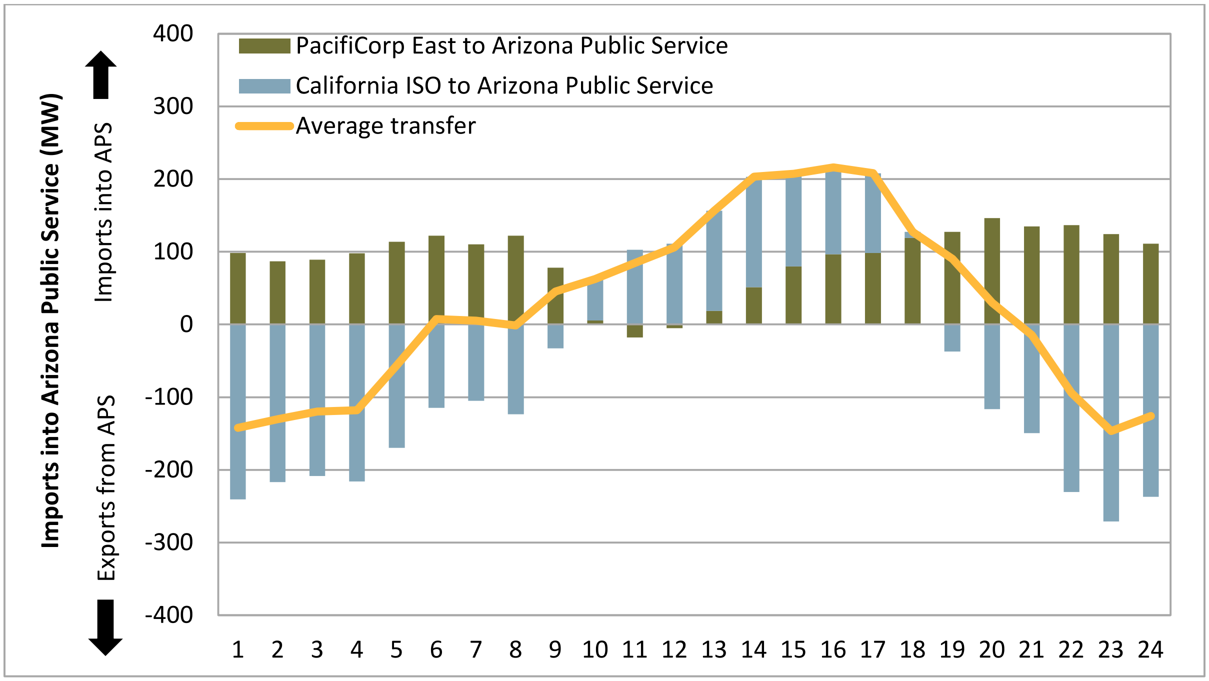
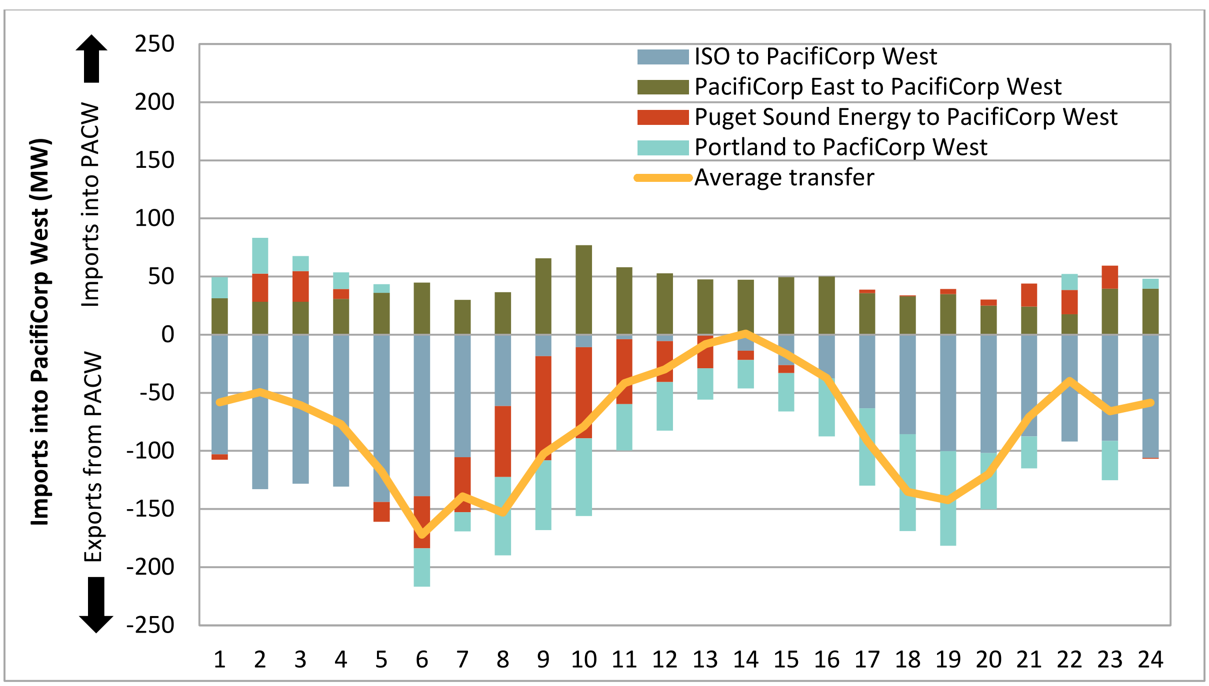


Figure 2.7 Average hourly imports into PacifiCorp West (October – December)



2.4 Load adjustments

Table 2.3 summarizes the average frequency and size of positive and negative load forecast adjustments for the energy imbalance market areas during the fourth 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 and Portland General Electric, while load adjustments were frequently negative in Puget Sound Energy. Of note, PacifiCorp East, PacifiCorp West, NV Energy, and Puget Sound Energy entered load adjustments significantly more frequently in the 5-minute market than in the 15-minute market during the fourth quarter.

Table 2.3 also includes the average absolute positive and negative load adjustment as a percent of area load. 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 2.3 Average frequency and size of load adjustments (October - December)

	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	42%	473	1.8%	6%	-297	1.3%	180
5-minute market	30%	251	1.0%	36%	-292	1.2%	-29
PacifiCorp East							
15-minute market	9%	94	1.9%	2%	-98	2.0%	6
5-minute market	31%	85	1.7%	19%	-76	1.6%	12
PacifiCorp West							
15-minute market	4%	55	2.5%	1%	-52	2.1%	2
5-minute market	16%	47	2.1%	12%	-40	1.7%	3
NV Energy							
15-minute market	10%	82	2.1%	0%	-125	3.6%	8
5-minute market	26%	65	1.7%	26%	-74	2.2%	-2
Puget Sound Energy							
15-minute market	3%	37	1.2%	50%	-48	1.6%	-23
5-minute market	4%	38	1.3%	65%	-50	1.7%	-31
Arizona Public Service							
15-minute market	87%	133	4.5%	3%	-65	2.4%	115
5-minute market	87%	133	4.5%	2%	-68	2.5%	115
Portland General Electric							
15-minute market	23%	30	1.2%	4%	-33	1.4%	6
5-minute market	31%	30	1.2%	5%	-36	1.5%	7

3 Special issues

This section provides information about the following special issues:

- The total quantity of the wind and solar generation dispatched down increased significantly from the previous year. This was particularly true between February and April where wind and solar output in the ISO was reduced by around 3 to 4 percent each month from the total forecast output. In the energy imbalance market, the quantity of energy from wind and solar resources dispatched down increased significantly during the fourth quarter.
- Aliso gas price scalars were activated during two periods in the fourth quarter. In both cases, prevailing prices for same-day gas trades were significantly higher than the gas prices used in the real-time market before but not after activation. Activation of the scalars does not appear to significantly impact the merit order of commitment cost dispatch.
- DMM estimates that excess bid cost recovery payments resulting from Aliso gas price scalars were about $5.5 million in 2017. In the fourth quarter, about $1 million of excess bid cost recovery was accrued in December, mostly during Southern California wildfires.
- The ISO made annual capacity procurement designations for 2018 in response to sub-area deficiencies. This is the first time the ISO has made such procurement for an annual period. Designations were made for three resources for over 500 MW of capacity in the San Diego Gas and Electric area and more than 500 MW of capacity in the Pacific Gas and Electric area. The estimated cost of these designations is about $80 million.
- The ISO procured the Metcalf resource (593 MW) through a reliability must-run procurement for 2018. This resource has a fixed revenue requirement of about $72 million for the year. Metcalf owners elected to operate the resource under condition 2, under which the resource will only participate in the market when the ISO issues a reliability must-run dispatch.
- Four capacity procurement mechanism designations occurred this quarter via the intra-monthly process. Each designation was made to one of the Mandalay resources. In late October one designation was triggered by an exceptional dispatch for relief on a local line in the San Diego Gas and Electric area. Three additional designations were made to manage potential local reliability while wildfires were impacting Southern California.
- DMM notes that the use of net import capability and net export capability in the 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. DMM recommends that the ISO reevaluate this interaction in a manner that does not impact the independence of consecutive hourly sufficiency tests.

3.1 Wind and solar downward dispatch and curtailment

When the amount of supply on-line exceeds demand, the market dispatches generation down. Generally, generators are dispatched down in merit order from highest bid to lowest. As with typical incremental dispatch, the last unit dispatched sets the system price and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, wind and solar resources, which generally have very low or negative bids, are dispatched down. The condition in which these resources are dispatched down is referred to as *oversupply*. If the supply of bids to decrease energy is completely exhausted in the real-time market, the software relaxes the power balance constraint for excess energy up to 30 MW. If scheduled supply exceeds demand by more than 30 MW, self-scheduled generation can be curtailed including self-scheduled wind and solar generation.

Renewable output can be reduced by dispatching renewable generation down or by curtailing self-scheduled renewable generation. Figure 3.1 shows the total quantity of wind and solar in the ISO that was dispatched down economically as well as curtailments of self-scheduled wind and solar generation. The figure also includes the total reduction of wind and solar as a percent of total wind and solar 5-minute forecasts (yellow line on right axis).

Figure 3.1 shows that nearly all of the reduction in wind and solar output during 2017 was the result of economic downward dispatches rather than self-scheduled curtailments. The majority of renewable generation in the ISO dispatched down were solar resources, rather than wind resources, primarily because market participants bid more economic downward capacity for these resources. Because of increased frequency of negative real-time prices during the spring of 2017, the total quantity of the wind and solar generation dispatched down increased significantly from the previous year. This was particularly true between February and April where wind and solar output was reduced by around 3 to 4 percent in each month from the total forecast output.

Figure 3.1 also shows the amount of economic downward dispatch to energy imbalance market wind and solar resources. As shown in the figure, the quantity of energy from wind and solar resources dispatched down increased significantly during the fourth quarter in the energy imbalance market. Nearly all renewable energy dispatched down in the energy imbalance market was from PacifiCorp East wind resources. Specifically, transmission limits between Wyoming wind generation and the surrounding areas were lower in October and November resulting in increased congestion and downward dispatch during these months.

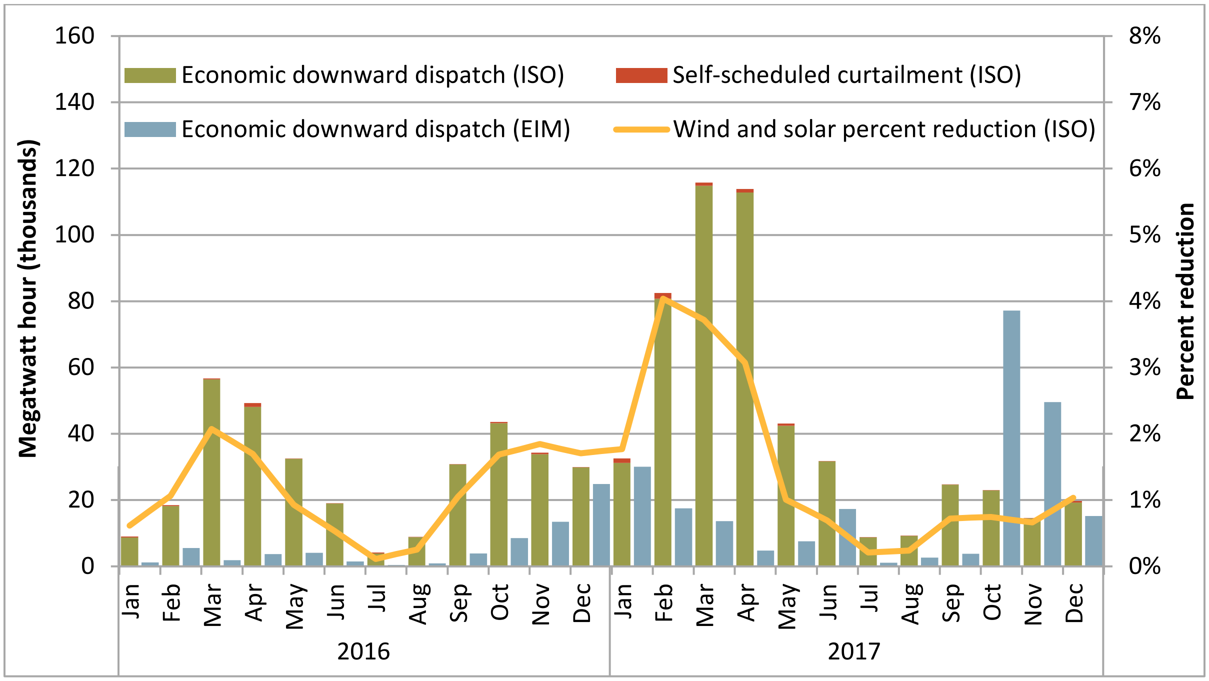
In 2017, the ISO began posting daily and monthly curtailment amounts on the ISO website.[37] Reported quantities describe different measurements than the curtailment amounts reported by DMM in Figure 3.1. The ISO's historical amounts account for upward ramping limitations on wind and solar resources within each 5-minute interval. For example, with ramping limitations it may not be feasible for a renewable resource to be dispatched back to its forecast output during a single interval after several consecutive intervals of downward dispatch.

The ISO calculates curtailment as the difference between the maximum ramp-feasible dispatch level and the 5-minute market dispatch during any interval. DMM's analysis of downward dispatch accounts for the total dispatch below forecast. This reflects the total reduction in wind and solar generation as a result of oversupply conditions in the market. The ISO announced their intention to switch methodologies for the curtailment totals beginning with values posted for January 2018.

In addition, the ISO's published figures included energy imbalance market resources in the total curtailment amounts prior to February 7, 2017, but not after this date. Figure 3.1 distinguishes energy imbalance market resources in the blue shaded bars.

[37] For further information on these amounts, see: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

Figure 3.1 Reduction of wind and solar generation by month



3.2 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. 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. These tools were available to operators beginning June 2, 2016.[38] 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.[39]

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

39 *FERC Order on Tariff Revisions - Aliso Canyon Gas-Electric Coordination Enhancements Phase 3,* November 28, 2017:

However, the December 15, 2017, FERC Order extended the ISO's previously held authority to utilize the gas constraints for one additional year.[40]

In the fourth quarter of 2017, the ISO did not enforce any of the gas constraints in the market. Previously, the ISO enforced these constraints in the real-time market on three occasions: January 23-January 26, 2017, some hours on August 3, 2017, and a few intervals on August 4, 2017.

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.[41] 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.[42]

These adders were available in the real-time market for three days in October and during all but the first week of December. The ISO used the adders in the market from October 23 through October 25 in response to high temperatures and supply disruptions caused by pipeline outages in Southern California.[43]

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.[44] These concerns, in addition to the Southern California wildfires, caused the ISO to

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http://www.caiso.com/Documents/Nov28_2017_Order_TariffRevisions-AlisoCanyonGas-ElectricCoordinationEnhancementsPhase3_ER17-2568.pdf

40 *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

41 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.

42 *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.

43 *Market Notices - Adjustment of Gas Price Index Scaling Factors,* October 22, 25 2017: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactorsEffective102317.html http://www.caiso.com/Documents/Adjustment-GasPriceIndexScalingFactorsEffective102617.html

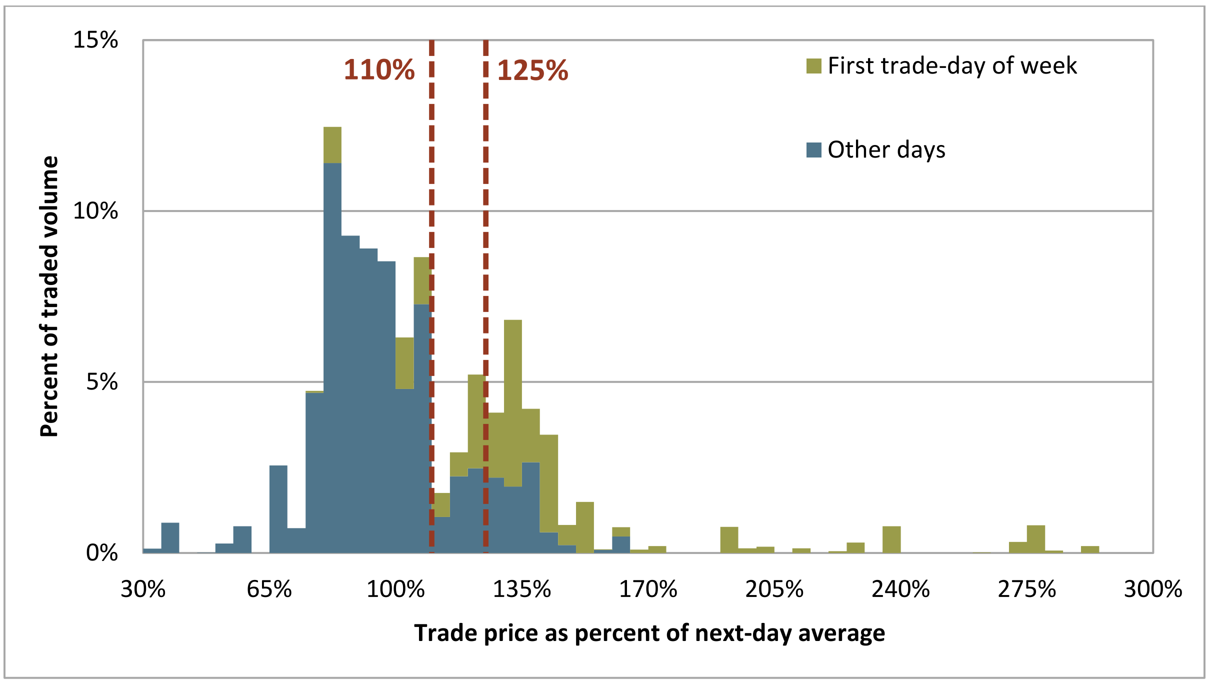
44 *Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement,* November 28, 2017: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221863_20171128T103411_Aliso_Canyon_Winter_Risk_Assesment_Technical_Report_201718_Supp.pdf

reinstate the gas adders on December 7, 2017. The adders remained in place until January 31, 2018.[45], [46]

Figure 3.2 shows Intercontinental Exchange (ICE) same-day natural gas trade prices for SoCal Citygate compared to the next-day average price from October through December 2017. Planned and unplanned natural gas pipeline outages, local natural gas storage use restrictions, and recent wildfires caused high next-day prices as well as significant same-day price volatility on some days during the fourth quarter.

About 10 percent of traded volume at SoCal Citygate exceeded the normal 10 percent adder and 26 percent of the traded volume exceeded the 25 percent adder. Figure 3.2 also shows that the most extreme same-day prices relative to next-day averages occurred on days that were the first trading day of the week, which was typically a Monday. These are shown as green bars on the chart.

Figure 3.2 Same-day trade prices compared to next-day index (October – December)



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

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

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

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 3.3 and Figure 3.4 show a comparison between SoCal Citygate next-day index and same-day price distribution before and after 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 3.3, gas price scalars were raised to 175 percent and 125 percent from October 23 through October 25, 2017, due to anticipated days of high temperatures and potential for gas curtailments in Southern California. In this case, same-day gas prices rose sharply on October 23, 2017, averaging about 260 percent of the next-day gas price index. 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 October 24 and October 25, these scalars then caused gas prices used in the real-time market to be two to three times greater than actual gas prices in the same-day market.

On December 7, the gas price scalars were activated for the second time in the fourth quarter of 2017. As shown in Figure 3.4, on each of the days the scalars were active in December, the gas price used in the real-time commitment costs was much higher than the observed same-day gas prices on that day.

Under the ISO's current process, gas limitations occurring during any point of an operating day cannot be reflected in scalars applied to the real-time market until the following operating day. In December, prevailing prices for same-day gas trades were significantly higher than the index used in the real-time market on the trade day prior to the scalars' activation and significantly lower thereafter for the duration of the scalars' activation (specifically for commitment costs).

Figure 3.3 SoCal Citygate next-day index versus ICE same-day price distribution (October 19 – 27)

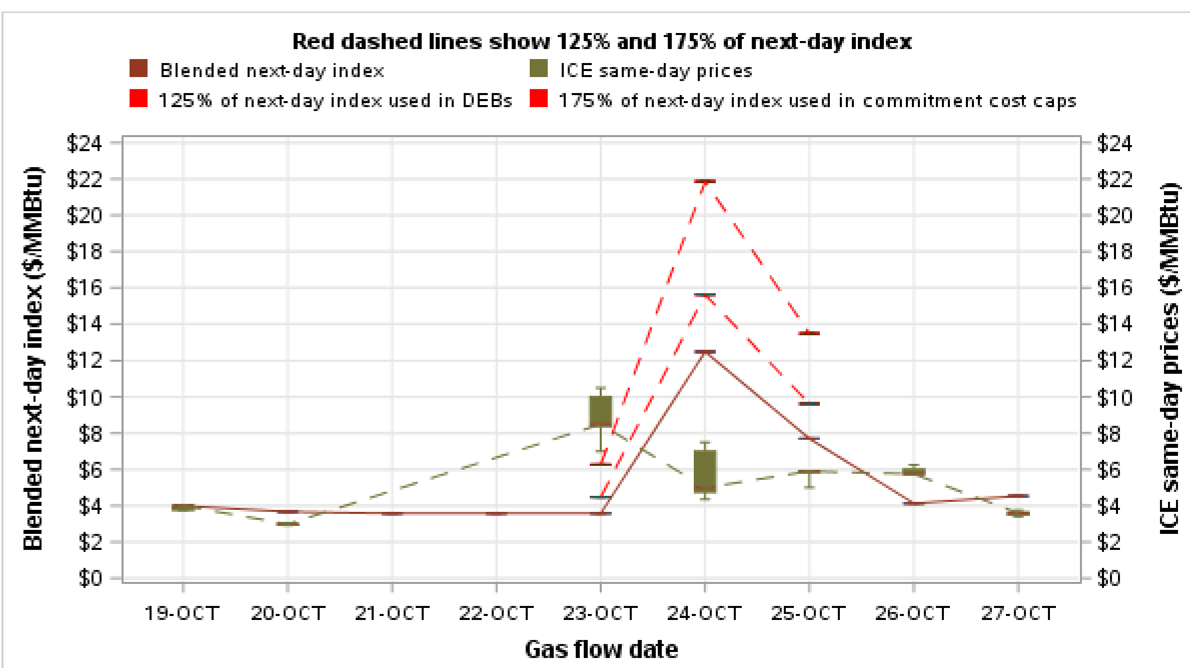
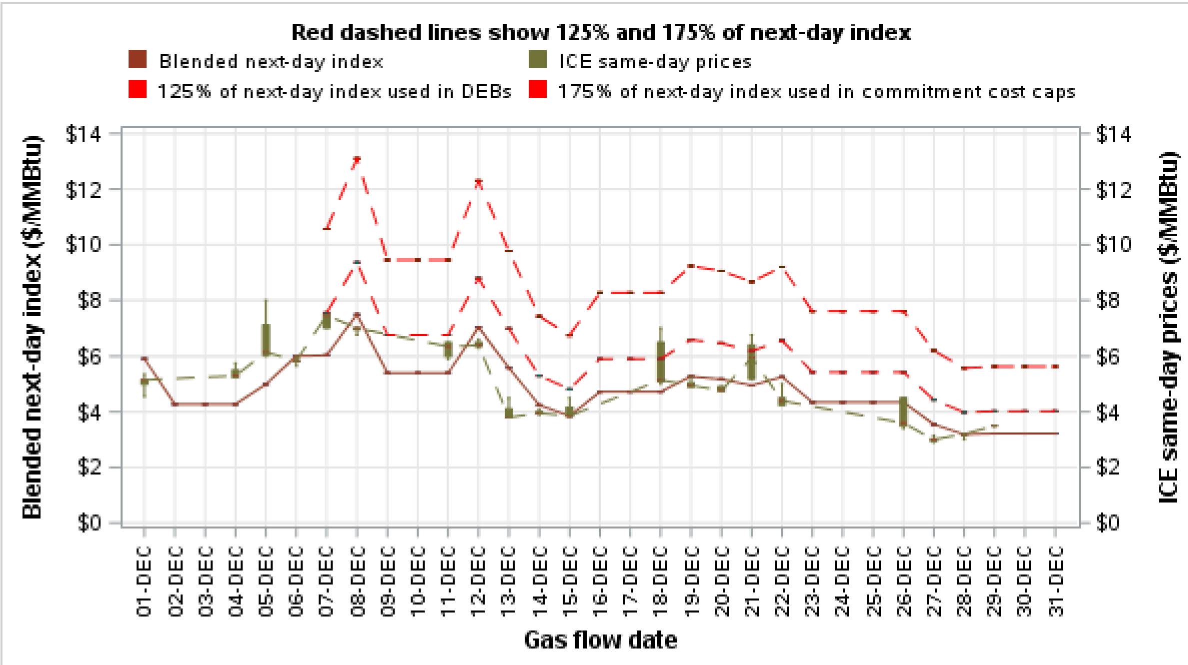


Figure 3.4 SoCal Citygate next-day index versus ICE same-day price distribution (December)



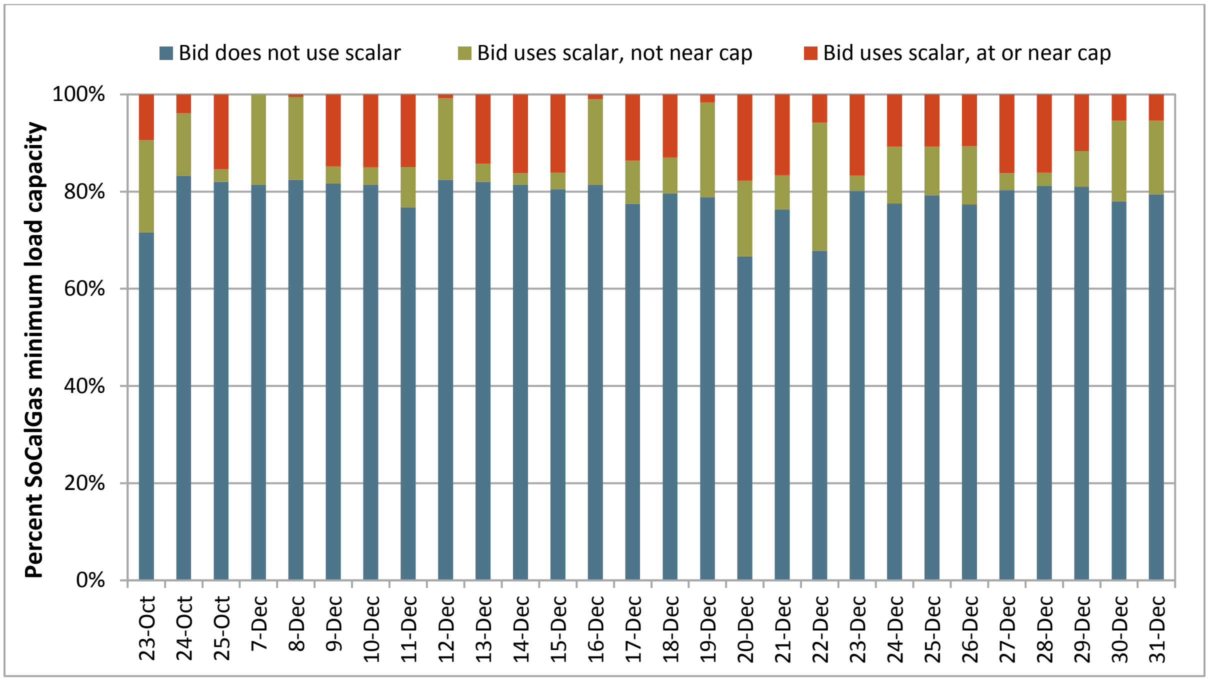
As mentioned earlier, the gas price scalars were also implemented to change the merit order of gas resources on SoCalGas system. This is achieved by using a 175 percent scalar in the gas price used in calculating the commitment cost caps for these resources. The resulting commitment costs are intended to be high enough to allow Southern California resources to be committed for local reliability needs and not for system needs. However, on the days with high temperatures and wildfires 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 additional scalar.

Figure 3.5 shows the bidding pattern of minimum load bids for all gas capacity [47] on the SoCalGas system during the days when the gas price scalars were active during the fourth quarter of 2017. 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 80 percent of capacity on the SoCalGas system did not use the additional headroom provided by the scalar for minimum load costs. 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.

[47] 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

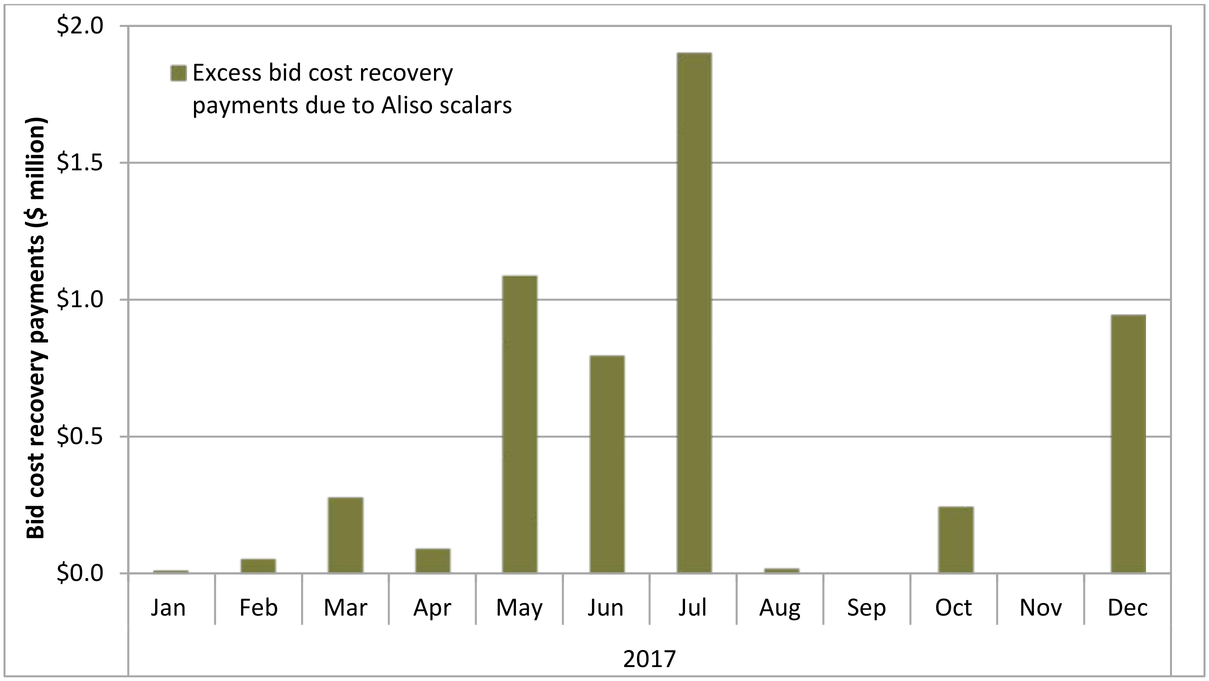


DMM estimates that activation of the gas price scalars in 2017 resulted in over $5 million in excess uplift payments to resources using the scalar. Figure 3.6 shows an estimate of monthly excess bid cost recovery payments made in the real-time market in 2017 due to the use of these scalars.[48] Total estimated payments in 2017 were about $5.5 million. In the fourth quarter, approximately $1 million of these payments were accrued in December, most of it during Southern California wildfires.

This analysis clearly 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.

[48] The gas price scalars were not active in September and November.

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

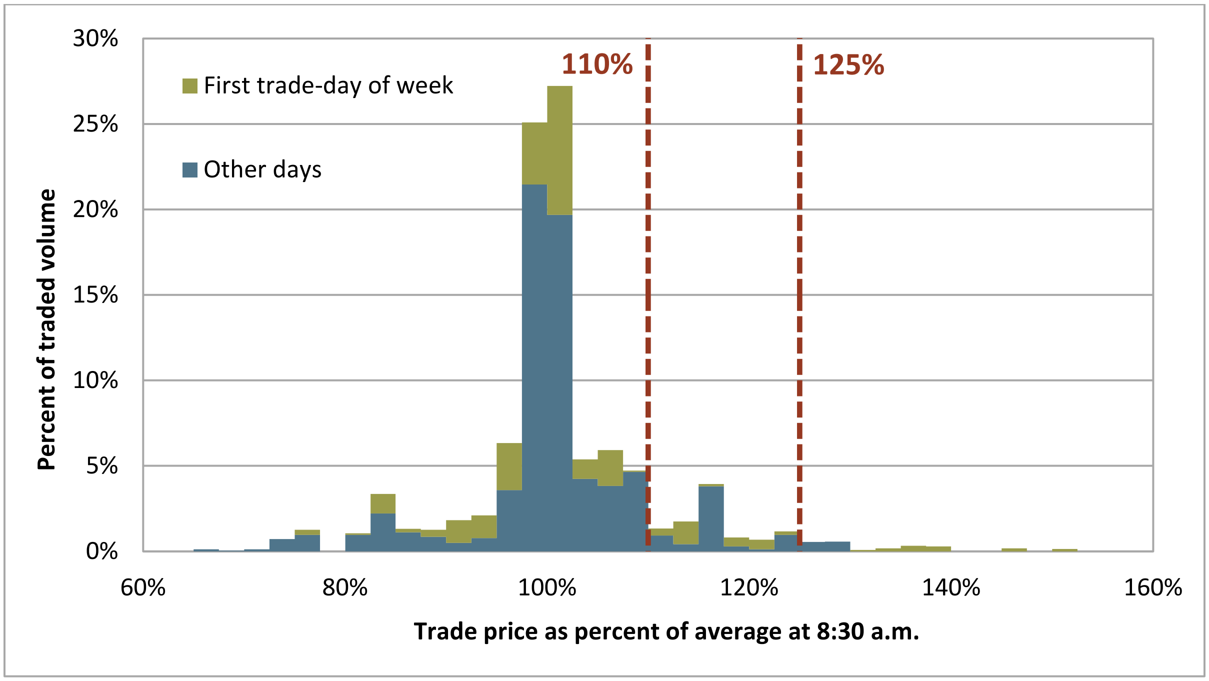


DMM continues to recommend that the ISO develop the ability to adjust gas prices used in the real-time market based on observed prices on ICE the morning of each operating day. This approach would closely align the gas price used in the ISO's real-time market with the actual costs for gas purchased in the same-day gas market.[49]

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. This figure shows that if the real-time gas prices were updated using an updated same-day price, then about 88 percent of the same-day trades would have been at or below the 10 percent adder at SoCal Citygate. About 9 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 that the most extreme same-day prices relative to updated same-day price occurred on 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.

[49] *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

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



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.[50]

Figure 3.8 and Figure 3.9 illustrate the benefit of using the updated natural gas price index in the fourth quarter of 2017. Figure 3.8 shows next-day trade prices reported on ICE for the SoCal Citygate during the fourth 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 16 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids. About 14 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 5 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

50 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 (Oct - Dec)

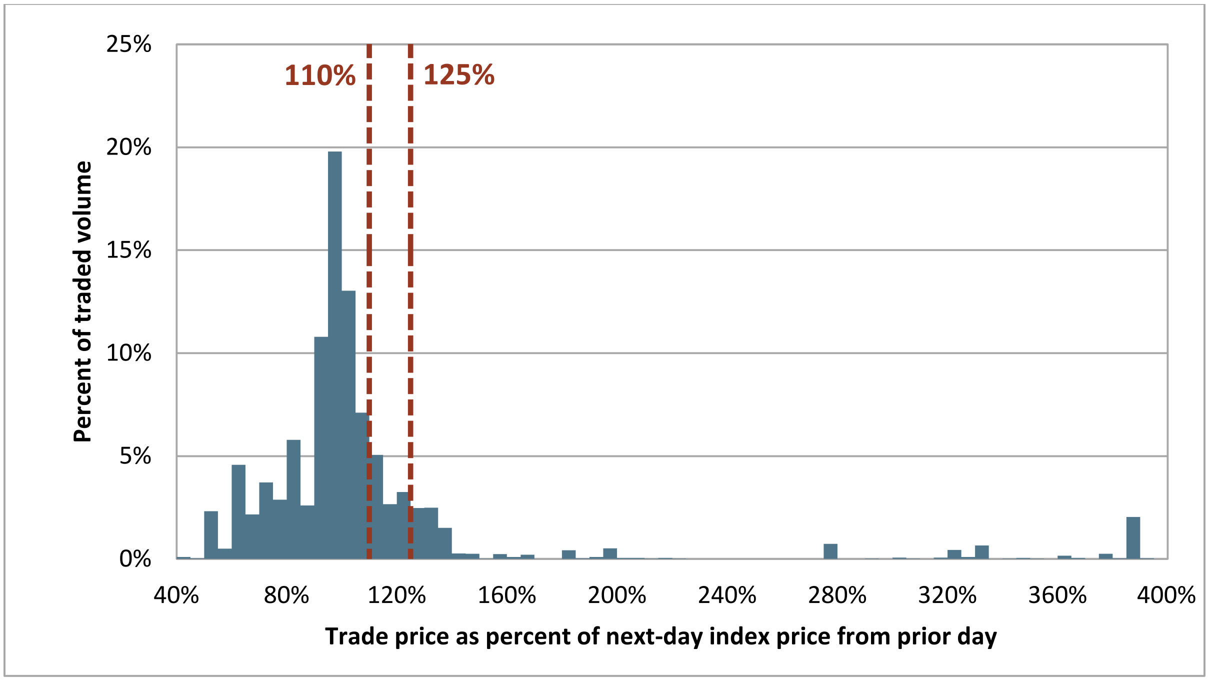
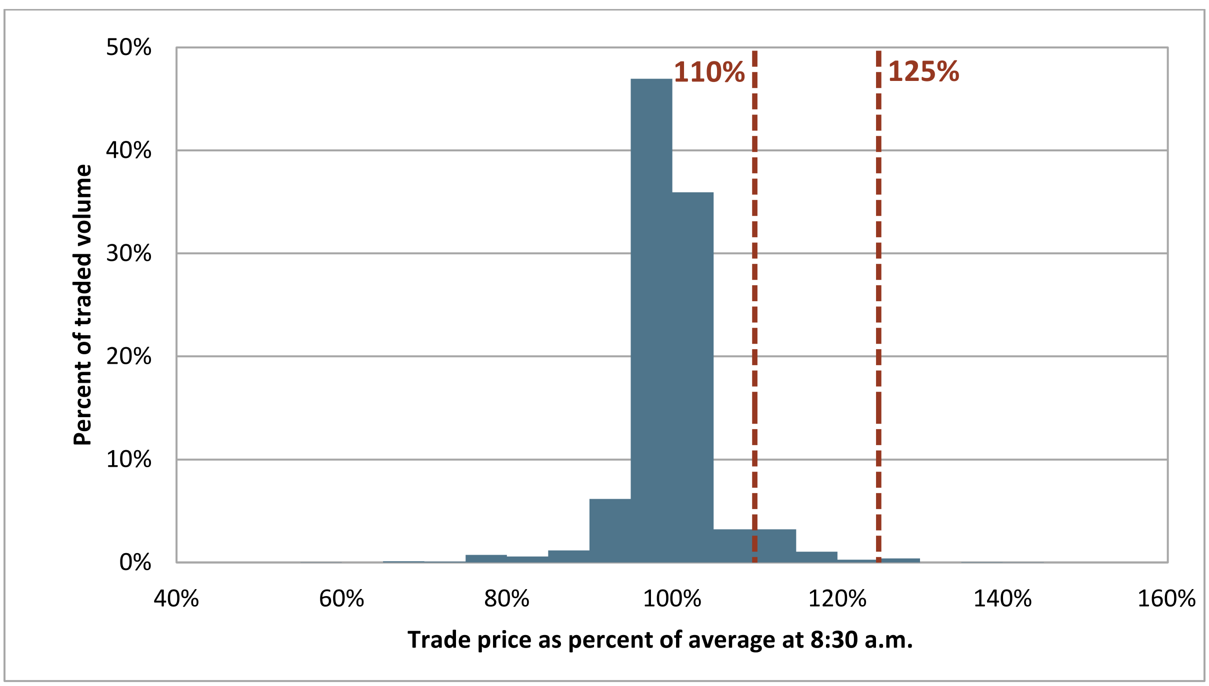


Figure 3.9 Next-day trade prices compared to updated next-day average price (Oct - Dec)



3.3 Resource adequacy and backstop capacity procurement

3.3.1 Capacity procurement mechanism

The capacity procurement mechanism within the ISO tariff provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism establishes a price at which the ISO can procure backstop capacity to meet local resource adequacy capacity requirements that are not met through bilateral purchases. This backstop authority also mitigates the potential exercise of locational market power by resources needed to meet local reliability requirements.[51]

There were multiple designations for capacity by the capacity procurement mechanism issued in the fourth quarter of 2017. The first occurred on October 24, and was triggered by an exceptional dispatch of the Mandalay 3 resource for system reliability needs, compensated at the $6.31/kW-month soft offer cap. On December 5, there were three additional capacity designations made for a total of 560 MW from the Mandalay 1, 2, and 3 resources. This capacity was needed to manage potential local reliability issues that resulted from the large Thomas wildfire in Southern California. Each of these resources was also compensated at the soft offer cap of $6.31/kW-month.

Several additional designations were declined by one scheduling coordinator. Scheduling coordinators that received exceptional dispatch instructions for capacity not designated through the resource adequacy process may decline a capacity procurement mechanism designation by contacting the ISO through appropriate channels within 24 hours. If the designation occurred during business hours, a scheduling coordinator may receive a courtesy notice of a designation via electronic mail. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation and reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

The total estimated cost of capacity procurement mechanism designations issued in the intra-monthly process during the fourth quarter was about $8 million. About $7 million of this cost was charged to the Southern California Edison transmission access charge (TAC) area and the remaining amount was allocated across the entire system.

Table 3.1 Intra-monthly capacity procurement mechanism costs

Resource	CPM designation (MW)	CPM deisgnation dates	Price ($/kW-mon)	Estimated cost ($ million)	Local capacity area	Exceptional dispatch CPM trigger
MANDALAY GEN STA. UNIT 3	119.4	10/24-11/22	$6.31	$0.73	System	Higher loads in real-time
MANDALAY GEN STA. UNIT 2	215	12/05-2/02	$6.31	$2.67	SCE	Local availability for wildfire
MANDALAY GEN STA. UNIT 1	215	12/05-2/02	$6.31	$2.67	SCE	Local availability for wildfire
MANDALAY GEN STA. UNIT 3	130	12/05-2/02	$6.31	$1.61	SCE	Local availability for wildfire

In addition to the intra-monthly designations, there were also three annual designations made for capacity via the capacity procurement mechanism during December for 2018. These are the first annual

51 Additional background on the capacity procurement mechanism may be found in the *Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 79-82: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

designations made by the capacity procurement mechanism, since initial implementation in 2016. Annual designations may vary by month and are determined as the aggregate of the deficiencies in all of the local areas within each transmission access charge area where the resource is located. The ISO believes that the capacities procured will be reduced for the Encina units.[52]

The annual designation for the Moss Landing resource was made through the competitive solicitation process at $6.19/kW-month, as bid by the scheduling coordinator, just below the soft offer cap. The Encina units will be compensated at the soft offer cap of $6.31/kW-month, as a result of bids generated by the ISO. At these prices and quantities the total estimated cost for this capacity procured is about $80 million for 2018.

Table 3.2 Annual capacity procurement mechanism costs

Resource	CPM designation (MW)	Price ($/kW-mon)	Estimated cost ($ million)	Local capacity area	Exceptional dispatch CPM trigger
MOSS LANDING POWER BLOCK 1	510	$6.19	$38.4	PG&E	Material sub-area deficiency
ENCINA UNIT 4	272	$6.31	$20.9	SDG&E	Material sub-area deficiency
ENCINA UNIT 5	273	$6.31	$21.0	SDG&E	Material sub-area deficiency

Proposed changes to the risk of retirement capacity procurement mechanism

On January 12, 2018, the ISO filed a tariff amendment with FERC to change the provisions for the risk of retirement (ROR) capacity procurement mechanism, to be effective April 13 and apply to the request window opening on May 1, 2018.[53] The risk of retirement capacity procurement mechanism is a tool that allows the ISO to procure resources needed for reliability that did not receive a resource adequacy award in the current or successive compliance year. The changes outlined by the ISO were designed to accomplish three goals:

1. Allow for designations earlier in the year so that resource owners have sufficient time to plan for potential changes related to a designation. The proposal allows for one window early in the year, where resource owners may receive designations for the current year and the following year, and one window prior to the end of the year where resource owners may receive designations for the following year.

2. Change the payments for designations from the $6.31/kW-month soft offer cap to payments inclusive of fixed cost recovery, similar to the payments made for the reliability must-run mechanism.

3. Require the resource to retire if it is not sold to another entity, does not receive a resource adequacy contract, or is not procured through an ISO backstop process.

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52 *Year Ahead Local CPM Designation Report*, December 22, 2019: http://www.caiso.com/Documents/December222017YearAheadLocalCPMDesignationReport.pdf.

53 *Tariff Amendment to Improve the Risk of Retirement Capacity Procurement Mechanism*, January 12, 2018: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14796643.

On February 2, 2018, DMM filed a protest to the ISO's filing citing that the change in payments would be unjust and unreasonable.[54] The proposed payments for the risk of retirement capacity procurement mechanism would allow for resources to recover all sunk fixed costs, including a 12.5 percent return on investment, and would allow resources to retain all profits from operating in the ISO or bilateral markets. This level of compensation would create market inefficiencies, and undermine the resource adequacy mechanism program and capacity procurement mechanism competitive solicitation process.

3.3.2 Reliability must-run mechanism

The ISO made a reliability must-run designation at the end of the year for the Metcalf Energy Center (Metcalf) Calpine resource. This was part of negotiations for reliability must-run designations for three resources, which also included Yuba City and Feather River. These resources cited limited ability for fixed cost recovery in the day-ahead and real-time markets.

On June 2, 2017, Calpine announced that they were assessing suspension of operations at their Metcalf resource beginning on January 1, 2018, because of low potential expected revenues from the energy market. Calpine also noted that it would not pursue a capacity procurement mechanism designation, as compensation through that mechanism may also be inadequate. The ISO recommended that the ISO Board of Governors designate Metcalf a reliability must-run resource, and this was approved on November 2, 2017. The annual fixed revenue requirement for the resource is about $72 million for 2018, and will be paid in addition to variable operating costs including fuel.[55]

For each reliability must-run designation a resource may either: bid into the market and receive associated revenues (condition 1), or only participate in the market – without receiving market revenues – after receiving a dispatch notice for the unit from the ISO (condition 2).[56] After receiving the reliability must-run designation, the resource owners of the Metcalf resource elected to operate under condition 2. In response, DMM filed a protest to FERC for this designation, and argued that Metcalf would receive annual fixed revenues, inclusive of depreciation and capital cost recovery, and would only be committed to operate by a manual dispatch from the ISO.[57] While the ISO ratepayers are making payments to cover the resource's fixed and variable costs it is unreasonable not to have this resource available for typical dispatch in the market.

Similar to Metcalf, the Yuba City and Feather River resources also applied for reliability must-run designations for 2018. These were approved by the ISO Board of Governors in March 2017 and were subject to both resources not receiving a resource adequacy contract. On October 31, 2017, contracts had not been awarded to either resource. At this time the ISO began initial negotiations, overlapping

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54 *Motion to intervene and protest of the Department of Market Monitoring of the California Independent System Operator Corporation*, February 2, 2018: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14814722.

55 Metcalf filing for reliability must-run service agreement, November 2, 2017, pp. B-7: https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14741407.

56 California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff, Appendix G, Article 3.1, pp. 16-17: http://www.caiso.com/Documents/AppendixG_ProFormaReliabilityMustRunContract_asof_Apr1_2017.pdf.

57 Motion to intervene and protest of the Department of Market Monitoring of the California Independent System Operator Corporation, Docket No. ER18-240-000: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14762782.

with negotiations for the Metcalf resource, with Calpine for an acceptable rate for the reliability must-run designation. No agreement was reached between the two parties for these resources.

3.4 Flexible ramping sufficiency test requirement calculation and recommendations

DMM notes that the use of net import capability and net export capability in the 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.

In order to pass the hourly flexible ramping sufficiency test in a given direction (upward or downward), the balancing area needs to show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals in the hour. The area must pass all four 15-minute interval tests in order to pass the hourly flexible ramping sufficiency test for upward and downward ramping.

The requirement for the flexible ramping sufficiency test is calculated as the forecasted change in load plus the uncertainty requirement minus two discounts, diversity benefit and flexible ramping credits. The diversity benefit reflects that system-level flexible ramping needs are typically smaller than the sum of the individual balancing area flexible ramping needs because of reduced uncertainty across a larger footprint. As a result, balancing areas receive a prorated diversity benefit discount based on this proportion. In addition, credits reflect the ability to reduce exports to increase upward ramping capability or reduce imports to increase downward ramping capability. Further, the reduction in the sufficiency test requirement because of any diversity benefit or flexible ramping credit is capped by the area's net import capability for the upward direction or net export capability for the downward direction.

Figure 3.10 illustrates how the diversity benefit reduction is calculated. The diversity benefit factor is equal to the system uncertainty requirement divided by the sum of all of the individual balancing area uncertainty requirements. In this example, the diversity benefit factor is equal to 75 percent. The *reduction* to each area's upward sufficiency test requirement as a result of the energy imbalance market diversity benefit in this example is therefore equal to 25 percent of the area's uncertainty requirement.

Figure 3.11 illustrates the calculation of net import capability and upward flexible ramping credits for the upward sufficiency test.[58] The faded bars reflect the import scheduling limits on two interties with another energy imbalance market area. In this example the import limit for both interties is 200 MW, so the total import limit is 400 MW. The net transfer for the area is equal to total export energy transfer schedules minus import energy transfer schedules. In this example, that is equal to the export on intertie B (150 MW) minus the import on intertie A (50 MW), or 100 MW. Net import capability is calculated as the sum of the import scheduling limits in excess of the net incoming transfer, or 500 MW. The upward flexible ramping credit is calculated as the net export in excess of the base transfer.[59] In this example, there is a base export on intertie B of 25 MW. The upward flexible ramping credit is therefore 75 MW.

[58] The calculation for net export capability and downward flexible ramping credits for the downward sufficiency test mirrors the calculation in this example.

[59] The base energy imbalance market transfer for each energy imbalance market balancing authority area is the net of all base energy transfer schedules for that area.

Figure 3.10 Diversity benefit example (upward uncertainty)

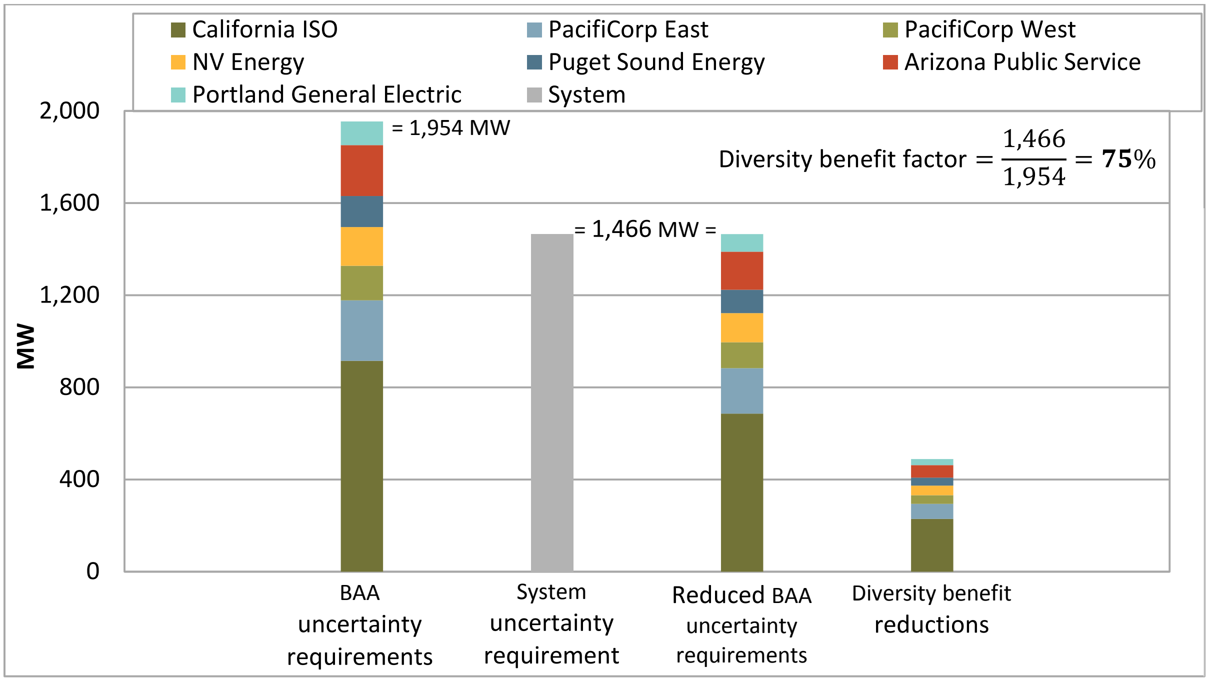
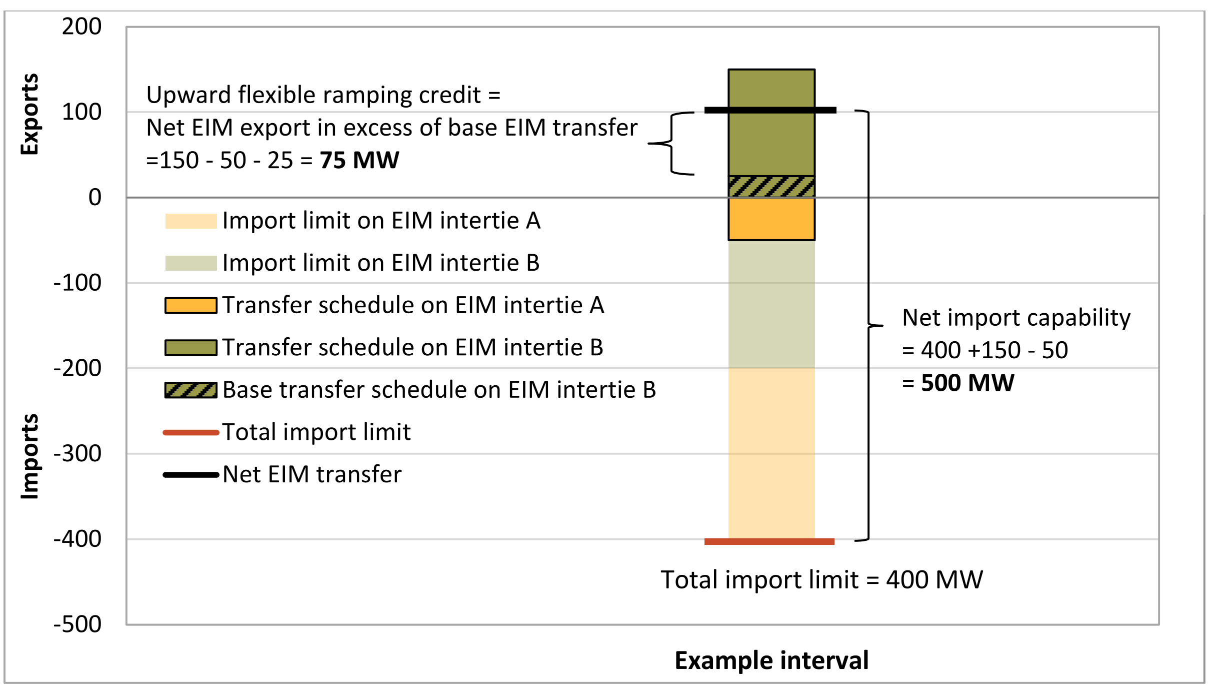


Figure 3.11 Net import capability and upward flexible ramping credit example



The credits, net import capability, and net export capability are calculated from the energy imbalance market transfers and limits in the last binding 15-minute interval prior to the hour that is being tested.

In most hours, net import (or export) capability is then calculated as the difference between total import (or export) limits and the net energy imbalance market transfer in that final 15-minute interval. However, if the balancing area failed the sufficiency test in the previous hour, net import or export capability – pulled from the last binding 15-minute interval – will be based on the limited transfer quantity as a result of failing the test rather than total energy imbalance market import and export limits.

DMM notes that the use of net import capability and net export capability in the sufficiency test, as a function of the sufficiency test result in the previous hour, can impact the ability of balancing areas to realize the benefits of increased resource diversity. In particular, balancing areas with otherwise sufficient transfer capability can be blocked from the benefit of a lower uncertainty requirement (as a result of less uncertainty spread over a larger area) regardless of the upper operating limits on the area's energy imbalance market transfers. DMM recommends that the ISO reevaluate this interaction in a manner that does not impact the independence of consecutive hourly sufficiency test results.

Also, when the flexible ramping sufficiency test was initially implemented, requirements were determined from procurement targets for the flexible ramping constraint. The flexible ramping constraint was replaced in November 2016 by the flexible ramping product. Unlike the flexible ramping constraint, the flexible ramping product uses a demand curve, rather than a fixed target, when procuring flexibility. When the ISO switched to the flexible ramping product, they began using the maximum requirement from the demand curve for the sufficiency test, instead of the old targets from the constraint. DMM has asked the ISO to reconsider use of the maximum point from the demand curve for the sufficiency tests as the maximum can change dramatically from hour to hour and they can be significantly larger than the old requirements.