California Independent System Operator Corporation

California ISO

Q4 Report on Market Issues and Performance

February 13, 2012

Prepared by: Department of Market Monitoring

Table of Contents

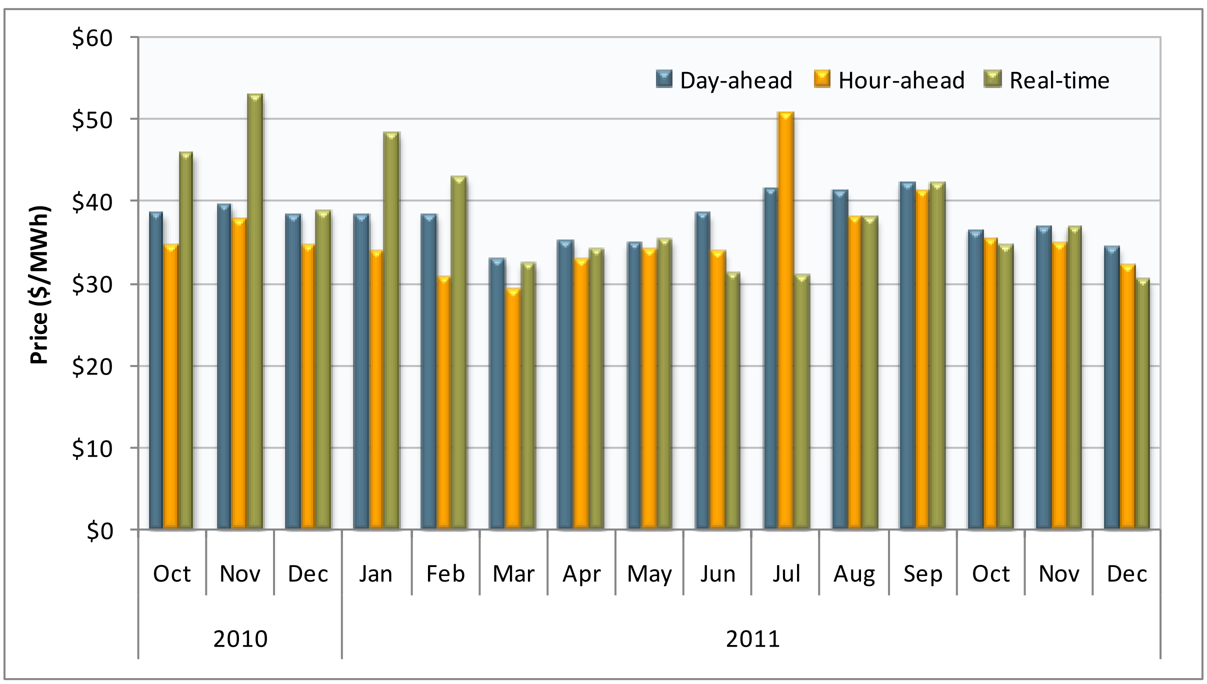
Executive summary

This report provides an overview of general market performance during the fourth quarter of 2011 (October – December) by the Department of Market Monitoring (DMM).

Energy market performance

- The day-ahead integrated forward market was stable and competitive. The level of load and supply scheduled in the day-ahead market continued to be within a few percentage points of actual loads in most hours. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.
- Average prices in the energy markets continued a trend toward improved price convergence that began in August (see Figure E.1). Average real-time prices were lower than day-ahead and hour-ahead prices during peak and off-peak hours in October and December, but approximately equal to day-ahead peak prices in November. Systematic differences in average hour-ahead and real-time prices also lessened in the fourth quarter of 2011 compared to the fourth quarter of 2010 and the first two quarters of 2011.

Figure E.1 Average monthly on-peak prices (PG&E area)



- Total bid cost recovery payments continued to decline in the fourth quarter relative to previous quarters. Bid cost recovery payments associated with real-time market commitments and dispatches fell by about 75 percent. This decrease occurred mainly because of the reduced frequency of exceptional dispatch commitment to meet seasonal system and south of Path 26 capacity needs.

- Congestion within the ISO system had minimal impact on overall prices. However, the frequency of day-ahead congestion remains relatively high, particularly on constraints in generation pockets and those relating to imports into the Pacific Gas and Electric (PG&E) area. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market. DMM continues to review the differences between the day-ahead and real-time congestion patterns on these constraints and has not identified any behavioral or market design related problems at this time.

Convergence bidding

The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Convergence bidding allows participants to place purely financial bids to buy power and offers to sell power into the day-ahead market, regardless of whether or not they own physical load or generation. These bids are automatically liquidated in the hour-ahead and real-time markets. These markets clear based on a physical re-dispatch of the system without these purely financial convergence bids.

Convergence bidders profit by arbitraging the difference between day-ahead, hour-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should drive day-ahead, hour-ahead and real-time prices closer. This arbitrage is complicated by a market feature that makes the California market design different from most other ISOs. California's market design re-optimizes imports and exports in a separate hour-ahead market. Unlike other ISOs, the ISO settles these inter-tie resources based on hour-ahead market clearing prices rather than 5-minute real-time prices. The same is true for convergence bids accepted in the day-ahead market on the inter-ties. These inter-tie convergence bids are liquidated and settled against hour-ahead prices rather than the 5-minute real-time prices.

Settling inter-tie convergence bids based on hour-ahead prices has led to uplifts, known as imbalance offset costs, which can occur when prices diverge between the hour-ahead and real-time markets. To address these uplifts, the ISO filed a request with the Federal Energy Regulatory Commission (FERC) to suspend convergence bidding on the inter-ties. Effective November 28, 2011, convergence bidding at inter-tie scheduling points was suspended temporarily pending further consideration of this issue through a FERC technical conference and additional written comments from participants.[1]

Convergence bidding activity is marked by several key trends in the fourth quarter:

- The vast majority of accepted virtual bids on inter-tie scheduling points consisted of virtual supply (or imports) from the start of convergence bidding in February until suspension of inter-tie bids on November 28.

- Most virtual bids accepted at scheduling points within the ISO have consisted of virtual demand since the start of convergence bidding in February through most of the fourth quarter. However, prior to suspension, most or all of this net virtual demand within the ISO was usually more than offset by virtual supply bids at inter-tie scheduling points. This caused the total impact of all accepted virtual bids to add net virtual supply to the day-ahead market.

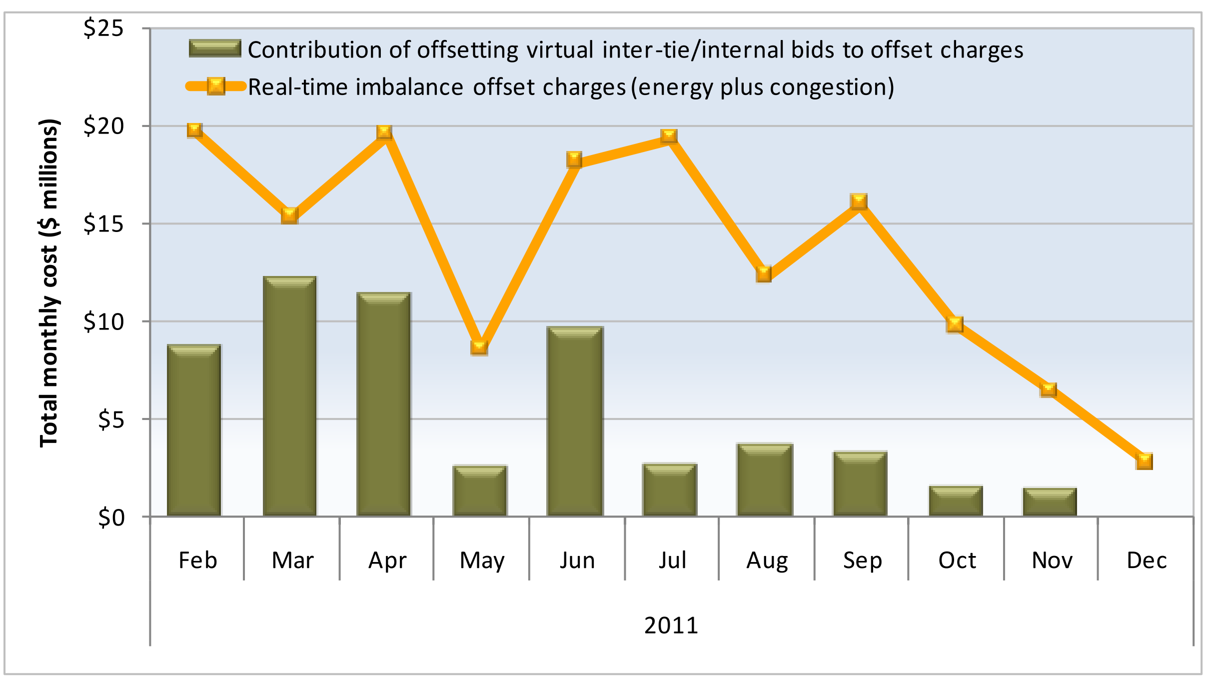
[1] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order.

- With the suspension of inter-tie convergence bids on November 28, the net impact of all virtual bids accepted in the day-ahead market during most hours shifted from net virtual supply to virtual demand. This pattern continued for several weeks until mid-December. During this period, average real-time prices were well below day-ahead prices, resulting in a period of financial losses for virtual demand positions on internal scheduling points. By late December, the net accepted virtual bidding position changed at the internal scheduling points in the day-ahead market from virtual demand to virtual supply.

- In the fourth quarter, net revenues paid out to convergence bidding entities totaled almost $2 million – significantly below the $9 million paid to convergence bidding entities in the third quarter. The lower net profits paid out for convergence bids reflect lower volumes of accepted virtual bids, improved price convergence, and the losses incurred by virtual demand at internal scheduling points during periods when average real-time prices were lower than day-ahead prices.

Before the suspension of convergence bids at the inter-ties, individual participants continued to successfully profit from systematic differences between hour-ahead and real-time prices by placing virtual bids at inter-ties that offset their positions at internal nodes (e.g., virtual supply at inter-ties offset by virtual demand within the ISO during hours when average hour-ahead prices were lower than real-time prices). However, the use of this bidding strategy declined in the third quarter and continued to recede in the fourth quarter prior to the suspension of inter-tie convergence bids. Even so, offsetting virtual positions by the same participant or different participants continued to impose imbalance costs of around $1.5 million per month in the months of October and November (see Figure E.2).

Figure E.2 Contribution of offsetting virtual supply and demand to real-time imbalance charges



As noted in DMM's memos for the August and October Board of Governors meetings, fundamental structural aspects of the current market design tend to create systematic differences in hour-ahead and real-time prices. Under this current market design, convergence bidding on inter-ties has allowed some participants to profit from persistent and predictable differences in hour-ahead and real-time price differences. These profits contribute to revenue imbalances that are allocated to load-serving entities without providing any significant market efficiency benefits.[2]

DMM's overall assessment of convergence bidding since its implementation in February is that because of the impact of virtual bids on the inter-ties in terms of offsetting virtual bids at points within the ISO, convergence bidding has had little or no overall benefit in terms of helping to improve price convergence or the efficiency of day-ahead unit commitment decisions. After the suspension of inter-tie bids, the aggregate system-wide impact of convergence bidding positions began to be more consistent with positions that would promote convergence of average prices in the day-ahead and 5-minute real-time markets. DMM believes that continued suspension of convergence bidding at the inter-ties remains important until the ISO addresses structural differences between how the hour-ahead and real-time markets are dispatched and settled.

Special Issues

- **Natural gas and electric market integration.** Natural gas fired generation plays a critical role in the ISO supply mix. Gas fired units most often set prices in the ISO markets both system-wide and within most major load pockets. During the second half of the year, the ISO had to deal with two natural gas integration situations. The first was related to pressure reductions on the PG&E natural gas pipeline system. The second was related to maintenance outages on the Southern California Gas pipeline. Both situations required that the pipeline operators and the ISO effectively coordinate their systems to manage both gas and electric reliability during these events.

- **Load forecast performance issues.** The ISO implemented a new load forecasting system known as ALFS3 in May 2011. After further review of the new load forecasting tool, the ISO has determined that the lack of model robustness has led to poor performance. Specifically, the performance of only a handful of days created significant issues between ALSF3 relative to the prior model known as ALFS2. The ISO has identified issues related to hardware, software and inputs, and has addressed many issues over the course of the year. Going forward, the ISO intends to develop a successor to ALFS3 known as ALFS5 to be tested and rolled out in 2012.

- **Flexible ramping constraint performance.** The ISO implemented a new flexible ramping constraint in the real-time market in mid-December. The constraint addresses non-contingency based deviations in load and supply between the real-time commitment and dispatch models (e.g., due to load and wind forecast variations). The constraint procures ramping capacity in the 15-minute real-time pre-dispatch process that is subsequently made available for use in the 5-minute real-time dispatch. Since the implementation of the constraint, the upward volatility of 5-minute real-time prices has dropped as fewer upward ramping infeasibilities have occurred. Although the FERC has approved the implementation of the flexible ramping constraint in the real-time market, the

[2] See Memorandum to the ISO Board of Governors, RE: Market Monitoring Report, October 20, 2011, available at http://www.caiso.com/Documents/111027Department_MarketMonitoringReport-Memo.pdf.

methodology to allocate the associated cost has not yet been approved.[3] The total payments made to flexible ramping capacity during the month of January 2012 were around $2.5 million; this compares with a monthly average payment of $1.2 million for spinning reserves units for the same period. DMM has recommended that the ISO also review how the flexible ramping constraint has affected the unit commitment decisions made in real-time. DMM believes that evaluating commitment decisions is an important measure of the overall effectiveness of the constraint.

3 FERC held a technical conference on January 31, 2012 to address the cost allocation of the flexible ramping constraint.

1 Energy market performance

Day-ahead market

The day-ahead integrated forward market continued to be stable and competitive in the fourth quarter. The level of load and supply scheduled in the day-ahead market continued to be within a few percentage points of actual loads in most hours. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.

Real-time market

Average prices in the energy markets in the fourth quarter continued a trend toward improved price convergence that began in August. Average real-time prices were lower than day-ahead and hour-ahead prices during peak and off-peak hours in October and December, but approximately equal to day-ahead peak prices in November. Systematic differences in average hour-ahead and real-time prices also lessened in the fourth quarter of 2012 compared to the fourth quarter of 2010 and the first two quarters of 2011.

Bid cost-recovery payments

Total bid cost recovery payments continued to decline in the fourth quarter relative to previous quarters. Bid cost recovery payments associated with real-time market commitments and dispatches fell by almost 75 percent. This decrease occurred mainly because of the reduced frequency of exceptional dispatch commitment to meet seasonal system and south of Path 26 capacity needs.

Congestion

Congestion within the ISO system had minimal impact on overall prices. However, the frequency of day-ahead congestion remains relatively high, particularly on constraints in generation pockets and those relating to imports into the PG&E area. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market. DMM continues to review the differences between the day-ahead and real-time congestion patterns on these constraints and has not identified any behavioral or market design related problems at this time.

1.1 Energy market performance

Overall, price convergence improved in the fourth quarter relative to previous quarters. Figure 1.1 and Figure 1.2, below, show monthly average prices for peak and off-peak periods for the PG&E area, respectively.

Figure 1.1 Average monthly on-peak prices (PG&E area)

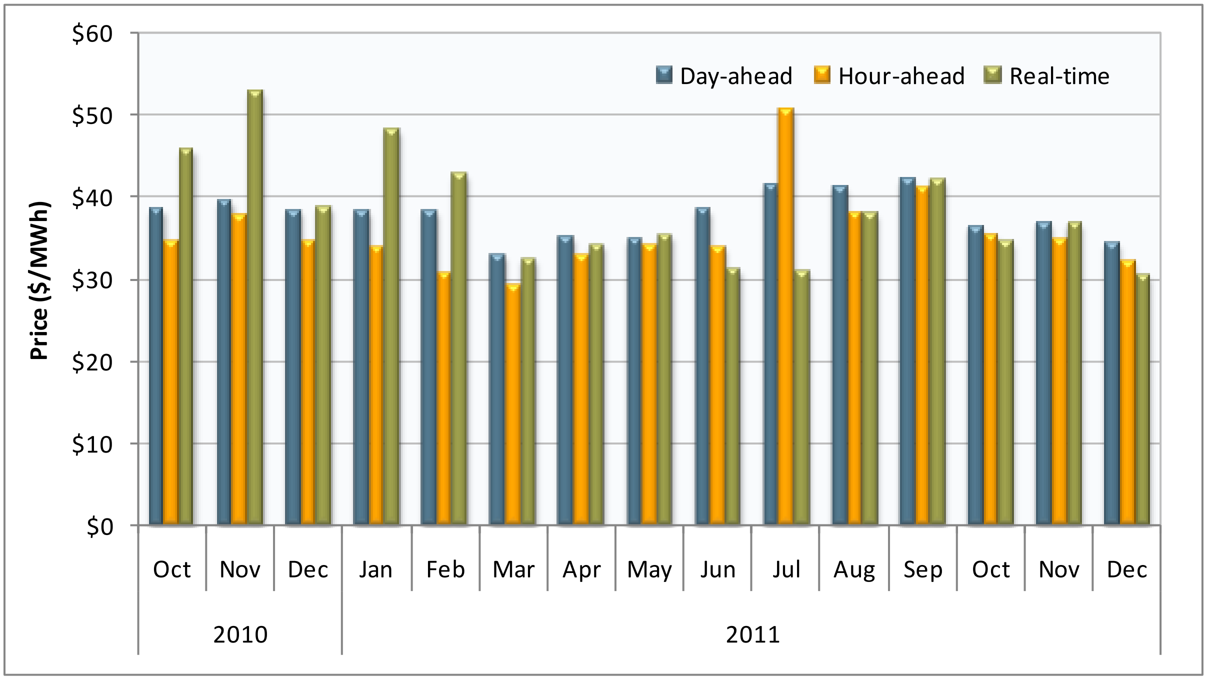
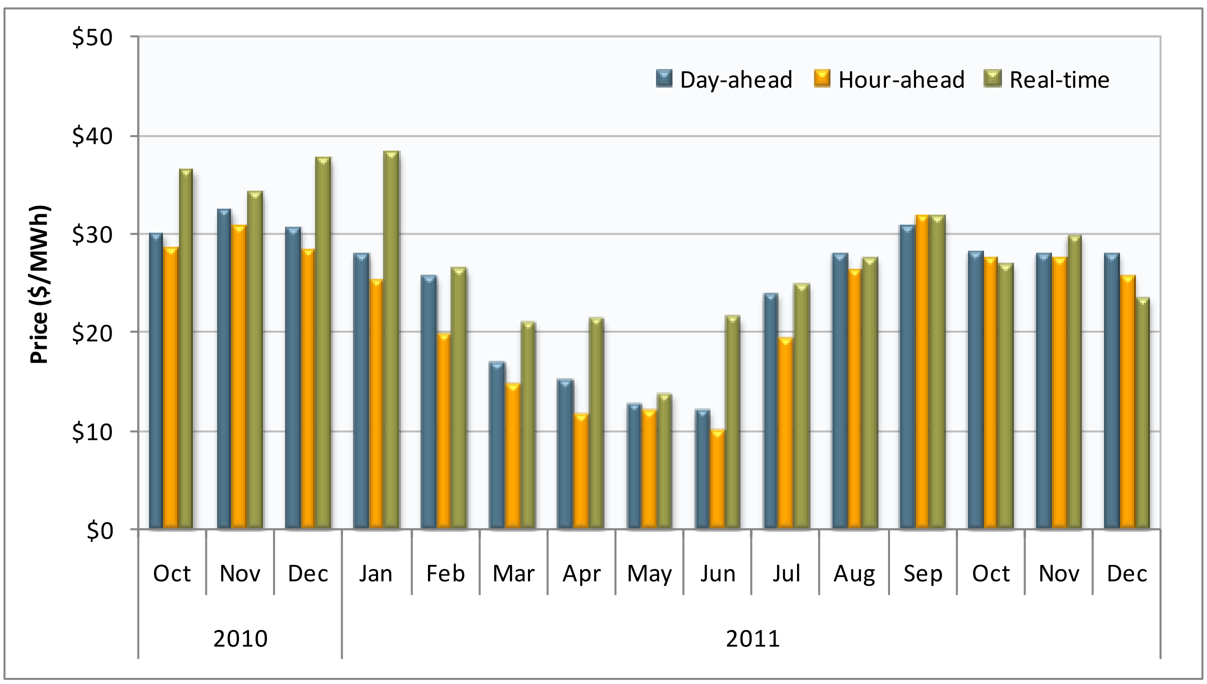


Figure 1.2 Average monthly off-peak prices (PG&E area)



- In peak and off-peak periods in the fourth quarter, hour-ahead prices remained lower than day-ahead prices. With the exception of peak hours in July and off-peak hours in September, this pattern has held for over the last year.
- In October and December, 5-minute real-time market prices were lower than day-ahead and hour-ahead prices in peak and off-peak periods.
- In November, real-time market prices were close to day-ahead prices in peak hours and slightly higher than day-ahead and real-time prices in off-peak hours.

Figure 1.1 and Figure 1.2 show that improvements in average hour-ahead and real-time market prices continued in the fourth quarter. Figure 1.3 and Figure 1.4 also indicate further improvements in hour-ahead and real-time price convergence in the fourth quarter, most notably in December.

- Figure 1.3 shows average hourly prices. Real-time prices differed from day-ahead and hour-ahead prices less consistently in this quarter than in August and September. Real-time prices were higher than day-ahead and hour-ahead prices in hours 15 through 21 in August and September, whereas in the fourth quarter real-time prices were higher in hours 9, 10, 19, 21 and 23. Furthermore, real-time prices were often much lower than both day-ahead and hour-ahead prices in hours 5 through 14 and in hour 22 in August and September, and only in hours 3 through 7 and 16 through 18 in the fourth quarter.
- Figure 1.4 highlights the magnitude of these differences by taking the average of the absolute difference in prices in the hour-ahead and real-time markets. When taking the straight average of prices (green line), price convergence appears to have improved significantly since January. However, when the average absolute differences are taken into account, the magnitude of price differences began to diverge in March, indicating that price divergence has grown.[4] This trend continued into July, fell to around $10/MWh in August and continued at that level through November. In December, the average absolute price divergence fell to around $6/MWh, the second lowest level since the nodal market began in April 2009 and 60 percent lower than December 2010.

These changes in hour-ahead and real-time price convergence are likely due to a combination of the following factors:

  - Decreases in 5-minute ramp limitation related price spikes due to the implementation of a flexible ramping constraint in the real-time market (see Section 1.2);
  - Continued use of operational load adjustments whereby loads are adjusted upward systematically in the hour-ahead and 15-minute pre-dispatch markets to compensate for modeling discrepancies; and
  - Changes in virtual demand positions relative to virtual supply positions due to the elimination of convergence bidding at the inter-ties.

[4] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. If the magnitude decreases, price convergence would be improving. If the magnitude increases, price convergence would be getting worse. DMM does not anticipate that the average absolute price convergence should be zero. This metric is considered secondary to the simple average metrics and helps to further interpret price convergence.

Figure 1.3 Hourly comparison of PG&E area prices – October through December 2011

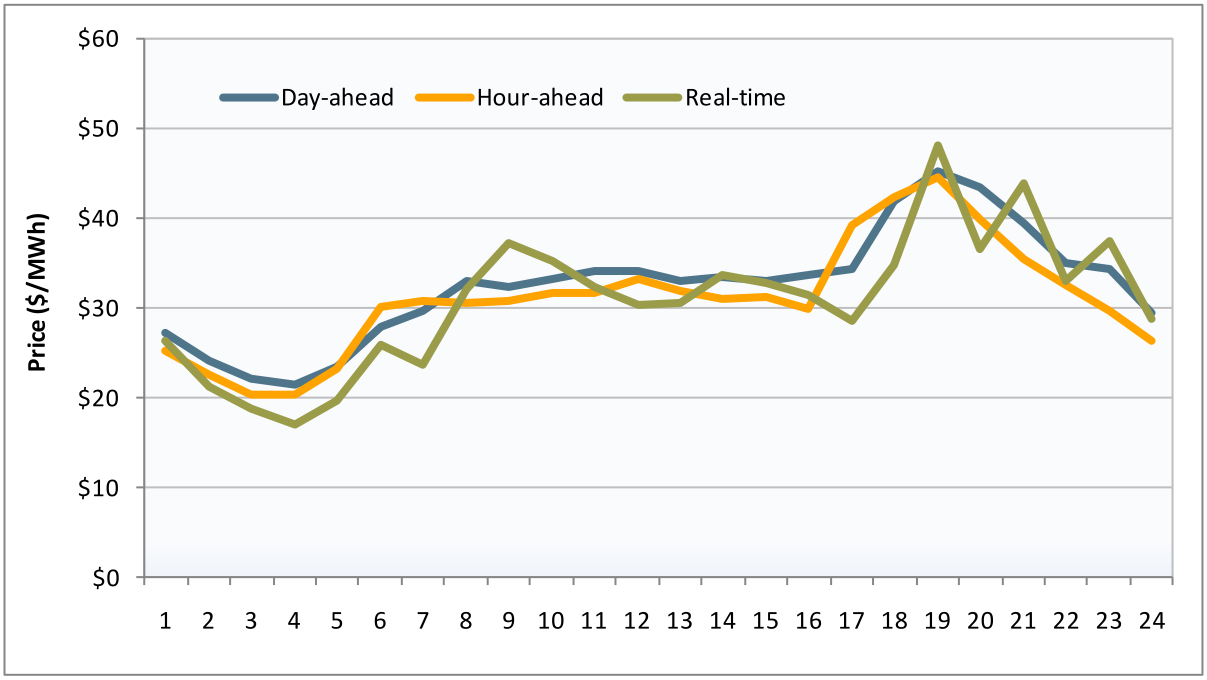
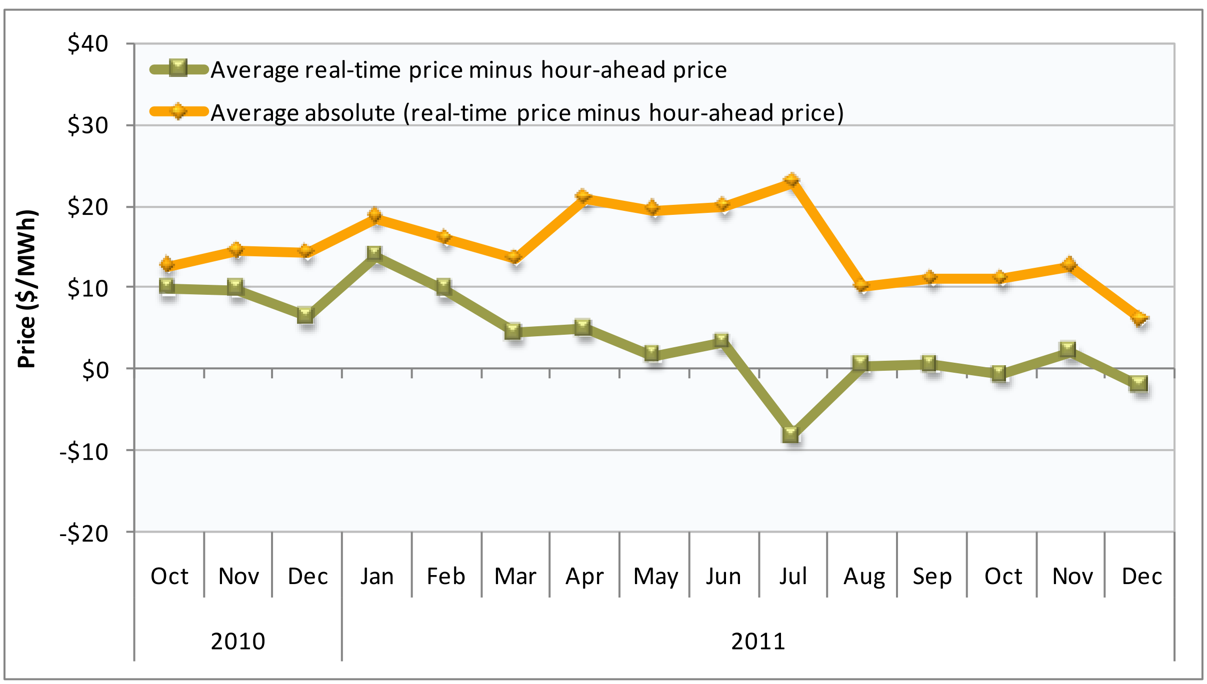


Figure 1.4 Difference in monthly hour-ahead and real-time prices when taking a simple average and absolute average of price differences (PG&E area, all hours)



1.2 Power balance constraint

The system-wide real-time power balance constraint continues to contribute to both large positive and negative real-time prices, but less so for upward ramping limitations in the fourth quarter. Overall, power balance constraint relaxations show a decreasing trend in 2011. Figure 1.5 and Figure 1.6 show the frequency the power balance constraint was relaxed in the 5-minute real-time market software since the fourth quarter of 2010.

- Figure 1.5 shows that the number of relaxations in the fourth quarter continued a downward trend reaching a two-year low in December 2011. Except for December, the constraint relaxations were dispersed over different hours of the day but were slightly more common between 4:00 p.m. and 8:00 p.m. during the evening load ramp and peak. The slight increase in the number of relaxations in October is likely due to decreases in average load with a corresponding increase in steepness in the evening load ramp. Implementation of the flexible ramping constraint in mid-December appears to have contributed to reducing many of the upward ramping limitations that have historically caused power balance constraint relaxations in peak-load periods.
- Figure 1.6 shows an increase in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy in the fourth quarter relative to the third quarter. Changes in expected wind output and unit commitment to meet early morning ramping requirements are contributors to decremental dispatch insufficiencies in the early morning hours. The flexible ramping constraint is not expected to resolve relaxations from insufficiencies of dispatchable decremental energy as the flexible ramping constraint has only been applied in the upward direction.
- Figure 1.7 shows a considerable decrease in the amount of price spikes in the real-time market in the fourth quarter, with December having the lowest percentage (0.1 percent) of price spikes since the beginning of the nodal market in April 2009. Overall, the trend during the fourth quarter demonstrates a continued decrease in the amount of real-time price spikes with the exception of November. Many of the price spikes in November occurred as a result of the loss of several hundred megawatts of inter-tie schedules resulting from an Interchange Authority Emergency declared by the Western Electricity Coordinating Council.[5] The considerable improvement in real-time prices in December can be attributed to a combination of effects including load adjustments, changes in convergence bidding patterns, and the implementation of the flexible ramping constraint in the real-time market.

[5] This emergency was declared as a result of problems with the OATI interchange tagging system, which affected multiple balancing authorities throughout the WECC.

Figure 1.5 Relaxation of power balance constraint because of insufficient upward ramping capacity

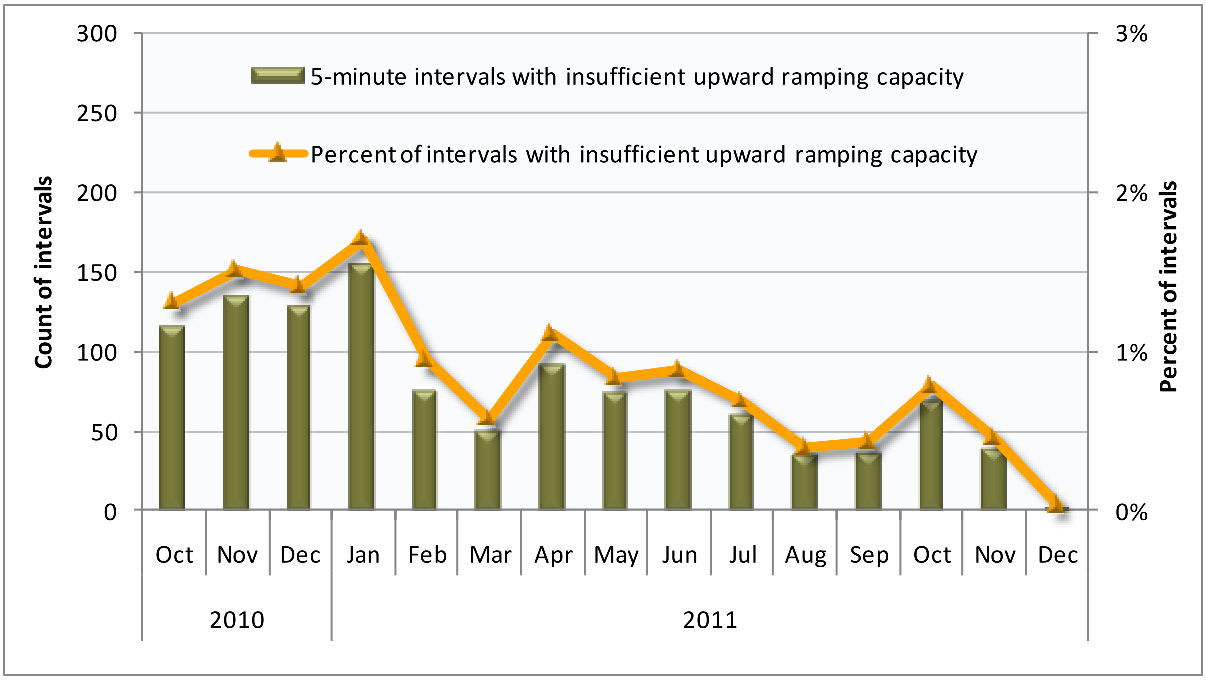


Figure 1.6 Relaxation of power balance constraint because of insufficient downward ramping capacity

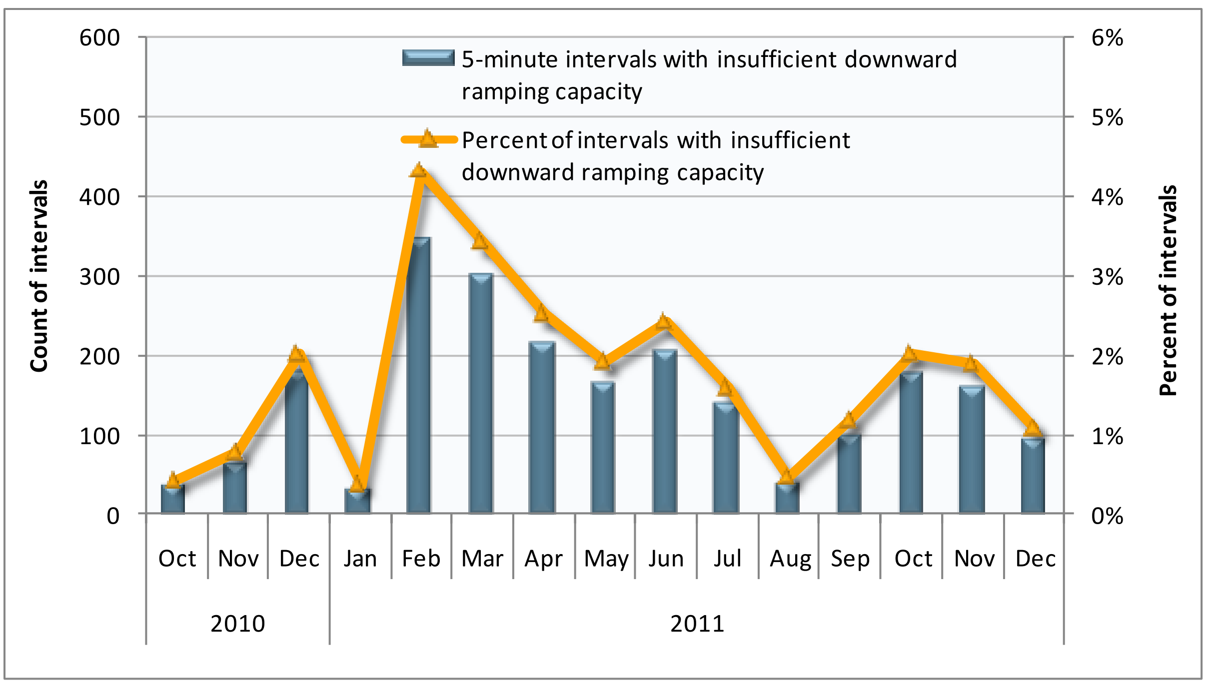
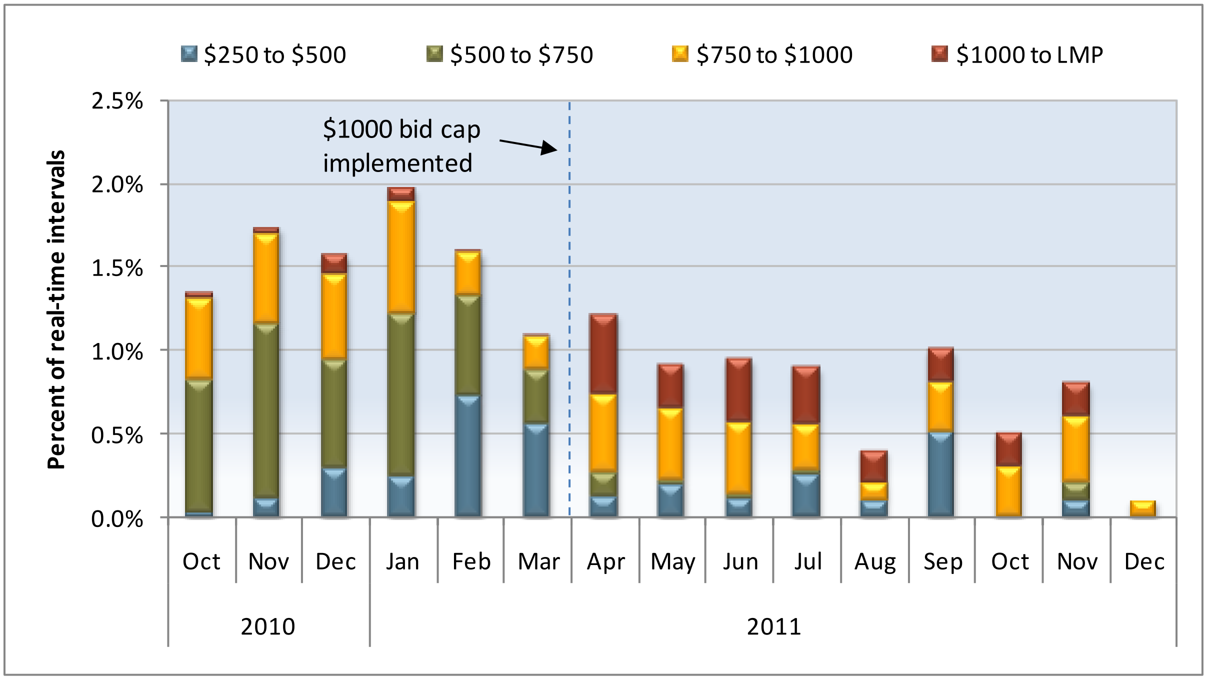


Figure 1.7 Frequency of price spikes (all LAP areas)



The power balance constraint was relaxed because of insufficient incremental energy in less than 0.5 percent of intervals in the fourth quarter and in only three intervals in December. Excluding the hours with power balance constraint relaxations, day-ahead prices remained slightly higher in the fourth quarter, on average, than prices in the hour-ahead and 5-minute real-time markets. Moreover, when the price spikes are excluded, real-time prices are lower, on average, than the hour-ahead prices. Power balance constraint relaxations increased average real-time prices by around 10 percent or $3/MWh in October and November and had a negligible impact on real-time prices in December.

1.3 Market competitiveness

DMM calculates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the marginal cost of gas-fired units and by using actual load. Results of this analysis show the following:

- The day-ahead market has continued to be very stable and competitive.
- Prices in the day-ahead market during each month of the fourth quarter continued to be approximately equal to or slightly lower than prices DMM estimates would result under perfectly competitive conditions. These conditions are based on competitive baseline prices DMM develops by re-running the day-ahead market with default energy bids reflecting each unit's actual marginal cost simulated under actual system load.

Methodology

To assess the competitiveness of the day-ahead market, DMM runs two simulations using its stand-alone copy of the day-ahead software.

- The first is a re-run of the day-ahead software using data for the applicable save case (the ISO's archive of market and system inputs and settings saved after completion of the final day-ahead market run). The results are benchmarked against actual day-ahead results to validate that the DMM stand-alone system is accurately reproducing results of the actual market software.[6] Days for which the stand-alone system does not produce results comparable to the actual market run are excluded from the analysis.[7]

- The second run of the stand-alone software is designed to represent a perfectly competitive scenario that provides a *competitive baseline* against which the re-run of actual day-ahead prices can be compared. In this second run, bids for gas-fired generating resources are replaced with their respective default energy bids (DEBs), which are designed to represent each unit's actual variable or opportunity costs.[8] The system demand is set to the actual system load. This run reflects the assumption that under perfectly competitive conditions, each resource would bid at their marginal operating or opportunity costs under the actual system load. The percentage difference between actual market prices and prices resulting under this competitive baseline scenario represents the *price-cost mark-up index* for the day-ahead market. Generally, DMM considers a market to be competitive if the index indicates no more than a 10 percent mark-up over the competitive baseline.

Figure 1.8 compares this competitive baseline price to average system-wide prices in the day-ahead and 5-minute real-time markets. As seen in Figure 1.8, prices in the day-ahead market have consistently been about equal to the competitive baseline prices. Since June, the competitive baseline prices exceeded the state-wide average prices by about 3 percent. Since May, average real-time prices have been closer to both average day-ahead prices and the competitive baseline than in 2010 and in January 2011. This change has mainly been the result of the decreased frequency of penalty prices associated with ramping limitations influencing real-time market prices (see Section 1.2).

In December 2011, real-time prices dropped below the competitive baseline prices by around $6/MWh. This may be because of the flexible ramp constraint as average real-time prices decreased in the second half of December after its implementation.[9]

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6 Results of the market software and DMM's stand-alone version can vary for several reasons. For example, DMM had difficulties loading and rerunning save cases for several months, thus the DMM system was rerun with subsequent versions of the network models and system updates. When model settings are changed, such as binding constraint corrections or multi-stage generation patches, a re-run may not duplicate the original day-ahead results.

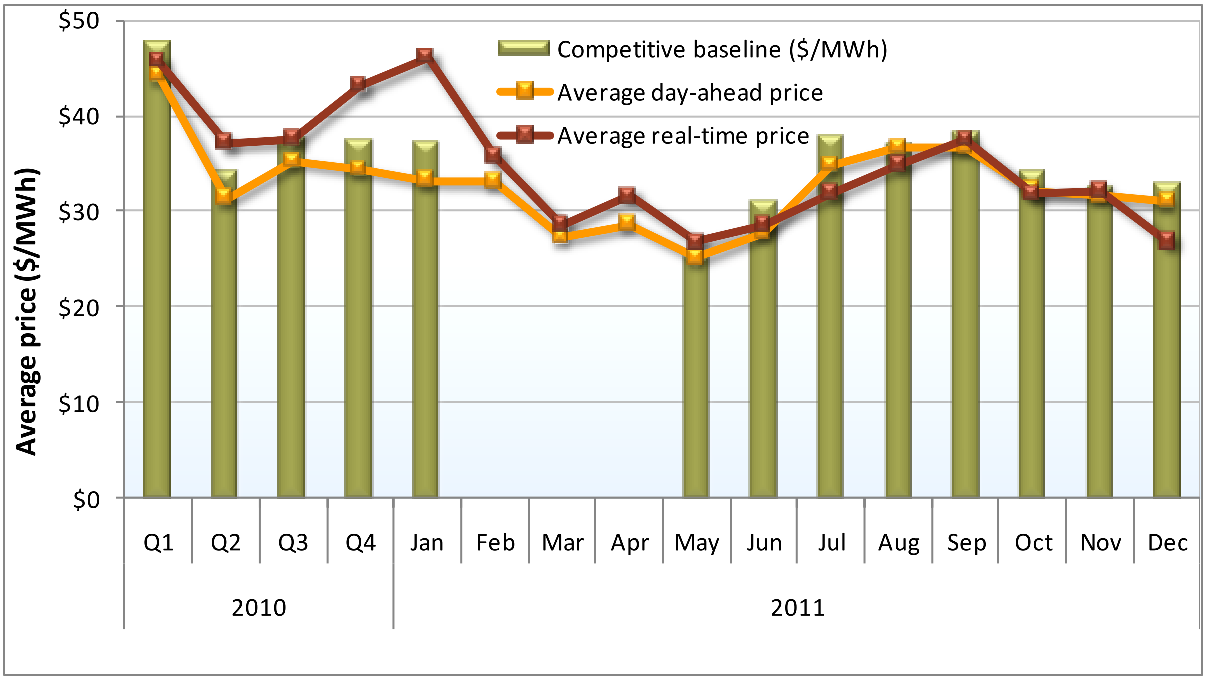
7 DMM expects the portion of re-runs that do not accurately replicate market outcomes (and are therefore excluded from such analyses) to decrease as updates to the day-ahead software decline, and as DMM is able to successfully perform a greater portion of re-runs with a smaller lag time from the date of actual market operation.

8 Under the market power mitigation provisions of the ISO tariff, cost-based default energy bids are increased by 10 percent to reflect potential costs that may not be entirely captured in the standard fuel and variable cost calculations upon which cost-based default energy bids are based (Tariff Section 39.7.1.1). Units such as use-limited resources may also have a default energy bid that reflects their opportunity costs under the negotiated cost option of the ISO tariff (Section 39.7.1.3, and *Business Practice Manual for Market Instruments*, Version 16, Revised: Sep 19, 2011, D-3 to D-4).

9 Further study is needed to determine whether additional capacity was committed because of the flexible ramping constraint during intervals when prices were well below the baseline.

A key factor driving the competitiveness of these markets is the high degree of forward contracting by load-serving entities. This significantly limits the ability and incentive for exercising market power in the day-ahead and real-time markets. Bids for the additional supply needed to meet remaining demand in the day-ahead and real-time energy markets have generally been highly competitive. Most additional supply needed to meet demand has been offered at prices close to default energy bids used in bid mitigation, which are designed to slightly exceed each unit's actual marginal or opportunity costs.

Figure 1.8 Comparison of competitive baseline with day-ahead and real-time prices[10]



1.4 Bid cost recovery payments

Bid cost recovery payments are designed to ensure that generators receive enough market revenues to cover the cost of all their accepted bids when dispatched by the ISO.[11] Early this year, the ISO had identified flaws in the calculation of these payments which – when exploited by certain manipulative bidding behaviors – led to excessively high bid cost recovery payments associated with the day-ahead market. The ISO made two emergency filings in April and June with FERC to modify bid cost recovery rules to mitigate this behavior.

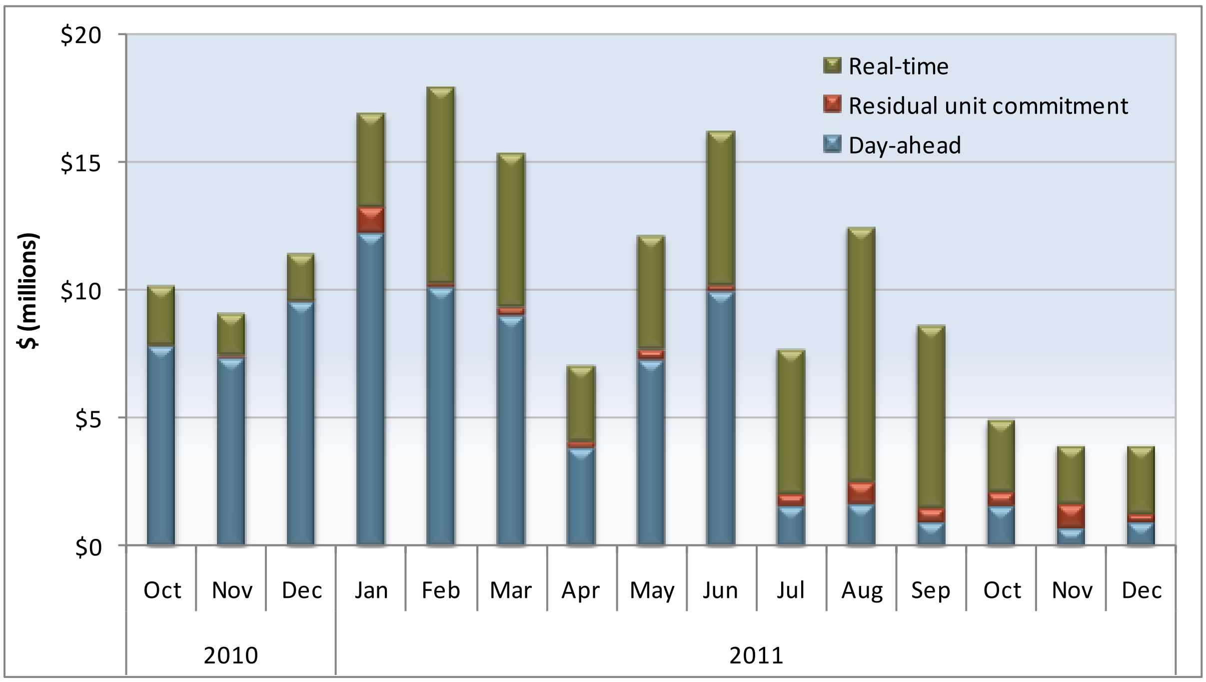
[10] The competitiveness results for February, March and April 2011 are unavailable due to problems related to the stand-alone software performance in the first half of 2011. These problems were addressed in the second half of the year.

[11] Bid cost recovery covers the bids for start-up, minimum load, ancillary services, residual unit commitment availability, and day-ahead and real-time energy.

Since these rule changes, bid cost recovery payments have dropped significantly, particularly for the day-ahead market. As shown in Figure 1.9:

- Overall bid cost recovery payments were down about 50 percent in second half of the year relative to the first half. Bid cost recovery payments associated with the day-ahead market (represented by the blue bar) have decreased by around 86 percent in the second half of the year since bid cost recovery rules were last modified.
- Bid cost recovery payments, especially the payments associated with the real-time market, decreased by 65 percent in the fourth quarter relative to the third quarter.

Figure 1.9 Bid cost recovery payments



Exceptionally dispatched capacity, which increased real-time bid cost recovery payments in the third quarter, decreased by 77 percent in the fourth quarter. As mentioned in DMM's 2011 third quarter report, exceptionally dispatched unit commitments are made after the day-ahead market to protect the system from voltage collapse and potential thermal overloads on critical inter-ties during worst-case contingencies. Also, some of the exceptionally dispatched units provide additional online capacity for south of Path 26 that can be ramped up in 30 minutes to meet a contingency such as an outage on the Nevada-Oregon Border (NOB) transmission path, also known as the Pacific DC Inter-tie (PDCI).[12] Exceptional dispatches for capacity are typically required more in the summer months during peak load conditions. As loads fell in the fourth quarter, the need to exceptionally dispatch for capacity abated.

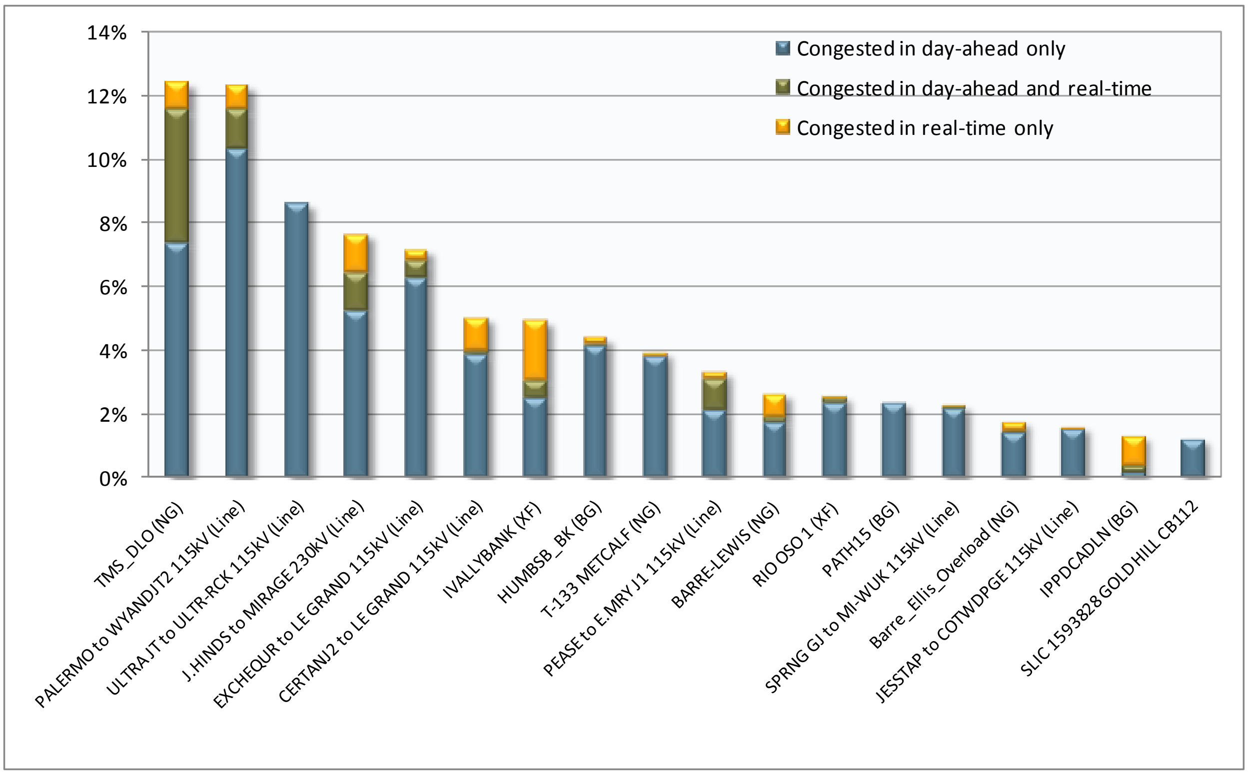
[12] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, November 8, 2011, p. 17, http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

DMM continues to recommend that the ISO monitor and limit the economic impact of exceptional dispatches needed to meet capacity needs. DMM suggests incorporating additional system or local capacity requirements in the day-ahead market to the extent possible to avoid these exceptional dispatches.[13] DMM would support tariff changes to facilitate these results, if necessary.

1.5 Congestion

Congestion within the ISO system had minimal impact on overall prices. However, the frequency of day-ahead congestion remains relatively high, particularly on constraints in generation pockets and those relating to imports into the PG&E area. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market.

Figure 1.10 Consistency of congestion in day-ahead and real-time markets (Oct - Dec 2011)



[13] The ISO plans to address the causes of exceptional dispatches that are within the control of the ISO – such as software, modeling and operational processes – in order to reduce exceptional dispatches.

A combination of planned and unplanned outages on Round Mountain – Table Mountain 500 kV line and the Table Mountain – Vaca 500 kV line contributed to congestion on the TMS_DLO (NG).[14] Congestion on the UltraJt to Ultra-Rck 115 kV line and the J.Hinds to Mirage 230 kV line were related to line conforming to maintain a reliability margin.

Also, congestion in generation pockets,[15] such as Exchequr to Le Grand 115 kV line and the CertanJ2 to Le Grand 115 kV line, have been discussed in previous quarterly reports.[16]

[14] This is a nomogram in the COI Master Operating Procedure (#6110). This procedure specifies system operating limits, provides normal and contingency operations, and provides background and guidance for all COI-related paths. Specifically this nomogram is for the loss of double 500 kV lines Table Mountain-Tesla and Table Mountain-Vaca to protect the 230 kV line Table Mountain-Rio Oso. ISO Operations Planning described the congestion as related to Northern California dispatch (that includes Northern California hydro plus Colusa, which is a combined cycle plant between Cottonwood and Vaca Dixon, and Hatchet Ridge wind farm north of Round Mountain) as one of the key reasons for congestion, along with the COI (N>S) flows and the local area load.

[15] Similar generation pocket constraints include Spring GJ to Mi-Wuk 115 kV line, Exchequr to Le Grand 115 kV line, Drum to Brnswkt2 115 kV line, Brnswkt1 to Dtch2tap 230 kV line, Electra to Bellota 230 kV line, Smrtsvle to Yubagold 60 kV line, Grizjct to bigben2 115 kV line and Swtwtrtp to Sweetwtr 9 kV line.

[16] In DMM's 2011 third quarter report, DMM looked closer into congestion inconsistences in certain generation pockets and identified the lack of congestion in the real-time market as a result of the following: 1) the functioning of the ISO markets; 2) operating procedures; and 3) a two-settlement system. DMM will continue to monitor and evaluate differences in congestion in the day-ahead and real-time markets.

2 Convergence bidding

Convergence bidding was implemented in the day-ahead market for February 1, 2011. Net revenues for convergence bidding entities have been around $41 million for the first 11 months of this market feature (February through December).[17] Net revenues declined as average price convergence improved in the fourth quarter (as shown in Section 1.1) and as volumes of convergence bids decreased. For instance, net revenues in the fourth quarter totaled about $2 million compared to $9 million in the third quarter. Also, average hourly cleared gross volumes of convergence bids fell to 2,700 MW in the fourth quarter from 4,000 MW in the third quarter.

Background

Convergence bidding is designed to allow participants to place purely financial bids for supply or demand in the day-ahead market regardless of whether or not they own physical load or generation. The virtual bids accepted in the day-ahead market are automatically liquidated in the hour-ahead and real-time markets, which are dispatched based on physical supply and demand only.

In theory, these participants profit by arbitraging the difference between day-ahead, hour-ahead and real-time prices. As participants take advantage of opportunities to profit through convergence bids, this activity should drive day-ahead, hour-ahead and real-time prices closer. The following illustrates how virtual demand and supply are designed to work.

- If prices are higher in the real-time market relative to the day-ahead market, convergence bidders should place virtual demand bids. Virtual demand will raise load in the day-ahead, which could lead to additional unit commitment. This additional unit commitment would occur because of higher prices in the day-ahead market. This additional unit commitment would be available in real-time and would have a dampening effect on real-time prices. The virtual demand would then be paid the difference between the real-time price and the day-ahead price for each virtual megawatt.

- If prices are lower in the real-time market relative to the day-ahead market, convergence bidders should place virtual supply bids. Virtual supply will displace the supply of physical generation in the day-ahead and could lead to units being committed lower on their bid curves. Also, it could potentially even displace additional unit commitments.[18] This reduction in physical commitment would occur because of lower prices in the day-ahead market. In real-time, these virtual supply resources would not materialize and should therefore have an elevating effect on real-time prices. The virtual supply would then be paid the difference between the real-time price and the day-ahead price for each virtual megawatt.

The California market design has a feature that makes it different from most other ISOs; it re-optimizes imports and exports in an hour-ahead market. Unlike other ISOs, the ISO settles these inter-tie resources based on hour-ahead prices rather than 5-minute real-time prices. The same is true for

[17] The net revenue and imbalance calculations in this report were updated from previous reports because of updates to DMM's data system tables related to price corrections. The affected figures include 2.5, 2.6 and 2.7.

[18] This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market to the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

convergence bids on the inter-ties. These bids also settle against hour-ahead prices rather than the 5-minute real-time prices.

This feature has led to uplifts, known as imbalance offset costs, which can occur when prices diverge between the hour-ahead and real-time markets. In order to address these uplifts, the ISO filed with FERC to suspend convergence bidding on the inter-ties. Effective November 28, 2011, convergence bidding at inter-tie scheduling points was suspended temporarily pending the outcome of a FERC technical conference in February.[19]

2.1 Convergence bidding activity

2.1.1 Convergence bidding volumes

While the pattern of overall convergence bidding volumes has changed over time, the vast majority of net positions were virtual supply on inter-ties, until suspension of inter-tie bids on November 28, 2011. Immediately after the suspension, the net convergence bidding position shifted to virtual demand at the internal nodes. This pattern remained until mid-December when the net position changed to virtual supply at the internal nodes.

Convergence bidding volumes increased steadily from the start of convergence bidding on February 1 until mid-April. After dropping in mid-April, convergence bidding volumes stabilized at a lower level until late November when volumes dropped sharply because of the suspension of convergence bidding at inter-tie nodes.

Figure 2.1 and Figure 2.2 show the quantities of both virtual demand and supply offered and cleared in the market. As shown in Figure 2.1:

- On average, 55 percent of virtual supply and demand bids cleared in the first year of convergence bidding.
- With the exception of the very first weeks of convergence bidding and the first few weeks of December, cleared virtual supply has outweighed cleared virtual demand on average by around 540 MW. In the fourth quarter this value fell to approximately 380 MW.
- A significant decrease of the virtual supply positions occurred after convergence bidding was suspended. This was followed by a sharp decrease of virtual demand in the last two weeks of December.

As shown in Figure 2.2:

- Virtual supply exceeded virtual demand in every hour of the day in October and November, especially during off-peak hours.
- In the period of November 28 through December 12, net virtual demand positions became predominant beginning in hour ending 7.

[19] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order.

- In the period of December 12 through December 31, the net virtual position shifted back to a predominantly virtual supply position, with only a few hours remaining as net virtual demand.

Figure 2.1 Monthly average offered and cleared virtual activity

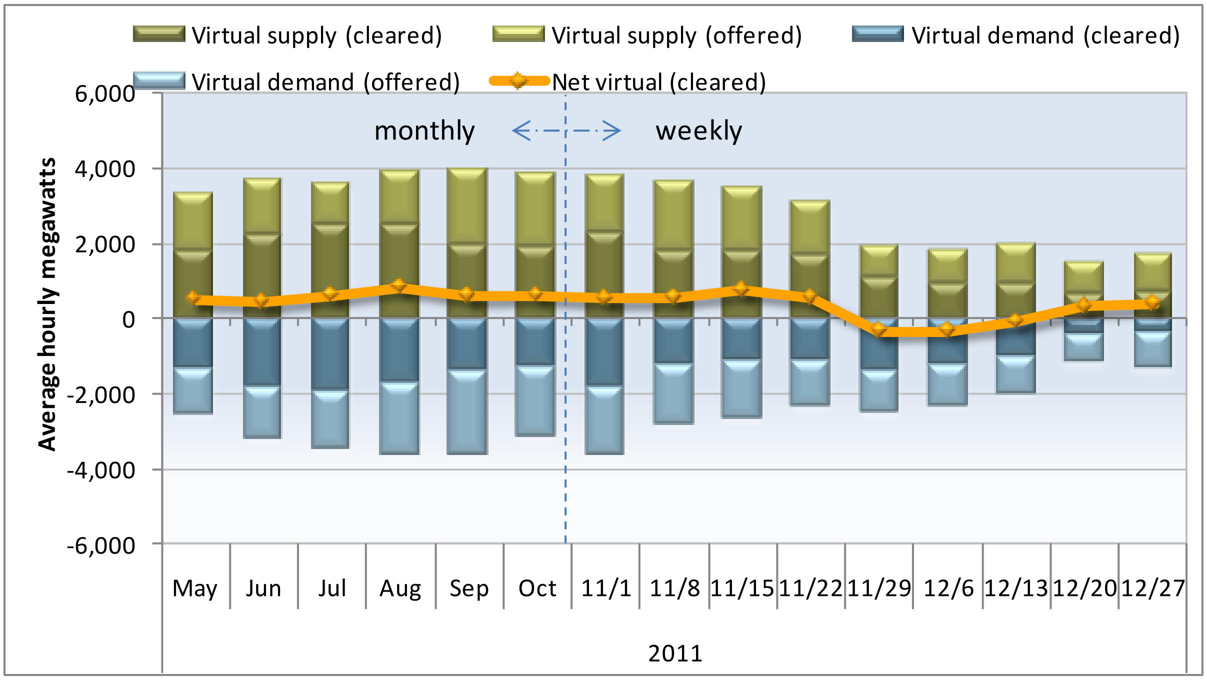
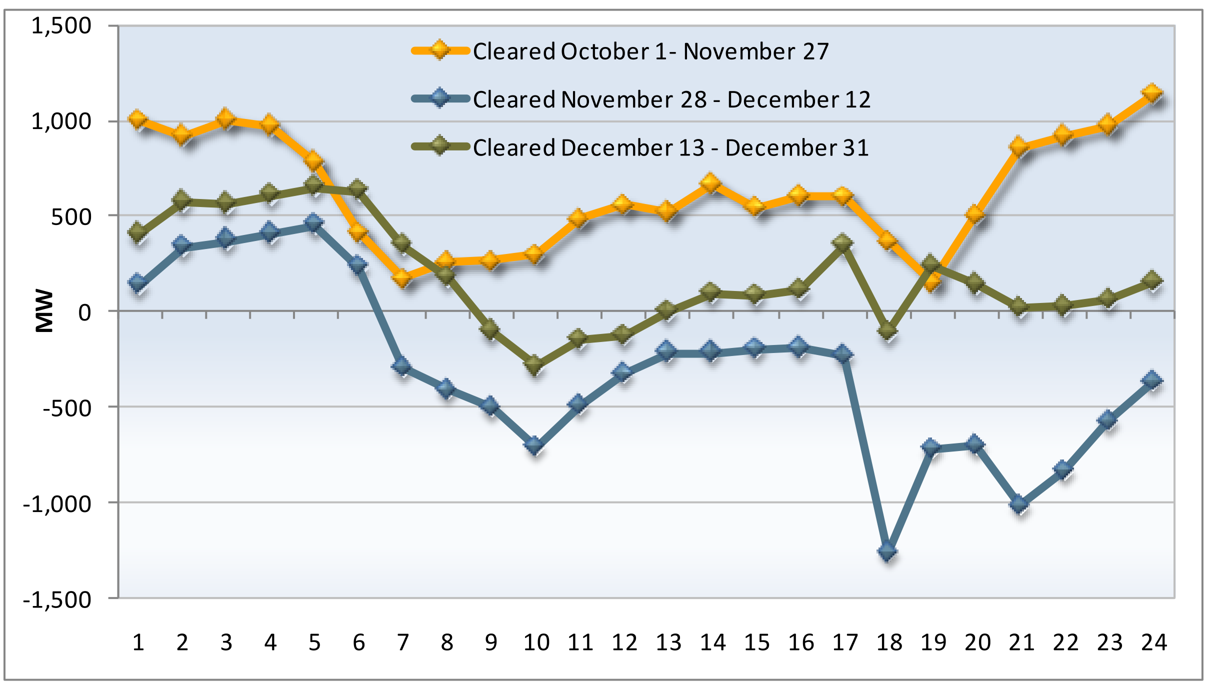


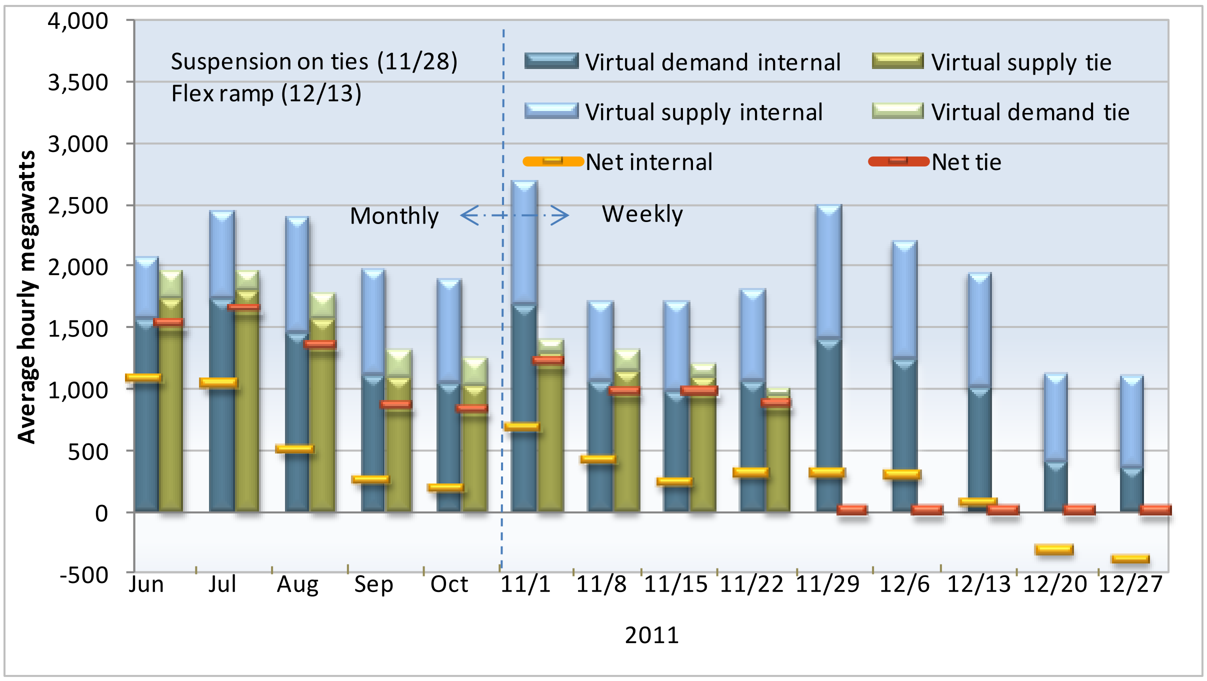
Figure 2.2 Hourly offered and cleared virtual activity (October-December 2011)



2.1.2 Virtual supply at the inter-ties and virtual demand at internal nodes

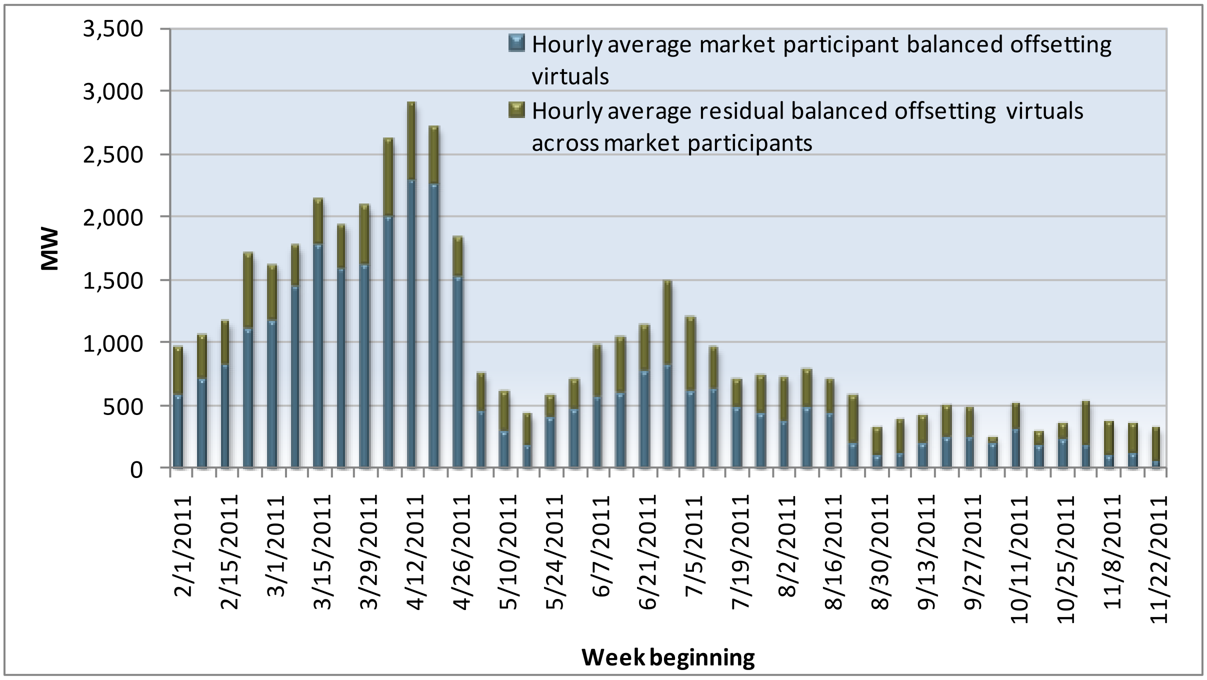
Convergence bidding positions at inter-ties and at internal scheduling points showed a distinctive pattern until inter-tie bidding was suspended. Virtual supply on inter-ties and virtual demand on internal nodes comprised 75 percent of the total trading volumes. In the third quarter, virtual supply volumes at internal nodes increased and offset internal virtual demand. In the fourth quarter, virtual supply volumes at internal nodes remained steady and offset internal virtual demand more than in previous quarters. As shown in Figure 2.3, convergence bidding on inter-ties (shown in green) is weighted toward virtual supply. Convergence bidding on internal locations (shown in blue) was typically weighted toward virtual demand. However, this pattern shifted in mid-December toward net virtual supply on internal nodes after the implementation of the flexible ramping constraint and after a few week period where virtual demand positions were losing revenues (see Section 2.2.1).

Figure 2.3 Average monthly cleared convergence bids at inter-ties and internal locations



From the start of convergence bidding until the suspension of inter-tie convergence bids, numerous market participants placed virtual supply positions at the inter-ties and then placed an equal and opposite virtual demand position at internal locations during the same hour. Figure 2.4 shows the volume of these offsetting virtual supply and demand positions. The blue bars represent the monthly average megawatts associated with virtual bids at inter-ties offset by virtual bids within the ISO during the same hour by the same participant. The green bars represent offsetting positions attributable to different market participants placing virtual positions at inter-ties offset by virtual positions within the ISO during the same hour. There was a sharp drop in offsetting positions in mid-April. After an uptick in June and July, the use of offsetting positions further declined until the suspension of the inter-ties in late November. No virtual offsetting positions occurred after the suspension of convergence bidding at the inter-ties.

Figure 2.4 Portion of cleared virtual bids attributable to offsetting virtual bids (virtual imports plus virtual internal demand)



As noted above, convergence bidding at the inter-ties settles against the hour-ahead market prices, whereas convergence bidding at internal nodes settles against the 5-minute real-time market prices. If prices in the hour-ahead market were consistent with 5-minute real-time market prices these positions would not contribute to imbalance costs. However, prices between these markets have been markedly different at times, which have led to continued uplifts that are outlined further in Section 2.2.3.

2.2 Convergence bidding effects on the market

If convergence bidding is working as intended, day-ahead, hour-ahead and 5-minute real-time market prices should converge. The following aspects about price convergence are described in detail in Section 1.1:

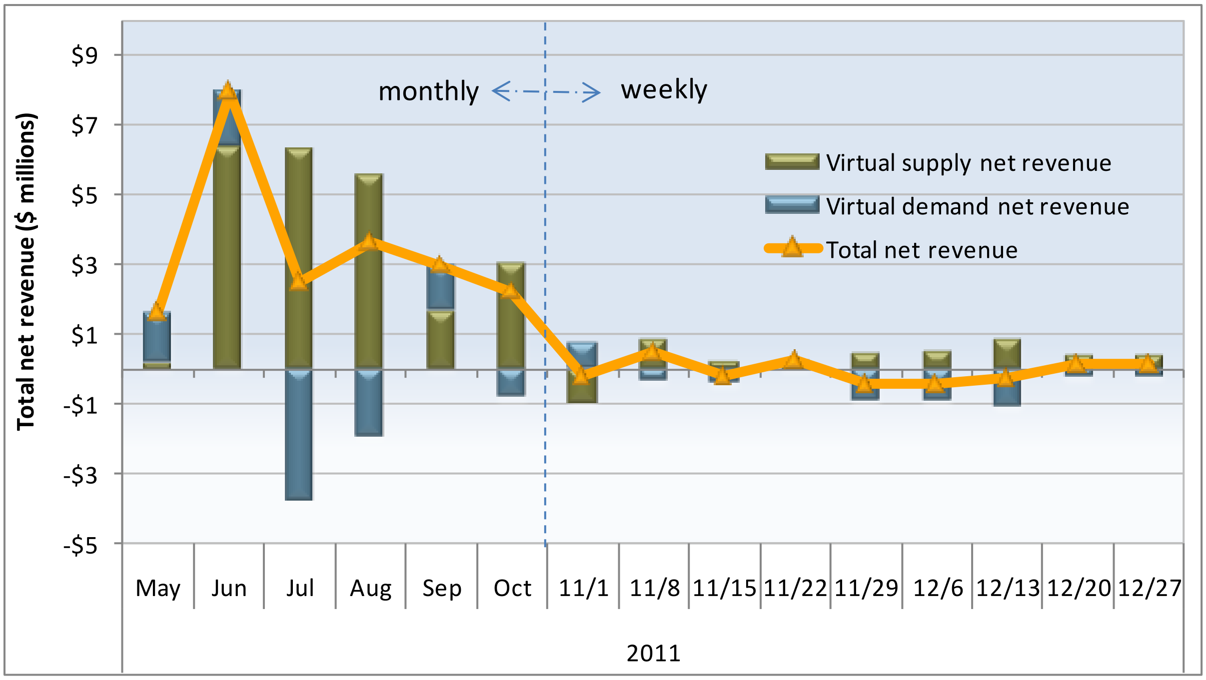
- Overall average price convergence improved in the fourth quarter on average as well as on an hourly basis.
- Much of the improvement in price convergence can be attributable to changes in ISO operational procedures and software changes to address ramping limitations in real-time.

2.2.1 Net revenues from convergence bidding

Figure 2.5 shows that virtual supply positions have had positive net revenues in most periods, whereas virtual demand positions have shifted from positive to negative net revenues from one period to the next. Virtual supply transactions were profitable in most periods except the month of May and the first week of November. Virtual demand net revenues paid to convergence bidding entities were positive in

May, June, September, and the first week of November. Over the course of the fourth quarter, net revenues paid out to convergence bidding entities totaled just under $2 million, down from $9 million paid in the third quarter. Total net revenues were negative in December, which was the first month with negative virtual bidding revenues since the convergence bidding market began in February.

Figure 2.5 Total monthly convergence bidding net revenues

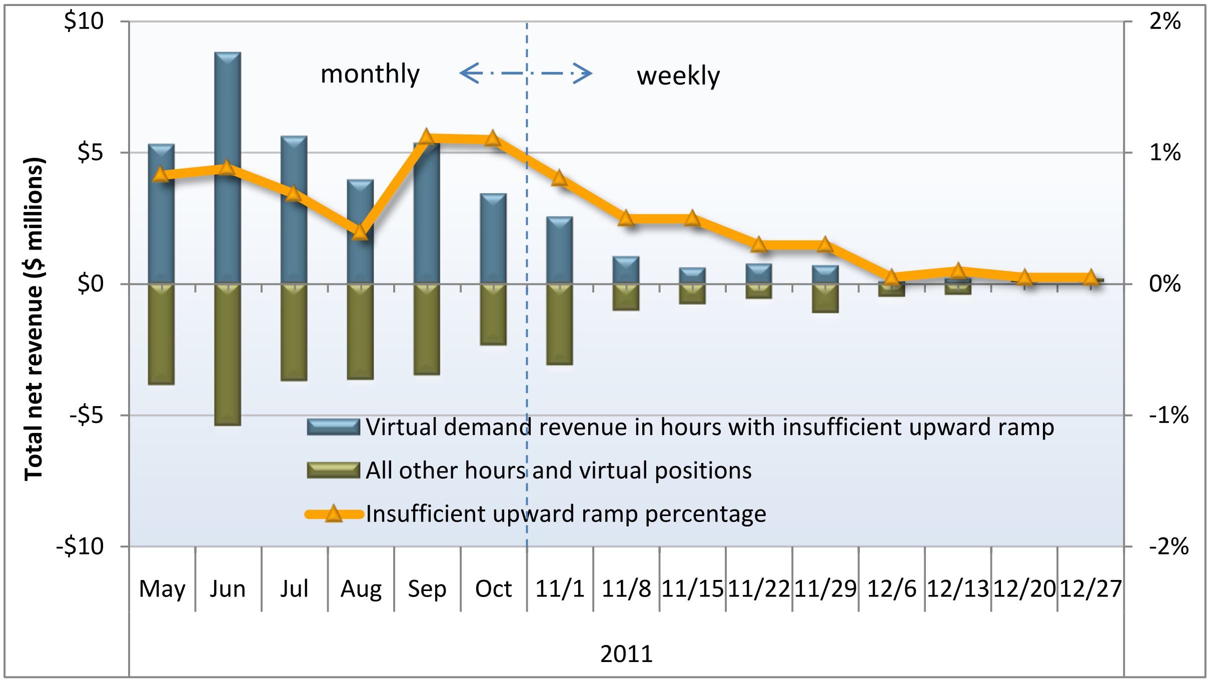


Net revenues on internal nodes

Since the start of convergence bidding in February, approximately 68 percent of cleared bids at internal locations have been virtual demand. This is down from 90 percent in the first three quarters. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Intervals when the system power balance constraint relaxes account for almost all of the positive revenues for internal virtual demand positions, as shown in Figure 2.6. For most of November and the entire month of December, the frequency of real-time price spikes decreased significantly. Correspondingly, net revenues on the internal nodes also decreased.

As noted in Section 1.2, when the power balance constraint is relaxed, the system marginal energy component of the price is set to the bid cap, which was $750/MWh in the first two months of convergence bidding and increased to $1,000/MWh on April 1. Net revenues received from these brief but extreme price spikes can be high enough to outweigh losses when the day-ahead price exceeds the real-time market price. In fact, having a single 5-minute interval price spike can yield enough aggregate income to compensate losses in the remaining hours of the day.

Figure 2.6 Convergence bidding revenues at internal nodes



These price spikes are typically associated with brief shortages of ramping capacity. Convergence bidding can potentially add additional capacity, but that capacity may not be enough to address the ramping limitations. Moreover, in the event of over-generation, real-time prices can be negative, but do not go below the bid floor of -$30/MWh unless congestion occurs. This diminishes the risk of market participants losing substantial money by bidding virtual demand as well as reduces the potential benefits to virtual supply bids at internal nodes.

As noted in Section 1.1, implementation of the flexible ramping constraint decreased the frequency of $1,000/MWh price spikes in late December. As a result, virtual demand positions became less profitable and ultimately participants shifted to a virtual supply position during the second half of December.

2.2.2 Changes in unit commitment

In the day-ahead market, if scheduled demand is less than the ISO forecasted demand, the residual unit commitment process procures additional capacity to meet the forecasted demand, as well as any forecasted shortfalls of minimum generation requirements.

Cleared virtual supply outweighed cleared virtual demand at the system level a majority of the time. As a result, more residual unit commitment capacity is needed to replace the net virtual supply with physical supply. This is likely to increase both the direct capacity procurement costs and bid cost recovery payments associated with residual unit commitment. After virtual bidding was suspended on the inter-ties, the initial bidding pattern shifted and cleared virtual demand outweighed cleared virtual supply in the day-ahead market. After mid-December, along with the implementation of the flexible ramping constraint, cleared virtual supply outweighed cleared virtual demand again.

In the fourth quarter of 2011, total direct residual unit commitment costs reached $433,000. Since convergence bidding started in February, direct residual unit commitment costs have totaled around

$1.1 million, compared to the 2010 total of $83,000. Bid cost recovery payments for the residual unit commitment capacity amounted to around $1.8 million in the fourth quarter. Since the beginning of convergence bidding, bid cost recovery payments for the residual unit commitment capacity reached $5 million, compared to $1.4 million in all of 2010.

2.2.3 Costs associated with continued price divergence and convergence bidding

Divergence in prices can pose unnecessary additional inefficiencies and costs on the system. When net imports decrease in the hour-ahead market, but real-time imbalance energy increases, the decrease in net imports may be inefficient.[20] Moreover, if net virtual supply on the inter-ties outweighs net virtual demand on internal nodes, and real-time imbalance energy increases, this may also be inefficient.

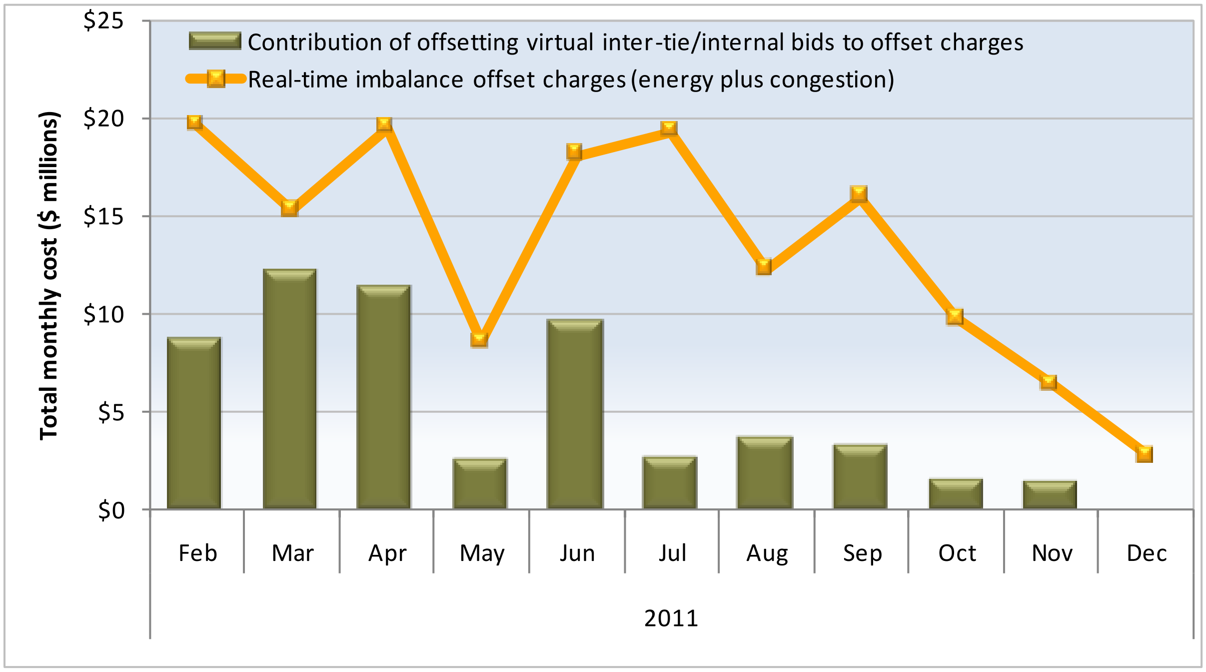
Such reductions are inefficient if hour-ahead prices are systematically lower than real-time prices, so that the ISO is selling both physical and virtual supply in the hour-ahead at a low price and then dispatching additional energy in real-time at a higher price. Conversely, if both physical supply and virtual demand are purchased in the hour-ahead market at high prices and then additional energy is dispatched down in real-time at lower prices, this can also create imbalances. These situations can create substantial uplifts that must be recovered from load-serving entities through the real-time imbalance energy and congestion offset charges.[21]

Figure 2.7 shows the breakdown of the estimated real-time imbalance cost associated with offsetting virtual supply on inter-ties and virtual demand at internal locations. Interestingly, imbalance costs associated with offsetting virtual positions are near $1.5 million in the months of October and November. This highlights that even though the total volumes of offsetting positions have decreased, the offsetting positions can still contribute significantly to imbalance costs. Since the market began in February until the suspension of inter-tie convergence bids, DMM estimates that charges associated with offsetting virtual positions have totaled $57 million, about 40 percent of the total imbalance costs. In the fourth quarter, DMM estimates that these charges totaled about $3 million.

[20] The inter-tie prices are relative to prices in neighboring systems. If prices outside of the ISO system are higher, it makes economic sense for net imports to decrease in the hour-ahead scheduling process. This can be accomplished by either reducing imports or increasing exports.

[21] More information about the Real-Time Imbalance Energy Offset charge can be found on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/Real-TimeImbalanceEnergyOffset2009.aspx.

Figure 2.7 Contribution of offsetting virtual supply and demand to real-time imbalance charges



3 Special Issues

Over the past few months, the ISO dealt with natural gas market integration issues related to two key natural gas pipeline events. These events include:

- Pressure reductions on the Pacific Gas and Electric natural gas pipeline; and
- Outages on the Southern California Gas pipeline due to maintenance outages.

The ISO also implemented software changes to improve real-time market performance. These changes include:

- The implementation of the new load forecasting system known as ALFS3; and
- The addition of the flexible ramping constraint to the real-time market models.

This section provides a review of these events and changes.

3.1 Natural gas and electric integration

Natural gas fired generation plays a critical role in the ISO supply mix. Gas fired generation most often sets prices in the markets and in some cases, such as within San Diego County, it is the fuel type for most generation within a load pocket.

3.1.1 Pressure reductions on the PG&E natural gas system

As a result of the National Transportation Safety Board investigation into the San Bruno pipeline rupture and fire[22] and a subsequent rulemaking from the California Public Utilities Commission (CPUC),[23] the PG&E gas pipeline utility was required to test the integrity of its natural gas pipeline system. As a precaution, the PG&E pipeline was required to reduce gas pressure on their system until testing revealed that the pressure could be increased.

Reducing pressure required pipeline customers to more closely match scheduled natural gas deliveries with actual system off-takes. At higher pressure levels, the natural gas system can more easily handle situations when a customer takes or leaves more gas than they scheduled. In order to enforce customer performance, the PG&E pipeline instituted operational flow orders (OFOs), which penalized daily over- and under-usage of gas within a tolerance band.[24] These OFOs began for the gas-operating day on July 8 and continued through November 30.

[22] For further details of the incident, please see the following report: http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf.

[23] Further details of the CPUC rulemaking can be found under Rulemaking 11-02-019: http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/136874.pdf.

[24] For further discussion, see the following PG&E press release: http://www.pge.com/pipeline/news/20110706_1539_news.shtml.

The ISO issues operating instructions to generators that are customers of the PG&E natural gas pipeline. These instructions can cause generators to deviate – above or below – scheduled natural gas levels. Recognizing this issue, the PG&E pipeline and the ISO operators developed procedures that successfully coordinated the reliability of both systems during the pressure reduction period. Both the PG&E pipeline and the ISO are prepared to coordinate in the future should similar situations arise.

3.1.2 Southern California Gas pipeline outages in San Diego[25]

During the fourth quarter, Southern California Gas took multiple outages of one of the three main natural gas pipelines that serve San Diego County.[26] The pipeline outages occurred on eight consecutive weekends starting on October 1 and lasting through the weekend of November 19. Most outages were scheduled from 6:00 a.m. Saturday to 6:00 a.m. Sunday, though many outages ended several hours early. Southern California Gas served all core natural gas customers during the outages.[27] However, non-core customers, including all power plants within San Diego County, were not able to bring natural gas into their facilities on the Southern California Gas system. Instead, a limited amount of natural gas came from the Baja Norte pipeline, which connects to the Southern California Gas system through Mexico and remained operational during the Southern California gas outage.

Southern California Gas successfully coordinated the outages with the ISO to ensure that the electric needs within San Diego County were served. To ensure reliability, the ISO performed studies to determine how best to ensure San Diego County's electric reliability during the outages. As a result of the studies, the ISO committed specific generation within San Diego through exceptional dispatch weeks in advance of the outages. The ISO examined various factors including heat rates, ramp rates, electric transmission availability, and San Diego electric import capability to determine which units would provide the most reliable outcome. Exceptionally dispatching the generation in advance allowed generators to procure the necessary natural gas transportation along the Baja Norte pipeline.

During the scheduled pipeline outages, the ISO used both the day-ahead and real-time market models to the fullest extent possible. The exceptionally dispatched generators continued to place bids into the market and market software evaluated their bids and mitigated accordingly. The ISO also procured non-spinning reserves in San Diego. In the event that one of the generators exceptionally dispatched became unavailable during the outage, non-spinning reserves would have received the natural gas to address the contingency. Non-spinning reserves were not called upon during the outages.

The ISO made some modifications to the market model in order to ensure reliability. It suspended convergence bidding for all nodes, zones, and trading hubs that affect the San Diego Gas and Electric zone for many of the outages. Given the reliability concerns, the ISO wanted to ensure that only physical resources were evaluated and scheduled by the software. After gaining experience with the outage modeling, the ISO allowed virtual bidding to resume in November without incident.[28] Furthermore, to ensure that capacity within San Diego met the needs of San Diego and not the ISO

[25] The following ISO technical bulletin contains further information: http://www.caiso.com/Documents/TechnicalBulletin-SanDiegoGas-ElectricCompanyGasPipelineMaintenanceImpact_ISOMarkets-Operation.pdf.

[26] Southern California Gas operates two pipes that go into San Diego County; one is a 30 inch pipe and the second is a 16 inch pipe. The third pipe, Baja Norte, is a 30 inch pipe with limited deliverability into San Diego County.

[27] Core natural gas customers were served through the 16 inch Southern California Gas pipe.

[28] Convergence bidding was reinstated for the San Diego region on November 6, 13, 19 and 20.

system, the ISO did not procure any regulation or spinning reserves within the San Diego region. Instead, these services were provided along San Diego County's ties with the rest of the ISO system.

DMM coordinated with the ISO throughout the outages, particularly with regards to mitigation. DMM observed no inappropriate behavior related to the outages. In the event that similar pipeline outages occur, DMM will again coordinate with the ISO.

3.2 Load forecast performance

The ISO has continued to review the performance of its new load forecasting software launched in the spring of 2011. The system, known as ALFS3, produces load forecasts at the 15-minute and 5-minute levels, whereas the previous forecast system, ALSF2, only produced 30-minute forecasts.[29] As DMM reported in its third quarter report, the ALSF3 system experienced significant problems.[30] Upon further review, the ISO has determined that when combining the performance of the forecasts for the different markets, ALFS3 has not made any significant improvement from ALFS2 for the period from May through November.[31] However, the ISO has indicated that when a handful of days are removed, the ALFS3 outperforms ALFS2 by around 5 percent on average.[32]

The reasons for the overall poor performance are related to the lack of robustness of the model. As noted above, the performance of only a handful of days created significant performance issues between ALSF3 relative to ALFS2. The ISO has identified issues related to hardware as well as software performance. Inputs, such as weather, have also affected the accuracy of the model. Furthermore, the model experienced issues related to holiday forecasting, midnight changeover from one day to the next and the daylight savings time switchover on November 6. In particular, load forecasting around holidays continued to cause the ISO problems into 2012.

Going forward, the ISO intends to develop a successor to ALFS3 known as ALFS5. Enhancements in ALFS5 include using multiple weather services instead of just one, a mixed forecast that uses both weather derived as well as an autoregressive forecast techniques, better pump load forecasts by including day-ahead awards in the forecast, better systems to validate input data including using load-serving entity load forecasts, and an optimizer that will determine which weather forecast to pick out of multiple forecast options. The ISO plans to begin parallel testing of the ALFS3 and ALFS5 in May 2012 with a switchover estimated to occur by the end of the year.

3.3 Real-time flexible ramp constraint performance

On December 13, 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in both the 15-minute real-time pre-dispatch (RTPD) and in the 5-minute real-time dispatch

[29] When the ISO used the ALSF2 system, the ISO used a separate tool to interpolate between 30-minute forecasts to get 15-minute and 5-minute forecasts.

[30] *Quarterly Report on Market Issues and Performance,* Department of Market Monitoring, November 8, 2011, p. 40. http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

[31] The ISO has measured performance by calculating the mean absolute percentage error at the 30-minute forecast level. This is the closest comparison between the systems as ALSF2 does not provide granular forecasts below 30 minutes.

[32] These days include May 28, June 5, 21 and 29, July 4, 13, 16, 17, 19 and 20, September 8 and 22, and November 6 and 7.

(RTD) market. The constraint will only be applied to internal generation resources and proxy demand response resources and not to external resources as noted in the December 12 FERC order.[33]

Application of the constraint in the real-time pre-dispatch market ensures that enough capacity is procured to meet the flexible ramping requirement. In addition to procuring flexible ramping capacity, the ISO procures additional incremental regulating and operating reserves in the 15-minute market. The 15-minute market also provides unit commitment of fast start units prior to the 5-minute dispatch. Application of the constraint in the 5-minute real-time market is to ensure that the cleared quantity is available for dispatch in the subsequent 5-minute intervals of the trading hour. The flexible ramping constraint in the 5-minute real-time market is resolved from the same set of resources that resolved the constraint in the 15-minute market.

The ISO in its FERC filling suggested allocating the cost of the flexible-ramping constraint to measured demand citing parity with ancillary services cost allocation.[34] Although the FERC has approved the implementation of the flexible ramping constraint in the 5-minute real-time market, the methodology to allocate the associated cost has not yet been approved by FERC.[35] FERC appointed a settlements judge to adjudicate on the cost allocation methodology. The total payments to units providing flexible ramping capacity during the month of January 2012 was around $2.5 million; this compares with a monthly average payment of $1.2 million for spinning reserves resources for the same period.

A majority of the spinning reserves available in the ISO market are contingent, which means that they cannot be deployed unless there is a severe forced outage in the system and the operators have to implement a contingency dispatch. The flexible ramping constraint was implemented to account for the non-contingency based variations in system conditions between the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch. Variations can stem from load and supply variability and uncertainties in the transmission network including forced outages and de-rates. The additional flexible ramping capacity will supplement the existing non-contingent spinning reserves in the system in managing these variations.

The ISO procures the available 15-minute dispatchable capacity from the available set of resources in the 15-minute real-time pre-dispatch run. If there is sufficient capacity already on-line, the ISO does not commit additional resources in the system, which often leads to a low (or sometimes 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 commits additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. The short-start units can be eligible for bid cost recovery payments in real-time.[36]

[33] See the December 12, 2011 FERC order for ER12-50-000 at: http://www.caiso.com/Documents/2011-12-12_ER12-50_FlexiRamporder.pdf.

[34] See CAISO FERC filing part III (Description of Stakeholder process) and section C (Cost Allocation) at: http://www.caiso.com/Documents/2011-10-07_ER12-50_FlexiRampConstraint_Amend.pdf.

[35] FERC held a technical conference on January 31, 2012 to address the cost allocation of the flexible ramping constraint.

[36] Further detailed information on the flexible ramping constraint implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/FlexibleRampingConstraint.aspx.

Analysis of the flexible ramping constraint

The ISO determines the amount of needed flexible ramping capacity on an hourly basis. When the flexible ramping constraint was first implemented, the ISO set a fixed flexible ramping requirement of 700 MW for each hour of the day. The flexible ramping capacity requirement was set at this level as a conservative number to allow the ISO to gain experience with how the constraint affected unit commitment in the 15-minute real-time pre-dispatch and ramping needs in the 5-minute real-time dispatch. As the ISO gained experience with the implementation, the requirement was subsequently adjusted gradually downward to a maximum of around 450 MW and a low of around zero depending on the hour of the day. Beginning in January, operators have been instructed to use their discretion in adjusting the hourly requirement levels based on the prevailing system conditions.

Table 3.1 provides a review of the weekly flexible ramping constraint activity in the 15-minute real-time market since implementation on December 13. The table shows the total overall payment to procured generators, percentage of binding 15-minute real-time pre-dispatch intervals, the average shadow price during constrained intervals, and the number of weekly flexible ramping procurement shortfalls when the flexible ramping constraint procurement did not meet the requirement. As shown in Table 3.1:

- The frequency of 15-minute intervals with binding flexible ramping constraints fell coincident with the lowering of the flexible ramping requirement during the last week of December; and
- The total payments to generators providing flexible ramping capacity decreased in the third week of implementation, dropping to an average payment of around a half million dollars a week.

Table 3.1 Flexible ramping constraint weekly summary

Week beginning	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall	Average shadow price
13-Dec-11	$ 1.41	25%	6	$ 45.27
20-Dec-11	$ 1.12	24%	7	$ 38.01
27-Dec-11	$ 0.56	14%	3	$ 59.41
03-Jan-12	$ 0.53	19%	7	$ 37.84
10-Jan-12	$ 0.56	11%	5	$ 44.95
17-Jan-12	$ 0.66	21%	11	$ 37.34
24-Jan-12	$ 0.37	14%	3	$ 30.95

Figure 3.1 provides a graphical representation of the weekly flexible ramping payment to generators, which is the total procured volume multiplied by the shadow price of the constraint. On a weekly level, the payments have averaged around $500,000. On a daily level, the payments varied from a low of $35 on January 14, 2012 to a high of about $516,000 on December 14, 2011.

Figure 3.1 Weekly flexible ramping constraint payments to generators

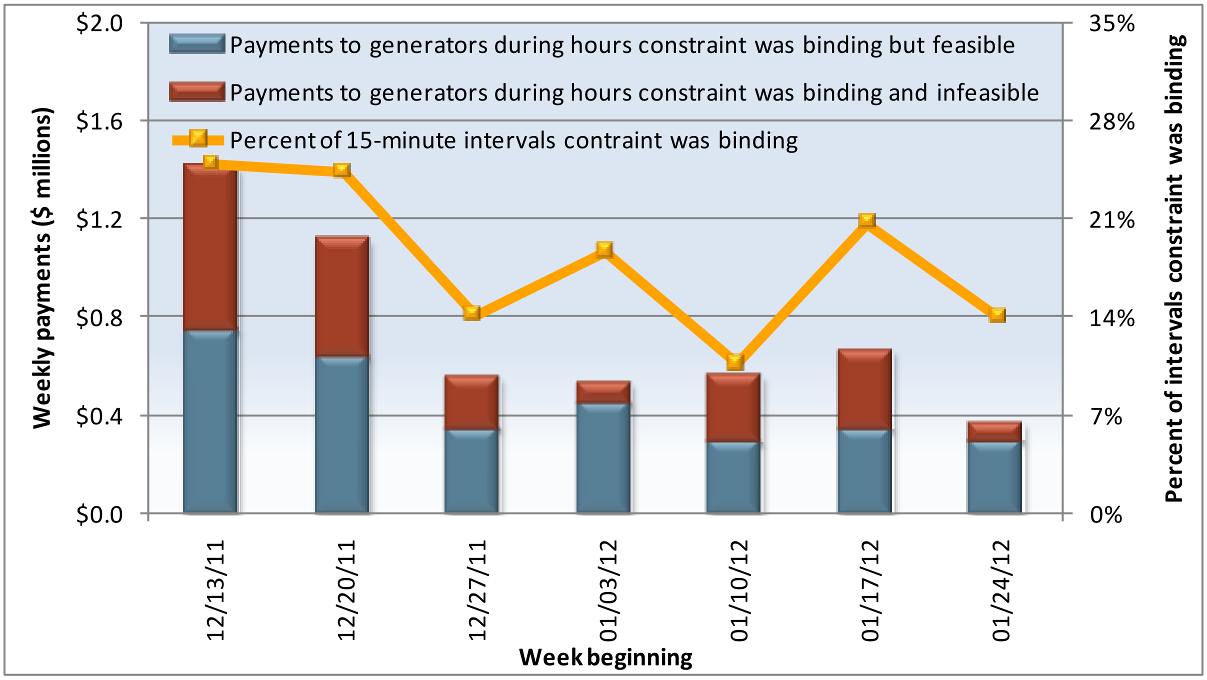
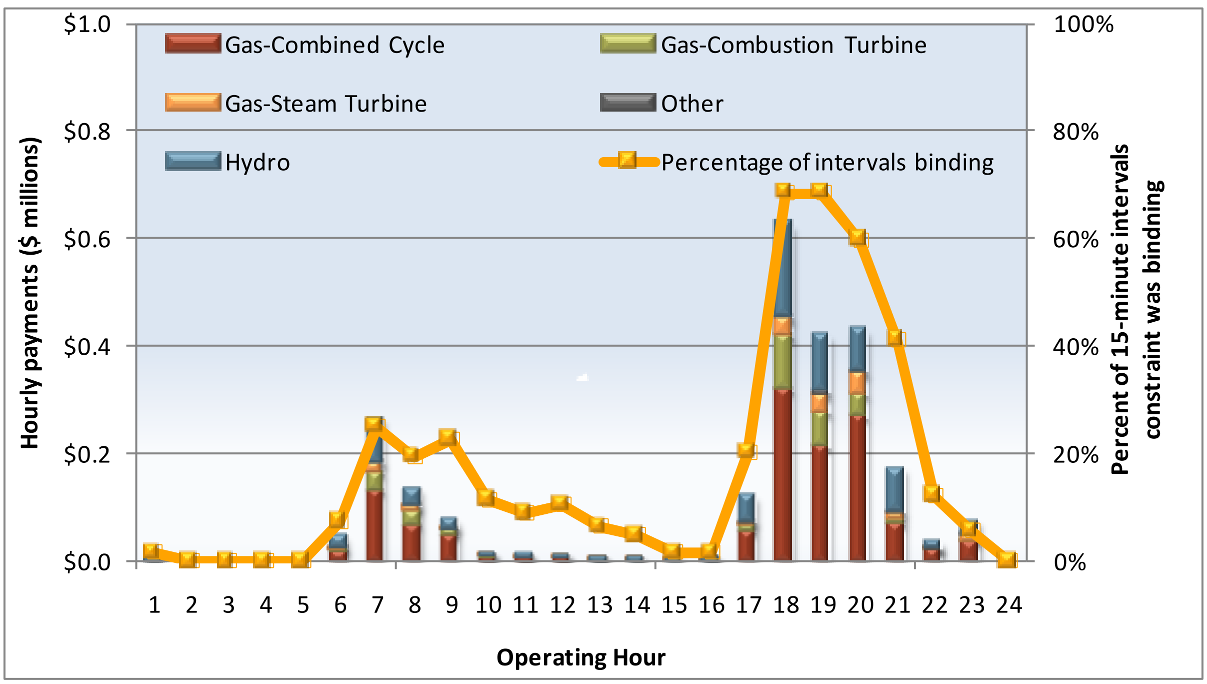


Figure 3.2 Hourly flexible ramping constraint payments to generators – January 2012



The payments to generators are further broken into 15-minute intervals with and without procurement shortfalls, also known as constraint infeasibilities.[37] Intervals with procurement shortfalls have accounted for only about 1 percent of all 15-minute intervals, but around 40 percent of the total flexible ramping costs have been incurred in these intervals over the first few weeks following implementation.

Figure 3.2 provides a representation of the hourly flexible ramping payment profile during the month of January. On an hourly level, the majority of payments (around 80 percent) are concentrated during the morning and evening load ramping up and peak hours. Most of the flexible ramping is provided by natural gas fired units (70 percent) as well as the hydro units (29 percent).

In addition to DMM, the ISO tracks several metrics related to the flexible ramping constraint performance. In particular, the ISO has developed and is still refining a utilization metric that determines how much procured flexible ramping capacity is utilized in the 5-minute real-time dispatch. The ISO has used this metric to determine how best to calibrate the overall flexible ramping requirement, which led to decreasing the maximum requirement from 700 MW to around 450 MW.

DMM has recommended that the ISO also review how the flexible ramping constraint has affected the unit commitment decisions made in real-time.[38] DMM believes that evaluating commitment decisions is an important measure of the overall effectiveness of the constraint. In addition, identifying commitment changes caused by the flexible ramping constraint will help to understand the secondary costs related to the constraint. These secondary costs include additional ancillary services payments and additional real-time bid cost recovery payments paid to short-term units committed to deliver energy and displace capacity on other units to provide flexible ramping capacity.

[37] In practice, the market software allows the constraint to be met to the extent the flexible capability does not conflict with other constraints. The constraint can relax through use of a penalty price (set at $250 in the pricing run) as the shadow price increases resulting from interplay between the flexible ramping constraint and other constraints such as energy, reserves or transmission constraints.

[38] The ISO plans to track the unit commitment patterns for the periods before and after the implementation of the flexible ramping constraint to discern any long-term change in unit commitment patterns and effects to the market results.