California Independent System Operator Corporation

California ISO

Q2 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 second quarter of 2014 (April – June).

- On May 1, the most significant set of enhancements to the ISO markets since the beginning of the nodal market in April 2009 went into effect. These changes were intended to make the real-time market more effective and efficient at integrating large amounts of renewable variable energy resources. The changes were made as part of the ISO's effort to comply with FERC Order No. 764, which required the ISO to establish intra-hour schedule changes in 15-minute increments.[1] A detailed description of the changes and implementation is outlined in Chapter 1.
- Energy market prices remained highly competitive through the second quarter of 2014. The overall combined wholesale cost of energy was about equal to the competitive baseline price that the Department of Market Monitoring (DMM) calculates using the day-ahead market software to estimate prices that would result under highly competitive conditions when suppliers bid at or near marginal costs.
- Day-ahead prices in the second quarter were similar to the first quarter of 2014.[2] Hour-ahead prices began diverging below day-ahead and real-time prices in April, and this trend continued after implementing FERC Order No. 764 market changes in May. The 15-minute market prices were lower than average prices in the day-ahead market for May and June. The 5-minute market prices dipped below day-ahead prices in June, but were higher in April and May.
- Price spikes above $250/MWh in the 15-minute market during May and June occurred in only 0.2 percent of all intervals. Negative prices below $0/MWh occurred in about 4 percent of all intervals. This was partly due to periods of over-generation resulting from unscheduled wind and solar generation.
- Congestion increased compared to the first quarter but remained low overall. 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 San Diego Gas & Electric area, which was related to a constraint to protect the Hoodoo Wash – North Gila 500 kV Line.
- Following implementation of FERC Order No. 764 market changes, the majority of imports scheduled in the day-ahead market have been self-scheduled in the real-time market. A drop in the additional supply of import and export bids offered in the real-time market has also been observed. This has led to concerns about potential liquidity issues when addressing unscheduled flows (i.e., loop flows) and imbalance in real time. This 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 of the ISO system. If these imports and exports are offered as fixed hourly blocks, suppliers face a risk that the 15-minute

[1] The existing 5-minute dispatch was retained to provide real-time balancing.

[2] 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.

prices used to settle accepted bids may be lower than the supplier's hourly bid price for imports (or higher than the bid price for exports).

- DMM estimates that day-ahead market prices remained about $4/MWh higher in the second quarter as a result of the state's greenhouse gas program.[3]
- Real-time imbalance offset costs totaled about $80 million in the second quarter of 2014, approximately double the $40 million value in the first quarter. The increase was a result of higher estimated energy imbalance offset costs that increased from $22 million in the first quarter to $41 million in the second quarter and congestion imbalance offset costs that rose to $38 million from $18 million in the first 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 day-ahead and real-time 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 $25 million in the second quarter of 2014, compared to $33 million in the second quarter of 2013. Moreover, bid cost recovery payments in May and June were around $8 and $9 million respectively, compared to $8 million in March and April.
- Net revenues received by convergence bidders, after accounting for bid cost recovery charges, were about $10.2 million in this quarter compared to about $0.8 million in the first quarter. Virtual supply revenues were most profitable in May as day-ahead prices were generally higher than 15-minute market prices. About 50 percent of all revenues were generated from three days – two days associated with virtual demand ($4 million) and one day with virtual supply ($1 million).
- Flexible ramping costs were around $2.3 million, down from around $3 million in the previous quarter. ISO operators decreased the flexible ramping requirement consistently during the morning and evening periods in the second quarter, averaging nearly 400 MW, which was down from 480 MW in the previous quarter.
- The congestion revenue rights balancing account had a $28 million net revenue shortfall in the first half of 2014 after including auction revenues. In 2012 and 2013, the balancing account had annual surpluses of $23 million and $3 million, respectively.

Energy market performance

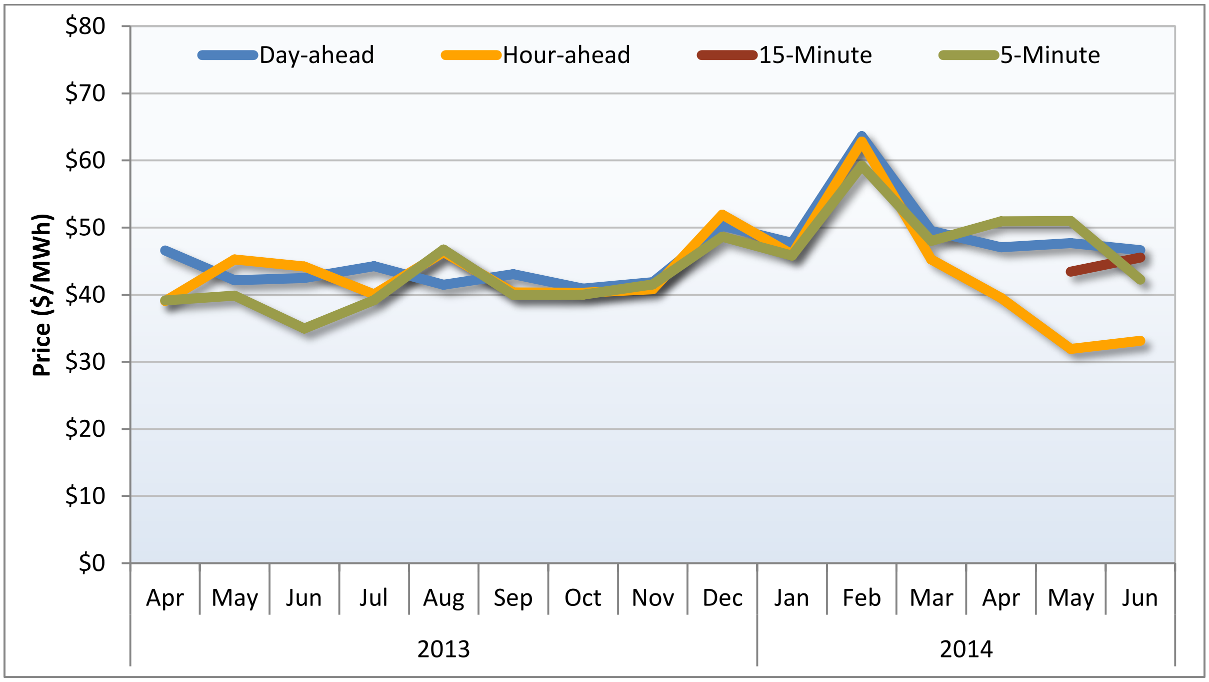
This section provides a more detailed summary of energy market performance in the second quarter.

Decreased 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 May and June (see Figure E.1), while 5-minute prices were higher than day-ahead prices in both April and May. Hour-ahead prices were consistently lower than all other markets

[3] This $4/MWh price impact is highly consistent with the cost of carbon emission credits and the efficiency of gas units typically setting prices in the day-ahead market during this period. The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the California Public Utilities Commission (CPUC) and other state entities. Under a 2012 CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs. More detailed information is provided in Section 3.3 of this report.

throughout the quarter. 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 increased in the second quarter. Price spikes above $250/MWh in the 15-minute market during May and June occurred in only 0.2 percent of all intervals. The frequency of prices over $250/MWh in the 5-minute market increased to 1.3 percent of 5-minute intervals compared to 0.5 percent of intervals in the first quarter. Negative prices below $0/MWh occurred in about 4 percent of all intervals in both the 15-minute and 5-minute markets. Positive and negative price variability is partly due to wind and solar generation variability and differences in day-ahead and real-time schedules.

The impact of congestion on day-ahead and real-time prices remained low. While congestion in the second quarter increased compared to the first quarter, it remained low overall. 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 SDG&E area and was related to a constraint to protect the Hoodoo Wash – North Gila 500 kV line.

Real-time congestion and energy imbalance offset costs increased in the second quarter. Real-time imbalance offset costs totaled about $80 million in the second quarter of 2014, which doubled the first quarter costs of $40 million. The increase was a result of higher estimated energy imbalance offset costs that increased from $22 million in the first quarter to $41 million in the second quarter and congestion imbalance offset costs that rose to $38 million from $18 million in the first quarter. As currently estimated, energy imbalance offset costs in the first half of 2014 were $63 million, which exceeds the total energy imbalance offset cost for 2013 ($57 million).

Bid cost recovery payments remain constant. Market enhancements after May 1 brought significant changes to the bid cost recovery payment rules. Before the rule changes, bid cost recovery payments from the day-ahead and real-time markets netted costs and revenues for the day. After May 1, the ISO instead 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 implementation of the new rules, there were concerns about potential increases in the bid cost recovery payments. Bid cost recovery payments were around $25 million in the second quarter of 2014, compared to $33 million in the second quarter of 2013. Moreover, bid cost recovery payments in May and June were around $8 and $9 million respectively, compared to around $8 million in March and April.

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). The ISO lowered the maximum adjustment for the flexible ramping constraint from 900 MW to 600 MW at the end of January. This contributed to a lower average procurement level compared to previous periods. Total payments to generators for the flexible ramping constraint were around $2.3 million, compared to around $3 million in the previous quarter.

Special issues

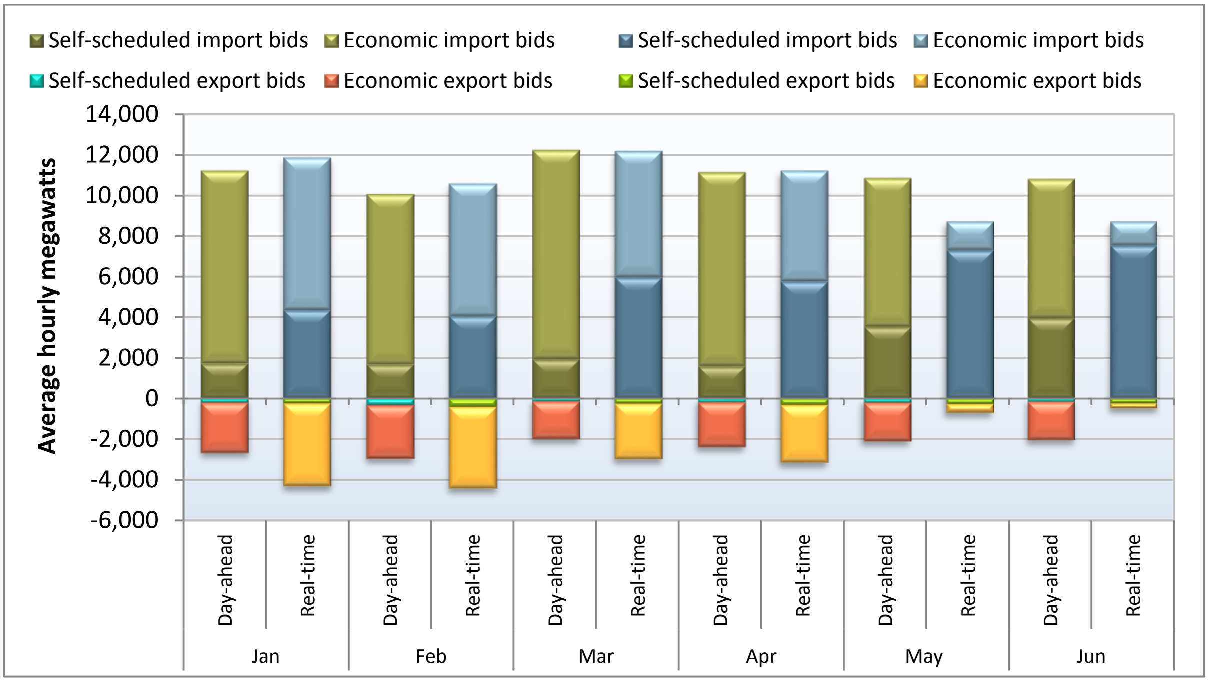
Impact of market changes on inter-ties

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 market changes in May. However, a significant decrease 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.

The majority of economic bidding on the inter-ties was in the hour-ahead market. In May and June, around 90 percent of economic import bids and around 80 percent of economic export bids were hourly blocks. The hourly economic bid block option with a single intra-hour economic schedule change was rarely used by the inter-tie resources. Only about 10 percent of economic import bids and 20 percent of economic export bids were 15-minute economic bids.

These changes have impacted reliability as well as the markets. Specifically, the ISO modified its approach to dealing with loop flows on the inter-ties away from using the transmission reliability margin mechanism, to more frequently curtailing transactions on the inter-ties due to the lack of bid liquidity. DMM also observed several instances on select constraints where inter-tie congestion, particularly in the hour-ahead, was influenced by penalty prices. Ultimately, the high degree of self-scheduling appears to have also contributed to congestion differences on some inter-ties.

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



Congestion revenue right revenue adequacy

The market for congestion revenue rights is designed such that congestion rents 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 a $28 million net revenue shortfall in the first half 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 second 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 occurred on the PACI, Palo Verde, and Tracy 500 inter-ties. The combined revenue inadequacy created by these constraints was around $40 million and was primarily a result of outages and derates.

Effect of cap-and-trade on ISO markets

Resources in the ISO market became subject to the state's greenhouse gas cap-and-trade program compliance requirements in January 2013. In the second quarter of 2014, allowance costs were fairly stable, beginning the quarter at $12.00/mtCO$_2$e and ending at $11.98/mtCO$_2$e. DMM estimates that, in the second quarter, the average impact of greenhouse gas compliance was about $4/MWh. This is consistent with the previous quarter as well as with the additional emissions costs for gas units typically setting prices in the ISO market.

1 Significant market changes

The ISO implemented several changes to the ISO 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 of the set of market changes, and highlights observed market effects of these changes in the second quarter. The market changes include:

- 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 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, to be followed by a gradual increase afterwards.
- Validating day-ahead pre-schedule e-tags against the residual unit commitment schedule instead of the day-ahead market. 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 renewable generation to bid downward dispatch into the market economically.
- Breaking out day-ahead bid cost recovery calculations from 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 used to offset net real-time costs, and vice versa.
- Changing how variable energy resources bid and schedule into the market. Specifically, a subset of variable energy 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 it has only been a couple months since implementing these new features, not enough time has passed to develop a firm understanding of the trends at this time. However, DMM has identified a number of general observations:

- Day-ahead electricity prices in the second quarter were similar to the previous quarter.[4] Hour-ahead prices began decreasing in April relative to the other markets, before the market changes in May. Hour-ahead prices remained lower than the other markets after implementation of the market changes in May. The 15-minute market prices were lower than average prices in the day-ahead market in May and June. However, on a weekly basis, 15-minute prices appear to be trending

[4] 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.

closer to day-ahead prices. The 5-minute market prices were higher than day-ahead prices in April and May and dipped below day-ahead prices in June.

- The hour-ahead prices were consistently lower than all other market prices. This market is the first real-time process to address any generation, particularly from renewables, that is not scheduled in the day-ahead market and to manage large volumes of self-scheduled energy on the inter-ties. This situation limits economic scheduling maneuverability and may also lower prices. Other factors include differences in variable energy resource forecasts and manual adjustments.

- The 15-minute market prices reached above $250/MWh in only 0.2 percent of all intervals, whereas 5-minute market prices exceeded $250/MWh in about 1.3 percent of all intervals. In general, negative prices occurred in about 4 percent of all intervals in both the 15-minute and 5-minute markets. This was partly due to real-time wind and solar generation schedules being higher than day-ahead schedules.

- Since May, the vast majority of the inter-tie import and export bids in the hour-ahead market have been self-scheduled, 85 and 42 percent respectively, which is a significant change from prior to the market changes. This has created concerns about potential liquidity problems in the 15-minute market and has likely contributed to the observed pricing patterns at inter-ties.

- The transmission reliability margin is a mechanism used by the ISO to reserve transmission on inter-ties to address loop flows and uncertainty of inter-tie transfer capacity. The ISO used this tool regularly prior to the market changes in May. Because most real-time market inter-tie bids have been self-scheduled since May, the liquidity of inter-tie bids in the real-time market has declined substantially. In other words, the likelihood that the model would have to cut self-schedules and set prices based on penalty parameters would be high. As a result, the transmission reliability margin mechanism has been used less frequently and the ISO has more frequently curtailed transactions to address reliability concerns.

- Beginning in May, the ISO no longer nets the costs and revenues for market participants between the day-ahead and real-time market. Instead, the ISO calculates the costs and revenues for the day-ahead and real-time markets separately for each day. 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.

- Initial implementation concerns arose for inter-tie resources related to the submission of pre-schedule e-tags in the day-ahead market which are now validated against residual unit commitment schedules rather than day-ahead market schedules. Since many inter-tie schedules were being reduced for reasons other than virtual bidding, this created significant concern from market participants. As a result, the ISO changed the penalty price for reducing integrated forward market inter-tie schedules in the residual unit commitment. This change gave priority to inter-tie resources, allowing the residual unit commitment to reduce integrated forward market internal resource schedules first. Both the change in penalty price for inter-tie self-schedules and increased market participant familiarity with the new e-tagging requirements have helped to resolve some of the initial spring release implementation issues.

- No reliability demand response resources were registered or available for dispatch in the ISO market during the second quarter. Even so, on a system-wide basis, there were no instances after May that would have triggered the use of the program.

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 other 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. Inter-tie and internal resources are now scheduled and settled in the same 15-minute market run in real time.
- 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.[5]

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.

Results from the 15-minute market produce schedules and prices 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:

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[5] 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.

- **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 a variable energy resource routinely submits high forecasts to the hour-ahead process because these would 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.[6] This change was primarily intended to provide incentives for renewable 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.

[6] 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

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.[7] An eligible intermittent resource can now choose to be scheduled and settled as a participating intermittent resource.[8] 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.[9] An eligible intermittent resource that does 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 bid-in value and the most recent forecast value for the average of the three 5-minute intervals making up that interval.

1.2 General market performance

This section provides summary highlights of select energy market performance in the second quarter. DMM cautions that since only a couple months have passed since implementation of the new market rules, conclusive trends and market performance cannot be reached at this time. 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.

On an hourly average, around 1,650 MW of physical imbalance energy was settled between the day-ahead and 15-minute markets. Around 450 MW of physical imbalance energy was settled between the 15-minute and 5-minute markets. These values indicate that in the second quarter around 80 percent of

[7] A variable energy resource is defined in the ISO tariff as a resource that has an energy source that has 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.

[8] A participating intermittent resource (PIR) is an eligible intermittent resource which fulfills several addition 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's 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.

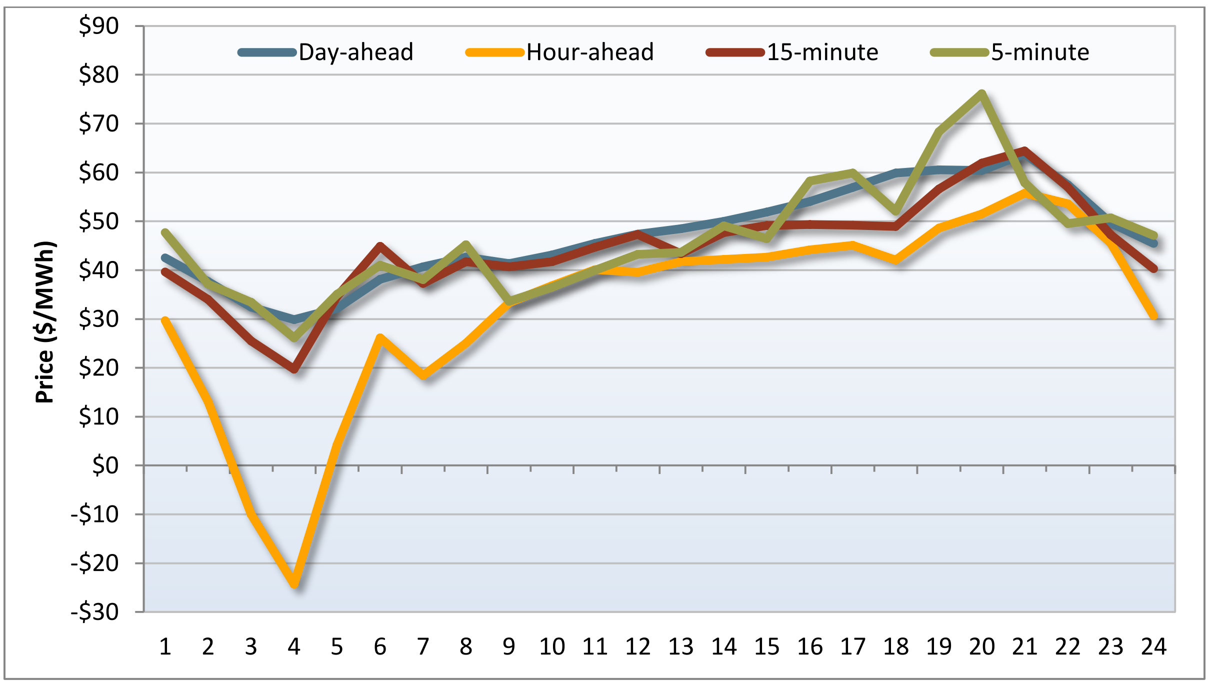
[9] Section 4.8.3.1 of the ISO tariff outlines the requirements for PIRP protective measure settlement. The ISO received applications for PIRP protective measure status from multiple resources within the application deadline, but at the time of publication the determination of final status is pending further information requests. Resources that choose to be settled under PIRP protective measures will lose that status should they submit an economic bid or self-schedule in the real-time market and will be settled as specified in section 11.12 of the ISO tariff.

physical imbalance energy is settled in the 15-minute market, whereas only 20 percent is settled in the 5-minute market. Thus, this relationship is important for understanding the relative weights associated with prices in this new market structure.

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 began decreasing relative to the other markets in April, and this relationship continued after the May market changes. Monthly hourly average system prices in the 15-minute real-time market were slightly lower than day-ahead market prices while the 5-minute market prices were lower in April and May and higher in June. Figure 1.1 shows hourly prices in May and June. Notably, the hour-ahead market prices were lower than the prices in the other markets. These prices were likely affected by increases in unscheduled wind and solar generation, as well as large volumes of self-scheduled inter-tie schedules.

Figure 1.1 Hourly comparison of system marginal energy prices (May – June)



Real-time price variability

Historically, 5-minute real-time market prices have been highly volatile, experiencing periods of both extreme positive and negative price spikes. In many instances, this price variability was the result of relaxations of 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

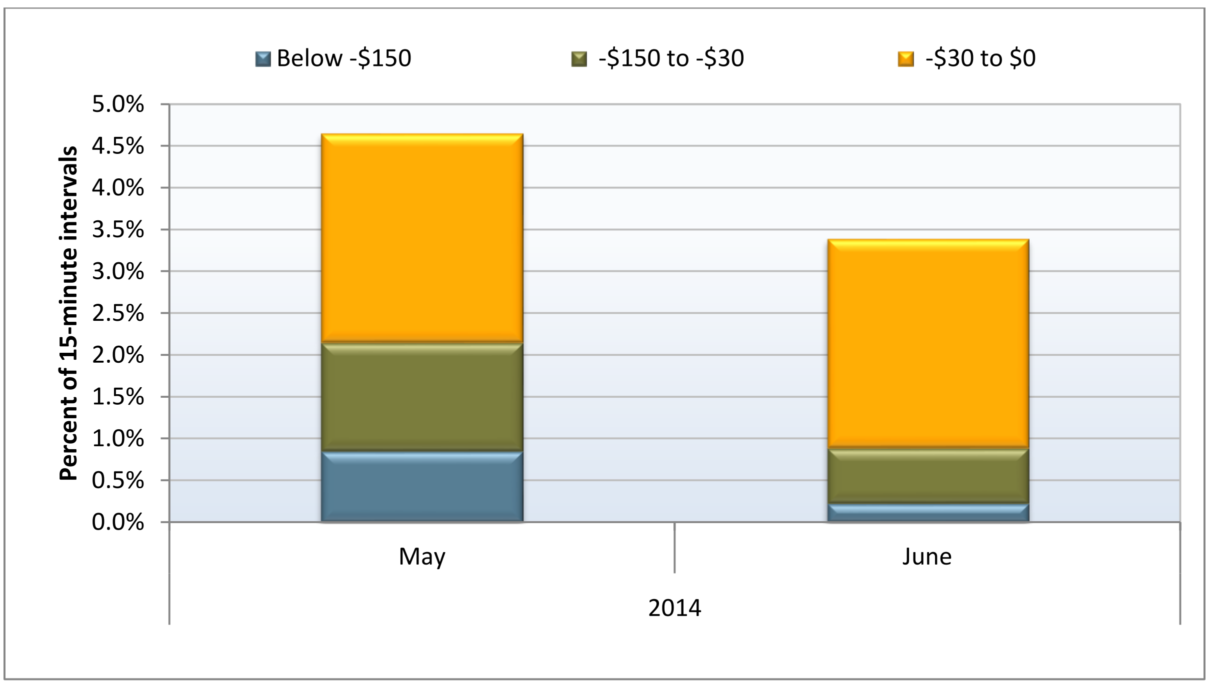
[10] Greater detail on system power balance constraints can be found in DMM's *2013 Annual Report on Market Issues and Performance*: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

lower impact as there is less settlement against the 5-minute real-time price.

Overall, 15-minute market prices were less variable than 5-minute market prices in May and June with regards to positive price spikes. For instance, 15-minute market prices reached above $250/MWh in only 0.2 percent of all intervals, whereas positive 5-minute market prices spiked above $250/MWh about 1.3 percent of the time. Part of this increase in variability was the result of unexpected changes in renewable generation and forecasting issues which were resolved in June.

With regards to negative prices, the 15-minute market and the 5 minute market had about the same percent of negative prices, about 4 percent, in the months of May and June. Figure 1.2 shows the frequency of negative price spikes in May and June in the 15-minute market. These prices 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. In some second quarter hours, total unscheduled solar and wind generation in the 15-minute market reached up to 3,000 MW. The reduction of the bid floor from -$30/MWh prior to May 1 and -$150/MWh afterwards did not appear to reduce the frequency of negative price spikes due to power balance constraint violations. However, the 5-minute prices did not appear to decrease as much after the change.

Figure 1.2 Frequency of negative 15-minute price spikes (all LAP areas)



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 bids offered into the real-time market.[11]

Figure 1.3 shows the level of self-scheduled imports and exports compared to the total offered imports and exports. Upon implementation of the new inter-tie rules in May, the market experienced a considerable increase in the quantity of self-scheduled inter-tie bids in both the day-ahead and real-time markets. The most striking change occurred in the real-time market where most of the inter-tie import and export bids were self-scheduled.

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 May and June, around 90 percent of economic import bids and around 80 percent of economic export bids were hourly blocks. The inter-tie resources rarely used the hourly economic bid block option with a single intra-hour economic schedule change. Only about 10 percent of economic import bids and 20 percent of economic export bids were 15-minute economic bids, as shown in Figure 1.4.

These changes in bidding behavior have impacted both reliability as well as the markets. Specifically, the ISO modified its approach to dealing with loop flows on the inter-ties away from using the transmission reliability margin mechanism, to more frequently curtailing transactions on the inter-ties. The operators have switched because of the lack of bid liquidity to resolve the adjustment of transmission and still account for self-schedules. In other words, the likelihood that the model would have to cut self-schedules and set prices based on penalty parameters would be high. As a result, curtailment of schedules has been preferred instead of the use of the transmission reliability margin. Even so, DMM observed several instances on select constraints where inter-tie congestion, particularly in the hour-ahead, was influenced by penalty prices. Ultimately, the high degree of self-scheduling appears to have contributed to congestion differences on some inter-ties.

[11] For further detail see Section 3.1.

Figure 1.3 Volume of self-scheduled and economic import and export bids

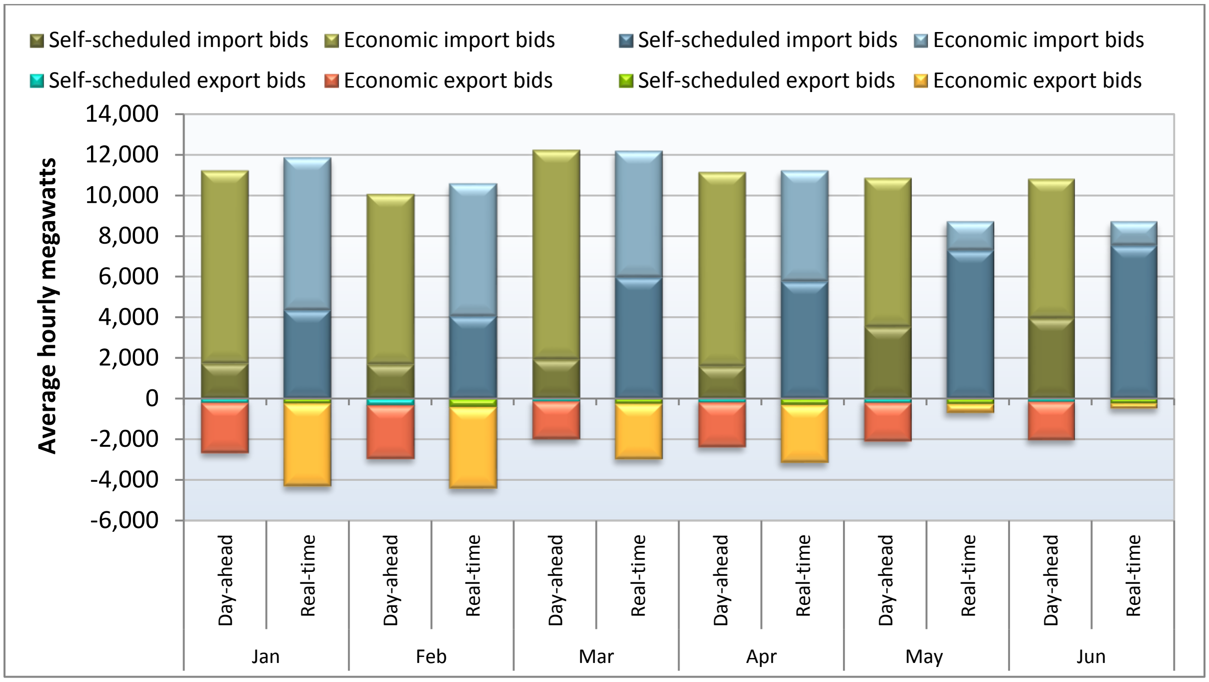
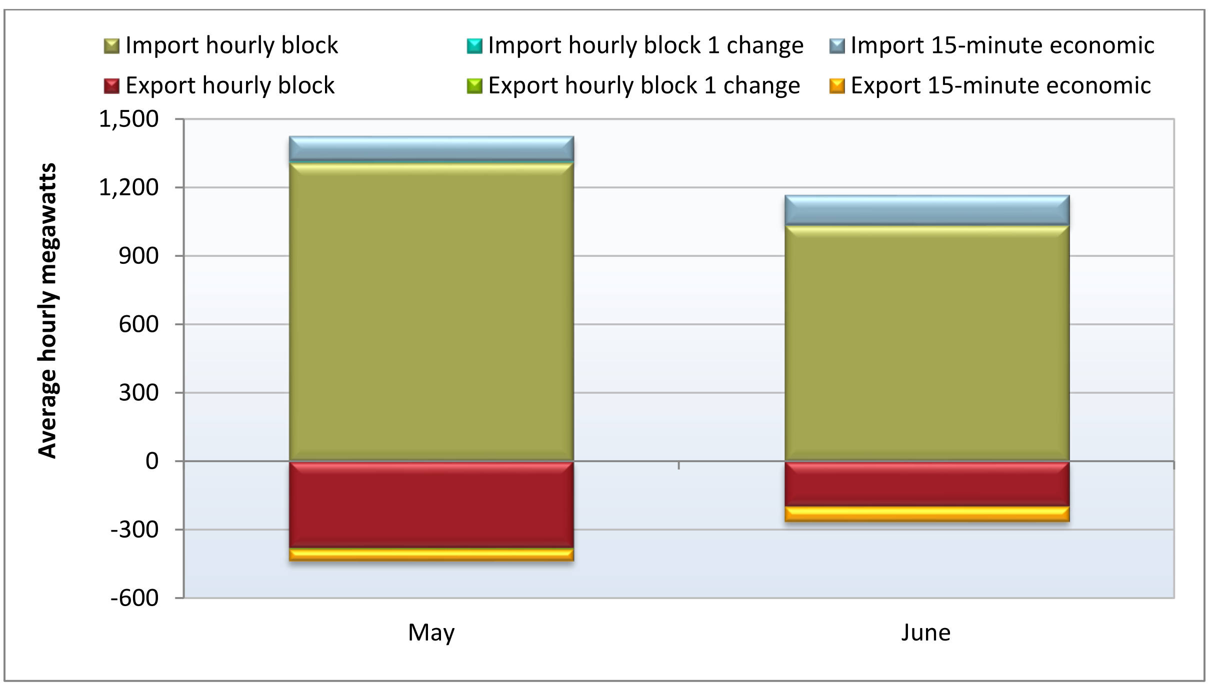


Figure 1.4 Economic import and export bids by bidding option



Reduction of inter-tie schedules in the residual unit commitment

The ISO day-ahead pre-schedule e-tag validation process changed as a result of the market changes on May 1. While there is no requirement to tag in the day-ahead, e-tags submitted for inter-tie resources scheduled in the day-ahead market are now validated against residual unit commitment schedules rather than day-ahead schedules, as had been done previously. The residual unit commitment market excludes all virtual bids, adjusts some participating intermittent resource program resource schedules[12] and solves to forecasted load. Schedules calculated in the day-ahead market may therefore differ substantially from residual unit commitment schedules.

Prior to the May market changes, any changes to inter-tie schedules in the residual unit commitment did not have any potential impact on the e-tag process. Beginning in May, any changes to inter-tie schedules could affect the day-ahead pre-scheduling e-tag validation. After concerns were raised by participants, the ISO changed a parameter within the model to give priority to inter-tie resources. Thus, internal generation would be decreased before inter-tie resources. This change was applied on May 20. Both the change in penalty price for inter-tie self-schedules and increased market participant familiarity with the new e-tagging requirements have helped to resolve some of the initial spring release implementation issues.[13]

Bid cost recovery

Due to the changes related to netting day-ahead and real-time costs and revenues, stakeholders were concerned that bid cost recovery payments would increase in May. 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.

Payments were around $25 million in the second quarter of 2014, compared to $33 million in the second quarter of 2013. Moreover, bid cost recovery payments in May and June were around $8 and $9 million respectively, compared to about $8 million each in March and April. More detail is provided in Section 2.5.

Variable energy resources

The spring release 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.

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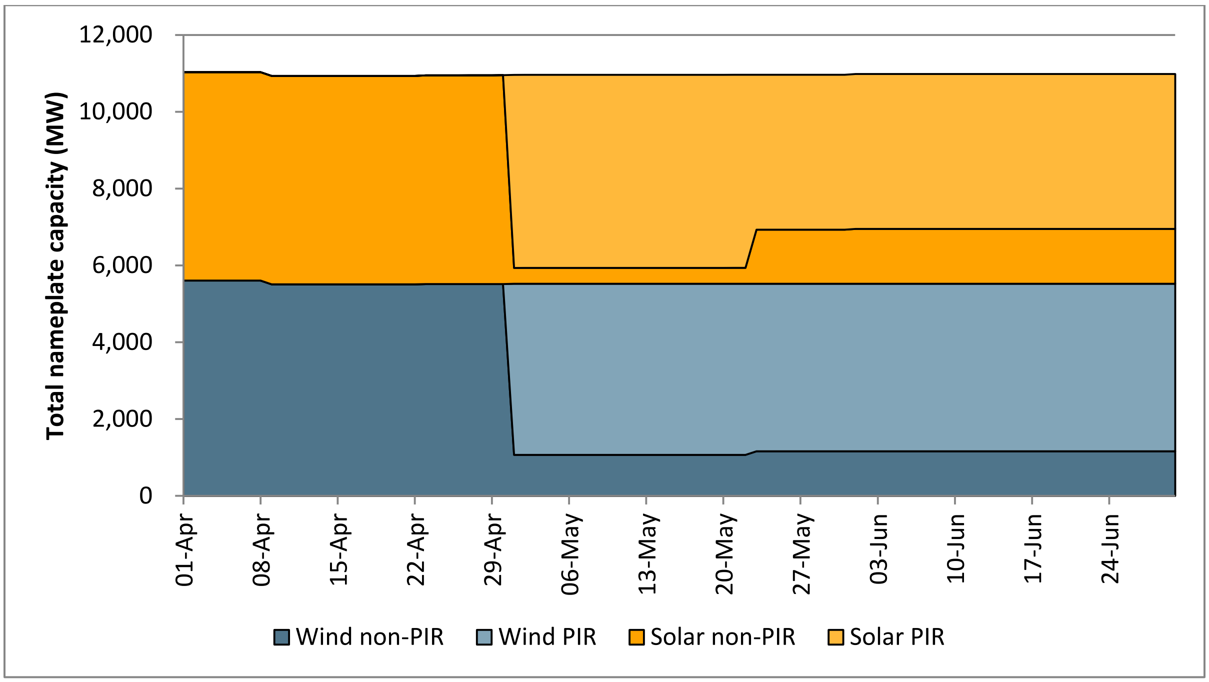
[12] For more detail see Section 1.7 of DMM's *Q1 2014 Report on Market Issues and Performance*, available at: http://www.caiso.com/Documents/2014FirstQuarterReport-MarketIssues_Performance-May2014.pdf.

[13] Further information is available in Section 3.1.5 and "Frequently Asked Questions - Tagging Requirements," available on the ISO website: http://www.caiso.com/Documents/FAQ_TaggingRequirements_May1.pdf.

Figure 1.5 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 1.5 Nameplate capacity of wind and solar by participating intermittent resource status



2 Market performance

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

- Day-ahead prices in the second quarter were similar to the first 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.
- For May and June, the 15-minute market prices were slightly lower than day-ahead market prices for both peak and off-peak periods.
- Peak and off-peak 5-minute market prices were higher than day-ahead prices in April and May, and dipped below day-ahead prices in June.
- The frequency of high 15-minute price spikes was relatively low for the quarter, whereas the frequency of 5-minute price spikes increased.
- The frequency of negative 15-minute and 5-minute market price spikes was about the same, affecting about 4 percent of intervals.
- Flexible ramping constraint payments were $2.3 million in the second quarter, down from about $3 million in the first quarter.
- Congestion in both the day-ahead and 5-minute markets increased in the second quarter; however, the percentages and costs remain historically low. Congestion in the 15-minute market was also low.
- Bid cost recovery payment levels were similar to the previous quarter and lower than in the second quarter of 2013.
- Real-time imbalance offset costs totaled almost $80 million in the second quarter of 2014, approximately double the $40 million costs seen in the first quarter of the year.
- Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 430 MW on average, a decrease from 590 MW of net virtual supply in the previous quarter.
- Total convergence bidding revenue, adjusted for bid cost recovery costs, was about $10.2 million.
- About 50 percent of convergence bidding revenues resulted from only three days – two days with high virtual demand revenues and one day with high virtual supply.

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 5-minute price levels were higher than hour-ahead and 15-minute prices in most peak and off-peak periods in the quarter.

- Day-ahead prices did not exhibit much monthly variability in both peak ($52/MWh) and off-peak ($40/MWh) periods. The day-ahead prices were higher than both hour-ahead and 15-minute market prices and mixed relative to 5-minute market prices.
- On a quarterly average basis, peak hour-ahead prices were lower than day-ahead prices in all months by an average of about $8/MWh. Hour-ahead off-peak prices averaged nearly $17/MWh lower than day-ahead prices.
- Peak period average system prices in the 15-minute market were slightly lower than day-ahead market prices in May (about $5/MWh) and June (about $1/MWh). Similarly, the difference between day-ahead and 15-minute prices in off-peak periods was about $3/MWh in May and about $1/MWh in June.
- In the second quarter, average peak system prices in the 5-minute market were higher than day-ahead prices in April and May but were lower in June, by $3/MWh, $2/MWh and -$7/MWh, respectively. Off-peak 5-minute prices were about $5/MWh higher than day-ahead prices in April and May and nearly $1/MWh lower in June.

On an hourly basis, Figure 2.3 further illustrates the market prices in May and June. Specifically, hour-ahead prices were consistently lower than all other markets during this period. The hour-ahead market is the first real-time market to address any unscheduled generation, particularly from wind and solar. Moreover, it also must address a large volume of self-scheduled energy on the inter-ties. Combined, this can create little economic dispatch maneuverability. Furthermore, the ISO has limited the use of load adjustments in the hour-ahead market in the second quarter compared to the first quarter of 2014 and the end of 2013.[14] Average peak load adjustments decreased per hour in the second quarter from about 260 MW to nearly 160 MW. Off-peak load adjustments also decreased to an average of about 27 MW during off-peak hours from nearly 120 MW in the first quarter.

Figure 2.3 also shows that the average hourly 5-minute prices were higher than day-ahead prices for most of the evening ramping and peak hours. 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 $16/MWh in hour ending 20. The difference between 15-minute market prices and day-ahead market prices was most pronounced in hours ending 4 and 18, averaging about $10/MWh for the period.

[14] For most of 2013, hourly load adjustments occurred throughout the day. Load adjustments increased in November and December to about 400 MW during the morning ramping period and up to 700 MW during the evening ramping period. For more information, see Section 9.2 of DMM's *2013 Annual Report on Market Issues and Performance*: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

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

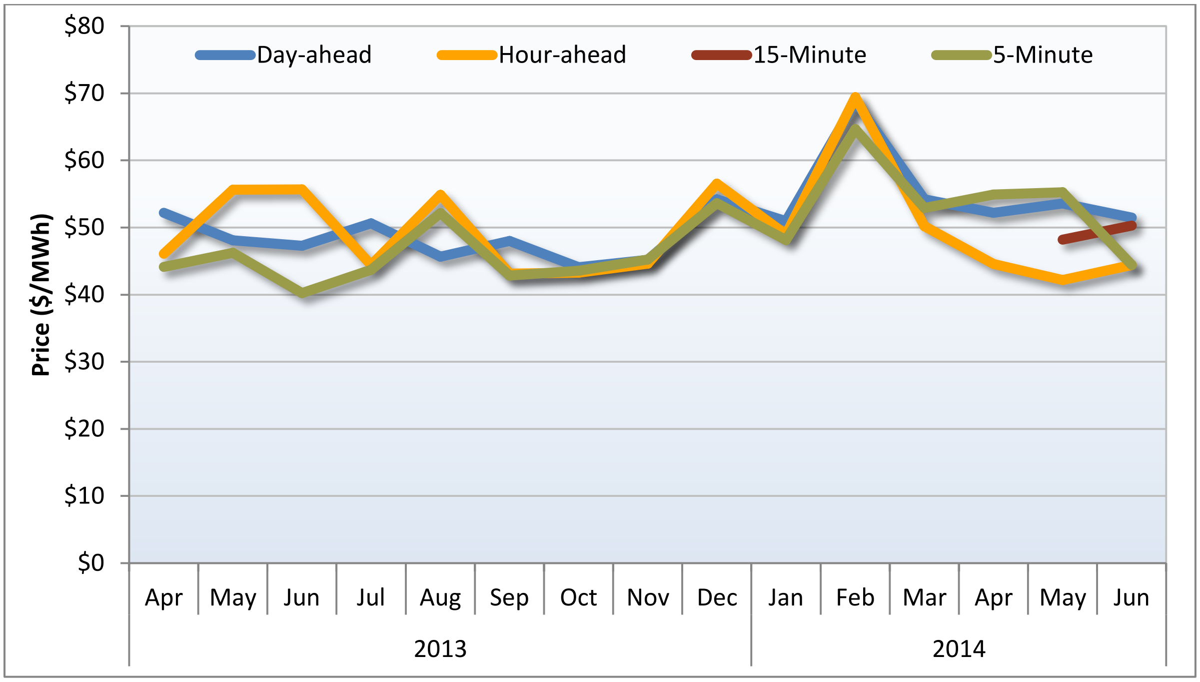


Figure 2.2 Average monthly off-peak prices – system marginal energy price

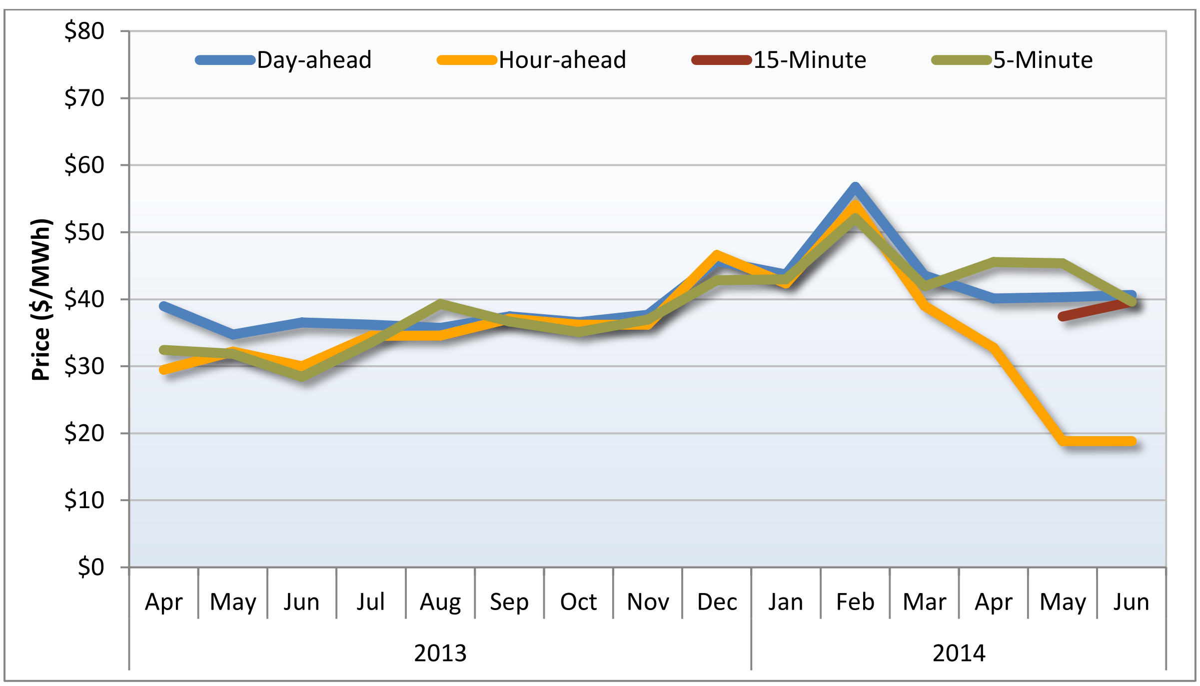
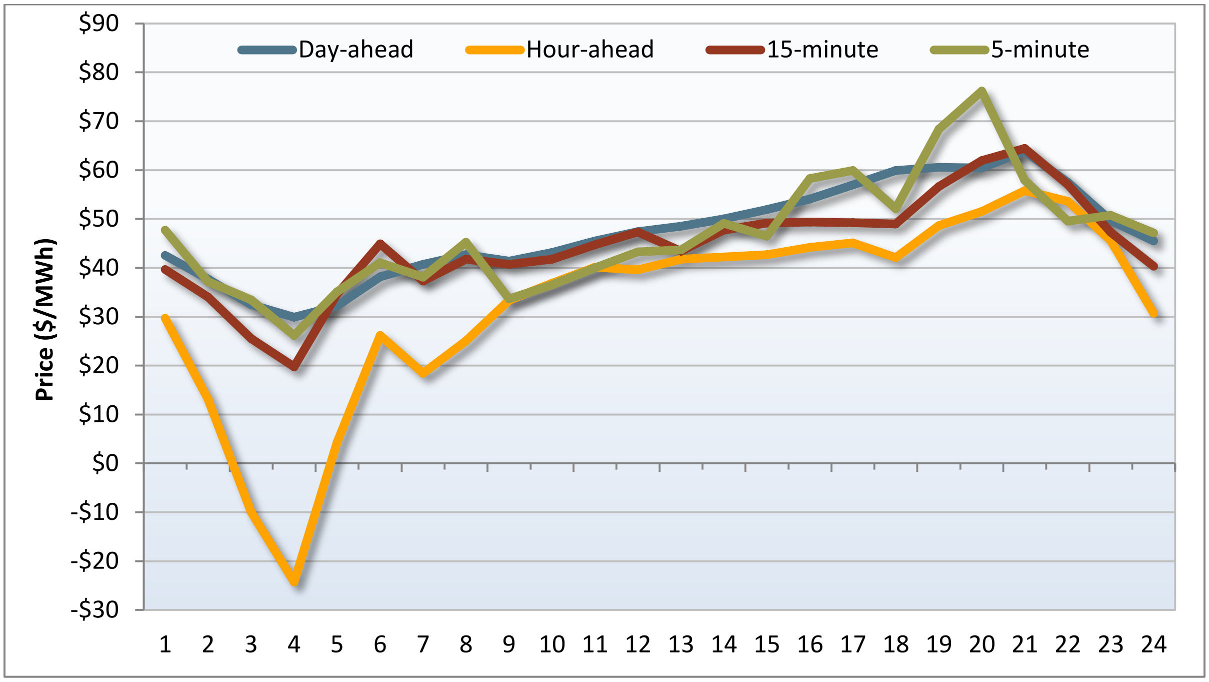


Figure 2.3 Hourly comparison of system marginal energy prices (May – June)



2.2 Price variability

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

DMM reviewed the energy imbalance between the day-ahead and real-time markets and found that, for May and June, around 80 percent of imbalance energy occurred in the 15-minute market and about 20 percent of imbalance energy occurred in the 5-minute market.[16] Thus, the variability of the 15-minute and 5-minute market prices needs to be understood through this context.

Overall, 15-minute market prices were less variable than 5-minute market prices in May and June with regards to positive price spikes. For instance, 15-minute market prices reached above $250/MWh in only 0.2 percent of all intervals,[17] whereas positive 5-minute market prices spiked above $250/MWh

[15] For further detail see Section 3.1 of DMM's *2013 Annual Report on Market Issues and Performance*: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

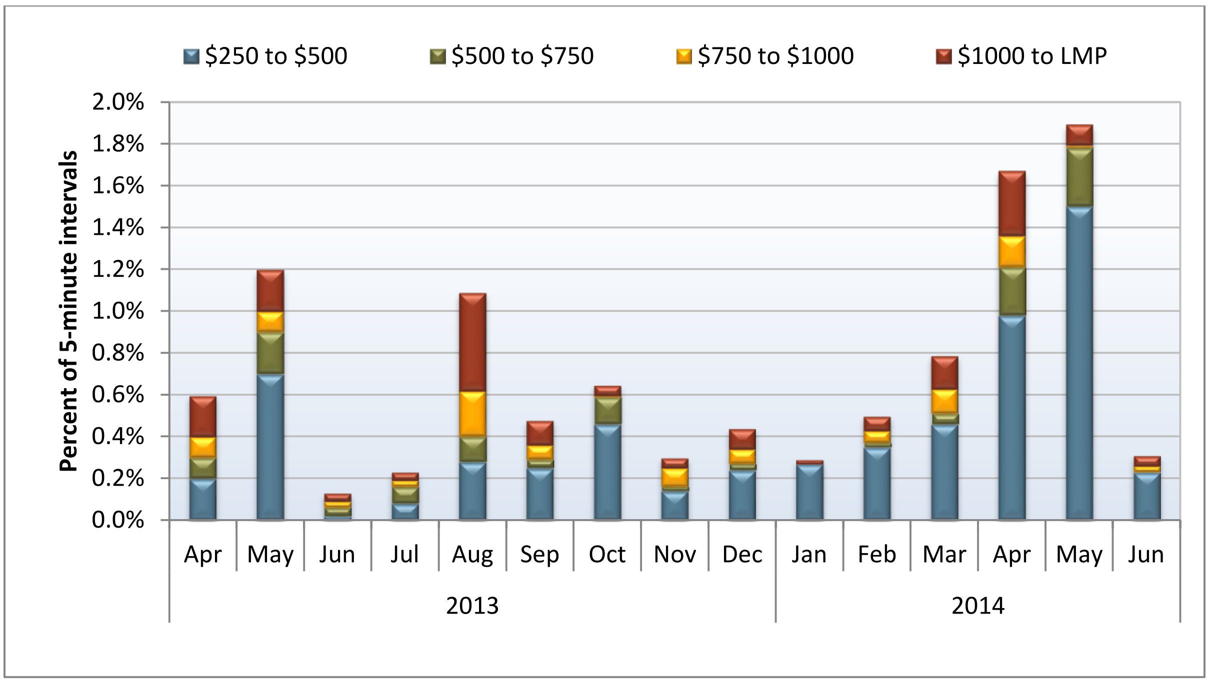
[16] DMM calculated the average of the absolute differences between the day-ahead market and the 15-minute market, which was approximately 1,650 MW of imbalance energy. DMM also calculated the average of the absolute differences between the 15-minute and 5-minute markets, which was around 450 MW of imbalance energy.

[17] We have not graphed the frequency of positive 15-minute price spikes given the infrequent number of instances and low overall magnitude.

about 1.3 percent of the time.

Figure 2.4 shows the frequency of positive price spikes that occur in the 5-minute market. In the second quarter, the frequency was about 1.3 percent, compared to 0.5 percent in the first quarter of 2014. Historically, the overall frequency of 5-minute price spikes is low but more frequent than 15-minute positive price spikes. The chart shows an increase in the frequency of price spikes in April and May followed by a significant decrease in June. This was partly due to ramping limitations resulting from unexpected drops in wind generation. Ramping limitations due to rapid decline of solar generation during the late afternoon load ramp also contributed to increases in the frequency of these price spikes. In addition, renewable forecast issues contributed to the higher levels in May.

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



With regards to negative price spikes, both 15-minute and 5-minute prices spiked negative in about 4 percent of intervals. Figure 2.5 shows the frequency of negative price spikes in May and June in the 15-minute market. These negative prices were mainly due to periods of over-generation resulting from unscheduled wind and solar generation in real time. Specifically, unscheduled solar generation resulted in negative prices during the rapid morning ramping hours. In some hours of the second quarter, total unscheduled solar and wind generation in the 15-minute market reached up to 3,000 MW.

Figure 2.6 shows an increase in the frequency of negative prices in the 5-minute market in the second quarter. This was also partly due to periods of over-generation resulting from unscheduled wind and solar generation. As part of the market changes in May, the bid floor was lowered from -$30/MWh to -$150/MWh. There was a noticeable change in the level of price spikes as more prices were observed between $0/MWh and -$30/MWh.

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

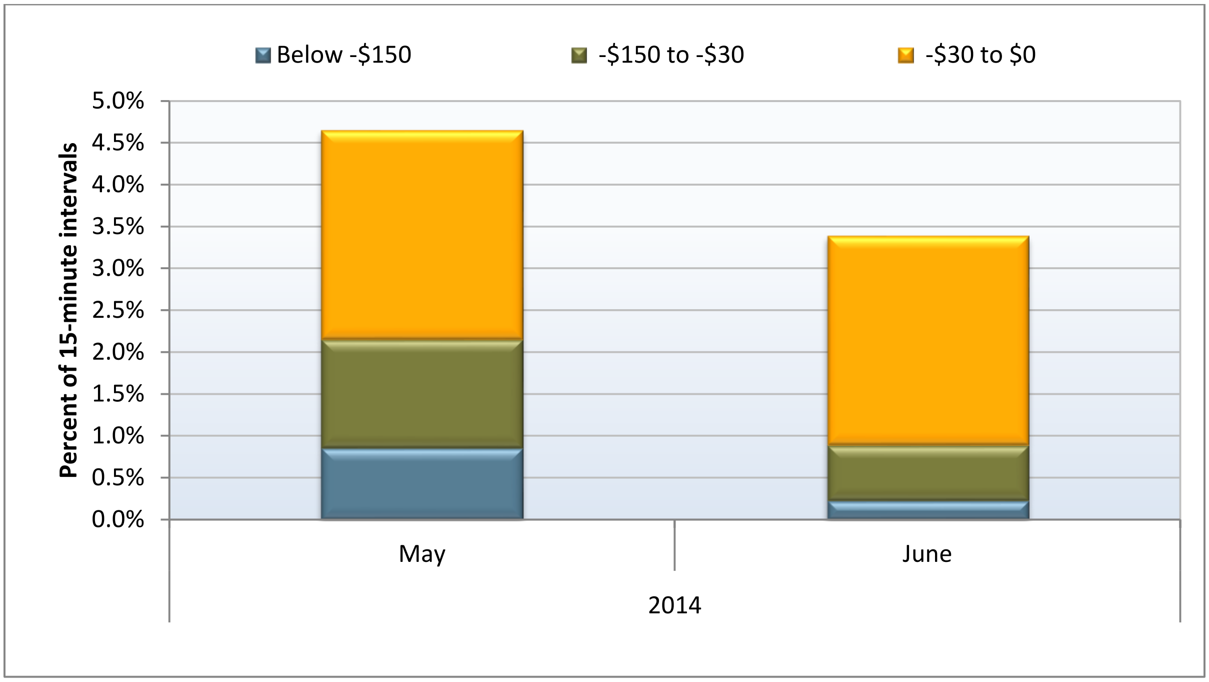
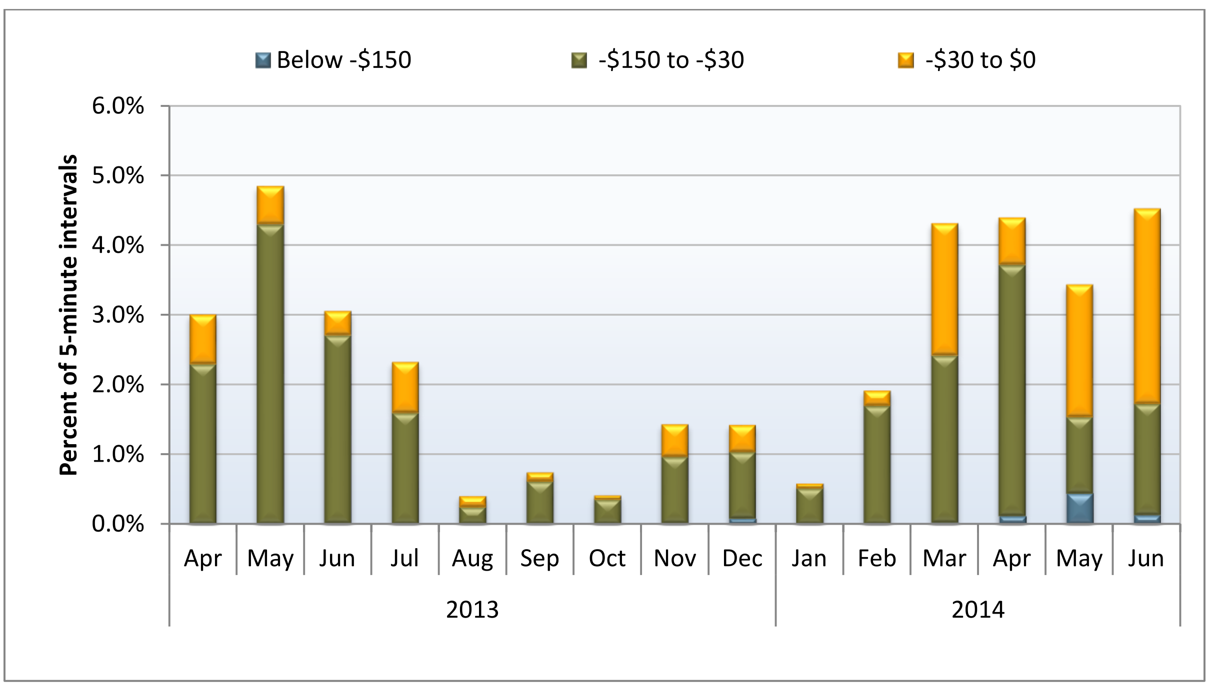


Figure 2.6 Frequency of negative 5-minute price spikes (all LAP areas)



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 $2.3 million in the second quarter, down from around $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 400 MW, which is down from 480 MW in the previous quarter.

Background

In December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute market.[18] 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.[19] The default requirement was set to 300 MW in the second quarter, but was occasionally adjusted to the maximum of 600 MW, typically in the morning and evening ramping hours.

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.[20]

Payments to the generators

Total payments for flexible ramping resources in the second quarter were around $2.3 million, down from around $3 million in the previous quarter.[21] Table 2.1 provides a review of monthly flexible ramping constraint activity in the 15-minute market. The table highlights the following:

- The frequency of intervals where the flexible ramping constraint was binding was around 7 percent, down from 9 percent in the previous quarter.
- The frequency of procurement shortfalls remained at 0.3 percent for all 15-minute intervals in both the first and second quarters.

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

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

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

[21] 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.

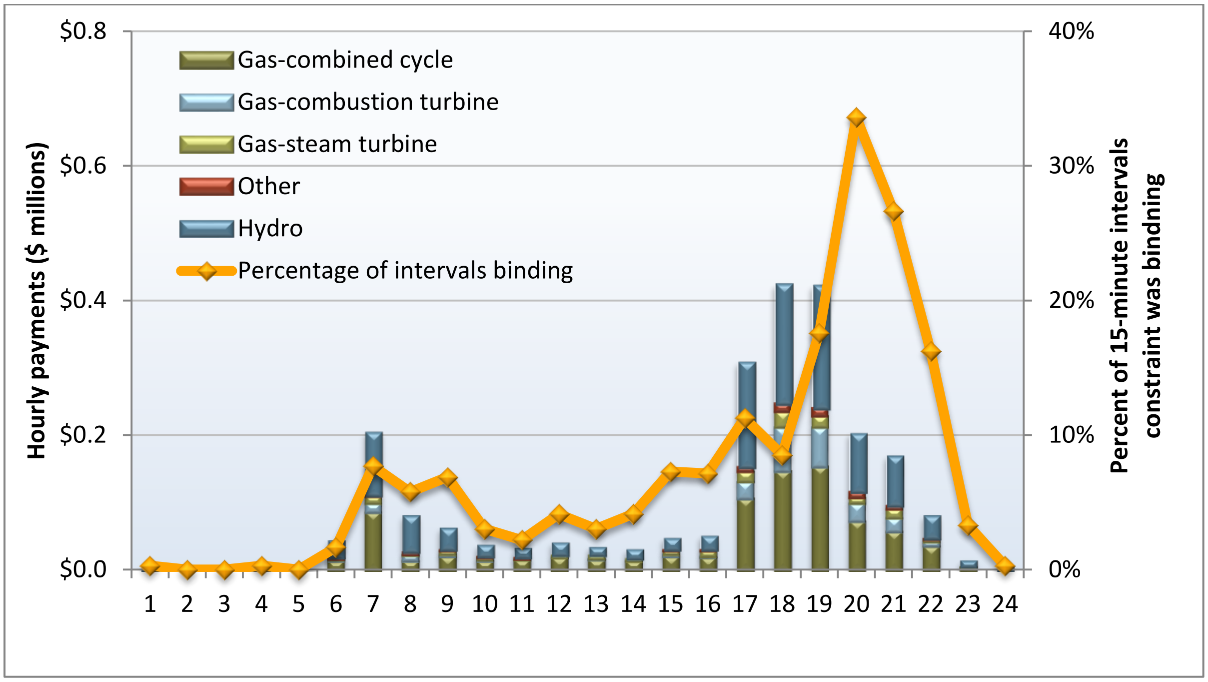
- The average shadow price when the flexible ramping constraint was binding was about $33/MWh, down from $36/MWh in the previous quarter.

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	Apr	$2.51	15%	1.6%	$54.62
2013	May	$2.73	13%	2.0%	$68.50
2013	Jun	$1.95	9%	1.3%	$72.97
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

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 second 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 (April – June)



2.4 Congestion

Although still low, congestion within the ISO system in the second 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.[22]

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 SDG&E area was primarily driven by the binding constraint to protect the Hoodoo Wash – North Gila 500 kV Line. Also, price impacts on individual constraints can differ between the day-ahead, 15-minute and 5-minute markets, as seen in the following sections.

[22] 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. As noted earlier, 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 second quarter (see Table 2.2).

In the PG&E area, 30880_HENTAP2_230_30900_GATES_230_BR_2_1 was the most congested constraint in the day-ahead market. This constraint was binding in nearly 30 percent of hours. During these hours, prices in the PG&E area increased by about $1.84/MWh while prices in the SCE and SDG&E areas remained unchanged. This constraint, located in the Fresno area, is heavily dependent on imports from the 230 kV system through the McCall, Herndon, and Henrietta banks, and local hydro generation. 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 increasing prices in the PG&E area was 6110_TM_BNK_FLO_TMS_DLO_NG at about 12 percent of hours. This constraint was activated to mitigate unscheduled flows on the California Oregon Inter-tie (COI).

In the SCE area, the Barre – Lewis 230 kV line was the most binding constraint in the second quarter. This constraint was congested in about 4 percent of hours due to contingencies. When this constraint was binding, the SCE and SDG&E area prices increased by about $1.52/MWh and $1.98/MWh, respectively, while prices decreased in the PG&E area by about $1.28/MWh. The second most congested constraint was Magunden – Vestal #2, which was binding in about 3 percent of the hours due to the potential loss of the Magunden – Vestal #1 230 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 $0.85/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 second quarter was 24086_LUGO_500_26105_VICTORVL_500_BR_1_1. This constraint was binding in about 27 percent of hours and increased prices in the SDG&E and SCE areas by $1.12/MWh and $0.51/MWh, respectively, while decreasing prices in the PG&E area by $0.80/MWh. This constraint was binding due to a contingency on the Hoodoo Wash – North Gila 500 kV line. The second most binding constraint, due to power flows and line adjustments in the San Diego area, was 7820_TL 230S_OVERLOAD_NG. With the exception of the 22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1_1 and the 22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1 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		
Area	**Constraint**	**Q1**	**Q2**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
PG&E	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	10.5%	29.9%	$0.36	-$0.27	-$0.27	$1.84		
	6110_TM_BNK_FLO_TMS_DLO_NG		11.9%				$0.71	-$0.89	-$0.89
	PATH15_BG	1.6%	9.4%	$4.56	-$3.65	-$3.65	$3.67	-$3.07	-$3.07
	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
	35922_MOSSLD _115_30750_MOSSLD _230_XF_1A		5.0%				$0.78		
	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
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1		0.4%				$4.69	-$4.08	-$4.08
	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_25201_LEWIS _230_BR_1 _1	6.6%	4.3%	-$1.48	$1.80	$0.96	-$1.28	$1.52	$1.98
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.9%					$0.85	
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	5.1%	2.0%	-$2.59	$2.98	$0.54	-$1.00	$1.49	$0.87
	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%	-$0.06	-$0.21	$0.87	-$0.80	$0.51	$1.12
	7820_TL 230S_OVERLOAD_NG	1.6%	5.7%	-$0.11		$1.89	-$1.25		$6.68
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	1.5%	4.2%			$4.85			$6.65
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	2.2%	3.0%			$1.90			-$2.79
	22448_MESAHGTS_69.0_22496_MISSION _69.0_BR_1 _1		1.4%						$2.08
	22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1		1.2%						$6.00
	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
	22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1		0.3%						$4.90
	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 LUGO-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			
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.2%		-$2.17	$1.69	$1.67			

15-minute market congestion

In May and June, 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 second quarter.

Overall, the most frequently congested constraint was 30880_HENTAP2_230_30900_ GATES_230_BR_2_1 located in the PG&E area, which was binding over 2 percent of the time in the second quarter. This constraint increased prices by about $5.56/MWh in the PG&E area and decreased prices in the SCE and SDG&E areas by $8.32/MWh. This constraint was binding due to the contingency loss of the Gates – Gregg 230 kV line.

Congestion on the Barre – Villa 230 kV line, which occurred in about 0.2 percent of intervals, increased prices in the SCE and SDG&E areas by about $4.50/MWh and $10.32/MWh, respectively. Congestion on this constraint decreased prices in the PG&E area by about $7.04/MWh. This constraint was impacted by Barre – Lewis 230 kV line contingencies.

The 22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1 drove 15-minute market prices up in the SDG&E area by about $16/MWh. The other remaining constraints in the SDG&E area were binding in less than 0.6 percent of all intervals, but had significant price impact on the SDG&E area prices when binding. These constraints include the 22886_SUNCREST_230_22832_SYCAMORE_230_BR_1_1 line and the 22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1 branch group.

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

Area	Constraint	Frequency	Load area		
			PG&E	SCE	SDG&E
PG&E	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	2.4%	$5.56	-$8.32	-$8.32
	6110_TM_BNK_FLO_TMS_DLO_NG	1.5%	$3.43	-$5.02	-$5.02
	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	0.2%	-$7.04	$4.50	$10.32
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.3%	-$0.95	$0.91	-$0.28
SDG&E	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
	7820_TL 230S_OVERLOAD_NG	0.5%	-$9.17		$47.97
	22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1	0.5%			$17.69
	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
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.1%	-$16.35	$5.74	$29.86
	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, as seen by a comparison of Table 2.2 and Table 2.3. In the second 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 30 percent of hours in the day-ahead market compared to around 2.4 percent of intervals in the 15-minute market. While this constraint increased day-ahead prices in the PG&E area by nearly $1.84/MWh, it increased prices by about $5.56/MWh in the 15-minute market. A similar pattern 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 the 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.[23] The congestion price impact differs across load areas and markets.

In the second quarter, congestion in the day-ahead market increased prices about 1.8 percent in the PG&E and SDG&E areas, $0.92/MWh and $0.81/MWh respectively, while decreasing the SCE area prices by about 0.5 percent or -$0.23/MWh. Congestion in the 15-minute market had a relatively small impact, about 0.6 percent, separating the load area prices by less than $0.30/MWh. Congestion in the 5-minute market[24] increased PG&E area prices by about $1.40/MWh (2.8 percent) while decreasing prices in both the SCE and SDG&E areas, $1/MWh (2.4 percent) and $0.50/MWh (1 percent).

Day-ahead price impacts

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

The SCE area experienced an overall decrease in day-ahead market prices due to the impact of congestion, about $0.23/MWh from the system average, while prices in the PG&E and SDG&E area increased by about $0.92/MWh and $0.81/MWh respectively. Compared to the previous quarter, the magnitude of PG&E and SDG&E area congestion tripled, from about $0.26/MWh, while congestion in the SCE area was similar in magnitude but opposite in direction.

The Path 15 branch group had the largest overall impact on prices in the second quarter. This constraint increased prices in the PG&E area by $0.35/MWh (0.71 percent) and decreased the SCE and SDG&E area prices by $0.29/MWh (0.62 percent). In the SCE area, the 24086_LUGO_500_26105_VICTORVL_500_BR_1_1 constraint increased prices by $0.14/MWh (0.3 percent), and increased prices in the SDG&E area by $0.28/MWh (0.57 percent), while decreasing prices in the PG&E area by $0.21/MWh (0.44 percent). In the SDG&E area, the 7820_TL 230S_OVERLOAD_NG increased the day-ahead prices by $0.38/MWh (0.79 percent) and decreased the PG&E area prices by about $0.01/MWh (0.02 percent). 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.

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

[24] As mentioned before, congestion in the real-time market often has a larger price effect in intervals when it occurs. However, the overall price impact of congestion depends on the frequency of congestion along with the magnitude of the price effect.

Table 2.4 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
PATH15_BG	$0.35	0.71%	-$0.29	-0.62%	-$0.29	-0.60%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.21	-0.44%	$0.14	0.30%	$0.28	0.57%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.55	1.14%				
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.02%			$0.38	0.79%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.28	0.57%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.06	-0.12%	$0.07	0.14%	$0.03	0.07%
33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.06	0.12%	-$0.04	-0.08%	-$0.04	-0.08%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.08	0.17%	-$0.03	-0.05%	-$0.03	-0.05%
LOSBANOSNORTH_BG	$0.04	0.09%	-$0.04	-0.08%	-$0.04	-0.07%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.04	0.09%	-$0.04	-0.08%	-$0.04	-0.07%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.03	-0.05%	$0.01	0.03%	$0.05	0.11%
SDGE_CFEIMP_BG	-$0.01	-0.02%	-$0.01	-0.02%	$0.07	0.15%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.08	-0.17%
SLIC 2249785 ELDORADO-LUGO_1_NG	$0.02	0.05%	-$0.02	-0.04%	-$0.04	-0.08%
T-135 VICTVLUGO_DVRB_NG	$0.03	0.05%	-$0.02	-0.04%	-$0.03	-0.06%
22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1					$0.07	0.15%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	-0.04%	$0.03	0.06%	$0.01	0.02%
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.02	-0.03%	$0.01	0.02%	$0.03	0.06%
24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	-$0.02	-0.03%	$0.01	0.03%	$0.02	0.05%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.03	0.07%	-$0.01	-0.02%	-$0.01	-0.02%
30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	$0.02	0.04%	-$0.02	-0.03%	-$0.02	-0.03%
SLIC 2237207 TL50002 DVRB	$0.02	0.03%	-$0.02	-0.04%	$0.01	0.02%
22636_PARADISX_69.0_22456_MIGUEL _69.0_BR_1 _1					$0.05	0.09%
35922_MOSSLD _115_30750_MOSSLD _230_XF_1A	$0.04	0.08%				
MIGUEL_BKs_MXFLW_NG					$0.03	0.07%
22448_MESAHGTS_69.0_22496_MISSION _69.0_BR_1 _1					$0.03	0.06%
22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1					$0.03	0.05%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1			$0.03	0.05%		
SLIC 2206489_PVCR_Out_EDLG	$0.01	0.01%	$0.00	-0.01%	-$0.01	-0.02%
30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
SOUTHLUGO_RV_BG	-$0.01	-0.01%	$0.01	0.01%	$0.01	0.01%
22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1					$0.02	0.03%
30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.01	0.01%				
Other	-$0.01	-0.02%			$0.04	0.08%
Total	$0.92	1.9%	-$0.23	-0.5%	$0.81	1.7%

15-minute price impacts

Table 2.5 shows the overall impact of 15-minute congestion on average prices in each load area in the second quarter by constraint. Congestion on the Path 15 constraint drove prices up in the PG&E area by about $0.23/MWh (0.51 percent) and down in the SCE and SDG&E areas by $0.19/MWh (0.43 percent). The overall impact of congestion elevated the PG&E and SDG&E areas prices by about $0.30 (0.6 percent) and decreased SCE area prices by about the same amount.

Table 2.5 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH15_S-N	$0.23	0.51%	-$0.19	-0.43%	-$0.19	-0.41%
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.01%			$0.22	0.49%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.14	0.30%	-$0.03	-0.07%	-$0.03	-0.06%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.05	0.11%	-$0.05	-0.12%	-$0.05	-0.11%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.15	0.32%
22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1	-$0.01	-0.02%			$0.09	0.20%
33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.02	0.05%	-$0.03	-0.08%	-$0.03	-0.07%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.08	-0.18%
22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1					$0.08	0.18%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.02	-0.05%	$0.01	0.02%	$0.04	0.08%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	-0.04%	$0.01	0.03%	$0.02	0.05%
24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	-$0.01	-0.03%	$0.01	0.02%	$0.02	0.04%
SLIC 2249785 ELDORADO-LUGO_1_NG	$0.01	0.03%	-$0.01	-0.02%	-$0.02	-0.04%
22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3					-$0.04	-0.08%
T-135 VICTVLUGO_DVRB_NG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.03%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.01	-0.03%	$0.01	0.03%		
SOUTH_OF_LUGO	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
Other	-$0.08	-0.18%	$0.02	0.04%	$0.08	0.17%
Total	$0.29	0.6%	-$0.25	-0.6%	$0.25	0.6%

Overall, the frequency of 15-minute congestion did not have a significant impact on the load area prices as compared to the day-ahead and 5-minute markets. During the first two months of implementation, the 15-minute market congestion did not separate prices significantly, nor was it consistent 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.

5-minute price impacts

After implementing the 15-minute market in May, the impact of 5-minute market congestion on overall settlements has been reduced. Even so, congestion in the 5-minute market is still important as 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 second quarter was 30880_HENTAP2 _230_30900_GATES_230_BR_2_1, which is located in the PG&E area. This constraint was binding in over 4 percent of intervals and increased prices by about $6/MWh in the PG&E area and decreased prices in the SCE and SDG&E areas by $8/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 Path 15 branch group. This constraint was binding in fewer than 4 percent of intervals and increased PG&E prices by about $26/MWh and decreased prices in both the SCE and SDG&E areas by about $21/MWh when binding.

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 second quarter, the impact of 5-minute market congestion changed significantly from the previous quarter. It increased PG&E area prices by about $1.40/MWh (2.8 percent), from -$0.57/MWh (-1 percent) in the previous quarter. Congestion impacts in Southern California decreased prices by $1/MWh (2.4 percent) in the SCE area and by $0.50/MWh (1 percent) the SDG&E area. This is different from the previous quarter when Southern California prices increased due to congestion.

2.5 Bid cost recovery

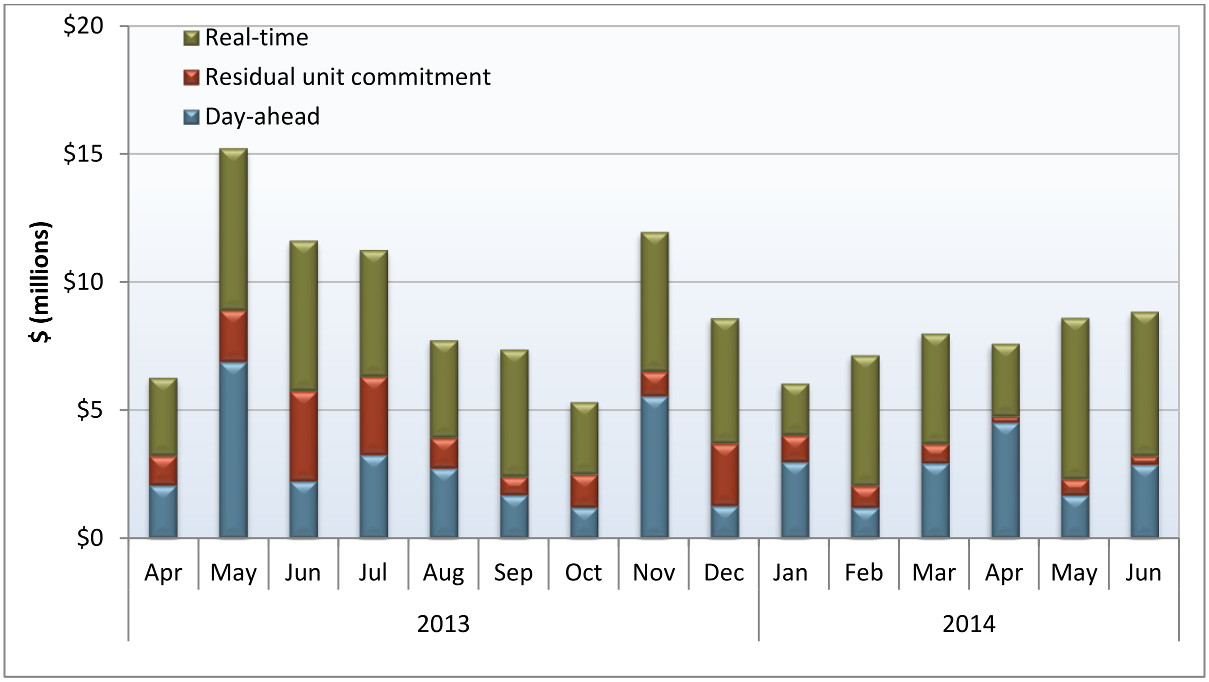
The market enhancements in May brought significant changes to the bid cost recovery payment rules. Before the rule changes, bid cost recovery payments were netted with revenues received among the day-ahead, residual unit commitment and real-time markets. For instance, if a unit was committed in the day-ahead 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.[25] 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.[26] DMM estimates that bid cost recovery payments were around $25 million in the second quarter of 2014, compared to $33 million in the second quarter of 2013. Moreover, bid cost recovery payments in May and June were around $8 and $9 million respectively, compared to around $8 million in March and April. Thus, there does not appear to have been a significant increase in bid cost recovery as a result of the change in the day-ahead and real-time netting rules. DMM will continue to track this change.

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

[26] 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



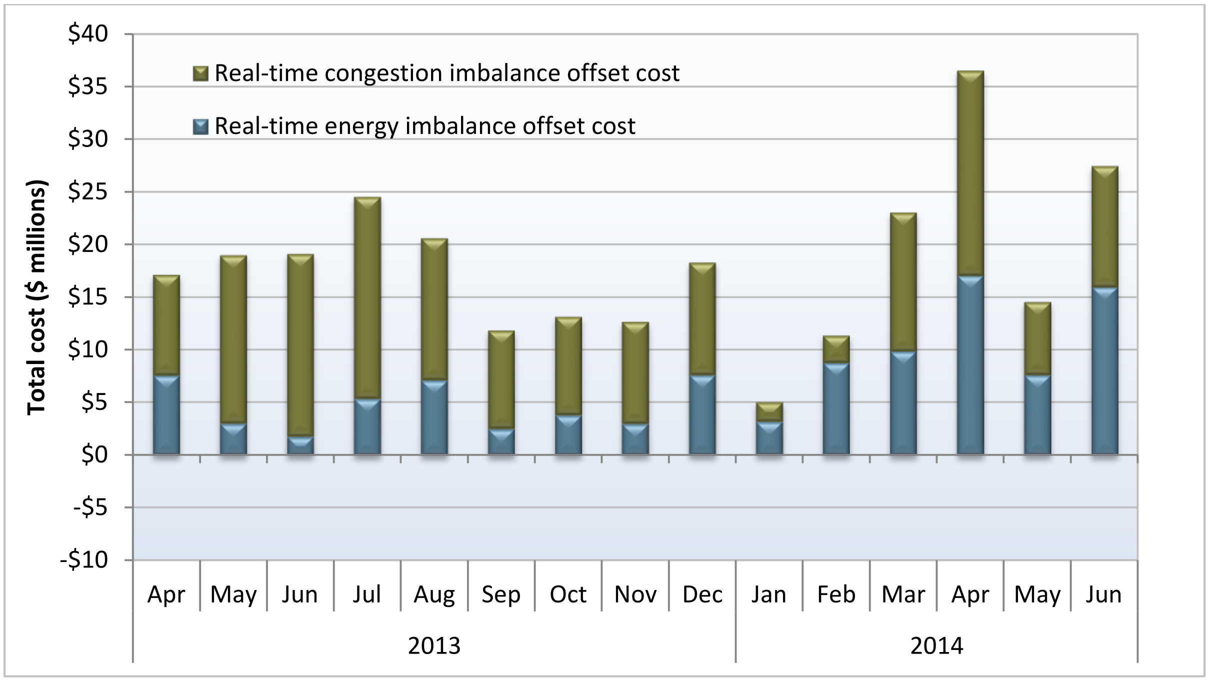
2.6 Real-time imbalance offset costs

Real-time imbalance offset costs totaled about $80 million in the second quarter of 2014, approximately double the $40 million value in the first quarter of the year. Total real-time imbalance offset costs in the second quarter were split evenly between energy imbalance offset costs and congestion imbalance offset costs. Currently, energy imbalance offset costs in the first half of 2014 ($63 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 the pending announcement of the identity of participating intermittent resource program protective measure resources.[27]

[27] Prior to the monthly recalculation of settlement for resources settling under PIRP protective measures and to the announcement of the identity of these resources, any generation of these resources will be settled as real-time uninstructed imbalance energy. When these resources are re-settled under PIRP protective measures, the uninstructed energy charges will be reversed and the resources 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 bids into the market, either economically or as a self-schedule, risks losing its PIRP status.

Figure 2.9 Real-time imbalance offset costs



The largest combined monthly value over the last several months was in April at $36 million, which occurred prior to the market changes in May. In this month, over $9 million of the estimated $17 million energy imbalance offset costs were incurred on seven days alone. On April 27, the energy imbalance offset was almost $3 million, accounting for over five percent of total energy imbalance offset for the quarter. Following the May market changes, the frequency of days with high imbalance offset charges declined. The monthly values appear to be the result of an increase in energy imbalance offset costs on days without extraordinarily high values, rather than being driven by charges incurred on a handful of days. This pattern may change when imbalance offset costs are recalculated, as noted above.

Congestion imbalance offset cost estimates rose substantially from $18 million in the first quarter to $38 million in the second 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.

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.[28] All numbers reported in this section reflect the prevailing settlement rules at the time the market ran.

Participants engaging in convergence bidding continued to earn positive returns from participation in ISO markets in the second quarter. The net revenues from the market were about $10.7 million, compared to about $3.8 million in the previous quarter. Virtual supply generated net revenues of about $6 million, while virtual demand accounted for approximately $4.7 million. The total payment to convergence bidders fell slightly to $10.2 million after taking into account virtual bidding bid cost recovery charges of $0.5 million.

About 50 percent of convergence bidding revenues occurred on only three days; two days with high virtual demand revenues and one day with high virtual supply revenues. On these days the virtual demand revenues are associated with wildfires as well as transmission and generation outages while the virtual supply revenue day was affected by unscheduled renewable generation.

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 60 percent of all accepted virtual bids in the second quarter, a decrease from 68 percent in the previous quarter.

Total hourly trading volumes increased in the second quarter to about 3,300 MW from 3,010 MW in the previous quarter. Virtual supply averaged around 1,800 MW while virtual demand averaged around 1,450 MW during each hour of the quarter. Cleared hourly volumes of virtual supply outweighed cleared virtual demand by 430 MW on average, a decrease from 590 MW of net virtual supply in the previous quarter.

For the quarter, net revenues from net virtual demand positions were positive due to short periods with elevated prices in the 15-minute market. Net revenues from net virtual supply positions were positive as prices were generally higher in the day-ahead market than the 15-minute market.

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.

[28] 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.

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.[29] 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 second quarter to 3,300 MW from 3,010 MW in the previous quarter. These volumes have remained relatively stable for the last few quarters. On average, about 53 percent of virtual supply and demand bids offered into the market cleared in the second quarter, which is down from about 61 percent in the first quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 430 MW on average, which is a decrease from 590 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours, by about 390 MW and 510 MW respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in hours ending 19 to 22, with the highest net virtual demand occurring in hour ending 21 at about 410 MW. The highest net cleared virtual supply period was just after the morning ramping period (hours ending 10 through 12) with hour ending 11 having the highest net cleared virtual supply at nearly 950 MW.

[29] 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.

Consistency of price differences and volumes

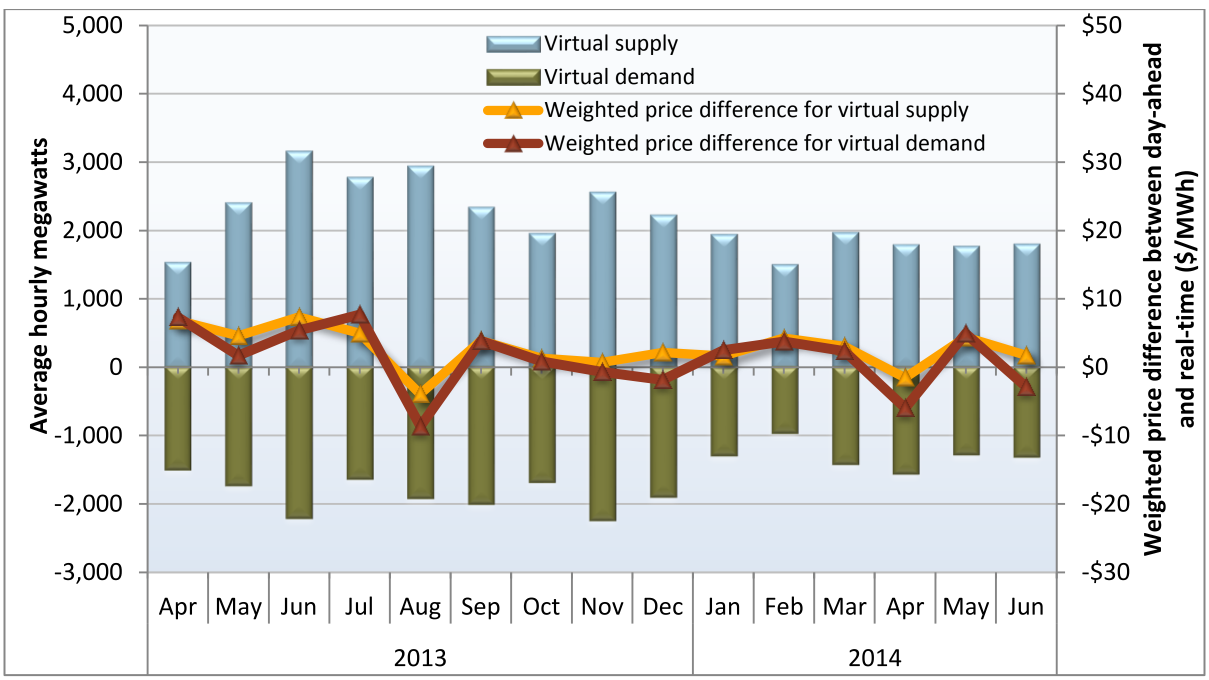
Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. In April and June, net convergence bidding volumes were relatively low and were only consistent with price differences between the day-ahead and real-time markets in only about half of the hours. In May, net convergence bidding was consistent with price differences between the day-ahead and real-time markets in 20 hours.

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.

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 were inconsistent with weighted average price differences for the hours in which virtual demand cleared the market for the month of May and were thus not profitable. However, in April and June, virtual demand positions were profitable as they were consistent with the weighted average price differences. These revenues were mainly associated with two days of high real-time prices associated with wildfires, as well as transmission and generation outages.

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.[30]

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.[31] 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 second quarter, the majority of cleared virtual bids were offsetting bids. Offsetting virtual positions accounted for an average of about 950 MW of virtual demand offset by 950 MW of virtual supply in each hour of the second quarter. These offsetting bids represent about 60 percent of all cleared virtual bids in the second quarter, which is a decrease from 68 percent in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion, although to a lesser extent than in previous periods.

2.7.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders. Similar to the previous quarter, convergence bidding participants earned positive revenue. In the second quarter, net revenues were about $10.7 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:

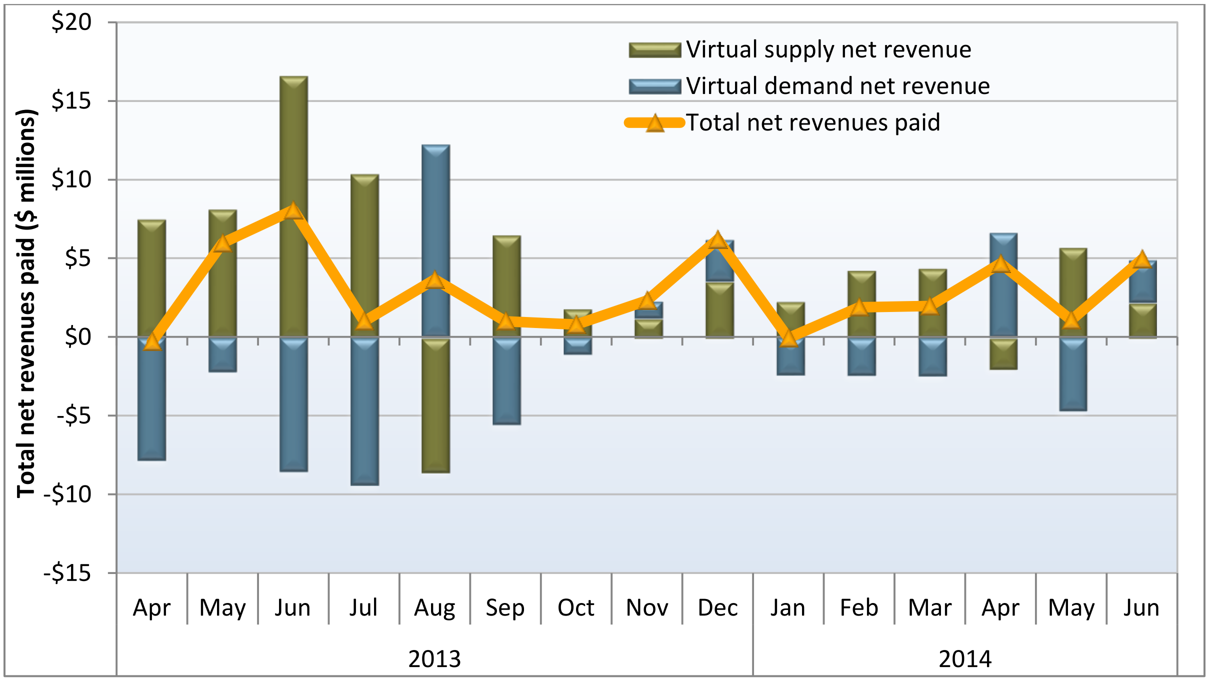
- The net revenues from the market were about $10.7 million in this quarter, compared to about $3.8 million in the previous quarter.
- Virtual supply revenues were most profitable in May as day-ahead prices were generally higher than 15-minute market prices. In total, virtual supply accounted for net payments of about $6 million for the quarter.
- Virtual demand revenues fluctuated dramatically in the quarter with positive revenues in April and June and negative in May. In total, virtual demand accounted for approximately $4.7 million in net payments for the quarter.

[30] 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.

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

- Convergence bidders were paid about $10.2 million, after subtracting virtual bidding bid cost recovery charges of $0.5 million for the quarter.
- About 50 percent of all revenues in the second quarter were generated from three days; two days associated with virtual demand ($4 million) and one day with virtual supply ($1 million).

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 $7.7 million (72 percent) of the total convergence bidding settlements, which is a dramatic increase from about $0.9 million or nearly 24 percent of revenue gains in the last quarter. Physical generation and load participants accounted for about 22 percent of volume and around 13 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.[32] As shown in Table 2.6, financial entities represent the largest segment of the virtual market, accounting for about 66 percent of

[32] 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.

volumes and about 72 percent of settlement dollars. Marketers represent about 12 percent of the trading volumes and 15 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 (13 percent). This is in contrast to last quarter when generation and load had the smallest volumes but greatest revenues.

Table 2.6 Convergence bidding volumes and revenues by participant type (April – June)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,076	1,000	2,076	$4.5	$3.1	$7.7
Marketer	148	234	383	$0.2	$1.4	$1.6
Physical generation	145	230	375	$0.0	$1.2	$1.3
Physical load	0	318	318	$0.0	$0.2	$0.2
Total	**1,370**	**1,782**	**3,152**	**$4.7**	**$6.0**	**$10.7**

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.[33] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs, and energy bid costs.[34]

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.[35]

Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[36] 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.[37] In this case, virtual supply leads to decreased unit commitment

[33] 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.

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

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

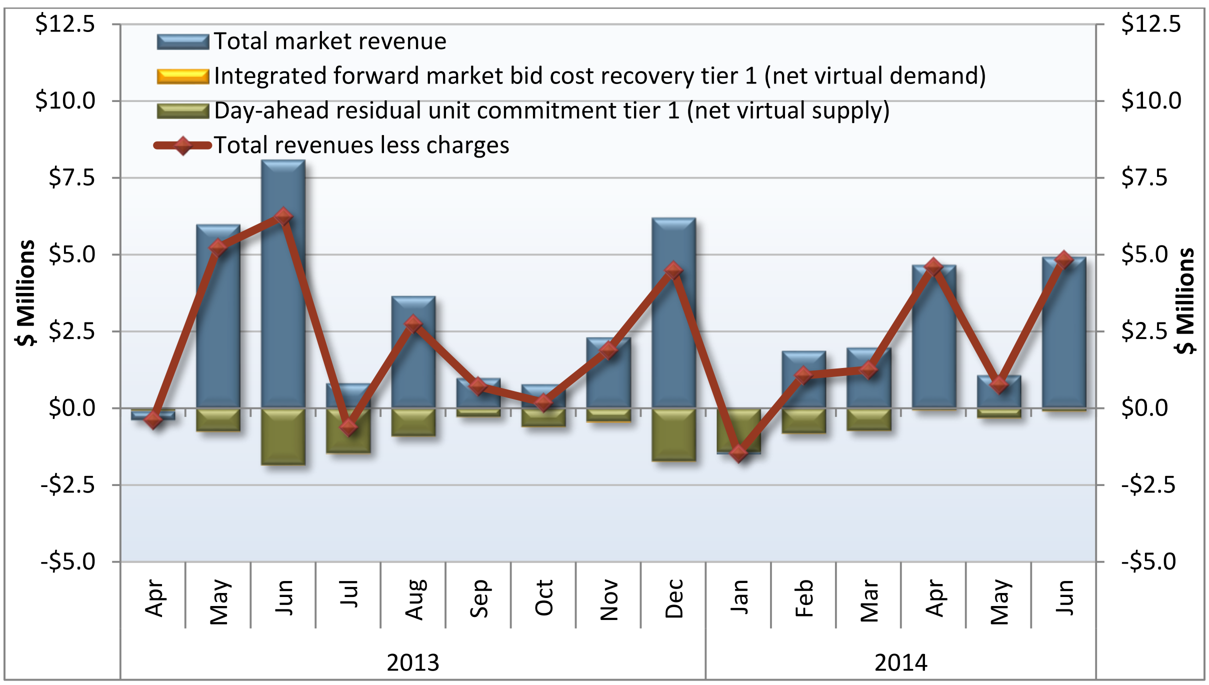
[36] For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

The day-ahead residual unit commitment tier 1 allocation charge associated with virtual bids continued a general decline from the previous quarter. In April and June, less than 1 percent of total bid cost recovery charges were attributed to the day-ahead residual unit commitment tier 1 allocation charge, while May reached only about 3 percent. In contrast, in January 2014 the day-ahead residual unit commitment tier 1 allocation charge accounted for around 24 percent of total bid cost recovery charges.

Figure 2.12 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery costs for the first quarter were close to $0.5 million. As noted earlier, the total estimated net revenue for convergence bidding was around $10.7 million. Total convergence bidding revenue adjusted for bid cost recovery costs was around $10.2 million.

Figure 2.12 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



[37] 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 Impact of market changes on inter-ties

FERC Order No. 764 brought major changes to the scheduling and dispatching of resources in the real-time market. One of the main impacts of the new 15-minute market was a notable increase in self-scheduled inter-tie bids in the real-time market. Overall, the amount of inter-tie imports cleared between the day-ahead and real-time markets has not changed materially after the implementation of the 15-minute market. This section summarizes the impacts of the new market changes on inter-ties.

3.1.1 Background

Implementation of the new 15-minute market brought major rule changes, including additional bidding options for inter-tie energy resources in the real-time market. Real-time inter-tie transactions no longer settle against hour-ahead prices, but now settle against 15-minute market prices. By changing the settlement market for inter-ties, the ISO was able to not only help facilitate 15-minute scheduling on the inter-ties consistent with FERC Oder No. 764, but also synchronize the settlement of inter-ties, convergence bids, and internal generation all within the same real-time market. This has the added benefit of reducing a source of uplifts paid by load-serving entities through the real-time imbalance energy offset charge.

Prior to May, inter-tie resources had only three real-time bid options. They could submit self-schedules, provide economic hourly bids in the hour-ahead market, or dynamically schedule in real time. The new market changes allows for multiple bidding options for inter-tie resources:

- Self-schedule
- Economic hourly block bid
- Economic hourly block bid with single intra-hour economic schedule change
- 15-minute economic bid
- Dynamic transfer

On average, around 96 percent of all inter-tie bids, both economic and self-schedule, were hourly block bids in May and June. Most of these hourly block bids were self-scheduled bids. Less than 0.5 percent of the bids during this period were hourly block bids with single intra-hour economic schedule change, around 1.5 percent of the bids were 15-minute economic bids, and around 1.5 percent of the bids were dynamic transfers.[38]

The only two options eligible for bid cost recovery payments are 15-minute economic and dynamic transfer bids. Bid cost recovery payments to these inter-tie resources were around $100,000 in May and June.

[38] Going forward, this analysis reviews the effects of the different bidding strategies listed here, but excludes dynamic transfers.

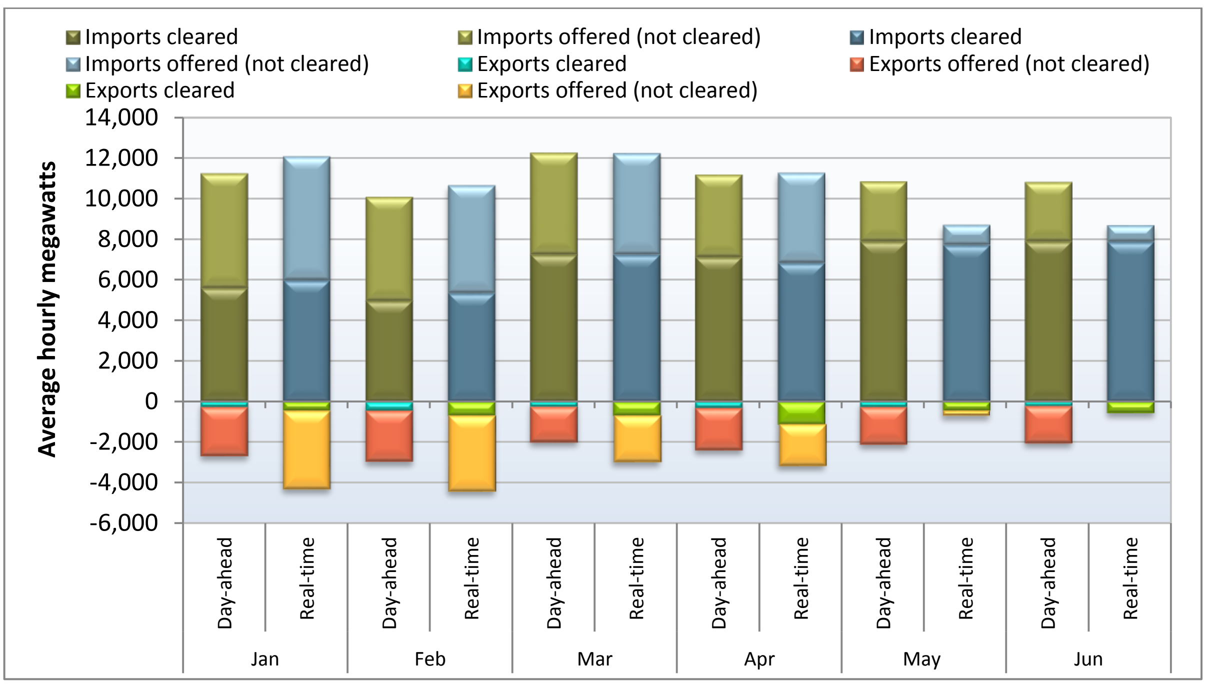
3.1.2 Amount of inter-tie bids offered and cleared in the market

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 market changes in May; however, there was a significant decrease in the amount of bids offered into the real-time market. Figure 3.1 shows the quantity of imports and exports bid in at inter-ties and cleared in the day-ahead and real-time markets.

Total import megawatts offered in the day-ahead market decreased slightly after May 1 while total cleared import megawatts increased. However, total import megawatts offered in the real-time markets decreased significantly. After May 1, day-ahead and real-time markets cleared nearly the same level of import megawatts.

There was no significant change in the export megawatts offered and cleared in the day-ahead market after May 1. However, export megawatts offered and cleared in the real-time markets decreased significantly. Some of the decreases in the cleared exports may be attributed to the increases in relative ISO prices in May and June.

Figure 3.1 Inter-tie imports and exports offered and cleared in the day-ahead and real-time markets



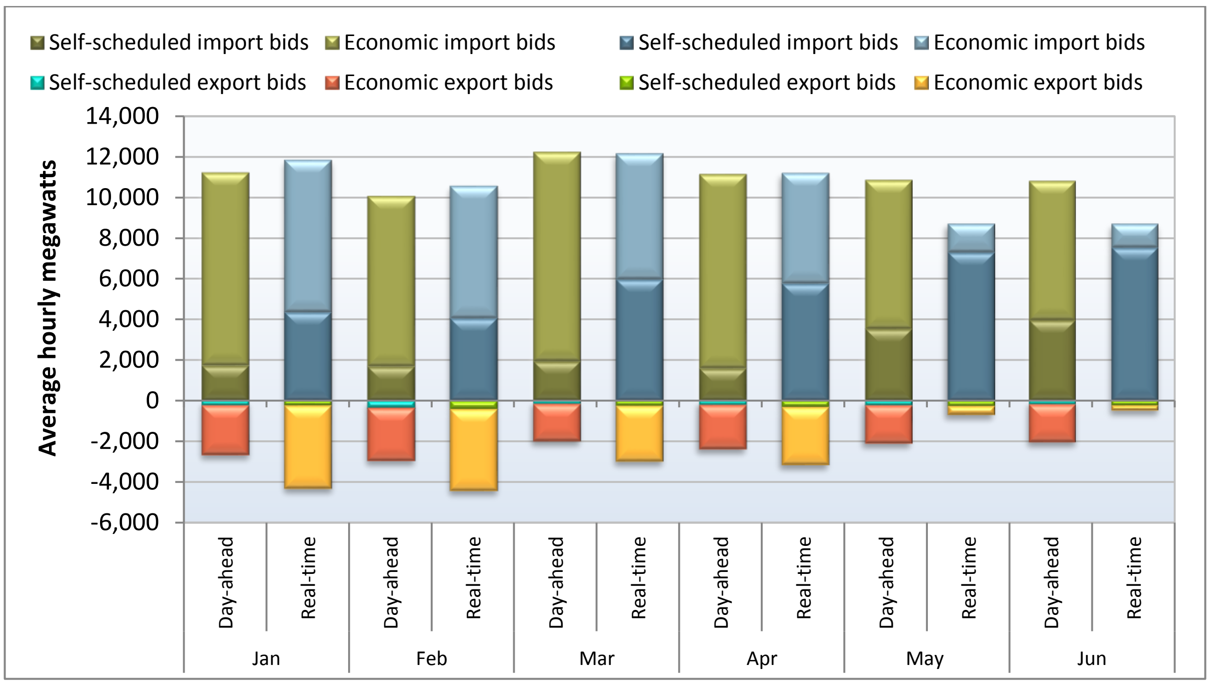
3.1.3 Self-scheduling of inter-ties

The market experienced a considerable increase in the quantity of self-scheduled inter-tie bids in both the day-ahead and real-time markets after implementing the May changes. The most striking change occurred in the real-time market where most of the inter-tie import and export bids were self-scheduled.

Increases in the amount and share of self-scheduled import and export bids created concerns about potential liquidity problems in the 15-minute market. The ability of market participants to schedule energy using the 15-minute bid option is a key limiting factor to dispatching energy in 15-minute blocks. Moreover, a majority of the market participants appear to prefer day-ahead energy prices and consequently opt for the self-schedule option, clearing the real-time market consistent with their day-ahead awards.

Figure 3.2 shows the volume of self-scheduled and economic import and export bids in the day-ahead and real-time markets in the first half of 2014.[39] Around 35 percent of the import bids in the day-ahead market were self-scheduled in May and June, compared to 16 percent in the first four months. Approximately 85 percent of import bids in the hour-ahead market were self-scheduled in May and June. In the first four months of 2014, 44 percent of imports were self-scheduled in the hour-ahead market.

Figure 3.2 Volume of self-scheduled and economic import and export bids



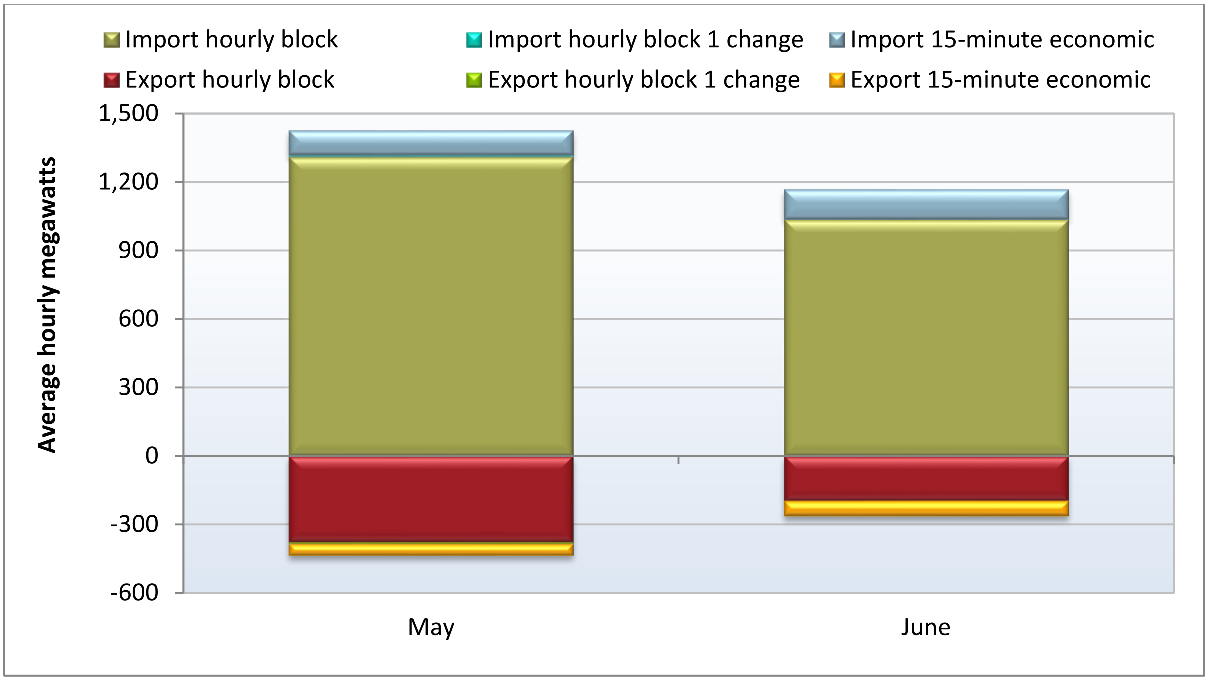
The self-scheduled export bids in the day-ahead market remained constant from the beginning of the year at about 10 percent. However, while the total volume of hour-ahead export bids decreased substantially in May and June, self-scheduled bids accounted for around 42 percent of the export bids in the hour-ahead market. This compared to only 8 percent in the real-time market in the first four months of 2014.

While lower than in previous months, the majority of the economic bidding on inter-ties was primarily in the hour-ahead market. Economic bidding on inter-ties in the 15-minute market was very limited. In May and June, around 90 percent of economic import bids and around 80 percent of economic export bids were hourly blocks. The hourly economic bid block option with a single intra-hour economic schedule change was rarely used. Only around 10 percent of economic import bids and about 20

[39] Since economic bidding was very limited in the 15-minute market, the majority of the real-time economic commitments took place in the hour-ahead market in May and June. Thus, DMM's analysis focuses on the cleared and offered bids in the hour-ahead market in the following sections.

percent of economic export bids were 15-minute economic bids. Figure 3.3 shows economic import and export bids by bidding option in the real-time market.

Figure 3.3 Economic import and export bids by bidding option



This increase in self-scheduling not only had an effect on the real-time markets and real-time congestion (see Section 3.1.4), but it also had an impact on operations and system reliability. Specifically, the ISO shifted its approach to dealing with loop flows on the inter-ties away from using the transmission reliability margin mechanism, to more frequently curtailing transactions on the inter-ties.

The transmission reliability margin is a mechanism to improve reliability along inter-tie paths.[40] The ISO can make certain adjustments in market processes before schedules are awarded in the hour-ahead market in anticipation of transmission constraints. This mechanism avoids the need for adjustments within the operating hour, which can be disruptive by causing curtailment of bilateral trades.

The ISO relied primarily on the transmission reliability margin tool to deal with uncertainties in inter-tie transfer capacities and loop flows between December 2012 and just prior to implementation of the new real-time market mechanisms in May. After the new real-time market changes in May, the transmission reliability margin has been used less frequently. This change stemmed from a significant increase in the quantity of self-scheduled real-time imports and exports. The increase in self-scheduling on the inter-

[40] "Transmission Reliability Margin (TRM) is an amount of transmission transfer capability reserved at a CAISO Inter-tie point that is necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change." For more information see: http://www.caiso.com/Documents/AppendixL_MethodToAssessAvailableTransferCapability_May1_2014.pdf.

ties decreased the liquidity of inter-tie bids in the real-time market to resolve changes in inter-tie transfer capabilities related to transmission reliability margin.

The lack of economic bids and reduction in liquidity in the real-time markets decreased the effectiveness of the transmission reliability margin adjustments, which would lead to penalty pricing. In other words, the likelihood that the model would have to cut self-schedules and set prices based on penalty parameters would be high. As a result, curtailment of schedules has been preferred. When unscheduled flows occurred, the ISO operators had to frequently curtail inter-tie schedules to mitigate the flows rather than implementing the transmission reliability margin.

3.1.4 Inter-tie congestion

Inter-tie congestion in the day-ahead market differs from congestion in the hour-ahead and 15-minute markets. Due to the temporal aspect of the real-time markets the ability to re-dispatch resources to relieve congestion is much more limited in the real-time markets than in the day-ahead market. This situation, along with a higher degree of self-scheduling of inter-ties, may lead to higher congestion related prices.

Overall, most inter-ties did not experience congestion in May and June. However, there was a subset of inter-ties that were affected by congestion. Table 3.1 provides a more detailed comparison of the frequency and consistency of congestion on inter-ties with neighboring control areas in the day-ahead, hour-ahead and 15-minute markets. The table highlights the following:

- The Nevada / Oregon Border (NOB) inter-tie was congested about 63 percent of the time in the day-ahead market, 36 percent in the hour-ahead market and about 7 percent in the 15-minute market. This congestion was primarily due to unscheduled flows, planned outages and seasonal flows of hydro generation.
- The Pacific AC inter-tie was congested just over 30 percent of the time in the day-ahead and 15-minute markets and nearly 44 percent in the hour-ahead market. As with the Nevada / Oregon Border inter-tie, the Pacific AC inter-tie was also congested primarily due to unscheduled flows, planned outages and seasonal flows of hydro generation.
- The Palo Verde inter-tie was congested about 7 percent of the time in the day-ahead and hour-ahead markets but only about 1 percent in the 15-minute market. This is the major inter-tie between California and the Southwest. This congestion was related to several scheduled outages. This congestion in the second quarter was much lower in both the day-ahead and hour-ahead markets than in the last two quarters, about 30 percent and 18 percent, respectively.

Table 3.1 Summary of day-ahead, hour-ahead, and 15-minute congestion on inter-ties

Constraint name	Full import rating (MW)	Total binding frequency in IFM	Average binding IFM shadow price	Total binding frequency in HASP	Average binding HASP shadow price	Total binding frequency in 15-min	Average binding 15-min shadow price
NOB_ITC	1,564	63.1%	$16	35.5%	$82	7.4%	$191
PACI_ITC	3,200	33.3%	$19	43.5%	$69	31.5%	$58
CASCADE_ITC	80	7.1%	$25	0.2%	$32	0.1%	$184
PALOVRDE_ITC	3,328	7.1%	$32	7.4%	$107	1.1%	$104
COTPISO_ITC	33	1.3%	$30	1.8%	$188	0.9%	$203
MEAD_ITC	1,619	1.1%	$17	2.0%	$47		
SUMMIT_ITC	85	0.7%	$18	1.1%	$214	0.1%	$217
ADLANTO-SP_ITC	1,401	0.3%	$4	0.3%	$24	0.1%	$206
IID-SCE_ITC	600			0.6%	$234	0.1%	$187
IID-SDGE_ITC	360			0.3%	$39		
VEA_ITC	264			0.1%	$186		

In the hour-ahead, shadow prices above $150 primarily occurred when locational prices were at the bid floor of -$150/MWh. This is indicative of instances where there were not enough market bids available to solve the transmission constraint. The lack of bid liquidity on the inter-ties in real time, as discussed in Section 3.1.3, is likely a factor in contributing not only to infeasible real-time inter-tie schedules, but also to the differences in hour-ahead and 15-minute prices at the inter-ties.

This can result in a couple different outcomes. First, with limited or no bids to adjust in the 15-minute market, congestion may not occur in the 15-minute market as a price will likely only be set by a penalty price. If the line rating remains the same between the two markets, any self-scheduled quantity will remain the same and market congestion will not occur in the subsequent market unless schedules need to be cut. Second, if there is a bid, the lack of a sufficient set of bids could result in large changes in prices if a bid is accepted. Thus, less bid liquidity can create a larger movement in prices than what may have happened if there was more bid liquidity.

3.1.5 Reduction of inter-tie schedules in the residual unit commitment

Implementation of FERC Order No. 764 in May included changes to the ISO validation process of day-ahead pre-scheduled e-tags. Although there is no ISO requirement to e-tag resources in the day-ahead pre-scheduling process, the ISO now validates e-tags submitted in the day-ahead pre-scheduling process against residual unit commitment schedules rather than the day-ahead market schedules. To the extent that schedules in the residual unit commitment process and the day-ahead market are the same, this change would not have any impact.[41]

The ISO introduced this change to prepare for the reintroduction of virtual bidding on the inter-ties.[42] The residual unit commitment excludes all virtual bids, including those on the inter-ties. Schedules

[41] Also, this change would not have any impact if the available transmission capacity exceeds the net e-tagged amount on an inter-tie in the pre-scheduling process.

[42] Although virtual bidding was reintroduced at the inter-ties on May 1, the position limit of inter-tie virtual bidding was set to zero for a year following implementation. The ISO plans to raise this limit gradually over 28 months.

calculated in the day-ahead market, which can include both virtual demand and supply schedules, may therefore differ substantially from residual unit commitment schedules, whether or not there are virtual bids on the inter-ties. Beginning in May, inter-tie limits must be feasible given both physical and virtual schedules in the day-ahead market, whereas physical schedules alone must be feasible in the residual unit commitment. Prior to May, the net physical inter-tie limit was enforced in both the day-ahead market and the residual unit commitment.

Residual unit commitment schedules may be lower than day-ahead market schedules for inter-tie resources for several reasons. For example, physical supply clearing the day-ahead market may exceed the residual unit commitment requirement which is based on forecast load.[43] In addition, removing virtual bids on internal locations may require the residual unit commitment to reduce physical schedules to resolve internal transmission constraints.

In February of this year, the ISO introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources.[44] This adjustment, called the eligible intermittent resource adjustment, can increase the schedule of a PIRP resource with a day-ahead market schedule below their forecast, thus reducing the demand in the residual unit commitment optimization for other resources, including those on the inter-ties. The residual unit commitment can commit but will not de-commit resources. However, once economic bids have been exhausted, inter-tie and internal schedules could be reduced.

Beginning on May 1, the change in the ISO e-tag validation process created significant confusion for two reasons. First, inter-tie schedules were being reduced, partly as a result of the change in the treatment of participating intermittent resource program resources that was implemented in February. Second, confusion rose concerning the e-tagging requirements. After working with market participants, the ISO determined that creating consistency between the inter-tie schedules between the day-ahead market and the residual unit commitment was appropriate.[45]

To effectuate the change, the ISO modified the penalty price associated with decreasing an inter-tie schedule in the residual unit commitment. The penalty price prior to May 20 for reducing day-ahead market inter-tie schedules in the residual unit commitment process was equal to that of internal resources: -$250/MWh. Effective May 20, the penalty price for inter-tie resources was set lower at -$300/MWh, allowing the residual unit commitment to reduce internal resource schedules before inter-tie resources. Both the change in penalty price for inter-tie self-schedules and increased market

[43] Moreover, the residual unit commitment could lower multi-stage generating units to lower configurations. This could create a situation where day-ahead schedules would be infeasible based on the change in configuration and could have settlement implications. The ISO is working on a market issues process to address this item; in the interim, the ISO adjusted the penalty price for the power balance relaxation in over-generation conditions in the residual unit commitment run to minimize the instances of multi-stage generating units being transitioned down.

[44] Specifically, the adjustment is only made for PIRP resources that have positive schedules in the day-ahead market. PIRP resources that are not scheduled in the day-ahead market are not adjusted at this time.

[45] However, it is important to note that once the position limits for virtual bids are increased, inter-tie schedules are likely to be curtailed in the residual unit commitment due to the exclusion of the inter-tie virtual bids and the enforcement of the physical inter-tie limit.

participant familiarity with the new e-tagging requirements have helped to resolve some of the initial spring release implementation issues related to the pre-schedule e-tag validation process.[46]

3.2 Congestion revenue right revenue adequacy

This section highlights the performance of the congestion revenue rights market over the first half of 2014. The congestion revenue rights balancing account had a $28 million net revenue shortfall in the first half of 2014 after including auction revenues. In 2012 and 2013, the balancing account had annual surpluses of $23 million and $3 million, respectively.

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.[47] 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 right model because transmission changes unanticipated at finalization of the congestion revenue right 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.

Revenue adequacy

Figure 3.4 shows the revenues, payments and overall revenue adequacy of the congestion revenue rights market by quarter for the last ten quarters.

- The dark blue bars represent day-ahead market congestion rent, which accounts for the main source of revenues in the balancing account.

[46] Further information is available in "Frequently Asked Questions - Tagging Requirements," available on the ISO website: http://www.caiso.com/Documents/FAQ_TaggingRequirements_May1.pdf.

[47] For a more detailed explanation of congestion revenue rights revenue adequacy 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.

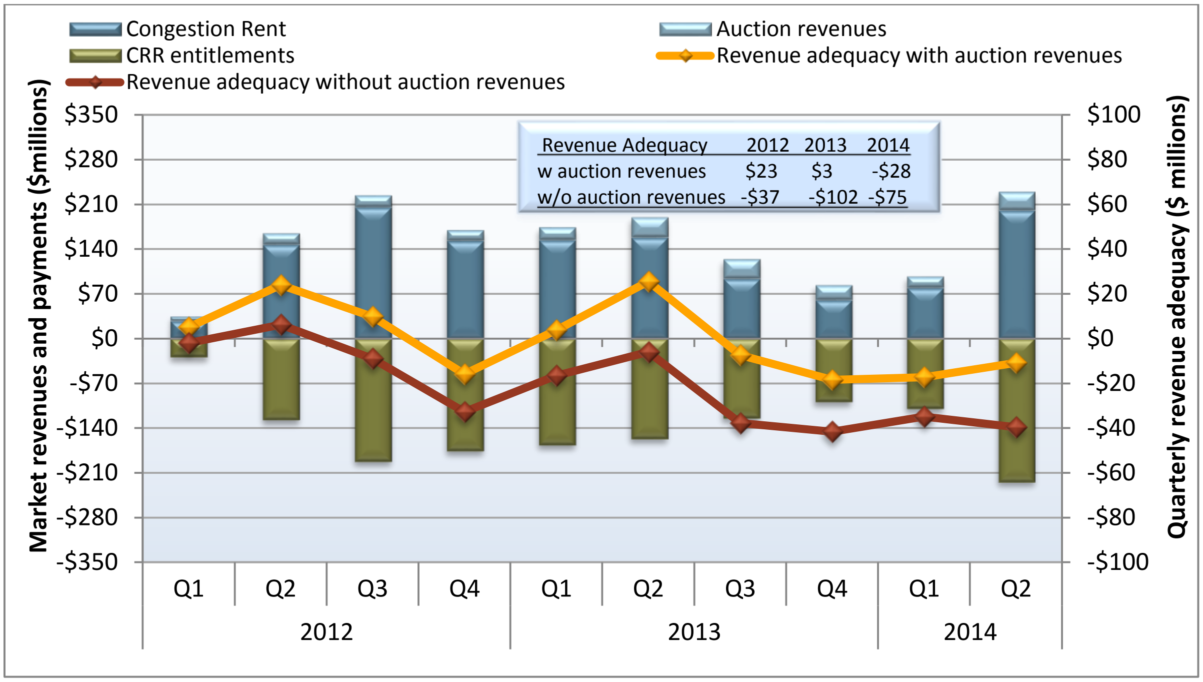
- Light blue bars show net revenues from the annual and monthly auctions for congestion revenue rights corresponding to each quarter. This includes revenues paid for positively priced congestion revenue rights in the direction of expected prevailing congestion, less payment made to entities purchasing 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 3.4, congestion revenue rights before accounting for auction revenues had significant levels of revenue shortfall in the first half of 2014. Shortfalls were due, in part, to the following differences between the network transmission model used in the congestion revenue rights process and the day-ahead market model:[48]

- **PACI inter-tie constraint**: The PACI inter-tie was de-rated in March and April due to several outages including transmission lines near the Grizzly Peak area and the Gates – Midway 500 kV line. These outages derated the limit of the interface below the amount applied in the seasonal congestion revenue right process for the second quarter. As a result, congestion revenue right revenue was inadequate for many days in March and April resulting in a shortfall of about $14 million.
- **Palo Verde inter-tie constraint:** For many days in March and April, the value of the Palo Verde inter-tie limit considered in the day-ahead market was more restrictive than the limit in the congestion revenue right model. Moreover, the Palo Verde inter-tie was de-rated by around 60 percent in March and April. A revenue shortfall of around $15 million occurred in these two months on this inter-tie.
- **Tracy 500 inter-tie constraint**: For several weeks in March and April, the Tracy 500 inter-tie import limit was de-rated to around 250 MW to 450 MW from a normal rating between 3,800 MW and 5,100 MW (depending on winter and summer ratings). The amount of congestion revenue rights from the annual allocation and seasonal auctions were higher than this limit. Revenue shortfall reached around $12 million on this inter-tie during this period.

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

Figure 3.4 Quarterly revenue adequacy



3.3 California greenhouse gas allowance market

Generating resources became subject to California's greenhouse gas cap-and-trade program compliance requirements starting in January 2013. This section highlights the impact of these requirements in 2014. These highlights include the following:

- The price of greenhouse gas emissions permits remained stable in the second quarter at an average of \$11.87/mtCO_2e, ending the quarter at \$11.98/mtCO_2e.[49] This average price is very similar to the average prices in the last couple quarters and lower than average prices in the first three quarters of 2013.
- DMM estimates that average wholesale energy prices are about \$4/MWh higher in the second quarter from cap-and-trade compliance costs, based on statistical analysis after implementing the program. This is consistent with the emissions costs for gas units typically setting prices in the ISO market.

Background

California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, directed the California Air Resources Board (CARB) to develop regulations to reduce greenhouse gas emissions to 1990 levels by

[49] mtCO_2e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

2020. The cap-and-trade program is one in a suite of regulatory measures adopted by CARB to achieve this goal.[50]

The cap-and-trade program covers major sources of greenhouse gas emissions including power plants.[51] The program includes an enforceable emissions cap that will decline over time. California will directly distribute and auction allowances, which are tradable permits equal to the emissions allowed under the cap.[52] Effective January 1, 2014, CARB's cap-and-trade program became linked with Quebec.[53] Formal linkage allows entities to use allowances issued in either Quebec or California for compliance in either region. The two regions held a practice joint auction on August 7, 2014, and plan to hold true joint auctions in November of this year. Until that occurs, only entities registered in the jurisdiction may participate in auctions, but allowances may be traded in the secondary over-the-counter market.

The cap-and-trade program affects wholesale electricity market prices in two ways. First, market participants covered by the program will presumably increase bids to account for the incremental cost of greenhouse gas allowances. Second, the ISO amended its tariff, effective January 1, 2013, to include greenhouse gas compliance cost in the calculation of each of the following:

- Resource commitment costs (start-up and minimum load costs).
- Default energy bids (bids used in the automated local market power mitigation process).
- Generated bids (bids generated on behalf of resource adequacy resources and as otherwise specified in the ISO tariff).[54]

The ISO calculates a greenhouse gas allowance index price as a daily measure of the cost of greenhouse gas allowances. The ISO greenhouse gas allowance price is calculated as the average of two market based indices.[55] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 3.5. In the second quarter, allowance costs were fairly stable, beginning the quarter at \$12.00/mtCO_2e and ending at \$11.98/mtCO_2e. The average index value for the quarter was \$11.87/mtCO_2e, reflecting a decrease

[50] For more information on this program, please see Chapter 5 of the *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[51] The cap-and-trade program covers major sources of greenhouse gas emissions in California such as refineries, power plants, industrial facilities, and transportation fuels. For the electricity sector, the covered entity is the first deliverer of electricity. The first deliverer is defined in the regulation as the operator of an in-state electricity generator, or an electricity importer. The compliance obligation for first deliverers is based on the emissions that are a result of the electricity they place on the grid. The threshold for inclusion in the program for electricity generated from an in-state facility, and for imported electricity from a specified source, is 25,000 metric tons of annual greenhouse gas emissions. For imported electricity from unspecified sources, there is no threshold and all emissions are covered.

[52] Additional background information can be found in the 2013 fourth quarter *Market Issues and Performance Report* at: https://www.caiso.com/Documents/2013FourthQuarterReport-MarketIssues_Performance-Feb2014.pdf.

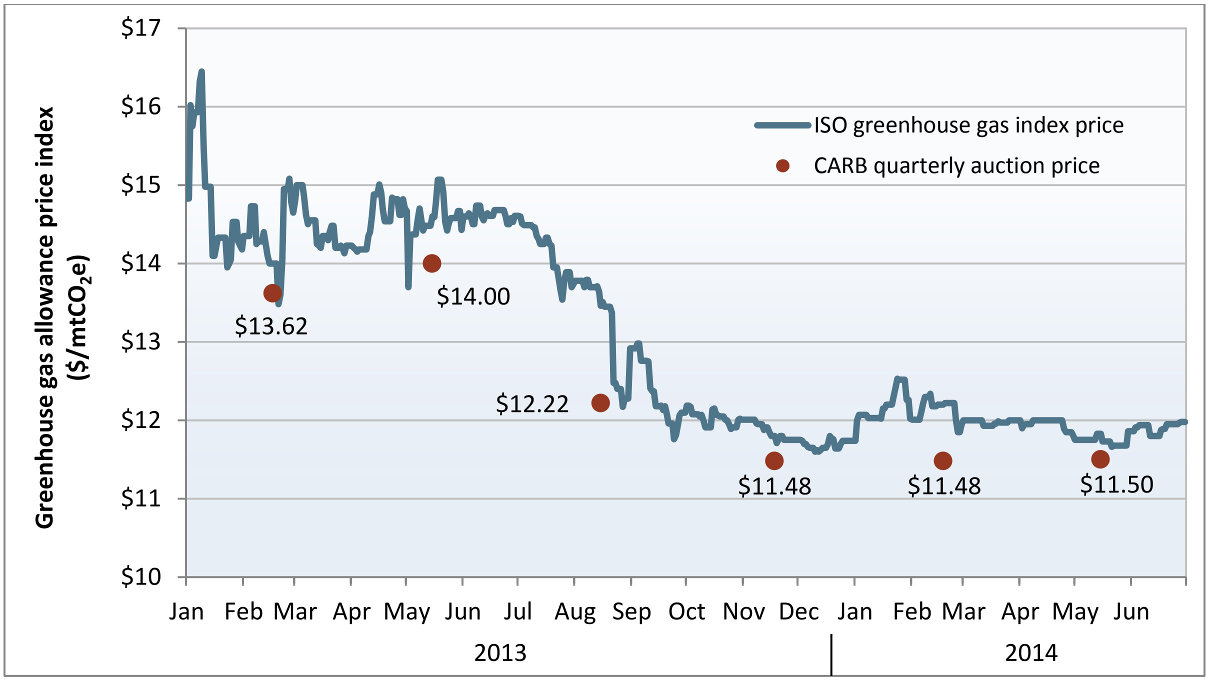
[53] Further information on linkage with Quebec is available here: http://www.arb.ca.gov/cc/capandtrade/linkage/linkage_fact_sheet.pdf or http://www.arb.ca.gov/newsrel/newsrelease.php?id=508.

[54] Details on each of the calculations may be found in the ISO Business Practice Manual for Market Instruments, Appendix K: http://bpmcm.caiso.com/BPM Document Library/Market Instruments/BPM_for_Market_Instruments_v26_clean.doc.

[55] The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, 2013, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume weighted price in mid-April 2013. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

for a period in May. The index price fell prior to CARB's quarterly auction held on May 15. The 2014 allowances cleared the auction at \$11.50/mtCO_2e and the 2017 allowances cleared at \$11.34/mtCO_2e.

Figure 3.5 ISO's greenhouse gas allowance price index



The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the CPUC and other state entities. As part of the cap-and-trade program, the CARB allocated allowances to the state's electric distribution utilities to help compensate electricity customers for the costs that will be incurred under the cap-and-trade program. The investor-owned electric utilities are required to sell all of their allowances at CARB's quarterly auctions, and the proceeds from the auction are to be used for the benefit of retail ratepayers, consistent with the goals of AB 32. Under a 2012 CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs.[56] The first residential climate credit, a semi-annual credit of \$35, was announced on the final day of the first quarter.[57]

Changes in market prices

Greenhouse gas compliance costs are expected to increase wholesale electricity costs as both market participant bids and the ISO's own calculation of default energy bids, resource commitment costs and generated bids increase to reflect the additional incremental variable cost of greenhouse gas compliance.

[56] Pursuant to CPUC decision Docket #R.11-03-012, the investor-owned utilities will distribute this revenue to emissions-intensive and trade-exposed businesses, to small businesses, and to residential ratepayers to mitigate carbon costs. Remaining revenues will be given to residential customers as an equal semi-annual bill credit. See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M039/K594/39594673.PDF.

[57] For more information, see http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K322/89322065.PDF.

DMM has adopted a statistical approach to estimate the impact of greenhouse gas costs on day-ahead market prices during the first period of greenhouse gas compliance.[58] This approach relies on the comparison of market data before cap-and-trade implementation with data from 2013 and 2014.[59] Results reported here are based on the linear model used in our first quarterly report of 2014.[60] As in the first quarter analysis, DMM has limited the sample to days in which the implied heat rate in every hour is less than 20,000 Btu/kWh.[61]

The energy price DMM chose to analyze was the day-ahead system marginal energy cost.[62] DMM decided to analyze changes in this value to limit the effects of transmission congestion when trying to isolate the effect of the greenhouse gas costs. While the system marginal energy cost does not eliminate transmission congestion effects, it can act as a reasonable benchmark for system prices.[63]

DMM estimates the impact of greenhouse gas compliance on wholesale energy prices by estimating average daily system energy prices as a linear function of a measure of greenhouse gas compliance cost, a weighted gas price index, a non-linear function of expected load, net virtual supply, scheduled generation availability for fuel types that we assume to be exogenous (hydro, wind, solar, geo-thermal, and nuclear), and imports (as modeled by exogenous gas price indices).[64]

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[58] As the ISO's market continues to evolve in ways that are not explicitly controlled for in DMM's linear model, the accuracy of the estimated greenhouse gas impact will decrease. Thus, DMM is developing an alternative technique to measure the greenhouse gas impact.

[59] As demonstrated in Figure 3.5, the ISO's estimated greenhouse gas compliance cost does not exhibit sufficient variation to determine the impact based on minor fluctuations in this value alone.

[60] A summary of our earlier analysis is available in the *Quarterly Report on Market Issues and Performance* for the first quarter 2014: http://www.caiso.com/Documents/2014FirstQuarterReport-MarketIssues_Performance-May2014.pdf. As in the first quarter model, we have included a variable to control for differences in convergence bidding volumes, assumed to be exogenous. For this analysis, DMM assumes that convergence bidding volumes are determinants of rather than determined by day-ahead energy prices. Virtual bids are assumed to be based on expectations of energy prices, and are thus exogenous.

[61] This selection eliminates 37 days in the 30 month period containing hours that DMM has determined to be outliers. In these hours, the day-ahead system marginal energy cost exceeds the marginal gas and greenhouse gas emissions cost of units with a heat rate of 20,000 Btu/kWh, a value far above the heat rate of all but a very few peaking units in the ISO market. In each hour, the greenhouse gas adjusted implied heat rate is calculated by dividing the system marginal energy costs by the sum of a weighted average gas price and an estimated greenhouse gas cost. In each hour, the gas price is a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations. Prices in the outlying hours may be driven by factors other than incremental variable cost, and, as such, an alternative to DMM's model might be more appropriate to explain changes in price in this subset of hours.

[62] This is the energy component of each of the locational marginal prices within the ISO system and excludes both congestion and transmission loss related costs.

[63] For further discussion on the system marginal energy price, please see Appendix C of the ISO tariff: http://www.caiso.com/Documents/CombinedConformedTariff_Jul1_2014.pdf.

[64] If import supply is elastic, imports may be endogenous. That is, scheduled imports may themselves be a function of electricity prices. Including an endogenous variable in the regression could bias our results, so DMM has used an instrumental variable approach to estimate the impact of greenhouse gas emission costs in a consistent manner. A useful set of instruments has two properties. First, the set should be a powerful predictor of the endogenous factor: imports. Second, the instruments should not be endogenous themselves. For this analysis, DMM uses daily gas price indices for multiple hubs outside of the ISO to instrument import levels. DMM's model is estimated using two stage least squares estimated with the ivreg() function of the AER package (Christian Kleiber and Achim Zeileis (2008). Applied Econometrics with R. New York: Springer-Verlag. ISBN 978-0-387-77316-2. http://CRAN.R-project.org/package=AER.) available in R (R Core Team (2013). R: A language and environment for statistical computing. R Foundation for Statistical Computing, Vienna, Austria. http://www.R-project.org/.)

$$\text{Average Electricity Price} = \beta_0 + \beta_1\text{GHG} + \beta_2\text{Load} + \beta_3\text{Load}^2 + \beta_4\text{Load}^3 + \beta_5\text{Gas}_{\text{Weighted}} + \beta_6\text{NetVS} + \beta_7\text{Wind} + \beta_8\text{Solar} + \beta_9\text{Hydro} + \beta_{10}\text{Nuclear} + \beta_{11}\text{Geothermal} + \beta_{12}\text{Imports\_IV} + \varepsilon$$

Using this model, DMM estimates that, in the second quarter of 2014, the average impact of greenhouse gas compliance was about $4.22/MWh or $0.34 per dollar of the allowance price.[65] Although rough, our model predicts the average ISO day-ahead system energy prices fairly well, explaining approximately 95 percent of the variation in this measure in both quarterly models.[66] This analysis will be refined or replaced as further data become available.

The statistical approach outlined above produces estimates that are consistent with expectations of the impact of greenhouse gas compliance costs on wholesale electricity costs during a period when market prices are being set close to the marginal operating cost of relatively efficient units. For example, a gas-fired unit with a heat rate of 8,000 Btu/kWh would have an expected emissions cost of $0.42 per dollar of greenhouse gas allowance costs. The $0.34 per dollar of the allowance price estimate represents the additional emissions cost of a unit with a heat rate of about 6,350 Btu/kWh.[67]

Figure 3.6 illustrates average monthly implied heat rates with and without an adjustment for greenhouse gas compliance costs. The implied heat rate is a standard measure of the maximum heat rate that would be profitable to operate given electricity prices and fuel costs, ignoring all non-fuel costs. The implied heat rate is calculated by dividing the electricity price, in this case the hourly day-

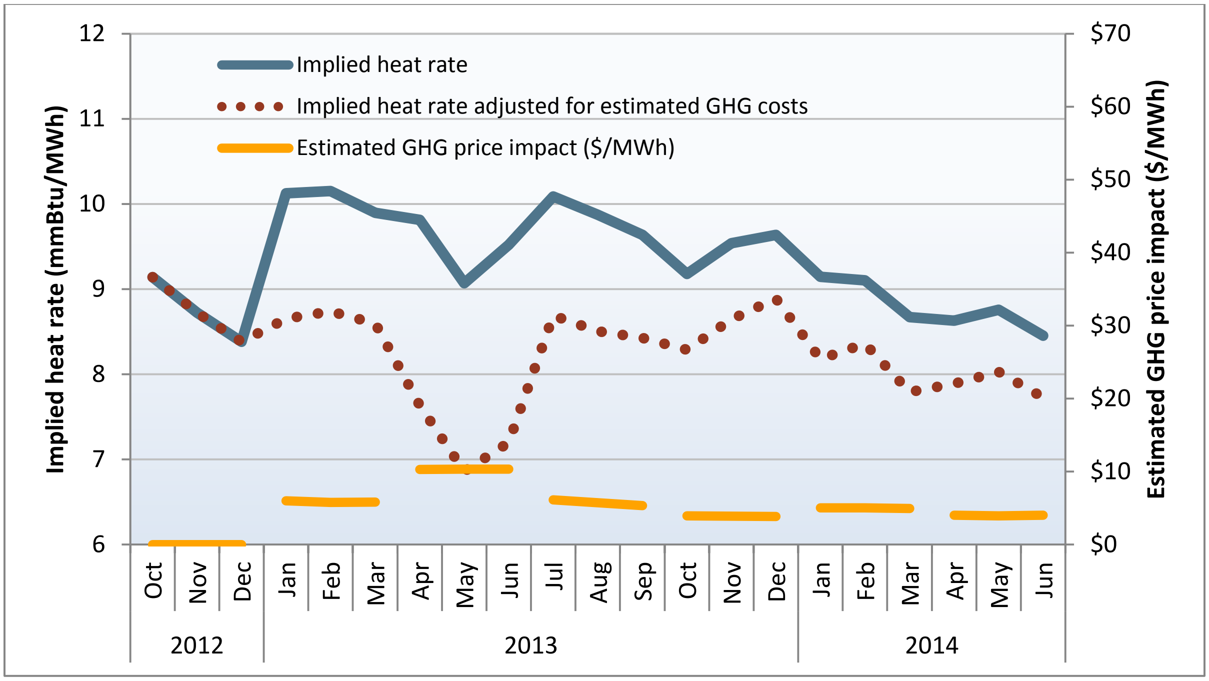
[65] Two alternative greenhouse gas measures are used. The first is an indicator variable equal to 1 in the greenhouse gas compliance period and 0 before that period. In this case, the coefficient estimate (β_1 in the equation above) may be interpreted as the estimated average impact of greenhouse gas compliance on electricity prices ($/MWh). The second greenhouse gas measure is the ISO's index of the greenhouse gas allowance value, set equal to zero before the compliance period. In this case, the coefficient estimate may be interpreted as the estimated impact of greenhouse gas compliance per allowance cost ($/MWh divided by $/mtCO$_2$e). Quarterly estimates were generated by using a set of quarterly indicator variables multiplied by the greenhouse gas measure in place of a single greenhouse gas measure. DMM's regression results are based on values from January 2012 through March 2014 to limit bias introduced by factors not yet included in the model. Load is the ISO's hourly day-ahead forecast of ISO load. We assume that the load forecast, which is based on weather indices and historical time series data, is not price responsive in the short-term, which allows us to estimate this model using ordinary least squares, rather than as a system of demand and supply equations. We also assume that the greenhouse gas allowance index price is exogenous rather than endogenously determined by electricity prices. Resource specific day-ahead schedules are summed by fuel type to calculate generation from wind, geothermal, nuclear, solar, hydro, and import sources. The gas price is a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations. Net virtual supply is the average of the hourly difference between cleared virtual supply and virtual demand in each hour.

[66] In the first case, $R^2 = 0.9473$ and the adjusted $R^2 = 0.9462$. In the second case, $R^2 = 0.9481$ and the adjusted $R^2 = 0.947$.

[67] 0.0530731 mtCO$_2$e /MMBtu x 8,000 Btu/kWh = $0.425/$ Greenhouse gas allowance price. The emissions factor, 0.0530731 mtCO$_2$e /MMBtu , is calculated as follows: 53.02 kg CO2/MMBtu + [(0.001 kg CH4/MMBtu)*21 kg CO2/kg CH4)] + [0.0001 kgN2O/MMBtu *310 kg CO2/kg N2O)] = 53.0731. The N20 and CH4 global warming potential values (310 and 21, respectively) are from table A1 of http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl. Default emissions factors are available in tables C1 and C2 of the same source. DMM thanks ARB staff for their assistance with this calculation. $0.337089 divided by an emissions factor of 0.0530731 = 6.3514.

ahead system marginal energy price, by fuel price. Because natural gas is often on the margin in the ISO market, we use a weighted average of daily natural gas prices.[68]

Figure 3.6 Implied heat rates with and without greenhouse gas compliance costs



DMM calculates the implied heat rate adjusted for greenhouse gas compliance costs by subtracting our estimate of the greenhouse gas compliance cost price impact derived above from the energy price and then dividing the result by the gas price index. In this case, DMM used quarterly estimates of the greenhouse gas impact: $0.40 per dollar of allowance cost in the first quarter of 2013, $0.71 in the second quarter, $0.43 in the third quarter, $0.33 in the fourth quarter, and $0.41 in the first quarter of 2014, and $0.34 in the second quarter.

The implied heat rate analysis shows that changes in gas prices and greenhouse gas compliance costs account for most of the electricity price increase between 2012 and 2014. Average adjusted implied heat rates in the first half of 2014 (8,000 Btu/kWh) and the average annual value in 2013 (8,400 Btu/kWh), were both slightly lower than the annual average implied heat rate in 2012 (8,600 Btu/kWh).

[68] For this calculation, DMM is using a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations.