California ISO

California Independent System Operator Corporation

California ISO

Q4 2015 Report on Market Issues and Performance

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TABLE OF CONTENTS

Executive summary

This report covers market performance during the fourth quarter of 2015 (October – December). Key highlights during this quarter include the following:

- On December 1, NV Energy became the second participant in the EIM markets, joining PacifiCorp which joined in November 2014. Because of the high transfer capability and limited congestion between NV Energy and the ISO, local NV Energy prices often closely reflected system prices. Very few power balance constraint or flexible ramping constraint relaxations also promoted stable prices and resulted in the price discovery mechanism having little impact on NV Energy area prices in this region.
- During the fourth quarter, the flexible ramping constraint was relaxed in over 10 percent of all intervals in PacifiCorp East. Constraint relaxations were frequent in October and most of November. This caused a significant impact on PacifiCorp East prices during those months, increasing prices by roughly the $60/MWh shadow price for the flexible ramping constraint during intervals when the constraint bound. However, flexible ramping constraint relaxations were infrequent at the end of November and throughout December after the return of several outages in the area and the addition of NV Energy into the EIM.
- The percentage of intervals where the flexible ramping constraint was binding, but was not relaxed, continued to increase in the fourth quarter in the PacifiCorp areas and the ISO. This trend may be driven in large part by a continuing increase in flexible ramping requirements in the third and fourth quarters of 2015. In the NV Energy area, the constraint bound during 76 percent of intervals during December – the first month of EIM implementation in that area. DMM's review indicates that during intervals when this constraint is binding but there are with no procurement shortfalls, the constraint appeared to be having only a relatively small upward impact on system marginal energy prices.
- In these cases, the shadow price reflected the opportunity cost of generation that provided flexible ramping capacity instead of energy, but had energy bids lower than the system marginal prices in the EIM and ISO. This result appears consistent with the design of the flexible ramping constraint.

Other highlights in the fourth quarter include the following:

- Day-ahead and 15-minute prices decreased to the lowest levels for the year, both in peak and off-peak periods. This was primarily caused by lower natural gas prices and lower loads.
- Prices in the 15-minute market continued to be lower than day-ahead prices for most of the quarter. However, higher than expected loads because of abnormally high temperatures on several days in October resulted in some very high real-time prices during the quarter.
- While the frequency of positive price spikes in the 5-minute and 15-minute markets increased, price spikes still remained relatively infrequent in the fourth quarter. This was driven by an unusually high percentage of intervals in October where prices spiked over $1,000/MWh in the real-time markets because of low day-ahead scheduled load and regional congestion.

- There was also an increase in the frequency of negative prices from the previous quarter, particularly in November and December, because of low seasonal loads, congestion, and under-scheduled renewable generation.
- Congestion was relatively low and had a small impact on overall average load area prices. Much of the congestion in the fourth quarter was because of transmission outages. In the PG&E area, congestion decreased prices by $0.04/MWh (0.1 percent) in the day-ahead market and increased prices by $0.13/MWh (0.4 percent) in the 15-minute market. Congestion increased day-ahead prices in SDG&E and SCE areas by about $0.09/MWh (0.3 percent) and $0.15/MWh (0.5 percent), respectively, and had a small negative effect in the 15-minute market.
- Total residual unit commitment volume decreased slightly in the fourth quarter compared to the previous quarter. However, these commitments increased by about 50 percent compared to the fourth quarter of 2014. The amount of virtual supply clearing the day-ahead market fell from an average of 874 MW per hour in the third quarter to 312 MW per hour in the fourth quarter. This decrease caused the residual unit commitment process to commit less capacity in the fourth quarter compared to the third quarter of 2015. Much of the residual unit commitment occurred due to high levels of virtual supply clearing the day-ahead market.
- Bid cost recovery payments were just above $18 million in the fourth quarter, compared to $31 million in the third quarter of 2015 and $25 million in the fourth quarter of 2014. The portion of bid cost recovery payments attributable to residual unit commitments dropped from about $10 million in the third quarter of 2015 to under $3 million in the fourth quarter. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $12 million in the fourth quarter, which is within the range of historical averages. Day-ahead bid cost recovery was particularly low during the fourth quarter.
- Virtual supply clearing in the day-ahead market outweighed virtual demand by only about 300 MW on average, compared to almost 900 MW of net virtual supply in the previous quarter. Total convergence bidding revenue for the quarter, adjusted for bid cost recovery charges, was about $5.5 million, compared to about $5 million in the previous quarter.
- Almost all imports scheduled in the day-ahead market continue to be self-scheduled in real time rather than re-bid in the real-time market. This overall trend has continued since the FERC Order No. 764 market changes were implemented in May 2014.
- The volume of 15-minute dispatchable import bids increased during the quarter by 19 percent compared to the third quarter, averaging about 420 MW each hour in the fourth quarter. In addition, 15-minute dispatchable economic export bids increased by 20 percent in the fourth quarter to an average of about 250 MW during each hour.
- Most of the economic bidding of 15-minute dispatchable imports and exports continued to be submitted by a small number of scheduling coordinators on just three inter-ties (Malin, Palo Verde and Rancho Seco).
- The average flexible ramping requirement continued to increase across each of the balancing areas. In the fourth quarter requirements rose to over 450 MW in the ISO, about 135 MW in PacifiCorp East and almost 100 MW in PacifiCorp West. The requirement averaged 85 MW in the NV Energy area during December.

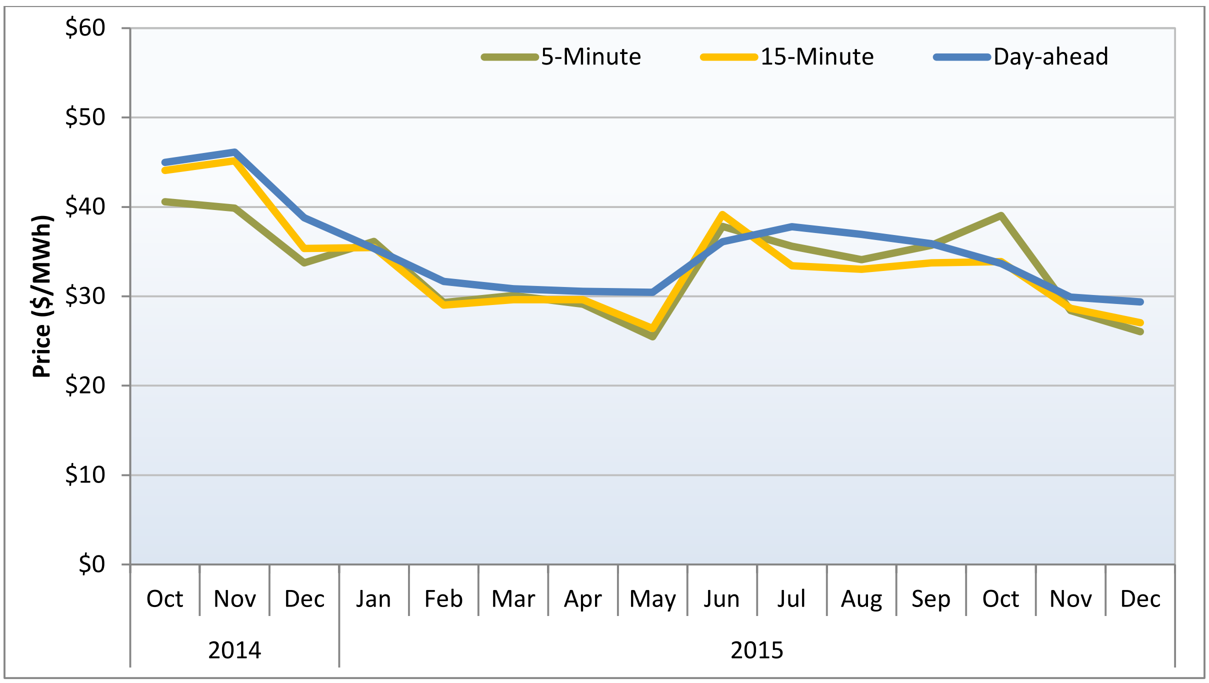
- Overall payments made for the flexible ramping constraint continue to be low, and remain significantly under $1/MWh of load in each balancing area. Payments for the flexible ramping requirement totaled under $2 million in the fourth quarter. Most payments were made to gas-fired capacity in the ISO and PacifiCorp East areas.

Energy market performance

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

Average energy prices remained relatively consistent in the fourth quarter. Average day-ahead prices tended to be higher than real-time prices during the quarter, except for on a few specific days in October where under-scheduling caused sharp increases in real-time prices. These increases impacted real-time monthly averages for October, particularly in the 5-minute market. Average prices decreased through the quarter and ended at 15-month lows during December. Prices in the fourth quarter were lower than in the third quarter as loads and natural gas prices decreased.

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



Upward price spikes increased in October, but overall remained low in the fourth quarter. In the fourth quarter, the frequency of price spikes in the 5-minute market was about 0.6 percent, up from 0.4 percent in the third quarter of 2015. This was mostly driven by an increase in the frequency of positive price spikes in October, where prices above $250/MWh were observed in just over 1 percent of 5-minute intervals primarily related to low load forecasts. Additional price spikes were associated with regional congestion.

The frequency of negative prices increased in the fourth quarter, but remained infrequent. Negative prices in November occurred in just under 2 percent of intervals in the 15-minute market and about 4 percent of intervals in the 5-minute market, while negative prices in December occurred in an average of almost 2 percent of intervals in both real-time markets. The was a large increase in negative prices from the latter two months of the quarter, but these still remained below historical averages. The negative price spikes during the fourth quarter largely occurred as a result of low seasonal loads, congestion on the Path 15 constraint, and unscheduled renewable generation.

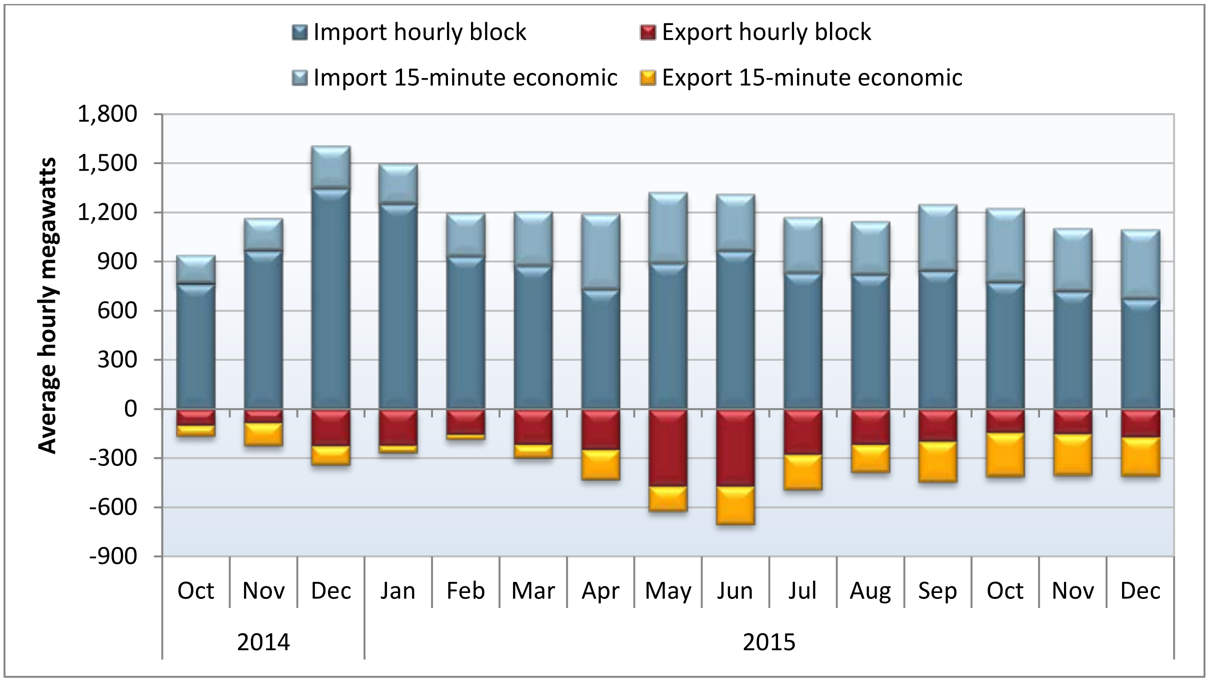
The amount of residual unit commitment procured for cleared virtual supply decreased significantly in the fourth quarter. During the second and third quarters of 2015 the total amount of residual unit commitment procured for virtual supply averaged about 740 MW and 870 MW per hour, respectively. These procurement amounts were larger than prior quarters and were largely driven by increases in virtual bids. In the fourth quarter, these totals decreased significantly to around 280 MW of residual unit procurement for cleared virtual supply per hour, in part because of the decline in cleared virtual supply positions.

Virtual bidding volumes and returns decreased in the fourth quarter. During the fourth quarter total trading virtual volume decreased 17 percent from 3,500 MW to 2,900 MW. Moreover, virtual bidding net revenues decreased by 30 percent from $9.7 million in the third quarter to $6.9 million in the fourth quarter. Virtual supply had greater returns than virtual demand, which has generally been true over the past several quarters. Average hourly virtual supply positions outweighed virtual demand positions by 300 MW for the quarter.

Special issues

Economic bids of exports in the 15-minute market increased. When 15-minute scheduling on inter-ties was implemented in May 2014, there was a significant decrease in the amount of inter-tie bids into the real-time market as well as an increase in the volume of self-scheduled inter-tie transactions. This overall trend continued into the fourth quarter. In addition, real-time economic bidding of imports and exports increased in the fourth quarter (see Figure E.2) to the highest levels since 15-minute bidding began. Most of the 15-minute dispatchable bids continued to be submitted by a small number of scheduling coordinators on just three inter-ties (Malin, Palo Verde and Rancho Seco).

Figure E.2 Economic import and export bids by bidding option



Of the economic inter-tie bids in the real-time markets, about 40 percent of import bids and 60 percent of export bids were available for dispatch on a 15-minute basis. The remaining bids were for fixed hourly blocks. The volume of 15-minute dispatchable import bids increased by 19 percent in the fourth quarter compared to the third quarter, averaging 421 MW each hour in the third quarter. Economic 15-minute dispatchable export bids increased to an average of 252 MW in the fourth quarter, up 20 percent from the third quarter. The volume of 15-minute economic import and export bids in the fourth quarter was the highest quarterly value since 15-minute inter-tie bidding began in May 2014.

Higher flexible ramping constraint requirements helped increase the frequency that the flexible ramping constraint was binding in all areas. During the fourth quarter, the average flexible ramping requirements in each balancing area were at their highest levels of the year. Higher requirements drove the total number of intervals where the constraint bound, but was not relaxed – and therefore was not subject to the $60/MWh relaxation parameter price – to annual highs as well. In the NV Energy area the constraint bound during 76 percent of intervals in December, a higher rate observed than in any other area.

DMM's review indicates that during intervals when this constraint is binding but there are with no procurement shortfalls, the constraint appeared to be having only a relatively small upward impact on system marginal energy prices. The constraint appeared to only incrementally affect the EIM system price rather than the local price. Within the NV Energy area, for instance, resources providing flexible ramping capacity generally have energy bids below prevailing system marginal prices in the EIM and ISO. Because the shadow price for providing flexible ramping capacity is the opportunity cost of holding back lower cost generation to provide flexible capacity instead of energy, the shadow prices were frequently set in the EIM areas by the difference between the non-dispatched energy bid of the marginal unit providing flexible capacity and the prevailing system price.

The load bias limiter would have had a small impact on prices during the fourth quarter. DMM estimated the impact of the load bias limiter in the absence of price discovery in the EIM and found that the impact would have dropped in the fourth quarter because there were fewer power balance constraint relaxations during the fourth quarter. Overall, DMM estimates that prices would have fallen by about 9 percent in the 15-minute and 5-minute PacifiCorp East markets, 7 percent in the 15-minute and 10 percent in the 5-minute PacifiCorp West markets, and would have had very little impact in either NV Energy area markets if the load bias limiter was in effect instead of the price discovery procedures.

1 Market performance

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

- Day-ahead and 15-minute prices for the quarter decreased to the lowest levels for the year during both peak and off-peak periods. This was driven by lower natural gas prices and lower loads.
- Prices in the 15-minute market continued to be lower than day-ahead prices for most of the quarter. However, higher than expected real-time loads on multiple days in October resulted in some very high real-time prices during the quarter.
- In the fourth quarter, the frequency of positive price spikes in the 5-minute and 15-minute market increased but remained relatively infrequent overall. This was driven by a higher percentage of intervals in October where prices spiked over $1,000/MWh in the real-time markets. There was also an increase in the frequency of negative prices from the previous quarter, particularly in November and December.
- Congestion during this quarter was low and had a relatively small impact on average load area prices. Much of the congestion in the fourth quarter was due to transmission outages. In the PG&E area, congestion decreased prices by $0.04/MWh (0.1 percent) in the day-ahead market and increased prices by $0.13/MWh (0.4 percent) in the 15-minute market. Congestion increased day-ahead prices in SDG&E and SCE areas by about $0.09/MWh (0.3 percent) and $0.15/MWh (0.5 percent), respectively, and had a small negative effect in the 15-minute market.
- Total residual unit commitment volume decreased slightly in the fourth quarter compared to the previous quarter. The amount of virtual supply clearing the day-ahead market fell from an average of 874 MW per hour in the third quarter to 312 MW per hour in the fourth quarter. This decrease caused the residual unit commitment process to commit less resources in the fourth quarter compared to the third quarter.
- Bid cost recovery payments were just above $18 million in the fourth quarter, compared to $31 million in the third quarter of 2015 and $25 million in the fourth quarter of 2014. The portion of bid cost recovery payments attributable to residual unit commitments dropped from about $10 million in the third quarter of 2015 to under $3 million in the fourth quarter. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $12 million in the fourth quarter, which is within the range of historical averages. Day-ahead bid cost recovery was particularly low during the fourth quarter.
- Virtual supply outweighed virtual demand by only about 300 MW on average, compared to almost 900 MW of net virtual supply in the previous quarter. Total convergence bidding revenue for the quarter, adjusted for bid cost recovery charges, was about $5.5 million, an increase from about $5 million in the previous quarter.

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 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively. As seen in these figures, average day-ahead market prices continue to be higher than 15-minute market prices. Overall, prices decreased in the fourth quarter, compared to the third quarter.

- Average day-ahead prices generally declined during the fourth quarter. Day-ahead prices in December were lower than in any month during the past 15-months, in both peak ($31/MWh) and off-peak ($27/MWh) periods. Day-ahead prices for the quarter averaged $33/MWh during peak periods and $28/MWh during off-peak periods.
- In the fourth quarter, 15-minute market prices also decreased. Prices in the 15-minute market in November and December were at nearly the lowest levels of the year, in both peak ($30/MWh) and off-peak ($26/MWh) periods. Average peak and off-peak system prices in the 15-minute market were lower than day-ahead prices during the quarter by about $1/MWh.
- The 5-minute market prices were higher than day-ahead and 15-minute prices in peak hours during October and off-peak hours during October and November. During October, peak and off-peak 5-minute market prices averaged $5/MWh above day-ahead prices. This was mostly driven by a period of high system prices on October 5 and October 13 where real-time load exceeded the forecasted and scheduled loads in the day-ahead market, which resulted in periods of power balance constraint relaxations.

Figure 1.1 Average monthly on peak prices – system marginal energy price

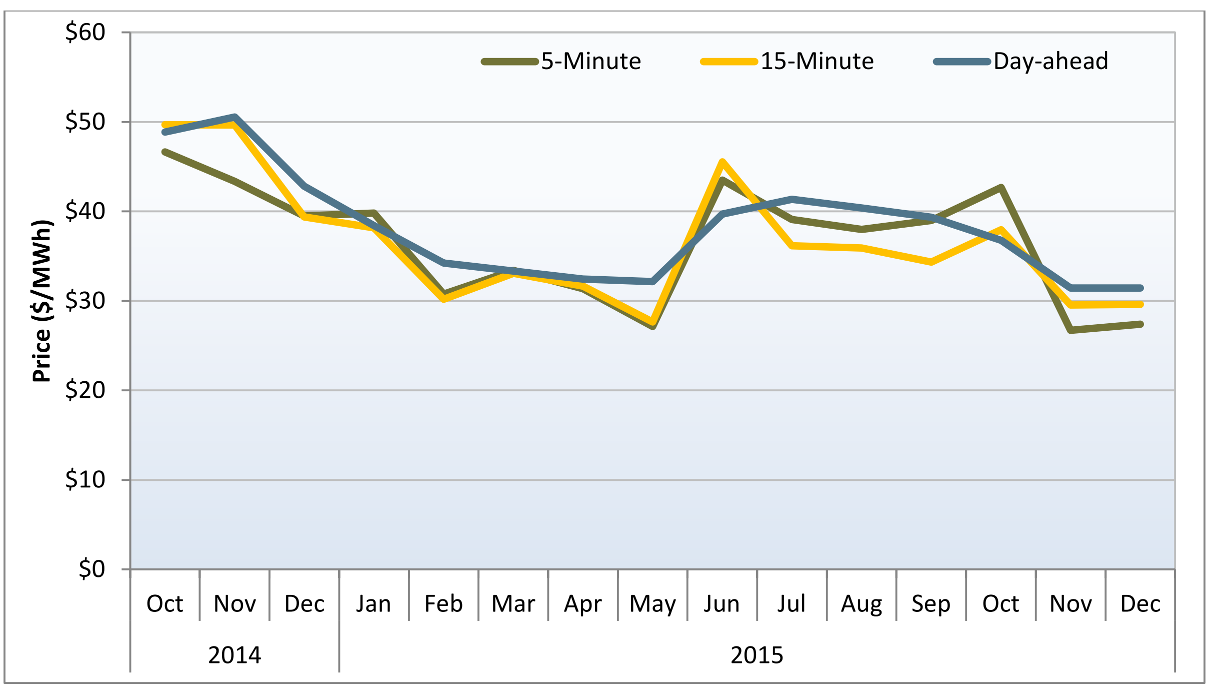


Figure 1.2 Average monthly off-peak prices – system marginal energy price

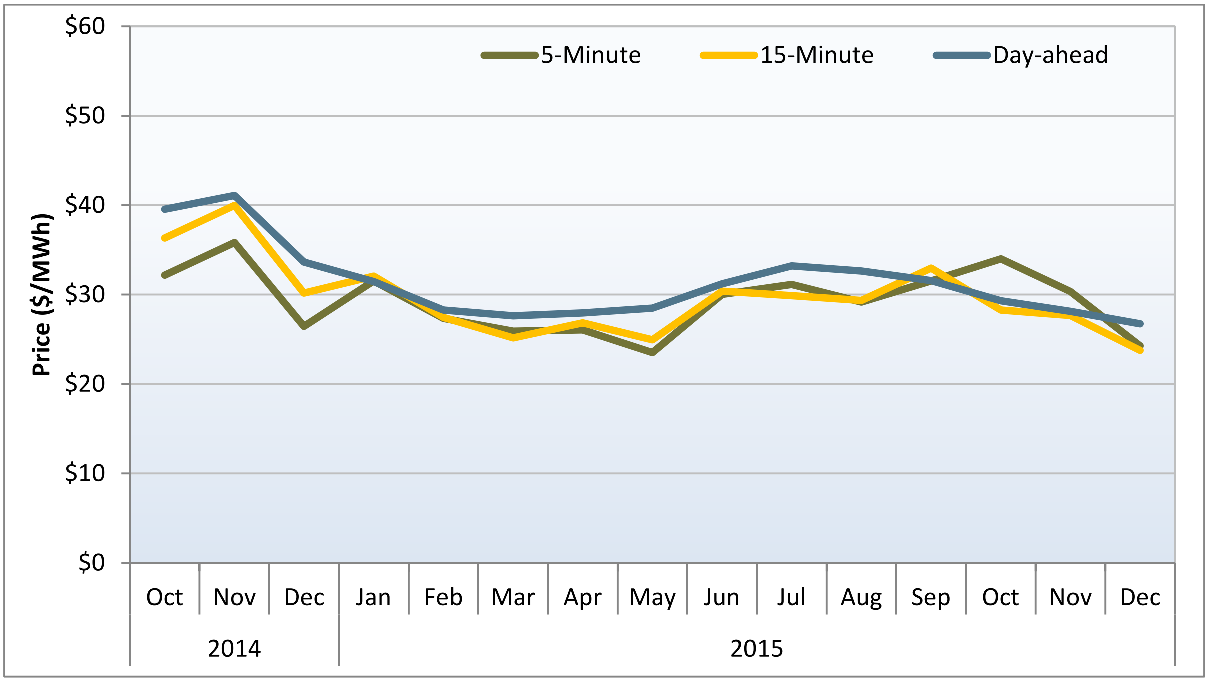


Figure 1.3 Hourly comparison of system marginal energy prices (October – December)

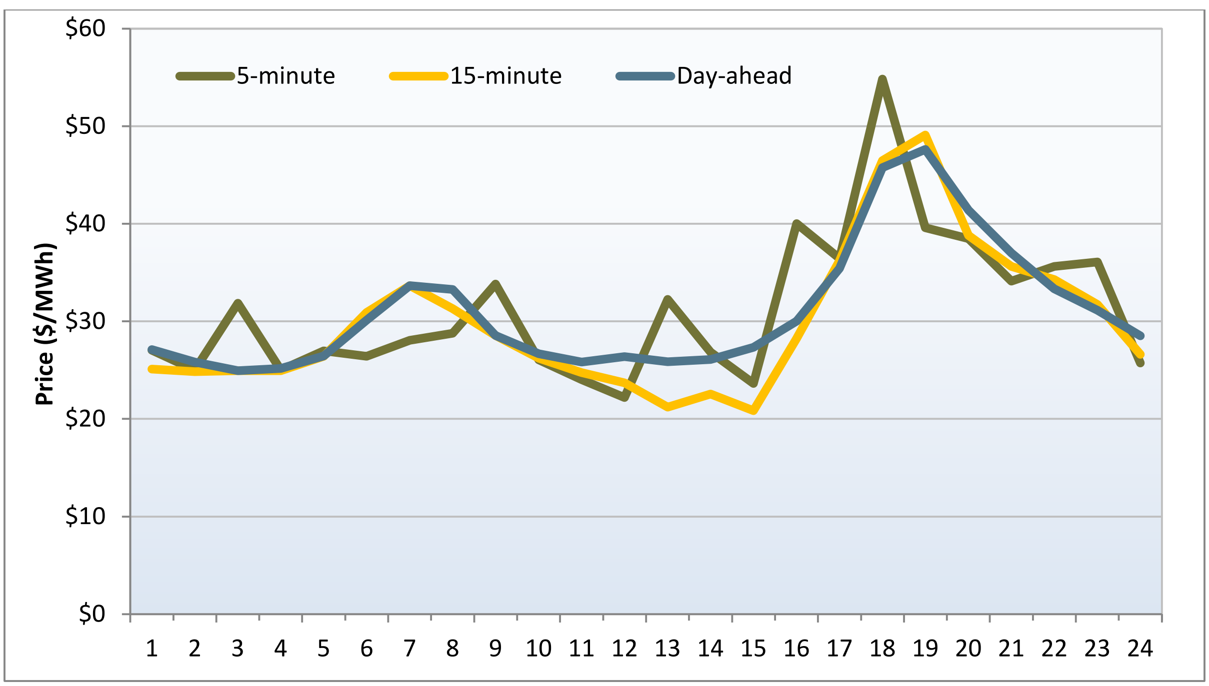


Figure 1.3 illustrates the system marginal energy prices on an hourly basis in the fourth quarter. Average prices in the 15-minute market were less than the day-ahead prices in the afternoon hours. Notably, prices in the 5-minute market were higher than the day-ahead and 15-minute markets in hours ending 16 and 18. In hour ending 16, 5-minute market prices averaged about $11/MWh higher than day-ahead and 15-minute market prices. This divergence was primarily driven by the period of high prices on October 5 and October 13, which resulted from higher than forecast real-time load.

1.2 Real-time price variability

Real-time market prices can be highly volatile with periods of extreme positive and negative price spikes. Even a short period of volatility can have a significant impact on average prices. In many instances, this price variability was the result of relaxing the power balance constraint to resolve the feasibility of the dispatch. The frequency of both positive and negative price spikes increased in both the 15-minute and 5-minute markets in the fourth quarter, compared to the prior quarter.

Frequency of price spikes

The frequency of positive price spikes grew in both the 15-minute and 5-minute markets in the fourth quarter compared to the previous quarter. Even so, the frequency of positive price spikes in the fourth quarter remained relatively infrequent overall. Prices above $250/MWh were observed in less than 0.1 percent of intervals in the 15-minute market and about 0.6 percent of intervals in the 5-minute market.

Figure 1.4 and Figure 1.5 show the frequency of positive price spikes occurring in the 15-minute market and 5-minute market, respectively. In the fourth quarter, the frequency of price spikes in the 5-minute market was about 0.6 percent, up from 0.4 percent in the third quarter. This was mostly driven by an increase in the frequency of positive price spikes in October, where prices above $250/MWh were observed in over 1 percent of 5-minute intervals because of higher than forecast real-time load on two days. Additional price spikes were associated with regional congestion.

During November and December, intervals with negative prices were much more common than high price intervals, though they remained relatively infrequent compared to previous periods. Figure 1.6 and Figure 1.7 show the frequency of negative price spikes in the 15-minute and 5-minute markets during the past 15 months. In the 15-minute market, negative prices were observed in about 1 percent of intervals during the quarter, an increase from 0.4 percent in the previous quarter, but significantly lower than frequencies during the second quarter. Negative prices were similarly infrequent in the 5-minute market, occurring in about 2 percent of intervals, compared to about 1 percent in the third quarter and about 8 percent of intervals in the second quarter.

Negative prices in October occurred in only 0.3 percent of intervals in the 5-minute market and less than 0.1 percent of intervals in the 15-minute market. These were among the lowest frequencies of negative price spikes in the previous 15 months. Alternatively, November and December had the highest frequency of negative prices in both real-time markets during the quarter, while remaining relatively low compared to historical averages. The increase in negative prices in the last two months of the quarter occurred as a result of a combination of factors including low seasonal loads, Path 15 congestion, and unscheduled renewable generation in the real-time market.

Figure 1.4 Frequency of positive 15-minute price spikes (ISO LAP areas)

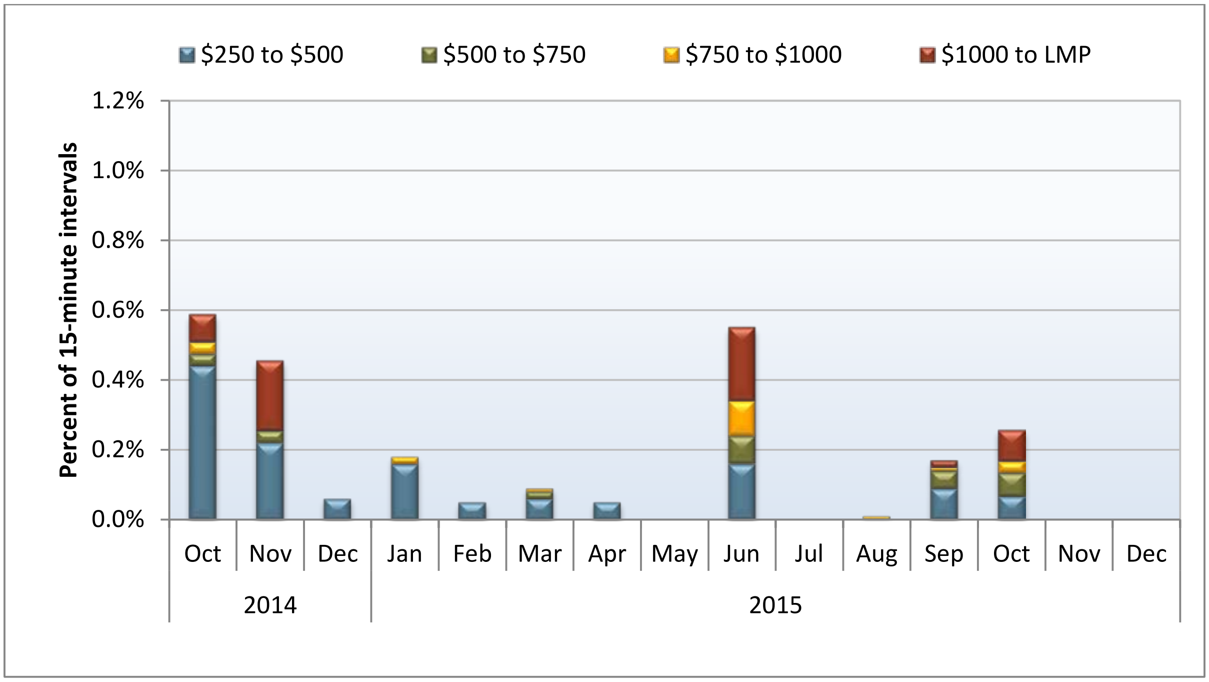


Figure 1.5 Frequency of positive 5-minute price spikes (ISO LAP areas)

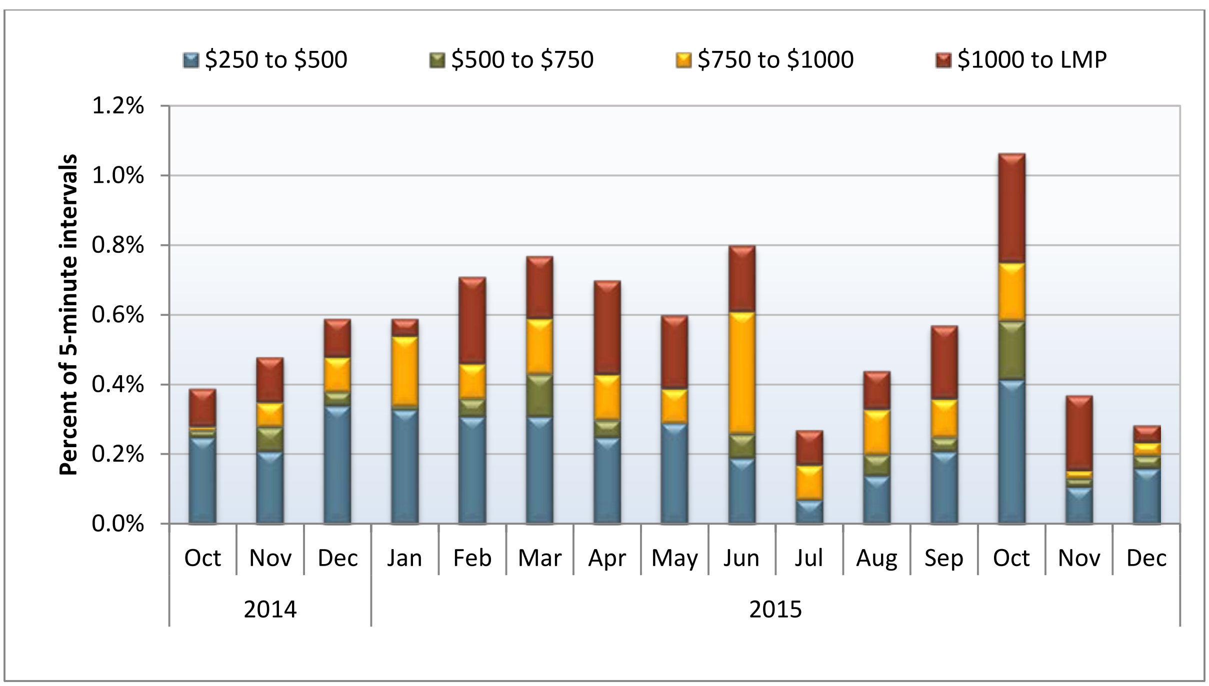


Figure 1.6 Frequency of negative 15-minute price spikes (ISO LAP areas)

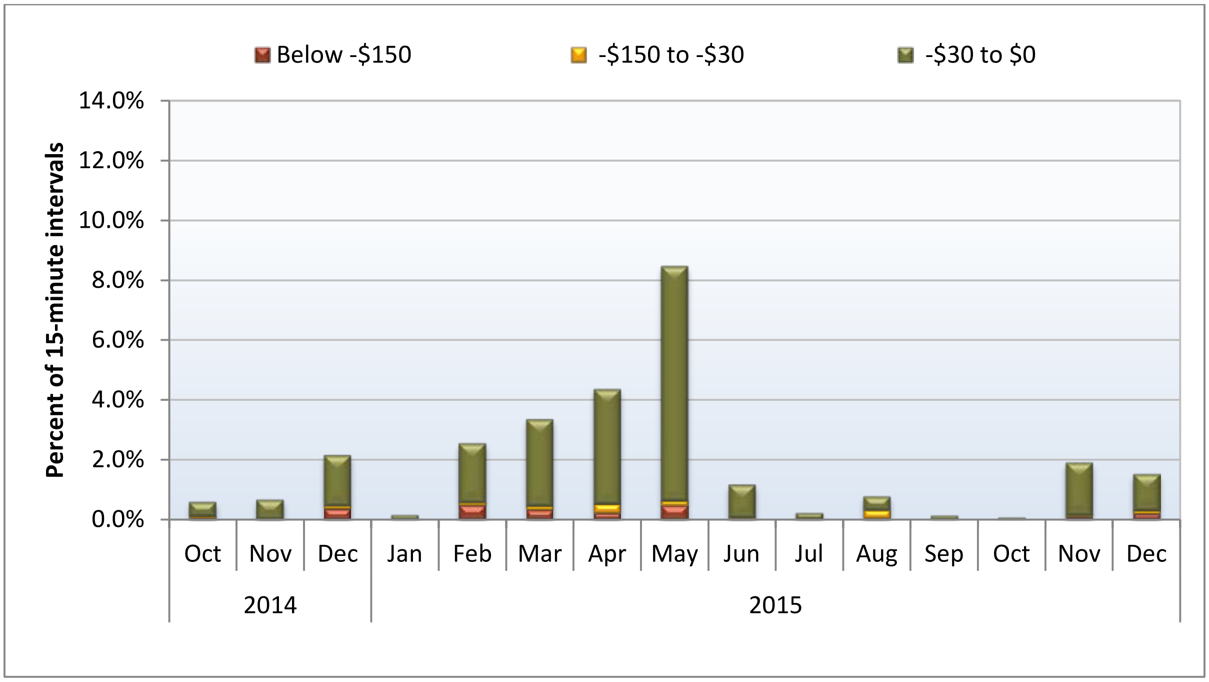
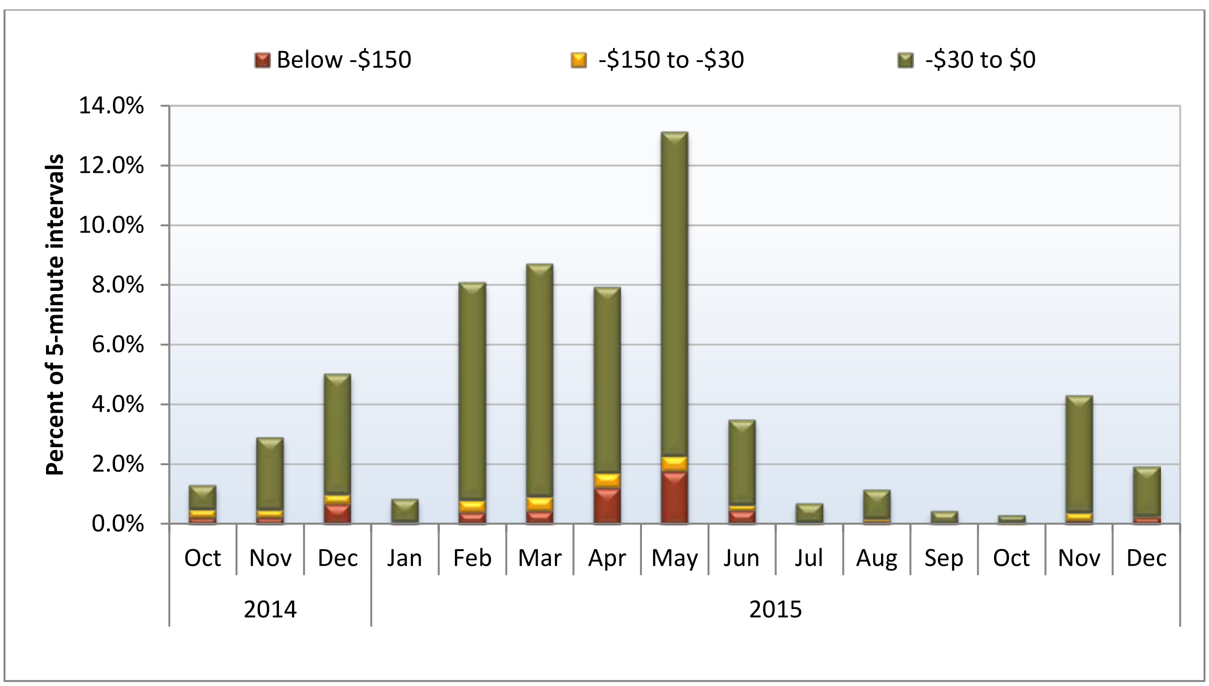


Figure 1.7 Frequency of negative 5-minute price spikes (ISO LAP areas)



1.3 Congestion

Overall, congestion had a low impact on load area prices across the ISO in the day-ahead and real-time markets. In the PG&E area, congestion on the constraints decreased prices by $0.04/MWh (0.1 percent) in the day-ahead market, and increased prices by $0.13/MWh (0.4 percent) in the 15-minute market. Congestion increased day-ahead prices in SDG&E and SCE areas by about $0.09/MWh (0.3 percent) and $0.15/MWh (0.5 percent), respectively. Additionally, system-wide constraints bound more frequently in the day-ahead than in the 15-minute market. However, the price impact was higher in the 15-minute market than in the day-ahead market when congestion occurred.

Much of the congestion in the fourth quarter was related to Path 15, Barre-Villa Park (220 kV) and the OMS 2319325 PDCI_NG constraints. Path 15 bound in the south-to-north direction because limits on the constraint were lowered due to nearby outages. Much of the congestion on the Barre-Villa Park (220 kV) constraint was due to an outage during most of December on the nearby Miraloma-Olinda (220 kV) line. The OMS 2319325 PDCI_NG constraint, representing imports into Southern California, bound due to an outage on the Pacific DC inter-tie, a component of the Southern California Import Transmission (SCIT) limit. The loss of this transmission capacity had a small impact on prices in Southern California.

1.3.1 Congestion impacts of individual constraints

Day-ahead congestion

Overall, the frequency and impact of congestion in the day-ahead market was small in the fourth quarter, but slightly larger than the prior quarter. There were a few constraints that bound frequently during the quarter, but overall had little impact on load area prices.

The constraint that bound most frequently in the PG&E area in the day-ahead market was Malin-Round Mountain (500 kV), at about 4 percent of total hours (see Table 1.1). While the constraint was binding, the associated shadow price increased PG&E area prices by $0.60/MWh, and decreased prices in the SCE and SDG&E areas by about $0.47/MWh and $0.61/MWh, respectively.

Similarly, in SCE the Barre-Villa Park (220 kV) constraint bound most frequently at about 12 percent of hours in the quarter. The constraint bound due to the loss of the Miraloma-Olinda (220 kV) line. While the constraint was binding, it decreased prices in PG&E and SDG&E areas by about $0.65/MWh and $0.49/MWh respectively, and caused price increases of $1.14/MWh in the SCE area.

Finally, the SDG&E constraint that bound most frequently in the fourth quarter was Doubletap-Friars (230 kV), at about 11 percent of all hours during the quarter. When binding, it only impacted the SDG&E area prices and decreased them by $1.20/MWh. The South Bay-Imperial Beach (69 kV) and South Bay Transformer (69 kV-138 kV) constraints, also in the SDG&E area, bound relatively frequently, and increased prices by about $0.25/MWh and $3.36/MWh, respectively, when they were active.

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	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3				3.6%										$0.60	-$0.47	-$0.61
	PATH15_S-N		9.1%	0.5%	2.5%				$4.05	-$3.65	-$3.42	$0.63	-$0.52	-$0.49	$1.17	-$0.97	-$0.90
	33020_MORAGA _115_30550_MORAGA _230_XF_3 _P				2.4%										$0.32	-$0.35	-$0.35
	30050_LOSBANOS_500_30069_L.BANS M_ 1.0_XF_1				0.3%										$1.26	-$1.05	-$0.99
	RM_TM21_NG			7.0%								$0.54		-$0.47			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1			1.4%								$3.24					
	30055_GATES1 _500_30900_GATES _230_XF_11_P		2.7%	0.7%					$0.70	-$0.60	-$0.59	$0.73	-$0.60	-$0.59			
	LOSBANOSNORTH_BG			0.2%								$6.49	-$5.71	-$5.27			
	PATH15_BG	6.2%	27.6%			$4.02	-$3.29	-$3.06	$4.54	-$3.86	-$3.64						
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		2.3%						$1.97	-$1.72	-$1.63						
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_1		1.5%						$2.02								
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2		1.3%						$4.13	-$6.42	-$6.20						
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		0.6%						$2.96	-$1.36							
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3		0.3%						$4.13	-$3.82	-$3.62						
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.0%	0.8%	3.9%	12.4%	-$0.95	$0.92	$1.51	-$1.78	$2.51	-$0.41	-$0.43	$0.86	-$2.68	-$0.65	$1.14	-$0.49
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.9%	0.9%	1.5%	1.5%	-$0.74	$1.00	-$0.59				-$0.44	$0.57		-$0.51	$0.72	-$0.41
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.2%						-$0.41	$0.49	$0.40						
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		2.4%	2.4%	11.1%						-$2.11			-$2.24			-$1.20
	22768_SOUTHBAY_69.0_22352_IMPRLBCH_69.0_BR_1 _1				3.7%												$0.25
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1	0.5%		1.3%	2.5%			$6.85						$2.26			$3.36
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80				1.7%												$0.74
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			2.3%	1.3%									-$1.83			-$1.18
	OMS 2319325 PDCI_NG				1.2%										-$2.60	$2.24	$2.78
	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1			1.3%	1.1%									$1.14			$1.40
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1				0.8%												$1.51
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1		1.3%	0.3%	0.7%						$9.18			$5.55			$10.61
	22408_LOSCOCHS_69.0_22412_LOSCOCHS_138_XF_2				0.2%												$5.20
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1		0.6%	6.1%							$5.26			$1.30			
	22609_OTAYMESA_230_22467_MLSXTAP _230_BR_1 _1			2.1%										$0.50			
	22668_POWAY _69.0_22664_POMERADO_69.0_BR_1 _1			1.0%										$1.06			
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		2.8%	0.6%							-$2.14			-$2.36			
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.3%	0.05%					-$5.06	$3.49	$7.21	-$13.67	$8.54	$12.63			
	22716_SANLUSRY_230_22504_MISSION _230_BR_2 _1		0.2%							$0.70	-$5.89						
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.2%	1.3%					-$0.47	-$0.72		$1.17						
	SLIC 2584248 50002_OOS_TDM		0.6%								$4.70						
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	24.7%						$5.04									
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	13.1%				-$2.80	$1.70	$5.15									
	IVALLY-ELCNTO_230_BR_1_1	1.7%				-$0.05		$1.47									
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	1.5%				-$3.81	$2.35	$6.50									

15-minute market congestion

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

In the SCE area, Barre-Villa Park (220 kV) was the constraint that bound most frequently during the quarter, occurring in about 1 percent of intervals. When the constraint bound it increased the SCE and SDG&E area prices by $4.20/MWh and $0.25/MWh respectively, and decreased the PG&E prices by about $2.73/MWh.

Path 15 S-N and the Southern California Import Transmission constraints bound nearly as frequently during the fourth quarter, at 0.8 percent and 0.7 percent of all the intervals, respectively. When Path 15 S-N bound, it increased PG&E prices by $21.54/MWh and decreased SCE and SDG&E prices by about $21.50/MWh and $20.10/MWh, respectively. In the 15-minute real-time market when the Southern California Import Transmission constraint bound, it increased prices in SCE and SDG&E areas by $7.73/MWh and $8.75/MWh respectively, and decreased prices in the PG&E area by $2.95/MWh. As mentioned above, this constraint was active because of the Pacific DC Inter-tie outage during most of November and December.

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

		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%	6.7%	0.5%	0.8%	$16.27	-$16.36	-$15.30	$14.16	-$14.62	-$13.81	$13.80	-$13.31	-$12.53	$21.54	-$21.50	-$20.10
	LBN_S-N				0.2%										$5.53	-$6.64	-$6.20
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2				0.1%										-$11.11	$9.24	$8.52
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2				0.1%										$17.57	$7.32	$5.72
	PATH15_N-S				0.1%										-$42.92	$29.59	$28.07
	30055_GATES1 _500_30900_GATES _230_XF_11_P			0.4%								$6.72	-$5.41	-$5.26			
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		0.3%						$6.59	-$6.62	-$6.29						
	6110_SOL10_NG		0.2%						$4.96	$2.13	$1.50						
	PATH15_BG	0.2%				$5.87	-$6.08	-$5.72									
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.5%	0.1%	0.8%	1.1%	-$3.09	$7.15	$3.45	-$5.92	$16.52	$2.76	-$1.45	$3.21	-$6.56	-$2.73	$4.20	$0.25
	24156_VINCENT _500_24155_VINCENT _230_XF_1 _P				0.1%										-$9.44	$10.38	$6.59
	PATH26_N-S	0.1%		0.5%		-$46.75	$44.20	$41.92				-$9.46	$7.08	$6.68			
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1			0.1%								-$5.14	$12.24	-$32.72			
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1		0.5%								$14.09						
	SLIC 2584248 50002_SCIT		0.1%						-$4.18	$9.51	$9.92						
SDG&E	OMS 2319325 PDCI_NG				0.7%										-$2.95	$7.73	$8.75
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			0.4%	0.7%									-$6.42			-$5.22
	OMS 3560161 TL50004_NG				0.1%												$46.71
	7820_TL 230S_OVERLOAD_NG			0.4%								-$1.97		$27.45			
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			0.2%										-$10.81			
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1		0.1%							$9.67	-$100.16						
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.1%						-$5.35	$5.99	$10.80						
	SDGEIMP_BG		0.1%						-$1.74	-$1.74	$24.03						
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		0.1%							$3.57	-$30.20						
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	2.7%						$14.80									
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	1.7%				-$7.01	$8.42	$19.96									
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.5%				-$9.33	$10.25	$25.01									

Overall, congestion occurred more frequently in the day-ahead market than in the 15-minute market, but had a smaller price impact when binding. In the quarter, the price impact on the most significant binding elements was larger in the 15-minute market than the day-ahead market. During the quarter, the Barre-Villa Park (220 kV) constraint was binding during roughly 12 percent of hours in the day-ahead market compared to around 1 percent of intervals in the 15-minute market. Prices increased by $4.20/MWh in the 15-minute market in SCE when the constraint bound, but only by $1.14/MWh in the day-ahead market. Differences in congestion in the day-ahead and real-time markets occur as system conditions change, virtual bids liquidate, and constraints are adjusted to account for discrepancies between market and actual flows, and provide a reliability margin.

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, this assessment is based on the average congestion component of the price as a percent of the total price during all congested and non-congested hours. This approach shows the impact of congestion when taking into account both the frequency with which congestion occurs and the magnitude of the impact.[1] The congestion price impact differs across load areas and markets.

[1] In addition, this approach identifies price differences caused by congestion without including price differences that result from variations in transmission losses at different locations.

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 in the quarter by constraint.[2] Overall this impact was small in both the day-ahead and real-time markets.

Congestion in the day-ahead market decreased PG&E prices by about $0.04/MWh (0.1 percent) and increased the SCE and SDG&E area prices by about $0.15/MWh (0.5 percent) and $0.09/MWh (0.3 percent), respectively. During this quarter and the last quarter, the congestion in the ISO has remained low, particularly compared to the high congestion levels observed during the second quarter.

The Barre-Villa Park (220 kV) constraint had the largest overall impact on prices in the fourth quarter. This constraint increased prices in the SCE area by $0.14/MWh (0.46 percent) and decreased the PG&E and SDG&E area prices by $0.08/MWh (0.26 percent) and $0.05/MWh (0.17 percent), respectively.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.08	-0.26%	$0.14	0.46%	-$0.05	-0.17%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.13	-0.43%
OMS 2319325 PDCI_NG	-$0.03	-0.10%	$0.03	0.09%	$0.03	0.11%
22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1					$0.08	0.27%
22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1					$0.08	0.25%
PATH15_S-N	$0.03	0.09%	-$0.02	-0.08%	-$0.02	-0.07%
40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.02	0.07%	-$0.02	-0.05%	-$0.02	-0.06%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.01	0.04%	$0.00	0.00%
22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1					$0.02	0.05%
22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1					-$0.02	-0.05%
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80					$0.01	0.04%
22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1					$0.01	0.04%
22408_LOSCOCHS_69.0_22412_LOSCOCHS_138_XF_2					$0.01	0.04%
33020_MORAGA _115_30550_MORAGA _230_XF_3 _P	$0.01	0.03%	$0.00	0.00%	$0.00	0.00%
22768_SOUTHBAY_69.0_22352_IMPRLBCH_69.0_BR_1 _1					$0.01	0.03%
30050_LOSBANOS_500_30069_L.BANS M_ 1.0_XF_1	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
Other	$0.01	0.05%	$0.01	0.04%	$0.08	0.26%
Total	-$0.04	-0.14%	$0.15	0.48%	$0.09	0.29%

[2] Due to data issues, details on specific constraints could not be calculated and were included in the 'other' category.

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.[3] Congestion in the 15-minute market was low overall, similar to the congestion in the day-ahead market during the third quarter of 2015. On a load area basis, congestion increased the PG&E area prices by about $0.13/MWh (0.43 percent) and had a small negative effect on SCE and SDG&E load area prices. Path 15 in the south-to-north direction had the largest congestion impact, followed by congestion due to the Southern California Import Transmission constraint.

Table 1.4 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
PATH15_S-N	$0.16	0.53%	-$0.16	-0.54%	-$0.15	-0.51%
OMS 2319325 PDCI_NG	-$0.02	-0.06%	$0.05	0.17%	$0.06	0.19%
PATH15_N-S	-$0.03	-0.09%	$0.02	0.06%	$0.02	0.06%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	-0.01%	$0.05	0.16%	$0.00	0.00%
LBN_S-N	$0.01	0.04%	-$0.02	-0.05%	-$0.01	-0.05%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.02	-0.05%	$0.01	0.04%	$0.01	0.04%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.04	-0.13%
24156_VINCENT _500_24155_VINCENT _230_XF_1 _P	-$0.01	-0.03%	$0.01	0.04%	$0.01	0.02%
OMS 3560161 TL50004_NG					$0.03	0.08%
30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.01	0.04%	$0.01	0.02%	$0.00	0.01%
Other	$0.02	0.06%	$0.02	0.08%	$0.06	0.19%
Total	$0.13	0.43%	-$0.01	-0.03%	-$0.03	-0.09%

1.4 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run after the day-ahead market and procures capacity sufficient to cover the gap between the amount of physical supply cleared in the day-ahead market and the day-ahead forecast load. In addition, when the market clears with net virtual supply, residual unit commitment capacity is needed to replace the net virtual supply with physical supply. Capacity procured in the residual unit commitment must be bid into the real-time market.

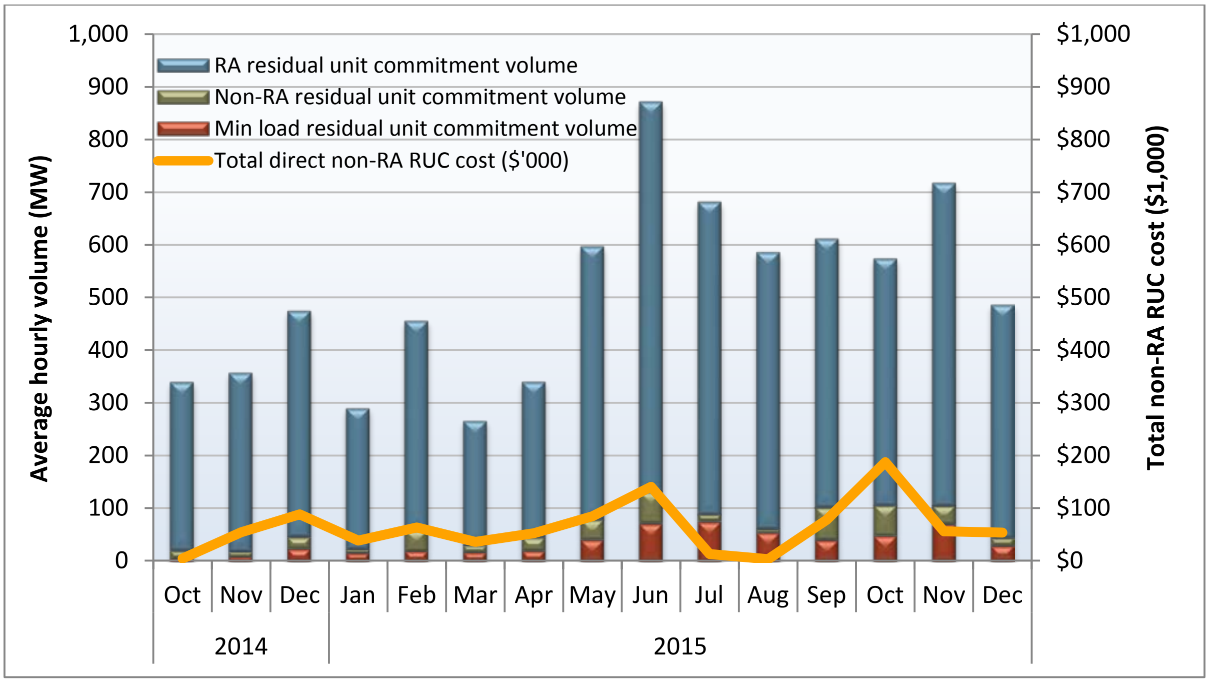
While capacity procured in the residual unit commitment must be bid into the real-time market, only a fraction of this capacity is committed to be on-line by the residual unit commitment process. Most of the capacity procured in the residual unit commitment process is from units that are already scheduled to be on-line through the day-ahead market or from short-start units that do not need to be started up unless actually needed in real time.

[3] Due to data issues, details on specific constraints could not be calculated and were included in the 'other' category.

1.4.1 Residual unit commitment costs and volumes

While total residual unit commitment volume decreased slightly in the fourth quarter when compared to the previous quarter, it was up compared to the fourth quarter in 2014. Figure 1.8 shows monthly average hourly residual unit commitment procurement, categorized as either non-resource adequacy or resource adequacy and minimum load. Total residual unit commitment procurement fell from an average of 627 MW per hour in the third quarter to 592 MW per hour in the fourth quarter. Compared to the fourth quarter of 2014, there was a 51 percent increase in total residual unit commitment procurement in the fourth quarter of 2015.

Figure 1.8 Residual unit commitment costs and volume



Out of the 592 MW total average hourly volume of residual unit commitment capacity in the fourth quarter, the capacity committed to operate at minimum load averaged 49 MW (8 percent) each hour, down slightly from 57 MW (9 percent) in the third quarter. Moreover, only a small fraction of this capacity (11 MW) was from long-start units committed to be on-line via the residual unit commitment process, which was down from 24 MW in the third quarter.[4]

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in the residual unit commitment receive capacity payments.[5] As shown by the very small green segment of each bar in Figure 1.8, the non-resource adequacy residual unit commitment was low in the fourth

[4] Long-start commitments are resources that require 300 or more minutes (5 hours) to start up. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, whereas the actual unit commitment decision for these units occurs in real time.

[5] Resource adequacy units receive bid cost recovery payments as well as payments through the resource adequacy process.

quarter, averaging only 36 MW per hour. However, this was an increase from 27 MW per hour in the previous quarter. The total direct cost of residual unit commitment, represented by the gold line in Figure 1.8, was about $0.30 million in the fourth quarter, an increase from direct costs of $0.09 million in the previous quarter.

1.4.2 Determinants of residual unit commitment procurement

As illustrated in Figure 1.9, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) fell from an average of 874 MW per hour in the third quarter to 312 MW per hour in the fourth quarter.

In 2014 the ISO introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources.[6] This eligible intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.9.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor increased residual unit commitment in October and November and decreased residual unit commitment in December. In addition, ISO operators can increase the amount of residual unit commitment requirements for reliability purposes. This tool, noted as operator adjustments (red bar) in the figure, was used more frequently in the fourth quarter of 2015 than in 2014 and averaged about 22 MW per hour. Even so, this still continues to be a very small factor driving overall procurement.

Figure 1.10 illustrates the determinants of residual unit commitment procurement during different operating hours of the fourth quarter. Operator adjustments were concentrated in the peak load hours of the day, during hours ending 9 through 17. Net virtual supply was a major driver of residual unit commitment procurement during non-ramping morning and evening hours. Physical supply differences primarily decreased requirements in peak hours and increased requirements in the late evening and early morning hours. Intermittent resource adjustments were greatest during hours ending 10 through 24.

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

Figure 1.9 Determinants of residual unit commitment procurement

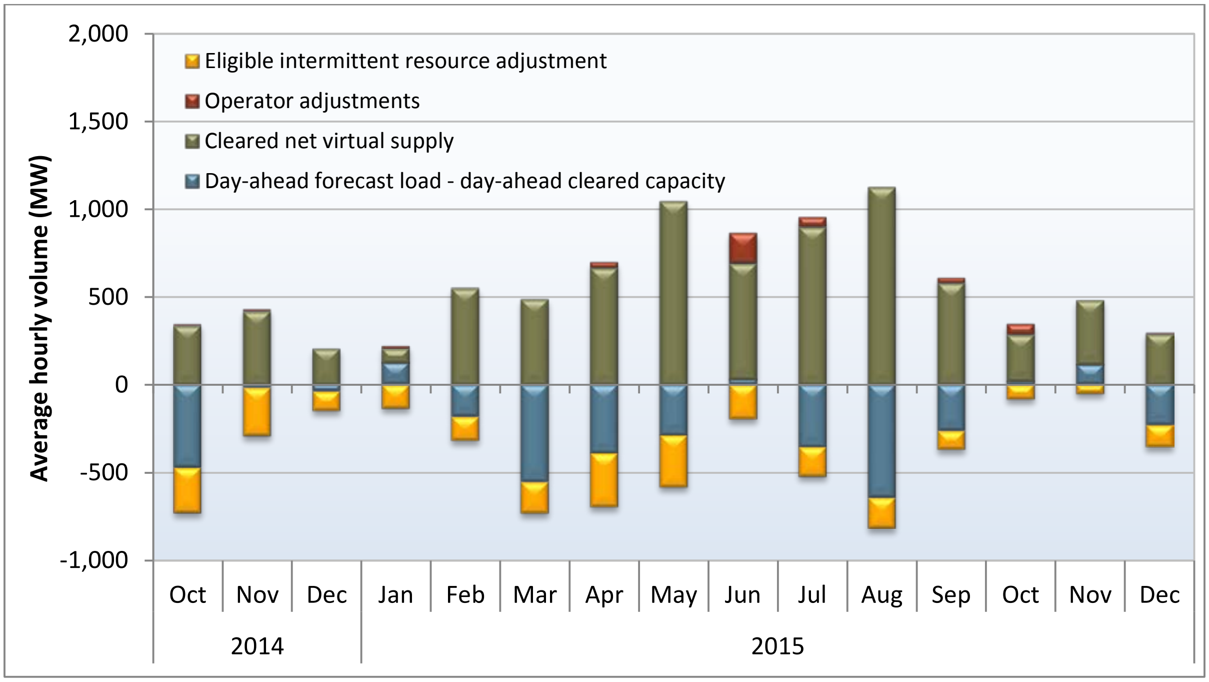
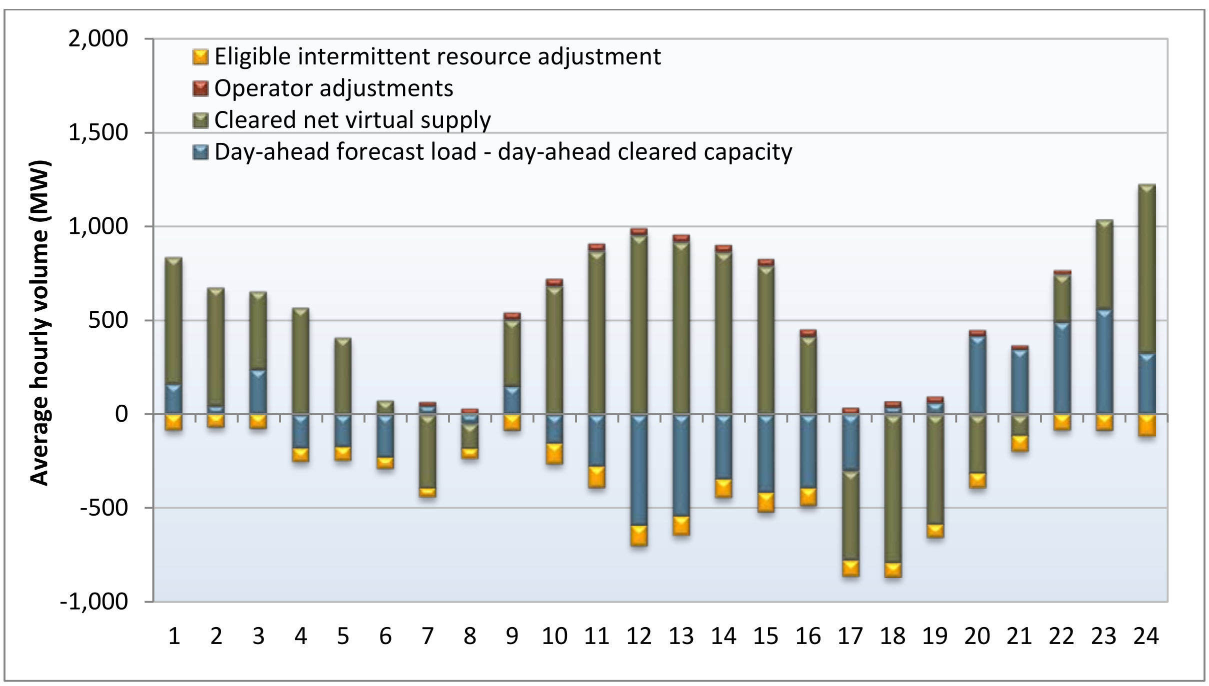


Figure 1.10 Average hourly determinant of residual unit commitment procurement (October – December)



1.5 Bid cost recovery

Estimated bid cost recovery payments for the fourth quarter totaled just over $18 million. This is a decrease when compared to about $31 million in the third quarter of 2015 and about $25 million in the fourth quarter of 2014. Real-time bid cost recovery decreased from about $16 million in the third quarter to about $12 million in the fourth quarter. Real-time bid cost recovery remains the largest category of bid cost recovery, but was not out of range of historical averages. Bid cost recovery attributed to the day-ahead market was lower than any fourth quarter result since 2011.

As seen in Figure 1.12, after netting against real-time revenues in the fourth quarter of 2015, both short-start and long-start resources received about $1.5 million from residual unit commitment bid cost recovery payments. Compared to the previous quarter, this was a 41 percent decrease for short-start resources and a 79 percent decrease for long-start resources. As noted in Section 1.4, lower volumes of net virtual supply primarily caused the residual unit commitment process to commit less resources in the fourth quarter, compared to the third quarter of 2015. Hence, the residual unit commitment bid cost recovery payments, especially for long-start resources, have decreased from the previous quarter.

Figure 1.11 Monthly bid cost recovery payments

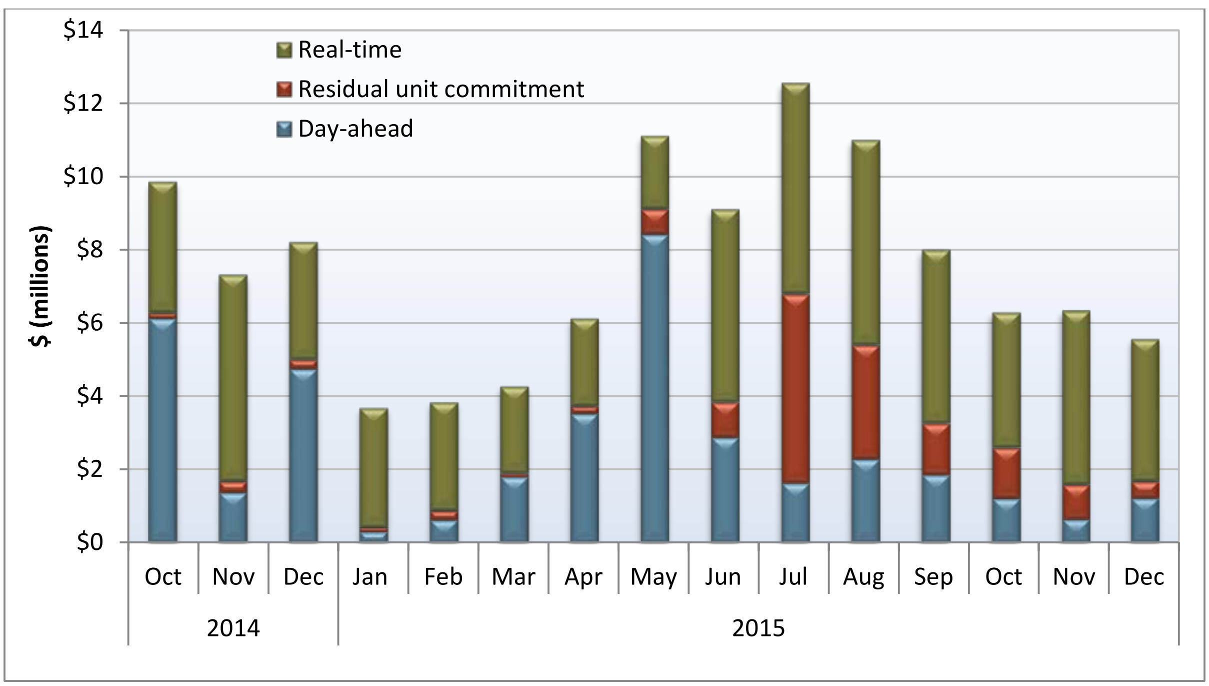
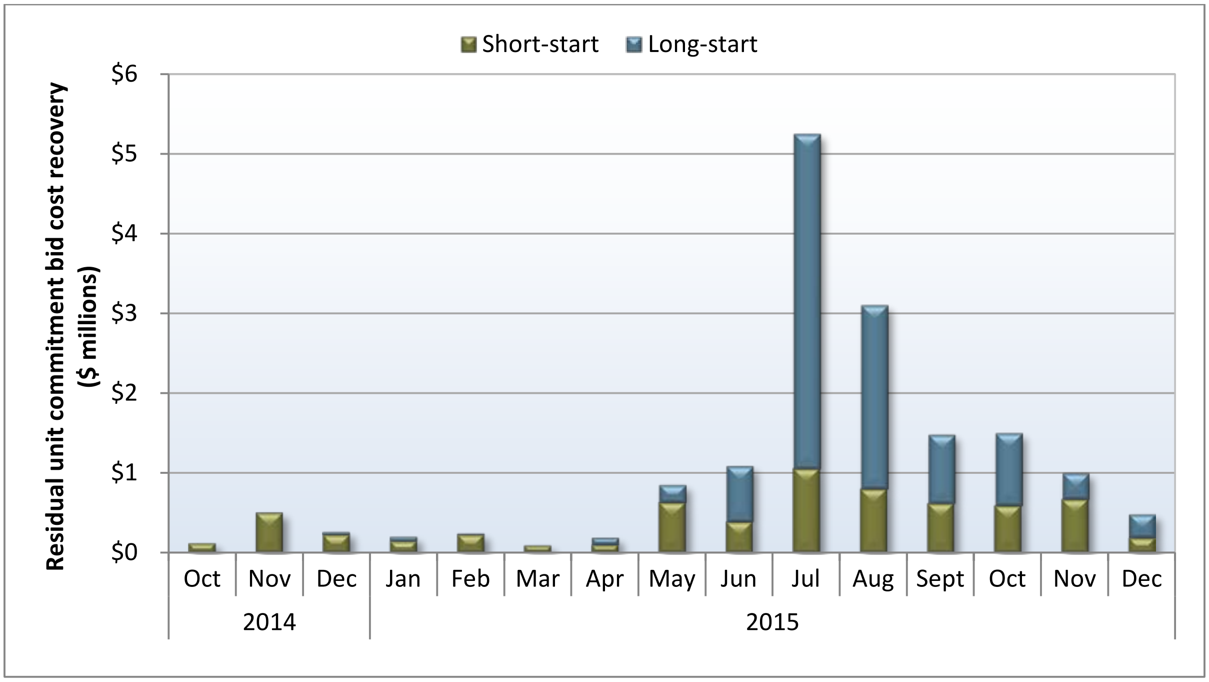


Figure 1.12 Residual unit commitment bid cost recovery payments by commitment type



1.6 Convergence bidding

Participants engaging in convergence bidding continued to earn positive returns in the fourth quarter. The net revenues from the market in these three months were about $6.9 million. Virtual supply generated net revenues of about $6.1 million while virtual demand accounted for approximately $0.8 million. The total payment to convergence bidders increased slightly, to about $5.5 million, after taking into account virtual bidding bid cost recovery charges of $1.4 million.

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 54 percent of all accepted virtual bids in the fourth quarter, similar to the level in the previous quarter.

Total hourly trading volumes decreased in the fourth quarter to about 2,900 MW from 3,500 MW in the previous quarter. Virtual supply averaged around 1,600 MW while virtual demand averaged around 1,300 MW during each hour of the quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 300 MW on average, a decrease from 880 MW of net virtual supply in the previous quarter.

Net revenues for most of the fourth quarter were positive from net virtual supply positions as prices were generally higher in the day-ahead market than the 15-minute market.[7] However, a higher

[7] For additional background please refer to Section 3.6 Convergence bidding in the *Q4 2014 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2014FourthQuarterReport_MarketIssuesandPerformance_March2015.pdf.

frequency of price spikes in the 15-minute market in October led to virtual demand positions being profitable for the quarter and reduced the profitability of virtual supply positions.

1.6.1 Convergence bidding trends

Total hourly trading volumes decreased in the fourth quarter to about 2,900 MW from 3,500 MW during the previous quarter. These volumes had remained relatively stable for the last few quarters. On average, about 57 percent of virtual supply and demand bids offered into the market cleared in the fourth quarter, which is down from 61 percent in the third quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 300 MW on average, which decreased from 880 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours, by about 210 MW and 500 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in hours ending 7 and 8, and hours ending 17 through 21 with the highest net virtual demand occurring in hour ending 18 at about 790 MW. In the remaining 17 hours, net cleared virtual supply exceeded net cleared demand. The highest net cleared virtual supply hour was hour ending 12 at about 950 MW.

Consistency of price differences and volumes

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 price differences between the day-ahead and real-time markets for an average of 16 hours. By month for the quarter, net convergence bidding volumes were consistent with price differences between the day-ahead and real-time markets for an average of 15, 14 and 16 hours for October, November and December, respectively.

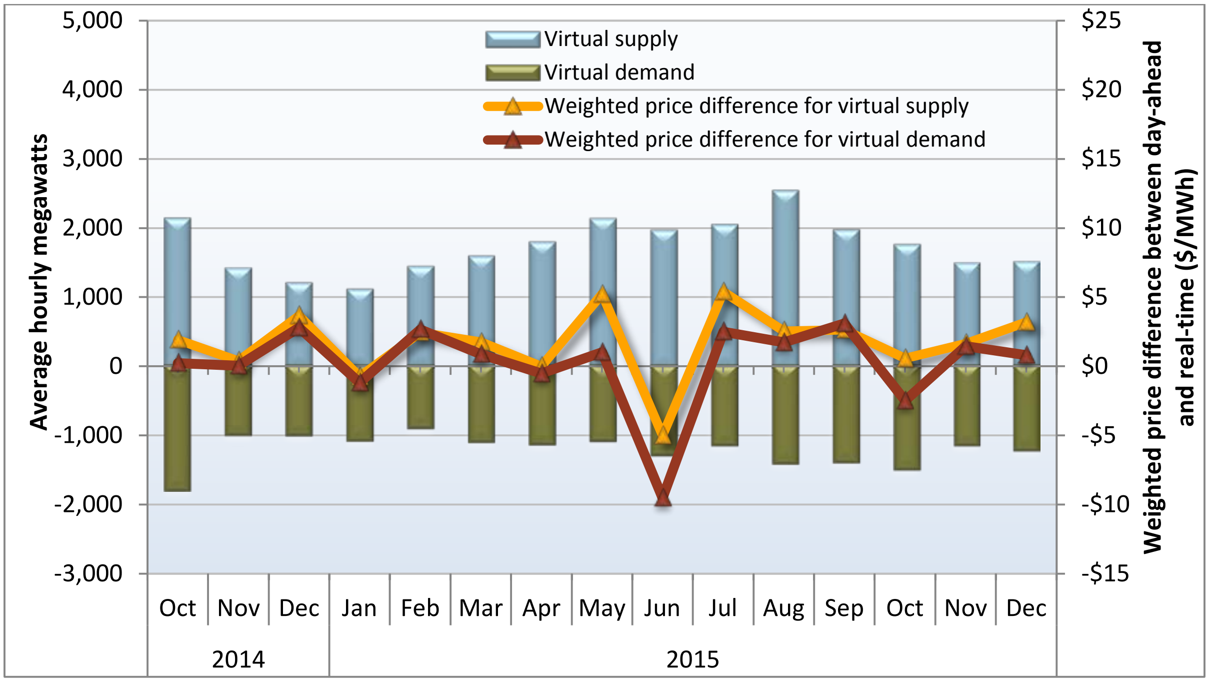
Figure 1.13 compares cleared convergence bidding volumes with the volume-weighted average price difference where the virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different locations.

When the red line is positive, it indicates that the weighted average price charged for virtual demand in the day-ahead market was higher than the weighted average real-time price paid for this virtual demand. When positive, it indicates that a virtual demand strategy was not profitable, and thus was directionally inconsistent with weighted average price differences.

Virtual demand volumes for the month of October were consistent with weighted average price differences for the hours in which virtual demand cleared the market and, thus, were profitable. However, virtual demand positions in November and December were unprofitable as they were inconsistent with the weighted average price differences.

The yellow line in Figure 1.13 represents the difference between the day-ahead price paid to virtual supply and the real-time market price at which virtual supply positions are liquidated, weighted by cleared virtual supply bids by time interval and location. Virtual supply positions in the fourth quarter were, on average, profitable in all three months.

Figure 1.13 Convergence bidding volumes and weighted price differences



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 due to congestion differences between the day-ahead and real-time markets.

The majority of cleared virtual bids in the fourth quarter were offsetting bids. Offsetting virtual positions accounted for an average of about 780 MW of virtual demand offset by 780 MW of virtual supply in each hour of the quarter. These offsetting bids represent about 54 percent of all cleared virtual bids in the fourth quarter, which is about the same as in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

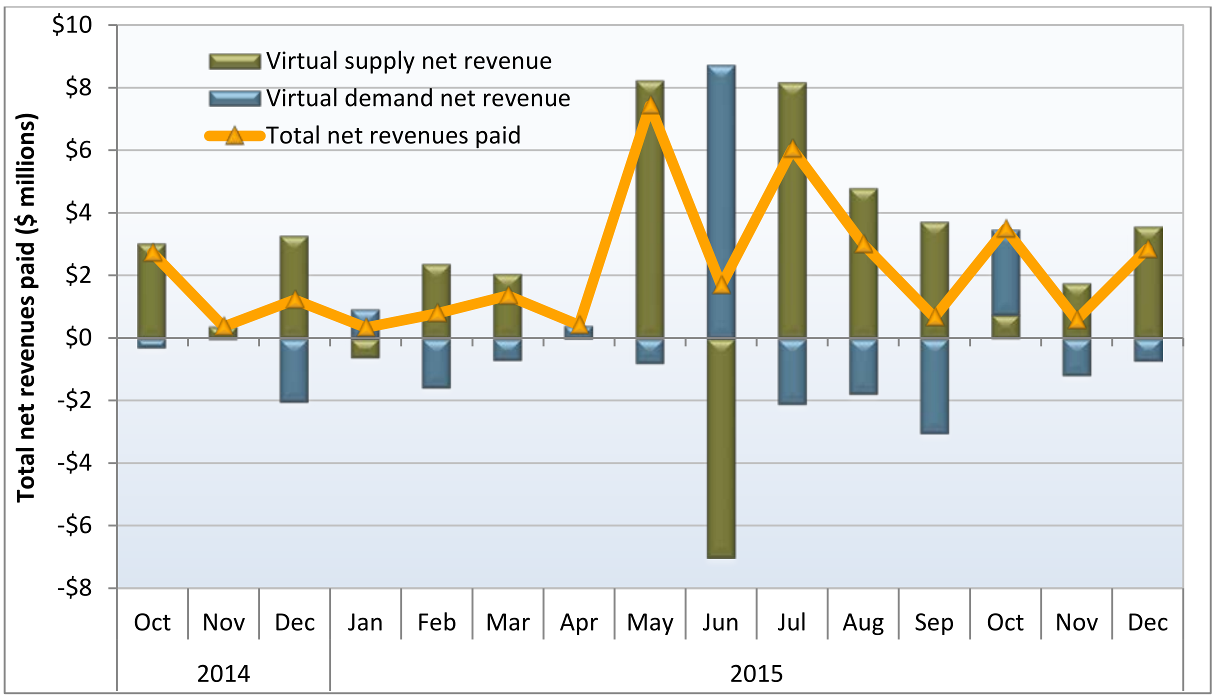
1.6.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the third quarter. Similar to the previous quarter, convergence bidding participants earned positive revenue. In the fourth quarter, net revenues were about $6.9 million from revenue collected on both virtual supply and demand positions.

Figure 1.14 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $6.9 million in the fourth quarter, compared to about $4.3 million in the same quarter in 2014, and $9.7 million in the previous quarter.
- Virtual supply revenues were most profitable in December as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply accounted for net payments of about $6.1 million during the quarter.
- Virtual demand revenues were negative in November and December and positive in October. In total, virtual demand accounted for net payments of about $0.8 million during the quarter.
- Convergence bidders were paid about $5.5 million after subtracting virtual bidding bid cost recovery charges of $1.4 million for the quarter.[8,9] These costs were about $0.4 million, $0.7 million and $0.3 million in October, November and December, respectively.

Figure 1.14 Total monthly net revenues paid from convergence bidding



[8] Further detail on bid cost recovery and convergence bidding can be found here: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

[9] The Business Practice Manual configuration guide has been updated for CC 6806 Day Ahead Residual Unit Commitment Tier 1 Allocation to ensure that the RUC Obligation does not receive an excess RUC TIER 1 charge or payment. For additional information, refer to BPM Change Management Proposed Revision Request.

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.[10] As shown in Table 1.5, financial entities represent the largest segment of the virtual bidding market in terms of volume, accounting for about 51 percent of volumes and about 38 percent of settlement dollars. Marketers represent about 36 percent of the trading volumes, but a high 51 percent of the settlement dollars. Generation owners and load-serving entities represent a slightly smaller segment of the virtual market in terms of volumes (about 14 percent) and an even smaller segment of the settlements portion (about 12 percent).

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

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	746	708	1,454	-$0.55	$3.14	$2.59
Marketer	501	514	1,014	$1.30	$2.20	$3.50
Physical load	0	212	212	$0.00	$0.29	$0.29
Physical generation	29	146	175	$0.08	$0.44	$0.52
Total	**1,276**	**1,580**	**2,856**	**$0.8**	**$6.1**	**$6.9**

Virtual bid cost recovery charges

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.[11] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up, minimum load, transition, and energy bid costs.[12]

[10] 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 inter-ties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

[11] If physical generation resources clearing 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 forecasted 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.

[12] Generating units, pumped-storage units, or resource-specific system resources are eligible for receiving bid cost recovery payments.

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[13]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[14] 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.[15] 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.

Market participants with net virtual supply, which contributes to residual unit commitment costs, share in the associated bid cost recovery charges. Day-ahead residual commitment costs associated with net virtual supply decreased from the previous quarter. Similar to the previous quarter, the integrated forward market bid cost recovery costs associated with net virtual demand remained low in the fourth quarter.

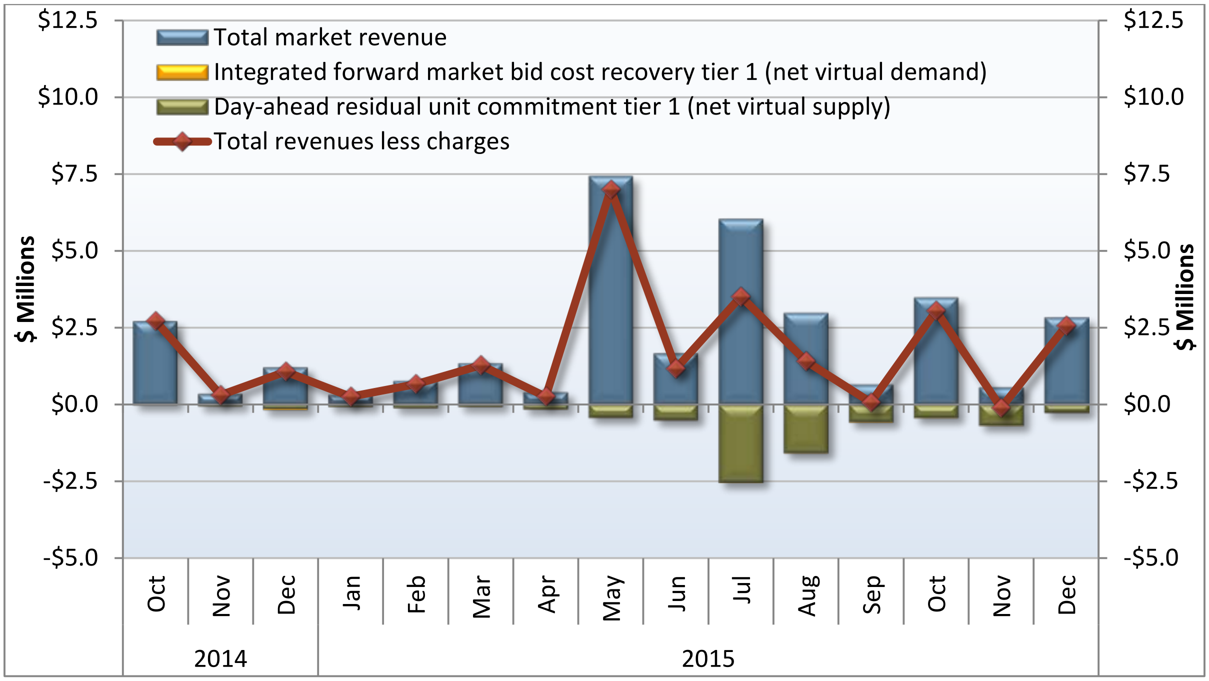
Figure 1.15 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery costs for the fourth quarter were about $1.4 million, a significant decrease from $4.7 million in the previous quarter. This decrease is related to the decrease in residual unit commitment levels and related bid cost recovery payments (see Section 1.4 and Section 1.5). The total monthly revenue to convergence bidders after taking into account these charges caused net losses in November (-$0.1 million) for the first time since January 2014.

[13] Both charge codes are calculated by hour and charged on a daily basis.

[14] Total integrated forward market (IFM) load and convergence bidding entities with a net virtual demand position may be charged an IFM Tier 1 uplift charge. This is triggered when the system-wide virtual demand is positive. Market participants with portfolios that clear with positive net virtual demand are charged. Market participants will not be charged if physical demand plus virtual demand minus virtual supply is equal to or less than measured demand. Specifically, the uplift obligation for virtual demand is based on how much additional unit commitment was driven by net virtual demand that resulted in the integrated forward market clearing above what was needed to satisfy measured demand. Physical load and virtual demand pay the same IFM uplift rate. The rate is calculated on an hourly basis and charged daily. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

[15] There are two payments associated with the day-ahead residual unit commitment. One is the residual unit commitment availability payment at the residual unit commitment price, and the other is residual unit commitment bid cost recovery. During the day-ahead market, if the scheduled demand is less than the forecast, residual unit commitment availability is procured to ensure that enough committed capacity is available and online to meet the forecasted demand. Awarded capacity is paid at the residual price. The residual unit commitment bid cost recovery uplift obligation is allocated when system-wide net virtual supply is positive. The virtual supply obligation to pay a residual unit commitment bid cost recovery tier 1 uplift is based on the pro-rata share of the total obligation as determined by market participants' total net virtual supply awards. Allocation of residual unit commitment compensation costs is calculated by hour and charged by the day. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

Figure 1.15 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



2 Special issues

2.1 Inter-tie bidding and scheduling

After implementing 15-minute scheduling on the inter-ties in May 2014, there was a significant decrease in the amount of inter-tie bids offered into the real-time market as well as an increase in the volume of self-scheduled inter-tie transactions. Overall, this trend held into 2015 and the fourth quarter.[16]

Figure 2.1 shows the hourly average level of economic bids and self-schedules for imports and exports in the real-time market. The figure further indicates whether the bids and self-schedules came from resources with or without day-ahead awards.[17] As seen in this figure, self-schedules from resources with day-ahead awards accounted for most of the real-time activity on the inter-ties.

In the fourth quarter, the percentage of bids that were self-scheduled (with or without day-ahead award) was around 83 percent for imports and 42 percent for exports. Of the economic bids, about 75 percent of import bids and more than 99 percent of export bids were without day-ahead awards. Overall, there were no major changes in these values compared to the third quarter. Figure 2.1 also shows that the total volume of bids and self-schedules decreased compared to the third quarter, by about 5 percent for imports and 16 percent for exports.

Most real-time economic inter-tie bids remained hourly block bids despite the introduction of 15-minute scheduling on the inter-ties. However, as shown in Figure 2.2, the share of 15-minute economic bids has gradually increased during 2015 reaching 37 percent for imports and 62 for exports in the fourth quarter.[18] These are the largest quarterly percentages of 15-minute bidding for both imports and exports since 15-minute inter-tie bidding began in May 2014.

The volume of 15-minute economic inter-tie bids also reached record levels in the fourth quarter for both imports and exports. The volume of 15-minute dispatchable import bids increased by 19 percent, compared to the third quarter, averaging 421 MW each hour in the fourth quarter. Similarly, 15-minute dispatchable economic export bids increased by 20 percent to an average of 252 MW for the same period.

Figure 2.3 shows the hourly average amount of 15-minute dispatchable economic import and export bids by inter-tie, with each color representing a different scheduling coordinator. As in previous quarters, these bids were concentrated on three inter-ties and submitted by a small number of participants. The majority of these participants were external balancing authority areas.

[16] For a comparison between the periods before and after May 2014, see the *Q2 2015 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2015_SecondQuarterReport-MarketIssues_Performance-August2015.pdf.

[17] The classification is made by MW at the resource level. For example, if a resource has a 10 MW award from the day-ahead market and places a 20 MW economic bid in the real-time market, then 10 MW is considered to be with a day-ahead award and 10 MW is considered without a day-ahead award.

[18] As with previous quarters, participants seldom used the hourly economic bid block option with a single intra-hour economic schedule change on the inter-ties.

Figure 2.1 Volume of import and export bids in the ISO real-time market

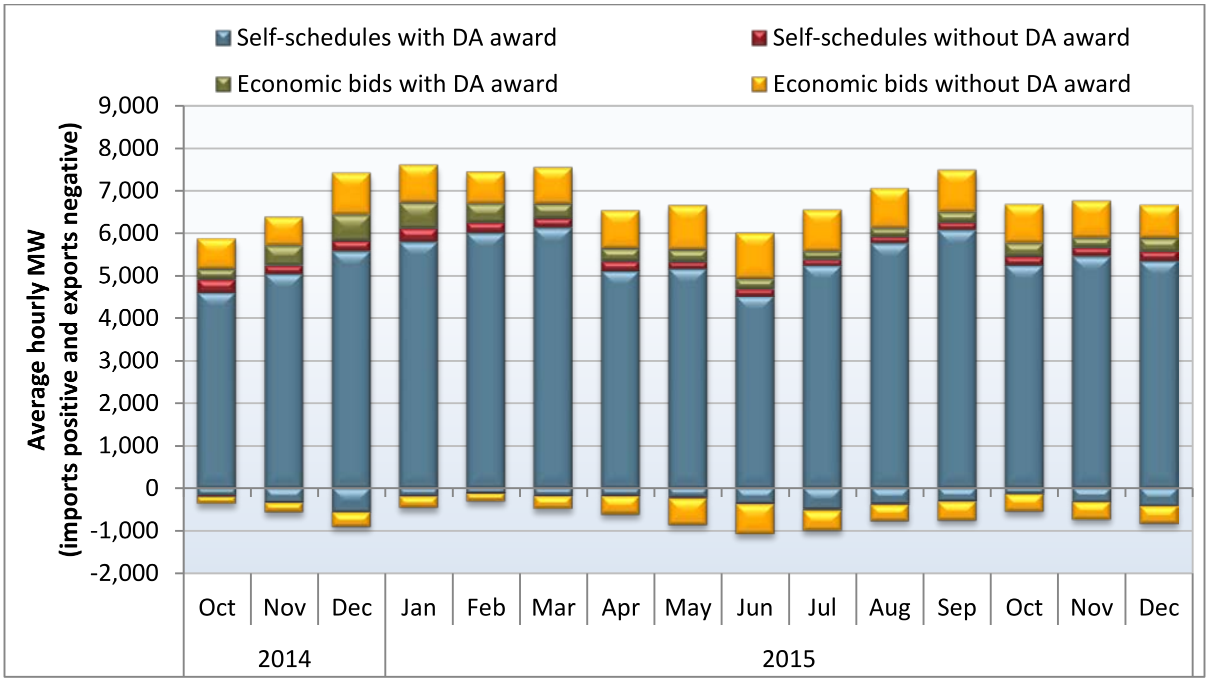
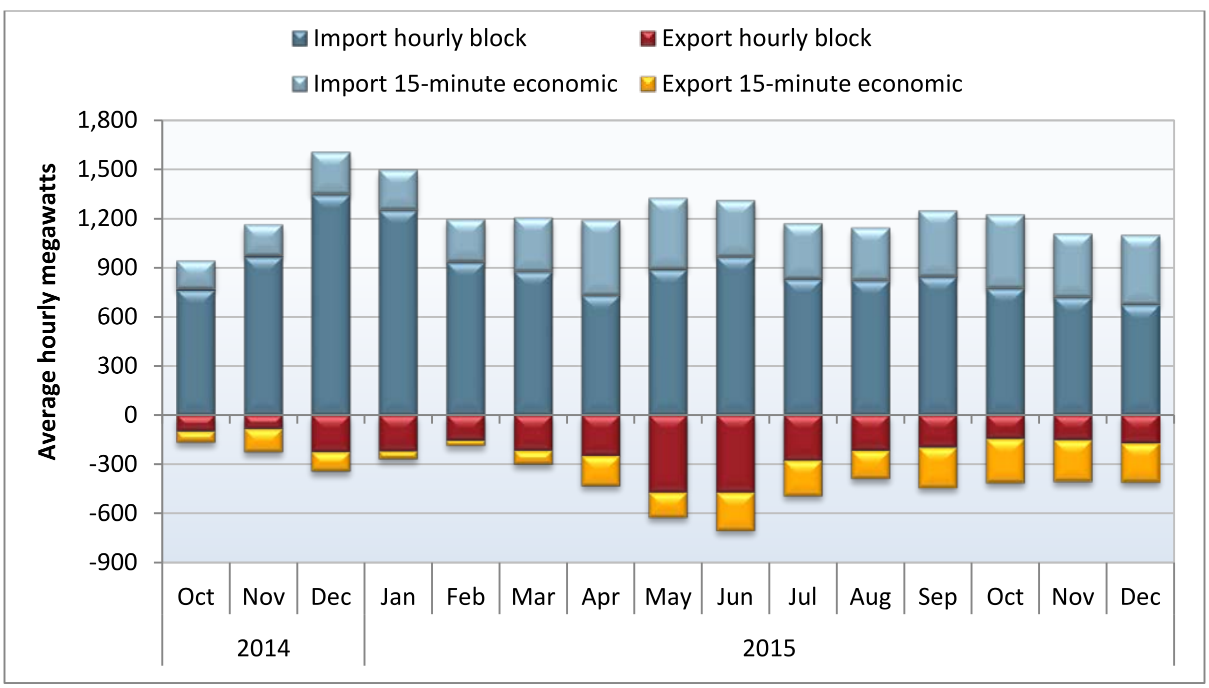
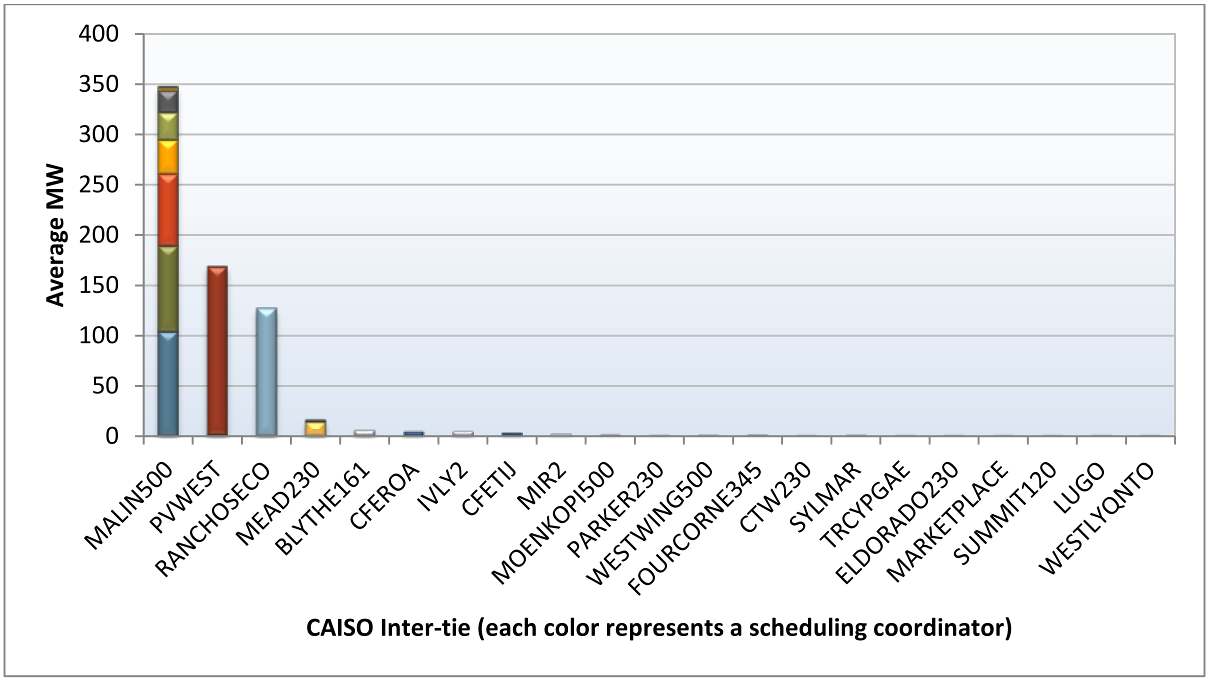


Figure 2.2 Economic import and export bids in the ISO by bidding option



DMM published a report in April 2015 discussing how the lack of liquidity on the inter-ties in the 15-minute market would be problematic if convergence bidding on the inter-ties were to be reintroduced.[19] FERC issued an order in late September 2015 requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at inter-ties.[20]

Figure 2.3 15-minute dispatchable economic bids by inter-tie and scheduling coordinator (October through December)



2.2 Flexible ramping constraint

This section highlights the performance of the flexible ramping constraint over the last quarter. Key trends include the following:

- The average flexible ramping requirement continued to increase across each of the balancing areas. In the fourth quarter, average requirements rose to 456 MW in the ISO, 137 MW in PacifiCorp East and 99 MW in PacifiCorp West. The requirement averaged 85 MW in the NV Energy area during December.
- The percentage of intervals where the flexible ramping constraint needed to be relaxed because of procurement shortfalls exceeded 10 percent in PacifiCorp East in the fourth quarter. Constraint relaxations were frequent in October and most of November and caused a significant impact in 15-minute area prices during those months as the shadow prices were at the cap of $60/MWh during

[19] The DMM report on potential issues with implementing convergence bidding on the inter-ties can be found here: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf. The analysis in the special report included bids by tie-generators, which are excluded from analysis in this section.

[20] For further details see: http://www.ferc.gov/CalendarFiles/20150925164451-ER15-1451-000.pdf.

these intervals. The constraint was relaxed infrequently during December after the return of several outages in the area and the addition of NV Energy into the EIM.

- The percentage of intervals where the flexible ramping constraint bound, but was not relaxed because of procurement shortfalls, continued to increase in the fourth quarter in all balancing areas. This trend is largely driven by the increase in flexible ramping requirements. In the NV Energy area, the flexible ramping constraint bound during 76 percent of intervals in December. This is a higher rate than observed in any other area.
- DMM's review of the increasing frequency of binding flexible ramping constraint intervals reveals that this often does not cause prices to increase within the EIM, but is instead a reflection of supply conditions in the EIM areas. Within the NV Energy area, for instance, resources providing flexible ramping capacity generally have marginal costs below prevailing system marginal prices and this difference, or opportunity cost, set shadow prices for the flexible ramping constraint.
- Overall payments made for the flexible ramping constraint continue to be low, remaining significantly under \$1/MWh of load in each balancing area. Payments for the flexible ramping constraint totaled under \$2 million in the fourth quarter. Most payments were made to gas-fired capacity in the ISO and PacifiCorp East areas.

Background

The flexible ramping constraint is a constraint included in the 15-minute market that is designed to help ensure sufficient ramping capacity is available in the 5-minute market within each balancing area. If sufficient capacity is on-line, the ISO software does not commit additional resources in the system, which often leads to a low (or often zero) shadow price for the procured flexible ramping capacity. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO software can commit short-start capacity or committing a multi-stage generating unit in a higher configuration. All generating units providing flexible ramping capacity in the 15-minute market are paid based primarily on the shadow price for this constraint.

The relaxation pricing parameter, or *penalty price*, for the flexible ramping constraint is normally set to \$60/MWh in the scheduling and pricing runs of the 15-minute market.[21] Thus, the market software will dispatch units so that this constraint is met as long as the additional cost of procurement does not exceed \$60/MWh. When this constraint is binding in the 15-minute market, the shadow price of this constraint represents the marginal *opportunity cost* of not dispatching energy bids lower than local prices in order to maintain enough ramping capacity to meet the constraint.

When this constraint cannot be met and is relaxed in the pricing run, this results in a shadow price at or near \$60/MWh and increases the 15-minute energy price by \$60/MWh. As discussed in Section 3, during much of the second half of 2015 average monthly prices in the PacifiCorp EIM areas have been driven up significantly by the relaxation of this constraint, particularly in PacifiCorp East. However, as shown in Figure 3.1, the frequency and price impact of flexible ramping constraint relaxation in the 15-minute PacifiCorp East area dropped sharply in December 2015. This trend began in late November and corresponded with an increase in available ramping capacity from several large generating units that

[21] In EIM areas, when the energy power balance constraint must be relaxed in the scheduling run, the parameter for both the power balance and flexible ramping constraint are both set to \$0/MW in the pricing run so that energy prices can be set using the special price discovery feature temporarily in effect.

returned from extended outages. This trend can also be attributed to the expansion of EIM in December to include the NV Energy area.

When the flexible ramping constraint binds but can be met, it generally does not have a significant impact on energy prices in the 15-minute market. A more detailed discussion of how the flexible ramping constraint prices are being set in EIM areas is provided later in this chapter.

Flexible ramping constraint requirement

The ISO implemented a tool to automatically calculate the flexible ramping requirement in both the ISO and EIM balancing areas in late March 2015. The tool determines the flexible ramping requirement independently for each 15-minute interval based on the observed ramping need for that interval in the preceding 40 instances.[22] The requirements are bounded within predefined lower and upper limits. Because the requirement is based on relatively few observations, and because each interval is considered independently, the resulting ramping requirement has been highly volatile and was often set to either the lower or upper bound.[23]

Table 2.1 shows the average amount, range and volatility of the flexible ramping constraint requirements by quarter for the ISO and EIM balancing areas. Volatility is measured as the standard deviation of the percent change in the requirements between intervals. A higher volatility implies more frequent and/or larger changes in the requirement from one interval to the next. Further, the table shows the percent of intervals when the requirement was equal to the lower or upper bounds.

As shown in this table, the volatility of the flexible ramping requirements was very high in the second quarter, the first quarter for which the balancing area ramping requirement tool was in use. In late June, the ISO increased the lower limits of the requirements which contributed to a reduced volatility in the third and fourth quarters. However, the volatility was still higher than prior to implementation of the tool. Further, the requirement was often set at either of the two bounds. For example, the requirement was set at the upper bound in 94 percent of intervals in PacifiCorp West during the fourth quarter.

Table 2.1 also shows that, over most of the year, average flexible ramping requirements progressively increased in each of the balancing areas. In the fourth quarter, requirements rose to 456 MW in the ISO, 137 MW in PacifiCorp East and 99 MW in PacifiCorp West. The requirement averaged 85 MW in the NV Energy area in December during their first month of EIM participation.

[22] Specifically, it sets the requirement at the 95th percentile of the 40 observations. Weekend days are considered as separate observations from weekdays.

[23] For a more detailed discussion about the implementation of the tool and the resulting increase in ramping requirement volatility see the *Q2 2015 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2015_SecondQuarterReport-MarketIssues_Performance-August2015.pdf.

Table 2.1 Flexible ramping requirement and volatility

BAA	Quarter	Requirement (MW) Avg	Min	Max	Volatility	Percent of intervals: Req = Lower bound	Req = Upper bound	Req = bounds
CAISO	Q1*	373	300	450	4%			
	Q2	307	80	500	68%	37%	39%	75%
	Q3	448	300	500	14%	22%	69%	90%
	Q4	456	300	500	17%	9%	64%	72%
NV Energy	Q4**	85	80	100	8%	69%	24%	94%
PacifiCorp East	Q1*	33	30	40	5%			
	Q2	49	20	150	92%	61%	11%	72%
	Q3	112	80	150	18%	45%	36%	81%
	Q4	137	80	150	16%	2%	59%	61%
PacifiCorp West	Q1*	26	25	30	3%			
	Q2	44	10	100	114%	34%	39%	74%
	Q3	84	60	100	18%	35%	55%	90%
	Q4	99	62	100	5%	0%	94%	94%

** Excludes March 30-31 because of implementation of BARR tool.*

*** December only.*

Impacts on market dispatch and pricing

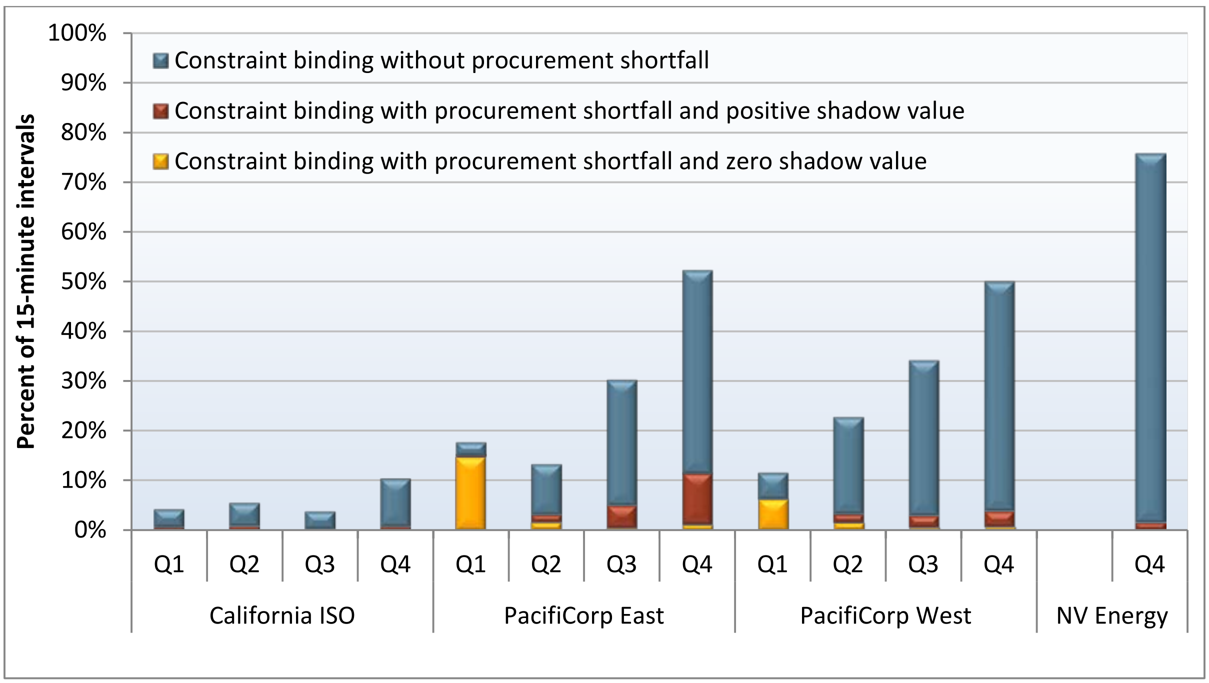
A sufficient amount of flexible capacity most often gets committed by the market regardless of the flexible ramping requirement. In these intervals the flexible ramping constraint is not binding in the 15-minute market and its shadow value is zero. This has been the case particularly in the ISO area for several years. However, in the EIM areas, particularly in the fourth quarter, this has not been the case.

Figure 2.4 shows the percent of 15-minute intervals where the flexible ramping constraint bound. The blue bars show intervals where the constraint bound but there was no shortfall in flexible ramping capacity. These are generally intervals when shadow price for the flexible ramping constraint is greater than $0/MWh but less than the $60/MWh penalty price. The red bars show intervals where the constraint needed to be relaxed in the scheduling run and resulted in a positive shadow price in the pricing run, typically equal to the $60/MWh penalty price. As previously noted, during these intervals, the need to relax the flexible ramping constraint increases the 15-minute energy price by $60/MWh.

The yellow bars in Figure 2.4 show the percent of 15-minute intervals where the flexible ramping constraint was relaxed in the scheduling run, but the shadow price was $0/MWh. This occurred in the PacifiCorp areas during the first and second quarters of 2015 for two reasons. Until early February, there were several software problems related to the flexible ramping credit and the relaxation parameter limits that prevented the flexible ramping constraint from binding in the pricing run. In addition, the penalty price for the flexible ramping constraint was set to $0/MWh in the pricing run for all intervals until mid-February.[24]

As seen in Figure 2.4, the flexible ramping constraint bound much more frequently in the EIM areas than in the ISO area. The portion of intervals during which the flexible ramping constraint was binding also increased significantly in the fourth quarter compared to previous quarters in all balancing areas. In the NV Energy area, this constraint was binding in about 76 percent of 15-minute intervals in December, the first month of EIM operations in the NV Energy area. The PacifiCorp East balancing area had the highest percentage of intervals with procurement shortfalls in the fourth quarter, where procurement shortfalls occurred in about 11 percent of 15-minute intervals. The average shadow value during intervals when the constraint was binding without a procurement shortfall ranged from about $8/MWh in PacifiCorp West to about $12/MWh in the ISO in the fourth quarter.

Figure 2.4 Percent of intervals with binding flexible ramping constraint



When the flexible ramping constraint is binding and feasible, DMM's review indicates that this does not generally have a significant upward impact on prices within the local EIM areas. This generally reflects the supply conditions within the EIM areas and only incrementally increases system prices as local

[24] This occurred as a result of implementation of the price discovery mechanism in the PacifiCorp areas. For this mechanism to work as intended, the penalty price for both the power balance and the flexible ramping constraint had to be set to $0/MWh when the power balance constraint was relaxed. However, due to software limitations, the penalty price for the flexible ramping constraint could not be set to $0/MWh in the pricing run only during intervals when the power balance constraint was relaxed. Therefore, due to this software limitation, the penalty price for the flexible ramping constraint was set to $0/MWh in the pricing during all intervals. In mid-February, a software enhancement was implemented that allows the penalty price for the flexible ramping constraint to be set at $0/MWh in the pricing run only during intervals when the penalty price for the power balance constraint is also set to $0/MWh.

capacity is backed down to meet the constraint instead of exporting power throughout the EIM system. In the NV Energy area, for instance, resources providing flexible ramping capacity generally have marginal costs below system marginal prices. The flexible ramping constraint causes these lower cost resources to be dispatched at lower levels to provide additional 15-minute ramping capacity. In this situation, the shadow price for flexible ramping constraint represents the difference between the energy price and the bid price of the marginal unit being held back to provide additional 15-minute ramping capacity.[25]

In this case, the shadow price reflects the relatively low energy price of units providing flexible ramping capacity, but does not represent the degree to which this constraint is increasing the energy price. Since the integration of NV Energy into EIM, prices in all EIM areas have been closely aligned with competitive system marginal prices throughout the ISO footprint, as well as prices at representative bilateral trading hubs.

In the ISO balancing area, units providing flexible ramping capacity tend to have higher marginal costs and, therefore, do not often have opportunity costs from providing available headroom as ramping capacity rather than providing energy. This often results in a $0/MWh shadow price for flexible ramping capacity in the ISO. When system conditions become tight in the ISO balancing area, the flexible ramping constraint may require units with lower marginal costs to withhold output, resulting in non-zero shadow prices. However, in the ISO this tends to only occur during the morning and evening ramping hours rather than throughout the day.

Flexible ramping procurement costs

Total payments to generators for providing flexible ramping capacity in the fourth quarter were below $2 million, but increased significantly from just over $1 million in the third quarter.[26] As shown in Figure 2.5, most of the payments in the fourth quarter were made to generators in the California ISO and PacifiCorp East areas.[27] The increase in payments for the fourth quarter occurred across all balancing areas and was consistent with the increase in the percent of intervals where the constraint bound. About 60 percent of payments were made to gas-fired capacity and 14 percent to hydro-electric capacity in the fourth quarter, with most of the hydro-electric capacity payments to units inside the ISO.

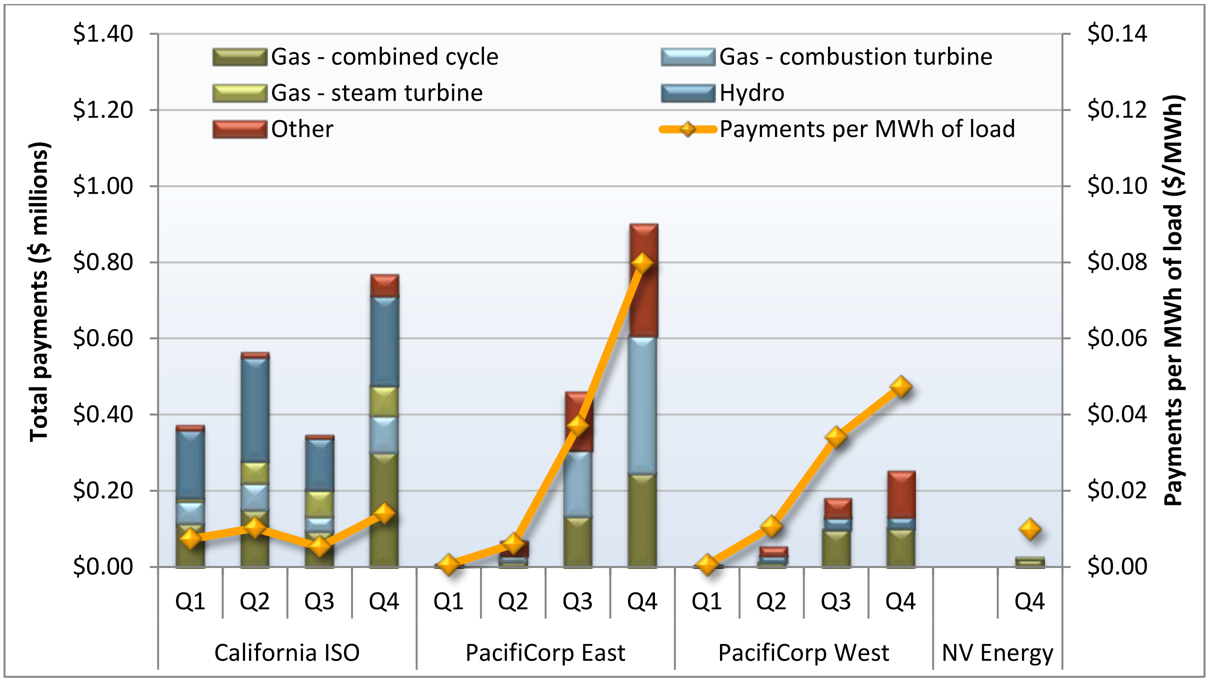
The gold markers and lines in Figure 2.5 show the amount of payments made to generators for flexible ramping capacity per MWh of total area load. This metric shows that in the fourth quarter costs for flexible ramping capacity in the PacifiCorp areas per MWh of area load are significantly higher than in the ISO and NV Energy areas. However, these costs are still relatively low overall, totaling only about $0.08/MWh of load in PacifiCorp East and about $0.05/MWh of load in PacifiCorp West in the fourth quarter. Flexible ramping costs totaled only about $0.01/MWh of load in the ISO and NV Energy areas during this same period.

[25] For example, if the EIM area price is $35/MWh and the highest priced energy bid being held back to provide flexible ramping capacity is $25/MWh, then the shadow price of the flexible ramping constraint is $10/MWh for that EIM area.

[26] The values presented are net payments after excluding rescissions for non-performance. However, secondary costs, such as bid cost recovery payments to cover the commitment costs and additional ancillary services payments, are not included in these calculations. Assessment of these costs is complex and beyond the scope of this analysis.

[27] The values for NV Energy represent December only.

Figure 2.5 Flexible ramping payments by fuel and balancing area (October - December)



Most payments for flexible ramping capacity in the ISO occurred during the morning and evening peak hours, whereas payments to EIM generators were more evenly spread out over the day. This pattern can be seen in Figure 2.6 and Figure 2.7, which show the payments made to generators in the fourth quarter by hour for the ISO and PacifiCorp balancing areas, respectively.[28] The figures also show the hourly percent of 15-minute intervals that the constraint was binding.

For the ISO, the constraint was most often binding during the morning and evening ramping periods and there is a clear correlation between the frequency with which the constraint is binding and the payments made. In the PacifiCorp balancing areas, the constraint was frequently binding during all hours of the day and the correlation between the frequency that the constraint is binding and payments made is less clear.

[28] The NV Energy balancing area is excluded from this analysis since only one month of data is available for the fourth quarter.

Figure 2.6 Hourly flexible ramping constraint payments to ISO generators (October - December)

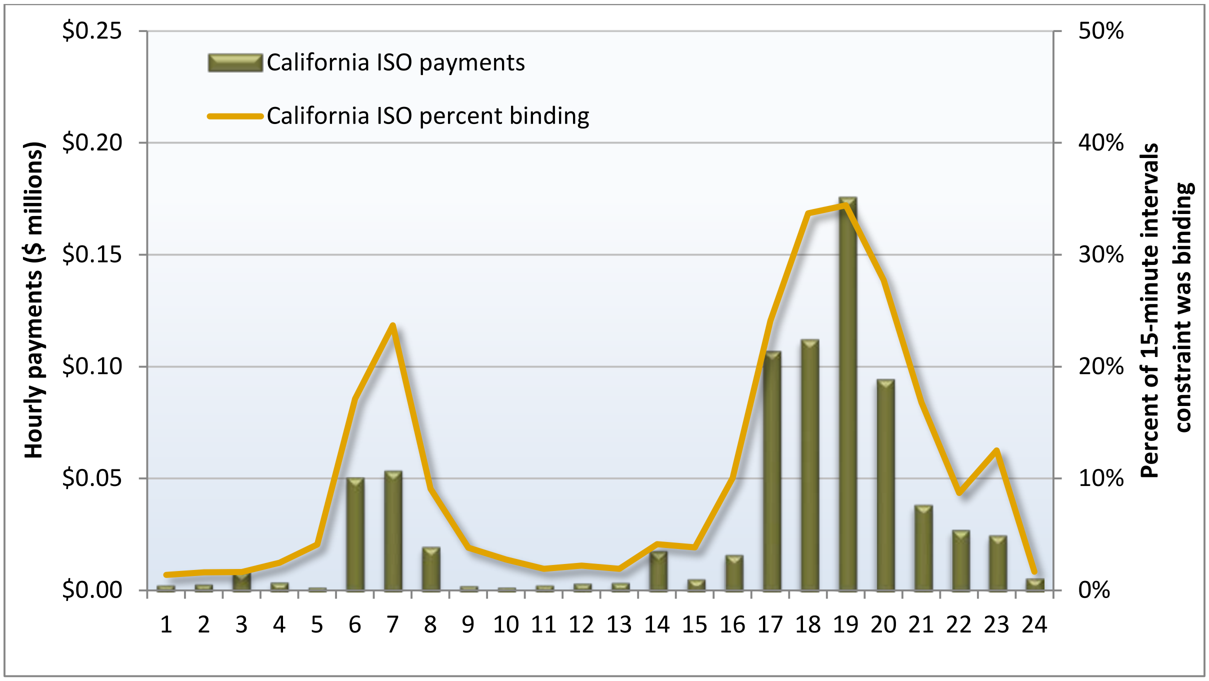
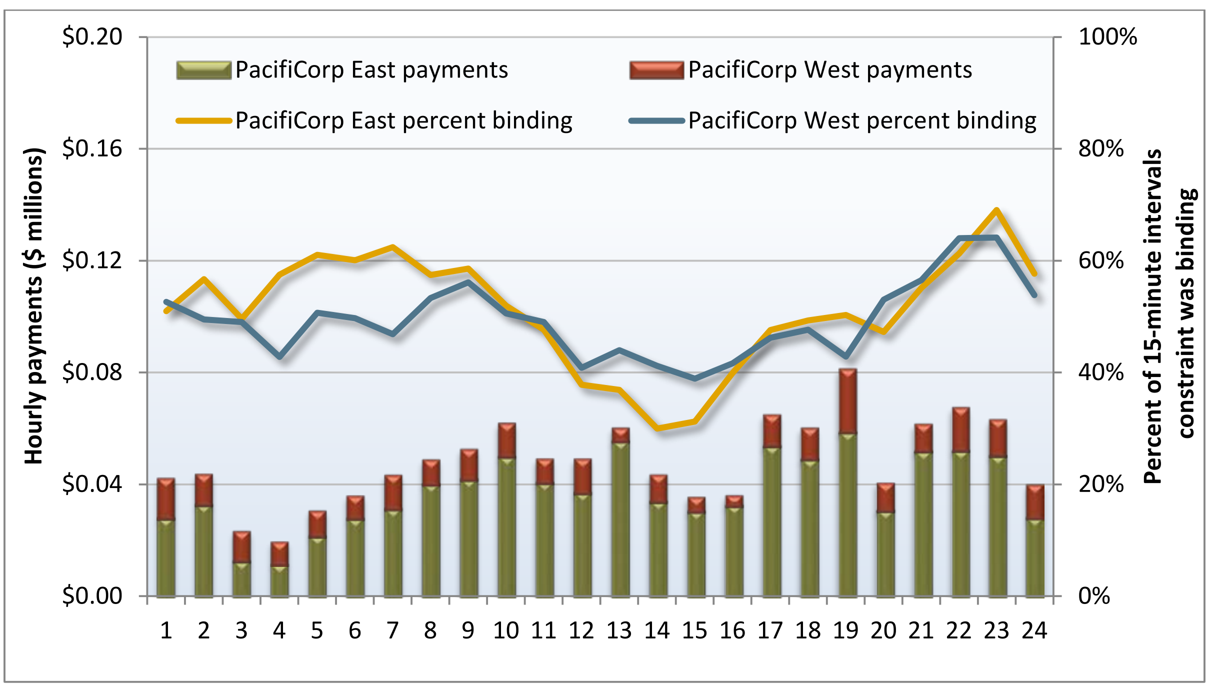


Figure 2.7 Hourly flexible ramping constraint payments to PacifiCorp generators (October - December)



3 Energy imbalance market

This section covers the energy imbalance market performance during the fourth quarter of 2015. Below are key observations and findings.

- On December 1, NV Energy became the second participant in the EIM markets, joining PacifiCorp. Because of the high transfer capability between the ISO and NV Energy, typically around 1,000 MW, and limited congestion between NV Energy and the ISO, local NV Energy prices often reflected overall system prices. Very few power balance constraint or flexible ramping constraint relaxations also helped keep prices stable and resulted in the price discovery mechanism having little impact on NV Energy area prices.

- The percentage of intervals where the flexible ramping constraint needed to be relaxed, due to procurement shortfalls, exceeded 10 percent in PacifiCorp East in the fourth quarter. Constraint relaxations were frequent in October and most of November and caused a significant impact on area prices during those months because of the $60/MWh shadow price. The constraint was relaxed infrequently during the latter part of November and December after the return of several outages in the area and the addition of NV Energy into the EIM.

- The frequency of intervals in which the power balance constraint was relaxed remained at low to average levels during the quarter, relative to prior quarters for each market. This resulted in good convergence between the EIM price and the EIM price without price discovery in all six markets.

- During the fourth quarter, the overall percentage of intervals with power balance constraint relaxations where DMM estimates that the load bias limiter would have been triggered decreased. However, because of the relative infrequency of power balance constraint relaxations, prices with and without price discovery remained similar. Thus, because the price discovery mechanism had a small effect on prices, the load bias limiter would also have had a relatively small impact on.

- There was an increase in power balance shortages in December in both the 15-minute and 5-minute markets in PacifiCorp West, causing an increase in price separation between the prices with and without price discovery in these markets. These differences continue to be significantly smaller than those observed during the first few months after market implementation.

- Higher flexible ramping requirements continue to result in significant increases in intervals when the flexible ramping constraint binds and is feasible. The frequency of binding and feasible intervals for the flexible ramping constraint was the highest in the fourth quarter since the implementation of the EIM. This is discussed in detail in Section 2.2.

3.1 Background

The energy imbalance market became financially binding with PacifiCorp beginning on November 1, 2014. During this quarter, on December 1, NV Energy became the second market region in EIM. The EIM allows balancing authority areas outside of the ISO balancing area to voluntarily take part in the ISO's real-time market. The energy imbalance market is expected to achieve benefits for customers and facilitate integration of higher levels of renewable generation.[29] The EIM includes both 15-minute and 5-minute financially binding schedules and settlement. Energy imbalances between 15-minute schedules and base (pre-market) schedules settle at the 15-minute market prices, and energy imbalances between 15-minute schedules and 5-minute schedules settle at 5-minute market prices.

During the initial EIM implementation for PacifiCorp East and PacifiCorp West, the amount of capacity available through the market clearing process was restricted and imbalance needs were exaggerated in ways that are not reflective of actual economic and operational conditions. This caused the need to relax ramping and system energy balance constraints in the market software more frequently than expected to enable the market to clear. The factors contributing to the need for constraint relaxation and steps being taken to address these issues have been addressed by the ISO as noted in its reports submitted to FERC.[30] When relaxing the power balance constraint for an EIM area, prices could be set based on the $1,000/MWh penalty price for this constraint used in the pricing run of the market model.

After review, the ISO determined that many of these outcomes were inconsistent with actual conditions. Consequently, on November 13, 2014, the ISO filed with federal regulators special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[31] These measures were approved by FERC on December 1 and were extended through subsequent orders. In addition, FERC ordered that the ISO and the Department of Market Monitoring provide reports every 30 days during the period of the waiver that outlines the issues driving the need for the EIM tariff waiver.[32] These waivers are set to expire in March when the ISO implements the available balancing capacity mechanism. With entry of NV Energy into EIM, FERC approved special transitional measures which allow for price discovery for the first six months of NV Energy operation.[33]

3.2 Energy imbalance market performance

Energy imbalance market prices

In the fourth quarter, overall EIM market prices remain close to bilateral market prices, except for prices in the 15-minute PacifiCorp East market. High prices in PacifiCorp East were because of an exceptionally high frequency of flexible ramping constraint relaxations during October and November, when prices are impacted by the $60/MWh shadow price associated with the binding constraint. Prices in this market returned to within the representative bilateral trading hub price range in December, after flexible ramping constraint failures dramatically declined in late November.

Figure 3.1 and Figure 3.2 provide a monthly summary of the frequency of constraint relaxation (green and blue bars), average prices with (gold line) and without price discovery (dashed red line), and average ranges of firm bilateral trading hub prices for comparison to EIM market prices (grey regions) for

[29] For more information see the quarterly benefits reports, which can be found here: http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

[30] The ISO *Energy Imbalance Market Pricing Waiver Report*s can be found here: http://www.caiso.com/rules/Pages/Regulatory/RegulatoryFilingsAndOrders.aspx.

[31] For further details, see http://www.caiso.com/Documents/Nov13_2014_PetitionWaiver_EIM_ER15-402.pdf.

[32] The DMM filings can be found here: http://www.caiso.com/rules/Pages/Regulatory/RegulatoryFilingsAndOrders.aspx .

[33] The FERC Order accepting the ISO Compliance Filing may can found here: http://www.caiso.com/Documents/Nov19_2015_OrderAcceptingComplianceFiling_EIMReadinessCriteria_ER15-861-004.pdf.

PacifiCorp East and PacifiCorp West, respectively.[34] Figure 3.3 shows the same statistics broken down on a weekly basis for NV Energy covering after they joined EIM on December 1.[35]

Figure 3.1 and Figure 3.2 show increased rates of flexible ramping constraint relaxations between September and November in the 15-minute markets in PacifiCorp East and PacifiCorp West. The frequency with which this constraint needed to be relaxed in PacifiCorp East increased consistently month after month beginning in July and continued through November. DMM believes that this trend was driven in large part by the continued high levels of flexible ramping requirements and a reduction of available ramping capacity due to generation outages. According to the ISO, other factors contributing to this trend include a software defect and data alignment issues.

Figure 3.1, Figure 3.2, and Figure 3.3 show that during the fourth quarter the power balance constraint did not need to be relaxed very frequently in any of the 15-minute markets in EIM. Although power balance constraint relaxations increased in PacifiCorp East during November and in PacifiCorp West during December, monthly frequencies continue to be lower than 2 percent of all 15-minute intervals. For NV Energy, the power balance constraint was not relaxed during any interval in the 15-minute market.

Prices with and without the price discovery provision applied in EIM continued to diverge in PacifiCorp East during the fourth quarter, but remained much more similar than spreads observed during the beginning of the year. In PacifiCorp West during December, when the total number of power balance relaxations increased, the separation between the prices with and without price discovery in the 15-minute market increased to about $9/MWh.

Figure 3.4 through Figure 3.6 provide the same information on prices and relaxations for daily average prices in the 5-minute market. As shown in Figure 3.4, the need to relax the power balance constraint in the 5-minute market declined in the fourth quarter for PacifiCorp East, and resulted in the lowest quarterly rate of relaxations since EIM implementation. Unlike the results in the 15-minute market, 5-minute prices in all EIM areas were below the lower bound of bilateral trading hub prices during the quarter.

Additionally, because of the low frequency of power balance shortages and resulting convergence between prices with and without price discovery in PacifiCorp East, EIM prices without price discovery were also lower than bilateral hub prices during all three months of the quarter. Similarly, prices without discovery in the 5-minute NV Energy market during December fell within the representative bilateral trading hub price range because of the low number of power balance constraint relaxations in that market. The higher number of power balance constraint relaxations in PacifiCorp West in October and December caused the prices without price discovery to be higher than the upper bound for bilateral trading hub prices.

As shown in Figure 3.1 through Figure 3.6, the price discovery mechanism approved under FERC's December 1 order has effectively mitigated the impact of constraint relaxation on market prices, particularly during the first six months after EIM launch in November 2014.

[34] The bilateral trading hub price range is calculated using the range of index price results between the ICE and Powerdex indices. For PacifiCorp, the bilateral hub price represents a daily average of peak and off-peak prices for four major western trading hubs (California Oregon Border, Mid-Columbia, Palo Verde and Four Corners). The NV Energy bilateral hub price represents a daily average of peak and off-peak prices for two major western trading hubs (Mead and Mid-Columbia).

[35] The first week and the last week included in Figure 3.3 and Figure 3.6 include observations from fewer than 7 days.

Figure 3.1 Frequency of constraint relaxation and average prices by month PacifiCorp East - 15-minute market

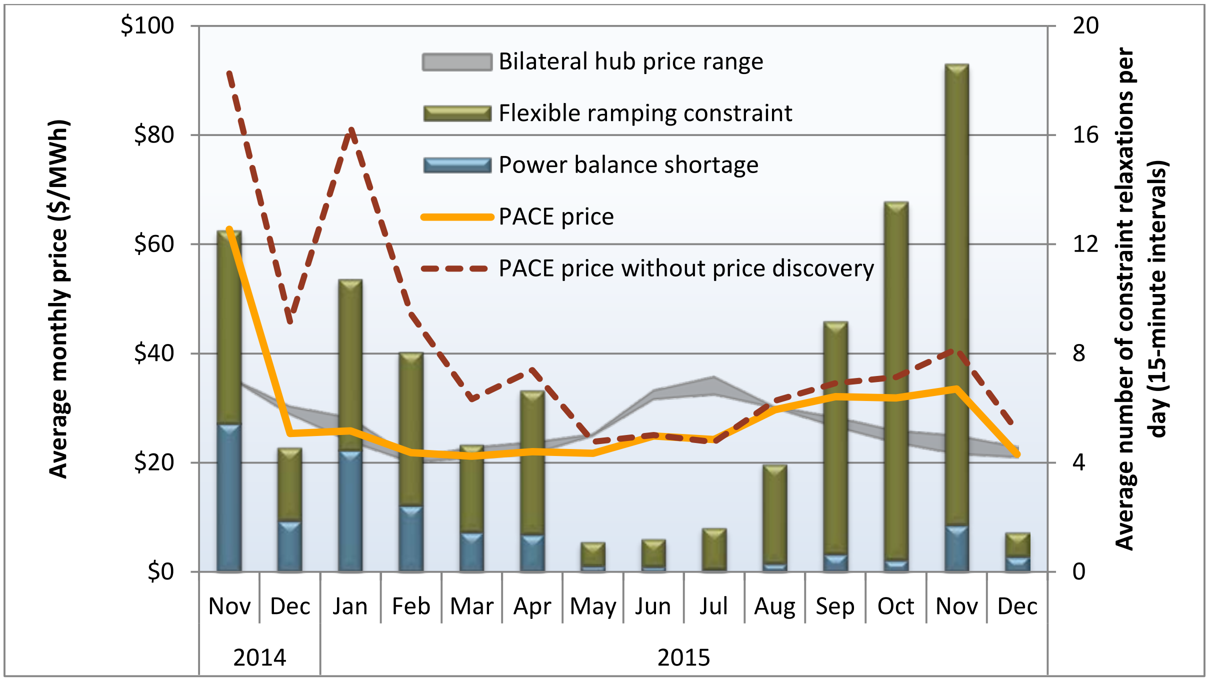


Figure 3.2 Frequency of constraint relaxation and average prices by month PacifiCorp West - 15-minute market

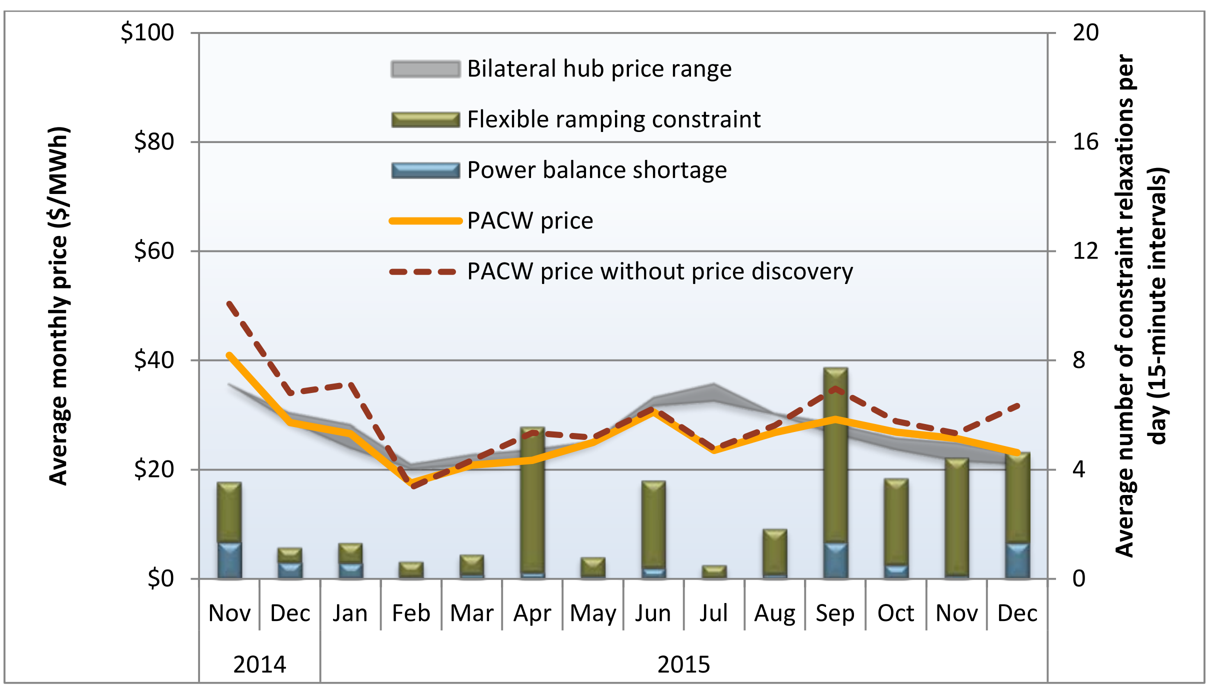


Figure 3.3 Frequency of constraint relaxation and average prices by week NV Energy - 15-minute market[36]

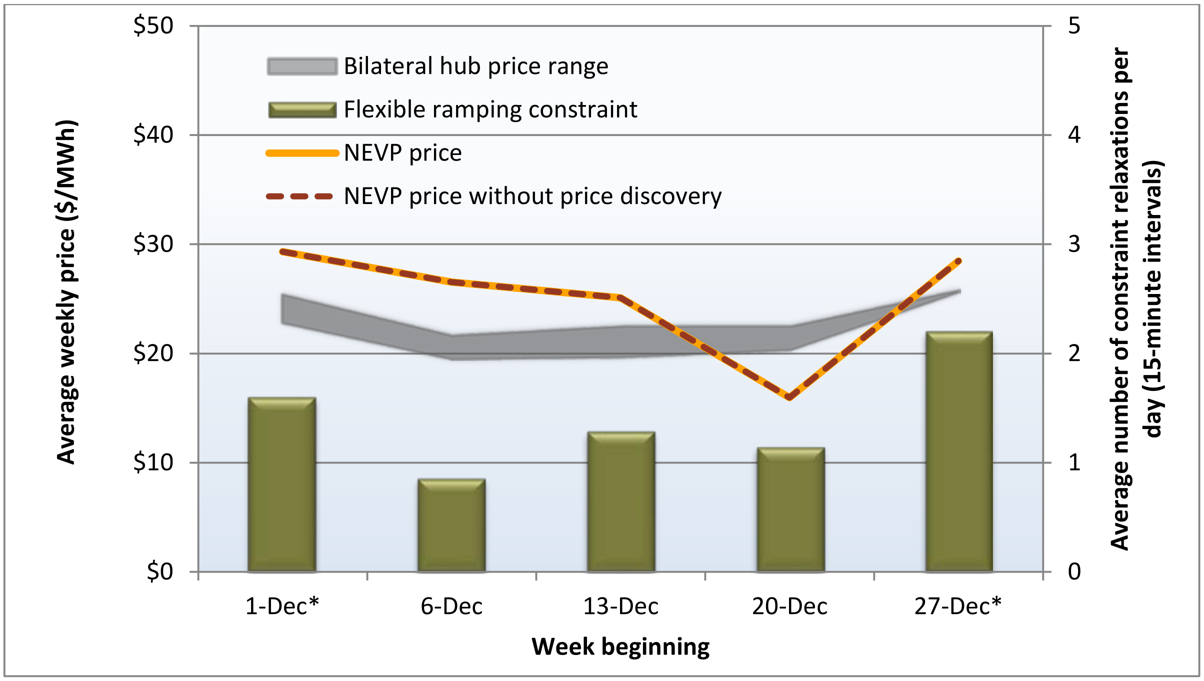
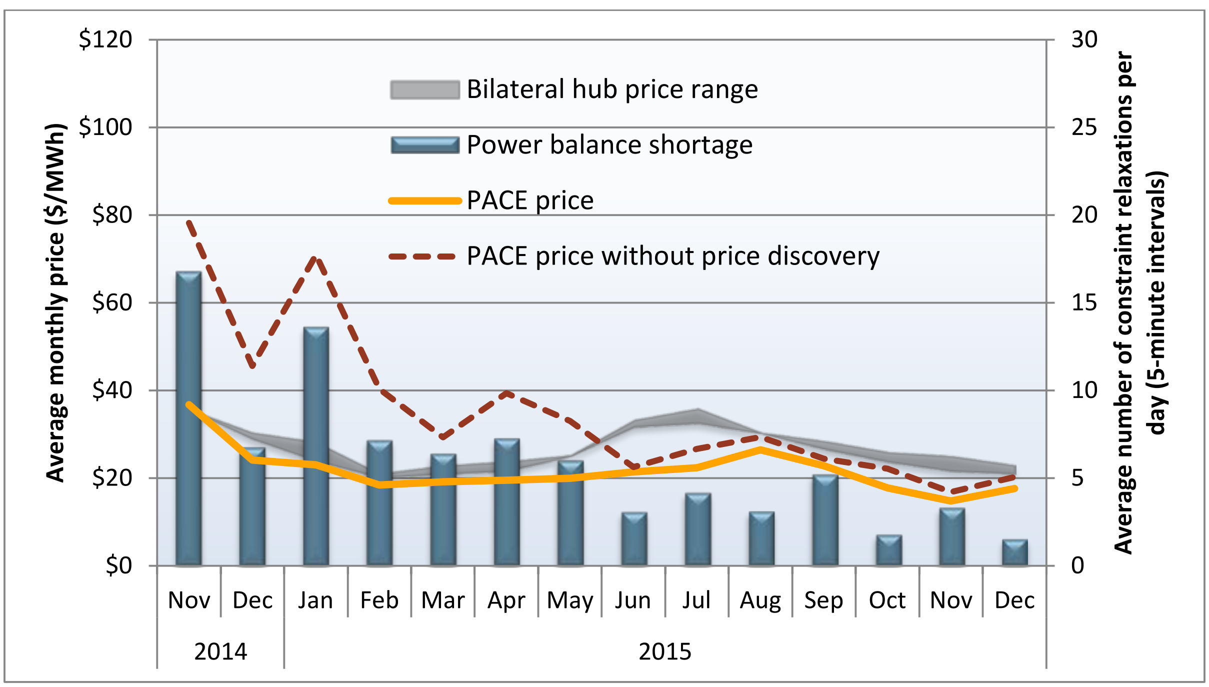


Figure 3.4 Frequency of constraint relaxation and average prices by month PacifiCorp East - 5-minute market



[36] The first and last weeks of December, denoted with asterisks, contained fewer than 7 days of observation.

Figure 3.5 Frequency of constraint relaxation and average prices by month PacifiCorp West – 5-minute market

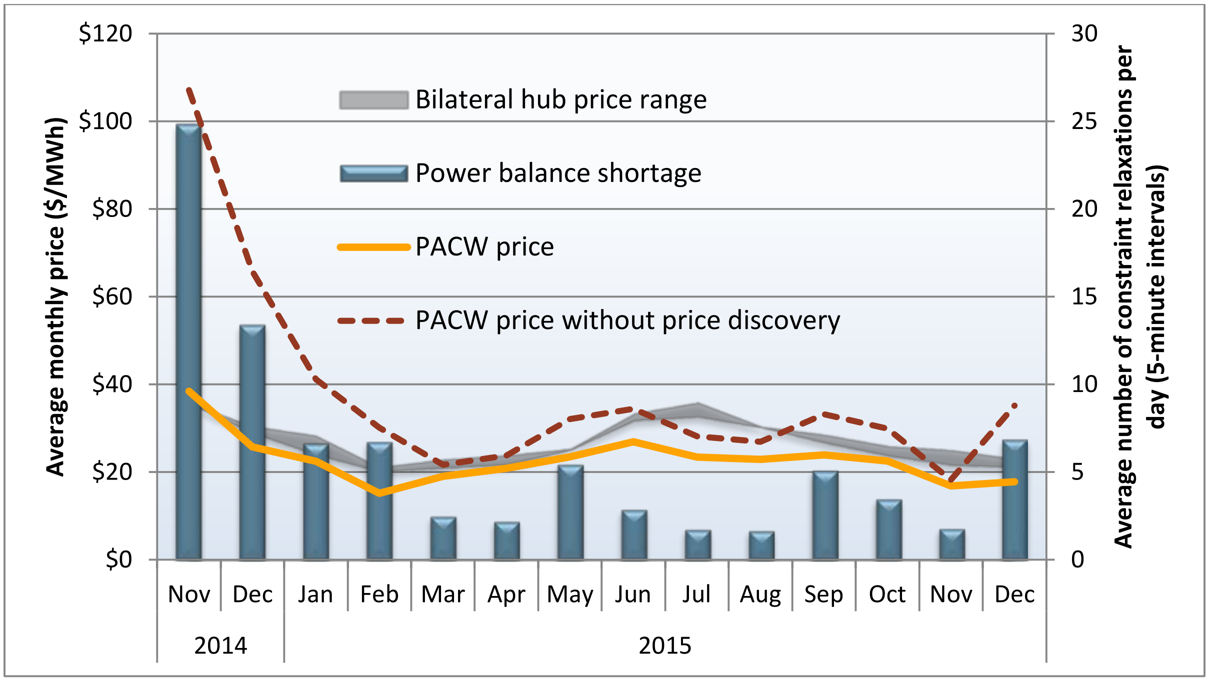
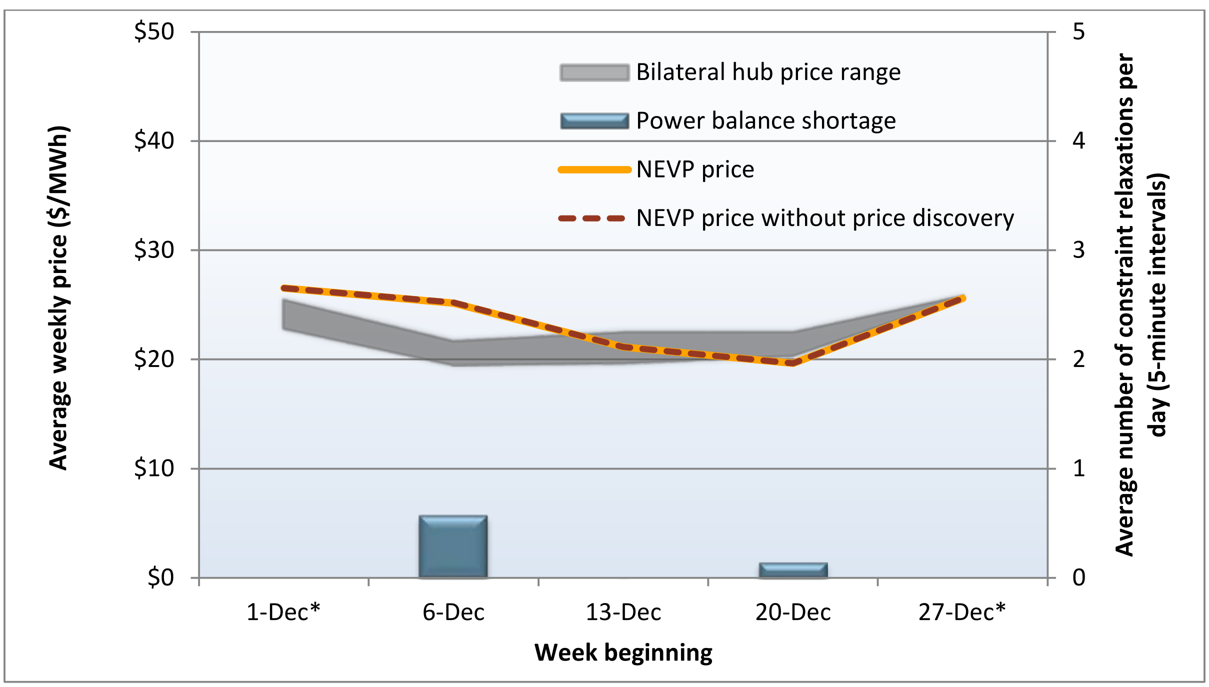


Figure 3.6 Frequency of constraint relaxation and average prices by week NV Energy - 5-minute market



Load bias limiter

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 fourth quarter. Without special price discovery provisions in effect, the load bias limiter feature would have been triggered during less than half of the power balance shortages observed in the fourth quarter in most cases. When triggered, the load bias limiter would have the same effect as the price discovery feature by causing prices to be set by the last economic bid dispatched rather than the $1,000/MWh penalty price for energy power balance shortages.[37]

A more detailed description of the load bias limiter was included in the DMM's April 2 monthly EIM report.[38] The ISO included discussion of the load bias limiter in its recent answer to comments regarding the ISO's response to the Commission's September 24, 2015 letter requesting additional information on the ISO's August 19, 2015 filing to implement its available balancing capacity proposal in the EIM.[39]

Figure 3.7 shows that during 15-minute intervals when power balance constraint shortages existed in the fourth quarter, about 40 percent would have also triggered the load bias limiter in both PacifiCorp areas. This result is a decrease from around 50 percent in the previous quarter. However, the frequency of intervals with power balance constraint shortages were much larger in the fourth quarter particularly in PacifiCorp East where the percent of these intervals increased from around 0.4 percent to almost 1 percent in the fourth quarter. As there were no power balance constraint relaxations for NV Energy in the 15-minute market, the load bias limiter would have had no impact in the area.

As shown in Figure 3.8, the load bias limiter would have been triggered during about 50 percent and 25 percent of the 5-minute intervals with power balance constraint relaxation in PacifiCorp East and PacifiCorp West, respectively.

Table 3.1 shows estimated EIM prices if prices were set at the $1,000/MWh penalty price during intervals when the load bias limiter would have been triggered and the price discovery provisions approved pursuant to FERC's December 2014 Order were not in effect. As shown in these tables, without existing price discovery provisions, the load bias limiter would have lowered 15-minute prices by over 9 percent in PaciCorp East and over 7 percent in PacifiCorp West. In the 5-minute market, the load bias limiter would have reduced average prices by about 15 percent in PacifiCorp East and 10 percent in PacifiCorp West. The load bias limiter would have had little impact on NV Energy prices due to the low frequency that this feature would have been triggered.

[37] The ISO implemented the load bias feature in March 2015 in the EIM areas. In the event that price discovery was not active, the load bias limiter would effectively limit prices in a similar manner as the price discovery feature when the amount of load bias exceeded the level of power balance relaxation. Like the price discovery mechanism, the resultant prices would be equal to the last dispatched bid rather than the $1,000/MWh penalty price for energy shortages.

[38] *Report on Energy Imbalance Market Issues and Performance*, Department of Market Monitoring, April 2, 2015, pp.34-35. http://www.caiso.com/Documents/Apr2_2015_DMM_AssessmentPerformance_EIM-Feb13-Mar16_2015_ER15-402.pdf.

[39] Answer of the California Independent systems Operator Corporation to Comments, November 24, 2015, pp. 13-21. http://www.caiso.com/Documents/Nov24_2015_Answer_Comments_AvailableBalancingCapacity_ER15-861-006.pdf.

Figure 3.7 Mitigation of power balance relaxation by load bias limiter – 15-minute market

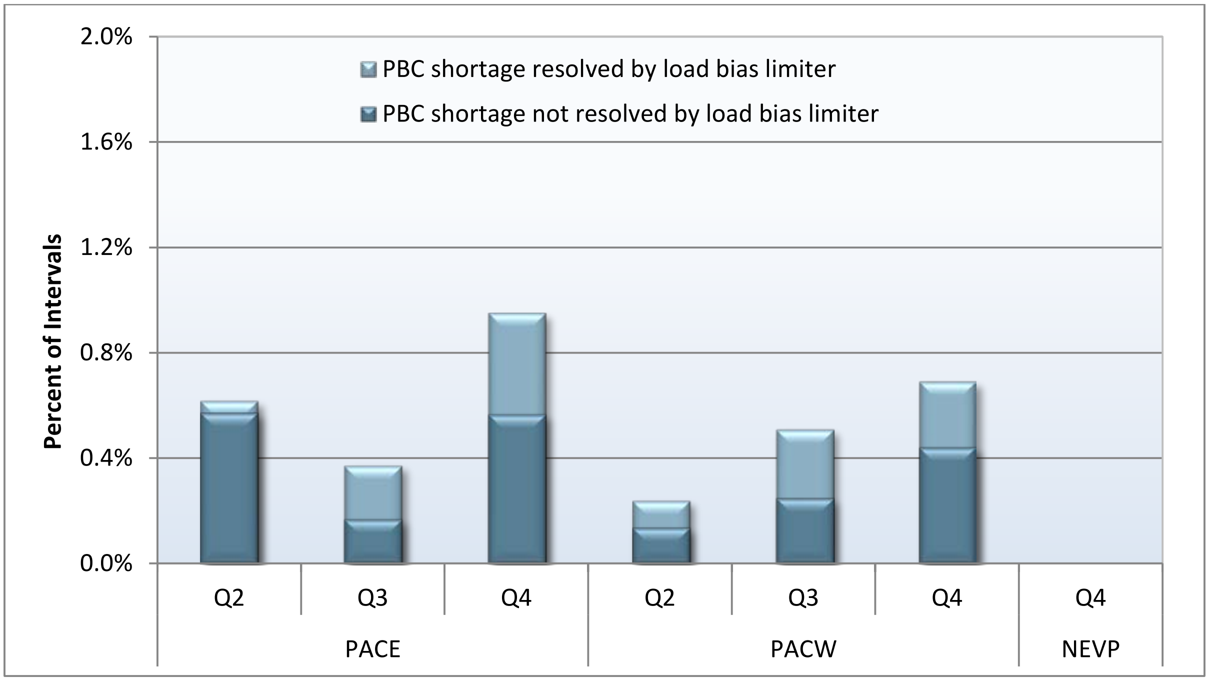


Figure 3.8 Mitigation of power balance relaxation by load bias limiter – 5-minute market

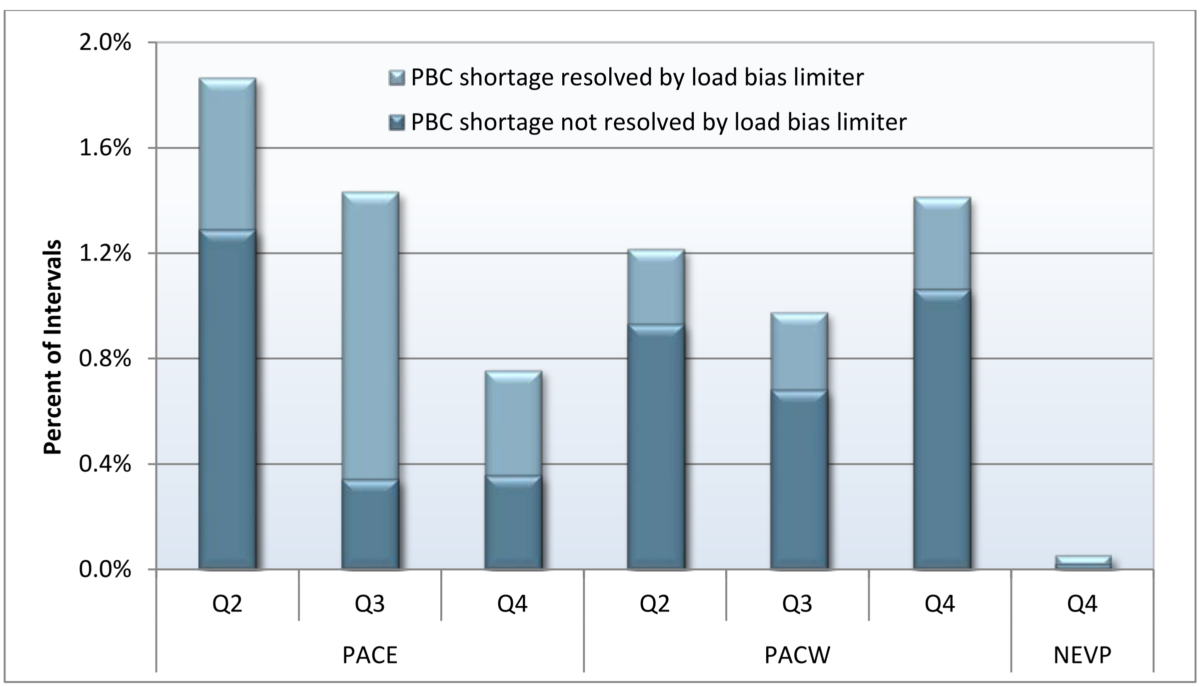


Table 3.1 Impact of load bias limiter on EIM prices (October – December)

	Bilateral trading hub range		Average EIM price	EIM price without price discovery	EIM price without price discovery or load bias limiter	Potential impact of load bias limiter	
	Low	High				Dollars	Percent
PacifiCorp East							
15-minute market (FMM)	$22.22	$24.63	$28.93	$34.02	$37.56	-$3.54	-9.4%
5-minute market (RTD)	$22.22	$24.63	$16.73	$19.76	$23.35	-$3.58	-15.4%
PacifiCorp West							
15-minute market (FMM)	$22.22	$24.63	$25.21	$29.10	$31.40	-$2.30	-7.3%
5-minute market (RTD)	$22.22	$24.63	$19.10	$27.89	$30.96	-$3.07	-9.9%
NV Energy							
15-minute market (FMM)	$21.27	$23.35	$24.60	$24.92	$24.92	$0.00	0.0%
5-minute market (RTD)	$21.27	$23.35	$23.30	$23.31	$23.60	-$0.28	-1.2%