California Independent System Operator Corporation

California ISO

Q1 2016 Report on Market Issues and Performance

June 13, 2016

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Executive summary

This report covers market performance during the first quarter of 2016 (January – March). Key highlights during this quarter include the following:

- The addition of NV Energy into the energy imbalance market in December 2015 added significant transfer capacity between the EIM areas and the ISO. With the new transfer capacity, real-time prices have become more uniform between most ISO and EIM areas. Very little congestion has been observed between the ISO and EIM areas, or between the EIM areas, which has also contributed to more uniform prices between the ISO and EIM.
- Overall, the ISO and NV Energy tend to be net importers in the EIM, while the PacifiCorp areas tend to be net exporters. EIM transfers during peak solar hours tend to be from the ISO to NV Energy and PacifiCorp East, while transfers during off-peak hours tend to be from PacifiCorp East to NV Energy and the ISO.
- Overall, performance of the EIM improved and remained very good during the first quarter. The percentage of intervals declined during the quarter when either the flexible ramping constraint or energy power balance constraint was relaxed to allow market software to balance modeled supply and demand.
- The ISO increased the regulation requirements in the day-ahead and real-time markets in late February, in response to growing needs for regulation to maintain reliability during periods of high renewable generation variability. Prices for regulation also increased as a result of the new requirements. Because both the procured amount and corresponding prices of regulation increased, the cost for procuring regulation increased by over 300 percent – from about $100,000 to over $400,000 per day.
- Solar generation set a new peak during the quarter at just over 7,500 MW and routinely provided 5,000 MW during midday hours.[1] This is an increase from about 4,400 MW during the same midday hours last quarter. The significant increase in solar generation, coupled with higher seasonal hydro and wind generation, caused an increase in the percentage of real-time intervals with negative prices.
- The frequency of flexible ramping constraint relaxations declined significantly since the fourth quarter of 2015 in PacifiCorp East. Constraint relaxations were frequent in October and most of November. This had a significant effect on PacifiCorp East prices during those months and increased prices by roughly the $60/MWh shadow price for the flexible ramping constraint during intervals when the constraint was binding. However, flexible ramping constraint relaxations were infrequent at the end of November and throughout December after the return of generation from outages and the addition of NV Energy into the EIM.

Other highlights in the first quarter include the following:

[1] Hours ending 11 through 16 were used to calculate solar generation during midday hours, as output during these hours is relatively stable.

- Day-ahead and 15-minute prices for the quarter continued to decrease to the lowest levels in the past 15 months during both peak and off-peak periods. This was driven by lower natural gas prices, modest loads, and increased output from renewable resources.
- Prices in the day-ahead market were higher than real-time market prices for most of the quarter, particularly during peak load hours where day-ahead prices averaged $6/MWh more than 15-minute prices and $12/MWh more than 5-minute prices.
- The frequency of negative prices in the 15-minute and 5-minute markets increased to around 4 percent and 7 percent of intervals, respectively. This was driven by market conditions in March where 5-minute prices were negative during 14 percent of intervals, typically in the late morning and afternoon hours. This primarily occurred as a result of low loads and increased renewable generation.
- There was also an increase in the frequency of positive price spikes from the previous quarter, particularly in March. This was largely because of price spikes occurring on March 5, which were a result of lower than forecast renewable generation.
- Congestion during this quarter was low and had a relatively small impact on average load area prices. Much of the congestion in the first quarter was due to transmission outages. In the SCE area, congestion decreased prices by $0.17/MWh (0.7 percent) in the day-ahead market and by $0.09/MWh (0.4 percent) in the 15-minute market. Congestion increased day-ahead prices in PG&E and SDG&E areas by about $0.13/MWh (0.5 percent) and $0.81/MWh (3 percent), respectively, and had a similar effect in the 15-minute market.
- Bid cost recovery payments were over $15 million in the first quarter, compared to about $20 million in the fourth quarter of 2015 and $13 million in the first quarter of 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $10 million in the first quarter, which was down from about $13 million in the previous quarter. Day-ahead and residual unit commitment bid cost recovery were both fairly consistent with the previous quarter at about $3 million each.
- Virtual supply exceeded virtual demand by an average of about 800 MW per hour, compared to about 300 MW of net virtual supply in the previous quarter. Total convergence bidding revenue, adjusted for bid cost recovery charges, was about $1.3 million in the first quarter, a decrease from about $5.5 million in the previous quarter.
- Overall payments made for the flexible ramping constraint decreased to about $1.3 million for the first quarter compared to about $2 million for the previous quarter. The decrease in total payments was driven by a large decrease in payments to generators in the PacifiCorp areas. Because of this decrease, the average payments per megawatt-hour of load were roughly equal across all balancing areas in the first quarter.
- The percentage of intervals where the flexible ramping constraint needed to be relaxed because of procurement shortfalls in the PacifiCorp areas decreased substantially compared to the fourth quarter of 2015. The percentage of such intervals decreased from 10 percent to 2 percent in PacifiCorp East and from 3 percent to less than 1 percent in PacifiCorp West on a quarterly basis.
- The percentage of intervals when the flexible ramping constraint bound, but was not relaxed because of procurement shortfalls, continued to be frequent in EIM areas. DMM's review of these

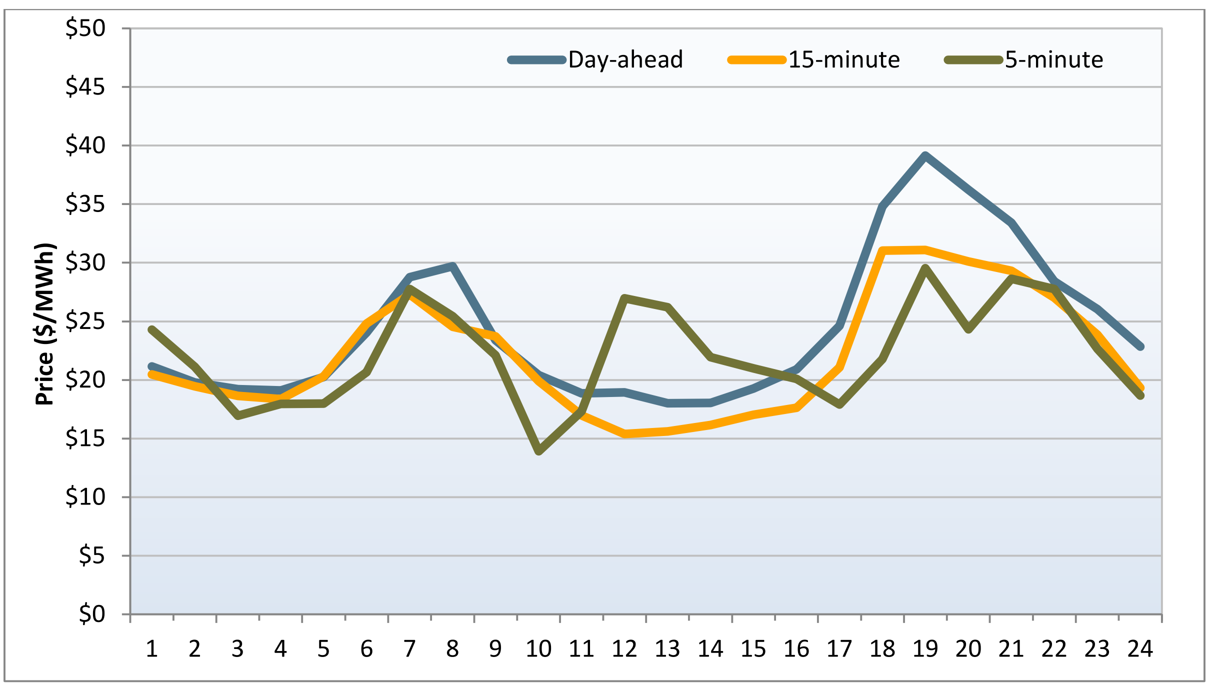
intervals reveals that they often have only a marginal impact on area prices, and are a reflection of supply conditions in the EIM areas. Within the NV Energy area, for instance, resources providing flexible ramping capacity generally have marginal costs below prevailing system marginal prices. This difference, or opportunity cost, sets shadow prices for the flexible ramping constraint.

Energy market performance

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

Average energy prices declined during the first quarter. Average prices in the day-ahead and real-time markets were lower in the first quarter than any other quarter since the implementation of nodal markets in 2009. Prices decreased because of continued lower natural gas prices and increased renewable generation. Prices in the 15-minute market were lower than day-ahead prices and followed a similar pattern during the quarter. Prices in the 5-minute market were also lower than day-ahead prices but were more volatile. Prices in the middle of the day, during peak solar generation, were consistently lower than prices during off-peak hours in the day-ahead and 15-minute markets. Overall higher percentages of intervals where renewable generating units set 5-minute prices pushed these prices below 15-minute averages, but power balance constraint relaxations – mostly on one specific day in March where renewable forecasts were low – caused higher 5-minute prices than 15-minute prices during some hours of the day.

Figure E.1 Hourly system marginal energy prices (January – March)



Upward price spikes increased in March, but remained low overall in the first quarter. In the first quarter, the frequency of price spikes in the 5-minute market was about 0.7 percent, up slightly from 0.6 percent in the fourth quarter of 2015. This was similar to prior quarters. In particular, shortages on

March 5, mostly from under-scheduled solar generation, resulted in multiple power balance shortages on this day.

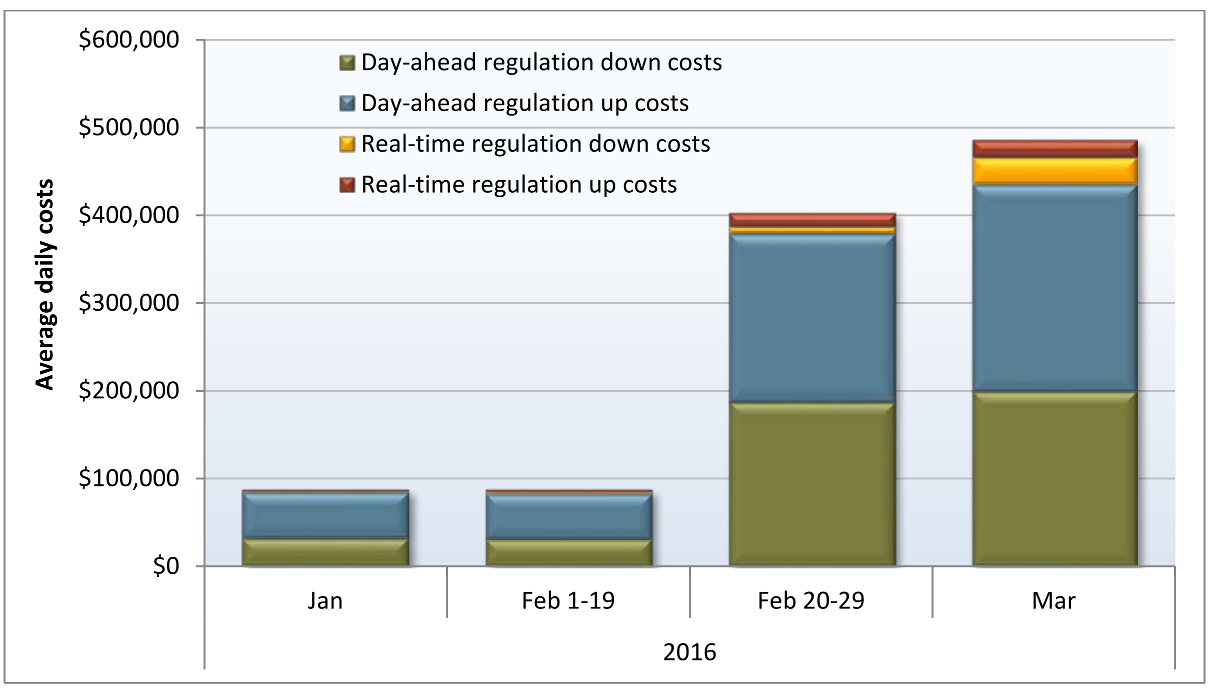
Negative prices were more frequent in the first quarter, particularly in March. Negative prices were more frequent in the 5-minute market, occurring in almost 7 percent of intervals during the quarter, compared to about 2 percent of intervals in the previous quarter and about 6 percent of intervals in the first quarter of 2015. Negative prices were particularly persistent during March, when about 14 percent of intervals in the 5-minute market had negative prices. This was largely the result of low loads and high availability of renewable generation, which included hydro, wind and solar, during the quarter.

Virtual bidding volumes and returns decreased in the first quarter. During the first quarter total virtual trading volume decreased to 2,700 MW from 2,900 MW in the previous quarter. Moreover, virtual bidding net revenues decreased to about $3.2 million in the first quarter from $6.9 million in the fourth quarter. Virtual supply had significant returns, at about $6.2 million, while virtual demand had net payments of about $3 million. Virtual supply revenues have typically exceeded virtual demand revenues during recent quarters. Average hourly virtual supply positions outweighed virtual demand positions by 800 MW for the quarter.

Special issues

Regulation requirements increased, resulting in higher prices and significantly higher payments. Requirements for regulation up and regulation down roughly doubled on February 20. Prior to this date, requirements were set between 300 MW and 400 MW for both services. Afterwards, the requirements were set between 600 MW and 800 MW. Requirements reached 800 MW on several days when high amounts of renewable generation were forecast and ISO operators required additional regulation availability to accommodate potential renewable generation volatility.

Figure E.2 Average daily regulation procurement costs (January – March)



As requirements increased, prices for these ancillary services increased as well. Prices for both regulation services roughly tripled, from about $5/MWh to about $15/MWh. With the increase in prices and requirements, total payments for regulation increased significantly from less than $100,000 to over $400,000 per day, as shown in Figure E.2.

While the flexible ramping constraint bound frequently in the EIM areas, it was relaxed infrequently. Average flexible ramping requirements in each balancing area continued to be at high levels compared to previous periods. The high requirements continued to drive the high frequency of intervals where the constraint bound, but was not relaxed. Because relaxations did not occur, these intervals were not subject to the $60/MWh relaxation parameter price. Relaxations in the fourth quarter of 2015 caused PacifiCorp East prices to increase, but with fewer relaxations in the first quarter prices were more in line with bilateral market prices. In the NV Energy area, the constraint bound – but was not relaxed – during more than 80 percent of intervals in the first quarter, which is a higher rate observed than in any other area.

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

1 Market performance

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

- Day-ahead and 15-minute prices for the quarter continued to decrease to the lowest levels in the past 15 months during both peak and off-peak periods. This was driven by lower natural gas prices, modest loads, and increased output from renewable resources.
- Prices in the day-ahead market were higher than real-time market prices for most of the quarter, particularly during peak load hours where day-ahead prices averaged $6/MWh more than 15-minute prices and $12/MWh more than 5-minute prices.
- In the first quarter, the frequency of negative prices in the 15-minute and 5-minute markets increased to around 4 and 7 percent of intervals, respectively. This was driven by market conditions in March where 5-minute prices were negative during 14 percent of intervals, typically in the late morning and afternoon hours. This primarily occurred as a result of low loads and increased renewable generation.
- There was also an increase in the frequency of positive price spikes from the previous quarter, particularly in March. This was largely because of price spikes occurring on March 5, which were a result of lower than forecast renewable generation.
- Congestion during this quarter was low and had a relatively small impact on average load area prices. Much of the congestion in the first quarter was due to prolonged transmission outages. In the SCE area, congestion decreased prices by $0.17/MWh (0.7 percent) in the day-ahead market and by $0.09/MWh (0.4 percent) in the 15-minute market. Congestion increased day-ahead prices in PG&E and SDG&E areas by about $0.13/MWh (0.5 percent) and $0.81/MWh (3 percent), respectively, and had a similar effect in the 15-minute market.
- Bid cost recovery payments were over $15 million in the first quarter, compared to about $20 million in the fourth quarter of 2015 and $13 million in the first quarter of 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $10 million in the first quarter, down from about $13 million in the previous quarter. Day-ahead and residual unit commitment bid cost recovery were both fairly consistent with the previous quarter at about $3 million each.
- Virtual supply outweighed virtual demand by about 800 MW on average, compared to about 300 MW of net virtual supply in the previous quarter. Total convergence bidding revenue, adjusted for bid cost recovery charges, was about $1.3 million in the first quarter, a decrease from about $5.5 million in the previous quarter.

1.1 Energy market performance

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

Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively. As seen in these figures, average day-ahead market prices continue to be higher than 15-minute market prices. Overall, prices continued to decrease in the first quarter, compared with prices observed in 2015. Lower prices resulted in part from lower natural gas prices and increased output from renewable resources in combination with relatively low loads.

- Average day-ahead prices declined during the first quarter, particularly in February and March. Day-ahead prices in March were notably low in both peak ($21/MWh) and off-peak ($17/MWh) periods. Day-ahead prices for the quarter averaged about $27/MWh during peak periods and $22/MWh during off-peak periods.
- In the first quarter, 15-minute market prices also decreased. Prices in the 15-minute market in March were at the lowest levels in the past 15 months, in both peak ($24/MWh) and off-peak ($20/MWh) periods. Average prices in the 15-minute market were lower than day-ahead prices during the quarter by about $3/MWh in peak periods and $2/MWh in off-peak periods. This continues a trend that began in 2014.
- Prices in the 5-minute market also trended downward, averaging about $24/MWh during peak periods and $20/MWh during off-peak periods in the quarter. Prices were lowest in March and averaged just $14/MWh in off-peak periods. During March, peak 5-minute market prices averaged about $1/MWh above day-ahead prices, largely driven by real-time energy shortages on one day, March 5, from lower than expected solar generation in the real-time market.

Figure 1.1 Average monthly peak prices – system marginal energy price

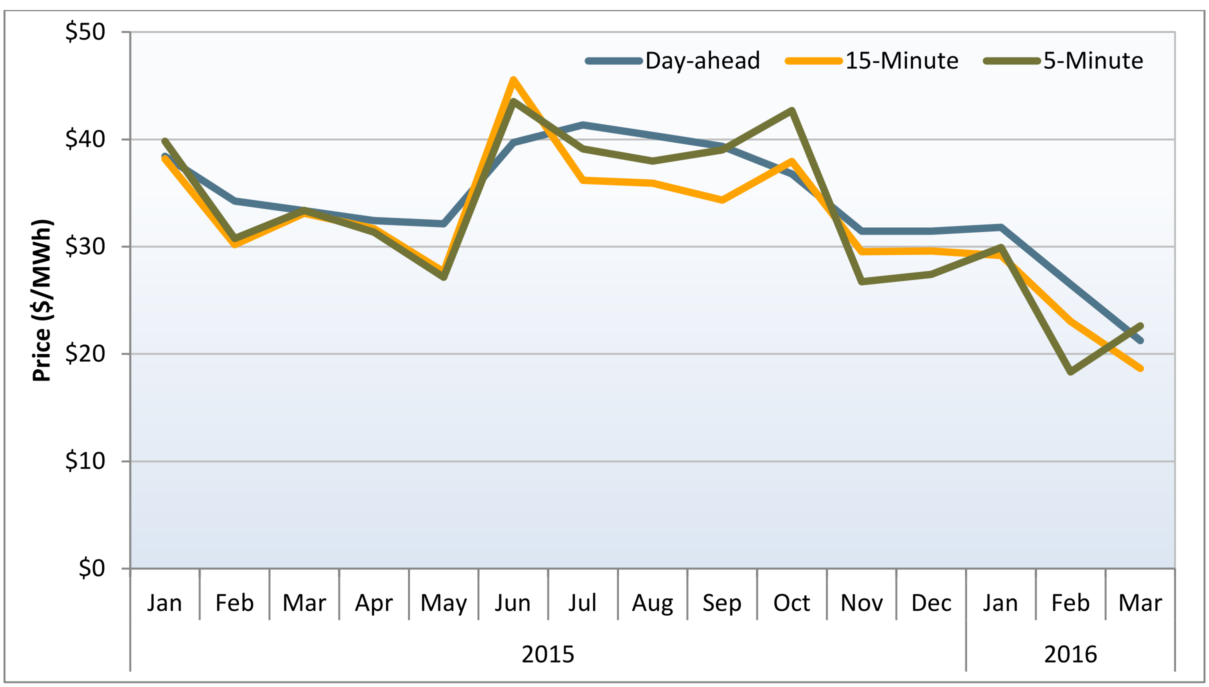


Figure 1.2 Average monthly off-peak prices – system marginal energy price

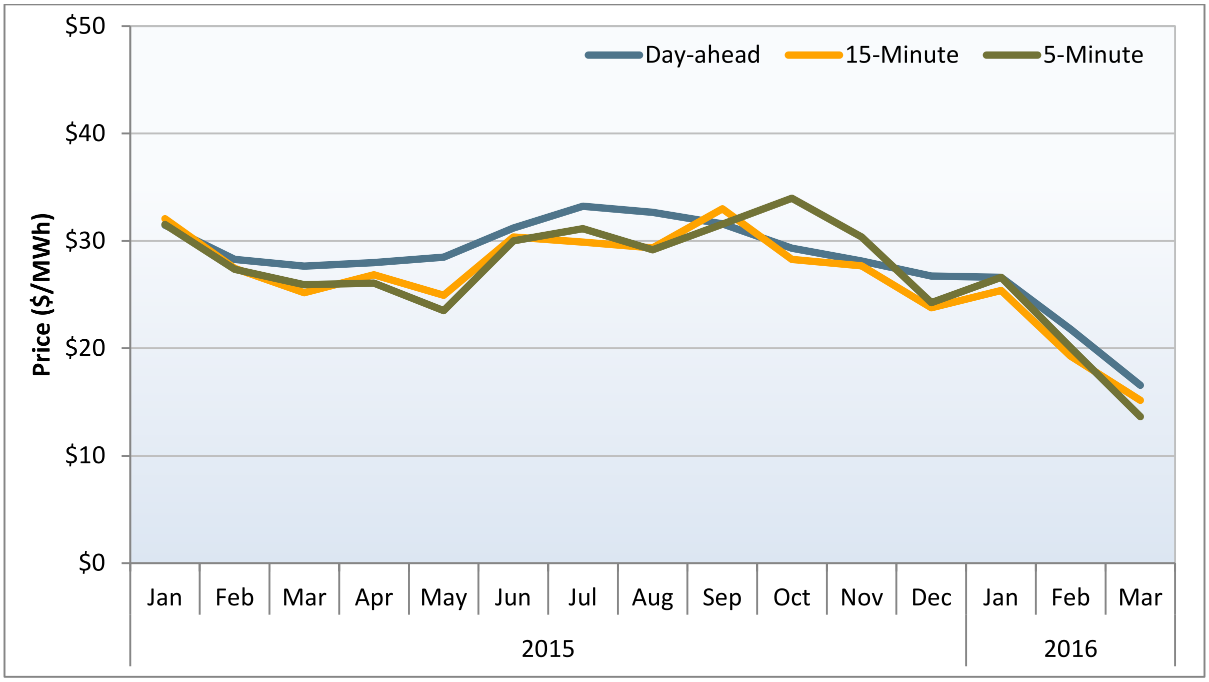


Figure 1.3 Hourly system marginal energy prices (January – March)

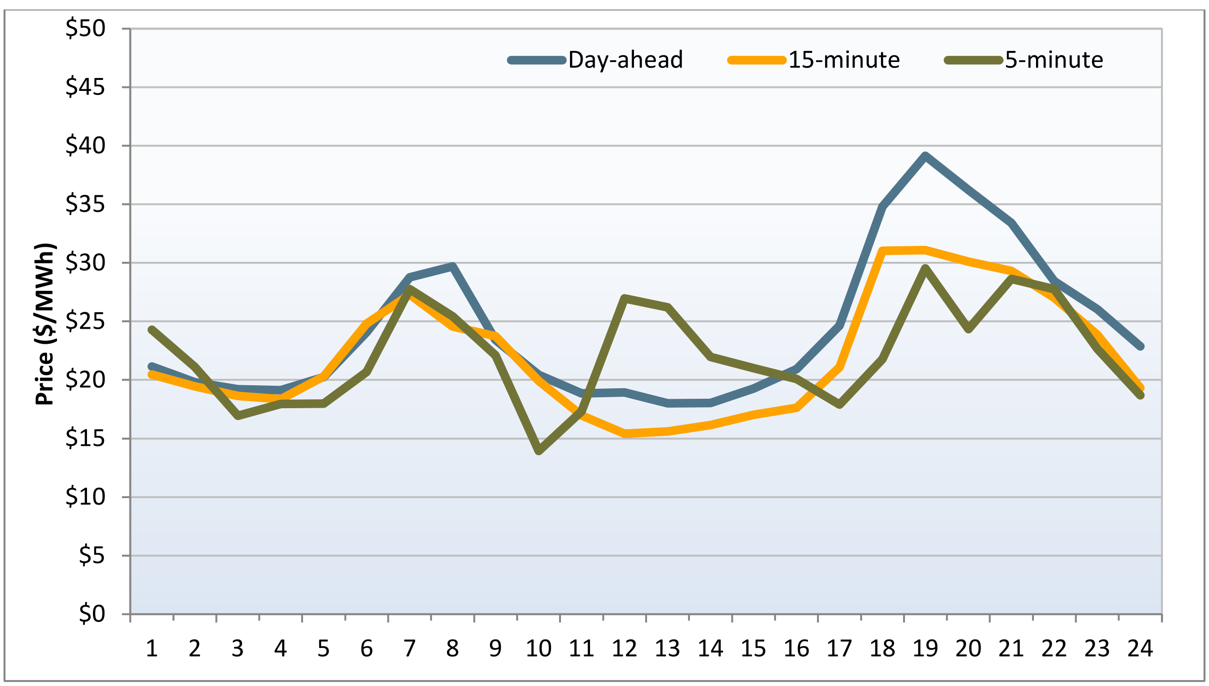


Figure 1.3 illustrates the system marginal energy prices on an hourly basis in the first quarter. The prices in this figure follow the net load "duck" pattern as energy prices are low during the early morning, mid-

day, and late evening hours, and are highest during the late morning and early evening peak hours. The low prices during the middle of the day represent times when low-priced solar generation is highest and significantly reducing net demand. Solar generation peaked at just over 7,500 MW during the quarter.

The figure also shows that average prices in the 15-minute market were less than day-ahead prices during most hours of the day. Notably, prices in the day-ahead market were significantly higher than the 15-minute and 5-minute markets in peak hours ending 18 through 20. In these hours, day-ahead market prices averaged almost $6/MWh and $12/MWh higher than 15-minute and 5-minute market prices, respectively.

1.2 Real-time price variability

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

Frequency of price spikes

The frequency of positive price spikes grew slightly in the 15-minute and 5-minute markets in the first quarter compared to the previous quarter, but remained relatively infrequent overall. Prices above $250/MWh were observed in only about 0.1 percent of intervals in the 15-minute market and 0.7 percent of intervals in the 5-minute market.

Figure 1.4 and Figure 1.5 show the frequency of positive price spikes occurring in the 15-minute and 5-minute markets, respectively. The frequency of 15-minute price spikes remained low, averaging just 0.1 percent of intervals in the first quarter. This is similar to previous quarters. In contrast, the frequency of price spikes in the 5-minute market was about 0.7 percent of intervals in the first quarter, up from 0.6 percent in the fourth quarter. This was mostly driven by an increase in the frequency of positive price spikes in March, where prices above $250/MWh were observed in just over 1 percent of 5-minute intervals. In particular, shortages on March 5 mostly from under-scheduled solar generation in the real-time market resulted in multiple power balance shortages on this day.

Intervals with negative prices were more common than high price intervals in the first quarter and occurred more frequently in comparison to the previous two quarters. Figure 1.6 and Figure 1.7 show the frequency of negative prices in the 15-minute and 5-minute markets during the past 15 months. In the 15-minute market, negative prices were observed in almost 4 percent of intervals during the quarter, an increase from about 1 percent in the previous quarter and 2 percent in the first quarter of 2015. Negative prices were more frequent in the 5-minute market, occurring in almost 7 percent of intervals during the quarter, compared to about 2 percent of intervals in the previous quarter and about 6 percent of intervals in the first quarter of 2015.

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

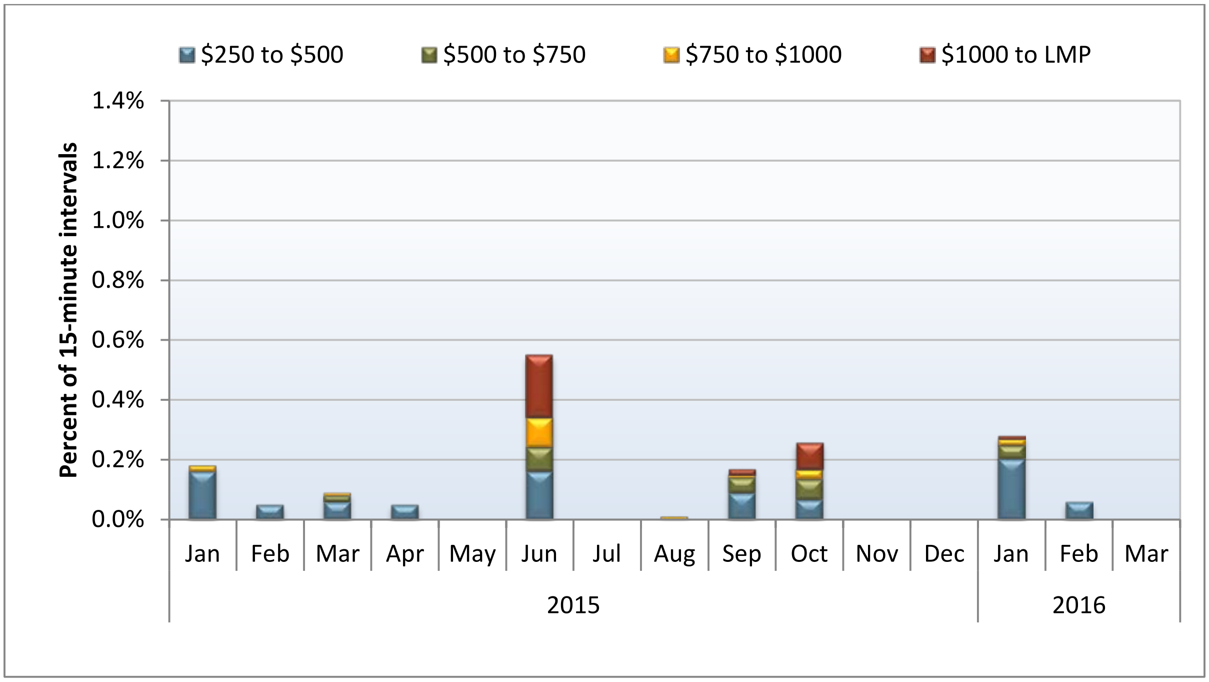


Figure 1.5 Frequency of positive 5-minute price spikes (ISO LAP areas)

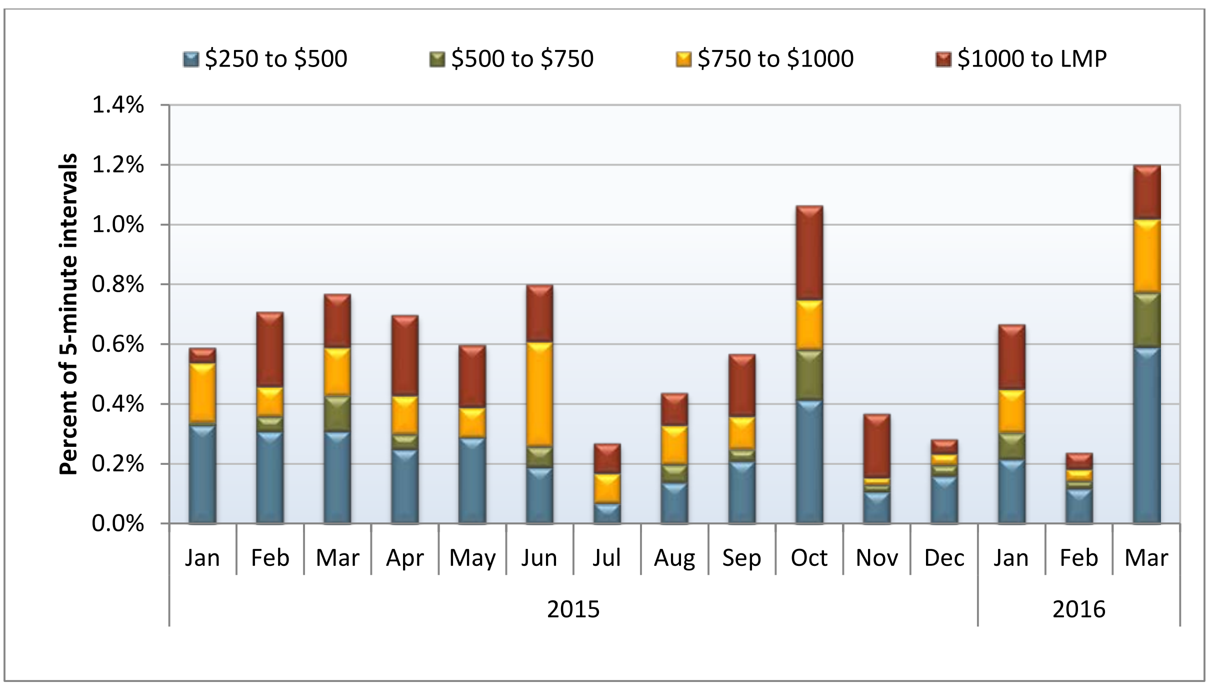


Figure 1.6 Frequency of negative 15-minute price spikes (ISO LAP areas)

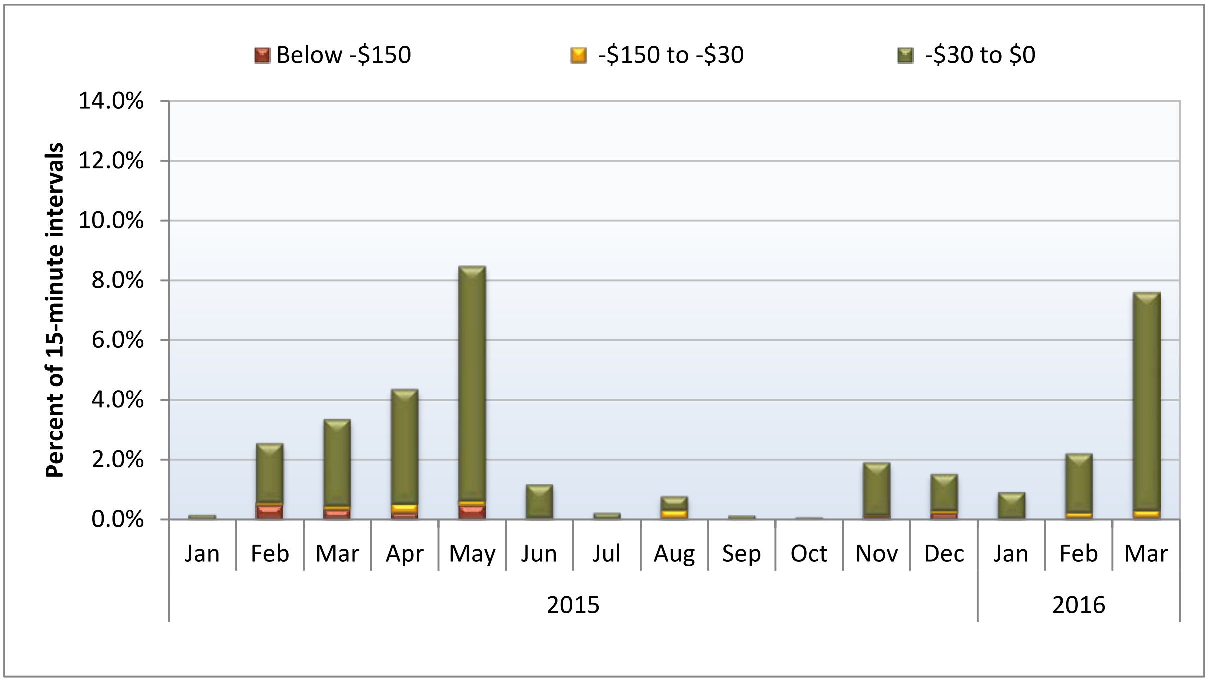
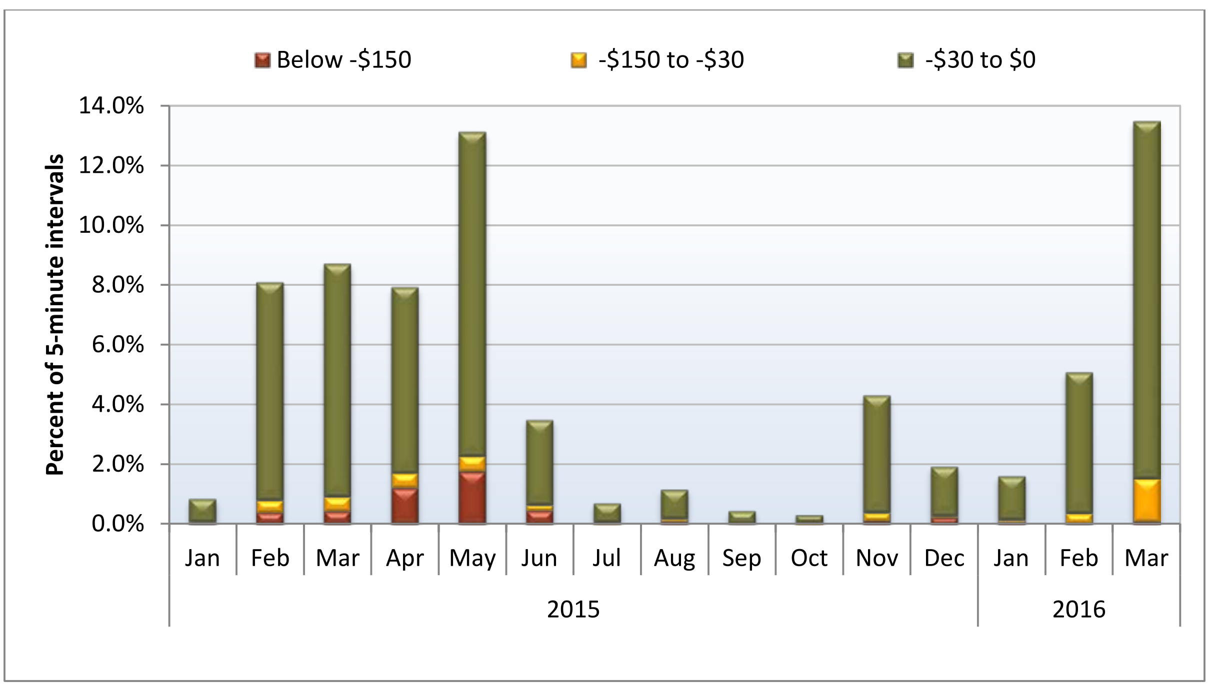


Figure 1.7 Frequency of negative 5-minute price spikes (ISO LAP areas)



Negative prices in March occurred in about 8 percent of intervals in the 15-minute market and about 14 percent of intervals in the 5-minute market. These were among the highest frequencies of negative prices in the previous 15 months. Negative prices between -$30/MWh and $0/MWh typically occurred in the late morning and afternoon hours and were primarily a result of low loads and high availability of renewable generation during those periods. Solar generation set a new record at just over 7,500 MW during the quarter and averaged nearly 5,000 MW during midday hours, compared to about 4,400 MW during the prior quarter and about 4,000 MW during the first quarter of 2015.[2]

1.3 Congestion

Overall, congestion had a small impact on load area prices across the ISO in the day-ahead and real-time markets, but was slightly higher when compared to the previous quarter. In the PG&E and SDG&E areas, congestion on the constraints increased prices by $0.13/MWh and $0.81/MWh, respectively, in the day-ahead market, and increased prices by $0.15/MWh and $0.51/MWh in the 15-minute market. Congestion decreased day-ahead and 15-minute SCE area prices by about $0.17/MWh and $0.09/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.

Much of the congestion in the first quarter accrued on Moss Landing-Panoche 230 kV, Barre-Villa Park 220 kV and a constraint modeling Southern California imports (OMS 2319325 PDCI_NG). Moss Landing-Panoche 230 kV bound because of an outage on the nearby Tesla-Metcalf 500 kV line, which was ongoing for almost the entire quarter. Much of the congestion on the Barre-Villa Park 220 kV line occurred early in the quarter from an outage on the nearby Miraloma-Olinda 220 kV line, which ended in mid-January. The constraint representing Southern California imports bound because of an outage on the Pacific DC intertie that returned to service at the end of January.

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 first quarter, but slightly larger than the prior quarter. Most of the constraints that bound were due to prolonged transmission outages with little impact on load area prices in the day-ahead market.

The constraint that bound most frequently in the PG&E area in the day-ahead market was Moss Landing-Panoche 230 kV from an outage on the Tesla-Metcalf 500 kV line. This constraint was congested in about 30 percent of total hours, as shown in Table 1.1. While the constraint bound, the associated shadow price increased PG&E area prices by just over $1/MWh, and decreased prices in the SCE and SDG&E areas by about the same amount.

Similarly, in SCE the Barre-Villa Park 220 kV constraint bound most frequently at about 6 percent of hours in the quarter. The constraint bound from the loss of the Miraloma-Olinda 220 kV line, which returned to service in mid-January 2016. While the constraint was binding, it decreased prices in PG&E and SDG&E areas by about $1/MWh and $0.50/MWh, respectively, and caused price increases of about $1.50/MWh in the SCE area.

[2] Hours ending 11 through 16 were used to compute solar generation during midday hours, as output during these hours is relatively stable. Significant increases in solar generation during midday hours, from 2015 to 2016, is largely a reflection of increases in installed capacity within the ISO during the year.

Finally, the SDG&E constraint that bound most frequently in the first quarter was the Miguel 500/230 kV transformer at about 5 percent of all hours during the quarter. When binding, it increased SDG&E area prices by over $11/MWh and decreased the PG&E prices by about $2/MWh.

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

		Frequency	Q1		
Area	Constraint	Q1	PG&E	SCE	SDG&E
PG&E	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	28.6%	$1.18	-$0.98	-$0.95
	PATH15_S-N	2.3%	$2.34	-$2.05	-$1.92
	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
	PATH26_BG	0.3%	-$2.54	$2.13	$2.01
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	6.1%	-$1.05	$1.52	-$0.50
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	2.2%	-$1.15	$1.50	
SDG&E	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	5.0%	-$1.83		$11.38
	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
	7820_TL 230S_OVERLOAD_NG	1.9%	-$0.20		$2.13
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	1.5%			$2.35
	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
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1	1.2%			$2.62
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1	0.9%	-$0.82		$3.88
	OMS 3636555 McC-Vic_6510	0.9%	-$3.55	$3.01	$3.66
	24016_BARRE _230_24044_ELLIS _230_BR_1 _1	0.8%	-$1.12		$5.31
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.6%	-$1.03		$6.87
	22464_MIGUEL _230_22461_MIGUEL60_138_XF_1	0.6%			$3.17
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.3%	-$4.66	$3.21	$6.61

15-minute market congestion

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

In the PG&E area, the Moss Landing-Panoche 230 kV constraint bound most frequently during the quarter, during about 2 percent of intervals. This congestion was due to an outage on the Tesla-Metcalf 500 kV line, which lasted almost the entire quarter. When the constraint bound it increased the PG&E area price by about $2/MWh, while decreasing SCE and SDG&E area prices by about the same amount.

In the SDG&E area, the Miguel 500/230 kV transformer and the constraint modeling Southern California import constraints were the top two binding constraints during the first quarter, at 1.1 percent and 0.4 percent of all the intervals, respectively. When Miguel 500/230 kV bound, it increased SDG&E prices by about $29/MWh and had no impact on the SCE and SDG&E area prices. In the 15-minute real-time market, when the constraint modeling imports into Southern California bound, it increased prices in SCE and SDG&E areas by about $54/MWh and $60/MWh, respectively, and decreased prices in the PG&E area by $23/MWh. This constraint bound because of an outage on the Pacific DC intertie that returned to service at the end of January.

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

Area	Constraint	Frequency Q1	Q1 PG&E	SCE	SDG&E
PG&E	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	2.2%	$2.29	-$1.89	-$1.80
	PATH15_S-N	0.3%	$18.34	-$19.11	-$18.02
	OMS 2592148 P15 HARD	0.2%	$8.58	-$8.51	-$8.02
	PATH26_N-S	0.1%	-$14.53	$12.27	$11.57
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.1%	-$15.84	$13.89	$12.80
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.4%	-$1.51	$8.20	$1.09
SDG&E	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	1.1%			$28.79
	OMS 2319325 PDCI_NG	0.4%	-$23.09	$54.26	$59.95
	22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1	0.3%			$24.44
	IID-SCE_BG	0.3%			-$7.05
	OMS 3716078 Cry-McC_6510	0.3%	-$5.30	$14.20	$16.15
	7820_TL 230S_OVERLOAD_NG	0.3%	-$1.23		$26.61
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1	0.2%			$23.74
	6510 SOL1_NG	0.1%	-$3.37	$8.63	$9.88
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.1%			$33.98
	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.[3] 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.

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

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load area in the quarter by constraint.[4] Overall this impact was small in PG&E and SCE areas in both day-ahead and real-time markets, but was slightly higher impact in the SDG&E load area.

Congestion in the day-ahead market increased PG&E and SDG&E prices by about $0.13/MWh (0.5 percent) and $0.81/MWh (3 percent), respectively, and decreased the SCE area price by about $0.17/MWh (0.7 percent).

The Moss Landing-Panoche 230 kV constraint had the largest overall impact on prices in the first quarter. This constraint increased prices in the PG&E area by about $0.30/MWh (1 percent) and decreased the SCE and SDG&E area prices by about the same amount.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	$0.34	1.36%	-$0.28	-1.17%	-$0.27	-1.07%
22464_MIGUEL _230_22468_MIGUEL _500_XF_81	-$0.09	-0.37%			$0.57	2.24%
22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1					$0.17	0.66%
OMS 2592148 P15 HARD	$0.06	0.25%	-$0.05	-0.21%	-$0.05	-0.19%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.06	-0.26%	$0.09	0.39%	$0.00	0.00%
PATH15_S-N	$0.05	0.22%	-$0.05	-0.20%	-$0.04	-0.17%
22464_MIGUEL _230_22472_MIGUELMP_ 1.0_XF_1	-$0.02	-0.06%			$0.09	0.37%
OMS 2319325 PDCI_NG	-$0.04	-0.14%	$0.03	0.12%	$0.04	0.14%
OMS 3636555 McC-Vic_6510	-$0.03	-0.13%	$0.03	0.11%	$0.03	0.13%
IID-SCE_BG					-$0.09	-0.34%
OMS 3624980 TL50001_NG	$0.00	-0.02%			$0.05	0.21%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.03	-0.10%	$0.03	0.14%		
24016_BARRE _230_24044_ELLIS _230_BR_1 _1	-$0.01	-0.04%			$0.04	0.17%
22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	-$0.01	-0.03%			$0.04	0.16%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.02	-0.06%	$0.01	0.04%	$0.02	0.08%
7820_TL 230S_OVERLOAD_NG	$0.00	-0.02%			$0.04	0.16%
24016_BARRE _230_24044_ELLIS _230_BR_4 _1	-$0.01	-0.03%			$0.03	0.13%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.04	0.14%
22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1					$0.03	0.12%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.01	-0.03%	$0.01	0.03%	$0.01	0.02%
PATH26_BG	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
22464_MIGUEL _230_22461_MIGUEL60_138_XF_1					$0.02	0.07%
Other	$0.00	0.00%	$0.01	0.03%	$0.04	0.14%
Total	**$0.13**	**0.5%**	**-$0.17**	**-0.7%**	**$0.81**	**3.19%**

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

15-minute price impacts

Table 1.4 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint.[5] During the first quarter of 2016, congestion in the 15-minute market was low in PG&E and SCE areas, with a slightly higher impact on SDG&E area prices. Congestion increased SDG&E area prices by about $0.50/MWh (2 percent) and had a small impact on SCE and PG&E load area prices. Major drivers of congestion in the SDG&E area were the constraint modeling imports into Southern California, from a Pacific DC intertie outage, and the Miguel 500/230 kV transformer outage.

Table 1.4 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
OMS 2319325 PDCI_NG	-$0.09	-0.41%	$0.22	0.97%	$0.24	0.98%
22464_MIGUEL _230_22468_MIGUEL _500_XF_81					$0.31	1.26%
PATH15_S-N	$0.06	0.28%	-$0.07	-0.29%	-$0.06	-0.25%
SCIT_BG	-$0.04	-0.16%	$0.07	0.31%	$0.07	0.30%
30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	$0.05	0.23%	-$0.03	-0.15%	-$0.03	-0.11%
OMS 3716078 Cry-McC_6510	-$0.02	-0.07%	$0.04	0.18%	$0.05	0.19%
22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1					$0.08	0.32%
7820_TL 230S_OVERLOAD_NG	$0.00	0.00%			$0.07	0.30%
OMS 2592148 P15 HARD	$0.02	0.09%	-$0.02	-0.09%	-$0.02	-0.08%
22464_MIGUEL _230_22472_MIGUELMP_ 1.0_XF_1					$0.05	0.19%
22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1					$0.04	0.17%
PATH26_N-S	-$0.02	-0.07%	$0.01	0.06%	$0.01	0.05%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.02	-0.07%	$0.01	0.06%	$0.01	0.05%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	0.00%	$0.04	0.16%	$0.00	0.01%
22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80					$0.04	0.14%
6510 SOL1_NG	-$0.01	-0.02%	$0.01	0.05%	$0.01	0.05%
IID-SCE_BG					-$0.02	-0.09%
24016_BARRE _230_24044_ELLIS _230_BR_4 _1	$0.00	-0.01%			$0.02	0.07%
OMS 3636555 McC-Vic_6510	$0.00	-0.02%	$0.01	0.03%	$0.01	0.03%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	$0.00	-0.01%	$0.00	0.02%	$0.01	0.04%
Other	$0.20	0.89%	-$0.38	-1.71%	-$0.38	-1.54%
Total	**$0.15**	**0.65%**	**-$0.09**	**-0.40%**	**$0.51**	**2.08%**

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

1.4 Bid cost recovery

Estimated bid cost recovery payments for the first quarter totaled over $15 million. This is a decrease when compared to about $20 million in the fourth quarter of 2015, but more than the about $13 million in the first quarter of 2015. Real-time bid cost recovery decreased to about $10 million in the first quarter from about $13 million in the fourth quarter. Real-time bid cost recovery remains the largest category of bid cost recovery, and remained low when compared to historical averages. Bid cost recovery attributed to the day-ahead market was particularly low, at under $3 million.

As seen in Figure 1.9, after netting against real-time revenues in the first quarter of 2016, short-start and long-start resources received about $1.9 million and $1.3 million, respectively, for residual unit commitment bid cost recovery payments, which is up slightly from the prior quarter. A large portion of these payments are a result of high net virtual supply clearing in March, which led to commitment of many short-start resources that were unable to recover their costs in real-time.

Figure 1.8 Monthly bid cost recovery payments

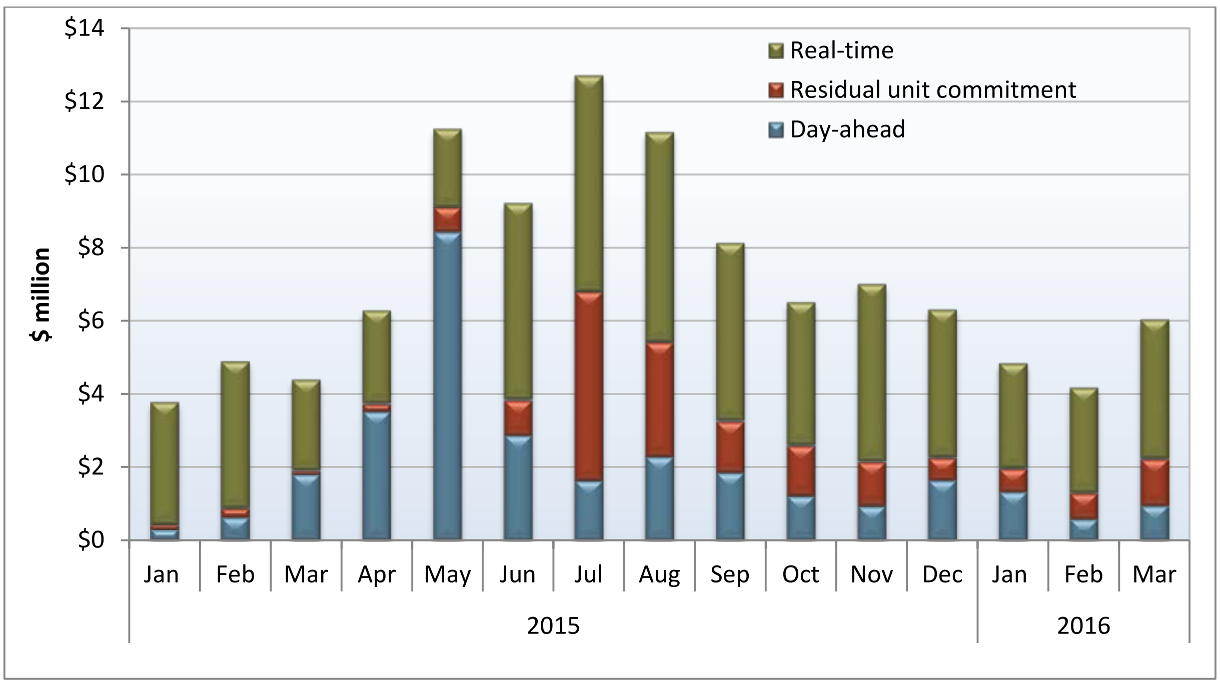
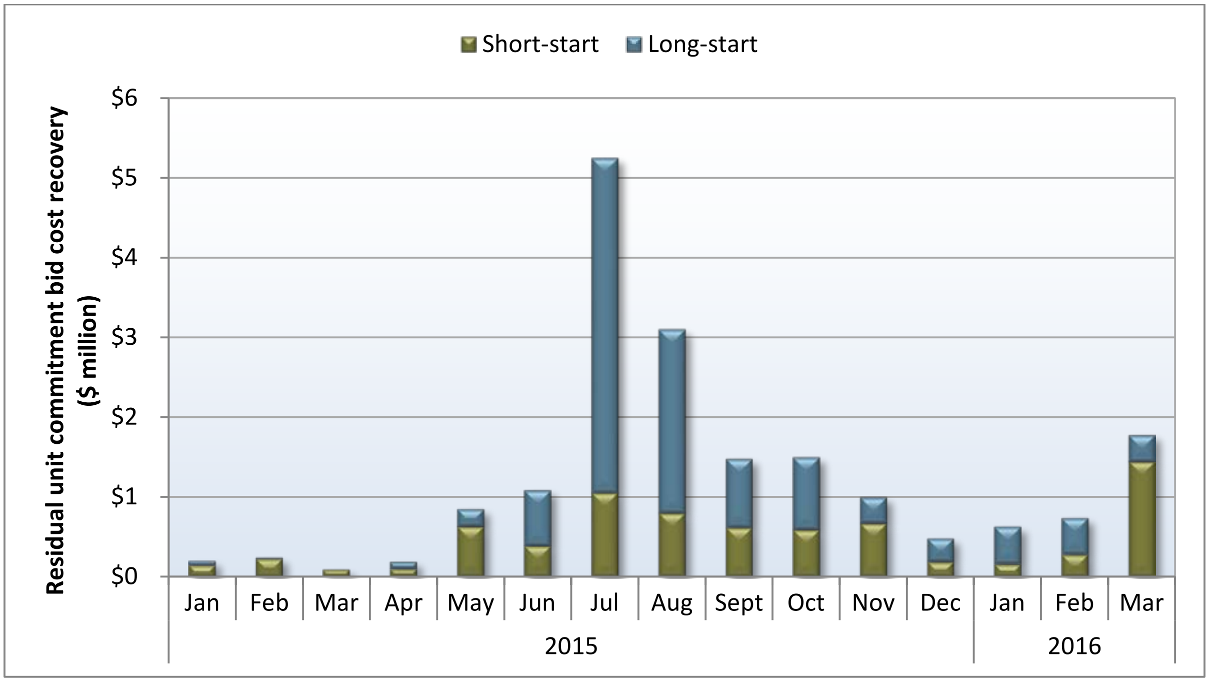


Figure 1.9 Residual unit commitment bid cost recovery payments by commitment type



1.5 Convergence bidding

Participants engaging in convergence bidding continued to earn positive returns in the first quarter. Net revenues from the market in these three months were about $3.2 million. Virtual supply generated net revenues of about $6.2 million, while virtual demand accounted for approximately $3 million in net payments to the market. Total payments to convergence bidders decreased to about $1.3 million after accounting for $1.9 million of virtual bidding bid cost recovery charges.

Offsetting virtual demand with supply bids at different locations is designed to profit from higher anticipated congestion between these locations in the real-time market. This type of offsetting bid represented about 50 percent of all accepted virtual bids in the first quarter, down from 54 percent in the previous quarter. This continues a 3-year trend of decreased offsetting virtual positions observed in the convergence bidding market.

Total hourly trading volumes decreased in the first quarter to about 2,700 MW from 2,900 MW in the previous quarter. Virtual supply averaged around 1,750 MW while virtual demand averaged around 950 MW during each hour of the quarter, compared to around 1,600 MW and 1,300 MW respectively in the previous quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 800 MW on average, an increase from 300 MW of net virtual supply in the previous quarter.

Net revenues for most of the first quarter were positive from net virtual supply positions as prices were generally higher in the day-ahead market than the 15-minute market.[6]

1.5.1 Convergence bidding trends

Total hourly trading volumes decreased in the first quarter to about 2,700 MW from 2,900 MW during the previous quarter. On average, about 55 percent of virtual supply and demand bids offered into the market cleared in the first quarter, which is down from 57 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 800 MW on average, which increased from 300 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours by about 900 MW and 700 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in only hour ending 7 at about 10 MW. In the remaining 23 hours, net cleared virtual supply exceeded net cleared demand. The highest net cleared virtual supply hour was hour ending 15 at over 1,400 MW.

Consistency of price differences and volumes

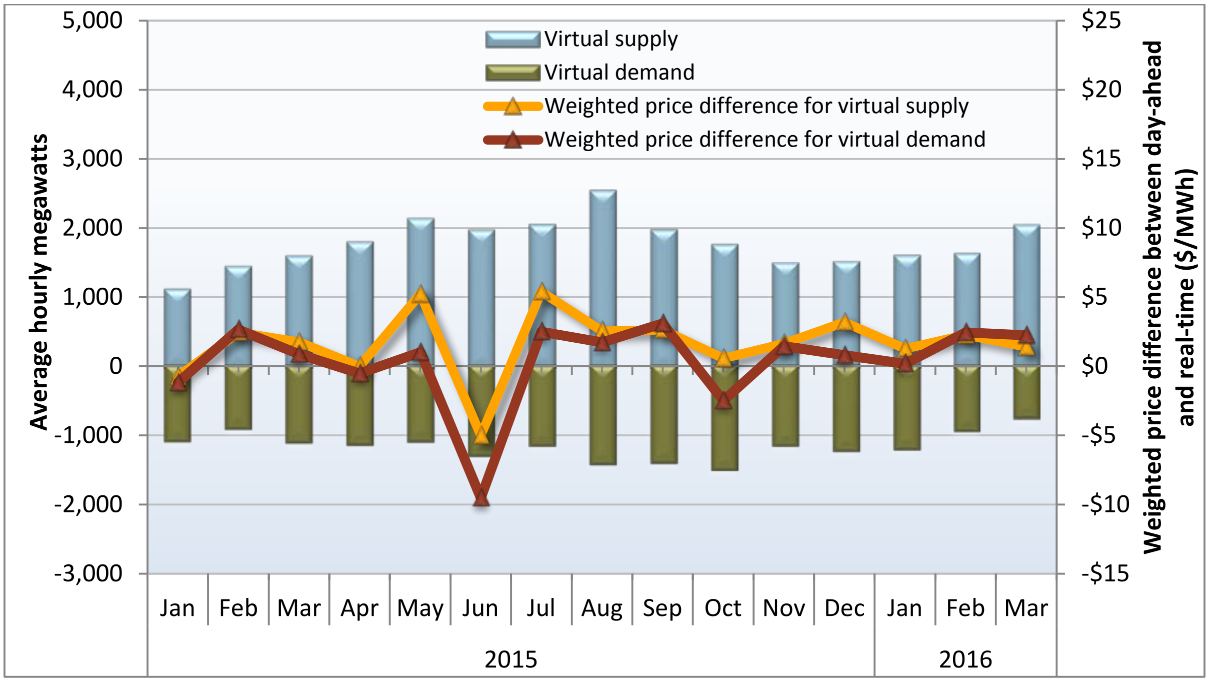
Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. For the quarter, net convergence bidding volumes were consistent with price differences between the day-ahead and real-time markets for an average of 16 hours. Figure 1.10 compares cleared convergence bidding volumes with the volume-weighted average price difference where the virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different locations.

When the red line is positive, it indicates that the weighted average price charged for virtual demand in the day-ahead market was higher than the weighted average real-time price paid for this virtual demand. When positive, it indicates that a virtual demand strategy was not profitable, and thus was directionally inconsistent with weighted average price differences. Virtual demand positions for all three months of the quarter were inconsistent with weighted average price differences for the hours in which virtual demand cleared the market and, thus, were not profitable on average.

The yellow line in Figure 1.10 represents the difference between the day-ahead price paid to virtual supply and the real-time market price at which virtual supply positions are liquidated, weighted by cleared virtual supply bids by time interval and location. Virtual supply positions in the first quarter were, on average, profitable in all three months.

[6] 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.

Figure 1.10 Convergence bidding volumes and weighted price differences



Offsetting virtual supply and demand bids

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

About half of cleared virtual bids in the first quarter were offsetting bids. Offsetting virtual positions accounted for an average of about 670 MW of virtual demand offset by 670 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 50 percent of all cleared virtual bids in the first quarter, which is a decrease from 54 percent in the previous quarter. This continues a downward trend in the proportion of offsetting bids observed over the past three years. While virtual bidding continues to be used to hedge or profit from congestion, offsetting virtual positions were used to a lesser extent than in prior quarters, likely because of the low levels of congestion over the last few years.

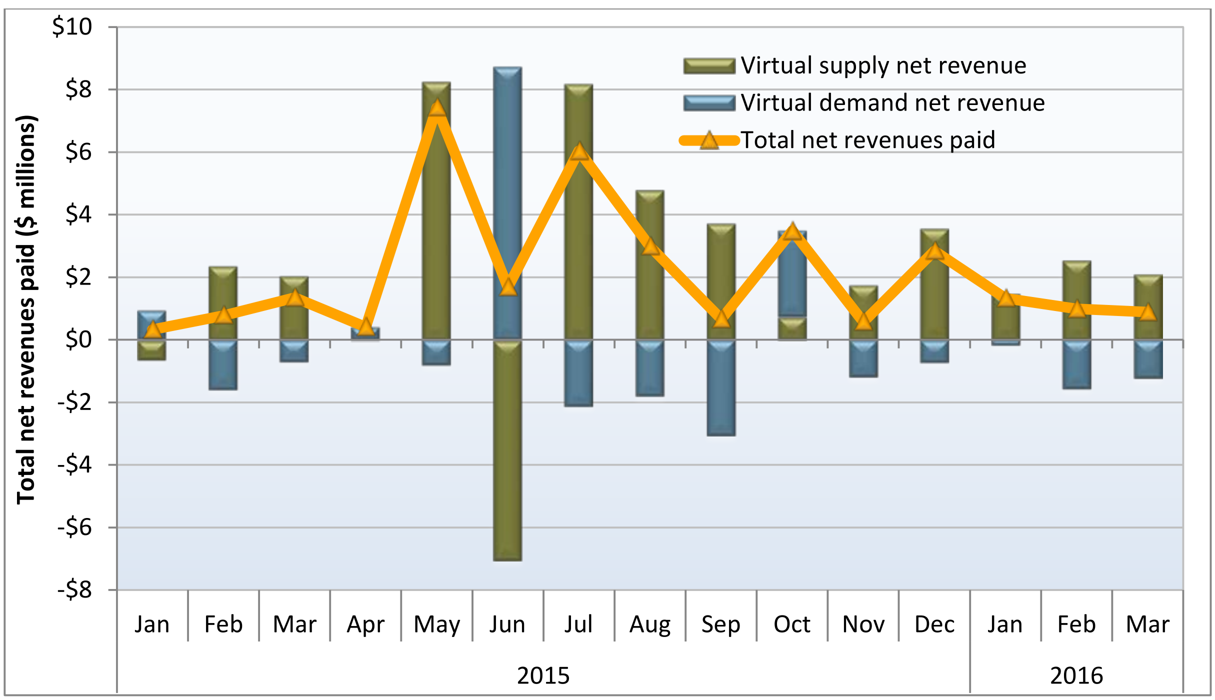
1.5.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the first quarter. Similar to the previous quarter, convergence bidding participants earned positive revenue. In the first quarter, net revenues were about $3.2 million from revenue collected on both virtual supply and demand positions.

Figure 1.11 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- Monthly net revenues were consistent throughout the first quarter and totaled about $3.2 million, which is relatively unchanged from the same quarter in 2015, and down significantly from about $6.9 million of net revenue during the previous quarter.
- Virtual supply revenues were most profitable in February as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply accounted for net payments of about $6.2 million during the quarter.
- Virtual demand revenues were negative in all three months of the quarter. In total, virtual demand accounted for around $3 million in net payments to the market for the quarter.
- Convergence bidders were paid about $1.3 million after subtracting bid cost recovery charges of $1.9 million for the quarter.[7,8] These costs were about $0.5 million, $0.4 million and $1 million in January, February and March, respectively.

Figure 1.11 Total monthly net revenues paid from convergence bidding



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

[8] 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 does not receive an excess residual unit commitment tier 1 charge or payment. For additional information on how this allocation may impact bid cost recovery, refer to BPM Change Management Proposed Revision Request.

Net revenues and volumes by participant type

Table 1.5 compares the distribution of convergence bidding cleared volumes and net revenues in millions of dollars among different groups of convergence bidding participants in the first quarter.[9] As shown in Table 1.5, financial entities represented the largest segment of the virtual bidding market in terms of volume, accounting for about 50 percent of volumes and about 40 percent of settlement dollars. Marketers represented about 30 percent of the trading volumes, but only about 20 percent of the settlement dollars. Generation owners and load-serving entities represented a slightly smaller segment of the virtual market in terms of volumes (about 20 percent) but a larger segment of settlement dollars (about 35 percent).

Table 1.5 Convergence bidding volumes and revenues by participant type (January – March)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	551	750	1,301	-$1.84	$3.23	$1.39
Marketer	315	536	851	-$0.82	$1.52	$0.71
Physical load	0	218	218	$0.00	$0.55	$0.55
Physical generation	81	243	324	-$0.30	$0.86	$0.55
Total	**947**	**1,748**	**2,694**	**-$3.0**	**$6.2**	**$3.2**

Virtual bid cost recovery charges

Virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[10] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up, minimum load, transition, and energy bid costs.[11]

[9] 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.

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

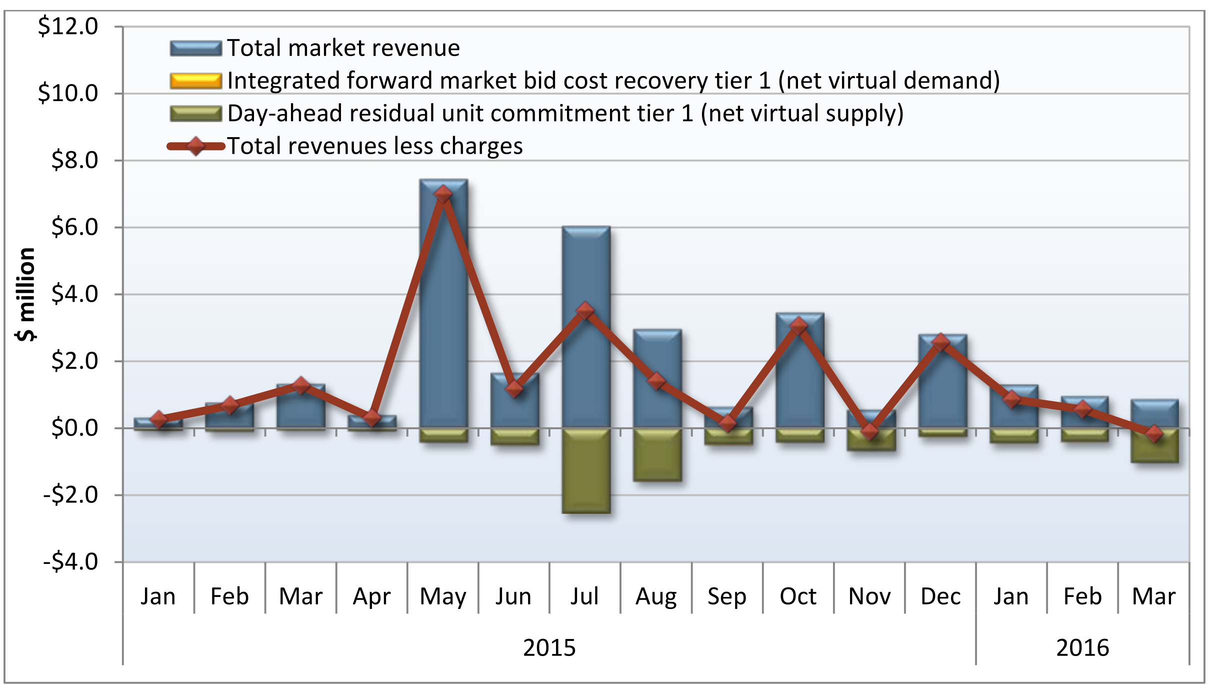
[11] Generating units, pumped-storage units, or resource-specific system resources are eligible to receive bid cost recovery payments.

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[12]

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

Figure 1.12 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery costs for the first quarter were about $1.9 million, an increase from $1.4 million in the previous quarter. This increase is related to the increase in residual unit commitment levels and related bid cost recovery payments (see Section 1.4). The total monthly revenue to convergence bidders after taking into account these charges was negative in March (-$0.2 million).

Figure 1.12 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



[12] Both charge codes are calculated by hour and charged on a daily basis. A detailed description of the charge codes can be found in the convergence bidding trends section of the 2015 Q4 report here: https://www.caiso.com/Documents/2015FourthQuarterReport-MarketIssuesandPerformanceFebruary_2016.pdf.

2 Energy imbalance market

This section covers the energy imbalance market performance during the first quarter of 2016. Key observations and findings include the following:

- Overall, market performance improved and remained very good in EIM during the first quarter. The percentage of intervals declined during the quarter when either the flexible ramping constraint or energy power balance constraint was relaxed to allow market software to balance modeled supply and demand.
- The addition of NV Energy into EIM in December 2015 added significant transfer capacity between the EIM areas and the ISO. With the new transfer capacity, real-time prices became more uniform between the ISO and EIM areas. Very little congestion has been observed between the ISO and EIM areas, or between the EIM areas, which has also contributed to more uniform prices between the ISO and EIM.
- The percentage of intervals where the flexible ramping constraint needed to be relaxed because of procurement shortfalls decreased significantly from the fourth quarter of 2015. DMM attributes much of this improvement in performance to reductions in generator outages and the additional transfer capacity that was added when NV Energy joined EIM in December 2015.
- The frequency of intervals in which the power balance constraint was relaxed remained very low during the quarter relative to prior quarters for each market. For PacifiCorp East and PacifiCorp West, this resulted in the lowest quarterly rates of power balance constraint relaxation since EIM implementation. As a result, special price discovery provisions in effect until March were rarely triggered and had a minimal impact on prices.
- The price discovery waiver expired for both PacifiCorp areas in March 2016 when the ISO implemented the available balancing capacity mechanism. If the price discovery feature had not been active for the entire quarter, the overall percentage of intervals with power balance constraint relaxations where the load bias limiter would have been triggered was about 15 percent. Because of the relative infrequency of intervals with power balance constraint relaxations, the load bias limiter feature would have had a relatively small impact on all EIM prices.
- Load forecast adjustments continue to be used in EIM to account for potential modeling inconsistencies and inaccuracies. As a percent of total area load, average load adjustments in the EIM were two to three times larger than adjustments in the ISO.

2.1 Background

The energy imbalance market became financially binding with PacifiCorp beginning on November 1, 2014. On December 1, 2015, NV Energy became the second market region in EIM. The EIM allows balancing authority areas outside of the ISO balancing area to voluntarily take part in the ISO's real-time market. The EIM includes both 15-minute and 5-minute financially binding schedules and settlement. Energy imbalances between 15-minute schedules and base (pre-market) schedules settle at the 15-minute market prices, and energy imbalances between 15-minute schedules and 5-minute schedules settle at 5-minute market prices.

During the initial EIM implementation for PacifiCorp East and PacifiCorp West, the amount of capacity available through the market clearing process was restricted and imbalance needs were exaggerated in ways that were not reflective of actual economic and operational conditions. This caused the need to relax ramping and system energy balance constraints in the market software more frequently than expected to enable the market to clear. The factors contributing to the need for constraint relaxation and steps being taken to address these issues have been addressed by the ISO as noted in its reports submitted to the Federal Energy Regulatory Commission.[13] When relaxing the power balance constraint for an EIM area, prices could be set based on the $1,000/MWh penalty price for this constraint used in the pricing run of the market model.

After review, the ISO determined that many of these outcomes were inconsistent with actual conditions. Consequently, on November 13, 2014, the ISO filed with federal regulators special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[14] These measures were approved by FERC on December 1, 2014, and were extended through subsequent orders. In addition, FERC ordered that the ISO and the Department of Market Monitoring provide reports every 30 days during the period of the waiver that outline the issues driving the need for the EIM tariff waiver.[15] These waivers expired for PacifiCorp in March 2016 when the ISO implemented the available balancing capacity mechanism.[16] With entry of NV Energy into EIM, FERC approved special transitional measures which allow for price discovery for the first six months of NV Energy operation and were set to expire at the end of May.[17]

The ISO has reported that the energy imbalance market has achieved benefits for customers through integration by enhancing the efficiency of dispatch instructions, reducing renewable curtailment and reducing the total requirements for flexible reserves.[18]

2.2 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.[19] 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

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

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

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

[16] The available balancing capacity mechanism will enhance EIM functionality by allowing the EIM to automatically recognize and account for capacity that participants have available to maintain reliable operations in their own balancing authority areas, thereby reducing the chance of an infeasibility based on false scarcity conditions. Further details can be found here: http://www.caiso.com/Documents/Aug19_2015_ComplianceFiling_EnergyImbalanceMarketEnhancements_AvailableCapacityAmendment_ER15-861_EL15-53.pdf.

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

[18] For more information on EIM benefits refer to the ISO Benefits Reports, which can be found here: http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

[19] Business Process 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.

weighted by the imbalance between forecasted load in the 15-minute market and forecasted load in the 5-minute market. The hourly shape and level of these settlement prices track relatively closely to 15-minute market prices. This occurs because settlement prices are weighted more heavily on prices in the 15-minute market as imbalance is generally greater between base load and 15-minute forecasted load than between forecasted load in the 15-minute and 5-minute markets.

Figure 2.1 Hourly settlement and bilateral trading hub prices – PacifiCorp (January – March)

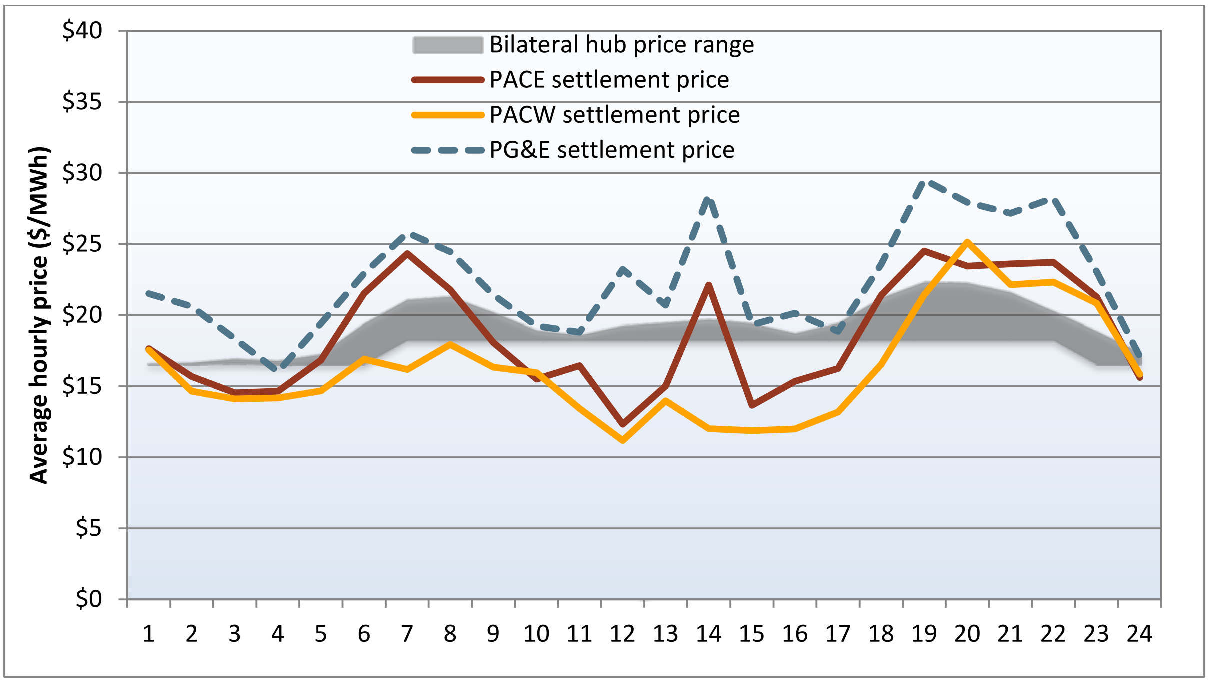


Figure 2.2 Hourly settlement and bilateral trading hub prices – NV Energy (January – March)

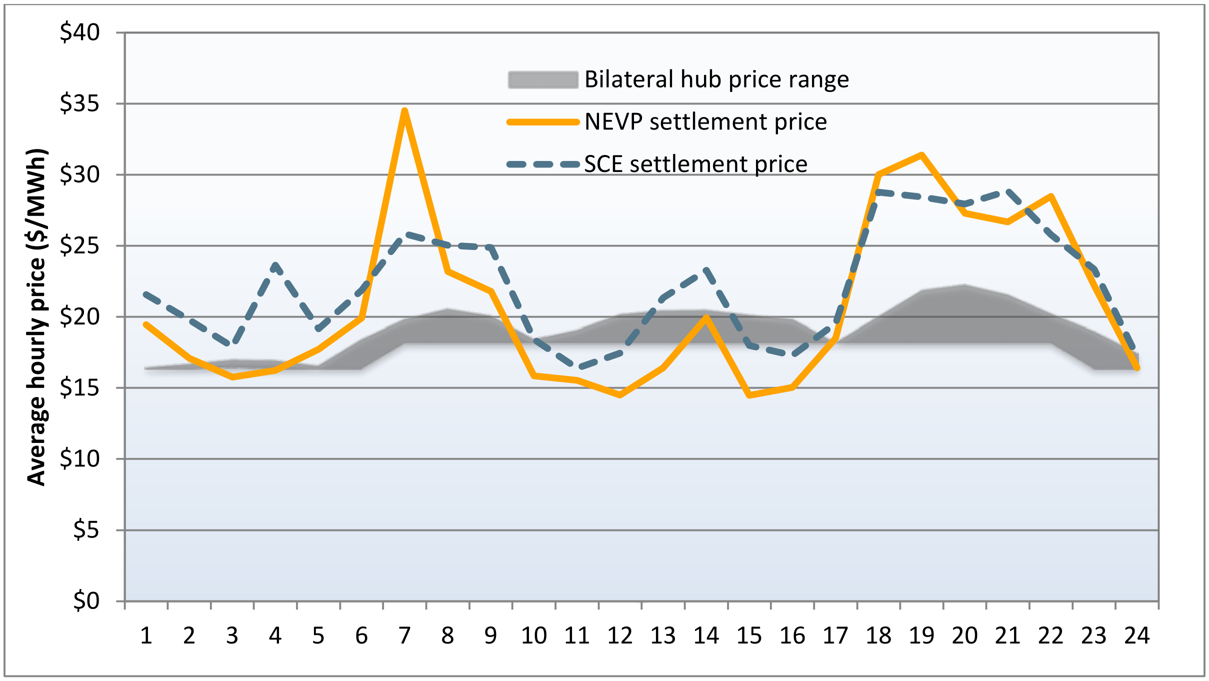


Figure 2.1 shows hourly average prices during the first quarter used in settlement of loads in PacifiCorp East, PacifiCorp West and the Pacific Gas and Electric area as well as the range of bilateral trading hub prices DMM uses as an additional benchmark for EIM prices.[20] Hourly average settlement prices in both areas tracked closely with bilateral trading hub prices, and were below the hourly average price for the PG&E load aggregation area in the ISO.[21] Prices used to settle load deviations in PacifiCorp East were about $19/MWh during the first quarter while prices in PacifiCorp West averaged about $16/MWh during the same period.

Figure 2.2 provides the same information on settlement prices for NV Energy and the Southern California Edison area. Hourly average settlement prices in NV Energy tracked closely with bilateral trading hub prices and were mostly below the hourly average price for the SCE load aggregation area in the ISO. Prices used to settle load deviations in NV Energy were about $21/MWh during the first quarter, compared with $22/MWh for SCE.

Overall EIM market prices in the first quarter remained close to bilateral market prices largely because prices in the EIM were infrequently increased from relaxations of the flexible ramping and power balance constraints. Figure 2.3, Figure 2.4 and Figure 2.5 provide a monthly summary of constraint relaxation frequency (green and blue bars), average prices with (gold line) and without price discovery

[20] 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).

[21] Pacific Gas & Electric and Southern California Edison settlement prices are used as an additional benchmark for competitiveness of the PacifiCorp areas and NV Energy area, respectively, as much of the energy transfer between the EIM areas and the ISO occurs at these respective regions.

(dashed red line), and average ranges of firm bilateral trading hub prices (grey regions) for comparison to 15-minute market EIM prices for PacifiCorp East, PacifiCorp West and NV Energy, respectively.

Figure 2.3 and Figure 2.4 show decreased rates of flexible ramping constraint relaxations between the fourth quarter of 2015 and the first quarter of 2016 in the 15-minute market in PacifiCorp East and PacifiCorp West. The large decline in flexible ramping constraint relaxations, which began in late November, coincided with the return of generating capacity from outage. In addition, the entrance of NV Energy to the EIM in December also helped to reduce the number of flexible ramping relaxations by providing a significant increase to the amount of transfer capacity available between NV Energy, PacifiCorp East and the ISO.

Figure 2.3, Figure 2.4, and Figure 2.5 show that during the first quarter the power balance constraint was relaxed infrequently in all EIM areas in the 15-minute market. Monthly frequencies decreased to less than 1 percent of 15-minute intervals across all EIM areas during the quarter. A generator trip on January 14 in the NV Energy area resulted in a series of power balance constraint relaxations in the 15-minute and 5-minute markets, but there were no further relaxations during the other months in the 15-minute market for NV Energy. The low number of power balance constraint relaxations caused prices with and without the price discovery mechanism to converge during the first quarter in all areas.

Figure 2.6 through Figure 2.8 provide the same information on prices and relaxations for daily average prices in the 5-minute market. As shown in Figure 2.6, the need to relax the power balance constraint in the 5-minute market continued to decline in the first quarter for PacifiCorp East and resulted in the lowest quarterly rate of relaxations since EIM implementation.

Additionally, EIM prices tracked closely with bilateral hub prices during all three months of the quarter. In PacifiCorp East and PacifiCorp West 15-minute prices fell within the representative bilateral trading hub price range. In the 5-minute market, prices in PacifiCorp West were 22 to 26 percent below the bilateral trading hub price range, while prices in PacifiCorp East were 1 to 7 percent below this range. NV Energy real-time prices tracked slightly above the bilateral price range.

Figure 2.3 Frequency of constraint relaxation and average prices by month PacifiCorp East – 15-minute market

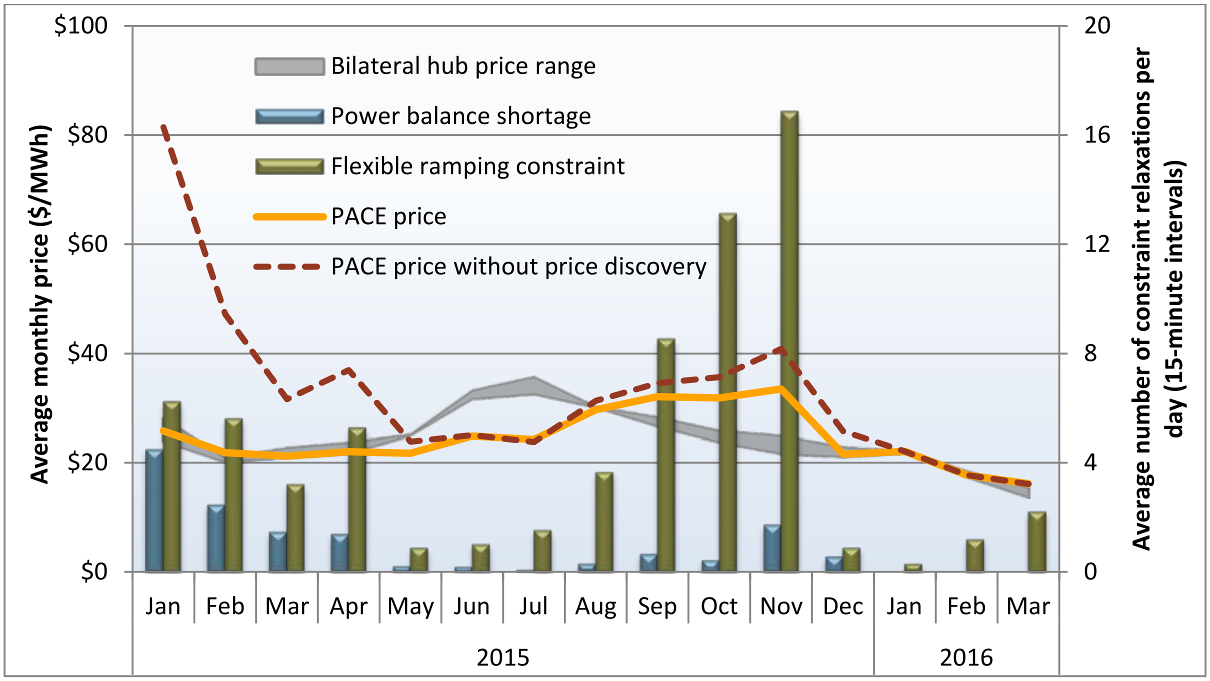


Figure 2.4 Frequency of constraint relaxation and average prices by month PacifiCorp West – 15-minute market

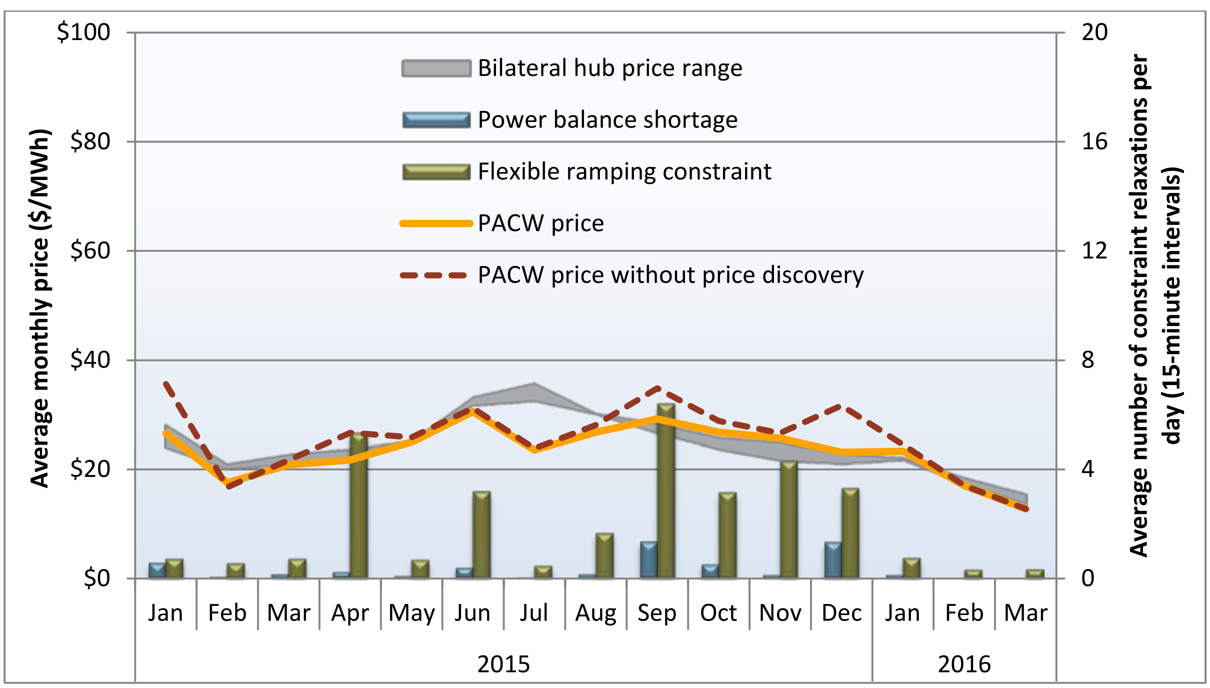


Figure 2.5 Frequency of constraint relaxation and average prices by month NV Energy – 15-minute market

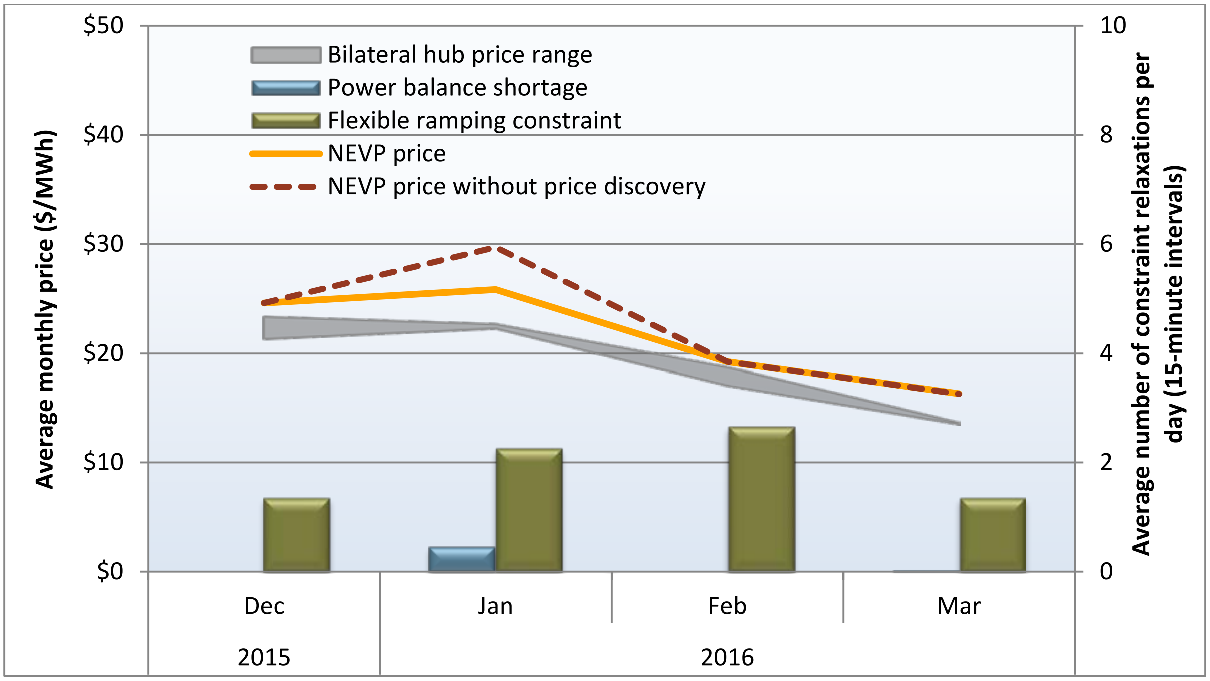


Figure 2.6 Frequency of constraint relaxation and average prices by month PacifiCorp East – 5-minute market

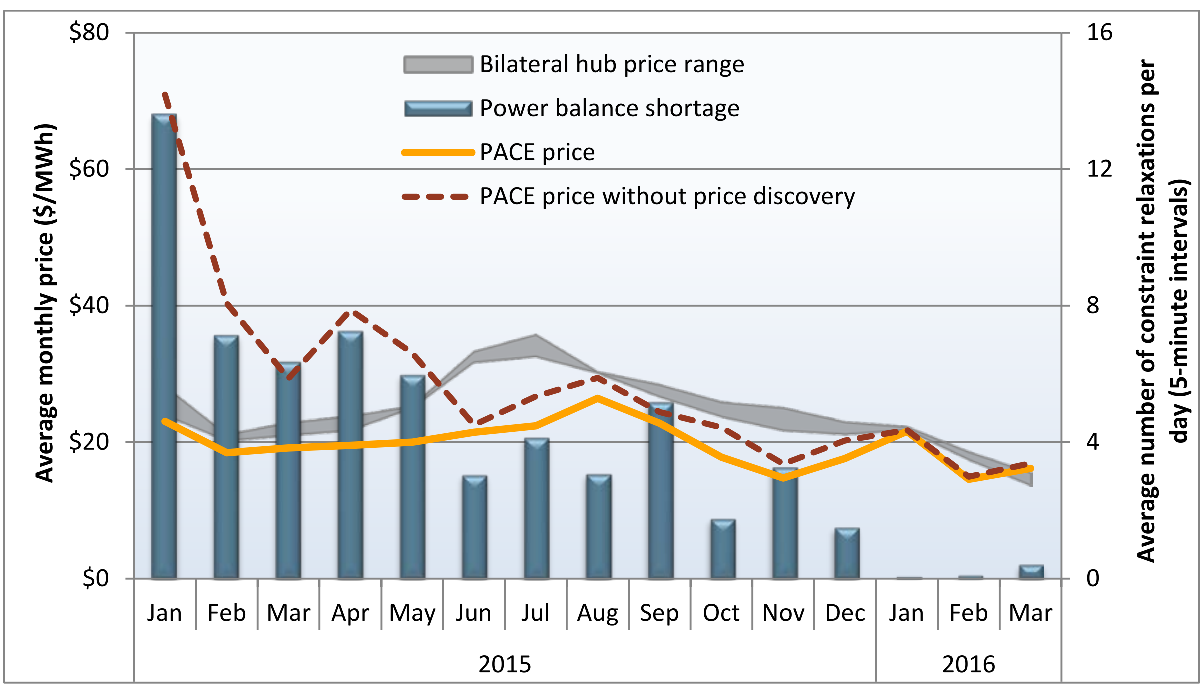


Figure 2.7 Frequency of constraint relaxation and average prices by month PacifiCorp West – 5-minute market

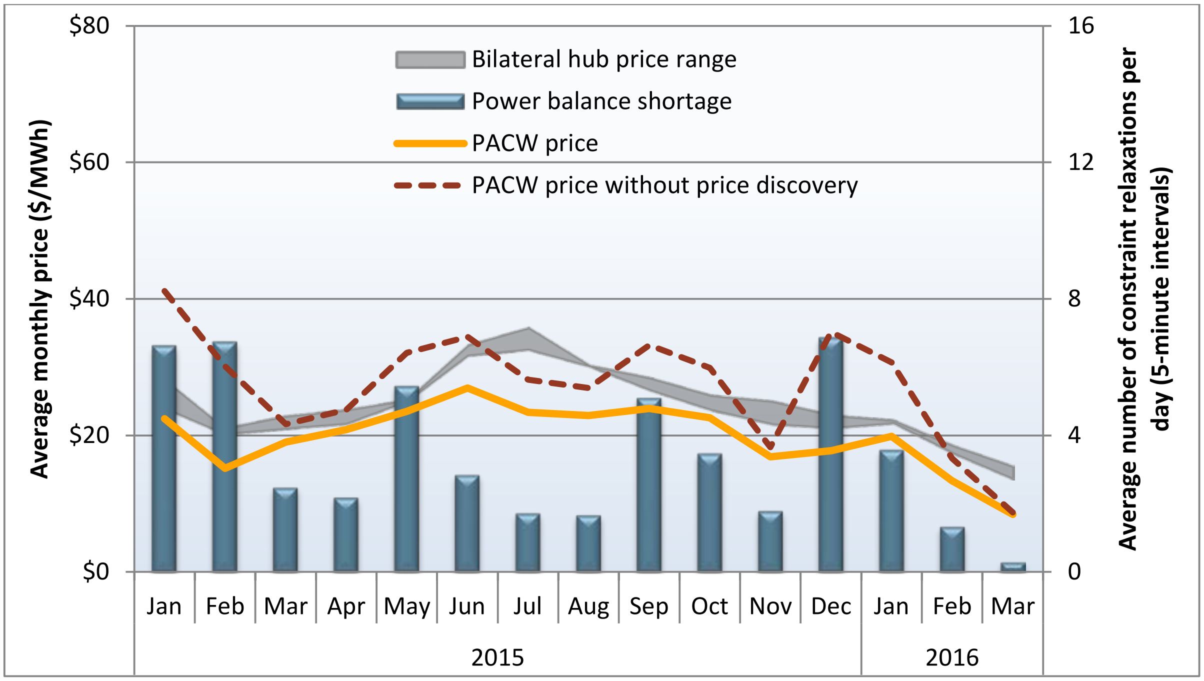
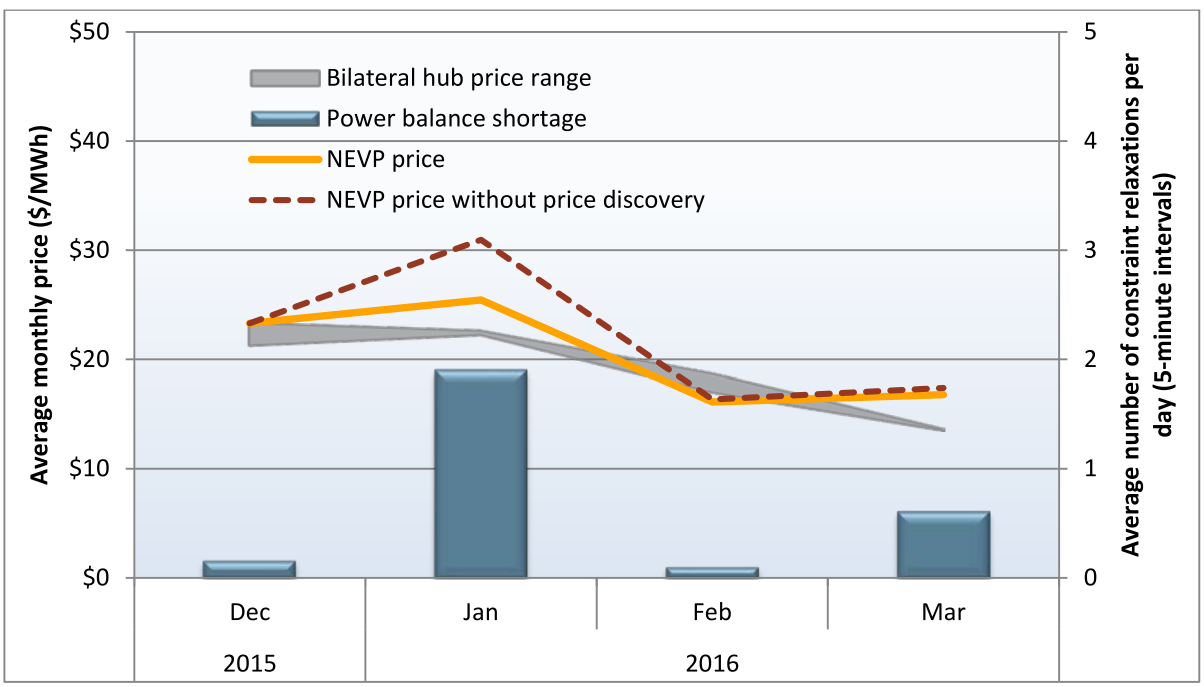


Figure 2.8 Frequency of constraint relaxation and average prices by month NV Energy – 5-minute market



Load forecast adjustments

Operators in the EIM can manually adjust load forecasts used in the market software through a load adjustment, or *load bias*. These adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators have listed multiple reasons for use of the load adjustment feature including managing load deviation, generation deviation, scheduled interchange variation, reliability events, and software issues.

In response to EIM stakeholder concerns about the impact and transparency of load biasing and adjustments, FERC has directed the ISO and EIM to collect and report additional information on the use and causes of load biasing. As explained in FERC's December 17, 2015, Order on the ISO's Available Balancing Capacity proposal:[22]

> …. 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.[23]

FERC also requested that DMM report on the frequency and use of load bias in the energy imbalance market:

> 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.[24]

With the implementation of the available balancing capacity mechanism, the ISO put a feature in place for EIM operators to log reasons for making load adjustments. This system was implemented on March 31, and DMM intends to provide analysis on these reasons in future quarterly reports.

The December 17 FERC Order also requires that the ISO submit quarterly reports on the available balancing capacity mechanism performance. DMM plans to review the ISO's analysis and provide feedback as necessary in future reports.

Table 2.1 shows the average frequency and size of positive and negative load adjustments for the ISO and EIM balancing areas in the first quarter. As shown in the table, positive load adjustments were most frequent in NV Energy and PacifiCorp East. Load adjustments in PacifiCorp West in either direction were relatively infrequent.

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[22] Order on Compliance Filing, ER15-861-006, December 17, 2015 (December 17 Order). http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

[23] Order on Compliance Filing, ER15-861-006, December 17, 2015 (December 17 Order) at ¶129 p. 50. http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

[24] December 17 Order at ¶130 p. 50. http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

Table 2.1 Average frequency and size of load adjustments

	Positive load adjustments			Negative load adjustments		
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load
CAISO						
15-minute market	10%	258	1%	37%	-280	1%
5-minute market	16%	271	1%	58%	-343	2%
NV Energy						
15-minute market	27%	110	3%	6%	-65	2%
5-minute market	36%	84	2%	12%	-67	2%
PacifiCorp East						
15-minute market	40%	108	2%	8%	-99	2%
5-minute market	40%	112	2%	15%	-103	2%
PacifiCorp West						
15-minute market	6%	75	3%	14%	-79	4%
5-minute market	7%	71	3%	21%	-73	4%

Table 2.1 also shows the average positive and negative load adjustment amount measured in both megawatts and as a percent of total area load. While load adjustments in EIM were typically smaller in magnitude than adjustments in the ISO, the table shows that in the first quarter average load adjustments in EIM as a percentage of load were two to three times larger than adjustments in the ISO.

Load bias limiter

Upon implementing the new available balancing capacity mechanism in late March, the special price discovery mechanism that was put in place in December 2014 was removed in the PacifiCorp balancing areas. When the price discovery feature was in effect the application of the load bias limiter was duplicative.[25] The analysis in this section estimates the effect that the load bias limiter would have had if the special price discovery feature had not been in effect for most of the quarter.

The percentage of intervals when the energy power balance constraint was relaxed to allow the market software to balance modeled supply and demand remained low during the first quarter. Without special price discovery provisions in effect, the load bias limiter feature would have been triggered during less than 14 percent of the power balance relaxations observed in the first quarter.

Figure 2.9 and Figure 2.10 show that in NV Energy the load bias limiter would have been triggered during about 20 percent of 15-minute and 5-minute intervals in the first quarter when power balance constraint relaxations occurred. Figure 2.10 shows the load bias limiter would have been triggered during only about 10 percent of the 5-minute intervals with power balance constraint relaxation in PacifiCorp West. Overall, there were very few intervals where the available balancing capacity mechanism would have impacted prices.

[25] The price discovery waiver expired for both PacifiCorp areas in March 2016 when the ISO implemented the available balancing capacity mechanism. Prior to March, the price discovery mechanism was active during any interval when there was a power balance relaxation, regardless of load adjustments. The price discovery mechanism was required for use in the NV Energy area for the first six months of market operation and was active until the end of May 2016.

Table 2.2 shows estimated EIM prices if prices were set at the $1,000/MWh penalty price during intervals when the load bias limiter would have been triggered and the price discovery provisions were not in effect. During the first quarter, the number of intervals when the load bias limiter would have been triggered when the power balance constraint bound was infrequent. Thus, the price impact of the load bias limiter was minimal. As shown in Table 2.2, without existing price discovery provisions, the load bias limiter would have lowered 15-minute prices in any EIM area by less than 1.5 percent and 5-minute prices by less than 3 percent during the quarter.

Figure 2.9 Mitigation of power balance relaxation by load bias limiter – 15-minute market

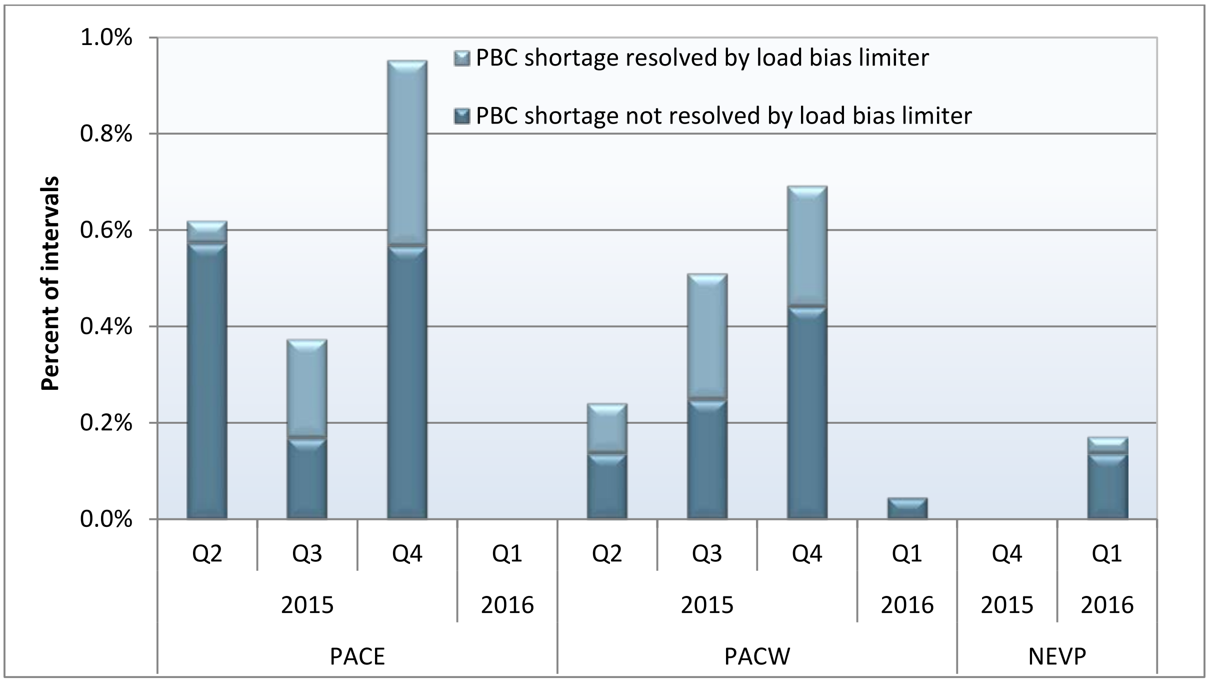


Figure 2.10 Mitigation of power balance relaxation by load bias limiter – 5-minute market

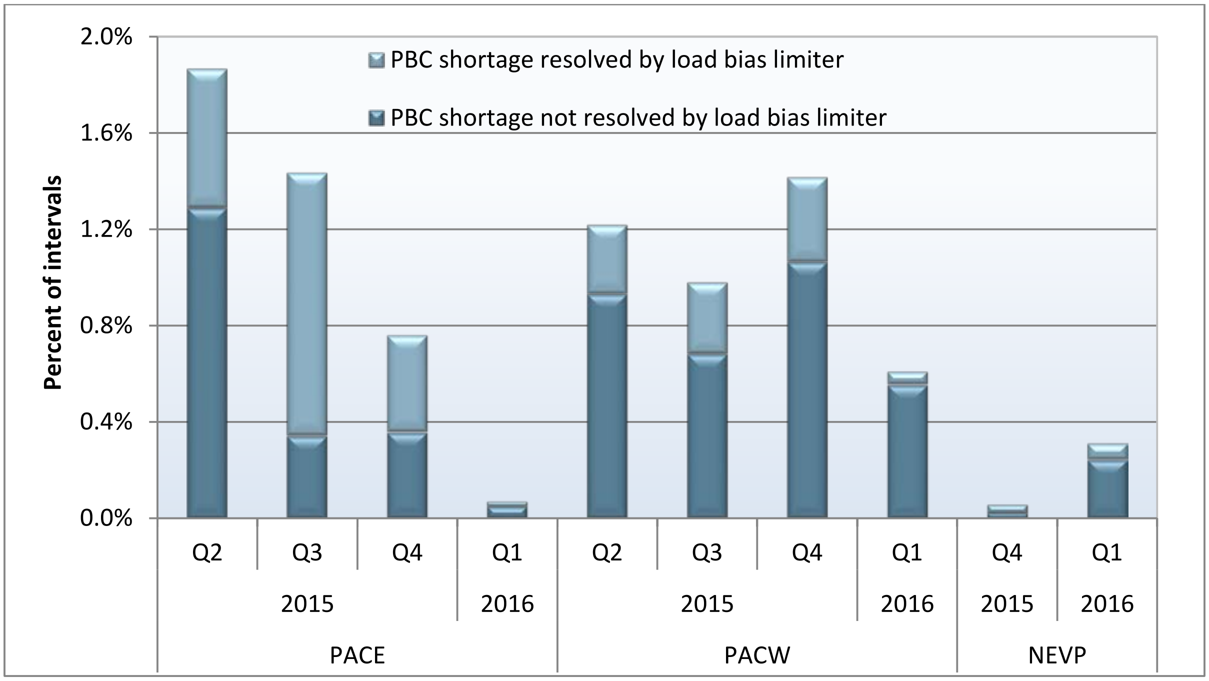


Table 2.2 Impact of load bias limiter on EIM prices (January – March)

	Bilateral trading hub range					Potential impact of load bias limiter	
	Low	High	Average EIM price	EIM price without price discovery	EIM price without price discovery or load bias limiter	Dollars	Percent
PacifiCorp East							
15-minute market (FMM)	$17.70	$18.82	$18.67	$18.67	$18.66	$0.01	0.0%
5-minute market (RTD)	$17.70	$18.82	$17.49	$17.93	$18.01	-$0.08	-0.4%
PacifiCorp West							
15-minute market (FMM)	$17.70	$18.82	$17.72	$18.14	$18.09	$0.05	0.3%
5-minute market (RTD)	$17.70	$18.82	$13.89	$18.71	$19.06	-$0.35	-1.8%
NV Energy							
15-minute market (FMM)	$17.62	$18.24	$20.49	$21.80	$22.11	-$0.31	-1.4%
5-minute market (RTD)	$17.62	$18.24	$19.51	$21.67	$22.18	-$0.51	-2.3%

2.3 Transfers

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

Table 2.3 shows the percentage of intervals that each EIM area and the ISO was a net exporter or net importer in the 15-minute market, and Table 2.4 shows additional detail on transfer quantities between the areas and congestion frequency. These tables show that scheduled transfers tended to flow out of the PacifiCorp areas and into the ISO and NV Energy areas. The ISO and NV Energy areas were more frequently net importers, while PacifiCorp East and PacifiCorp West were net exporters most of the time. NV Energy had the highest frequency of net imports, which means that there were times when NV Energy was importing energy and the ISO was exporting energy. Congestion on these transfers was low during the quarter, except for between the ISO and PacifiCorp West. This constraint bound during nearly 20 percent of intervals, but also had the lowest limit.

Table 2.3 EIM entities net transfer amounts

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	60%	-229	40%	316
NV Energy	80%	-258	20%	97
PacifiCorp East	24%	-184	76%	264
PacificCorp West	32%	-136	68%	126

Table 2.4 Congestion status and flows in EIM[26]

	Percent of intervals	Average transfer (MW)
NV Energy		
Congested from ISO	2%	770
Non-congested from ISO	48%	265
Non-congested to ISO	44%	-163
Congested to ISO	2%	-298
PacifiCorp East		
Congested from NVE and ISO	0%	470
Congested from ISO only	2%	375
Congested from NVE only	0%	49
Non-congested from NVE	14%	184
Non-congested to NVE	80%	-240
PacifiCorp West		
Congested from ISO	2%	225
Non-congested from ISO	19%	117
Non-congested to ISO	55%	-137
Congested to ISO	19%	-151

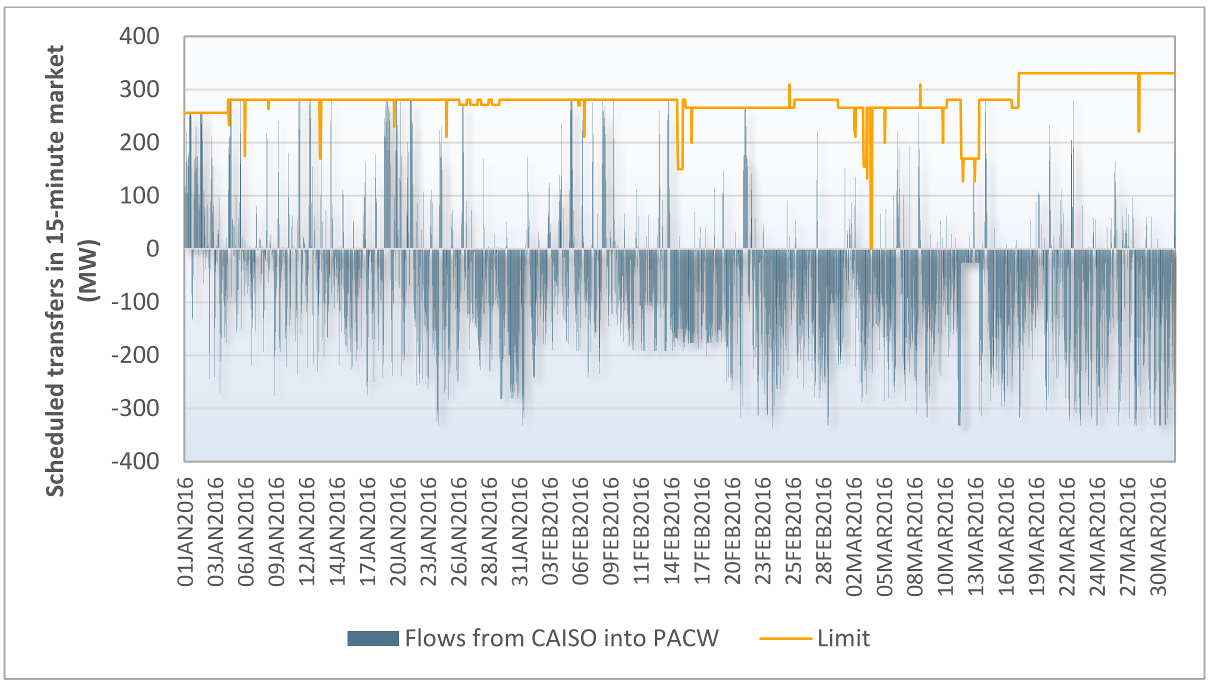
Figure 2.11 and Figure 2.12 show more detail on transfers between the ISO and PacifiCorp West and between the ISO and NV Energy during the first quarter. Figure 2.11 shows that PacifiCorp West often transfers energy to the ISO. Exports from PacifiCorp West to the ISO are represented on the graph with

[26] The listed categories do not sum to 100 percent because in some intervals EIM transfers are at 0 MW.

blue columns below the 0 MW axis. This generally indicates that PacifiCorp West has a price that is equal to or lower than the price in the ISO. When the ISO transfers energy to PacifiCorp West, the blue column is above the zero. When the column reaches the orange line, the transfers have reached the limit and the constraint binds. The chart shows that the transfer constraint is rarely binding, and that the market has not exhausted all competitively priced supply available through transfers from the ISO to meet load in PacifiCorp West.

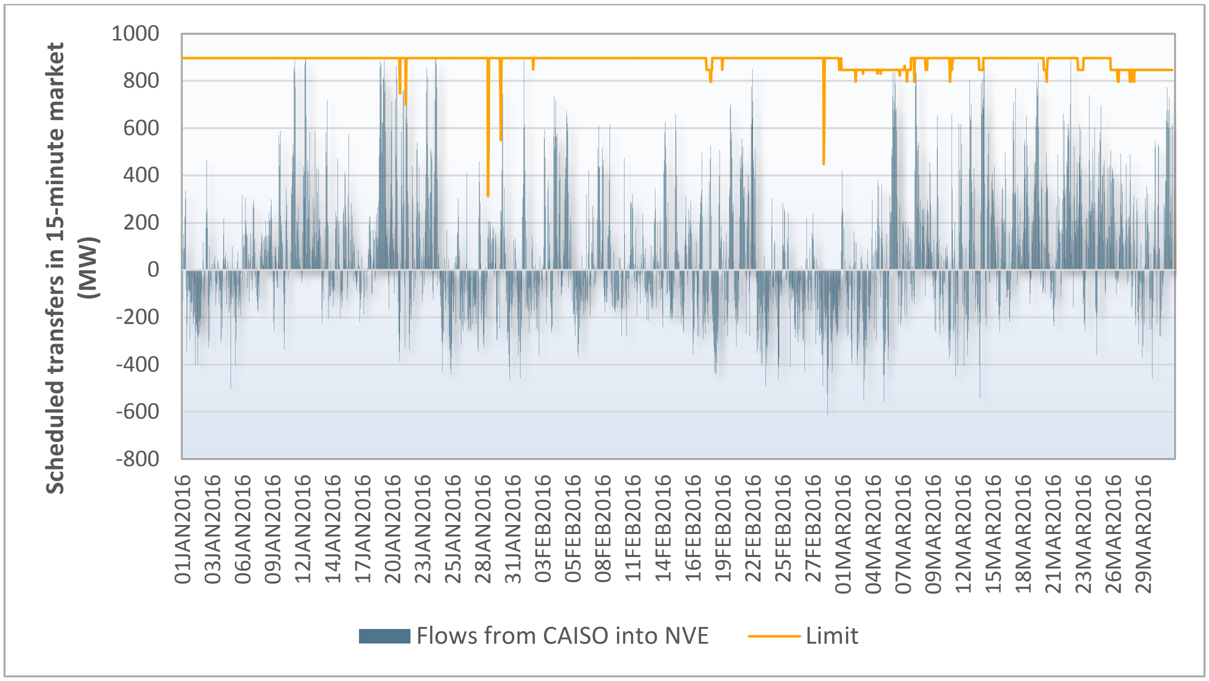
Figure 2.12 shows transfers between the ISO and NV Energy. Because generation from the ISO is considered to be competitively priced, when additional transfer capacity is available between the ISO and NV energy competitive prices will prevail in the NV Energy area as well.[27] In order for units with uncompetitive and higher prices to be dispatched, and therefore set area prices, competitively priced transfers from the ISO would first have to be exhausted. The chart shows that this rarely happens, and that potential opportunities to raise prices in the EIM balancing area are limited under current circumstance.

Figure 2.11 Hourly transfers from the ISO to PacifiCorp West



[27] *2015 Annual Report on Market Issues and Performance*, pp. 60-62: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

Figure 2.12 Hourly transfers from the ISO to NV Energy



3 Special issues

3.1 Regulation requirements

On February 20, 2016, the ISO increased the regulation requirements in the day-ahead and real-time markets, in response to growing needs for regulation to balance variable renewable generation. Prices for regulation also increased as a result of the new requirements. Because both the procured amount and corresponding prices of regulation increased, the cost for procuring regulation increased substantially.

Background

Regulation up and regulation down are two of the four ancillary service products that the ISO procures through co-optimization with energy in the day-ahead and real-time markets.[28] Most ancillary service capacity is procured in the day-ahead market. The ISO procures incremental ancillary services in the real-time market processes to replace unavailable ancillary service or to meet additional ancillary service requirements. A detailed description of the ancillary service market design implemented in 2009 is provided in DMM's 2010 annual report.[29]

In addition to a capacity payment, resources that provide regulation also receive a performance payment, which is referred to as mileage.[30] Since implementation of the mileage product in June 2013, the mileage payments have been very small compared to capacity payments.

Regulation requirements and prices

Regulation requirements in the day-ahead market ranged between 300 MW and 400 MW for regulation up and regulation down, and averaged 336 MW and 322 MW, respectively, from January 1 through February 19, 2016. The real-time market procurement requirements were consistently set at 300 MW for both regulation up and regulation down. After February 20, the ISO procured a minimum of 600 MW for regulation up and regulation down in the day-ahead and real-time markets.[31] On some days in late February and early March when weather forecasts indicated high renewable generation volatility, ISO operators further increased the procurement targets to 800 MW. On average, the ISO procured 617 MW of regulation up and 619 MW of regulation down in the day-ahead market between February 20 and March 31. The corresponding procurement in the real-time market was similar.

Average prices for regulation up and regulation down increased immediately following the change in requirements, as shown in Figure 3.1. This figure reports weekly weighted average day-ahead prices for regulation up and down during the first quarter. The vertical black line separates the figure into the time period before the requirement increase and the period after. The weighted average day-ahead

[28] The other two products are spinning and non-spinning reserves.

[29] *2010 Annual Report on Market Issues and Performance*, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

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

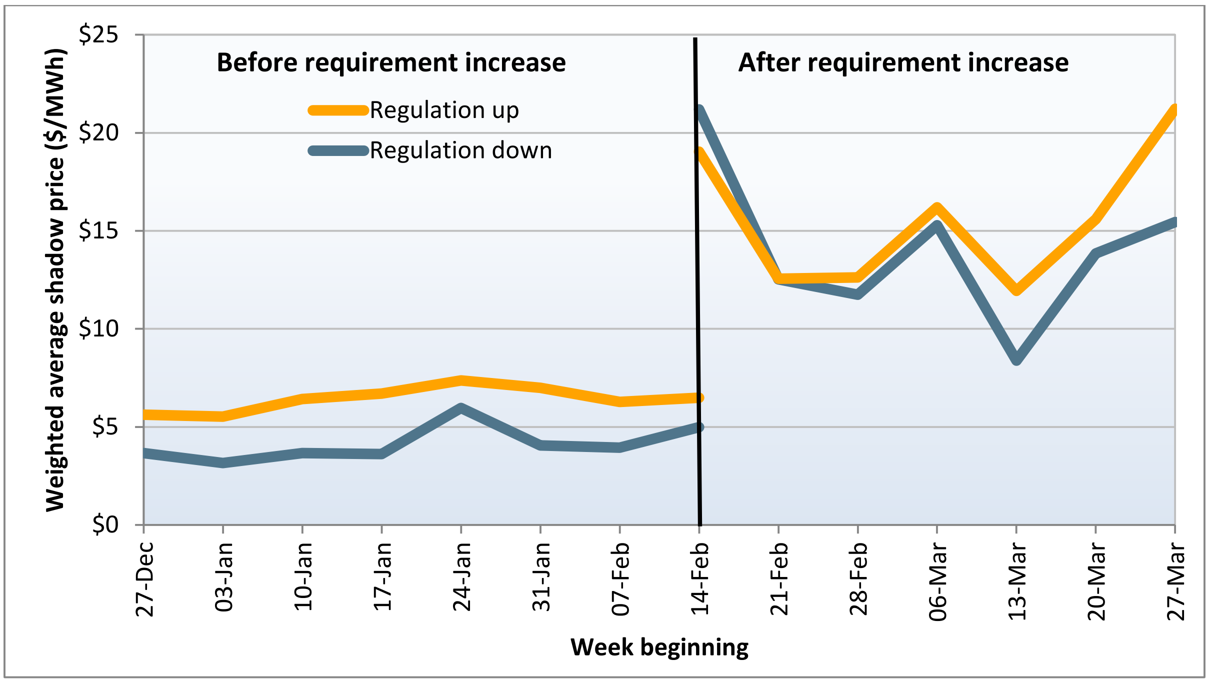
[31] One exception occurred during hours ending 22 through 24 on March 7, when the requirement was decreased to 400 MW in the day-ahead market.

price between January 1 and February 19 was $6.50/MWh for regulation up and $4.16/MWh for regulation down. Between February 20 and March 31, the weighted average price was $14.81/MWh and $12.92/MWh for regulation up and regulation down, respectively.

Average prices in the real-time market also increased substantially after February 20. The weighted average real-time price between January 1 and February 19 was $8.02/MWh for regulation up and $7.94/MWh for regulation down. After the requirement increase, these averages increased to $17.18/MWh for regulation up and $21.34/MWh for regulation down.

DMM has analyzed the bid behavior of participants in the regulation market around the time of the requirement increase and did not identify any significant changes in the supply bids offered to the market. The increase in regulation shadow prices can therefore likely be attributed to the increase in procurement quantities.

Figure 3.1 Weighted average day-ahead shadow prices for regulation (January – March)



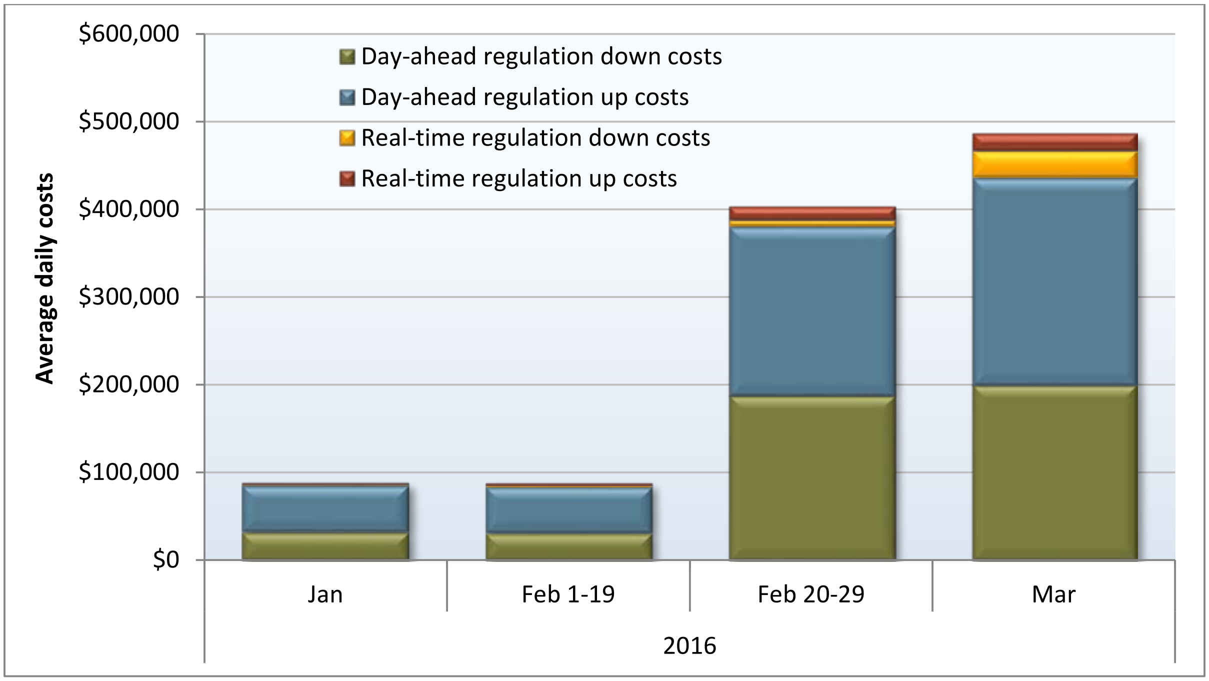
Regulation procurement costs

Because the procured amount and the corresponding price for regulation increased, the costs of procuring regulation increased dramatically. Figure 3.2 shows the average daily procurement costs for regulation by month, dividing February into a pre-increase and a post-increase period.[32] The average total daily costs to procure regulation capacity increased from less than $90,000 per day during January 1 through February 19 to almost $470,000 per day during February 20 through March 31. For comparison, the average total daily cost for regulation capacity in 2015 was about $75,000 per day. Day-ahead procurement costs, which made up the largest portion of total costs, increased by almost four times, from less than $85,000 per day to more than $420,000 per day during this period. The

[32] These costs are only for capacity payments and do not include mileage payments.

average daily costs for real-time regulation procurement increased by nearly 10 times, from less than $4,000 per day to more than $40,000 per day. The relatively higher increase for real-time costs compared to day-ahead costs likely reflects that after February 20 the ISO began enforcing the same procurement targets in the real-time market compared to the day-ahead market where targets had been lower beforehand.

Figure 3.2 Average daily regulation procurement costs (January – March)



Impacts on mileage

When the ISO increased the amount of regulation procurement, the amount of adjusted mileage delivered by resources providing regulation also increased. Comparing January 1 through February 19 with February 20 through March 31, the daily average amount of adjusted mileage increased by about 50 percent for mileage up and by about 70 percent for mileage down. However, the weighted average price for mileage remained close to $0 per unit of mileage throughout the first quarter, and therefore total payments for mileage remained low and averaged about $1,400 per day for the quarter.

3.2 Flexible ramping constraint

This section highlights the flexible ramping constraint performance during the first quarter. Key trends include the following:

- Overall payments made for the flexible ramping constraint decreased to about $1.3 million for the first quarter compared to about $2 million for the previous quarter. The decrease in total payments was driven by a large decrease in payments to generators in the PacifiCorp areas. Because of this decrease, the average payments per megawatt-hour of load were roughly equal across all balancing areas in the first quarter.

- The average flexible ramping requirement in the ISO decreased by about 5 percent compared to the fourth quarter and remained roughly unchanged in the EIM balancing areas. In the first quarter, average hourly requirements were 431 MW in the ISO, 140 MW in PacifiCorp East, 99 MW in PacifiCorp West and 84 MW in NV Energy.
- The percentage of intervals where the flexible ramping constraint needed to be relaxed because of procurement shortfalls in the PacifiCorp areas decreased substantially compared to the fourth quarter. The percentage of such intervals decreased from 10 percent to 2 percent in PacifiCorp East and from 3 percent to less than 1 percent in PacifiCorp West on a quarterly basis.
- The percentage of intervals when the flexible ramping constraint bound, but was not relaxed because of procurement shortfalls, continues to be frequent in EIM areas. DMM's review of these intervals reveals that they often have only a marginal impact on area prices, and are a reflection of supply conditions in the EIM areas. Within the NV Energy area, for instance, resources providing flexible ramping capacity generally have marginal costs below prevailing system marginal prices. This difference, or opportunity cost, sets shadow prices for the flexible ramping constraint.

Background

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

The relaxation pricing parameter, or *penalty price*, for the flexible ramping constraint is normally set to $60/MWh in the scheduling and pricing runs in the 15-minute market.[33] Thus, the market software will dispatch units so that this constraint is met as long as the additional cost of procurement does not exceed $60/MWh. When this constraint is binding in the 15-minute market, the shadow price of this constraint represents the marginal *opportunity cost* of not dispatching energy bids lower than local prices in order to maintain enough ramping capacity to meet the constraint.

Flexible ramping requirement

The ISO implemented a tool to automatically calculate the flexible ramping requirement in both the ISO and EIM balancing areas in late March 2015. Prior to implementing this tool, the requirement was static for each hour and determined manually by ISO operators. The tool determines the flexible ramping requirement independently for each 15-minute interval based on the observed ramping need for that

[33] For EIM areas that were subject to the temporary price discovery feature the penalty price for both the power balance and flexible ramping constraints was set to $0/MWh in the pricing run during intervals when the energy power balance constraint was relaxed in the scheduling run. This applied to NV Energy during all of the first quarter, and for the PacifiCorp areas until March 23.

interval in the preceding 40 instances.[34] After the tool calculates the requirement, it is bounded within predefined lower and upper thresholds. Because the requirement is calculated based on relatively few observations and each interval is considered independently, the resulting ramping requirement computed by the tool is highly volatile. The high variability is evident in the results from the second quarter of 2015. In later quarters of the year, the variability decreased significantly when the bounds were tighter and the requirements were frequently set at the bounds.[35]

Table 3.1 shows the average amount, range and volatility of the flexible ramping requirements by quarter for the ISO and EIM balancing areas. Volatility is measured as the standard deviation of the percent change in the requirements between intervals. A higher volatility implies more frequent and larger changes in the requirement from one interval to the next. Further, the table shows the percent of intervals when the requirement was equal to the lower or upper bounds.

As shown in this table, the volatility of the flexible ramping requirements was very high in the second quarter of 2015, the first quarter for which the balancing area ramping requirement tool was in use. In late June, the ISO increased the lower limits of the requirements that contributed to reduced volatility in subsequent quarters. However, the volatility was still higher than before implementing the tool, and the requirement was often set at either the upper or lower threshold. For example, the requirement was set at the upper bound in 90 percent of intervals in PacifiCorp West during the first quarter of 2016.

Table 3.1 also shows that average flexible ramping requirements in the first quarter generally remained close to the corresponding values for the previous quarter. In the first quarter, requirements decreased to 431 MW in the ISO and 84 MW in NV Energy while they increased to 140 MW in PacifiCorp East and remained unchanged at 99 MW in PacifiCorp West.

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[34] Specifically, on weekdays it sets the requirement at the 95th percentile of the 40 observations. Weekend days are considered as separate observations from weekdays. On weekend days it uses the preceding 20 weekend days. For more details about how these calculations have evolved over 2015 see: http://www.caiso.com/Documents/FlexibleRampingRequirementDiscussion-ISO_Presentation-February2016.pdf.

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

Table 3.1 Flexible ramping requirement and volatility

BAA	Year	Quarter	Requirement (MW) Avg	Min	Max	Volatility	Percent of intervals Req = Lower bound	Req = Upper bound	Req = bounds
CAISO	2015	Q1*	373	300	450	4%			
		Q2	307	80	500	68%	37%	39%	75%
		Q3	448	300	500	14%	22%	69%	90%
		Q4	456	300	500	17%	9%	64%	72%
	2016	Q1	431	300	500	20%	18%	50%	68%
NV Energy	2015	Q4**	85	80	100	8%	69%	24%	94%
	2016	Q1	84	80	100	9%	73%	17%	90%
PacifiCorp East	2015	Q1*	33	30	40	5%			
		Q2	49	20	150	92%	61%	11%	72%
		Q3	112	80	150	18%	45%	36%	81%
		Q4	137	80	150	16%	2%	59%	61%
	2016	Q1	140	80	150	17%	2%	62%	64%
PacifiCorp West	2015	Q1*	26	25	30	3%			
		Q2	44	10	100	114%	34%	39%	74%
		Q3	84	60	100	18%	35%	55%	90%
		Q4	99	62	100	5%	0%	94%	94%
	2016	Q1	99	60	100	7%	1%	94%	94%

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

*** December only.*

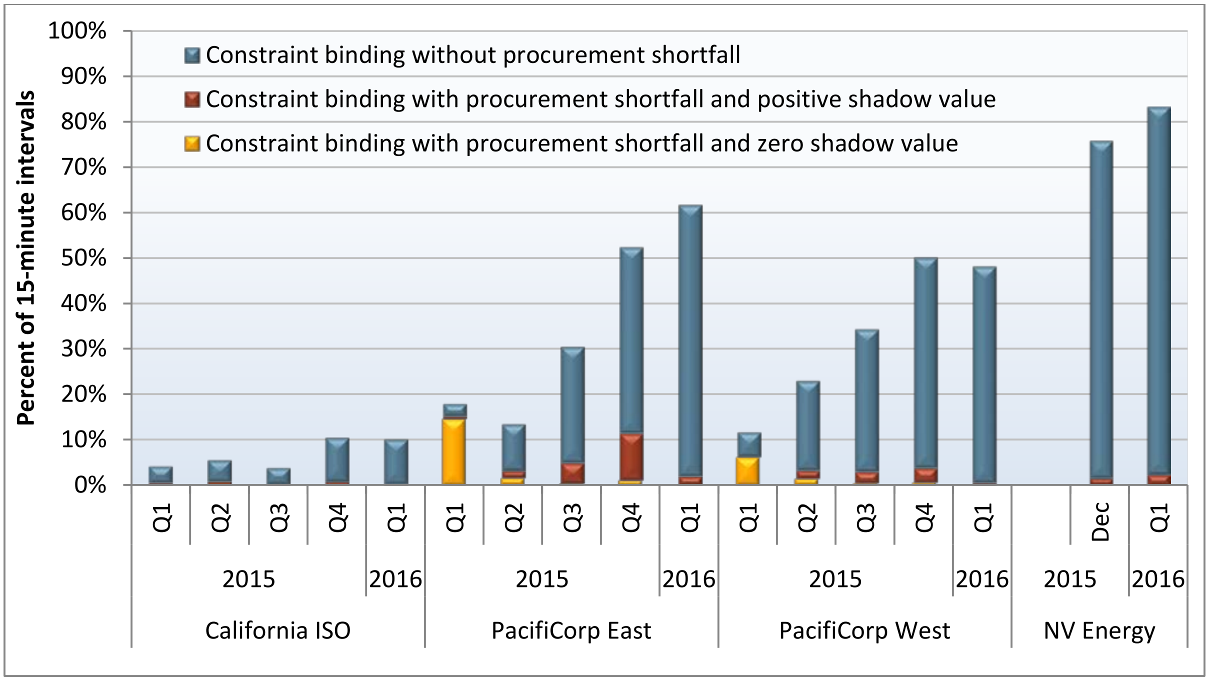
Impacts on market dispatch and pricing

A sufficient amount of flexible capacity often gets committed by the market regardless of the flexible ramping requirement. In these intervals the flexible ramping constraint does not bind in the 15-minute market and the shadow price is zero. This has been the case during most intervals in the ISO area for several years. However, in the EIM areas this became less frequent over the course of 2015 and into the first quarter of 2016.

Figure 3.3 shows the percent of 15-minute intervals where the flexible ramping constraint bound. The blue bars show intervals where the constraint bound but there was no shortfall in flexible ramping capacity. These are intervals when the constraint is not relaxed and shadow prices for the flexible ramping constraint are generally greater than $0/MWh but less than the $60/MWh penalty price. The red bars show intervals where the constraint needed to be relaxed in the scheduling run resulting in a positive shadow price in the pricing run, typically equal to the $60/MWh penalty price.

The yellow bars in Figure 3.3 show the percent of 15-minute intervals where the flexible ramping constraint was relaxed in the scheduling run, but the shadow price was $0/MWh. This occurred in the PacifiCorp areas during the first and second quarters of 2015 for two reasons. Until early February, there were several software problems related to the flexible ramping credit and relaxation parameter limits that prevented the flexible ramping constraint from binding in the pricing run. In addition, the penalty price for the flexible ramping constraint was set to $0/MWh in the pricing run for all intervals until mid-February.[36]

Figure 3.3 Percent of intervals with binding flexible ramping constraint



As discussed in greater detail in DMM's fourth quarter 2015 report,[37] flexible ramping constraint shadow prices can have a significant impact on energy prices during intervals with a flexible ramping procurement shortfall, but often only have a marginal impact on energy prices when the constraint is binding without a procurement shortfall.

As seen in Figure 3.3, the flexible ramping constraint continued to bind much more frequently in EIM areas than in the ISO in the first quarter. In the PacifiCorp East and NV Energy areas, the constraint bound during 62 percent and 83 percent of intervals, respectively, which is a significant increase from the prior quarter. The constraint bound in PacifiCorp West slightly less frequently than the prior quarter, at 48 percent of intervals, and continued to bind during 10 percent of intervals in the ISO.

Figure 3.3 further shows that the frequency of intervals with procurement shortfalls (red bars) in the PacifiCorp areas decreased dramatically in the first quarter. In PacifiCorp East, about 2 percent of

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

[37] *Q4 2015 Report on Market Issues and Performance:* http://www.caiso.com/Documents/2015FourthQuarterReport-MarketIssuesandPerformanceFebruary_2016.pdf.

15-minute intervals had procurement shortfalls in the first quarter, compared with more than 11 percent in the fourth quarter. In PacifiCorp West less than 1 percent of intervals in the first quarter had flexible ramping procurement shortfalls, compared to about 4 percent in the previous quarter.

Flexible ramping procurement costs

Total payments to generators for providing flexible ramping capacity in the first quarter decreased to about $1.3 million, compared to almost $2 million in the fourth quarter.[38] As shown in Figure 3.4, most of the payments in the first quarter were made to generators in the ISO. Total payments to generators in the PacifiCorp areas decreased by about 70 percent compared to the fourth quarter, and averaged about $0.02/MWh of load in both PacifiCorp West and East. The decrease in payments to generators in PacifiCorp areas during the first quarter is primarily a result of the decreased frequency of intervals with flexible ramping procurement shortfalls in the areas.

Average payments in the NV Energy area increased to just over $0.02/MWh in the first quarter, compared to around $0.01/MWh in December. Payments to generators in the ISO increased slightly, and average payments converged to about $0.02/MWh in all four areas in the first quarter. About 59 percent of payments were made to gas-fired capacity and 17 percent to hydro-electric capacity in the first quarter, with most of the hydro-electric capacity payments to units in the ISO.

Most payments for flexible ramping capacity occurred during the morning and evening peak hours. This pattern can be seen in Figure 3.5 and Figure 3.6, which show the payments made to generators in the first quarter by hour for the ISO and EIM balancing areas, respectively. The figures also show the hourly percent of 15-minute intervals that the constraint was binding.

In both the ISO and EIM areas, the constraint bound most often during the morning and evening ramping periods and there is a correlation between the frequency with which the constraint bound and the payments made. In previous quarters, this pattern has been observed in the ISO area but not in the EIM areas. For example, for the PacifiCorp areas in the previous quarter, the constraint was frequently binding during all hours of the day and the correlation between the frequency that the constraint was binding and payments made was less clear.[39] This change is likely a result of greater transmission capacity between the EIM areas and the ISO that occurred when NV Energy joined EIM in December.

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

[39] *Q4 2015 Report on Market Issues and Performance:* http://www.caiso.com/Documents/2015FourthQuarterReport-MarketIssuesandPerformanceFebruary_2016.pdf.

Figure 3.4 Flexible ramping payments by fuel and balancing area

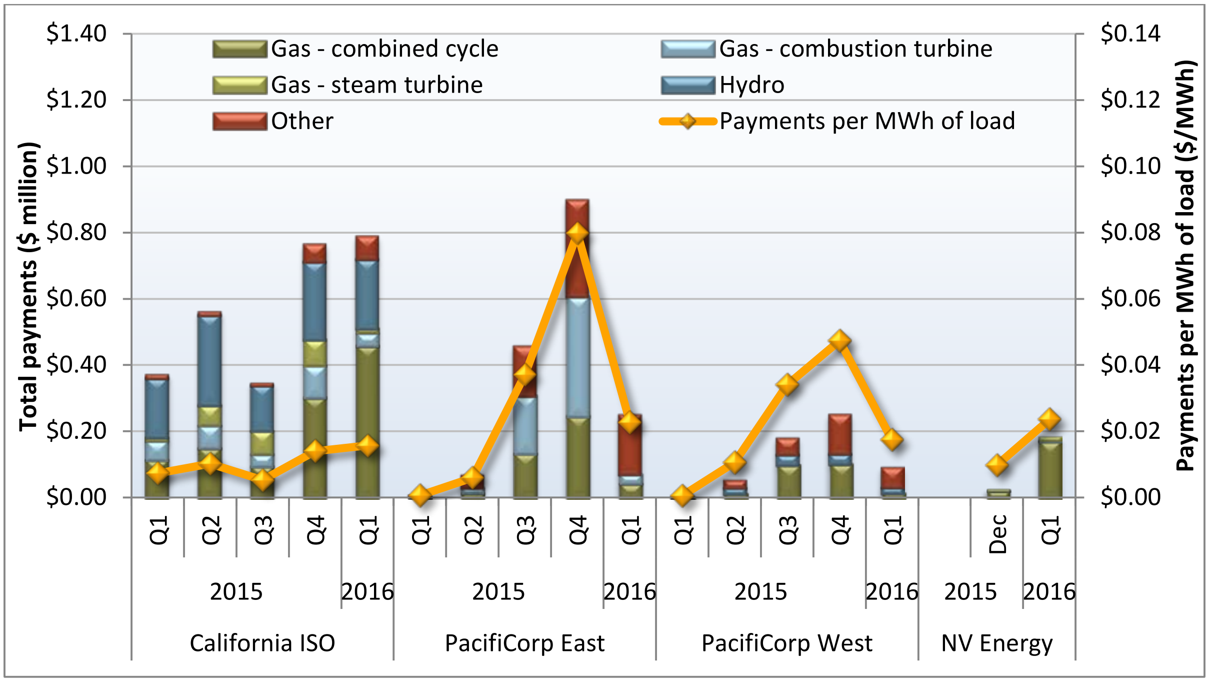

Figure 3.5 Hourly flexible ramping constraint payments to ISO generators (January – March)

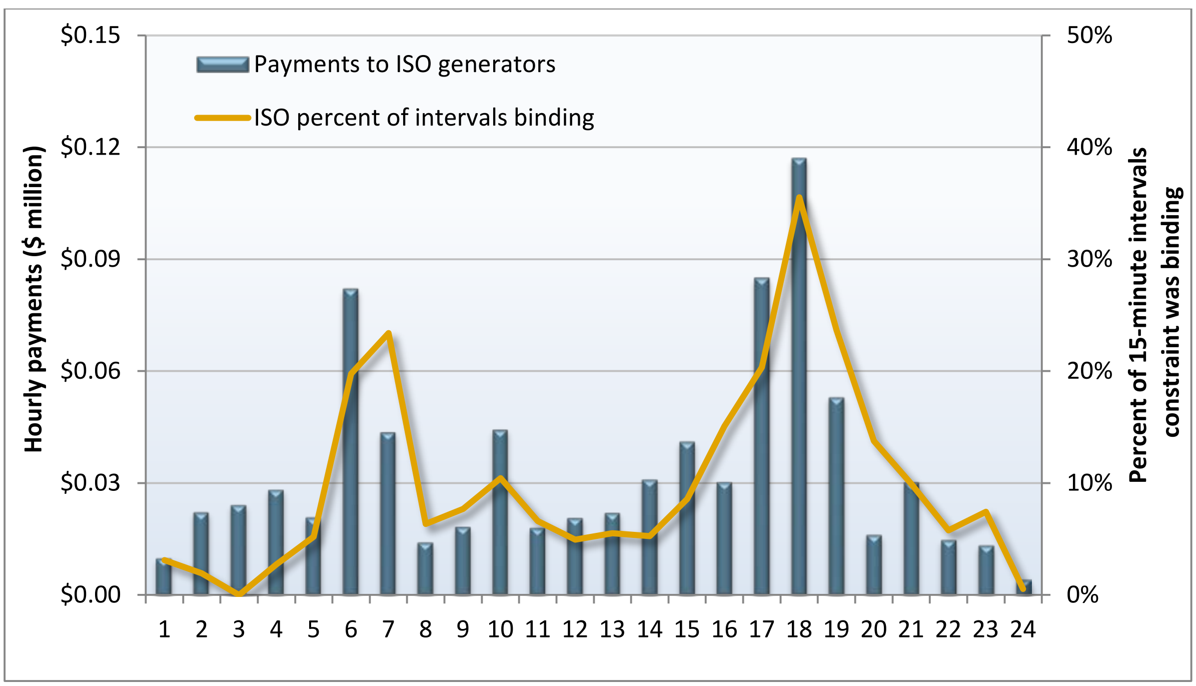

Figure 3.6 Hourly flexible ramping constraint payments to EIM generators (January – March)