California Independent System Operator Corporation

California ISO

Q3 2014 Report on Market Issues and Performance

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Executive summary

This report provides highlights of significant market changes and general market performance during the third quarter of 2014 (July – September).

- Energy market prices remained highly competitive through the third quarter of 2014. The overall combined wholesale cost of energy was just slightly above prices that the Department of Market Monitoring (DMM) estimates would result under highly competitive conditions when suppliers bid at or near marginal costs.
- Day-ahead prices in the third quarter were similar to the first and second quarters of 2014.[1] Hour-ahead prices began diverging below day-ahead and real-time prices in April. While this trend continued through the third quarter, price convergence improved.
- The 15-minute market prices were slightly lower than average prices in the day-ahead market in July and August, but slightly higher than average day-ahead prices in September. The 5-minute market prices were slightly lower than average day-ahead prices in all months of the quarter. This continued the trend observed in the final months of last quarter as average prices in the 15-minute market exceeded prices in the 5-minute market in all months of this quarter.
- Both 15-minute and 5-minute market prices reached above $250/MWh in only around 0.4 percent of all intervals.
- The 15-minute and the 5-minute markets had a similar percentage of negative prices, about 0.7 percent and 1 percent, respectively. Since there were more available units with quick ramping capabilities and higher loads in the summer months, rapid changes in wind and solar generation did not frequently cause over-generation conditions and the frequency of negative price spikes decreased notably.
- Congestion increased compared to the previous quarter. Much of the congestion that did occur was related to modeled flow adjustments to constraints related to the Gates – Gregg 230 kV line in the Pacific Gas and Electric area. Another source of congestion was in the Southern California Edison area, related to the Barre – Villa Park 220 kV line.
- Following the FERC Order No. 764 market changes implemented in May, a majority of imports scheduled in the day-ahead market have been self-scheduled in the real-time market.
- The amount of additional import and export bids offered in the real-time market also dropped following the FERC Order No. 764 changes implemented in May. This trend continued through the third quarter. This has led to concerns about potential liquidity issues when addressing unscheduled flows (i.e., loop flows) and imbalance in real time.
- The drop in import and export bids may be attributed to a combination of factors. While the ISO allows 15-minute scheduling of imports and exports, some imports may not be modified on a 15-minute basis due to resource or scheduling constraints outside the ISO system. If these imports and

[1] This is true when excluding the extreme February gas price increase on a couple days as a result of significant cold weather throughout the county, which affected natural gas storage inventories and natural gas supplies.

exports are offered as fixed hourly blocks, suppliers face a risk that the 15-minute prices used to settle accepted bids may be lower than the suppliers' hourly bid price for imports (or higher than the bid price for exports).

- Real-time imbalance offset costs totaled almost $70 million in the third quarter of 2014, which is about 13 percent lower than the $79 million value in the second quarter. Real-time imbalance energy offset costs include several components that are offset by settlement values elsewhere in the market and thus are not true uplift costs. One cost in this category is transmission loss obligation charges, which are currently included in the real-time imbalance energy offset and allocated to measured demand through a separate settlements process. These charges may account for up to $9 million of real-time energy offset costs in the third quarter.

- As part of the market changes taking effect in May, bid cost recovery payments are now calculated separately for the day-ahead and real-time markets without any netting of the costs and revenues across the markets. This change was made to encourage greater and more competitive participation in the real-time market. Despite these changes, bid cost recovery payments did not increase. Bid cost recovery payments were around $24 million in the third quarter of 2014, compared to $26 million in the third quarter of 2013.

- Net revenues received by convergence bidders, after accounting for bid cost recovery charges, were about $9.8 million in July and August.[2] Virtual supply revenues were most profitable in August as day-ahead prices were generally higher than 15-minute market prices. In August, virtual demand tended to be unprofitable due to lower 15-minute market prices.

- Flexible ramping costs were around $0.6 million, down from around $2.3 million in the previous quarter. ISO operators decreased the flexible ramping requirement during the morning and evening periods in the third quarter, averaging nearly 310 MW, which was down from 400 MW in the previous quarter. Higher availability of ramping capacity because of higher loads may have also contributed to lower costs.

- Revenue shortfalls for congestion revenue rights, before accounting for auction revenues, reached around $162 million in the first three quarters of 2014. The congestion revenue rights balancing account had an $81 million net revenue shortfall after including auction revenues. The shortfall in the third quarter alone, before accounting for auction revenues, was about $88 million, equal to approximately 63 percent of all congestion revenue. This shortfall was largely due to discrepancies between the network models used when allocating congestion revenue rights and the transmission capacity actually available. In 2012 and 2013, the balancing account had annual surpluses of $23 million and $3 million, respectively.

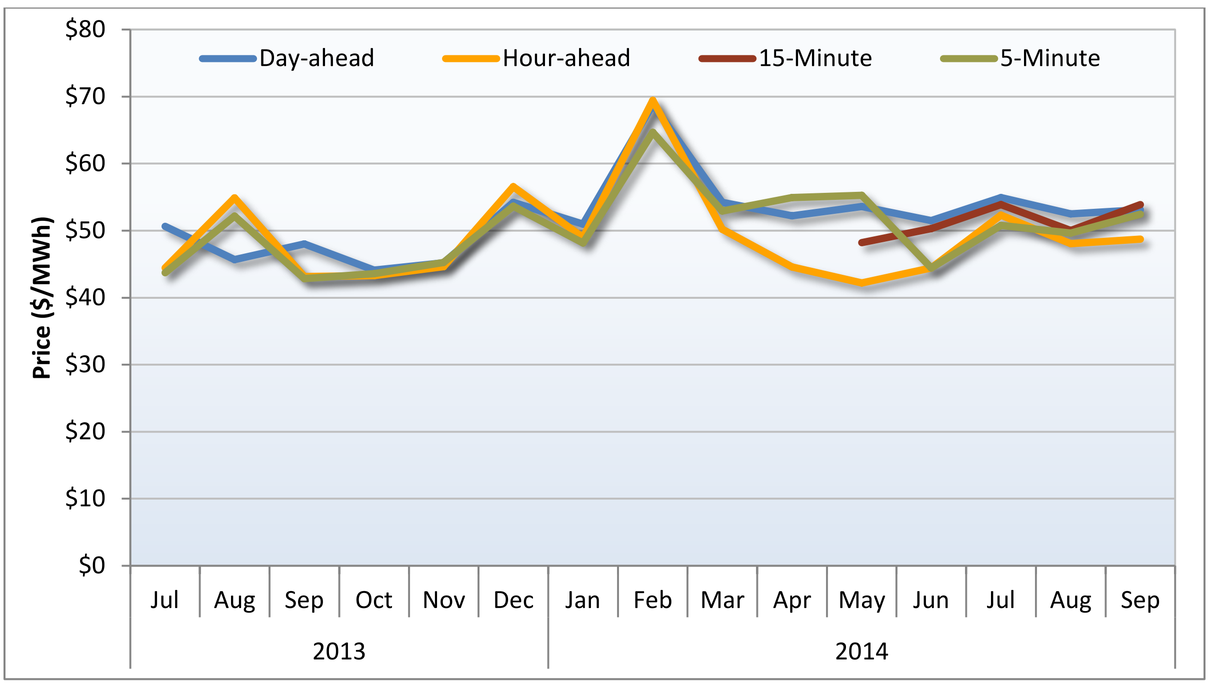
[2] Due to data issues, convergence bidding price and payment reporting only covers the months of July and August.

Energy market performance

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

Improved convergence between average day-ahead and real-time system energy prices. Average system energy prices in the 15-minute market (excluding congestion) were lower than average prices in the day-ahead market in July and August, but slightly higher than day-ahead prices in September (see Figure E.1). The 5-minute price levels were lower than hour-ahead and 15-minute prices in most peak and off-peak periods in the quarter, while each of the three categories of real-time prices were lower than day-ahead prices, on average. Hour-ahead prices were consistently lower than all other markets throughout the quarter, but to a lesser degree than in April and May. 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.

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



Price variability decreases in the third quarter. Price spikes above $250/MWh in the 15-minute market during the third quarter occurred in only 0.4 percent of all intervals. The frequency of prices over $250/MWh in the 5-minute market decreased to 0.4 percent of 5-minute intervals compared to 1.3 percent of intervals in the second quarter. Negative prices below $0/MWh occurred in about 0.7 and 1 percent of all intervals in the 15-minute and 5-minute markets, respectively. This decrease in positive and negative price variability is partly due to increased ramping capability and higher loads in the summer months that minimize the impact of sudden changes in renewable generation on real-time prices.

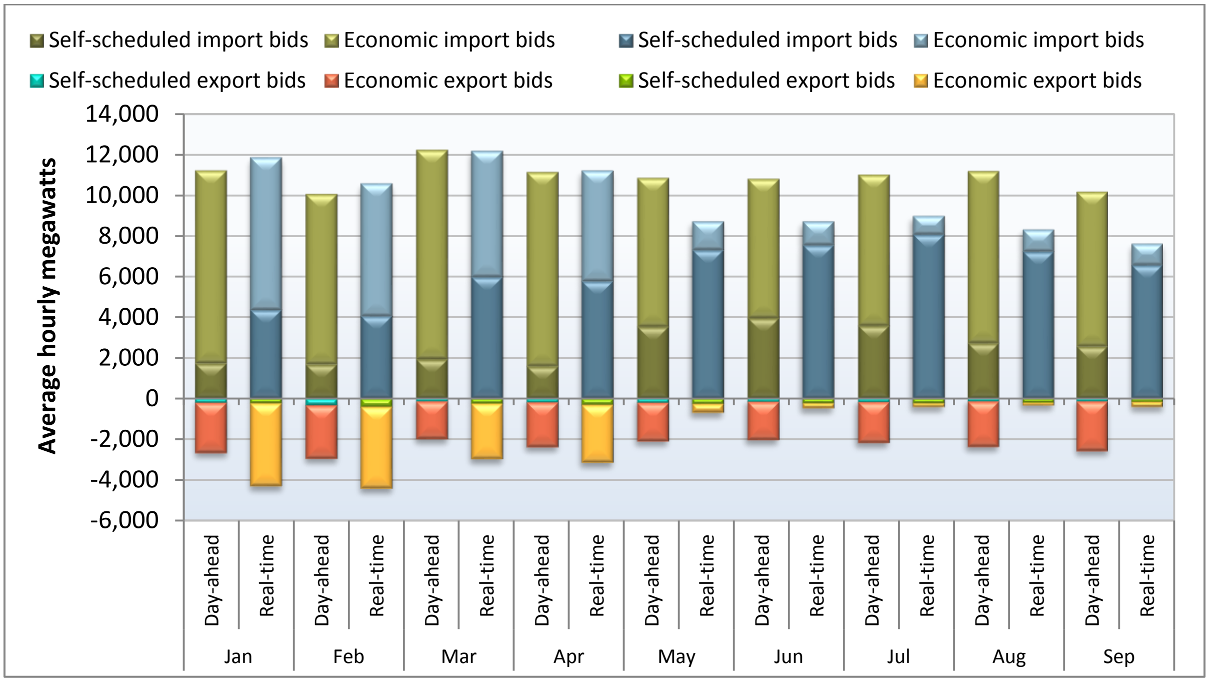
The impact of congestion on day-ahead and real-time prices remained low. Congestion in the third quarter increased compared to the second quarter. Much of the congestion that did occur was related to modeled flow adjustments to constraints related to the Gates – Gregg 230 kV line in the PG&E area. Another source of much of the congestion was in the SCE area, related to the Barre – Villa Park 220 kV line. However, although overall congestion costs were low, revenue inadequacy for congestion revenue rights increased relative to 2013. In the third quarter, the revenue shortfall was approximately equal to 63 percent of all congestion revenue in the quarter.

Real-time congestion and energy imbalance offset costs were similar to costs in the previous quarter. Real-time imbalance offset costs totaled almost $70 million in the third quarter of 2014, approximately 20 percent greater than the $57 million value in the third quarter of the prior year, and slightly below the value in the second quarter of 2014. Total real-time imbalance offset costs in the third quarter were the sum of approximately $39 million of congestion imbalance offset costs and $29 million in energy imbalance offset costs. Currently, energy imbalance offset costs in the first three quarters of 2014 ($92 million) exceed energy imbalance offset costs for all of 2013 ($57 million). As discussed in further detail in Chapter 2, real-time energy offset costs include several components that are offset by settlement values elsewhere in the market and thus are not true uplift costs.

Real-time economic import and export bid quantities remained relatively low. The amount of inter-tie imports and exports cleared between the day-ahead and real-time markets has not changed considerably after implementing the market changes 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 (see Figure E.2). The most striking change occurred in the real-time market where most of the inter-tie import and export bids were self-scheduled or scheduled in the day-ahead with no economic bid to adjust in real-time. This trend continued in the third quarter.

Since implementation of the FERC Order No. 764, there are three options for offering an inter-tie bid economically into the real-time market: 1) hourly bid, 2) hourly bid with an opportunity for one change per hour and 3) bid for 15 minute change. The majority of real-time economic bidding on the inter-ties was in the hour-ahead market. In the third quarter, around 84 percent of economic import bids and around 62 percent of economic export bids were hourly blocks. The inter-tie resources seldom used the hourly economic bid block option with a single intra-hour economic schedule change. Only about 16 percent of economic import bids and 37 percent of economic export bids were 15-minute economic bids.

Figure E.2 Volume of self-scheduled and economic import and export bids



Bid cost recovery payments remain constant. Market enhancements in May also brought significant changes to the bid cost recovery payment rules. Previously, bid cost recovery payments from the day-ahead and real-time markets netted costs and revenues for the day. 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. However, bid cost recovery payments were around $24 million in the third quarter of 2014, compared to $26 million in the third quarter of 2013. Total bid cost recovery payments in July and August were around $9 and $8 million, respectively, similar to May and June totals. A slight decrease occurred in September with costs totaling $7.5 million.

Flexible ramping constraint payments decreased. The flexible ramping constraint is designed to help mitigate short-term deviations in load and supply between the real-time commitment and dispatch models (such as load and wind forecast variations and deviations between generation schedules and output). Total payments to generators for the flexible ramping constraint were around $0.6 million, compared to around $2.3 million in the previous quarter. ISO operators decreased the flexible ramping requirement during the morning and evening periods in the third quarter, averaging nearly 310 MW, which was down from 400 MW in the previous quarter. The decrease in procurement levels contributed to the decrease in payments.

Special issues

Revenue adequacy for congestion revenue rights

The market for congestion revenue rights is designed such that congestion rent collected from the day-ahead energy market is sufficient to cover payments to congestion revenue rights holders. This is referred to as revenue adequacy. However, the congestion revenue rights balancing account had an $81 million net revenue shortfall in the first nine months of 2014 after including auction revenues. In 2012 and 2013, the balancing account had annual surpluses of $23 million and $3 million, respectively.

The shortfalls in the third quarter were due in part to differences between the network transmission model used in the congestion revenue rights process and the day-ahead market model. Notably, congestion differences occurring on Magunden to Vestal nomogram area constraints, the Helms Pump nomogram constraint and the Warnerville to Wilson transmission lines, which were exacerbated this year by low hydro conditions due to the drought, accounted for more than half of revenue inadequacy in the third quarter.

1 Recent market changes

The ISO implemented numerous significant changes to the markets on May 1. The primary change was related to FERC Order No. 764, which required 15-minute scheduling of inter-ties. This section provides a brief background review of market changes and their effects in the third quarter. The market changes include the following:

- Initiating a financially binding 15-minute market to facilitate renewable energy generation. This was done by enabling scheduling and settling of inter-tie and internal resources in the 15-minute market.
- Allowing participants additional options to schedule inter-ties in real time using a variety of different options, including hourly block self-scheduling and economic bidding, hourly block bidding with one change in the 15-minute market, and 15-minute scheduling.
- Settling convergence bidding in the 15-minute market with a phased reintroduction of inter-tie convergence bids. Inter-tie convergence bidding position limits were set to zero for the first year, which is to be followed by a gradual increase afterwards.
- Considering the residual unit commitment schedule when validating the day-ahead pre-schedule e-tags. This was done in concert with implementing convergence bidding at the inter-ties.
- Lowering the bid floor from -$30/MWh to -$150/MWh. This change was intended to provide incentives for generation to bid downward dispatch into the market economically.
- Breaking out day-ahead bid cost recovery calculations from both residual unit commitment and real-time bid cost recovery calculations. For instance, any net revenues received in the day-ahead market would no longer be net against real-time and residual unit commitment costs, and vice versa. The residual unit commitment and real-time markets are netted together.
- Changing how variable energy resources bid and schedule into the market. Specifically, a subset of variable energy resources, participating intermittent resources, submitting either a self-schedule or economic bid in real time will be scheduled and settled in the 15-minute market at the minimum of the bid-in value and the most recent forecast value for the average of the three 5-minute intervals making up that interval.
- Allowing reliability demand response resources to be dispatched as part of the market optimization during a system emergency. When an emergency condition is declared, reliability demand response resources can now enter the bid stack at prices between $950/MWh to $1,000/MWh.

Given that a few months have passed since implementing these new features, some trends have begun to emerge. These trends and observations include:

- Day-ahead electricity prices in the third quarter were similar to the previous quarter. Hour-ahead prices were lower than all other market prices in both peak and off-peak periods, though to a lesser degree than in the second quarter.
- For July and August, 15-minute market prices were slightly lower than day-ahead market prices for both peak and off-peak periods. In September, 15-minute market prices were slightly higher than day-ahead market prices. Peak and off-peak 5-minute market prices were slightly lower than both day-ahead and 15-minute market prices in all months of the quarter.

- Since May, the vast majority of inter-tie import and export bids in the hour-ahead market have been self-scheduled, 87 and 46 percent respectively, which is a significant change from before the market changes in May. This has created concerns about potential liquidity problems in the 15-minute market but has not caused any significant reliability issues.
- DMM has not seen significant changes in bid cost recovery as a result of the changes in the bid cost recovery rules. DMM estimates that bid cost recovery payments were around $24 million in the third quarter of 2014, compared to $26 million in the third quarter of 2013.
- No reliability demand response resources were registered or available for dispatch in the ISO market during the third quarter.

1.1 Background

Several enhancements were made to the ISO market on May 1. Most notably, FERC Order No. 764 required the ISO to establish 15-minute intra-hour schedule changes along inter-ties to facilitate the integration of large amounts of renewable variable energy resources. The ISO went beyond the minimum requirements outlined in the order to implement a number of other market changes aimed at achieving additional benefits, including:

- More granular scheduling of resources, which was intended to accommodate scheduling variable energy resources over the inter-ties as well as allowing all resources to be scheduled more effectively with shortened forecast lead times.
- Reducing settlement uplift charges attributed to settling inter-tie resources at hourly prices while settling internal resources at 5-minute prices. With the exception of hourly block scheduled inter-tie resources, which are scheduled in the hour-ahead market, inter-tie and internal resources are now scheduled in the same 15-minute market run and all inter-tie and internal resources are settled at the same 15-minute market price.
- Complying with FERC Order No. 764 requirements to allow for 15-minute energy inter-tie scheduling, while including provisions for hourly inter-tie transactions to remain.
- Correcting the problems that led to suspension of convergence bidding at the inter-ties.[3]

The new real-time market includes both 15-minute and 5-minute financially binding schedules and settlement. The 15-minute market produces schedules and prices for all resources, including internal and inter-tie transactions. Differences between 15-minute schedules and day-ahead schedules settle at the 15-minute market prices.

The real-time market maintains the 5-minute dispatch for internal resources, participating load, and dynamically scheduled inter-tie transactions. Differences between 5-minute market dispatches and 15-minute market schedules settle at the 5-minute price.

[3] Although convergence bidding at the inter-ties has been reinstated, a position limit was initially set to zero until the market changes have been in place for 12 months. This will gradually increase until 28 months after implementation when the limits will be removed.

Results from the 15-minute market produce schedules and prices in an optimization that begins 37 minutes before the applicable interval, compared to 75 minutes prior to the change. This is designed to incorporate the most current forecast for renewable generation and reduce lead time and forecast error.

The real-time market continues to include an hour-ahead scheduling process. However, it is only used to schedule inter-tie transactions that must be fixed for the hour. These fixed hourly schedules are no longer guaranteed the price projected by the hour-ahead scheduling process. Rather, they are paid the price in each of the 15-minute settlement intervals during the hour they are scheduled.

The ISO continues to settle load in the real-time market at load aggregation point prices calculated using an average of the 15-minute and 5-minute prices. The prices are weighted by the respective load forecasts used by the 15-minute and 5-minute market runs. Load continues to be metered hourly but is settled on a 5-minute basis.

Many options for scheduling inter-tie transactions were implemented to accommodate the 15-minute market structure, including:

- **15-minute economic bid:** Market participants have the option to submit economic bids that the ISO can schedule in 15-minute intervals based on price. These transactions are settled at the 15-minute price.
- **Fixed hourly self-schedules:** Market participants can submit fixed self-schedules for the hour. These transactions are settled at the average 15-minute price over the operating hour.
- **Fixed hourly economic bid:** Market participants can submit economic bids for inter-tie transactions that are a fixed quantity for the hour and that the ISO schedules in the hour-ahead scheduling process based on price. These transactions are settled at the average 15-minute price over the operating hour.
- **Fixed hourly economic bid with single intra-hour schedule change:** Similar to the fixed hourly economic bid option above, market participants can submit economic bids for inter-tie transactions that are a fixed quantity for the hour and that the ISO schedules based on price. However, this option allows for the schedule to be changed once per hour during the 15-minute market. These transactions are settled against 15-minute market prices.
- **Dynamic transfer:** Market participants continue to be able to establish dynamic transfer arrangements that enable 5-minute dispatch and settlement of inter-tie transactions. These are settled similar to internal generation.

A penalty is applied if an import from a variable energy resource routinely submits high forecasts to the hour-ahead process which could displace other inter-tie resources. This penalty or the 5-minute price, depending on the circumstances, is also applied to other inter-tie schedules that are not delivered.

In addition to the changes regarding 15-minute scheduling, several other changes were also introduced as part of the May market enhancements. These include:

Bid floor

Negative bids serve an important function in the spot markets by allowing resources to indicate their costs for curtailing energy output and to provide demand (including exporters) the flexibility to increase their energy purchases during times of excess supply. On May 1, the bid floor was lowered to a hard bid floor of -$150/MWh from a soft bid floor of -$30/MWh.[4] This change was primarily intended to provide incentives for generation to bid downward dispatch into the market economically.

Bid cost recovery

Prior to May, bid cost recovery for market participants was calculated by using any net revenues received in the day-ahead market to offset net real-time costs, and vice versa. After May 1, the ISO no longer nets the costs and revenues between the day-ahead and real-time market. Instead, the ISO calculates the costs and revenues for day-ahead and real-time markets separately for each day. This was intended to provide an incentive to increase economic bidding in the real-time market.

In addition to the net revenue calculation change, two inter-tie bid options are eligible for bid cost recovery payments: both 15-minute economic and dynamic transfer bids.

Variable energy resources

The spring release introduced a new settlement and scheduling option for variable energy resources.[5] An eligible intermittent resource can now choose to be scheduled and settled as a participating intermittent resource.[6] Alternatively, eligible intermittent resources had the option of applying for participating intermittent resource program (PIRP) protective measure status within 30 days of FERC Order No. 764 implementation.[7] An eligible intermittent resource that did not qualify for protective status or choose to be a participating intermittent resource will be scheduled and settled as a regular generating unit.

Participating intermittent resources submitting either a self-schedule or economic bid in real time will be scheduled and settled in the 15-minute market at the minimum of the most recent forecast value (averaged over the three 5-minute intervals making up that interval) and the bid-in or self-scheduled value.

[4] This change was also intended to eliminate inconsistencies between the scheduling run and the pricing run. Previously, bids could be submitted below the bid floor and included in the market solution but were not allowed to set the price. Having a hard bid floor eliminated these inconsistencies. For more information see: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/PriceInconsistencyMarketEnhancements.aspx.

[5] A variable energy resource is defined in the ISO tariff as a resource that has an energy source with the following characteristics: renewable, cannot be stored by the facility owner or operator, and has variability that is beyond the control of the facility owner or operator.

[6] A participating intermittent resource (PIR) is an eligible intermittent resource which fulfills several additional requirements including providing the meteorological and production data necessary for the ISO to produce a forecast. An eligible intermittent resource is defined in the ISO tariff as "A Variable Energy Resource that is a Generating Unit or Dynamic System Resource subject to a Participating Generator Agreement, Net Scheduled PGA, Dynamic Scheduling Agreement for Scheduling Coordinators, or Pseudo-Tie Participating Generator Agreement." The detailed requirements for eligible intermittent resource status are detailed in Appendix Q: http://www.caiso.com/Documents/AppendixQ_EligibleIntermittentResourcesProtocolEIRP_May1_2014.pdf.

[7] Section 4.8.3.1 of the ISO tariff outlines the requirements for PIRP protective measure settlement. Currently, there are nine resources being settled under PIRP protective measures with total capacity of over 500 MW. Resources that choose to be settled under PIRP protective measures will lose that status should they submit an economic bid in the real-time market and will be settled as specified in section 11.12 of the tariff.

1.2 General market performance

This section provides summary highlights of select energy market performance in the third quarter. As the market has been operating with the new enhancements for a few months, some trends can be noted. Even so, DMM cautions that conditions can still change as a result of shifting market dynamics both within and outside of the California ISO. DMM continues to monitor market performance and notes the following observations since implementation of these market changes.

Real-time imbalance energy

Beginning in May, incremental or decremental changes to day-ahead schedules are financially settled through a two-step process in the real-time market. First, imbalance is between day-ahead and 15-minute energy schedules, then the imbalance is between 15-minute and 5-minute energy schedules. Similar to the previous quarter, in the third quarter about 80 percent of physical imbalance energy was settled in the 15-minute market, whereas only around 20 percent was settled in the 5-minute market. Thus, this relationship is important for understanding the relative weights associated with prices in this new market structure after the launch of the 15-minute market.

Energy prices

As noted above, most real-time market settlement occurs based on the 15-minute market. This change appears to have had little impact on day-ahead market prices in either peak or off-peak hours, which could be affected by changes in convergence bidding. Hour-ahead prices have remained lower than the prices in all other markets; this trend began in April prior to the market changes. These prices were likely affected by increases in unscheduled wind and solar generation, as well as large volumes of inter-tie self-schedules. While hour-ahead prices have remained lower than the other markets, the divergence decreased in the third quarter. Price convergence among the day-ahead, 15-minute and 5-minute markets improved relative to the second quarter of 2014, but diverged compared to other periods.

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 implementation of the May market changes. However, there was a significant decrease in the amount of inter-tie bids offered into the real-time market. These trends continued in the third quarter.[8]

Figure 1.1 shows the level of self-scheduled imports and exports compared to the total offered imports and exports. The market experienced a considerable increase in the quantity of self-scheduled inter-tie bids in both the day-ahead and real-time markets following the new inter-tie rules implemented in May. The most striking change occurred in the real-time market where most of the inter-tie import and export bids were self-scheduled. Around 87 percent of import bids and 46 percent of export bids in the hour-ahead market were self-schedules between May and September. In the first four months of 2014,

[8] The Bonneville Power Administration began allowing 15-minute scheduling on October 21. In addition, 15-minute changes are not allowed on the PDCI and IPPDC inter-ties.

44 percent of import bids and only 8 percent of export bids were self-scheduled in the hour-ahead market.

Figure 1.1 Volume of self-scheduled and economic import and export bids

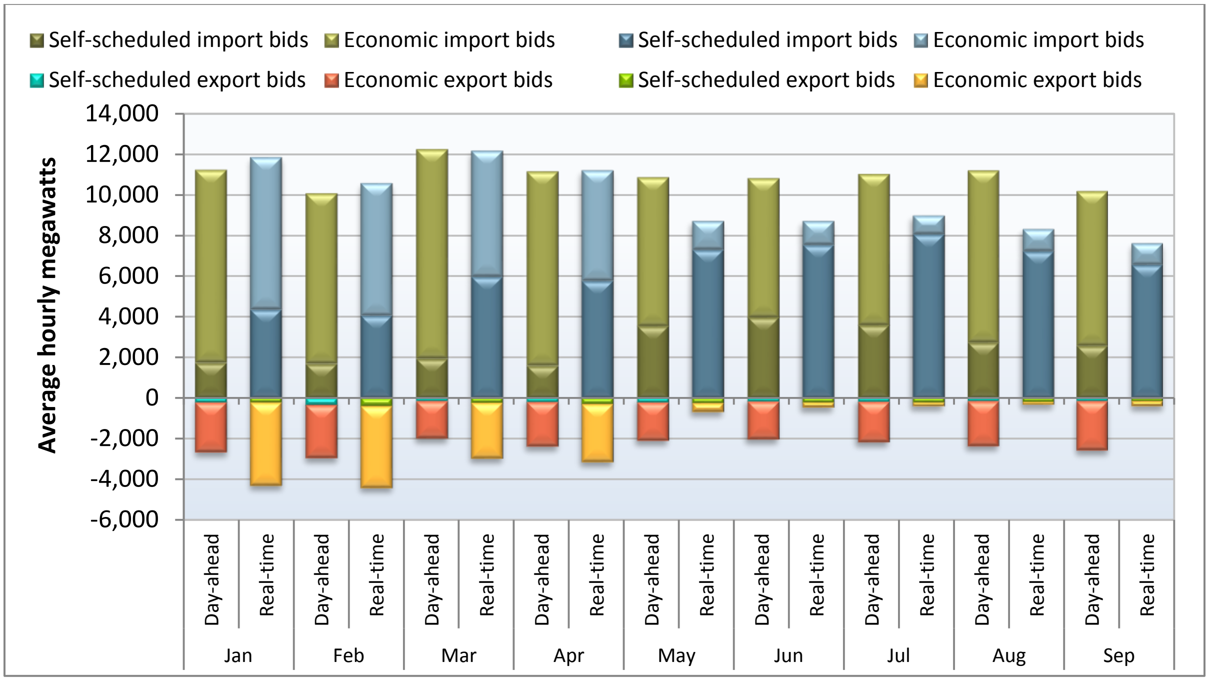
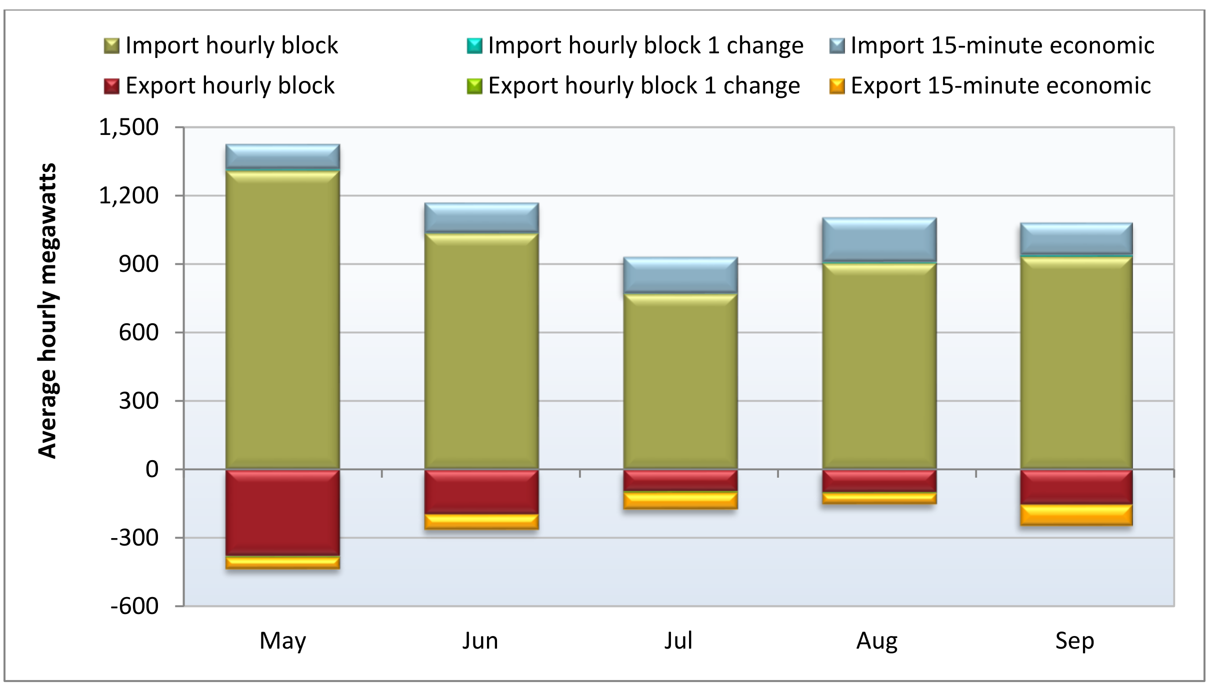


Figure 1.2 Economic import and export bids by bidding option



The majority of economic bidding on the inter-ties was in the hour-ahead market. This translated to very limited levels of economic inter-tie bids in the 15-minute market. In the third quarter, around 84 percent of economic import bids and around 62 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 16 percent of economic import bids and 37 percent of economic export bids were 15-minute economic bids, as shown in Figure 1.2.

Bid cost recovery

Stakeholders were concerned that bid cost recovery payments would increase in May due to changes in the netting of day-ahead and real-time costs and revenues. However, there does not appear to have been a significant increase in bid cost recovery payments as a result of the changes in the day-ahead and real-time netting rules.

DMM estimates that bid cost recovery payments were around $24 million in the third quarter of 2014, compared to $26 million in the third quarter of 2013. Total bid cost recovery payments in July and August were around $9 million and $8 million respectively, which is similar to May and June totals. A slight decrease occurred in September with a total of around $7.5 million, which was primarily due to decreases in both day-ahead and real-time payments. Further detail is provided in Section 2.5.

Variable energy resources

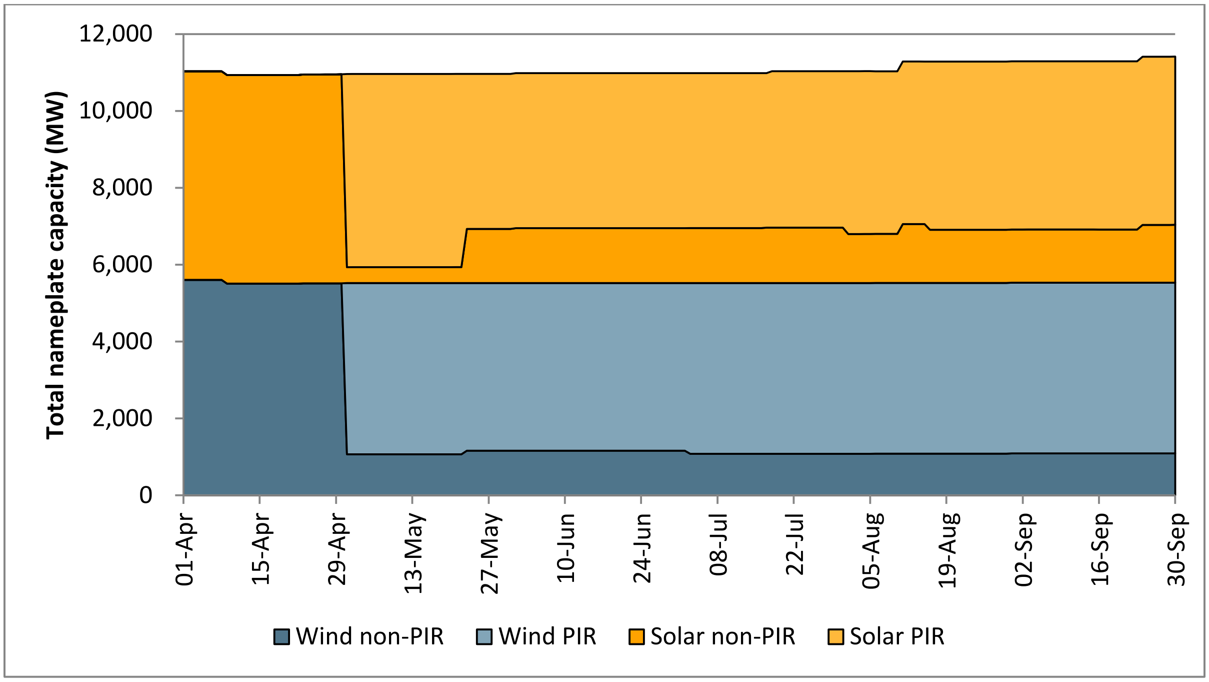
Market changes implemented in May also introduced a new settlement and scheduling option for variable energy resources. An eligible intermittent resource can choose to be scheduled and settled as a participating intermittent resource.

Participating intermittent resources submitting either a self-schedule or economic bid in real time will be scheduled and settled in the 15-minute market at the minimum of the bid-in value and the most recent forecast value for the average of the three 5-minute intervals making up that interval. As an alternative to using the ISO forecast, scheduling coordinators may choose to submit their own forecasts. The scheduling coordinator forecast is then used for both scheduling and settlement in place of the ISO forecast. Although multiple resources have qualified to use their own forecast, very few have chosen to do so.

Figure 1.3 illustrates the total nameplate capacity of wind and solar resources by day in the second quarter of 2014, by participating intermittent resource status. As indicated by the figure, most wind and solar capacity in May qualified as participating intermittent resources. The decrease in participating intermittent resource capacity in late May was due to the re-categorization of resources that were assigned to participating intermittent resource status before the ISO had acquired the data necessary to establish a forecast. This implementation error was rectified several weeks after rollout.

Prior to the May implementation of these changes, DMM had expressed concerns that scheduling coordinators submitting their own forecasts might use an inaccurate forecast to reserve inter-tie capacity that would not then be available to inter-tie supply resources with fixed hourly schedules. DMM has not identified any issue at this time with respect to this concern and will continue to monitor for this going forward.

Figure 1.3 Nameplate capacity of wind and solar by participating intermittent resource status



2 Market performance

This section highlights key performance indicators of third quarter market performance:

- Day-ahead prices in the third quarter were similar to the second quarter prices in both peak and off-peak periods.
- Hour-ahead prices were lower than all other market prices in both peak and off-peak periods, but converged better with other market prices in the third quarter compared to the second quarter.
- For July and August, 15-minute market prices were slightly lower than day-ahead market prices for both peak and off-peak periods. In September, 15-minute market prices were slightly higher than day-ahead market prices.
- Peak and off-peak 5-minute market prices were slightly lower than both day-ahead and 15-minute market prices in all months of the quarter.
- In the third quarter, both 15-minute and 5-minute market prices reached above $250/MWh in only around 0.4 percent of all intervals.
- The 15-minute and the 5-minute markets had a similar percentage of negative prices, about 0.7 percent and 1 percent, respectively. Because more ramping capacity was online and loads were higher in the summer months, rapid changes in wind and solar generation did not cause over-generation conditions as frequently, and, therefore, the frequency of negative price spikes decreased notably.
- Flexible ramping constraint payments were $0.6 million in the third quarter, down from about $2.3 million in the second quarter.
- Congestion in both the day-ahead and 5-minute markets increased in the third quarter; however, the percentages and costs remain historically low. Congestion in the 15-minute market was also low.
- Bid cost recovery payments were around $24 million in the third quarter of 2014, compared to $26 million in the third quarter of 2013.
- Real-time imbalance offset costs settlement values totaled almost $70 million in the third quarter of 2014, approximately 20 percent higher than the $57 million value in the third quarter of 2013.
- Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 480 MW on average, an increase from 430 MW of net virtual supply in the previous quarter.
- Total convergence bidding revenue for July and August, adjusted for bid cost recovery costs, was about $9.8 million.[9]

[9] Due to data issues, the convergence bidding price and payment reporting does not cover the month of September. This will be updated for the next quarterly report.

2.1 Energy market performance

This section assesses the efficiency of the energy market 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 2.1 and Figure 2.2 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 did not exhibit much monthly variability in both peak ($54/MWh) and off-peak ($41/MWh) periods. Overall, the 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 $4/MWh. Hour-ahead off-peak prices averaged nearly $5/MWh lower than day-ahead prices.
- Peak period average system prices in the 15-minute market were lower than day-ahead market prices in July (about $1/MWh) and August (about $2.50/MWh) while slightly higher in September ($0.75/MWh). In July and August, 15-minute prices in off-peak periods were about $1.50/MWh lower than day-ahead prices, while only minimally lower ($0.25/MWh) in September.
- In the third quarter, average peak system prices in the 5-minute market were lower than day-ahead prices in July, August and September by $4/MWh, $3/MWh and $0.70/MWh, respectively. Off-peak 5-minute prices were also lower than day-ahead prices in July, August and September by $3.50/MWh, $2.70/MWh and $0.70/MWh, respectively.

Figure 2.3 further illustrates the market prices on an hourly basis in the third quarter. Hour-ahead prices were the most volatile during the morning ramping period and were consistently lower than all other markets during the evening peak period.

In general, the 15-minute market prices followed the day-ahead market prices closely, although in one hour (hour ending 19) the 15-minute market prices were on average about $4/MWh lower than day-ahead prices during the quarter.

Figure 2.3 also shows that the average hourly 5-minute prices were lower than day-ahead prices for most of the day, except for the evening peak hours ending 19 and 20. This is typically a transition period when solar electricity generation is rapidly ramping down while other generating units prepare to compensate with a steep upward ramping period. For instance, 5-minute market prices exceeded day-ahead market prices, on an average basis, by about $3.50/MWh in hour ending 20.

Figure 2.1 Average monthly on-peak prices – system marginal energy price

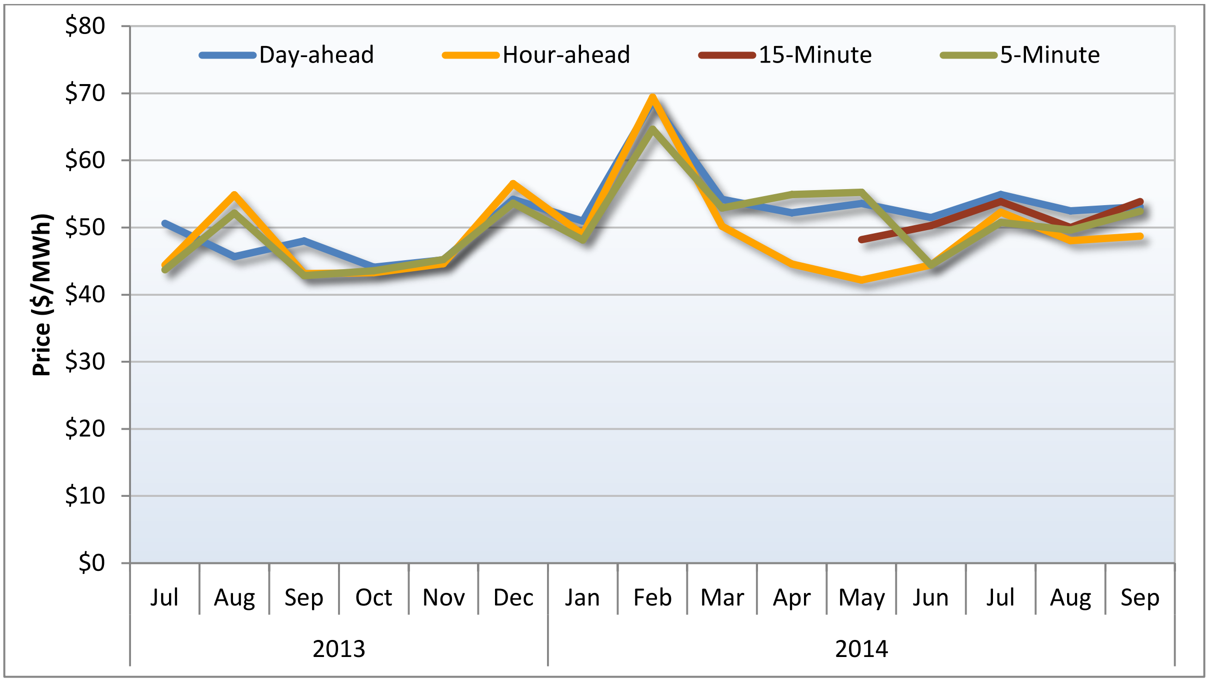


Figure 2.2 Average monthly off-peak prices – system marginal energy price

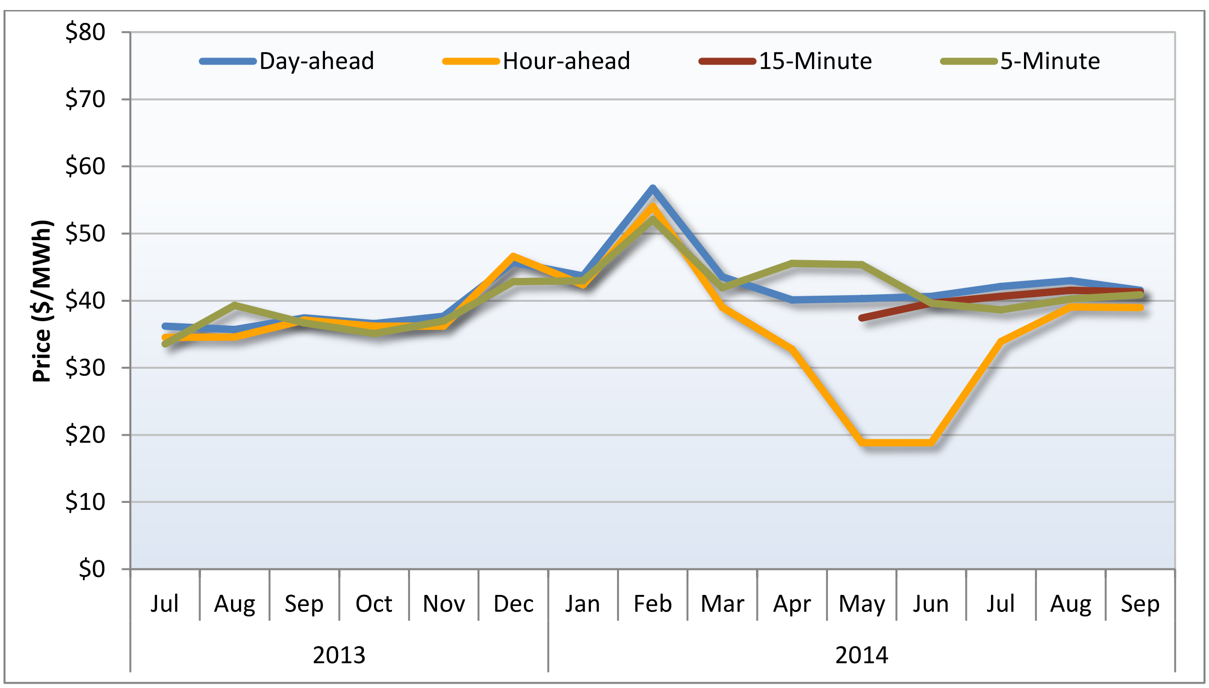
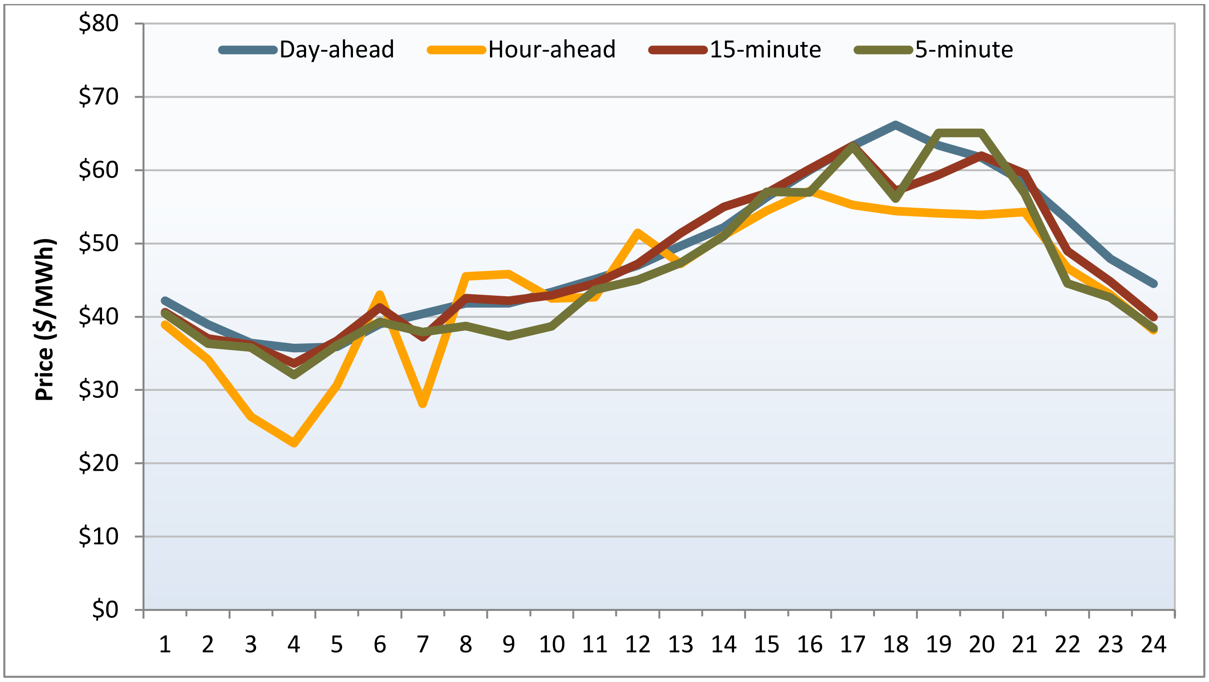


Figure 2.3 Hourly comparison of system marginal energy prices (July – September)



2.2 Real-time price variability

Historically, 5-minute real-time market prices have been highly volatile, with periods of both extreme positive and negative price spikes. In many instances, this price variability was the result of relaxing the power balance constraint in order to resolve the feasibility of the dispatch.[10] With the implementation of the new 15-minute market in May, price variability in the 5-minute market now has a lower impact as there is less settlement against the 5-minute real-time price.

Overall, both 15-minute and 5-minute market prices were stable in the third quarter with regards to positive price spikes. For instance, both 15-minute and 5-minute market prices reached above $250/MWh in only around 0.4 percent of all intervals.

DMM reviewed the energy imbalance between the day-ahead and real-time markets and found that, for the third quarter, about 80 percent of imbalance energy occurred in the 15-minute market and about 20 percent of imbalance energy occurred in the 5-minute market. Thus, the variability of the 15-minute and 5-minute market prices needs to be understood through this context.

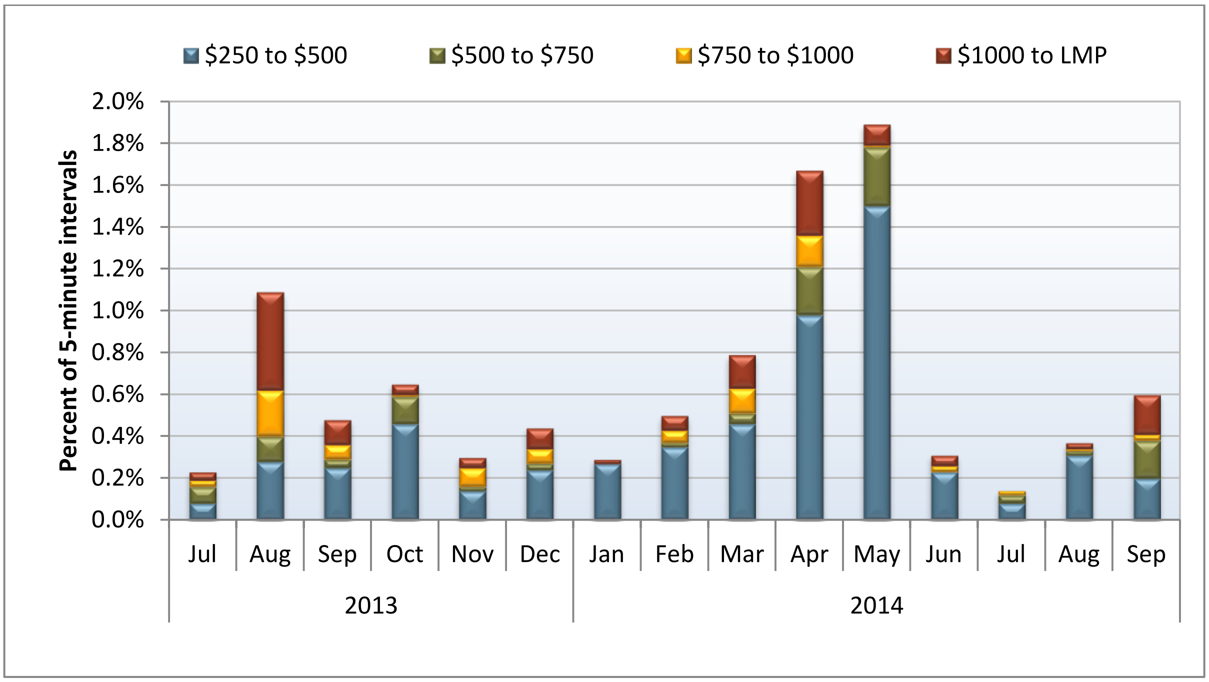
Figure 2.4 shows the frequency of positive price spikes that occur in the 5-minute market. In the third quarter, the frequency was about 0.4 percent, compared to 1.3 percent in the second quarter of 2014. The overall frequency of 5-minute price spikes is low compared to previous periods. The chart shows an increase in the frequency of price spikes in April and May followed by a significant decrease in the

[10] 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.

following months.

The relatively high frequency of positive spikes in the spring was partly due to ramping limitations resulting from rapid decline of solar generation during the late afternoon and unexpected drops in wind generation. The 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. A late summer heat wave caused a surge in both the frequency and level of price spikes in September.

Figure 2.4 Frequency of positive 5-minute price spikes (all LAP areas)



With regards to negative prices in the third quarter, the 15-minute and 5-minute markets had a similar percentage of negative prices, about 0.7 percent and 1 percent, respectively. Figure 2.5 shows the frequency of negative price spikes in the past five months in the 15-minute market. Figure 2.6 shows the frequency of negative price spikes in the 5-minute market for the past 15 months.

Negative prices in May and June were partly due to periods of over-generation resulting from unscheduled wind and solar generation. Specifically, unscheduled solar generation resulted in situations of over-generation during the rapid morning ramping hours. Since there were higher loads and more ramping capacity in the summer months, rapid changes in wind and solar generation did not cause over-generation conditions as frequently. Therefore, the frequency of negative price spikes decreased notably in the third quarter in both the 15-minute and 5-minute markets.

Figure 2.5 Frequency of negative 15-minute price spikes (all LAP areas)

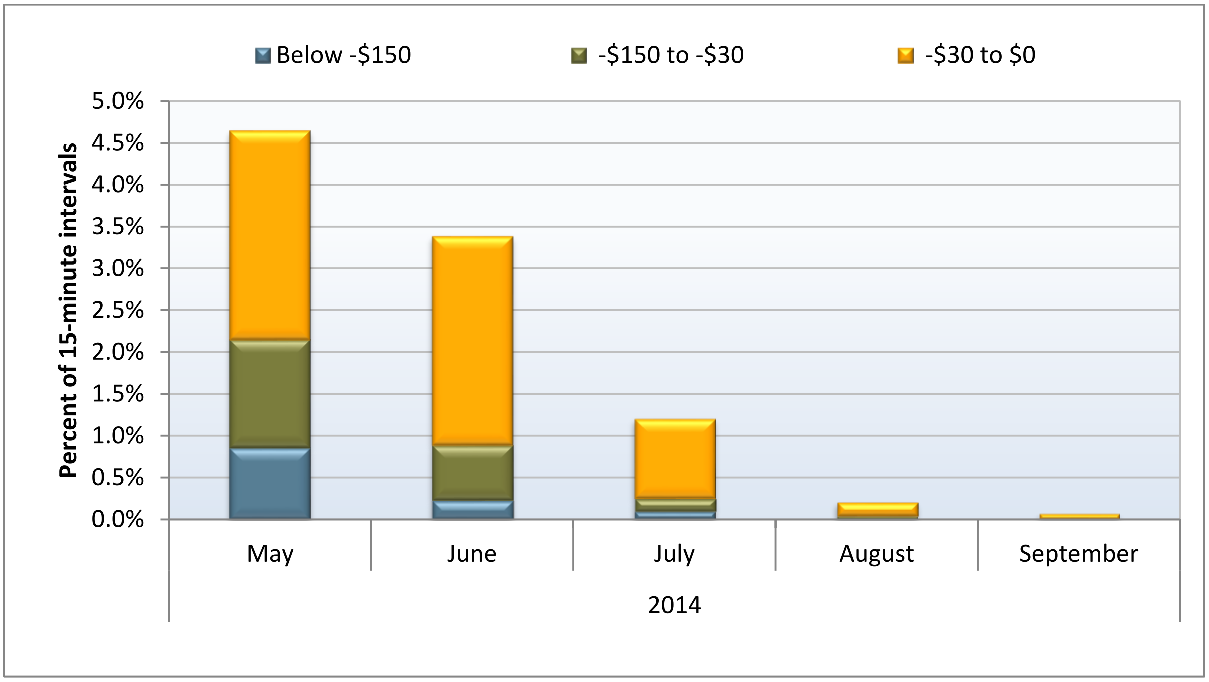
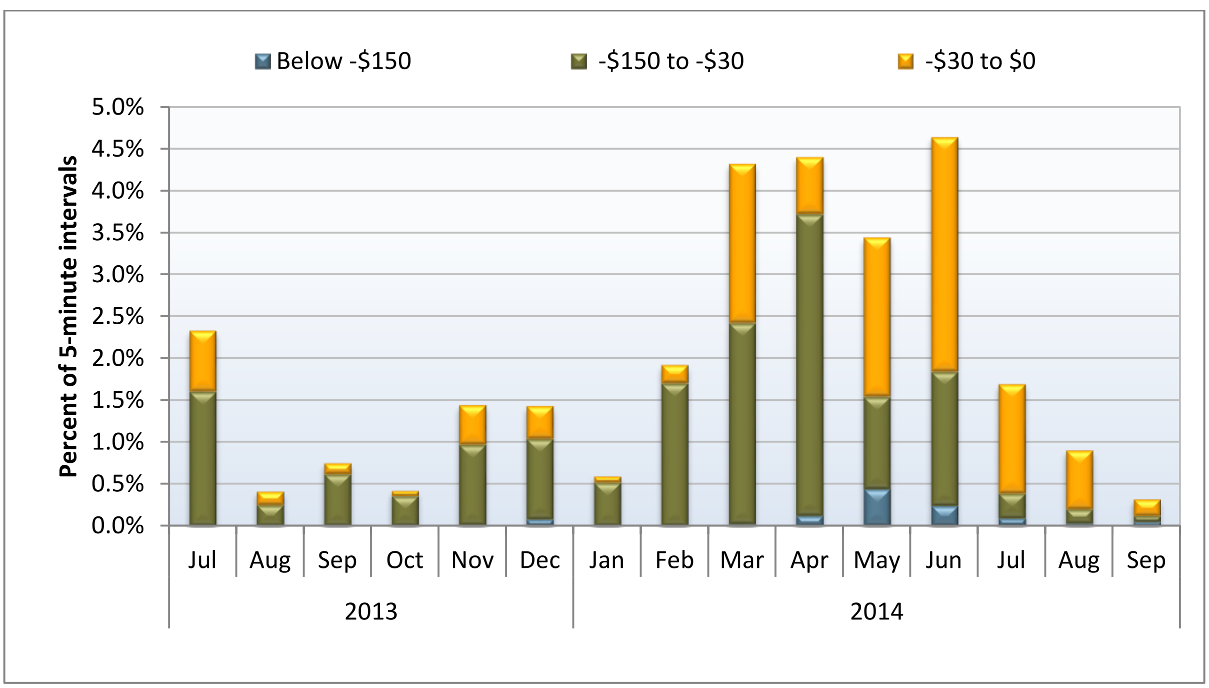


Figure 2.6 Frequency of negative 5-minute price spikes (all LAP areas)



2.3 Flexible ramping constraint performance

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

- Flexible ramping costs were around $0.6 million in the third quarter, down from around $2.3 million in the previous quarter.
- ISO operators adjusted the flexible ramping requirement consistently during the morning and evening periods in the second quarter, averaging nearly 310 MW, which is down from 400 MW in the previous quarter.

Background

The ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute market in December 2011.[11] The constraint is only applied to internal generation, dynamic inter-ties and proxy demand response resources. ISO operators adjust the flexible ramping requirement level to ensure enough upward ramping flexibility, particularly during ramping periods. After an empirical study, the ISO lowered the maximum adjustment for the flexible ramping constraint from 900 MW to 600 MW in January 2014.[12] The default requirement was set to 300 MW in the third quarter, but was rarely adjusted to the maximum of 600 MW.

If sufficient capacity is online, the ISO 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 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.[13]

Payments to the generators

Total payments for flexible ramping resources in the third quarter were around $0.6 million, down from around $2.3 million in the previous quarter.[14] Table 2.1 provides a review of monthly flexible ramping constraint activity in the 15-minute market. The table highlights the following:

- The flexible ramping constraint was binding in around 3 percent of intervals, down from 7 percent in the previous quarter.

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

[12] These limits are outlined in Operating Procedure 2250: http://www.caiso.com/Documents/2250.pdf.

[13] The penalty price associated with procurement shortfalls is set to just under $250.

[14] 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. Assessment of these costs is complex and beyond the scope of this analysis.

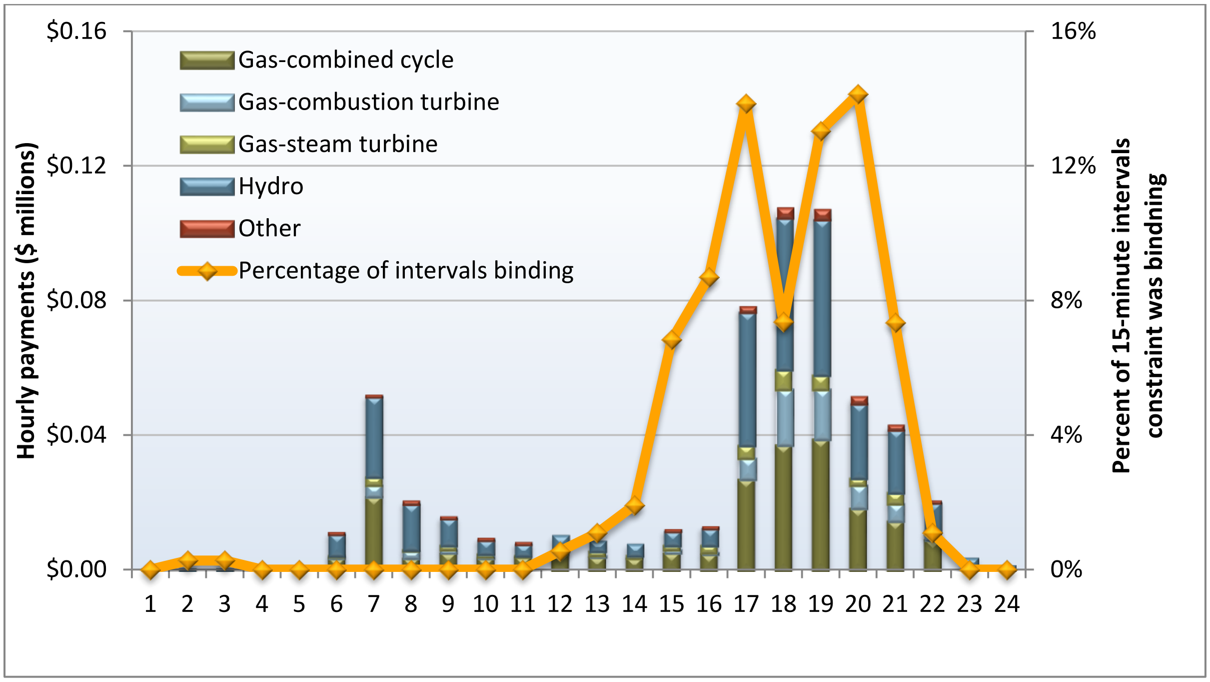
- The frequency of procurement shortfalls decreased to 0.1 percent for all 15-minute intervals compared to 0.3 percent in the previous two quarters.
- The average shadow price when the flexible ramping constraint was binding was about $36/MWh, up from $33/MWh in the previous quarter.

Table 2.1 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	Jul	$0.90	10%	0.4%	$36.19
2013	Aug	$1.51	14%	0.7%	$42.22
2013	Sep	$0.84	7%	0.2%	$34.83
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

Most payments for ramping capacity occurred during the evening peak hours. Figure 2.7 shows the hourly flexible ramping payment by technology type during the third quarter. As shown in this figure, the highest payment periods were during hours ending 7 and between 17 and 21. Natural gas fired capacity accounted for about 52 percent of these payments with hydro-electric capacity accounting for 46 percent.

Figure 2.7 Hourly flexible ramping constraint payments to generators (July – September)



2.4 Congestion

Congestion within the ISO system in the third quarter increased compared to the previous quarter. This affected overall prices in the day-ahead and real-time markets more than in the previous two quarters.[15]

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

Much of the congestion was related to unscheduled flows, planned outages and the operation of the Helms Pump in the PG&E area. 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.

[15] Since the implementation of the market changes in May, DMM has increased focus on real-time congestion analysis in the 15-minute market as opposed to the 5-minute market. The majority of real-time settlement now occurs in the 15-minute market.

2.4.1 Congestion impacts of individual constraints

Day-ahead congestion

Compared to previous quarters, both the frequency and impact of congestion in the day-ahead market increased in the third quarter.

In the PG&E area, 30875_MC CALL_230_30880_HENTAP2_230_BR_1_1 and 30880_HENTAP2 _230_30900_GATES_230_BR_2_1 were the most congested constraints in the day-ahead market.

- The 30875_MC CALL_230_30880_HENTAP2_230_BR_1_1 constraint was binding in about 34 percent of hours and the 30880_HENTAP2_230_30900_GATES_230_BR_2_1 line was binding in about 21 percent of hours.
- When 30875_MC CALL_230_30880_HENTAP2_230_BR_1_1 was constrained, prices in the PG&E area increased by about $1.82/MWh while prices in the SCE and SDG&E areas decreased by $1.56/MWh.
- When 30880_HENTAP2_230_30900_GATES_230_BR_2_1 was constrained, prices in the PG&E area increased by about $2/MWh while prices in the SCE and SDG&E areas decreased by $0.56/MWh.

These constraints, located in the Fresno area, are 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 third quarter. The constraint is to protect for thermal overload from the contingency loss of the Barre – Lewis 220 kV line. This constraint was congested in about 17 percent of hours due to contingencies. When this constraint was binding, the SCE and SDG&E area prices increased by about $0.91/MWh and $0.51/MWh, respectively, while price decreased in the PG&E area by about $0.75/MWh.

The second most congested constraint in the SCE area was Magunden – Vestal #2, which was binding in about 16 percent of the hours due to the potential loss of the Magunden – Vestal #1 220 kV line. These constraints incorporated mitigation for low hydro generation, especially during peak load conditions. When congestion occurred on this constraint, prices in the SCE area increased by $3.34/MWh, while the PG&E and SDG&E area prices remained unchanged.

In the SDG&E area, the constraint with the largest impact in the third quarter was 24086_LUGO_500_26105_VICTORVL_500_BR_1_1. This constraint was binding in about 10 percent of hours and increased prices in the SDG&E and SCE areas by $0.57/MWh and $0.31/MWh, respectively, while decreasing prices in the PG&E area by $0.61/MWh. This constraint was binding due to a contingency on the Hoodoo Wash – North Gila 500 kV line.

The second most binding constraint in the SDG&E area, due to planned outages in the San Diego area, was 22835_SXTAP2_230_22504_MISSION_230_BR_1A_1. This constraint only affected the SDG&E prices by about $3.75/MWh for the quarter. With the exception of the 7820_TL 230S_OVERLOAD_NG and the 30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2 constraints, other internal congestion occurred infrequently and typically had a minimal impact on overall day-ahead energy prices.

Table 2.2 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency			Q1			Q2			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1			34.1%							$1.82	-$1.56	-$1.56
	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	10.5%	29.9%	21.6%	$0.36	-$0.27	-$0.27	$1.84			$2.01	-$0.56	-$0.56
	6110_TM_BNK_FLO_TMS_DLO_NG		11.9%	14.8%				$0.71	-$0.89	-$0.89	$0.45	-$0.50	-$0.50
	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
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	2.5%	7.6%		$0.33	-$0.24	-$0.24	$0.80	-$0.70	-$0.70			
	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%	-$2.59	$2.98	$0.54	-$1.00	$1.49	$0.87	-$0.75	$0.91	$0.51
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.9%	15.5%					$0.85			$3.34	
	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	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
	7820_TL 230S_OVERLOAD_NG	1.6%	5.7%	3.0%	-$0.11		$1.89	-$1.25		$6.68	-$0.29		$2.68
	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
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1			1.4%									
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	2.2%	3.0%	0.7%			$1.90			-$2.79			-$1.61
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1			0.4%									
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1			0.4%									
	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						

15-minute market congestion

The third quarter was the first 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 2.3 shows the frequency and magnitude of congestion in the third quarter.[16]

Overall, the two most frequently congested constraints were the 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 and 30880_HENTAP2 _230_30900_GATES _230_BR_2 _1 located in the PG&E area, both were binding over 3 percent of the time in the third quarter. These constraints

[16] For the entire quarter, nine 15-minute intervals for all areas were excluded from the calculation of the impact of congestion on the 15-minute prices by load aggregation point because of data issues.

increased prices in the PG&E area, by about $4.50/MWh and $5.40/MWh respectively. Prices decreased in the SCE and SDG&E areas, by around $3.70/MWh and $2.90/MWh respectively, due to congestion on these constraints. These constraints were binding due to the contingency loss of the Gates – Gregg 230 kV line.

Congestion on the Barre – Villa Park 230 kV line, which occurred in about 1.5 percent of intervals, increased prices by about $4.75/MWh in the SCE area and about $1.70 in the SDG&E area. Congestion on this constraint decreased prices in the PG&E area by over $4/MWh. This constraint was impacted by Barre – Lewis 220 kV line contingencies.

The 22835_SXTAP2_230_22504_MISSION_230_BR_1A_1 drove 15-minute market prices up in the SDG&E area by over $14/MWh in about 1.4 percent of intervals. The other remaining constraints in the SDG&E area were binding in less than 0.7 percent of all intervals, but had significant price impact on the SDG&E area prices when binding. These constraints include the 7820_TL 230S_OVERLOAD_NG nomogram and the 22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1 branch group.

Table 2.3 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

		Frequency		Q2			Q3		
Area	Constraint	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1		3.4%				$4.50	-$3.68	-$3.68
	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	2.4%	3.1%	$5.56	-$8.32	-$8.32	$5.37	-$2.94	-$2.94
	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
	PATH15_S-N	0.6%		$37.94	-$30.37	-$30.37			
	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		1.5%				-$4.19	$4.75	$1.71
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.3%	0.6%	-$0.95	$0.91	-$0.28	$5.14	-$3.84	-$3.34
	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
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.2%		-$7.04	$4.50	$10.32			
SDG&E	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
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.1%	0.1%	-$16.35	$5.74	$29.86	-$14.44	$10.70	$37.31
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	0.9%				$16.02			
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1	0.5%		-$2.42		$17.09			
	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			

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 third 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 30880_HENTAP2_230_30900_GATES_230_BR_2_1 constraint was binding in roughly 21 percent of hours in the day-ahead market compared to around 3 percent of intervals in the 15-minute market. While this constraint increased day-ahead prices in the PG&E area by about

$2/MWh, it increased prices by about $5.40/MWh in the 15-minute market. A similar pattern in the SCE area can also be seen with the 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 constraint.

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.

2.4.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional prices in the day-ahead and 15-minute markets caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, 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.[17] The congestion price impact differs across load areas and markets.

In the third quarter, congestion in the day-ahead market increased prices in all load areas. In the PG&E area load prices increased by about 3.1 percent ($1.54/MWh), while in the SCE and SDG&E areas it increased at about 0.7 percent ($0.34/MWh) and 0.4 percent ($0.20/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 ($0.48). In the PG&E and SCE areas, prices decreased by less than $0.02/MWh. Congestion in the 5-minute market increased SDG&E area prices by about $1.83/MWh (3.8 percent) and increased prices in both the PG&E and SCE areas by $0.40/MWh (0.9 percent) and $0.07/MWh (0.15 percent), respectively.

Day-ahead price impacts

Table 2.4 shows the overall impact of day-ahead congestion on average prices in each load area in the third quarter by constraint.

The PG&E area experienced the largest increase in day-ahead market prices due to the impact of congestion, about $1.54/MWh from the system average, while prices in the SCE and SDG&E area increased by about $0.34/MWh and $0.20/MWh respectively. Compared to the previous quarter, PG&E congestion increased in magnitude, congestion in the SCE area was similar but in the opposite direction, and SDG&E congestion decreased.

The 30875_MC CALL_230_30880_HENTAP2_230_BR_1_1 had the largest overall impact on prices in the third quarter. This constraint increased prices in the PG&E area by $0.62/MWh (1.25 percent) and decreased the SCE and SDG&E area prices by $0.32/MWh (0.65 percent).

In the SCE area, the 24087_MAGUNDEN_230_24153_VESTAL_230_BR_2_1 constraint increased prices by $0.52/MWh (1 percent), and had no significant impact on PG&E and SDG&E area prices.

In the SDG&E area, the 22835_SXTAP2_230_22504_MISSION_230_BR_1A_1 increased the day-ahead prices by $0.30/MWh (0.6 percent) and had no significant impact on PG&E and SCE area prices.

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

All other constraints had a significantly smaller impact on day-ahead prices, with the exception of the 30880_HENTAP2 _230_30900_GATES_230_BR_2_1 constraint.

Table 2.4 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.62	1.25%	-$0.32	-0.65%	-$0.32	-0.64%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1			$0.52	1.06%		
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.43	0.87%	-$0.01	-0.02%	-$0.01	-0.02%
22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1					$0.30	0.60%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.13	-0.25%	$0.15	0.31%	$0.01	0.02%
7430 SOL-2_NO_HELMS_PUMP_NG_SUM	$0.21	0.41%				
7500_SOL1_NG	-$0.06	-0.11%	$0.08	0.16%	-$0.06	-0.11%
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$0.15	0.30%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.06	-0.12%	$0.03	0.06%	$0.05	0.10%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.07	0.13%	-$0.03	-0.06%	-$0.03	-0.06%
7430_SOL_15_DA_NG_SUM	$0.12	0.23%				
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.02%			$0.08	0.16%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.04	0.07%	-$0.03	-0.05%	-$0.03	-0.05%
SCIT_BG	-$0.04	-0.07%	$0.02	0.04%	$0.02	0.05%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.02	-0.04%	$0.01	0.03%	$0.01	0.03%
35922_MOSSLD _115_30750_MOSSLD _230_XF_1A	$0.04	0.07%	$0.00	0.00%	$0.00	0.00%
PATH15_BG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1					$0.03	0.06%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.02	0.04%
22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1					$0.02	0.03%
30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	$0.02	0.03%				
SLIC 2412157 PARDEE-SYLMAR2_NG	$0.00	0.00%			-$0.01	-0.03%
22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1					$0.01	0.02%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.01	-0.02%
Other	$0.31	0.62%	-$0.09	-0.18%	-$0.03	-0.05%
Total	$1.54	3.1%	$0.34	0.7%	$0.20	0.4%

15-minute price impacts

Table 2.5 shows the overall impact of 15-minute congestion on average prices in each load area in the third quarter by constraint. The overall impact of congestion elevated the SDG&E area price by about $0.48/MWh (1 percent) and had a small negative effect on PG&E and SCE area prices. Congestion was most pronounced in the Fresno area as well as in San Diego.

The third quarter was the first complete quarter after implementation of the 15-minute market. Congestion in the 15-minute market was low overall, and it did not occur as consistently or with the same magnitude as in the day-ahead market. As mentioned earlier, differences in congestion can be attributed to differences in market conditions and changes associated with conforming line limits to make market flows reflect actual flows and to provide a reliability margin.

Table 2.5 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCIT_BG	-$0.17	-0.36%	$0.10	0.21%	$0.11	0.22%
7820_TL 230S_OVERLOAD_NG	-$0.03	-0.07%	-$0.01	-0.02%	$0.33	0.66%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.15	0.32%	-$0.09	-0.19%	-$0.09	-0.18%
22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1					$0.20	0.39%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.17	0.35%				
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.06	-0.13%	$0.07	0.15%		
6110_TM_BNK_FLO_TMS_DLO_NG	$0.04	0.08%	-$0.04	-0.09%	-$0.04	-0.08%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.04	-0.09%	$0.03	0.07%	$0.03	0.06%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.03	0.07%	-$0.03	-0.05%	-$0.02	-0.04%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.03	-0.07%	$0.04	0.08%		
PATH26_N-S	-$0.02	-0.05%	$0.02	0.04%	$0.02	0.04%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.02	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.02%	$0.01	0.02%	$0.03	0.06%
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$0.04	0.08%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.01	-0.01%			$0.03	0.07%
30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	$0.03	0.06%				
15090_HASSYAMP_500_22342_HDWSH _500_BR_1 _1	-$0.01	-0.01%			$0.02	0.05%
SLIC 2377852 TL50001_NG					$0.03	0.05%
Other	-$0.20	-0.42%	-$0.23	-0.48%	-$0.19	-0.38%
Total	-$0.15	-0.31%	-$0.14	-0.30%	$0.48	0.96%

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 third quarter was the 30875_MC CALL_230_30880_HENTAP2_230_BR_1_1 constraint, which is located in the PG&E area. This constraint was binding in about 10 percent of intervals and increased prices by about $4.70/MWh in the PG&E area, and decreased prices in the SCE and SDG&E areas by $3.65/MWh when the constraint was binding. The constraint is adjusted to protect for thermal overload from the contingency loss of the Gates – Gregg 230 kV line.

The second most congested constraint was associated with the 30880_HENTAP2 _230_30900_GATES_230_BR_2_1.[18] This constraint was binding in fewer than 8 percent of intervals and increased PG&E prices by about $6/MWh, and also decreased prices in both the SCE and SDG&E areas by about $4.60/MWh and $5.50/MWh, respectively, when binding.

[18] For the entire quarter, three 5-minute intervals in the SCE area and seven in the SDG&E area were excluded from the calculation of percent and price impact because of data issues.

The price impact of congestion differs across load areas and markets when taking into account both the frequency with which congestion occurs and the magnitude of the impact. Overall in the third quarter, the impact of 5-minute market congestion changed significantly from the previous quarter. It increased prices in all load areas. The SDG&E area prices increased by about $1.80/MWh (about 4 percent), from negative $0.50/MWh (1 percent) in the previous quarter. Congestion impacts in the PG&E and SCE areas increased prices to about $0.42/MWh (about 1 percent) and by $0.07/MWh (0.2 percent), respectively. This pattern is different from the previous quarter when 5-minute prices in Southern California decreased due to congestion.

2.5 Bid cost recovery

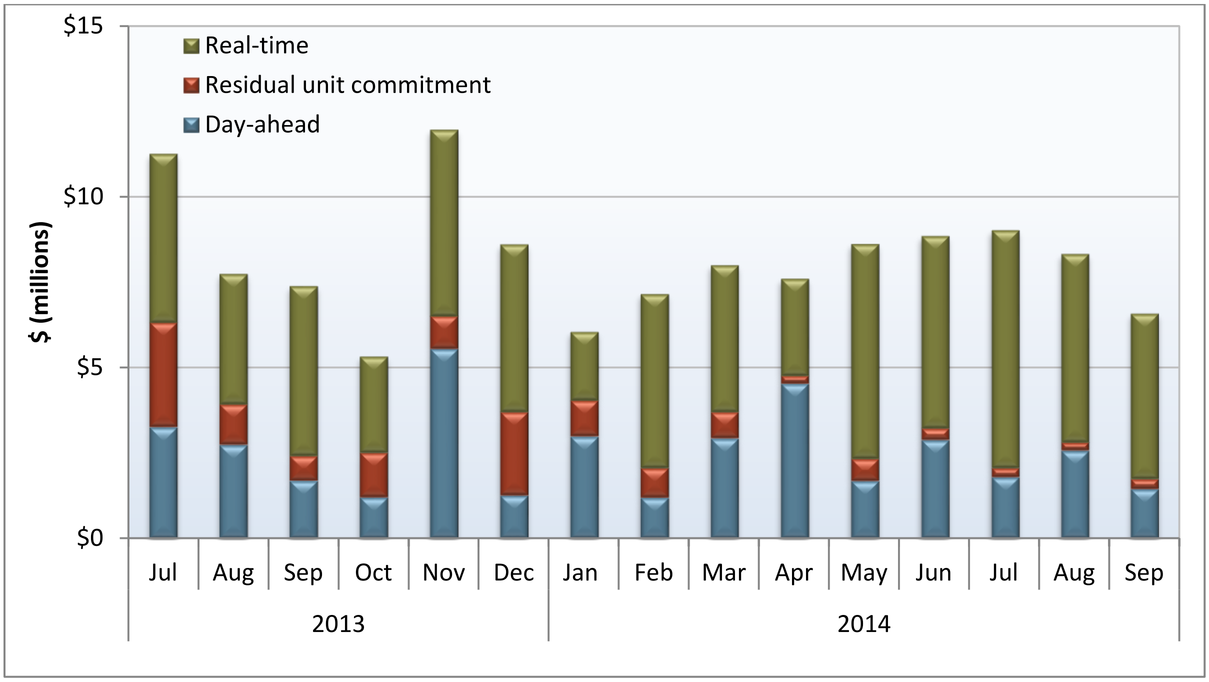
The market enhancements in May brought significant changes to the bid cost recovery payment rules. Before the rule changes, bid cost recovery payments were netted with revenues received among the day-ahead, residual unit commitment and real-time markets. For instance, if a unit was committed in the day-ahead market and required bid cost recovery payments, these payments would be adjusted by any positive net revenues received in the real-time market. After May 1, the ISO no longer nets the costs and revenues between the day-ahead and real-time markets.[19] Instead, the ISO calculates the costs and revenues for day-ahead and real-time markets separately for each day.

Before implementing these new rules, there were concerns that this change could significantly increase bid cost recovery payments. Figure 2.8 shows monthly bid cost recovery payments over the past 15 months.[20] DMM estimates that bid cost recovery payments were around $24 million in the third quarter of 2014, compared to $26 million in the third quarter of 2013. Total bid cost recovery payments in July and August were around $9 and $8 million respectively, similar to May and June totals. A slight decrease occurred in September with a total of around $7.5 million, which was primarily due to decreases in both day-ahead and real-time payments.

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

[20] The ISO is still addressing calculation issues with May and June. 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 2.8 Monthly bid cost recovery payments



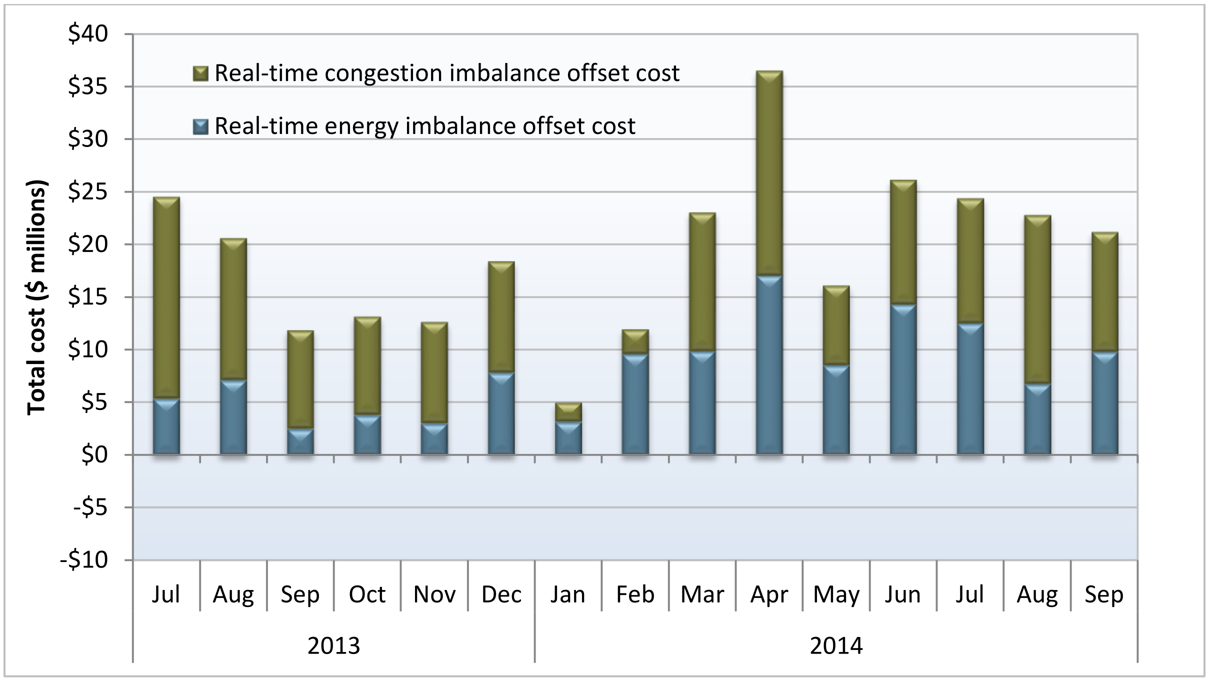
2.6 Real-time imbalance offset costs

Real-time imbalance offset costs totaled about $68 million in the third quarter of 2014, approximately 20 percent greater than the $57 million value in the third quarter of the prior year and about 13 percent lower than the $79 million value in the second quarter of 2014. Total real-time imbalance offset costs in the third quarter were the sum of approximately $39 million in congestion imbalance offset costs and $29 million in energy imbalance offset costs. Currently, energy imbalance offset costs in the first three quarters of 2014 ($92 million) exceed energy imbalance offset costs for all of 2013 ($57 million).

Values reported here are the most current reported settlement imbalance charges, but are subject to change. In addition to the routine causes for recalculation, including the submission of final meter data, imbalance charges after May 1 are subject to recalculation due to resettlement of participating intermittent resource program protective measure resources.[21]

[21] When these resources are re-settled under PIRP protective measures, the uninstructed energy charges associated with these resources will be reversed and will instead be settled on the sum of forecast energy settled at the simple average of real-time prices during the hour and the monthly sum of hourly differences between forecast and metered generation multiplied by the weighted average real-time price, weighted by metered generation. Any resource with PIRP protective measure status that submits economic bids into the market risks losing its PIRP status. Currently, there are nine resources being settled under PIRP protective measures with total capacity of over 500 MW.

Figure 2.9 Real-time imbalance offset costs



Congestion imbalance offset costs rose substantially from $17 million in the first quarter to $39 million in the second quarter and $39 million in the third quarter of 2014. The current quarterly estimate is similar to the average quarterly congestion imbalance offset in 2012 and 2013. Congestion offset costs are likely due to unscheduled flows, market modeling differences and other potential factors. Congestion offset costs of over $3 million occurred on a single day, September 16, which account for about 8 percent of the total congestion offset for the quarter. Congestion on this day was primarily due to the 7820_TL 230S_OVERLOAD (NG) with shadow values in both the 5-minute and 15-minute real-time markets over $1,000/MWh for much of the peak period. This constraint was not binding in the day-ahead market.

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. Transmission loss obligation charges may account for up to $9 million of real-time energy offset costs in the third quarter of 2014 and $29 million for the first nine months of 2014.

An accelerated transmission loss payback arrangement with Arizona Public Service (APS) accounted for approximately $7.5 million of real-time imbalance energy offset this quarter and a total of $15 million through the third quarter of 2014. Under the accelerated payback arrangement which began on April 1, the ISO provides APS with 75 MWh of energy per hour. This energy compensates for historic undercompensation of transmission losses resulting from an APS loss calculation error. This additional payment is scheduled to continue through April 2015, adding approximately $2.5 million per month to real-time imbalance energy offset costs.[22] This cost is not reflected in transmission loss obligation charges and is not offset by settlement values elsewhere in the market.[23]

2.7 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.[24] All numbers reported in this section reflect the prevailing settlement rules at the time the market ran. Additionally, due to data issues, convergence bidding price and payment reporting only cover the months of July and August.

Participants engaging in convergence bidding continued to earn positive returns from participation in ISO markets in July and August. The net revenues from the market in these two months were about $9.9 million. Virtual supply generated net revenues of about $8 million, while virtual demand accounted for approximately $1 million. The total payment to convergence bidders fell slightly to $9.8 million after taking into account virtual bidding bid cost recovery charges of $0.15 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 67 percent of all accepted virtual bids in the third quarter, an increase from 60 percent in the previous quarter.

Total hourly trading volumes increased in the third quarter to about 3,900 MW from 3,300 MW in the previous quarter. Virtual supply averaged around 2,200 MW while virtual demand averaged around 1,700 MW during each hour of the quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by about 480 MW on average, an increase from 430 MW of net virtual supply in the previous quarter.

For July, net revenues from net virtual demand positions were positive due to short periods with elevated prices in the 15-minute market, while generally August did not experience elevated prices in the 15-minute market and virtual demand revenues were negative. Net revenues from net virtual supply positions were positive as prices were generally higher in the day-ahead market than the 15-minute market.

[22] Further detail on the accelerated payback is available here: http://www.caiso.com/Documents/AcceleratedTransmissionLossesReturn_ArizonaPublicService.htm.

[23] Further details of the role of transmission loss obligation charges and other potential causes of real-time imbalance energy offset are outlined in the following DMM white paper: http://www.caiso.com/Documents/ReviewofReal-TimeImbalanceEnergyOffset-DMMWhitePaper.pdf.

[24] 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.

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:

- 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.[25] 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 price convergence between the day-ahead and 15-minute prices.

2.7.1 Convergence bidding trends

Total hourly trading volumes increased in the third quarter to 3,900 MW from 3,300 MW in the previous quarter. These volumes have remained relatively stable for the last few quarters. On average, about

[25] 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.

53 percent of virtual supply and demand bids offered into the market cleared in the third quarter, which is similar to the second quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 480 MW on average, which is an increase from 430 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours, by about 330 MW and 770 MW respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in hours ending 18 to 20, with the highest net virtual demand occurring in hour ending 19 at about 180 MW. The highest net cleared virtual supply hours were hours ending 4 and 5 with 880 MW and 990 MW, respectively.

Consistency of price differences and volumes

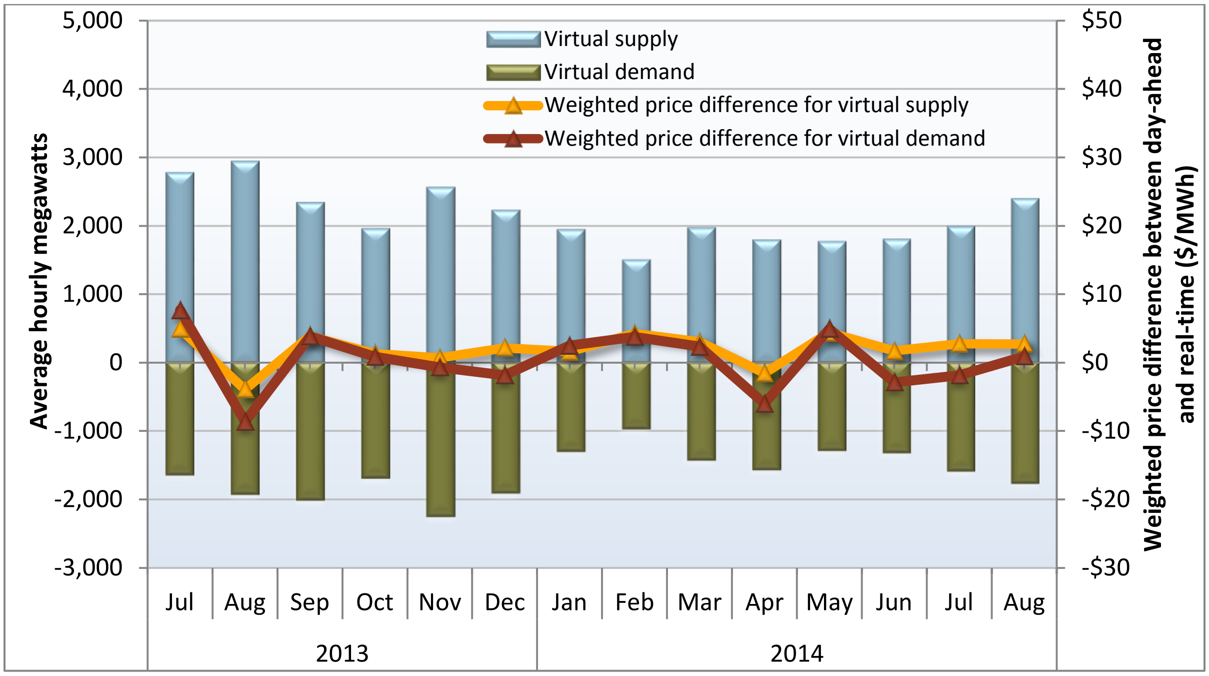
Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. Net convergence bidding volumes were relatively low and were only consistent with price differences between the day-ahead and real-time markets in July and August for 10 hours and 17 hours, respectively.

Figure 2.10 compares cleared convergence bidding volumes with the volume-weighted average price difference where the virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different locations. This figure does not include data for September, the final month of the third quarter, due to a delay in access to data needed for this analysis.

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 August were inconsistent with weighted average price differences for the hours in which virtual demand cleared the market and were thus not profitable. However, in July, virtual demand positions were profitable as they were consistent with the weighted average price differences.

Figure 2.10 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 2.10 represents the difference between the day-ahead price paid to virtual supply and the real-time market price at which virtual supply positions are liquidated, weighted by cleared virtual supply bids by time interval and location. On average, virtual supply positions have been consistently profitable since January 2012, with the exception of August 2013 and April 2014.[26]

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.[27] 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 third quarter, the majority of cleared virtual bids were offsetting bids. Offsetting virtual positions accounted for an average of about 1,300 MW of virtual demand offset by 1,300 MW of virtual supply in each hour of the third quarter. These offsetting bids represent about 67 percent of all cleared virtual

[26] 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.

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

bids in the third quarter, which is an increase from 60 percent in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

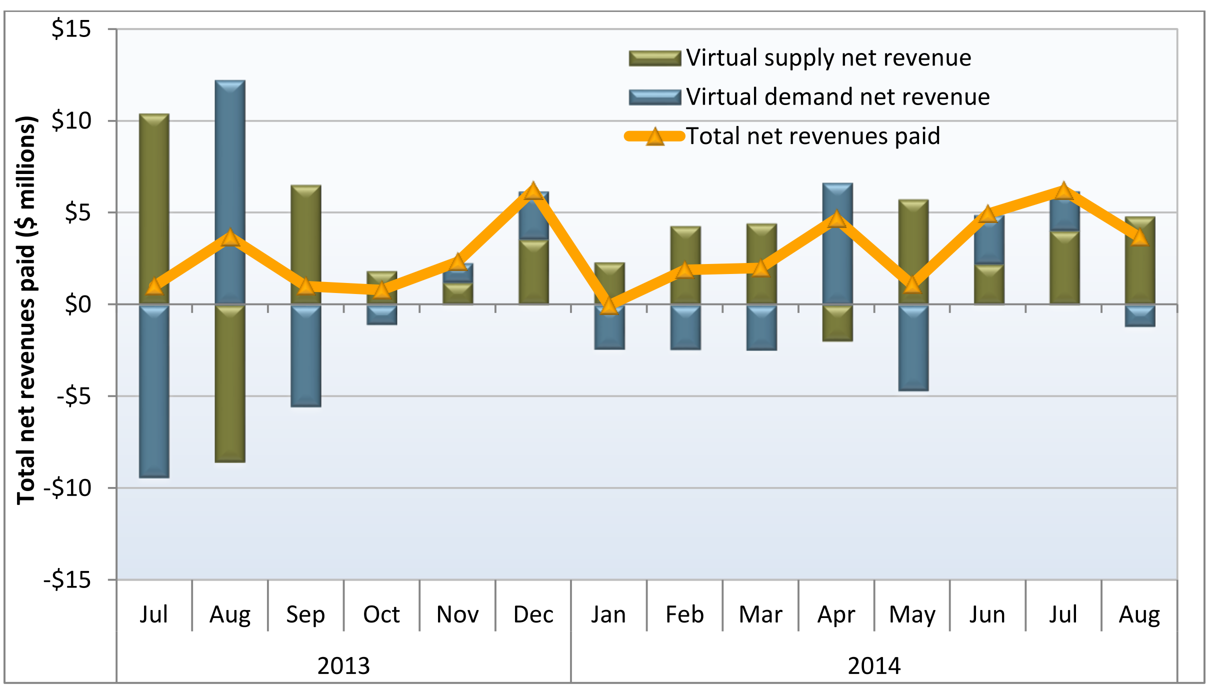
2.7.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders in the first two months of the third quarter. Similar to the previous quarter, convergence bidding participants earned positive revenue. In July and August, net revenues were about $9.9 million from revenue collected on both virtual supply and demand positions.

Figure 2.11 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $9.9 million in July and August, compared to about $4.6 million in the same months in 2013.
- Virtual supply revenues were most profitable in August as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply accounted for net payments of about $9 million during July and August.
- Virtual demand revenues were positive in July and negative in August. In total, virtual demand accounted for around $1 million in net payments for July and August.
- Convergence bidders were paid about $9.8 million, after subtracting virtual bidding bid cost recovery charges of $0.15 million for July and August.

Figure 2.11 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 $7.4 million (75 percent) of the total convergence bidding settlements for July and August, which is an increase from about $5.4 million or nearly 65 percent of revenue gains from the same months in 2013. Physical generation and load participants accounted for about 22 percent of volume and around 17 percent of revenues, which was primarily from virtual supply positions.

Table 2.6 compares the distribution of convergence bidding cleared volumes and net revenues in millions of dollars among different groups of convergence bidding participants.[28] As shown in Table 2.6, financial entities represent the largest segment of the virtual market, accounting for about 68 percent of volumes and about 75 percent of settlement dollars. Marketers represent about 10 percent of the trading volumes and 9 percent of the settlement dollars. Generation owners and load-serving entities represent a small segment of the virtual market in terms of volumes (about 22 percent) and an even smaller segment of the settlements portion (16 percent).

Table 2.6 Convergence bidding volumes and revenues by participant type (July – August)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,305	1,295	2,600	$0.7	$6.7	$7.4
Marketer	133	268	400	$0.3	$0.6	$0.9
Physical generation	209	270	479	$0.1	$0.8	$0.9
Physical load	5	353	358	$0.0	$0.8	$0.7
Total	**1,652**	**2,185**	**3,838**	**$1.0**	**$8.8**	**$9.9**

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

[28] 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.

[29] 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.

cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs, and energy bid costs.[30]

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.[31]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[32] 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.[33] 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 July and August totaled only about $0.15 million, $0.07 and $0.08 million, respectively. As noted earlier, the total estimated net revenue for convergence bidding was around $9.9 million for this period. Total convergence bidding revenue is essentially the same at $9.8 million when accounting for this adjustment.

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

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

[32] 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.

[33] 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.

3 Special Issues

3.1 Revenue adequacy for congestion revenue rights

This section highlights the performance of the congestion revenue rights market over the first nine months of 2014. Revenue shortfalls for congestion revenue rights, before accounting for auction revenues, reached around $162 million in the first nine months of 2014. The shortfall in the third quarter alone was about $88 million, equal to approximately 63 percent of all congestion revenue. The congestion revenue rights balancing account had an $81 million net revenue shortfall in the first nine months of 2014 after including auction revenues. In 2012 and 2013, the balancing account had annual surpluses of $23 million and $3 million, respectively. The ISO has taken steps to address the revenue inadequacy by accounting for more constraints in the congestion revenue right model in future auctions.

Background

The market for congestion revenue rights is designed such that congestion rent collected from the day-ahead energy market is sufficient to cover payments to congestion revenue rights holders. This is referred to as revenue adequacy.[34] The day-ahead congestion rents and congestion revenue right payments are placed in a balancing account. All revenues from the annual and monthly auction processes are added to the balancing account to offset deficits due to revenue inadequacy, if needed. Any shortfall or surplus in the balancing account at the end of each month is allocated to measured demand.

Congestion rents collected in the day-ahead market may not be sufficient to cover payments to congestion revenue rights holders. Revenue inadequacy is generally due to differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model. In general, the day-ahead model may be more restrictive than the congestion revenue rights model. This is because transmission changes unanticipated at finalization of the congestion revenue rights model are more likely to reduce available transmission capacity than to increase it, as transmission flows are de-rated to account for unplanned outages and other unanticipated conditions. In addition, new nomograms not in place when the congestion revenue rights full network model is finalized may impose limits on transmission capacity in the day-ahead market. Therefore, the quantity of congestion revenue rights released in the monthly and annual congestion revenue rights processes for a path may be higher than the actual transmission capacity available in the day-ahead market, increasing the potential for revenue inadequacy.

[34] For a more detailed explanation of revenue adequacy for congestion revenue rights and the simultaneous feasibility test, please see the ISO's 2013 reports on congestion revenue rights at: http://www.caiso.com/market/Pages/ProductsServices/CongestionRevenueRights/Default.aspx.

Potential causes of revenue imbalances for congestion revenue rights[35]

- **Unexpected or non-modeled outages:** Any forced outages during the congestion revenue rights settlement month, or outages that become known before the settlement month but after the deadline for inclusion in the congestion revenue rights model, can create negative revenue imbalances. Outages reported after the congestion revenue rights model deadline on transmission lines not controlled by participating transmission owners in the ISO system can also affect the available transmission capacity.

  The timing of the congestion revenue rights auction process creates opportunities for entities to target reported outages and modeling discrepancies between the congestion revenue rights network model and the day-ahead market model. Outages reported after a certain deadline cannot be included in the congestion revenue rights model. However, these outages will be included in the day-ahead market model. Therefore, any outages reported during the roughly month-long period after the outage reporting deadline but before the congestion revenue rights auction closes will create modeling discrepancies that can be actively targeted by congestion revenue rights auction participants.

- **Granularity differences:** Congestion revenue rights are issued for monthly (or greater) terms, while the day-ahead market runs daily. Transmission outages may last days or hours. Therefore, constraints can be modeled to precisely reflect the timeframe of outages in the day-ahead market, with different limits during different days and hours. However, constraints must be modeled with one single limit for the entire month (or longer) in the congestion revenue rights model. This difference in modeling granularity can create revenue imbalances. Due to these inherent differences in modeling granularity, revenue adequacy cannot be guaranteed. This is because the surpluses in some days and hours will not necessarily cover the deficits in other days and hours.

- **General modeling discrepancies and errors:** There is always the possibility of discrepancies and errors between the congestion revenue rights and day-ahead models. This creates the possibility that awards based on the congestion revenue rights model will create settled flows larger than day-ahead market settled flows.

  Also, modeling errors and discrepancies can create situations where a large or unconstrained quantity of congestion revenue rights can be purchased at or near zero cost. Consider two nodes that are electrically located in the same spot except for one constraint between them. If this constraint is not included in the congestion revenue rights model, congestion revenue rights that source and sink at the two nodes will have no effect on other constraints (as net injections would be zero). Their price in the congestion revenue rights market will be $0 because any binding constraint in the congestion revenue rights market will have the same price impact on both the source and sink. If the two nodes are not the same but very similar, the net flows created by congestion revenue rights at the nodes will be very close to zero, and the effects of binding constraints on congestion revenue rights prices will be small. For example, congestion revenue rights purchased at a price of $0 received about $7.4 million of revenue from the Palo Verde ITC in March 2014.

[35] These causes are explained in greater detail in DMM's white paper, "Allocating CRR Revenue Inadequacy by Constraint to CRR Holders," available at: http://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

- **Unsettled flows in the day-ahead market:** Ideally all day-ahead market flows over a constraint would settle at the shadow value of the constraint. However, unsettled flows might occupy space on transmission constraints reducing the day-ahead market congestion rent used to pay congestion revenue right holders. Unsettled flows can occur for several reasons, including: differences in actual AC flows and calculated flows from linearized DC shift factors; the use of lossless shift factors; threshold levels on shift factors for inclusion in the day-ahead optimization; and non-settled injections or withdrawals.

Revenue adequacy

Figure 3.1 shows the revenues, payments and overall revenue adequacy of the congestion revenue rights market by quarter for the last eleven quarters.

- The dark blue bars represent day-ahead market congestion rent, which accounts for the main source of revenues in the balancing account.
- Light blue bars show net revenues from the annual and monthly auctions for congestion revenue rights corresponding to each quarter. This includes revenues paid for positively priced congestion revenue rights in the direction of expected prevailing congestion, less payment made to entities purchasing negatively priced counter-flow congestion revenue rights.
- Dark green bars show net payments made to holders of congestion revenue rights. This includes payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities purchasing counter-flow congestion revenue rights.
- The orange line shows the sum of monthly total revenue adequacy for the three months in each quarter when revenues from the auction are included.
- The red line shows total quarterly revenue adequacy when auction revenues are excluded.

As seen in Figure 3.1, by far the largest revenue inadequacy in the past several quarters occurred in the third quarter of 2014 when revenue shortfalls before accounting for auction revenues reached $88 million. Auction revenues decreased the shortfall in the balancing account to around $53 million.

Internal constraints played a major role in third quarter revenue shortfalls.[36] More than half of the revenue shortfall resulted from differences on three constraints between the network transmission model used in the congestion revenue rights process and the day-ahead market model:[37]

- Magunden to Vestal nomogram area constraints;
- Helms Pump nomogram constraint; and
- Warnerville to Wilson transmission line.

[36] In the second quarter, inter-tie constraints significantly contributed to revenue inadequacy. Additional detail for reasons behind revenue shortfalls from inter-tie constraints is provided in the *Quarterly Report on Market Issues and Performance* for the second quarter 2014: http://www.caiso.com/Documents/2014SecondQuarterReport-MarketIssuesandPerformance-August2014.pdf.

[37] The ISO market performance metric catalog for 2014 provides greater detail: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=5520CF84-6265-4155-8E03-FD91F3495C08.

Revenue inadequacy that occurred on these three constraints was mainly due to unexpected or non-modeled outages and unsettled flows in the day-ahead market. The ISO has taken steps to address the revenue inadequacy by accounting for more constraints in the congestion revenue right model in future auctions. This will essentially limit the amount of congestion revenue rights that are auctioned off going forward.

Figure 3.1 Quarterly revenue adequacy