California Independent System Operator Corporation

California ISO

Q2 2016 Report on Market Issues and Performance

August 22, 2016

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Executive summary

This report covers market performance during the second quarter of 2016 (April – June). Key highlights during this quarter include the following:

- Day-ahead prices in April and May continued to remain low compared to previous periods, in both peak and off-peak periods. However, prices increased in June as loads rose because of warmer temperatures and natural gas prices trended up.
- Prices in the day-ahead market were slightly higher than 15-minute market prices for most of the quarter. However, tight supply conditions contributed to significantly higher 5-minute market prices than day-ahead and 15-minute prices during several peak load hours in the quarter.
- Despite a significant increase in generation from hydroelectric and renewable resources, the frequency of negative prices remained about the same in the second quarter of 2016 as the second quarter of 2015. In addition, the frequency of prices at or below the -$150/MWh bid floor dropped to about 0.1 percent of 5-minute intervals in the second quarter compared to about 1 percent during the same quarter in 2015. This reflects a significant decrease in the 5-minute intervals when the supply of negatively priced real-time bids to decrease generation was exhausted and some resources needed to be curtailed.
- 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, very little congestion has been observed between the ISO, PacifiCorp East and NV Energy areas. As a result, real-time prices have become much more uniform between the ISO and EIM areas.
- The ISO and PacifiCorp East were net exporters in the EIM, while NV Energy and PacifiCorp West tended to be net importers. However, the direction and volume of transfers between the ISO and different EIM areas fluctuated significantly based on actual real-time market conditions.
- The ISO decreased regulation requirements in the day-ahead and real-time markets to levels similar to those observed prior to February 2016, starting on June 10. As a result, regulation prices reverted back to lower levels, and the procurement costs decreased to $80,000 per day compared to $400,000 per day or more, during February through early June, when requirements were higher.

Energy imbalance market

This report also provides analysis and recommendations relating to several recent Federal Energy Regulatory Commission (FERC) orders on the energy imbalance market.

Structural market power

In July DMM completed its third report on the structural market competitiveness in the PacifiCorp balancing authority areas.[1] This report provided analysis showing that the frequency of potential structural market power in the PacifiCorp areas had dramatically reduced with the additional transfer capacity that became available between the EIM areas and the ISO when NV Energy joined the energy imbalance market. This structural competitiveness mitigates the potential for the exercise of market power through both economic and physical withholding during most intervals.

Enhanced market power mitigation procedures

During the limited number of intervals when competitive supply from ISO into the EIM is constrained by congestion on EIM transfer constraints, the ISO's automated real-time market power mitigation procedures are designed to mitigate the potential exercise of market power. DMM has recommended that the ISO implement enhancements to automate market power mitigation procedures to ensure that bid mitigation is triggered in the real-time market when congestion occurs on structurally uncompetitive constraints. The ISO has indicated it will seek to implement these enhancements in the 15-minute market in 2016 and has filed for approval to implement enhancements in the 5-minute market in 2017.

These enhancements are also needed to address concerns about potential *economic withholding* expressed in FERC's November 19, 2015, Order on the market based rate filings for PacifiCorp and NV Energy in the energy imbalance market, which is discussed below.

Enforcement of internal constraints

In FERC's November 19, 2015, Order, the Commission found that the market power analyses of the expanded EIM footprint by PacifiCorp and NV Energy failed to demonstrate a lack of market power in EIM. The Commission therefore imposed the following two conditions on the Berkshire EIM Sellers' participation in the EIM at market-based rates:[2]

1. They must offer EIM participating units at or below each unit's default energy bid; and
2. They must facilitate the ISO's enforcement of all internal transmission constraints in the PacifiCorp and NV Energy balancing authority areas.

DMM's review indicates that by the second quarter of 2016 a significant number of constraints within EIM areas were being enforced. However, a significant number of constraints that had been incorporated in the network model were also not being enforced. Consequently, DMM has requested that the ISO and EIM entities further review this issue and provide a report to FERC identifying constraints that are not modeled or enforced, along with an explanation of the reasons some constraints were not enforced.

DMM's review indicates that one factor that may be contributing to the lack of congestion within the PacifiCorp area is that some scheduling limits associated with transmission contracts (between

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

[2] *Order on Proposed Market-Based Tariff Changes*, November 19, 2015, 153 FERC 61,206, ER15-2281-000: https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

PacifiCorp and non-PacifiCorp entities owning transmission within the PacifiCorp balancing area) are not incorporated in the full network model. DMM has recommended that the ISO and EIM entities assess whether these transmission contract limits can be directly enforced by the energy imbalance market software. This could allow more efficient dispatch of different resources to meet scheduling limits and avoid the need for EIM participants to not offer or limit generation in the market in an effort to avoid exceeding scheduling limits.

Enhanced outage reporting

FERC also expressed concern in the November 19, 2015, Order about the potential for *physical withholding* in EIM from the lack of a must-offer requirement. To enhance DMM's ability to monitor capacity not offered in the EIM, DMM requested that the ISO and EIM entities develop a set of more descriptive categories that can be entered in the ISO's outage management system to indicate the reason for unit outages or de-rates. This recommendation remains under consideration by the ISO.

Available balancing capacity

The ISO implemented the available balancing capacity mechanism in EIM on March 23, 2016. This enhancement allows the market software to account for capacity that an EIM entity has available for reliable system operations but is not bid into the EIM. The available balancing capacity mechanism enables system software to deploy such capacity through the market, and prevents market infeasibilities that may arise without the availability of this capacity.[3]

FERC's December 17, 2015, Order 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. In this report, DMM provides a short summary of the available balancing capacity since implementation of the mechanism in late March.

Since implementation, the frequency of hours in which available balancing capacity was offered varied widely for different EIM areas. When available, balancing capacity offered in an EIM area typically ranged from 50 to 100 MW, and was dispatched during a relatively small portion of intervals. Because the balancing capacity was dispatched infrequently, it had a very limited effect on market performance.

Load biasing

FERC's December 17, 2015, Order on the ISO's available balancing capacity proposal directed the ISO to collect additional data on load biasing, or manual load adjustments, made by EIM entities. The Commission also indicated DMM should monitor and evaluate this information, and include an analysis of the impacts of EIM entities' load forecast adjustments in DMM quarterly reports. Pursuant to the December 17 Order, this report provides a summary and analysis of load biasing in the EIM.

DMM previously provided recommendations to the ISO on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load bias adjustments on creating power balance shortages. Specifically, DMM has recommended considering the adjustment based on a combination of

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

factors that includes the change in load bias from one interval to the next and the duration of an adjustment rather than a calculation based solely on the absolute value of the current load bias.

Congestion revenue rights

This report also provides an update on analysis and recommendations on congestion revenue rights provided in DMM's 2015 annual report.

- As discussed in DMM's 2015 annual report, since 2012 electric ratepayers who ultimately pay for the cost of transmission managed by the ISO received an average of about $130 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments received by entities purchasing these rights.[4] In the first half of 2016 congestion revenue rights auction revenues were $27 million less than congestion payments made to non-load serving entities purchasing these congestion revenue rights. This represents $0.63 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down from $0.72 in the first half of 2015.
- Most congestion payments were paid to purely financial entities that purchase congestion revenue rights but are not engaged in serving load or managing generation in the ISO markets. DMM believes this trend warrants reassessing the standard electricity market design under which independent system operator's auction off excess transmission capacity remaining after allocating congestion revenue rights to load serving entities.
- This report outlines a potential approach for addressing this issue by modifying the congestion rights auction into a *market* for congestion revenue rights based on bids submitted by entities willing to buy or sell congestion revenue rights. With this approach, generators could still seek to purchase hedges for locational price differences, and financial entities or other participants could participate and submit bids reflecting a willingness to sell a hedge for locational price differences to other auction participants. Bids to buy transmission congestion rights would only be cleared if there were sufficient bids from entities willing to sell transmission revenue rights, ensuring that sellers would be willing to assume the obligation to pay congestion charges to entities purchasing these rights.
- DMM believes following the outlined approach would be more equitable for customers of load serving entities and would produce more efficient prices that reflect the willingness of participants to buy or sell congestion revenue rights at the market clearing price. DMM recommends that the ISO begin assessing this issue, and is prepared to work with the ISO and stakeholders to further develop and assess options to address this issue. In response to DMM's recommendation at the June 2016 Board meeting, ISO management indicated the ISO would consider scheduling an initiative on this issue as part of the ISO's next stakeholder initiative catalog process in the fall of 2016.

Energy market performance

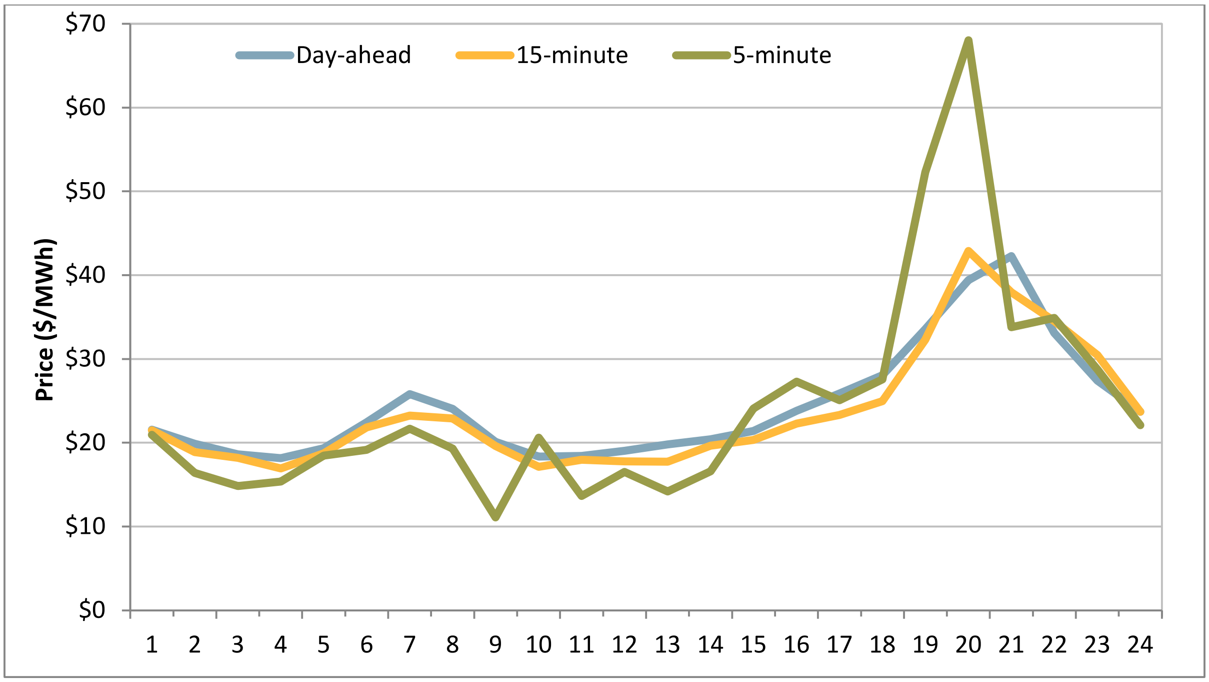
This section provides a more detailed summary of energy market performance in the second quarter.

Average energy prices remained low in April and May but increased in June. Higher prices in June resulted in part from higher natural gas prices and also from seasonally higher loads. Prices in the

[4] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 182-190, 225-226: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

15-minute market were often lower and tracked closely to day-ahead prices during the quarter. Prices in the 5-minute market were lower than day-ahead prices in April and May but averaged higher in June. 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. The higher 5-minute prices during hours 19 and 20 were caused by numerous factors, which included tight supply conditions during evening ramp and significant differences in operator load adjustments between the 15-minute and 5-minute markets.

Figure E.1 Hourly system marginal energy prices (April – June)



Price spikes increased in the second quarter, but remained relatively low. The frequency of high prices in the 5-minute market was about 1 percent – higher than any other quarter in the past 3 years. This was largely driven by high prices in hours ending 19 and 20 because of tight supply conditions while ramping to evening peak loads, power balance relaxations from insufficient upward ramping capabilities or operator load adjustment differences between the 15-minute and 5-minute markets.

Negative prices were more frequent in the second quarter. Negative prices were more frequent in the 5-minute market, occurring in almost 16 percent of intervals during the late morning/early afternoon hours. During the quarter, negative prices occurred in over 8 percent of the intervals compared to about 7 percent of intervals in the previous quarter and about 8 percent of intervals in the second quarter of 2015. Negative prices in April occurred in about 15 percent of intervals in the 5-minute market. This was the highest frequency of negative prices in the 5-minute market during a month in the past several years, again largely because of the high quantities of renewable generation on-line and relatively low loads.

Flexible ramping capacity payments in the ISO and EIM increased but remained low in the second quarter. Total payments were around $2.1 million, an increase from about $1.3 million during the previous quarter. About 60 percent of these payments were made to generators in the ISO. The increase in payments is likely attributable to supply conditions during the months of April and May when fewer units were on-line to provide flexible ramping capacity because of high renewable generation and low seasonal loads.

Payments to entities purchasing congestion revenue rights in the auction continued to exceed auction revenues received by ratepayers. During the first half of 2016, auction revenues as a percent of payments fell to 63 percent, compared to 72 percent in the first half of 2015. This represents a loss to ratepayers of $27 million in the first two quarters of 2016 when compared to a market design in which unallocated congestion revenue rights are not auctioned off. This was a 5 percent increase from nearly $26 million ratepayers lost in the first half of 2015.

Virtual bidding volumes and returns increased in the second quarter. Total virtual trading volume increased to 3,200 MW from 2,700 MW in the previous quarter. Moreover, virtual bidding net revenues increased to about $6.4 million in the second quarter from $3.2 million in the first quarter. Virtual supply and virtual demand generated net revenues of about $3.9 million and $2.5 million, respectively. Average hourly virtual supply positions outweighed virtual demand positions by 820 MW for the quarter.

Special issues

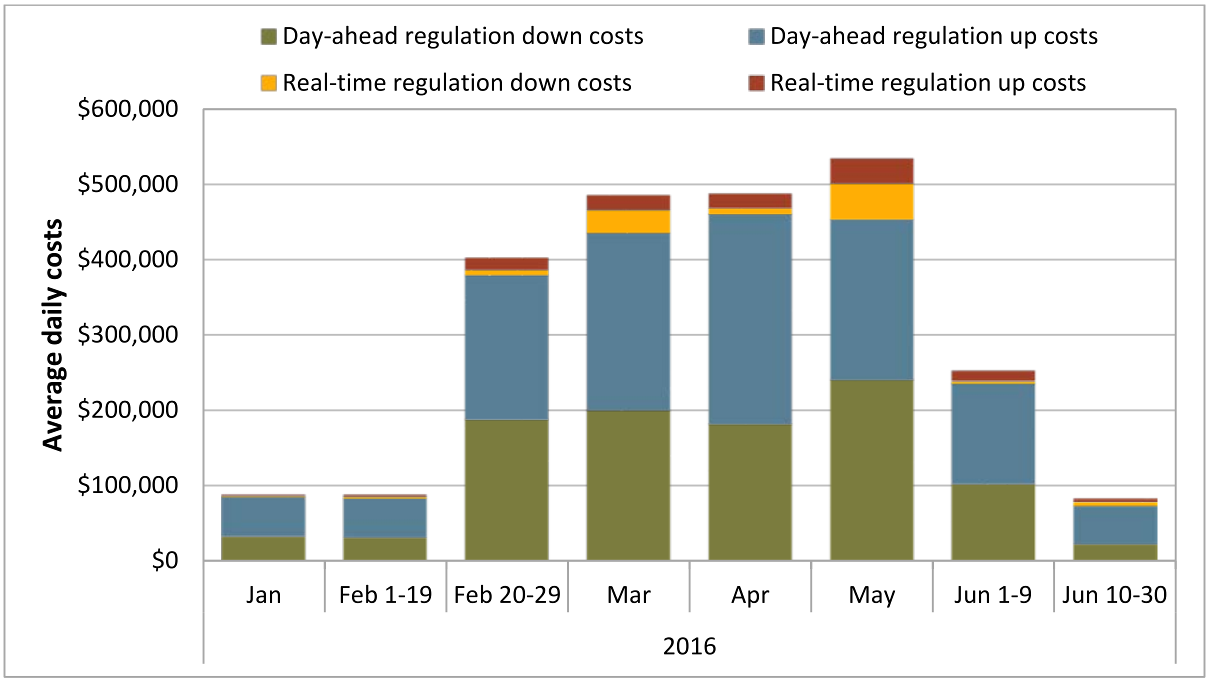
The frequency of positive load adjustments increased in the ISO and Nevada areas while the frequency of negative load adjustments increased in the PacifiCorp area. Table E.1 summarizes the average frequency and size of positive and negative load forecast adjustments for the ISO and EIM balancing areas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

Table E.1 Average frequency and size of load adjustments (April – June)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	37%	450	1.6%	19%	-292	1.3%	112
5-minute market	49%	455	1.7%	29%	-301	1.3%	137
PacifiCorp East							
15-minute market	3%	83	1.7%	42%	-110	2.1%	-44
5-minute market	7%	85	1.7%	64%	-130	2.7%	-77
PacifiCorp West							
15-minute market	9%	59	2.7%	29%	-55	2.6%	-11
5-minute market	12%	63	2.9%	39%	-57	2.8%	-15
NV Energy							
15-minute market	48%	127	2.8%	2%	-171	5.1%	57
5-minute market	47%	90	2.0%	10%	-70	1.9%	36

Regulation requirements and prices decreased to historic levels starting June 10. From February 20 through June 9, 2016, the ISO increased the requirements to a minimum of 600 MW for regulation up and regulation down in both the day-ahead and real-time markets. Average prices for these two ancillary services increased immediately following the change in requirements in February and reverted back to lower levels again in June. Regulation procurements costs continued to average over $400,000 per day when the requirements were higher and fell to $80,000 per day when the requirements were lowered beginning June 10 (see Figure E.2).

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



Aliso Canyon gas-electric coordination measures were phased in. Features that went into effect on June 2 include the following: 1) a set of constraints to limit the gas burn or deviations in gas burn compared to day-ahead schedules; 2) ability to rebid commitment costs for resources not committed in the day-ahead market; 3) authority to reserve internal transfer capability; and 4) the authority to suspend virtual bidding. Market conditions in June did not warrant the use of these tools by the ISO. On July 6, the ISO included a 25 percent and 75 percent adder to the gas prices used in the calculation of default energy bids and commitment costs, respectively, in the real-time markets. The ISO did not begin to use an updated natural gas price index based on the next-day trades in the day-ahead market, because the ISO was not able to confirm that this price would be consistent with the FERC policy statement on natural gas indices. DMM continues to support implementing this functionality as soon as possible. On July 1, the ISO filed a limited tariff waiver with FERC to suspend the effectiveness of the tariff revisions until no later than August 5, 2016, so as to allow additional time to explore possible solutions. Overall, the measures implemented by the ISO appear to have been sufficient to help manage the limitations on the Southern California Gas Company (SoCalGas) system during the summer.

1 Market performance

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

- Day-ahead prices in April and May continued to remain low compared to previous periods, in both peak and off-peak periods. However, prices increased in June as loads rose because of warmer temperatures and as natural gas prices trended up.
- Prices in the day-ahead market were slightly higher than 15-minute market prices for most of the quarter. However, 5-minute market prices were significantly above day-ahead and 15-minute prices during several peak evening ramping hours during the quarter.
- In the second quarter, the frequency of price spikes in the 5-minute market increased to about 1 percent of intervals. This was mostly driven by tight supply conditions in hours ending 19 and 20 when 5-minute prices were above $250/MWh during about 6 percent of intervals.
- There was also an increase in the frequency of negative prices from the previous quarter, particularly in April and May. This was largely due to high solar generation in combination with modest loads in hours ending 9 through 18 during those months.
- Total payments for the flexible ramping constraint during the second quarter increased to about $2.1 million, compared to about $1.3 million for the first quarter.
- Congestion during the second quarter was low and had a relatively small impact on average load area prices, but was slightly higher when compared to the previous quarter. Much of the congestion in the second quarter was due to prolonged transmission outages and contingencies. In the day-ahead market, congestion increased Pacific Gas and Electric and San Diego Gas and Electric load area prices by about $0.20/MWh and $1.10/MWh, respectively, while decreasing Southern California Edison area prices by about $0.20/MWh. In the 15-minute market, congestion had a low impact on Pacific Gas and Electric and Southern California Edison area prices but increased the San Diego Gas and Electric load area prices by about $0.40/MWh.
- Ratepayer payments to auctioned congestion revenue rights continued to exceed the auction revenues received by ratepayers. Payments exceeded auction revenues by $27 million in the first half of 2016 compared to $26 million in the first half of 2015. Ratepayers received just $0.63 in auction revenue for every dollar paid to auctioned rights, down from $0.72 in the first half of 2015.
- Financial entities continued to receive the most profits from the congestion revenue rights sold in the auction. In the first half of 2016 profits garnered by financial entities totaled $22.5 million. Marketers received $3.9 million in profits, while generating companies received $0.8 million.
- Bid cost recovery payments were over $21 million in the second quarter, compared to about $15 million in the first quarter and $27 million in the second quarter of 2015. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $15 million in the second quarter, up from low real-time costs in the first quarter of about $10 million. About $3 million of real-time payments during the quarter were made to units that were exceptionally dispatched. Day-ahead bid cost recovery payments totaled about $4 million, while payments for residual unit commitment totaled about $2 million.

- Virtual supply outweighed virtual demand by about 820 MW on average, compared to about 800 MW of net virtual supply in the previous quarter. Total convergence bidding revenue, adjusted for bid cost recovery charges, was about $4.4 million in the second quarter, which is an increase from about $1.3 million in the previous quarter.

1.1 Energy market performance

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

Figure 1.1 shows average monthly system marginal energy prices during all hours. As seen in this figure, average day-ahead market prices were slightly higher than 15-minute market prices during the quarter. Overall, prices continued to remain low in April and May before increasing in June. Higher prices in June resulted in part from higher natural gas prices and seasonally higher loads. The increase in average prices in June by roughly $10/MWh in the day-ahead, 15-minute, and 5-minute markets was similar to what occurred in June of last year.

- Average day-ahead prices increased during the second quarter, particularly in June. Day-ahead prices in June were about $34/MWh during peak periods and about $26/MWh during off-peak periods. Day-ahead prices for the quarter averaged about $27/MWh during peak periods and $21/MWh during off-peak periods.

- In the second quarter, 15-minute market prices also increased and tracked closely to day-ahead prices. Average prices in the 15-minute market continue to be lower than day-ahead prices for the quarter, by about $1/MWh during peak periods and $0.30/MWh during off-peak periods.

- Average prices in the 5-minute market remained at about $20/MWh in April and May, then increased to about $34/MWh in June. During June, 5-minute market prices averaged $4/MWh above day-ahead prices and $6/MWh above 15-minute market prices. This was largely driven by high system prices during evening hours because of tight supply conditions while ramping up to evening peak loads.

Figure 1.2 illustrates the system marginal energy prices on an hourly basis in the second quarter alongside average hourly net load.[5] The prices in this figure follow the net load 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. Lower prices during the middle of the day correspond to times when low-priced solar generation is greatest, and thus net demand is low. Solar generation continued to grow in the ISO during the quarter, and utility scale solar set a new record at 7,946 MW on June 24. As additional solar continues to come on-line, the net load curve during the middle of the day continues to decrease along with average system prices as solar and other renewable generation set prices more frequently.

Figure 1.2 also shows that average prices in the 15-minute market were typically less than day-ahead prices during most hours of the day. Although the two prices were nearly converged, the greatest difference continues to persist during the middle of the day when solar generation is greatest. This

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

difference is often driven by less solar generation scheduled in the day-ahead market than what is actually available in the real-time markets.

Prices in the 5-minute market were significantly higher (more than $20/MWh) than day-ahead and 15-minute market prices during hours 19 and 20. These hours frequently had tight supply conditions with significant differences in load adjustments between the 15-minute and 5-minute markets. This contributed to price spikes in the 5-minute market because of the narrow planning horizon and the significant amount of generation required to replace solar generation ramping down for the day as well as increases in system loads during the evening peak.

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

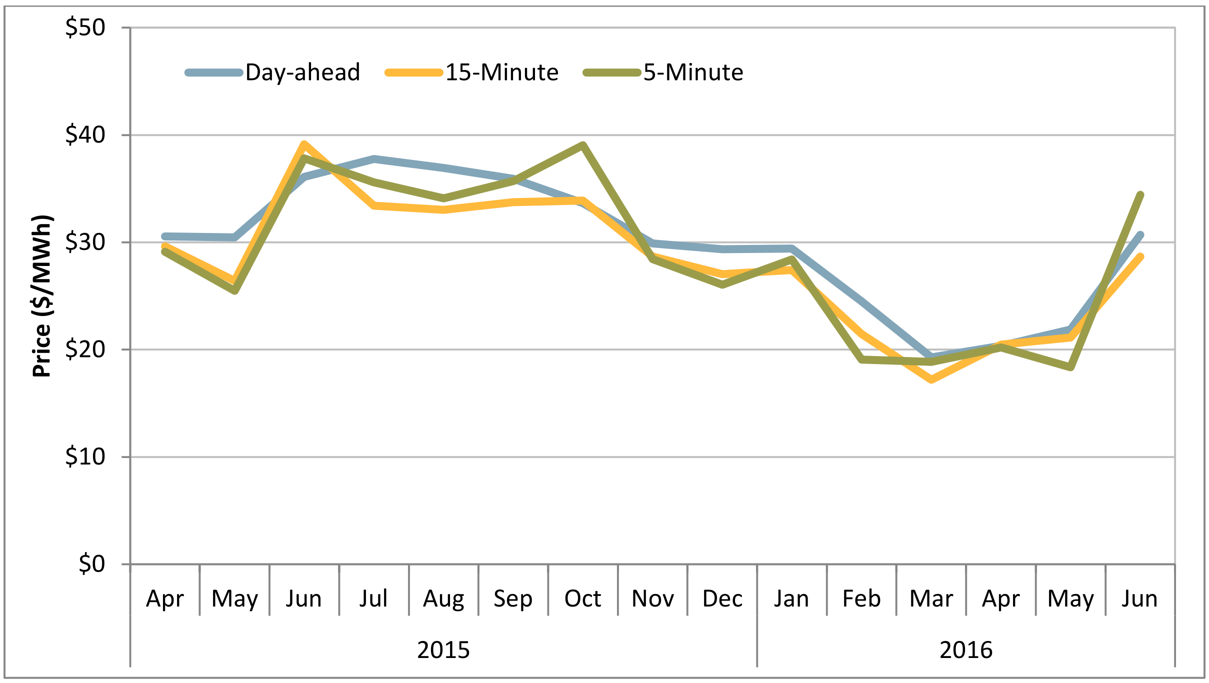
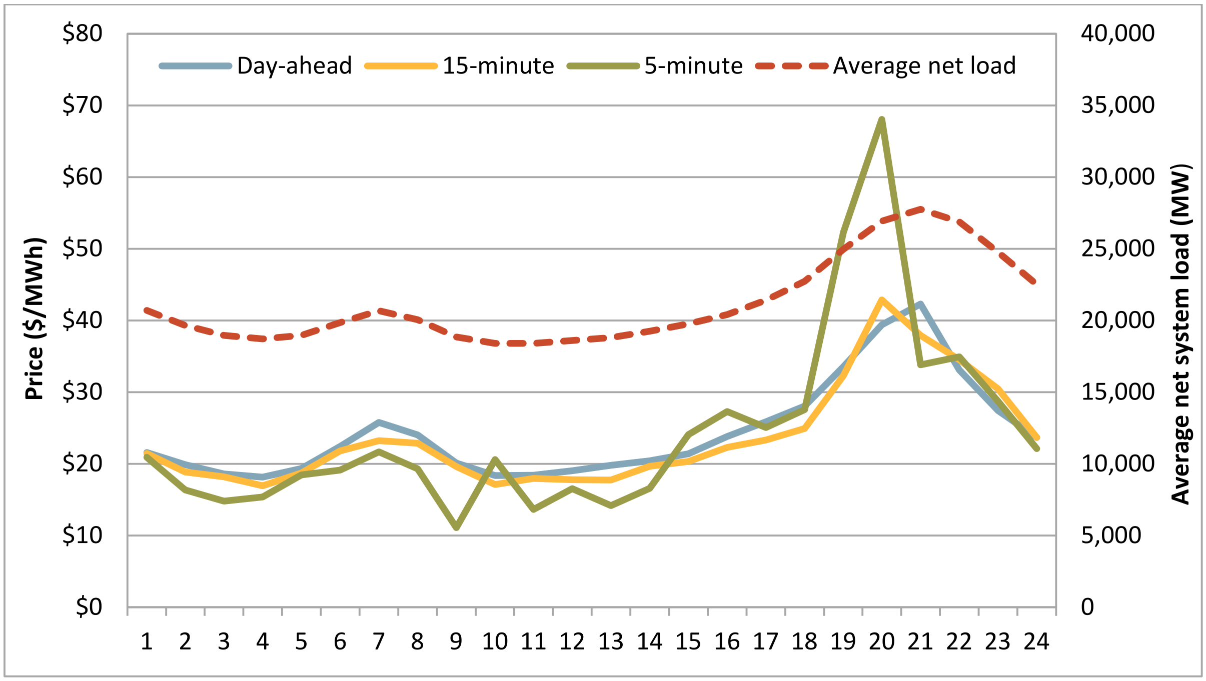


Figure 1.2 Hourly system marginal energy prices (April – June)



1.2 Real-time price variability

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

High prices

During the second quarter, the frequency of high price spikes decreased in the 15-minute market compared to the prior quarter and the second quarter of 2015. Prices in the 5-minute market increased slightly compared to both the previous quarter and the second quarter of 2015, but remained relatively low overall. Prices above $250/MWh were observed in only about 0.1 percent of intervals in the 15-minute market and 1 percent of intervals in the 5-minute market.

Figure 1.3 shows the frequency of high price spikes occurring in the 5-minute market on an hourly basis.[6] The frequency of price spikes in the 5-minute market was low at about 1 percent of intervals in the second quarter, up from 0.7 percent during the first quarter. This was largely driven by an increase in the frequency of positive price spikes in hours ending 19 and 20 during the second quarter.

Hours 19 and 20, when loads were high, had significantly more intervals when prices were above $250/MWh than other times of the day. During these hours about 6 percent of 5-minute intervals had prices above $250/MWh, and were primarily a result of tight supply conditions while ramping to meet

[6] The frequency of 15-minute price spikes remained very low, averaging just 0.1 percent of intervals in the second quarter, similar to previous quarters. Price spikes in the 15-minute market predominantly occurred during several peak load hours in June.

evening peak loads. During the majority of intervals when prices were greater than $750/MWh, either significant south-to-north congestion was present or the power balance constraint was relaxed because of insufficient upward ramping capacity.

Negative prices

The frequency of negative prices increased in the 15-minute and 5-minute markets in the second quarter compared to the prior quarter and the second quarter of 2015, as renewable resources continued to set market prices more frequently. However, the frequency of prices at or below the -$150/MWh bid floor dropped to about 0.1 percent of 5-minute intervals in the second quarter compared to about 1 percent during the same quarter in 2015. This reflects a significant decrease in the 5-minute intervals when the supply of negatively priced real-time bids to decrease generation was exhausted and some resources needed to be curtailed. This has been partly the result of an increase in bidding flexibility of renewable resources as well as increased transfer capability in the real-time market as a result of EIM. The percentage of intervals with prices below -$150/MWh has been persistently low during the last 12 months.

Overall, negative prices occurred during about 16 percent of intervals in late morning/early afternoon hours of the quarter, mostly because of more renewable generation on the system combined with lower loads and increased hydro-electric generation. During the quarter, negative prices occurred in over 8 percent of the intervals compared to about 7 percent of intervals in the previous quarter and about 8 percent of intervals in the second quarter of 2015.

Figure 1.4 and Figure 1.5 show the frequency of negative prices by hour in the 15-minute and 5-minute markets during the quarter. In the 15-minute and 5-minute markets, negative prices primarily occurred during April and May as a result of high availability of renewable generation, particularly solar, in combination with modest loads in hours ending 9 through 18. During these hours, negative prices occurred during about 8 percent of 15-minute intervals and 16 percent of 5-minute intervals. Solar generation set a new record at nearly 8,000 MW during the quarter and averaged nearly 6,800 MW during midday hours, compared to about 5,200 MW during the second quarter of 2015.[7]

Figure 1.6 shows the frequency of negative prices occurring in the 5-minute market by month. Negative prices in April occurred in about 8 percent of intervals in the 15-minute market and just over 15 percent of intervals in the 5-minute market. This was the highest frequency of negative prices in the 5-minute market during a month in the past several years, again largely because of the high quantities of renewable generation on-line and relatively low loads. A corresponding figure for the 15-minute market was not included, but reflects a similar pattern with higher frequencies of negative prices during March and April.

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

Figure 1.3 Hourly frequency of high 5-minute price spikes (April – June)

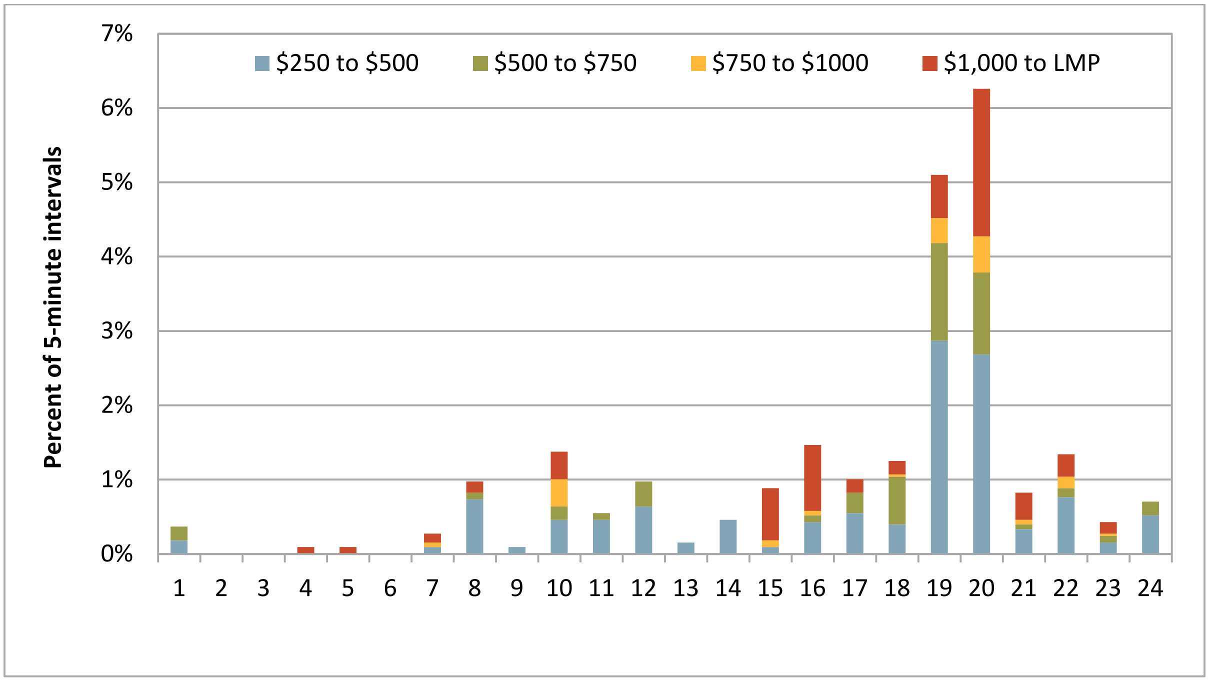


Figure 1.4 Hourly frequency of negative 15-minute prices (April – June)

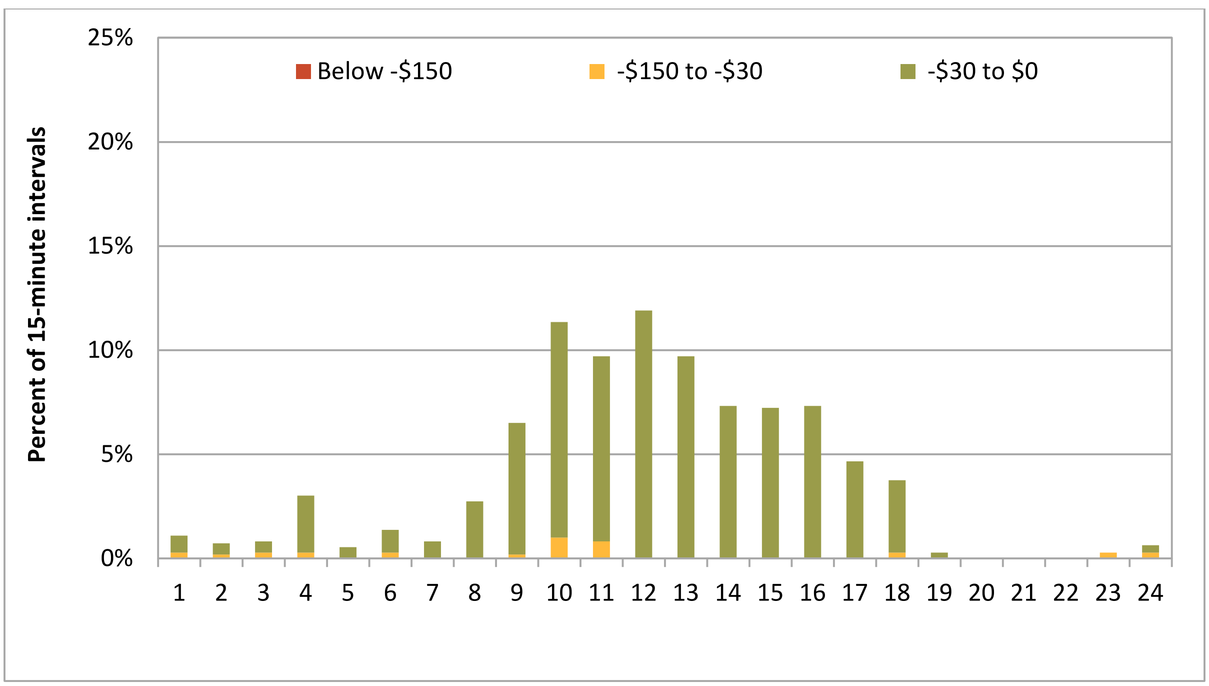


Figure 1.5 Hourly frequency of negative 5-minute prices (April – June)

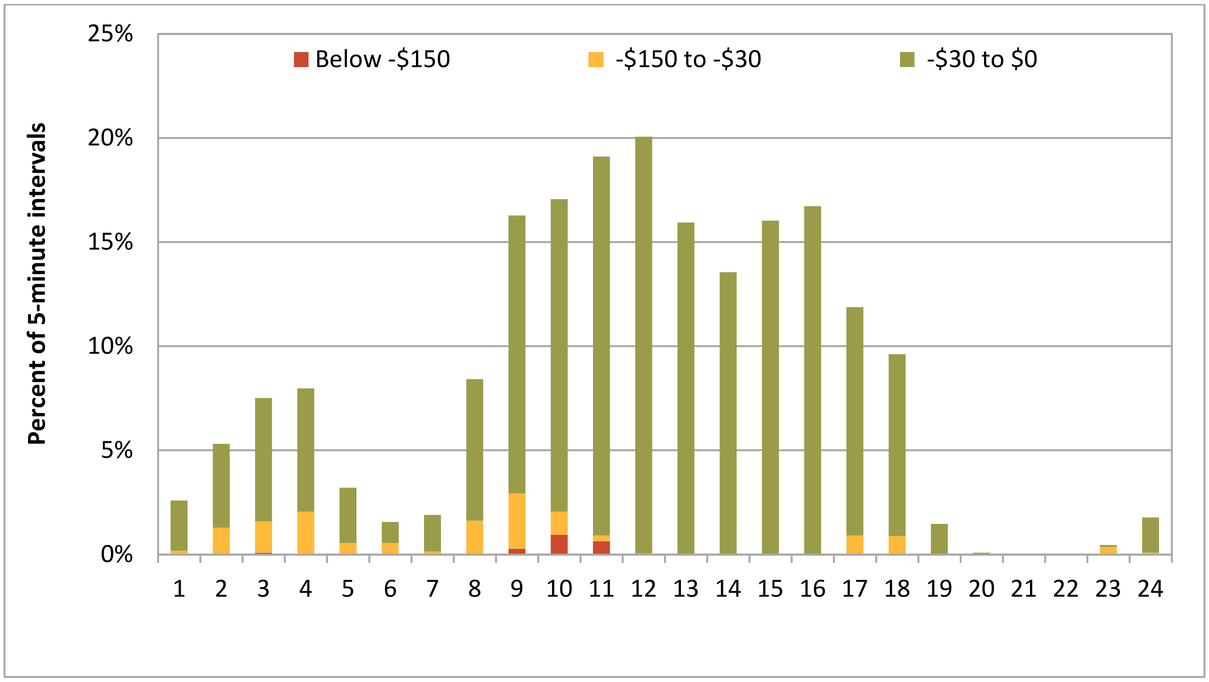
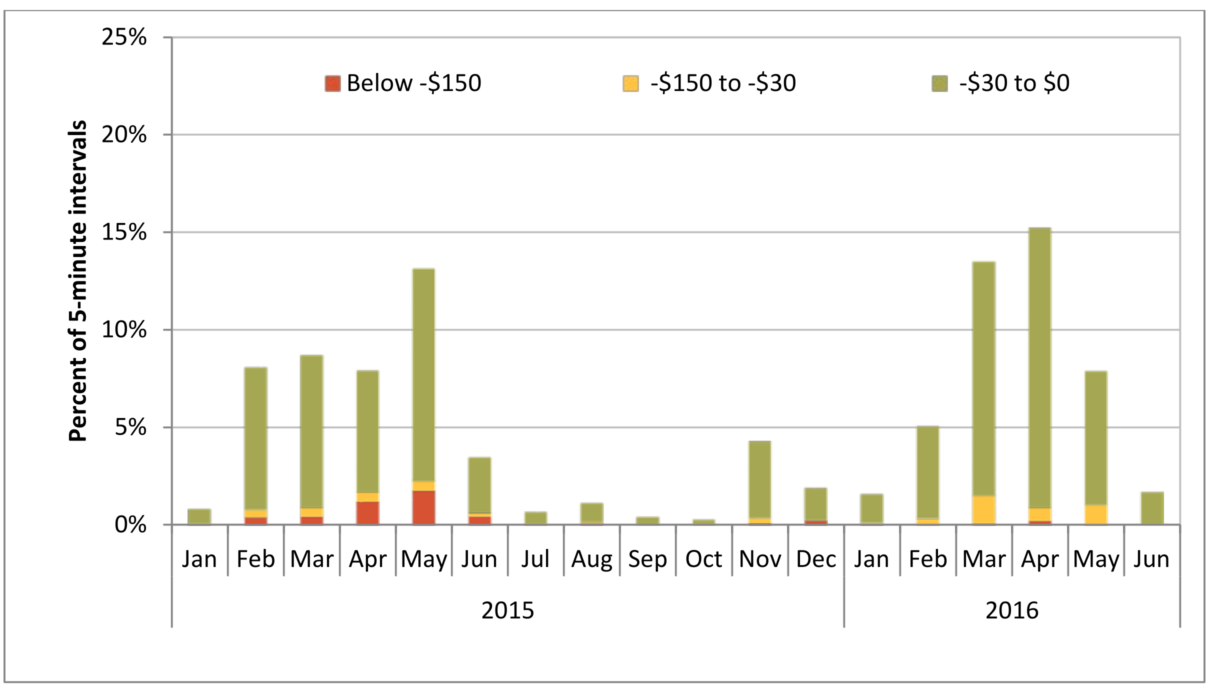


Figure 1.6 Frequency of negative 5-minute prices by month



1.3 Flexible ramping payments

Total payments to generators in the ISO and EIM areas for providing flexible ramping capacity remained low during the second quarter, totaling about $2.1 million compared to $1.3 million during the previous quarter.

There were no significant changes in the flexible ramping requirements in the second quarter compared to the first quarter. The increase in costs was likely attributable to supply conditions. For example, fewer units were on-line and available to provide flexible ramping capacity during April and May when renewable output was high and loads were generally lower.

The majority of payments for procuring flexible ramping capacity were made to units in the ISO, at over $1 million, while less than $1 million was accrued in all EIM areas combined for the quarter. Regionally, increases in procurement costs were a result of increases in the ISO, from about $800,000 in the first quarter to about $1.3 million in the second, as well as increased procurement costs in PacifiCorp West that rose from about $100,000 to about $400,000 for the same period.

Table 1.1 shows monthly payments made for flexible ramping capacity by area. More than $500,000 of payments were made to resources in the ISO in April and May, which resulted in relatively high total payments for both months.[8] This is likely a result of high renewable generation on-line and seasonal low loads during these months, resulting in fewer units available to provide flexible ramping capacity in the real-time market. Payments for flexible ramping capacity in the ISO are also directly influenced by the prices for spinning reserves which were also relatively high during the spring months. In June, lower total expenditures were observed for flexible ramping capacity, when increased loads resulted in more commitment of units capable of providing flexible ramping capacity.

Figure 1.7 shows quarterly expenditures for flexible ramping capacity in each area. The gold lines show the amount of payments made to generators for flexible ramping capacity per megawatt-hour of total area load. This metric shows that costs for flexible ramping capacity in all areas for the last six quarters have remained below $0.10/MWh of load and continue to be relatively inexpensive.

During the second quarter, costs were particularly low in the ISO, PacifiCorp East and NV Energy totaling only about $0.02/MWh of load, and were higher at $0.10/MWh of load in PacifiCorp West. Higher payments per megawatt-hour of load in PacifiCorp West may have been the result of an increased frequency of flexible ramping shortages in PacifiCorp West compared to previous quarters.

Figure 1.7 also shows that most of the payments (about 60 percent) in the second quarter were made to generators in the ISO. About half of all payments were made to gas-fired capacity, about a third to hydro-electric capacity, and the remainder to units with other fuel types. Most of the hydro-electric capacity payments were made to units located in the ISO.

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[8] The payments reported in Table 1.1 are net of recessions for non-performance. Prior to the fourth quarter of 2015, flexible ramping payments reported in DMMs quarterly reports represented gross payments. The payments reported in Table 1.1 may therefore differ slightly from earlier reports.

During the second quarter, costs were particularly low in the ISO, PacifiCorp East and NV Energy totaling only about $0.02/MWh of load, and were higher at $0.10/MWh of load in PacifiCorp West. Higher payments per megawatt-hour of load in PacifiCorp West may have been the result of an increased frequency of flexible ramping shortages in PacifiCorp West compared to previous quarters.

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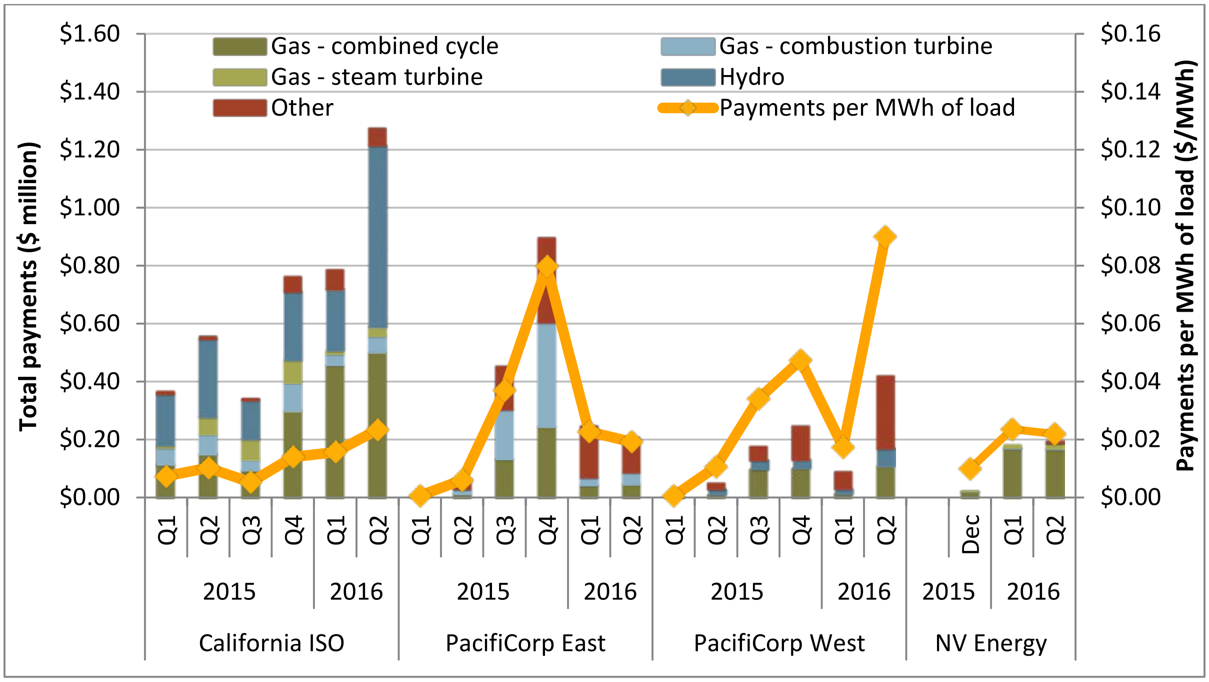
Table 1.1 Total payments to generators for flexible ramping capacity by area

Year	Month	ISO ($ thousands)	PacifiCorp East ($ thousands)	PacifiCorp West ($ thousands)	NV Energy ($ thousands)	Total ($ thousands)
2015	Jan	$38.5	$0.3	$0.0		$38.8
	Feb	$93.9	$1.2	$0.5		$95.6
	Mar	$238.9	$5.5	$2.1		$246.5
	Apr	$240.4	$31.6	$15.0		$287.1
	May	$67.2	$7.8	$3.7		$78.7
	Jun	$247.1	$27.9	$33.2		$308.2
	Jul	$109.0	$29.3	$10.2		$148.4
	Aug	$117.5	$155.5	$69.5		$342.6
	Sep	$119.2	$305.6	$111.3		$536.2
	Oct	$359.1	$463.5	$101.4		$924.1
	Nov	$309.0	$405.6	$96.4		$811.1
	Dec	$95.8	$26.3	$52.5	$30.7	$205.2
2016	Jan	$99.2	$25.5	$18.9	$33.4	$177.1
	Feb	$181.4	$70.9	$15.7	$61.7	$329.8
	Mar	$507.6	$163.7	$58.6	$86.7	$816.5
	Apr	$542.5	$106.3	$243.5	$74.4	$966.6
	May	$549.4	$60.2	$130.2	$71.6	$811.5
	Jun	$182.3	$43.8	$50.9	$51.6	$328.7

Figure 1.7 Flexible ramping payments by fuel and balancing area



1.4 Congestion

Congestion was slightly higher when compared to the previous quarter, but had a small overall impact on load aggregation point prices across the ISO in the day-ahead and real-time markets.

1.4.1 Congestion impacts of individual constraints

Day-ahead congestion

The frequency and impact of congestion in the day-ahead market was low in the second quarter, but slightly higher when compared to the prior quarter.

In the day-ahead market, congestion increased Pacific Gas and Electric and San Diego Gas and Electric load area prices by about $0.20/MWh and $1.10/MWh, respectively, while decreasing Southern California Edison area prices by about $0.20/MWh. In the 15-minute market, congestion had a low impact on Pacific Gas and Electric and Southern California Edison area prices but increased the San Diego Gas and Electric load area prices by about $0.40/MWh. 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.

In the Pacific Gas and Electric area, the constraint modeling thermal conditions on Round Mountain-Cottonwood 230 kV (6110_SOL10_NG) and the Path 15 constraint (OMS 3602720_Path15) bound the most frequently during the second quarter, at 16 percent and 8 percent of all intervals, respectively. When Round Mountain-Cottonwood 230 kV bound it had a very small impact on load area prices. However, when Path 15 bound, it increased Pacific Gas and Electric area prices by about $6/MWh, while decreasing Southern California Edison and San Diego Gas and Electric area prices by about $5/MWh and $4/MWh, respectively.

Similarly, in the Southern California Edison area, the Vincent 500/230 kV transformer bound most frequently at about 4 percent of hours in the quarter. While the constraint bound it increased prices in the Southern California Edison and San Diego Gas and Electric areas by about $4/MWh and $5/MWh, respectively, and caused a price decrease of about $6/MWh in the Pacific Gas and Electric area.

Lastly, Mission-Carlton Hills 138 kV bound most frequently in the San Diego Gas and Electric area during the second quarter at about 5 percent of all hours. When binding it increased San Diego Gas and Electric area prices by about $3/MWh and had no impact on Pacific Gas and Electric and Southern California Edison load area prices.

Table 1.2 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency		Q1			Q2		
Area	**Constraint**	**Q1**	**Q2**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
PG&E	6110_SOL10_NG		16.2%				$0.07	-$0.07	-$0.07
	OMS 3602720_Path15		8.3%				$6.10	-$4.78	-$4.49
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		1.1%				$2.01	-$2.06	
	PATH15_S-N	2.3%	1.0%	$2.34	-$2.05	-$1.92	$4.04	-$3.32	-$3.10
	LOSBANOSNORTH_BG		0.7%				$4.60	-$3.80	-$3.52
	6310_SOL3_NG_SUM		1.4%				-$0.80	$0.65	$0.60
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	28.6%		$1.18	-$0.98	-$0.95			
	OMS 2592148 P15 HARD	1.8%		$3.44	-$2.87	-$2.69			
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.5%		-$1.67	$1.40	$1.29			
	PATH26_BG	0.3%		-$2.54	$2.13	$2.01			
SCE	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P		3.7%				-$6.20	$4.41	$4.69
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1		3.0%				-$1.75	$1.44	$1.07
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		1.2%				-$4.23	$3.25	$4.72
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	6.1%	1.2%	-$1.05	$1.52	-$0.50	-$0.99	$1.08	$1.30
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	2.2%	1.1%	-$1.15	$1.50		-$0.62	$0.90	$1.05
	24156_VINCENT _500_24155_VINCENT _230_XF_1 _P		0.5%				-$2.33	$1.93	$1.94
SDG&E	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1	1.2%	5.4%			$2.62			$3.21
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	1.5%	5.2%			$2.35			$5.94
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1		3.2%						$0.46
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	5.0%	3.0%	-$1.83		$11.38	-$1.62		$11.97
	7820_TL 230S_OVERLOAD_NG	1.9%	2.4%	-$0.20		$2.13	-$0.25		$3.30
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1		1.1%						$6.99
	OMS 3725346 IV_NGILA		1.1%				-$1.10	$0.87	$1.20
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		1.0%						$5.09
	OMS 3725348 50002_OOS_TDM		0.7%						$3.48
	OMS 4079303 TL50001_NG		0.4%				-$1.01		$12.95
	22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1		0.1%						$89.43
	IID-SCE_BG	3.7%				-$2.35			
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1	2.5%				$6.82			
	OMS 2319325 PDCI_NG	2.0%		-$1.74	$1.43	$1.78			
	22464_MIGUEL _230_22472_MIGUELMP_ 1.0_XF_1	1.3%		-$1.14		$7.33			
	OMS 3624980 TL50001_NG	1.3%		-$0.35		$4.20			
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1	0.9%		-$0.82		$3.88			
	OMS 3636555 McC-Vic_6510	0.9%		-$3.55	$3.01	$3.66			
	24016_BARRE _230_24044_ELLIS _230_BR_1 _1	0.8%		-$1.12		$5.31			
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.6%		-$1.03		$6.87			
	22464_MIGUEL _230_22461_MIGUEL60_138_XF_1	0.6%				$3.17			
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.3%		-$4.66	$3.21	$6.61			

15-minute market congestion

Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had larger price effects. This is typical of congestion patterns in the real-time market and matches patterns in recent quarters. Table 1.3 shows the frequency and magnitude of 15-minute market congestion in the quarter.

In the Pacific Gas and Electric area, similar to the day-ahead markets, the Round Mountain-Cottonwood 230 kV (6110_SOL10_NG) and the Path 15 (OMS 3602720_Path15) constraints bound most frequently during the second quarter at 2 percent and 1 percent of all the intervals, respectively. These constraints were also the most congested in the day-ahead market. When Round Mountain-Cottonwood 230 kV bound it increased Pacific Gas and Electric area prices by about $2/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by less than $1/MWh. When the Path 15 constraint bound in the 15-minute market it increased Pacific Gas and Electric area prices by about $12/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by about $10/MWh and $9/MWh, respectively.

In the San Diego Gas and Electric area, the constraint modeling the 500/230 kV transformer bank outage at Miguel bound most frequently during the quarter, but bound during less than 1 percent of intervals in the 15-minute market. When Miguel 500/230 kV transformer bound it increased San Diego Gas and Electric area prices by about $27/MWh and had no impact on the Pacific Gas and Electric and Southern California Edison area prices.

Table 1.3 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

Area	Constraint	Frequency		Q1			Q2		
		Q1	Q2	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	6110_SOL10_NG		2.0%				$2.17	$0.70	$0.53
	OMS 3602720_Path15		1.0%				$11.53	-$10.07	-$9.46
	PATH26_N-S	0.1%	0.5%	-$14.53	$12.27	$11.57	-$29.51	$19.67	$18.51
	30055_GATES1 _500_30900_GATES _230_XF_11_P		0.1%				$11.75	-$7.62	-$7.41
	PATH15_N-S		0.1%				-$5.53	$4.49	$4.23
	PATH15_BG		0.1%				$9.16	-$8.12	-$7.64
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	2.2%		$2.29	-$1.89	-$1.80			
	PATH15_S-N	0.3%		$18.34	-$19.11	-$18.02			
	OMS 2592148 P15 HARD	0.2%		$8.58	-$8.51	-$8.02			
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.1%		-$15.84	$13.89	$12.80			
SCE	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.2%				-$9.31	$12.57	$16.40
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1		0.1%				$10.54	$16.70	$16.49
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.4%		-$1.51	$8.20	$1.09			
SDG&E	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	1.1%	0.5%			$28.79			$26.91
	7820_TL 230S_OVERLOAD_NG	0.3%	0.4%	-$1.23		$26.61	-$0.57	$0.40	$13.62
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.1%	0.3%			$33.98	-$1.27	-$1.48	$15.99
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1		0.3%						$11.50
	OMS 2319325 PDCI_NG	0.4%		-$23.09	$54.26	$59.95			
	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			
	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			
	24016_BARRE _230_24044_ELLIS _230_BR_4 _1	0.1%		-$4.37		$26.82			

1.4.2 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.[9] The congestion price impact differs across load areas and markets.

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

Day-ahead price impacts

Table 1.4 shows the overall impact of day-ahead congestion on average prices in each load area during the quarter by constraint.[10] Overall this impact was small and less than $1/MWh (less than 1 percent) in the Pacific Gas and Electric and Southern California Edison areas, and just above a $1/MWh (4 percent) impact on San Diego Gas and Electric area prices. The congestion on Path 15, because of the Diablo-Gates 500 kV outage, had the largest overall impact on prices in the second quarter, and increased prices in the Pacific Gas and Electric area by about $0.50/MWh (2 percent) and decreased Southern California Edison and San Diego Gas and Electric area prices by about $0.40/MWh.

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

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

Table 1.4 Impact of congestion on overall day-ahead prices

Constraint	PG&E		SCE		SDG&E	
	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
OMS 3602720_Path15	$0.51	2.06%	-$0.40	-1.66%	-$0.37	-1.44%
24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	-$0.23	-0.93%	$0.16	0.68%	$0.17	0.67%
22464_MIGUEL _230_22468_MIGUEL _500_XF_81	-$0.05	-0.19%			$0.36	1.37%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.31	1.20%
22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1					$0.17	0.66%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.05	-0.21%	$0.04	0.17%	$0.06	0.23%
PATH15_S-N	$0.04	0.16%	-$0.03	-0.13%	-$0.03	-0.12%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.03	-0.13%	$0.03	0.11%	$0.03	0.12%
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.02%			$0.08	0.31%
22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1					$0.08	0.32%
LOSBANOSNORTH_BG	$0.03	0.13%	-$0.03	-0.11%	-$0.02	-0.09%
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1					$0.08	0.30%
OMS 4079303 TL50001_NG	$0.00	-0.02%			$0.05	0.21%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					$0.05	0.19%
OMS 3725346 IV_NGILA	-$0.01	-0.05%	$0.01	0.04%	$0.01	0.05%
24156_VINCENT _500_24155_VINCENT _230_XF_1 _P	-$0.01	-0.05%	$0.01	0.04%	$0.01	0.04%
6310_SOL3_NG_SUM	-$0.01	-0.05%	$0.01	0.04%	$0.01	0.03%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.05%	$0.01	0.05%	$0.00	0.01%
6110_SOL10_NG	$0.01	0.04%	$0.00	-0.02%	-$0.01	-0.05%
OMS 3725348 50002_OOS_TDM					$0.02	0.09%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.02	0.09%	$0.00	-0.01%		
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.03%	$0.01	0.04%	$0.00	0.01%
PATH26_BG	-$0.01	-0.03%	$0.00	0.02%	$0.00	0.02%
22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1					$0.01	0.06%
Other	$0.02	0.09%	$0.01	0.02%	$0.05	0.19%
Total	**$0.20**	**0.8%**	**-$0.17**	**-0.7%**	**$1.13**	**4.37%**

15-minute price impacts

Table 1.5 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint.[11] Congestion during the second quarter of 2016 increased San Diego Gas and Electric area prices by about $0.40/MWh (2 percent) with minimal impact on Pacific Gas and Electric and Southern California Edison area prices. Drivers of congestion in the San Diego Gas and Electric area were the Miguel 500/230 kV transformer bank outage and Path 26 congestion in the north-to-south direction.

[11] Details on constraints with shift factors less than 2 percent have been grouped in the 'other' category.

Table 1.5 Impact of congestion on overall 15-minute prices

Constraint	PG&E $/MWh	PG&E Percent	SCE $/MWh	SCE Percent	SDG&E $/MWh	SDG&E Percent
PATH26_N-S	-$0.14	-0.59%	$0.09	0.39%	$0.09	0.35%
OMS 3602720_Path15	$0.12	0.50%	-$0.10	-0.44%	-$0.10	-0.38%
22464_MIGUEL _230_22468_MIGUEL _500_XF_81					$0.14	0.55%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.02	-0.09%	$0.03	0.13%	$0.04	0.16%
6110_SOL10_NG	$0.04	0.18%	$0.01	0.06%	$0.01	0.03%
7820_TL 230S_OVERLOAD_NG	$0.00	0.00%	$0.00	0.00%	$0.05	0.19%
22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	$0.00	0.00%	$0.00	0.00%	$0.05	0.18%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.02	0.07%	-$0.01	-0.05%	-$0.01	-0.04%
24155_VINCENT _230_24091_MESA CAL_230_BR_2 _1	-$0.02	-0.07%	$0.01	0.04%	$0.01	0.05%
22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1					$0.04	0.14%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.01	0.03%	$0.01	0.05%	$0.01	0.05%
PATH15_BG	$0.01	0.04%	-$0.01	-0.04%	-$0.01	-0.04%
PATH15_N-S	-$0.01	-0.03%	$0.01	0.03%	$0.01	0.02%
24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.01	0.02%			-$0.01	-0.04%
GON-RBS_3430_ZB			-$0.01	-0.03%	-$0.01	-0.03%
Other	-$0.02	-0.08%	$0.00	0.01%	$0.14	0.56%
Total	**$0.00**	**-0.01%**	**$0.04**	**0.16%**	**$0.44**	**1.74%**

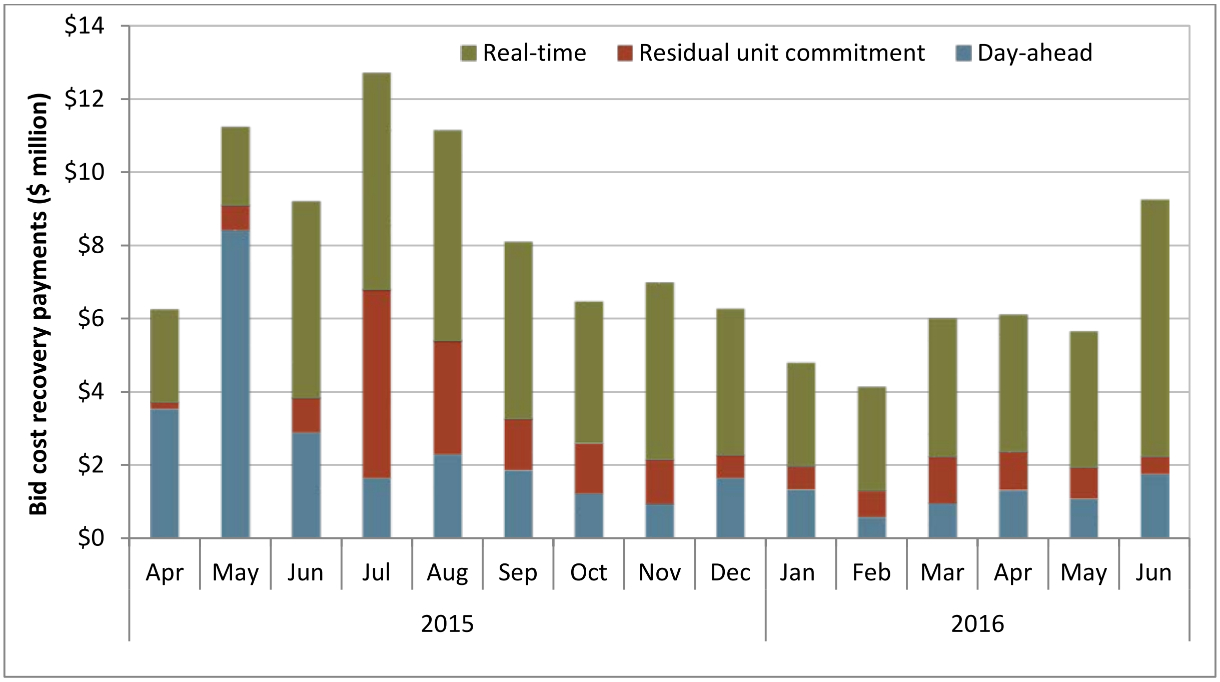
1.5 Bid cost recovery

Estimated bid cost recovery payments for the second quarter totaled about $21 million. This is a decrease from about $27 million paid during the second quarter of 2015, but more than the $15 million paid for bid cost recovery in the first quarter of 2016.

Bid cost recovery attributed to the day-ahead market totaled about $3 million, while bid cost recovery for residual unit commitments remained low when compared to historical averages at about $2 million. Real-time payments continued to make up the majority of bid cost recovery payments, at about $14 million in the second quarter, up from about $10 million in the first quarter.

A significant amount of the real-time bid cost recovery payments occurred on a small number of days in June when loads were high and expensive units were committed in the real-time market. Real-time bid cost recovery payments can increase when more units are exceptionally dispatched. In the second quarter real-time payments to units that were exceptionally dispatched made up almost $3 million of the total payments, with most being made during May and June.

Figure 1.8 Monthly bid cost recovery payments



1.6 Convergence bidding

Participants engaging in convergence bidding continued to earn positive returns in the second quarter. Net revenues from the market in these three months were about $6.4 million. Virtual supply generated net revenues of about $3.9 million, while virtual demand generated net revenues of about $2.5 million. Total payments to convergence bidders decreased to about $4.4 million after accounting for $2 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 51 percent of all accepted virtual bids in the second quarter, which is about the same frequency as similar virtual activity in the previous quarter.

Total hourly trading volumes increased in the second quarter to about 3,200 MW from 2,700 MW in the previous quarter. Virtual supply averaged around 2,000 MW while virtual demand averaged around 1,200 MW during each hour of the quarter, compared to around 1,750 MW and 950 MW, respectively, in the previous quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 820 MW on average, similar to the level in the previous quarter.

Net revenues for most of the second quarter were positive from net virtual supply positions as prices were generally higher in the day-ahead market than the 15-minute market.[12]

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

1.6.1 Convergence bidding trends

Total hourly trading volumes increased in the second quarter to about 3,200 MW from 2,700 MW during the previous quarter. On average, about 49 percent of virtual supply and demand bids offered into the market cleared in the second quarter, which is down from 55 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 820 MW on average, which is similar to the level of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours by about 780 MW and 920 MW, respectively. For the quarter, net cleared virtual supply exceeded net cleared virtual demand in all hours. The highest net cleared virtual supply hour was hour 10 at over 1,100 MW.

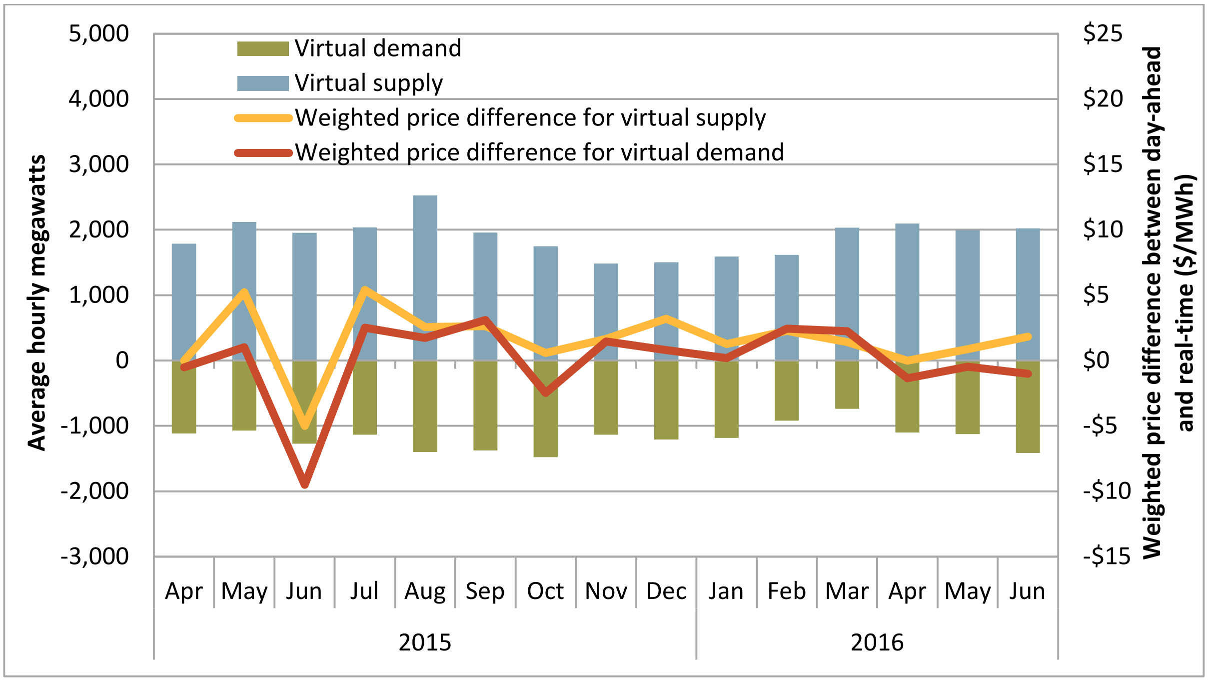
Consistency of price differences and volumes

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 1.9 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 consistent with weighted average price differences for the hours in which virtual demand cleared the market and, thus, were profitable on average.

The yellow line in Figure 1.9 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 second quarter were on average profitable in May and June.

Figure 1.9 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 second quarter were offsetting bids. Offsetting virtual positions accounted for an average of about 830 MW of virtual demand offset by 830 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 51 percent of all cleared virtual bids in the second quarter, which is about the same as in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

1.6.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the second quarter. Similar to the previous quarter, convergence bidding participants earned positive revenue. In the second quarter, net revenues were about $6.4 million from revenue collected on both virtual supply and demand positions.

Figure 1.10 Total monthly net revenues paid from convergence bidding

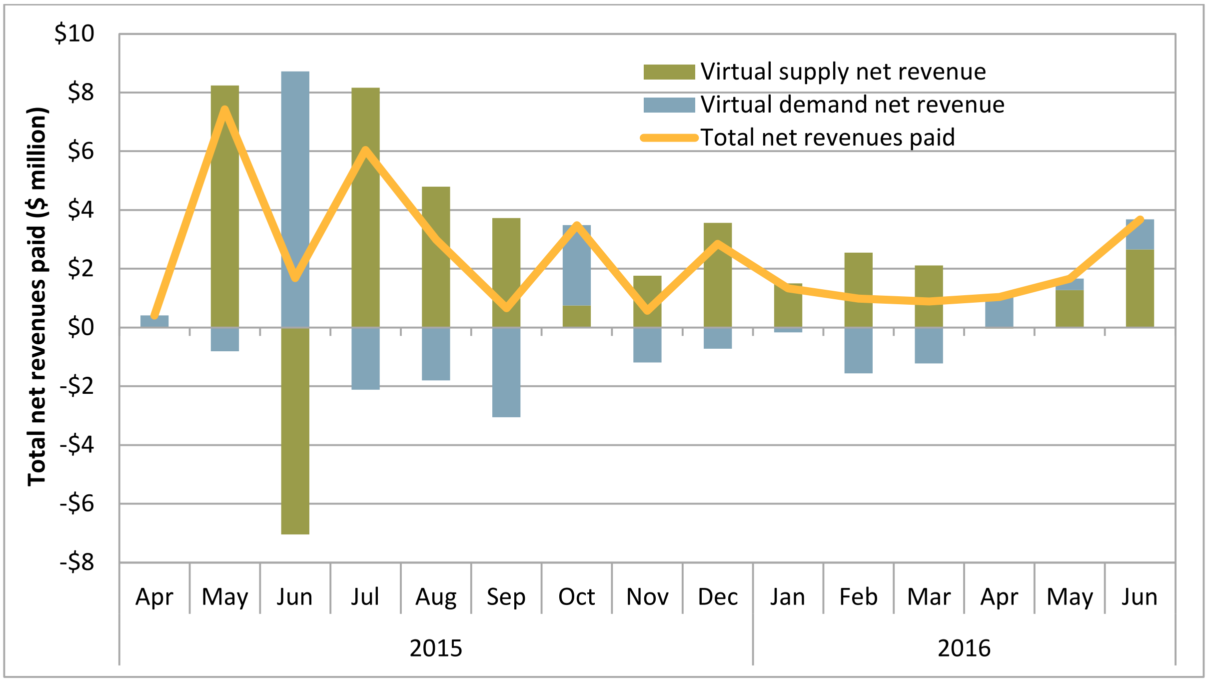


Figure 1.10 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- Monthly net revenues were consistent throughout the second quarter and totaled about $6.4 million, compared to about $9.5 million in the same quarter in 2015, and about $3.2 million during the previous quarter.
- Virtual supply revenues were most profitable in June as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply generated net revenues of about $3.9 million during the quarter.
- Virtual demand revenues were positive in all three months of the quarter. In total, virtual demand generated net revenues of around $2.5 million during the quarter. A significant portion of this revenue can be attributable to a couple high load days in June.

- Convergence bidders were paid about $4.4 million after subtracting bid cost recovery charges of $2 million for the quarter.[13,14] These costs were about $0.8 million, $0.7 million and $0.4 million in April, May and June, respectively.

Net revenues and volumes by participant type

Table 1.6 compares the distribution of convergence bidding cleared volumes and net revenues in millions of dollars among different groups of convergence bidding participants in the second quarter.[15] As shown in Table 1.6, financial entities represented the largest segment of the virtual bidding market in terms of volume, accounting for about 54 percent of volume and about 65 percent of settlement revenue. Marketers represented about 28 percent of the trading volumes, but only about 20 percent of the settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of volumes (about 18 percent) and an even smaller segment of settlement dollars (about 16 percent).

Table 1.6 Convergence bidding volumes and revenues by participant type (April – June)

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	825	942	1,766	$1.87	$2.79	$4.66
Marketer	314	588	901	$0.66	$0.75	$1.41
Physical load	2	375	377	$0.01	$0.71	$0.72
Physical generation	71	130	201	-$0.05	-$0.36	-$0.41
Total	**1,211**	**2,035**	**3,246**	**$2.5**	**$3.9**	**$6.4**

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.[16] When the ISO commits units, it may pay market participants through the bid

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

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

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

[16] If physically generating resources clearing in the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecasted

cost recovery mechanism to ensure that market participants are able to recover start-up, minimum load, transition, and energy bid costs.[17]

Because virtual bids can influence unit commitment, they share associated costs. Specifically, virtual bids can be charged bid cost recovery payments under two charge codes.[18]

- 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 increase 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.

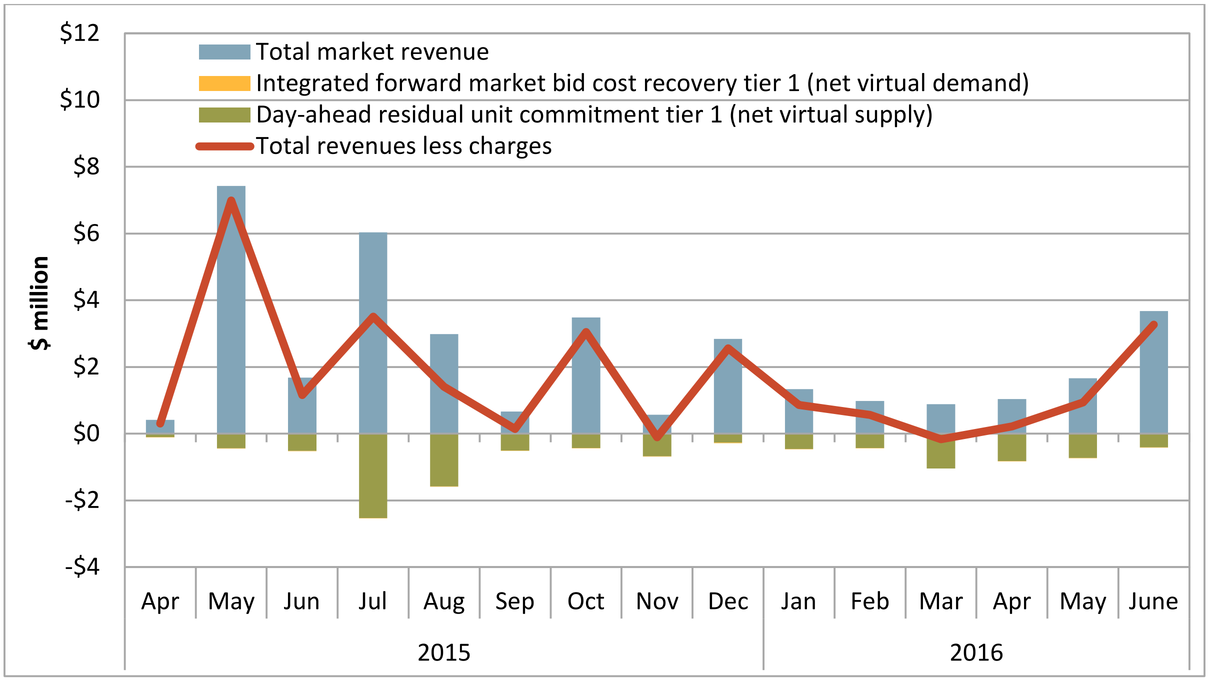
Figure 1.11 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery charges for the second quarter were about $2 million, a slight increase from $1.9 million in the previous quarter.

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.

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

[18] 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.

Figure 1.11 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



2 Energy imbalance market

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

- 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, very little congestion has been observed between the ISO, PacifiCorp East and NV Energy areas. As a result, real-time prices have become much more uniform between the ISO and EIM areas.
- The price discovery waiver expired for both PacifiCorp areas in March 2016 when the ISO implemented the available balancing capacity mechanism. The price discovery waiver expired for NV Energy at the end of May 2016 following the initial six months of market operation. Thus, prices will no longer be automatically reduced to the last dispatched bid during power balance relaxations and can now reflect the offer cap and floor for shortage and excess events.
- The frequency of intervals in which the power balance constraint was relaxed remained very low during the quarter for each market. As a result, the load bias limiter (and price discovery for NV Energy in April and May) rarely triggered and had a minimal impact on prices.
- The percentage of intervals where the flexible ramping constraint needed to be relaxed because of procurement shortfalls increased in PacifiCorp West in the second quarter of 2016, and was particularly frequent in April.
- The available balancing capacity mechanism was implemented on March 23, 2016. Although some available balancing capacity has been offered in each EIM area, the frequency and volume of capacity offered in the PacifiCorp areas has often been very limited, particularly downward capacity in PacifiCorp West. Moreover, no upward capacity was offered in NV Energy through the end of the second quarter. In all EIM areas, no upward capacity was available for dispatch during most of the intervals when the power balance constraint was relaxed.

2.1 Energy imbalance market performance

Energy imbalance market prices

The load settlement price is an average of 15-minute and 5-minute prices, weighted by the amount of estimated load imbalance in each of these markets.[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 weighted by the imbalance between forecasted load in the 15-minute market and forecasted load in the 5-minute market.[20]

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

[20] During the quarter, settlement prices in EIM were weighted slightly more on prices in the 15-minute market (about 54 percent) and less on prices in the 5-minute market (about 46 percent).

Figure 2.1 shows hourly average settlement prices during the second quarter in PacifiCorp East, PacifiCorp West, Southern California Edison (SCE), and the Pacific Gas and Electric (PG&E) areas as well as the range of bilateral trading hub prices DMM uses as an additional benchmark for EIM prices.[21]

Figure 2.2 provides the same information for settlement prices in NV Energy and the Southern California Edison area. Because of the large transfer capabilities and little congestion between the ISO, NV Energy, and PacifiCorp East, average settlement prices in PacifiCorp East and NV Energy are largely reflective of system conditions in the ISO depicted by the Southern California Edison and the Pacific Gas and Electric prices.

During the quarter several price spikes occurred in the ISO during hours 19 and 20 when system conditions were tight, and, at the same time, roughly the same prices were also observed in PacifiCorp East and NV Energy. Similarly, during other hours PacifiCorp East and NV Energy prices also tracked closely with prices in the ISO.

Settlement prices in PacifiCorp West did not reflect prices in the ISO as closely as NV Energy and PacifiCorp East prices because of less available transmission between the two areas. During many of the intervals in hours 19 and 20, when high prices were present in the ISO, NV Energy and PacifiCorp East, transmission into the ISO from PacifiCorp West bound, which resulted in local resources setting the price in PacifiCorp West instead of system prices reflecting shortage conditions.

Settlement prices in PacifiCorp East averaged about $21/MWh during the second quarter, while prices in PacifiCorp West averaged about $13/MWh. Settlement prices in NV Energy were about $24/MWh during the second quarter, compared with $25/MWh for Southern California Edison. Pacific Gas and Electric settlement prices averaged around $24/MWh during the quarter.

[21] 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).

Figure 2.1 Hourly settlement and bilateral trading hub prices – PacifiCorp (April – June)

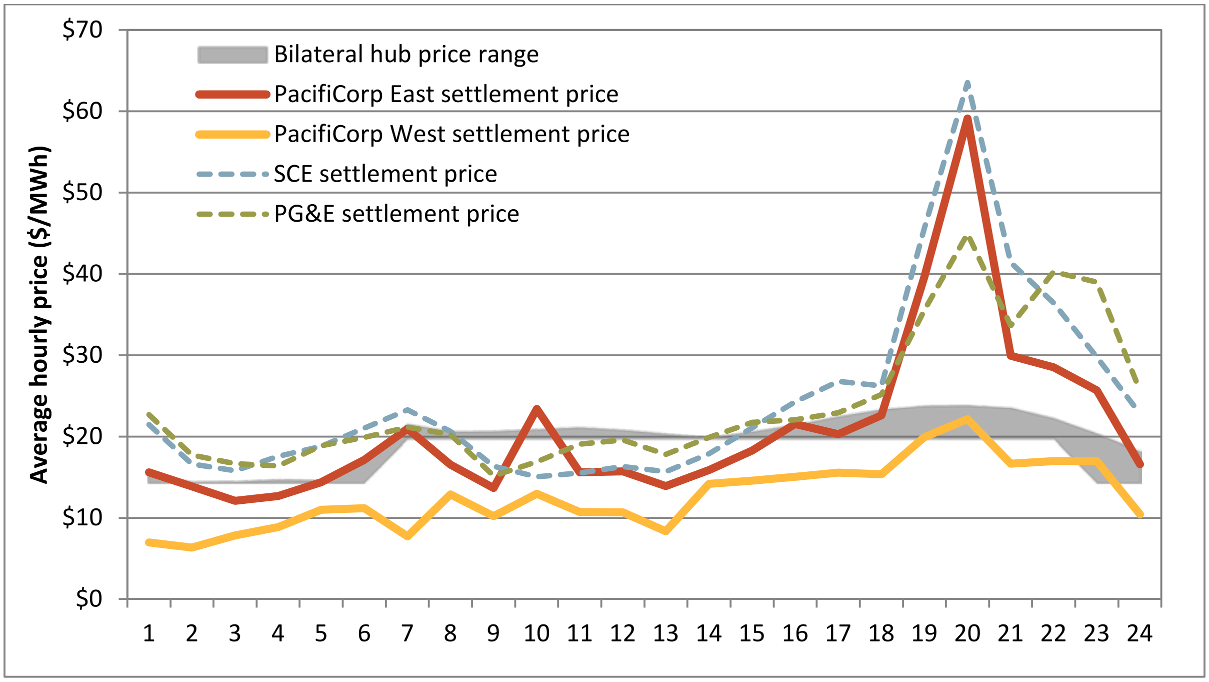
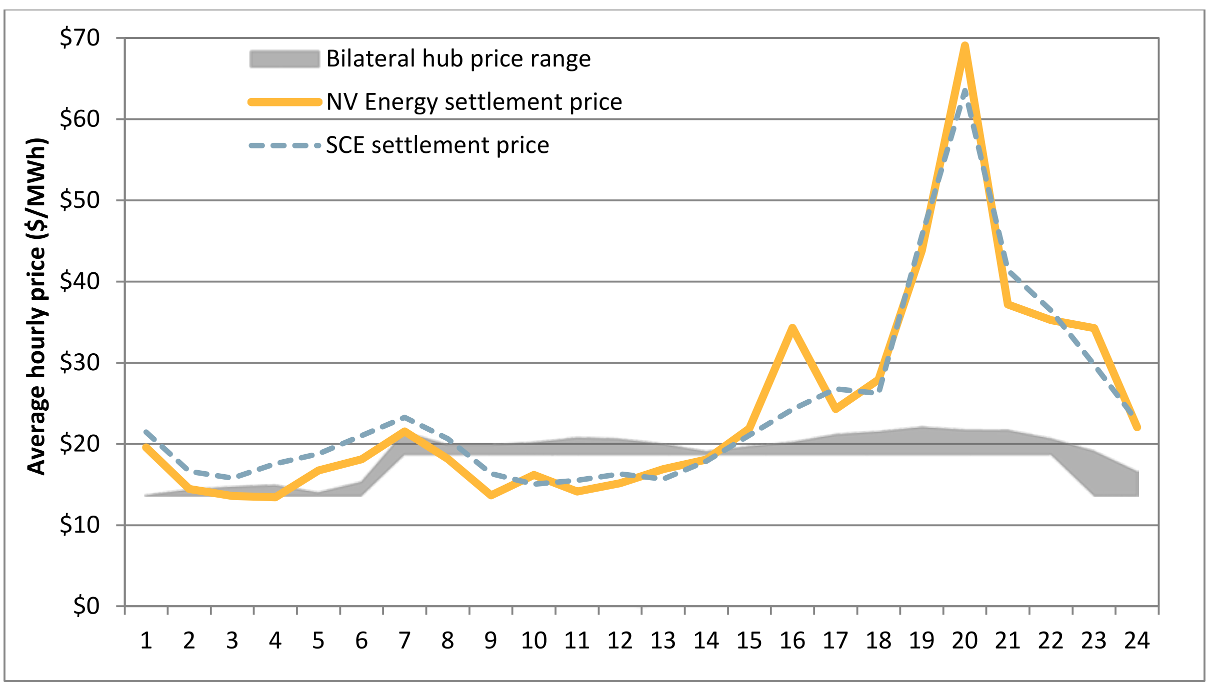


Figure 2.2 Hourly settlement and bilateral trading hub prices – NV Energy (April – June)



Overall energy imbalance market prices in the second quarter remained close to bilateral market prices. Figure 2.3 through Figure 2.5 provide a monthly summary of constraint relaxation frequency (green and blue bars), average prices with (gold line) and without price discovery or load bias limiter (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 2.4 shows a significant increase in flexible ramping constraint relaxations between the first and second quarters of 2016 in the 15-minute market in PacifiCorp West. When this constraint cannot be met and is relaxed in the pricing run, a shadow price is set at or near $60/MWh, resulting in increased 15-minute energy prices. In PacifiCorp West during April, the flexible ramping constraint was relaxed in almost 8 percent of intervals. However, very infrequent relaxation of the power balance constraint and low prices in PacifiCorp West during the quarter resulted in prices below the bilateral hub price range.

Figure 2.3 through Figure 2.5 show that the power balance constraint was relaxed infrequently in all EIM areas in the 15-minute market during the quarter. The available balancing capacity mechanism, which was implemented at the end of the previous quarter, had minimal influence on the low frequency of power balance constraint relaxations.

Figure 2.6 through Figure 2.8 provide the same information on prices and relaxations for the 5-minute market. As shown in these figures, the power balance constraint in the 5-minute market was also relaxed infrequently during the second quarter for all EIM areas. Power balance constraint relaxation in the 5-minute market was most significant in NV Energy during June, occurring in about 0.7 percent of intervals.

Additionally, EIM prices tracked closely to bilateral hub prices during all three months of the quarter. In PacifiCorp West, monthly 15-minute market and 5-minute market prices fell within or below the bilateral hub price range. PacifiCorp East and NV Energy monthly real-time prices averaged higher than respective bilateral hub price ranges largely because of higher real-time prices in the ISO which were reflected locally because of significant transfer capacity between these EIM areas and the ISO.

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

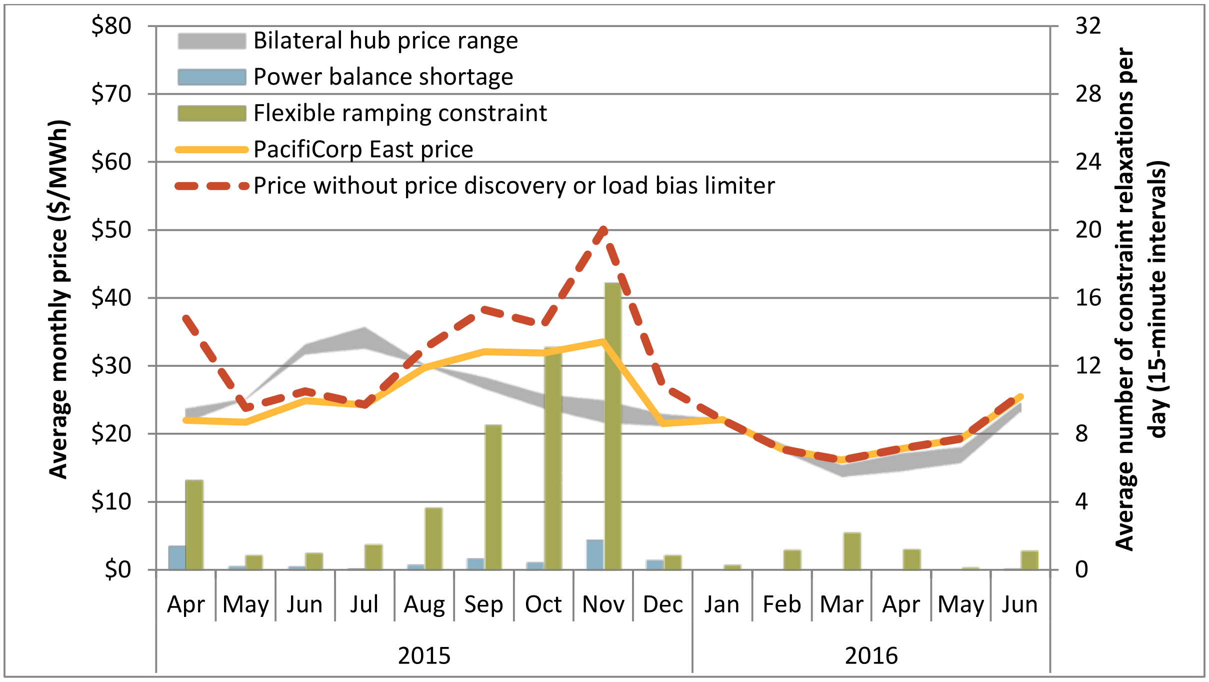


Figure 2.4 Frequency of constraint relaxation and average prices by month PacifiCorp West – 15-minute market

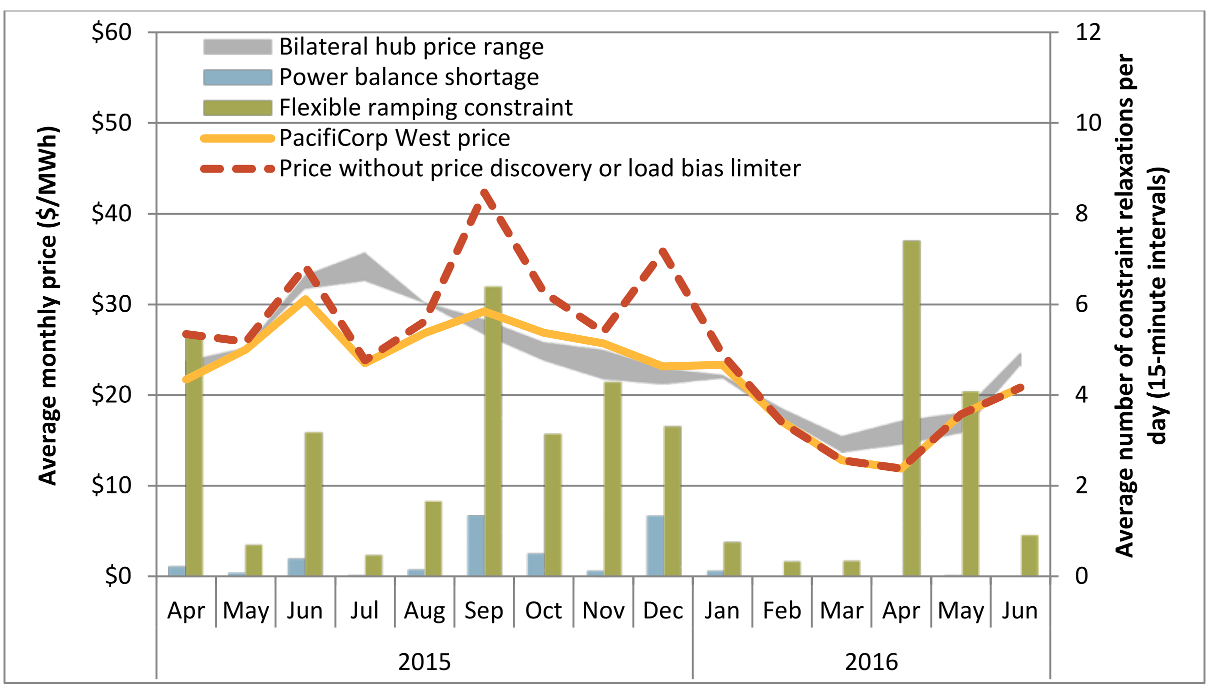


Figure 2.5 Frequency of constraint relaxation and average prices by month NV Energy – 15-minute market

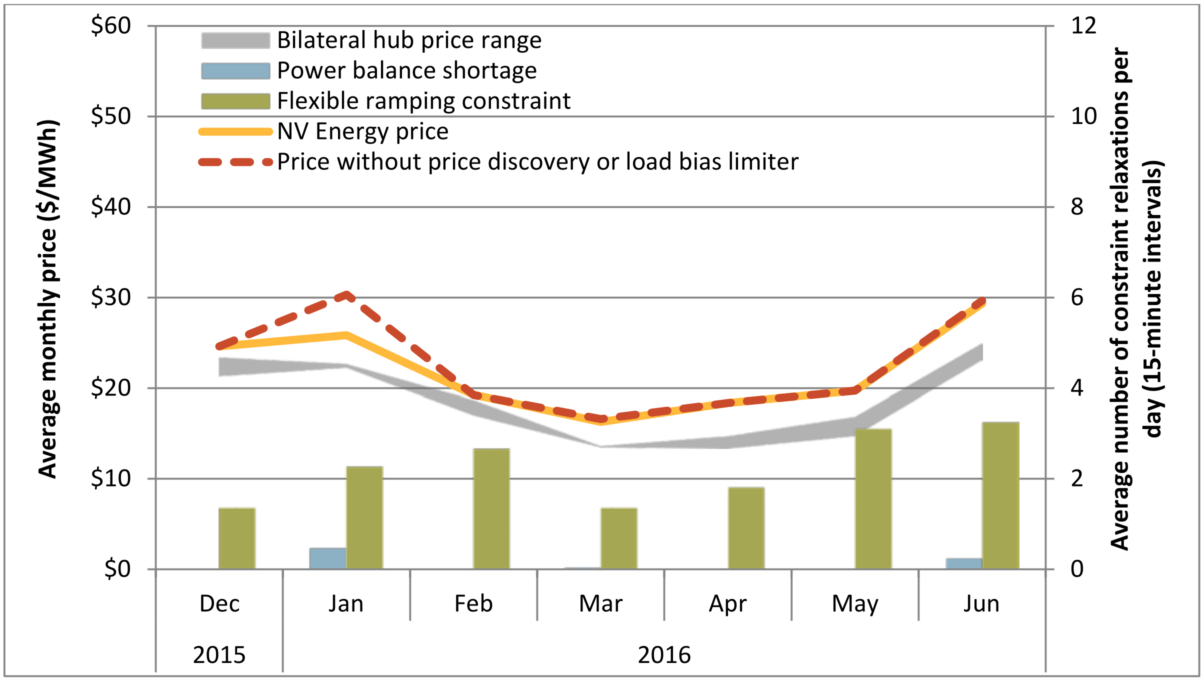


Figure 2.6 Frequency of constraint relaxation and average prices by month PacifiCorp East – 5-minute market

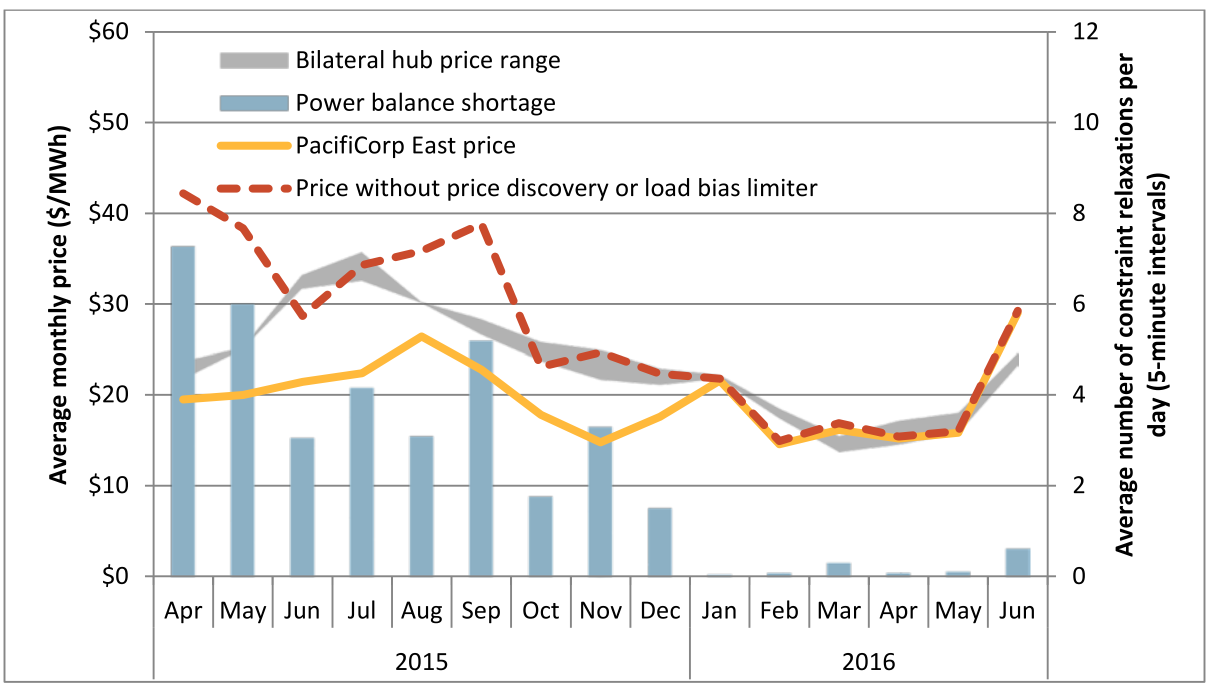


Figure 2.7 Frequency of constraint relaxation and average prices by month PacifiCorp West – 5-minute market

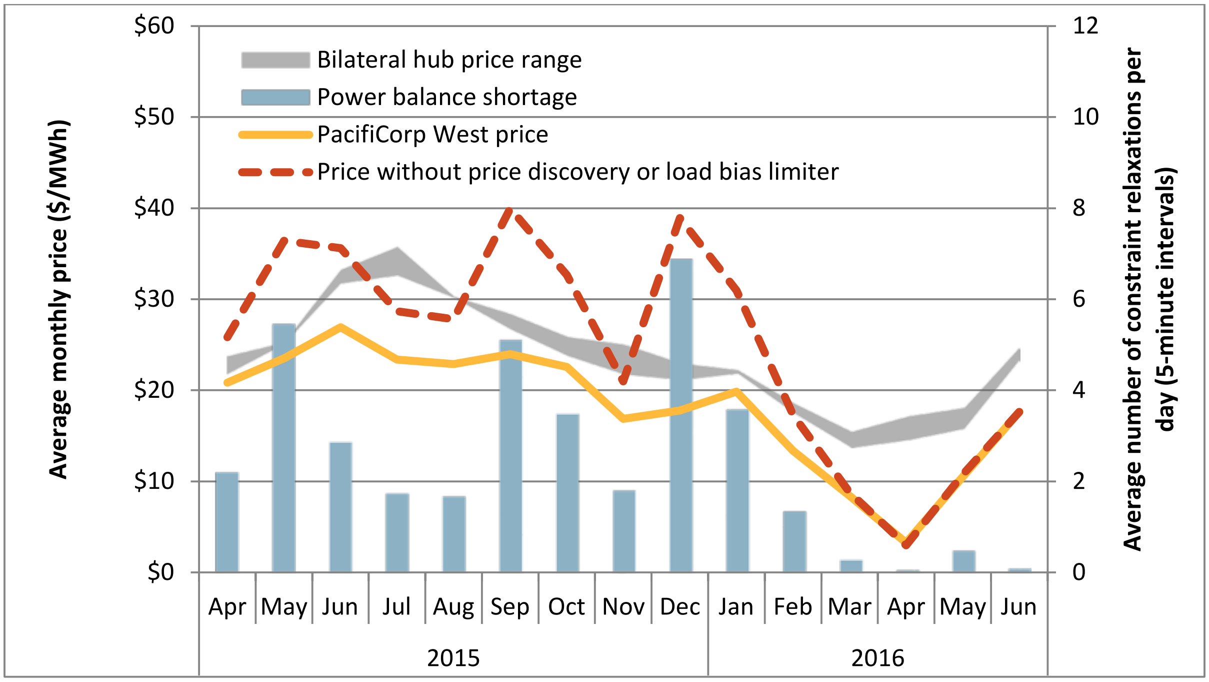
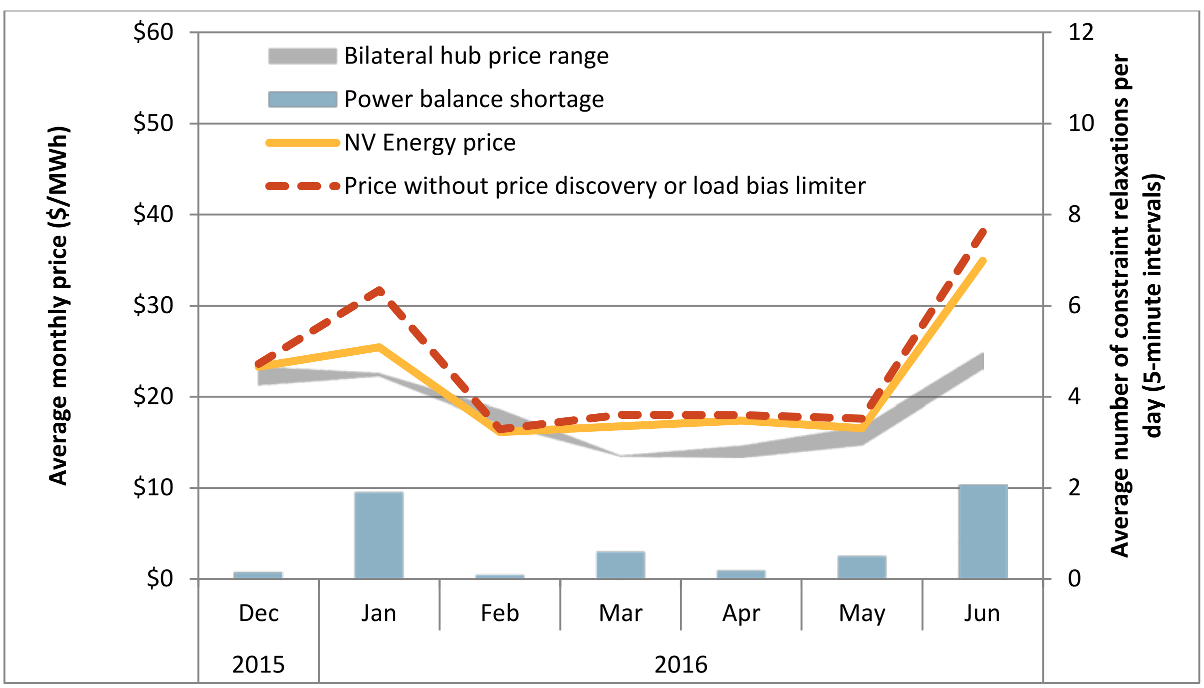


Figure 2.8 Frequency of constraint relaxation and average prices by month NV Energy – 5-minute market



Energy imbalance market congestion

As shown in Table 2.1, the frequency of congestion in EIM has been extremely low, even after an extensive set of constraints was enforced following FERC's November 19, 2015, Order.[22] Congestion for all quarters and all EIM areas since the implementation of EIM has been below 0.5 percent, except in PacifiCorp East during the fourth quarter of 2015 and the first quarter of 2016.

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

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

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

Table 2.1 Percent of intervals with binding internal EIM constraints

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

Manual dispatches

It is possible that a local constraint may not be enforced in the EIM network model but could bind in actual conditions. In this scenario, an EIM entity may need to rely on adjustments to base schedules or manual dispatches to mitigate congestion outside of the EIM software. In addition, even if local constraints are enforced in the EIM network model, manual dispatches may be needed to manage local congestion caused by temporary outages, discrepancies between modeled and actual flows, and other factors.

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

Figure 2.9 Manual dispatches – PacifiCorp areas

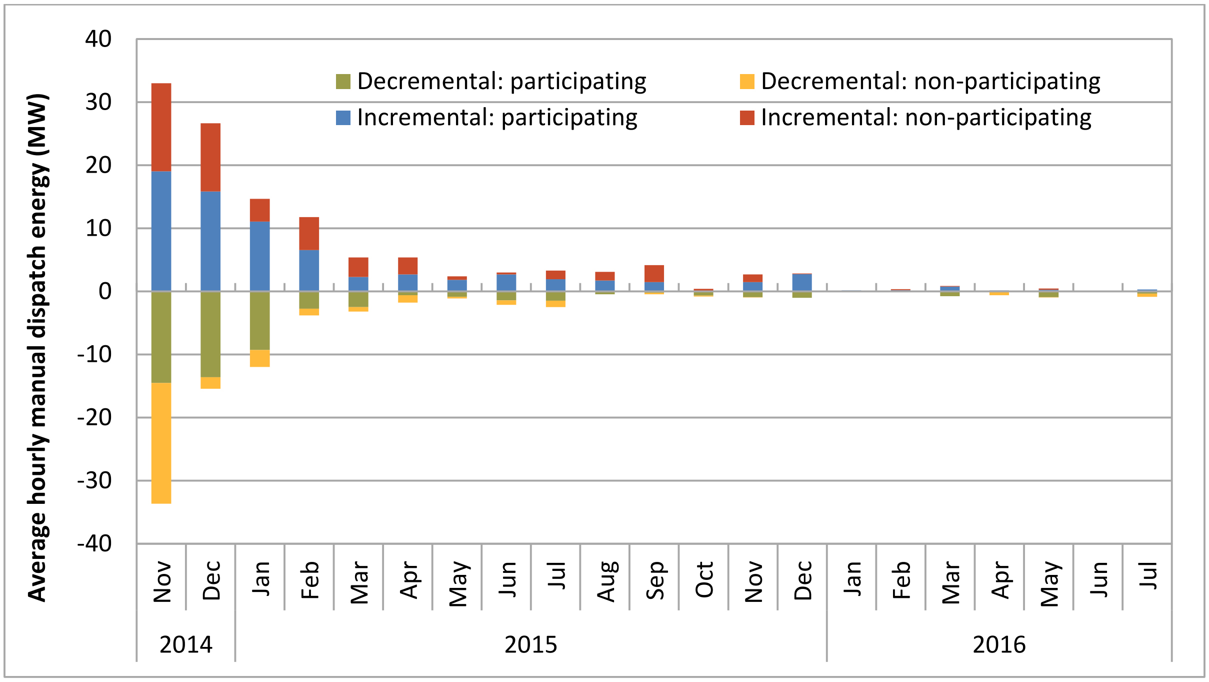
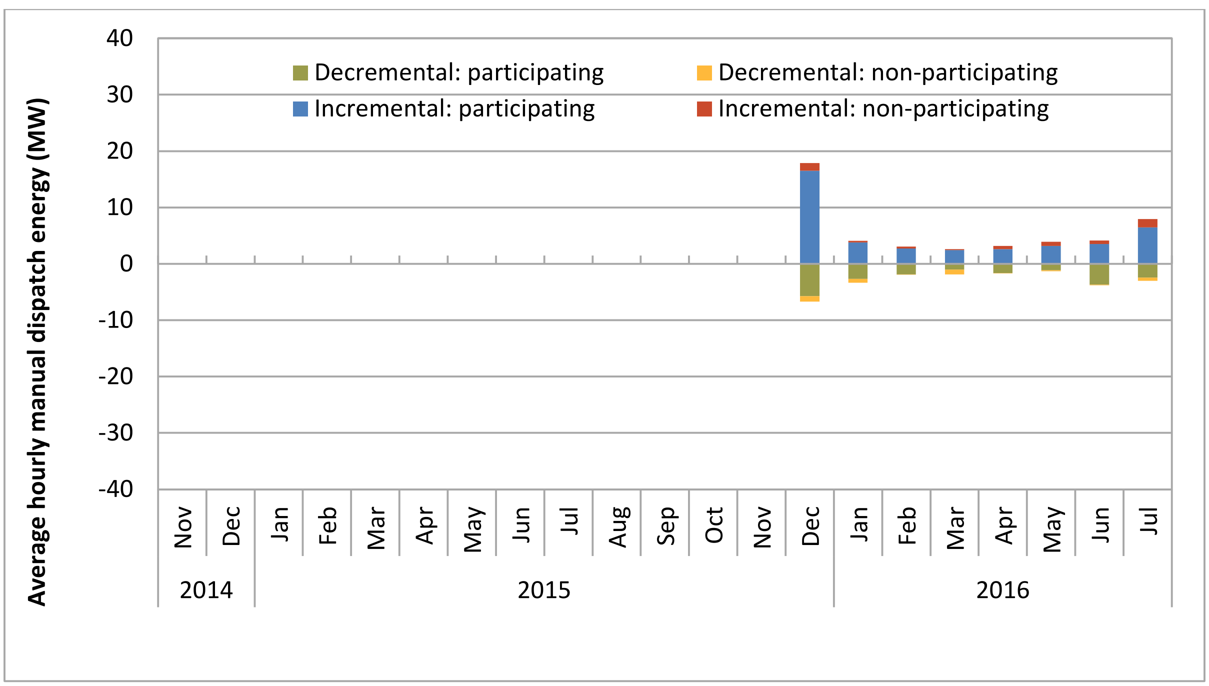


Figure 2.10 Manual dispatches – NV Energy area



Manual dispatches in EIM do not set market clearing prices in the same way that units exceptionally dispatched do not set prices in the ISO. However, while exceptional dispatches in the ISO may be paid based on their bid price if it exceeds the market clearing price, all EIM manual dispatches are settled on market clearing prices. This prevents concerns about manually dispatched resources in EIM exercising market power by either setting prices or by being paid at above-market prices.

As shown in Figure 2.9 and Figure 2.10, the amount of manual dispatches in the EIM has been low. In the PacifiCorp areas, the volume of manual dispatch declined throughout 2016. In the NV Energy area, manual dispatch volume fell in the early months of 2016. While volumes of manual dispatch in the NV Energy area have increased slightly into the summer months, overall volumes of manual dispatches continue to be relatively low.

Available balancing capacity

The ISO implemented the available balancing capacity (ABC) mechanism in EIM on March 23, 2016. This enhancement to EIM functionality allows for market recognition and accounting of capacity that an EIM entity has available for reliable system operations but is not bid into the EIM. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each EIM entity in their hourly resource plans. The available balancing capacity mechanism enables system software to deploy such capacity through the EIM, and prevents market infeasibilities that may arise without the availability of this capacity.[23]

FERC's December 17, 2015, Order on the available balancing capacity proposal requires that the ISO submit quarterly reports on the available balancing capacity mechanism performance.[24] DMM plans to review the ISO's analysis and provide feedback as necessary in future reports. In this report, DMM provides a short summary of the available balancing capacity mechanism since it was implemented in late March.

Since implementation, the frequency of hours in which available balancing capacity was offered varied widely for different EIM areas. When available balancing capacity was offered in an EIM area, the amount offered typically ranged from 50 MW to 100 MW. This capacity was dispatched during a relatively small portion of intervals, and therefore had a very limited effect on market performance.

Figure 2.11 and Figure 2.12 summarize the frequency of upward and downward available balancing capacity offered by each EIM area. PacifiCorp East offered available balancing capacity in both directions with the greatest consistency, with upward and downward capacity offered peaking in April at about 80 percent of hours. In each of the other EIM areas, available balancing capacity was typically offered in only one direction. In PacifiCorp West, the greatest upward available balancing capacity was offered in June during about 65 percent of hours and very little downward capacity was offered during any month. NV Energy offered available balancing capacity exclusively in the downward direction during about 72 percent of hours in April, and 98 percent of hours during all other months of the period.

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

[24] Ibid.

Figure 2.11 Hourly frequency of upward available balancing capacity offered

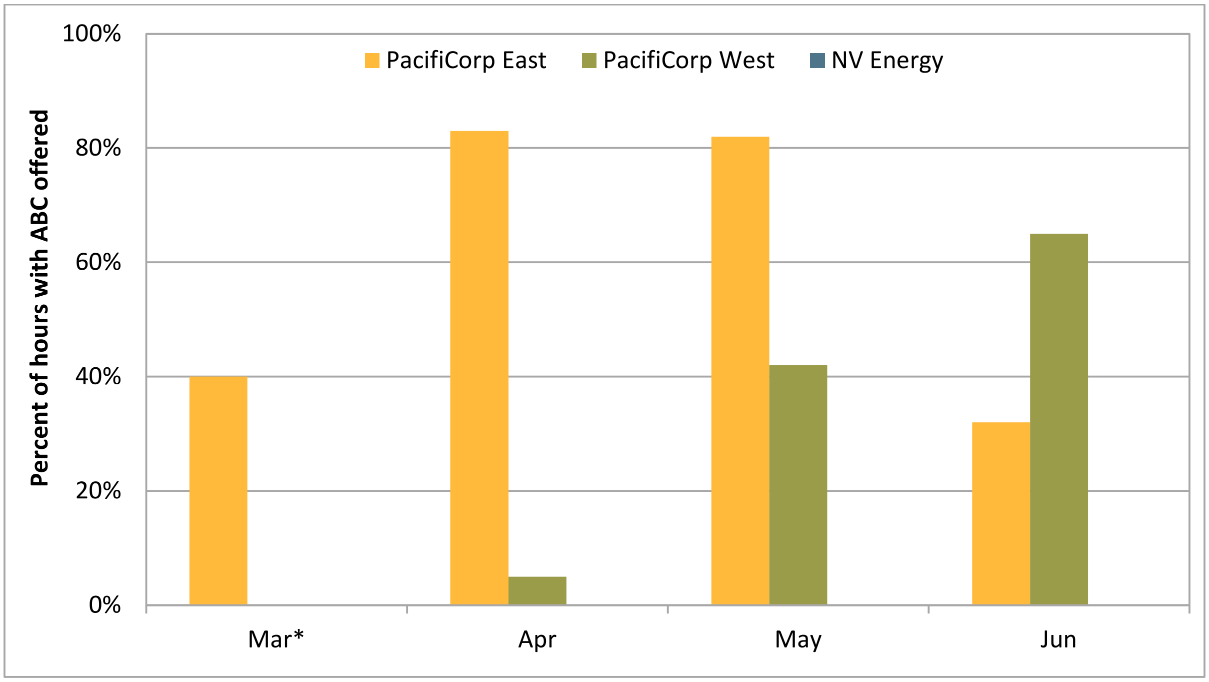
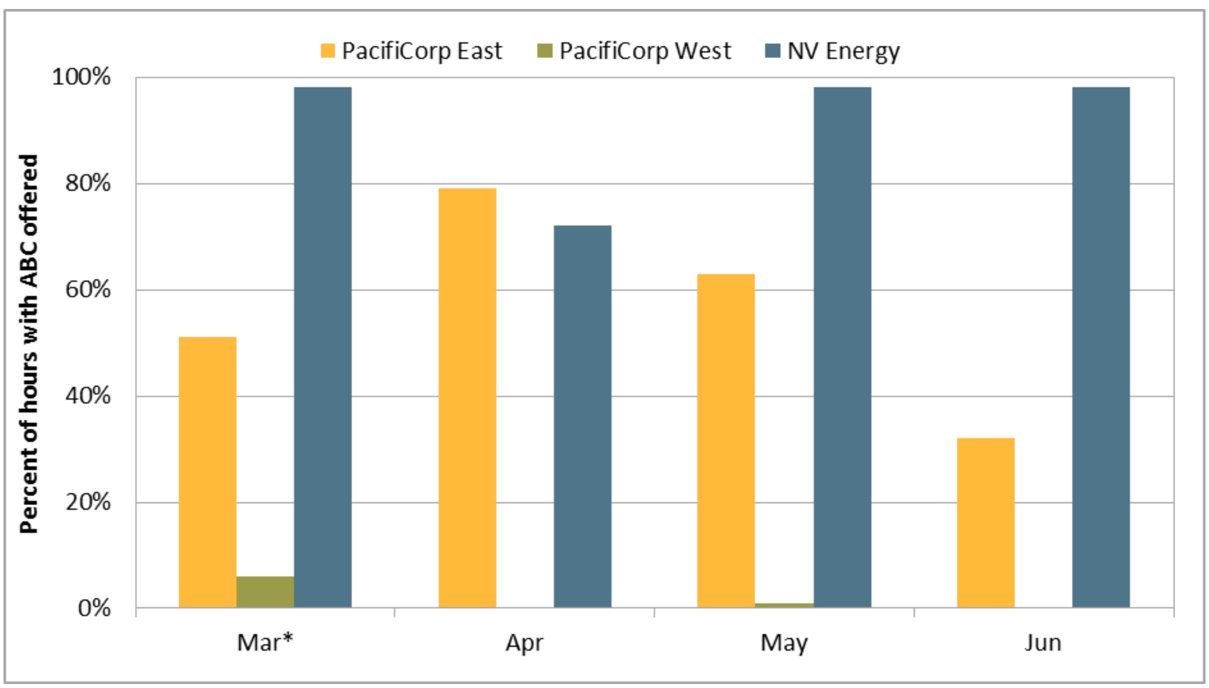


Figure 2.12 Hourly frequency of downward available balancing capacity offered



*March 23 through 31

Available balancing capacity is bid into the market on an hourly basis and dispatched to resolve infeasibilities in the 15-minute and 5-minute energy imbalance markets.

Table 2.2 shows the total number of 5-minute intervals by month and EIM area where upward and downward available balancing capacity was offered and dispatched. When available balancing capacity was offered in an EIM area, the amount offered typically ranged from 50 to 100 MW. As shown in the table, available balancing capacity was not dispatched frequently. When available balancing capacity was dispatched, the quantity was usually relatively small and was often limited by ramping limitations.

During 94 percent of intervals when shortage infeasibilities existed in EIM areas after the available balancing capacity feature was implemented, no upward available balancing capacity was available for dispatch. During 99 percent of intervals when surplus infeasibilities existed, no downward available balancing capacity was available for dispatch.

Table 2.2 Available balancing capacity offered and dispatched (5-minute market)

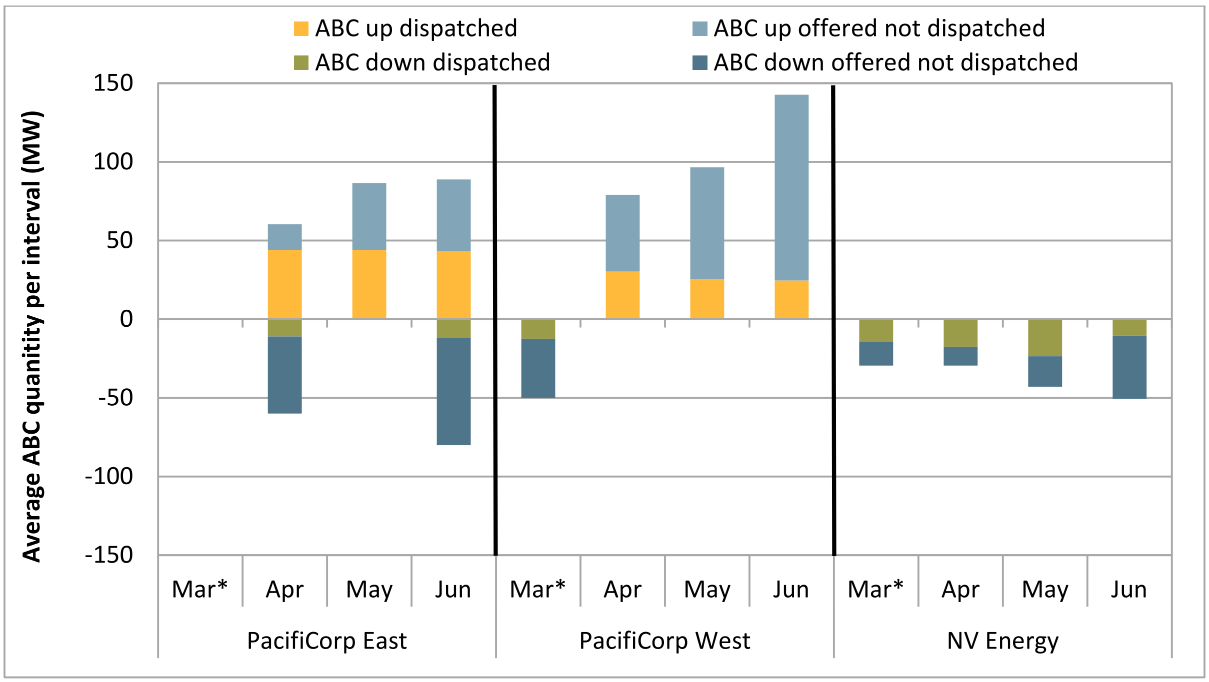
	ABC Up		ABC Down	
	Total intervals ABC dispatched	Total intervals ABC offered	Total intervals ABC dispatched	Total intervals ABC offered
PacifiCorp East				
Mar 2016*	0 (0%)	1,032 (40%)	0 (0%)	1,332 (51%)
Apr 2016	27 (0.3%)	7,164 (83%)	2 (0%)	6,792 (79%)
May 2016	29 (0.3%)	7,356 (82%)	0 (0%)	5,628 (63%)
Jun 2016	12 (0.1%)	2,748 (32%)	1 (0%)	2,736 (32%)
PacifiCorp West				
Mar 2016*	0 (0%)	0 (0%)	1 (0%)	156 (6%)
Apr 2016	3 (0%)	444 (5%)	0 (0%)	0 (0%)
May 2016	31 (0.3%)	3,732 (42%)	0 (0%)	132 (1.5%)
Jun 2016	65 (0.8%)	5,580 (65%)	0 (0%)	0 (0%)
NV Energy				
Mar 2016*	0 (0%)	0 (0%)	2 (0.1%)	2,532 (98%)
Apr 2016	0 (0%)	0 (0%)	37 (0.4%)	6,240 (72%)
May 2016	0 (0%)	0 (0%)	14 (0.2%)	8,736 (98%)
Jun 2016	0 (0%)	0 (0%)	100 (1.2%)	8,460 (98%)

During 5-minute intervals when available balancing capacity was dispatched, the quantity of capacity dispatched in each area tended to be less than the amount offered. Figure 2.13 displays the average amount of available balancing capacity offered and dispatched in the 5-minute market during intervals when available balancing capacity was dispatched. This may indicate that the total amount of available balancing capacity offered may be ramp constrained and less than the amount available for dispatch during any particular interval.[25]

[25] Several intervals were observed where the amount of available balancing capacity offered was greater than a power balance constraint shortfall or excess. However, because of ramp limitations on the available balancing capacity, the penalty parameter from the power balance constraint was enforced.

There were some intervals when the quantity of available balancing capacity dispatched exactly equaled the quantity offered. However, in some of these intervals, there was no shortage or surplus reflected in market prices. Such intervals were primarily concentrated in April. DMM is working with the ISO to review these cases, and suggested that the ISO continue further analysis and review of these and similar instances.

Figure 2.13 Average available balancing capacity offered during intervals when dispatched



2.2 Energy imbalance market 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 5-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 during most intervals.

Table 2.3 also shows that although the ISO imported energy more frequently than it exported energy, it tended to export at greater quantities and overall was a net exporter. Similarly, although PacifiCorp West tended to export energy more frequently, it overall was a net importer of energy although quantities were very small. NV Energy tended to be a net importer and imported during a majority of intervals, while PacifiCorp East tended to be a net exporter and exported during a majority of intervals in the second quarter.

Table 2.3 Net EIM transfers (April – June)

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	54%	-270	46%	436
PacifiCorp East	40%	-220	60%	255
PacifiCorp West	46%	-143	54%	113
NV Energy	62%	-292	38%	165

Table 2.4 details the percentage of intervals when there was congestion between the ISO and each of the EIM areas in the 5-minute market, and the average flows when there was and was no congestion between each of the areas. The table shows that overall congestion was relatively infrequent in the 5-minute market between the ISO and NV Energy and that congestion was infrequent between the ISO and PacifiCorp East.[26] However, there was congestion between the ISO and PacifiCorp West during about one third of all intervals.

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

Figure 2.14 shows further detail about how energy flowed between NV Energy, the ISO and PacifiCorp East on an hourly basis during the quarter. The figure shows that during the midday hours, when there was a lot of solar generation on-line in the ISO, the ISO exported several hundred megawatts of energy to NV Energy, which then exported some of that energy to PacifiCorp East. More generally, during the midday hours there were west-to-east flows from the ISO through NV Energy to PacifiCorp East in the real-time market.

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

Table 2.4 Congestion status and flows in EIM (April – June)

	Percent of intervals	Average transfer (MW)
PacifiCorp East		
Congested from NVE and ISO	0%	551
Congested from ISO only	5%	377
Non-congested from NVE	40%	201
Non-congested to NVE	47%	-199
Congested toward the ISO	6%	-392
PacifiCorp West		
Congested from ISO	6%	21
Non-congested from ISO	32%	109
Non-congested to ISO	46%	-119
Congested to the ISO	23%	-93
NV Energy		
Congested from ISO	4%	842
Non-congested from ISO	48%	339
Non-congested to ISO	45%	-216
Congested to ISO	1%	-602

Figure 2.14 Hourly imports into NV Energy from the ISO and PacifiCorp East (April – June)

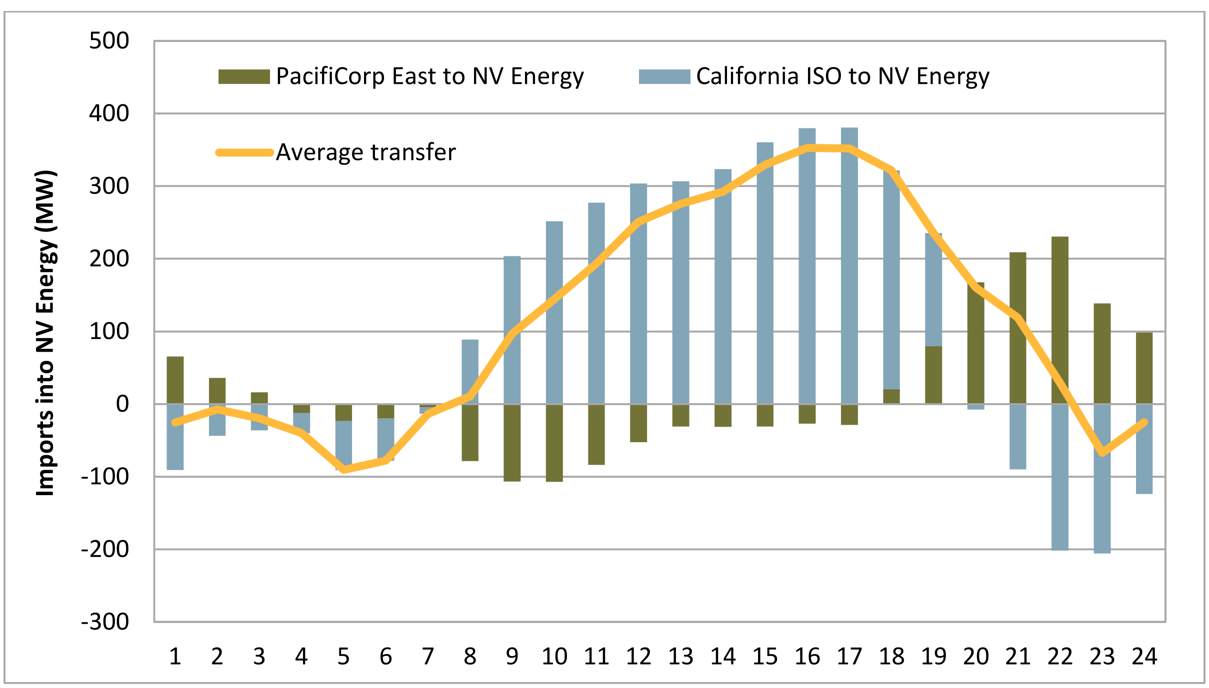


Figure 2.14 also shows that the midday trend rapidly shifts, as solar generation in the ISO slows and loads approach the evening peak, to one where NV Energy begins replacing imports from the ISO with imports from PacifiCorp East. Beginning in hour 20, NV Energy continues to be a net importer, but begins exporting energy to the ISO, or, more generally, a pattern of east-to-west energy flows begins and persists through most of the off-peak hours. These are hours when energy flows from PacifiCorp East through NV Energy to the ISO in the real-time market.

2.3 Structural competitiveness of EIM areas

In its June 19, 2014, Order, the Federal Energy Regulatory Commission directed the ISO to provide the Commission with informational status reports every six months for two years following the launch of the EIM on the presence of structural market power in PacifiCorp's balancing authority areas (BAAs) due to limits on transmission interties into and between these areas. The Commission indicated it will use the information in these reports to determine if any action is necessary to address structural market power in PacifiCorp's balancing authority areas under the EIM structure.[27]

In July 2016, DMM completed its third report on the structural market competitiveness in the PacifiCorp balancing authority areas that covered the first 18 months of EIM implementation ending in May 2016.[28] This report provided analysis showing that the frequency of potential structural market power in the PacifiCorp balancing authority areas has been dramatically reduced by the additional transfer capacity between the EIM areas and the ISO with the entry of NV Energy. With this additional transfer capacity, congestion between the ISO and the various EIM areas has dropped significantly and real-time prices have become more uniform between the ISO and most EIM areas.

This structural competitiveness mitigates the potential for the exercise of market power through both economic and physical withholding during most intervals. During the limited number of intervals when competitive supply from the ISO into the EIM is constrained by congestion on EIM transfer constraints, the ISO's automated real-time market power mitigation procedures are designed to mitigate the potential exercise of market power.

DMM has recommended that the ISO implement enhancements to these procedures to ensure these procedures are triggered in the real-time market when congestion occurs on structurally uncompetitive constraints. The ISO has indicated it will seek to implement these enhancements in the 15-minute market in 2016 and has filed for approval to implement enhancements in the 5-minute market in 2017.[29]

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27 *Order Conditionally Accepting Proposed Tariff Revisions To Implement Energy Imbalance Market,* June 19, 2014, p.216: http://www.caiso.com/Documents/Jun19_2014_OrderConditionallyAcceptingEIMTariffRevisions_ER14-1386.pdf.

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

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

2.4 Special FERC mitigation measures

In FERC's November 19, 2015 Order, the Commission found that the market power analyses of the expanded EIM footprint by PacifiCorp and NV Energy (Berkshire EIM Sellers[30]) were deficient and failed to demonstrate a lack of market power in the expanded EIM.[31] The Commission also outlined concerns regarding the ability of the ISO's market power mitigation rules and procedures to mitigate the Berkshire EIM Sellers' market power in the expanded EIM. The Commission therefore imposed the following two conditions on the Berkshire EIM Sellers' participation in the EIM at market-based rates:

1. They must offer EIM participating units at or below each unit's default energy bids; and
2. They must facilitate the ISO's enforcement of all internal transmission constraints in the PacifiCorp and NV Energy balancing authority areas.

On May 19, 2016 the Commission issued an order denying rehearing and providing clarification of the several issue regarding market power analysis requirements for new EIM entrants.[32]

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

2.4.1 Energy imbalance market transfer scheduling limits

One concern cited in FERC's orders on Berkshire Hathaway sellers' market-based rate authority in EIM was the amount of competitive supply available for transfer into each EIM area because of EIM scheduling limits.[33] In this order the Commission clarified that assessments of market power should consider actual EIM scheduling limit constraints.

As noted in recent DMM reports to the Commission, with the addition of NV Energy to EIM in December 2015, the amount of transmission capacity available to support transfers of competitive supply from the ISO into the PacifiCorp East and NV Energy balancing areas has increased significantly.[34] During most

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

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

[32] *Order Denying Rehearing and Granting Clarification*, May 19, 2016, ER15-22-81-001: http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14460668.

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

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

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

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

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

2.4.2 Enhanced bid mitigation procedures

The ISO's automated bid mitigation procedures address the potential to exercise market power through *economic withholding*. The Commission's November 19 Order cited concerns about the effectiveness of the ISO's bid mitigation procedures in cases when congestion is not projected to occur on a constraint so that mitigation may not be triggered when congestion actually occurs in the real-time market.[35] DMM highlighted this issue in prior reports and continues to closely monitor its impact.[36]

Although this issue has not adversely affected prior market competitiveness, DMM continued to work with the ISO to develop software enhancements to effectively address the issue of potential under-mitigation in the real-time market.[37] As a result of this effort, enhancements to address the issue of under-mitigation are scheduled for implementation in the 15-minute market in 2016 and enhancements to the 5-minute software are anticipated in 2017. DMM continues to work with the ISO to help ensure these enhancements are implemented.

2.4.3 Enhanced outage reporting

The Commission's November 19 Order also noted concern with the potential for *physical withholding* due to the lack of a must-offer requirement in the EIM.[38] The available balancing capacity feature implemented in March 2016 established new requirements for EIM entities to identify capacity scheduled for operating reserves as well as capacity available for dispatch in the event other bids in the EIM were insufficient to meet the power balance constraint for each EIM area. These new requirements increase the ability for DMM to effectively monitor the potential for physical withholding.

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

[36] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 143-150: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

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

[38] As noted in the November 19 Order:

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

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

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

2.4.4 Enforcement of energy imbalance market transmission constraints

In its November 19 Order, the Commission expressed concern that if constraints within EIM areas are not enforced mitigation procedures will not be triggered and therefore potential local market power will not be mitigated. Therefore, the Commission has required Berkshire EIM Sellers to "facilitate CAISO's enforcement of all internal transmission constraints in the PacifiCorp and NV Energy balancing authority areas."[39]

DMM's review of this issue indicates that by the second quarter of 2016 a significant number of constraints within EIM areas, but not all incorporated in the network model, were being enforced. Consequently, DMM requested that the ISO and EIM entities further review this issue and provide a report to FERC identifying constraints that are not modeled or enforced, along with an explanation of the reasons that some constraints were not being enforced. This expectation is also echoed by FERC in the November 19 Order.[40]

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

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

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

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

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

DMM also believes it is important to clarify what would occur in the event a local constraint were not enforced in the EIM network model but bound under actual conditions; EIM entities would find it necessary to rely on adjustments to base schedules, as described above, or manual dispatches to mitigate congestion. As discussed in Section 2.1, manual dispatches in the EIM were very infrequent in all EIM areas in the second quarter.[41] Additionally, DMM's first quarter 2015 report shows a review of operator logs associated with EIM manual dispatches and indicates that manual dispatches have rarely, if ever, been used to manage internal transmission constraints.[42] Further review of manual dispatches and discussions with EIM entities indicates this trend has continued through 2016.

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

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

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

3 Congestion revenue rights

As discussed in DMM's 2015 annual report, since 2012 electric ratepayers who ultimately pay for the cost of transmission managed by the ISO received an average of about $130 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments received by entities purchasing these rights.[43] In the first half of 2016 congestion revenue rights auction revenues were $27 million less than congestion payments made to non-load serving entities purchasing these congestion revenue rights. This represents $0.63 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down from $0.72 in the first half of 2015.

Most congestion payments are paid to purely financial entities that purchase congestion revenue rights but are not engaged in serving load or managing generation in the ISO markets. DMM believes this trend warrants reassessing the standard electricity market design under which ISOs auction off excess transmission capacity remaining after allocating congestion revenue rights to load serving entities.

This report outlines a potential approach for addressing this issue by modifying the congestion rights auction into a *market* for congestion revenue rights based on bids submitted by entities willing to buy or sell congestion revenue rights. With this approach, generators could still seek to purchase hedges for locational price differences, and financial entities or other participants could participate and submit bids reflecting a willingness to sell a hedge for locational price differences to other auction participants. Bids to buy transmission congestion rights would only be cleared if there were sufficient bids from entities willing to sell transmission revenue rights, ensuring that sellers would be willing to assume the obligation to pay congestion charges to entities purchasing these rights.

DMM believes following the outlined approach would be more equitable for customers of load serving entities and would produce more efficient prices that reflect the willingness of participants to buy or sell congestion revenue rights at the market clearing price. DMM recommends that the ISO begin assessing this issue, and is prepared to work with the ISO and stakeholders to further develop and assess options to address this issue. In response to DMM's recommendation at the June 2016 Board meeting, ISO management indicated the ISO would consider scheduling an initiative on this issue as part of the ISO's next stakeholder initiative catalog process in the fall of 2016.

Background

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

The owners of transmission – or entities paying for the cost of building and maintaining transmission – are entitled to congestion revenues associated with transmission capacity in the day-ahead market. In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities and other

[43] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp. 182-190, 225-226: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

load-serving entities through the transmission access charge (TAC).[44] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred.

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

As explained in DMM's 2015 annual report, DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction. [45]

Analysis of congestion revenue right auction returns

As described above, the performance of the congestion revenue rights auction can be assessed by comparing the auction revenues ratepayers received to the ratepayer payments to non-load serving entities purchasing congestion revenue rights in the auction. Note that payments and charges to ratepayers are through load-serving entities. Figure 3.1 compares the following:

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

Ratepayers lost $27 million in the first two quarters of 2016 as a result of congestion payments made to auctioned congestion revenue rights in excess of auction revenues. This was a small increase from the nearly $26 million ratepayers lost in the first half of 2015.

Auction revenues as a percent of payments fell to 63 percent in the first half of 2016 from 72 percent in the first half of 2015. This was because of auction revenues falling more than ratepayer payments to auctioned rights. First half auction revenues fell 30 percent in 2016 to $45 million from $65 million in 2015. Ratepayer payments to auctioned rights fell 20 percent in 2016 to $72 million from $90 million in 2015.

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

[45] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2016, pp.182-190. http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

Figure 3.1 Congestion revenue rights revenues and payments to non-load-serving entities

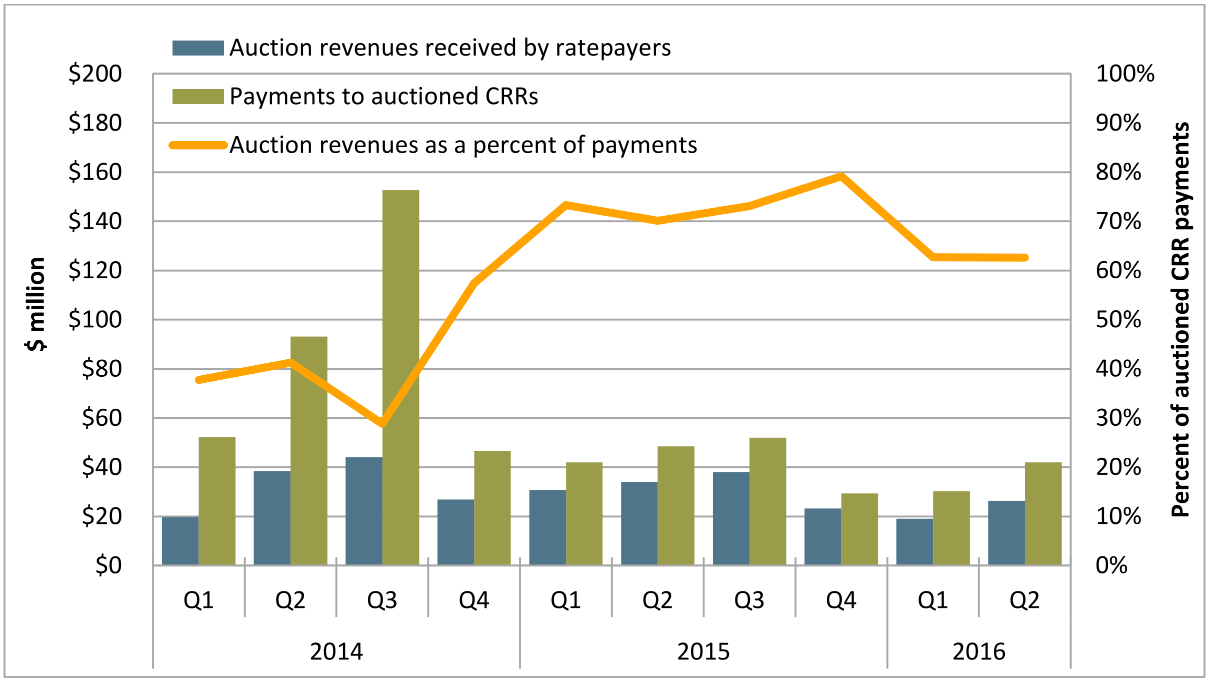


Figure 3.2 through Figure 3.5 show quarterly auction revenues paid to entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- Financial entities participate in the ISO markets only through the convergence bidding and congestion revenue right products.
- Marketers participate in the ISO energy markets primarily through intertie transactions rather than generators or loads internal to the ISO.
- Physical generation and load have generators and loads within the ISO footprint.

As shown in Figure 3.2 through Figure 3.5, during the first half of the year:

- Financial entities continued to have the highest profits among all entity types at $22.5 million. This was down from $26.7 million in the first half of 2015. Marketer profits were $3.9 million up from a $1.8 million loss in 2015. Generator profits were $0.8 million down from $1.0 million in 2015.
- Financial entities paid the least auction revenue per dollar of payments received at 49 cents per dollar. This was up from 45 cents in the first half of 2015. Marketers paid 82 cents down from 106 cents in 2015. Generators paid 85 cents down from 90 cents in 2015.
- Load-serving entities on net continued to sell rights into the auction from their explicit bidding. Load-serving entities gained about $0.4 million from rights they explicitly sold in the auction in the first half of 2016, down from $11.4 million in the first half of 2015.

Figure 3.2 Congestion revenue rights auction revenues and payments (Financial entities)

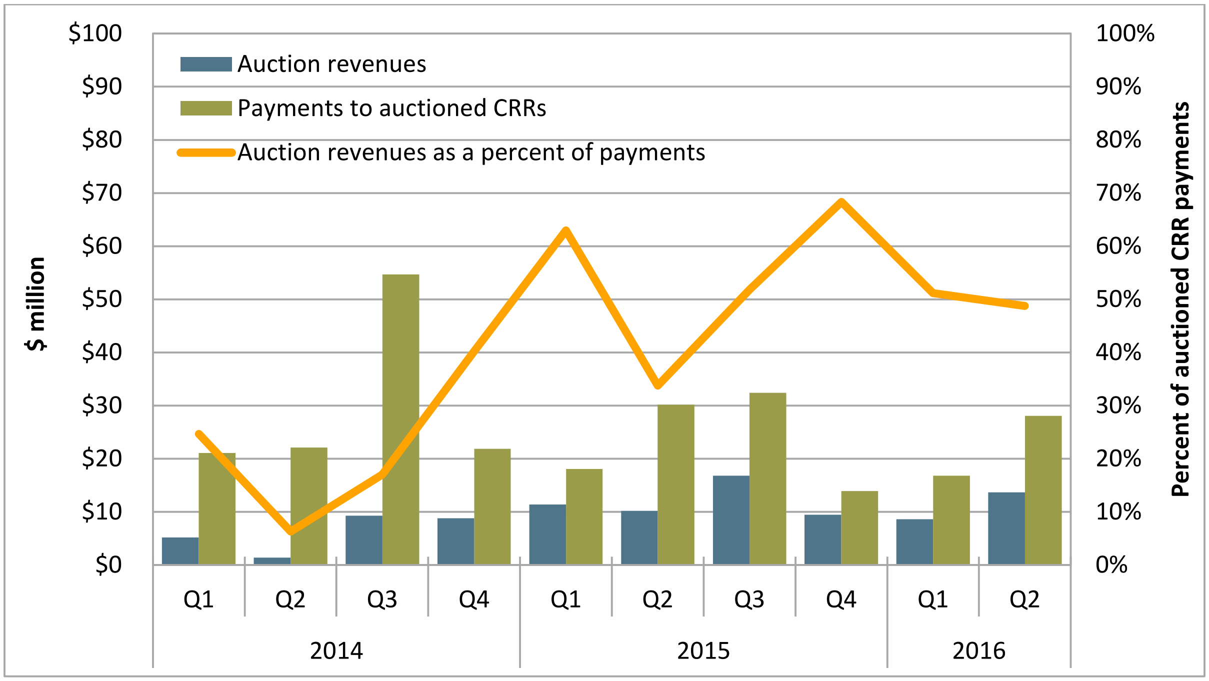


Figure 3.3 Congestion revenue rights auction revenues and payments (Marketers)

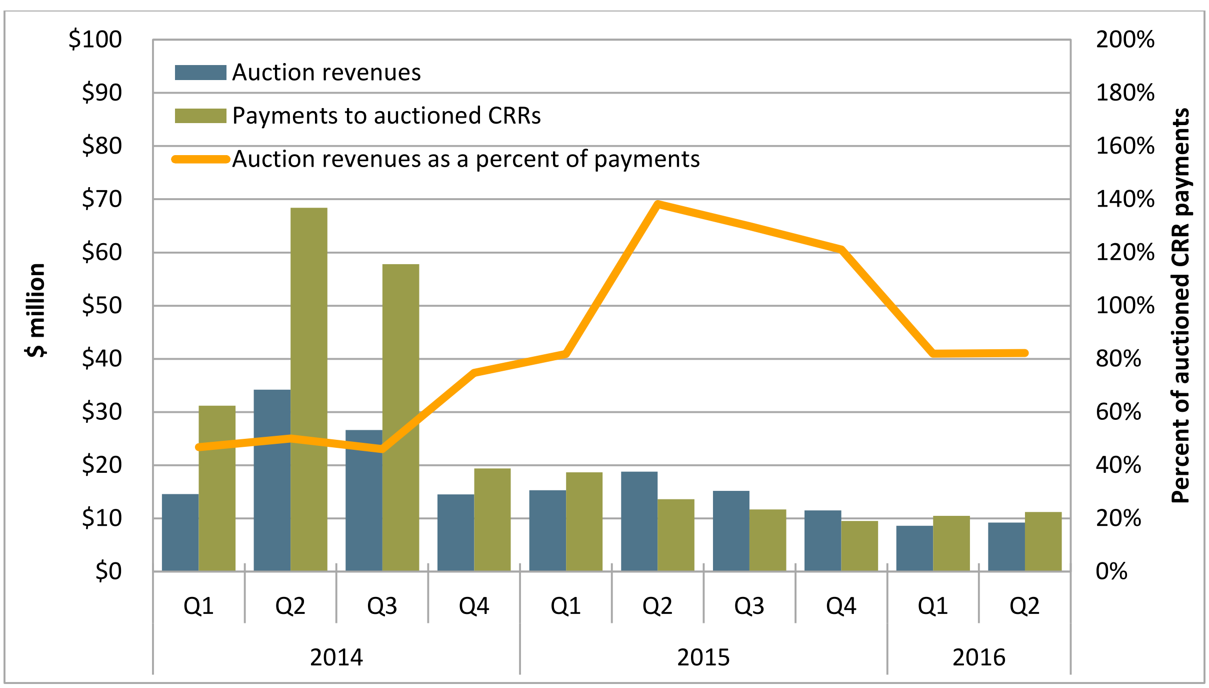


Figure 3.4 Congestion revenue rights auction revenues and payments (Generators)

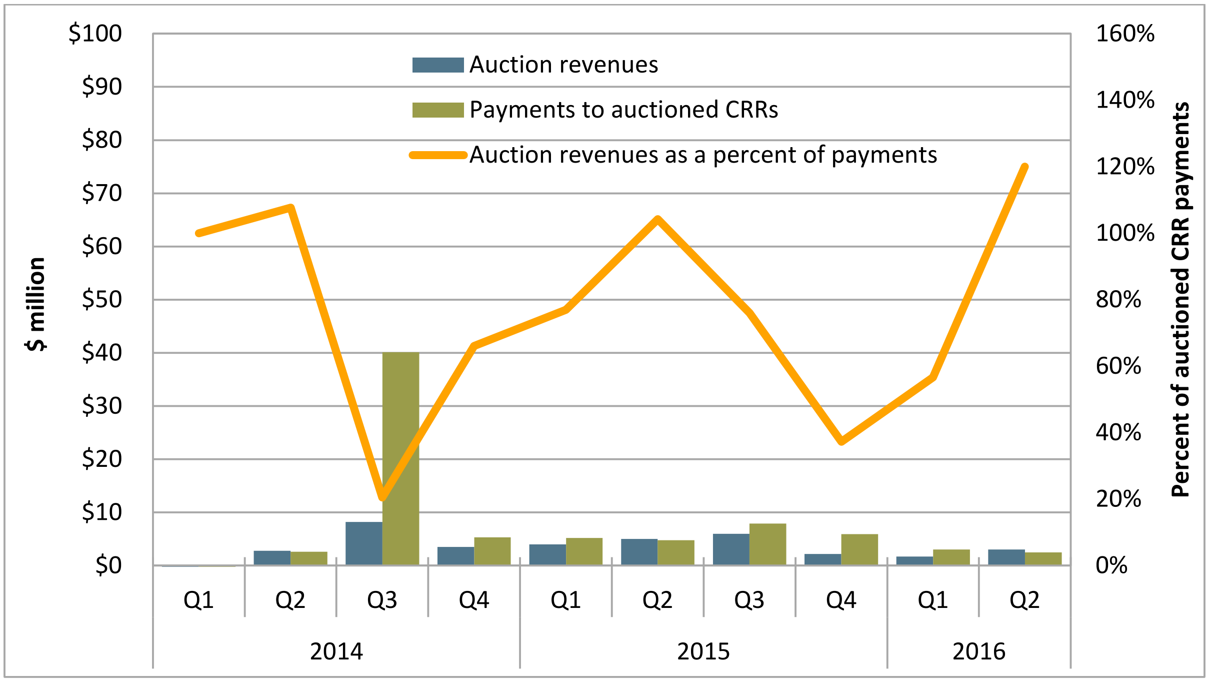
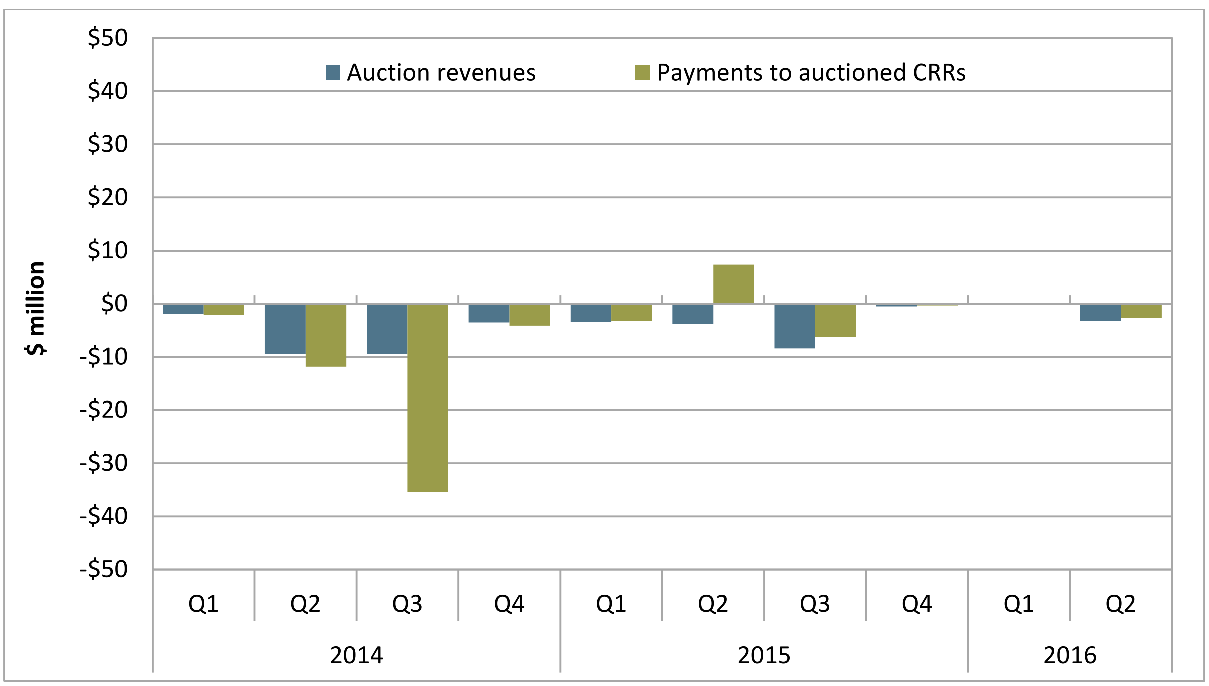


Figure 3.5 Congestion revenue rights auction revenues and payments (Load-serving entities)



Potential improvements to the congestion revenue rights auction

DMM believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off excess transmission capacity remaining after the congestion revenue right allocations. DMM continues to strongly recommend that the ISO begin to assess this issue. The remainder of this section provides additional discussion of options to address this issue.

The losses to ratepayers from the congestion revenue rights auction could be avoided if load-serving entities purchased the congestion revenue rights at the auction from themselves. With this approach, the ISO could still run a *market* for congestion revenue rights. However, this market would be run only with bids voluntarily submitted by various participants willing to essentially buy or sell congestion revenue rights. Participants could include generators, marketers, purely financial entities, or load-serving entities.

In this market, any entity that values hedging against locational price differences, such as generators or marketers, could submit bids to purchase congestion revenue rights. Financial entities, other participants willing to sell hedges, or entities wishing to speculate on locational price differences could submit bids to sell congestion revenues rights.

With this market design, congestion revenue rights would only be sold if there was an entity willing to sell the congestion revenue right and take on the obligation to pay congestion revenues at the market clearing price. For example, a generator purchasing a hedge would pay the price at which another participant — such as a bank, hedge fund or other financial entity — was willing to sell the same hedge.

Load-serving entities could participate in this market if they wanted to buy or sell more rights than they were allocated. However, they would receive all congestion revenues from transmission rights they did not explicitly want to sell through the auction. They would also not be subject to any losses or charges for congestion revenue rights they did not offer to sell.

DMM believes replacing the congestion revenue rights *auction* with this type of congestion revenue rights *marke*t would be more equitable, produce more efficient prices set by willing buyers and sellers, and greatly reduce the loss of congestion revenues for ratepayers by the current congestion revenue rights auction design. DMM believes it is likely that implementing this type of market would not be more complex than the effort needed to implement the current congestion revenues rights auction.

DMM recommends that the ISO begin assessing this issue, and is prepared to work with the ISO and stakeholders to further develop and assess options during this process. In response to DMM's recommendation at the June 2016 Board meeting, ISO management indicated the ISO would consider scheduling an initiative on this issue as part of the ISO's next stakeholder initiative catalog process in the fall of 2016.

4 Load forecast adjustments

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

- The use of negative load adjustments by PacifiCorp increased significantly during the quarter. In June, negative load adjustments occurred during about 84 percent of intervals in PacifiCorp East and about 57 percent of intervals in PacifiCorp West.
- During May and June, the frequency of positive load adjustments in the ISO increased significantly to around 48 percent of intervals in the 15-minute market and 63 percent of intervals in the 5-minute market.
- For PacifiCorp these load adjustments were primarily for generation deviation and automatic time error correction.[46] Load adjustments by NV Energy were most frequently for reliability based control and load forecast deviation.
- The percentage of intervals when the energy power balance constraint was relaxed to allow the market software to balance modeled supply and demand remained very low during the quarter in EIM, and therefore the load bias limiter had a minor impact on EIM prices.
- DMM has provided recommendations to the ISO on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load adjustments on creating power balance relaxations. Specifically, DMM has recommended considering the adjustment based on a combination of factors including the change in load adjustment from one interval to the next and the duration of an adjustment rather than solely the absolute value of any load adjustment.

Background

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

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

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

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

> …. we direct CAISO to collect relevant data from each EIM Entity, for both the 15- and five-minute markets, on the frequency and magnitude of an EIM Entity's use of load biasing, load forecast adjustments, the reason for the adjustments, as well as any alternatives considered (e.g., use of manual dispatch). The CAISO should also retain documentation regarding the reliability needs that were addressed by these load forecast adjustments or load bias actions.[47]

FERC also indicated that:

> Additionally, we expect CAISO's Department of Market Monitoring to monitor and evaluate this information and include an analysis of the impacts of EIM Entities' load forecast adjustments or load bias actions on the EIM in its public Quarterly Report on Market Issues and Performance. Inclusion of this information in the Department of Market Monitoring's quarterly reports will assist the Commission in assessing the effects these actions have on market outcomes.[48]

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

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

- A summary of the general frequency, direction and magnitude of the load adjustments in the different EIM areas. The same data for the ISO are provided as a point of comparison and reference.
- A summary of the reasons for load adjustments as reported by operators using standard categories developed for tracking the reasons for load adjustments on an interval-by-interval basis in the real-time market.
- Several examples illustrating how in some selected cases the reason for the use of the load adjustment is readily apparent and system data suggest the load adjustment is likely to have helped make the real-time market dispatch more accurate.
- An analysis of how load adjustments impacted prices by triggering the load bias limiter mechanism incorporated in the real-time software.

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

[48] Ibid, p. 50.

Frequency and size of load forecast adjustments

Figure 4.1 and Figure 4.2 show the frequency of positive and negative load forecast adjustments for PacifiCorp East, PacifiCorp West, and NV Energy during the previous six months for the 15-minute and 5-minute markets, respectively. The same data for the ISO is provided as a point of comparison and reference.

Table 4.1 summarizes the average frequency and size of positive and negative load forecast adjustments for the ISO and EIM balancing areas during the second quarter. As shown in the table, positive load adjustments were most frequent in NV Energy and the ISO, while negative load adjustments were most frequent in the PacifiCorp areas. Average load adjustments in EIM were typically smaller in absolute magnitude than adjustments in the ISO, but as a percentage of area load were generally larger than adjustments in the ISO.

In both PacifiCorp areas the frequency of negative load adjustments increased significantly during the quarter, with negative load adjustments most frequent during June. In June they occurred during about 84 percent of intervals in PacifiCorp East and about 57 percent of intervals in PacifiCorp West. During intervals with negative adjustments, the adjustment averaged around -120 MW for PacifiCorp East (or about 2.5 percent of load) and around -60 MW for PacifiCorp West (or about 2.7 percent of load) during the quarter, as shown in Table 4.1.

In the NV Energy area, positive load adjustments were made during about 50 percent of all intervals, while negative load adjustments were made during only about 10 percent of 5-minute intervals. Positive adjustments in NV Energy averaged around 110 MW (or about 2.5 percent of load) in both real-time markets, a slight increase from around 100 MW in the first quarter.

For comparison, ISO operators entered load adjustments in a higher percentage of intervals than EIM area operators, but the load adjustments tend to be smaller as a percentage of total load, 1.3 percent of ISO load compared to 1.7 percent of EIM load, as shown in Table 4.1.

Figure 4.1 Average frequency of positive and negative load adjustments by BAA (15-minute market)

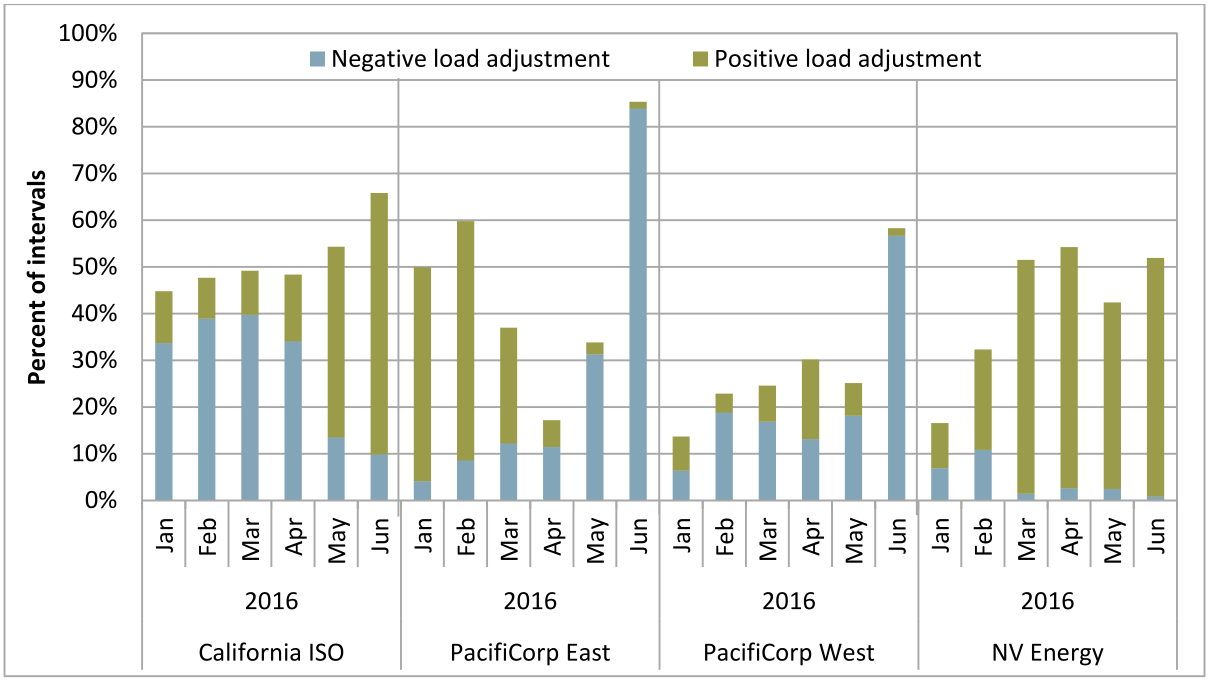


Figure 4.2 Average frequency of positive and negative load adjustments by BAA (5-minute market)

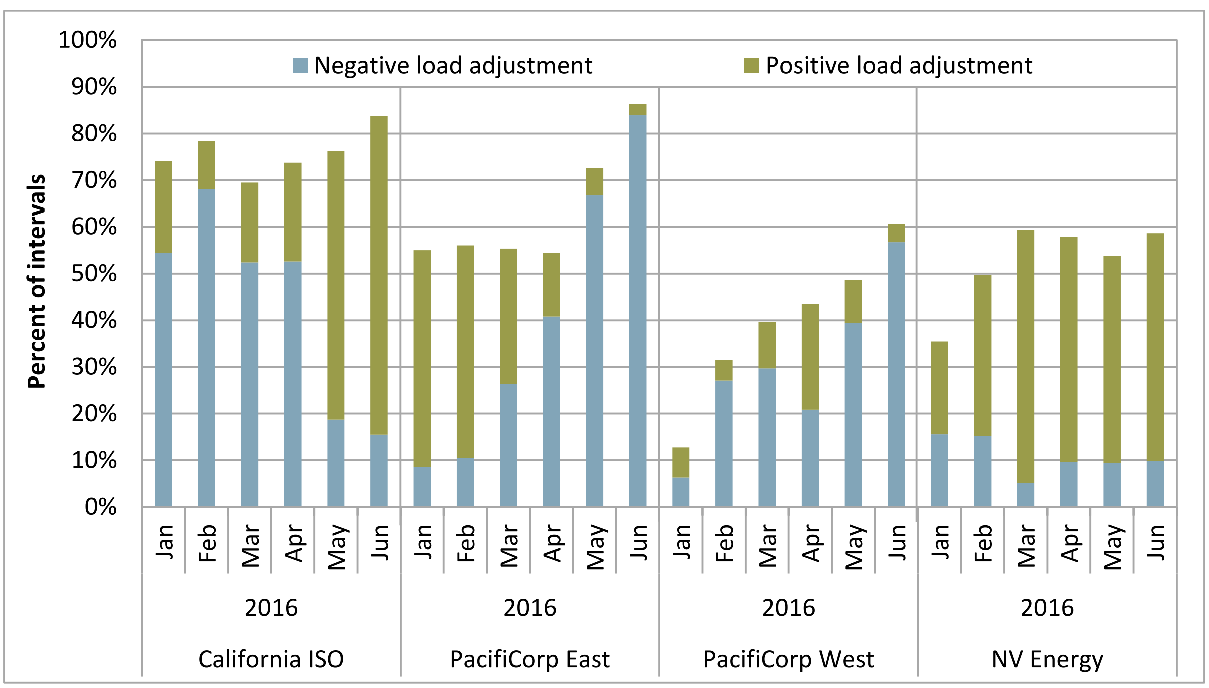


Table 4.1 Average frequency and size of load adjustments (April – June)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	37%	450	1.6%	19%	-292	1.3%	112
5-minute market	49%	455	1.7%	29%	-301	1.3%	137
PacifiCorp East							
15-minute market	3%	83	1.7%	42%	-110	2.1%	-44
5-minute market	7%	85	1.7%	64%	-130	2.7%	-77
PacifiCorp West							
15-minute market	9%	59	2.7%	29%	-55	2.6%	-11
5-minute market	12%	63	2.9%	39%	-57	2.8%	-15
NV Energy							
15-minute market	48%	127	2.8%	2%	-171	5.1%	57
5-minute market	47%	90	2.0%	10%	-70	1.9%	36

Figure 4.3 shows the average hourly load forecast adjustment profile for the 15-minute and 5-minute markets during the second quarter for PacifiCorp East and PacifiCorp West. Differences between adjustments in the 15-minute market and 5-minute markets can arise from differences in either the frequency or magnitude of positive and negative load adjustments.

As shown by the solid lines in Figure 4.3, load in PacifiCorp East was adjusted more frequently in the negative direction in the 5-minute market than in the 15-minute market during the quarter resulting in a more negative net bias, particularly during early morning, midday, and late evening hours. This was largely driven by differences in April and May where negative adjustments in PacifiCorp East were more than twice as frequent in the 5-minute market than in the 15-minute market.

In PacifiCorp West load adjustments were more similar in the 5-minute and 15-minute market. However, adjustments in the 5-minute market also tended to be more frequent than 15-minute adjustments during early morning and late evening hours.

Figure 4.4 provides the same information on load forecast adjustments for NV Energy. In the NV Energy area, the hourly average adjustment generally followed the load pattern. Adjustments were low during the early morning and late evening hours and were highest during the evening peak load hours. The frequency of positive load adjustments were similar in the 15-minute and 5-minute markets. Greater average adjustments in the 15-minute market than the 5-minute market occurred because of larger positive adjustments in the 15-minute market and more frequent negative adjustments in the 5-minute market.

Figure 4.5 shows the average hourly load adjustments for the 15-minute and 5-minute markets in the ISO during the second quarter. Like NV Energy, the shape of the hourly average adjustment is reflective of the shape of hourly net load. Positive load adjustments were most frequent during morning and evening peak net load periods. Alternatively, negative load adjustments were most frequent during early morning, midday, and late evening hours.

Differences in load adjustments by the ISO between the 15-minute market and 5-minute market were largely related to the hourly frequency in which positive and negative load adjustments occurred. In particular, negative load adjustments were significantly more frequent during hours ending 23 and 24 in the 5-minute market than in the 15-minute market while 5-minute positive load adjustments were more frequent in hours ending 5, 6, and 7. In addition, positive and negative load adjustments in the 5-minute market were typically greater in magnitude than in the 15-minute market. These differences in inputs can result in significantly different market outcomes.

Figure 4.3 Average hourly load adjustment – PacifiCorp (April – June)

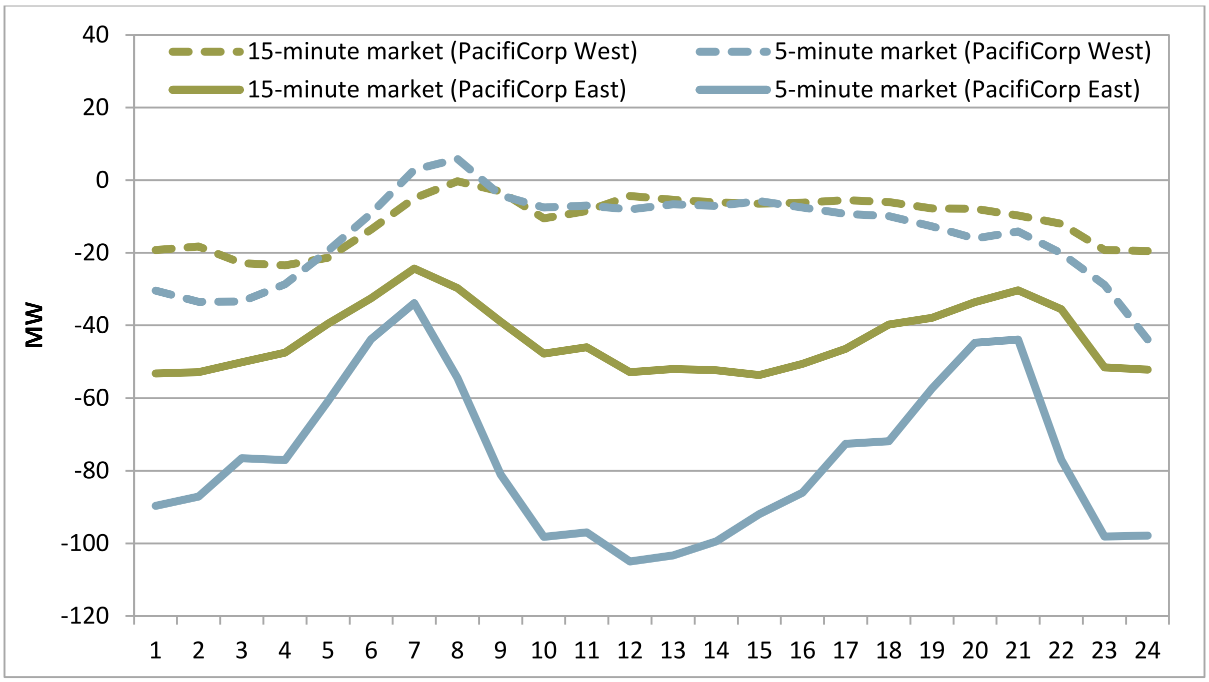


Figure 4.4 Average hourly load adjustment – NV Energy (April – June)

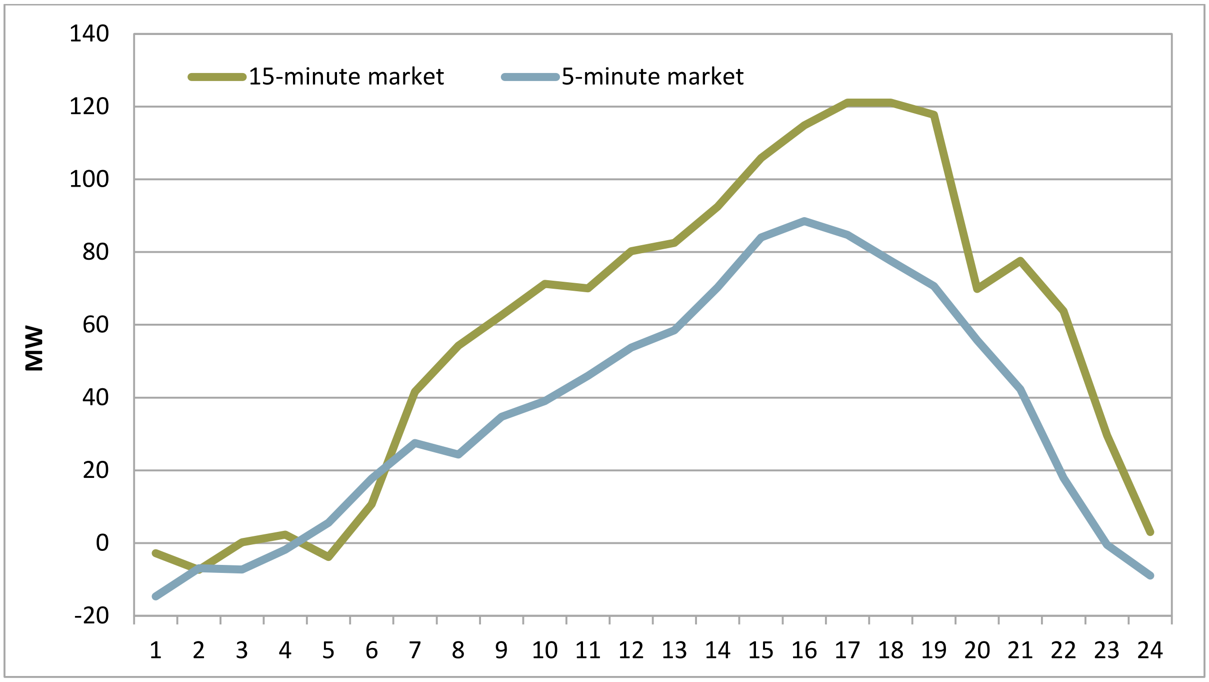
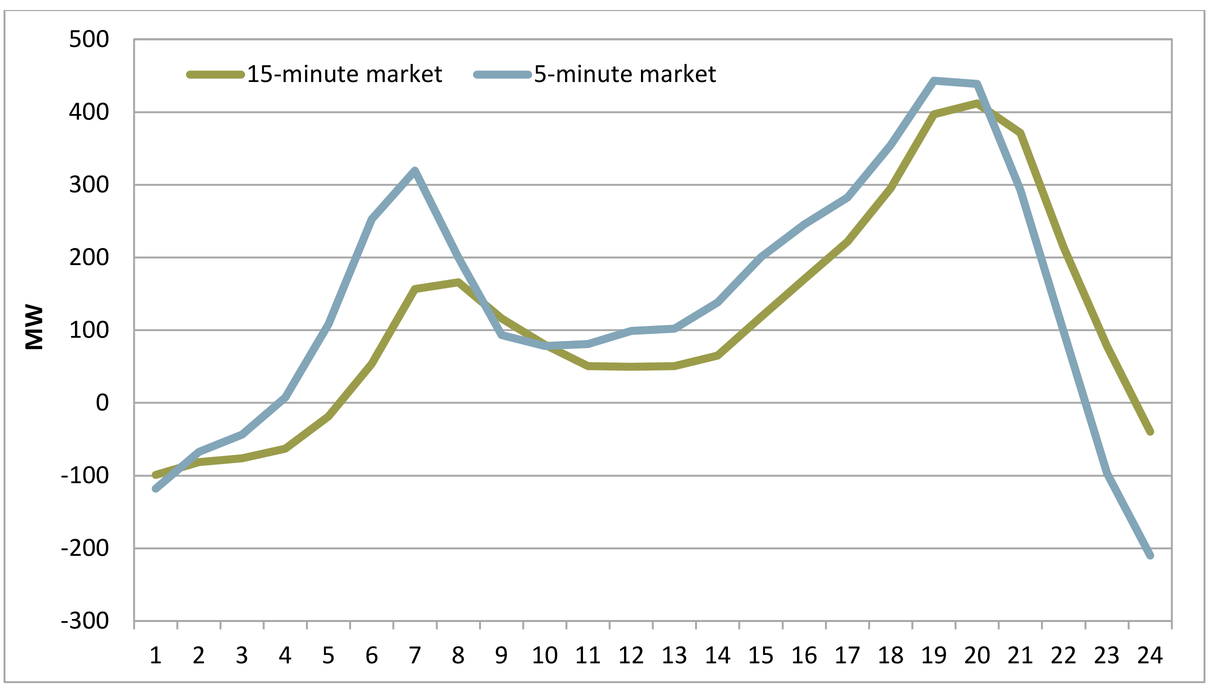


Figure 4.5 Average hourly load adjustment – ISO (April – June)



Reasons for load adjustments

With the implementation of the available balancing capacity mechanism, the ISO developed a feature for operators to log pre-specified reasons for making load adjustments using a drop down menu. EIM operators began regularly logging reasons for adjustments in the 15-minute and 5-minute markets on April 5, 2016. These reasons are summarized below.

In the ISO, reasons for load adjustments were classified into four groups:

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

In the EIM, the common reasons for load adjustments were as follows:

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

When operators enter a load adjustment duration and quantity, operators now have the option to select a reason for the load adjustment from a list of predefined reasons.[49] In addition, operators have the ability to explain additional details about why a load adjustment is entered in a free-form text box. If operators make a load adjustment for more than one reason, they only have the ability to select only one preset reason from the list. However, additional reasons can be entered in a free-form text box. Logging additional details or reasons through the text box is optional.

During the quarter, PacifiCorp East and PacifiCorp West operators included additional detail during about 69 percent and 44 percent, respectively, of intervals when load adjustments were entered. PacifiCorp frequently used this feature to cite additional reasons beyond the single reason selected from the list. Operators in NV Energy rarely used the additional details text box during most of the quarter, but began adding more details during a majority of intervals in the last week of June.

At this time, the only method for additional details about the load adjustment, including details about reliability needs and alternative options evaluated prior to entering a load adjustment, is the free-form text box. There is no secondary drop down function in the tool that operators use for load adjustments. DMM has not observed any input in the free-form text box that addresses the logging of details on alternative options and therefore cannot provide any additional information on them at this time. DMM

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

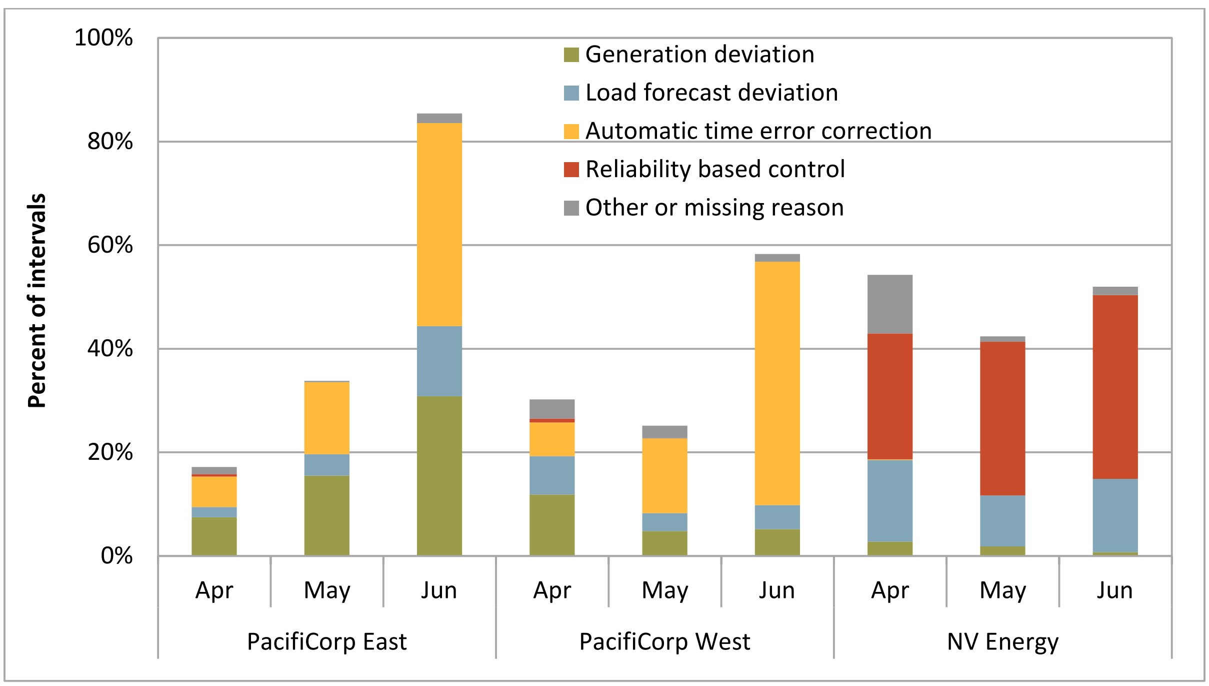
recommends that the ISO modify its tool to allow operators to enter this information or to provide for another process to capture it.

Figure 4.6 and Figure 4.7 show the frequency of load adjustments in the EIM areas by the reason selected for the adjustment during the previous three months for the 15-minute and 5-minute markets, respectively.[50] The figures show that the main reasons reported by PacifiCorp operators for adjusting loads was for generation deviation and automatic time error correction.

As shown in Figure 4.7, generation deviation in the 5-minute market was selected during about half of the intervals when load adjustments were entered in PacifiCorp East and about 25 percent of load adjustments in PacifiCorp West during the quarter. For PacifiCorp, generation deviation was often logged because of generation deviations from wind resources.

In NV Energy, operators reported adjusting loads most frequently for reliability based control and load forecast deviation. NV Energy operators selected reliability based control during about 30 percent of intervals with load adjustments while load forecast deviation was selected during about 15 percent of intervals.[51]

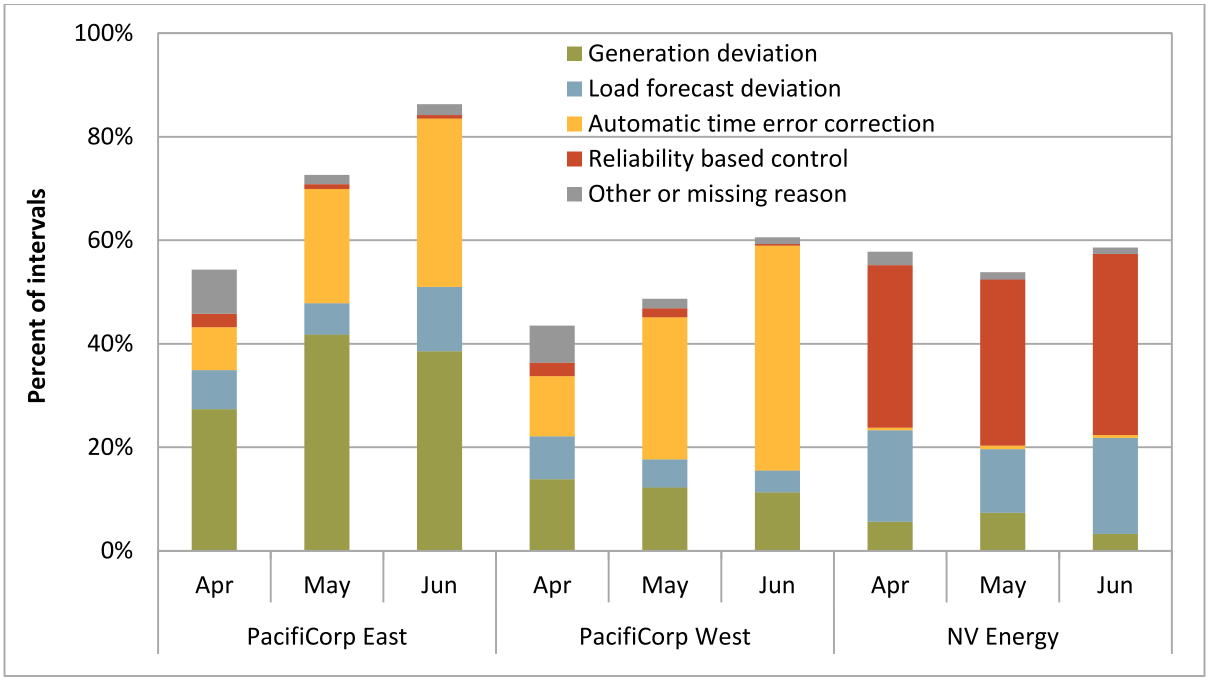
Figure 4.6 Frequency of load forecast adjustments by reason (15-minute market)



[50] Analysis was completed for intervals when a bias was entered and a particular reason from the predefined list was specifically selected. They do not include intervals when the reason, also from the list, was indirectly logged as an additional detail in the free-form text box. This occurred in PacifiCorp East and PacifiCorp West during about 50 and 29 percent of intervals with biases, respectively.

[51] Operators entered in fewer reasons for load adjustments in both markets in April because of the novelty of the logging system and changes in the software.

Figure 4.7 Frequency of load forecast adjustments by reason (5-minute market)



Examples of load adjustments

Figure 4.8 and Figure 4.9 show two specific examples of load adjustments made by EIM operators during the second quarter. The first example shows how load adjustments were used to account for renewable generation deviation. Figure 4.8 shows that forecasted wind gradually increased between 8:00 am and 10:00 am while actual wind generation rapidly increased during the same period. In response, EIM operators made load adjustments that roughly corresponded to the difference in forecast and actual wind generation during those hours. At around 10:00 am, the forecast value nearly matched the actual output of the renewable generation once again. Consequently, the EIM operators increased the load adjustment by 400 MW to match the change in the forecast value.

The second example shows a case where load adjustments were used to account for load deviation from the forecast. Figure 4.9 shows the difference between actual load, forecasts in the 5-minute market, and load adjustments in the 5-minute market. In this example, a systematic and increasing difference between the real-time load forecast and actual loads is apparent between 7:00 a.m. and 10:35 a.m. During this period, positive load adjustments were entered at up to 250 MW to correct for the deviation.

Figure 4.8 Example 1 – Wind deviation from forecast in PacifiCorp East (April 13, 2016)

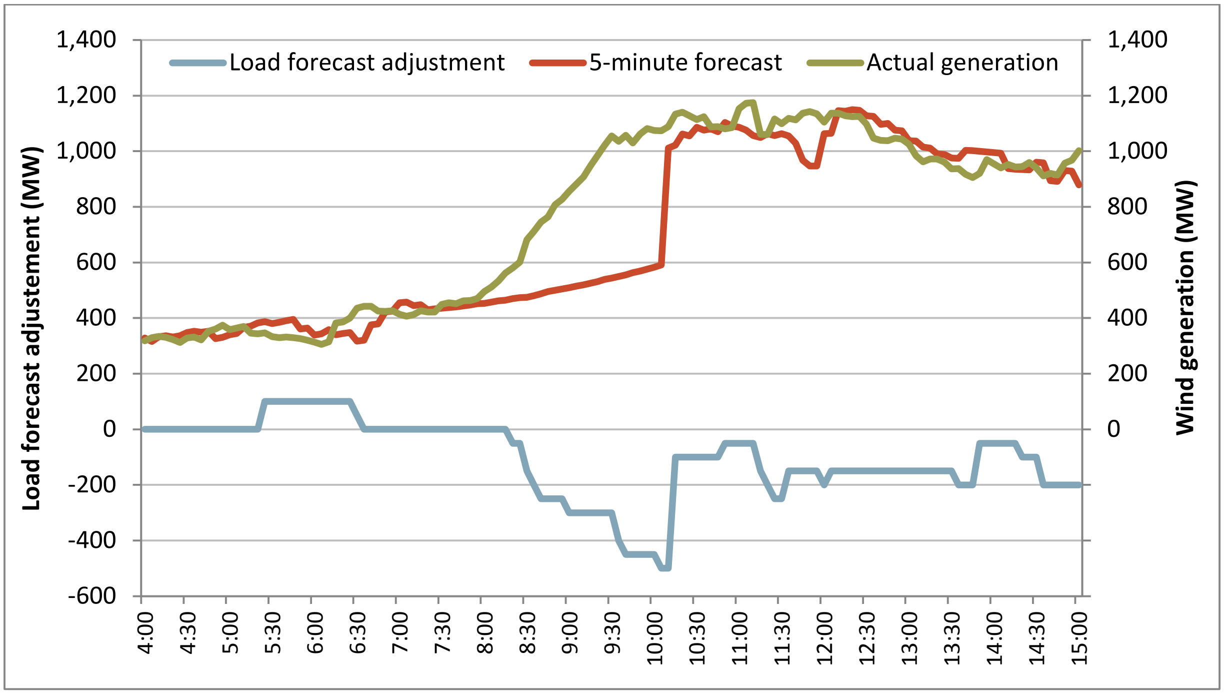
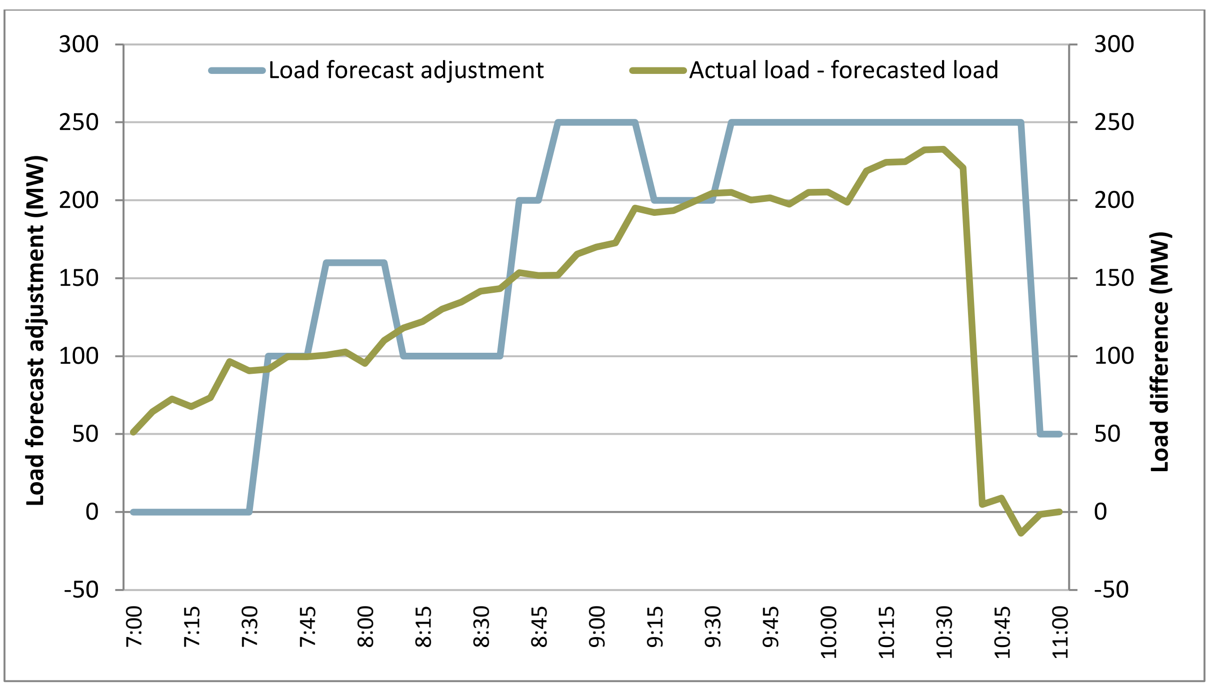


Figure 4.9 Example 2 – Load deviation from forecast in PacifiCorp East (July 8, 2016)



Impact of load adjustments on prices

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

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

When the load bias limiter is triggered it results in a feasible market solution in the pricing run, so that the price is set by the highest priced supply dispatched, rather than the $1,000/MWh shortage penalty price for the power balance constraint if there is insufficient upward ramping capacity. The resulting price, from the unit entering the highest economic bid, is often significantly less than the $1,000/MWh penalty price. The functionality of the load bias limiter is similar to the price discovery feature that was in effect in EIM until this spring as they both set price to the offer price of the last dispatched resource during power balance relaxations.[52]

In the second quarter, the load bias limiter feature would have been triggered during about half of the power balance relaxations observed in all EIM areas during the quarter. However, the percentage of intervals when the energy power balance constraint was relaxed to allow the market software to balance modeled supply and demand remained very low during the second quarter, and therefore the load bias limiter had a small impact on overall prices.

Figure 4.10 and Figure 4.11 show that the load bias limiter would have been triggered in NV Energy during about 14 percent of 15-minute intervals and 63 percent of 5-minute intervals in the second quarter, when power balance constraint relaxations occurred due to insufficient incremental energy. Thus, during more than half of the power balance relaxations in the 5-minute market in NV Energy, operators made load adjustments in greater magnitude than the size of the infeasibility. The majority of these relaxations occurred in June following the expiration of price discovery. The load bias limiter triggered during less than 0.5 percent of 5-minute intervals in NV Energy during June so average prices were only marginally affected by the load bias limiter.

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

Figure 4.10 Mitigation of power balance relaxation by load bias limiter – 15-minute market

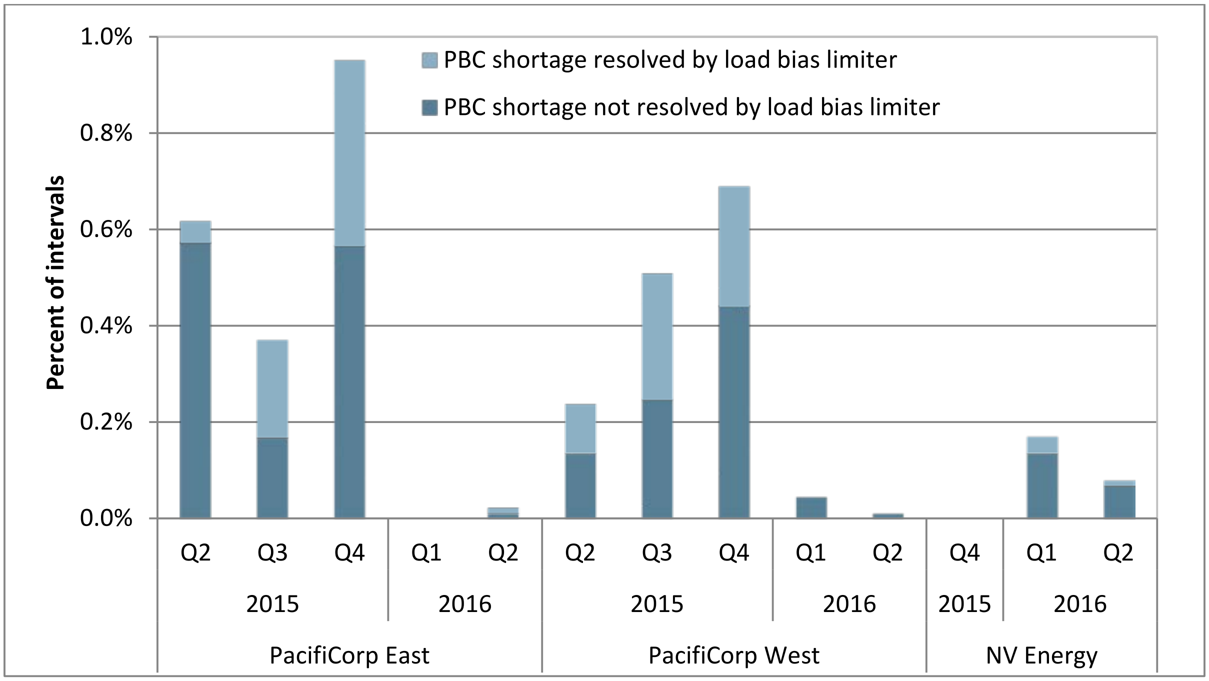


Figure 4.11 Mitigation of power balance relaxation by load bias limiter – 5-minute market

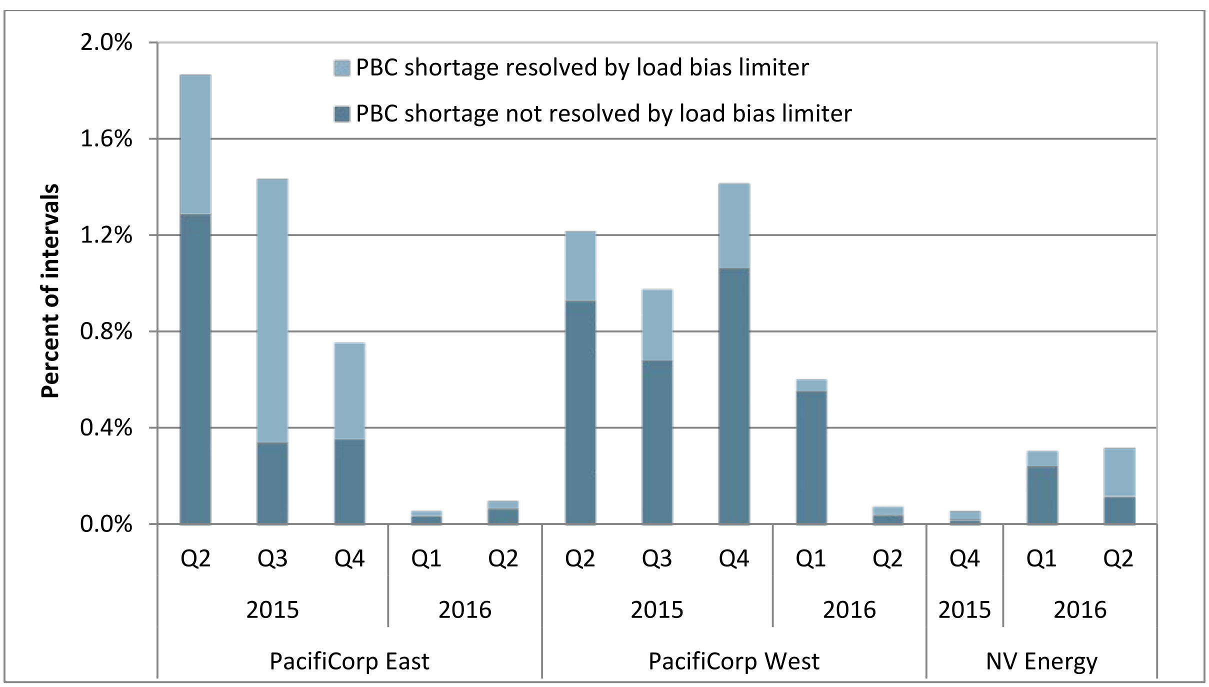


Figure 4.11 shows that the load bias limiter would have been triggered during about 31 and 45 percent of these 5-minute intervals with power balance constraint relaxation in PacifiCorp East and PacifiCorp West, respectively. However, these load bias limiter outcomes in PacifiCorp occurred during only about 0.01 percent of 15-minute intervals and 0.03 percent of 5-minute intervals and therefore did not have a significant impact on prices.

Table 4.2 shows estimated EIM prices if prices were set at the $1,000/MWh penalty price during intervals when either the load bias limiter triggered or, for NV Energy in April and May, would have been triggered had price discovery provisions not been in effect. Table 4.2 shows that the load bias limiter lowered 15-minute prices in PacifiCorp East and NV Energy by less than $0.20/MWh. In the 5-minute market, the load bias limiter also had a small impact on prices in the PacifiCorp areas, but impacted NV Energy prices slightly by about $1.50/MWh (6 percent) during the quarter.

Table 4.2 Impact of load bias limiter on EIM price (April – June)

	Bilateral trading hub range		Average EIM price	EIM price without price discovery*	EIM price without price discovery or load bias limiter*	Estimated impact of load bias limiter	
	Low	High				Dollars	Percent
PacifiCorp East							
15-minute market (FMM)	$17.90	$19.10	$20.84	$20.84	$20.93	-$0.10	-0.5%
5-minute market (RTD)	$17.90	$19.10	$19.97	$19.97	$20.18	-$0.20	-1.0%
PacifiCorp West							
15-minute market (FMM)	$17.90	$19.10	$16.86	$16.86	$16.86	$0.00	0.0%
5-minute market (RTD)	$17.90	$19.10	$10.47	$10.47	$10.46	$0.01	0.1%
NV Energy							
15-minute market (FMM)	$17.04	$17.60	$22.45	$22.45	$22.55	-$0.10	-0.5%
5-minute market (RTD)	$17.04	$17.60	$22.87	$23.06	$24.49	-$1.42	-5.8%

**Without price discovery applies to NV Energy in April and May only*

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

5 Special issues

This section provides an update on two special issues that include the impacts of a significant increase in regulation requirements made between February and June 2016, and the special measures implemented to mitigate potential impacts of limitations on gas availability in Southern California because of the moratorium imposed on the Aliso Canyon natural gas storage facility. Below are the key observations and findings:

- The ISO decreased regulation requirements in the day-ahead and real-time markets to typical levels observed prior to February 2016, starting on June 10. As a result, regulation prices reverted back to lower levels and the procurement costs decreased to $80,000 per day compared to $400,000 per day or more when requirements were higher.
- Multiple market features were phased in during the quarter for the coordination needed between the gas and electricity markets because of limitations at the Aliso Canyon gas storage facility. However, conditions did not require the use of many of the tools that could potentially be called on by system operators. DMM continues to monitor the market for potential withholding and opportunities for market participants to exercise market power. In addition, DMM is examining other market constructs, particularly the virtual market and the congestion revenue rights market, for potential manipulative behavior from market distortions related to Aliso Canyon.

5.1 Regulation requirements

During the period between February 20 and June 9, 2016, the ISO increased 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 increased at the same time as a result of the higher requirements. Because both the procured amount and corresponding prices of regulation increased, the cost for procuring regulation increased substantially during this period. Since June 10, the regulation requirements and associated costs have reverted back to levels similar to what was observed before February 20.

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.[53] 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, which was implemented in 2009, is provided in DMM's 2010 annual report.[54]

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

[54] *2010 Annual Report on Market Issues and Performance*, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

In addition to a capacity payment, resources that provide regulation also receive a performance payment, which is referred to as mileage.[55] Since implementation of the mileage product in June 2013, mileage payments have been very small compared to capacity payments.

Regulation requirements and prices

Prior to February 20, 2016, regulation up and regulation down requirements in the day-ahead market ranged between 300 MW and 400 MW. The corresponding requirements in the real-time market were consistently set at 300 MW. During the period of February 20 through June 9, 2016, the ISO increased the requirements to a minimum of 600 MW for regulation up and regulation down in both the day-ahead and real-time markets.[56] 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. Starting June 10, the ISO lowered the regulation requirements back to the 300 MW to 400 MW range in the day-ahead market and 300 MW in the real-time market.[57]

Average prices for regulation up and regulation down increased immediately following the change in requirements in February and reverted back to lower levels again in June, as shown in Figure 5.1. This figure reports weekly weighted average day-ahead prices for regulation up and down during the first and second quarters of 2016. The vertical black lines indicate the beginning and the end of the time period with higher regulation requirements. For the second quarter, the weighted average day-ahead price between April 1 and June 9 was $16.05/MW for regulation up and $13.72/MW for regulation down. Between June 10 and June 30, the weighted average price was $6.51/MW and $3.09/MW for regulation up and regulation down, respectively.

Average prices in the real-time market also increased substantially after February 20 prior to the decrease after June 10. The weighted average real-time price between April 1 and June 9 was $21.01/MW for regulation up and $26.84/MW for regulation down. After the requirement decrease, these averages decreased to $7.94/MW for regulation up and $11.53/MW for regulation down.

Analysis of the bidding behavior of participants in the regulation market around the time of the requirement changes did not identify any significant changes in the supply bids offered to the market. The increase in regulation prices can therefore primarily be attributed to the increase in procurement quantities. However, other supply conditions may also have contributed to the higher regulation shadow values. For example, lower numbers of natural gas-fired generators committed, primarily because of high levels of renewable generation and relatively low loads, may have partly caused higher regulation prices during the spring months.

Average spinning reserve prices were also relatively high during the spring months, with the highest day-ahead monthly weighted average prices observed in March and April at around $8/MW.[58] While spinning reserve prices may have been influenced by the higher regulation requirements, they were also affected by other supply conditions. For example, snowmelt in the spring months created high levels of

[55] 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.

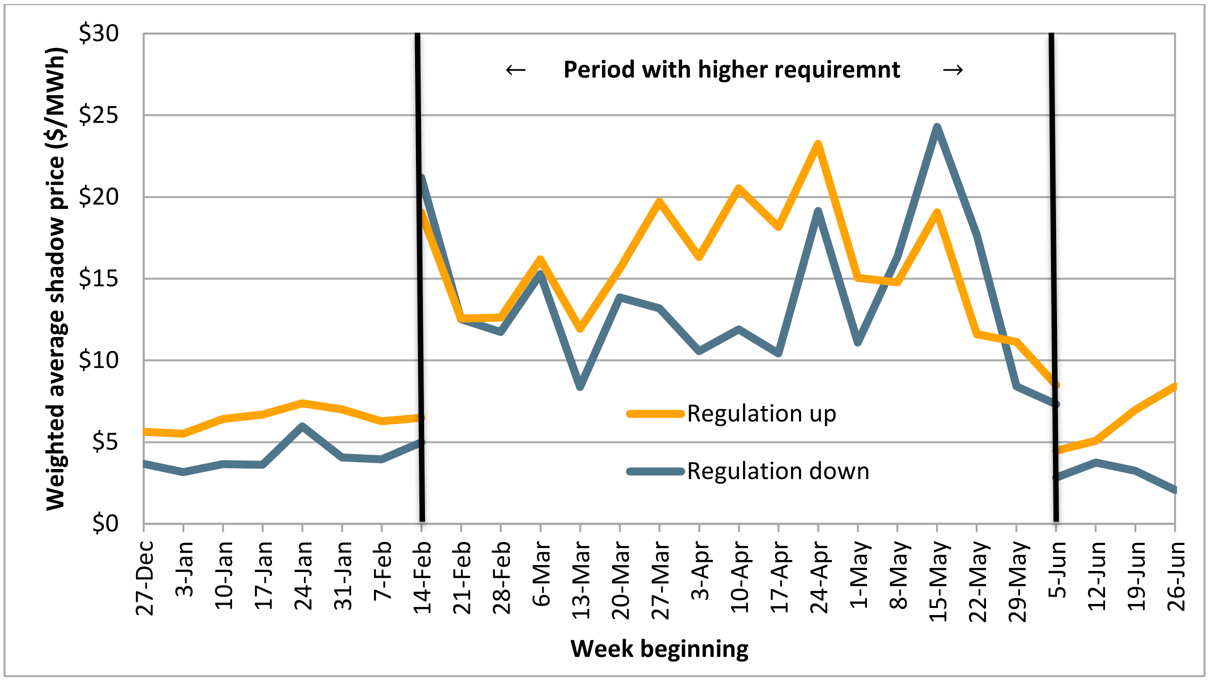
[56] One exception occurred during hours ending 22 through 24 on March 7, when the requirement was decreased to 400 MW in the day-ahead market.

[57] Real-time requirements were temporarily increased to 500 MW for some intervals on June 21, 23 and 24.

[58] For comparison, the weighted average day-ahead spin price in 2015 was $3.68/MW.

hydro runoff that required hydro-electric resources to produce electricity rather than provide spinning reserves.

Figure 5.1 Weighted average day-ahead shadow prices for regulation (January – June)



Regulation procurement costs

Because both the procured amount and the price for regulation increased between February 20 and June 9, the costs of procuring regulation were significantly higher during the same time period. Figure 5.2 shows the average daily procurement costs for regulation by month, dividing February and June into pre-change and post-change periods.[59]

When the regulation requirements were between 300 MW and 400 MW (January 1 through February 19 and June 10 through June 30) the average daily cost to procure regulation was below $90,000 per day.[60] The average daily cost during the period with higher regulation requirements was about $470,000 per day, with procurement costs above $535,000 per day in May. During the beginning of June, when regulation requirements were still high, the daily average procurement costs decreased to about $250,000 per day. This was likely related to higher system loads increasing the number of committed resources and the supply for regulation.

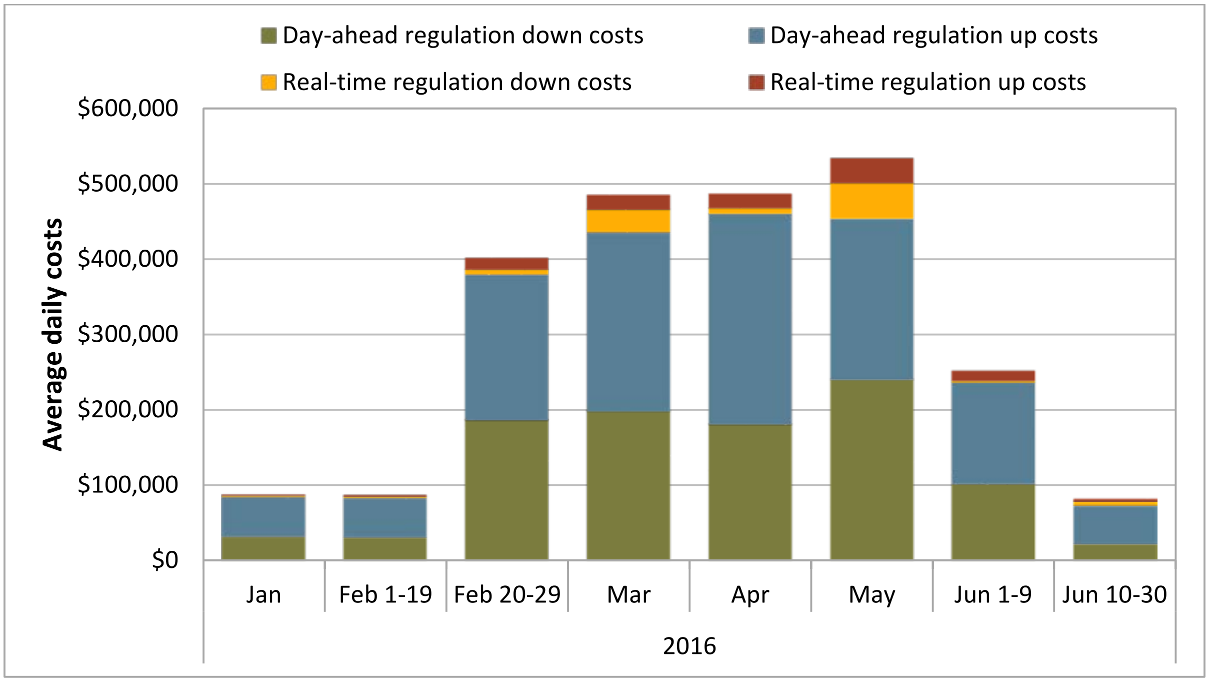
Day-ahead procurement costs, which made up the largest portion of total costs, averaged almost $430,000 per day during the period with higher requirements, compared to about $81,000 per day when requirements were lower. The corresponding values for real-time regulation procurement were about $50,000 per day during the period when high requirements were in place and about $5,000 per day when requirements were lower. The relatively larger real-time costs compared to day-ahead costs

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

[60] For comparison, the average total daily cost for regulation capacity in 2015 was about $75,000 per day.

when the requirements were higher likely reflect that the same procurement targets were enforced in the real-time and day-ahead markets, whereas higher targets in the day-ahead market were typical during the periods with lower requirements.

Figure 5.2 Average daily regulation procurement costs (January – June)



Impacts on mileage

During the period with higher regulation procurement, the amount of adjusted mileage delivered by resources providing regulation also increased. The daily average amount of adjusted mileage delivered for mileage up and mileage down combined was 49 percent higher during February 20 through June 9, compared to other days in the first and second quarters. However, the weighted average price for mileage remained close to $0 per unit of mileage throughout both the first and second quarters, and therefore total payments for mileage remained low. The average daily payment for mileage during the second quarter was less than $400 per day. For comparison, the average daily payment for mileage in 2015 was about $3,000 per day.

5.2 Aliso Canyon gas-electric coordination

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

The ISO, California Energy Commission and the California Public Utilities Commission published in April 2016 a risk assessment and technical report finding that the limited operability of Aliso Canyon posed a significant risk to electric reliability during summer months of 2016.[61] To address these reliability concerns, the ISO in May 2016 filed for FERC approval of several temporary tariff amendments.[62] These tariff amendments, which are described in further detail below, were approved by FERC on June 1 and will remain in effect until November 30, 2016.[63]

Implementation of temporary Aliso Canyon measures

The ISO developed a set of operational tools allowing operators to restrict the gas burn of ISO resources. The tools, which are implemented as a set of nomogram constraints, can be used to limit either the total gas burn or deviations in gas burn compared to day-ahead schedules for natural gas-fired resources. These tools have been available to operators since June 2. However, during the second quarter, based on observed system conditions operators did not elect to enforce these constraints.[64]

The temporary tariff amendments also give the ISO authority to reserve internal transmission capacity to manage issues related to a constrained natural gas system. For example, the ISO may need to reserve transmission capacity on Path 26 in the day-ahead market to create additional flexibility that could be used in real time. As with the gas burn constraints, operators have had this ability since the beginning of June but based on market conditions did not choose to implement them during the second quarter.

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

The tariff amendments also included an increased ability of the ISO to limit or suspend virtual bidding. A restriction on virtual bidding may be necessary if operators choose to reserve transmission capacity in the day-ahead market for use in real time since that could cause systematic and predictable price differences between day-ahead and real-time markets. Virtual bidders could take advantage of such price differences, which would undo the intent of restricting the transfer capability and could have

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

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

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

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

negative impacts on market efficiency. The ISO did not find the need to use this feature in the second quarter.

The ISO has also granted an ability for resources to rebid their commitment costs in the real-time market for hours without day-ahead schedules or once committed in real time for hours spanning minimum run times. This ability was activated on June 2.

Starting July 6, in order to allow natural gas-fired generators in the SoCalGas system to reflect higher same-day natural gas prices, and to avoid having these resources dispatched for system needs in the event of constrained gas conditions in Southern California, the ISO adjusted the gas price indices used to calculate the commitment cost caps and default energy bids in the real-time market for natural gas-fired generators in this area. A 75 percent adder was added to the fuel cost component used for calculating proxy commitment costs for resources on the SoCalGas system. For the fuel cost component of default energy bids, the ISO included a 25 percent adder. The 75 percent and 25 percent levels implemented by the ISO were based on analysis presented by DMM in its comments on the final Aliso Canyon gas-electric coordination proposal.[65] DMM is continually monitoring the extent market participants are making use of the additional headroom for commitment costs, and plans to provide details on this in future quarterly reports.

In addition to these tools, the ISO asked in its May FERC filing for permission to use a more timely natural gas price for calculating default energy bids and proxy commitment costs in the day-ahead market. With this modification, the ISO would base the natural gas price index on next-day trades from the morning of the day-ahead market run, instead of index prices from the prior day that are currently used. The target implementation date for this measure was July 6; however, this change was not implemented because the ISO was not able to confirm that this price would be consistent with the FERC policy statement on natural gas indices.[66] DMM continues to support implementing this functionality as soon as possible. We further note that gas costs used by participants in generating reference bids in other RTO and ISO markets may not be explicitly limited to or by indices that are approved under the FERC policy statement on natural gas indices.[67]

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

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

[67] More information on how other RTO and ISO markets incorporate gas costs can be found under FERC Docket No. RM16-5-000: http://www.ferc.gov/whats-new/comm-meet/2016/012116/E-1.pdf.