California Independent System Operator Corporation

California ISO

Quarterly Report on Market Issues and Performance

November 9, 2016

Prepared by: Department of Market Monitoring

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Executive summary

This report covers market performance during the third quarter of 2016 (July – September). Key highlights are summarized here and further detail is provided in the next section.

- Day-ahead prices increased in the third quarter compared to the second quarter. This is primarily a result of higher seasonal loads during the summer months.
- Prices in the day-ahead market were slightly higher than 15-minute market prices for most of the quarter. During September, 15-minute market prices were above day-ahead and 5-minute prices, primarily because of significant congestion in the real-time market on September 26.
- Price spikes remained infrequent in the 15-minute market, but increased to 0.3 percent of intervals in the third quarter from 0.1 percent during the prior quarter. This increase was also largely driven by the congestion on September 26.
- Day-ahead congestion was lower overall this quarter compared to the prior quarter. Real-time congestion remained low, but increased from the prior quarter. Particularly, congestion in Southern California was higher in September primarily because of planned outages.
- Over the first three quarters of the year, congestion revenue rights auction revenues received by ratepayers were $22 million less than what was paid out to auctioned rights holders. This represented approximately $0.78 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders.
- Bid cost recovery payments totaled $19 million in the third quarter, which was about the same as last quarter and about 40 percent lower than last summer. Day-ahead bid cost recovery payments totaled $2 million and were the lowest in any quarter since 2013.
- Virtual bidding net revenues totaled $12.6 million. This was the highest quarterly net revenue since virtual bids switched from settling against 5-minute to the 15-minute real-time prices in 2014. This was driven by high virtual demand payments because of real-time congestion on September 26.
- Minimal congestion occurred between the ISO, PacifiCorp East and NV Energy areas, and the energy imbalance market continues to be an efficient tool to manage generation in the real-time market in these areas. As a result, real-time prices continue to be fairly uniform between the ISO and these EIM areas.
- The ISO and NV Energy were net importers in the EIM, while PacifiCorp East and PacifiCorp West tended to be net exporters. However, the direction and volume of transfers between the ISO and different EIM areas fluctuated significantly based on actual real-time market conditions.
- The available balancing capacity mechanism, which was implemented in March, continued to have a limited impact on reducing the number of power balance constraint relaxations in the third quarter. NV Energy offered available balancing capacity into the market for most hours in the third quarter, while PacifiCorp East and PacifiCorp West did so infrequently.
- Load adjustments in EIM were typically smaller in magnitude, but generally larger as a percentage of area load, than adjustments in the ISO. The pattern of adjustments was similar in the third quarter,

compared to the second quarter, where NV Energy tended to make positive adjustments to load and the PacifiCorp areas tended to make negative adjustments to load.

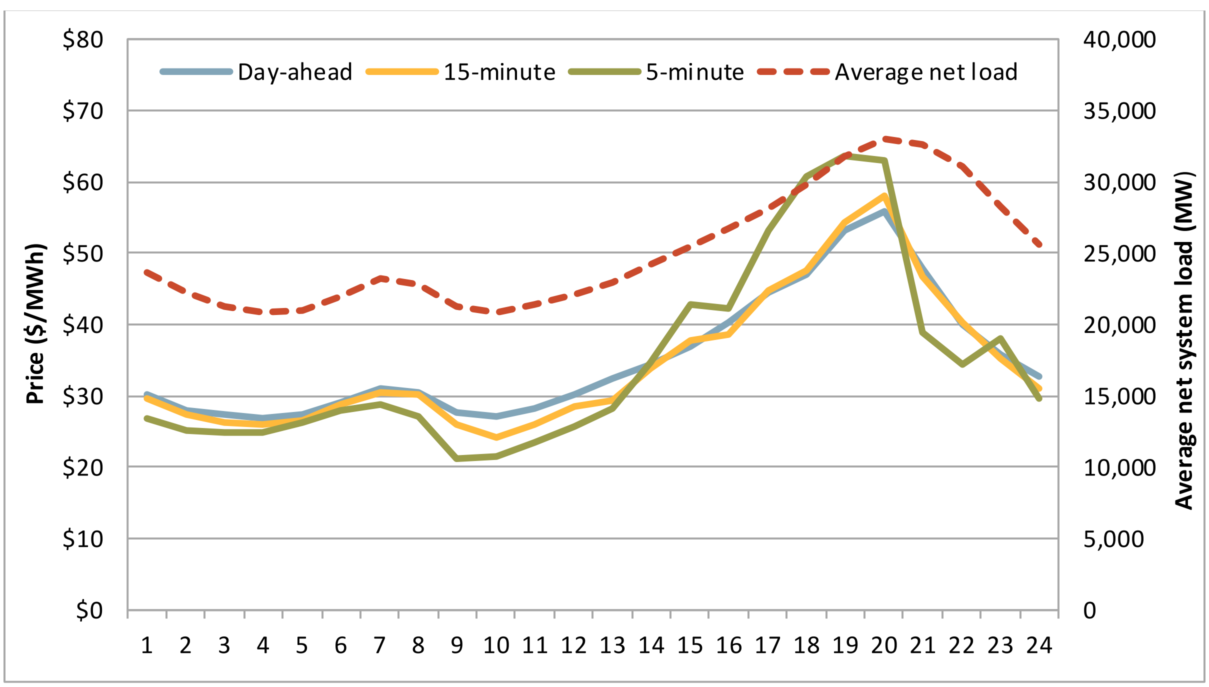
- Because of favorable system conditions and participant actions, ISO operators did not use many of the operational tools implemented to help manage limitations caused by the outage of the Aliso Canyon natural gas storage facility.
- DMM did not find systematic needs for the real-time commitment cost and incremental energy natural gas cost scalars used to increase bid caps implemented as Aliso Canyon mitigation measures. In addition, we find that the higher bid caps did not have a significant detrimental impact on market results.

Energy market performance

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

Average energy prices increased compared to the previous quarter. Monthly average energy prices were relatively constant during the third quarter at around $35/MWh with only minor differences between the day-ahead, 15-minute and 5-minute markets. This represents an increase of about 44 percent in the average price compared to the second quarter but is similar to prices observed in the third quarter of 2015. Higher prices during the summer months are primarily a result of higher temperatures leading to higher loads. As seen in Figure E.1, hourly average prices in the day-ahead and 15-minute markets continued to track closely and generally followed the average net load pattern. Prices in the 5-minute market were higher than day-ahead and 15-minute prices during the evening hours when system ramping needs were highest, but tended to be lower in other hours.

Figure E.1 Hourly system marginal energy prices (July – September)



Relatively high frequency of price spikes in the 15-minute market in September. In September, prices above $250/MWh occurred during about 0.8 percent of 15-minute intervals across all load area prices, higher than any monthly frequency since the 15-minute market was implemented in May 2014. Most of these price spikes occurred on September 26 when there was significant congestion on Lugo-Miraloma 500 kV that resulted from nearby planned outages.

Lower frequency of negative prices. The frequency of negative prices decreased significantly in the 15-minute and 5-minute markets in the third quarter compared to the prior quarter. Almost 15 percent of 5-minute intervals in April had negative prices, compared to the third quarter, where no month had negative 5-minute prices during more than 5 percent of intervals. These results are consistent with higher seasonal loads in the summer. However, negative prices were more frequent during the quarter compared to the third quarter of 2015. This was largely driven by more solar generation coming on-line during the last year.

Low levels of congestion in the day-ahead market. The frequency and average price impact of congestion in the day-ahead market was low when compared to the prior quarter as the overall congestion impact in all regions was less than $0.27/MWh compared to $1.13/MWh. However, in the real-time market, the congestion was higher than the previous quarter, reaching $0.90/MWh in San Diego compared to $0.44/MWh during the prior quarter. Constraints bound more frequently in the day-ahead than in the 15-minute market, but price impacts were greater in the 15-minute market when congestion occurred, which is consistent with prior congestion results.

Auction revenues from congestion revenue rights continue to fall short of payments made by ratepayers for the first three quarters of the year. In the first three quarters of 2016, congestion revenue rights auction revenues were $22 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents $0.78 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, up from $0.72 in the first three quarters of 2015.

Bid cost recovery payments fell. Overall bid cost recovery payments were $19 million in the third quarter, compared to about $21 million in the second quarter and $32 million in the third quarter of 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $15 million in the third quarter, about the same as the last quarter. At $2 million, day-ahead bid cost recovery payments were at the lowest levels since 2013. Bid cost recovery payments for residual unit commitment totaled about $1 million, significantly lower than about $10 million in the third quarter of 2015.

Virtual bidding returns increased. Total virtual trading volume remained about the same in the third quarter compared to the second quarter at about 3,200 MW on average. Net revenues increased to about $12.6 million compared to about $9.7 million in the third quarter of 2015 and $6.4 million in the prior quarter. This was the highest net revenues since May 2014 when virtual bids began settling against 15-minute market prices. The increase in revenues was primarily driven by high revenues from virtual demand positions in September.

EIM prices were fairly uniform with ISO prices. The frequency of intervals in which the power balance constraint or flexible ramping constraint was relaxed remained very low during the quarter for each market. Moreover, there was little congestion observed between the ISO, PacifiCorp East and NV Energy areas. As a result, real-time prices continue to be fairly uniform between the ISO and these EIM areas. Settlement prices in NV Energy were about $31/MWh during the third quarter, while settlement prices in PacifiCorp East averaged about $27/MWh during the third quarter and prices in PacifiCorp West averaged about $25/MWh.

Special issues

Overall, the frequency and size of load adjustments were similar to the second quarter. Table E.1 summarizes the average frequency and size of positive and negative load forecast adjustments for the ISO and EIM balancing areas during the third quarter. Load adjustments in EIM were typically smaller in magnitude than adjustments in the ISO, but as a percentage of area load were generally larger than adjustments in the ISO. For PacifiCorp, these load adjustments were primarily for generation deviation and automatic time error correction. Load adjustments by NV Energy were most frequently for reliability based control and load forecast deviation.

Table E.1 Average frequency and size of load adjustments (July – September)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	44%	471	1.4%	14%	-274	1.1%	169
5-minute market	56%	438	1.4%	27%	-300	1.1%	162
PacifiCorp East							
15-minute market	5%	91	1.6%	42%	-101	1.9%	-38
5-minute market	9%	88	1.5%	63%	-125	2.4%	-71
PacifiCorp West							
15-minute market	3%	38	1.5%	43%	-49	2.2%	-20
5-minute market	4%	42	1.7%	49%	-58	2.6%	-27
NV Energy							
15-minute market	48%	132	2.3%	1%	-171	3.6%	62
5-minute market	44%	95	1.7%	11%	-83	1.7%	32

Aliso Canyon gas-electric coordination measures did not have a significant impact on market performance. Several temporary tariff amendments related to the restricted availability of the Aliso Canyon natural gas storage facility were in effect during the third quarter. During the quarter, ISO operators did not use the gas burn nomogram constraints nor did they reserve internal transfer capacity because of gas system limitations. Therefore, there was no need to consider suspending virtual bidding or to deem transmission paths uncompetitive.

The temporary tariff amendments further granted natural gas generators on the SoCalGas and San Diego Gas and Electric systems additional bidding flexibility. DMM's analysis indicates that there was no systematic need to include the adders and that in the few instances where there was same day gas market variability, the additional flexibility was sufficient to cover most natural gas price variability. Furthermore, while DMM determined that there was limited need for these tools, we also found that there was limited impact on bid cost recovery payments and that there appeared to be no significant detrimental impacts to the market during the summer.

In addition to the measures implemented by the ISO, several other efforts and circumstances helped manage the gas limitations and promote reliability. These include tighter natural gas balancing rules, improved gas-electric operator coordination, and relatively well-forecasted load and weather conditions.

The ISO did not begin using an updated natural gas price index based on the next-day trades in the day-ahead market during the third quarter. This feature was instead implemented in late October after the ISO received further clarification from the Federal Energy Regulatory Commission. The ISO has filed with FERC for approval of an extension of most of the temporary provisions until November 30, 2017. DMM supports this effort and has filed additional recommendations for enhancing the ISO's proposal with FERC.

1 Market performance

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

- Average day-ahead and real-time prices continued to increase between June and July, but were fairly constant through the summer. This is primarily a result of higher load levels during the summer months.
- Prices in the day-ahead market were slightly higher than 15-minute market prices for most of the quarter. However, 15-minute market prices were above day-ahead and 5-minute prices during September.
- Prices in the 5-minute market were significantly higher than day-ahead and 15-minute market prices during hours ending 17 through 20. This was mostly driven by tight supply conditions during these hours while ramping to meet summer net load peaks.
- The frequency of price spikes in the 15-minute market increased significantly to about 0.3 percent of intervals in the third quarter from less than 0.1 percent in the last quarter. This was largely driven by congestion on one day in September.
- In the day-ahead market, congestion was lower when compared to the previous quarter and had a small impact overall on aggregate load prices across the ISO. However, in the real-time market, congestion was higher than the previous quarter and increased the Southern California Edison and San Diego Gas and Electric area prices by $0.40/MWh and $0.90/MWh, respectively. Much of the congestion was the result of enforcement of operating procedures to mitigate for contingencies or system conditions.
- Ratepayer auction revenues from congestion revenue rights exceeded payments made by ratepayers during the third quarter. However, on a year-to-date basis, ratepayer payments continued to exceed auction revenues. Congestion revenue rights auction revenues in the first three quarters of 2016 were $22 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents $0.78 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, up from $0.72 in the first three quarters of 2015.
- Profits made by financial entities in the first three quarters of 2016 from congestion revenue rights totaled $19 million. Marketers made $2 million in profits, while generating companies received $0.7 million.
- Bid cost recovery payments were $19 million in the third quarter, compared to about $21 million in the previous quarter and $32 million in the third quarter of 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $15 million in the third quarter, about the same as the last quarter. At $2 million, day-ahead bid cost recovery payments were at the lowest levels since 2013. Residual unit commitment totaled about $1 million, significantly lower than about $10 million in the third quarter of 2015.
- Virtual supply outweighed virtual demand by about 870 MW on average, compared to about 820 MW of net virtual supply in the previous quarter. Total convergence bidding revenue, adjusted

for bid cost recovery charges, was about $11.7 million in the third quarter, which increased from about $4.5 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 shows average monthly system marginal energy prices during all hours. Overall, average prices were relatively constant during the quarter after increasing slightly from June. Monthly average prices were similar to prices in the third quarter of 2015.

- Average day-ahead prices increased by about 44 percent during the third quarter compared to the second quarter largely due to higher seasonal load. Day-ahead prices for the quarter averaged about $39/MWh during peak periods and $30/MWh during off-peak periods.
- 15-minute market prices in the third quarter increased and tracked closely to day-ahead prices. Average peak system prices in the 15-minute market were lower than day-ahead prices in July and August by about $2/MWh continuing typical patterns observed in the ISO. Average 15-minute market prices during peak hours in September were higher than day-ahead prices by about $4/MWh. Off-peak 15-minute prices were lower than day-ahead prices in all three months.
- Monthly average prices in the 5-minute market remained relatively stable at about $40/MWh during peak periods and $28/MWh during off-peak periods.

Figure 1.2 illustrates system marginal energy prices on an hourly basis in the third quarter compared to average hourly net load.[1] The prices in this figure follow the net load pattern as energy prices were lowest during the early morning, mid-day, and late evening hours, and were highest during the evening peak hours. Lower prices during the middle of the day corresponded to periods when low-priced solar generation was greatest, and thus low net demand. Solar generation continued to grow in the ISO during the quarter as utility scale solar set a new record at around 8,400 MW on September 14. As additional solar is built and interconnected with the system, net loads and average system prices during the middle of the day decrease. This happens as a result of less expensive units setting price with lower net demand, including solar or other renewable resources.

Figure 1.2 also shows that average prices in the 15-minute market were very close to day-ahead prices during most hours. Although there was convergence between these prices, the greatest differences occurred during the late morning hours while solar generation ramped up to peak output.

Average prices in the 5-minute market were as much as $14/MWh higher than day-ahead and 15-minute market prices during hours ending 17 through 20. During the quarter, these hours frequently experienced tight supply conditions while ramping needs were greatest. This contributed to price spikes in the 5-minute market because of the narrow planning horizon and the significant amount of rampable generation required to replace solar generation coming offline and increases in system loads toward the evening peak.

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

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

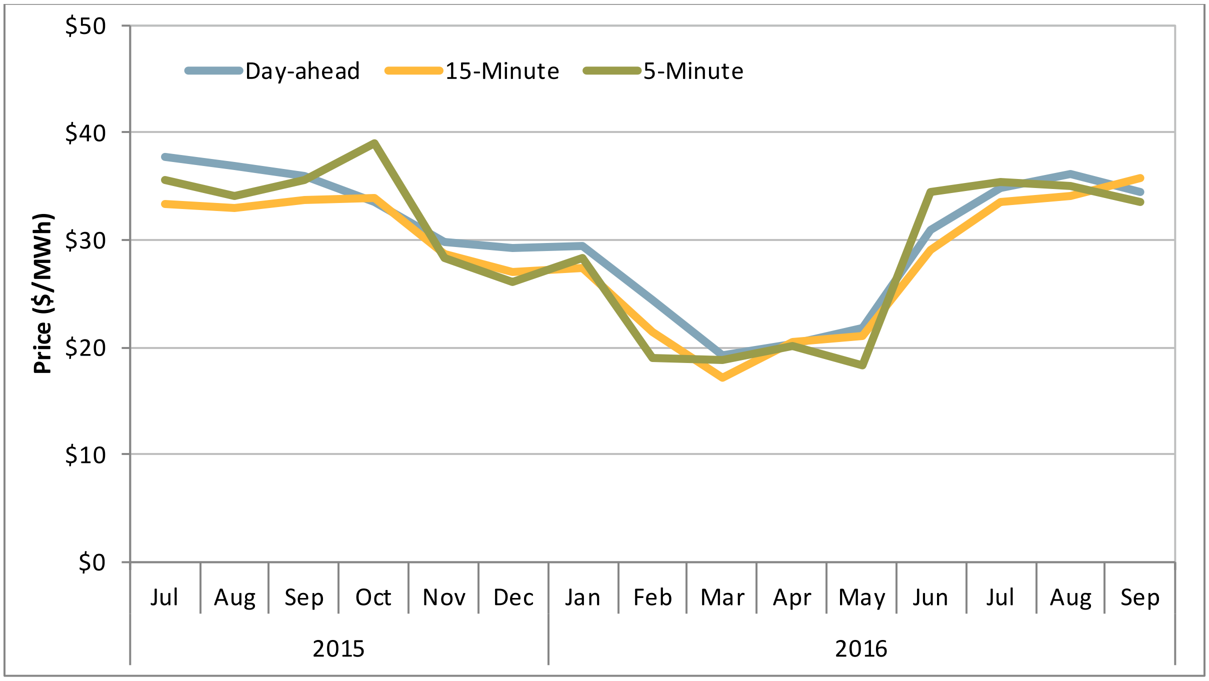
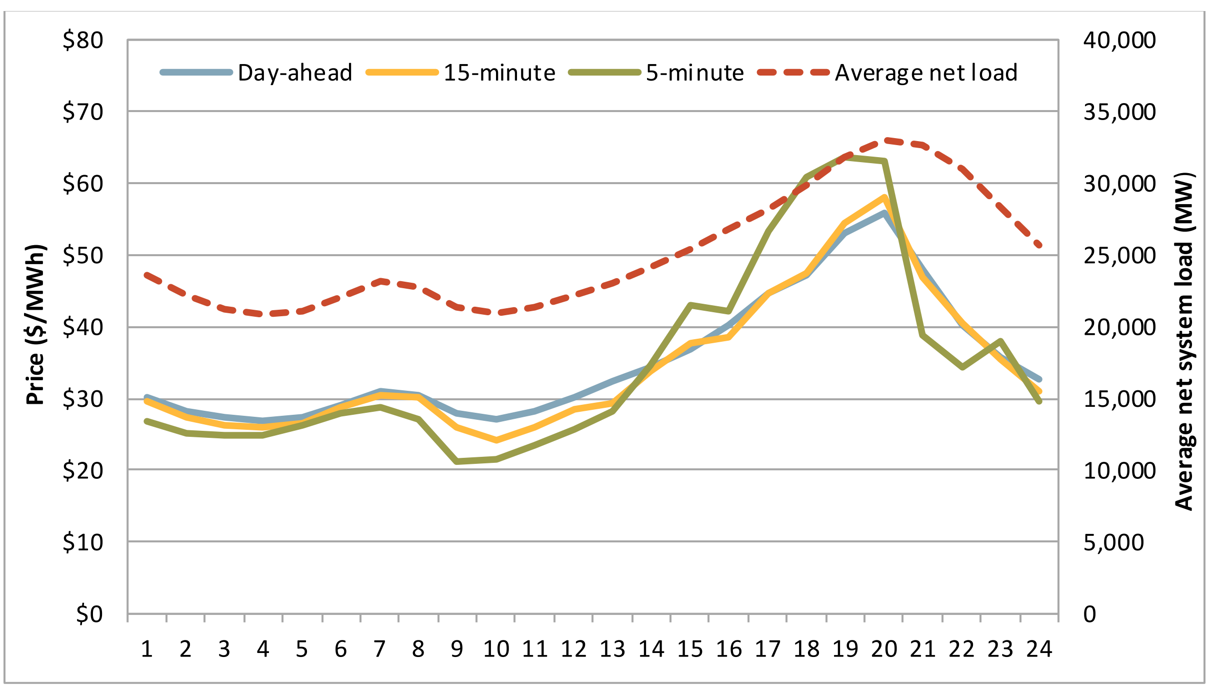


Figure 1.2 Hourly system marginal energy prices (July – September)



1.2 Real-time price variability

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

High prices

The frequency of high price spikes during the third quarter significantly increased in the 15-minute market because of a relatively high frequency of price spikes in September. During this month, prices above $250/MWh occurred during about 0.8 percent of 15-minute intervals across all aggregate load areas. This was the highest monthly frequency since the 15-minute market was implemented in May 2014. Over 60 percent of these September price spikes occurred during one day, September 26, because of significant congestion associated with the Lugo-Miraloma 500 kV line to mitigate for line contingencies.

The frequency of price spikes above $250/MWh in the 5-minute market decreased slightly compared to the previous quarter but remained significantly higher than the third quarter of 2015. However, the frequency of more extreme 5-minute prices larger than $750/MWh increased from the previous quarter, particularly in July and September, when these prices were observed in 0.5 and 0.4 percent of intervals, respectively. During the majority of these intervals, either significant congestion occurred or the power balance constraint was relaxed because of insufficient upward ramping capacity.

Figure 1.3 shows the frequency of positive price spikes occurring in the 5-minute market on an hourly basis. Price spikes in the 5-minute market were largely concentrated between hours ending 15 through 20. During these hours, over 3 percent of 5-minute intervals had prices above $250/MWh during the quarter. This outcome largely resulted from resource ramping limitations and subsequent tight supply conditions during intervals when system ramping needs were greatest. During these intervals, steep increases in net load can also exceed procured flexible ramping capacity used to ensure sufficient ramping capacity is available in the 5-minute market.

Negative prices

The frequency of negative prices decreased significantly in the 15-minute and 5-minute markets in the third quarter compared to the prior quarter, which was consistent with increases in seasonal load. Figure 1.4 shows the frequency of negative prices occurring in the 5-minute market by month.[2] Overall, negative prices were more frequent during this quarter compared to the third quarter of 2015. This was largely driven by the month of September, when negative prices occurred in about 2 percent of intervals in the 15-minute market and almost 5 percent of intervals in the 5-minute market. Negative prices typically occurred between hours ending 9 through 13 when net demand is low and solar generation is on-line. New solar generation continued to come on-line during the quarter, setting a new peak record of about 8,400 MW of generation, and averaged nearly 7,600 MW during midday hours. In the third quarter of 2015 solar generation averaged about 5,600 MW during midday hours.[3]

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

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

Figure 1.3 Hourly frequency of high 5-minute price spikes (July – September)

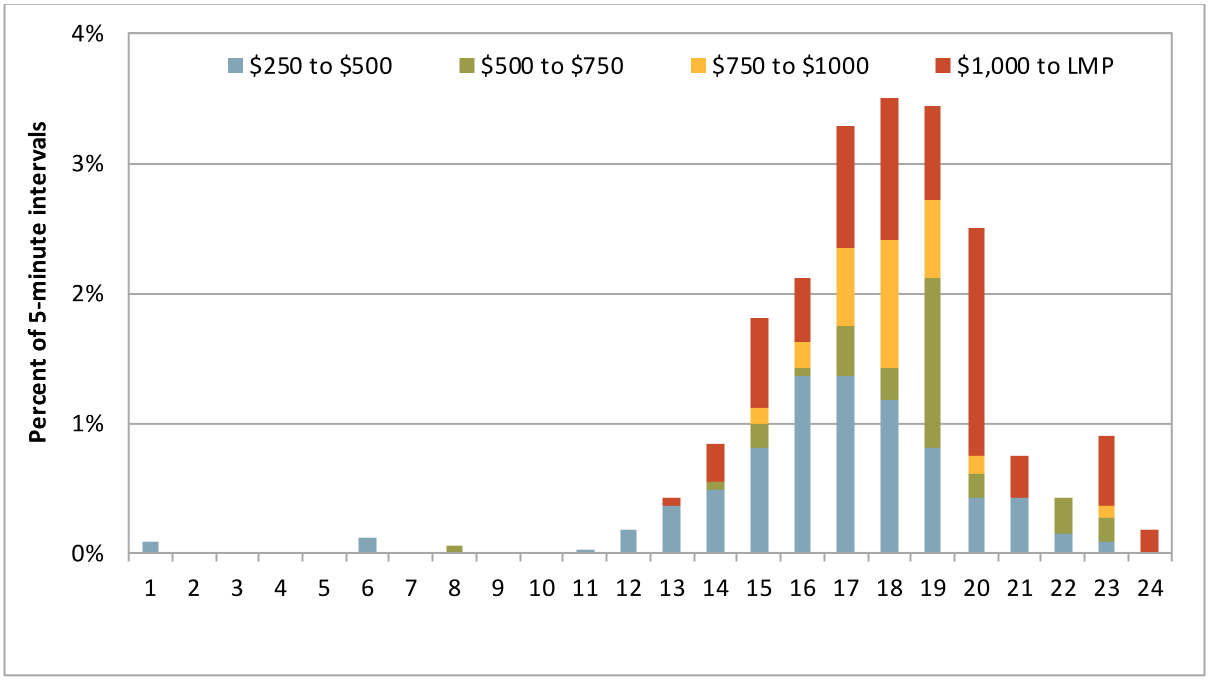
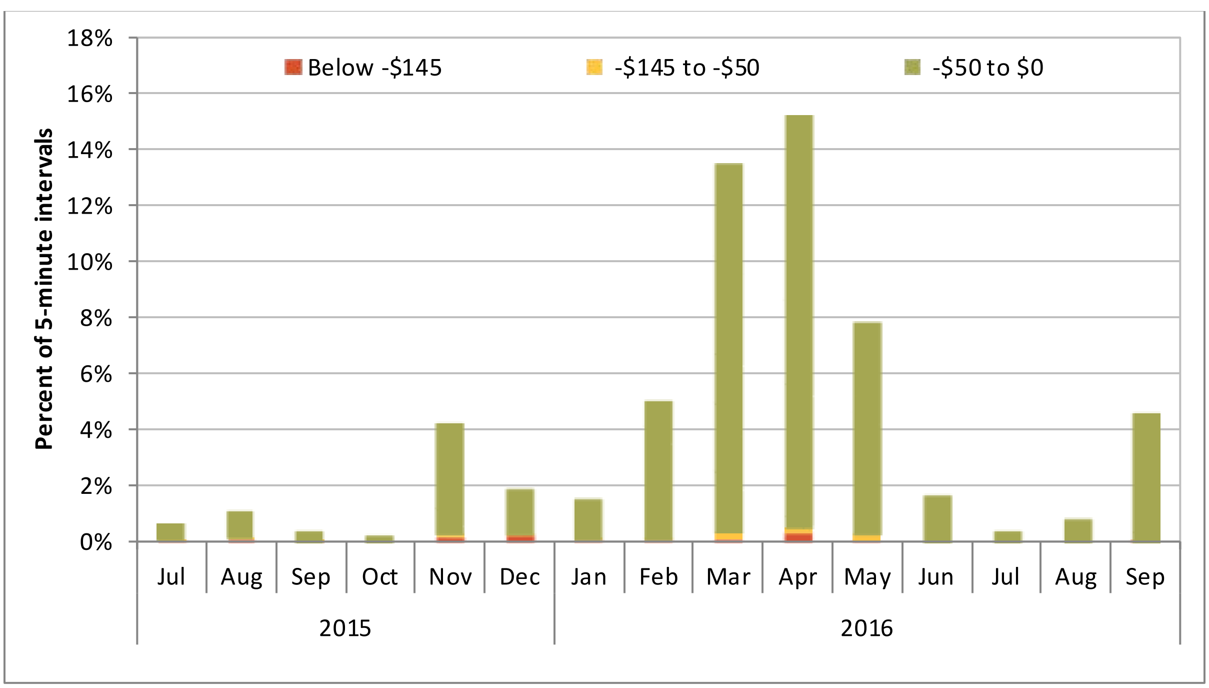


Figure 1.4 Frequency of negative 5-minute prices by month



1.3 Congestion

In the day-ahead market, congestion was lower when compared to the previous quarter and had a small overall impact on load aggregation point prices across the ISO. However, in the real-time market, the congestion was higher than the previous quarter and increased the Southern California Edison and San Diego Gas and Electric area prices by $0.40/MWh and $0.90/MWh, respectively. Constraints bound more frequently in the day-ahead than in the 15-minute market, but price impacts were greater in the 15-minute market when congestion occurred.

1.3.1 Congestion impacts of individual constraints

Day-ahead congestion

The frequency and impact of congestion in the day-ahead market was low in the third quarter when compared to the prior quarter.

In the Pacific Gas and Electric area, the Path 15 constraint bound most frequently in the south-to-north direction during the third quarter at 4 percent of all intervals. When Path 15 bound, it increased Pacific Gas and Electric area prices by about $3/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by about $2/MWh. This congestion was primarily the result of planned maintenance, and derates to provide a reliability margin.

Similarly, in the Southern California Edison area, the Lugo-Victorville 500 kV line and Path 26 in the north-to-south direction bound most frequently at 4 percent and 2 percent of intervals, respectively. The Lugo-Victorville 500 kV line bound during the quarter because an operating procedure was in effect to mitigate for line contingencies following both planned outages and a forced outage related to the Blue Cut Fire. Major price differences were observed while Path 26 bound which increased prices in the Southern California Edison and San Diego Gas and Electric areas by about $4/MWh and $3/MWh, respectively, and decreased prices by about $6/MWh in the Pacific Gas and Electric area.

In the San Diego Gas and Electric area, the constraint modeling the contingency of the Imperial Valley-North Gila 500 kV line (7820_TL 230S_OVERLOAD_NG) bound most frequently at about 4 percent of all hours. While binding this constraint increased San Diego Gas and Electric area prices by about $4/MWh and had no impact on Southern California Edison load area prices.

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

		Frequency			Q1			Q2			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	2.3%	1.0%	4.3%	$2.34	-$2.05	-$1.92	$4.04	-$3.32	-$3.10	$2.74	-$2.22	-$2.06
	30055_GATES1 _500_30900_GATES _230_XF_11_P			1.6%							$0.32	-$0.25	-$0.24
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1			1.0%							$1.96		
	6310_SOL3_NG_SUM		1.4%	0.5%				-$0.80	$0.65	$0.60	-$0.96	$0.76	$0.69
	OMS 4059507 Path15_S_N			0.4%							$2.39	-$1.78	-$1.65
	OMS 3938352 LBN_S-N			0.3%							$1.98	-$1.56	-$1.42
	OMS 3969865 Path15_S_N			0.1%							$3.46	-$2.78	-$2.60
	6110_SOL10_NG		16.2%					$0.07	-$0.07	-$0.07			
	OMS 3602720_Path15		8.3%					$6.10	-$4.78	-$4.49			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		1.1%					$2.01	-$2.06				
	LOSBANOSNORTH_BG		0.7%					$4.60	-$3.80	-$3.52			
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	28.6%			$1.18	-$0.98	-$0.95						
	OMS 2592148 P15 HARD	1.8%			$3.44	-$2.87	-$2.69						
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.5%			-$1.67	$1.40	$1.29						
SCE	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1		3.0%	3.8%				-$1.75	$1.44	$1.07	-$1.07	$0.61	-$0.53
	PATH26_BG	0.3%		1.9%	-$2.54	$2.13	$2.01				-$5.77	$3.66	$3.45
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	2.2%	1.1%	1.8%	-$1.15	$1.50		-$0.62	$0.90	$1.05	-$0.39	$0.53	
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	6.1%	1.2%	1.8%	-$1.05	$1.52	-$0.50	-$0.99	$1.08	$1.30	-$0.39	$0.48	
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		1.2%	0.5%				-$4.23	$3.25	$4.72	-$2.63	$1.84	$2.83
	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P		3.7%					-$6.20	$4.41	$4.69			
	24156_VINCENT _500_24155_VINCENT _230_XF_1 _P		0.5%					-$2.33	$1.93	$1.94			
SDG&E	7820_TL 230S_OVERLOAD_NG	1.9%	2.4%	3.7%	-$0.20		$2.13	-$0.25		$3.30	-$0.32		$3.66
	OMS 4000872 DVSB_NG3			2.7%									-$1.92
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			0.9%									-$3.28
	22464_MIGUEL _230_22504_MISSION _230_BR_1 _1			0.8%									$2.24
	22464_MIGUEL _230_22504_MISSION _230_BR_2 _1			0.7%									$3.24
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1			0.7%									$8.52
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	1.5%	5.2%	0.7%			$2.35			$5.94			$3.64
	Miguel_rerate_SOL2			0.4%									$6.71
	OMS 4143457 TL50004_NG			0.3%							-$0.40		$6.74
	OMS 4169254_Cima-ELD-PISG_SCIT			0.3%							-$6.42	$3.66	$4.78
	OMS 4282482 CRY_NV_SCIT			0.3%							-$4.43	$2.82	$3.55
	OMS 4235148 TL50001_NG			0.2%							-$0.56		$8.00
	OMS 4216681 TL50001OUT_NG			0.1%							-$1.09		$13.44
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1	1.2%	5.4%				$2.62			$3.21			
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1		3.2%							$0.46			
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	5.0%	3.0%		-$1.83		$11.38	-$1.62		$11.97			
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1		1.1%							$6.99			
	OMS 3725346 IV_NGILA		1.1%					-$1.10	$0.87	$1.20			
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		1.0%							$5.09			
	OMS 3725348 50002_OOS_TDM		0.7%							$3.48			
	OMS 4079303 TL50001_NG		0.4%					-$1.01		$12.95			
	22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1		0.1%							$89.43			
	IID-SCE_BG	3.7%					-$2.35						
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1	2.5%					$6.82						
	OMS 2319325 PDCI_NG	2.0%			-$1.74	$1.43	$1.78						
	22464_MIGUEL _230_22472_MIGUELMP_ 1.0_XF_1	1.3%			-$1.14		$7.33						
	OMS 3624980 TL50001_NG	1.3%			-$0.35		$4.20						
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1	0.9%			-$0.82		$3.88						
	OMS 3636555 McC-Vic_6510	0.9%			-$3.55	$3.01	$3.66						
	24016_BARRE _230_24044_ELLIS _230_BR_1 _1	0.8%			-$1.12		$5.31						
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.6%			-$1.03		$6.87						
	22464_MIGUEL _230_22461_MIGUEL60_138_XF_1	0.6%					$3.17						
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.3%			-$4.66	$3.21	$6.61						

15-minute market congestion

Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had a larger effect on prices. 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 for the quarter.

In the Pacific Gas and Electric area, Path 15 and Los Banos constraints bound most frequently in the south-to-north direction during the third quarter at 1 percent and 0.4 percent of intervals, respectively. When Path 15 bound it increased Pacific Gas and Electric area prices by about $10/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by $8/MWh. When the Los Banos constraint bound in the 15-minute market it increased Pacific Gas and Electric area prices by about $5/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by about $5/MWh. These constraints bound because of ratings limitations accounting for nearby outages.

In the Southern California Edison and San Diego Gas and Electric areas, the constraints which bound most were Path 26 in the north-to-south direction and the Southern California Import Transmission (SCIT) nomogram (6510 SOL1_NG) at about 0.4 percent of intervals, respectively. When Path 26 bound, it increased Southern California Edison and San Diego Gas and Electric area prices by about $9/MWh and decreased Pacific Gas and Electric area prices by about $14/MWh. The constraint modeling Southern California imports bound to maintain reliability margin, and when it bound it increased Southern California Edison and San Diego Gas and Electric area prices by about $27/MWh and $33/MWh, respectively, and decreased Pacific Gas and Electric area prices by about $15/MWh.

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

		Frequency			Q1			Q2			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	PATH15_S-N	0.3%		1.0%	$18.34	-$19.11	-$18.02				$9.61	-$8.14	-$7.60
	LBN_S-N			0.4%	$0.00						$5.29	-$5.42	-$5.03
	30055_GATES1 _500_30900_GATES _230_XF_11_P			0.3%							$2.94	-$1.92	-$1.86
	6110_SOL10_NG		2.0%					$2.17	$0.70	$0.53			
	OMS 3602720_Path15		1.0%					$11.53	-$10.07	-$9.46			
	30055_GATES1 _500_30900_GATES _230_XF_11_P		0.1%					$11.75	-$7.62	-$7.41			
	PATH15_N-S		0.1%					-$5.53	$4.49	$4.23			
	PATH15_BG		0.1%					$9.16	-$8.12	-$7.64			
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	2.2%			$2.29	-$1.89	-$1.80						
	OMS 2592148 P15 HARD	0.2%			$8.58	-$8.51	-$8.02						
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.1%			-$15.84	$13.89	$12.80						
SCE	PATH26_N-S	0.1%	0.5%	0.4%	-$14.53	$12.27	$11.57	-$29.51	$19.67	$18.51	-$13.58	$9.20	$8.66
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.2%	0.2%				-$9.31	$12.57	$16.40	-$69.81	$77.74	$101.69
	7750_DV2_N2DV500_NG			0.1%								$17.31	
	24091_MESA CAL_230_24158_WALNUT _230_BR_1 _1			0.1%							-$82.08	$78.34	$130.30
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P			0.1%							-$6.24	$7.22	$21.69
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1		0.1%					$10.54	$16.70	$16.49			
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.4%			-$1.51	$8.20	$1.09						
SDG&E	6510 SOL1_NG			0.4%							-$15.38	$27.49	$32.99
	OMS 4162323 Miguel Bk 80 SOL 3			0.2%									$32.13
	7820_TL 230S_OVERLOAD_NG	0.3%	0.4%	0.2%	-$1.23		$26.61	-$0.57	$0.40	$13.62	-$0.50		$19.41
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	1.1%	0.5%	0.1%			$28.79			$26.91	-$34.54	$35.85	$99.83
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.1%	0.3%	0.1%			$33.98	-$1.27	-$1.48	$15.99			$35.56
	OMS 4282482 CRY_NV_SCIT			0.1%							-$51.35	$73.06	$82.29
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1			0.1%									$24.16
	Miguel_rerate_SOL2			0.1%									$33.10
	22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1	0.3%		0.1%			$24.44						$21.90
	92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1			0.1%									$34.60
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1		0.3%							$11.50			
	OMS 2319325 PDCI_NG	0.4%			-$23.09	$54.26	$59.95						
	IID-SCE_BG	0.3%					-$7.05						
	OMS 3716078 Cry-McC_6510	0.3%			-$5.30	$14.20	$16.15						
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1	0.2%					$23.74						
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1	0.1%			-$4.37		$26.82						

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, which focused on only hours where congestion was present, this assessment is based on the average congestion component as a percent of the total price during all congested and non-congested intervals. This approach shows the impact of congestion when taking into account both the frequency with which congestion occurs and the magnitude of the impact.[4] The congestion price impact differs across load areas and markets.

The impact of congestion on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load area during the quarter by constraint.[5] As shown in the table, the impact of congestion on the load area prices was minimal. The constraint that bound most frequently during the quarter was Path 15, which bound in the south-to-north direction as a result of, for example, large amounts of solar generation and because of operator adjustments to account for outages.

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

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

Table 1.3 Impact of congestion on overall day-ahead prices

Constraint	PG&E		SCE		SDG&E	
	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH15_S-N	$0.12	0.34%	-$0.10	-0.28%	-$0.09	-0.25%
PATH26_BG	-$0.11	-0.31%	$0.07	0.20%	$0.07	0.18%
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.03%			$0.13	0.38%
22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1					$0.06	0.16%
OMS 4000872 DVSB_NG3					-$0.05	-0.14%
OMS 4169254_Cima-ELD-PISG_SCIT	-$0.02	-0.06%	$0.01	0.03%	$0.02	0.04%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.04%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.01	-0.02%	$0.00	0.01%	-$0.02	-0.06%
22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1					-$0.03	-0.08%
OMS 4282482 CRY_NV_SCIT	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.03%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.03	0.07%
Miguel_rerate_SOL2					$0.02	0.07%
OMS 4059507 Path15_S_N	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
OMS 4143457 TL50004_NG	$0.00	0.00%			$0.02	0.06%
22464_MIGUEL _230_22504_MISSION _230_BR_2 _1					$0.02	0.06%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.02	0.06%				
22464_MIGUEL _230_22504_MISSION _230_BR_1 _1					$0.02	0.05%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.01	0.03%		
OMS 3938352 LBN_S-N	$0.01	0.02%	-$0.01	-0.01%	$0.00	-0.01%
OMS 4235148 TL50001_NG	$0.00	0.00%			$0.02	0.04%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.02%	$0.01	0.02%		
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.01	0.02%	$0.00	-0.01%	$0.00	-0.01%
OMS 4216681 TL50001OUT_NG	$0.00	0.00%			$0.01	0.03%
6310_SOL3_NG_SUM	-$0.01	-0.02%	$0.00	0.01%	$0.00	0.01%
OMS 3969865 Path15_S_N	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
Other	$0.02	0.06%	$0.00	0.00%	$0.04	0.12%
Total	**-$0.01**	**0.0%**	**$0.01**	**0.0%**	**$0.27**	**0.75%**

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.[6] Congestion during the quarter increased San Diego Gas and Electric and Southern California Edison area prices by about $0.90/MWh (2 percent) and $0.40/MWh (1 percent), respectively, and decreased Pacific Gas and Electric area prices by about $0.26/MWh (0.75 percent). Major drivers of congestion in the Southern California area were the Lugo-Miraloma 500 kV and Mesa-Walnut 230 kV lines. Lugo-Miraloma 500 kV bound due to the enforcement of an operating procedure to mitigate for line contingencies and the Mesa-Walnut 230 kV line was congested because of the nearby Blue Cut Fire on August 16.

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

Table 1.4 Impact of congestion on overall 15-minute prices

Constraint	PG&E		SCE		SDG&E	
	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.12	-0.36%	$0.14	0.39%	$0.18	0.48%
24091_MESA CAL_230_24158_WALNUT _230_BR_1 _1	-$0.09	-0.25%	$0.08	0.23%	$0.14	0.37%
6510 SOL1_NG	-$0.06	-0.16%	$0.10	0.28%	$0.12	0.31%
PATH15_S-N	$0.10	0.29%	-$0.08	-0.23%	-$0.08	-0.21%
OMS 4282482 CRY_NV_SCIT	-$0.06	-0.18%	$0.09	0.25%	$0.10	0.26%
22464_MIGUEL _230_22468_MIGUEL _500_XF_81	-$0.01	-0.03%	$0.01	0.03%	$0.13	0.34%
PATH26_N-S	-$0.05	-0.16%	$0.04	0.10%	$0.04	0.09%
OMS 4162323 Miguel Bk 80 SOL 3					$0.08	0.20%
24156_VINCENT _500_24155_VINCENT _230_XF_3	-$0.02	-0.06%	$0.02	0.06%	$0.02	0.05%
LBN_S-N	$0.02	0.06%	-$0.02	-0.06%	-$0.02	-0.05%
22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80					$0.04	0.12%
Miguel_rerate_SOL2					$0.04	0.10%
7820_TL 230S_OVERLOAD_NG	$0.00	0.00%			$0.03	0.09%
22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1					$0.03	0.08%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1					$0.03	0.07%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	$0.00	-0.01%	$0.00	0.01%	$0.01	0.04%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
7750_DV2_N2DV500_NG			$0.02	0.06%		
22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1					$0.02	0.06%
Other	$0.03	0.08%	$0.01	0.04%	$0.01	0.02%
Total	**-$0.26**	**-0.75%**	**$0.40**	**1.13%**	**$0.90**	**2.39%**

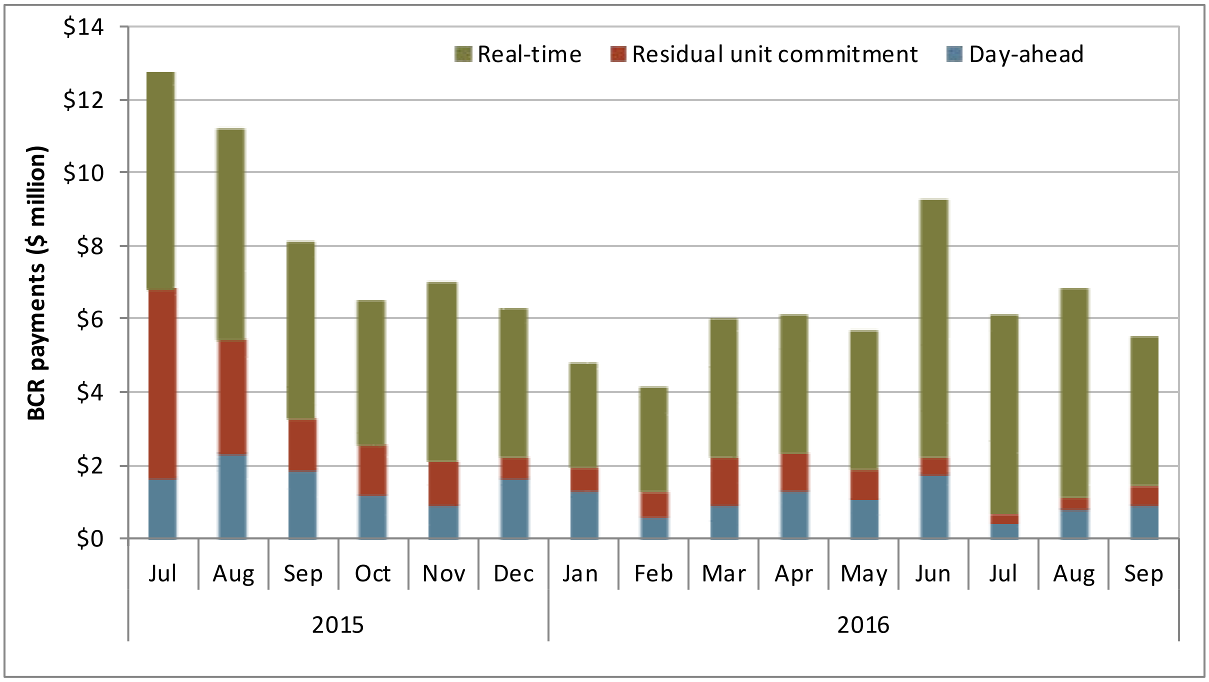
1.4 Bid cost recovery

Estimated bid cost recovery payments for the third quarter totaled about $19 million. This is a significant decrease from about $32 million paid during the third quarter of 2015, and a decrease from $21 million paid during the second quarter of 2016.

Bid cost recovery attributed to the day-ahead market totaled just $2 million, which is the lowest quarterly value since 2013. Also, bid cost recovery payments for residual unit commitment were low at just over $1 million. In the third quarter of last year, payments for residual unit commitment costs approached $10 million, which accounts for most of the year-over-year decrease in total payments. Real-time payments continued to make up the majority of bid cost recovery payments at about $15 million in the third quarter, which remained at about the same level as the prior quarter.

A significant amount of the real-time bid cost recovery payments occurred on a small number of days throughout the quarter when loads were high or expected to be high and expensive units were committed in the real-time market. On some of these days there were significant differences in day-ahead load forecasts compared to real-time loads. These differences can increase real-time exceptional dispatches, particularly for units with faster ramping capability, and thus increase the total amount of real-time bid cost recovery payments made.

Figure 1.5 Monthly bid cost recovery payments[7]



1.5 Convergence bidding

Participants engaging in convergence bidding continued to earn positive returns in the third quarter. Net revenues from the market in these three months were about $12.6 million. This was the highest quarterly net revenue since virtual bids switched from settling against the 5-minute real-time prices to the 15-minute real-time prices in 2014. Virtual supply generated net revenues of about $5 million, while virtual demand generated net revenues of about $7.6 million. Total payments to convergence bidders decreased to about $11.7 million after accounting for $0.9 million of virtual bidding bid cost recovery charges.

Offsetting virtual demand with supply bids at different locations profits from higher anticipated congestion between these locations in the real-time market. This type of offsetting bid represented about 45 percent of all accepted virtual bids in the third quarter, down from 51 percent in the previous quarter.

Total hourly trading volumes were about the same in the third quarter at about 3,200 MW. Virtual supply averaged around 2,000 MW while virtual demand averaged around 1,200 MW during each hour of the quarter, similar to the previous quarter.

[7] The reported monthly figures for bid cost recovery in the third quarter have been adjusted to correct for a known software issue. This issue is currently being corrected by the ISO settlements team.

Revenues for most of the third quarter were positive for net virtual supply positions as prices were generally higher in the day-ahead market than the 15-minute market.[8] However, a higher frequency of price spikes in the 15-minute market in September led to virtual demand positions being profitable for the quarter and reduced the profitability of virtual supply positions.

1.5.1 Convergence bidding trends

Total hourly trading volumes were about the same in the third quarter compared to the second quarter at about 3,200 MW. On average, about 43 percent of virtual supply and demand bids offered into the market cleared in the third quarter, which is down from 49 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 870 MW on average, which is similar to the level of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours by about 810 MW and 1,000 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in only hour ending 21. In the remaining 23 hours, net cleared virtual supply exceeded net cleared virtual demand. The highest net cleared virtual supply hour was hour 10 at over 1,500 MW.

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 18 hours.

Offsetting virtual supply and demand bids

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

Offsetting virtual positions accounted for an average of about 710 MW of virtual demand offset by 710 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 45 percent of all cleared virtual bids in the third quarter, down from about 51 percent in the previous quarter. This is the lowest quarterly proportion observed in the past three years, and continued a downward trend in the proportion of offsetting bids in the market.

[8] 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.

1.5.2 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. Net revenues in the third quarter were about $12.6 million from revenue collected on both virtual supply and demand positions.

Figure 1.6 Total monthly net revenues paid from convergence bidding

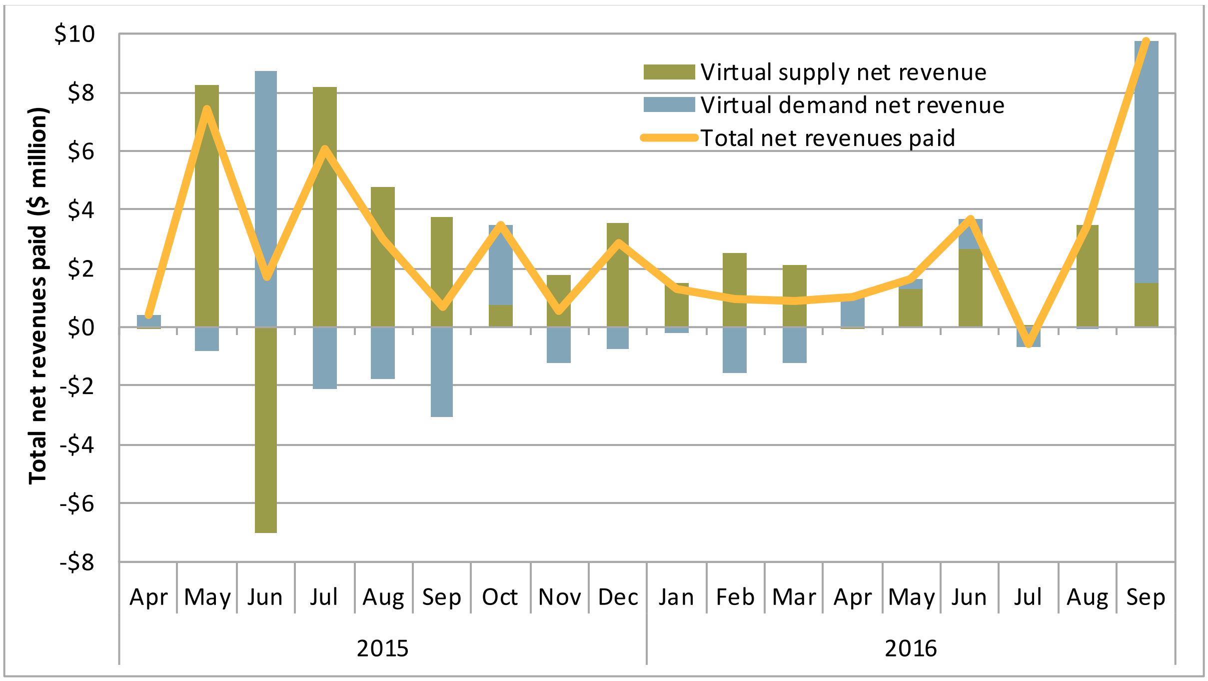


Figure 1.6 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- Monthly net revenues during the third quarter totaled about $12.6 million, compared to about $9.7 million in the same quarter in 2015, and about $6.4 million during the previous quarter. This is the highest quarterly net revenue since virtual bids switched from settling against the 5-minute real-time prices to the 15-minute real-time prices in 2014.
- Virtual supply was profitable in all three months of the quarter. Virtual supply revenues were most significant in August as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply generated net revenues of about $5 million during the quarter.
- Virtual demand net revenues were negative in July and August but were very high in September. This was primarily driven by a single day where congestion on the Lugo-Miraloma 500 kV line resulted in price spikes in the 15-minute market. In total, virtual demand generated net revenues of around $7.6 million during the quarter.

- Convergence bidders were paid about $11.7 million after subtracting bid cost recovery charges of $0.9 million for the quarter.[9,10] Bid cost recovery charges were about $0.2 million, $0.2 million and $0.5 million in July, August and September, respectively.

Net revenues and volumes by participant type

Table 1.5 compares the distribution of convergence bidding cleared volumes and net revenues in millions of dollars among different groups of convergence bidding participants in the third quarter.[11] As shown in Table 1.5, financial entities represented the largest segment of the virtual bidding market in terms of volume, accounting for about 61 percent of volume and about 57 percent of settlement revenue. Marketers represented only about 23 percent of the trading volumes, but about 42 percent of the settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of volumes (about 16 percent) and an even smaller segment of settlement dollars (about 2 percent).

Table 1.5 Convergence bidding volumes and revenues by participant type (July – September)

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	850	1,098	1,948	$3.44	$3.73	$7.17
Marketer	276	452	727	$4.18	$1.07	$5.25
Physical load	6	360	365	$0.01	$0.20	$0.21
Physical generation	22	113	135	-$0.05	$0.03	-$0.01
Total	**1,153**	**2,022**	**3,175**	**$7.6**	**$5.0**	**$12.6**

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

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

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

1.6 Congestion revenue rights

As discussed in DMM's 2015 annual report, since 2012 electric ratepayers – who ultimately pay for the cost of transmission managed by the ISO – received an average of about $130 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments made to entities purchasing these rights.[12] During the first three quarters of 2016, congestion revenue rights auction revenues were $22 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents $0.78 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, up from $0.72 in the first three quarters of 2015.

Background

Congestion revenue rights are paid (or charged), for each megawatt held, the difference between the hourly day-ahead congestion prices at the sink and source node defining the right. These rights can have monthly or seasonal (quarterly) terms, and can include on-peak or off-peak hourly prices. Congestion revenue rights are allocated to entities serving load. Congestion revenue rights can also be procured in monthly and seasonal auctions.

The owners of transmission – or entities paying for the cost of building and maintaining transmission – are entitled to congestion revenues associated with transmission capacity in the day-ahead market. In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities and other load-serving entities through the transmission access charge (TAC).[13] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred.

Load-serving entities then pass that transmission access charge through to ratepayers in their customers' electricity bill. Therefore, these ratepayers are entitled to the revenues from this transmission. When auction revenues are less than the payments transferred to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments represents a loss, which is paid out from the day-ahead congestion rent. The losses therefore cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

As explained in DMM's 2015 annual report, DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction.[14]

Analysis of congestion revenue right auction returns

As described above, the performance of the congestion revenue rights auction can be assessed by comparing the auction revenues ratepayers received to the ratepayer payments to non-load-serving

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[12] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 182-190, 225-226: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

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

[14] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 182-190: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

entities purchasing congestion revenue rights in the auction. Note that payments and charges to ratepayers are through load-serving entities. Figure 1.7 compares the following:

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

Ratepayers lost $22 million in the first three quarters of 2016 as a result of congestion payments made to auctioned congestion revenue rights in excess of auction revenues. This was a decrease from the nearly $39 million ratepayers lost in the first three quarters of 2015.

Auction revenues as a percent of payments were 78 percent in the first three quarters of 2016, up from 72 percent in the first three quarters of 2015. This was because auction revenues fell less than ratepayer payments to auctioned rights. Auction revenues fell 24 percent in 2016 to $78 million from $102 million in 2015. Ratepayer payments to auctioned rights fell 30 percent in 2016 to $100 million from $142 million in 2015.

Figure 1.7 Congestion revenue rights revenues and payments to non-load-serving entities

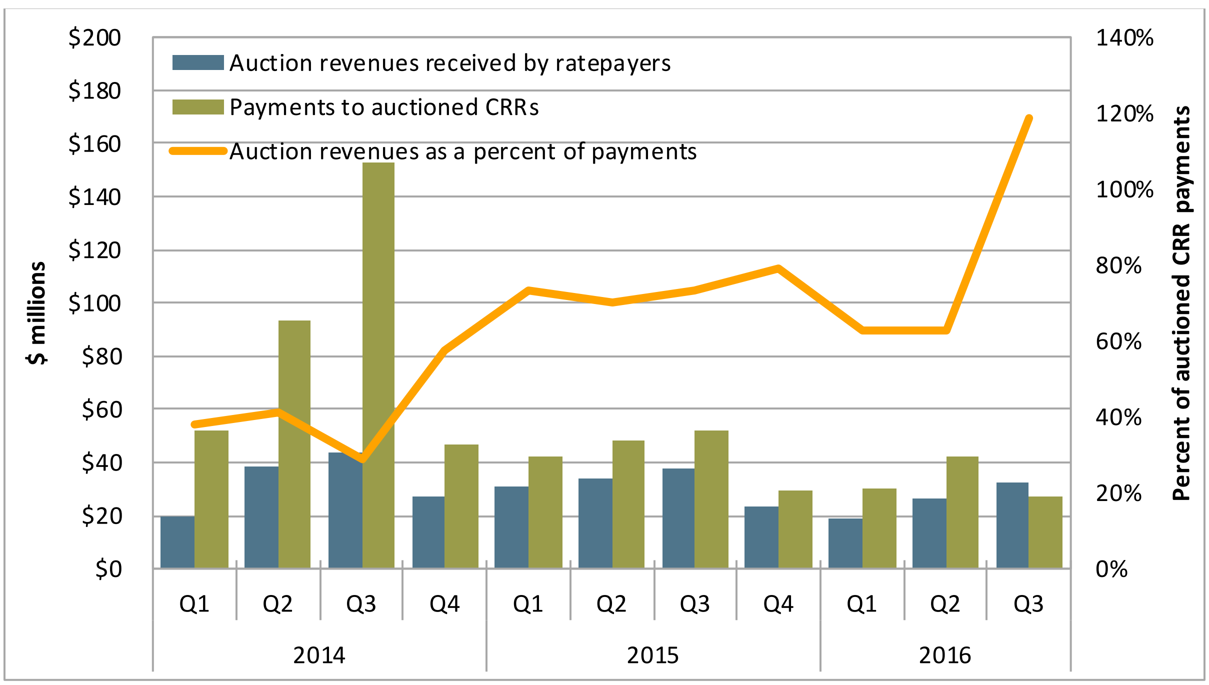


Figure 1.8 through Figure 1.11 show quarterly auction revenues paid to entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- Financial entities participate in the ISO markets only through the convergence bidding and congestion revenue right products.

- Marketers participate in the ISO energy markets primarily through intertie transactions rather than generators or loads internal to the ISO.
- Physical generation and load have generators and loads within the ISO footprint.

As shown in Figure 1.8 through Figure 1.11, during the first three quarters of the year:

- Financial entities continued to have the highest profits among all entity types at $19 million. This was down from $42 million in the first three quarters of 2015. Marketer profits were $2 million, up from a $5 million loss in 2015. Generator profits were $0.7 million, down from $3 million in 2015.
- Financial entities paid the least auction revenue per dollar of payments received at 69 cents per dollar. This was up from 48 cents in the first three quarters of 2015. Marketers paid 93 cents, down from 112 cents in 2015. Generators paid 91 cents, up from 84 cents in 2015.
- Load-serving entities, on net, continued to sell rights into the auction from their explicit bidding. Load-serving entities gained about $4 million from rights they explicitly sold in the auction in the first three quarters of 2016, down from $14 million in the first half of 2015.

Figure 1.8 Congestion revenue rights auction revenues and payments (Financial entities)

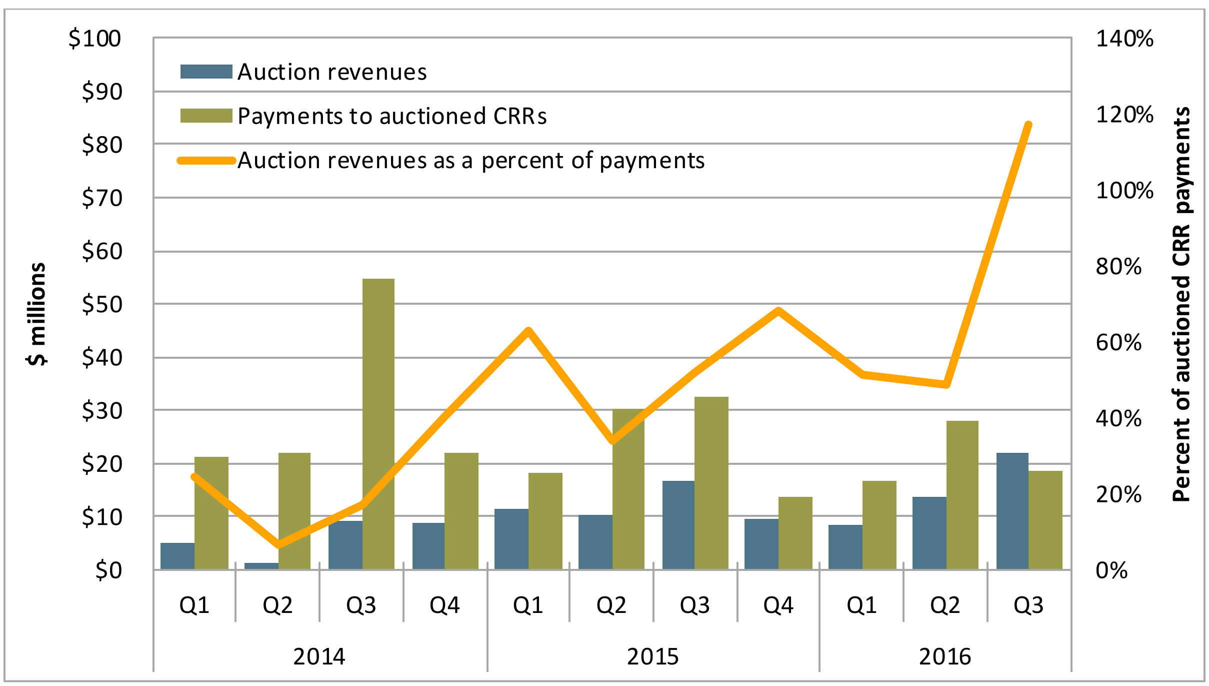


Figure 1.9 Congestion revenue rights auction revenues and payments (Marketers)

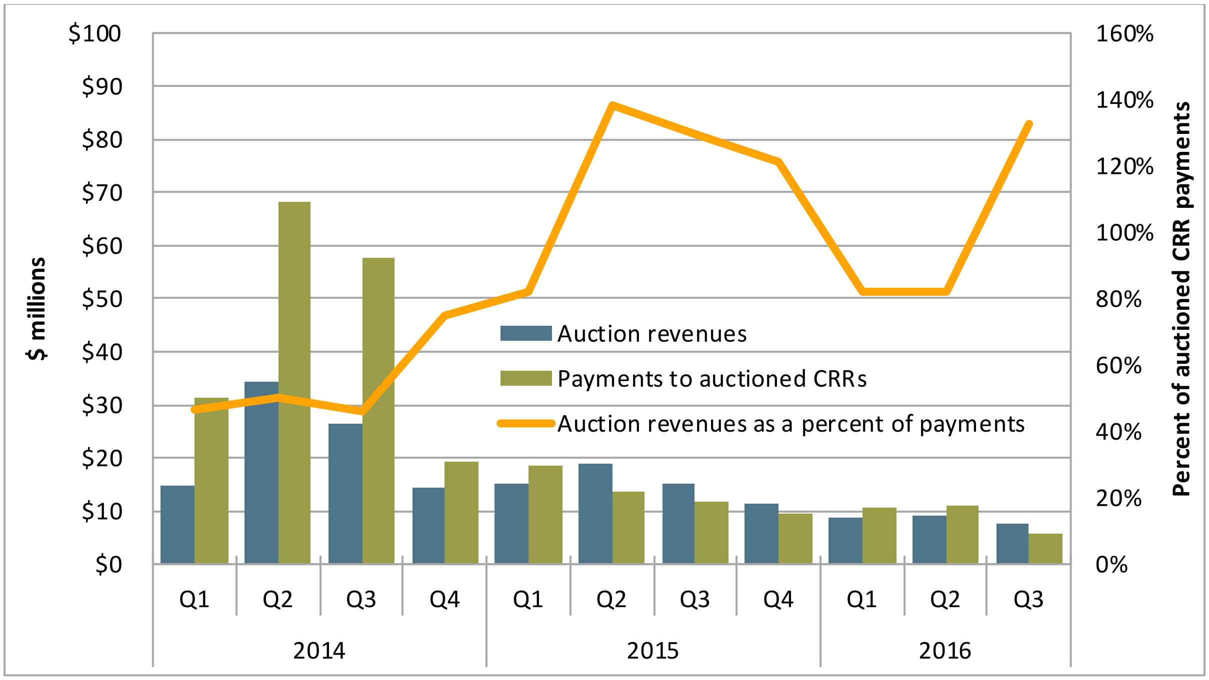


Figure 1.10 Congestion revenue rights auction revenues and payments (Generators)

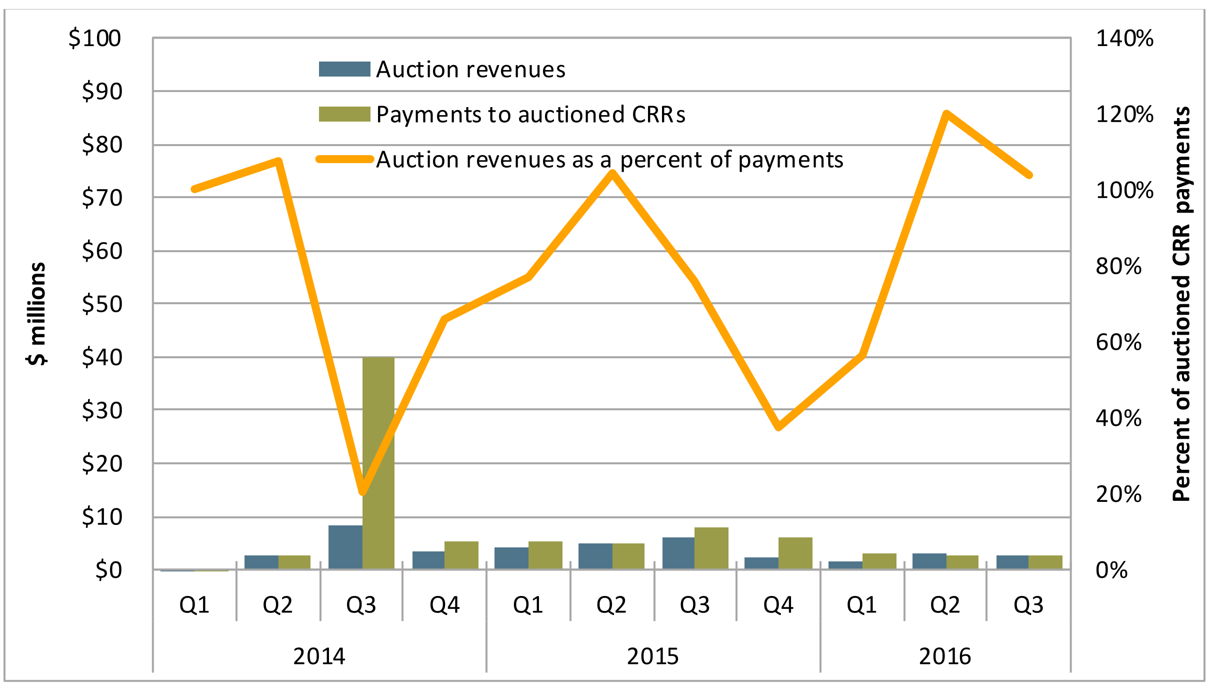
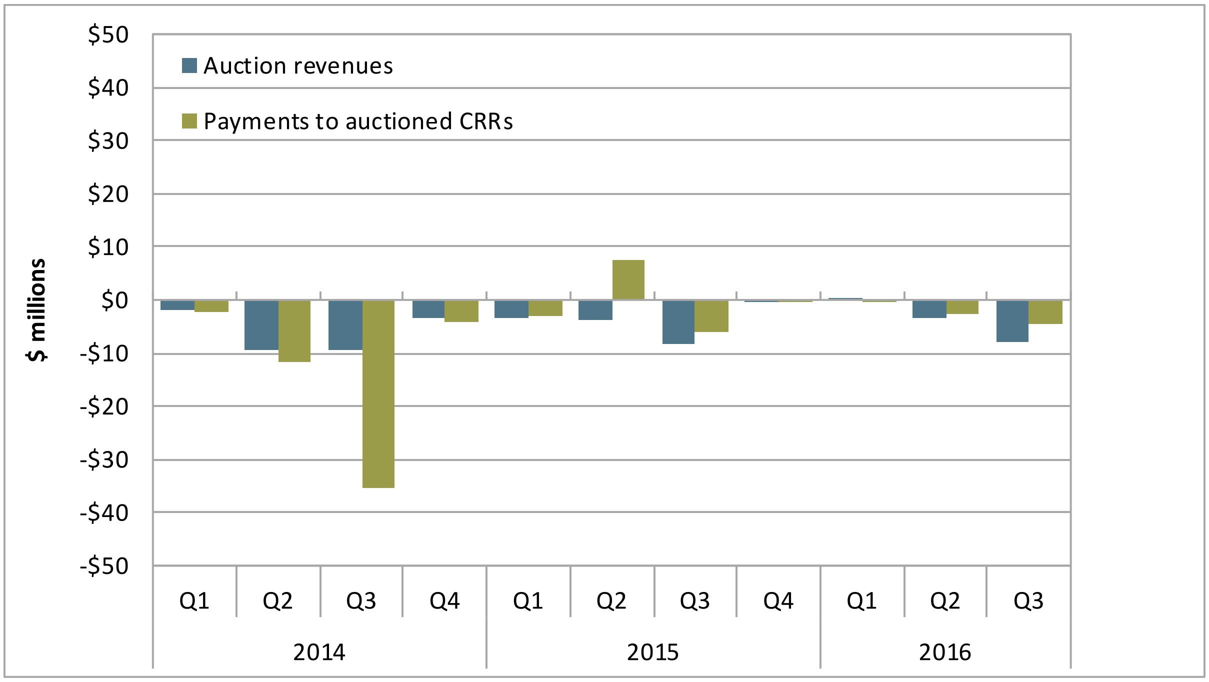


Figure 1.11 Congestion revenue rights auction revenues and payments (Load-serving entities)



Potential improvements to the congestion revenue rights auction

DMM believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off excess transmission capacity remaining after the congestion revenue right allocations. DMM continues to recommend that the ISO begin to assess this issue. DMM's last quarterly report outlined a potential approach for addressing this issue by modifying the congestion rights auction into a *market* for congestion revenue rights based on bids submitted by entities willing to buy or sell congestion revenue rights.[15]

In response to DMM's recommendation at the June 2016 Board meeting, ISO management indicated the ISO would consider scheduling an initiative on this issue as part of the next stakeholder initiative catalog process in the fall of 2016. The ISO is currently considering a potential initiative on congestion revenue rights auction modifications that could include DMM's recommendations as part of the stakeholder initiative catalog for 2017.

[15] *Q2 2016 Report on Market Issues and Performance*, Department of Market Monitoring, August 22, 2016, p. 56: http://www.caiso.com/Documents/2016SecondQuarterReportMarketIssuesandPerformance.pdf.

2 Energy imbalance market

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

- Congestion continued to be very infrequent between the ISO, PacifiCorp East and NV Energy areas, and the energy imbalance market continues to be an efficient tool to manage generation in the real-time market in these areas. As a result, real-time prices continue to be fairly uniform between the ISO and these energy imbalance market areas.
- The frequency of intervals in which the power balance constraint or flexible ramping constraint was relaxed remained very low during the quarter for each market.
- The available balancing capacity mechanism, which was implemented on March 23, 2016, continued to have a limited impact on market outcomes in the third quarter. NV Energy offered available balancing capacity into the market for most hours in the third quarter, while PacifiCorp East and PacifiCorp West did so infrequently.

2.1 Energy imbalance market performance

Energy imbalance market prices

The load settlement price is an average of 15-minute and 5-minute prices, weighted by the amount of estimated load imbalance in each of these markets.[16] The 15-minute market prices are weighted by the imbalance between base load and forecasted load in the 15-minute market, and the 5-minute prices are weighted by the imbalance between forecasted load in the 15-minute market and forecasted load in the 5-minute market.[17]

Figure 2.1 shows hourly average settlement prices during the third quarter in PacifiCorp East, PacifiCorp West, Southern California Edison (SCE), and the Pacific Gas and Electric (PG&E) areas as well as the range of bilateral trading hub prices DMM uses as an additional benchmark for energy imbalance market prices.[18]

Between hours 17 through 20, high system prices above $250/MWh in the ISO during the quarter occurred during about 3 percent of intervals in the 5-minute market and about 2 percent of intervals in the 15-minute market. When there is no congestion between the regions, local prices in the energy imbalance market tended to be set close to the system price. However, during peak load hours, high system prices tended to increase generation from PacifiCorp East and PacifiCorp West, where

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[16] Business Practice Manual Configuration Guide: Real-Time Price Pre-calculation, Settlements and Billing, October 29, 2015: https://bpmcm.caiso.com/BPM%20Document%20Library/Settlements%20and%20Billing/Configuration%20Guides/Pre-Calcs/BPM%20-%20CG%20PC%20Real%20Time%20Price_5.13.doc.

[17] During the quarter, settlement prices in the energy imbalance market were weighted more on prices in the 15-minute market (about 59 percent) and less on prices in the 5-minute market (about 41 percent).

[18] 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 an average of prices for four major western trading hubs (California Oregon Border, Mid-Columbia, Palo Verde and Four Corners). The NV Energy bilateral hub price represents an average of prices for two major western trading hubs (Mead and Mid-Columbia).

generation is relatively less expensive, which caused regional congestion in these areas. This resulted in the price separation observed in Figure 2.1 between the ISO, PacifiCorp East, and particularly PacifiCorp West during peak load hours.

Figure 2.2 provides the same information for settlement prices in NV Energy and the Southern California Edison area. Because of large transfer capabilities and little congestion between the ISO and NV Energy, average settlement prices in NV Energy during the quarter were reflective of system conditions in the ISO depicted by the Southern California Edison prices.

Settlement prices in PacifiCorp West did not reflect prices in the ISO as closely as NV Energy and PacifiCorp East prices because of less available transmission between the two areas. During many of the intervals between hours 17 through 20, when prices were highest in the ISO, transmission between the ISO from PacifiCorp West reached its limit. This resulted in local resources setting the price in PacifiCorp West instead of system prices reflecting shortage conditions.

Settlement prices in PacifiCorp East averaged about $27/MWh during the third quarter, while prices in PacifiCorp West averaged about $25/MWh. Settlement prices in NV Energy were about $31/MWh during the third quarter, compared with $37/MWh for Southern California Edison. Pacific Gas and Electric settlement prices averaged around $35/MWh during the quarter.

Figure 2.1 Hourly settlement and bilateral trading hub prices – PacifiCorp (July – September)

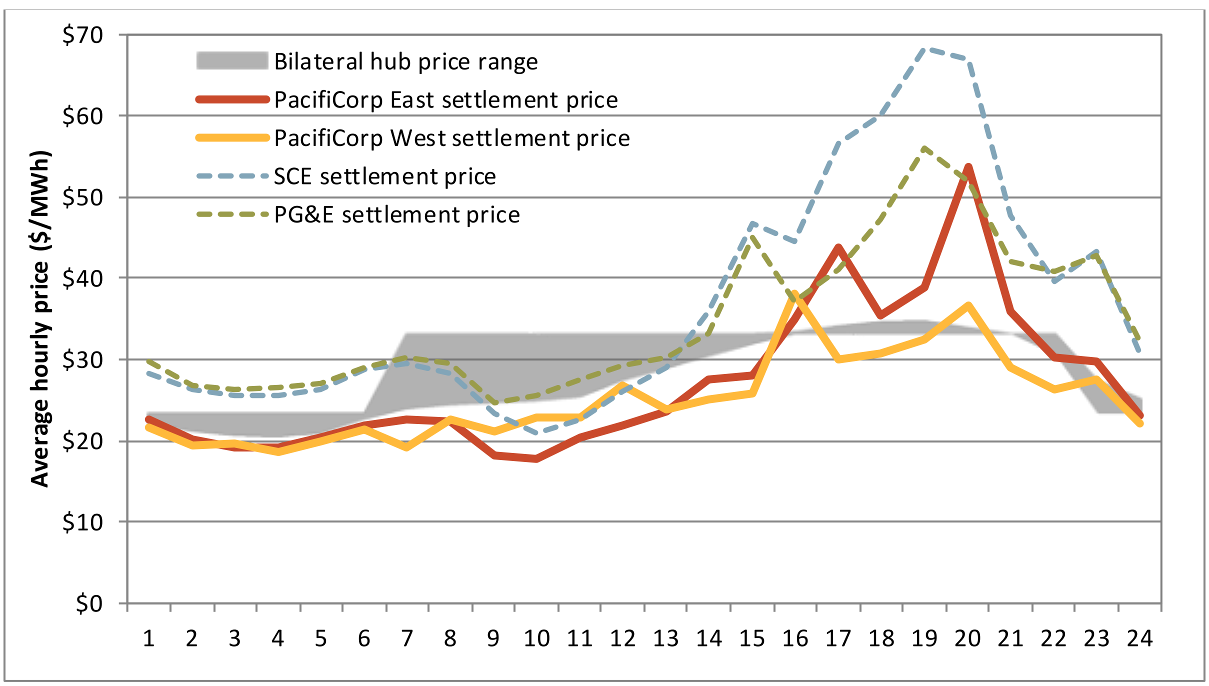
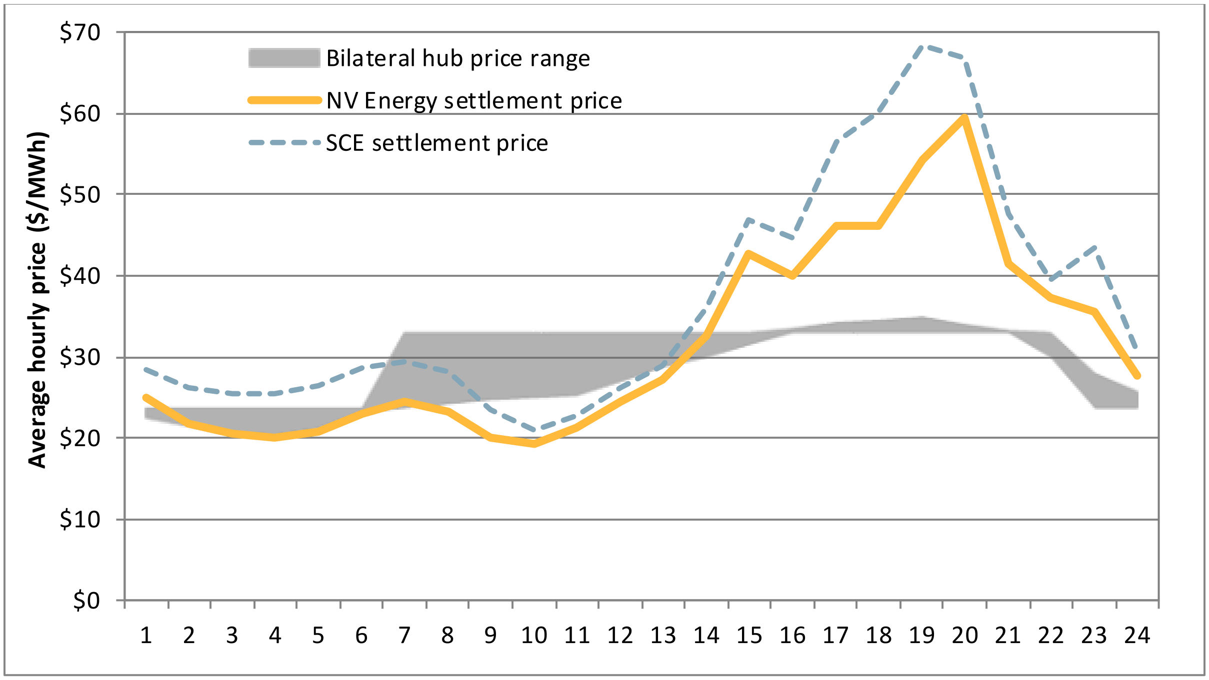


Figure 2.2 Hourly settlement and bilateral trading hub prices – NV Energy (July – September)



During the quarter, the power balance constraint was relaxed very infrequently in all energy imbalance market areas in the 15-minute and 5-minute markets. When the power balance constraint is relaxed due to insufficient upward ramping capacity, prices could be set using the $1,000/MWh penalty price for this constraint. During the third quarter, power balance constraint relaxations in the 15-minute market were limited to NV Energy and PacifiCorp West where they occurred during less than 0.1 percent of intervals. In the 5-minute market, the power balance constraint was relaxed in less than 0.2 percent of the time in each of the energy imbalance market areas during the quarter. The available balancing capacity mechanism, described later in this section, appeared to have a minimal impact on the frequency of power balance constraint relaxations.

The flexible ramping constraint was also relaxed relatively infrequently in all energy imbalance market areas during the quarter. When this constraint is not met and is relaxed, a shadow price is set at or near $60/MWh, resulting in increased 15-minute energy prices. In PacifiCorp East and PacifiCorp West, the flexible ramping constraint was relaxed in less than 1 percent of 15-minute intervals in both PacifiCorp areas and about 2.5 percent of 15-minute intervals in NV Energy.

Overall, the low frequency of constraint relaxations kept energy imbalance market prices in the third quarter near or below the bilateral trading hub price range. During the quarter, average 15-minute market prices in PacifiCorp East and PacifiCorp West as well as 5-minute market prices in all three energy imbalance market areas fell within or below the representative bilateral trading hub price range. Average 15-minute market prices for NV Energy tracked slightly above this range.[19]

Energy imbalance market congestion

As shown in Table 2.1, the frequency of congestion in the energy imbalance market has been extremely low, even after an increased number of constraints were enforced following FERC's November 19, 2015, Order.[20] For all quarters since the implementation of the energy imbalance market internal congestion occurred in less than 0.5 percent of intervals in all areas, except in PacifiCorp East where internal congestion was somewhat more frequent during some quarters.

Persistent low congestion may potentially be a result of the following:

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

These reasons may be more possible because most of the generation within each energy imbalance market area is scheduled by a single entity.

Table 2.1 Percent of intervals with congestion on internal EIM constraints

	2014	2015				2016		
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
15-minute market (FMM)								
PacifiCorp East	0.1%	0.2%	0.2%	0.5%	2.6%	2.2%	0.2%	1.3%
PacifiCorp West	0.1%	0.0%	0.0%	0.2%	0.1%	0.1%	0.0%	0.1%
NV Energy					0.0%	0.0%	0.1%	0.3%
5-minute market (RTD)								
PacifiCorp East	0.0%	0.3%	0.2%	0.4%	2.3%	2.2%	0.2%	1.3%
PacifiCorp West	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%
NV Energy					0.0%	0.0%	0.2%	0.3%

[19] While we show the bilateral trading hubs for reference, they are not a perfect comparison. For instance, the hour-to-hour variation in bilateral trading prices is less variable because bilateral trades are typically not as granular as trades in the energy imbalance market. Furthermore, EIM prices reflect real-time operational limitations, including ramping limitations, which may not be accurately reflected in the day-ahead bilateral trading hub indices.

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

Available balancing capacity

The ISO implemented the available balancing capacity (ABC) mechanism in the energy imbalance market in late March 2016. This enhancement to the energy imbalance market functionality allows for market recognition and accounting of capacity that entities in these areas have available for reliable system operations, but is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each energy imbalance market entity in their hourly resource plans. The available balancing capacity mechanism enables system software to deploy such capacity through the energy imbalance market, and prevents market infeasibilities that may arise without the availability of this capacity.[21]

FERC's December 17, 2015, Order on the available balancing capacity proposal requires that the ISO submit quarterly reports on the available balancing capacity mechanism performance.[22] DMM plans to review the ISO's analysis once these reports are filed and provide feedback as necessary in future quarterly reports. In this report, DMM provides a short summary of the available balancing capacity mechanism since it was implemented in March.

Figure 2.3 and Figure 2.4 summarize the frequency of upward and downward available balancing capacity offered by each energy imbalance market area. The frequency available balancing capacity was offered in the PacifiCorp East and PacifiCorp West areas fell in the third quarter compared to the second quarter. The frequency of upward available balancing capacity offered in the PacifiCorp East area in the third quarter was highest in July, with capacity offered in 6 percent of hours. This level remained relatively constant over the quarter. In PacifiCorp West, the highest frequency of upward available balancing capacity offered in the third quarter was also in July, with capacity offered in 44 percent of hours. Upward available balancing capacity in PacifiCorp West was offered in only 1 percent of hours in August, and during no hours in September.

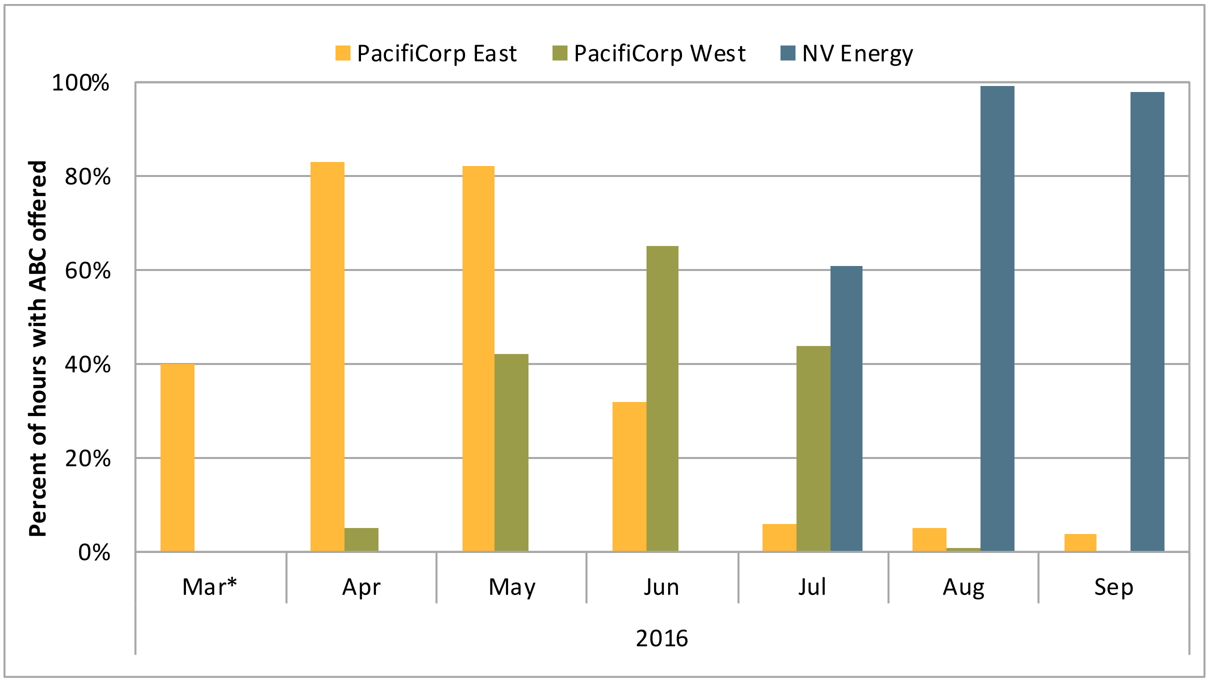
Downward available balancing capacity in the PacifiCorp areas was offered in 1 percent of hours in the month of August in the PacifiCorp East area only. No downward available capacity was offered in the third quarter in the PacifiCorp West area. While the frequency of downward available balancing capacity offered in PacifiCorp West has been consistently low, the third quarter represents a significant decline in the frequency of available capacity offered in PacifiCorp East, down from a monthly average 60 percent of hours in the second quarter.

The frequency of upward available balancing capacity offered in the NV Energy area increased in the third quarter, with capacity offered in nearly all hours of August and September. Downward available balancing capacity was offered in the NV Energy area during approximately 99 percent of hours in the third quarter. The frequency of downward available balancing capacity offered in the NV Energy areas represents a continuation of a trend that began in May.

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

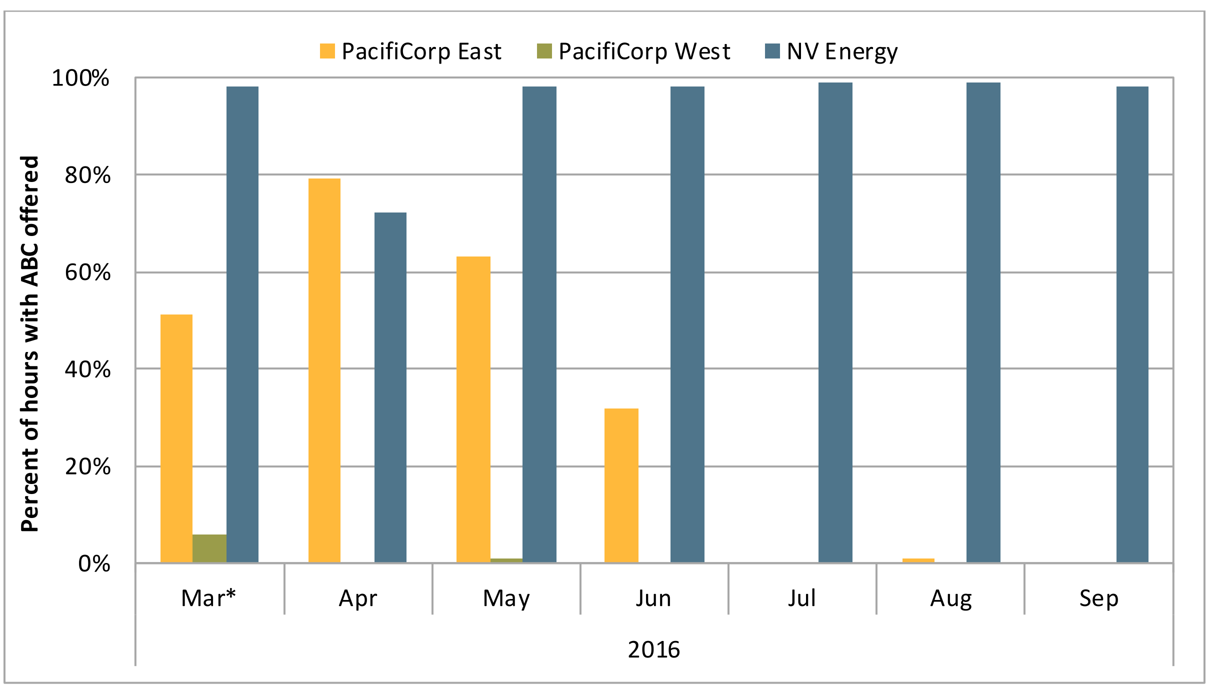
[22] Ibid.

Figure 2.3 Frequency of upward available balancing capacity offered



*March 23 through 31

Figure 2.4 Frequency of downward available balancing capacity offered



*March 23 through 31

Available balancing capacity is bid into the market on an hourly basis. The design of the available balancing capacity mechanism is to dispatch offered capacity for the purpose of resolving infeasibilities within the energy imbalance market balancing authority area offering the capacity, and for such capacity to participate in congestion management when dispatched. When available balancing capacity was offered in an energy imbalance market area in the third quarter, the amount offered typically ranged from 50 MW to 100 MW. The reported dispatch frequency of available balancing capacity increased in the third quarter but remained relatively infrequent overall.

Available balancing capacity dispatch was reported in about 3 percent of 5-minute intervals in the NV Energy area for both upward and downward available capacity, and in a negligible percentage of intervals in the PacifiCorp East and PacifiCorp West areas. While these percentages already represent relatively infrequent dispatch of available balancing capacity, instances of available balancing capacity dispatch for the purpose of resolving infeasibilities as intended may be considerably fewer.

DMM is aware of multiple instances where megawatt quantities reported as dispatched available balancing capacity may not actually represent capacity dispatched to resolve an infeasibility within an energy imbalance market balancing authority area. These apparent dispatches of available balancing capacity may be, for example, the result of a resource ramping up or down and crossing the capacity range designated as available balancing capacity in the process. DMM continues to work with the ISO to better understand all potential reasons for which a given market quantity may be reported as dispatched available balancing capacity.[23]

2.2 Energy imbalance market transfers

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

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

Table 2.2 also shows that when the ISO and NV Energy were importing, they imported greater net quantities of energy than when they were exporting. Similarly, PacifiCorp East and PacifiCorp West tended to export energy more frequently than they imported, and when they exported they tended to export greater quantities of energy than while importing during the third quarter.

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

Table 2.2 Net EIM transfers (July – September)

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	76%	-287	24%	66
PacifiCorp East	8%	-9	92%	313
PacifiCorp West	34%	-32	66%	72
NV Energy	64%	-186	36%	63

When there is no congestion between the regions, local prices tend to be set close to the system price. This is frequently happening between the ISO, NV Energy, and PacifiCorp East, where prices in all three areas are effectively being set by aggregate supply and demand conditions for all three areas. When the ISO, NV Energy or PacifiCorp East experience particularly high prices, constraints out of PacifiCorp West frequently bind and cause price separation between PacifiCorp West and prevailing prices in the other three areas. Intervals when PacifiCorp West does experience congestion tend to be concentrated in hours when prices are higher in the ISO.

Table 2.3 shows that there is little congestion between the ISO and NV Energy, and prices were different in these two areas during only about 2 percent of all intervals during the third quarter because of congestion. The table also shows that there was congestion in the direction of the ISO from PacifiCorp East during about 14 percent of intervals during the quarter, but there was little congestion in the reverse direction.[24] These results differed from the prior quarter, in that east-to-west congestion in the third quarter tended to be between PacifiCorp East and NV Energy, while the limited congestion in the second quarter tended to be between NV Energy and the ISO. This change is a result of the ISO shifting to a net importer from a net exporter and PacifiCorp East predominantly exporting energy during the quarter.

Table 2.3 also shows that there was frequent congestion between PacifiCorp West and the ISO, during about one quarter of all intervals, again with a majority of congestion in the direction of the ISO, and PacifiCorp East, from PacifiCorp West. Congestion in PacifiCorp West tended to occur during intervals when the demands on ramp were the greatest and system prices tended to be higher. Low cost generation in the area combined with tight transmission limits contributed to the congestion in PacifiCorp West.

Figure 2.5 shows further detail about how energy flowed between NV Energy, the ISO and PacifiCorp East on an hourly basis during the quarter. The green bars in this figure show that NV Energy received imports from PacifiCorp East during all hours of the day. The blue bars show that NV Energy received imports from the ISO during midday hours when solar generation was on-line, and exported energy to the ISO during almost all other hours. This resulted in a general pattern of east-to-west energy flows from PacifiCorp East through NV Energy to the ISO during most hours of the day. Energy flowed from both PacifiCorp East and the ISO into NV Energy during the midday hours. These results differ from the second quarter when the ISO was a net exporter and west-to-east flows, from the ISO through NV Energy to PacifiCorp East, occurred during midday hours when solar generation was on-line. This

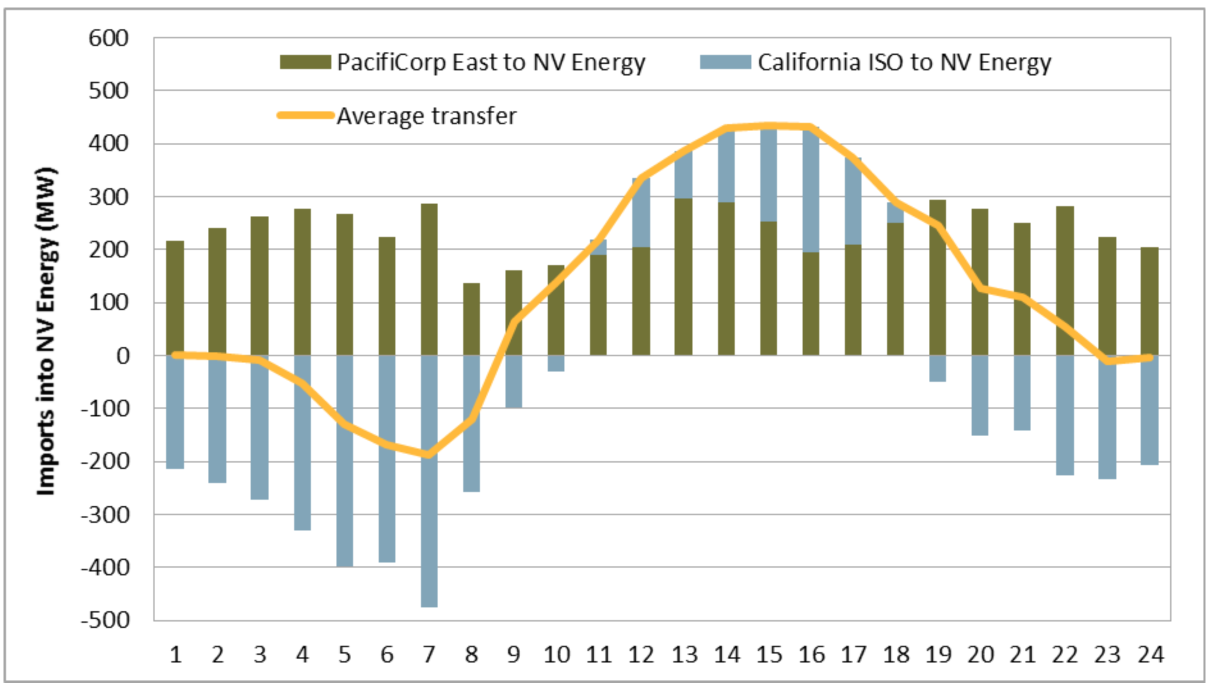
[24] Because there is no direct intertie between the ISO and PacifiCorp East, congestion between the two areas is calculated by comparing the congestion component of load aggregation point prices during each interval.

change is a result of increased system load in the ISO and less solar generation available for export during the midday hours.

Table 2.3 Congestion status and flows in EIM (July – September)

	Percent of intervals	Average transfer (MW)
PacifiCorp East		
Congested from ISO	1%	-209
Congested toward ISO	14%	562
PacifiCorp West		
Congested from ISO	1%	-131
Congested to ISO	26%	121
NV Energy		
Congested from ISO	1%	-691
Congested to ISO	1%	334

Figure 2.5 Average hourly imports into NV Energy from the ISO and PacifiCorp East (July – September)



2.3 Special FERC mitigation measures

In FERC's November 19, 2015, Order, the Commission found that the market power analyses of the expanded energy imbalance market footprint by PacifiCorp and NV Energy (Berkshire EIM Sellers[25]) were deficient and failed to demonstrate a lack of market power in the expanded energy imbalance market.[26] The Commission also outlined concerns regarding the ability of the ISO's market power mitigation rules and procedures to mitigate the Berkshire EIM Sellers' market power in the expanded energy imbalance market. The Commission therefore imposed the following two conditions on the Berkshire EIM Sellers' participation in the energy imbalance market at market-based rates:

1. They must offer participating units in the energy imbalance market at or below each unit's default energy bids; and

2. They must facilitate the ISO's enforcement of all internal transmission constraints in the PacifiCorp and NV Energy balancing authority areas.

On May 19, 2016, the Commission issued an order denying rehearing and providing clarification on several issues regarding market power analysis requirements for new energy imbalance market entrants.[27]

During 2016 DMM has been monitoring for compliance with the special requirements imposed on energy imbalance market entities under FERC's November 2015 Order. DMM also provided analysis and recommendations to the ISO and energy imbalance market entities to address several specific concerns about market power mitigation noted in the Commission's November 2015 Order, as described in the following sections.

2.3.1 Energy imbalance market transfer scheduling limits

One concern cited in FERC's orders on Berkshire Hathaway sellers' market-based rate authority in the energy imbalance market was the amount of competitive supply available for transfer into each energy imbalance market area because of scheduling limits.[28] In this order the Commission clarified that assessments of market power should consider actual energy imbalance market scheduling limit constraints.

As noted in recent DMM reports to the Commission, with the addition of NV Energy to the energy imbalance market in December 2015, the amount of transmission capacity available to support transfers of competitive supply from the ISO into the PacifiCorp East and NV Energy balancing areas has increased

[25] As of November 19, 2015, only units that were owned by PacifiCorp, a Berkshire Hathaway subsidiary, had bid energy into the energy imbalance market in PacifiCorp East and PacifiCorp West. Since that time, only one other resource, not owned by a Berkshire Hathaway subsidiary, has bid into the energy imbalance market. Similarly, in the NV Energy area all units currently bidding in the market are owned by NV Energy, also a Berkshire Hathaway subsidiary.

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

[27] *Order Denying Rehearing and Granting Clarification*, May 19, 2016, ER15-2281-001: http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14460668.

[28] *Order on Proposed Market-Based Rate Tariff Changes*, November 19, 2015, ER15-2281-000, p. 8, ¶17: https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

significantly.[29] During most intervals, the amount of this transfer capacity is sufficient to avoid congestion — and effectively deter and mitigate the potential for both economic and physical withholding.

During the limited number of intervals when competitive supply from the ISO into the energy imbalance market is constrained by congestion on transfer constraints, the ISO's automated real-time market power mitigation procedures are designed to mitigate the potential exercise of market power. As described in the following section, DMM has recommended that the ISO implement enhancements to these procedures to ensure that they are triggered in the real-time market when congestion occurs on structurally uncompetitive constraints.

2.3.2 Enhanced bid mitigation procedures

The ISO's automated bid mitigation procedures address the potential to exercise market power through *economic withholding*. The Commission's November 19 Order cited concerns about the effectiveness of the ISO's bid mitigation procedures in cases when congestion is not projected to occur on a constraint so that mitigation may not be triggered when congestion actually occurs in the real-time market.[30] DMM highlighted this issue in prior reports and continues to closely monitor its impact.[31]

Although this issue has not adversely affected prior market competitiveness, DMM continued to work with the ISO to develop software enhancements to effectively address the issue of potential under-mitigation in the real-time market.[32] As a result of this effort, enhancements to address the issue of under-mitigation are scheduled for implementation in the 15-minute market in 2016 and enhancements to the 5-minute software are anticipated in 2017. DMM continues to work with the ISO to help ensure these enhancements are implemented.

2.3.3 Enhanced outage reporting

The Commission's November 19 Order also noted a concern with the potential for *physical withholding* due to the lack of a must-offer requirement in the energy imbalance market.[33] The available balancing

[29] *Q1 2016 Report on Market Issues and Performance*, Department of Market Monitoring, June 13, 2016, pp. 1, 36-39: http://www.caiso.com/Documents/2016FirstQuarterReportMarketIssuesandPerformance.pdf; and

Report on Structural Competitiveness of Energy Imbalance Market, July 7, 2016: http://www.caiso.com/Documents/Jul8_2016_DepartmentMarketMonitoring_EIM_StructuralMarketPowerInformationalReport_ER14-1386.pdf.

[30] November 19 Order, ¶53 p. 19. See also ¶47 p. 17, which notes that "while we recognize Truckee Donner's concern about under-mitigation in the NV Energy portion of the energy imbalance market, we believe this concern is alleviated by [the requirement to bid at or below each unit's Default Energy Bid]."

[31] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 143-150: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

[32] *Tariff Amendments to Enhance Local Market Power Mitigation Procedures*, June 21, 2016, ER16-1983-000: http://www.caiso.com/Documents/Jun21_2016_TariffAmendment-LocalMarketPowerMitigationEnhancements_ER16-1983.pdf.

[33] As noted in the November 19 Order:

capacity feature implemented in March 2016 established new requirements for energy imbalance market entities to identify capacity scheduled for operating reserves as well as capacity available for dispatch in the event other bids in the area are insufficient to meet the power balance constraint for each energy imbalance market area. These new requirements increase the ability for DMM to effectively monitor the potential for physical withholding.

To enhance DMM's ability to monitor capacity not offered in the energy imbalance market, DMM requested that the ISO and energy imbalance market entities develop a set of more descriptive categories that can be entered in the ISO's outage management system to indicate the reason for unit outages or de-rates. For example, based on DMM's review and discussions with energy imbalance market entities, DMM understands that reasons for outages and de-rates in the energy imbalance market may include transmission contract limitations, unit operating constraints not reflected in ISO dispatch, or the need to manage capacity available for operating reserve obligations.

DMM has recommended that the ISO work with energy imbalance market entities to develop a list of various additional reasons for outage or de-rates which are not represented in the "pick list" of categories in the current ISO outage system software. In some cases, DMM notes that new categories may be appropriate for resources in the energy imbalance market but may not be appropriate for ISO resources with must-offer requirements. DMM has recommended that these additional categories be reviewed, explained in business practice manuals and then incorporated in the ISO's outage reporting system. This recommendation remains under consideration by the ISO.

2.3.4 Enforcement of energy imbalance market transmission constraints

In its November 19 Order, the Commission expressed concern that if constraints within the energy imbalance market areas are not enforced mitigation procedures will not be triggered and therefore potential local market power will not be mitigated. Therefore, the Commission has required Berkshire EIM Sellers to "facilitate CAISO's enforcement of all internal transmission constraints in the PacifiCorp and NV Energy balancing authority areas."[34]

DMM's review of this issue indicates that by the second quarter of 2016 a significant number of constraints within the energy imbalance market areas, but not all incorporated in the network model, were being enforced. Consequently, DMM requested that the ISO and the energy imbalance market entities further review this issue and provide a report to FERC identifying constraints that are not modeled or enforced, along with an explanation of the reasons that some constraints were not being enforced. This expectation is also echoed by FERC in the November 19 Order.[35]

> … outside of the CAISO's balancing authority area, the energy imbalance market is a voluntary market, which allows participants to decide which resources they bid into the energy imbalance market and which resources they do not. Therefore, a market participant may be able to strategically bid its resources such that the LMP does not reflect the economic unit, but rather reflects a unit the market participant selects to bid with potentially higher cost, to the benefit of its lower cost units. The same concern is not present for resources with must-offer requirements, such as the resources that participate inside of the CAISO balancing authority area. (¶58 pp.17-18)

[34] *Order on Proposed Market-Based Rate Tariff Changes*, November 19, 2015, ER15-2281-000, p.21, ¶58: https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

[35] *Order on Proposed Market-Based Rate Tariff Changes*, November 19, 2015, ER15-2281-000, p.21, ¶59: https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

As discussed in Section 2.1, the frequency of internal congestion in the energy imbalance market areas has been extremely low, even after an extensive set of constraints was enforced beginning in 2016. This may be attributable to system topology and the relative bid prices of different resources.

However, DMM's review indicates that one factor that may be contributing to the lack of congestion within the PacifiCorp area is that some scheduling limits associated with transmission contracts (between PacifiCorp and non-PacifiCorp entities owning transmission within the PacifiCorp balancing area) are not incorporated in the full network model. As discussed in Section 2.1, these scheduling limits are enforced by PacifiCorp through base schedules or by entering de-rates for some generating units in the ISO outage software. When generation is limited in this manner to meet these transmission contract limits, this may have the effect of preventing congestion on physical constraints that might otherwise bind in the real-time energy imbalance markets.

DMM has recommended that the ISO and energy imbalance market entities assess whether these transmission contract limits can be directly enforced by the market software. This could allow more efficient dispatch of different resources to meet scheduling limits and avoid the need for energy imbalance market participants to not offer or limit generation in the market, in an effort to avoid exceeding scheduling limits. As noted in the prior section, DMM has also recommended that whenever these scheduling limits are managed by limiting output from a resource through a de-rate in the ISO outage system, the reason for the de-rate be clearly logged in the outage reporting system using a standard outage category.

DMM also believes it is important to clarify what would occur in the event a local constraint were not enforced in the energy imbalance market network model but bound under actual conditions; energy imbalance market entities would find it necessary to rely on adjustments to base schedules, as described above, or manual dispatches to mitigate congestion. As discussed in Section 2.1, manual dispatches in the energy imbalance market were very infrequent in all areas in the third quarter.[36] Additionally, a review in DMM's first quarter 2015 report of operator logs associated with energy imbalance market manual dispatches shows that manual dispatches have rarely, if ever, been used to manage internal transmission constraints.[37] Further review of manual dispatches and discussions with energy imbalance market entities indicates this trend has continued through 2016.

However, DMM has recommended that the ISO work with energy imbalance market entities to develop a more detailed list of reasons for why manual dispatches occur. This will enhance the ability of DMM, the ISO and energy imbalance market entities to track reasons for manual dispatches more robustly over time, including the frequency of any manual dispatches that may be associated with congestion on internal constraints.

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[36] In the energy imbalance market, manual dispatches do not set market clearing prices, in the same way that *exceptional dispatches* do not set prices in the ISO system. While exceptional dispatches in the ISO may be paid based on their bid price if this exceeds the market clearing price, all manual dispatches are settled on the energy imbalance market clearing prices. In effect, resources manually dispatched in the energy imbalance market are price takers. This mitigates any concern that resources being manually dispatched in the energy imbalance market may exercise market power by either setting prices or being paid above-market prices.

[37] *Q1 2015 Report on Market Issues and Performance*, Department of Market Monitoring, June 10, 2015, pp. 36-39: http://www.caiso.com/Documents/2015FirstQuarterReportMarketIssuesandPerformanceJune2015.pdf.

3 Load forecast adjustments

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

- PacifiCorp continued to use negative load adjustments relatively frequently during the quarter. Load adjustments in PacifiCorp East were more frequent in the 5-minute market than in the 15-minute market.
- NV Energy continued to use positive load adjustments relatively frequently, at around 48 percent of intervals in the 15-minute market and 44 percent of intervals in the 5-minute market.
- PacifiCorp adjusted load primarily for generation deviation and automatic time error correction, while NV Energy adjusted load for reliability based control.[38]
- The percentage of intervals when the energy power balance constraint was relaxed to allow the market software to balance modeled supply and demand remained very low during the quarter in the energy imbalance market, and therefore the load bias limiter had little impact on energy imbalance market prices.
- DMM provided recommendations to the ISO for enhancements to the load bias limiter feature to better reflect the impact of excessive load adjustments on creating power balance relaxations. Specifically, DMM recommended considering the change in adjustments from one interval to the next and the duration of an adjustment rather than solely the absolute value of any load adjustment.

Background

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. This is sometimes referred to as *load bias* or *load conformance*. These adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of the load adjustment feature including managing load and generation deviations, automatic time error correction, scheduled interchange variation, reliability events, and software issues.

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

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

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

> …. we direct CAISO to collect relevant data from each EIM Entity, for both the 15- and five-minute markets, on the frequency and magnitude of an EIM Entity's use of load biasing, load forecast adjustments, the reason for the adjustments, as well as any alternatives considered (e.g., use of manual dispatch). The CAISO should also retain documentation regarding the reliability needs that were addressed by these load forecast adjustments or load bias actions.[39]

FERC also indicated that:

> Additionally, we expect CAISO's Department of Market Monitoring to monitor and evaluate this information and include an analysis of the impacts of EIM Entities' load forecast adjustments or load bias actions on the EIM in its public Quarterly Report on Market Issues and Performance. Inclusion of this information in the Department of Market Monitoring's quarterly reports will assist the Commission in assessing the effects these actions have on market outcomes.[40]

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

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

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

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

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

Frequency and size of load forecast adjustments

Figure 3.1 and Figure 3.2 show the frequency of positive and negative load forecast adjustments for PacifiCorp East, PacifiCorp West, and NV Energy during the previous six months for the 15-minute and 5-minute markets, respectively. The same data for the ISO is provided as a point of comparison and reference.

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

In both PacifiCorp areas the frequency of negative load adjustments continued to be prevalent relative to positive load adjustments. In PacifiCorp East, negative load adjustments were much more frequent during the quarter in the 5-minute market (about 63 percent of intervals) than in the 15-minute market (about 42 percent of intervals). During intervals with negative adjustments, the adjustment averaged around -110 MW for PacifiCorp East (or about 2.1 percent of load) and around -50 MW for PacifiCorp West (or about 2.4 percent of load) during the quarter, as shown in Table 3.1.

In the NV Energy area, positive load adjustments were made during almost half of all real-time intervals during the quarter, while negative load adjustments were made during about 11 percent of 5-minute intervals and just 1 percent of 15-minute intervals. Positive adjustments in NV Energy averaged around 110 MW (or about 2 percent of load) in both real-time markets, similar to the previous quarter.

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

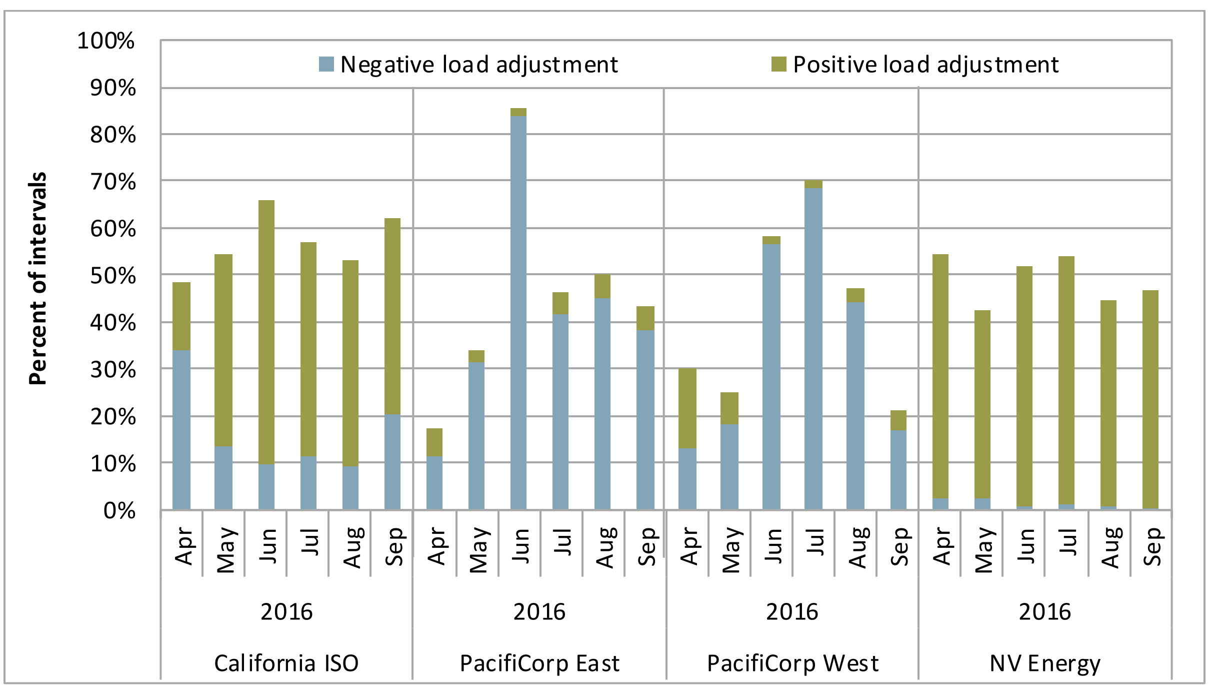


Figure 3.2 Average frequency of positive and negative load adjustments by BAA (5-minute market)

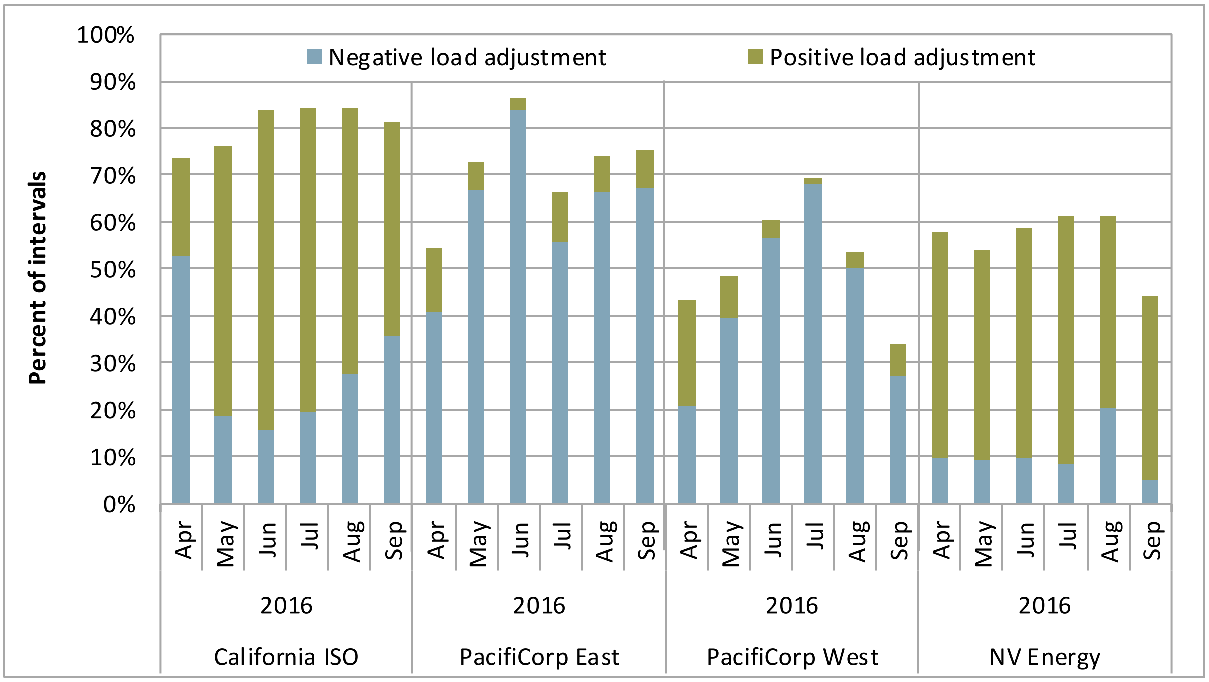


Table 3.1 Average frequency and size of load adjustments (July – September)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	44%	471	1.4%	14%	-274	1.1%	169
5-minute market	56%	438	1.4%	27%	-300	1.1%	162
PacifiCorp East							
15-minute market	5%	91	1.6%	42%	-101	1.9%	-38
5-minute market	9%	88	1.5%	63%	-125	2.4%	-71
PacifiCorp West							
15-minute market	3%	38	1.5%	43%	-49	2.2%	-20
5-minute market	4%	42	1.7%	49%	-58	2.6%	-27
NV Energy							
15-minute market	48%	132	2.3%	1%	-171	3.6%	62
5-minute market	44%	95	1.7%	11%	-83	1.7%	32

Figure 3.3 shows the average hourly load forecast adjustment profile for the 15-minute and 5-minute markets during the third quarter for PacifiCorp East, PacifiCorp West, and NV Energy. Differences

between adjustments in the 15-minute and 5-minute markets can arise from differences in either the frequency or magnitude of positive and negative load adjustments.

As shown by the green lines in Figure 3.3, load in PacifiCorp East was adjusted more negatively in the 5-minute market than in the 15-minute market during the quarter, particularly during late morning and late evening hours. Significantly negative net load adjustments between hours 8 and 10 in the 5-minute market may be due to differences in forecast and actual solar generation during the morning ramp period.

The blue lines show that in PacifiCorp West load was adjusted by similar amounts in the 5-minute and 15-minute markets. However, adjustments in the 5-minute market were slightly more frequent than 15-minute adjustments during early morning and late evening hours.

The red lines in Figure 3.3 provide information on load forecast adjustments for NV Energy, and show that load adjustments followed the load pattern. Adjustments were low during the early morning and late evening hours and were highest during the evening peak load hours. The frequency of positive load adjustments were similar in the 15-minute and 5-minute markets. Greater average net adjustments in the 15-minute market than the 5-minute market occurred primarily due to more frequent negative adjustments in the 5-minute market.

For comparison, Figure 3.4 shows the average hourly load adjustments for the 15-minute and 5-minute markets in the ISO during the third quarter. Like NV Energy, the shape of the hourly average adjustment reflects the shape of hourly net load. Positive load adjustments were entered most frequently during morning and evening peak net load periods. Conversely, negative load adjustments were entered most frequently during early morning, midday, and late evening hours.

Differences in average load adjustments by the ISO between the 15-minute and 5-minute markets were largely related to the hourly frequency in which positive and negative load adjustments occurred. In particular, negative load adjustments were significantly more frequent during hours ending 1, 22, 23, and 24 in the 5-minute market than in the 15-minute market while 5-minute positive load adjustments were more frequent between hours ending 4 through 7. Differences in load adjustments between the 5-minute and 15-minute markets may result in significantly different market outcomes.

Figure 3.3 Average hourly load adjustment – EIM areas (July – September)

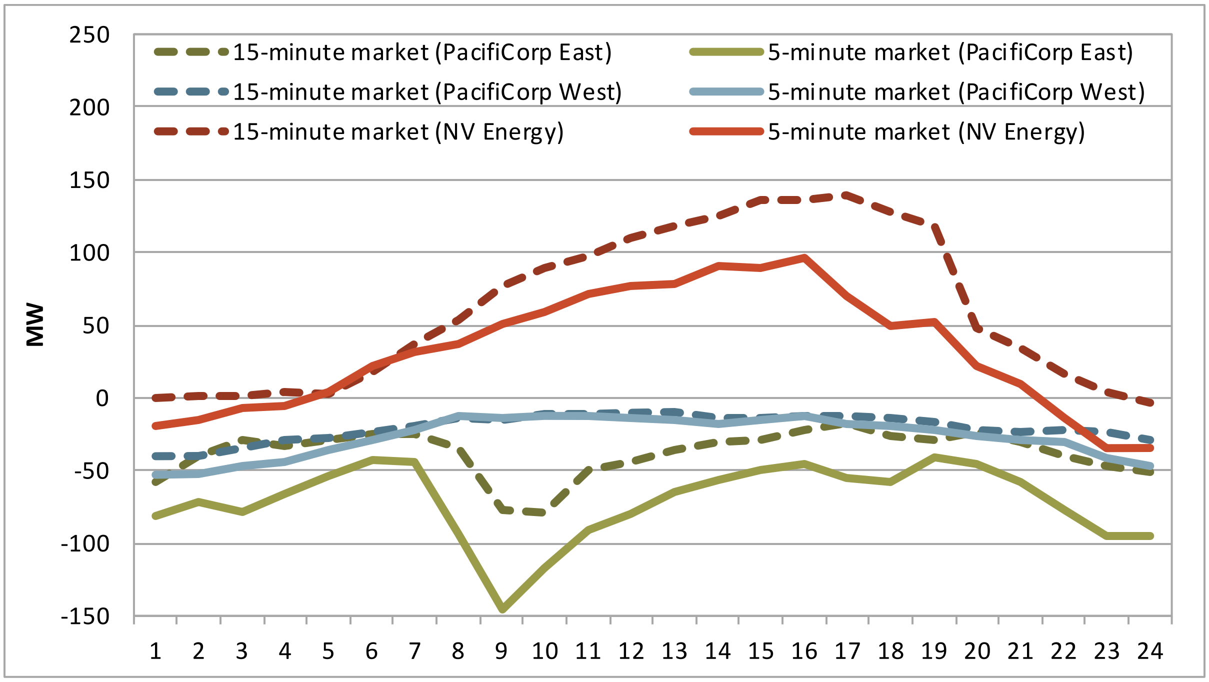
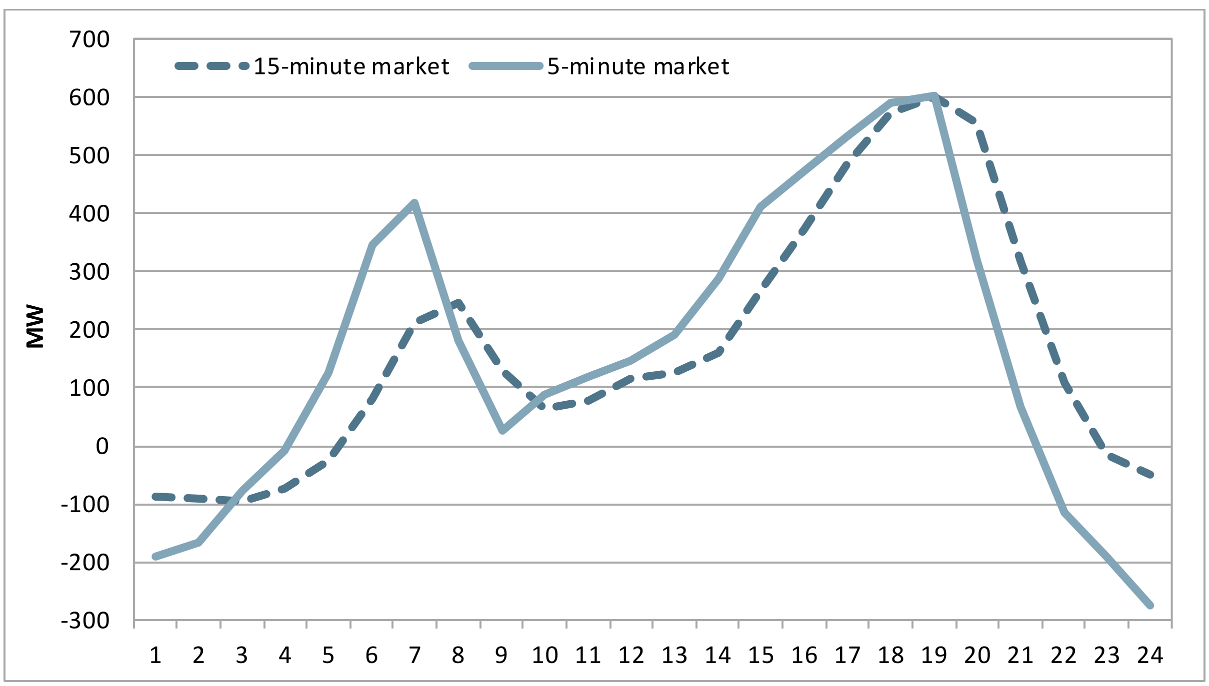


Figure 3.4 Average hourly load adjustment – ISO (July – September)



Reasons for load adjustments

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

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

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

Reasons for load adjustment in the energy imbalance market included:

- load forecast deviation (load deviation from the forecast);
- generation deviation (includes deviation in forecast for variable energy resources, generator startup or shutdown resulting in generation below its minimum operating level, and generation testing);
- reliability based control (informing the market of a need for generation increase or decrease to comply with the balancing authority area limit standard); and
- automatic time error correction (informing the market of automatic generation control deviation from 0 area control error due to automatic time error correction).

When operators enter a load adjustment duration and quantity, operators now have the option to select a reason for the load adjustment from a list of predefined reasons.[41] In addition, operators have the ability to include detail about why a load adjustment is entered in a free-form text box. If operators enter a load adjustment for more than one reason, they have the ability to select only one preset reason from the list. However, additional reasons can be entered in a free-form text box. Logging additional details or reasons through the text box is optional.

During the quarter, PacifiCorp operators were more apt to include additional detail in the 5-minute market than in the 15-minute market. PacifiCorp East operators entered information in the free-form text box during about 70 percent of 5-minute intervals when load adjustments were entered while PacifiCorp West operators entered additional information during about 40 percent of intervals. PacifiCorp frequently used this feature to cite additional reasons beyond the single reason selected from the predefined list. Operators in NV Energy used the additional details text box significantly more frequently than in the previous quarter, and included additional details during over 80 percent of 15-minute and 5-minute intervals when load adjustments were entered.

At this time, the only method for evaluating additional details about the load adjustment, including details about reliability needs and alternative options evaluated prior to entering a load adjustment, is

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

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

Figure 3.5 and Figure 3.6 show the frequency of load adjustments in the energy imbalance market areas by the reason selected for the adjustment during the previous six months for the 15-minute and 5-minute markets, respectively.[42] During the third quarter, the distribution of reasons selected for all areas remained very similar to the previous quarter. The figures show that the primary reasons reported by PacifiCorp operators for adjusting loads were for generation deviation and automatic time error correction.

As shown in Figure 3.6, generation deviation in the 5-minute market was selected during about 54 percent of the intervals when load adjustments were entered in PacifiCorp East, and about 19 percent of load adjustments in PacifiCorp West during the quarter. For PacifiCorp, generation deviation was often logged because of generation deviations from wind or solar resources.

In NV Energy, operators reported adjusting loads most frequently for reliability based control. Through the free-form text box, operators have indicated that this option is primarily selected when the load adjustment is used to adjust generation to comply with the balancing authority area limit standard. NV Energy operators selected reliability based control during about 85 percent of intervals with load adjustments.

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

Figure 3.5 Frequency of load forecast adjustments by reason (15-minute market)

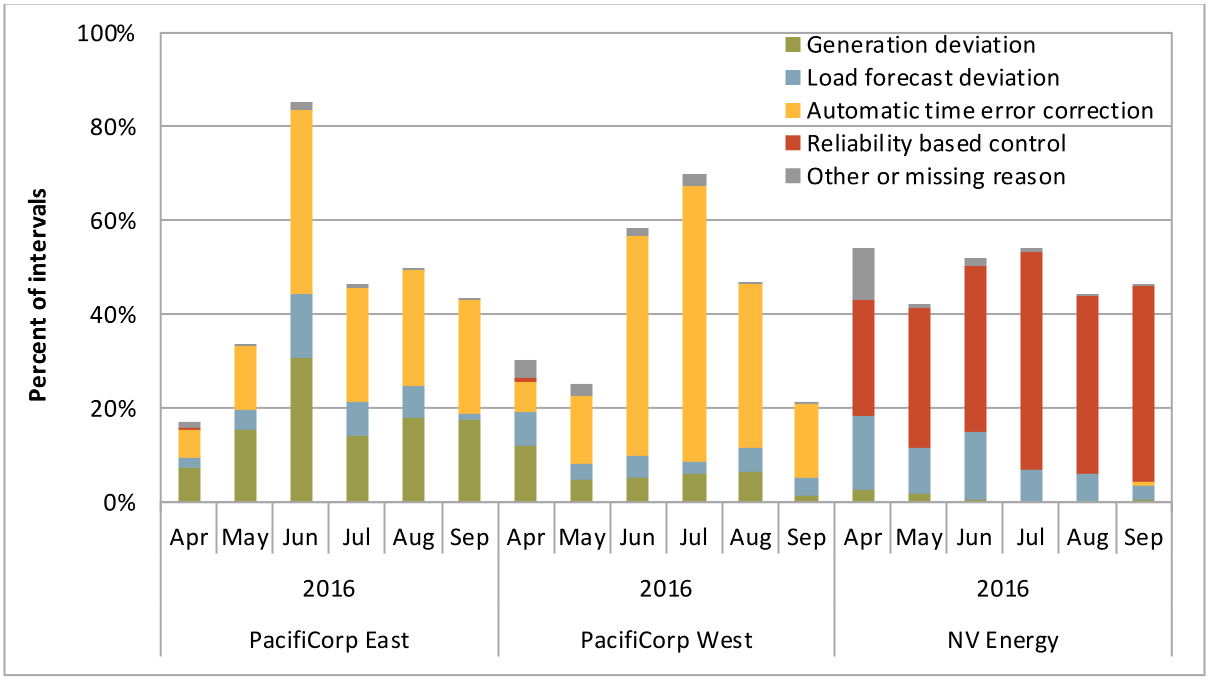
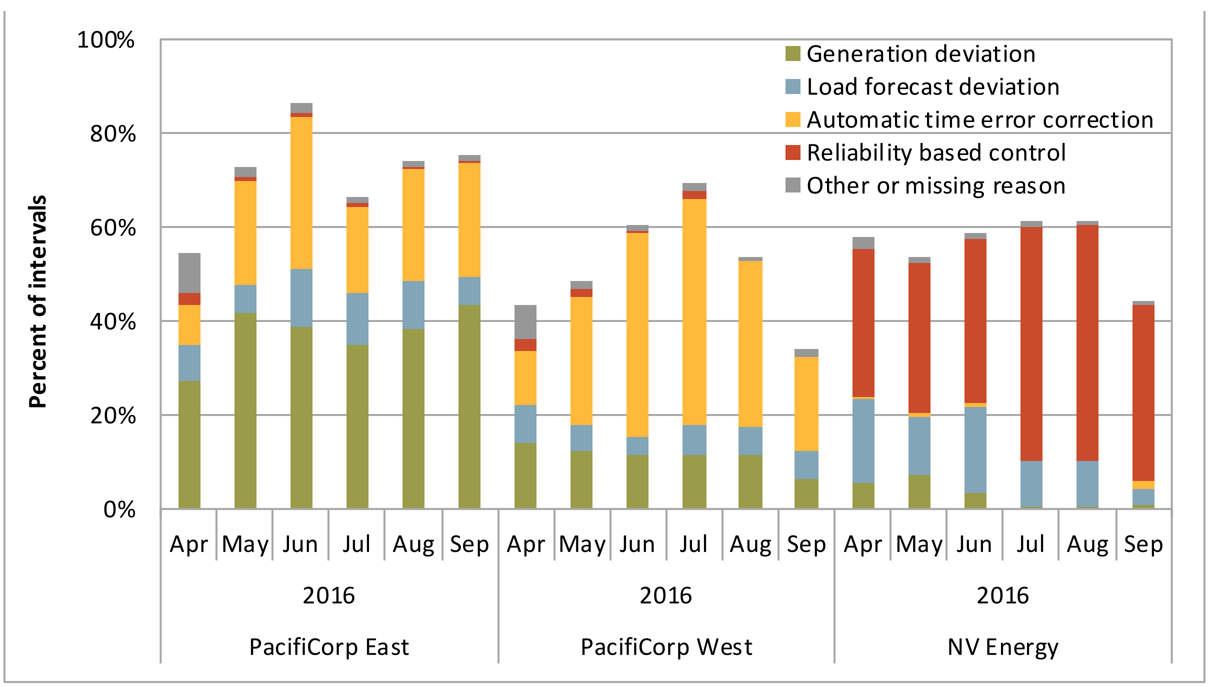


Figure 3.6 Frequency of load forecast adjustments by reason (5-minute market)



Impact of load adjustments on prices

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

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

When the load bias limiter is triggered it results in a feasible market solution in the pricing run such that the price is set by the highest priced supply dispatched, rather than the $1,000/MWh shortage penalty price for the power balance constraint if there is insufficient upward ramping capacity. The resulting price is often significantly less than the $1,000/MWh penalty price. The functionality of the load bias limiter is similar to the price discovery feature that was in effect in the energy imbalance market until this spring as they both set price to the offer price of the last dispatched resource during power balance relaxations.[43]

In the third quarter, the load bias limiter feature triggered during about 55 percent of the power balance relaxations from insufficient incremental energy observed in all energy imbalance market areas. However, the power balance constraint was relaxed very infrequently during the third quarter, and therefore the load bias limiter had a very minor impact on overall prices.

Table 3.2 shows estimated prices if prices were set at the $1,000/MWh penalty price during intervals when the load bias limiter was triggered. Table 3.2 shows that the load bias limiter lowered average 15-minute and 5-minute prices in NV Energy by just over $0.60/MWh. For PacifiCorp, the load bias limiter is estimated to have reduced 5-minute market prices by less than $0.22/MWh.

[43] The price discovery waiver expired for both PacifiCorp areas in March 2016 when the ISO implemented the available balancing capacity mechanism. The price discovery waiver expired for NV Energy at the end of May 2016. The price discovery mechanism was active during any interval when there was a power balance relaxation, regardless of load adjustments.

Table 3.2 Impact of load bias limiter on EIM price (July – September)

	Bilateral trading hub range		Average EIM price	Estimated EIM price without load bias limiter	Estimated impact of load bias limiter	
	Low	High			Dollars	Percent
PacifiCorp East						
15-minute market (FMM)	$27.51	$30.03	$27.62	$27.60	$0.02	0.1%
5-minute market (RTD)	$27.51	$30.03	$24.95	$25.16	-$0.21	-0.8%
PacifiCorp West						
15-minute market (FMM)	$27.51	$30.03	$27.60	$27.55	$0.05	0.2%
5-minute market (RTD)	$27.51	$30.03	$22.35	$22.50	-$0.14	-0.6%
NV Energy						
15-minute market (FMM)	$27.35	$29.70	$30.01	$30.61	-$0.60	-2.0%
5-minute market (RTD)	$27.35	$29.70	$29.31	$29.96	-$0.65	-2.2%

DMM has provided recommendations to the ISO on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load adjustments on creating power balance relaxations. Specifically, DMM has recommended considering the adjustment based on a combination of factors including the *change* in load adjustment from one interval to the next and the *duration* of an adjustment rather than solely the *absolute* value of any load adjustment.

4 Special issues

This section provides an update on the special measures implemented to mitigate potential impacts of limitations on gas availability in Southern California because of the moratorium imposed on the Aliso Canyon natural gas storage facility. Below are the key observations and findings.

- During the third quarter, ISO operators did not use many of the operational tools made available by the temporary tariff provisions. Thus, there was no need to suspend virtual bidding or deem transmission paths uncompetitive during the quarter.
- DMM did not observe any systematic need for the additional bidding flexibility afforded to the affected natural gas generators in Southern California, though there were a few instances of increased natural gas volatility during periods of high load. Correspondingly, DMM did not find any significant detrimental impacts in terms of market power and excessive or unnecessary market uplift costs as a result of this increased flexibility.
- The ISO has applied for FERC approval to extend the temporary tariff amendments for one additional year. Overall, DMM is supportive of this proposal. However, we recommend additional enhancements including making the update of natural gas prices for the day-ahead permanent and applying mitigation to exceptional dispatches that are made to manage natural gas limitations.

4.1 Aliso Canyon gas-electric coordination

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

The ISO, Los Angeles Department of Water and Power, California Energy Commission and California Public Utilities Commission published in April 2016 a risk assessment and technical report finding that the limited operability of Aliso Canyon posed a significant risk to electric reliability during the summer months of 2016.[44] To address these reliability concerns, these agencies took many steps to manage system conditions, including the ISO which filed for FERC approval of several temporary tariff

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

amendments in May 2016.[45] These tariff amendments, which are described in further detail below, were approved by FERC on June 1 to remain in effect until November 30, 2016.[46]

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

A follow-up risk assessment study, focusing on the upcoming winter months, was published in August.[47] In September, FERC organized a technical conference where both the ISO and DMM discussed the effectiveness of the temporary Aliso Canyon measures. Following these studies and discussions, the ISO in October 2016 filed for FERC approval to allow most of the tariff amendments to remain in effect through November 30, 2017.[48] DMM filed comments that, overall, were supportive of the ISO's filing, but also recommended additional enhancements including making the update of natural gas prices for the day-ahead permanent and applying mitigation to exceptional dispatches that are made to manage natural gas limitations.[49]

Operational tools and corresponding mitigation measures

The ISO has developed a set of operational tools to manage potential gas-system limitations that allows operators to restrict the gas burn of ISO natural gas-fired generating units. The tools, which were implemented as a set of nomogram constraints, can be used to limit either the total gas burn or deviations in gas burn compared to day-ahead schedules. These tools were available to operators beginning June 2. However, based on observed system conditions, operators did not elect to enforce these constraints during the second or third quarters.[50]

The temporary tariff amendments also give the ISO authority to reserve internal transmission capacity to manage issues related to a constrained natural gas system. For example, the ISO may need to reserve transmission capacity on Path 26 in the day-ahead market to create additional flexibility that could be used in real time. As with the gas burn constraints, operators have had this ability since the beginning of

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

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

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

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

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

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

June but based on system conditions chose not to impose them. The ISO in its October FERC filing did not ask that this particular tariff amendment be extended beyond November 30, 2016.

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

The tariff amendments also included the ability of the ISO to limit or suspend virtual bidding. A restriction on virtual bidding may be necessary if operators choose to reserve transmission capacity in the day-ahead market for use in the real-time market or if operators need to use the gas nomogram constraints differently in the day-ahead and real-time markets as these actions could cause systematic and predictable price differences between day-ahead and real-time prices. Virtual bidders could take advantage of such price differences, which may undo the intent of virtual bidding and could have negative impacts on market efficiency. Because the ISO did not implement the gas constraints or limit flows on internal transmission, there was no need to consider suspending virtual bidding this summer.

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

Additional bidding flexibility for SoCalGas resources

Starting July 6, to allow natural gas-fired generators in the SoCalGas system to reflect higher same-day natural gas prices and to avoid having these resources dispatched for system needs in the event of constrained gas conditions in Southern California, the ISO adjusted the gas price indices used to calculate the commitment cost caps and default energy bids in the real-time market for natural gas-fired generators on the SoCalGas systems. A 75 percent adder was included in the fuel cost component used for calculating proxy commitment costs for resources on the SoCalGas systems in real time. The ISO also included a 25 percent adder for the fuel cost component of default energy bids in the real-time market. The 75 percent and 25 percent adders implemented by the ISO were based on analysis presented by DMM in its comments on the final Aliso Canyon gas-electric coordination proposal.[51]

DMM's analysis of same day natural gas price volatility in Southern California during the summer months shows that this additional flexibility has been sufficient to cover the vast majority of same day natural gas transaction prices. For example, of the same day traded volume observed on the InterContinental Exchange (ICE) at the SoCal Citygate during June through September 78 percent was less than 10 percent higher than the next day index and 99.6 percent of same day traded volume was

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

less than 25 percent higher than the next-day index price. A more detailed analysis and discussion of the increased bidding flexibility is available in DMM's comments to the ISO's October FERC filing.[52]

Resources were also granted the ability to rebid their commitment costs in the real-time market for hours without day-ahead schedules or for hours spanning minimum run times if committed in the real-time market. This ability was activated on June 2. As discussed in DMM's comments to the ISO's October filing, almost all of the capacity that made use of the ability to rebid commitment costs with the additional headroom were bid in by one scheduling coordinator and the bidding pattern did not appear linked to changes in same day price movements. DMM believes this indicates that the 75 percent gas scalar for commitment costs did not end up having a significant benefit in terms of helping to manage gas use this summer. Conversely, DMM's analysis did not find that the ability to rebid commitment costs with a scalar adder had a significant impact on total bid cost recovery payments, nor did we find other detrimental market effects during this period. However, we remain prepared to recommend lowering these adders should we identify any market harm.[53]

In addition to these tools, the ISO asked in its May FERC filing for permission to use a more timely natural gas price for calculating default energy bids and proxy commitment costs in the day-ahead market. With this modification, the ISO would base natural gas price indices on next-day trades from the morning of the day-ahead market run instead of indices from the prior day. The target implementation date for this measure was July 6. However, this change was not implemented during the third quarter because the ISO was not able to confirm that this price would be consistent with a FERC policy statement on natural gas indices.[54] FERC issued an order on this motion for clarification on October 20, confirming that the price update is consistent with the policy statement.[55] Consequently, the ISO implemented the new methodology on October 22. DMM is very supportive of this change and recommended in its October 20 filing that this be permanently extended.[56]

Exceptional dispatch mitigation

While the ISO did not use operational tools to manage gas limitations this summer, it did use exceptional dispatches to help manage a broader set of conditions affecting gas supply in Southern

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

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

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

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

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

California. However, at this time, the ISO is not able to mitigate exceptional dispatches for gas constraints, only noncompetitive transmission constraints and a few other specific reasons. As part of our FERC filing on October 20, DMM has recommended that incremental and decremental exceptional dispatches issued to manage Aliso Canyon gas issues be considered non-competitive and subject to market power mitigation because of the potential for high market concentration of resources that could be exceptionally dispatched to address the gas constraints.[57] DMM does not believe this issue should require an extensive market design and stakeholder process to address. However, if the ISO believes it will take a major effort to address this issue, DMM recommends that the ISO and FERC place a much higher priority on addressing other issues identified by DMM as part of the 2017 stakeholder initiatives catalog process.[58]

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

[58] See *Comments on the Draft Stakeholder Initiatives Catalog*, Department of Market Monitoring, September 30, 2016: http://www.caiso.com/Documents/DMMComments_Draft2017StakeholderInitiativesCatalog.pdf.