California Independent System Operator Corporation

California ISO

Q4 2014 Report on Market Issues and Performance

March 3, 2015

Prepared by: Department of Market Monitoring

TABLE OF CONTENTS

Executive summary

This report provides highlights of significant market changes and general market performance during the fourth quarter of 2014 (October – December). The ISO markets continued to perform well overall in the fourth quarter:

- Real-time imbalance offset cost settlement values totaled $3 million. This represents a significant drop from $44 million in the fourth quarter of 2013 and $60 million in the third quarter of 2014.
- Following the FERC Order No. 764 market changes implemented in May, the amount of import and export bids offered in the real-time market dropped. The amount of import and export bids offered in the real-time market increased in the fourth quarter, most notably in December. This increase may be related to the Bonneville Power Administration's implementation of 15-minute scheduling on October 21 or other potential factors.
- Bid cost recovery payments in the ISO system were around $25 million, compared to $24 million in the third quarter of 2014 and $26 million in the fourth quarter of 2013.

On November 1, the ISO fully implemented the energy imbalance market (EIM). EIM performance issues discussed in this report include the following:

- During most intervals, prices in the EIM have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand.
- The impact of constraint relaxation on EIM prices has been effectively mitigated by the price discovery mechanism approved under FERC's December 1 Order. Average EIM prices since the November 14 effective date of the price discovery provisions have been slightly lower than bilateral market price indices that were used to set prices in the PacifiCorp areas prior to EIM implementation.
- Bid cost recovery payments in the EIM were around $250,000 from November and December 2014. This is just over $0.02/MWh of total EIM load, compared to ISO real-time bid cost recovery costs of about $0.24/MWh of total ISO load. The relatively low level of bid cost recovery payments in the EIM reflects the fact that there are currently very few quick start units that can be committed through an EIM dispatch.
- Several problems with how the flexible ramping constraint was implemented as part of the EIM design in the fourth quarter were identified and have been mitigated. Several issues involving how the flexible ramping credit is calculated resulted in calculation of excessive flexible ramping credit.[1] Another issue involves how the flexible ramping constraint was enforced in the pricing run. The

[1] As noted in the ISO's February 19 report to FERC, the ISO "is also revisiting and reviewing the flexible ramp constraint and associated credit accounting in the flexibility sufficiency test and towards satisfying the flexible ramp requirements in the market optimization," *Energy Imbalance Market Pricing Waiver Report, January 1 – February 12, 2015*, February 19, 2015, p. 25: http://www.caiso.com/Documents/Feb19_2015_EIM_Informational_Report_ER15-402.pdf.

impact of these issues was to reduce the quantity of flexible ramping procured and prevented the flexible ramping constraint from being binding in the ISO market. These issues appear to have been mitigated by changes made by the ISO in February 2015. Additional information on these issues will be provided by the ISO and in future DMM reports.

- Flexible ramping constraint payments to resources in the ISO were extremely low after implementation of EIM in November due to the issues noted above. After EIM was implemented, flexible ramping constraint payments in the ISO totaled around $0.2 million compared to $3.4 million in November and December 2013.[2]

Energy market performance

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

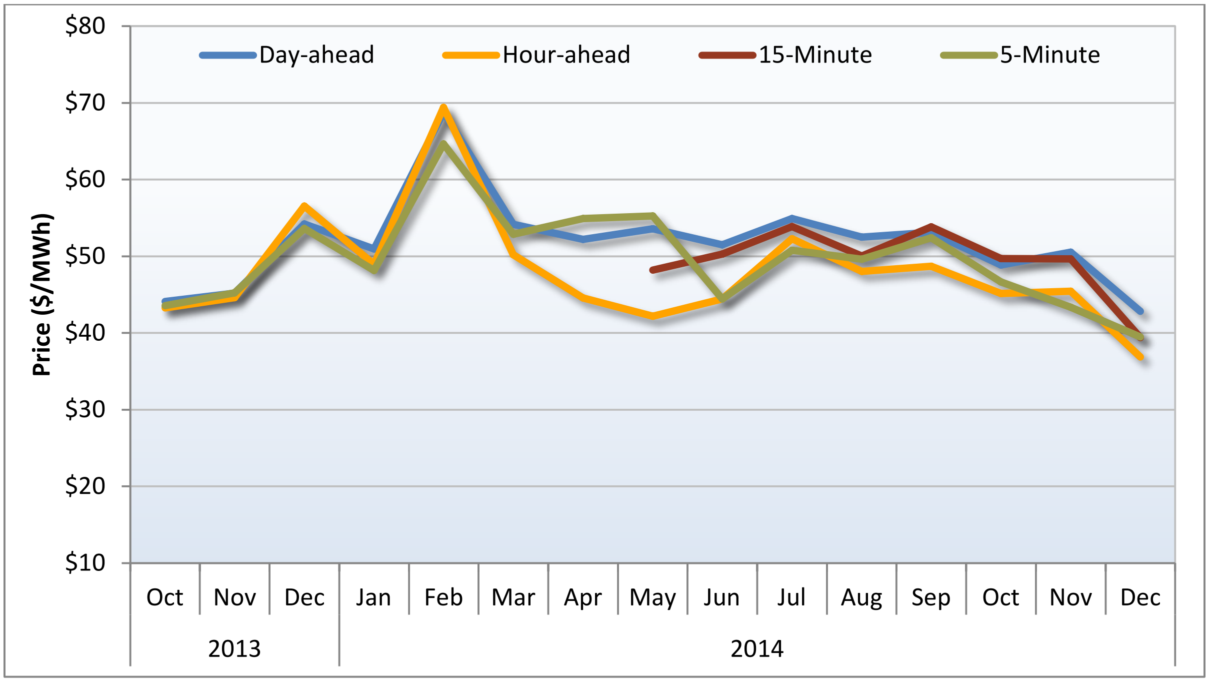
Differences between average day-ahead and 5-minute prices increased. Average system energy prices in the 15-minute market (excluding congestion) were slightly lower than average prices in the day-ahead market in November and December, but slightly higher than day-ahead prices in October (see Figure E.1). The 5-minute price levels were lower than 15-minute prices in most peak and off-peak periods in October and November. On average, each of the three categories of real-time prices were generally lower than day-ahead prices. Hour-ahead prices were regularly lower than all other markets except for November where hour-ahead prices were higher than 5-minute prices. The hour-ahead market is the first real-time market to address any unscheduled generation changes, particularly from wind and solar. Moreover, it also must address a large volume of self-scheduled energy on the inter-ties. The combination of these factors can create limited economic dispatch maneuverability.

Negative price variability increased in the fourth quarter. Price spikes above $250/MWh in the 15-minute market during the quarter occurred in only 0.4 percent of all intervals, about the same as in the previous quarter. The frequency of prices over $250/MWh in the 5-minute market was about 0.5 percent of 5-minute intervals, a slight increase compared to 0.4 percent of intervals in the third quarter. Negative prices occurred in about 1 and 3 percent of all intervals in the 15-minute and 5-minute markets, respectively. This was an increase from 0.7 and 1 percent, respectively, in the third quarter. The increase in negative price variability is partly due to decreased downward ramping capability and lower loads in the fall months that increase the impact of changes in renewable generation on real-time prices.

The impact of congestion on day-ahead and real-time prices remained low. While overall congestion remained low, congestion within the ISO system in the fourth quarter was mixed in the day-ahead market and similar in the real-time market compared to the previous quarter. Much of the congestion was related to unscheduled flows and planned outages. In the PG&E area, the most congested constraint was 6110_TM_BNK_FLO_TMS_DLO_NG. This constraint considered unscheduled flows on the California Oregon Inter-tie (COI). Congestion in the SCE area was primarily driven by congestion on the Barre – Villa Park 220 kV line.

[2] In December, the constraint's shadow price was $0/MWh in all 15-minute intervals. However, total payments were around $20,000 for December. This was because flexible ramping payment settlements are based on a combination of factors including the constraint's shadow prices and the 15-minute ancillary services marginal price for spinning reserves. Details of the formula can be found in Section 12.1 of the Market Instruments Business Practice Manual: http://bpmcm.caiso.com/BPM Document Library/Market Instruments/BPM_for_Market Instruments_V35_clean.doc.

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



Real-time congestion and energy imbalance offset costs were lower than the previous quarter. Real-time imbalance offset costs are currently estimated to have reached historically low levels in the fourth quarter within the ISO system. Total offset costs totaled about $3 million in the fourth quarter of 2014, compared to $44 million in the fourth quarter of the prior year and $60 million in the third quarter of 2014. Total real-time imbalance offset costs were the sum of approximately $10 million in congestion imbalance offset costs, $2 million in loss offset charges and an estimated credit of $9 million in energy imbalance offset costs.

Bid cost recovery payments decreased. Beginning in May, the ISO calculates the costs and revenues of each resource for day-ahead and real-time markets separately and settles the bid cost recovery payments for each market for each day. Before the new rules were implemented, there were concerns that these changes could significantly increase bid cost recovery payments. Bid cost recovery payments were around $25 million in the fourth quarter of 2014, compared to $24 million in the third quarter of 2014 and $26 million in the fourth quarter of 2013.

Flexible ramping constraint payments were lower because of issues related to EIM implementation. Several problems with how the flexible ramping constraint was implemented as part of the EIM design resulted in lower payments for flexible capacity in the ISO system. Several issues involving how the flexible ramping credit is calculated resulted in calculation of excessive flexible ramping credit. Another issue involved how the flexible ramping constraint was enforced in the pricing run. These issues reduced the quantity of flexible ramping procured and prevented the flexible ramping constraint from being binding in the ISO market. These issues appear to have been mitigated by changes made by the ISO in February 2015. Additional information on these issues will be provided by the ISO and in future DMM reports.

Flexible ramping constraint payments to resources in the ISO system were extremely low after implementation of EIM in November due to the issues noted above. Flexible ramping constraint payments in the ISO in November and December totaled around $0.2 million compared to $3.4 million in November and December 2013. Payments were around $20,000 in the month of December, the lowest monthly value since implementing the flexible ramping constraint in December 2011. The average shadow price in December was $0/MWh because the constraint was not binding in any interval during the month for the ISO balancing area and was also $0/MWh for most of the month of November.[3]

Special topics

Real-time economic import and export bid quantities increased. The amount of inter-tie imports and exports cleared between the day-ahead and real-time markets has not changed considerably since implementation of 15-minute inter-tie scheduling in May. However, a significant decrease compared to pre-May conditions occurred in the amount of inter-tie bids offered into the real-time market combined with a significant increase in the amount of self-scheduling of inter-ties in both the day-ahead and real-time markets. The most striking change occurred in the real-time market where most of the inter-tie import and export bids were self-scheduled with limited amounts of economic bids to adjust in real-time. This trend continued in the third quarter. However, in the fourth quarter, the amount of economic import and export bids offered in the real-time market started to increase and reached their highest levels since the changes in May (see Figure E.2).[4] Hourly block bids showed the largest increase along with a small increase in 15-minute economic bids.

Energy imbalance market

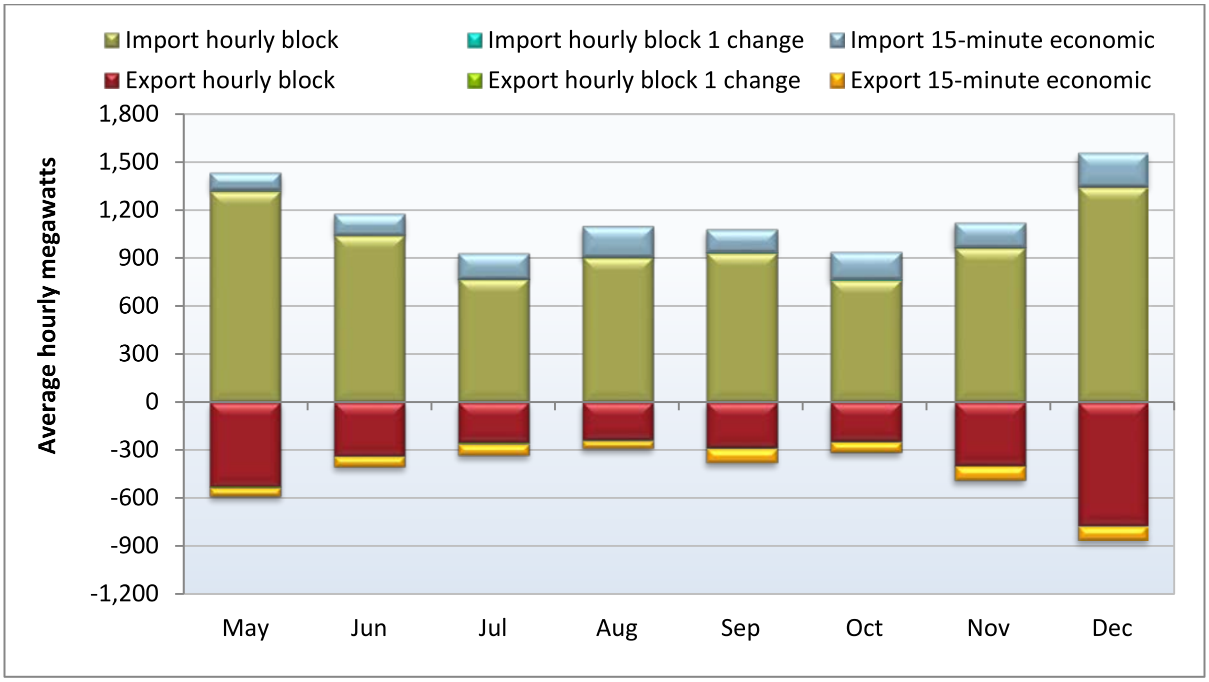
Section 1 provides an outline of the recent market changes that occurred in the fall including the energy imbalance market. Section 2 provides a more detailed review of EIM performance in the fourth quarter of 2014.

[3] In December, the constraint's shadow price was $0/MWh in all 15-minute intervals. However, total payments were around $20,000. This was because flexible ramping payments settlements are based on a combination of factors including the constraint's shadow prices and the 15-minute ancillary services marginal price for spinning reserves. Details of the formula can be found in Section 12.1 of the Market Instruments Business Practice Manual:

http://bpmcm.caiso.com/BPM Document Library/Market Instruments/BPM_for_Market Instruments_V35_clean.doc.

[4] As in previous reports, our report includes only CAISO (non-EIM) imports and exports.

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



1 Recent market changes

The ISO implemented significant changes and enhancements to the markets in the fourth quarter. The ISO:

- Implemented the energy imbalance market;
- Enhanced the full network model;
- Modified operating reserve procurement requirements to comply with FERC Order No. 789; and
- Upgraded the inter-tie transaction scheduling system.

This section provides a review of market changes and their effects on market performance in the fourth quarter. The primary change was implementing the energy imbalance market (EIM) on November 1. A more detailed summary of EIM issues and performance in November and December is provided in Section 2.

1.1 Background

The ISO made several significant modifications and enhancements to its systems in the fourth quarter.

Implemented the energy imbalance market

The energy imbalance market became financially binding with its first participant on November 1. Balancing authority areas outside of the ISO balancing authority area can now voluntarily take part in the ISO's real-time market. The energy imbalance market is expected to achieve benefits for customers and facilitate integration of higher levels of renewable generation.[5]

The EIM includes both 15-minute and 5-minute financially binding schedules and settlement. Energy imbalances between 15-minute schedules and base (pre-market) schedules settle at the 15-minute market prices, and energy imbalances between 15-minute schedules and 5-minute schedules settle at 5-minute market prices. With the EIM, the ISO also modified the flexible ramping constraint construct. This is outlined in further detail in Section 3.3.

During the initial EIM implementation, the amount of capacity available through the market clearing process was restricted and imbalance needs were exaggerated in ways that are not reflective of actual economic and operational conditions. This caused the need to relax ramping and system energy balance constraints in the market software more frequently than expected to enable the market to clear. The factors contributing to the need for constraint relaxation, and steps being taken to address these issues, have been addressed by the ISO in three reports submitted to FERC.[6] When relaxing the power balance

[5] *Benefits for Participating in EIM* report, February 11, 2015: http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf.

[6] *Energy Imbalance Market Pricing Waiver Report*, December 15, 2014, January 15, 2015, and February 19, 2015: http://www.caiso.com/Documents/Jan15_2015_EnergyImbalanceMarket_REPORT_ER15-402.pdf.

constraint for an EIM area, prices could be set based on the $1,000/MW penalty price for this constraint used in the pricing run of the market model.

After review, the ISO determined that many of these outcomes were inconsistent with actual conditions. Consequently, on November 13, 2014, the ISO filed for and FERC approved special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[7] FERC approved the filing on December 1 with an effective date of November 14, 2014. In addition, FERC ordered that the ISO and the Department of Market Monitoring provide informational reports every 30 days during the period of the waiver, outlining the issues driving the need for the EIM tariff waiver.[8]

Section 2 provides a more detailed review of EIM performance in the fourth quarter of 2014.

Enhanced the full network model

The ISO implemented beginning October 15 what is referred to as a *full network model* in the day-ahead and real-time markets. This software enhancement is designed to improve ISO system modeling by expanding the topology and inputs used to project actual power flows in the day-ahead and real-time market models. By expanding the market model to include other balancing areas, the ISO will also be able to reflect outages and other reliability parameters on those external systems and analyze how they may affect the ISO market. This provides the opportunity for substantial reliability benefits under scenarios such as that which led to the major southwest blackout on September 8, 2011.

These modeling enhancements may also improve market efficiency by allowing better management of congestion. This expanded model will be used to model the unscheduled electrical flows that will occur within the ISO balancing area caused by the load, generation and interchanges forecast for other balancing areas in the western interconnection. The goal of this is to produce day-ahead and real-time schedules and prices that more accurately reflect actual system constraints and the impact schedules have on these constraints. Expanding the ISO network model to a regional level that includes other balancing authority areas is also a key component needed to ensure the efficiency and future expansion of the energy imbalance market.

As noted in DMM's memo to the ISO Board of Governors on this initiative, the accuracy with which unscheduled flows can be projected will depend on a variety of other modeling assumptions that must be made, such as which generation schedules in other balancing areas are ultimately increased or decreased as a result of imports or exports within the ISO system.[9] Consequently, DMM has noted that monitoring the impact that this has on projections of unscheduled flow and congestion in the day-ahead and real-time market models – and modifying these models in response to this monitoring – is critical.

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

[8] The two ISO filings and the two DMM filings for November and December can be found at the following links:
http://www.caiso.com/Documents/Dec15_2014_EnergyImbalanceMarketPerformanceReport_ER15-402.pdf
http://www.caiso.com/Documents/Jan15_2015_EnergyImbalanceMarket_REPORT_ER15-402.pdf
http://www.caiso.com/Documents/Dec18_2014_DMMReport_EIMPerformance_November2014_ER15-402.pdf
http://www.caiso.com/Documents/Jan23_2015_DMMAssessment_December2014EIMPerformance.pdf.

[9] See http://www.caiso.com/Documents/DepartmentMarketMonitoringReport-Memo-Feb2014.pdf.

The ISO has performed some impact assessments of the full network model enhancements before and after implementation. DMM has provided specific recommendations to the ISO for more detailed and targeted metrics for assessing the impact of the full network model. Metrics recommended by DMM include the following enhancements to those currently used by the ISO:

- DMM recommends that the ISO full network model metrics include individual constraints within the ISO, instead of only including inter-ties with other balancing areas;
- Unless the estimated or actual flow on a line is actually near a limit in the day-ahead or real-time market, there may be little or no consequences of any improvement of projected flows in terms of reliability or market costs. Therefore, DMM recommends that these automated metrics focus on the impact that the full network model is having on estimated flows on specific constraints which are at or near their limits in the day-ahead and real-time markets based on estimated or actual flows; and
- DMM also recommends that the ISO metrics and analysis focus on constraints on which the actual market impact of congestion is highest. As identified in prior reports by DMM, the bulk of real-time energy congestion offset costs that have been incurred in the past are associated with a relatively small number of constraints in any given period. Automated metrics can be used to quickly identify these constraints and allow resources to focus on modeling improvements or adjustments that have the highest value in terms of reliability and market benefits.

DMM has performed limited analysis of the full network model performance based on this general approach. Based on this analysis, DMM identified that discrepancies between day-ahead and real-time base injections and line conformances contributed to some significant differences between congestion in the day-ahead and real-time markets. DMM's analysis contributed to identifying the following modeling issues:

- **Table Mountain nomogram in October.** ISO operators alleviated inaccurate flow during most real-time intervals by conforming the real-time limit of the Table Mountain nomogram constraint upwards. However, the ISO did not correspondingly conform the day-ahead limit of the nomogram upwards. As a result, there was heavy day-ahead congestion but mild real-time congestion. Base injection flow impact and incorrect network modeling were contributing factors to the heavy day-ahead congestion.
- **No day-ahead base injections over Pacific DC Intertie.** Real-time base injections over the Pacific DC Intertie contributed to significant real-time congestion over the Victorville – Lugo 500 kV line in the first few weeks of December. Because of an implementation error related to time stamps dating back to the initial full network model implementation, the ISO was not including any base injections over the Pacific DC Intertie in the day-ahead market. Omitting these PDCI base injections from the day-ahead market contributed to Victorville – Lugo 500 kV having significantly higher congestion in real time than day-ahead over the first few weeks of December. In the coming weeks, the ISO is expecting to publish a technical bulletin with thorough analysis of the PDCI modeling issues from the fourth quarter of 2014.

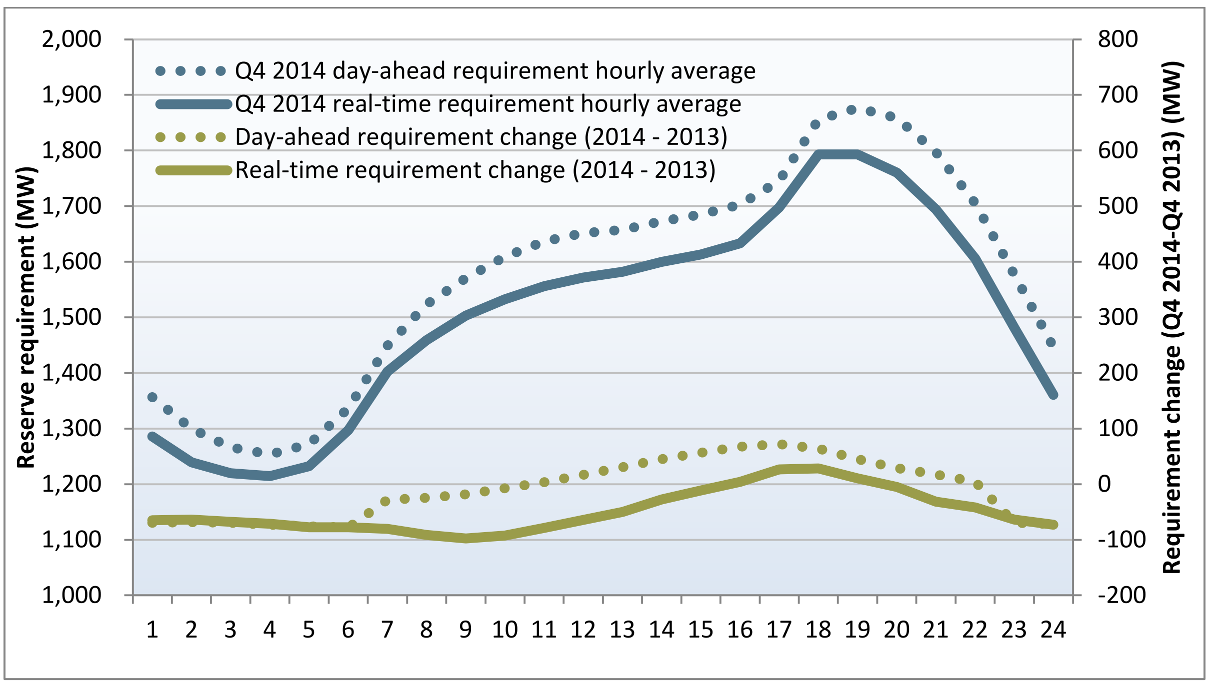
DMM continues to work with the ISO and the Market Surveillance Committee in developing more automated and enhanced metrics and other analysis to assess and improve the full network model.

Implemented FERC Order No. 789

The ISO modified its operating reserve requirement calculations beginning October 1 to be compliant with new operating reserve standards.[10] Under the previous standard, the ISO calculated total operating reserve requirements as the maximum of the single most severe contingency and the sum of 7 percent of load served by hydroelectric resources and 5 percent of remaining load. Under the new standard, the total operating reserve requirement is calculated as the maximum of the single most severe contingency and 3 percent of the sum of load, internal generation and net pseudo and dynamic imports. To the extent that the ISO relies on static imports to serve load, this would result in lower operating reserve requirements under the new requirements.

Figure 1.1 illustrates average hourly operating reserve requirements in the fourth quarter of 2014, along with a comparison of the difference between the 2014 fourth quarter requirements and the 2013 fourth quarter requirements. The ISO procures operating reserves in both the day-ahead and real-time market. As was the case under the preexisting requirement, the ISO appears to procure more operating reserves than required by the regional reliability standard in the day-ahead market.[11] As illustrated in Figure 1.1, the lowest average requirements are in the real-time market under the new requirements.

Figure 1.1 Hourly average spinning and non-spinning reserve requirements (Q4)



[10] Specifically, the new procedures are consistent with the Western Electricity Coordinating Council (WECC) regional reliability standard on contingency resources (BAL-002-WECC-2). BAL-002-WECC-2 was approved by FERC under Order No. 789 http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order789_BAL-002-WECC-2_RM13-13_20131121.pdf, which became effective on January 28, 2014.

[11] On October 1, 2014, the ISO began to calculate day-ahead operating reserve requirements as 6 percent of forecast load including pumping load. The ISO intends to refine the day-ahead operating reserve requirement setting tool to calculate the day-ahead requirement based on the expected value of the real-time ancillary service requirement rather than as a fixed percent of forecast load alone.

Implementing FERC Order No. 789 also included new e-tagging requirements for import resources providing ancillary services in the 15-minute real-time market. Beginning October 1, resources providing ancillary services in the real-time market are required to have a valid e-tag for the operating reserve awarded in the day-ahead market (real-time awards are capped at the e-tagged quantity). Submitted e-tags are validated to assure that the resource is qualified to provide ancillary services, that the transmission and generation are firm, and that the e-tag appropriately specifies that the nature of the transaction is providing ancillary services.

Upgraded the interchange transaction scheduling system

The ISO's fall release included an upgrade of its interchange transaction scheduling system. The interchange transaction scheduler keeps track of energy and ancillary services transactions that are scheduled between different balancing authority areas. The upgraded interchange transaction scheduler provides additional NERC e-tag validations, which results in more accurate information sent to the market as well as to the energy management and settlements systems. ISO operators have access to additional automation and features with the new interchange transaction scheduler. This has improved the ISO operators' situational awareness in managing scheduled interchanges.

2 Energy imbalance market performance

This section covers the energy imbalance market performance in November and December 2014. Below are key observations and findings.

- During most intervals, prices in the EIM have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand.
- The frequency of constraint relaxations in the 15-minute market was relatively high following EIM implementation in November and then declined significantly through most of December. However, the need to relax the power balance and flexible ramping constraints in the 15-minute market rose significantly in January 2015.
- The need to relax the power balance constraint in the 5-minute market has also remained relatively high in both PacifiCorp East and PacifiCorp West since EIM implementation. This reflects the fact that supply in the 5-minute market is much more constrained – including schedules between EIM balancing areas and the ISO.
- The impact of constraint relaxation on market prices has been effectively mitigated by the price discovery mechanism approved under FERC's December 1 Order. Average EIM prices since the November 14 effective date of the price discovery provisions have been slightly lower than bilateral market price indices that were used to set prices in the PacifiCorp areas prior to EIM implementation. Without these provisions, EIM prices since November 14 would have been significantly higher than these bilateral market price indices.
- Bid cost recovery payments in the EIM were around $250,000 from November and December 2014. This is just over $0.02/MWh of total EIM load, compared to ISO real-time bid cost recovery costs of about $0.24/MWh of total ISO load. The relatively low level of bid cost recovery payments in the EIM reflects the fact that there are currently very few quick start units that can be committed through an EIM dispatch.
- Several problems with how the flexible ramping constraint was implemented as part of the EIM design in the fourth quarter were identified and have been mitigated. These issues reduced the quantity of flexible ramping procured and prevented the flexible ramping constraint from being binding in the ISO market. These issues appear to have been mitigated by changes made by the ISO in February 2015. Additional information on these issues will be provided by the ISO and in future DMM reports.

2.1 Energy imbalance market prices

Prices in the EIM during most intervals have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand.

Figure 2.1 and Figure 2.2 provide a weekly summary of the frequency of constraint relaxation, average prices with and without price discovery, and bilateral market prices for PacifiCorp East and PacifiCorp West, respectively.

As shown in Figure 2.1, the frequency of constraint relaxations in the 15-minute market in PacifiCorp East was relatively high during the first month of EIM, and then declined significantly through most of December. As shown in Figure 2.2, the frequency of constraint relaxations in the 15-minute market in PacifiCorp West dropped substantially during November and remained relatively low through the end of December. However, the need to relax the power balance and flexible ramping constraints in the 15-minute market rose significantly in the first few weeks of January 2015.[12] This trend addressed in the ISO's February 19, 2015 EIM report.

These two figures also show average daily prices in the 15-minute market with and without the special price discovery mechanism being applied to mitigate prices in PacifiCorp East and PacifiCorp West, respectively. These figures also provide a comparison of EIM prices to bilateral market price indices that were used to set prices in the PacifiCorp areas prior to EIM implementation.[13] These figures show that without the price discovery provisions being applied in EIM, average daily prices would consistently exceed the bilateral market price index reflective of prices for imbalance energy in the PacifiCorp areas prior to EIM. However, with price discovery, EIM prices track very closely with this bilateral price index.

Figure 2.3 and Figure 2.4 provide the same weekly summary for the 5-minute market. As shown in these figures, the need to relax the power balance constraint in the 5-minute market has also remained relatively high in both PacifiCorp East and PacifiCorp West since EIM implementation. This reflects the fact that in the 5-minute market the supply of ramping capacity within PacifiCorp is more constrained. This also reflects the fact that incremental transfers into PacifiCorp from the ISO in the 5-minute market have been essentially prevented during almost all intervals. The dynamic transfer constraint (DTC), which constrains the extent to which transfers between PacifiCorp and the ISO scheduled in the 15-minute market can change in the 5-minute market, has been set to a limit of less than 0.003 MW during more than 92 percent of 5-minute market intervals between November 1 and December 31.[14]

As shown in Figure 2.1 through Figure 2.4, the price discovery mechanism approved under FERC's December 1 Order has effectively mitigated the impact of constraint relaxation on market prices. Table 2.1 shows average EIM prices in the 15-minute and 5-minute markets with and without application of price discovery, along with average bilateral market prices.

[12] See Market Performance and Planning Forum, January 20, 2015, *Department of Market Monitoring – Energy Imbalance Market Update*, pp. 41-47, http://www.caiso.com/Documents/Agenda-Presentation_MarketPerformance-PlanningForum_Jan20_2015.pdf.

[13] The bilateral market index represents a daily average of peak and off-peak prices for four major western trading hubs (California Oregon Border, Mid-Columbia, Palo Verde and Four Corners). Prior to EIM implementation, DMM identified this bilateral price index to stakeholders and regulators as a benchmark DMM would use to assess the competitiveness and overall performance of EIM.

[14] On February 4, 2015, the ISO started to adjust the dynamic transfer constraint between PacifiCorp and the ISO to about 20 MW in the 5-minute market during the peak hours. During the off-peak hours, the ISO occasionally adjusted the constraint to above 300 MW.

Figure 2.1 Frequency of constraint relaxation and average prices by week PacifiCorp East - 15-minute market

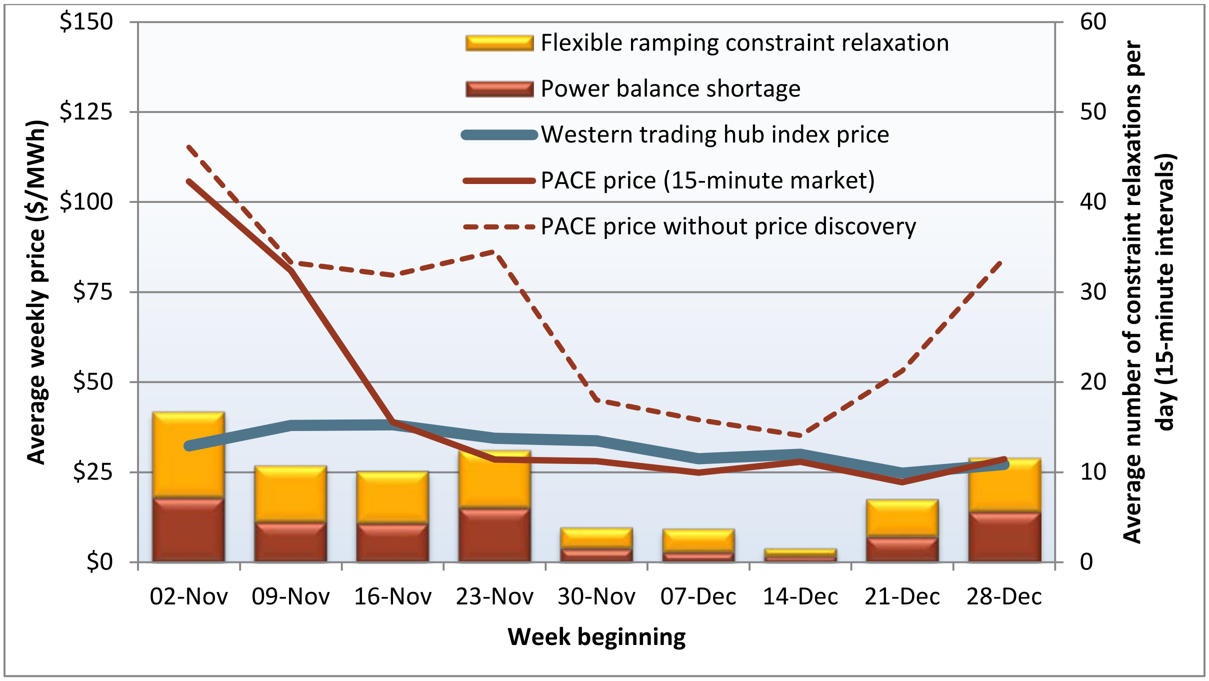


Figure 2.2 Frequency of constraint relaxation and average prices by week PacifiCorp West - 15-minute market

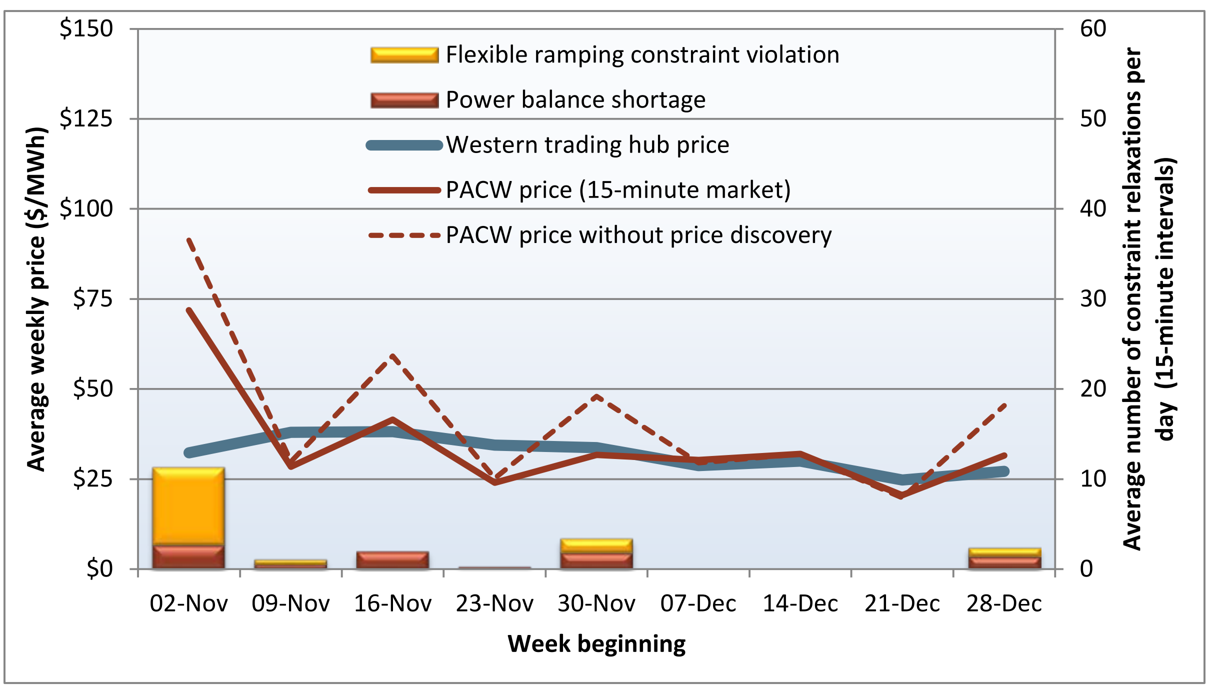


Figure 2.3 Frequency of constraint relaxation and average prices by week PacifiCorp East - 5-minute market

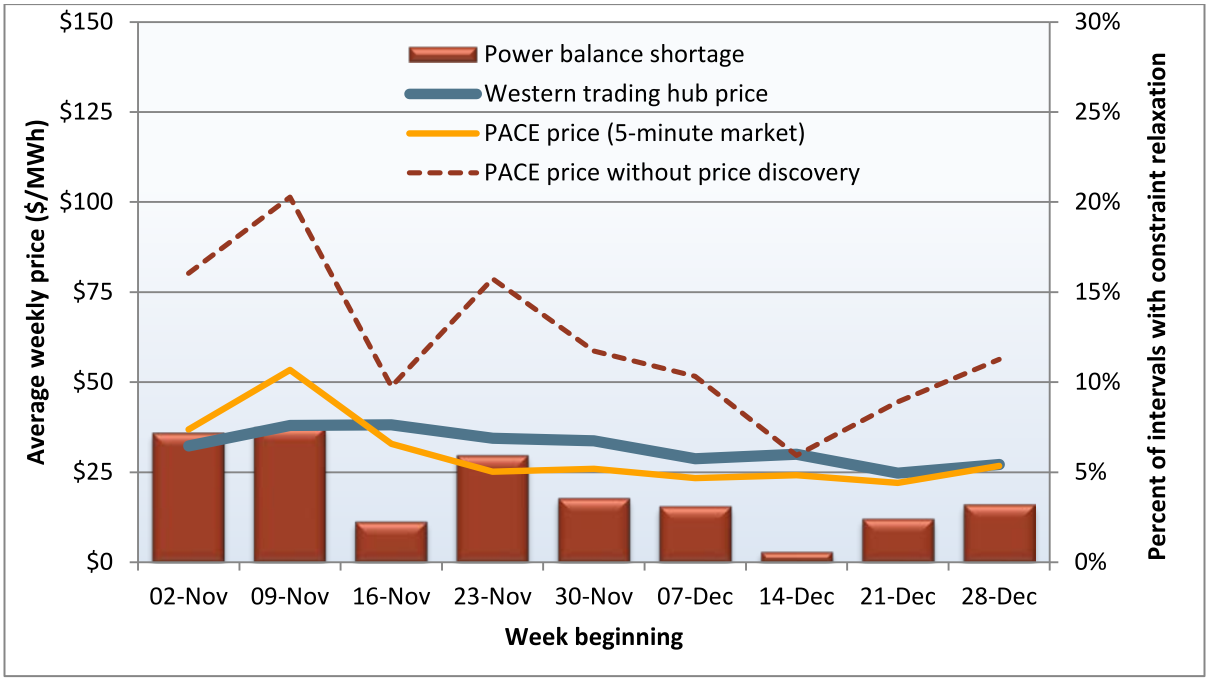


Figure 2.4 Frequency of constraint relaxation and average prices by week PacifiCorp West - 5-minute market

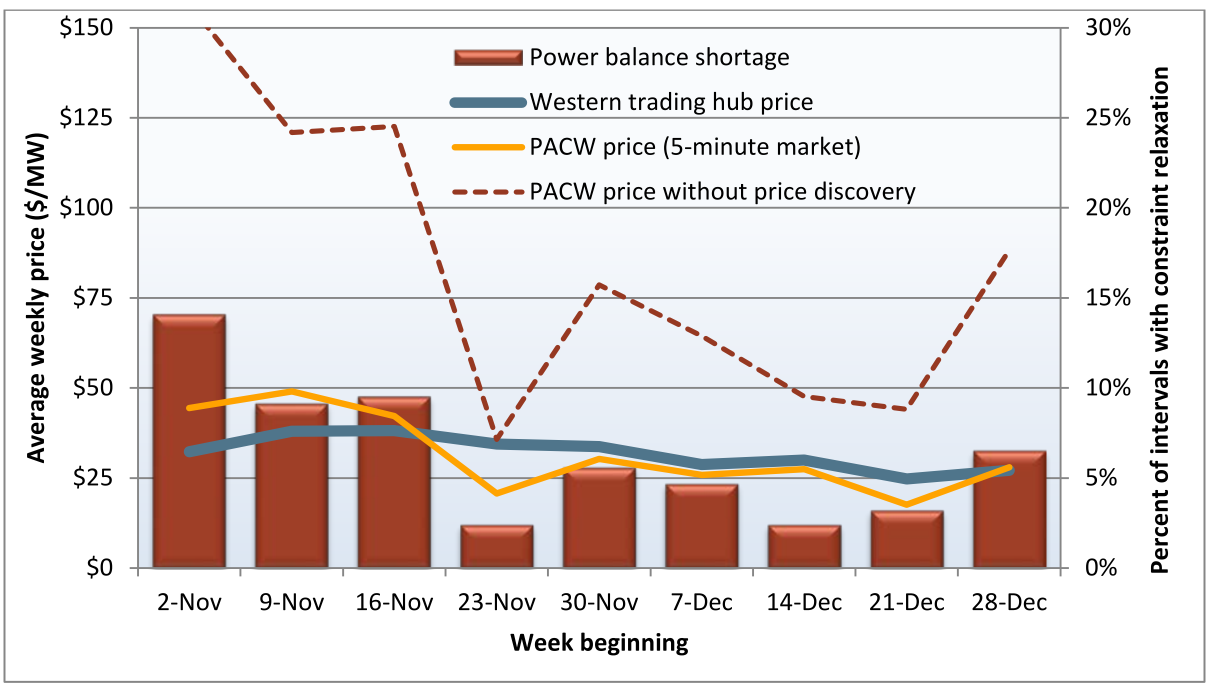


Table 2.1 Average prices in EIM and bilateral markets (November 15, 2014 – December 31, 2014)

	Western trading hub average price	Average EIM price	EIM price without price discovery
PacifiCorp East			
15-minute market (FMM)	$31.46	$28.33	$57.65
5-minute market (RTD)	$31.46	$26.11	$52.72
PacifiCorp West			
15-minute market (FMM)	$31.46	$29.81	$36.00
5-minute market (RTD)	$31.46	$27.65	$69.89

As shown in Table 2.1:

- Application of the price discovery mechanism has made average EIM prices in the 15-minute market in PacifiCorp East about 10 percent lower than bilateral market price indices that were used to set rates in the PacifiCorp area prior to EIM. Prices in PacifiCorp West in the 15-minute market after price discovery have been about 5 percent lower than these bilateral prices.
- Prices in the 5-minute market since the price discovery mechanism has been in effect have been lower than these bilateral market price indices by about 17 percent in PacifiCorp East and about 12 percent in PacifiCorp West.
- Without price discovery, prices in PacifiCorp East would be about 80 percent higher than bilateral market price indices in the 15-minute market and about 70 percent higher in the 5-minute market.
- In PacifiCorp West, prices without price discovery would be about 15 percent higher than bilateral market prices in the 15-minute market and more than twice as high in the 5-minute market.

Market software constraint relaxation

EIM performance has been impacted by the need to periodically relax several key constraints in the EIM market model. This section provides additional information on the frequency and causes of various constraint violations in the EIM during November and December.

Figure 2.5 and Figure 2.6 summarize the percent of intervals in which the power balance and flexible ramping constraints have been relaxed by month in PacifiCorp East and PacifiCorp West, respectively.

As shown in Figure 2.5, in PacifiCorp East the frequency of constraint relaxation dropped significantly in December but is still in the 2 to 3 percent range in the 15-minute and 5-minute markets.

As shown in Figure 2.6, in PacifiCorp West the frequency of constraint relaxation also dropped significantly in December, but the power balance constraint was still relaxed in about 5 percent of intervals in the 5-minute market.

Figure 2.5 Frequency of constraint relaxation by month – PacifiCorp East (PACE)

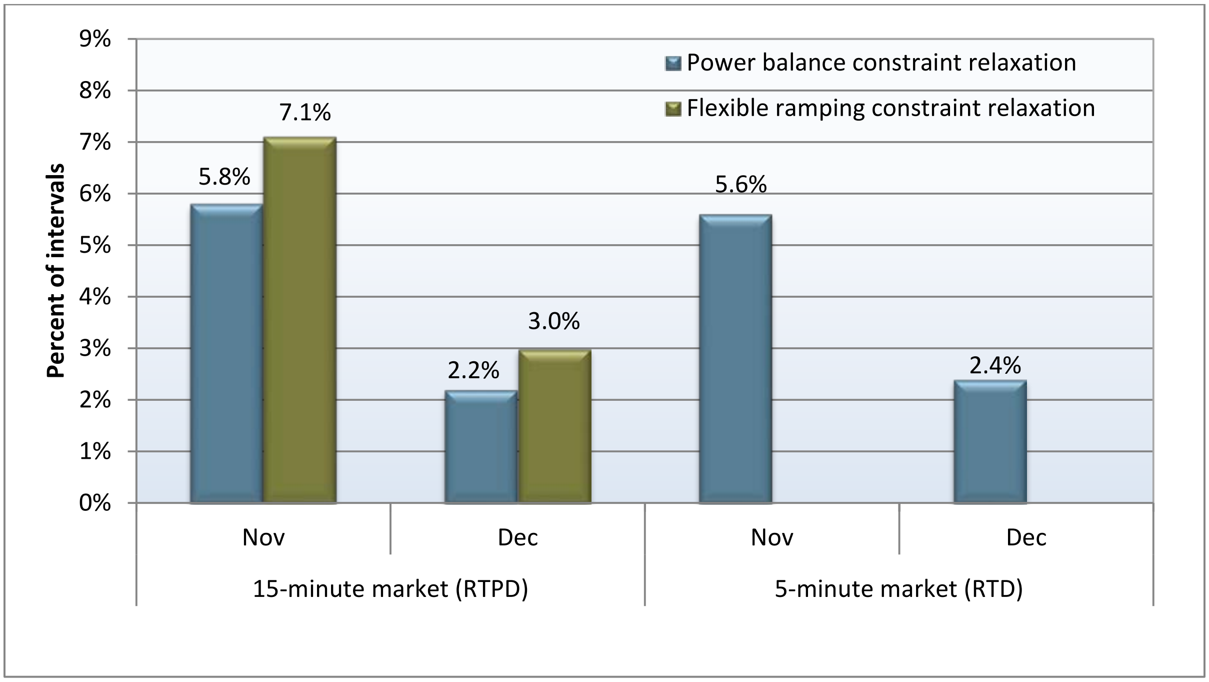


Figure 2.6 Frequency of constraint relaxation by month – PacifiCorp West (PACW)

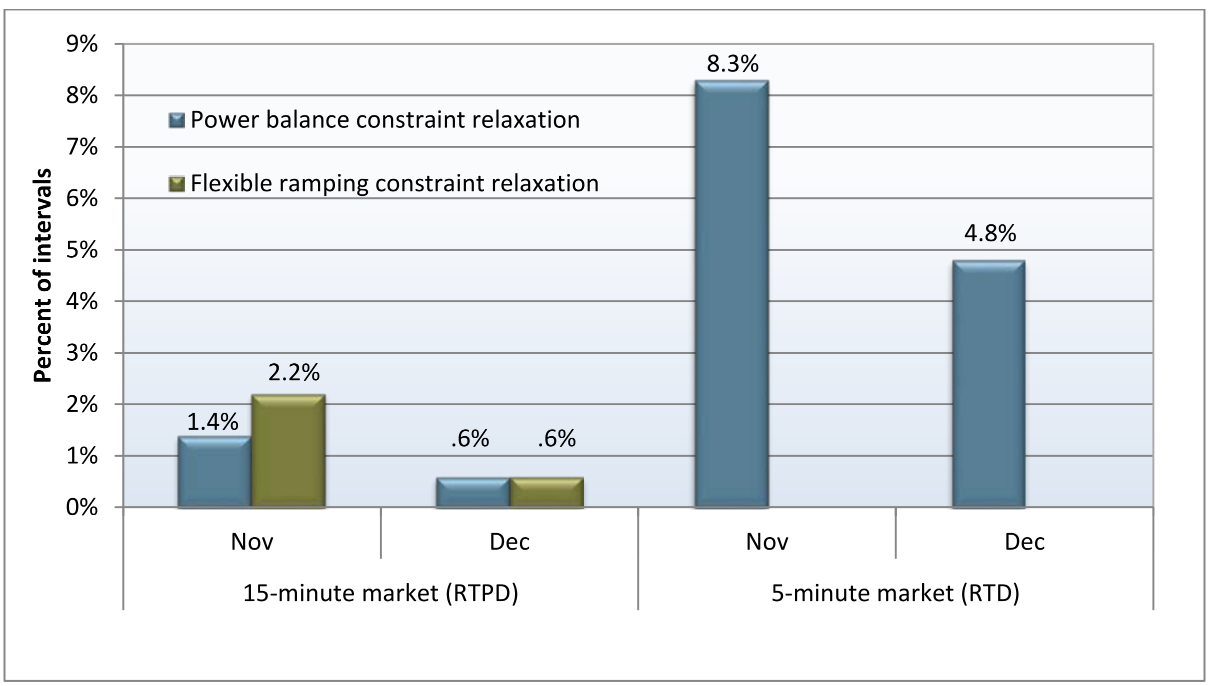


Figure 2.7 Major causes of power balance constraint relaxation PacifiCorp East - 15-minute market (December 2014)

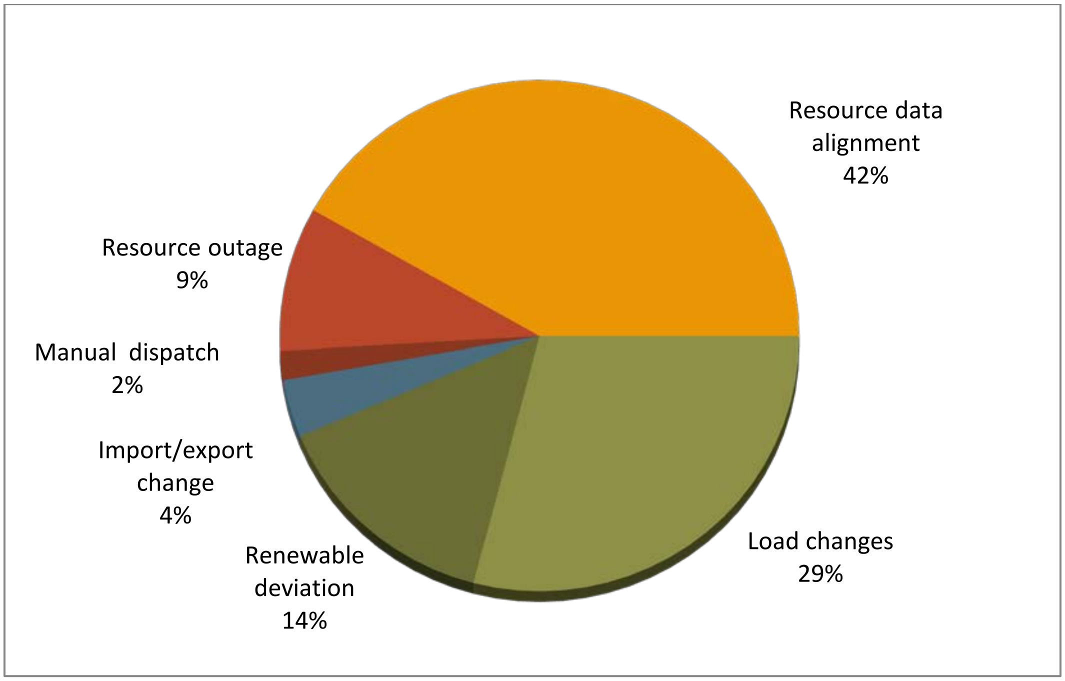


Figure 2.8 Major causes of power balance constraint relaxation PacifiCorp West - 15-minute market (December 2014)

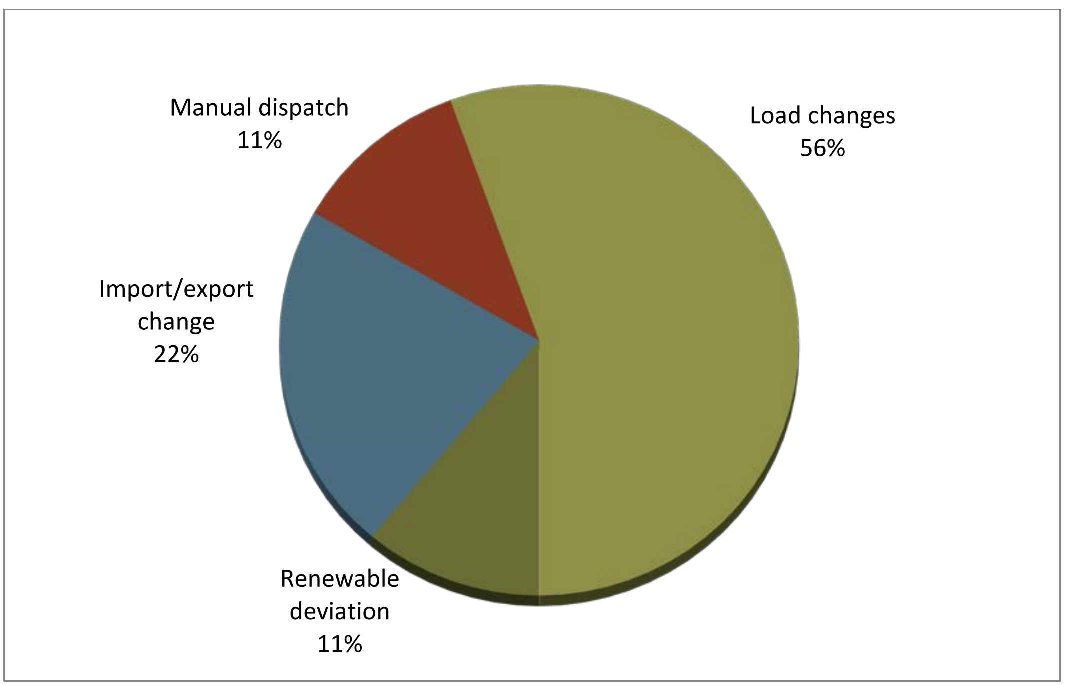


Figure 2.9 Major causes of power balance constraint relaxation PacifiCorp East - 5-minute market (December 2014)

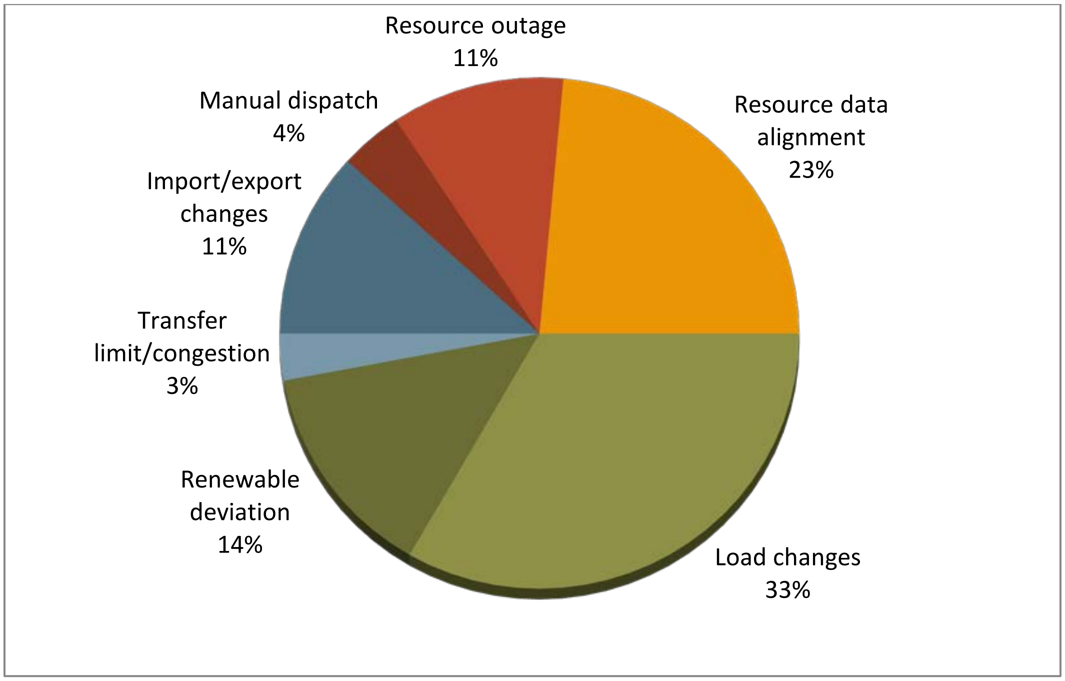
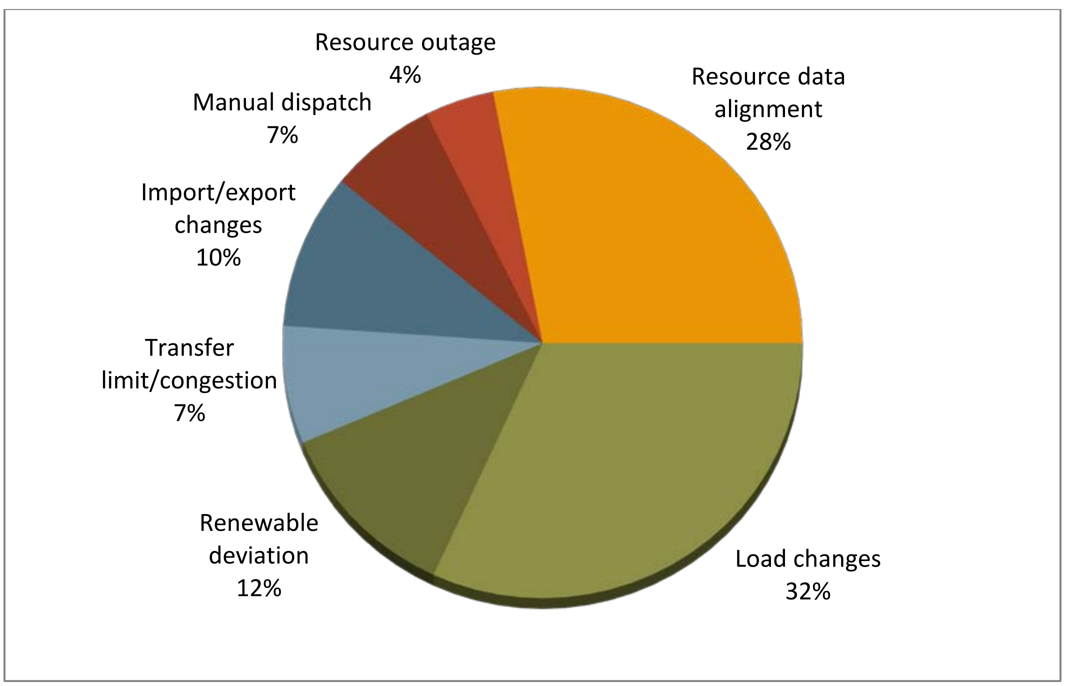


Figure 2.10 Major causes of power balance constraint relaxation PacifiCorp West - 5-minute market (December 2014)



As described in the ISO's January 15 report, the ISO has reviewed each interval in which the power balance constraint was relaxed because of supply insufficiency in December and categorized each of these in terms of a primary cause for the supply insufficiency.[15] DMM has aggregated data underlying Figures 11 and 12 of the ISO's January 15 report to highlight the relative magnitude of the different factors driving supply insufficiency events in December. These data are provided in Figure 2.7 through Figure 2.10.

Provided below is a summary of the primary causes of EIM supply insufficiencies, in the approximate order of the frequency of which these issues caused supply insufficiencies in December, based on data underlying the ISO report.[16]

- **Resource data alignment.** As shown in Figure 2.7, this category is cited as the primary cause of 42 percent of supply insufficiencies in the 15-minute market in PacifiCorp East during December as examined by the ISO. This category is cited as the primary cause for about one-fourth of insufficiencies in the 5-minute market in both PacifiCorp areas. The ISO report explains that "this group accounts for resources deviating from their dispatch, differences between base schedules and bids or dispatches, and changes between markets."[17] Based on DMM's review of the ISO's analysis, and discussions with the ISO, many of these events appear to be related to issues related to how multi-state generating units are scheduled, bid and dispatched in the market. The ISO and PacifiCorp have indicated they are working to improve how this software functionality is utilized to reduce this type of issue.
- **Load changes.** This category is cited as the primary cause of 56 percent of supply insufficiencies in the 15-minute market in PacifiCorp West during December, and about one-third of supply insufficiencies in the 5-minute EIM market. The ISO report indicates that this category includes conditions where either the load forecast is adjusted or there is a change in the load bias. In practice, it should be noted that load forecast adjustment or biasing is often the tool by which the EIM operator may seek to account for many sources of modeling discrepancies besides actual fluctuation in loads versus forecasts. For instance, if the EIM operator overestimates the amount of load adjustment or bias actually needed, this may create a supply insufficiency that does not reflect actual system conditions. DMM notes that the need to rely on load adjustments may be reduced by modeling improvements, and that using adjustments may improve as EIM operators gain additional experience, as occurred in the ISO system over time.
- **Renewable deviation.** This category is cited as the primary cause of 11 to 14 percent of supply insufficiencies in the 15-minute and 5-minute markets in both PacifiCorp areas in December. This category represents cases in which changes in wind generation led to the loss of capacity and the need to increase generation from other resources. DMM notes that wind deviations appear to represent a higher portion of total load in PacifiCorp than the ISO. As noted in the ISO report, PacifiCorp is working to improve wind generation forecasting in its area.

[15] See Figures 11 and 12, page 17, in *Energy Imbalance Market Pricing Waiver Report*, December 1 - 31, 2014, January 15, 2015, http://www.caiso.com/Documents/Jan15_2015_EnergyImbalanceMarket_REPORT_ER15-402.pdf.

[16] The causes behind supply insufficiencies are not mutually exclusive and more than one issue can contribute in any interval.

[17] See p. 9 in *Energy Imbalance Market Pricing Waiver Report*, December 1 - 31, 2014, January 15, 2015, http://www.caiso.com/Documents/Jan15_2015_EnergyImbalanceMarket_REPORT_ER15-402.pdf.

- **Resource outages.** This category is cited as the primary cause of about 10 percent of supply insufficiencies in the 15-minute and 5-minute markets in PacifiCorp East during December. When a generating resource outage occurs, the market software needs to increase generation from other resources. When a resource is no longer on outage and is scheduled by an EIM entity, it is also important that the outage cancellation be reported in a timely manner so that the market software represents that this capacity is available. Otherwise, the market software perceives that there is capacity shortage to meet the load. As noted in the ISO report, PacifiCorp is working to improve the timeliness with which outages are reported and cancelled.

- **Manual dispatch.** This category is cited as the primary cause of about 11 percent of supply insufficiencies in the 15-minute market and 7 percent in the 5-minute market in PacifiCorp West. Manual dispatches are issued to dispatch additional generation when outages or other issues occur causing a sudden need for additional generation. However, if these out-of-market dispatches are not entered into the market software, this generation is not reflected in the available supply modeled in the market software, which can cause a supply insufficiency in the market software. As indicated in the ISO report, the ISO and PacifiCorp have discussed the need for improving the timeliness of manual dispatch logging processes.

- **Import/export changes**. This category is cited as the primary cause of about 22 percent of supply insufficiencies in the 15-minute market in PacifiCorp West, and about 10 percent in the 5-minute market in both PacifiCorp areas. This category involves delays in making adjustments and updates to import and export schedules in the market software during resources outage times or steep load ramping conditions. Although additional energy may be procured for import in the bilateral market, e-tags are not due until 20 minutes prior to the operating hour. If this energy is not e-tagged before the 15-minute market is run 37.5 minutes prior to the operating interval, this energy is not available to meet demand in the EIM 15-minute market.

- **Transfer constraints/congestion**. This category is cited as the primary cause of about 7 percent of supply insufficiencies in the 5-minute market in PacifiCorp West and 3 percent in the 5-minute market in PacifiCorp East. This category appears to include cases where energy was transferred out of an EIM area in the 15-minute market, and then was needed to meet demand within that area, but was not available since transfers out of the EIM area could not be reduced to the limits placed on EIM transfers in the 5-minute market. In practice, the amount of changes made to 15-minute schedules in the 5-minute market in the EIM have been set to not more than 0.003 MW during most intervals (about 92 percent between November 1 and December 31), so that no significant changes can be made to net EIM transfers in the 5-minute market. DMM has identified this as a major contributing factor to supply insufficiencies in the EIM during most intervals.

Flexible ramping sufficiency test

As noted in DMM's report on EIM performance from November to December 2014, DMM's estimates of EIM prices that would result without price discovery include the impact of provisions that are triggered when the EIM balancing area fails to pass the flexible ramping requirement test under a business practice manual modification made just before EIM go-live.[18] Shortly prior to EIM go-live, the Business Practice Manual for the Energy Imbalance Market was changed so that when an EIM area failed the ramping sufficiency test, the price discovery mechanism would be applied in the event any constraint,

[18] See pp. 12-15, http://www.caiso.com/Documents/Jan23_2015_DMMAssessment_December2014EIMPerformance.pdf.

such as the power balance or flexible ramping constraint, was relaxed in the 15-minute or 5-minute market. This mechanism avoids having prices reflect conditions that do not account for other manual actions the EIM balancing area may be taking to meet flexibility needs.[19] The ISO explained that this procedure was necessary in situations where the EIM is partially isolated and must make use of its available flexible capacity without leaning on the ISO or other EIM areas.

The following section provides a summary of the frequency when this provision of the business practice manual would impact EIM prices, to provide transparency on this issue to FERC and stakeholders.

Figure 2.11 through Figure 2.14 show the frequency of failures of the ramping sufficiency test, along with the portion of these events during which the power balance or flexible ramping constraint was subsequently relaxed in the 15-minute or 5-minute market in the PacifiCorp areas.

As shown in Figure 2.11 through Figure 2.14:

- Failures of the ramping sufficiency test are relatively frequent in the PacifiCorp East area, but much less frequent in PacifiCorp West. In the 15-minute market, while the power balance or flexible ramping constraints at times need to be relaxed when an area fails to meet the ramping sufficiency test, during many intervals this is not the case.
- When an area fails to meet the ramping sufficiency test, chances are relatively high that the power balance constraint will need to be relaxed in the 5-minute market.

[19] See p. 35, Business *Practice Manual for the Energy Imbalance Market*, as revised 10/30/2014: http://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V2_redline.pdfhttp://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V2_redline.pdf.

Figure 2.11 Frequency of constraint relaxation when flexible ramping sufficiency test failed PacifiCorp East - 15-minute market

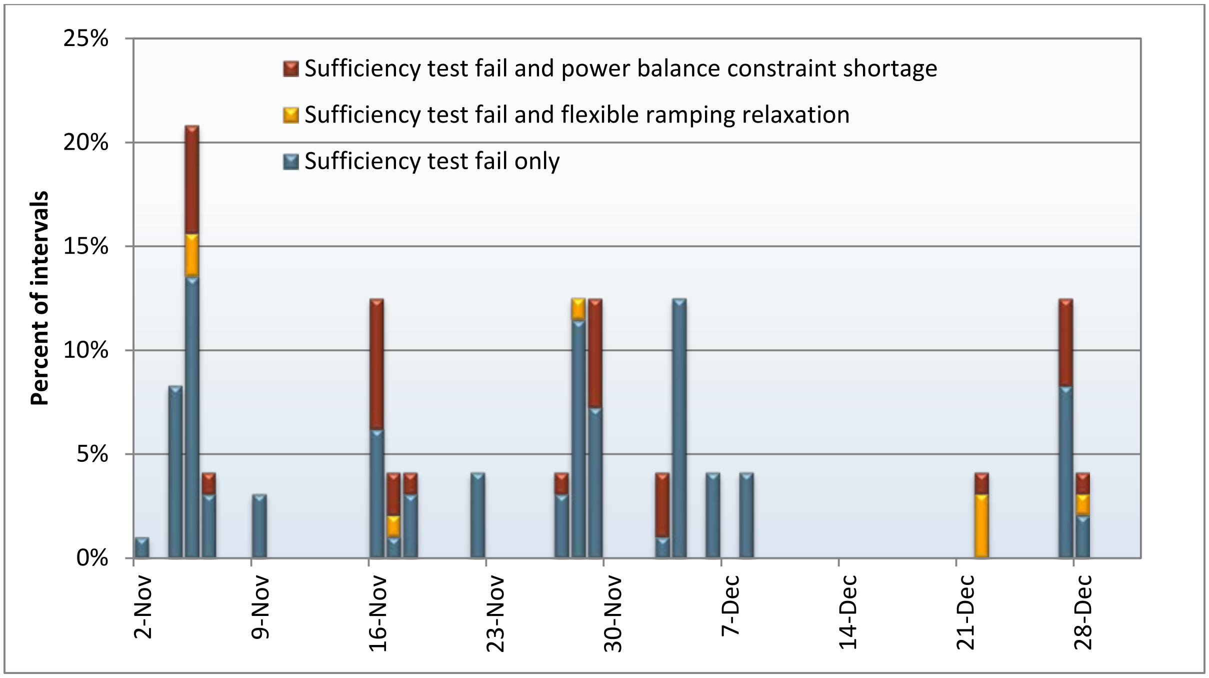


Figure 2.12 Frequency of constraint relaxation when flexible ramping sufficiency test failed PacifiCorp West - 15-minute market

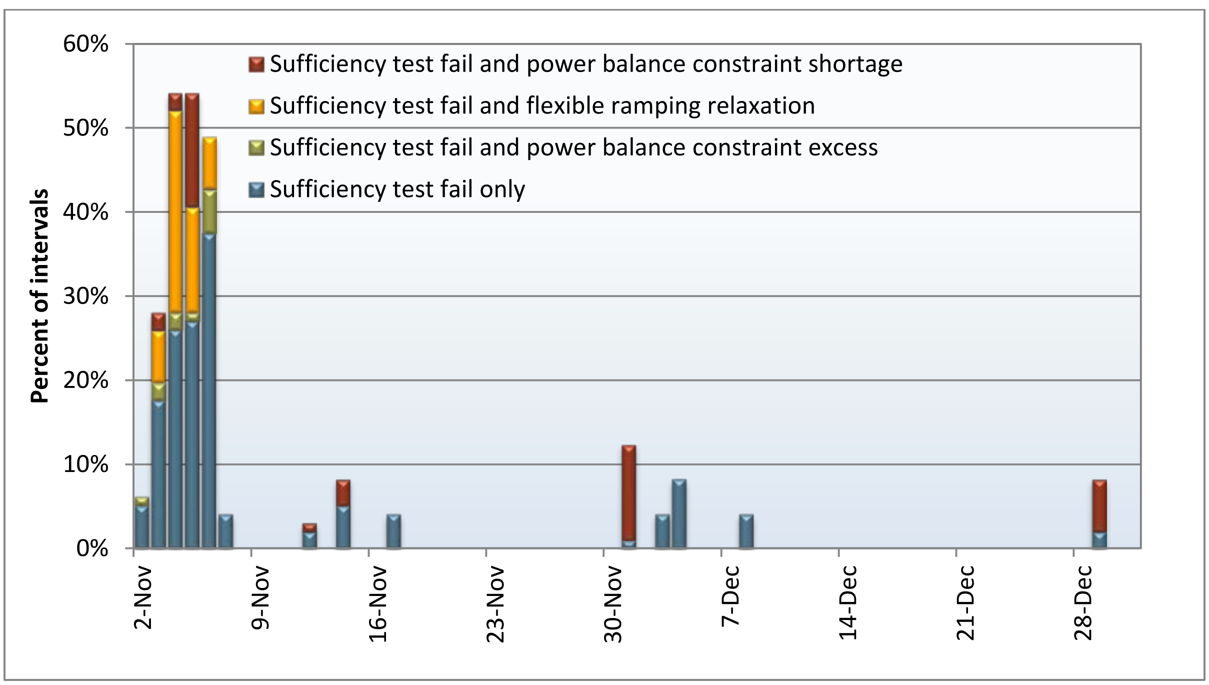


Figure 2.13 Frequency of constraint relaxation when flexible ramping sufficiency test failed PacifiCorp East - 5-minute market

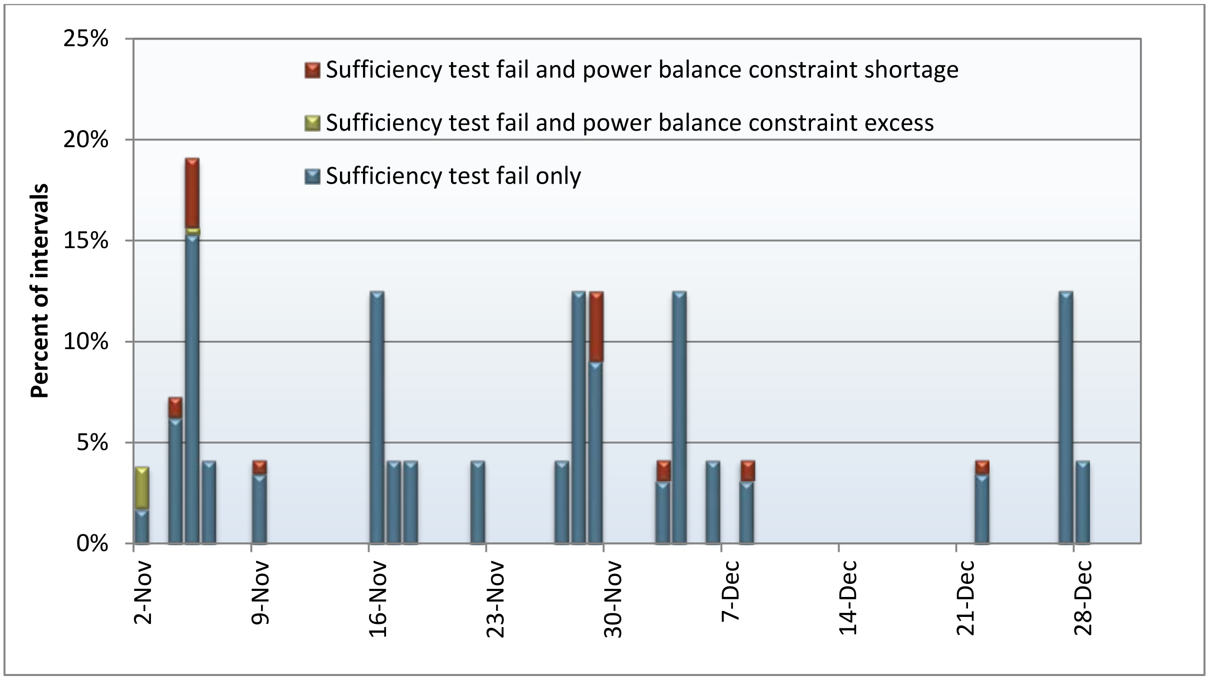
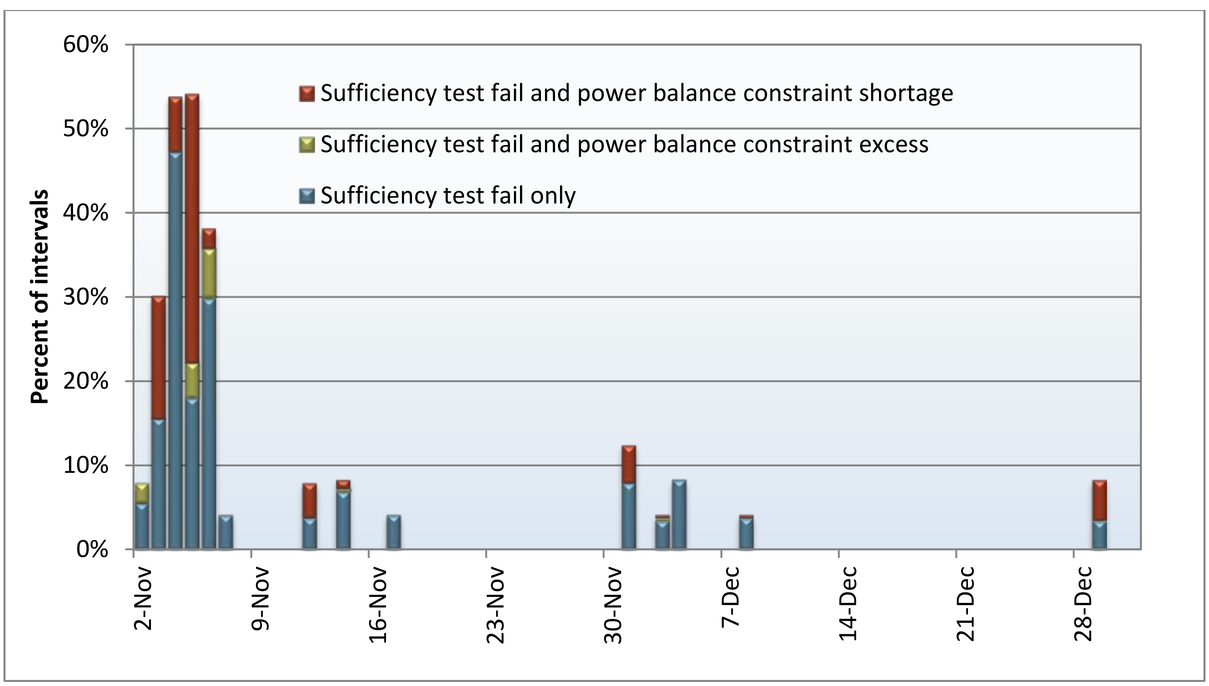


Figure 2.14 Frequency of constraint relaxation when flexible ramping sufficiency test failed PacifiCorp West - 5-minute market

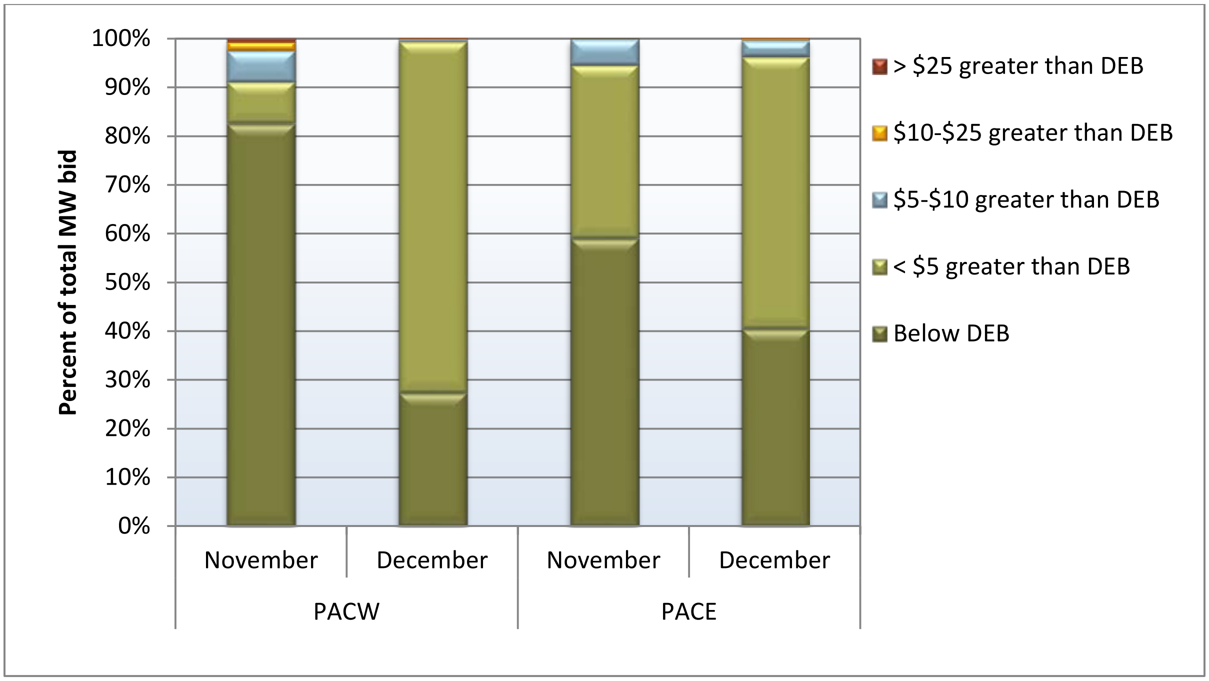


Market bidding and mitigation

Bidding in the EIM has been highly competitive with bids for most capacity slightly below or above default energy bids (DEBs) used in market power mitigation. Thus, when relatively high EIM prices have occurred, these prices reflect penalty prices for software constraints rather than bid prices. In addition, when bids are mitigated due to market power mitigation provisions, these procedures generally result in modest reductions in bid prices.

Figure 2.15 summarizes a comparison of bid prices in PacifiCorp East and PacifiCorp West for thermal and hydro units compared to default energy bids used in market power mitigation. These default energy bids are based on the marginal operating costs of thermal resources or opportunity cost for hydro resources with limited energy and energy storage capabilities.

Figure 2.15 Market bids compared to default energy bids



During December in PacifiCorp East about 40 percent of bids have been lower than the default energy bids, with another 55 percent of bids being not more than $5/MW above default energy bids. Almost all the remaining 5 percent of bids have been no more than $10/MW above default energy bids. In PacifiCorp West during December about 27 percent of bids have been lower than the default energy bids, and almost all of the remaining bids have been no more than $5/MW above default energy bids.

Bid cost recovery payments

Bid cost recovery payments in the EIM were around $250,000 from November and December 2014.[20] This is just over $0.02/MWh of total EIM load, compared to ISO real-time bid cost recovery costs of

[20] This represents DMM's estimate of final bid cost recovery payments after expected settlement corrections.

about $0.24/MWh of total ISO load. The relatively low level of bid cost recovery payments in the EIM reflects the fact that there are currently very few quick start units that can be committed through an EIM dispatch.

Flexible ramping constraint

Several problems stemming from how the flexible ramping credit was introduced as part of the EIM design and how the flexible ramping constraint was modified after implementation of price discovery in the EIM appear to significantly reduce the amount of capacity procured and prices for flexible ramping capacity in the ISO market. These issues appear to have primarily affected the ISO market and are discussed in Section 3.3 of this report.

3 Market performance

This section highlights key performance indicators of fourth quarter ISO market performance.

- Day-ahead prices in the fourth quarter were lower than the third quarter prices in both peak and off-peak periods.
- Hour-ahead prices were similar to 5-minute market prices but were lower than day-ahead and 15-minute prices in both peak and off-peak periods. Also, hour-ahead prices slightly diverged from day-ahead and 15-minute prices compared to the third quarter.
- Peak and off-peak 15-minute market prices were lower than day-ahead prices but higher than 5-minute market prices in all months of the quarter.
- 5-minute market prices were lower than day-ahead and 15-minute market prices for both peak and off-peak periods.
- In the fourth quarter, prices above $250/MWh were observed in less than 0.4 percent of intervals in the 15-minute market and in less than 0.5 percent of intervals in the 5-minute market.
- In the 15-minute market, negative prices were observed in about 1 percent of intervals. Negative prices were more frequent in the 5-minute market, occurring in just over 3 percent of intervals. In December, negative prices occurred in slightly more than 5 percent of intervals in the 5-minute market.
- After EIM was implemented, flexible ramping constraint payments totaled around $0.2 million in the ISO compared to $3.4 million in November and December 2013. Payments were around $20,000 in the month of December, which is the lowest monthly value since implementation of the flexible ramping constraint in December 2011.
- Congestion within the ISO system in the fourth quarter was mixed in the day-ahead market and similar in the real-time market compared to the previous quarter. Congestion had less of an effect on overall prices in the day-ahead and real-time markets in this quarter than in the previous three quarters.
- Bid cost recovery payments were around $25 million in the fourth quarter of 2014, compared to $26 million in the fourth quarter of 2013.
- Real-time imbalance offset cost settlement values totaled $3 million in the fourth quarter of 2014. This is approximately 7 percent of the $44 million value in the fourth quarter of the prior year and 5 percent of the $60 million value in the third quarter of 2014.
- Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 330 MW on average, a decrease from 480 MW of net virtual supply in the previous quarter.
- Total convergence bidding revenue for the quarter, adjusted for bid cost recovery costs, was about $4 million.

3.1 Energy market performance

This section assesses the energy market efficiency based on an analysis of the system energy component of day-ahead, hour-ahead, 15-minute and 5-minute market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources.

Figure 3.1 and Figure 3.2 show monthly system marginal energy prices for peak and off-peak periods, respectively. As seen in these figures, average day-ahead and 15-minute price levels were higher than hour-ahead and 5-minute prices in most peak and off-peak periods in the quarter.

- Day-ahead prices were lower in December compared to October and November in both peak ($43/MWh) and off-peak ($34/MWh) periods. Overall, day-ahead prices were higher than hour-ahead, 15-minute and 5-minute market prices for the quarter.
- On a quarterly average basis, peak hour-ahead prices were lower than day-ahead prices in all months by an average of about $5/MWh. Hour-ahead off-peak prices averaged nearly $6/MWh lower than day-ahead prices.
- The average fourth quarter peak system prices in the 15-minute market were slightly higher than day-ahead prices in October by $0.80/MWh, while lower than day-ahead prices in November and December by $0.90/MWh and $3.40/MWh, respectively. Off-peak 15-minute prices were lower than day-ahead prices in October, November and December by $3.20/MWh, $1.10/MWh and $3.50/MWh, respectively.
- Peak period average system prices in the 5-minute market were lower than day-ahead market prices in all three months. The difference ranged from about $2/MWh in October to about $7/MWh in November, then narrowed to about $3/MWh in December. In October, the 5-minute prices in off-peak periods were about $7/MWh lower than day-ahead prices and around $5/MWh lower in November while about $7/MWh lower in December.

Figure 3.3 further illustrates the market prices on an hourly basis in the fourth quarter. Notably, prices in the three real-time markets were less than the day-ahead prices in the early afternoon hours (hours ending 10 through 15). Solar generation typically peaks during this period and results in driving net loads down.[21]

Prices in the 5-minute market increased the most during the morning ramping period and were higher than the other three markets in hour ending 7. In contrast, 5-minute market prices were consistently lower than all other markets during the evening peak period (hours ending 17 through 20).

In general, prices in all markets followed a similar pattern throughout the day. On average, the 15-minute market prices were much lower than the day-ahead market prices between hours ending 10 and 15 as well as hours ending 21 to 24. In one hour (hour ending 19), however, the 15-minute market prices were on average about $2.65/MWh higher than day-ahead prices during the quarter.

[21] Net load is the difference between system load and solar and wind generation.

Figure 3.1 Average monthly on-peak prices – system marginal energy price

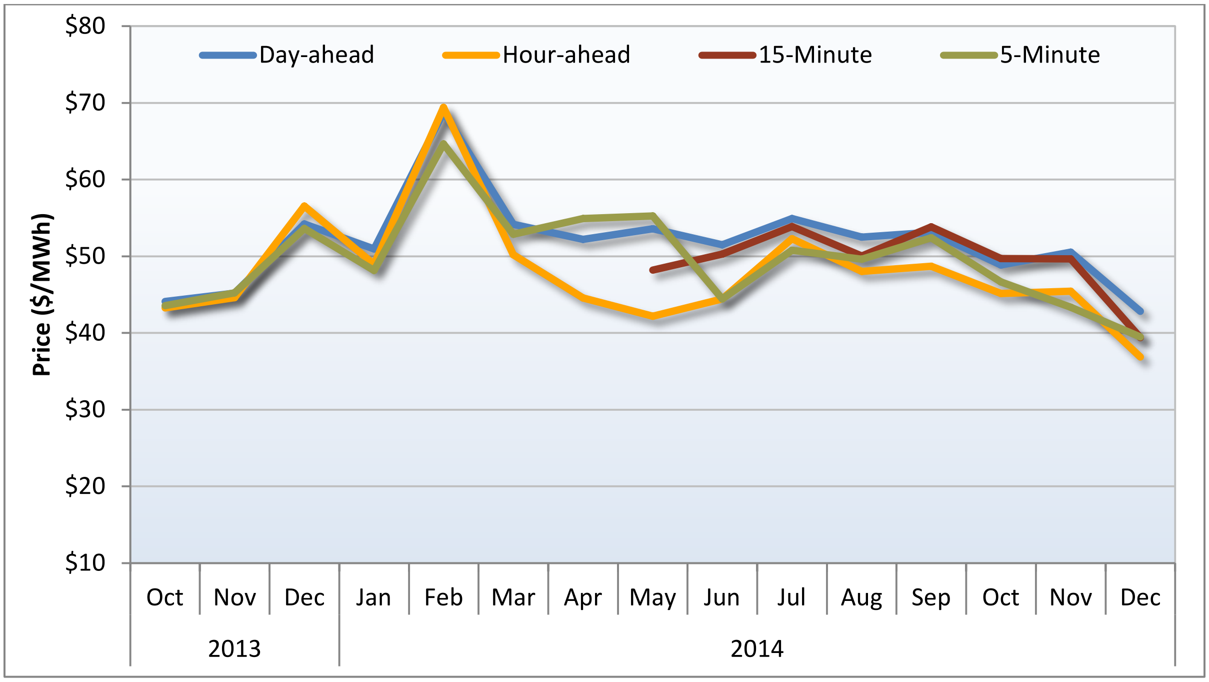


Figure 3.2 Average monthly off-peak prices – system marginal energy price

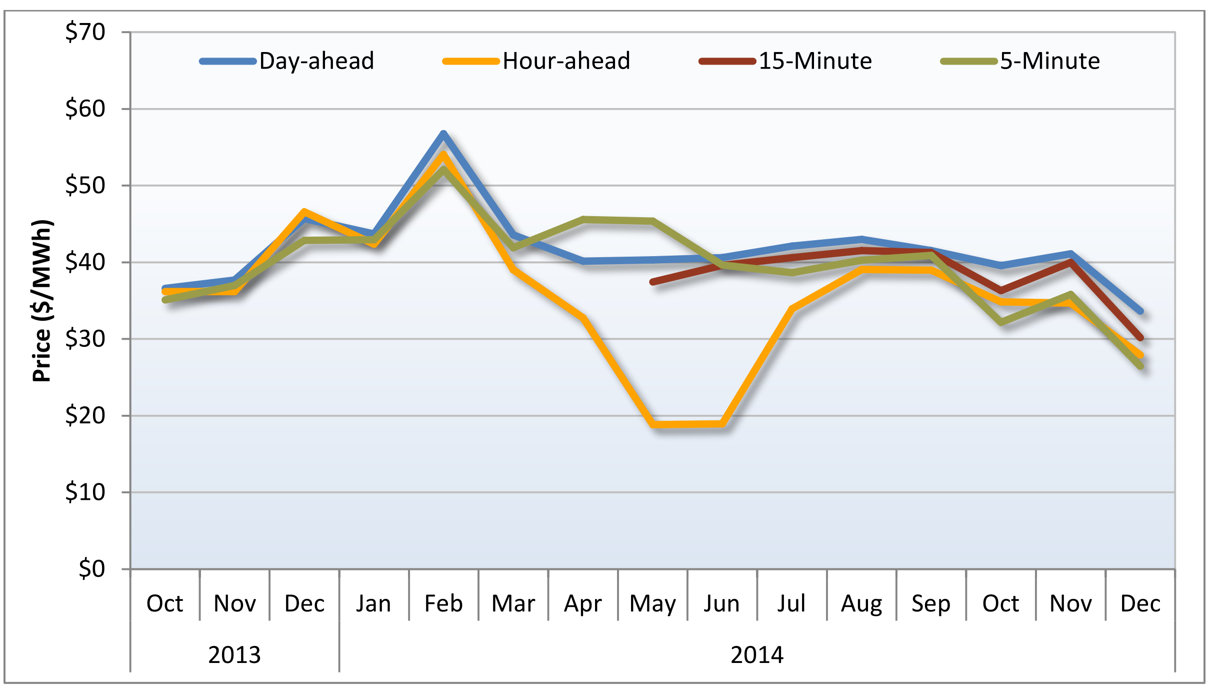
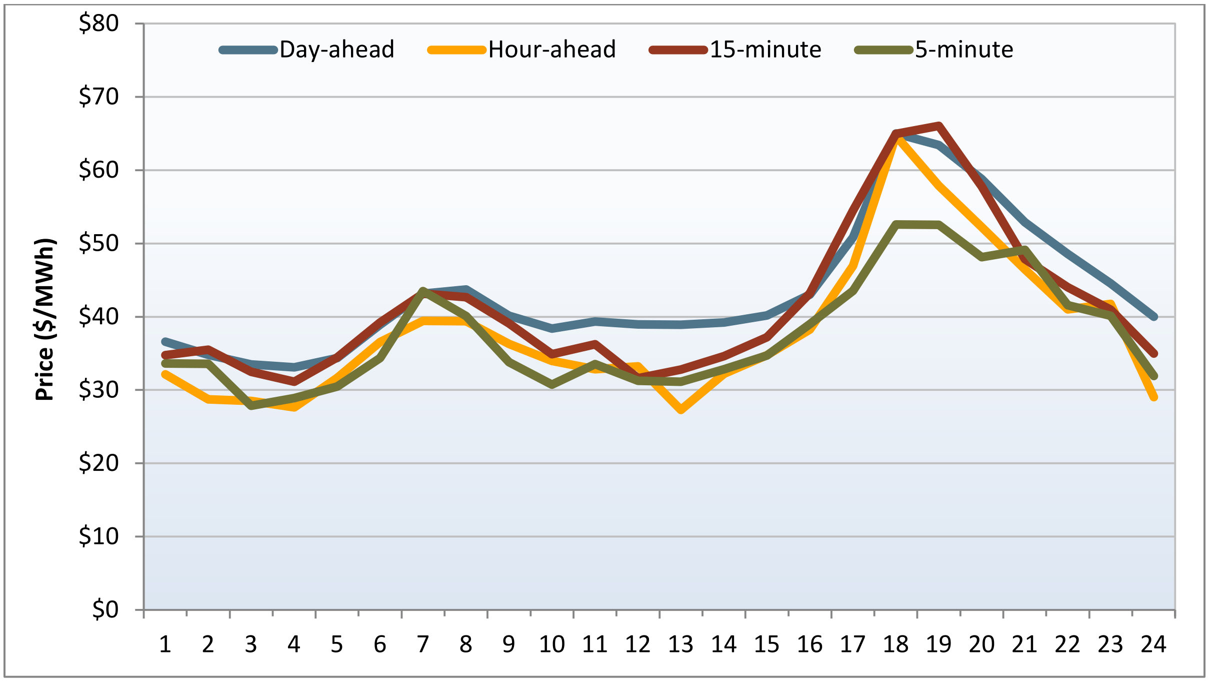


Figure 3.3 Hourly comparison of system marginal energy prices (November – December)



3.2 Real-time price variability

Historically, 5-minute real-time market prices have been highly volatile with periods of extreme positive and negative price spikes. This price variability in many instances was the result of relaxing the power balance constraint to resolve the feasibility of the dispatch.[22] Upon implementing the new 15-minute market in May, price variability in the 5-minute market has a lower impact as there is less settlement using the 5-minute real-time price.

Overall, positive fourth quarter price spikes were infrequent in the 15-minute and 5-minute markets. Prices above $250/MWh were observed in less than 0.4 percent of intervals in the 15-minute market and in less than 0.5 percent of intervals in the 5-minute market.

Figure 3.4 shows the frequency of positive price spikes occurring in the 5-minute market. In the third and fourth quarters, the frequency in the 5-minute market was about 0.4 percent, compared to 1.3 percent in the second quarter of 2014. The overall frequency of 5-minute price spikes is low compared to previous periods. The relatively high frequency of positive spikes in the spring was partly due to ramping limitations resulting from the rapid decline of solar generation during the late afternoon hours and unexpected drops in wind generation. Increased availability of ramping resources in the higher load summer months significantly decreased the frequency of positive price spikes caused by sudden changes in renewable generation.

[22] Greater detail on system power balance constraints can be found in DMM's *2013 Annual Report on Market Issues and Performance*: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

Negatively priced intervals were more frequent than high price intervals in the fourth quarter. In the 15-minute market, negative prices were observed in just over 1 percent of intervals during the quarter. Negative prices were even more frequent in the 5-minute market, occurring in more than 3 percent of intervals.

Figure 3.5 shows the frequency of negative price spikes in the past eight months in the 15-minute market. Figure 3.6 shows the frequency of negative price spikes in the 5-minute market for the past 15 months. In December, negative prices occurred in over 5 percent of intervals in the 5-minute market; this is the highest monthly frequency of negative prices observed in any month since June 2012 and more than three times higher than the frequency observed in December 2014. Negative prices in the fourth quarter were especially common in periods of relatively low load prior to the steep evening load ramp as solar generation peaked for the day and other generation resources remained available to meet the ramp.

Figure 3.4 Frequency of positive 5-minute price spikes (all LAP areas)

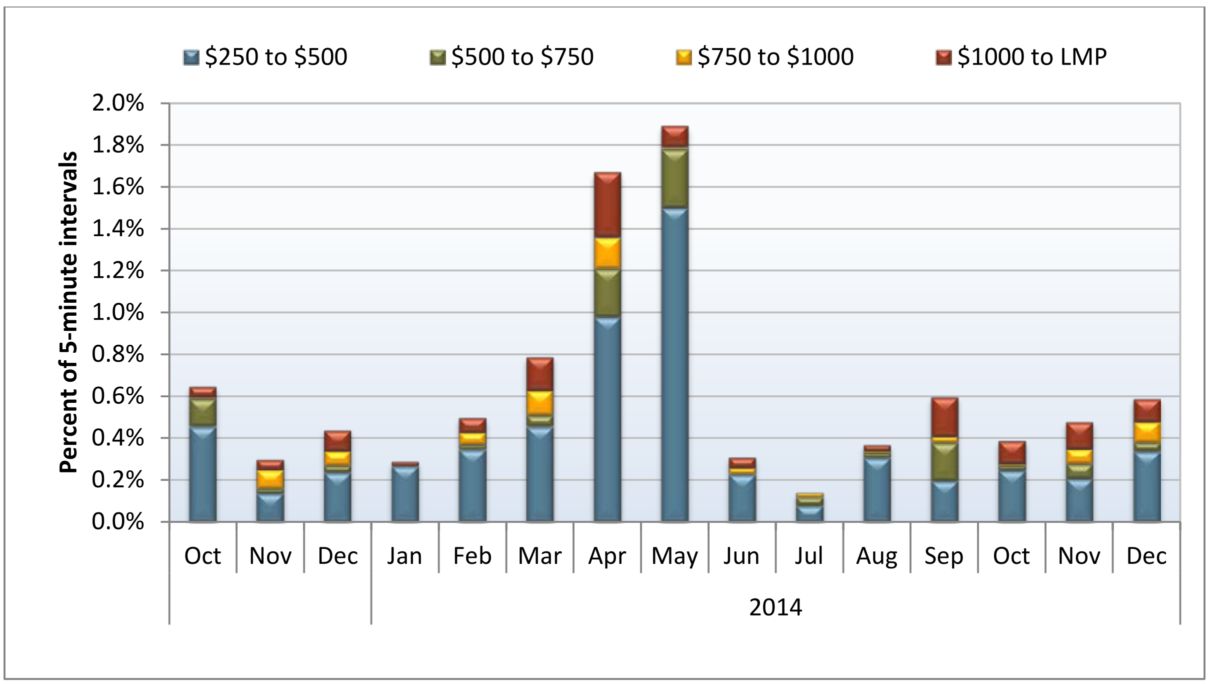


Figure 3.5 Frequency of negative 15-minute price spikes (all LAP areas)

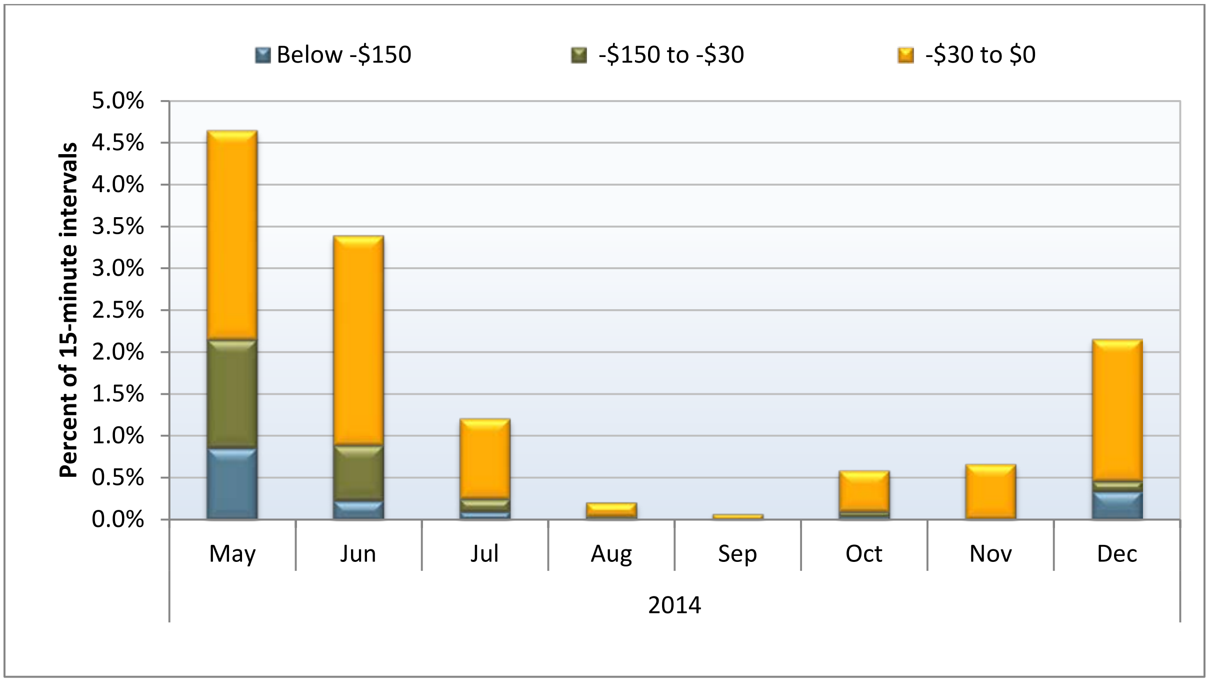
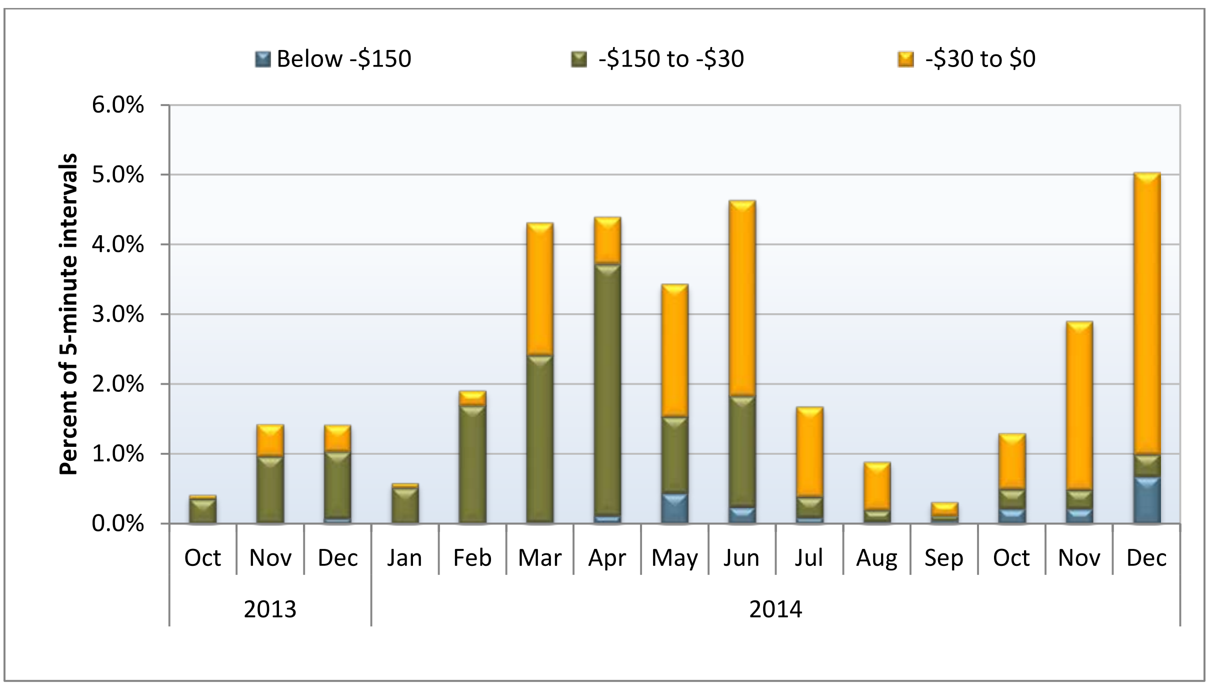


Figure 3.6 Frequency of negative 5-minute price spikes (all LAP areas)



3.2.1 Flexible ramping constraint

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

- Flexible ramping costs were around $630,000 in the fourth quarter, which is up from around $570,000 in the previous quarter. After EIM was implemented, flexible ramping constraint payments totaled around $0.2 million in the ISO compared to $3.4 million in November and December 2013.
- ISO operators adjusted the ISO balancing area flexible ramping requirement to 450 MW consistently during the morning and evening ramping periods during the fourth quarter. The requirement was typically set to 300 MW during the off-peak hours and 400 MW during the middle of the day.
- The flexible ramping requirement was set to a little over 30 MW in PacifiCorp East and a little over 25 MW in PacifiCorp West for most of the day. These requirements were adjusted a little higher during the morning ramping hours, but remained fairly constant throughout the day.
- Several errors in how the EIM flexible ramping credit has been calculated had the direct effect of reducing the quantity of flexible ramping capacity purchased in the ISO. This, in turn, would have had the indirect effect of lowering prices paid to suppliers of flexible ramping capacity.

Background

The ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute market in December 2011.[23] The constraint is applied to internal generation, dynamic inter-ties and proxy demand response resources within the ISO balancing area and beginning in November 2014 in the EIM balancing areas as well. Operators adjust the flexible ramping requirement level to ensure enough upward ramping flexibility is available, particularly during ramping periods. In the fourth quarter, ISO operators typically set the requirement for the ISO balancing area to 300 MW during the off-peak hours. They gradually moved this to 450 MW in the morning and evening ramping periods and set the requirement to 400 MW during the day.

If sufficient capacity is on line, the ISO software does not commit additional resources in the system, which often leads to a low (or often zero) shadow price for the procured flexible ramping capacity. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO software can commit additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. Units committed to meet the flexible ramping requirement can be eligible for bid cost recovery payments in the 15-minute market. A procurement shortfall of flexible ramping capacity will occur when there is a shortage of available supply bids to meet the flexible ramping requirement or when there is energy scarcity in the 15-minute market.[24]

[23] The flexible ramping constraint is also binding in the second, but not the first, interval of the 5-minute real-time market.

[24] The penalty price associated with procurement shortfalls was set to $247 before January 15, 2015. Beginning January 15, 2015, the penalty price is now set to $60. For more information, see: http://www.caiso.com/Documents/Dec18_2014_OrderAcceptingFlexibleRampingConstraintParameterAmendment_ER15-50.pdf.

Modeling the flexible ramping constraint in the EIM

Initially, the flexible ramping constraint was applied to internal generation, dynamic inter-ties and proxy demand response resources within the ISO. Upon implementing the energy imbalance market, the constraint is now also applied to each EIM balancing authority area, as group combinations of balancing authority areas, and for the entire EIM footprint. In total there are seven flexible ramping constraints used in the model.

The flexible ramping requirement for each EIM balancing authority area is determined using a similar methodology to that which has been historically used for the ISO area. The market operator calculates the amount of 5-minute flexibility requirements for each individual area and then again for the entire EIM footprint.

Individual balancing authority areas before each operating hour need to meet the flexible ramping requirement to ensure enough upward ramping capacity is available prior to the 15-minute market run. Before the market runs the ISO performs a test, called the flexible ramping sufficiency test, to ensure sufficient capacity in each balancing area.

Market operators calculate the flexible ramping requirement values used in the flexible ramping constraint sufficiency test for each area. For instance, the ISO calculates the requirement for the ISO balancing area and PacifiCorp calculates the requirement for the PacifiCorp East and West areas. The final requirement value for each area reflects the pro rata share of the EIM diversity benefit and the flexible ramping requirement credit of each balancing area.[25] The diversity benefit is the difference between the sum of individual balancing authority area flexible ramp requirements and the flexible ramping requirement for the combined balancing areas as a whole.[26]

Should an EIM balancing area fail the hourly sufficiency test, it cannot increase imports from any other area for that hour. This rule was designed to ensure that a balancing area is not leaning on the flexibility of another area.[27] If all the areas pass the test, the flexible ramping requirement for each area is adjusted in the 15-minute market optimization by the credits for each area, available net import capacity into each area and available net export capacity from the other areas. Diversity benefits from the sufficiency test are not included in the 15-minute market optimization.

[25] For example, if a balancing authority area has a flexible ramping requirement of 300 MW without diversity benefit or credit, and the pro rata diversity benefit for that balancing authority area is 20 MW, and the balancing authority area also has a 30 MW requirement credit, then the final requirement value for the balancing authority area in the flexible ramping sufficiency test will be 300 - 20 - 30 = 250 MW. Other factors can also affect the final value of the flexible ramping requirement used in the sufficiency test. Details of the calculation methodology can be found in the Business Practice Manual for Energy Imbalance Market, Section 10.3.2.1: http://bpmcm.caiso.com/BPM Document Library/Energy Imbalance Market/BPM_for_Energy Imbalance Market_V2_clean.docx.

[26] For example, if the flexible ramping requirement for the two balancing authority areas in the EIM is 400 MW and 200 MW, and the entire EIM footprint has a requirement of 450 MW, then the EIM diversity benefit is equal to 150 MW (600 MW- 450 MW). This diversity benefit of 150 MW will be distributed among the balancing authority areas in proportion to their individual requirements. In this case, the first balancing authority area will receive 100 MW and the other will receive 50 MW of the diversity benefit.

[27] As stated in the Business Practice Manual for Energy Imbalance Market, Section 10.3.2.1; for details see: http://bpmcm.caiso.com/BPM Document Library/Energy Imbalance Market/BPM_for_Energy Imbalance Market_V2_clean.docx.

According to the initial EIM design, the flexible ramping requirement credit should equal the net energy export (net outgoing EIM transfer).[28] If an EIM balancing area is a net exporter, the market operator will apply a flexible ramping requirement credit for that area. This reflects the assumption that if additional ramping energy was needed within a balancing area, any net EIM transfers out of that area could be immediately reduced to zero in the EIM. Thus, the EIM design did not allow for any credit to be given to a balancing area with a net incoming EIM transfer.

As discussed in the following section of this report, DMM's fourth quarter analysis highlighted flexible ramping constraint results in the ISO and EIM that appeared inconsistent with the EIM design and market conditions. After DMM referred these results to the ISO for further review, the ISO determined that a variety of software and design errors were driving these results. As noted below, the ISO took steps to mitigate these issues in February 2015.

Flexible ramping requirement and procurement

Figure 3.7 and Figure 3.8 show the hourly flexible ramping requirement and procurement levels for the ISO area and the combined PacifiCorp East and West area in November and December. Figure 3.9 and Figure 3.10 show the hourly average flexible ramping requirement and procurement levels for PacifiCorp East and PacifiCorp West area constraints in November and December.

As shown in Figure 3.7, the amount of flexible ramping capacity procured in the ISO during these months was reduced substantially by a credit applied by the EIM software. However, the ISO has determined that the large flexible ramping capacity credit received by the ISO was driven by several errors or design flaws with the calculation of this credit.

The overall result of these issues was to reduce the amount of flexible ramp capacity procured and prevented the flexible ramping constraint from being binding in the ISO in the pricing run of the 15-minute market. The flexible ramping constraint for the ISO was not binding at any point in December. In November, the constraint was binding in the ISO during the first week, but afterwards was only binding in one other interval. The change in results appears to have been the result of errors in the flexible ramping credit.

This reduced flexible ramping payments in the ISO (and EIM areas) by reducing the quantity purchased and lowering (or eliminating) the compensation paid to generators based on the shadow price of this constraint when this constraint is binding.

These issues appear to have been mitigated by changes made by the ISO in February 2015. DMM understands that additional information on these issues will be provided by the ISO. DMM will also provide additional information and analysis of these issues in future DMM reports.

[28] An EIM transfer is a transfer of real-time energy between an EIM balancing authority area and the ISO authority area or between EIM balancing authority areas using transmission capacity available in the EIM.

Figure 3.7 ISO area average hourly flexible ramping capacity (November – December)

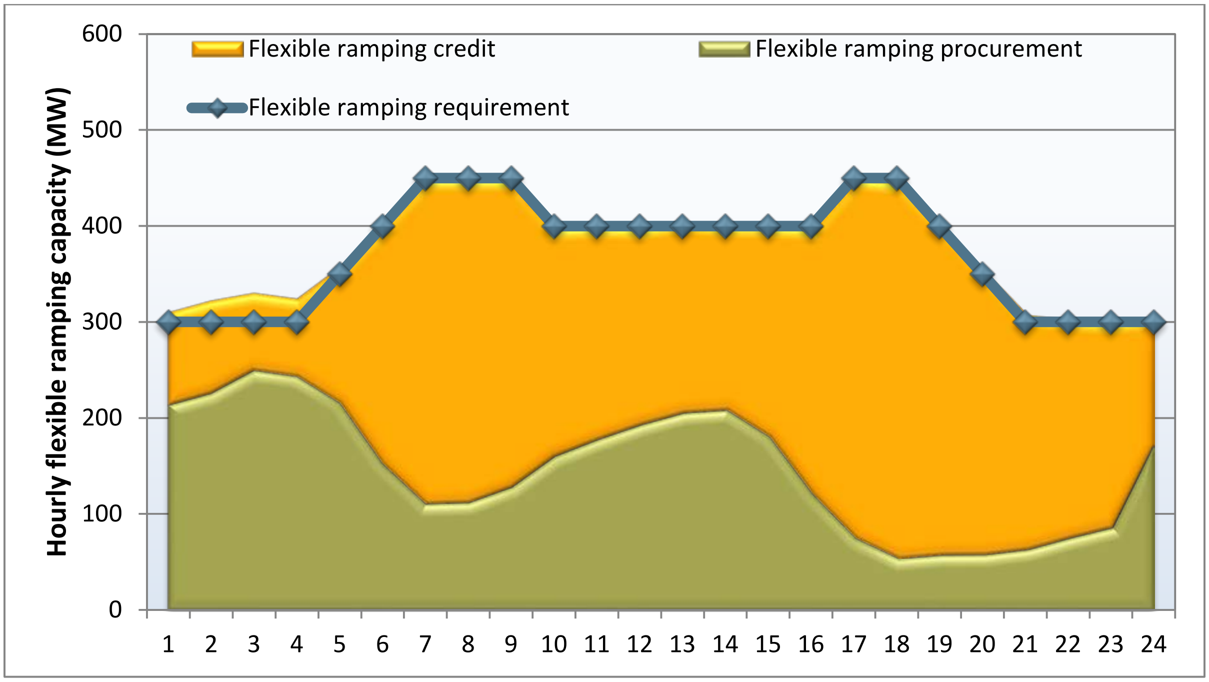


Figure 3.8 Combined PacifiCorp East and West average hourly flexible ramping capacity (November – December)

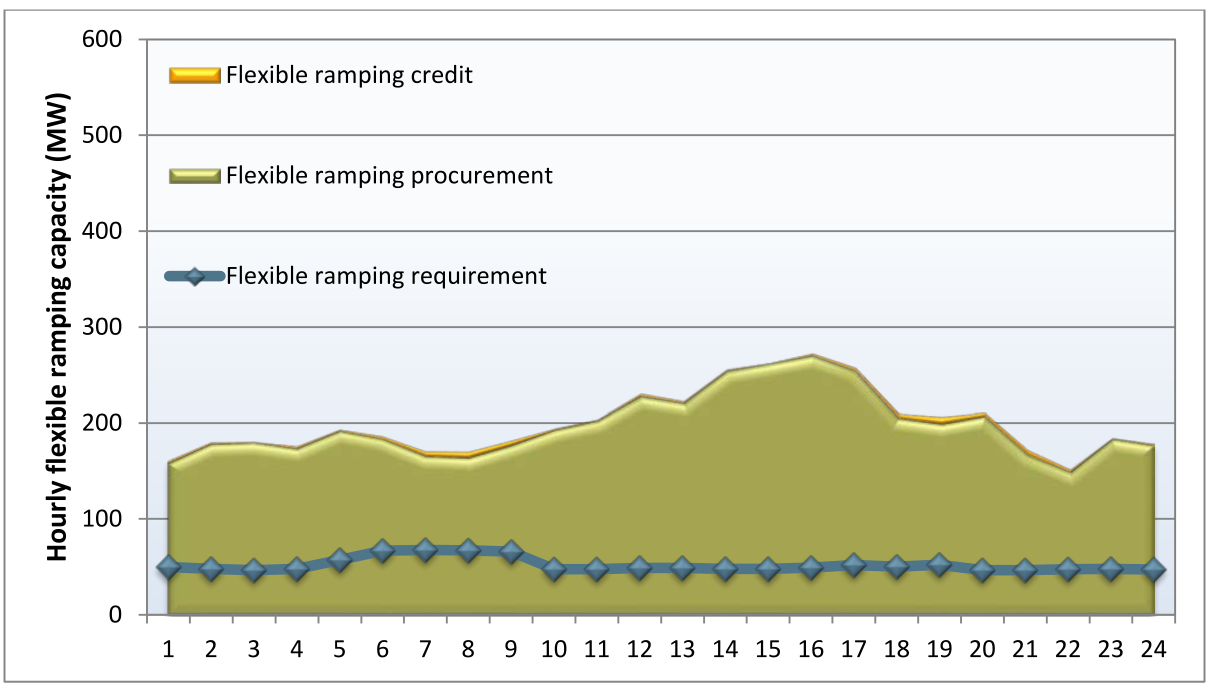


Figure 3.9 PacifiCorp East average hourly flexible ramping capacity (November – December)

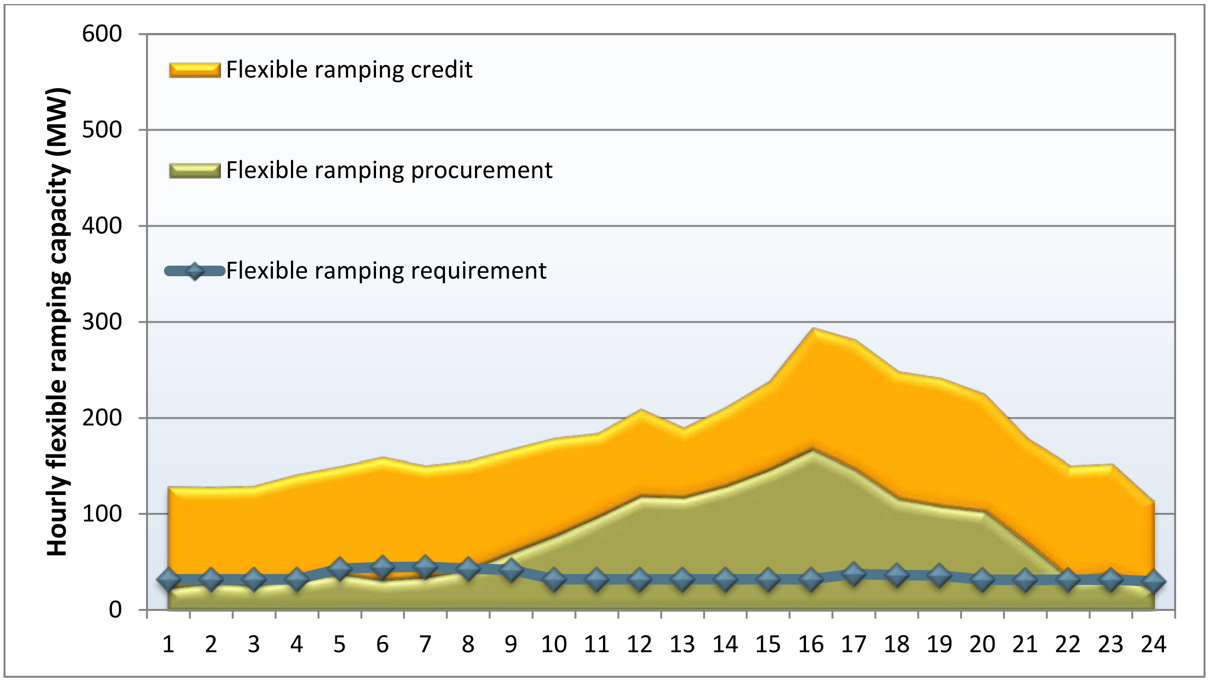
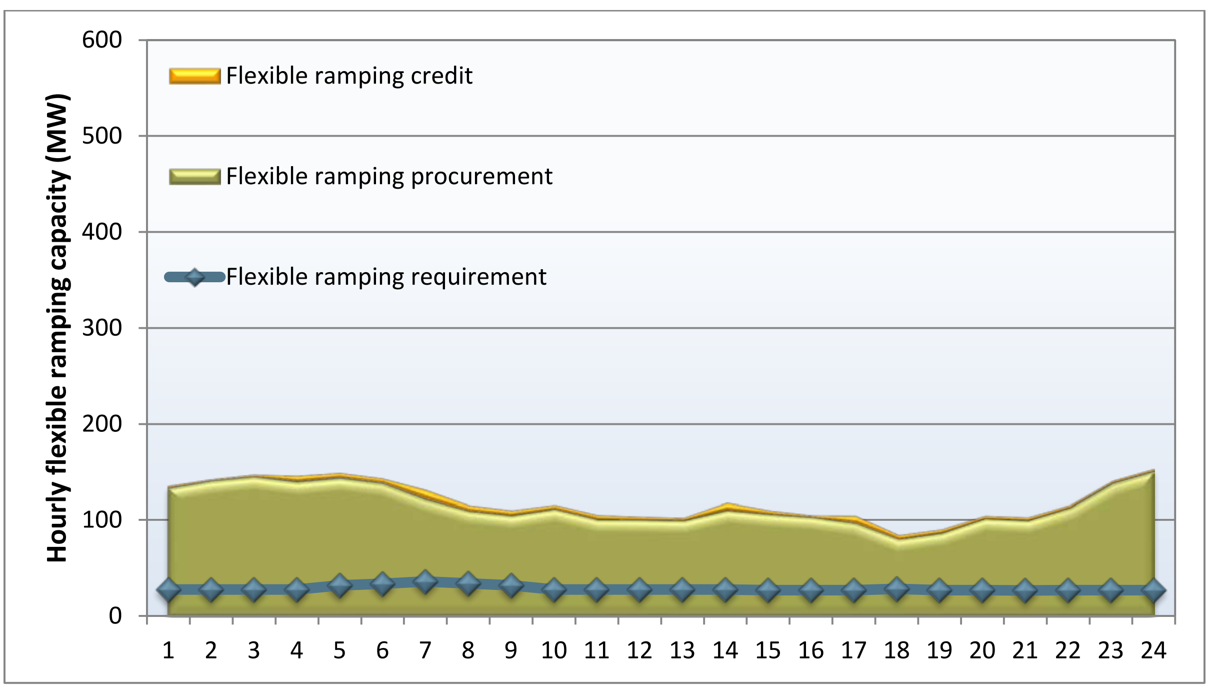


Figure 3.10 PacifiCorp West average hourly flexible ramping capacity (November – December)



Flexible ramping procurement costs

As noted in the prior section, several errors in calculating the EIM flexible ramping credit had the direct effect of reducing the quantity of flexible ramping capacity purchased in the ISO. This, in turn, would have had the indirect effect of lowering prices paid to suppliers of flexible ramping capacity.

Total payments for flexible ramping resources in the fourth quarter were around $630,000, up from around $570,000 in the previous quarter.[29] Table 3.1 provides a review of monthly flexible ramping constraint activity in the 15-minute market.[30] The table highlights the following:

- The flexible ramping constraint was binding in around 2 percent of intervals, which is slightly down from 3 percent in the previous quarter.
- The frequency of procurement shortfalls increased to 0.2 percent for all 15-minute intervals compared to 0.1 percent in the previous quarter.
- The average shadow price when the flexible ramping constraint was binding was about $42/MWh in October and $74/MWh in November – both higher than the average $36/MWh in the previous quarter.
- The constraint did not bind in December.

Table 3.1 Flexible ramping constraint monthly summary

Year	Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
2013	Oct	$1.90	15%	0.7%	$40.39
2013	Nov	$0.80	13%	0.1%	$17.15
2013	Dec	$2.64	17%	1.2%	$36.00
2014	Jan	$1.27	10%	0.1%	$28.37
2014	Feb	$0.56	4%	0.4%	$45.68
2014	Mar	$1.20	12%	0.3%	$34.37
2014	Apr	$1.32	11%	0.8%	$44.59
2014	May	$0.72	7%	0.1%	$28.96
2014	Jun	$0.25	4%	0.1%	$25.97
2014	Jul	$0.25	3%	0.1%	$49.23
2014	Aug	$0.11	3%	0.1%	$25.06
2014	Sep	$0.21	4%	0.1%	$33.10
2014	Oct	$0.42	4%	0.4%	$41.84
2014	Nov	$0.19	1%	0.2%	$74.48
2014	Dec	$0.02	0%	0.0%	$0.00

[29] There are also secondary costs such as those related to bid cost recovery payments to cover the commitment costs of the units committed by the constraint and additional ancillary services payments. Assessing these costs is complex and beyond the scope of this analysis.

[30] DMM had problems with data availability between October 16 and October 30, and thus did not include the data from that period in the calculation.

3.3 Congestion

Fourth quarter congestion within the ISO system was mixed in the day-ahead and real-time markets compared to the previous quarter. Congestion had less of an effect on overall prices in the day-ahead and real-time markets in this quarter than in the previous three quarters.

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

Much of the congestion was related to unscheduled flows and planned outages. Congestion in the SCE area was primarily driven by the binding constraint of the Barre – Villa Park 220 kV line. Price impacts on individual constraints can differ between the day-ahead, 15-minute and 5-minute markets, as seen in the following sections.

3.3.1 Congestion impacts of individual constraints

Day-ahead congestion

Compared to the previous quarter, the frequency and impact of congestion in the day-ahead market decreased.

In the PG&E area, 6110_TM_BNK_FLO_TMS_DLO_NG was the most congested constraint in the day-ahead market and was binding in about 8.5 percent of hours. During these hours, prices in the PG&E area increased by about $3.17/MWh while prices in the SCE and SDG&E areas also increased by about $1.80/MWh. This constraint was activated to mitigate expected unscheduled flows on the California Oregon Inter-tie (COI).

The second most congested constraint in the PG&E area was the 30880_HENTAP2_230 _30900_GATES_230_BR_2_1, which increased prices about $0.50/MWh in the PG&E area while causing prices in the SCE and SDG&E areas to decrease by $0.36/MWh. This Fresno area constraint is heavily dependent on imports from the 230 kV system through the McCall, Herndon and Henrietta banks, and local hydro generation. The constraints are adjusted to protect for thermal overload from the contingency loss of the Gates – Gregg 230 kV line.

In the SCE area, the Barre – Villa Park 220 kV line was the most binding constraint in the fourth quarter, which protects for thermal overload from the contingency loss of the Barre – Lewis 220 kV line. This constraint was congested in about 12 percent of hours due to contingencies. When this constraint was binding, the SCE and SDG&E area prices increased by about $1.91/MWh and $0.18/MWh, respectively, while prices decreased in the PG&E area by about $0.90/MWh.

The second most congested constraint in the SCE area was the 7500_SOL1_NG nomogram, which was binding in about 1 percent of the hours due to the potential loss of the Magunden – Vestal #1 220 kV line. When congestion occurred on this constraint, prices in the SCE area increased by $0.54/MWh, while the PG&E and SDG&E area prices decreased by about $0.57/MWh.

Table 3.2 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency				Q1			Q2			Q3			Q4		
Area	**Constraint**	**Q1**	**Q2**	**Q3**	**Q4**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
PG&E	6110_TM_BNK_FLO_TMS_DLO_NG		11.9%	14.8%	8.5%				$0.71	-$0.89	-$0.89	$0.45	-$0.50	-$0.50	$3.17	$1.83	$1.70
	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	10.5%	29.9%	21.6%	3.8%	$0.36	-$0.27	-$0.27	$1.84			$2.01	-$0.56	-$0.56	$0.50	-$0.36	-$0.36
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_1				3.5%										$0.87	-$1.36	-$2.41
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2				2.5%										$1.11		
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	2.5%	7.6%		1.4%	$0.33	-$0.24	-$0.24	$0.80	-$0.70	-$0.70				$1.37		
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1				1.1%										$4.28	-$3.92	-$3.92
	SLIC 2512269 SOL1				0.6%										$0.88		-$1.07
	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1			34.1%								$1.82	-$1.56	-$1.56			
	35922_MOSSLD _115_30750_MOSSLD _230_XF_1A		5.0%	5.7%					$0.78			$0.61	-$0.56	-$0.56			
	30915_MORROBAY_230_30916_SOLARSS _230_BR		0.4%	1.3%					$4.69	-$4.08	-$4.08	$7.70	-$3.52	-$3.52			
	SLIC 2412157 PARDEE-SYLMAR2_NG			0.5%								$0.58		-$2.71			
	PATH15_BG	1.6%	9.4%	0.3%		$4.56	-$3.65	-$3.65	$3.67	-$3.07	-$3.07	$3.86	-$3.25	-$3.25			
	SLIC 2249785 ELDORADO-LUGO_1_NG		3.8%						$0.62	-$0.43	-$1.01						
	SLIC 2237207 TL50002 DVRB		2.1%						$0.75	-$0.92	$0.71						
	T-135 VICTVLUGO_DVRB_NG	6.1%	2.0%			$0.62	-$0.48	-$0.78	$1.23	-$1.02	-$1.46						
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1		1.6%						$2.74	-$2.30	-$2.30						
	LOSBANOSNORTH_BG		1.1%						$3.75	-$3.16	-$3.16						
	SLIC 2206489_PVCR_Out_EDLG		0.8%						$0.74	-$0.52	-$1.38						
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1		0.3%						$2.21	-$1.87	-$1.87						
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1		0.2%						$2.20	-$1.70	-$1.70						
	SLIC 2207662 NGila-HWD PVDV	1.7%				$0.43	-$0.45	$0.26									
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	5.1%	2.0%	16.7%	12.2%	-$2.59	$2.98	$0.54	-$1.00	$1.49	$0.87	-$0.75	$0.91	$0.51	-$0.89	$1.91	$0.18
	7500_SOL1_NG				1.1%										-$0.57	$0.54	-$0.57
	SLIC 2285023 PATH 15 N-S SOL				0.4%										-$2.53	$1.81	$1.81
	SLIC 2319206 HDW-HASS_SCIT				0.4%										-$4.14	$3.62	$3.69
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.9%	15.5%						$0.85			$3.34				
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.2%		1.5%		-$2.17	$1.69	$1.67				-$1.37	$0.93	$0.90			
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	6.6%	4.3%			-$1.48	$1.80	$0.96	-$1.28	$1.52	$1.98						
	PATH26_BG	1.4%				-$2.18	$1.69	$1.69									
	25201_LEWIS _230_24137_SERRANO _230_BR_1 _1	0.4%				-$4.54	$4.07	-$1.10									
SDG&E	7820_TL 230S_OVERLOAD_NG	1.6%	5.7%	3.0%	4.2%	-$0.11		$1.89	-$1.25		$6.68	-$0.29		$2.68	-$0.27	$0.22	$3.32
	IVALLY-ELCNTO_230_BR_1_1				3.2%										-$0.06		$2.98
	22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1				2.7%												$5.37
	6510 SOL1_NG				2.6%										-$4.55	$3.70	$5.05
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1				1.9%												$0.50
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1			3.2%	1.7%												$3.57
	SLIC 2300985 Hoodoo_H.Gila_S-Lin				1.6%												$2.04
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	2.2%	3.0%	0.7%	1.0%			$1.90			-$2.79			-$1.61			-$0.95
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P				1.3%										-$1.11	$0.59	$2.64
	IID-SCE_BG				1.1%												-$1.51
	SLIC 2422498 TL50001_NG				0.5%										-$0.62		$10.61
	SLIC 2474810 CFE ROA-HRA_NG				0.3%											$0.81	$16.51
	SLIC 2474667 CFE MEP-TOY_NG				0.2%											$1.09	$24.02
	SLIC 2474777 CFE_HRA-MEP_NG				0.2%											$0.90	$19.38
	SLIC 2481747 CFE MEP-TOY_NG				0.2%											$0.25	$5.21
	SLIC 2481748 CFE HRA-MEP_NG				0.2%											$0.46	$9.06
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1			0.4%	0.2%												$12.94
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.2%	26.8%	10.1%		-$0.06	-$0.21	$0.87	-$0.80	$0.51	$1.12	-$0.61	$0.31	$0.57			
	22835_SXTAP2 _230_22504_MISSION _230_BR_1A _1		0.3%	7.9%							$4.90			$3.74			
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1			1.4%										$1.57			
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1			0.4%										$4.18			
	22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1		1.2%	0.2%							$6.00			$6.48			
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	1.5%	4.2%					$4.85			$6.65						
	22448_MESAHGTS_69.0_22496_MISSION _69.0_BR_1 _1		1.4%								$2.08						
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1		0.7%						-$0.47		$3.43						
	SDGE_CFEIMP_BG		0.7%						-$1.02	-$1.02	$10.16						
	22636_PARADISX_69.0_22456_MIGUEL _69.0_BR_1 _1		0.4%								$10.92						
	MIGUEL_BKs_MXFLW_NG		0.4%								$7.94						
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P		0.4%						-$7.10	$3.95	$14.39						
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P		0.3%						-$4.89	$2.86	$9.28						
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1		0.3%						-$5.84	$4.14	$8.54						
	SOUTHLUGO_RV_BG	2.1%	0.1%			-$2.60	$1.80	$2.70	-$5.08	$3.44	$4.44						
	SLIC 2157511 LUG0-MIRA LOMA 3	4.1%				-$1.74	$1.28	$1.57									
	22136_CLAIRMNT_69.0_22140_CLARMTTP_69.0_BR_1 _1	0.5%						$3.52									
	SLIC 2196141 MIDWAY SOL1	0.4%				-$1.26	$1.04	$1.04									
	24155_VINCENT _230_24126_RIOHONDO_230_BR_1 _1	0.2%				-$4.14	$3.22	$3.57									

In the SDG&E area, the constraint with the largest impact in the fourth quarter was 7820_TL 230S_OVERLOAD_NG. This constraint was binding in about 4 percent of hours and increased prices in the SDG&E and SCE areas by $3.32/MWh and $0.22/MWh, respectively, while decreasing prices in the PG&E area by $0.27/MWh. This constraint helps protect the Imperial Valley – El Centro 230 kV line for a loss of the Imperial Valley – North Gila 500 kV line.

The second most binding constraint in the SDG&E area, mainly due to planned outages in the San Diego area, was IVALLY-ELCNTO_230_BR_1_1. This constraint only affected the SDG&E prices by about $2.98/MWh for the quarter. The 22356_IMPRLVLY_230_20118_ROA-230_230_BR_1_1 and 6510 SOL1_NG constraints were binding about 2.6 percent of the time with around $5/MWh impact on the SDG&E area prices. Other internal congestion occurred infrequently and typically had a minimal impact on overall day-ahead energy prices.

15-minute market congestion

The fourth quarter was the second full quarter for the 15-minute market. Congestion in the 15-minute market occurred less frequently than in the day-ahead market, but often had a larger price effect. Table 3.3 shows the frequency and magnitude of congestion in the fourth quarter.

Overall, the two most frequently congested constraints were the 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 (protecting for the loss of Barre – Lewis 220 kV) and 24086_LUGO_500_26105 _VICTORVL_500_BR_1_1. Located in the SCE area, these constraints were binding in about 1.8 percent and 1.2 percent of the time in the fourth quarter. The 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 constraint decreased prices in the PG&E area by about $3.47/MWh while increasing the SDG&E prices by about $1/MWh and the SCE area prices by about $8/MWh.

The 35922_MOSSLD_115_30751_MOSSLDB_230_XF_2 constraint drove 15-minute market prices up in the PG&E area by over $9/MWh in about 0.4 percent of intervals. The other remaining constraints in the PG&E area were binding in less than 0.3 percent of all intervals, but had significant negative price impact in the other load areas when binding. These constraints include 30735_METCALF_230_30042_METCALF _500_XF_13, 30880_HENTAP2_230_30900_GATES_230_BR_2_1, PATH15_S-N and 30915_MORROBAY_230_30916_SOLARSS_230_BR_2_1.

Congestion on 24138_SERRANO_500_24137_SERRANO_230_XF_2_P occurred in about 0.4 percent of intervals in the fourth quarter and increased prices in the SDG&E and SCE areas by about $5.21/MWh and $5.16/MWh respectively. This constraint decreased prices in the PG&E area by about $3.29/MWh. The second highest congested constraint in the SDG&E area was the 6510 SOL1_NG, which was congested in about 0.4 percent of intervals and increased both SDG&E and SCE area prices by $12.66/MWh and $10.79/MWh, respectively. This constraint replaced the Southern California Import Transmission (SCIT) nomogram.

Overall, congestion occurred more frequently in the day-ahead market than in the 15-minute market, but had a smaller price impact when binding. In the fourth quarter, the price impact on the most significant binding elements was larger in the 15-minute market than the day-ahead market. For instance, the 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 constraint was binding in roughly 12 percent of hours in the day-ahead market compared to around 2 percent of intervals in the 15-minute market. While this constraint increased day-ahead prices in the SCE area by about $2/MWh, it increased prices by about $7.80/MWh in the 15-minute market.

Differences in congestion in the day-ahead and real-time markets occur as system conditions change, virtual bids liquidate and constraints are adjusted to account for discrepancies between market and actual flows and to provide a reliability margin.

Table 3.3 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

		Frequency			Q2			Q3			Q4		
Area	Constraint	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2			0.4%							$9.94		
	30735_METCALF _230_30042_METCALF _500_XF_13			0.1%							$13.42	-$7.28	-$7.28
	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	2.4%	3.1%	0.3%	$5.56	-$8.32	-$8.32	$5.37	-$2.94	-$2.94	$10.09	-$10.95	-$11.64
	PATH15_S-N	0.6%		0.1%	$37.94	-$30.37	-$30.37				$37.78	-$33.75	-$31.82
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1			0.1%							$14.67	-$7.20	-$7.20
	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1		3.4%					$4.50	-$3.68	-$3.68			
	6110_TM_BNK_FLO_TMS_DLO_NG	1.5%	0.7%		$3.43	-$5.02	-$5.02	$5.42	-$7.56	-$7.56			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1		0.1%					$19.69	-$7.51	-$7.51			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		0.1%					$17.28	-$15.22	-$15.22			
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	0.4%			$13.14	-$8.17	-$8.17						
	T-135 VICTVLUGO_DVRB_NG	0.3%			$3.26	-$2.42	-$4.01						
	SLIC 2249785 ELDORADO-LUGO_1_NG	0.3%			$4.27	-$3.19	-$6.88						
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.2%	1.5%	1.8%	-$7.04	$4.50	$10.32	-$4.19	$4.75	$1.71	-$3.47	$7.82	$0.97
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.3%	0.6%	1.2%	-$0.95	$0.91	-$0.28	$5.14	-$3.84	-$3.34	$2.14	$2.30	-$0.05
	SLIC 2319206 HDW-HASS_SCIT			0.3%							-$3.76	$12.32	$12.23
	PATH26_N-S			0.1%							-$32.16	$28.88	$27.34
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1		0.6%					-$4.81	$5.81	$2.11			
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2		0.2%					-$23.39	$17.59	$17.17			
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.1%	0.1%	0.4%	-$16.35	$5.74	$29.86	-$14.44	$10.70	$37.31	-$3.29	$5.16	$5.21
	6510 SOL1_NG			0.4%							-$4.44	$10.79	$12.66
	IVALLY-ELCNTO_230_BR_1_1			0.1%							-$10.37	-$10.43	$60.75
	SLIC 2474808 CFE ROA-HRA_NG			0.1%								$2.09	$46.34
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1	0.5%		0.1%	-$2.42		$17.09						$64.91
	22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1	0.5%	1.4%				$17.69			$14.58			
	7820_TL 230S_OVERLOAD_NG	0.5%	0.7%		-$9.17		$47.97	-$4.80	-$2.86	$49.17			
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1		0.5%							$9.01			
	SCIT_BG		0.3%					-$55.33	$32.00	$35.33			
	SLIC 2377852 TL50001_NG		0.1%							$22.88			
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	0.9%					$16.02						
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	0.5%					-$17.84						
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	0.2%			-$8.01	$5.48	$11.00						
	22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3	0.1%					-$25.41						
	SOUTH_OF_LUGO	0.1%			-$11.81	$8.33	$11.45						

3.3.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional prices in the day-ahead and 15-minute markets caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is based on the average congestion component of the price as a percent of the total price during all congested and non-congested hours. This approach shows the impact of congestion when taking into account both the frequency with which congestion occurs and the magnitude of the impact.[31] The congestion price impact differs across load areas and markets.

Congestion in the day-ahead market in the fourth quarter increased prices in all load areas. In the PG&E area, load prices increased by about 0.5 percent ($0.24/MWh), while in the SCE and SDG&E areas it increased by about 1.2 percent ($0.52/MWh) and 2.4 percent ($1.07/MWh), respectively. Congestion in the 15-minute market had a significant impact in the SDG&E area where it increased the prices by about 1 percent ($0.52/MWh). In the PG&E and SCE areas, prices increased by less than $0.15/MWh (0.35 percent) and $0.25/MWh (0.6 percent), respectively. Congestion in the 5-minute market increased

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

prices in the SDG&E and SCE areas by about $1.31/MWh (3.3 percent) and $0.88/MWh (2.2 percent), respectively, while increasing PG&E area prices by about $0.07/MWh (0.2 percent).

Day-ahead price impacts

Table 3.4 shows the overall fourth quarter impact of day-ahead congestion on average prices in each load area by constraint.

The SDG&E area experienced the largest increase in day-ahead market prices from congestion, about $1.07/MWh more than the system average, while prices in the PG&E and SCE areas increased by about $0.24/MWh and $0.52/MWh, respectively. Compared to the previous quarter, PG&E congestion decreased in magnitude while the opposite occurred in the SDG&E and SCE areas.

Table 3.4 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.05	0.11%	-$0.03	-0.07%	-$0.03	-0.06%
IVALLY-ELCNTO_230_BR_1_1					$0.10	0.21%
SLIC 2422498 TL50001_NG					$0.06	0.13%
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$0.06	0.13%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.03%	$0.01	0.02%	$0.03	0.08%
SLIC 2474810 CFE ROA-HRA_NG					$0.05	0.12%
SLIC 2319206 HDW-HASS_SCIT	-$0.02	-0.04%	$0.02	0.03%	$0.02	0.03%
SLIC 2474667 CFE MEP-TOY_NG					$0.04	0.10%
SLIC 2474777 CFE_HRA-MEP_NG					$0.04	0.08%
35922_MOSSLD _115_30751_MOSSLDB _230_XF_1	$0.03	0.07%				
SLIC 2300985 Hoodoo_H.Gila_S-Lin					$0.03	0.07%
22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1					$0.03	0.07%
35922_MOSSLD _115_30751_MOSSLDB _230_XF_2	$0.03	0.06%				
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.02	0.04%				
SLIC 2285023 PATH 15 N-S SOL	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.02	0.04%				
SLIC 2481748 CFE HRA-MEP_NG			$0.00	0.00%	$0.02	0.04%
IID-SCE_BG					-$0.02	-0.04%
SLIC 2512269 SOL1	$0.01	0.01%			-$0.01	-0.01%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.01	-0.02%
SLIC 2481747 CFE MEP-TOY_NG					$0.01	0.02%
22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1					$0.01	0.02%
7500_SOL1_NG			$0.01	0.01%		
Other	$0.06	0.13%	$0.02	0.05%	$0.07	0.16%
Total	$0.24	0.5%	$0.52	1.2%	$1.07	2.4%

The IVALLY-ELCNTO_230_BR_1_1 had the largest overall impact on prices in the fourth quarter. This constraint increased prices in the SDG&E area by $0.10/MWh (0.21 percent) but had negligible impact on the other areas.

In the PG&E area, the 30915_MORROBAY_230_30916_SOLARSS_230_BR_2_1 constraint increased prices by $0.05/MWh (0.1 percent) and decreased prices in the SDG&E and SCE areas by about $0.03/MWh.

In the SCE area, the SLIC 2319206 HDW-HASS_SCIT increased the day-ahead prices by $0.02/MWh with about the same impact on SDG&E prices while decreasing PG&E area prices by the same amount.

15-minute price impacts

Table 3.5 shows the overall impact of 15-minute congestion in the fourth quarter on average prices in each load area by constraint.[32] The overall impact of congestion bumped the SDG&E area price by about $0.52/MWh (1 percent), SCE area prices by about $0.25/MWh (0.6 percent) and PG&E area prices by about $0.15/MWh (0.35 percent). The most pronounced congestion that occurred was related to the Barre – Lewis line contingencies.

Table 3.5 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.03	-0.07%	$0.14	0.32%	$0.01	0.02%
PATH15_S-N	$0.06	0.13%	-$0.05	-0.12%	-$0.05	-0.11%
6510 SOL1_NG	-$0.02	-0.04%	$0.04	0.09%	$0.05	0.11%
PATH26_N-S	-$0.04	-0.08%	$0.03	0.07%	$0.03	0.07%
IVALLY-ELCNTO_230_BR_1_1					$0.08	0.18%
SLIC 2319206 HDW-HASS_SCIT	-$0.01	-0.02%	$0.03	0.08%	$0.03	0.07%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.03	0.07%	-$0.02	-0.04%	-$0.02	-0.04%
24029_DELAMO _230_24016_BARRE _230_BR_1 _1	$0.02	0.04%	-$0.01	-0.02%	-$0.04	-0.08%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.02	0.06%	$0.03	0.06%		
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.03%	$0.02	0.04%	$0.02	0.04%
22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1					$0.05	0.11%
35922_MOSSLD _115_30751_MOSSLDB _230_XF_2	$0.04	0.09%				
SLIC 2474808 CFE ROA-HRA_NG					$0.03	0.08%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.02	0.05%	-$0.01	-0.01%	-$0.01	-0.01%
30735_METCALF _230_30042_METCALF _500_XF_13	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
40687_MALIN _500_30010_INDSPRNG_500_BR_2 _3	$0.01	0.02%	$0.01	0.02%	$0.01	0.02%
Other	$0.05	0.10%	$0.05	0.12%	$0.33	0.76%
Total	$0.15	0.35%	$0.25	0.60%	$0.52	1.19%

5-minute price impacts

After implementing the 15-minute market in May, 5-minute market congestion has had a reduced impact on overall settlements. Even so, congestion in the 5-minute market is still important and is outlined below.

Congestion in the 5-minute market occurs less frequently than in the day-ahead market, but often has a larger price effect. Overall, the most frequently congested constraint in the fourth quarter was 24016_BARRE_230_24154_VILLA PK_230_BR_1_1, which is located in the SCE area. This constraint was binding in about 5 percent of intervals and increased SCE and SDG&E area prices by about $5.45/MWh

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

and $1.96/MWh, respectively, and decreased prices in the PG&E area by $3.16/MWh when the constraint was binding. The constraint is adjusted to protect for thermal overload from the contingency loss of the Barre – Lewis 220 kV line.

The second most congested constraint was associated with 24086_LUGO_500_26105_VICTORVL _500_BR_1_1. This constraint was binding in about 3 percent of intervals and increased prices primarily in the SCE and PG&E areas by about $4.70/MWh and $4.50/MWh, respectively, while also increasing prices in the SDG&E area by about $0.60/MWh when binding.

The price impact of congestion differs across load areas and markets when taking into account the frequency with which congestion occurs and the magnitude of the impact. Overall in the fourth quarter, the impact of 5-minute market congestion was similar to the previous quarter and increased prices in all load areas. The SDG&E area prices increased by about $1.30/MWh (about 3.3 percent) from -$1.80/MWh (about 4 percent) in the previous quarter. Congestion impacts in the SCE and PG&E areas increased prices to about $0.88/MWh (about 2.2 percent) and by $0.07/MWh (0.2 percent), respectively.

3.4 Bid cost recovery

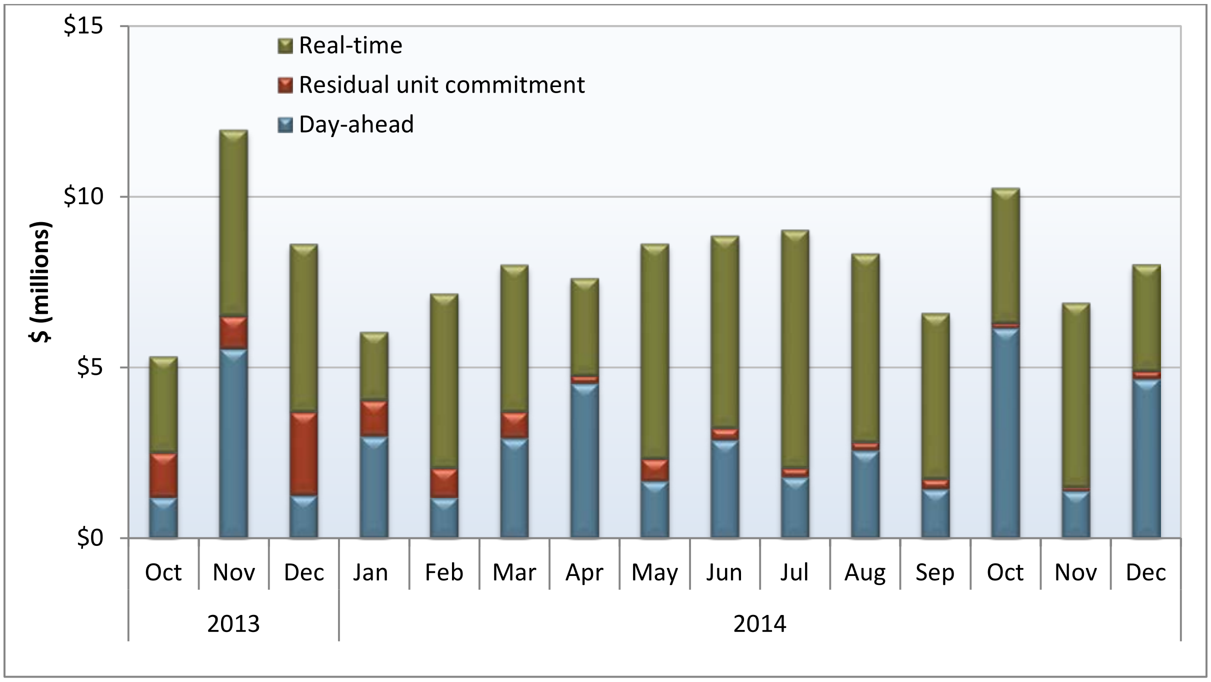
Market enhancements implemented in May brought significant changes to the bid cost recovery payment rules. Before May, bid cost recovery payments were calculated by netting all bid costs and revenues from the day-ahead, residual unit commitment and real-time markets. For instance, if a unit was committed in the day-ahead market and required bid cost recovery payments, these payments would be adjusted by any positive net revenues received in the real-time market. Beginning in May, the ISO no longer nets the costs and revenues between the day-ahead and real-time markets.[33] Instead, the ISO calculates the costs and revenues for day-ahead and real-time markets separately for each day. These changes were made to reduce incentives to self-schedule and increase incentives for suppliers to submit bids in the real-time market that reflected their actual marginal operating costs.

Before implementing these new rules, there were concerns that they could significantly increase bid cost recovery payments. Figure 3.11 shows monthly bid cost recovery payments over the past 15 months in the ISO markets.[34] DMM estimates that bid cost recovery payments were around $25 million in the fourth quarter of 2014, compared to $26 million in the fourth quarter of 2013. Total monthly bid cost recovery payments in October, November and December were about $10.3 million, $6.9 million and $8 million, respectively. The increase in the day-ahead bid cost recovery payments in December were primarily associated with commitment costs resulting from minimum online commitment constraints.

[33] The residual unit commitment and real-time markets are netted together.

[34] The ISO is still addressing calculation issues with May, June, October and November. DMM has adjusted the settlement numbers in the chart to reflect DMM's best estimate of the bid cost recovery payments for these months. DMM will update these numbers in a subsequent report after any settlements corrections have been made.

Figure 3.11 Monthly bid cost recovery payments



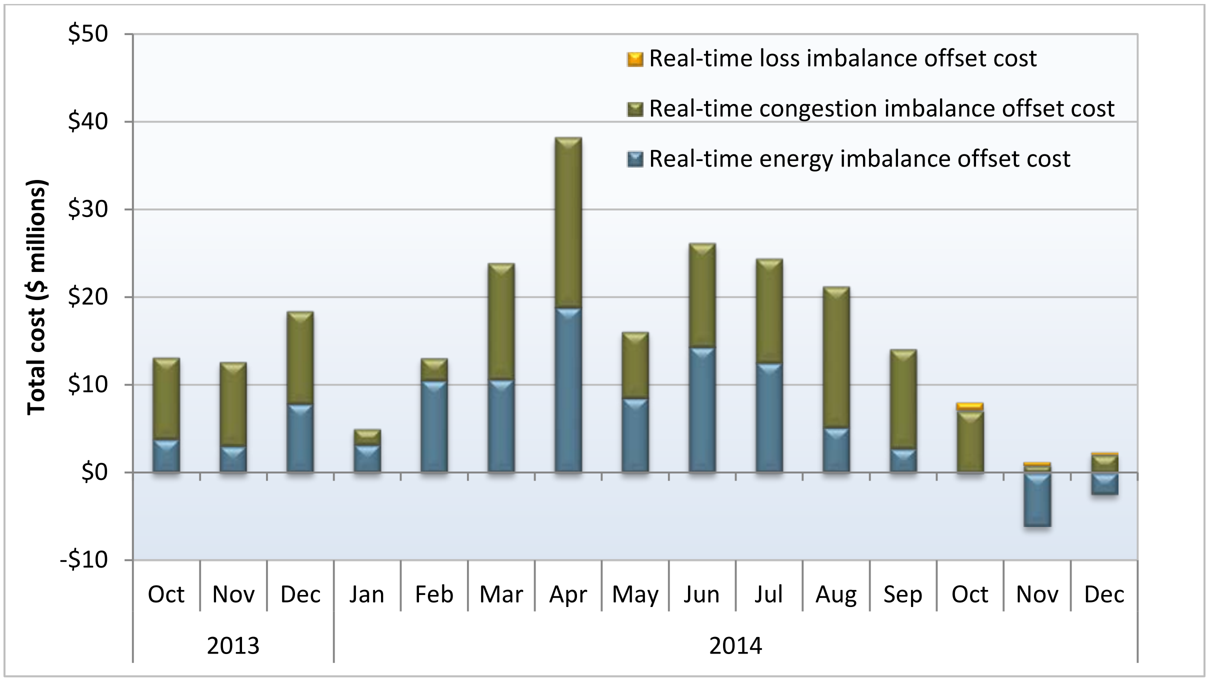
3.5 Real-time imbalance offset costs

Real-time imbalance offset costs are currently estimated to have reached historically low levels in the fourth quarter of 2014 within the ISO system. Total offset costs were about $3 million in the fourth quarter of 2014, compared to $44 million in the fourth quarter of the prior year and $60 million in the third quarter of 2014. Total real-time imbalance offset costs in the fourth quarter were the sum of approximately $10 million in congestion imbalance offset costs, $2 million in loss offset charges and an estimated credit of $9 million in energy imbalance offset costs.

Values reported here are the most current reported settlement imbalance charges, but are subject to change. In addition to the routine causes for recalculation, the ISO has determined that a metering error resulted in under-metering of actual power flow over a handful of inter-ties. Offset costs calculated on the basis of under-metered flow will be corrected. The inter-tie meter difference from actual flow is estimated to have generated approximately $19 million of real-time imbalance energy offset between June and August 2014 alone. The ISO has resolved the inter-tie metering issue. Revised settlements will reflect this change following the normal settlements timeline.

Figure 3.12 reports monthly real-time imbalance offset costs including real-time energy imbalance offset, real-time congestion imbalance offset and, for the first time, real-time imbalance loss offset costs. Until October 1, the ISO aggregated real-time loss imbalance offset costs with real-time energy imbalance costs. The loss imbalance offset accounted for approximately 54 percent of the total imbalance offset cost this quarter.

Figure 3.12 Real-time imbalance offset costs



Congestion imbalance offset costs fell substantially from $39 million in the second and third quarters of 2014 to $10 million in the fourth quarter. The current quarterly estimate is lower than any estimated quarterly congestion offset cost since the first quarter of 2013. Low real-time imbalance congestion offset is consistent with the low impact and frequency of congestion this quarter. Although real-time congestion imbalance offset costs were low this quarter, real-time congestion due to conditions unanticipated in the day-ahead market can still result in substantial imbalance offsets. Three days this quarter are currently estimated to have real-time imbalance congestion offset costs over $1 million.

The settlement values reported for the real-time energy imbalance offset include several components that are offset by settlement values elsewhere in the market and thus are not true uplift costs. For example, transmission loss obligation charges for transmission loss paybacks are currently allocated to measured demand through a separate settlements process. When a scheduling coordinator schedules imports involving certain transmission access outside of the ISO, losses associated with these imports are paid back to the appropriate balancing authority area in the form of energy. Transmission loss obligation charges to the scheduling coordinator reflect the amount paid to ISO generators to provide the transmission loss payback energy.

3.6 Convergence bidding

Beginning in May, virtual bids switched from settling against the 5-minute real-time prices to the 15-minute real-time prices for internal locations, and switched from hour-ahead prices to 15-minute prices for inter-ties.[35] All numbers reported in this section reflect the prevailing settlement rules at the time the market ran.

Participants engaging in convergence bidding continued to earn positive returns from participation in ISO markets in the fourth quarter. The net revenues from the market in these two months were about $4.3 million. Virtual supply generated net revenues of about $6.7 million, while virtual demand accounted for approximately $2.4 million in net payments to the market. The total payment to convergence bidders fell slightly to about $4 million after taking into account virtual bidding bid cost recovery charges of $0.26 million.

Offsetting virtual demand with supply bids at different locations is designed to profit from higher anticipated congestion between these locations in the real-time market. This type of offsetting bid represented about 70 percent of all accepted virtual bids in the fourth quarter, which is an increase from 67 percent in the previous quarter.

Total hourly trading volumes increased in the fourth quarter to about 4,200 MW from 3,900 MW in the previous quarter. Virtual supply averaged around 1,500 MW while virtual demand averaged around 1,200 MW during each hour of the quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 330 MW on average, a decrease from 480 MW of net virtual supply in the previous quarter.

In general for the fourth quarter, net revenues from net virtual supply positions were positive as prices were generally higher in the day-ahead market than the 15-minute market. There were few instances in December of elevated prices in the 15-minute market. As a result, net virtual demand positions were negative for the month and quarter.

Background

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similar to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the hour-ahead and the 15-minute markets, which are dispatched based on physical supply and demand alone. Virtual bids accepted in the day-ahead market are liquidated financially in the 15-minute market as follows:

- Participants with virtual demand bids cleared in the day-ahead market pay the day-ahead price for virtual demand and are then paid the 15-minute market price for these bids.
- Participants with cleared virtual supply bids are paid the day-ahead price for this virtual supply and are then charged the 15-minute market price for this supply.

Thus, virtual bidding allows participants to profit from any difference between day-ahead and 15-minute market prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to make prices in these different markets closer as illustrated by the following:

[35] Virtual bidding at the inter-ties was suspended in late 2011 but is being gradually reintroduced with the 2014 spring release. For 12 months after implementation, position limits for inter-tie virtual bids will be zero. This will be relaxed to 5 percent between 12 and 20 months, then to 25 percent between 20 to 24 months and 50 percent between 24 and 28 months. No limit will be enforced after 28 months.

- If prices in the 15-minute market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average 15-minute prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing 15-minute prices.

- If 15-minute market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[36] This would tend to increase average 15-minute market prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing 15-minute market prices.

The degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been fully assessed. However, there are settlement charges associated with virtual bidding that may prevent full convergence between the day-ahead and 15-minute prices.

3.6.1 Convergence bidding trends

Total hourly trading volumes increased in the fourth quarter to 4,200 MW from 3,900 MW in the previous quarter. These volumes have remained relatively stable for the last few quarters. On average, about 57 percent of virtual supply and demand bids offered into the market cleared in the fourth quarter, which is slightly up from 53 percent in the third quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 330 MW on average, which is a decrease from 480 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours, by about 200 MW and 570 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in hours ending 7 and 17 to 19, with the highest net virtual demand occurring in hour ending 18 at about 470 MW. In the remaining hours net cleared virtual supply exceeded net cleared demand. The highest net cleared virtual supply hours were hours ending 23 and 24 with about 630 MW and 890 MW, respectively.

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 relatively high and were consistent with price differences between the day-ahead and real-time markets for an average of 21 hours.

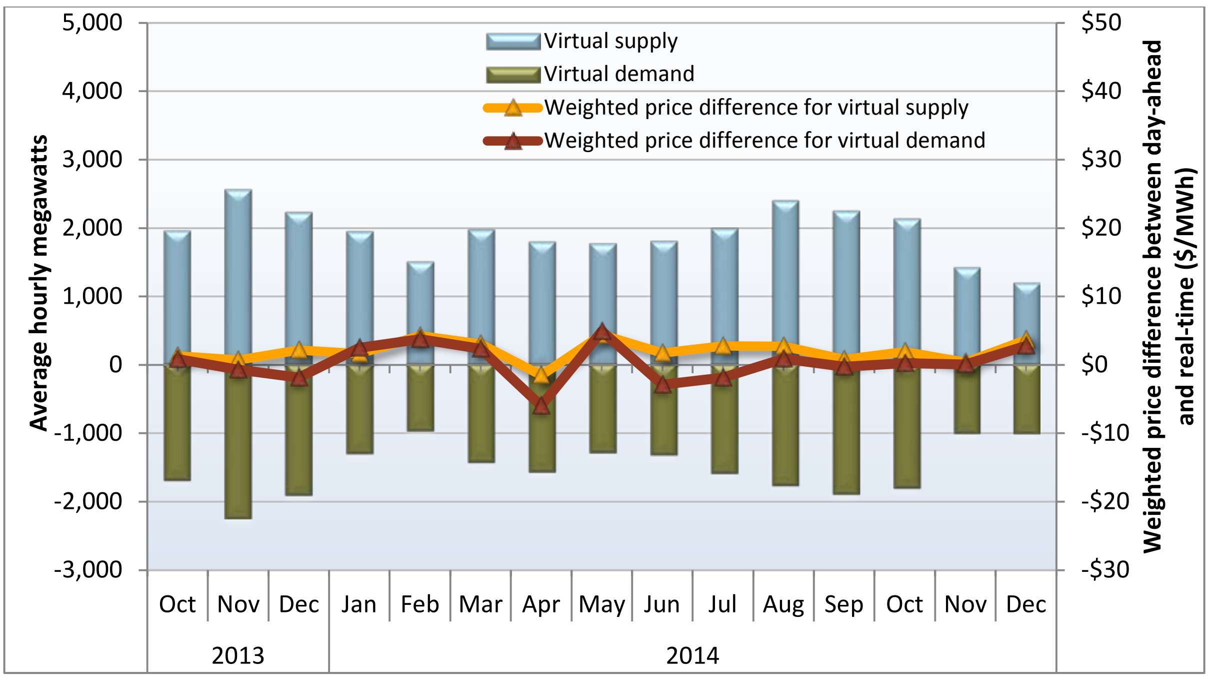
[36] Net virtual supply will not create a reliability issue because the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-optimizes the market to meet ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

Figure 3.13 compares cleared convergence bidding volumes with the volume-weighted average price difference where the virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different locations.

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

Virtual demand volumes for the month of December were inconsistent with weighted average price differences for the hours in which virtual demand cleared the market and were thus not profitable. However, in November, virtual demand positions were slightly profitable as they were consistent with the weighted average price differences.

Figure 3.13 Convergence bidding volumes and weighted price differences



Virtual supply positions continued to be consistent with the weighted average difference between day-ahead and real-time prices. The yellow line in Figure 3.13 represents the difference between the day-ahead price paid to virtual supply and the real-time market price at which virtual supply positions are liquidated, weighted by cleared virtual supply bids by time interval and location. On average, virtual supply positions have been consistently profitable since January 2012, with the exception of August 2013 and April 2014.[37]

[37] System-wide real-time price spikes, related to ramping constraints, occurred on only a handful of hours for a few days in April 2014 which caused negative revenues for virtual supply bids for the entire month.

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.[38] When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable due to congestion differences between the day-ahead and real-time markets.

In the fourth quarter, the majority of cleared virtual bids were offsetting bids. Offsetting virtual positions accounted for an average of about 920 MW of virtual demand offset by 920 MW of virtual supply in each hour of the fourth quarter. These offsetting bids represent about 70 percent of all cleared virtual bids in the fourth quarter, which is an increase from 67 percent in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

3.6.2 Convergence bidding revenues

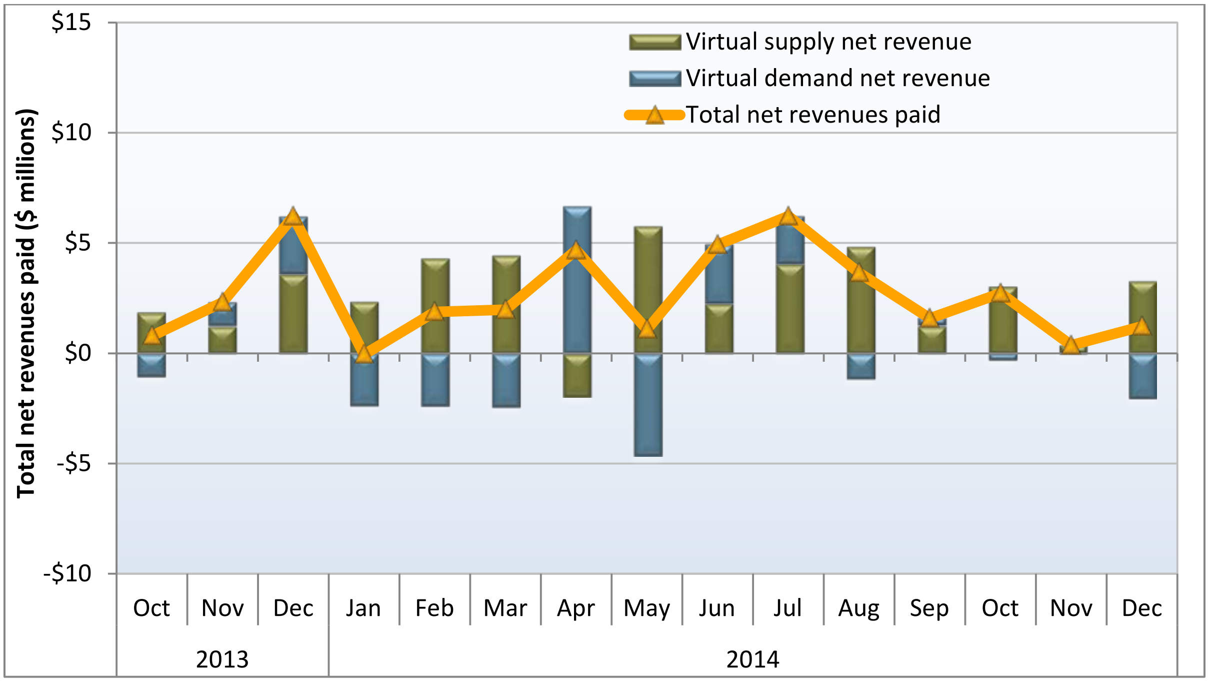
This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the fourth quarter. Similar to the previous quarter, convergence bidding participants earned positive revenue. In the fourth quarter, net revenues were about $4.3 million from revenue collected on both virtual supply and demand positions.

Figure 3.14 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $4.3 million in the fourth quarter, compared to about $9.3 million in the same quarter in 2013.
- Virtual supply revenues were most profitable in October as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply accounted for net payments of about $6.7 million during the quarter.
- Virtual demand revenues were negative in October and December and slightly positive in November. In total, virtual demand accounted for around $2.4 million in net payments to the market for the quarter.
- Convergence bidders were paid just over $4 million, after subtracting virtual bidding bid cost recovery charges of $0.26 million for the quarter.

[38] Please refer to the discussion at the end of this section for detailed analysis of bid cost recovery charges to convergence bidders.

Figure 3.14 Total monthly net revenues paid from convergence bidding



Net revenues and volumes by participant type

DMM's analysis continues to find that most convergence bidding activity is conducted by entities engaging in pure financial trading that do not serve load or transact physical supply. These entities accounted for $1.9 million (43 percent) of the total convergence bidding settlements for the fourth quarter, which is a decrease from about $8 million or nearly 85 percent of revenue gains from the same period in 2013. Physical generation and load participants accounted for about 18 percent of volume and around 35 percent of revenues, which was primarily from virtual supply positions.

Table 3.6 compares the distribution of convergence bidding cleared volumes and net revenues in millions of dollars among different groups of convergence bidding participants.[39] As shown in Table 3.6, financial entities represent the largest segment of the virtual market, accounting for about 70 percent of volumes and about 43 percent of settlement dollars. Marketers represent about 12 percent of the trading volumes and 22 percent of the settlement dollars. Generation owners and load-serving entities represent a small segment of the virtual market in terms of volumes (about 18 percent) but a significant segment of the settlements portion (35 percent).

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

Table 3.6 Convergence bidding volumes and revenues by participant type (October – December)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	998	986	1,984	-$2.1	$3.9	$1.9
Marketer	107	225	332	$0.0	$1.0	$0.9
Physical generation	149	215	364	-$0.3	$1.0	$0.7
Physical load	0	155	155	$0.0	$0.8	$0.8
Total	**1,254**	**1,581**	**2,836**	**-$2.4**	**$6.7**	**$4.3**

Virtual bid cost recovery charges

As previously noted, 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.[40] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up, minimum load, transition and energy bid costs.[41]

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[42]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[43] In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.[44] 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.

The costs associated with the two bid cost recovery charge codes for the fourth quarter totaled only about $0.26 million. Specifically, for October, November and December the costs were about $0.01

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

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

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

[43] For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

[44] For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

million, $0.06 million and $0.19 million, respectively. As noted earlier, the total estimated net revenue for convergence bidding was around $4.3 million for this period. Total convergence bidding revenue is reduced slightly to about $4.03 million when accounting for this adjustment.

4 Special Issues

4.1 Inter-tie bidding and scheduling

The amount of inter-tie imports and exports cleared between the day-ahead and real-time markets has not changed considerably after implementing 15-minute scheduling on the inter-ties in May. However, there was a significant decrease in the amount of inter-tie bids offered into the real-time market and a corresponding increase in the volume of self-scheduled inter-tie transactions. While this overall trend continued into the fourth quarter, there was an uptick in the volume of economic bidding in real time in December for both hourly and 15-minute transactions.

Figure 4.1 and Figure 4.2 show the level of self-scheduled imports and exports compared to the total offered imports and exports in the day-ahead and real-time markets, respectively. Initially, the market experienced a considerable increase in the quantity of self-scheduled inter-tie import bids in both the day-ahead and real-time markets following the new inter-tie rules implemented in May. In the second part of the year, especially in the fourth quarter, the quantity and share of self-scheduled import bids in the day-ahead market decreased while self-scheduled export bids increased slightly. However, in the real-time market most of the inter-tie import bids remained self-scheduled. Around 85 percent of import bids and 12 percent of export bids in the hour-ahead market were self-schedules between May and December. In the first four months of 2014, 44 percent of import bids and 8 percent of export bids were self-scheduled in the hour-ahead market.

Figure 4.1 and Figure 4.2 also show an increasing trend in the volume of both import and export bids by the end of the year. This increase may be related to the Bonneville Power Administration's implementation of 15-minute scheduling on October 21 or other potential factors.

As has been the case since May, the majority of economic bidding on the inter-ties was in the hour-ahead market. In the fourth quarter, around 85 percent of economic import bids and around 84 percent of economic export bids were hourly blocks. Inter-tie resources seldom used the hourly economic bid block option with a single intra-hour economic schedule change. Around 15 percent of economic import bids and 16 percent of economic export bids were 15-minute economic bids, as shown in Figure 4.3. The overall bidding pattern between hourly and 15-minute bids was similar for import bidding compared to the third quarter. There was an increase in the percentage of hourly block bids for exports in the fourth quarter compared to the third quarter.

Figure 4.1 Volume of self-scheduled and economic import and export bids in the day-ahead market

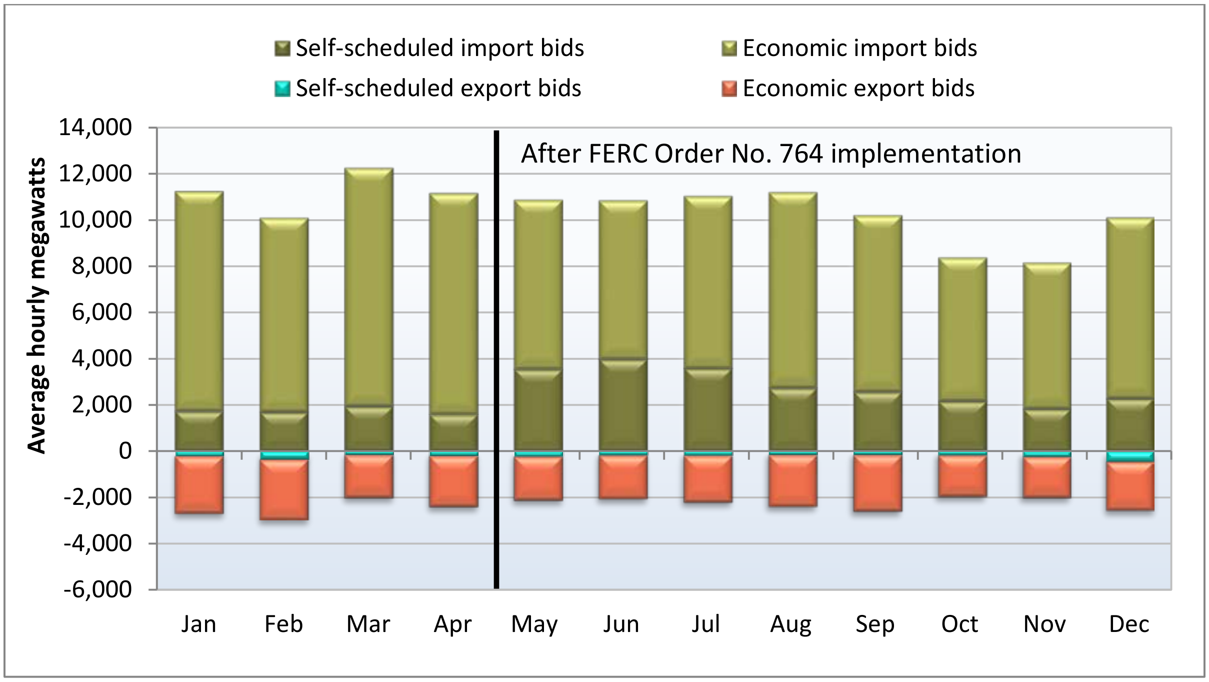


Figure 4.2 Volume of self-scheduled and economic import and export bids in the real-time market

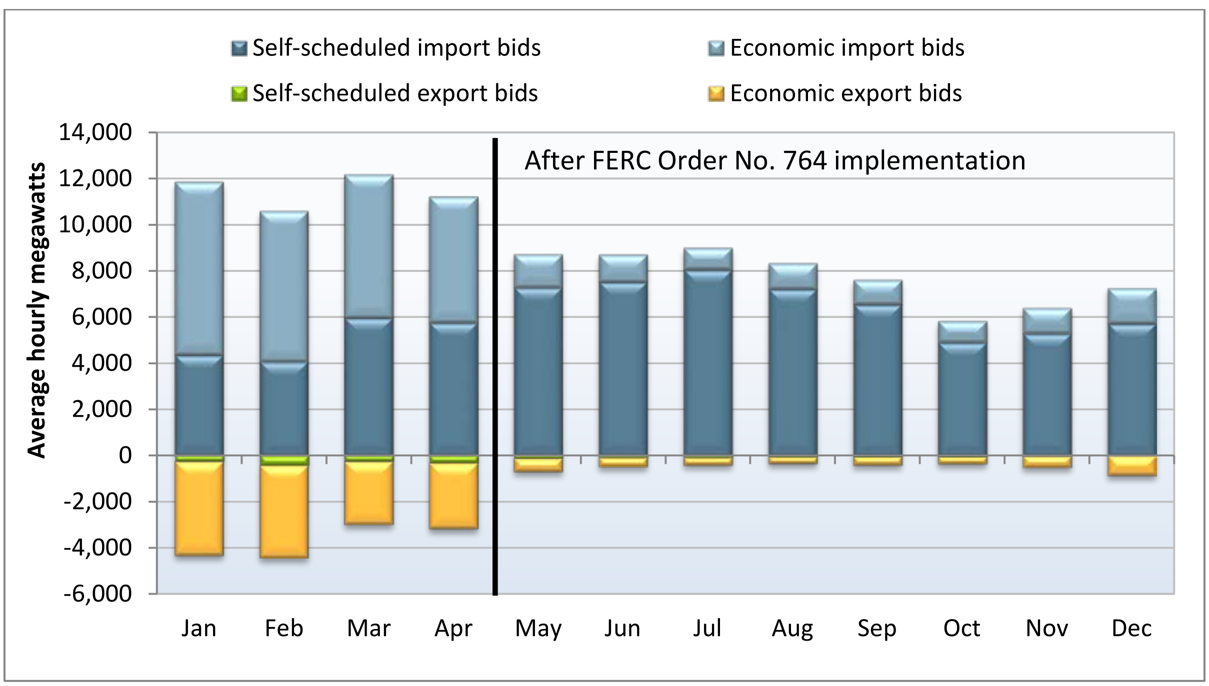


Figure 4.3 Economic import and export bids by bidding option