California Independent System Operator Corporation

California ISO

Q4 2016 Report on Market Issues and Performance

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Executive summary

This report covers market performance during the fourth quarter of 2016 (October – December). Several key changes in the market were implemented in the quarter. Key highlights regarding these changes include the following:

- On October 1, Arizona Public Service (APS) and Puget Sound Energy (PSE) joined the energy imbalance market.
- Given the significant amount of transfer capacity between Arizona Public Service and the ISO, there was little congestion between these regions. Moreover, Arizona Public Service added significant transfers with PacifiCorp East and there was minimal congestion between these regions. Energy imbalance market prices in the Arizona Public Service area were close to those observed in NV Energy, PacifiCorp East and the ISO during the quarter, at about $30/MWh.
- Energy imbalance market prices in Puget Sound Energy were similar to prices in PacifiCorp West, at about $23/MWh. Puget Sound Energy is connected to the energy imbalance market by 300 MW of transfer capacity into and out of PacifiCorp West. These transfers did not limit flows in most cases, which resulted in little congestion between these regions and similar prices.
- However, there continued to be congestion in the energy imbalance market from PacifiCorp West toward the ISO and PacifiCorp East. This caused price separation between these two areas and the rest of the energy imbalance market. Prices in Puget Sound Energy and PacifiCorp West were lower than those in the ISO and other energy imbalance areas as a result of this congestion.
- The flexible ramping product was introduced on November 1, replacing the flexible ramping constraint. This product has several key differences from the constraint including the following: procuring flexibility in the upward and downward directions, using a demand curve to determine the quantity and price for flexibility instead of a fixed quantity, and imposing charges for resources increasing the need for flexibility.
- Payments for flexible capacity increased since implementation of the flexible ramping product, but still remain low at less than $0.10/MWh of load. Total payments for flexibility were about $5 million in the fourth quarter.
- The flexible ramping sufficiency test ensures that each balancing area has sufficient ramping capacity to meet ramping needs. With the introduction of the flexible ramping product on November 1, this test included both upward and downward capacity. Arizona Public Service failed the sufficiency test in both directions during many hours in November and December. Failure of these tests limits the amount of energy that area may transfer, and contributed to power balance relaxations in this area during the quarter. However, because Arizona Public Service is still in the energy imbalance market transition period, power balance relaxations had little effect on market outcomes since prices during these intervals were set by the last dispatched bid, rather than the power balance constraint penalty parameter.
- The ISO's capacity procurement mechanism tariff authority expired in 2016 and was replaced on November 1 with a new approach that allows competition between different resources that are able to meet capacity needs, when possible. The total cost of capacity procurement mechanism

designations issued in November and December was $6.6 million. Of that total, $2.6 million was paid for capacity needed in the Pacific Gas and Electric area, $0.4 million was paid for capacity procured for needs in the Southern California Edison area, and $3.7 million for capacity procured for the total system area.

- The ISO began using a new method for calculating day-ahead regulation requirements on October 10. This method provides a more targeted way for the ISO to procure regulation during the hours when it is likely to be needed due to expected variability. Procurement costs with the new requirements were less than those when changes were implemented in the spring of 2016, but costs were somewhat higher than compared to earlier periods.

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

- Average day-ahead and real-time prices were competitive compared to benchmark prices and were similar to price levels in the previous quarter during October and December, but lower during November because of lower natural gas prices.

- Average prices in the day-ahead market continued to be higher than 15-minute market prices for the quarter. This pattern was particularly noticeable between hours ending 18 through 21 when day-ahead prices averaged $5/MWh more than 15-minute market prices.

- The frequency of price spikes in the 5-minute market increased during the quarter, particularly in November when prices above $250/MWh occurred during about 1.5 percent of intervals. Prices in the 5-minute market were greater than $750/MWh during more than 0.6 percent of intervals, which is a higher frequency than in recent quarters.

- During 2016, congestion revenue rights auction revenues were $47 million less than payments made to non-load-serving entities purchasing congestion revenue rights. This represents $0.68 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down from $0.73 during 2015.

- Day-ahead congestion in the San Diego Gas and Electric area increased prices by about $1/MWh for the quarter, but had little impact on prices in the Pacific Gas and Electric and Southern California Edison load areas.

- Bid cost recovery payments were $19 million in the fourth quarter, about the same as the previous quarter and the fourth quarter of 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $11 million in the fourth quarter, down by about $3 million from the prior quarter.

- Convergence bidding was slightly unprofitable during the fourth quarter after accounting for bid cost recovery charges. Total net revenues for entities engaging in convergence bidding during this quarter were about negative $2.6 million. In addition, the percent of virtual supply and demand bids offered into the market that cleared decreased to a record low at about 37 percent.

- The ISO and NV Energy were net importers in the energy imbalance market, while PacifiCorp East and Arizona Public Service tended to be net exporters. Puget Sound Energy was a slight net importer and PacifiCorp West was a slight net exporter. However, the direction and volume of transfers between the ISO and different EIM areas fluctuated significantly based on actual real-time market conditions.

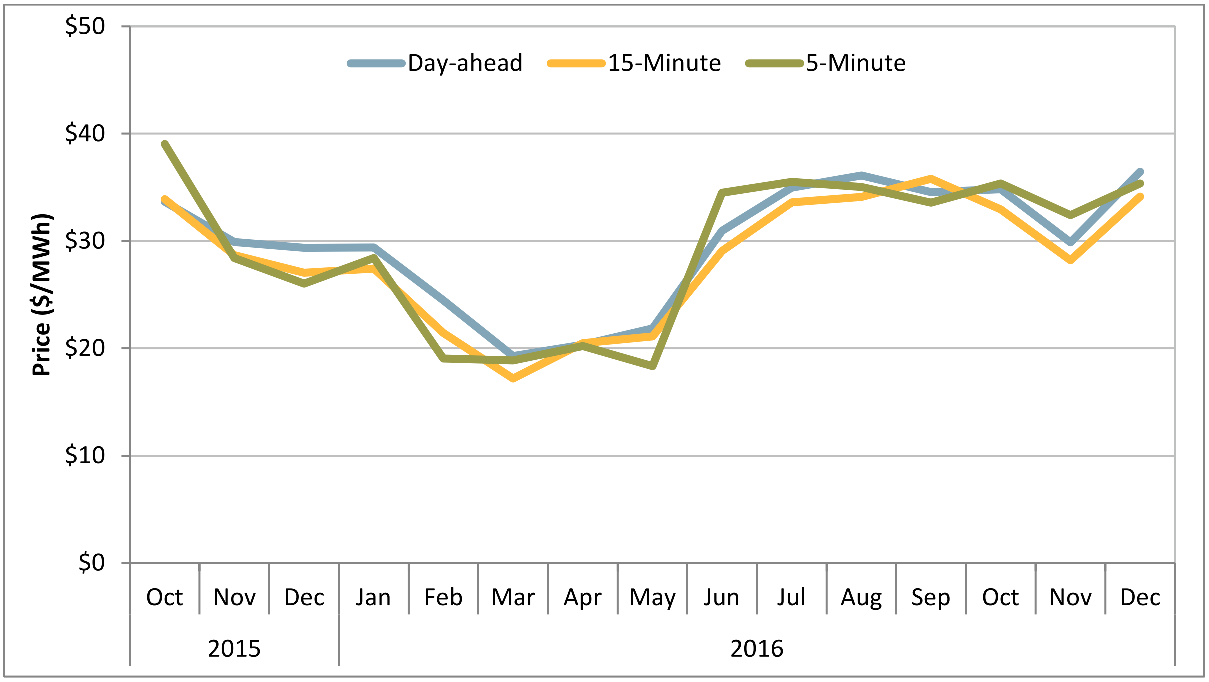
- The available balancing capacity mechanism continued to have a limited impact on addressing power balance constraint relaxations in the fourth quarter. NV Energy and Puget Sound Energy offered available balancing capacity into the market for most hours during the quarter, while PacifiCorp East and PacifiCorp West did so infrequently. Arizona Public Service offered available balancing capacity during almost all intervals in October, during fewer intervals in November, and in less than half of all intervals in December.
- Load adjustments in energy imbalance market areas were typically smaller in magnitude, but generally larger as a percentage of area load, than adjustments in the ISO. The pattern of adjustments was similar to prior quarters, where NV Energy tended to make positive adjustments to load and the PacifiCorp areas tended to make negative adjustments to load. Arizona Public Service and Puget Sound Energy used load adjustments infrequently when compared to the ISO and other energy imbalance market areas.
- As part of a set of temporary measures related to Aliso Canyon, the ISO began using a more up-to-date source for calculating the natural gas price index used by the day-ahead market. This update removed a one-day lag in the natural gas price information used in the day-ahead market, and greatly improved the accuracy of the ISO's index.
- DMM did not find systematic need for the real-time commitment cost and incremental energy natural gas cost scalars used to increase bid caps, which were implemented as Aliso Canyon mitigation measures. In addition, we find that the higher bid caps did not appear to have a significant detrimental impact on market results.

Energy market performance

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

Average energy prices during October and December were similar compared to the previous quarter, but prices in November were lower. Monthly average day-ahead energy prices were around $35/MWh during October and December, and around $30/MWh in November. This coincided with a decrease in natural gas prices between October and November, followed by an increase in natural gas prices in December. Prices in the 15-minute market continued to be consistently lower than day-ahead prices and moved in about the same direction and magnitude of day-ahead prices each month. Prices in the 5-minute market tended to be higher than day-ahead and 15-minute market prices during the quarter. These prices were higher because of several days when solar forecasts were considerably higher than actual generation, primarily during periods of inclement weather.

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



Price spikes in the 5-minute market were more frequent in November. As shown in Figure E.1, prices in the 5-minute market were higher than day-ahead or 15-minute market prices during November. During this month, prices above $250/MWh occurred during about 1.5 percent of intervals across all load area prices, higher than any monthly frequency since May 2014. Many of these higher prices corresponded to days when solar forecasts were higher than actual generation. Prices in the 15-minute market were below $250/MWh for almost all intervals during the quarter.

Negative prices occurred more frequently. The frequency of negative prices increased in the 15-minute and 5-minute markets in the fourth quarter compared to the prior quarter and the fourth quarter of 2015. Negative prices in the 15-minute market were observed during about 1.8 percent of intervals while negative prices in the 5-minute market were observed during about 4.7 percent of intervals. Negative prices typically occurred between hours ending 9 through 15 when net demand was low and solar generation was greatest. During the quarter, solar generation was highest in October and decreased significantly during each successive month, following typical seasonal patterns. However, solar generation increased significantly from the fourth quarter of 2015 because of additions to utility scale solar generation in the ISO. There continue to be very few intervals when the price was below -$50/MWh or less, and the price was almost never set by the power balance constraint penalty parameter for excess generation at -$155/MWh.

Congestion was low in the day-ahead market. Day-ahead congestion in the San Diego Gas and Electric area increased prices by about $1/MWh during the quarter. This congestion was because of enforcement of operating procedures to mitigate for contingencies and adjustments to transfer limits to account for outages. Day-ahead congestion had little overall impact on market prices in the Pacific Gas and Electric and Southern California Edison load areas.

Auction revenues from congestion revenue rights continue to fall short of payments made by ratepayers for the year. In 2016, congestion revenue rights auction revenues were $47 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents only $0.68 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down from $0.73 in 2015. Financial participants continued to earn the highest profits at $33 million (paying 63 cents in the auction per dollar of congestion revenue rights revenue), followed by marketers at $10 million (paying 78 cents per dollar of revenue), then generators at $5 million (paying 63 cents per dollar of revenue) followed by load-serving entities at $3 million. Load-serving entities continued to be net sellers in the congestion revenue rights market and gained about $3 million from rights that they explicitly sold in the market.

Bid cost recovery payments remained constant. Overall bid cost recovery payments were $19 million in the fourth quarter, about the same as the prior quarter and the fourth quarter in 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $11 million in the fourth quarter, down about $3 million from the last quarter. At $3 million, day-ahead bid cost recovery payments continued to be low. Bid cost recovery payments for residual unit commitment totaled about $5 million, with a large portion of payments made to one specific unit.

Virtual bidding revenues were negative. Net revenues decreased to negative $2.6 million (a payment) from a positive revenue of $12.6 million in the third quarter. Quarterly revenues were negative, after accounting for bid cost recovery charges, for the first time since the first quarter of 2013. Auction revenues for virtual supply and demand totaled $1.3 million, which was smaller than bid cost recovery charges of $3.9 million. Total cleared virtual volume decreased in the fourth quarter to about 2,600 MW on average compared to 3,200 MW in the third quarter.

Special issues

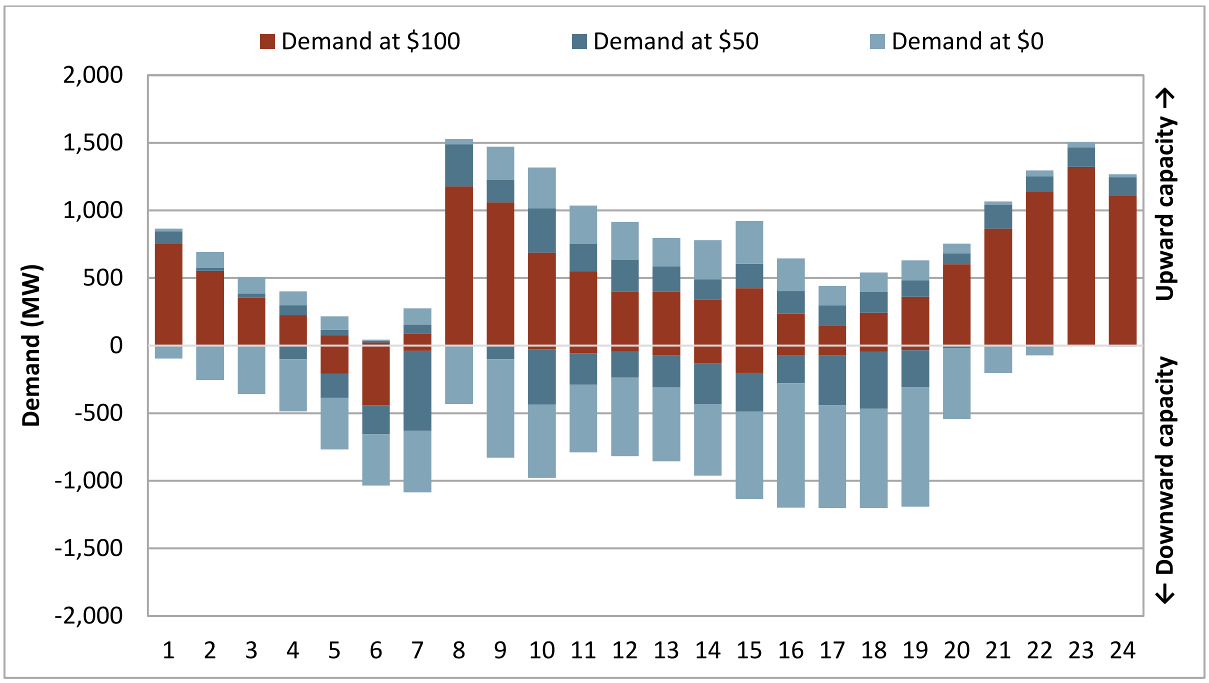
The ISO has moved forward on recommendations from DMM on the load bias limiter. DMM has provided recommendations to the ISO on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load adjustments on creating power balance relaxations. Specifically, DMM has recommended considering the adjustment based on a combination of factors including the *change* in load adjustment from one interval to the next and the *duration* of an adjustment rather than solely the *absolute* value of any load adjustment. The ISO hosted a call with stakeholders regarding implementing these changes and posted a white paper on the ISO website outlining the proposed changes.[1]

The flexible ramping product was implemented in November. The flexible ramping product replaced the flexible ramping constraint on November 1. The flexible ramping product differs from the flexible ramping constraint in several important ways. First, the constraint procured flexibility in only the upward direction in the 15-minute market, whereas the new mechanism procures flexibility up and down in both the 5-minute and 15-minute markets. Second, the amount of flexibility procured and the willingness to pay for the flexibility procured by the new product is determined by a sloped demand curve, rather than a set price-quantity pair at $60/MWh. Third, the new mechanism compensates units providing flexibility, and charges resources that are creating more need for flexibility.

[1] *Load Conformance Limiter Enhancement*, December 28, 2016: http://www.caiso.com/Documents/TechnicalBulletin_LoadConformanceLimiterEnhancement.pdf.

A demand curve is generated for the ISO area, each balancing area in the energy imbalance market, and the aggregate of all areas.[2] Each specific curve is calculated as the expected cost of a power balance relaxation for each amount of flexible capacity procured for that region. The probability of a power balance constraint relaxation is calculated using historical net load forecast error, and not historical ramping needs. This methodology results in a 15-minute system-level demand curve in the upward direction that has a maximum quantity close to 0 MW in hour ending 6, and extends up to about 1,500 MW in hours ending 8, 9 and 23. Similarly, the downward demand curve extends to over 1,000 MW in early evening hours (15 through 19) and is very small in the late evening and early morning hours. This curve is shown in Figure E.2 below.

Figure E.2 Hourly average system-level flexible ramping demand curves in 15-minute market (November – December)



Total payments to generators increased following implementation of the flexible ramping product to about $1.7 million in November and $2.3 million in December, up from payments of less than $1 million per month prior to implementation. However, flexible payments continued to make up a small portion of overall energy costs, and totaled less than $0.10/MWh of load. About 59 percent of payments during these two months were to ISO generators, which reflects the majority of flexible ramping capacity awards.

The new capacity procurement mechanism was implemented in November. The new capacity procurement mechanism implemented on November 1 is designed to allow competition between different resources that may meet capacity needs, when possible. The new program allows resources to

[2] See Section 4.1 of this report for additional details about formation of the flexible ramping product demand curves.

submit bids for capacity through the competitive solicitation process (CSP). The ISO will look to those bids first when possible to fulfill procurement needs.

Capacity procurement mechanism designations issued in 2016 were all triggered by exceptional dispatch in the intra-monthly competitive solicitation process. All but one of these designations were for capacity that had not been designated as resource adequacy capacity and for which the scheduling coordinator did not submit a bid in the competitive solicitation process.[3] The ISO generates bids for such capacity at a price above the soft $6.31/kW-month soft cap. Prices for accepted designations in this range were set at the soft offer cap of $6.31/kW-month. Several additional designations were declined by scheduling coordinators.

The total cost of capacity procurement mechanism designations issued in November and December was $6.6 million. Of that total, $2.6 million was paid for capacity needed in the Pacific Gas and Electric transmission access charge area, $0.4 million in the Southern California Edison area, and $3.7 million in the total system area.

Regulation requirements were enhanced in November. On October 10, the ISO began using a new method for determining day-ahead regulation procurement requirements. With the new method, requirements were calculated for each hour, and that calculation was based on observed regulation needs in the same month during the prior year. These requirements are updated approximately monthly. Furthermore, the ISO adjusts requirements when large weather systems moved across California. This methodology differs from the one in place prior to October 10, where requirements varied less across hours.

The new method was implemented in response to growing needs for regulation to balance variable renewable generation. The ISO had a similar need in the spring of 2016 when regulation requirements were increased in a less targeted way. For most of the spring, regulation requirements were roughly doubled from 2015 levels, and set at 600 MW for both regulation up and regulation down during all hours of the day. This resulted in a significant increase in regulation procurement costs.[4] The new more targeted procurement method has resulted in a much smaller increase in procurement costs than the method implemented in the spring.

3 At the December 7, 2016, Market Performance and Planning Forum, the ISO indicated that there were some initial implementation issues that may have affected some of the designations.

4 For more information see DMM's *Q2 2016 Quarterly Report on Market Issues and Performance*, pp. 71 – 74: http://www.caiso.com/Documents/2016SecondQuarterReportMarketIssuesandPerformance.pdf.

1 Market performance

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

- Average day-ahead and real-time prices were similar to the previous quarter during October and December, but were lower during November because of lower natural gas costs.
- Average prices in the day-ahead market continued to be higher than 15-minute market prices for the quarter. This pattern was particularly noticeable between hours ending 18 through 21 when day-ahead prices averaged $5/MWh more than 15-minute market prices.
- Prices in the 5-minute market were significantly higher than day-ahead and 15-minute market prices during hours 14 through 18. This was mostly driven by tight supply conditions as a result of solar deviations or ramping needs to meet net load peaks.
- The frequency of price spikes in the 5-minute market increased during the quarter, particularly in November when prices above $250/MWh occurred during about 1.5 percent of intervals. Prices in the 5-minute market were greater than $750/MWh during more than 0.6 percent of intervals, which is a higher frequency than in recent quarters.
- During 2016, congestion revenue rights auction revenues were $47 million less than payments made to non-load-serving entities purchasing congestion revenue rights. This represents $0.68 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down from $0.73 during 2015.
- Day-ahead congestion in the San Diego Gas and Electric area increased prices by about $1/MWh during the quarter. This congestion was because of enforcement of operating procedures to mitigate for contingencies and adjustments to transfer limits to account for outages. Day-ahead congestion had little overall impact on market prices in the Pacific Gas and Electric and Southern California Edison load areas.
- Bid cost recovery payments were $19 million in the fourth quarter, about the same as the previous quarter and the fourth quarter of 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $11 million in the fourth quarter, down by about $3 million from the prior quarter. Day-ahead bid cost recovery payments totaled about $3 million and costs associated with residual unit commitment were about $5 million.
- Convergence bidding was slightly unprofitable during the fourth quarter after accounting for bid cost recovery charges. Total net revenues for entities engaging in convergence bidding during this quarter were negative $2.6 million. In addition, the percent of virtual supply and demand bids offered into the market that cleared decreased to a record low at about 37 percent.

1.1 Energy market performance

This section assesses the efficiency of the energy market 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. Overall, average prices were relatively similar to the previous quarter during October and December, while average prices during November were lower.

- During November, average day-ahead and 15-minute market prices decreased by about $5/MWh from the previous month to about $30/MWh and $28/MWh, respectively. This mirrored gas prices, which were lower during November.
- Average 15-minute market prices in the fourth quarter were about $2/MWh below day-ahead prices during the quarter, continuing a regular pattern observed between these markets. Prices in the 15-minute market averaged about $29/MWh during off-peak periods and $34/MWh during peak periods.
- Overall, monthly average prices in the 5-minute market remained relatively stable at about $34/MWh, similar to the third quarter. During off-peak periods in November, average 5-minute market prices were about $8/MWh more than day-ahead and 15-minute market prices. Prices in the 5-minute market tended to be higher because of more intervals where high cost generation was deployed for tight system conditions, or prices were set by power balance constraint shortages, resulting in roughly $1,000/MWh energy prices. During the fourth quarter, this outcome occurred on several occasions as a result of deviations of the 5-minute market solar forecast from the 15-minute market solar forecast.

Figure 1.2 illustrates system marginal energy prices on an hourly basis in the fourth quarter compared to average hourly net load.[5] The prices in this figure follow the net load pattern as energy prices were lowest during the early morning, mid-day, and late evening hours, and were highest during the morning and evening peak load hours. Lower prices during the middle of the day corresponded to periods when low-priced solar generation was greatest, and net demand was lowest. Solar generation continued at a high level in early October, but declined through the rest of the quarter as storms moved into Southern California. As additional solar is built and interconnected with the system, net loads and average system prices during the middle of the day may continue to decrease. This is a result of less expensive units setting prices during periods when net demand is lower, driven by increases in solar or other renewable generation.

Figure 1.2 also shows that average prices in the day-ahead market were higher than 15-minute market prices during most hours of the day. Notably, prices in the day-ahead market were significantly higher than 15-minute prices in hours ending 18 through 21. In these hours, day-ahead prices averaged about $5.50/MWh higher than 15-minute market prices.

During hours ending 14 through 18, average prices in the 5-minute market were about $11/MWh and $14/MWh higher than day-ahead and 15-minute market prices, respectively. During the quarter, these hours often had tight supply conditions as a result of weather related solar deviations or large ramping needs. In particular, differences in forecasting methodology for solar between the 15-minute and 5-minute markets resulted in significantly lower solar forecasts in the 5-minute market relative to the 15-minute market in multiple periods. This caused a larger net load in the 5-minute market than in the 15-minute market and contributed to the higher prices observed in the fourth quarter.

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

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

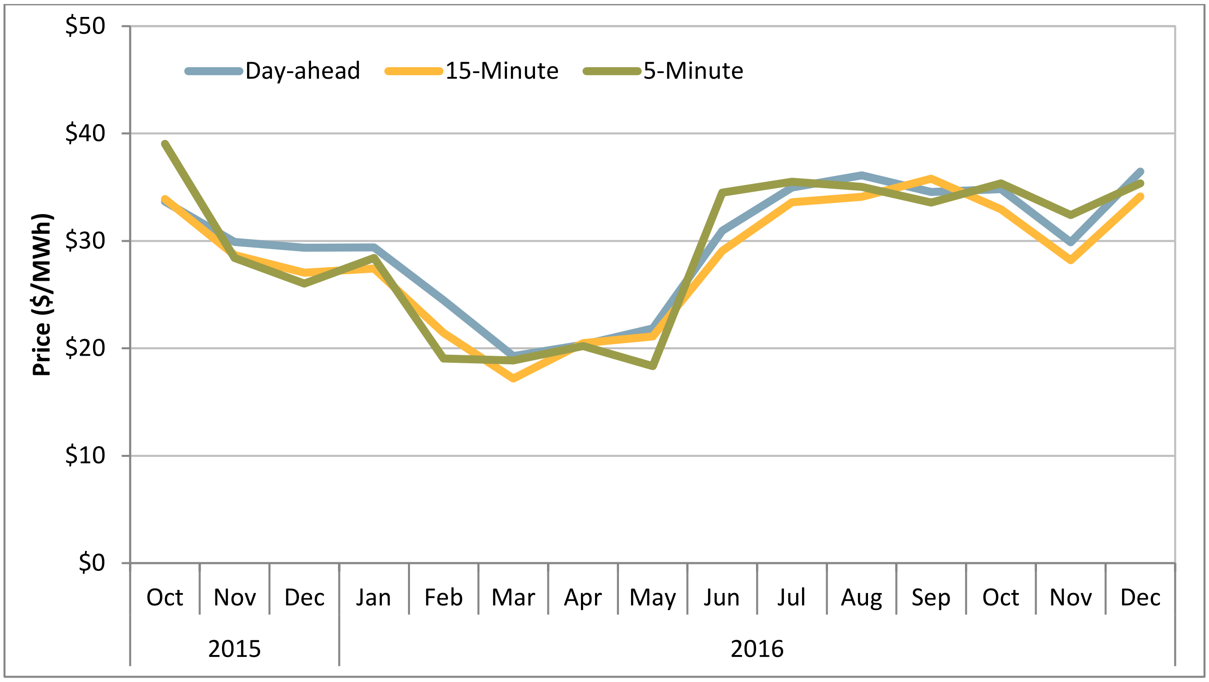
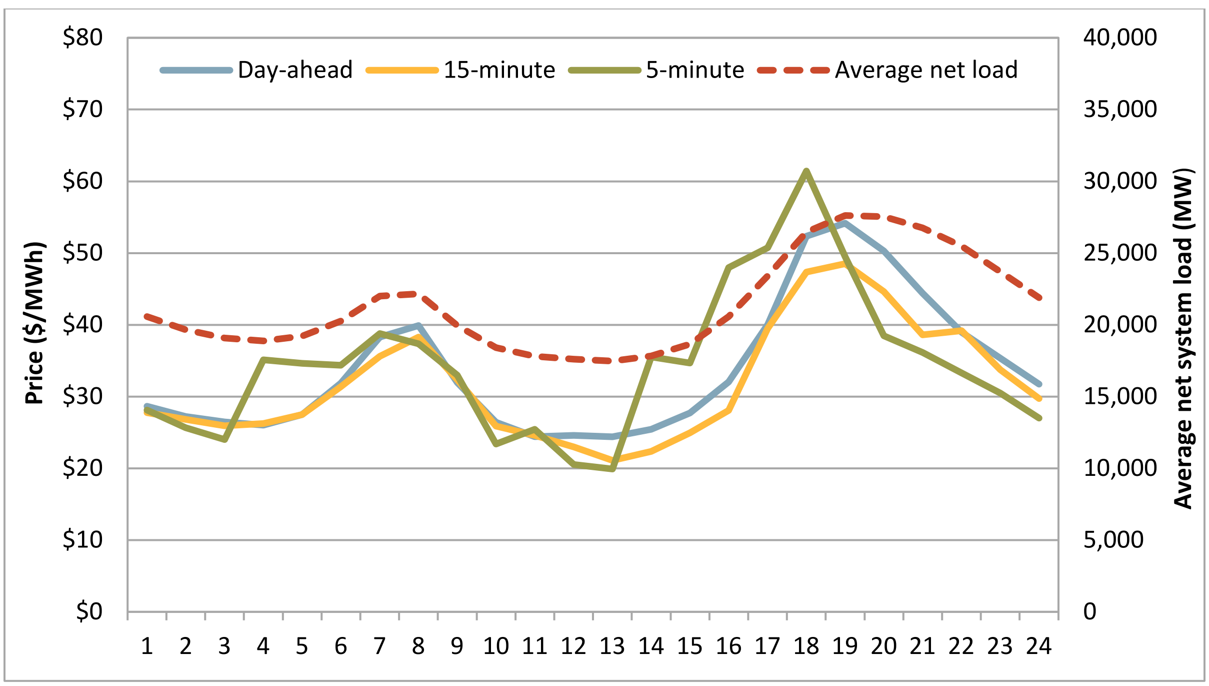


Figure 1.2 Hourly system marginal energy prices (October – December)



1.2 Real-time price variability

Real-time market prices can be highly volatile with periods of extreme positive and negative prices. Even a short period of extremely high or low prices can have a significant impact on average prices. In some instances, extreme prices are the result of relaxing the power balance constraint to resolve the feasibility of the dispatch.

High prices

The frequency of high price spikes during the fourth quarter increased in the 5-minute market. Figure 1.3 shows the frequency of positive price spikes occurring in the 5-minute market by month. During November, prices above $250/MWh occurred during about 1.5 percent of 5-minute intervals across all aggregate load areas. This was the highest monthly frequency in the 5-minute market since May 2014.

In addition, the frequency of more extreme 5-minute prices larger than $750/MWh increased significantly to a relatively high 0.6 percent of intervals, compared to 0.4 percent of intervals in the previous quarter and 0.3 percent of intervals in the fourth quarter of 2015. Price spikes greater than $750/MWh were most concentrated between hours ending 14 through 19.

This outcome resulted in part from a combination of solar deviations and tight supply conditions during intervals when system ramping needs were greatest. Solar deviations below the day-ahead forecast can arise from weather fronts, creating forecasting challenges. When real-time net load forecasts were underestimated during the quarter, relative to the day-ahead forecasts, high real-time prices arose. In addition, differences in forecasting methodologies used for the 15-minute and 5-minute markets for solar generation also resulted in forecast and price differences between the two real-time markets on cloudy days with higher uncertainty in output. These net load forecast issues resulted in high 5-minute market price spikes on several days during the fourth quarter. The ISO worked to enhance forecasting software to better align the 15-minute and 5-minute market solar forecasts and implemented changes by the end of December.

In the 15-minute market during the quarter, price spikes above $250/MWh were observed very infrequently, occurring in only 0.2 percent of intervals in November.

Negative prices

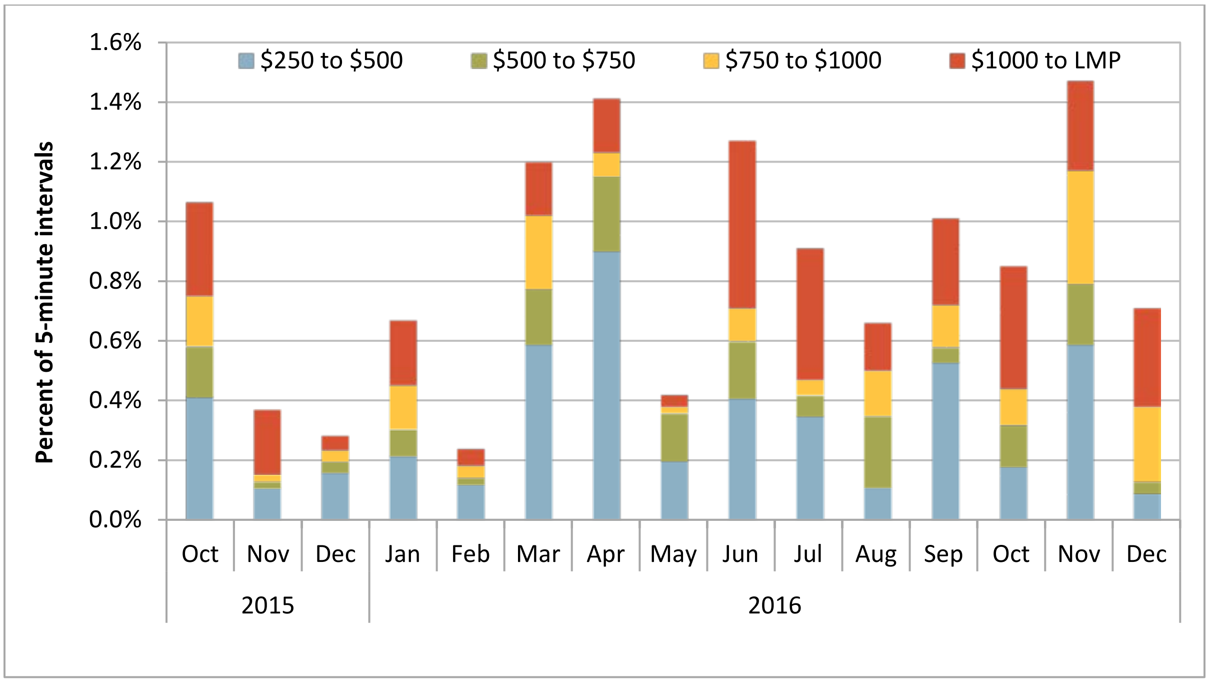
The frequency of negative prices increased significantly in the 15-minute and 5-minute markets in the fourth quarter compared to the prior quarter and the fourth quarter of 2015. Negative prices in the 15-minute market were observed in about 1.8 percent of intervals while negative prices in the 5-minute market were observed in about 4.7 percent of intervals. Figure 1.4 shows the frequency of negative prices occurring in the 5-minute market by hour during the quarter.[6] Negative prices typically occurred between hours ending 9 through 15 when net demand was low and solar generation was greatest. During the quarter, solar generation was highest in October and decreased significantly during each successive month, following typical seasonal weather patterns. However, solar generation increased

[6] Corresponding values for the 15-minute market show a similar pattern but lower percentages of intervals.

significantly from the fourth quarter of 2015, and averaged just over 5,700 MW during mid-day hours during the quarter compared to 4,400 MW during mid-day hours in the fourth quarter of 2015.[7]

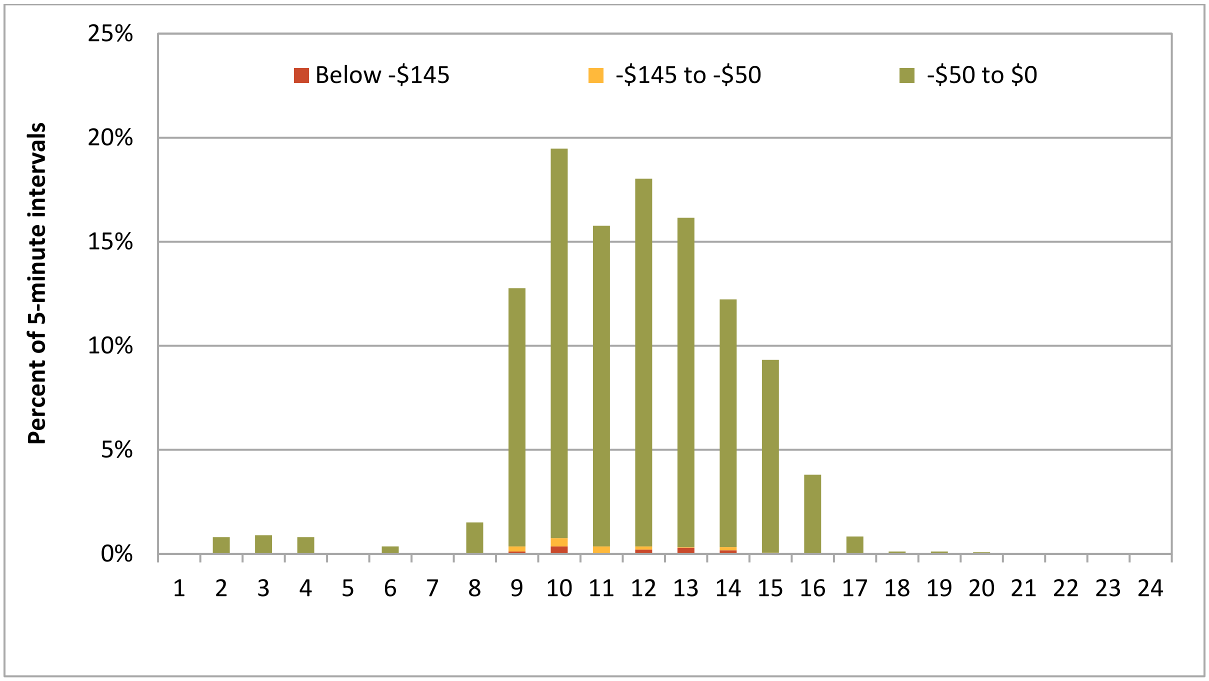
Negative prices less than -$50/MWh only occurred during October on several days when significant congestion was present. The majority of these occurred on October 4 where congestion on the Barre-Villa Park 230 kV and Barre-Lewis 230 kV resulted in negative prices in the San Diego Gas and Electric area.

Figure 1.3 Frequency of high 5-minute price spikes by month



[7] Hours ending 11 through 16 were used to compute solar generation during mid-day hours. The increase in solar generation from 2015 to 2016 reflects an increase in the installed capacity.

Figure 1.4 Hourly frequency of negative 5-minute prices (October – December)



1.3 Congestion

Congestion had a small impact on prices in the day-ahead and real-time markets in the fourth quarter. Day-ahead congestion was slightly larger compared to the previous quarter and modestly increased San Diego Gas and Electric and Pacific Gas and Electric area prices by about $0.90/MWh and $0.20/MWh, respectively. The frequency of congestion increased in the real-time market but the overall impact was low, compared to the prior quarter. Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had larger effect on prices, which is similar to patterns observed in prior quarters.

1.3.1 Congestion impacts of individual constraints

Day-ahead congestion

The frequency of congestion in the day-ahead market was higher in the fourth quarter when compared to the third quarter, but the impact on load area prices was low.

In the Pacific Gas and Electric area, the Path 15 constraint bound most frequently in the south-to-north direction during the fourth quarter during 8 percent of all intervals. When Path 15 bound, it increased Pacific Gas and Electric area prices by about $4/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by about $4/MWh and $3/MWh, respectively. This congestion was primarily the result of operator adjustments to path limits to account for outages, availability of Remedial Action Scheme (RAS) and to maintain a reliability margin.

In the Southern California Edison area, the Barre-Villa Park 230 kV and Lugo-Victorville 500 kV line bound most frequently during about 6 percent of intervals. The Lugo-Victorville 500 kV line bound during the quarter because an operating procedure was in effect to mitigate for the loss of the nearby Palo Verde-Colorado River 500 kV line. Similarly, Barre-Villa Park 230 kV bound because of an operating procedure enforced to avoid thermal overloading for the loss of Barre-Lewis 230 kV line.

Lastly, in the San Diego Gas and Electric area, the constraints modeling the outage on Imperial Valley 500/230 kV transformer bank (22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81 and OMS 4379177 IVALLY BK81) bound most frequently, during about 11 percent and 9 percent of all hours, respectively. While binding, these constraints increased San Diego Gas and Electric area prices by $4/MWh and had no impact on Southern California Edison load area prices on average.

Table 1.1 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency				Q1			Q2			Q3			Q4		
Area	Constraint	Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	2.3%	1.0%	4.3%	8.4%	$2.34	-$2.05	-$1.92	$4.04	-$3.32	-$3.10	$2.74	-$2.22	-$2.06	$4.32	-$3.62	-$3.32
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2				0.6%										$1.26	-$0.92	-$1.34
	OMS 4186537 Path15_S-N				0.5%										$5.40	-$4.65	-$4.24
	OMS 4008879 Path15_SN				0.5%										$1.51	-$1.21	-$1.11
	OMS 4008893 Path15_SN				0.3%										$5.07	-$4.19	-$3.90
	OMS_3849098_LBN_SN				0.3%										$3.74	-$3.18	-$2.84
	OMS 3959238 Path15_SN				0.2%										$2.06	-$1.67	-$1.55
	30055_GATES1 _500_30900_GATES _230_XF_11_P			1.6%								$0.32	-$0.25	-$0.24			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1			1.0%								$1.96					
	6310_SOL3_NG_SUM		1.4%	0.5%					-$0.80	$0.65	$0.60	-$0.96	$0.76	$0.69			
	OMS 4059507 Path15_S_N			0.4%								$2.39	-$1.78	-$1.65			
	OMS 3938352 LBN_S-N			0.3%								$1.98	-$1.56	-$1.42			
	OMS 3969865 Path15_S_N			0.1%								$3.46	-$2.78	-$2.60			
	6110_SOL10_NG		16.2%						$0.07	-$0.07	-$0.07						
	OMS 3602720_Path15		8.3%						$6.10	-$4.78	-$4.49						
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		1.1%						$2.01	-$2.06							
	LOSBANOSNORTH_BG		0.7%						$4.60	-$3.80	-$3.52						
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	28.6%				$1.18	-$0.98	-$0.95									
	OMS 2592148 P15 HARD	1.8%				$3.44	-$2.87	-$2.69									
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.5%				-$1.67	$1.40	$1.29									
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	6.1%	1.2%	1.8%	5.9%	-$1.05	$1.52	-$0.50	-$0.99	$1.08	$1.30	-$0.39	$0.48		-$1.08	$1.71	-$6.28
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1		3.0%	3.8%	5.7%				-$1.75	$1.44	$1.07	-$1.07	$0.61	-$0.53	-$1.03	$0.84	$0.82
	OMS 4158606 ELD-LUGO				2.5%										-$0.73	$0.76	-$0.38
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	2.2%	1.1%	1.8%	1.1%	-$1.15	$1.50		-$0.62	$0.90	$1.05	-$0.39	$0.53		-$0.88	$1.02	
	PATH26_BG	0.3%		1.9%	0.5%	-$2.54	$2.13	$2.01				-$5.77	$3.66	$3.45	-$4.91	$3.56	$3.34
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		1.2%	0.5%					-$4.23	$3.25	$4.72	-$2.63	$1.84	$2.83			
	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P		3.7%						-$6.20	$4.41	$4.69						
	24156_VINCENT _500_24155_VINCENT _230_XF_1 _P		0.5%						-$2.33	$1.93	$1.94						
SDG&E	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81				11.4%												$1.50
	OMS 4379177 IVALLEY BNK81_NG2				9.1%												$5.33
	7820_TL 230S_OVERLOAD_NG	1.9%	2.4%	3.7%	8.1%	-$0.20		$2.13	-$0.25		$3.30	-$0.32		$3.66	-$0.53		$6.02
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		1.0%		3.9%						$5.09						-$1.30
	23040_CROSSTRIP				3.0%										-$0.22		$3.43
	MIGUEL_BKs_MXFLW_NG				1.0%										-$0.63		$8.00
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1			0.7%	1.0%									$8.52			$1.74
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1				0.8%												$4.36
	OMS 4250740_Devers 230 NBus				0.7%												-$24.06
	IID-SCE_BG	3.7%			0.5%			-$2.35									-$1.67
	OMS 4497618 TL23055_NG				0.4%										-$0.32		$5.28
	OMS 4391827 TL50003_NG				0.3%										-$0.52		$5.33
	OMS 4392033 TL50003_NG				0.3%										-$0.55		$5.40
	OMS 4489686 TL23055_NG				0.3%										-$0.40		$6.02
	OMS 4402394 TL50003_NG				0.2%										-$0.59		$5.62
	OMS 4000872 DVSB_NG3			2.7%										-$1.92			
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			0.9%										-$3.28			
	22464_MIGUEL _230_22504_MISSION _230_BR_1 _1			0.8%										$2.24			
	22464_MIGUEL _230_22504_MISSION _230_BR_2 _1			0.7%										$3.24			
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	1.5%	5.2%	0.7%				$2.35			$5.94			$3.64			
	Miguel_rerate_SOL2			0.4%										$6.71			
	OMS 4143457 TL50004_NG			0.3%								-$0.40		$6.74			
	OMS 4169254_Cima-ELD-PISG_SCIT			0.3%								-$6.42	$3.66	$4.78			
	OMS 4282482 CRY_NV_SCIT			0.3%								-$4.43	$2.82	$3.55			
	OMS 4235148 TL50001_NG			0.2%								-$0.56		$8.00			
	OMS 4216681 TL50001OUT_NG			0.1%								-$1.09		$13.44			
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1	1.2%	5.4%					$2.62			$3.21						
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1		3.2%								$0.46						
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	5.0%	3.0%			-$1.83		$11.38	-$1.62		$11.97						
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1		1.1%								$6.99						
	OMS 3725346 IV_NGILA		1.1%						-$1.10	$0.87	$1.20						
	OMS 3725348 50002_OOS_TDM		0.7%								$3.48						
	OMS 4079303 TL50001_NG		0.4%						-$1.01		$12.95						
	22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1		0.1%								$89.43						
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1	2.5%						$6.82									
	OMS 2319325 PDCI_NG	2.0%				-$1.74	$1.43	$1.78									
	22464_MIGUEL _230_22472_MIGUELMP_ 1.0_XF_1	1.3%				-$1.14		$7.33									
	OMS 3624980 TL50001_NG	1.3%				-$0.35		$4.20									
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1	0.9%				-$0.82		$3.88									
	OMS 3636555 McC-Vic_6510	0.9%				-$3.55	$3.01	$3.66									
	24016_BARRE _230_24044_ELLIS _230_BR_1 _1	0.8%				-$1.12		$5.31									
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.6%				-$1.03		$6.87									
	22464_MIGUEL _230_22461_MIGUEL60_138_XF_1	0.6%						$3.17									
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.3%				-$4.66	$3.21	$6.61									

15-minute market congestion

Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had larger effects on prices. This is typical of congestion patterns in the real-time market and is similar to patterns in recent quarters. Table 1.2 shows the frequency and magnitude of 15-minute market congestion for the quarter.

In the Pacific Gas and Electric area, Path 15 and Los Banos constraints bound most frequently in the south-to-north direction during the fourth quarter at 3 percent and 1 percent of intervals, respectively. When Path 15 bound it increased Pacific Gas and Electric area prices by about $11/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by $12/MWh and $11/MWh, respectively. When the Los Banos constraint bound in the 15-minute market it increased Pacific Gas and Electric area prices by about $8/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by about $10/MWh. These constraints bound primarily because of adjustments to their transfer limits to account for nearby outages.

In the Southern California Edison area, the Barre-Villa Park 230 kV constraint bound most frequently and was congested in about 1.5 percent of all intervals during the quarter. When binding, it increased Southern California Edison prices by $12/MWh and decreased Pacific Gas and Electric and San Diego Gas and Electric area prices by $1/MWh and $18/MWh, respectively. As mentioned earlier, the main reason for this congestion is due to an enforcement of an operating procedure to avoid thermal overloading on this line for the loss of Barre-Lewis 230 kV line.

Similarly, in the San Diego Gas and Electric area, the constraint modeling the outage on Imperial Valley 500/230 kV transformer bank (OMS 4379177 IVALLY BK81) bound most frequently at about 4 percent of all intervals. When it bound, it increased San Diego Gas and Electric area prices by about $9/MWh and had no effect on Pacific Gas and Electric and Southern California Edison load area prices.

Table 1.2 Impact of congestion on 15-minute prices by load aggregation point in congested intervals[8]

		Frequency				Q1			Q2			Q3			Q4		
Area	Constraint	Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	1.0%		3.1%	2.8%	$18.34	-$19.11	-$18.02				$9.61	-$8.14	-$7.60	$11.39	-$11.76	-$10.95
	6110_SOL10_NG		6.0%		1.3%				$2.17	$0.70	$0.53				$1.30	$0.90	$0.73
	LBN_S-N			1.1%	1.1%	$0.00						$5.29	-$5.42	-$5.03	$7.71	-$10.18	-$9.37
	OMS 4008879 Path15_SN				0.4%										$14.27	-$13.58	-$12.70
	OMS 4008893 Path15_SN				0.4%										$5.31	-$5.06	-$4.77
	OMS_3849098_LBN_SN				0.3%										$19.24	-$27.07	-$24.42
	30735_METCALF _230_30042_METCALF _500_XF_13				0.3%										$14.81	-$6.77	-$6.65
	OMS 4186537 Path15_S-N				0.2%										$7.65	-$8.10	-$7.55
	30055_GATES1 _500_30900_GATES _230_XF_11_P		0.4%	0.9%					$11.75	-$7.62	-$7.41	$2.94	-$1.92	-$1.86			
	OMS 4059507 Path15_S_N			0.2%								$7.66	-$6.73	-$6.26			
	TMS_DLO_NG			0.8%								$2.06	$1.30	$0.65			
	OMS 3602720_Path15		3.1%						$11.53	-$10.07	-$9.46						
	PATH15_N-S		0.4%						-$5.53	$4.49	$4.23						
	PATH15_BG		0.3%						$9.16	-$8.12	-$7.64						
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	6.7%				$2.29	-$1.89	-$1.80									
	OMS 2592148 P15 HARD	0.7%				$8.58	-$8.51	-$8.02									
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.3%				-$15.84	$13.89	$12.80									
	OMS_3820942_Metcalf_SPS_NG	0.2%				$7.52	-$5.08	-$4.94									
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	1.3%			1.5%	-$1.51	$8.20	$1.09							-$1.37	$11.91	-$18.15
	OP-6610_ELD-LUGO				0.9%										$2.89	$6.25	$4.64
	OMS 4158606 ELD-LUGO				0.8%										$2.14	$4.50	$2.20
	24086_LUGO _500_24238_RANCHVST_500_BR_1 _1				0.4%										-$3.79	$8.47	$8.62
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1				0.2%										$0.00	$15.45	-$25.28
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.7%	0.5%	0.2%				-$9.31	$12.57	$16.40	-$69.81	$77.74	$101.69	-$5.87	$13.70	$14.06
	PATH26_N-S	0.3%	1.4%	1.2%		-$14.53	$12.27	$11.57	-$29.51	$19.67	$18.51	-$13.58	$9.20	$8.66			
	7750_DV2_N2DV500_NG			0.4%									$17.31				
	24091_MESA CAL_230_24158_WALNUT _230_BR_1 _1			0.3%								-$82.08	$78.34	$130.30			
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P			0.2%								-$6.24	$7.22	$21.69			
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1		0.2%						$10.54	$16.70	$16.49						
SDG&E	OMS 4379177 IVALLEY BNK81_NG2				3.6%												$8.95
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81				3.3%												$2.89
	23040_CROSSTRIP				1.1%												$11.37
	MIGUEL_BKs_MXFLW_NG				0.7%												$10.26
	OMS 4410597 TL23055_NG				0.3%												$49.17
	OMS 4488708 TL23055_NG				0.3%												$11.48
	OMS 4368629 TL23055_NG				0.2%												$49.15
	6510 SOL1_NG	0.4%		1.1%		-$3.37	$8.63	$9.88				-$15.38	$27.49	$32.99			
	OMS 4162323 Miguel Bk 80 SOL 3			0.6%										$32.13			
	7820_TL 230S_OVERLOAD_NG	0.8%	1.1%	0.5%		-$1.23		$26.61	-$0.57	$0.40	$13.62	-$0.50		$19.41			
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	3.2%	1.6%	0.3%				$28.79			$26.91	-$34.54	$35.85	$136.19			
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.3%	0.9%	0.4%				$33.98	-$1.27	-$1.48	$15.99			$35.56			
	OMS 4282482 CRY_NV_SCIT			0.4%								-$51.35	$73.06	$82.29			
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1			0.4%										$24.16			
	Miguel_rerate_SOL2			0.4%										$33.10			
	22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1	1.0%		0.3%				$24.44						$21.90			
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1			0.2%										$34.60			
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1		0.9%								$11.50						
	OMS 2319325 PDCI_NG	1.2%				-$23.09	$54.26	$59.95									
	IID-SCE_BG	1.0%						-$7.05									
	OMS 3716078 Cry-McC_6510	0.9%				-$5.30	$14.20	$16.15									
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1	0.5%	0.2%					$23.74			$15.77						
	22430_SILVERGT_230_22596_OLD TOWN_230_BR_1 _1		0.2%								$13.96						
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1	0.2%				-$4.37		$26.82									

8 Values for congestion appearing in prior reports for the 15-minute market were updated based on an updated calculation.

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. Unlike the analysis provided in the previous section that focused on only hours where congestion was present, this assessment 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 with which congestion occurs and the magnitude of the impact.[9] The congestion price impact differs across load areas and markets.

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.[10] The impact of congestion increased San Diego Gas and Electric and Pacific Gas and Electric area prices by about $0.88/MWh (2.6 percent) and $0.23/MWh (0.7 percent), respectively, and decreased Southern California Edison area prices by about $0.18/MWh (0.5 percent). The constraint modeling the N-1 contingency of the Imperial Valley-North Gila 500 kV line (7820_TL 230S_OVERLOAD_NG) had the greatest impact on San Diego Gas and Electric prices, and increased those prices by about $0.50/MWh. In the Pacific Gas and Electric area, Path 15 constraint in the south-to-north direction was congested because of limit adjustments to account for nearby outages and adjustments for reliability margins.

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

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

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint	PG&E		SCE		SDG&E	
	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH15_S-N	$0.36	1.05%	-$0.30	-0.92%	-$0.28	-0.81%
7820_TL 230S_OVERLOAD_NG	-$0.04	-0.12%			$0.49	1.41%
OMS 4379177 IVALLEY BNK81_NG2					$0.48	1.40%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.06	-0.19%	$0.10	0.30%	-$0.09	-0.26%
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81					$0.17	0.50%
OMS 4250740_Devers 230 NBus					-$0.16	-0.47%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.06	-0.16%	$0.04	0.13%	$0.05	0.14%
23040_CROSSTRIP	-$0.01	-0.02%			$0.10	0.30%
MIGUEL_BKs_MXFLW_NG	$0.00	-0.01%			$0.08	0.23%
OMS 4186537 Path15_S-N	$0.03	0.08%	-$0.02	-0.07%	-$0.02	-0.06%
PATH26_BG	-$0.02	-0.06%	$0.02	0.05%	$0.02	0.04%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.05	-0.15%
OMS 4158606 ELD-LUGO	-$0.01	-0.03%	$0.02	0.05%	-$0.01	-0.03%
OMS 4008893 Path15_SN	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1					$0.03	0.10%
OMS_3849098_LBN_SN	$0.01	0.03%	-$0.01	-0.03%	-$0.01	-0.03%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.03%	$0.01	0.04%		
30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
OMS 4489686 TL23055_NG	$0.00	0.00%			$0.02	0.06%
OMS 4497618 TL23055_NG	$0.00	0.00%			$0.02	0.06%
OMS 4392033 TL50003_NG	$0.00	-0.01%			$0.02	0.05%
OMS 4391827 TL50003_NG	$0.00	-0.01%			$0.02	0.05%
OMS 4008879 Path15_SN	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1					$0.02	0.05%
OMS 4402394 TL50003_NG	$0.00	0.00%			$0.01	0.04%
OMS 3959238 Path15_SN	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
IID-SCE_BG					-$0.01	-0.03%
Other	$0.02	0.05%	-$0.01	-0.02%	$0.02	0.05%
Total	**$0.23**	**0.67%**	**-$0.18**	**-0.54%**	**$0.88**	**2.54%**

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.[11] Congestion during the quarter increased San Diego Gas and Electric and Pacific Gas and Electric area prices by about $0.30/MWh (1 percent) and $0.60/MWh (2 percent), respectively, and decreased Southern California Edison area prices by about $0.30/MWh (0.8 percent). Similar to the day-ahead market, Path 15 constraint in the south-to-north direction had an impact on all of the load area prices. Surplus generation during high solar periods, operator adjustments to the Path 15 limit to account for outages and reliability margin are the main drivers for congestion on Path 15.

[11] Details on constraints with shift factors less than two 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
PATH15_S-N	$0.32	0.97%	-$0.33	-1.06%	-$0.31	-0.97%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	-0.01%	$0.18	0.57%	-$0.27	-0.82%
OMS 4379177 IVALLEY BNK81_NG2					$0.32	1.01%
LBN_S-N	$0.09	0.26%	-$0.11	-0.36%	-$0.11	-0.33%
OMS_3849098_LBN_SN	$0.05	0.15%	-$0.07	-0.22%	-$0.06	-0.20%
OMS 4008879 Path15_SN	$0.06	0.18%	-$0.06	-0.18%	-$0.05	-0.17%
OMS 4410597 TL23055_NG					$0.13	0.40%
23040_CROSSTRIP					$0.12	0.38%
OP-6610_ELD-LUGO	$0.03	0.07%	$0.06	0.17%	$0.04	0.13%
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_81					$0.10	0.30%
24086_LUGO _500_24238_RANCHVST_500_BR_1 _1	-$0.02	-0.05%	$0.04	0.11%	$0.04	0.11%
OMS 4368629 TL23055_NG					$0.08	0.26%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1			$0.03	0.10%	-$0.05	-0.16%
30735_METCALF _230_30042_METCALF _500_XF_13	$0.04	0.12%	-$0.02	-0.06%	-$0.02	-0.05%
MIGUEL_BKs_MXFLW_NG					$0.07	0.22%
OMS 4158606 ELD-LUGO	$0.02	0.05%	$0.03	0.11%	$0.02	0.05%
OMS 4008893 Path15_SN	$0.02	0.07%	-$0.02	-0.07%	-$0.02	-0.06%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.01	-0.03%	$0.02	0.06%	$0.02	0.06%
OMS 4186537 Path15_S-N	$0.02	0.04%	-$0.02	-0.05%	-$0.02	-0.05%
6110_SOL10_NG	$0.02	0.05%	$0.01	0.04%	$0.01	0.03%
OMS 4361698 TL23055_NG					$0.03	0.11%
OMS 4488708 TL23055_NG					$0.03	0.11%
Other	$0.01	0.04%	$0.00	0.01%	$0.21	0.64%
Total	$0.64	1.91%	-$0.26	-0.84%	$0.32	1.00%

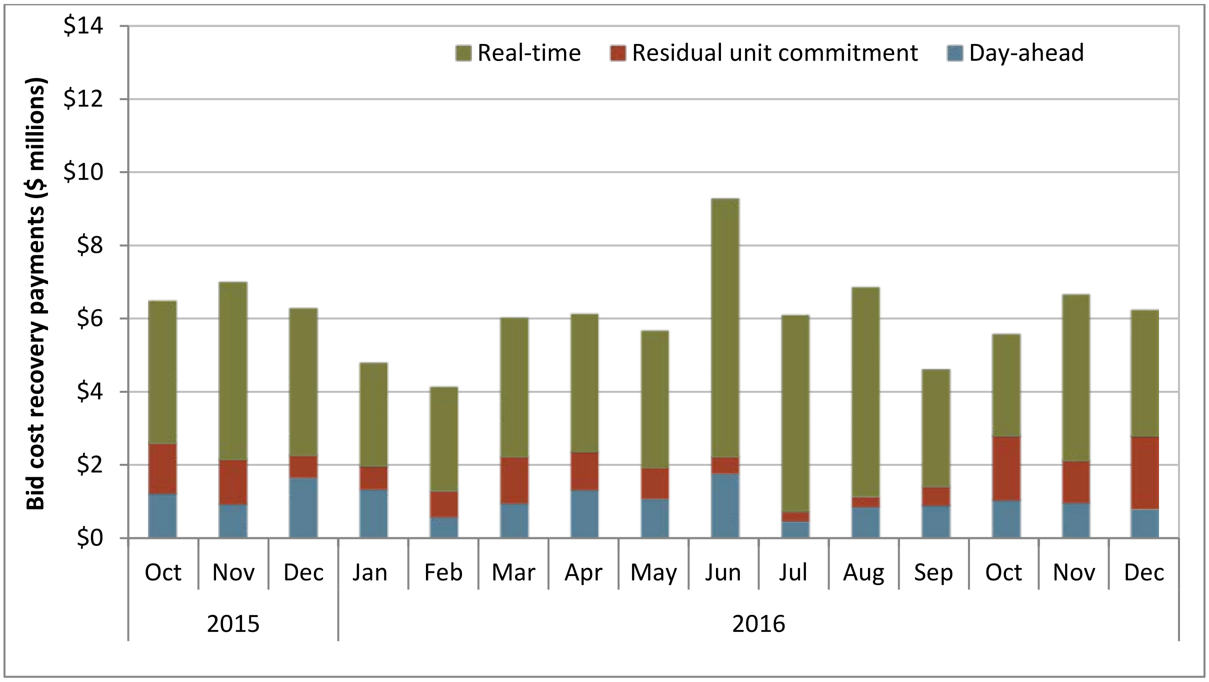
1.4 Bid cost recovery

Estimated bid cost recovery payments for the fourth quarter totaled about $19 million. This is about the same amount paid during the fourth quarter of 2015 and during the third quarter of 2016.

Bid cost recovery attributed to the day-ahead market totaled about $3 million, up about $0.5 million from the prior quarter, when values were very low. In the fourth quarter, bid cost recovery payments for residual unit commitment totaled about $5 million, the highest amount during the last four quarters.

Bid cost recovery attributed to the real-time market totaled about $11 million, down about $3 million from the prior quarter. Unlike the prior quarter, real-time bid cost recovery payments were somewhat uniformly distributed throughout the quarter with no specific days where payments were particularly large. These real-time bid cost recovery payments were paid to a number of units in the real-time market whose payments were less than variable costs. There was little concentration on particular units and much of these payments did not originate from exceptional dispatches or minimum online commitments.

Figure 1.5 Monthly bid cost recovery payments



1.5 Convergence bidding

Convergence bidding was slightly unprofitable overall during the fourth quarter, and was just the second quarter that virtual bidding was not profitable since implementation in February 2011. Net revenues from the market during the quarter were about $1.3 million. Virtual supply generated net revenues of about $4.9 million, while virtual demand accounted for approximately $3.5 million in net payments to the market. However, combined net revenues for virtual supply and demand totaled negative $2.6 million (payments) after including about $3.9 million of virtual bidding bid cost recovery charges.

Offsetting virtual demand with supply bids at different locations is designed to profit from higher anticipated congestion between these locations in the real-time market. This type of offsetting bid represented about 49 percent of all accepted virtual bids in the fourth quarter, up from 45 percent in the previous quarter.

Total hourly cleared volumes decreased in the fourth quarter to about 2,600 MW from about 3,200 MW during the previous quarter. Virtual supply averaged around 1,600 MW while virtual demand averaged around 1,000 MW during each hour of the quarter, both decreases from the previous quarter.

1.5.1 Convergence bidding trends

Total cleared virtual volume decreased in the fourth quarter to about 2,600 MW from about 3,200 MW during the previous quarter. On average, about 37 percent of virtual supply and demand bids offered into the market cleared in the fourth quarter, which is down from 43 percent in the previous quarter. This continues a trend of less cleared volume since the third quarter of 2015 and reflects the lowest quarterly percentage cleared since convergence bidding began in 2011.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 630 MW on average, which decreased from 870 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours by about 670 MW and 550 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in only hours ending 18 and 19. In the remaining 22 hours, net cleared virtual supply exceeded net cleared virtual demand. The highest net cleared virtual supply hour was hour ending 13 when almost 1,400 MW more of virtual supply cleared than virtual demand.

Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. For the quarter, net convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 18 of 24 hours.

Offsetting virtual supply and demand bids

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

Offsetting virtual positions accounted for an average of about 630 MW of virtual demand offset by 630 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 49 percent of all cleared virtual bids in the fourth quarter, up from about 45 percent in the previous quarter when the proportion of offsetting bids was at a three year low.

1.5.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the fourth quarter. Participants engaged in convergence bidding in the fourth quarter paid more into the ISO markets than they received *after* accounting for bid cost recovery charges. This resulted in net payments of about $2.6 million. Revenues before accounting for bid cost recovery charges were $1.3 million. Thus, the net payments by virtual bids were driven primarily by charges associated with bid cost recovery payments.

Virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[12] When the ISO commits units, it may pay market participants through the bid

[12] If physically generating resources clearing in the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecast demand. Convergence bidding increases unit commitment requirements to ensure sufficient generation in real time when the net position is virtual supply. The opposite is true when virtual demand exceeds virtual supply.

cost recovery mechanism to ensure that market participants are able to recover start-up, minimum load, transition, and energy bid costs.

Because virtual bids can influence unit commitment, they share any associated costs. Specifically, virtual bids can be charged bid cost recovery payments under two charge codes.

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand. In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply. In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

Figure 1.6 shows total monthly net revenues for virtual supply (green bar), total net revenues for virtual demand (blue bar), the total amount paid for bid cost recovery charges (red bar), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). This chart shows that residual unit commitment costs paid for by convergence bids increased from the previous quarter, as a result of higher overall residual unit commitment costs in 2016 during the fourth quarter.

Before accounting for bid cost recovery charges:

- Total market revenues were positive in November and December, but negative in October. Monthly net revenues during the fourth quarter totaled about $1.3 million, compared to about $6.9 million during the same quarter in 2015, and about $12.6 million during the previous quarter. This was one of the lowest values for net revenue recorded since virtual bidding began in 2011.
- Virtual supply was profitable during all three months of the quarter as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply generated net revenues of about $4.9 million during the quarter before accounting for bid cost recovery charges.
- Virtual demand revenues were negative in all three months of the quarter. In total, virtual demand accounted for around $3.5 million in net payments to the market for the quarter.

After accounting for bid cost recovery charges:

- Convergence bidders paid about $2.6 million after subtracting bid cost recovery charges of about $3.9 million for the quarter.[13,14] Bid cost recovery charges were about $1 million, $0.9 million and $2 million in October, November and December, respectively.

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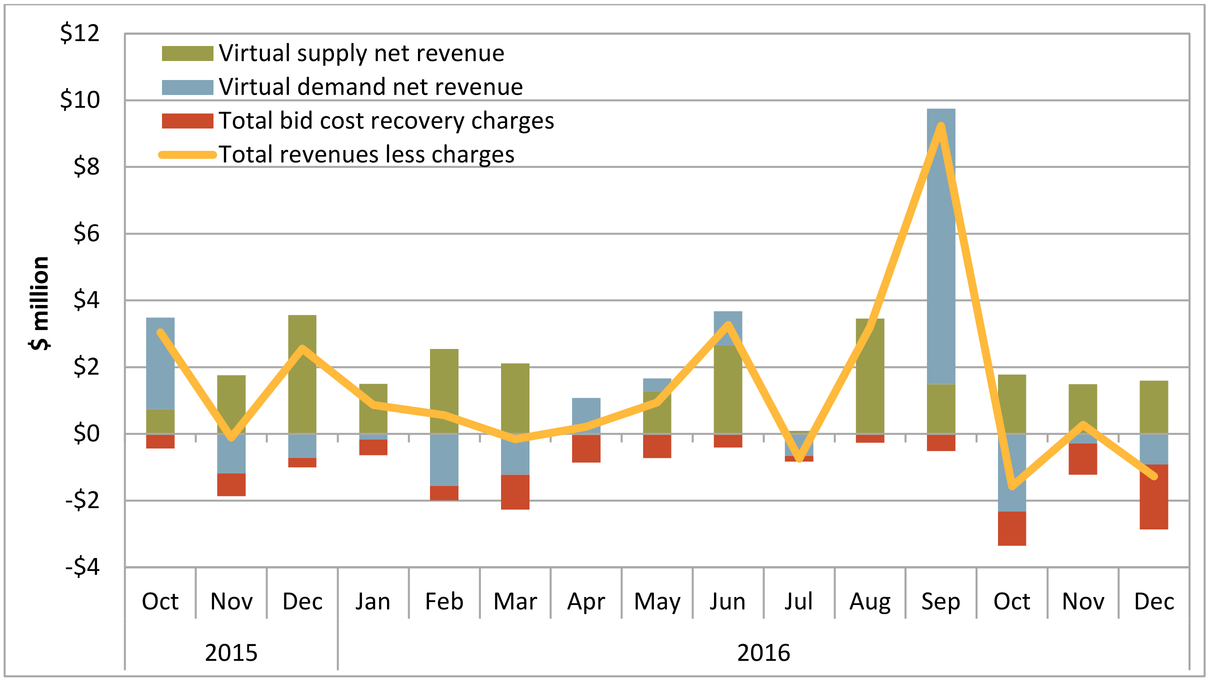
13 Further detail on bid cost recovery and convergence bidding can be found here, p.25: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

14 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.

Figure 1.6 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.5 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.[15] As shown in Table 1.5, financial entities represented the largest segment of the virtual bidding market in terms of volume, accounting for about 61 percent of volume and about 68 percent of settlement revenue. Marketers represented about 27 percent of the trading volumes, but only about 18 percent of the settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of volumes (about 12 percent) and settlement dollars (about 14 percent).

[15] 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.

Table 1.5 Convergence bidding volumes and revenues by participant type (October – December)

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	670	903	1,573	-$2.25	$3.26	$1.01
Marketer	275	434	710	-$1.00	$1.26	$0.26
Physical load	0	179	179	$0.00	$0.14	$0.14
Physical generation	32	91	123	-$0.28	$0.21	-$0.07
Total	**978**	**1,607**	**2,584**	**-$3.5**	**$4.9**	**$1.3**

1.6 Congestion revenue rights

As discussed in DMM's 2015 annual report, since 2012 electric ratepayers – who ultimately pay for the cost of transmission managed by the ISO – received an average of about $130 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments made to entities purchasing these rights.[16] During 2016, congestion revenue rights auction revenues were $47 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents $0.68 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down from $0.73 during 2015.

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).[17] 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

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16 *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 182-190, 225-226: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

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

transmission. When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments represents a loss to ratepayers. The losses therefore cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

As explained in DMM's 2015 annual report, DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction.[18]

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 the ratepayer payments 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 1.7 compares the following:

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

Ratepayers lost a total of $47 million during 2016 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This was a slight increase from nearly $46 million ratepayers lost during 2015.

Auction revenues were only 68 percent of payments made to non-load-serving entities during 2016, down from 73 percent during 2015. This was because auction revenues fell more than ratepayer payments to auctioned rights holders. Auction revenues fell 21 percent in 2016 to $99 million from $126 million in 2015. Ratepayer payments to auctioned rights holders fell 15 percent to $147 million from $172 million.

[18] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 182-190: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

Figure 1.7 Auction revenues and payments to non-load-serving entities

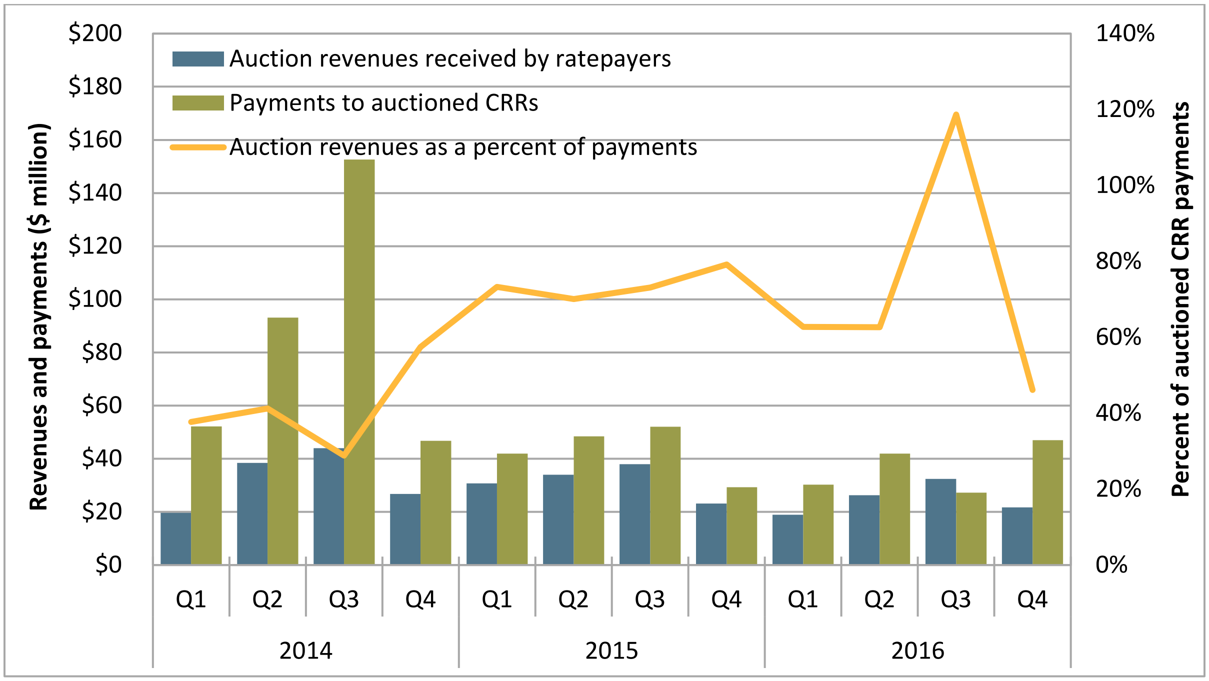


Figure 1.8 through Figure 1.11 show quarterly auction revenues paid to all entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- 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.

Figure 1.8 through Figure 1.11 show congestion revenue right auction results for all four participant types: financial, marketer, generator, and load-serving entity. Similar to Figure 1.7, these charts show auction revenues and congestion revenue rights payments from 2014 through 2016. Highlights from these figures show the following for 2016:

- Financial entities continued to have the highest profits between the entity types, at $33 million. This was down from $47 million in 2015. Marketer profits were $10 million, up from a $7 million loss in 2015. Generator profits were $5 million, down from $7 million in 2015.
- Financial entities paid 63 cents in auction revenue per dollar received. This was up from 51 cents paid in 2015. Generators also paid 63 cents, down from 72 cents in 2015. Marketers paid 78 cents, down from 114 cents in 2015.
- 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 gained about $3 million from rights they explicitly sold in the auction in 2016, down from $14 million in 2015.

Figure 1.8 Auction revenues and payments (financial entities)

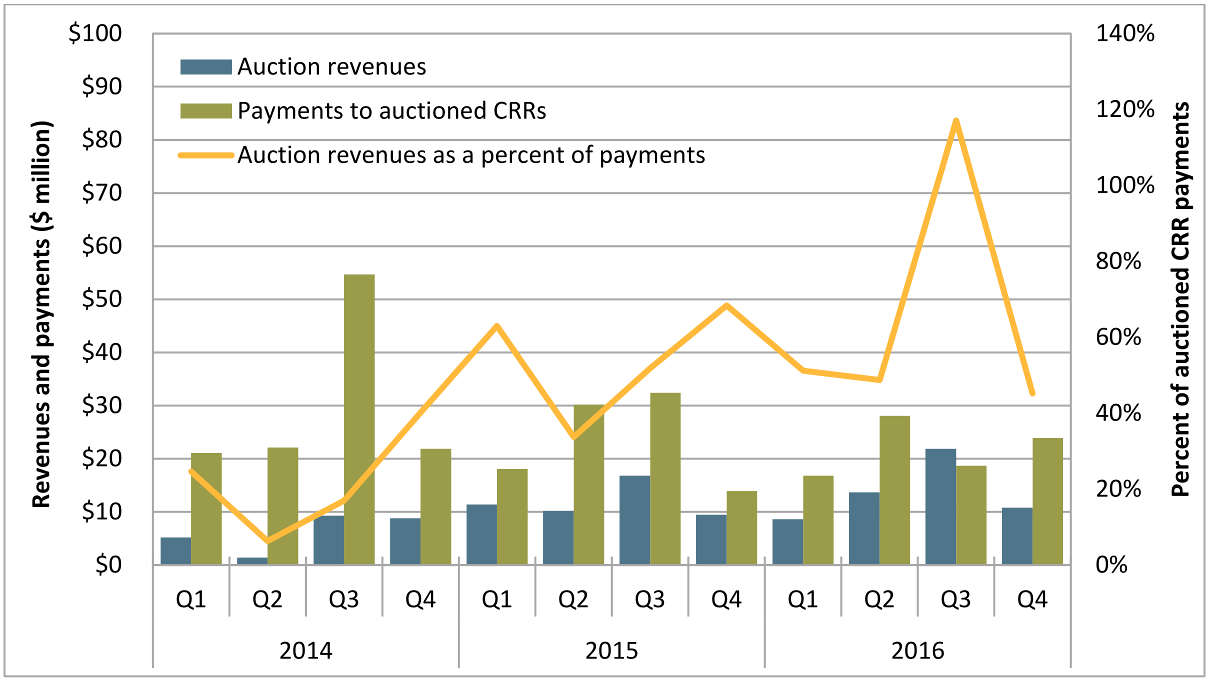


Figure 1.9 Auction revenues and payments (marketers)

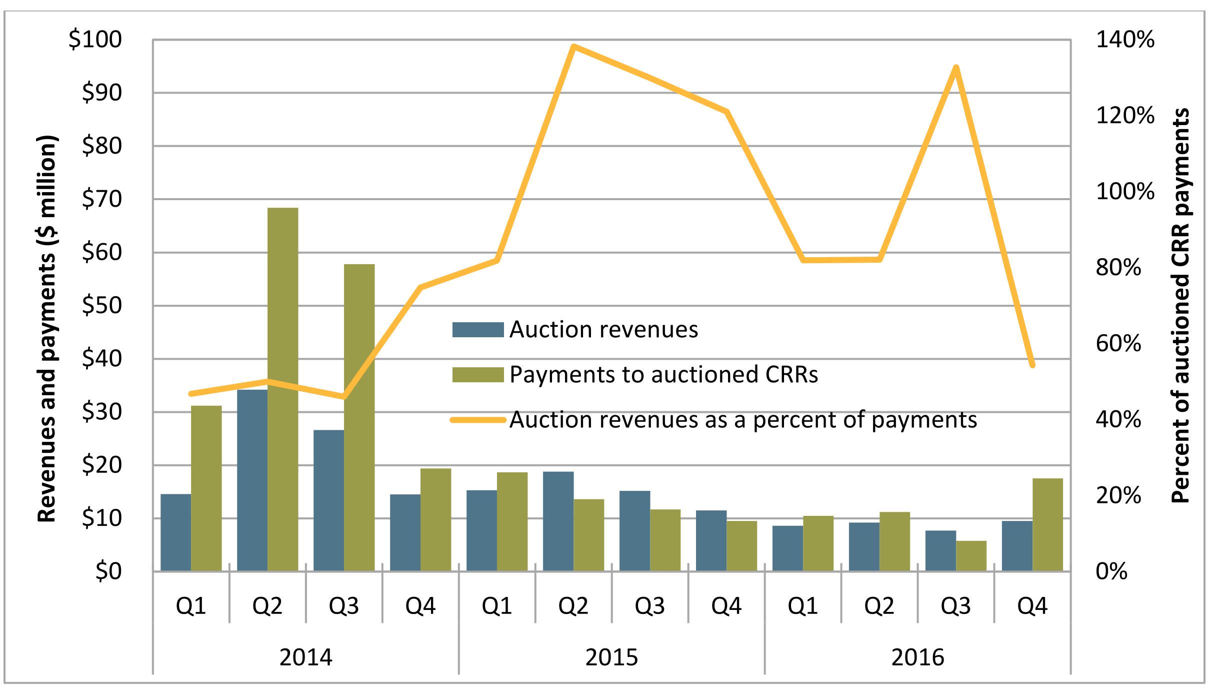


Figure 1.10 Auction revenues and payments (generators)

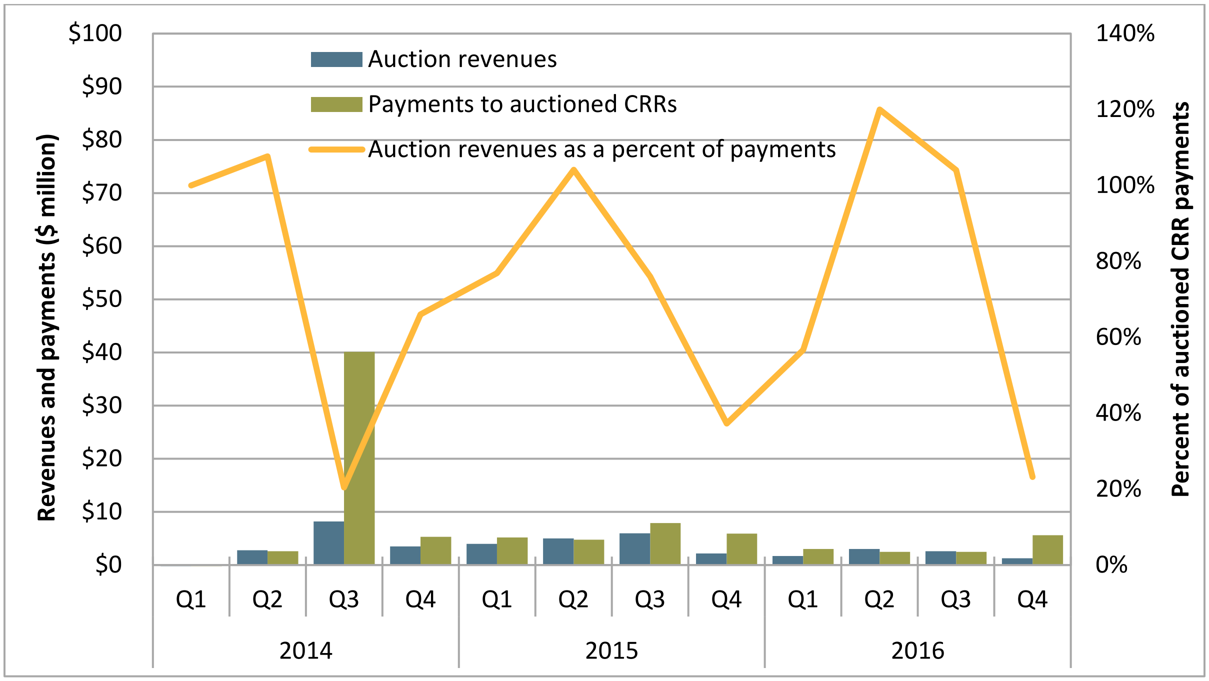
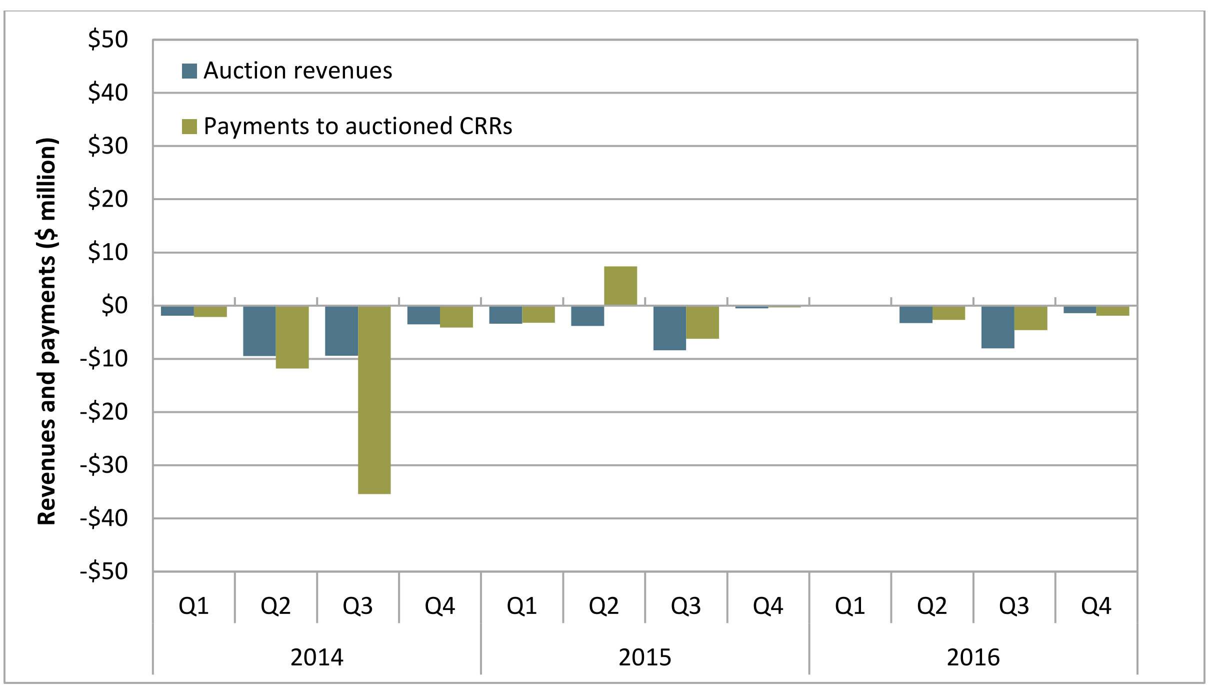


Figure 1.11 Auction revenues and payments (load-serving entities)



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.[19] DMM believes the current auction is unnecessary and could be eliminated. 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 indicated the ISO would consider scheduling an initiative on this issue and included it in the 2017 stakeholder initiative catalog.[20] The ISO is currently planning an initiative to investigate congestion revenue rights auction efficiency slated for the latter half of 2017.[21]

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

20 2017 *Stakeholder initiatives catalog*, November 4, 2016, p.27: http://www.caiso.com/Documents/RevisedDraft_2017StakeholderInitiativesCatalog.pdf.

21 *Policy update – Market performance and planning forum*, January 18, 2017, p.71: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum_Jan18_2017.pdf.

2 Energy imbalance market

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

- Settlement prices were about $30/MWh in PacifiCorp East, NV Energy, and Arizona Public Service for the fourth quarter. This is a result of little transfer congestion between these areas and the ISO during the quarter.
- Settlement prices in PacifiCorp West and Puget Sound Energy were $23/MWh and were lower than the other energy imbalance market area prices because of continued congestion from PacifiCorp West into the ISO and PacifiCorp East.
- The frequency of intervals that the power balance constraint was relaxed remained very low during the quarter in each balancing area.
- The number of hours in which a balancing area failed the upward sufficiency test increased significantly in November for all areas. In addition, Arizona Public Service failed the downward sufficiency test frequently in November and December.
- The ISO and NV Energy were net importers in the energy imbalance market, while PacifiCorp East and Arizona Public Service tended to be net exporters. Puget Sound Energy was a slight net importer and PacifiCorp West was a slight net exporter. However, the direction and volume of transfers between the ISO and different EIM areas fluctuated significantly based on actual real-time market conditions.
- The available balancing capacity mechanism continued to have a limited impact on reducing the number of power balance constraint relaxations in the fourth quarter. NV Energy and Puget Sound Energy offered available balancing capacity into the market for most hours in the fourth quarter, while PacifiCorp East and PacifiCorp West did so infrequently. Arizona offered available balancing capacity during almost all intervals during October, offered less frequently in November, and less than half of all intervals in December.

2.1 Energy imbalance market performance

Energy imbalance market prices

Puget Sound Energy and Arizona Public Service became participants in the energy imbalance market on October 1 joining PacifiCorp and NV Energy. As seen in Figure 2.1, average settlement prices in the energy imbalance market differed between two distinct regions in the fourth quarter.[22] Average prices in the region including PacifiCorp East, NV Energy, and Arizona Public Service were $30/MWh. The balancing areas in this region had similar prices with each other and the ISO because of large transfer capacities and little congestion with the ISO. This differed somewhat from the third quarter when prices

[22] The load settlement price is an average of 15-minute and 5-minute prices, weighted by the amount of estimated load imbalance in each of these markets. The 15-minute market prices are weighted by the imbalance between base load and forecasted load in the 15-minute market, and the 5-minute prices are weighted by the imbalance between forecasted load in the 15-minute market and forecasted load in the 5-minute market.

in NV Energy were very similar to prices in the ISO, but prices were lower in PacifiCorp East because of increased exports. These exports resulted in congestion in the direction of the ISO, and slightly lower prices in PacifiCorp East. Additional transfer capacity in the energy imbalance market with the entry of Arizona Public Service appears to have contributed to reduced congestion from PacifiCorp East.

Prices in PacifiCorp West and Puget Sound Energy formed a second pricing region, averaging about $23/MWh in the fourth quarter. Prices here were lower than prices in the ISO because of limited transmission available from PacifiCorp West into the ISO and PacifiCorp East. This continued a trend from earlier in the year as a similar amount of congestion occurred from PacifiCorp West into the ISO during earlier quarters.

Figure 2.1 Monthly settlement prices

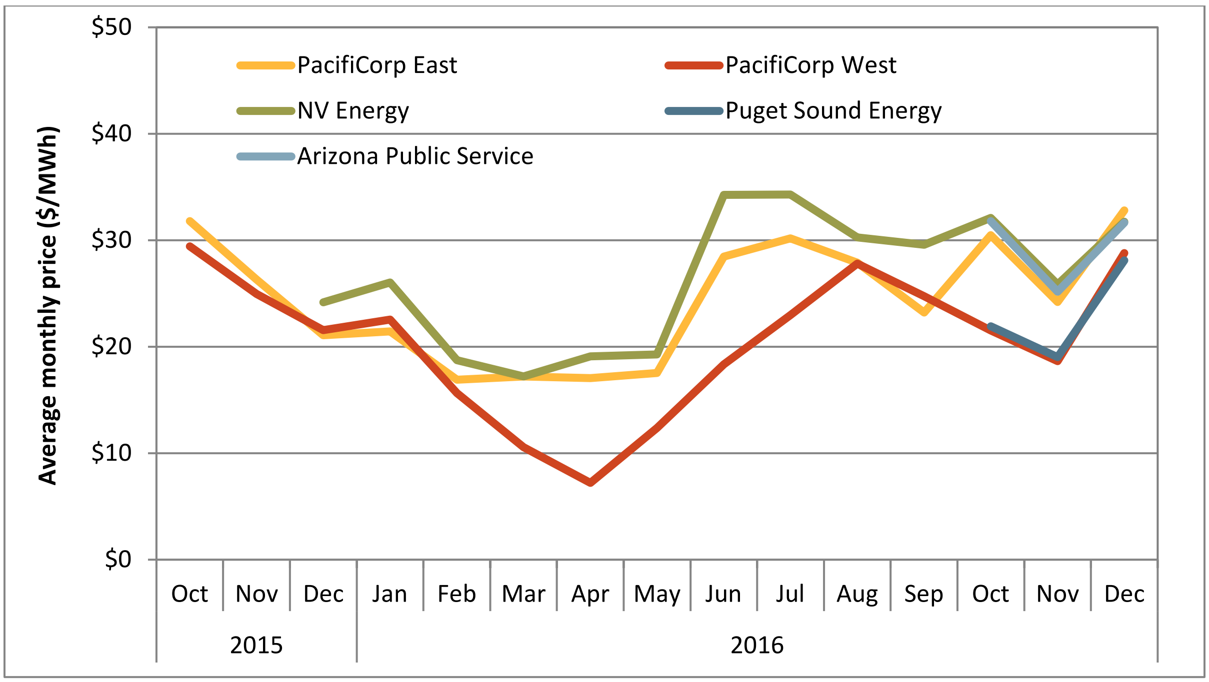
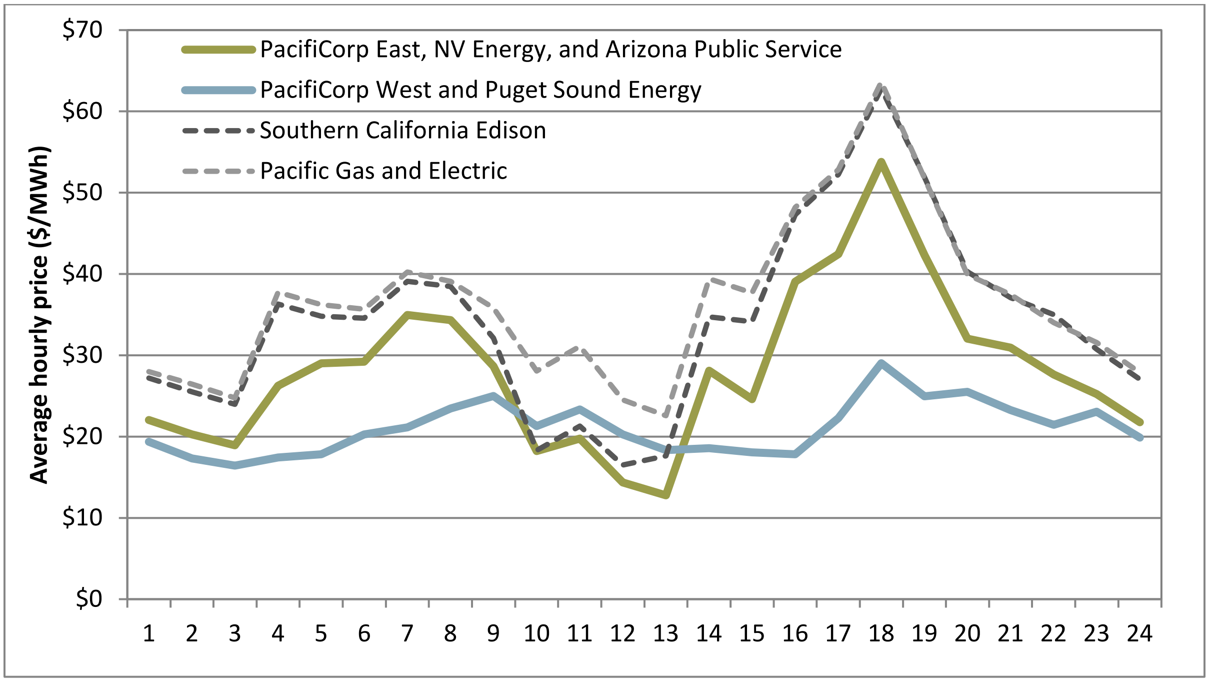


Figure 2.2 shows hourly average combined 5-minute prices for PacifiCorp East, NV Energy, and Arizona Public Service as well as combined prices for PacifiCorp West and Puget Sound Energy.[23] The figures also show 5-minute market prices for Southern California Edison and Pacific Gas and Electric for comparison with the ISO. Lower hourly prices for PacifiCorp East, NV Energy, and Arizona Public Service than the ISO were in part driven by greenhouse gas prices, but otherwise tracked very closely to system prices.[24] As noted above, hourly prices in PacifiCorp West and Puget Sound Energy typically tracked below the other areas because of congestion from PacifiCorp West.

[23] The individual balancing areas were grouped this way because of similar hourly pricing. Hourly 15-minute market prices show a similar pattern but at lower prices during peak load hours.

[24] Greenhouse gas prices were typically just over $5/MWh, and were applied to an energy imbalance area when energy was deemed delivered from that area into the ISO.

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



When the power balance constraint is relaxed due to insufficient upward ramping capacity (under-supply), prices could be set using the $1,000/MWh penalty price for this constraint. Power balance constraint relaxation due to insufficient downward ramping capacity (over-supply) can set prices at -$155/MWh in the pricing run.

During the fourth quarter, valid under-supply infeasibilities were very infrequent, particularly in comparison to levels observed in EIM in 2015. Valid under-supply infeasibilities occurred during about 0.2 percent of intervals in the 5-minute market for both Puget Sound Energy and Arizona Public Service and about 0.3 percent of intervals in the 15-minute market for Arizona Public Service. In addition, valid over-supply infeasibilities occurred during about 1 percent of real-time intervals for Arizona Public Service. However, because special transitional pricing is currently in effect in these areas, prices during power balance relaxations are based on the last dispatched bid price rather than the penalty price.[25] Further information on the price impact of transitional pricing can be seen in Section 3.

In the remaining areas, valid under-supply and over-supply infeasibilities occurred during less than 0.1 percent of 15-minute and 5-minute market intervals. The low frequency of infeasibilities during the quarter helped converge prices between the two regions mentioned above.

Energy imbalance market congestion

Table 2.1 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. During the fourth quarter, internal congestion in PacifiCorp East and NV Energy increased

[25] The special transitional pricing is in effect for the first six months of EIM participation. Transitional pricing is sometimes referred to as price discovery.

significantly compared to previous quarters. Congestion in PacifiCorp East was mainly a result of a modelling enhancement that resulted in a single constraint binding during 15 percent of intervals in both the 15-minute and 5-minute markets. In the NV Energy area, the constraints were binding due to their limits being conformed down because the transmission elements were rated incorrectly. In the rest of the energy imbalance market areas, internal congestion was low, even after an increased number of constraints were enforced following FERC's November 19, 2015, Order.[26]

Persistent low congestion 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 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 may be more possible because almost all of the generation within each energy imbalance market area is scheduled by a single entity.

Table 2.1 Percent of intervals with congestion on internal EIM constraints

	2014	2015				2016			
	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%
PacifiCorp West	0.1%	0.0%	0.0%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%
NV Energy					0.0%	0.0%	0.1%	0.3%	3.2%
Puget Sound Energy									0.0%
Arizona Public Service									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%
PacifiCorp West	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
NV Energy					0.0%	0.0%	0.2%	0.3%	3.2%
Puget Sound Energy									0.0%
Arizona Public Service									0.0%

Available balancing capacity

The ISO implemented the available balancing capacity (ABC) mechanism in the energy imbalance market in late March 2016. This enhancement allows for market recognition and accounting of capacity that

26 *Order on Proposed Market-Based Tariff Changes*, November 19, 2015, ER15-2281-000: https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

entities in these areas have available for reliable system operations, but is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each energy imbalance market entity in their hourly resource plans. The available balancing capacity mechanism enables the ISO system software to deploy such capacity through the energy imbalance market, and prevents market infeasibilities that may arise without the availability of this capacity.[27]

In this report, DMM provides a short summary of the available balancing capacity mechanism since it was implemented in March, and highlights issues from the fourth quarter. FERC's December 17, 2015, Order on the available balancing capacity proposal requires that the ISO submit quarterly reports on its performance.[28] The ISO filed the initial report with FERC on November 10, 2016.[29]

Figure 2.3 and Figure 2.4 summarize the frequency of upward and downward available balancing capacity offered by each energy imbalance market area. Capacity in the upward and downward directions in the NV Energy area was offered in almost all hours of the fourth quarter. The frequency of offered capacity in the PacifiCorp East area was negligible in the fourth quarter. The frequency of offered capacity in PacifiCorp West was greater overall, with upward capacity offered more frequently at the end of the quarter and downward capacity offered more frequently at the beginning of the quarter.

The frequency of upward available balancing capacity offered in the PacifiCorp East area in the fourth quarter peaked in October, with capacity offered in 6 percent of hours. In PacifiCorp West, the highest frequency of upward available balancing capacity offered in the fourth quarter was in December, with capacity offered in 31 percent of hours. Upward available balancing capacity in PacifiCorp West was not offered in October, and was offered in only 2 percent of hours in November.

The most frequent offering of downward available balancing capacity in the fourth quarter in the PacifiCorp areas occurred in the month of October. During this month, downward available balancing capacity was offered in PacifiCorp West during 31 percent of hours. However, this level fell to 4 percent of hours in November and no downward capacity was offered by PacifiCorp in December.

Historically, the frequency of downward available balancing capacity offered in PacifiCorp West has been low. The month of October represents the most frequent offering of downward capacity in the PacifiCorp West area since the mechanism was implemented. No downward available capacity was offered in the fourth quarter in the PacifiCorp East area. The lack of downward available balancing capacity in PacifiCorp East in the fourth quarter continues a trend of low levels of capacity offered in PacifiCorp East that began in the third quarter.

Arizona Public Service and Puget Sound Energy became energy imbalance market participants in the fourth quarter. Arizona Public Service offered available balancing capacity in nearly all hours in both directions in October. However, the frequency of available balancing capacity offered by Arizona Public

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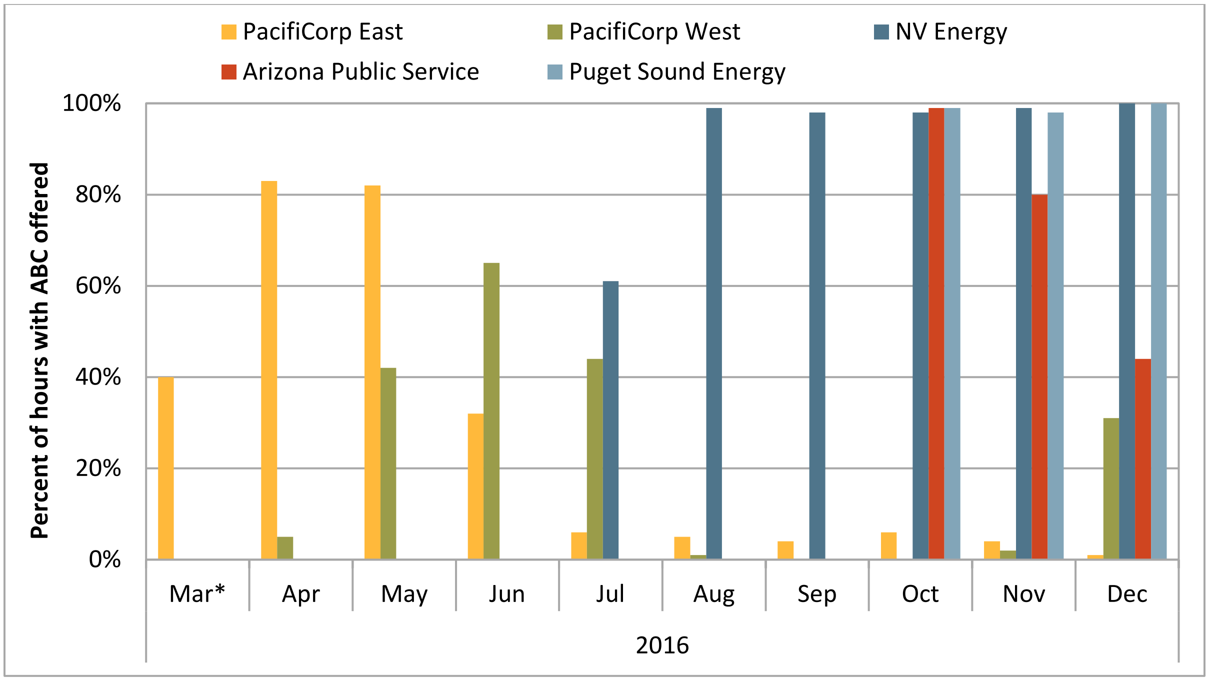
27 See *Order Accepting Compliance Filing – Available Balancing Capacity* (ER15-861-006), December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

28 Ibid.

29 See *EIM Available Balancing Capacity Quarterly Report for March 23 – June 30, 2016* (ER15-861), November 10, 2016: http://www.caiso.com/Documents/Nov10_2016_EIM_AvailableBalancingCapacityQuarterlyReport_March23-June30_2016_ER15-861.pdf.

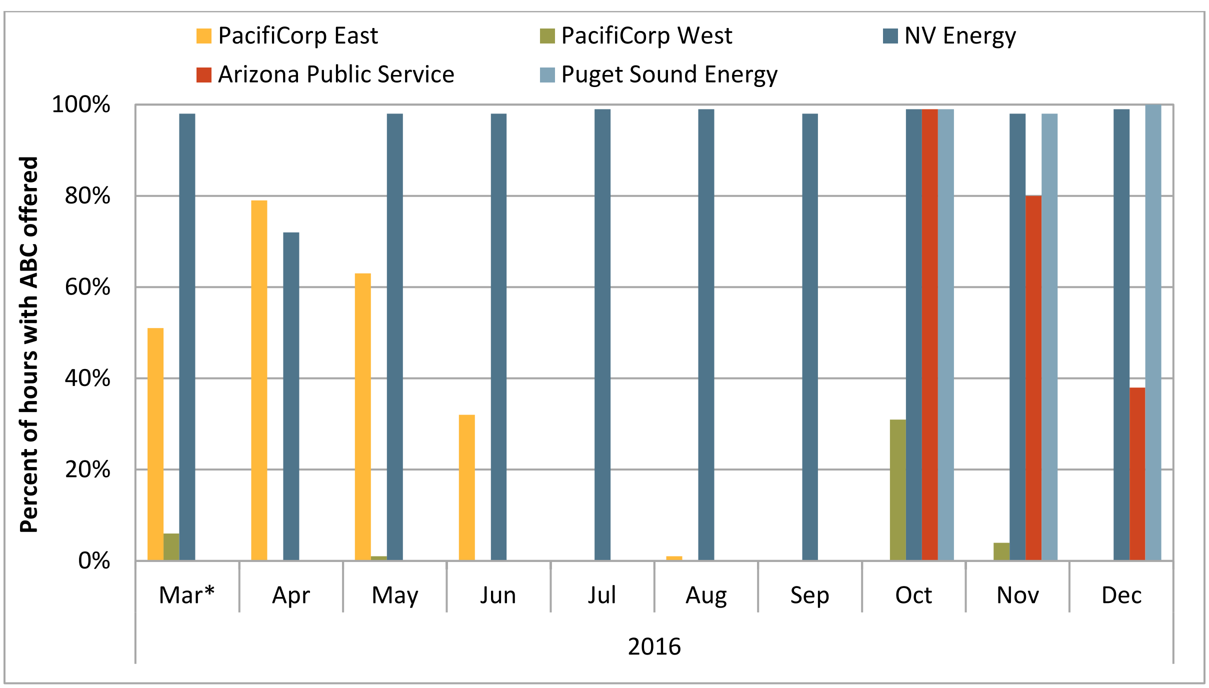
Service fell over the quarter, declining to 40 percent of hours by December. Puget Sound Energy offered available balancing capacity in nearly all hours in each direction throughout the fourth quarter.

Figure 2.3 Frequency of upward available balancing capacity offered



*March 23 through 31

Figure 2.4 Frequency of downward available balancing capacity offered



*March 23 through 31

Available balancing capacity is offered to the market on an hourly basis. The design of the available balancing capacity mechanism is to dispatch offered capacity for the purpose of resolving infeasibilities within the energy imbalance market balancing authority area offering the capacity, and for such capacity to participate in congestion management when dispatched. When available balancing capacity was offered in an energy imbalance market area in the fourth quarter, the amount offered typically ranged from 25 MW to 100 MW. The reported frequency of available balancing capacity dispatch remained relatively infrequent in the fourth quarter.

For the PacifiCorp areas and the Puget Sound Energy area, available balancing capacity dispatch in either direction was reported in less than 1 percent of 5-minute intervals in the fourth quarter. In the NV Energy area, the dispatch of downward capacity in October was reported in about 3 percent of 5-minute intervals, and dispatch of upward capacity occurred during less than 1 percent of 5-minute intervals. Both upward and downward capacity for November and December in the NV Energy area occurred in less than 1 percent of 5-minute intervals.

The Arizona Public Service area had the greatest reported frequency of available balancing capacity dispatch in the fourth quarter. Downward capacity was reported to be dispatched in the Arizona Public Service area in 8 percent of 5-minute intervals in October and November, and 2 percent of intervals in December. Dispatch of upward capacity in this area was reported in approximately 1 percent of intervals in the fourth quarter.

While the reported dispatch of available balancing capacity was infrequent, the number of instances of dispatch for the purpose of resolving infeasibilities as intended may be fewer. In addition, there may be instances where capacity was available, and dispatch may have been expected, but did not occur.

DMM is aware of instances where megawatt quantities reported as dispatched available balancing capacity may not actually represent capacity dispatched to resolve an infeasibility within a balancing authority area. These apparent dispatches may be, for example, the result of a resource ramping up or down and crossing the capacity range designated as available balancing capacity in the process. Additionally, DMM has observed instances where capacity is not dispatched when expected. Resource ramping limitations may be one explanation for such outcomes.

DMM continues to work with the ISO to better understand all potential reasons for which a given market quantity may be reported as dispatched available balancing capacity. This includes the potential reasons discussed here, as well as any potential reporting issues on quantities of available balancing capacity dispatch.[30] Such understanding may facilitate more detailed analysis by DMM at a later time.

2.2 Flexible ramping sufficiency test

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

[30] The ISO implemented a fix in early October to resolve some issues where available balancing capacity was reported as dispatched but a dispatch did not occur.

Since the beginning of the energy imbalance market there has been an upward ramping sufficiency test. A downward ramping sufficiency test was added in November. If an area fails the upward sufficiency test, energy imbalance market transfers into that area cannot be increased.[31] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased. This effect on transfers can impact the feasibility of the market solution as well as contribute to price separation across balancing areas.

An area will also fail the flexible ramping sufficiency test for any hour when the capacity test fails. The capacity test is a test designed to ensure that there is sufficient resource capacity available to meet forecasts and net exports for any given hour.[32]

Prior to June 2015, the flexible ramping sufficiency test requirement was calculated as the cumulative sum of the flexible ramping requirement for each of the 15-minute intervals during each operating hour. This method was recognized as overestimating the ramping requirements for an energy imbalance market entity because the total flexible ramping requirements for the 15-minute intervals within each operating hour are not additive. Therefore, in June 2015 the ISO modified the test to eliminate this cumulative summation so that it instead was based directly on the requirement for each 15-minute interval.

In November 2016, the ISO implemented the flexible ramping product, which replaced the flexible ramping constraint, as a new mechanism to ensure that there is sufficient upward and downward ramping capability available to account for forecasted net load changes and forecast ramping uncertainty. The ramping requirement also changed with the implementation of the flexible ramping product. Unlike the flexible ramping constraint, the demand for flexible ramping was no longer a point, but rather a demand curve (see Section 4.1). As such, the input to the flexible ramping sufficiency test requirement became the maximum requirement from the demand curve.[33,34]

Figure 2.5 shows the average number of hours per day in which an energy imbalance market area failed the sufficiency test in the upward direction.[35] The gray segments above Puget Sound Energy and Arizona Public Service reflect hours where the ISO indicated that the sufficiency test failed due to an underlying issue.[36] As shown in Figure 2.5, the number of hours where an area failed the sufficiency test increased significantly in November following the implementation of the flexible ramping product.

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31 *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.

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

33 For further detail, see DMM's presentation on January 18, 2017, to the Market Performance and Planning forum on the calculation of the flexible ramping sufficiency requirement: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum_Jan18_2017.pdf.

34 DMM has asked the ISO to reconsider how it uses the requirement from the demand curve and how the flexible ramping credit is calculated.

35 Some weeks shown in Figure 2.5 and Figure 2.6 reflect partial weeks. The end of October and beginning of November were split into two weeks for the chart. The week starting December 24 contains eight days.

36 Data pertaining to corrected sufficiency tests for Puget Sound Energy and Arizona Public Service was readily available to DMM as a part of the ISO's monthly EIM informational report on balancing areas under transitional pricing. Sufficiency tests that failed in error for other areas are not accounted for in Figure 2.5 and Figure 2.6. However, the ISO estimates that there should not be many of these cases.

Figure 2.6 provides the same information on failed sufficiency tests for the downward direction. Notably, Arizona Public Service validly failed the downward sufficiency test frequently, during about 12 percent of all hours.

Figure 2.5 Frequency of upward failed sufficiency tests by week

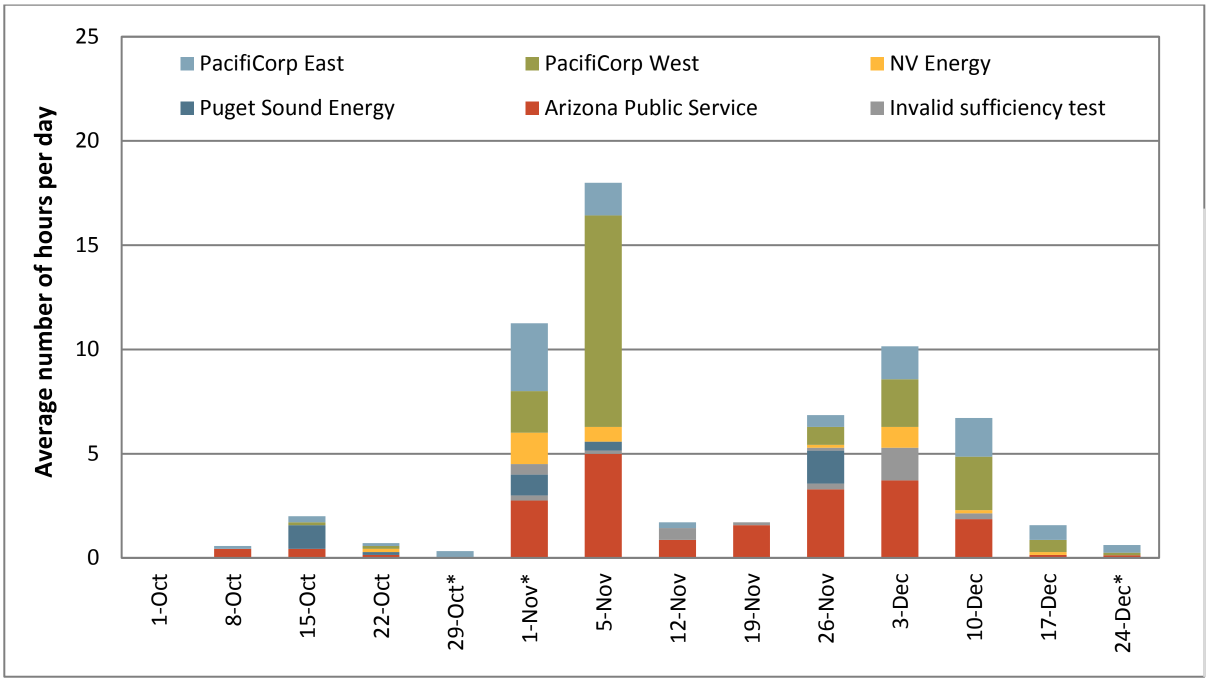
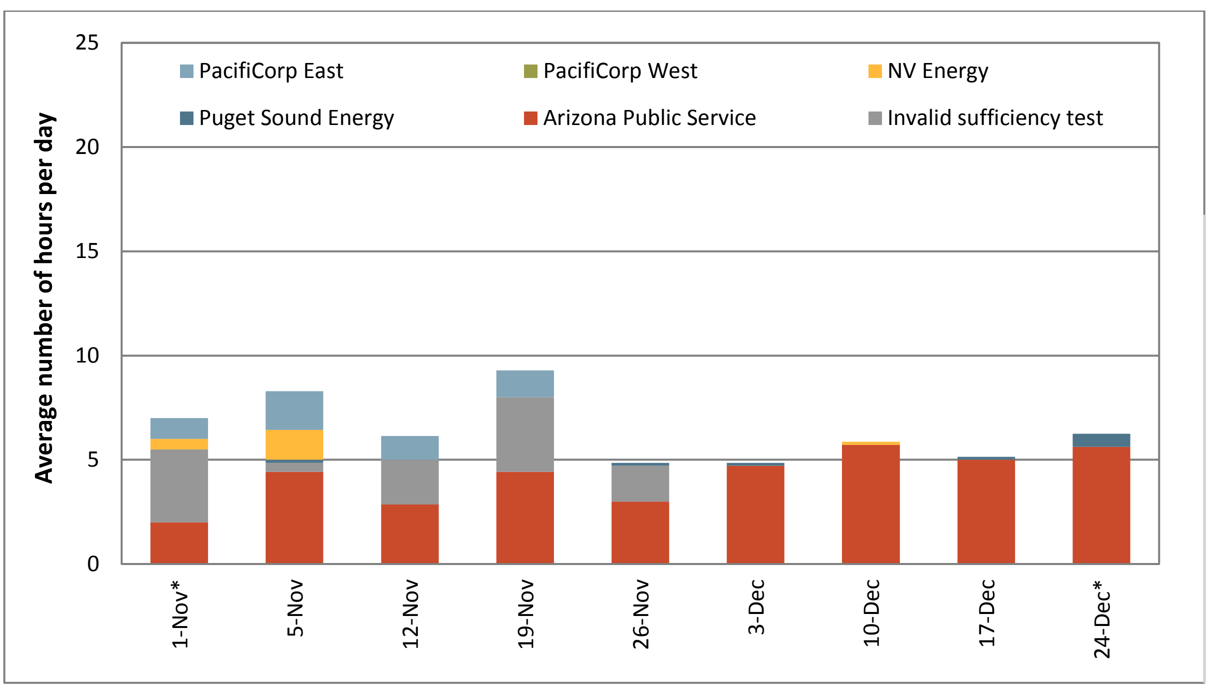


Figure 2.6 Frequency of downward failed sufficiency tests by week



2.3 Energy imbalance market transfers

The ability to transfer energy between the energy imbalance market areas and the ISO in the 15-minute and 5-minute markets is an important part of the value of the energy imbalance market. Transfers between the energy imbalance market areas and the ISO occur automatically based on bid-in costs of generation in the different regions. Different generation mixes and supply costs in each of the areas have given rise to predictable patterns for transfers between these areas and the ISO.

Table 2.2 shows the percentage of intervals that each energy imbalance market area and the ISO was either a net exporter or net importer and the net import quantity in the 5-minute market. Table 2.3 shows additional detail on transfer congestion in each area, including frequencies of transfer congestion and average transfers during congested intervals. These tables show that scheduled transfers tended to flow out of the PacifiCorp areas and into the ISO and NV Energy areas during the majority of intervals.

Table 2.2 shows that the ISO and NV Energy were net importers during the quarter, and that they imported greater quantities of energy than when exporting. Similarly, PacifiCorp East and Arizona Public Service tended to export energy more frequently than they imported, and when they exported they tended to export greater quantities of energy than while importing during the fourth quarter. Puget Sound Energy was a slight net importer and PacifiCorp West was a slight net exporter.

When there is no congestion between the regions, local prices tend to be set close to the system price. This is frequently happening between the ISO, NV Energy, PacifiCorp East, and Arizona Public Service where prices in all four areas were effectively set by aggregate supply and demand conditions in the combination of these areas during the quarter. When these areas experienced higher prices, constraints out of PacifiCorp West into the ISO and PacifiCorp East frequently bound and caused price separation between the PacifiCorp West and Puget Sound Energy areas and prices in the other energy imbalance market areas.

Table 2.2 Average net energy imbalance market transfers (October – December)

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	81%	-439	19%	95
PacifiCorp East	17%	-34	83%	344
PacifiCorp West	44%	-56	56%	65
NV Energy	71%	-186	29%	41
Puget Sound Energy	55%	-54	43%	42
Arizona Public Service	26%	-36	74%	194

Table 2.3 shows that there was almost no congestion between the ISO and NV Energy, and hence prices were very similar between the two areas during the quarter. There was also very little congestion

between the ISO, PacifiCorp East, and Arizona Public Service.[37] These results show somewhat different results from the prior quarter as east-to-west congestion was less during the fourth quarter, which appears to be a result of Arizona Public Service joining the energy imbalance market and adding a significant amount of additional transfer capability. Finally, this table also shows that there continued to be frequent congestion between PacifiCorp West and the ISO during about one quarter of all intervals. Most of this congestion was in the direction of the ISO and PacifiCorp East from PacifiCorp West.

Table 2.3 Congestion status and flows in EIM (October – December)[38]

	Percent of intervals	Average transfer (MW)
PacifiCorp East		
Congested from ISO	1%	-220
Congested toward ISO	4%	669
PacifiCorp West		
Congested from ISO	6%	-190
Congested to ISO	26%	131
NV Energy		
Congested from ISO	0%	-443
Congested to ISO	0%	161
Puget Sound Energy		
Congested from ISO	2%	-80
Congested toward ISO	14%	80
Arizona Public Service		
Congested from ISO	1%	-71
Congested to ISO	5%	189

Figure 2.7 shows further detail about how energy flowed between NV Energy, the ISO and PacifiCorp East on an hourly basis during the quarter. The green bars in this figure show that NV Energy received imports from PacifiCorp East during all hours of the day, on average. The blue bars show that NV Energy received imports from the ISO during mid-day hours, when solar generation was on-line, and exported energy to the ISO during almost all other hours. This resulted in a general pattern of east-to-west energy flows from PacifiCorp East through NV Energy to the ISO during the late evening and early morning hours and flows from both the ISO and PacifiCorp East into NV Energy during the peak solar hours of the day. Results in the fourth quarter were different from the third quarter, in that NV Energy was no longer a net exporter during the late morning hours.

Figure 2.8 shows similar information, but for Arizona Public Service rather than NV Energy. This chart shows that Arizona Public Service was a net exporter of energy, on average, during all hours of the day, and that the exports were almost entirely to the ISO. Additionally, during almost all hours of the day,

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37 Because there is no direct intertie between the ISO and PacifiCorp East and Puget Sound Energy, congestion between the two areas is calculated by comparing the congestion component of load aggregation point prices during each interval.

38 Table 2.3 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.

Arizona Public Service imported energy from PacifiCorp East. The import transfers from PacifiCorp East were generally smaller in magnitude than the corresponding exports to the ISO.

Figure 2.7 Average hourly imports into NV Energy from the ISO and PacifiCorp East (October – December)

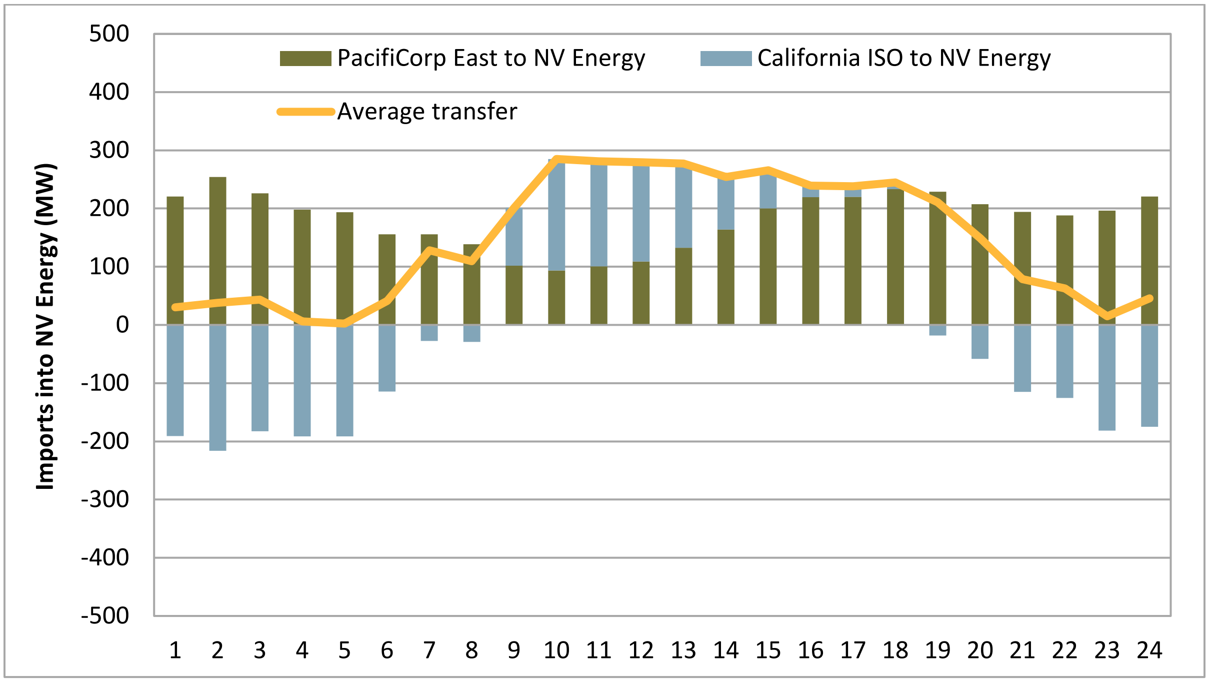


Figure 2.8 Average hourly imports into Arizona Public Service from the ISO and PacifiCorp East (October – December)

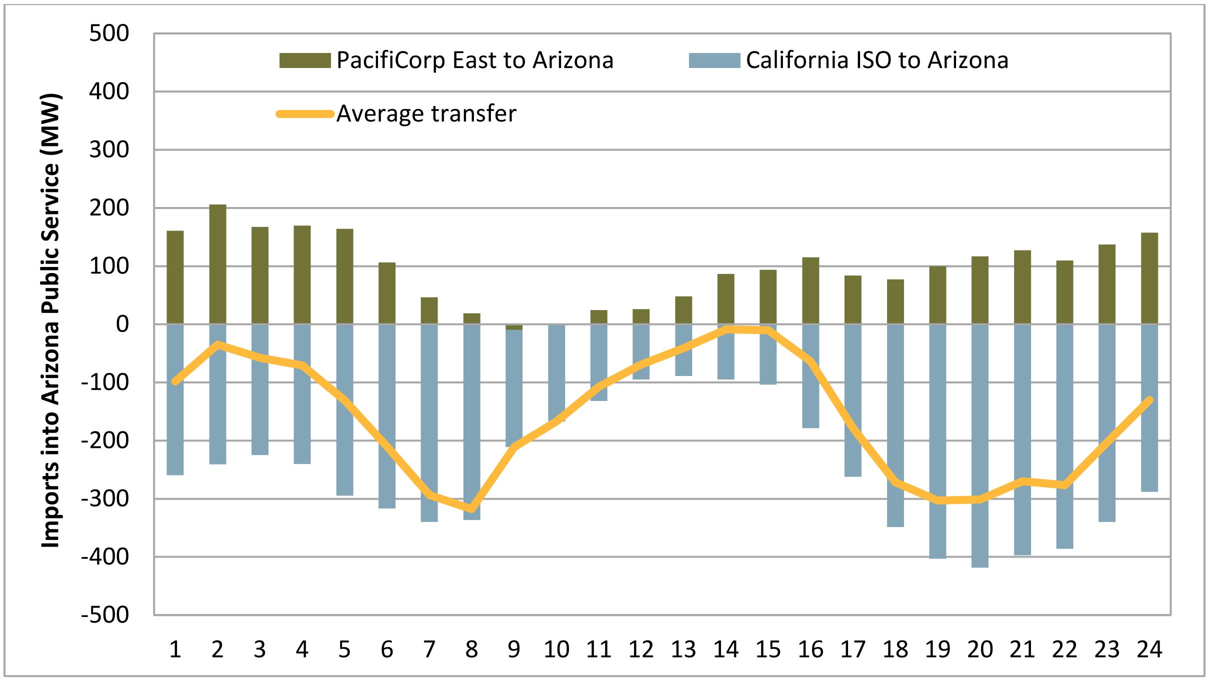
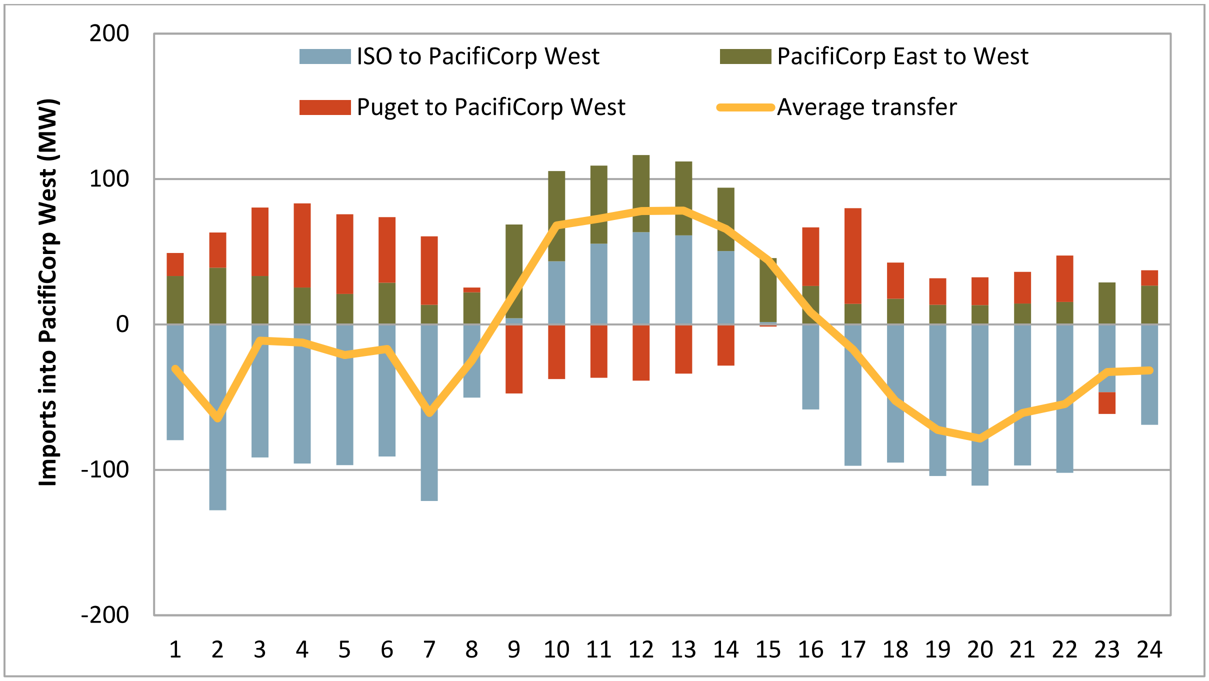


Figure 2.9 shows transfer flows between PacifiCorp West and the ISO, Puget Sound Energy, and PacifiCorp East. This figure shows that flows were considerably smaller to and from PacifiCorp West than transfers observed in NV Energy or Arizona Public Service. This reflects lower transfer capability between PacifiCorp West and the ISO and PacifiCorp East. The yellow line in this figure shows that PacifiCorp West is generally importing during midday hours and exporting during other hours of the day.

For most hours of the day, including the late afternoon through morning, PacifiCorp West tended to import energy from Puget Sound Energy and export to the ISO, indicating electricity moved in a north-to-south direction. During peak solar hours of the day the reverse was true, and PacifiCorp West imported energy from the ISO and exported to Puget Sound Energy. Figure 2.9 shows that PacifiCorp West always receives imports from PacifiCorp East. This is a byproduct of the transfer limits imposed between the two areas that specify that transfers only occur in the east-to-west direction between these two areas.

Figure 2.9 Average hourly imports into PacifiCorp West (October – December)



3 Load forecast adjustments

This section provides a summary of load forecast adjustments during the fourth quarter. Key trends include the following:

- NV Energy continued to use positive load adjustments frequently, at around 36 percent of intervals in the 15-minute market and 22 percent of intervals in the 5-minute market. Negative adjustments continued to be infrequent during the quarter. Adjustments in NV Energy followed a similar pattern to those applied in the ISO.
- PacifiCorp continued to use negative load adjustments somewhat frequently during the quarter. Load adjustments in PacifiCorp East were more frequent in the 5-minute market than in the 15-minute market.
- Adjustments in either direction were infrequent in Arizona Public Service and Puget Sound Energy.
- PacifiCorp adjusted load primarily for generation deviation and automatic time error correction, NV Energy adjusted load for reliability based control, while Arizona Public Service and Puget Sound Energy adjusted primarily for load forecast deviation.[39]
- The percentage of intervals when the energy power balance constraint was relaxed to allow the market software to balance modeled supply and demand remained relatively low during the quarter in the energy imbalance market, and therefore the load bias limiter had little impact on energy imbalance market prices.
- DMM provided recommendations to the ISO for enhancements to the load bias limiter feature to better reflect the impact of excessive load adjustments on creating power balance relaxations. Specifically, DMM recommended considering the change in adjustments from one interval to the next and the duration of an adjustment rather than solely the absolute value of any load adjustment. The ISO intends to implement this change. A technical bulletin on the enhancement was released on December 28 and a stakeholder call occurred on January 11 to review the proposed enhancement.[40]

Background

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. These adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of load adjustments including

39 Automatic time error correction is used to maintain interconnection frequency and to ensure that time error corrections and primary inadvertent interchange payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection. For more information refer to: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-004-WECC-02.pdf.

40 More information on the proposed changes to the load bias limiter can be found here: http://www.caiso.com/Documents/TechnicalBulletin_LoadConformanceLimiterEnhancement.pdf.

managing load and generation deviations, automatic time error correction, scheduled interchange variation, reliability events, and software issues.

The ISO enhanced the real-time market software in December 2012 to limit load forecast adjustments made by operators to only the available amount of system ramp. Beyond this level of load adjustment, a shortage of ramping energy occurs that triggers a penalty price through the relaxation of the power balance constraint without achieving any increase in actual system energy. With this software enhancement, known as the *load bias limiter*, load adjustments made by operators may be less likely to have extreme effects on market prices. This tool was extended to the energy imbalance market balancing areas in March 2015.

In response to concerns about the impact and transparency of load biasing and adjustments, FERC directed the ISO and EIM participants to collect and report additional information on the use and causes of load adjustments. As explained in FERC's December 17, 2015, Order on the ISO's available balancing capacity proposal:

> …. we direct CAISO to collect relevant data from each EIM Entity, for both the 15- and five-minute markets, on the frequency and magnitude of an EIM Entity's use of load biasing, load forecast adjustments, the reason for the adjustments, as well as any alternatives considered (e.g., use of manual dispatch). The CAISO should also retain documentation regarding the reliability needs that were addressed by these load forecast adjustments or load bias actions.[41]

FERC also indicated that:

> Additionally, we expect CAISO's Department of Market Monitoring to monitor and evaluate this information and include an analysis of the impacts of EIM Entities' load forecast adjustments or load bias actions on the EIM in its public Quarterly Report on Market Issues and Performance. Inclusion of this information in the Department of Market Monitoring's quarterly reports will assist the Commission in assessing the effects these actions have on market outcomes.[42]

In practice, DMM notes that it is not possible to determine whether the load adjustment entered by the operator makes the load estimate in the market software more accurate or less accurate. This is because the actual load is a combination of various factors and cannot actually be determined precisely in real-time but rather is a series of estimates and approximations of the true load. In addition, DMM notes that the load adjustment feature is designed to allow the operator to adjust for factors other than load forecast error that impact the overall net demand for imbalance energy that needs to be met by the real-time market software. For example, the load adjustment is also the mechanism by which operators can compensate for differences between modeled and actual generation.

Consequently, this report addressed the Commission's December 17 Order by providing the following information on the use and impacts of the load adjustment:

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41 The Order on Compliance Filing (December 17, 2015 Order, p. 50) can be found here: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

42 The Order on Compliance Filing (December 17, 2015 Order, p. 50) can be found here: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

- A summary of the general frequency, direction and magnitude of the load adjustments in the different energy imbalance market areas. The same data for the ISO are provided as a point of comparison and reference.
- A summary of the reasons for load adjustments reported by operators using standard categories developed for tracking the reasons for load adjustments on an interval-by-interval basis in the real-time market.
- An analysis of how load adjustments impacted prices by triggering the load bias limiter mechanism incorporated in the real-time software.

Frequency and size of load forecast adjustments

Figure 3.1 and Figure 3.2 show the frequency of positive and negative load forecast adjustments for PacifiCorp East, PacifiCorp West, NV Energy, Puget Sound Energy (PSE), and Arizona Public Service (APS) during the previous six months for the 15-minute and 5-minute markets, respectively. The same data for the ISO are provided as a point of comparison and reference.

Table 3.1 summarizes the average frequency and size of positive and negative load forecast adjustments in the 15-minute and 5-minute markets during the fourth quarter. As shown in the table, positive load adjustments were most frequent in NV Energy and the ISO, while negative load adjustments were most frequent in the PacifiCorp areas. For comparison, average load adjustments in the energy imbalance market were typically smaller in absolute magnitude than adjustments in the ISO, but made up a larger percentage of area load.

Though positive load adjustments were more frequent in PacifiCorp East compared to the previous quarter, the frequency of negative load adjustments in both PacifiCorp areas continued to prevail relative to positive adjustments during the fourth quarter. During intervals with negative adjustments, the amounts averaged around -105 MW for PacifiCorp East (about 2.3 percent of area load) and around -53 MW for PacifiCorp West (about 2.1 percent of area load) during the quarter, as shown in Table 3.1. PacifiCorp East and PacifiCorp West adjusted load forecasts much more frequently in the 5-minute market than in the 15-minute market.

In the NV Energy area, load adjustments in the 15-minute market were primarily in the positive direction, occurring in 36 percent of intervals compared to 2 percent of intervals in the negative direction. However, negative load adjustments were entered during 22 percent of intervals at around minus 80 MW in the 5-minute market, which was significantly more frequent than negative adjustments in the 15-minute market. Positive adjustments averaged almost 100 MW in the 15-minute market and around 70 MW in the 5-minute market.

Puget Sound Energy and Arizona Public Service adjusted the load forecast in either direction much less frequently than other areas. Puget Sound Energy adjusted the load forecast in either direction during about 15 percent of 15-minute intervals and 25 percent of 5-minute intervals. Similarly, operators in Arizona Public Service moved the load forecast in either direction during about 12 percent of 15-minute intervals and 18 percent of 5-minute intervals. However, the magnitude of load forecast adjustments as a percent of area load were generally larger in Arizona Public Service than other areas.

Figure 3.1 Average frequency of positive and negative load adjustments by BAA (15-minute market)

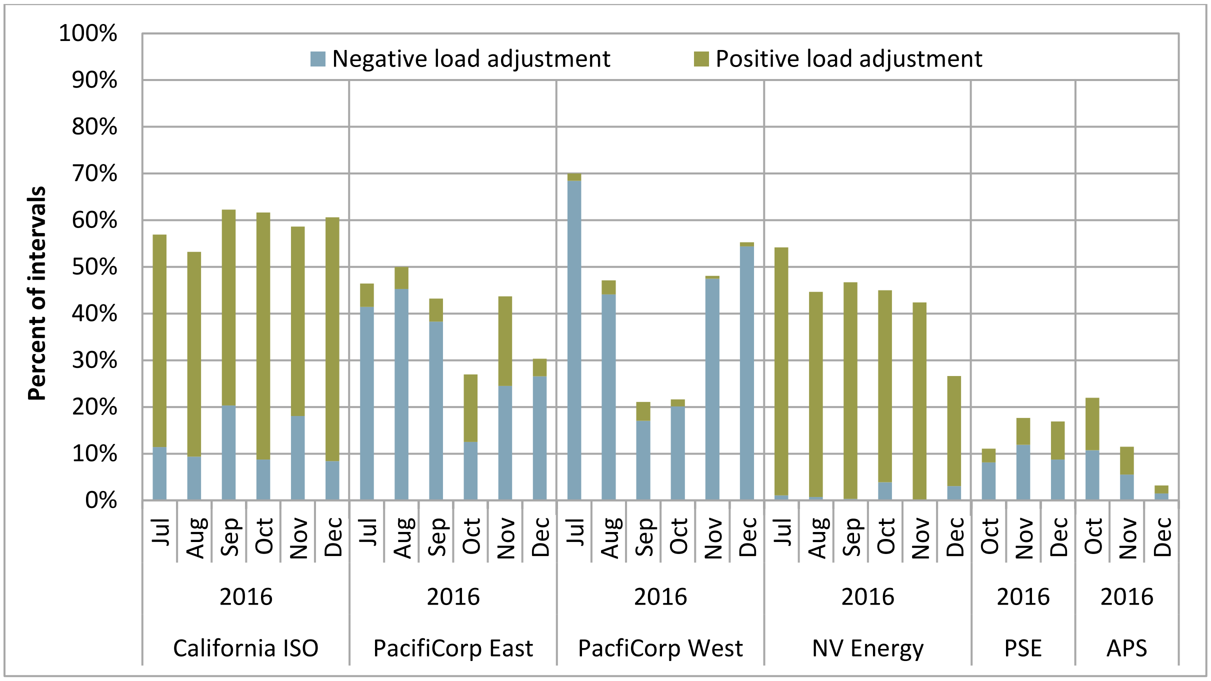


Figure 3.2 Average frequency of positive and negative load adjustments by BAA (5-minute market)

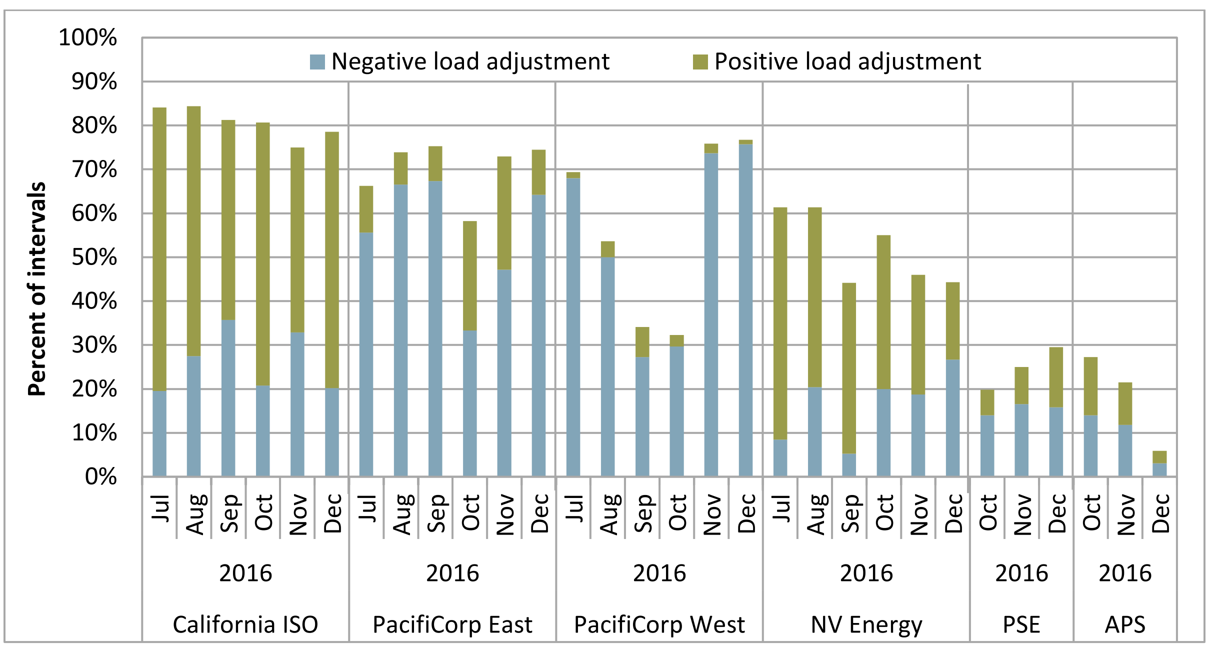


Table 3.1 Average frequency and size of load adjustments (October – December)

	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	49%	529	2.1%	12%	-274	1.2%	226
5-minute market	54%	437	1.8%	25%	-279	1.2%	167
PacifiCorp East							
15-minute market	12%	114	2.4%	21%	-104	2.2%	-8
5-minute market	20%	107	2.2%	48%	-107	2.2%	-30
PacifiCorp West							
15-minute market	1%	50	1.9%	41%	-51	2.1%	-20
5-minute market	2%	54	2.3%	60%	-56	2.3%	-32
NV Energy							
15-minute market	36%	97	2.6%	2%	-195	5.3%	30
5-minute market	27%	69	1.8%	22%	-80	2.3%	1
Puget Sound Energy							
15-minute market	6%	77	2.3%	10%	-68	2.5%	-2
5-minute market	9%	68	2.1%	15%	-66	2.3%	-4
Arizona Public Service							
15-minute market	6%	105	3.0%	6%	-121	4.4%	-1
5-minute market	9%	107	3.1%	10%	-126	4.6%	-3

Figure 3.3 shows the average hourly load forecast adjustment profile for the 15-minute and 5-minute markets during the fourth quarter for PacifiCorp East, PacifiCorp West, and NV Energy. Differences between adjustments in the 15-minute and 5-minute markets can arise from differences in either the frequency or magnitude of adjustments.

As shown by the blue lines in Figure 3.3, load in PacifiCorp East was adjusted more negatively in the 5-minute market than in the 15-minute market during the quarter, particularly during mid-day and late evening hours. Significant negative net load adjustments between hours ending 8 and 15 in the 5-minute market may be due to differences in forecasted and actual solar generation during generating hours.

The green lines show that in PacifiCorp West load was adjusted more frequently in the negative direction in the 5-minute market than in the 15-minute market resulting in lower net adjustments in the 5-minute market during all hours.

The red lines in Figure 3.3 provide information on load forecast adjustments for NV Energy, and show that load adjustments followed the load pattern. Net adjustments were low during the early morning, mid-day, and late evening hours and were highest during the evening peak load hours. Greater average net adjustments in the 15-minute market than the 5-minute market were primarily driven by more frequent negative adjustments in the 5-minute market.

Figure 3.4 shows the average hourly load adjustment for the 15-minute and 5-minute markets in Puget Sound Energy and Arizona Public Service. Because of the low frequency of load adjustments in these two areas, average hourly net load adjustments were relatively low. Overall, load adjustments followed their net load as they were highest during their morning and evening peak load hours. Significantly negative load forecast adjustments by Arizona Public Service in the morning hours may be related to overestimated net load as a result of higher than expected solar during the morning solar ramp or lower than expected load while demand is decreasing from its morning peak.

For comparison, Figure 3.5 shows the average hourly load adjustments for the 15-minute and 5-minute markets in the ISO during the fourth quarter. Like many of the other areas, the shape of the hourly average adjustment reflects the shape of hourly net load. Positive load adjustments were entered most frequently during morning and evening peak net load periods. In contrast, negative load adjustments were entered most frequently during early morning, mid-day, and late evening hours.

Differences in average load adjustments by the ISO between the 15-minute and 5-minute markets were largely related to the hourly frequency in which positive and negative load adjustments occurred. In particular, negative load adjustments were significantly more frequent during hours ending 9 through 12 and hours ending 18 through 24 in the 5-minute market than in the 15-minute market. Differences in load adjustments between the 5-minute and 15-minute markets may result in significantly different market outcomes.

Figure 3.3 Average hourly load adjustment – PacifiCorp and NV Energy (October – December)

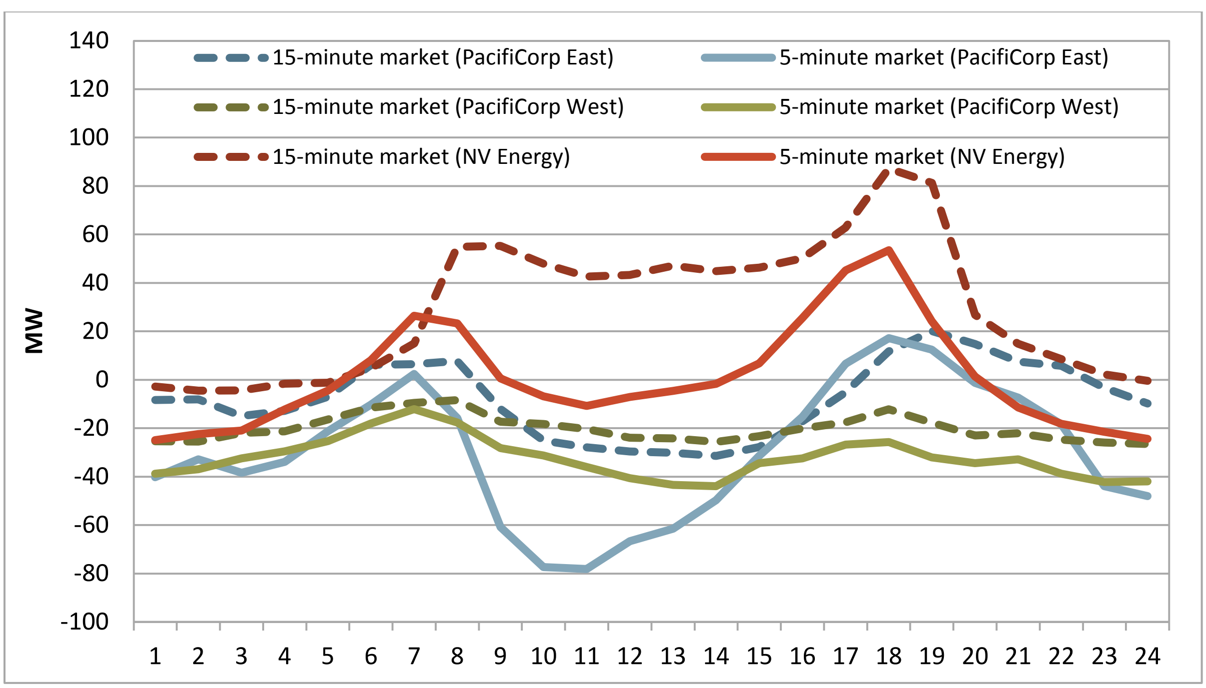


Figure 3.4 Average hourly load adjustment – Puget Sound Energy and Arizona Public Service (October – December)

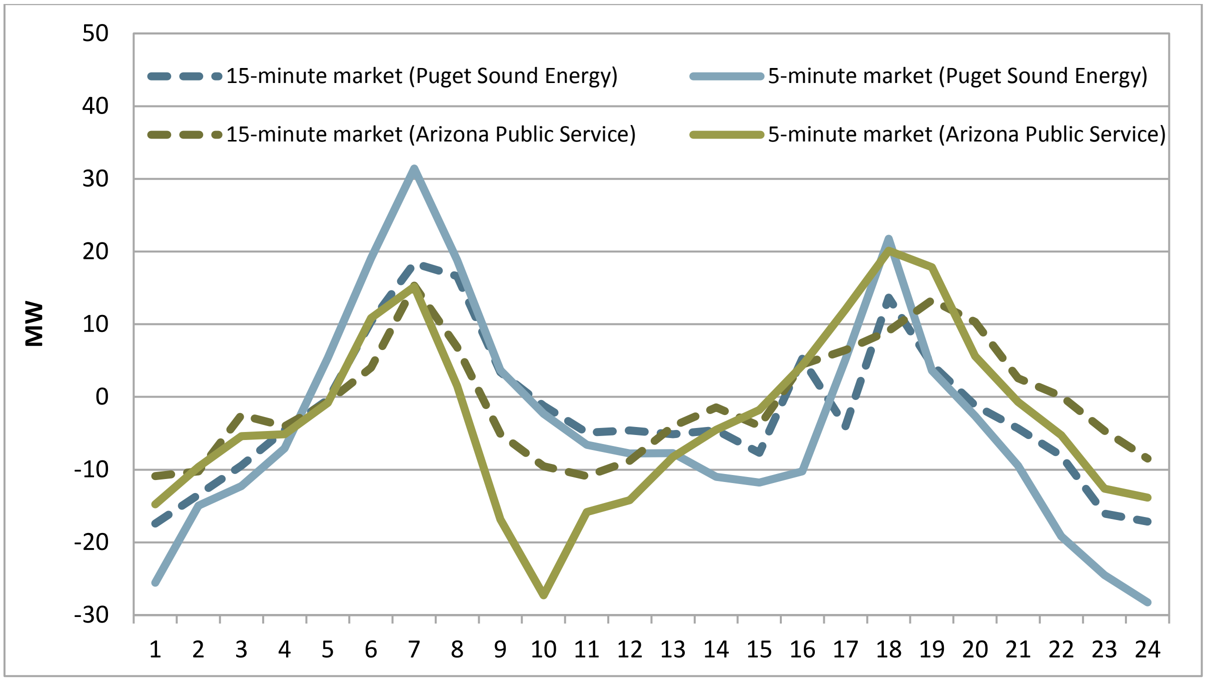
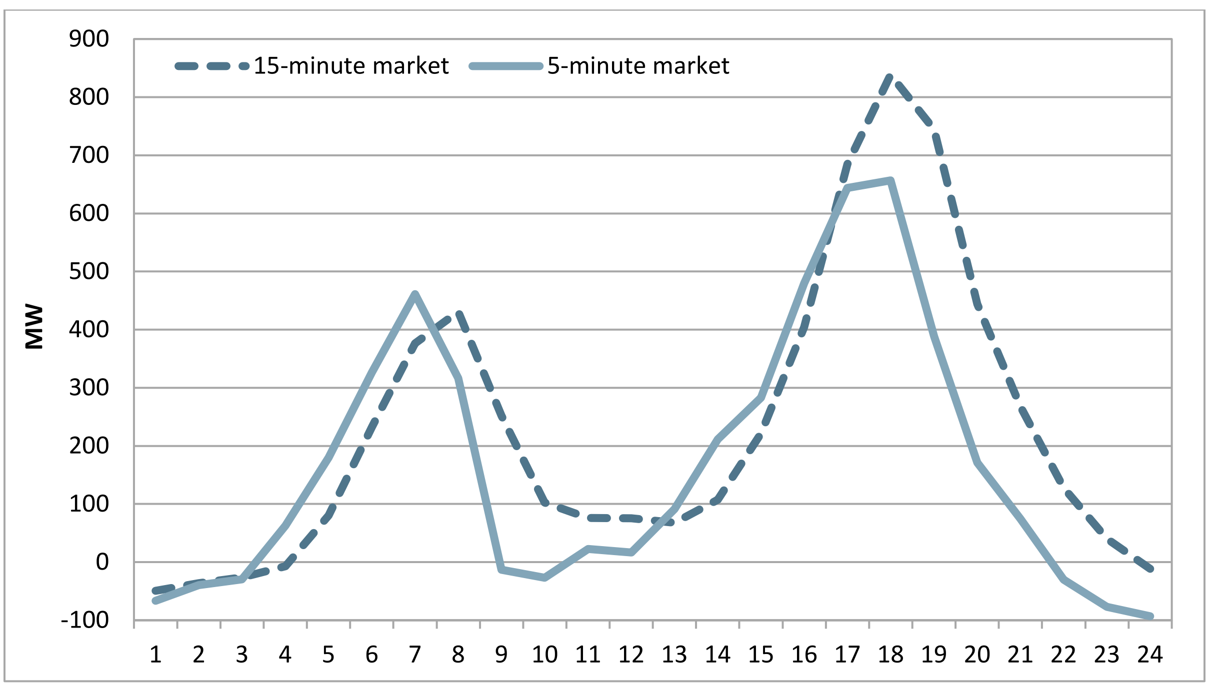


Figure 3.5 Average hourly load adjustment – ISO (October – December)



Reasons for load adjustments

When the available balancing capacity mechanism was implemented the ISO developed a feature for operators to log pre-specified reasons for making load adjustments using a drop down menu. Operators in the energy imbalance market began regularly logging reasons for adjustments in the 15-minute and 5-minute markets at the beginning of April. These reasons are summarized below.

Reasons for load adjustment in the ISO were classified into four groups:

- load deviation (differences between the load value in the market and actual or expected load);
- resource deviation (difference between resource dispatch operating targets and actual or expected output);
- reliability event (managing transmission exceedance or operating reserves); and
- software issue (errors in market inputs usually driven by other software).

Reasons for load adjustment in the energy imbalance market included:

- load forecast deviation (load deviation from the forecast);
- generation deviation (includes deviation in forecast for variable energy resources, generator startup or shutdown resulting in generation below its minimum operating level, and generation testing);
- reliability based control (informing the market of a need for generation increase or decrease to comply with the balancing authority area limit standard);
- automatic time error correction (informing the market of automatic generation control deviation from zero area control error due to automatic time error correction); and
- schedule interchange variation (changes in scheduled interchange after 40 minutes prior to the interval).

When operators enter a load adjustment duration and quantity, operators now have the option to select a reason for the load adjustment from a list of predefined reasons.[43] In addition, operators have the ability to include detail about why a load adjustment is entered in a free-form text box. If operators enter a load adjustment for more than one reason, they have the ability to select only one preset reason from the list. However, additional reasons can be entered in a free-form text box. Logging additional details or reasons through the text box is optional.

During the quarter, PacifiCorp operators were more apt to include additional detail in the 5-minute market than in the 15-minute market. PacifiCorp East operators entered information in the free-form text box during about 71 percent of 5-minute intervals when load adjustments were entered while PacifiCorp West operators entered additional information during about 51 percent of adjustments. PacifiCorp frequently used this feature to cite additional reasons beyond the single reason selected from the predefined list. Operators in NV Energy used the additional details text box very frequently, including additional information during over 95 percent of 15-minute and 5-minute intervals when load adjustments were entered. Puget Sound Energy used the free-form text box about 24 percent of the

[43] For the EIM, in addition to four commonly listed reasons, four less frequently used options are: disturbance response, stranded load, stranded generation, and other event.

time load was adjusted in the real-time market, while Arizona Public Service used this feature less often, including additional details only about 13 percent of the time.

At this time, the only method for evaluating additional details about the load adjustment, including details about reliability needs and alternative options evaluated prior to entering a load adjustment, is with the free-form text box. There is no secondary drop down function for operators to track these details. DMM has not observed input in the free-form text box that addresses alternative options to load adjustments considered, and therefore cannot provide any additional information on them at this time. DMM recommends that the ISO modify its tool to allow operators to enter this information or to provide for another process to capture it.

Figure 3.6 and Figure 3.7 show the frequency of load adjustments in the energy imbalance market areas by the reason selected for the adjustment during the previous six months for the 15-minute and 5-minute markets, respectively.[44] During the fourth quarter, the reasons selected most frequently varied significantly across the EIM entities.

PacifiCorp East most frequently selected generation deviation, during about 60 percent of 15-minute and 5-minute load adjustments. These actions were often made to account for wind and solar deviation. Starting this quarter, PacifiCorp East operators also began selecting schedule interchange variation regularly, during about 25 percent of 15-minute and 5-minute load adjustments. PacifiCorp West operators primarily selected automatic time error correction. This item was selected for about 60 percent of 15-minute and 5-minute load adjustments to account for inadvertent energy.

In NV Energy, operators continued to adjust loads most frequently for reliability based control. Through the free-form text box, operators have indicated that this option is primarily selected when the load adjustment is used to adjust generation to comply with the balancing authority area limit standard. NV Energy operators selected reliability based control during about 84 percent of intervals with load adjustments.

Puget Sound Energy and Arizona Public Service selected load forecast deviation most often. Puget Sound Energy chose load forecast deviation during about 90 percent of load adjustments while Arizona Public Service selected this option from the list during about 60 percent of 15-minute and 5-minute load adjustments.

44 Analysis was completed for intervals when a bias was entered and a particular reason from the predefined list was specifically selected. They do not include intervals when the reason, also from the list, was indirectly logged as an additional detail in the free-form text box.

Figure 3.6 Frequency of load forecast adjustments by reason (15-minute market)

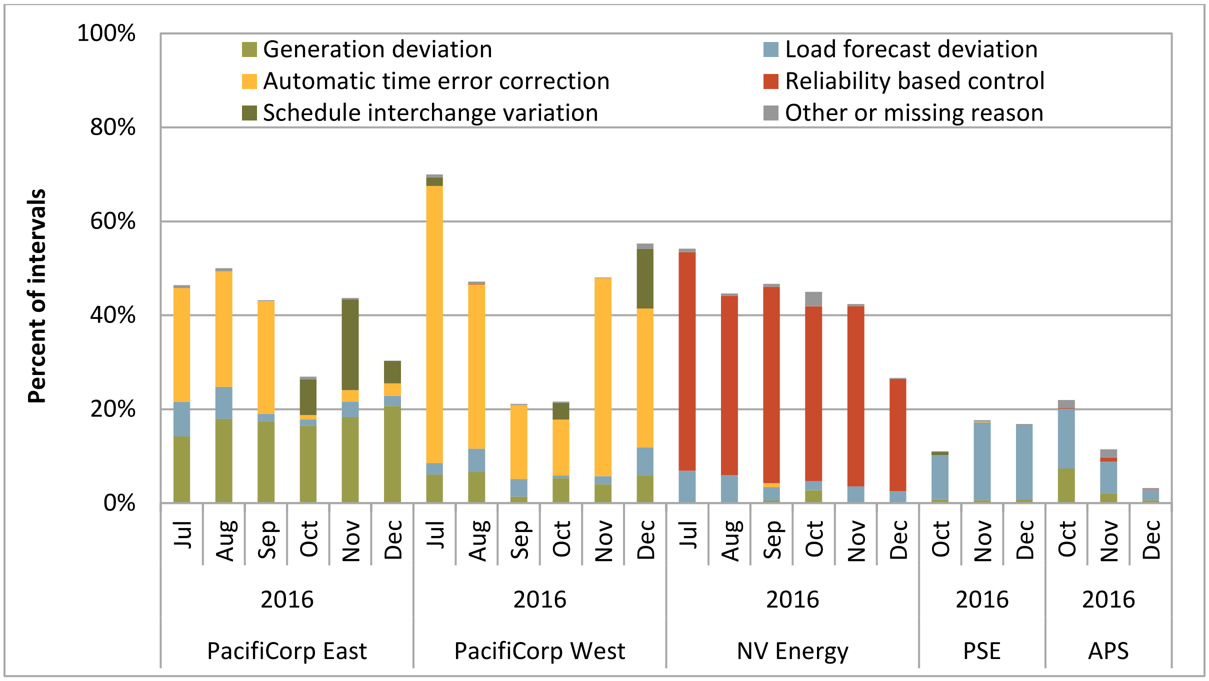
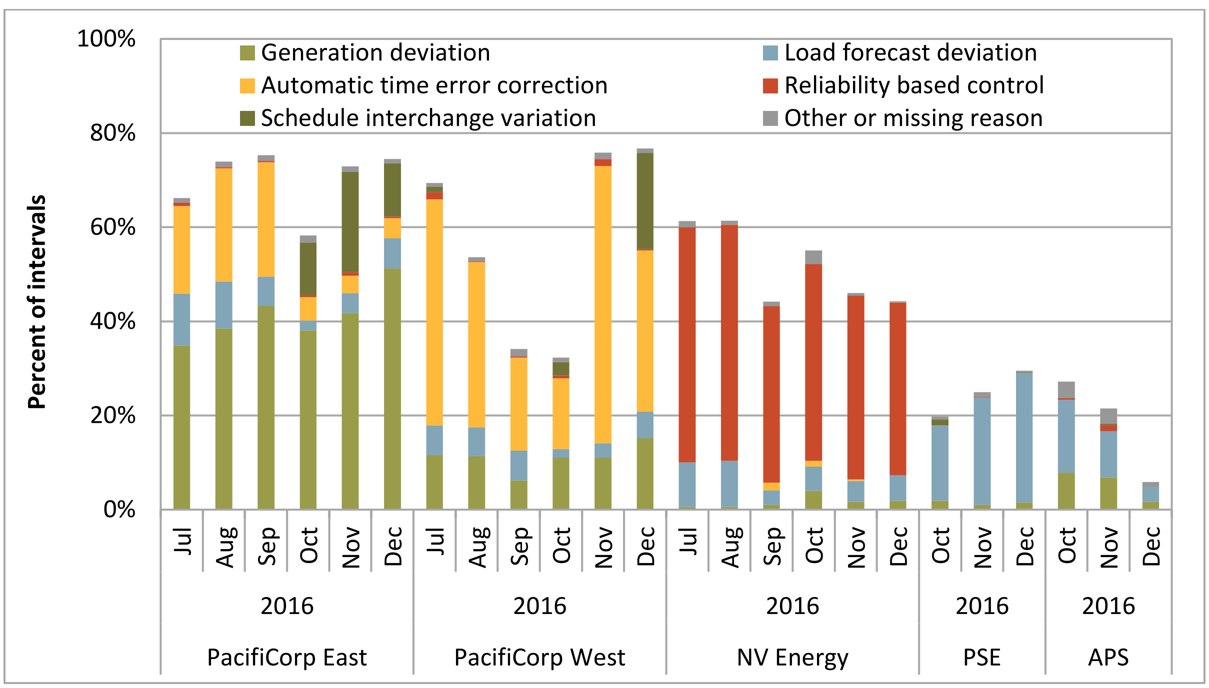


Figure 3.7 Frequency of load forecast adjustments by reason (5-minute market)



Impact of load adjustments on prices

The impacts that load adjustments have on prices can range widely and cannot be readily determined or estimated. When load is adjusted upwards, this tends to put upward pressure on prices in the immediate intervals by increasing the demand forecast. However, this upward adjustment may actually help to decrease prices in subsequent intervals by ramping up generation and making more supply available in subsequent periods. Likewise, downward adjustments can help keep prices lower in immediate intervals, but may decrease the available supply in subsequent intervals.

The impact of the load adjustment can be quantitatively assessed in cases when the load bias limiter is triggered. The ISO implemented this feature to limit the effect of load adjustments on prices when adjustments cause power balance constraint relaxations. Prior to the pricing run, the ISO software performs a test to see if operator load adjustments contributed to the relaxation of the power balance constraint in the scheduling run. Specifically, the software compares the magnitude and direction of the power balance relaxation to the size and direction of the operator load adjustment for both shortage and excess events. If the operator load adjustment exceeded the quantity of the relaxation in the same direction, the size of the load adjustment is automatically reduced in the pricing run to prevent the shortage or excess.

When the load bias limiter is triggered it results in a market solution in the pricing run such that the price is set by the highest priced supply dispatched, rather than the $1,000/MWh shortage penalty price for the power balance constraint if there is insufficient upward ramping capacity. The resulting price can be significantly less than the $1,000/MWh penalty price. The functionality of the load bias limiter is similar to the price discovery feature that is in effect in Puget Sound Energy and Arizona Public Service, as they both set price to the offer price of the last dispatched resource during power balance relaxations.[45]

As mentioned in Section 2, valid power balance constraint relaxations were very infrequent during the fourth quarter. Had price discovery not been in effect, the load bias limiter would have triggered in Puget Sound Energy and Arizona Public Service during about 8 percent of under-supply infeasibilities and about 22 percent of over-supply infeasibilities. Table 3.2 shows the estimated net impact of price discovery and the load bias limiter on Puget Sound Energy and Arizona Public Service prices in the fourth quarter.

In the remaining energy imbalance market areas, the power balance constraint was relaxed less frequently, but the load bias limiter triggered in a larger percentage of the infeasibilities. Across PacifiCorp East, PacifiCorp West and NV Energy, the load bias limiter triggered during about 87 percent of under-supply infeasibilities in the fourth quarter. Table 3.2 shows that the load bias limiter lowered average 15-minute and 5-minute prices in NV Energy by about $0.50/MWh. For PacifiCorp, the load bias limiter reduced 5-minute market prices by only about $0.20/MWh.

[45] The outcomes from the load bias limiter do not impact Puget Sound Energy and Arizona Public Service because of the price discovery feature that sets the price for *all* power balance constraint relaxations to the price of the last dispatched resource. The price discovery feature is active for the first six months of market operation for new energy imbalance market entities and is currently in effect for Puget Sound Energy and Arizona Public Service.

Table 3.2 Impact of load bias limiter on EIM price (October – December)

	Average proxy price	Average EIM price	EIM price without price discovery*	EIM price without price discovery or load bias limiter*	Potential impact of load bias limiter	
					Dollars	Percent
PacifiCorp East						
15-minute market (FMM)	$24.22	$26.94	$26.94	$27.23	-$0.29	-1.1%
5-minute market (RTD)	$24.22	$27.86	$27.86	$28.06	-$0.19	-0.7%
PacifiCorp West						
15-minute market (FMM)	$24.22	$24.64	$24.64	$24.64	$0.00	0.0%
5-minute market (RTD)	$24.22	$21.32	$21.32	$21.54	-$0.22	-1.0%
NV Energy						
15-minute market (FMM)	$22.82	$28.12	$28.12	$28.55	-$0.43	-1.5%
5-minute market (RTD)	$22.82	$29.42	$29.42	$29.98	-$0.56	-1.9%
Puget Sound Energy						
15-minute market (FMM)	$23.17	$23.61	$23.93	$23.93	$0.00	0.0%
5-minute market (RTD)	$23.17	$20.76	$22.06	$22.24	-$0.17	-0.8%
Arizona Public Service						
15-minute market (FMM)	$24.22	$26.39	$25.21	$25.18	$0.03	0.1%
5-minute market (RTD)	$24.22	$27.28	$27.73	$27.46	$0.27	1.0%

**Without price discovery applies to Puget Sound Energy and Arizona Public Service only*

DMM has provided recommendations to the ISO on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load adjustments on creating power balance relaxations. Specifically, DMM has recommended considering the adjustment based on a combination of factors including the *change* in load adjustment from one interval to the next and the *duration* of an adjustment rather than solely the *absolute* value of any load adjustment. The ISO intends to implement this change. A technical bulletin on the enhancement was released on December 28 and a stakeholder call occurred on January 11 to review the proposed enhancement.[46]

[46] The technical bulletin on the Load Conformance Limiter Enhancement (December 28, 2016) can be found here: http://www.caiso.com/Documents/TechnicalBulletin_LoadConformanceLimiterEnhancement.pdf.

4 Special issues

This section provides information about the following four special issues:

- The ISO implemented the flexible ramping product on November 1. The flexible ramping product differs from the former flexible ramping constraint by compensating or charging for forecast ramping movements, procuring flexible capacity using a demand curve and procuring for both upward and downward ramping needs. Overall costs for flexible ramping remained low, at less than $0.10/MWh of load.

- The ISO's capacity procurement mechanism tariff authority expired in 2016 and was replaced on November 1 with a new approach that allows competition between different resources that may meet any capacity needs when possible. The total cost of the capacity procurement mechanism designations issued in November and December was $6.6 million. Of that total $0.4 million was paid to units in the Southern California Edison area, $2.6 million to units in the Pacific Gas and Electric area, and $3.7 million to the total system transmission access charge area.

- The ISO began using a new method for calculating day-ahead regulation requirements on October 10. This method provides a more targeted way to procure regulation during the hours when it is likely to be needed. Procurement costs were less with the new requirements compared to the procurement increase that occurred in the spring of 2016.

- As part of a set of temporary measures related to Aliso Canyon, the ISO began using a more up-to-date source for calculating its natural gas price index used by the day-ahead market. This update removed a one-day lag in the natural gas price information used in the day-ahead market, and greatly improved the accuracy of the ISO's index.

4.1 Flexible ramping

On November 1, 2016, the ISO implemented a new market feature for procuring real-time flexible ramping capacity. This new feature is known as the flexible ramping product. The product replaced the previous procurement mechanism, which was called the flexible ramping constraint. This section describes the differences between the product and the constraint, and provides information about market outcomes for the flexible ramping product during November and December.

Differences between the constraint and the product

The flexible ramping constraint was a constraint included in the 15-minute market to help ensure that enough upward ramping capacity was committed in the 15-minute market to meet ramping needs in the 5-minute market. For each 15-minute market interval, the required amount of flexible capacity was calculated using historical data. Separate requirements were calculated for the ISO and for each energy imbalance market area. The flexible ramping constraint relaxation pricing parameter was $60/MWh, such that the market software would dispatch units to meet the constraint as long as the additional cost of procurement did not exceed $60/MWh.[47]

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, the procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market runs, and the corresponding 5-minute market runs for the same time period. The 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 with a fixed price. 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. More information about the calculation of these demand curves is provided below.

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. This feature is explained further in the final part of this section.[48]

Demand curves for the flexible ramping product

This section describes the demand curve implemented for the flexible ramping product. The demand curve is based on the expected cost of a power balance relaxation for each amount of flexible capacity procured. For example, assume there is a 5 percent probability of a power balance shortage relaxation in the 5-minute market during an interval when 100 MW of upward flexible capacity was procured in the corresponding 15-minute market interval. Since the penalty price for a power balance shortage is $1,000/MWh, the expected cost of a power balance shortage relaxation is then $50/MWh (5 percent multiplied by $1,000/MWh). Therefore, at 100 MW, the expected cost of a power balance relaxation, and therefore the willingness-to-pay for an additional megawatt of flexible capacity, is $50/MWh. Using this approach, the willingness-to-pay for additional flexible ramping capacity can be derived for any quantity. This relationship between price and quantity defines the demand curve.[49]

As noted, the ISO uses the $1,000/MWh penalty price for power balance shortages to calculate the upward flexible demand curve. Similarly, the ISO uses the -$155/MWh penalty price for power balance excesses to calculate the downward flexible demand curve. The probability of a power balance

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[47] For more information about the flexible ramping constraint, see DMM's *2015 Annual Report on Market Issues and Performance*, May 2016, pp. 84 – 91: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

[48] For additional details about the flexible ramping product, see the ISO's *Business Practice Manual for Market Operations*: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations.

[49] The demand curves are capped such that the price cannot exceed $247/MWh in the upward direction and -$152/MWh in the downward direction. These caps are intended to prevent flexible ramping procurement from replacing ancillary services and energy procurement.

constraint relaxation is calculated using historical net load forecast error data.[50] The ISO calculates demand curves independently for each hour and market, using historical error values during that hour and specific 15-minute and 5-minute markets.[51]

The flexible ramping product includes separate demand curves for each energy imbalance market area (including the ISO), in addition to a system-level demand curve. However, the demand curves for individual areas will not bind when there is sufficient transfer capability to procure flexibility from other areas.[52] In November and December many of the intervals when local demand curves bound occurred when a local area failed the sufficiency tests that constrained imports or exports between other areas area. For more information about the sufficiency test, see Section 2.2.

Figure 4.1 shows average system-level flexible ramping demand in the 15-minute market for November and December.[53] The positive bars show demand for upward capacity, and the negative bars show demand for downward capacity. For example, in hour 10, the ISO demanded more than 1,300 MW of upward capacity if the price was $0/MWh, but less than 700 MW if the price was $100/MWh. Figure 4.1 shows the quantity demanded at three price points ($0, $50 and $100). As noted above, the underlying demand curves can have up to nine steps, and the prices and quantities for those steps will differ across hours and markets.

As seen in Figure 4.1, upward demand was very low in hours 5 through 7, and increased sharply in hour ending 8. This is because most net load forecast errors in the sample used to calculate the demand curves were negative in hours 5 through 7, while most were positive in hour 8. Further, upward demand was relatively low in the afternoon but very high in the late evening. This might not be intuitive, since net load is ramping up in the late afternoon and down in the late evening. However, demand for flexible ramping capacity is driven by forecast errors, and not by predictable ramping needs.

Figure 4.1 also shows that the willingness-to-pay for upward capacity is typically higher than for downward capacity. This is largely because the cost of a power balance shortage is $1,000/MWh whereas the penalty price for a power balance excess is only -$155/MWh.

In addition to demand curves for the system-level, there are also demand curves for individual energy imbalance market areas and for the ISO. Depending on the net load forecast error sample, each area's demand curves have a different hourly profile. For example, the demand curves for PacifiCorp East show less variation across hours than the system-level demand curves shown in Figure 4.1.

The shape of the demand curves used in the 5-minute market are similar to those for the 15-minute market, with the main difference being lower quantities at a given price. For example, system-level

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50 For the 5-minute market, the net load forecast error for a specific interval is measured as the difference between the net load for the first advisory interval of a 5-minute market run and the binding net load during the following 5-minute market run. For the 15-minute market, the net load forecast error is measured as the difference between the net load for the first advisory interval of the 15-minute market run and the corresponding 5-minute market binding intervals.

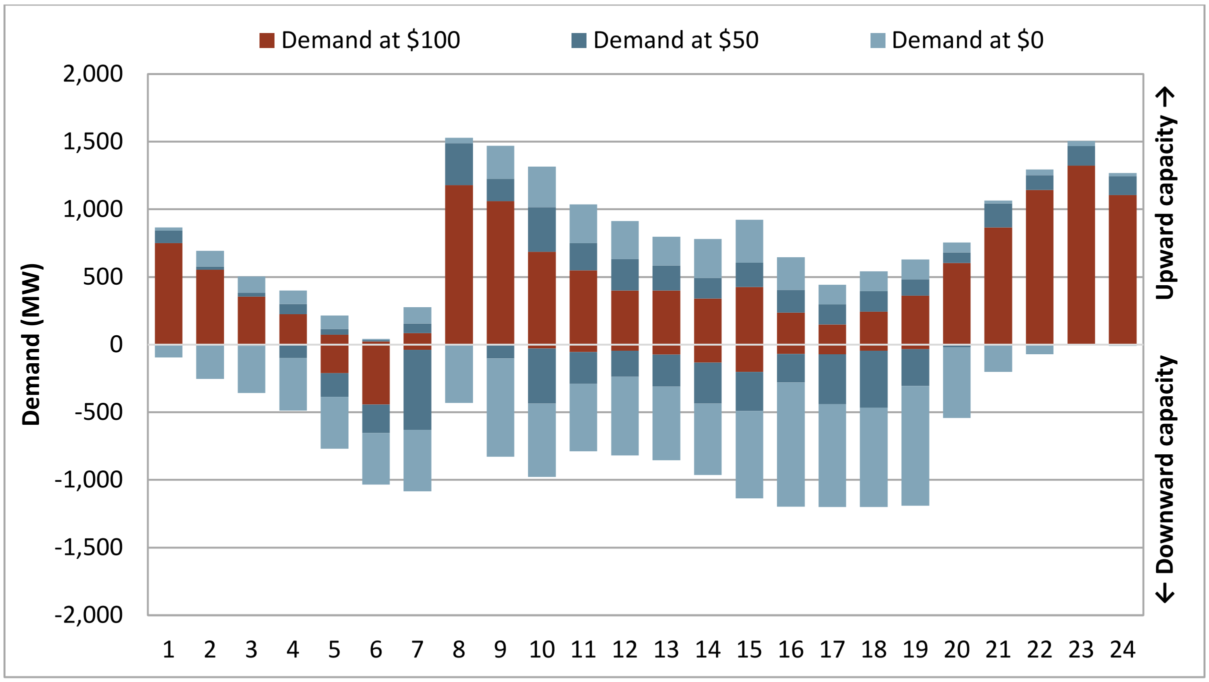
51 To enter these curves into the market software the demand curves are implemented as piecewise linear step-functions, with up to nine steps per curve. Additional information about the construction of demand curves was provided by the ISO at the December 7, 2016, Market Performance and Planning Forum (pp. 25-40): http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Dec7_2016.pdf.

52 Because of the method used by the ISO for implementing the demand curves for the different areas, the area-specific demand curves sometimes affect the system-level procurement, even when sufficient transfer capability is available.

53 Demand curves are recalculated daily. Figure 4.1 shows an average for all demand curves used in November and December.

demand at $0/MWh in hour 10 was more than 1,300 MW in the 15-minute market, but only about 300 MW in the 5-minute market. This is because of smaller load forecast errors in the 5-minute market than the 15-minute market, which is caused by the reduction in time between market runs and observed market outcomes, and that the 15-minute market forecast corresponds to multiple 5-minute market intervals.

Figure 4.1 Hourly average system-level flexible ramping demand curves in 15-minute market (November – December)



Market outcomes for flexible ramping product

This section describes the amount of flexible ramping capacity that was procured in November and December, and the corresponding flexible ramping shadow prices.

A sufficiently large amount of flexible ramping capacity sometimes was committed by the market regardless of the demand for the flexible ramping product. In such intervals, the demand curve did not bind and the flexible ramping shadow price was $0/MWh. Figure 4.2 shows the percent of intervals when the system-level flexible ramping demand curve bound, and had a positive shadow price, in the 15-minute market during November and December.

The system-level demand curves bound much more frequently in the upward direction than in the downward direction. Overall, 15-minute non-zero prices were observed for flexibility in the upward direction during about 30 percent of intervals, while only about 3 percent of intervals were observed in the downward direction. Figure 4.2 further shows that positive prices were more frequent in hours with high demand for flexible ramping. The average system-level shadow price when the demand curve was binding was $8.62/MWh in the upward direction and $3.98/MWh in the downward direction.

In the 5-minute market, system-level flexible ramping prices were positive during less than 1 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.

In addition to the system-level shadow price, an area-specific demand curve may be binding, creating an additional price for resources in that area. These demand curves were infrequently binding for most areas during November and December. However, for the Arizona Public Service area, 15-minute market prices were positive during about 2 percent of intervals in the upward direction and 8 percent of intervals in the downward direction. This is because of higher frequency of sufficiency test failures in this area (see Section 2.2).

Figure 4.2 Hourly frequency of positive 15-minute market flexible ramping shadow price (November – December)

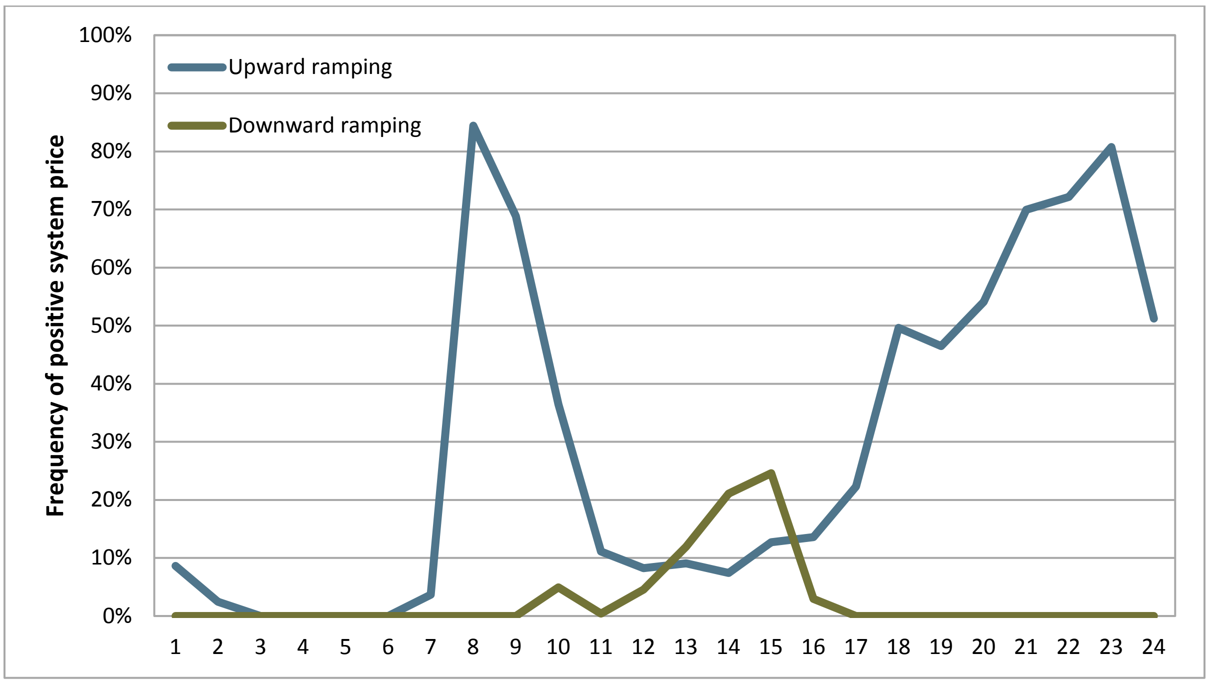
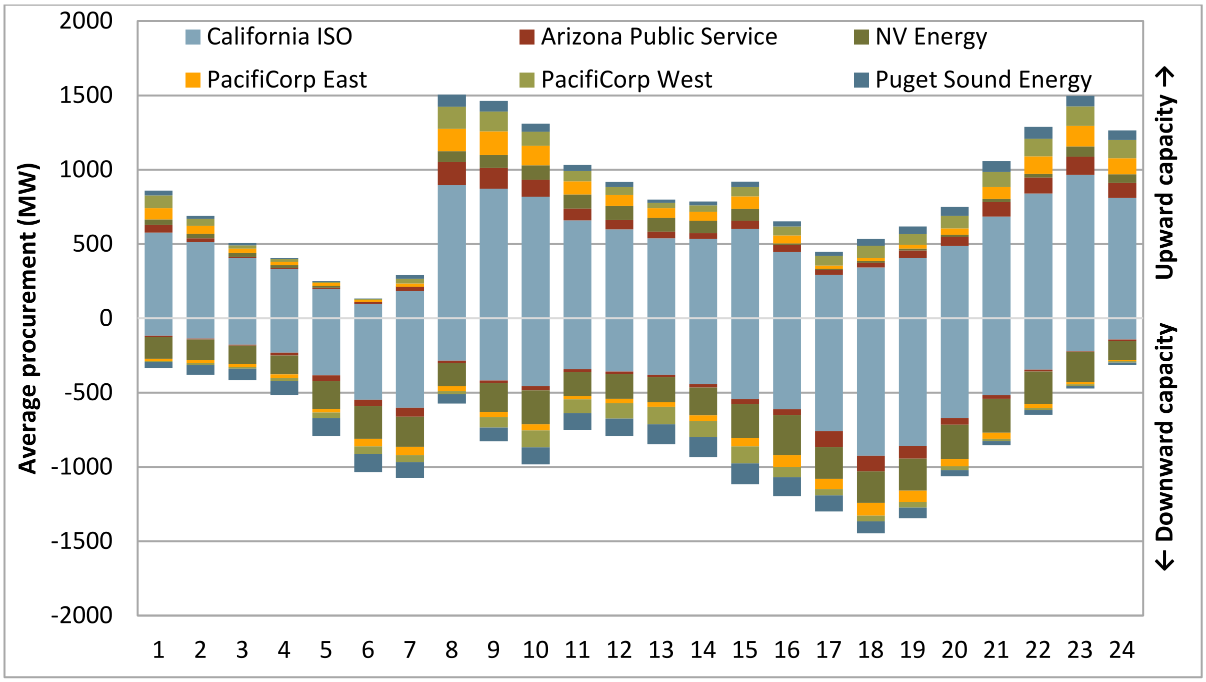


Figure 4.3 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during November and December. This capacity may have been procured to satisfy system-level demand, an area-specific demand, or both. The different colors indicate from which area the capacity was procured. The positive bars show procurement for upward flexible ramping, and the negative bars for downward flexible ramping. As shown in this figure, the hourly procurement profile is similar to the hourly profile of the system-level demand curves shown in Figure 4.1. This reflects that most of the flexible ramping capacity was procured to meet the system-level demand curve. Overall, the ISO procured an average of about 830 MW each for upward and downward capacity in the 15-minute market during November and December.

The total average quantity of flexible ramping capacity procured in the 5-minute market was about 220 MW in the upward direction and 280 MW in the downward direction. Compared to the 15-minute market, ISO resources were awarded a larger share of flexible ramping capacity in the 5-minute market.

ISO resources accounted for about 89 percent of the upward and downward flexible ramping capacity in the 5-minute market, compared to 59 percent in the 15-minute market.

Figure 4.3 Hourly average flexible ramping capacity procurement in 15-minute market (November – December)



Flexible ramping payments

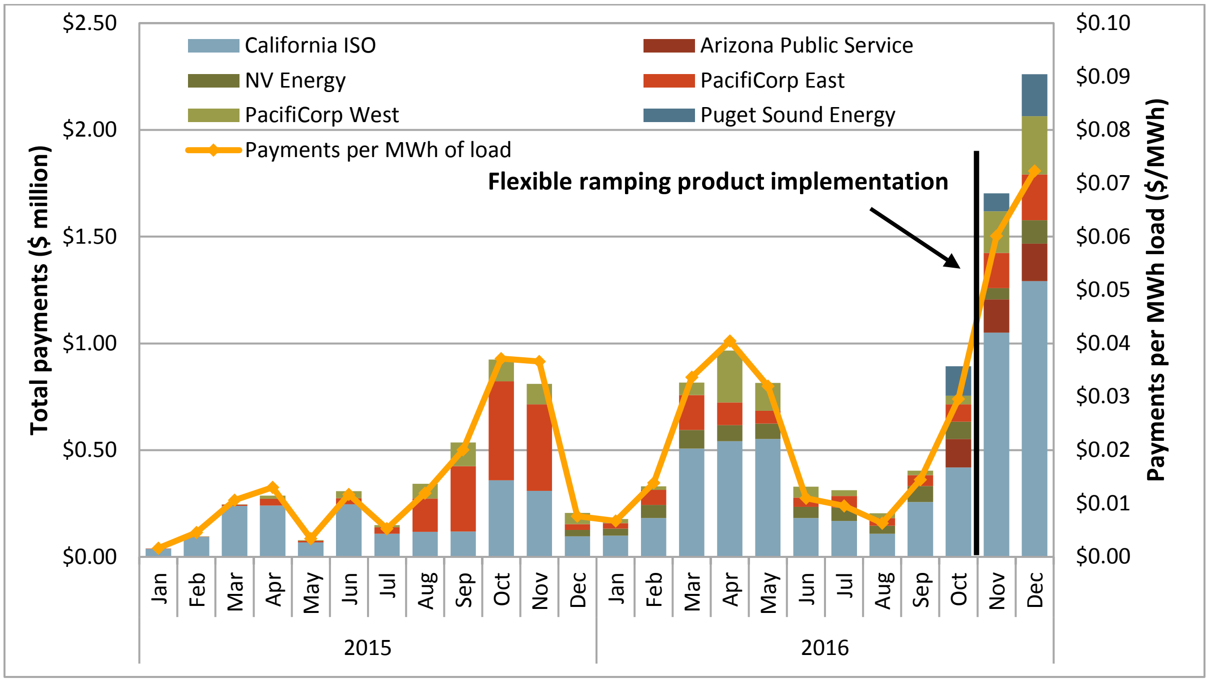
Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the flexible ramping shadow price. In addition, the flexible ramping shadow price is also used to pay or charge for forecast ramping movements for all generation and load. This means that generators that were dispatched (or forecast) by the market to increase output were paid the upward flexible ramping price and charged the downward flexible ramping price. Similarly, load that was forecast to increase its level was charged the upward flexible ramping price and paid the downward flexible ramping price.[54]

The sum of all charges and payments for all forecasted movements in a given market interval typically balance to about zero. However, the total net capacity payments to resources used to satisfy the demand for flexible ramping capacity typically are positive.

[54] 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.

Figure 4.4 shows the total net payments to generators for flexible ramping by month and balancing area.[55] For the time period before the flexible ramping product implementation, prior to November 2016, Figure 4.4 shows net payments to generators from the flexible ramping constraint.[56] The values for November and December reflect net payments to generators from the flexible ramping product. This includes the total net amount paid for upward and downward flexible ramping capacity in both the 15-minute and 5-minute markets, as well as any residual net payments for forecasted ramping movements.

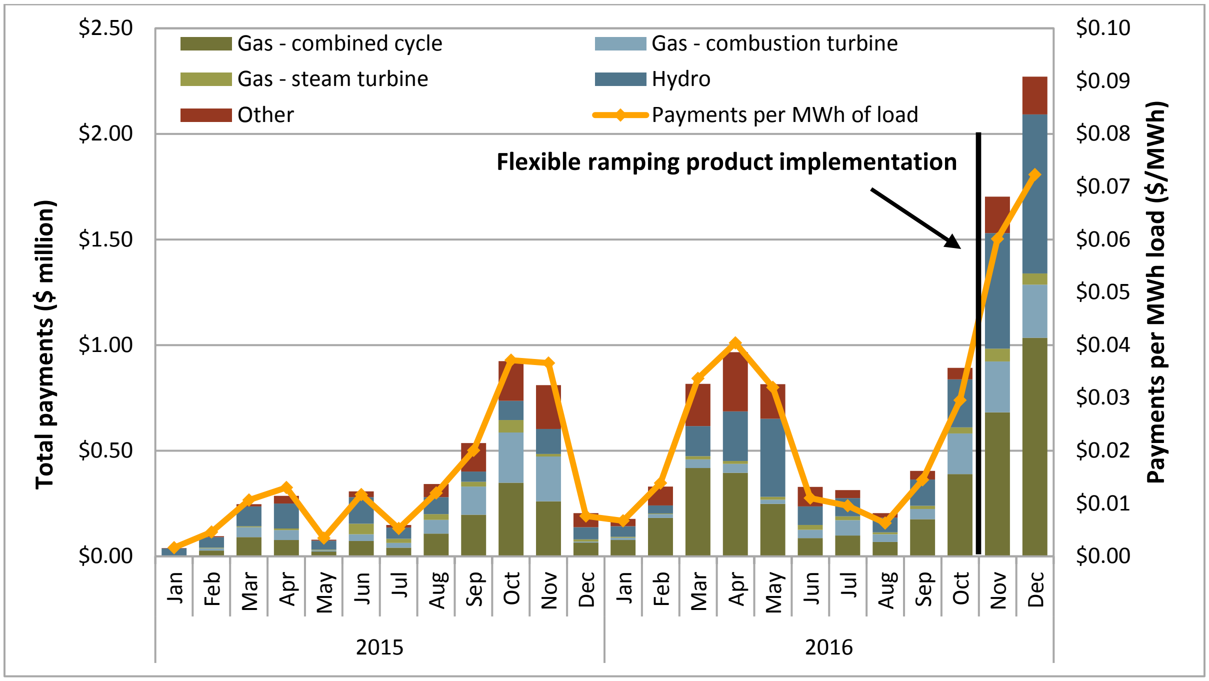
Figure 4.4 Monthly flexible ramping payments by balancing area



55 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.

56 Rescissions for non-performance have been excluded.

Figure 4.5 Monthly flexible ramping payments by fuel



As shown in Figure 4.4, total payments to generators increased following implementation of the flexible ramping product to about $1.7 million in November and $2.3 million in December. About 59 percent of payments during these two months were to ISO generators, which reflects the majority of flexible ramping capacity awards.

Figure 4.5 shows the same information as Figure 4.4 but breaks down the payments by fuel instead of balancing area. About 58 percent of payments in November and December were to gas-fired generators, and about 33 percent were to hydro-electric generation.

Although flexible ramping payments increased with the implementation of the flexible ramping product, payments per megawatt-hour of load remained low.[57] Average net payments per megawatt-hour of load during November and December were about $0.07/MWh. For comparison, payments for ancillary services in the ISO were about $0.46/MWh of load during the same time period.

Areas of continued review

The method used to calculate the flexible ramping demand curves represents an improvement compared to the method that was used for determining the flexible ramping constraint requirements. Nevertheless, there may be possibilities for additional enhancements after further study of the flexible ramping product.

It may be undesirable to have drastic changes in demand from the final interval of one hour to the first interval of the next hour. For example, the differences in the demand curve from hour 7 to hour 8 are significant and a mechanism to smooth these might be appropriate. The ISO could consider smoothing

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

such changes over multiple 15-minute or 5-minute intervals, such that the change between two intervals is not overly significant. This may also be addressed by changing the time periods the historical values are drawn from in building the demand curve.

The number of observations for the 15-minute demand curve is only derived from errors observed during the same hour from the prior 40 days.[58] This sample size may result in additional fluctuation from one hour to the next.

The hourly profile of the flexible ramping demand curves suggests that there are systematic net load forecast errors for some hours of the day. A better understanding of the underlying causes for these errors would be valuable.

In the current implementation of the flexible ramping product, the demand curves for individual balancing areas are 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. DMM continues to work with the ISO to better understand this issue, and to find possible alternatives.

4.2 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.

The ISO's capacity procurement mechanism tariff authority expired in 2016 and was replaced with a new approach. In a 2011 order, FERC instructed the ISO to develop enhanced backstop provisions that would:

1) procure capacity at a price that accounts for market conditions that change over time;

2) provide a reasonable opportunity for suppliers to recover fixed costs; and

3) support incremental investment for existing resources to perform long-term maintenance or make improvements that are necessary to satisfy environmental requirements or address reliability needs associated with renewable resource integration.

In response, the ISO proposed replacement of the administrative rate with a competitive bid solicitation process to determine the backstop capacity procurement price for the mechanism. DMM supported the tariff revision as a means of balancing the ISO's need to procure backstop capacity for reliability and mitigate potential local market power with the broader goal of providing an incentive for capacity to be met by resource adequacy capacity procured in the bilateral market. In October 2015, FERC issued an

[58] The last 40 weekdays are used for weekdays, and the last 20 weekend days are used for weekends.

order accepting the ISO's proposed tariff revisions amending the existing capacity procurement mechanism.[59]

The amended capacity procurement mechanism implemented on November 1 is designed to allow competition between different resources that may meet capacity needs when possible. The new program allows resources to submit bids for capacity through a competitive solicitation process (CSP). The ISO will look to those bids first, when possible, to fulfill procurement needs.

The tariff revisions include a soft offer cap initially set at $75.68/kW-year (or $6.31/kW-month) by adding a 20 percent premium to the estimated going-forward fixed costs for a mid-cost 550 MW combined cycle resource with duct firing, as estimated in a 2014 report by the California Energy Commission.[60] However, a supplier may apply to FERC to cost-justify a price higher than the soft offer cap prior to offering the resource into the competitive solicitation process or after receiving a capacity procurement mechanism designation by the ISO.

Scheduling coordinators may submit competitive solicitation process bids for three offer types: yearly, monthly and intra-monthly. In each case, the quantity offered is limited to the difference between the resource's maximum capacity and capacity already procured as either resource adequacy capacity or through the ISO's capacity procurement mechanism.

The ISO inserts bids significantly above the soft offer cap for each resource with qualified resource adequacy capacity not offered in the competitive solicitation process up to the maximum capacity of each resource as additional capacity that could be procured. If capacity in the ISO generated bid range receives a designation through the capacity procurement mechanism, the clearing price will be set at the soft offer cap. A scheduling coordinator receiving a designation for capacity with an ISO generated bid may choose to decline that designation within 24 hours of receiving notice by electronic mail.

The ISO uses the competitive solicitation process to procure backstop capacity in three distinct processes. First, if insufficient cumulative system, local, or flexible capacity is shown in annual resource adequacy plans the ISO may procure backstop capacity through an annual competitive solicitation process using the annual competitive solicitation process bids. The annual process may also be used to procure backstop capacity to resolve a collective deficiency in any local area.

Second, the ISO may procure backstop capacity through a monthly competitive solicitation process in the event that insufficient cumulative capacity is shown in monthly resource adequacy plans for local, system or flexible resource adequacy. The monthly process may also be used to procure backstop capacity in the event that cumulative system capacity is insufficient due to planned outages.

Third, the intra-monthly competitive solicitation process can be triggered by exceptional dispatch or other significant events. Capacity procurement mechanism designations for risk of retirement are not included in the annual, monthly or intra-monthly competitive solicitation processes.

The first capacity procurement mechanism designations for 2016 were issued following implementation of the amended mechanism on November 1. In the final two months of 2016, the ISO issued capacity

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[59] *Order Accepting CAISO's Proposed Capacity Procurement Mechanism Tariff Revisions* (ER15-1783), October 1, 2015: http://www.caiso.com/Documents/Oct1_2015_OrderAcceptingTariffRevisions_CapacityProcurementMechanism_ER15-1783.pdf.

[60] Rhyne, Ivin, Joel Klein. 2014. *Estimated Cost of New Renewable and Fossil Generation in California*. California Energy Commission. CEC-200-2014-003-SD.: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf

procurement mechanism designations for 1,131 MW-months of capacity, a value far in excess of the annual designations of 132 MW-months in 2015. Publicly available data on each designation is included in Table 4.1 below.

Capacity procurement mechanism designations issued in 2016 were all triggered by exceptional dispatch in the intra-monthly competitive solicitation process. All but one of these designations were for capacity that had not been designated as resource adequacy capacity and for which the scheduling coordinator did not submit a bid in the competitive solicitation process.[61] The ISO generates bids for such capacity at a price above the $6.31/kW-month soft cap. Prices for accepted designations in this range were set at the soft offer cap of $6.31/kW-month.

The ISO may designate capacity with ISO generated bids even when lower priced bids from other resources were submitted in cases when the competitive solicitation process cannot be utilized or system conditions require selection on a basis other than capacity offer price alone. This can occur for several reasons. In some cases operational conditions may require exceptionally dispatched resources to be selected with insufficient time to assess capacity offer prices. In other cases, only a few specific resources may be able to effectively resolve a specific reliability or operational need.

Several additional designations were declined by one scheduling coordinator. Scheduling coordinators receiving an exceptional dispatch for capacity that is not designated through the resource adequacy process may choose to decline a capacity procurement mechanism designation by contacting the ISO through appropriate channels within 24 hours. If the designation occurs within 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 to 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 November and December was $6.6 million. Of the total cost, $2.6 million was charged to the Pacific Gas and Electric area, $0.4 million to the Southern California Edison transmission access charge area, and $3.7 million to the system area.

[61] At the December 7, 2016, Market Performance and Planning Forum, the ISO indicated that there were some initial implementation issues that may have affected some of the designations.

Table 4.1 Capacity procurement mechanism costs

Resource	CPM designation (MW)	CPM designation dates	Price $/kw-mon	Estimated cost $ million	Local capacity area	Exceptional Dispatch CPM trigger
MANDALAY GEN STA. UNIT 2	20.01	11/8 - 1/6	$6.31	$0.25	SCE TAC	transmission outage in Santa Clara sub-area
MANDALAY GEN STA. UNIT 3	130.00	11/9 -12/9	$6.31	$0.82	System	Emergency event caused by a market disruption. Emergency event involved area control error and low system frequency.
Pio Pico Unit 1	102.67	11/9 -12/9	$6.31	$0.65	System	
Pio Pico Unit 2	102.67	11/9 -12/9	$6.31	$0.65	System	
Pio Pico Unit 3	102.67	11/9 -12/9	$6.31	$0.65	System	
Sentinel Unit 1	1.00	11/9 -12/9	$6.31	$0.01	System	
Sentinel Unit 2	1.00	11/9 -12/9	$6.31	$0.01	System	
Sentinel Unit 3	1.00	11/9 -12/9	$6.31	$0.01	System	
Sentinel Unit 6	1.00	11/9 -12/9	$6.31	$0.01	System	
DELTA ENERGY CENTER AGGREGATE	114.00	12/14 - 2/11	$6.31	$1.44	PG&E TAC	Transmission outage
Los Medanos Energy Center AGGREGATE	89.79	12/14 - 2/11	$6.31	$1.13	PG&E TAC	
MOSS LANDING POWER BLOCK 1	141.04	12/18 - 1/17	$6.31	$0.89	System	Cold temperatures, potential gas supply issues and potential loss of imports
Mountainview Gen Sta. Unit 3	36.37	12/19 - 2/16	$1.90	$0.14	SCE TAC	Outages in the West of Devers sub-area

4.3 Regulation requirements

On October 10, 2016, the ISO began using a new method for determining day-ahead regulation procurement requirements. The new method was implemented in response to growing needs for regulation to balance variable renewable generation. With the new method, each hour has a different requirement, which is based on observed regulation needs during the same month in the prior year. These requirements are updated approximately monthly. Furthermore, the ISO adjusts requirements when large weather systems move across California. This methodology differs from the one in place prior to October 10, where requirements varied less across hours.

The ISO had a similar need in the spring of 2016, when regulation requirements were increased in a less targeted way. For most of the spring, regulation requirements were roughly doubled and set at 600 MW for both regulation up and regulation down during all hours of the day. This resulted in a significant increase in regulation procurement costs.[62] As shown in this section, the new more targeted procurement method has resulted in a much smaller increase in procurement costs than the method implemented in the spring.

Background

Regulation up and regulation down are two of the four ancillary service products that the ISO procures through co-optimization with energy in the day-ahead and real-time markets.[63] Most ancillary service capacity is procured in the day-ahead market. The ISO procures incremental ancillary services in the real-time market to replace unavailable ancillary service or to meet additional ancillary service

62 For more information see DMM's *Q2 2016 Quarterly Report on Market Issues and Performance*, August 2016, pp. 71 – 74: http://www.caiso.com/Documents/2016SecondQuarterReportMarketIssuesandPerformance.pdf.

63 The other two are spinning and non-spinning reserves.

requirements. A detailed description of the ancillary service market design, which was implemented in 2009, is provided in DMM's 2010 annual report.[64]

In addition to a capacity payment, resources that provide regulation also receive a performance payment, which is referred to as mileage.[65] Since implementation of the mileage product in June 2013, mileage payments have been very small compared to capacity payments.

Regulation requirements

Figure 4.6 shows average day-ahead regulation requirements by month for 2016. The average regulation requirements were highest during the spring months, when the ISO set the requirement to 600 MW for almost all hours for both regulation up and regulation down. These higher requirements were in effect from February 20 through June 9 and were used for both the day-ahead and the real-time markets. Before February 20, and between June 10 and October 9, regulation requirements in the day-ahead market ranged between 300 MW and 400 MW. These requirements were determined by an older method which had been in place for several years. With the older method, requirements in the real-time market were consistently set at 300 MW.

After the new method was implemented on October 10, day-ahead requirements averaged about 320 MW for regulation up and 390 MW for regulation down. As seen in Figure 4.6, this represents a small increase on average compared to the third quarter. However, the requirements varied more from hour-to-hour, and were at most 750 MW each for regulation up and regulation down. Figure 4.7 summarizes the hourly profile of the day-ahead regulation requirements for October 10 through December 31. The figure shows, for each hour, the minimum, average and maximum amount used during this time period. The regulation up requirements are shown as positive values and the regulation down requirements as negative values. Regulation up requirements were highest on average during the afternoon ramping period. Requirements for regulation down were typically higher around hours ending 9 and 10 and hours ending 18 and 19.

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[64] *2010 Annual Report on Market Issues and Performance*, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

[65] For more information about the mileage product see DMM's *2013 Annual Report on Market Issues and Performance*, April 2014, pp. 146-151: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

Figure 4.6 Monthly average day-ahead regulation requirements

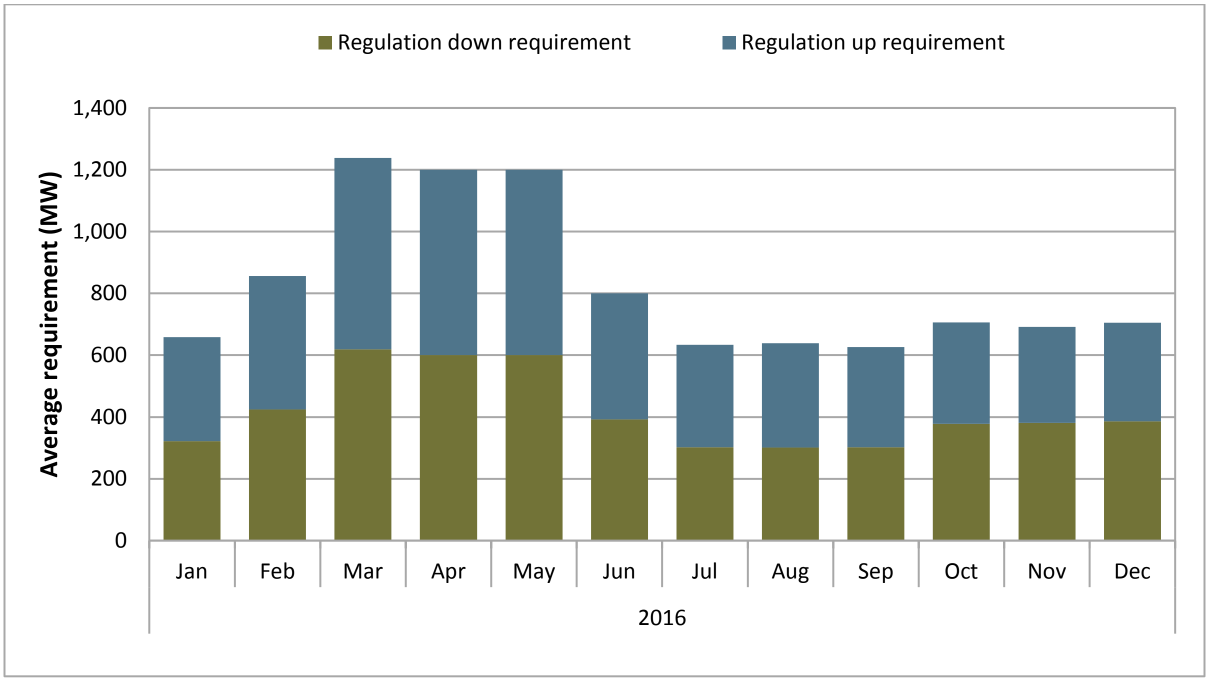
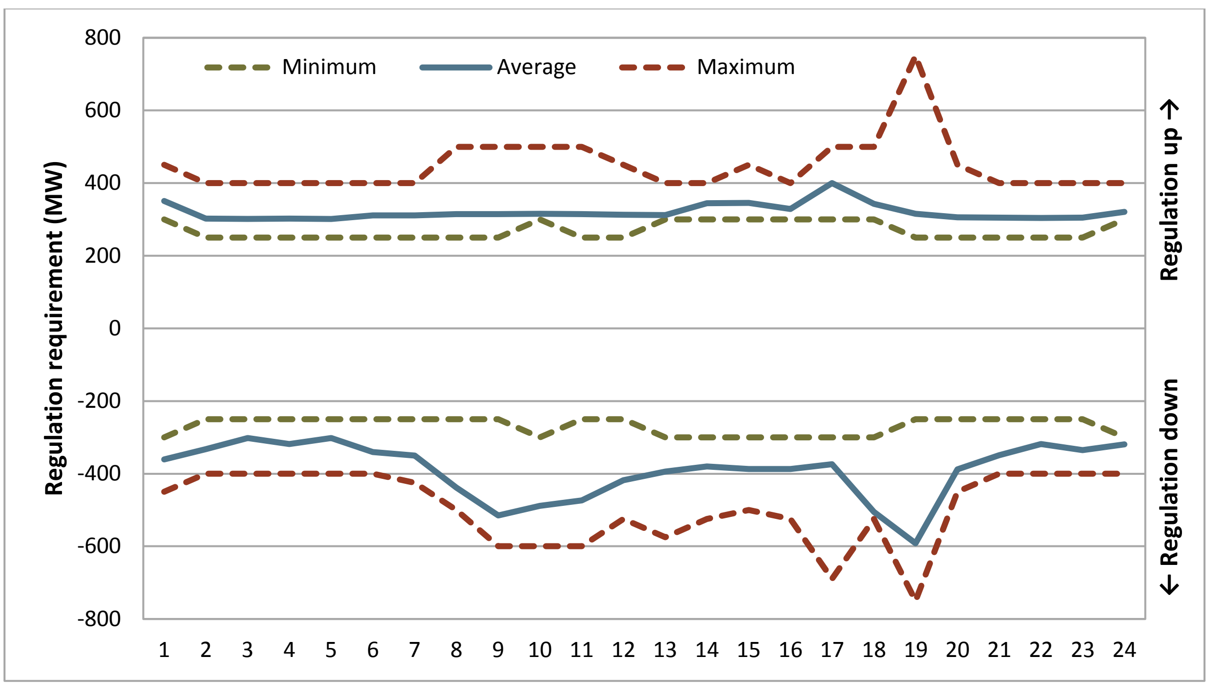


Figure 4.7 Hourly average day-ahead regulation requirements (October 10 – December 31)

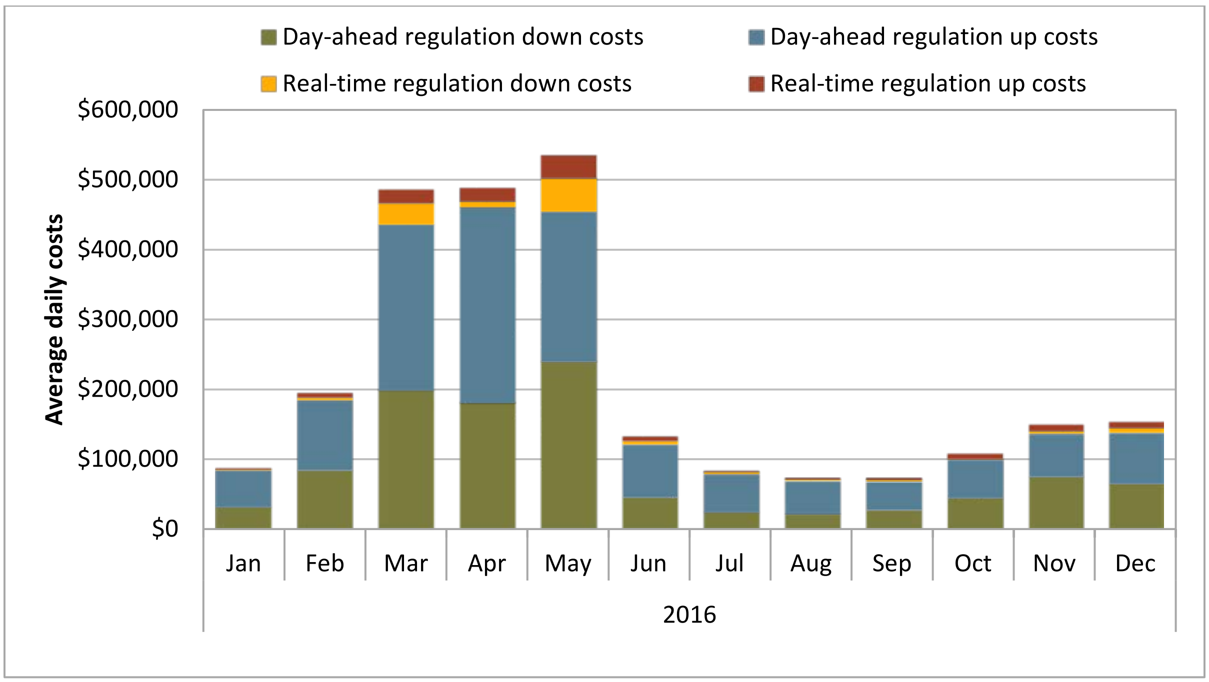


Because of software limitations, the new requirements were not used for the real-time market during the fourth quarter.[66] Instead, real-time requirements remained at 300 MW on most days, with occasional temporary increases based on operator judgement.

Regulation procurement costs

Figure 4.8 shows average daily cost for regulation capacity procurement by month. The average cost for the fourth quarter was about $140,000 per day, up from about $80,000 per day during the third quarter. This can be compared to an average daily cost of about $470,000 during February 20 through June 9, when requirements were higher. Also shown in the figure, day-ahead costs represented 90 percent of the total regulation costs. The fourth quarter value was similar at 91 percent.

Figure 4.8 Average daily regulation procurement costs



4.4 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.

[66] After addressing the limitations, the ISO began using the new requirements in real time beginning in mid-January.

The ISO, Los Angeles Department of Water and Power, California Energy Commission and California Public Utilities Commission published a risk assessment and technical report in April 2016 finding that the limited operability of Aliso Canyon posed a significant risk to electric reliability during the summer months of 2016.[67] To address these reliability concerns, these agencies took many steps to manage system conditions, including the ISO which filed for FERC approval of several temporary tariff amendments in May 2016.[68] These tariff amendments, which are described in further detail below, were approved by FERC on June 1 and remained in effect until November 30, 2016.[69]

Other actions included SoCalGas adjusting its natural gas balancing rules to provide stronger incentives for natural gas customers, such as electric generators, to align their natural gas purchases and burns. Furthermore, electric operators and gas system operators developed enhanced coordination procedures that were used throughout the summer. Finally, relatively well-forecasted load and weather conditions may also have contributed to ensuring reliable conditions this past summer.

A follow-up risk assessment study, focusing on the upcoming winter months, was published in August.[70] In September, FERC organized a technical conference where both the ISO and DMM discussed the effectiveness of the temporary Aliso Canyon measures.[71] Following these studies and discussions, the ISO in October 2016 filed for FERC approval to allow most of the tariff amendments to remain in effect through November 30, 2017.[72] DMM filed comments that, overall, were supportive of the ISO's filing, but also recommended additional enhancements including making the update of natural gas prices for

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67 *Aliso Canyon Risk Assessment Technical Report*, April 5, 2016: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf.

68 *Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility*, May 9, 2016: http://www.caiso.com/Documents/May9_2016_TariffAmendment_EnhanceGas-ElectricCoordination_LimitedOperation_AlisoCanyonNaturalGasStorageFacility_ER16-1649.pdf.

69 FERC order accepting tariff revisions, subject to condition, and establishing a technical conference: http://www.caiso.com/Documents/Jun1_2016_OrderAcceptingTariffRevisions_Establishing_TechnicalConference_AlisoCanyon_ER16-1649.pdf.

70 *Aliso Canyon Winter Risk Assessment Technical Report*, August 23, 2016: http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN212913_20160823T090035_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report.pdf.

71 The technical conference agenda and presentations can be found here: https://www.ferc.gov/eventcalendar/EventDetails.aspx?ID=8413&CalType=.

72 *Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, October 14, 2016: http://www.caiso.com/Documents/Oct14_2016_TariffAmendment_AlisoCanyonGasElectricCoordination_Phase2_ER17-110.pdf.

the day-ahead permanent and applying mitigation to exceptional dispatches that are made to manage natural gas limitations.[73] FERC approved the extension on November 28, 2016.[74]

Operational tools and corresponding mitigation measures

The ISO has developed a set of operational tools to manage potential gas system limitations that allows 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.[75]

Based on observed system conditions, operators did not elect to enforce these constraints during the second or third quarters. In the fourth quarter, ISO operators temporarily used the functionality as a precautionary measure when managing a specific pipeline maintenance outage in the San Diego area. This had a very limited impact on market outcomes.

The temporary tariff amendments also give the ISO authority to reserve internal transmission capacity to manage issues related to a constrained natural gas system. For example, the ISO may need to reserve transmission capacity on Path 26 in the day-ahead market to create additional flexibility that could be used in real time. As with the gas burn constraints, operators could make adjustments beginning in June but based on system conditions chose not to reserve internal transmission. The ISO in its October FERC filing did not ask that this particular tariff amendment be extended beyond November 30, 2016.

The effectiveness of the ISO's market power mitigation procedures may be adversely affected if operators enforce the gas burn constraints. The gas burn constraints would limit the amount of generation available to relieve congestion on a transmission constraint in a way that market power mitigation procedures would not account for. A transmission path may therefore be deemed competitive when in fact the amount of supply that can be dispatched to relieve congestion on these constraints is more restricted and uncompetitive because of the constraints. To address this limitation, the temporary tariff amendments include the authority for the ISO to deem transmission paths uncompetitive. Because of the limited use of the gas burn constraints during 2016, this feature was also not used.

The tariff amendments also included the ability of the ISO to limit or suspend virtual bidding. A restriction on virtual bidding may be necessary if operators choose to reserve transmission capacity in the day-ahead market for use in the real-time market or if operators need to use the gas nomogram constraints differently in the day-ahead and real-time markets as these actions could cause systematic and predictable price differences between day-ahead and real-time prices. Virtual bidders could take advantage of such price differences, which may undo the intent of virtual bidding and could have

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[73] *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000.

[74] FERC order accepting tariff revisions, subject to condition: http://www.caiso.com/Documents/Nov28_2016_OrderAcceptingTariffAmendment_AlisoCanyonElectricGasCoordinationPhase2_ER17-110.pdf.

[75] Refer to *Operating Procedure 4120C used during SoCalGas area limitations or outages:* http://www.caiso.com/Documents/4120C.pdf.

negative impacts on market efficiency. Because the ISO did not implement the gas constraints or limit flows on internal transmission, there was no need to consider suspending virtual bidding.

The ISO has requested to temporarily keep the ability to use the maximum gas limit constraint. As such, having the ability to suspend virtual bidding remains an important tool to protect against potential market inefficiencies, should they arise.

Additional bidding flexibility for SoCalGas resources

Starting July 6, to allow natural gas-fired generators in the SoCalGas system to reflect higher same day natural gas prices and to avoid having these resources dispatched for system needs in the event of constrained gas conditions in Southern California, the ISO adjusted the gas price indices used to calculate the commitment cost caps and default energy bids in the real-time market for natural gas-fired generators on the SoCalGas systems. A 75 percent adder was included in the fuel cost component used for calculating proxy commitment costs for resources on the SoCalGas systems in real time. The ISO also included a 25 percent adder for the fuel cost component of default energy bids in the real-time market. The 75 percent and 25 percent adders implemented by the ISO were based on analysis presented by DMM in its comments on the final Aliso Canyon gas-electric coordination proposal.[76]

DMM's analysis of same day natural gas price volatility in Southern California during 2016 shows that this additional flexibility has been sufficient to cover the vast majority of same day natural gas transaction prices. For example, of the same day traded volume observed on the InterContinental Exchange (ICE) at the SoCal Citygate during June through December, 74 percent was less than 10 percent higher than the next day index and 98.6 percent of same day traded volume was less than 25 percent higher than the next day index price. Thus, there was a very limited need overall for the increased bidding flexibility. A more detailed analysis and discussion of the increased bidding flexibility, focusing on the summer months of 2016, is available in DMM's comments to the ISO's October FERC filing.[77]

Resources were also granted the ability to rebid their commitment costs in the real-time market, except for hours with day-ahead schedules or hours spanning minimum run times if committed in the real-time market. This ability was activated on June 2. As discussed in DMM's comments to the ISO's October filing, almost all of the capacity that made use of the ability to rebid commitment costs with the additional headroom during the summer months were bid in by one scheduling coordinator and the bidding pattern did not appear linked to same day price movements.

This continued to be the case during the fourth quarter. DMM believes these results indicate that the 75 percent gas scalar for commitment costs did not end up having a significant benefit in terms of helping to manage gas use in 2016. Conversely, DMM's analysis did not find that the ability to rebid commitment costs with a scalar adder had a significant impact on total bid cost recovery payments, nor

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[76] *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.

[77] *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 7-9.

did we find other detrimental market effects during this period. However, we remain prepared to recommend lowering these adders should we identify any market harm.[78]

More timely natural gas prices for the day-ahead market

In addition to the tools described above, the ISO asked in its May FERC filing for permission to use a more timely natural gas price for calculating default energy bids and proxy commitment costs in the day-ahead market. With this modification, the ISO is basing natural gas price indices on next-day trades from the morning of the day-ahead market run instead of indices from the prior day.

The target implementation date for this measure was July 6. However, the ISO was not able to confirm that this price would be consistent with a FERC policy statement on natural gas indices.[79] FERC issued an order on this motion for clarification on October 20, confirming that the price update is consistent with the policy statement.[80] Consequently, the ISO implemented the new methodology on October 22. DMM was very supportive of this change and recommended in its October 20 filing that this be permanently extended.[81]

Figure 4.9 and Figure 4.10 illustrate the benefit of using the updated natural gas price index. Figure 4.9 shows next-day trade prices reported on ICE for the SoCal Citygate during June through December, 2016, 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 4.9, about 10 percent of next day trades are at a price in excess of the 10 percent adder normally included in default energy bids and 0.1 percent are in excess of the 25 percent headroom normally included in commitment cost bid caps.

Figure 4.10 shows the same data but compares the price of each trade to a weighted average of 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 4.10, all trade prices are now within the 10 percent adder normally included in default energy bids.

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78 *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 7-9.

79 For more information see the following limited tariff waiver petition: http://www.caiso.com/Documents/Jul12016_AlisoCanyonLtdTariffWaiverPetition_ER16-1649.pdf.

80 FERC order granting petition for extension of limited waiver and dismissing motion for clarification, October 20, 2016: http://www.caiso.com/Documents/Oct20_2016_OrderGrantingPetition_Extension_LimitedWaiver_DismissingMotion_Clarification_ER16-1649.pdf.

81 *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 1-2.

Figure 4.9 Next-day trade prices compared to next-day index from prior day (June – December)

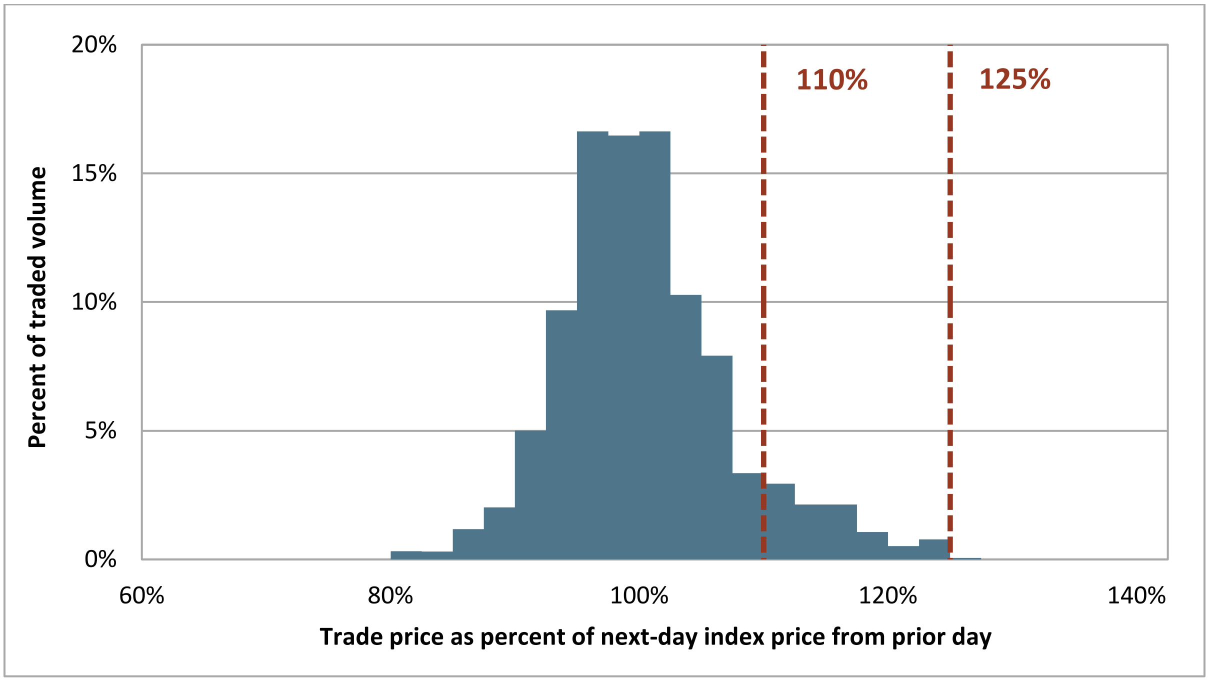
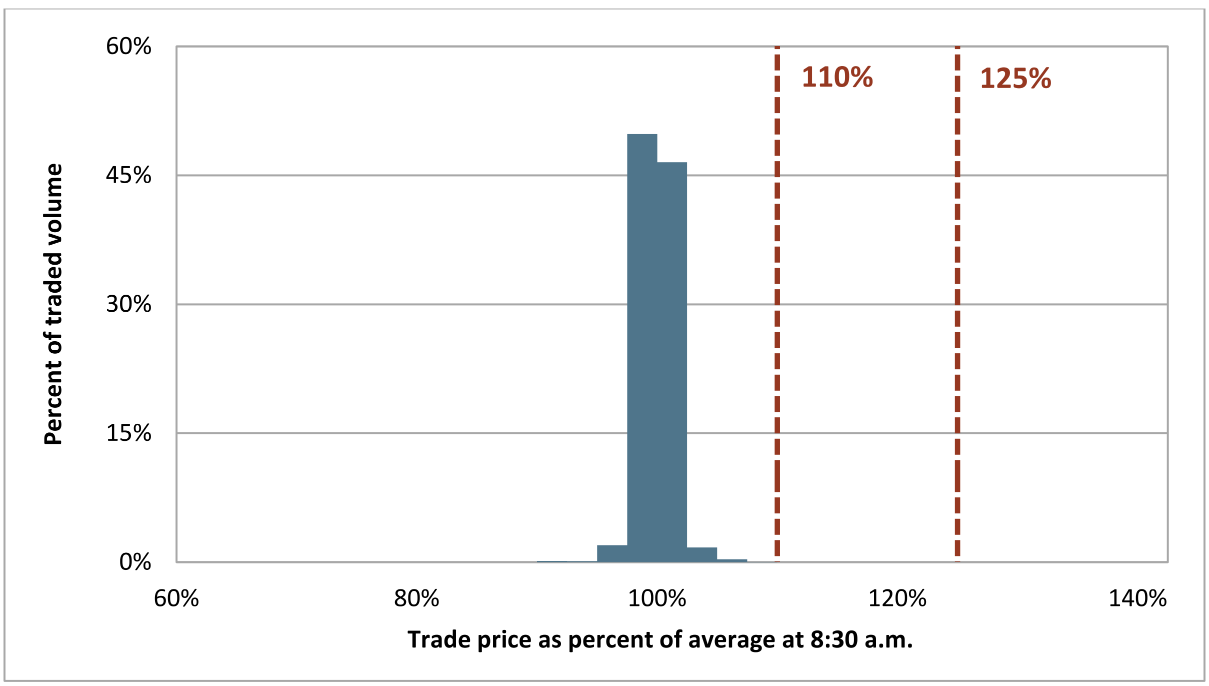


Figure 4.10 Next-day trade prices compared to updated next-day average price (June – December)



Exceptional dispatch mitigation

While the ISO only made very limited use of the operational tools to manage gas limitations in 2016, it did use exceptional dispatches to help manage a broader set of conditions affecting gas supply in Southern California, including on December 17 and 18. However, at this time, the ISO is not able to mitigate exceptional dispatches for gas constraints, only noncompetitive transmission constraints and a few other specific reasons. As part of our FERC filing on October 20, DMM recommended that upward and downward exceptional dispatches issued to manage Aliso Canyon gas issues be considered non-competitive and subject to market power mitigation because of the potential for high market concentration of resources that could be exceptionally dispatched to address the gas constraints.[82] The ISO has included mitigation of exceptional dispatches as one of the topics to be addressed in the Commitment Costs and Default Energy Bid Enhancements stakeholder process.[83]

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[82] *Comments of the Department of Market Monitoring of the California Independent System Operator on the Tariff Amendment Filed to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility*, Department of Market Monitoring, October 19, 2016, FERC Docket No. ER17-110-000, pp. 12-17.

[83] *Commitment Costs and Default Energy Bid Enhancements Issue Paper*, November 18, 2016: http://www.caiso.com/Documents/IssuePaper_CommitmentCost_DefaultEnergyBidEnhancements.pdf.